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September 15, 2015

NWN OPUC Advice No. 15-12 / UG 298
SUPPLEMENT A
(UM 1496)

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97301-1088

Re: Replacement Filing: UG 298
Annual Purchased Gas Cost and Technical Rate Adjustments

UM 1496: Request for Amortization of Certain Deferred Accounts Relating to Gas Costs

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions to its Tariff, P.U.C. Or. 25, stated to become effective with service on and after November 1, 2015, as follows:

Third Revision of Sheet P-2,
Schedule P,
"Purchased Gas Cost Adjustments (continued)'"

Third Revision of Sheet P-3,
Schedule P,
"Purchased Gas Cost Adjustments (continued);"

Third Revision of Sheet P-5,
Schedule P,
"Purchased Gas Cost Adjustments (continued);"

Fifth Revision of Sheet 162-1,
Schedule 162,
"Temporary (Technical) Adjustments to Rates;"

Fifth Revision of Sheet 162-2,
Schedule 162,
"Temporary (Technical) Adjustments to Rates (continued);"

Fourth Revision of Sheet 164-1,
Schedule 164,
"Purchased Gas Cost Adjustments to Rates;" and

First Revision of Sheet 187-1,
Schedule 187,
"Special Rate Adjustment for Mist Capacity Recall."

This filing replaces, in the entirety, the advice letter, all tariff sheets and Exhibits A, B, and C, originally filed under NWN OPUC Advice No. 15-12 dated July 31, 2015.

The purpose of this replacement filing is to:

(1) Develop the temporary rate adjustments associated with the amortization of gas cost credit or debit balances in Federal Energy Regulatory Commission (FERC) Account 191, deferred under Docket UM 1496 and proposed to be effective November 1, 2015, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2014;

(2) Develop the commodity (Weighted Average Cost of Gas "WACOG") and non-commodity ("demand" or "pipeline capacity" charge) purchased gas costs to be effective November 1, 2015;

(3) Develop the permanent rate increments associated with a recall of Mist storage capacity; and

(4) Update the presentation of the Calculation of Monthly Gas Costs for Deferral Purposes (table in Sheet P-5) to align the months and costs presented with the PGA year, November 1, 2015 through October 31, 2015.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2014.

The number of customers affected by the changes proposed in this filing is 571,204 residential customers, 59,817 commercial customers, and 805 industrial customers.

In addition to the supporting materials submitted as part of this filing, the Company will separately submit work papers in electronic format, all of which are incorporated herein by reference.

I. <u>Amortization of Gas Cost Deferrals (UM 1496) and removal of Temporary Rate Adjustments Currently in Effect</u>

The net effect of this portion of the filing is to decrease the Company's annual revenues by $20,023,339, or about 2.9%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2014, is a decrease of $16,814,949; and the effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under Docket UM 1496 is a decrease of $3,208,390.

The proposed adjustments to customer rates are comprised of the following: (1) a credit of $0.01844 per therm for all sales service customers representing a credit balance in Account 191 commodity accounts, and (2) a debit of $0.01484 per therm for all firm sales service customers and a debit of $0.00189 per therm for all interruptible sales service customers, representing a credit balance in Account 191 demand accounts. The net effect of all

Account 191 amortizations is a credit of $0.00360 per therm for firm sales service customers and a credit of $0.01655 per therm for interruptible sales service customers.

The Company has developed the adjustments to rates proposed in this filing in accordance with the PGA Filing Guidelines as prescribed by the most recent Commission Order in Docket UM 1286.

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

II. Purchased Gas Cost Adjustment (PGA)

The net effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $69,151,756, or about 10.2%; the change in commodity cost is a decrease of $67,472,094 and the change in demand cost is a decrease of $1,679,662.

The change in gas costs results in a proposed Annual Sales WACOG of $0.32582 per therm, and a proposed Winter Sales WACOG of $0.33689. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.33497 and a proposed Winter Sales Billing WACOG of $0.34635.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.11525 per therm, or $1.71 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01371 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.11849 per therm or $1.76 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01410 per therm.

If there are material 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.

This filing applies the method for calculating the proposed Annual Sales Weighted Average Cost of Gas ("WACOG") that is set forth in a joint party stipulation approved by the Commission in OPUC Order No. 08-504, Docket UM 1286, as modified by the approval of a stipulation affirmed in OPUC Order No. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in the most recent Commission Order No. 14-238 in Docket UM 1286.

A. Post-Carry Wells (UM 1717)

The Company's initial Request for Amortization of Certain Deferred Accounts Relating to Gas Costs dated July 31, 2015, included the effects of a stipulation NW Natural and other parties reached in UM 1717 related to Post-Carry Wells gas reserves from the Jonah Field. That stipulation and supporting brief were filed in the UM 1717 docket on August 26th. As of the date of this filing the Commission has not issued an order regarding that settlement. As such, this final filing does not reflect the terms of that stipulation and excludes costs related to the Post-Carry wells. Should the Commission issue an order adopting the Stipulation in docket

UM 1717 in time for inclusion in this PGA cycle, the Company will file replacement Tariff Sheets as needed to reflect that decision.

If the Post Carry Wells were included in this filing, the net effect of the PGA portion would be a decrease to the Company's annual revenues by about $68,434,566, or about 10.1%; the change in commodity cost would be a decrease of $66,754,904 and the change in demand cost would be a decrease of $1,679,662.

The change in gas costs would result in a proposed Annual Sales WACOG, including the Post Carry Wells, of $0.32684 per therm, and the proposed Winter Sales WACOG of $0.33795. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.33602 and a proposed Winter Sales Billing WACOG of $0.34744.

The Post Carry Wells has no effect on demand charges.

III. Storage Recall

This portion of the filing represents the permanent rate effects of the recall of 300,000 therms per day of Mist reservoir capacity and 300,000 therms per day of compression capacity from upstream market activities for use by the Company's core customers. This adjustment is calculated in the same manner as all Mist expansion projects. The effect of this portion of the filing is to increase the Company's annual revenues by $234,753.

The effect of applying the adjustment to customer rates is an increase on a percent of margin basis of $0.00045 on residential Schedule 2 customer rates, and an increase on a percent of margin basis of $0.00032 on commercial Schedule 3 rates. The adjustments for all other rate schedules can be found in Exhibit A, Page 12 to this filing.

IV. Combined Effect on Customer Bills

The combined effects of this filing is to decrease the Company's annual revenues by about $88,940,342, or about 13.1%; the change in purchased gas costs is a decrease of $69,151,756 and the change in temporary adjustments to rates is an increase of $20,023,339.

The average monthly bill impact of the changes proposed in this filing is shown in the table below:

Class	Rate Schedule	Average Monthly Bill Change ($)	Average Monthly Bill Change (%)
Residential	Schedule 2	-$6.89	-11.2%
Commercial	Schedule 3	-$30.35	-12.8%
Commercial Firm Sales	Schedule 31	-$420.31	-16.1%
Industrial Firm Sales	Schedule 32	-$2,692.72	-21.4%
Industrial Interruptible Sales	Schedule 32	-$6,249.23	-25.5%

The monthly bill effects for all other rate classes can be found in the separately provided workpapers.

Please note that the monthly bill effects for Rate Schedule 31 and Rate Schedule 32 do not include the effect of changes in the pipeline capacity charge due to the customer option to elect either an MDDV-based capacity charge or a volumetric-based capacity charge. If a customer served under Rate Schedule 32 Industrial Firm Sales Service elected the volumetric pipeline capacity option, the change in the monthly bill effective November 1, 2015 would be $82.96, or 3.19%.

UM 1286 Natural Gas Portfolio Development Guidelines

In addition to the supporting materials submitted as part of this filing as Exhibit A and Exhibit B, the Company provides Exhibit C which contains the data required by the Natural Gas Portfolio Development Guidelines Sections IV and V as adopted by the Commission in OPUC Order No. 11-196 in Docket UM 1286 ("the OPUC Order"). Some of the information contained in Section V is confidential and highly confidential and is subject to the Modified Protective Order in Docket UM 1286, Order No. 10-337.

Commission Staff's Attachment A through Attachment D, required by Section 5 of the PGA Filing Guidelines, are included in the Company's work papers, incorporated herein by reference, which will be submitted under separate cover.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2015.

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

The Company waives paper service in this proceeding. Please address correspondence on this matter to Kyle Walker at Kyle.Walker@nwnatural.com, with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2516
Telephone: (503) 226-4211, x3589
eFiling@nwnatural.com and

Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King
Rates & Regulatory Affairs

Attachments: Exhibit A – Purchased Gas Cost Deferral Amortizations
Exhibit B – Purchased Gas Costs
Exhibit C – PGA Portfolio Guidelines Sections IV and V

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective: November 1, 2015:		(T)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.33497**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.32582**	(R)

8. Estimated Winter Sales WACOG: The Company’s weighted average Commodity Cost of Gas for the five-month period November through March.

Effective: November 1, 2015:		(T)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.34635**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.33689**	(R)

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

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.

Effective: November 1, 2015:		(T)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.11849**	(R)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11525**	(R)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.

Effective: November 1, 2015:		(T)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01410**	(R)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01371**	(R)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.

Effective: November 1, 2015:		(T)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.76**	(R)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.71**	(R)

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

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

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

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

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

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

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

2. A debit or credit entry shall be made equal to 100% of any monthly difference between actual monthly fixed charge recoveries and Monthly Seasonalized Fixed Charges. The Monthly Seasonalized Fixed Charges for the period November 1, 2015 through October 31, 2016 are: (C) (C) (T)

November	2015	$8,530,506
December	2015	$12,155,128
January	2016	$11,445,540
February	2016	$9,583,025
March	2016	$8,143,837
April	2016	$6,042,536
May	2016	$3,912,397
June	2016	$2,374,325
July	2016	$2,063,471
August	2016	$2,048,574
September	2016	$2,196,176
October	2016	$4,970,518
ANNUAL TOTAL		$73,466,033

(C)
(C)

3. A debit or credit entry shall be made equal to 80% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%. (C)

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

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

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

(continue to Sheet P-6)

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

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 the Company's Account 191 deferred revenue and gas cost accounts.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 27 Rate Schedule 32
Rate Schedule 3 Rate Schedule 31 Rate Schedule 33

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2015 (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	Total Adjustment
2		($0.01844)	$0.01484	**($0.00360)**
3 CSF		($0.01844)	$0.01484	**($0.00360)**
3 ISF		($0.01844)	$0.01484	**($0.00360)**
27		($0.01844)	$0.01484	**($0.00360)**
31 CSF	Block 1	($0.01844)	$0.01484	**($0.00360)**
	Block 2	($0.01844)	$0.01484	**($0.00360)**
31 CTF	Block 1	N/A	N/A	**$0.00000**
	Block 2	N/A	N/A	**$0.00000**
31 ISF	Block 1	($0.01844)	$0.01484	**($0.00360)**
	Block 2	($0.01844)	$0.01484	**($0.00360)**
31 ITF	Block 1	N/A	N/A	**$0.00000**
	Block 2	N/A	N/A	**$0.00000**

(C)
(C)

(D)

(continue to Sheet 162-2)

Issued September 15, 2015 Effective with service on
NWN OPUC Advice No. 15-12A and after November 1, 2015

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2015 (T)

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Total Adjustment	
32 CSF	Block 1	($0.01844)	$0.01484	**($0.00360)**	(C)
	Block 2	($0.01844)	$0.01484	**($0.00360)**	
	Block 3	($0.01844)	$0.01484	**($0.00360)**	
	Block 4	($0.01844)	$0.01484	**($0.00360)**	
	Block 5	($0.01844)	$0.01484	**($0.00360)**	
	Block 6	($0.01844)	$0.01484	**($0.00360)**	
32 ISF	Block 1	($0.01844)	$0.01484	**($0.00360)**	
	Block 2	($0.01844)	$0.01484	**($0.00360)**	
	Block 3	($0.01844)	$0.01484	**($0.00360)**	
	Block 4	($0.01844)	$0.01484	**($0.00360)**	
	Block 5	($0.01844)	$0.01484	**($0.00360)**	
	Block 6	($0.01844)	$0.01484	**($0.00360)**	
32 CTF/ITF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
32 CSI	Block 1	($0.01844)	$0.00189	**($0.01655)**	
	Block 2	($0.01844)	$0.00189	**($0.01655)**	
	Block 3	($0.01844)	$0.00189	**($0.01655)**	
	Block 4	($0.01844)	$0.00189	**($0.01655)**	
	Block 5	($0.01844)	$0.00189	**($0.01655)**	
	Block 6	($0.01844)	$0.00189	**($0.01655)**	
32 ISI	Block 1	($0.01844)	$0.00189	**($0.01655)**	
	Block 2	($0.01844)	$0.00189	**($0.01655)**	
	Block 3	($0.01844)	$0.00189	**($0.01655)**	
	Block 4	($0.01844)	$0.00189	**($0.01655)**	
	Block 5	($0.01844)	$0.00189	**($0.01655)**	
	Block 6	($0.01844)	$0.00189	**($0.01655)**	
32 CTI/ITI	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
33 TI		N/A	N/A	**$0.00000**	
33 TF		N/A	N/A	**$0.00000**	(C)

(D)

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

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27
Rate Schedule 31 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2015 (T)

Annual Sales WACOG [1]	$0.33497	(R)
Winter Sales WACOG [2]	$0.34635	
Firm Sales Service Pipeline Capacity Component [4]	$0.11849	
Firm Sales Service Pipeline Capacity Component [5]	$1.76000	
Interruptible Sales Service Pipeline Capacity Component [6]	$0.01410	(R)

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

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

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the Company's recall of Mist storage capacity for use by the Company's core Sales Service Customers.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 31
	Rate Schedule 27	Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2015 (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)

Rate Schedule/Class	Block	Mist Recall Base Adjustment		Schedule	Block	Mist Recall Base Adjustment
2		**$0.00045**		31 CSF	Block 1	**$0.00024**
03 CSF		**$0.00032**			Block 2	**$0.00022**
03 ISF		**$0.00027**		31 ISF	Block 1	**$0.00017**
27		**$0.00037**			Block 2	**$0.00016**
32 CSF	Block 1	**$0.00014**		32 CSI	Block 1	**$0.00010**
	Block 2	**$0.00012**			Block 2	**$0.00008**
	Block 3	**$0.00008**			Block 3	**$0.00006**
	Block 4	**$0.00005**			Block 4	**$0.00003**
	Block 5	**$0.00003**			Block 5	**$0.00002**
	Block 6	**$0.00001**			Block 6	**$0.00001**
32 ISF	Block 1	**$0.00010**		32 ISI	Block 1	**$0.00009**
	Block 2	**$0.00009**			Block 2	**$0.00008**
	Block 3	**$0.00006**			Block 3	**$0.00006**
	Block 4	**$0.00004**			Block 4	**$0.00003**
	Block 5	**$0.00002**			Block 5	**$0.00002**
	Block 6	**$0.00001**			Block 6	**$0.00001**

(C)

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

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

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496

NWN OPUC Advice No. 15-12A / UG 298

September 15, 2015

NW NATURAL

EXHIBIT A

Supporting Material

Purchased Gas Cost Deferral Amortizations – UM 1496

NWN OPUC ADVICE NO. 15-12A/ UG 298

NW Natural
Rates & Regulatory Affairs
2015-16 PGA - Oregon: September Filing
Summary of TEMPORARY Increments

1
2
3

Line	Schedule	Block	Current Temporaries	WACOG Deferral	Demand Deferral - FIRM	Demand Deferral - INTERRUPTIBLE	Total Proposed Temps	Net Effect of Temps
5								(N = M - A)
6	Schedule	Block	A	B	C	D	M	N
7	2R		0.02381	(0.01844)	0.01484	0.00000	0.03510	0.01129
8	3C Sales Firm		0.05288	(0.01844)	0.01484	0.00000	0.07018	0.01730
9	3I Sales Firm		0.03900	(0.01844)	0.01484	0.00000	0.03227	(0.00673)
10	27 Dry Out		0.02332	(0.01844)	0.01484	0.00000	0.00939	(0.01393)
11	31C Sales Firm	Block 1	0.05295	(0.01844)	0.01484	0.00000	0.06747	0.01452
12		Block 2	0.05298	(0.01844)	0.01484	0.00000	0.06675	0.01377
13	31C Trans Firm	Block 1	(0.00072)	0.00000	0.00000	0.00000	0.00996	0.01068
14		Block 2	(0.00071)	0.00000	0.00000	0.00000	0.00910	0.00981
15	31I Sales Firm	Block 1	0.03909	(0.01844)	0.01484	0.00000	0.02894	(0.01015)
16		Block 2	0.03911	(0.01844)	0.01484	0.00000	0.02836	(0.01075)
17	31I Trans Firm	Block 1	(0.00002)	0.00000	0.00000	0.00000	0.00628	0.00630
18		Block 2	(0.00001)	0.00000	0.00000	0.00000	0.00569	0.00570
19	32C Sales Firm	Block 1	0.03903	(0.01844)	0.01484	0.00000	0.02755	(0.01148)
20		Block 2	0.03906	(0.01844)	0.01484	0.00000	0.02684	(0.01222)
21		Block 3	0.03907	(0.01844)	0.01484	0.00000	0.02564	(0.01343)
22		Block 4	0.03911	(0.01844)	0.01484	0.00000	0.02444	(0.01467)
23		Block 5	0.03912	(0.01844)	0.01484	0.00000	0.02372	(0.01540)
24		Block 6	0.03915	(0.01844)	0.01484	0.00000	0.02324	(0.01591)
25	32I Sales Firm	Block 1	0.03916	(0.01844)	0.01484	0.00000	0.02646	(0.01270)
26		Block 2	0.03918	(0.01844)	0.01484	0.00000	0.02593	(0.01325)
27		Block 3	0.03921	(0.01844)	0.01484	0.00000	0.02504	(0.01417)
28		Block 4	0.03922	(0.01844)	0.01484	0.00000	0.02415	(0.01507)
29		Block 5	0.03925	(0.01844)	0.01484	0.00000	0.02362	(0.01563)
30		Block 6	0.03924	(0.01844)	0.01484	0.00000	0.02327	(0.01597)
31	32 Trans Firm	Block 1	0.00004	0.00000	0.00000	0.00000	0.00351	0.00347
32		Block 2	0.00004	0.00000	0.00000	0.00000	0.00301	0.00297
33		Block 3	0.00006	0.00000	0.00000	0.00000	0.00216	0.00210
34		Block 4	0.00007	0.00000	0.00000	0.00000	0.00133	0.00126
35		Block 5	0.00009	0.00000	0.00000	0.00000	0.00082	0.00073
36		Block 6	0.00008	0.00000	0.00000	0.00000	0.00049	0.00041
37	32C Sales Interr	Block 1	0.04615	(0.01844)	0.00000	0.00189	0.01326	(0.03289)
38		Block 2	0.04615	(0.01844)	0.00000	0.00189	0.01274	(0.03341)
39		Block 3	0.04619	(0.01844)	0.00000	0.00189	0.01188	(0.03431)
40		Block 4	0.04620	(0.01844)	0.00000	0.00189	0.01102	(0.03518)
41		Block 5	0.04623	(0.01844)	0.00000	0.00189	0.01049	(0.03574)
42		Block 6	0.04622	(0.01844)	0.00000	0.00189	0.01016	(0.03606)
43	32I Sales Interr	Block 1	0.04626	(0.01844)	0.00000	0.00189	0.01326	(0.03300)
44		Block 2	0.04626	(0.01844)	0.00000	0.00189	0.01277	(0.03349)
45		Block 3	0.04629	(0.01844)	0.00000	0.00189	0.01194	(0.03435)
46		Block 4	0.04630	(0.01844)	0.00000	0.00189	0.01112	(0.03518)
47		Block 5	0.04633	(0.01844)	0.00000	0.00189	0.01062	(0.03571)
48		Block 6	0.04632	(0.01844)	0.00000	0.00189	0.01029	(0.03603)
49	32 Trans Interr	Block 1	0.00004	0.00000	0.00000	0.00000	0.00316	0.00312
50		Block 2	0.00005	0.00000	0.00000	0.00000	0.00271	0.00266
51		Block 3	0.00006	0.00000	0.00000	0.00000	0.00196	0.00190
52		Block 4	0.00007	0.00000	0.00000	0.00000	0.00120	0.00113
53		Block 5	0.00009	0.00000	0.00000	0.00000	0.00076	0.00067
54		Block 6	0.00010	0.00000	0.00000	0.00000	0.00045	0.00035
55	33		0.00000	0.00000	0.00000	0.00000	0.00020	0.00020

NW Natural
Rates & Regulatory Affairs
2015-16 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1					**WACOG Deferral**			**Demand Deferral - FIRM**			**Demand Deferral - INTERRUPTIBLE**		
2			**Oregon PGA**	**Proposed Amount:**	(12,264,303) Temporary Increment			9,037,065 Temporary Increment			106,502 Temporary Increment		
3			**Volumes page,**	**Revenue Sensitive Multiplier:**	2.732% add revenue sensitive factor			2.732% add revenue sensitive factor			2.732% add revenue sensitive factor		
4			**Column F**	**Amount to Amortize:**	**(12,608,775)** to all sales			**9,290,892** to all firm sales			**109,493** to all interruptible sales		
5					**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**		**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
7	2R		365,285,306		1.0	365,285,306	(0.01844)	1.0	365,285,306	0.01484	0.0	0	0.00000
8	3C Firm Sales		158,936,755		1.0	158,936,755	(0.01844)	1.0	158,936,755	0.01484	0.0	0	0.00000
9	3I Firm Sales		3,811,735		1.0	3,811,735	(0.01844)	1.0	3,811,735	0.01484	0.0	0	0.00000
10	27 Dry Out		700,552		1.0	700,552	(0.01844)	1.0	700,552	0.01484	0.0	0	0.00000
11	31C Firm Sales	Block 1	20,701,736		1.0	20,701,736	(0.01844)	1.0	20,701,736	0.01484	0.0	0	0.00000
12		Block 2	15,317,497		1.0	15,317,497	(0.01844)	1.0	15,317,497	0.01484	0.0	0	0.00000
13	31C Firm Trans	Block 1	1,022,480		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
14		Block 2	1,238,213		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
15	31I Firm Sales	Block 1	4,178,853		1.0	4,178,853	(0.01844)	1.0	4,178,853	0.01484	0.0	0	0.00000
16		Block 2	9,536,789		1.0	9,536,789	(0.01844)	1.0	9,536,789	0.01484	0.0	0	0.00000
17	31I Firm Trans	Block 1	181,494		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
18		Block 2	680,650		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
19	32C Firm Sales	Block 1	26,567,626		1.0	26,567,626	(0.01844)	1.0	26,567,626	0.01484	0.0	0	0.00000
20		Block 2	7,804,067		1.0	7,804,067	(0.01844)	1.0	7,804,067	0.01484	0.0	0	0.00000
21		Block 3	829,092		1.0	829,092	(0.01844)	1.0	829,092	0.01484	0.0	0	0.00000
22		Block 4	20,793		1.0	20,793	(0.01844)	1.0	20,793	0.01484	0.0	0	0.00000
23		Block 5	0		1.0	0	(0.01844)	1.0	0	0.01484	0.0	0	0.00000
24		Block 6	0		1.0	0	(0.01844)	1.0	0	0.01484	0.0	0	0.00000
25	32I Firm Sales	Block 1	4,645,409		1.0	4,645,409	(0.01844)	1.0	4,645,409	0.01484	0.0	0	0.00000
26		Block 2	5,152,955		1.0	5,152,955	(0.01844)	1.0	5,152,955	0.01484	0.0	0	0.00000
27		Block 3	1,826,257		1.0	1,826,257	(0.01844)	1.0	1,826,257	0.01484	0.0	0	0.00000
28		Block 4	627,963		1.0	627,963	(0.01844)	1.0	627,963	0.01484	0.0	0	0.00000
29		Block 5	(0)		1.0	(0)	(0.01844)	1.0	(0)	0.01484	0.0	0	0.00000
30		Block 6	0		1.0	0	(0.01844)	1.0	0	0.01484	0.0	0	0.00000
31	32 Firm Trans	Block 1	12,006,597		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
32		Block 2	16,315,496		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
33		Block 3	9,641,378		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
34		Block 4	16,134,178		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
35		Block 5	21,282,059		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
36		Block 6	1,920,752		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
37	32C Interr Sales	Block 1	5,686,222		1.0	5,686,222	(0.01844)	0.0	0	0.00000	1.0	5,686,222	0.00189
38		Block 2	7,563,208		1.0	7,563,208	(0.01844)	0.0	0	0.00000	1.0	7,563,208	0.00189
39		Block 3	3,897,038		1.0	3,897,038	(0.01844)	0.0	0	0.00000	1.0	3,897,038	0.00189
40		Block 4	4,445,365		1.0	4,445,365	(0.01844)	0.0	0	0.00000	1.0	4,445,365	0.00189
41		Block 5	71,870		1.0	71,870	(0.01844)	0.0	0	0.00000	1.0	71,870	0.00189
42		Block 6	0		1.0	0	(0.01844)	0.0	0	0.00000	1.0	0	0.00189
43	32I Interr Sales	Block 1	7,186,289		1.0	7,186,289	(0.01844)	0.0	0	0.00000	1.0	7,186,289	0.00189
44		Block 2	8,946,142		1.0	8,946,142	(0.01844)	0.0	0	0.00000	1.0	8,946,142	0.00189
45		Block 3	5,135,755		1.0	5,135,755	(0.01844)	0.0	0	0.00000	1.0	5,135,755	0.00189
46		Block 4	10,445,179		1.0	10,445,179	(0.01844)	0.0	0	0.00000	1.0	10,445,179	0.00189
47		Block 5	4,597,392		1.0	4,597,392	(0.01844)	0.0	0	0.00000	1.0	4,597,392	0.00189
48		Block 6	1		1.0	1	(0.01844)	0.0	0	0.00000	1.0	1	0.00189
49	32 Interr Trans	Block 1	8,779,332		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
50		Block 2	15,689,249		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
51		Block 3	11,306,695		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
52		Block 4	28,429,084		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
53		Block 5	56,035,539		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
54		Block 6	78,278,646		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
55	33		0		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
56													
57	TOTALS		962,859,686			683,917,844	(0.01844)		625,943,383	0.01484		57,974,461	0.00189

NW Natural
Rates and Regulatory Affairs
2015-2016 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months		
1		Ended 06/30/15		
2				
3	Total Billed Gas Sales Revenues	635,125,404		
4	Total Oregon Revenues	657,765,960		
5				
6	Regulatory Commission Fees [1]	1,697,120	0.250%	Statutory rate
7	City License and Franchise Fees	15,291,561	2.325%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	1,032,745	0.157%	Line 8 ÷ Line 4
9				
10	Total	18,021,426	**2.732%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)
15 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2015-2016 PGA Filing - September Filing
Summary of Deferred Accounts Included in the PGA

Account	Balance 6/30/2015	Adjustment	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2015	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection	Amounts Excluded from PGA Filing	Amounts Included in PGA Filing
A	B	C	D	E	F	G1	G2	H	I	J
					F = sum B thru E		1.93%	H = F + G2		Excl. Rev Sens
Miscellaneous Amortizations										
254309 AMORT SIP COS RESERVE	(173,741)		88,397	(819)	(86,163)	1.93%	(903)	(87,066)	include in 186XXX Sch 178 Adj	**0**
186232 DEFER INDUSTRIAL DSM (Mar 14 - Feb 15 activity only)	3,226,086		0	0	3,226,086					
186233 AMOR INDUSTRIAL DSM	384,097		(490,299)	938	(105,264)					
Subtotal	3,610,183		(490,299)	938	3,120,822	1.93%	32,722	3,153,544		**3,153,544**
254315 PROPERTY SALES AMORT	(6,405)		(15,404)	(75)	(21,883)	1.93%	(229)	(22,112)	include in 186XXX Sch 178 Adj	**0**
186307 AMR AMORT	5,263		1,366	34	6,663	1.93%	70	6,733	include in 186XXX Sch 178 Adj	**0**
191031 WORKING GAS DEFERRAL AMORT	31,103		7,376	202	38,681	1.93%	406	39,087	include in 186XXX Sch 178 Adj	**0**
186XXX Schedule 178 Residual Adjustments									residual balances for 254315, 186307, 191031, and 254309	**(63,358)**
Gas Cost Deferrals and Amortizations										
191401 AMORTIZE OREGON WACOG	6,097,889		(3,678,927)	27,060	2,446,021					
191405 POST-CARRY WELL DEFERRAL	0		0	0	0					
191400 WACOG - ACCRUE OREGON	(14,210,931)		0	(372,136)	(14,583,067)					
Subtotal	(8,113,042)	0	(3,678,927)	(345,076)	(12,137,046)	1.93%	(127,257)	(12,264,303)		**(12,264,303)**
191411 AMORTIZE DEMAND OREGON	(1,464,448)		763,679	(6,844)	(707,612)					
191410 DEMAND - ACCRUE OREGON	(4,302,008)		0	(112,655)	(4,414,663)					
191417 DEMAND - ACCRUE COOS BAY	101,600		0	0	101,600					
191450 OREGON DEMAND ACCRUE VOLUME	13,710,339		0	359,028	14,069,367					
Subtotal	8,045,484	0	763,679	239,528	9,048,692	1.93%	94,875	9,143,567		**9,143,567**
GRAND TOTAL	**24,514,502**		**(4,425,499)**	**394,586**	**20,483,589**			**20,698,360**		**20,698,360**

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Commodity gas cost deferral
Account Number: 191400
Docket UM 1496
Current reauthorization to defer was granted in Order No. 13-365

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG embedded as defined in the related annual PGA. From Nov 09 forward the deferral election is 90%.

	Debit (Credit) Month/Year	Note	Commodity Deferral	Interest	Interest Rate	Storage Adjustment	Hedge Adjustment	Transfer	Activity	Deferral Plus Int. GL Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5										
6	Beginning Bal									
90	Nov-13	**1**	(1,018,327)	(3,307)	7.78%	(1,778)	0	2,453,528	1,430,116	(1,023,412)
91	Dec-13		2,370,209	1,040	7.78%	(2,701)	0		2,368,548	1,345,136
92	Jan-14		111,637	9,075	7.78%	(2,527)	0		118,185	1,463,320
93	Feb-14		8,008,055	35,439	7.78%	(2,275)	0		8,041,219	9,504,540
94	Mar-14		7,058,076	84,496	7.78%	(1,481)	0		7,141,091	16,645,631
95	Apr-14		25,070	107,997	7.78%	(1,175)	0		131,892	16,777,522
96	May-14		1,344,869	113,132	7.78%	(639)	0		1,457,362	18,234,884
97	Jun-14		1,214,886	122,159	7.78%	(579)	0		1,336,466	19,571,351
98	Jul-14		840,727	129,611	7.78%	(455)	0		969,883	20,541,234
99	Aug-14		1,274,857	137,307	7.78%	(446)	0		1,411,718	21,952,952
100	Sep-14		189,585	142,941	7.78%	(477)	0		332,049	22,285,001
101	Oct-14		283,371	145,397	7.78%	(757)	0	(37)	427,974	22,712,975
102	Nov-14	**1**	941,419	19,994	7.78%	(7,383)	(21,218)	(20,085,459)	(19,152,647)	3,560,329
103	Dec-14		(1,096,163)	19,345	7.78%	(8,370)	(48,635)		(1,133,824)	2,426,505
104	Jan-15		(3,864,444)	3,058	7.78%	(8,464)	(36,749)		(3,906,599)	(1,480,094)
105	Feb-15		(2,693,034)	(18,417)	7.78%	(5,905)	(22,227)		(2,739,583)	(4,219,677)
106	Mar-15		(3,753,477)	(39,548)	7.78%	(5,138)	(2,063)		(3,800,226)	(8,019,903)
107	Apr-15		(3,322,626)	(62,800)	7.78%	(4,806)	(5,519)		(3,395,751)	(11,415,653)
108	May-15		(1,154,540)	(77,770)	7.78%	(2,946)	(1,941)	2	(1,237,195)	(12,652,848)
109	Jun-15	**2**	(1,466,735)	(86,808)	7.78%	(1,912)	(648)	(1,979)	(1,558,083)	(14,210,931)

115 **History truncated for ease of viewing**

117 **NOTES:**
118 **1** -Transfer June balance plus July-October interest on June balance to account 191401 for amortization
119 **2** -Transfer includes one-time adjustment for true-up to ending GL balance

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 191401
Dockets UM 1496 and UG 278
Amortization of 2013-14 deferral approved in Order No. 14-383

1 Debit (Credit)

Row	Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(e2)	(f)	(g)
7	Beginning Balance							
99	Dec-13		838,830		(4,235)	1.38%	834,595	(3,267,455)
100	Jan-14		909,111		(3,235)	1.38%	905,876	(2,361,579)
101	Feb-14		822,889		(2,243)	1.38%	820,646	(1,540,933)
102	Mar-14		602,877		(1,425)	1.38%	601,452	(939,481)
103	Apr-14		441,435		(827)	1.38%	440,609	(498,872)
104	May-14		311,224		(395)	1.38%	310,829	(188,043)
105	Jun-14		215,425		(92)	1.38%	215,333	27,291
106	Jul-14		183,943		137	1.38%	184,080	211,370
107	Aug-14		156,199		333	1.38%	156,532	367,902
108	Sep-14		163,354		517	1.38%	163,871	531,773
109	Oct-14		194,343		723	1.38%	195,067	726,840
110	Nov-14	old rates	142,460		918	1.38%	143,378	870,217
111	Nov-14	new rates **(1)**	(956,938)	20,085,396	28,920	1.77%	19,157,378	20,027,596
112	Dec-14		(2,868,241)		27,425	1.77%	(2,840,816)	17,186,780
113	Jan-15		(3,138,278)	0	23,036	1.77%	(3,115,241)	14,071,538
114	Feb-15		(2,304,492)		19,056	1.77%	(2,285,436)	11,786,102
115	Mar-15		(1,955,025)		15,943	1.77%	(1,939,082)	9,847,020
116	Apr-15		(1,666,258)		13,295	1.77%	(1,652,963)	8,194,057
117	May-15		(1,268,133)	(0)	11,151	1.77%	(1,256,982)	6,937,074
118	Jun-15		(848,792)		9,606	1.77%	(839,186)	6,097,889
119	Jul-15	*forecast*	(704,186)		8,475	1.77%	(695,711)	5,402,178
120	Aug-15	*forecast*	(700,060)		7,452	1.77%	(692,608)	4,709,570
121	Sep-15	*forecast*	(740,329)		6,401	1.77%	(733,928)	3,975,642
122	Oct-15	*forecast*	(1,534,353)		4,732	1.77%	(1,529,620)	2,446,021

124 **History truncated for ease of viewing**

126 **NOTES:**

127 **1** - Transfer in authorized balance from account 191400.

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Demand cost deferral
Account Number: 191410
Docket UM 1496
Current reauthorization to defer was granted in Order No. 14-365

Narrative: Deferral of 100% of the Difference between actual demand cost incurred and the demand cost embedded as defined in the related state's annual PGA.

	Month/Year	Note	Demand Deferral	Interest	Interest Rate	Adjustment	Transfer	Activity	Deferral Plus Int. GL Balance
1	Debit (Credit)								
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(I)
5									
6	Beginning Bal								
90	Nov-13	**1,4**	293,813	952	7.78%		2,067,411	2,362,176	294,766
91	Dec-13		(162,444)	1,384	7.78%			(161,060)	133,706
92	Jan-14		(192,372)	243	7.78%			(192,128)	(58,423)
93	Feb-14		(399,481)	(1,674)	7.78%			(401,155)	(459,577)
94	Mar-14		(233,370)	(3,736)	7.78%			(237,106)	(696,683)
95	Apr-14		(368,450)	(5,711)	7.78%			(374,161)	(1,070,844)
96	May-14		(475,075)	(8,483)	7.78%			(483,557)	(1,554,401)
97	Jun-14		(510,221)	(11,732)	7.78%			(521,953)	(2,076,354)
98	Jul-14		(374,325)	(14,675)	7.78%			(389,000)	(2,465,354)
99	Aug-14		(521,150)	(17,673)	7.78%			(538,823)	(3,004,178)
100	Sep-14		(506,271)	(21,118)	7.78%			(527,389)	(3,531,567)
101	Oct-14		(551,151)	(24,683)	7.78%		(2)	(575,836)	(4,107,403)
102	Nov-14	**1**	(1,152,318)	(16,682)	7.78%		1,850,024	681,024	(3,165,976)
103	Dec-14		(108,541)	(20,878)	7.78%			(129,418)	(3,295,394)
104	Jan-15		(137,525)	(21,811)	7.78%			(159,336)	(3,454,730)
105	Feb-15		(144,116)	(22,865)	7.78%			(166,981)	(3,621,712)
106	Mar-15		(98,578)	(23,800)	7.78%			(122,379)	(3,744,090)
107	Apr-15		(142,781)	(24,737)	7.78%			(167,518)	(3,911,608)
108	May-15		(174,769)	(25,927)	7.78%		0	(200,695)	(4,112,304)
109	Jun-15		(162,516)	(27,188)	7.78%			(189,704)	(4,302,008)

114 **History truncated for ease of viewing**

115

116 **NOTES**

117 **1** -Transfer June balance plus July-October interest on June balance to account 191411 for amortization

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon Demand Deferral
Account Number: 191411
Dockets UM 1496 and UG 278
Amortization of 2013-14 deferral approved in Order No. 14-383

1 Debit (Credit)

	Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)		(f)	(g)
7	Beginning Balance							
99	Dec-13	**2**	130,511	(2)	(1,466)	1.38%	129,042	(1,211,225)
100	Jan-14		142,193		(1,311)	1.38%	140,882	(1,070,343)
101	Feb-14		128,465		(1,157)	1.38%	127,308	(943,035)
102	Mar-14		92,549		(1,031)	1.38%	91,518	(851,517)
103	Apr-14		66,365		(941)	1.38%	65,424	(786,094)
104	May-14		45,726		(878)	1.38%	44,848	(741,246)
105	Jun-14		30,392		(835)	1.38%	29,557	(711,688)
106	Jul-14		25,684		(804)	1.38%	24,880	(686,808)
107	Aug-14		21,298		(778)	1.38%	20,521	(666,288)
108	Sep-14		22,359		(753)	1.38%	21,605	(644,682)
109	Oct-14		26,696		(726)	1.38%	25,970	(618,713)
110	Nov-14	old rates	28,119		(695)	1.38%	27,424	(591,289)
111	Nov-14	new rates **(1)**	198,030	(4,229,742)	(6,093)	1.77%	(4,037,804)	(4,629,093)
112	Dec-14		665,846		(6,337)	1.77%	659,509	(3,969,584)
113	Jan-15		732,357		(5,315)	1.77%	727,042	(3,242,542)
114	Feb-15		529,731		(4,392)	1.77%	525,339	(2,717,203)
115	Mar-15		441,604		(3,682)	1.77%	437,922	(2,279,282)
116	Apr-15		369,891		(3,089)	1.77%	366,802	(1,912,480)
117	May-15		277,168	0	(2,617)	1.77%	274,552	(1,637,928)
118	Jun-15		175,767		(2,286)	1.77%	173,480	(1,464,448)
119	Jul-15	*forecast*	140,130		(2,057)	1.77%	138,074	(1,326,374)
120	Aug-15	*forecast*	139,447		(1,854)	1.77%	137,593	(1,188,781)
121	Sep-15	*forecast*	148,050		(1,644)	1.77%	146,406	(1,042,375)
122	Oct-15	*forecast*	336,052		(1,290)	1.77%	334,763	(707,612)

124 **History truncated for ease of viewing**

126 **NOTES:**

127 **1** - Transfer in authorized balances from accounts 191410, 191450, 191417

Company: Northwest Natural Gas Company
State: Oregon
Description: Coos County Demand
Account Number: 191417
Class of Customers: Core
Docket UM 1179 Order 04-702

Narrative: Deferral of transportation charge payable by NW Natural for use of the natural gas transmission pipeline owned by Coos County.

1 Debit (Credit)

	Month/Year	Note	Deferral	Adjustment	Transfer	Interest	Activity	Balance
6	Beginning Bal							
90	Nov-13	**1**	21,683	(6,644)	(146,831)		(131,792)	15,039
91	Dec-13		21,683	(11,702)			9,981	25,020
92	Jan-14		21,683	(9,456)			12,227	37,246
93	Feb-14		17,048	(8,723)			8,325	45,571
94	Mar-14	**2**	17,048	(129,796)			(112,748)	(67,177)
95	Apr-14		17,048	(5,827)			11,221	(55,956)
96	May-14		17,048	(8,780)			8,268	(47,688)
97	Jun-14		17,048	(5,984)			11,064	(36,624)
98	Jul-14		17,048	(5,725)			11,323	(25,302)
99	Aug-14		17,048	(5,410)			11,638	(13,664)
100	Sep-14		17,049	(5,300)			11,750	(1,914)
101	Oct-14		17,048	(5,283)			11,765	9,851
102	Nov-14	**1**	17,048	(7,823)	36,624		45,849	55,700
103	Dec-14		17,048	(9,081)			7,968	63,667
104	Jan-15		17,048	(7,452)			9,596	73,263
105	Feb-15		16,636	(24,493)			(7,857)	65,406
106	Mar-15		16,636	(9,112)			7,524	72,930
107	Apr-15		16,636	(8,128)			8,508	81,438
108	May-15		16,636	(6,941)			9,695	91,133
109	Jun-15		16,636	(6,169)			10,467	101,600

114 **History truncated for ease of viewing**

116 **NOTES**

117 **1** -Transfer June balance balance to account 191411 for amortization

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Demand Collection Deferral
Account Number: 191450
Docket UM 1496
Current reauthorization to defer was granted in Order No. 14-365

Narrative: Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs as defined in the state's annual PGA.

1	Debit (Credit)							Deferral
2			Demand					Plus Int.
3	Month/Year	Note	Deferral	Interest	Interest Rate	Transfer	Activity	GL Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
5								
6	Beginning Bal							
90	Nov-13	**1**	(328,275)	(1,064)	7.78%	(196,089)	(525,427)	(329,339)
91	Dec-13		(1,282,369)	(6,292)	7.78%		(1,288,661)	(1,618,000)
92	Jan-14		(864,778)	(13,293)	7.78%		(878,071)	(2,496,071)
93	Feb-14		(1,999,668)	(22,665)	7.78%		(2,022,333)	(4,518,404)
94	Mar-14		1,311,653	(25,042)	7.78%		1,286,611	(3,231,793)
95	Apr-14		369,268	(19,756)	7.78%		349,512	(2,882,281)
96	May-14		1,002,149	(15,438)	7.78%		986,711	(1,895,570)
97	Jun-14		(374,228)	(13,503)	7.78%		(387,731)	(2,283,301)
98	Jul-14		58,809	(14,613)	7.78%		44,197	(2,239,104)
99	Aug-14		47,709	(14,362)	7.78%		33,347	(2,205,757)
100	Sep-14		107,662	(13,952)	7.78%		93,710	(2,112,047)
101	Oct-14		1,648,665	(8,349)	7.78%	(1)	1,640,315	(471,732)
102	Nov-14	**1**	1,232,252	16,127	7.78%	2,343,093	3,591,472	3,119,740
103	Dec-14		2,325,178	27,764	7.78%		2,352,941	5,472,682
104	Jan-15		1,638,415	40,792	7.78%		1,679,208	7,151,889
105	Feb-15		2,512,045	54,511	7.78%		2,566,556	9,718,446
106	Mar-15		2,355,018	70,642	7.78%		2,425,660	12,144,106
107	Apr-15		463,254	80,236	7.78%		543,490	12,687,596
108	May-15		587,343	84,162	7.78%	(1)	671,503	13,359,099
109	Jun-15		263,774	87,467	7.78%		351,240	13,710,339

114 **History truncated for ease of viewing**

115

116 **NOTES**

117 **1** -Transfer June balance plus July-October interest on June balance to account 191411 for amortization

NW Natural
Rates & Regulatory Affairs
2015-16 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

Line	Schedule	Block	Oregon PGA Volumes page, Column F	Billing Rate from Rates page, Column A	WACOG & Demand from Rates page, Column B+C+D*	Temps from Temporary Increment page, Column A	MARGIN Rate	Volumetric Margin	Customer Charge	Customers	Total Margin		Mist Capacity Recall Multiplier	Allocation to RS	Increment
2												Proposed Amount:	234,753	PERMANENT Increment	
3												Revenue Sensitive Multiplier:	N/A	rev sensitive factor is built in	
4												Amount to Amortize:	**234,753**	to all classes and schedules	
5							E=B-C-D								
6			A	B	C	D	E	F = E * A	G	H	I		P	Q	R
7	2R		365,285,306	1.01330	0.55622	0.02381	0.43327	158,267,164	$8.00	571,204	213,102,748		1.0	163,536	0.00045
8	3C Firm Sales		158,936,755	0.95518	0.55622	0.05288	0.34608	55,004,832	$15.00	56,928	65,251,872		1.0	50,075	0.00032
9	3I Firm Sales		3,811,735	0.93199	0.55622	0.03900	0.33677	1,283,678	$15.00	278	1,333,718		1.0	1,024	0.00027
10	27 Dry Out		700,552	0.90927	0.55622	0.02332	0.32973	230,993	$6.00	1,517	340,217		1.0	261	0.00037
11	31C Firm Sales	Block 1	20,701,736	0.69453	0.43383	0.05295	0.20775	7,208,200	$325.00	903	10,729,900		1.0	8,234	0.00024
12		Block 2	15,317,497	0.67662	0.43383	0.05298	0.18981						1.0		0.00022
13	31C Firm Trans	Block 1	1,022,480	0.17309	0.00000	(0.00072)	0.17381	374,420	$575.00	62	802,220		0.0	0	0.00000
14		Block 2	1,238,213	0.15815	0.00000	(0.00071)	0.15886						0.0		0.00000
15	31I Firm Sales	Block 1	4,178,853	0.63779	0.43383	0.03909	0.16487	2,109,663	$325.00	199	2,885,763		1.0	2,215	0.00017
16		Block 2	9,536,789	0.62191	0.43383	0.03911	0.14897						1.0		0.00016
17	31I Firm Trans	Block 1	181,494	0.15988	0.00000	(0.00002)	0.15990	127,382	$575.00	8	182,582		0.0	0	0.00000
18		Block 2	680,650	0.14450	0.00000	(0.00001)	0.14451						0.0		0.00000
19	32C Firm Sales	Block 1	26,567,626	0.56907	0.43383	0.03903	0.09621	3,242,704	$675.00	346	6,045,304		1.0	4,639	0.00014
20		Block 2	7,804,067	0.55465	0.43383	0.03906	0.08176						1.0		0.00012
21		Block 3	829,092	0.53064	0.43383	0.03907	0.05774						1.0		0.00008
22		Block 4	20,793	0.50663	0.43383	0.03911	0.03369						1.0		0.00005
23		Block 5	0	0.49221	0.43383	0.03912	0.01926						1.0		0.00003
24		Block 6	0	0.48261	0.43383	0.03915	0.00963						1.0		0.00001
25	32I Firm Sales	Block 1	4,645,409	0.56814	0.43383	0.03916	0.09515	983,960	$675.00	48	1,372,760		1.0	1,053	0.00010
26		Block 2	5,152,955	0.55389	0.43383	0.03918	0.08088						1.0		0.00009
27		Block 3	1,826,257	0.53013	0.43383	0.03921	0.05709						1.0		0.00006
28		Block 4	627,963	0.50636	0.43383	0.03922	0.03331						1.0		0.00004
29		Block 5	(0)	0.49210	0.43383	0.03925	0.01902						1.0		0.00002
30		Block 6	0	0.48263	0.43383	0.03924	0.00956						1.0		0.00001
31	32 Firm Trans	Block 1	12,006,597	0.09488	0.00000	0.00004	0.09484	3,960,067	$925.00	116	5,247,667		0.0	0	0.00000
32		Block 2	16,315,496	0.08064	0.00000	0.00004	0.08060						0.0		0.00000
33		Block 3	9,641,378	0.05697	0.00000	0.00006	0.05691						0.0		0.00000
34		Block 4	16,134,178	0.03327	0.00000	0.00007	0.03320						0.0		0.00000
35		Block 5	21,282,059	0.01906	0.00000	0.00009	0.01897						0.0		0.00000
36		Block 6	1,920,752	0.00959	0.00000	0.00008	0.00951						0.0		0.00000
37	32C Interr Sales	Block 1	5,686,222	0.57809	0.43383	0.04615	0.09811	1,572,249	$675.00	61	2,066,349		1.0	1,586	0.00010
38		Block 2	7,563,208	0.56339	0.43383	0.04615	0.08341						1.0		0.00008
39		Block 3	3,897,038	0.53889	0.43383	0.04619	0.05887						1.0		0.00006
40		Block 4	4,445,365	0.51438	0.43383	0.04620	0.03435						1.0		0.00003
41		Block 5	71,870	0.49967	0.43383	0.04623	0.01961						1.0		0.00002
42		Block 6	0	0.48989	0.43383	0.04622	0.00984						1.0		0.00001
43	32I Interr Sales	Block 1	7,186,289	0.57815	0.43383	0.04626	0.09806	2,201,208	$675.00	71	2,776,308		1.0	2,131	0.00009
44		Block 2	8,946,142	0.56345	0.43383	0.04626	0.08336						1.0		0.00008
45		Block 3	5,135,755	0.53895	0.43383	0.04629	0.05883						1.0		0.00006
46		Block 4	10,445,179	0.51445	0.43383	0.04630	0.03432						1.0		0.00003
47		Block 5	4,597,392	0.49977	0.43383	0.04633	0.01961						1.0		0.00002
48		Block 6	1	0.48997	0.43383	0.04632	0.00982						1.0		0.00001
49	32 Interr Trans	Block 1	8,779,332	0.09620	0.00000	0.00004	0.09616	5,569,605	$925.00	85	6,513,105		0.0	0	0.00000
50		Block 2	15,689,249	0.08179	0.00000	0.00005	0.08174						0.0		0.00000
51		Block 3	11,306,695	0.05777	0.00000	0.00006	0.05771						0.0		0.00000
52		Block 4	28,429,084	0.03373	0.00000	0.00007	0.03366						0.0		0.00000
53		Block 5	56,035,539	0.01933	0.00000	0.00009	0.01924						0.0		0.00000
54		Block 6	78,278,646	0.00975	0.00000	0.00010	0.00965						0.0		0.00000
55	33		0	0.00554	0.00000	0.00000	0.00554	0	$38,000.00	0	0		0.0	0	0.00000
56															
57	TOTALS		962,859,686					242,136,125			318,650,513		305,904,939	234,754	

58

59 **Sources for line 2 above:**

60 **Inputs page** — Line 37

61

62 **Tariff Schedules**

63 **Rate Adjustment Schedule** — Sched 187

64

65 Note: Allocation to rate schedules or blocks with zero volumes is calculated on an overall margin percentage change basis.

66 * Since Billing Rates for all schedules above 31 do not include demand, column c for those schedules is WACOG only

NW Natural
2015-2016 PGA Filing
Recall of Mist Storage for Core
Allocation Between States

	Total Investment	
Net Investment recalled for core	$1,801,429	*From recall memo*

Allocation based on Actual Firm Sales volumes (12 mos ended 06/30/15):

			Allocated Investment	Revenue Requirement	
Oregon	528,944,984	88.04%	$1,585,978	$234,753	*Amount included in PGA*
Washington	71,846,975	11.96%	$215,451	TBD	
	600,791,959	100.0%	$1,801,429	$234,753	

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 15-12A/UG 298

September 15, 2015

NW NATURAL

EXHIBIT B

Supporting Material

Purchased Gas Cost

NWN OPUC ADVICE NO. 15-12A/ UG 298

NW Natural
2015-2016 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

SYSTEM COSTS

(a)	(b)	(c) November	(d) December	(e) January	(f) February	(g) March	(h) April	(i) May	(j) June	(k) July	(l) August	(m) September	(n) October	(o) TOTAL
		1	2	3	4	5	6	7	8	9	10	11	12	
COSTS														
Commodity Cost from Supply		$22,334,688	$22,181,509	$20,134,576	$16,390,636	$15,990,932	$13,770,151	$8,803,354	$5,349,751	$4,567,118	$4,542,423	$5,017,178	$12,079,725	$151,162,041
tab commodity cost from supply, column cd, lines 93-105 plus														
tab commodity cost from gas reserve, column q, lines 59-70														
Volumetric Pipeline Chgs		$281,822	$307,742	$283,753	$229,083	$210,049	$193,859	$130,323	$83,613	$72,581	$71,704	$77,079	$163,166	$2,104,774
tab commodity cost from vol pipe, column e, line 78-90														
Commodity Cost from Storage		$1,706,960	$16,506,928	$16,564,544	$14,144,715	$9,507,010	$467,215	$110,343	$106,784	$110,343	$110,343	$106,784	$110,343	$59,552,312
tab Commodity Cost from Storage, column k, line 61-73														
Commodity Cost from Gas Reserves		$2,831,999	$2,873,511	$2,845,244	$2,696,139	$2,823,250	$2,674,883	$2,699,857	$2,618,139	$2,648,706	$2,619,230	$2,587,387	$2,565,547	$32,483,893
tab Commodity Cost from Gas Reserve, column p, line 59-70														
Total Commodity Cost		$27,155,469	$41,869,690	$39,828,117	$33,460,574	$28,531,241	$17,106,109	$11,743,877	$8,158,287	$7,398,748	$7,343,701	$7,788,427	$14,918,780	$245,303,020
VOLUMES														
Commodity Volumes at Receipt Points		85,463,372	78,957,507	71,635,594	58,756,696	59,230,103	63,577,019	42,722,321	27,414,590	23,804,109	23,516,745	25,275,221	53,508,733	613,862,010
Pipeline Fuel Use		2,171,541	1,881,748	1,681,713	1,368,720	1,424,769	1,727,448	1,103,163	675,095	573,995	566,144	616,648	1,429,887	15,220,870
Gas Arriving at City Gate		83,291,831	77,075,759	69,953,881	57,387,976	57,805,334	61,849,571	41,619,158	26,739,495	23,230,114	22,950,601	24,658,573	52,078,846	598,641,139
Storage Gas Withdrawals		3,954,946	45,574,296	45,940,093	39,987,556	25,487,896	1,194,429	248,000	240,000	248,000	248,000	240,000	248,000	163,611,216
Pipeline Fuel Use for Alberta-sourced Storage		113,306	439,484	448,287	278,008	95,088	0	0	0	0	0	0	0	1,374,172
Storage Gas Deliveries at City Gate		3,841,640	45,134,811	45,491,806	39,709,548	25,392,809	1,194,429	248,000	240,000	248,000	248,000	240,000	248,000	162,237,044
Total Gas At City Gate (Storage and Commodity)		87,133,471	122,210,571	115,445,687	97,097,524	83,198,142	63,044,000	41,867,158	26,979,495	23,478,114	23,198,601	24,898,573	52,326,846	760,878,183
Unaccounted for Gas		538,851	498,637	452,562	371,268	373,968	400,132	269,252	172,989	150,286	148,477	159,527	336,921	3,872,870
Load Served		86,594,620	121,711,934	114,993,125	96,726,257	82,824,175	62,643,868	41,597,906	26,806,505	23,327,828	23,050,124	24,739,046	51,989,926	757,005,313

WACOG Calculations

30	**Gas Reserves Supply:**													
31	Total cost (line 12 above)	$2,831,999	$2,873,511	$2,845,244	$2,696,139	$2,823,250	$2,674,883	$2,699,857	$2,618,139	$2,648,706	$2,619,230	$2,587,387	$2,565,547	$32,483,893
32	Load served by gas reserves	5,360,221	5,485,799	5,412,874	4,997,584	5,273,755	5,039,290	5,142,647	4,916,039	5,018,641	4,959,164	4,743,191	4,844,758	61,193,961
33														
34	**Total Load Served**													
35	Oregon	78,199,532	109,619,139	103,604,276	87,148,787	74,844,912	56,724,684	37,703,844	24,361,463	21,320,422	21,056,914	22,425,093	46,908,779	683,917,844
36	Washingon	8,395,088	12,092,795	11,388,849	9,577,470	7,979,263	5,919,184	3,894,062	2,445,043	2,007,406	1,993,209	2,313,953	5,081,146	73,087,470
37	Total (same as line 29 +/- rounding)	86,594,620	121,711,934	114,993,125	96,726,257	82,824,175	62,643,868	41,597,906	26,806,505	23,327,828	23,050,124	24,739,046	51,989,926	757,005,313
38														
39	**Washington WACOG Calculation**													
40														
41	**Hedged Rockies supply excluding Gas Reserves**													
42	Hedged Rockies supply volumes	14,788,500	15,281,450	10,697,015	4,288,665	4,584,435	2,957,700	3,056,290	2,957,700	3,056,290	3,056,290	2,957,700	6,112,580	73,794,615
43	Hedged Rockies supply cost	$4,825,238	$4,986,079	$3,688,031	$1,705,671	$1,823,304	$825,975	$853,508	$825,975	$853,508	$853,508	$825,975	$1,778,548	$23,845,318
44	Hedged Rockies supply price per therm	$0.32628	$0.32628	$0.34477	$0.39772	$0.39772	$0.27926	$0.27926	$0.27926	$0.27926	$0.27926	$0.27926	$0.29097	$0.32313
45														
46	Load served by gas reserves	5,360,221	5,485,799	5,412,874	4,997,584	5,273,755	5,039,290	5,142,647	4,916,039	5,018,641	4,959,164	4,743,191	4,844,758	61,193,961
47	Gas Reserves cost	$2,831,999	$2,873,511	$2,845,244	$2,696,139	$2,823,250	$2,674,883	$2,699,857	$2,618,139	$2,648,706	$2,619,230	$2,587,387	$2,565,547	$32,483,893
48	Gas Reserves price per therm	$0.52834	$0.52381	$0.52564	$0.53949	$0.53534	$0.53081	$0.52499	$0.53257	$0.52777	$0.52816	$0.54549	$0.52955	$0.53083
49														
50	Washington percentage of total load (line 36 ÷ line 37)	9.7%	9.9%	9.9%	9.9%	9.6%	9.4%	9.4%	9.1%	8.6%	8.6%	9.4%	9.8%	9.7%
51														
52	Total System Commodity Cost (line 14 above)	$27,155,469	$41,869,690	$39,828,117	$33,460,574	$28,531,241	$17,106,109	$11,743,877	$8,158,287	$7,398,748	$7,343,701	$7,788,427	$14,918,780	$245,303,020
53	Less: Commodity Cost of Rockies Hedged Supplies (from line 43)	$4,825,238	$4,986,079	$3,688,031	$1,705,671	$1,823,304	$825,975	$853,508	$825,975	$853,508	$853,508	$825,975	$1,778,548	$23,845,318
54	Less: Commodity Cost of Gas Reserves (from line 12)	$2,831,999	$2,873,511	$2,845,244	$2,696,139	$2,823,250	$2,674,883	$2,699,857	$2,618,139	$2,648,706	$2,619,230	$2,587,387	$2,565,547	$32,483,893
55	Less: Cost of Index Adder for Gas Reserves Allocated to Baseload	$1,971	$2,225	$2,484	$2,558	$2,978	$3,110	$3,443	$3,548	$3,884	$4,095	$4,161	$4,501	$38,958
56	Total System Commodity Cost excluding Rockies hedged & Gas Reserves	$19,496,262	$34,007,875	$33,292,358	$29,056,205	$23,881,709	$13,602,140	$8,187,069	$4,710,626	$3,892,651	$3,866,868	$4,370,904	$10,570,185	$188,934,852
57														
58	Total System Load Served (from line 29)	86,594,620	121,711,934	114,993,125	96,726,257	82,824,175	62,643,868	41,597,906	26,806,505	23,327,828	23,050,124	24,739,046	51,989,926	757,005,313
59	Less: load from Rockies hedged supplies (from line 32)	14,788,500	15,281,450	10,697,015	4,288,665	4,584,435	2,957,700	3,056,290	2,957,700	3,056,290	3,056,290	2,957,700	6,112,580	73,794,615
60	Less: load served by gas reserves (from line 32)	5,360,221	5,485,799	5,412,874	4,997,584	5,273,755	5,039,290	5,142,647	4,916,039	5,018,641	4,959,164	4,743,191	4,844,758	61,193,961
61	Total System load excluding Rockies hedged & Gas Reserves	66,445,899	100,944,685	98,883,236	87,440,007	72,965,985	54,646,879	33,398,969	18,932,767	15,252,897	15,034,670	17,038,156	41,032,588	622,016,737
62														
63	System price excluding Rockies hedged & Gas Reserves (line 55 ÷ line 72)	$0.29342	$0.33690	$0.33668	$0.33230	$0.32730	$0.24891	$0.24513	$0.24881	$0.25521	$0.25720	$0.25654	$0.25760	$0.30375
64														
65	**Washington allocation of Rockies hedged supply**													
66	Rockies hedged supply needed for Washington (line 50 * (line 42 + line 46))	1,954,426	2,055,958	1,594,879	919,339	946,386	751,717	770,700	716,510	694,444	689,329	723,884	1,073,819	12,891,391
67	Cost of Rockies hedged supply allocated to Washington (line 65 * line 44)	$637,690	$670,818	$549,866	$365,640	$376,397	$209,924	$215,226	$200,093	$193,930	$192,502	$202,152	$312,449	$4,126,687
68														
69	**Washington portfolio**													
70	Volumes													
71	Total Washington load	8,395,088	12,092,795	11,388,849	9,577,470	7,979,263	5,919,184	3,894,062	2,445,043	2,007,406	1,993,209	2,313,953	5,081,146	73,087,470
72	Washington load met by Rockies hedged supply	1,954,426	2,055,958	1,594,879	919,339	946,386	751,717	770,700	716,510	694,444	689,329	723,884	1,073,819	12,891,391
73	Remaining Washington load	6,440,662	10,036,837	9,793,970	8,658,131	7,032,877	5,167,467	3,123,362	1,728,533	1,312,962	1,303,880	1,590,069	4,007,327	60,196,079
74														
75	Cost													
76	Cost of Rockies hedged supply allocated to Washington (line 66)	$637,690	$670,818	$549,866	$365,640	$376,397	$209,924	$215,226	$200,093	$193,930	$192,502	$202,152	$312,449	$4,126,687
77	Cost of remaining Washington load (line 72 * line 62)	$1,889,819	$3,381,410	$3,297,434	$2,877,097	$2,301,861	$1,286,234	$765,630	$430,076	$335,081	$335,358	$407,916	$1,032,288	$18,340,204
78	Total cost of Washington portfolio	$2,527,509	$4,052,228	$3,847,300	$3,242,736	$2,678,257	$1,496,159	$980,855	$630,169	$529,012	$527,860	$610,068	$1,344,737	$22,466,891
79														
80	**Washington Sales WACOG** (line 77 ÷ line 70)	$0.30107	$0.33509	$0.33781	$0.33858	$0.33565	$0.25276	$0.25188	$0.25773	$0.26353	$0.26483	$0.26365	$0.26465	$0.30740
81														
82	**WASHINGTON BILLING WACOG**	$0.31483	$0.35041	$0.35325	$0.35406	$0.35100	$0.26432	$0.26340	$0.26951	$0.27558	$0.27694	$0.27570	$0.27675	$0.32145
83														
84	**Oregon WACOG Calculation**													
85														
86	Total system commodity cost	$27,155,469	$41,869,690	$39,828,117	$33,460,574	$28,531,241	$17,106,109	$11,743,877	$8,158,287	$7,398,748	$7,343,701	$7,788,427	$14,918,780	$245,303,020
87	Commodity cost allocated to Washington portfolio	$2,527,509	$4,052,228	$3,847,300	$3,242,736	$2,678,257	$1,496,159	$980,855	$630,169	$529,012	$527,860	$610,068	$1,344,737	$22,466,891
88	Total commodity cost for Oregon	$24,627,960	$37,817,462	$35,980,817	$30,217,837	$25,852,984	$15,609,950	$10,763,021	$7,528,119	$6,869,737	$6,815,840	$7,178,359	$13,574,044	$222,836,12[illegible]
89														
90	**Oregon Sales WACOG (line 88 ÷ line 35)**	$0.31494	$0.34499	$0.34729	$0.34674	$0.34542	$0.27519	$0.28546	$0.30902	$0.32221	$0.32369	$0.32010	$0.28937	$0.3258[illegible]
91														
92	**OREGON BILLING WACOG**	$0.32379	$0.35468	$0.35704	$0.35648	$0.35512	$0.28292	$0.29348	$0.31770	$0.33126	$0.33278	$0.32909	$0.29750	$0.3349[illegible]

NW Natural
2015-2016 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
		30	31	31	29	31	30	31	30	31	31	30	31	366
Transport charges by transporter:														
Northwest Pipeline		$4,252,026	$4,393,760	$4,393,760	$4,110,290	$4,393,760	$4,152,211	$4,290,618	$4,152,211	$4,290,618	$4,290,618	$4,152,211	$4,290,618	$51,162,700
Alberta: AECO Storage		67,586	67,586	67,586	67,586	67,586	0	0	0	0	0	0	0	337,928
Alberta: NOVA		658,173	658,173	658,173	658,173	658,173	658,173	658,173	658,173	658,173	658,173	658,173	658,173	7,898,079
Alberta: Foothills		351,318	351,318	351,318	351,318	351,318	313,580	313,580	313,580	313,580	313,580	313,580	351,318	3,989,385
Alberta: GTN		540,136	558,141	501,145	468,813	501,145	408,140	421,745	408,140	421,745	421,745	408,140	501,145	5,560,180
BC: Southern Crossing		626,539	646,524	646,524	606,555	646,524	626,539	646,524	626,539	646,524	646,524	626,539	646,524	7,638,379
BC: Spectra (Westcoast)		369,000	381,300	381,300	356,700	381,300	369,000	381,300	369,000	381,300	381,300	369,000	381,300	4,501,800
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,258
Total System Demand		$6,883,465	$7,075,489	$7,018,494	$6,638,123	$7,018,494	$6,546,331	$6,730,628	$6,546,331	$6,730,628	$6,730,628	$6,546,331	$6,847,766	$81,312,709

Detail in file "Capacity Contract Monthly Summary for Tracker 2015-16.xls"

NW Natural
2015-2016 PGA - SYSTEM: August Filing
Derivation of Oregon per therm Non-Commodity Charges
ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

Line				
1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$81,312,709	
5	Oregon Allocation Factor 1/		89.70%	
6	Oregon Demand		$72,937,500	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		625,943,383	
9	Oregon Interruptible Sales Forecasted Normal Volumes		57,974,461	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11525	$0.11849
13	Proposed Interruptible Demand 2/		$0.01371	$0.01410
14	Proposed MDDV Demand Charge		$1.71	$1.76
15				
16	Current Firm Demand Per Therm		$0.11899	$0.12239
17	Current Interruptible Demand		$0.01415	$0.01455
18	Current MDDV Demand Charge		$1.77	$1.82
19				
20	Percent Change in Firm Demand		-3.14%	
21				
22				
23	1/Allocation Factor: 2015-16 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	71,896,148	625,943,383	697,839,531
26		10.30%	89.70%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		0.969	
31				
32	Firm Demand (line 8 * line 34)		$0.11525	$72,142,913
33	Interruptible Demand (line 9 * line 35)		$0.01371	$794,587
34				$72,937,500
35				$0

NW Natural
2015-2016 PGA - SYSTEM: August Filing
Calculation of Winter WACOG
Prices are per therm

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.23306		
6	December	$0.23984		
7	January	$0.24536		
8	February	$0.24604		
9	March	$0.24193		
10	April	$0.22696		
11	May	$0.22431		
12	June	$0.22495		
13	July	$0.22543		
14	August	$0.22783		
15	September	$0.22845		
16	October	$0.23567		
17				
18				
19	Average price, November-March		$0.24125	average lines 5-9
20				
21	Annual average price, November-October		$0.23332	average lines 5-16
22				
23	Ratio of winter to annual		1.03399	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.32582	$0.33497
OR	Oregon Winter WACOG		$0.33689	$0.34635
			line 23 * $0.32582	
WA	Washington Annual WACOG		$0.30740	$0.32145
WA	Washington Winter WACOG		$0.31785	$0.33238
			line 23 * $0.3074	

NW Natural
2015-2016 PGA - OREGON: October Filing
Derivation of Oregon Seasonalized Fixed Charges

Line			Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Demand Increment Eff. 11/01/15	Interr. Demand Increment Eff. 11/01/15	Seasonalized Fixed Charges
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
5										
6	November	2015	44,299,737	26,054,779	2,478,751	5,366,265	78,199,532	$0.11609	$0.01381	$8,530,506
7	December	2015	64,804,593	36,307,524	2,931,461	5,575,561	109,619,139	$0.11609	$0.01381	$12,155,128
8	January	2016	60,606,861	34,275,583	3,035,403	5,686,429	103,604,276	$0.11609	$0.01381	$11,445,540
9	February	2016	50,295,028	28,869,220	2,765,044	5,219,495	87,148,787	$0.11609	$0.01381	$9,583,025
10	March	2016	41,979,347	24,985,230	2,554,610	5,325,725	74,844,912	$0.11609	$0.01381	$8,143,837
11	April	2016	30,062,225	18,896,816	2,461,683	5,303,960	56,724,684	$0.11609	$0.01381	$6,042,536
12	May	2016	17,918,894	12,980,024	2,262,994	4,541,932	37,703,844	$0.11609	$0.01381	$3,912,397
13	June	2016	9,326,736	8,492,706	2,105,764	4,436,257	24,361,463	$0.11609	$0.01381	$2,374,325
14	July	2016	7,289,851	7,755,038	2,251,606	4,023,927	21,320,422	$0.11609	$0.01381	$2,063,471
15	August	2016	7,298,639	7,754,336	2,133,440	3,870,499	21,056,914	$0.11609	$0.01381	$2,048,574
16	September	2016	8,164,120	7,878,368	2,402,350	3,980,255	22,425,093	$0.11609	$0.01381	$2,196,176
17	October	2016	23,939,828	15,927,942	2,396,853	4,644,156	46,908,779	$0.11609	$0.01381	$4,970,518
18										
19										
20										
21			365,985,857	230,177,565	29,779,961	57,974,461	683,917,844			$73,466,033

	Encana Gas Reserves Deal		Projected November 2015	Projected December 2015	Projected January 2016	Projected February 2016	Projected March 2016	Projected April 2016	Projected May 2016	Projected June 2016	Projected July 2016	Projected August 2016	Projected September 2016	Projected October 2016	Projected PGA Totals
1	Therms Delivered (000s)														
2	Total Therms		5,436.88	5,564.26	5,490.29	5,069.06	5,349.18	5,111.36	5,216.20	4,986.35	5,090.42	5,030.09	4,811.03	4,914.05	62,069.14
3	Rate per Therm (Depletion Rate)		0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604	0.2604
4	Delivery Value		1,415.96	1,449.14	1,429.87	1,320.17	1,393.12	1,331.19	1,358.49	1,298.63	1,325.73	1,310.02	1,252.97	1,279.80	16,165.09
5															0.2604
6	Opex / Severance / Ad Valorem														
7	Operating Cost		589.25	595.52	592.95	575.01	636.21	574.99	579.34	569.88	574.79	572.12	612.69	567.33	7,040.06
8	Severance and Ad Valorem Taxes		183.28	198.94	202.84	184.56	187.83	164.39	167.57	161.60	171.87	168.11	157.34	164.82	2,113.15
9	Total		772.52	794.45	795.79	759.57	824.03	739.37	746.91	731.48	746.66	740.23	770.03	732.15	9,153.21
10															0.1475
11	Average Rate Base		77,004.18	76,059.49	75,145.70	74,298.33	73,406.79	72,552.75	71,682.18	70,847.85	69,997.11	69,155.88	68,349.19	67,526.26	
12															
13	Carrying Cost														
14	Equity	9.5000%	304.81	301.07	297.45	294.10	290.57	287.19	283.74	280.44	277.07	273.74	270.55	267.29	
15	Equity % of Cap Struct	50.0000%													
16	Equity Pretax	39.4589%	454.57	443.70	435.93	434.72	427.31	427.71	420.51	416.20	407.04	402.06	399.44	391.22	
17	Debt	6.0560%	194.31	191.92	189.62	187.48	185.23	183.07	180.88	178.77	176.63	174.50	172.47	170.39	
18	Total Carrying Cost		648.87	635.62	625.55	622.20	612.54	610.78	601.39	594.98	583.67	576.56	571.91	561.61	7,245.68
19															0.1167
20	Total Cost		2,837.36	2,879.21	2,851.22	2,701.94	2,829.70	2,681.34	2,706.79	2,625.08	2,656.06	2,626.81	2,594.90	2,573.56	32,563.97
21	Total Volume		5,436.88	5,564.26	5,490.29	5,069.06	5,349.18	5,111.36	5,216.20	4,986.35	5,090.42	5,030.09	4,811.03	4,914.05	62,069.14
22	Total Rate Per Therm		0.522	0.517	0.519	0.533	0.529	0.525	0.519	0.526	0.522	0.522	0.539	0.524	0.525

NW Natural
Rates & Regulatory Affairs
2015-16 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule
ALL VOLUMES IN THERMS

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

Advice 15-12
See note [8]

Line	Schedule	Block	Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2014 Billing Rates	11/1/2014 Current Average Bill	Proposed 11/1/2015 PGA Rates	Proposed 11/1/2015 PGA Average Bill	Proposed 11/1/2015 PGA % Bill Change
5								F=D+(C * E)		Z=D+(C * Y)	AA = (Z - F)/F
6	Schedule	Block	A	B	C	D	E	F	Y	Z	AA
7	2R		365,285,306	N/A	53.0	8.00	1.01330	61.70	0.88317	54.81	-11.2%
8	3C Firm Sales		158,936,755	N/A	233.0	15.00	0.95518	237.56	0.82492	207.21	-12.8%
9	3I Firm Sales		3,811,735	N/A	1,143.0	15.00	0.93199	1,080.26	0.80168	931.32	-13.8%
10	27 Dry Out		700,552	N/A	38.0	6.00	0.91	40.55	0.77906	35.60	-12.2%
11	31C Firm Sales	Block 1	20,701,736	2,000	3,324.0	325.00	0.69453		0.56809		
12		Block 2	15,317,497	all additional			0.67662		0.55016		
13		**Total**						**2,609.90**		**2,189.59**	-16.1%
14	31C Firm Trans	Block 1	1,022,480	2,000	1,374.0	575.00	0.17309		0.17309		
15		Block 2	1,238,213	all additional			0.15815		0.15815		
16		**Total**						**812.83**		**812.83**	0.0%
17	31I Firm Sales	Block 1	4,178,853	2,000	5,744.0	325.00	0.63779		0.51128		
18		Block 2	9,536,789	all additional			0.62191		0.49539		
19		**Total**						**3,929.01**		**3,202.30**	-18.5%
20	31I Firm Trans	Block 1	181,494	2,000	8,981.0	575.00	0.15988		0.15988		
21		Block 2	680,650	all additional			0.14450		0.14450		
22		**Total**						**1,903.51**		**1,903.51**	0.0%
23	32C Firm Sales	Block 1	26,567,626	10,000	8,483.0	675.00	0.56907		0.44253		
24		Block 2	7,804,067	20,000			0.55465		0.42809		
25		Block 3	829,092	20,000			0.53064		0.40404		
26		Block 4	20,793	100,000			0.50663		0.38000		
27		Block 5	0	600,000			0.49221		0.36556		
28		Block 6	0	all additional			0.48261		0.35594		
29		**Total**						**5,502.42**		**4,428.98**	-19.5%
30	32I Firm Sales	Block 1	4,645,409	10,000	21,272.0	675.00	0.56814		0.44156		
31		Block 2	5,152,955	20,000			0.55389		0.42730		
32		Block 3	1,826,257	20,000			0.53013		0.40351		
33		Block 4	627,963	100,000			0.50636		0.37972		
34		Block 5	(0)	600,000			0.49210		0.36544		
35		Block 6	0	all additional			0.48263		0.35596		
36		**Total**						**12,599.85**		**9,907.13**	-21.4%
37	32 Firm Trans	Block 1	12,006,597	10,000	55,532.0	925.00	0.09488		0.09488		
38		Block 2	16,315,496	20,000			0.08064		0.08064		
39		Block 3	9,641,378	20,000			0.05697		0.05697		
40		Block 4	16,134,178	100,000			0.03327		0.03327		
41		Block 5	21,282,059	600,000			0.01906		0.01906		
42		Block 6	1,920,752	all additional			0.00959		0.00959		
43		**Total**						**4,810.05**		**4,810.05**	0.0%
44	32C Interr Sales	Block 1	5,686,222	10,000	29,595.0	675.00	0.57809		0.43148		
45		Block 2	7,563,208	20,000			0.56339		0.41676		
46		Block 3	3,897,038	20,000			0.53889		0.39224		
47		Block 4	4,445,365	100,000			0.51438		0.36770		
48		Block 5	71,870	600,000			0.49967		0.35298		
49		Block 6	0	all additional			0.48989		0.34319		
50		**Total**						**17,495.53**		**13,156.21**	-24.8%
51	32I Interr Sales	Block 1	7,186,289	10,000	42,618.0	675.00	0.57815		0.43153		
52		Block 2	8,946,142	20,000			0.56345		0.41682		
53		Block 3	5,135,755	20,000			0.53895		0.39230		
54		Block 4	10,445,179	100,000			0.51445		0.36777		
55		Block 5	4,597,392	600,000			0.49977		0.35308		
56		Block 6	1	all additional			0.48997		0.34327		
57		**Total**						**24,525.97**		**18,276.74**	-25.5%
58	32 Interr Trans	Block 1	8,779,332	10,000	194,626.0	925.00	0.09620		0.09620		
59		Block 2	15,689,249	20,000			0.08179		0.08179		
60		Block 3	11,306,695	20,000			0.05777		0.05777		
61		Block 4	28,429,084	100,000			0.03373		0.03373		
62		Block 5	56,035,539	600,000			0.01933		0.01933		
63		Block 6	78,278,646	all additional			0.00975		0.00975		
64		**Total**						**8,913.82**		**8,913.82**	0.0%
65	33		0	N/A	0.0	38,000.00	0.00554	38,000.00	0.00554	38,000.00	0.0%
66											
67	**Totals**		962,859,686								
68			0								
69											

70 **Sources:**

71	Direct Inputs		per Tariff		per Tariff				
72									
73	Rates in summary					Column A		Column A	
74	Permanents								
75	Temporaries							Add: Cols B+ C	
76	PRIOR YEAR Temporaries							Add: Cols B+ C	

77

78 [1] For convenience of presentation, the cent per therm demand charge is used, rather than the available MDDV demand option for Rate Schedules 31 and 32.

NW Natural
Rates and Regulatory Affairs
2015-2016 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months		
1		Ended 06/30/15		
2				
3	Total Billed Gas Sales Revenues	635,125,404		
4	Total Oregon Revenues	657,765,960		
5				
6	Regulatory Commission Fees [1]	1,697,120	0.250%	Statutory rate
7	City License and Franchise Fees	15,291,561	2.325%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	1,032,745	0.157%	Line 8 ÷ Line 4
9				
10	Total	18,021,426	**2.732%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)			
15	[2] Represents the normalized net write-offs based on a three-year average.			

NW Natural
Rates & Regulatory Affairs
2015-2016 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Tariff Advice 15-12: PGA Gas Costs and Gas Cost Deferrals

Line	Description	Including Revenue Sensitve Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($67,472,094)
6		
7	Demand Capacity Cost Change	(1,679,662)
8		
9	**Total Gas Cost Change**	**(69,151,756)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	(16,814,949)
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(3,208,390)
18		
19		
20	**Net Temporary Rate Adjustment**	**(20,023,339)**
21		
22	**Permanent Rate Adjustments**	
23		
24	Storage Recall for Core	234,753
25		
26	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($88,940,342)**
27		
28		
29		
30	2014 Oregon Earnings Test Normalized Total Revenues	$678,848,000
31		
32	Effect of this filing, as a percentage change (line 26 ÷ line 30)	-13.10%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL
SUPPORTING MATERIALS

Purchased Gas Costs

NWN OPUC Advice No. 15-12A/UG 298
September 15, 2015

NW NATURAL

EXHIBIT C

OPUC Advice No. 15-12A

OPUC ORDER No. 11-196

DOCKET UM 1286

SECTION IV and V. PGA PORTFOLIO GUIDELINES

DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	Definitions!A1	
b)	Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.	IV.1b!A1	
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.	IV.1c!A1	
2	Workpapers		
a)	PGA Summary Sheet	IV.2a!A1	
b)	Gas Supply Portfolio and Related Transportation		
1	Summary of portfolio planning	IV.2b 1-6'!A1	
2	LDC sales system demand forecasting	IV.2b 1-6'!A1	
3	Natural gas price forecasts	IV.2b 1-6'!A1	
4	Physical resources for the portfolio	IV.2b 1-6'!A1	CONFIDENTIAL
		IV.2b.4 Tables 1 - 5	
5	Financial resources for the portfolio (derivatives and other financial arrangements).	IV.2b 1-6'!A1	CONFIDENTIAL
6	Storage resources.	IV.2b 1-6'!A1	
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.	IV.2b.7!A1	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	IV.2b.8!A1	
9	Summary of portfolio documentation provided	IV.2b.9!A1	
V.1	**Physical Gas Supply**	V.1.a pg 1'!A1	**HIGHLY CONFIDENTIAL**
		V.1.a pg 2'!A1	**HIGHLY CONFIDENTIAL**
		V.1.a pg3'!A1	**HIGHLY CONFIDENTIAL**
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:		
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.		

NW NATURAL

EXHIBIT C

OPUC Advice No. 15-12A

OPUC ORDER No. 11-196
DOCKET UM 1286
SECTION IV and V. PGA PORTFOLIO GUIDELINES
DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a “winning” bid, and any special pricing or delivery provisions negotiated as part of the bidding process.		
3	Brief explanation of each contract’s role within the portfolio.		
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	V.1.b!A1	
1	An explanation of the utility’s spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	V.1.b!A1	
2	Any contract provisions that materially deviate from the standard NAESB contract.	V.1.b!A1	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	V.2!A1	HIGHLY CONFIDENTIAL
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	V.3.a!A1	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	V.3.b!A1	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	V.3.c!A1	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,		
1	Annual for each customer class	V.3.d.1!A1	
2	Annual and monthly baseload.	V.3.d.2!A1	
3	Annual and monthly non-baseload.	V.3.d.3!A1	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	V.3.d.4!A1	
V.4	**Market Information**		
	General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	V.4!A1	
V.5	**Data Interpretation**		

NW NATURAL

EXHIBIT C

OPUC Advice No. 15-12A

OPUC ORDER No. 11-196
DOCKET UM 1286
SECTION IV and V. PGA PORTFOLIO GUIDELINES
DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
	If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	V.5!A1	
V.6	**Credit Worthiness Standards**		
	A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	V.6!A1	
	Attachment 1 to V.6	V.6 attachment'!A1	**CONFIDENTIAL/HIGHLY CONFIDENTIAL**
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.		
a)	Type of storage (e.g., depleted field, salt dome).	V.7.a-c'!A1	
b)	Location of each storage facility.	V.7.a-c'!A1	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	V.7.a-c'!A1	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	V.7.d-e'!A1	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	V.7.d-e'!A1	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	V.7.f!A1	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	V.7.g!A1	
h)	For LDCs that own and operate storage:	V.7.h!A1	**CONFIDENTIAL**
a.	The date and results of the last engineering study for that storage.		
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.		
V.8	**Attestation as to Consistency**	See IV.1.c	

NW Natural
PGA Portfolio Development Guidelines
OPUC Order No. 11-196, Docket UM 1286

Section IV. 1 General Information
a) Definitions and Acronyms

AECO — The industry acronym used for Alberta sourced natural gas supply. It originally

Base Load gas (contract) — Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.

Base Rate — The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment.

Base Rate Adjustment — A permanent adjustment to rates approved by the Commission outside of a general rate case process.

Btu — British thermal unit. 100,000 Btus is equivalent to one therm.

CGPR — Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing

Collar — Financial hedges that set ceiling and floor values on the price of gas purchases.

Commodity Component — The Tariff term used to refer to the cost of gas component of a customer's billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas.

Dth — Dekatherm. A unit of measure equal to 10 therms or one million Btu.

Demand [Charge] — The term used to refer to Pipeline Capacity related costs.

Derivative products — Financial transactions related to gas supply, including but not limited to hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.

EIA — U.S. Energy Information Administration

FERC — Federal Energy Regulatory Commission

Financial swaps — Transactions that involve an exchange of cash flows with a counterparty.

Financially hedged — Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time.

FOM — First of Month

Fuel-in-Kind (KIG) — The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements.

GMR-NWP Rockies — Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices.

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

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

IV General Information and Forecasting

1 General Information

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

The interdependencies between the electric sector and natural gas utilities took center stage in February 2011 when an extreme cold weather event in the southwestern U.S. affected service to 4.4 million electric customers and over 50,000 natural gas customers. FERC, NERC and various other agencies have held hearings and issued reports since then, and other studies are still ongoing. Many of the calls for better coordination and preparedness were already anticipated by energy utilities in the Pacific Northwest, in part due to our own regional outage event that occurred in December 2009, and also in part due to past planning efforts that have drawn together many of the same stakeholders.

FERC issued a Notice of Proposed Rulemaking (NOPR) on March 20, 2014, Docket No. RM-14-2-000, which proposed changes to the start time for the "gas day," the timelines for scheduling gas, and the introduction of more "nomination" cycles. NW Natural was an active participant in this process through several broad coalitions. The Final Rule was issued by FERC on April 16, 2015, and it adopted the changes that were supported by those gas industry coalitions. Pipeline implementation of the new scheduling standards is expected to occur in April 2016. The ultimate impact on NW Natural's operations should be minimal.

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

IV	General Information and Forecasting
1	General Information
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing and
8	Attestation of verification of consistency

In accordance with the PGA Portfolio Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc., upon which the gas supply portfolio for this PGA filing is based, uses the methodology and data sources that are consistent with the Company's recently acknowledged 2014 IRP.

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To 1 million)*	($58,000,000)	Refer to workpaper "PGA filing Summary Effects"
B) Percent *(To 1 percent)*	-8.55%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	(69,151,756)	Refer to workpaper "PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	(24,227,752)	"
C) Add New Temporary Increment	29,290,766	"
necessary)		
1) Net Safety Programs	687,020	Refer to workpaper "PGA filing Summary Effects"
2) Mist Recall	234,753	"
3) Schedule 182	5,140,437	
4)	0	
5)	0	
6)	0	
E) Total Proposed Change	(58 026 531)	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$1.01330	Refer to workpaper "2015-16 Rate Development"
2) Proposed Billing Rate per Therm	$0.93326	"
3) Rate Change Per Therm	($0.08004)	"
4) Percent Change per Therm *(to 1%)*	-7.9%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	53.0	Refer to workpaper "2015-16 Rate Development"
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$61.70	"
4) Proposed Average Monthly Bill	$57.46	"
5) Change in Average Monthly Bill	($4.24)	"
6) Percent change in Average Monthly Bill *(to 1%)*	-6.9%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	96.0	N/A
2) Customer Charge	$8.00	N/A
3) Current Average January Bill	$105.05	N/A
4) Proposed Average January Bill	$97.39	N/A
5) Change in Average January Bill	($7.67)	N/A
6) Percent change in Average January Bill (*to 1%*)	-7.3%	N/A
	Amount	**Location in Company Filing (cite)**
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	316,918,813	2014-15 PGA filing
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Volumetric Cost (assoc. w/ supply)	$2 095 245	2014-15 PGA filing
e) Total Storage Cost (assoc. w/ supply)	68,887,280	2014-15 PGA filing
f) Other	$37,776,597	2014-15 PGA filing
2) Total Transportation Cost *(Pipeline related)*	83,208,295	2014-15 PGA filing
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	0	
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	0	
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	0	
5) Total Gas Costs	$400,127,108	
B) Projected For New Rates		
1) Total Commodity Cost	245,303,020	Exhibit B, Page 1
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Vaporization Cost (assoc. w/ supply)		
e) Total Volumetric Cost (assoc. w/ supply)	$2,104,774	Exhibit B, Page 1
f) Total Storage Cost (assoc. w/ supply)	59,552,312	Exhibit B, Page 1
g) Other (A&G Benchmark Savings)	$32,483,893	Exhibit B, Page 1
2) Total Transportation Cost *(Pipeline related)*	81,312,709	Exhibit B, Page 3
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	0	
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	0	
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	0	
5) Total Gas Costs	$326,615,729	

	Amount	Location in Company Filing (cite)
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.43383	N/A
b. Without revenue sensitive	$0.42178	N/A
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.12239	N/A
b. Without revenue sensitive	$0.11899	N/A
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.33497	Exhibit B, Page 2
b. Without revenue sensitive	$0.32582	Exhibit B Page 2
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.11849	Exhibit B, Page 4
b. Without revenue sensitive	$0.11525	Exhibit B, Page 4
6) Therms Sold	757,005,313	Exhibit B, Page 1

7) Purchasing/ Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues Within the summary include:*

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

1) Firm Pipeline Capacity		
a) Year-round supply contracts	N/A	Exhibit A, IV.2.b 1-7
b) Winter-only contracts	N/A	"
c) Reliance on Spot Gas/Other Short Term Contracts	N/A	"
d) Other - e.g. Supply area storage	N/A	"
2) Market Area Storage		
a) Underground-owned	N/A	"
b) Underground- contracted	N/A	"
c) LNG-owned	N/A	"
d) LNG-contracted	N/A	"
3) Other Resources		
a) Recallable Supply	N/A	"
b) City gate Deliveries	N/A	"
c) Owned-Production	N/A	"
d) Propane/Air	N/A	"

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

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

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1. Summary of Portfolio Planning Process

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

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

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/NIT, to maximize buying 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) Reduce spot purchase requirements during the winter due to the l kely correlation of high requirements with high spot prices; (5) Take advantage of favorable pricing opportunities to use supply-basin storage when poss ble; (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.

One item that would have been found in the above list in prior years was an objective to use a variety of term contract durations to avoid having to re-contract all physcial gas supplies every year. More recently, with the surge in supplies represented by shale gas, the Company has decreased its reliance on multi-year physical term contracts, and as they have expired, replaced them with 1-year or shorter term purchases.

[1] "Design" year criteria is developed and discussed in the Company's Integrated Resource Plan (IRP).

2. *LDC sales system demand forecasting.*

The company's methodology for forecasting annual sales and firm peak day requirements follow the methodology established in its Integrated Resource Plan (IRP). Also applicable here is the load forecast methodology previously established for PGA filings.

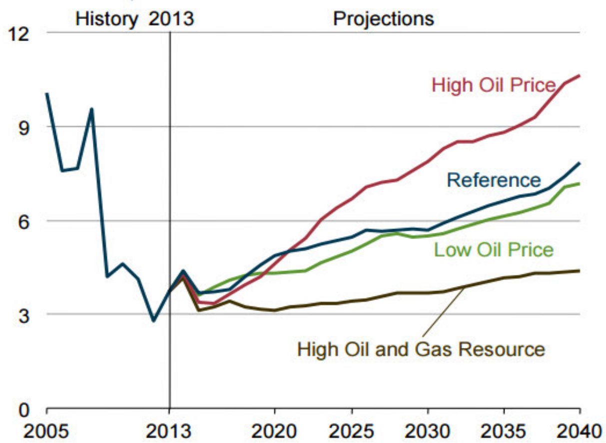
This means that while the demand forecast reflects "normal" weather, the company still is planning for the possil bity of extreme cold weather during the upcoming heating season. Where these two differing load forecasts collide is in the dispatch of storage resources. To handle this conflict in load forecasting criteria, implicit in the resource dispatch are constraints that limit storage withdrawals to the extent needed to maintain maximum daily deliverabilities into early February. This addresses the need to maintain reliability of service to firm customers should extreme cold weather arise this coming winter, while at the same time complying with the PGA load forecast requirements.

3. *Natural gas price forecasts.*

NWN relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the IHS CERA consulting firm as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NWN by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints.

As an example, below is the latest long-range natural gas price forecast - Reference (base case) along with three alternate scenarios - from EIA's 2015 Annual Energy Outlook dated April 2015. It indicates that prices currently have bottomed out. Even though EIA predicts natural gas production would continue to grow, in most cases this is offset by demand growth that is led by gas exports in the form of LNG as well as via pipeline to Mexico.

Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



Fundamental forecasts that call for rising gas prices have spurred NWN to formulate hedging strategies around locking in prices on a longer term basis for a larger portion of its expected purchase volumes. This was discussed in the company's 2014 IRP and is now the topic of Oregon docket UM 1720.

4. *Physical resources for the portfolio.*

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

Four significant changes to the physical supply resource portfolio were discussed in last year's PGA filing: (1) removal of 601,00 therms/day from the Plymouth LNG plant due to uncertainty over its reliability after a Northwest Pipeline curtailment of its related TF-2 pipeline transportation service (this occurred several months <u>prior</u> to the Plymouth plant explosion/outage); (2) addition of a 200,000 therms/day citygate peaking supply contract with a gas marketing company to offset a portion of the lost Plymouth capacity; (3) reliance on "segmented" capacity of 438,000 therms/day from Sumas/Huntingdon as a stopgap measure to offset the rest of the Plymouth loss; and (4) termination of our 600,000 therms/day T-South pipeline contract on the Westcoast Energy (Spectra) pipeline system in British Columbia, which changed the purchasing location for certain supplies from Station 2 to Sumas/Huntingdon. An additional matter that was discussed - but not changed lat year - was the (5) company's continuing reliance on "subordinate" TF-2 service to transport a portion of its supplies from the Jackson Prairie storage facility (135,250 therms/day). The current status for each of these items is discussed below.

(1) The situation regarding the Plymouth LNG plant has not changed. While there may be columns or rows in certain spreadsheets labeled for Plymouth, these are holdovers from prior files and there should be no actual entries (or just zeros) in those cells. This is unl kely to change in the future unless Northwest Pipeline develops a primary firm transportation service from Plymouth that greatly improves the cost-effectiveness of the service, which no doubt would be analyzed in an IRP-type process prior to its appearance in any PGA filing.

(2) The 200,000 therms/day citygate peaking supply contract is expected to continue for another winter under the same terms as last winter, though those negotiations are not yet complete.

(3) The need for segmented capacity as a stopgap measure essentially was eliminated through the combination of the citygate peaking supply mentioned above and a 300,000 therm/day Mist "recall" that took effect on May 1, 2015. This recall is in accordance with the action plan in the acknowledged 2014 IRP. Accordingly, the company is not reflecting segmented capacity in its current peak day resource plan.

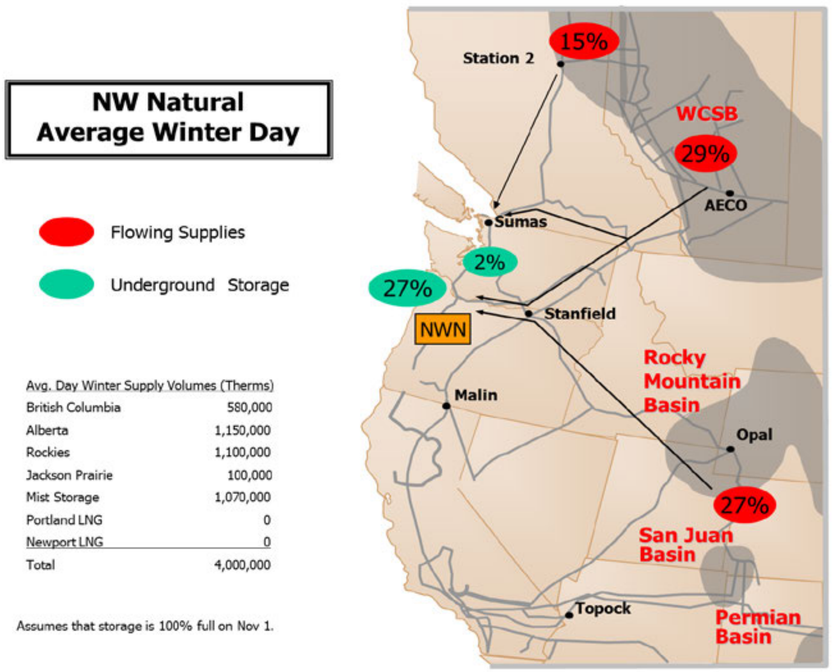
(4) T-South capacity has been evaluated for this coming year and a 300,000 therm/day contract has been secured through a gas marketing capacity. The economic analysis is provided in a separate spreadsheet in this file labeled "T-South analysis". In sum, there were three reasons for this turnabout: (1) lower T-South toll rates due to recontracting on the Westcoast system; (2) a further reduction in the effective cost in U.S. dollars due to favorable movement in the U.S./Canadian currency exchange rate; and (3) a widening in the spread between Station 2 and Sumas/Huntingdon commodity prices.

(5) The company has signed an MOU with Northwest Pipeline that would provide 135,250 therms/day of discounted TF-1 service from Jackson Prairie, eliminating reliance on the "subordinate" capacity, subject to approval in this PGA process. This agreement was analyzed and filed as an IRP update with the Oregon PUC on May 8, 2015, under docket LC 60. The company will make separate arrangements to provide the analysis to the WUTC as appropriate.

As a reminder from prior years, a small "de-rate" continues to be in place for the Newport LNG tank capacity. This reflects the gradual accumulation of frozen carbon dioxide (commonly known as "dry ice") on the tank floor over the plant's 35 years of operation. This has not reduced Newport's design peak day delivery rate. In the 2014 IRP, a project to refurbish Newport was described and acknowledged. That project is now underway, and one element of the project address the dry ice issue, gradually and safely eliminating the problem over a multi-year period.

The company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011 with Encana. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA will reflect the regulatory settlement tentatively reached in mid-July regarding those seven wells, i.e., those volumes will be included at the settlement price. As a reminder, all of the gas reserve volumes essentially function as a financial tool, i.e., they displace an identical volume of financial derivatives that the company otherwise would have executed. For the purposes of this filing, the Encana and Jonah Energy gas reserve volumes have no impact on the company's physical supply portfolio.

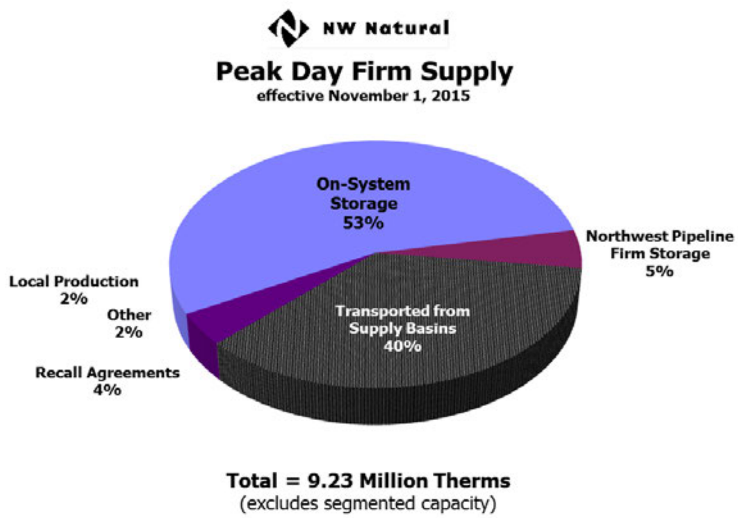
Using its mix of transportation and storage resources, the company achieves the following profile on a typical winter day.



Avg. Day Winter Supply Volumes (Therms)	
British Columbia	580,000
Alberta	1,150,000
Rockies	1,100,000
Jackson Prairie	100,000
Mist Storage	1,070,000
Portland LNG	0
Newport LNG	0
Total	4,000,000

Assumes that storage is 100% full on Nov 1.

Should its “design” peak day occur, all physical resources would be used in the following proportions (segmented capacity is excluded but presumably would be used if available and if spot gas purchases to fill that capacity make economic or operational sense):



A summary of the company’s physical supply resources is provided in Tables 1 through 5.

Regarding physical supply purchasing, NWN will have contracts with suppliers for 650,000 therms per day of firm deliveries on a daily basis over the upcoming November 2015 through October 2016 period. This reflects the relatively stable daily component of NWN’s demand, including some portion of storage injection requirements in the summer months.

For the November 2015 through March 2016 heating season, NWN will have contracts for an additional 1.175 million therms/day of supply under baseload agreements, another 300,000 therms/day under peaking (swing) contracts in the supply basins, and another 200,000 therms/day of peaking supply under a citygate delivery agreement. This reflects the higher consumption of customers during those months. Buying under term supply contracts lessens the need to rely extensively on the spot market during periods of high demand when competition for supplies may be intense. The baseload contracts that have a maximum total of 1.825 million therms/day (650,000 year-round plus 1.175 million winter season) are purchased on a take-or-pay basis. The remaining 500,000 therms/day (300,000 in the supply area plus 200,000 at the citygate) are made available to NWN on a daily basis in exchange either for payment of a fixed “reservation” charge or for equivalent value in the form of put options during the summer months. These swing contracts have no minimum daily, monthly or seasonal purchase requirement, but they provide additional daily supply flexibility, which is especially valuable since winter weather can fluctuate rapidly between mild and cool temperatures, resulting in rapidly changing customer requirements.

This means between 1.16 and 1.46 million therms/day of upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. Accordingly, on days when all upstream capacity is in use, purchases will be split among three categories – year-round contracts, winter term contracts and spot purchases.

5. *Financial resources for the portfolio (derivatives instruments and other financial*

NWN "swaps" monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage, including any supply-basin storage arrangements, provide another form of hedging. In addition, gas reserves provide a hedge for Oregon customers in a completely different form. Overall, NWN's target this year is to hedge the prices of approximately 75% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. As storage currently accounts for about 23% of annual purchase quantities, gas reserves will amount to roughly 9% for this tracker year and local (Mist) gas production adds another 1%, approximately 42% is left to be financially hedged. This is about the same as last year. Actual financial hedging targets are set by an executive level oversight committee within the company - the Gas Acquisition Strategy & Policies (GASP) Committee - and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

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

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

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

6. *Storage resources.*

NWN relies on four storage facilities and three supply-basin storage arrangements in Alberta to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at the Jackson Prairie underground facility in Washington state. The three Alberta supply-basin storage arrangements are with AECO Gas Storage Partnership (a subsidiary of Niska Partners and commonly referred to as Niska), and J. Aron & Company (a subsidiary of Goldman Sachs), and Tenaska Marketing Canada.

Storage provides the following benefits to customers:

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

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

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

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

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

Additional benefits attr butable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large "lumpy" resource additions requiring years of preparation, the "pre-build" of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development. The 300,000 therm/day Mist recall this year is a perfect example since it could be sized to replace a portion of the terminated Plymouth capacity, rather than having to equal the size of an entire Mist reservoir/expansion project.

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

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

IV General Information and Forecasting

CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

T-South Contract Economic Analysis - May 2015

(assumes no optimization value, i.e., capacity is used by NWN 100% year-round)

T-South Contract- [redacted]
Year-Round Scenario

	Closing Financial Prices-U.S. $/Dth, as of 5/08/2015					Station 2	Sumas	AECO	Rockies
		AECO	Sumas	Rockies	*Index Adder*				
30	Nov-15	2.5645	3.0470	2.947		[redacted]	[redacted]	[redacted]	[redacted]
31	Dec-15	2.6325	3.4225	3.15		[redacted]	[redacted]	[redacted]	[redacted]
31	Jan-16	2.7095	3.2720	3.247		[redacted]	[redacted]	[redacted]	[redacted]
29	Feb-16	2.6995	3.1295	3.217		[redacted]	[redacted]	[redacted]	[redacted]
31	Mar-16	2.6350	3.0150	3.1375		[redacted]	[redacted]	[redacted]	[redacted]
30	Apr-16	2.4845	2.6545	2 8195		[redacted]	[redacted]	[redacted]	[redacted]
31	May-16	2.4610	2.4835	2 8185		[redacted]	[redacted]	[redacted]	[redacted]
30	Jun-16	2.4815	2.5115	2.849		[redacted]	[redacted]	[redacted]	[redacted]
31	Jul-16	2.4830	2.6805	2.988		[redacted]	[redacted]	[redacted]	[redacted]
31	Aug-16	2.4805	2.6830	2.953		[redacted]	[redacted]	[redacted]	[redacted]
30	Sep-16	2.4850	2.7100	2 89		[redacted]	[redacted]	[redacted]	[redacted]
31	Oct-16	2.5875	2.8075	2.95		[redacted]	[redacted]	[redacted]	[redacted]
					Displaced Purchases	[redacted]	[redacted]	[redacted]	

	T-South volumetric costs				Commodity Spread				Station 2 Commodity Savings
	Variable ($/Dth)	Fuel (%)	Fuel ($/Dth)	Total ($/Dth)	Sumas ($/Dth)	Aeco ($/Dth)	Rockies ($/Dth)	Monthly Volume (Dth)	($)
Nov-15	$ 0.043	2.02%	$ [redacted]	$ [redacted]	$ [redacted]			[redacted]	$ 585,201
Dec-15	$ 0.043	2.10%	$ [redacted]	$ [redacted]	$ [redacted]			[redacted]	$ 887,557
Jan-16	$ 0.043	2.32%	$ [redacted]	$ [redacted]	$ [redacted]			[redacted]	$ 669,512
Feb-16	$ 0.043	2.07%	$ [redacted]	$ [redacted]	$ [redacted]			[redacted]	$ 516,583
Mar-16	$ 0.043	1.88%	$ [redacted]	$ [redacted]	$ [redacted]			[redacted]	$ 511,024
Apr-16	$ 0.043	1.82%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 324,395
May-16	$ 0.043	1.50%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 353,587
Jun-16	$ 0.043	1.63%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 346,063
Jul-16	$ 0.043	1.80%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 411,194
Aug-16	$ 0.043	1.52%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 399,681
Sep-16	$ 0.043	1.85%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 354,030
Oct-16	$ 0.043	1.97%	$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]	[redacted]	$ 345,844
									$ 5,704,671

	Alberta volumetric costs			
Apr-16	$ 0.006	0.9019%	$ [redacted]	$ [redacted]
May-16	$ 0.006	0.9973%	$ [redacted]	$ [redacted]
Jun-16	$ 0.006	1.1989%	$ [redacted]	$ [redacted]
Jul-16	$ 0.006	0.6048%	$ [redacted]	$ [redacted]
Aug-16	$ 0.006	0.4032%	$ [redacted]	$ [redacted]
Sep-16	$ 0.006	0.7958%	$ [redacted]	$ [redacted]
Oct-16	$ 0.006	1.1034%	$ [redacted]	$ [redacted]

	Demand Charge			
GJ/day	$ [redacted]	CAD	[redacted]	
Dth/day	$ [redacted]	Capacity	[redacted]	dth
Monthly	$ [redacted]			
Annual	$ [redacted]			

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2015/2016 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia				
Tenaska Marketing Canada	Nov-Oct	10,000		10/31/2016
PetroChina International	Nov-Oct	5,000		10/31/2016
Conoco Phillips	Nov-Oct	5,000		10/31/2016
EDF Trading	Nov-Mar	5,000		3/31/2016
Powerex	Nov-Mar	5,000		3/31/2016
Conoco Phillips	Nov-Mar	5,000		3/31/2016
J. Aron	Nov-Mar	5,000		3/31/2016
PetroChina International	Nov-Mar	2,500		3/31/2016
Alberta:				
Conoco Phillips	Nov-Mar	5,000		3/31/2016
Suncor Energy	Nov-Mar	5,000		3/31/2016
Cargill	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
Husky	Nov-Oct	5,000		10/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
Husky	Nov-Mar	5,000		3/31/2016
Shell Energy North America (Canada)	Nov-Mar	10,000		3/31/2016
Conoco Phillips	Nov-Mar	5,000		3/31/2016
Suncor Energy	Nov-Mar	5,000		3/31/2016
TD Energy Trading	Nov-Mar	5,000		3/31/2016
TD Energy Trading	Nov-Mar	5,000		3/31/2016
Pending	Nov-Mar		10,000	3/31/2016
Pending	Apr-Oct		10,000	10/31/2016
Rockies:				
Ultra Resources	Nov-Oct	10,000		10/31/2016
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
QEP Marketing Company	Nov-Oct	5,000		10/31/2016
Macquarie Energy	Nov-Oct	10,000		10/31/2016
Castleton Commodities	Nov-Mar	5,000		3/31/2016
BioUrja Trading	Nov-Mar	5,000		3/31/2016
Macquarie Energy	Nov-Oct	5,000		10/31/2016
Ultra Resources	Nov-Mar	10,000		3/31/2016
Pending	Nov-Mar		20,000	3/31/2016
Pending	Apr-Oct		20,000	10/31/2016
Macquarie Energy	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Oct	5,000		10/31/2016
Anadarko Energy Services	Nov-Oct	5,000		10/31/2016
Total, November-March		182,500	30,000	
Total, April-October		65,000	30,000	

Notes:

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

Table 2

NW Natural
Firm Transportation Capacity
for the 2015/2016 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2025
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2020
Occidental cap. acq. (#139153)	1,046	10/31/2024
Occidental cap. acq. (#139154)	4,000	3/31/2025
International Paper cap. acq. (#138065)	4,147	10/31/2024
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2016
Net NWP Capacity	331,237	
TransCanada - GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2016
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2016
1995 Rationalization	57,417	10/31/2016
Engage Capacity Acquisition	3,708	10/31/2016
2004 Capacity Acquisition	48,669	10/31/2016
Total Foothills Capacity	157,521	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2020
1995 Rationalization	57,909	10/31/2020
Engage Capacity Acquisition	3,739	10/31/2020
2004 Capacity Acquisition	49,138	10/31/2020
Total NOVA Capacity	158,921	
T-South Capacity (through Tenaska)	30,000	10/31/2016
Southern Crossing Pipeline	48,000	10/31/2020

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contract, which is through a 1-year contract with Tenaska.
2. The Southern Crossing contract is denominated in volumetric units, hence the Dth units shown are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
4. The 10/31/2024 termination dates for the NWP contract #100005, #138065 and #139153 will revert to 10/31/2020 if the MOU mentioned in section IV.2.b is not accepted.

Table 3

NW Natural
Firm Storage Resources
for the 2015/2016 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-year notice
TF-2 (primary firm portion)	23,038	839,046	Upon 1-year notice
TF-2 (primary firm portion)	9,467	281,242	Upon 1-year notice
TF-1 (per MOU)	*13,525*		*10/31/2023*
Firm On-System Storage Plants:			
Mist (reserved for core)	305,000	10,644,758	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	900,000	n/a
Total On-System Storage	485,000	12,144,758	
Total Firm Storage Resource	531,030	13,265,046	

Notes:

1. The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.
2. The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.
3. On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full..
4. Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan, including a "recall" of 30,000 Dth/day of deliverability (with associated working gas) effective 5/1/2015. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate/Intrastate storage customers.
5. The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1010 Btu/cf. The current heat content used for both Newport and Portland LNG is 1000 Btu/cf, but that is under review and likely to be increased for both plants, though not by an amount that would create a material impact on the annual PGA.
6. Newport tank capacity de-rated from 1,000,000 Dth pending CO2 removal project.
7. The Company's Plymouth-related contracts terminate on October 31, 2015, so they are no longer reflected in this table.
8. NW Natural has supply-basin storage contracts in Alberta that are NOT included in this table to avoid double-counting resources because their deliverability relies on portions of the same upstream pipeline capacity already included in Table 2. These contracts are with:
   AECO Gas Storage Partnership (Niska) - 1,895,634 Dth
   J. Aron & Company - 1,530,000 Dth
   Tenaska Marketing Canada - 947,817 Dth

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2015/2016 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2016
International Paper	8,000	40	Upon 1-year notice
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
Shell Energy North America (US)	20,000	5	3/31/2016
Mist Production:			
Enerfin Resources	≈2,000	n/a	Life of the wells

Notes:
1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.
2. Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.

Table 5

NW Natural
Peak Day Resource Summary
for the 2015/2016 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	331,237
Off-System Storage (Jackson Prairie only - No Plymouth)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	485,000
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	20,000
Nominal Mist Production Gas	2,000
Segmented Capacity (not primary firm)	43,800
Total Peak Day Resources - excluding segmented capacity	923,267

NW Natural

PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

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

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

	2014/2015
Forecast Annual Demand (therms)	747,790,904
Forecast Peak Demand (therms) - Normal	4,249,592
Forecast Peak Demand (therms) - Design	9,452,960
Forecast DSM Annual (therms)	0
Forecast DSM Peak (therms) - Design Peak	0
Forecast Annual Demand with Forecast DSM	747,790,904
Forecast Peak Demand with Forecast DSM - Normal	4,249,592
Forecast Peak Demand with Forecast DSM - Design	9,452,960

NOTE: As of this filing date, the DSM data was not available from the Energy Trust.

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

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

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

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
9	Summary of portfolio documentation provided

See Index to this Worksheet.

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, Docket UM 1286

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

See V.1.a, Page 1 through 4

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Northwest Natural Gas Company

PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2015 - October 31, 2016
Physical Natural Gas term contracts

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

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location
QEP Marketing Company (NGR's)	11/1/2015	10/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Anadarko Energy Service Company (NGR's)	11/1/2015	10/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Macquarie Energy, LLC (NGR's)	11/1/2015	10/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal
berdrola Energy Services, LLC (NGR's)	11/1/2015	10/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal
Ultra Resources, Inc. (1)	11/1/2015	10/31/2016	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal
Shell Energy North America (US), LP (2)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Iberdrola Energy Services, LLC (2)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Macquarie Energy, LLC (3)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal
Castleton Commodities Merchant Trading, LP (4	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
BioUrja Trading, LLC (4)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Macquarie Energy, LLC (4)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Ultra Resources, Inc. (5)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal
PENDING Winter Call	**11/1/2015**	**3/31/2016**				**up to 20,000**			

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Opal	4	[redacted]	Price
(2) Rocky Mountain Pool	4		Price
(3) Opal	6		Price
(4) Rocky Mountain Pool	5		Price
(5) Opal	3		Price

(NGR's) These purchases are tied to the expected production volumes of the Natural Gas Reserves Deal.

Northwest Natural Gas Company

PGA Filing Guidelines

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November 1, 2015 - October 31, 2016
Physical Natural Gas term contracts

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Approved Counterparties all have executed NAESB contracts with NW Natural

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	
EDF Trading North America, LLC (1)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				
Powerex Corp. (1)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				
ConocoPhillips Canada Marketing & Trading, LLC (2)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				
Petro China International (Canada) Trading, Ltd. (3)	11/1/2015	3/31/2016	[redacted]	IFGMR-NWP Canadian Border FOM	2,500				
Shell Energy North America (US), LP (4)	12/1/2015	2/29/2016	[redacted]	Gas Daily - Canadian Border (Sumas)		20,000	$ 0.02	5 days call max	NWP Mainline Citygate (Deer Island, Portland West)

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	4	[redacted]	Price & Supplier
(2)	4	[redacted]	Price
(3)	4	[redacted]	Price
(4) Citygate	1		Price & Supplier

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Northwest Natural Gas Company

PGA Filing Guidelines

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November 1, 2015 - October 31, 2016
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's
Tenaska Marketing Canada (1)	11/1/2015	10/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000
J. Aron & Company (2)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000
PetroChina International (Canada) Trading, Ltd. (3)	11/1/2015	10/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000
ConocoPhillips Canada Marketing & Trading LLC (4)	11/1/2015	10/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	1	[redacted]	Price
(2)	5	[redacted]	Price

Northwest Natural Gas Company

PGA Filing Guidelines

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November 1, 2015 - October 31, 2016
Physical Natural Gas term contracts

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

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Contractual Conditions
ConocoPhillips Canada Marketing (1)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Suncor Energy Marketing (1)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Iberdrola Energy Services (2)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Cargill Ltd (2)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Husky Oil Operations Ltd. (3)	11/1/2015	10/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Husky Oil Operations Ltd. (3)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Iberdrola Energy Services (4)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Shell Energy North America (Canada) Inc. (5)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
ConocoPhillips Canada Marketing (6)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Suncor Energy Marketing (6)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
TD Energy Trading (7)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
TD Energy Trading (8)	11/1/2015	3/31/2016	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
PENDING Winter Call	**11/1/2015**	**3/31/2016**				**up to 10,000**	
PENDING Summer Put	**4/1/2016**	**10/31/2016**				**up to 10,000**	

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	5	[redacted]	Price
(2)	4	[redacted]	Price
(3)	5	[redacted]	Price & Supplier
(4)	6	[redacted]	Price
(5)	5	[redacted]	Price
(6)	4	[redacted]	Price
(7)	3	[redacted]	Price
(8)	4	[redacted]	Price

NW Natural

PGA Portfolio Guidelines
2015-2016 Oregon PGA

V.1 b) Physical Gas Supply

For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

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

1. The purchasing of baseload and spot supplies for the 2015-2016 PGA follows the Gas Acquisition Plan as prepared by the Gas Supply department and overseen by the company's Gas Acquisition Strategy and Policies (GASP) Committee. GASP members include the company's CEO, CFO and other senior company management.

2. In our gas purchasing for 2015-2016, we target diversity of supply on a regional basis and among approved counterparties, as listed in the company's Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while maintaining a diversity of suppliers and avoiding over-reliance on any one trading point or counterparty.

3. Diversity of contracts in the portfolio is determined by the forecasted usage of NW Natural customers.

a. One year and greater baseload (take or pay) contract volumes are meant to meet low end of sales requirements while avoiding the potential for excess supply that might have to be sold at a loss when sales volumes are low. Pricing is comparable to shorter term contracts and the administrative needs are a bit simpler.

b. November – March winter term contracts are aligned to meet the forecasted seasonal increase during the heating season and are divided between baseload and winter call option ("swing") contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.

c. April – October summer put option contracts are tied to winter call option contracts to capture a discounted monthly index price and avoid payment of a reservation fee. The volume of the put option contracts is kept to a minimum to avoid over supply during the summer months when added to year-round term volumes.

d. Spot purchases are used to fill in requirements on a very short-term basis, from one day up to one month, throughout the PGA year. One month spot purchases are negotiated to capture the best monthly index pricing using either the publication *Inside FERC's Gas Market Report* for Rockies and Sumas purchases, or the publication *Canadian Gas Price Reporter* for Canadian purchases in Alberta. Daily spot purchasing utilizes either a daily index (in the case of Rocky Mountain or Sumas supply as published in *Gas Daily*) or a fixed price in U.S. dollars as negotiated directly with the suppliers. The electronic trading platform Intercontinental Exchange (ICE) provides real-time pricing for Rocky Mountain, Sumas, Station 2 and Alberta supplies as a reference tool for such price negotiations.

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

None for the vast bulk of the company's purchases made in the Rockies and western Canada.

There is a small percentage (approximately 1%) of the company's purchases sourced from the Mist field, i.e., native gas that continues to be locally produced there. These purchases do not rely on a NAESB contract but instead on a custom-written contract that dates back to 1995. As an example, gas quality and measurement is a relatively simple matter in the NAESB contract because the gas needs to conform to the tariff provisions of one or more applicable interstate pipelines, but it requires a lot more attention for Mist production gas because there are no transporting interstate pipelines over which the gas is delivered to the company.

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2015-2016 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	2015-16 Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT	Including Multi-Year	
11-Dec-12	2012-76	[redacted]	[redacted]	AECO	Nov-Feb (2013-2016)	121	2,500	302,500	[redacted]	[redacted]	302,500	$1,175,817.50
12-Dec-12	2012-77	[redacted]	[redacted]	AECO	Nov-Feb (2013-2016)	121	2,500	302,500	[redacted]	[redacted]	302,500	$1,161,600.00
4-Jun-13	2013-33	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,635,520.00
14-Jun-13	2013-36	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,561,800.00
21-Jun-13	2013-39	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,414,550.00
5-Jul-13	2013-45	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,362,300.00
26-Jul-13	2013-57	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,372,750.00
29-Jul-13	2013-58	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,349,950.00
2-Aug-13	2013-62	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,472,500.00
23-Aug-13	2013-68	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,372,940.00
30-Aug-13	2013-73	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,528,360.00
6-Sep-13	2013-77	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,364,200.00
20-Sep-13	2013-81	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,400,300.00
25-Sep-13	2013-82	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,483,140.00
8-Aug-14	2014-43	[redacted]	[redacted]	AECO	Nov-Mar (2014-2017)	152	2,500	380,000	[redacted]	[redacted]	757,500	$2,912,587.50
15-Aug-14	2014-45	[redacted]	[redacted]	AECO	Nov-Mar (2014-2017)	152	2,500	380,000	[redacted]	[redacted]	757,500	$2,842,518.75
25-Nov-14	2014-70	[redacted]	[redacted]	Sumas	Nov-Mar	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,535,770.00
25-Nov-14	2014-71	[redacted]	[redacted]	Sumas	Nov-Mar	152	2,500	380,000	[redacted]	[redacted]	380,000	$1,547,550.00
21-Jan-15	2015-1	[redacted]	[redacted]	Sumas	Nov-Mar	152	5,000	760,000	[redacted]	[redacted]	760,000	$2,452,900.00
21-Jan-15	**2015-2**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$798,250.00**
21-Jan-15	**2015-3**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**5,000**	**150,000**	[redacted]	[redacted]	**150,000**	**$377,250.00**
5-Feb-15	2015-4	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,575,490.00
12-Mar-15	2015-5	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,931,265.00
19-Mar-15	**2015-6**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$712,200.00**
26-Mar-15	2015-7	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,805,087.50
27-Mar-15	**2015-8**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$704,250.00**
30-Mar-15	**2015-9**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$745,550.00**
30-Mar-15	**2015-10**	[redacted]	[redacted]	**AECO**	**Nov**	**30**	**2,500**	**75,000**	[redacted]	[redacted]	**75,000**	**$174,937.50**
8-Apr-15	2015-11	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,885,790.00
10-Apr-15	2015-12	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,023,640.00
14-Apr-15	2015-13	[redacted]	[redacted]	AECO	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	2,270,000	$5,391,250.00
15-Apr-15	**2015-14**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$733,925.00**
20-Apr-15	2015-15	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,759,687.50
24-Apr-15	**2015-16**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$690,900.00**
27-Apr-15	**2015-17**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$687,000.00**
30-Apr-15	**2015-18**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$775,775.00**
30-Apr-15	2015-19	[redacted]	[redacted]	Rockies	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,708,612.50
7-May-15	2015-20	[redacted]	[redacted]	Rockies	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,390,580.00
7-May-15	2015-20	[redacted]	[redacted]	Rockies	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,390,580.00
7-May-15	2015-21	[redacted]	[redacted]	Rockies	Nov-Jan	92	10,000	920,000	[redacted]	[redacted]	920,000	$2,765,520.00
22-May-15	2015-22	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,912,345.00
22-May-15	2015-23	[redacted]	[redacted]	Rockies	Oct	31	10,000	310,000	[redacted]	[redacted]	310,000	$914,190.00
27-May-15	2015-24	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,081,525.00
27-May-15	**2015-25**	[redacted]	[redacted]	**AECO**	**Apr-May**	**61**	**10,000**	**610,000**	[redacted]	[redacted]	610,000	$1,453,325.00
28-May-15	**2015-26**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**5,000**	**150,000**	[redacted]	[redacted]	150,000	$350,250.00
29-May-15	2015-27	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$2,991,860.00

HIGHLY CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

4-Jun-15	2015-28	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$2,955,540.00
5-Jun-15	2015-29	[redacted]	[redacted]	AECO	Nov-Mar	152	5,000	760,000	[redacted]	[redacted]	760,000	$1,776,120.00
22-Jun-15	2015-30	[redacted]	[redacted]	AECO	Nov-Mar	152	5,000	760,000	[redacted]	[redacted]	760,000	$1,861,240.00
24-Jun-15	2015-31	[redacted]	[redacted]	AECO	Oct	31	10,000	310,000	[redacted]	[redacted]	310,000	$757,950.00
25-Jun-15	2015-32	[redacted]	[redacted]	AECO	Nov-Mar	152	5,000	760,000	[redacted]	[redacted]	760,000	$1,887,840.00
30-Jun-15	2015-33	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	152	2,500	380,000	[redacted]	[redacted]	1,135,000	$3,020,802.50
30-Jun-15	2015-34	[redacted]	[redacted]	AECO	Apr-May	61	5,000	305,000	[redacted]	[redacted]	305,000	$696,620.00
7-Jul-15	2015-35	[redacted]	[redacted]	AECO	Apr-May	61	5,000	305,000	[redacted]	[redacted]	305,000	$681,675.00
22-Jul-15	2015-36	[redacted]	[redacted]	AECO	Sep	30	10,000	300,000	[redacted]	[redacted]	300,000	$706,500.00
24-Jul-15	2015-37	[redacted]	[redacted]	AECO	Jun	30	10,000	300,000	[redacted]	[redacted]	300,000	$676,800.00
29-Jul-15	2015-38	[redacted]	[redacted]	AECO	Nov	30	10,000	300,000	[redacted]	[redacted]	300,000	$717,000.00
31-Jul-15	2015-39	[redacted]	[redacted]	AECO	Apr	30	7,500	225,000	[redacted]	[redacted]	225,000	$507,825.00
13-Aug-15	2015-40	[redacted]	[redacted]	AECO	Nov	30	7,500	225,000	[redacted]	[redacted]	225,000	$535,050.00
14-Aug-15	15-MM-5	[redacted]	[redacted]	Rockies	Nov-Dec	61	5,000	305,000	[redacted]	[redacted]	305,000	$885,720.00
18-Aug-15	15-MM-8	[redacted]	[redacted]	Rockies	Nov-Dec	61	5,000	305,000	[redacted]	[redacted]	305,000	$860,252.50
24-Aug-15	15-MM-10	[redacted]	[redacted]	Rockies	Nov-Dec	61	5,000	305,000	[redacted]	[redacted]	305,000	$828,075.00
28-Aug-15	15-MM-16	[redacted]	[redacted]	AECO	May	31	2,500	77,500	[redacted]	[redacted]	77,500	$170,112.50
31-Aug-15	15-MM-17	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	[redacted]	155,000	$354,020.00
2-Sep-15	15-MM-18	[redacted]	[redacted]	AECO	Nov	30	5,000	150,000	[redacted]	[redacted]	150,000	$337,500.00
Total Hard Hedges								25,957,500	[redacted]	[redacted]	35,317,500	$103,894,731.25

CONFIDENTIAL

2014-2015 FINANCIAL SOFT HEDGES (counterparty owns option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Total Trade Volume	Amount OTM	NOTIONAL AMOUNT	CALL STRIKE PRICE
Total Soft Hedges								0	[redacted]	[redacted]	
Total Hard and Soft Hedges								[redacted]	[redacted]	[redacted]	
Total Spot (This must match Gas Acq Plan WACOG Tab) (MANUAL FORMULAS -- SUM OF SPOT)								[redacted]		[redacted]	
Total Baseload Hedges								[redacted]		[redacted]	[redacted]
Total Baseload Hedges including Index Adjustments										[redacted]	

Hedges by Counterparty:	Approved for Multi-Year Hedges	Hedges for Nov 2015 - Oct 2016			All Hedges Nov15 Forward		NOTIONAL RANK *
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7
[redacted]			[redacted]				
[redacted]			[redacted]				
[redacted]			[redacted]				
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10
[redacted]			[redacted]				
[redacted]			[redacted]				
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
[redacted]			[redacted]				
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
[redacted]							10
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
		0	[redacted]	$0.00	0	$0.00	

Yellow denotes active counterparties (not on credit hold, ISDAs in place)

*Notional Rank is used for risk diversity. When counterparties tie for the lowest offer, the deal goes to the counterparty with the lowest notional value shown here.
Notional values include hedges in place from the beginning of the prompt tracker year forward.

NW Natural

UM 1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

	Customer Cnt Jul-14	Revenue Jul-14	Customer Cnt Aug-14	Revenue Aug-14	Customer Cnt Sep-14	Revenue Sep-14
Total	**696,677**	$ 29,398,717.56	**695,902**	$ 26,382,229.04	**696,172**	$ 27,226,396.58
Oregon	622,708	26,455,756.11	621,872	23,839,563.47	622,053	24,593,632.76
Washington	73,969	2,942,961.45	74,030	2,542,665.57	74,119	2,632,763.82
Total Residential	630,262	14,884,815.81	629,627	13,113,856.94	629,968	13,422,344.10
Total Commercial	65,427	9,250,068.64	65,290	8,188,775.63	65,215	8,479,500.25
Total Industrial	585	1,787,699.74	583	1,736,778.93	586	1,897,327.51
Total Interruptible	147	2,199,987.83	146	2,056,346.47	147	2,119,431.70
Total Transportation - Commercial Firm	47	82,850.13	47	82,088.47	47	84,106.55
Total Transportation - Industrial Firm	110	588,294.91	110	581,320.29	110	596,020.85
Total Transportation - Interruptible	99	605,000.50	99	623,062.31	99	627,665.62
Unbilled Revenue		(3,329,329.50)		515,356.64		687,614.47
Agency Fees						
Net Balancing/Overrun		47.00		11.00		-
Total Gas Operating Revenue		**$ 26,069,435.06**		**$ 26,897,596.68**		**$ 27,914,011.05**

NW Natural

UM 1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

	Customer Cnt Oct-14	Revenue Oct-14	Customer Cnt Nov-14	Revenue Nov-14	Customer Cnt Dec-14	Revenue Dec-14
Total	**697,704**	$ 30,954,625.86	**700,842**	$ 58,623,155.35	**704,644**	$ 105,202,223.27
Oregon	623,406	28,000,155.58	626,236	53,049,915.37	629,634	94,522,707.95
Washington	74,298	2,954,470.28	74,606	5,573,239.98	75,010	10,679,515.32
Total Residential	631,412	15,529,790.70	634,171	34,821,997.83	637,411	65,918,724.88
Total Commercial	65,302	9,619,957.54	65,647	16,874,598.89	66,204	31,853,411.90
Total Industrial	587	1,969,279.70	572	2,169,716.51	571	2,559,990.07
Total Interruptible	147	2,464,525.77	140	3,202,860.81	142	3,299,447.23
Total Transportation - Commercial Firm	47	93,504.44	98	208,433.22	100	221,633.07
Total Transportation - Industrial Firm	110	625,983.20	114	688,930.16	116	698,315.76
Total Transportation - Interruptible	99	651,584.51	100	656,617.93	100	650,700.36
Unbilled Revenue		9,673,361.67		35,692,017.79		(1,521,265.73)
Agency Fees						
Net Balancing/Overrun		-		-		8,741.00
Total Gas Operating Revenue		**$ 40,627,987.53**		**$ 94,315,173.14**		**$ 103,689,698.54**

NW Natural

UM 1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

	Customer Cnt Jan-15	Revenue Jan-15	Customer Cnt Feb-15	Revenue Feb-15	Customer Cnt Mar-15	Revenue Mar-15
Total	**706,102**	$ 117,162,074.27	**706,861**	$ 90,251,116.31	**707,472**	$ 76,780,740.34
Oregon	630,888	105,551,630.06	631,556	81,437,220.44	632,054	69,623,635.26
Washington	75,214	11,610,444.21	75,305	8,813,895.87	75,418	7,157,105.08
Total Residential	638,876	73,883,919.15	639,599	56,217,286.96	640,235	46,825,624.40
Total Commercial	66,201	35,705,737.58	66,238	27,231,038.42	66,214	23,139,322.56
Total Industrial	569	2,617,771.65	569	2,336,831.96	566	2,174,843.82
Total Interruptible	140	3,375,959.37	140	3,006,653.94	141	3,170,700.55
Total Transportation - Commercial Firm	100	218,530.70	100	185,898.47	100	179,269.85
Total Transportation - Industrial Firm	116	707,041.28	116	657,370.35	117	665,725.81
Total Transportation - Interruptible	100	653,114.54	99	616,036.21	99	625,253.35
Unbilled Revenue		(10,489,606.82)		(10,589,225.94)		(5,848,278.05)
Agency Fees						
Net Balancing/Overrun		-		740.00		-
Total Gas Operating Revenue		**$ 106,672,467.45**		**$ 79,662,630.37**		**$ 70,932,462.29**

NW Natural

UM 1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

	Customer Cnt Apr-15	Revenue Apr-15	Customer Cnt May-15	Revenue May-15	Customer Cnt Jun-15	Revenue Jun-15
Total	**707,588**	$ 64,400,212.73	**707,756**	$ 50,601,306.40	**707,539**	$ 27,051,350.57
Oregon	632,066	58,455,750.11	632,138	45,950,660.52	631,843	23,631,958.97
Washington	75,522	5,944,462.62	75,618	4,650,645.88	75,696	3,419,391.60
Total Residential	640,437	38,615,876.12	640,682	28,423,380.34	640,581	13,456,039.28
Total Commercial	66,128	19,378,974.78	66,052	16,401,503.00	65,936	9,447,223.00
Total Industrial	568	2,083,642.68	569	1,901,518.23	568	1,291,303.59
Total Interruptible	140	2,853,434.90	138	2,461,717.82	137	1,511,086.37
Total Transportation - Commercial Firm	100	174,386.39	100	143,178.62	100	121,996.57
Total Transportation - Industrial Firm	116	664,426.38	116	640,710.14	117	603,901.45
Total Transportation - Interruptible	99	629,471.48	99	629,298.25	100	619,800.31
Unbilled Revenue		(3,703,323.34)		(8,033,521.38)		(5,133,463.18)
Agency Fees						
Net Balancing/Overrun		189.00		-		3,089.00
Total Gas Operating Revenue		**$ 60,697,078.39**		**$ 42,567,785.02**		**$ 21,920,976.39**

NW Natural

UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

	2015/2016 Forecasted	2014/2015	2013/2014	2012/2013	2011/2012	2010/2011
System peak demand (therms)	**9,452,960**	9,369,764	9,320,242	9,252,236	9,424,400	9,450,100

NW Natural

UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

Gas Year	**Forecasted 2015/2016**	**2014/2015**	**2013/2014**	**2012/2013**	**2011/2012**	**2010/2011**
Annual Demand (therms)	757,005,313	747,790,904	746,847,556	732,272,081	759,952,952	764,740,025

NW Natural

UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

V.3.d.

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

1. Annual for each customer class

Gas Year	**Forecasted 2015/2016**	**2014/2015**	**2013/2014**	**2012/2013**	**2011/2012**	**2010/2011**
Residential (therms)	413,822,757	340,361,989	416,389,181	385,909,967	412,646,882	417,058,269
Commercial (therms)	251,595,828	216,426,531	254,877,091	237,490,341	251,126,608	252,595,462
Industrial Firm (therms)	32,420,945	32,273,813	34,838,443	33,521,314	36,591,001	37,507,291
Industrial Interruptible (therms)	59,165,782	58,789,923	62,513,367	58,152,459	59,495,487	59,897,024

Updated for actuals

NW Natural

UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

2. Annual and monthly base load

Gas Year	Forecasted 2015-2016	2014/2015	2013/2014	2012/2013	2011/2012	2010/2011
November	22,351,644	22,999,936	22,397,233	22,308,001	22,343,188	22,177,486
December	22,916,079	24,282,715	23,202,872	23,064,485	23,284,414	23,034,172
January	22,938,449	24,362,006	23,196,614	23,081,208	23,283,122	23,064,136
February	21,874,421	22,159,174	20,943,260	20,859,821	21,819,517	20,779,477
March	22,968,882	23,866,828	23,202,391	23,109,951	23,298,952	23,041,150
April	22,440,684	22,869,798	22,513,500	22,379,225	22,514,758	22,275,981
May	22,997,543	23,238,337	23,254,362	23,138,668	23,251,908	22,972,378
June	22,470,443	22,332,108	22,556,453	22,399,655	22,449,749	22,181,087
July	23,023,353	23,019,887	23,314,587	23,152,520	22,784,459	23,022,789
August	23,050,124	23,015,123	23,324,427	23,162,291	23,007,978	23,030,526
September	22,527,362	22,737,568	22,537,805	22,425,676	22,273,329	22,193,140
October	23,100,640	23,881,459	23,359,078	23,196,701	23,035,735	23,025,826
Annual	272,659,625	278,764,939	273,802,581	272,278,201	273,347,109	270,798,148

NW Natural

UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

3. Annual and monthly non-base load

Gas Year	Forecasted 2015/2016	2014/2015	2013/2014	2012/2013	2011/2012	2010/2011
November	64,242,976	62,486,370	62,248,709	61,226,239	40,491,499	33,153,463
December	98,795,855	96,475,524	95,405,022	90,481,345	86,534,833	81,321,773
January	92,054,676	90,486,111	91,382,451	86,593,507	97,758,992	97,632,484
February	74,851,835	71,804,677	72,204,387	69,575,367	78,530,912	76,125,402
March	59,855,292	58,202,117	58,522,284	56,408,082	74,169,045	79,134,329
April	40,203,184	38,491,513	38,745,792	37,886,663	54,489,168	55,063,637
May	18,600,362	17,127,632	17,039,845	15,982,505	25,616,766	37,973,515
June	4,336,063	3,488,689	4,181,989	3,799,251	13,742,491	18,528,871
July	304,475	25,201	707,612	393,204	4,443,994	3,792,900
August	0	-	769,863	358,541	569,565	456,282
September	2,211,685	2,291,298	3,220,573	1,673,213	1,867,959	1,657,358
October	28,889,285	28,146,833	28,616,445	27,584,476	27,756,549	9,101,863
Annual	484,345,688	469,025,965	473,044,975	451,962,394	505,971,773	493,941,877

NW Natural
UM1286 PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

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

2015/2016	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,347,447.94	1,336,533.22	1,088,921.16	7,164,671.24	1,118,833.49	50,956,161.19	12,186,963.44	8,395,088.45
December	7,836,295.92	1,787,428.92	1,382,993.52	8,547,507.08	1,405,199.94	73,884,493.47	15,316,960.57	12,092,795.13
January	6,474,390.15	1,561,885.71	1,345,623.14	8,709,150.27	1,105,837.67	68,745,424.15	16,852,994.94	11,388,849.00
February	5,364,568.02	1,336,887.75	1,158,687.47	6,376,727.01	900,165.14	57,916,842.34	12,772,899.18	9,275,407.22
March	4,291,632.11	1,190,965.36	1,116,232.37	5,739,005.38	831,872.61	49,956,558.20	12,016,131.58	7,979,262.76
April	3,717,424.97	1,033,248.34	772,305.42	4,973,590.38	767,476.88	35,685,468.75	9,352,805.79	5,919,184.33
May	2,617,201.38	705,999.75	561,020.08	3,595,245.26	535,960.95	22,826,264.71	6,278,363.99	3,894,061.68
June	1,617,716.07	497,850.60	399,828.36	2,562,756.50	439,672.99	14,173,296.80	4,038,734.73	2,445,042.68
July	1,488,650.31	495,881.90	383,491.48	2,075,021.78	490,694.73	12,492,961.79	3,813,083.42	2,007,406.44
August	1,479,219.93	479,254.36	384,282.11	2,049,536.76	472,835.77	12,526,063.49	3,810,438.47	1,993,209.49
September	1,592,096.66	564,981.94	390,221.02	2,288,161.22	532,175.03	13,374,514.73	4,252,164.30	2,313,953.24
October	3,069,884.99	918,372.72	644,530.95	4,194,629.11	753,884.61	29,648,628.37	8,380,428.68	5,081,146.29
Annual	43,896,528	11,909,291	9,628,137	58,276,002	9,354,610	442,186,678	109,071,969	72,785,407

2014/2015	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,296,002	1,320,717	1,076,035	7,079,887	1,105,594	50,353,163	12,042,747	8,212,161
December	7,743,564	1,766,277	1,366,628	8,446,359	1,388,571	73,010,169	15,135,705	11,900,966
January	6,397,774	1,543,403	1,329,699	8,606,089	1,092,752	67,931,914	16,653,562	11,292,923
February	5,301,086	1,321,067	1,144,976	6,301,267	889,513	57,231,474	12,621,749	9,152,719
March	4,240,846	1,176,872	1,103,023	5,671,092	822,029	49,365,389	11,873,937	7,815,757
April	3,673,434	1,021,021	763,166	4,914,735	758,395	35,263,179	9,242,128	5,725,253
May	2,586,230	697,645	554,381	3,552,700	529,619	22,556,146	6,204,068	3,685,179
June	1,598,573	491,959	395,097	2,532,430	434,470	14,005,575	3,990,942	2,371,752
July	1,471,034	490,014	378,953	2,050,467	484,888	12,345,124	3,767,961	2,056,647
August	1,461,715	473,583	379,735	2,025,283	467,240	12,377,834	3,765,347	2,064,385
September	1,573,256	558,296	385,603	2,261,084	525,877	13,216,245	4,201,846	2,306,658
October	3,033,557	907,505	636,904	4,144,991	744,963	29,297,777	8,281,258	4,981,337
Annual	43,377,072	11,768,360	9,514,201	57,586,384	9,243,911	436,953,991	107,781,248	71,565,737

2013/2014	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3,004,316	923,615	752,502	4,951,166	773,173	35,213,397	8,421,835	5,303,793
December	7,773,336	1,773,068	1,371,882	8,478,833	1,393,910	73,290,876	15,193,898	11,654,376
January	7,314,992	1,764,673	1,520,332	9,839,902	1,249,414	77,670,980	19,041,102	12,893,003
February	6,676,619	1,663,860	1,442,076	7,936,329	1,120,325	72,081,981	15,896,859	11,761,142
March	4,458,858	1,237,372	1,159,727	5,962,629	864,287	51,903,144	12,484,347	8,469,900
April	3,776,291	1,049,610	784,535	5,052,348	779,630	36,250,554	9,500,909	5,960,021
May	2,855,731	770,344	612,151	3,922,913	584,808	24,906,632	6,850,569	4,016,235
June	1,904,412	586,081	470,687	3,016,935	517,593	16,685,126	4,754,490	2,725,858
July	1,529,333	509,434	393,972	2,131,730	504,105	12,834,379	3,917,290	2,201,958
August	1,527,740	494,974	396,887	2,116,763	488,345	12,936,929	3,935,424	2,197,227
September	1,614,086	572,785	395,611	2,319,765	539,525	13,559,242	4,310,895	2,446,469
October	3,024,425	904,773	634,987	4,132,514	742,721	29,209,583	8,256,329	5,070,191
Annual	45,460,140	12,250,590	9,935,348	59,861,827	9,557,836	456,542,823	112,563,947	74,700,173

2012/2013	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3,980,097	983,796	694,036	4,029,196	790,299	32,332,665	7,420,633	5,068,731
December	5,425,390	1,368,991	1,023,998	6,374,613	1,082,073	55,049,568	11,982,401	8,655,000
January	7,623,154	1,794,161	1,547,874	8,535,059	1,485,395	80,560,285	17,009,938	12,874,734
February	6,143,084	1,592,883	1,247,819	7,750,244	1,059,617	63,211,648	15,987,682	10,413,124
March	4,823,792	1,349,940	1,002,932	6,319,169	1,035,028	49,517,478	12,577,871	8,201,439
April	3,629,993	1,071,117	855,673	4,976,097	843,776	36,067,438	9,392,593	5,920,050
May	1,857,990	805,939	560,211	3,370,006	579,423	23,346,350	6,872,771	4,031,753
June	2,560,019	697,834	508,908	3,181,901	611,895	19,329,442	5,292,184	3,189,278
July	1,219,385	541,620	412,307	2,382,000	534,531	13,262,177	3,717,540	2,323,146
August	1,512,651	455,146	385,474	2,083,420	455,522	12,633,978	3,864,820	2,129,820
September	1,559,715	520,752	406,860	2,226,461	495,474	12,409,027	4,099,341	2,381,260
October	2,992,666	845,202	684,478	4,068,548	660,832	28,585,041	8,058,735	4,885,676
Annual	43,327,935	12,027,380	9,330,571	55,296,713	9,633,865	426,305,098	106,276,509	70,074,010

2011/2012	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,032,300	1,043,485	694,789	4,335,771	819,203	38,101,060	7,961,438	5,846,641
December	6,826,726	1,609,168	1,173,478	7,127,402	1,197,923	66,714,075	14,466,075	10,704,400
January	7,244,894	1,749,261	1,427,007	8,180,957	1,317,644	72,265,506	17,064,895	11,791,950
February	5,768,697	1,453,877	1,229,563	7,089,548	1,027,839	59,425,230	14,407,850	9,947,825
March	5,941,986	1,529,200	1,162,827	7,098,060	1,140,416	57,459,593	13,777,217	9,358,698
April	4,855,992	1,215,344	882,146	5,831,247	933,197	43,907,494	12,128,901	7,249,605
May	2,981,769	929,068	591,413	4,227,761	706,099	27,357,160	7,606,195	4,469,209
June	2,268,518	695,422	478,994	3,382,472	604,564	20,004,273	5,474,400	3,283,597
July	1,749,433	592,175	487,817	2,689,960	503,152	14,464,650	4,229,684	2,511,582
August	1,519,580	456,248	387,755	2,079,852	454,293	12,679,160	3,878,432	2,122,223
September	1,565,359	522,071	409,063	2,220,195	494,284	12,463,199	4,103,146	2,363,972
October	3,009,207	848,974	689,977	4,060,120	660,920	28,609,400	8,061,371	4,852,315
Annual	47,764,461	12,644,293	9,614,828	58,323,345	9,859,534	453,450,800	113,159,604	74,502,017

2010/2011	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3,457,654	956,469	690,565	4,157,224	702,364	32,625,567	7,655,176	5,085,930
December	6,206,851	1,555,645	1,192,475	6,621,319	1,211,342	64,006,649	13,394,071	10,167,593
January	6,938,995	1,767,004	1,473,980	7,641,086	1,283,562	73,368,900	16,245,941	11,977,152
February	5,524,303	1,441,394	1,101,653	6,325,956	1,023,155	58,990,655	12,959,886	9,537,877
March	5,626,311	1,584,417	1,122,046	6,717,675	1,122,964	61,645,159	14,252,465	10,104,442
April	4,421,411	1,248,356	892,877	5,204,951	964,103	45,612,072	11,324,134	7,671,714
May	3,629,256	1,058,840	704,922	4,515,425	806,518	34,854,739	9,298,238	6,077,955
June	2,301,553	730,766	486,742	3,396,094	594,258	22,960,838	6,398,509	3,841,198
July	1,770,424	592,333	399,425	2,323,979	502,209	14,417,184	4,261,741	2,548,394
August	1,579,277	511,889	371,098	2,195,527	497,320	12,454,469	3,714,731	2,162,497
September	1,593,461	470,109	376,434	2,211,756	544,272	12,471,427	3,973,400	2,209,639
October	2,257,067	615,666	474,390	2,599,456	527,724	17,891,415	4,849,366	2,912,605
Annual	45,306,563	12,532,888	9,286,607	53,910,448	9,779,791	451,299,074	108,327,658	74,296,996

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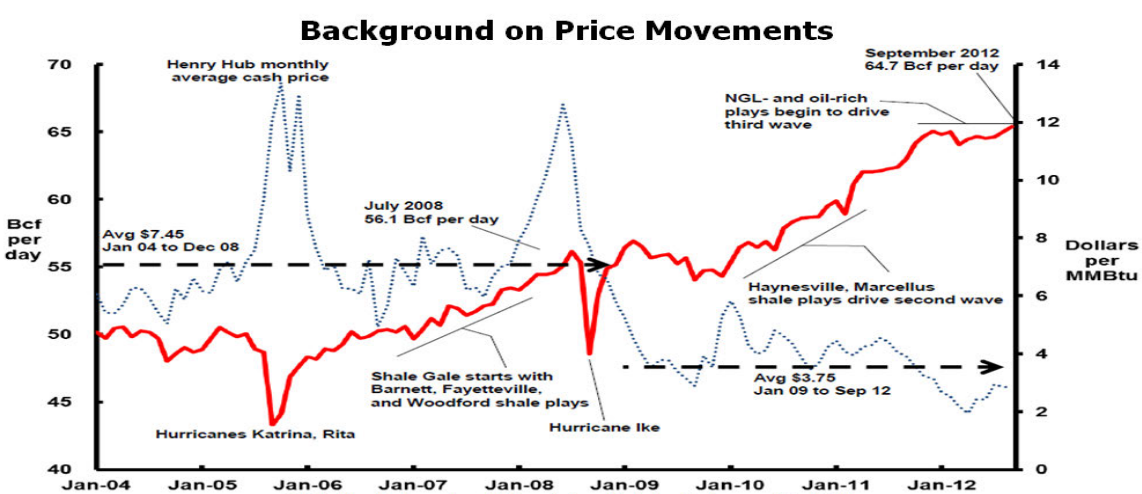
V.4 Market Information:
General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply,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

Deregulation from the late 1970s to early 1990s was a response to perceived natural gas shortages. In the new unregulated environment, prices dropped due to competition, increased efficiencies, technological improvements, and the discovery of more natural gas.

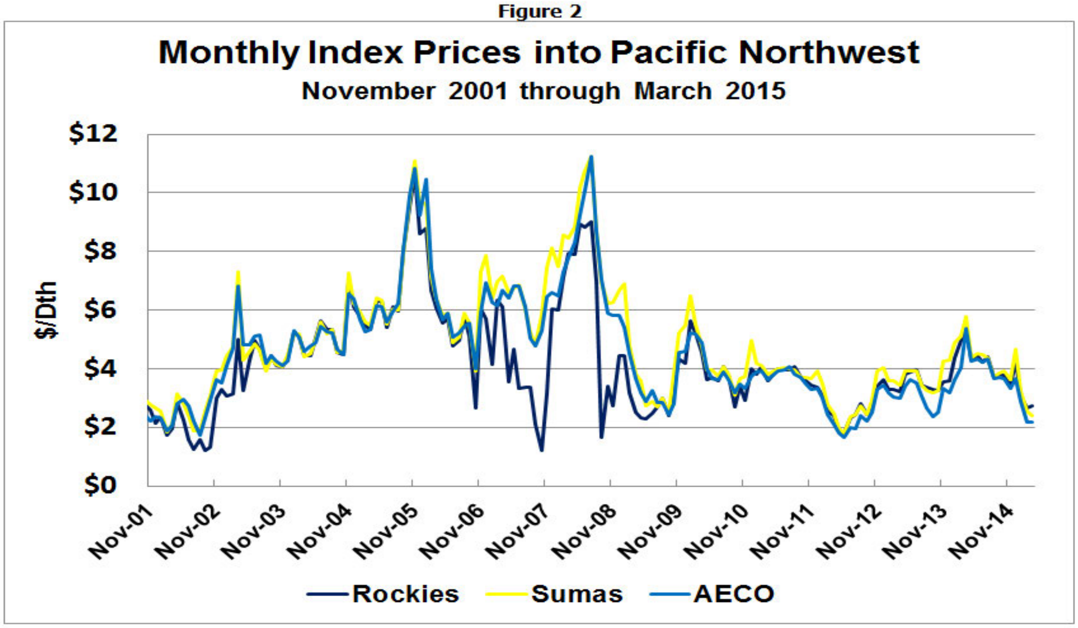
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were tightening and that demand growth would be dependent on bringing additional supplies to North America in the form of LNG imports. Catastrophic hurricanes (Katrina, Rita, et al) in 2005 interrupted natural gas supplies from the Gulf of Mexico and prices spiked again. Gas prices soared in the spring and summer of 2008 on the tails of predicted supply shortfalls. At that time, Henry Hub prices peaked at $13.31. Within months, the onset of a global economic recession reduced demand while the advent of horizontal drilling into shale formations unleashed a surge of production. Prices soon tumbled (Figure 1). Historical indexed prices into the Pacific Northwest at NW Natural's major supply points reflected national trends (Figure 2).

Figure 1



CERA, North American Natural Gas Update, February 28, 2013

Figure 2

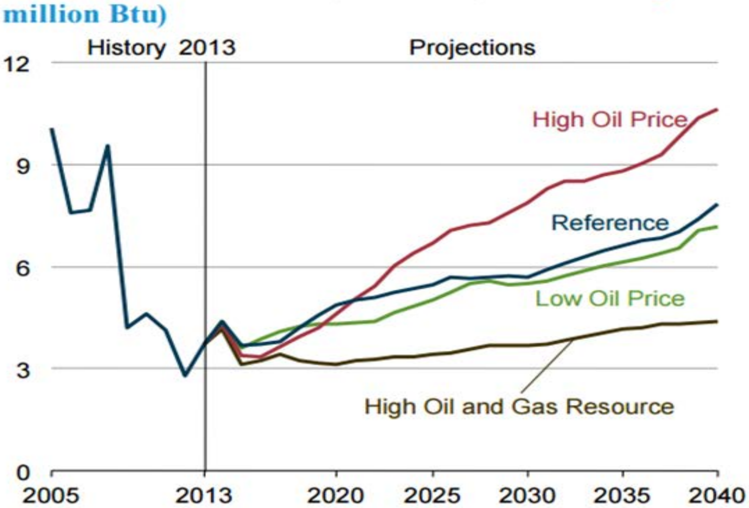


As mentioned, production began ramping up in 2008 with the surge in shale drilling innovations. Prices fell dramatically but as shown in Figure 2, bottomed out by spring 2012

Prices are expected to rise. The U.S. Energy Information Administration's (EIA) Annual Energy Outlook dated April 2015 examined three scenarios in addition to a reference case and the question is not whether, but by how much and how quickly will prices increase over time (Figure 3).

Figure 3

Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



The major factors affecting this outlook are:

1. Natural gas production in the U.S. is at record levels and continues to grow, pushing down prices. Growth will continue through 2015 and 2016 according to most experts. Bentek expects a 4.2 Bcfd increase for November 2014 through October 2015 compared to the prior 12 months. The EIA says production will jump by 3.7 Bcfd in 2015 with another 1.6 Bcfd increase in 2016. IHS is forecasting a 2.7 Bcfd production increase in 2015 and another 1.1 in 2016.

Production forecasts were traditionally based on drilling rig counts, which seemed like the clearest leading indicator of future production levels. However, U.S. gas drilling rig counts fell from 992 in 2011 to 268 in March 2015, the lowest level in 20 years, yet production continued to rise. Several reasons have contributed to the breakdown of traditional methods for estimating natural gas production. The development of shale resources increased integration of oil and gas production. Natural gas is often produced from rigs that target oil. Also, there have been increases in drilling efficiency, or the number of wells drilled per rig each month. And there is a backlog of wells that have been drilled but not yet completed. That acts as a cushion for well additions, offsetting immediate decreases in drilling activity and delaying the production impact.

2. Power generation has become the gyroscope for U.S. natural gas, helping to balance supply and demand and keep prices within a certain range. Gas and coal battle for power generation load. Price often dictates the winner, with a small change in price creating a large change in demand. Increases in gas supply or decreases in demand can cause gas prices to drop below coal prices. Power generators then switch from coal to gas. Gas demand goes up. Gas prices start moving back up. Power generators eventually switch back to coal. Gas demand drops. Gas prices drop. The cycle repeats.

Fuel switching for price occurs more often in Eastern states due to higher coal prices in the Central Appalachian region (CAPP). Recently, natural gas prices have even dipped below cheaper coal prices in the Powder River Basin (PRB), a region centered in Wyoming. Sometimes a small price change has a huge impact on demand. A drop in Henry Hub prices from about $2.50 to $2.00/Dth could trigger a 5 Bcfd increase in natural gas for power generation.

Bentek says natural gas prices will reach a low point in 2015 and then rise, diffusing some future fuel switching incentive for power generators. Nevertheless, coal plant retirements should push gas power demand to record levels.

A very recent development is the June 29, 2015, decision by the Supreme Court to overturn EPA's Mercury and Air Toxics Standards (MATS) rule. Initial reactions seem to indicate that this decision will have a relatively modest impact on the future generation mix due to the investments already made by power companies to comply with EPA's regulations.

3. An industrial renaissance is expected in the U.S. in response to lower gas prices, but the timing and location(s) of that response are highly uncertain. For the next year or two, the impact in the Pacific Northwest is likely to be small. Given that any very large-scale plant expansions would take at least a couple of years to construct, we should be able to estimate their impact well in advance of operation.

4. Gas exports in the form of LNG are likely to be restricted to the Gulf of Mexico region for at least the next several years, and so have an indirect and generally limited impact on prices in the Pacific Northwest. The longer-term prospects for LNG exports from British Columbia are very real and we would expect a significant impact on local gas prices further out into the future, probably well before the end of this decade. A mitigating factor will be shale gas developments in British Columbia, specifically, how well (or poorly) the timing of that productions matches up with LNG export plans. Impetus for an LNG export terminal in Oregon, especially the Jordan Cove (Coos Bay)project, does not seem to be diminishing and is starting to gain some notice. For example, in our IRP process, scenarios are now included regarding the two Oregon projects and their associated pipeline connections to the larger regional grid.

Meanwhile, gas exports via pipeline to Mexico continue to gain ground. Exports to Mexico were 2.1 Bcfd in 2014. IHS predicts exports of 2.4 Bcfd in 2015, 3.6 Bcfd in 2016, and 4.1 Bcfd in 2016. Citicorp says those exports will hit 5 Bcfd by 2018. Mexico plans to add at least 28 gigawatts of power generating capacity over the next 12 years to accommodate more global manufacturers (especially auto manufacturers). Mexico is now a cheaper manufacturing hub then China, and energy costs for companies in Mexico fell by 37% over the past decade. While the gas that is exported comes primarily from Texas, it creates a void in California that is filled with gas from the Rockies, which in turn could impact price spreads between the Rockies and western Canadian gas.

5. Deviations from "Normal" Conditions. Temperatures, hydro levels and storage inventories are examples of factors that can have large short-term effects, but when looking a year or more into the future, are normalized to some extent in price forecasts. This means variations in any of these factors from normal or expected conditions will increase price volatility if not outright price levels. For example, the 2013-2014 winter was extremely cold (the term "Polar Vortex" became very popular) and storage inventories were drained down to levels not seen in over a decade. The "hangover" from that winter was through the following year because it affected both the cost to refill storage during summer 2014 as well as influence 2014-2015 winter prices. Then the 2014-2015 winter arrived and it was just as cold in the eastern half of the country, but the utilities were ready for it and the impact (price spikes, storage levels) much more contained.

In the west, very mild and dry winter weather is likely to lead to low hydroelectric generation this year. So while storage inventories were relatively untouched during the winter, the expectation is for higher gas prices through the hotter periods of the summer as gas generation makes up for the loss of hydro power.

Incidentally, one factor that previously fell into this category was hurricane activity. However, with the continuing migration of gas production from off-shore (Gulf of Mexico) to on-shore (shale play) sources, the destructive impact of hurricanes is fast approaching a point at which it is more likely to suppress as much demand as it does supply, leaving only the psychological impact to influence pricing.

Regarding liquidity at our major supply points in the Rockies and western Canada, it is likely to continue to be very strong for the next couple of years. That is, Rockies and western Canadian gas that typically flowed to mid-Continent and east coast markets will continue to be displaced by the growth in gas supplies from eastern shale plays such as Marcellus . It is likely, though, that demand growth - some combination of power gen, industrial loads and regional LNG exports - will catch up with available supplies, spurring a strong price response. The magnitude of the price response will depend on the ability of gas producers to tap more supplies from western Canada (B.C. shales) and the Rockies.

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V.5 Data Interpretation

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

See this Exhibit C, IV.2.b.

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V.6 Credit Worthiness Standards

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

IV. Credit Risk Management

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

	Procedure	Responsible Office
1	Analyzes the counterparty's profile to determine credit risk tolerances.	Mid Office
2	Sets counterparty credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies).	Mid Office
3	Monitors credit exposure and coordinates with the Front Office to mitigate risk.	Mid Office
4	If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation.	Mid Office
5	Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions.	Mid Office
6	Determines any appropriate action in response to physical transaction violations.	Front Office Executive
7	Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Front Office Executive
8	Determines any appropriate action in response to financial transaction violations that are not already addressed in the Derivatives Policy.	Mid Office Executive
9	Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Mid Office Executive
10	Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio.	Mid Office
11	Calculates and records appropriate credit reserves on a monthly basis.	Mid Office
12	Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made.	Mid Office
13	Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all established counterparties.	Front Office Mid Office Back Office

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2015

NW NATURAL

Gas Supply Risk Management Policies

Index No. 110

December 2014

Original Date of Approval: March 29, 2005

I. Introduction

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II. Oversight and Organizational Responsibilities

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III. Derivatives Policy (Financial Products)

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IV. Physical Gas Commodity Transactions Policy

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V. Exhibits

Exhibit "A"

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Exhibit “B”

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Exhibit "C"

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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Exhibit "E"

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Exhibit "F"

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Northwest Natural Gas Company
PGA Portfolio Guidelines
2015-2016 Oregon PGA

V.7 Storage

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

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)
Jackson Prairie - aquifer - Chehalis, WA	46,030	1,120,288
J. Aron Storage - virtual storage - Alberta, Canada	16,813	1,530,000
Tenaska Marketing Canada - virtual storage - Alberta, Canada	19,000	947,817
Niska Storage - depleted field - Alberta, Canada	31,595	1,895,634
Mist (share allocated to Utility) - depleted field - Mist, OR	305,000	10,644,758
Portland LNG - LNG Plant - Portland, OR	120,000	600,000
Newport LNG - LNG Plant - Newport, OR	60,000	900,000

Northwest Natural Gas Company
PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

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

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-10	123,357,378	$ 72,645,617.50	0.58890	9,410,501	$ 5,373,535.47	4,395,990	$ 2,432,943.95	0.55345	118,342,867	$ 69,705,025.98	0.58901
Feb	118,342,867	$ 69,705,025.98	0.58901	4,879,344	$ 2,627,742.75	2,365,397	$ 1,217,833.57	0.51485	115,828,920	$ 68,295,116.80	0.58962
Mar	115,828,920	$ 68,295,116.80	0.58962	7,912,236	$ 4,425,625.23	2,309,560	$ 985,508.03	0.42671	110,226,244	$ 64,854,999.60	0.58838
Apr	110,226,244	$ 64,854,999.60	0.58838	15,503,891	$ 8,614,804.86	1,670,862	$ 646,032.16	0.38665	96,393,215	$ 56,886,226.90	0.59015
May	96,393,215	$ 56,886,226.90	0.59015	1,927,556	$ 793,228.54	9,406,506	$ 3,645,785.79	0.38758	103,872,165	$ 59,738,784.15	0.57512
Jun	103,872,165	$ 59,738,784.15	0.57512	652,061	$ 363,386.29	5,713,773	$ 2,465,796.73	0.43155	108,933,877	$ 61,841,194.59	0.56769
Jul	108,933,877	$ 61,841,194.59	0.56769	287,609	$ 183,359.98	12,279,896	$ 5,485,162.22	0.44668	120,926,164	$ 67,142,996.83	0.55524
Aug	120,926,164	$ 67,142,996.83	0.55524	405,287	$ 249,157.52	5,090,346	$ 2,304,088.84	0.45264	125,611,223	$ 69,197,928.15	0.55089
Sep	125,611,223	$ 69,197,928.15	0.55089	271,651	$ 167,341.59	13,753,326	$ 4,504,967.37	0.32755	139,092,898	$ 73,535,553.93	0.52868
Oct	139,092,898	$ 73,535,553.93	0.52868	2,687,797	$ 1,156,185.84	14,129,691	$ 4,843,395.19	0.34278	150,534,792	$ 77,222,763.28	0.51299
Nov	150,534,792	$ 77,222,763.28	0.51299	10,700,976	$ 4,746,126.96	5,072,131	$ 1,953,821.35	0.38521	144,905,947	$ 74,430,457.67	0.51365
Dec	144 905 947	$ 74 430 457.67	0.51365	7 060 485	$ 3 161 021.50	1 684 010	$ 679 171.39	0.40331	139 529 472	$ 71 948 607.56	0.51565
	TOTAL 2010 ACTIVITY			61,699,394	$ 31,861,516.53	77,871,488	$ 31,164,506.59				
Jan-11	139,529,472	$ 71,948,607.56	0.51565	16,536,581	$ 7,960,155.79	4,534,550	$ 1,898,587.33	0.41869	127,527,441	$ 65,887,039.10	0.51665
Feb	127,527,441	$ 65,887,039.10	0.51665	12,055,968	$ 6,039,266.36	3,407,810	$ 1,383,289.09	0.40592	118,879,283	$ 61,231,061.83	0.51507
Mar	118,879,283	$ 61,231,061.83	0.51507	7,076,302	$ 3,517,454.99	2,822,600	$ 1,085,126.04	0.38444	114,625,581	$ 58,798,732.88	0.51296
Apr	114,625,581	$ 58,798,732.88	0.51296	5,732,315	$ 2,519,434.50	2,628,886	$ 1,088,941.38	0.41422	111,522,152	$ 57,368,239.76	0.51441
May	111,522,152	$ 57,368,239.76	0.51441	10,792,274	$ 5,520,359.51	3,546,961	$ 1,499,222.91	0.42268	104,276,839	$ 53,347,103.16	0.51159
Jun	104,276,839	$ 53,347,103.16	0.51159	278,481	$ 153,669.85	4,613,636	$ 2,022,089.98	0.43829	108,611,994	$ 55,215,523.29	0.50837
Jul	108,611,994	$ 55,215,523.29	0.50837	348,655	$ 193,744.00	20,717,911	$ 8,891,484.55	0.42917	128,981,250	$ 63,913,263.84	0.49552
Aug	128,981,250	$ 63,913,263.84	0.49552	288,531	$ 159,121.73	7,526,103	$ 3,115,834.52	0.41400	136,218,822	$ 66,869,976.63	0.49090
Sep	136,218,822	$ 66,869,976.63	0.49090	322,758	$ 178,017.13	14,891,055	$ 5,710,632.39	0.38349	150,787,119	$ 72,402,591.89	0.48016
Oct	150,787,119	$ 72,402,591.89	0.48016	3,380,719	$ 1,404,966.55	27,967,660	$ 9,873,518.03	0.35303	175,374,060	$ 80,871,143.37	0.46114
Nov	175,374,060	$ 80,871,143.37	0.46114	9,465,008	$ 3,550,962.54	2,945,068	$ 1,024,003.04	0.34770	168,854,120	$ 78,344,183.87	0.46398
Dec	168 854 120	$ 78 344 183.87	0.46398	11 517 779	$ 4 952 519.39	2 644 302	$ 893 127.66	0.33776	159 980 643	$ 74 284 792.14	0.46434
	TOTAL 2011 ACTIVITY			77,795,371	$ 36,149,672.34	98,246,542	$ 38,485,856.92				
Jan-12	159,980,643	$ 74,284,792.14	0.46434	11,911,891	$ 4,669,327.57	2,279,590	$ 649,110.97	0.28475	150,348,342	$ 70,264,575.54	0.46735
Feb	150,348,342	$ 70,264,575.54	0.46735	8,672,041	$ 3,187,445.76	348,590	$ 88,897.46	0.25502	142,024,891	$ 67,166,027.24	0.47292
Mar	142,024,891	$ 67,166,027.24	0.47292	12,658,159	$ 5,455,394.54	3,460,810	$ 739,939.28	0.21381	132,827,542	$ 62,450,571.98	0.47016
Apr	132,827,542	$ 62,450,571.98	0.47016	23,051,846	$ 10,194,050.58	4,500,360	$ 869,525.78	0.19321	114,276,056	$ 53,126,047.18	0.46489
May	114,276,056	$ 53,126,047.18	0.46489	2,790,265	$ 1,071,649.57	3,842,187	$ 895,679.98	0.23312	115,327,978	$ 52,950,077.59	0.45913
Jun	115,327,978	$ 52,950,077.59	0.45913	2,209,903	$ 643,407.48	6,310,010	$ 1,367,411.71	0.21671	119,428,085	$ 53,674,081.82	0.44943
Jul	119,428,085	$ 53,674,081.82	0.44943	922,095	$ 285,082.42	7,056,836	$ 1,790,152.04	0.25368	125,562,826	$ 55,179,151.44	0.43945
Aug	125,562,826	$ 55,179,151.44	0.43945	289,508	$ 151,844.55	3,112,036	$ 792,432.45	0.25463	128,385,354	$ 55,819,739.34	0.43478
Sep	128,385,354	$ 55,819,739.34	0.43478	207,941	$ 113,206.61	10,098,405	$ 2,607,874.72	0.25825	138,275,818	$ 58,314,407.45	0.42173
Oct	138,275,818	$ 58,314,407.45	0.42173	5,444,783	$ 1,384,452.69	25,766,796	$ 8,855,633.86	0.34368	158,597,831	$ 65,785,588.62	0.41480
Nov	158,597,831	$ 65,785,588.62	0.41480	4,580,684	$ 1,750,833.09	2,489,966	$ 929,470.94	0.37329	156,507,113	$ 64,964,226.47	0.41509
Dec	156 507 113	$ 64 964 226.47	0.41509	8 384 530	$ 2 953 010.06	2 106 485	$ 850 861.58	0.40392	150 229 068	$ 62 862 077.99	0.41844
	TOTAL 2012 ACTIVITY			81 123 646	$ 31 859 704.92	71 372 071	$ 20 436 990.77				
Jan-13	150,229,068	$ 62,862,077.99	0.41844	14,677,497	$ 5,405,016.60	5,093,510	$ 1,831,966.73	0.35967	140,645,081	$ 59,289,028.12	0.42155
Feb	140,645,081	$ 59,289,028.12	0.42155	13,800,354	$ 5,335,663.36	1,262,630	$ 409,713.41	0.32449	128,107,357	$ 54,363,078.17	0.42436
Mar	128,107,357	$ 54,363,078.17	0.42436	3,567,521	$ 1,115,677.83	5,501,939	$ 1,964,738.34	0.35710	130,041,775	$ 55,212,138.68	0.42457
Apr	130,041,775	$ 55,212,138.68	0.42457	21,459,008	$ 8,365,699.38	4,538,540	$ 1,807,682.82	0.39830	113,121,307	$ 48,654,122.12	0.43011
May	113,121,307	$ 48,654,122.12	0.43011	4,818,397	$ 1,845,435.83	8,574,316	$ 2,707,134.37	0.31573	116,877,226	$ 49,515,820.66	0.42366
Jun	116,877,226	$ 49,515,820.66	0.42366	175,511	$ 91,369.64	8,915,841	$ 3,055,934.87	0.34275	125,524,403	$ 52,469,340.89	0.41800
Jul	125,524,403	$ 52,469,340.89	0.41800	565,039	$ 240,881.44	15,007,288	$ 4,532,440.74	0.30202	139,966,652	$ 56,760,897.49	0.40553
Aug	139,966,651	$ 56,760,897.49	0.40553	274,464	$ 135,425.37	17,596,859	$ 4,711,223.75	0.26773	157,289,046	$ 61,336,695.87	0.38996
Sep	157,289,046	$ 61,336,695.87	0.38996	285,901	$ 140,062.88	10,388,350	$ 2,723,301.45	0.26215	167,391,495	$ 63,919,934.44	0.38186
Oct	167,391,495	$ 63,919,934.44	0.38186	4,070,753	$ 1,272,892.19	10,841,958	$ 4,013,141.26	0.37015	174,162,700	$ 66,660,183.51	0.38275
Nov	174,162,700	$ 66,660,183.51	0.38275	7,315,178	$ 2,342,207.60	12,577,745	$ 4,710,632.15	0.37452	179,425,267	$ 69,028,608.06	0.38472
Dec	179 425 267	$ 69 028 608.06	0.38472	46 561 323	$ 17 032 482.39	6 732 330	$ 3 374 222.26	0.50120	139 596 274	$ 55 370 347.93	0.39665
	TOTAL 2013 ACTIVITY			117,570,946	$ 43,322,817.21	107,031,306	$ 35,842,132.15				
Jan-14	139,596,274	$ 55,370,347.93	0.39665	30,835,168	$ 11,843,590.19	1,760,410	$ 767,548.02	0.43601	110,521,516	$ 44,294,305.76	0.40078
Feb	110,521,516	$ 44,294,305.76	0.40078	29,228,201	$ 12,337,686.61	2,109,060	$ 1,410,671.47	0.66886	83,402,375	$ 33,367,290.62	0.40008
Mar	83,402,375	$ 33,367,290.62	0.40008	4,103,948	$ 1,427,892.69	5,235,359	$ 2,778,669.67	0.53075	84,533,786	$ 34,718,067.60	0.41070
Apr	84,533,786	$ 34,718,067.60	0.41070	2,620,950	$ 1,039,548.32	7,343,259	$ 3,410,003.35	0.46437	89,256,095	$ 37,088,522.63	0.41553
May	89,256,095	$ 37,088,522.63	0.41553	179,202	$ 87,337.55	15,343,377	$ 6,883,358.12	0.44862	104,420,270	$ 43,884,543.20	0.42027
Jun	104,420,270	$ 43,884,543.20	0.42027	409,025	$ 200,391.58	15,898,061	$ 7,384,324.83	0.46448	119,909,306	$ 51,068,476.45	0.42589
Jul	119,909,306	$51,068,476.45	0.42589	150,183	$ 70,223.64	25,904,013	$ 10,835,078.53	0.41828	145,663,136	$61,833,331.34	0.42450
Aug	145,663,136	$61,833,331.34	0.42450	12,428	$ 5,479.26	25,531,734	$ 10,129,576.35	0.39674	171,182,442	$71,957,428.43	0.42036
Sep	171,182,442	$71,957,428.43	0.42036	62,586	$ 30,087.78	17,516,192	$ 7,008,362.97	0.40011	188,636,048	$78,935,703.62	0.41846
Oct	188,636,048	$78,935,703.62	0.41846	1,483,225	$ 756,854.52	10,968,256	$ 4,113,318.43	0.37502	198,121,080	$82,292,167.52	0.41536
Nov	198,121,080	$82,292,167.52	0.41536	13,322,697	$ 5,892,179.83	4,433,490	$ 1,873,768.24	0.42264	189,231,873	$78,273,755.94	0.41364
Dec	189 231 873	$78 273 755.94	0.41364	13 750 118	$ 5 897 877.99	2 358 363	$ 663 443.82	0.28132	177 840 118	$73 039 321.77	0.41070
	TOTAL 2014 ACTIVITY			96,157,731	$ 39,589,149.96	134,401,574	$ 57,258,123.80				
Jan-15	177,840,118	$73,039,321.77	0.41070	14,245,904	$6,012,586.29	888,310	$262,325.07	0.29531	164,482,524	$67,289,060.55	0.40910
Feb	164,482,524	$67,289,060.55	0.40910	7,292,629	$3,141,852.01	6,012,346	$1,426,726.22	0.23730	163,202,241	$65,573,934.75	0.40180
Mar	163,202,241	$65,573,934.75	0.40180	1,830,436	$805,376.16	4,745,680	$1,098,192.39	0.23141	166,117,485	$65,866,750.98	0.39651
Apr	166,117,485	$65,866,750.98	0.39651	4,171,954	$1,638,956.58	5,066,936	$1,154,126.03	0.22778	167,012,467	$65,381,920.43	0.39148
May	167,012,467	$65,381,920.43	0.39148	113,933	$49,743.72	7,893,979	$2,197,251.85	0.27835	174,792,513	$67,529,428.55	0.38634
Jun	174 792 513	$67 529 428.55	0.38634	294 416	$130 693.66	8 657 668	$2 011 544.95	0.23234	183 155 765	$69 410 279.85	0.37897
	TOTAL 2015 ACTIVITY			27,949,272	$ 11,779,208.42	33,264,919	$ 8,150,166.51				

Northwest Natural Gas Company
PGA Portfolio Guidelines
2015-2016 Oregon PGA

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

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing unhedged discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last. If storage injections exceed unhedged gas purchases, then average cost of hedged gas would be used to value the remainder of the storage injections.) This price would represent commodity cost, transportation cost, and fuel-in-kind (FIK) at either the NNG city gas (internal storage) or at the external storage site. In addition, this price will include all storage reservation charges.

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

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

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

*Injections into Canadian storage sites are valued using specific commodity deals plus added costs to maintain specific contract terms for each site.

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

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

THIS SERVICE AGREEMENT (Agreement) by and between Northwest Pipeline GP (Transporter) and Northwest Natural Gas Company (Shipper) restates the Service Agreement made and entered into on January 01, 1998.

WHEREAS:

A Pursuant to Section 11.4 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter and Shipper desire to restate the Service Agreement dated January 01, 1998("Contract # 100502") in the format of Northwest's currently effective Form of Service Agreement and to make certain additional non-substantive changes, while preserving all pre-existing, substantive contractual rights.

B Shipper orginally acquired capacity by entering into a binding precedent agreement through the open season for incremental firm storage service at Jackson Prairie; as authorized by FERC in Docket No. CP06-416.

THEREFORE, in consideration of the premises and mutual covenants set forth herein, Transporter and Shipper agree as follows:

1. Tariff Incorporation. Rate Schedule SGS-2F and the General Terms and Conditions (GT&C) that apply to Rate Schedule SGS-2F, as such may be revised from time to time in Transporter's FERC Gas Tariff (Tariff), are incorporated by reference as part of this Agreement, except to the extent that any provisions thereof may be modified by non-conforming provisions herein.

2. Storage Service. Subject to the terms and conditions that apply to service under this Agreement, Transporter agrees to inject, store and withdraw natural gas for Shipper, on a firm basis. Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best efforts basis as provided in Rate Schedule SGS-2F. The Contract Demand and Storage Capacity are set forth on Exhibit A.

3. Storage Rates. Shipper agrees to pay Transporter for all services rendered under this Agreement at the rates set forth or referenced herein. The maximum currently effective rates (Recourse Rates) set forth in the Statement of Rates in the Tariff, as revised from time to time, that apply to the Rate Schedule SGS-2F customer category identified on Exhibit A will apply to service hereunder unless and to the extent that discounted Recourse Rates or awarded capacity release rates apply as set forth on Exhibit A or negotiated rates apply as set forth on Exhibit D.

4. Service Term. This Agreement becomes effective on the date first set forth above. The primary term begin date for the storage service hereunder is set forth on Exhibit A. This Agreement will remain in full force and effect through the primary term end date set forth on Exhibit A and, if Exhibit A indicates that an evergreen provision applies, through the established evergreen rollover periods thereafter until terminated in accordance with the notice requirements under the applicable evergreen provision.

5. Non-Conforming Provisions. All aspects in which this Agreement deviates from the Tariff, if any, are set forth as non-conforming provisions on Exhibit B. If Exhibit B includes any material non-conforming provisions, Transporter will file the Agreement with the Federal Energy Regulatory Commission (Commission) and the effectiveness of such non-conforming provisions will be subject to the Commission acceptance of Transporter's filing of the non-conforming Agreement.

6. Capacity Release. If Shipper is a temporary capacity release Replacement Shipper, any capacity release conditions, including recall rights and the amount of the Releasing Shipper's Working Gas Quantity released to Shipper for the initial Storage Cycle, are set forth on Exhibit A.

7. Exhibit Incorporation. Exhibit A is attached hereto and incorporated as part of this Agreement. If Exhibits B and/or D apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement.

8. Regulatory Authorization. Storage service under this Agreement is authorized pursuant to the Commission regulations set forth on Exhibit A.

9. Superseded Agreements. When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Original Service Agreement dated January 1, 1998.

IN WITNESS WHEREOF, Transporter and Shipper have executed this Restated Agreement on January 21, 2008.

Northwest Natural Gas Company	Northwest Pipeline GP
By: /S/	By: /S/

Name: RANDOLPH S. FRIEDMAN

Title: DIRECTOR, GAS SUPPLY

Name: JANE F HARRISON

Title: MANAGER NWP MARKETING SERVICES

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT
(Continued)

EXHIBIT A
(Dated January 21, 2008, Effective January 21, 2008)
to the
Rate Schedule SGS-2F Service Agreement
(Contract No. 100502)
between Northwest Pipeline GP
and Northwest Natural Gas Company

SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper

2. Contract Demand: 46,030 Dth per day

3. Storage Capacity: 1,120,288 Dth

4. Recourse or Discounted Recourse Storage Rates:

   (Show Not Applicable if Exhibit D is attached.)

   a. Demand Charge (per Dth of Contract Demand):

      Maximum Currently Effective Tariff Rate

   b. Capacity Demand Charge (per Dth of Storage Capacity):

      Maximum Currently Effective Tariff Rate

   c. Rate Discount Conditions Consistent with Section 3.2 of Rate Schedule SGS-2F:

      Not Applicable

5. Service Term:

   a. Primary Term Begin Date:

      November 01, 1998

   b. Primary Term End Date:

      October 31, 2004

   c. Evergreen Provision:

      Yes, grandfathered unilateral evergreen under Section 15.3 of Rate Schedule SGS-2F

6. Regulatory Authorization: 18 CFR 284.223

7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

TF0350 000004P126Original Sheet No. 50
TF04
TF05Laren M. Gertsch, Director
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the purchase c natural gas storage service from Transporter when Shipper and Transporter have executed a Service Agreement for the storage of gas under this Rate Schedule and have arranged for the related transportation of gas to and from the Jackson Prairie Storage Project under one of Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability. This Rate Schedule shall apply to firm storage ga service consisting of Transporter's injection, storage and withdrawal o Shipper's gas at the Jackson Prairie Storage Project. The executed Service Agreement for service under this Rate Schedule will specify the Shipper category, i.e., whether the Shipper is a Pre-Expansion Shipper or an Expansion Shipper. The Jackson Prairie Storage Project capacity available for this Rate Schedule will be Transporter's undivided interest as an owner in the Project, excluding any portion of such interest which may be authorized for use by Transporter for transportation balancing. Delivery of natural gas by Shipper to Transporter for injection and by Transporter to Shipper upon withdrawal shall be at the point of interconnection between the Jackson Prairie Storage Project and Transporter's main transmission line.

2.2 Character of Service. Storage gas service rendered to Shipper under this Rate Schedule, up to Shipper's Contract Demand and Storage Capacity and subject to the limitations of this Rate Schedule and the executed Service Agreement, shall be firm and shall not be subject to curtailment or interruption except as provided in Sections 9, 10, 12, and 14 of the General Terms and Conditions.

2.3 Capacity Release. Shippers releasing firm storage rights shall d so in accordance with the capacity release provisions outlined in Section 22 of the General Terms and Conditions. Any such release is subject to the terms and conditions of this Rate Schedule.

3. MONTHLY RATE

Each month, Shipper will pay Transporter for service rendered under this Rate Schedule the amounts specified in this Section 3, as applicable.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.1 Storage Service. The sum of (a),(b) and (c) below:

(a) Demand Charge: The sum of the daily product of Shipper's Contract Demand and the Demand Charge stated on Sheet No. of this Tariff that applies to the customer category identified in the Service Agreement.

(b) Capacity Demand Charge: The sum of the daily product of Shipper's Storage Capacity and the Capacity Demand Charge stated on Sheet No. 7 of this Tariff that applies to the customer category identified in the Service Agreement.

The related transportation of gas to and from the Jackson Prairie storage facility shall be subject to separate transportation charges under applicable open-access Rate Schedules. The rates set forth in th sub-paragraphs above are exclusive of the aforementioned transportation charges.

3.2 Discounted Recourse Rates. Transporter reserves the right to discount at any time the Recourse Rates for any individual Shipper unde any service agreement without discounting any other Recourse Rates for that or another Shipper; provided, however, that such discounted Recourse Rates shall not be less than the Minimum Currently Effective Rates set forth on Sheet No. 7 of this Tariff, or any superseding tariff. Such discounted Recourse Rates may apply to specific volumes o gas such as volumes injected, withdrawn or stored above or below a certain level or all volumes if volumes exceed a certain level, and volumes of gas injected, withdrawn or stored during specific time periods. If Transporter discounts any Recourse Rates to any Shipper, Transporter will file with the Commission any required reports reflecting such discounts.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.3 Charges for Capacity Release Service: The rates for capacity release service are set forth in Sheet No. 7. See Section 22 of the General Terms and Conditions for information about rates for capacity release service, including information about acceptable bids. In the event of a base tariff maximum and/or minimum rate change, the Replacement Shipper will be obligated to pay:

(a) the lesser of the awarded bid rate and the new maximum base tariff rate, or the greater of the awarded bid rate and the new minimum base tariff rate, as applicable, for the remaining term of the release for capacity release transactions with a term of more than one year and where the awarded bid rate was not tied to the maximum rate as it may change from time to time;

(b) the greater of the minimum base tariff rate and the awarded bid rate for the remaining term of the release for capacity release transactions with a term of one year or less that take effect on or before one year from the date on which Transporter is notified of the release and where the award bid rate was not tied to the maximum tariff rate; or

(c) the new maximum rate or, if applicable, the percentage of the new maximum rate for capacity release transactions where the awarded bid rate was tied to the maximum rate as it may change from time to time.

For capacity release service subject to demand charges, the payments by the Replacement Shipper shall be equal to the sum of the daily product of the accepted Demand Charge bid rate and the Contract Demand, plus the sum of the daily product of the accepted Capacity Demand Charge bid rate and the Storage Capacity.

For capacity release service subject to volumetric bid rates, the payments by the Replacement Shipper shall be equal to the accepted volumetric bid rate for withdrawals multiplied by the actual volumes withdrawn each day plus the accepted volumetric bid rate for storage multiplied by the actual volumes in storage each day.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

The SGS-2F Volumetric Bid Charge will be calculated as set forth in section 3.1 herein except that (a) and (b) change as specified below

(a) Withdrawal Charge: Per Dth of Withdrawals during the applicable month.

(b) Storage Charge: Per Dth of Shipper's Working Gas Inventory per day.

3.4 Negotiated Rates. Notwithstanding the general provisions of this Section 3, if Transporter and Shipper mutually agree to Negotiated Rates for service hereunder, such Negotiated Rates will apply in lieu of the otherwise applicable rates identified in this Section 3.

4. MINIMUM MONTHLY BILL

Unless Transporter and Shipper mutually agree otherwise, the Minimum Monthly Bill will consist of the sum of the Demand and Capacity Demand Charges specified in Section 3 of this Rate Schedule, as applicable.

5. FUEL GAS REIMBURSEMENT

Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions.

6. CONTRACT DEMAND

The Contract Demand shall be the largest number of Dth Transporte is obligated to withdraw and deliver to Shipper, and Shipper is entitle to receive from Transporter, at Jackson Prairie on any one day, to the limitations set forth in Section 9 below, and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Contract Demand, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

7. STORAGE CAPACITY

Shipper's Storage Capacity shall be the maximum quantity of gas in Dth which Transporter is obligated to store for Shipper's account and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Storage Capacity, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions.

8. DEFINITIONS

8.1 A Storage Cycle is the twelve-month period beginning October 1 of any calendar year and ending September 30 of the following calendar year.

8.2 Shipper's Working Gas Inventory shall be the actual quantity of working gas in storage for Shipper's account at the beginning of any given day.

8.3 Shipper's Working Gas Quantity for a Storage Cycle shall be determined as of October 1 and shall be the lesser of:

(a) Shipper's Working Gas Inventory as of October 1, the beginning of the Storage Cycle; or

(b) The minimum quantity of Shipper's Working Gas Inventory at any time between August 31 and September 30 of the preceding Storage Cycle divided by 0.80; or

(c) The minimum quantity of Shipper's Working Gas Inventory at any time between June 30 and September 30 of the preceding Storage Cycle divided by 0.35.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

8. DEFINITIONS (Continued)

In addition to the quantity calculated above, an Expansion Shipper's Working Gas Quantity will include any increases in its Storag Capacity during the current Storage Cycle.

The above method of determining Shipper's Working Gas Quantity ma be modified consistent with any comparable modification under the January 15, 1998 Gas Storage Project Agreement, or superseding agreement, permitted by the Jackson Prairie Storage Project Management Committee. A Shipper's Working Gas Quantity will be adjusted for any Working Gas Quantity released as indicated on Exhibit A to a Replacemen Shipper's Service Agreement.

8.4 Shipper's Available Working Gas on any day during the Storage Cycle shall be equal to Shippers' Working Gas Inventory less Shipper's Unavailable Working Gas.

8.5 Shipper's Unavailable Working Gas on any day during the Storage Cycle shall be equal to the highest level of Shipper's Working Gas Inventory during the preceding days of the current Storage Cycle less Shipper's Working Gas Quantity.

9. WITHDRAWALS OF STORAGE GAS

9.1 General Procedure. When Shipper desires the withdrawal of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas within Shipper's Available Working Gas which it desires withdrawn under this Rate Schedule during such day. Transporter shall thereupon withdraw the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

9. WITHDRAWALS OF STORAGE GAS (Continued)

9.2 Withdrawal Obligation. Transporter's daily withdrawal obligation shall be at 100 percent of the Shipper's Contract Demand as long as Shipper's Available Working Gas is greater than or equal to 60 percent of Shipper's Storage Capacity. On any day when Shipper's Available Working gas is less than 60 percent of Shipper's Storage Capacity, Transporter's daily withdrawal obligation shall be reduced by two percent of Shipper's Contract Demand for each one percent that Shipper' Available Working Gas is less than 60 percent of Shipper's Storage Capacity, until a minimum daily withdrawal rate equal to 10 percent of Shipper's Contract Demand is reached.

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

Shipper shall provide written notice to Transporter prior to May of each year, of the volumes of gas to be injected for the account of Shipper during the period of May 1 through September 30 of such year. When Shipper desires the injection of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas it desires injected under this Rate Schedule during such day, including the applicable fuel reimbursement requirements. Transporter shall thereupon inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject to delivery of such volume, and shall retain any fuel use reimbursement furnished in-kind in accordance with Section 14 of the General Terms and Conditions in addition to any fuel reimbursement required from the part under whose Service Agreement the gas is to be transported to Jackson Prairie.

11. WITHDRAWALS AND INJECTIONS SUBSEQUENT TO THE INTRADAY 2 NOMINATION CYCL

To the extent Transporter's existing transportation and storage obligations are not compromised, Shipper may request up to two changes in scheduled daily withdrawal or injection quantities following the Intraday 2 Nomination Cycle for the remainder of the Gas Day. Transporter will thereupon withdraw or inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule including fuel gas reimbursement requirements and subject as necessary to confirmation of the nomination changes for the related transportatio service agreement.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

Shipper may request Transporter to cause gas to be injected into or withdrawn from storage for Shipper's account at any time during the year. Available injection capacity will be allocated to each Shipper proportionate to such Shipper's Storage Capacity. In no event shall th balance of gas stored in Shipper's account exceed Shipper's Storage Capacity as defined under Section 6 of this Rate Schedule.

After the commencement of an annual Storage Cycle, withdrawals from Shipper's Available Working Gas may be replaced both to maintain deliverability and to restore the quantity available for withdrawals. Additional working gas may also be injected during the Storage Cycle; provided, however, that Shipper's Unavailable Working Gas as defined in Section 8 above shall not be available for withdrawal during the curren Storage Cycle.

13. WITHDRAWALS IN EXCESS OF FIRM ENTITLEMENT (BEST-EFFORTS WITHDRAWALS)

Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best-efforts basis; provided, however, that the total volume withdrawn may not exceed the level of Shipper's Available Working Gas. Transporter may make such excess withdrawal, consistent with the priority of service provisions contained in Section 12 of the General Terms and Conditions, if and to the extent that capacity is available to make such withdrawal after Transporter's needs for withdrawal capacity to satisfy its system balancing requirements have been met.

14. TRANSFER OF WORKING GAS INVENTORY

Shippers subject to either this Rate Schedule or to Rate Schedule SGS-2I may agree to transfer their respective Working Gas Inventories between themselves. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory in writing, prior to the beginning of the gas day in which such transfe will occur. Transfers of Working Gas Inventory may not result in any Shipper taking title to Working Gas Inventory volumes that exceed such Shipper's Rate Schedule SGS-2F Storage Capacity or Rate Schedule SGS-2I Interruptible Storage Capacity.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

14. TRANSFER OF WORKING GAS INVENTORY (Continued)

Pursuant to the January 15, 1998 Gas Storage Project Agreement, owners of the Jackson Prairie Storage Project may transfer portions of their respective available working gas inventories, as defined in the Project Agreement, to each other. Upon agreement of the parties, and subject to the terms of the Project Agreement, Transporter may utilize its ownership account on behalf of a Rate Schedule SGS-2F Shipper to transfer such Shipper's Working Gas Inventory to an owner's available working gas inventory account. Conversely, an owner may transfer its available working gas inventory to a Rate Schedule SGS-2F Shipper's Working Gas Inventory account.

15. EVERGREEN PROVISION

15.1 Standard Unilateral Evergreen Provision. If Transporter and Shipper agree to include a standard unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

(a) The established rollover period will be one year.

(b) Shipper may terminate the Service Agreement in its entiret upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving written notice to Transporter so stating at least five years before the terminatio date.

(c) The termination notice required under Section 15.1(b) will be deemed given when posted on Transporter's Designated Site.

15.2 Standard Bi-Lateral Evergreen Provision. If Transporter and Shipper agree to include a standard bi-lateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

(i) one month for a Service Agreement with a primary ter of less than one year; or

(ii) one year for a Service Agreement with a primary term of one year or more.

(b) Either Transporter or Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving the other party termination notice at least:

(i) ten Business Days before the termination date if Section 15.2(a)(i) applies; or

(ii) one year before the termination date if Section 15.2(a)(ii) applies.

(c) The termination notice required under Section 15.2(b) will be deemed given when posted on Transporter's Designated Site. If Transporter gives termination notice, such termination notice als will be given via Internet E-mail or fax if specified by Shipper on the Business Associate Information form.

15.3 Grandfathered Unilateral Evergreen Provision. If a Shipper with Service Agreement containing a unilateral evergreen provision elects: (i) to restate such Service Agreement in the format of the Form of Service Agreement contained in this Tariff, or (ii) to permanently release all or a portion of its firm contract rights, including its unilateral evergreen rights, to a Replacement Shipper at the Maximum Base Tariff Rate pursuant to Section 22.5 of the General Terms and Conditions, then the Exhibit A of the applicable restated or replacemen Service Agreement will indicate that the following grandfathered unilateral evergreen conditions will apply:

(a) The established rollover period will be one year, at Shipper's sole option.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(b) Shipper may terminate all or any portion of service under its Service Agreement either at the expiration of the primary term, or upon any anniversary thereafter, by giving written notice to Transporter so stating at least twelve months in advance.

(c) Shipper also will have the sole option to enter into a new Service Agreement for all or any portion of the service under it Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent tha this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurren pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR 284.221(d)(2)(i) as promulgated by Order No. 636 on May 8, 1992.

(d) The termination notice required under Section 15.3(b) will be deemed given when posted on Transporter's Designated Site.

16. INTERIM BEST-EFFORTS WITHDRAWAL CHARGE REVENUE CREDITING

One hundred percent (100%) of Interim Best-Efforts Withdrawal Charge revenues received by Transporter pursuant to Section 3.1 will be credited to Rate Schedule SGS-2F Pre-Expansion Shippers, excluding such Shippers receiving service under capacity release Service Agreements. For each month Transporter receives Interim Best-Efforts Withdrawal Charge revenues, credits for such revenues will be allocated to the eligible Rate Schedule SGS-2F Pre-Expansion Shippers pro rata in proportion to the Demand Charge revenues, net of credits from capacity releases as described in Section 23 of the General Terms and Conditions, received from each eligible Rate Schedule SGS-2F Pre-Expansion Shipper for that month. Such allocated monthly revenue credits will be accrued during a calendar year and reflected as credit billing adjustments on the eligible Shippers' March invoices following such calendar year.

17. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, except Sections 13, 16 and 21 and except as modified in the executed Service Agreement, are applicable to this Rate Schedule and are hereby made a part hereof.

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

See Attachment 1 to this Exhibit C titled: "Attachment 1 Exhibit C V.7.g. Svc Agreement NW Pipeline Rate Sch SGS-2F.pdf.

Northwest Natural Gas Company
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2015-2016 Oregon PGA

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

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

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

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a. See Attachment 1 to V.7.h to this Exhibit C dated July 2014, identified as Confidential and subject to Modified Protective Order No. 10-337.

b, There have been no significant changes in physical or operational parameters of the storage facility since completion of the July 2014 study.

NW Natural®

Confidential

Capacity Performance Study
Of the Mist Underground Natural Gas Storage Field
Mist Field,
Columbia County,Oregon

Clayton L. Roth P.E, P.G.

July 2015

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V.8 Attestation as to Consistency

See IV.1.c