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July 29, 2016

NWN OPUC Advice No. 16-17 / UG 313
(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 97308-1088

Re: 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[1] ("the Tariff"), stated to become effective with service on and after November 1, 2016, as follows:

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

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

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

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

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

Fifth Revision of Sheet 164-1,
Schedule 164,
"Purchased Gas Cost Adjustments to Rates."

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[1] Tariff P.U.C. Or. 25 originated November 1, 2012 with Docket UG 221; OPUC Order No. 12-408 as supplemented by Order No. 12-437, and was filed pursuant to ORS 767.205 and OAR 860-022-0005.

This filing is made in accordance with OAR 860-022-0025, OAR 860-022-0030, and OAR 860-022-0070.

Introduction and Summary

The purpose of this 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, 2016, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2015; and

(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, 2016.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2015.

The number of customers affected by the changes proposed in this filing is 579,129 residential customers, 60,040 commercial customers, and 669 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. Amortization of Gas Cost Deferrals (UM 1496) and removal of Temporary Rate Adjustments Currently in Effect

The net effect of this portion of the filing is to increase the Company's annual revenues by $2,127,633, or about 0.33%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2015, is an increase of $2,648,070; 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 $520,437.

The proposed adjustments to customer rates are comprised of the following: (1) a credit of $0.01321 per therm for all sales service customers related to the 191 commodity accounts, and (2) a debit of $0.01345 per therm for all firm sales service customers and a debit of $0.00160 per therm for all interruptible sales service customers related to 191 demand accounts. The net effect of all Account 191 amortizations is a debit of $0.00024 per therm for firm sales service customers and a credit of $0.01161 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 $19,468,977, or about 2.98%; the change in commodity cost is a decrease of $18,799,230 and the change in demand cost is a decrease of $669,747.

The change in gas costs results in a proposed Annual Sales WACOG of $0.29892 per therm, and a proposed Winter Sales WACOG of $0.31087. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.30775 and a proposed Winter Sales Billing WACOG of $0.32005.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.11607 per therm, or $1.72 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01381 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.11950 per therm or $1.77 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01422 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.

III. Combined Effect on Customer Bills

The combined effects of this filing is to decrease the Company's annual revenues by about $17,341,344, or about 2.65%; the change in purchased gas costs is a decrease of $19,468,977 and the change in temporary adjustments to rates is an increase of $2,127,633.

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	-$1.23	-2.2%
Commercial	Schedule 3	-$5.72	-2.6%
Commercial Firm Sales	Schedule 31	-$79.08	-3.5%
Industrial Firm Sales	Schedule 32	-$538.61	-5.2%
Industrial Interruptible Sales	Schedule 32	-$1,010.89	-5.4%

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, 2016 would be a decrease of $517.07, or 5.0%.

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, 2016.

In accordance with ORS 757.205, 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.

Notice to customers will be made in accordance with OAR 860-022-0017.

Please address correspondence on this matter to Kyle Walker at Kyle.Walker@nwnatural.com, with copies to:

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

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, 2016:		(T)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.30775**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.29892**	(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, 2016:		(T)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.32005**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.31087**	(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, 2016:		(T)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.11950**	(I)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11607**	(I)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective: November 1, 2016:		(T)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01422**	(I)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01381**	(I)

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

Effective: November 1, 2016:		(T)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.77**	(I)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.72**	(I)

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

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

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

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

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

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

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects

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, 2016 through October 31, 2017 are: (T)

November	2016	$8,005,757	(C)
December	2016	$11,640,157	
January	2017	$11,130,302	
February	2017	$10,026,917	
March	2017	$7,639,872	
April	2017	$5,509,413	
May	2017	$3,840,649	
June	2017	$2,679,935	
July	2017	$2,314,001	
August	2017	$2,286,378	
September	2017	$2,528,162	
October	2017	$4,666,210	
ANNUAL TOTAL		$72,267,753	(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%.

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)

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, 2016 (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		($0.01321)	$0.01345	**$0.00024**
3 CSF		($0.01321)	$0.01345	**$0.00024**
3 ISF		($0.01321)	$0.01345	**$0.00024**
27		($0.01321)	$0.01345	**$0.00024**
31 CSF	Block 1	($0.01321)	$0.01345	**$0.00024**
	Block 2	($0.01321)	$0.01345	**$0.00024**
31 CTF	Block 1	N/A	N/A	**$0.00000**
	Block 2	N/A	N/A	**$0.00000**
31 ISF	Block 1	($0.01321)	$0.01345	**$0.00024**
	Block 2	($0.01321)	$0.01345	**$0.00024**
31 ITF	Block 1	N/A	N/A	**$0.00000**
	Block 2	N/A	N/A	**$0.00000**

(C)

(C)

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2016 (T)

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Total Adjustment	
32 CSF	Block 1	($0.01321)	$0.01345	**$0.00024**	(C)
	Block 2	($0.01321)	$0.01345	**$0.00024**	
	Block 3	($0.01321)	$0.01345	**$0.00024**	
	Block 4	($0.01321)	$0.01345	**$0.00024**	
	Block 5	($0.01321)	$0.01345	**$0.00024**	
	Block 6	($0.01321)	$0.01345	**$0.00024**	
32 ISF	Block 1	($0.01321)	$0.01345	**$0.00024**	
	Block 2	($0.01321)	$0.01345	**$0.00024**	
	Block 3	($0.01321)	$0.01345	**$0.00024**	
	Block 4	($0.01321)	$0.01345	**$0.00024**	
	Block 5	($0.01321)	$0.01345	**$0.00024**	
	Block 6	($0.01321)	$0.01345	**$0.00024**	
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	($0.01321)	$0.00160	**($0.01161)**	
	Block 2	($0.01321)	$0.00160	**($0.01161)**	
	Block 3	($0.01321)	$0.00160	**($0.01161)**	
	Block 4	($0.01321)	$0.00160	**($0.01161)**	
	Block 5	($0.01321)	$0.00160	**($0.01161)**	
	Block 6	($0.01321)	$0.00160	**($0.01161)**	
32 ISI	Block 1	($0.01321)	$0.00160	**($0.01161)**	
	Block 2	($0.01321)	$0.00160	**($0.01161)**	
	Block 3	($0.01321)	$0.00160	**($0.01161)**	
	Block 4	($0.01321)	$0.00160	**($0.01161)**	
	Block 5	($0.01321)	$0.00160	**($0.01161)**	
	Block 6	($0.01321)	$0.00160	**($0.01161)**	
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)

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, 2016 (T)

Annual Sales WACOG [1]	$0.30775	(C)
Winter Sales WACOG [2]	$0.32005	
Firm Sales Service Pipeline Capacity Component [4]	$0.11950	
Firm Sales Service Pipeline Capacity Component [5]	$1.77000	
Interruptible Sales Service Pipeline Capacity Component [6]	$0.01422	(C)

[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.

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496

NWN OPUC Advice No. 16-17 / UG 313

July 29, 2016

NW NATURAL

EXHIBIT A

Supporting Material

Purchased Gas Cost Deferral Amortizations – UM 1496

NWN OPUC ADVICE NO. 16-17/ UG 313

NW Natural
Rates & Regulatory Affairs
2016-17 PGA - Oregon: August Filing
Summary of TEMPORARY Increments

1			**Current Temporaries**	**WACOG Deferral**	**Demand Deferral - FIRM**	**Demand Deferral - INTERRUPTIBLE**	**Subtotal**
2							
3	Schedule	Block	**A**	**B**	**C**	**D**	**E**
4	2R		0.03592	(0.01321)	0.01345	0.00000	0.00024
5	3C Sales Firm		0.07100	(0.01321)	0.01345	0.00000	0.00024
6	3I Sales Firm		0.03309	(0.01321)	0.01345	0.00000	0.00024
7	27 Dry Out		0.01021	(0.01321)	0.01345	0.00000	0.00024
8	31C Sales Firm	Block 1	0.06829	(0.01321)	0.01345	0.00000	0.00024
9		Block 2	0.06757	(0.01321)	0.01345	0.00000	0.00024
10	31C Trans Firm	Block 1	0.00996	0.00000	0.00000	0.00000	0.00000
11		Block 2	0.00910	0.00000	0.00000	0.00000	0.00000
12	31I Sales Firm	Block 1	0.02976	(0.01321)	0.01345	0.00000	0.00024
13		Block 2	0.02918	(0.01321)	0.01345	0.00000	0.00024
14	31I Trans Firm	Block 1	0.00628	0.00000	0.00000	0.00000	0.00000
15		Block 2	0.00569	0.00000	0.00000	0.00000	0.00000
16	32C Sales Firm	Block 1	0.02837	(0.01321)	0.01345	0.00000	0.00024
17		Block 2	0.02766	(0.01321)	0.01345	0.00000	0.00024
18		Block 3	0.02646	(0.01321)	0.01345	0.00000	0.00024
19		Block 4	0.02526	(0.01321)	0.01345	0.00000	0.00024
20		Block 5	0.02454	(0.01321)	0.01345	0.00000	0.00024
21		Block 6	0.02406	(0.01321)	0.01345	0.00000	0.00024
22	32I Sales Firm	Block 1	0.02728	(0.01321)	0.01345	0.00000	0.00024
23		Block 2	0.02675	(0.01321)	0.01345	0.00000	0.00024
24		Block 3	0.02586	(0.01321)	0.01345	0.00000	0.00024
25		Block 4	0.02497	(0.01321)	0.01345	0.00000	0.00024
26		Block 5	0.02444	(0.01321)	0.01345	0.00000	0.00024
27		Block 6	0.02409	(0.01321)	0.01345	0.00000	0.00024
28	32 Trans Firm	Block 1	0.00351	0.00000	0.00000	0.00000	0.00000
29		Block 2	0.00301	0.00000	0.00000	0.00000	0.00000
30		Block 3	0.00216	0.00000	0.00000	0.00000	0.00000
31		Block 4	0.00133	0.00000	0.00000	0.00000	0.00000
32		Block 5	0.00082	0.00000	0.00000	0.00000	0.00000
33		Block 6	0.00049	0.00000	0.00000	0.00000	0.00000
34	32C Sales Interr	Block 1	0.01408	(0.01321)	0.00000	0.00160	(0.01161)
35		Block 2	0.01356	(0.01321)	0.00000	0.00160	(0.01161)
36		Block 3	0.01270	(0.01321)	0.00000	0.00160	(0.01161)
37		Block 4	0.01184	(0.01321)	0.00000	0.00160	(0.01161)
38		Block 5	0.01131	(0.01321)	0.00000	0.00160	(0.01161)
39		Block 6	0.01098	(0.01321)	0.00000	0.00160	(0.01161)
40	32I Sales Interr	Block 1	0.01408	(0.01321)	0.00000	0.00160	(0.01161)
41		Block 2	0.01359	(0.01321)	0.00000	0.00160	(0.01161)
42		Block 3	0.01276	(0.01321)	0.00000	0.00160	(0.01161)
43		Block 4	0.01194	(0.01321)	0.00000	0.00160	(0.01161)
44		Block 5	0.01144	(0.01321)	0.00000	0.00160	(0.01161)
45		Block 6	0.01111	(0.01321)	0.00000	0.00160	(0.01161)
46	32 Trans Interr	Block 1	0.00316	0.00000	0.00000	0.00000	0.00000
47		Block 2	0.00271	0.00000	0.00000	0.00000	0.00000
48		Block 3	0.00196	0.00000	0.00000	0.00000	0.00000
49		Block 4	0.00120	0.00000	0.00000	0.00000	0.00000
50		Block 5	0.00076	0.00000	0.00000	0.00000	0.00000
51		Block 6	0.00045	0.00000	0.00000	0.00000	0.00000
52	33		0.00020	0.00000	0.00000	0.00000	0.00000

NW Natural
Rates & Regulatory Affairs
2016-17 PGA - Oregon: August Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

Line	Schedule	Block	Oregon PGA Volumes page, Column F		WACOG Deferral			Demand Deferral - FIRM			Demand Deferral - INTERRUPTIBLE		
1					**WACOG Deferral**			**Demand Deferral - FIRM**			**Demand Deferral - INTERRUPTIBLE**		
2				**Proposed Amount:**	(8,639,593)	Temporary Increment		8,044,581	Temporary Increment		89,501	Temporary Increment	
3				**Revenue Sensitive Multiplier:**	2.868%	add revenue sensitive factor		2.868%	add revenue sensitive factor		2.868%	add revenue sensitive factor	
4				**Amount to Amortize:**	**(8,894,693)**	to all sales		**8,282,112**	to all firm sales		**92,144**	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		356,358,823		1.0	356,358,823	(0.01321)	1.0	356,358,823	0.01345	0.0	0	0.00000
8	3C Firm Sales		161,456,307		1.0	161,456,307	(0.01321)	1.0	161,456,307	0.01345	0.0	0	0.00000
9	3I Firm Sales		4,186,772		1.0	4,186,772	(0.01321)	1.0	4,186,772	0.01345	0.0	0	0.00000
10	27 Dry Out		776,455		1.0	776,455	(0.01321)	1.0	776,455	0.01345	0.0	0	0.00000
11	31C Firm Sales	Block 1	17,706,769		1.0	17,706,769	(0.01321)	1.0	17,706,769	0.01345	0.0	0	0.00000
12		Block 2	12,889,553		1.0	12,889,553	(0.01321)	1.0	12,889,553	0.01345	0.0	0	0.00000
13	31C Firm Trans	Block 1	1,364,169		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
14		Block 2	1,632,747		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
15	31I Firm Sales	Block 1	4,263,241		1.0	4,263,241	(0.01321)	1.0	4,263,241	0.01345	0.0	0	0.00000
16		Block 2	9,188,740		1.0	9,188,740	(0.01321)	1.0	9,188,740	0.01345	0.0	0	0.00000
17	31I Firm Trans	Block 1	175,539		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
18		Block 2	517,230		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
19	32C Firm Sales	Block 1	27,396,213		1.0	27,396,213	(0.01321)	1.0	27,396,213	0.01345	0.0	0	0.00000
20		Block 2	8,169,994		1.0	8,169,994	(0.01321)	1.0	8,169,994	0.01345	0.0	0	0.00000
21		Block 3	807,546		1.0	807,546	(0.01321)	1.0	807,546	0.01345	0.0	0	0.00000
22		Block 4	11,819		1.0	11,819	(0.01321)	1.0	11,819	0.01345	0.0	0	0.00000
23		Block 5	0		1.0	0	(0.01321)	1.0	0	0.01345	0.0	0	0.00000
24		Block 6	0		1.0	0	(0.01321)	1.0	0	0.01345	0.0	0	0.00000
25	32I Firm Sales	Block 1	4,897,403		1.0	4,897,403	(0.01321)	1.0	4,897,403	0.01345	0.0	0	0.00000
26		Block 2	5,116,186		1.0	5,116,186	(0.01321)	1.0	5,116,186	0.01345	0.0	0	0.00000
27		Block 3	1,948,136		1.0	1,948,136	(0.01321)	1.0	1,948,136	0.01345	0.0	0	0.00000
28		Block 4	580,946		1.0	580,946	(0.01321)	1.0	580,946	0.01345	0.0	0	0.00000
29		Block 5	0		1.0	0	(0.01321)	1.0	0	0.01345	0.0	0	0.00000
30		Block 6	0		1.0	0	(0.01321)	1.0	0	0.01345	0.0	0	0.00000
31	32 Firm Trans	Block 1	14,611,752		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
32		Block 2	17,230,536		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
33		Block 3	9,911,484		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
34		Block 4	17,461,606		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
35		Block 5	21,764,847		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
36		Block 6	2,455,153		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
37	32C Interr Sales	Block 1	6,252,115		1.0	6,252,115	(0.01321)	0.0	0	0.00000	1.0	6,252,115	0.00160
38		Block 2	8,553,424		1.0	8,553,424	(0.01321)	0.0	0	0.00000	1.0	8,553,424	0.00160
39		Block 3	4,339,671		1.0	4,339,671	(0.01321)	0.0	0	0.00000	1.0	4,339,671	0.00160
40		Block 4	5,183,222		1.0	5,183,222	(0.01321)	0.0	0	0.00000	1.0	5,183,222	0.00160
41		Block 5	89,527		1.0	89,527	(0.01321)	0.0	0	0.00000	1.0	89,527	0.00160
42		Block 6	0		1.0	0	(0.01321)	0.0	0	0.00000	1.0	0	0.00160
43	32I Interr Sales	Block 1	7,427,326		1.0	7,427,326	(0.01321)	0.0	0	0.00000	1.0	7,427,326	0.00160
44		Block 2	8,841,797		1.0	8,841,797	(0.01321)	0.0	0	0.00000	1.0	8,841,797	0.00160
45		Block 3	4,869,921		1.0	4,869,921	(0.01321)	0.0	0	0.00000	1.0	4,869,921	0.00160
46		Block 4	9,961,831		1.0	9,961,831	(0.01321)	0.0	0	0.00000	1.0	9,961,831	0.00160
47		Block 5	2,051,108		1.0	2,051,108	(0.01321)	0.0	0	0.00000	1.0	2,051,108	0.00160
48		Block 6	0		1.0	0	(0.01321)	0.0	0	0.00000	1.0	0	0.00160
49	32 Interr Trans	Block 1	8,822,944		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
50		Block 2	16,011,309		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
51		Block 3	11,561,774		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
52		Block 4	29,665,818		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
53		Block 5	56,877,518		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
54		Block 6	83,025,918		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		966,415,190			673,324,846	(0.01321)		615,754,904	0.01345		57,569,942	0.00160
58	**Sources for line 2 above:**												
59	**Inputs page**				Line 33			Line 35			Line 37		
60	**Tariff Schedules**												
61	**Rate Adjustment Schedule**				Sched 162			Sched 162			Sched 162		

NW Natural
Rates and Regulatory Affairs
2016-2017 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months		
1		Ended 06/30/16		
2				
3	Total Billed Gas Sales Revenues	606,080,614		
4	Total Oregon Revenues	611,607,847		
5				
6	Regulatory Commission Fees [1]	1,633,358	0.275%	Statutory rate
7	City License and Franchise Fees	14,818,591	2.423%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	1,036,942	0.170%	Line 8 ÷ Line 4
9				
10	Total	17,488,891	**2.868%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed occurred mid gas year, the difference between the previous fee of 0.25%
16 and the new fee of 0.275% is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2016-2017 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 16-17: PGA Gas Costs and Gas Cost Deferrals

	Including Revenue Sensitve Amount
Purchased Gas Cost Adjustment (PGA)	
Commodity Cost Change	($18,799,230)
Demand Capacity Cost Change	(669,747)
Total Gas Cost Change	**(19,468,977)**
Temporary Increments	
Removal of Current Temporary Increments	
Amortization of 191.xxx Account Gas Costs	2,648,070
Addition of Proposed Temporary Increments	
Amortization of 191.xxx Account Gas Costs	(520,437)
TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES	**($17,341,344)**
2015 Oregon Earnings Test Normalized Total Revenues	$653,343,000
Effect of this filing, as a percentage change (line 20 ÷ line 24)	-2.65%

NW Natural
Rates & Regulatory Affairs
2016-2017 PGA Filing - August Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2016	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2016	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	F1	F2	G	H	I
					E = sum B thru D	2.20%		G = E + F2		Excl. Rev Sens
33										
34	**Gas Cost Deferrals and Amortizations**									
35	191401 AMORTIZE OREGON WACOG	(3,327,556)	1,988,115	(16,122)	(1,355,564)					
36	191400 WACOG - ACCRUE OREGON	(6,998,677)	0	(183,272)	(7,181,949)					
37	Subtotal	(10,326,234)	1,988,115	(199,394)	(8,537,513)	2.20%	(102,080)	(8,639,593)		**(8,639,593)**
38										
39	191411 AMORTIZE DEMAND OREGON	2,160,358	(1,463,403)	10,094	707,049					
40	191410 DEMAND - ACCRUE OREGON	(1,309,442)	0	(34,290)	(1,343,731)					
41	191417 DEMAND - ACCRUE COOS BAY	113,338	0	0	113,338					
42	191450 OREGON DEMAND ACCRUE VOLUME	8,342,847	0	218,471	8,561,318					
43	Subtotal	9,307,101	(1,463,403)	194,275	8,037,974	2.20%	96,108	8,134,082		**8,134,082**

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. 15-337

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 2009 - Oct 2015 the deferral election was 90%. Effective Nov 2015 the deferral election is 80%.

1	Debit (Credit)									Deferral
2			Commodity			Storage	Hedge			Plus Int.
3	Month/Year	Note	Deferral **(3)**	Interest	Interest Rate	Adjustment **(2)**	Adjustment	Transfer	Activity	GL Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5										
6	Beginning Bal									
101	Oct-14		317,398	144,505	7.78%	(757)	0		461,146	22,591,571
102	Nov-14	**1**	1,037,284.21	19,517.78	7.78%	(7,383.00)	(21,218.00)	(20,085,458.67)	(19,057,257.68)	3,534,313.73
103	Dec-14		(1,108,409.43)	19,136.25	7.78%	(8,370.00)	(48,635.00)		(1,146,278.18)	2,388,035.55
104	Jan-15		(3,827,916.08)	2,927.04	7.78%	(8,464.00)	(36,749.00)		(3,870,202.04)	(1,482,166.49)
105	Feb-15		(2,757,885.72)	(18,640.72)	7.78%	(5,905.00)	(22,227.00)		(2,804,658.44)	(4,286,824.93)
106	Mar-15		(3,732,850.64)	(39,916.92)	7.78%	(5,138.00)	(2,063.00)		(3,779,968.56)	(8,066,793.49)
107	Apr-15		(3,403,268.36)	(63,365.44)	7.78%	(4,806.00)	(5,519.00)		(3,476,958.80)	(11,543,752.29)
108	May-15		(1,064,277.19)	(78,307.87)	7.78%	(2,946.00)	(1,941.00)		(1,147,472.06)	(12,691,224.35)
109	Jun-15		(1,497,097.85)	(87,142.83)	7.78%	(1,912.00)	(648.00)		(1,586,800.68)	(14,278,025.03)
110	Jul-15		(1,146,321.76)	(96,297.90)	7.78%	(1,809.00)	(2,112.00)		(1,246,540.66)	(15,524,565.69)
111	Aug-15		(798,326.62)	(103,257.48)	7.78%	(1,774.00)	(3,974.00)		(907,332.10)	(16,431,897.79)
112	Sep-15		(1,626,854.72)	(111,834.29)	7.78%	(2,276.00)	(6,082.00)		(1,747,047.01)	(18,178,944.80)
113	Oct-15		(1,186,996.00)	(121,762.23)	7.78%	(3,009.00)	(14,241.00)	260.53	(1,325,747.70)	(19,504,692.50)
114	Nov-15	**1**	(1,134,028.54)	(34,369.45)	7.78%	(15,740.21)	(4,661.05)	14,780,707.62	13,591,908.37	(5,912,784.13)
115	Dec-15		(2,937,780.12)	(47,960.89)	7.78%	(18,896.55)	(12,887.96)		(3,017,525.52)	(8,930,309.66)
116	Jan-16		(3,013,129.51)	(67,813.35)	7.78%	(19,337.43)	(26,200.52)		(3,126,480.82)	(12,056,790.47)
117	Feb-16		(3,079,041.43)	(88,262.41)	7.78%	(13,756.73)	(21,100.21)		(3,202,160.78)	(15,258,951.25)
118	Mar-16		(4,448,261.52)	(113,440.22)	7.78%	(13,194.02)	(15,054.10)		(4,589,949.85)	(19,848,901.10)
119	Apr-16		(1,647,135.91)	(134,082.25)	7.78%	(7,236.68)	(9,958.41)		(1,798,413.26)	(21,647,314.35)
120	May-16		(1,500,647.87)	(145,267.67)	7.78%	(5,436.05)	(11,935.80)		(1,663,287.38)	(23,310,601.74)
121	Jun-16		(485,020.63)	(43,490.90)	7.78%	(4,242.71)	(4,894.48)	16,849,573.00	16,311,924.28	(6,998,677.46)
122	Jul-16			(45,374.76)	7.78%				(45,374.76)	(7,044,052.22)
123	Aug-16			(45,668.94)	7.78%				(45,668.94)	(7,089,721.16)
124	Sep-16			(45,965.03)	7.78%				(45,965.03)	(7,135,686.19)
125	Oct-16			(46,263.03)	7.78%				(46,263.03)	(7,181,949.22)
126										

127 **History truncated for ease of viewing**

128

129 **NOTES:**

130 **1** -Transfer June balance plus July-October interest on June balance to account 191401 for amortization

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 191401
Dockets UM 1496 and UG 294
Amortization of 2014-15 deferral approved in Order No. 15-331

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							
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		(669,967)		8,500	1.77%	(661,467)	5,436,422
120	Aug-15		(629,190)		7,555	1.77%	(621,635)	4,814,787
121	Sep-15		(712,698)		6,576	1.77%	(706,122)	4,108,665
122	Oct-15		(871,903)		5,417	1.77%	(866,486)	3,242,178.43
123	Nov-15	old rates	(583,314.79)		4,352.02	1.77%	(578,962.77)	2,663,215.66
124	Nov-15	new rates **(1)**	477,098.53	(14,043,711.50)	(22,203.30)	1.93%	(13,588,816.27)	(10,925,600.61)
125	Dec-15		1,702,692.31		(16,202.76)	1.93%	1,686,489.55	(9,239,111.07)
126	Jan-16		1,993,147.81		(13,256.75)	1.93%	1,979,891.06	(7,259,220.01)
127	Feb-16		1,358,223.17		(10,583.01)	1.93%	1,347,640.16	(5,911,579.84)
128	Mar-16		1,201,786.20		(8,541.35)	1.93%	1,193,244.85	(4,718,334.99)
129	Apr-16		895,596.97		(6,868.45)	1.93%	888,728.52	(3,829,606.47)
130	May-16		587,552.33		(5,686.79)	1.93%	581,865.54	(3,247,740.93)
131	Jun-16		16,788,580.08	(16,849,573.00)	(18,822.36)	1.93%	(79,815.28)	(3,327,556.21)
132	Jul-16	*forecast*	383,902.96		(5,043.10)	1.93%	378,859.86	(2,948,696.35)
133	Aug-16	*forecast*	383,914.14		(4,433.76)	1.93%	379,480.38	(2,569,215.97)
134	Sep-16	*forecast*	400,187.23		(3,810.34)	1.93%	396,376.89	(2,172,839.08)
135	Oct-16	*forecast*	820,110.66		(2,835.14)	1.93%	817,275.52	(1,355,563.56)

137 **History truncated for ease of viewing**

139 **NOTES:**

140 **1** - Transfer in authorized balance from accounts 191400 and 191405.

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. 15-337

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.

1	Debit (Credit)							Deferral
2			Demand					Plus Int.
3	Month/Year	Note	Deferral **(2)**	Interest	Interest Rate	Transfer	Activity	GL Balance
4	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(I)
5								
6	Beginning Bal							
101	Oct-14		(551,151)	(24,683)	7.78%	(2)	(575,836)	(4,107,403)
102	Nov-14	**1**	(1,152,317.85)	(16,682.49)	7.78%	1,850,024.21	681,023.95	(3,165,975.53)
103	Dec-14		(108,540.57)	(20,877.93)	7.78%		(129,418.42)	(3,295,393.96)
104	Jan-15		(137,525.47)	(21,810.95)	7.78%		(159,336.34)	(3,454,730.30)
105	Feb-15		(144,116.13)	(22,865.34)	7.78%		(166,981.39)	(3,621,711.69)
106	Mar-15		(98,578.42)	(23,800.32)	7.78%		(122,378.66)	(3,744,090.35)
107	Apr-15		(142,780.79)	(24,737.03)	7.78%		(167,517.74)	(3,911,608.10)
108	May-15		(174,768.86)	(25,926.80)	7.78%		(200,695.58)	(4,112,303.68)
109	Jun-15		(162,516.01)	(27,188.26)	7.78%		(189,704.19)	(4,302,007.87)
110	Jul-15		(271,439.26)	(28,771.27)	7.78%		(300,210.45)	(4,602,218.32)
111	Aug-15		(220,432.94)	(30,552.29)	7.78%		(250,985.15)	(4,853,203.47)
112	Sep-15		(329,341.85)	(32,532.55)	7.78%		(361,874.32)	(5,215,077.80)
113	Oct-15		(380,876.04)	(35,045.76)	7.78%		(415,921.72)	(5,630,999.52)
114	Nov-15	**1**	284,630.66	(6,963.24)	7.78%	4,414,662.82	4,692,330.32	(938,669.20)
115	Dec-15		(169,707.02)	(6,635.84)	7.78%		(176,342.78)	(1,115,011.98)
116	Jan-16		(7,176.90)	(7,252.26)	7.78%		(14,429.08)	(1,129,441.06)
117	Feb-16		(50,813.26)	(7,487.26)	7.78%		(58,300.44)	(1,187,741.50)
118	Mar-16		(15,389.83)	(7,750.41)	7.78%		(23,140.16)	(1,210,881.67)
119	Apr-16		(127,150.65)	(8,262.73)	7.78%		(135,413.30)	(1,346,294.97)
120	May-16		501,494.76	(7,102.80)	7.78%		494,392.04	(851,902.93)
121	Jun-16		(450,555.03)	(6,983.72)	7.78%		(457,538.67)	(1,309,441.60)
122	Jul-16			(8,489.55)	7.78%		(8,489.47)	(1,317,931.07)
123	Aug-16			(8,544.59)	7.78%		(8,544.51)	(1,326,475.58)
124	Sep-16			(8,599.98)	7.78%		(8,599.90)	(1,335,075.49)
125	Oct-16			(8,655.74)	7.78%		(8,655.66)	(1,343,731.15)

127 **History truncated for ease of viewing**

129 **NOTES**

130 **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 2014-15 deferral approved in Order No. 15-331

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)		(f)	(g)
6								
7	Beginning Balance							
109	Oct-14		26,696		(845)	1.38%	25,851	(722,058)
110	Nov-14	old rates	28,119		(814)	1.38%	27,305	(694,753)
111	Nov-14	new rates **(3)**	198,030	(4,229,742)	(6,093)	1.77%	(4,037,804)	(4,732,557)
112	Dec-14		665,846		(6,489)	1.77%	659,356	(4,073,201)
113	Jan-15		732,357		(5,468)	1.77%	726,889	(3,346,312)
114	Feb-15		529,731		(4,545)	1.77%	525,186	(2,821,126)
115	Mar-15		441,604		(3,835)	1.77%	437,768	(2,383,358)
116	Apr-15		369,891		(3,243)	1.77%	366,648	(2,016,710)
117	May-15		277,168	0	(2,770)	1.77%	274,398	(1,742,311)
118	Jun-15		175,767		(2,440)	1.77%	173,326	(1,568,985)
119	Jul-15		140,400		(2,211)	1.77%	138,189	(1,430,796)
120	Aug-15		129,587		(2,015)	1.77%	127,572	(1,303,224)
121	Sep-15		149,925		(1,812)	1.77%	148,113	(1,155,111)
122	Oct-15		185,752	(0)	(1,567)	1.77%	184,185	(970,926.25)
123	Nov-15	old rates	137,180.72		(1,330.95)	1.77%	135,849.77	(835,076.48)
124	Nov-15	new rates **(1)**	(344,103.54)	9,756,304.40	15,414.67	1.93%	9,427,615.53	8,592,539.05
125	Dec-15		(1,360,659.75)		12,725.47	1.93%	(1,347,934.28)	7,244,604.78
126	Jan-16		(1,603,178.16)		10,362.52	1.93%	(1,592,815.64)	5,651,789.14
127	Feb-16		(1,076,585.12)		8,224.21	1.93%	(1,068,360.91)	4,583,428.23
128	Mar-16		(942,161.32)		6,614.03	1.93%	(935,547.29)	3,647,880.95
129	Apr-16		(694,689.49)		5,308.36	1.93%	(689,381.13)	2,958,499.82
130	May-16		(439,870.80)		4,404.52	1.93%	(435,466.28)	2,523,033.53
131	Jun-16		(366,439.18)		3,763.20	1.93%	(362,675.98)	2,160,357.55
132	Jul-16	*forecast*	(273,583.19)		3,254.57	1.93%	(270,328.62)	1,890,028.93
133	Aug-16	*forecast*	(271,957.45)		2,821.10	1.93%	(269,136.35)	1,620,892.58
134	Sep-16	*forecast*	(286,694.28)		2,376.39	1.93%	(284,317.89)	1,336,574.69
135	Oct-16	*forecast*	(631,167.80)		1,642.09	1.93%	(629,525.71)	707,048.98

137 **History truncated for ease of viewing**

139 **NOTES:**

140 **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							
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		16,636.00	(6,168.59)			10,467.41	101,600.27
110	Jul-15		16,636.00	(5,711.47)			10,924.53	112,524.80
111	Aug-15		16,636.00	(5,109.35)			11,526.65	124,051.45
112	Sep-15		16,636.00	(5,377.23)			11,258.77	135,310.22
113	Oct-15		16,636.00	(6,090.02)			10,545.98	145,856.20
114	Nov-15	1	16,636.00	(4,786.01)	(101,600.27)		(89,750.28)	56,105.92
115	Dec-15		16,636.00	(6,714.01)			9,921.99	66,027.91
116	Jan-16		16,636.00	(8,610.72)			8,025.28	74,053.19
117	Feb-16	2	16,635.00	(23,472.11)			(6,837.11)	67,216.08
118	Mar-16		16,637.17	(6,572.87)			10,064.30	77,280.38
119	Apr-16		16,635.00	(5,211.62)			11,423.38	88,703.76
120	May-16		16,635.00	(4,468.13)			12,166.87	100,870.63
121	Jun-16		16,635.00	(4,167.18)			12,467.82	113,338.45
122	Jul-16						0.00	113,338.45
123	Aug-16						0.00	113,338.45
124	Sep-16						0.00	113,338.45
125	Oct-16						0.00	113,338.45

127 **History truncated for ease of viewing**

129 **NOTES**

130 **1** - June balance transferred to account 191411 for amortization

131 **2** - Additional adjustment represents a true-up of previous year's demand charges.

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. 15-337

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							
101	Oct-14		1,648,665	(8,349)	7.78%		1,640,316	(471,730)
102	Nov-14	1	1,232,252	16,127	7.78%	2,343,093	3,591,472	3,119,741
103	Dec-14		2,325,178	27,764	7.78%		2,352,941	5,472,683
104	Jan-15		1,638,415	40,792	7.78%		1,679,208	7,151,890
105	Feb-15		2,512,045	54,511	7.78%		2,566,556	9,718,447
106	Mar-15		2,355,018	70,642	7.78%		2,425,660	12,144,107
107	Apr-15		463,254	80,236	7.78%		543,490	12,687,597
108	May-15		587,343	84,162	7.78%		671,505	13,359,102
109	Jun-15		263,773.56	87,466.57	7.78%		351,240.21	13,710,341.83
110	Jul-15		47,138.52	89,041.52	7.78%		136,180.12	13,846,521.94
111	Aug-15		67,059.68	89,989.00	7.78%		157,048.76	14,003,570.70
112	Sep-15		(380,179.01)	89,557.40	7.78%		(290,621.53)	13,712,949.17
113	Oct-15		1,628,087.06	94,183.34	7.78%		1,722,270.48	15,435,219.65
114	Nov-15	1	(479,675.83)	7,300.33	7.78%	(14,069,366.95)	(14,541,742.36)	893,477.28
115	Dec-15		1,355,017.05	10,185.22	7.78%		1,365,202.34	2,258,679.63
116	Jan-16		451,529.59	16,107.48	7.78%		467,637.15	2,726,316.77
117	Feb-16		1,790,612.47	23,480.19	7.78%		1,814,092.74	4,540,409.51
118	Mar-16		721,136.36	31,774.67	7.78%		752,911.11	5,293,320.62
119	Apr-16		1,974,641.73	40,719.49	7.78%		2,015,361.29	7,308,681.91
120	May-16		880,686.27	50,239.51	7.78%		930,925.86	8,239,607.77
121	Jun-16		49,664.48	53,581.08	7.78%	(6.39)	103,239.25	8,342,847.02
122	Jul-16			54,089.46	7.78%		54,089.54	8,396,936.56
123	Aug-16			54,440.14	7.78%		54,440.22	8,451,376.78
124	Sep-16			54,793.09	7.78%		54,793.17	8,506,169.94
125	Oct-16			55,148.34	7.78%		55,148.42	8,561,318.36

126

127 **History truncated for ease of viewing**

128

129 **NOTES**

130 **1** -Transfer June balance plus July-October interest on June balance to account 191411 for amortization.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 16-17 / UG 313

July 29, 2016

NW NATURAL

EXHIBIT B

Supporting Material

Purchased Gas Cost

NWN OPUC ADVICE NO. 16-17/ UG 313

NW Natural
2016-2017 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

SYSTEM COSTS

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	**Commodity Cost from Supply**		$18,401,257	$20,801,989	$19,833,772	$14,162,459	$13,109,717	$11,468,271	$8,249,159	$5,685,000	$4,889,493	$4,958,600	$5,625,640	$10,617,424	$137,802,780
6	tab commodity cost from supply, column cd, lines 93-104 plus														
7	tab commodity cost from gas reserve, column q, lines 59-70														
8	**Volumetric Pipeline Chgs**		$260,829	$289,767	$271,307	$218,738	$182,360	$178,275	$126,966	$91,539	$79,021	$78,636	$86,061	$153,349	$2,016,848
9	tab commodity cost from vol pipe, column e, line 78-89														
10	**Commodity Cost from Storage**		$896,316	$12,329,013	$12,293,677	$15,031,104	$8,549,647	$173,538	$109,204	$105,681	$109,204	$109,204	$105,681	$109,204	$49,921,473
11	tab Commodity Cost from Storage, column k, line 61-72														
12	**Commodity Cost from Gas Reserves**		$2,714,018	$2,754,710	$2,727,056	$2,526,330	$2,707,081	$2,560,920	$2,636,746	$2,506,958	$2,535,391	$2,509,418	$2,481,776	$2,458,989	$31,119,392
13	tab Commodity Cost from Gas Reserve, column p, line 59-70														
14	**Total Commodity Cost**		$22,272,419	$36,175,478	$35,125,813	$31,938,630	$24,548,805	$14,381,004	$11,122,074	$8,389,178	$7,613,109	$7,655,858	$8,299,159	$13,338,965	$220,860,493
15															
16	**VOLUMES**														
17	Commodity Volumes at Receipt Points		79,918,063	81,391,254	76,969,345	57,721,422	55,291,255	58,946,453	42,013,446	30,363,760	26,255,905	26,129,302	28,562,404	50,520,287	614,082,899
18	Pipeline Fuel Use		2,083,545	2,078,141	1,938,476	1,477,182	1,413,031	1,628,355	1,075,843	756,897	636,208	632,599	705,559	1,366,028	15,791,864
19	Gas Arriving at City Gate		77,834,518	79,313,114	75,030,870	56,244,240	53,878,225	57,318,098	40,937,603	29,606,863	25,619,698	25,496,703	27,856,845	49,154,260	598,291,035
20															
21	Storage Gas Withdrawals		3,993,176	38,136,812	37,527,866	45,065,053	24,400,928	422,413	248,000	240,000	248,000	248,000	240,000	248,000	151,018,248
22	Pipeline Fuel Use for Alberta-sourced Storage		74,946	260,581	255,661	170,163	81,583	0	0	0	0	0	0	0	842,934
23	Storage Gas Deliveries at City Gate		3,918,230	37,876,231	37,272,205	44,894,890	24,319,345	422,413	248,000	240,000	248,000	248,000	240,000	248,000	150,175,314
24															
25	Total Gas At City Gate (Storage and Commodity)		81,752,748	117,189,345	112,303,075	101,139,130	78,197,570	57,740,511	41,185,603	29,846,863	25,867,698	25,744,703	28,096,845	49,402,260	748,466,349
26															
27	Unaccounted for Gas		484,910	494,122	467,443	350,402	335,662	357,093	255,042	184,451	159,611	158,845	173,549	306,232	3,727,362
28															
29	Load Served		81 267 838	116 695 223	111 835 631	100 788 727	77 861 907	57 383 419	40 930 561	29 662 412	25 708 086	25 585 858	27 923 297	49 096 028	744 738 987

	(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
	WACOG Calculations														
30	**Gas Reserves Supply:**														
31	Total cost (line 12 above)		$2,714,018	$2,754,710	$2,727,056	$2,526,330	$2,707,081	$2,560,920	$2,636,746	$2,506,958	$2,535,391	$2,509,418	$2,481,776	$2,458,989	$31,119,392
32	Load served by gas reserves		4,350,473	4,436,826	4,379,915	3,906,157	4,270,989	4,082,705	4,168,019	3,985,725	4,070,425	4,023,487	3,849,397	3,933,042	49,457,160
33															
34	**Total Load Served**														
35	Oregon		73,434,998	105,108,098	100,826,064	90,889,799	70,519,206	52,190,383	37,095,830	26,924,518	23,408,025	23,284,464	25,294,960	44,348,501	673,324,846
36	Washingon		7,832,840	11,587,124	11,009,567	9,898,928	7,342,702	5,193,035	3,834,732	2,737,894	2,300,062	2,301,394	2,628,337	4,747,527	71,414,142
37	Total (same as line 25 +/- rounding)		81,267,838	116,695,222	111,835,631	100,788,727	77,861,907	57,383,419	40,930,561	29,662,412	25,708,087	25,585,858	27,923,297	49,096,028	744,738,987
38															
39	**Washington WACOG Calculation**														
40															
41	**Hedged Rockies supply excluding Gas Reserves**														
42	Hedged Rockies supply volumes		12,576,600	12,995,820	12,995,820	7,595,280	8,409,060	5,918,400	6,115,680	2,959,200	3,057,840	3,057,840	2,959,200	4,586,760	83,227,500
43	Hedged Rockies supply cost		$3,766,688	$3,892,244	$3,892,244	$2,328,655	$2,578,154	$1,548,450	$1,600,065	$803,625	$830,413	$830,413	$803,625	$1,240,388	$24,114,961
44	Hedged Rockies supply price per therm		$0.29950	$0.29950	$0.29950	$0.30659	$0.30659	$0.26163	$0.26163	$0.27157	$0.27157	$0.27157	$0.27157	$0.27043	$0.28975
45															
46	Load served by gas reserves		4,350,473	4,436,826	4,379,915	3,906,157	4,270,989	4,082,705	4,168,019	3,985,725	4,070,425	4,023,487	3,849,397	3,933,042	49,457,160
47	Gas Reserves cost		$2,714,018	$2,754,710	$2,727,056	$2,526,330	$2,707,081	$2,560,920	$2,636,746	$2,506,958	$2,535,391	$2,509,418	$2,481,776	$2,458,989	$31,119,392
48	Gas Reserves price per therm		$0.62384	$0.62087	$0.62263	$0.64676	$0.63383	$0.62726	$0.63261	$0.62898	$0.62288	$0.62369	$0.64472	$0.62521	$0.62922
49															
50	Washington percentage of total load (line 36 ÷ line 37)		9.6%	9.9%	9.8%	9.8%	9.4%	9.0%	9.4%	9.2%	8.9%	9.0%	9.4%	9.7%	9.6%
51															
52	Total System Commodity Cost (line 14 above)		$22,272,419	$36,175,478	$35,125,813	$31,938,630	$24,548,805	$14,381,004	$11,122,074	$8,389,178	$7,613,109	$7,655,858	$8,299,159	$13,338,965	$220,860,493
53	Less: Commodity Cost of Rockies Hedged Supplies (from line 43)		$3,766,688	$3,892,244	$3,892,244	$2,328,655	$2,578,154	$1,548,450	$1,600,065	$803,625	$830,413	$830,413	$803,625	$1,240,388	$24,114,961
54	Less: Commodity Cost of Gas Reserves (from line 12)		$2,714,018	$2,754,710	$2,727,056	$2,526,330	$2,707,081	$2,560,920	$2,636,746	$2,506,958	$2,535,391	$2,509,418	$2,481,776	$2,458,989	$31,119,392
55	Less: Cost of Index Adder for Gas Reserves Allocated to Baseload		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
56	Total System Commodity Cost excluding Rockies hedged & Gas Reserves		$15,791,714	$29,528,525	$28,506,513	$27,083,646	$19,263,570	$10,271,634	$6,885,264	$5,078,595	$4,247,305	$4,316,028	$5,013,757	$9,639,589	$165,626,139
57															
58	Total System Load Served (from line 29)		81,267,838	116,695,223	111,835,631	100,788,727	77,861,907	57,383,419	40,930,561	29,662,412	25,708,086	25,585,858	27,923,297	49,096,028	744,738,987
59	Less: load from Rockies hedged supplies (from line 42)		12,576,600	12,995,820	12,995,820	7,595,280	8,409,060	5,918,400	6,115,680	2,959,200	3,057,840	3,057,840	2,959,200	4,586,760	83,227,500
60	Less: load served by gas reserves (from line 32)		4,350,473	4,436,826	4,379,915	3,906,157	4,270,989	4,082,705	4,168,019	3,985,725	4,070,425	4,023,487	3,849,397	3,933,042	49,457,160
61	Total System load excluding Rockies hedged & Gas Reserves		64,340,765	99,262,576	94,459,896	89,287,290	65,181,859	47,382,314	30,646,862	22,717,487	18,579,821	18,504,531	21,114,699	40,576,226	612,054,327
62															
63	System price excluding Rockies hedged & Gas Reserves (line 56 ÷ line 61)		$0.24544	$0.29748	$0.30178	$0.30333	$0.29554	$0.21678	$0.22466	$0.22355	$0.22860	$0.23324	$0.23745	$0.23757	$0.27061
64															
65	**Washington allocation of Rockies hedged supply**														
66	Rockies hedged supply needed for Washington (line 50 * (line 42 + line 46))		1,624,999	1,725,832	1,702,822	1,127,141	1,191,925	900,099	966,668	638,933	634,416	637,319	640,008	826,421	12,616,583
67	Cost of Rockies hedged supply allocated to Washington (line 66 * line 44)		$486,687	$516,887	$509,995	$345,570	$365,432	$235,493	$252,909	$173,515	$172,288	$173,077	$173,807	$223,489	$3,629,150
68															
69	**Washington portfolio**														
70	Volumes														
71	Total Washington load		7,832,840	11,587,124	11,009,567	9,898,928	7,342,702	5,193,035	3,834,732	2,737,894	2,300,062	2,301,394	2,628,337	4,747,527	71,414,142
72	Washington load met by Rockies hedged supply		1,624,999	1,725,832	1,702,822	1,127,141	1,191,925	900,099	966,668	638,933	634,416	637,319	640,008	826,421	12,616,583
73	Remaining Washington load		6,207,841	9,861,292	9,306,745	8,771,787	6,150,777	4,292,936	2,868,064	2,098,961	1,665,646	1,664,075	1,988,329	3,921,106	58,797,559
74															
75	Cost														
76	Cost of Rockies hedged supply allocated to Washington (line 67)		$486,687	$516,887	$509,995	$345,570	$365,432	$235,493	$252,909	$173,515	$172,288	$173,077	$173,807	$223,489	$3,629,150
77	Cost of remaining Washington load (line 73 * line 63)		$1,523,652	$2,933,537	$2,808,589	$2,660,746	$1,817,801	$930,623	$644,339	$469,223	$380,767	$388,129	$472,129	$931,537	$15,961,072
78	Total cost of Washington portfolio		$2,010,340	$3,450,424	$3,318,585	$3,006,316	$2,183,233	$1,166,116	$897,249	$642,738	$553,055	$561,206	$645,936	$1,155,026	$19,590,222
79															
80	**Washington Sales WACOG** (line 78 ÷ line 71)		$0.25666	$0.29778	$0.30143	$0.30370	$0.29733	$0.22455	$0.23398	$0.23476	$0.24045	$0.24385	$0.24576	$0.24329	$0.27432
81															
82	**WASHINGTON BILLING WACOG**		$0.26839	$0.31139	$0.31521	$0.31758	$0.31092	$0.23482	$0.24468	$0.24549	$0.25144	$0.25500	$0.25700	$0.25441	$0.28686
83															
84	**Oregon WACOG Calculation**														
85															
86	Total system commodity cost		$22,272,419	$36,175,478	$35,125,813	$31,938,630	$24,548,805	$14,381,004	$11,122,074	$8,389,178	$7,613,109	$7,655,858	$8,299,159	$13,338,965	$220,860,493
87	Commodity cost allocated to Washington portfolio		$2,010,340	$3,450,424	$3,318,585	$3,006,316	$2,183,233	$1,166,116	$897,249	$642,738	$553,055	$561,206	$645,936	$1,155,026	$19,590,222
88	Total commodity cost for Oregon		$20,262,080	$32,725,054	$31,807,228	$28,932,314	$22,365,572	$13,214,889	$10,224,826	$7,746,440	$7,060,054	$7,094,652	$7,653,223	$12,183,939	$201,270,271
89															
90	**Oregon Sales WACOG (line 88 ÷ line 35)**		$0.27592	$0.31135	$0.31547	$0.31832	$0.31716	$0.25321	$0.27563	$0.28771	$0.30161	$0.30469	$0.30256	$0.27473	$0.29892
91															
92	**OREGON BILLING WACOG**		$0.28407	$0.32054	$0.32478	$0.32772	$0.32652	$0.26069	$0.28377	$0.29621	$0.31052	$0.31369	$0.31149	$0.28284	$0.30775

NW Natural
2016-2017 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c) November	(d) December	(e) January	(f) February	(g) March	(h) April	(i) May	(j) June	(k) July	(l) August	(m) September	(n) October	(o) TOTAL
Transport charges by transporter:														
Northwest Pipeline		$4,240,522	$4,381,872	$4,546,280	$4,106,318	$4,546,280	$4,299,811	$4,443,138	$4,299,811	$4,443,138	$4,443,138	$4,299,811	$4,443,138	$52,493,257
Alberta: NOVA		622,069	622,069	622,069	622,069	622,069	622,069	622,069	622,069	622,069	622,069	622,069	622,069	7,464,828
Alberta: Foothills		326,042	326,042	326,042	326,042	326,042	291,019	291,019	291,019	291,019	291,019	291,019	326,042	3,702,366
Alberta: GTN		484,979	501,145	501,145	452,647	501,145	408,140	421,745	408,140	421,745	421,745	408,140	501,145	5,431,861
BC: Southern Crossing		607,319	626,030	626,030	569,898	626,030	607,319	626,030	607,319	626,030	626,030	607,319	626,030	7,381,384
BC: Spectra (Westcoast)		313,500	323,950	323,950	292,600	323,950	313,500	323,950	313,500	323,950	323,950	313,500	323,950	3,814,250
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,256
Total System Demand		$6,613,119	$6,799,796	$6,964,204	$6,388,262	$6,964,204	$6,560,546	$6,746,639	$6,560,546	$6,746,639	$6,746,639	$6,560,546	$6,861,062	$80,512,202

Detail in file "Capacity Contract Monthly Summary for 2016-17 PGA Year.xls"

NW Natural
2016-2017 PGA - SYSTEM: August Filing
Derivation of Oregon per therm Non-Commodity Charges
ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

		Without Revenue Sensitive	WITH Revenue Sensitive
(a)	(b)	(c)	(d)
System Demand		$80,512,202	
Oregon Allocation Factor 1/		89.76%	
Oregon Demand		$72,267,753	
Oregon Firm Sales Forecasted Normal Volumes		615,754,904	
Oregon Interruptible Sales Forecasted Normal Volumes		57,569,942	
Proposed Firm Demand Per Therm 2/		$0.11607	$0.11950
Proposed Interruptible Demand 2/		$0.01381	$0.01422
Proposed MDDV Demand Charge		$1.72	$1.77
Current Firm Demand Per Therm		$0.11525	$0.11849
Current Interruptible Demand		$0.01371	$0.01410
Current MDDV Demand Charge		$1.71	$1.76
Percent Change in Firm Demand		0.71%	
1/Allocation Factor: 2016-17 PGA forecast firm sales volumes:			
	Washington	Oregon	System
Firm Sales	70,224,167	615,754,904	685,979,071
	10.24%	89.76%	100.00%
2/Calculation of Proposed Demand Rates:			
Demand change factor		1.007	
Firm Demand (line 16 * line 30)		$0.11607	$71,472,829
Interruptible Demand (line 17 * line 30)		$0.01381	$794,924
			$72,267,753

NW Natural
2016-2017 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	$0.19307		
6	December	$0.21870		
7	January	$0.22821		
8	February	$0.22789		
9	March	$0.22318		
10	April	$0.20261		
11	May	$0.19961		
12	June	$0.19909		
13	July	$0.19864		
14	August	$0.20462		
15	September	$0.20524		
16	October	$0.21696		
17				
18				
19	Average price, November-March		$0.21821	average lines 5-9
20				
21	Annual average price, November-October		$0.20982	average lines 5-16
22				
23	Ratio of winter to annual		1.03999	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.29892	$0.30775
OR	Oregon Winter WACOG		$0.31087	$0.32005
			line 23 * $0.29892	
WA	Washington Annual WACOG		$0.27432	$0.28686
WA	Washington Winter WACOG		$0.28529	$0.29833
			line 23 * $0.27432	

NW Natural
2016-2017 PGA - OREGON: August Filing
Derivation of Oregon Seasonalized Fixed Charges

Line			Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Demand Increment Eff. 11/01/16	Interr. Demand Increment Eff. 11/01/16	Seasonalized Fixed Charges
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
5										
6	November	2016	40,711,502	24,937,710	2,719,615	5,066,172	73,434,999	$0.11950	$0.01422	$8,005,757
7	December	2016	61,365,594	35,192,088	3,073,577	5,476,839	105,108,098	$0.11950	$0.01422	$11,640,157
8	January	2017	58,503,342	33,677,376	3,043,080	5,602,266	100,826,064	$0.11950	$0.01422	$11,130,302
9	February	2017	52,734,864	30,290,246	2,750,863	5,113,826	90,889,799	$0.11950	$0.01422	$10,026,917
10	March	2017	38,519,846	23,964,564	2,700,285	5,334,511	70,519,206	$0.11950	$0.01422	$7,639,872
11	April	2017	26,905,569	17,474,347	2,446,864	5,363,604	52,190,384	$0.11950	$0.01422	$5,509,413
12	May	2017	17,947,196	12,326,024	2,273,668	4,548,942	37,095,830	$0.11950	$0.01422	$3,840,649
13	June	2017	11,008,391	9,537,485	2,024,318	4,354,324	26,924,518	$0.11950	$0.01422	$2,679,935
14	July	2017	8,608,320	8,666,463	2,191,938	3,941,303	23,408,024	$0.11950	$0.01422	$2,314,001
15	August	2017	8,472,897	8,571,153	2,169,233	4,071,181	23,284,464	$0.11950	$0.01422	$2,286,378
16	September	2017	9,902,336	9,092,899	2,310,885	3,988,840	25,294,960	$0.11950	$0.01422	$2,528,162
17	October	2017	22,455,422	14,707,845	2,477,099	4,708,135	44,348,501	$0.11950	$0.01422	$4,666,210
18										
19										
20										
21			357,135,279	228,438,200	30,181,425	57,569,943	673,324,847			$72,267,753

#	Encana Gas Reserves Deal		Projected November 2016	Projected December 2016	Projected January 2017	Projected February 2017	Projected March 2017	Projected April 2017	Projected May 2017	Projected June 2017	Projected July 2017	Projected August 2017	Projected September 2017	Projected October 2017	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		4,161.83	4,247.12	4,195.12	3,743.43	4,095.21	3,916.61	4,000.31	3,827.03	3,909.99	3,866.42	3,700.51	3,782.25	47,445.83
3	**Rate per Therm (Depletion Rate)**		0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228	0.3228
4	**Delivery Value**		1,343.47	1,371.00	1,354.21	1,208.41	1,321.96	1,264.31	1,291.33	1,235.39	1,262.17	1,248.11	1,194.55	1,220.94	15,315.85
5															0.3228
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		523.60	528.84	527.10	507.86	571.75	512.79	566.26	509.12	512.88	511.13	554.12	507.71	6,333.15
8	**Severance and Ad Valorem Taxes**		137.41	160.70	164.29	144.80	147.05	123.18	125.81	121.28	127.68	127.19	120.84	125.79	1,626.04
9	**Total**		661.01	689.54	691.39	652.65	718.81	635.97	692.08	630.40	640.56	638.32	674.96	633.50	7,959.18
10															0.1678
11	**Average Rate Base**		68,553.44	67,675.30	66,816.48	66,045.94	65,206.65	64,402.27	63,581.52	62,794.64	61,991.55	61,196.97	60,434.82	59,656.69	
12															
13	**Carrying Cost**														
14	**Equity**	**9.5000%**	271.36	267.88	264.48	261.43	258.11	254.93	251.68	248.56	245.38	242.24	239.22	236.14	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**39.4589%**	400.32	385.75	378.15	379.45	372.50	375.45	368.56	364.59	356.36	350.80	347.76	340.19	
17	**Debt**	**6.0560%**	172.98	170.77	168.60	166.66	164.54	162.51	160.44	158.45	156.43	154.42	152.50	150.53	
18	**Total Carrying Cost**		573.30	556.52	546.75	546.10	537.04	537.96	529.00	523.04	512.79	505.22	500.26	490.72	6,358.71
19															0.1340
20	**Total Cost**		2,577.78	2,617.06	2,592.36	2,407.16	2,577.81	2,438.24	2,512.40	2,388.84	2,415.51	2,391.65	2,369.77	2,345.16	29,633.74
21	**Total Volume**		4,161.83	4,247.12	4,195.12	3,743.43	4,095.21	3,916.61	4,000.31	3,827.03	3,909.99	3,866.42	3,700.51	3,782.25	47,445.83
22	**Total Rate Per Therm**		0.619	0.616	0.618	0.643	0.629	0.623	0.628	0.624	0.618	0.619	0.640	0.620	0.625

NW Natural
2016-17 - OREGON PGA Filing
Jonah Gas Reserves Deal

			Projected November 2016	Projected December 2016	Projected January 2017	Projected February 2017	Projected March 2017	Projected April 2017	Projected May 2017	Projected June 2017	Projected July 2017	Projected August 2017	Projected September 2017	Projected October 2017	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		248.63	250.88	245.18	216.58	234.66	222.39	225.17	213.64	216.56	212.54	201.97	205.02	2,693.22
3	**Rate per Therm (Depletion Rate)**		0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722	0.3722
4	**Delivery Value**		92.55	93.39	91.27	80.62	87.35	82.78	83.82	79.53	80.61	79.12	75.18	76.32	1,002.55
5															0.3722
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		25.88	26.07	25.86	24.64	25.35	24.75	24.87	24.39	24.53	24.37	23.92	24.06	298.71
8	**Severance and Ad Valorem Taxes**		8.21	9.49	9.60	8.38	8.43	6.99	7.08	6.77	7.07	6.99	6.60	6.82	92.43
9	**Total**		34.09	35.56	35.46	33.02	33.78	31.75	31.95	31.16	31.60	31.36	30.52	30.88	391.14
10															0.1452
11	**Average Rate Base**		4,436.95	4,375.06	4,315.95	4,263.29	4,206.56	4,152.59	4,097.99	4,045.99	3,993.33	3,941.58	3,892.22	3,842.16	
12															
13	**Carrying Cost**														
14	**Equity**	**9.5000%**	17.56	17.32	17.08	16.88	16.65	16.44	16.22	16.02	15.81	15.60	15.41	15.21	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**39.4589%**	29.01	28.61	28.22	27.87	27.50	27.15	26.79	26.45	26.11	25.77	25.45	25.12	
17	**Debt**	**6.0560%**	11.20	11.04	10.89	10.76	10.61	10.48	10.34	10.21	10.08	9.95	9.82	9.70	
18	**Total Carrying Cost**		40.21	39.64	39.11	38.63	38.12	37.63	37.13	36.66	36.19	35.72	35.27	34.82	449.13
19															0.1668
20	**Total Cost**		166.84	168.60	165.84	152.27	159.25	152.16	152.91	147.36	148.40	146.20	140.97	142.01	1,842.81
21	**Total Volume**		248.63	250.88	245.18	216.58	234.66	222.39	225.17	213.64	216.56	212.54	201.97	205.02	2,693.22
22	**Total Rate Per Therm [1]**		0.671	0.672	0.676	0.703	0.679	0.684	0.679	0.690	0.685	0.688	0.698	0.693	0.684

[1] The actual price included within WACOG is $4.725/Dth per Order No. 15-297

NW Natural
Rates & Regulatory Affairs
2016-17 PGA - Oregon: August Filing
Attachment C: 3% Test

	Surcharge	Credit	
2015-2016 PGA Gas Cost True-Up		(520,437)	
Non-Gas Cost Amortizations			
Intervenor Funding	201,819		
Oregon Regulatory Fee	178,043		
Industrial DSM	3,592,066		
Decoupling	13,209,442		
Subtotal	17,181,370	(520,437)	
Total	16,660,933		
Total Proposed Amortization			16,660,933
Less:			
Intervenor Funding[1]			(201,819)
Industrial DSM[1]			(3,592,066)
Decoupling[1]			(13,209,442)
Net Proposed Amortizations (subject to the 3% test)			(342,394)
Utility Gross Revenues (2015) [2]			653,343,000
3% of Utility Gross Revenues			19,600,290
Allowed Amortization			(342,394)
Allowed Amortization as % of Gross Revenues			-0.1%

Notes:

[1] Amortizations of the deferral are not subject to the 3% test pursuant to ORS 757.259 as they are automatic adjustment clauses.

[2] Unadjusted general revenues as shown in the most recent ROO.

NW Natural
Rates & Regulatory Affairs
2016-17 PGA - Oregon: August Filing Effects
on Average Bill by Rate Schedule [1] ALL
VOLUMES IN THERMS

Advice 16-17
See note [7]

1			Oregon PGA		Normal				Proposed	Proposed	Proposed
2			Normalized		Therms	Minimum	11/1/2015	11/1/2015	11/1/2016	11/1/2016	11/1/2016
3			Volumes page,	Therms in	Monthly	Monthly	Billing	Current	PGA	PGA	PGA
4			Column D	Block	Average use	Charge	Rates	Average Bill	Rates	Average Bill	% Bill Change
5								F=D+(C * E)		W = D+(C * V)	X = (W- F)/F
6	Schedule	Block	A	B	C	D	E	F	V	W	X
7	2R		356,358,823	N/A	51	$8.00	$0.93513	$55.69	$0.91089	$54.46	-2.2%
8	3C Firm Sales		161,456,307	N/A	236	$15.00	$0.87993	$222.66	$0.85569	$216.94	-2.6%
9	3I Firm Sales		4,186,772	N/A	1,008	$15.00	$0.83072	$852.37	$0.80648	$827.93	-2.9%
10	27 Dry Out		776,455	N/A	36	$6.00	$0.80313	$34.91	$0.77889	$34.04	-2.5%
11	31C Firm Sales	Block 1	17,706,769	2,000	3,132	$325.00	$0.61817	**$2,239.46**	$0.59292	**$2,160.38**	-3.5%
12		Block 2	12,889,553	all additional			$0.59905		$0.57380		
13	31C Firm Trans	Block 1	1,364,169	2,000	1,601	$575.00	$0.19118	**$881.08**	$0.19118	**$881.08**	0.0%
14		Block 2	1,632,747	all additional			$0.17480		$0.17480		
15	31I Firm Sales	Block 1	4,263,241	2,000	5,389	$325.00	$0.53466	**$3,149.18**	$0.50941	**$3,013.11**	-4.3%
16		Block 2	9,188,740	all additional			$0.51781		$0.49256		
17	31I Firm Trans	Block 1	175,539	2,000	5,773	$575.00	$0.17031	**$1,496.44**	$0.17031	**$1,496.44**	0.0%
18		Block 2	517,230	all additional			$0.15394		$0.15394		
19	32C Firm Sales	Block 1	27,396,213	10,000	8,022	$675.00	$0.46316	**$4,390.47**	$0.43791	**$4,187.91**	-4.6%
20		Block 2	8,169,994	20,000			$0.44762		$0.42237		
21		Block 3	807,546	20,000			$0.42176		$0.39651		
22		Block 4	11,819	100,000			$0.39586		$0.37061		
23		Block 5	0	600,000			$0.38034		$0.35509		
24		Block 6	0	all additional			$0.36996		$0.34471		
25	32I Firm Sales	Block 1	4,897,403	10,000	21,331	$675.00	$0.46083	**$10,333.30**	$0.43558	**$9,794.69**	-5.2%
26		Block 2	5,116,186	20,000			$0.44568		$0.42043		
27		Block 3	1,948,136	20,000			$0.42039		$0.39514		
28		Block 4	580,946	100,000			$0.39514		$0.36989		
29		Block 5	0	600,000			$0.37996		$0.35471		
30		Block 6	0	all additional			$0.36991		$0.34466		
31	32 Firm Trans	Block 1	14,611,752	10,000	41,387	$925.00	$0.10049	**$4,325.62**	$0.10049	**$4,325.62**	0.0%
32		Block 2	17,230,536	20,000			$0.08542		$0.08542		
33		Block 3	9,911,484	20,000			$0.06036		$0.06036		
34		Block 4	17,461,606	100,000			$0.03528		$0.03528		
35		Block 5	21,764,847	600,000			$0.02021		$0.02021		
36		Block 6	2,455,153	all additional			$0.01022		$0.01022		
37	32C Interr Sales	Block 1	6,252,115	10,000	35,083	$675.00	$0.45065	**$15,961.70**	$0.42650	**$15,114.45**	-5.3%
38		Block 2	8,553,424	20,000			$0.43505		$0.41090		
39		Block 3	4,339,671	20,000			$0.40905		$0.38490		
40		Block 4	5,183,222	100,000			$0.38306		$0.35891		
41		Block 5	89,527	600,000			$0.36743		$0.34328		
42		Block 6	0	all additional			$0.35709		$0.33294		
43	32I Interr Sales	Block 1	7,427,326	10,000	41,859	$675.00	$0.45043	**$18,727.71**	$0.42628	**$17,716.82**	-5.4%
44		Block 2	8,841,797	20,000			$0.43491		$0.41076		
45		Block 3	4,869,921	20,000			$0.40899		$0.38484		
46		Block 4	9,961,831	100,000			$0.38308		$0.35893		
47		Block 5	2,051,108	600,000			$0.36752		$0.34337		
48		Block 6	0	all additional			$0.35718		$0.33303		
49	32 Interr Trans	Block 1	8,822,944	10,000	195,043	$925.00	$0.10132	**$9,353.93**	$0.10132	**$9,353.93**	0.0%
50		Block 2	16,011,309	20,000			$0.08615		$0.08615		
51		Block 3	11,561,774	20,000			$0.06087		$0.06087		
52		Block 4	29,665,818	100,000			$0.03556		$0.03556		
53		Block 5	56,877,518	600,000			$0.02041		$0.02041		
54		Block 6	83,025,918	all additional			$0.01029		$0.01029		
55	33		0	N/A	0	$38,000.00	$0.00586	$38,000.00	$0.00586	$38,000.00	0.0%
56											
57	**Totals**		966,415,190								
58											

59 [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.
60 [2] Tariff Advice Notice 16-10: Non-Gas Cost Deferral Amortizations - Intervenor Funding
61 [3] Tariff Advice Notice 16-15: Non-Gas Cost Deferral Amortizations - Industrial DSM
62 [4] Tariff Advice Notice 16-14: Non-Gas Cost Deferral Amortizations - SRRM
63 [5] Tariff Advice Notice 16-16: Non-Gas Cost Deferral Amortizations - Decoupling
64 [6] Tariff Advice Notice 116-13: Non-Gas Cost Deferral Amortizations - Oregon PUC Fee
65 [7] Tariff Advice Notice 16-17: PGA

NW Natural
Rates and Regulatory Affairs
2016-2017 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/16		
1				
2				
3	Total Billed Gas Sales Revenues	$606,080,614		
4	Total Oregon Revenues	$611,607,847		
5				
6	Regulatory Commission Fees [1]	$1,633,358	0.275%	Statutory rate
7	City License and Franchise Fees	$14,818,591	2.423%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$1,036,942	0.170%	Line 8 ÷ Line 4
9				
10	Total	$17,488,891	**2.868%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed occurred mid gas year, the difference between the previous fee of 0.25%
16 and the new fee of 0.275% is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2016-2017 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 16-17: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitve Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($18,799,230)
6		
7	Demand Capacity Cost Change	(669,747)
8		
9	**Total Gas Cost Change**	**(19,468,977)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	2,648,070
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(520,437)
18		
19	**Net Temporary Rate Adjustment**	**2,127,633**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($17,341,344)**
22		
23		
24		
25	2015 Oregon Earnings Test Normalized Total Revenues	$653,343,000
26		
27	Effect of this filing, as a percentage change (line 21 ÷ line 25)	-2.65%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 16-17 / UG 313

July 29, 2016

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	4	-
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.	6	-
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.	7	
2	Workpapers		
a)	PGA Summary Sheet	8	-
b)	Gas Supply Portfolio and Related Transportation		
1	Summary of portfolio planning	10	-
2	LDC sales system demand forecasting	11	-
3	Natural gas price forecasts	11	-
4	Physical resources for the portfolio	12	
	Supporting Tables	17-21	- CONFIDENTIAL
5	Financial resources for the portfolio (derivatives and other financial arrangements).	15	CONFIDENTIAL
6	Storage resources.	15	-
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.	22	-
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	22	-
9	Summary of portfolio documentation provided	22	-
V.1	**Physical Gas Supply**		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:	23	
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.	23	
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.	23	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
3	Brief explanation of each contract's role within the portfolio.	23	
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:	25	
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.	25	
2	Any contract provisions that materially deviate from the standard NAESB contract.	25	
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.	27	HIGHLY CONFIDENTIAL
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	29	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	30	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	30	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,	30	
1	Annual for each customer class	30	
2	Annual and monthly baseload.	31	
3	Annual and monthly non-baseload.	31	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	31	
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.	33	
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.	37	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
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.	38	
	NW Natural Gas Supply Risk Management Policies	39	CONFIDENTIAL
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.	66	
a)	Type of storage (e.g., depleted field, salt dome).	66	
b)	Location of each storage facility.	66	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	66	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	66	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	66	
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.	68	
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.	69	
h)	For LDCs that own and operate storage:		CONFIDENTIAL
a.	The date and results of the last engineering study for that storage.	83	
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.	98	
V.8	**Attestation as to Consistency**	99	

Section IV. General Information and Forecasting

1. General Information

a) Definitions of all major terms and acronyms in the data and information provided.

AECO	The industry acronym used for Alberta sourced natural gas supply. It originally comes from Alberta Energy Company which was incorporated in 1973 by the Alberta government (fully divested in 1993).
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 distributed or sold by NW Natural are at a maximum. May be theoretical (the "design day") or actual.
Pipeline Capacity	The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand".
Recallable gas supply/capacity	Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties.
Revenue Sensitive	The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.
Technical Rate Adjustments	Also referred to as Temporary Rate Adjustments.
Therm	A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas.

Total Commodity Cost	The combined costs for all purchased gas supplies, excluding transportation costs.
Total Gas Cost	The combined costs of all purchased gas supplies and associated transportation costs.
Transportation Cost	The combined costs for all pipeline related demand, capacity or reservation charges
Transportation Resources	The various upstream pipeline capacity agreements held by the company.
Upstream pipeline	Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural's service territory.
Upstream pipeline capacity	Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines.
WACOG	The Company's weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG.
Winter Sales WACOG	The Company's winter period weighted average commodity cost of gas (excluding transportation cost).

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 occurred on April 1, 2016. The impact on NW Natural's operations has been minimal so far.

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.**

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.

2. Workpapers

a) PGA Summary

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	($22,400,000)	Refer to workpaper "PGA filing Summary Effects"
B) Percent *(To .1 percent)*	-3.43%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	($19,468,977)	Refer to workpaper "PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	($29,851,086)	"
C) Add New Temporary Increment	$26,934,510	"
D) Other Additions or Subtractions (*Break out & List each below -- Attach additional sheet if necessary*)		
1)		Refer to workpaper "PGA filing Summary Effects"
2)		
3)		
4)		
5)		
6)		
E) Total Proposed Change	($22,385,553)	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$0.93513	Refer to workpaper "2015-16 Rate Development"
2) Proposed Billing Rate per Therm	$0.89736	"
3) Rate Change Per Therm	($0.03777)	"
4) Percent Change per Therm (to .1%)	-4.0%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	51.0	Refer to workpaper "2015-16 Rate Development"
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$55.69	"
4) Proposed Average Monthly Bill	$53.77	"
5) Change in Average Monthly Bill	($1.92)	"
6) Percent change in Average Monthly Bill (to .1%)	-3.4%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use (forecasted weather-normalized)	118.0	N/A
2) Customer Charge	$8.00	N/A
3) Current Average January Bill	$118.35	N/A
4) Proposed Average January Bill	$113.76	N/A
5) Change in Average January Bill	($4.59)	N/A

6) Percent change in Average January Bill (to .1%)	-3.9%	N/A
	Amount	**Location in Company Filing (cite)**
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	$246,010,878	2015-16 PGA filing
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Volumetric Cost (assoc. w/ supply)	$2,104,774	2015-16 PGA filing
e) Total Storage Cost (assoc. w/ supply)	$59,552,312	2015-16 PGA filing
f) Other	$34,269,038	2015-16 PGA filing
2) Total Transportation Cost *(Pipeline related)*	$81,312,709	2015-16 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	$327,323,587	
B) Projected For New Rates		
1) Total Commodity Cost	$220,860,493	Exhibit B, Page 1
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Vaporization Cost (assoc. w/ supply)		Exhibit B, Page 1
e) Total Volumetric Cost (assoc. w/ supply)	$2,016,848	Exhibit B, Page 1
f) Total Storage Cost (assoc. w/ supply)	$49,921,473	Exhibit B, Page 1
g) Other (A&G Benchmark Savings)	$31,119,392	Exhibit B, Page 3
2) Total Transportation Cost (Pipeline related)	$80,512,202	
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	$301,372,695	
	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	$0.33602	N/A
b. Without revenue sensitive	$0.32684	N/A
2) WACOG (Non-Commodity)		

a. With revenue sensitive	$0.11849	N/A
b. Without revenue sensitive	$0.11525	N/A
B) Proposed for New Rates		
1) WACOG (Commodity Only)		
a. With revenue sensitive	$0.30775	Exhibit B, Page 6 and Page 9
b. Without revenue sensitive	$0.29892	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.11950	Exhibit B, Page 8
b. Without revenue sensitive	$0.11607	"
6) Therms Sold	622,857,896	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	"

b) Gas Supply Portfolio and Related Transportation

1. Summary of portfolio planning

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

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

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 likely correlation of high requirements with high spot prices;
(5) Take advantage of favorable pricing opportunities to use supply-basin storage when possible;
(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 physical 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.

2. LDC sales system demand forecasting

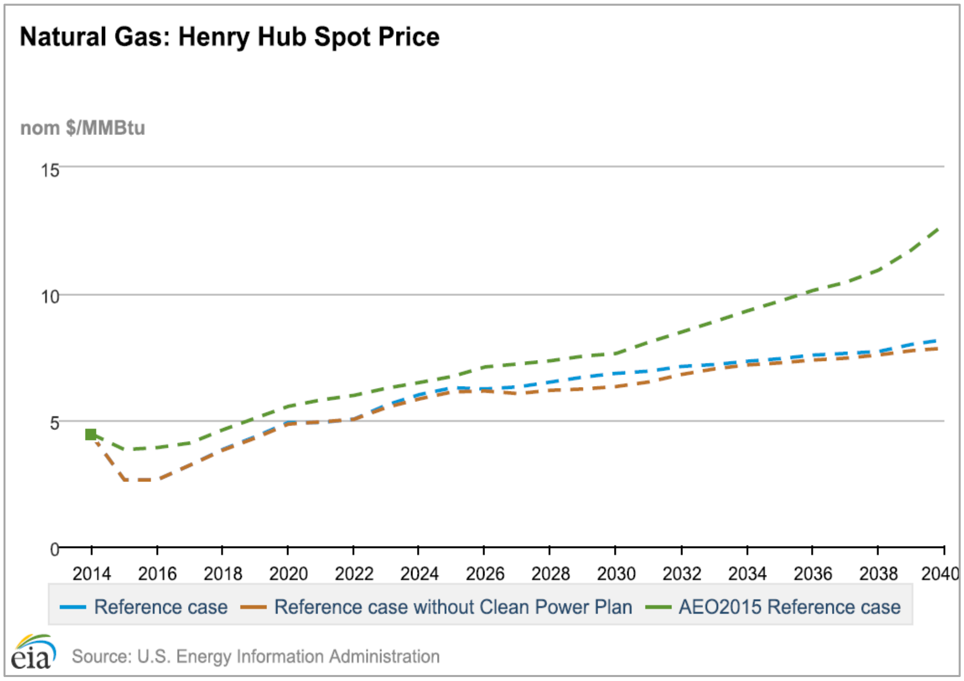
The company's methodology for forecasting annual sales and firm peak day requirements follow the methodology established in its Integrated Resource Plan (IRP), of which the latest is the draft 2016 IRP filed with the WUTC and provided to the OPUC on June 28, 2016. Also applicable here is the load forecast methodology previously established for PGA filings.

This means that while the demand forecast reflects "normal" weather, the company still is planning for the possibility 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 (formerly known as 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 embedded in EIA's 2016 Annual Energy Outlook (this chart was downloaded from the EIA website as the actual report has not been published yet). The 2016 Reference case is shown along with an alternate scenario, and for purposes of comparison, the Reference case from EIA's 2015 Annual Energy Outlook also is shown. It indicates that prices currently have bottomed out. Even though EIA predicts natural gas production will continue to grow, this is generally offset by demand growth that is led by gas exports in the form of LNG as well as via pipeline to Mexico.



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.

Five significant changes to the physical supply resource portfolio were discussed in last year's PGA filing:

(1) Termination effective 11/1/2015 of the 601,000 therm/day storage contract at the Plymouth LNG plant due to uncertainty over its reliability after a Northwest Pipeline curtailment of its related TF-2 pipeline transportation service during the 2013/14 winter (this occurred several months prior to the Plymouth plant explosion/outage);
(2) Continuation of a 200,000 therm/day citygate peaking supply contract with a gas marketing company to offset a portion of the lost Plymouth capacity;
(3) Continued reliance on "segmented" capacity of 438,000 therms/day from Sumas/Huntingdon as a stopgap measure to offset the rest of the Plymouth loss;
(4) The signing of a 300,000 therm/day contract for T-South pipeline capacity on the Westcoast Energy (Spectra) pipeline system in British Columbia, which moves the purchasing location of equivalent supply volumes from Sumas/Huntingdon to Station 2; and
(5) The signing of a contract with Northwest Pipeline to provide 135,250 therms/day of discounted TF-1 service from Jackson Prairie, eliminating reliance on an equivalent volume of "subordinate" TF-2 capacity from that storage facility.

This year, there are five significant changes to the physical supply resource portfolio to discuss, as follow:

(1) Segmented Capacity. There is no incremental demand charge for segmented capacity; its only pipeline costs are the small variable and fuel-in-kind charges for volumes actually delivered. That makes it

incredibly cost-effective as a resource **if** the capacity can be considered reliable. NWN's confidence has grown in the reliability of segmented capacity from Sumas, at least for the next several years, per an analysis provided in Chapter 3 of the recently filed 2016 draft IRP. Accordingly, NWN not only continues to use segmented capacity as a component of its firm resource portfolio, but has been able to increase its segmented capacity position from 438,000 to 607,000 therms/day.

(2) Storage Plant Heat Content Adjustment. NWN's two LNG facilities in Portland and Newport were designed and permitted in volumetric units, which then are converted to energy units for IRP and PGA purposes. This also is the practice for the working gas capacity at Mist, through not for Mist deliverability, which always has been designated in energy units through the "Mist recall" process. Heat content in Btus per cubic foot (Btu/cf) is the conversion factor from volumetric to energy units, and it was relatively stable in the past. In recent years, though, a glut of natural gas liquids (NGLs) has developed in the supply basins. With falling commodity prices, the incentive to process NGLs out of the gas stream has shrunk. In particular, the profit margins for separating ethane are such that a noticeable amount of ethane is being left in the natural gas stream. The heat content on Northwest Pipeline's system has moved from a range around 1020 Btu/cf to a range closer to 1080-1090 Btu/cf.

(3) March Point Contract. NWN entered into an agreement with the March Point Cogeneration Company in 2008 to acquire its Northwest Pipeline firm TF-1 capacity contract. This capacity has been part of NW Natural's IRP planning since that time. The capacity is 120,000 therms/day from the Rockies, and as part of the agreement, the capacity (and responsibility for the capacity payments) does not transfer from March Point to NWN until January 1, 2017. Hence, this is the first PGA filing that willl include costs for this contract.

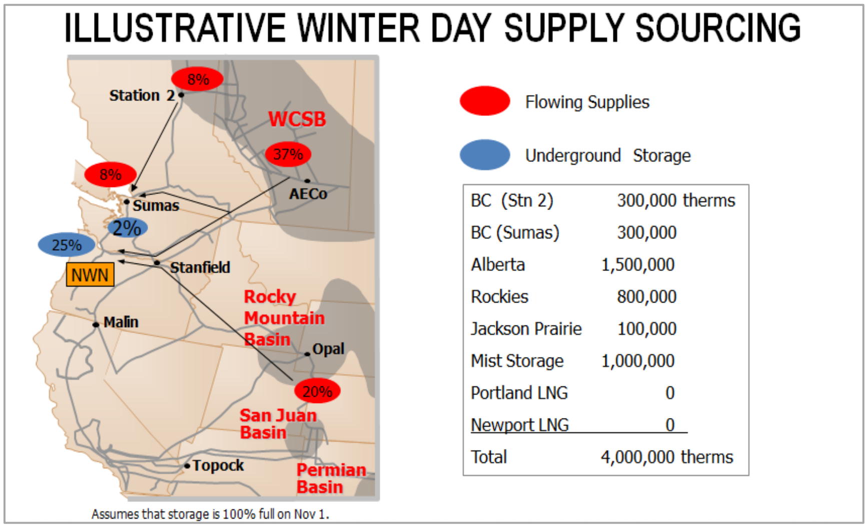
(4) Citygate Deliveries. The increases in segmented capacity and LNG plant deliverability, along with the commencement of the March Point capacity, have eliminated the need to contract for citygate deliveries for this coming winter.

(5) T-South Capacity. Last year's 300,000 therm/day contract had a 1-year term and will expire 10/31/2016. New contracts were offered from various gas marketers at varying prices that were all higher than last year due to widening spreads between Station 2 and Sumas commodity prices. NWN has signed a new T-South contract for 190,000 therms/day for a 2-year term starting 11/1/2016. The economic analysis is provided in a separate spreadsheet in this file labeled "T-South analysis".

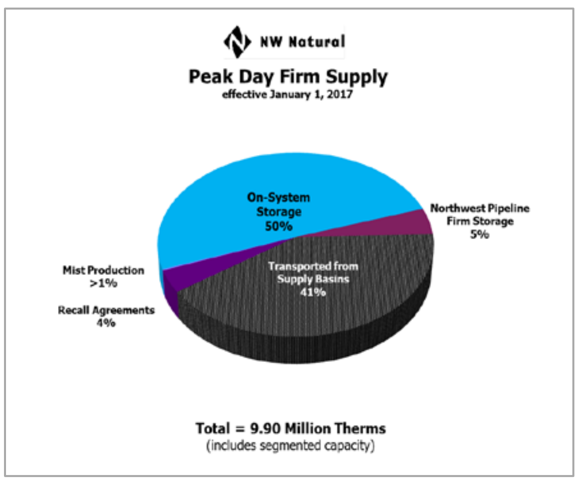
As a reminder from prior years, a small "de-rate" continues to be in place for the Newport LNG tank capacity. This reflects the gradual accumulation of frozen carbon dioxide (commonly known as "dry ice") on the tank floor over the plant's 35 years of operation. This has not reduced Newport's design peak 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 addresses 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 reflects the regulatory settlement regarding those seven wells, i.e., those volumes are 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.



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 2016 through October 2017 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 2016 through March 2017 heating season, NWN will have contracts for an additional 1.15 million therms/day of supply under baseload agreements, and another 300,000 therms/day under peaking ("swing") contracts in the supply basins. 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 thus have a maximum total of 1.80 million therms/day (0.65 million year-round plus 1.15 million winter season) that are purchased on a take-or-pay basis. The remaining 0.30 million therms/day of swing gas is 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 1.33 and 1.63 million therms/day of firm upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. And up to an additional 0.61 million therms/day could be purchased on the spot market if the segmented capacity is utilized. Accordingly, on days when all upstream capacity is in use, purchases would be split among three categories – year-round contracts, winter term contracts and spot purchases.

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

NWN "swaps" monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage, 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 sales requirements for the upcoming 12-month period commencing November 1st. As storage currently accounts for about 19% of annual purchase quantities, gas reserves will amount to roughly 7% for this tracker year and local (Mist) gas production adds another 1%, approximately 48% is left to be financially hedged. 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.

[START CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

6. Storage resources

NWN relies on four storage facilities and two 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 two Alberta supply-basin storage arrangements are with 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 attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large “lumpy” resource additions requiring years of preparation, the “pre-build” of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development. The 300,000 therm/day Mist recall that occurred last year was 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.

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Supporting information to IV.2.b.4

T-South Contract Economic Analysis - January 2016

[redacted]

Supporting information to IV.2.b.4

TABLE 1
NW Natural Firm Off-System Gas Supply Contracts
for the 2016-2017 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia:				
PetroChina International	Nov-Mar	5,000		3/31/2017
Conoco Phillips	Nov-Oct	5,000		10/31/2017
J. Aron	Nov-Oct	5,000		10/31/2017
Pending	Nov-Mar	10,000		3/31/2017
Pending	Nov-Mar	10,000		3/31/2017
Pending	Nov-Mar	5,000		3/31/2017
Alberta:				
Conoco Phillips	Nov-Mar	5,000		3/31/2017
Suncor Energy	Nov-Mar	5,000		3/31/2017
Cargill	Nov-Mar	10,000		3/31/2017
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2017
Pending	Nov-Oct	10,000		10/31/2017
Pending	Nov-Oct	5,000		10/31/2017
Pending	Nov-Mar	5,000		3/31/2017
Pending	Nov-Mar	5,000		3/31/2017
Pending	Nov-Mar	10,000		3/31/2017
Pending	Nov-Mar	5,000		3/31/2017
J. Aron	Nov-Mar		10,000	3/31/2017
J. Aron	Apr-Oct		10,000	10/31/2017
Rockies:				
Anadarko Energy Services	Nov-Mar	5,000		3/31/2017
QEP Energy Company	Nov-Mar	5,000		3/31/2017
Enstor Energy Services	Nov-Oct	10,000		10/31/2017
Macquarie Energy	Nov-Oct	10,000		10/31/2017
Occidental	Nov-Mar	5,000		3/31/2017
Macquarie Energy	Nov-Mar	5,000		3/31/2017
Anadarko Energy Services	Nov-Oct	5,000		10/31/2017
Pending	Nov-Mar	15,000		3/31/2017
Pending	Nov-Oct	5,000		10/31/2017
Pending	Nov-Oct	10,000		10/31/2017
Pending	Nov-Mar		20,000	3/31/2017
Pending	Apr-Oct		20,000	10/31/2017
Total, November-March		180,000	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 at the supplier's discretion.

Total, April-October	**45,000**	**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 at the supplier's discretion.

Supporting information to IV.2.b.4

TABLE 2
NW Natural Firm Transportation
for the 2016-2017 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
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to - Portland General Electric	(30,000)	10/31/2018
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2021
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2017
1995 Rationalization	57,417	10/31/2017
Engage Capacity Acquisition	3,708	10/31/2017
2004 Capacity Acquisition	48,669	10/31/2017
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)	19,000	10/31/2018
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 2-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. March Point capacity commences January 1, 2017.
5. Segmented capacity has not been included in this table.

Supporting information to IV.2.b.4

TABLE 3
NW Natural Firm Storage Resources
for the 2016-2017 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	13,525	n/a	10/31/2023
Firm On-System Storage Plants:			
Mist (reserved for core)	305,000	10,960,560	n/a
Portland LNG Plant	128,800	644,400	n/a
Newport LNG Plant	65,340	980,100	n/a
Total On-System Storage	499,140	12,585,060	
Total Firm Storage Resource	545,170	13,705,348	

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. 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 1040 Btu/cf. The current heat content used for Newport is 1074 Btu/cf and Portland LNG is 1089 Btu/cf.
6. Newport tank capacity de-rated from 1,000,000 Dth pending CO2 removal project.
7. The Company's Plymouth-related contracts terminated 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:

   J. Aron & Company – 1,530,000 Dth
   Tenaska Marketing Canada – 947,817 Dth

Supporting information to IV.2.b.4

TABLE 4

NW Natural Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2016-2017 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2018
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:			
None	-		
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 2016-2017 Tracker Year

Resource Type	(Dth/day)
Net Deliverability over Upstream Pipeline Capacity	343,237
Off-System Storage (Jackson Prairie only)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	499,140
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	-
Nominal Mist Production Gas	2,000
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	990,107

Notes:
1. Per 2016 IRP draft filed 6/28/2016 (specfically page 2.43), design peak day firm sales forecast for the 2016-17 winter is 978,000 Dth.
2. Per 2016 IRP draft filed 6/28/2016 (specfically page 3.19), Segmented Capacity currently is included as a firm resource until 11/1/2020.
3. Since firm resources (including Segmented Capacity) exceed the design peak day firm sales forecast, Citygate Deliveries are not being pursued for this tracker year.

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.

	2016/2017
Forecast Annual Demand (therms)	744,738,987
Forecast Peak Demand (therms) - Normal	4,071,427
Forecast Peak Demand (therms) - Design	9,777,033
Forecast DSM Annual (therms)	0
Forecast DSM Peak (therms) - Design Peak	0
Forecast Annual Demand with Forecast DSM	744,738,987
Forecast Peak Demand with Forecast DSM - Normal	4,071,427
Forecast Peak Demand with Forecast DSM - Design	9,777,033

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

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.

9. Summary of portfolio documentation provided

See Index.

Section 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.

See Tables 1-4 below.

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

See Tables 1-4 below.

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

See Tables 1-4 below. **[BEGIN HIGHLY CONFIDENTIAL]**

TABLE 1

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2016 - October 31, 2017
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per 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
Enstor Energy Services, LLC (NGRs)	11/1/2016	10/31/2017	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal
QEP Energy Company (1)	11/1/2016	3/31/2017		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
MacQuarie Energy, LLC (2)	11/1/2016	3/31/2017		IFGMR-NWP Rockies FOM	5,000				Opal
Anadarko Energy Services Company (3)	11/1/2016	10/31/2017		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
MacQuarie Energy, LLC (4)	11/1/2016	10/31/2017		IFGMR-NWP Rockies FOM	10,000				Opal
Anadarko Energy Services Company (5)	11/1/2016	3/31/2017		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Occidental Energy Marketing (5)	11/1/2016	3/31/2017		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool

PENDING:
NGR's: 10,000 Dth's
One Year Baseload: 5,000 Dth's
Winter Baseload: 15,000 Dth's

Transactions for new PGA year

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

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

TABLE 2

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2016 - October 31, 2017
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per 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	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions
PetroChina International (Canada) Trading Ltd. (1)	11/1/2016	3/31/2017	[redacted]	IFGMR-NWP Canadian Border FOM	5,000			

PENDING:
Winter Baseload: 20,000 Dth's

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	5	+$0.015 to +$0.025	Price

TABLE 3

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2016 - October 31, 2017
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per 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
ConocoPhillips Canada Marketing & Trading ULC (1)	11/1/2016	10/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000
J. Aron & Company (2)	11/1/2016	10/31/2017		CGPR AECO FOM (7A) $US/Dth	5,000

PENDING:
Winter Baseload: 5,000 Dth's

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	7	[redacted]	Price
(2)	3		Price

TABLE 4

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2016 - October 31, 2017
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per 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
Cargill Ltd. (1)	11/1/2016	3/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		
Suncor Energy Marketing (2)	11/1/2016	3/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Shell Energy North America (Canada) (3)	11/1/2016	3/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
ConocoPhillips Canada Marketing & Trading (4)	11/1/2016	3/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
PENDING: **One Year Baseload: 15,000 Dth's** **Winter Baseload: 25,000 Dth's**							
J. Aron & Company	11/1/2016	3/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth		up to 10,000	NW Natural Call Option
J. Aron & Company	4/1/2017	10/31/2017	[redacted]	CGPR AECO FOM (7A) $US/Dth		up to 10,000	J. Aron Put Option

Transactions for new PGA year

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

[END CONFIDENTIAL]

b) For purchases of physical natural gas supply resources 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 complete by the utility.

1. The purchasing of baseload and spot supplies for the 2016-2017 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 2016-2017, 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.

Section 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.

2016-2017 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	2016-17 Days	Daily Volume	Trade Volume	[redacted]	[redacted]	Including Multi-Year	
8-Aug-14	2014-43	[redacted]	[redacted]	AECO	Nov-Mar (2014-2017)	151	2,500	377,500	[redacted]	[redacted]	757,500	$2,912,587.50
15-Aug-14	2014-45	[redacted]	[redacted]	AECO	Nov-Mar (2014-2017)	151	2,500	377,500	[redacted]	[redacted]	757,500	$2,842,518.75
26-Mar-15	2015-7	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,805,087.50
10-Apr-15	2015-12	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,023,640.00
20-Apr-15	2015-15	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,759,687.50
30-Apr-15	2015-19	[redacted]	[redacted]	Rockies	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,708,612.50
22-May-15	2015-22	[redacted]		Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,912,345.00
27-May-15	2015-24	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,081,525.00
29-May-15	2015-27	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,991,860.00
4-Jun-15	2015-28	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,955,540.00
30-Jun-15	2015-33	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$3,020,802.50
18-Sep-15	2015-44	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,803,450.00
25-Sep-15	2015-46	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,733,080.00
1-Oct-15	2015-50	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,636,037.50
21-Oct-15	2015-53	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,620,715.00
27-Oct-15	15-MM-22	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	$2,594,610.00
24-Feb-16	**2016-1**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$514,050.00**
8-Mar-16	**2016-2**	[redacted]	[redacted]	**AECO**	**Nov**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$490,500.00**
9-Mar-16	2016-3	[redacted]		Rockies	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,163,800.00
10-Mar-16	**2016-4**	[redacted]	[redacted]	**AECO**	**Nov**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$522,750.00**
10-Mar-16	**2016-5**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**5,000**	**155,000**	[redacted]	[redacted]	**155,000**	**$303,025.00**
15-Mar-16	2016-6	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,197,047.50
16-Mar-16	**2016-7**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$574,200.00**
18-Mar-16	**2016-8**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$576,600.00**
21-Mar-16	2016-9	[redacted]	[redacted]	Stn 2	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,064,030.00
22-Mar-16	2016-10	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,204,408.75
28-Mar-16	2016-11	[redacted]	[redacted]	Stn 2	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$937,480.00
29-Mar-16	2016-12	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,318,225.00
30-Mar-16	2016-13	[redacted]		Rockies	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,275,580.00
31-Mar-16	**2016-14**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$591,900.00**
31-Mar-16	2016-15	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,613,243.75
6-Apr-16	2016-16	[redacted]	[redacted]	Rockies	Apr-May	61	5,000	305,000	[redacted]	[redacted]	305,000	$713,395.00
7-Apr-16	**2016-17**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$582,450.00**
8-Apr-16	**2016-18**	[redacted]	[redacted]	**AECO**	**Nov-Dec**	**61**	**10,000**	**610,000**	[redacted]	[redacted]	**610,000**	**$1,187,060.00**
11-Apr-16	**2016-19**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$564,900.00**
11-Apr-16	2016-20	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,307,466.25
12-Apr-16	**2016-21**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$622,170.00**
18-Apr-16	2016-22	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,519,812.50
19-Apr-16	2016-23	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,722,080.00
20-Apr-16	2016-24	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,570,208.75
21-Apr-16	2016-25	[redacted]		Rockies	Oct	31	5,000	155,000	[redacted]	[redacted]	155,000	$409,975.00
22-Apr-16	2016-26	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,624,568.75
25-Apr-16	2016-27	[redacted]		AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,618,340.00
28-Apr-16	**2016-28**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$679,520.00**
28-Apr-16	2016-29	[redacted]		Rockies	Apr-May	61	5,000	305,000	[redacted]	[redacted]	305,000	$788,120.00
29-Apr-16	2016-30	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,532,267.50
10-May-16	2016-31	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,468,281.25
12-May-16	2016-32	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,115,390.00
16-May-16	2016-33	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,402,030.00
18-May-16	2016-34	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,334,080.00
20-May-16	2016-35	[redacted]		Sumas	Nov-Mar	151	5,000	755,000	[redacted]	[redacted]	755,000	$2,219,700.00
23-May-16	2016-36	[redacted]		AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,567,943.75
24-May-16	**2016-37**	[redacted]	[redacted]	**AECO**	**May**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$585,900.00**
24-May-16	**2016-38**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	**$646,970.00**
26-May-16	2016-39	[redacted]		AECO	Oct	31	5,000	155,000	[redacted]	[redacted]	155,000	$335,187.50
27-May-16	2016-40	[redacted]		AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,658,543.75
1-Jun-16	2016-41	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,522,641.25
2-Jun-16	2016-42	[redacted]	[redacted]	Stn 2	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$2,188,150.00
14-Jun-16	2016-43	[redacted]		Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$3,568,507.50
20-Jun-16	2016-44	[redacted]		AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,720,265.00
23-Jun-16	2016-45	[redacted]		Sumas	Nov-Feb	120	5,000	600,000	[redacted]	[redacted]	600,000	$1,999,200.00
24-Jun-16	2016-46	[redacted]		Rockies	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,460,500.00
27-Jun-16	2016-47	[redacted]	[redacted]	Stn 2	Nov-Jan	92	5,000	460,000	[redacted]	[redacted]	460,000	$1,059,380.00
29-Jun-16	**2016-48**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**5,000**	**155,000**	[redacted]	[redacted]	**155,000**	**$348,285.00**
29-Jun-16	**2016-49**	[redacted]	[redacted]	**AECO**	**Nov**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	**$651,750.00**
30-Jun-16	2016-50	[redacted]		AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	$2,788,781.25
11-Jul-16	2016-51	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	$3,007,770.00
								0		[redacted]		
Total Hard Hedges								27,997,500	[redacted]	[redacted]	53,707,500	$140,840,528.75
(Hedges during 2016)								0		$0.00		$0.00

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2016-2017 FINANCIAL SOFT HEDGES (counterparty owns option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Total Trade Volume	[redacted]	[redacted]	CALL STRIKE PRICE
Total Soft Hedges								0	[redacted]	[redacted]	
Total Hard and Soft Hedges								[redacted]	[redacted]	[redacted]	
[redacted]											
Total Baseload Hedges								[redacted]		[redacted]	
Total Baseload Hedges including Index Adjustments										[redacted]	

Hedges by Counterparty:	Approved for Multi-Year Hedges	Hedges for Nov 2016 - Oct 2017			All Hedges Nov16 Forward	
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted] place)		0		$0.00	0	$0.00

*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, including extendible options and multi-year hedges in place.

Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

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

	2016/2017 Forecasted	2015/2016	2014/2015	2013/2014	2012/2013	2011/2012
System peak demand (therms)	9,777,033	9,452,960	9,369,764	9,320,242	9,252,236	9,424,400

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

Gas Year	Forecasted 2016/2017	2015/2016	2014/2015	2013/2014	2012/2013	2011/2012
Annual Demand (therms)	744,738,987	757,005,313	747,790,904	746,847,556	732,272,081	759,952,952

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 2016/2017	2015/2016	2014/2015	2013/2014	2012/2013	2011/2012
Residential (therms)	403,236,093	413,822,757	402,683,123	396,647,034	388,025,253	424,142,259
Commercial (therms)	249,799,490	251,595,828	248,351,476	245,792,366	234,253,226	257,323,299
Industrial Firm (therms)	32,943,487	32,420,945	34,513,268	33,853,619	37,619,102	36,394,872
Industrial Interruptible (therms)	58,759,917	59,165,782	62,243,048	70,554,536	64,343,014	61,458,451

2. Annual and monthly baseload.

Gas Year	Forecasted 2016/2017	2015/2016	2014/2015	2013/2014	2012/2013	2011/2012
November	24,554,895.58	22,351,644	22,999,936	22,397,233	22,308,001	22,343,188
December	25,262,436.80	22,916,079	24,282,715	23,202,872	23,064,485	23,284,414
January	25,346,740.02	22,938,449	24,362,006	23,196,614	23,081,208	23,283,122
February	24,129,267.19	21,874,421	22,159,174	20,943,260	20,859,821	21,819,517
March	25,387,380.30	22,968,882	23,866,828	23,202,391	23,109,951	23,298,952
April	24,778,007.82	22,440,684	22,869,798	22,513,500	22,379,225	22,514,758
May	25,382,611.30	22,997,543	23,238,337	23,254,362	23,138,668	23,251,908
June	24,738,270.85	22,470,443	22,332,108	22,556,453	22,399,655	22,449,749
July	25,327,244.58	23,023,353	23,019,887	23,314,587	23,152,520	22,784,459
August	25,304,863.03	23,050,124	23,015,123	23,324,427	23,162,291	23,007,978
September	24,686,183.77	22,527,362	22,737,568	22,537,805	22,425,676	22,273,329
October	25,342,154.07	23,100,640	23,881,459	23,359,078	23,196,701	23,035,735
Annual	300,240,055	272,659,625	278,764,939	273,802,581	272,278,201	273,347,109

3. Annual and monthly non-baseload

Gas Year	Forecasted 2016/2017	2015/2016	2014/2015	2013/2014	2012/2013	2011/2012
November	56,712,943	64,242,976	62,486,370	62,248,709	61,226,239	40,491,499
December	91,432,786	98,795,855	96,475,524	95,405,022	90,481,345	86,534,833
January	86,488,891	92,054,676	90,486,111	91,382,451	86,593,507	97,758,992
February	76,659,460	74,851,835	71,804,677	72,204,387	69,575,367	78,530,912
March	52,474,527	59,855,292	58,202,117	58,522,284	56,408,082	74,169,045
April	32,605,411	40,203,184	38,491,513	38,745,792	37,886,663	54,489,168
May	15,547,950	18,600,362	17,127,632	17,039,845	15,982,505	25,616,766
June	4,924,141	4,336,063	3,488,689	4,181,989	3,799,251	13,742,491
July	380,842	304,475	25,201	707,612	393,204	4,443,994
August	280,995	0	-	769,863	358,541	569,565
September	3,237,113	2,211,685	2,291,298	3,220,573	1,673,213	1,867,959
October	23,753,874	28,889,285	28,146,833	28,616,445	27,584,476	27,756,549
Annual	444,498,932	484,345,688	469,025,965	473,044,975	451,962,394	505,971,773

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

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

2016/2017	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	4,626,396	1,266,745	305,942	1,021,354	229,064	5,918,390	900,673	47,034,489	12,361,009	7,603,775	81,267,838
December	6,486,729	1,677,495	398,066	1,361,129	325,759	7,642,412	1,158,143	69,827,181	16,556,948	11,261,365	116,695,227
January	6,130,821	1,608,354	383,135	1,333,577	311,899	7,439,868	1,110,454	67,027,366	15,792,489	10,697,667	111,835,629
February	5,421,535	1,492,557	302,994	1,221,107	278,819	6,584,532	1,010,187	60,193,409	14,663,474	9,620,109	100,788,724
March	4,424,025	1,376,868	345,308	918,303	193,426	5,925,363	953,752	44,466,178	12,109,408	7,149,276	77,861,907
April	3,755,263	1,122,353	306,344	638,501	122,637	4,800,163	811,601	31,353,286	9,402,872	5,070,398	57,383,419
May	2,800,835	805,707	239,624	510,194	88,665	3,587,469	648,649	22,093,513	6,409,840	3,746,066	40,930,562
June	2,075,691	604,706	175,256	420,563	69,351	2,813,419	514,864	15,441,144	4,878,873	2,668,543	29,662,411
July	1,697,093	575,128	154,233	398,247	63,377	2,350,769	494,120	13,592,346	4,146,090	2,236,685	25,708,086
August	1,827,401	564,485	145,334	392,083	64,345	2,372,166	489,606	13,424,975	4,068,414	2,237,049	25,585,858
September	1,985,435	606,579	157,379	409,815	70,825	2,474,363	496,288	14,368,236	4,796,865	2,557,512	27,923,296
October	3,162,338	854,563	219,385	596,595	124,301	3,970,869	668,494	26,932,624	7,943,633	4,623,226	49,096,029
Annual	44,393,561	12,555,539	3,133,001	9,221,470	1,942,469	55,879,782	9,256,832	425,754,746	113,129,915	69,471,673	744,738,987

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

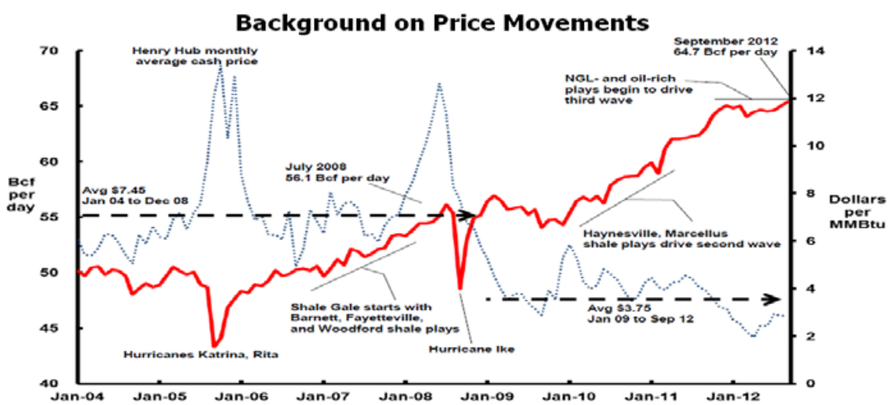
Section V.4 - Market Information

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.

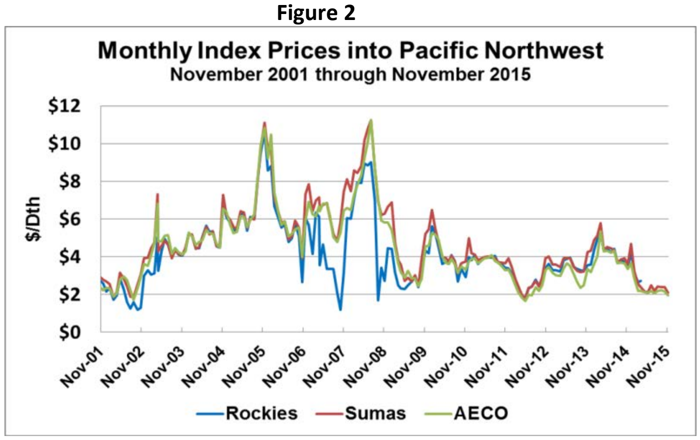
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were 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

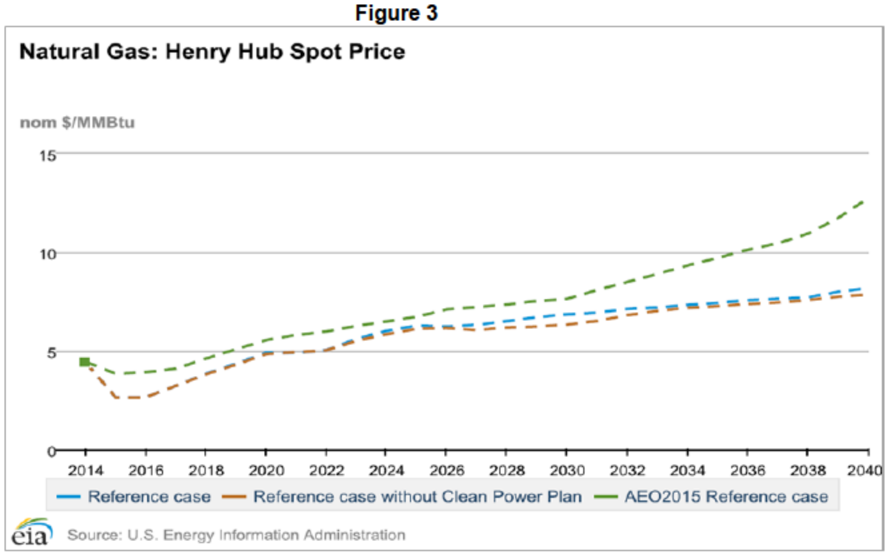
Figure 2



As mentioned, production began ramping up in 2008 with the surge in shale drilling innovations. Prices fell dramatically, and as shown in Figure 2, bottomed out in spring 2012. Prices then rose and fell again, aided primarily by the weather. First there was the so-called "Polar Vortex" that swept the eastern half of the country in 2013/14 and again in 2014/15, then the exceedingly warm El Niño winter of 2015/2016.

Prices are expected to rise from today's low levels. The U.S. Energy Information Administration's (EIA) 2016 Annual Energy Outlook has not been published yet, but its natural gas price forecast can be downloaded from the EIA website and is shown in Figure 3. Even though EIA predicts natural gas production will continue to grow, this is generally offset by demand growth that is led by gas exports in the form of LNG as well as via pipeline to Mexico.

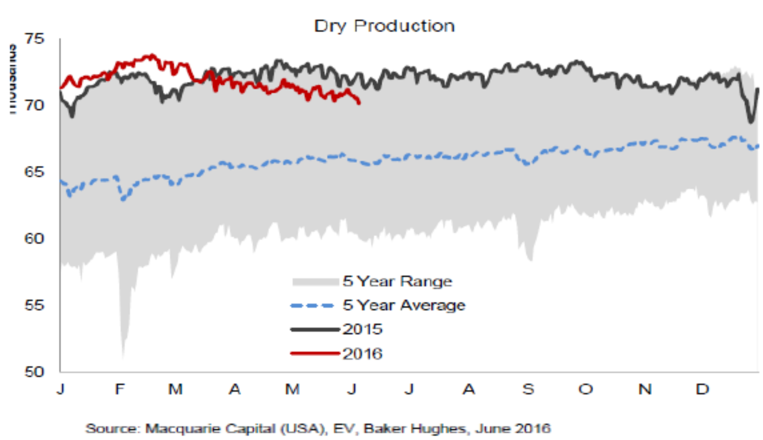
Figure 3



Some of the major factors affecting this outlook are:

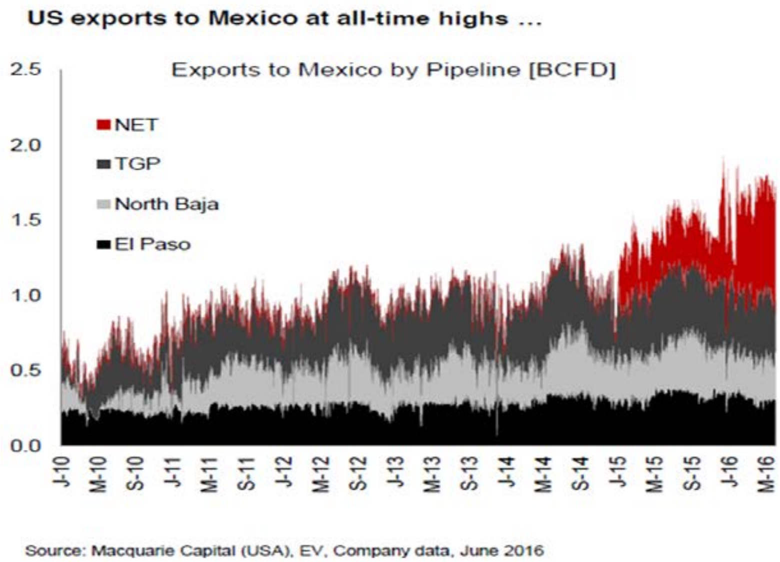
1. EIA may be too optimistic regarding natural gas production growth, especially in the near term. Current levels are starting to decline on a year-over-year basis (see Figure 4), and IHS expects Lower-48 production to decrease 1.7 Bcf/d this summer while Canadian imports dip 2.2 Bcf/d. Continued low prices have compelled over 60 companies in the exploration and production (E&P) business to declare bankruptcy since January 2015, many other E&P companies have scaled back their capital expenditures, and the inventory of drilled-but-uncompleted wells (known as DUCs) will dwindle to zero in early 2017 if not sooner.

Figure 4



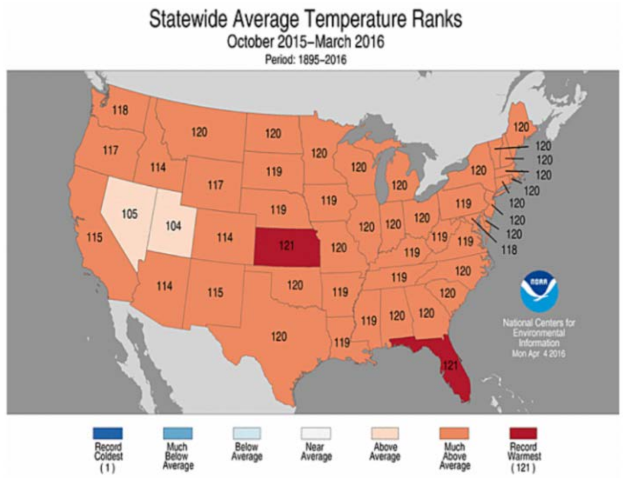
2. Gas exports will continue to grow. While LNG export terminals rightfully gather major headlines, the increase of exports via pipeline to Mexico goes largely unnoticed. In reality, gas exports to Mexico will soon approach an amount equivalent to one LNG tanker load every day (see Figure 5).

Figure 5



3. 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 probably when many people first started hearing the term "Polar Vortex," and the extremely cold temperatures drained storage inventories down to levels that had not been seen in over a decade. The "hangover" from that winter continued 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 came the exceedingly warm winter of 2015/2016 (see Figure 6), and not surprisingly, storage inventories now are at record high levels across the country. It is unlikely that last winter's record warm weather will repeat again this winter, so temperature-related demand is also certain to be higher this coming winter than last, which would put upward pressure on natural gas prices.

Figure 6



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.

Section V.5 - Data Interpretation

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

See Exhibit C, IV.2.b

Section 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

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

September 2015

Original Date of Approval: March 29, 2005

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Derivatives Policy

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Derivatives Policy

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Derivatives Policy

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Section 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).**
See Table 1 below.

b) **Location of each storage facility.**
See Table 1 below.

c) **Total level of storage in terms of deliverability and capacity held during the gas year.**
See Table 1 below.
.

TABLE 1

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
Mist (share allocated to Utility) - depleted field - Mist, OR	305,000	10,644,758
Portland LNG - LNG Plant - Portland, OR	128,800	644,400
Newport LNG - LNG Plant - Newport, OR	65,340	980,100

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

See Table 2 below.

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

See Table 2 below.

TABLE 2

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

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	$ 240,884.14	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	177,840,117	$ 73,039,321.77	0.41070	14,245,904	$ 6,012,586.29	888,310	$ 262,325.07	0.29531	164,482,523	$ 67,289,060.55	0.40910
Feb	164,482,523	$ 67,289,060.55	0.40910	7,292,629	$ 3,141,852.01	6,012,346	$ 1,426,726.22	0.23730	163,202,240	$ 65,573,934.76	0.40180
Mar	163,202,240	$ 65,573,934.76	0.40180	1,830,436	$ 805,376.16	4,745,680	$ 1,098,192.39	0.23141	166,117,484	$ 65,866,750.99	0.39651
Apr	166,117,484	$ 65,866,750.99	0.39651	4,171,954	$ 1,638,956.58	5,066,936	$ 1,154,126.03	0.22778	167,012,466	$ 65,381,920.44	0.39148
May	167,012,466	$ 65,381,920.44	0.39148	113,933	$ 49,743.72	7,893,979	$ 2,109,511.88	0.26723	174,792,512	$ 67,441,688.60	0.38584
Jun	174,792,512	$ 67,441,688.60	0.38584	294,416	$ 129,698.39	8,657,668	$ 2,004,911.84	0.23158	183,155,764	$ 69,316,902.05	0.37846
Jul	183,155,764	$ 69,316,902.05	0.37846	299,408	$ 131,777.68	5,312,087	$ 1,249,966.44	0.23531	188,168,443	$ 70,435,090.81	0.37432
Aug	188,168,443	$ 70,435,090.81	0.37432	265,134	$ 116,504.21	10,284,977	$ 2,520,779.67	0.24509	198,188,286	$ 72,839,366.27	0.36753
Sep	198,188,286	$ 72,839,366.27	0.36753	292,458	$ 128,767.66	4,899,483	$ 1,221,204.70	0.24925	202,795,311	$ 73,931,803.31	0.36456
Oct	202,795,311	$ 73,931,803.31	0.36456	2,277,409	$ 813,221.62	2,847,073	$ 670,156.87	0.23538	203,364,975	$ 73,788,738.56	0.36284
Nov	203,364,975	$ 73,788,738.56	0.36284	10,693,933	$ 4,130,133.60	1,901,500	$ 384,080.18	0.20199	194,572,542	$ 70,042,685.14	0.35998
Dec	194,572,542	$ 70,042,685.14	0.35998	15,224,286	$ 5,264,682.89	-	$ -	-	179,348,256	$ 64,778,002.25	0.36119
TOTAL 2015 ACTIVITY				57,001,900	22,363,301	58,510,039	14,101,981				
Jan-16	179,348,259	$ 64,778,002.22	0.36119	14,375,950	$ 4,938,031.01	418,320	$ 87,775.80	0.20983	165,390,629	$ 59,927,747.01	0.36234
Feb	165,390,629	$ 59,927,747.01	0.36234	7,364,928	$ 2,243,437.76	-	$ -	-	158,025,701	$ 57,684,309.25	0.36503
Mar	158,025,701	$ 57,684,309.25	0.36503	2,222,649	$ 959,777.96	1,763,451	$ 191,087.31	0.10836	157,566,503	$ 56,915,618.59	0.36122
Apr	157,566,503	$ 56,915,618.59	0.36122	1,057,389	$ 358,785.15	4,694,562	$ 435,552.52	0.09278	161,203,676	$ 56,992,385.97	0.35354
May	161,203,676	$ 56,992,385.97	0.35354	278,494	$ 122,520.76	3,596,484	$ 422,136.36	0.11737	164,521,666	$ 57,292,001.56	0.34823
Jun	164,521,666	$ 57,292,001.56	0.34823	435,454	$ 189,445.52	3,366,849	$ 568,276.71	0.16879	167,453,061	$ 57,670,832.76	0.34440
TOTAL 2016 ACTIVITY				25,734,864	8,811,998	13,839,666	1,704,829				

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.

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), fuel-in-kind (SGS) and actual material costs incurred (Newport) can be added to the base cost when determined significant.

* Injections into virtual storage sites are valued using specific commodity deals plus added costs for fuel and 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.

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 below for the Form of Rate Schedule SGS-2F Service Agreement.

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	Name: JANE F HARRISON
Title: DIRECTOR, GAS SUPPLY	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
TF06121907 013108

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.

TF0351 0010004P126First Revised Sheet No. 51
TF04 Original Sheet No. 51
TF05Larèn M. Gertsch, Director
TF06092508 110108

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.

TF0352 0020004P126Second Revised Sheet No. 52
TF04 First Revised Sheet No. 52
TF05Laren M. Gertsch, Director
TF06012109 022009
TF07

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 tc 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.

TF0352-A 0010004P156First Revised Sheet No. 52-A
TF04 Original Sheet No. 52-A
TF05Laren M. Gertsch, Director
TF06012109 022009
TF07

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.

h) For LDC's that own and operate storage:

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

See Capacity Performance Study of the Mist Underground Natural Gas Storage Field, Columbia County, OR

Confidential and subject to Modified Protective Order No. 10-337

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[redacted]

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[redacted]

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.

There have been no significant changes in physical or operational parameters of the storage facility since completion of the July 2015 study.

Section V.8 - Attestation as to Consistency

See IV.1.c

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing unredacted version of the Confidential and Highly Confidential portions of NWN OPUC Advice No. 16-17/UG 313 Exhibit C, subject to Modified Protective Order 10-337, via U.S. MAIL in Docket UM 1286.

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DATED at Portland, Oregon, this 29th day of July 2016.

/s/ Shannon L. Seagondollar
Shannon L. Seagondollar
Rates & Regulatory Affairs – Specialist 3
NW NATURAL