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September 15, 2017

NWN OPUC Advice No. 17-12A / UG 334
Supplement
(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: Supplemental Filing
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, 2017, as follows:

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

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

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

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

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

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

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

[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.

The Company's initial July 28, 2017 filing is hereby withdrawn in its entirety.

Introduction and Summary

This supplemental filing is made in accordance with the PGA Filing Guidelines which requires an update to the initial filing be made no later than September 15th. Specifically, the purpose of this filing is to:

(1) Update 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, 2017, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2017; and

(2) Update the commodity (Weighted Average Cost of Gas "WACOG") and non-commodity ("demand" or "pipeline capacity" charge) purchased gas costs to be effective November 1, 2017.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2016.

The number of customers affected by the changes proposed in this filing is 588,720 residential customers, 60,765 commercial customers, and 673 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 decrease the Company's annual revenues by $15,215,592, or about -2.36%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2016, is an increase of $408,763; 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 $15,624,355.

The proposed adjustments to customer rates are comprised of the following: (1) a credit of $0.00836 per therm for all sales service customers related to the 191 commodity accounts, and (2) a credit of $0.01656 per therm for all firm sales service customers and a credit of $0.00197 per therm for all interruptible sales service customers related to 191 demand accounts. The net effect of all Account 191 amortizations is a credit of $0.02492 per therm for firm sales service customers and a credit of $0.01033 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 $16,507,486, or about -2.56%; the change in commodity cost is a decrease of $15,137,099 and the change in demand cost is a decrease of $1,370,387.

The change in gas costs results in a proposed Annual Sales WACOG of $0.28370 per therm, and a proposed Winter Sales WACOG of $0.30227. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.29186 and a proposed Winter Sales Billing WACOG of $0.31096.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.11588 per therm, or $1.72 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01379 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.11921 per therm or $1.77 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01419 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 $31,723,078, or about -4.92%; the change in purchased gas costs is a decrease of $16,507,486 and the change in temporary adjustments to rates is a decrease of $15,215,592.

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	-$2.54	-4.8%
Commercial	Schedule 3	-$11.73	-5.5%
Commercial Firm Sales	Schedule 31	-$140.07	-6.9%
Industrial Firm Sales	Schedule 32	-$923.13	-10.2%
Industrial Interruptible Sales	Schedule 32	-$762.08	-5.0%

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

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, 2017 would be a decrease of $963.15, or -8.5%.

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 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, 2017.

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 was made following the Company's initial filing dated July 28, 2017 by newspaper notice published in the Eugene Register-Guard on August 8th, and the Oregonian, the Salem Statesman-Journal, and the Coos Bay World on August 9th, in accordance with OAR 860-022-0017. The Company does not plan to re-notice customers with this filing.

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

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

Sincerely,

NW NATURAL

/s/ Gail Hammer

Gail Hammer
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, 2017:		(C)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.29186**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.28370**	(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, 2017:		(C)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.31096**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.30227**	(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, 2017:		(C)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.11921**	(R)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11588**	(R)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective: November 1, 2017:		(C)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01419**	(R)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01379**	(R)

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

Effective: November 1, 2017:		(C)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.77**	(R)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.72**	(R)

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

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

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

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

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

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

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

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, 2017 through October 31, 2018 are: (C)

November	2017	$7,991,278	(C)
December	2017	$11,683,410	
January	2018	$11,182,727	
February	2018	$8,969,613	
March	2018	$7,619,111	
April	2018	$5,464,331	
May	2018	$3,775,621	
June	2018	$2,624,222	
July	2018	$2,249,916	
August	2018	$2,223,720	
September	2018	$2,494,682	
October	2018	$4,657,037	
ANNUAL TOTAL		$70,935,668	(C)

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. 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, 2017 (C)

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		($0.00836)	($0.01656)	**($0.02492)**
3 CSF		($0.00836)	($0.01656)	**($0.02492)**
3 ISF		($0.00836)	($0.01656)	**($0.02492)**
27		($0.00836)	($0.01656)	**($0.02492)**
31 CSF	Block 1	($0.00836)	($0.01656)	**($0.02492)**
	Block 2	($0.00836)	($0.01656)	**($0.02492)**
31 CTF	Block 1	N/A	N/A	**$0.00000**
	Block 2	N/A	N/A	**$0.00000**
31 ISF	Block 1	($0.00836)	($0.01656)	**($0.02492)**
	Block 2	($0.00836)	($0.01656)	**($0.02492)**
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, 2017 (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	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Total Adjustment
32 CSF	Block 1	($0.00836)	($0.01656)	**($0.02492)**
	Block 2	($0.00836)	($0.01656)	**($0.02492)**
	Block 3	($0.00836)	($0.01656)	**($0.02492)**
	Block 4	($0.00836)	($0.01656)	**($0.02492)**
	Block 5	($0.00836)	($0.01656)	**($0.02492)**
	Block 6	($0.00836)	($0.01656)	**($0.02492)**
32 ISF	Block 1	($0.00836)	($0.01656)	**($0.02492)**
	Block 2	($0.00836)	($0.01656)	**($0.02492)**
	Block 3	($0.00836)	($0.01656)	**($0.02492)**
	Block 4	($0.00836)	($0.01656)	**($0.02492)**
	Block 5	($0.00836)	($0.01656)	**($0.02492)**
	Block 6	($0.00836)	($0.01656)	**($0.02492)**
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	($0.00836)	($0.00197)	**($0.01033)**
	Block 2	($0.00836)	($0.00197)	**($0.01033)**
	Block 3	($0.00836)	($0.00197)	**($0.01033)**
	Block 4	($0.00836)	($0.00197)	**($0.01033)**
	Block 5	($0.00836)	($0.00197)	**($0.01033)**
	Block 6	($0.00836)	($0.00197)	**($0.01033)**
32 ISI	Block 1	($0.00836)	($0.00197)	**($0.01033)**
	Block 2	($0.00836)	($0.00197)	**($0.01033)**
	Block 3	($0.00836)	($0.00197)	**($0.01033)**
	Block 4	($0.00836)	($0.00197)	**($0.01033)**
	Block 5	($0.00836)	($0.00197)	**($0.01033)**
	Block 6	($0.00836)	($0.00197)	**($0.01033)**
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)

(C)

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, 2017 (C)

Annual Sales WACOG [1]	$0.29186	(R)
Winter Sales WACOG [2]	$0.31096	
Firm Sales Service Pipeline Capacity Component [3]	$0.11921	
Firm Sales Service Pipeline Capacity Component [4]	$1.77	
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01419	(R)

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

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

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496

NWN OPUC Advice No. 17-12A / UG 334

September 15, 2017

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations – UM 1496

NWN OPUC ADVICE NO. 17-12A / UG 334

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: September Filing
Summary of TEMPORARY Increments

1			**Current Temporaries**	**WACOG Deferral**	**Demand Deferral - FIRM**	**Demand Deferral - INTERRUPTIBLE**	**Total Proposed Temps**	**Net Effect of Temps**
2								**(P = O - A)**
3	Schedule	Block	**A**	**B**	**C**	**D**	**O**	**P**
4	2R		$0.02604	($0.00836)	($0.01656)	$0.00000	($0.01727)	($0.04331)
5	3C Sales Firm		$0.07356	($0.00836)	($0.01656)	$0.00000	$0.03136	($0.04220)
6	3I Sales Firm		$0.04138	($0.00836)	($0.01656)	$0.00000	$0.01614	($0.02524)
7	27 Dry Out		$0.01693	($0.00836)	($0.01656)	$0.00000	($0.01561)	($0.03254)
8	31C Sales Firm	Block 1	$0.07048	($0.00836)	($0.01656)	$0.00000	$0.04321	($0.02727)
9		Block 2	$0.06959	($0.00836)	($0.01656)	$0.00000	$0.04264	($0.02695)
10	31C Trans Firm	Block 1	$0.01139	$0.00000	$0.00000	$0.00000	$0.00669	($0.00470)
11		Block 2	$0.01042	$0.00000	$0.00000	$0.00000	$0.00613	($0.00429)
12	31I Sales Firm	Block 1	$0.03737	($0.00836)	($0.01656)	$0.00000	$0.01371	($0.02366)
13		Block 2	$0.03665	($0.00836)	($0.01656)	$0.00000	$0.01326	($0.02339)
14	31I Trans Firm	Block 1	$0.00892	$0.00000	$0.00000	$0.00000	$0.00560	($0.00332)
15		Block 2	$0.00809	$0.00000	$0.00000	$0.00000	$0.00508	($0.00301)
16	32C Sales Firm	Block 1	$0.03666	($0.00836)	($0.01656)	$0.00000	$0.01347	($0.02319)
17		Block 2	$0.03561	($0.00836)	($0.01656)	$0.00000	$0.01279	($0.02282)
18		Block 3	$0.03388	($0.00836)	($0.01656)	$0.00000	$0.01166	($0.02222)
19		Block 4	$0.03214	($0.00836)	($0.01656)	$0.00000	$0.01052	($0.02162)
20		Block 5	$0.03090	($0.00836)	($0.01656)	$0.00000	$0.00955	($0.02135)
21		Block 6	$0.03021	($0.00836)	($0.01656)	$0.00000	$0.00909	($0.02112)
22	32I Sales Firm	Block 1	$0.03491	($0.00836)	($0.01656)	$0.00000	$0.01206	($0.02285)
23		Block 2	$0.03415	($0.00836)	($0.01656)	$0.00000	$0.01160	($0.02255)
24		Block 3	$0.03289	($0.00836)	($0.01656)	$0.00000	$0.01082	($0.02207)
25		Block 4	$0.03163	($0.00836)	($0.01656)	$0.00000	$0.01004	($0.02159)
26		Block 5	$0.03068	($0.00836)	($0.01656)	$0.00000	$0.00930	($0.02138)
27		Block 6	$0.03018	($0.00836)	($0.01656)	$0.00000	$0.00899	($0.02119)
28	32 Trans Firm	Block 1	$0.00459	$0.00000	$0.00000	$0.00000	$0.00273	($0.00186)
29		Block 2	$0.00393	$0.00000	$0.00000	$0.00000	$0.00232	($0.00161)
30		Block 3	$0.00283	$0.00000	$0.00000	$0.00000	$0.00164	($0.00119)
31		Block 4	$0.00172	$0.00000	$0.00000	$0.00000	$0.00097	($0.00075)
32		Block 5	$0.00106	$0.00000	$0.00000	$0.00000	$0.00056	($0.00050)
33		Block 6	$0.00062	$0.00000	$0.00000	$0.00000	$0.00029	($0.00033)
34	32C Sales Interr	Block 1	$0.02154	($0.00836)	$0.00000	($0.00197)	$0.02601	$0.00447
35		Block 2	$0.02093	($0.00836)	$0.00000	($0.00197)	$0.02562	$0.00469
36		Block 3	$0.01992	($0.00836)	$0.00000	($0.00197)	$0.02497	$0.00505
37		Block 4	$0.01890	($0.00836)	$0.00000	($0.00197)	$0.02433	$0.00543
38		Block 5	$0.01829	($0.00836)	$0.00000	($0.00197)	$0.02394	$0.00565
39		Block 6	$0.01773	($0.00836)	$0.00000	($0.00197)	$0.02349	$0.00576
40	32I Sales Interr	Block 1	$0.02161	($0.00836)	$0.00000	($0.00197)	$0.02602	$0.00441
41		Block 2	$0.02101	($0.00836)	$0.00000	($0.00197)	$0.02563	$0.00462
42		Block 3	$0.02001	($0.00836)	$0.00000	($0.00197)	$0.02499	$0.00498
43		Block 4	$0.01901	($0.00836)	$0.00000	($0.00197)	$0.02434	$0.00533
44		Block 5	$0.01841	($0.00836)	$0.00000	($0.00197)	$0.02396	$0.00555
45		Block 6	$0.01788	($0.00836)	$0.00000	($0.00197)	$0.02353	$0.00565
46	32 Trans Interr	Block 1	$0.00384	$0.00000	$0.00000	$0.00000	$0.00226	($0.00158)
47		Block 2	$0.00329	$0.00000	$0.00000	$0.00000	$0.00192	($0.00137)
48		Block 3	$0.00237	$0.00000	$0.00000	$0.00000	$0.00136	($0.00101)
49		Block 4	$0.00146	$0.00000	$0.00000	$0.00000	$0.00079	($0.00067)
50		Block 5	$0.00090	$0.00000	$0.00000	$0.00000	$0.00045	($0.00045)
51		Block 6	$0.00054	$0.00000	$0.00000	$0.00000	$0.00023	($0.00031)
52	33		$0.00024	$0.00000	$0.00000	$0.00000	$0.00009	($0.00015)

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

Row	Schedule	Block	Oregon PGA Volumes page, Column F		WACOG Deferral			Demand Deferral - FIRM			Demand Deferral - INTERRUPTIBLE		
2				Proposed Amount:	(5,331,668) Temporary Increment			(9,760,700) Temporary Increment			(95,286) Temporary Increment		
3				Revenue Sensitive Multiplier:	2.795% add revenue sensitive factor			2.795% add revenue sensitive factor			2.795% add revenue sensitive factor		
4				Amount to Amortize:	**(5,484,973)** to all sales			**(10,041,356)** to all firm sales			**(98,026)** 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		353,902,060		1.0	353,902,060	($0.00836)	1.0	353,902,060	($0.01656)	0.0	0	$0.00000
8	3C Firm Sales		159,700,612		1.0	159,700,612	($0.00836)	1.0	159,700,612	($0.01656)	0.0	0	$0.00000
9	3I Firm Sales		4,602,931		1.0	4,602,931	($0.00836)	1.0	4,602,931	($0.01656)	0.0	0	$0.00000
10	27 Dry Out		1,205,372		1.0	1,205,372	($0.00836)	1.0	1,205,372	($0.01656)	0.0	0	$0.00000
11	31C Firm Sales	Block 1	13,316,134		1.0	13,316,134	($0.00836)	1.0	13,316,134	($0.01656)	0.0	0	$0.00000
12		Block 2	12,481,400		1.0	12,481,400	($0.00836)	1.0	12,481,400	($0.01656)	0.0	0	$0.00000
13	31C Firm Trans	Block 1	1,525,441		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	2,009,166		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
15	31I Firm Sales	Block 1	4,070,024		1.0	4,070,024	($0.00836)	1.0	4,070,024	($0.01656)	0.0	0	$0.00000
16		Block 2	8,722,092		1.0	8,722,092	($0.00836)	1.0	8,722,092	($0.01656)	0.0	0	$0.00000
17	31I Firm Trans	Block 1	125,106		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	276,784		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
19	32C Firm Sales	Block 1	25,883,715		1.0	25,883,715	($0.00836)	1.0	25,883,715	($0.01656)	0.0	0	$0.00000
20		Block 2	8,661,618		1.0	8,661,618	($0.00836)	1.0	8,661,618	($0.01656)	0.0	0	$0.00000
21		Block 3	1,237,042		1.0	1,237,042	($0.00836)	1.0	1,237,042	($0.01656)	0.0	0	$0.00000
22		Block 4	165,932		1.0	165,932	($0.00836)	1.0	165,932	($0.01656)	0.0	0	$0.00000
23		Block 5	0		1.0	0	($0.00836)	1.0	0	($0.01656)	0.0	0	$0.00000
24		Block 6	0		1.0	0	($0.00836)	1.0	0	($0.01656)	0.0	0	$0.00000
25	32I Firm Sales	Block 1	4,719,808		1.0	4,719,808	($0.00836)	1.0	4,719,808	($0.01656)	0.0	0	$0.00000
26		Block 2	5,298,281		1.0	5,298,281	($0.00836)	1.0	5,298,281	($0.01656)	0.0	0	$0.00000
27		Block 3	1,764,186		1.0	1,764,186	($0.00836)	1.0	1,764,186	($0.01656)	0.0	0	$0.00000
28		Block 4	508,368		1.0	508,368	($0.00836)	1.0	508,368	($0.01656)	0.0	0	$0.00000
29		Block 5	0		1.0	0	($0.00836)	1.0	0	($0.01656)	0.0	0	$0.00000
30		Block 6	0		1.0	0	($0.00836)	1.0	0	($0.01656)	0.0	0	$0.00000
31	32 Firm Trans	Block 1	16,254,618		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	18,153,953		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	10,538,827		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	19,469,774		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	21,237,750		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
36		Block 6	3,397,316		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
37	32C Interr Sales	Block 1	5,242,630		1.0	5,242,630	($0.00836)	0.0	0	$0.00000	1.0	5,242,630	($0.00197)
38		Block 2	7,424,480		1.0	7,424,480	($0.00836)	0.0	0	$0.00000	1.0	7,424,480	($0.00197)
39		Block 3	3,966,495		1.0	3,966,495	($0.00836)	0.0	0	$0.00000	1.0	3,966,495	($0.00197)
40		Block 4	4,896,519		1.0	4,896,519	($0.00836)	0.0	0	$0.00000	1.0	4,896,519	($0.00197)
41		Block 5	236,893		1.0	236,893	($0.00836)	0.0	0	$0.00000	1.0	236,893	($0.00197)
42		Block 6	0		1.0	0	($0.00836)	0.0	0	$0.00000	1.0	0	($0.00197)
43	32I Interr Sales	Block 1	6,200,783		1.0	6,200,783	($0.00836)	0.0	0	$0.00000	1.0	6,200,783	($0.00197)
44		Block 2	7,447,078		1.0	7,447,078	($0.00836)	0.0	0	$0.00000	1.0	7,447,078	($0.00197)
45		Block 3	3,991,226		1.0	3,991,226	($0.00836)	0.0	0	$0.00000	1.0	3,991,226	($0.00197)
46		Block 4	8,413,466		1.0	8,413,466	($0.00836)	0.0	0	$0.00000	1.0	8,413,466	($0.00197)
47		Block 5	1,938,065		1.0	1,938,065	($0.00836)	0.0	0	$0.00000	1.0	1,938,065	($0.00197)
48		Block 6	0		1.0	0	($0.00836)	0.0	0	$0.00000	1.0	0	($0.00197)
49	32 Interr Trans	Block 1	8,753,845		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
50		Block 2	15,798,206		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
51		Block 3	11,612,336		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
52		Block 4	31,071,223		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
53		Block 5	59,059,181		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
54		Block 6	91,219,916		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		966,500,651			655,997,209	$ (0.00836)		606,239,575	$ (0.01656)		49,757,635	$ (0.00197)

NW Natural
Rates and Regulatory Affairs
2017-2018 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/17		
1				
2				
3	Total Billed Gas Sales Revenues	$ 674,696,212		
4	Total Oregon Revenues	$ 678,088,466		
5				
6	Regulatory Commission Fees [1]	n/a	0.300%	Statutory rate
7	City License and Franchise Fees	$ 16,069,889	2.370%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 848,945	0.125%	Line 8 ÷ Line 4
9				
10	Total		**2.795%**	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 change occurred mid gas year, the difference between the previous fee of 0.275%
16 and the new fee of 0.3% 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
2017-2018 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Tariff Advice 17-12A: PGA Gas Costs and Gas Cost Deferrals

Line	Description	Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($15,137,099)
6		
7	Demand Capacity Cost Change	(1,370,387)
8		
9	**Total Gas Cost Change**	**(16,507,486)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	408,763
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(15,624,355)
18		
19	**Net Temporary Rate Adjustment**	**(15,215,592)**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($31,723,078)**
22		
23		
24		
25	2016 Oregon Earnings Test Normalized Total Revenues	$645,156,000
26		
27	Effect of this filing, as a percentage change (line 21 ÷ line 25)	-4.92%

NW Natural
Rates & Regulatory Affairs
2017-2018 PGA Filing - September Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2017	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2017	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	2.38%		G = E + F2		Excl. Rev Sens
41	**Gas Cost Deferrals and Amortizations**									
42	191401 AMORTIZE OREGON WACOG	28,643	1,446,255	4,649	1,479,547					
43	191400 WACOG - ACCRUE OREGON	(6,571,082)	0	(172,030)	(6,743,112)					
44	Subtotal	(6,542,439)	1,446,255	(167,381)	(5,263,565)	2.38%	(68,103)	(5,331,668)		**(5,331,668)**
45										
46	191411 AMORTIZE DEMAND OREGON	269,172	(1,330,857)	(2,032)	(1,063,717)					
47	191410 DEMAND - ACCRUE OREGON	328,417	0	8,598	337,015					
48	191417 DEMAND - ACCRUE COOS BAY	244,678	0	0	244,678					
49	191450 OREGON DEMAND ACCRUE VOLUME	(9,012,133)	0	(235,936)	(9,248,069)					
50	Subtotal	(8,169,866)	(1,330,857)	(229,370)	(9,730,093)	2.38%	(125,893)	(9,855,986)		**(9,855,986)**

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Commodity gas cost deferral
Account Number: 191400
Docket UM 1496
Last deferral reauthorization was approved in Order 16-384

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG embedded in customer rates. From Nov 2015 - Oct 2016 the deferral election was 80%. Effective Nov 2016 the deferral election is 90%.

1 Debit (Credit)

			Commodity	Storage	Hedge					
3	Month/Year	Note	Deferral	Adjustment	Adjustment	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(c)	(d)	(e)	(f1)	(f2)	(g)	(h)	(i)
5										
6	Beginning Bal									
121	Jun-16	**1**	(485,300.48)	(4,243.36)	(4,894.48)	(43,489.99)	7.78%	16,849,573.00	16,311,645	(6,998,676.01)
122	Jul-16		(87,714.81)	(3,888.24)	(4,533.96)	(45,686.39)	7.78%		(141,823)	(7,140,499.41)
123	Aug-16		(178,977.42)	(3,650.66)	(5,183.30)	(46,903.06)	7.78%		(234,714)	(7,375,213.86)
124	Sep-16		(38,345.85)	(4,583.07)	(3,276.08)	(47,965.75)	7.78%		(94,171)	(7,469,384.61)
125	Oct-16	**2**	(997,814.36)	(8,392.74)	(6,317.57)	(51,708.79)	7.78%	(1.63)	(1,064,235)	(8,533,619.69)
126	Nov-16	**1**	(700,831.39)	(3,462.14)	19,907.80	(10,979.06)	7.778%	7,181,949.22	6,486,584	(2,047,035.27)
127	Dec-16		1,622,359.46	(7,117.85)	(14,507.40)	(8,080.49)	7.778%		1,592,654	(454,381.54)
128	Jan-17		714,538.28	(8,201.73)	(16,294.00)	(708.84)	7.778%		689,334	234,952.16
129	Feb-17		(2,175,707.56)	(5,609.16)	(1,202.60)	(5,550.30)	7.778%		(2,188,070)	(1,953,117.45)
130	Mar-17		(2,947,035.53)	(4,705.65)	9,467.00	(22,194.88)	7.778%		(2,964,469)	(4,917,586.50)
131	Apr-17		(1,703,279.38)	(3,379.07)	(259.80)	(37,405.99)	7.778%		(1,744,324)	(6,661,910.74)
132	May-17		(221,606.13)	(2,064.18)	(2,417.30)	(43,913.00)	7.778%		(270,001)	(6,931,911.35)
133	Jun-17		405,864.95	(1,427.06)	10.80	(43,619.59)	7.778%		360,829	(6,571,082.25)
134	Jul-17					(42,591.56)	7.778%		(42,592)	(6,613,673.81)
135	Aug-17					(42,867.63)	7.778%		(42,868)	(6,656,541.44)
136	Sep-17					(43,145.48)	7.778%		(43,145)	(6,699,686.92)
137	Oct-17					(43,425.14)	7.778%		(43,425)	(6,743,112.06)

139 **History truncated for ease of viewing**

141 **NOTES:**
141 **1** -Transferred June balance plus July-October interest on June balance to account 191401 for amortization.
142 **2** -Transfer represents true-up of balance to the general ledger.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon WACOG Deferral
Account Number:	191401
	Dockets UM 1496 and UG 313
	Amortization of 2015-16 deferral approved in Order No. 16-403

1 Debit (Credit)

	Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
7	Beginning Balance							
131	Jun-16		16,788,580.08	(16,849,573.00)	(18,822.36)	1.93%	(79,815.28)	(3,327,556.63)
132	Jul-16		865,947.11		(4,655.45)	1.93%	861,291.66	(2,466,264.97)
133	Aug-16		361,503.02		(3,675.87)	1.93%	357,827.15	(2,108,437.82)
134	Sep-16		390,507.19		(3,077.04)	1.93%	387,430.15	(1,721,007.67)
135	Oct-16		574,454.60		(2,306.00)	1.93%	572,148.60	(1,148,859.07)
136	Nov-16	old rates	407,940.78		(1,519.70)	1.93%	406,421.08	(742,437.99)
137	Nov-16	new rates **(1)**	293,121.40	(7,181,949.22)	(12,898.21)	2.20%	(6,901,726.03)	(7,644,164.02)
138	Dec-16		1,227,993.12		(12,888.64)	2.20%	1,215,104.48	(6,429,059.54)
139	Jan-17		1,916,111.24		(10,030.17)	2.20%	1,906,081.07	(4,522,978.47)
140	Feb-17		1,489,288.11		(6,926.95)	2.20%	1,482,361.16	(3,040,617.32)
141	Mar-17		1,167,276.60		(4,504.46)	2.20%	1,162,772.14	(1,877,845.18)
142	Apr-17		865,692.26		(2,649.16)	2.20%	863,043.10	(1,014,802.08)
143	May-17	**2**	646,824.22	1.13	(1,267.55)	2.20%	645,557.80	(369,244.28)
144	Jun-17		398,199.38		(311.93)	2.20%	397,887.45	28,643.17
145	Jul-17	*Forecast*	*279,838.64*		309.03	2.20%	280,147.67	308,790.84
146	Aug-17	*Forecast*	*278,216.12*		821.15	2.20%	279,037.27	587,828.11
147	Sep-17	*Forecast*	*298,092.04*		1,350.94	2.20%	299,442.98	887,271.09
148	Oct-17	*Forecast*	*590,108.34*		2,167.60	2.20%	592,275.94	1,479,547.03

150 **History truncated for ease of viewing**

152 **NOTES:**

153 **1** - Transferred in authorized balance from accounts 191400 and 191405.

154 **2** - Transfer represents a true-up to the general ledger.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand cost deferral
Account Number:	191410
	Docket UM 1496
	Last deferral reauthorization was approved in Order 16-384
Narrative:	Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

1 Debit (Credit)

			Demand					
3	Month/Year	Note	Deferral	Transfer	Interest	Interest Rate	Activity	Balance
4	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
5								
6	Beginning Bal							
121	Jun-16		(450,555.03)		(6,983.72)	7.78%	(457,538.67)	(1,309,441.60)
122	Jul-16		(16,512.87)		(8,543.08)	7.78%	(25,055.87)	(1,334,497.47)
123	Aug-16		(9,432.85)		(8,682.57)	7.78%	(18,115.34)	(1,352,612.81)
124	Sep-16		(11,796.45)		(8,807.68)	7.78%	(20,604.05)	(1,373,216.87)
125	Oct-16	**2**	8,712.56	(1.14)	(8,874.79)	7.78%	(163.29)	(1,373,380.16)
126	Nov-16	**1**	65,712.39840	1,343,731.46	20.79	7.778%	1,409,464.65	36,084.49020
127	Dec-16		11,395.03		270.82	7.778%	11,665.85	47,750.34
128	Jan-17		(31,117.10)		208.66	7.778%	(30,908.44)	16,841.90
129	Feb-17		161,358.86		632.10	7.778%	161,990.96	178,832.86
130	Mar-17		88,426.17		1,445.71	7.778%	89,871.88	268,704.74
131	Apr-17		65,552.63		1,954.10	7.778%	67,506.73	336,211.46
132	May-17		47,370.84		2,332.73	7.778%	49,703.57	385,915.03
133	Jun-17		(59,805.29)		2,307.55	7.778%	(57,497.74)	328,417.29
134	Jul-17				2,128.69	7.778%	2,128.69	330,545.98
135	Aug-17				2,142.49	7.778%	2,142.49	332,688.47
136	Sep-17				2,156.38	7.778%	2,156.38	334,844.85
137	Oct-17				2,170.35	7.778%	2,170.35	337,015.20

139 **History truncated for ease of viewing**

141 **NOTES**

142 **1** -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.

143 **2** -Transfer represents true-up to gerneral ledger.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon Demand Deferral
Account Number:	191411
	Dockets UM 1496 and UG 313
	Amortization of 2015-16 deferral approved in Order No. 16-403

1 Debit (Credit)

2

Line	Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
6								
7	Beginning Balance							
136	Nov-16	old rates	(343,420.93)		1,374.02	1.93%	(342,046.91)	683,977.77
137	Nov-16	new rates **(1)**	(252,067.75)	7,330,925.04	13,208.97	2.20%	7,092,066.26	7,776,044.03
138	Dec-16		(1,203,661.71)		13,152.72	2.20%	(1,190,508.99)	6,585,535.05
139	Jan-17		(1,907,657.53)		10,324.79	2.20%	(1,897,332.74)	4,688,202.30
140	Feb-17		(1,476,251.99)		7,241.81	2.20%	(1,469,010.18)	3,219,192.12
141	Mar-17		(1,140,964.20)		4,855.97	2.20%	(1,136,108.23)	2,083,083.89
142	Apr-17		(837,211.73)		3,051.54	2.20%	(834,160.19)	1,248,923.69
143	May-17		(615,963.49)		1,725.06	2.20%	(614,238.43)	634,685.26
144	Jun-17		(366,341.19)		827.78	2.20%	(365,513.41)	269,171.85
145	Jul-17	*Forecast*	*(250,620.59)*		263.75	2.20%	(250,356.84)	18,815.01
146	Aug-17	*Forecast*	*(249,782.90)*		(194.47)	2.20%	(249,977.37)	(231,162.36)
147	Sep-17	*Forecast*	*(267,797.27)*		(669.28)	2.20%	(268,466.55)	(499,628.91)
148	Oct-17	*Forecast*	*(562,656.54)*		(1,431.75)	2.20%	(564,088.29)	(1,063,717.20)

149

150 **History truncated for ease of viewing**

151

152 **NOTES:**

153 **1** - Transferred in authorized balances from accounts 191410, 191450, and 191417.

Company: Northwest Natural Gas Company
State: Oregon
Description: Coos County Demand
Account Number: 191417
Docket UM 1179 Order 04-702 **3**

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
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
6	Beginning Bal							
121	Jun-16		16,635.00	(4,167.18)			12,467.82	113,338.45
122	Jul-16		16,635.00	(4,093.51)			12,541.49	125,879.94
123	Aug-16		16,635.00	(4,023.57)			12,611.43	138,491.37
124	Sep-16		16,635.00	(3,459.90)			13,175.10	151,666.47
125	Oct-16		16,635.00	(4,980.33)			11,654.67	163,321.14
126	Nov-16	**1**	16,635.00	(5,148.76)	(113,338.45)		(101,852.21)	61,468.93
127	Dec-16		16,635.00	(8,564.61)			8,070.39	69,539.31
128	Jan-17		16,635.00	(11,302.20)			5,332.80	74,872.11
129	Feb-17		23,783.00	(7,671.01)			16,111.99	90,984.10
130	Mar-17		23,783.00	(8,991.09)			14,791.91	105,776.01
131	Apr-17		23,783.00	(6,685.68)			17,097.32	122,873.33
132	May-17	**2**	23,783.00	78,824.62			102,607.62	225,480.95
133	Jun-17		23,783.00	(4,586.06)			19,196.94	244,677.89
134	Jul-17						0.00	244,677.89
135	Aug-17						0.00	244,677.89
136	Sep-17						0.00	244,677.89
137	Oct-17						0.00	244,677.89

139 **History truncated for ease of viewing**

141 **NOTES**

142 **1** - June balance transferred to account 191411 for amortization.

143 **2** - Includes approx. $85K true-up of previous year's demand charges based on actual 2016 costs.

144 **3** - As a condition of the Coos Bay Stipulation in UG-152, the company agreed to annually evaluate the Coos County Charge to determine whether it is fully recovering the NW Natural's cost of transportation on the County pipeline. For the current period, based on loads form Coos County customers, the charge is not fully recovering transportation costs.

Company: Northwest Natural Gas Company
State: Oregon
Description: Seasonalized Demand Collection Deferral
Account Number: 191450
Docket UM 1496
Last deferral reauthorization was approved in Order 16-384

Narrative: Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs embedded in customer rates.

	Debit (Credit)							
2			Demand					
3	Month/Year	Note	Deferral	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
5								
6	Beginning Bal							
121	Jun-16	**2**	49,664.48	53,581.08	7.78%	(6.39)	103,239.25	8,342,847.02
122	Jul-16		(66,671.33)	53,873.33	7.78%		(12,797.92)	8,330,049.10
123	Aug-16		42,955.67	54,145.73	7.78%		97,101.48	8,427,150.58
124	Sep-16		(356,208.92)	53,481.32	7.78%		(302,727.52)	8,124,423.05
125	Oct-16	**2**	204,947.24	53,337.71	7.78%	(0.32)	258,284.71	8,382,707.76
126	Nov-16	**1**	1,582,936.75	3,972.34	7.778%	(8,561,318.05)	(6,974,408.96)	1,408,298.80
127	Dec-16		(1,987,604.89)	2,686.63	7.778%		(1,984,918.26)	(576,619.47)
128	Jan-17		(4,570,905.39)	(18,551.00)	7.778%		(4,589,456.39)	(5,166,075.85)
129	Feb-17		(1,682,967.13)	(38,939.00)	7.778%		(1,721,906.13)	(6,887,981.98)
130	Mar-17		(1,152,976.62)	(48,382.21)	7.778%		(1,201,358.83)	(8,089,340.81)
131	Apr-17		(879,886.56)	(55,283.98)	7.778%		(935,170.54)	(9,024,511.35)
132	May-17		41,412.96	(58,359.66)	7.778%		(16,946.70)	(9,041,458.05)
133	Jun-17		87,645.12	(58,319.67)	7.778%		29,325.45	(9,012,132.60)
134	Jul-17			(58,413.64)	7.778%		(58,413.64)	(9,070,546.24)
135	Aug-17			(58,792.26)	7.778%		(58,792.26)	(9,129,338.50)
136	Sep-17			(59,173.33)	7.778%		(59,173.33)	(9,188,511.83)
137	Oct-17			(59,556.87)	7.778%		(59,556.87)	(9,248,068.70)

138
139 **History truncated for ease of viewing**
140
141 **NOTES**
142 **1** -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.
143 **2** -Transfer represents true-up to general ledger.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 17-12A / UG 334

September 15, 2017

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 17-12A / UG 334

NW Natural
2017-2018 PGA - SYSTEM: September Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

SYSTEM COSTS

1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	**Commodity Cost from Supply**		$18,951,067	$21,159,770	$19,918,131	$12,423,374	$14,759,884	$10,604,562	$7,365,529	$5,032,648	$4,289,158	$3,766,934	$4,400,051	$9,219,337	$131,890,445
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**		$265,780	$296,008	$94,112	$69,218	$73,605	$56,734	$40,750	$29,526	$26,177	$23,615	$26,313	$49,331	$1,051,169
9	tab commodity cost from vol pipe, column e, line 78-89														
10	**Commodity Cost from Storage**		$444,641	$10,868,363	$10,874,850	$12,391,936	$5,179,554	$94,546	$222,956	$219,804	$97,697	$1,080,041	$1,078,984	$97,697	$42,651,069
11	tab Commodity Cost from Storage, column k, line 61-72														
12	**Commodity Cost from Gas Reserves**		$2,563,265	$2,749,136	$2,561,384	$2,368,729	$2,498,044	$2,414,492	$2,471,856	$2,371,904	$2,365,549	$2,340,435	$2,266,758	$2,290,794	$29,262,347
13	tab Commodity Cost from Gas Reserve, column p, line 59-70														
14	**Total Commodity Cost**		$22,224,753	$35,073,277	$33,448,478	$27,253,256	$22,511,087	$13,170,334	$10,101,091	$7,653,883	$6,778,580	$7,211,025	$7,772,106	$11,657,159	$204,855,030
15															
16	**VOLUMES**														
17	Commodity Volumes at Receipt Points		82,125,185	85,151,833	80,702,673	52,532,039	63,414,222	58,162,663	40,852,525	28,902,022	25,215,445	22,465,941	25,454,256	50,128,685	615,107,491
18	Pipeline Fuel Use		2,201,839	2,284,264	2,145,316	1,291,929	1,604,561	1,768,774	1,159,910	790,434	671,563	585,697	682,760	1,516,285	16,703,333
19	Gas Arriving at City Gate		79,923,347	82,867,569	78,557,357	51,240,110	61,809,661	56,393,889	39,692,615	28,111,588	24,543,882	21,880,244	24,771,496	48,612,400	598,404,158
20															
21	Storage Gas Withdrawals		1,760,584	35,319,635	34,868,597	40,193,590	16,461,753	240,000	561,000	553,000	248,000	2,593,000	2,590,000	248,000	135,637,160
22	Pipeline Fuel Use for Off-site Storage		61,959	248,900	214,479	227,334	88,588	0	0	0	0	0	0	0	841,260
23	Storage Gas Deliveries at City Gate		1,698,625	35,070,735	34,654,118	39,966,256	16,373,164	240,000	561,000	553,000	248,000	2,593,000	2,590,000	248,000	134,795,899
24															
25	Total Gas At City Gate (Storage and Commodity)		81,621,972	117,938,304	113,211,476	91,206,366	78,182,826	56,633,889	40,253,615	28,664,588	24,791,882	24,473,244	27,361,496	48,860,400	733,200,057
26															
27	Unaccounted for Gas		626,731	649,819	616,020	401,807	484,690	442,222	311,256	220,441	192,465	171,577	194,250	381,202	4,692,480
28															
29	Load Served		80,995,240	117,288,485	112,595,456	90,804,559	77,698,135	56,191,667	39,942,359	28,444,147	24,599,417	24,301,667	27,167,246	48,479,198	728,507,577

WACOG Calculations

30	**Gas Reserves Supply:**													
31	Total cost (line 12 above)	$2,563,265	$2,749,136	$2,561,384	$2,368,729	$2,498,044	$2,414,492	$2,471,856	$2,371,904	$2,365,549	$2,340,435	$2,266,758	$2,290,794	$29,262,347
32	Load served by gas reserves	4,010,902	4,087,389	4,018,926	3,582,571	3,910,634	3,731,795	3,809,096	3,642,084	3,719,247	3,676,283	3,517,270	3,593,859	45,300,056
33														
34	**Total Load Served**													
35	Oregon	72,942,638	105,319,475	101,167,397	81,586,485	70,085,841	50,864,343	36,007,558	25,640,906	22,262,114	21,973,745	24,498,317	43,648,390	655,997,209
36	Washingon	8,052,602	11,969,010	11,428,058	9,218,074	7,612,295	5,327,324	3,934,802	2,803,240	2,337,303	2,327,922	2,668,929	4,830,808	72,510,367
37	Total (same as line 25 +/- rounding)	80,995,240	117,288,485	112,595,456	90,804,559	77,698,135	56,191,667	39,942,359	28,444,147	24,599,417	24,301,667	27,167,246	48,479,198	728,507,577
38														
39	**Washington WACOG Calculation**													
40														
41	**Hedged Rockies supply excluding Gas Reserves**													
42	Hedged Rockies supply volumes	14,067,600	14,536,520	14,536,520	8,983,520	9,946,040	4,442,400	4,590,480	4,442,400	3,060,320	3,060,320	2,961,600	4,590,480	89,218,200
43	Hedged Rockies supply cost	$4,287,750	$4,430,675	$4,430,675	$2,766,820	$3,063,265	$1,088,100	$1,124,370	$1,088,100	$764,770	$764,770	$740,100	$1,142,970	$25,692,365
44	Hedged Rockies supply price per therm	$0.30480	$0.30480	$0.30480	$0.30799	$0.30799	$0.24494	$0.24494	$0.24494	$0.24990	$0.24990	$0.24990	$0.24899	$0.28797
45														
46	Load served by gas reserves	4,010,902	4,087,389	4,018,926	3,582,571	3,910,634	3,731,795	3,809,096	3,642,084	3,719,247	3,676,283	3,517,270	3,593,859	45,300,056
47	Gas Reserves cost	$2,563,265	$2,749,136	$2,561,384	$2,368,729	$2,498,044	$2,414,492	$2,471,856	$2,371,904	$2,365,549	$2,340,435	$2,266,758	$2,290,794	$29,262,347
48	Gas Reserves price per therm	$0.63907	$0.67259	$0.63733	$0.66118	$0.63878	$0.64701	$0.64894	$0.65125	$0.63603	$0.63663	$0.64447	$0.63742	$0.64597
49														
50	Washington percentage of total load (line 36 ÷ line 37)	9.9%	10.2%	10.1%	10.2%	9.8%	9.5%	9.9%	9.9%	9.5%	9.6%	9.8%	10.0%	10.0%
51														
52	Total System Commodity Cost (line 14 above)	$22,224,753	$35,073,277	$33,448,478	$27,253,256	$22,511,087	$13,170,334	$10,101,091	$7,653,883	$6,778,580	$7,211,025	$7,772,106	$11,657,159	$204,855,030
53	Less: Commodity Cost of Rockies Hedged Supplies (from line 43)	$4,287,750	$4,430,675	$4,430,675	$2,766,820	$3,063,265	$1,088,100	$1,124,370	$1,088,100	$764,770	$764,770	$740,100	$1,142,970	$25,692,365
54	Less: Commodity Cost of Gas Reserves (from line 12)	$2,563,265	$2,749,136	$2,561,384	$2,368,729	$2,498,044	$2,414,492	$2,471,856	$2,371,904	$2,365,549	$2,340,435	$2,266,758	$2,290,794	$29,262,347
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	$15,373,738	$27,893,466	$26,456,418	$22,117,708	$16,949,778	$9,667,742	$6,504,865	$4,193,878	$3,648,262	$4,105,820	$4,765,248	$8,223,395	$149,900,318
57														
58	Total System Load Served (from line 29)	80,995,240	117,288,485	112,595,456	90,804,559	77,698,135	56,191,667	39,942,359	28,444,147	24,599,417	24,301,667	27,167,246	48,479,198	728,507,577
59	Less: load from Rockies hedged supplies (from line 42)	14,067,600	14,536,520	14,536,520	8,983,520	9,946,040	4,442,400	4,590,480	4,442,400	3,060,320	3,060,320	2,961,600	4,590,480	89,218,200
60	Less: load served by gas reserves (from line 32)	4,010,902	4,087,389	4,018,926	3,582,571	3,910,634	3,731,795	3,809,096	3,642,084	3,719,247	3,676,283	3,517,270	3,593,859	45,300,056
61	Total System load excluding Rockies hedged & Gas Reserves	62,916,738	98,664,576	94,040,010	78,238,468	63,841,461	48,017,473	31,542,783	20,359,663	17,819,850	17,565,063	20,688,376	40,294,859	593,989,321
62														
63	System price excluding Rockies hedged & Gas Reserves (line 56 ÷ line 61)	$0.24435	$0.28271	$0.28133	$0.28270	$0.26550	$0.20134	$0.20622	$0.20599	$0.20473	$0.23375	$0.23033	$0.20408	$0.25236
64														
65	**Washington allocation of Rockies hedged supply**													
66	Rockies hedged supply needed for Washington (line 50 * (line 42 + line 46))	1,789,772	1,899,639	1,874,100	1,281,741	1,357,954	776,548	831,558	800,364	644,059	646,714	634,929	818,434	13,355,812
67	Cost of Rockies hedged supply allocated to Washington (line 66 * line 44)	$545,523	$579,010	$571,226	$394,763	$418,236	$190,208	$203,682	$196,041	$160,950	$161,614	$158,669	$203,782	$3,783,703
68														
69	**Washington portfolio**													
70	Volumes													
71	Total Washington load	8,052,602	11,969,010	11,428,058	9,218,074	7,612,295	5,327,324	3,934,802	2,803,240	2,337,303	2,327,922	2,668,929	4,830,808	72,510,367
72	Washington load met by Rockies hedged supply	1,789,772	1,899,639	1,874,100	1,281,741	1,357,954	776,548	831,558	800,364	644,059	646,714	634,929	818,434	13,355,812
73	Remaining Washington load	6,262,830	10,069,371	9,553,958	7,936,333	6,254,341	4,550,776	3,103,244	2,002,876	1,693,244	1,681,208	2,034,000	4,012,374	59,154,555
74														
75	Cost													
76	Cost of Rockies hedged supply allocated to Washington (line 67)	$545,523	$579,010	$571,226	$394,763	$418,236	$190,208	$203,682	$196,041	$160,950	$161,614	$158,669	$203,782	$3,783,703
77	Cost of remaining Washington load (line 73 * line 63)	$1,530,323	$2,846,712	$2,687,815	$2,243,601	$1,660,527	$916,253	$639,951	$412,573	$346,658	$392,982	$468,491	$818,845	$14,964,732
78	Total cost of Washington portfolio	$2,075,845	$3,425,722	$3,259,041	$2,638,365	$2,078,764	$1,106,461	$843,633	$608,614	$507,608	$554,596	$627,160	$1,022,627	$18,748,435
79														
80	**Washington Sales WACOG** (line 78 ÷ line 71)	$0.25779	$0.28622	$0.28518	$0.28622	$0.27308	$0.20770	$0.21440	$0.21711	$0.21718	$0.23824	$0.23499	$0.21169	$0.25856
81														
82	**WASHINGTON BILLING WACOG**	$0.26958	$0.29931	$0.29822	$0.29931	$0.28556	$0.21720	$0.22420	$0.22704	$0.22711	$0.24913	$0.24573	$0.22137	$0.27038
83														
84	**Oregon WACOG Calculation**													
85														
86	Total system commodity cost	$22,224,753	$35,073,277	$33,448,478	$27,253,256	$22,511,087	$13,170,334	$10,101,091	$7,653,883	$6,778,580	$7,211,025	$7,772,106	$11,657,159	$204,855,030
87	Commodity cost allocated to Washington portfolio	$2,075,845	$3,425,722	$3,259,041	$2,638,365	$2,078,764	$1,106,461	$843,633	$608,614	$507,608	$554,596	$627,160	$1,022,627	$18,748,435
88	Total commodity cost for Oregon	$20,148,908	$31,647,555	$30,189,437	$24,614,892	$20,432,323	$12,063,873	$9,257,458	$7,045,269	$6,270,972	$6,656,429	$7,144,946	$10,634,532	$186,106,595
89														
90	**Oregon Sales WACOG (line 88 ÷ line 35)**	$0.27623	$0.30049	$0.29841	$0.30170	$0.29153	$0.23718	$0.25710	$0.27477	$0.28169	$0.30293	$0.29165	$0.24364	$0.28370
91														
92	**OREGON BILLING WACOG**	$0.28417	$0.30913	$0.30699	$0.31037	$0.29991	$0.24400	$0.26449	$0.28267	$0.28979	$0.31164	$0.30004	$0.25065	$0.29186

NW Natural
2017-2018 PGA - SYSTEM: September Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
		30	31	31	28	31	30	31	30	31	31	30	31	365
Transport charges by transporter:														
Northwest Pipeline		$4,400,118	$4,546,788	$4,359,348	$3,937,476	$4,359,348	$4,123,063	$4,260,498	$4,123,063	$4,260,498	$4,260,498	$4,123,063	$4,232,479	$50,986,239
Alberta: NOVA		677,289	677,289	677,289	677,289	677,289	677,289	677,289	677,289	677,289	677,289	677,289	677,289	8,127,471
Alberta: Foothills		275,448	275,448	275,448	275,448	275,448	245,860	245,860	245,860	245,860	245,860	245,860	275,448	3,127,846
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	5,431,862
BC: Southern Crossing		621,917	640,248	640,248	585,256	640,248	621,917	640,248	621,917	640,248	640,248	621,917	640,248	7,554,660
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	224,258
Total System Demand		$6,791,939	$6,983,556	$6,796,117	$6,239,404	$6,796,117	$6,408,457	$6,588,278	$6,408,457	$6,588,278	$6,588,278	$6,408,457	$6,669,248	$79,266,586

Detail in file "Capacity Contract Monthly Summary for 2017-18 PGA Year.xls"

NW Natural
2017-2018 PGA - SYSTEM: September Filing
Derivation of Oregon per therm Non-Commodity Charges
ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$79,266,586	
5	Oregon Allocation Factor 1/		89.49%	
6	Oregon Demand		$70,935,668	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		606,239,575	
9	Oregon Interruptible Sales Forecasted Normal Vol		49,757,635	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11588	$0.11921
13	Proposed Interruptible Demand 2/		$0.01379	$0.01419
14	Proposed MDDV Demand Charge		$1.72	$1.77
15				
16	Current Firm Demand Per Therm		$0.11784	$0.12132
17	Current Interruptible Demand		$0.01402	$0.01443
18	Current MDDV Demand Charge		$1.75	$1.80
19				
20	Percent Change in Firm Demand		-1.66%	
21				
22				
23	1/Allocation Factor: 2017-18 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	71,202,188	606,239,575	677,441,763
26		10.51%	89.49%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		0.983	
31				
32	Firm Demand (line 16 * line 30)		$0.11588	$70,249,682
33	Interruptible Demand (line 17 * line 30)		$0.01379	$685,986
34				$70,935,668
35				$0

NW Natural

2017-2018 PGA - SYSTEM: September Filing

Calculation of Winter WACOG

Prices are per therm

Line		AECO/NIT			
1	Forecast price for AECO gas:				
2					
3		AECO/NIT			
4					
5	November	$0.19711			
6	December	$0.20936			
7	January	$0.21528			
8	February	$0.21599			
9	March	$0.21224			
10	April	$0.18691			
11	May	$0.18614			
12	June	$0.18631			
13	July	$0.18784			
14	August	$0.18871			
15	September	$0.18735			
16	October	$0.19201			
17					
18					
19	Average price, November-March		$0.21000		average lines 5-9
20					
21	Annual average price, November-October		$0.19710		average lines 5-16
22					
23	Ratio of winter to annual		1.06545		line 19 ÷ line 21
24					
25			Without Rev	WITH Rev	
26			Sensitive	Sensitive	
OR	Oregon Annual WACOG		$0.28370	$0.29186	
OR	Oregon Winter WACOG		$0.30227	$0.31096	
			line 23 * $0.2837		
WA	Washington Annual WACOG		$0.25856	$0.27038	
WA	Washington Winter WACOG		$0.27548	$0.28807	
			line 23 * $0.25856		

NW Natural
2017-2018 PGA - OREGON: September Filing
Derivation of Oregon Seasonalized Fixed Charges

Line	(a)	(b)	Normalized Residential Volumes (c)	Normalized Commercial Volumes (d)	Firm Industrial Volumes (e)	Interruptible Volumes (f)	Total (g)	Firm Demand Increment Eff. 11/01/17 (h)	Interr. Demand Increment Eff. 11/01/17 (i)	Seasonalized Fixed Charges (j)
5										
6	November	2017	41,272,940	24,641,128	2,511,540	4,517,030	72,942,638	$0.11589	$0.01379	$7,991,278
7	December	2017	62,372,487	34,829,521	3,016,462	5,101,005	105,319,475	$0.11589	$0.01379	$11,683,410
8	January	2018	59,445,591	33,229,268	3,200,031	5,292,507	101,167,397	$0.11589	$0.01379	$11,182,727
9	February	2018	47,141,315	26,950,762	2,749,219	4,745,189	81,586,485	$0.11589	$0.01379	$8,969,613
10	March	2018	38,996,902	23,526,413	2,642,628	4,919,898	70,085,841	$0.11589	$0.01379	$7,619,111
11	April	2018	27,165,131	17,054,856	2,435,225	4,209,131	50,864,343	$0.11589	$0.01379	$5,464,331
12	May	2018	18,054,946	11,939,390	2,125,945	3,887,276	36,007,558	$0.11589	$0.01379	$3,775,621
13	June	2018	11,012,786	9,230,817	1,998,461	3,398,842	25,640,906	$0.11589	$0.01379	$2,624,222
14	July	2018	8,580,234	8,399,498	2,052,220	3,230,161	22,262,114	$0.11589	$0.01379	$2,249,916
15	August	2018	8,449,642	8,326,157	2,038,494	3,159,452	21,973,745	$0.11589	$0.01379	$2,223,720
16	September	2018	9,907,736	8,857,334	2,362,418	3,370,829	24,498,317	$0.11589	$0.01379	$2,494,682
17	October	2018	22,707,722	14,461,310	2,553,045	3,926,313	43,648,390	$0.11589	$0.01379	$4,657,037
18										
19										
20										
21			355,107,432	221,446,453	29,685,690	49,757,635	655,997,209			$70,935,668

#	Encana Gas Reserves Deal		Projected November 2017	Projected December 2017	Projected January 2018	Projected February 2018	Projected March 2018	Projected April 2018	Projected May 2018	Projected June 2018	Projected July 2018	Projected August 2018	Projected September 2018	Projected October 2018	Projected PGA Totals
1	Therms Delivered (000s)														
2	Total Therms		3,879.59	3,954.34	3,888.24	3,466.73	3,784.65	3,611.98	3,687.45	3,526.37	3,601.68	3,560.65	3,407.17	3,481.88	43,850.73
3	Rate per Therm (Depletion Rate)		0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750	0.34750
4	Delivery Value		1,348.17	1,374.14	1,351.17	1,204.70	1,315.17	1,255.17	1,281.40	1,225.42	1,251.59	1,237.33	1,184.00	1,209.96	15,238.22
5															0.3475
6	Opex / Severance / Ad Valorem														
7	Operating Cost		515.26	672.53	517.02	498.86	518.80	524.19	563.45	532.51	502.00	500.31	493.80	496.90	6,335.63
8	Severance and Ad Valorem Taxes		135.10	151.05	152.27	134.09	134.99	106.20	103.53	100.28	107.63	106.84	101.41	103.21	1,436.62
9	Total		650.36	823.58	669.30	632.96	653.79	630.39	666.98	632.80	609.63	607.15	595.21	600.11	7,772.24
10															0.1772
11	Average Rate Base		58,758.88	57,888.00	57,033.52	56,267.73	55,435.04	54,638.69	53,826.45	53,048.11	52,253.92	51,468.36	50,715.09	49,946.11	
12															
13	Carrying Cost														
14	Equity	9.5000%	232.59	229.14	225.76	222.73	219.43	216.28	213.06	209.98	206.84	203.73	200.75	197.70	
15	Equity % of Cap Struct	50.0000%													
16	Equity Pretax	39.4589%	333.66	321.22	314.19	315.52	308.98	314.58	309.84	305.58	296.85	291.53	288.41	282.12	
17	Debt	6.0560%	148.27	146.07	143.91	141.98	139.88	137.87	135.82	133.86	131.85	129.87	127.97	126.03	
18	Total Carrying Cost		481.92	467.29	458.10	457.50	448.86	452.46	445.66	439.44	428.70	421.40	416.38	408.15	5,325.87
19															0.1215
20	Total Cost		2,480.45	2,665.02	2,478.57	2,295.15	2,417.82	2,338.01	2,394.03	2,297.66	2,289.93	2,265.88	2,195.58	2,218.22	28,336.33
21	Total Volume		3,879.59	3,954.34	3,888.24	3,466.73	3,784.65	3,611.98	3,687.45	3,526.37	3,601.68	3,560.65	3,407.17	3,481.88	43,850.73
22	Total Rate Per Therm		0.639	0.674	0.637	0.662	0.639	0.647	0.649	0.652	0.636	0.636	0.644	0.637	0.646

Non-Carry Wells Gas Reserves Deal		Projected November 2017	Projected December 2017	Projected January 2018	Projected February 2018	Projected March 2018	Projected April 2018	Projected May 2018	Projected June 2018	Projected July 2018	Projected August 2018	Projected September 2018	Projected October 2018	Projected PGA Totals
Therms Delivered (000s)														
Total Therms		183.31	186.04	182.80	162.30	176.69	168.20	171.04	162.93	165.79	163.30	155.71	158.58	2,036.69
Rate per Therm (Depletion Rate)		0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285	0.4285
Delivery Value		78.54	79.71	78.32	69.54	75.70	72.07	73.28	69.81	71.03	69.97	66.71	67.94	872.62
														0.4285
Opex / Severance / Ad Valorem														
Operating Cost		19.77	19.94	19.81	18.93	19.70	19.65	20.65	19.72	18.96	18.86	18.54	18.65	233.19
Severance and Ad Valorem Taxes		6.38	7.11	7.16	6.28	6.30	4.95	4.80	4.63	4.95	4.90	4.63	4.70	66.80
Total		26.15	27.04	26.97	25.21	26.00	24.60	25.46	24.35	23.91	23.76	23.17	23.35	299.99
														0.1473
Average Rate Base		3,673.44	3,621.71	3,571.82	3,527.24	3,478.93	3,432.82	3,385.98	3,341.24	3,295.76	3,250.92	3,208.05	3,164.44	
Carrying Cost														
Equity	**9.5000%**	14.54	14.34	14.14	13.96	13.77	13.59	13.40	13.23	13.05	12.87	12.70	12.53	
Equity % of Cap Struct	**50.0000%**													
Equity Pretax	**39.4589%**	24.02	23.68	23.35	23.06	22.75	22.44	22.14	21.85	21.55	21.26	20.98	20.69	
Debt	**6.0560%**	9.27	9.14	9.01	8.90	8.78	8.66	8.54	8.43	8.32	8.20	8.09	7.98	
Total Carrying Cost		33.29	32.82	32.37	31.96	31.52	31.11	30.68	30.28	29.86	29.46	29.07	28.67	371.09
														0.1822
Total Cost		137.98	139.57	137.66	126.71	133.23	127.77	129.42	124.44	124.81	123.18	118.95	119.97	1,543.71
Total Volume		183.31	186.04	182.80	162.30	176.69	168.20	171.04	162.93	165.79	163.30	155.71	158.58	2,036.69
Total Rate Per Therm [1]		0.753	0.750	0.753	0.781	0.754	0.760	0.757	0.764	0.753	0.754	0.764	0.757	0.758

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

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: September Filing
Attachment C: 3% Test

Line	Description	Surcharge	Credit	
1		**Surcharge**	**Credit**	
2	**2017-2018 PGA Gas Cost True-Up**		(15,624,355)	
3				
4	**Non-Gas Cost Amortizations**			
5	WARM	(4,959,640)		
	Residual Deferral	(55,770)		
6	Intervenor Funding	89,497		
7	Oregon Regulatory Fee	290,836		
8	Industrial DSM	3,880,011		
9	Decoupling	12,379,031		
10	Subtotal	11,623,965	(15,624,355)	
11				
12	Total	(4,000,390)		
13				
14	**Total Proposed Amortization**			(4,000,390)
15	Less:			
16	Intervenor Funding[1]			(89,497)
17	Industrial DSM[1]			(3,880,011)
18	Decoupling[1]			(12,379,031)
19				
20	**Net Proposed Amortizations (subject to the 3% test)**			(20,348,929)
21				
22	**Utility Gross Revenues (2016)** [2]			607,209,577
23				
24	**3% of Utility Gross Revenues**			18,216,287
25				
26	**Allowed Amortization**			(20,348,929)
27				
28	**Allowed Amortization as % of Gross Revenues**			-3.4%
29				

30 Notes:
31 [1] Amortizations of the deferral are not subject to the 3% test pursuant to ORS 757.259 as they are
32 automatic adjustment clauses.
33 [2] Unadjusted general revenues as shown in the most recent ROO.

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]

Advice 17-12A

ALL VOLUMES IN THERMS

Schedule	Block	Oregon PGA Normalized Volumes page, Column D A	Therms in Block B	Normal Therms Monthly Average use C	Minimum Monthly Charge D	11/1/2016 Billing Rates E	11/1/2016 Current Average Bill F=D+(C * E) F	Proposed 11/1/2017 PGA Rates V	Proposed 11/1/2017 PGA Average Bill W = D+(C * V) W	See note [9] Proposed 11/1/2017 PGA % Bill Change X = (W- F)/F X
2R		353,902,060	N/A	50	$8.00	$0.90723	$53.36	$0.85645	$50.82	-4.8%
3C Firm Sales		159,700,612	N/A	231	$15.00	$0.86447	$214.69	$0.81369	$202.96	-5.5%
3I Firm Sales		4,602,931	N/A	1,118	$15.00	$0.82099	$932.87	$0.77021	$876.09	-6.1%
27 Dry Out		1,205,372	N/A	51	$6.00	$0.79183	$46.38	$0.74105	$43.79	-5.6%
31C Firm Sales	Block 1	13,316,134	2,000	2,878	$325.00	$0.59951	**$2,033.45**	$0.55084	**$1,893.38**	-6.9%
	Block 2	12,481,400	all additional			$0.58022		$0.53155		
31C Firm Trans	Block 1	1,525,441	2,000	1,718	$575.00	$0.19261	**$905.90**	$0.19261	**$905.90**	0.0%
	Block 2	2,009,166	all additional			$0.17612		$0.17612		
31I Firm Sales	Block 1	4,070,024	2,000	5,101	$325.00	$0.52142	**$2,932.08**	$0.47275	**$2,683.81**	-8.5%
	Block 2	8,722,092	all additional			$0.50443		$0.45576		
31I Firm Trans	Block 1	125,106	2,000	5,582	$575.00	$0.17295	**$1,480.91**	$0.17295	**$1,480.91**	0.0%
	Block 2	276,784	all additional			$0.15634		$0.15634		
32C Firm Sales	Block 1	25,883,715	10,000	6,918	$675.00	$0.45060	**$3,792.25**	$0.40193	**$3,455.55**	-8.9%
	Block 2	8,661,618	20,000			$0.43472		$0.38605		
	Block 3	1,237,042	20,000			$0.40833		$0.35966		
	Block 4	165,932	100,000			$0.38189		$0.33322		
	Block 5	0	600,000			$0.36585		$0.31718		
	Block 6	0	all additional			$0.35526		$0.30659		
32I Firm Sales	Block 1	4,719,808	10,000	18,967	$675.00	$0.44761	**$9,026.91**	$0.39894	**$8,103.78**	-10.2%
	Block 2	5,298,281	20,000			$0.43223		$0.38356		
	Block 3	1,764,186	20,000			$0.40657		$0.35790		
	Block 4	508,368	100,000			$0.38095		$0.33228		
	Block 5	0	600,000			$0.36535		$0.31668		
	Block 6	0	all additional			$0.35515		$0.30648		
32 Firm Trans	Block 1	16,254,618	10,000	42,165	$925.00	$0.10157	**$4,409.93**	$0.10157	**$4,409.93**	0.0%
	Block 2	18,153,953	20,000			$0.08634		$0.08634		
	Block 3	10,538,827	20,000			$0.06103		$0.06103		
	Block 4	19,469,774	100,000			$0.03567		$0.03567		
	Block 5	21,237,750	600,000			$0.02045		$0.02045		
	Block 6	3,397,316	all additional			$0.01035		$0.01035		
32C Interr Sales	Block 1	5,242,630	10,000	31,274	$675.00	$0.43726	**$13,982.77**	$0.41537	**$13,298.18**	-4.9%
	Block 2	7,424,480	20,000			$0.42157		$0.39968		
	Block 3	3,966,495	20,000			$0.39542		$0.37353		
	Block 4	4,896,519	100,000			$0.36927		$0.34738		
	Block 5	236,893	600,000			$0.35356		$0.33167		
	Block 6	0	all additional			$0.34299		$0.32110		
32I Interr Sales	Block 1	6,200,783	10,000	34,814	$675.00	$0.43711	**$15,379.11**	$0.41522	**$14,617.03**	-5.0%
	Block 2	7,447,078	20,000			$0.42148		$0.39959		
	Block 3	3,991,226	20,000			$0.39539		$0.37350		
	Block 4	8,413,466	100,000			$0.36930		$0.34741		
	Block 5	1,938,065	600,000			$0.35364		$0.33175		
	Block 6	0	all additional			$0.34310		$0.32121		
32 Interr Trans	Block 1	8,753,845	10,000	208,347	$925.00	$0.10200	**$9,686.23**	$0.10200	**$9,686.23**	0.0%
	Block 2	15,798,206	20,000			$0.08673		$0.08673		
	Block 3	11,612,336	20,000			$0.06128		$0.06128		
	Block 4	31,071,223	100,000			$0.03582		$0.03582		
	Block 5	59,059,181	600,000			$0.02055		$0.02055		
	Block 6	91,219,916	all additional			$0.01038		$0.01038		
33		0	N/A	0	$38,000	$0.00590	$38,000.00	$0.00590	$38,000.00	0.0%
Totals		966,500,651								

[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.
[2] Tariff Advice Notice 17-05: Non-Gas Cost Deferral Amortizations - Intervenor Funding
[3] Tariff Advice Notice 17-06: Non-Gas Cost Deferral Amortizations - Residual Account
[4] Tariff Advice Notice 17-07: Non-Gas Cost Deferral Amortizations - Oregon PUC Fee
[5] Tariff Advice Notice 17-08: Non-Gas Cost Deferral Amortizations - SRRM
[6] Tariff Advice Notice 17-09: Non-Gas Cost Deferral Amortizations - Industrial DSM
[7] Tariff Advice Notice 17-10: Non-Gas Cost Deferral Amortizations - Decoupling
[8] Tariff Advice Notice 17-11: Non-Gas Cost Deferral Amortizations - WARM
[9] Tariff Advice Notice 17-12A: PGA

NW Natural
Rates and Regulatory Affairs
2017-2018 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/17		
1				
2				
3	Total Billed Gas Sales Revenues	$ 674,696,212		
4	Total Oregon Revenues	$ 678,088,466		
5				
6	Regulatory Commission Fees [1]	n/a	0.300%	Statutory rate
7	City License and Franchise Fees	$ 16,069,889	2.370%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 848,945	0.125%	Line 8 ÷ Line 4
9				
10	Total		**2.795%**	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 change occurred mid gas year, the difference between the previous fee of 0.275%
16 and the new fee of 0.3% 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
2017-2018 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Tariff Advice 17-12A: PGA Gas Costs and Gas Cost Deferrals

Line	Description	Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($15,137,099)
6		
7	Demand Capacity Cost Change	(1,370,387)
8		
9	**Total Gas Cost Change**	**(16,507,486)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	408,763
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(15,624,355)
18		
19	**Net Temporary Rate Adjustment**	**(15,215,592)**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($31,723,078)**
22		
23		
24		
25	2016 Oregon Earnings Test Normalized Total Revenues	$645,156,000
26		
27	Effect of this filing, as a percentage change (line 21 ÷ line 25)	-4.92%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 17-12A / UG 334

September 15, 2017

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	17-20	
5	Financial resources for the portfolio (derivatives and other financial arrangements).	14	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.	21	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	21	
9	Summary of portfolio documentation provided	21	
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:	22	
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.	22	
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.	22	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
3	Brief explanation of each contract's role within the portfolio.	22	
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:	24	
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.	24	
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.	26	HIGHLY CONFIDENTIAL
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	28	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	29	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	29	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,	29	
1	Annual for each customer class	29	
2	Annual and monthly baseload.	30	
3	Annual and monthly non-baseload.	30	
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.	32	
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.	36	

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.	37	
	NW Natural Gas Supply Risk Management Policies	38	CONFIDENTIAL
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.	65	
a)	Type of storage (e.g., depleted field, salt dome).	65	
b)	Location of each storage facility.	65	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	65	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	65	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	65	
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.	67	
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.	67	CONFIDENTIAL
h)	For LDCs that own and operate storage:		CONFIDENTIAL
a.	The date and results of the last engineering study for that storage.	86	
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.	101	
V.8	**Attestation as to Consistency**	102	

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 administration of President Trump has created many uncertainties in the natural gas industry, including the potential roll-back of certain regulations, renegotiation of NAFTA, encouragement of LNG exports, and the tax treatment of foreign goods. That last item could encompass the two-thirds of our gas supplies that are purchased in western Canada and imported into the United States, the steel pipeline used by the industry, and so on. However, the only uncertainty that is currently of tangible concern in this filing is the timing to confirm at least two new FERC commissioners. FERC has lacked a quorum for several months, and so an uncontested settlement between Northwest Pipeline and its shippers to lower rates effective January 1, 2018, still awaits FERC approval. The expectation is that new commissioners will be in place well before the end of this year, and so the negotiated rate reduction of about 7%, and a future reduction of less than 1% effective October 1, 2018, are reflected in our PGA filing.

The WUTC issued a Policy Statement on Natural Gas Hedging Practices in March 2017. It created no impact on the formulation of the current PGA filing, and its effect on future PGA filings is still being assessed.

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

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 2016 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)*	($41,152,695)	"PGA filing Summary Effects"
B) Percent *(To .1 percent)*	-6.38%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	($16,507,486)	"PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	($27,046,184)	"
C) Add New Temporary Increment	$2,400,975	"
D) Other Additions or Subtractions *(Break out & List each below -- Attach additional sheet if necessary)*		
1)		"PGA filing Summary Effects"
2)		
3)		
4)		
5)		
6)		
E) Total Proposed Change	($41,152,695)	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$0.90723	"2016-17 Rate Development"
2) Proposed Billing Rate per Therm	$0.83850	"2017-18 Rate Development"
3) Rate Change Per Therm	($0.06873)	"
4) Percent Change per Therm (to .1%)	-7.6%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	50.0	"2017-18 Rate Development"
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$53.36	"2016-17 Rate Development"
4) Proposed Average Monthly Bill	$49.93	"2017-18 Rate Development"
5) Change in Average Monthly Bill	($3.43)	"
6) Percent change in Average Monthly Bill (to .1%)	-6.4%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use (forecasted weather-normalized)	150.0	"2017-18 Rate Development"
2) Customer Charge	$8.00	"
3) Current Average January Bill	$144.30	"2016-17 Rate Development"
4) Proposed Average January Bill	$133.98	"2017-18 Rate Development"
5) Change in Average January Bill	($10.32)	"
6) Percent change in Average January Bill (to .1%)	-7.2%	"

	Amount	Location in Company Filing (cite)
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	$223,199,160	2016-17 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)	$2,015,456	2016-17 PGA filing
e) Total Storage Cost (assoc. w/ supply)	$48,040,220	2016-17 PGA filing
f) Other	$31,263,614	2016-17 PGA filing
2) Total Transportation Cost *(Pipeline related)*	$80,512,202	2016-17 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	$303,711,362	
B) Projected For New Rates		
1) Total Commodity Cost	$204,855,030	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)		
e) Total Volumetric Cost (assoc. w/ supply)	$1,051,169	Exhibit B, Page 1
f) Total Storage Cost (assoc. w/ supply)	$42,651,069	Exhibit B, Page 1
g) Other (A&G Benchmark Savings)	$29,262,347	Exhibit B, Page 1
2) Total Transportation Cost (Pipeline related)	$79,266,586	Exhibit B, Page 3
a) Total Upstream Canadian Toll	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$284,121,616	
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.31517	N/A
b. Without revenue sensitive	$0.30613	N/A
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.12132	N/A
b. Without revenue sensitive	$0.11784	N/A

	Amount	Location in Company Filing (cite)
B) Proposed for New Rates		
1) WACOG (Commodity Only)		
a. With revenue sensitive	$0.29186	Exhibit B, Page 2 and Page 5
b. Without revenue sensitive	$0.28370	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.11921	Exhibit B, Page 4
b. Without revenue sensitive	$0.11588	"
6) Therms Sold	655,997,209	Exhibit B, Page 2
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

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers at a reasonable cost.

To ensure adequate reliability, NW Natural 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 and use 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 NW Natural; (2) Obtain upstream capacity along the path from NW Natural's service territory to points generally recognized for their liquidity, such as AECO/NIT, to maximize buying opportunities and minimize price volatility; and (3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible.

Upstream gas supply contracts have been negotiated with the following objectives in mind:

(1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors;
(2) Try to match our year-round customer requirements to baseload (take-or-pay) annual or multi-year supply contracts to obtain the most favorable pricing;
(3) Use winter only (Nov-Mar) term contracts to match our rise in requirements during the heating season;
(4) Reduce spot purchase requirements during the winter due to the 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

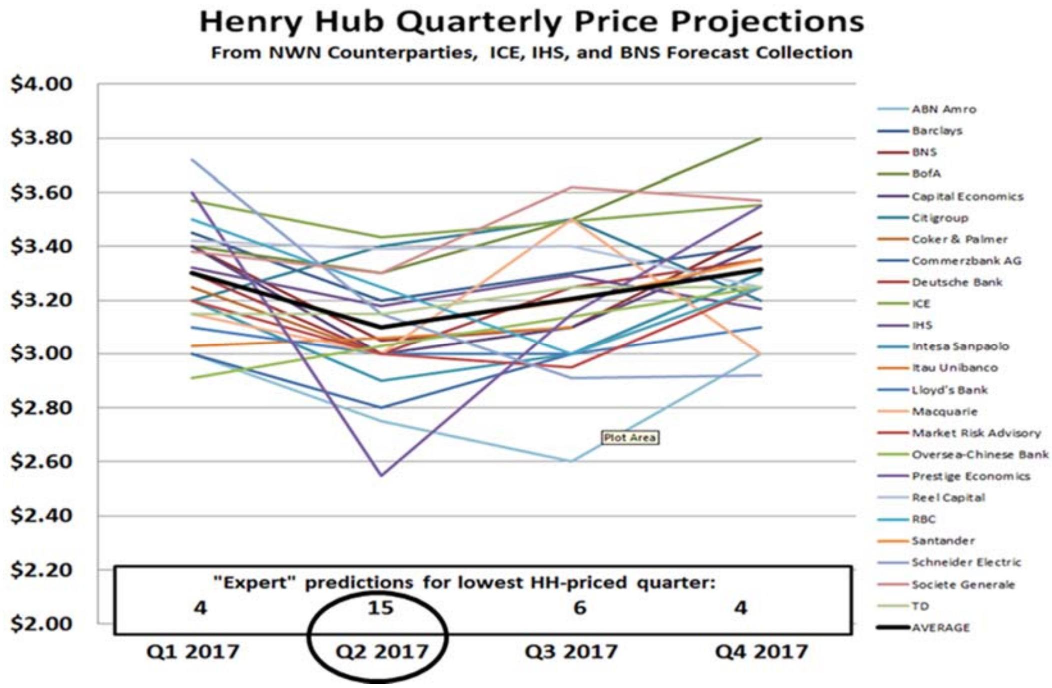
The Company's methodology for forecasting annual sales and firm peak day requirements is described in its Integrated Resource Plan (IRP), of which the latest is the 2016 IRP filed in August 2016 and subsequently acknowledged by the OPUC and the WUTC. Also applicable here is the load forecast methodology previously established for the PGA process.

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 during the coming winter, while at the same time complying with the PGA load forecast requirements.

3. Natural gas price forecasts

NW Nautral relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the IHS consulting firm (formerly known as CERA and now moving to the name IHS Markit) as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NW Natural 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, the chart below contains 24 forecasts that NW Natural collected in late 2016 for Henry Hub prices during 2017. From this collection, a view emerges that prices could be lowest in the 2nd quarter of 2017. An analysis performed by NW Natural suggests that current prices are strongly correlated to the futures market, that is, a dip in current prices will drop future prices for the upcoming PGA year, and vice versa. Therefore, a low current price period is more opportune to perform gas price hedging for the PGA year than a high priced period.



4. Physical resources for the portfolio

As mentioned above, NW Natural'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 some portion of the interstate pipeline system.

Five significant changes to the physical supply resource portfolio were discussed in last year's PGA filing. As a reminder, these were:

(1) the continuing and expanded usage of segmented capacity as a resource, increasing from 438,000 to 607,000 therms/day;

(2) adjustments to the on-system storage plant capabilities to reflect recent increases in the heat content of gas delivered over the interstate pipeline system due to a glut of natural gas liquids (NGLs) in the market that has reduced the processing of NGLs out of the natural gas stream;

(3) the commencement of 120,000 therms/day of new Northwest Pipeline capacity (the "March Point" contract) that became effective on January 1, 2017;

(4) the elimination of the need to continue a call option agreement for citygate deliveries due to the three resource increases mentioned above; and,

(5) the negotiation of a two-year T-South service agreement for 190,000 therms/day, which did not increase gas delivered to NW Natural's system but was done for economic reasons as well as to ease the Company's total reliance on purchases of British Columbia sourced gas at Huntingdon/Sumas.

This year, there are no significant changes to the physical supply resource portfolio, but some items of note are:

(1) Cold weather during the 2016/17 winter provided many opportunities to use segmented capacity as a resource, and its performance justifies its continued inclusion in the Company's resource portfolio;

(2) Updated load forecasts show that customer growth is being offset by lower usage per customer, such that new resources to bring more supplies to the Company's system are not needed for the coming PGA year;

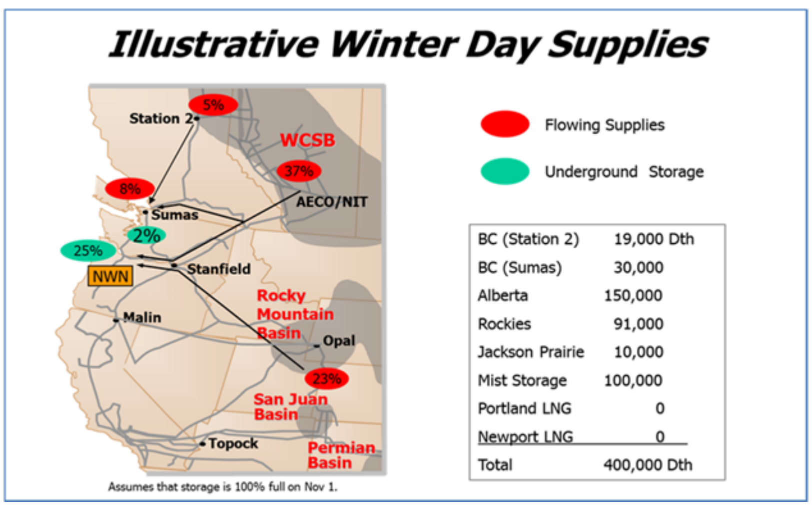
(3) The previously identified trend of rising heat content has not abated, leading to slightly higher deliverability from the Portland LNG plant and slighly more working gas capacity for utility customers at Mist;

(4) Operational issues have reduced somewhat the working gas capacities of the Portland and Newport LNG plants; and

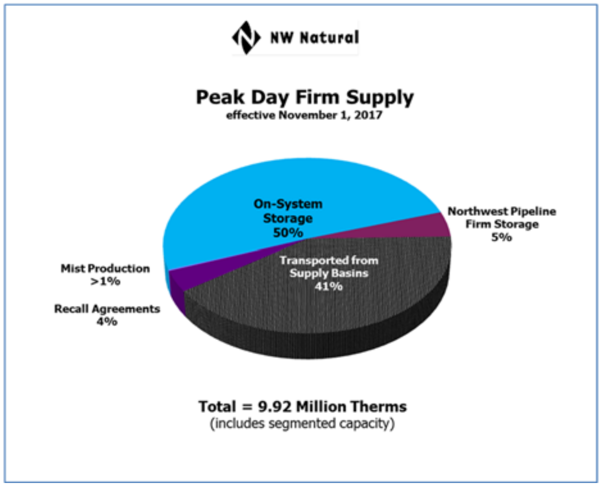
(5) The Company is participating in an expansion of the T-South pipeline system in British Columbia, which will allow more purchases at Station 2 in lieu of Sumas and potentially Alberta and the Rockies. The analysis that led to participation in this expansion will be included in the Company's IRP Update filing later this summer. Since this expansion will not be in service until at least November 1, 2020, it has no impact on this or the next two PGA filings.

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 continues to reflect the approved regulatory treatment for both sets of reserves. As a reminder, the seven Jonah Energy wells have an approved regulatory treatment that is different from the reserves obtained under the original program with Encana, but 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 (607,000 therms/day of segmented capacity is included):



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

Regarding physical supply purchasing, NW Natural will have contracts with suppliers for 550,000 therms per day of firm deliveries on a daily basis throughout the upcoming November 2017 through October 2018 period. This reflects the relatively stable daily component of NWN's demand, i.e., water heater and other non-space heating loads that are not seasonal in nature. This has been reduced slightly from last year to ensure we are not over-committed during the summer months.

For the November 2017 through March 2018 heating season, NW Natural will have contracts for an additional 1.25 million therms/day of supply under baseload agreements, and another 100,000 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 (0.55 million year-round plus 1.25 million winter season) that are purchased on a take-or-pay basis. The remaining 0.10 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 1.53 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 additional therms could be purchased on the spot market if the segmented capacity is available and 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, with spot gas comprising the largest component.

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, NW Natural's target this year is to financially hedge the prices of approximately 49% of its expected annual sales requirements for the upcoming 12-month period commencing November 1st. Gas reserves are expected to account for another 6% of hedge volumes. Storage gas (which is purchased on the spot market) will account for another 19%, and local Mist gas production (which is indexed to our average gas purchase cost) adds another 1%. The remaining 25% of our annual purchase volumes, when combined with our purchases for storage, means about 45% of NW Natural's total volumes are purchased on an unhedged basis.

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]

[redacted]

[redacted]

[END CONFIDENTIAL]

6. Storage resources

NWN relies on four storage facilities and one 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 Alberta supply-basin storage arrangement is with J. Aron & Company (a subsidiary of Goldman Sachs).

Storage provides the following benefits to customers:

a. Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads. This benefit applies to the storage located on NW Natural's system, and partially applies to Jackson Prairie storage, which is eligible for a Northwest Pipeline transportation service that is less expensive than normal year-round firm service. This benefit does not apply to storage located in the supply basins such as Alberta

b. Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak. Supply-basin storage is pursued when this potential benefit is sufficient to offset the cost of the storage service.

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 in 2015 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. And revisions to the customer load forecast have meant that previously planned storage additions for the utility could be deferred with multiple benefits to customers, e.g., rate base additions are deferred while revenue sharing from the interstate storage service continues.

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

Supporting information to IV.2.b.4

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2017/2018 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia:				
ConocoPhillips (Canada)	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2018
BP Canada Energy Group ULC	Nov-Mar	10,000		3/31/2018
TD Energy Trading, Inc.	Nov-Oct	5,000		10/31/2018
BP Canada Energy Group ULC	Nov-Oct	5,000		10/31/2018
Alberta:				
ConocoPhillips (Canada)	Nov-Mar	5,000		3/31/2018
TD Energy	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
Enstor Energy Services	Nov-Mar	5,000		3/31/2018
Powerex	Nov-Oct	5,000		10/31/2018
Suncor Energy	Nov-Mar	5,000		3/31/2018
Enstor Energy LLC	Nov-Oct	5,000		10/31/2018
Shell Energy North America (Canada)	Nov-Oct	5,000		10/31/2018
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2018
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2018
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2018
TD Energy Trading, Inc.	Nov-Mar	5,000		3/31/2018
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2018
Rockies:				
Anadarko Energy Services	Nov-Mar	5,000		3/31/2018
Citadel Energy Marketing	Nov-Oct	5,000		10/31/2018
Citadel Energy Marketing	Nov-Oct	5,000		10/31/2018
MacQuarie Energy	Nov-Mar	5,000		3/31/2018
Ultra Resources	Nov-Mar	10,000		3/31/2018
J. Aron	Nov-Mar		10,000	3/31/2018
J. Aron	Apr-Oct		10,000	10/31/2018
Ultra Resources	Nov-Oct	5,000		10/31/2018
MacQuarie Energy, LLC	Nov-Oct	5,000		10/31/2018
IGI Resources	Nov-Oct	5,000		10/31/2018
ConocoPhillips Company	Nov-Oct	5,000		10/31/2018
Concord Energy, LLC	Nov-Mar	5,000		3/31/2018
Anadarko Energy Services Company	Nov-Mar	5,000		3/31/2018
ConocoPhillips Company	Nov-Mar	5,000		3/31/2018
MacQuarie Energy, LLC	Nov-Mar	5,000		3/31/2018
ConocoPhillips Company	Nov-Mar	5,000		3/31/2018
Total, November-March		180,000	10,000	
Total, April-October		55,000	10,000	

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 Capacity
for the 2017/2018 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2031
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2025
Occidental cap. acq. (#139153)	1,046	10/31/2030
Occidental cap. acq. (#139154)	4,000	10/31/2030
International Paper cap. acq. (#138065)	4,147	10/31/2030
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	10/31/2018
1995 Rationalization	57,417	10/31/2018
Engage Capacity Acquisition	3,708	10/31/2018
2004 Capacity Acquisition	48,669	10/31/2018
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. Segmented capacity has not been included in this table.
5. T-South capacity does not include the new T-South Expansion contract of approximately 25,000 Dth/day, which will begin no earlier than November 1, 2020.
6. Termination dates have been updated to reflect the Memorandum of Understanding with Northwest Pipeline dated August 29, 2017.

Supporting information IV.2.b4

Table 3

NW Natural
Firm Storage Resources
for the 2017/2018 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2025
TF-2 (primary firm portion)	23,038	839,046	10/31/2025
TF-2 (primary firm portion)	9,467	281,242	10/31/2025
TF-1	13,525	n/a	10/31/2031
Firm On-System Storage Plants:			
Mist (reserved for core)	305,000	11,266,191	n/a
Portland LNG Plant	130,680	490,050	n/a
Newport LNG Plant	65,340	827,640	n/a
Total On-System Storage	501,020	12,583,881	
Total Firm Storage Resource	547,050	13,704,169	

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 1069 Btu/cf. The current heat content used for Newport and Portland LNG is 1089 Btu/cf.
6. Newport tank capacity de-rated from 1 Bcf pending CO2 removal project.
7. Due to an ongoing Engineering analysis of the Portland LNG tank, liquifaction will be limited to 75% of the tank's capacity.
8. The Company's Plymouth-related contracts terminated on October 31, 2015, so they are no longer reflected in this table.
9. NW Natural has a supply-basin storage contract in Alberta that is NOT included in this table to avoid double-counting resources because its deliverability relies on portions of the same upstream pipeline capacity already included in Table 2. This contract is with:
   J. Aron & Company - 1,530,000 Dth
10. Termination dates have been updated to reflect the Memorandum of Understanding with Northwest Pipeline dated August 29, 2017.

Supporting information IV.2.b4

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2017/2018 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 2017/2018 Tracker Year

Resource Type	Max. Daily Rate (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)	501,020
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	991,987

Notes:
1. The design firm sales peak day forecast for 2017-18 is 973,144 Dth as updated by Strategic Planning on 7/6/2017.
2. Per 2016 IRP filed 8/26/2016 (specifically 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.

	2017/2018
Forecast Annual Demand (therms)	728,507,577
Forecast Peak Demand (therms) - Normal	4,235,612
Forecast Peak Demand (therms) - Design	9,751,743
Forecast DSM Annual (therms)	0
Forecast DSM Peak (therms) - Design Peak	0
Forecast Annual Demand with Forecast DSM	728,507,577
Forecast Peak Demand with Forecast DSM - Normal	4,235,612
Forecast Peak Demand with Forecast DSM - Design	9,751,743

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. **[START HIGHLY CONFIDENTIAL]**

TABLE 1

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2017 - October 31, 2018
Physical Natural Gas term contracts

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

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
Citadel Energy Marketing LLC (1)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-AL-18
Citadel Energy Marketing LLC (2)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal	17-AL-22
Anadarko Energy Services Company (3)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-AL-8
MacQuarie Energy, LLC (4)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal	17-AL-13
Ultra Resources (5)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal	17-MM-29
Ultra Resources (6)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal	17-MM-31
MacQuarie Energy, LLC (7)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-MM-32
ConocoPhillips Company (8)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-MM-33
MacQuarie Energy, LLC (9)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-MM-34
IGI Resources (10)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-MM-38
ConocoPhillips Company (11)	11/1/2017	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-AL-28
Concord Energy, LLC (12)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal	17-AL-31
Anadarko Energy Services Company (13)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-AL-32
ConocoPhillips Company (14)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	17-AL-39
J. Aron & Company (15)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Rockies FOM		up to 10,000	NW Natural Cal l Option		Rocky Mountain Pool	17-AL-26
J. Aron & Company (15)	4/1/2018	10/31/2018	[redacted]	IFGMR-NWP Rockies FOM		up to 10,000	J. Aron Put Option		Rocky Mountain Pool	17-AL-27

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Rocky Mountain Pool	6	[redacted]	Price
(2) Opal	5		Price
(3) Rocky Mountain Pool	5		Price
(4) Opal	5		Price
(5) Opal	4		Price
(6) Opal	3		Price
(7) Rocky Mountain Pool	3		Price
(8) Rocky Mountain Pool	4		Price
(9) Rocky Mountain Pool	4		Price
(10) Rocky Mountain Pool	3		Price
(11) Rocky Mountain Pool	5		Price
(12) Opal	5		Price
(13) Rocky Mountain Pool	6		Price
(14) Rocky Mountain Pool	4		Price
(15) Rocky Mountain Pool	3		Price & option flexibility

TABLE 2

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2017 - October 31, 2018
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
J. Aron & Company (1)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	17-AL-11
ConocoPhillips Canada (2)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	17-AL-24
ConocoPhillips Canada (3)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	17-AL-35
BP Cnaada Energy Group ULC (4)	11/1/2017	3/31/2018	[redacted]	IFGMR-NWP Canadian Border FOM	10,000				Huntingdon	17-AL-37

Transactions for new PGA year

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

TABLE 3

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2017 - October 31, 2018
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Default Receipt Pt. Purchase Location	Internal Reference No.
J. Aron & Company (1)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	17-AL-19
TD Energy Trading, Inc. (2)	11/1/2017	10/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	17-AL-29
BP Canada Energy Group ULC (3)	11/1/2017	10/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	17-AL-38

Transactions for new PGA year

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

TABLE 4

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2017 - October 31, 2018
Physical Natural Gas term contracts

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

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Contractual Conditions	Internal Reference No.
Powerex (1)	11/1/2017	10/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-25
ConocoPhillips Canada (2)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-16
TD Energy Trading, Inc. (3)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-15
J. Aron & Company (4)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-16
Enstor Energy LLC (5)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-26
Suncor (6)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-27
Macquarie Energy Canada (7)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-34
Shell Energy North America (Canada) (8)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-37
Macquarie Energy Canada (9)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-MM-39
Shell Energy North America (Canada) (10)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-30
Enstor Energy LLC (11)	11/1/2017	10/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-34
Shell Energy North America (Canada) (12)	11/1/2017	10/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-36
TD Energy Trading, Inc. (13)	11/1/2017	3/31/2018	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			17-AL-41

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	3	[redacted]	Price
(2)	4	[redacted]	Price
(3)	5	[redacted]	Price
(4)	5	[redacted]	Price
(5)	3	[redacted]	Price
(6)	3	[redacted]	Price
(7)	4	[redacted]	Price
(8)	4	[redacted]	Price
(9)	3	[redacted]	Supplier Diversity
(10)	5	[redacted]	Price
(11)	5	[redacted]	Price
(12)	5	[redacted]	Price
(13)	3	[redacted]	Price

[END HIGHLY 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 2017-2018 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 2017-2018, 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.

2017-2018 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	2017-18 Days	Daily Volume	Trade Volume	[redacted]	[redacted]	Including Multi-Tracker	
26-Mar-15	2015-7	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
10-Apr-15	2015-12	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
20-Apr-15	2015-15	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
30-Apr-15	2015-19	[redacted]	[redacted]	Rockies	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
22-May-15	2015-22	[redacted]	[redacted]	Sumas	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
27-May-15	2015-24	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
29-May-15	2015-27	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
4-Jun-15	2015-28	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
30-Jun-15	2015-33	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
18-Sep-15	2015-44	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
25-Sep-15	2015-46	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
1-Oct-15	2015-50	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
21-Oct-15	2015-53	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
27-Oct-15	15-MM-22	[redacted]	[redacted]	AECO	Nov-Mar (2015-2018)	151	2,500	377,500	[redacted]	[redacted]	1,135,000	[redacted]
15-Mar-16	2016-6	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
22-Mar-16	2016-10	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
29-Mar-16	2016-12	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
31-Mar-16	2016-15	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
11-Apr-16	2016-20	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
18-Apr-16	2016-22	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
20-Apr-16	2016-24	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
22-Apr-16	2016-26	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
25-Apr-16	2016-27	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
29-Apr-16	2016-30	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
10-May-16	2016-31	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
16-May-16	2016-33	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
18-May-16	2016-34	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
23-May-16	2016-36	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
27-May-16	2016-40	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
1-Jun-16	2016-41	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
14-Jun-16	2016-43	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
20-Jun-16	2016-44	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
30-Jun-16	2016-50	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
3-Oct-16	2016-66	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
18-Oct-16	2016-69	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
19-Oct-16	2016-70	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
20-Oct-16	2016-71	[redacted]	[redacted]	AECO	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
26-Oct-16	2016-74	[redacted]	[redacted]	Rockies	Nov-Mar (2016-2019)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
22-Feb-17	2017-1	[redacted]	[redacted]	Rockies	Oct	31	5,000	155,000	[redacted]	[redacted]	155,000	[redacted]
23-Feb-17	**2017-2**	[redacted]	[redacted]	**AECO**	**April**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	[redacted]
24-Feb-17	**2017-3**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	[redacted]
27-Feb-17	2017-4	[redacted]	[redacted]	AECO	Sep-Oct	61	5,000	305,000	[redacted]	[redacted]	305,000	[redacted]
22-Mar-17	**2017-5**	[redacted]	[redacted]	**AECO**	**April**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	[redacted]
27-Mar-17	**2017-6**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	[redacted]
29-Mar-17	2017-7	[redacted]	[redacted]	Rockies	Apr-June	91	5,000	455,000	[redacted]	[redacted]	455,000	[redacted]
30-Mar-17	2017-8	[redacted]	[redacted]	AECO	Apr-June	91	5,000	455,000	[redacted]	[redacted]	455,000	[redacted]
10-Apr-17	**2017-9**	[redacted]	[redacted]	**AECO**	**Apr**	**30**	**10,000**	**300,000**	[redacted]	[redacted]	**300,000**	[redacted]
19-Apr-17	2017-10	[redacted]	[redacted]	Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
20-Apr-17	**2017-11**	[redacted]	[redacted]	**AECO**	**Nov-Jan**	**92**	**5,000**	**460,000**	[redacted]	[redacted]	**460,000**	[redacted]
21-Apr-17	**2017-12**	[redacted]	[redacted]	**AECO**	**Oct**	**31**	**10,000**	**310,000**	[redacted]	[redacted]	**310,000**	[redacted]
24-Apr-17	2017-13	[redacted]	[redacted]	Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
26-Apr-17	2017-14	[redacted]	[redacted]	Sumas	Nov-Mar (2017-2020)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
27-Apr-17	2017-15	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
5-May-17	2017-16	[redacted]	[redacted]	Rockies	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
9-May-17	2017-17	[redacted]	[redacted]	Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
16-May-17	2017-18	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
19-May-17	2017-19	[redacted]	[redacted]	Sumas	Nov-Mar (2017-2020)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
23-May-17	2017-20	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
24-May-17	2017-21	[redacted]	[redacted]	Sumas	Nov-Mar (2017-2020)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
25-May-17	2017-22	[redacted]	[redacted]	Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
2-Jun-17	2017-23	[redacted]		Sumas	Nov-Mar (2017-2020)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
6-Jun-17	2017-24	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
13-Jun-17	2017-25	[redacted]		Sumas	Nov-Mar (2017-2020)	151	2,500	377,500	[redacted]	[redacted]	1,132,500	[redacted]
23-Jun-17	2017-26	[redacted]		AECO	Nov-Jan (2017-2018)	92	5,000	460,000	[redacted]	[redacted]	460,000	[redacted]
21-Jun-17	2017-27	[redacted]	[redacted]	AECO	Nov-Jan (2017-2018)	92	5,000	460,000	[redacted]	[redacted]	460,000	[redacted]
26-Jun-17	2017-28	[redacted]	[redacted]	Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
28-Jun-17	2017-29	[redacted]		Rockies	Nov-Jan (2017-2020)	92	2,500	230,000	[redacted]	[redacted]	690,000	[redacted]
27-Jul-17	2017-30	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	[redacted]	1,070,000	[redacted]
18-Aug-17	2017-31	[redacted]	[redacted]	AECO	Nov-Jan (2017-2018)	92	5,000	460,000	[redacted]	[redacted]	460,000	[redacted]
28-Aug-17	2017-32	[redacted]	[redacted]	AECO	Nov-Mar (2017-2018)	151	5,000	755,000	[redacted]	[redacted]	755,000	[redacted]
Total Hard Hedges								**29,827,500**	[redacted]	[redacted]	**65,087,500**	[redacted]

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CONFIDENTIAL — 2017-2018 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]	[redacted]
Total Baseload Hedges including Index Adjustments										[redacted]	

Variance $0.00

Hedges by Counterparty:

	Hedges for Nov 2017 - Oct 2018			All Hedges Nov17 Forward		NOTIONAL RANK *
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9
[redacted]						
[redacted]						
[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10
[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8
[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	

Counterparty is on hold. No hedge transactions permitted.
Counterparty is approved for hedges only through prompt tracker year.
Counterparty is approved for multi-tracker hedges.

*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 all hedges in place for the prompt tracker year forward including extendible options and multi-year hedges.

Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

	Customer Cnt Jul-16	Revenue Jul-16	Customer Cnt Aug-16	Revenue Aug-16	Customer Cnt Sep-16	Revenue Sep-16
Total	**717,689**	$ 27,374,264.78	**717,691**	$ 25,673,625.58	**718,139**	$ 27,110,227.10
Oregon	639,597	24,726,473.81	639,483	23,183,267.66	639,785	24,515,116.78
Washington	78,092	2,647,790.97	78,208	2,490,357.92	78,354	2,595,110.32
Total Residential	650,220	14,386,217.08	650,378	13,176,043.20	650,950	13,957,227.44
Total Commercial	66,294	8,660,321.21	66,136	8,061,223.07	66,009	8,487,512 69
Total Industrial	656	1,509,655.09	658	1,538,909.17	661	1,700,700.11
Total Interruptible	134	1,318,556.46	134	1,370,326.86	134	1,422,590 02
Total Transportation - Commercial Firm	165	204,032.06	165	201,479.48	165	221,100 98
Total Transportation - Industrial Firm	120	636,258.22	120	635,532.47	119	637,086 25
Total Transportation - Interruptible	100	659,224.66	100	690,111.33	101	684,009 61
Unbilled Revenue		(1,415,034.21)		(90,243.65)		2,826,907.47
Agency Fees						
Net Balancing/Overrun		4,418.00		753.00		183 00
Total Gas Operating Revenue		**$ 25,963,648.57**		**$ 25,584,134.93**		**$ 29,937,317.57**

	Customer Cnt Oct-16	Revenue Oct-16	Customer Cnt Nov-16	Revenue Nov-16	Customer Cnt Dec-16	Revenue Dec-16
Total	**719,820**	$37,031,959.62	**722,599**	$ 50,358,252.14	**725,146**	$ 96,493,979.87
Oregon	641,274	33,574,596.40	643,675	45,644,590.67	645,883	87,639,473.38
Washington	78,546	3,457,363.22	78,924	4,713,661.47	79,263	8,854,506.49
Total Residential	652,480	20,646,759.89	654,808	30,223,675.10	656,855	61,968,678.67
Total Commercial	66,160	10,921,872.45	66,607	14,579,424.56	67,109	28,087,598.52
Total Industrial	662	2,066,279.32	657	1,951,895.30	655	2,167,735.31
Total Interruptible	133	1,771,365.10	133	1,931,812.96	133	2,390,292.95
Total Transportation - Commercial Firm	165	263,238.48	168	303,153.60	169	400,652.40
Total Transportation - Industrial Firm	119	674,954.03	125	695,568.64	123	767,964.55
Total Transportation - Interruptible	101	687,490.35	101	672,721.98	102	711,057.47
Unbilled Revenue		11,953,162.33		16,112,738.91		20,210,969.94
Agency Fees						
Net Balancing/Overrun		836.00		-		349,463.00
Total Gas Operating Revenue		**$48,985,957.95**		**$ 66,470,991.05**		**$ 117,054,412.81**

	Customer Cnt Jan-17	Revenue Jan-17	Customer Cnt Feb-17	Revenue Feb-17	Customer Cnt Mar-17	Revenue Mar-17
Total	**727,388**	$ 139,539,319.27	**728,804**	$ 110,793,822.36	**730,067**	$ 89,071,858.53
Oregon	647,831	124,907,598.30	649,043	99,590,568.21	650,077	80,155,392.82
Washington	79,557	14,631,720.97	79,761	11,203,254.15	79,990	8,916,465.71
Total Residential	658,839	88,862,604.75	660,241	69,824,566.27	661,217	55,246,777.73
Total Commercial	67,370	43,528,109.81	67,380	34,543,653.03	67,668	27,491,550.81
Total Industrial	653	2,582,918.37	659	2,371,923.82	660	2,174,315.17
Total Interruptible	132	2,629,946.11	131	2,297,781.37	131	2,382,286.52
Total Transportation - Commercial Firm	170	432,731.98	170	363,606.50	170	345,901.94
Total Transportation - Industrial Firm	124	791,218.48	123	730,593.26	123	734,089.34
Total Transportation - Interruptible	100	711,789.77	100	661,698.11	98	696,937.02
Unbilled Revenue		(6,126,765.33)		(14,403,263.87)		(5,697,782.80)
Agency Fees						
Net Balancing/Overrun		36,681.00		641.00		2,704.00
Total Gas Operating Revenue		**$ 133,449,234.94**		**$ 96,391,199.49**		**$ 83,376,779.73**

	Customer Cnt Apr-17	Revenue Apr-17	Customer Cnt May-17	Revenue May-17	Customer Cnt Jun-17	Revenue Jun-17
Total	**730,515**	$ 69,102,798.57	**730,852**	$ 52,375,620.91	**730,968**	$ 23,855,236.59
Oregon	650,375	62,487,143.66	650,545	47,392,222.47	650,512	20,482,035.12
Washington	80,140	6,615,654.91	80,307	4,983,398.44	80,456	3,373,201.47
Total Residential	661,802	42,678,246.61	662,209	31,217,612.25	662,376	13,050,161.27
Total Commercial	67,530	20,832,694.57	67,461	15,921,979.37	67,410	7,260,926.73
Total Industrial	657	1,917,341.88	657	1,746,763.71	658	1,087,301.63
Total Interruptible	131	1,977,934.08	131	1,827,668.93	130	880,894.78
Total Transporta ion - Commercial Firm	170	318,789.58	171	257 921.98	170	231,104.51
Total Transporta ion - Industrial Firm	123	702,277.50	123	687 815.57	124	660,591.56
Total Transporta ion - Interrup ible	102	675,514.35	100	715 859.10	100	684,256.11
Unbilled Revenue		(7,524,081.53)		(11,337 861.56)		(4,729,240.35)
Agency Fees						
Net Balancing/Overrun		-		-		2,054.10
Total Gas Operating Revenue		**$ 61,578,717.04**		**$ 41,037,759.35**		**$ 19,128,050.34**

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

	2017/2018 Forecasted	2016/2017	2015/2016	2014/2015	2013/2014	2012/2013
System peak demand (therms)	9,751,743	9,777,033	9,452,960	9,369,764	9,320,242	9,252,236

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

Gas Year	Forecasted 2017/2018	2016/2017	2015/2016	2014/2015	2013/2014	2012/2013
Annual Demand (therms)	728,507,577	744,738,987	757,005,313	747,790,904	746,847,556	732,272,081

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 2017/2018	2016/2017	2015/2016	2014/2015	2013/2014	2012/2013
Residential (herms)	402,002,465	403,236,093	413,822,757	402,683,123	396,647,034	388,025,253
Commercial (therms)	242,981,349	249,799,490	251,595,828	248,351,476	245,792,366	234,253,226
Industrial Firm (therms)	32,457,949	32,943,487	32,420,945	34,513,268	33,853,619	37,619,102
Industrial Interruptible (therms)	51,065,814	58,759,917	59,165,782	62,243,048	70,554,536	64,343,014

2. Annual and monthly baseload.

Gas Year	Forecasted 2017-2018	2016/2017	2015/2016	2014/2015	2013/2014	2012/2013
November	23,614,499.82	24,554,895.58	22,351,644	22,999,936	22,397,233	22,308,001
December	23,641,080.52	25,262,436.80	22,916,079	24,282,715	23,202,872	23,064,485
January	23,661,616.64	25,346,740.02	22,938,449	24,362,006	23,196,614	23,081,208
February	23,676,659.65	24,129,267.19	21,874,421	22,159,174	20,943,260	20,859,821
March	23,692,533.31	25,387,380.30	22,968,882	23,866,828	23,202,391	23,109,951
April	23,699,550.78	24,778,007.82	22,440,684	22,869,798	22,513,500	22,379,225
May	23,708,824.06	25,382,611.30	22,997,543	23,238,337	23,254,362	23,138,668
June	23,713,005.21	24,738,270.85	22,470,443	22,332,108	22,556,453	22,399,655
July	23,710,087.55	25,327,244.58	23,023,353	23,019,887	23,314,587	23,152,520
August	23,708,249.43	25,304,863.03	23,050,124	23,015,123	23,324,427	23,162,291
September	23,717,107.35	24,686,183.77	22,527,362	22,737,568	22,537,805	22,425,676
October	23,742,625.86	25,342,154.07	23,100,640	23,881,459	23,359,078	23,196,701
Annual	284,285,840	300,240,055	272,659,625	278,764,939	273,802,581	272,278,201

3. Annual and monthly non-baseload

Gas Year	Forecasted 2017/2018	2016/2017	2015/2016	2014/2015	2013/2014	2012/2013
November	57,380,740	56,712,943	64,242,976	62,486,370	62,248,709	61,226,239
December	93,647,405	91,432,786	98,795,855	96,475,524	95,405,022	90,481,345
January	88,933,839	86,488,891	92,054,676	90,486,111	91,382,451	86,593,507
February	67,127,899	76,659,460	74,851,835	71,804,677	72,204,387	69,575,367
March	54,005,602	52,474,527	59,855,292	58,202,117	58,522,284	56,408,082
April	32,492,116	32,605,411	40,203,184	38,491,513	38,745,792	37,886,663
May	16,233,535	15,547,950	18,600,362	17,127,632	17,039,845	15,982,505
June	4,731,141	4,924,141	4,336,063	3,488,689	4,181,989	3,799,251
July	889,329	380,842	304,475	25,201	707,612	393,204
August	593,417	280,995	0	-	769,863	358,541
September	3,450,139	3,237,113	2,211,685	2,291,298	3,220,573	1,673,213
October	24,736,573	23,753,874	28,889,285	28,146,833	28,616,445	27,584,476
Annual	444,221,737	444,498,932	484,345,688	469,025,965	473,044,975	451,962,394

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

2017/2018	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	4,595,377	1,258,251	303,891	1,014,506	235,491	5,878,709	894,635	46,719,136	12,278,132	7,817,111	80,995,240
December	6,499,774	1,680,868	398,866	1,363,866	336,495	7,657,781	1,160,472	69,967,603	16,590,244	11,632,516	117,288,485
January	6,151,576	1,613,799	384,432	1,338,091	323,755	7,465,054	1,114,214	67,254,279	15,845,952	11,104,303	112,595,456
February	4,866,596	1,339,781	271,980	1,096,117	259,642	5,910,552	906,786	54,032,124	13,162,548	8,958,432	90,804,559
March	4,396,838	1,368,407	343,186	912,660	200,528	5,888,949	947,891	44,192,918	12,034,992	7,411,766	77,698,135
April	3,659,850	1,093,837	298,561	622,279	125,808	4,678,202	790,980	30,556,670	9,163,966	5,201,516	56,191,667
May	2,718,668	782,070	232,594	495,227	90,979	3,482,224	629,620	21,445,360	6,221,796	3,843,823	39,942,359
June	1,976,734	575,877	166,901	400,513	71,006	2,679,291	490,318	14,704,996	4,646,276	2,732,234	28,444,147
July	1,614,014	546,973	146,682	378,751	64,403	2,235,690	469,931	12,926,949	3,943,123	2,272,901	24,599,417
August	1,724,534	532,710	137,153	370,012	65,087	2,238,633	462,045	12,669,262	3,839,397	2,262,835	24,301,667
September	1,922,905	587,476	152,422	396,908	71,919	2,396,435	480,658	13,915,721	4,645,792	2,597,010	27,167,246
October	3,112,415	841,072	215,922	587,177	126,482	3,908,183	657,941	26,507,450	7,818,230	4,704,327	48,479,198
Annual	43,239,281	12,221,120	3,052,591	8,976,108	1,971,595	54,419,702	9,005,491	414,892,468	110,190,448	70,538,773	728,507,577

2016/2017	Albany	Astoria	Coos Bay	The Dalles (OR	The Dalles (W	Eugene	Newport	Portland	Salem	Vancouver	Total
November	3,003,230	866,732	244,968	577,151	138,181	3,710,737	662,395	29,583,502	7,379,381	4,592,272	50,758,549
December	6,057,420	1,587,331	425,823	1,071,584	321,684	6,465,606	1,342,518	64,675,278	12,434,157	9,483,114	103,864,513
January	8,917,184	2,243,860	561,692	1,816,082	433,633	9,767,406	1,610,061	100,280,072	21,394,925	16,404,941	163,429,856
February	6,378,898	1,783,591	417,441	1,575,289	311,503	7,956,474	1,166,305	77,162,935	17,771,326	12,361,070	126,884,830
March	5,274,286	1,554,099	408,833	1,115,885	217,752	6,598,937	1,119,451	58,462,872	14,551,440	9,638,087	98,941,642
April	4,075,561	1,250,351	330,786	782,657	157,473	5,165,565	958,829	42,782,622	10,904,867	6,945,582	73,354,293
May	2,930,675	963,140	280,474	592,666	89,307	4,245,719	733,482	30,962,201	8,642,168	5,020,020	54,459,853
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	47,385,211	13,454,563	3,521,605	9,748,618	2,061,732	57,892,029	10,256,413	487,668,806	118,912,138	78,768,102	829,669,216

2015/2016	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,074,744	846,306	494,121	3,799,048	702,449	30,577,070	6,134,192	4,402,104	50,030,034
December	5,810,458	1,586,640	1,118,426	7,180,600	1,151,546	65,454,108	13,991,455	10,431,152	106,724,386
January	6,859,044	1,746,878	1,379,298	8,245,535	1,345,348	77,006,101	16,857,523	12,573,721	126,013,448
February	4,560,345	1,326,755	979,876	6,136,769	869,227	50,609,904	12,137,199	8,326,569	84,946,643
March	4,210,415	1,209,540	832,358	5,426,045	898,389	44,305,807	10,493,399	7,082,115	74,458,068
April	2,860,334	982,126	608,204	4,626,706	708,780	31,109,796	8,853,355	5,222,831	54,972,131
May	1,966,950	704,500	365,481	3,282,636	582,555	19,755,223	5,517,571	3,190,935	35,365,850
June	1,589,927	652,322	324,374	2,863,446	541,081	16,487,323	4,364,444	2,761,428	29,584,345
July	1,276,440	569,474	315,360	2,512,049	512,910	13,549,814	4,137,273	2,348,586	23,327,828
August	1,094,713	490,165	309,016	2,301,093	484,354	11,915,029	3,596,497	2,087,015	23,050,124
September	1,290,982	519,961	308,947	2,343,325	535,853	13,080,874	3,890,952	2,248,661	24,739,046
October	2,058,103	655,682	400,183	2,906,804	633,634	20,461,984	5,354,997	3,227,248	51,989,926
Annual	36,652,454	11,290,349	7,435,643	51,624,055	8,966,126	394,313,032	95,328,857	63,902,363	685,201,829

2014/2015	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,490,958	869,406	739,467	4,017,243	761,672	33,112,773	6,228,375	4,808,471	54,028,365
December	5,847,679	1,367,602	1,245,731	6,776,032	921,294	59,955,127	13,259,278	9,648,654	99,021,398
January	6,351,751	1,511,674	1,385,617	7,384,910	1,127,141	65,692,741	14,491,558	10,585,680	108,531,072
February	4,503,610	1,122,974	1,087,328	5,805,289	768,470	47,086,091	11,421,381	7,829,682	79,624,824
March	4,158,320	1,121,188	913,284	5,503,855	806,489	38,235,877	9,848,434	6,201,912	66,789,358
April	3,717,325	981,132	727,827	4,717,038	774,036	32,236,045	8,249,792	5,074,817	56,478,012
May	2,664,122	782,272	580,411	3,898,397	634,775	23,625,974	6,697,473	3,789,305	42,672,730
June	1,840,466	647,219	429,546	2,824,482	551,338	15,117,689	4,430,159	2,542,401	28,383,298
July	1,432,574	550,017	382,927	2,328,798	491,887	11,488,733	3,356,047	1,895,492	21,926,476
August	1,479,412	496,116	392,405	2,151,660	453,438	10,679,209	3,115,291	1,785,762	20,553,293
September	1,731,118	511,828	426,199	2,268,709	504,023	12,315,742	3,477,020	2,079,370	23,314,009
October	2,061,765	577,540	473,559	2,809,490	492,610	15,383,719	4,344,711	2,494,906	28,638,300
Annual	39,279,100	10,538,968	8,784,299	50,485,903	8,287,172	364,929,719	88,919,520	58,736,452	629,961,134

2013/2014	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,004,316	923,615	752,502	4,951,166	773,173	35,213,397	8,421,835	5,303,793	59,343,797
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	120,930,179
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	131,294,398
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	118,579,191
March	4,458,858	1,237,372	1,159,727	5,962,629	864,287	51,903,144	12,484,347	8,469,900	86,540,264
April	3,776,291	1,049,610	784,535	5,052,348	779,630	36,250,554	9,500,909	5,960,021	63,153,898
May	2,855,731	770,344	612,151	3,922,913	584,808	24,906,632	6,850,569	4,016,235	44,519,383
June	1,904,412	586,081	470,687	3,016,935	517,593	16,685,126	4,754,490	2,725,858	30,661,182
July	1,597,377	562,799	415,682	2,491,542	502,615	13,198,442	3,914,695	2,234,904	24,918,056
August	1,511,671	530,842	380,067	2,240,954	468,602	10,815,694	3,171,714	1,812,836	20,932,379
September	1,637,412	510,399	390,868	2,220,473	483,630	11,242,660	3,430,400	1,899,175	21,815,016
October	1,980,952	517,141	420,442	2,571,228	459,522	13,984,555	3,967,612	2,228,583	26,130,034
Annual	44,491,967	11,889,804	9,720,950	58,685,251	9,197,509	437,244,041	106,628,429	70,959,826	748,817,777

2012/2013	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,980,097	983,796	694,036	4,029,196	790,299	32,332,665	7,420,633	5,068,731	55,299,453
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	90,962,033
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	131,430,600
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	107,406,100
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	84,827,650
April	3,629,993	1,071,117	855,673	4,976,097	843,776	36,067,438	9,392,593	5,920,050	62,756,736
May	1,857,990	805,939	560,211	3,370,006	579,423	23,346,350	6,872,771	4,031,753	41,424,443
June	2,560,019	697,834	508,908	3,181,901	611,895	19,329,442	5,292,184	3,189,278	35,371,462
July	1,219,385	541,620	412,307	2,382,000	534,531	13,262,177	3,717,540	2,323,146	24,392,706
August	1,826,950	544,793	367,119	2,229,168	527,684	12,014,710	3,731,707	2,079,382	23,321,513
September	1,562,984	514,216	383,906	2,422,690	473,131	12,267,612	3,721,567	2,089,454	23,435,560
October	3,810,945	717,439	615,143	3,575,465	707,577	23,151,713	6,242,844	3,839,276	42,660,402
Annual	44,463,783	11,982,727	9,219,927	55,145,608	9,730,428	420,111,086	103,949,731	68,685,367	723,288,657

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/Dth. 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

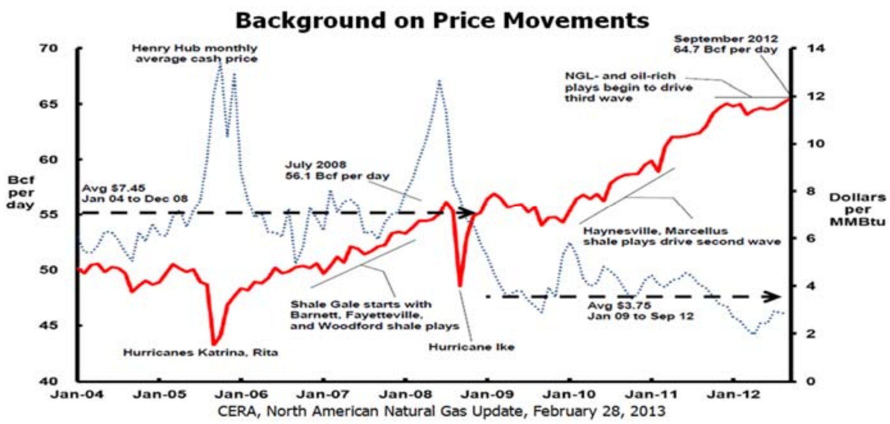
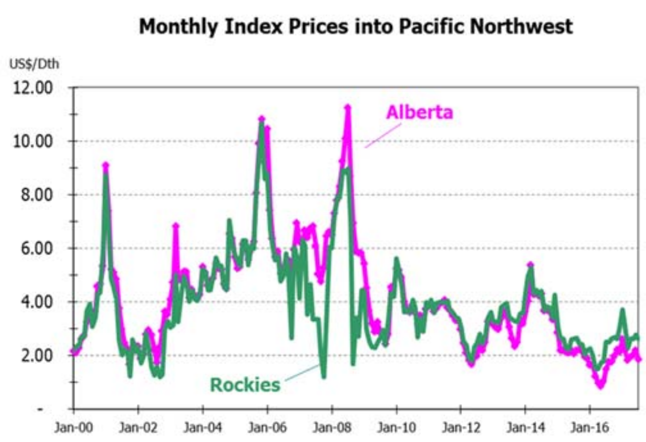


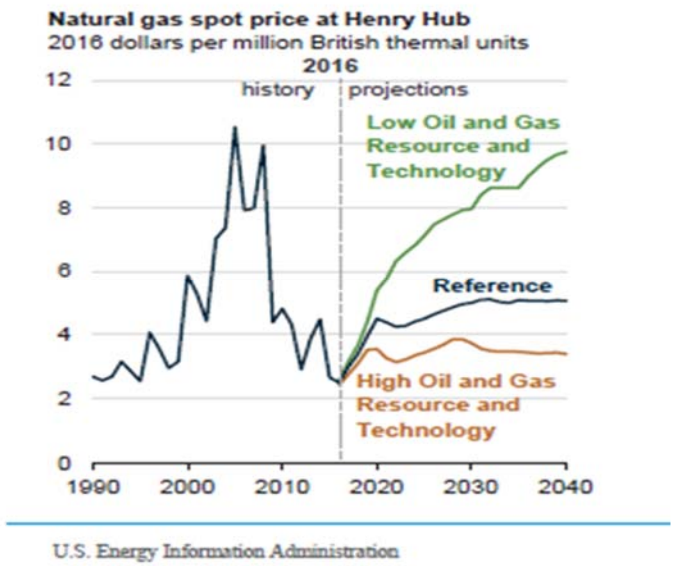
Figure 2



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.

The U.S. Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) has a reference case price forecast, as well as high and low cases that reflect the potential impact of new technologies. EIA expects prices to rise the new few years from today's low levels. Thereafter, price movements become increasing dependent on the pace of technological innovation. The EIA price forecast for the Henry Hub in 2016$ is shown in Figure 3.

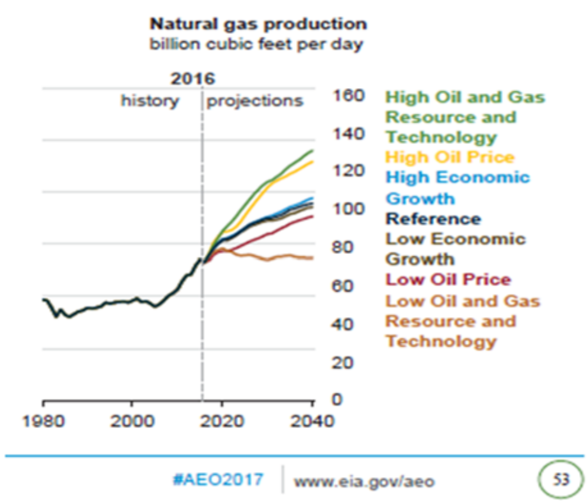
Figure 3



Some of the major factors affecting this outlook are:

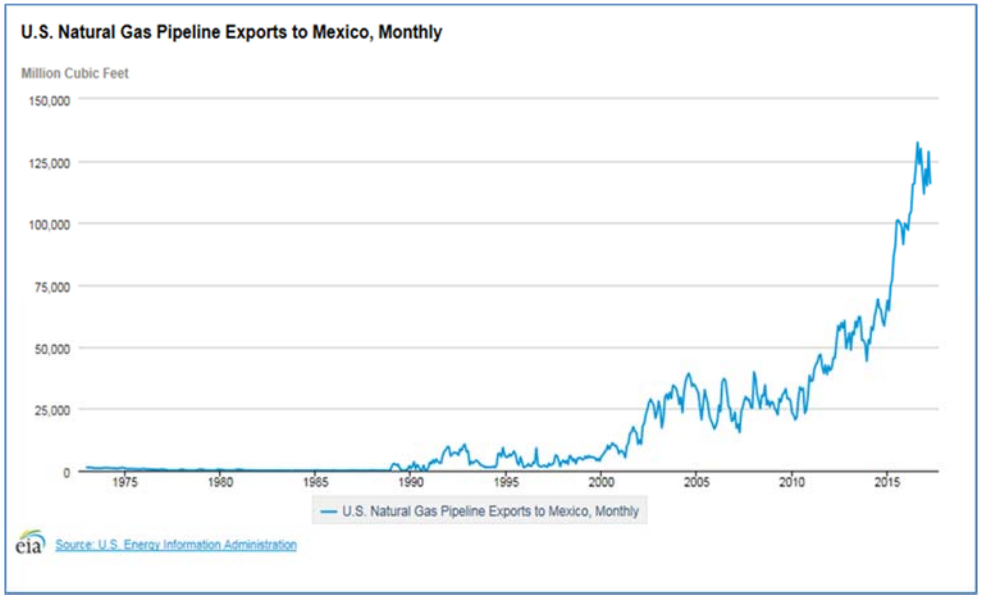
1. In its 2017 AEO, EIA forecasts that natural gas production will continue to grow quickly under most scenarios (see Figure 4). However, in its *Natural Gas Monthly* published on June 30, 2017, EIA reported that April 2017 marked the 14th consecutive month in which natural gas production decreased from the same year a year earlier.

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 3 Bcf LNG tanker load *every day* (see Figure 5).

Figure 5

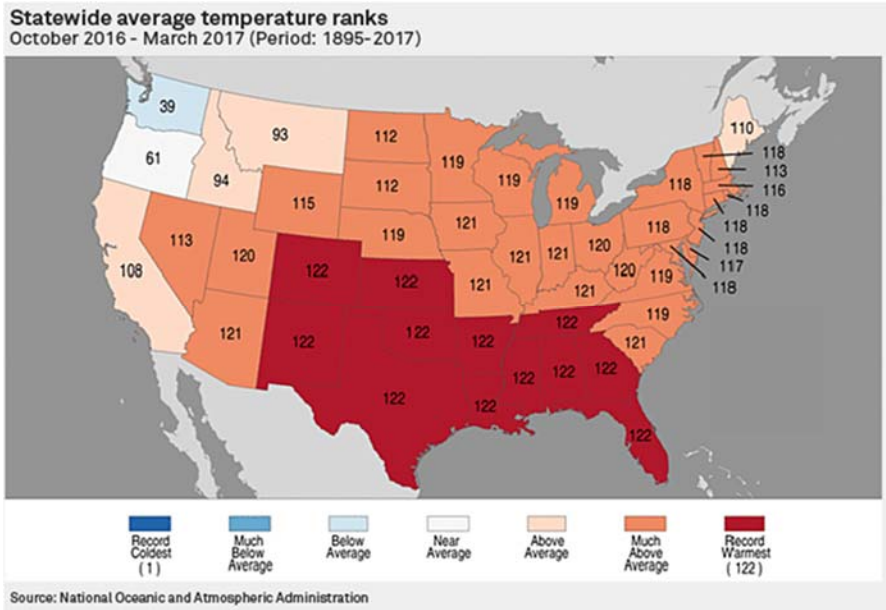


3. Deviations from "Normal" Conditions. Temperatures, hydro levels and storage inventories are examples of factors that can have large short-term effects, but when looking a year or more into the future, are normalized to some extent in price forecasts. This means variations in any of these factors from 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, which ranks as the #1 hottest winter (October-March) in the 122 years that the National Oceanic and Atmospheric Administration (NOAA) has tracked temperatures. Not too surprisingly, storage inventory levels across the country reached a record high in November 2016. And then warm weather struck again with the winter of 2016/2017 rated #2 by NOAA in terms of warmth over the last 122 years.

   Figure 5 shows the temperature pattern of last winter on a state-by-state basis. Only Oregon and Washington experienced anything close to cooler or colder than normal weather, but our gas demand is not nearly large enough to sway continental natural gas prices.

   It is unlikely that the warmth of the last two winters will repeat again this year, so temperature-related demand is also certain to be higher this coming winter, 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 22, 2016

Original Date of Approval: March 29, 2005

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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CONFIDENTIAL SUBJECT TO
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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
Mist (share allocated to Utility) - depleted field - Mist, OR	305,000	11,266,191
Portland LNG - LNG Plant - Portland, OR	130,680	490,050
Newport LNG - LNG Plant - Newport, OR	65,340	827,640

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
PGA Portfolio Guidelines
2017-2018 Oregon PGA

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-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	$ 87,922.80	0.20983	165,390,629	$ 59,927,894.01	0.36234
Feb	165,390,629	$ 59,927,894.01	0.36234	7,364,928	$ 2,243,437.76	-	$ -	-	158,025,701	$ 57,684,456.24	0.36503
Mar	158,025,701	$ 57,684,456.24	0.36503	2,222,649	$ 959,777.96	1,763,451	$ 191,087.31	0.10836	157,566,503	$ 56,915,765.59	0.36122
Apr	157,566,503	$ 56,915,765.59	0.36122	1,057,389	$ 358,801.37	4,694,562	$ 438,244.89	0.09278	161,203,676	$ 56,995,209.11	0.35354
May	161,203,676	$ 56,995,209.11	0.35354	278,494	$ 122,520.76	3,596,484	$ 422,136.36	0.11737	164,521,666	$ 57,294,824.71	0.34823
Jun	164,521,666	$ 57,294,824.71	0.34823	435,454	$ 189,445.52	3,366,849	$ 568,276.71	0.16879	167,453,061	$ 57,673,655.90	0.34440
Jul	167,453,061	$ 57,673,655.90	0.34442	269,411	$ 118,504.52	5,608,504	$ 1,122,283.87	0.20010	172,792,154	$ 58,677,435.25	0.33958
Aug	172,792,154	$ 58,677,435.25	0.33958	205,324	$ 91,088.63	5,982,972	$ 1,151,367.95	0.19244	178,569,802	$ 59,737,714.57	0.33453
Sep	178,569,802	$ 59,737,714.57	0.33453	197,222	$ 86,897.34	4,882,475	$ 1,187,474.19	0.24321	183,255,055	$ 60,838,291.42	0.33199
Oct	183,255,055	$ 60,838,291.42	0.33199	1,056,059	$ 313,511.00	1,880,810	$ 483,228.96	0.25693	184,079,806	$ 61,008,009.38	0.33142
Nov	184,079,806	$ 61,008,009.38	0.33142	2,445,979	$ 519,391.23	2,651,577	$ 550,271.16	0.20753	184,285,404	$ 61,038,889.31	0.33122
Dec	184,285,404	$ 61,038,889.31	0.33122	41,956,760	$ 13,229,908.36	3,321,350	$ 1,094,211.31	0.32945	145,649,994	$ 48,903,192.26	0.33576
TOTAL 2016 ACTIVITY				71,865,619	23,171,315	38,167,354	7,296,506				
Jan-17	145,649,994	$ 48,903,192.26	0.33576	34,412,044	$ 10,618,258.84	970,160	$ 301,841.76	0.31113	112,208,110	$ 38,586,775.18	0.34389
Feb	112,208,110	$ 38,586,775.18	0.34389	6,091,545	$ 1,334,519.38	1,156,690	$ 285,920.63	0.24719	107,273,255	$ 37,538,176.43	0.34993
Mar	107,273,255	$ 37,538,176.43	0.34993	2,529,712	$ 508,063.47	12,163,490	$ 2,795,959.60	0.22986	116,907,033	$ 39,826,072.56	0.34066
Apr	116,907,033	$ 39,826,072.56	0.34066	392,914	$ 128,470.77	4,116,895	$ 1,016,838.56	0.24699	120,631,014	$ 40,714,440.35	0.33751
May	120,631,014	$ 40,714,440.35	0.33751	255,999	$ 107,906.02	16,616,184	$ 4,183,845.45	0.25179	136,991,199	$ 44,790,379.78	0.32696
Jun	136,991,199	$ 44,790,379.78	0.32696	457,220	$ 201,460.40	9,984,353	$ 2,235,016.36	0.22385	146,518,332	$ 46,823,935.74	0.31958
TOTAL 2017 ACTIVITY				44,139,434	12,898,679	45,007,772	10,819,422				

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 NWN 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, fuel-in-kind and actual material costs incurred 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 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 and the Alberta storage contract[1].

[1] Use of the storage facilities also requires the use of transportation service agreements controlled by the tariffs of the applicable upstream pipelines as and when needed to inject gas into and withdraw gas from each of these facilities.

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

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

WHEREAS:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Name: RANDOLPH S. FRIEDMAN

Title: DIRECTOR, GAS SUPPLY

Name: JANE F HARRISON

Title: MANAGER NWP MARKETING SERVICES

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

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

SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper

2. Contract Demand: 46,030 Dth per day

3. Storage Capacity: 1,120,288 Dth

4. Recourse or Discounted Recourse Storage Rates:

   (Show Not Applicable if Exhibit D is attached.)

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

      Maximum Currently Effective Tariff Rate

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

      Maximum Currently Effective Tariff Rate

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

      Not Applicable

5. Service Term:

   a. Primary Term Begin Date:

      November 01, 1998

   b. Primary Term End Date:

      October 31, 2004

   c. Evergreen Provision:

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

6. Regulatory Authorization: 18 CFR 284.223

7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

TF0350 000004P126Original Sheet No. 50
TF04
TF05Laren M. Gertsch, Director
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
TF05Laren 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 to the maximum rate as it may change from time to time;

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

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

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

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

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

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

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.

TF0353 000004P126Original Sheet No. 53
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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.

TF0354 000004P126Original Sheet No. 54
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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.

TF0355 000004P126Original Sheet No. 55
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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.

TF0356 000004P126Original Sheet No. 56
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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:

TF0357 000004P126Original Sheet No. 57
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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.

TF0358 000004P126Original Sheet No. 58
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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.

[redacted]

[redacted]

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

[redacted]

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

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

See Attachment 1 to V.7.h to this Exhibit C dated July 2017, identified as Confidential and subject to Modified Protective Order No. 10-337.

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

[redacted]

[redacted]

**CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337**

[redacted]

[redacted]

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

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[redacted]

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

[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 2016 study.

Section V.8 - Attestation as to Consistency

See IV.1.c

NW Natural

CERTIFICATE OF SERVICE

I hereby certify that on September 15, 2017 I have served the foregoing unredacted version of the Confidential and Highly Confidential portions of NWN OPUC Advice No. 17-12A / UG 334 Exhibit C, subject to Modified Protective Order 10-337, via U.S. MAIL in Docket UM 1286.

Public Utility Commission of Oregon (C)(HC)
Attention: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, OR 97308-1088

Lisa Gorsuch (C)(HC)
Public Utility Commission of Oregon
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Robert Jenks (C)(HC)
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Chad Stokes (C)
Cable Huston Benedict Haagensen & Lloyd
1001 SW Fifth Avenue, STE 2000
Portland, OR 97204-1136

DATED at Portland, Oregon, this 15th day of September 2017.

/s/ Erica Lee
Erica Lee
Rates & Regulatory Affairs – Staff Assistant 3
NW NATURAL