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September 15, 2014

NWN OPUC Advice No. 14-16 / UG 278
(UM 1496)
SUPPLEMENT A

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Park Drive SE
Post Office Box 1088
Salem, Oregon 97308-1088

Attn: Filing Center

Re: **Replacement 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, stated to become effective with service on and after November 1, 2014, as follows:

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

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

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

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

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

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

First Revision of Sheet 165-1,
Schedule 165,
"Special Adjustment to Rates – Gas Reserves Credit."

This filing replaces, in the entirety, the advice letter, all tariff sheets and Exhibit A, B and C, originally filed under NWN OPUC Advice No. 14-16 dated August 1, 2014.

Introduction and Summary

The purpose of this replacement filing is to:

(1) Apply 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, 2014, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2013;

(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, 2014;

(3) Reflect the termination of the gas cost reserve credit adjustment placed into effect November 1, 2013 under Schedule 165; and

(4) Incorporate into Exhibit A two new documents: (i) a description of the Company's demand deferral methodology (Exhibit A, page 12); and (ii) an explanation of the resolution of certain accounting issues (Exhibit A, pages 13-17).

The Company revises rates for changes in purchased gas costs annually; its last filing was effective November 1, 2013.

The number of customers affected by the changes proposed in this filing is 563,128 residential customers, 59,490 commercial customers, and 620 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

This portion of the filing has not changed from the initial August 1, 2014 filing.

The net effect of this portion of the filing is to increase the Company's annual revenues by $22,952,580, or about 4.08%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2013, is an increase of $6,137,631; and the effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under Docket UM 1496 is an increase of $16,814,949.

The proposed adjustments to customer rates are comprised of the following: (1) a collection of $0.03226 per therm for all sales service customers representing a debit balance in Account 191 commodity accounts, and (2) a credit of $0.00804 per therm for all firm sales service customers and a credit of $0.00096 per therm for all interruptible sales service customers, representing a credit balance in Account 191 demand accounts. The net effect of all Account 191 amortizations is a collection of $0.02422 per therm for firm sales service customers and a collection of $0.03130 per therm for interruptible sales service customers.

The Account 191 demand account also includes the collection of $260,403 relating to an under-deferral of demand charges from the 2012-2013 PGA year discovered in December 2013. Specifically, a relevant demand charge should have been updated in December in accordance with a previously established methodology, but was actually updated beginning in November. The December update, which has been the Company's practice since 1999, is required to ensure that the seasonalized demand charge and the embedded demand charge are appropriately matched. The incorrect timing of the update resulted in an under-deferral of the Company's demand charges of $260,403. The Company proposes with this filing to include this amount in rates effective for November 1, 2014. Details about this adjustment can be found at Exhibit A, at page 8 and at page 16.

It should be noted that the Schedule 162 tariff sheets (Third Revision of Sheet 162-1 and Sheet 162-2) proposed with this filing reflect the following: (1) the effects of the working gas deferral amortization (See Schedule 180, NWN OPUC Advice 14-15 dated August 2, 2014), is included in the Account 191 Commodity Adjustment column. This is why the per therm adjustment shown in the Account 191 Commodity Adjustment column differs from the WACOG deferral increment shown at Exhibit A, page 1 of this filing; and (2) the Account 186 Adjustment column reflects the November 1, 2013 effective increments. The Company will file a separate combined effects filing that will consolidate each of the proposed November 1, 2014 Account 186 adjustments into Schedule 162.

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)

This portion of the filing has been updated primarily to reflect changes in commodity costs based on current average forward market prices and additional physical and hedge contracts entered into subsequent to the August 1, 2014 filing.

The net effect of the PGA portion of this filing is to increase the Company's annual revenues by about $4,471,036, or about 0.67%; the change in commodity cost is an increase of $17,419,760 and the change in demand cost is a decrease of $12,948,724.

The change in gas costs results in a proposed Annual Sales WACOG of $0.42178 per therm, and a proposed Winter Sales WACOG of $0.45358. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.43383 and a proposed Winter Sales Billing WACOG of $0.46654.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.11899 per therm, or $1.77 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01415 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.12239 per therm or $1.82 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01455 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 of Changes in Purchased Gas Costs on Customer Bills

The combined effects of this filing is to increase the Company's annual revenues by about $27,423,616, or about 4.08%; the change in purchased gas costs is an increase of $4,471,036 and the change in temporary adjustments to rates is an increase of $22,952,580.

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

Class	**Rate Schedule**	**Average Monthly Bill Change ($)**	**Average Monthly Bill Change (%)**
Residential	Schedule 2	$1.99	3.3%
Commercial	Schedule 3	$8.75	3.8%
Commercial Firm Sales	Schedule 31	$214.96	8.5%
Industrial Firm Sales	Schedule 32	$1,176.32	11.4%
Industrial Interruptible Sales	Schedule 32	$2,689.38	13.1%

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

Please note that the monthly bill effects for Rate Schedule 31 and Rate Schedule 32 do not include the effect of changes in the pipeline capacity charge due to the customer option to elect either an MDDV-based capacity charge or a volumetric-based capacity charge. If, for instance, 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, 2014 would be $723.53, or 7.0%.

UM 1286 Natural Gas Portfolio Development Guidelines

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

Commission Staff's Attachment A through Attachment D, required by Section 5 of the PGA Filing Guidelines, are included in the Company's work papers, incorporated herein by reference, and 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, 2014.

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

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

eFiling
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2516
Telephone: (503) 226-4211, x3589
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Cristan Kelley, Rate Analyst
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Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King
Rates & Regulatory Affairs

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

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective November 1, 2014:		(T)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.43383**	(I)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.42178**	(I)

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

Effective November 1, 2014:		(T)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.46654**	(I)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.45358**	(I)

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

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

Effective November 1, 2014:		(T)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.12239**	(R)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11899**	(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, 2014: (T)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
$0.01455 (R)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):
$0.01415 (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, 2014: (T)
Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
$1.82 (R)
Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive):
$1.77 (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)

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

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2014 through November 30, 2015 are: (T)

November 2014	$10,101,512 (C)
December 2014	$8,701,498
January 2015	$12,394,443
February	$11,662,660
March	$9,490,914
April	$8,315,588
May	$6,156,819
June	$3,985,421
July	$2,402,055
August	$2,065,327
September	$2,062,521
October	$2,230,184
November	$5,103,844
ANNUAL TOTAL	$74,571,274 (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)

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

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in all of the Company's conventional deferred revenue and gas cost accounts, Accounts 186 and 191, respectively.

APPLICABLE:
To the following Rate Schedules of this Tariff:

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, 2014 (T)

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [2]	Total Temporary Adjustment
2		$0.03217	$(0.00804)	$0.01051	**$0.03464**
3 CSF		$0.03219	$(0.00804)	$0.02107	**$0.04522**
3 ISF		$0.03220	$(0.00804)	$0.01295	**$0.03711**
27		$0.03218	$(0.00804)	$(0.00595)	**$0.01819**
31 CSF	Block 1	$0.03221	$(0.00804)	$0.02228	**$0.04645**
	Block 2	$0.03222	$(0.00804)	$0.02255	**$0.04673**
31 CTF	Block 1	N/A	N/A	$(0.00385)	**$(0.00385)**
	Block 2	N/A	N/A	$(0.00352)	**$(0.00352)**
31 ISF	Block 1	$0.03222	$(0.00804)	$0.01425	**$0.03843**
	Block 2	$0.03223	$(0.00804)	$0.01447	**$0.03866**
31 ITF	Block 1	N/A	N/A	$(0.00251)	**$(0.00251)**
	Block 2	N/A	N/A	$(0.00224)	**$(0.00224)**

(C)
(C)

[1] Includes the temporary adjustment identified in Schedule 180.
[2] The sum of the temporary adjustments identified in Schedules 172, 177, 178, 179, 183, 188, & 190.

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2014 (T)

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [2]	Total Temporary Adjustment
32 CSF	Block 1	$0.03223	$(0.00804)	$0.01401	**$0.03820**
	Block 2	$0.03224	$(0.00804)	$0.01434	**$0.03854**
	Block 3	$0.03224	$(0.00804)	$0.01489	**$0.03909**
	Block 4	$0.03225	$(0.00804)	$0.01543	**$0.03964**
	Block 5	$0.03225	$(0.00804)	$0.01576	**$0.03997**
	Block 6	$0.03226	$(0.00804)	$0.01598	**$0.04020**
32 ISF	Block 1	$0.03224	$(0.00804)	$0.01482	**$0.03902**
	Block 2	$0.03224	$(0.00804)	$0.01507	**$0.03927**
	Block 3	$0.03225	$(0.00804)	$0.01549	**$0.03970**
	Block 4	$0.03225	$(0.00804)	$0.01591	**$0.04012**
	Block 5	$0.03226	$(0.00804)	$0.01616	**$0.04038**
	Block 6	$0.03226	$(0.00804)	$0.01632	**$0.04054**
32 CTF/ITF	Block 1	N/A	N/A	$(0.00130)	**$(0.00130)**
	Block 2	N/A	N/A	$(0.00106)	**$(0.00106)**
	Block 3	N/A	N/A	$(0.00066)	**$(0.00066)**
	Block 4	N/A	N/A	$(0.00027)	**$(0.00027)**
	Block 5	N/A	N/A	$(0.00003)	**$(0.00003)**
	Block 6	N/A	N/A	$0.00013	**$0.00013**
32 CSI	Block 1	$0.03224	$(0.00096)	$0.01467	**$0.04595**
	Block 2	$0.03224	$(0.00096)	$0.01490	**$0.04618**
	Block 3	$0.03225	$(0.00096)	$0.01528	**$0.04657**
	Block 4	$0.03225	$(0.00096)	$0.01566	**$0.04695**
	Block 5	$0.03226	$(0.00096)	$0.01589	**$0.04719**
	Block 6	$0.03226	$(0.00096)	$0.01605	**$0.04735**
32 ISI	Block 1	$0.03224	$(0.00096)	$0.01499	**$0.04627**
	Block 2	$0.03224	$(0.00096)	$0.01522	**$0.04650**
	Block 3	$0.03225	$(0.00096)	$0.01559	**$0.04688**
	Block 4	$0.03225	$(0.00096)	$0.01597	**$0.04726**
	Block 5	$0.03226	$(0.00096)	$0.01619	**$0.04749**
	Block 6	$0.03226	$(0.00096)	$0.01634	**$0.04764**
32 CTI/ITI	Block 1	N/A	N/A	$(0.00111)	**$(0.00111)**
	Block 2	N/A	N/A	$(0.00090)	**$(0.00090)**
	Block 3	N/A	N/A	$(0.00055)	**$(0.00055)**
	Block 4	N/A	N/A	$(0.00020)	**$(0.00020)**
	Block 5	N/A	N/A	$0.00001	**$0.00001**
	Block 6	N/A	N/A	$0.00015	**$0.00015**
33 TI		N/A	N/A	$(0.00009)	**$(0.00009)**
33 TF		N/A	N/A	$(0.00009)	**$(0.00009)**

(C)
(C)

[1] Includes the temporary adjustments identified in Schedule 180.
[2] The sum of the temporary adjustments identified in Schedules 172, 177, 178, 179, 183, 188, & 190.

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

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

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

APPLICABLE:
To the following Rate Schedules of this Tariff:

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

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2014 (T)

Annual Sales WACOG [1]	**$0.43383**	(I)
Winter Sales WACOG [2]	**$0.46654**	(I)
Firm Sales Service Pipeline Capacity Component [4]	**$0.12239**	(R)
Firm Sales Service Pipeline Capacity Component [5]	**$1.82**	(R)
Interruptible Sales Service Pipeline Capacity Component [6]	**$0.01455**	(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). (T)
[5] Applies to Rate Schedule 32 Interruptible Sales Service (per therm). (T)

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.

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

SCHEDULE 165
SPECIAL ADJUSTMENT TO RATES – GAS RESERVES CREDIT

PURPOSE:
To identify a one-time credit to Sales Service Customers for the calculation of the difference in cost of capital used to calculate the price of gas reserves included in the annual Purchased Gas Adjustment (PGA) filing pursuant to a Stipulation adopted by the Commission in Docket UM 1520/UG 204, OPUC Order No. 11-140 dated April 28, 2011.

APPLICABLE:
To Sales Service Customers on the Rate Schedules of this Tariff listed below:

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

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2014 (T)

$(0.00000) per therm (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 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. 14-16A / UG 278
September 15, 2014

Exhibit A
Supporting Materials
Purchased Gas Cost Deferral Amortizations
NWN OPUC Advice No. 14-16A / UG 278

NW Natural
Rates & Regulatory Affairs
2014-15 PGA - Oregon: September Filing
Summary of TEMPORARY Increments

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

Schedule	Block	Current Temporaries	WACOG Deferral	Demand Deferral FIRM	Demand Deferral INTERR	Total Proposed Temps	Net Effect of Temps (P = O - A)
		A	B	C	D	O	P
2R		0.00870	0.03226	(0.00804)	0.00000	0.02422	0.01552
3C Sales Firm		0.01652	0.03226	(0.00804)	0.00000	0.02422	0.00770
3I Sales Firm		0.00746	0.03226	(0.00804)	0.00000	0.02422	0.01676
27 Dry Out		(0.00768)	0.03226	(0.00804)	0.00000	0.02422	0.03190
31C Sales Firm	Block 1	0.01583	0.03226	(0.00804)	0.00000	0.02422	0.00839
	Block 2	0.01571	0.03226	(0.00804)	0.00000	0.02422	0.00851
31C Trans Firm	Block 1	(0.00385)	0.00000	0.00000	0.00000	0.00000	0.00385
	Block 2	(0.00352)	0.00000	0.00000	0.00000	0.00000	0.00352
31I Sales Firm	Block 1	0.00674	0.03226	(0.00804)	0.00000	0.02422	0.01748
	Block 2	0.00662	0.03226	(0.00804)	0.00000	0.02422	0.01760
31I Trans Firm	Block 1	(0.00251)	0.00000	0.00000	0.00000	0.00000	0.00251
	Block 2	(0.00224)	0.00000	0.00000	0.00000	0.00000	0.00224
32C Sales Firm	Block 1	0.00582	0.03226	(0.00804)	0.00000	0.02422	0.01840
	Block 2	0.00573	0.03226	(0.00804)	0.00000	0.02422	0.01849
	Block 3	0.00558	0.03226	(0.00804)	0.00000	0.02422	0.01864
	Block 4	0.00542	0.03226	(0.00804)	0.00000	0.02422	0.01880
	Block 5	0.00532	0.03226	(0.00804)	0.00000	0.02422	0.01890
	Block 6	0.00526	0.03226	(0.00804)	0.00000	0.02422	0.01896
32I Sales Firm	Block 1	0.00596	0.03226	(0.00804)	0.00000	0.02422	0.01826
	Block 2	0.00589	0.03226	(0.00804)	0.00000	0.02422	0.01833
	Block 3	0.00578	0.03226	(0.00804)	0.00000	0.02422	0.01844
	Block 4	0.00566	0.03226	(0.00804)	0.00000	0.02422	0.01856
	Block 5	0.00559	0.03226	(0.00804)	0.00000	0.02422	0.01863
	Block 6	0.00554	0.03226	(0.00804)	0.00000	0.02422	0.01868
32 Trans Firm	Block 1	(0.00130)	0.00000	0.00000	0.00000	0.00000	0.00130
	Block 2	(0.00106)	0.00000	0.00000	0.00000	0.00000	0.00106
	Block 3	(0.00066)	0.00000	0.00000	0.00000	0.00000	0.00066
	Block 4	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00027
	Block 5	(0.00003)	0.00000	0.00000	0.00000	0.00000	0.00003
	Block 6	0.00013	0.00000	0.00000	0.00000	0.00000	(0.00013)
32C Sales Interr	Block 1	0.00679	0.03226	0.00000	(0.00096)	0.03130	0.02451
	Block 2	0.00672	0.03226	0.00000	(0.00096)	0.03130	0.02458
	Block 3	0.00661	0.03226	0.00000	(0.00096)	0.03130	0.02469
	Block 4	0.00650	0.03226	0.00000	(0.00096)	0.03130	0.02480
	Block 5	0.00643	0.03226	0.00000	(0.00096)	0.03130	0.02487
	Block 6	0.00640	0.03226	0.00000	(0.00096)	0.03130	0.02490
32I Sales Interr	Block 1	0.00706	0.03226	0.00000	(0.00096)	0.03130	0.02424
	Block 2	0.00700	0.03226	0.00000	(0.00096)	0.03130	0.02430
	Block 3	0.00689	0.03226	0.00000	(0.00096)	0.03130	0.02441
	Block 4	0.00679	0.03226	0.00000	(0.00096)	0.03130	0.02451
	Block 5	0.00672	0.03226	0.00000	(0.00096)	0.03130	0.02458
	Block 6	0.00668	0.03226	0.00000	(0.00096)	0.03130	0.02462
32 Trans Interr	Block 1	(0.00111)	0.00000	0.00000	0.00000	0.00000	0.00111
	Block 2	(0.00090)	0.00000	0.00000	0.00000	0.00000	0.00090
	Block 3	(0.00055)	0.00000	0.00000	0.00000	0.00000	0.00055
	Block 4	(0.00020)	0.00000	0.00000	0.00000	0.00000	0.00020
	Block 5	0.00001	0.00000	0.00000	0.00000	0.00000	(0.00001)
	Block 6	0.00015	0.00000	0.00000	0.00000	0.00000	(0.00015)
33		(0.00009)	0.00000	0.00000	0.00000	0.00000	0.00000

Sources:

Direct Inputs	Oct 2013 Filing				

Equal ¢ per therm		Column D	Column G	Column J	
Equal % of margin					

Tariff Schedules

Rate Adjustment Schedule		Sched 162	Sched 162	Sched 162	

NW Natural
Rates & Regulatory Affairs
2014-15 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

				WACOG Deferral			Demand Deferral - FIRM			Demand Deferral - INTERRUPTIBLE		
		Oregon PGA	Proposed Amount:	21,211,625	Temporary Increment		(4,806,981)	Temporary Increment		(56,646)	Temporary Increment	
		Volumes page,	Revenue Sensitive Multiplier:	2.777%	add revenue sensitive factor		2.777%	add revenue sensitive factor		2.777%	add revenue sensitive factor	
		Column F	Amount to Amortize:	**21,817,497**	to all sales		**(4,944,284)**	to all firm sales		**(58,264)**	to all interruptible sales	
Schedule	Block	A		Multiplier B	Volumes C	Increment D	Multiplier E	Volumes F	Increment G	Multiplier H	Volumes I	Increment J
2R		356,638,984		1.0	356,638,984	0.03226	1.0	356,638,984	(0.00804)	0.0	0	0.00000
3C Firm Sales		157,954,905		1.0	157,954,905	0.03226	1.0	157,954,905	(0.00804)	0.0	0	0.00000
3I Firm Sales		4,657,733		1.0	4,657,733	0.03226	1.0	4,657,733	(0.00804)	0.0	0	0.00000
27 Dry Out		796,593		1.0	796,593	0.03226	1.0	796,593	(0.00804)	0.0	0	0.00000
31C Firm Sales	Block 1	20,699,674		1.0	20,699,674	0.03226	1.0	20,699,674	(0.00804)	0.0	0	0.00000
	Block 2	23,498,664		1.0	23,498,664	0.03226	1.0	23,498,664	(0.00804)	0.0	0	0.00000
31C Firm Trans	Block 1	388,881		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 2	545,978		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
31I Firm Sales	Block 1	4,173,740		1.0	4,173,740	0.03226	1.0	4,173,740	(0.00804)	0.0	0	0.00000
	Block 2	10,396,538		1.0	10,396,538	0.03226	1.0	10,396,538	(0.00804)	0.0	0	0.00000
31I Firm Trans	Block 1	165,160		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 2	807,983		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
32C Firm Sales	Block 1	16,554,938		1.0	16,554,938	0.03226	1.0	16,554,938	(0.00804)	0.0	0	0.00000
	Block 2	6,660,345		1.0	6,660,345	0.03226	1.0	6,660,345	(0.00804)	0.0	0	0.00000
	Block 3	1,153,455		1.0	1,153,455	0.03226	1.0	1,153,455	(0.00804)	0.0	0	0.00000
	Block 4	248,040		1.0	248,040	0.03226	1.0	248,040	(0.00804)	0.0	0	0.00000
	Block 5	0		1.0	0	0.03226	1.0	0	(0.00804)	0.0	0	0.00000
	Block 6	0		1.0	0	0.03226	1.0	0	(0.00804)	0.0	0	0.00000
32I Firm Sales	Block 1	4,334,225		1.0	4,334,225	0.03226	1.0	4,334,225	(0.00804)	0.0	0	0.00000
	Block 2	5,158,108		1.0	5,158,108	0.03226	1.0	5,158,108	(0.00804)	0.0	0	0.00000
	Block 3	1,793,731		1.0	1,793,731	0.03226	1.0	1,793,731	(0.00804)	0.0	0	0.00000
	Block 4	516,050		1.0	516,050	0.03226	1.0	516,050	(0.00804)	0.0	0	0.00000
	Block 5	0		1.0	0	0.03226	1.0	0	(0.00804)	0.0	0	0.00000
	Block 6	0		1.0	0	0.03226	1.0	0	(0.00804)	0.0	0	0.00000
32 Firm Trans	Block 1	11,412,253		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 2	15,830,951		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 3	9,285,426		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 4	16,096,253		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 5	21,498,809		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 6	2,621,489		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
32C Interr Sales	Block 1	6,122,694		1.0	6,122,694	0.03226	0.0	0	0.00000	1.0	6,122,694	(0.00096)
	Block 2	8,160,076		1.0	8,160,076	0.03226	0.0	0	0.00000	1.0	8,160,076	(0.00096)
	Block 3	4,328,184		1.0	4,328,184	0.03226	0.0	0	0.00000	1.0	4,328,184	(0.00096)
	Block 4	5,489,488		1.0	5,489,488	0.03226	0.0	0	0.00000	1.0	5,489,488	(0.00096)
	Block 5	242,825		1.0	242,825	0.03226	0.0	0	0.00000	1.0	242,825	(0.00096)
	Block 6	0		1.0	0	0.03226	0.0	0	0.00000	1.0	0	(0.00096)
32I Interr Sales	Block 1	7,354,982		1.0	7,354,982	0.03226	0.0	0	0.00000	1.0	7,354,982	(0.00096)
	Block 2	9,533,015		1.0	9,533,015	0.03226	0.0	0	0.00000	1.0	9,533,015	(0.00096)
	Block 3	5,139,982		1.0	5,139,982	0.03226	0.0	0	0.00000	1.0	5,139,982	(0.00096)
	Block 4	10,419,813		1.0	10,419,813	0.03226	0.0	0	0.00000	1.0	10,419,813	(0.00096)
	Block 5	4,025,372		1.0	4,025,372	0.03226	0.0	0	0.00000	1.0	4,025,372	(0.00096)
	Block 6	173,013		1.0	173,013	0.03226	0.0	0	0.00000	1.0	173,013	(0.00096)
32 Interr Trans	Block 1	8,967,105		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 2	15,920,961		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 3	11,590,796		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 4	30,144,365		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 5	57,187,852		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
	Block 6	78,650,314		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
33		0		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000
TOTALS		957,339,742			676,225,166	0.03226		615,235,722	(0.00804)		60,989,444	(0.00096)
											0	

Sources for line 2 above:

Inputs page	Line 49	Line 51	Line 53

Tariff Schedules

Rate Adjustment Schedule	Sched 162	Sched 162	Sched 162

NW Natural
Rates and Regulatory Affairs
2014-2015 PGA Filing - OREGON
Basis for Revenue Related Costs

1		Twelve Months Ended 06/30/14		
2				
3	Total Billed Gas Sales Revenues	668,271,650		
4	Total Oregon Revenues	691,523,698		
5				
6	Regulatory Commission Fees [1]	1,728,809	0.250%	Statutory rate
7	City License and Franchise Fees	16,182,350	2.340%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	1,290,601	0.187%	Line 8 ÷ Line 4
9				
10	Total	19,201,760	**2.777%**	Sum lines 8-9
11				
12				

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

NW Natural
Rates & Regulatory Affairs
2014-2015 PGA Filing - September Filing
Summary of Deferred Accounts Included in the PGA

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

	Account	Balance 6/30/2014	Adjustment	Jul-Sep Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2014	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection	Amounts Excluded from PGA Filing	Amounts Included in PGA Filing
	A	B	C	D	E	F	G1	G2	H	I	J
						F = sum B thru E		1.77%	H = F + G2		Excl. Rev Sens
1	**Miscellaneous Amortizations**										
2											
3	191441 GAS RESERVES AMORT	(190,538)		199,302	(491)	8,272	1.77%	80	8,352	to 191401	**0**
4											
5	**Gas Cost Deferrals and Amortizations**										
6	191401 AMORTIZE OREGON WACOG	27,291		886,782	1,846	915,919					
7	191400 WACOG - ACCRUE OREGON	19,572,910		0	512,549	20,085,459					
8	Total	19,600,201	0	886,782	514,395	21,001,378	1.77%	201,895	21,203,273	includes 191441 residual	**21,211,625**
9											
10											
11	191411 AMORTIZE DEMAND OREGON	(711,688)		127,152	(3,038)	(587,575)					
12	191410 DEMAND - ACCRUE OREGON	(1,796,169)		0	(53,855)	(1,850,024)					
13	191417 DEMAND - ACCRUE COOS BAY	(36,624)		0	0	(36,624)					
14	191450 OREGON DEMAND ACCRUE VOLUME	(2,283,301)		0	(59,792)	(2,343,093)					
15	Total	(4,827,783)	0	127,152	(116,685)	(4,817,316)	1.77%	(46,311)	(4,863,627)		**(4,863,627)**

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 191401
Dockets UM 1496 and UG 262
Amortization of 12-13 deferral approved in Order No. 13-394

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

Debit (Credit)

Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
(a)	(b)	(c)	(d)	(e)	(e2)	(f)	(g)
Beginning Balance							
Oct-13		406,135		(2,868)	1.47%	403,267	(2,141,313)
Nov-13	old rates	289,436		(2,446)	1.47%	286,991	(1,854,323)
	new rates **(1)**	208,502	(2,453,528)	(2,702)	1.38%	(2,247,728)	(4,102,051)
Dec-13		838,830		(4,235)	1.38%	834,595	(3,267,455)
Jan-14		909,111		(3,235)	1.38%	905,876	(2,361,579)
Feb-14		822,889		(2,243)	1.38%	820,646	(1,540,933)
Mar-14		602,877		(1,425)	1.38%	601,452	(939,481)
Apr-14		441,435		(827)	1.38%	440,609	(498,872)
May-14		311,224		(395)	1.38%	310,829	(188,043)
Jun-14		215,425		(92)	1.38%	215,333	27,291
Jul-14	forecast	173,807		131	1.38%	173,939	201,229
Aug-14	forecast	174,645		332	1.38%	174,977	376,206
Sep-14	forecast	180,629		537	1.38%	181,166	557,371
Oct-14	forecast	357,701		847	1.38%	358,547	915,919

History truncated for ease of viewing

NOTES:
1 - Transfer in is from the October balances of deferral account 191400.

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon Demand Deferral
Account Number: 191411
Dockets UM 1496 and UG 262
Amortization of 12-13 deferral approved in Order No. 13-394

Debit (Credit)

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance
(a)	(b)	(c)	(d)	(e)		(f)	(g)
Beginning Balance							
Oct-13		84,559		299	1.47%	84,858	286,701
Nov-13	old rates	70,168		394	1.47%	70,563	357,264
	new rates **(1)**	28,927	(1,724,491)	(1,967)	1.38%	(1,697,531)	(1,340,267)
Dec-13	**2**	130,511	(2)	(1,466)	1.38%	129,042	(1,211,225)
Jan-14		142,193		(1,311)	1.38%	140,882	(1,070,343)
Feb-14		128,465		(1,157)	1.38%	127,308	(943,035)
Mar-14		92,549		(1,031)	1.38%	91,518	(851,517)
Apr-14		66,365		(941)	1.38%	65,424	(786,094)
May-14		45,726		(878)	1.38%	44,848	(741,246)
Jun-14		30,392		(835)	1.38%	29,557	(711,688)
Jul-14	forecast	24,189		(805)	1.38%	23,385	(688,303)
Aug-14	forecast	24,164		(778)	1.38%	23,387	(664,917)
Sep-14	forecast	25,379		(750)	1.38%	24,629	(640,288)
Oct-14	forecast	53,418		(706)	1.38%	52,713	(587,575)

History truncated for ease of viewing

NOTES:

1 - Transfer in is from the October balances of deferral accounts 191410, 191450, 191417

2 - Transfer represents a balance true-up adjustment

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Commodity gas cost deferral
Account Number: 191400
Docket UM 1496
Current reauthorization to defer was granted in Order No. 13-441

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

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

1	Debit (Credit)									Deferral
2			Commodity			Storage	Hedge			Plus Int.
3	Month/Year	Note	Deferral	Interest	Interest Rate	Adjustment **(2)**	Adjustment	Transfer	Activity	GL Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
91	Oct-13		617,552	(20,749)	7.78%	(10,580)	0		586,223	(2,917,642)
92	Nov-13	**1**	(1,018,327)	(3,307)	7.78%	(1,778)	0	2,453,528	1,430,116	(1,023,412)
93	Dec-13		2,370,209	1,040	7.78%	(2,701)	0		2,368,548	1,345,136
94	Jan-14		111,637	9,075	7.78%	(2,527)	0		118,185	1,463,320
95	Feb-14		8,008,055	35,439	7.78%	(2,275)	0		8,041,219	9,504,540
96	Mar-14		7,058,076	84,496	7.78%	(1,481)	0		7,141,091	16,645,631
97	Apr-14		26,017	108,000	7.78%	(1,175)	0		132,842	16,778,473
98	May-14		1,345,223	113,139	7.78%	(640)	0		1,457,722	18,236,195
99	Jun-14		1,215,126	122,168	7.78%	(579)	0		1,336,715	19,572,910
100	Jul-14			126,898	7.78%				126,898	19,699,808
101	Aug-14			127,720	7.78%				127,720	19,827,528
102	Sep-14			128,548	7.78%				128,548	19,956,077
103	Oct-14			129,382	7.78%				129,382	20,085,459
104										

105 **History truncated for ease of viewing**

106

107 **NOTES:**
108 **1** - October balance transferred to account 191401 for amortization.
109 **2** - Adjustment for storage true up.

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Demand cost deferral
Account Number: 191410
Docket UM 1496
Current reauthorization to defer was granted in Order No. 13-441

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

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

Debit (Credit)

Month/Year	Note	Demand Deferral	Interest	Interest Rate	Adjustment	Transfer	Activity	Deferral Plus Int. GL Balance	Adjustment	Adjusted GL Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Oct-13	**2**	(62,359)	(13,117)	7.78%		(2)	(75,478)	(2,067,411)		(2,067,411)
Nov-13	**1**	312,658	1,014	7.78%		2,067,411	2,381,083	313,672		313,672
Dec-13		(162,444)	1,507	7.78%			(160,937)	152,735		152,735
Jan-14		(192,372)	367	7.78%			(192,005)	(39,270)		(39,270)
Feb-14		(399,481)	(1,550)	7.78%			(401,030)	(440,301)		(440,301)
Mar-14		(233,370)	(3,611)	7.78%			(236,981)	(677,281)		(677,281)
Apr-14		(368,450)	(5,585)	7.78%			(374,035)	(1,051,316)		(1,051,316)
May-14		(475,075)	(8,356)	7.78%			(483,431)	(1,534,747)		(1,534,747)
Jun-14	**3**	(510,221)	(11,604)	7.78%			(521,826)	(2,056,573)	260,403	(1,796,169)
Jul-14			(13,333)	7.78%			(13,333)	(2,069,906)		(1,809,503)
Aug-14			(13,420)	7.78%			(13,420)	(2,083,326)		(1,822,923)
Sep-14			(13,507)	7.78%			(13,507)	(2,096,833)		(1,836,430)
Oct-14			(13,594)	7.78%			(13,594)	(2,110,427)		(1,850,024)

History truncated for ease of viewing

NOTES

1 - October balance transferred to account 191411 for amortization.
2 - Adjustment was made to true-up the balance with actual results.
3 - In December 2013**,** an error was identified related to the calculation of the deferred demand charges from the 2012-2013 PGA year. Specifically, instead of updating a relevant demand charge in December, which is appropriate under a previously established methodology (refer to p. 12), it was updated beginning in November. For the 2012-13 demand deferral, which is currently being collected in rates, the Company under-deferred $260,403. Interest is not accrued on this adjustment.

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Demand Collection Deferral
Account Number: 191450
Docket UM 1496
Current reauthorization to defer was granted in Order No. 13-441

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

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

Debit (Credit)

Month/Year	Note	Demand Deferral	Interest	Interest Rate	Transfer	Activity	Deferral Plus Int. GL Balance
(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
Oct-13	**3**	(597,139)	3,186	7.78%	(1)	(593,953)	196,089
Nov-13	**1**	(328,275)	(1,064)	7.78%	(196,089)	(525,427)	(329,339)
Dec-13		(1,282,369)	(6,292)	7.78%		(1,288,661)	(1,618,000)
Jan-14		(864,778)	(13,293)	7.78%		(878,071)	(2,496,071)
Feb-14		(1,999,668)	(22,665)	7.78%		(2,022,333)	(4,518,404)
Mar-14		1,311,653	(25,042)	7.78%		1,286,611	(3,231,793)
Apr-14		369,268	(19,756)	7.78%		349,512	(2,882,281)
May-14		1,002,149	(15,438)	7.78%		986,711	(1,895,570)
Jun-14		(374,228)	(13,503)	7.78%		(387,731)	(2,283,301)
Jul-14			(14,803)	7.78%		(14,803)	(2,298,104)
Aug-14			(14,899)	7.78%		(14,899)	(2,313,004)
Sep-14			(14,996)	7.78%		(14,996)	(2,328,000)
Oct-14			(15,093)	7.78%		(15,093)	(2,343,093)

History truncated for ease of viewing

NOTES

1 - October balance transferred to account 191411 for amortization.
2 - Adjustment was made to true-up the balance with actual results.

Company: Northwest Natural Gas Company
State: Oregon
Description: Coos County Demand
Account Number: 191417
Class of Customers: Core

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

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

1 Debit (Credit)
2
3

4	Month/Year	Note	Deferral	Adjustment	Transfer	Interest	Activity	Balance
5								
91	Oct-13		21,691	(7,216)			14,475	146,831
92	Nov-13	**1**	21,683	(6,644)	(146,831)		(131,792)	15,039
93	Dec-13		21,683	(11,702)			9,981	25,020
94	Jan-14		21,683	(9,456)			12,227	37,246
95	Feb-14		17,048	(8,723)			8,325	45,571
96	Mar-14	**2**	17,048	(129,796)			(112,748)	(67,177)
97	Apr-14		17,048	(5,827)			11,221	(55,956)
98	May-14		17,048	(8,780)			8,268	(47,688)
99	Jun-14		17,048	(5,984)			11,064	(36,624)
100	Jul-14						0	(36,624)
101	Aug-14						0	(36,624)
102	Sep-14						0	(36,624)
103	Oct-14						0	(36,624)

104
105 **History truncated for ease of viewing**
106
107 **NOTES**
108 **1** - October balance transferred to account 191411 for amortization
109 **2** - Additional adjustment represents a true-up of previous year's demand charges.

Note: The information presented below is consistent with Tariff Advice No. 14-16 (August 2014 filing).

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization Gas Reserves Credit
Account Number:	191442
Info:	Docket UG 204
	Authorization to amortize in Order 13-391

Debit (Credit)

Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Total Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Beginning Balance							
Nov-13	**1**	46,860	(1,159,882)	1.38%	(1,307)	(1,114,329)	(1,114,329)
Dec-13		187,912		1.38%	(1,173)	186,738	(927,590)
Jan-14		203,835		1.38%	(950)	202,885	(724,705)
Feb-14		184,438		1.38%	(727)	183,711	(540,994)
Mar-14		135,048		1.38%	(544)	134,504	(406,491)
Apr-14		98,892		1.38%	(411)	98,481	(308,009)
May-14		69,747		1.38%	(314)	69,433	(238,576)
Jun-14		48,284		1.38%	(247)	48,038	(190,538)
Jul-14	forecast	39,063		1.38%	(197)	38,866	(151,672)
Aug-14	forecast	39,251		1.38%	(152)	39,099	(112,573)
Sep-14	forecast	40,596		1.38%	(106)	40,490	(72,083)
Oct-14	forecast	80,392		1.38%	(37)	80,356	8,272

NOTES

1 - Transfer in is from the October balance of 191440 Gas Reserves Credit

NW Natural
Rates & Regulatory Affairs
2014-15 PGA - Oregon: September Filing
Demand Deferral Methodology

The demand deferral accounting methodology dates back to December 1999, when the Commission ordered a change from prior practice as a component of the UG 132 rate case. Before that, the Company only deferred the difference between the demand cost incurred and the demand cost embedded in the PGA. Recoveries of demand were not considered.

Because of the timing of the change in method, and an unintended earnings consequence of the change in that year, a deferral method was set up that uses a revenue string and a cost string (accounting strings) that both run from December to November and that equal each other for that same period. As used in deferring revenues and costs, the use of these accounting strings to defer demand revenues against (using the seasonalized demand string) and to defer demand costs against (the embedded cost string) produce the same result for the December through November period as if revenues were directly deferred against costs.

Subsequent to the initial 1999-2000 tracker year, the Company moved first to an October to September tracker year and then to the current November to October tracker year. The accounting strings for purposes of deferral have retained the December to November year, though, to ensure that the original accounting strings were able to zero out over the full 12 months, and that each year's subsequent accounting strings were also able to do so. Because of the need to allow the accounting strings to fully zero out, and given the one month mismatch between the November to December PGA year and the December to November accounting string, the November amounts for the current PGA year seasonalized demand and for embedded demand use the November balance from one PGA year earlier. Because the November embedded demand amount that is retained is on a system basis, the allocation ratio from one PGA year earlier also is retained.

NW Natural
Rates & Regulatory Affairs
2014-15 PGA - Oregon: September Filing
Explanation of Resolution of Certain Accounting Issues

Contained in this year's series of PGA filings are a few adjustments that NW Natural has discussed with the parties, and which were included in NW Natural's initial filings (NWN OPUC Advice 14-13, NWN OPUC Advice 14-14, and NWN OPUC 14-16). These adjustments are made to correct for certain accounting issues that NW Natural identified earlier this year, and which were raised with stakeholders and Staff at that time.

The following descriptions provide more information about these adjustments, per a request by Staff and parties after NW Natural's initial August 1 filing. Specifically, the descriptions below contain the details around each issue, including the specific deferrals or rate adjustments that were affected, and the authorities under which those deferrals or adjustments were made.

Decoupling Deferral Miscalculation (NWN OPUC Advice 14-13)

Factual Description

Under NW Natural's decoupling mechanism, NW Natural defers margin that is lost due to reduced usage per customer, as compared against a baseline that was established in our last rate case. Before this comparison is done, the actual use-per-customer is weather normalized during the heating season. See Schedule 190, Sheet 190-1. NW Natural uses data produced for its Weather Adjustment Rate Mechanism (WARM) calculation for this weather normalized actual use-per-customer. The weather normalization adjustment is based on comparing actual degree days with normal degree days. Actual degree days are reported in NW Natural's Customer Information System (CIS) on a one-day lag because the final weather data for a particular day is not published until the following day. Normal degree days, however, represent the 25-year average for that day as presented in NW Natural's last rate case, docket UG 221. For comparison purposes, the normal degree days for one day should appropriately be compared with the actual degree days in CIS for the previous date.[1]

[1] For example, the weather data in CIS for February 1, 2013, actually represented temperatures for January 31st. In order to compare the appropriate degree days for the weather normalization adjustment, the February 1st weather data should have been compared with the January 31st normal data.

The comparison of degree days was performed by the Company's Accounting Department as a check for the monthly WARM unbilled calculation. Beginning in January 2013, this check was found to be unnecessary and therefore, it was discontinued. Instead, the underlying data was pulled and separately summarized in a useable format for the decoupling calculation. In the process, an error was made during the heating season by failing to account for the one-day lag in weather data. For instance, the February 1st actual degree days in CIS were inappropriately compared with February 1st normal degree days, rather than adjusting for the one-day lag described above.

Upon discovering this error shortly before the 2013-2014 PGA was filed, NW Natural made Staff aware of the mistake, and provided its estimate of the financial effect of the error, which at that time NW Natural believed was a $32,391 over-deferral by the Company, and the inclusion of that amount in customers' rates. NW Natural offered to Staff that it would return the $32,391 (plus interest) to customers in the next PGA filing in order to rectify the mistake. Staff agreed with the Company's proposal, in consideration of the circumstances and tight timeline. Subsequent to that time, NW Natural continued to investigate the error and concluded that when viewed in its totality the error actually represented an over-deferral of $812,292 including interest through October 31, 2013. Worksheets showing the correction of the error in the deferral balance were filed as Attachment A, pp. 3, 5, and 7 of OPUC Advice No. 14-13.

In late January and early February, NW Natural informed CUB, NWIGU, and Staff of this error, along with the other issues described below. NW Natural has put in place controls to ensure the integrity of the spreadsheets and to document the purposes for which they are used, so that the problem can be avoided in the future.

Deferrals Affected

The miscalculation affected the Company's decoupling deferral balance. The residential and commercial balances are recorded in accounts 186275 and 186270, respectively, and are filed with the Commission as part of the Company's quarterly deferred accounting report. The error affected the deferrals for the months of January 2013 through April of 2013. These account balances were included as temporary adjustments to NW Natural's rates in the 2013-14 PGA, as approved by the Commission in Order No. 13-402.

Authority for Deferral

Authority to record the deferred amounts comes from 1) Schedule 190, which describes the deferral, and 2) the Commission's granting of NW Natural's application for reauthorization of deferral for the Company's Distribution Margin Normalization, UM 1027. The authority to collect these amounts through rates came through the Commission's Order No. 13-485.

SIP Forecast Adjustment (NWN OPUC Advice 14-14 and 14-14A)

Factual Description

Under NW Natural's System Integrity Program cost recovery mechanism, the Company includes in permanent rates, on an annual basis, the most recent actual SIP costs incurred during the program year, plus an estimate of activity through October 31st (the date before the PGA rates go into effect). *See* Order No. 09-067, Appendix B, page 3.

As part of its 2013-2014 PGA, the Company calculated the cost of service for actual investments through July plus estimated expenditures for August through October to be included in base rates effective November 1, 2013. Subsequent to November 1, 2013, the Company discovered that the actual costs capitalized for August through October were $3.9 million lower than the estimated amounts. Upon investigation, the Company found that the forecast amount provided in the PGA filing was based on calculations that the Company believed was not a good estimate of actual expected expenditures. This stemmed from turnover at the Company in the positions that develop the forecast and a miscommunication between departments. The Company has since emphasized the appropriate forecasting process and put in place measures to ensure that this problem does not reoccur.

NW Natural informed the Parties of this finding at the same time as the above items.

Deferrals Affected

The SIP amounts included in rates are not part of a deferral. Instead, they are included as an adjustment to permanent rates, in accordance with Schedule 177, Sheet 177-3.

Authority for Deferral

The rate adjustment established in Schedule 177 was approved by the Commission in Order No. 13-405, Docket UG 261.

Demand Charge Miscalculation (NWN OPUC Advice 14-16 and 14-16A)

Factual Description

As part of its PGA, NW Natural includes the cost of demand charges paid by NW Natural in the rates paid by customers. Throughout the year, the Company then defers any difference between actual demand charges paid, and those that were assumed when setting the PGA. (*See* Schedule P, Sheets P-1, P-2, and P-4, defining Demand Costs, Non-Commodity Costs, and setting forth the deferral of 100% of the variances between estimated and actual Non-Commodity Costs).

In December 2013, NW Natural discovered an error related to the Company's calculation of its deferred demand charges from the 2012-2013 PGA year, which is currently being passed through to customers. Specifically, the error was that instead of updating a relevant demand charge in December, which is appropriate under a prior established methodology, it was updated beginning in November. This error was the result of turnover in NW Natural staff, and a failure to document the methodology within the process. The December timing, agreed to and implemented since 1999, is required to ensure that the seasonalized demand charge and the embedded demand charge are appropriately matched. (*See* Docket No. UG 132, and Jan. 3, 2000 letter agreement between NW Natural and Staff, which Staff recommended for approval by the Commission on Jan. 14, 2000). The incorrect timing of the update had the effect of causing the Company to under-defer $260,403 for its demand charges. NW Natural's PGA filing shows the correction of these amounts in Attachment A, p. 8, Advice Filing 14-16. NW Natural has put controls in place to ensure that the problem does not reoccur.

NW Natural informed the parties of this finding at the same time as the above-described issues.

Deferrals Affected

The miscalculation affected the Company's demand deferral balance. This balance is recorded in account 191410, and is filed with the Commission as part of the Company's quarterly deferred accounting report. The balances for the months of November 2012 through October 2013 were affected. This account balance was included as a temporary adjustment to NW Natural's rates in the 2013-14 PGA, as approved by the Commission in Order No. 13-394.

Authority for Deferral

NW Natural's authority to record the deferred amounts comes from Schedule P, Sheets P-1, P-2, and P-4, defining Demand Costs, Non-Commodity Costs, and setting forth the deferral of 100% of the variances between estimated and actual Non-Commodity Costs, and from the Commission's granting of NW Natural's application for reauthorization of deferral for gas commodity and demand costs. The authority to collect these amounts through rates came through the Commission's Order No. 13-441.

Adjustment

NW Natural has included in its PGA filing a resolution of these issues through the following approach:

1) With respect to the decoupling deferral error, the Company has included an adjustment in the November 1, 2013, beginning balances of the residential and commercial decoupling deferrals and will continue to accrue interest in customers' favor on the over-deferred amount until it is included in rates effective November 1, 2014. The total that will reduce residential and commercial customer rates in the 2014-2015 PGA is $877,791.

2) With respect to the demand deferral calculation error, NW Natural has made an adjustment to the demand deferral account in the amount of $260,403, which will be included in rates effective November 1, 2014.

3) With respect to the SIP investment overstatement, the Company has agreed to defer the $575,841 cost of service on the $3.9 million difference and include the amount as a reduction to customers rates effective November 1, 2014.

Specifically, the total net effect of correcting these accounting issues will be a credit to customers of $1,193,229, effective on November 1, 2014, in conjunction with new rates becoming effective under NW Natural's PGA.

To the extent possible, this puts customers back in the same financial position that they would have been in but for the miscalculated deferrals (both the over- and under-deferral) and over-forecast of SIP project capital costs.

NW Natural makes these adjustments while continuing to preserve any arguments it has about whether such adjustments are required under Commission precedent and relevant law. NW Natural believes that it was important to make these adjustments in light of the fact that the miscalculations led to rates that were set higher than they would have been without the miscalculations, and therefore has included these adjustments which provide, on net, a reduction to customers' rates.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

SUPPORTING MATERIALS

Purchased Gas Costs
UM 1496

NWN OPUC Advice No.14-16A / UG 278
September 15, 2014

Exhibit B
Supporting Materials
Purchased Gas Costs
NWN OPUC Advice No. 14-16A / UG 278

Commodity and Non-Commodity Costs

NW Natural
2014-2015 PGA - SYSTEM: September Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

SYSTEM COSTS

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	**Commodity Cost from Supply**		$31,369,014	$30,895,437	$28,413,065	$19,331,529	$20,001,466	$20,580,568	$13,034,911	$7,372,655	$6,198,160	$6,233,796	$7,096,501	$17,632,589	$208,159,691
6	tab commodity cost from supply, column cd, lines 93-105 plus														
7	tab commodity cost from gas reserve, column p, lines 59-70														
8	**Volumetric Pipeline Chgs**		$280,904	$308,275	$293,200	$213,013	$204,432	$196,862	$130,876	$81,812	$71,184	$71,163	$77,363	$166,161	$2,095,245
9	tab commodity cost from vol pipe, column e, line 78-90														
10	**Commodity Cost from Storage**		$2,384,971	$18,464,134	$17,961,533	$17,812,732	$11,459,449	$112,775	$116,534	$112,775	$116,534	$116,534	$112,775	$116,534	$68,887,280
11	tab Commodity Cost from Storage, column k, line 61-73														
12	**Commodity Cost from Gas Reserves**		$3,581,930	$3,635,516	$3,308,727	$3,099,671	$3,206,028	$3,069,412	$3,093,670	$2,991,103	$3,021,012	$3,034,213	$2,820,764	$2,914,550	$37,776,597
13	tab Commodity Cost from Gas Reserve, column o, line 59-70														
14	**Total Commodity Cost**		$37,616,819	$53,303,362	$49,976,525	$40,456,945	$34,871,375	$23,959,617	$16,375,991	$10,558,345	$9,406,889	$9,455,706	$10,107,403	$20,829,834	$316,918,813
15															
16	**VOLUMES**														
17	Commodity Volumes at Receipt Points		83,421,378	80,846,800	74,813,971	53,640,126	57,417,196	63,981,833	42,469,572	26,508,942	23,051,529	23,044,884	25,062,758	53,973,391	608,232,379
18	Pipeline Fuel Use		1,578,902	1,446,945	1,324,719	929,540	1,025,266	1,311,329	814,442	478,733	406,742	406,607	449,434	1,081,083	11,253,741
19	Gas Arriving at City Gate		81,842,476	79,399,855	73,489,252	52,710,586	56,391,930	62,670,504	41,655,130	26,030,209	22,644,787	22,638,277	24,613,324	52,892,308	596,978,638
20															
21	Storage Gas Withdrawals		5,386,210	43,542,363	42,326,239	42,239,206	27,127,322	240,000	248,000	240,000	248,000	248,000	240,000	248,000	162,333,341
22	Pipeline Fuel Use for Alberta-sourced Storage		122,840	312,945	340,282	208,240	85,172	0	0	0	0	0	0	0	1,069,480
23	Storage Gas Deliveries at City Gate		5,263,370	43,229,418	41,985,956	42,030,966	27,042,150	240,000	248,000	240,000	248,000	248,000	240,000	248,000	161,263,860
24															
25	Total Gas At City Gate (Storage and Commodity)		87,105,846	122,629,273	115,475,208	94,741,552	83,434,080	62,910,504	41,903,130	26,270,209	22,892,787	22,886,277	24,853,324	53,140,308	758,242,498
26															
27	Unaccounted for Gas		660,088	640,387	592,716	425,129	454,820	505,459	335,963	209,943	182,638	182,586	198,515	426,590	4,814,834
28															
29	Load Served		86,445,758	121,988,886	114,882,492	94,316,423	82,979,260	62,405,045	41,567,167	26,060,266	22,710,149	22,703,691	24,654,809	52,713,718	753,427,664

WACOG Calculations

Line	Description	1	2	3	4	5	6	7	8	9	10	11	12	Total
30	**Gas Reserves Supply:**													
31	Total cost (line 12 above)	$3,581,930	$3,635,516	$3,308,727	$3,099,671	$3,206,028	$3,069,412	$3,093,670	$2,991,103	$3,021,012	$3,034,213	$2,820,764	$2,914,550	$37,776,597
32	Load served by gas reserves	6,697,383	6,858,089	6,741,011	5,988,546	6,524,778	6,216,984	6,327,969	6,034,494	6,146,891	6,061,413	5,593,240	5,899,345	75,090,142
33														
34	**Total Load Served**	1	2	3	4	5	6	7	8	9	10	11	12	
35	Oregon	78,080,644	109,906,197	103,510,913	85,002,569	74,987,153	56,503,806	37,660,552	23,612,724	20,668,544	20,656,546	22,294,818	47,574,900	680,459,366
36	Washington	8,365,114	12,082,689	11,371,582	9,313,850	7,992,103	5,901,243	3,906,614	2,447,543	2,041,596	2,047,145	2,359,990	5,138,829	72,968,298
37	Total (same as line 29 +/- rounding)	86,445,758	121,988,886	114,882,495	94,316,419	82,979,256	62,405,049	41,567,166	26,060,267	22,710,140	22,703,691	24,654,808	52,713,729	753,427,664
38														0
39	**Washington WACOG Calculation**													
40														
41	**Hedged Rockies supply excluding Gas Reserves**													
42	Hedged Rockies supply volumes	10,368,750	10,714,375	10,714,375	6,502,022	6,690,217	5,922,000	6,119,400	2,962,500	1,530,625	1,530,625	2,962,500	6,119,400	72,136,789
43	Hedged Rockies supply cost	$4,267,433	$4,409,681	$4,409,681	$2,597,845	$2,675,659	$2,324,175	$2,401,648	$1,119,975	$564,045	$564,045	$1,108,350	$2,355,225	$28,797,762
44	Hedged Rockies supply price per therm	$0.41157	$0.41157	$0.41157	$0.39954	$0.39994	$0.39246	$0.39246	$0.37805	$0.36851	$0.36851	$0.37413	$0.38488	$0.39921
45														
46	Load served by gas reserves	6,697,383	6,858,089	6,741,011	5,988,546	6,524,778	6,216,984	6,327,969	6,034,494	6,146,891	6,061,413	5,593,240	5,899,345	75,090,142
47	Gas Reserves cost	$3,581,930	$3,635,516	$3,308,727	$3,099,671	$3,206,028	$3,069,412	$3,093,670	$2,991,103	$3,021,012	$3,034,213	$2,820,764	$2,914,550	$37,776,597
48	Gas Reserves price per therm	$0.53483	$0.53011	$0.49084	$0.51760	$0.49136	$0.49371	$0.48889	$0.49567	$0.49147	$0.50058	$0.50432	$0.49405	$0.50308
49														
50	Washington percentage of total load (line 36 ÷ line 37)	9.7%	9.9%	9.9%	9.9%	9.6%	9.5%	9.4%	9.4%	9.0%	9.0%	9.6%	9.7%	9.7%
51														
52	Total System Commodity Cost (line 14 above)	$37,616,819	$53,303,362	$49,976,525	$40,456,945	$34,871,375	$23,959,617	$16,375,991	$10,558,345	$9,406,889	$9,455,706	$10,107,403	$20,829,834	$316,918,813
53	Less: Commodity Cost of Rockies Hedged Supplies (from line 43)	$4,267,433	$4,409,681	$4,409,681	$2,597,845	$2,675,659	$2,324,175	$2,401,648	$1,119,975	$564,045	$564,045	$1,108,350	$2,355,225	$28,797,762
54	Less: Commodity Cost of Gas Reserves (from line 12)	$3,581,930	$3,635,516	$3,308,727	$3,099,671	$3,206,028	$3,069,412	$3,093,670	$2,991,103	$3,021,012	$3,034,213	$2,820,764	$2,914,550	$37,776,597
55	Total System Commodity Cost excluding Rockies hedged & Gas Reserves	$29,767,456	$45,258,165	$42,258,117	$34,759,429	$28,989,688	$18,566,030	$10,880,674	$6,447,267	$5,821,833	$5,857,448	$6,178,289	$15,560,059	$250,344,454
56														
57	Total System Load Served (from line 29)	86,445,758	121,988,886	114,882,492	94,316,423	82,979,260	62,405,045	41,567,167	26,060,266	22,710,149	22,703,691	24,654,809	52,713,718	753,427,664
58	Less: load from Rockies hedged supplies (from line 32)	10,368,750	10,714,375	10,714,375	6,502,022	6,690,217	5,922,000	6,119,400	2,962,500	1,530,625	1,530,625	2,962,500	6,119,400	72,136,789
59	Less: load served by gas reserves (from line 32)	6,697,383	6,858,089	6,741,011	5,988,546	6,524,778	6,216,984	6,327,969	6,034,494	6,146,891	6,061,413	5,593,240	5,899,345	75,090,142
60	Total System load excluding Rockies hedged & Gas Reserves	69,379,625	104,416,422	97,427,106	81,825,856	69,764,265	50,266,061	29,119,798	17,063,272	15,032,633	15,111,653	16,099,070	40,694,973	606,200,733
61														
62	System price excluding Rockies hedged & Gas Reserves (line 55 ÷ line 72)	$0.42905	$0.43344	$0.43374	$0.42480	$0.41554	$0.36936	$0.37365	$0.37784	$0.38728	$0.38761	$0.38377	$0.38236	$0.41297
63														
64	**Washington allocation of Rockies hedged supply**													
65	Rockies hedged supply needed for Washington (line 50 * (line 42 + line 46))	1,655,415	1,739,674	1,728,083	1,236,566	1,268,640	1,153,203	1,170,053	845,717	690,976	683,283	821,351	1,165,818	14,158,779
66	Cost of Rockies hedged supply allocated to Washington (line 65 * line 44)	$681,319	$715,998	$711,227	$494,058	$507,380	$452,586	$459,199	$319,723	$254,632	$251,797	$307,292	$448,700	$5,603,910
67														
68	**Washington portfolio**													
69	Volumes													
70	Total Washington load	8,365,114	12,082,689	11,371,582	9,313,850	7,992,103	5,901,243	3,906,614	2,447,543	2,041,596	2,047,145	2,359,990	5,138,829	72,968,298
71	Washington load met by Rockies hedged supply	1,655,415	1,739,674	1,728,083	1,236,566	1,268,640	1,153,203	1,170,053	845,717	690,976	683,283	821,351	1,165,818	14,158,779
72	Remaining Washington load	6,709,699	10,343,015	9,643,499	8,077,284	6,723,463	4,748,040	2,736,561	1,601,826	1,350,620	1,363,862	1,538,639	3,973,011	58,809,519
73														
74	Cost													
75	Cost of Rockies hedged supply allocated to Washington (line 66)	$681,319	$715,998	$711,227	$494,058	$507,380	$452,586	$459,199	$319,723	$254,632	$251,797	$307,292	$448,700	$5,603,910
76	Cost of remaining Washington load (line 72 * line 62)	$2,878,796	$4,483,076	$4,182,771	$3,431,230	$2,793,868	$1,753,736	$1,022,516	$605,234	$523,068	$528,647	$590,483	$1,519,120	$24,312,547
77	Total cost of Washington portfolio	$3,560,116	$5,199,074	$4,893,998	$3,925,288	$3,301,248	$2,206,322	$1,481,715	$924,957	$777,700	$780,443	$897,776	$1,967,821	$29,916,457
78														
79	**Washington Sales WACOG (line 77 ÷ line 70)**	$0.42559	$0.43029	$0.43037	$0.42145	$0.41306	$0.37387	$0.37928	$0.37791	$0.38093	$0.38123	$0.38041	$0.38293	$0.40999
80														
81	**WASHINGTON BILLING WACOG**	$0.44505	$0.44996	$0.45005	$0.44072	$0.43194	$0.39096	$0.39662	$0.39519	$0.39835	$0.39866	$0.39780	$0.40044	$0.42873
82														
83	**Oregon WACOG Calculation**													
84														
85	Total system commodity cost	$37,616,819	$53,303,362	$49,976,525	$40,456,945	$34,871,375	$23,959,617	$16,375,991	$10,558,345	$9,406,889	$9,455,706	$10,107,403	$20,829,834	$316,918,813
86	Commodity cost allocated to Washington portfolio	$3,560,116	$5,199,074	$4,893,998	$3,925,288	$3,301,248	$2,206,322	$1,481,715	$924,957	$777,700	$780,443	$897,776	$1,967,821	$29,916,457
87	Total commodity cost for Oregon	$34,056,704	$48,104,288	$45,082,527	$36,531,657	$31,570,127	$21,753,295	$14,894,276	$9,633,388	$8,629,190	$8,675,263	$9,209,628	$18,862,013	$287,002,356
88														
89	**Oregon Sales WACOG (line 87 ÷ line 35)**	$0.43617	$0.43768	$0.43553	$0.42977	$0.42101	$0.38499	$0.39549	$0.40797	$0.41750	$0.41998	$0.41308	$0.39647	$0.42178
90														
91	**OREGON BILLING WACOG**	$0.44863	$0.45018	$0.44797	$0.44205	$0.43304	$0.39599	$0.40679	$0.41962	$0.42943	$0.43198	$0.42488	$0.40779	$0.43383

NW Natural
2014-2015 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		$4,307,323	$4,486,176	$4,486,171	$4,052,025	$4,486,171	$4,341,457	$4,486,171	$4,341,457	$4,486,171	$4,486,171	$4,341,457	$4,486,171	$52,786,921
Alberta: Transcanada		38,888	37,123	37,123	37,123	37,123	37,123	37,123	37,123	37,123	37,123	37,123	37,123	447,240
Alberta: AECO Storage		81,016	77,339	77,339	77,339	77,339	77,339	77,339	77,339	77,339	77,339	77,339	77,339	931,747
Alberta: NOVA		842,756	725,148	725,148	725,148	725,148	725,148	725,148	725,148	725,148	725,148	725,148	725,148	8,819,383
Alberta: Foothills		373,053	401,816	401,816	401,816	401,816	358,654	358,654	358,654	358,654	358,654	358,654	401,816	4,534,054
Alberta: GTN		555,703	574,228	574,228	518,658	574,228	467,658	483,246	467,658	483,246	483,246	467,658	574,228	6,223,985
BC: Southern Crossing		787,678	780,931	780,931	712,325	780,931	758,062	780,931	758,062	780,931	780,931	758,062	780,931	9,240,706
BC: Spectra (Westcoast)		0	0	0	0	0	0	0	0	0	0	0	0	0
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		$7,005,105	$7,101,449	$7,101,444	$6,543,122	$7,101,444	$6,784,129	$6,967,300	$6,784,129	$6,967,300	$6,967,300	$6,784,129	$7,101,444	$83,208,295

Detail in file "Capacity Contract Monthly Summary for Tracker 2013-14 August Filing.xls"

NW Natural
2014-2015 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		$83,208,295	
5	Oregon Allocation Factor 1/		89.62%	
6	Oregon Demand		$74,571,274	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		619,469,932	
9	Oregon Interruptible Sales Forecasted Normal Volumes		60,989,435	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11899	$0.12239
13	Proposed Interruptible Demand 2/		$0.01415	$0.01455
14	Proposed MDDV Demand Charge		$1.77	$1.82
15				
16	Current Firm Demand Per Therm		$0.14163	$0.14587
17	Current Interruptible Demand		$0.01684	$0.01734
18	Current MDDV Demand Charge		$2.11	$2.17
19				
20	Percent Change in Firm Demand		-15.99%	
21				
22				
23	1/Allocation Factor: 2013-14 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	71,714,701	619,469,932	691,184,633
26		10.38%	89.62%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		0.840	
31				
32	Firm Demand (line 8 * line 34)		$0.11899	$73,708,418
33	Interruptible Demand (line 9 * line 35)		$0.01415	$862,856
34				$74,571,274

NW Natural
2014-2015 PGA - SYSTEM: September Filing
Calculation of Winter WACOG
Prices are per therm

Line		AECO/NIT	Without Rev Sensitive	WITH Rev Sensitive
1	Forecast price for AECO gas:			
5	November	$0.38606		
6	December	$0.39153		
7	January	$0.39613		
8	February	$0.39407		
9	March	$0.38475		
10	April	$0.34521		
11	May	$0.34188		
12	June	$0.34012		
13	July	$0.34245		
14	August	$0.34301		
15	September	$0.34180		
16	October	$0.35051		
19	Average price, November-March		$0.39051	average lines 5-9
21	Annual average price, November-October		$0.36313	average lines 5-16
23	Ratio of winter to annual		1.0754	line 19 ÷ line 21
27	Oregon Annual WACOG		$0.42178	$0.43383
28	Oregon Winter WACOG		$0.45358	$0.46654
29			line 23 * $0.42178	

NW Natural
2014-2015 PGA - OREGON: September Filing
Derivation of Oregon Seasonalized Fixed Charges

(a)	(b)	Normalized Residential Volumes (c)	Normalized Commercial Volumes (d)	Firm Industrial Volumes (e)	Interruptible Volumes (f)	Total (g)	Firm Demand Increment Eff. 11/01/14 (h)	Interr. Demand Increment Eff. 11/01/14 (i)	Seasonalized Fixed Charges (j)
November	2014								$10,101,512
December	2014	43,898,498	25,846,256	2,718,030	5,617,860	78,080,644	$0.11899	$0.01415	$8,701,498
January	2015	64,175,647	35,994,349	3,222,481	6,513,720	109,906,197	$0.11899	$0.01415	$12,394,443
February	2015	60,024,419	33,983,009	3,267,989	6,235,495	103,510,913	$0.11899	$0.01415	$11,662,660
March	2015	48,256,779	27,718,002	3,083,136	5,944,652	85,002,569	$0.11899	$0.01415	$9,490,914
April	2015	41,597,793	24,784,473	2,816,381	5,788,506	74,987,153	$0.11899	$0.01415	$8,315,588
May	2015	29,812,600	18,758,246	2,530,710	5,402,250	56,503,806	$0.11899	$0.01415	$6,156,819
June	2015	17,788,355	12,892,888	2,251,344	4,727,965	37,660,552	$0.11899	$0.01415	$3,985,421
July	2015	9,257,105	8,431,189	2,037,120	3,887,310	23,612,724	$0.11899	$0.01415	$2,402,055
August	2015	7,209,689	7,680,083	2,021,076	3,757,696	20,668,544	$0.11899	$0.01415	$2,065,327
September	2015	7,217,670	7,678,983	1,989,053	3,770,840	20,656,546	$0.11899	$0.01415	$2,062,521
October	2015	8,092,341	7,813,227	2,358,300	4,030,950	22,294,818	$0.11899	$0.01415	$2,230,184
November	2015	23,727,775	15,800,456	2,734,479	5,312,191	47,574,901	$0.11899	$0.01415	$5,103,844
		361,058,670	227,381,163	31,030,099	60,989,435	680,459,368			$74,571,274

NW Natural
2014-2015 PGA - OREGON: September Filing
Encana Gas Reserves Deal

			Projected November 2014	Projected December 2014	Projected January 2015	Projected February 2015	Projected March 2015	Projected April 2015	Projected May 2015	Projected June 2015	Projected July 2015	Projected August 2015	Projected September 2015	Projected October 2015	Projected PGA Totals
1	Therms Delivered (000s)														
2	Total Therms		6,782.16	6,944.90	6,826.34	6,064.35	6,607.37	6,295.68	6,408.07	6,110.88	6,224.70	6,138.14	5,664.04	5,974.02	76,040.64
3	Rate per Therm (Depletion Rate)		0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437	0.2437
4	Delivery Value		1,652.93	1,692.59	1,663.70	1,477.99	1,610.33	1,534.37	1,561.76	1,489.33	1,517.07	1,495.97	1,380.42	1,455.97	18,532.41
5															0.2437
6	Opex / Severance / Ad Valorem														
7	Operating Cost		873.21	881.22	594.64	611.63	584.06	568.36	572.97	560.49	565.66	612.01	541.69	555.11	7,521.04
8	Severance and Ad Valorem Taxes		315.79	337.00	336.76	297.78	313.54	271.36	274.66	264.28	273.55	270.60	248.88	265.27	3,469.48
9	Total		1,188.99	1,218.22	931.40	909.41	897.60	839.72	847.64	824.76	839.21	882.61	790.57	820.39	10,990.52
10															0.1445
11	Average Rate Base		89,116.68	88,001.88	86,917.07	85,944.69	84,892.19	83,885.68	82,862.59	81,883.35	80,887.31	79,904.04	78,990.73	78,031.68	
12															
13	Carrying Cost														
14	Equity	9.5000%	352.75	348.34	344.05	340.20	336.03	332.05	328.00	324.12	320.18	316.29	312.67	308.88	
15	Equity % of Cap Struct	50.0000%													
16	Equity Pretax	39.4589%	515.12	502.63	494.33	495.44	483.91	485.93	477.52	472.63	462.98	456.34	452.71	443.62	
17	Debt	6.0560%	224.87	222.06	219.32	216.87	214.21	211.67	209.09	206.62	204.11	201.62	199.32	196.90	
18	Total Carrying Cost		739.99	724.69	713.65	712.30	698.12	697.60	686.61	679.25	667.08	657.97	652.03	640.52	8,269.81
19															0.1088
20	Total Cost		3,581.91	3,635.50	3,308.75	3,099.70	3,206.05	3,071.69	3,096.00	2,993.34	3,023.36	3,036.55	2,823.03	2,916.88	37,792.75
21	Total Volume		6,782.16	6,944.90	6,826.34	6,064.35	6,607.37	6,295.68	6,408.07	6,110.88	6,224.70	6,138.14	5,664.04	5,974.02	76,040.64
22	Total Rate Per Therm		0.52814	0.52348	0.48470	0.51113	0.48522	0.48790	0.48314	0.48984	0.48570	0.49470	0.49841	0.48826	0.49701

NW Natural
Rates & Regulatory Affairs
2014-15 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule
ALL VOLUMES IN THERMS

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

Schedule	Block	Oregon PGA Normalized Volumes page, Column D A	Therms in Block B	Normal Therms Monthly Average use C	Minimum Monthly Charge D	11/1/2013 Billing Rates E	11/1/2013 Current Average Bill F=D+(C * E) F	Proposed 11/1/2014 PGA Rates Y	Proposed 11/1/2014 PGA Average Bill Z=D+(C * Y) Z	Proposed 11/1/2014 **PGA % Bill Change** AA = (Z - F)/F AA
2R		360,262,077	N/A	53.0	8.00	0.99317	60.64	1.03069	62.63	3.3%
3C Firm Sales		158,380,592	N/A	233.0	15.00	0.91427	228.02	0.95179	236.77	3.8%
3I Firm Sales		4,657,729	N/A	1,302.0	15.00	0.89909	1,185.62	0.93661	1,234.47	4.1%
27 Dry Out		796,593	N/A	44.0	6.00	0.87	44.46	0.91153	46.11	3.7%
31C Firm Sales	Block 1	20,755,459	2,000	3,524.0	325.00	0.62962		0.69062		
	Block 2	23,561,992	all additional			0.61164		0.67264		
	Total						**2,516.38**		**2,731.34**	8.5%
31C Firm Trans	Block 1	388,881	2,000	1,800.0	575.00	0.16800		0.16800		
	Block 2	545,978	all additional			0.15344		0.15344		
	Total						**877.40**		**877.40**	0.0%
31I Firm Sales	Block 1	4,173,736	2,000	6,227.0	325.00	0.57905		0.64005		
	Block 2	10,396,529	all additional			0.56309		0.62409		
	Total						**3,863.28**		**4,243.13**	9.8%
31I Firm Trans	Block 1	165,160	2,000	10,137.0	575.00	0.15680		0.15680		
	Block 2	807,983	all additional			0.14173		0.14173		
	Total						**2,041.86**		**2,041.86**	0.0%
32C Firm Sales	Block 1	16,599,553	10,000	8,643.0	675.00	0.50956		0.57056		
	Block 2	6,678,295	20,000			0.49513		0.55613		
	Block 3	1,156,563	20,000			0.47106		0.53206		
	Block 4	248,708	100,000			0.44698		0.50798		
	Block 5	0	600,000			0.43253		0.49353		
	Block 6	0	all additional			0.42290		0.48390		
	Total						**5,079.13**		**5,606.35**	10.4%
32I Firm Sales	Block 1	4,334,221	10,000	19,284.0	675.00	0.50877		0.56977		
	Block 2	5,158,103	20,000			0.49449		0.55549		
	Block 3	1,793,730	20,000			0.47070		0.53170		
	Block 4	516,049	100,000			0.44689		0.50789		
	Block 5	2	600,000			0.43259		0.49359		
	Block 6	0	all additional			0.42311		0.48411		
	Total						**10,353.55**		**11,529.87**	11.4%
32 Firm Trans	Block 1	11,412,253	10,000	58,140.0	925.00	0.09321		0.09321		
	Block 2	15,830,951	20,000			0.07925		0.07925		
	Block 3	9,285,426	20,000			0.05607		0.05607		
	Block 4	16,096,253	100,000			0.03282		0.03282		
	Block 5	21,498,809	600,000			0.01888		0.01888		
	Block 6	2,621,489	all additional			0.00961		0.00961		
	Total						**4,830.65**		**4,830.65**	0.0%
32C Interr Sales	Block 1	6,122,693	10,000	32,719.0	675.00	0.51260		0.57953		
	Block 2	8,160,075	20,000			0.49787		0.56480		
	Block 3	4,328,184	20,000			0.47331		0.54024		
	Block 4	5,489,487	100,000			0.44878		0.51571		
	Block 5	242,825	600,000			0.43402		0.50095		
	Block 6	0	all additional			0.42426		0.49119		
	Total						**17,045.33**		**19,235.21**	12.8%
32I Interr Sales	Block 1	7,354,981	10,000	40,182.0	675.00	0.51281		0.57974		
	Block 2	9,533,013	20,000			0.49810		0.56503		
	Block 3	5,139,981	20,000			0.47356		0.54049		
	Block 4	10,419,812	100,000			0.44904		0.51597		
	Block 5	4,025,372	600,000			0.43431		0.50124		
	Block 6	173,012	all additional			0.42452		0.49145		
	Total						**20,586.89**		**23,276.27**	13.1%
32 Interr Trans	Block 1	8,967,105	10,000	193,929.0	925.00	0.09476		0.09476		
	Block 2	15,920,961	20,000			0.08060		0.08060		
	Block 3	11,590,796	20,000			0.05698		0.05698		
	Block 4	30,144,365	100,000			0.03335		0.03335		
	Block 5	57,187,852	600,000			0.01919		0.01919		
	Block 6	78,650,314	all additional			0.00977		0.00977		
	Total						**8,802.20**		**8,802.20**	0.0%
33		0	N/A	0.0	38,000.00	0.00542	38,000.00	0.00542	38,000.00	0.0%
Totals		961,573,943								

NW Natural
Rates and Regulatory Affairs
2014-2015 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/14		
1				
2				
3	Total Billed Gas Sales Revenues	668,271,650		
4	Total Oregon Revenues	691,523,698		
5				
6	Regulatory Commission Fees [1]	1,728,809	0.250%	Statutory rate
7	City License and Franchise Fees	16,182,350	2.340%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	1,290,601	0.187%	Line 8 ÷ Line 4
9				
10	Total	19,201,760	**2.777%**	Sum lines 8-9
11				
12				

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

NW Natural
Rates & Regulatory Affairs
2014-2015 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Tariff Advice 14-16A: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitve Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	$17,419,760
6		
7	Demand Capacity Cost Change	(12,948,724)
8		
9	**Total Gas Cost Change**	**4,471,036**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	6,137,631
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	16,814,949
18		
19		
20	**Net Temporary Rate Adjustment**	**22,952,580**
21		
22		
23	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$27,423,616**
24		
25		
26		
27	2013 Oregon Earnings Test Normalized Total Revenues	$672,195,000
28		
29	Effect of this filing, as a percentage change (line 23 ÷ line 27)	4.08%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL
SUPPORTING MATERIALS

Purchased Gas Costs

NWN OPUC Advice No. 14-16A / UG 278
September 15, 2014

NW NATURAL **EXHIBIT C**

OPUC Advice No. 14-16A

OPUC ORDER No. 11-196

DOCKET UM 1286

SECTION IV and V. PGA PORTFOLIO GUIDELINES

DATA AND ANALYSIS

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

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

Guideline Reference	Data Requirement	Location/Link	Status
3	Brief explanation of each contract's role within the portfolio.		
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	V.1.b!A1	
1	An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	V.1.b!A1	
2	Any contract provisions that materially deviate from the standard NAESB contract.	V.1.b!A1	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	V.2!A1	**HIGHLY CONFIDENTIAL**
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	V.3.a!A1	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	V.3.b!A1	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	V.3.c!A1	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,		
1	Annual for each customer class	V.3.d.1!A1	
2	Annual and monthly baseload.	V.3.d.2!A1	
3	Annual and monthly non-baseload.	V.3.d.3!A1	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	V.3.d.4!A1	
V.4	**Market Information**		
	General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	V.4!A1	
V.5	**Data Interpretation**		
	If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	V.5!A1	

NW NATURAL **EXHIBIT C**

OPUC Advice No. 14-16A

OPUC ORDER No. 11-196

DOCKET UM 1286

SECTION IV and V. PGA PORTFOLIO GUIDELINES

DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
V.6	**Credit Worthiness Standards**		
	A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	V.6!A1	
	Attachment 1 to V.6	V.6 attachment'!A1	**CONFIDENTIAL/HIGHLY CONFIDENTIAL**
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.		
a)	Type of storage (e.g., depleted field, salt dome).	V.7.a-c'!A1	
b)	Location of each storage facility.	V.7.a-c'!A1	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	V.7.a-c'!A1	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	V.7.d-e'!A1	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	V.7.d-e'!A1	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	V.7.f!A1	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	V.7.g!A1	
h)	For LDCs that own and operate storage:	V.7.h!A1	**CONFIDENTIAL**
a.	The date and results of the last engineering study for that storage.		
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.		
V.8	**Attestation as to Consistency**	See IV.1.c	

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

Section IV. 1 General Information
a) Definitions and Acronyms

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

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

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

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

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

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

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

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

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

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

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

EIA — U.S. Energy Information Administration

FERC — Federal Energy Regulatory Commission

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

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

FOM — First of Month

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

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

IRP	Integrated Resource Plan
MDDV	Maximum Daily Delivery Volume
NWP	Northwest Pipeline
Off-system storage	Storage facilities located outside NW Natural's service territory.
On-system storage	Storage facilities located inside NW Natural's service territory.
PGA	Purchased Gas Adjustment
Peak day	The day in which volumes 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).

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

IV General Information and Forecasting

1 General Information

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), a piece of legislation totaling more than 2,300 pages, was signed into law in July 2010 with the expectation that it would take effect in July 2011. However, the process of writing the rules that would clarify Dodd-Frank's multitude of provisions caused several delays. As mentioned in last year's filing, though, we believe that all of the provisions that might be applicable to our company have been enacted. So, unless something new develops, we will not mention it further.

The interdependencies between the electric sector and natural gas utilities took center stage in February 2011 when an extreme cold weather event in the southwestern U.S. affected service to 4.4 million electric customers and over 50,000 natural gas customers. FERC, NERC and various other agencies have held hearings and issued reports since then, and other studies are still ongoing. Many of the calls for better coordination and preparedness were already anticipated by energy utilities in the Pacific Northwest, in part due to our own regional outage event that occurred in December 2009, and also in part due to past planning efforts that have drawn together many of the same stakeholders. There have not yet been any mandated regulatory changes, but FERC issued a Notice of Proposed Rulemaking (NOPR) on March 20, 2014, Docket No. RM-14-2-000, which could lead to changes such as the start time for the "gas day" and the introduction of more "nomination" cycles. We are an active participant in this process, which is unlikely to affect gas supply activities through most if not all of the Nov14-Oct15 PGA period.

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

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

In accordance with the PGA Portfolio Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc., upon which the gas supply portfolio for this PGA filing is based, uses the methodology and data sources that are consistent with the Company's recently filed Draft IRP except for the demand side management (DSM) impacts on load. At the time of this PGA filing, the Company is finalizing its load forecast assumptions for the August 29, 2014 IRP filing and the updated DSM assumptions will be incorporated into a final load forecast for the September 15, 2014 PGA update filing.

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

	Amount	Location in Company Filing (cite)
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	$23,000,000	Refer to workpaper "PGA filing Summary Effects"
B) Percent *(To .1 percent)*	3.43%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	4,471,036	Refer to workpaper "PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	(7,166,178)	"
C) Add New Temporary Increment	24,227,752	"
necessary)		
1) Net Safety Programs	1,958,504	Refer to workpaper "PGA filing Summary Effects"
2) Gasco Source Control	(442,992)	"
3)	0	
4)	0	
5)	0	
6)	0	
E) Total Proposed Change	23,048,122	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$0.99317	Refer to workpaper "2014-15 Rate Development"
2) Proposed Billing Rate per Therm	$1.01330	"
3) Rate Change Per Therm	$0.02013	"
4) Percent Change per Therm *(to .1%)*	2.0%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	53.0	Refer to workpaper "2014-15 Rate Development"
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$60.64	"
4) Proposed Average Monthly Bill	$62.63	"
5) Change in Average Monthly Bill	$1.99	"
6) Percent change in Average Monthly Bill *(to .1%)*	3.3%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	105.6	N/A
2) Customer Charge	$8.00	N/A
3) Current Average January Bill	$112.88	N/A
4) Proposed Average January Bill	$115.00	N/A
5) Change in Average January Bill	$2.12	N/A
6) Percent change in Average January Bill (*to .1%)*	1.9%	N/A
	Amount	**Location in Company Filing (cite)**
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	0	
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Volumetric Cost (assoc. w/ supply)	$232,234,835	2013-14 PGA filing
e) Total Storage Cost (assoc. w/ supply)	0	
f) Other	$2,652,409	2013-14 PGA filing
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	43,803,006	2013-14 PGA filing
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	52,752,231	2013-14 PGA filing
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$59,798,063	2013-14 PGA filing
4) Capacity Release Credits	0	
5) Total Gas Costs	$391,240,544	2013-14 PGA filing
B) Projected For New Rates		
1) Total Commodity Cost	0	
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Vaporization Cost (assoc. w/ supply)	0	
e) Total Volumetric Cost (assoc. w/ supply)	$245,936,288	Exhibit B, Page 1
f) Total Storage Cost (assoc. w/ supply)	0	
g) Other (A&G Benchmark Savings)	$2,095,245	Exhibit B, Page 1
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	30,197,116	Exhibit B, Page 1
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	53,011,179	Exhibit B, Page 1
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$68,887,280	Exhibit B, Page 1
4) Capacity Release Credits	0	
5) Total Gas Costs	$400,127,108	Exhibit B, Page 1

	Amount	Location in Company Filing (cite)
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		

1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.40805	N/A
b. Without revenue sensitive	$0.39618	N/A
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.14587	N/A
b. Without revenue sensitive	$0.14163	N/A
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.43383	Exhibit B, Page 6 and Page 9
b. Without revenue sensitive	$0.42178	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.12239	Exhibit B, Page 8
b. Without revenue sensitive	$0.11899	"
6) Therms Sold	753,427,664	Exhibit B, Page 1

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

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

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

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

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

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1. Summary of Portfolio Planning Process

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

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

Upstream pipeline capacity has been contracted with the following objectives in mind: (1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NWN; (2) Obtain upstream capacity along the path from NWN's service territory to points generally recognized for their liquidity, such as AECO/NIT, to maximize buying opportunities and minimize price volatility; and (3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible.

Upstream gas supply contracts have been negotiated with the following objectives in mind: (1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors; (2) Try to match our year-round customer requirements to baseload (take-or-pay) annual or multi-year supply contracts to obtain the most favorable pricing; (3) Use winter only (Nov-Mar) term contracts to match our rise in requirements during the heating season; (4) Reduce spot purchase requirements during the winter due to the likely correlation of high requirements with high spot prices; (5) Use a variety of term contract durations to avoid having to re-contract all supplies at the same time every year; (6) Take advantage of favorable pricing opportunities to use supply-basin storage when possible; (7) 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; (8) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and (9) 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.

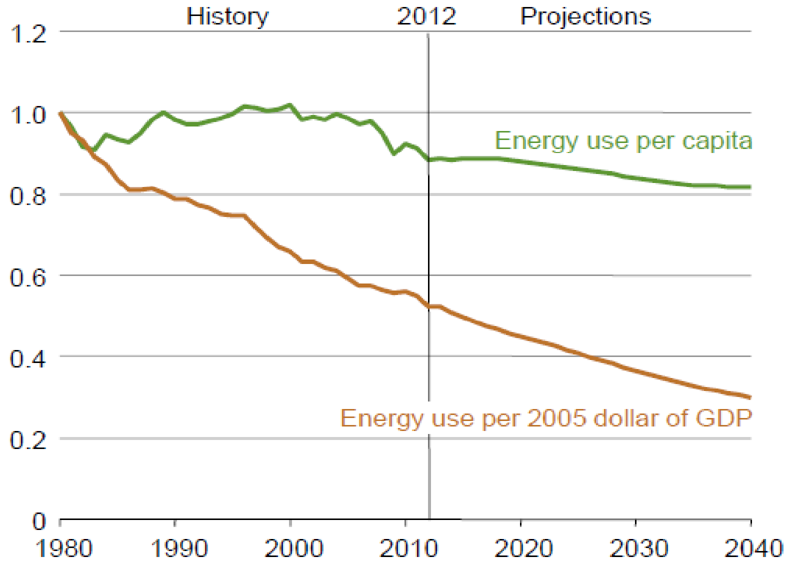
[1] "Design" year criteria is developed and discussed in the Company's Integrated Resource Plan (IRP).

2. LDC sales system demand forecasting.

Customer growth has not equated to load growth in recent years. Conservation and price elasticity among existing residential and commercial customers have offset customer gains. Due in part to a 5-day curtailment of interruptible sales customers in December 2008 and then a 3-day curtailment in December 2009, many industrial sales customers switched to transportation service, further suppressing sales demand. While interruptible customers do not affect peak day planning and requirements, their annual sales volumes are accounted for in the company's purchasing plans. As a result, the company's annual sales outlook has declined from prior years on a weather-adjusted basis. This mirrors national trends as shown below.

In the United States, average energy use per person declines from 2012 to 2040

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040 (index, 1980 = 1)



Source: EIA 2014 Annual Energy Outlook

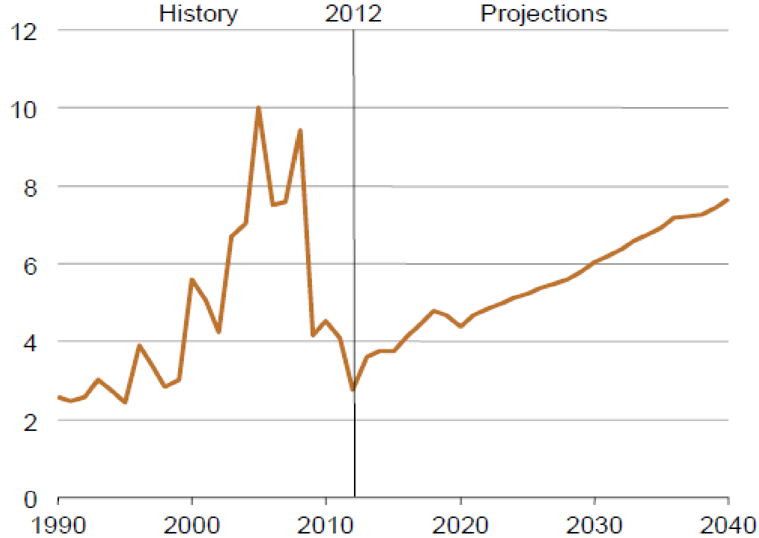
The company's methodology for forecasting annual sales and firm peak day requirements follow the methodology established in its Integrated Resource Plan (IRP).

3. *Natural gas price forecasts.*

NWN relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the IHS CERA consulting firm as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NWN by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints. As an example, below is the latest long-range natural gas forecast from EIA's 2014 Annual Energy Outlook (AEO) dated April 2014.

Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)



In this case, the sharp drop in natural gas prices experienced over the last few years, coupled with forecasts for rising prices, leads NWN to formulate hedging strategies around locking in prices on a longer term basis for a portion of its expected purchase volumes.

4. Physical resources for the portfolio.

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

Two significant changes have or will occur to the company's physical supply resources for the upcoming PGA period: (1) we have removed the Plymouth LNG plant from our firm resource stack; and (2) we expect to terminate most, if not all, of our T-South pipeline contract on the Westcoast Energy (Spectra) pipeline system in British Columbia. These two changes has been discussed during the company's current IRP process and will be described in more detail below.

The removal of Plymouth is probably one of the most significant changes in the company's resource portfolio in many years. NW Natural has Rate Schedule TF-2 transportation agreements with Northwest Pipeline (NWP) to move gas from both the Plymouth and Jackson Prairie storage facilities to its service territory, with the Plymouth TF-2 contract having a maximum capacity of 601,000 therms per day. The company has counted on these TF-2 agreements to help meet customer heating season requirements, but for the first time, on December 6, 2013, NWP curtailed the company's Plymouth TF-2 service for the following gas day. This curtailment pointed out that TF-2 transportation service on NWP's system through the Columbia River Gorge was not as reliable as previously believed, a reliance that had seemed assured through a period that spanned the deregulated era and back to the inception of Plymouth service in the late 1970s.

The curtailment of TF-2 service led to numerous discussions with NWP. NWP stated that it performed an historical analysis of NW Natural's Plymouth TF-2 service examining NWP's highest peak day of demand in the I-5 corridor for each of the last 14 years. NWP's analysis indicated that NW Natural's Plymouth TF-2 service would have been reliable in 12 of those prior 14 years. Of course none of these prior 14 years experienced weather conditions comparable to the company's peak design. The company concluded, reluctantly, that it could no longer count on Plymouth TF-2 service as a firm resource during design cold weather events. It might flow, or it might be curtailed due to its secondary nature,there is no way to know in advance as it depends on the actions of other NWP TF-1 transportation service holders. Accordingly, the company removed Plymouth TF-2 deliveries from its firm resource stack in the current IRP analysis.

Interestingly, NWN also learned that Puget Sound Energy (PSE) came to the same conclusion regarding its own Plymouth TF-2 service, i.e., that it was no longer reliable enough to include in its firm resource stack, as shown in PSE's May 2013 IRP (http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chap6.pdf starting at page 6-17).

It should be noted that while the Plymouth LNG plant suffered a serious accident on March 31, 2014, NW Natural came to its conclusion to remove Plymouth from its resource stack at least a month before this accident (e.g., see Chapter 1 of our 2014 Draft IRP filed 2/28/2014).

Both the storage service at Plymouth under Rate Schedule LS-1, and the associated TF-2 transportation agreement, have contract years that start on November 1. Termination requires at least one-year's prior notice to NWP. Hence, both of these contracts will continue to be reflected in the upcoming PGA period. The company is still exploring ways to make use of these contracts during the upcoming winter, but with only 70 therms left in its account at the end of the last heating season, and with no ability to liquefy this summer due to the March accident, there is no expectation at the moment for any greater use of Plymouth.

The Plymouth TF-2 curtailment also resulted in inquiries to NWP regarding the reliability of the company's TF-2 service from Jackson Prairie. While the pathway from Jackson Prairie to NW Natural's service territory has not been constrained since the inception of this particular service in 1989, a NWP curtailment of secondary TF-2 capacity is possible in the future. Over the long term, it does not appear prudent to rely on this type of capacity because eventually the loads on the NWP system being served from Sumas will grow and reduce the reliability of any transportation that is less than TF-1 primary firm service. However, given the slow load growth in the region, it seems reasonable to expect that the 135,250 therms/day of Jackson Prairie subordinate TF-2 capacity will remain useful for at least the next five years. Five years is based primarily on the regional coal plant shutdowns that are scheduled to start in 2020, which should result in the addition and utilization of new power generation, some of which likely will be gas-fired and located in the I-5 corridor between Sumas and NW Natural's service territory. For that reason, the subordinate TF-2 service from Jackson Prairie has been retained in the first five years of the IRP analysis and so continues to appear in our PGA resource stack.

The Plymouth situation creates an immediate resource deficiency that NW Natural is currently addressing.

One eventual solution will be additional utilization of Mist storage through the recall of capacity developed for Interstate Storage Services. However, such recall requires advance notice since the capacity is currently fully contracted to third parties on a firm basis. So while Mist recall is not a solution for the coming winter, it will be a big part of the solution for subsequent PGA periods.

One alternative, which is relatively inexpensive, would be for the company to rely in part on what is known as "segmented capacity" on the NWP system. Segmented capacity allows NW Natural to move additional gas supplies from Sumas, although again on a secondary or subordinate basis on NWP. Thus it cannot be counted upon as a permanent solution to the current resource deficiency.

Because of its secondary nature, the Company has refrained from including segmented capacity in its past resource analyses. The Plymouth situation, however, and the related discussion pertaining to Jackson Prairie, caused a reassessment of this approach. As with the subordinate TF-2 capacity from Jackson Prairie, NW Natural has created segmented capacity that flows from the north (Sumas) in a path that has not experienced any constraints, even during the coldest weather events in recent years. For that reason, segmented capacity has been included for the first time in the company's 2014 IRP and will be used in this PGA period.

There are no NWP demand charges for segmented capacity, only the very low variable costs of transportation. The company currently has 438,000 therms/day of segmented capacity that it will use from Sumas, and will evaluate if more can be created.

Another potential solution would be the acquisition of supplies delivered by third parties to the company's service territory. The company is exploring the costs and availability of such arrangements, but probably will not have enough information in time to include in the August 1st preliminary PGA filing.

September update - A placeholder for 20,000 Dth/day of citygate deliveries was identified as *pending* in the August 1st filing. Such a contract was executed towards the end of July, too late for inclusion in the narrative.

This resource bridges the gap between the firm design day sales forecast for the coming winter, as developed in the IRP, and the sum of the current supply resources in NW Natural's portfolio (including the segmented capacity mentioned above). This contract obligates a third party to bundle together supplies sourced from Sumas, along with their own transportation service on NWP, to deliver gas on a limited basis to NW Natural's service territory. The limitation is that NW Natural can only call on the physical supply for up to five (5) days during the period of December 1, 2014 through February 28, 2015. There is a daily reservation charge for this service and, if called upon, the commodity cost of the delivered gas will be extremely high. NW Natural analyzed several alternatives before choosing this particular arrangments See the separate sheet in this file labeld "Resource options" for more details.

This is the Company's first citygate delivery agreement since 2004. Whether this resource could and should be re-contracted for future winters will be evaluated after the winter season.

The other change to the portfolio mentioned above pertains to the upcoming termination of the company's T-South contract on the Westcoast Energy Inc. (WEI) system in British Columbia. This contract was negotiated during the aftermath of the West Coast Energy Crisis of 2000-2001 and commenced in 2003 for an 11-year term. It will terminate on 10/31/2014. The T-South contract quantity is 1,241.3 thousand cubic metrics per day, which equates to about 580,000 therms/day.

The T-South contract allows the company to buy gas at the trading hub in northern British Columbia known as Station 2. The T-South contract is used to transport Station 2 purchases to the international border where WEI interconnects with NWP, a point known as Huntingdon on the Canadian side of the border and Sumas on the U.S. side.

The company originally entered into the T-South contract to avoid extreme price volatility experienced at the Huntingdon/Sumas trading hub. Similarly, the company entered into transportation contracts on the Southern Crossing Pipeline (SCP), Foothills and NGTL to further diversify its purchases away from Huntingdon/Sumas. The SCP contract does not end until 2020, so expiration of the T-South contract has been the first opportunity in a decade to re-evaluate a return to term gas buying at Huntingdon/Sumas.

This evaluation consisted of a cost/benefit analysis, including the customer benefits accruing from optimization of the T-South contract, and also an assessment of supply availability/reliability.

An example of the cost/benefit analysis is in the spreadhsheet in this file labeled "T-South analysis". While commodity prices and hence price spreads change continuously, it is representative of the results that continue to indicate that the costs of holding T-South capacity exceed the benefits, at least for the upcoming PGA period.

Three factors could change these results. First, if the price spread between Station 2 and Sumas were to "blow out", then the value of holding T-South capacity would greatly increase. Over the long term, NW Natural believes this is a real possibility, driven by events such as LNG export terminals on the coast of British Columbia. But in the short term, this is much less of a concern, and there is no value to holding capacity for such a futrure event since from a rate standpoint, there is no distinction between "vintage" capacity and new capacity on Canadian pipelines.

Second, when T-South capacity would otherwise be unused by NW Natural, there is some optimization value that can be generated. It does not appear to be enough value to tip the scales under our current AMA structure, but If our AMA partner is willing to share more of this value with the company, then more benefit can be generated for customers. However, as shown in the "T-South analysis" spreadsheet, such a change is still not likely to be enough to change the decision.

The third factor would be if WEI changes its T-South capacity offering to something other than a 12-month service. This has been done in prior years, including last year, with WEI offering a 17-month service contract commencing November 1st. In effect, this means service for two winters but only one summer, and since summer is when the capacity has its lowest value, this could be enough to change our decision. Unfortunately, if WEI follows its pattern from last year, such an offering will not be made until sometime in August, so we cannot count on such a benefit in our current decision-making.

Finally, regarding supply availability/reliability, the company has been pursuing Huntingdon/Sumas supplies for the last several months. We have found the market to be comparable to Station 2 and not a source of concern.

As a reminder from last year, a small "de-rate" of 1 million therms continues to be in place for the Newport LNG tank capacity. This reflects the gradual accumulation of frozen carbon dioxide (commonly known as "dry ice") on the tank floor over the plant's 35 years of operation. This has not reduced Newport's design peak day delivery rate. A project to remove the dry ice is in the formative stages and no changes are expected at Newport during the PGA period.

The company’s portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011 with Encana. That agreement was amended in March 2014 and new gas wells are being drilled with the successor company Jonah Energy LLC. While the status of that arrangement is still under discussion with the OPUC, the projected gas reserve volumes from Jonah Energy (as well as Encana) have been included in this filing. It is worth noting that in both cases, the gas reserve volumes essentially function as a financial tool, i.e., they displace 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.

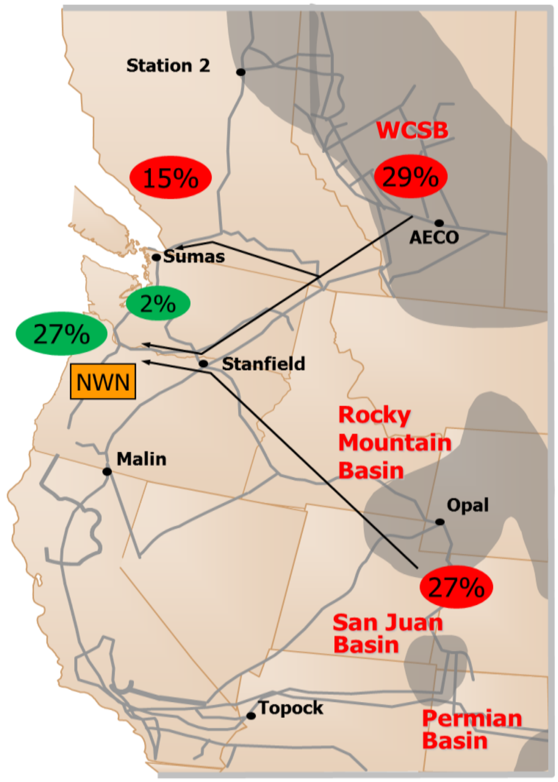
NW Natural Average Winter Day

Flowing Supplies

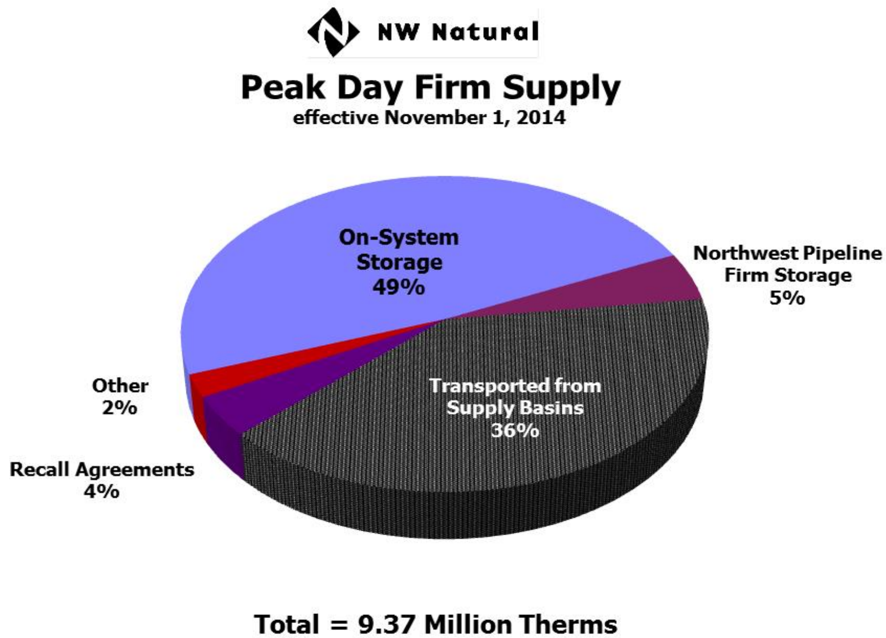
Underground Storage

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

Assumes that storage is 100% full on Nov 1.



Should its “design” peak day occur, all physical resources would be used in the following proportions:



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

Regarding physical supply purchasing, NWN will have contracts with suppliers for 650,000 therms per day of firm deliveries on a daily basis over the upcoming November 2014 through October 2015 period. This reflects the relatively stable daily component of NWN’s demand, including some portion of storage injection requirements in the summer months.

For the November 2014 through March 2015 heating season, NWN will have contracts for an additional 1.50 million therms/day of supply under baseload and peaking (swing) agreements. 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. Most of the winter contracted volume (1.2 million therms/day) is purchased on a take-or-pay basis. The remaining 300,000 therms/day are made available to NWN on a daily basis in exchange either for payment of a fixed “reservation” charge or for equivalent value in the form of put options during the summer months. These swing contracts have no minimum daily, monthly or seasonal purchase requirement, but they provide additional daily supply flexibility, which is especially valuable since winter weather can fluctuate rapidly between mild and cool temperatures, resulting in rapidly changing customer requirements.

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

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

NWN “swaps” monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage, including any supply-basin storage arrangements, provide another form of hedging. In addition, gas reserves provide a hedge for Oregon customers in a completely different form. Overall, NWN’s target this year is to hedge the prices of approximately 75% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. As storage currently accounts for about 23% of annual purchase quantities, gas reserves will amount to roughly 10% for this tracker year and local (Mist) gas production adds another 1%, approximately 41% is left to be financially hedged. This is a drop from prior years when over 50% of expected purchases were hedged with financial derivatives. Actual financial hedging targets are set by an executive level oversight committee within the company - the Gas Acquisition Strategy & Policies (GASP) Committee - and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

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

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

The company decided not to engage in multi-year financial hedges earlier in 2014 due to the sharp increase in the forward market over the next few years as a result of the extreme cold winter experienced last winter across most of the country. However, storage injections have been extremely strong so far this spring/summer, and along with mild summer temperatures and continuing growth in gas production, the forward curve has been coming down recently. This could lead to the company doing some amount of multi-year (actually multi-winter) financial hedges before its hedging is completely done.

6. *Storage resources.*

NWN relies on four storage facilities and three supply-basin storage arrangements in Alberta to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at the Jackson Prairie underground facility in Washington state. The three Alberta supply-basin storage arrangements are with TransCanada Gas Storage Partnership, AECO Gas Storage Partnership (a subsidiary of Niska Partners and commonly referred to as Niska), and J. Aron (a subsidiary of Goldman Sachs), respectively. [The status of the Plymouth LNG plant was covered in a previous section and so will not be discussed again here.]

Storage provides the following benefits to customers:

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

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

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

d. Helps balance daily demand with supplies, reducing the potential of 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 arrangements.

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.

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

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

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SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

IV General Information and Forecasting

T-South Contract Economic Analysis

1. Commodity Price Impact

Closing Financial Prices, in U.S. $/Dth, as of 4/10/2014:

	AECO		Sumas
Nov-14	$ 4.559	Nov-14	$ 5.169
Dec-14	$ 4.604	Dec-14	$ 5.452
Jan-15	$ 4.634	Jan-15	$ 5.364
Feb-15	$ 4.613	Feb-15	$ 5.193
Mar-15	$ 4.537	Mar-15	$ 5.107

assuming 58,000 Dth/day contract
baseloaded during the winter, no summer purchases

Convert to Physical Prices assuming:
Station 2 = AECO - $ 0.1000
Sumas = Sumas + $ 0.0225

Equivalent Physical Prices:

	Station 2		Sumas	T-South volumetric costs Variable ($/Dth)	FIK (%)	FIK ($/Dth)	Total ($/Dth)	Commodity Spread ($/Dth)	Monthly Volume (Dth)	Station 2 Commodity Savings ($)
Nov-14	$ 4.459	Nov-14	$ 5.191	$ 0.032	1.50%	$ 0.067	$ 0.099	$ 0.63	1,740,000	$ 1,102,503
Dec-14	$ 4.504	Dec-14	$ 5.474	$ 0.032	1.50%	$ 0.068	$ 0.100	$ 0.87	1,798,000	$ 1,565,051
Jan-15	$ 4.534	Jan-15	$ 5.386	$ 0.032	1.50%	$ 0.068	$ 0.100	$ 0.75	1,798,000	$ 1,352,991
Feb-15	$ 4.513	Feb-15	$ 5.216	$ 0.032	1.50%	$ 0.068	$ 0.100	$ 0.60	1,624,000	$ 978,955
Mar-15	$ 4.437	Mar-15	$ 5.129	$ 0.032	1.50%	$ 0.067	$ 0.099	$ 0.59	1,798,000	$ 1,067,927
										$ 6,067,427

2. Demand Charges

Contract Demand = 1,594.9 $10^3 m^3$/day (this equates to 58,552 Dth/day assuming 1040 Btu/cf)
Westcoast 1 year rate = $ 631.00 per $10^3 m^3$/day per month
One month demand charge = $ 1,006,382
Annual demand charge = $ 12,076,582.80

[redacted]

4. Comparison of Costs and Benefits of Holding T-South Contract

a. With Current Optimization Structure

Commodity Savings	$ 6,067,427
Demand Charges	$ (12,076,583)
Optimzation Benefit	[redacted]
Total Benefit to Customers	

b. With Modification of Optimization Structure (75% to NWN, so effectively 50% of total to customers)

Commodity Savings	$ 6,067,427
Demand Charges	$ (12,076,583)
Optimzation Benefit	[redacted]
Total Benefit to Customers	

c. NWN does not release capacity for Optimization but somehow is able to achieve same benefits (100% to customers)

Commodity Savings	$ 6,067,427
Demand Charges	$ (12,076,583)
Optimzation Benefit	[redacted]
Total Benefit to Customers	

Recommendation for Addressing 2014/15 Resource Deficiency

[redacted]

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NW Natural
Winter 2014-2015
Proposals for 20K City gate purchases

[redacted]

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2014/2015 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia				
Conoco Phillips	Nov-Mar	10,000		3/31/2015
Noble	Nov-Mar	5,000		3/31/2015
PetroChina	Nov-Mar	10,000		3/31/2015
Powerex	Nov-Mar	5,000		3/31/2015
Iberdrola	Nov-Mar	5,000		3/31/2015
PetroChina	Nov-Mar	5,000		3/31/2015
Pending	Nov-Mar	5,000		3/31/2015
Alberta:				
Macquarie Energy	Nov-Mar	5,000		3/31/2015
Noble	Nov-Mar	5,000		3/31/2015
BNP Paribas	Nov-Mar	5,000		3/31/2015
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2015
TD Energy Trading	Nov-Mar	5,000		3/31/2015
Cargill	Nov-Mar	5,000		3/31/2015
Conoco Phillips	Nov-Mar	5,000		3/31/2015
J. Aron	Nov-Mar	5,000		3/31/2015
Cargill	Nov-Mar	5,000		3/31/2015
Husky Energy Marketing	Nov-Oct	10,000		10/31/2015
Shell Energy North America (Canada)	Nov-Oct	5,000		10/31/2015
J. Aron	Nov-Oct	5,000		10/31/2015
Pending	Nov-Mar		10,000	3/31/2015
Pending	Apr-Oct		10,000	10/31/2015
Rockies:				
Shell Energy North America (US)	Nov-Oct	5,000		10/31/2015
Chevron Natural Gas	Nov-Oct	5,000		10/31/2015
IGI Resources	Nov-Oct	10,000		10/31/2015
Enserco Energy	Nov-Mar	5,000		3/31/2015
Conoco Phillips	Nov-Mar	5,000		3/31/2015
Anadarko Energy Services	Nov-Mar	5,000		3/31/2015
Macquarie Energy	Nov-Mar	5,000		3/31/2015
Macquarie Energy	Nov-Oct	5,000		10/31/2015
Ultra Resources	Nov-Oct	10,000		10/31/2015
Chevron Natural Gas	Nov-Mar	5,000		3/31/2015
Anadarko Energy Services	Nov-Mar	5,000		3/31/2015
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2015
Enserco Energy	Apr-Oct	5,000		10/31/2015
Ultra Resources	Nov-Oct	5,000		10/31/2015
Pending	Nov-Mar		20,000	3/31/2015
Total, November-March		125,000	30,000	
Total, April-October		65,000	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.

Table 2

NW Natural
Firm Transportation Capacity
for the 2014/2015 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
Occidental	1,046	3/31/2016
Occidental	4,000	3/31/2025
International Paper Cap. Acq.	4,147	11/30/2016
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2016
Net NWP Capacity	331,237	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2016
Total GTN Capacity	106,165	
TransCanada's BC System:		
1993 Expansion	47,727	10/31/2015
1995 Rationalization	57,417	10/31/2015
Engage Capacity Acquisition	3,708	10/31/2015
2004 Capacity Acquisition	48,669	10/31/2016
Total TCPL-BC Capacity	157,521	
TransCanada's Alberta System:		
1993 Expansion	48,135	10/31/2015
1995 Rationalization	57,909	10/31/2015
Engage Capacity Acquisition	3,739	10/31/2015
2004 Capacity Acquisition	49,138	10/31/2015
Total TCPL-ALberta Capacity	158,921	
WEI T-South Capacity	*58,000*	*10/31/2014*
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.
2. The WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
4. As indicated in the table, the termination date for the WEI T-South Capacity is October 31, 2014. Currently, Northwest Natural does not intend to extend the contract beyond this termination date per the discussion and analysis provided in Section IV.2b of the PGA filing documents.

Table 3

NW Natural
Firm Storage Resources
for the 2014/2015 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-year notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-year notice
TF-2 (redelivery service)	13,406	281,242	Upon 1-year notice
Plymouth LNG:			
LS-1	*60,100*	*478,900*	*Upon 1-year notice*
TF-2 (redelivery service)	*60,100*	*478,900*	*Upon 1-year notice*
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	275,000	9,976,780	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	900,000	n/a
Total On-System Storage	455,000	11,476,780	
Total Firm Storage Resource	561,130	13,075,968	
Firm Storage Resource w/o Plymouth	501,030	12,597,068	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option.
2. For Jackson Prairie TF-2 service, 9,586 Dth/day of the first agreement listed above and 3,939 Dth/day of the second agreement are "subordinated" firm service. However, on cold weather days, when flows are maximized on NWP's system, service on this agreement should be highly reliable.
3. On-system storage peak deliverability is based on design criteria.
4. Mist numbers shown are the portions reserved for service to utility core customers per the company's Integrated Resource Plan. Additional capacity and deliverability has been contracted under varying terms to off-system customers. The number is approximate as it depends on the heat content of the stored gas, which in turn is dependent on the blended heat content of upstream pipeline gas together with Mist production gas. Current heat content factor is 1010 Btu/cf.
5. Newport tank capacity de-rated from 1,000,000 Dth pending CO_2 removal project.
6. The company has ongoing supply-basin storage contracts in Alberta with TransCanada Gas Storage Partnership in the amount of 947,817 Dth, with AECO Gas Storage Partnership (Niska) in the amount of 1,895,817 Dth, and with J. Aron & Company in the amount of 1,153,000 Dth. Theses volumes are not included above because deliverability relies on portions of the same upstream pipeline capacity already included in Table 2.
7. As discussed in Section IV.2b of the PGA filing documents, the current amount in inventory at Plymouth is only 7 Dth. Although the Company is still exploring ways to make use of its Plymouth contracts, since there is no ability to liquefy this summer due to the March 31, 2014 plant accident, expectations are limited. The Company currently intends to terminate its Plymouth contracts, which would take effect on November 1, 2015.

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2014/2015 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2016
International Paper	8,000	40	10/31/2015
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
Shell Energy North America (US)	20,000	5	2/28/2015
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. All of the recall arrangements include delivery to NW Natural's system.
2. Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation to take gas from existing wells continues for the life of those wells.

Table 5

NW Natural
Peak Day Resource Summary
for the 2014/2015 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	331,237
Off-System Storage (Jackson Prairie only - No Plymouth)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	455,000
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	20,000
Nominal Mist Production Gas	2,000
Segmented Capacity	43,800
Total Peak Day Resources	937,067

1. The segmented capacity listed above is discussed in Section IV.2b of the PGA filing documents, and the Company continues to examine whether more segmented capacity could be created that would be of reasonable reliability during cold weather events.

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NW Natural

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

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

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

	2014/2015
Forecast Annual Demand (therms)	747,790,904
Forecast Peak Demand (therms) - Normal	4,209,468
Forecast Peak Demand (therms) - Design	9,369,764
Forecast DSM Annual (therms)	0
Forecast DSM Peak (therms) - Design Peak	0
Forecast Annual Demand with Forecast DSM	747,790,904
Forecast Peak Demand with Forecast DSM - Normal	4,209,468
Forecast Peak Demand with Forecast DSM - Design	9,369,764

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

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

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

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

NW Natural
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9 Summary of portfolio documentation provided

See Index to this Worksheet.

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFED PROTECTIVE ORDER 10-337

November 1, 2014 - October 31, 2015
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
Macquarie Energy, LLC (NGR's)	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal/Rocky Mountain Pool
Shell Energy North America (US), Inc. (NGR	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal/Rocky Mountain Pool
Chevron Natural Gas. (NGR's)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal/Rocky Mountain Pool
Enserco Energy Inc. (NGR's)	4/1/2015	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Wyoming Pool (Opal, Shute Creek, Green G)
IGI Resources, Inc. (NGR's)	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal/Rocky Mountain Pool
Ultra Resources, Inc. (1)	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	10,000				Opal
ConocoPhillips Company (2)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal
Enserco Energy Inc. (3)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Wyoming Pool (Opal, Shute Creek, Green G)
Anadarko Energy Services Company (4)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Macquarie Energy, LLC. (4)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Anadarko Energy Services Company (5)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Shell Energy North America (US), Inc (6)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool
Ultra Resources, Inc. (7)	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal
Chevron Natural Gas (8)	11/1/2014	10/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal
PENDING - Winter Call	11/1/2014	3/31/2015			20,000				

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Opal	5	[redacted]	Price
(2) Opal	4		Price
(3) Wyoming Pool	5		Price and Location (Supplier must agree to no Frontier Plant deliveries)
(4) Rocky Mountain Pool	7		Price
(5) Rocky Mountain Pool	5		Price
(6) Rocky Mountain Pool	7		Price
(7) Opal	4		Price
(8) Opal	5		Price

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

Northwest Natural Gas Company
PGA Filing Guidelines

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November 1, 2014 - October 31, 2015
Physical Natural Gas term contracts

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Approved Counterparties all have executed NAESB contracts with NW Natural

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's
Conoco Phillips Canada Marketing (1)	11/1/2014	3/31/2015	[redacted]	IFGMR-NWP Canadian Border FOM	10,000
Noble Americas Gas & Power Corp (1)	11/1/2014	3/31/2015		IFGMR-NWP Canadian Border FOM	5,000
PetroChina International (America) Inc. (1)	11/1/2014	3/31/2015		IFGMR-NWP Canadian Border FOM	10,000
Powerex Corp. (2)	11/1/2014	3/31/2015		IFGMR-NWP Canadian Border FOM	5,000
PetroChina International (America) Inc. (3)	11/1/2014	3/31/2015		IFGMR-NWP Canadian Border FOM	5,000
Iberdrola Canada Energy Services Ltd. (3)	11/1/2014	3/31/2015		IFGMR-NWP Canadian Border FOM	5,000
PENDING - Winter Term Baseload	11/1/2014	3/31/2015			5,000

Transactions for new PGA year

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

Northwest Natural Gas Company
PGA Filing Guidelines

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November 1, 2014 - October 31, 2015
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
Husky Oil Operations Limited (1)	11/1/2014	10/31/2015	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		
Shell Energy North America (Canada) Inc. (1)	11/1/2014	10/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
Macquarie Energy Canada Ltd. (2)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
Noble Americas Gas & Power Corp (2)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
BNP Paribas Energy Trading Canada Corp. (3)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
Shell Energy North America (Canada) Inc. (3)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
TD Energy Trading Inc. (4)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
Cargill, Ltd. (5)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
ConocoPhillips Canada Marketing (5)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
J. Aron & Company (6)	11/1/2014	10/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
Cargill, Ltd. (7)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
J. Aron & Company (7)	11/1/2014	3/31/2015		CGPR AECO FOM (7A) $US/Dth	5,000		
PENDING - Winter Call	11/1/2014	3/31/2015			10,000		
PENDING - Summer Put	4/1/2015	10/31/2015			10,000		

Transactions for new PGA year

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

NW Natural
PGA Portfolio Guidelines
2014-2015 Oregon PGA

V.1 b) Physical Gas Supply
For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

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

1. The purchasing of baseload and spot supplies for the 2014-2015 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 2014-2015, 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.

2014-2015 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	2012-13 Days	Daily Volume	Trade Volume	[redacted]	Including Multi-Year	
24-May-12	2012-26	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,302,375.00
24-May-12	2012-27	[redacted]	[redacted]	Rockies	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,409,962.50
7-Jun-12	2012-33	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,248,581.25
29-Jun-12	2012-37	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,299,166.25
12-Jul-12	2012-38	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,308,037.50
31-Jul-12	2012-42	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,384,481.25
2-Aug-12	2012-49	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,313,700.00
16-Aug-12	2012-50	[redacted]	[redacted]	Rockies	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,393,918.75
16-Aug-12	2012-51	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,282,933.75
23-Aug-12	2012-53	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,275,006.25
6-Sep-12	2012-58	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,256,131.25
6-Sep-12	2012-59	[redacted]	[redacted]	Rockies	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,362,775.00
14-Sep-12	2012-62	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,305,206.25
21-Sep-12	2012-63	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,323,137.50
2-Oct-12	2012-64	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,421,287.50
5-Oct-12	2012-74	[redacted]	[redacted]	AECO	Nov-Mar (2012-2015)	151	2,500	377,500	[redacted]	377,500	$1,393,918.75
11-Dec-12	2012-76	[redacted]	[redacted]	AECO	Nov-Feb (2013-2016)	120	2,500	300,000	[redacted]	602,500	$2,341,917.50
11-Dec-12	2012-77	[redacted]	[redacted]	AECO	Nov-Feb (2013-2016)	120	2,500	300,000	[redacted]	602,500	$2,313,600.00
4-Jun-13	2013-33	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$3,260,280.00
14-Jun-13	2013-36	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$3,113,325.00
21-Jun-13	2013-39	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,819,793.75
5-Jul-13	2013-45	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,715,637.50
26-Jul-13	2013-57	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,736,468.75
29-Jul-13	2013-58	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,691,018.75
2-Aug-13	2013-62	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,935,312.50
23-Aug-13	2013-68	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,736,847.50
30-Aug-13	2013-73	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$3,046,665.00
6-Sep-13	2013-77	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,719,425.00
20-Sep-13	2013-81	[redacted]	[redacted]	AECO	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,791,387.50
25-Sep-13	2013-82	[redacted]	[redacted]	Rockies	Nov-Mar (2013-2016)	151	2,500	377,500	[redacted]	757,500	$2,956,522.50
22-Jan-14	2014-1	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$511,125.00
24-Jan-14	2014-2	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	155,000	$519,250.00
27-Jan-14	2014-3	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	155,000	$524,210.00
29-Jan-14	2014-4	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$508,500.00
29-Jan-14	2014-5	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$507,750.00
21-Feb-14	2014-6	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$508,500.00
24-Feb-14	2014-7	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$508,500.00
24-Feb-14	2014-8	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$507,750.00
27-Feb-14	2014-9	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	155,000	$536,300.00
28-Feb-14	2014-10	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	155,000	$535,137.50
20-Mar-14	2014-11	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$537,000.00
21-Mar-14	2014-12	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$536,250.00
26-Mar-14	2014-13	[redacted]	[redacted]	AECO	Oct	31	5,000	155,000	[redacted]	155,000	$558,620.00
28-Mar-14	2014-14	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$543,375.00
31-Mar-14	2014-15	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$527,250.00
21-Apr-14	2014-16	[redacted]	[redacted]	AECO	Apr-Oct	214	5,000	1,070,000	[redacted]	1,070,000	$3,967,025.00
23-Apr-14	2014-17	[redacted]	[redacted]	AECO	Nov	30	5,000	150,000	[redacted]	150,000	$685,125.00
23-Apr-14	2014-18	[redacted]	[redacted]	AECO	Nov	30	5,000	150,000	[redacted]	150,000	$681,750.00
24-Apr-14	2014-19	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$563,100.00
25-Apr-14	2014-20	[redacted]	[redacted]	AECO	Apr	30	5,000	150,000	[redacted]	150,000	$558,375.00
25-Apr-14	2014-21	[redacted]	[redacted]	AECO	May	31	5,000	155,000	[redacted]	155,000	$565,750.00

29-Apr-14	**2014-22**	[redacted]	**AECO**	**Oct**	**31**	**5,000**	**155,000**	[redacted]	**155,000**	**$587,450.00**
29-Apr-14	**2014-23**		**AECO**	**Oct**	**31**	**5,000**	**155,000**		**155,000**	**$586,675.00**
7-May-14	2014-24		Rockies	Apr-May	61	5,000	305,000		305,000	$1,230,675.00
13-May-14	**2014-25**		**AECO**	**Apr-May**	**61**	**5,000**	**305,000**		**305,000**	**$1,096,475.00**
21-May-14	2014-26		Rockies	Apr-May	61	5,000	305,000		305,000	$1,194,990.00
21-May-14	**2014-27**		**AECO**	**Nov**	**30**	**5,000**	**150,000**		**150,000**	**$645,750.00**
21-May-14	**2014-28**		**AECO**	**Nov**	**30**	**5,000**	**150,000**		**150,000**	**$643,125.00**
22-May-14	2014-29		Rockies	Oct	31	5,000	155,000		155,000	$605,430.00
28-May-14	**2014-30**		**AECO**	**Nov**	**30**	**5,000**	**150,000**		**150,000**	**$655,800.00**
30-May-14	**2014-31**		**AECO**	**Nov-Jan**	**92**	**5,000**	**460,000**		**460,000**	**$2,021,240.00**
5-Jun-14	**2014-32**		**AECO**	**Nov-Jan**	**92**	**5,000**	**460,000**		**460,000**	**$2,081,500.00**
19-Jun-14	2014-33		Sumas	Nov-Jan	92	5,000	460,000		460,000	$2,398,900.00
23-Jun-14	2014-34		Rockies	Nov-Jan	92	5,000	460,000		460,000	$2,132,100.00
26-Jun-14	2014-35		Sumas	Nov-Jan	92	5,000	460,000		460,000	$2,332,200.00
27-Jun-14	2014-36		Rockies	Oct	31	5,000	155,000		155,000	$603,337.50
7-Jul-14	2014-37		AECO	Apr-Oct	214	5,000	1,070,000		1,070,000	$3,787,800.00
9-Jul-14	2014-38		Rockies	Apr-Jun	91	5,000	455,000		455,000	$1,723,312.50
17-Jul-14	2014-39		AECO	Apr-May	61	5,000	305,000		305,000	$1,036,390.00
21-Jul-14	2014-40		Rockies	Nov-Jan	92	5,000	460,000		460,000	$1,871,740.00
24-Jul-14	2014-41		Rockies	Oct	31	5,000	155,000		155,000	$564,587.50
7-Aug-14	2014-42		Rockies	Nov-Mar	151	5,000	755,000		755,000	$3,075,115.00
8-Aug-14	2014-43		AECO	Nov-Mar (2014-2017)	151	2,500	377,500		1,135,000	$4,364,075.00
13-Aug-14	2014-44		AECO	Oct	31	5,000	155,000		155,000	$541,725.00
15-Aug-14	2014-45		AECO	Nov-Mar (2014-2017)	151	2,500	377,500		1,135,000	$4,259,087.50
15-Aug-14	**2014-46**		**AECO**	**Oct**	**31**	**5,000**	**155,000**		**155,000**	**$537,075.00**
20-Aug-14	2014-47		Sumas	Nov-Mar	151	5,000	755,000		755,000	$3,338,610.00
22-Aug-14	2014-48		Rockies	Sept	30	5,000	150,000		150,000	$556,500.00
4-Sep-14	2014-49		Rockies	Apr-Oct	214	5,000	1,070,000		1,070,000	$3,861,630.00
Total Hard Hedges							**25,795,000**		**32,475,000**	**$123,682,757.50**

CONFIDENTIAL **2014-2015 FINANCIAL SOFT HEDGES (counterparty owns option)**

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Total Trade Volume	Amount OTM	NOTIONAL AMOUNT	CALL STRIKE PRICE
Total Soft Hedges								**0**	[redacted]		
Total Hard and Soft Hedges								**25,795,000**			
Total Baseload Hedges Only (MANUAL FORMULA: DELETE SPOT HEDGES FROM TOTAL ABOVE)											
Total Baseload on Supply Region Tabs											#VALUE!
Total Spot (This must match Gas Acq Plan WACOG Tab) (MANUAL FORMULA FOR VOLUMES -- TOTAL OF SPOT)								**5,170,000**			
Total Baseload with Index Adjustments											

Hedges by Counterparty:

	Hedges for Nov 2014 - Oct 2015		All Hedges Nov14 Forward		NOTIONAL RANK *
[redacted]	[redacted]				#N/A
					#N/A
					#N/A
					6
					7
					3
					2
					4
					5
Yellow denotes active counterparty (not on credit hold)	**0**	**$0.00**	**0**	**$0.00**	

*Notional Rank is used for risk diversity. When counterparties tie for the lowest offer, the deal goes to the counterparty with the lowest notional value shown here.

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

	Customer Cnt Jul-13	Revenue Jul-13	Customer Cnt Aug-13	Revenue Aug-13	Customer Cnt Sep-13	Revenue Sep-13
Total	**687,379**	$ 27,164,323.45	**686,489**	$ 26,023,816.61	**687,018**	$ 26,720,653.58
Oregon	615,286	24,353,812.31	614,288	23,459,275.81	614,664	24,118,369.47
Washington	72,093	2,810,511.14	72,201	2,564,540.80	72,354	2,602,284.11
Total Residential	621,866	13,938,097.71	621,276	13,258,834.49	621,625	13,490,360.07
Total Commercial	64,545	8,431,782.17	64,243	7,963,475.16	64,423	8,129,694.88
Total Industrial	582	1,656,346.64	580	1,648,296.32	583	1,884,490.58
Total Interruptible	138	1,886,441.62	142	1,867,446.37	140	1,958,379.52
Total Transportation - Commercial Firm	39	69,031.02	39	69,791.42	40	70,928.58
Total Transportation - Industrial Firm	107	547,134.43	107	545,797.11	106	533,481.62
Total Transportation - Interruptible	102	635,489.86	102	670,175.74	101	653,318.33
Unbilled Revenue		(2,668,812.71)		(416,159.44)		4,853,901.66
Agency Fees						
Net Balancing/Overrun		334.00		8,202.00		(369.00)
Total Gas Operating Revenue		**$ 24,495,844.74**		**$ 25,615,859.17**		**$ 31,574,186.24**

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UM 1286 PGA Portfolio Guidelines
2014-2015 Oregon PGA

V.3.a Customer count and revenue by m

	Customer Cnt Oct-13	Revenue Oct-13	Customer Cnt Nov-13	Revenue Nov-13	Customer Cnt Dec-13	Revenue Dec-13
Total	**689,084**	$ 42,914,847.84	**691,916**	$ 61,188,444.91	**694,873**	$ 111,858,169.25
Oregon	616,477	38,795,132.70	618,998	55,473,180.00	621,618	100,337,464.02
Washington	72,607	4,119,715.14	72,918	5,715,264.91	73,255	11,520,705.23
Total Residential	623,583	24,172,338.59	626,062	37,285,203.01	628,634	71,646,570.44
Total Commercial	64,527	12,260,840.12	64,886	17,720,744.64	65,272	32,905,899.35
Total Industrial	582	2,177,475.11	580	2,354,776.00	563	2,475,691.63
Total Interruptible	143	2,934,604.42	132	2,425,903.38	148	3,407,579.96
Total Transportation - Commercial Firm	40	83,730.83	47	131,686.04	49	129,102.05
Total Transportation - Industrial Firm	106	575,484.63	106	624,438.44	107	654,519.42
Total Transportation - Interruptible	103	710,374.14	103	645,693.40	100	638,806.40
Unbilled Revenue		14,096,925.20		22,047,521.94		8,425,464.23
Agency Fees						
Net Balancing/Overrun		908.00		20.00		1,267.00
Total Gas Operating Revenue		**$ 57,012,681.04**		**$ 83,235,986.85**		**$ 120,284,900.48**

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UM 1286 PGA Portfolio Guidelines
2014-2015 Oregon PGA

V.3.a Customer count and revenue by m

	Customer Cnt Jan-14	Revenue Jan-14	Customer Cnt Feb-14	Revenue Feb-14	Customer Cnt Mar-14	Revenue Mar-14
Total	**696,888**	$ 125,160,230.24	**697,751**	$ 112,754,953.82	**698,372**	$ 87,254,960.72
Oregon	623,333	112,568,802.38	624,088	101,125,741.95	624,589	78,671,701.34
Washington	73,555	12,591,427.86	73,663	11,629,211.87	73,783	8,583,259.38
Total Residential	630,163	78,448,555.97	631,011	71,221,690.51	631,557	53,840,141.36
Total Commercial	65,744	39,011,079.21	65,763	34,436,578.28	65,836	26,616,180.53
Total Industrial	577	2,897,723.39	575	2,611,432.27	580	2,367,745.12
Total Interruptible	148	3,351,117.81	147	3,115,863.40	144	3,044,725.87
Total Transportation - Commercial Firm	48	131,622.46	47	128,247.49	47	118,244.93
Total Transportation - Industrial Firm	108	668,369.62	108	639,100.05	108	636,729.36
Total Transportation - Interruptible	100	651,761.78	100	602,041.82	100	631,193.55
Unbilled Revenue		(6,225,389.06)		(8,356,069.97)		(13,122,914.02)
Agency Fees						
Net Balancing/Overrun		2,728.00		566,975.00		73,999.00
Total Gas Operating Revenue		**$ 118,937,569.18**		**$ 104,965,858.85**		**$ 74,206,045.70**

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UM 1286 PGA Portfolio Guidelines
2014-2015 Oregon PGA

V.3.a Customer count and revenue by m

	Customer Cnt Apr-14	Revenue Apr-14	Customer Cnt May-14	Revenue May-14	Customer Cnt Jun-14	Revenue Jun-14
Total	**698,498**	$ 66,299,517.38	**698,143**	$ 47,634,394.55	**697,422**	$ 23,625,384.52
Oregon	624,637	60,047,737.22	624,230	43,206,826.05	623,469	20,382,694.89
Washington	73,861	6,251,780.16	73,913	4,427,568.50	73,953	3,242,689.63
Total Residential	631,648	39,814,657.55	631,413	27,487,911.27	630,868	12,083,012.38
Total Commercial	65,867	20,097,603.13	65,748	14,353,431.37	65,572	7,309,245.85
Total Industrial	582	2,131,059.39	580	1,898,123.34	583	1,288,206.52
Total Interruptible	146	2,921,705.56	147	2,594,589.18	143	1,659,997.30
Total Transportation - Commercial Firm	47	106,632.49	47	95,106.00	47	86,992.58
Total Transportation - Industrial Firm	115	610,833.22	108	592,536.00	110	592,496.74
Total Transportation - Interruptible	93	617,026.04	100	612,697.39	99	605,433.15
Unbilled Revenue		(4,962,408.90)		(12,225,256.79)		(1,559,390.68)
Agency Fees						
Net Balancing/Overrun						-
Total Gas Operating Revenue		**$ 61,337,108.48**		**$ 35,409,137.76**		**$ 22,065,993.84**

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UM1286 PGA Portfolio Guidelines
2014-2015 Oregon PGA

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

	2014/2015 Forecasted	2013/2014	2012/2013	2011/2012	2010/2011	2009/2010
System peak demand (therms)	**9,369,764**	9,320,242	9,252,236	9,424,400	9,450,100	9,174,643

[1] Normalized peak as used for purposes of the Annual PGA Filing

[2] Source: NWN Annual Report - Total Peak Delivery

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2014-2015 Oregon PGA

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

Gas Year	Forecasted 2014/2015	2013/2014	2012/2013	2011/2012 [1]	2010/2011 [1]	2009/2010
Annual Demand (therms)	747,790,904	746,847,556	732,272,081	759,952,952	764,740,025	713,350,202

[1] Updated for actuals

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V.3.d.

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

1. Annual for each customer class

Gas Year	Forecasted 2014/2015	2013/2014	2012/2013	2011/2012	2010/2011	2009/2010
Residential (therms)	402,683,123	416,389,181	385,909,967	412,646,882	417,058,269	381,201,339
Commercial (therms)	248,351,476	254,877,091	237,490,341	251,126,608	252,595,462	233,227,309
Industrial Firm (therms)	34,513,268	34,838,443	33,521,314	36,591,001	37,507,291	37,715,952
Industrial Interruptible (therms)	62,243,048	62,513,367	58,152,459	59,495,487	59,897,024	62,505,844

Updated for actuals

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

2. Annual and monthly base load

Gas Year	Forecasted 2014-2015	2013/2014	2012/2013	2011/2012[1]	2010/2011 [1]	2009/2010[1]
November	22,999,936	22,397,233	22,308,001	22,343,188	22,177,486	22,368,074
December	24,282,715	23,202,872	23,064,485	23,284,414	23,034,172	23,309,822
January	24,362,006	23,196,614	23,081,208	23,283,122	23,064,136	23,367,602
February	22,159,174	20,943,260	20,859,821	21,819,517	20,779,477	20,987,986
March	23,866,828	23,202,391	23,109,951	23,298,952	23,041,150	23,184,270
April	22,869,798	22,513,500	22,379,225	22,514,758	22,275,981	22,392,041
May	23,238,337	23,254,362	23,138,668	23,251,908	22,972,378	23,123,968
June	22,332,108	22,556,453	22,399,655	22,449,749	22,181,087	22,206,833
July	23,019,887	23,314,587	23,152,520	22,784,459	23,022,789	22,939,571
August	23,015,123	23,324,427	23,162,291	23,007,978	23,030,526	22,973,358
September	22,737,568	22,537,805	22,425,676	22,273,329	22,193,140	22,241,292
October	23,881,459	23,359,078	23,196,701	23,035,735	23,025,826	22,993,292
Annual	278,764,939	273,802,581	272,278,201	273,347,109	270,798,148	272,088,110

[1] Updated for actuals

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

3. Annual and monthly non-base load

Gas Year	Forecasted 2014/2015	2013/2014	2012/2013	2011/2012 [1]	2010/2011 [1]	2009/2010[1]
November	62,486,370	62,248,709	61,226,239	40,491,499	33,153,463	41,313,882
December	96,475,524	95,405,022	90,481,345	86,534,833	81,321,773	83,307,972
January	90,486,111	91,382,451	86,593,507	97,758,992	97,632,484	91,849,305
February	71,804,677	72,204,387	69,575,367	78,530,912	76,125,402	61,712,656
March	58,202,117	58,522,284	56,408,082	74,169,045	79,134,329	50,195,196
April	38,491,513	38,745,792	37,886,663	54,489,168	55,063,637	47,177,713
May	17,127,632	17,039,845	15,982,505	25,616,766	37,973,515	29,743,398
June	3,488,689	4,181,989	3,799,251	13,742,491	18,528,871	18,510,754
July	25,201	707,612	393,204	4,443,994	3,792,900	4,870,382
August	-	769,863	358,541	569,565	456,282	574,125
September	2,291,298	3,220,573	1,673,213	1,867,959	1,657,358	3,269,478
October	28,146,833	28,616,445	27,584,476	27,756,549	9,101,863	8,737,232
Annual	469,025,965	473,044,975	451,962,394	505,971,773	493,941,877	441,262,092

[1] Updated for actuals

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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

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

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

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

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

2010/2011	Albany	Astoria	The Dalles (OR	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3457654	956469	690565	4157224	702,364	32,625,567	7,655,176	5,085,930
December	6206851	1555645	1192475	6621319	1,211,342	64,006,649	13,394,071	10,167,593
January	6938995	1767004	1473980	7641086	1,283,562	73,368,900	16,245,941	11,977,152
February	5524303	1441394	1101653	6325956	1,023,155	58,990,655	12,959,886	9,537,877
March	5626311	1584417	1122046	6717675	1,122,964	61,645,159	14,252,465	10,104,442
April	4421411	1248356	892877	5204951	964,103	45,612,072	11,324,134	7,671,714
May	3629256	1058840	704922	4515425	806,518	34,854,739	9,298,238	6,077,955
June	2301553	730766	486742	3396094	594,258	22,960,838	6,398,509	3,841,198
July	1770424	592333	399425	2323979	502,209	14,417,184	4,261,741	2,548,394
August	1579277	511889	371098	2195527	497,320	12,454,469	3,714,731	2,162,497
September	1593461	470109	376434	2211756	544,272	12,471,427	3,973,400	2,209,639
October	2257067	615666	474390	2599456	527,724	17,891,415	4,849,366	2,912,605
Annual	45,306,563	12,532,888	9,286,607	53,910,448	9,779,791	451,299,074	108,327,658	74,296,996

2009/2010	Albany	Astoria	The Dalles (OR	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3958516	968524	703552	4370947	736,861	38,814,912	8,125,283	6,003,361
December	6772815	1604810	1234519	7379170	1,203,057	64,354,442	13,715,517	10,353,464
January	6070896	1544701	1498610	7575728	1,108,916	69,550,378	16,105,104	11,762,574
February	4831240	1204871	1047212	5743681	921299	49129022	11,741,477	8,081,840
March	4587575	1187139	883460	5485529	860701	42640221	10,757,366	6,977,475
April	4436188	1110783	773939	5525032	867080	39833508	10,655,298	6,367,926
May	3162615	958600	585146	4540385	679126	30025275	7,968,938	4,947,281
June	2321219	765367	454378	3359201	635811	23278201	6,007,833	3,895,577
July	1601212	555689	354528	2446357	522058	15162414	4,387,896	2,779,799
August	1452341	541319	326196	2200458	494599	12518415	3,742,908	2,271,247
September	1646010	532130	351180	2324260	479149	13537420	4,170,741	2,469,880
October	2066157	570602	408501	2692505	563,386	17,404,864	4,996,634	3,027,875
Annual	42,906,784	11,544,535	8,621,221	53,643,253	9,072,043	416,249,072	102,374,995	68,938,299

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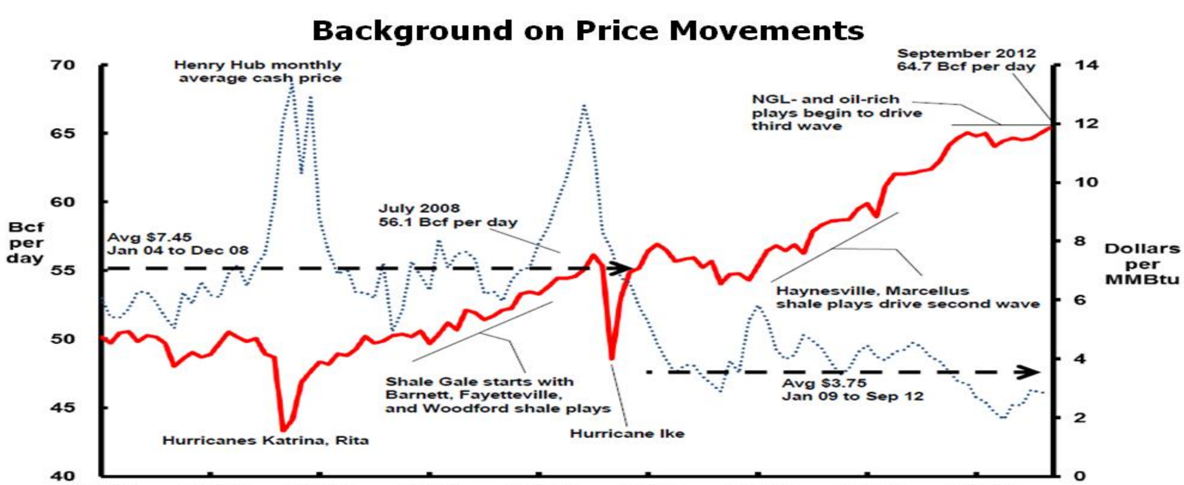
V.4 Market Information:
General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply,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

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

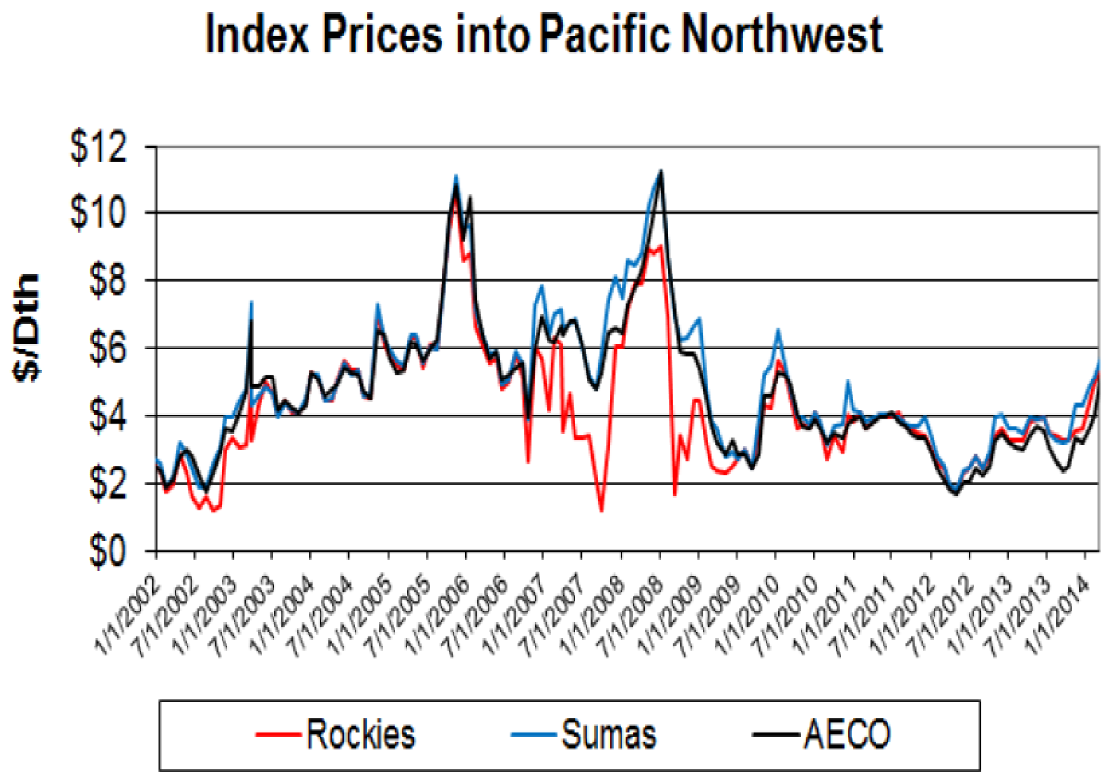
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were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

Figure 1



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

Figure 2



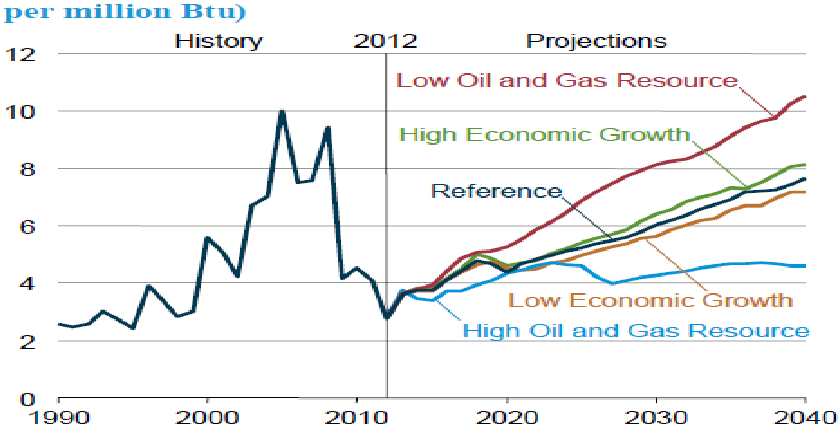
As mentioned, production began ramping up in 2008 with the surge in shale drilling innovations. Prices fell dramatically but as shown in Figure 2, bottomed out by spring 2012

Prices are expected to rise. The U.S. Energy Information Administration's (EIA) Annual Energy Outlook dated April 2014 examined four scenarios in addition to a reference case and the quesiton is not whether, but by how much will prices increase over time (Figure 3).

Figure 3

Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



The major factors affecting this outlook are:

1. Growth in gas supplies driven by shale exploration along with continuing improvements in drilling efficiencies. It should be noted that we have not seen a "base case" price forecast that reflects anything other than the current regulatory environment, i.e., no new fracking regulations or other changes that could restrict the availability of gas supplies and/or increase drilling costs. That is probably a good assumption in any short-term price forecast since any new environmental regulations likely would take years to be approved and implemented.

2. Demand growth from power generation. Coal plant retirements and support for renewable energy are common underpinnings for the expected growth in gas-fired electric generation. Something that is probably still too new to factor into these forecasts is the potential for the pre-mature retirement of nuclear units. San Onofre units 2 and 3 in southern California had been off-line since early 2012, so the announcement of their retirement in 2013 may have been a non-event. However, the February 2013 announcement by Duke and the August 2013 announcement by Entergy to prematurely retire their Crystal River and Vermont Yankee nuclear plants, respectively, could auger a new trend due to the age of the nuclear generation fleet . If so, the expectation would be for another upward boost to gas price forecasts (source: *Gas Daily* , August 28, 2013).

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

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

5. Deviations from "Normal" Conditions. Temperatures, hydro levels and storage inventories are examples of factors that can have large short-term effects, but when looking a year or more into the future, are normalized to some extent in price forecasts. This means variations in any of these factors from normal or expected conditions will increase price volatility if not outright price levels. For example, the 2013-2014 winter turned out to be the 2nd coldest for the U.S. over the last 35 years, draining storage inventories down to levels not seen in over a decade. The "hangover" from last winter will be felt through the upcoming PGA period because it affects both the cost to refill storage this summer as well as winter prices. One factor that previously fell into this category was hurricane activity. However, with the continuing migration of gas production from off-shore (Gulf of Mexico) to on-shore (shale play) sources, the destructive impact of hurricanes is fast approaching a point at which it is more likely to suppress as much demand as it does supply, leaving only the psychological impact to influence pricing.

As for the Pacific Northwest, liquidity at our major supply points in the Rockies and western Canada is likely to be very strong for the next couple of years until demand growth catches up with the available supplies. Local prices increasingly will be affected by the availability of Rockies and western Canadian gas that typically would have flowed to mid-Continent and east coast markets, but now are being displaced by the continuing growth in gas supplies from eastern shale plays such as Marcellus .

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V.5 Data Interpretation

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

See this Exhibit C , IV.2.b.

Northwest Natural Gas Company

UM1286 PGA Portfolio Guidelines
2014-2015 Oregon PGA

V.6 Credit Worthiness Standards

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

IV. Credit Risk Management

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

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

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2008

Northwest Natural Gas Company
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V.6 Credit Worthiness Standards

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

See Attachment 1 to V.6 to this Exhibit C - NW Natural General Procedure 110 "Gas Supply Risk Management Policy".
HIGHLY CONFIDENTIAL and CONFIDENTIAL
Subject to Modified Protective Order 10-337

NW NATURAL

Gas Supply Risk Management Policies

Index No. 110

September 2013

Original Date of Approval: March 29, 2005

Northwest Natural Gas Company
PGA Portfolio Guidelines
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V.7 **Storage**

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

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)
Jackson Prairie - aquifer - Chehalis, WA	46,030	1,120,288
J. Aron Storage - virtual storage - Alberta, Canada	17,000	1,530,000
TransCanada Storage - depleted field - Alberta, Canada	16,018	947,817
Niska Storage - depleted field - Alberta, Canada	31,595	1,895,634
Mist (share allocated to Utility) - depleted field - Mist, OR	275,000	9,976,780
Portland LNG - LNG Plant - Portland, OR	120,000	600,000
Newport LNG - LNG Plant - Newport, OR	60,000	900,000

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

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

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-09	127,633,824	$ 86,133,798.02	0.67485	21,470,123	$ 14,421,841.03	1,969,140	$ 915,206.80	0.46477	108,132,841	$ 72,627,163.79	0.67165
Feb	108,132,841	$ 72,627,163.79	0.67165	8,052,347	$ 5,259,751.99	3,917,370	$ 1,541,494.90	0.39350	103,997,864	$ 68,908,906.70	0.66260
Mar	103,997,864	$ 68,908,906.70	0.66260	7,169,301	$ 3,809,030.51	15,685,782	$ 5,335,886.23	0.34017	112,514,345	$ 70,435,762.42	0.62602
Apr	112,514,345	$ 70,435,762.42	0.62602	12,549,307	$ 6,792,634.68	6,003,002	$ 1,863,485.18	0.31043	105,968,040	$ 65,506,612.92	0.61817
May	105,968,040	$ 65,506,612.92	0.61817	6,257,410	$ 3,304,746.27	5,698,237	$ 2,601,331.17	0.45652	105,408,867	$ 64,803,197.82	0.61478
Jun	105,408,867	$ 64,803,197.82	0.61478	1,920,050	$ 700,166.12	10,701,397	$ 5,542,374.50	0.51791	114,190,214	$ 69,645,406.20	0.60991
Jul	114,190,214	$ 69,645,406.20	0.60991	902,489	$ 333,164.85	14,375,074	$ 7,356,483.97	0.51175	127,662,799	$ 76,668,725.32	0.60056
Aug	127,662,799	$ 76,668,725.32	0.60056	850,513	$ 355,286.25	12,119,369	$ 6,151,720.64	0.50759	138,931,655	$ 82,465,159.71	0.59357
Sep	138,931,655	$ 82,465,159.71	0.59357	844,063	$ 357,760.71	10,236,492	$ 5,276,073.94	0.51542	148,324,084	$ 87,383,472.94	0.58914
Oct	148,324,084	$ 87,383,472.94	0.58914	4,176,560	$ 1,736,106.06	10,379,167	$ 4,536,149.64	0.43704	154,526,691	$ 90,183,516.52	0.58361
Nov	154,526,691	$ 90,183,516.52	0.58361	2,628,536	$ 1,135,797.56	4,189,298	$ 1,447,394.43	0.34550	156,087,453	$ 90,495,113.39	0.57977
Dec	156,087,453	$ 90,495,113.39	0.57977	38,007,275	$ 20,770,776.55	5,277,200	$ 2,921,280.66	0.55357	123,357,378	$ 72,645,617.50	0.58890
	TOTAL 2009 ACTIVITY			104,827,974	$ 58,977,062.58	100,551,528	$ 45,488,882.06				
Jan-10	123,357,378	$ 72,645,617.50	0.58890	9,410,501	$ 5,373,535.47	4,395,990	$ 2,432,943.95	0.55345	118,342,867	$ 69,705,025.98	0.58901
Feb	118,342,867	$ 69,705,025.98	0.58901	4,879,344	$ 2,627,742.75	2,365,397	$ 1,217,833.57	0.51485	115,828,920	$ 68,295,116.80	0.58962
Mar	115,828,920	$ 68,295,116.80	0.58962	7,912,236	$ 4,425,625.23	2,309,560	$ 985,508.03	0.42671	110,226,244	$ 64,854,999.60	0.58838
Apr	110,226,244	$ 64,854,999.60	0.58838	15,503,891	$ 8,614,804.86	1,670,862	$ 646,032.16	0.38665	96,393,215	$ 56,886,226.90	0.59015
May	96,393,215	$ 56,886,226.90	0.59015	1,927,556	$ 793,228.54	9,406,506	$ 3,645,785.79	0.38758	103,872,165	$ 59,738,784.15	0.57512
Jun	103,872,165	$ 59,738,784.15	0.57512	652,061	$ 363,386.29	5,713,773	$ 2,465,796.73	0.43155	108,933,877	$ 61,841,194.59	0.56769
Jul	108,933,877	$ 61,841,194.59	0.56769	287,609	$ 183,359.98	12,279,896	$ 5,485,162.22	0.44668	120,926,164	$ 67,142,996.83	0.55524
Aug	120,926,164	$ 67,142,996.83	0.55524	405,287	$ 249,157.52	5,090,346	$ 2,304,088.84	0.45264	125,611,223	$ 69,197,928.15	0.55089
Sep	125,611,223	$ 69,197,928.15	0.55089	271,651	$ 167,341.59	13,753,326	$ 4,504,967.37	0.32755	139,092,898	$ 73,535,553.93	0.52868
Oct	139,092,898	$ 73,535,553.93	0.52868	2,687,797	$ 1,156,185.84	14,129,691	$ 4,843,395.19	0.34278	150,534,792	$ 77,222,763.28	0.51299
Nov	150,534,792	$ 77,222,763.28	0.51299	10,700,976	$ 4,746,126.96	5,072,131	$ 1,953,821.35	0.38521	144,905,947	$ 74,430,457.67	0.51365
Dec	144,905,947	$ 74,430,457.67	0.51365	7,060,485	$ 3,161,021.50	1,684,010	$ 679,171.39	0.40331	139,529,472	$ 71,948,607.56	0.51565
	TOTAL 2010 ACTIVITY			61,699,394	$ 31,861,516.53	77,871,488	$ 31,164,506.59				
Jan-11	139,529,472	$ 71,948,607.56	0.51565	16,536,581	$ 7,960,155.79	4,534,550	$ 1,898,587.33	0.41869	127,527,441	$ 65,887,039.10	0.51665
Feb	127,527,441	$ 65,887,039.10	0.51665	12,055,968	$ 6,039,266.36	3,407,810	$ 1,383,289.09	0.40592	118,879,283	$ 61,231,061.83	0.51507
Mar	118,879,283	$ 61,231,061.83	0.51507	7,076,302	$ 3,517,454.99	2,822,600	$ 1,085,126.04	0.38444	114,625,581	$ 58,798,732.88	0.51296
Apr	114,625,581	$ 58,798,732.88	0.51296	5,732,315	$ 2,519,434.50	2,628,886	$ 1,088,941.38	0.41422	111,522,152	$ 57,368,239.76	0.51441
May	111,522,152	$ 57,368,239.76	0.51441	10,792,274	$ 5,520,359.51	3,546,961	$ 1,499,222.91	0.42268	104,276,839	$ 53,347,103.16	0.51159
Jun	104,276,839	$ 53,347,103.16	0.51159	278,481	$ 153,669.85	4,613,636	$ 2,022,089.98	0.43829	108,611,994	$ 55,215,523.29	0.50837
Jul	108,611,994	$ 55,215,523.29	0.50837	348,655	$ 193,744.00	20,717,911	$ 8,891,484.55	0.42917	128,981,250	$ 63,913,263.84	0.49552
Aug	128,981,250	$ 63,913,263.84	0.49552	288,531	$ 159,121.73	7,526,103	$ 3,115,834.52	0.41400	136,218,822	$ 66,869,976.63	0.49090
Sep	136,218,822	$ 66,869,976.63	0.49090	322,758	$ 178,017.13	14,891,055	$ 5,710,632.39	0.38349	150,787,119	$ 72,402,591.89	0.48016
Oct	150,787,119	$ 72,402,591.89	0.48016	3,380,719	$ 1,404,966.55	27,967,660	$ 9,873,518.03	0.35303	175,374,060	$ 80,871,143.37	0.46114
Nov	175,374,060	$ 80,871,143.37	0.46114	9,465,008	$ 3,550,962.54	2,945,068	$ 1,024,003.04	0.34770	168,854,120	$ 78,344,183.87	0.46398
Dec	168,854,120	$ 78,344,183.87	0.46398	11,517,779	$ 4,952,519.39	2,644,302	$ 893,127.66	0.33776	159,980,643	$ 74,284,792.14	0.46434
	TOTAL 2011 ACTIVITY			77,795,371	$ 36,149,672.34	98,246,542	$ 38,485,856.92				
Jan-12	159,980,643	$ 74,284,792.14	0.46434	11,911,891	$ 4,669,327.57	2,279,590	$ 649,110.97	0.28475	150,348,342	$ 70,264,575.54	0.46735
Feb	150,348,342	$ 70,264,575.54	0.46735	8,672,041	$ 3,187,445.76	348,590	$ 88,897.46	0.25502	142,024,891	$ 67,166,027.24	0.47292
Mar	142,024,891	$ 67,166,027.24	0.47292	12,658,159	$ 5,455,394.54	3,460,810	$ 739,939.28	0.21381	132,827,542	$ 62,450,571.98	0.47016
Apr	132,827,542	$ 62,450,571.98	0.47016	23,051,846	$ 10,194,050.58	4,500,360	$ 869,525.78	0.19321	114,276,056	$ 53,126,047.18	0.46489
May	114,276,056	$ 53,126,047.18	0.46489	2,790,265	$ 1,071,649.57	3,842,187	$ 895,679.98	0.23312	115,327,978	$ 52,950,077.59	0.45913
Jun	115,327,978	$ 52,950,077.59	0.45913	2,209,903	$ 643,407.48	6,310,010	$ 1,367,411.71	0.21671	119,428,085	$ 53,674,081.82	0.44943
Jul	119,428,085	$ 53,674,081.82	0.44943	922,095	$ 285,082.42	7,056,836	$ 1,790,152.04	0.25368	125,562,826	$ 55,179,151.44	0.43945
Aug	125,562,826	$ 55,179,151.44	0.43945	289,508	$ 151,844.55	3,112,036	$ 792,432.45	0.25463	128,385,354	$ 55,819,739.34	0.43478
Sep	128,385,354	$ 55,819,739.34	0.43478	207,941	$ 113,206.61	10,098,405	$ 2,607,874.72	0.25825	138,275,818	$ 58,314,407.45	0.42173
Oct	138,275,818	$ 58,314,407.45	0.42173	5,444,783	$ 1,384,452.69	25,766,796	$ 8,855,633.86	0.34368	158,597,831	$ 65,785,588.62	0.41480
Nov	158,597,831	$ 65,785,588.62	0.41480	4,580,684	$ 1,750,833.09	2,489,966	$ 929,470.94	0.37329	156,507,113	$ 64,964,226.47	0.41509
Dec	156,507,113	$ 64,964,226.47	0.41509	8,384,530	$ 2,953,010.06	2,106,485	$ 850,861.58	0.40392	150,229,068	$ 62,862,077.99	0.41844
	TOTAL 2012 ACTIVITY			81,123,646	$ 31,859,704.92	71,372,071	$ 20,436,990.77				
Jan-13	150,229,068	$ 62,862,077.99	0.41844	14,677,497	$ 5,405,016.60	5,093,510	$ 1,831,966.73	0.35967	140,645,081	$ 59,289,028.12	0.42155
Feb	140,645,081	$ 59,289,028.12	0.42155	13,800,354	$ 5,335,663.36	1,262,630	$ 409,713.41	0.32449	128,107,357	$ 54,363,078.17	0.42436
Mar	128,107,357	$ 54,363,078.17	0.42436	3,567,521	$ 1,115,677.83	5,501,939	$ 1,964,738.34	0.35710	130,041,775	$ 55,212,138.68	0.42457
Apr	130,041,775	$ 55,212,138.68	0.42457	21,459,008	$ 8,365,699.38	4,538,540	$ 1,807,682.82	0.39830	113,121,307	$ 48,654,122.12	0.43011
May	113,121,307	$ 48,654,122.12	0.43011	4,818,397	$ 1,845,435.83	8,574,316	$ 2,707,134.37	0.31573	116,877,226	$ 49,515,820.66	0.42366
Jun	116,877,226	$ 49,515,820.66	0.42366	175,511	$ 91,369.64	8,915,841	$ 3,055,934.87	0.34275	125,524,403	$ 52,469,340.89	0.41800
Jul	125,524,403	$ 52,469,340.89	0.41800	565,039	$ 240,884.14	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
	TOTAL 2014 ACTIVITY			67,376,494	$ 26,936,446.94	47,689,526	$ 22,634,575.46				

Northwest Natural Gas Company
PGA Portfolio Guidelines
2014-2015 Oregon PGA

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

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

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

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

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

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

Withdrawals at each facility (Mist, Gasco, etc.) are priced at the average inventory price as established at the beginning of each month. The beginning of the month cost at each facility is adjusted for any withdrawals and any injections (priced as per tab #29) to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

NW Natural

PGA Portfolio Guidelines
2014-2015 Oregon PGA

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

See Attachments to this Exhibit C. titled: "V.7.g. Contracts and Agreements.pdf"; "V.7.g. Svc Agreement NW Pipeline Rate Sch SGS-2F.pdf"; and "V.7.g. Svc Agreement NW Pipeline Rate Sch LS-1.pdf"

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 tc the maximum rate as it may change from time to time;

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

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

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

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

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

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

3. MONTHLY RATE (Continued)

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

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

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

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

4. MINIMUM MONTHLY BILL

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

5. FUEL GAS REIMBURSEMENT

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

6. CONTRACT DEMAND

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

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.

SERVICE AGREEMENT
(Liquefaction - Storage Gas Service under Rate Schedule LS-1)

THIS AGREEMENT, made and entered into this 12th day of January 12, 1994, by and between NORTHWEST PIPELINE CORPORATION, a Delaware corporation, hereinafter called "Transporter", and NORTHWEST NATURAL GAS COMPANY, hereinafter called "Shipper".

In consideration of the mutual covenants and agreements as herein set forth, the parties hereto agree as follows:

ARTICLE I - GAS TO BE STORED AND DELIVERED

Subject to the terms, conditions, and limitations hereof and of the applicable Rate Schedule LS-1, Transporter agrees to liquefy, store in liquid phase, vaporize and deliver to Shipper for transportation, and Shipper agrees to receive from Transporter, up to the following quantities of natural gas:

A Storage Demand Volume of 60,100 MMBtus,
A Storage Capacity of 478,900 MMBtus.

ARTICLE II - DELIVERY OF GAS

Delivery of natural gas by Transporter to Shipper for transportation shall be at or near the point of vaporization at Transporter's LNG facilities. Shipper shall arrange for redelivery transportation to mainline delivery points under Transporter's transportation rate schedules.

ARTICLE III - APPLICABLE RATE SCHEDULE

Shipper agrees to pay Transporter for all natural gas service rendered under the terms of this Agreement in accordance with Transporter's Rate Schedule LS-1 as filed with the Federal Energy Regulatory Commission ("FERC"), and as such rate schedule may be amended or superseded from time to time. This Agreement shall be subject to the provisions of such rate schedule and the General Terms and Conditions applicable thereto on file with the FERC and effective from time to time, which by this reference are incorporated herein and made a part hereof.

ARTICLE IV - TERM OF AGREEMENT

This Agreement shall become effective on the date so designated by the FERC and shall continue in effect for a period continuing through October 31, 2004 and year to year thereafter at Shipper's sole option. Shipper may terminate all or any portion of service under this Agreement either at the expiration of the primary term, or upon any anniversary thereafter by giving at least twelve (12) months in advance. Shipper also shall have the sole option to enter into a new agreement for all or any portion of the service under this Agreement at or after the end of the primary term of this Agreement. It is Transporter's and Shipper's intent that this term provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR § 284.221 (d)(2)(i) as promulgated by Order 636 on May 8, 1992.)

ARTICLE V - CANCELLATION OF PRIOR AGREEMENTS

When this Agreement takes effect, it supersedes, cancels and terminates the following agreements:

Service Agreement (Liquefaction-Storage Gas Service) dated October 1, 1992 between Northwest Pipeline Corporation, "Seller" and Northwest Natural Gas Company, "Buyer".

ARTICLE VI - SUCCESSORS AND ASSIGNS

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above set forth.

"TRANSPORTER"
NORTHWEST PIPELINE CORPORATION

By: Joe H. Fields
Joe H. Fields
Attorney-In-Fact

1/12/94
FES

ATTEST:

By: ______________________

"SHIPPER"
NORTHWEST NATURAL GAS COMPANY

LEGAL DEPARTME
Approved As To For
This Date 1/18/
By SEP

By: Dwayne L. Foley
Name: Dwayne L. Foley
Title: Sr. Vice President

TF0370 000004P126Original Sheet No. 70
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service

1. AVAILABILITY

This Rate Schedule is available only to those existing Shippers who (i) have contracted for Rate Schedule LS-1 liquefaction-storage service and have received authorization under Section 7(c) of the Natural Gas Act for the purchase of such service from Transporter when Shipper and Transporter have executed Service Agreements for service under this Rate Schedule, and (ii) have arranged for the related transportation of gas to and from the Plymouth LNG Facility under one o Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

This Rate Schedule shall apply to the liquefaction-storage gas service rendered by Transporter to Shipper under the executed Service Agreement for such service.

Service under this Rate Schedule shall consist of the liquefactic and storage by Transporter for Shipper's account of gas transported to the LNG facility under a separate executed Service Agreement pursuant t Rate Schedules TF-1 or TI-1, the vaporization of such stored gas, and delivery to Shipper for transportation under a separate executed Servic Agreement pursuant to Rate Schedules TF-1, TF-2 or TI-1. Delivery of natural gas by Shipper to Transporter for liquefaction and by Transporter to Shipper upon vaporization shall be at the point of interconnection between Transporter's Plymouth LNG Facility and Transporter's main transmission line.

Service rendered to Shipper under this Rate Schedule, within the limitations described in the Service Agreement and in Sections 7 and 8 of this Rate Schedule, 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.

TF0371 010004P126First Revised Sheet No. 71
TF04 Original Sheet No. 71
TF05Laren M. Gertsch, Director
TF06040708 050808
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

3. RATE

Shipper shall pay Transporter each month for service rendered hereunder, the sum of the following amounts:

(a) Demand Charge: The sum of the daily product of Shipper's Storage Demand and the Demand Charge.

(b) Capacity Charge: The sum of the daily product of Shipper's Storage Capacity and the Capacity Charge.

(c) Liquefaction Charge: Per Dth of gas liquefied and stored for Shipper's account during the month.

(d) Vaporization Charge: Per Dth of gas vaporized and schedule for delivery to Shipper during the month.

The unit rates shall be those as set forth from time to time in the currently effective Sheet No. 8 of this Tariff.

The related transportation of gas to and from the Plymouth LNG storage facility shall be subject to separate transportation charges under applicable Rate Schedules. The rates set forth above in subparagraphs (a) through (d) are exclusive of the aforementioned charges.

4. MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall consist of the sum of the Demand Charge and the Capacity Charge specified in Section 3 of this Rate Schedule.

TF0372 000004P126Original Sheet No. 72
TF04
TF05Laren M. Gertsch, Director
TF06121907021897RP97-180 013108
TF077861157

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

5. FUEL GAS REIMBURSEMENT

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

6. DEFINITIONS

6.1 Storage Demand Volume. The Storage Demand Volume shall be the largest number of Dth Transporter is obligated to vaporize for, and Shipper is entitled to receive from, Transporter's liquefied natural ga storage plant under this Rate Schedule on any one day, subject to the limitations described in Section 8 of this Rate Schedule, and shall be specified in the executed Service Agreement between Transporter and Shipper.

6.2 Storage Capacity Volume. The Storage Capacity Volume shall be th maximum quantity of gas in Dth which Transporter is obligated to liquef and store in liquid form for Shipper's account and shall be specified i the executed Service Agreement between Transporter and Shipper.

6.3 Liquefaction Period. The Liquefaction Period shall be the seven consecutive months beginning on April 1 of any year and extending through the next succeeding October 31.

6.4 Vaporization Period. The Vaporization Period shall be the five consecutive months beginning on November 1 of any year and extending through the next succeeding March 31.

6.5 Storage Capacity Balance. Shipper's Storage Capacity Balance at any particular time shall be the quantity of gas in storage in liquid form for Shipper at such time.

TF0373 000004P126Original Sheet No. 73
TF04
TF05Laren M. Gertsch, Director
TF06121907021897RP97-180 013108
TF077861157

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

6. DEFINITIONS (Continued)

6.6 Nominated Storage Volume. Shipper's Nominated Storage Volume shall be the quantity of gas in Dth, up to Shipper's Storage Capacity Volume, which Shipper nominates to have liquefied and stored in liquid form by Transporter for Shipper's account and shall be provided to Transporter in writing on or before April 1 of each year. In the event that Shipper does not submit a storage volume nomination by April 1, Shipper's Nominated Storage Volume for the Liquefaction Period shall be Shipper's Storage Capacity Volume. Shipper upon ten (10) days written notice to Transporter may elect to change its Nominated Storage Volume during the liquefaction period. Such change shall not reduce the Nominated Storage Volume below Shipper's Storage Capacity Balance at th time of election.

7. LIQUEFACTION INTO STORAGE FOR SHIPPER'S ACCOUNT

During a liquefaction period, Shipper is entitled to tender to Transporter for liquefaction and storage sufficient quantities of gas t fill Shipper's Storage Capacity Volume. Such tenders shall commence on April 1 and shall consist of uniform daily quantities equal to 1/200th of Shipper's Nominated Storage Volume (except for the last day of liquefaction) until Shipper's Storage Capacity Balance is equal to Shipper's Nominated Storage Volume. In addition, Transporter may schedule the liquefaction period and rate of liquefaction to fit system operating conditions.

Transporter shall not be obligated to liquefy and store gas for Shipper in excess of Shipper's Storage Capacity Volume.

The tender by Shipper to Transporter shall be made by Shipper scheduling such tendered volumes on any day as transportation volumes delivered under an executed Service Agreement for liquefaction and storage.

Upon request of Shipper, Transporter may permit Shipper to nominate gas for liquefaction and storage during a Vaporization Period in replacement of gas vaporized during such Vaporization Period; provided, however, the liquefaction of such gas shall be at such times as may be agreed upon between Transporter and Shipper. Where necessary daily liquefaction capacity of Transporter shall be prorated among Shippers in proportion to the storage capacity volumes of Shippers desiring such liquefaction on such day.

TF0374 000004P126Original Sheet No. 74
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

8. VAPORIZATION FROM STORAGE AND DELIVERY TO SHIPPER

8.1 General Procedure. When Shipper desires the vaporization of gas on any day during the Vaporization Period, it shall give notice to Transporter's dispatcher, specifying the volume of gas it desires vaporized under this Rate Schedule during such day. Transporter shall vaporize and deliver for transportation the volume of gas so nominated out of Shipper's Storage Capacity Balance, subject to the limitations set forth in this Rate Schedule.

8.2 Notice Required. The notice given by Shipper to Transporter for vaporization on any day shall be prior to the commencement of such day; provided, however, that commencement of actual delivery for transportation shall be determined by system operating conditions. Shipper may request a change in the daily quantity scheduled for vaporization during the Intraday 1 and Intraday 2 Nomination Cycles pursuant to Section 14.1 of the General Terms and Conditions. In addition, and to the extent existing transportation and storage obligations are not compromised, Shipper may request up to two additional changes in the daily quantity scheduled for vaporization following the Intraday 2 Nomination Cycle for the remainder of the Gas Day, provided such change does not reduce the volume below any volume already taken during that day and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

8.3 Daily Vaporization in Excess of Shipper's Storage Demand Volume. Transporter may, upon request of Shipper, schedule for delivery for transportation on any day a volume of gas in excess of Shipper's Storag Demand Volume if in Transporter's judgment it can do so without adversely affecting its operations or curtailing other services.

8.4 Vaporization During a Liquefaction Period. Upon request of Shipper, Transporter may permit Shipper to nominate gas out of Shipper' Storage Capacity Balance for vaporization and delivery for transportation to Shipper on any day during the liquefaction period. However, such vaporization and delivery shall not adversely affect Transporter's operations or that of Transporter's other Shippers.

TF0375 000004P126Original Sheet No. 75
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

9. EVERGREEN PROVISION

9.1 Grandfathered Unilateral Evergreen Provision. For Service Agreements under this Rate Schedule, the following grandfathered unilateral evergreen conditions will apply:

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

(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 8.1(b) will be deemed given when posted on Transporter's Designated Site.

10. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, except Sections 13, 16, 17, 18, 21, 22, 23, 25, 27 and 28 and except as modified in the executed Service Agreement, are applicable to this Rate Schedule and are hereby made a part hereof.

SERVICE AGREEMENT
(Liquefaction - Storage Gas Service under Rate Schedule LS-1)

THIS AGREEMENT, made and entered into this 12th day of January 12, 1994, by and between NORTHWEST PIPELINE CORPORATION, a Delaware corporation, hereinafter called "Transporter", and NORTHWEST NATURAL GAS COMPANY, hereinafter called "Shipper".

In consideration of the mutual covenants and agreements as herein set forth, the parties hereto agree as follows:

ARTICLE I - GAS TO BE STORED AND DELIVERED

Subject to the terms, conditions, and limitations hereof and of the applicable Rate Schedule LS-1, Transporter agrees to liquefy, store in liquid phase, vaporize and deliver to Shipper for transportation, and Shipper agrees to receive from Transporter, up to the following quantities of natural gas:

A Storage Demand Volume of 60,100 MMBtus,
A Storage Capacity of 478,900 MMBtus.

ARTICLE II - DELIVERY OF GAS

Delivery of natural gas by Transporter to Shipper for transportation shall be at or near the point of vaporization at Transporter's LNG facilities. Shipper shall arrange for redelivery transportation to mainline delivery points under Transporter's transportation rate schedules.

ARTICLE III - APPLICABLE RATE SCHEDULE

Shipper agrees to pay Transporter for all natural gas service rendered under the terms of this Agreement in accordance with Transporter's Rate Schedule LS-1 as filed with the Federal Energy Regulatory Commission ("FERC"), and as such rate schedule may be amended or superseded from time to time. This Agreement shall be subject to the provisions of such rate schedule and the General Terms and Conditions applicable thereto on file with the FERC and effective from time to time, which by this reference are incorporated herein and made a part hereof.

ARTICLE IV - TERM OF AGREEMENT

This Agreement shall become effective on the date so designated by the FERC and shall continue in effect for a period continuing through October 31, 2004 and year to year thereafter at Shipper's sole option. Shipper may terminate all or any portion of service under this Agreement either at the expiration of the primary term, or upon any anniversary thereafter by giving at least twelve (12) months in advance. Shipper also shall have the sole option to enter into a new agreement for all or any portion of the service under this Agreement at or after the end of the primary term of this Agreement. It is Transporter's and Shipper's intent that this term provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR § 284.221 (d)(2)(i) as promulgated by Order 636 on May 8, 1992.)

ARTICLE V - CANCELLATION OF PRIOR AGREEMENTS

When this Agreement takes effect, it supersedes, cancels and terminates the following agreements:

Service Agreement (Liquefaction-Storage Gas Service) dated October 1, 1992 between Northwest Pipeline Corporation, "Seller" and Northwest Natural Gas Company, "Buyer".

ARTICLE VI - SUCCESSORS AND ASSIGNS

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above set forth.

"TRANSPORTER"
NORTHWEST PIPELINE CORPORATION

By: [signature]
Joe H. Fields
Attorney-In-Fact

1/12/93
PES

ATTEST:

By: ______________________

"SHIPPER"
NORTHWEST NATURAL GAS COMPANY

LEGAL DEPARTME
Approved As To For
This Date 1/18/
By SEF

By: [signature]
Name: Dwayne L. Foley
Title: Sr. Vice President

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service

1. AVAILABILITY

This Rate Schedule is available only to those existing Shippers who (i) have contracted for Rate Schedule LS-1 liquefaction-storage service and have received authorization under Section 7(c) of the Natural Gas Act for the purchase of such service from Transporter when Shipper and Transporter have executed Service Agreements for service under this Rate Schedule, and (ii) have arranged for the related transportation of gas to and from the Plymouth LNG Facility under one of Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability. This Rate Schedule shall apply to the liquefaction-storage gas service rendered by Transporter to Shipper under the Service Agreement for such service.

2.2 Service Components. Service under this Rate Schedule shall consist of the liquefaction and storage by Transporter for Shipper's account of gas transported to the Plymouth LNG Facility under a separate Service Agreement, the vaporization of such stored gas, and delivery to Shipper for transportation under a separate Service Agreement . Delivery of natural gas by Shipper to Transporter for liquefaction and by Transporter to Shipper upon vaporization shall be at the point of interconnection between Transporter's Plymouth LNG Facility and Transporter's main transmission line.

2.3 Character of Service. Storage service rendered to Shipper under this Rate Schedule, within the limitations described in the Service Agreement and this Rate Schedule, shall be firm and shall not be subject to curtailment or interruption except as expressly provided in the General Terms and Conditions.

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

3. RATE

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

3.1 Storage Service. The sum of (a) through (d) below:

(a) The demand charge will be the sum of the daily product of Shipper's Storage Demand and the Demand Charge rate.

(b) The capacity demand charge will be the sum of the daily product of Shipper's Storage Capacity and the Capacity Demand Charge rate.

(c) The liquefaction charge will be the sum of the daily product of Shipper's gas per Dth scheduled for liquefaction into Shipper's storage account (except as provided in Section 9 of this Rate Schedule) and the Liquefaction rate.

(d) The vaporization charge will be the sum of the daily product of Shipper's gas per Dth scheduled for vaporization and the Vaporization rate.

The unit rates that are applicable to this Rate Schedule shall be those as set forth from time to time in the Statement of Rates of this Tariff.

The related transportation of gas to and from the Plymouth LNG Facility shall be subject to separate transportation charges under applicable Rate Schedules. The rates set forth above in subparagraphs (a) through (d) are exclusive of the aforementioned charges.

4. MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall consist of the sum of the demand charge and the capacity demand charge specified in Section 3 of this Rate Schedule.

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

5. FUEL GAS REIMBURSEMENT

5.1 Fuel Gas Reimbursement. Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions upon liquefaction and vaporization of Shipper's gas.

5.2 Vaporization Fuel. Shipper's fuel reimbursement quantities for vaporization will not be supplied from Shipper's gas nominated for vaporization, but instead will be supplied from Shipper's Boil-off balance. Any amount of Shipper's fuel reimbursement quantities for vaporization that would reduce Shipper's Boil-off balance below zero will be reimbursed to Transporter in-kind within 30 days of Shipper's vaporization nomination, unless other arrangements are made between Transporter and Shipper.

6. DEFINITIONS

6.1 Storage Demand. The Storage Demand shall be the largest number of Dth Transporter is obligated to vaporize for and Shipper is entitled to receive from the Plymouth LNG Facility under this Rate Schedule on any one day, subject to the limitations described in Section 8 of this Rate Schedule, and shall be specified in the Service Agreement between Transporter and Shipper.

6.2 Storage Capacity. The Storage Capacity shall be the maximum quantity of gas in Dth which Transporter is obligated to liquefy and store in liquid form for Shipper's account and shall be specified in the Service Agreement between Transporter and Shipper.

6.3 Liquefaction Period. The Liquefaction Period shall be the seven consecutive months beginning on April 1 of any year and extending through the next succeeding October 31.

6.4 Vaporization Period. The Vaporization Period shall be the five consecutive months beginning on November 1 of any year and extending through the next succeeding March 31.

6.5 Storage Capacity Balance. Shipper's Storage Capacity Balance at any particular time shall be the quantity of gas in storage in liquid form for Shipper at such time.

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service (Continued)

6. DEFINITIONS (Continued)

6.6 Annual Liquefaction Quantity. Shipper's Annual Liquefaction Quantity shall be the quantity of gas in Dth, up to Shipper's Storage Capacity, which Shipper desires to have liquefied and stored in liquid form by Transporter for Shipper's account during the Liquefaction Period, and shall be provided to Transporter in writing on or before April 1 of each year. In the event that Shipper does not submit an Annual Liquefaction Quantity by April 1, Shipper's Annual Liquefaction Quantity for the Liquefaction Period shall be the quantity difference between Shipper's Storage Capacity and Shipper's Storage Capacity Balance on April 1. Shipper upon 10 days written notice to Transporter may elect to change its Annual Liquefaction Quantity during the Liquefaction Period. Such change shall not reduce the Annual Liquefaction Quantity below Shipper's pro rata share of gas that has been liquefied at the time of the election change. A Shipper's pro rata share will be derived by multiplying (a) the quantity of gas liquefied to date to meet the Annual Liquefaction Quantities of all LS-1, LS-2F, and LS-2I Shippers by (b) the ratio of the Shipper's Annual Liquefaction Quantity to the total Annual Liquefaction Quantities for LS-1, LS-2F, and LS-2I Shippers prior to the election change.

7. LIQUEFACTION INTO STORAGE FOR SHIPPER'S ACCOUNT

During a Liquefaction Period, Shipper shall nominate for liquefaction and storage sufficient quantities of gas to fill Shipper's Annual Liquefaction Quantity. Such nominations shall commence on April 1 and shall consist of uniform daily quantities equal to 1/200th of Shipper's Annual Liquefaction Quantity (except for the last day of liquefaction) unless a different nomination pattern is operationally feasible and mutually agreed upon by Transporter and Shipper. In addition, Transporter may schedule the Liquefaction Period and rate of liquefaction to fit system operating conditions.

Transporter shall not be obligated to liquefy and store gas for Shipper in excess of Shipper's Storage Capacity.

The tender by Shipper to Transporter shall be made by Shipper scheduling such tendered volumes on any day as transportation volumes delivered under a Service Agreement for liquefaction and storage.

If posted as available, Shipper may nominate gas for liquefaction and storage during a Vaporization Period in replacement of gas vaporized during such Vaporization Period; provided, however, the liquefaction of such gas shall be at such times as may be agreed upon between Transporter and Shipper. Such liquefaction will be in accordance with the priority of service and curtailment policy delineated in Section 12 of the General Terms and Conditions.

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

8. VAPORIZATION FROM STORAGE AND DELIVERY TO SHIPPER

8.1 General Procedure. When Shipper desires the vaporization of gas on any day during the Vaporization Period, it shall submit a nomination to Transporter, specifying the volume of gas it desires vaporized under this Rate Schedule during such day. Transporter shall vaporize and deliver for transportation the volume of gas so nominated out of Shipper's Storage Capacity Balance, subject to the limitations set forth in this Rate Schedule.

8.2 Daily Vaporization in Excess of Shipper's Storage Demand. Shipper may submit a nomination for quantities in excess of Shipper's Storage Demand specified in the Service Agreement under this Rate Schedule and Transporter will schedule such excess in accordance with the priority of service and curtailing policy delineated in Section 12 of the General Terms and Conditions.

8.3 Vaporization During a Liquefaction Period. If posted as available, Shipper may nominate gas out of Shipper's Storage Capacity Balance for vaporization and for transportation to Shipper on any day during the Liquefaction Period. However, such vaporization and delivery will be in accordance with the priority of service and curtailment policy delineated in Section 12 of the General Terms and Conditions.

9. LNG BOIL-OFF

9.1 Calculation of LNG Boil-off. Shipper will be allocated a pro rata share of monthly LNG Boil-off quantities of gas in Dths by multiplying the monthly Boil-off quantity by the quotient of the Shipper's average daily Storage Capacity Balance for the month and the sum of the average daily Storage Capacity Balances for the month of all Shippers' Service Agreements under Rate Schedules LS-1, LS-2F and LS-2I.

9.2 LNG Boil-off Balance. Shipper's allocated share of monthly LNG Boil-off will be subtracted from Shipper's Storage Capacity Balance no later than the 15th of the following month and will be added to Shipper's Boil-off balance due from Transporter. This Boil-off balance will be deemed to be at the Plymouth LNG Facility. Shipper may either choose to nominate the Boil-off balance for re-liquefaction or transport the Boil-off balance from the Plymouth LNG Facility under one of Transporter's transportation rate schedules. Nominations for the re-liquefaction of Boil-off will be subject to fuel use reimbursement. Such nominations will not be subject to the liquefaction charge so long as the settlement approved in Docket No. RP12-490 remains in effect.

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

9. LNG BOIL-OFF (Continued)

9.3 LNG Boil-off Balance Tolerance. The sum of Shipper's Storage Capacity Balance and Shipper's Boil-off balance cannot exceed Shipper's Storage Capacity. Additional tolerances regarding the Boil-off balance are detailed in Section 15 of the General Terms and Conditions.

10. EVERGREEN PROVISION

10.1 Grandfathered Unilateral Evergreen Provision. For Service Agreements under this Rate Schedule, the following grandfathered unilateral evergreen conditions will apply:

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

(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 its Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent that this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent 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 10.1(b) will be deemed given when posted on Transporter's Designated Site.

11. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, are applicable to this Rate Schedule and are hereby made a part hereof.

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

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

WHEREAS:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Name: RANDOLPH S. FRIEDMAN	Name: JANE F HARRISON
Title: DIRECTOR, GAS SUPPLY	Title: MANAGER NWP MARKETING SERVICES

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

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

SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper

2. Contract Demand: 46,030 Dth per day

3. Storage Capacity: 1,120,288 Dth

4. Recourse or Discounted Recourse Storage Rates:

   (Show Not Applicable if Exhibit D is attached.)

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

      Maximum Currently Effective Tariff Rate

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

      Maximum Currently Effective Tariff Rate

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

      Not Applicable

5. Service Term:

   a. Primary Term Begin Date:

      November 01, 1998

   b. Primary Term End Date:

      October 31, 2004

   c. Evergreen Provision:

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

6. Regulatory Authorization: 18 CFR 284.223

7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

TF0350 000004P126Original Sheet No. 50
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

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

2. APPLICABILITY AND CHARACTER OF SERVICE

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

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

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

3. MONTHLY RATE

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

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

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

3. MONTHLY RATE (Continued)

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

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

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

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

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

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

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

3. MONTHLY RATE (Continued)

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

(a) the lesser of the awarded bid rate and the new maximum base tariff rate, or the greater of the awarded bid rate and the new minimum base tariff rate, as applicable, for the remaining term of the release for capacity release transactions with a term of more than one year and where the awarded bid rate was not tied 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
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

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

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

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

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

14. TRANSFER OF WORKING GAS INVENTORY

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

TF0356 000004P126Original Sheet No. 56
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

14. TRANSFER OF WORKING GAS INVENTORY (Continued)

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

15. EVERGREEN PROVISION

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

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

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

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

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

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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.

Northwest Natural Gas Company
PGA Portfolio Guidelines
2014-2015 Oregon PGA

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

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

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

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

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