Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

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IDAHO PUBLIC
UTILITIES COMMISSION

AVISTA Corp.

August 30, 2017

State of Idaho
Idaho Public Utilities Commission
472 W. Washington Street
Boise, Idaho 83702-5983

Case No. AVU-G-17-0 4 /Advice No. 17-03-G

Attention: Ms. Diane Hanian

I.P.U.C. No. 27 – Natural Gas Service

Enclosed for electric filing with the Commission are the following revised tariff sheets:

Twenty-Fourth Revision Sheet 150	canceling	**Twenty-Third Revision Sheet 150**
Nineteenth Revision Sheet 155	canceling	**Eighteenth Revision Sheet 155**

The Company requests that the proposed tariff sheets be made effective November 1, 2017.

These tariff sheets reflect the Company's annual Purchased Gas Cost Adjustment ("PGA"). If approved, the Company's annual revenue will *decrease* by approximately $1.7 million or approximately 2.7%. The proposed changes have no effect on the Company's earnings. Detailed information related to the Company's request is included in the attached Application and supporting workpapers.

If the Company's request is approved, a residential or small commercial customer using an average of 61 therms per month will see *decrease* of $1.23 per month, or approximately 2.4%. The present bill for 61 therms is $51.10 while the proposed bill is $49.87. The Company will issue a notice to its customers through a bill insert in the September 2017 to October 2017 timeframe. A copy of the bill insert has been included in the Company's filing.

If you have any questions regarding this filing, please contact Patrick Ehrbar at (509) 495-8620 or Annette Brandon at (509) 495-4324.

Sincerely,

Patrick Ehrbar for

David J. Meyer
Vice President and Chief Counsel for Regulatory and Governmental Affairs

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have served Avista Corporation dba Avista Utilities' Advice filing ADV 17-03-G (Tariff IPUC No. 27 Natural Gas Service) by mailing a copy thereof, postage prepaid to the following:

Diane Hanian, Secretary
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 83720-5983

Edward A. Finklea
Northwest Industrial Gas Users
545 Grandview Drive
Ashland, OR 97520

Chad Stokes
Cable Huston Benedict Haagensen &
Lloyd, LLP
1001 SW 5th, Suite 2000
Portland, OR 97204-1136

Curt Hibbard
St. Joseph Regional Medical Center
PO Box 816
Lewiston, ID 83501

Dated at Spokane, Washington this 30th day of August 2017.

Patrick Ehrbar
Senior Manager, State & Federal Regulation

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
AVISTA UTILITIES FOR AN ORDER APPROVING	)	CASE: AVU-G-17-04
A CHANGE IN NATURAL GAS RATES AND CHARGES	)	

Application is hereby made to the Idaho Public Utilities Commission for an Order approving a revised schedule of rates and charges for natural gas service in the state of Idaho. The Applicant requests that the proposed rates included in this Purchased Gas Cost Adjustment ("PGA") filing be made effective on November 1, 2017. If approved as filed, the Company's annual revenue will decrease by approximately $1.7 million or about 2.7%. In support of this Application, Applicant states as follows:

I.

The name of the Applicant is AVISTA CORPORATION, doing business as AVISTA UTILITIES (hereinafter Avista, Applicant or Company), a Washington corporation, whose principal business office is 1411 East Mission Avenue, Spokane, Washington, and is qualified to do business in the state of Idaho. Applicant maintains district offices in Moscow, Lewiston, Coeur d'Alene, and Kellogg, Idaho. Communications in reference to this Application should be addressed to:

Patrick D. Ehrbar
Senior Manager, Rates and Tariffs
Avista Utilities
1411 E. Mission Avenue
Spokane, WA 99220-3727
Phone: (509) 495-8620
Fax: (509) 495-8851
Pat.ehrbar@avistacorp.com

II.

Attorney for the Applicant and his address is as follows:

David J. Meyer
Vice President and Chief Counsel for Regulatory
And Governmental Affairs
Avista Utilities
1411 E. Mission Avenue
Spokane, WA 99220-3727
Phone: (509) 495-4316
Fax: (509) 495-8851
David.meyer@avistacorp.com

III.

The Applicant is a public utility engaged in the distribution of natural gas in certain portions of Northern Idaho, Eastern and Central Washington, and Southwestern and Northeastern Oregon, and further engaged in the generation, transmission, and distribution of electricity in Northern Idaho and Eastern Washington.

IV.

Twenty-Fourth Revision Sheet 150, which Applicant requests the Commission approve, is filed herewith as Exhibit "A". Additionally, Nineteenth Revision Sheet 155, which Applicant requests the Commission approve, is also filed herewith as Exhibit "A". Also included in Exhibit "A" is a copy of Twenty-Third Revision Sheet 150 and Eighteenth Revision Tariff Sheet 155 with the changes underlined and a copy of Twenty-Third Revision Sheet 150 and Eighteenth Revision Tariff Sheet 155 with the proposed changes shown by lining over the current language or rates.

V.

The existing rates and charges for natural gas service on file with the Commission and designated as Applicant's Tariff IPUC No. 27, which will be superseded by the rates and charges filed herewith, are incorporated herein as though fully attached hereto.

VI.

Notice to the Public of Applicant's proposed tariffs is to be given simultaneously with the filing of this Application by posting, at each of the Company's district offices in Idaho, a Notice in the form attached hereto as Exhibit "B" and by means of a press release distributed to various informational agencies, a draft copy attached hereto in Exhibit "E". In addition, Exhibit "E" to this Application also contains the form of customer notice that the Company will send to its customers in its monthly bills in the September – October timeframe.

VII.

The circumstances and conditions relied on for approval of Applicant's revised rates are as follows: Applicant purchases natural gas for customer usage and transports it over Williams Northwest Pipeline, Gas Transmission Northwest (GTN), TransCanada - Alberta, TransCanada - BC and Spectra Energy Pipeline systems, and defers the effect of timing differences due to implementation of rate changes and differences between Applicant's actual weighted average cost of gas ("WACOG") purchased and the WACOG embedded in rates. Applicant also defers various pipeline refunds or charges and miscellaneous revenue received from natural gas related transactions including pipeline capacity releases.

VIII.

This filing reflects the Company's proposed annual PGA to: 1) pass through changes in the estimated cost of natural gas for the November 2017 through October 2018 twelve-month period (Schedule 150), and 2) revise the amortization rate(s) to refund or collect the balance of deferred gas costs (Schedule 155). Below is a table summarizing the proposed changes reflected in this filing.[1]

Service	Sch. No.	Commodity Change per therm	Demand Change per therm	Total Sch. 150 Change	Amortization Change per therm	Total Rate Change per therm	**Overall Percent Change**
General	101	$ (0.02167)	$ (0.00831)	$ (0.02998)	$ 0.00982	$ (0.02016)	**-2.5%**
Lg. General	111	$ (0.02167)	$ (0.00831)	$ (0.02998)	$ 0.00982	$ (0.02016)	**-3.8%**

IX.

Commodity Costs

As shown in the table above, the estimated WACOG change is a *decrease* of 2.2 cents per therm. The proposed WACOG, including the revenue conversion factor, is 21.9 cents per therm compared to the present WACOG of 24.1 cents per therm included in rates. The overall reduction in the WACOG is generally the result of the continued high natural gas production levels and an abundance of nature gas in storage.

The Company's natural gas Procurement Plan ("Plan") uses a diversified approach to procure natural gas for the coming PGA year. While the Plan generally incorporates a more structured approach for the hedging portion of the portfolio, the Company exercises flexibility and discretion in all areas of the plan based on changes in the wholesale market. The Company typically meets with Commission Staff semi-annually to discuss the state of the wholesale market and the status of the Company's Plan. In addition, the Company communicates with Staff when it believes it makes sense to deviate from its Plan and/or opportunities arise in the market.

Avista has been hedging natural gas on both a periodic and discretionary basis throughout 2016-2017 for the forthcoming PGA year (twelve months). Approximately 32% of estimated annual load requirements for the PGA year (November 2017 through October 2018) will be hedged at a fixed-price derived from the Company's Plan. These volumes are comprised of: 1) volumes hedged for a term of one year or less, and 2) volumes from prior multi-year hedges. Through July, the hedge volumes for the PGA year have been executed at a weighted average price of $2.62 per dekatherm ($0.26 per therm). Ultimately, approximately 46% of the estimated load requirements for the PGA year will be hedged with fixed priced natural gas purchases. These additional hedges will be executed throughout the PGA year according to the guidelines within the Company's Plan.

The Company used a 30-day historical average of forward prices and supply basins (ending July 31, 2017) to develop an estimated cost associated with index purchases. The estimated monthly volumes to be purchased by basin are multiplied by the 30-day average forward price for the corresponding month and basin. These index purchases represent approximately 68% of estimated annual load requirements

[1] The overall percentage change for all schedules is a decrease of 2.7%. Customers on Schedules 112 and 132 receive either a one-time rebate or surcharge rather than participate in the Schedule 155 amortization. The amount rebated to customers on these schedules totaled $81,394 for an overall proposed revenue decrease of $1,737,062. The overall present billed revenue excluding customers on 112 and 132 is $61,257,000 making the percentage decrease 2.7% (-$1,655,671 / 61,257,000 = -2.7%).

for the coming year. The annual weighted average price for these volumes is $2.14 per dekatherm ($0.21 per therm).

X.

Demand Costs

Demand costs reflect the cost of pipeline transportation to the Company's system, as well as fixed costs associated with natural gas storage. As shown in the table above, demand costs are expected to decrease for residential customers by approximately $0.00831 per therm. This reduction is primarily due to new transportation rates for Williams Northwest Pipeline effective both on January 1, 2018 and October 1, 2018.[2]

XI.

Schedule 155 / Amortization Rate Change

As shown in the table above, the proposed amortization rate change for Schedule 101 and Schedule 111 is a decrease of $0.00982 per therm. The current rate applicable to Schedule 101 and Schedule 111 is $0.09844 per therm in the rebate direction; the proposed rate is $0.08862 per therm also in the rebate direction. The Company was able to replace most of the present rebate due, in part, to a combination of lower actual natural gas prices versus the embedded WACOG, as well as through optimization efforts (both storage as well as fixed transportation contract)

XII.

If approved as filed, the Company's annual revenue will *decrease* by approximately $1.7 million or about 2.7% effective November 1, 2017. Residential or small commercial customers using an average of 61 therms per month would see a *decrease* of $1.23 per month, or approximately 2.4%. The present bill for 61 therms is $51.10 while the proposed bill is $49.87.

XIII.

Exhibit "C" attached hereto contains support workpapers for the rates proposed by Applicant contained in Exhibit "A".

XIV.

Avista requests that the rates proposed in this filing be approved to become effective on November 1, 2017, and requests that the matter be processed under the Commission's Modified Procedure rules through the use of written comments. Avista stands ready for immediate consideration on its Application.

---

[2] The Williams Northwest Pipeline Settlement agreement is pending approval before the Federal Energy Regulatory Commission (FERC).

XV.

WHEREFORE, Avista requests the Commission issue its Order finding its proposed rates to be just, reasonable, and nondiscriminatory and to become effective for all natural gas service on and after November 1, 2017.

Dated at Spokane, Washington, this 30th day of August 2017.

AVISTA UTILITIES
BY

David J. Meyer
Vice President and Chief Counsel for
Regulatory and Governmental Affairs

<u>VERIFICATION</u>

STATE OF WASHINGTON)
)
County of Spokane)

David J. Meyer, being first duly sworn on oath, deposes and says: That he is the Vice President and Chief Counsel for Regulatory and Governmental Affairs of Avista Utilities and makes this verification for and on behalf of Avista Corporation, being thereto duly authorized;

That he has read the foregoing filing, knows the contents thereof, and believes the same to be true.

____

SIGNED AND SWORN to before me this 30th day of August 2017, by David J. Meyer

PATTY L HANSON
Commission Expires
NOTARY
PUBLIC
11-23-2017
STATE OF WASHINGTON

Patty L. Hanson
NOTARY PUBLIC in and for the State of Washington, residing at Spokane.

Commission Expires: 11/23/2017

Idaho Public Utilities Commission
Office of the Secretary
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Boise, Idaho

AVISTA UTILITIES

Case No. AVU-G-17-04

EXHIBIT "A"

Proposed Tariff Sheets

August 30, 2017

SCHEDULE 150
PURCHASE GAS COST ADJUSTMENT - IDAHO

APPLICABLE:
To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:
To pass through changes in costs resulting from purchasing and transporting natural gas, to become effective as noted below.

RATE:

(a) The retail rates of firm gas Schedules 101, 111 and 112 are to be increased by 32.449¢ per therm in all blocks of these rate schedules.

(b) The rates of interruptible Schedules 131 and 132 are to be increased by 21.891¢ per therm.

(c) The rate for transportation under Schedule 146 is to be decreased by 0.000¢ per therm.

WEIGHTED AVERAGE GAS COST:
The above rate changes are based on the following weighted average cost of gas per therm as of the effective date shown below:

	Demand	Commodity	Total
Schedules 101	10.558¢	21.891¢	32.449¢
Schedules 111 and 112	10.558¢	21.891¢	32.449¢
Schedules 131 and 132	0.000¢	21.891¢	21.891¢

The above amounts include a gross revenue factor.

	Demand	Commodity	Total
Schedules 101	10.497¢	21.765¢	32.262¢
Schedules 111 and 112	10.497¢	21.765¢	32.262¢
Schedules 131 and 132	0.000¢	21.765¢	21.765¢

The above amounts do not include a gross revenue factor.

BALANCING ACCOUNT:
The Company will maintain a Purchase Gas Adjustment (PGA) Balancing Account whereby monthly entries into this Balancing Account will be made to reflect differences between the actual purchased gas costs collected from customers and the actual purchased gas costs incurred by the Company. Those differences are then collected from or refunded to customers under Schedule 155 – Gas Rate Adjustment.

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 150
PURCHASE GAS COST ADJUSTMENT - IDAHO

APPLICABLE:

To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:

To pass through changes in costs resulting from purchasing and transporting natural gas, to become effective as noted below.

RATE:

(a) The retail rates of firm gas Schedules 101, 111 and 112 are to be increased by ~~35.447¢~~ per therm in all blocks of these rate schedules.

(b) The rates of interruptible Schedules 131 and 132 are to be increased by ~~24.058¢~~ per therm.

(c) The rate for transportation under Schedule 146 is to be decreased by 0.000¢ per therm.

WEIGHTED AVERAGE GAS COST:

The above rate changes are based on the following weighted average cost of gas per therm as of the effective date shown below:

	Demand	Commodity	Total
Schedules 101	~~11.389¢~~	~~24.058¢~~	~~35.447¢~~
Schedules 111 and 112	~~11.389¢~~	~~24.058¢~~	~~35.447¢~~
Schedules 131 and 132	0.000¢	24.058¢	24.058¢

The above amounts include a gross revenue factor.

	Demand	Commodity	Total
Schedules 101	~~11.331¢~~	~~23.935¢~~	~~35.265¢~~
Schedules 111 and 112	~~11.331¢~~	~~23.935¢~~	~~35.265¢~~
Schedules 131 and 132	0.000¢	~~23.935¢~~	~~23.935¢~~

The above amounts do not include a gross revenue factor.

BALANCING ACCOUNT:

The Company will maintain a Purchase Gas Adjustment (PGA) Balancing Account whereby monthly entries into this Balancing Account will be made to reflect differences between the actual purchased gas costs collected from customers and the actual purchased gas costs incurred by the Company. Those differences are then collected from or refunded to customers under Schedule 155 – Gas Rate Adjustment.

Issued January 3, 2017 Effective February 3, 2017

Issued by Avista Utilities
By Kelly Norwood Kelly O. Norwood - Vice-President, State & Federal Regulation

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 150
PURCHASE GAS COST ADJUSTMENT - IDAHO

APPLICABLE:

To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:

To pass through changes in costs resulting from purchasing and transporting natural gas, to become effective as noted below.

RATE:

(a) The retail rates of firm gas Schedules 101, 111 and 112 are to be increased by 32.449¢ per therm in all blocks of these rate schedules.

(b) The rates of interruptible Schedules 131 and 132 are to be increased by 21.891¢ per therm.

(c) The rate for transportation under Schedule 146 is to be decreased by 0.000¢ per therm.

WEIGHTED AVERAGE GAS COST:

The above rate changes are based on the following weighted average cost of gas per therm as of the effective date shown below:

	Demand	Commodity	Total
Schedules 101	10.558¢	21.891¢	32.449¢
Schedules 111 and 112	10.558¢	21.891¢	32.449¢
Schedules 131 and 132	0.000¢	21.891¢	21.891¢

The above amounts include a gross revenue factor.

	Demand	Commodity	Total
Schedules 101	10.497¢	21.765¢	32.262¢
Schedules 111 and 112	10.497¢	21.765¢	32.262¢
Schedules 131 and 132	0.000¢	21.765¢	21.765¢

The above amounts do not include a gross revenue factor.

BALANCING ACCOUNT:

The Company will maintain a Purchase Gas Adjustment (PGA) Balancing Account whereby monthly entries into this Balancing Account will be made to reflect differences between the actual purchased gas costs collected from customers and the actual purchased gas costs incurred by the Company. Those differences are then collected from or refunded to customers under Schedule 155 – Gas Rate Adjustment.

Issued August 30, 2017 Effective November 1, 2017

Issued by Avista Utilities
By Kelly Norwood Kelly O. Norwood - Vice-President, State & Federal Regulation

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 155
GAS RATE ADJUSTMENT - IDAHO

AVAILABLE:

To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:

To adjust gas rates for amounts generated by the sources listed below.

MONTHLY RATE:

(a) The rates of firm gas Schedules 101 and 111 are to be decreased by 8.862¢ per therm in all blocks of these rate schedules.

(b) The rate of interruptible gas Schedule 131 is to be decreased by 0.000¢ per therm.

SOURCES OF MONTHLY RATE:

Changes in the monthly rates above result from amounts which have been accumulated in the Purchase Gas Adjustment (PGA) Balancing Account as described in Schedule 150 – Purchase Gas Cost Adjustment.

SPECIAL TERMS AND CONDITIONS:

The above Monthly Rate is subject to the provisions of Tax Adjustment Schedule 158.

SCHEDULE 155
GAS RATE ADJUSTMENT - IDAHO

AVAILABLE:
To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:
To adjust gas rates for amounts generated by the sources listed below.

MONTHLY RATE:
(a) The rates of firm gas Schedules 101 and 111 are to be decreased by ~~9.844¢~~ per therm in all blocks of these rate schedules.
(b) The rate of interruptible gas Schedule 131 is to be decreased by ~~10.222¢~~ per therm.

SOURCES OF MONTHLY RATE:
Changes in the monthly rates above result from amounts which have been accumulated in the Purchase Gas Adjustment (PGA) Balancing Account as described in Schedule 150 – Purchase Gas Cost Adjustment.

SPECIAL TERMS AND CONDITIONS:
The above Monthly Rate is subject to the provisions of Tax Adjustment Schedule 158.

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 155
GAS RATE ADJUSTMENT - IDAHO

AVAILABLE:
To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:
To adjust gas rates for amounts generated by the sources listed below.

MONTHLY RATE:
(a) The rates of firm gas Schedules 101 and 111 are to be decreased by 8.862¢ per therm in all blocks of these rate schedules.
(b) The rate of interruptible gas Schedule 131 is to be decreased by 0.000¢ per therm.

SOURCES OF MONTHLY RATE:
Changes in the monthly rates above result from amounts which have been accumulated in the Purchase Gas Adjustment (PGA) Balancing Account as described in Schedule 150 – Purchase Gas Cost Adjustment.

SPECIAL TERMS AND CONDITIONS:
The above Monthly Rate is subject to the provisions of Tax Adjustment Schedule 158.

Issued August 30, 2017 Effective November 1, 2017

Issued by Avista Utilities
By Kelly Norwood Kelly Norwood, Vice President, State & Federal Regulation

Idaho Public Utilities Commission
Office of the Secretary
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Boise, Idaho

AVISTA UTILITIES

Case No. AVU-G-17-04

EXHIBIT "B"

Notice of Public Applicant's Proposed Tariffs

August 30, 2017

AVISTA UTILITIES
NOTICE OF IDAHO TARIFF CHANGE
(Natural Gas Service Only)

Notice is hereby given that the "Sheets" listed below of Tariff IPUC No. 27, covering natural gas service applicable to Idaho customers of Avista Utilities have been filed with the Idaho Public Utilities Commission (IPUC) in Boise, Idaho.

Twenty-Fourth Revision Sheet 150	canceling	**Twenty-Third Revision Sheet 150**
Nineteenth Revision Sheet 155	canceling	**Eighteenth Revision Sheet 155**

Eighteenth Revision Sheet 155 updates the amortization rate used to refund or recover previous gas cost differences and Twentieth Revision Sheet 150 updates the forward-looking cost of natural gas purchased for customer usage.

These tariffs request an annual revenue *decrease* of approximately $1.6 million, or about 2.7%. This filing requests an effective date of November 1, 2017.

PGAs are filed each year to balance the actual cost of wholesale natural gas purchased by Avista to serve customers with the amount included in rates. This includes the natural gas commodity cost as well as the cost to transport natural gas on interstate pipelines to Avista's local distribution system. If the request is approved, Avista residential customers using an average of 61 therms a month could expect their bill to decrease by 1.23, or 2.41 percent, for a revised monthly bill of $49.87 beginning Nov. 1, 2017. Avista's natural gas revenues would decrease by $1.6 million, or approximately 2.7 percent. The requested natural gas rate change by customer segment is as follows:

General Service - Firm - Schedule 101 - Residential & Small Commercial	-2.5%
Large General Service - Firm - Schedules - Commercial 111 & 112	-3.8%
High Annual Load Factor Large - Interruptible Service Schedules 132	-0.0%

Avista does not mark up the cost of natural gas purchased to meet customer needs, so the filing does not increase or decrease company earnings.

The Company's application is a proposal, subject to public review and a Commission decision. Copies of the application are available for public review at the offices of both the Commission and Avista, and on the Commission's homepage (www.puc.idaho.gov). Customers may file with the Commission written comments related to the Company's filing. Customers may also subscribe to the Commission's RSS feed (http://www.puc.idaho.gov/rssfeeds/rss.htm) to receive periodic updates via e-mail about the case. Copies of rate filing are also available on our website, www.avistautilities.com/rates.

If you would like to submit comments on the proposed rate decrease, you can do so by going to the Commission website or mailing comments to:
Idaho Public Utilities Commission
P. O. Box 83720
Boise, ID 83720-0074

Copies of the proposed tariff changes are also available for inspection in the Company's offices, its website (www.avistautilities.com/rates), by calling (509) 495-4565 or by writing:

Avista Utilities
Attention: Senior Manager, Rates & Tariffs
P.O. Box 3727
Spokane, WA. 99220-3727

August 30, 2017

Idaho Public Utilities Commission
Office of the Secretary
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AUG 3 1 2017

Boise, Idaho

AVISTA UTILITIES

Case No. AVU-G-17-04

EXHIBIT "C"

Workpapers

August 30, 2017

Title	Description	Page Number
TARRIF CHANGE COMPARISONS		
Revenue Change Summary'!A1	Change in Revenue as a result of filing	2
Rate Change Summary'!A1	Change in rate, by schedule, Schedule 150 and 155	3
PGA COMPONENT CALCULATIONS		
Input!A1	Demand Volumes and Customers Inputs	4
Input!A26	Commodity Inputs	5
Commodity!A1	Commodity WACOG Calculation	6
Input - Demand Contracts'!A1	Demand WACOG Calculation	7
Amortization!A1	Amortization WACOG Calculation	8
OTHER		
Conversion Factor'!A1	Revenue Conversion Factor	9
GRI Funding	GRI Funding	10
Lost and Unaccounted for Gas	Lost and Unaccounted for Gas	11

Schedule	Therms		Rate Change		Revenue Incr (Decr)
Schedule 150 PGA					
Rate Schedule 101	58,396,771	$	(0.02998)	$	(1,750,536)
Rate Schedule 111	23,738,006	$	(0.02998)	$	(711,584)
Rate Schedule 112	0	$	(0.02998)	$	-
Rate Schedule 131	0	$	(0.02167)	$	-
Rate Schedule 132	0	$	(0.02167)	$	-
	82,134,778				(2,462,120)
Schedule 155 Amortization					
Rate Schedule 101	58,396,771	$	0.00982	$	573,375
Rate Schedule 111	23,738,006	$	0.00982	$	233,074
Rate Schedule 112	0	$	-	$	-
Rate Schedule 131	0	$	0.10222	$	-
Rate Schedule 132	0	$	-	$	-
Customer 1				$	(80,581)
Customer 2				$	(807)
Customer 3					
Customer 4				$	(3)
	82,134,778			$	725,058
Total Change 150 & 155					
Rate Schedule 101	58,396,771	$	(0.02016)	$	(1,177,161)
Rate Schedule 111	23,738,006	$	(0.02016)	$	(478,510)
Rate Schedule 112	0	$	(0.02998)		
Rate Schedule 131		$	0.08055	$	-
Rate Schedule 132		$	(0.02167)	$	-
Customer 1				$	(80,581)
Customer 2				$	(807)
Customer 3				$	-
Customer 4				$	(3)
Customer 5				$	-
Total Change	82,134,778			$	(1,737,062)
Rate Schedule 146 & Special Contracts	0			$	-
Total				**$**	**(1,737,062)**

Summary of Rate Change

	Proposed Rates		Present Billed Revenue	% Change
Rate Schedule 101	(1,177,161)	$	47,993,000	-2.5%
Rate Schedule 111	(478,510)	$	12,776,000	-3.8%
Rate Schedule 112	0	$	-	0.0%
Rate Schedule 131	0	$	-	0.0%
Rate Schedule 132	0	$	0	0.0%
Rate Schedule 146		$	385,000	0.0%
Rate Schedule 148		$	103,000	0.0%
Total Change	(1,655,671)	$	61,257,000	-2.7%

Commodity	17,843,532	29%
Demand	8,621,960	14%
Amortization	(7,211,838)	-12%

Avista Utilities
State of Idaho
Summary of Changes

	Summary of Changes		Without Revenue Sensitive Costs			With Revenue Sensitive Costs		
			Rate Sch 150 (Deferral)	Rate Sch 155 (Amortization)	Total Gas Cost Rate	Rate Sch 150 (Deferral)	Rate Sch 155 (Amortization)	Total Gas Cost Rate
	Present							
1	Rate Schedule 101		$0.35265	($0.09308)	$0.25957	$0.35447	($0.09844)	$0.25603
2	Rate Schedule 111		$0.35265	($0.09308)	$0.25957	$0.35447	($0.09844)	$0.25603
3	Rate Schedule 112		$0.35265	$0.00000	$0.35265	$0.35447	$0.00000	$0.35447
4	Rate Schedule 131	(no customers)	$0.23935	($0.09665)	$0.14270	$0.24058	($0.10222)	$0.13836
5	Rate Schedule 132	(no customers)	$0.23935		$0.23935	$0.24058		$0.24058
6								
7	**Proposed**					**GRF:**	**1.005812**	
8	Rate Schedule 101		$0.32262	($0.08811)	$0.23451	$0.32449	($0.08862)	$0.23587
9	Rate schedule 111		$0.32262	($0.08811)	$0.23451	$0.32449	($0.08862)	$0.23587
10	Rate Schedule 112		$0.32262	$0.00000	$0.32262	$0.32449	$0.00000	$0.32449
11	Rate Schedule 131	(no customers)	$0.21765	$0.00000	$0.21765	$0.21891	$0.00000	$0.21891
12	Rate Schedule 132	(no customers)	$0.21765	$0.00000	$0.21765	$0.21891	$0.00000	$0.21891
13								
14	**Change**							
15	Rate Schedule 101		($0.03003)	$0.00497	($0.02506)	($0.02998)	$0.00982	($0.02016)
16	Rate schedule 111		($0.03003)	$0.00497	($0.02506)	($0.02998)	$0.00982	($0.02016)
17	Rate Schedule 112		($0.03003)	$0.00000	($0.03003)	($0.02998)	$0.00000	($0.02998)
18	Rate Schedule 131	(no customers)	($0.02170)	$0.09665	$0.07495	($0.02167)	$0.10222	$0.08055
19	Rate Schedule 132	(no customers)	($0.02170)	$0.00000	($0.02170)	($0.02167)	$0.00000	($0.02167)
20								

STATE OF IDAHO
ANNUAL PGA FILING

*AN -- Allocated North sum of Washington + Idaho

Line No.	VOLUME FORECAST													12 month Ended
1	**Demand Forecast**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	Total
2	Rate Schedule 101	7,575,380	10,596,116	10,009,763	7,780,202	6,946,610	4,314,120	2,436,163	1,445,578	1,206,631	1,092,032	1,370,575	3,623,603	58,396,771
3	Rate Schedule 111/112	3,258,628	3,467,722	3,312,282	2,525,917	2,364,175	1,485,732	970,693	885,781	1,028,906	1,172,408	1,101,196	2,164,566	23,738,006
5	**FIRM DEMAND THERMS**	**10,834,008**	**14,063,838**	**13,322,045**	**10,306,119**	**9,310,785**	**5,799,852**	**3,406,856**	**2,331,359**	**2,235,537**	**2,264,439**	**2,471,771**	**5,788,170**	**82,134,778**
4	Rate Schedule 132	0	0	0	0	0	0	0	0	0	0	0	0	-
5	**COMMODITY THERMS (SALES)**	**10,834,008**	**14,063,838**	**13,322,045**	**10,306,119**	**9,310,785**	**5,799,852**	**3,406,856**	**2,331,359**	**2,235,537**	**2,264,439**	**2,471,771**	**5,788,170**	**82,134,778**
6	Fuel	162,510	210,958	199,831	154,592	139,662	86,998	51,103	34,970	33,533	33,967	37,077	86,823	1,232,022
7	Lost and Unaccounted for	44,752	58,094	55,030	42,572	38,460	23,958	14,073	9,630	9,234	9,354	10,210	23,909	339,276
7	**TOTAL PURCHASE THERMS**	**11,041,271**	**14,332,889**	**13,576,905**	**10,503,282**	**9,488,907**	**5,910,807**	**3,472,031**	**2,375,959**	**2,278,304**	**2,307,760**	**2,519,058**	**5,898,901**	**83,706,076**
8														
9	CUSTOMER FORECAST													12 month Ended
10	**Demand Forecast**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	Total
11	Rate Schedule 101	80,798	81,146	81,283	81,281	81,269	81,234	81,223	81,212	81,319	81,402	81,601	81,755	975,522
12	Rate Schedule 111	1,457	1,457	1,461	1,463	1,465	1,467	1,468	1,470	1,472	1,473	1,475	1,477	17,607
13	Rate Schedule 132	0	0	0	0	0	0	0	0	0	0	0	0	-
14	**Total Customers**	**82,255**	**82,603**	**82,744**	**82,744**	**82,734**	**82,701**	**82,691**	**82,682**	**82,791**	**82,875**	**83,076**	**83,232**	**993,128**
15														

Row		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Total
16														
17	**COMMODITY**													
18														
19	Commodity Allocation (based on Calendar Volumes)	31.67%	30.49%	30.01%	29.37%	30.56%	30.71%	31.71%	32.77%	34.73%	35.21%	33.32%	32.87%	
20														
21	**Hedges**													
22														
23	**Executed**													
24	AN* System Total Volumes (Th)	15,037,500	17,863,750	16,701,250	14,035,001	14,376,250	1,185,001	1,224,500	1,185,001	1,224,500	1,224,500	1,185,000	1,224,500	86,466,753
25	AN* System Total Dollars ($)	$ 4,086,382	$ 4,719,389	$ 4,495,782	$ 3,831,912	$ 3,994,745	$ 218,040	$ 225,308	$ 218,040	$ 225,308	$ 225,308	$ 218,040	$ 225,308	$ 22,683,562
26														
27	ID Volumes (Th)	4,762,376	5,446,657	5,012,045	4,122,080	4,393,382	363,914	388,289	388,325	425,269	431,146	394,842	402,493	26,530,818
28	ID Dollars ($)	1,294,157	1,438,942	1,349,184	1,125,433	1,220,794	66,960	71,445	71,452	78,249	79,331	72,651	74,059	6,942,657
29	WACOG	$ 0.27175	$ 0.26419	$ 0.26919	$ 0.27303	$ 0.27787	$ 0.18400	$ 0.18400	$ 0.18400	$ 0.18400	$ 0.18400	$ 0.18400	$ 0.18400	$ 0.26168
30														
31	**Deferred Exchange Credits**													
32	AN* Deferred Exchange	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (375,000)	$ (4,500,000)
33														
34	ID Deferred Exchange	$ (118,763)	$ (114,338)	$ (112,538)	$ (110,138)	$ (114,600)	$ (115,163)	$ (118,913)	$ (122,888)	$ (130,238)	$ (132,038)	$ (124,950)	$ (123,263)	$ (1,437,825)
35														
36	**Price Forecast**	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Total
37	30 Day average Price based on: 7-31-2017													
38	Aeco	$ 2.009	$ 2.135	$ 2.192	$ 2.197	$ 2.153	$ 1.878	$ 1.879	$ 1.879	$ 1.901	$ 1.899	$ 1.889	$ 1.921	
39	Sumas	$ 2.703	$ 3.228	$ 3.185	$ 2.946	$ 2.636	$ 1.888	$ 1.899	$ 1.890	$ 2.141	$ 2.130	$ 2.129	$ 2.143	
40	Rockies	$ 2.714	$ 2.998	$ 3.100	$ 3.074	$ 2.862	$ 2.392	$ 2.317	$ 2.323	$ 2.437	$ 2.443	$ 2.420	$ 2.411	
41														
42	**Basin Weighting**													
43	Aeco	70.39%	74.98%	87.66%	91.42%	100.00%	100.00%	100.00%	75.86%	78.62%	92.94%	83.73%	78.52%	82%
44	Sumas	3.89%	4.81%	11.77%	8.40%	0.00%	0.00%	0.00%	24.14%	14.80%	5.79%	12.95%	1.30%	11%
45	Rockies	25.73%	20.21%	0.58%	0.18%	0.00%	0.00%	0.00%	0.00%	6.59%	1.26%	3.32%	20.18%	6%
46														
47	Basin-Weighted Index Price	$ 2.2175	$ 2.3617	$ 2.3141	$ 2.2612	$ 2.1527	$ 1.8783	$ 1.8789	$ 1.8818	$ 1.9717	$ 1.9197	$ 1.9379	$ 2.0223	
48	Index Volumes (DTh)	6,278,895	8,886,232	8,564,860	6,381,202	5,095,525	5,546,893	3,083,742	1,987,634	1,853,035	1,876,614	2,124,216	5,496,408	57,175,258
49	Index Cost	$ 1,392,346	$ 2,098,631	$ 1,981,963	$ 1,442,902	$ 1,096,914	$ 1,041,859	$ 579,404	$ 374,042	$ 365,371	$ 360,253	$ 411,658	$ 1,111,538	$ 12,256,882
50														
51	**Embedded Charges**													
52	Variable Transportation	$ 5,258	$ 6,264	$ 5,516	$ 3,935	$ 5,091	$ 9,664	$ 12,247	$ 9,176	$ 8,589	$ 8,568	$ 2,755	$ 4,756	81,818
53														
54														
55														
56														
57	**AMORTIZATION BALANCES**													
58														

Row		Amortization Rate	Customer 1	Customer 2	Customer 3	Customer 4	Total
59							
60							
61	Unamortized Deferrals (191000)	$ (239,344)	$ (56)	$ 8	$ -	$ (3)	$ (239,395)
64	Current Deferrals (191010)	$ (6,972,494)	$ (80,525)	$ (815)	$ -	$ -	$ (7,053,835)
65	Total	$ (7,211,838)	$ (80,581)	$ (807)	$ -	$ (3)	$ (7,293,230)

Avista Utilities
State of Idaho
Gas Cost Calculation (per Therm)

	Executed Hedges		Index Cost		Total Cost to Serve Average Load (including fuel)		Variable Charges	Deferred Exchange	Total Estimated Commodity Costs	Sales Volumes (to customers)	WACOG
	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Dollars	Dollars	Dollars		
	(a)	(b)	(c)	(d)	(a) + (c) = (e)	(b) + (d) = (f)	(h)	(i)	(j)		
Nov-17	4,762,376	$ 1,294,157	6,278,895	$ 1,392,346	11,041,271	$ 2,686,503	$ 5,258	$ (118,763)	$ 2,572,999	10,834,008	$ 0.2375
Dec-17	5,446,657	$ 1,438,942	8,886,232	$ 2,098,631	14,332,889	$ 3,537,573	$ 6,264	$ (114,338)	$ 3,429,499	14,063,838	$ 0.2439
Jan-18	5,012,045	$ 1,349,184	8,564,860	$ 1,981,963	13,576,905	$ 3,331,147	$ 5,516	$ (112,538)	$ 3,224,125	13,322,045	$ 0.2420
Feb-18	4,122,080	$ 1,125,433	6,381,202	$ 1,442,902	10,503,282	$ 2,568,335	$ 3,935	$ (110,138)	$ 2,462,133	10,306,119	$ 0.2389
Mar-18	4,393,382	$ 1,220,794	5,095,525	$ 1,096,914	9,488,907	$ 2,317,708	$ 5,091	$ (114,600)	$ 2,208,199	9,310,785	$ 0.2372
Apr-18	363,914	$ 66,960	5,546,893	$ 1,041,859	5,910,807	$ 1,108,819	$ 9,664	$ (115,163)	$ 1,003,321	5,799,852	$ 0.1730
May-18	388,289	$ 71,445	3,083,742	$ 579,404	3,472,031	$ 650,849	$ 12,247	$ (118,913)	$ 544,184	3,406,856	$ 0.1597
Jun-18	388,325	$ 71,452	1,987,634	$ 374,042	2,375,959	$ 445,494	$ 9,176	$ (122,888)	$ 331,782	2,331,359	$ 0.1423
Jul-18	425,269	$ 78,249	1,853,035	$ 365,371	2,278,304	$ 443,620	$ 8,589	$ (130,238)	$ 321,971	2,235,537	$ 0.1440
Aug-18	431,146	$ 79,331	1,876,614	$ 360,253	2,307,760	$ 439,584	$ 8,568	$ (132,038)	$ 316,114	2,264,439	$ 0.1396
Sep-18	394,842	$ 72,651	2,124,216	$ 411,658	2,519,058	$ 484,309	$ 2,755	$ (124,950)	$ 362,114	2,471,771	$ 0.1465
Oct-18	402,493	$ 74,059	5,496,408	$ 1,111,538	5,898,901	$ 1,185,597	$ 4,756	$ (123,263)	$ 1,067,091	5,788,170	$ 0.1844
	26,530,818	6,942,657	57,175,258	12,256,882	83,706,076	**$ 19,199,539**	$ 81,818	$ (1,437,825)	**$ 17,843,532**	82,134,778	$ 0.21725
Average		$ 0.26168		$ 0.2144		$ 0.2294					
		32%		68%							

GRI Funding (no change)	0.00040
TOTAL Rate	**0.21765**

RCF: 1.005812

Proposed Rate	
Proposed WACOG without RCF	$ 0.21765
Proposed WACOG with RCF	**$ 0.21891**

Present Rate	
Present WACOG without RCF	$ 0.23935
Present WACOG with RCF	**$ 0.24058**

Change	
Change WACOG without RCF	$ (0.02170)
Change WACOG with RCF	$ (0.02167)

Avista Utilities
WA Gas Operations
Demand Cost Calculation (per Therm)

Line No.	Description	Estimated Demand Expense	Allocator	Allocation Percentage ID	Idaho Allocation
1	Northwest Pipeline Corporation (NWP)	$ 14,746,420	ID System Allocated	30.94%	$ 4,562,542
2					
3	TCPL - Gas Transmission Northwest	$ 2,614,309	ID System Allocated	30.94%	$ 808,867
4					
5	**Total Fixed Domestic Transportation Costs**	**17,360,728**			**$ 5,371,409**
6					
7	TransCanada - AB (NOVA System)	$ 6,660,601	ID System Allocated	30.94%	$ 2,060,790
8					
9	TransCanada - BC (Foothills Pipe Line Ltd.)	$ 2,850,465	ID System Allocated	30.94%	$ 881,934
10					
11	Spectra - Westcoast Energy Inc	$ 994,914	ID System Allocated	30.94%	$ 307,827
12					
13	**Total Fixed Canadian Transportation Costs**	**$ 10,505,980**			**$ 3,250,550**
14					
15	**Total Fixed Pipeline Charges**	**$ 27,866,709**			**$ 8,621,960**
16					
17	**Demand Costs**	**$ 27,866,709**			**$ 8,621,960**
18	Demand Volumes				82,134,778
19	**Demand Rate**				$ 0.10497
20					
21					
22				RCF:	**1.0058120**
23					
24					
25					

Rate Change Calculation: Proposed	
Proposed WACOG without Revenue Sensitive Costs	$ 0.10497
Proposed WACOG with Revenue Sensitive Costs	**$ 0.10558**

Rate Change Calculation: Prsent	
Proposed WACOG without Revenue Sensitive Costs	$ 0.11331
Proposed WACOG with Revenue Sensitive Costs	**$ 0.11389**

$ (0.00831)

JURISDICTIC	AN
PROFIT CENTER	LDC

Sum of US DOLLARS													
Row Labels	**201711**	**201712**	**201801**	**201802**	**201803**	**201804**	**201805**	**201806**	**201807**	**201808**	**201809**	**201810**	**Grand Total**
GTNW	$ 244,577	$ 252,729	$ 252,729	$ 228,272	$ 252,729	$ 185,335	$ 191,513	$ 185,335	$ 191,513	$ 191,513	$ 185,335	$ 252,729	$ 2,614,309
NWPL	$ 1,232,724	$ 1,270,441	$ 1,217,579	$ 1,099,748	$ 1,217,579	$ 1,178,302	$ 1,217,579	$ 1,178,302	$ 1,296,147	$ 1,296,147	$ 1,254,336	$ 1,287,538	$14,746,420
Grand Total	**$ 1,477,301**	**$ 1,523,171**	**$ 1,470,308**	**$ 1,328,020**	**$ 1,470,308**	**$ 1,363,637**	**$ 1,409,091**	**$ 1,363,637**	**$ 1,487,660**	**$ 1,487,660**	**$ 1,439,671**	**$ 1,540,267**	**$17,360,728**

JURISDICTION	AN
PROFIT CENTER	LDC

***Sum of CDN DOLLARS**													
Row Labels	**201711**	**201712**	**201801**	**201802**	**201803**	**201804**	**201805**	**201806**	**201807**	**201808**	**201809**	**201810**	**Grand Total**
QPC	$ -	$ -											$ -
TCPL AB	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 555,050	$ 6,660,601
TCPL BC	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 237,539	$ 2,850,465
WEI	$ 93,743	$ 93,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 80,743	$ 994,914
Grand Total	**$ 886,332**	**$ 886,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$ 873,332**	**$10,505,980**

*Canadian Transportation priced at par

Avista Utilities
Idaho Gas Operations
Development of Amortization Rate

Line No.		Sales Therms		Amortization		Interest		Balance
				SALES AMORTIZATION (Sch 101-131)				
1		Sales Therms		Amortization		Interest		Balance
2			$	(0.08811)		1.00%		
3								
4	**Rate Schedule: 101-132**						$	(7,211,838)
5								
6	Nov-17	10,834,008	$	954,576.89	$	(5,612.12)	$	(6,262,873.39)
7	Dec-17	14,063,838	$	1,239,154.91	$	(4,702.75)	$	(5,028,421.23)
8	Jan-18	13,322,045	$	1,173,796.05	$	(3,701.27)	$	(3,858,326.45)
9	Feb-18	10,306,119	$	908,064.91	$	(2,836.91)	$	(2,953,098.45)
10	Mar-18	9,310,785	$	820,366.77	$	(2,119.10)	$	(2,134,850.78)
11	Apr-18	5,799,852	$	511,020.90	$	(1,566.12)	$	(1,625,396.00)
12	May-18	3,406,856	$	300,175.66	$	(1,229.42)	$	(1,326,449.76)
13	Jun-18	2,331,359	$	205,414.37	$	(1,019.79)	$	(1,122,055.18)
14	Jul-18	2,235,537	$	196,971.59	$	(852.97)	$	(925,936.56)
15	Aug-18	2,264,439	$	199,518.17	$	(688.48)	$	(727,106.87)
16	Sep-18	2,471,771	$	217,786.00	$	(515.18)	$	(509,836.05)
17	Oct-18	5,788,170	$	509,991.57	$	(212.37)	$	(56.85)
18		82,134,778	$	7,236,837.79	$	(25,056.48)	$	(56.85)

TOTAL AMORTIZATION RATES

RCF:		**1.00581**
Sales Amortization		
Proposed Amort. Rate without revenue sensitive costs	$	(0.08811)
Proposed Amort. Rate with revenue sensitive costs	**$**	**(0.08862)**

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Natural Gas System
TWELVE MONTHS ENDED DECEMBER 31, 2014

(Final Settlement - per Stipulation)

Line No.	Description		Factor
1	**Revenues**		1.000000
	Expenses:		
2	Uncollectibles		0.003407
3	Commission Fees		0.002371
4	Idaho State Income Tax	(zeroed out for PGA)	0.000000
5	Total Expenses		0.005778
6	Net Operating Income Before FIT		0.994222
7	Federal Income Tax @ 35%		0.347978
8	REVENUE CONVERSION FACTOR		0.64624
	REVENUE GROSS UP:	(1/1-.05778)	*1.005812*

Avista Utilities
State of Idaho
Voluntary GRI Funding

	Northwest Pipeline		Transcanada - GTN Pipeline		Total
	TF-1 Reservation	TF-1 Volumetric	TF-1 Reservation	TF-1 Volumetric	
Previous Pipeline Rate (Per Therm)	$0.00086	$0.00088	$0.00086	$0.00088	
Current Pipeline Rate (Per Therm)	$0.00076	$0.00075	$0.00076	$0.00075	
Reduction in Pipeline Funding Rate (Per Therm)	$0.00010	$0.00013	$0.00010	$0.00013	
Monthly Rate (Daily Rate X 365 Days/12 Months)	$0.00316		$0.00316		
NWP Demand Billing Determinants	558,085,000		0		
Estimated Transportation Volumes (Therms)		0		0	
GRI Funding Shortfall	$1,764,000	$0	$0	$0	
Idaho Percentage	30.01%	30.57%	30.01%	30.57%	
Total Idaho GRI Funding Shortfall	$14,000	$3,000	$9,000	$6,000	$32,000

Set the GRI Funding at the 11/1/99 Level.

12 MONTHS ENDED TOTAL
LOSS & UNACCOUNTED FOR GAS

BY DELIVERY POINT - THERMS

IDAHO	DELIVERY	REVENUE	LOSS +/-	% OF PURCHASE
ID SPO-CDA area	55,220,996	54,947,548	273,448	0.50
ID LEWIS-CLARK area	66,836,328	66,807,938	28,390	0.04
	122,057,324	121,755,487	301,837	0.25
Bonners	2,925,260	5,439,646	(2,514,386)	(85.95)
Genesee	272,750	254,800	17,950	6.58
Kellogg	4,714,250	5,055,520	(341,270)	(7.24)
Moscow	7,391,730	7,334,622	57,108	0.77
Pinehurst-Kingston	861,110	551,107	310,003	36.00
Sandpoint	8,365,020	5,771,858	2,593,162	31.00
Smelterville-Page	510,180	326,964	183,216	35.91
IDAHO TOTAL	147,097,624	146,490,005	607,619	0.41

Idaho Public Utilities Commission
Office of the Secretary
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Boise, Idaho

AVISTA UTILITIES

Case No. AVU-G-17-04

EXHIBIT "D"

Pipeline Tariffs

August 30, 2017

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate(1),(3) Minimum	Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.41000
15 Year Evergreen Exp.	.00000	.36263
25 Year Evergreen Exp.	.00000	.34234
Volumetric (2)		
(Large Customer)		
System-Wide	.00813	.03000
15 Year Evergreen Exp.	.00813	.00813
25 Year Evergreen Exp.	.00813	.00813
(Small Customer) (6)	.00813	.72155
Scheduled Overrun (2)	.00813	.44000
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.41000
Volumetric	.00813	.03000
Scheduled Daily Overrun	.00813	.44000
Annual Overrun	.00813	.44000
Rate Schedule TI-1 (2)		
Volumetric (7)	.00813	.44000
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Entitlement Unauthorized Overrun and Underrun (8)	Rate
General System Unauthorized Daily Overrun	(9)
General System Unauthorized Daily Underrun	10.00000
General System Unauthorized Underrun Imbalances not eliminated after 72 hours	10.00000
Customer-Specific Entitlement Penalty	10.00000

Footnotes

(1) Rate excludes surcharges approved by the Commission.
(2) Annual Charge Adjustment ("ACA") surcharge may be applicable. Section 16 of the General Terms and Conditions describes the basis and applicability of the ACA surcharge.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

Footnotes (Continued)

(3) To the extent Transporter discounts the Maximum Base Tariff Rate, such discounts will be applied on a non-discriminatory basis, subject to the policies of Order No. 497.

Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

An incremental facilities charge or other payment method provided for in Section 21 or 29 of the General Terms and Conditions, is payable in addition to all other rates and charges if such a charge is included in Exhibit C to a Shipper's Transportation Service Agreement.

In addition to the rates set forth on Sheet No. 5, Puget Sound Energy, Inc.'s Transportation Service Agreement No. 140053 is subject to an annual incremental facility charge pursuant to Section 21 of the General Terms and Conditions for the South Seattle Delivery Lateral Expansion Project. The effective annual incremental facility charge is $3,417,062 and is billed in equal monthly one-twelfth increments. The daily incremental facility charge is $0.14651 per Dth.

In addition to the reservation rates shown on Sheet No. 5, Shippers who contract for Columbia Gorge Expansion Project capacity are subject to a facility reservation surcharge pursuant to Section 3.4 of Rate Schedule TF-1. The facility charge used in deriving the Columbia Gorge Expansion Project facility reservation surcharge has a minimum rate of $0 and a maximum rate during the indicated months or calendar years as follows:

(Dollars per Dth)

Year	Rate	Year	Rate	Year	Rate
2013	$0.09549	2017	$0.07471	2021	$0.05409
2014	$0.09255	2018	$0.06876	2022	$0.05273
2015	$0.08661	2019	$0.06282	2023	$0.05137
2016	$0.08044	2020	$0.05671	2024	$0.05023

January 1, 2025 - March 31, 2025 $0.02442

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of $0.35843 and $0.33814 for transmission costs and $0.00420 and $0.00420 for storage costs, respectively. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.40580 for transmission costs and $0.00420 for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00775 for transmission costs and $0.00038 for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.02962 for transmission costs and $0.00038 for storage costs.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(5) Rates for Rate Schedules TF-1, TF-2 and TFL-1 are also applicable to capacity release service except for short-term capacity release transactions for 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, which are not subject to the stated Maximum Base Tariff Rate. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The reservation rate is the comparable volumetric bid reservation charge applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

(6) For Rate Schedule TF-1 (Small Customer), the Maximum Base Tariff Rate is comprised of $0.71277 for transmission costs and $0.00878 for storage costs. Transporter will not schedule gas for delivery to a Small Customer subject to this Rate Schedule TF-1 under any transportation Service Agreement (excluding its Rate Schedule TF-2 Service Agreement at Plymouth held at the time of storage service unbundling in RP93-5) unless such Small Customer has scheduled its full Contract Demand for firm service under its Rate Schedule TF-1 (Small Customer) Service Agreement(s)for that day.

(7) Rate Schedule TI-1 maximum base tariff volumetric rate is comprised of $0.43542 for transmission costs and $0.00458 for storage costs.

(8) Applicable to Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 pursuant to Section 15.5 of the General Terms and Conditions.

(9) The Unauthorized Overrun Charge per Dth is the greater of $10 or 150 percent of the highest midpoint price at NW Wyo. Pool, NW s. of Green River, Stanfield Ore., NW Can. Bdr. (Sumas), Kern River Opal, or El Paso Bondad as reflected in the Daily Price Survey published in "Gas Daily."

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules DEX-1 and PAL

(Dollars per Dth)

Type of Rate	Base Tariff Rate (1),(3) Minimum	Base Tariff Rate (1),(3) Maximum
Rate Schedule DEX-1 (2),(4)		
Deferred Exchange	.00000	.44000
Rate Schedule PAL		
Park and Loan	.00000	.44000

Footnotes

(1) Rate excludes surcharges approved by the Commission.

(2) ACA surcharge may be applicable. Section 16 of the General Terms and Conditions describes the basis and applicability of the ACA surcharge.

(3) To the extent Transporter discounts the maximum currently effective tariff rate, such discounts will be applied on a non-discriminatory basis, subject to the policies of Order No. 497.

(4) Shippers receiving service under this rate schedule are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14, except as provided in Section 4 of Rate Schedule DEX-1.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules SGS-2F and SGS-2I

(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate (1) Minimum	Base Tariff Rate (1) Maximum
Rate Schedule SGS-2F (2) (3) (4) (5)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01562
Expansion Shipper	0.00000	0.04056
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00348
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01562
Expansion Shipper	0.00000	0.04056
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00348
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00224

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules SGS-2F and SGS-2I (Continued)

Footnotes (Continued)

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

Rates are also applicable to capacity release service except for short-term capacity release transactions for 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, which are not subject to the stated Maximum Base Tariff Rate. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Withdrawal Charge and Storage Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

RESERVED FOR FUTURE USE

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules LS-2F and LS-2I

(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate (1) Minimum	Maximum
Rate Schedule LS-2F (3)		
Demand Charge (2)	0.00000	0.02587
Capacity Demand Charge (2)	0.00000	0.00331
Volumetric Bid Rates		
Vaporization Demand-Related Charge (2)	0.00000	0.02587
Storage Capacity Charge (2)	0.00000	0.00331
Liquefaction	0.90855	0.90855
Vaporization	0.03386	0.03386
Rate Schedule LS-2I		
Volumetric	0.00000	0.00662
Liquefaction	0.90855	0.90855
Vaporization	0.03386	0.03386

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

(3) Rates are also applicable to capacity release service except for short-term capacity release transactions for 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, which are not subject to the stated Maximum Base Tariff Rate. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Vaporization Demand-Related Charge and Storage Capacity Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules LS-3F and LD-4I

(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate (1) Minimum	Maximum
Rate Schedule LS-3F (3)		
Demand Charge (2)	0.00000	0.02587
Capacity Demand Charge (2)	0.00000	0.00331
Volumetric Bid Rates		
Vaporization Demand-Related Charge (2)	0.00000	0.02587
Storage Capacity Charge (2)	0.00000	0.00331
Liquefaction Charge (4)	0.90855	0.90855
Vaporization Charge	0.03386	0.03386
Rate Schedule LD-4I		
Volumetric Charge	0.00000	0.78872
Liquefaction Charge (4)	0.90855	0.90855

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

(3) Rates are also applicable to capacity release service except for short-term capacity release transactions for 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, which are not subject to the stated Maximum Base Tariff Rate. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Vaporization Demand-Related Charge and Storage Capacity Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

(4) The Liquefaction Charge will be trued-up annually pursuant to Section 14.20 of the General Terms and Conditions.

RESERVED FOR FUTURE USE

STATEMENT OF FUEL USE REQUIREMENTS FACTORS
FOR REIMBURSEMENT OF FUEL USE

Applicable to Transportation Service Rendered Under
Rate Schedules Contained in this Tariff, Fifth Revised Volume No. 1

The rates set forth on Sheet Nos. 5, 6, 7, 8 and 8-A are exclusive of fuel use requirements. Shipper shall reimburse Transporter in-kind for its fuel use requirements in accordance with Section 14 of the General Terms and Conditions contained herein.

The fuel use reimbursement furnished by Shippers shall be as follows for the applicable Rate Schedules included in this Tariff:

Rate Schedules TF-1, TF-2, TI-1, and DEX-1	1.28%
Rate Schedule TF-1 - Evergreen Expansion	
Incremental Surcharge (1)	0.50%
Rate Schedule TFL-1	-
Rate Schedule TIL-1	-
Rate Schedules SGS-2F and SGS-2I	0.15%
Rate Schedules LS-2F, LS-3F and LS-2I	
Liquefaction	0.53%
Vaporization	0.53%
Rate Schedule LD-4I	
Liquefaction	0.53%

The fuel use factors set forth above shall be calculated and adjusted as explained in Section 14 of the General Terms and Conditions. Fuel reimbursement quantities to be supplied by Shippers to Transporter shall be determined by applying the factors set forth above to the quantity of gas nominated for receipt by Transporter from Shipper for transportation, Jackson Prairie injection, Plymouth liquefaction, Plymouth vaporization, or for deferred exchange, as applicable.

Footnote

(1) In addition to the Rate Schedule TF-1 fuel use requirements factor, the Evergreen Expansion Incremental Surcharge will apply to the quantity of gas nominated for receipt at the Sumas, SIPI or Pacific Pool receipt points under Evergreen Expansion service agreements.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northwest Pipeline LLC	)	Docket No. RP17-___
	)	

STIPULATION AND SETTLEMENT AGREEMENT

Pursuant to Rule 207(a)(5) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 385.207(a)(5) (2016), Northwest Pipeline LLC ("Northwest") submits this Stipulation and Settlement Agreement ("Settlement") to modify the transportation rates set forth in Northwest's FERC Gas Tariff, Fifth Revised Volume No. 1 ("Tariff"), pursuant to the terms below. Northwest and the other Settling Parties (as defined in Article II) stipulate and agree to the following:

BACKGROUND

On March 15, 2012, Northwest filed a Petition for Approval of Settlement in Docket No. RP12-490-000 ("2012 Settlement"). The 2012 Settlement satisfied the requirement to file a general rate case under Section 4 of the Natural Gas Act ("NGA") by July 1, 2012, as required by Northwest's previous general rate case settlement in Docket No. RP06-416.[1] On April 26, 2012, the Commission approved the 2012 Settlement.[2]

Section 14.4 of the 2012 Settlement requires Northwest to file an NGA Section 4 general rate case not later than July 1, 2017, for rates to become effective not later than January 1, 2018, unless Northwest has entered into a pre-filing settlement effectively satisfying the NGA Section 4 general rate case filing requirement ("2017 Rate Filing").[3] In anticipation of the 2017 Rate Filing, Northwest invited all of its shippers to engage in discussions to determine if a pre-filing settlement might be reached. Numerous and extensive meetings and discussions among Northwest and its shippers have been held from September 2016 through December 2016. During the course of these meetings and discussions, the

[1] *Northwest Pipeline Corp.*, 118 F.E.R.C. ¶ 61,272 (2007).
[2] *Northwest Pipeline GP*, 139 F.E.R.C. ¶ 61,071 (2012).
[3] Because July 1, 2017 is a Saturday, the effective filing deadline for the 2017 Rate Filing is June 30, 2017.

parties exchanged documentation, including several offers and counteroffers. This Settlement is the product of the documents exchanged and these extensive meetings and discussions.

Through this Settlement, the Settling Parties[4] have successfully resolved their issues in a practical and carefully constructed fashion, eliminating the need for testimony, discovery, hearing and briefing of the matters resolved. The avoidance of litigation is a valuable outcome, benefiting the Settling Parties, the Commission and the public interest.

Northwest does not expect this Settlement to be contested because 100 percent of the shippers who actively participated in the settlement discussions support this Settlement. Of Northwest's long-term firm transportation and storage capacity, 92 percent support, and 8 percent do not oppose this Settlement.

The Settling Parties agree that if this Settlement is timely approved by the Commission, then Northwest will have satisfied the 2017 Rate Filing requirement as to the Settling Parties. Accordingly, the Settling Parties have requested that the Commission approve this Settlement on or before March 1, 2017, to avoid the burden of Northwest having to prepare and file the 2017 Rate Filing and for the other Settling Parties having to respond to such filing.

ARTICLE I
INDIVISIBILITY OF SETTLEMENT TERMS

The Settling Parties have engaged in extensive settlement negotiations in an effort to resolve among themselves issues that may have been raised in the 2017 Rate Filing and this Settlement provides for a reasonable negotiated resolution of those issues. This Settlement is a carefully crafted compromise among many parties with diverse and often conflicting interests. This Settlement is an integrated package and the Settling Parties request that it be approved in its entirety, without modification or condition.

[4] "Settling Parties" is defined in Article II of the Settlement.

ARTICLE II
SCOPE OF SETTLEMENT

This Settlement shall apply to all Settling Parties. A "Settling Party" is (a) any party identified in Appendix A or (b) any party or shipper not identified in Appendix A that either supports, or does not oppose this Settlement as a whole and/or any of its underlying provisions. This Settlement represents a negotiated resolution of only the issues expressly set forth in this Settlement.

ARTICLE III
ANNUAL COST-OF-SERVICE

The rates established by this Settlement ("Settlement Rates") are determined on the basis of an annual cost-of-service of $440 million, and consist of two phases of rates. Phase 1 Rates, as set forth in Appendix B, will be effective from January 1, 2018, through September 30, 2018, and Phase 2 Rates, as set forth on Appendix C, will be effective from October 1, 2018, through the remaining Settlement Term (as defined in Section 11.7).

ARTICLE IV
RATE DESIGN

The Settlement Rates incorporate the following specific principles with respect to rate design:

Section 4.1

General Transmission System: The rates for all transportation Rate Schedules are based on a straight fixed variable ("SFV") rate design.

Section 4.2

Storage: The rates for the Plymouth LNG and Jackson Prairie Rate Schedules reflect an agreement between the Settling Parties to keep the rates the same as those established in the 2012 Settlement.

Section 4.3

Evergreen 15-Year Contract Roll-In: The rates for Rate Schedule TF-1 (Large Customer), TF-1 (25-Year Evergreen), Rate Schedule TF-2 and the Rate Schedule TI-1 to be effective January 1, 2018, through September 30, 2018, as shown on Appendix B, reflect the allocation of costs to the TF-1 (15-

Year Evergreen) contracts. The rates for Rate Schedule TF-1 (Large Customer), TF-1 (25-Year Evergreen), Rate Schedule TF-2, and the Rate Schedule TI-1 to be effective October 1, 2018, through the remainder of the Settlement Term, as shown on Appendix C, reflect the roll-in of the TF-1 (15-Year Evergreen) contracts that will expire on September 30, 2018.

ARTICLE V
DEPRECIATION, AMORTIZATION AND NET NEGATIVE SALVAGE RATES

Section 5.1

The depreciation, amortization and net negative salvage rates used in deriving the Settlement Rates are shown in Appendix D. Effective January 1, 2018, and continuing through the Settlement Term, Northwest will utilize the depreciation, amortization and net negative salvage rates in Appendix D for recording depreciation, amortization and net negative salvage expenses.

Section 5.2

Northwest will continue to use separate sub-accounts to record net negative salvage.

Section 5.3

Nothing in this Settlement shall preclude Northwest from continuing to utilize accelerated depreciation for tax purposes nor from continuing to follow Generally Accepted Accounting Principles and the Internal Revenue Code of 1954, as amended, and regulations promulgated thereunder (collectively, the "Code"), which utilize tax normalization.

ARTICLE VI
U.S. FEDERAL CORPORATE INCOME TAX RATE

Section 6.1

If the current U.S. federal income tax rate of 35 percent applicable to corporations should be reduced for any taxable period(s) between January 1, 2018, and the end of the Settlement Term ("Reduced Tax Rate"), then Northwest shall record in a regulatory liability account, to be ultimately returned to the Settling Parties other than Northwest: (a) the dollar amount shown in Appendix E for the

Reduced Tax Rate[5] multiplied by (b) the number of years and/or partial years (prorated monthly) during the Settlement Term that the Reduced Tax Rate is in effect. Northwest shall amortize the balance of the regulatory liability account over a period of 5 years beginning with the effective date of Northwest's new rates in the first Post-Moratorium[6] NGA Section 4 or 5 general rate case filing or pre-filing settlement.

Section 6.2

If the current U.S. federal income tax rate of 35 percent applicable to corporations should be increased for any taxable period(s) between January 1, 2018, and the end of the Settlement Term ("Increased Tax Rate"), then Northwest shall record in a regulatory asset account, to be ultimately recovered by Northwest: (a) the dollar amount shown in Appendix E for the Increased Tax Rate[7] multiplied by (b) the number of years and/or partial years (prorated monthly) during the Settlement Term that the Increased Tax Rate is in effect. Northwest shall amortize the balance of the regulatory asset account over a period of 5 years beginning with the effective date of Northwest's new rates in the first Post-Moratorium NGA Section 4 or 5 general rate case filing or pre-filing settlement.

Section 6.3

If the current U.S. federal income tax rate applicable to corporations of 35 percent should decrease or increase for any taxable period during the Settlement Term, then the terms and provisions of this Article VI shall continue in effect beyond the Settlement Term until the applicable five-year amortization period is complete.

[5] Any fraction of a percent shall be rounded to the nearest one-tenth percent and the difference between the dollar amounts reflected in Appendix E shall be interpolated accordingly.
[6] The "Moratorium" is defined in Section 12.1. The phrase "Post-Moratorium" means an action having an effective date any time on or after October 2, 2018.
[7] Any fraction of a percent shall be rounded to the nearest one-tenth percent and the difference between the dollar amounts reflected in Appendix E shall be interpolated accordingly.

ARTICLE VII
POST-RETIREMENT BENEFITS OTHER THAN PENSIONS

Article VI of the 2012 Settlement addresses the ongoing treatment of Post-Retirement Benefits Other than Pensions ("PBOP"). Section 6.7 of Article VI of the 2012 Settlement provides that, "With the exception of Section 6.1, the terms and provisions of this Article VI shall continue in effect beyond the Settlement Term until the Commission, in response to any party carrying the burden of persuasion, determines to modify or change the terms and provisions relating to PBOPs as set forth herein." Section 6.1 sets forth the amount of the regulatory liability that existed at that time, which has now been updated to be $30,586,547 as of December 31, 2016, in FERC Account No. 254.

ARTICLE VIII
SETTLEMENT RATES

The Settlement Rates shown in Appendix B shall become effective January 1, 2018, and remain in effect through September 30, 2018.[8] The Settlement Rates shown in Appendix C shall become effective October 1, 2018, and remain in effect through the remainder of the Settlement Term. The Settlement Rates are computed consistent with the terms of this Settlement and are reflected as daily rates on the *pro forma* tariff sheets submitted herewith in Appendix F. This Settlement becoming effective in accordance with Article XI shall constitute the Commission authority necessary for Northwest to place into effect final tariff sheets reflecting the Settlement Rates.

ARTICLE IX
COMMENTS OF SETTLING PARTIES

Settling Parties agree that, to the extent that any comments are filed by a Settling Party with the Commission in response to the submission of this Settlement, such comments will not be in opposition to any provision of this Settlement.

[8] To be consistent with the "Gas Day" defined in Northwest's Tariff, the Settlement Rates will become effective at 8:00 a.m. Mountain Standard Time.

ARTICLE X
CONTESTED SETTLEMENT PROCEDURES

Parties who contest one or more provisions of this Settlement will be deemed to oppose this Settlement and shall be known as "Contesting Parties." To the extent this Settlement is approved by the Commission, this Settlement shall become effective as to the Settling Parties (subject to their rights described in Article XI) notwithstanding the objections of Contesting Parties. As to any Contesting Party excluded from the terms of this Settlement pursuant to this Article X, Northwest will file an NGA Section 4 general rate case by no later than June 30, 2017, consistent with the 2017 Rate Filing requirement, and may submit additional NGA Section 4 general rate case filings affecting the Contesting Parties at any time thereafter. Northwest will have the same rights as to the Contesting Parties in such Section 4 proceeding(s) as it would have had absent this Settlement. Contesting Parties shall not have any rights or obligations under this Settlement. Except as otherwise expressly provided in this Settlement, any Commission order during the Settlement Term related to any NGA Section 4 or 5 general rate case filing shall only become effective as to Contesting Parties. Further, no rate, surcharge, or allocation of costs applicable to any Settling Party shall be modified as a result of the election of any other party to become a Contesting Party.

ARTICLE XI
EFFECTIVENESS AND TERM

Section 11.1

If the Commission issues an order approving this Settlement without modification or condition, then: (a) the Settling Parties waive any and all rights to file requests for rehearing, clarification and/or reconsideration of such an order and (b) this Settlement shall become effective on the date that such an order becomes a "Final Order."[9] If the Commission issues an order approving this Settlement subject to

[9] A "Final Order" means an order by the Commission for which no request for rehearing or petition for review or certiorari is pending and for which the statutory time period within which to seek rehearing, review or certiorari has expired.

modification or condition, then this Settlement shall become effective on the date that such an order becomes a Final Order, subject to the rights of the Settling Parties enumerated in this Article XI.

Section 11.2

If the Commission issues an order approving this Settlement subject to modification or condition, then within seven (7) calendar days of the date of such an order, the Settling Parties will initiate a good-faith meet-and-confer process to: (a) determine whether the Commission-imposed modification or condition can be accepted by all Settling Parties, or, if not, then (b) make such mutually agreeable changes to this Settlement as are necessary so it is acceptable to all the Settling Parties. If within fourteen (14) calendar days of the date of such an order the Settling Parties are unable to mutually agree as provided for in (a) or (b) in the preceding sentence, then the obligation to meet and confer in good faith shall cease and the Settling Parties may pursue their rights set forth in Sections 11.3, 11.4, 11.5 and 11.6.

Section 11.3

If the Commission issues an order approving this Settlement subject to modification or condition, then within twenty-one (21) calendar days of the issuance of such an order and following the good faith efforts prescribed in Section 11.2, Northwest shall provide written notice to the Commission and all parties in this proceeding stating whether it will withdraw this Settlement and, if it does not withdraw this Settlement, whether it will seek rehearing of such order. Failure to provide such notice shall be deemed Northwest's election not to withdraw this Settlement, but shall not prevent Northwest from seeking rehearing. If Northwest does not withdraw this Settlement, then this Settlement shall remain in effect with the modification or condition required by the Commission, subject to the outcome of any request for rehearing. If Northwest elects to file a request for rehearing, it must be consistent with the terms of this Settlement and no other Settling Party shall oppose such a request for rehearing.[10] Within

[10] However, another Settling Party may challenge whether Northwest's request for rehearing is, in fact, consistent with the terms of this Settlement.

seven (7) calendar days of a Final Order denying any request for rehearing that is consistent with this Settlement, Northwest shall have the option to withdraw this Settlement by providing written notice of withdrawal of this Settlement to the Commission and all parties in this proceeding.

Section 11.4

If the Commission issues an order approving this Settlement subject to modification or condition, then within twenty-one (21) calendar days of the issuance of such an order and following the good faith efforts prescribed in Section 11.2, each Settling Party that no longer supports the settlement, other than Northwest shall provide written notice to the Commission and all parties in this proceeding stating it will no longer continue participating in this Settlement. Failure to provide such notice shall be deemed such Settling Party's election to continue its participation in this Settlement, but shall not prevent such Settling Party from seeking rehearing. If such Settling Party continues participating in this Settlement, then such Settling Party shall be bound by this Settlement as modified or conditioned by the Commission, subject to the outcome of any request for rehearing. If such Settling Party elects to file a request for rehearing, it must be consistent with the terms of this Settlement and no other Settling Party will oppose such request for rehearing.[11] Within seven (7) calendar days of a Final Order denying any request for rehearing that is consistent with this Settlement, any Settling Party other than Northwest shall have the option to cease participating in this Settlement by providing written notice of withdrawal from participation in this Settlement to the Commission and all parties in this proceeding.

Section 11.5

If a Settling Party other than Northwest provides notice in compliance with Section 11.4 that it no longer wishes to participate in this Settlement, then such Settling Party shall cease to be a Settling Party and shall be deemed to be a Contesting Party as of the date of such notice. Within seven (7) calendar days of receipt of a notice that any Settling Party other than Northwest elects to become a

[11] However, another Settling Party may challenge whether such Settling Party's request for rehearing is, in fact, consistent with the terms of this Settlement.

Contesting Party, Northwest shall have the option, but not the obligation, to withdraw this Settlement by providing written notice of withdrawal of this Settlement to the Commission and all parties in this proceeding.

Section 11.6

If Northwest withdraws this Settlement in compliance with this Article XI or this Settlement is otherwise rejected in its entirety in a Final Order, then all Settling Parties' rights, obligations and commitments under this Settlement are deemed null and void, and all Settling Parties are returned to the *status quo ante*.

Section 11.7

The term of this Settlement shall begin on the effective date determined in accordance with this Article XI and shall end the day before Northwest's new rates become effective pursuant to the first Post-Moratorium NGA Section 4 or 5 general rate case filing or pre-filing settlement ("Settlement Term").[12]

ARTICLE XII
MORATORIUM AND MANDATORY FILING REQUIREMENT

Section 12.1

This Settlement establishes a moratorium on any Settling Party proposing any NGA Section 4 or 5 changes to the levels of Northwest's general rates or other matters specifically addressed and resolved by this Settlement that would seek to place such new rates or changes into effect as among the Settling Parties any earlier than October 2, 2018 ("Moratorium"). The Moratorium will not preclude Northwest from making other filings at FERC that do not conflict with or change the provisions of this Settlement such as: requests for authorization to construct and operate new facilities; requests to provide new services not covered by this Settlement; requests for incremental, maximum recourse and/or other rates and/or rate schedules associated with such new facilities or new services; requests for new or modified

[12] However, there are certain provisions of this Settlement that will by their express terms survive beyond the end of the Settlement Term.

terms or conditions of service; entering into discounted rate agreements; entering into negotiated rate agreements; or other tariff changes that do not change the provisions of this Settlement, including, but not limited to, adjustments for fuel, rate adjustments for the recovery of surcharges for items such as the Commission's Annual Charge Adjustment and contributions to the Gas Technology Institute, or compliance tariff changes required under this Settlement or by the Commission.

Section 12.2

Neither Northwest nor any other Settling Party shall be precluded from seeking enforcement of the terms of this Settlement.

Section 12.3

To the extent that the Commission considers any change to the provisions of this Settlement during the Moratorium, the standard of review for any changes to this Settlement proposed by a Settling Party shall be the *Mobile-Sierra* "public interest" standard.[13] The standard of review for changes proposed by a non-Settling Party or the Commission, acting *sua sponte*, shall be the ordinary "just and reasonable" standard.[14]

Section 12.4

Northwest will file an NGA Section 4 general rate case at FERC for rates to become effective not later than January 1, 2023, unless: (a) Northwest has entered into a pre-filing settlement or (b) a Post-Moratorium NGA Section 5 general rate case has been filed on or before January 1, 2023, regarding Northwest's rates.

[13] *United Gas Pipe Line v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 554 U.S. 527 (2008) (*Morgan Stanley*).
[14] *See Morgan Stanley*, 554 U.S. at 535.

ARTICLE XIII
RESERVATIONS

Section 13.1

The various provisions of this Settlement are not severable. If this Settlement does not become effective in accordance with Article XI, then it shall be privileged, and all discussions held and materials provided by any party in reaching this Settlement shall be treated as if it were subject to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R §385.602 (2016), regardless of whether Rule 602 applies. The provisions of this Settlement relate only to the specific matters resolved by this Settlement and no Settling Party waives any claim or right which it otherwise may have with respect to any matters not expressly provided for in this Settlement.

Section 13.2

The Commission's approval of this Settlement shall constitute a finding that the Settlement is fair and reasonable and in the public interest, but shall not constitute a determination on the merits of the specific provisions of this Settlement. The Commission's approval of this Settlement shall not constitute Commission precedent regarding any principle or issue. The methods or practices observed in deriving rates and the presence or absence of methods of establishing rates as referenced in this Settlement shall not be used to prejudice any otherwise available rights or arguments of any participant in a future proceeding, other than to enforce the terms of this Settlement or collect rates due for the service provided while this Settlement remains in effect, and shall not be used as evidence that a particular method is a "long-standing practice" as that term is used in *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578 (D.C. Cir. 1979), or a "settled practice" as that term is used in *Public Service Commission of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

Section 13.3

No party shall be deemed the drafter of this Settlement, and this Settlement shall not be construed against any party as the drafter.

Section 13.4

This Settlement shall be interpreted in accordance with and governed by the laws of the State of Utah, without regard to its conflicts of laws principles.

ARTICLE XIV
POTENTIAL TIMING ISSUES

Section 14.1

If the Settlement approval process is not completed[15] before June 30, 2017, then Northwest will file an NGA Section 4 general rate case to satisfy the 2017 Rate Filing requirement. The other Settling Parties shall have the right to respond to such filing without limitation or restriction. If the Settlement approval process is completed after June 30, 2017, but before January 1, 2018, then Northwest will withdraw the 2017 Rate Filing as to the other Settling Parties. If the Settlement approval process is completed on, or after January 1, 2018, then Northwest will withdraw the 2017 Rate Filing as to the other Settling Parties and refunds and surcharges will be addressed in accordance with Section 14.2.

Section 14.2

If the Settlement approval process is completed by January 1, 2018, then no refund or surcharge will be due any Settling Party. If the Settlement approval process is completed after January 1, 2018, then any refunds and surcharges resulting from the 2017 Rate Filing will be assessed so as to place the Settling Parties in the same position as if the Settlement approval process had been completed by January 1, 2018.

ARTICLE XV
NO RECENT RATE REVIEW

This Settlement does not constitute a recent rate review under the Commission's *Policy Statement on Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶

[15] Completion of the Settlement approval process means a Final Order by the Commission from which: (a) Northwest has no remaining right to withdraw pursuant to Sections 11.3 or 11.5 (if applicable) and (b) no other Settling Party has a remaining right to cease its participation pursuant to Section 11.4 (if applicable).

61,047, *clarification denied*, 152 F.E.R.C. ¶ 61,046 (2015) ("Policy Statement"). This Article XV shall not preclude Northwest from requesting Commission approval of a cost recovery mechanism pursuant to the Policy Statement that would take effect after the Moratorium.

DATED this 23rd day of January, 2017.

Respectfully submitted

NORTHWEST PIPELINE LLC

Bruce Reemsnyder

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Director, Rates & Tariffs	Senior Counsel
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Appendix A	Settling Parties
Appendix B	Summary of Daily Settlement Rates Exclusive of Surcharges Effective January 1, 2018, through September 30, 2018
Appendix C	Summary of Daily Settlement Rates Exclusive of Surcharges effective October 1, 2018
Appendix D	Summary of Depreciation, Amortization and Net Negative Salvage Rates
Appendix E	Regulatory Asset or Liability Related to Change in U.S. Federal Corporate Income Tax Rate
Appendix F	*Pro Forma* Tariff Sheets

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Petition for Approval of Settlement and Stipulation and Settlement Agreement on each of Northwest Pipeline LLC's shippers and affected state regulatory commissions.

Dated this 23rd day of January, 2017.

Bruce Reemsnyder

Bruce Reemsnyder
Senior Counsel
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Bruce.Reemsnyder@Williams.com

Appendix A

Northwest Pipeline LLC
Docket No. RP17-
Settling Parties

Supporting:
Avista Corporation
Cardinal FG Company
Cascade Natural Gas Corporation
Citadel Energy Marketing LLC
City of Blanding
City Of Ellensburg
City Of Enumclaw
Cross Timbers Energy Services, Inc.
Cyanco Company, LLC
EP Minerals, LLC
FortisBC Energy Inc.
Georgia-Pacific LLC
Harvey's Tahoe Management Co., Inc.
Idaho Power Company
Idahoan Foods, LLC
IGI Resources, Inc.
Intermountain Gas Company
International Paper
Kinect Energy Group
Longview Fibre Paper and Packaging, Inc.
Newmont USA Ltd
Northwest Industrial Gas Users
Northwest Natural Gas Company
Northwest Pipeline LLC
Occidental Energy Marketing, Inc.
Portland General Electric Company
Premier Magnesia, LLC
Puget Sound Energy, Inc.
Questar Gas
Roseburg Forest Products
Shell Energy North America (US), L.P.
Sierra Pacific Power Company
Snohomish County PUD No. 1
Southwest Gas Corporation
Town Of Rangely
United States Gypsum Company

Northwest Pipeline LLC
Docket No. RP17-
Settling Parties
(continued)

Not Opposing:
Black Hills Gas Distribution, LLC
Chevron U.S.A. Inc.
Clearwater Paper Corporation
Columbia Properties Tahoe, LLC dba Mont Bleu Resort Casino & Spa
Columbia Pacific Bio-Refinery
Evraz Inc. NA
Frederickson Power LP
Marathon Oil Company
Morgan Stanley Capital Group Inc.
Nippon Dynawave Packaging Co.
North Pacific Paper Company, LLC
Pacificorp
Public Utility District No. 1 of Clark County
The Boeing Company
TransAlta Energy Marketing (US) Inc.
Weyerhaeuser NR Company

Appendix B

NORTHWEST PIPELINE LLC
Docket No. RP17-
Summary of Daily Settlement Rates 1/
Exclusive of Surcharges
Effective January 1, 2018

Line	Rate Schedule (a)		Rate (b)
1	TF-1		
2	Reservation Charge	- Large Customer	$0.39294
3		- Evergreen - 15-year	$0.35077
4		- Evergreen - 25-year	$0.32093
5	Volumetric Charge	- Large Customer	$0.00832
6		- Evergreen - 15-year	$0.00832
7		- Evergreen - 25-year	$0.00832
8		- Small Customer	$0.69427
9	TF-2		
10	Reservation Charge		$0.39294
11	Volumetric Charge		$0.00832
12	TI-1		
13	Maximum Volumetric Charge 2/		$0.40126
14	Minimum Volumetric Charge		$0.00832
15	SGS-2F Pre-Expansion		
16	Demand Charge		$0.01562
17	Capacity Demand Charge		$0.00057
18	SGS-2F Expansion		
19	Demand Charge		$0.04056
20	Capacity Demand Charge		$0.00348
21	SGS-2I		
22	Volumetric Charge		$0.00224
23	SGS-2F Volumetric Bid Rates Pre-Expansion		
24	Withdrawal Charge		$0.01562
25	Storage Charge		$0.00057
26	SGS-2F Volumetric Bid Rates Expansion		
27	Withdrawal Charge		$0.04056
28	Storage Charge		$0.00348
29	LS-2F		
30	Demand Charge		$0.02587
31	Capacity Demand Charge		$0.00331
32	Liquefaction Charge		$0.90855
33	Vaporization Charge		$0.03386
34	LS-2I 3/		
35	Maximum Volumetric Charge		$0.00662
36	Minimum Volumetric Charge		$0.00000
37	LS-2F Volumetric Bid 3/		
38	Vaporization Demand Related Charge		$0.02587
39	Storage Capacity Charge		$0.00331
40	DEX-1		
41	Maximum Volumetric Charge		$0.40126
42	Minimum Volumetric Charge		$0.00000
43	PAL		
44	Maximum Volumetric Charge		$0.40126
45	Minimum Volumetric Charge		$0.00000
46	Facilities Reservation Surcharge for the Columbia Gorge 1999 Expansion 4/		$0.09855

1/ Reflects reservation, demand and capacity demand charges as daily rates.

2/ Designed on a 100% load factor basis of the Rate Schedule TF-1 (Large Customer) rates.

3/ LS-2I and LS-2F volumetric bid service will also be assessed Rate Schedule LS-2F liquefaction and vaporization charges.

4/ Rates for the years 2018 forward are as follows (surcharge ends March 31, 2025):

2018	$0.09855
2019	$0.09189
2020	$0.08667
2021	$0.08194
2022	$0.07696
2023	$0.07199
2024	$0.06680
2025	$0.06552

Appendix C

NORTHWEST PIPELINE LLC
Docket No. RP17-
Summary of Daily Settlement Rates 1/
Exclusive of Surcharges
Effective October 1, 2018

Line	Rate Schedule (a)	Rate (b)
1	TF-1	
2	Reservation Charge - Large Customer	$0.39033
3	- Evergreen - 25-year	$0.32039
5	Volumetric Charge - Large Customer	$0.00832
6	- Evergreen - 25-year	$0.00832
7	- Small Customer	$0.69427
8	TF-2	
9	Reservation Charge	$0.39033
10	Volumetric Charge	$0.00832
11	TI-1	
12	Maximum Volumetric Charge 2/	$0.39865
13	Minimum Volumetric Charge	$0.00832
14	SGS-2F Pre-Expansion	
15	Demand Charge	$0.01562
16	Capacity Demand Charge	$0.00057
17	SGS-2F Expansion	
18	Demand Charge	$0.04056
19	Capacity Demand Charge	$0.00348
20	SGS-2I	
21	Volumetric Charge	$0.00224
22	SGS-2F Volumetric Bid Rates Pre-Expansion	
23	Withdrawal Charge	$0.01562
24	Storage Charge	$0.00057
25	SGS-2F Volumetric Bid Rates Expansion	
26	Withdrawal Charge	$0.04056
27	Storage Charge	$0.00348
28	LS-2F	
29	Demand Charge	$0.02587
30	Capacity Demand Charge	$0.00331
31	Liquefaction Charge	$0.90855
32	Vaporization Charge	$0.03386
33	LS-2I 3/	
34	Maximum Volumetric Charge	$0.00662
35	Minimum Volumetric Charge	$0.00000
36	LS-2F Volumetric Bid 3/	
37	Vaporization Demand Related Charge	$0.02587
38	Storage Capacity Charge	$0.00331
39	DEX-1	
40	Maximum Volumetric Charge	$0.39865
41	Minimum Volumetric Charge	$0.00000
42	PAL	
43	Maximum Volumetric Charge	$0.39865
44	Minimum Volumetric Charge	$0.00000
45	Facilities Reservation Surcharge for the Columbia Gorge 1999 Expansion 4/	$0.09855

1/ Reflects reservation, demand and capacity demand charges as daily rates.

2/ Designed on a 100% load factor basis of the Rate Schedule TF-1 (Large Customer) rates.

3/ LS-2I and LS-2F volumetric bid service will also be assessed Rate Schedule LS-2F liquefaction and vaporization charges.

4/ Rates for the years 2018 forward are as follows (surcharge ends March 31, 2025):

2018	$0.09855
2019	$0.09189
2020	$0.08667
2021	$0.08194
2022	$0.07696
2023	$0.07199
2024	$0.06680
2025	$0.06552

NORTHWEST PIPELINE LLC
Docket No. RP17-
Summary of Depreciation, Amortization and Net Negative Salvage Rates

Line (a)	Description (b)	Straight Line Rate (c)	Net Negative Salvage Rate (d)	Total Rate (e)
1	General System Transmission	2.50%	0.30%	2.80%
2	Evergreen 15-Year	2.95%	0.30%	3.25%
3	Evergreen 25-Year	2.95%	0.30%	3.25%
4	Other Transmission:			
5	Albertson's	6.67%	0.30%	6.97%
6	Berwick	3.92%	0.30%	4.22%
7	Centralia	5.00%	0.30%	5.30%
8	Columbia Gorge	4.44%	0.30%	4.74%
9	Elmore	3.33%	0.30%	3.63%
10	Nampa	6.67%	0.30%	6.97%
11	North Seattle	6.67%	0.30%	6.97%
12	Olympia	6.67%	0.30%	6.97%
13	South Seattle	6.67%	0.30%	6.97%
14	Tumwater	5.00%	0.30%	5.30%
15	Underground Storage Plant (Pre-Expansion and Expansion)	2.23%	0.53%	2.76%
16	Other Storage Plant – LNG	1.45%	0.15%	1.60%
17	General Plant:			
18	Structures and Improvements 1/	LOL	None	LOL
19	Office Furniture	6.67%	None	6.67%
20	Computer Hardware	33.33%	None	33.33%
21	Computer Software	20.00%	None	20.00%
22	Office Equipment	6.67%	None	6.67%
23	Transportation Equipment	25.00%	None	25.00%
24	Tools, Shop, and Garage Equipment	6.67%	None	6.67%
25	Laboratory Equipment	10.00%	None	10.00%
26	Power Operated Equipment	12.00%	None	12.00%
27	Communications Equipment	6.67%	None	6.67%
28	Communications Equipment -Telephone	6.67%	None	6.67%
29	Communications Structures	4.00%	None	4.00%
30	Communications SCADA	10.00%	None	10.00%
31	Miscellaneous Equipment	10.00%	None	10.00%
32	Intangible Plant:			
33	Organization	4.00%	None	4.00%
34	Franchises and Consents	4.00%	None	4.00%
35	Miscellaneous Intangible Plant	6.67%	None	6.67%

1/ LOL means "Life of Lease".

Appendix E

Northwest Pipeline LLC
Docket No. RP17-
Regulatory Asset or Liability Related to Change in Federal Income Tax Rate

Line	Federal Income Tax Rate 1/	Change From 35% Rate
(a)	(b)	(c)
1	Rate Increases	
2	36%	2,079,044
3	37%	4,224,089
4	38%	6,438,329
5	39%	8,725,167
6	40%	11,088,233
7	41%	13,531,403
8	42%	16,058,820
9	43%	18,674,919
10	44%	21,384,450
11	45%	24,192,509
12	46%	27,104,570
13	47%	30,126,520
14	48%	33,264,699
15	49%	36,525,944
16	50%	39,917,639
17	51%	43,447,770
18	52%	47,124,991
19	53%	50,958,688
20	54%	54,959,068
21	55%	59,137,243
22	56%	63,505,335
23	57%	68,076,594
24	58%	72,865,532
25	59%	77,888,076
26	60%	83,161,748
27	61%	88,705,865
28	62%	94,541,777
29	63%	100,693,144
30	64%	107,186,253
31	65%	114,050,398
32	66%	121,318,315
33	67%	129,026,712
34	68%	137,216,885
35	69%	145,935,455
36	70%	155,235,263

1/ Any fraction of a percent shall be rounded to the nearest one-tenth percent and the difference between the dollar amounts reflected above shall be interpolated accordingly.

Northwest Pipeline LLC
Docket No. RP17-
Regulatory Asset or Liability Related to Change in Federal Income Tax Rate
(continued)

Line	Federal Income Tax Rate 1/	Change From 35% Rate
(a)	(b)	(c)
1	Rate Reductions	
2	34%	(2,016,042)
3	33%	(3,971,904)
4	32%	(5,870,241)
5	31%	(7,713,553)
6	30%	(9,504,200)
7	29%	(11,244,405)
8	28%	(12,936,272)
9	27%	(14,581,786)
10	26%	(16,182,827)
11	25%	(17,741,173)
12	24%	(19,258,510)
13	23%	(20,736,436)
14	22%	(22,176,466)
15	21%	(23,580,040)
16	20%	(24,948,524)
17	19%	(26,283,219)
18	18%	(27,585,360)
19	17%	(28,856,125)
20	16%	(30,096,633)
21	15%	(31,307,952)
22	14%	(32,491,102)
23	13%	(33,647,052)
24	12%	(34,776,731)
25	11%	(35,881,024)
26	10%	(36,960,777)
27	9%	(38,016,799)
28	8%	(39,049,864)
29	7%	(40,060,713)
30	6%	(41,050,054)
31	5%	(42,018,568)
32	4%	(42,966,903)
33	3%	(43,895,686)
34	2%	(44,805,513)
35	1%	(45,696,961)
36	0%	(46,570,579)

1/ Any fraction of a percent shall be rounded to the nearest one-tenth percent and the difference between the dollar amounts reflected above shall be interpolated accordingly.

Appendix F

NORTHWEST PIPELINE LLC
Docket No. RP17-
Pro Forma Tariff Sheets

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate(1),(3) Minimum	Base Tariff Rate(1),(3) Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.39294
15 Year Evergreen Exp.	.00000	.35077
25 Year Evergreen Exp.	.00000	.32093
Volumetric (2)		
(Large Customer)		
System-Wide	.00832	.00832
15 Year Evergreen Exp.	.00832	.00832
25 Year Evergreen Exp.	.00832	.00832
(Small Customer) (6)	.00832	.69427
Scheduled Overrun (2)	.00832	.40126
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.39294
Volumetric	.00832	.00832
Scheduled Daily Overrun	.00832	.40126
Annual Overrun	.00832	.40126
Rate Schedule TI-1 (2)		
Volumetric (7)	.00832	.40126
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

Footnotes (Continued)

(3) To the extent Transporter discounts the Maximum Base Tariff Rate, such discounts will be applied on a non-discriminatory basis, subject to the policies of Order No. 497.

Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

An incremental facilities charge or other payment method provided for in Section 21 or 29 of the General Terms and Conditions, is payable in addition to all other rates and charges if such a charge is included in Exhibit C to a Shipper's Transportation Service Agreement.

In addition to the rates set forth on Sheet No. 5, Puget Sound Energy, Inc.'s Transportation Service Agreement No. 140053 is subject to an annual incremental facility charge pursuant to Section 21 of the General Terms and Conditions for the South Seattle Delivery Lateral Expansion Project. The effective annual incremental facility charge is $3,625,910 and is billed in equal monthly one-twelfth increments. The daily incremental facility charge is $0.15546 per Dth.

In addition to the reservation rates shown on Sheet No. 5, Shippers who contract for Columbia Gorge Expansion Project capacity are subject to a facility reservation surcharge pursuant to Section 3.4 of Rate Schedule TF-1. The facility charge used in deriving the Columbia Gorge Expansion Project facility reservation surcharge has a minimum rate of $0 and a maximum rate during the indicated months or calendar years as follows:

(Dollars per Dth)

Year	Rate	Year	Rate	Year	Rate
2018	$0.09855	2021	$0.08194	2023	$0.07199
2019	$0.09189	2022	$0.07696	2024	$0.06680
2020	$0.08667				

January 1, 2025 - March 31, 2025 $0.06552

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of $0.34641 and $0.31657 for transmission costs and $0.00436 and $0.00436 for storage costs, respectively. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.38858 for transmission costs and $0.00436 for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00806 for transmission costs and $0.00026 for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.00806 for transmission costs and $0.00026 for storage costs.

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate(1),(3) Minimum	Base Tariff Rate(1),(3) Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.39294~~.41000~~
15 Year Evergreen Exp.	.00000	.35077~~.36263~~
25 Year Evergreen Exp.	.00000	.32093~~.34234~~
Volumetric (2)		
(Large Customer)		
System-Wide	.00832~~.00813~~	.00832~~.03000~~
15 Year Evergreen Exp.	.00832~~.00813~~	.00832~~.00813~~
25 Year Evergreen Exp.	.00832~~.00813~~	.00832~~.00813~~
(Small Customer) (6)	.00832~~.00813~~	.69427~~.72155~~
Scheduled Overrun (2)	.00832~~.00813~~	.40126~~.44000~~
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.39294~~.41000~~
Volumetric	.00832~~.00813~~	.00832~~.03000~~
Scheduled Daily Overrun	.00832~~.00813~~	.40126~~.44000~~
Annual Overrun	.00832~~.00813~~	.40126~~.44000~~
Rate Schedule TI-1 (2)		
Volumetric (7)	.00832~~.00813~~	.40126~~.44000~~
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

Footnotes (Continued)

(3) To the extent Transporter discounts the Maximum Base Tariff Rate, such discounts will be applied on a non-discriminatory basis, subject to the policies of Order No. 497.

Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

An incremental facilities charge or other payment method provided for in Section 21 or 29 of the General Terms and Conditions, is payable in addition to all other rates and charges if such a charge is included in Exhibit C to a Shipper's Transportation Service Agreement.

In addition to the rates set forth on Sheet No. 5, Puget Sound Energy, Inc.'s Transportation Service Agreement No. 140053 is subject to an annual incremental facility charge pursuant to Section 21 of the General Terms and Conditions for the South Seattle Delivery Lateral Expansion Project. The effective annual incremental facility charge is $3,625,910 and is billed in equal monthly one-twelfth increments. The daily incremental facility charge is $0.15546 per Dth.

In addition to the reservation rates shown on Sheet No. 5, Shippers who contract for Columbia Gorge Expansion Project capacity are subject to a facility reservation surcharge pursuant to Section 3.4 of Rate Schedule TF-1. The facility charge used in deriving the Columbia Gorge Expansion Project facility reservation surcharge has a minimum rate of $0 and a maximum rate during the indicated months or calendar years as follows:

(Dollars per Dth)

Year	Rate	Year	Rate	Year	Rate
2018	$0.09855	2021	$0.08194	2023	$0.07199
2019	$0.09189	2022	$0.07696	2024	$0.06680
2020	$0.08667				
~~2013~~	~~$0.09549~~	~~2017~~	~~$0.07471~~	~~2021~~	~~$0.05409~~
~~2014~~	~~$0.09255~~	~~2018~~	~~$0.06876~~	~~2022~~	~~$0.05273~~
~~2015~~	~~$0.08661~~	~~2019~~	~~$0.06282~~	~~2023~~	~~$0.05137~~
~~2016~~	~~$0.08044~~	~~2020~~	~~$0.05671~~	~~2024~~	~~$0.05023~~

January 1, 2025 - March 31, 2025 $0.06552~~0.02442~~

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 01/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of $0.34641~~0.35843~~ and $0.31657~~0.33814~~ for transmission costs and $0.00436~~0.00420~~ and $0.00436~~0.00420~~ for storage costs, respectively. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.38858~~0.40580~~ for transmission costs and $0.00436~~0.00420~~ for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00806~~0.00775~~ for transmission costs and $0.00026~~0.00038~~ for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.00806~~0.02962~~ for transmission costs and $0.00026~~0.00038~~ for storage costs.

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 10/01/2018

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate(1),(3) Minimum	Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.39033
25 Year Evergreen Exp.	.00000	.32039
Volumetric (2)		
(Large Customer)		
System-Wide	.00832	.00832
25 Year Evergreen Exp.	.00832	.00832
(Small Customer) (6)	.00832	.69427
Scheduled Overrun (2)	.00832	.39865
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.39033
Volumetric	.00832	.00832
Scheduled Daily Overrun	.00832	.39865
Annual Overrun	.00832	.39865
Rate Schedule TI-1 (2)		
Volumetric (7)	.00832	.39865
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 10/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of $0.31603 for transmission costs and $0.00436 for storage costs. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.38597 for transmission costs and $0.00436 for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00806 for transmission costs and $0.00026 for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.00806 for transmission costs and $0.00026 for storage costs.

RATE SETTLEMENT PRO FORMA TARIFF SHEET - EFFECTIVE 10/01/2018

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate(1),(3) Minimum	Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.39033~~.39294~~
~~15 Year Evergreen Exp.~~	~~.00000~~	~~.35077~~
25 Year Evergreen Exp.	.00000	.32039~~.32093~~
Volumetric (2)		
(Large Customer)		
System-Wide	.00832	.00832
~~15 Year Evergreen Exp.~~	~~.00832~~	~~.00832~~
25 Year Evergreen Exp.	.00832	.00832
(Small Customer) (6)	.00832	.69427
Scheduled Overrun (2)	.00832	.39865~~.40126~~
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.39033~~.39294~~
Volumetric	.00832	.00832
Scheduled Daily Overrun	.00832	.39865~~.40126~~
Annual Overrun	.00832	.39865~~.40126~~
Rate Schedule TI-1 (2)		
Volumetric (7)	.00832	.39865~~.40126~~
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

RATE SETTLEMENT PROFORMA TARIFF SHEET - EFFECTIVE 10/01/2018

STATEMENT OF RATES (Continued)

Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the ~~15-Year and~~ 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the ~~15-Year and~~ 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of ~~$0.34641 and~~ $0.316030~~.31657~~ for transmission costs and ~~$0.00436 and~~ $0.00436 for storage costs~~, respectively~~. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.385970~~.38858~~ for transmission costs and $0.00436 for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00806 for transmission costs and $0.00026 for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.00806 for transmission costs and $0.00026 for storage costs.

Table of Contents

FERC GAS TARIFF

FOURTH REVISED VOLUME NO. 1-A

OF

GAS TRANSMISSION NORTHWEST LLC

FILED WITH THE

FEDERAL ENERGY REGULATORY COMMISSION

Communications Concerning This Tariff
Should Be Addressed To:

Joan Collins
Manager, Tariffs and Compliance
Gas Transmission Northwest LLC
Mailing Address: P.O. Box 2446
Houston, TX 77252-2446
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Houston, TX 77002-2700
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STATEMENT OF RATES

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR TRANSPORTATION OF NATURAL GAS

Rate Schedules FTS-1 and LFS-1

	RESERVATION DAILY MILEAGE (a) (Dth-MILE)		RESERVATION DAILY NON-MILEAGE (b) (Dth)		DELIVERY (c) (Dth-MILE)		FUEL (d) (Dth-MILE)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	0.000434	0.000000	0.034393	0.000000	0.000016	0.000016	0.0050%	0.0000%
STF (e)	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
E-2 (h) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h) (Diamond 2)	0.001166	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3 (i)	0.001282	0.000000	0.001283	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (p)	---	---	0.166475	0.000000	0.000000	0.000000	---	---
OVERRUN CHARGE (j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	(k)	(k)	---	---

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS (a)

Rate Schedule ITS-1

	MILEAGE (n) (Dth-Mile)		NON-MILEAGE (o) (Dth)		DELIVERY (c) (Dth-Mile)		FUEL (d) (Dth-Mile)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (Medford) (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
COYOTE SPRINGS								
E-3 (Coyote Springs) (i)	0.001282	0.000000	0.001283	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (Carty Lateral) (p)	---	---	0.166475	0.000000	0.000000	0.000000	---	---
SURCHARGES								
ACA (k)	---	---	(k)	(k)	---	---	---	---

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

Notes:

(a) The mileage component shall be applied per pipeline mile to gas transported by GTN for delivery to shipper based on the primary receipt and delivery points in Shipper's contract. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(b) The non-mileage component is applied per Shipper's MDQ at Primary Point(s) of Delivery on Mainline Facilities.

(c) The delivery rates are applied per pipeline mile to gas transported by GTN for delivery to shipper based on distance of gas transported. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(d) Fuel Use: Shipper shall furnish gas used for compressor station fuel, line loss, and other utility purposes, plus other unaccounted-for gas used in the operation of GTN's combined pipeline system in an amount equal to the sum of the current fuel and line loss percentage and the fuel and line loss percentage surcharge in accordance with Section 6.38 of this tariff, multiplied by the distance in pipeline miles transported from the receipt point to the delivery point multiplied by the transportation quantities of gas received from Shipper under these rate schedules. The current fuel and line loss percentage shall be adjusted each month between the maximum rate of 0.0050% per Dth per pipeline mile and the minimum rate of 0.0000% per Dth per mile. The fuel and line loss percentage surcharge is 0.0002% per Dth per pipeline mile. No fuel use charges will be assessed for backhaul service. Currently effective fuel charges may be found on GTN's Internet website under "Informational Postings."

(e) Seasonal recourse rates apply to short-term firm (STF) service under Rate Schedule FTS-1 (i.e., firm service that has a term of less than one year and that does not include multiple-year seasonal service) and IT Service under Rate Schedule ITS-1. By March 1 of each year GTN may designate up to four (4) months as peak months during a twelve-month period beginning on June 1 of the same year through May 31 of the following year. All other months will be considered off-peak months. Reservation rate components that apply to STF service and per-unit-rate IT service are as follows (delivery charges and applicable surcharges continue to apply):

	4 Peak Mos.	3 Peak Mos.	2 Peak Mos.	1 Peak Mo.	0 Peak Mos.
Peak NM Res.	$0.048150	$0.048150	$0.048150	$0.048150	$0.034393
Peak Mi. Res.	$0.000608	$0.000608	$0.000608	$0.000608	$0.000434

Off-Pk NM Res.	\$0.027515	\$0.029807	\$0.031642	\$0.033142	\$0.034393
Off-Pk Mi. Res.	\$0.000347	\$0.000376	\$0.000399	\$0.000418	\$0.000434

Months currently designated as "Peak Months" may be found on GTN's Internet website under "Informational Postings." By March 1 of each year, GTN will post the Peak Months for the upcoming twelve-month period beginning June 1 of the same year.

(f) Applicable to firm service on GTN's Medford Extension.

(g) Reserved for Future Use.

(h) E-2 (Diamond 1) is a negotiated reservation charge of \$0.002972 per Dth per day for first 45,000 Dth/d and E-2 (Diamond 2) is a negotiated reservation charge of \$0.001166 per Dth per day for the second 45,000 Dth/d. During leap years, E-2 (Diamond 1) is a negotiated reservation charge of \$0.002964 per Dth per day for first 45,000 Dth/d and E-2 (Diamond 2) is a negotiated reservation charge of \$0.001163 per Dth per day for the second 45,000 Dth/d.

(i) Applicable to firm service on GTN's Coyote Springs Extension.

(j) The Overrun Charge shall be equal to the rates and charges set forth for interruptible service under Rate Schedule ITS-1.

(k) In accordance with Section 6.22 of the Transportation General Terms and Conditions of this FERC Gas Tariff, Fourth Revised Volume No. 1-A, all Transportation services that involve the physical movement of gas shall pay an ACA unit adjustment. The currently effective ACA unit adjustment as published on the Commission's website (www.ferc.gov) is incorporated herein by reference. This adjustment shall be in addition to the Base Tariff Rate(s) specified above.

(l) Reserved for Future Use.

(m) Reserved.

(n) The Rate Schedule ITS-1 Mileage Component shall be applied per pipeline mile to gas transported by GTN based on the distance of gas transported. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(o) The Rate Schedule ITS-1 Non-Mileage Component shall be applied per Dth of gas transported by GTN for immediate delivery to the facilities of another entity or an extension facility.

(p) Applicable to firm service on GTN's Carty Lateral Extension.

RESERVED FOR FUTURE USE

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS FOR

Parking and Lending Service
($/Dth)

	BASE TARIFF RATE	
	MINIMUM	MAXIMUM
PAL Parking and Lending Service:	0.0	0.243541/d

Notes:

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULES FTS-1 AND LFS-1

SHIPPER	TERM OF CONTRACT	RATE SCHEDULE	DTH/D	PRIMARY RECEIPT POINT	PRIMARY DELIVERY POINT	RATE /2 /3
Avista Corporation /1	11/1/01 - 10/31/25	FTS-1	20,000	Medford	Medford Ext. Meter	/7
Powerex Corp./1	04/01/16 - 10/31/16	FTS-1	20,000	Kingsgate	Malin	/5

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

Negotiated Rate Agreements Under Rate Schedules FTS-1 and LFS-1

Explanatory Footnotes for Negotiated Rates
under Rate Schedules FTS-1 and LFS-1

/1 This contract does not deviate in any material aspect from the Form of Service Agreement in this Tariff.

/2 Unless otherwise noted, all Shippers pay GTN's maximum Reservation Charge, Delivery Charge, ACA, and contribute fuel in-kind in accordance with this Tariff.

/3 Index Price References: Unless otherwise noted, references to "Daily Index Price" shall mean the price survey midpoint for the specified point as published in Gas Daily for the day of gas flow. Weekend and holiday prices will be determined using the next available Gas Daily publication. Unless otherwise noted, the references to the "NGI FOM" for a specified point shall mean Natural Gas Intelligence's First of Month Bid Week Survey (Supplement to NGI's Weekly Gas Index) Spot Gas Price for the specified point.

/4 Reserved

/5 GTN and Shipper have agreed to a Fixed Reservation Rate Charge of $0.26300 inclusive of the mileage and non-mileage components, which shall be applicable to the Primary Receipt and Delivery Points as well as secondary points, as follows:

Secondary Receipt Points: All points on GTN's system
Secondary Delivery Points: All points on GTN's system

In addition, Shipper shall pay all applicable charges and surcharges in accordance with GTN's FERC Gas Tariff.

/6 Reserved

/7 The Reservation charge shall be equal to the rate set forth in GTN's FERC Gas Tariff identified as FTS-1 E-2 (WWP), or its successor, multiplied by the appropriate Effective Period Percentage as shown in the following table.

Effective Period	Percentage
11/1/01-10/31/02	75%
11/1/02-10/31/03	80%
11/1/03-10/31/04	85%
11/1/04-10/31/05	90%

11/1/05-10/31/06	95%
11/1/06-10/31/25	100%

The Daily Delivery Charge shall be equal to the 100% load factor equivalent of the FTS-1 E-2 rate, or its successor, and shall be multiplied by the positive difference between (a) volumes delivered and (b) the contract MDQ times the appropriate Effective Period Percentage.

Daily Delivery Charge = [Dth Delivered - (MDQ * Effective Period %)] * 100% Load Factor Equivalent FTS-1 E-2

/8 Reserved

/9 Reserved

/10 Reserved

/11 Reserved

/12 Reserved

/13 Reserved

/14 Reserved

/15 Reserved

/16 Reserved

/17 Reserved

/18 Reserved

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULE ITS-1 AND PAL

SHIPPER	TERM OF CONTRACT	RATE SCHEDULE	DTH/D	PRIMARY RECEIPT POINT	PRIMARY DELIVERY POINT	RATE /2 /3

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULE ITS-1 AND PAL

Explanatory Footnotes for Negotiated Rates under Rate Schedule ITS-1 and PAL

/1 This contract does not deviate in any material aspect from the Form of Service Agreement in this Tariff.

/2 Unless otherwise noted, all Shippers pay GTN's maximum Mileage and Non-Mileage Charge, ACA, and contribute fuel in-kind in accordance with this Tariff.

/3 Index Price References: Unless otherwise noted, references to "Daily Index Price" shall mean the price survey midpoint for the specified point as published in Gas Daily for the day of gas flow. Weekend and holiday prices will be determined using the next available Gas Daily publication. Unless otherwise noted, the references to the "NGI FOM" for a specified point shall mean Natural Gas Intelligence's First of Month Bid Week Survey (Supplement to NGI's Weekly Gas Index) Spot Gas Price for the specified point.

NON-CONFORMING SERVICE AGREEMENTS
PURSUANT TO § 154.112(b)

Name of Shipper	Contract Number	Rate Schedule	Effective Date	Termination Date
Cascade Natural Gas Corporation	152	FTS-1	11/1/1993	10/31/2023
Chevron USA Inc.	153	FTS-1	11/1/1993	10/31/2023
City of Burbank	154	FTS-1	11/1/1993	10/31/2023
IGI Resources, Inc.	158	FTS-1	11/1/1993	10/31/2013
Northern California Power Agency	163	FTS-1	11/1/1993	10/31/2023
Talisman Energy Inc	167	FTS-1	11/1/1993	10/31/2023
Paramount Resources US Inc.	168	FTS-1	11/1/1993	10/31/2023
Petro-Canada Hydrocarbons, Inc.	169	FTS-1	11/1/1993	10/31/2023
Sacramento Municipal Utility District	170	FTS-1	11/1/1993	10/31/2023
Avista Corporation	177	FTS-1	11/1/1993	10/31/2023
Avista Corporation	178	FTS-1	11/1/1993	10/31/2023
Cascade Natural Gas Corporation	179	FTS-1	11/1/1993	10/31/2023
Northwest Natural Gas Company	180	FTS-1	11/1/1993	10/31/2023
Puget Sound Energy, Inc.	181	FTS-1	11/1/1993	10/31/2023
Avista Corporation	182	FTS-1	11/1/1993	10/31/2023
Avista Corporation	2591	FTS-1	8/1/1995	10/31/2025
Avista Corporation	2857	FTS-1	11/1/1995	10/31/2025
Avista Corporation	2858	FTS-1	11/1/1995	10/31/2025
Iberdrola Renewables, Inc.	7828	FTS-1	6/3/2001	10/31/2025
Avista Corporation	8035	FTS-1	11/1/2001	10/31/2025
Pacific Gas and Electric Company	111	ITS-1	2/1/1992	10/31/2010
Northwest Natural Gas Company	112	ITS-1	4/1/1992	3/31/2011
Petro-Canada Hydrocarbons, Inc.	119	ITS-1	4/22/1992	4/22/2011
Morgan Stanley Capital Group Inc.	144	ITS-1	7/23/1993	9/30/2010
Shell Energy North America (US), L.P.	146	ITS-1	8/1/1993	8/1/2010
BP Canada Energy Marketing Corp.	4621	AIS-1	12/1/1996	12/31/2010
Sempra Energy Trading Corp.	4721	AIS-1	1/1/1997	12/31/2010
EnCana Marketing (USA) Inc.	4770	AIS-1	1/25/1997	12/31/2010
Nexen Marketing U.S.A., Inc.	6759	AIS-1	6/17/1999	12/31/2010
Shell Energy North America (US), L.P.	7047	AIS-1	4/10/2000	12/31/2010
Sierra Pacific Power Company	7068	AIS-1	4/27/2000	12/4/2019
City of Glendale	7804	AIS-1	5/30/2001	12/31/2021
Iberdrola Renewables, Inc.	7806	AIS-1	5/30/2001	12/31/2021
Petro-Canada Hydrocarbons, Inc.	7807	AIS-1	5/30/2001	12/31/2021
Chevron U.S.A. Inc.	7812	AIS-1	5/30/2001	12/31/2021
Salmon Resources Ltd.	7816	AIS-1	5/30/2001	12/31/2021
Constellation Energy Commodities Group, Inc.	8038	AIS-1	8/2/2001	8/31/2021
Enserco Energy Inc.	8176	AIS-1	11/27/2001	11/30/2021
ConocoPhillips Company	8228	AIS-1	1/8/2002	1/31/2022
UBS AG (London Branch)	8318	AIS-1	4/11/2002	4/30/2023

Concord Energy LLC	8421	AIS-1	7/22/2002	7/31/2012
Tenaska Marketing Ventures	8559	AIS-1	1/1/2003	12/31/2012
Cargill, Inc.	8594	AIS-1	3/19/2003	3/31/2013
Merrill Lynch Commodities, Inc.	8674	AIS-1	6/13/2003	6/13/2023
Apache Corporation	8670	AIS-1	7/1/2003	6/30/2013
Tenaska Marketing Ventures	8880	AIS-1	12/1/2003	11/30/2013
California Dept. of Water Resources	8887	AIS-1	12/1/2003	7/1/2011
United Energy Trading, LLC	9002	AIS-1	3/1/2004	2/28/2014
Select Natural Gas LLC	8978	AIS-1	3/3/2004	3/3/2014
National Fuel Marketing Company LLC	9035	AIS-1	4/27/2004	4/30/2014
Fortis Energy Marketing & Trading GP	9115	AIS-1	7/17/2004	6/30/2014
Powerex Corp.	9149	AIS-1	8/16/2004	7/31/2014
Louis Dreyfus Energy Services L.P.	9281	AIS-1	11/8/2004	10/31/2014
Pacific Summit Energy LLC	9285	AIS-1	11/15/2004	10/31/2010
Devlar Energy Marketing, LLC	9630	AIS-1	6/1/2005	5/31/2015
Suncor Energy Marketing Inc.	9774	AIS-1	10/1/2005	9/30/2015
CanNat Energy Inc.	10197	AIS-1	7/26/2006	7/25/2011
Eagle Energy Partners I, LP	10308	AIS-1	10/27/2006	10/31/2011
Sequent Energy Management LP	10336	AIS-1	11/1/2006	10/31/2010
Occidental Energy Marketing, Inc.	10359	AIS-1	12/22/2006	12/31/2010
NextEra Energy Power Marketing, LLC	10625	AIS-1	4/10/2008	4/30/2018
Natural Gas Exchange, Inc.	10639	AIS-1	4/29/2008	4/30/2018
Citigroup Energy Inc.	10646	AIS-1	5/30/2008	5/31/2018
IGI Resources, Inc.	4576	PS-1	12/1/1996	12/31/2010
Macquarie Cook Energy, LLC	4619	PS-1	12/1/1996	12/31/2010
Sempra Energy Trading Corp.	4720	PS-1	1/1/1997	12/31/2010
EnCana Marketing (USA) Inc.	4868	PS-1	3/1/1997	12/31/2010
Shell Energy North America (US), L.P.	4908	PS-1	3/5/1997	12/31/2010
Husky Gas Marketing Inc.	5348	PS-1	7/3/1997	12/31/2010
Enserco Energy Inc.	5677	PS-1	10/6/1997	12/31/2010
National Fuel Marketing Company LLC	5679	PS-1	10/7/1997	12/31/2010
United States Gypsum Company	5837	PS-1	11/3/1997	5/17/2010
Northwest Natural Gas Company	5992	PS-1	2/13/1998	12/31/2023
Chevron U.S.A. Inc.	6226	PS-1	5/14/1998	12/31/2010
San Diego Gas & Electric Company	6378	PS-1	8/25/1998	12/31/2010
Southern California Gas Company	6613	PS-1	12/14/1998	12/31/2010
Puget Sound Energy, Inc.	7061	PS-1	4/20/2000	4/20/2020
Hermiston Generating Company, L.P.	7798	PS-1	5/30/2001	12/31/2021
City of Glendale	7803	PS-1	5/30/2001	12/31/2021
Iberdrola Renewables, Inc.	7805	PS-1	5/30/2001	12/31/2021
Questar Energy Trading Company	7819	PS-1	5/30/2001	12/31/2021
El Paso Energy Marketing Company	7820	PS-1	5/30/2001	12/31/2021
Sempra Energy Trading Corp.	7833	PS-1	6/14/2001	6/8/2020
Constellation Energy Commodities Group, Inc.	8037	PS-1	8/2/2001	8/31/2021
ConocoPhillips Company	8229	PS-1	1/8/2002	1/31/2022
Tractebel Energy Marketing, Inc.	8283	PS-1	3/14/2002	3/31/2022
UBS AG (London Branch)	8316	PS-1	4/11/2002	4/30/2023

RWE Trading Americas Inc.	8324	PS-1	4/16/2002	4/30/2022
Fortis Energy Marketing & Trading GP	8340	PS-1	5/2/2002	5/31/2022
Concord Energy LLC	8406	PS-1	7/22/2002	7/31/2012
Select Natural Gas LLC	8534	PS-1	11/15/2002	10/31/2012
Tenaska Marketing Ventures	8539	PS-1	12/1/2002	11/30/2012
Cargill, Inc.	8595	PS-1	3/19/2003	3/31/2013
United Energy Trading, LLC	8652	PS-1	5/23/2003	5/31/2013
Apache Corporation	8668	PS-1	7/1/2003	6/30/2013
Occidental Energy Marketing, Inc.	8784	PS-1	9/10/2003	8/31/2013
Tenaska Marketing Ventures	8873	PS-1	12/1/2003	11/30/2013
California Dept. of Water Resources	8886	PS-1	12/1/2003	7/1/2011
Devon Canada Marketing Corporation	8923	PS-1	2/1/2004	1/31/2014
Merrill Lynch Commodities, Inc.	9018	PS-1	4/7/2004	4/7/2014
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Devlar Energy Marketing, LLC	9584	PS-1	5/2/2005	4/30/2015
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J.P. Morgan Ventures Energy Corporation	9948	PS-1	2/1/2006	1/31/2016
CanNat Energy Inc.	10195	PS-1	7/26/2006	7/25/2011
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Sequent Energy Management LP	10332	PS-1	11/1/2006	10/31/2011
El Paso Ruby Holding Company, LLC	12071	FTS-1	11/1/2012	3/31/2018
Portland General Electric Company	17293	FTS-1	10/31/2015	10/31/2045

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STATEMENT OF RATES

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR TRANSPORTATION OF NATURAL GAS

Rate Schedules FTS-1 and LFS-1

	RESERVATION DAILY MILEAGE (a) (Dth-MILE)		DAILY NON-MILEAGE (b) (Dth)		DELIVERY (c) (Dth-MILE)		FUEL (d) (Dth-MILE)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	0.000434	0.000000	0.034393	0.000000	0.000016	0.000016	0.0050%	0.0000%
STF (e)	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
E-2 (h) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h) (Diamond 2)	0.001166	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3 (i)	0.001282	0.000000	0.001283	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (p)	---	---	0.166475	0.000000	0.000000	0.000000	---	---
OVERRUN CHARGE (j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	(k)	(k)	---	---

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS (a)

Rate Schedule ITS-1

	MILEAGE (n) (Dth-Mile)		NON-MILEAGE (o) (Dth)		DELIVERY (c) (Dth-Mile)		FUEL (d) (Dth-Mile)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (Medford) (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
COYOTE SPRINGS								
E-3 (Coyote Springs) (i)	0.001282	0.000000	0.001283	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (Carty Lateral) (p)	---	---	0.166475	0.000000	0.000000	0.000000	---	---
SURCHARGES								
ACA (k)	---	---	(k)	(k)	---	---	---	---

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

Notes:

(a) The mileage component shall be applied per pipeline mile to gas transported by GTN for delivery to shipper based on the primary receipt and delivery points in Shipper's contract. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(b) The non-mileage component is applied per Shipper's MDQ at Primary Point(s) of Delivery on Mainline Facilities.

(c) The delivery rates are applied per pipeline mile to gas transported by GTN for delivery to shipper based on distance of gas transported. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(d) Fuel Use: Shipper shall furnish gas used for compressor station fuel, line loss, and other utility purposes, plus other unaccounted-for gas used in the operation of GTN's combined pipeline system in an amount equal to the sum of the current fuel and line loss percentage and the fuel and line loss percentage surcharge in accordance with Section 6.38 of this tariff, multiplied by the distance in pipeline miles transported from the receipt point to the delivery point multiplied by the transportation quantities of gas received from Shipper under these rate schedules. The current fuel and line loss percentage shall be adjusted each month between the maximum rate of 0.0050% per Dth per pipeline mile and the minimum rate of 0.0000% per Dth per mile. The fuel and line loss percentage surcharge is 0.0002% per Dth per pipeline mile. No fuel use charges will be assessed for backhaul service. Currently effective fuel charges may be found on GTN's Internet website under "Informational Postings."

(e) Seasonal recourse rates apply to short-term firm (STF) service under Rate Schedule FTS-1 (i.e., firm service that has a term of less than one year and that does not include multiple-year seasonal service) and IT Service under Rate Schedule ITS-1. By March 1 of each year GTN may designate up to four (4) months as peak months during a twelve-month period beginning on June 1 of the same year through May 31 of the following year. All other months will be considered off-peak months. Reservation rate components that apply to STF service and per-unit-rate IT service are as follows (delivery charges and applicable surcharges continue to apply):

	4 Peak Mos.	3 Peak Mos.	2 Peak Mos.	1 Peak Mo.	0 Peak Mos.
Peak NM Res.	$0.048150	$0.048150	$0.048150	$0.048150	$0.034393
Peak Mi. Res.	$0.000608	$0.000608	$0.000608	$0.000608	$0.000434

Off-Pk NM Res.	$0.027515	$0.029807	$0.031642	$0.033142	$0.034393
Off-Pk Mi. Res.	$0.000347	$0.000376	$0.000399	$0.000418	$0.000434

Months currently designated as "Peak Months" may be found on GTN's Internet website under "Informational Postings." By March 1 of each year, GTN will post the Peak Months for the upcoming twelve-month period beginning June 1 of the same year.

(f) Applicable to firm service on GTN's Medford Extension.

(g) Reserved for Future Use.

(h) E-2 (Diamond 1) is a negotiated reservation charge of $0.002972 per Dth per day for first 45,000 Dth/d and E-2 (Diamond 2) is a negotiated reservation charge of $0.001166 per Dth per day for the second 45,000 Dth/d. During leap years, E-2 (Diamond 1) is a negotiated reservation charge of $0.002964 per Dth per day for first 45,000 Dth/d and E-2 (Diamond 2) is a negotiated reservation charge of $0.001163 per Dth per day for the second 45,000 Dth/d.

(i) Applicable to firm service on GTN's Coyote Springs Extension.

(j) The Overrun Charge shall be equal to the rates and charges set forth for interruptible service under Rate Schedule ITS-1.

(k) In accordance with Section 6.22 of the Transportation General Terms and Conditions of this FERC Gas Tariff, Fourth Revised Volume No. 1-A, all Transportation services that involve the physical movement of gas shall pay an ACA unit adjustment. The currently effective ACA unit adjustment as published on the Commission's website (www.ferc.gov) is incorporated herein by reference. This adjustment shall be in addition to the Base Tariff Rate(s) specified above.

(l) Reserved for Future Use.

(m) Reserved.

(n) The Rate Schedule ITS-1 Mileage Component shall be applied per pipeline mile to gas transported by GTN based on the distance of gas transported. Consult GTN's system map in Section 3 for receipt and delivery point and milepost designations.

(o) The Rate Schedule ITS-1 Non-Mileage Component shall be applied per Dth of gas transported by GTN for immediate delivery to the facilities of another entity or an extension facility.

(p) Applicable to firm service on GTN's Carty Lateral Extension.

RESERVED FOR FUTURE USE

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS FOR

Parking and Lending Service
($/Dth)

	BASE TARIFF RATE MINIMUM	MAXIMUM
PAL Parking and Lending Service:	0.0	0.243541/d

Notes:

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULES FTS-1 AND LFS-1

SHIPPER	TERM OF CONTRACT	RATE SCHEDULE	DTH/D	PRIMARY RECEIPT POINT	PRIMARY DELIVERY POINT	RATE /2 /3
Avista Corporation /1	11/1/01 - 10/31/25	FTS-1	20,000	Medford	Medford Ext. Meter	/7
Powerex Corp./1	04/01/16 - 10/31/16	FTS-1	20,000	Kingsgate	Malin	/5

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

Negotiated Rate Agreements Under Rate Schedules FTS-1 and LFS-1

Explanatory Footnotes for Negotiated Rates
under Rate Schedules FTS-1 and LFS-1

/1 This contract does not deviate in any material aspect from the Form of Service Agreement in this Tariff.

/2 Unless otherwise noted, all Shippers pay GTN's maximum Reservation Charge, Delivery Charge, ACA, and contribute fuel in-kind in accordance with this Tariff.

/3 Index Price References: Unless otherwise noted, references to "Daily Index Price" shall mean the price survey midpoint for the specified point as published in Gas Daily for the day of gas flow. Weekend and holiday prices will be determined using the next available Gas Daily publication. Unless otherwise noted, the references to the "NGI FOM" for a specified point shall mean Natural Gas Intelligence's First of Month Bid Week Survey (Supplement to NGI's Weekly Gas Index) Spot Gas Price for the specified point.

/4 Reserved

/5 GTN and Shipper have agreed to a Fixed Reservation Rate Charge of $0.26300 inclusive of the mileage and non-mileage components, which shall be applicable to the Primary Receipt and Delivery Points as well as secondary points, as follows:

Secondary Receipt Points: All points on GTN's system
Secondary Delivery Points: All points on GTN's system

In addition, Shipper shall pay all applicable charges and surcharges in accordance with GTN's FERC Gas Tariff.

/6 Reserved

/7 The Reservation charge shall be equal to the rate set forth in GTN's FERC Gas Tariff identified as FTS-1 E-2 (WWP), or its successor, multiplied by the appropriate Effective Period Percentage as shown in the following table.

Effective Period	Percentage
11/1/01-10/31/02	75%
11/1/02-10/31/03	80%
11/1/03-10/31/04	85%
11/1/04-10/31/05	90%

11/1/05-10/31/06	95%
11/1/06-10/31/25	100%

The Daily Delivery Charge shall be equal to the 100% load factor equivalent of the FTS-1 E-2 rate, or its successor, and shall be multiplied by the positive difference between (a) volumes delivered and (b) the contract MDQ times the appropriate Effective Period Percentage.

Daily Delivery Charge = [Dth Delivered - (MDQ * Effective Period %)] * 100% Load Factor Equivalent FTS-1 E-2

/8 Reserved

/9 Reserved

/10 Reserved

/11 Reserved

/12 Reserved

/13 Reserved

/14 Reserved

/15 Reserved

/16 Reserved

/17 Reserved

/18 Reserved

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULE ITS-1 AND PAL

SHIPPER	TERM OF CONTRACT	RATE SCHEDULE	DTH/D	PRIMARY RECEIPT POINT	PRIMARY DELIVERY POINT	RATE /2 /3

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

NEGOTIATED RATE AGREEMENTS UNDER RATE SCHEDULE ITS-1 AND PAL

Explanatory Footnotes for Negotiated Rates under Rate Schedule ITS-1 and PAL

/1 This contract does not deviate in any material aspect from the Form of Service Agreement in this Tariff.

/2 Unless otherwise noted, all Shippers pay GTN's maximum Mileage and Non-Mileage Charge, ACA, and contribute fuel in-kind in accordance with this Tariff.

/3 Index Price References: Unless otherwise noted, references to "Daily Index Price" shall mean the price survey midpoint for the specified point as published in Gas Daily for the day of gas flow. Weekend and holiday prices will be determined using the next available Gas Daily publication. Unless otherwise noted, the references to the "NGI FOM" for a specified point shall mean Natural Gas Intelligence's First of Month Bid Week Survey (Supplement to NGI's Weekly Gas Index) Spot Gas Price for the specified point.

NON-CONFORMING SERVICE AGREEMENTS
PURSUANT TO § 154.112(b)

Name of Shipper	Contract Number	Rate Schedule	Effective Date	Termination Date
Cascade Natural Gas Corporation	152	FTS-1	11/1/1993	10/31/2023
Chevron USA Inc.	153	FTS-1	11/1/1993	10/31/2023
City of Burbank	154	FTS-1	11/1/1993	10/31/2023
IGI Resources, Inc.	158	FTS-1	11/1/1993	10/31/2013
Northern California Power Agency	163	FTS-1	11/1/1993	10/31/2023
Talisman Energy Inc	167	FTS-1	11/1/1993	10/31/2023
Paramount Resources US Inc.	168	FTS-1	11/1/1993	10/31/2023
Petro-Canada Hydrocarbons, Inc.	169	FTS-1	11/1/1993	10/31/2023
Sacramento Municipal Utility District	170	FTS-1	11/1/1993	10/31/2023
Avista Corporation	177	FTS-1	11/1/1993	10/31/2023
Avista Corporation	178	FTS-1	11/1/1993	10/31/2023
Cascade Natural Gas Corporation	179	FTS-1	11/1/1993	10/31/2023
Northwest Natural Gas Company	180	FTS-1	11/1/1993	10/31/2023
Puget Sound Energy, Inc.	181	FTS-1	11/1/1993	10/31/2023
Avista Corporation	182	FTS-1	11/1/1993	10/31/2023
Avista Corporation	2591	FTS-1	8/1/1995	10/31/2025
Avista Corporation	2857	FTS-1	11/1/1995	10/31/2025
Avista Corporation	2858	FTS-1	11/1/1995	10/31/2025
Iberdrola Renewables, Inc.	7828	FTS-1	6/3/2001	10/31/2025
Avista Corporation	8035	FTS-1	11/1/2001	10/31/2025
Pacific Gas and Electric Company	111	ITS-1	2/1/1992	10/31/2010
Northwest Natural Gas Company	112	ITS-1	4/1/1992	3/31/2011
Petro-Canada Hydrocarbons, Inc.	119	ITS-1	4/22/1992	4/22/2011
Morgan Stanley Capital Group Inc.	144	ITS-1	7/23/1993	9/30/2010
Shell Energy North America (US), L.P.	146	ITS-1	8/1/1993	8/1/2010
BP Canada Energy Marketing Corp.	4621	AIS-1	12/1/1996	12/31/2010
Sempra Energy Trading Corp.	4721	AIS-1	1/1/1997	12/31/2010
EnCana Marketing (USA) Inc.	4770	AIS-1	1/25/1997	12/31/2010
Nexen Marketing U.S.A., Inc.	6759	AIS-1	6/17/1999	12/31/2010
Shell Energy North America (US), L.P.	7047	AIS-1	4/10/2000	12/31/2010
Sierra Pacific Power Company	7068	AIS-1	4/27/2000	12/4/2019
City of Glendale	7804	AIS-1	5/30/2001	12/31/2021
Iberdrola Renewables, Inc.	7806	AIS-1	5/30/2001	12/31/2021
Petro-Canada Hydrocarbons, Inc.	7807	AIS-1	5/30/2001	12/31/2021
Chevron U.S.A. Inc.	7812	AIS-1	5/30/2001	12/31/2021
Salmon Resources Ltd.	7816	AIS-1	5/30/2001	12/31/2021
Constellation Energy Commodities Group, Inc.	8038	AIS-1	8/2/2001	8/31/2021
Enserco Energy Inc.	8176	AIS-1	11/27/2001	11/30/2021
ConocoPhillips Company	8228	AIS-1	1/8/2002	1/31/2022
UBS AG (London Branch)	8318	AIS-1	4/11/2002	4/30/2023

Concord Energy LLC	8421	AIS-1	7/22/2002	7/31/2012
Tenaska Marketing Ventures	8559	AIS-1	1/1/2003	12/31/2012
Cargill, Inc.	8594	AIS-1	3/19/2003	3/31/2013
Merrill Lynch Commodities, Inc.	8674	AIS-1	6/13/2003	6/13/2023
Apache Corporation	8670	AIS-1	7/1/2003	6/30/2013
Tenaska Marketing Ventures	8880	AIS-1	12/1/2003	11/30/2013
California Dept. of Water Resources	8887	AIS-1	12/1/2003	7/1/2011
United Energy Trading, LLC	9002	AIS-1	3/1/2004	2/28/2014
Select Natural Gas LLC	8978	AIS-1	3/3/2004	3/3/2014
National Fuel Marketing Company LLC	9035	AIS-1	4/27/2004	4/30/2014
Fortis Energy Marketing & Trading GP	9115	AIS-1	7/17/2004	6/30/2014
Powerex Corp.	9149	AIS-1	8/16/2004	7/31/2014
Louis Dreyfus Energy Services L.P.	9281	AIS-1	11/8/2004	10/31/2014
Pacific Summit Energy LLC	9285	AIS-1	11/15/2004	10/31/2010
Devlar Energy Marketing, LLC	9630	AIS-1	6/1/2005	5/31/2015
Suncor Energy Marketing Inc.	9774	AIS-1	10/1/2005	9/30/2015
CanNat Energy Inc.	10197	AIS-1	7/26/2006	7/25/2011
Eagle Energy Partners I, LP	10308	AIS-1	10/27/2006	10/31/2011
Sequent Energy Management LP	10336	AIS-1	11/1/2006	10/31/2010
Occidental Energy Marketing, Inc.	10359	AIS-1	12/22/2006	12/31/2010
NextEra Energy Power Marketing, LLC	10625	AIS-1	4/10/2008	4/30/2018
Natural Gas Exchange, Inc.	10639	AIS-1	4/29/2008	4/30/2018
Citigroup Energy Inc.	10646	AIS-1	5/30/2008	5/31/2018
IGI Resources, Inc.	4576	PS-1	12/1/1996	12/31/2010
Macquarie Cook Energy, LLC	4619	PS-1	12/1/1996	12/31/2010
Sempra Energy Trading Corp.	4720	PS-1	1/1/1997	12/31/2010
EnCana Marketing (USA) Inc.	4868	PS-1	3/1/1997	12/31/2010
Shell Energy North America (US), L.P.	4908	PS-1	3/5/1997	12/31/2010
Husky Gas Marketing Inc.	5348	PS-1	7/3/1997	12/31/2010
Enserco Energy Inc.	5677	PS-1	10/6/1997	12/31/2010
National Fuel Marketing Company LLC	5679	PS-1	10/7/1997	12/31/2010
United States Gypsum Company	5837	PS-1	11/3/1997	5/17/2010
Northwest Natural Gas Company	5992	PS-1	2/13/1998	12/31/2023
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United Energy Trading, LLC	8652	PS-1	5/23/2003	5/31/2013
Apache Corporation	8668	PS-1	7/1/2003	6/30/2013
Occidental Energy Marketing, Inc.	8784	PS-1	9/10/2003	8/31/2013
Tenaska Marketing Ventures	8873	PS-1	12/1/2003	11/30/2013
California Dept. of Water Resources	8886	PS-1	12/1/2003	7/1/2011
Devon Canada Marketing Corporation	8923	PS-1	2/1/2004	1/31/2014
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TransCanada | Customer Express

NGTL System

TransCanada's - NGTL System Transportation Rates & Abandonment Surcharge

2017 Final Rates - Effective June 1, 2017

Receipt and delivery transportation Rates below do not include applicable abandonment surcharges.

Receipt Services	Tariff Rate	Information Purposes		
	$/10³m³ (Cdn)	¢/GJ/d (Cdn)	¢/Mcf/d (Cdn)	¢/MMBtu/d (US)
FT-R Average Demand Rate (3 yr term) [1]	233.92/mo	20.3	21.8	15.7
IT-R (Interruptible Receipt)	8.84/d	23.4	25.0	18.1

Delivery Services	Tariff Rate	Information Purposes		
	$GJ (Cdn)	¢/GJ/d (Cdn)	¢/Mcf/d (Cdn)	¢/MMBtu/d (US)
FT-D Demand Rate (1 yr term) [2]				
Group 1:				
Empress/McNeill Border	5.84/mo	19.2	20.6	14.8
Alberta-B.C. Border	5.37/mo	17.7	18.9	13.6
Gordondale Border/Boundary Lk Border	5.37/mo	17.7	18.9	13.6
ATCO: Clairmont/Shell Creek/Edson	5.37/mo	17.7	18.9	13.6

Group 2:				
All Group 2 delivery points	5.37/mo	17.7	18.9	13.6
Group 3:				
All Group 3 delivery points	6.44/mo	21.2	22.7	16.4
IT-D (Interruptible Delivery)				
Group 1:				
Empress/McNeill Border		21.13	22.63	16.3
Alberta-B.C. Border		19.41	20.78	15.0
Gordondale Border / Boundary Lk Border		19.41	20.78	15.0
ATCO: Clairmont/Shell Creek/Edson		19.41	20.78	15.0
Group 2:				
All Group 2 delivery points		19.41	20.78	15.0

[1] Find more details on Receipt Price Points at Receipt Point Rates

1-2 year term: 105% (Price Point C)

3-4 year term: 100% (Price Point B)

5+ year term: 95% (Price Point A)

[2] Find more details on Delivery Price Points at Delivery Point Rates

1-2 year term: 100% (Price Point Z)

3-4 year term: 95% (Price Point Y)

5+ year term: 90% (Price Point X)

- Aggregate charges for service will be determined in accordance with the NGTL System tariff and as such. shall include the applicable abandonment surcharge(s).
- Rates are payable in Canadian dollars.
- For billing purposes. 10^3m^3 units are used to Receipt Services and GJ units are for Delivery services
- Mcf and MMBtu units are provided for illustrative purposes only.
- Conversion factors below have been used to calculate the rates provided for information purposes:

CdnS/USS	1.366 - subject to change (updated May 1, 2017)
¢/GJ to ¢/MMBtu	1.06
$/10³m³ to ¢/GJ	37.8 MJ/m³

Actual heating value is dependent upon specific receipt or delivery points and ranges from 36.0 MJ/m3 to 44.0 MJ/m3.

FT-R Rate Range	$/10³m³	¢/GJ/d	¢/Mcf/d	¢/MMBtu/d
FT-R Floor Rate	148.02/mo	12.9	13.8	9.9
FT-R Ceiling Rate	319.81/mo	27.8	29.8	21.5

- Rates do not include GST.

2017 Abandonment Surcharges - Effective January 1, 2017

Abandonment surcharges are in addition to applicable receipt and delivery transportation rates.

Abandonment Surcharges	Tariff Rate		Information Purposes
	$/10³m³ (Cdn)	$/GJ (Cdn)	$/Mcf (Cdn)
Monthly Abandonment Surcharge	11.38/mo	0.30/mo	0.32/mo
Daily Abandonment Surcharge	0.37/d	0.0099/d	0.01/d

- The services to which abandonment surcharges apply are denoted on the NGTL Tariff Table of Rates, Tolls and Charges.

Other information for TransCanada's NGTL System:

Current	Archives
Receipt Point Rates	Receipt Point Rates
Fuel Rates	Fuel Rates (2004 - 2010) (22 KB, XLS)
AB Border Heat Values	Fuel Rates (2000 - 2004) (41 KB, DOC)
Delivery Point Rates	AB Border Heat Values (61 KB, PDF)

TransCanada

In business to deliver

Summary of 2017 Final Delivery Point Rates: ($/GJ/month, except IT which is $/GJ/d) Effective June 1, 2017											
			Delivery Point Rates				Rates Plus Applicable Abandonment Surcharge				
Group 1 Deliveries		Premium/ Discount:	Point Z 100%	Point Y 95%	Point X 90%	110%					
Station Number	Station Name	Station Mnemonic	FT-D PRICE 1 to 2 Year Term	FT-D PRICE 3 to 4 Year Term	FT-D PRICE > 5 Year Term	IT-D PRICE	FT-D + Surcharge 1 to 2 Year Term	FT-D + Surcharge 3 to 4 Year Term	FT-D + Surcharge > 5 Year Term	IT-D + Surcharge
2000	ALBERTA-B.C. BORDER	ALTBC	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	ALCINT	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
31110	ALLIANCE EDSON INTERCONNECT APN	ALEINT	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	ALSINT	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
3002	BOUNDARY LAKE BORDER	BNDLK	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
1958	EMPRESS BORDER	EMPRS	5.84	5.55	5.26	0.2113	6.14	5.85	5.56	0.2212
3886	GORDONDALE BORDER	GRDINT	5.37	5.10	4.83	0.1941	5.67	5.40	5.13	0.2040
6404	MCNEILL BORDER	MCNEL	5.84	5.55	5.26	0.2113	6.14	5.85	5.56	0.2212

Monthly Abandonment Surcharge ($/GJ/month)	Daily Abandonment Surcharge ($/GJ/d)
0.30	0.0099

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Foothills System - BC

TransCanada's Foothills BC Transportation Rates & Abandonment Surcharges

2017 Rates Effective January 1, 2017

Transportation Rates below do not include applicable Abandonment Surcharges

Service	Tariff Rate	Information Purposes AB/BC to Kingsgate		
	$/GJ/km(Cdn)	¢/GJ/d (Cdn)	¢/Mcf/d (Cdn)	¢/MMbtu/d (US)
FT Firm Service - Zone 8				
FT Rate	0.0125111530(Monthly)	7.0	7.5	5.5
IT Interruptible Service - Zone 8				
IT Rate	0.0004524581(Daily)	7.7	8.3	6.1

Aggregate charges for service will be determined in accordance with the Foothills Pipe Lines Gas Transportation Tariff and as such, shall include the applicable abandonment surcharge(s)

2017 Abandonment Surcharges Effective January 1, 2017

Abandonment surcharges are in addition to applicable Transportation Rates.

Abandonment Surcharges	Tariff Rate	Information Purposes All Transportation Services		
	$/GJ (Cdn)	¢/GJ (Cdn)	¢/Mcf (Cdn)	¢/MMbtu (US)
Monthly Abandonment Surcharge	0.0923237647(monthly)	9.2	9.9	7.3
Daily Abandonment Surcharge	0.0030353019(Daily)	0.30	0.33	0.24

The services to which abandonment surcharges apply are denoted on the Foothills Pipe Lines Table of Effective Rates

1. For information purposes, the maximum Shipper's Haul Distance used in the Shipper's monthly charge for Service calculation is 170.7 km.

2. Rates are payable in Canadian dollars and GJ units are used for billing purposes. Mcf and MMbtu units are provided for information purposes only.

3. Conversion Factors below have been used to calculate the rates provided for information purposes:

Cdn$/US$	1.339 - subject to change (updated Oct 27, 2016)
¢/GJ to ¢/MMBtu	x 1.055056
¢/GJ to ¢/Mcf	at a heat value of 37.8 MJ/m^3

4. All rates are based on 100 per cent load factor utilization. The IT rate is 110 per cent of the FT rate.

5. Rates do not include G.S.T.

6. Inquiries regarding the BC System may be directed to:

Ashley Stowkowy
Phone: 1.403.920.5828
Email: ashley_stowkowy@transcanada.com

Kyle Mathewson
Phone: 1.403.920.7956
Email: kyle_mathewson@transcanada.com

Other information for TransCanada's Foothills (BC) System:

Current	Archives
Fuel Rates and Heating Values	Heating Values
AB Border Heat Values	AB Border Heat Values (61 KB, PDF)

Disclaimer:

The pricing and tolls information included on this website is intended to be used for planning purposes only and although TransCanada endeavours to maintain the information in such a way that is accurate and current, it may not provide accurate results. Use of this information is at user's sole risk and TransCanada shall not be liable for user's use or reliance on any results obtained from it.

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

TRANSPORTATION SERVICE - SOUTHERN

DEFINITIONS

1. In this Toll Schedule, the following term shall have the following meaning:

   (a) "Enhanced T-South Service" means Transportation Service – Southern provided pursuant to a Service Agreement under which gas is to be delivered to the Huntingdon Delivery Area and, subject to the fulfillment of the conditions specified in the Service Agreement, to the Kingsgate Export Point;

   (b) "Kingsgate Export Point" means the point on the international boundary between Canada and the United States of America near Kingsgate, British Columbia, where the Foothills Pipe Lines (South BC) Ltd. pipeline facilities connect with the pipeline facilities of Gas Transmission Northwest Corporation; and

   (c) "Service Term" means in respect of each Firm Transportation Service – Southern specified in a Firm Service Agreement, the term of each such Firm Transportation Service – Southern as determined in accordance with Section 3.

   All other terms used in this Toll Schedule shall have the same meaning as set forth in the General Terms and Conditions.

APPLICATION

2. This Toll Schedule applies to all Firm Transportation Service - Southern, AOS and Interruptible Transportation Service - Southern, including Import Backhaul Service, provided by Westcoast on facilities in Zone 4 under the provisions of a Firm Service Agreement or an Interruptible Service Agreement into which the General Terms and Conditions and this Toll Schedule are incorporated by reference.

3. For all purposes of this Toll Schedule, the Demand Toll applicable to any Firm Transportation Service - Southern provided pursuant to a Firm Service Agreement shall be determined based upon the Service Term, and the Service Term for each such service shall be determined as follows:

   (a) in the case of each Firm Transportation Service – Southern provided for in a Firm Service Agreement entered into by a Shipper with Westcoast prior to November 1, 2005, the number of whole years remaining in the term of each such service as of November 1, 2005;

   (b) in the case of each Firm Transportation Service – Southern provided for in a Firm Service Agreement entered into by a Shipper with Westcoast after November 1, 2005, the number of whole years in the term of each such service specified in the Firm Service Agreement;

   (c) in the case of each such Firm Transportation Service – Southern which is renewed by a Shipper after November 1, 2005 in accordance with Section 2.06 of the

General Terms and Conditions, the number of whole years in the renewal term of each such service, with effect from the first day of the renewal term; and

(d) in the case of each Firm Transportation Service – Southern provided for in a Firm Service Agreement which is extended by the Shipper and Westcoast after December 31, 2005, the number of whole years remaining in the term of each such service, including the period of the extension, with effect from the first day of the month immediately following the execution by the Shipper of an amendment to the Firm Service Agreement providing for such extension.

MONTHLY BILL - FIRM TRANSPORTATION SERVICE - SOUTHERN

4. The amount payable by a Shipper to Westcoast in respect of Firm Transportation Service - Southern provided in any month pursuant to a Firm Service Agreement shall be an amount equal to:

(a) the product obtained by multiplying the Contract Demand for Firm Transportation Service - Southern specified in the Firm Service Agreement by the applicable Demand Toll specified in Appendix A for Firm Transportation Service – Southern; and

(b) the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for the month,

less the amount of any Contract Demand Credits to which the Shipper is entitled for the month pursuant to the General Terms and Conditions.

MONTHLY BILL - AOS, INTERRUPTIBLE TRANSPORTATION SERVICE - SOUTHERN AND IMPORT BACKHAUL SERVICE

5. If on any day Shipper has unutilized Firm Transportation Service - Southern at a Delivery Point in Zone 4 and would incur on such day tolls for AOS and Interruptible Transportation Service, other than Import Backhaul Service, at that Delivery Point or at any other Delivery Point in Zone 4, then, notwithstanding the provisions of the General Terms and Conditions and for the sole purpose of determining the amount of the Commodity Tolls payable by Shipper in accordance with this Toll Schedule for AOS and Interruptible Transportation Service - Southern, the following rules shall apply:

(a) firstly, in the case where Shipper would otherwise incur tolls on such day for AOS and Interruptible Transportation Service – Southern at a Delivery Point where Shipper has unutilized Firm Transportation Service – Southern, Shipper shall be deemed to have utilized Firm Transportation Service at such Delivery Point on such day in respect of a volume of gas not exceeding the volume of unutilized Firm Transportation Service at such Delivery Point;

(b) secondly, in the case where a Delivery Point at which Shipper has unutilized Firm Transportation Service – Southern is within the Huntingdon Delivery Area and Shipper has any remaining volume of unutilized Firm Transportation Service at such Delivery Point after applying the rule set out in paragraph (a) above, then Shipper shall be deemed to have made a diversion on such day pursuant to Section 7.01(a)

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

of the General Terms and Conditions of a volume of gas not exceeding the amount of the remaining volume of unutilized Firm Transportation Service, from that Delivery Point to any other Delivery Point within the Huntingdon Delivery Area at which Shipper would otherwise incur tolls for AOS and Interruptible Transportation Service - Southern;

(c) thirdly, if Shipper has any remaining volume of unutilized Firm Transportation Service – Southern at any Delivery Point after applying the rules set out in paragraphs (a) and (b) above, then Shipper shall be deemed to have made a diversion on such day pursuant to Section 7.01(c) of the General Terms and Conditions of a volume of gas not exceeding the amount of such remaining volume of unutilized Firm Transportation Service from such Delivery Point to the nearest Downstream Delivery Point at which Shipper would otherwise incur tolls for AOS and Interruptible Transportation Service - Southern; and

(d) fourthly, if Shipper has any remaining volume of unutilized Firm Transportation Service – Southern at any Delivery Point after applying the rules set out in paragraphs (a), (b) and (c) above, then Shipper shall be deemed to have made a diversion on such day pursuant to Section 7.01(b) of the General Terms and Conditions of a volume of gas not exceeding the amount of such remaining volume of unutilized Firm Transportation Service, from such Delivery Point to the nearest Upstream Delivery Point at which Shipper would otherwise incur tolls for AOS and Interruptible Transportation Service – Southern.

6. The amount payable by a Shipper to Westcoast in respect of AOS, Interruptible Transportation Service - Southern, and Import Backhaul Service provided on each day in a month shall be an amount equal to the sum of:

(a) the product obtained by multiplying the applicable Commodity Toll specified in Appendix A for AOS, Interruptible Transportation Service - Southern and Import Backhaul Service, respectively, by the Receipt Volume for such AOS or Interruptible Transportation Service - Southern (as determined after applying the rules set out in Section 5) or for such Import Backhaul Service, respectively, at the point from which the residue gas is sourced, which is thermally equivalent to the volume of residue gas (i) delivered to or for the account of Shipper at the Delivery Point, or (ii) transmitted through Zone 4 for the account of Shipper on each such day during the month;

(b) the product obtained by multiplying the difference between the Commodity Tolls specified in Section 7.03 of the General Terms and Conditions by the volume of gas deemed to be diverted to a Downstream Delivery Point in accordance with Section 4(c) on each such day during the month; and

(c) the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for each day in the month.

APPENDIX A

DEMAND AND COMMODITY TOLLS
TRANSPORTATION SERVICE - SOUTHERN

Firm Transportation Service – Southern

Year Round Service

	Demand Tolls $\$/10^3m^3/mo.$			
Service Term	PNG Delivery Point	Inland Delivery Area	Huntingdon Delivery Area	FortisBC Kingsvale to Huntingdon*
1 year	90.06	234.99	397.34	162.35
2 years	87.44	228.15	385.77	157.62
3 years	84.81	221.31	374.20	152.89
4 years	83.94	219.02	370.34	151.32
5 years or more	83.07	216.74	366.48	149.74

* For Firm Transportation Service - Southern provided by Westcoast pursuant to a Firm Service Agreement dated April 15, 2002 between Westcoast and FortisBC Energy Inc.

Plus the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for each day in the month.

Winter Firm Service

	Demand Tolls $\$/10^3m^3/mo.$	
	Huntingdon Delivery Area	
Service Term	WF Service *November to March*	Revertible WF Service*
1 year	596.01	397.34
2 years	578.66	385.77
3 years	561.30	374.20
4 years	555.51	370.34
5 years or more	549.72	366.48

* WF Service which has been designated as Revertible WF Service pursuant to Section 23.10 of the General Terms and Conditions – Service to provide for firm transmission of residue gas in Zone 4 all days of the year.

Plus the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for each day in the month.

Effective Date: April 1, 2017

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

AOS and Interruptible Transportation Service – Southern

Months	Commodity Tolls $\$/10^3m^3$ PNG Delivery Point	Inland Delivery Area	Huntingdon Delivery Area	FortisBC Kingsvale to Huntingdon*
April 1, 2017 to October 31, 2017	2.947	7.691	13.004	5.313
November 1, 2017 to December 31, 2017	3.929	10.255	14.304	7.084

* For AOS provided by Westcoast pursuant to a Firm Service Agreement dated April 15, 2002 between Westcoast and FortisBC Energy Inc.

Plus the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for each day in the month.

Import Backhaul Service

Months	Commodity Tolls $\$/10^3m^3$ Inland Delivery Area	PNG Delivery Point	Compressor Station No. 2
April 1, 2017 to October 31, 2017	5.313	10.057	13.004
November 1, 2017 to December 31, 2017	4.049	10.375	14.304

Plus the amount of tax on fuel gas consumed in operations payable under the Motor Fuel Tax Act (British Columbia) and the Carbon Tax Act (British Columbia) which is allocated to Shipper by Westcoast for each day in the month.