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 26, 2016

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

Case No. AVU-G-16-0_2_/Advice No. 16-02-G

Attention: Ms. Jean D. Jewell

I.P.U.C. No. 27 – Natural Gas Service

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

Twenty-Second Revision Sheet 150	canceling	**Twenty-First Revision Sheet 150**
Eighteenth Revision Sheet 155	canceling	**Seventeenth Revision Sheet 155**

The Company requests that the proposed tariff sheets be made effective November 1, 2016.

These tariff sheets reflect the Company's annual Purchased Gas Cost Adjustment ("PGA"). If approved, the Company's annual revenue will *decrease* by approximately $6.1 million or approximately 7.8%. 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 $4.65 per month, or approximately 8.4%. The present bill for 61 therms is $55.59 while the proposed bill is $50.94. The Company will issue a notice to its customers through a bill insert starting on or about September 2, 2016 and ending on or about October 1, 2016. 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 Ryan Finesilver at (509) 495-4873.

Sincerely,

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 16-02-G (Tariff IPUC No. 27 Natural Gas Service) by mailing a copy thereof, postage prepaid to the following:

Jean D Jewell, Secretary
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 83720-5983

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

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

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

Dated at Spokane, Washington this 26th day of August 2016.

Patrick Ehrbar
Senior Manager, State & Federal Regulation

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2016 AUG 29 AM 9: 13
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA UTILITIES FOR AN ORDER APPROVING A CHANGE IN NATURAL GAS RATES AND CHARGES	)))	CASE: AVU-G-16-02

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, 2016. If approved as filed, the Company's annual revenue will decrease by approximately $6.1 million or about 7.8%. 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:

Kelly O. Norwood
Vice President of State & Federal Regulation
Avista Utilities
1411 E. Mission Avenue
Spokane, WA 99220-3727
Phone: (509) 495-4267
Fax: (509) 495-8851
Kelly.norwood@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-Second Revision Sheet 150, which Applicant requests the Commission approve, is filed herewith as Exhibit "A". Additionally, Eighteenth 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-Second Revision Sheet 150 and Eighteenth Revision Tariff Sheet 155 with the changes underlined and a copy of Twenty-First Revision Sheet 150 and Seventeenth 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 starting on or about September 2, 2016 and will end on or about October 1, 2016.

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 2016 through October 2017 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	$ (0.01140)	$ 0.00480	$ (0.00660)	$ (0.06958)	$ (0.07618)	-7.7%
Lg. General	111	$ (0.01140)	$ 0.00480	$ (0.00660)	$ (0.06958)	$ (0.07618)	-7.7%
Interruptible	131	$ (0.01140)	$ -	$ (0.01140)	$ (0.07202)	$ (0.08342)	0.0%

IX.

Commodity Costs

As shown in the table above, the estimated WACOG change is a *decrease* of 1.14 cents per therm. The proposed WACOG, including the revenue conversion factor, is 24.06 cents per therm compared to the present WACOG of 25.2 cents per therm included in rates. The overall reduction in the WACOG is generally the result of the continued increase in natural gas supply coupled with an overall reduction in customer demand due to a warmer than normal winter of 2015-2016, resulting in lower wholesale natural gas prices. The downward pressure on wholesale prices has continued even after the winter period due to the abundance of natural gas in storage and continued high natural gas production levels.

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 2015-2016 for the forthcoming PGA year (twelve months). Approximately 45% of estimated annual load requirements for the PGA year (November 2016 through October 2017) 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, 2) volumes from prior multi-year hedges. Through June, the planned hedge volumes for the PGA year have been executed at a weighted average price of $2.60 per dekatherm ($0.26 per therm).

The Company used a 30-day historical average of forward prices and supply basins (ending July 15, 2016) 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 55% of estimated annual load requirements for the coming year. The annual weighted average price for these volumes is $2.44 per dekatherm ($0.24 per therm).

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[1] The overall percentage change for all schedules is a decrease of 7.8%. 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 $81,784 for an overall proposed revenue decrease of $6,119,167. The overall present billed revenue is $78,661,797 making the percentage decrease 7.8% (-$6,119,167 / 78,661,797 = -7.8%).

X.

Demand Costs

Demand costs primarily represent the cost of transporting natural gas on interstate pipelines to the Company's local distribution system. As shown in the table above, there is a slight increase in the overall demand rate of $0.00480 per therm for Schedules 101 and 111 which is, in part, related to the reduction in Northwest Pipeline capacity release revenue Avista had been receiving.

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 rate decrease of $0.06958 per therm. The current rate applicable to Schedule 101 and Schedule 111 is $0.02886 per therm in the <u>rebate</u> direction; the proposed rate is $0.09844 per therm also in the <u>rebate</u> direction. Contributing to the proposed amortization rebate rate, as discussed in the Commodity Cost Section of this Application, are the effects of wholesale natural gas prices that were lower than the level approved in the Company's 2015 PGA. As a result of the lower prices, the amount of revenue collected from customers exceeded the Company's costs. However, a portion of the benefit of reduced wholesale natural gas prices was offset by an under collection of fixed demand costs which was the result of a warmer than normal winter.

XII.

If approved as filed, the Company's annual revenue will *decrease* by approximately $6.1 million or about 7.8% effective November 1, 2016. Residential or small commercial customers using an average of 61 therms per month would see a *decrease* of $4.65 per month, or approximately 8.4%. The present bill for 61 therms is $55.59 while the proposed bill is $50.94.

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, 2016, 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.

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, 2016.

Dated at Spokane, Washington, this 26th day of August 2016.

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 26th day of August 2016, by David J. Meyer

WENDY D. MANSKEY
Notary Public
State of Washington
My Commission Expires
October 09, 2018

Wendy D. Manskey

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

Commission Expires: 10.09.18

AVISTA UTILITIES

Case No. AVU-G-16-02

EXHIBIT "A"

Proposed Tariff Sheets

August 26, 2016

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¢	35.477¢
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.

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 ~~36.107¢~~ per therm in all blocks of these rate schedules.

(b) The rates of interruptible Schedules 131 and 132 are to be increased by ~~25.198¢~~ 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	~~10.909¢~~	~~25.198¢~~	~~36.107¢~~
Schedules 111 and 112	~~10.909¢~~	~~25.198¢~~	~~36.107¢~~
Schedules 131 and 132	0.000¢	~~25.198¢~~	~~25.198¢~~

The above amounts include a gross revenue factor.

	Demand	Commodity	Total
Schedules 101	~~10.855¢~~	~~25.072¢~~	~~35.927¢~~
Schedules 111 and 112	~~10.855¢~~	~~25.072¢~~	~~35.927¢~~
Schedules 131 and 132	0.000¢	~~25.072¢~~	~~25.072¢~~

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.

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¢	35.477¢
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.

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 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.

Issued August 26, 2016 Effective November 1, 2016

Issued by Avista Utilities
By Kelly Norwood Kelly 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 ~~2.886¢~~ per therm in all blocks of these rate schedules.

(b) The rate of interruptible gas Schedule 131 is to be decreased by ~~3.020¢~~ 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 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 UTILITIES

Case No. AVU-G-16-02

EXHIBIT "B"

Notice of Public Applicant's Proposed Tariffs

August 26, 2016

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-Second Revision Sheet 150	canceling	**Twenty-First Revision Sheet 150**
Eighteenth Revision Sheet 155	canceling	**Seventeenth 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 $6.1 million, or about 7.8%. This filing requests an effective date of November 1, 2016.

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 $4.65, or 8.36 percent, for a revised monthly bill of $50.94 beginning Nov. 1, 2016. Avista's natural gas revenues would decrease by $6.1 million, or approximately 7.8 percent. The requested natural gas rate change by customer segment is as follows:

General Service - Firm - Schedule 101 - Residential & Small Commercial	-7.7%
Large General Service - Firm - Schedules - Commercial 111 & 112	-7.7%
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: Manager, Rates & Tariffs
P.O. Box 3727
Spokane, WA. 99220-3727

August 26, 2016

AVISTA UTILITIES

Case No. AVU-G-16-02

EXHIBIT "C"

Workpapers

August 26, 2016

Avista Utilities
State of Idaho
Revenue Rate Change Sumamry

Based on 12 months November 1, 2016 - October 31, 2017

Line No.	Schedule	Therms		Rate Change		Revenue Incr (Decr)
1	Schedule 150 PGA Commodity					
2	Rate Schedule 101	56,026,100	$	(0.01140)	$	(638,698)
3	Rate Schedule 111	23,224,517	$	(0.01140)	$	(264,759)
4	Rate Schedule 112	0	$	(0.01140)	$	-
5	Rate Schedule 131	0	$	(0.01140)	$	-
6	Rate Schedule 132	0	$	(0.01140)	$	-
7		79,250,617				(903,457)
8						
9	Schedule 150 PGA Demand					
10	Rate Schedule 101	56,026,100	$	0.00480	$	268,875
11	Rate Schedule 111	23,224,517	$	0.00480	$	111,457
12	Rate Schedule 112	0	$	0.00480	$	-
13	Rate Schedule 131	0	$	-	$	-
14	Rate Schedule 132	0	$	-	$	-
15		79,250,617			$	380,332
16						
17	Schedule 155 Amortization					
18	Rate Schedule 101	56,026,100	$	(0.06958)	$	(3,898,296)
19	Rate Schedule 111	23,224,517	$	(0.06958)	$	(1,615,962)
20	Rate Schedule 112	0	$	-	$	-
21	Rate Schedule 131	0	$	(0.07202)	$	-
22	Rate Schedule 132	0	$	-	$	-
23	Customer 1	0	$	-	$	(81,614)
24	Customer 2	0	$	-	$	(154)
25	Customer 3	0	$	-	$	-
26	Customer 4	0	$	-	$	8
27	Customer 5	0	$	-	$	(24)
28		79,250,617			$	(5,596,042)
29						
30	Total Change 150 & 155					
31	Rate Schedule 101	56,026,100	$	(0.07618)	$	(4,268,119)
32	Rate Schedule 111	23,224,517	$	(0.07618)	$	(1,769,264)
33	Rate Schedule 112	0	$	(0.00660)	$	-
34	Rate Schedule 131	0	$	(0.08342)	$	-
35	Rate Schedule 132	0	$	(0.01140)	$	-
36	Customer 1	0			$	(81,614)
37	Customer 2	0			$	(154)
38	Customer 3	0			$	-
39	Customer 4	0			$	8
40	Customer 5	0			$	(24)
41	Total Change	79,250,617			$	(6,119,167)
42						
43	Rate Schedule 146 & Special Contracts	0			$	-
44						
45	Total				**$**	**(6,119,167)**
46	% Change from Current Billed Revenue					

Summary of Rate Change

	Proposed Rates		Present Billed Revenue	% Change
Rate Schedule 101	(4,268,119)	$	55,714,011	-7.7%
Rate Schedule 111	(1,769,264)	$	22,947,786	-7.7%
Rate Schedule 112	0			
Rate Schedule 131	0			
Rate Schedule 132	0	$	0	0.0%
Customer Refunds	(81,784)			
Total Change	(6,119,167)	$	78,661,797	-7.8%

Avista Utilities
State of Idaho
Summary of Changes

		Schedule 150					
	Summary of Changes	**Without Revenue Sensitive Costs**			**With Revenue Sensitive Costs**		
		Firm (Demand)	Sales (Commodity)	Total Gas Cost Rate	Firm (Demand)	Sales (Commodity)	Total Gas Cost Rate
	Present				**GRF:**	**1.005165**	
1	WACOG before revenue sensitive						
2	Rate Schedule 101	$0.10855	$0.25072	$0.35927	$0.10909	$0.25198	$0.36107
3	Rate Schedule 111	$0.10855	$0.25072	$0.35927	$0.10909	$0.25198	$0.36107
4	Rate Schedule 112	$0.10855	$0.25072	$0.35927	$0.10909	$0.25198	$0.36107
5	Rate Schedule 131		$0.25072	$0.25072		$0.25198	$0.25198
6	Rate Schedule 132	$0.00000	$0.25072	$0.25072	$0.00000	$0.25198	$0.25198
7							
8	**Proposed**				**GRF:**	**1.057611**	
9	WACOG before revenue sensitive						
10	Rate Schedule 101	$0.11331	$0.23935	$0.35265	$0.11389	$0.24058	$0.35447
11	Rate schedule 111	$0.11331	$0.23935	$0.35265	$0.11389	$0.24058	$0.35447
12	Rate Schedule 112	$0.11331	$0.23935	$0.35265	$0.11389	$0.24058	$0.35447
13	Rate Schedule 131		$0.23935	$0.23935		$0.24058	$0.24058
14	Rate Schedule 132	$0.00000	$0.23935	$0.23935	$0.00000	$0.24058	$0.24058
15							
16	**Change**						
17	WACOG before revenue sensitive						
18	Rate Schedule 101	$0.00476	($0.01137)	($0.00661)	$0.00480	($0.01140)	($0.00660)
19	Rate schedule 111	$0.00476	($0.01137)	($0.00661)	$0.00480	($0.01140)	($0.00660)
20	Rate Schedule 112	$0.00476	($0.01137)	($0.00661)	$0.00480	($0.01140)	($0.00660)
21	Rate Schedule 131		($0.01137)	($0.01137)		($0.01140)	($0.01140)
22	Rate Schedule 132	$0.00000	($0.01137)	($0.01137)	$0.00000	($0.01140)	($0.01140)
23							
24							
25							

		Schedule 155					
26							
27	**Summary of Changes**	**Without Revenue Sensitive Costs**			**With Revenue Sensitive Costs**		
28		Firm (Demand) Amort	Sales (Commodity) Amort	Total Amort Rate	Firm (Demand) Amort	Sales (Commodity) Amort	Total Amort Rate
29	**Present**				**GRF:**	**1.005165**	
30	WACOG before revenue sensitive						
31	Rate Schedule 101	$0.00133	($0.03004)	($0.02871)	$0.00134	($0.03020)	($0.02886)
32	Rate Schedule 111	$0.00133	($0.03004)	($0.02871)	$0.00134	($0.03020)	($0.02886)
33	Rate Schedule 112						
34	Rate Schedule 131		($0.03004)	($0.03004)		($0.03020)	($0.03020)
35	Rate Schedule 132			$0.00000			$0.00000
36							
37	**Proposed**				**GRF:**	**1.057611**	
38	WACOG before revenue sensitive						
39	Rate Schedule 101	$0.00357	($0.09665)	($0.09308)	$0.00378	($0.10222)	($0.09844)
40	Rate schedule 111	$0.00357	($0.09665)	($0.09308)	$0.00378	($0.10222)	($0.09844)
41	Rate Schedule 112						
42	Rate Schedule 131		($0.09665)	($0.09665)		($0.10222)	($0.10222)
43	Rate Schedule 132						
44							
45	**Change**						
46	WACOG before revenue sensitive						
47	Rate Schedule 101	$0.00224	($0.06661)	($0.06437)	$0.00244	($0.07202)	($0.06958)
48	Rate schedule 111	$0.00224	($0.06661)	($0.06437)	$0.00244	($0.07202)	($0.06958)
49	Rate Schedule 112						
50	Rate Schedule 131		($0.06661)	($0.06661)		($0.07202)	($0.07202)
51	Rate Schedule 132						
52							

STATE OF IDAHO
ANNUAL PGA FILING

*AN -- Allocated North sum of Washington + Idaho

Line No.	VOLUME FORECAST													12 month Ended
1	**Demand Forecast**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	Total
2	Rate Schedule 101	6,910,394	9,813,977	9,674,232	7,656,439	6,797,742	4,196,766	2,379,682	1,405,293	1,112,174	1,038,979	1,377,687	3,662,733	56,026,100
3	Rate Schedule 111	2,813,239	3,291,101	3,301,346	2,617,433	2,317,973	1,429,719	921,758	818,004	1,022,685	1,233,277	1,247,584	2,210,399	23,224,517
5	**FIRM DEMAND THERMS**	**9,723,633**	**13,105,078**	**12,975,578**	**10,273,872**	**9,115,715**	**5,626,485**	**3,301,440**	**2,223,297**	**2,134,859**	**2,272,256**	**2,625,272**	**5,873,132**	**79,250,617**
4	Rate Schedule 132	0	0	0	0	0	0	0	0	0	0	0	0	-
5	**COMMODITY THERMS (SALES)**	**9,723,633**	**13,105,078**	**12,975,578**	**10,273,872**	**9,115,715**	**5,626,485**	**3,301,440**	**2,223,297**	**2,134,859**	**2,272,256**	**2,625,272**	**5,873,132**	**79,250,617**
6	Fuel	123,942	140,342	137,046	118,881	117,531	69,473	40,657	27,366	47,873	51,098	59,063	105,469	1,038,740
7	Lost and Unaccounted for	72,349	97,508	96,545	76,443	67,825	41,864	24,564	16,542	15,884	16,907	19,533	43,699	589,664
7	**TOTAL PURCHASE THERMS**	**9,919,924**	**13,342,928**	**13,209,169**	**10,469,197**	**9,301,071**	**5,737,821**	**3,366,662**	**2,267,205**	**2,198,616**	**2,340,260**	**2,703,868**	**6,022,300**	**80,879,020**
8														
9	CUSTOMER FORECAST													12 month Ended
10	**Demand Forecast**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	Total
11	Rate Schedule 101	78,886	79,210	79,340	79,352	79,347	79,298	79,272	79,230	79,323	79,389	79,591	79,743	951,979
12	Rate Schedule 111	1,441	1,442	1,445	1,447	1,449	1,451	1,453	1,454	1,456	1,459	1,460	1,463	17,422
13	Rate Schedule 132	0	0	0	0	0	0	0	0	0	0	0	0	-
14	**Total Customers**	**80,328**	**80,653**	**80,786**	**80,798**	**80,795**	**80,749**	**80,724**	**80,684**	**80,779**	**80,848**	**81,051**	**81,206**	**969,400**
15														

Row		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
16														
17	**COMMODITY**	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
18														
19	Commodity Allocation (based on Calendar Volumes)	31.73%	31.23%	30.48%	29.71%	30.63%	30.73%	30.93%	32.33%	34.90%	37.21%	35.54%	33.44%	32.405%
20														
21	**Hedges**													
22														
23	**Executed**													
24	AN* System Total Volumes (Th)	14,085,000	21,250,500	21,250,500	19,194,000	14,554,500	1,500,000	1,550,000	750,000	775,000	775,000	750,000	1,550,000	97,984,500
25	AN* System Total Dollars ($)	$ 3,940,640	$ 5,505,966	$ 5,523,543	$ 4,987,620	$ 4,071,995	$ 297,769	$ 307,694	$ 144,806	$ 149,633	$ 149,633	$ 144,806	$ 320,133	$ 25,544,239
26														
27	ID Volumes (Th)	4,468,910	6,635,837	6,477,041	5,702,841	4,458,066	460,947	479,489	242,479	270,489	288,384	266,522	518,330	30,269,334
28	ID Dollars ($)	$ 1,250,292	$ 1,719,333	$ 1,683,547	$ 1,481,901	$ 1,247,258	$ 91,504	$ 95,185	$ 46,817	$ 52,225	$ 55,680	$ 51,459	$ 107,055	$ 7,882,254
29	WACOG	$ 0.27978	$ 0.25910	$ 0.25993	$ 0.25985	$ 0.27978	$ 0.19851	$ 0.19851	$ 0.19308	$ 0.19308	$ 0.19308	$ 0.19308	$ 0.20654	$ 0.26040
30														
31	**Remaining to be Executed**													
32	AN* System Total Volumes (Th)	1,575,000	4,696,500	4,696,500	4,242,000	1,627,500	1,500,000	-	-	-	-	-	1,550,000	19,887,500
33	AN* System Total Dollars ($)	$ 332,798	$ 1,114,245	$ 1,162,149	$ 1,046,077	$ 393,530	$ 332,700	$ -	$ -	$ -	$ -	$ -	$ 357,663	$ 4,739,160
34														
35														
36	ID Volumes (Th)	499,718	1,466,564	1,431,469	1,260,365	498,506	460,947	0	0	0	0	0	518,330	6,135,899
37	ID Dollars ($)	$ 105,590	$ 347,942	$ 354,217	$ 310,806	$ 120,539	$ 102,238	$ -	$ -	$ -	$ -	$ -	$ 119,605	$ 1,460,937
38	WACOG	$ 0.21130	$ 0.23725	$ 0.24745	$ 0.24660	$ 0.24180	$ 0.22180	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.23075	$ 0.23810
39														
40	**Deferred Exchange Credits**													
41	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)
42														
43	ID Deferred Exchange	$ (118,981)	$ (117,100)	$ (114,298)	$ (111,418)	$ (114,863)	$ (115,237)	$ (116,005)	$ (121,239)	$ (130,882)	$ (139,541)	$ (133,261)	$ (125,402)	$ (1,458,227)
44														
45	**Price Forecast**	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
46	30 Day average Price based on: 7-15-2016													
47	Aeco	$ 2.123	$ 2.374	$ 2.482	$ 2.472	$ 2.417	$ 2.177	$ 2.140	$ 2.127	$ 2.118	$ 2.176	$ 2.171	$ 2.270	
48	Sumas	$ 3.057	$ 3.549	$ 3.437	$ 3.335	$ 3.054	$ 2.375	$ 2.326	$ 2.327	$ 2.506	$ 2.571	$ 2.597	$ 2.730	
49	Rockies	$ 2.937	$ 3.338	$ 3.427	$ 3.395	$ 3.158	$ 2.762	$ 2.748	$ 2.776	$ 2.854	$ 2.867	$ 2.835	$ 2.889	
50														
51	**Basin Weighting**													
52	Aeco	59.94%	67.47%	70.93%	97.98%	87.35%	95.73%	97.35%	100.00%	74.54%	78.78%	70.92%	81.11%	82%
53	Sumas	34.02%	27.61%	25.02%	0.00%	3.24%	0.31%	0.57%	0.00%	22.84%	3.31%	18.94%	11.08%	12%
54	Rockies	6.05%	4.92%	4.05%	2.02%	9.41%	3.96%	2.08%	0.00%	2.63%	17.91%	10.14%	7.82%	6%
55														
56	Basin-Weighted Index Price	$ 2.4898	$ 2.7455	$ 2.7594	$ 2.4908	$ 2.5074	$ 2.2011	$ 2.1536	$ 2.1266	$ 2.2258	$ 2.3128	$ 2.31919	$ 2.36935	
57	Index Volumes (Th)	4,951,296	5,240,528	5,300,659	3,505,990	4,344,500	4,815,927	2,887,172	2,024,727	1,928,127	2,051,876	2,437,346	4,985,639	44,473,788
58	Index Cost	$ 12,327,936	$ 14,387,669	$ 14,626,478	$ 8,732,781	$ 10,893,292	$ 10,600,113	$ 6,217,903	$ 4,305,870	$ 4,291,673	$ 4,745,652	$ 5,652,662	$ 11,812,708	$ 108,594,737
59														
60	**Embedded Charges**													
61	Variable Transportation	$ 15,744	$ 14,352	$ 15,964	$ 14,372	$ 15,579	$ 21,810	$ 19,563	$ 18,589	$ 12,948	$ 10,737	$ 14,565	$ 18,056	192,277
62														
63														
64														
65														

Row		Firm Customers (Demand)	Sales Customers (Commodity)	Customer 1	Customer 2	Customer 3	Customer 4	Customer 5	Customer 6	Total
66	**AMORTIZATION BALANCES**									
67										
68		Firm Customers (Demand)	Sales Customers (Commodity)	Customer 1	Customer 2	Customer 3	Customer 4	Customer 5	Customer 6	Total
69										
70	Unamortized Deferrals (191000)	$ 350,683	$ (584,483)	$ (21)	$ 0	$ -	$ 8	$ (3)		$ (233,816)
73	Current Deferrals (191010)	$ (67,847)	$ (7,075,103)	$ (81,592)	$ (154)	$ -	$ -	$ (21)	$ -	$ (7,224,718)
74	Total	$ 282,836	$ (7,659,586)	$ (81,614)	$ (154)	$ -	$ 8	$ (24)	$ -	$ (7,458,534)

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

	Executed Hedges		Planned 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	Volumes	Dollars	Dollars	Dollars	Dollars		
	(a)	(b)	(c)	(d)	(g)	(h)	(a) + (c) + (e) + (g)	(b) + (d) + (f) + (h)	(i)	(j)	(k)		
Nov-16	4,468,910	$ 1,250,292	499,718	$ 105,590	4,951,296	$ 1,232,794	9,919,924	$ 2,588,676	$ 15,744	$ (118,981)	$ 2,485,439	9,723,633	$ 0.2556
Dec-16	6,635,837	$ 1,719,333	1,466,564	$ 347,942	5,240,528	$ 1,438,767	13,342,928	$ 3,506,042	$ 14,352	$ (117,100)	$ 3,403,294	13,105,078	$ 0.2597
Jan-17	6,477,041	$ 1,683,547	1,431,469	$ 354,217	5,300,659	$ 1,462,648	13,209,169	$ 3,500,412	$ 15,964	$ (114,298)	$ 3,402,077	12,975,578	$ 0.2622
Feb-17	5,702,841	$ 1,481,901	1,260,365	$ 310,806	3,505,990	$ 873,278	10,469,197	$ 2,665,985	$ 14,372	$ (111,418)	$ 2,568,939	10,273,872	$ 0.2500
Mar-17	4,458,066	$ 1,247,258	498,506	$ 120,539	4,344,500	$ 1,089,329	9,301,071	$ 2,457,126	$ 15,579	$ (114,863)	$ 2,357,842	9,115,715	$ 0.2587
Apr-17	460,947	$ 91,504	460,947	$ 102,238	4,815,927	$ 1,060,011	5,737,821	$ 1,253,753	$ 21,810	$ (115,237)	$ 1,160,326	5,626,485	$ 0.2062
May-17	479,489	$ 95,185	0	$ -	2,887,172	$ 621,790	3,366,662	$ 716,975	$ 19,563	$ (116,005)	$ 620,533	3,301,440	$ 0.1880
Jun-17	242,479	$ 46,817	0	$ -	2,024,727	$ 430,587	2,267,205	$ 477,404	$ 18,589	$ (121,239)	$ 374,753	2,223,297	$ 0.1686
Jul-17	270,489	$ 52,225	0	$ -	1,928,127	$ 429,167	2,198,616	$ 481,392	$ 12,948	$ (130,882)	$ 363,458	2,134,859	$ 0.1702
Aug-17	288,384	$ 55,680	0	$ -	2,051,876	$ 474,565	2,340,260	$ 530,245	$ 10,737	$ (139,541)	$ 401,441	2,272,256	$ 0.1767
Sep-17	266,522	$ 51,459	0	$ -	2,437,346	$ 565,266	2,703,868	$ 616,725	$ 14,565	$ (133,261)	$ 498,029	2,625,272	$ 0.1897
Oct-17	518,330	$ 107,055	518,330	$ 119,605	4,985,639	$ 1,181,271	6,022,300	$ 1,407,930	$ 18,056	$ (125,402)	$ 1,300,583	5,873,132	$ 0.2214
	30,269,334	7,882,254	6,135,899	1,460,937	44,473,788	10,859,474	80,879,020	$ 20,202,665	$ 192,277	$ (1,458,227)	$ 18,936,715	79,250,617	$ 0.2389
Average		$ 0.2604		$ 0.2381		$ 0.2442		$ 0.2498					
		37.4%		7.6%		55%							

GRI Funding (no change)	0.00040
TOTAL Rate	**0.23935**

RCF: 1.005165

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

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

Line No.	Description		Estimated Demand Expense	Allocator	Allocation Percentage		Idaho Allocation
					ID		
1	Northwest Pipeline Corporation (NWP)	$	17,163,194	ID System Allocated	29.47%	$	5,057,993
2							
3	TCPL - Gas Transmission Northwest	$	2,614,309	ID System Allocated	29.47%	$	770,437
4							
5	**Total Fixed Domestic Transportation Costs**		**19,777,502**			**$**	**5,828,430**
6							
7	TransCanada - AB (NOVA System)	$	6,348,994	ID System Allocated	29.47%	$	1,871,049
8							
9	TransCanada - BC (Foothills Pipe Line Ltd.)	$	3,305,495	ID System Allocated	29.47%	$	974,129
10							
11	Spectra - Westcoast Energy Inc	$	1,038,626	ID System Allocated	29.47%	$	306,083
12							
13	**Total Fixed Canadian Transportation Costs**	**$**	**10,693,115**			**$**	**3,151,261**
14							
15	**Total Fixed Pipeline Charges**	**$**	**30,470,618**			**$**	**8,979,691**
16							
17	**Demand Costs**	**$**	**30,470,618**			**$**	**8,979,691**
18	Demand Volumes						79,250,617
19	**Demand Rate**					$	0.11331
20							
21							
22					**RCF:**		**1.0051650**
23		**Rate Change Calculation:**					
24		Proposed WACOG without Revenue Sensitive Costs				$	0.11331
25		**Proposed WACOG with Revenue Sensitive Costs**				**$**	**0.11389**

JURISDICTIOI AN
PROFIT CENT LDC

Sum of US DOLLARS

SHORT NAN	CHARGE TYPE	PIPELINE CONTRACT	MILES	MILAGE RATE	NON MILAGE RA	MMBTU PER DAY		Grand Total
GTNW	**DMD**	17013	**27**	0	**0**	300	$	2,532
						879	$	7,380
		17014	**56**	0	**0**	1,000	$	10,702
						1,827	$	19,445
		17015	**59**	0	**0**	2,500	$	27,501
						3,327	$	36,399
		17017	**85**	0	**0**	150	$	1,954
						191	$	2,474
		17020	**98**	0	**0**	250	$	3,512
						871	$	12,170
		17024	**108**	0	**0**	3,400	$	50,641
						7,165	$	106,136
		17027	**121**	0	**0**	2,000	$	31,832
						3,241	$	51,302
		17029	**134**	0	**0**	150	$	2,543
						233	$	3,928
		17030	**146**	0	**0**	100	$	1,787
						183	$	3,252
		17032	**159**	0	**0**	100	$	1,891
						224	$	4,213
		17035	**183**	0	**0**	50	$	1,041
						133	$	2,753
		17038	**108**	0	**0**	45,000	$	670,254
						61,549	$	911,734
		17043	**98**	0	**0**	2,758	$	77,281
		17044	**108**	0	**0**	2,470	$	73,378
		17045	**121**	0	**0**	15,077	$	478,617
		17046	**134**	0	**0**	117	$	3,956
		17047	**146**	0	**0**	117	$	4,169
		17048	**159**	0	**0**	146	$	5,508
		17049	**183**	0	**0**	97	$	4,026
	DMD Total						**$**	**2,614,309**
GTNW Total							**$**	**2,614,309**
NWPL	**CR**	100010	**0**	0	**0**	0	$	-
						2,000	$	(298,482)

NWPL	**CR**	100010	**0**	0	**0**	2,841	$ (423,994)
						3,360	$ (83,804)
						4,100	$ -
						4,517	$ -
						5,400	$ (1,611,805)
						6,450	$ (962,606)
						7,159	$ (1,068,418)
						8,056	$ (1,202,287)
						9,211	$ (1,374,661)
						10,000	$ (2,984,824)
						10,394	$ (1,551,213)
						15,400	$ (2,298,314)
						19,432	$ (5,800,110)
						20,394	$ (3,043,625)
		100164	**0**	0	**0**	1,500	$ (447,724)
						8,500	$ (1,268,550)
		115163	**0**	0	**0**	7,000	$ (61,107)
		135133	**0**	0	**0**	17,682	$ (2,638,883)
		135198	**0**	0	**0**	17,394	$ (2,595,901)
		137227	**0**	0	**0**	8,500	$ -
		137337	**0**	0	**0**	4,100	$ -
		137341	**0**	0	**0**	2,130	$ (317,884)
		141059	**0**	0	**0**	8,056	$ (1,202,287)
		190203	**0**	0	**0**	2,841	$ (847,988)
		190204	**0**	0	**0**	7,159	$ (2,136,836)
		195151	**0**	0	**0**	2,841	$ (423,994)
		195152	**0**	0	**0**	6,709	$ (1,001,259)
	CR Total						**$(35,646,557)**
	DMD	100010	**0**	0	**0**	132,687	$ 19,802,403
		100164	**0**	0	**0**	10,000	$ 1,492,412
		100314	**0**	0	**0**	7,962	$ 1,188,258
		115161	**0**	0	**0**	2,841	$ 423,994
		115163	**0**	0	**0**	7,159	$ 1,068,418
		135132	**0**	0	**0**	19,432	$ 2,900,055
		135133	**0**	0	**0**	19,432	$ 2,900,055
		135198	**0**	0	**0**	20,394	$ 3,043,625
		135199	**0**	0	**0**	10,394	$ 1,551,213
		135200	**0**	0	**0**	10,000	$ 1,492,412
		136948	**0**	0	**0**	5,000	$ 746,206
		136950	**0**	0	**0**	5,330	$ 795,456
		137226	**0**	0	**0**	8,500	$ 1,268,550
		137227	**0**	0	**0**	8,500	$ -
		137286	**0**	0	**0**	9,211	$ 1,374,661
		137287	**0**	0	**0**	9,211	$ -
		137333	**0**	0	**0**	5,400	$ -
		137334	**0**	0	**0**	5,400	$ 805,902
		137335	**0**	0	**0**	2,000	$ 298,482
		137337	**0**	0	**0**	4,100	$ -
		137339	**0**	0	**0**	4,517	$ -
		137340	**0**	0	**0**	10,000	$ -
		137341	**0**	0	**0**	15,400	$ 2,298,314
		137343	**0**	0	**0**	5,400	$ 805,902
		137346	**0**	0	**0**	17,682	$ 2,638,883
		137347	**0**	0	**0**	17,682	$ -
		137348	**0**	0	**0**	8,500	$ -
		137349	**0**	0	**0**	8,500	$ -
		137852	**0**	0	**0**	4,100	$ -
		137853	**0**	0	**0**	4,100	$ -
		137899	**0**	0	**0**	1,500	$ 223,862
		137900	**0**	0	**0**	1,500	$ 223,862
		137901	**0**	0	**0**	1,500	$ -
		140278	**0**	0	**0**	2,130	$ 317,884
		140279	**0**	0	**0**	2,130	$ -
		140546	**0**	0	**0**	8,056	$ 1,202,287
		140547	**0**	0	**0**	8,056	$ -
		141059	**0**	0	**0**	8,056	$ 961,830
		190203	**0**	0	**0**	2,841	$ 423,994
		190204	**0**	0	**0**	7,159	$ 1,068,418
		195151	**0**	0	**0**	2,841	$ 423,994
		195152	**0**	0	**0**	7,159	$ 1,068,418
	DMD Total						**$ 52,809,751**
NWPL Total							**$ 17,163,194**
Grand Total							**$ 19,777,502**

JURISDICTIOI	AN
PROFIT CENT	LDC

Sum of CDN DOLLARS							
SHORT NAM	**CHARGE TYPE**	**PIPELINE CONTRACT**	**MILES**	**MILAGE RATE**	**NON MILAGE RA**	**CDN VOLUME PER D**	**Grand Total**
TCPL AB	**DMD**	2010-445834	**0**	0	**5**	12,776	$ 749,719
		2010-445835	**0**	0	**5**	8,947	$ 524,992
		2010-445836	**0**	0	**5**	15,609	$ 915,954
		2010-445837	**0**	0	**5**	746	$ 43,787
		2010-447082	**0**	0	**5**	46,825	$ 2,747,697
		2014-623869	**0**	0	**5**	23,293	$ 1,366,845
	DMD Total						**$ 6,348,994**
TCPL AB Total							**$ 6,348,994**
TCPL BC	**DMD**	AVA	**0**	0	**3**	-	$ -
		AVA-F2	**0**	0	**3**	5,011	$ 155,369
		AVA-F4	**0**	0	**3**	40,799	$ 1,264,912
		AVA-F6	**0**	0	**3**	11,772	$ 364,972
		AVA-F8	**0**	0	**3**	49,034	$ 1,520,243
	DMD Total						**$ 3,305,495**
TCPL BC Total							**$ 3,305,495**
WEI	**DMD**	2,483	**0**	0	**387**	8,427	$ 1,022,426
		ACCTSP - 100370	**(blank)**	(blank)	**(blank)**	(blank)	$ 16,200
	DMD Total						**$ 1,038,626**
WEI Total							**$ 1,038,626**
Grand Total							**$ 10,693,115**

30,470,618

Avista Utilities
Idaho Gas Operations
Development of Amortization Rate

Line No.		SALES AMORTIZATION (Sch 101-131)					FIRM AMORTIZATION (Sch 101 and 111)			
1		Sales Therms	Amortization	Interest	Balance		Firm Sales	Amortization	Interest	Balance
2			$ (0.09665)	1.00%			Therms	$ 0.00357	1.00%	
3										
4	**Rate Schedule: 101-132**				$ (7,659,586)	**Rate Schedule: 101-121**				$ 282,836
5										
6	Nov/16	9,723,633	$ 939,790.81	$ (5,991.41)	$ (6,725,786.21)	Nov/16	9,723,633	$ (34,713.37)	$ 221.23	$ 248,343.80
7	Dec/16	13,105,078	$ 1,266,608.02	$ (5,077.07)	$ (5,464,255.26)	Dec/16	13,105,078	$ (46,785.13)	$ 187.46	$ 201,746.13
8	Jan/17	12,975,578	$ 1,254,091.83	$ (4,031.01)	$ (4,214,194.44)	Jan/17	12,975,578	$ (46,322.81)	$ 148.82	$ 155,572.14
9	Feb/17	10,273,872	$ 992,971.52	$ (3,098.09)	$ (3,224,321.01)	Feb/17	10,273,872	$ (36,677.72)	$ 114.36	$ 119,008.78
10	Mar/17	9,115,715	$ 881,035.44	$ (2,319.84)	$ (2,345,605.41)	Mar/17	9,115,715	$ (32,543.10)	$ 85.61	$ 86,551.29
11	Apr/17	5,626,485	$ 543,800.71	$ (1,728.09)	$ (1,803,532.79)	Apr/17	5,626,485	$ (20,086.55)	$ 63.76	$ 66,528.50
12	May/17	3,301,440	$ 319,084.73	$ (1,369.99)	$ (1,485,818.05)	May/17	3,301,440	$ (11,786.14)	$ 50.53	$ 54,792.89
13	Jun/17	2,223,297	$ 214,882.05	$ (1,148.65)	$ (1,272,084.65)	Jun/17	2,223,297	$ (7,937.17)	$ 42.35	$ 46,898.07
14	Jul/17	2,134,859	$ 206,334.47	$ (974.10)	$ (1,066,724.28)	Jul/17	2,134,859	$ (7,621.45)	$ 35.91	$ 39,312.53
15	Aug/17	2,272,256	$ 219,613.93	$ (797.43)	$ (847,907.78)	Aug/17	2,272,256	$ (8,111.95)	$ 29.38	$ 31,229.96
16	Sep/17	2,625,272	$ 253,732.95	$ (600.87)	$ (594,775.70)	Sep/17	2,625,272	$ (9,372.22)	$ 22.12	$ 21,879.86
17	Oct/17	5,873,132	$ 567,639.17	$ (259.13)	$ (27,395.66)	Oct/17	5,873,132	$ (20,967.08)	$ 9.50	$ 922.28
18		79,250,617	$ 7,659,585.63	$ (27,395.68)	$ (27,395.66)		79,250,617	$ (282,924.69)	$ 1,011.03	$ 922.28

TOTAL AMORTIZATION RATES

RCF:	1.05761
Sales Amortization	
Proposed Amort. Rate without revenue sensitive costs	$ (0.09665)
Proposed Amort. Rate with revenue sensitive costs	**$ (0.10222)**

RCF:	1.05761
Firm Amortization	
Proposed Amort. Rate without revenue sensitive costs	$ 0.00357
Proposed Amort. Rate with revenue sensitive costs	**$ 0.00378**

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

Line No.	Description		Factor
1	**Revenues**		1.000000
	Expenses:		
2	Uncollectibles		0.003407
3	Commission Fees		0.002371
4	Idaho State Income Tax		0.048695
5	Total Expenses		0.054473
6	Net Operating Income Before FIT		0.945527
7	Federal Income Tax @ 35%		0.330934
8	REVENUE CONVERSION FACTOR		0.61459
	REVENUE GROSS UP:	(1/1-.054473)	*1.057611*
		Prior RCF	*1.005165*

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	45,043,559	44,640,037	403,522	0.90
ID LEWIS-CLARK area	54,824,788	54,741,524	83,264	0.15
	99,868,347	99,381,561	486,785	0.49
Bonners	2,463,920	4,475,910	(2,011,990)	(81.66)
Genesee	231,140	206,816	24,324	10.52
Kellogg	4,021,370	4,220,058	(198,688)	(4.94)
Moscow	6,357,060	6,298,431	58,629	0.92
Pinehurst-Kingston	724,400	454,864	269,536	37.21
Sandpoint	6,893,350	4,746,440	2,146,910	31.14
Smelterville-Page	398,990	274,504	124,486	31.20
IDAHO TOTAL	120,958,577	120,058,585	899,991	0.74

AVISTA UTILITIES

Case No. AVU-G-16-02

EXHIBIT "D"

Pipeline Tariffs

August 26, 2016

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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 0.0000% 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
Pacific Summit Energy LLC	9173	PS-1	8/30/2004	8/30/2010
Louis Dreyfus Energy Canada LP	9263	PS-1	10/29/2004	10/31/2010
Louis Dreyfus Energy Services L.P.	9273	PS-1	11/4/2004	10/31/2014
Devlar Energy Marketing, LLC	9584	PS-1	5/2/2005	4/30/2015
Suncor Energy Marketing Inc.	9772	PS-1	10/1/2005	9/30/2015
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
Eagle Energy Partners I, LP	10310	PS-1	10/27/2006	10/31/2011
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

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	.40888
15 Year Evergreen Exp.	.00000	.36164
25 Year Evergreen Exp.	.00000	.34140
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	.40888
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 $3,625,910 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
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 $0.35745 and $0.33721 for transmission costs and $0.00419 and $0.00419 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 $.40469 for transmission costs and $0.00419 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 transport gas for delivery for Small Customers subject to this Rate Schedule TF-1 under any interruptible Service Agreement or under any capacity release Service Agreement unless such Small Customer has exhausted its daily levels of firm service entitlement 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	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	Maximum
Rate Schedule SGS-2F (2) (3) (4) (5)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01558
Expansion Shipper	0.00000	0.04045
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00347
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01558
Expansion Shipper	0.00000	0.04045
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00347
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.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

Type of Rate	Base Tariff Rate (1)
Demand Charge (2)	0.02580
Capacity Demand Charge (2)	0.00330
Liquefaction	0.90855
Vaporization	0.03386

Footnotes

(1) Shippers receiving service under this rate schedule are required to furnish fuel reimbursement in-kind at the rate 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.

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	0.02580
Capacity Demand Charge (2)	0.00000	0.00330
Volumetric Bid Rates		
Vaporization Demand-Related Charge (2)	0.00000	0.02580
Storage Capacity Charge (2)	0.00000	0.00330
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	Base Tariff Rate (1) Maximum
Rate Schedule LS-3F (3)		
Demand Charge (2)	0.00000	0.02580
Capacity Demand Charge (2)	0.00000	0.00330
Volumetric Bid Rates		
Vaporization Demand-Related Charge (2)	0.00000	0.02580
Storage Capacity Charge (2)	0.00000	0.00330
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.

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) of the

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

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.

Effective Date: April 1, 2014

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

APPENDIX A

DEMAND AND COMMODITY TOLLS
TRANSPORTATION SERVICE - SOUTHERN

Firm Transportation Service - Southern

Service Term	PNG Delivery Point	Inland Delivery Area	Huntingdon Delivery Area*	FortisBC Kingsvale to Huntingdon**
	Demand Tolls $\$/10^3m^3/mo.$			
1 year	89.70	229.37	395.91	166.54
2 years	87.09	222.69	384.38	161.69
3 years	84.48	216.01	372.85	156.84
4 years	83.60	213.79	369.01	155.22
5 years or more	82.73	211.56	365.16	153.60

* To be increased to the percentage amount of the applicable toll specified in a Service Agreement for Enhanced T-South Service

** 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.

AOS and Interruptible Transportation Service – Southern

Months	PNG Delivery Point	Inland Delivery Area	Huntingdon Delivery Area	FortisBC Kingsvale to Huntingdon*
	Commodity Tolls $\$/10^3m^3$			
May 1, 2016 to October 31, 2016	2.929	7.490	12.928	5.438
November 1, 2016 to December 31, 2016	3.905	9.987	17.237	7.251

* 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.

Effective Date: May 1, 2016

Westcoast Energy Inc.

TOLL SCHEDULES - SERVICE

Import Backhaul Service

	Commodity Tolls $\$/10^3m^3$		
Months	Inland Delivery Area	PNG Delivery Point	Compressor Station No. 2
May 1, 2016 to October 31, 2016	5.438	9.999	12.928
November 1, 2016 to December 31, 2016	7.250	13.332	17.237

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.

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $ 229.87/10^3m^3
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D [1]	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points $ 5.45/GJ FT-D Demand Rate for Group 2 Delivery Points $ 5.08/GJ FT-D Demand Rate for Group 3 Delivery Points $ 6.09/GJ
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point
6. Rate Schedule FT-P [1]	Refer to Attachment "3" for applicable FT-P Demand Rate per month
7. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 1-5 years — 11.75 20 years — 7.81
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month $ 129.55/10^3m^3
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point
10. Rate Schedule IT-D [1]	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
12. Rate Schedule PT	Schedule No. — PT Rate — PT Gas Rate 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
13. Rate Schedule OS	Schedule No. — Charge 2016732105 — $ 143.73 /10^3m^3 / month 2016732103 — $ 143.73 /10^3m^3 / month 2016732101 — $ 143.73 /10^3m^3 / month 2016732102 — $ 143.73 /10^3m^3 / month 2016732106 — $ 143.73 /10^3m^3 / month 2011475772 — $ 9,250.00 / month 2016732104 — $ 805.00 / month 2003004522 — Applicable IT-R and IT-D Rate 2011476052 / 2011476054 — $ 0.1665 / GJ subject to $ 717,000.00 Minimum Annual Charge 2011475056 / 2011476092 / 2016721799 — $ 0.095 / GJ and $ 1,000.00 / month
14. Rate Schedule CO2	Tier — CO_2 Rate ($/$10^3m^3$) 1 — 544.24 2 — 430.63 3 — 279.70
15. Monthly Abandonment Surcharge [2]	$11.94/$10^3m^3$/month — $0.32/GJ/month
16. Daily Abandonment Surcharge [3]	$ 0.39/10^3m^3/day — $0.0104/GJ/day

1. Service under rate Schedules FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedules OS No. 2011476092, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

2. Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, STFT, LRS-3, and the following Rate Schedules OS: 2016732105, 2016732103, 2016732101, 2016732102, and 2016732106.

3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2011475056, 2011476092, 2016721799, 2003004522, and if applicable Over-Run Gas.

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)
2000	ALBERTA-B.C. BORDER	5.08	0.1832
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	5.08	0.1832
31110	ALLIANCE EDSON INTERCONNECT APN	5.08	0.1832
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	5.08	0.1832
3002	BOUNDARY LAKE BORDER	5.08	0.1832
1958	EMPRESS BORDER	5.94	0.2141
3886	GORDONDALE BORDER	5.08	0.1832
6404	MCNEILL BORDER	5.94	0.2141

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
31000	A.T. PLASTICS SALES APN	5.08	0.1832	Yes
31001	ADM AGRI INDUSTRIES SALES APN	5.08	0.1832	Yes
3880	AECO INTERCONNECTION	5.08	0.1832	
31003	AGRIUM CARSELAND SALES APS	5.08	0.1832	
31002	AGRIUM FT. SASK SALES APN	5.08	0.1832	Yes
31004	AGRIUM REDWATER SALES APN	5.08	0.1832	
31005	AINSWORTH SALES APGP	5.08	0.1832	
31006	AIR LIQUIDE SALES APN	5.08	0.1832	
3214	AKUINU RIVER WEST SALES	5.08	0.1832	
31007	ALBERTA ENVIROFUELS SALES APN	5.08	0.1832	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	5.08	0.1832	Yes
3868	ALBERTA-MONTANA BORDER	5.08	0.1832	
3297	ALDER FLATS SOUTH NO 2 SALES	5.08	0.1832	
3059	ALLISON CREEK SALES	5.08	0.1832	
31009	ALTASTEEL SALES APN	5.08	0.1832	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	5.08	0.1832	
31012	APL JASPER SALES APN	5.08	0.1832	Yes
3488	ARDLEY SALES	5.08	0.1832	
3237	ASPEN SALES	5.08	0.1832	
3662	ATUSIS CREEK EAST SALES	5.08	0.1832	
3216	AURORA NO 2 SALES	5.08	0.1832	
3135	AURORA SALES	5.08	0.1832	
3288	BANTRY SALES	5.08	0.1832	
3423	BASHAW WEST SALES	5.08	0.1832	
31013	BAYMAG SALES APS	5.08	0.1832	
31014	BEAR CREEK COGEN SALES APGP	5.08	0.1832	
3299	BEAR RIVER WEST SALES	5.08	0.1832	
3068	BEAVER HILLS SALES	5.08	0.1832	
3268	BENBOW SOUTH SALES	5.08	0.1832	
3933	BIG EDDY INTERCONNECTION	5.08	0.1832	
3655	BIG PRAIRIE SALES	5.08	0.1832	
3067	BIGSTONE SALES	5.08	0.1832	
3285	BILBO SALES	5.08	0.1832	
3468	BLEAK LAKE SALES	5.08	0.1832	
3295	BOOTIS HILL SALES	5.08	0.1832	
3225	BOTHA SALES	5.08	0.1832	
3259	BOULDER CREEK SALES	5.08	0.1832	
3164	BRAINARD LAKE SALES	5.08	0.1832	
3289	BRAZEAU EAST SALES	5.08	0.1832	
3918	BUFFALO CREEK INTERCONNECTION	5.08	0.1832	
31015	BURDETT COGEN SALES APS	5.08	0.1832	
3265	BURNT TIMBER SALES	5.08	0.1832	
3204	CABIN SALES	5.08	0.1832	
3293	CADOGAN SALES	5.08	0.1832	
3109	CALDWELL SALES	5.08	0.1832	
31016	CALGARY ENERGY CENTRE SALES APS	5.08	0.1832	Yes
3262	CALUMET RIVER SALES	5.08	0.1832	
3634	CANOE LAKE SALES	5.08	0.1832	
3165	CANOE LAKE SALES NO 2	5.08	0.1832	
3866	CARBON INTERCONNECTION	5.08	0.1832	
3484	CARIBOU LAKE SALES	5.08	0.1832	
3157	CARIBOU LAKE SOUTH SALES	5.08	0.1832	
3106	CARMON CREEK SALES	5.08	0.1832	
3248	CARMON CREEK EAST SALES	5.08	0.1832	
3101	CAROLINE SALES	5.08	0.1832	
31017	CARSELAND COGEN SALES APS	5.08	0.1832	
3275	CARSON CREEK SALES	5.08	0.1832	
3495	CAVALIER SALES	5.08	0.1832	
31018	CHAIN LAKES COOP SALES APS	5.08	0.1832	
3907	CHANCELLOR INTERCONNECTION	5.08	0.1832	
3151	CHEECHAM WEST NO 2 SALES	5.08	0.1832	
3622	CHEECHAM WEST SALES	5.08	0.1832	
6014	CHEVRON AURORA SALES	5.08	0.1832	
31019	CHEVRON FT. SASK SALES APN	5.08	0.1832	Yes
3097	CHICKADEE CREEK SALES	5.08	0.1832	
3305	CHIGWELL NORTH SALES	5.08	0.1832	

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
3496	CHIPEWYAN RIVER SALES	5.08	0.1832	
3163	CHRISTINA LAKE NORTH SALES	5.08	0.1832	
31020	CLOVERBAR FIBERGLASS SALES APN	5.08	0.1832	Yes
31021	CLOVERBAR POWER PLANT SALES APN	5.08	0.1832	Yes
3158	CLYDE NORTH SALES	5.08	0.1832	
31022	COALDALE COGEN SALES APS	5.08	0.1832	
1417	COLD LAKE BORDER	5.08	0.1832	
3168	COLLICUTT SALES	5.08	0.1832	
3239	CONKLIN SALES	5.08	0.1832	
3416	COUSINS A SALES	5.08	0.1832	
1963	COUSINS B & C SALES	5.08	0.1832	
3483	CRAMMOND SALES	5.08	0.1832	
3202	CRANBERRY LAKE EAST SALES	5.08	0.1832	
3219	CRANBERRY LAKE EAST SALES NO 2	5.08	0.1832	
3105	CRANBERRY LAKE SALES	5.08	0.1832	
3897	CROSSFIELD EAST INTERCONNECTION	5.08	0.1832	
3291	CROSSFIELD EAST NO 3 SALES	5.08	0.1832	
3172	CROSSFIELD SALES	5.08	0.1832	
5024	CROW LAKE SALES	5.08	0.1832	
3071	CYNTHIA SALES	5.08	0.1832	
3199	DAWES LAKE NORTH SALES	5.08	0.1832	
3147	DAWES LAKE SALES	5.08	0.1832	
3184	DAWES LAKE SALES NO 2	5.08	0.1832	
3119	DEADRICK CREEK SALES (RETURN RUN)	5.08	0.1832	
3085	DEEP VALLEY CREEK SALES	5.08	0.1832	
3124	DEEP VALLEY CREEK SOUTH SALES	5.08	0.1832	
31023	DEGUSSA CANADA INC. SALES APN	5.08	0.1832	
3465	DEMMITT SALES	5.08	0.1832	
3121	DEMMITT SALES NO 2	5.08	0.1832	
3277	DEMMITT NO 3 SALES	5.08	0.1832	
31024	DEVONIA LAKE SALES APN	5.08	0.1832	
6011	DOVER SALES	5.08	0.1832	
3186	DUNKIRK RIVER SALES	5.08	0.1832	
3098	DUTCH CREEK SALES	5.08	0.1832	
3632	EAST CALGARY SALES	5.08	0.1832	
31027	EASYFORD SALES APN	5.08	0.1832	
31028	ECHO MIDPOINT SALES APN	5.08	0.1832	
3175	EGG LAKE SALES	5.08	0.1832	
3129	EKWAN SALES	5.08	0.1832	
3456	ELK POINT SALES	5.08	0.1832	
3270	ELK RIVER SOUTH NO 2 SALES	5.08	0.1832	
3082	ELK RIVER SOUTH SALES	5.08	0.1832	
3651	ELK RIVER SOUTHWEST SALES	5.08	0.1832	
31029	ENVIROFORS PRESERVERS SALES APN	5.08	0.1832	Yes[2]
3469	EVERGREEN SALES	5.08	0.1832	
31030	EXSHAW LIME SALES APS	5.08	0.1832	
31031	FALHER ALFALFA PLANT 1 SALES APWM	5.08	0.1832	Yes
31032	FALHER ALFALFA PLANT 2 SALES APWM	5.08	0.1832	Yes
3185	FAWCETT RIVER NORTH SALES	5.08	0.1832	
3159	FAWCETT RIVER SALES	5.08	0.1832	
3107	FERGUSON SALES	5.08	0.1832	
3623	FERINTOSH NORTH SALES (RETURN RUN)	5.08	0.1832	
3430	FERINTOSH SALES	5.08	0.1832	
3182	FERRIER SOUTH A SALES	5.08	0.1832	
3077	FIRE CREEK SALES	5.08	0.1832	
3154	FIREBAG SALES	5.08	0.1832	
3138	FISHER CREEK SALES	5.08	0.1832	
31033	FORESTBURG SALES APNI	5.08	0.1832	
3247	FORT KENT NO 2 SALES	5.08	0.1832	
31034	FORT MACLEOD COGEN SALES APS	5.08	0.1832	
31036	FT SASK SULPHIDES SALES APN	5.08	0.1832	Yes
31035	FT SASK VEGETABLE OIL SALES APN	5.08	0.1832	
31010	FT. SASK FRAC SALES APN	5.08	0.1832	Yes
31011	FT. SASK UTILITY SALES APN	5.08	0.1832	Yes
3490	GAETZ LAKE SALES	5.08	0.1832	
3128	GARRINGTON SALES	5.08	0.1832	
3616	GAS CITY SALES	5.08	0.1832	
31037	GENESEE PLANT GROUP SALES APN	5.08	0.1832	
31038	GEON CANADA INC. SALES APN	5.08	0.1832	
31039	GEORGIA PACIFIC SALES APN	5.08	0.1832	Yes
3201	GERMAIN SALES	5.08	0.1832	
3195	GILBY SALES	5.08	0.1832	
3624	GODS LAKE SALES (RETURN RUN)	5.08	0.1832	
3087	GOLD CREEK SALES	5.08	0.1832	
31040	GOLDEN SPIKE SALES APN	5.08	0.1832	
3213	GORDONDALE EAST SALES	5.08	0.1832	
3659	GRAHAM SALES	5.08	0.1832	
31041	GRANDE CACHE MINE SALES APGC	5.08	0.1832	
3055	GRANDE PRAIRIE SALES	5.08	0.1832	
3183	GRANOR SALES	5.08	0.1832	

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
3464	GREENCOURT WEST SALES	5.08	0.1832	
3229	GRIST LAKE SALES	5.08	0.1832	
3117	GRIZZLY SALES	5.08	0.1832	
3224	HANGINGSTONE SALES	5.08	0.1832	
3414	HANNA SOUTH B SALES	5.08	0.1832	
3294	HARMATTAN-ELKTON SALES	5.08	0.1832	
3437	HARMATTAN SALES	5.08	0.1832	
3615	HAYNES SALES	5.08	0.1832	
3100	HEART RIVER SALES	5.08	0.1832	
3240	HEART RIVER NO 2 SALES	5.08	0.1832	
31091	HEARTLAND OFFGAS SALES APN	5.08	0.1832	Yes
31042	HEARTLAND UPGRADER SALES APN	5.08	0.1832	
3276	HEISLER SALES	5.08	0.1832	
3661	HERMIT LAKE NO 2 SALES	5.08	0.1832	
3162	HOOLE SALES NO 2	5.08	0.1832	
3181	HOOLE SALES NO 3	5.08	0.1832	
3153	HORIZON SALES	5.08	0.1832	
31043	HR MILNER POWER PLANT SALES APGC	5.08	0.1832	
3125	HUGGARD CREEK SALES	5.08	0.1832	
31044	HUSKY OIL LLOYDMINISTER SALES APN	5.08	0.1832	Yes
31045	I.O.L STRATHCONA REFINERY SALES APN	5.08	0.1832	Yes[2]
3472	INNISFAIL SALES	5.08	0.1832	
3193	IPIATIK LAKE SALES	5.08	0.1832	
3282	IROQUOIS CREEK SALES	5.08	0.1832	
3156	JACKFISH SALES	5.08	0.1832	
3166	JACKPINE SALES	5.08	0.1832	
3133	JACKPOT CREEK SALES (RETURN RUN)	5.08	0.1832	
3860	JANUARY CREEK INTERCONNECTION	5.08	0.1832	
6012	JAPAN CANADA SALES	5.08	0.1832	
3246	JAPAN CANADA NO 2 SALES	5.08	0.1832	
3618	JENNER EAST SALES	5.08	0.1832	
3864	JOFFRE INTERCONNECTION	5.08	0.1832	
3269	JONES LAKE NO 2 SALES	5.08	0.1832	
3152	JOSLYN CREEK SALES	5.08	0.1832	
3078	JUDY CREEK SALES	5.08	0.1832	
31129	JUMPING POUND SALES APS	5.08	0.1832	
3273	KAYBOB SALES	5.08	0.1832	
3222	KAYBOB SOUTH NO 3 SALES	5.08	0.1832	
3242	KAYBOB SOUTH SALES	5.08	0.1832	
3192	KEARL SALES	5.08	0.1832	
31046	KEEPHILLS 3 SALES APN	5.08	0.1832	
3179	KENT SALES	5.08	0.1832	
3150	KETTLE RIVER NORTH NO 2 SALES	5.08	0.1832	
3249	KETTLE RIVER SALES	5.08	0.1832	
3258	KIDNEY LAKE SALES	5.08	0.1832	
3203	KOMIE EAST SALES	5.08	0.1832	
3931	KV OIL SANDS EX	5.08	0.1832	
3476	LAC LA BICHE SALES	5.08	0.1832	
31047	LAFARGE SALES APS	5.08	0.1832	
31048	LAMB WESTON SALES APS	5.08	0.1832	
3460	LANDON LAKE SALES	5.08	0.1832	
31049	LEGAL ALFALFA SALES APN	5.08	0.1832	
31131	LINQUIST COULEE SALES APS	5.08	0.1832	
3187	LITTLE SUNDANCE SALES	5.08	0.1832	
3196	LIVOCK SALES	5.08	0.1832	
3474	LLOYD CREEK SALES	5.08	0.1832	
31133	LOBSTICK SALES APN	5.08	0.1832	
3462	LONE PINE CREEK SALES	5.08	0.1832	
3606	LOSEMAN LAKE SALES	5.08	0.1832	
3080	LOUISE CREEK SALES	5.08	0.1832	
31132	LUNNFORD SALES APN	5.08	0.1832	
3236	MACKAY SALES	5.08	0.1832	
3146	MAHIHKAN SALES	5.08	0.1832	
31096	MANAWAN LAKE SALES APN	5.08	0.1832	
31099	MASKWA CREEK SALES APN	5.08	0.1832	
3604	MARGUERITE LAKE SALES	5.08	0.1832	
3209	MARLOW CREEK SALES	5.08	0.1832	
3110	MARSH HEAD CREEK WEST SALES	5.08	0.1832	
31135	MAZEPPA SALES APS	5.08	0.1832	
31050	MCCAIN FOODS SALES APS	5.08	0.1832	
3211	MEGA RIVER SALES	5.08	0.1832	
6021	MILDRED LAKE NORTH SALES	5.08	0.1832	
3120	MILDRED LAKE SALES	5.08	0.1832	
31051	MILLAR WESTERN FOREST PROD LTD SALES APNI	5.08	0.1832	Yes
3653	MINNEHIK BUCK LAKE SALES	5.08	0.1832	
3111	MINNOW LAKE SOUTH SALES	5.08	0.1832	
31052	MITSUE PLANT SALES APNI	5.08	0.1832	
3889	MITSUE SALES INTERCONNECTION	5.08	0.1832	
31053	MOBIL FUEL GAS SALES APN	5.08	0.1832	Yes
31521	MONTANA BAND AP	5.08	0.1832	

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
3167	MOOREHEAD SALES	5.08	0.1832	
3930	MOOSA EXCHANGE	5.08	0.1832	
3261	MUSKEG CREEK SALES	5.08	0.1832	
3280	MUSKWA RIVER SALES	5.08	0.1832	
3208	MUSREAU LAKE NO 2 SALES	5.08	0.1832	
31123	NCL REDWATER FRACTIONATOR NORTH SALES APN	5.08	0.1832	
31055	NCL REDWATER FRACTIONATOR SALES APN	5.08	0.1832	
3658	NOSE MOUNTAIN SALES	5.08	0.1832	
3479	NOSEHILL CREEK NORTH SALES	5.08	0.1832	
3470	NOSEHILL CREEK SALES	5.08	0.1832	
31056	NOVA CHEMICALS SALES APS	5.08	0.1832	
31057	OBED MOUNTAIN COAL SALES APN	5.08	0.1832	
31098	OHATON SALES APN	5.08	0.1832	
3660	OLDS SALES	5.08	0.1832	
31134	OLDS SALES APS	5.08	0.1832	
3478	ONETREE SALES	5.08	0.1832	
3300	OTAUWAU SALES	5.08	0.1832	
31130	PADDLE RIVER SALES APN	5.08	0.1832	
3072	PADDY CREEK SALES	5.08	0.1832	
31058	PEMBINA CTS NO 9 SALES APN	5.08	0.1832	
31059	PETROCAN AIR PRODUCTS SALES APN	5.08	0.1832	Yes[2]
31060	PETROCAN REFINERY SALES APN	5.08	0.1832	Yes[2]
31061	PIGEON LAKE SALES APN	5.08	0.1832	
3444	PINCHER CREEK SALES	5.08	0.1832	
3086	PINE CREEK SALES	5.08	0.1832	
3178	POINTE LA BICHE SALES	5.08	0.1832	
31062	PRAIRIE CREEK SALES APGC	5.08	0.1832	
3287	PROGRESS SALES	5.08	0.1832	
3174	QUIRK CREEK SALES NO 2	5.08	0.1832	
3076	RAINBOW SALES	5.08	0.1832	
3131	RASPBERRY LAKE SALES	5.08	0.1832	
3819	RAT CREEK WEST INTERCONNECT	5.08	0.1832	
31063	RED DEER GRAIN PROCESSORS SALES APN	5.08	0.1832	Yes
31064	REDWATER COGEN SALES APN	5.08	0.1832	
31120	REDWATER CONSERVATION PLANT SALES APN	5.08	0.1832	
31344	REDWATER UPGRADER UTILITY SALES APN	5.08	0.1832	
31065	RENAISSANCE SALES APS	5.08	0.1832	
3256	RESTHAVEN SALES	5.08	0.1832	
3298	RICINUS SALES	5.08	0.1832	
3283	RIMBEY SALES	5.08	0.1832	
3652	ROBB SALES	5.08	0.1832	
31066	ROCKY RAPIDS SALES APN	5.08	0.1832	
3635	ROD LAKE SALES DELIVERY	5.08	0.1832	
31093	RODINO SALES APN	5.08	0.1832	
31067	ROGERS SUGAR SALES APS	5.08	0.1832	Yes
3448	ROSS CREEK SALES	5.08	0.1832	
3189	SAAMIS SALES	5.08	0.1832	
3095	SAKWATAMAU SALES	5.08	0.1832	
3139	SALESKI SALES	5.08	0.1832	
3050	SARATOGA SALES	5.08	0.1832	
3609	SARRAIL SALES	5.08	0.1832	
3207	SATURN SALES	5.08	0.1832	
3301	SAULTEAUX SALES	5.08	0.1832	
3241	SAWN LAKE EAST NO 2 SALES	5.08	0.1832	
3238	SAWN LAKE EAST SALES	5.08	0.1832	
31068	SCHULLER INT JOHNS MANVILLE SALES APS	5.08	0.1832	Yes
31125	SCOTFORD HYDROGEN SALES APN	5.08	0.1832	
31069	SCOTFORD UP EXP PHASE 1 SALES APN	5.08	0.1832	
3264	SEDGEWICK SALES	5.08	0.1832	
3862	SEVERN CREEK INTERCONNECTION	5.08	0.1832	
3613	SHANTZ SALES	5.08	0.1832	
31070	SHEERNESS SALES APSI	5.08	0.1832	
31071	SHELL SCOTFORD SALES APN	5.08	0.1832	
31072	SHELL UPGRADER MASTER SALES APN	5.08	0.1832	
31127	SHEPARD ENERGY CENTRE SALES APS	5.08	0.1832	Yes
31073	SHERRITT INTERNATIONAL SALES APN	5.08	0.1832	Yes
3494	SILVER VALLEY SALES	5.08	0.1832	
3274	SIMONETTE NO 2 SALES	5.08	0.1832	
31074	SLAVE LAKE PULP MILL SALES APNI	5.08	0.1832	
3210	SNUFF MOUNTAIN NORTH SALES	5.08	0.1832	
3099	SOUSA CREEK EAST SALES	5.08	0.1832	
3140	SOUTH ELKTON SALES	5.08	0.1832	
3149	SOUTH TERMINAL SALES	5.08	0.1832	
3429	ST. PAUL SALES	5.08	0.1832	
3272	STEEN RIVER SALES	5.08	0.1832	
3600	STORNHAM COULEE SALES	5.08	0.1832	
3271	STRACHAN SALES	5.08	0.1832	
31075	STRATHCONA BUILDING PRODUCTS SALES APN	5.08	0.1832	Yes
31076	STYRENE PLANT SALES APN	5.08	0.1832	
31077	SUMMIT LIME WORKS SALES APSI	5.08	0.1832	Yes

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
31078	SUN GRO HORTICULTURE LTD SALES APN	5.08	0.1832	
3130	SUNDANCE CREEK EAST SALES	5.08	0.1832	
3205	SUNDAY CREEK SOUTH NO 2 SALES	5.08	0.1832	
3497	SUNDAY CREEK SOUTH SALES	5.08	0.1832	
31092	SWAN HILLS MISCIBLE INJECTION SALES APN	5.08	0.1832	
31079	SWAN HILLS WASTE TREATMENT SALES APN	5.08	0.1832	
31080	TABER COGEN SALES APS	5.08	0.1832	
3218	TEEPEE CREEK SALES	5.08	0.1832	
3656	TONY CREEK NORTH SALES	5.08	0.1832	
31081	TRANSALTA POWER PLANTS SALES APN	5.08	0.1832	
3198	TREMBLAY NO 2 SALES	5.08	0.1832	
3221	TREMBLAY WEST SALES	5.08	0.1832	
31122	TRIBUTE SALES APN	5.08	0.1832	
3144	TUCKER LAKE SLS	5.08	0.1832	
3113	TWINLAKES CREEK SALES	5.08	0.1832	
1250	UNITY BORDER	5.08	0.1832	
31082	UNIVERSITY OF ALBERTA SALES APN	5.08	0.1832	Yes
3088	VALHALLA SALES	5.08	0.1832	
3292	VANDERSTEENE LAKE SALES	5.08	0.1832	
31083	VIOLET GROVE SALES APN	5.08	0.1832	
3296	VIRGINIA HILLS NO 2 SALES	5.08	0.1832	
3103	VIRGO SALES	5.08	0.1832	
3206	WAPASU CREEK SALES	5.08	0.1832	
3281	WAPITI CENTRAL SALES	5.08	0.1832	
3227	WAPITI NORTH SALES	5.08	0.1832	
3251	WAPITI SOUTH SALES	5.08	0.1832	
3177	WARWICK SOUTH SALES	5.08	0.1832	
3948	WARWICK SOUTHEAST INTERCONNECTION	5.08	0.1832	
3074	WATERTON SALES	5.08	0.1832	
3171	WATERTON SALES NO 1	5.08	0.1832	
3254	WATINO SALES	5.08	0.1832	
3412	WAYNE NORTH B SALES	5.08	0.1832	
31084	WELDWOOD HINTON SALES APN	5.08	0.1832	Yes
3255	WEMBLEY NO 2 SALES	5.08	0.1832	
3114	WEMBLEY SALES	5.08	0.1832	
3173	WEMBLEY SOUTH SALES	5.08	0.1832	
3230	WEMBLEY WEST SALES	5.08	0.1832	
31085	WEST EDMONTON CEMENT SALES APN	5.08	0.1832	Yes
31086	WEST EDMONTON PLASTICS SALES APN	5.08	0.1832	Yes
3228	WEST ELLS SALES	5.08	0.1832	
3486	WESTERDALE SALES	5.08	0.1832	
3871	WESTLOCK SALES INTERCONNECTION	5.08	0.1832	
31087	WEYERHAEUSER EDSON SALES APN	5.08	0.1832	Yes
31088	WEYERHAUSER DRAYTON VALLEY SALES APN	5.08	0.1832	Yes
31089	WEYERHAUSER GRANDE PRAIRIE SALES APGP	5.08	0.1832	
3191	WHISKEY JACK LAKE SALES	5.08	0.1832	
3267	WHITBURN EAST SALES	5.08	0.1832	
31090	WHITECOURT POWER LP SALES APNI	5.08	0.1832	
3663	WHITECOURT SALES	5.08	0.1832	
3176	WHITESANDS SALES	5.08	0.1832	
3231	WIAU LAKE SALES	5.08	0.1832	
3069	WILSON CREEK SOUTH SALES	5.08	0.1832	
3421	WIMBORNE SALES	5.08	0.1832	
3263	WINDFALL SALES	5.08	0.1832	
3148	WINEFRED SALES	5.08	0.1832	

1. Subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.
2. ATCO Pipelines Franchise Fee is currently 0.00% at these locations.

Group 3 Delivery Point Name	FT-D Demand Rate per Month ($/GJ)
All Group 3 Delivery Points	6.09

TransCanada
In business to deliver

NGTL System

TransCanada's - NGTL System Transportation Rates & Abandonment Surcharge

2016 Final Rates - Effective January 1, 2016

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]	229.87/mo	19.9	21.3	16.0
IT-R (Interruptible Receipt)	8.67/d	22.9	24.6	18.4

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	5.94/mo	19.5	20.8	15.6
Alberta-B.C. Border	5.08/mo	16.7	17.8	13.3
Gordondale Border/Boundary Lk Border	5.08/mo	16.7	17.8	13.3
ATCO: Clairmont/Shell Creek/Edson	5.08/mo	16.7	17.8	13.3
Group 2:				
All Group 2 delivery points	5.08/mo	16.7	17.8	13.3
Group 3:				
All Group 3 delivery points	6.09/mo	20.0	21.4	16.0
IT-D (Interruptible Delivery)				
Group 1:				

	$/10³m³ (Cdn)	¢/GJ/d (Cdn)	¢/Mcf/d (Cdn)
Monthly Abandonment Surcharge	11.94/mo	0.32/mo	0.34/mo
Daily Abandonment Surcharge	0.39/d	0.0104/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)

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.

Page Updated: 2016-05-24 17:06:41h CT

Customer Express Home » Pricing & Tolls » **NGTL System**

TABLE OF EFFECTIVE RATES

1. Rate Schedule FT, Firm Transportation Service

	Demand Rate ($/GJ/Km/Month)
Zone 6	0.0065420922
Zone 7	0.0036177806
Zone 8*	0.0145216983
Zone 9	0.0086057582

2. Rate Schedule OT, Overrun Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 6	0.0002359443
Zone 7	0.0001304773

3. Rate Schedule IT, Interruptible Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 8*	0.0005237334
Zone 9	0.0003103716

4. Monthly Abandonment Surcharge**

All Zones 0.1047843362 ($/GJ/Month)

5. Daily Abandonment Surcharge***

All Zones 0.0034355520 ($/GJ/Day)

* For Zone 8, Shippers Haul Distance shall be 170.7 km.

**Monthly Abandonment Surcharge applicable to Rate Schedule Firm Transportation Service, and Short Term Firm Transportation Service for all zones.

***Daily Abandonment Surcharge applicable to Rate Schedule Overrun Transportation Service for zone 6 & 7, Interruptible Transportation Service for zone 8 & 9, and Small General Service for zone 9.

AVISTA UTILITIES

Case No. AVU-G-16-02

EXHIBIT "E"

Copy of Press Release and Customer Notice

August 26, 2016

Contact: **DRAFT**
Media: Casey Fielder (509) 495-4916, casey.fielder@avistacorp.com
Investors: Lauren Pendergraft (509) 495-2998, lauren.pendergraft@avistacorp.com
Avista 24/7 Media Access (509) 495-4174

Avista Requests Natural Gas Price Decrease in Idaho

Annual price adjustment would take effect Nov. 1, 2016

SPOKANE, Wash. Aug. 29, 2015, 1:05 p.m. PST: Avista **(NYSE: AVA)** customers in Idaho could see an overall 7.8 percent decrease in their natural gas rates on Nov. 1, 2016 if the Idaho Public Utilities Commission (IPUC or Commission) approves the company's annual Purchased Gas Cost Adjustment (PGA) filed today.

If the request is approved, Avista residential customers using an average of 61 therms a month could expect their bill to decrease by $4.65, or 8.4 percent, for a revised monthly bill of $50.94 beginning Nov. 1, 2016. Avista's natural gas revenues would decrease by $6.1 million. 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 requested natural gas rate change by customer segment is as follows:

General Service - Firm - Schedule 101 - Residential & Small Commercial	-7.7%
Large General Service - Firm – Schedules 111 & 112 - Commercial	-7.7%

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. The primary driver for the company's requested decrease is a reduction in natural gas commodity costs due to a warmer than normal winter, an abundance of natural gas held in storage, and continued high production levels of natural gas.

About 50 percent of an Avista natural gas customer's bill is the combined cost of purchasing natural gas on the wholesale market and transporting it to Avista's system. These costs fluctuate up and down based on market prices. The costs are not marked up by Avista. The remaining 50 percent covers the cost of delivering the natural gas -- the equipment and people needed to provide safe and reliable service.

Rate Application Procedure

Avista's applications are proposals, subject to public review and a Commission decision. Copies of the applications are available for public review at the offices of both the Commission and Avista, and on the Commission's website (www.puc.idaho.gov). Customers may file with the Commission written comments related to Avista's filings. 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 filings are also available on Avista's website at www.avistautilities.com/rates.

About Avista Corp.
Avista Corp. is an energy company involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is our operating division that provides electric service to 375,000 customers and natural gas to 335,000 customers. Its service territory covers 30,000 square miles in eastern Washington, northern Idaho and parts of southern and eastern Oregon, with a population of 1.6 million. Alaska Energy and Resources Company is an Avista subsidiary that provides retail electric service in the city and borough of Juneau, Alaska, through its subsidiary Alaska Electric Light and Power Company. Avista stock is traded under the ticker symbol "AVA." For more information about Avista, please visit www.avistacorp.com.

This news release contains forward-looking statements regarding the company's current expectations. Forward-looking statements are all statements other than historical facts. Such statements speak only as of the date of the news release and are subject to a variety of risks and uncertainties, many of which are beyond the company's control, which could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all of the factors discussed in the company's Annual Report on Form 10-K for the year ended Dec. 31, 2015 and the Quarterly Report on Form 10-Q for the quarter ended June 30, 2016.

SOURCE: Avista Corporation

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To unsubscribe from Avista's news release distribution, send a reply message to lena.funston@avistacorp.com

Important Notice for Idaho Natural Gas Customers

(Sept. 2016)

Proposed Natural Gas Rate Adjustment Filed to be Effective Nov. 1, 2016

Avista has filed its annual Purchased Gas Cost Adjustment (PGA) request with the Idaho Public Utilities Commission (Commission), with a requested effective date of Nov. 1, 2016. The PGA is 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.

The proposed PGA would decrease natural gas rates by an overall 7.8 percent and Avista's natural gas revenues by $6.1 million. If the request is approved, Avista residential customers using an average of 61 therms a month could expect their bill to decrease by $4.65, or 8.4 percent, for a revised monthly bill of $50.94 beginning Nov. 1, 2016.

The requested natural gas rate change by customer segment is as follows:

General Service - Firm - Schedule 101	
Residential & Small Commercial	-7.7%
Large General Service - Firm - Schedules 111 & 112	
Commercial	-7.7%

The Company's applications are proposals, subject to public review and a Commission decision. Copies of the applications 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 filings. 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 filings are also available on our website, **avistautilities.com/rates.**

If you would like to submit comments on the proposed 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

To assist customers in managing their energy bills, Avista offers services such as comfort level billing, payment arrangements and Customer Assistance Referral and Evaluation Services (CARES). CARES provides assistance to special-needs customers through referrals to area agencies and churches for help with housing, utilities, medical assistance and other needs. To learn more, visit **avistautilities.com.** There, customers can also find information on energy efficiency rebates and incentives, as well as online tools for managing energy use.