EXECUTIVE OFFICES

INTERMOUNTAIN GAS COMPANY

555 SOUTH COLE ROAD • P.O. BOX 7608 • BOISE, IDAHO 83707 • (208) 377-6000 • FAX: 377-6097

August 7, 2015

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington St.
P.O. Box 83720
Boise, ID 83720-0074

RE: Case No. INT-G-15-02

Dear Ms. Jewell:

Attached for consideration by this Commission are the original and seven (7) copies of Intermountain Gas Company's Application for Authority to Decrease Its Prices on October 1, 2015.

If you should have any questions regarding this Application please contact me at 377-6168.

Sincerely,

Michael P. McGrath
Director-Regulatory Affairs
Intermountain Gas Company

Enclosure

cc: Scott Madison
Ronald L. Williams

INTERMOUNTAIN GAS COMPANY

CASE NO. INT-G-15-02

APPLICATION,

EXHIBITS,

AND

WORKPAPERS

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY
For Authority to Decrease Its Prices on October 1, 2015

(October 1, 2015 Purchased Gas Cost Adjustment Filing)

Ronald L. Williams, ISB 3034
Williams Bradbury PC
1015 W. Hays St.
Boise, Idaho 83702
Telephone: (208) 344-6633
Attorney for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY for Authority to Decrease Its Prices	Case No. INT-G-15-02 **APPLICATION**

Intermountain Gas Company ("Intermountain" or "Company"), a subsidiary of MDU Resources Group, Inc. with general offices located at 555 South Cole Road, Boise, Idaho, pursuant to the Rules of Procedure of the Idaho Public Utilities Commission ("Commission"), hereby requests authority, pursuant to Idaho Code Sections 61-307 and 61-622, to place into effect October 1, 2015 new rate schedules which will decrease its annualized revenues by $15.3 million. Because of changes in Intermountain's gas related costs, as described more fully in this Application, Intermountain's earnings will not decrease as a result of the proposed decrease in prices and revenues. Intermountain's current rate schedules showing proposed changes are attached hereto as Exhibit No. 1 and are incorporated herein by reference. Intermountain's proposed rate schedules are attached hereto as Exhibit No. 2 and are incorporated herein by reference.

Communications in reference to this Application should be addressed to:

Michael P. McGrath
Director – Regulatory Affairs
Intermountain Gas Company
Post Office Box 7608
Boise, ID 83707
and
Ronald L. Williams
Williams Bradbury PC
1015 W. Hays St.
Boise, Idaho 83702

In support of this Application, Intermountain does allege and state as follows:

I.

Intermountain is a gas utility, subject to the jurisdiction of the Commission, engaged in the sale of and distribution of natural gas within the State of Idaho under authority of Commission Certificate No. 219 issued December 2, 1955, as amended and supplemented by Order No. 6564, dated October 3, 1962.

Intermountain provides natural gas service to the following Idaho communities and counties and adjoining areas:

Ada County - Boise, Eagle, Garden City, Kuna, Meridian, and Star;
Bannock County – Arimo, Chubbuck, Inkom, Lava Hot Springs, McCammon, and Pocatello;
Bear Lake County - Georgetown, and Montpelier;
Bingham County - Aberdeen, Basalt, Blackfoot, Firth, Fort Hall, Moreland/Riverside, and Shelley;
Blaine County - Bellevue, Hailey, Ketchum, and Sun Valley;
Bonneville County - Ammon, Idaho Falls, Iona, and Ucon;
Canyon County - Caldwell, Greenleaf, Middleton, Nampa, Parma, and Wilder;
Caribou County - Bancroft, Grace, and Soda Springs;
Cassia County - Burley, Declo, Malta, and Raft River;
Elmore County - Glenns Ferry, Hammett, and Mountain Home;
Fremont County - Parker, and St. Anthony;
Gem County - Emmett;
Gooding County - Gooding, and Wendell;
Jefferson County - Lewisville, Menan, Rigby, and Ririe;
Jerome County - Jerome;
Lincoln County - Shoshone;
Madison County - Rexburg, and Sugar City;
Minidoka County - Heyburn, Paul, and Rupert;
Owyhee County – Bruneau, and Homedale;
Payette County - Fruitland, New Plymouth, and Payette;
Power County - American Falls;
Twin Falls County - Buhl, Filer, Hansen, Kimberly, Murtaugh, and Twin Falls;
Washington County - Weiser.

Intermountain's properties in these locations consist of transmission pipelines, liquefied natural gas storage facilities, a compressor station, distribution mains, services, meters and regulators, and general plant and equipment.

II.

Intermountain seeks with this Application to pass through to each of its customer classes changes in gas related costs resulting from: 1) costs billed to Intermountain from firm transportation providers including Northwest Pipeline LLC ("Northwest" or "Northwest Pipeline"), 2) a decrease in Intermountain's Weighted Average Cost of Gas, or "WACOG", 3) an updated customer allocation of gas related costs pursuant to the Company's Purchased Gas Cost Adjustment ("PGA") provision, 4) the inclusion of temporary surcharges and credits for one year relating to natural gas purchases and interstate transportation costs from Intermountain's deferred gas cost accounts, and 5) benefits resulting from Intermountain's management of its storage and firm capacity rights on various pipeline systems. Intermountain also seeks with this Application to eliminate the temporary surcharges and credits included in its current prices during the past 12 months, pursuant to Case No. INT-G-14-01. The aforementioned changes would result in a price decrease to Intermountain's customers.

These price decreases are applicable to service rendered under rate schedules affected by and subject to Intermountain's PGA, initially approved by this Commission in Order No. 26109, Case No. INT-G-95-1, and additionally approved through subsequent proceedings.

Exhibit No. 3 contains pertinent excerpts from applicable pipeline tariffs. Exhibit No. 4 summarizes the price changes in: 1) Intermountain's base rate gas costs, 2) its rate class allocation, and 3) adjusting temporary surcharges or credits flowing through to Intermountain's direct sales customers. Exhibit Nos. 3 and 4 are attached hereto and incorporated herein by reference.

III.

The current prices of Intermountain are those approved by this Commission in Order No. 33139, Case No. INT-G-14-01.

IV.

Intermountain's proposed prices incorporate all changes in costs relating to the Company's firm interstate transportation capacity including, but not limited to, any price changes or projected cost adjustments implemented by the Company's pipeline suppliers as well as any volumetric adjustments in contracted transportation agreements which have occurred since Intermountain's PGA filing in Case No. INT-G-14-01.

The Company's Application includes $1.4 million related to the acquisition of additional Plymouth LNG storage capacity on Northwest's delivery system. The Plymouth facility has been a valuable asset for the Company given its ability to help ensure supply and delivery to Intermountain's core market customers during extreme weather events. Additionally, extreme weather events in the Northwest typically bring with them considerably higher natural gas spot market prices. Plymouth LNG supplies have helped to insulate Intermountain's customers from these extreme weather related price spikes. The Company recently was able to acquire an incremental amount of Plymouth capacity of 378,900 MMBtu with a daily deliverability of

41,975 MMBtu. In addition to the operational and price mitigating benefits this added capacity brings to Intermountain's customers, had this incremental Plymouth capacity not been subscribed to, Intermountain would have been faced with a rise in costs associated with its existing (lower) Plymouth capacity in excess of the costs associated with this incremental acquisition.

Intermountain continues to effectively manage its natural gas storage assets at Northwest's Jackson Prairie and Questar Pipeline's Clay Basin storage facilities. Supporting documents relating to Line 20 of Exhibit No. 4 include $1.8 million in savings from Intermountain's management of these storage assets.

Exhibit No. 4, Lines 1 through 20, details the proposed changes to Intermountain's prices resulting from Intermountain's cost of storage, and interstate and upstream capacity from its various suppliers.

V.

The WACOG reflected in Intermountain's proposed prices is $0.32764 per therm, as shown on Exhibit No. 4, Line 22, Col. (f). This compares to $0.39482 per therm currently included in the Company's tariffs.

Deliverable shale gas reserves in North America continue to be significant which, combined with the anemic growth in our nation's economy, contributed towards the decrease in the Company's WACOG. From a historical perspective, robust natural gas supplies combined with significant storage balances have kept natural gas prices lower as compared to just a year ago.

Additionally, the proposed WACOG includes benefits to Intermountain's customers generated by the Company's management of its significant natural gas storage assets. Because gas added to storage is procured during the summer season when prices are typically lower than during the winter, the cost of Intermountain's storage gas is normally less than what could be obtained on the open market in winter months. Additionally, in an effort to further stabilize the prices paid by our customers during the upcoming winter period, Intermountain has entered into various fixed price agreements to lock-in the price for portions of its underground storage and other winter "flowing" supplies.

Intermountain believes that the WACOG proposed in this Application, subject to the effect of actual supply and demand and based on current market conditions, provides today's most reasonable forecast of gas costs for the 2015-2016 PGA period. Intermountain will employ, in addition to those fixed price agreements already in place, cost effective price arrangements to further secure the price of flowing gas embedded within this Application when, and if, those pricing opportunities materialize in the marketplace.

Intermountain believes that timely natural gas price signals enhance its customer's ability to make informed and appropriate energy use decisions. The Company is committed to alert customers to any significant impending price changes before their winter natural gas usage occurs. By employing the use of customer mailings, the Company's website, and various media resources, Intermountain will continue to educate its customers regarding the wise and efficient use of natural gas, billing options available to help manage their energy budget, and any pending natural gas price changes.

VI.

Pursuant to the Commission's Order in Case No. INT-G-14-01, Intermountain included temporary credits in its October 1, 2014 prices for the principal reason of passing back to its customers deferred gas cost benefits. Line 27 of Exhibit No. 4 reflects the elimination of these temporary credits.

VII.

Intermountain's PGA tariff includes provisions whereby Intermountain's proposed prices will be adjusted for updated customer class sales volumes and purchased gas cost allocations, pursuant to the Company's approved cost of service methodology. Intermountain's proposed prices include a fixed cost collection adjustment pursuant to these PGA provisions, as outlined on Exhibit No. 5, Line 25. The price impact of this adjustment is included on Exhibit No. 4, Line 28. The Fixed Cost Collection Rate resulting from the adjustment plus the annual difference in demand charges from Exhibit No. 4, Lines 1 – 20, Col. (h) is shown on Exhibit No. 5, Line 29. Exhibit No. 5 is attached hereto and incorporated herein by reference.

VIII.

Intermountain proposes to pass through to its customers the benefits that will be generated from the management of its transportation capacity totaling $3.9 million as outlined on Exhibit No. 7. These benefits include credits from a segmented release of a portion of Intermountain's firm capacity rights on Northwest Pipeline and other non-segmented capacity releases. Intermountain proposes to pass back these credit amounts via the per therm credits, as detailed on Exhibit No. 7 and included on Exhibit No. 6, Line 1. Exhibit Nos. 6 and 7 are attached hereto and incorporated herein by reference.

IX.

Intermountain proposes to allocate deferred gas costs from its Account No. 191 balance to its customers through temporary price adjustments to be effective during the 12-month period ending September 30, 2016, as follows:

1) Intermountain has deferred fixed gas costs in its Account No. 191. The debit amount shown on Exhibit No. 8, Line 7, Col. (b) of $1.1 million is attributable to a true-up of the collection of interstate pipeline capacity costs, the true-up of expense issues previously ruled on by this Commission, and mitigating capacity release credits generated from the incremental release of Intermountain's pipeline capacity. Intermountain proposes to pass back these balances via the per therm debits and credits, as detailed on Exhibit No. 8 and included on Exhibit No. 6, Line 2. Exhibit No. 8 is attached hereto and incorporated herein by reference.

2) Intermountain has also deferred in its Account No. 191 a variable gas cost debit of $0.7 million, as shown on Exhibit No. 9, Line 2, Col. (b). This deferred debit is attributable to Intermountain's variable gas costs since October 1, 2014. Intermountain proposes to collect this balance via a per therm debit, as shown on Exhibit No. 9, Line 4, Col. (b) and included on Exhibit No. 6, Line 3.

3) Finally, Intermountain has deferred in its Account No. 191 deferred gas costs related to Lost and Unaccounted For Gas as shown on Exhibit No. 9, Lines 5 through 20, Col. (b). This deferral results in net per therm decreases to Intermountain's sales customers, as illustrated on Exhibit No. 9, Line 12, Col. (b), and included on Exhibit No. 6, Line 3. The Lost and Unaccounted For Gas deferral results in a per therm decrease for Intermountain's transportation customers as shown on Exhibit No. 9, Line 20, Col. (b). Exhibit No. 9 is attached hereto and incorporated herein by reference.

X.

Pursuant to Commission Order No. 33139, Case No. INT-G-14-01, Intermountain has deferred in its Account No. 191 variable gas cost credits associated with sales of liquefied natural gas at its Nampa, Idaho facility. Intermountain proposes to pass back this $689,367 sales credit as outlined on Exhibit No. 10, Line 7. Exhibit No. 10 is attached hereto and incorporated herein by reference.

XI.

Intermountain has allocated the proposed price decreases to each of its customer classes based upon Intermountain's PGA provision. However, a straight cent per therm price decrease was not utilized for the LV-1 tariff as no fixed costs are currently recovered in the tail block of the LV-1 tariff. The proposed changes in the WACOG, and variable deferred debits and credits as outlined on Exhibit No.'s 9 and 10, are applied to all three blocks of the LV-1 tariff. However, all adjustments relating to fixed costs are applied only to the first two blocks of the LV-1 tariff.

XII.

As outlined on Exhibit No. 1, Page 1, Lines 33 through 44, the T-3, T-4 and T-5 tariffs include the following adjustments: a) removal of existing temporary price changes; b) the uniform Lost and Unaccounted For Gas decrease from Exhibit No. 9, Line 20, Col. (b) is applied to each tariff; and c) the LNG Sales Credits are applied to T-4 and T-5 as illustrated on Exhibit No. 10, Line 7, Cols. (g-h).

XIII.

Exhibit No. 11 is an analysis of the overall price decreases by class of customer. Exhibit No. 11 is attached hereto and incorporated herein by reference.

XIV.

The proposed price decreases herein requested among the classes of service of Intermountain reflect a just, fair, and equitable pass-through of changes in gas related costs to Intermountain's customers.

XV.

This Application has been brought to the attention of Intermountain's customers through a Customer Notice and by a Press Release sent to daily and weekly newspapers, and major radio and television stations in Intermountain's service area. The Press Release and Customer Notice are attached hereto and incorporated herein by reference. Copies of this Application, its Exhibits, and Workpapers have been provided to those parties regularly intervening in Intermountain's rate proceedings.

XVI.

Intermountain requests that this matter be handled under modified procedure pursuant to Rules 201-204 of the Commission's Rules of Procedure. Intermountain stands ready for immediate consideration of this matter.

WHEREFORE, Intermountain respectfully petitions the Idaho Public Utilities Commission as follows:

a. That the proposed rate schedules herewith submitted as Exhibit No. 2 be approved without suspension and made effective as of October 1, 2015 in the manner shown on Exhibit No. 2.

b. That this Application be heard and acted upon without hearing under modified procedure, and

c. For such other relief as this Commission may determine proper herein.

DATED at Boise, Idaho, this 7th day of August, 2015.

INTERMOUNTAIN GAS COMPANY

By /s/ Michael P. McGrath
Michael P. McGrath
Director – Regulatory Affairs

Williams Bradbury PC

By /s/ Ronald L. Williams
Ronald L. Williams
Attorney for Intermountain Gas Company

<u>CERTIFICATE OF MAILING</u>

I HEREBY CERTIFY that on this 7th day of August, 2015, I served a copy of the foregoing Case No. INT-G-15-02 upon:

Ed Finklea
Northwest Industrial Gas Users
326 5th St
Lake Oswego, OR 97034

Chad Stokes
Cable Huston et al.
1001 SW Fifth Avenue, Suite 2000
Portland, Oregon 97204-1136

R. Scott Pasley
J. R. Simplot Company
PO Box 27
Boise, ID 83707

Don Sturtevant
J. R. Simplot Company
PO Box 27
Boise, ID 83707

by depositing true copies thereof in the United States Mail, postage prepaid, in envelopes addressed to said persons at the above addresses.

<u>/s/ Michael P. McGrath</u>
Michael P. McGrath
Director – Regulatory Affairs

EXHIBIT NO. 1

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

CURRENT TARIFFS

Showing Proposed Price Changes

(12 pages)

INTERMOUNTAIN GAS COMPANY
Comparison of Proposed October 1, 2015 Prices
To October 1, 2014 Prices

Line No.	Rate Class	Prices per INT-G-14-01	Proposed Adjustment	Proposed October 1, 2015 Prices
	(a)	(b)	(c)	(d)
1	RS-1			
2	April - November	$ 0.90500	$ (0.03233)	$ 0.87267
3	December - March	0.79244	(0.03233)	0.76011
4	RS-2			
5	April - November	0.76036	(0.04851)	0.71185
6	December - March	0.72673	(0.04851)	0.67822
7	GS-1			
8	April - November			
9	Block 1	0.77064	(0.04146)	0.72918
10	Block 2	0.74891	(0.04146)	0.70745
11	Block 3	0.72789	(0.04146)	0.68643
12	December - March			
13	Block 1	0.71979	(0.04146)	0.67833
14	Block 2	0.69859	(0.04146)	0.65713
15	Block 3	0.67813	(0.04146)	0.63667
16	CNG Fuel	0.67813	(0.04146)	0.63667
17	IS-R (1)			
18	April - November	0.72673	(0.04851)	0.67822
19	December - March	0.72673	(0.04851)	0.67822
20	IS-C (2)			
21	April - November			
22	Block 1	0.71979	(0.04146)	0.67833
23	Block 2	0.69859	(0.04146)	0.65713
24	Block 3	0.67813	(0.04146)	0.63667
25	December - March			
26	Block 1	0.71979	(0.04146)	0.67833
27	Block 2	0.69859	(0.04146)	0.65713
28	Block 3	0.67813	(0.04146)	0.63667
29	LV-1			
30	Block 1	0.53796	(0.04284) (3)	0.49512
31	Block 2	0.49947	(0.04284) (3)	0.45663
32	Block 3	0.41818	(0.08376) (4)	0.33442
33	T-3			
34	Block 1	0.05617	(0.00152) (5)	0.05465
35	Block 2	0.02357	(0.00152) (5)	0.02205
36	Block 3	0.00944	(0.00152) (5)	0.00792
37	T-4			
38	Block 1	0.05983	(0.00206) (6)	0.05777
39	Block 2	0.02134	(0.00206) (6)	0.01928
40	Block 3	0.00661	(0.00206) (6)	0.00455
41	T-5			
42	Demand Charge	0.84253	-	0.84253
43	Commodity Charge	0.00279	(0.00168) (6)	0.00111
44	Over-Run Service	0.04538	(0.00168) (6)	0.04370

(1) The IS-R price is based on the RS-2 December - March price and receives the same PGA adjustments.
(2) The IS-C price is based on the GS-1 December - March price and receives the same PGA adjustments.
(3) See Workpaper No. 6, Line 13, Column (e)
(4) See Workpaper No. 6, Line 17, Column (e)
(5) Remove INT-G-14-01 temporary and add the temporary from Exhibit 9, Line 20.
(6) Remove INT-G-14-01 temporary and add the temporaries from Exhibit 9, Line 20 and Exhibit 10, Line 7.

Rate Schedule RS-1
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, who does not have both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - ~~$0.90500~~ per therm* $0.87267

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - ~~$0.79244~~ per therm* $0.76011

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.03501)~~ $(0.00085)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule RS-2
RESIDENTIAL SERVICE- SPACE AND WATER HEATING

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, which must include at a minimum, both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - ~~$0.76036~~ per therm* $0.71185

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - ~~$0.72673~~ per therm* $0.67822

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.02704)~~ $(0.00968)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff Rate Schedules ~~Fiftieth~~ Revised Fifty-First	Sheet No. 03 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.00 per bill

Commodity Charge -	First	200 therms per bill @ ~~$0.77064~~* $0.72918
	Next	1,800 therms per bill @ ~~$0.74891~~* $0.70745
	Over	2,000 therms per bill @ ~~$0.72789~~* $0.68643

For billing periods ending December through March

Customer Charge - $9.50 per bill

Commodity Charge -	First	200 therms per bill @ ~~$0.71979~~* $0.67833
	Next	1,800 therms per bill @ ~~$0.69859~~* $0.65713
	Over	2,000 therms per bill @ ~~$0.67813~~* $0.63667

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.03550)~~ $(0.01323)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge - $9.50 per bill

Commodity Charge - ~~$0.67813~~ per therm* $0.63667

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.03550)~~ $(0.01323)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS-1 or RS-2 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - ~~$0.72673~~ per therm* $0.67822

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - ~~$0.72673~~ per therm* $0.67822

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.02704)~~ $(0.00968)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

I.P.U.C. Gas Tariff Rate Schedules ~~Seventh~~ Revised Eighth	Sheet No. 5 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

<u>For billing periods ending April through November</u>

Customer Charge – $2.00 per bill

Commodity Charge –	First	200 therms per bill @ ~~$0.71979~~*	$0.67833
	Next	1,800 therms per bill @ ~~$0.69859~~*	$0.65713
	Over	2,000 therms per bill @ ~~$0.67813~~*	$0.63667

<u>For billing periods ending December through March</u>

Customer Charge – $9.50 per bill

Commodity Charge –	First	200 therms per bill @ ~~$0.71979~~*	$0.67833
	Next	1,800 therms per bill @ ~~$0.69859~~*	$0.65713
	Over	2,000 therms per bill @ ~~$0.67813~~*	$0.63667

*Includes:

Temporary purchased gas cost adjustment of ~~$(0.03550)~~ $(0.01323)
Weighted average cost of gas of ~~$0.39482~~ $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~April 1, 2015~~ October 1, 2015

I.P.U.C. Gas Tariff Rate Schedules Fifty-~~Eighth~~ Revised Ninth	Sheet No. 7 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~March 23, 2015~~ **~~April 1, 2015~~**
Jean D. Jewell Secretary

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Commodity Charge:

Block 1:	First	250,000 therms per bill @ ~~$0.53796~~*	$0.49512
Block 2:	Next	500,000 therms per bill @ ~~$0.49947~~*	$0.45663
Block 3:	Amount Over	750,000 therms per bill @ ~~$0.41818~~**	$0.33442

The above prices include weighted average cost of gas of ~~$0.39482~~ $0.32764
* Includes temporary purchased gas cost adjustment of ~~$(0.01450)~~ $(0.02707)
** Includes temporary purchased gas cost adjustment of ~~$0.01675~~ $0.00017

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such usage may be transported and billed under either secondary rate schedule T-3 or T-4. The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.

3. Embedded in this service is the cost of purchased gas per the Company's PGA, firm interstate pipeline reservation charges, and distribution system costs.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~April 1, 2015~~ October 1, 2015

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Block One:	First	100,000 therms transported @ ~~$0.05617~~*	$0.05465
Block Two:	Next	50,000 therms transported @ ~~$0.02357~~*	$0.02205
Block Three:	Amount over	150,000 therms transported @ ~~$0.00944~~*	$0.00792

*Includes temporary purchased gas cost adjustment of ~~$0.00057~~ $(0.00095)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.

4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.

5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.

6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.

7. An existing LV-1, T-4, or T-5 customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE
(Continued)

BILLING ADJUSTMENTS:

1. Any T-3 customer who has exited the T-3 service at any time (including, but not limited to, the expiration of the contract term), will pay to Intermountain Gas Company, upon exiting the T-3 service, all Purchased Gas Cost Adjustment ("PGA") related costs incurred on the customer's behalf not paid by the customer during said contract period. Any T-3 customer who has exited the T-3 service will have refunded to them, upon exiting the T-3 service, any PGA related credits attributable to the customer during said contract period.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Commodity Charge:

Block One:	First	250,000 therms transported @ ~~$0.05983~~*	$0.05777
Block Two:	Next	500,000 therms transported @ ~~$0.02134~~*	$0.01928
Block Three:	Amount over	750,000 therms transported @ ~~$0.00661~~*	$0.00455

*Includes temporary purchased gas cost adjustment of ~~$0.00000~~ $(0.00206)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in the contract and in effect throughout the term of the service contract.

5. An existing LV-1, T-3, or T-5 customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-4 customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing T-5 customer whose daily contract demand on any given day meets or exceeds a predetermined level agreed to by the customer and the Company upon execution of a one-year minimum written service contract for firm distribution service in excess of 200,000 therms per year.

MONTHLY RATE:

Firm Service	Rate Per Therm
Demand Charge:	
Firm Daily Demand	$0.84253
Commodity Charge:	
For Firm Therms Transported	~~$0.00279~~* $0.00111
Over-Run Service	
Commodity Charge:	
For Therms Transported In Excess Of MDFQ:	~~$0.04538~~* $0.04370

*Includes temporary purchased gas cost adjustment of ~~$0.00033~~ $(0.00135)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in and will be in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Firm Daily Demand rate. Firm demand relief will be afforded to those T-5 customers paying both demand and commodity charges for gas when, in the Company's judgment, such relief is warranted.

4. The actual therm usage for the month or the MDFQ times the number of days in the billing month, whichever is less, will be billed at the applicable commodity charge for firm therms.

5. All therms not billed at the commodity charge for firm therms transported rate will be billed at the Overrun Service rate.

EXHIBIT NO. 2

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

PROPOSED TARIFFS

(11 pages)

Rate Schedule RS-1
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, who does not have both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - $0.87267 per therm*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - $0.76011 per therm*

*Includes:

Temporary purchased gas cost adjustment of $(0.00085)
Weighted average cost of gas of $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Rate Schedule RS-2
RESIDENTIAL SERVICE- SPACE AND WATER HEATING

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, which must include at a minimum, both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - $0.71185 per therm*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - $0.67822 per therm*

*Includes:

Temporary purchased gas cost adjustment of $(0.00968)
Weighted average cost of gas of $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.00 per bill

Commodity Charge -	First	200 therms per bill @ $0.72918*
	Next	1,800 therms per bill @ $0.70745*
	Over	2,000 therms per bill @ $0.68643*

For billing periods ending December through March

Customer Charge - $9.50 per bill

Commodity Charge -	First	200 therms per bill @ $0.67833*
	Next	1,800 therms per bill @ $0.65713*
	Over	2,000 therms per bill @ $0.63667*

*Includes:

Temporary purchased gas cost adjustment of $(0.01323)
Weighted average cost of gas of $0.32764

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge - $9.50 per bill

Commodity Charge - $0.63667 per therm*

*Includes:

Temporary purchased gas cost adjustment of $(0.01323)
Weighted average cost of gas of $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS-1 or RS-2 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

<u>For billing periods ending April through November</u>

Customer Charge - $2.50 per bill

Commodity Charge - $0.67822 per therm*

<u>For billing periods ending December through March</u>

Customer Charge - $6.50 per bill

Commodity Charge - $0.67822 per therm*

*Includes:

Temporary purchased gas cost adjustment of $(0.00968)
Weighted average cost of gas of $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company**.**

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

For billing periods ending April through November

Customer Charge – $2.00 per bill

Commodity Charge –	First	200 therms per bill @ $0.67833*
	Next	1,800 therms per bill @ $0.65713*
	Over	2,000 therms per bill @ $0.63667*

For billing periods ending December through March

Customer Charge – $9.50 per bill

Commodity Charge –	First	200 therms per bill @ $0.67833*
	Next	1,800 therms per bill @ $0.65713*
	Over	2,000 therms per bill @ $0.63667*

*Includes:

Temporary purchased gas cost adjustment of $(0.01323)
Weighted average cost of gas of $0.32764

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Commodity Charge:

Block 1:	First	250,000 therms per bill @ $0.49512*
Block 2:	Next	500,000 therms per bill @ $0.45663*
Block 3:	Amount Over	750,000 therms per bill @ $0.33442**

The above prices include weighted average cost of gas of $0.32764
* Includes temporary purchased gas cost adjustment of $(0.02707)
** Includes temporary purchased gas cost adjustment of $0.00017

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such usage may be transported and billed under either secondary rate schedule T-3 or T-4. The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.

3. Embedded in this service is the cost of purchased gas per the Company's PGA, firm interstate pipeline reservation charges, and distribution system costs.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Block One:	First	100,000 therms transported @ $0.05465*
Block Two:	Next	50,000 therms transported @ $0.02205*
Block Three:	Amount over	150,000 therms transported @ $0.00792*

*Includes temporary purchased gas cost adjustment of $(0.00095)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.

4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company’s distribution system.

5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.

6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.
7. An existing LV-1, T-4, or T-5 customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE
(Continued)

BILLING ADJUSTMENTS:

1. Any T-3 customer who has exited the T-3 service at any time (including, but not limited to, the expiration of the contract term), will pay to Intermountain Gas Company, upon exiting the T-3 service, all Purchased Gas Cost Adjustment ("PGA") related costs incurred on the customer's behalf not paid by the customer during said contract period. Any T-3 customer who has exited the T-3 service will have refunded to them, upon exiting the T-3 service, any PGA related credits attributable to the customer during said contract period.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Commodity Charge:

Block One:	First	250,000 therms transported @ $0.05777*
Block Two:	Next	500,000 therms transported @ $0.01928*
Block Three:	Amount over	750,000 therms transported @ $0.00455*

*Includes temporary purchased gas cost adjustment of $(0.00206)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in the contract and in effect throughout the term of the service contract.

5. An existing LV-1, T-3, or T-5 customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-4 customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing T-5 customer whose daily contract demand on any given day meets or exceeds a predetermined level agreed to by the customer and the Company upon execution of a one-year minimum written service contract for firm distribution service in excess of 200,000 therms per year.

MONTHLY RATE:

Firm Service	Rate Per Therm
Demand Charge:	
Firm Daily Demand	$0.84253
Commodity Charge:	
For Firm Therms Transported	$0.00111*
Over-Run Service	
Commodity Charge:	
For Therms Transported In Excess Of MDFQ:	$0.04370*

*Includes temporary purchased gas cost adjustment of $(0.00135)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in and will be in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Firm Daily Demand rate. Firm demand relief will be afforded to those T-5 customers paying both demand and commodity charges for gas when, in the Company's judgment, such relief is warranted.

4. The actual therm usage for the month or the MDFQ times the number of days in the billing month, whichever is less, will be billed at the applicable commodity charge for firm therms.

5. All therms not billed at the commodity charge for firm therms transported rate will be billed at the Overrun Service rate.

EXHIBIT NO. 3

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

PERTINENT EXCERPTS PERTAINING TO INTERSTATE PIPELINES AND RELATED FACILITIES

(37 pages)

NORTHWEST PIPELINE LLC

(10 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Letter Order Pursuant to § 375.307
Northwest Pipeline GP
Docket No. RP12-490-001

Issued: December 20, 2012

Northwest Pipeline GP
P.O. Box 58900
Salt Lake City, UT 84158-0900

Attention: Ms. Pam Barnes
Manager, Certificates and Tariffs

Reference: Filing to Place Settlement Rates into Effect

Dear Ms. Barnes:

On November 27, 2012, Northwest Pipeline GP (Northwest) filed revised tariff records[1] to comply with an April 26, 2012, Commission Letter Order approving a rate settlement filed by Northwest in Docket No. RP12-490-000 (April 2012 order).[2] The April 2012 order directed Northwest to file tariff records consistent with the *pro forma* tariff records set forth in Appendix F of the settlement, to be effective January 1, 2013. The tariff records identified in the Appendix are accepted effective January 1, 2013, in compliance with the April 2012 order.

Public notice of the filing was issued on November 28, 2012, allowing for protests to be filed as provided in section 154.210 of the Commission's regulations. No protests or adverse comments were filed.

This acceptance for filing shall not be construed as a waiver of the requirements of section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your tariff; nor shall

[1] See Appendix for identification of tariff records.

[2] *Northwest Pipeline GP*, 139 FERC ¶ 61,071 (2012).

such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2012).

Sincerely,

Nils Nichols, Director
Division of Pipeline Regulation

Appendix

Northwest Pipeline GP
Fifth Revised Volume No. 1
FERC NGA Gas Tariff

Tariff Records Accepted Effective January 1, 2013

Sheet No. 5, Statement of Rates: TF-1, TF-2, TI-1, TFL-1 and TIL-1, 4.0.0
Sheet No. 5-B, Statement of Rates: TF-1, TF-2, TI-1, TFL-1 and TIL-1, 3.0.0
Sheet No. 5-C, Statement of Rates: TF-1, TF-2, TI-1, TFL-1 and TIL-1, 3.0.0
Sheet No. 5-D, Statement of Rates: TF-1, TF-2, TI-1, TFL-1 and TIL-1, 2.0.0
Sheet No. 6, Statement of Rates: DEX-1 and PAL, 3.0.0
Sheet No. 7, Statement of Rates: SGS-2F and SGS-2I, 4.0.0
Sheet No. 8, Statement of Rates: LS-1, 3.0.0
Sheet No. 8-A, Statement of Rates: LS-2F and LS-2I, 3.0.0

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

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

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules 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	0.01562
Expansion Shipper	0.00000	0.04056
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00348
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01562
Expansion Shipper	0.00000	0.04056
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00057
Expansion Shipper	0.00000	0.00348
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00224

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

STATEMENT OF RATES (Continued)

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

(Dollars per Dth)

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

Footnotes

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

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

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

STATEMENT OF FUEL USE REQUIREMENTS FACTORS
FOR REIMBURSEMENT OF FUEL USE

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

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

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

Rate Schedules TF-1, TF-2, TI-1, and DEX-1	1.11%
Rate Schedule TF-1 - Evergreen Expansion	
Incremental Surcharge (1)	0.50%
Rate Schedule TFL-1	-
Rate Schedule TIL-1	-
Rate Schedules SGS-2F and SGS-2I	0.40%
Rate Schedules LS-1, LS-2F, LS-3F and LS-2I	
Liquefaction	1.05%
Vaporization	0.85%
Rate Schedule LD-4I	
Liquefaction	1.05%

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

Footnote

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

Williams

Northwest Pipeline
P.O. Box 58900
Salt Lake City, UT 84158-0900
Phone: (801) 584-7278
FAX: (801) 584-7076

MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding ("Memorandum") is made and entered into on July 29, 2015, by and between Northwest Pipeline LLC ("Northwest" or "Transporter"), and Intermountain Gas Company ("Intermountain" or "Shipper"); Northwest and Intermountain are sometimes referred to individually as "Party" and collectively as the "Parties."

RECITALS:

A. Northwest owns and operates an interstate natural gas transmission system subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC");

B. Intermountain desires to acquire 378,900 Dth of Storage Capacity and 41,975 Dth/d of Storage Demand at Northwest's Plymouth LNG storage facility; and

C. Intermountain desires to acquire TF-2 storage redelivery transportation service from Plymouth to the delivery points listed on Intermountain's TF-1 Contract No. 100004 with an Annual Contract Quantity of 378,900 Dth.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, and subject to all of the terms, conditions, and provisions herein set forth, Northwest and Intermountain do hereby memorialize their understanding as follows:

ARTICLE I: CAPACITY COMMITMENTS

1. On or before August 15, 2015, Intermountain will submit a binding bid for Rate Schedule LS-2F service from Northwest's Plymouth LNG storage facility consisting of 378,900 Dth of Storage Capacity and 41,975 Dth/d of Storage Demand at the maximum tariff rates (as they may change from time to time).

   a. The primary term effective date will be the date that Northwest posts that its Plymouth LNG storage capacities have been restored back to their full design capacities.

   b. The primary term end date will be March 31, 2023.

   c. The bid will contain the following Non-Conforming Provision: The RP12-490 Plymouth LNG firm annual demand billing determinants of 111,434,500 (305,300 Dth/d X 365 days) and firm annual capacity billing determinants of 871,620,000 (2,388,000 Dth X 365 days) will be used in deriving the recourse rates for firm Plymouth LNG services that become effective on or before January 1, 2018.

2. Within five (5) Business Days of Intermountain submitting a request for the capacity specified in Article I, Paragraph 1 above, Northwest will post such capacity for competitive bid with Intermountain as the pre-arranged shipper. The capacity will be

awarded pursuant to Section 25 of Northwest's Tariff. Northwest will calculate the Incremental Economic Value of any competitive bids according to the net present value of bids for a portion or all of the posted capacity, and may aggregate bids for different portions of capacity from multiple shippers if doing so would produce a higher net present value. Included in the posting will be a provision that will allow the winning Shipper to request up to 41,975 Dth/d of TF-2 capacity from Plymouth.

3. Within five (5) Business Days of awarding the capacity pursuant to Article I, Paragraph 2 above, provided the capacity is awarded to Intermountain, Intermountain will, at Northwest's sole discretion, submit a request for Rate Schedule TF-2 capacity with a Transportation Contract Demand equal to the Storage Demand and an Annual Contract Quantity equal to the Storage Capacity that Intermountain is awarded pursuant to Article I, Paragraph 2; or (2) accept a permanent release with similar terms from a third party that Northwest will identify.

    a. The primary term effective date will be the date that Northwest posts that its Plymouth LNG storage capacities have been restored back to their full design capacities.

    b. The primary term end date will be March 31, 2023.

ARTICLE II: TERMINATION

1. This MOU will terminate upon the final execution of all the contracts and future amendments contemplated in this MOU.

ARTICLE III: NOTIFICATIONS AND COMMUNICATIONS

Except as otherwise provided herein, any notice contemplated or required by this Memorandum will be in writing, and will be considered duly delivered when sent by registered or certified mail, or by facsimile, to the appropriate Party at the appropriate address or phone number, as applicable, set forth below, or at such other address or phone number as a Party may from time to time designate by express written notice.

Northwest Pipeline LLC
295 Chipeta Way
Salt Lake City, UT 84108
Phone.: (801) 584-7278
Attn: Mike Rasmuson

Intermountain Gas Company
400 North 4th Street
Bismarck, ND 58501
Phone No: (701) 222-7870
Attn: Bob Morman

ARTICLE IV: ENTIRE AGREEMENT

This Memorandum contains the entire agreement between Northwest and Intermountain with respect to the subject matter hereof, and supersedes any and all prior agreements, understandings and commitments, whether oral or written, concerning the subject matter hereof. No amendments to or modifications of this Memorandum will be effective unless agreed upon in a written instrument executed by Northwest and Intermountain, which expressly refers to this Memorandum.

ARTICLE V: GOVERNING LAW AND DISPUTE RESOLUTION

1. The construction, interpretation, and enforcement of this Memorandum will be governed by the laws of the State of Utah, notwithstanding any conflict of law rule, which would refer any matter to the laws of another jurisdiction.

2. In the event of any dispute arising out of or relating to this Memorandum which the Parties have been unable to settle within ten (10) days after the dispute arose, then either Party may refer the dispute to a meeting of senior management, in which case each Party shall nominate a senior officer of its management to meet at a mutually agreed time and place not later than thirty (30) days after the dispute arose to attempt to resolve the dispute. If a resolution is not reached within sixty (60) days after the meeting of senior officers, then either Party may refer the dispute to mediation. The parties will mutually select a mediator, provided that if the parties cannot mutually agree to a mediator, the mediator shall be the Director of FERC's Office of Dispute Resolution Services or successor position to the extent it is willing to serve in that capacity.

ARTICLE VI: COUNTERPARTS

This Memorandum may be executed in one or more counterparts (delivery of which may be made by facsimile), each of which shall be deemed an original but all of which together shall constitute one and the same.

IN WITNESS WHEREOF, the Parties hereto have caused this Memorandum to be duly executed as of the day and year first above written.

NORTHWEST PIPELINE LLC
By:
Mike Rasmuson
Mike Rasmuson
Director Marketing Services

Intermountain Gas Company
By:
Mike Gardner
EVP Combined Utility Support

NOVA GAS TRANSMISSION LTD.

(4 pages)

TransCanada
In business to deliver

450 – 1 Street S.W.
Calgary, Alberta T2P 5H1

Phone: (403) 920-2603
Fax: (403) 920-2347
Email: bernard_pelletier@transcanada.com

July 29, 2015 Filed Electronically

National Energy Board
517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

Re: NOVA Gas Transmission Ltd. (NGTL)
Gas Transportation Tariff (Tariff)
Updated Attachments 1 and 2 to the Table of Final 2015 Rates, Tolls and Charges (Final 2015 Rates)

NGTL attaches for filing with the Board pursuant to section 60(1)(a) of the *National Energy Board Act* an updated Attachment 1 (Receipt Point Specific Rates) and Attachment 2 (Delivery Point Specific Rates) to the Table of Final 2015 Rates (Table) for the Tariff, effective August 1, 2015.

The updates to Attachments 1 and 2 to the Table of Final 2015 Rates are required to reflect meter stations expected to go into service shortly.

Attachment 1 to the Table has been updated to include new receipt points at the Ansell South receipt meter station, Cynthia receipt meter station, Elk River Southwest receipt meter station, Livingstone Creek receipt meter station, Minnow Lake West receipt meter station and Yellowhead receipt meter station. The 2015 FT-R and IT-R rates for the stations are provided in the following table:

Station Number	Station Name	Legal Description	FT-R Demand Rate ($/10^{3}m^3/month)	IT-R Rate ($/10^{3}m^3)	Page No. on Attachment 1
5154	ANSELL SOUTH	15-02-053-18-W5	154.60	5.85	1
5166	CYNTHIA	NW-10-049-11-W5	139.83	5.29	5
5165	ELK RIVER SOUTHWEST	11-03-047-14-W5	139.83	5.29	6
5144	LIVINGSTONE CREEK	NW-26-078-18-W6	294.03	11.12	10
5170	MINNOW LAKE WEST	NW-09-052-17-W5	161.75	6.12	11
5164	YELLOWHEAD	12-02-046-14-W5	139.83	5.29	18

Attachment 2 to the Table has been updated to include the Scotford Hydrogen Sales APN delivery meter station, Alder Flats South No. 2 Sales delivery point at the existing Alder Flats South No. 2 receipt meter station, the Ricinus Sales delivery point at the existing Ricinus receipt meter station and the Virginia Hill No. 2 Sales delivery point at the existing Virginia Hills receipt meter station. The 2015 FT-D and IT-D rates for the stations are provided in the following table:

Station Number	Station Name	Legal Description	FT-D Demand Rate ($/GJ/month)	IT-D Rate ($/GJ)	Page No. on Attachment 2
3297	ALDER FLATS SOUTH NO 2 SALES	10-09-045-08-W5	4.55	0.1646	1
3298	RICINUS SALES	NW-02-037-10-W5	4.55	0.1646	4
31125	SCOTFORD HYDROGEN SALES APN	06-31-055-21-W4	4.55	0.1646	4
3296	VIRGINIA HILLS NO 2 SALES	09-17-064-13-W5	4.55	0.1646	5

The rates were determined in accordance with NGTL's current rate design methodology approved by the Board in Reasons for Decision RHW-1-2010 and Order TG-04-2010 on August 12, 2010.

If the Board requires additional information regarding this filing, please contact Mark Manning by phone at (403) 920-6098 or by email at mark_manning@transcanada.com.

Yours truly,
NOVA Gas Transmission Ltd.

Original signed by Mark Manning for

Bernard Pelletier
Director, Tolls and Tariffs
Regulatory Affairs

Attachments

cc: TTFP
NGTL System Shippers

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) $ 225.73/10^3m^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 $ 5.32/GJ FT-D Demand Rate for Group 2 Delivery Points $ 4.55/GJ FT-D Demand Rate for Group 3 Delivery Points $ 5.46/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	<u>Contract Term</u> — <u>Effective LRS Rate ($/$10^3m^3$/day)</u> 1-5 years — 11.52 20 years — 7.66
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	<u>Schedule No.</u> — <u>PT Rate</u> — <u>PT Gas Rate</u> 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
13. Rate Schedule OS	<u>Schedule No.</u> — <u>Charge</u> 2015659057 — $ 878.00 / month 2015659060 — $ 1347.00 / month 2015657921 — $ 12.00 / month 2015657920 — $ 122.00 / month 2015657919 — $ 67.00 / month 2015657918 — $ 18.00 / month 2015657917 — $ 303.00 / month 2011475772 — $ 9,250.00 / month 2015657915 — $ 1,259.00 / month 2003004522 — Applicable IT-R and IT-D Rate 2011476052 / 2011476054 — $ 0.1496 / GJ subject to $ 717,000.00 Minimum Annual Charge 2011475056 / 2011476092 / 2011476050 — $ 0.095 / GJ and $ 1,000.00 / month
14. Rate Schedule CO2	<u>Tier</u> — <u>CO_2 Rate ($/$10^3m^3$)</u> 1 — 542.06 2 — 428.98 3 — 279.71
15. Monthly Abandonment Surcharge [2]	$12.45/$10^3m^3$/month — $0.33/GJ/month
16. Daily Abandonment Surcharge [3]	$ 0.41/10^3m^3/day — $0.0108/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, and LRS-3.

3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2011475056, 2011476092, 2011476050, 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	5.01	0.1811
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.55	0.1646
31110	ALLIANCE EDSON INTERCONNECT APN	4.55	0.1646
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.55	0.1646
3002	BOUNDARY LAKE BORDER	4.55	0.1646
1958	EMPRESS BORDER	5.62	0.2034
3886	GORDONDALE BORDER	4.55	0.1646
6404	MCNEILL BORDER	5.62	0.2034

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	4.55	0.1646	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.55	0.1646	Yes
3880	AECO INTERCONNECTION	4.55	0.1646	
31003	AGRIUM CARSELAND SALES APS	4.55	0.1646	
31002	AGRIUM FT. SASK SALES APN	4.55	0.1646	Yes
31004	AGRIUM REDWATER SALES APN	4.55	0.1646	
31005	AINSWORTH SALES APGP	4.55	0.1646	
31006	AIR LIQUIDE SALES APN	4.55	0.1646	
3214	AKUINU RIVER WEST SALES	4.55	0.1646	
31007	ALBERTA ENVIROFUELS SALES APN	4.55	0.1646	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	4.55	0.1646	Yes
3868	ALBERTA-MONTANA BORDER	4.55	0.1646	
3297	ALDER FLATS SOUTH NO 2 SALES	4.55	0.1646	
3059	ALLISON CREEK SALES	4.55	0.1646	
31009	ALTASTEEL SALES APN	4.55	0.1646	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	4.55	0.1646	
31012	APL JASPER SALES APN	4.55	0.1646	Yes
3488	ARDLEY SALES	4.55	0.1646	
3237	ASPEN SALES	4.55	0.1646	
3216	AURORA NO 2 SALES	4.55	0.1646	
3135	AURORA SALES	4.55	0.1646	
3288	BANTRY SALES	4.55	0.1646	
3423	BASHAW WEST SALES	4.55	0.1646	
31013	BAYMAG SALES APS	4.55	0.1646	
31014	BEAR CREEK COGEN SALES APGP	4.55	0.1646	
3068	BEAVER HILLS SALES	4.55	0.1646	
3268	BENBOW SOUTH SALES	4.55	0.1646	
3933	BIG EDDY INTERCONNECTION	4.55	0.1646	
3067	BIGSTONE SALES	4.55	0.1646	
3285	BILBO SALES	4.55	0.1646	
3468	BLEAK LAKE SALES	4.55	0.1646	
3295	BOOTIS HILL SALES	4.55	0.1646	
3225	BOTHA SALES	4.55	0.1646	
3259	BOULDER CREEK SALES	4.55	0.1646	
3164	BRAINARD LAKE SALES	4.55	0.1646	
3289	BRAZEAU EAST SALES	4.55	0.1646	
3918	BUFFALO CREEK INTERCONNECTION	4.55	0.1646	
31015	BURDETT COGEN SALES APS	4.55	0.1646	
3265	BURNT TIMBER SALES	4.55	0.1646	
3204	CABIN SALES	4.55	0.1646	
3293	CADOGAN SALES	4.55	0.1646	
3109	CALDWELL SALES	4.55	0.1646	
31016	CALGARY ENERGY CENTRE SALES APS	4.55	0.1646	Yes
3634	CANOE LAKE SALES	4.55	0.1646	
3165	CANOE LAKE SALES NO 2	4.55	0.1646	
3866	CARBON INTERCONNECTION	4.55	0.1646	
3484	CARIBOU LAKE SALES	4.55	0.1646	
3157	CARIBOU LAKE SOUTH SALES	4.55	0.1646	
3106	CARMON CREEK SALES	4.55	0.1646	
3248	CARMON CREEK EAST SALES	4.55	0.1646	
3101	CAROLINE SALES	4.55	0.1646	
31017	CARSELAND COGEN SALES APS	4.55	0.1646	
3275	CARSON CREEK SALES	4.55	0.1646	
3495	CAVALIER SALES	4.55	0.1646	
31018	CHAIN LAKES COOP SALES APS	4.55	0.1646	
3907	CHANCELLOR INTERCONNECTION	4.55	0.1646	
3151	CHEECHAM WEST NO 2 SALES	4.55	0.1646	
3622	CHEECHAM WEST SALES	4.55	0.1646	
6014	CHEVRON AURORA SALES	4.55	0.1646	
31019	CHEVRON FT. SASK SALES APN	4.55	0.1646	Yes
3097	CHICKADEE CREEK SALES	4.55	0.1646	
3305	CHIGWELL NORTH SALES	4.55	0.1646	

FOOTHILLS PIPE LINES LTD.

(3 pages)

TransCanada
In business to deliver
450 – 1 Street SW
Calgary, Alberta T2P 5H1
Tel: (403) 920-5052
Fax: (403) 920-2347
Email: robert_tarvydas@transcanada.com

October 31, 2014

National Energy Board
517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Filed Electronically

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

Re: Foothills Pipe Lines Ltd. (Foothills)
Statement of Rates and Charges effective January 1, 2015

Foothills encloses for filing pursuant to section 60(1)(a) of the *National Energy Board Act*[1] rates and charges for transportation service on Foothills Zones 6, 7, 8 and 9 to be effective January 1, 2015 (Effective 2015 Rates).

The following attachments are included with this letter:

- Attachment 1 consists of supporting Schedules A through F
- Attachments 2 and 3 are black-lined and clean copies, respectively, of the relevant section of the Tariff showing the Effective 2015 Rates

The rates and charges are based on the methodology approved by the Board in Decision TG-8-2004, as amended by Order TG-03-2007.

In addition to the rates and charges included in the Table of Effective Rates, Foothills shippers will be required to pay an abandonment surcharge as directed by the National Energy Board in MH-001-2013 Decision and Order MO-095-2014. The abandonment surcharge will be contained in a compliance filing to be made before December 5, 2014.

Foothills met with shippers and interested parties on October 9, 2014, and presented the preliminary 2015 revenue requirement and preliminary Effective 2015 Rates. Updated cost and related rate information were subsequently provided to shippers and interested parties. On the basis of these consultations, Foothills is not aware of any objections to its proposal for establishing the Effective 2015 Rates.

---

[1] R.S.C. 1985, c. N-7, as amended, and the regulations made thereunder.

Foothills understands that any party that is opposed to the rates and charges will advise the Board accordingly.

Foothills will notify its shippers and interested parties of this filing and post a copy of it on TransCanada's Foothills System website at:

http://www.transcanada.com/customerexpress/934.html

Communication regarding this application should be directed to:

Darren Hoeving
Project Manager, Regulatory Services
TransCanada PipeLines Limited
450 – 1 Street SW
Calgary, Alberta T2P 5H1
Telephone: (403) 920-4526
Facsimile: (403) 920-2347
Email: darren_hoeving@transcanada.com

Joel Forrest
Associate General Counsel, Regulatory, Pipelines Law
TransCanada PipeLines Limited
450 – 1 Street SW
Calgary, Alberta T2P 5H1
Telephone: (403) 920-6156
Facsimile: (403) 920-2308
Email: joel _forrest@transcanada.com

Yours truly,
Foothills Pipe Lines Ltd.

Original signed by

Robert Tarvydas
Vice-President, Regulatory Affairs

cc: Foothills Firm Shippers, Interruptible Shippers and Interested Parties

Attachments

TABLE OF EFFECTIVE RATES

1. Rate Schedule FT, Firm Transportation Service

	Demand Rate ($/GJ/Km/Month)
Zone 6	0.0066077414
Zone 7	0.0051745157
Zone 8*	0.0146248074
Zone 9	0.0110366323

2. Rate Schedule OT, Overrun Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 6	0.0002389649
Zone 7	0.0001871332

3. Rate Schedule IT, Interruptible Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 8*	0.0005288971
Zone 9	0.0003991330

4. Monthly Abandonment Surcharge**

All Zones 0.1098584422 ($/GJ/Month)

5. Daily Abandonment Surcharge***

All Zones 0.0036117844 ($/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.

GAS TRANSMISSION NORTHWEST LLC

(12 pages)

151 FERC ¶ 61,280
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

June 30, 2015

In Reply Refer To:
Gas Transmission Northwest LLC
Docket No. RP15-904-000

Gas Transmission Northwest LLC
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

Attention: John A. Roscher
Director, Rates & Tariffs

Dear Mr. Roscher:

1. On April 23, 2015, and as amended May 1, 2015, Gas Transmission Northwest LLC (GTN) submitted, pursuant to Rule 207(a)(5),[1] a petition for approval of a Stipulation and Agreement of Settlement (Settlement) regarding changes to GTN's transportation service rates. GTN included *pro forma* tariff sheets implementing the revised rates and other terms of the Settlement, which is uncontested.

2. On August 12, 2011, GTN filed a Petition for Approval of Stipulation and Agreement of Settlement (2011 Settlement) that was approved by the Commission on November 30, 2011.[2] Article V.A. of the 2011 Settlement established a four-year moratorium period during which the parties were prohibited from taking certain actions, including any filings under sections 4 and 5 of the Natural Gas Act (NGA) that would be inconsistent with the 2011 Settlement. Under the 2011 Settlement, GTN was required to file an NGA general section 4 rate case on or about June 30, 2015, for rates to become effective on January 1, 2016. GTN states that its April 23, 2015 Settlement is filed in lieu of its obligation to file a general rate case, and obviates the need for GTN to make that NGA general section 4 rate filing.

[1] 18 C.F.R. § 385.207(a)(5) (2014).

[2] *Gas Transmission Northwest LLC*, 137 FERC ¶ 61,163 (2011).

3. GTN explains that it entered into settlement negotiations with interested parties, including shippers and state regulators (Settling Parties) from February 2015 through April 2015 to resolve their differences regarding issues that might have been raised in an NGA general section 4 rate filing. GTN states that these meetings resulted in GTN and the Settling Parties reaching agreement regarding GTN's rates, terms, and conditions of service, reflected in the Settlement filed in this proceeding.

4. GTN states that it is mindful that the Commission encourages pipelines and their customers to resolve rate and tariff matters before filing with the Commission[3] to change its rates or other tariff provisions as such a process enables the prompt, efficient resolution of rate and tariff related matters for the benefit of all concerned, without the expense of a hearing and lengthy litigation. GTN states the Settlement achieves this goal and provides for interim rate relief to be effective on July 1, 2015,[4] and further rate reductions conditioned as set forth in the agreement. Therefore, GTN submits that the Settlement is in the public interest and should be approved, effective January 1, 2016, without modification or conditions.

5. The terms of the Settlement are summarized below.

6. Article I provides background information about GTN's previous rate settlement. It also discusses the negotiation process that GTN, its customers and other interested parties engaged in to reach the instant Settlement.

7. Article II provides that the terms of the Settlement are an integrated package and therefore the Settling Parties request that the Settlement be approved in its entirety.

8. Article III defines the terms "Settling Parties" and "Contesting Parties".

9. Article IV provides the proposed effective date and details the order of events to occur if the Settlement is subject to modification or condition.

10. Article V requires GTN to file a NGA general section 4 rate case with an effective date of no later than January 1, 2022. It also provides that either GTN or any Settling Party may make filings pursuant to the NGA, provided, however, that neither GTN nor any Settling Party shall take any action that would result in rates other than the Phase I Settlement Rates becoming effective prior to January 2, 2016, except for the Interim Rate Relief provided for in Article VI.B.

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[3] *See Dominion Transmission, Inc.*, 111 FERC ¶ 61,285, at P 30 (2005).

[4] GTN has separately filed, in Docket No. RP15-1028-000, tariff records to implement this interim rate relief, effective July 1, 2015, consistent with the Settlement.

11. Article VI provides details regarding the Settlement Rates for all GTN mainline transportation services. Article VI.B provides Interim Rate Relief for Settling Parties, which GTN will file to place into effect as of July 1, 2015. Contesting Parties will not be entitled to Interim Rate Relief.

12. Article VII sets forth an annual depreciation rate of 3.5 percent for mainline natural gas turbines and 1.8 percent for all other mainline transmission facilities.

13. Article VIII provides that GTN will file actual tariff records as they appear in Appendix B-1 at least 30 calendar days before the January 1, 2016 effective date. Article VIII also provides for contingencies if a Commission order approving the Settlement has not been issued by December 1, 2015.

14. Article IX describes how Post Retirement Benefits Other Than Pensions (PBOP) will be funded, and the treatment of PBOPs in the next rate case. It also details PBOP disbursements, and steps GTN must take if it seeks to terminate the PBOP trust.

15. Article X provides that upon the effective date of the Settlement, it shall supersede the 2011 Settlement in its entirety.

16. Article XI generally states that no party shall be bound or prejudiced by the Settlement unless it becomes effective in accordance with its provisions and that approval of the Settlement does not constitute approval of, or precedent regarding, any principle or issue. Further, it provides that to the extent that the Commission considers any changes to the terms of the Settlement prior to January 2, 2016, the standard of review shall be the most stringent standard permissible under applicable law.

17. Article XII provides that until the Settlement is approved by the Commission and becomes effective, it shall be privileged and of no effect, and shall not be admissible in evidence.

18. Article XIII provides that Commission approval of the Settlement shall constitute Commission authorization and approval for GTN to implement the rates and tariff changes reflected in the Settlement without suspension or conditions, other than those specified in the Settlement. It also states that the Commission's approval of the Settlement shall constitute all authorization necessary to carry out any provision of the Settlement.

19. Article XIV provides that GTN and Settling Parties understand and agree that GTN is responsible to maintain and operate its pipeline facilities in full compliance with all applicable safety and reliability laws and regulations.

20. Public notice of the filing was issued on May 1, 2015, allowing for protests to be filed as provided in section 154.210 of the Commission's regulations (18 C.F.R. § 154.210 (2014)). No protests or adverse comments were filed.

21. Consistent with the Commission's guidance for filing settlements outside the context of an existing proceeding set forth in *Dominion Transmission, Inc.*,[5] the Settlement resolves GTN's cost of service issues without the need for protracted litigation and hearings. The Commission explained in *Dominion* that when a pipeline negotiates an agreement with its customers and others to change its rates or terms and conditions of service, and it desires approval of the agreement before making an actual NGA section 4 tariff filing, it may file, pursuant to Rule 207(a)(5),[6] a petition for approval of the agreement, along with *pro forma* tariff sheets reflecting how the agreement will be implemented. This is the procedure GTN has followed here.

22. Because the Settlement provides that the standard of review for any changes to the terms of the Settlement considered by the Commission prior to January 2, 2016 is "the most stringent standard permissible under applicable law," we clarify the framework that would apply if the Commission were required to determine the standard of review in a later challenge to the Settlement.

23. The *Mobile-Sierra*[7] "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption. In *New England Power Generators Ass'n, Inc. v. FERC*,[8] however, the D.C. Circuit determined that the Commission is legally authorized to impose a more rigorous application of the statutory "just and reasonable" standard of review on future changes to agreements that fall within the second category described above.

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[5] 111 FERC ¶ 61,285 (2005) (*Dominion*).

[6] 18 C.F.R. § 385.207(a)(5) (2014).

[7] *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) (collectively, *Mobile-Sierra*).

[8] 707 F.3d 364, 370-71 (D.C. Cir. 2013).

24. The Commission finds that the Settlement appears to be fair and reasonable and in the public interest and it is hereby approved.[9]

25. The Commission's approval of this Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[9] *See* 18 C.F.R. § 385.602(g)(3) (2014).

Gas Transmission Northwest LLC

FERC Gas Tariff, Fourth Revised Volume No. 1-A

Pro Forma (1/1/2016 – 12/31/2019)

Clean Tariff

Tariff Section	Version
4.1 - Statement of Rates, FTS-1 and LFS-1 Rates	v.11.0.0
4.2 - Statement of Rates, ITS-1 Rates	v.4.0.0
4.3 - Statement of Rates, Footnotes to Statement of Effective Rates and Charges	v.8.0.0
4.5 - Statement of Rates, Parking and Authorized Imbalance Services	v.3.0.0

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS

Rate Schedules FTS-1 and LFS-1

	RESERVATION							
	DAILY MILEAGE (a) (Dth-MILE)		DAILY NON-MILEAGE (b) (Dth)		DELIVERY (c) (Dth-MILE)		FUEL (d) (Dth-MILE)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	0.000434	0.000000	0.034393	0.000000	0.000016	0.000016	0.0050%	0.0000%
STF (e)	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
E-2 (h)(l) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h)(l) (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	---	---
OVERRUN CHARGE (j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	(k)	(k)	---	---

TransCanada
In business to deliver

Gas Transmission Northwest LLC
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

John A. Roscher
Director, Rates & Tariffs

tel 832.320.5675
fax 832.320.6675
email John_Roscher@TransCanada.com
web www.gastransmissionnw.com

July 15, 2015

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Gas Transmission Northwest LLC
Compliance Filing, Docket No, CP12-494-000
Docket No. RP15-___

Dear Ms. Bose:

Pursuant to Section 4 of the Natural Gas Act ("NGA") and Part 154 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations,[1] Gas Transmission Northwest LLC ("GTN") hereby submits for filing certain tariff sections[2] to be part of its FERC Gas Tariff, Fourth Revised Volume No. 1-A ("Tariff"). These revised tariff sections are being submitted to comply with the Commission's March 14, 2013, Order Issuing Certificate in Docket No. CP12-494-000.[3] GTN requests that the Commission accept the proposed tariff sections to become effective on the date the facilities are placed into service, which is anticipated to occur on or about October 1, 2015.

Correspondence

The names, titles and mailing address of the persons to whom correspondence and communications concerning this filing should be directed are as follows:

[1] 18 C.F.R. Part 154 (2015).
[2] Specifically, Section 4.1 – Statement of Rates, FTS-1 and LFS-1 Rates ("Section 4.1"); Section 4.2 – Statement of Rates, ITS-1 Rates ("Section 4.2") and Section 4.3 – Statement of Rates, Footnotes to Statement of Effective Rates and Charges ("Section 4.3").
[3] *Gas Transmission Northwest LLC*, 142 FERC ¶ 61,186 (2013) ("Order Issuing Certificate" or "Order").

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* Persons designated for official service pursuant to Rule 2010.

Statement of Nature, Reasons and Basis for Filing

On July 31, 2012, GTN filed an abbreviated application pursuant to section 7(c) of the Natural Gas Act ("NGA")[4] and Part 157 of the Commission's Regulations[5] ("Application") for authorization to construct, own and operate the Carty Lateral in Morrow County, Oregon ("Carty Lateral") in order to provide up to 175,000 dekatherms ("Dth") per day of firm transportation service to Portland General Electric Company's Carty Generating Station. In its Application, GTN submitted *pro forma* tariff sections with recourse rates applicable to service on the Carty Lateral, which were derived using a return on equity ("ROE") of 13 percent. On March 14, 2013, the Commission issued the Order Issuing Certificate, wherein it denied GTN's proposed ROE of 13 percent and instructed GTN to make a filing no later than 60 days before the in-service date of the Carty Lateral to revise the recourse rates to reflect GTN's currently authorized ROE.[6]

In compliance with the Commission's Order, GTN is submitting a revised Exhibit P for the Carty Lateral that reflects a cost-of-service and recourse rates based upon an ROE of 12.20 percent, GTN's last approved ROE.[7] As a result of the change in ROE, the proposed recourse rate has decreased from $0.172430 per dekatherm to $0.166475 per dekatherm. As further required by the Order, GTN is

[4] 15 U.S.C. § 717f (2012).
[5] 18 C.F.R. Part 157 (2014).
[6] Order Issuing Certificate at P 18.
[7] GTN's last approved ROE is pursuant to the Section 4 proceeding in Docket No. RP94-149-000. *See Pacific Gas Transmission Company*, 76 FERC ¶ 61,246 (1996), *reh'g sub nom, PG&E Gas Transmission, Northwest Corp.*, 82 FERC ¶ 61,289 (1998).

submitting, as Appendix A, live tariff sections to place into effect the revised recourse rates applicable to service on the Carty Lateral.[8]

Effective Date

Regarding the proposed effective date for the tariff sections included in the instant filing, pursuant to the FERC's *Implementation Guide for Electronic Tariff Filing*,[9] and for administrative ease, GTN is reflecting an effective date of December 31, 9998, as a placeholder until the actual in-service date is known. Upon the Carty Lateral's in-service, GTN will submit a notification to the Commission of the actual date to reflect in the tariff sections, anticipated to occur on or about October 1, 2015. GTN respectfully requests that the Commission grant all waivers of its regulations and GTN's Tariff necessary to accept this filing and approve the tariff sections included at Appendix A to become effective as requested herein.

Other Filings Which May Affect This Proceeding

There are no other filings before the Commission that may significantly affect the changes proposed herein.

Contents of Filing

In accordance with Section 154.7 of the Commission's Regulations, GTN is submitting the following via its electronic tariff filing:

1. This transmittal letter;
2. A clean version of the tariff sections (Appendix A);
3. A marked version of the tariff sections (Appendix B);
4. Revised Exhibit P (Appendix C).

Certificate of Service

As required by Sections 154.7(b) and 154.208 of the Commission's regulations, copies of this filing are being served upon all parties in this proceeding, all of GTN's existing customers and interested state regulatory agencies. A copy of this letter, together with the other attachments, is available during regular business hours for public inspection at GTN's principal place of business.

[8] Order Issuing Certificate at ordering paragraph (F). As GTN anticipates an in-service date of October 1, 2015, the instant filing meets the requirement set forth in the Order that GTN make a filing no later than 60 days before the in-service date of the Carty Lateral.

[9] Office of the Secretary of the Commission, *Implementation Guide for Electronic Filing of Parts 35, 154,284 300 and 341 Tariff Filings (*2014).

Pursuant to Section 385.2005 and Section 385.2011, the undersigned has read this filing and knows its contents, and the contents are true as stated, to the best of his knowledge and belief. Additionally, the undersigned possesses full power and authority to sign such filing.

Any questions regarding this filing may be directed to Joan Collins at (832) 320-5651.

Respectfully submitted,
GAS TRANSMISSION NORTHWEST LLC

John A. Roscher
Director, Rates & Tariffs

Enclosures

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	0.000483	0.000000	0.038402	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)	0.003290	0.000000	0.005498	0.000000	0.000026	0.000026	---	---
E-2 (h)(l) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h)(l) (Diamond 2)	0.001166	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3 (i)	0.001412	0.000000	0.001420	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)	---	---

QUESTAR PIPELINE COMPANY

(3 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Letter Order Pursuant to § 375.307
Questar Pipeline Company
Docket No. RP15-207-000

December 10, 2014

Questar Pipeline Company
333 South State Street
P.O. Box 45360
Salt Lake City, UT 84145-0360

Attention: L. Bradley Burton, General Manager
Federal Regulatory Affairs and FERC Compliance Officer

Reference: Fuel Gas Reimbursement Percentage Filing

Dear Mr. Burton:

On November 25, 2014, Questar Pipeline Company (Questar) filed a tariff record[1] to reflect a change in its Fuel Gas Reimbursement Percentage (FGRP) as provided by section 12.15 of the General Terms & Conditions of its Tariff. The proposed tariff record decreases Questar's FGRP from the currently effective 1.97% to 1.86%. Questar's tariff record is accepted effective January 1, 2015, as proposed.

Public notice of the filing was issued on November 26, 2014. Interventions and protests were due as provided in section 154.210 of the Commission's regulations (18 C.F.R. § 154.210 (2014)). Pursuant to Rule 214 (18 C.F.R. § 385.214 (2014)), all timely filed motions to intervene and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. No protests or adverse comments were filed.

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[1] Questar Pipeline Company, FERC NGA Gas Tariff, Tariffs, Statement of Rates, Statement of Rates, 9.0.0.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or any which may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2014).

Sincerely,

Nils Nichols, Director
Division of Pipeline Regulation

STATEMENT OF RATES

Rate Schedule/ Type of Charge (a)	Base Tariff Rate ($) (b)
PEAKING STORAGE	
Firm Peaking Storage Service - PKS	
Monthly Reservation Charge	
Maximum 4/	2.87375
Minimum	0.00000
Usage Charge	
Injection	0.03872
Withdrawal	0.03872
CLAY BASIN STORAGE	
Firm Storage Service - FSS	
Monthly Reservation Charge	
Deliverability	
Maximum 4/	2.85338
Minimum	0.00000
Capacity	
Maximum	0.02378
Minimum	0.00000
Usage Charge	
Injection1/	0.01049
Withdrawal	0.01781
Authorized Overrun Charge	
Maximum1/	0.30315
Minimum1/	0.01781
Interruptible Storage Service - ISS	
Usage Charge	
Inventory 5/	
Maximum	0.05927
Minimum	0.00000
Injection1/	0.01049
Withdrawal	0.01781
OPTIONAL VOLUMETRIC RELEASES /	
Peaking Storage Service - PKS	
Maximum 4/	3.40890
Minimum	0.00000
Firm Storage Service - FSS	
Maximum 4/	0.57068
Minimum	0.00000
Storage Usage Charges Applicable to Volumetric Releases 6/	
Peaking Storage Service - PKS:	
Injection	0.03872
Withdrawal	0.03872
Clay Basin Storage Service - FSS:	
Injection1/	0.01049
Withdrawal	0.01781
PARK AND LOAN SERVICE - PAL1	
Daily Charge	
Maximum	0.30315
Minimum	0.00000
Delivery Charge1/	0.02830

FUEL REIMBURSEMENT - 2.0% (0.2% utility and 1.8% compressor fuel) for Rate Schedule PAL1

EXHIBIT NOS. 4-11

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

(8 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Gas Cost Changes

Line No.	Description	Annual Therms/ Billing Determinants INT-G-14-01	10/1/2014 Prices INT-G-14-01	Total Annual Cost INT-G-14-01	Annual Therms/ Billing Determinants INT-G-15-02	10/1/2015 Prices INT-G-15-02	Total Annual Cost INT-G-15-02	Annual Difference	Cost of Service Allocation of Gas Cost Adjustment [1] RS-1	RS-2	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	DEMAND CHARGES:											
2	Transportation:											
3	NWP TF-1 Reservation (Full Rate) [2]	862,787,350	$ 0.04180	$ 36,062,090	901,768,740	$ 0.04170	$ 37,607,152	$ 1,545,062	$ 180,456	$ 845,570	$ 501,425	$ 17,611
4	NWP TF-1 Reservation (Discounted) [3]	205,101,900	0.02342	4,803,373	187,413,960	0.02305	4,319,523	(483,850)	(56,511)	(264,798)	(157,026)	(5,515)
5	Upstream Capacity (Full Rate) [4]	689,050,380	0.01145	7,888,741	676,070,280	0.01089	7,362,973	(525,768)	(61,407)	(287,738)	(170,630)	(5,993)
6	Upstream Capacity (Discounted) [5]	573,879,950	0.01545	8,866,107	590,358,000	0.01629	9,614,818	748,711	87,446	409,749	242,982	8,534
7	Storage:											
8	SGS-1											
9	Demand	303,370 [6]	0.00156	172,960 [7]	303,370 [6]	0.00156	173,436 [7]	476	56	261	154	5
10	Capacity Demand	10,920,990 [6]	0.00006	227,211 [7]	10,920,990 [6]	0.00006	227,831 [7]	620	72	340	201	7
11	TF-2 Reservation	10,920,990 [6]	0.04100	447,753	10,920,990 [6]	0.04111	448,979	1,226	143	671	398	14
12	TF-2 Redelivery Charge	10,920,990 [6]	0.00300	32,763	10,920,990 [6]	0.00300	32,763	-	-	-	-	-
13	LS											
14	Demand	1,132,000 [6]	0.00259	1,068,897 [7]	1,551,750 [6]	0.00259	1,469,262 [7]	400,365	46,761	219,109	129,932	4,563
15	Capacity	10,962,350 [6]	0.00033	1,324,416 [7]	14,751,350 [6]	0.00033	1,787,066 [7]	462,650	54,035	253,196	150,146	5,273
16	Liquefaction	10,962,350 [6]	0.09086	995,984	14,751,350 [6]	0.09086	1,340,234	344,250	40,207	188,398	111,721	3,924
17	Vaporization	10,962,350 [6]	0.00339	37,119	14,751,350 [6]	0.00339	49,948	12,829	1,498	7,022	4,163	146
18	TF-2 Reservation	10,962,350 [6]	0.04100	449,456	14,751,350 [6]	0.04111	606,395	156,939	18,330	85,888	50,932	1,789
19	TF-2 Redelivery Charge	10,962,350 [6]	0.00300	32,887	14,751,350 [6]	0.00300	44,254	11,367	1,328	6,220	3,689	130
20	Other Storage Facilities							- [8]	-	-	-	-
21	COMMODITY CHARGES:											
22	Total Producer/Supplier Purchases Including Storage	333,850,840	0.39482	131,810,989	333,850,840	0.32764	109,382,889	(22,428,100)	(2,324,218)	(12,291,762)	(7,422,085)	(390,035)
23	TOTAL ANNUAL COST DIFFERENCE							$ (19,753,223)	$ (2,011,804)	$ (10,827,874)	$ (6,553,998)	$ (359,547)
24	Normalized Sales Volumes (1/1/14 - 12/31/14)								34,596,870	182,967,574	110,480,570	5,805,826
25	Average Base Rate Change (Line 23 divided by Line 24)								$ (0.05815)	$ (0.05918)	$ (0.05932)	$ (0.06193)
26	Other Permanent Changes Proposed:											
27	Elimination of Temporary Credits (Surcharges) from Case No. INT-G-14-01								0.03501	0.02704	0.03550	0.01450
28	Adjustment to Fixed Cost Collection Rate [9]								(0.00834)	(0.00669)	(0.00441)	0.03166
29	Total Permanent Changes Proposed (Lines 25 through 28)								(0.03148)	(0.03883)	(0.02823)	(0.01577)
30	Temporary Surcharge (Credit) Proposed [10]								(0.00085)	(0.00968)	(0.01323)	(0.02707)
31	Proposed Average Per Therm Change in Intermountain Gas Company Tariff (Lines 29 through 30)								$ (0.03233)	$ (0.04851)	$ (0.04146)	$ (0.04284)

[1] See Workpaper No. 4, Line 8
[2] See Workpaper No. 1, Page 1 of 2
[3] See Workpaper No. 1, Page 2 of 2
[4] See Workpaper No. 2, Page 1 of 2
[5] See Workpaper No. 2, Page 2 of 2
[6] Represents Non-Additive Demand Charge Determinants
[7] Price Reflects Daily Charge; Annual Charge (Column (d) &(g)) equals Price (Column (c) & (f)) times Annual Therms/Billing Determinants (Column (b) & (e)) times 366. Actual prices include 6 decimals.
[8] See Workpaper No. 3, Line 29, Column (e)
[9] See Exhibit 5, Line 25
[10] See Exhibit No. 6, Line 5, Columns (b)-(e)

INTERMOUNTAIN GAS COMPANY
Summary of Fixed Gas Cost Charges

Line No.	Description	Annual Therms/ Billing Determinants INT-G-14-01	10/1/2014 Prices INT-G-14-01	Annual Cost INT-G-14-01	Cost of Service Allocation of Gas Cost Adjustment [1] RS-1	RS-2	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	DEMAND CHARGES:							
2	Transportation:							
3	NWP TF-1 Reservation (Full Rate)	862,787,350	$ 0.04180	$ 36,062,090	$ 4,211,872	$ 19,735,808	$ 11,703,374	$ 411,036
4	NWP TF-1 Reservation (Discounted)	205,101,900	0.02342	4,803,373	561,010	2,628,756	1,558,858	54,749
5	Upstream Capacity (Full Rate)	689,050,380	0.01145	7,888,741	921,366	4,317,294	2,560,165	89,916
6	Upstream Capacity (Discounted)	573,879,950	0.01545	8,866,107	1,035,517	4,852,181	2,877,353	101,056
7	Storage:							
8	SGS-1							
9	Demand	303,370	0.00156	172,960 [2]	20,201	94,657	56,131	1,971
10	Capacity Demand	10,920,990	0.00006	227,211 [2]	26,537	124,346	73,738	2,590
11	TF-2 Reservation	10,920,990	0.04100	447,753	52,295	245,044	145,311	5,103
12	TF-2 Redelivery Charge	10,920,990	0.00300	32,763	3,827	17,930	10,633	373
13	LS-1							
14	Demand	1,132,000	0.00259	1,068,897 [2]	124,842	584,979	346,893	12,183
15	Capacity	10,962,350	0.00033	1,324,416 [2]	154,685	724,817	429,818	15,096
16	Liquefaction	10,962,350	0.09086	995,984	116,326	545,075	323,231	11,352
17	Vaporization	10,962,350	0.00339	37,119	4,335	20,315	12,046	423
18	TF-2 Reservation	10,962,350	0.04100	449,456	52,494	245,975	145,864	5,123
19	TF-2 Redelivery Charge	10,962,350	0.00300	32,887	3,841	17,998	10,673	375
20	Other Storage Facilities			3,080,420	359,778	1,685,830	999,701	35,111
21	Total Fixed Gas Cost Charges			$ 65,490,177	$ 7,648,926	$ 35,841,005	$ 21,253,789	$ 746,457
22	Normalized Sales Volumes (INT-G-15-02 Estimated Volumes)				34,756,272	188,743,869	112,217,436	5,983,891
23	Fixed Cost Collection per Therm (Line 21 divided by Line 22)				$ 0.22007	$ 0.18989	$ 0.18940	$ 0.12474
24	INT-G-14-01 Fixed Cost Collection per Therm				0.22841	0.19658	0.19381	0.09308
25	Adjustment to Fixed Cost Collection (Line 23 minus Line 24)				$ (0.00834)	$ (0.00669)	$ (0.00441)	$ 0.03166
26	FIXED COST COLLECTION RATE CALCULATION:							
27	Adjusted Fixed Cost Collection Per Therm (Line 23)				$ 0.22007	$ 0.18989	$ 0.18940	$ 0.12474
28	Incremental Fixed Cost Collection [3]				0.00903	0.00800	0.00786	0.00525
29	INT-G-15-02 Fixed Costs Collected (Lines 27 through 28)				$ 0.22910	$ 0.19789	$ 0.19726	$ 0.12999

[1] See Workpaper No. 4, Line 8
[2] Price Reflects Daily Charge; Annual Charge (Column (d)) equals Price (Column (c)) times Annual Therms (Column (b)) times 366.
[3] See Exhibit 4, (Sum of Lines 1-20 divided by Line 24)

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Temporary Surcharges (Credits)

		Cost of Service Allocation of Deferred Gas Costs			
Line No.	Description	RS-1	RS-2	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)
1	Management of Pipeline Transportation Capacity [1]	$ (0.01330)	$ (0.01178)	$ (0.01157)	$ (0.00773)
2	Proposed Temporary Surcharge (Credit) - Fixed Deferral [2]	0.01425	0.00371	(0.00008)	(0.01951)
3	Proposed Temporary Surcharge (Credit) - Variable Deferral	(0.00014) [3]	(0.00014) [3]	(0.00014) [3]	0.00114 [4]
4	LNG Sales Credits [5]	(0.00166)	(0.00147)	(0.00144)	(0.00097)
5	Total Proposed Temporary Surcharges (Credits)	$ (0.00085)	$ (0.00968)	$ (0.01323)	$ (0.02707)

(1) See Exhibit No. 7, Line 5, Columns (c) - (f)
(2) See Exhibit No. 8, Line 9, Columns (c) - (f)
(3) See Exhibit No. 9, Line 4, Column (b) plus Line 12, Column (b)
(4) See Exhibit No. 9, Line 4, Column (b) plus Line 20, Column (b)
(5) See Exhibit No. 10, Line 7, Columns (c) - (f)

INTERMOUNTAIN GAS COMPANY

Allocation of Annualized Credits Resulting from Management of Pipeline Transportation Capacity

Line No.	Description	Total	Cost of Service Allocation of Deferred Gas Costs [1]			
			RS-1	RS-2	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)
1	Long Term Northwest Pipeline Capacity Releases	$ (3,600,000)	$ (420,462)	$ (1,970,183)	$ (1,168,322)	$ (41,033)
2	Upstream Pipeline Capacity Releases	(340,000)	(39,710)	(186,073)	(110,342)	(3,875)
3	Total Management of Pipeline Transportation Capacity	$ (3,940,000)	$ (460,172)	$ (2,156,256)	$ (1,278,664)	$ (44,908)
4	Normalized Sales Volumes (1/1/14 - 12/31/14)		34,596,870	182,967,574	110,480,570	5,805,826
5	Proposed Price Adjustment Per Therm		$ (0.01330)	$ (0.01178)	$ (0.01157)	$ (0.00773)

[1] See Workpaper No. 4, Line 8

INTERMOUNTAIN GAS COMPANY
Proposed Temporary Surcharges (Credits) - Fixed Costs

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2015 Balance [1]	RS-1	RS-2	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)
1	From INT-G-14-01 (Accounts 1910.2050 - 2090)	$ (933,930)	$ (181,213)	$ (415,102)	$ (365,046)	$ 27,431
2	Fixed Cost Collection Adjustment (Account 1910.2200)	7,126,700	1,304,486	3,894,510	2,020,181	(92,477)
3	Capacity Releases (Account 1910.2320) [2]	(4,829,537)	(564,066)	(2,643,075)	(1,567,349)	(55,047)
4	Interest (Account 1910.2430) [2]	(691)	(81)	(378)	(224)	(8)
5	Management of Pipeline Transportation Capacity (Account 1910.2530)	(3,886,165)	(462,430)	(2,132,192)	(1,260,664)	(30,879)
6	Amortization of 1910.2530 (Accounts 1910.2540 - 1910.2550)	3,573,651	396,400	1,975,676	1,163,894	37,681
7	Total Fixed Costs	$ 1,050,028	$ 493,096	$ 679,439	$ (9,208)	$ (113,299)
8	Normalized Sales Volumes (1/1/14 - 12/31/14)		34,596,870	182,967,574	110,480,570	5,805,826
9	Proposed Temporary Surcharge (Credit)-Fixed Costs		$ 0.01425	$ 0.00371	$ (0.00008)	$ (0.01951)

[1] See Workpaper No. 5, Pages 3 - 4
[2] See Workpaper No. 4, Line 8

Exhibit No. 8
Case No. INT-G-15-02
Intermountain Gas Company

INTERMOUNTAIN GAS COMPANY

Proposed Temporary Surcharges (Credits) - Variable Costs

Line No.	Description	Amount
	(a)	(b)
1	Account 1910 Variable Amounts Which Apply to RS-1, RS-2, GS-1, and LV-1:	
2	Account 1910 Variable Costs	$ 696,361 [1]
3	Normalized Sales Volumes (1/1/14 - 12/31/14)	333,850,840
4	Proposed Temporary Surcharge (Credit) - Variable Costs	$ 0.00209
5	Lost and Unaccounted For Gas Amounts Which Apply to RS-1, RS-2, and GS-1:	
6	Lost and Unaccounted For Gas Amounts from INT-G-14-01 (Account 1910-2120)	$ 477,530 [2]
7	Lost and Unaccounted For Gas Amortization (Account 1910-2130)	(435,680) [3]
8	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-14-01	41,850
9	Lost and Unaccounted For Gas INT-G-15-02	(771,881) [4]
10	Total Lost and Unaccounted For Gas Amounts Which Apply to RS-1, RS-2, and GS-1	$ (730,031)
11	Normalized Sales Volumes (1/1/14 - 12/31/14)	328,045,014
12	Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs	$ (0.00223)
13	Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, T-4, and T-5:	
14	Lost and Unaccounted For Gas Amounts from INT-G-14-01 (Account 1910-2120)	$ 156,537 [5]
15	Lost and Unaccounted For Gas Amortization (Account 1910-2140)	(158,981) [6]
16	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-14-01	(2,444)
17	Lost and Unaccounted For Gas INT-G-15-02	(257,308) [7]
18	Total Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, T-4 and T-5	$ (259,752)
19	Normalized Sales Volumes (1/1/14 - 12/31/14)	273,541,337
20	Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs	$ (0.00095)

[1] See Workpaper No. 5, Page 1
[2] See Workpaper No. 5, Page 2, Line 2, Column (c)
[3] See Workpaper No. 5, Page 2, Line 8, Column (d)
[4] See Workpaper No. 5, Page 2, Line 23, Column (d) plus Line 29, Column (e)
[5] See Workpaper No. 5, Page 2, Line 3, Column (c)
[6] See Workpaper No. 5, Page 2, Line 12, Column (d)
[7] See Workpaper No. 5, Page 2, Line 24, Column (d) plus Line 33, Column (e)

INTERMOUNTAIN GAS COMPANY
Allocation of LNG Sales Credits

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2015 Balance [1]	Cost of Service Allocation of Deferred Gas Costs [2]					
			RS-1	RS-2	GS-1	LV-1	T-4	T-5
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	From INT-G-14-01 (Accounts 1910.2800 - 2810)	$ (9,956)	$ (829)	$ (3,885)	$ (2,304)	$ (81)	$ (2,750)	$ (107)
2	Interest (Account 1910.2815)	(15)	(1)	(7)	(3)	-	(4)	-
3	LNG Sales Deferral - Margin Sharing (Account 1910.2820)	(568,583)	(47,350)	(221,872)	(131,570)	(4,621)	(157,053)	(6,117)
4	LNG Sales Deferral - O&M Recovery (Account 1910.2825)	(110,813)	(9,228)	(43,241)	(25,642)	(901)	(30,609)	(1,192)
5	Total LNG Sales Credits	$ (689,367)	$ (57,408)	$ (269,005)	$ (159,519)	$ (5,603)	$ (190,416)	$ (7,416)
6	Normalized Sales Volumes (1/1/14 - 12/31/14)		34,596,870	182,967,574	110,480,570	5,805,826	171,964,410	18,378,657
7	Proposed Price Adjustment Per Therm		$ (0.00166)	$ (0.00147)	$ (0.00144)	$ (0.00097)	$ (0.00111)	$ (0.00040)

[1] See Workpaper No. 5, Page 5, Lines 1 - 12, Column (d)
[2] See Workpaper No. 8, Line 5

INTERMOUNTAIN GAS COMPANY
Analysis of Annualized Price Change by Class of Service
Normalized Volumes for Twelve Months Ended December 31, 2014

			Average Prices Effective per Case No. INT-G-14-01 Commission Order No. 33139		Proposed Adjustments Effective 10/1/2015		Proposed Average Prices Effective 10/1/2015		
Line No.	Description	Annual Therms/CD Vols.	Revenue	$/Therm	Revenue	$/Therm	Revenue	$/Therm	Percent Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Sales:								
2	RS-1 Residential	34,596,870	$ 31,444,057	$ 0.90887	$ (1,118,517)	$ (0.03233)	$ 30,325,540	$ 0.87654	-3.56%
3	RS-2 Residential	182,967,574	145,226,853	0.79373	(8,875,757)	(0.04851)	136,351,096	0.74522	-6.11%
4	GS-1 General Service	110,480,570	80,866,253	0.73195	(4,580,524)	(0.04146)	76,285,729	0.69049	-5.66%
5	LV-1 Large Volume	5,805,826	3,122,257	0.53778	(248,722)	(0.04284)	2,873,535	0.49494	-7.97%
6	Total Gas Sales	333,850,840	260,659,420	0.78077	(14,823,520)	(0.04440)	245,835,900	0.73637	-5.69%
7	T-3 Transportation	77,392,444	1,420,151	0.01835	(117,637)	(0.00152)	1,302,514	0.01683	-8.28%
8	T-4 Transportation	171,964,410	7,406,507	0.04307	(354,247)	(0.00206)	7,052,260	0.04101	-4.78%
9	T-5 Transportation (Demand)	-	-	0.84253	-	-	-	0.84253	0.00%
10	T-5 Transportation (Commodity)	18,378,657	51,276	0.00279	(30,876)	(0.00168)	20,400	0.00111	-60.22%
11	Total T-5 (1)	18,378,657	51,276	0.00279	(30,876)	(0.00168)	20,400	0.00111	-60.22%
12	Total Transportation	267,735,511	8,877,934	0.03316	(502,760)	(0.00188)	8,375,174	0.03128	-5.67%
13	Total	601,586,351	$ 269,537,354	$ 0.44804	$ (15,326,280)	$ (0.02548)	$ 254,211,074	$ 0.42256	-5.69%

(1) Demand volumes removed from the $/therm calculations

NEWS RELEASE

and

CUSTOMER NOTICE

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

(2 Pages)

NEWS RELEASE

555 S. Cole Rd.
Boise, ID 83709

Intermountain Gas Company files annual PGA

BOISE, IDAHO – ***August 7, 2015*** -- Intermountain Gas Company filed its annual Purchased Gas Cost Adjustment (PGA) application with the Idaho Public Utilities Commission to change its prices by an overall average decrease of 5.69%, or $15.3 million. If approved, the decrease would be effective Oct.1, 2015. The primary reason behind the proposed decrease is a decline in the price of natural gas that Intermountain purchases for its customers. With this proposed decrease, Intermountain's combined residential and commercial prices would be 35% lower as compared to 2005. Intermountain's earnings will not decrease as a result of the proposed change in prices and revenues.

If approved, residential customers using natural gas for space and water heating will see an average decrease of 6.11%, or $3.12 per month. Customers using natural gas for space heating only will see an average decrease of $1.36 per month, or 3.56%, based on average weather and usage. Commercial customers, on average, would see a decrease of $12.15 per month or 5.66%.

The company is also proposing to eliminate the temporary surcharges and credits that have been included in its current prices during the past year. Newer temporary surcharges and credits will be included going forward.

Scott Madison, Executive Vice President and General Manager of Intermountain said, "The decrease in the cost of natural gas is mainly a supply and demand issue, and natural gas supplies remain plentiful. Additionally, last winter's warm weather in the western U.S reduced demand on natural gas storage levels in our region, adding to the availability of natural gas heading into next winter. We continue to see increased domestic natural gas production, and we anticipate prices will remain fairly stable in the coming year."

Even with this proposed price decrease, Intermountain continues to urge all its customers to use energy wisely. Conservation tips, information on government payment energy assistance, and programs to help customers level out their energy bills over the year can be found on the company's website, www.intgas.com.

A Purchased Gas Cost Adjustment application is filed each year to ensure the costs Intermountain incurs on behalf of its customers are reflected in its sales prices. The request is a proposal, and is subject to public review and approval by the Idaho Public Utilities Commission. A copy of the application is available at the Commission's office and on its homepage at www.puc.idaho.gov as well as on Intermountain's website at www.intgas.com . Written comments regarding the application may be filed with the Commission. Customers may also subscribe to the Commission's RSS feed to receive periodic updates via email.

Intermountain Gas Company is a natural gas distribution company serving approximately 334,000 residential, commercial and industrial customers in 75 communities in southern Idaho. Intermountain is a subsidiary of MDU Resources Group, Inc., a multidimensional natural resources enterprise traded on the New York Stock Exchange as "MDU." For more information about MDU Resources, visit the company's website at www.mdu.com. For more information about Intermountain, visit www.intgas.com.

Media Contact: Byron Defenbach at (208) 377-6080.

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

Customer Notice
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WORKPAPER NOS. 1-8

CASE NO. INT-G-15-02

INTERMOUNTAIN GAS COMPANY

(15 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Full Rate Demand Costs

Line No.	Transportation	INT-G-14-01 Annual Therms	INT-G-14-01 Prices	INT-G-14-01 Annual Cost
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	412,537,600	$ 0.041849	$ 17,264,201
2	TF-1 Reservation Contract #2	25,550,000	0.054215	1,385,194
3	TF-1 Reservation Contract #3	73,000,000	0.041000	2,993,000
4	TF-1 Reservation Contract #4	26,429,650	0.041000	1,083,614
5	TF-1 Reservation Contract #5	32,850,000	0.041000	1,346,850
6	TF-1 Reservation Contract #6	0	0.000000	0
7	TF-1 Reservation Contract #7	87,600,000	0.041000	3,591,600
8	TF-1 Reservation Contract #8	18,250,000	0.041000	748,250
9	TF-1 Reservation Contract #9	104,495,850	0.041000	4,284,334
10	TF-1 Reservation Contract #10	26,462,500	0.041000	1,084,966
11	TF-1 Reservation Contract #11	51,081,750	0.041000	2,094,351
12	TF-1 Reservation Contract #12	4,530,000	0.041000	185,730
13	Total	862,787,350		$ 36,062,090

Line No.	Transportation	INT-G-15-02 Annual Therms [1]	INT-G-15-02 Prices	INT-G-15-02 Annual Cost
	(a)	(b)	(c)	(d)
14	TF-1 Reservation Contract #1	413,667,840	$ 0.041816	$ 17,297,914
15	TF-1 Reservation Contract #2	25,620,000	0.052596	1,347,516
16	TF-1 Reservation Contract #3	73,200,000	0.041000	3,001,200
17	TF-1 Reservation Contract #4	26,502,060	0.041000	1,086,582
18	TF-1 Reservation Contract #5	32,940,000	0.041000	1,350,540
19	TF-1 Reservation Contract #6	36,600,000	0.041000	1,500,600
20	TF-1 Reservation Contract #7	87,840,000	0.041000	3,601,440
21	TF-1 Reservation Contract #8	18,300,000	0.041000	750,300
22	TF-1 Reservation Contract #9	104,782,140	0.041000	4,296,072
23	TF-1 Reservation Contract #10	26,535,000	0.041000	1,087,939
24	TF-1 Reservation Contract #11	51,221,700	0.041000	2,100,089
25	TF-1 Reservation Contract #12	4,560,000	0.041000	186,960
26	Total	901,768,740		$ 37,607,152
27	Total Annual Cost Difference (Row 26 minus Row 13)			$ 1,545,062 [2]

[1] Daily Contract Demand multiplied by 366 days

[2] See Exhibit 4, Line 3, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Discounted Demand Costs

Line No.	Transportation	INT-G-14-01 Annual Therms	INT-G-14-01 Prices	INT-G-14-01 Annual Cost
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	18,250,000	$ 0.026650	$ 486,366
2	TF-1 Reservation Contract #2	29,404,400	0.021747	639,444
3	TF-1 Reservation Contract #3	58,400,000	0.023409	1,367,104
4	TF-1 Reservation Contract #4	36,500,000	0.026650	972,725
5	TF-1 Reservation Contract #5	32,850,000	0.008499	279,203
6	TF-1 Reservation Contract #6	11,497,500	0.036900	424,261
7	TF-1 Reservation Contract #7	18,200,000	0.034850	634,270
8	Total	205,101,900		$ 4,803,373

Line No.	Transportation	INT-G-15-02 Annual Therms [1]	INT-G-15-02 Prices	INT-G-15-02 Annual Cost
	(a)	(b)	(c)	(d)
9	TF-1 Reservation Contract #1	18,300,000	$ 0.026650	$ 487,699
10	TF-1 Reservation Contract #2	29,484,960	0.022698	669,240
11	TF-1 Reservation Contract #3	58,560,000	0.024600	1,440,576
12	TF-1 Reservation Contract #4	36,600,000	0.027776	1,016,595
13	TF-1 Reservation Contract #5	32,940,000	0.008500	279,990
14	TF-1 Reservation Contract #6	11,529,000	0.036900	425,423
15	TF-1 Reservation Contract #7	0	0.000000	0
16	Total	187,413,960		$ 4,319,523
17	Total Annual Cost Difference (Row 16 minus Row 8)			$ (483,850) [2]

[1] Daily Contract Demand multiplied by 366 days

[2] See Exhibit 4, Line 4, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Upstream Capacity Full Rate Demand Costs

Line No.	Transportation	INT-G-14-01 Annual Therms	INT-G-14-01 Prices	INT-G-14-01 Annual Cost	
	(a)	(b)	(c)	(d)	
1	Upstream Agreement #1	25,933,250	$ 0.009036	$ 234,330	
2	Upstream Agreement #2	351,503,260	0.009042	3,178,200	
3	Upstream Agreement #3	26,962,550	0.009036	243,631	
4	Upstream Agreement #4	37,288,400	0.009036	336,934	
5	Upstream Agreement #5	26,126,700	0.017735	463,347	
6	Upstream Agreement #6	128,898,520	0.017735	2,285,964	
7	Upstream Agreement #7	54,750,000	0.017735	970,969	
8	Upstream Agreement #8	-	-	-	(1)
9	Upstream Agreement #9	37,587,700	0.017968	675,366	(2)
10	Total	689,050,380		8,388,741	
11	Estimated Upstream Capacity Release Credits			(500,000)	
12	Total Annual Cost Including Capacity Release Credits			$ 7,888,741	

Line No.	Transportation	INT-G-15-02 Annual Therms (3)	INT-G-15-02 Prices	INT-G-15-02 Annual Cost	
	(a)	(b)	(c)	(d)	
13	Upstream Agreement #1	26,004,300	$ 0.009016	$ 234,456	
14	Upstream Agreement #2	352,589,060	0.009019	3,179,971	
15	Upstream Agreement #3	27,036,420	0.009016	243,768	
16	Upstream Agreement #4	37,236,840	0.009016	335,736	
17	Upstream Agreement #5	26,198,280	0.016504	432,369	
18	Upstream Agreement #6	129,355,380	0.016633	2,151,588	
19	Upstream Agreement #7	54,900,000	0.016504	906,052	
20	Upstream Agreement #8	22,750,000	0.016661	379,033	(1)
21	Upstream Agreement #9	-	-	-	(2)
22	Total	676,070,280		7,862,973	
23	Estimated Upstream Capacity Release Credits			(500,000)	
24	Total Annual Cost Including Capacity Release Credits			$ 7,362,973	
25	Total Annual Cost Difference (Row 24 minus Row 12)			$ (525,768)	(4)

(1) Renegotiated to full rate. See Workpaper 2, Page 2, Lines 2 and 8, Column (d).
(2) Renegotiated to a discounted rate. See Workpaper 2, Page 2, Lines 5 and 11, Column (d).
(3) Daily Contract Demand multiplied by 366 days
(4) See Exhibit 4, Line 5, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Upstream Capacity Discounted Demand Costs

Line No.	Transportation	INT-G-14-01 Annual Therms	INT-G-14-01 Prices	INT-G-14-01 Annual Cost	
	(a)	(b)	(c)	(d)	
1	Upstream Agreement #1	62,050,000	$ 0.012414	$ 770,302	
2	Upstream Agreement #2	22,500,000	0.009931	223,456	(1)
3	Upstream Agreement #3	37,018,300	0.015074	558,029	
4	Upstream Agreement #4	452,311,650	0.016171	7,314,320	
5	Upstream Agreement #5	-	-	-	(2)
6	Total	573,879,950		$ 8,866,107	

Line No.	Transportation	INT-G-15-02 Annual Therms [3]	INT-G-15-02 Prices	INT-G-15-02 Annual Cost	
	(a)	(b)	(c)	(d)	
7	Upstream Agreement #1	62,220,000	$ 0.013584	$ 845,197	
8	Upstream Agreement #2	-	-	-	(1)
9	Upstream Agreement #3	37,009,920	0.014550	538,482	
10	Upstream Agreement #4	453,550,860	0.016749	7,596,696	
11	Upstream Agreement #5	37,577,220	0.016884	634,443	(2)
12	Total	590,358,000		$ 9,614,818	
13	Total Annual Cost Difference (Row 12 minus Row 6)			$ 748,711	(4)

(1) Renegotiated to full rate. See Workpaper 2, Page 1, Lines 8 and 20, Column (d).

(2) Renegotiated to a discounted rate. See Workpaper 2, Page 1, Lines 9 and 21, Column (d).

(3) Daily Contract Demand multiplied by 366 days

(4) See Exhibit 4, Line 6, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Other Storage Facility Costs

Line No.	Storage Facilities	INT-G-14-01 Monthly Billing Determinant		INT-G-14-01 Prices	INT-G-14-01 Monthly Cost	INT-G-14-01 Annual Cost
	(a)	(b)		(c)	(d)	(e)
1	Demand Costs -					
2	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652
3	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732
4	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360
5	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724
6	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768
7	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384
8	Total Demand Costs	84,135,000	(3)		$ 400,135	$ 4,801,620
9	Rexburg LNG Facility -					
10	Transportation Reservation					$ 66,000
11	Variable Transportation					22,800
12	Total Rexburg LNG Facility Costs					$ 88,800
13	Storage Demand Charge Credit					$ (1,810,000)
14	Total Costs Including Storage Credit					$ 3,080,420

Line No.	Storage Facilities	INT-G-15-02 Monthly Billing Determinant		INT-G-15-02 Prices	INT-G-15-02 Monthly Cost	INT-G-15-02 Annual Cost	
	(a)	(b)		(c)	(d)	(e)	
15	Demand Costs -						
16	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652	
17	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732	
18	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360	
19	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724	
20	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768	
21	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384	
22	Total Demand Costs	84,135,000	(3)		$ 400,135	$ 4,801,620	
23	Rexburg LNG Facility -						
24	Transportation Reservation					$ 66,000	
25	Variable Transportation					22,800	
26	Total Rexburg LNG Facility Costs					$ 88,800	
27	Estimated Storage Demand Charge Credit					$ (1,810,000)	
28	Total Costs Including Storage Credit					$ 3,080,420	
29	Total Annual Cost Difference Including Storage Credit (Row 28 minus Row 14)					$ -	(4)

(1) Charge Based on Maximum Daily Withdrawal

(2) Charge Based on Maximum Contractual Capacity

(3) Non Additive Billing Determinants; Includes only Capacity Volumes

(4) See Exhibit 4, Line 20, Column (h)

INTERMOUNTAIN GAS COMPANY
Peak Day Analysis for Demand Allocators

Line		Peak Firm Sales				Total
No.	Description	RS-1	RS-2	GS-1	LV-1	Peak Sales
	(a)	(b)	(c)	(d)	(e)	(f)
1	DEMAND ALLOCATORS PER CASE NO. INT-G-14-01:					
2	Peak Day Therms	378,105	1,743,375	1,030,778	25,250	3,177,508
3	Percent of Total	11.8994%	54.8662%	32.4398%	0.7946%	100.0000%
4	PROPOSED DEMAND ALLOCATORS PER CASE NO. INT-G-15-02:					
5	Peak Day Usage Per Customer	5.87	7.97	34.66		
6	January 2015 Actual Customers	67,821	234,058	31,916		333,795
7	INT-G-15-02 Peak Day Therms (Line 5 mulitplied by Line 6)	398,109	1,865,442	1,106,209	38,850 (1)	3,408,610
8	Percent of Total	11.6795%	54.7273%	32.4534%	1.1398%	100.0000%

(1) Contract Demand Therms

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2015

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	ACCOUNT 1910 VARIABLE AMOUNTS:					
2	Net Cumulative Deferred Gas Balance in 1910.2010 as of 10/1/14			$ 5,343,107.56		
3	Amortization in 1910.2020 as of 6/30/15		$ (4,495,933.55)			
4	Estimated Therm Sales 7/1 through 9/30/15	25,439,160				
5	Amortization Rate	$ (0.01662)	(422,798.84)			
6	Estimated Amortization in 1910.2020 at 9/30/15			(4,918,732.39)		
7	Estimated Balance in 1910.2010 at 9/30/15				$ 424,375.17	
8	Deferred Gas Costs From Producers/Suppliers in 1910.2180 at 10/1/14			$ (1,055,352.85)		
9	Deferred Gas Costs From Producers/Suppliers in 1910.2180 through 6/30/15			1,913,562.04		
10	Estimated Deferred Costs in 1910.2180 from 7/1 through 9/30/15			(584,953.75)		
11	Estimated Balance in 1910.2180 at 9/30/15				273,255.44	
12	Daily Gas Excess Sales Deferred in 1910.2240 at 6/30/15				-	
13	Interest Deferred in 1910.2340 at 10/1/14			$ (206.68)		
14	Interest Deferred in 1910.2340 through 6/30/15			(1,064.35)		
15	Estimated Interest from 7/1 through 9/30/15			0.96		
16	Estimated Balance in 1910.2340 at 9/30/15				(1,270.07)	
17	ESTIMATED ACCOUNT 1910 VARIABLE BALANCE AT 9/30/15					$ 696,360.54

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2015

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	ACCOUNT 1910 LOST AND UNACCOUNTED FOR AMOUNTS:					
2	Core Cumulative Deferred Gas Balance in 1910.2120 as of 10/1/14		$ 477,530.32			
3	Industrial Cumulative Deferred Gas Balance in 1910.2120 as of 10/1/14		156,536.55			
4	Net Cumulative Deferred Gas Balance in 1910.2120 as of 10/1/14			$ 634,066.87		
5	Core Amortization in 1910.2130 as of 6/30/15		$ (399,446.33)			
6	Estimated Therm Sales 7/1 through 9/30/15	23,996,074				
7	Amortization Rate	$ (0.00151)	(36,234.07)			
8	Estimated Amortization in 1910.2130 at 9/30/15			(435,680.40)		
9	Industrial Amortization in 1910.2140 as of 6/30/15		$ (124,111.18)			
10	Estimated Therm Sales 7/1 through 9/30/15	61,175,276				
11	Amortization Rate	$ (0.00057)	(34,869.91)			
12	Estimated Amortization in 1910.2140 at 9/30/15			(158,981.09)		
13	Estimated Balance in 1910.2120 at 9/30/15				$ 39,405.38	
14	Lost & Unaccounted For Gas Deferral in 1910.2150 at 10/1/14			$ 102,714.59		
15	Total Lost & Unaccounted For Gas through 6/30/15	$ 15,824.48				
16	Estimated Lost & Unaccounted For Gas 7/1 through 9/30/15	(91,990.91)				
17	Estimated Total Lost & Unaccounted For Gas at 9/30/15		$ (76,166.43)			
18	Base Rate Collection of Lost & Unaccounted For Gas through 6/30/15	$ 900,690.67				
19	Estimated Base Rate Collection of Lost & Unaccounted For Gas 7/1 through 9/30/15	155,019.94				
20	Estimated Base Rate Collection of Lost & Unaccounted For Gas at 9/30/15		1,055,710.61			
21	Estimated Lost & Unaccounted For Deferral (Line 17 minus Line 20)			(1,131,877.04)		
22	Estimated Balance in 1910.2150 at 9/30/15			(1,029,162.45)		
23	Core Allocation of Lost & Unaccounted For Gas Deferral	75%		(771,871.84)		
24	Industrial Allocation of Lost & Unaccounted For Gas Deferral	25%		(257,290.61)		
25	Estimated Balance in 1910.2150 at 9/30/15				(1,029,162.45)	
26	Core Lost & Unaccounted For Interest Deferred in 1910.2420 at 10/1/14			$ 38.95		
27	Core Lost & Unaccounted For Interest Deferred in 1910.2420 through 6/30/15			(30.08)		
28	Estimated Core Interest from 7/1 through 9/30/15			(18.33)		
29	Estimated Balance in 1910.2420 at 9/30/15				(9.46)	
30	Industrial Lost & Unaccounted For Interest Deferred in 1910.2360 at 10/1/14			$ 15.84		
31	Industrial Lost & Unaccounted For Interest Deferred in 1910.2360 through 6/30/15			(27.04)		
32	Estimated Industrial Lost & Unaccounted For Interest from 7/1 through 9/30/15			(6.23)		
33	Estimated Balance in 1910.2360 at 9/30/15				(17.43)	
34	ESTIMATED ACCOUNT 1910 LOST AND UNACCOUNTED FOR GAS BALANCE AT 9/30/15					$ (989,783.96)

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2015

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	ACCOUNT 1910 FIXED AMOUNTS:					
2	Net Cumulative Deferred Gas Balance in 1910.2050 at 10/1/14			$ (11,430,391.58)		
3	RS-1 Deferred Gas Balance in 1910.2060 at 10/1/14		$ (40,850.83)			
4	Amortization for RS-1 in 1910.2060 at 6/30/15		1,088,559.46			
5	Estimated RS-1 Therm Sales 7/1 through 9/30/15	861,816				
6	RS-1 Amortization Rate	$ 0.03809	32,826.57			
7	Estimated RS-1 Balance in 1910.2060 at 9/30/15			1,080,535.20		
8	RS-2 Deferred Gas Balance in 1910.2070 at 10/1/14		$ (15,044.84)			
9	Amortization for RS-2 in 1910.2070 at 6/30/15		4,788,154.47			
10	Estimated RS-2 Therm Sales 7/1 through 9/30/15	13,898,460				
11	RS-2 Amortization Rate	$ 0.03208	445,862.60			
12	Estimated RS-2 Balance in 1910.2070 at 9/30/15			5,218,972.23		
13	GS-1 Deferred Gas Balance in 1910.2080 at 10/1/14		$ 23,369.95			
14	Amortization for GS-1 in 1910.2080 at 6/30/15		3,628,334.86			
15	Estimated Therm Sales 7/1 through 9/30/15	9,235,797				
16	GS-1 Amortization Rate	$ 0.04096	378,298.25			
17	Estimated GS-1 Balance in 1910.2080 at 9/30/15			4,030,003.06		
18	LV-1 Deferred Gas Balance in 1910.2090 at 10/1/14		$ 10,921.53			
19	Amortization for LV-1 in 1910.2090 at 6/30/15		119,101.17			
20	Estimated LV-1 Block 1 & 2 Therm Sales 7/1 through 9/30/15	1,443,086				
21	LV-1 Amortization Rate	$ 0.02559	36,928.57			
22	Estimated LV-1 Balance in 1910.2090 at 9/30/15			166,951.27		
23	Estimated Cumulative Balance in 1910.2050 at 9/30/15				$ (933,929.82)	
24	Fixed Cost Collection Deferred in 1910.2200 at 10/1/14			$ 1,042,764.07		
25	Fixed Cost Collection Deferred in 1910.2200 through 6/30/15			(5,495,204.09)		
26	Estimated Fixed Cost Collection Deferred from 7/1 through 9/30/15			11,579,139.96		
27	Estimated Balance in 1910.2200 at 9/30/15				$ 7,126,699.94	
28	Capacity Released/Purchased Deferred in 1910.2320 at 10/1/14			$ (280,778.83)		
29	Capacity Released/Purchased Deferred in 1910.2320 through 6/30/15			(3,457,758.15)		
30	Estimated Capacity Released/Purchased Deferred from 7/1 through 9/30/15			(1,091,000.00)		
31	Estimated Balance in 1910.2320 at 9/30/15				(4,829,536.98)	
32	Interest in 1910.2430 at 10/1/14			$ 78.93		
33	Interest Deferred in 1910.2430 through 6/30/15			(673.84)		
34	Estimated Interest from 7/1 through 9/30/15			(96.26)		
35	Estimated Balance in 1910.2430 at 9/30/15				(691.17)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2015

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	Management of Pipeline Transportation Capacity Deferred in 1910.2530 at 10/1/14		$ -			
2	Management of Pipeline Transportation Capacity Deferred in 1910.2530 through 6/30/15		(3,886,165.01)			
3	Estimated Deferral in 1910.2530 from 7/1 through 9/30/15		-			
4	Estimated Balance in 1910.2530 at 9/30/15			$ (3,886,165.01)		
5	RS-1 Amortization in 1910.2540 at 6/30/15		$ 384,369.23			
6	Estimated RS-1 Therm Sales from 7/1 through 9/30/15	861,816				
7	RS-1 Amortization Rate	$ 0.01396	12,030.95			
8	Estimated RS-1 Amortization in 1910.2540 at 9/30/15		396,400.18			
9	RS-2 Amortization in 1910.2540 at 6/30/15		$ 1,806,948.74			
10	Estimated RS-2 Therm Sales from 7/1 through 9/30/15	13,898,460				
11	RS-2 Amortization Rate	$ 0.01214	168,727.30			
12	Estimated RS-2 Amortization in 1910.2540 at 9/30/15		1,975,676.04			
13	GS-1 Amortization in 1910.2540 at 6/30/15		$ 1,055,373.53			
14	Estimated GS-1 Therm Sales from 7/1 through 9/30/15	9,235,797				
15	GS-1 Amortization Rate	$ 0.01175	108,520.61			
16	Estimated GS-1 Amortization in 1910.2540 at 9/30/15		1,163,894.14			
17	Estimated Core Amortization in 1910.2540 at 9/30/15 (Sum of Lines 8, 12 and 16, Column (c))			3,535,970.36		
18	LV-1 Amortization in 1910.2550 at 6/30/15		$ 29,513.06			
19	Estimated LV-1 Block 1&2 Therm Sales from 7/1 through 9/30/15	1,443,086				
20	LV-1 Amortization Rate	$ 0.00566	8,167.87			
21	Estimated LV-1 Amortization in 1910.2550 at 9/30/15		37,680.93			
22	Estimated Industrial Amortization in 1910.2550 at 9/30/15			37,680.93		
23	Estimated Balance in 1910.2530 at 9/30/15				$ (312,513.72)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2015

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	LNG Sales Credits Deferred in 1910.2800 at 10/1/14			$ (405,441.12)		
2	LNG Amortization in 1910.2810 at 10/1/14		$ 36.31			
3	Amortization in 1910.2810 at 6/30/15		346,608.06			
4	Estimated Amortization 7/1 through 9/30/15		48,840.83			
5	Estimated Balance in 1910.2810 at 9/30/15			395,485.20		
6	LNG Sales Interest Deferred in 1910.2815 at 10/1/14		$ 10.79			
7	LNG Sales Interest Deferred in 1910.2815 through 6/30/15		(4.30)			
8	Estimated LNG Sales Interest from 7/1 through 9/30/15		(21.47)			
9	Estimated Balance in 1910.2815 at 9/30/15			(14.98)		
10	LNG Sales Deferral - Margin Sharing Deferred in 1910.2820 through 6/30/15			(568,582.69)		
11	LNG Sales Deferral - O&M Recovery Deferred in 1910.2825 through 6/30/15			(110,813.33)		
12	Estimated LNG Sales Credit Balance at 9/30/15				$ (689,366.92)	
13	ESTIMATED ACCOUNT 1910 FIXED BALANCE AT 9/30/15					$ 360,661.33
14	TOTAL DEFERRED ACCOUNT 1910 BALANCE					$ 67,237.91

INTERMOUNTAIN GAS COMPANY
Analysis of LV-1 Tariff Block 1, Block 2, and Block 3 Adjustments

Line No.	Description	Block 1 Therm Sales	Block 2 Therm Sales	Block 3 Therm Sales	Total
	(a)	(b)	(c)	(d)	(e)
1	LV-1 Therm Sales (1/1/14 - 12/31/14)	5,805,826	0	0	5,805,826
2	Blocks 1 and 2 Therm Sales	5,805,826	0		5,805,826
3	Percent Therm Sales between Blocks 1 and 2	100.000%	0.000%		100.000%
4	Proposed Adjustment to LV-1 Tariff [(1)]				$ 0.02434
5	LV-1 Therm Sales (1/1/14 - 12/31/14)				5,805,826
6	Annualized Adjustment (Line 4 multiplied by Line 5)				$ 141,314
7	Annualized Adjustment (Line 6)				$ 141,314
8	Percent Annualized Sales included in Block 1 and Block 2				100.000%
9	Adjustment to Block 1 and 2 (Line 7 multiplied by Line 8)				$ 141,314
10	Block 1 and 2 Therms				5,805,826
11	Price Adjustment/Therm Block 1 and 2 (Line 9 divided by Line 10)				$ 0.02434
12	WACOG Commodity Charge Change [(2)]				(0.06718)
13	Total Price Adjustment/Therm Block 1 and Block 2				$ (0.04284)
14	Price Adjustment/Therm Block 3 [(3)]				$ 0.00017
15	WACOG Commodity Charge Change [(2)]				(0.06718)
16	Eliminate INT-G-14-01 Variable Temporary				(0.01675)
17	Total Price Adjustment/Therm Block 3				$ (0.08376)

[(1)] See Exhibit No. 4, Line 31, Column (l) minus the difference of Line 22, Column (f) minus Line 22, Column (c)

[(2)] See Exhibit No. 4, Line 22, Column (f) minus Line 22, Column (c)

[(3)] See Exhibit No. 6, Line 3, Column (e), plus Line No. 4, Column (e)

INTERMOUNTAIN GAS COMPANY
Analysis of Lost and Unaccounted For Gas ("L&U")

Line No.	Description (a)	Detail (b)	Amount (c)
1	**Lost and Unaccounted For Gas INT-G-14-01 (Therms)**		
2	Actual Oct 13 - Sep 14 L&U (Therms)	880,946	
3	Actual Oct 13 - Sep 14 Sales	613,948,721	
4	**Oct 13 - Sep 14 L&U Factor (line 2 divided by line 3)**		0.143%
5	**Lost and Unaccounted For Gas INT-G-15-02 (Therms)**		
6	Projected Oct 14 - Sep 15 L&U (Therms)	2,288,309	
7	Estimated Oct 14 - Sep 15 Sales (1)	580,060,776	
8	**Oct 14 - Sep 15 L&U Factor (line 6 divided by line 7)**		0.394%
9	**Lost and Unaccounted For Gas INT-G-15-02 (Dollars)**		
10	Lost & Unaccounted For Gas (1910-2150) (2)		$ (76,166)
11	Estimated Oct 14 - Sep 15 Sales (1)	580,060,776	
12	L&U rate per therm embedded in base rates	$ 0.00182	
13	Oct 14 - Sep 15 Collection of Lost & Unaccounted for Gas		1,055,711
14	**Projected L&U (Over)/Under Collection (Line 10 minus Line 13)**		$ (1,131,877)

(1) Estimated Oct 14 - Sep 15 Sales (Therms)

RS-1	29,442,728
RS-2	163,806,894
GS-1	98,627,422
Industrial	288,183,732
Total Sales	580,060,776

(2) See Workpaper No. 5, Page 2, Line 17, Column (c)

INTERMOUNTAIN GAS COMPANY

Lost and Unaccounted For Gas Statistics [1]

Check for Dead Orders

Year	Check for Dead Orders	Found Dead	Percent Found Dead	Accounted For Therms
2010	12,441	569	5%	
2011	10,093	795	8%	
2012	5,089	513	10%	
2013	5,041	796	16%	213,590
2014	6,102	923	15%	258,839
2015 [2]	4,561	745	16%	187,091

Drive Rate Errors

Year	Occurrences	Accounted For Therms
2010	13	
2011	14	
2012	3	
2013	3	2,331
2014	15	26,559
2015 [2]	6	6,464

Pressure Errors

Year	Occurrences	Accounted For Therms
2010	19	
2011	8	
2012	15	
2013	17	(64,400)
2014	7	10,245
2015 [2]	2	25,015

Gas Loss from Line Breaks

Year	Occurrences	Accounted For Therms
2010	175	88,947
2011	154	49,856
2012	177	68,221
2013	163	66,063
2014	187	119,291
2015 [2]	128	34,815

[1] Gas loss resulting from these occurrences becomes accounted for gas
[2] Through June 2015

INTERMOUNTAIN GAS COMPANY
Peak Day Analysis for LNG Sales Credit Demand Allocators

		Peak Usage						
Line No.	Description	RS-1	RS-2	GS-1	LV-1 [1]	T-4 [1]	T-5 [1]	Total Peak Sales
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	PROPOSED LNG SALES CREDIT DEMAND ALLOCATORS PER CASE NO. INT-G-15-02:							
2	Peak Day Usage Per Customer	5.87	7.97	34.66				
3	January 2015 Actual Customers	67,821	234,058	31,916				333,795
4	INT-G-15-02 Peak Day Therms (Line 2 mulitplied by Line 3)	398,109	1,865,442	1,106,209	38,850	1,320,472	51,435	4,780,517
5	Percent of Total	8.3277%	39.0219%	23.1399%	0.8127%	27.6219%	1.0759%	100.0000%

[1] Contract Demand Therms