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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR AUTHORITY TO CHANGE ITS PRICES (2011 PURCHASED GAS COST ADJUSTMENT).	**CASE NO. INT-G-11-01** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Karl T. Klein, Deputy Attorney General, in response to the Notice of Application and Notice of Modified Procedure (Order No. 32329) submits the following comments.

BACKGROUND

On August 11, 2011, Intermountain Gas Company filed its annual Purchased Gas Cost Adjustment (PGA) Application requesting authority to decrease its annualized revenues by $14.4 million, for an overall decrease of about 5.3%. Application at 2. The PGA mechanism is used to adjust rates to reflect annual changes in Intermountain's costs for the purchase of natural gas from suppliers, including transportation, storage, and other related costs. Reference Order No. 26019. The Company contends the proposed changes will decrease its customer rates while not affecting the Company's earnings. Application at 2 and 4. The Company asks the Commission to process the Application by Modified Procedure, and that the new rates take effect October 1, 2011. *Id.* at 9.

Intermountain seeks to pass-through to each customer class a net change in gas-related costs resulting from (1) a cost increase billed to Intermountain by Northwest Pipeline GP ("Northwest" or "Northwest Pipeline"); (2) a cost decrease from Intermountain's "upstream" pipeline suppliers and its storage facilities; (3) a decrease in Intermountain's weighted average cost of gas ("WACOG"); (4) an updated customer allocation of gas-related costs pursuant to the Company's Purchased Gas Cost Adjustment provision; (5) 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 (6) benefits included in Intermountain's firm transportation and storage costs resulting from Intermountain's management of its storage and firm capacity rights on various pipeline systems. Application at 3-4.

Intermountain proposes decreasing the WACOG from $0.49211 per therm to $0.45342 per therm. The Application maintains that "[c]ontinued weakness in the regional and national economies has put downward pressure on new customer growth and weather adjusted demand for natural gas. At the same time, natural gas supplies are ample and U.S. dry gas production is at an all time high. Robust supply coupled with flat demand has kept the near term prices for natural gas relatively low." *Id.* at 5.

Pursuant to Order No. 32077, Intermountain included temporary surcharges and credits in its October 1, 2010 prices to pass back to customers deferred gas cost charges and benefits. Intermountain now seeks to eliminate the temporary surcharges and credits included in its current prices during the past 12 months. The proposed changes would result in an overall price decrease to Intermountain's customers. Application at 4 and 6.

The Company asserts that the proposed WACOG includes the benefits resulting from Intermountain's storage of significant amounts of natural gas "procured during the summer season when prices are typically lower than during the winter, [making] the cost of Intermountain's storage gas normally less than what could be obtained on the open market in winter months." Additionally, and to further stabilize prices paid by customers during the upcoming winter period, Intermountain has entered into fixed price agreements to lock-in the price for significant portions of its underground storage and other winter "flowing" supplies. *Id.* at 5.

The Company proposes allocating deferred gas costs from its Account No. 186 balance to its customers through temporary price adjustments to be effective during the 12-month period ending September 30, 2012, as follows: (1) fixed gas costs credit of $5.9 million attributable to the collection of interstate pipeline capacity costs, the true-up of expense issues previously ruled on by the Commission, and mitigating capacity release credits generated from the incremental release of Intermountain's pipeline capacity; (2) deferred gas cost amounts of $12.2 million attributable to variable gas costs since October 1, 2010; and (3) deferred gas costs related to lost and unaccounted-for gas ("L&U"), which results in a net per-therm decrease to both sales and transportation customers. *Id.* at 6-7.

Intermountain says it did not use a straight cents-per-therm price decrease for the LV-1 tariff. There are no fixed costs recovered in the tail block of the LV-1 tariff. The proposed changes in the WACOG, and variable deferred credits (outlined in Exhibit 9) are applied to all three blocks of the LV-1 tariff, but adjustments relating to fixed costs are applied only to the first two blocks of the LV-1 tariff. Each block of the proposed LV-1, T-3, T-4 and T-5 tariffs include a uniform cents-per-therm decrease to adjust for L&U. *Id.* at 7.

Intermountain notified customers about its Application through a customer notice and press release. *Id.* at 8. The Company asserts that the proposed overall price changes reflect a just, fair, and equitable pass-through of changes in gas-related costs to Intermountain's customers. *Id.*

STAFF REVIEW

Staff reviewed the Company's Application and gas purchases for the year to verify that the filing will not change the Company's earnings, that the deferred costs are prudent, and to determine the reasonableness of the WACOG request. The table below illustrates how the proposed decrease will impact the customer classes served by the Company:

Table: 1

Customer Class:	Proposed Change in Class Revenue	Purposed Average Change in $/Therm	Purposed Average % Change	Purposed Average Price $/Therm
1 Residential	(1,618,870)	(0.04864)	-5.13%	0.89988
RS-2 Residential[1]	(6,047,561)	(0.03444)	-4.15%	0.79476
GS-1 General Service[1]	(6,431,277)	(0.06124)	-7.65%	0.73878
LV-1 Large Volume	(81,735)	(0.03026)	-5.30%	0.54099
T-3 Transportation	(56,008)	(0.00090)	-5.27%	0.01618
T-4 Transportation	(124,102)	(0.00090)	-2.12%	0.04147
T-5 Transportation	(17,852)	(0.00090)	-3.02%	0.02893
	(14,377,405)		-5.32%	

The Company's proposed changes decrease Intermountain's annual revenue by $14,377,405, as follows:

Table 2:

Deferrals:		
Removal of INT-G-10-03 Temporaries	$ 21,459,356	
Removal of INT-G-10-03 Lost and Unaccounted for Gas	$ 547,731	
INT-G-11-01 Temporaries	$ (21,807,555)	
Total Deferrals		$ 199,532
Lost and Unaccounted for Gas (INT-G-11-01)		$ (1,446,804)
Reallocation of fixed costs		$ (1,116,356)
Changes in the Weighted Average Cost of Gas		$ (12,248,241)
Fixed Cost Changes:		
Northwest Pipeline	$ 1,034,554	
New Upstream Capacity Costs	$ (543,569)	
Other Storage Facilities (Clay Basin) Cost Changes	$ (256,521)	
Total Fixed Cost Changes		$ 234,464
Total Annual Price Change		**$ (14,377,405)**

[1] There were no therm sales under the IS-R and IS-C tariffs. However, the IS-R price is based on the RS-2 December-March price and receives the same PGA adjustments and the IS-C price is based on the GS-1 December-March price and receives the same PGA adjustments.

Weighted Average Cost of Gas (WACOG)

Intermountain Gas proposes to reduce the WACOG from $0.49211 per therm to $0.45342 per therm. This is a 7.86% decrease from the previous year's Commission-approved PGA filing (Commission Order No. 32077). Based on the following analysis, Staff believes (a) the Company's methods are solid and accurate; (b) the proposed WACOG reduction compared to the previous WACOG correlates with current and future economic factors that influence the natural gas market; and (c) the WACOG value reasonably compares to benchmark market prices. Staff recommends the Commission accept the Company's proposed WACOG. Staff also recommends that the Company return to the Commission with a new filing if prices significantly deviate from the proposed rates during the upcoming year.

The WACOG is used to determine the rate changes proposed by the Company's PGA filing. The Company estimates a volume-weighted average cost by averaging the sum of forward natural gas prices multiplied by projected purchase volumes for each supply source and contracting instrument the Company utilizes. First, forward natural gas prices are established for each supply source using various future price indexes and forecasts adjusted by economic factors that affect the natural gas market and by the Company's established purchasing practices. Then, projected purchase volumes are allocated for each source and contract instrument considering pipeline capacity constraints, current contracts, and future prices.

The Company used an authorized WACOG of $0.49211 per therm to establish last year's rates. Because the authorized rate exceeded actual gas cost, the Company over-collected about $12.2 million in revenue due to an overestimated WACOG. This amount is being netted out of the 2011 PGA filing. Through the adjusted rates, the Company will credit the over-collection back to customers over the next year.

Staff reviewed the Company's proposed WACOG in three different ways. First, Staff reviewed the Company's filing to determine if the Company's methodology and calculations were sound. Second, Staff analyzed trends in the Company's WACOG to understand if the Company's proposal is reasonable given current and future market conditions. Finally, Staff analyzed whether the proposed WACOG reasonably compares to third-party market prices.

Method and Accuracy Review

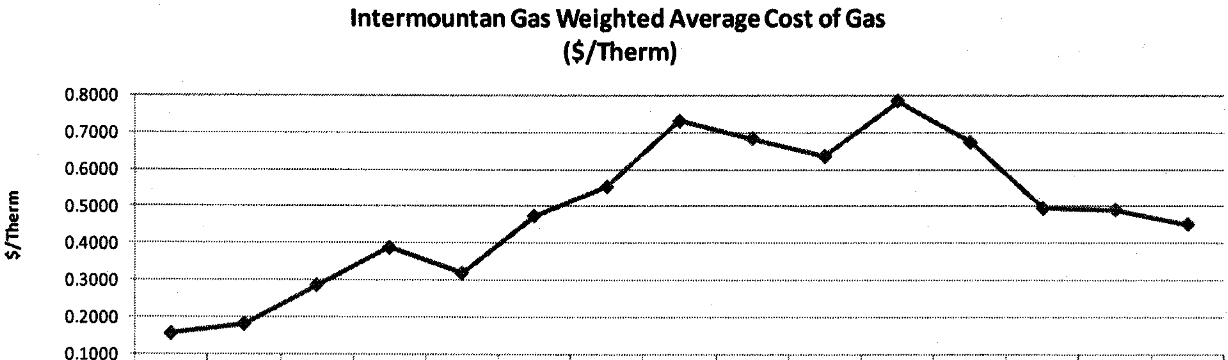
After completing the first part of the analysis, Staff concluded that the Company's methodology is sound. However, Staff makes three recommendations for next year's filing:

1. Approval of the fixed cost collection rate for the upcoming year should be done through the authorization of the Company's PGA proposal rather than through a separate approval by Staff after the PGA has been authorized. The Company should include all documents in the post PGA approval process as exhibits to the PGA filing. This will create procedural efficiency by eliminating an unnecessary extra step.
2. The basis for determining how fixed gas costs are spread across customer classes uses "peak day demand allocators" from a 1990 study. This study should be reviewed to determine if it remains valid given current conditions. However, beyond the age of the study, there are no indications the allocation is invalid and should not be used for this year's PGA application.
3. Staff auditors had difficulty locating and reviewing gas contracts and documents that the Company used to develop the WACOG. Much of the problem can be attributed to employee turnover and a lack of organization. Staff recommends that the Company establish a document control process for regulatory filings that is not person dependent.

Market Trend Analysis

After analyzing the WACOG trend given current and future market conditions, Staff concluded that a continued trend for a decrease in the Company's WACOG is valid and reasonable. As reflected in Chart 1.0, the proposed WACOG, if approved, will be the third consecutive decrease. It is about equivalent to the 2003 WACOG in nominal dollars.

Chart: 1.0

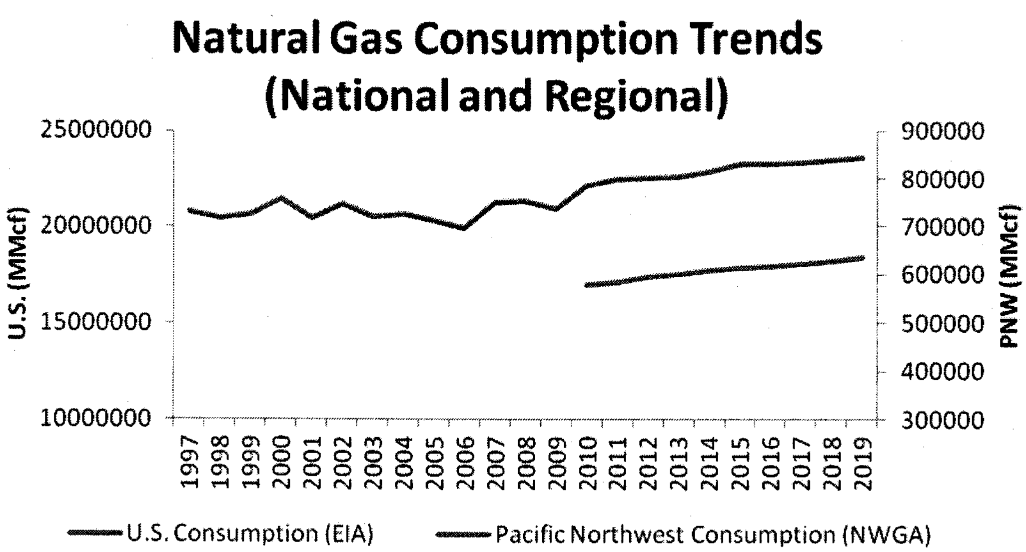


	'98	'99	'00	'01	'02	'03	'04	'05	'06	'07	'08	'08 (Dec.)*	'09**	'10	'11 (prop.)
WACOG ($/Therm)	0.1568	0.1825	0.2867	0.3880	0.3200	0.4750	0.5549	0.7322	0.6850	0.6358	0.7848	0.6748	0.4960	0.4921	0.4534
% Inc. or Dec. from Prev. Year	0.0%	16.4%	57.1%	35.3%	(17.5%)	48.4%	16.8%	31.9%	(6.4%)	(7.2%)	23.4%	6.1%	(26.5%)	(0.8%)	(7.9%)

* Percent increase based on previous year's PGA filing
** Percent decrease based on December filing

The Company's WACOG continues to decline for two reasons. First, the natural gas industry expects relatively low near-term demand growth in both regional and national markets due to lingering weak economic conditions as reflected in Chart 2.0.

Chart: 2.0



In addition, the market supply of natural gas continues to grow in spite of lower natural gas prices. This is due to reduced costs in accessing unconventional gas resources and the use of newer more advanced drilling technology.

Staff's final analysis showed that the Company's proposed WACOG is conservative but reasonably compares to other industry natural gas price benchmarks. Staff compared the Company's projected monthly cost of purchased gas used in determining the proposed WACOG to EIA's monthly forecasts[2] and to NYMEX futures prices.[3] For comparison purposes, Staff calculated two volume-weighted cost of purchased gas estimates using volume allocation percentages for the three hubs where Intermountain purchases gas.[4] The first estimate used NYMEX/NGX futures prices and differentials based on August 26th settles; the second used Company-adjusted price forecasts based on NYMEX /NGX futures prices and differentials based on August 3rd settles included in the PGA application.[5]

Chart: 3.0

This section of Staff's Comments contains confidential information

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[2] EIA, *STEO* (Sept 7, 2011 STEO), Table 5b. U.S.Regional Natural Gas Prices, (http://www.eia.gov/emeu/steo/pub/cf_tables/steotables.cfm?tableNumber=16)

[3] Prices are based on settlements that occurred on August 26, 2011.

[4] These allocation percentages are forecasts based on historical allocations supplied by the company through audit requests. These are not the same allocations used in the WACOG calculation for the PGA.

[5] Intermountain Gas is supplied by three natural gas hubs (Rockies, Sumas, & AECO). Futures settlement prices are reported daily as a price differential from the NYMEX Henry's Hub price.

The analysis, illustrated in Chart 3.0, shows the Company's monthly purchased gas cost to be generally higher than Staff's estimates, especially during the winter months. Reasons for the difference include:

- the softening of prices between the August 3rd settlement price used by the Company and the August 26th settlement price used by Staff;
- the inclusion of a small amount of variable upstream transportation costs from Canadian hubs embedded in the Company's purchased gas cost not included in Staff's estimate;
- the Company assuming future monthly spot prices to be equivalent to term index contract prices plus their adjustment factors;
- the Company allocating [redacted] of its volume to the Rockies hub during summer months (April through September) which currently has the second highest future price between the three basins (see chart 4.0 in the Pipeline Transportation section) while Staff's estimates used the Company's projected allocations which are considerably more realistic; and
- Intermountain Gas having [redacted] of its gas volume "locked in" during the winter months (October through March) through the use of hedging strategies and contracts which are currently greater than the future indexed price of gas;

Although the Company's monthly purchased gas cost is generally higher than Staff's estimates, the largest differences occur during the winter, mostly due to hedging. As discussed in the next section, Staff believes the Company struck a good balance between price stability and ability to take advantage of future bargain prices. In all, these factors combine to give Intermountain's purchased gas cost and resulting WACOG a conservative bias. Given the level of forecast error typical of future natural gas prices and EIA forecasts, the Staff considers the Company's proposed WACOG reasonable.

Risk Management and Gas Purchasing

Intermountain Gas lowered its winter hedging ratios from [redacted] (used during the previous two years) to [redacted]. This will allow the Company to buy natural gas at lower prices than purchases the Company would have obtained had it continued with previous ratios. The current situation provides an example of the continual review of risk management policies by the Company and Staff. One question to consider now relates to the proper hedging ratio. With a proposed WACOG being reduced to 2003 nominal prices, it is Staff's opinion that the Company took a conservative but appropriate position by allowing for increased opportunities to take advantage of softening prices, while maintaining sufficient protection against increased market prices.

The Company's risk management and purchasing strategies are dynamic, flexible, and allow the Company to make decisions based on fundamentals of the natural gas environment. The primary purpose of the Company's purchasing strategies is to:

- ensure availability of adequate gas supplies to customers;
- mitigate the adverse impact of significant gas commodity price movements; and
- minimize the credit risk inherent in the implementation of certain price risk reducing strategies.

The Company's Gas Supply Oversight Committee (GSOC) makes decisions by using market fundamentals and management guidelines within the "Gas Supply Risk Management Program" to evaluate the risk of price volatility to customers. This includes decisions based on weather and hurricane forecasts, storage levels, drill rig counts, new Gulf of Mexico and shale gas supplies, LNG levels, interstate pipeline transportation changes, and consumption patterns. All of these factors affect how the Company (a) executes a given hedge strategy, (b) layers-in the execution of a given hedge strategy, (c) fixes the price for a given time frame, or (d) utilizes other forms of financial pricing.

So far, the Company's ability to dynamically adapt to market conditions continues to offer customers savings and, more importantly, mitigate price volatility by hedging intelligently. For example, stagnant economic conditions and the Company's hedging strategies allowed the Company to purchase gas for less than the current WACOG set in rates during the past year. This contributed to an over-collection of approximately $12.2 million now being credited back to customers during this year's PGA.

Temporary Surcharges and Credits

Pursuant to Order No. 32077, Intermountain included temporary credits in its October 1, 2010 prices to pass back to customers deferred gas cost charges and benefits. The temporary credits consisted of three items: (1) a credit of about $3.8 million in benefits generated by releasing some pipeline transportation capacity; (2) an additional $2.1 million credit attributable to the collection of pipeline capacity costs, the true-up of expenses from the 2009 PGA, and capacity release credits generated from the release of Intermountain's pipeline capacity; and (3) the $15.6 million deferred credit balance, which is the difference from the commodity costs that Intermountain actually paid for natural gas and the WACOG that was included in rates. When the temporary credit items are totaled to account for the drop in revenue proposed by the Company, the credits total $21.5 million. In the same case, Lost and Unaccounted for Gas temporary credit deferrals were $600,000.

The new temporary credits also consist of three items: (1) a credit of about $3.7 million in benefits generated by releasing some pipeline transportation capacity; (2) an additional $5.9 million credit attributable to the collection of pipeline capacity costs, the true-up of expenses from the 2010 PGA, and capacity release credits generated from the release of Intermountain's pipeline capacity; and (3) the $12.2 million deferred credit balance, which is the difference from the commodity costs that Intermountain actually paid for natural gas and the WACOG that was included in rates. When the temporary credit items are totaled to account for the drop in revenue proposed by the Company, the credits total $21.8 million. However, when offset by the removal of prior temporaries (including Lost and Unaccounted for Gas) the reduction in revenue is $200,000. As shown on page 4, Table 2, the total reduction in revenue is $14.4 million. This is the combination of the current Lost and Unaccounted for Gas credit of $1.4 million, the proposed $12.2 million revenue reduction due to the reduced WACOG, additional fixed cost changes and the $200,000 temporary surcharges and credits discussed above.

Natural Gas Storage

Intermountain uses natural gas storage to (1) avoid high winter prices by procuring gas during the summer when prices are cheaper, and (2) provide system designed peaking capacity for unusually high demand events or backup for potential pipeline disruptions and curtailments.

Underground storage is typically used to fulfill the Company's winter storage needs and acts as a hedge to shield consumers from higher winter natural gas prices. The Company has 95 million therms in contracted underground storage capacity at Northwest Pipeline's Jackson Prairie and Questar Pipeline's Clay Basin facilities. All of this capacity will be filled going into the winter heating season. This represents [redacted] of the Company's November 2011 to March 2012 supply requirement. Through various supply agreements, these storage injections have been locked in at prices ranging from $0.4080 to $0.4871 per therm. These rates bracket this year's proposed WACOG. Any overall differences will be reconciled in customer rates next year.

The Company uses Liquid Natural Gas (LNG) storage throughout the year to meet system peaks and to supplement local flows due to pipeline congestion or curtailments. Intermountain has 18.5 million therms in total LNG storage capacity at Northwest Pipeline's Plymouth facility and two Company-owned facilities in Nampa and Rexburg, Idaho. LNG represents approximately [redacted] of the Company's total storage, however, the Company expects to keep this below capacity throughout the winter. As of September 13, 2011, the Company's LNG storage was at approximately [redacted] capacity. Storing significantly more LNG than what is expected to be used during the winter would come at an additional expense to ratepayers because of Intermountain's cost to maintain LNG at a specific temperature.

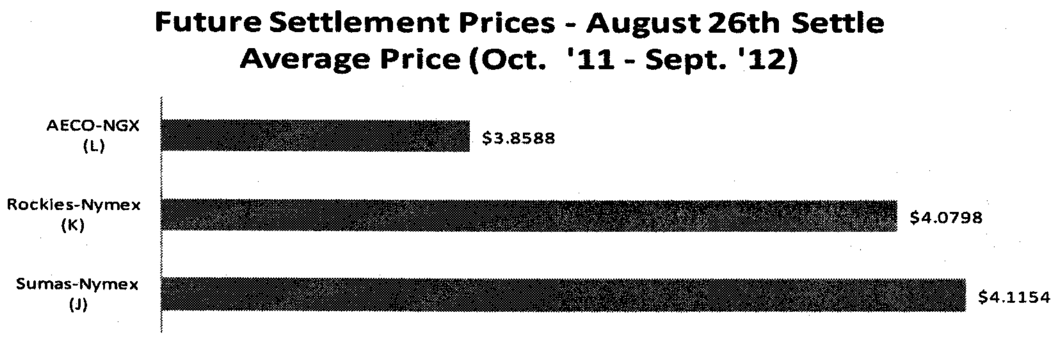
Pipeline Transportation

Intermountain delivers transported natural gas to its Idaho city gates through Northwest Pipeline, an interstate transportation provider whose pipeline runs through Intermountain's service territory. The Company also moves gas from Canada to Northwest Pipeline by utilizing capacity on Gas Transmission Northwest (GTN), TransCanada's Foothills Pipeline system (Foothills), and its Alberta system known as Nova Gas Transmission (Nova). Intermountain's pipeline capacity rates for Nova decreased in 2011, resulting in a decrease of approximately $500,000. Northwest Pipeline updated its rates effective April 4, 2011. Traditionally, Northwest Pipeline and other fuel providers change rates annually, but these annual changes do not largely affect the price Intermountain charges to customers. The pipeline transportation rate billed to Intermountain remains unchanged. Contractual terms with Northwest Pipeline increased daily volume as well as capacity costs by approximately $1 million. Capacity on these pipelines remains a key component in serving customers and maintaining supply diversity. Intermountain will also determine when its contracted interstate transportation is under-utilized due to warmer weather or declines in industrial demand. This capacity will be posted for release to others with the release payments received benefiting Intermountain customers.

Intermountain's proximity to several interstate pipelines allows it to effectively allocate its natural gas supply mix from different basins based on price differentials, and to subsequently redeliver that specified volume on its own distribution pipeline network at the lowest possible price. Intermountain has traditionally sourced a higher percentage of gas from the Rockies Basin, because of Northwest Pipeline's close proximity to the Company's service territory and lower price.

The recent completion of the Rockies Express (November 2009) and Ruby (July 2011) pipelines has opened access of Rockies Basin natural gas to the East and to the West, respectively. There are indications that this is changing the market that the Company uses to source its gas by increasing competition and price for Rockies Basin gas while decreasing competition and the price of gas out of Alberta Canada (AECO-C) as shown in Chart 4.0.

Chart: 4.0



Last year, approximately [redacted] of the Company's gas was purchased from the Rockies Basin, with the remaining [redacted] coming from Canada ([redacted] from Sumas in British Columbia; [redacted] from AECO in Alberta). This proportion is lower than in past years when the percentage from the Rockies Basin was in the [redacted] range indicating that the Company is shifting its sources in response to changing market conditions.

Recovery of Lost and Unaccounted for Gas

L&U is the difference, or variance, between the physical purchase of natural gas from suppliers and the volumes billed to customers. Intermountain asks to the recover L&U through a per therm surcharge that is considered above and beyond that which is included in Commission-approved base rates from 1985. Due to concerns that the Company's requests for L&U recovery was becoming excessive, the Commission placed a 0.85% cap on allowed L&U as a percentage of total throughput. Order No. 30649. The Commission also ordered the Company to submit quarterly reports outlining (1) the Company's framework for how it has tested for, identified, and remediated equipment measurement errors or leaks; and (2) the business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing.

Table 3.0 below shows the Company's L&U estimates submitted in the past three PGA applications along with the percentage change in these estimates experienced over the same time period.

Table: 3.0

Year	Time Period	L&U Gas[6] (Therms)	Annual Throughput[14] (Therms)	L&U (% of Throughput)	% Change from Previous Year
2007	Oct '06 - Sept '07	3,700,000	513,583,000	0.72%	n/a
2008	Oct '07 - Sept '08	4,800,000	559,313,840	0.86%	19.1%
2009	Oct '08 - Sept '09	2,414,773	531,960,560	0.45%	-47.1%
2010	Oct '09 - Sept '10	1,077,361	549,583,146	0.20%	-56.8%
2011	Oct '10 - Sept '11	-894,032	563,763,803	-0.16%	-180.9%

This year the Company is in a "found gas" position, with 894 thousand therms more of gas being metered into Intermountain's service area than were metered at the point of consumption. The Company says this can happen if measurement error occurs on the high side at Intermountain's city gates and/or on the low side at the customer's meter, even if the error is within acceptable tolerances. Because the absolute value of L&U as a percent of total yearly throughput is below what was reported last year, this may indicate that the amount of measurement error is improving and the measures the Company has put into place to improve on reducing L&U are working.

The Company has continued to meet requirements stipulated in Order No. 30649 by filing semi-annual reports mentioned earlier. One of the measures the Company has taken to identify potential leaks, identify errors, or find faulty meters is to audit and flag potentially inaccurate billing data, which can then be investigated further to determine root cause through a "check-for-dead" meter order. During 2010, the Company performed 12,441 "check-for-dead" billing audits and found approximately 4.8% of meters were dead or had drive/pressure related issues. This percentage has gone down from both 2008 and 2009, which respectively had 14.7% and 8.9% of meters with issues.

In 1985, the Commission established $0.00182 per therm as the normalized unit cost that can be collected as part of base rates. This past year, the total normalized level of L&U gas

[6] See INT-G-11-01, INT-G-09-02, INT-G-08-03, and INT-G-08-04 filing.

embedded in base rates yields an amount of $1,026,050 of L&U already collected.[7] Intermountain wants to reimburse the sum of the total estimated October 2010 to September 2011 L&U gas of $480,202 (which is negative due to its "found gas" position) and the $1,026,050 normalized level of L&U gas revenue already collected in current base rates. This yields a total of $1,506,252, which the Company asks be passed back to customers.

Staff recommends that the Commission allow the Company to refund $1,506,252 to customers for L&U requested in this PGA. This is based on amounts the Company has already collected and the amount of estimated L&U gas from this past year. Furthermore, results are showing that concerns about higher than normal L&U are being addressed. Although the Company has reduced L&U, Staff recommends that the Company continue to submit semi-annual L&U reports for review. Staff also maintains its view that losses due to errors in faulty meters or measurement control practices should not be recovered in the PGA; however, the Commission would expect the Company to file for an accounting order authorizing the Company to defer the costs of repair and the cost of lost gas in the event of a catastrophic failure. Finally, Staff recommends the Commission maintain the maximum L&U gas recovery at 0.85% of total throughput as specified in Order No. 30649.

CUSTOMER RELATIONS

Customer Notice and Press Release

The Customer Notice and Press Release were included in Intermountain's Application. The Application was received on August 11, 2011. Staff reviewed the customer notice and press release and determined they complied with IPUC Rules of Procedure 125.04 and 125.05. IDAPA 31.01.01.125. The customer notice was mailed with cyclical billings beginning August 12, 2011 and ending September 14, 2011.

Customer Comments

Customers were given until September 21, 2011 to file comments. As of September 19, one comment had been received. Although the customer misunderstood what was driving Intermountain Gas to decrease its rates, the customer was nevertheless pleased with a rate decrease.

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[7] This is shown on Workpaper No. 8 included in the Company's PGA application.

Financial Assistance for Paying Heating Bills

If approved, residential customers will see an approximate 5% decrease in their natural gas rates. Nonetheless, energy costs continue to challenge some customers. Because some customers still struggle to make ends meet, Staff would like to remind qualified customers to take advantage of the energy assistance available through the federally-funded Low Income Home Energy Assistance Program (LIHEAP) and non-profit fuel funds such as Project Share in southwestern Idaho and Project Warmth and Helping Hand in southeastern Idaho. For more information on these programs, customers may call the nearest Community Action Agency, Intermountain Gas Company, the Idaho Public Utilities Commission, or the 2-1-1 Idaho Care Line.

STAFF RECOMMENDATION

After examining the Company's Application and gas procurements for the year, Staff recommends that the Commission accept the Company's Application and filed tariffs decreasing the Company's annual revenue by approximately $14.4 million and establishing a WACOG at $0.45342/therm. Staff further recommends that the Commission continue to require semi-annual L&U gas reports and maintain a cap for L&U gas recovery at 0.85% of total throughput.

Respectfully submitted this 21st day of September 2011.

for

Karl T. Klein
Deputy Attorney General

Technical Staff: Shelby Baker
Mike Louis
Marilyn Parker

i:umisc/comments/intg11.1kkphsbmkmp comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF SEPTEMBER 2011, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-11-01, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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