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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S APPLICATION TO SELL LIQUEFIED NATURAL GAS.	**CASE NO. INT-G-13-2** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Intermountain Gas Company's ("Intermountain Gas"; "Company") Application to sell Liquefied Natural Gas.

BACKGROUND

On January 23, 2013, the Company applied for authority to sell excess liquefied natural gas ("LNG") to non-utility customers at market-based prices.[1] The Company asked for the new service to take effect on March 10, 2013. On February 1, 2013, the Commission issued a Notice of Application and Notice of Modified Procedure that suspended the proposed effective date to September 9, 2013 or until the Commission issues an earlier decision in the case. *See* Order No. 32735.

In its Application, the Company says it expects to have excess LNG capacity for the next few years. Application at 4. It proposes to sell LNG from this excess capacity, less a 50% reserve

[1] Exhibit 2 to the Application attached the Company's proposed standard contract for LNG sales. On March 14, 2013, the Company filed a substitute Exhibit 2 containing a new proposed standard contract. These comments address the Application as modified by the substitute Exhibit 2.

margin, to non-utility customers until system growth requires the Company to use its entire LNG capacity to meet core market peak-day needs. *Id.* For the near future, however, the Company says it can meet utility-customer needs and still have enough LNG to provide an extra 6 million therms (or 7.3 million gallons) of LNG for year-round non-utility sales. *Id.* at 5. The Company says it will use any and all stored LNG to first satisfy utility-customer demand even if that LNG was initially designated for non-utility use. *Id.*

The Company says that non-utility customers must sign a contract before buying LNG. The Company says the contract will protect utility customers from financial risk, and the Company from risks arising after the LNG is transferred to the non-utility customer. The contract also will ensure that only surplus LNG is available for sale under the new service. *Id.* at 6.

The Company says it will accept all financial risk of the venture. Further, it will insulate utility customers from any costs associated with non-utility sales by separately accounting for any quantities of natural gas liquefied for non-utility sales and tracking all related costs independent of utility costs. The Company will separately identify all costs associated with non-utility sales deferring all amounts benefiting utility customers until the next Purchased Gas Cost Adjustment ("PGA") case.[2] The Company then will provide actual sales calculations to Commission Staff during the annual PGA audit. *Id.* at 4-5.

The Company proposes to pass the benefit of reduced operating costs to its firm customers. The Company proposes a 2.5¢ credit per each gallon sold to recover any direct operations and maintenance ("O&M") costs that may result from non-utility LNG sales. The Company expects that the booked credit amounts ultimately will offset base-utility O&M over and above the O&M related to non-utility sales. *Id.* at 5-6. The Company also acknowledges that increased use of the LNG facility may accelerate capital expenditures or increase maintenance costs at the Nampa facility. *Id.* at 6. The Company thus proposes to set aside another 2.5¢ per each gallon of LNG sold to defray any such costs. *Id.*

The Company proposes to share all net margins from LNG sales on a 50/50 basis with utility customers through the PGA deferral mechanism. *Id.* at 6. The ratepayer part of net margins would be deferred as credits in a new deferral account and passed back to applicable sales and firm

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[2] The PGA or "Purchased Gas Cost Adjustment" mechanism is used to adjust rates to reflect annual changes in the Company's costs for the purchase of natural gas from suppliers – including transportation, storage, and other related costs.

transportation customers in a similar manner to other peaking demand costs during the next PGA. *Id.*

The Company says its proposal will not increase utility customer rates. It could, however, potentially decrease the future prices that the Company's sales customers pay when the projected deferred credits become part of future PGA filings. *Id.*

STAFF REVIEW

Staff's review of the Company's Application focused on six areas: (1) the LNG market and market pricing; (2) the Company's capacity to produce LNG; (3) the costs associated with producing LNG; (4) the sharing of potential benefits to core customers; (5) the allocation of benefits to core customer classes; and (6) the standard contract to be used to minimize risk to utility customers. Details of the analysis and justification for Staff recommendations are found in the following sections.

Market Price Analysis

Staff analyzed the LNG market in detail. Staff's largest concern is how the Company proposes to set prices and how the price will impact LNG customers. Staff believes customers will not be harmed so long as the Company sets market-based prices.

Although the Company has stated that prices will be market based, its proposed method for setting prices combines cost and market-based factors. Intermountain Gas plans to base its price off the first-of-month index price of natural gas (published by Platts or FERC) and charge a margin adder sufficient to cover its costs, make a reasonable profit, and place the price within the range of LNG market prices. While the Company's pricing method does not differentiate between retail and wholesale customers, Staff believes the Company's proposal provides flexibility to adjust margin adders resulting in either a wholesale or retail market price.

Retail market prices are readily available since they are indexed off the price of diesel fuel offset by a discount; however, there are currently no public exchanges trading LNG that would allow transparency to establish a wholesale market price. Because the market and the selling of LNG are in their infancy, Staff believes it is unlikely that harm from potential uncompetitive pricing will arise in the short-term. But if the market develops and barriers-to-entry occur due to monopolistic pricing, then the Company and the Commission should remain open to changing the framework for selling LNG.

Capacity Analysis

Staff analyzed whether the Company's LNG production and storage capabilities have sufficient capacity to meet the Nampa facility's peak-shaving needs while selling LNG to non-utility customers. Based on its analysis, Staff believes the following:

1) The Company has sufficient idle capacity at its Nampa facility to sell LNG to third parties; and
2) The Company could sell LNG indefinitely into the future as long as a market exists and the facility continues to operate consistent with the peak-supply role it plays in the Company's system.

The Company's Nampa LNG facility was constructed in 1976 to meet extreme peak demand periods and emergency situations due to system integrity issues. The facility has the capacity to liquefy 42,000 gallons per day and store over 7 million gallons of LNG (vaporization capacity is not an issue for this analysis because it is not required to sell LNG).[3] The facility was designed to meet peak winter weather and temperature extremes during the coldest five-day period of the coldest year over the last 30 years. Because of cost considerations and time required to liquefy sufficient quantities of LNG for winter-peaking purposes, gas is only withdrawn when all other forms of flowing gas and gas storage have been utilized.

Because of the facility's peak-supply role, the Company believes there is enough excess capacity to sell LNG on the open market while maintaining capability to meet the facility's intended purpose. Staff's analysis is reflected in Table 1 below. It illustrates the capacity available for LNG sales given different percentages of storage levels covering the actual range at the Nampa facility over the last four years ranging from 50 to 78 percent.[4]

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[3] *See* Intermountain Gas 2011 Integrated Resource Plan, P. 57 (12.1 gallons/Dth conversion rate)

[4] Due to additional costs to maintain LNG at a specific temperature, the Company only stores enough LNG to meet expected use during the winter months. The percentages of utilized storage capacity reported in Staff's comments over the past 4 PGA's are: 50% in INT-G-12-01, 78% in INT-G-11-01, 59% in INT-G-10-03, and 59% in INT-G-09-02.

Table 1

Percent Storage Capacity Required to meet System Peak	50%	60%	70%	80%	90%	100%
LNG Required for System Peak	3.5	4.2	4.9	5.6	6.3	7.0
Max Sales Capacity (net of winter storage needs)	11.9	11.2	10.5	9.8	9.1	7.7
Twice-thu-cycle Sales Capacity (net of winter storage needs)	10.5	9.8	9.1	8.4	7.7	7.0

(Million of Gallons)

Staff determined the Company could sell a maximum of between 7.7 and 11.9 million gallons of LNG based on total liquefaction capacity net of capacity needed to fill winter storage requirements. However, the ability to utilize 100% of idle liquefaction capacity could be limited by potential up-stream capacity shortages during winter months or down-stream blocking conditions caused by fully utilized storage capacity and inconsistent LNG sales. Therefore, Staff believes an estimate of between 7 and 10.5 million gallons is more realistic based on an annual, twice-through fill cycle[5].

Staff believes the ability to sell LNG from the Nampa facility is not limited by growth of core market needs as suggested in the Company's Application. For winter peaking needs, the constraining resource is the size of the storage tank. But Staff believes the ability to continue selling LNG hinges on the amount of liquefaction capacity available, not on the utilization of the storage tank. LNG sales only require sufficient storage capacity to buffer the sale of tanker truck loads in up to 10,000 gallon increments. As Staff's analysis shows, even when 100% of the storage tank is needed for peak winter months, the Company still can use about 7.0 million gallons of liquefaction capacity for LNG sales.

Cost Analysis

Staff reviewed the Company's plans to insulate utility customers from cost resulting from LNG sales. As a result of its analysis, Staff identified several important findings and made a number of recommendations as listed below:

1) The method the Company proposes to pay for future capital cost due to additional wear and tear is reasonable but the amount of 2.5¢ per gallon should be audited during future PGA filings and adjusted as needed;

[5] A twice-through fill cycle assumes the storage tank can be filled twice annually with one of the cycles partially used to meet winter peak. The remainder would be available for sales of LNG on the open market.

2) Staff believes the method the Company proposes to pay for O&M cost related to producing and selling LNG allows the Company to double recover costs. Staff recommends that 100% of the 2.5¢ per gallon for O&M be credited to customers for each gallon sold. However, these costs should be tracked and the method and amounts should be adjusted based on actual operation;
3) The method the Company proposes to separate purchases of natural gas for utility and non-utility customers and resolve monthly imbalances should ensure gas purchases for LNG sales minimize any adverse affect on the cost of gas for utility customers; and
4) Staff recommends that actual purchased gas cost for LNG be tracked and reported separately in the Company's quarterly Weighted Average Cost of Gas ("WACOG") report.

Staff's analysis focused on three elements of cost affected by the sale of LNG: capital cost, O&M cost, and the cost of purchased gas. In traditional cost-based regulation methods, capital costs are recovered through rates based on a depreciation schedule over the facility's useful life. If LNG customers were a separate class, they would be expected to pay their share of depreciated capital cost plus the authorized rate of return. However, the Nampa LNG facility, except for some recent minor upgrades, is fully depreciated.[6] In cases when the useful life of a large asset is exceeded but still in operation, the only remaining capital costs are small capital acquisitions to maintain the overall operation of the asset due to wear and tear. Because the sale of LNG is not purely based on cost of service, the Company has proposed to instead set aside 2.5¢ for every gallon sold into a separate account to cover the cost of future incremental capital replacement cost. This account's funds will be withdrawn and used to replace capital equipment as needed due to increased wear and tear from LNG sales.

Staff believes this is an equitable and reasonable method to cover this type of cost. But Staff also believes that these funds should only be used for capital replacement costs of existing equipment and not to buy extra capacity or improve currently functioning equipment. Staff also recommends that all purchases using these funds be audited during the Company's yearly PGA and the per gallon amount adjusted as required. If the account balance becomes unreasonably large, the Commission should also consider crediting a portion of the funds back to utility customers.

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[6] *See* Order No. 28311, Case INT-G-99-02; Order No. 32427, Case INT-G-11-02.

O&M is the second category of cost incurred from the sale of LNG. Examples of this cost include liquefying LNG, filling tanker trucks, and performing additional maintenance on the facility as a result of selling LNG. The Company has proposed to directly assign these costs as an LNG cost and pay for them with funds from an account that accumulates 2.5¢ per gallon of LNG sold.

Staff believes that the Company's method allows the Company to double-recover a portion of O&M cost. As described previously, the Company only uses and staffs the Nampa facility to meet infrequent peak-demand situations. Staff believes initial incremental quantities produced and sold as LNG will more fully utilize idle resources, which are theoretically included in or "internal" to base rates. Because it is difficult to separate "internal" costs from incremental costs, Staff believes the Company should err on the side of utility customers by crediting 100% of the 2.5¢ per gallon O&M cost to customers for more fully utilizing existing resources.

In conversations between Staff and the Company, the Company has concurred with Staff's recommended treatment of O&M. However, Staff also recommends the Company track all LNG sales-related actual costs to determine how much of the total cost is "internal" to current O&M resource cost and how much is incremental so that more accurate figures can be determined. Staff recommends this be reviewed in subsequent PGAs and the amount be adjusted accordingly. Staff also believes, after reviewing actual cost, that it may be better to modify the overall method by crediting customers a fixed amount for "internal" O&M cost, while accounting for incremental O&M on a cost per gallon basis.

The final cost element is the cost of natural gas purchased to produce LNG for sale to non-utility customers. Staff's largest concern is ensuring incremental gas purchased for LNG sales does not adversely affect the cost of gas consumed by utility customers. In response to a Staff information request, the Company says it plans to track all purchases of natural gas for non-utility sales separate from purchases used for utility sales.[7] In cases where there are monthly imbalances between nominations and daily usage, the Company plans to adjust the utility and non-utility accounts by purchasing shortages at the actual monthly WACOG or by selling any overage at the lesser of the actual non-utility cost or a price not to exceed the utility's actual monthly WACOG. Adherence to this methodology alleviates Staff's concern. In order to provide transparency, Staff

[7] *See* Production Request Nos. 9 and 14, INT-G-13-02

recommends that the Company's quarterly WACOG reports separate the balances for non-utility and utility sales.

Benefit Analysis

Intermountain Gas proposes sharing 50% of all net margins from the sale of LNG with utility customers. Staff evaluated the Company's proposal and came to the following conclusions:

1) Even with a 50/50 sharing percentage, the sale of LNG benefits both the Company and utility customers; and
2) The sharing of net margin should be adjusted to be more in-line with current sharing percentages applied to net power costs in other Idaho utilities' Power Cost Adjustment (PCA) mechanisms. Staff recommends net margins be shared 70% to customers and 30% to the Company.

The sale of LNG is analogous to off-system sales of electricity. Idaho electric utilities currently reduce their customers' net power costs by selling surplus electricity on the open market. To encourage the utility to maximize net benefit from off-system sales (and other operational behaviors reducing customer rates), the Commission allows the utility to share net benefits with its customers through annual PCAs. In the case of Idaho electric utilities, the utility is allowed to keep 5 to 10% of the net benefit.

Although 95/5 or 90/10 sharing is reasonable for electric utilities and provides a benchmark for sharing net margin of LNG sales, Staff believes the amount of risk Intermountain Gas will incur is likely higher than a utility transacting off-system sales of electricity. It is inherently more risky because: (1) the LNG market is in its infancy; (2) LNG customers have incurred large amounts of debt by investing in LNG infrastructure, which affects their credit worthiness; (3) LNG sales can be more volatile and uncertain than off-system electricity sales due to unforeseen market conditions; and (4) the Company must buy gas to be converted to LNG several weeks before it receives payment for delivered LNG. These combined factors make it more likely that customers will default on LNG orders, payments, or both, which can lead to losses that the Company has agreed to fully absorb. Staff believes this additional risk entitles the Company to receive a higher share of reward than that received by electric utilities.

However, the Company's utility customers also have a stake in the outcome. Utility customers have removed any capital risk by paying for all LNG infrastructure necessary for the

Company to produce and sell LNG. Because of the facility's large capital cost, Staff believes the capital risk alleviated by ratepayer investment is more than all other risk the Company is likely to absorb, and that ratepayers therefore deserve more than 50% of the benefits the Company has proposed in its Application. Based on this rationale, Staff believes the Company's share in benefits should be between the 50% proposed by the Company and the 10% used in electric utility PCAs. The table below shows the amount of O&M and profit margin the Company and utility customers will share given various sharing percentages. These figures are based on assumptions contained in Exhibit 1 of the Company's Application and in Staff's capacity analysis contained in Attachment A.[8]

Table 2

Company Share Percentage	50%	40%	30%	20%	10%
Total Annual Net Margin (based on twice-through fill cycle)	$3,512,536	$3,512,536	$3,512,536	$3,512,536	$3,512,536
Utility Ratepayer O&M Reimbursement	$228,087	$228,087	$228,087	$228,087	$228,087
Utility Ratepayer Share of Margin	$1,756,268	$2,107,521	$2,458,775	$2,810,029	$3,161,282
Total Utility Ratepayer Benefit	$1,984,355	$2,335,608	$2,686,862	$3,038,115	$3,389,369
Company Share of Margin	$1,756,268	$1,405,014	$1,053,761	$702,507	$351,254

Staff recommends the sharing percentage be set at 30% to the Company and 70% to customers for no other reason than it is the halfway point of the range. This could provide roughly $1 million annually to the Company and roughly $2.7 million in total net benefit to utility customers. Staff also encourages the Company to gather actual data to quantify the Company's risk and propose changes to the sharing percentage if appropriate.

Class Allocation of Benefits

Staff has reviewed the Company's proposed method of allocating shared benefits back to customer classes and believes it to be fair and reasonable. The percentages are based on peak-day allocators used to allocate demand charges as illustrated in Exhibit 3 of the Company's Application. It includes transportation customer classes (T-4 and T-5) because a portion of LNG facility costs are included in transportation customer base rates. The Company plans to credit the utility customers' shares of profit margin to a deferral account each month and allocate them to each applicable rate

[8] Sales are based on maximum utilization of liquefaction capacity based on a twice-through fill cycle, 70% of storage required for peak-shaving purposes, and a liquefaction rate of 42.3 thousand gallons/day.

class in future PGA filings. Staff believes this method should also be used to allocate the 2.5¢ per gallon O&M reimbursement.

Analysis of Standard Contract

Because of the short lead time potential customers will need to take delivery of LNG once a contract is signed, the Company is requesting the Commission pre-approve a standard contract. The request and a copy of the standard contract are included as Exhibit 2 to the Application. *See* footnote 1, above. Staff has reviewed the contract and has come to the following conclusions and recommendations:

1) Staff believes the standard contract contains all the necessary provisions to execute the sale of LNG aligned to the expectations and method stipulated in the Company's Application;
2) Staff recommends that the standard contract be approved as part of the overall Application; and
3) Subsequent approvals of individual contracts are not necessary as long as the standard contract is utilized or the contract used is not materially different from the standard contract.

Each contract is structured with an extendable three-year term. Individual purchases are executed using a transaction confirmation that identifies aspects of the transaction that can vary but are bounded by terms and conditions in the contract. Included in the transaction confirmation is the price (index price of gas plus a margin adder), additional costs the buyer is obligated to pay, the quantity, whether the sale is firm or non-firm, and the amount of liquidated damages the seller or buyer agrees to pay for not delivering or not taking delivery, respectively.

According to the Company, the contract will "protect utility customers from any financial risk, the Company from any operational difficulties or risk after LNG is transferred to a non-utility customer, and ensures that only surplus LNG would be available for sale under this new service."[9] Staff believes a contract can never completely shield the Company from potential risk. If sufficient harm comes to the Company, it can affect the Company's ability to attract low-cost capital for future reinvestment in the utility, which can potentially harm utility customers. However, through

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[9] *See* Application, INT-G-13-02, p. 6.

the contract's terms and conditions, Staff believes the Company has sufficiently minimized risk to its core customers and to the Company. Through its contract analysis, Staff believes the contract: (1) ensures that LNG buyers assume all risk due to buyer equipment malfunction and for any expense or risk after the point of delivery; (2) allows the Company to refuse to deliver LNG to potential buyers who pose a safety risk, risk of default, or generally cannot adhere to any provision in the contract; (3) obligates the Company to deliver LNG only if there is sufficient LNG to meet core customer peak-shaving needs; and (4) relieves the seller (and buyer) of obligations due to Force Majeure.

STAFF RECOMMENDATIONS

After a thorough review of the Company's Application, Staff recommends that the Commission approve the Application with the following additions and changes:

1. Require the Company to obtain Commission approval for any contracts to sell LNG that materially differ from the standard contract;
2. Limit the Company's use of future capital expense funds to the replacement of existing Nampa Plant Capital Infrastructure due to accelerated wear and tear from producing LNG for sale. Recovery of incremental capital expense required to increase capacity or improve existing capital infrastructure must be done separately through standard Commission approval processes and procedures;
3. Require the Company to provide a 2.5¢ credit for every gallon of LNG sold for O&M related expenses and pass through 100% of this amount to utility customers through the PGA using the same class allocation method proposed to distribute shared net margin. The Company concurs with this recommendation;
4. Require the Company to credit 70% of total net margin to ratepayers for sales of LNG through the PGA, allowing the Company to keep 30%;
5. Require the Company to prepare a review of all costs and benefits as a result of selling LNG as part of the annual PGA filing;
6. As part of the next IRP filing, require the Company to prepare a review of the method and framework for selling LNG and whether the Company should continue to sell it; and
7. Require the Company to separately track actual purchased gas cost for LNG sales and report the results in the Company's quarterly WACOG report.

Respectfully submitted this 18th day of March 2013.

Karl T. Klein
Deputy Attorney General

Technical Staff: Mike Louis

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Capacity Analysis of LNG facility

	Capacity Assumptions:				Notes:
1	LNG Gallon Conversion Rate (Gal/Dth)	12.10009			Exhibit 1 of Application
2	Std. Tanker Size (gallons LNG)	10,000			
3	Days of operation	365			
4	Number days of winter peak requirements	183			
5	Storage space required to liquify (Gal)	10000			
6	In-kind Mainline to Citygate Fuel Rate (%)	1.40%			Exhibit 1 of Application
7	Estimated Liquefaction Fuel (%)	22.00%			Exhibit 1 of Application
		Dth	**Gallons**	**Truckloads**	
8	Total Nampa Storage Capacity	580,000	7,018,053	702	2011 Intermountain IRP
		Dth/day	**Gals/day**	**Trcklds/day**	
9	Max. Liquifaction Rate	3500	42350	4.24	2011 Intermountain IRP
10	[1]Max. Vaporization rate	60000	726006	72.60	2011 Intermountain IRP
	Unit Cost Assumptions:	**$/Dth**	**$/Gal**	**$/Trckld**	
11	Estimated Mainline Gas Cost	$3.000	$0.2479	$2,479	Exhibit 1 of Application
12	In-kind Mainline to Citygate Fuel Rate Cost	$0.043	$0.0035	$35	= line 11 x line 6/(1- line 6)
13	Commodity Transport Cost	$0.032	$0.0026	$26	Exhibit 1 of Application
14	Reservation Transport Cost	$0.041	$0.0034	$34	Exhibit 1 of Application
15	Delivered Cost at Nampa	$3.11540	$0.257	$2,575	= line11+line12+line13+line14
16	Liquifaction Fuel Cost	$0.68539	$0.0566	$566	= line15 x line 7
17	Cost of LNG	$3.801	$0.314	$3,141	= line15 + line16
18	O&M Recovery	$0.303	$0.025	$250	Exhibit 1 of Application
19	Future Capital Cost Recovery	$0.303	$0.025	$250	Exhibit 1 of Application
20	Dlvd Cost of LNG at Nampa fueling Station	$4.406	$0.364	$3,641	= line17+line18+line19
21	Estimated Sales Price Adder	$4.659	$0.3850	$3,850	Exhibit 1 of Application
22	Estimated Sales Price	$9.064	$0.749	$7,491	= line20 + line21

Percent Storage Capacity Required to meet System Peak	50%	60%	70%	80%	90%	100%
LNG Required for System Peak (dekatherms)	290,000	348,000	406,000	464,000	522,000	580,000
LNG Required for System Peak (Gal.)	3,509,027	4,210,832	4,912,637	5,614,443	6,316,248	7,018,053
LNG Required for System Peak (truckloads)	351	421	491	561	632	702
Days to fill Storage Rqd for System Peak	83	99	116	133	149	166
Days to Empty Storage	5	6	7	8	9	10
Capacity Availability for LNG Sales						
Winter Storage Available for LNG Sales (gallons)	3,509,027	2,807,221	2,105,416	1,403,611	701,805	-
Days available for Liquifaction for LNG Sales	282	266	249	232	216	183
Max Sales Capacity (net winter storage needs - Gal.)	11,948,841	11,247,035	10,545,230	9,843,425	9,141,619	7,728,934
Twice-thu-cycle Sales Capacity (net winter storage needs - Gal.)	10,527,080	9,825,275	9,123,469	8,421,664	7,719,859	7,018,053
Sales Based on Maximum Capacity						
Total Revenue	$8,951,020	$8,425,289	$7,899,558	$7,373,827	$6,848,096	$5,789,837
Delivered cost	$4,350,716	$4,095,180	$3,839,644	$3,584,109	$3,328,573	$2,814,197
Net Margin	$4,600,304	$4,330,109	$4,059,914	$3,789,719	$3,519,523	$2,975,639
Sales Based on Twice-through-cycle capacity						
Total Revenue	$7,885,961	$7,360,231	$6,834,500	$6,308,769	$5,783,038	$5,257,308
Delivered cost	$3,833,036	$3,577,500	$3,321,964	$3,066,429	$2,810,893	$2,555,357
Net Margin	$4,052,926	$3,782,731	$3,512,536	$3,242,341	$2,972,146	$2,701,951
Rate Payer Share based on Twice-through-cycle Capacity						
O&M Reimbursement	$263,177	$245,632	$228,087	$210,542	$192,996	$175,451
Rate-payer Share of Margin plus O&M						
50%	$2,289,640	$2,136,997	$1,984,355	$1,831,712	$1,679,069	$1,526,427
60%	$2,694,932	$2,515,270	$2,335,608	$2,155,946	$1,976,284	$1,796,622
70%	$3,100,225	$2,893,543	$2,686,862	$2,480,180	$2,273,498	$2,066,817
80%	$3,505,518	$3,271,816	$3,038,115	$2,804,414	$2,570,713	$2,337,012
90%	$3,910,810	$3,650,090	$3,389,369	$3,128,648	$2,867,927	$2,607,207
Company Share based on Twice-through-cycle Capacity						
Company Share of Margin						
50%	$2,026,463	$1,891,365	$1,756,268	$1,621,170	$1,486,073	$1,350,975
40%	$1,621,170	$1,513,092	$1,405,014	$1,296,936	$1,188,858	$1,080,780
30%	$1,215,878	$1,134,819	$1,053,761	$972,702	$891,644	$810,585
20%	$810,585	$756,546	$702,507	$648,468	$594,429	$540,390
10%	$405,293	$378,273	$351,254	$324,234	$297,215	$270,195

[1] Rate is bounded by how fast distribution system can absorb vaporized gas.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **18TH** DAY OF MARCH 2013, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-13-02, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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