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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	)))))))	**CASE NO. INT-G-22-07**

DIRECT TESTIMONY OF RONALD J. AMEN

FOR INTERMOUNTAIN GAS COMPANY

DECEMBER 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Intermountain Gas Company ("Intermountain" or "Company").

II. STATEMENT OF QUALIFICATIONS

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 24 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing; competitive market analysis; regulatory planning and policy development; resource planning and acquisition; strategic business planning; merger and acquisition analysis; organizational restructuring; new product and service development; and load research studies. I have prepared and presented expert testimony before utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Exhibit 1 to my testimony.

Q. Have you previously testified before the Idaho Public Utilities Commission?

A. No.

III. PURPOSE OF TESTIMONY

Q. Please summarize your testimony.

A. First, I will present the load study analysis for purposes of determining each customer class's contribution to the system's peak load. Next, I present the development of the Company's allocated Cost of Service Study ("COSS") for the test year ended December 31, 2022, including a comprehensive overview of the schedules created in support of them. Finally, I present the Company's proposed rates and the resulting customer bill impacts based on the Company's requested revenue increase.

My testimony consists of the following topics:

- Load Study and Analysis
- Theoretical Principles of Cost Allocation
- Intermountain's COSS
- A Summary of the COSS Results by Rate Class
- Determination of Proposed Class Revenues
- Rate Design
- Customer Bill Impacts

Q. Are you sponsoring any exhibits to your direct testimony?

A. Yes. I am sponsoring the following 5 Exhibits, all of which were prepared by me or under my supervision and direction.:

Exhibit 1 – Resume of Ronald J. Amen

Exhibit 2 – Cost of Service Study

Exhibit 3 – Proposed Revenue Targets

Exhibit 4 – Proposed Rate Design and Proof of Revenue

Exhibit 5 – Customer Bill Impacts

I. LOAD STUDY AND ANALYSIS

Q. What is a load study?

A. A load study determines each customer class's contribution to the natural gas utility's pipeline system peak load. This information is used to develop allocators for purposes of allocating shared costs, or costs that cannot be directly assigned, such as plant and equipment, operation, and maintenance expenses ("O&M"), and some administrative costs to each customer class on the basis of peak day usage. Natural gas pipeline systems are designed and constructed to satisfy peak day demand under design weather conditions and a load study identifies each class's relative contribution to the peak day demand.

Q. Did Intermountain develop a load study in its previous general rate case proceeding, No. INT-G-16-02 ("2016 Case")?

A. No. In its last case, the Company reported that it did not have adequate data to perform a detailed load study. Instead, the Company estimated peak demand for each class by deducting known daily metered industrial and transportation demand from its aggregate peak to arrive at the peak demand for the non-daily metered residential and commercial classes. The Company then allocated between residential and commercial classes on the basis of peak month usage. A load study requires sufficient data for each class to determine the response of load in a particular class to changes in heating degree days ("HDD"). In its last general rate proceeding, the Commission found that the Company lacked sufficient data to definitively allocate the revenue requirement between its non-daily metered classes.[1] As such, the Commission determined that a gradual move of 50% towards cost-of-service was reasonable and warranted for the affected customer classes.[2] Lastly, the Commission encouraged the Company to participate with Staff and other interested parties to determine the best way forward as it relates to class cost-of-service and the acquisition of appropriate cost causation and load data.[3]

Q. Has Intermountain acquired sufficient data to develop a load study in this filing?

A. Yes. The Company has dramatically expanded its daily metering capability through Advanced Metering Infrastructure ("AMI"). Table 1 below shows the availability of daily metered data for the residential and commercial classes for each of Intermountain's seven distinct weather zones. Intermountain also had AMI in place for many of its Large Volume ("LV") customers, (Large Volume, Transport, and Interruptible Transport), however those classes yielded weak regression results due either to lack of weather sensitivity, lack of available data or small number of customers, and as a result, daily metered data for those classes was not relied upon for projecting peak load for the LV customers.

Table 1 Percent of Residential and Commercial Premises with Daily Meter Readings

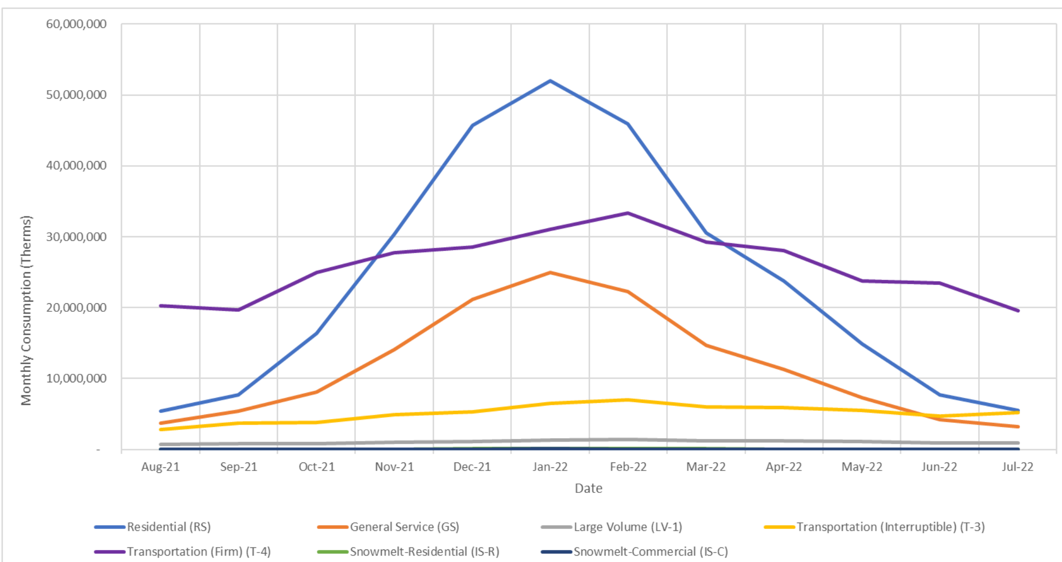
	350 Canyon County	450 Boise	500 Sun Valley	600 Twin Falls	700 Rexburg	750 Idaho Falls	800 Pocatello
Residential	93.2%	84.6%	35.3%	0.0%	45.2%	0.0%	0.0%
Commercial	95.2%	87.4%	48.2%	0.0%	58.3%	0.0%	0.0%

Q. Please describe the characteristics of Intermountain's gas load.

[1] Idaho PUC Order No. 33757, Case No. INT-G-16-02 (April 28, 2017) at 28.
[2] Ibid.
[3] Id., at 28-29.

A. Intermountain serves customers throughout a geographically and economically diverse service territory. There are seven primary rate classes (Residential ("RS") Commercial ("GS"), Large Volume ("LV-1"), Transport ("T-4"), Interruptible Transport ("T-3"), Interruptible Snowmelt-Residential ("IS-R"), and Interruptible Snowmelt-Commercial ("IS-C")). Intermountain's customers are spread across seven diverse geographic areas with differing weather patterns and elevations (Canyon County, Boise, Hailey (or Sun Valley), Twin Falls, Rexburg, Idaho Falls, and Pocatello). Below is a chart showing total monthly consumption for each rate class for the twelve months ended July 31, 2022.

Figure 1 Intermountain Monthly Consumption by Rate Class



Intermountain's Residential and Commercial customers are weather sensitive and are spread across all seven weather zones. The Company's Large Volume customers are made of a mix of industrial and commercial loads and use in excess of 200,000 therms per year. These customers may be subject to one of three rate classes: a bundled sales tariff (LV-1), a distribution system only transportation tariff (T-4), and an interruptible transportation tariff (T-3). The LV customers, on average, account for roughly 50% of Intermountain's annual throughput and approximately 25% of the projected design peak day. The vast majority of the LV throughput reflects distribution system-only transportation and as a whole the LV gas usage pattern is not weather sensitive. The Company has Residential Interruptible Snow Melt Customers, which are separately metered from the premises and are fully interruptible with at least two hours of notice. Similarly, there are Small Commercial Interruptible Snowmelt Service customers that are also interruptible with two hours of notice. Lastly, the Company has Irrigation Customers, which do not contribute to the winter peak and do not factor into the load study.

Table 2 below provides a summary of premises and annual consumption projected for the test year ended 2022 as a percentage of Intermountain's whole system throughput.

Table 2 Test Year Premises and Consumption Data for Intermountain's Gas System[4]

	Premises	% Premises	Test Year Consumption (Therms)	% Consumption
Residential	368,350	91.23%	282,067,442	35.03%
Commercial	34,966	8.66%	137,726,944	17.11%
Large Volume	34	0.01%	13,566,644	1.69%
Transport	102	0.03%	41,523,144	5.16%
Interruptible Transport	7	0.00%	329,449,906	40.92%
Residential Snowmelt	220	0.05%	455,543	0.06%
Commercial Snowmelt	53	0.01%	269,444	0.03%
Irrigation	9	0.00%	71,505	0.01%
TOTAL	**403,742**	**100.00%**	**805,130,573**	**100.00%**

Q. How does the Company define its design day?

A. The Company's design day represents the coldest temperatures that can be expected to occur during an extreme cold or peak weather event. Intermountain used a statistical model to

4 Based on average monthly customers and total therms projected for the test year (January 2022 – December 2022) with actuals through September 2022 and projected thereafter.

develop probability-derived peak HDD values to characterize its design day, corresponding to an exceedance probability that Intermountain considers appropriate for its intended use. Intermountain used exceedance probability results to review data associated with both a 50-year and 100-year probability event, as shown below in Table 3. The Company's practice has been to rely on a 50-year probability event, which results in a 78 heating-degree-day ("HDD"), for use in the design weather model.

Table 3 Peak Day HDD65 Event by Region

	350 Canyon County	450 Boise	500 Sun Valley	600 Twin Falls	700 Rexburg	750 Idaho Falls	800 Pocatello	Total Company
50-Year Event	**78**	**75**	**82**	**77**	**88**	**87**	**82**	**78.43**
100-Year Event	81	79	85	80	91	89	85	81.75
Max Degree Days5	83	81	88	80	92	88	83	82.88

Q. Please describe the methodology and approach for developing the Peak Load Study.

A. The development of the Peak Load Study began by performing regression analyses to identify weather sensitive loads, measuring the historical linear relationship between metered daily volumes and HDD for each customer class and weather zone. Regressions were performed on all available daily AMI data, and on monthly billing data, for the period from January 1, 2019, to July 31, 2022, regressing heating degree days (using 65 degrees as the baseline) against average daily use per customer for each customer class and weather zone combination. The daily AMI reads were in CCF, so it was necessary to apply a monthly billing adjustment factor for each rate class, month, and weather zone to account for the heating value and pressure to arrive at delivered therms. The goal is to project the design day

[5] Max Degree Days reflect the coldest day on record.

peak, i.e., the 50-year event using the results of the linear regression equations or another reasonable estimate of peak load by rate class. The regression results were relied upon to project design day load for the residential and commercial classes, or "Core"[6] customer classes. For the large volume classes, either due to lack of weather sensitivity (LV-1), lack of consistent and strong regression results (T-4), or due to lack of data (T-3), other means of estimating peak day results were used.

Q. Please describe the regression analyses using daily AMI metered data for the residential and commercial customer classes and the development of the "Blended" peak load sendout model.

A. As indicated in Table 1 above, there is significant penetration of daily AMI meters for the residential and commercial classes for two primary weather zones, 350 Canyon County (93.2% residential ("RS") and 95.2% commercial ("GS")); and 450 Boise (84.6% RS and 87.4% GS). There was moderate penetration of daily AMI meters for two additional weather zones 500 Sun Valley (or Hailey) (35.3% RS and 48.2% GS); and 700 Rexburg (45.2% RS and 58.3% GS). There were no daily AMI data for residential or commercial classes for Twin Falls (600), Idaho Falls (750); or Pocatello (800)[7]. The results of the daily regressions are listed below in Table 4

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[6] Core customers is defined in Intermountain's 2021-2026 IRP as, "All residential and commercial customers of Intermountain Gas Company. Includes all customers receiving service under the RS and GS tariffs."

[7] Pocatello did reflect data for one daily metered residential customer with intermittent usage in December 2019, but that customer did not bring the percentage of daily metered customers above zero.

Table 4 Daily Regression Results (January 2019 – July 2022)

Regression Results	350	450	500	600	700	750	800
Residential Class							
Adjusted R^2	0.937	0.952	0.952	No data	0.562	No data	0.009
x coefficient	0.110	0.121	0.105	No data	0.056	No data	0.009
x t-stat	139.897	161.085	160.277	No data	40.964	No data	3.591
x std. error	0.001	0.001	0.001	No data	0.001	No data	0.002
y coefficient	0.271	0.404	0.346	No data	0.411	No data	(0.033)
y t-stat	17.666	28.024	19.449	No data	10.764	No data	(0.560)
y std. error	0.015	0.014	0.018	No data	0.038	No data	0.059
Commercial Class							
Adjusted R^2	0.906	0.936	0.906	No data	0.583	No data	No data
x coefficient	0.451	0.468	0.243	No data	0.283	No data	No data
x t-stat	112.345	138.829	112.087	No data	42.799	No data	No data
x std. error	0.004	0.003	0.002	No data	0.007	No data	No data
y coefficient	1.517	1.947	0.419	No data	1.424	No data	No data
y t-stat	19.321	29.996	7.083	No data	7.751	No data	No data
y std. error	0.079	0.065	0.059	No data	0.184	No data	No data

Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute data for a customer which lacks sufficient information, providing that customers are of relatively similar size. Where daily results were determined to be sufficiently robust, (i.e., Adjusted R^2 in excess of 0.90, and where the t-statistic on both the x- and y-coefficients were in excess of 10.0), the results were brought forward into the peak load model. Where daily results were not sufficiently strong, or where data was lacking, monthly regression results were substituted for the daily data. This dataset is referred to as the "Blended Model" since it includes regressions performed on both daily and monthly data. The Blended Model includes daily regression results for the Residential class in weather zones 350, 450, and 500; and the Commercial class in weather zones 350 and 450. The remaining data used in the Blended Model was based on monthly regressions.

Q. Please describe the regression analyses using monthly billing data for the residential and commercial customer classes and the development of the "Monthly" peak load sendout model.

A. The monthly data regressions were performed on Intermountain's monthly billing data. This data had the advantage of covering all customers within the class and weather zone, and was already in therms so no adjustments to the data were necessary. In the monthly data regressions, average daily HDD was regressed against average daily use per customer by month, for each class and weather zone. The results of the monthly data regressions for the residential and commercial classes are reported in Table 5. These results are referred to as the "Monthly Model."

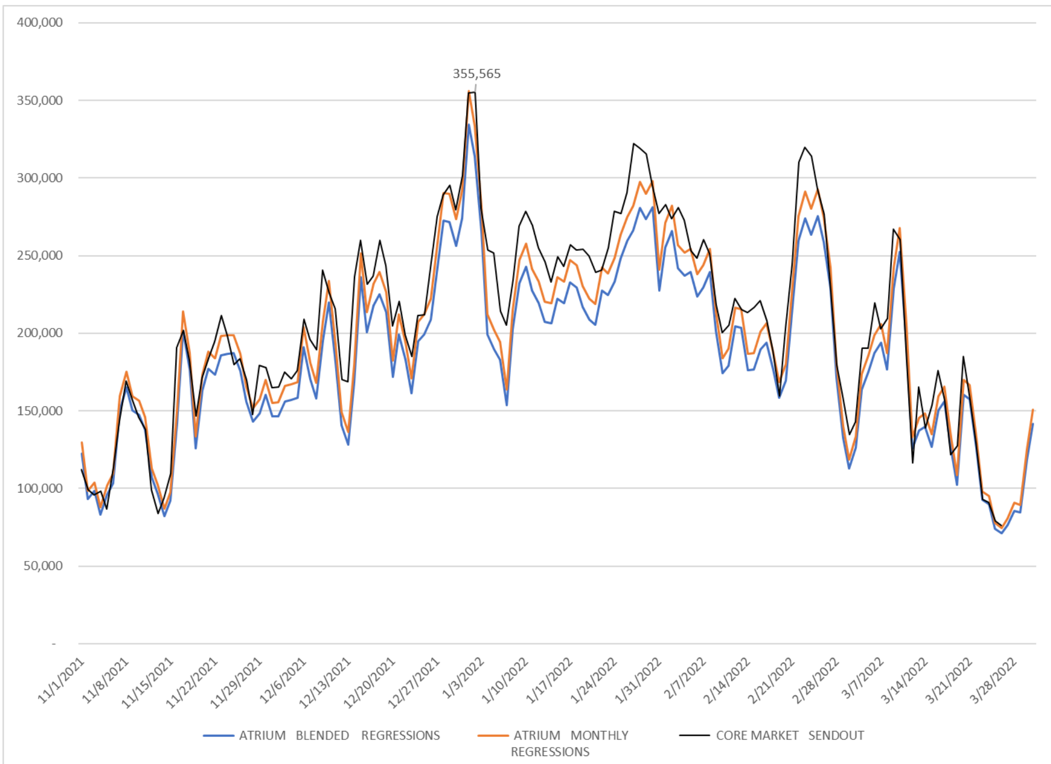
Table 5 Monthly Regression Results (January 2019 – July 2022)

Regression Results	350	450	500	600	700	750	800
Residential Class							
Adjusted R^2	0.979	0.990	0.967	0.982	0.993	0.990	0.983
x coefficient	0.115	0.126	0.162	0.101	0.071	0.085	0.093
x t-stat	44.098	64.639	35.372	48.431	75.560	65.060	48.621
x std. error	0.003	0.002	0.005	0.002	0.001	0.001	0.002
y coefficient	0.210	0.353	0.289	0.162	0.396	0.327	0.168
y t-stat	4.104	9.528	2.349	3.511	14.722	8.859	3.590
y std. error	0.051	0.037	0.123	0.046	0.027	0.037	0.047
Commercial Class							
Adjusted R^2	0.881	0.982	0.920	0.970	0.988	0.982	0.972
x coefficient	0.522	0.582	0.320	0.507	0.412	0.447	0.463
x t-stat	17.682	47.353	22.044	36.669	58.217	47.918	37.897
x std. error	0.030	0.012	0.015	0.014	0.007	0.009	0.012
y coefficient	3.427	2.365	1.437	2.093	2.150	1.139	1.140
y t-stat	5.956	10.153	3.681	6.897	10.820	4.330	3.823
y std. error	0.575	0.233	0.390	0.303	0.199	0.263	0.298

Q. Was there a validation step performed to check the accuracy of the "Blended" or the "Monthly" peak load sendout models in predicting the winter peak load?

A. Yes. To check the appropriateness of the modeling results, “Blended” and “Monthly” peak load sendout models were validated by comparing each to actual historical sendout, using actual historical HDD by weather zone and the class/weather zone regressions for the period November 1, 2021, to March 31, 2022. The results of that comparison are illustrated below.

Figure 2 Blended and Monthly Models versus IGC Core Sendout



As illustrated in Figure 2 above, the peak use during the illustrated period occurred on January 2, 2022, with an average HDD across all weather zones of 53.47, and core market load of 355,565 MMBtu. This HDD was slightly lower than the coldest day of the period, January 1, 2022, at 57.02 HDD, but since January 1st was a holiday, the sendout was lower than on January 2nd, even though the HDD was higher. As Figure 2 shows, the Monthly data does a slightly better job of predicting the peak than the Blended data. This disparity could be explained by the fact that daily data tends to be less stable and more volatile than monthly data and that some of the HDD sensitivity may be lost in the "noise" in the daily data. In addition, it is likely that there may be large, highly weather-sensitive customers that are not yet daily metered and therefore not reflected in the daily regressions. For these reasons, it has been determined that the Monthly peak load sendout model will be the best predictor of Intermountain's design day peak.

Q. What were the results of the Monthly Peak Load Sendout Model for Intermountain's Core Residential and Commercial Customers?

A. The regression results were extrapolated from the Monthly peak load sendout model to the average test year number of customers for each weather zone for each of the Core classes, RS and GS. The results are shown in Table 6 below.

Table 6 Peak Load Sendout for Core Customers

Core Rate Class	Customers[8]	Peak Load (Therms)
Residential	368,350	3,360,303
Commercial	34,966	1,483,938
Total Core Customers	403,316	4,844,241

[8] Based on average monthly customers projected for the test year (January 2022 – December 2022) with actuals through September 2022 and projected thereafter. Totals exclude interruptible snowmelt classes, CNG, and Irrigation.

Q. How did you estimate the peak day sendout for the LV rate classes?

A. Because the LV customers are not as weather sensitive as the residential and commercial customers, forecasting their volumes using standard regression techniques based on projected weather may not provide statistically significant results. Also, the LV customer counts are so few that they may fall below the number required to provide an adequate statistical population/sample size. As such, the maximum contract demand was used for these large volume customers to project loads at peak. For the LV-1 class and the T-4 class, the maximum daily firm quantity (MDFQ) was used as of September 2022. The MDFQ reflects the maximum amount of daily gas and/or capacity Intermountain must be prepared to provide to its firm LV customers on any given day, including the projected system peak day. These amounts represent a contracted daily requirement and reflects the known peak day obligation for each customer. The September 2022 MDFQ amounts were 1,485,410 therms for the T-4 class, and 74,405 therms for the LV-1 class. It is reasonable to expect that on a peak day these customers will be using their full contracted MDFQ. I note that this treatment is consistent with how the Peak Day Sendout was developed in the 2021 IRP.[9]

The daily peak sendout for the Interruptible Transport Class, T-3, was determined based on the test year average daily load for the twelve months ending December 2022. T-3 customers are interruptible and as such there are no assurances of the amount of capacity that they may be granted on any given day. However, given that Intermountain has rarely interrupted these customers, it is reasonable to provide a peak day allocation for their contribution to the system peak. Peak day sendout results have been provided *with* and

[9] Intermountain Gas Company, Integrated Resource Plan 2021- 2026, at p. 126.

without the interruptible customers; and note that interruptible customers have previously been excluded from Intermountain's peak load analyses. The average daily usage for the T-3 customers was 113,762 therms for the test year twelve-month period ending December 31, 2022.

Q. Was the peak day sendout estimated for the Interruptible Snowmelt Classes?

A. Yes. The peak day sendout for the Interruptible snowmelt classes (IS-R and IS-C) were estimated based on their average daily use for the month of January 2022. These classes are also fully interruptible with two hours of notice and could not be assured of capacity during any given peak day. However, as the Company has rarely interrupted these customers, they have been included in the Peak Load Study for reference.

Q. Please provide the results for Intermountain's total peak day sendout.

A. The results of the peak load study and the resulting allocations *with* and *without* the inclusion of interruptible customers were prepared and summarized in Table 7 below.

Table 7 Peak Day Sendout with and without Interruptible Classes – Monthly Model

50-Year Peak Day Event – Monthly Model				
	Firm & Interruptible		Firm Only	
Rate Class:	**Therms**	**%**	**Therms**	**%**
Residential (RS)	3,360,303	51.5%	3,360,303	52.5%
General Service (GS)	1,483,938	22.8%	1,483,938	23.2%
Large Volume (LV-1)	74,405	1.1%	74,405	1.2%
Transportation (Interruptible) (T-3)	113,762	1.7%	-	0.0%
Transportation (Firm) (T-4)	1,485,410	22.8%	1,485,410	23.2%
Snowmelt - Residential (IS-R)	2,404	0.0%	-	0%
Snowmelt - Commercial (IS-C)	1,421	0.0%	-	0%
TOTAL	**6,521,643**		**6,404,055**	

For comparative purposes, the results of the Blended peak load model have been included, which incorporated the daily meter readings, where appropriate. As shown below, the

Blended model provides a very similar class allocation relative to the peak compared to the Monthly model.

Table 8 Peak Day Sendout with and without Interruptible Classes – Blended Model

50-Year Peak Day Event – Blended Model				
	Firm & Interruptible		Firm Only	
Rate Class:	**Therms**	**%**	**Therms**	**%**
Residential (RS)	3,222,662	51.8%	3,222,662	52.8%
General Service (GS)	1,324,700	21.3%	1,324,700	21.7%
Large Volume (LV-1)	74,405	1.2%	74,405	1.2%
Transportation (Interruptible) (T-3)	113,762	1.8%	-	0.0%
Transportation (Firm) (T-4)	1,485,410	23.9%	1,485,410	24.3%
Snowmelt - Residential (IS-R)	2,404	0.0%	-	0.0%
Snowmelt - Commercial (IS-C)	1,421	0.0%	-	0.0%
TOTAL	**6,224,765**		**6,107,177**	

For purposes of this allocated class cost of service study, the results shown in Table 7 were selected, which use the Monthly peak load sendout model to determine the Core peak day sendout since I believe it provides superior results in predicting peak day sendout as illustrated above in Figure 2. These results are aligned with Intermountain's projections of peak day sendout in their 2021-2026 IRP, which projected 613,523 MMBtu for 2022 and 626,676 MMBtu for 2023 for firm demand (RS, GS, LV-1, and T-4). This corresponds to the Monthly model result of 6,404,055 therms (640,406 MMBtu), which exceeds the IRP's estimated peak day sendout for 2023 by 13,730 MMBtu. This variance is largely attributable to increases in MDFQ's for LV-1 and T-4 since the IRP was published in 2021. The IRP estimated MDFQ's for LV-1 and T-4 classes of 140,779 MMBtu, compared to the MDFQ's of 155,982 MMBtu used in the Monthly model, a difference of 15,203 MMBtu.

IV. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Intermountain's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecasted test year or some combination of historical and future costs. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers’ loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Intermountain because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles, and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent, they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual, and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

V. INTERMOUNTAIN'S COST OF SERVICE STUDY

Q. Please describe the process of performing Intermountain's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include storage, transmission, distribution, and general (customer). The general function includes costs that cannot be directly assigned to the primary operating functions of storage, transmission, and distribution. These costs are functionalized in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity, along with an additional revenue classification consisting of working capital items and revenue. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state legislative and regulatory policies and evidentiary requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Intermountain's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of Idaho as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple pressure based or a single pressure-based operation.

Q. What are the specific physical characteristics of Intermountain's system?

A. The physical configuration of Intermountain's system is a dispersed / multiple city-gate, storage, transmission, distribution, and multi pressure-based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available. Intermountain maintains many detailed plant accounting records for its distribution-related facilities.

Q. How are Intermountain's classes structured for purposes of the COSS?

A. The COSS evaluated five customer classes: Residential (RS, IS-R), General (GS, IS-C), Large Volume (LV-1), Interruptible Transport (T-3), and Firm Transport (T-4).

Q. Do you propose any modifications to the current classes?

A. No.

Q. Please describe the process of performing Intermountain's COSS analysis.

A. The detailed process description of Intermountain's COSS analysis is presented in Exhibit 2 - Cost of Service Study. Exhibit 2 provides a full scope of the COSS development process and the results.

Q. Please discuss the content of Exhibit 2.

A. Exhibit 2 – Cost of Service Study consists of three sections detailing the process of developing the COSS. The first section includes an introduction, the general purpose, and an overview of the excel-based fully functional COSS model presented in this proceeding. The second section presents the COSS development process specific to the Company including Functionalization, Classification, and Allocation. The Allocation section specifically describes all internal and external allocation factors and development bases and processes used in the COSS. The last section depicts the results of the cost of service study, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the schedules included in Exhibit 2.

A. The following is the list of Schedules included in Exhibit 2:

- Schedule 1 - Account Balances, Functionalization, Classification and Allocation
- Schedule 2 - External Allocation Factors
- Schedule 3 - Internal Allocation Factors
- Schedule 4 - Cost of Service and Rate of Return under Present and Proposed Rates
- Schedule 5 - Cost of Service Allocation Study Detail by Account

- Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 7 – Alternative Cost of Service and Rate of Return Under Present and Proposed Rates

Q. Please explain the COSS information contained in Schedules 1 through 7.

A. Schedule 1 displays revenue requirements presented by FERC accounts with corresponding selections of functions, classifications, and allocations methods applied to the accounts. Schedule 2 and Schedule 3 depict the derivation of external and internal allocation factors that are explained in detail in Exhibit 2. Schedule 4 is a summary of the cost to serve as compared to revenues under present and proposed rates. Schedule 5 is a detailed cost of service study presented by the FERC accounts for the individual rate classes. Schedule 6 presents a summary of functionalized and classified rate base and revenue requirements along with derived unit cost by customer class. Lastly, Schedule 7 presents a summary of the cost of service similar to Schedule 4, based on the peak load study with interruptible customers included, which is discussed below in this testimony.

Q. How did the COSS classify and allocate underground storage plant?

A. The storage plant accounts contain the costs related to the Company's LNG facilities. These facilities are needed to provide deliverability and reliability during peak periods. Because of the cost and cycle characteristics, LNG withdrawals are typically reserved for needle peaking during very cold weather events or for system integrity events. Therefore, the storage plant accounts are classified as demand and allocated on a peak day basis.

Q. How did the COSS classify and allocate transmission plant?

A. The transmission plant accounts contain the costs related to the Company's high pressure transmission facilities. These facilities were designed and sized to provide deliverability during peak periods. Therefore, the transmission plant accounts are classified as demand and allocated on a peak day basis.

Q. How did the Company's COSS classify and allocate investment in Distribution Mains?

A. The Company classified 55.3% of its investment in distribution mains as customer-related and 44.7% of the investment as demand-related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Intermountain's distribution system. The demand related investment was allocated to the customer classes based on the respective contributions to peak day demand.

Q. Please explain the basis for the Company's choice of classification and allocation methods?

A. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses current unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter squared inches) of the weighted distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual current installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

For purposes of determining the customer component of distribution mains to be used in Intermountain's COSS, the zero-intercept method was employed, the detailed development process of which is presented in Exhibit 2.

Q. Was the same method to classify and allocate distribution mains utilized in the 2016 Case?

A. Yes. The Company used similar classification and allocation methods in its previous general rate case proceeding.

Q. How did the COSS classify and allocate the remainder of the distribution plant?

A. Special studies were performed for the allocation of Accounts 380 (Services), 381 (Meters), and 385 (Industrial Measuring and Regulating Station Equipment). The costs in account 383 (House Regulators) were classified and allocated based upon the results of the meters study. The development steps of these are discussed in Exhibit 2.

The plant costs in Account 378 (Measuring and Regulating Station Equipment – General) and Account 379 (Measuring and Regulating Station Equipment – City Gas Stations) were classified as capacity or demand-related and allocated on a customer and peak demand composite allocator.

Account 374 (Land and Land Rights) are associated with distribution mains and therefore, were allocated on the same factor as distribution mains. Account 375 (Structures and Improvements) was allocated based on the allocation of the distribution plant accounts.

Q. How did the COSS classify and allocate general plant?

A. General Plant was classified and allocated to the rate schedules based upon the allocation of storage, transmission, and distribution plant. Mathematically, this is the sum of storage, transmission, and distribution plant accounts that were allocated by rate class. That total by rate class is then divided by the total company amount to find each rate class's percentage allocation. Account 391 (Office Furniture and Equipment) was allocated based on the factor derived based on the Company's labor cost records.

Q. How are other rate base components classified and allocated in the COSS?

A. Accumulated Provision for Depreciation and Amortization is presented by FERC accounts and allocated based on the same allocation factor as the related plant in service accounts. This treatment ensures that the net plant for each FERC account is allocated consistently to each customer class. Accumulated Deferred Income Taxes are presented on the functional level and allocated based on the relevant internal plant allocator as shown in Exhibit 2.

Account 154 (Material and Supplies) was allocated based on the allocation of storage, transmission, and distribution plant. Account 164 (LNG Inventory) balance was allocated based on the peak day factor as the inventory exists to ensure reliability during peak periods. Customer Account 252 (Advances for Construction) was allocated based on the mains and service plant balances.

Q. How are operation and maintenance ("O&M"), customer accounts, customer services and information ("Customer"), and administrative and general ("A&G") expenses classified and allocated in COSS?

A. A utility's O&M expenses generally are thought to support the corresponding plant in service accounts. In general, O&M expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. The majority of Customer expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class, except for Account No. 904 (Uncollectible Accounts Expense), which is allocated based upon the three-year average of uncollectible write-offs. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to the plant in service, such as maintenance of the general plant and property taxes, were allocated based on the plant allocator. The detailed classification and allocation methods applied to these expense categories can be found on Schedule 1 of Exhibit 2.

Q. Were any additional studies performed in Intermountain's COSS?

A. Yes. Certain categories of gas supply and gas system control related O&M expenses include salaries and benefits of personnel in the following responsibility centers: Gas Supply Resource Planning, Gas Supply, and Gas Control. The corresponding labor expenses were distributed among the three categories of Gas Planning, Gas Supply, and Gas Control based on the time allocations reported by the personnel in these responsibility centers. These expenses were first segregated between sales and transportation classes and then allocated to customer classes as discussed in Exhibit 2.

Q. Please discuss the classification and allocation of the remaining expenses.

A. Depreciation and amortization expense is presented on the functional level and allocated based on the relevant internal plant allocator, as demonstrated in Exhibit 2. Taxes other than income are allocated in a manner that reflected the specific cost associated with each tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category and can be grouped into the following categories: (1) labor; (2) plant; and (3) revenue. In the Intermountain's COSS, all non-income taxes were assigned to one of the above stated categories and relevant allocation factors.

Current income taxes were allocated based on each class's net income before taxes. Income taxes for the total revenue requirement were allocated to each class based on the allocation of the required net income by rate class. Income taxes at proposed revenues by class were allocated to each class based on the proposed income prior to taxes for each class.

Q. Please summarize the results of Intermountain's COSS.

A. Table 9 below presents a summary of the results of the Company's COSS that can be reviewed in detail in Schedule 4 of Exhibit 2. The COSS shows an overall revenue deficiency to the Company of $11.3 million.

Table 9 Summary Results of the COSS

Customer Classes	Current Revenues	Cost to Serve	Current Rate of Return	Deficiency/ (Surplus)	Current Revenue to Cost Ratio	Current Parity Ratio
Residential Service	$ 70,391,038	$ 88,420,214	2.4%	$ 18,029,176	0.80	0.88
General Service	26,030,361	22,043,765	11.5%	(3,986,596)	1.18	1.30
Large Volume	677,926	520,638	13.9%	(157,288)	1.30	1.43
Transport Service(Interruptible)	537,118	84,154	236.9%	(452,964)	6.27	6.92
Transport Service(Firm)	9,713,387	7,619,006	12.9%	(2,094,381)	1.27	1.40
Subtotal	**$ 107,349,830**	**$ 118,687,777**		**$11,337,947**		
Other Revenues	2,450,925	2,450,925		-		
Total System	**$ 109,800,755**	**$ 121,138,702**	**5.2%**	**$11,337,947**	**0.91**	**1.00**

Table 9 presents the revenue deficiency/excess for each rate class, the class rate of return on net rate base at current rates, the revenue to cost ratio, and the associated parity ratio. Regarding rate class revenue levels, the results show that all classes except Residential, are being charged rates that recover more than their indicated costs of service.

Q. Please discuss the COSS results prepared based on the peak load study inclusive of the interruptible customer classes.

A. An additional COSS analysis was prepared based on the peak load study results inclusive of the interruptible customers, as discussed earlier in the testimony and presented in Table 7. The summary of the COSS results under the alternative peak load allocation study ("Alternative COSS") is presented in Schedule 7 of Exhibit 2. Table 10 below depicts the results of the Alternative COSS.

Table 10 Summary Results of the Alternative COSS

Customer Classes	Current Revenues	Cost to Serve	Current Rate of Return	Deficiency/ (Surplus)	Current Revenue to Cost Ratio	Current Parity Ratio
Residential Service	$ 70,391,038	$ 88,171,773	2.5%	$ 17,780,735	0.80	0.89
General Service	26,030,361	21,935,558	11.6%	(4,094,803)	1.18	1.31
Large Volume	677,926	514,914	14.3%	(163,012)	1.31	1.45
Transport Service(Interruptible)	537,118	560,802	6.7%	23,684	0.96	1.06
Transport Service(Firm)	9,713,387	7,504,730	13.3%	(2,208,657)	1.29	1.42
Subtotal	**$ 107,349,830**	**$ 118,687,777**		**$11,337,947**		
Other Revenues	2,450,925	2,450,925		-		
Total System	**$ 109,800,755**	**$ 121,138,702**	**5.2%**	**$11,337,947**	**0.91**	**1.00**

Q. Why are you presenting an Alternative COSS in this proceeding?

A. The Transportation Service Interruptible class has a limited presence in the Company's design day peak for purposes of the IRP. For peak event modeling purposes, the IRP assumes T-3 customers are reduced to minimal emergency plant-heat only.[10] As noted earlier in Section IV. Load Study and Analysis, T-3 customers are interruptible, and therefore, have no assurance of the amount of capacity that they may be granted on any given peak day. However, given that Intermountain has rarely interrupted these customers, it is reasonable to provide a level of demand as their contribution to the system peak for purposes of the COSS. The alternative COSS is intended to demonstrate the impact particularly on the Transportation Interruptible class by their inclusion at a 100% load factor demand level in the allocation of system demand related costs.

Q. How do the COSS results compare to the alternative method that is based on the peak load study inclusive of the interruptible customer classes?

A. Table 11 below provides a comparison between the two options. As expected under the Alternative COSS method Transportation Service Interruptible Class shows an increase in

[10] Ibid, at pg. 39.

cost to serve. However, the resulting class revenue to cost ratio ("R:C") of .96 remains above the system R:C ratio of .91, compared to the 6.27 R:C level when no system demand contribution is attributable to the class.

Table 11 Comparison of COSS Results under Proposed and Alternative Methods

Customer Classes	Cost to Serve	Cost to Serve (Alternative)	Difference	Revenue to Cost Ratio	Revenue to Cost Ratio (Alternative)
Residential Service	$ 88,420,214	$ 88,171,773	$ 248,441	0.80	0.80
General Service	22,043,765	21,935,558	108,207	1.18	1.18
Large Volume	520,638	514,914	5,724	1.30	1.31
Transport Service(Interruptible)	84,154	560,802	(476,648)	6.27	0.96
Transport Service(Firm)	7,619,006	7,504,730	114,276	1.27	1.29
Subtotal	**$ 118,687,777**	**$ 118,687,777**	**$ -**		
Other Revenues	2,450,925	2,450,925	-		
Total System	**$ 121,138,702**	**$ 121,138,702**	**$ -**	**0.91**	**0.91**

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service;
(2) Efficiency;
(3) Value of Service;
(4) Stability/Gradualism;
(5) Non-Discrimination;
(6) Administrative Simplicity; and
(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[11]

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative

[11] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Intermountain's proposed revenue increase of $11.3 million to its rate schedules.

A. The apportionment of revenues among rate schedules consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) rate schedule contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Intermountain's rate schedules.

Q. Have various rate schedule revenue options been considered in conjunction with your evaluation and determination of Intermountain's interclass revenue proposal?

A. Yes. Using Intermountain's proposed revenue increase, and the results of its COSS, a few options were evaluated for the assignment of that increase among its rate schedules and, in conjunction with Intermountain personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that was evaluated under Intermountain's proposed total revenue level was to adjust the revenue level for each rate schedule so that the R:C ratio for each class was equal to parity or 1.00 (Unity), as shown in Exhibit 3, under *Scenario A: Revenues at Equalized Rates of Return*. Rate schedules above parity would suggest the need for revenue decreases in order to move them closer to cost (*i.e.*, a convergence of the resulting revenue-to-cost ratios towards unity or 1.00).

The resulting customer impact implications for the Residential Service class have led to the conclusion, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes. From a policy perspective, Intermountain believed that every rate schedule should participate in the proposed overall revenue increase. Therefore, as a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue question. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option considered was assigning the increase in revenues to Intermountain's rate schedules based on an equal percentage basis of its current margin revenues (see *Scenario B, Equal Percentage Increase)*, in Exhibit 3. By definition, this option resulted in each rate schedule receiving an increase in revenues equal to the system average. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Intermountain's rate schedules (*i.e.,* there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Intermountain's class revenue proposal.

A third option considered was moderately assigning the increase in revenues to all Intermountain's rate schedules (*Scenario C: Moderated based on Current Parity Ratio),* which is the proposed revenue allocation method in this proceeding.

Q. What was the result of this process?

A. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. After further discussions with Intermountain, the conclusion reached was the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Intermountain's rate schedules.

The Residential margin revenue increase was limited to 13.20% or 1.25 of the relative system increase (10.56%). The minimum increase was applied to the Interruptible Transport of 0.25 of the relative system increase, which resulted in 2.64% of margin revenue increase. The remainder of the margin revenue increase was allocated among General Service, Large Volume, and Firm Transport rate schedules, which resulted in an 5.58% margin revenue increase or 0.53 of the relative system increase. This revenue apportion is shown in Direct Exhibit 3 as *Proposed Scenario C: Moderated based on the Current Parity Ratio*.

Q. What is the recommended increase for each rate class?

A. In summary, this preferred revenue allocation approach resulted in reasonable movement of the customer classes' revenue-to-cost ratio toward unity as shown on Table 12 below, while providing moderation of the revenue impact by requiring some level of revenue increase responsibility from all rate schedules for the Company's total proposed revenue requirement.

Table 12 Current and Proposed Parity Ratios

Customer Classes	Current Parity Ratio	Proposed Parity Ratio
Residential Service	0.88	0.90
General Service	1.30	1.24
Large Volume	1.43	1.37
Transport Service(Interruptible)	6.92	6.44
Transport Service(Firm)	1.40	1.34
Total System	**1.00**	**1.00**

From a class cost of service standpoint, this type of rate schedule movement, and modest reduction in the existing class rate subsidies, is desirable.

The following Table 13 summarizes the proposed distribution margin revenue change for each rate class and the percent change in distribution margin revenues resulting from the above-described process.

Table 13 Proposed Class Revenue Apportionment

Customer Classes	Margin Revenues at Current Rates	Margin Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Increase Relative to System Increase	Proposed Parity Ratio
Residential Service	$ 70,391,038	$ 79,684,135	$ 9,293,097	13.20%	1.25	0.90
General Service	26,030,361	27,481,668	1,451,307	5.58%	0.53	1.24
Large Volume	677,926	715,723	37,797	5.58%	0.53	1.37
Transport Service(Interruptible)	537,118	551,300	14,182	2.64%	0.25	6.44
Transport Service(Firm)	9,713,387	10,254,951	541,564	5.58%	0.53	1.34
Subtotal	**$ 107,349,830**	**$ 118,687,777**	**$ 11,337,947**	**10.56%**	**1.00**	
Other Revenues	2,450,925	2,450,925	-	-		
Total System	**$ 109,800,755**	**$ 121,138,702**	**$ 11,337,947**	**10.33%**		**1.00**

VIII. INTERMOUNTAIN'S RATE DESIGN

Q. Please summarize the rate design changes Intermountain has proposed in this rate proceeding.

A. The proposed rate design includes (1) increases in the fixed monthly customer charges for Residential and General Service classes, (2) increases in demand rates to Large Volume and Firm Transport classes, (3) introduction of fixed monthly customer charges to Large Volume, Interruptible Transport, and Firm Transport classes, and (4) modification of the declining block rates for the Large Volume class. Once the fixed monthly customer charge targets and demand rates were set for each rate class, the remaining proposed revenues for each rate class were recovered through the volumetric charges.

Q. Please describe the changes to the monthly customer charge levels.

A. Table 14 provides a summary of current and proposed customer charges by rate schedule as compared to the COSS results:

Table 14 Current and Proposed Customer Charge

Rate Classes	Current Customer Charge	COSS Unit Cost	Proposed Customer Charge	Change	Percent Change
Residential Service	$ 5.50	$ 12.60	$ 9.00	$ 3.50	63.64%
Residential Service (Interruptible)	$ 5.50	$ 12.60	$ 8.00	$ 2.50	45.45%
General Service	$ 9.50	$ 33.65	$ 15.00	$ 5.50	57.89%
General Service (Interruptible)	$ 9.50	$ 33.65	$ 12.50	$ 3.00	31.58%
Large Volume	$ -	$ 500.03	$ 150.00	$ 150.00	-
Transport Service (Firm)	$ -	$ 1,063.73	$ 150.00	$ 150.00	-
Transport Service (Interruptible)	$ -	$ 1,018.02	$ 300.00	$ 300.00	-

Overall, the proposed customer charges are within reasonable range of increases considering the customer unit costs per rate class supported by the COSS results, as indicated on Schedule 6 of Exhibit 2. These increases to the basic customer charges will provide significant improvement in the recovery of the fixed customer-related costs via fixed charges. To offset the foregoing increases to the basic customer charges, all blocks of the volumetric rates in the respective tariff schedules were reduced ratably based on the margin revenue in each block, with one exception. The block structure of the Large Volume Firm Sales Service tariff was changed, which is discussed later in this section.

Q. Why is the Company proposing to increase the fixed monthly customer charges?

A. The primary goal of rate design was to move towards recovery of fixed costs by increasing all customer charges. This resulted in better alignment between the fixed costs incurred by Intermountain and the charges incurred by customers.

Q. Please describe the changes proposed to the demand rate.

A. The current demand charge in Large Volume and Firm Transportation classes of $0.30 per therms per month is proposed to be raised to $0.32, which will recover approximately 90% of the unit demand-related costs for these customer classes.

Q. What changes do you propose to the Large Volume block rate structure?

A. Under Intermountain's current tariff, any new customer under Large Volume Firm Sales Service (Tariff Sheet No. 7) is required not to exceed usage of 500,000 therms annually, while the current block rate is structured as follows:

- Block 1 - First 250,000 therms per bill
- Block 2 - Next 500,000 therms per bill
- Block 3 - Over 750,000 therms per bill

Under this scenario, customers are unable to benefit from the declining block rates. By reviewing historical usage patterns, a new block structure was developed as follows:

- Block 1 - First 35,000 therms per bill
- Block 2 - Next 35,000 therms per bill

- Block 3 - Over 70,000 therms per bill

Q. Have you provided an exhibit detailing the proposed rates and corresponding revenues?

A. Yes. Exhibit 4 shows the derivation of each rate component for each of Intermountain's tariff schedules and the corresponding revenues generated from those proposed rates.

Q. Have you prepared bill impacts?

A. Yes. Exhibit 5 provides monthly bill impacts for Residential, General, and Interruptible Transportation rate classes presented as a range of monthly usage (therms) and corresponding bills under current and proposed rates. The bill impacts for Large Volume and Firm Transportation customers are presented as various scenarios of monthly usage and MDFQ with corresponding bills under current and proposed rates.

IX. CONCLUDING REMARKS

Q. Please summarize your recommendations.

For purposes of Intermountain's allocated class cost of service study, the Load Study results which use the Monthly peak load sendout model to determine the Core peak day sendout are recommended. It provides superior results in predicting peak day sendout. These results are aligned with Intermountain's projections of peak day sendout in its 2021-2026 IRP.

I recommend the Commission accept the COSS presented in Section VI of this testimony, including the proposed class revenue apportionment. The COSS represents a fair and reasonable allocation of cost responsibility for each rate class, based on the Company's proposed total system revenue increase. The Company's proposed COSS allocation method for distribution mains best reflects the cost causative characteristics of extending service to new customers and sized to meet peak demand requirements. As such, the Commission should rely on the Company's proposed COSS to guide revenue targets for each rate class.

The revenue targets proposed by Intermountain reasonably balance the concepts of cost of service, current revenue contributions, and gradualism, while moving all classes closer to parity. Lastly, the COSS model demonstrates that fixed costs, both customer-related and demand-related are materially higher than the current level of customer charges; therefore, the proposed increases to customer charges should be approved by the Commission to better align fixed cost occurrence with fixed cost recovery and price signals received by customers.

Q. Does this conclude your testimony?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	CASE NO. INT-G-22-07

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

EXHIBIT 1 TO ACCOMPANY THE

DIRECT TESTIMONY OF RONALD J. AMEN

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska,
Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage

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R. Amen, IGC
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d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018, 2021)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)
Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)
Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)
Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Confidential Multi-Jurisdiction Gas Utility (2021-2022)
Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight on the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Summit Natural Gas of Maine, Inc. (2022)

Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness support for the utility's gas general rate case before the Maine Public Utilities Commission. The case is currently pending before the Maine PUC.

Black Hills Energy Arkansas (2021-2022)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for the utility's gas general rate case before the Arkansas Public Service Commission. The case resulted in a settlement before the Arkansas PSC.

Until Electric System and Northern Utilities, Inc. (2021)

Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)

Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission and North Dakota Public Service Commission. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. Mr. Amen provided electric cost of service, class revenue apportionment, rate design, and expert witness support in Montana-Dakota's 2022 general rate case before the North Dakota PSC. The case is pending.

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018, 2022)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Future project work involves innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:

- Application Fees
- Non-Compliance Fees

- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)
Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)
For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)
Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007,

2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)
Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)
Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)
Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)
Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending

mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)
Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)
Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)
In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond

Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)
Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)
Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)
Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	CASE NO. INT-G-22-07

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

EXHIBIT 2 TO ACCOMPANY THE

DIRECT TESTIMONY OF RONALD J. AMEN

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

Case No. INT-G-22-07

INTERMOUNTAIN GAS COMPANY

EXHIBIT 2

COST OF SERVICE ALLOCATION STUDY
TEST YEAR DECEMBER 31, 2022

Witness: Ronald J. Amen

ATRIUM ECONOMICS
CENTERED ON ENERGY

Contents

I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for Intermountain Gas Company ("Intermountain" or the "Company") based on the Test Year ended December 31, 2022 ("Test Year").

The document is organized into three sections. The first section includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the COSS study.

1. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of Ronald J. Amen in Exhibit 2. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e., production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of costs of gas, income taxes, working capital, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Analysis Process

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, commodity, and demand categories. Accounting costs are reported by FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per therm, per dekatherm of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary, the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. INTERMOUNTAIN'S COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of Intermountain's cost allocation:

- Storage
- Transmission
- Distribution
- General (Customer)

Intermountain's assigned functional categories are presented on Schedule 1.

2. Classification

The following classification categories were identified for purposes of Intermountain's cost allocation:

- Demand
- Customer

Intermountain's assigned classification categories are presented on Schedule 1.

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External (Schedule 2) and Internal (Schedule 3) Allocation Factors are utilized to allocate costs among various customer classes. Intermountain's assigned Allocation Factors are presented on Schedule 1.

3.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

- Residential Service
- General Service
- Large Volume
- Transport Service (Interruptible)
- Transport Service (Firm)

3.2. External Allocation Factors

Intermountain's External Allocation Factors are presented on Schedule 2. The External Allocation Factors are developed based on the special studies conducted using various detailed data as discussed below.

Commodity and Revenue Allocation Factors

Costs classified as "Commodity" are allocated among customer classes based on the weather-normalized volumes for the test year.

<u>REV</u> – Factor developed to directly assign associated current base rate revenues to the specific class in the Test Year.

<u>COM</u> – Factor developed to directly assign Weather Normalized Volumes/Throughput to the specific class in the Test Year.

Customer Allocation Factors

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

<u>CUST</u> – Customer Count factor is based on the average number of customers per customer class in the Test Year.

<u>CUST_SALES_TRANS</u> - The costs associated with planning, gas supply, and control activities were specifically identified and allocated to the sales and transportation customer classes based on the time reported by the personnel in these responsibility centers. First, the expenses were segregated between sales and transport classes according to the assigned labor hours and then allocated among the customer classes. A portion of control activities was allocated to customer classes based on the number of alarms for the specifically identified customer classes and the

remaining costs were allocated based on the peak demand factor. The planning and supply related costs were allocated based on the test year weather normalized volumes. Based on these various components a composite allocator was created to incorporate this study into COSS.

<u>MTRS</u> – Meter Allocation factor is based on the weighted customer class cost of meters used to serve gas customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific customer class, and related meter replacement costs. First, the meter records were grouped into three categories – Group 1, Group 2, and Group 3 based on the meter size. Next, the average unit cost per group for each customer class was derived. Then the relative weighting factor was derived by prorating to Residential Class unit cost. To derive the allocation basis, the weighted factor was multiplied by the test year customer bill counts for each customer class prorated by the groups.

<u>M&R</u> – The factor was derived to allocate FERC Account 385 Industrial measuring and regulating station equipment. The analysis was performed based on the same set of data used to derive the Meters allocation factor. Similar steps were taken to develop an allocation basis, but only relying on Group 3 data and excluding the Residential Class.

<u>SERV</u> – The analysis relies upon the data contained in the Company's property records which provide an inventory and original cost of the service lines and service lines by diameter. The original cost data was restated in terms of current cost using Handy-Whitman indices for services to determine current unit cost. The interruptible snowmelt customer counts were removed for the purpose of this analysis, due to their shared service lines with the customer premise. The records were grouped into three groups: the Small Service group included service diameters of up to one inch, the next group of Medium Services included service diameters between one and two inches, and service lines with over two-inch diameters were identified as Large Services. Then, the unit cost per group was derived. Using meter data records, customers were grouped into similar groups (small meters, medium meters, and industrial meters). Applying service unit cost to relative customer group counts determined total estimated service costs by customer class and service cost per customer. Then the relative customer class unit cost was developed based on the Residential Class and multiplied by the test year customer count for each customer class.

<u>ACT_904</u> – The factor is based on the three-year (2019-2021) average of Bad Debt write-offs.

Demand Allocation Factors

<u>PDAY_F&I</u> – The factor is based on Peak Day capacity demand throughput for each customer class including Firm and Interruptible customer classes.

<u>PDAY_F</u> – The factor is based on Peak Day capacity demand throughput for each customer class including Firm customer classes only.

<u>CUST_DEM_F&I</u> – The composite factor is based on the CUST and PDAY_F&I factors prorated to the customer and demand components determined in the Mains Analysis.

<u>CUST_DEM_F</u> – The composite factor is based on the CUST and PDAY_F factors prorated to the customer and demand components determined in the Mains Analysis.

Mains Analysis

The allocation of investment in facilities serving a distribution function should recognize that the cost of these facilities is driven by two principal factors. First is the cost of extending the system to connect individual customers. Second is the cost associated with the capacity requirements of the customers connected.

There are two widely accepted methods for the classification of mains between customer-related costs and demand-related costs. The two methods are the Minimum System Method and the Zero-Intercept Method, both relying on the Company's property record data to determine the cost of pipe by size and type. Diameter groups that did not contain enough sample data were removed. The unit cost for pipe in any year is determined by dividing the booked costs by the amount of pipe installed in a standard unit of measurement. A variety of factors, such as the length of pipe installed, location, installation conditions, etc., cause the annual unit cost of pipe by size and type to vary significantly. Thus, a simple average of the yearly costs is not adequate for a determination of the cost for each size of the pipe as it will not reflect a consistent set of data. Therefore, the original cost data was restated in terms of current cost using the Handy-Whitman index.

Zero-Intercept Study:

The zero-intercept study was performed using a Weighted Linear Regression (WLR) on the cost per foot by pipe diameter. Based on this relationship, the study estimates the cost of installing a hypothetical pipe with zero capacity, which is where the estimated diameter is zero (i.e., the zero-intercept). The zero-intercept determined value is then multiplied by all quantities of distribution mains currently installed by the utility to arrive at a total minimum system cost. Total minimum system cost divided by total system cost derives the portion of the system that is considered a fixed investment and is classified as customer-related.

Zero-Intercept (Weighted Linear Regression)

Material	Quantity	Cost 2022	Zero-Intercept Cost (2022)	Customer Component	Customer Component Percentage
Plastic	23,707,720	$257,506,229	$ 5.65	$ 133,850,942	52.0%
Steel	7,718,299	$520,929,589	$ 38.38	$ 296,243,752	56.9%
Total	**31,426,019**	**$ 778,435,819**		**$ 430,094,694**	**55.3%**

The distribution main investment is functionalized to distribution, classified based on the results of the zero-intercept study to demand (44.7%) and customer (55.3%). The demand component of the mains investment is allocated based on each class's allocation of peak day. The customer component of the mains investment is allocated based on each class's number of customers.

Other Mains Studies:

In addition to the zero-intercept study discussed above, for comparison purposes two other mains studies were conducted: one using the minimum system method adjusted to the load-carrying capacity, and a different zero-intercept study using ordinary least squares regression. The minimum system study used 2" as the minimum-sized steel mains and 2" as the minimum-sized plastic mains. The minimum system study yielded a customer component of 68.7% for distribution mains as depicted below.

Minimum System

Material	Quantity	Cost 2022	Minimum Size Cost (2022)	Customer Component	Customer Component Percentage
Plastic	23,707,720	$257,506,229	$9.03	$214,082,249	83.1%
Steel	7,718,299	$520,929,589	$46.81	$361,275,904	69.4%
Total	**31,426,019**	**$778,435,819**		**$575,358,154**	**73.9%**
Minimum System Adjusted for Load Carrying Capacity					**68.9%**

The zero-intercept study using ordinary least squares is simple linear regression performed for each material type with unit costs as the dependent variable and the squared pipe diameter as the independent variable. This study produced very similar results (i.e. customer component of 54.6%) as the zero-intercept WLR.

Zero-Intercept (Ordinary Least Squares)

Material	Quantity	Cost 2022	Zero-Intercept Cost (2022)	Customer Component	Customer Component Percentage
Plastic	23,707,720	$257,506,229	$ 8.01	$ 189,853,388	73.7%
Steel	7,718,299	$520,929,589	$ 30.46	$ 235,123,466	45.1%
Total	**31,426,019**	**$ 778,435,819**		**$ 424,976,854**	**54.6%**

3.3.Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated cost based the external allocation factors, representing various forms of the composite external and internal factors as mathematical sums.

<u>INT_RATEBASE</u> – The factor is based on the derived rate base by customer class.

<u>INT_REV_REQ</u> – The factor is based on the derived revenue requirement by customer class.

<u>INT_REQ_INCOME</u> – The factor is based on the derived customer class required return on the rate base.

<u>INT_TOTPLT</u> – The factor is based on the total plant in service balance allocated to the customer classes.

<u>INT_STORPT</u> – The factor is based on the total Storage plant in service balance allocated to the customer classes.

<u>INT_INTGPLT</u> – The factor is based on the total Intangible plant in service balance allocated to the customer classes.

<u>INT_STOR_TRANSM_DIST_SUBTOTAL</u> – The factor is based on the Storage, Transmission, and Distribution plant in service balances allocated to the customer classes.

INT_DIST_SUBTOTAL – The factor is based on the Distribution plant in service balance by customer class excluding FERC Account 375 -Structures and Improvements.

INT_DISTPT –The factor is based on the total Distribution plant in service balance allocated to the customer classes.

INT_DMAINS_SERV – The factor is based on the FERC Accounts 376 - Mains and 380 - Services balances allocated to the customer classes.

INT_GENPLT – The factor is based on the General plant in service balance allocated to the customer classes.

INT_TRANSPT – The factor is based on the Transmission plant in service balance allocated to the customer classes.

INT_CUSTACC – The factor is based on the Customer Account expenses allocated to the customer classes, excluding FERC Account 901- Supervision.

INT_OML – The factor is based on the total customer class allocated labor-related Operation and Maintenance Expenses.

INT_DIST_OL - The factor is based on the customer class allocated Distribution labor-related Operation Expenses.

INT_DIST_ML - The factor is based on the customer class allocated Distribution labor-related Maintenance Expenses.

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	$ 2,506	INT_STOR_TRANSM_DIST_SUBTOTAL					
5	Franchises & Consents	302.0	429,487	INT_STOR_TRANSM_DIST_SUBTOTAL					
6	Misc. Intangible Plant - Plant Related	303.0	11,659,883	INT_STOR_TRANSM_DIST_SUBTOTAL					
7	Misc. Intangible Plant - Customer Related	303.0	0						
8	Misc. Intangible Plant - Labor Related	303.0	46,595,509	INT_OML					
9	Subtotal - Intangible Plant		$ 58,687,385						
10	**Natural Gas Other Storage Plant**								
11	Land & Land Rights	360.0	$ 292,588		STORAGE	DEMAND	PDAY		
12	Structures & improvement	361.0	10,211,065		STORAGE	DEMAND	PDAY		
13	Gas Holders	362.0	10,871,165		STORAGE	DEMAND	PDAY		
14	Purification Equipment	363.0	19,205,253		STORAGE	DEMAND	PDAY		
15	Subtotal - Natural Gas Other Storage Plant		$ 40,580,071						
16	**Transmission plant**								
17	Land and Land Rights	365.1	$ 782,865		TRANSMISSION	DEMAND	PDAY		
18	Rights-of-Way	365.2	0						
19	Structures and improvements	366.0	77,152		TRANSMISSION	DEMAND	PDAY		
20	Mains	367.0	69,918,045		TRANSMISSION	DEMAND	PDAY		
21	Compressor station equipment	368.0	2,167,366		TRANSMISSION	DEMAND	PDAY		
22	Measuring and regulating station equipment	369.0	0						
23	Communication equipment	370.0	714,440		TRANSMISSION	DEMAND	PDAY		
24	Other equipment	371.0	0						
25	ARO for Transmission Plant	372.0	0						
26	Subtotal - Transmission plant		$ 73,659,868						
27	**Distribution Plant**								
28	Land and land rights	374.0	$ 2,120,601		DISTRIBUTION	DEMAND	CUST_DEM		
29	Structures and improvements	375.0	86,895	INT_DIST_SUBTOTAL					
30	Mains	376.0	260,788,927		DISTRIBUTION	DEMAND	CUST_DEM		
31	Compressor station equipment	377.0	0						
32	Measuring and regulating station equipment—general	378.0	13,262,760		DISTRIBUTION	DEMAND	CUST_DEM		
33	Measuring and regulating station equipment—city gate check stations	379.0	97,219		DISTRIBUTION	DEMAND	CUST_DEM		
34	Services	380.0	214,568,497		CUSTOMER	CUSTOMER			SERV
35	Meters	381.0	80,601,889		CUSTOMER	CUSTOMER			MTRS
36	Meter installations	382.0	0						
37	House regulators	383.0	19,011,355		CUSTOMER	CUSTOMER			MTRS
38	House regulatory installations	384.0	0						
39	Industrial measuring and regulating station equipment	385.0	13,277,094		CUSTOMER	CUSTOMER			M&R
40	Other property on customers' premises	386.0	0						
41	Other equipment	387.0	0						
42	Asset retirement costs for distribution plant	388.0	0						
43	Subtotal - Distribution Plant		$ 603,815,237						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
44	**General Plant**								
45	Land and Land Rights	389.0	$ 3,598,925	INT_STOR_TRANSM_DIST_SUBTOTAL					
46	Structures and Improvements	390.0	26,123,545	INT_STOR_TRANSM_DIST_SUBTOTAL					
47	Office Furniture and Equipment	391.0	6,475,232	INT_OML					
48	Transportation Equipment	392.0	13,285,846	INT_STOR_TRANSM_DIST_SUBTOTAL					
49	Stores Equipment	393.0	45,565	INT_STOR_TRANSM_DIST_SUBTOTAL					
50	Tools, Shop, and Garage Equipment	394.0	8,470,948	INT_STOR_TRANSM_DIST_SUBTOTAL					
51	Laboratory Equipment	395.0	0						
52	Power Operated Equipment	396.0	1,847,313	INT_STOR_TRANSM_DIST_SUBTOTAL					
53	Communication Equipment	397.0	3,377,789	INT_STOR_TRANSM_DIST_SUBTOTAL					
54	Misc. Equipment	398.0	21,290	INT_STOR_TRANSM_DIST_SUBTOTAL					
55	Other Intangible Property	399.0	0						
56	ARO for General Plant	399.1	0						
57	Subtotal - General Plant		$ 63,246,453						
58	**Total Plant in Service**		$ 839,989,014						
59	**Accumulated Provision for Depreciation & Amortization**								
60	**Intangible Plant**								
61	Organization	301.0	$ (2,506)	INT_STOR_TRANSM	-	-	-	-	-
62	Franchises & Consents	302.0	(429,487)	INT_STOR_TRANSM	-	-	-	-	-
63	Misc. Intangible Plant - Plant Related	303.0	(5,432,750)	INT_STOR_TRANSM	-	-	-	-	-
64	Misc. Intangible Plant - Customer Related	303.0	0	-	-	-	-	-	-
65	Misc. Intangible Plant - Labor Related	303.0	(21,710,489)	INT_OML	-	-	-	-	-
66	Subtotal - Intangible Plant		$ (27,575,232)						
67	**Natural Gas Other Storage Plant**								
68	Land & Land Rights	360.0	$ -	0	STORAGE	DEMAND	PDAY	-	-
69	Structures & improvement	361.0	(3,074,406)	0	STORAGE	DEMAND	PDAY	-	-
70	Gas Holders	362.0	(3,796,957)	0	STORAGE	DEMAND	PDAY	-	-
71	Purification Equipment	363.0	(9,401,006)	0	STORAGE	DEMAND	PDAY	-	-
72	Subtotal - Natural Gas Other Storage Plant		$ (16,272,369)						
73	**Transmission plant**								
74	Land and Land Rights	365.1	$ (458,901)	0	TRANSMISSION	DEMAND	PDAY	-	-
75	Rights-of-Way	365.2	0	0	0	0	0	-	-
76	Structures and improvements	366.0	(59,206)	0	TRANSMISSION	DEMAND	PDAY	-	-
77	Mains	367.0	(49,147,989)	0	TRANSMISSION	DEMAND	PDAY	-	-
78	Compressor station equipment	368.0	(570,780)	0	TRANSMISSION	DEMAND	PDAY	-	-
79	Measuring and regulating station equipment	369.0	0	0	0	0	0	-	-
80	Communication equipment	370.0	(751,405)	0	TRANSMISSION	DEMAND	PDAY	-	-
81	Other equipment	371.0	0	0	0	0	0	-	-
82	ARO for Transmission Plant	372.0	0	0	0	0	0	-	-
83	Subtotal - Transmission plant		$ (50,988,281)						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
84	**Distribution Plant**								
85	Land and land rights	374.0	$ (440,513)	0	DISTRIBUTION	DEMAND	CUST_DEM	-	-
86	Structures and improvements	375.0	(20,501)	INT_DIST_SUBTC	0	0	0	-	-
87	Mains	376.0	(118,437,511)	0	DISTRIBUTION	DEMAND	CUST_DEM	-	-
88	Compressor station equipment	377.0	0	0	0	0	0	-	-
89	Measuring and regulating station equipment—general	378.0	(3,263,649)	0	DISTRIBUTION	DEMAND	CUST_DEM	-	-
90	Measuring and regulating station equipment—city gate check stations	379.0	559	0	DISTRIBUTION	DEMAND	CUST_DEM	-	-
91	Services	380.0	(116,439,054)	0	CUSTOMER	CUSTOMER	0	-	SERV
92	Meters	381.0	(30,579,658)	0	CUSTOMER	CUSTOMER	0	-	MTRS
93	Meter installations	382.0	0	0	0	0	0	-	-
94	House regulators	383.0	(6,900,827)	0	CUSTOMER	CUSTOMER	0	-	MTRS
95	House regulatory installations	384.0	0	0	0	0	0	-	-
96	Industrial measuring and regulating station equipment	385.0	(7,373,388)	0	CUSTOMER	CUSTOMER	0	-	M&R
97	Other property on customers' premises	386.0	0	0	0	0	0	-	-
98	Other equipment	387.0	0	0	0	0	0	-	-
99	Asset retirement costs for distribution plant	388.0	0	0	0	0	0	-	-
100	Subtotal - Distribution Plant		$ (283,454,542)						
101	**General Plant**								
102	Land and Land Rights	389.0	$ -	INT_STOR_TRANSM	-	-	-	-	-
103	Structures and Improvements	390.0	(9,732,176)	INT_STOR_TRANSM	-	-	-	-	-
104	Office Furniture and Equipment	391.0	(3,415,517)	INT_OML	-	-	-	-	-
105	Transportation Equipment	392.0	(5,137,199)	INT_STOR_TRANSM	-	-	-	-	-
106	Stores Equipment	393.0	(9,895)	INT_STOR_TRANSM	-	-	-	-	-
107	Tools, Shop, and Garage Equipment	394.0	(3,560,197)	INT_STOR_TRANSM	-	-	-	-	-
108	Laboratory Equipment	395.0	0	-	-	-	-	-	-
109	Power Operated Equipment	396.0	(612,161)	INT_STOR_TRANSM	-	-	-	-	-
110	Communication Equipment	397.0	(1,750,656)	INT_STOR_TRANSM	-	-	-	-	-
111	Misc. Equipment	398.0	(12,536)	INT_STOR_TRANSM	-	-	-	-	-
112	Other Intangible Property	399.0	0	-	-	-	-	-	-
113	ARO for General Plant	399.1	0	-	-	-	-	-	-
114	Subtotal - General Plant		$ (24,230,337)						
115	**Amortization**								
116	Intangible Plant	111.0	0						
117	Production Plant	111.0	0						
118	Natural gas storage and processing plant	111.0	0						
119	Transmission plant	111.0	0						
120	Distribution plant	111.0	0						
121	General plant	111.0	0						
122	Subtotal - Amortization		-						
123	**Total Accumulated Provision for Depreciation & Amortization**		$ (402,520,761)						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
124	**Other Rate Base Items**								
125	Natural gas plant acquisition adjustments	114.0	$ -						
126	Accumulated provision for asset acquisition adjustments	115.0	0						
127	Materials And Supplies	154.0	6,477,488	INT_STOR_TRANSM_DIST_SUBTOTAL					
128	Stores Expense Undistributed	163.0	0						
129	Gas Stored Underground - PA	164.1	0						
130	LNG Inventory	164.2	3,072,269		STORAGE	DEMAND	PDAY		
131	Prepayments	165.0	0						
132	Other regulatory assets	182.3	0						
133	Miscellaneous deferred debits	186.0	0						
134	Accumulated deferred income taxes	190.0	0						
135	Accumulated provision for property insurance	228.1	0						
136	Accumulated provision for injuries and damages	228.2	0						
137	Accumulated provision for pensions and benefits	228.3	0						
138	Accumulated miscellaneous operating provisions	228.4	0						
139	Accumulated provision for rate refunds	229.0	0						
140	Asset retirement obligations	230.0	0						
141	Customer deposits	235.0	0						
142	Other deferred credits	253.0	0						
143	Accumulated deferred income taxes—accelerated amortization property	281.0	0						
144	Accumulated deferred income taxes—Storage Plant	282.1	(2,499,689)	INT_STORPT					
145	Accumulated deferred income taxes—Transmission Plant	282.2	(4,537,370)	INT_TRANSPT					
146	Accumulated deferred income taxes—Distribution Plant	282.3	(37,194,379)	INT_DISTPT					
147	Accumulated deferred income taxes—General Plant	282.4	(3,895,915)	INT_GENPLT					
148	Accumulated deferred income taxes—other	283.0	0						
149	Accumulated deferred investment tax credits	255.0	0						
150	Customer advances for construction	252.0	(11,377,344)	INT_DMAINS_SERV					
151	Other regulatory liabilities	254.0	0						
152	Working capital allowance	N/A	0						
153	Subtotal - Other Rate Base Items		$ (49,954,940)						
154	**TOTAL RATE BASE**		$ 387,513,313						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
155	**OPERATION AND MAINTENANCE EXPENSE**								
156	**Production, Storage, LNG, Transmission, and Distribution Expense**								
157	**Other Gas Supply Expenses**								
158	Natural gas well head purchases	800.0	$ -						
159	Natural gas well head purchases, intracompany transfers	800.1	0						
160	Natural gas field line purchases	801.0	0						
161	Natural gas gasoline plant outlet purchases	802.0	0						
162	Natural gas transmission line purchases	803.0	0						
163	Natural gas city gate purchases	804.0	0						
164	Liquefied natural gas purchases	804.1	0						
165	Other gas purchases	805.0	0						
166	Purchased gas cost adjustments	805.1	0						
167	Exchange gas	806.0	0						
168	Well expenses—Purchased gas.	807.1	0						
169	Operation of purchased gas measuring stations.	807.2	0						
170	Maintenance of purchased gas measuring stations.	807.3	0						
171	Purchased gas calculations expenses.	807.4	0						
172	Other purchased gas expenses.	807.5	0						
173	Gas withdrawn from storage—debit	808.1	0						
174	Gas delivered to storage—credit	808.2	0						
175	Withdrawals of liquefied natural gas held for processing—debt	809.1	0						
176	Deliveries of natural gas for processing—credit	809.2	0						
177	Gas used for compressor station fuel—credit	810.0	0						
178	Gas used for products extraction—credit	811.0	0						
179	Other gas supply expenses - Gas Supply	813.1	301,989		DISTRIBUTION	CUSTOMER			CUST_SALES_TRAN
180	Other gas supply expenses	813.0	67,802		DISTRIBUTION	CUSTOMER			CUST
181	**Subtotal - Other Gas Supply Expenses**		$ 369,791						
182	**Other Storage Expenses - Operation**								
183	Operation supervision and engineering	840.0	$ 960		STORAGE	DEMAND	PDAY		
184	Operation labor and expenses	841.0	647,172		STORAGE	DEMAND	PDAY		
185	Rents	842.0	0						
186	Fuel	842.1	124,132		STORAGE	DEMAND	PDAY		
187	Power	842.2	109,214		STORAGE	DEMAND	PDAY		
188	Gas losses	842.3	0						
189	Subtotal - Other Storage Expenses - Operation		$ 881,479						

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
190	**Other Storage Expenses - Maintenance**								
191	Maintenance supervision and engineering	843.1	$ -						
192	Maintenance of structures and improvements	843.2	1,525		STORAGE	DEMAND	PDAY		
193	Maintenance of gas holders	843.3	299		STORAGE	DEMAND	PDAY		
194	Maintenance of purification equipment	843.4	1,761		STORAGE	DEMAND	PDAY		
195	Maintenance of liquefaction equipment	843.5	64,944		STORAGE	DEMAND	PDAY		
196	Maintenance of vaporizing equipment	843.6	109,460		STORAGE	DEMAND	PDAY		
197	Maintenance of compressor equipment	843.7	28,919		STORAGE	DEMAND	PDAY		
198	Maintenance of measuring and regulating equipment	843.8	0						
199	Maintenance of other equipment	843.9	30,000		STORAGE	DEMAND	PDAY		
200	Subtotal - Other Storage Expenses - Maintenance		$ 236,909						
201	**Transmission Operation Expenses**								
202	Operation supervision and engineering	850.0	$ -						
203	System control and load dispatching	851.0	0						
204	Communication system expenses	852.0	27,314		TRANSMISSION	DEMAND	PDAY		
205	Compressor station labor and expenses	853.0	86,348		TRANSMISSION	DEMAND	PDAY		
206	Gas for compressor station fuel	854.0	0						
207	Other fuel and power for compressor stations	855.0	0						
208	Mains expenses	856.0	1,885		TRANSMISSION	DEMAND	PDAY		
209	Measuring and regulating station expenses	857.0	0						
210	Transmission and compression of gas by others	858.0	0						
211	Other expenses	859.0	0						
212	Rents	860.0	0						
213	Subtotal - Transmission Operation Expenses		$ 115,547						
214	**Transmission Maintenance Expenses**								
215	Maintenance supervision and engineering	861.0	$ -						
216	Maintenance of structures and improvements	862.0	0						
217	Maintenance of mains	863.0	17,387		TRANSMISSION	DEMAND	PDAY		
218	Transmission Mains - Pipeline Integrity	863.1	28,262		TRANSMISSION	DEMAND	PDAY		
219	Maintenance of compressor station equipment	864.0	0						
220	Maintenance of measuring and regulating station equipment	865.0	0						
221	Maintenance of communication equipment	866.0	133,623		TRANSMISSION	DEMAND	PDAY		
222	Maintenance of other equipment	867.0	0						
223	Subtotal - Transmission Maintenance Expenses		$ 179,272						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
224	**Distribution Operation Expenses**								
225	Operation supervision and engineering	870.0	$ 4,317,916	INT_DIST_OL					
226	Operation supervision and engineering- Gas Supply and Control	870.1	62,783		DISTRIBUTION	CUSTOMER			CUST_SALES_TRAN
227	Distribution load dispatching	871.0	253,255		DISTRIBUTION	CUSTOMER			CUST_SALES_TRAN
228	Compressor station fuel and power (major only)	873.0	0						
229	Mains and services expenses	874.0	4,725,499	INT_DMAINS_SERV					
230	Measuring and regulating station expenses—general	875.0	437,602		DISTRIBUTION	DEMAND	CUST_DEM		
231	Measuring and regulating station expenses—industrial	876.0	330,316		DISTRIBUTION	CUSTOMER			M&R
232	Measuring and regulating station expenses—city gate check stations	877.0	0						
233	Meter and house regulator expenses	878.0	1,633,964		CUSTOMER	CUSTOMER			MTRS
234	Meter and house regulator expenses - installation credits	878.3	(1,833,969)		CUSTOMER	CUSTOMER			MTRS
235	Customer installations expenses	879.0	2,404,356		CUSTOMER	CUSTOMER			CUST
236	Other expenses	880.0	4,819,166	INT_DISTPT					
237	Rents	881.0	241,488	INT_DIST_OL					
238	Subtotal - Distribution Operation Expenses		$ 17,392,377						
239	**Distribution Maintenance Expenses**								
240	Maintenance supervision and engineering	885.0	$ 252,408	INT_DIST_ML					
241	Maintenance of structures and improvements	886.0	0						
242	Maintenance of mains	887.0	1,559,102		DISTRIBUTION	DEMAND	CUST_DEM		
243	Distribution Mains - Pipeline Integrity	887.1	90,461		DISTRIBUTION	DEMAND	CUST_DEM		
244	Maintenance of compressor station equipment	888.0	0						
245	Maintenance of measuring and regulating station equipment—general	889.0	577,682		DISTRIBUTION	DEMAND	CUST_DEM		
246	Maintenance of measuring and regulating station equipment—industrial	890.0	122,251		CUSTOMER	CUSTOMER			M&R
247	Maintenance of measuring and regulating station equipment—city gate	891.0	0						
248	Maintenance of services	892.0	3,159,609		DISTRIBUTION	CUSTOMER			SERV
249	Maintenance of meters and house regulators	893.0	1,235,301		DISTRIBUTION	CUSTOMER			MTRS
250	Maintenance of other equipment	894.0	569,681	INT_DIST_ML					
251	Subtotal - Distribution Maintenance Expenses		$ 7,566,497						
252	**Total Production, Storage, LNG, Transmission, and Distribution Expense**		$ 26,741,871						
253	**Customer Accounts, Service, and Sales Expense**								
254	**Customer Account**								
255	Supervision	901.0	$ 177,085	INT_CUSTACC					
256	Meter reading expenses	902.0	1,078,574		CUSTOMER	CUSTOMER			CUST
257	Customer records and collection expenses	903.0	7,216,280		CUSTOMER	CUSTOMER			CUST
258	Uncollectible accounts	904.0	510,784		CUSTOMER	CUSTOMER			ACT_904
259	Miscellaneous customer accounts expenses	905.0	0						
260	Subtotal - Customer Account		$ 8,982,723						

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
261	**Customer Service & Information Expenses**								
262	Supervision	907.0	$ -						
263	Customer assistance expenses	908.0	835,629		CUSTOMER	CUSTOMER			CUST
264	Informational and instructional advertising expenses	909.0	126,903		CUSTOMER	CUSTOMER			CUST
265	Miscellaneous customer service and informational expenses	910.0	0						
266	Subtotal - Customer Service & Information Expenses		$ 962,532						
267	**Sales Expenses**								
268	Supervision	911.0	$ 231,731		CUSTOMER	CUSTOMER			CUST
269	Demonstrating and selling expenses	912.0	1,241,710		CUSTOMER	CUSTOMER			CUST
270	Advertising expenses	913.0	40,610		CUSTOMER	CUSTOMER			CUST
271	Miscellaneous sales expenses	916.0	0						
272	Subtotal - Sales Expenses		$ 1,514,051						
273	**Total Customer Accounts, Service, and Sales Expense**		$ 11,459,306						
274	**Administrative and General Expenses**								
275	Administrative and general salaries	920.0	$ 6,169,823	INT_OML					
276	Administrative and general salaries - Gas Supply and Control	920.1	164,929		CUSTOMER	CUSTOMER			CUST_SALES_TRAN
277	Office supplies and expenses	921.0	5,722,640	INT_OML					
278	Outside services employed	923.0	596,622	INT_OML					
279	Property insurance	924.0	122,539	INT_TOTPLT					
280	Injuries and damages	925.0	1,221,147	INT_OML					
281	Employee pensions and benefits	926.0	1,594,449	INT_OML					
282	Franchise requirements	927.0	0						
283	Regulatory commission expenses	928.0	118,537		CUSTOMER	CUSTOMER			REV
284	Duplicate charges—Credit	929.0	0						
285	General advertising expenses	930.1	78,048		CUSTOMER	CUSTOMER			CUST
286	Miscellaneous general expenses	930.2	436,330	INT_DIST_SUBTOTAL					
287	Rents	931.0	819,634	INT_OML					
288	Maintenance of general plant	935.0	4	INT_GENPLT					
289	Subtotal - Administrative and General Expenses		$ 17,044,704						
290	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		$ 55,245,881						
291	**Adjustments, Depreciation and Amortization Expense**								
292	**Depreciation Expense**								
293	Depreciation expense intangible plant	403.1	$ 4,703,175	INT_INTGPLT					
294	Depreciation expense storage and terminaling	403.2	1,112,919	INT_STORPT					
295	Depreciation expense transmission	403.3	1,064,501	INT_TRANSPT					
296	Depreciation expense distribution	403.4	13,524,126	INT_DISTPT					
297	Depreciation expense general plant	403.5	1,725,030	INT_GENPLT					
298	Subtotal - Depreciation Expense		$ 22,129,750						

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
299	**Amortization Expense**								
300	Amortization and depletion of producing natural gas land and land	404.1	$ -						
301	Amortization of underground storage land and land rights	404.2	0						
302	Amortization of other limited-term gas plant	404.3	0						
303	Amortization of other gas plant	405.0	0						
304	Amortization of gas plant acquisition adjustments	406.0	0						
305	Amortization of property losses, unrecovered plant and regulatory	407.1	0						
306	Amortization of conversion expense	407.2	0						
307	Subtotal - Amortization Expense		-						
308	**Total Adjustments, Depreciation and Amortization Expense**		$ 22,129,750						
309	**Taxes**								
310	**Taxes Other Than Income Taxes**								
311	Taxes Other Than Income Taxes - Payroll	408.1	$ 2,282,838	INT_OML					
312	Taxes Other Than Income Taxes - Property	408.2	3,623,049	INT_TOTPLT					
313	Taxes Other Than Income Taxes - Franchise	408.3	13,950		CUSTOMER	CUSTOMER			REV
314	Taxes Other Than Income Taxes - IPUC Fee	408.4	520,047		CUSTOMER	CUSTOMER			REV
315	Subtotal - Taxes Other Than Income Taxes		$ 6,439,884						
316	**Income Taxes**								
317	Income Taxes - federal taxes utility operating income	409.1	$ 5,054,746	INT_REQ_INCOME					
318	Income Taxes - state taxes utility operating income	409.1	771,296	INT_REQ_INCOME					
319	Income Taxes - other taxes utility operating income	410.1	0	INT_REQ_INCOME					
320	Provision for deferred income taxes—credit, utility operating income	411.1	0						
321	Investment Tax credit Adj.	411.4	0						
322	Subtotal - Income Taxes		$ 5,826,042						
323	**Total Taxes**		$ 12,265,926						
324	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
325	**Test Year Expenses at Current Rates**		$ 89,641,557						
326	**Return on Rate Base**		$ 28,559,731	INT_RATEBASE					
327	**Gross Up Items**								
328	Federal Income Tax		$ 2,233,076	INT_REQ_INCOME					
329	State Income Tax		654,723	INT_REQ_INCOME					
330	Uncollectible Account - Increase		26,996		CUSTOMER	CUSTOMER			ACT_904
331	Taxes Other Than Income Taxes - IPUC Fee		22,619		CUSTOMER	CUSTOMER			REV
332	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**$ 121,138,702**						

Intermountain Gas Company
Class Cost of Service Study - Development of External Allocators
Test Year Ended December 31, 2022
Schedule 2 - External Allocation Factors

Allocator Code	Description	Classifier	Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
				RS	GS	LV-1	T-3	T-4
CUSTOMER EXTERNAL ALLOCATORS								
CUST	**Average Number Customers**	**CUS**	**100.0%**	**91.3%**	**8.7%**	**0.0%**	**0.0%**	**0.0%**
			403,743	368,571	35,029	34	7	102
CUST_SALES_TRANS	**Gas Supply and Control Cost Allocation**	**CUS**	**100.0%**	**34.9%**	**16.1%**	**2.9%**	**2.4%**	**43.7%**
			782,956	273,270	126,059	22,872	18,773	341,983
MTRS	**Customer Meters**	**CUS**	**100.0%**	**73.9%**	**25.4%**	**0.1%**	**0.1%**	**0.5%**
	Weighted Customer Cost		5,986,091	4,422,848	1,519,086	7,226	6,346	30,585
M&R	**Industrial measuring and regulating station equipment**	**CUS**	**100.0%**	**0.0%**	**91.1%**	**3.0%**	**0.4%**	**5.5%**
	Weighted Customer Cost		9,362		8,532	279	36	515
SERV	**Services**	**CUS**	**100.0%**	**81.4%**	**17.8%**	**0.2%**	**0.0%**	**0.6%**
	Weighted Customer Cost		452,446	368,350	80,593	729	132	2,642
ACT_904	**Uncollectible accounts**	**CUS**	**100.0%**	**85.4%**	**14.2%**	**0.1%**	**0.0%**	**0.3%**
	Uncollectible accounts - Residential		476,351	476,351				
	Uncollectible accounts - Commercial		79,180		79,180			
	Uncollectible accounts - Industrial		2,473			591	121	1,761
	Uncollectible accounts		558,004	476,351	79,180	591	121	1,761
COMMODITY EXTERNAL ALLOCATORS								
REV	**Total Sales and Transportation**	**REV**	**100.0%**	**65.6%**	**24.2%**	**0.6%**	**0.5%**	**9.0%**
			107,349,830	70,391,038	26,030,361	677,926	537,118	9,713,387
COM	**Weather Normalized Volumes**	**COM**	**100.0%**	**35.1%**	**17.1%**	**1.7%**	**5.2%**	**40.9%**
			805,130,573	282,522,986	138,067,893	13,566,644	41,523,144	329,449,906
DEMAND EXTERNAL ALLOCATORS								
PDAY_F&I	**Peak Day (Design Day) Firm & Interruptible**	**DEM**	**100.0%**	**51.6%**	**22.8%**	**1.1%**	**1.7%**	**22.8%**
			6,521,643	3,362,707	1,485,359	74,405	113,762	1,485,410
PDAY_F	**Peak Day (Design Day) Firm**	**DEM**	**100.0%**	**52.5%**	**23.2%**	**1.2%**	**0.0%**	**23.2%**
			6,404,055	3,360,303	1,483,938	74,405		1,485,410
CUST_DEM_F&I	**Customer and Demand Composite Factor**	**DEM**	**100.0%**	**73.5%**	**15.0%**	**0.5%**	**0.8%**	**10.2%**
	CUST		1.0000	0.9129	0.0868	0.0001	0.0000	0.0003
	CUST Customer Component - Zero-Intercept (WLR)	55.3%	0.5525	0.5044	0.0479	0.0000	0.0000	0.0001
	PDAY_F&I		1.0000	0.5156	0.2278	0.0114	0.0174	0.2278
	PDAY Demand Components	44.7%	0.4475	0.2307	0.1019	0.0051	0.0078	0.1019
CUST_DEM_F	**Customer and Demand Composite Factor**	**DEM**	**100.0%**	**73.9%**	**15.2%**	**0.5%**	**0.0%**	**10.4%**
	CUST		1.0000	0.9129	0.0868	0.0001	0.0000	0.0003
	CUST Customer Component - Zero-Intercept (WLR)	55.3%	0.5525	0.5044	0.0479	0.0000	0.0000	0.0001
	PDAY_F		1.0000	0.5247	0.2317	0.0116	-	0.2319
	PDAY Demand Components	44.7%	0.4475	0.2348	0.1037	0.0052	-	0.1038

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 3 - Internal Allocation Factors

Allocator Code	Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
ALLOCATION FACTOR BASIS						
INT_INTGPLT	$ 58,687,385	$ 43,141,262	$ 11,473,761	$ 275,179	$ 64,619	$ 3,732,565
INT_STORPT	$ 40,580,071	$ 21,292,963	$ 9,403,152	$ 471,476	$ -	$ 9,412,480
INT_TRANSPT	$ 73,659,868	$ 38,650,421	$ 17,068,351	$ 855,811	$ -	$ 17,085,284
INT_DISTPT	$ 603,815,237	$ 452,566,741	$ 117,505,276	$ 2,310,976	$ 221,437	$ 31,210,808
INT_GENPLT	$ 63,246,453	$ 45,316,166	$ 12,640,703	$ 317,377	$ 25,969	$ 4,946,238
INT_TOTPLT	$ 839,989,014	$ 600,967,553	$ 168,091,243	$ 4,230,819	$ 312,025	$ 66,387,375
INT_RATEBASE	$ 387,513,313	$ 278,312,371	$ 77,282,709	$ 1,889,417	$ 153,217	$ 29,875,599
INT_DMAINS_SERV	$ 475,357,424	$ 367,457,769	$ 77,763,063	$ 1,713,647	$ 65,158	$ 28,357,788
INT_OML	$ 19,453,208	$ 14,407,914	$ 3,777,971	$ 89,306	$ 25,421	$ 1,152,595
INT_DIST_OL	$ 9,662,687	$ 7,232,893	$ 1,878,272	$ 42,086	$ 11,669	$ 497,767
INT_DIST_ML	$ 4,801,667	$ 3,704,475	$ 916,093	$ 13,527	$ 1,846	$ 165,726
INT_CUSTACC	$ 8,805,638	$ 8,008,293	$ 792,138	$ 1,245	$ 254	$ 3,708
INT_DIST_SUBTOTAL	$ 14,758,214	$ 11,265,162	$ 2,674,581	$ 60,271	$ 12,033	$ 746,167
INT_STOR_TRANSM_DIST_SUBTOTAL	$ 718,055,176	$ 512,510,125	$ 143,976,779	$ 3,638,263	$ 221,437	$ 57,708,572
INT_REQ_INCOME	$ 28,559,731	$ 20,511,622	$ 5,695,736	$ 139,250	$ 11,292	$ 2,201,832
INT_REV REQ	$ 121,138,702	$ 90,246,109	$ 22,498,973	$ 531,389	$ 85,891	$ 7,776,340
ALLOCATION FACTOR						
INT_INTGPLT	100.00%	73.51%	19.55%	0.47%	0.11%	6.36%
INT_STORPT	100.00%	52.47%	23.17%	1.16%	0.00%	23.19%
INT_TRANSPT	100.00%	52.47%	23.17%	1.16%	0.00%	23.19%
INT_DISTPT	100.00%	74.95%	19.46%	0.38%	0.04%	5.17%
INT_GENPLT	100.00%	71.65%	19.99%	0.50%	0.04%	7.82%
INT_TOTPLT	100.00%	71.54%	20.01%	0.50%	0.04%	7.90%
INT_RATEBASE	100.00%	71.82%	19.94%	0.49%	0.04%	7.71%
INT_DMAINS_SERV	100.00%	77.30%	16.36%	0.36%	0.01%	5.97%
INT_OML	100.00%	74.06%	19.42%	0.46%	0.13%	5.92%
INT_DIST_OL	100.00%	74.85%	19.44%	0.44%	0.12%	5.15%
INT_DIST_ML	100.00%	77.15%	19.08%	0.28%	0.04%	3.45%
INT_CUSTACC	100.00%	90.95%	9.00%	0.01%	0.00%	0.04%
INT_DIST_SUBTOTAL	100.00%	76.33%	18.12%	0.41%	0.08%	5.06%
INT_STOR_TRANSM_DIST_SUBTOTAL	100.00%	71.37%	20.05%	0.51%	0.03%	8.04%
INT_REQ_INCOME	100.00%	71.82%	19.94%	0.49%	0.04%	7.71%
INT_REV REQ	100.00%	74.50%	18.57%	0.44%	0.07%	6.42%

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 4 – Cost of Service and Rate of Return under Present and Proposed Rates

Line No.	Revenue Requirement Summary	Total System	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
1	**Rate Base**						
2	Plant in Service	$ 839,989,014	$ 600,967,553	$ 168,091,243	$ 4,230,819	$ 312,025	$ 66,387,375
3	Accumulated Reserve	(402,520,761)	(285,734,187)	(81,310,557)	(2,125,239)	(144,006)	(33,206,772)
4	Other Rate Base Items	(49,954,940)	(36,920,995)	(9,497,977)	(216,163)	(14,802)	(3,305,004)
5	**Total Rate Base**	**$ 387,513,313**	**$ 278,312,371**	**$ 77,282,709**	**$ 1,889,417**	**$ 153,217**	**$ 29,875,599**
6	**Rate of Return Under Current ROR**						
7	**Revenue at Current Rates**						
8	Gas Service Revenue	$ 107,349,830	$ 70,391,038	$ 26,030,361	$ 677,926	$ 537,118	$ 9,713,387
9	Other Revenues	2,450,925	1,825,894	455,208	10,751	1,738	157,334
10	**Total Revenue**	**$ 109,800,755**	**$ 72,216,932**	**$ 26,485,569**	**$ 688,677**	**$ 538,856**	**$ 9,870,721**
11	**Expenses at Current Rates**						
12	O&M and A&G Expenses	$ 55,245,881	$ 42,832,979	$ 9,357,577	$ 209,613	$ 53,188	$ 2,792,524
13	Depreciation and Amortization Expense	22,129,750	15,972,322	4,400,679	107,768	10,847	1,638,135
14	Taxes Other Than Income	6,439,884	4,633,021	1,297,843	32,101	7,001	469,918
15	**Total Operating Expenses**	**$ 83,815,515**	**$ 63,438,322**	**$ 15,056,099**	**$ 349,481**	**$ 71,035**	**$ 4,900,577**
16	**Earnings Before Interest and Taxes**	**$ 25,985,240**	**$ 8,778,610**	**$ 11,429,470**	**$ 339,196**	**$ 467,821**	**$ 4,970,144**
17	Current State/Federal Income Taxes	$ 5,826,042	$ 1,968,215	$ 2,562,554	$ 76,050	$ 104,888	$ 1,114,335
18	Deferred Income Tax	-	-	-	-	-	-
19	**Total Income Taxes**	**$ 5,826,042**	**$ 1,968,215**	**$ 2,562,554**	**$ 76,050**	**$ 104,888**	**$ 1,114,335**
20	**Total Expenses at Current Rates**	**$ 89,641,557**	**$ 65,406,537**	**$ 17,618,653**	**$ 425,531**	**$ 175,923**	**$ 6,014,912**
21	**Operating Income at Current Rates**	**$ 20,159,198**	**$ 6,810,395**	**$ 8,866,916**	**$ 263,146**	**$ 362,933**	**$ 3,855,809**
22	**Current Rate of Return**	**5.20%**	**2.45%**	**11.47%**	**13.93%**	**236.88%**	**12.91%**
23	**Relative Rate of Return**	**1.00**	**0.47**	**2.21**	**2.68**	**45.53**	**2.48**
24	**Current Revenue to Cost Ratio**	**0.91**	**0.80**	**1.18**	**1.30**	**6.27**	**1.27**
25	**Current Parity Ratio**	**1.00**	**0.88**	**1.30**	**1.43**	**6.92**	**1.40**

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 4 – Cost of Service and Rate of Return under Present and Proposed Rates

Line No.	Revenue Requirement Summary	Total System	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
26	Rate of Return Under Equal ROR						
27	**Revenue Requirement Required Return at Equal Rates of Return**						
28	Required Return	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
29	Required Operating Income	$ 28,559,731	$ 20,511,622	$ 5,695,736	$ 139,250	$ 11,292	$ 2,201,832
30	**Expenses at Required Return**						
31	O&M and A&G Expenses	$ 55,245,881	$ 42,832,979	$ 9,357,577	$ 209,613	$ 53,188	$ 2,792,524
32	Depreciation and Amortization Expense	22,129,750	15,972,322	4,400,679	107,768	10,847	1,638,135
33	Taxes Other Than Income	6,439,884	4,633,021	1,297,843	32,101	7,001	469,918
34	**Total Operating Expenses**	**$ 83,815,515**	**$ 63,438,322**	**$ 15,056,099**	**$ 349,481**	**$ 71,035**	**$ 4,900,577**
35	Deferred Income Tax	$ -	$ -	$ -	$ -	$ -	$ -
36	Current State/Federal Income Taxes	5,826,042	4,184,268	1,161,902	28,406	2,304	449,163
37	**Income Taxes and Other**	**$ 5,826,042**	**$ 4,184,268**	**$ 1,161,902**	**$ 28,406**	**$ 2,304**	**$ 449,163**
38	Increase - Federal Income Tax	$ 2,233,076	$ 1,603,797	$ 445,348	$ 10,888	$ 883	$ 172,160
39	Increase - State Utility Tax	654,723	470,223	130,573	3,192	259	50,476
40	Increase - Bad Debts	26,996	23,046	3,831	29	6	85
41	Increase - Annual Filing Fee	22,619	14,832	5,485	143	113	2,047
42	**Revenue Increase Related Expenses**	**$ 2,937,414**	**$ 2,111,897**	**$ 585,236**	**$ 14,252**	**$ 1,261**	**$ 224,769**
43	**Total Expenses at Required Return**	**$ 92,578,971**	**$ 69,734,487**	**$ 16,803,237**	**$ 392,139**	**$ 74,599**	**$ 5,574,508**
44	**Total Revenue Requirement Required Return at Equal Rates of Return**	**$ 121,138,702**	**$ 90,246,109**	**$ 22,498,973**	**$ 531,389**	**$ 85,891**	**$ 7,776,340**
45	LESS						
46	Current Miscellaneous Revenue Margin	2,450,925	1,825,894	455,208	10,751	1,738	157,334
47	**Total Rate Margin at Equal Rates of Return**	**$ 118,687,777**	**$ 88,420,214**	**$ 22,043,765**	**$ 520,638**	**$ 84,154**	**$ 7,619,006**
48	**Total Current Rate Margin**	**$ 107,349,830**	**$ 70,391,038**	**$ 26,030,361**	**$ 677,926**	**$ 537,118**	**$ 9,713,387**
49	**Base Rate Margin (Deficiency)/Surplus**	**$ (11,337,947)**	**$ (18,029,176)**	**$ 3,986,596**	**$ 157,288**	**$ 452,964**	**$ 2,094,381**
50	**Proposed Margin Increase**	**$ 11,337,947**	**$ 9,293,097**	**$ 1,451,307**	**$ 37,797**	**$ 14,182**	**$ 541,564**
51	**Total Revenue Increase as Proposed**	**$ 121,138,702**	**$ 81,510,029**	**$ 27,936,876**	**$ 726,475**	**$ 553,038**	**$ 10,412,285**
52	Income Prior to Taxes	$ 37,273,572	$ 18,033,829	$ 12,871,461	$ 376,822	$ 481,884	$ 5,509,576
53	Income Taxes and Other	$ 8,713,841	$ 6,258,288	$ 1,737,822	$ 42,486	$ 3,445	$ 671,799
54	**Proposed Operating Income**	**$ 28,559,731**	**$ 11,775,542**	**$ 11,133,639**	**$ 334,335**	**$ 478,439**	**$ 4,837,777**
55	**Proposed Rate of Return**	**7.37%**	**4.23%**	**14.41%**	**17.70%**	**312.26%**	**16.19%**
56	**Relative Rate of Return**	**1.00**	**0.57**	**1.95**	**2.40**	**42.37**	**2.20**
57	**Proposed Revenue to Cost Ratio**	**1.00**	**0.90**	**1.24**	**1.37**	**6.44**	**1.34**
58	**Proposed Parity Ratio**	**1.00**	**0.90**	**1.24**	**1.37**	**6.44**	**1.34**

Intermountain Gas Company
Gas Class Cost of Service Study
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Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
1	**RATE BASE**							
2	**Plant in Service**							
3	**Intangible Plant**							
4	Organization	301	$ 2,506	$ 1,789	$ 502	$ 13	$ 1	$ 201
5	Franchises & Consents	302	429,487	306,545	86,116	2,176	132	34,517
6	Misc. Intangible Plant - Plant Related	303	11,659,883	8,322,213	2,337,916	59,079	3,596	937,080
7	Misc. Intangible Plant - Customer Related	303	-	-	-	-	-	-
8	Misc. Intangible Plant - Labor Related	303	46,595,509	34,510,715	9,049,226	213,911	60,890	2,760,767
9	Subtotal - Intangible Plant		$ 58,687,385	$ 43,141,262	$ 11,473,761	$ 275,179	$ 64,619	$ 3,732,565
10	**Natural Gas Other Storage Plant**							
11	Land & Land Rights	360	$ 292,588	$ 153,525	$ 67,798	$ 3,399	$ -	$ 67,865
12	Structures & improvement	361	10,211,065	5,357,897	2,366,092	118,636	-	2,368,440
13	Gas Holders	362	10,871,165	5,704,261	2,519,050	126,306	-	2,521,549
14	Purification Equipment	363	19,205,253	10,077,280	4,450,212	223,135	-	4,454,627
15	Subtotal - Natural Gas Other Storage Plant		$ 40,580,071	$ 21,292,963	$ 9,403,152	$ 471,476	$ -	$ 9,412,480
16	**Transmission plant**							
17	Land and Land Rights	365.1	$ 782,865	$ 410,781	$ 181,404	$ 9,096	$ -	$ 181,584
18	Rights-of-Way	365.2	-	-	-	-	-	-
19	Structures and improvements	366	77,152	40,483	17,878	896	-	17,895
20	Mains	367	69,918,045	36,687,032	16,201,302	812,337	-	16,217,374
21	Compressor station equipment	368	2,167,366	1,137,249	502,219	25,181	-	502,717
22	Measuring and regulating station equipment	369	-	-	-	-	-	-
23	Communication equipment	370	714,440	374,877	165,549	8,301	-	165,713
24	Other equipment	371	-	-	-	-	-	-
25	ARO for Transmission Plant	372	-	-	-	-	-	-
26	Subtotal - Transmission plant		$ 73,659,868	$ 38,650,421	$ 17,068,351	$ 855,811	$ -	$ 17,085,284
27	**Distribution Plant**							
28	Land and land rights	374	$ 2,120,601	$ 1,567,513	$ 321,541	$ 11,125	$ 20	$ 220,402
29	Structures and improvements	375	86,895	66,328	15,748	355	71	4,393
30	Mains	376	260,788,927	192,770,880	39,542,668	1,368,093	2,498	27,104,787
31	Compressor station equipment	377	-	-	-	-	-	-
32	Measuring and regulating station equipment—general	378	13,262,760	9,803,614	2,010,994	69,576	127	1,378,449
33	Measuring and regulating station equipment—city gate check stations	379	97,219	71,863	14,741	510	1	10,104
34	Services	380	214,568,497	174,686,888	38,220,396	345,553	62,659	1,253,001
35	Meters	381	80,601,889	59,553,036	20,454,286	97,296	85,452	411,819
36	Meter installations	382	-	-	-	-	-	-
37	House regulators	383	19,011,355	14,046,618	4,824,498	22,949	20,155	97,135
38	House regulatory installations	384	-	-	-	-	-	-
39	Industrial measuring and regulating station equipment	385	13,277,094	-	12,100,406	395,518	50,452	730,717
40	Other property on customers' premises	386	-	-	-	-	-	-
41	Other equipment	387	-	-	-	-	-	-
42	Asset retirement costs for distribution plant	388	-	-	-	-	-	-
43	Subtotal - Distribution Plant		$ 603,815,237	$ 452,566,741	$ 117,505,276	$ 2,310,976	$ 221,437	$ 31,210,808

Intermountain Gas Company
Gas Class Cost of Service Study
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Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
44	**General Plant**							
45	Land and Land Rights	389	$ 3,598,925	$ 2,568,724	$ 721,618	$ 18,235	$ 1,110	$ 289,238
46	Structures and Improvements	390	26,123,545	18,645,616	5,238,015	132,364	8,056	2,099,494
47	Office Furniture and Equipment	391	6,475,232	4,795,846	1,257,543	29,727	8,462	383,655
48	Transportation Equipment	392	13,285,846	9,482,740	2,663,936	67,317	4,097	1,067,755
49	Stores Equipment	393	45,565	32,522	9,136	231	14	3,662
50	Tools, Shop, and Garage Equipment	394	8,470,948	6,046,118	1,698,504	42,921	2,612	680,792
51	Laboratory Equipment	395	-	-	-	-	-	-
52	Power Operated Equipment	396	1,847,313	1,318,515	370,404	9,360	570	148,465
53	Communication Equipment	397	3,377,789	2,410,889	677,278	17,115	1,042	271,466
54	Misc. Equipment	398	21,290	15,196	4,269	108	7	1,711
55	Other Intangible Property	399	-	-	-	-	-	-
56	ARO for General Plant	399.1	-	-	-	-	-	-
57	Subtotal - General Plant		$ 63,246,453	$ 45,316,166	$ 12,640,703	$ 317,377	$ 25,969	$ 4,946,238
58	**Total Plant in Service**		$ 839,989,014	$ 600,967,553	$ 168,091,243	$ 4,230,819	$ 312,025	$ 66,387,375
59	**Accumulated Provision for Depreciation & Amortization**							
60	**Intangible Plant**							
61	Organization	301	$ (2,506)	$ (1,789)	$ (502)	$ (13)	$ (1)	$ (201)
62	Franchises & Consents	302	(429,487)	(306,545)	(86,116)	(2,176)	(132)	(34,517)
63	Misc. Intangible Plant - Plant Related	303	(5,432,750)	(3,877,612)	(1,089,317)	(27,527)	(1,675)	(436,619)
64	Misc. Intangible Plant - Customer Related	303	-	-	-	-	-	-
65	Misc. Intangible Plant - Labor Related	303	(21,710,489)	(16,079,758)	(4,216,353)	(99,669)	(28,371)	(1,286,339)
66	Subtotal - Intangible Plant		$ (27,575,232)	$ (20,265,704)	$ (5,392,289)	$ (129,385)	$ (30,179)	$ (1,757,675)
67	**Natural Gas Other Storage Plant**							
68	Land & Land Rights	360	$ -	$ -	$ -	$ -	$ -	$ -
69	Structures & improvement	361	(3,074,406)	(1,613,186)	(712,397)	(35,720)	-	(713,103)
70	Gas Holders	362	(3,796,957)	(1,992,319)	(879,825)	(44,115)	-	(880,698)
71	Purification Equipment	363	(9,401,006)	(4,932,847)	(2,178,387)	(109,225)	-	(2,180,548)
72	Subtotal - Natural Gas Other Storage Plant		$ (16,272,369)	$ (8,538,353)	$ (3,770,608)	$ (189,059)	$ -	$ (3,774,349)
73	**Transmission plant**							
74	Land and Land Rights	365.1	$ (458,901)	$ (240,792)	$ (106,336)	$ (5,332)	$ -	$ (106,441)
75	Rights-of-Way	365.2	-	-	-	-	-	-
76	Structures and improvements	366	(59,206)	(31,066)	(13,719)	(688)	-	(13,733)
77	Mains	367	(49,147,989)	(25,788,676)	(11,388,496)	(571,022)	-	(11,399,794)
78	Compressor station equipment	368	(570,780)	(299,497)	(132,260)	(6,632)	-	(132,391)
79	Measuring and regulating station equipment	369	-	-	-	-	-	-
80	Communication equipment	370	(751,405)	(394,273)	(174,114)	(8,730)	-	(174,287)
81	Other equipment	371	-	-	-	-	-	-
82	ARO for Transmission Plant	372	-	-	-	-	-	-
83	Subtotal - Transmission plant		$ (50,988,281)	$ (26,754,305)	$ (11,814,926)	$ (592,403)	$ -	$ (11,826,647)

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
84	**Distribution Plant**							
85	Land and land rights	374	$ (440,513)	$ (325,620)	$ (66,794)	$ (2,311)	$ (4)	$ (45,784)
86	Structures and improvements	375	(20,501)	(15,649)	(3,715)	(84)	(17)	(1,037)
87	Mains	376	(118,437,511)	(87,547,058)	(17,958,336)	(621,321)	(1,135)	(12,309,662)
88	Compressor station equipment	377	-	-	-	-	-	-
89	Measuring and regulating station equipment—general	378	(3,263,649)	(2,412,436)	(494,858)	(17,121)	(31)	(339,203)
90	Measuring and regulating station equipment—city gate check stations	379	559	413	85	3	0	58
91	Services	380	(116,439,054)	(94,796,656)	(20,740,914)	(187,520)	(34,003)	(679,961)
92	Meters	381	(30,579,658)	(22,593,906)	(7,760,179)	(36,913)	(32,420)	(156,240)
93	Meter installations	382	-	-	-	-	-	-
94	House regulators	383	(6,900,827)	(5,098,704)	(1,751,218)	(8,330)	(7,316)	(35,258)
95	House regulatory installations	384	-	-	-	-	-	-
96	Industrial measuring and regulating station equipment	385	(7,373,388)	-	(6,719,918)	(219,650)	(28,019)	(405,801)
97	Other property on customers' premises	386	-	-	-	-	-	-
98	Other equipment	387	-	-	-	-	-	-
99	Asset retirement costs for distribution plant	388	-	-	-	-	-	-
100	Subtotal - Distribution Plant		$ (283,454,542)	$ (212,789,615)	$ (55,495,847)	$ (1,093,247)	$ (102,945)	$ (13,972,889)
101	**General Plant**							
102	Land and Land Rights	389	$ -	$ -	$ -	$ -	$ -	$ -
103	Structures and Improvements	390	(9,732,176)	(6,946,317)	(1,951,392)	(49,311)	(3,001)	(782,154)
104	Office Furniture and Equipment	391	(3,415,517)	(2,529,684)	(663,321)	(15,680)	(4,463)	(202,368)
105	Transportation Equipment	392	(5,137,199)	(3,666,663)	(1,030,056)	(26,029)	(1,584)	(412,866)
106	Stores Equipment	393	(9,895)	(7,063)	(1,984)	(50)	(3)	(795)
107	Tools, Shop, and Garage Equipment	394	(3,560,197)	(2,541,082)	(713,853)	(18,039)	(1,098)	(286,125)
108	Laboratory Equipment	395	-	-	-	-	-	-
109	Power Operated Equipment	396	(612,161)	(436,928)	(122,744)	(3,102)	(189)	(49,198)
110	Communication Equipment	397	(1,750,656)	(1,249,526)	(351,023)	(8,870)	(540)	(140,697)
111	Misc. Equipment	398	(12,536)	(8,948)	(2,514)	(64)	(4)	(1,007)
112	Other Intangible Property	399	-	-	-	-	-	-
113	ARO for General Plant	399.1	-	-	-	-	-	-
114	Subtotal - General Plant		$ (24,230,337)	$ (17,386,211)	$ (4,836,887)	$ (121,145)	$ (10,882)	$ (1,875,211)
115	**Amortization**							
116	Intangible Plant	111	$ -	$ -	$ -	$ -	$ -	$ -
117	Production Plant	111	-	-	-	-	-	-
118	Natural gas storage and processing plant	111	-	-	-	-	-	-
119	Transmission plant	111	-	-	-	-	-	-
120	Distribution plant	111	-	-	-	-	-	-
121	General plant	111	-	-	-	-	-	-
122	Subtotal - Amortization		$ -	$ -	$ -	$ -	$ -	$ -
123	**Total Accumulated Provision for Depreciation & Amortization**		$ (402,520,761)	$ (285,734,187)	$ (81,310,557)	$ (2,125,239)	$ (144,006)	$ (33,206,772)

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
124	**Other Rate Base Items**							
125	Natural gas plant acquisition adjustments	114	$ -	$ -	$ -	$ -	$ -	$ -
126	Accumulated provision for asset acquisition adjustments	115	-	-	-	-	-	-
127	Materials And Supplies	154	6,477,488	4,623,291	1,298,797	32,820	1,998	520,582
128	Stores Expense Undistributed	163	-	-	-	-	-	-
129	Gas Stored Underground - PA	164.1	-	-	-	-	-	-
130	LNG Inventory	164.2	3,072,269	1,612,065	711,901	35,695	-	712,608
131	Prepayments	165	-	-	-	-	-	-
132	Other regulatory assets	182.3	-	-	-	-	-	-
133	Miscellaneous deferred debits	186	-	-	-	-	-	-
134	Accumulated deferred income taxes	190	-	-	-	-	-	-
135	Accumulated provision for property insurance	228.1	-	-	-	-	-	-
136	Accumulated provision for injuries and damages	228.2	-	-	-	-	-	-
137	Accumulated provision for pensions and benefits	228.3	-	-	-	-	-	-
138	Accumulated miscellaneous operating provisions	228.4	-	-	-	-	-	-
139	Accumulated provision for rate refunds	229	-	-	-	-	-	-
140	Asset retirement obligations	230	-	-	-	-	-	-
141	Customer deposits	235	-	-	-	-	-	-
142	Other deferred credits	253	-	-	-	-	-	-
143	Accumulated deferred income taxes—accelerated amortization property	281	-	-	-	-	-	-
144	Accumulated deferred income taxes—Storage Plant	282.1	(2,499,689)	(1,311,624)	(579,224)	(29,042)	-	(579,799)
145	Accumulated deferred income taxes—Transmission Plant	282.2	(4,537,370)	(2,380,825)	(1,051,392)	(52,717)	-	(1,052,435)
146	Accumulated deferred income taxes—Distribution Plant	282.3	(37,194,379)	(27,877,632)	(7,238,201)	(142,354)	(13,640)	(1,922,553)
147	Accumulated deferred income taxes—General Plant	282.4	(3,895,915)	(2,791,428)	(778,654)	(19,550)	(1,600)	(304,683)
148	Accumulated deferred income taxes—other	283	-	-	-	-	-	-
149	Accumulated deferred investment tax credits	255	-	-	-	-	-	-
150	Customer advances for construction	252	(11,377,344)	(8,794,842)	(1,861,204)	(41,015)	(1,560)	(678,724)
151	Other regulatory liabilities	254	-	-	-	-	-	-
152	Working capital allowance	N/A	-	-	-	-	-	-
153	Subtotal - Other Rate Base Items		$ (49,954,940)	$ (36,920,995)	$ (9,497,977)	$ (216,163)	$ (14,802)	$ (3,305,004)
154	**TOTAL RATE BASE**		$ 387,513,313	$ 278,312,371	$ 77,282,709	$ 1,889,417	$ 153,217	$ 29,875,599

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
155	**OPERATION AND MAINTENANCE EXPENSE**							
156	**Production, Storage, LNG, Transmission, and Distribution Expense**							
157	**Other Gas Supply Expenses**							
158	Natural gas well head purchases	800	$ -	$ -	$ -	$ -	$ -	$ -
159	Natural gas well head purchases, intracompany transfers	800.1	-	-	-	-	-	-
160	Natural gas field line purchases	801	-	-	-	-	-	-
161	Natural gas gasoline plant outlet purchases	802	-	-	-	-	-	-
162	Natural gas transmission line purchases	803	-	-	-	-	-	-
163	Natural gas city gate purchases	804	-	-	-	-	-	-
164	Liquefied natural gas purchases	804.1	-	-	-	-	-	-
165	Other gas purchases	805	-	-	-	-	-	-
166	Purchased gas cost adjustments	805.1	-	-	-	-	-	-
167	Exchange gas	806	-	-	-	-	-	-
168	Well expenses—Purchased gas.	807.1	-	-	-	-	-	-
169	Operation of purchased gas measuring stations.	807.2	-	-	-	-	-	-
170	Maintenance of purchased gas measuring stations.	807.3	-	-	-	-	-	-
171	Purchased gas calculations expenses.	807.4	-	-	-	-	-	-
172	Other purchased gas expenses.	807.5	-	-	-	-	-	-
173	Gas withdrawn from storage—debit	808.1	-	-	-	-	-	-
174	Gas delivered to storage—credit	808.2	-	-	-	-	-	-
175	Withdrawals of liquefied natural gas held for processing—debt	809.1	-	-	-	-	-	-
176	Deliveries of natural gas for processing—credit	809.2	-	-	-	-	-	-
177	Gas used for compressor station fuel—credit	810	-	-	-	-	-	-
178	Gas used for products extraction—credit	811	-	-	-	-	-	-
179	Other gas supply expenses - Gas Supply	813.1	301,989	105,401	48,621	8,822	7,241	131,904
180	Other gas supply expenses	813	67,802	61,896	5,882	6	1	17
181	Subtotal - Other Gas Supply Expenses		$ 369,791	$ 167,297	$ 54,504	$ 8,828	$ 7,242	$ 131,921
182	**Other Storage Expenses - Operation**							
183	Operation supervision and engineering	840	$ 960	$ 504	$ 223	$ 11	$ -	$ 223
184	Operation labor and expenses	841	647,172	339,581	149,962	7,519	-	150,111
185	Rents	842	-	-	-	-	-	-
186	Fuel	842.1	124,132	65,134	28,764	1,442	-	28,792
187	Power	842.2	109,214	57,306	25,307	1,269	-	25,332
188	Gas losses	842.3	-	-	-	-	-	-
189	Subtotal - Other Storage Expenses - Operation		$ 881,479	$ 462,525	$ 204,255	$ 10,241	$ -	$ 204,458

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
190	**Other Storage Expenses - Maintenance**							
191	Maintenance supervision and engineering	843.1	$ -	$ -	$ -	$ -	$ -	$ -
192	Maintenance of structures and improvements	843.2	1,525	800	353	18	-	354
193	Maintenance of gas holders	843.3	299	157	69	3	-	69
194	Maintenance of purification equipment	843.4	1,761	924	408	20	-	409
195	Maintenance of liquefaction equipment	843.5	64,944	34,077	15,049	755	-	15,064
196	Maintenance of vaporizing equipment	843.6	109,460	57,435	25,364	1,272	-	25,389
197	Maintenance of compressor equipment	843.7	28,919	15,174	6,701	336	-	6,708
198	Maintenance of measuring and regulating equipment	843.8	-	-	-	-	-	-
199	Maintenance of other equipment	843.9	30,000	15,741	6,951	349	-	6,958
200	Subtotal - Other Storage Expenses - Maintenance		$ 236,909	$ 124,310	$ 54,896	$ 2,753	$ -	$ 54,951
201	**Transmission Operation Expenses**							
202	Operation supervision and engineering	850	$ -	$ -	$ -	$ -	$ -	$ -
203	System control and load dispatching	851	-	-	-	-	-	-
204	Communication system expenses	852	27,314	14,332	6,329	317	-	6,335
205	Compressor station labor and expenses	853	86,348	45,308	20,008	1,003	-	20,028
206	Gas for compressor station fuel	854	-	-	-	-	-	-
207	Other fuel and power for compressor stations	855	-	-	-	-	-	-
208	Mains expenses	856	1,885	989	437	22	-	437
209	Measuring and regulating station expenses	857	-	-	-	-	-	-
210	Transmission and compression of gas by others	858	-	-	-	-	-	-
211	Other expenses	859	-	-	-	-	-	-
212	Rents	860	-	-	-	-	-	-
213	Subtotal - Transmission Operation Expenses		$ 115,547	$ 60,629	$ 26,774	$ 1,342	$ -	$ 26,801
214	**Transmission Maintenance Expenses**							
215	Maintenance supervision and engineering	861	$ -	$ -	$ -	$ -	$ -	$ -
216	Maintenance of structures and improvements	862	-	-	-	-	-	-
217	Maintenance of mains	863	17,387	9,123	4,029	202	-	4,033
218	Transmission Mains - Pipeline Integrity	863.1	28,262	14,829	6,549	328	-	6,555
219	Maintenance of compressor station equipment	864	-	-	-	-	-	-
220	Maintenance of measuring and regulating station equipment	865	-	-	-	-	-	-
221	Maintenance of communication equipment	866	133,623	70,114	30,963	1,552	-	30,994
222	Maintenance of other equipment	867	-	-	-	-	-	-
223	Subtotal - Transmission Maintenance Expenses		$ 179,272	$ 94,066	$ 41,541	$ 2,083	$ -	$ 41,582

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
224	**Distribution Operation Expenses**							
225	Operation supervision and engineering	870	$ 4,317,916	$ 3,232,126	$ 839,334	$ 18,807	$ 5,215	$ 222,435
226	Operation supervision and engineering- Gas Supply and Control	870.1	62,783	21,913	10,108	1,834	1,505	27,423
227	Distribution load dispatching	871	253,255	88,392	40,775	7,398	6,072	110,618
228	Compressor station fuel and power (major only)	873	-	-	-	-	-	-
229	Mains and services expenses	874	4,725,499	3,652,875	773,038	17,035	648	281,903
230	Measuring and regulating station expenses—general	875	437,602	323,468	66,352	2,296	4	45,482
231	Measuring and regulating station expenses—industrial	876	330,316	-	301,042	9,840	1,255	18,179
232	Measuring and regulating station expenses—city gate check stations	877	-	-	-	-	-	-
233	Meter and house regulator expenses	878	1,633,964	1,207,261	414,650	1,972	1,732	8,348
234	Meter and house regulator expenses - installation credits	878.3	(1,833,969)	(1,355,035)	(465,405)	(2,214)	(1,944)	(9,370)
235	Customer installations expenses	879	2,404,356	2,194,901	208,601	204	42	607
236	Other expenses	880	4,819,166	3,612,022	937,832	18,444	1,767	249,099
237	Rents	881	241,488	180,763	46,941	1,052	292	12,440
238	Subtotal - Distribution Operation Expenses		$ 17,392,377	$ 13,158,686	$ 3,173,269	$ 76,668	$ 16,588	$ 967,165
239	**Distribution Maintenance Expenses**							
240	Maintenance supervision and engineering	885	$ 252,408	$ 194,732	$ 48,156	$ 711	$ 97	$ 8,712
241	Maintenance of structures and improvements	886	-	-	-	-	-	-
242	Maintenance of mains	887	1,559,102	1,152,463	236,402	8,179	15	162,043
243	Distribution Mains - Pipeline Integrity	887.1	90,461	66,867	13,716	475	1	9,402
244	Maintenance of compressor station equipment	888	-	-	-	-	-	-
245	Maintenance of measuring and regulating station equipment—general	889	577,682	427,013	87,592	3,031	6	60,041
246	Maintenance of measuring and regulating station equipment—industrial	890	122,251	-	111,416	3,642	465	6,728
247	Maintenance of measuring and regulating station equipment—city gate	891	-	-	-	-	-	-
248	Maintenance of services	892	3,159,609	2,572,336	562,811	5,088	923	18,451
249	Maintenance of meters and house regulators	893	1,235,301	912,708	313,482	1,491	1,310	6,312
250	Maintenance of other equipment	894	569,681	439,508	108,687	1,605	219	19,662
251	Subtotal - Distribution Maintenance Expenses		$ 7,566,497	$ 5,765,627	$ 1,482,263	$ 24,221	$ 3,034	$ 291,351
252	**Total Production, Storage, LNG, Transmission, and Distribution Expense**		$ 26,741,871	$ 19,833,141	$ 5,037,502	$ 126,137	$ 26,864	$ 1,718,227
253	**Customer Accounts, Service, and Sales Expense**							
254	**Customer Account**							
255	Supervision	901	$ 177,085	$ 161,050	$ 15,930	$ 25	$ 5	$ 75
256	Meter reading expenses	902	1,078,574	984,615	93,577	91	19	272
257	Customer records and collection expenses	903	7,216,280	6,587,637	626,082	612	125	1,823
258	Uncollectible accounts	904	510,784	436,041	72,479	541	111	1,612
259	Miscellaneous customer accounts expenses	905	-	-	-	-	-	-
260	Subtotal - Customer Account		$ 8,982,723	$ 8,169,343	$ 808,069	$ 1,270	$ 260	$ 3,782

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
261	**Customer Service & Information Expenses**							
262	Supervision	907	$ -	$ -	$ -	$ -	$ -	$ -
263	Customer assistance expenses	908	835,629	762,834	72,499	71	14	211
264	Informational and instructional advertising expenses	909	126,903	115,848	11,010	11	2	32
265	Miscellaneous customer service and informational expenses	910	-	-	-	-	-	-
266	Subtotal - Customer Service & Information Expenses		$ 962,532	$ 878,681	$ 83,509	$ 82	$ 17	$ 243
267	**Sales Expenses**							
268	Supervision	911	$ 231,731	$ 211,544	$ 20,105	$ 20	$ 4	$ 59
269	Demonstrating and selling expenses	912	1,241,710	1,133,539	107,730	105	22	314
270	Advertising expenses	913	40,610	37,072	3,523	3	1	10
271	Miscellaneous sales expenses	916	-	-	-	-	-	-
272	Subtotal - Sales Expenses		$ 1,514,051	$ 1,382,155	$ 131,359	$ 128	$ 26	$ 383
273	**Total Customer Accounts, Service, and Sales Expense**		$ 11,459,306	$ 10,430,179	$ 1,022,936	$ 1,480	$ 302	$ 4,408
274	**Administrative and General Expenses**							
275	Administrative and general salaries	920	$ 6,169,823	$ 4,569,647	$ 1,198,230	$ 28,325	$ 8,063	$ 365,560
276	Administrative and general salaries - Gas Supply and Control	920.1	164,929	57,564	26,554	4,818	3,954	72,038
277	Office supplies and expenses	921	5,722,640	4,238,443	1,111,383	26,272	7,478	339,064
278	Outside services employed	923	596,622	441,885	115,869	2,739	780	35,350
279	Property insurance	924	122,539	87,670	24,521	617	46	9,685
280	Injuries and damages	925	1,221,147	904,436	237,157	5,606	1,596	72,353
281	Employee pensions and benefits	926	1,594,449	1,180,920	309,655	7,320	2,084	94,471
282	Franchise requirements	927	-	-	-	-	-	-
283	Regulatory commission expenses	928	118,537	77,727	28,743	749	593	10,726
284	Duplicate charges—Credit	929	-	-	-	-	-	-
285	General advertising expenses	930.1	78,048	71,249	6,771	7	1	20
286	Miscellaneous general expenses	930.2	436,330	333,057	79,075	1,782	356	22,061
287	Rents	931	819,634	607,058	159,180	3,763	1,071	48,563
288	Maintenance of general plant	935	4	3	1	0	0	0
289	Subtotal - Administrative and General Expenses		$ 17,044,704	$ 12,569,659	$ 3,297,139	$ 81,996	$ 26,021	$ 1,069,889
290	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		$ 55,245,881	$ 42,832,979	$ 9,357,577	$ 209,613	$ 53,188	$ 2,792,524
291	**Adjustments, Depreciation and Amortization Expense**							
292	**Depreciation Expense**							
293	Depreciation expense intangible plant	403.1	$ 4,703,175	$ 3,457,317	$ 919,501	$ 22,053	$ 5,179	$ 299,126
294	Depreciation expense storage and terminaling	403.2	1,112,919	583,965	257,884	12,930	-	258,140
295	Depreciation expense transmission	403.3	1,064,501	558,559	246,664	12,368	-	246,909
296	Depreciation expense distribution	403.4	13,524,126	10,136,494	2,631,858	51,761	4,960	699,053
297	Depreciation expense general plant	403.5	1,725,030	1,235,987	344,772	8,656	708	134,907
298	Subtotal - Depreciation Expense		$ 22,129,750	$ 15,972,322	$ 4,400,679	$ 107,768	$ 10,847	$ 1,638,135

Line No.	Account Description	FERC Account	Account Balance	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
299	**Amortization Expense**							
300	Amortization and depletion of producing natural gas land and land	404.1	-	-	-	-	-	-
301	Amortization of underground storage land and land rights	404.2	-	-	-	-	-	-
302	Amortization of other limited-term gas plant	404.3	-	-	-	-	-	-
303	Amortization of other gas plant	405	-	-	-	-	-	-
304	Amortization of gas plant acquisition adjustments	406	-	-	-	-	-	-
305	Amortization of property losses, unrecovered plant and regulatory	407.1	-	-	-	-	-	-
306	Amortization of conversion expense	407.2	-	-	-	-	-	-
307	Subtotal - Amortization Expense		-	-	-	-	-	-
308	**Total Adjustments, Depreciation and Amortization Expense**		$ 22,129,750	$ 15,972,322	$ 4,400,679	$ 107,768	$ 10,847	$ 1,638,135
309	**Taxes**							
310	**Taxes Other Than Income Taxes**							
311	Taxes Other Than Income Taxes - Payroll	408.1	$ 2,282,838	$ 1,690,772	$ 443,346	$ 10,480	$ 2,983	$ 135,257
312	Taxes Other Than Income Taxes - Property	408.2	3,623,049	2,592,099	725,013	18,248	1,346	286,343
313	Taxes Other Than Income Taxes - Franchise	408.3	13,950	9,147	3,383	88	70	1,262
314	Taxes Other Than Income Taxes - IPUC Fee	408.4	520,047	341,003	126,102	3,284	2,602	47,056
315	Subtotal - Taxes Other Than Income Taxes		$ 6,439,884	$ 4,633,021	$ 1,297,843	$ 32,101	$ 7,001	$ 469,918
316	**Income Taxes**							
317	Income Taxes - federal taxes utility operating income	409.1	$ 5,054,746	$ 3,630,323	$ 1,008,080	$ 24,646	$ 1,999	$ 389,699
318	Income Taxes - state taxes utility operating income	409.1	771,296	553,945	153,821	3,761	305	59,464
319	Income Taxes - other taxes utility operating income	410.1	-	-	-	-	-	-
320	Provision for deferred income taxes—credit, utility operating income	411.1	-	-	-	-	-	-
321	Investment Tax credit Adj.	411.4	-	-	-	-	-	-
322	Subtotal - Income Taxes		$ 5,826,042	$ 4,184,268	$ 1,161,902	$ 28,406	$ 2,304	$ 449,163
323	**Total Taxes**		$ 12,265,926	$ 8,817,289	$ 2,459,744	$ 60,507	$ 9,304	$ 919,081
324	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**							
325	**Test Year Expenses at Current Rates**		$ 89,641,557	$ 67,622,590	$ 16,218,001	$ 377,888	$ 73,339	$ 5,349,740
326	**Return on Rate Base**		$ 28,559,731	$ 20,511,622	$ 5,695,736	$ 139,250	$ 11,292	$ 2,201,832
327	**Gross Up Items**			-	-	-	-	-
328	Federal Income Tax		$ 2,233,076	$ 1,603,797	$ 445,348	$ 10,888	$ 883	$ 172,160
329	State Income Tax		654,723	470,223	130,573	3,192	259	50,476
330	Uncollectible Account - Increase		26,996	23,046	3,831	29	6	85
331	Taxes Other Than Income Taxes - IPUC Fee		22,619	14,832	5,485	143	113	2,047
332	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**$ 121,138,702**	**$ 90,246,109**	**$ 22,498,973**	**$ 531,389**	**$ 85,891**	**$ 7,776,340**

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
1	**Functional Rate Base**						
2	**Storage**						
3	Demand	$ 28,145,723	$ 14,768,477	$ 6,521,884	$ 327,009	$ -	$ 6,528,354
4	Commodity	-	-	-	-	-	-
5	Customer	-	-	-	-	-	-
6	Subtotal	$ 28,145,723	$ 14,768,477	$ 6,521,884	$ 327,009	$ -	$ 6,528,354
7	**Transmission**						
8	Demand	$ 22,994,119	$ 12,065,354	$ 5,328,162	$ 267,155	$ -	$ 5,333,448
9	Commodity	-	-	-	-	-	-
10	Customer	-	-	-	-	-	-
11	Subtotal	$ 22,994,119	$ 12,065,354	$ 5,328,162	$ 267,155	$ -	$ 5,333,448
12	**Distribution**						
13	Demand	$ 156,337,840	$ 115,562,357	$ 23,705,053	$ 820,145	$ 1,498	$ 16,248,788
14	Commodity	-	-	-	-	-	-
15	Customer	6,635,543	4,359,288	1,673,239	54,799	29,842	518,376
16	Subtotal	$ 162,973,383	$ 119,921,645	$ 25,378,291	$ 874,944	$ 31,340	$ 16,767,163
17	**Customer**						
18	Demand	$ -	$ -	$ -	$ -	$ -	$ -
19	Commodity	-	-	-	-	-	-
20	Customer	173,400,088	131,556,895	40,054,372	420,309	121,877	1,246,634
21	Subtotal	$ 173,400,088	$ 131,556,895	$ 40,054,372	$ 420,309	$ 121,877	$ 1,246,634
22	**Total**						
23	Demand	$ 207,477,682	$ 142,396,188	$ 35,555,098	$ 1,414,309	$ 1,498	$ 28,110,589
24	Commodity	-	-	-	-	-	-
25	Customer	180,035,631	135,916,183	41,727,611	475,108	151,719	1,765,010
26	**TOTAL RATE BASE**	$ 387,513,313	$ 278,312,371	$ 77,282,709	$ 1,889,417	$ 153,217	$ 29,875,599

Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
27	**Functional Revenue Requirement**						
28	**Storage**						
29	Demand	$ 5,862,968	$ 3,076,386	$ 1,358,558	$ 68,118	$ -	$ 1,359,906
30	Commodity	-	-	-	-	-	-
31	Customer	-	-	-	-	-	-
32	Subtotal	$ 5,862,968	$ 3,076,386	$ 1,358,558	$ 68,118	$ -	$ 1,359,906
33	**Transmission**						
34	Demand	$ 4,375,009	$ 2,295,632	$ 1,013,770	$ 50,831	$ -	$ 1,014,776
35	Commodity	-	-	-	-	-	-
36	Customer	-	-	-	-	-	-
37	Subtotal	$ 4,375,009	$ 2,295,632	$ 1,013,770	$ 50,831	$ -	$ 1,014,776
38	**Distribution**						
39	Demand	$ 39,444,861	$ 29,156,992	$ 5,980,910	$ 206,927	$ 378	$ 4,099,655
40	Commodity	-	-	-	-	-	-
41	Customer	12,472,938	8,355,536	3,105,063	94,456	50,268	867,616
42	Subtotal	$ 51,917,799	$ 37,512,527	$ 9,085,972	$ 301,383	$ 50,646	$ 4,967,270
43	**Customer**						
44	Demand	$ -	$ -	$ -	$ -	$ -	$ -
45	Commodity	-	-	-	-	-	-
46	Customer	58,982,926	47,361,563	11,040,672	111,058	35,246	434,388
47	Subtotal	$ 58,982,926	$ 47,361,563	$ 11,040,672	$ 111,058	$ 35,246	$ 434,388
48	**Total**						
49	Demand	$ 49,682,838	$ 34,529,010	$ 8,353,238	$ 325,876	$ 378	$ 6,474,337
50	Commodity	-	-	-	-	-	-
51	Customer	71,455,864	55,717,099	14,145,735	205,513	85,514	1,302,003
52	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 121,138,702	$ 90,246,109	$ 22,498,973	$ 531,389	$ 85,891	$ 7,776,340
53	Demand	41.01%	38.26%	37.13%	61.33%	0.44%	83.26%
54	Energy	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Customer	58.99%	61.74%	62.87%	38.67%	99.56%	16.74%

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
56	**Unit Costs**						
57	**Storage**						
58	Demand	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ -	$ 0.08
59	Commodity	$ -	$ -	$ -	$ -	$ -	$ -
60	Customer	$ -	$ -	$ -	$ -	$ -	$ -
61	**Transmission**						
62	Demand	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ -	$ 0.06
63	Commodity	$ -	$ -	$ -	$ -	$ -	$ -
64	Customer	$ -	$ -	$ -	$ -	$ -	$ -
65	**Distribution**						
66	Demand	$ 0.51	$ 0.72	$ 0.34	$ 0.23	$ -	$ 0.23
67	Commodity	$ -	$ -	$ -	$ -	$ -	$ -
68	Customer	$ 2.57	$ 1.89	$ 7.39	$ 229.82	$ 598.43	$ 708.84
69	**Customer**						
70	Demand	$ -	$ -	$ -	$ -	$ -	$ -
71	Commodity	$ -	$ -	$ -	$ -	$ -	$ -
72	Customer	$ 12.17	$ 10.71	$ 26.27	$ 270.21	$ 419.59	$ 354.89
73	**Total**						
74	Commodity	$ -	$ -	$ -	$ -	$ -	$ -
75	Customer (per cust month)	$ 14.75	$ 12.60	$ 33.65	$ 500.03	$ 1,018.02	$ 1,063.73
76	Demand & Customer (per cust month)	$ 25.00	$ 20.40	$ 53.53	$ 1,292.92	$ 1,022.52	$ 6,353.22
77	Demand (per MDFQ)				$ 0.36		$ 0.36
78	**BILLING DETERMINANTS**						
79	Demand (Peak Day Demand * 12)	76,848,665	40,323,630	17,807,254	892,860	0	17,824,920
80	Commodity	805,130,573	282,522,986	138,067,893	13,566,644	41,523,144	329,449,906
81	Customers (Number of Bills)	4,844,910	4,422,848	420,343	411	84	1,224
82	Demand	19,013,507			903,088		18,110,419

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 7 – Alternative Cost of Service and Rate of Return under Present and Proposed Rates

Line No.	Revenue Requirement Summary	Total System	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
1	**Rate Base**						
2	Plant in Service	$ 839,989,014	$ 598,517,569	$ 167,024,168	$ 4,174,370	$ 5,012,456	$ 65,260,451
3	Accumulated Reserve	(402,520,761)	(284,507,567)	(80,776,311)	(2,096,977)	(2,497,346)	(32,642,561)
4	Other Rate Base Items	(49,954,940)	(36,798,682)	(9,444,704)	(213,345)	(249,466)	(3,248,743)
5	**Total Rate Base**	**$ 387,513,313**	**$ 277,211,320**	**$ 76,803,153**	**$ 1,864,049**	**$ 2,265,644**	**$ 29,369,147**
6	**Rate of Return Under Current ROR**						
7	**Revenue at Current Rates**						
8	Gas Service Revenue	$ 107,349,830	$ 70,391,038	$ 26,030,361	$ 677,926	$ 537,118	$ 9,713,387
9	Other Revenues	2,450,925	1,820,764	452,973	10,633	11,581	154,974
10	**Total Revenue**	**$ 109,800,755**	**$ 72,211,802**	**$ 26,483,334**	**$ 688,559**	**$ 548,699**	**$ 9,868,361**
11	**Expenses at Current Rates**						
12	O&M and A&G Expenses	$ 55,245,881	$ 42,757,743	$ 9,324,809	$ 207,879	$ 197,532	$ 2,757,918
13	Depreciation and Amortization Expense	22,129,750	15,913,889	4,375,229	106,422	122,954	1,611,257
14	Taxes Other Than Income	6,439,884	4,619,025	1,291,747	31,778	33,853	463,480
15	**Total Operating Expenses**	**$ 83,815,515**	**$ 63,290,657**	**$ 14,991,785**	**$ 346,079**	**$ 354,339**	**$ 4,832,655**
16	**Earnings Before Interest and Taxes**	**$ 25,985,240**	**$ 8,921,145**	**$ 11,491,550**	**$ 342,480**	**$ 194,360**	**$ 5,035,706**
17	Current State/Federal Income Taxes	$ 5,826,042	$ 2,000,173	$ 2,576,472	$ 76,786	$ 43,577	$ 1,129,035
18	Deferred Income Tax	-	-	-	-	-	-
19	**Total Income Taxes**	**$ 5,826,042**	**$ 2,000,173**	**$ 2,576,472**	**$ 76,786**	**$ 43,577**	**$ 1,129,035**
20	**Total Expenses at Current Rates**	**$ 89,641,557**	**$ 65,290,829**	**$ 17,568,257**	**$ 422,865**	**$ 397,916**	**$ 5,961,690**
21	**Operating Income at Current Rates**	**$ 20,159,198**	**$ 6,920,972**	**$ 8,915,077**	**$ 265,694**	**$ 150,783**	**$ 3,906,671**
22	**Current Rate of Return**	**5.20%**	**2.50%**	**11.61%**	**14.25%**	**6.66%**	**13.30%**
23	**Relative Rate of Return**	**1.00**	**0.48**	**2.23**	**2.74**	**1.28**	**2.56**
24	**Current Revenue to Cost Ratio**	**0.91**	**0.80**	**1.18**	**1.31**	**0.96**	**1.29**
25	**Current Parity Ratio**	**1.00**	**0.89**	**1.31**	**1.45**	**1.06**	**1.42**

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Schedule 7 – Alternative Cost of Service and Rate of Return under Present and Proposed Rates

Line No.	Revenue Requirement Summary	Total System	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
26	Rate of Return Under Equal ROR						
27	**Revenue Requirement Required Return at Equal Rates of Return**						
28	Required Return	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
29	Required Operating Income	$ 28,559,731	$ 20,430,474	$ 5,660,392	$ 137,380	$ 166,978	$ 2,164,506
30	**Expenses at Required Return**						
31	O&M and A&G Expenses	$ 55,245,881	$ 42,757,743	$ 9,324,809	$ 207,879	$ 197,532	$ 2,757,918
32	Depreciation and Amortization Expense	22,129,750	15,913,889	4,375,229	106,422	122,954	1,611,257
33	Taxes Other Than Income	6,439,884	4,619,025	1,291,747	31,778	33,853	463,480
34	**Total Operating Expenses**	**$ 83,815,515**	**$ 63,290,657**	**$ 14,991,785**	**$ 346,079**	**$ 354,339**	**$ 4,832,655**
35	Deferred Income Tax	$ -	$ -	$ -	$ -	$ -	$ -
36	Current State/Federal Income Taxes	5,826,042	4,167,714	1,154,692	28,025	34,063	441,548
37	**Income Taxes and Other**	**$ 5,826,042**	**$ 4,167,714**	**$ 1,154,692**	**$ 28,025**	**$ 34,063**	**$ 441,548**
38	Increase - Federal Income Tax	$ 2,233,076	$ 1,597,452	$ 442,584	$ 10,742	$ 13,056	$ 169,242
39	Increase - State Utility Tax	654,723	468,362	129,763	3,149	3,828	49,621
40	Increase - Bad Debts	26,996	23,046	3,831	29	6	85
41	Increase - Annual Filing Fee	22,619	14,832	5,485	143	113	2,047
42	**Revenue Increase Related Expenses**	**$ 2,937,414**	**$ 2,103,692**	**$ 581,662**	**$ 14,063**	**$ 17,003**	**$ 220,994**
43	**Total Expenses at Required Return**	**$ 92,578,971**	**$ 69,562,063**	**$ 16,728,139**	**$ 388,167**	**$ 405,405**	**$ 5,495,198**
44	**Total Revenue Requirement Required Return at Equal Rates of Return**	**$ 121,138,702**	**$ 89,992,537**	**$ 22,388,531**	**$ 525,547**	**$ 572,383**	**$ 7,659,704**
45	LESS						
46	Current Miscellaneous Revenue Margin	2,450,925	1,820,764	452,973	10,633	11,581	154,974
47	**Total Rate Margin at Equal Rates of Return**	**$ 118,687,777**	**$ 88,171,773**	**$ 21,935,558**	**$ 514,914**	**$ 560,802**	**$ 7,504,730**
48	**Total Current Rate Margin**	**$ 107,349,830**	**$ 70,391,038**	**$ 26,030,361**	**$ 677,926**	**$ 537,118**	**$ 9,713,387**
49	**Base Rate Margin (Deficiency)/Surplus**	**$ (11,337,947)**	**$ (17,780,735)**	**$ 4,094,803**	**$ 163,012**	**$ (23,684)**	**$ 2,208,657**
50	**Proposed Margin Increase**	**$ 11,337,947**	**$ 9,293,097**	**$ 1,451,307**	**$ 37,797**	**$ 14,182**	**$ 541,564**
51	**Total Revenue Increase as Proposed**	**$ 121,138,702**	**$ 81,504,898**	**$ 27,934,641**	**$ 726,356**	**$ 562,881**	**$ 10,409,925**
52	Income Prior to Taxes	$ 37,273,572	$ 18,176,364	$ 12,933,541	$ 380,106	$ 208,423	$ 5,575,138
53	Income Taxes and Other	$ 8,713,841	$ 6,233,529	$ 1,727,039	$ 41,916	$ 50,947	$ 660,411
54	**Proposed Operating Income**	**$ 28,559,731**	**$ 11,942,835**	**$ 11,206,503**	**$ 338,190**	**$ 157,476**	**$ 4,914,727**
55	**Proposed Rate of Return**	**7.37%**	**4.31%**	**14.59%**	**18.14%**	**6.95%**	**16.73%**
56	**Relative Rate of Return**	**1.00**	**0.58**	**1.98**	**2.46**	**0.94**	**2.27**
57	**Proposed Revenue to Cost Ratio**	**1.00**	**0.91**	**1.25**	**1.38**	**0.98**	**1.36**
58	**Proposed Parity Ratio**	**1.00**	**0.91**	**1.25**	**1.38**	**0.98**	**1.36**

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	CASE NO. INT-G-22-07

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

EXHIBIT 3 TO ACCOMPANY THE

DIRECT TESTIMONY OF RONALD J. AMEN

Intermountain Gas Company
Gas Class Cost of Service Study
Test Year Ended December 31, 2022
Exhibit 3 – Proposed Revenue Targets

Line No.	Description	Total System	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)
1	**Total Rate Base**	$ 387,513,313	$ 278,312,371	$ 77,282,709	$ 1,889,417	$ 153,217	$ 29,875,599
2	Gas Service Revenue	$ 107,349,830	$ 70,391,038	$ 26,030,361	$ 677,926	$ 537,118	$ 9,713,387
3	Other Revenues	2,450,925	1,825,894	455,208	10,751	1,738	157,334
4	**Total Revenue**	**$ 109,800,755**	**$ 72,216,932**	**$ 26,485,569**	**$ 688,677**	**$ 538,856**	**$ 9,870,721**
5	**Current Revenue to Cost Ratio**	0.91	0.80	1.18	1.30	6.27	1.27
6	**Current Parity Ratio**	1.00	0.88	1.30	1.43	6.92	1.40
7	**Scenario A: Revenues at Equalized Rates of Return**						
8	Revenue Increase/(Decrease)	$ 11,337,947	$ 18,029,176	$ (3,986,596)	$ (157,288)	$ (452,964)	$ (2,094,381)
9	Total Rate Revenue at Equalized Rates of Return	118,687,777	88,420,214	22,043,765	520,638	84,154	7,619,006
10	Other Revenues	2,450,925	1,825,894	455,208	10,751	1,738	157,334
11	**Total Revenue at Equalized Rates of Return**	**$ 121,138,702**	**$ 90,246,109**	**$ 22,498,973**	**$ 531,389**	**$ 85,891**	**$ 7,776,340**
12	**% Increase of Total Revenues**	10.33%	24.97%	-15.05%	-22.84%	-84.06%	-21.22%
13	**% Increase of Margin Revenues**	10.56%	25.61%	-15.32%	-23.20%	-84.33%	-21.56%
14	**Resulting Revenue to Cost Ratio**	1.00	1.00	1.00	1.00	1.00	1.00
15	**Resulting Parity Ratio**	1.00	1.00	1.00	1.00	1.00	1.00
16	**Scenario B: Equal Percentage Increase on Gas Service Revenue**						
17	Percent Increase	10.56%	10.56%	10.56%	10.56%	10.56%	10.56%
18	Revenue Increase/(Decrease)	$ 11,337,947	$ 7,434,477	$ 2,749,244	$ 71,600	$ 56,729	$ 1,025,897
19	Total Rate Revenue	118,687,777	77,825,515	28,779,605	749,526	593,847	10,739,284
20	Other Revenues	2,450,925	1,825,894	455,208	10,751	1,738	157,334
21	**Total Revenue at Equal Percentage Increase**	**$ 121,138,702**	**$ 79,651,409**	**$ 29,234,813**	**$ 760,278**	**$ 595,584**	**$ 10,896,618**
22	**Resulting Revenue to Cost Ratio**	1.00	0.88	1.30	1.43	6.93	1.40
23	**Resulting Parity Ratio**	1.00	0.88	1.30	1.43	6.93	1.40
24	**Proposed Scenario C: Moderated based on the Current Parity Ratio**						
25	Multiple of System Increase		1.25	0.53	0.53	0.25	0.53
26	Percent Increase		13.20%	5.58%	5.58%	2.64%	5.58%
27	Revenue Increase/(Decrease)	**$ 11,337,947**	**$ 9,293,097**	**$ 1,451,307**	**$ 37,797**	**$ 14,182**	**$ 541,564**
28	Total Rate Revenue	118,687,777	79,684,135	27,481,668	715,723	551,300	10,254,951
29	Other Revenues	2,450,925	1,825,894	455,208	10,751	1,738	157,334
30	**Total Revenue at Proposed**	$ 121,138,702	$ 81,510,029	$ 27,936,876	$ 726,475	$ 553,038	$ 10,412,285
31	**Base Rate Margin at Proposed**	$ 118,687,777	$ 79,684,135	$ 27,481,668	$ 715,723	$ 551,300	$ 10,254,951
32	Percent Increase on Base Rate Margin	10.56%	13.20%	5.58%	5.58%	2.64%	5.58%
33	**Proposed Revenue to Cost Ratio**	1.00	0.90	1.24	1.37	6.44	1.34
34	**Proposed Parity Ratio**	1.00	0.90	1.24	1.37	6.44	1.34

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	CASE NO. INT-G-22-07

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

EXHIBIT 4 TO ACCOMPANY THE

DIRECT TESTIMONY OF RONALD J. AMEN

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
Residential

Description	Units	Billing Determinants	Current Base Rates – Rates	Current Base Rates – Revenues	Proposed Base Rates – Rates	Proposed Base Rates – Revenues	Difference – $	Difference – %
RS_RESIDENTIAL SERVICE								
Customer Charge	Cust Bills	4,420,205	$ 5.50	$ 24,311,128	$ 9.00	$ 39,781,845	$ 15,470,718	63.64%
Distribution Charge	Therms	282,067,442	$ 0.16305	$ 45,991,097	$ 0.14116	$ 39,816,640	$ (6,174,457)	-13.43%
Total Base Revenues				$ 70,302,225		$ 79,598,485	$ 9,296,260	13.22%
IS-R_RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE								
Customer Charge	Cust Bills	2,643	$ 5.50	$ 14,537	$ 8.00	$ 21,144	$ 6,608	45.46%
Distribution Charge	Therms	455,543	$ 0.16305	$ 74,276	$ 0.14116	$ 64,305	$ (9,972)	-13.43%
Total Base Revenues				$ 88,813		$ 85,449	$ (3,364)	-3.79%
Total Customer Charge Revenue	Cust			$ 24,325,664		$ 39,802,989	$ 15,477,325	63.63%
Total Distribution Charge Revenue	Therms			$ 46,065,374		$ 39,880,945	$ (6,184,429)	-13.43%
Total Base Revenues				$ 70,391,038		$ 79,683,934	$ 9,292,896	13.20%

Target Revenue								
$ 79,684,135								
	Cust Bills	4,420,205	$ 5.50	$ 24,311,128	**$ 9.00**	$ 39,781,845	$15,470,718	63.64%
	Cust Bills	2,643	$ 5.50	14,537	**$ 8.00**	21,144	6,608	45.46%
	Therms	282,522,986	$ 0.16305	$ 46,065,374	$ 0.14116	$ 39,881,146	($6,184,228)	-13.43%
Total Base Revenues				**$ 70,391,038**		**$ 79,684,135**	**$ 9,293,097**	13.20%
Target Revenue Difference						$ (201)		
Target Revenue Difference %						0.00%		

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
General Service

Description	Units	Billing Determinants	Current Base Rates: Rates	Current Base Rates: Revenues	Proposed Base Rates: Rates	Proposed Base Rates: Revenues	Difference: $	Difference: %
GS-1_GENERAL SERVICE								
Customer Charge	Cust	419,593	$ 9.50	$ 3,986,134	$ 15.00	$ 6,293,895	$ 2,307,762	57.90%
Block 1 - First 200 therms per bill	Therms	38,275,720	$ 0.18465	$ 7,067,612	$ 0.17745	$ 6,792,026	$ (275,585)	-3.90%
Block 2 - Next 1,800 therms per bill	Therms	66,831,695	0.16117	10,771,263	0.15489	10,351,561	(419,702)	-3.90%
Block 3 - Next 8,000 therms per bill	Therms	27,156,148	0.13850	3,761,127	0.13310	3,614,483	(146,643)	-3.90%
Block 4 - Over 10,000 therms per bill	Therms	5,463,381	0.06994	382,109	0.06721	367,194	(14,915)	-3.90%
		137,726,944		$ 21,982,110		$ 21,125,265	$ (856,845)	-3.90%
Total Base Revenues				$ 25,968,244		$ 27,419,160	$ 1,450,916	5.59%
GS-1 IRRIGATION CUSTOMERS								
Customer Charge	Cust	109	$ 9.50	$ 1,036	$ 15.00	$ 1,635	$ 599.50	57.90%
Block 1 - First 200 therms per bill	Therms	11,063	$ 0.18465	$ 2,044	$ 0.17745	$ 1,963	$ (80.66)	-3.95%
Block 2 - Next 1,800 therms per bill	Therms	47,781	0.16117	7,701	0.15489	7,401	(300.06)	-3.90%
Block 3 - Next 8,000 therms per bill	Therms	12,661	0.13850	1,754	0.13310	1,685	(68.37)	-3.90%
Block 4 - Over 10,000 therms per bill	Therms	0	0.06994	-	0.06721	-	-	0.00%
		71,505		$ 11,498		$ 11,049	$ (449.09)	-3.91%
Total Base Revenues				$ 12,534		$ 12,684	$ 150.41	1.20%
GS-1 - COMPRESSED NATURAL GAS								
Customer Charge	Cust	6	$ 9.50	$ 57.00	$ 15.00	$ 90.00	$ 33.00	57.90%
Block 1 - First 10,000 therms per bill	Therms	0	$ 0.13850	-	$ 0.13310	-	-	0.00%
Block 2 - Over 10,000 therms per bill	Therms	0	0.06994	-	0.06721	-	-	0.00%
		0		$ -		$ -	$ -	0.00%
Total Base Revenues				$57		$90	$33	57.90%
IS-C - SMALL COMMERCIAL INTERRUPTIBLE SNOWMELT SERVICE								
Customer Charge	Cust	635	$ 9.50	$ 6,033	**$ 12.50**	$ 7,938	$ 1,905.0	31.58%
Block 1 - First 200 therms per bill	Therms	56,452	$ 0.18465	$ 10,424	$ 0.17745	$ 10,017	$ (406)	-3.90%
Block 2 - Next 1,800 therms per bill	Therms	157,470	0.16117	25,379	0.15489	24,390	(989)	-3.90%
Block 3 - Next 8,000 therms per bill	Therms	55,522	0.13850	7,690	0.13310	7,390	(300)	-3.90%
Block 4 - Over 10,000 therms per bill	Therms	0	0.06994	-	0.06721	-	-	0.00%
		269,444		$ 43,493		$ 41,798	$ (1,695)	-3.90%
Total Base Revenues				$ 49,526		$ 49,735	$ 210	0.42%

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
General Service

Description	Units	Billing Determinants	Current Base Rates - Rates	Current Base Rates - Revenues	Proposed Base Rates - Rates	Proposed Base Rates - Revenues	Difference $	Difference %
General Service Total:								
Customer Charge	Cust	420,343		$ 3,993,259		$ 6,303,558	$ 2,310,299	57.86%
Block 1 - First 200 therms per bill	Therms	38,343,235		7,080,079		6,804,007	(276,072)	-3.90%
Block 2 - Next 1,800 therms per bill	Therms	67,036,946		10,804,344		10,383,353	(420,991)	-3.90%
Block 3 - Next 8,000 therms per bill	Therms	27,224,331		3,770,570		3,623,558	(147,011)	-3.90%
Block 4 - Over 10,000 therms per bill	Therms	5,463,381		382,109		367,194	(14,915)	-3.90%
Total Base Revenues				**$ 26,030,360**		**$ 27,481,669**	**$ 1,451,309**	5.58%

Target Revenue								
$ 27,481,668								
Customer Charge	Cust	419,708	$ 9.50	$ 3,987,226	**$ 15.00**	$ 6,295,620	$ 2,308,394	57.90%
Customer Charge - Interruptible	Cust	635	$ 9.50	6,033	**$ 12.50**	$ 7,938	$ 1,905	31.58%
Block 1 - First 200 therms per bill	Therms	38,343,235	$ 0.18465	$ 7,080,078	$ 0.17745	$ 6,804,101	$ (275,977)	-3.90%
Block 2 - Next 1,800 therms per bill	Therms	67,036,946	0.16117	10,804,345	0.15489	10,383,199	(421,146)	-3.90%
Block 3 - Next 8,000 therms per bill	Therms	27,224,331	0.13850	3,770,570	0.13310	3,623,596	(146,974)	-3.90%
Block 4 - Over 10,000 therms per bill	Therms	5,463,381	0.06994	382,109	0.06721	367,215	(14,894)	-3.90%
		138,067,893		$ 22,037,102		$ 21,178,111	$ (858,991)	-3.90%
Total Base Revenues				**$ 26,030,361**		**$ 27,481,668**	$ 1,451,308	5.58%
Target Revenue Difference						**$ 1**		
Target Revenue Difference %						0.00%		

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
Large Volume

Description	Units	Billing Determinants	Current Base Rates		Proposed Base Rates		Difference	
			Rates	Revenues	Rates	Revenues	$	%
LV-1_LARGE VOLUME								
Customer Charge	Cust	411	$ -	$ -	$ 150.00	$ 61,650	$ 61,650	
Demand Charge	Demand	895,110	$ 0.3000	$ 268,533	$ 0.3200	$ 286,435	$ 17,902	6.67%
Overrun Demand Charge	Demand	7,978	$ 0.3000	$ 2,393	0.3200	$ 2,553	$ 160	6.67%
Current								
Block 1 - First 250,000 therms per bill	Therms	13,566,644	$ 0.03000	$ 406,999				
Block 2 - Next 500,000 therms per bill	Therms	0	$ 0.01211	-				
Block 3 - Over 750,000 therms per bill	Therms	0	$ 0.00307	-				
				$ 406,999				
Proposed								
Block 1 - First 35,000 therms per bill	Therms	10,083,597			$ 0.03000	$ 302,508		
Block 2 - Next 35,000 therms per bill	Therms	2,221,333			0.01908	42,390		
Block 3 - Over 70,000 therms per bill	Therms	1,261,714			0.01600	20,187		
				$ 406,999		$ 365,085	$ (41,914)	-10.30%
Total Base Revenues				**$ 677,926**		**$ 715,723**	**$ 37,798**	**5.58%**
Target Revenue						**$ 715,723**		
Target Revenue Difference						-		
Target Revenue Difference %						0.00%		

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
Transportation

Description	Units	Billing Determinants	Current Base Rates: Rates	Current Base Rates: Revenues	Proposed Base Rates: Rates	Proposed Base Rates: Revenues	Difference: $	Difference: %
T-3 - TRANSPORT INTERRUPTIBLE								
Basic Service Charge	Cust	84	$ -	$0	$ 300.00	$ 25,200	$ 25,200	0.00%
Block 1 - First 100,000 therms per bill	Therms	7,990,121	$ 0.03853	$ 307,859	$ 0.03774	$ 301,544	$ (6,315)	-2.05%
Block 2 - Next 50,000 therms per bill	Therms	3,576,050	0.01569	56,108	0.01537	54,957	(1,151)	-2.05%
Block 3 - Over 150,000 therms per bill	Therms	29,956,973	0.00578	173,151	0.00566	169,599	(3,552)	-2.05%
All Volume		41,523,144		$ 537,118		$ 526,100	$ (11,018)	-2.05%
Total Base Revenues				**$ 537,118**		**$ 551,300**	**$ 14,182**	**2.64%**
Target Revenue						**551,300**		
Target Revenue Difference						-		
Target Revenue Difference %						0.00%		

Intermountain Gas Company
Exhibit 4 - Proposed Rate Design and Proof of Revenue
Transportation

Description	Units	Billing Determinants	Current Base Rates: Rates	Current Base Rates: Revenues	Proposed Base Rates: Rates	Proposed Base Rates: Revenues	Difference: $	Difference: %
T-4 - TRANSPORT FIRM								
Basic Service Charge	Cust	1224	$ -	$ -	$ 150.00	$ 183,600	$ 183,600	0.00%
Demand Charge	Demand	17,824,920	$ 0.3000	$ 5,347,476	$ 0.3200	$ 5,703,974	$ 356,498	6.67%
Overrun Demand Charge	Demand	285,499	$ 0.3000	$ 85,650	$ 0.3200	$ 91,360	$ 5,710	6.67%
Block 1 - First 250,000 therms per bill	Therms	131,975,926	$ 0.02395	$ 3,160,823	$ 0.02393	$ 3,157,689	$ (3,134)	-0.10%
Block 2 - Next 500,000 therms per bill	Therms	103,237,613	0.00847	874,423	0.00846	873,556	(867)	-0.10%
Block 3 - Over 750,000 therms per bill	Therms	94,236,367	0.00260	245,015	0.00260	244,772	(243)	-0.10%
All Volumes		329,449,906		$ 4,280,261		$ 4,276,017	$ (4,244)	-0.10%
Total Base Revenues				**$ 9,713,387**		**$ 10,254,951**	**$ 541,564**	**5.58%**
Target Revenue						**$ 10,254,951**		
Target Revenue Difference						-		
Target Revenue Difference %						0.00%		

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE IN THE STATE OF IDAHO	CASE NO. INT-G-22-07

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

EXHIBIT 5 TO ACCOMPANY THE

DIRECT TESTIMONY OF RONALD J. AMEN

Intermountain Gas Company
Exhibit 5 – Bill Impact
Residential

RS_RESIDENTIAL SERVICE

	CURRENT RATES	PROPOSED RATES
CUSTOMER CHARGE	$ 5.50	$ 9.00
DISTRIBUTION CHARGE	$0.16305	$0.14116
COG	$0.55523	$0.55523
EE	$0.01564	$0.01564

	THERM	CURRENT	PROPOSED	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
		$	$	$	
	Usage Per THERM				
	0	5.50	9.00	3.50	63.64%
	10	12.84	16.12	3.28	25.56%
	20	20.18	23.24	3.06	15.18%
	30	27.52	30.36	2.84	10.33%
	40	34.86	37.48	2.62	7.53%
	50	42.20	44.60	2.41	5.70%
(1)	60	49.54	51.72	2.19	4.41%
	70	56.87	58.84	1.97	3.46%
	80	64.21	65.96	1.75	2.72%
	90	71.55	73.08	1.53	2.14%
	100	78.89	80.20	1.31	1.66%
	110	86.23	87.32	1.09	1.27%
	120	93.57	94.44	0.87	0.93%
	130	100.91	101.56	0.65	0.65%
	140	108.25	108.68	0.44	0.40%
	150	115.59	115.80	0.22	0.19%
	160	122.93	122.92	(0.00)	0.00%
	170	130.27	130.05	(0.22)	-0.17%
	180	137.61	137.17	(0.44)	-0.32%
	190	144.94	144.29	(0.66)	-0.45%
	200	152.28	151.41	(0.88)	-0.58%
	210	159.62	158.53	(1.10)	-0.69%
	220	166.96	165.65	(1.32)	-0.79%
	230	174.30	172.77	(1.53)	-0.88%
	240	181.64	179.89	(1.75)	-0.97%
	250	188.98	187.01	(1.97)	-1.04%
	260	196.32	194.13	(2.19)	-1.12%
	270	203.66	201.25	(2.41)	-1.18%
	280	211.00	208.37	(2.63)	-1.25%
	290	218.34	215.49	(2.85)	-1.30%
	300	225.68	222.61	(3.07)	-1.36%

(1) Rs_Residential Service average monthly usage

Intermountain Gas Company
Exhibit 5 – Bill Impact
Residential

IS-R_RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

	CURRENT RATES	PROPOSED RATES
CUSTOMER CHARGE	$ 5.50	$ 8.00
DISTRIBUTION CHARGE	$0.16305	$0.14116
COG	$0.57313	$0.57313
EE	$0.00000	$0.00000

	THERM	CURRENT	PROPOSED	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
		$	$	$	
	Usage Per THERM				
	0	5.50	8.00	2.50	45.45%
	10	12.86	15.14	2.28	17.74%
	20	20.22	22.29	2.06	10.20%
	30	27.59	29.43	1.84	6.68%
	40	34.95	36.57	1.62	4.65%
	50	42.31	43.71	1.41	3.32%
	60	49.67	50.86	1.19	2.39%
	70	57.03	58.00	0.97	1.70%
	80	64.39	65.14	0.75	1.16%
	90	71.76	72.29	0.53	0.74%
	100	79.12	79.43	0.31	0.39%
	110	86.48	86.57	0.09	0.11%
	120	93.84	93.71	(0.13)	-0.14%
	130	101.20	100.86	(0.35)	-0.34%
	140	108.57	108.00	(0.56)	-0.52%
	150	115.93	115.14	(0.78)	-0.68%
	160	123.29	122.29	(1.00)	-0.81%
(1)	170	130.65	129.43	(1.22)	-0.93%
	180	138.01	136.57	(1.44)	-1.04%
	190	145.37	143.72	(1.66)	-1.14%
	200	152.74	150.86	(1.88)	-1.23%
	210	160.10	158.00	(2.10)	-1.31%
	220	167.46	165.14	(2.32)	-1.38%
	230	174.82	172.29	(2.53)	-1.45%
	240	182.18	179.43	(2.75)	-1.51%
	250	189.55	186.57	(2.97)	-1.57%
	260	196.91	193.72	(3.19)	-1.62%
	270	204.27	200.86	(3.41)	-1.67%
	280	211.63	208.00	(3.63)	-1.71%
	290	218.99	215.14	(3.85)	-1.76%
	300	226.35	222.29	(4.07)	-1.80%

(1) Is-R_Residential Interruptible Snowmelt Service average monthly usage

Intermountain Gas Company
Exhibit 5 – Bill Impact
General Service

GS-1_GENERAL SERVICE
GS-1 IRRIGATION CUSTOMERS

		CURRENT RATES	PROPOSED RATES
CUSTOMER CHARGE		$ 9.50	$15.00
Block 1	200	$0.18465	$0.17745
Block 2	1800	$0.16117	$0.15489
Block 3	8000	$0.13850	$0.13310
Block 4	10000	$0.06994	$0.06721
COG		$0.56651	$0.56651
EE		$0.00320	$0.00320

	THERM	CURRENT	PROPOSED	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
		$	$	$	
	Usage Per THERM				
	-	9.50	15.00	5.50	57.89%
	100	84.94	89.72	4.78	5.63%
	200	160.37	164.43	4.06	2.53%
(1)	300	233.46	236.89	3.43	1.47%
	400	306.55	309.35	2.80	0.91%
	500	379.64	381.81	2.18	0.57%
	600	452.72	454.27	1.55	0.34%
(2)	700	525.81	526.73	0.92	0.17%
	800	598.90	599.19	0.29	0.05%
	900	671.99	671.65	(0.34)	-0.05%
	1000	745.08	744.11	(0.96)	-0.13%
	1100	818.16	816.57	(1.59)	-0.19%
	1200	891.25	889.03	(2.22)	-0.25%
	1300	964.34	961.49	(2.85)	-0.30%
	1400	1,037.43	1,033.95	(3.48)	-0.34%
	1500	1,110.52	1,106.41	(4.10)	-0.37%
	1600	1,183.60	1,178.87	(4.73)	-0.40%
	1700	1,256.69	1,251.33	(5.36)	-0.43%
	1800	1,329.78	1,323.79	(5.99)	-0.45%
	1900	1,402.87	1,396.25	(6.62)	-0.47%
	2000	1,475.96	1,468.71	(7.24)	-0.49%
	2100	1,546.78	1,538.99	(7.78)	-0.50%
	2200	1,617.60	1,609.27	(8.32)	-0.51%
	2300	1,688.42	1,679.56	(8.86)	-0.52%
	2400	1,759.24	1,749.84	(9.40)	-0.53%
	2500	1,830.06	1,820.12	(9.94)	-0.54%
	2600	1,900.88	1,890.40	(10.48)	-0.55%
	2700	1,971.70	1,960.68	(11.02)	-0.56%
	2800	2,042.52	2,030.96	(11.56)	-0.57%
	2900	2,113.35	2,101.24	(12.10)	-0.57%
	3000	2,184.17	2,171.52	(12.64)	-0.58%

(1) GS-1 Geneneral Service average monthly usage
(2) GS-1 Irrigation Service average monthly usage

Intermountain Gas Company
Exhibit 5 – Bill Impact
General Service

GS-1 - COMPRESSED NATURAL GAS

		CURRENT RATES	PROPOSED RATES
CUSTOMER CHARGE		$ 9.50	$ 15.00
Block 1	10,000	$0.13850	$0.13310
Block 2	10,000	$0.06994	$0.06721
COG		$0.56651	$0.56651
EE		$0.00000	$0.00000

THERM	CURRENT	PROPOSED	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	$	$	$	
Usage Per THERM				
-	9.50	15.00	5.50	57.89%
1000	714.51	714.61	0.10	0.01%
2000	1,419.52	1,414.22	(5.30)	-0.37%
3000	2,124.53	2,113.83	(10.70)	-0.50%
4000	2,829.54	2,813.44	(16.10)	-0.57%
5000	3,534.55	3,513.05	(21.50)	-0.61%
6000	4,239.56	4,212.66	(26.90)	-0.63%
7000	4,944.57	4,912.27	(32.30)	-0.65%
8000	5,649.58	5,611.88	(37.70)	-0.67%
9000	6,354.59	6,311.49	(43.10)	-0.68%
10000	7,059.60	7,011.10	(48.50)	-0.69%
11000	7,696.05	7,644.82	(51.23)	-0.67%
12000	8,332.50	8,278.54	(53.96)	-0.65%
13000	8,968.95	8,912.26	(56.69)	-0.63%
14000	9,605.40	9,545.98	(59.42)	-0.62%
15000	10,241.85	10,179.70	(62.15)	-0.61%
16000	10,878.30	10,813.42	(64.88)	-0.60%
17000	11,514.75	11,447.14	(67.61)	-0.59%
18000	12,151.20	12,080.86	(70.34)	-0.58%
19000	12,787.65	12,714.58	(73.07)	-0.57%
20000	13,424.10	13,348.30	(75.80)	-0.56%
21000	14,060.55	13,982.02	(78.53)	-0.56%
22000	14,697.00	14,615.74	(81.26)	-0.55%
23000	15,333.45	15,249.46	(83.99)	-0.55%
24000	15,969.90	15,883.18	(86.72)	-0.54%
25000	16,606.35	16,516.90	(89.45)	-0.54%
26000	17,242.80	17,150.62	(92.18)	-0.53%
27000	17,879.25	17,784.34	(94.91)	-0.53%
28000	18,515.70	18,418.06	(97.64)	-0.53%
29000	19,152.15	19,051.78	(100.37)	-0.52%
30000	19,788.60	19,685.50	(103.10)	-0.52%

Intermountain Gas Company
Exhibit 5 – Bill Impact
General Service

IS-C - SMALL COMMERCIAL INTERRUPTIBLE SNOWMELT SERVICE

		CURRENT RATES	PROPOSED RATES
CUSTOMER CHARGE		$ 9.50	$ 12.50
Block 1	200	$0.18465	$0.17745
Block 2	1800	$0.16117	$0.15489
Block 3	8000	$0.13850	$0.13310
Block 4	10000	$0.06994	$0.06721
COG		$0.56651	$0.56651
EE		$0.00000	$0.00000

	THERM	CURRENT	PROPOSED	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
		$	$	$	
	Usage Per THERM				
	-	9.50	12.50	3.00	31.58%
	100	84.62	86.90	2.28	2.69%
	200	159.73	161.29	1.56	0.98%
	300	232.50	233.43	0.93	0.40%
(1)	400	305.27	305.57	0.30	0.10%
	500	378.04	377.71	(0.32)	-0.09%
	600	450.80	449.85	(0.95)	-0.21%
	700	523.57	521.99	(1.58)	-0.30%
	800	596.34	594.13	(2.21)	-0.37%
	900	669.11	666.27	(2.84)	-0.42%
	1000	741.88	738.41	(3.46)	-0.47%
	1100	814.64	810.55	(4.09)	-0.50%
	1200	887.41	882.69	(4.72)	-0.53%
	1300	960.18	954.83	(5.35)	-0.56%
	1400	1,032.95	1,026.97	(5.98)	-0.58%
	1500	1,105.72	1,099.11	(6.60)	-0.60%
	1600	1,178.48	1,171.25	(7.23)	-0.61%
	1700	1,251.25	1,243.39	(7.86)	-0.63%
	1800	1,324.02	1,315.53	(8.49)	-0.64%
	1900	1,396.79	1,387.67	(9.12)	-0.65%
	2000	1,469.56	1,459.81	(9.74)	-0.66%
	2100	1,540.06	1,529.77	(10.28)	-0.67%
	2200	1,610.56	1,599.73	(10.82)	-0.67%
	2300	1,681.06	1,669.70	(11.36)	-0.68%
	2400	1,751.56	1,739.66	(11.90)	-0.68%
	2500	1,822.06	1,809.62	(12.44)	-0.68%
	2600	1,892.56	1,879.58	(12.98)	-0.69%
	2700	1,963.06	1,949.54	(13.52)	-0.69%
	2800	2,033.56	2,019.50	(14.06)	-0.69%
	2900	2,104.07	2,089.46	(14.60)	-0.69%
	3000	2,174.57	2,159.42	(15.14)	-0.70%

(1) Is-C - Small Commercial Interruptible Snowmelt Service average monthly usage

Intermountain Gas Company
Exhibit 5 – Bill Impact
Large Volume

LV-1_LARGE VOLUME

	Current Rates	Current Block	Proposed Rates	Proposed Block
Customer Charge	$ -		$ 150.0	
Demand Charge	$ 0.30000		$ 0.32000	
Block 1	$ 0.03000	250,000	$ 0.03000	35,000
Block 2	$ 0.01211	500,000	$ 0.01908	35,000
Block 3	$ 0.00307	750,000	$ 0.01600	70,000
COG	$ 0.51173		$ 0.51173	

Customer Usage Scenario	Monthly Average	MDFQ	Current Monthly Bill	Proposed Monthly Bill	Difference $	Difference %
High Use / High Demand	40,000	6,000	$ 23,469	$ 23,685	$ 215	0.92%
High Use / Low Demand	40,000	2,000	$ 22,269	$ 22,405	$ 135	0.61%
Avg. Use / Avg. Demand	30,000	3,000	$ 17,152	$ 17,362	$ 210	1.22%
Low Use / High Demand	20,000	3,000	$ 11,735	$ 11,945	$ 210	1.79%
Low Use / Low Demand	20,000	1,000	$ 11,135	$ 11,305	$ 170	1.53%

Intermountain Gas Company
Exhibit 5 – Bill Impact
Transportation

T-3 - TRANSPORT INTERRUPTIBLE

	Current Block	Current	Proposed
Customer Charge		$ -	$ 300
Demand Charge		$ -	$ -
Block 1	100,000	$ 0.03853	$ 0.03774
Block 2	50,000	$ 0.01569	$ 0.01537
Block 3	150,000	$ 0.00578	$ 0.00566
COG		$ (0.00082)	$ (0.00082)

Monthly Average Usage (Therm)	MDFQ (Therm)	Current Monthly Bill	Proposed Monthly Bill	Difference $	Difference %
-	-	$ -	$ 300	$ 300	0.00%
100,000	-	$ 3,771	$ 3,992	$ 221	5.86%
200,000	-	$ 4,763	$ 4,962	$ 199	4.18%
300,000	-	$ 5,259	$ 5,446	$ 187	3.56%
400,000	-	$ 5,755	$ 5,930	$ 175	3.04%
500,000	-	$ 6,251	$ 6,414	$ 163	2.61%
600,000	-	$ 6,747	$ 6,898	$ 151	2.24%
700,000	-	$ 7,243	$ 7,382	$ 139	1.92%
800,000	-	$ 7,739	$ 7,866	$ 127	1.64%
900,000	-	$ 8,235	$ 8,350	$ 115	1.40%
1,000,000	-	$ 8,731	$ 8,834	$ 103	1.18%
1,100,000	-	$ 9,227	$ 9,318	$ 91	0.99%
1,200,000	-	$ 9,723	$ 9,802	$ 79	0.81%
1,300,000	-	$ 10,219	$ 10,286	$ 67	0.66%
1,400,000	-	$ 10,715	$ 10,770	$ 55	0.51%
1,500,000	-	$ 11,211	$ 11,254	$ 43	0.38%
1,600,000	-	$ 11,707	$ 11,738	$ 31	0.26%
1,700,000	-	$ 12,203	$ 12,222	$ 19	0.16%
1,800,000	-	$ 12,699	$ 12,706	$ 7	0.06%
1,900,000	-	$ 13,195	$ 13,190	$ (5)	-0.04%
2,000,000	-	$ 13,691	$ 13,674	$ (17)	-0.12%

Intermountain Gas Company
Exhibit 5 – Bill Impact
Transportation

T-4 - TRANSPORT FIRM

	Current Block	Current Rates	Proposed Rates
Customer Charge		$ -	$ 150.00
Demand Charge		$ 0.30000	$ 0.32000
Block 1	250,000	$ 0.02395	$ 0.02393
Block 2	500,000	$ 0.00847	$ 0.00846
Block 3	750,000	$ 0.00260	$ 0.00260
COG		$ (0.01968)	$ (0.01968)

Customer Usage Scenario	Monthly Average Usage (Therm)	MDFQ (Therm)	Current Monthly Bill	Proposed Monthly Bill	Difference $	Difference %
High Use / High Demand	1,000,000	150,000	$ 52,921	$ 56,061	$ 3,140	5.93%
High Use / Low Demand	1,000,000	50,000	$ 24,889	$ 26,029	$ 1,140	4.58%
Avg. Use / Avg. Demand	300,000	30,000	$ 14,821	$ 15,565	$ 744	5.02%
Low Use / High Demand	50,000	7,500	$ 3,300	$ 3,599	$ 299	9.06%
Low Use / Low Demand	50,000	2,500	$ 1,898	$ 2,097	$ 199	10.48%