Intermountain Gas Company

Integrated Resource Plan

2025 – 2030

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

In the Community to Serve®

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I. Executive Summary

1.1 Overview

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and electric power peaking plants, all rely on natural gas to provide an economic, efficient, environmentally friendly, comfortable form of heating energy. Intermountain Gas Company (Intermountain, IGC, or Company) encourages the wise and efficient use of energy in general and, in particular, natural gas for end uses across Intermountain's service area.

The Integrated Resource Plan (IRP) is a document that describes the currently anticipated customer demand conditions over a five-year planning horizon, the anticipated resource selections to meet that demand, and the process for making resource decisions. Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of the IRP planning process. The demand forecasting and resource decision making process is ongoing and accordingly the Company files with the Idaho Public Utilities Commission an update to the IRP every two years. This IRP represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions, as conditions will change over the planning horizon impacting areas covered by this plan. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

1.1.1 About the Company

Intermountain Gas, a subsidiary of MDU Resources Group, Inc., is a natural gas local distribution company that was founded in 1950. The Company served its first customer in 1956. Intermountain is the sole distributor of natural gas in southern Idaho. Its service area extends across the entire breadth of southern Idaho as illustrated in Figure 2 (see page 6), an area of 50,000 square miles. At the end of 2020, Intermountain served approximately 444,600 total customers in 76 communities through a system of over 13,300 miles of transmission, distribution and service lines. In 2024, approximately 851 million therms were delivered to customers and additional transmission, distribution, and service lines were added to accommodate new customer additions and maintain service for Intermountain’s growing customer base.

1.1.2 Customer Base

The economy of Intermountain’s service area is based primarily on agriculture and related industries. Major crops are potatoes, milk and sugar beets. Major agricultural-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and service to two major markets: the residential/commercial market and the large volume market. The Company's residential and commercial customers use natural gas primarily for space and water heating. Intermountain's large volume customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications. Large volume demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. During 2020, nearly 50% of the throughput on Intermountain's system was attributable to large volume sales and transportation.

1.1.3 The IRP Process

Intermountain's Integrated Resource Plan is assembled by a talented cross-functional team from various departments within the Company. The IRP begins with a five-year forecast that considers customer demand and supply and delivery resources. The optimization model used in the development of the IRP identifies potential deficits and considers all available resources to meet the needs of Intermountain's customers on a consistent and comparable basis. A high-level overview of the process is described below. Each step in the process will be outlined in greater detail in later sections of this document.

1.1.4 Demand

As a starting point, Intermountain develops base case, high growth, and low growth scenarios to project the customer demand on its system for both core market and large volume customers. The core market includes residential and commercial customers. Large volume customers are high usage customers that are not eligible for residential or commercial service.

For the core market, the first step involves forecasting customer growth for both residential and commercial customers. Next, Intermountain develops design weather. Then the Company determines the core market usage per customer using historical usage, weather and geographic data. The usage per customer number is then applied to the customer forecast under design weather conditions to determine the core market demand.

To forecast both therm usage and contract demand for large volume customers, the Company analyzes historical usage, economic trends, and direct input from large volume customers. This approach is appropriate given the small population size of these customer classes. Because large volume customers typically use natural gas for industrial processes, weather data is not generally considered.

Both core market and large volume demand forecasts are developed by areas of interest (AOI) and then aggregated to provide a total company perspective. Analyzing demand by AOI allows the Company to consider factors specifically related to a geographic area when considering potential capacity enhancements.

1.1.5 Supply & Delivery Resources

After determining customer demand for the five-year period, the Company identifies and reviews currently available supply and delivery resources. Additionally, the Company includes in its resource portfolio analysis various non-traditional resources as well as potential therm savings resulting from its energy efficiency program.

1.1.6 Optimization

The final step in the development of the IRP is the optimization modeling process, which matches demand against supply and deliverability resources by AOI and for the entire Company to identify any potential deficits. Potential capacity enhancements are then analyzed to identify the most cost effective and operationally practical option to address potential deficits. The Planning Results section shows how all deficits will be met over the planning horizon of the study. Figure 1 provides a visual overview of the IRP process.

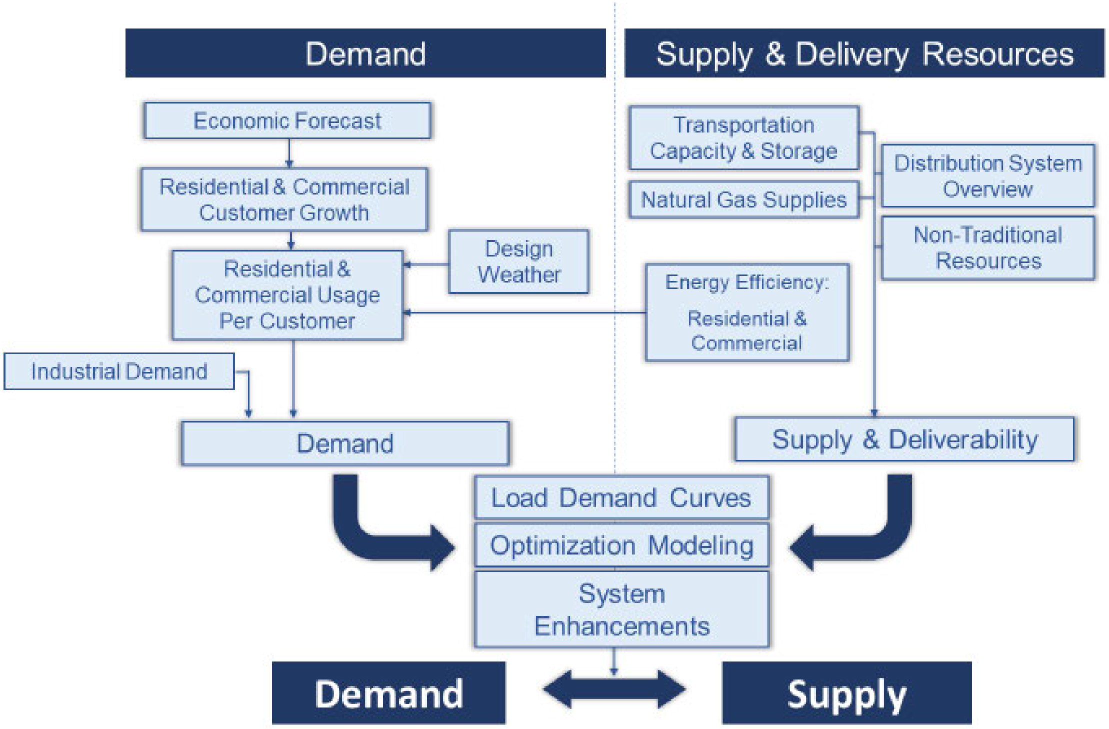

Figure 1: The IRP Process

1.1.7 Intermountain Gas Resource Advisory Committee

To enhance the Integrated Resource Plan development, the Company established the Intermountain Gas Resource Advisory Committee (IGRAC). The intent of the committee is to provide a forum through which public participation can occur as the IRP is developed.

Advisory committee members were solicited from across Intermountain's service territory as representatives of the communities served by Intermountain. Exhibit 1, Section A, is a sample of the invitation to join the committee. Committee members have varied backgrounds in regulation, economic development, and business.

Intermountain held its IGRAC meetings on a virtual platform to ensure that committee members from across the state could safely and easily participate. A total of four virtual meetings were held in 2025 between the months of July and December. Included in Exhibit 1 are meeting minutes and presentations from the meetings.

After each meeting, for members who were unable to attend, an email containing the materials covered was sent out. The Company provided a comment period after each meeting to ensure feedback was timely and could be incorporated into the IRP. Intermountain also established an email account where feedback and information requests could be managed. Finally, the

Company has a dedicated webpage where meeting minutes, presentations, and video recordings are presented shortly after each IGRAC meeting.[1]

1.1.8 Summary

Through the process explained above, Intermountain analyzed residential, commercial and large volume demand growth and the consequent impact on Intermountain's distribution system using design weather conditions under various scenarios. Forecast demand under each of the customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of potential delivery deficits, both from a total company perspective as well as an AOI perspective. The resources needed to meet these projected deficits were analyzed within a framework of traditional, non-traditional and energy efficiency options to determine the most cost effective and operationally practical means available to manage the deficits. In utilizing these options, Intermountain's core market and firm transportation customers can continue to rely on safe, reliable, affordable firm service both now and in the future.

[1] *See:* https://www.intgas.com/rates-services/rates-tariffs/integrated-resource-plan/

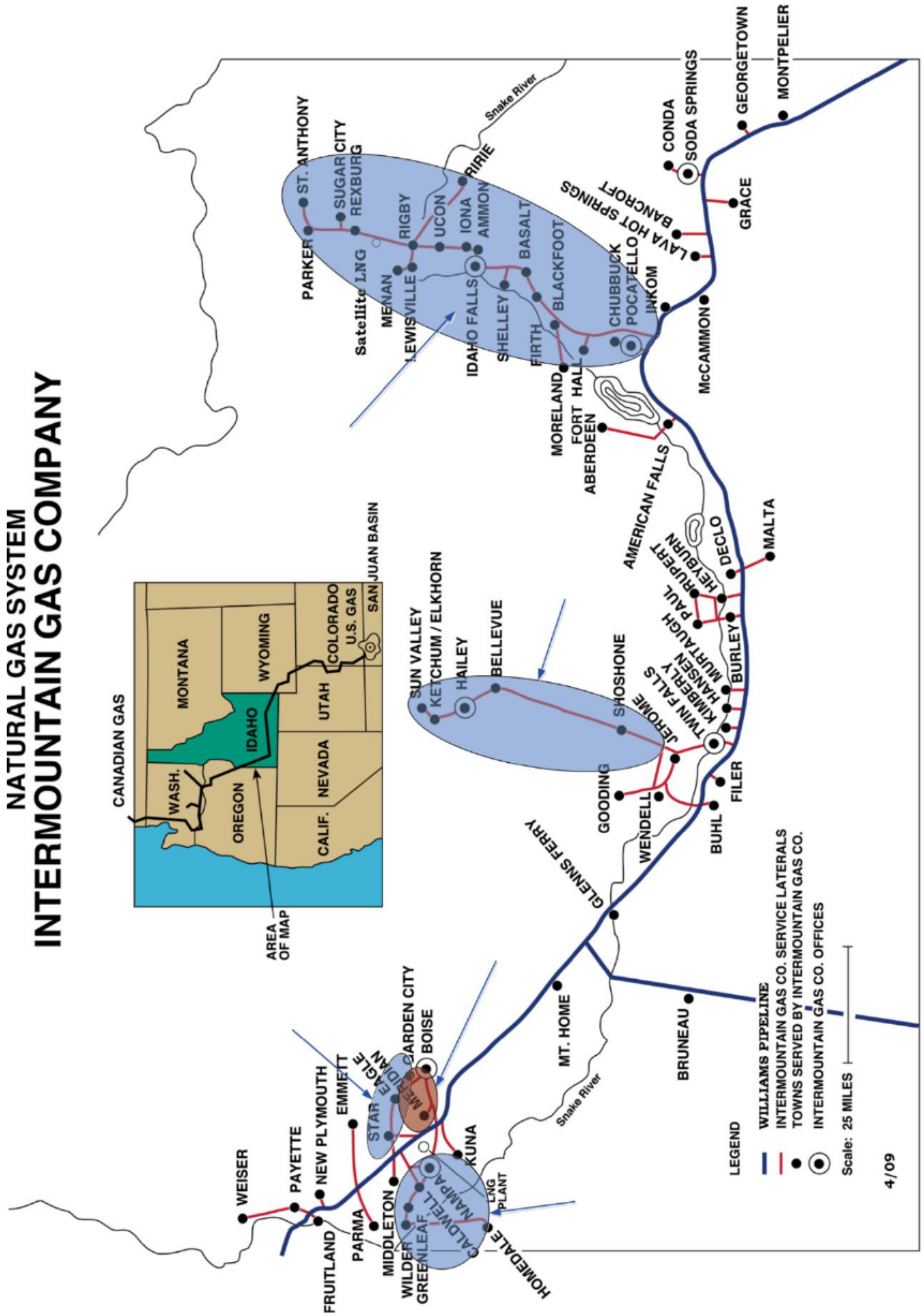

Figure 2: Intermountain Gas System Map

1.1.9 Natural Gas and the National Energy Picture

The blue flame. Curling up next to a natural gas fireplace, starting the morning with a hot shower, coming home to a warm house. The blue flame of natural gas represents warmth and comfort, and provides warmth and comfort in the cleanest, safest, most affordable way possible.

Natural gas remains the cleanest-burning fossil fuel, producing primarily heat and water vapor. In 2025, U.S. natural gas consumption is projected to reach 91.4 billion cubic feet per day (Bcf/d), driven by residential, commercial, and industrial sectors.[1] Distribution system CO_2 emissions remain low, with annual emissions under 0.1 million metric tons of CO_2e, thanks to ongoing infrastructure upgrades.[2]

The U.S. natural gas industry has added over 815,000 miles of pipeline since 1990, serving more than 77 million customers. These investments have helped reduce methane emissions from distribution systems by over 69% since 1990, according to the EPA.

Natural gas pipelines remain the safest and most efficient transportation method, outperforming rail and truck. Safety and reliability are prioritized at every stage, from design to maintenance.[3]

Natural gas is also cost-effective. As of 2025, households using natural gas save an average of $1,068 annually compared to electric-only homes. Despite rising global demand, U.S. prices are forecasted to average around $3.90/MMBtu, thanks to record production levels.[4]

The U.S. has at least a century's worth of natural gas reserves, ensuring long-term supply stability.[5]

1.1.10 The Direct Use of Natural Gas

The direct use of natural gas refers to employing natural gas at the end-use point for space heating, water heating, and other applications. This is opposed to the indirect use of natural gas to generate electricity which is then transported to the end-use point and employed for space or water heating. The direct use of natural gas is 91% efficient from production to the consumer end-use, compared to an efficiency of only 36% for the indirect use of natural gas.

As electric generating capacity becomes more constrained in the Pacific Northwest, additional peak generating capacity will primarily be natural gas fired. Direct use will mitigate the need for

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[1] https://www.forbes.com/sites/rrapier/2025/04/02/us-natural-gas-in-2025-record-supply-and-demand/
[2] https://bipartisanpolicy.org/download/?file=/wp-content/uploads/2025/09/BPC_Natural_Gas_Report_September-2025.pdf
[3] https://bipartisanpolicy.org/download/?file=/wp-content/uploads/2025/09/BPC_Natural_Gas_Report_September-2025.pdf
[4] https://www.forbes.com/sites/rrapier/2025/04/02/us-natural-gas-in-2025-record-supply-and-demand/
[5] https://www.igu.org/igu-reports/global-gas-report-2025

future generating capacity. If more homes and businesses use natural gas for heating and commercial applications, then the need for additional generating resources will be reduced.

From a resource and environmental perspective, the direct use of natural gas makes the most sense. More energy is delivered using the same amount of natural gas, resulting in lower cost and lower CO_2 emissions. This direct, and therefore, more efficient natural gas usage will serve to keep natural gas prices, as well as electricity prices, lower in the future.

Intermountain plays a critical role in providing energy throughout southern Idaho. The Company's residential customers use over 201.5 million therms a year for space heating applications. If this demand had to be served by electricity, it would mean that Intermountain's residential customers would require approximately 5,079,000 megawatt hours a year to replace the natural gas currently used to heat their homes. This would require nearly doubling the total residential electric load currently being supplied in the region. This scenario would prove a considerable burden for both electric generation and transmission.

Ultimately, using natural gas for direct use in heating applications is the best use of the resource, and mitigates the need for costly generation and infrastructure expansion across the U.S. electric grid.

1.1.11 Clean Energy Future

Natural gas is not only safe, reliable and affordable, but the natural gas distribution system will also be a critical component in delivering clean energy in the future. Intermountain is actively involved in the research and development of low- and zero-carbon energy technologies through its participation in Gas Technology Institute (GTI) and the Low-Carbon Resources Initiative (LCRI).

LCRI is a joint venture of GTI and the Electric Power Research Institute. Its mission is to accelerate the deployment of the low- and zero-carbon energy technologies that will be required for deep decarbonization. LCRI is specifically targeting advances in the production, distribution, and application of low-carbon, alternative energy carriers and the cross-cutting technologies that enable their integration at scale. These energy carriers - which include hydrogen, ammonia, synthetic fuels, and biofuels - are needed to enable affordable pathways to achieve deep carbon reductions across the energy economy. The LCRI is focused on technologies that can be developed and deployed beyond 2030 to support the achievement of a net zero emission economy by 2050.

Intermountain is also playing an important role in the growth and development of the emerging Renewable Natural Gas (RNG) industry. The Company's RNG Facilitation agreement allows Intermountain to provide access to its distribution system for RNG producers to transport RNG to their end use customers. RNG takes a waste stream that is currently emitting greenhouse gasses, captures it, and puts it to a beneficial end use. Although RNG is currently more expensive than traditional natural gas, as the technology matures the Company anticipates the costs will continue to decrease which will make it a viable supply option for customers in the future.

2. Demand

2.1 Demand Forecast Overview

The starting point for resource planning is developing a reliable forecast of future load requirements. This involves more than simply projecting overall growth, it requires an understanding of how many customers will require service, how much natural gas those customers are likely to use, and the weather conditions that will influence demand. To capture the full picture, contracted maximum deliveries to large industrial customers are also incorporated into the demand forecast.

Intermountain's approach integrates several key elements, including forecasts of customer counts, calculations of gas usage per customer, and a range of weather profiles. Each of these is explored in greater detail later in this document. By combining them in different ways, Intermountain develops separate demand forecast scenarios for core market customers, which are then used to test system needs under a range of possible conditions. When combined with large volume customers, these scenarios create a total company demand outlook. This perspective is essential for planning because it includes not only monthly and annual loads but also daily usage patterns, including peak demand events. Such detail allows Intermountain to assess whether existing supply arrangements and delivery capacity are sufficient under varying demand situations. Further discussion of these forecasts is provided in the following sections.

To ensure resource planning is both comprehensive and precise, Intermountain also evaluates distinct segments of its distribution system, referred to as Areas of Interest (AOI). These AOIs capture the diversity of customer demand across the service territory, and the results of each analysis are then aggregated to form a company-wide perspective. The AOIs used for planning purposes are as follows:

- The Canyon County Area: serves core market customers in Canyon County.
- Central Ada County Area: serves core market customers in Ada County between Chinden Boulevard and Victory Road (north–south) and between Maple Grove Road and Black Cat Road (east–west).
- The Sun Valley Lateral: serves core market customers in Blaine and Lincoln Counties.
- The Idaho Falls Lateral: serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison Counties.
- The State Street Lateral: serves core market customers in Ada County north of the Boise River, bounded on the west by Kingsbury Road (west of Star) and on the east by State Highway 21.
- The All Other Segment: serves core market customers in Ada County not included in the State Street Lateral or Central Ada Area, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington Counties.

2.2 Residential & Commercial Customer Growth Forecast

This section of Intermountain's IRP describes and summarizes the residential and commercial customer growth forecast for the years 2025 through 2030. This forecast provides the anticipated magnitude and direction of Intermountain's residential and commercial customer growth by the identified Areas of Interest (AOI) for Intermountain's service territory. Customer growth is the primary driving factor in Intermountain's five-year demand forecast contained within this IRP.

In this IRP, Intermountain utilized an ARIMAX model (Autoregressive Integrated Moving Average with Exogenous Variables) to forecast residential and commercial customer counts. This model combines a regression component with an ARIMA error structure, allowing it to incorporate explanatory variables such as the number of households, employment forecasts, and other drivers described below. ARIMA-based models are widely used for time series forecasting because they capture both nonseasonal and seasonal patterns in the data. The nonseasonal components are represented by the parameters (p, d, q), while the seasonal components are represented by (P, D, Q). These components are automatically selected to minimize the corrected Akaike Information Criterion (AICc), ensuring the best-performing model for the data. The ARIMAX approach is particularly beneficial because it accounts for both historical patterns and external drivers, improving forecast accuracy. The household variable reflects actual and forecasted household growth by county within Intermountain's service territory, and employment data captures actual and projected full- and part-time jobs by place of work. Generally, increases in household counts are associated with increases in residential customers, while rising employment tends to correlate with growth in commercial customer counts, hence their inclusion as explanatory variables. To capture annual seasonality, Fourier terms with K harmonics are also included, each harmonic adds a pair of sine and cosine terms that help represent seasonal patterns. A deterministic trend component may be added to account for any remaining underlying trend, and lagged versions of household and/or employment data may also be incorporated. Whether a variable is included depends on its impact on model performance relative to other tested models. Coefficients are estimated by the modeling software to best represent the relationship between each explanatory variable and the outcome variable. Each county and customer type combination in Intermountain's service territory is modeled separately. The general customer count forecast model is shown below, though not every model includes all the explanatory variables listed. As noted, the final combination of explanatory variables, lag structures of those explanatory variables, a trend component, ARIMA error components, and Fourier terms is determined based on model performance during the selection process. This approach differs from the previous IRP, and the equation below is representative only.

The customer forecast model is as follows:

$$Customers_t = \beta_0 + \beta_1 HH_t + \beta_2 Emp_t + Trend_t + \ Fourier(\text{“}year\text{”}, K)_t + \eta_t$$

Where:

- t: $time\ index$.
- $Customers_t$: $Total\ customer\ count\ at\ time\ t$.
- HH_t: $Number\ of\ households\ at\ time\ t$.
- Emp_t: $Employment\ at\ time\ t$.
- $Trend_t$: $Deterministic\ trend\ component\ at\ time\ t$.
    - This captures the long-term gradual growth or decline of customers over time.
- $Fourier("year", K)_t$: $Captures\ yearly\ seasonality\ using\ K\ harmonics\ at\ time\ t$.
    - These terms capture the predictable seasonal swings (e.g., yearly highs or lows).
- $\eta_t\ is\ the\ error\ term\ modeled\ as\ an\ ARIMA(p, d, q)(P, D, Q)\ process\ with$: $p\ nonseasonal\ autoregressive\ terms, d\ nonseasonal\ differencing,$ $q\ nonseasonal\ moving\ average\ terms, P\ seasonal\ autoregressive$ $terms, D\ seasonal\ differencing, Q\ seasonal\ moving\ average\ terms$.
    - This component jointly models the error term using an ARIMA process to capture autocorrelation and other patterns not explained by the explicitly modeled variables. By incorporating this structure into the model, forecast accuracy improves and the remaining innovations behave like white noise.

Similar to the 2023 IRP, Intermountain's growth projections remain strong. Figure 3 below illustrates the combined residential and commercial customer additions by AOI.

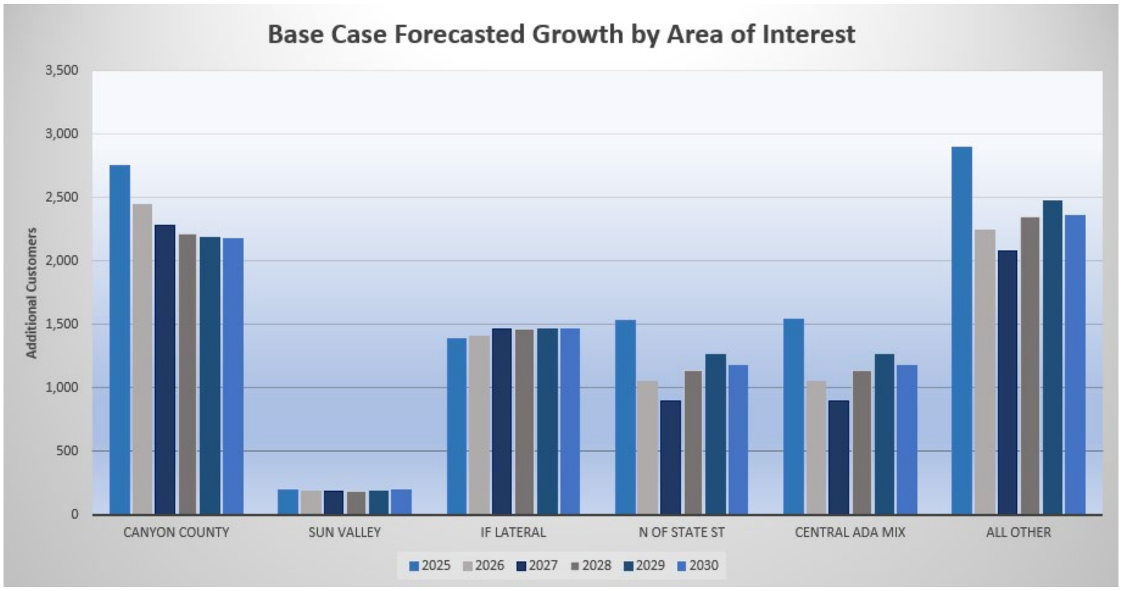

Figure 3: Base Case Forecasted Growth by Area of Interest

The forecast includes three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model and developed three five-year core market customer growth forecasts. Figure 4 below displays the annual additional customer projections for each of the three economic scenarios.

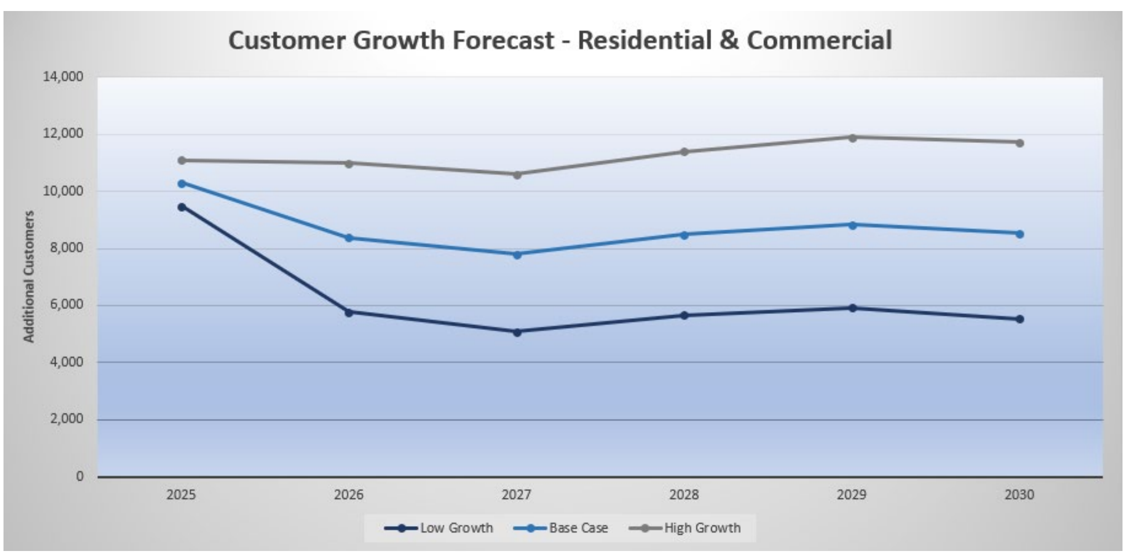

Figure 4: Customer Growth Forecast - Residential & Commercial

Figure 5 below shows the difference in the base case forecasted annual customer growth between the 2023 IRP and the 2025 IRP, where the two forecasts overlap.

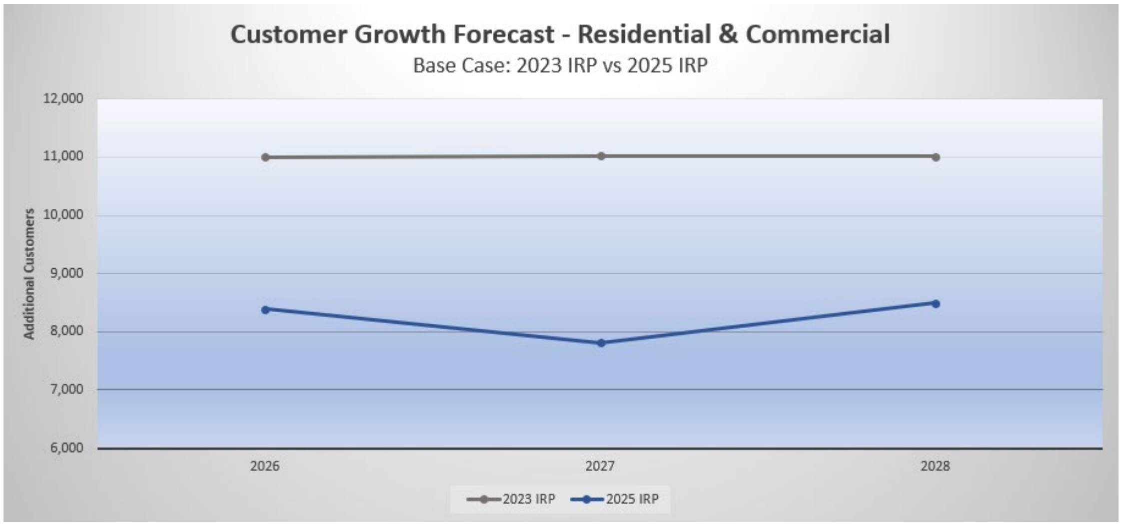

Figure 5: Customer Growth Forecast – Base Case: 2023 IRP vs. 2025 IRP

The following two tables present the results of the five-year customer growth forecast for each economic scenario. Table 1 shows the projected customer growth under each scenario, while Table 2 displays the forecasted total number of customers for each scenario.

Forecasted Customer Growth						
	2025	2026	2027	2028	2029	2030
Low Growth	9,476	5,780	5,073	5,665	5,918	5,541
Base Case	10,291	8,385	7,809	8,495	8,840	8,542
High Growth	11,105	10,998	10,595	11,409	11,890	11,715

Table 1: Forecasted Customer Growth

Forecasted Total Customers						
	2025	2026	2027	2028	2029	2030
Low Growth	432,632	438,412	443,485	449,150	455,068	460,608
Base Case	433,446	441,832	449,641	458,136	466,975	475,517
High Growth	434,260	445,258	455,853	467,263	479,152	490,867

Table 2: Forecasted Total Customers

The following sections explore the different components of the customer forecast in greater detail.

2.2.1 The Base Case Economic Growth Scenario

Under the Base Case Scenario of the Idaho Economic Forecast, it is projected that Idaho will continue to be an attractive environment for future economic, population, and household growth.

From 2015 to 2019, Idaho's nonfarm employment grew at a strong pace, with an average year-over-year percent change of 2.91%. This amounted to a gain of about 136,600 jobs over that period. Population growth was also a major driver of economic expansion leading up to the COVID-19 pandemic. At the start of 2020, Idaho entered the year with a historically strong economy, including a record-low unemployment rate of 2.5%. However, the onset of the COVID-19 pandemic caused a sharp slowdown. On March 25, 2020, Governor Brad Little issued a statewide stay-at-home order, leading to the closure of nonessential businesses. By April, the state's unemployment rate surged to 11.8%, the highest in recorded history, leaving over 100,000 Idahoans unemployed and reducing nonfarm employment by 78,500 jobs, effectively erasing four years of job growth in a single month. Industries such as leisure and hospitality, other services, education and health services, and information were among the hardest hit.

Despite this severe disruption, the recovery began quickly. By May 2020, Idaho launched the "Rebound Idaho" phased reopening plan. The unemployment rate declined to 9%, and nonfarm employment rebounded by 3.3%, regaining roughly a year's worth of job growth. Overall, Idaho still managed a year-over-year gain of about 1.5% in nonfarm jobs in 2020, an increase of roughly 15,310. From 2021 through 2024, the recovery accelerated. Total nonfarm employment increased year-over-year at an average rate of 3.31%, adding about 143,242 jobs. In 2021, Idaho recorded its largest annual gain in nonfarm employment since 1994, with an increase of 5.95% (about 61,698 jobs). This strong, and relatively rapid rebound, highlights an economy with continued upward momentum and strong future growth prospects.

Population growth has closely paralleled these employment gains. Even through the pandemic, Idaho's population growth remained robust. From 2019 to 2021, the state posted the highest year-over-year percentage change in population in the nation, averaging about 2.37% annually, an increase of roughly 97,470 people over three years. The 2021 gain of 2.98% was the largest single-year increase since 1994.

Although growth has moderated slightly since then, it remains strong. The Bureau of Labor Statistics estimates that Idaho's population grew by 1.36% in 2023 (about 26,823 people) and 1.52% in 2024 (about 30,497 people). Even at these lower rates, Idaho's growth still exceeded the national weighted average of about 0.98%, meaning the state continued to outpace most of the country. Much of this growth has been driven by domestic migration from more expensive and densely populated states such as Oregon, Washington, and California. Overall, Idaho's rapid population growth has fueled job creation, strengthened the economy, and positioned the state for continued expansion.

2.2.2 Population & Employment

Idaho is expected to maintain its strong growth trajectory through the second half of the decade, though at a more measured pace than the rapid expansion seen immediately after the pandemic. Between 2025 and 2030, the state's population is projected to increase by approximately 112,858 residents, reflecting an average annual growth rate of 0.92%. Over the same period, nonfarm employment is forecast to expand by roughly 93,179 jobs, an average annual increase of 1.27%.

Growth will remain highly concentrated in Ada and Canyon Counties. Together, these counties are projected to account for the majority of new residents and jobs, with an additional 74,550 people (an average annual growth rate of 1.51%) and 54,582 jobs (an average annual increase of 1.67%). This represents about two-thirds of Idaho's projected population growth and about 58.58% of job creation statewide.

In the central part of the state, where the Company provides service to Blaine and Lincoln Counties through the Sun Valley Lateral, population is projected to rise by 1,366, an average annual growth rate of 0.73%, while employment is expected to grow by 1,161 jobs, also an average annual increase of 0.73%. These gains make up 1.25% of Idaho's total growth. In eastern Idaho, within the Idaho Falls Lateral (covering Bingham, Bonneville, Fremont, Jefferson, and Madison Counties), population is projected to increase by 18,627, an average annual growth rate of 1.05%, representing 16.50% of statewide growth. Employment in this area is expected to expand by 11,705 jobs, an average annual increase of 1.20%, making up 12.56% of the total projected gains in Idaho.

The Education and Health Services supersector has been one of Idaho's fastest-growing industries. From 2019 to 2024, employment increased by 15.23% (28,287 jobs), reflecting an average annual growth rate of 3.41%. Projections for 2025–2030 indicate continued strength, with an additional 26,930 jobs expected, an average annual increase of 2.70%. Most of this growth will come from health care and social assistance (21,776 jobs). Employment gains in Ada and Canyon Counties are expected to total 15,047 jobs, an average annual increase of 3.19%, accounting for more than half of statewide growth in this sector. Blaine and Lincoln Counties are projected to add 265 jobs, an average annual increase of 2.03%, while the Idaho Falls Lateral is forecast to see an increase of 3,999 jobs, an average annual increase of 2.35%.

This expansion is supported by structural drivers such as population growth, demographic shifts, policy support, and new investment in hospitals, schools, and assisted living facilities. For the Company, this implies sustained demand for natural gas in residential, commercial, and institutional settings.

Manufacturing recovered quickly after the pandemic, adding 5,725 jobs between 2019 and 2024, including gains of 2,013 jobs in 2021 and 3,346 jobs in 2022. Looking ahead, growth is projected to slow, with only 1,676 additional jobs statewide from 2025–2030, an average annual increase of 0.34%. Ada and Canyon Counties are projected to see a decline of 505 jobs, an average annual decrease of 0.27%, while Blaine and Lincoln Counties are expected to add 71 jobs, an average annual increase of 1.63%. The Idaho Falls Lateral is forecasted to add 636 jobs, an average annual increase of 1.05%. Although statewide manufacturing growth is modest, the sector continues to demonstrate resilience. Challenges include labor shortages, skills gaps, and competition from faster-growing industries, while automation and technology are reshaping production and allowing output growth with fewer workers.

Construction also experienced significant momentum in recent years, fueled by population inflows and housing demand. Between 2019 and 2024, employment in the sector increased by 20,640 jobs, reflecting an average annual growth rate of 4.29%. For the period 2025–2030, Woods & Poole forecasts a gain of 882 jobs, an average annual increase of 0.16%, while the Idaho Department of Labor projects a much stronger 25.6% increase between 2022 and 2032. Regardless of the precise pace, construction activity is expected to remain robust as new residents drive demand for housing, schools, health care facilities, and infrastructure. These developments could translate into additional natural gas demand in both residential and commercial applications.

The combined sectors of retail trade, transportation and warehousing, wholesale trade, and utilities added nearly 38,000 jobs between 2019 and 2024, reflecting an average annual growth rate of 3.26%. From 2025 to 2030, growth is projected to moderate, with an increase of 8,766 jobs statewide, an average annual increase of 0.66%. Ada and Canyon Counties are expected to account for 6,339 of those jobs, an average annual increase of 0.91%, underscoring their central role in Idaho's logistics and distribution networks.

Broadly defined, the services industries are expected to lead Idaho's job growth. These include professional and technical services, education, health care, government, accommodation and food services, and other services. Together, they added 65,148 jobs between 2019 and 2024, reflecting an average annual growth rate of 2.41%. Looking forward, the sector is projected to add 57,298 jobs from 2025 to 2030, an average annual increase of 1.85%, accounting for over 61% of statewide job creation. Of this growth, 34,367 jobs are projected in Ada and Canyon Counties, an average annual increase of 2.53%, making up nearly 60% of the total gains for this group in the State. Blaine and Lincoln Counties are expected to add 616 jobs, an average annual increase of 0.97%, while the Idaho Falls Lateral is forecast to add 7,801 jobs, an average annual increase of 1.79%.

Although growth is expected to slow somewhat compared with the extraordinary post-pandemic rebound, Idaho remains on a trajectory of steady expansion. Factors such as moderating wage gains, slower population growth, and a shifting balance between retirees and working-age residents will temper momentum, but strong demand for services, continued in-migration, and investment in key industries should keep the state among the nation's stronger performers. These trends point to continued demand for the Company's services.

2.2.3 Households

Woods & Poole defines households as:

> *Occupied housing units. A housing unit may be a single-family home, an apartment, a group of rooms, or a single room occupied as separate living quarters. The occupants may consist of one family, a single individual, multiple families living together, or unrelated persons sharing the same space. All individuals are part of a household except those who live in group quarters, such as prisons, nursing homes, dormitories, or military barracks. Average household size is calculated by subtracting the group-quarters population from the total population and dividing by the number of households.*

In previous IRPs, population was used as an explanatory variable in residential customer models. For this IRP, household counts are used instead, as they provide a more accurate measure of potential residential service connections. While population growth may reflect more people moving into the state, multiple individuals often share the same home, meaning that household growth aligns more closely with utility service needs. Household data also better reflects development trends and provides greater stability and consistency with regional planning assumptions. For example, if a city adds 1,000 new homes, that translates directly into 1,000 potential new residential customers, regardless of whether 2,000 or 3,000 people move into those homes.

Between 2019 and 2024, Idaho added 94,435 households, with an average annual growth rate of 2.25%. The surge in 2022 and 2023 marked record highs, reflecting strong population inflows during, and immediately, following the pandemic. Looking ahead, growth is expected to remain strong but at a more moderate pace. From 2025 through 2030, Idaho is projected to add 69,161 households, with an average annual increase of 1.16%. Ada and Canyon Counties are expected to account for about 51.88% of this increase, adding 35,879 households at an average annual growth rate of 1.89%. The Sun Valley Lateral (Blaine and Lincoln Counties) is forecasted to contribute 806 new households, representing 1.17% of the statewide total and growing at an average annual rate of 1.01%. The Idaho Falls Lateral is projected to add 8,474 households, an average annual growth rate of 1.43%, or 12.25% of the statewide increase.

2.2.4 Customer Growth Scenarios

In addition to the base case forecast, which represents the most likely outcome, two alternative scenarios are developed: a low customer growth scenario and a high customer growth scenario. These scenarios provide a structured way to evaluate uncertainty in future customer growth. Both are constructed using the historical standard deviation of annual customer growth rates, ensuring that they are grounded in observed patterns and remain straightforward to audit and reproduce.

2.2.5 The Low Customer Growth Scenario

The low growth scenario applies a downward adjustment equivalent to one standard deviation below the base case customer growth rate. This adjustment is converted into a monthly compounding growth factor by taking the twelfth root of the annual growth rate, which is then applied iteratively by using the cumulative product function to simulate the effect of compounding over time. The resulting vector provides a potential trajectory that reflects a slower pace of customer additions compared with the base forecast.

This scenario assumes that Idaho's long-standing trend of strong in-migration slows relative to recent history. Migration out of Oregon, Washington, and California would increasingly be captured by neighboring states such as Utah, Nevada, and Arizona, reflecting patterns observed in the 1990s and early 2000s. Idaho could also face additional headwinds if a major employer were to close or relocate operations, reducing its ability to attract job seekers. In this scenario, weaker economic growth, fewer employment opportunities, and slower population inflows would all contribute to more limited customer growth for the Company.

2.2.6 The High Customer Growth Scenario

The high growth scenario increases the base case forecast by one standard deviation above the base case customer growth rate, again applying a compounding monthly factor derived from the annual growth adjustment. This produces a trajectory that reflects faster customer growth than in the base case.

Under this scenario, Idaho captures a larger share of both business relocations and in-migration from neighboring states. Firms based in California, Oregon, and Washington could increasingly seek out Idaho for its relatively lower taxes, operating costs, and regulatory environment. This would continue a pattern that has occurred over the past three decades, when Nevada, Arizona, and Utah attracted substantial economic and population growth through business relocations and migration flows. In this case, Idaho is assumed to become a more prominent destination, drawing not only businesses but also individuals and families seeking more affordable housing and less congestion than in neighboring coastal states. The result would be stronger growth in both households and employment levels, resulting in a higher number of natural gas customers than in the base case.

2.2.7 Residential Customer Forecast

The following graphs show the forecasted residential customer counts by AOI and total Company for each of the growth scenarios using the methodology previously outlined.

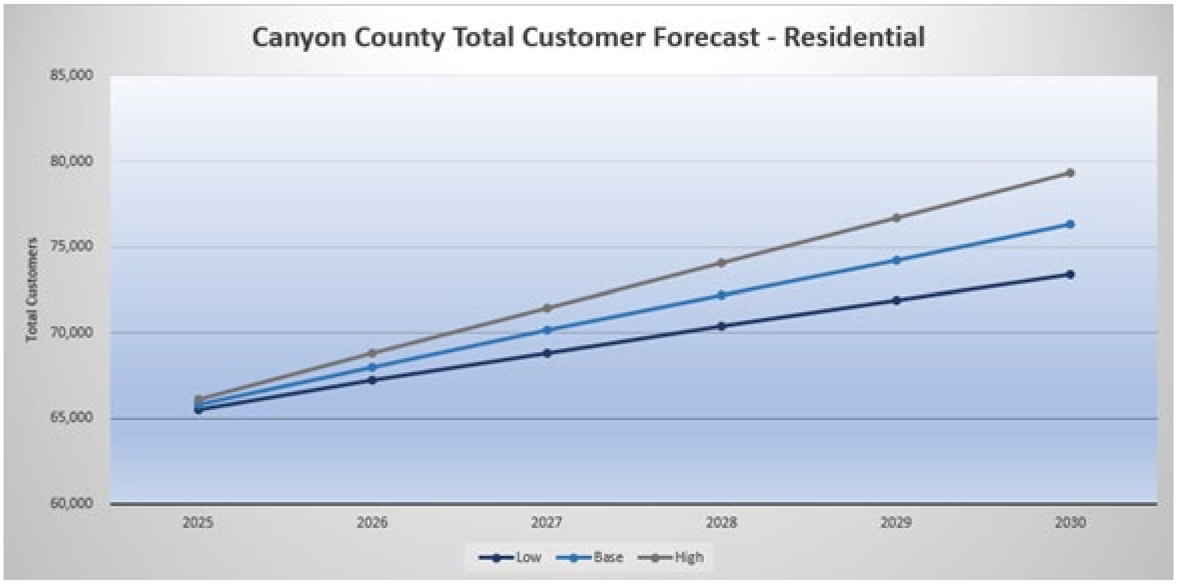

Figure 6: Canyon County Total Customer Forecast - Residential

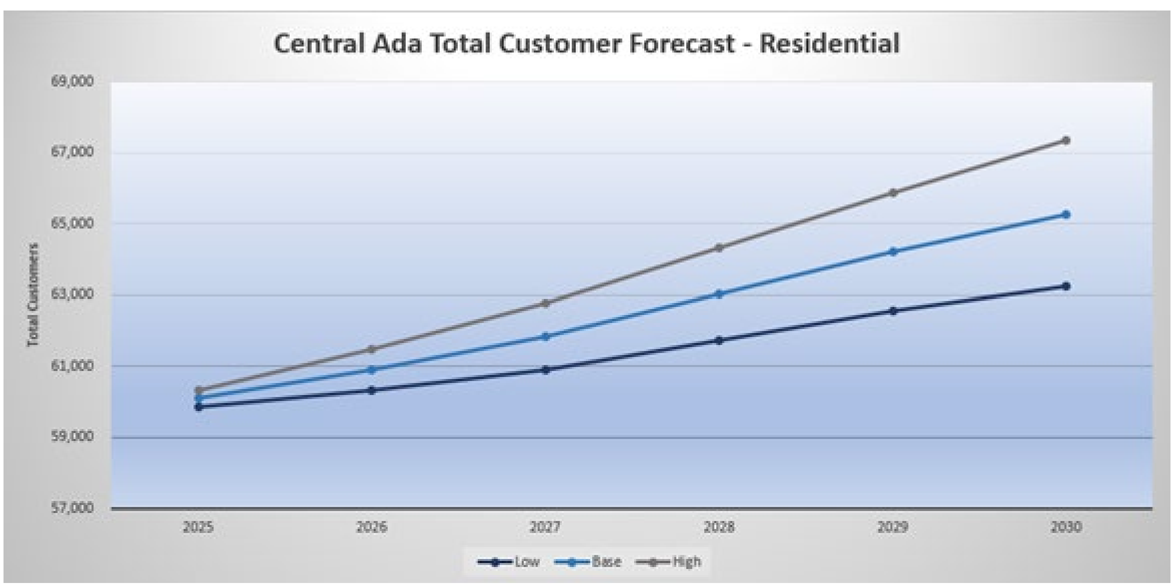

Figure 7: Central Ada Total Customer Forecast – Residential

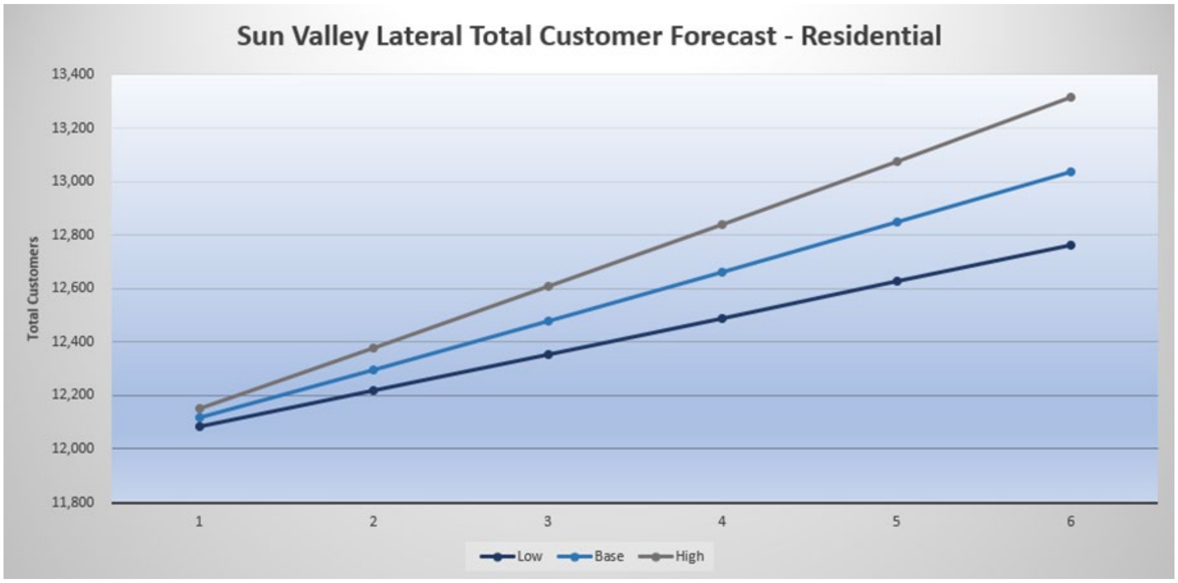

Figure 8: Sun Valley Lateral Total Customer Forecast – Residential

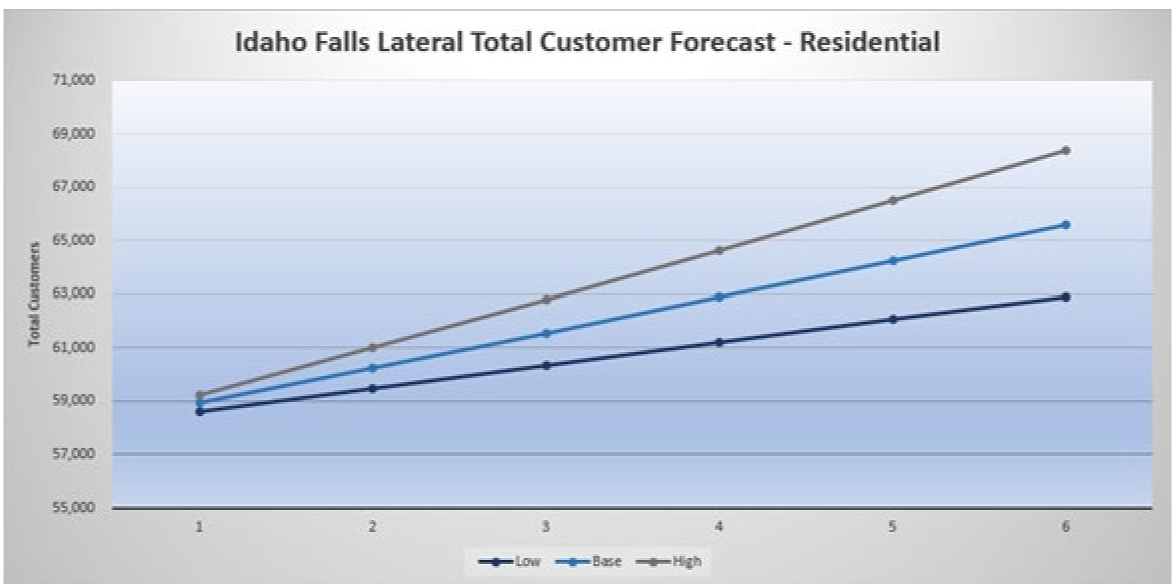

Figure 9: Idaho Falls Lateral Total Customer Forecast – Residential

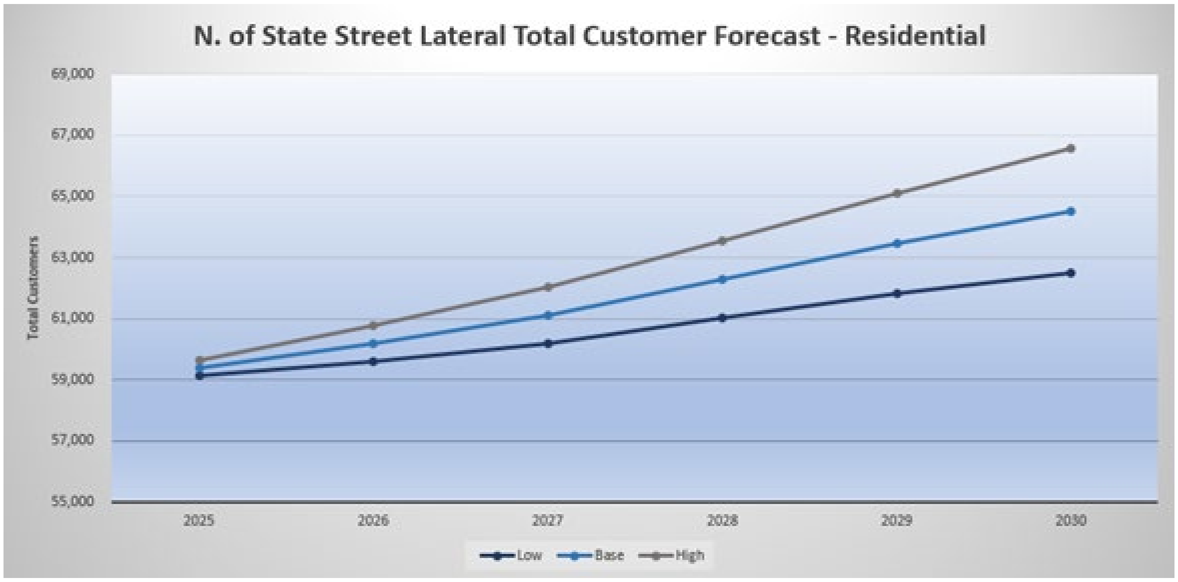

Figure 10: N. of State Street Lateral Total Customer Forecast – Residential

Figure 11: Total Company Customer Forecast – Residential

2.2.8 Commercial Customer Forecast

The following graphs show the forecasted commercial customer counts by AOI and total Company for each of the growth scenarios using the methodology previously outlined.

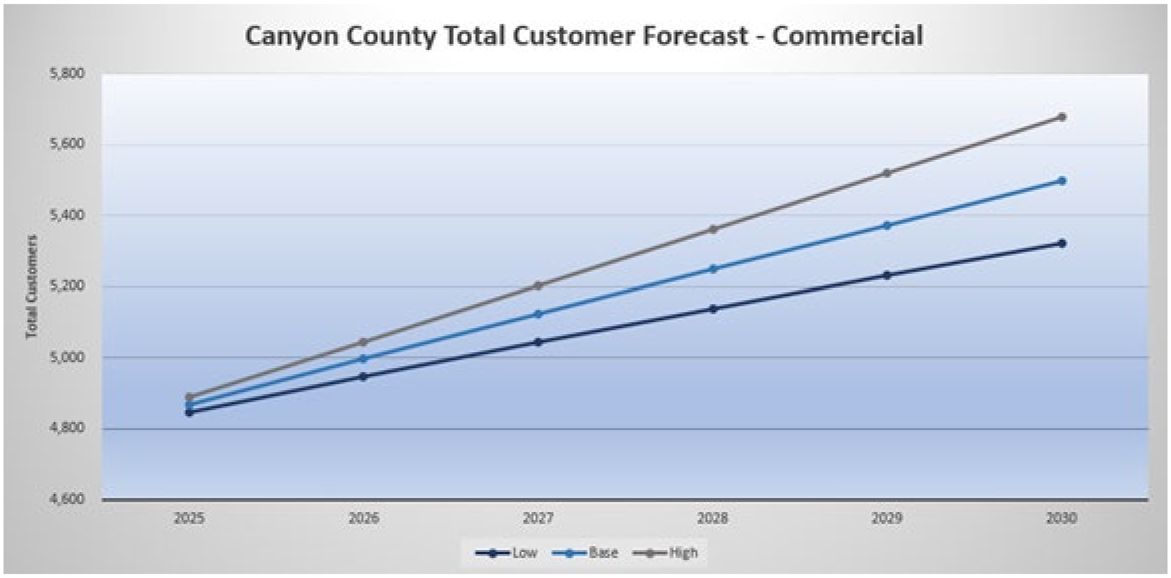

Figure 12: Canyon County Total Customer Forecast – Commercial

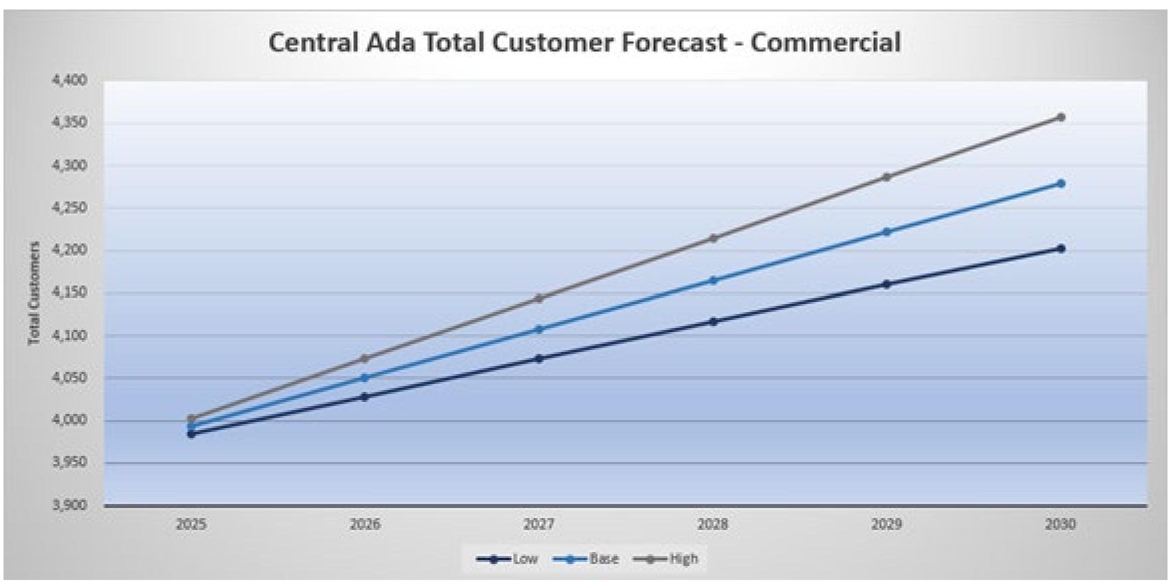

Figure 13: Central Ada Total Customer Forecast – Commercial

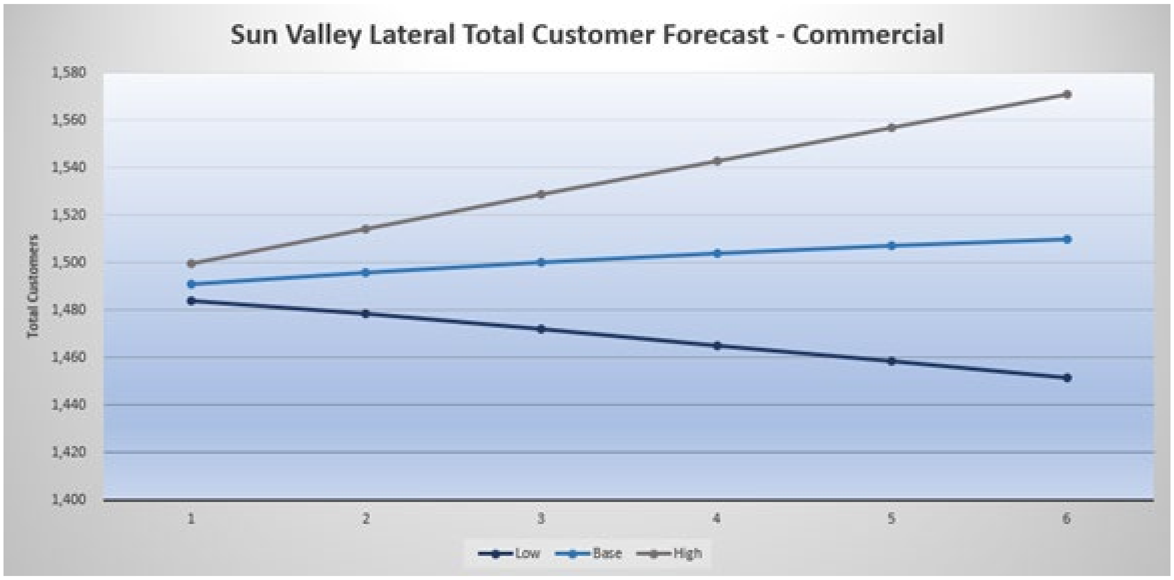

Figure 14: Sun Valley Lateral Total Customer Forecast – Commercial

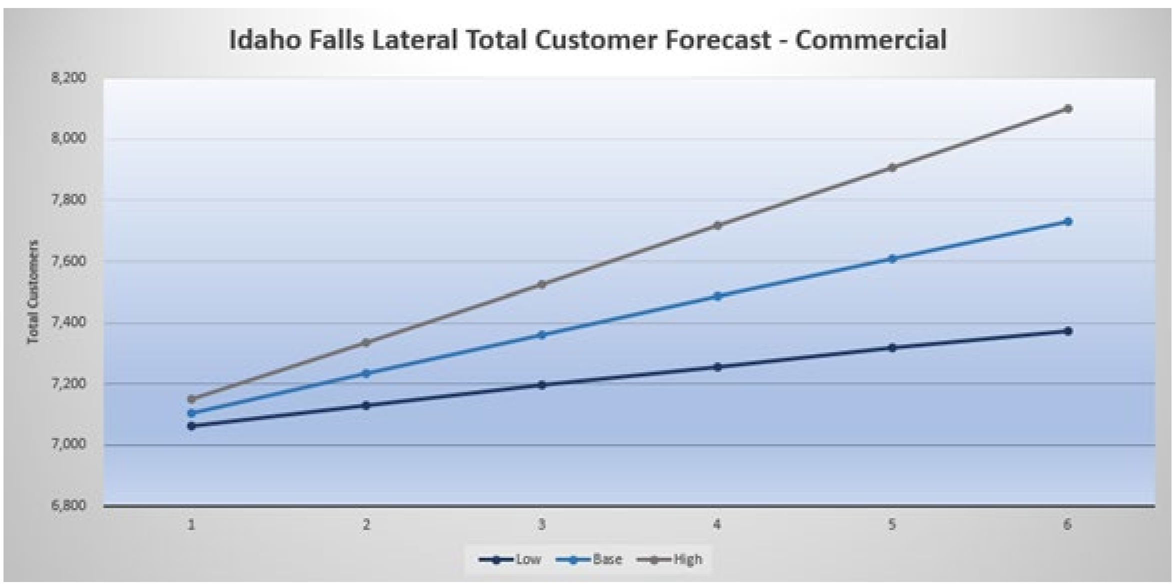

Figure 15: Idaho Falls Lateral Total Customer Forecast – Commercial

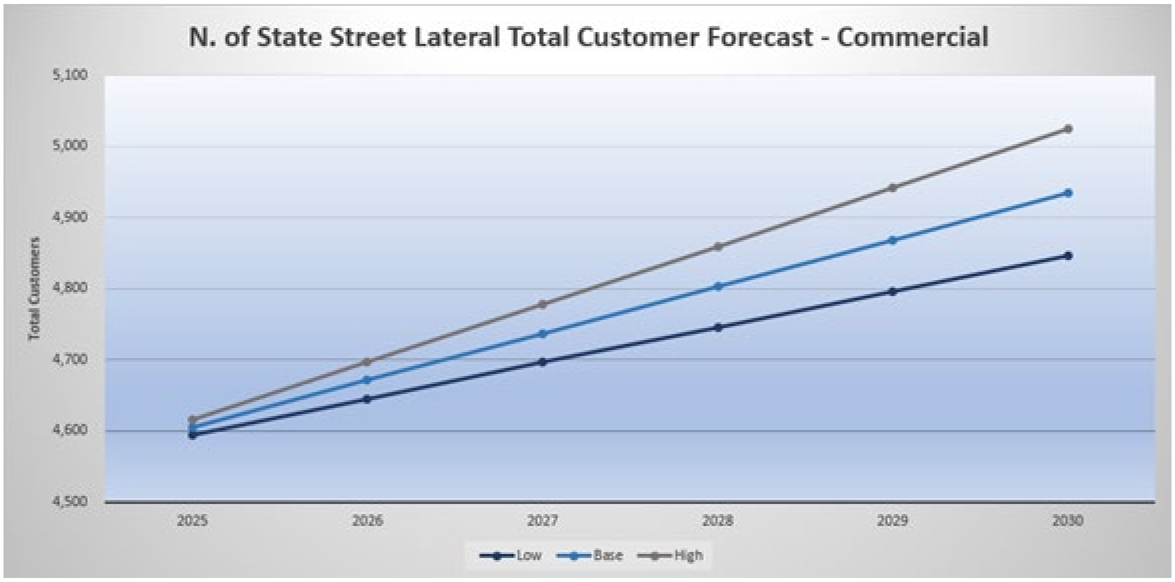

Figure 16: N. of State Street Lateral Total Customer Forecast – Commercial

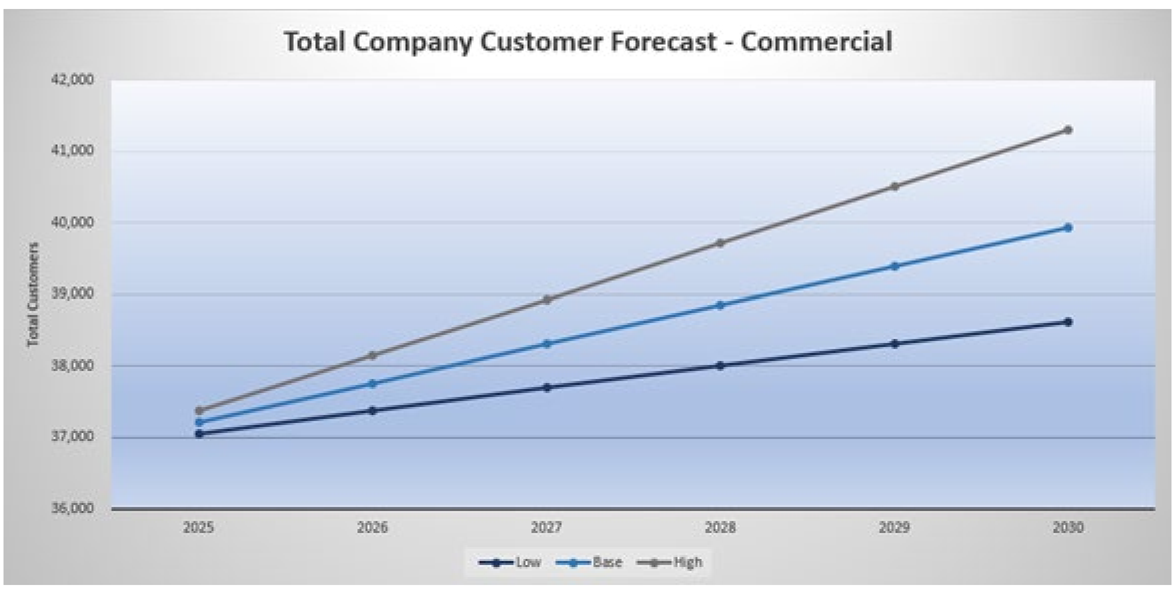

Figure 17: Total Company Customer Forecast – Commercial

2.3 Heating Degree Days & Design Weather

Intermountain’s demand forecast captures the influence weather has on system loads by using Heating Degree Days (HDDs) as an input. HDDs are a measure of the coldness of the weather based on the extent to which the daily mean temperature falls below a reference temperature base. HDD values are inversely related to temperature, which means that as temperatures decline, HDDs increase. The standard HDD base, and the one Intermountain utilizes in its IRP, is 65°F (also called HDD65). As an example, if one assumes a day where the mean outdoor temperature is 30°F, the resulting HDD65 would be 35 (i.e. 65°F base minus the 30°F mean temperature = 35 Heating Degree Days). Two distinct groups of heating degree days are used in the development of the IRP: Normal Degree Days and Design Degree Days.

Since Intermountain’s service territory is composed of a diverse geographic area with differing weather patterns and elevations, Intermountain uses weather data from seven National Oceanic and Atmospheric Administration (NOAA) weather stations located throughout the communities it serves. This weather data is weighted by the quantity of residential and commercial customers in each of the weather districts to best reflect the temperatures experienced across the service territory. Several AOIs are also addressed specifically by this IRP. Those segments are assigned unique degree days as discussed in further detail below.

2.3.1 Normal Degree Days

A Normal Degree Day is calculated based on historical data, and represents the weather that could reasonably be expected to occur on a given day. The Normal Degree Day that Intermountain utilizes in the IRP is computed based on weather data for the thirty years ended December 2024. The HDD65 for January 1st for each year of the thirty-year period is averaged to come up with the average HDD65 for the thirty-year period for January 1st. This method is used for each day of the year to arrive at a year’s worth of Normal Degree Days.

2.3.2 Design Degree Days

Design Degree Days represent the coldest temperatures that can be expected to occur for a given day. Design Degree Days are a critical input for modelling the level of customer demand that may occur during extreme cold or “peak” weather events. For IRP load forecasting purposes, Intermountain makes use of design weather assumptions.

Intermountain’s design year is based on the premise that the coldest weather experienced for any month, season, or year could occur again. The Company reviewed NOAA temperature data over the period of record and found the coldest twelve consecutive months in Intermountain’s service territory to be the 1984/1985 heating season (October 1984 through September 1985).

That year, with certain modifications discussed below, represents the base year for design weather.

2.3.3 Peak Heating Degree Day Calculation

Intermountain engaged the services of Dr. Russell Qualls, Idaho State Climatologist, to perform a review of the methodology used to calculate design weather, and to provide suggestions to enhance the design weather planning. Dr. Qualls assisted Intermountain in developing a method to calculate probability-derived peak HDD values, as well as in designing the days surrounding the peak day.

To develop the peak heating degree day, or coldest day of the design year, Dr. Qualls fitted probability distributions to as much of the entire period of record from seven weather station locations (Caldwell, Boise, Hailey, Twin Falls, Pocatello, Idaho Falls, and Rexburg) as was deemed reliable. From these distributions he calculated monthly and annual minimum daily average temperatures for each weather location, corresponding to different values of exceedance probability. Two probability distributions were fitted, a Normal Distribution, and a Pearson Type III (P3) distribution. Dr. Qualls suggested it is more appropriate for Intermountain to use the P3 distribution as it is more conservative from a risk reduction standpoint. The final climatology report can be found attached as Exhibit 3.

According to Dr. Qualls, "selecting design temperatures from the values generated by these probability distributions is preferable over using the coldest observed daily average temperature, because exceedance probabilities corresponding to values obtained from the probability distributions are known. This enables IGC to choose a design temperature, from among a range of values, which corresponds to an exceedance probability that IGC considers appropriate for the intended use".

Intermountain used Dr. Qualls' exceedance probability results to review the data associated with both the 50 and 100 year probability events. After careful consideration of the data, Intermountain determined that the company-wide 50 year probability event, which was a 78 degree day, would be appropriate to use in the design weather model.

2.3.4 Base Year Design Weather

To create a design weather year from the base year, a few adjustments were made to the base design year. First, since the coldest month of the last thirty years was December 1985, the weather profile for December 1985 replaced the January 1985 data in the base design year. For planning purposes, the aforementioned peak day event was placed on January 15th.

To model the days surrounding the peak event, Dr. Qualls suggested calculating a 5-day moving average of the temperatures for the past thirty-year period to select the 5 coldest consecutive days from the period. December 1990 contained this cold data. The coldest day of the peak month (December 1985) was replaced with the 78 degree day peak day. Then, the day prior and three days following the peak day, were replaced with the 4 cold days surrounding the December 1990 peak day.

While taking a closer look at the heating degree days used for the Load Demand Curves (LDCs), the Company noticed that the design HDDs in some of the shoulder and summer months were lower than the normal weather HDDs for those months. This occurred because, while the 1985 heating year was overall the coldest on record, the shoulder months were in some cases warmer than normal. Manipulating the shoulder and summer month design weather to make it colder would add degree days to the already coldest year on record, creating an unnecessary layer of added degree days. Intermountain decided not to adjust the summer and shoulder months of the design year.

After design modifications were completed, the total design HDD curve assumed a bell-shaped curve with a peak at mid-January (see Figure 18 below). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.

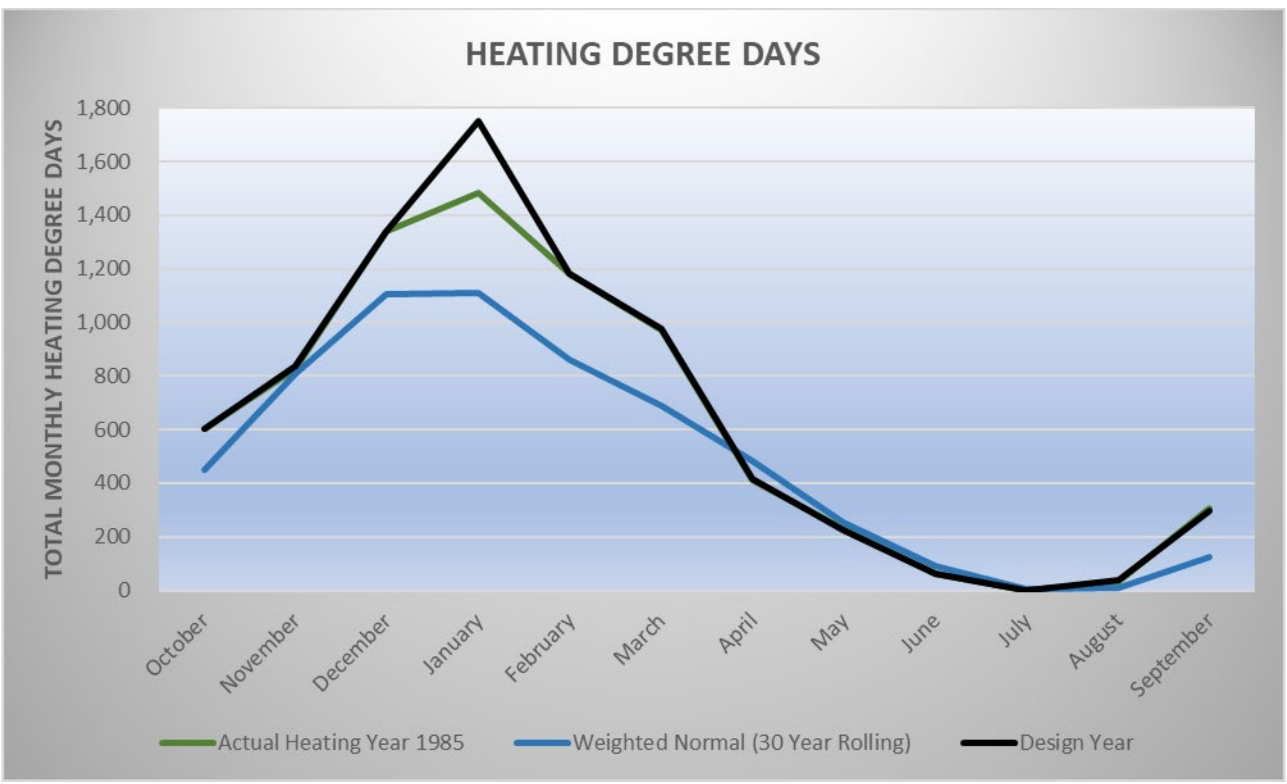

Figure 18: Design Heating Degree Days

The resulting Normal, Base Year (1985), and Design Year degree days by month are outlined in the table below:

Monthly Heating Degree Days			
	Actual Heating Year 1985	Weighted Normal (30 Year Rolling)	Design Year
October	604	443	604
November	827	786	826
December	1,338	1,085	1,338
January	1,483	1,092	1,633
February	1,180	896	1,178
March	972	699	970
April	413	492	411
May	231	258	231
June	62	80	62
July	-	-	-
August	36	7	36
September	306	120	306
Total	7,452	5,958	7,595

Table 3: Monthly Heating Degree Days

2.3.5 Area Specific Degree Days

As noted earlier in this IRP, Intermountain has identified certain areas of interest. These are areas Intermountain carefully manages to ensure adequate delivery capabilities either due to a unique geographic location, customer growth, or both.

The temperatures in these areas can be quite different from each other and from the total company. For example, the temperatures experienced in Idaho Falls or Sun Valley can be significantly different from those experienced in Boise or Pocatello. Intermountain continues to work on improving its capability to uniquely forecast loads for these distinct areas. A key driver to these area specific load forecasts is area specific heating degree days.

Intermountain has developed Normal and Design Degree Days for each of the areas of interest. The methods employed to calculate the Normal and Design Degree Days for each AOI mirrors the methods used to calculate Total Company Normal and Design Degree Days.

2.4 Large Volume Customer Forecast

2.4.1 Introduction

The Large Volume (LV) customer group is comprised of approximately 152 of the largest customers on Intermountain's system from both an annual therm use and a peak day basis. Only customers that use at least 200,000 therms per year are eligible for Intermountain's LV tariffs. The LV tariffs provide two firm delivery services: a bundled sales tariff (LV-1) and a distribution system only transport tariff (T-4). The Company also offers an interruptible distribution system only transportation tariff (T-3).

The LV customers are made up of a mix of industrial and commercial loads and, on average, they account for nearly 49% of Intermountain's 2024 annual throughput and 24% of the projected 2025 design Base Case peak day. Nearly 97% of 2026 LV throughput reflects distribution system-only transportation tariffs where customer-owned natural gas supplies are delivered to Intermountain's various Citygate stations for ultimate redelivery to the customers' facilities.

Because the LV customers' volumes account for such a large part of Intermountain's overall throughput, the method of forecasting these customers' overall usage is an important part of the IRP. These customers' growth and usage patterns differ significantly from the residential and commercial customer groups in two significant ways. First, the LV customers' gas usage pattern as a whole is not nearly as weather sensitive as the core market customers, meaning that forecasting their volumes using standard regression techniques based on projected weather does not provide statistically significant results. Secondly, the total LV customer count is so few that it falls below the number required to provide an adequate statistical population/sample size.

Therefore, Intermountain has developed and utilizes an alternate, but very accurate, method of forecasting based on historical usage, economic trends, and direct input from these Large Volume customers. Figure 19 shows a comparison of total actual LV therm use against base case forecast therm use from the 2023 IRP for the years 2023 – 2025.

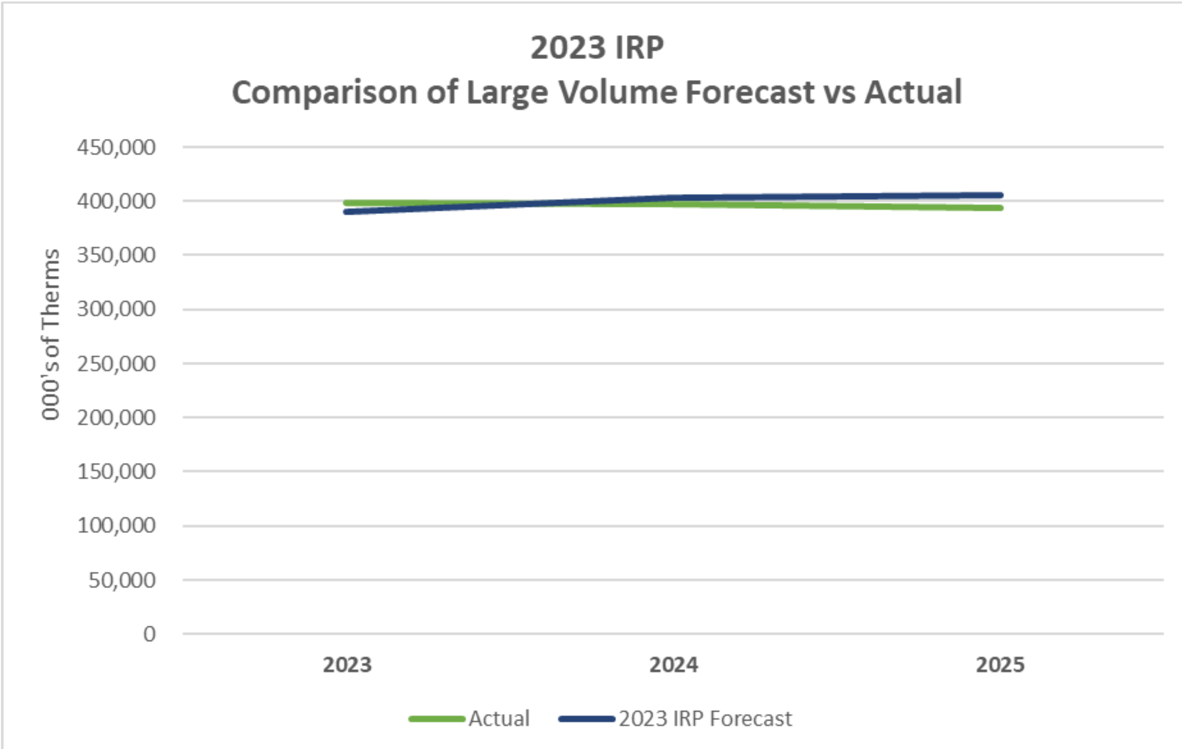

Figure 19: Large Volume Therms - 2023 IRP Forecasted vs Actuals

2.4.2 Method of Forecasting

Intermountain maintains a historical therm use database containing over thirty years of monthly therm use data. The LV forecasting methodology begins by assessing each LV customer's monthly usage for the most recent three years. Then a representative twelve-month period is selected as the "base" year. Typically, more weight is applied to the most recent twelve-month period available unless known material variations would suggest a different base year.

2.4.3 Forecast Scenarios

For the IRP, Intermountain prepared three separate LV monthly gas consumption forecasts (Base Case, High Growth and Low Growth). The Base Case forecast started with the adjusted base year data as described above. That data was then combined with assumptions based on the most likely economic trend to develop during the five-year Base Case forecast. Other available data, including economic development organizations and alternate economic forecasts/assumptions were utilized to develop the High Growth and Low Growth scenarios. For ease of analysis, the 152 existing and up to ten projected new customers (per the High Growth scenario) were combined into six homogeneous market segments:

<u>2025 Customers by Market Segment:</u>

- 18 potato processors
- 52 other food processors including sugar, milk, beef, and seed companies
- 3 chemical and fertilizer companies
- 33 light manufacturing companies including electronics, paper, and asphalt companies
- 33 schools, hospitals, and other weather sensitive customers
- 13 “other” companies including transportation-related businesses

2.4.4 Contract Demand

Every LV customer is required to sign a contract to receive service under any of the LV tariffs. An important element of the firm LV-1 sales and T-4 transportation contracts is the Maximum Daily Firm Quantity (“MDFQ”) which reflects the agreed upon maximum amount of daily gas and/or capacity the Company must be prepared to provide that firm LV customer on any given day including the projected system peak day that would occur during design weather.

T-3 interruptible customers’ contracts include a Maximum Daily Quantity or “MDQ” which only represents the maximum amount of gas the Company’s service line and meter can flow. Because T-3 service is interruptible, Intermountain makes no assurances of the amount of distribution capacity that will be available on any given day. For peak event modeling purposes, the IRP assumes T-3 customers are reduced to minimal emergency plant-heat only. This IRP uses the term contract demand (CD) when referencing both MDFQ and MDQ. Intermountain utilized LV customer CDs as they existed on January 1, 2025 for the beginning point for Base Case CDs.

While many LV customers are predicted to increase their annual usage requirements through 2030, their peak day requirements are not projected to grow by a similar rate of increase. This is due in part to their increased use of extended work schedules, adding additional daily shifts or adding production in weeks or months not previously utilized at 100% load factor (i.e., seasonal increases) and to the fact that customers often take time to “grow” past an existing CD. Therefore, a certain pattern of therm use will not necessarily equate with a commensurate level of growth in CD.

2.4.5 “Load Profile” vs MDFQ

Even though a monthly therm usage projection (i.e., load profile) is available for each customer, the IRP optimization model does not use the load profile for modeling purposes. The model instead uses the LV CDs because, as explained above, the LV customer group is not significantly weather sensitive so attempting to estimate daily usage using degree days, as is done for the core market, does not provide acceptable results. And without weather as the driver, it is difficult to estimate daily usage patterns. For these reasons using the customer CD as the daily requirement is methodologically appropriate, as it reflects the known peak day obligation for every customer and each Area of Interest (AOI). Most importantly, since Intermountain does not provide gas supply or interstate pipeline capacity for any of the transportation customers, the model does not need to project gas supply requirements for these customers, only the maximum amount of distribution capacity they will need on any given day; customer CDs provide this data.

Once the CDs are final, they are loaded directly into the optimization model by AOI and period. The optimization model also assumes that transport customers deliver an amount of zero cost gas supply equal to their aggregated CD for each transport rate class by AOI and period. That assumption allows the model to recognize that gas supply and/or interstate capacity requirements for the transport customers needs to be delivered each day but because it is not provided by Intermountain, there is no need to attempt to calculate an unknown cost that is not relevant to Intermountain.

2.4.6 System Reliability

Of import, before adding new firm load, engineers test the system via Intermountain's modeling system to determine whether or not the Company could serve that added load under design weather peak day loads before proceeding. This analysis is always completed prior to executing any firm contract for any new customer or an existing customer's expansion. Since the Company knows the various parts of the system that may be at or nearing constraints, those AOI's are given particular attention under load growth scenarios. This procedure assures current firm customers that new customers are not negatively affecting peak day deliverability.

2.4.7 General Assumptions

All current customers were assumed to remain on their current tariff and all forecast scenarios used the 2024 operating budget as a starting point. The model also calculated LV therm use and MDFQ by AOI so that each geographic area of concern can be accurately determined.

2.4.8 Base Case Scenario Summary

The Base Case was compiled using historical usage with adjustments made to reflect known or probable changes of existing customers. The projected annual usage in the Base Case forecast increased by 40 million therms (or an annualized rate of 2.0%) as seen in the table below. The rate of projected annualized growth is largely driven by a significant expansion by one of the Company's manufacturing customers.

Large Volume Therm Forecast - Base Case Scenario by Market Segment (Thousands of Therms)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**Rate of Growth**
Potato (A)	106,320	106,651	106,651	106,651	106,651	106,651	0.1%
Other Food (B)	124,828	124,697	125,497	125,497	125,497	125,497	0.1%
Meat, Dairy and Ag (C)	64,822	64,839	65,193	66,340	66,491	66,646	0.6%
Chemical/Fertilizer (D)	31,325	32,141	32,141	32,141	32,141	32,141	0.5%
Manufacturing (E)	26,278	38,954	46,026	52,003	54,136	57,618	17.0%
Institutional (F)	24,097	24,581	24,581	24,581	26,249	27,850	2.9%
Other (G)	16,417	17,819	17,819	18,319	18,319	18,319	2.2%
Total Base Case	394,087	409,682	417,908	425,532	429,484	434,722	2.0%

Table 4: Large Volume Therm Forecast - Base Case Scenario

A. The Potato Processors group is projected to see minimal growth over the forecast period. No new plants are assumed in the forecast. Most of the plants in this group are looking for ways to lower the overall cost of production, conserve resources and maximize efficiencies leading to the flat projected usage for most customers.

B. The Other Food Processing group is also projected to see minimal growth over the forecast period.

C. The Meat, Dairy and Ag segment is projected to see growth which largely reflects the ramp up of two new plants in the forecast.

D. The Chemical/Fertilizer production segment usage is expected to remain relatively flat over the forecast period.

E. The Manufacturing segment is seeing significant usage growth, which is due to a very large planned expansion by one of the customers in this group.

F. The Institutional group is projected to have relatively flat growth, with a small amount of growth due to a planned customer expansion towards the end of the IRP period.

G. The usage in the Other group is projected to see minor growth as customers ramp up who use natural gas as part of their process to produce renewable natural gas.

2.4.9 High Growth Forecast Summary

The High Growth forecast incorporates adjustments for additional growth that would occur if inflation trends at a lower rate than that recently experienced and the economy starts to see growth. The scenario assumes very competitive natural gas prices compared to other alternatives. The Company forecasts projected sales in 2026 as flat to the base case scenario, however by year 2028, the high case scenario is 1.2% above Base Case. The following table summarizes the High Growth changes over the forecast period:

Large Volume Therm Forecast - High Growth Scenario by Market Segment (Thousands of Therms)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**Rate of Growth**
Potato (A)	106,320	106,651	106,651	106,651	106,651	106,651	0.1%
Other Food (B)	124,828	124,697	126,947	126,947	126,947	126,947	0.3%
Meat, Dairy and Ag (C)	64,822	64,839	65,193	68,840	68,991	69,146	1.3%
Chemical/Fertilizer (D)	31,325	32,141	32,141	32,141	32,141	32,141	0.5%
Manufacturing (E)	26,278	38,954	46,026	52,003	54,136	57,618	17.0%
Institutional (F)	24,097	24,581	24,581	24,831	26,499	28,100	3.1%
Other (G)	16,417	17,819	19,319	19,319	19,319	19,319	3.3%
Total Base Case	394,087	409,682	420,858	430,732	434,684	439,922	2.2%

Table 5: Large Volume Therm Forecast - High Growth Scenario

A. The Potato Processors group is projected to see no growth increase over the forecast period. No new plants are assumed in this forecast. In this scenario, natural gas prices are predicted to stay competitive and steady which would keep the plants using gas rather than other energy sources.

B. The other Food Processors segment is forecasted to bring on 2 facilities beginning in 2027 as demand for sugar, frozen foods and other vegetables continues to increase.

C. The Meat, Dairy and Ag group is projected to show strong growth as existing facilities expand and additional new meat producers ramp up. Two new dairy processors are part of this high growth forecast period.

D. The Chemical/Fertilizer group is anticipated to see a minimal increase over the five-year period.

E. The Manufacturing group is projected to see significant growth over the forecast period, again as a result of a planned existing customer expansion. This scenario also assumes the addition of one manufacturing related facility.

F. The institutional group is expected to slightly grow over the five-year period as some growth is projected in a few of the larger universities and several hospitals and one hospital is built into the forecast.

G. Growth is expected to be strong in the Other segment as the increase for traditional natural gas is being used in the production of renewable natural gas. Two producers are coming online and two more are built into the forecast.

2.4.10 Low Growth Forecast Summary

The projected usage for this scenario is based upon the assumption that the economy enters a long-term stall due to inflation or recession. Natural gas prices are also assumed to be less competitive and other renewable sources begin to increase market share *vis-à-vis* natural gas. With those assumptions, the potato, other food and institutional segments of the economy will be flat with very little growth in sales and production. Intermountain reduced usage projections for the Other Food segment assuming a potential shut down of one large plant. Manufacturing shows growth because of an expansion that is currently underway. The Other segment is expected to stay flat as the renewable fuels market declines and compressed natural gas (CNG) markets are replaced by electric vehicles (EVs). Projected sales in year 2026 of the Low Growth Scenario are approximately 7.3% below the Base Case but by 2030 the projected sales are 32.9 million therms (8.6%) under Base Case. The following table summarizes the Low Growth changes over the forecast period:

Large Volume Therm Forecast - Low Growth Scenario by Market Segment (Thousands of Therms)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**Rate of Growth**
Potato (A)	106,320	106,651	106,651	106,651	106,651	106,651	0.1%
Other Food (B)	124,828	94,697	94,697	94,697	94,697	94,697	-5.4%
Meat, Dairy and Ag (C)	64,822	64,839	65,049	65,049	65,049	65,049	0.1%
Chemical/Fertilizer (D)	31,325	32,141	32,141	32,141	32,141	32,141	0.5%
Manufacturing (E)	26,278	38,954	46,026	52,003	54,136	57,618	17.0%
Institutional (F)	24,097	24,581	24,581	24,581	26,249	27,850	2.9%
Other (G)	16,417	17,819	17,819	17,819	17,819	17,819	1.7%
Total Base Case	394,087	379,682	386,964	392,941	396,742	401,825	0.4%

Table 6: Large Volume Therm Forecast - Low Growth Scenario

A. The price of natural gas is assumed to be less competitive against the delivered price of oil and other energy sources and overall market demand is expected to decline. This group, as a whole, looks at any way possible to conserve energy and make its plants more efficient.

B. In the Other Food Processor group the Company assumed one plant shutdown, resulting in reduced volumes. Existing facilities will remain flat.

C. The Meat and Dairy group is projected to see only a slight increase over the period as demand for meat and dairy is expected to remain steady.

D. The Chemical/Fertilizer segment is forecast with a very small increase in gas usage.

E. The Manufacturing group will see large growth due to the already in process massive plant expansion, which will result in an increase over the period of 47%.

F. The institutional group is projected to show very minimal growth until 2029 when there is a planned facility expansion that will increase annual gas usage.

G. The Other group is projected to see flat usage. No new renewable natural gas facilities are forecasted to come on.

3. Supply & Delivery Resources Overview

3.1 Overview

Once future load requirements have been forecasted, currently available supply and delivery resources are matched with demand to identify system deficits. Essential components considered when reviewing supply and delivery resources include identifying currently available supply resources, delivery capacity, and other resources that can offset demand such as energy efficiency programs or large volume customers with alternative fuel sources.

Supply and deliverability are considered by AOI to identify system constraints that result from forecasted demand. By comparing demand versus capacity for each AOI, the Company is better able to select capacity constraint solutions that consider cost effectiveness, operations and maintenance impacts, project viability, and future growth.

After analyzing resource requirements for each AOI, the data is aggregated to provide a total company perspective. Supply and delivery resources that are currently available are compared to the six total company demand scenarios that were established in the demand forecast. In the Load Demand Curves Section, demand and capacity are compared to clearly identify deficits. Alternative solutions for how the deliverability deficits will be resolved are considered in the Optimization and Planning Results sections of this Integrated Resource Plan.

3.2 Traditional Supply Resources

3.2.1 Overview

Natural gas is a fundamental fuel for Idaho's economic and environmental future: heating homes, powering businesses, moving vehicles, and serving as a key component in many of the most vital industrial processes. The natural gas marketplace continues to change but Intermountain's commitment to act with integrity to provide secure, reliable and price- competitive firm natural gas delivery to its customers has not. In today's energy environment, Intermountain bears the responsibility to structure and manage a gas supply and delivery portfolio that will effectively, efficiently, reliably and with best value meet its customers' year- round energy needs. Through its long-term planning, Intermountain continues to identify, evaluate and employ best-practice strategies as it builds a portfolio of resources that will provide the value of service that its customers expect.

The Traditional Supply Resources section outlines the energy molecule and related infrastructure resources upstream of Intermountain's distribution system necessary to deliver natural gas to the Company's distribution system. Specifically included in this discussion is the natural gas commodity (or the gas molecule), various types of storage facilities, and interstate gas transportation pipeline capacity. This section will identify and discuss the supply, storage, and transportation capacity resources available to Intermountain and how they may be employed in the Company's portfolio approach to gas delivery management.

3.2.2 Background

The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Natural gas is a fossil fuel; a naturally occurring mixture of combustible gases, principally methane, found in porous geologic formations beneath the surface of the earth. It is produced or extracted by drilling into those underground formations or reservoirs and then moving the gas through gathering systems and pipelines to customers in often far away locations.

Intermountain is fortunate to be located between two prolific gas producing regions in North America. The first, the Western Canadian Sedimentary Basin (WCSB) in Alberta and British Columbia traditionally supplies approximately 79% of Intermountain's natural gas portfolio. The other region, known as the Rockies, includes many different producing basins in the states of Wyoming, Colorado, and Utah where the remainder of the Company's supplies are sourced. The Company also utilizes storage facilities to store natural gas supply during the summer when prices are traditionally lower and save it for use during the winter to offset higher seasonal pricing.

Intermountain's access to the gas produced in these basins is wholly dependent upon the availability of pipeline transportation capacity to move gas from those supply basins to Intermountain's distribution system. The Company is fortunate, in that the interstate pipeline that runs through Intermountain's service territory is a bi-directional pipeline. This means it can bring gas from the north or south. Having the bi-directional flow capability allows Intermountain's customers to benefit from the least cost gas pricing in most situations and ample capacity to transport natural gas to Intermountain's citygates.

3.2.3 Gas Supply Resource Options

Since approximately 2008, advances in technology have allowed for the discovery and development of abundant supplies of natural gas within shale plays across the United States and Canada. This shale gas revolution has changed the energy landscape in the United States. Natural gas production levels continue to surpass expectations despite low gas prices (see Figure 20 below).

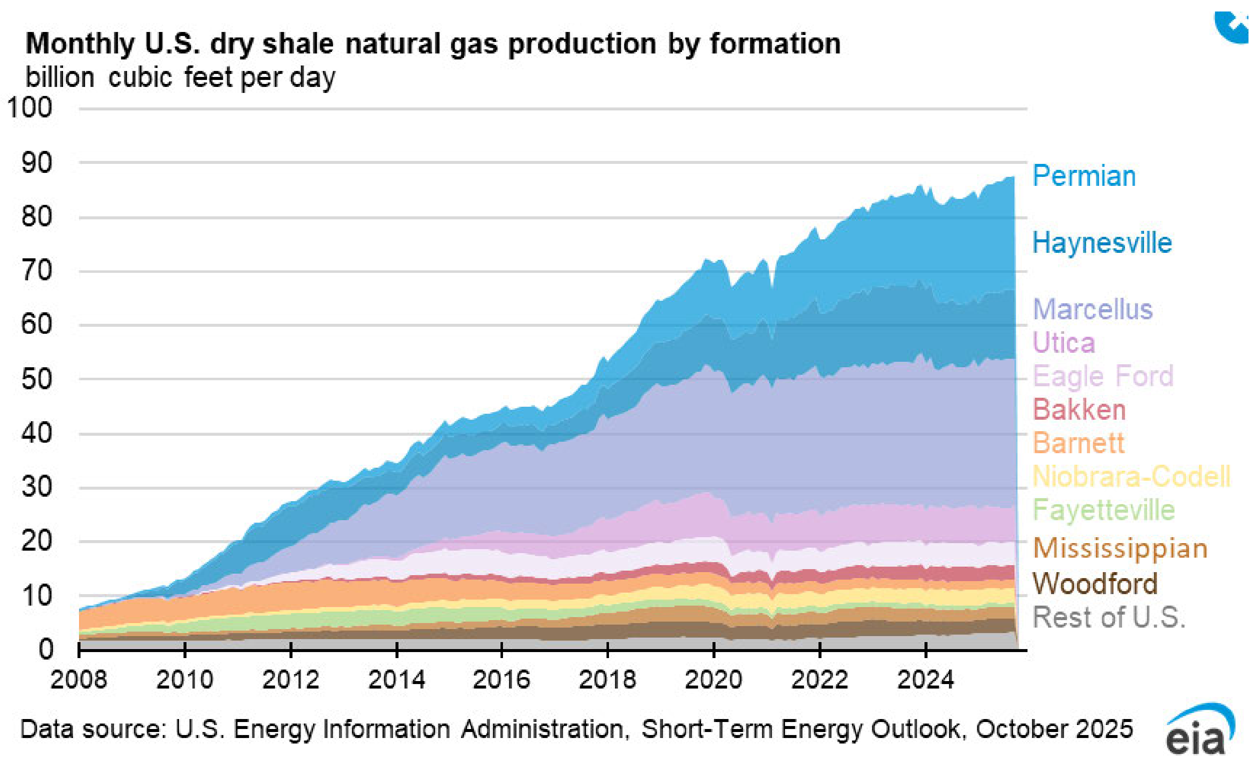

Figure 20: Natural Gas Sources

Projected low prices for natural gas have made it a very attractive fuel for natural gas fired electric generation as utilities are replacing coal-fired generation. Combine this with the industrial sector's recovery from the 2007-2009 recession as they take advantage of low natural gas prices, and the result is a significant change in demand loads. See Figure 21 below for consumption by sector, 2000-2050.

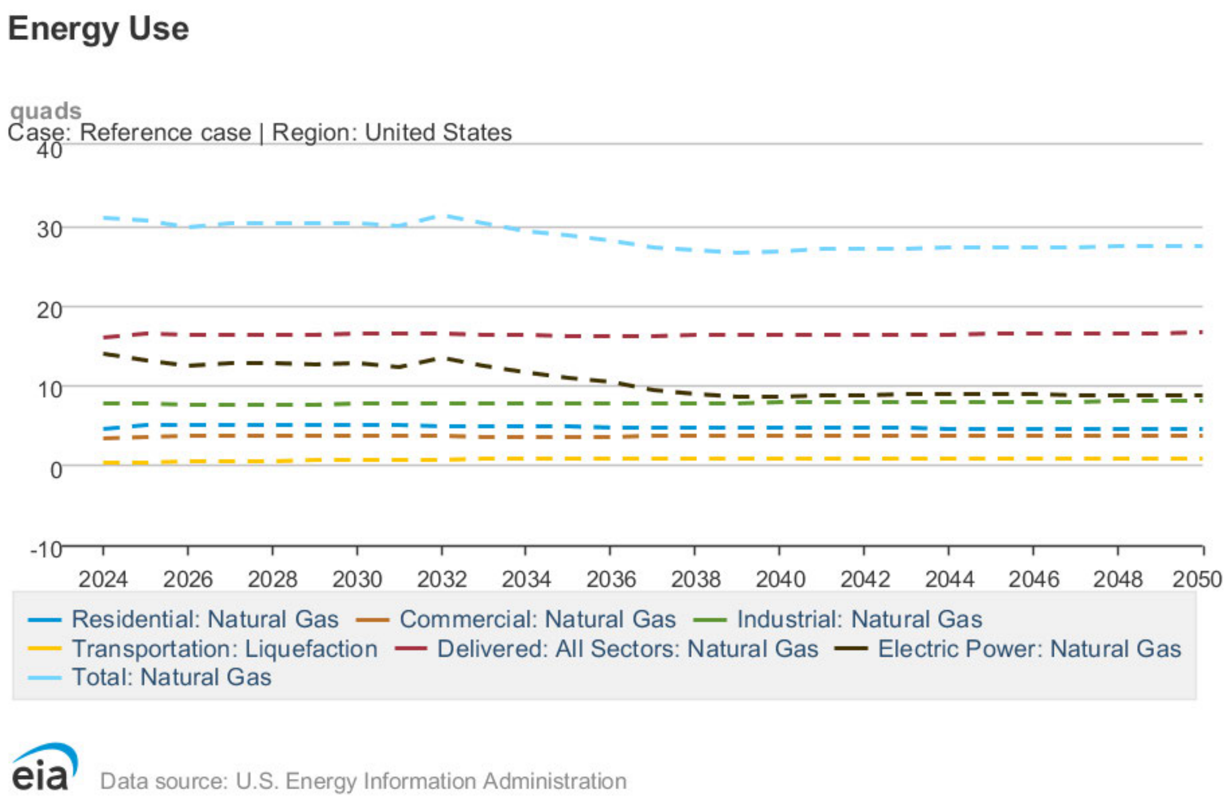

Figure 21: Natural Gas Consumption by Sector

Improved technologies for finding and producing nonconventional gas supplies have led to dramatic increases in gas supplies. Figure 22 below shows that shale gas production is not only replacing declines in other sources but is projected to increase total annual production levels to the early 2030's and then flatting out through 2050.

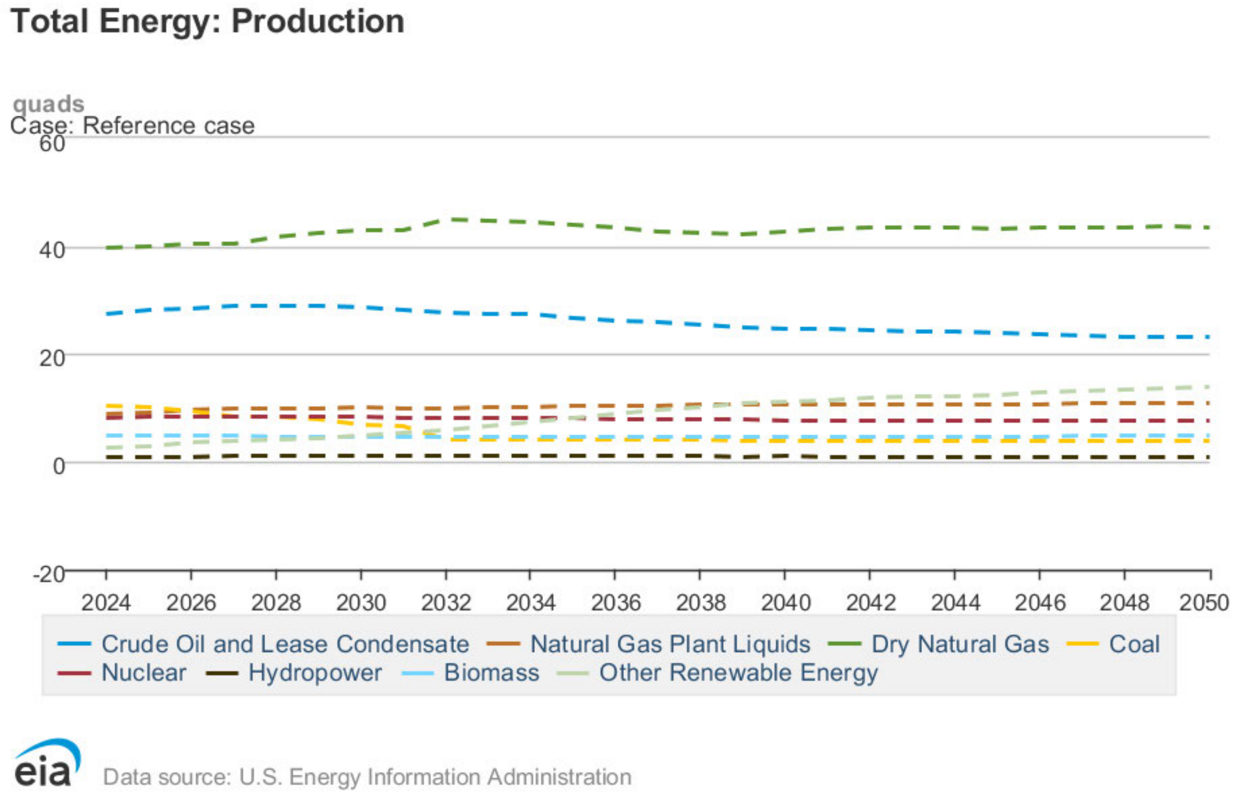

Figure 22: Shale Gas Production Trend

While natural gas prices continue to exhibit volatility from national, global, and regional perspectives, the laws of supply and demand clearly govern the availability and pricing of natural gas. Recent history shows that periods of growing demand tends to drive prices up which in turn generally results in consumers seeking to lower consumption. At the same time, producers typically increase investment in activities that will further enhance production. Thus, falling demand coupled with increasing supplies tends to swing prices lower. This in turn leads to falling supplies and increased demand which begins the cycle anew (see Figure 21 for shifting demand). Finding equilibrium in the market has been challenging for all market participants but at the end of the day, the competitive market clearly works; the challenge is avoiding huge swings that result in either demand destruction or financial distress in the exploration and production business.

Driven by technological breakthroughs in unconventional gas production, major increases in North American natural gas reserves and production have led to supply growth significantly outgaining forecasts in recent years. Thus, natural gas producers have sought new and additional sources of demand for the newfound volumes. The abundant supply of natural gas discussed above has resulted in the United States becoming a net exporter of liquefied natural gas (LNG) versus being a net importer several years ago. The currently operational LNG export facilities in the United States together with additional new facilities on the drawing board will result in a significant new market for the incremental gas supplies being developed and produced.

3.2.4 Shale Gas

Shale gas has changed the face of U.S. energy. Today, reserve and production forecasts predict ample and growing gas supplies through 2050 because of shale gas. The fact that shale gas is being produced in the mid-section of the U.S has displaced production from more traditional supply basins in Canada and the Gulf Coast. There have been some perceived environmental issues relating to shale production, but most studies indicate that if done properly, shale gas can be produced safely. Customers now enjoy the lowest natural gas prices in years due to the increased production of shale gas. Figure 23 below identifies the shale plays in the lower 48 states.

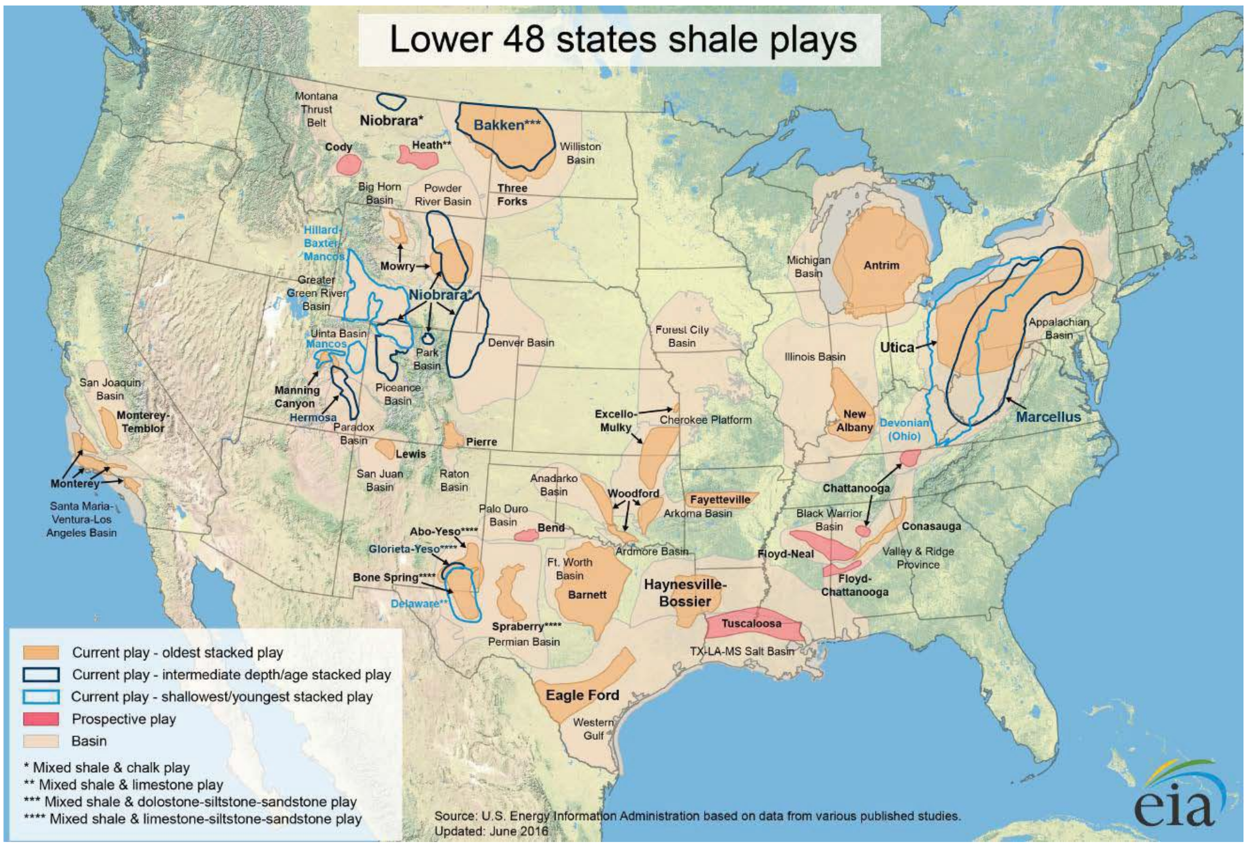

Figure 23: US Lower 48 States Shale Plays

Source: Energy Information Administration based on data from various published studies.

The COVID-19 pandemic had a profound and immediate impact on U.S. energy consumption. In 2020, total delivered energy demand across the residential, commercial, transportation, and industrial sectors fell to approximately 90% of 2019 levels, a sharper decline than the drop in real GDP. This contraction was roughly 70% larger than the decline observed during the 2008 financial crisis.

Initial projections from the U.S. Energy Information Administration (EIA), such as those in the Annual Energy Outlook 2021 (AEO2021), suggested that energy demand would not return to pre-pandemic levels until 2029. However, more recent data indicates a faster-than-expected recovery. By 2025, most sectors had rebounded to near-2019 consumption levels, with transportation and industrial activity driving the resurgence.

- Residential and Commercial Sectors: These sectors stabilized earlier than expected, aided by persistent remote work patterns and weather-normalized heating and cooling loads.
- Transportation Sector: After lagging through 2022, transportation fuel demand surged in 2023–2024, with vehicle miles traveled and jet fuel consumption approaching pre-pandemic norms.
- Industrial Sector: Energy use rebounded alongside economic growth, particularly in manufacturing-intensive regions.
- Electricity Demand: Grid-level demand normalized by 2023, although regional patterns shifted during mitigation efforts.

Intermountain's demand forecasting models incorporate these updated recovery trends to ensure that post-pandemic consumption patterns are accurately reflected in long-term planning. The Company continues to monitor EIA projections and other market indicators to refine its assumptions and ensure defensibility across planning horizons.

3.2.5 Supply Regions

As previously stated, Intermountain's natural gas supplies are obtained primarily from the WCSB and the Rockies. Access to those abundant supplies is completely dependent upon the amount of firm transportation capacity held on the applicable pipelines for delivering such gas to Intermountain's service territory. Transportation capacity is so important that a discussion of the Company's purchases of natural gas cannot be fully explored without also addressing pipeline capacity. On average, Intermountain currently purchases approximately 79% of its gas supplies from the WCSB and the remainder from the Rockies. However, due to certain flexibility in Intermountain's firm transportation portfolio, it is afforded the opportunity to procure some portion of its annual needs from supply basins which may offer lower cost gas supplies in the future.

Alberta

Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Energy via NOVA Gas Transmission Ltd. (NGTL) and Foothills Pipe Lines Ltd. (Foothills)) and two U.S. pipelines (Gas Transmission Northwest (GTN) and Williams Northwest Pipeline (NWP)) as seen below in Figure 24.

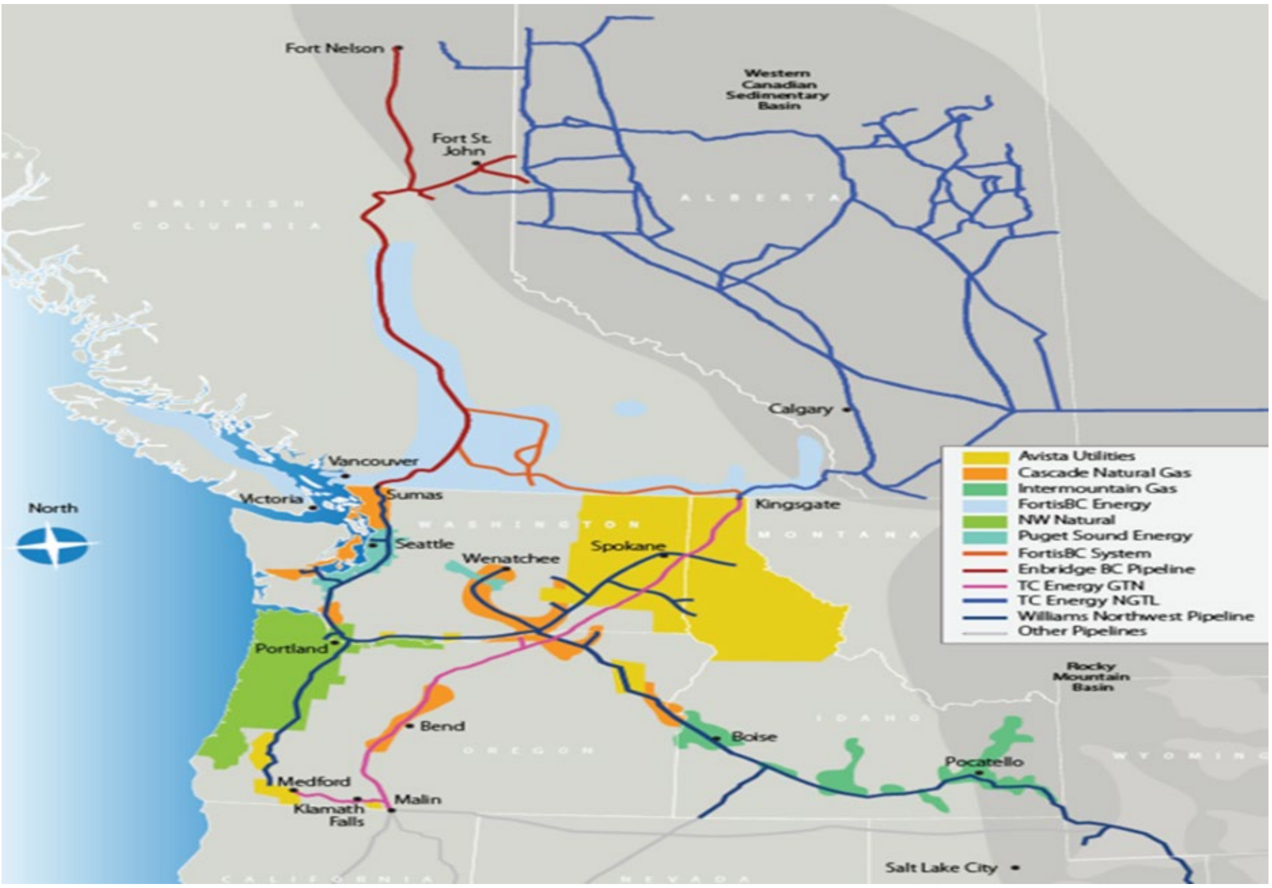

Figure 24: Supply Pipeline Map
Source: Northwest Gas Association 2024 Gas Market Outlook

Intermountain will continue to utilize a significant amount of Alberta supplies in its portfolio. The Stanfield interconnect between NWP and GTN offers operational reliability and flexibility over other receipts points both north and south. Where these supplies once amounted to a minor portion of the Company’s portfolio, today’s purchases amount to approximately 76% of the Company's annual purchases.

British Columbia

British Columbia has traditionally been a source of competitively priced and abundant gas supplies for the Pacific Northwest. Gas supplies produced in the province are transported by Enbridge (Westcoast) to an interconnect with NWP near Sumas, WA. Historically, much of the provincial supply had been somewhat captive to the region due to the lack of alternative pipeline options into eastern Canada or the midwestern U.S. However, pipeline expansions into these regions have eliminated that bottleneck. Although these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to impede ultimate delivery to Intermountain's citygates. An exception to pipeline constraints occurred during the winter of 2018 when Enbridge had a major disruption from a pipeline rupture that occurred on October 9, 2018. The ensuing winter months saw a reduction in capacity in British Columbia gas supplies to be delivered at Sumas due to the incident and pipeline integrity testing required by the Canada Energy Regulator[1] in Canada to ensure safe and reliable pipeline conditions. Those interruptions along with a cold and long winter had a significant impact on pricing. However, due to the predominance of Intermountain's supplies coming from Alberta and being delivered via GTN at Stanfield, coupled with Intermountain's ability to utilize its liquefied natural gas storage contracts on NWP's system, it was able to mitigate the impact to its customers of the dramatic short-term price increases.

Rockies

Rockies supply has been the second largest source of supply for Intermountain because of the ever-growing reserves and production from the region coupled with firm pipeline capacity available to Intermountain. Additionally, Rockies supplies have been readily available and highly reliable. Historically, pipeline capacity to move Rockies supplies out of the region has been limited, which has forced producers to compete to sell their supplies to markets with firm pipeline takeaway capacity. Several pipeline expansions out of the Rockies have greatly minimized or eliminated most of the capacity bottlenecks, so these supplies can now more easily move to higher priced markets found in the Midwest, East or in California. Consequently, even though growth in Rockies reserves and production continues at a rapid pace reflecting increased success in finding tight sand, coal seam and shale gas, the more efficient pipeline system has largely eliminated the price advantage that Pacific Northwest markets had enjoyed.

While Intermountain's firm transportation portfolio does provide for accessing Rockies gas supplies, as discussed above, Intermountain has prioritized purchasing its annual supply needs predominantly out of Alberta due to the lower cost environment from that supply basin.

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[1] The Canada Energy Regulator (CER) is the agency of the Government of Canada under its Natural Resources Canada portfolio, which licenses, supervises, regulates, and enforces all applicable Canadian laws as regards to interprovincial and international oil, gas, and electric utilities. The agency came into being on August 28, 2019, under the provision of the Canada Energy Regulator Act of the Parliament of Canada superseding the National Energy Board from which it took over responsibilities.

However, due to its close proximity, Intermountain does purchase the lower cost Rockies gas supplies in the summer for injection into its Clay Basin storage accounts located in northeastern Utah.

3.2.6 Export LNG

Growth in North American natural gas supplies (see Shale Gas above) has eliminated discussion about LNG import facilities. Because LNG is traded on the global market, where prices are typically tied to oil, U.S. produced LNG is very competitive. LNG exports now play a role in the overall supply portfolio of U.S. supply, with several new LNG export facilities proposed or in production. As seen in Figure 25 below, the U.S. is now a net exporter of natural gas in large part due to LNG.

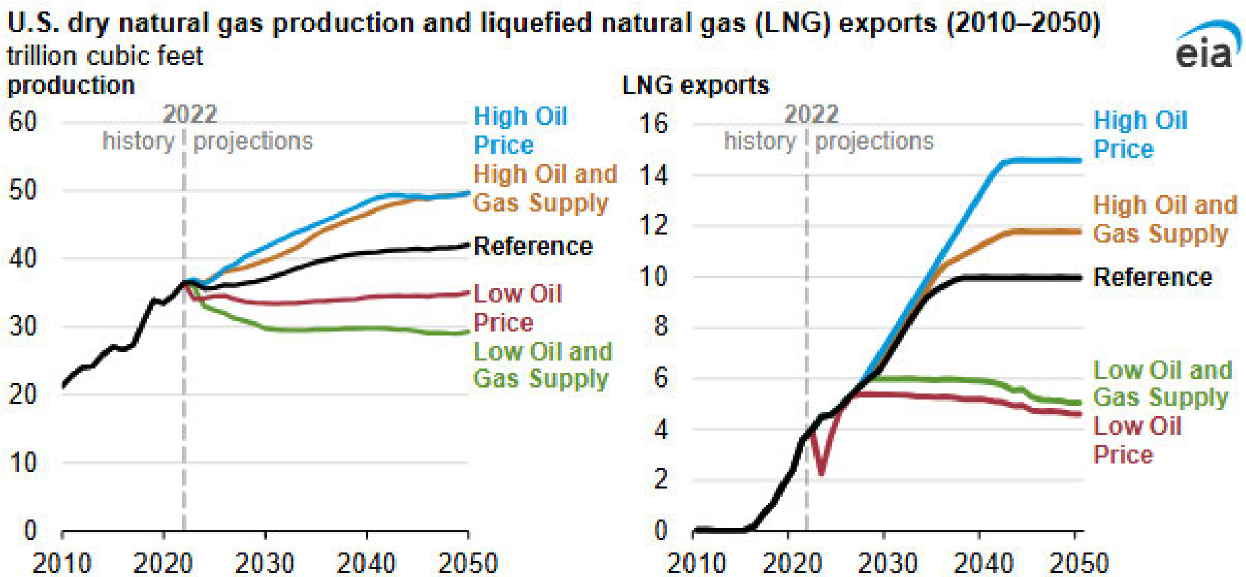

Figure 25: Natural Gas Sources

Source: U.S. Energy Information Administration, Annual Energy Outlook 2023 (AEO2023)

3.2.7 Types of Supply

There are essentially two main types of gas supply: firm and interruptible. Firm gas commits the seller to make the contracted amount of gas available each day during the term of the contract and commits the buyer to take that gas each day. The only exception would be force majeure events where one or both parties cannot control external events that make delivery or receipt impossible. Interruptible or best-efforts gas supply typically is bought and sold with the understanding that either party, for various reasons, does not have a firm or binding commitment to take or deliver the gas.

Intermountain builds its supply portfolio on a base of firm, long-term gas supply contracts but includes all the types of gas supplies as described below:

1. Long-term: gas that is contracted for a period of over one year.
2. Short-term: gas that is often contracted for one month at a time.
3. Spot: gas that is not under a long-term contract; it is generally purchased in the short-term on a day ahead basis for day gas and during bid week prior to the beginning of the month for monthly spot gas.
4. Winter Baseload: gas supply that is purchased for a multi-month period most often during winter or peak load months.
5. Citygate Delivery: natural gas supply that is bundled with interstate transportation capacity and delivered to the Intermountain citygate meaning that it does not use the Company's existing transportation capacity.

3.2.8 Pricing

The Company does not currently utilize NYMEX based products to hedge forward prices but buys a portion of its gas supply portfolio at fixed priced forward physicals. Purchasing fixed price physicals provides the same price protection without the credit issues that come with financial instruments. A certain level of fixed price contracts allows Intermountain to participate in the competitive market while avoiding upside pricing exposure. While the Company does not utilize a fully mechanistic approach, its Gas Supply Oversight Committee meets frequently to discuss all gas portfolio issues which helps to provide stable and competitive prices for its customers.

For IRP purposes, the Company develops a base, high, and low natural gas price forecast. Demand, oil price volatility, the global economy, electric generation, environmental policies, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. Intermountain considers price forecasts from several sources, such as Wood Mackenzie, EIA, S&P Global, NYMEX Henry Hub, and Northwest Power and Conservation Council, as well as Intermountain's own observations of the market to develop the low, base, and high price forecasts. For optimization purposes, Intermountain uses pricing forecasts from four sources for the AECO, Rockies and Sumas pricing points along with a proprietary model based upon those forecasts. The selected forecast includes a monthly base price projection for each of the three purchase points, as seen in Figure 26.

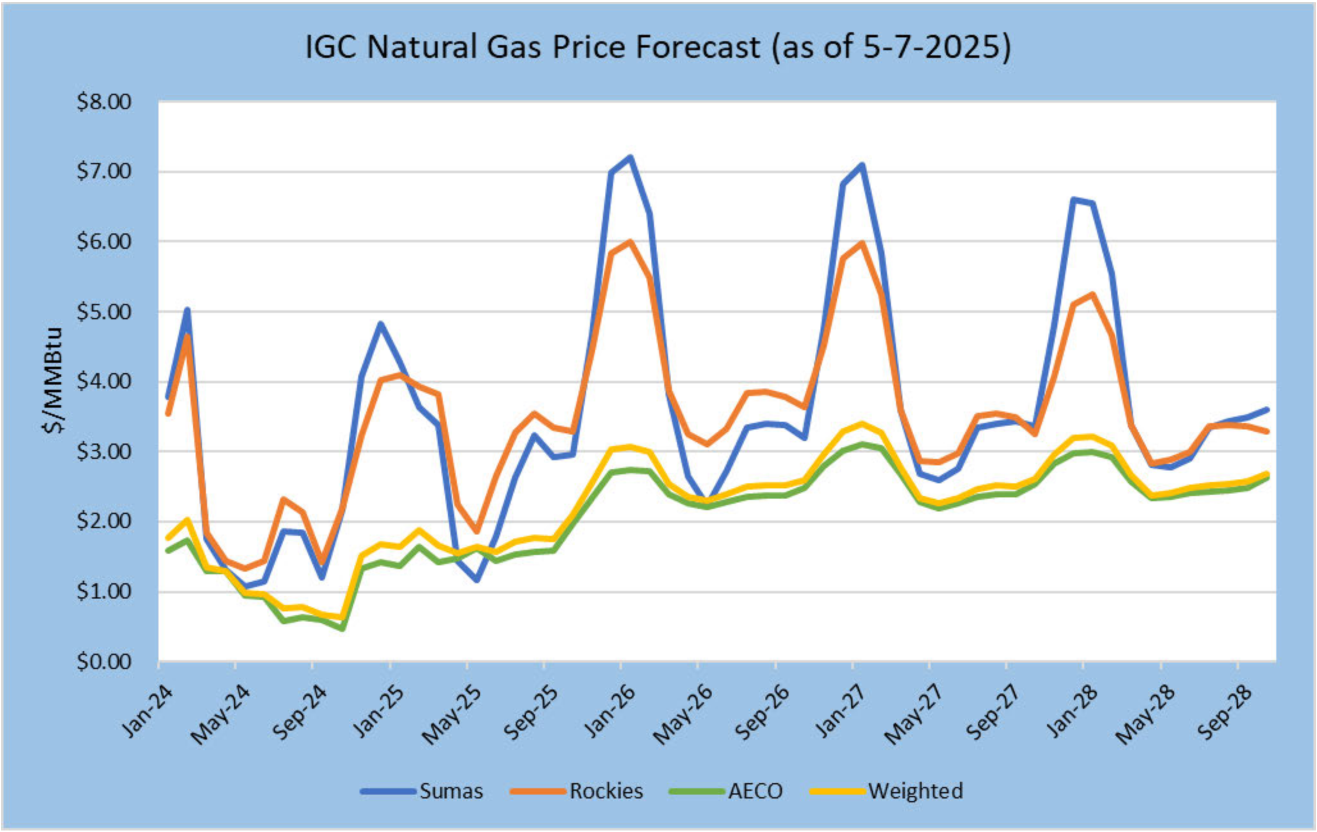

Figure 26: Intermountain Price Forecast as of 05/07/2025

3.2.9 Storage Resources

The production of natural gas and the amount of available pipeline capacity are very linear in nature; changes in temperatures or market demand does not materially affect how much of either is available daily. As the Resource Optimization Section discusses, a peak day only occurs for, at most, a few days out of the year. The demand curve then drops rapidly back to more normal winter supply levels before dropping off drastically headed into the summer months. Attempting to serve the entire year at levels required to meet peak demand would be enormously expensive. So, the ability to store natural gas during periods of non-peak demand for use during peak periods is a cost-effective way to fill the gap between static levels of supply and capacity versus the non-linear demand curve.

Intermountain utilizes storage capacity in four different facilities from western Washington to northeastern Utah. Two are operated by NWP: one is an underground project located near Jackson Prairie, WA (JP) and the other is a liquefied gas (LS) facility located near Plymouth, WA (see Figure 27 below). Intermountain also leases capacity from Dominion Energy Pipeline's Clay Basin underground storage field in Wyoming, and operates its own LNG facility located in Nampa, ID. Additionally, Intermountain owns a satellite LNG facility in Rexburg, ID. The Rexburg facility is supplied with LNG from the Nampa LNG facility.

All storage resources allow Intermountain to inject gas into storage during off-peak periods and then hold it for withdrawal whenever the need arises. The advantage is three-fold: 1) the Company can serve the extreme winter peak while minimizing year-round firm gas supplies; 2) storage allows the Company to minimize the amount of the year-round interstate capacity resources required and helps it to use existing capacity more efficiently; and 3) storage provides a natural price hedge against the typically higher winter gas prices. Thus, storage allows the Company to meet its winter loads more efficiently and in a cost-effective manner.

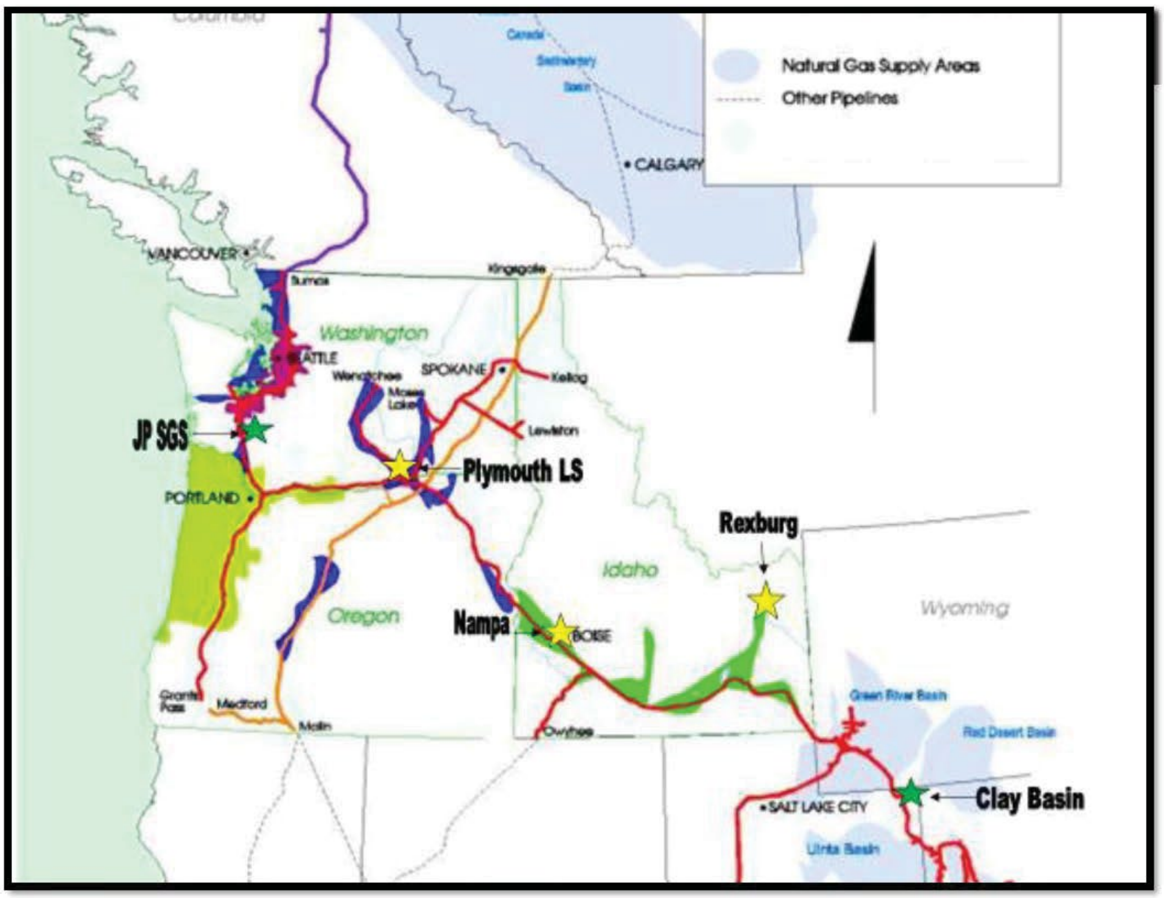

Figure 27: Intermountain Storage Facilities

Liquefied Storage

Liquefied storage facilities make use of a process that super cools and liquefies gaseous methane under pressure until it reaches approximately minus 260°F. LNG occupies only one-six-hundredth the volume compared to its gaseous state, so it is an efficient method for storing peak requirements. LNG is also non-toxic; it is non-corrosive and will only burn when vaporized to a 5-15% concentration with air. Because of the characteristics of liquid, its natural propensity to boil-off and the enormous amount of energy stored, LNG is normally stored in man-made steel tanks.

Liquefying natural gas is, relatively-speaking, a time-consuming process, the compression and storage equipment is costly, and liquefaction requires large amounts of added energy. It typically requires as much as one unit of natural gas burned as fuel for every three to four units liquefied. Also, a full liquefaction cycle may take five to six months to complete. Because of the high cost and length of time involved in filling a typical LNG facility, they are usually cycled only once per year and are reserved for peaking purposes. This makes the unit cost of the gas withdrawn somewhat expensive when compared to other options.

Vaporization, or the process of changing the liquid back into the gaseous state, on the other hand, is a very efficient process. Under typical atmospheric and temperature conditions, the natural state of methane is gaseous and lighter than air as opposed to the dense state in its liquid form. Consequently, vaporization requires little energy and can happen very quickly. Vaporization of LNG is usually accomplished by utilizing pressure differentials by opening and closing valves in concert with the use of some hot-water bath units. The high-pressure LNG is vaporized as it is warmed and is then allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and, as opposed to the long liquefaction cycle, a typical full withdrawal cycle may last 10 days or less at full rate. 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.

Neither of the two LNG facilities utilized by Intermountain require the use of year-round transportation capacity for delivery of withdrawals to Intermountain's customers. The Plymouth facility is bundled with redelivery capacity for delivery to Intermountain and the Nampa and Rexburg LNG tank withdrawals go directly into the Company's distribution system. The IRP assumes liquid storage will serve as a needle peak supply.

Underground Storage

This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities typically require less hardware compared to LNG projects and are usually less expensive to build and operate than liquefaction storage facilities. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. The lower costs allow for the more frequent cycling of inventory and in fact, many such projects are utilized to arbitrage variations in market prices.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, maximum daily injection levels are much higher, so a typical underground injection season is much shorter, typically lasting only three to four months. But the lower pressures also mean that maximum withdrawals are typically much less than liquefied storage at maximum withdrawal. So, it could take 35 days or more to completely empty an underground facility. The longer withdrawal period and minimal commodity costs make underground storage an ideal tool for winter baseload or daily load balancing, and therefore, Intermountain normally uses underground storage before liquid storage is withdrawn. Underground storage is not ideal for delivering a large amount of gas quickly, however, so LNG is a better solution for satisfying a peak situation.

Intermountain contracts with two pipelines for underground storage: Dominion Energy for capacity at its Clay Basin facility in northeastern Utah and NWP for capacity at its Jackson Prairie facility in Washington. Clay Basin provides the Company with the largest amount of seasonal storage and daily withdrawal. However, since Clay Basin is not bundled with redelivery capacity, Intermountain must use its year-round capacity when these volumes are withdrawn. For this reason, the Company normally uses Clay Basin withdrawals during the November to March winter period to satisfy baseload needs.

Just like NWP's Plymouth LS facility, NWP's JP storage is bundled with redelivery capacity so Intermountain typically layers JP withdrawals between Clay Basin and its LNG withdrawals. The IRP uses Clay Basin as a winter baseload supply and JP is used as the first layer of peak supply. Table 7 below outlines the Company's storage resources for this IRP.

		Daily Withdrawal (Dth)		Daily Injection (Dth)		
Facility	Seasonal Capacity	Max Vol	% of 2025 Peak	Max Vol	# of Days	Redelivery Capacity
Nampa	600,000	50,000	9%	3,500	166	None
Plymouth	1,475,135	155,175	29%	12,500	213	TF-2
Subtotal Liquid	2,075,135	205,175	39%	16,000		
Jackson Prairie	1,092,099	30,337	6%	30,337	36	TF-2
Clay basin	8,413,500	70,114	13%	70,114	120	TF-1
Subtotal Underground	9,505,599	100,451	19%	100,451		
Grand Total	11,580,734	305,626	58%	116,451		

Table 7: Storage Resources

All the storage facilities require the use of Intermountain's every day, year-round capacity for injection or liquefaction. Because injections usually occur during the summer months, use of year-round capacity for injections helps the Company make more efficient use of its everyday transport capacity and term gas supplies during those off-peak months when the core market loads are lower.

Nampa LNG Plant

The primary purpose of the Nampa LNG plant is to supplement gas supply onto Intermountain Gas' distribution system. The Nampa LNG plant can store up to 600 million cubic feet of natural gas in liquid form and can re-gasify back into Intermountain's system at a rate of approximately 50 million cubic feet per day.

During a needle peak event the plant is able to supplement supply during gas storage shortages or transportation restrictions into Idaho, and the plant has the added benefit of supplying natural gas directly into the connected Canyon County and Ada County distribution systems without use of interstate pipeline transportation, which eliminates another risk variable typically associated with gas supply. The Nampa LNG plant typically performs liquefaction operations during non-peak weather times of the year, resulting in lower priced natural gas going into liquid storage, and providing potential cost savings when re-gasification occurs during peak cold weather events, gas supply shortages and interstate transportation restrictions.

Storage Summary

The Company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lesser extent, for system balancing. Intermountain believes that the geographic and operational diversity of the four facilities utilized offers the Company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the Company flexibility to determine its best use compared to other supply alternatives such as winter baseload or peak protection gas, price arbitrage or system balancing.

3.2.10 Interstate Pipeline Transportation Capacity

As discussed earlier, Intermountain is dependent upon firm pipeline transportation capacity to move natural gas from the areas where it is produced, to end-use customers who consume the gas. In general, firm transportation capacity provides a mechanism whereby a pipeline will reserve the right, on behalf of a designated and approved shipper, to receive a specified amount of natural gas supply delivered by that shipper, at designated receipt points on its pipeline system and subsequently redeliver that volume to delivery point(s) as designated by the shipper.

Intermountain holds firm capacity on four different pipeline systems including NWP. NWP is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system (other than Nampa LNG) via citygate taps with NWP. Table 8 below summarizes the Company's year-round capacity on NWP (TF-1) and its storage specific redelivery capacity (TF-2). Between the amount of capacity Intermountain holds on the GTN, Foothills, and NGTL pipelines and firm- purchase contracts at Stanfield, it controls enough capacity to deliver a volume of gas commensurate with the Company's Stanfield takeaway capacity on NWP. Upstream pipelines bring natural gas from the production fields in Canada to the interconnect with NWP.

City Gate Delivery Quantity (MMBtu per day)	2025	2026	2027	2028	2029	2030
TF-1 Capacity -						
Sumas Base Capacity	90,941	90,941	90,941	90,941	90,941	90,941
Sumas Segmentation and Release	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)
Sumas Winter Only Capacity	3,000	-	-	-	-	-
Stanfield Base Capacity	133,624	133,624	133,624	133,624	133,624	133,624
Stanfield Capacity Via Segmentation	90,941	90,941	90,941	90,941	90,941	90,941
Rockies	59,328	59,328	59,328	59,328	59,328	59,328
Total TF-1 Capacity	286,893	283,893	283,893	283,893	283,893	283,893
City Gate Supply	10,000	10,000	10,000	10,000	10,000	10,000
Total City Gate Delivery Before TF-2	296,893	293,893	293,893	293,893	293,893	293,893
TF-2 Capacity -						
Plymouth (LS)	155,175	155,175	155,175	155,175	155,175	155,175
Jackson Prairie (JP)	30,337	30,337	30,337	30,337	30,337	30,337
Total TF-2 Capacity	185,512	185,512	185,512	185,512	185,512	155,175
Nampa and Rexburg LNG	55,500	55,500	55,500	55,500	55,500	55,500
Total City Gate Delivery	537,405	534,405	534,405	534,405	534,405	534,405

Table 8: Northwest Pipeline Transport Capacity

Northwest Pipeline's facilities essentially run from the Four Corners area north to western Wyoming, across southern Idaho to western Washington. The pipeline then continues up the I-5 corridor where it interconnects with Spectra Energy, a Canadian pipeline in British Columbia, near Sumas, Washington. The Sumas interconnect receives natural gas produced in British Columbia. Gas supplies produced in the province of Alberta are delivered to NWP via NOVA, Foothills and then GTN near Stanfield, Oregon. NWP also connects with other U.S. pipelines and gathering systems in several western U.S. states (Rockies) where it receives gas produced in basins located in Wyoming, Utah, Colorado, and New Mexico. The major pipelines in the Pacific Northwest, several of which NWP interconnects with can be seen below (Figure 28).

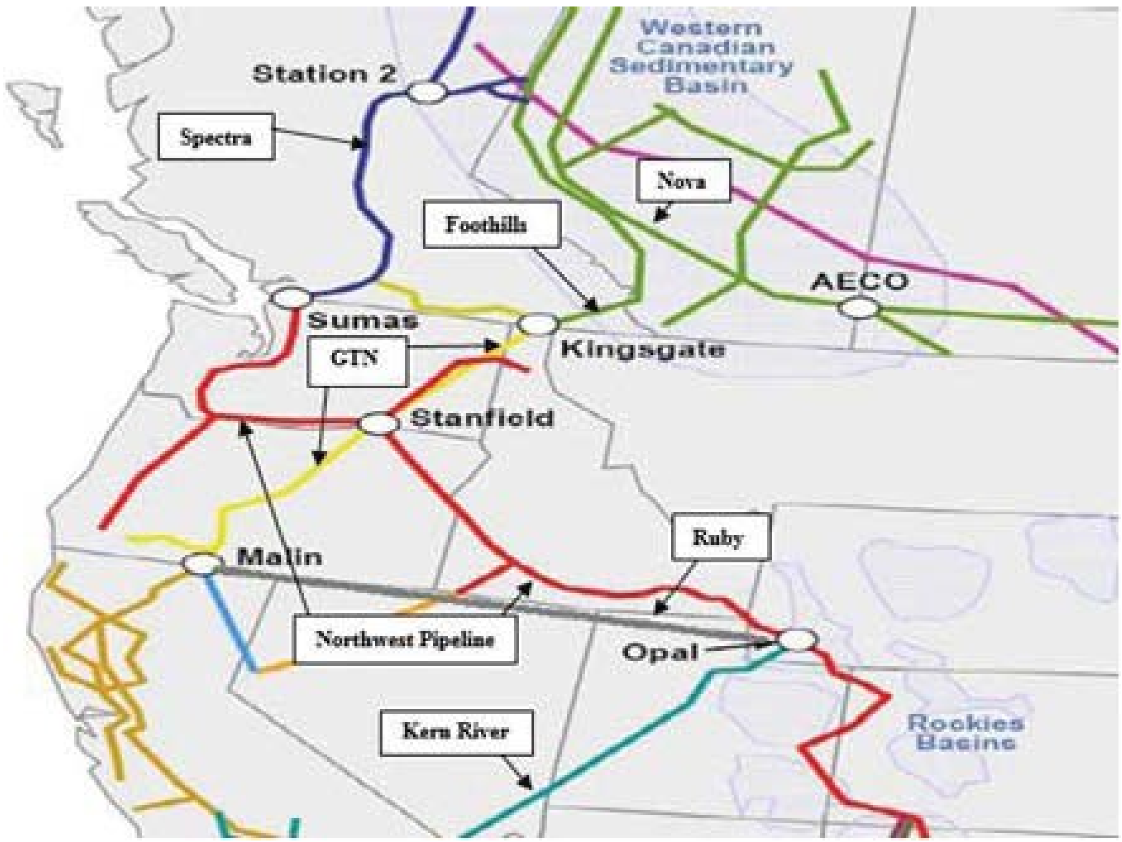

Figure 28: Map - Pacific Northwest Pipelines

Because natural gas must flow along pipelines with finite flow capabilities, demand frequently cannot be met from a market's preferred basin. Competition among markets for these preferred gas supplies can cause capacity bottlenecks and these bottlenecks often result in pricing variations between basins supplying the same market area. In the short to medium term, producers in constrained basins invariably must either discount or in some fashion differentiate their product to compete with other also constrained supplies. In the longer run however, disproportionate regional pricing encourages capacity enhancements on the interstate pipeline grid, from producing areas with excess supply, to markets with constrained delivery capacity. Such added capacity nearly always results in a more integrated, efficient delivery system that tends to eliminate or at least minimize such price variances.

Consequently, new pipeline capacity - or expansion of existing infrastructure – in western North America has increased take-away capacity out of the WCSB and the Rockies, providing producers with access to higher priced markets in the East, Midwest and in California. Therefore, less-expensive gas supplies once captive to the northwest region of the continent, now have greater access to the national market resulting in less favorable price differentials for the Pacific Northwest market. Today, wholesale prices at the major trading points supplying the Pacific Northwest region (other than Alberta supplies) are trending towards equilibrium. At the same time, new shale gas production in the mid-continent is beginning to displace traditionally higher-priced supplies from the Gulf coast which, from a national perspective, has been causing an overall softening trend in natural gas prices with less regional differentials.

Today, Intermountain and the Pacific Northwest operate within an increasingly interconnected mega-regional marketplace, where market conditions across North America, including pipeline capacity constraints, LNG export dynamics, and storage levels, continue to influence regional supply availability and pricing. According to the U.S. Energy Information Administration (EIA), Henry Hub natural gas prices are projected to average $3.50 per MMBtu in 2025, nearly double the 2024 average, due to early-year cold weather events that depleted Lower 48 storage inventories.[2] Despite net injections beginning in March, inventories remain below recent norms, contributing to upward price pressure. At the same time, strong global demand for U.S. liquefied natural gas (LNG) and sustained domestic consumption for electric power generation have limited downward movement in prices.[3] These factors underscore the importance of flexible procurement strategies and diversified supply portfolios to mitigate volatility in Intermountain's planning horizon.

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[2] *See:* https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

[3] *See:* EIA expects higher wholesale U.S. natural gas prices as demand increases - U.S. Energy Information Administration (EIA)

3.2.11 Supply Resources Summary

Because of the dynamic environment in which it operates, the Company will continue to evaluate customer demand to provide an efficient mix of supply resources to meet its goal of providing reliable, secure, and economic firm service to its customers. Intermountain actively manages its supply and delivery portfolio and consistently seeks additional resources where needed. The Company actively monitors natural gas pricing and production trends to maintain a secure, reliable and price competitive portfolio and seeks innovative techniques to manage its transportation and storage assets to provide both economic benefits to customers and operational efficiencies to its interstate and distribution assets. The IRP process culminates with the optimization model that helps to ensure that the Company's strategies meet its traditional gas supply goals and are based on sound, real-world, economic principles (see the Optimization Section).

3.3 Capacity Release & Mitigation Process

3.3.1 Overview

Capacity release was implemented by FERC to allow markets to more efficiently utilize pipeline transportation and storage capacity. This mechanism allows a shipper with any such unused capacity to auction the excess to another shipper that offers the highest bid. Thus, capacity that would otherwise sit idle can be used by a replacement shipper. The result is a more efficient use of capacity as replacement shippers maximize annualized use of existing capacity. One effect of maximizing the utilization of existing capacity is that pipelines are less inclined to build new capacity until the market recognizes that it is really needed and is willing to pay for new infrastructure. However, a more fully utilized pipeline can also mean existing shippers have less operational flexibility.

Intermountain has and continues to be active in the capacity release market. Intermountain obtains significant amounts of unutilized capacity mitigation on NWP and GTN via capacity releases. The Company frequently releases seasonal and/or daily capacity during periods of reduced demand. Intermountain also utilizes a specific type of capacity release called segmentation to convert capacity from Sumas to Idaho into two paths of Sumas to Stanfield and Stanfield to Idaho. Intermountain uses the Stanfield to Idaho component to take delivery of the lower cost AECO gas supplies that are delivered by GTN to the interconnect with NWP at Stanfield. IGI Resources, Inc. (IGI) is then able to market the upper segment of Sumas to Stanfield to other customers.

Capacity release has also resulted in a bundled service called citygate, in which gas marketers bundle gas supplies with available capacity to be delivered directly to a market's gate station. This grants additional flexibility to customers attempting to procure gas supplies for a specified period (i.e. during a peak or winter period) by allowing the customer to avoid contracting for year-round capacity which would not be used during off-peak periods.

Pursuant to the requirements under the Services Agreement between Intermountain and IGI, IGI is obligated to generate the maximum cost mitigation possible on any unutilized firm transportation capacity Intermountain has throughout the year. In performing this obligation, IGI must also ensure that: 1) in no way will there be any degradation of firm service to Intermountain's residential and commercial customers, and 2) that Intermountain always has first call rights on any of its firm transportation capacity throughout the year and if necessary Intermountain has the right to recall any previously released capacity if needed to meet core market demands.

With the introduction of natural gas deregulation under FERC Order 436 in 1985 and the subsequent FERC Orders 636, 712, 712A and 712B, the rules and regulations around capacity release transactions for interstate pipeline capacity were developed. These rules cover such activity as: 1) shipper must have title; 2) prohibition against tying arrangements and 3) illegal buy/sell transactions. These rules and regulations are very strict and must always be adhered to or the shipper is subject to significant fines (up to $1 million per day per violation) if ever violated. IGI is very aware of these regulations and at all times ensures adherence to such when looking for replacement shippers of Intermountain's unutilized pipeline capacity.

The FERC jurisdiction of interstate pipelines for which Intermountain holds capacity are NWP and GTN. To facilitate capacity release transactions, all pipelines have developed an Electronic Bulletin Board (EBB) for which such transactions are to be posted. All released transportation capacity must be posted to the applicable pipeline EBB and in a manner that allows a competing party to bid on it.

3.3.2 Capacity Release Process

Because of its significant market presence in the Pacific Northwest, IGI has been able to generate several millions of dollars per year in released capacity mitigation dollars on behalf of Intermountain for pass-back to its core market customers and to reduce the cost of unutilized firm transportation capacity rights. In this effort, IGI can determine what the appetite is in the competitive marketplace for firm transportation releases on NWP and GTN. It does this via direct communication with third parties or by market intelligence it receives from its marketing team as it deals with its customers and other markets throughout the region. However, the most effective way of determining interest in capacity releases is using the EBB. IGI performs its obligation to Intermountain in one of two ways. First, if IGI itself is interested in utilizing any of Intermountain's unutilized firm transportation capacity, it determines what it believes is a market competitive offer for such and that is then posted to the EBB as a pre-arranged deal. As a pre-arranged deal, the transaction remains on the EBB for the requisite time and any third party has the opportunity to offer a higher bid. If this is done, then IGI can chose to match the higher bid and retain the use of the capacity, or not to match and the capacity will be awarded to the higher third-party bidder.

Second, if IGI is not interested in securing any unutilized Intermountain capacity then it will post such capacity to the EBB as available and subject to open bidding by any third party. As such, the unutilized capacity will be awarded to the highest bidder. It should be noted that IGI posts to the EBB, as available capacity, certain volumes of capacity for certain periods every month during bid week. This affords the most exposure to parties that may be interested in securing certain capacity rights. However, to date, third parties have chosen to bid on such available capacity only a handful of times over all these years.

It should also be noted, that to protect the availability of firm transportation to Intermountain's residential and commercial customers during the year, all released capacity postings to the EBB, whether pre-arranged or not, are posted as recallable capacity. This means that Intermountain can recall the capacity at any time, if necessary, to cover its customer demand.

3.3.3 Mitigation Process

IGI is also obligated to use its best efforts to mitigate the cost of transportation on the pipeline facilities of Nova and Foothills when they are not being used by Intermountain for its own needs. These pipelines are located in Canada and as such are not subject to the rules and regulations of FERC Order 436, 636, 712(A) and 712(B). However, IGI uses much the same evaluation methods for these Canadian pipelines as it does for NWP and GTN. IGI periodically inquires with third parties as to any interest in potential unused capacity on Nova and Foothills for certain periods of time known to be available. IGI also determines if it has any interest in such available capacity for its use in serving other markets in the Pacific Northwest. There is no EBB process on these Canadian pipelines. However, IGI employs much the same process as on NWP and GTN to determine the best mitigation value for Intermountain. Also, similar to the process on NWP and GTN, any of the unused NOVA and Foothills capacity used by IGI or other third parties is always subject to recall should Intermountain have any need for that capacity to serve its customers.

3.4 Non-Traditional Supply Resources

Non-traditional supply resources help supplement the traditional supply-side resources during peak demand conditions. Non-traditional resources consist of energy supplies not received from an interstate pipeline supplier, producer or interstate storage operator. Seven non-traditional supply resources were considered in this IRP and are as follows:

Non-Traditional Supply Resources

1. Diesel/Fuel Oil
2. Coal
3. Wood Chips
4. Propane
5. Satellite/Portable LNG Facilities
6. Renewable Natural Gas (RNG)
7. Hydrogen

While a large volume industrial customer's load profile is relatively flat compared to most residential and commercial customers, the Company's industrial customers are still a significant contributor to overall peak demand. However, some industrial customers have the ability to use alternate fuel sources to temporarily reduce their reliance on natural gas. By using alternative energy resources such as coal, propane, diesel and wood chips, an industrial customer can lower their natural gas requirement during peak load periods while continuing to receive the energy required for their specific process. Although these alternative resources and related equipment typically have the ability to operate any time during the year, most are ideally suited to run during peak demand from a supply resource perspective. However, only the industrial market has the ability to use any of the aforementioned alternate fuels in large enough volumes to make any material difference in system demand. In order to rely on these types of peak supplies Intermountain would need to engage in negotiations with specific customers to ensure availability. The overall expense of these kinds of arrangements, if any, is difficult to assess.

The non-traditional resources of satellite/portable liquid natural gas (LNG) facilities and RNG do not technically reduce system demand. However, LNG typically has the ability to provide additional natural gas supply at favorable locations within a potentially constrained distribution system. RNG and hydrogen production could potentially supply a distribution system in a similar fashion, however, the location of such facilities, which are determined by the producer, may not align with a constrained location of the distribution system, thus limiting their potential efficacy as a non-traditional supply resource.

3.4.1 Diesel/Fuel Oil

Intermountain is aware of two large volume customers along the IFL that currently have the potential to use diesel or fuel oil as a natural gas supplement. The facilities are able to switch their boilers over to burn oil and decrease a portion of their gas usage. Burning diesel or fuel oil in lieu of natural gas requires permitting from the local governing agencies, increases the level of emissions, and can have a lengthy approval process depending on the specific type of fuel oil used. The cost of diesel or fuel oil varies depending on fuel grade and classification, time of purchase and quantity of purchase.

3.4.2 Coal

Coal use is very limited as a non-traditional supply resource for firm industrial customers within Intermountain's service territory. A coal user must have a separate coal burning boiler installed along with their natural gas burning boilers and typically must have additional equipment installed to transport the large quantities of coal within their facility. Regulations and permitting requirements can also be a challenge. Intermountain is currently aware of only one industrial customer on its system that has a coal backup system.

The cost of coal varies depending on the quality of the coal. Lower BTU coal would range from 8,000 – 13,000 BTU per pound while higher quality coal would range from 12,000 - 15,000 BTU per pound.

3.4.3 Wood Chips

Historically Intermountain has had one large volume industrial customer on the IFL that had the ability to utilize wood chips as an alternative fuel. However, after a recent expansion it is unclear how much or often this customer utilizes this alternative fuel. In order to accommodate wood burning there must be additional equipment installed, such as wood fired boilers, wood chip transport and dry storage facilities. The wood is supplied from various tree clearing and wood mill operations that produce chips within regulatory specifications to be used as fuel. The chips are then transported by truck to the location where the customer could utilize them as a fuel source for a few months each year.

The cost of wood is continually changing based on transportation, availability, location and the type of wood processing plant that is providing the chips. Wood has a typical value of 5,000-6,000 BTU's per pound, which converts into 16-20 pounds of wood being burned to produce one therm of natural gas.

3.4.4 Propane

Since propane is similar to natural gas, the conversion to propane is much easier than a conversion to most other non-traditional supply resources. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce an industrial customer's natural gas needs by 100%. The use of propane requires onsite storage, additional piping and a reliable supply of propane to maintain adequate storage. Currently there are no industrial customers on Intermountain's system that have the ability to use propane as a feasible alternative to natural gas.

Capital costs for propane facilities can become relatively high due to storage requirements. As with oil, storage facilities should be designed to accommodate a peak day delivery load for approximately seven (7) days. One gallon of propane is approximately 91,600 BTU.

3.4.5 Satellite/Portable LNG Equipment

Satellite/Portable LNG equipment allows natural gas to be transported in tanker trucks in a cooled liquid form; meaning that larger BTU quantities can be delivered to key supply locations that can support LNG deliveries. Liquefied natural gas has tremendous withdrawal capability because the natural gas is in a denser state of matter. Portable equipment has the ability to boil LNG back to a gaseous form and deliver it into the distribution system by heating the liquid from -260 degree Fahrenheit to a typical temperature of 50 – 70 degree Fahrenheit. This portable equipment is available to lease or purchase from various companies and can be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG production plants and are dependent upon the specific location where the portable LNG equipment is placed. The available delivery pressure from LNG equipment ranges from 150 psig to 650 psig with a typical flow capability of approximately 2,000 - 8,000 therms per hour.

Intermountain Gas currently operates a portable LNG unit on the northern end of the Idaho Falls Lateral to assist in peak shaving the system. In addition to the portable equipment, Intermountain also has a permanent LNG facility on the IFL that is designed to accommodate the portable equipment, provide an onsite control building and allow onsite LNG storage capabilities. The ability to store LNG onsite allows Intermountain to partially mitigate the risk associated with relying on truck deliveries during critical flow periods. The LNG delivery risk is also reduced now that Intermountain has the ability to withdraw LNG from the Nampa LNG Storage Tank and can transport this LNG across the state in a timely manner. With Nampa LNG readily available the cost and dependence on third-party supply is removed.

3.4.6 Renewable Natural Gas

RNG can be defined as utilizing any biomass material to produce a renewable fuel gas. Biomass is any biodegradable organic material that can be derived from plants, animals, animal byproduct, wastewater, food/production byproduct and municipal solid waste. After processing of RNG to industry purity standards the gas can then be used within Company facilities.

Idaho is one of the nation's largest dairy producing states which make it a prime location for RNG production utilizing the abundant supply of animal and farm byproducts. Southern Idaho currently has four RNG producers on Intermountain's distribution system. All four producers supply RNG from dairy operations and are located in the Twin Falls area. In addition to these current producers, the Company is currently working with multiple prospective projects and expects additional RNG producers to come onto Intermountain's distribution systems in coming years.

Intermountain has included RNG as a potential resource to solve any supply shortfalls the Company may have. RNG that has been cleaned to the Company's specifications can be used interchangeably with traditional natural gas in Intermountain's pipelines and in the customers' end use equipment. The Company estimated the price of RNG at current regional market rates considering the limited selling opportunities for RNG producers.

3.4.7 Hydrogen

Hydrogen is a clean alternative to methane. "Hydrogen can be produced from various conventional and renewable energy sources including as a responsive load on the electric grid. Hydrogen has many current applications and many more potential applications, such as energy for transportation—used directly in fuel cell electric vehicles (FCEVs), as a feedstock for synthetic fuels, and to upgrade oil and biomass—feedstock for industry (e.g., for ammonia production, metals refining, and other end uses), heat for industry and buildings, and electricity storage. Owing to its flexibility and fungibility, a hydrogen intermediate could link energy sources that have surplus availability to markets that require energy or chemical feedstocks, benefiting both." [1] Hydrogen can be produced by a variety of sources that are delineated by colors:

- Blue hydrogen: Hydrogen produced using natural gas to create steam while capturing CO2;
- Green hydrogen: Hydrogen produced through electricity from renewables;
- Brown hydrogen: Hydrogen produced by coal;
- Pink hydrogen: Hydrogen produced through electricity from nuclear reactors; and

[1] https://www.nrel.gov/docs/fy21osti/77610.pdf

- Gray hydrogen: Hydrogen produced using natural gas to create steam without capturing CO_2;

"The coalition estimated that the levelized cost of green hydrogen could reach $2.05 per kilogram in 2030, even without government incentives. By factoring in the production tax credit authorized by the US Inflation Reduction Act in 2022, that price cost could fall below 70 cents, allowing hydrogen to compete with diesel in the trucking industry as soon as 2026, the report said. [2] There is significant global interest in hydrogen. In June 2021, the U.S. Department of Energy launched its "Hydrogen Shot" which seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade ("1 1 1"). [3] With the current pricing of hydrogen, however, Intermountain is only monitoring hydrogen at this time and will continue to consider it as a potential resource in future IRPs.

[2] https://www.spglobal.com/market-intelligence/en/news-insights/articles/2023/3/study-finds-green-hydrogen-can-be-competitive-with-fossil-fuels-as-soon-as-2030-74961136
[3] https://www.energy.gov/eere/fuelcells/hydrogen-shot

3.5 Lost and Unaccounted for Natural Gas Monitoring

Intermountain Gas Company (IGC) is pro-active in finding and eliminating sources of Lost and Unaccounted For (LAUF) natural gas. LAUF is the difference between volumes of natural gas delivered to IGC's distribution system and volumes of natural gas billed to IGC's customers. Intermountain Gas Company is consistently one of the best performing companies in the industry with a LAUF percentage of 1.1% over the period of July 2024 to June of 2025.

IGC utilizes a system to monitor and maintain a historically low amount of LAUF natural gas. This system is made up of the following combination of business practices:

- Perform ongoing billing and meter audits
- Routinely rotate and test meters for accuracy
- Conduct leak surveys on one-year and four-year cycles to find leaks on the system
- Natural gas line damage prevention and monitoring
- Implementing an advanced metering infrastructure system to improve the meter reading audit process
- Monitor ten weather location points to ensure the accuracy of temperature related billing factors
- Utilize hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors

3.5.1 Billing and Meter Audits

Intermountain Gas Company conducts billing audits to identify irregular usage with each billing cycle. IGC also works to ensure billing accuracy of newly installed meters. These audits are performed to ensure that the meter and billing system are functioning correctly to avoid billing errors. If errors are identified, then corrective action is taken.

IGC also compares on a daily and monthly basis its telemetered usage versus the metered usage that Northwest Pipeline records. These frequent comparisons enable Intermountain to find any material measurement variances between Intermountain's distribution system meters and Northwest Pipeline's meters.

Billing and Meter Audit Results			
	2022	**2023**	**2024**
Dead Meters	164	235	171
Drive Rate Errors	2	48	4
Pressure Errors	14	25	37
Totals	197	308	212

Table 9: 2022 - 2024 Billing and Meter Audit Results

3.5.2 Meter Rotation and Testing

Meter rotations are also an important tool in keeping LAUF levels low. IGC regularly tests samples of its meters for accuracy. Sampled meters are pulled from the field and brought to the meter shop for testing. The results of tests are evaluated by meter family to determine the pass/fail of a family based on sampling procedure allowable defects. If the sample audit determines that the accuracy of certain batches of purchased meters are in question, additional targeted samples are pulled and any necessary follow up remedial measures are taken.

In addition to these regular meter audits, IGC also identifies the potential for incorrectly sized and/or type of meter in use by the larger industrial customers. IGC conducts a monthly comparison to the billed volumes as determined by the customer's meter. If a discrepancy exists between the two measured volumes, remedial action is taken.

3.5.3 Leak Survey

On a regular and programmed basis, IGC technicians check the company's entire distribution system for natural gas leaks using sophisticated equipment that can detect even the smallest leak. The surveys are done on a one-year cycle in business districts and a four-year cycle in other areas. This is more frequent than the code requirement, which mandates leak surveys on one-year and five-year cycles. When such leaks are identified, which is very infrequent, they are graded and addressed according to grade. Grade 1 leaks are repaired immediately, Grade 2 leaks are addressed within six months, and Grade 3 leaks are addressed within 15 months. This approach is more aggressive than the industry standard, where lower grade leaks are often monitored for safety and not repaired immediately.

3.5.4 Damage Prevention and Monitoring

Unfortunately, human error leads to unintentional excavation damage to the distribution system. When such a gas loss situation occurs, an estimate is made of the escaped gas and that gas then becomes "found gas" and not "lost gas".

When the Public Awareness and Damage Prevention department was created, it's focus was on education to individuals, businesses, and agencies that partner with and interact with Intermountain Gas Company. Industry education and awareness was centered around gathering damage statistics and focused on meeting the regulatory requirements for educating the public, excavation contractors and emergency responders.

Intermountain's recent efforts are aimed at educating the affected public and excavation contractors on the importance of calling 811 prior to any type of digging. IGC has participated in a variety of informational activities, including sponsored events, general awareness mailings, and multi-media advertising, as well as site visits and training sessions on safe excavation practices with excavation contractors.

The focus on education and awareness with the affected public has had an impact to reduce excavation damage. However, the leading factor for damage to IGC facilities is still from excavation contractors or individuals not submitting a locate request with the state one call center before digging. IGC will continue to focus on public awareness and damage prevention efforts on working with all excavation parties to increase awareness of the importance of submitting a locate request and to use safe excavation practices while excavating, so individuals and professional excavators can remain safe while excavating and reduce damage to IGC underground facilities. Figure 29 shows the damage rate per 1,000 locates, and Figure 30 shows the total locates for 2022 through 2024.

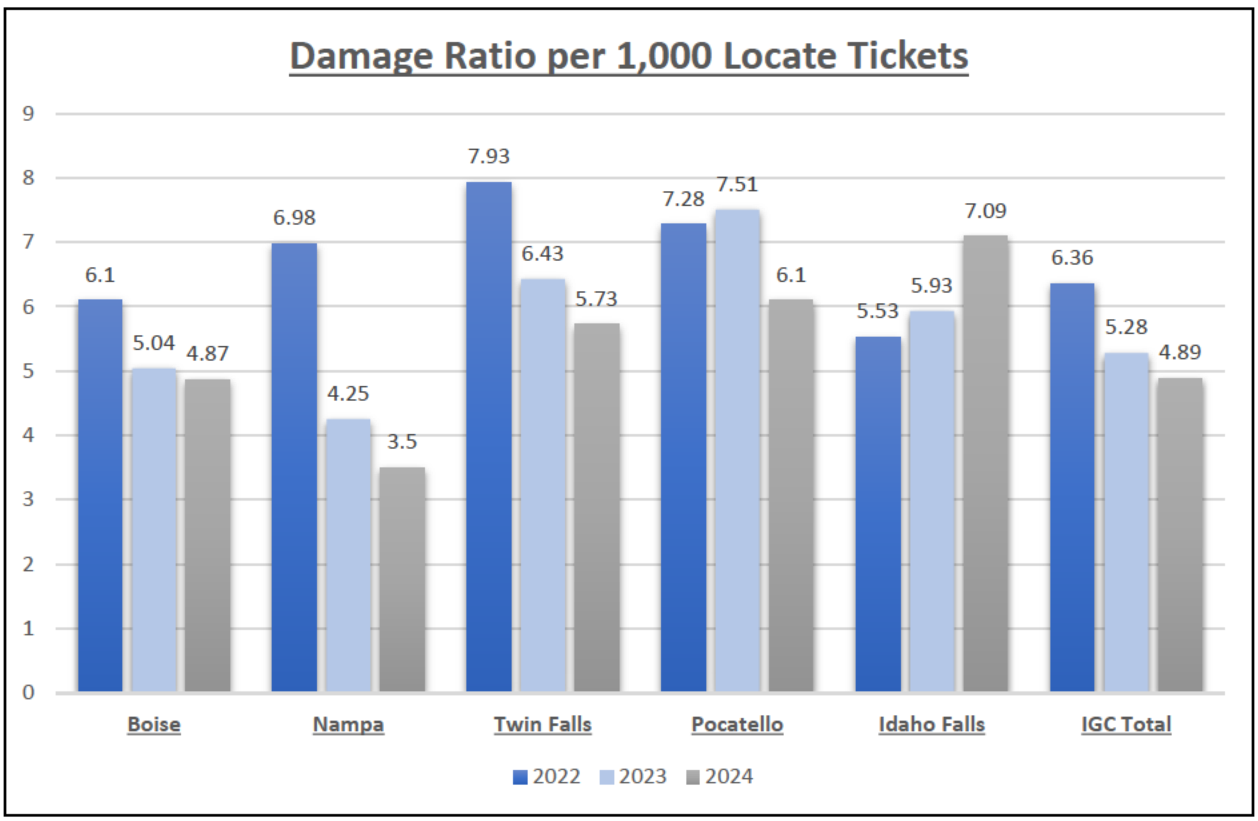

Figure 29: Damage Rates per 1,000 Locates by District

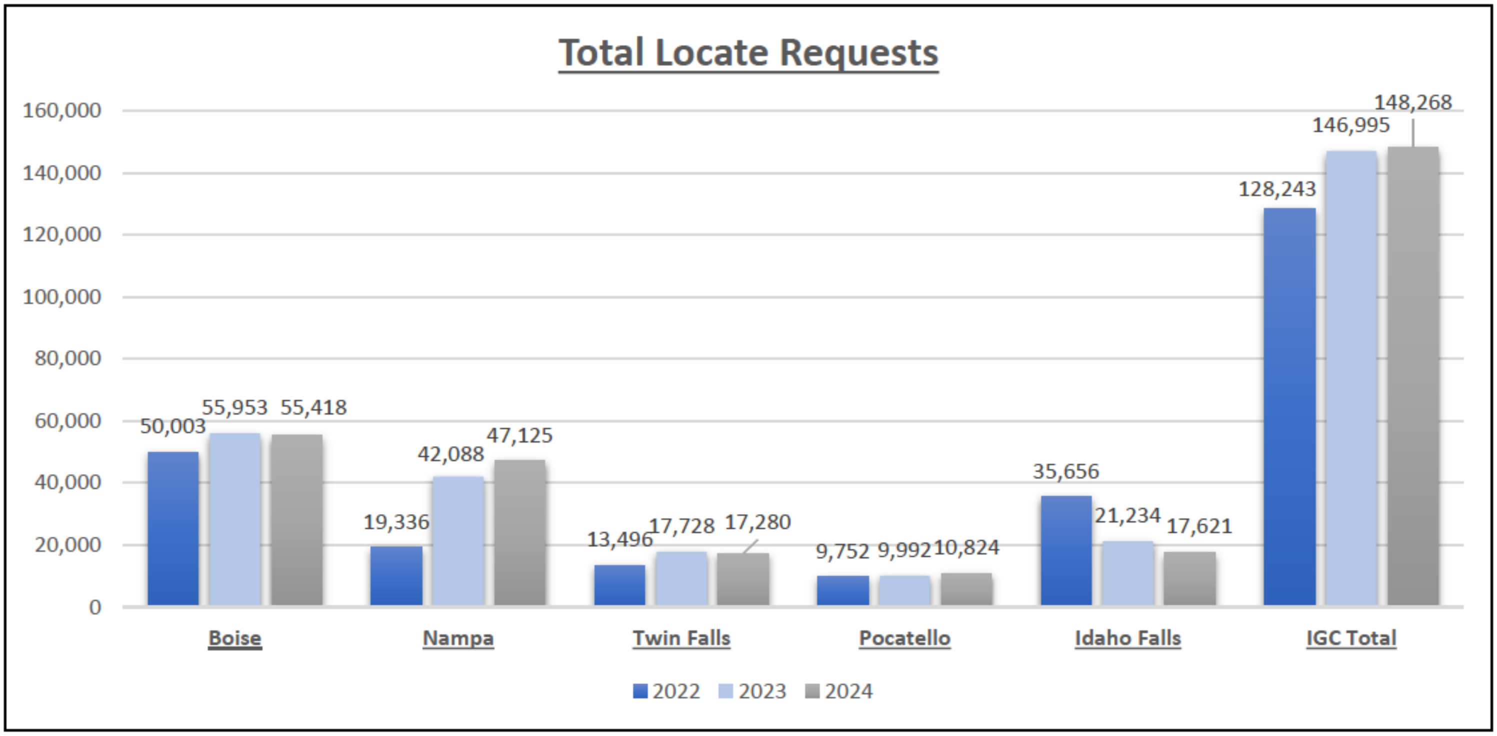

Figure 30: Intermountain Locate Requests by District

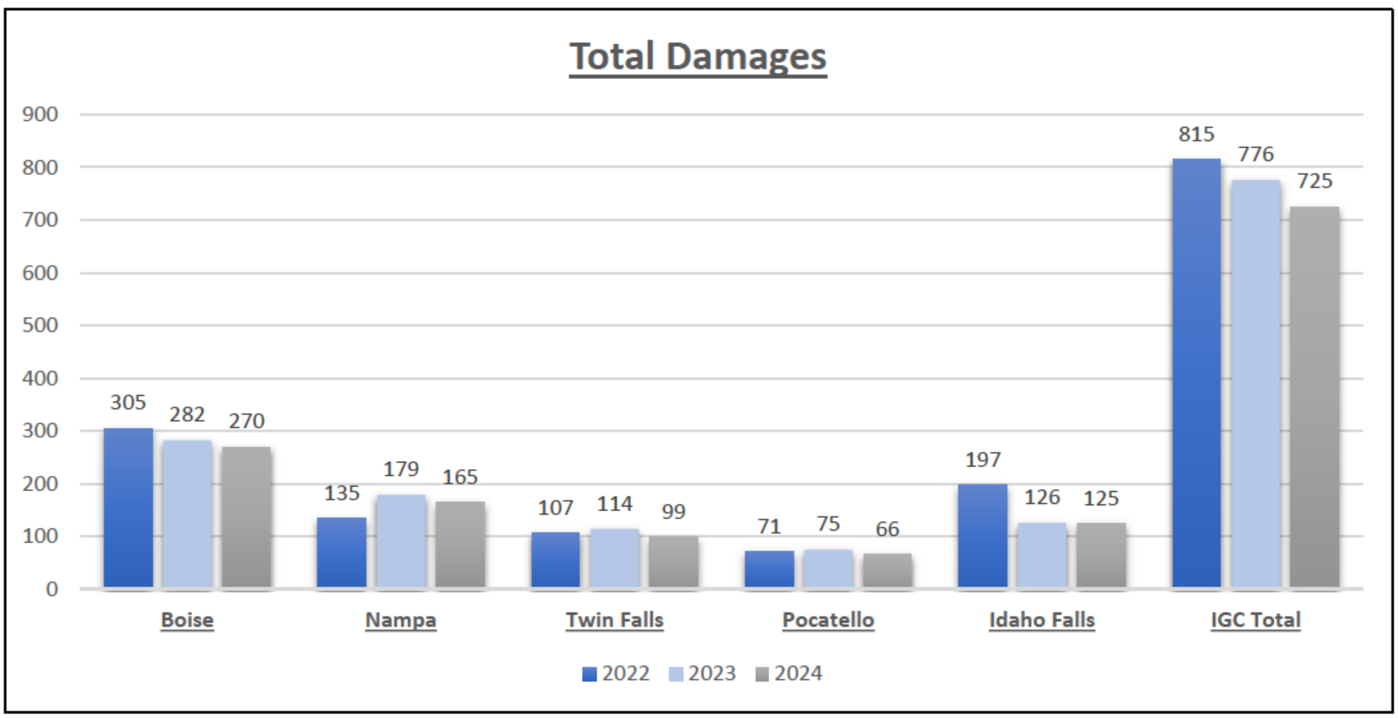

Figure 31: Intermountain Total Damages by District

3.5.5 Weather and Temperature Monitoring

Intermountain Gas Company increased the number of weather monitoring stations in the early 2000’s, from five to ten weather location points, to ensure the accuracy of temperature related billing factors. Additionally, IGC utilizes hourly temperatures for a 24-hour period, averting a daily temperature average, ensuring accurate temperature averages for billing factors. The weather and temperature monitoring provide for a better temperature component of the billing factor used to calculate customer energy consumption.

3.5.6 Summary

Intermountain Gas Company continues to monitor LAUF levels and continuously improves business processes to ensure the Company maintains a LAUF rate among the lowest in the natural gas distribution industry.

3.6 Core Market Energy Efficiency

The Company's Residential and Commercial Energy Efficiency Programs promote the wise and efficient use of natural gas, which helps the Company's customers save money and energy. Additionally, the Company's Energy Efficiency Programs will, over time, help negate or delay the need for expensive system upgrades while still allowing Intermountain to provide safe, reliable, and affordable service to its customers.

3.6.1 Residential & Commercial Energy Efficiency Programs

The goal of Intermountain's Residential and Commercial Energy Efficiency Programs (EE Program) is to acquire cost-effective demand side resources. Unlike supply side resources, which are purchased directly from a supplier, demand side resources are acquired through the reduction of natural gas consumption due to increases in the efficiency of energy use. Demand side resources acquired through the Company's EE Program (also referred to as Demand Side Management or DSM) ultimately allows Intermountain to displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcements on the Company's distribution system. The Company strives to raise awareness about energy efficiency and inspire customers to reduce their individual demand for gas through outreach and education.

An Energy Efficiency Charge for funding the Residential EE Program began on October 1, 2017. Active promotion and staffing of the Residential EE Program launched in January 2018. Since the launch, the Residential EE Program has continued to grow year over year in number of total rebates claimed by customers. Intermountain launched its Commercial EE Program on April 1, 2021, and began collecting funds through a commercial Energy Efficiency Charge. Due to the slow uptake of the Commercial EE Program, the EE was reduced to zero to decrease the over-collection of funds while the commercial program gains awareness and participation.

3.6.2 Conservation Potential Assessment

In its 2023 IRP, the Company estimated DSM therm savings based on the Conservation Potential Assessment (CPA) commissioned by Intermountain. The CPA provided a robust analysis of all cost-effective DSM measures and is intended to support both short-term energy efficiency planning and long-term resource planning activities. The objective of the CPA is to assess achievable energy savings potential for the Intermountain service territory and apply the results to:

- Inform Intermountain's energy efficiency goals, portfolio planning and budget setting,
- Contribute to Intermountain's Integrated Resource Planning process, and
- Identify new energy efficiency savings opportunities.

Guidehouse was retained to perform the CPA. Guidehouse leveraged both IGC data and secondary research and data sources to inform the modeling inputs for energy efficiency potential. The scope of the study included conservation potential for both the residential and commercial sectors over the 2024-2044 time period. During the time of the 2023 CPA, Guidehouse also developed a model that would allow for updating inputs for future use.

Since the CPA was conducted for the 2023 IRP, there have been no changes to the energy efficiency program. The Company weighed the fact that there have been no program changes with the expense of commissioning a new full-scale study. To ensure responsible use of resources, the Company opted for a targeted update rather than a comprehensive study, as the existing model required only minor adjustments due to the absence of significant program changes. This approach allowed the Company to achieve the necessary improvements at a fraction of the cost of a full-scale study. Guidehouse was commissioned to update the global input forecasts and measure inputs and extend the forecast period by two years. The methodology used to conduct the 2023 conservation potential assessment is provided in the full report in Exhibit 4. The model updates used to calculate the inputs for the 2025 IRP discussed in the following section are provided in Exhibit 1.

Using data provided by the Company, Guidehouse updated the following global inputs in the model:

- Building stock and sales
- Retail rates
- Avoided costs
- Inflation rate, and
- Discount rate

Compared to the 2023 CPA,

- Building stock and sales were forecasted slightly higher for the commercial sector and modestly lower for the residential sector.
- Retail rates were forecasted to be higher for 2026 and beyond.
- Avoided costs are forecasted to be lower than the 2023 CPA.
- Inflation rate is forecasted to be higher at 3.99% compared to 3.15% in the 2023 CPA, and
- Discount rate is forecasted to be lower at 2.68%, compared to 3.51% in the previous CPA.

The measure inputs, savings, costs, and estimated useful lifetimes, were updated using the IGC Technical Reference Manual. The following commercial measures were updated: commercial kitchen fryer, steamer, convection oven, combination oven, dishwasher, high efficiency condensing boiler, smart thermostat, storage water heater, tankless water heater, furnace gas heat pump, condensing unit heater, boiler reset control and pipe insulation. The following residential measures were updated: Whole Home Tier I and II, 95% AFUE furnace, 97% AFUE

Furnace, smart thermostat, storage water heater, tankless water heater, 95% AFUE boiler and 95% AFUE combination boiler.

3.6.3 Energy Efficiency Potential

To develop an estimate of the potential for gas energy efficiency in Intermountain's service territory over a 20-year horizon, three categories of potential savings were calculated by Guidehouse: technical, economic, and achievable energy savings. Technical potential assumes all eligible customers adopt the highest level of efficiency available, regardless of cost effectiveness. Next, measures are screened for cost-effectiveness to estimate economic potential. Economic potential is a subset of technical potential but includes only the measures that have passed the benefit-cost test chosen for measure screening. Intermountain uses the Utility Cost Test (UCT) for cost-effectiveness testing. The third category of savings potential, achievable potential, is a calculation of energy efficiency savings that could be expected in response to specific levels of program incentives and assumptions about existing policies, market influences, and barriers. This screening of savings potential is illustrated in Figure 32.

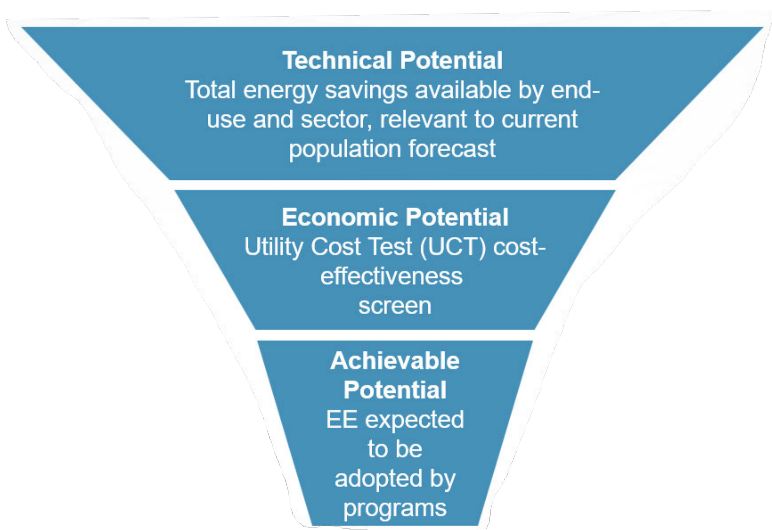

Figure 32: Guidehouse: Types of Savings Potential

The three types of savings potential for the study time period is shown in Figure 33.

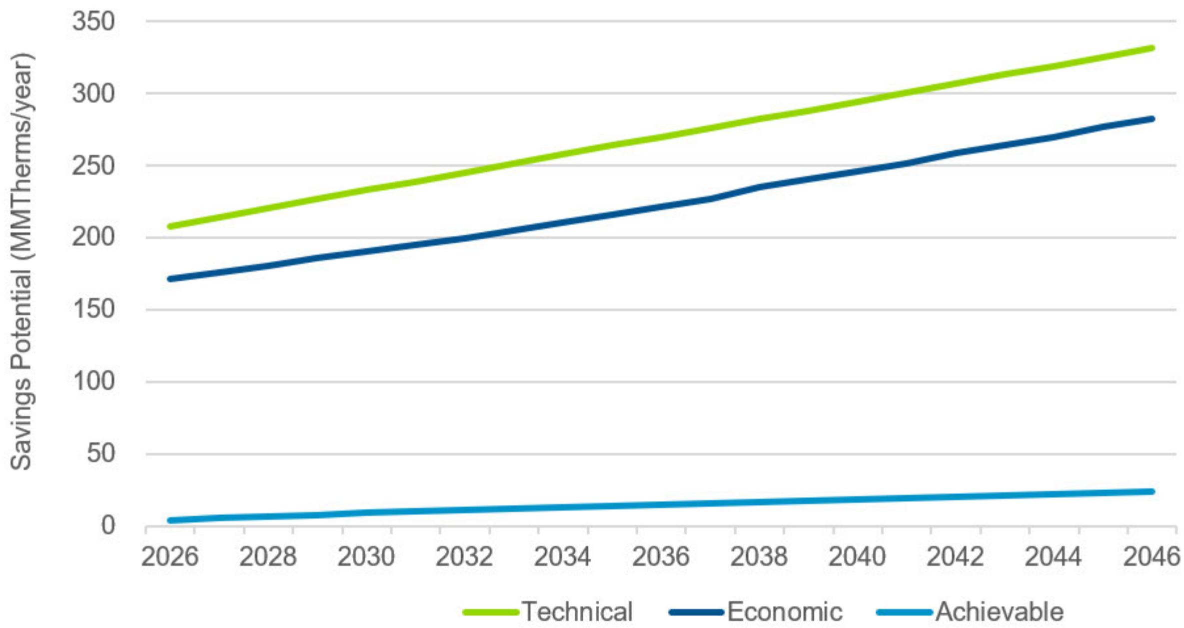

Figure 33: Guidehouse Analysis 2025: Savings Potential

Figure 34 illustrates the gas energy achievable potential by sector as a percentage of forecasted sales.

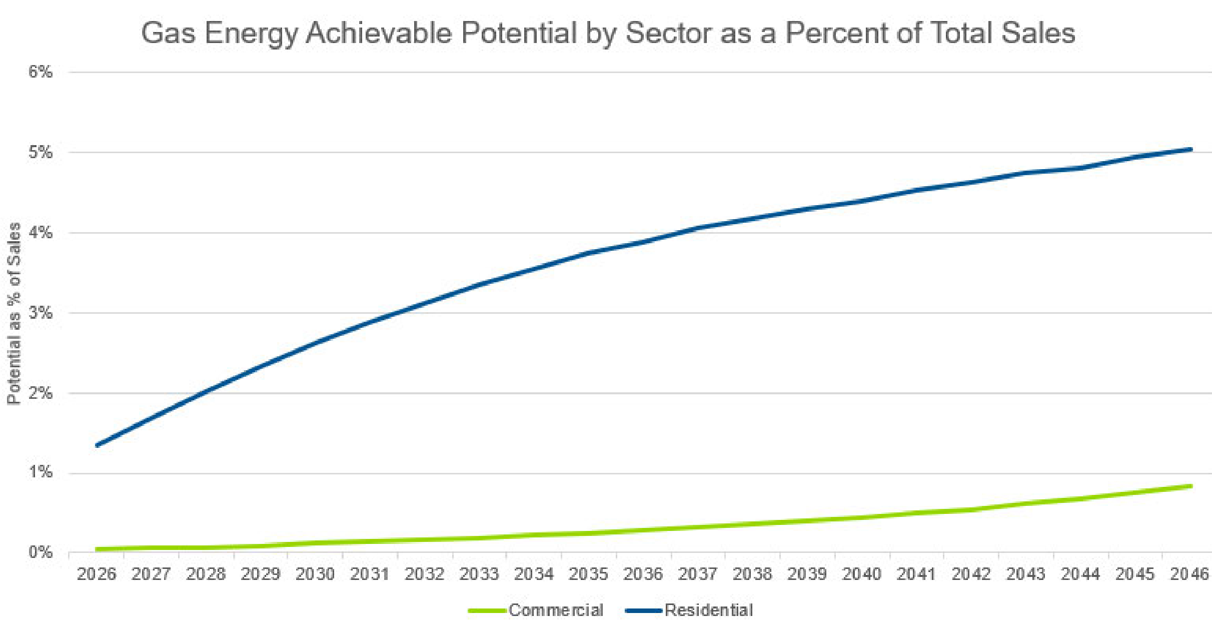

Figure 34: Guidehouse Analysis 2025: Achievable Potential as a Percent of Total Sales

As was explored in the 2023 CPA, Guidehouse ran the same four scenarios to examine how changes in customer attitudes and awareness regarding energy efficiency, and approaches to incentive amounts, could impact potential savings. The four scenarios examined included Business as Usual (BAU), Unconstrained Historical budget, Medium Incentive, and combined High Incentive, High Adoption. Scenario details are outlined in Figure 35, while savings potential for all scenarios is shown in chart format in Figure 36.

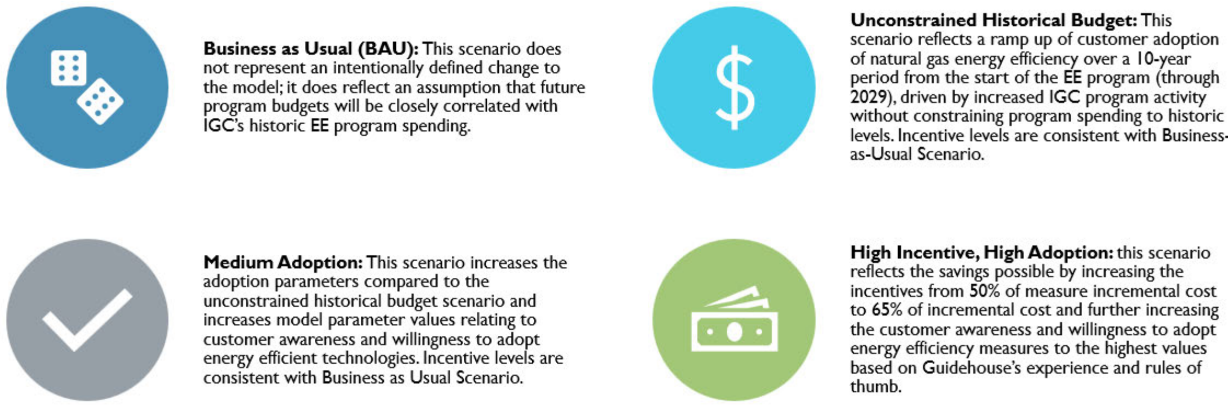

Figure 35: Guidehouse Savings Potential Scenarios

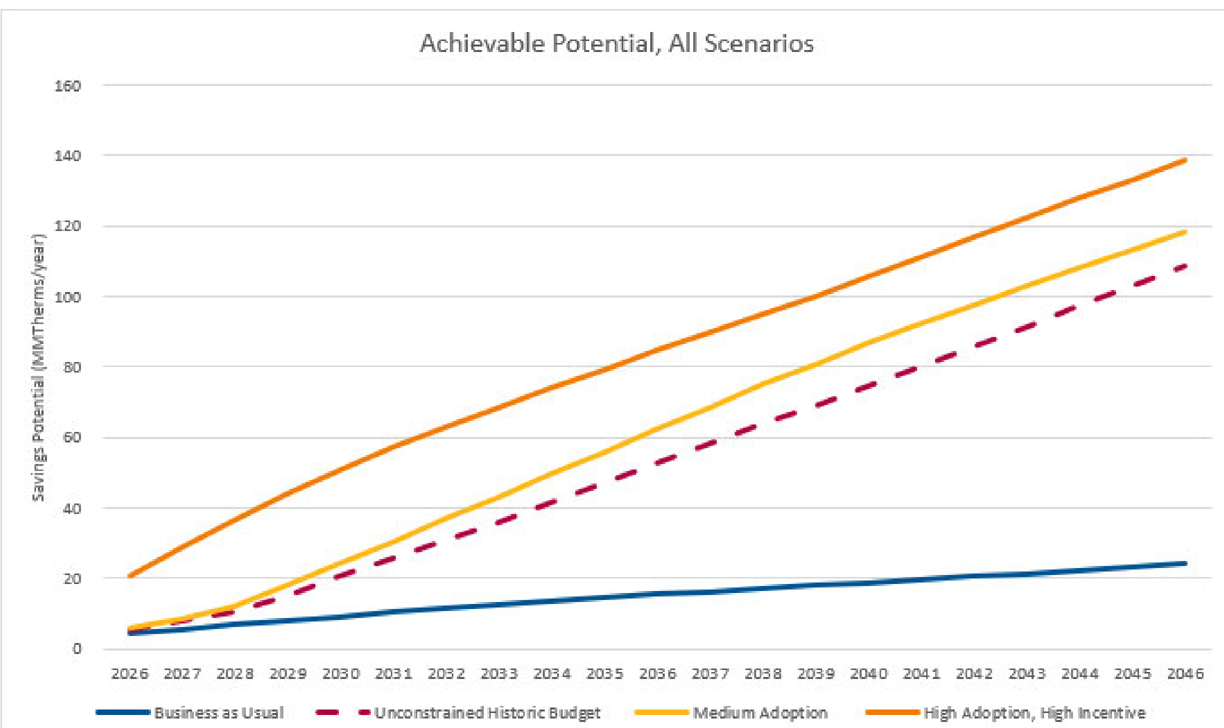

Figure 36: Guidehouse Analysis 2025: Four Scenarios of Achievable Potential

Guidehouse also compared Intermountain's historic accomplishments to the achievable potential estimated in the 2023 CPA and the current 2025 CPA, illustrated in Figure 37. A measure competition group is a group of measures that serve the same purpose. The measure competition group with the highest potential is Residential Furnaces, serving space heating. The Residential Furnace competition group consists of 95 AFUE Furnace, 97 AFUE Furnace and Gas Heat Pump. The key change with the 2025 CPA is that savings and costs for the 95 AUFE and 97 AFUE furnaces were reduced by approximately 75% when the model was updated with saving and cost estimates from the IGC Technical Reference Manual. The gas heat pump measure, which has much higher savings, is cost-effective in more cases than in the previous CPA, but the increase in savings for gas heat pumps is not enough to offset the reduction from the furnace measures.

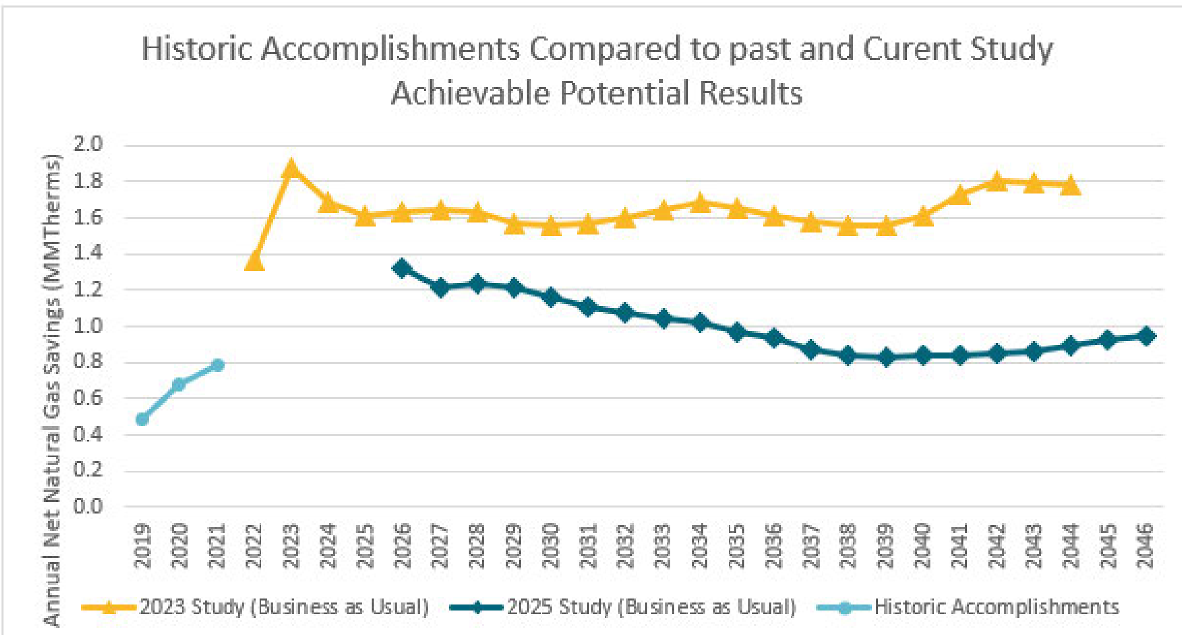

Figure 37: Guidehouse Analysis 2025

The combined effect of the global input updates increased benefit-cost ratios (UCT) compared to the 2023 CPA. This was driven by higher avoided costs in later years, combined with a lower discount rate, making the future years more important.

Figure 38 illustrates that for the Business-as-Usual scenario achievable potential results are overall lower than the 2023 CPA, and the difference grows over time.

Incremental Achievable Potential (therms/yr)

BAU (Scen 1)		2024	2025	2026	2027	2028	2029	2030	2035	2040
2023 CPA	Total	1,681,489	1,609,817	1,636,834	1,639,515	1,629,649	1,569,179	1,555,721	1,658,211	1,616,968
2025 CPA	Total	1,435,954	1,563,629	1,325,611	1,219,682	1,232,025	1,217,600	1,164,390	973,022	836,745
	Change	-15%	-3%	-19%	-26%	-24%	-22%	-25%	-41%	-48%
2023 CPA	Residential	1,656,777	1,582,970	1,607,031	1,606,593	1,593,441	1,529,423	1,511,952	1,587,032	1,497,466
2025 CPA	Residential	1,420,173	1,537,652	1,297,384	1,188,569	1,198,097	1,180,763	1,124,447	910,776	733,919
	Change	-14%	-3%	-19%	-26%	-25%	-23%	-26%	-43%	-51%
2023 CPA	Commercial	24,712	26,848	29,804	32,921	36,208	39,756	43,769	71,179	119,502
2025 CPA	Commercial	15,781	25,977	28,227	31,113	33,928	36,837	39,943	62,246	102,826
	Change	-36%	-3%	-5%	-5%	-6%	-7%	-9%	-13%	-14%

Figure 38: Guidehouse Analysis 2025

The Business-as-Usual scenario based on achievable potential is the most conservative estimate for IRP planning and was also applied in the 2023 IRP. By using this scenario, the Company bases IRP resource decisions on achievable, cost-effective savings that reflect actual program data and market conditions. This approach offers a stable foundation for long-term planning and accommodates future adjustments in response to program enhancements or market developments.

3.7 Large Volume Energy Efficiency

Through discussions with customers, maximizing plant efficiency by optimizing production volumes while using the least amount of energy is a very high priority for the owners, operators, and managers of Intermountain's large volume facilities. Nearly twenty years ago Intermountain developed an informational tool using Supervisory Control and Data Acquisition (SCADA) and remote radio telemetry technology to gather, transmit and record the customer's hourly therm usage data. This data is saved in an internal database and made available to customers and their marketers/agents via an internal server on a password protected website.

Figure 39: Large Volume Website Login

In addition to SCADA, a new technology, Encoder Receiver Transmitters (ERTs) are being added to some meters that did not have SCADA. The equipment is able to transmit usage information via fixed network, similar to SCADA, and provide timely usage information on usage.

Regardless of which technology is being implemented, usage data is useful in tracking and evaluating energy saving measures, new production procedures and/or usage characteristics of new customer equipment. To deploy these tools, Intermountain installs equipment on customers' meters to record the meter volume each hour. That data is then transmitted via radio/telemetry communication technology to Intermountain's servers so it can be made available to customers.

In order to provide Intermountain customers access to this data, the Company has designed and hosts a Large Volume website, which is pictured in Figure 39. The website is available on a 24/7 basis for Large Volume customers to log-in via the Internet using company specific username and customer managed passwords. After a successful log-in, the user immediately sees a chart showing the last 30 days of hourly usage for the applicable meter or meters. The customer also has the option to adjust the date range to see just a few hours or up to several years of usage data. An example of a month's worth of data is provided in Figure 40. The user can also download the data in CSV format to review, evaluate, save, and analyze natural gas consumption at their specific facility on an hourly, weekly, monthly, and annual basis as far back as 2017. Each customer may elect to allow one or multiple employees to access the site. Logins can also be created to make this same data available to a transport customer's natural gas marketer.

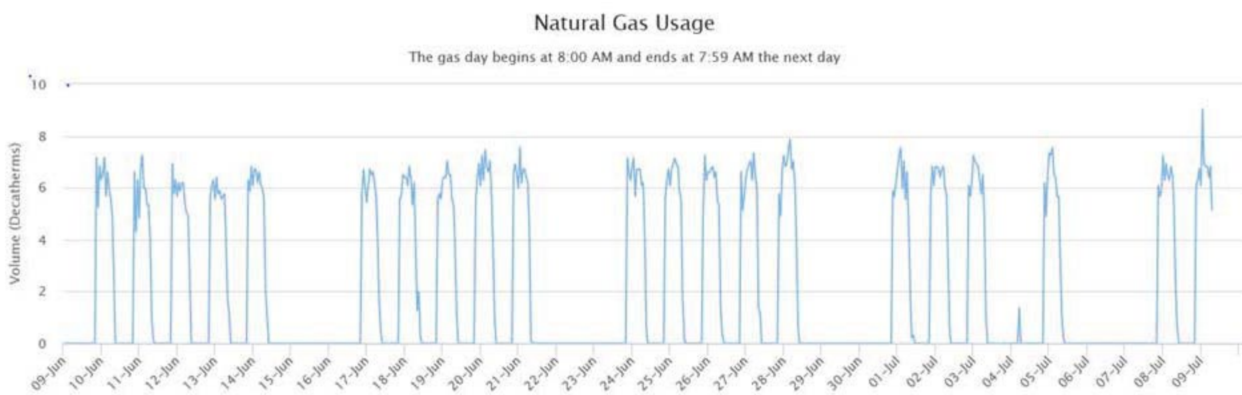

Figure 40: Natural Gas Usage History

The website also contains a great deal of additional information useful to the Large Volume customer. Customers can access information such as the different tariff services offered, answers to frequently asked questions and a potential marketer list for those interested in exploring transport service. The customer is also provided a "Contact Us" link and, in order to keep this site in the most usable format for the customer, a website feedback link is provided. The site allows the Company to post information regarding things such as system maintenance, price changes, rate case information and any other communication that might assist the customer or its marketer.

3.8 Avoided Costs

3.8.1 Overview

The avoided cost represents those costs that the Company does not incur as a result of energy savings generated by its Energy Efficiency Program. The calculation is used both to economically evaluate the present value of the therms saved over the life span of a measure and to track the performance of the program as a whole.

Avoided costs are forecasted out 30 years in order to properly assess Energy Efficiency measures with longer lifespans. This forecast is based on the performance of the Company's portfolio under expected market conditions. The Avoided Cost values can be found in Exhibit 5.

3.8.2 Costs Incorporated

Intermountain's avoided cost calculation contains the following components:

$$AC_{nominal} = CC + TC + VDC$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year.
- CC = Commodity Costs
- TC = Transportation Costs
- VDC = Variable Distribution Costs

The following parameters are also used in the calculation of the avoided cost:

- The assumed forward-looking annual inflation rate is 2.68%. (Inflation was updated to 3.99% this year to account for the high inflation rates).
- The discount rate is derived using Intermountain's tax-effected cost of capital.
- Standard present value and levelized cost methodologies are utilized to develop a real and nominal levelized avoided cost by year.

3.8.3 Understanding Each Component

Commodity Costs

Commodity costs represent the purchase price of the natural gas molecules that the Company does not need to buy due to therm savings generated by its Energy Efficiency Program. To calculate the commodity costs, the Company first utilizes price forecasts included in its IRP for three primary basins (AECO, Sumas, and Rockies) then weights these forecasts based on Intermountain's historical day-gas purchase data. Day-gas purchases represent the first costs that could be avoided through Energy Efficiency Program savings. To account for the seasonal nature of energy savings, the weighted price is shaped by normal monthly weather, measured in heating degree days with a base of 65 degrees. The original basin price forecasts span through 2040 and then an escalator is applied through the remainder of the forecast period. The gas price forecasts will be updated in each IRP planning cycle.

Transportation Costs

Transportation costs are the costs the Company incurs to deliver gas to its distribution system. As the Company's Energy Efficiency Program generates therm savings, the Company can reduce pipeline capacity needs and monetize any excess capacity to reduce costs for all customers through credits in the Company's annual Purchased Gas Cost Adjustment (PGA) filing. The Company calculates the per therm transportation cost as the weighted average of the gas transportation costs listed on the Company's residential and commercial tariffs. The nominal value of the transportation cost is increased each year by the model inflation rate of 3.99%. The inflated nominal value is then discounted back to today's dollars as part of the final step in the avoided cost calculation. The Company will update the transportation cost each year to reflect the most current gas transportation cost as filed in its PGA.

Variable Distribution Costs

Variable distribution costs are the avoidable portion of costs incurred by Intermountain to deliver gas to customers via its distribution system. Lowering gas consumption through the Company's Energy Efficiency Program allows Intermountain to delay costly capacity expansion projects and utilize existing pipeline infrastructure more efficiently. While these cost benefits are intuitively apparent, the Company and its Stakeholder group are investigating methods to quantify these savings. The Company is currently using a placeholder value of zero for this component.

4. Optimization

4.1 Distribution System Planning

4.1.1 Overview

Intermountain strives to provide safe and reliable service to its customers. As part of Intermountain's distribution planning process Intermountain reviews it's systems for predicted growth and will identify and address capacity deficits related to growth. If a capacity deficit is identified, reinforcement alternatives are compared, and the optimized reinforcement is selected and budgeted within Intermountain's five year budget with consideration to cost, system benefits and long term planning.

This section will cover how Intermountain models its distribution systems, identifies deficits, proposes reinforcement options to address deficits, reviews and selects reinforcement options, and how projects are put into the capital budget.

4.1.2 System Dynamics

Intermountain operates a diverse system through Idaho over a range of pipeline diameters and operating pressures. Intermountain's natural gas distribution system consists of approximately 7,471 miles of distribution and 284 miles of transmission in Idaho. Intermountain system is also composed of facilities including regulator stations, valve stations, odorizers, heaters and compressor stations.

In general, Intermountain's distribution systems originate at a gate station connected to an interstate pipeline. At the gate station, Intermountain takes custody of the natural gas and provides odorization and pressure control to serve downstream distribution and transmission pipelines.

4.1.3 Network Design Fundamentals

A natural gas pipeline is constrained by the laws of fluid mechanics which dictate that a pressure differential must exist to move gas from a source to any other location on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a pipeline system, typically during the operation of natural gas equipment, then the pressure in the system at that point becomes lower than the supply pressure in the system. This pressure differential causes gas to flow from the supply pressure to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to Intermountain’s distribution systems. It is important that engineers design a distribution system in which the beginning pressure sources, which could be from interstate pipelines, compressor stations or regulator stations, have adequately high pressure, and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity; which is constrained by minimum pressure allowances at a determined point, or points, along the distribution system, and/or maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment, and/or maximum volumetric flow through facilities.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain diameter and length within specified operating pressures; the laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and distribution system can be ascertained for any set of known gas demand data. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day.

To evaluate intricate pipeline structures, a system model is created to assist Intermountain’s engineering team in determining the flow capacity and dynamics of those pipeline structures. For example, before a large usage customer is incorporated into an existing distribution system the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer, and which capacity enhancement option is optimal. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipate future customer growth.

4.2 Modeling Methodology

Intermountain utilizes a hydraulic gas network modeling and analysis software program called Synergi Gas, distributed and supported by DNV (software provider), to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program, individual models have been created for each of Intermountain’ s various distribution systems including transmission and high pressure laterals, regulator stations, compressor stations, distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Intermountain defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in the system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. Intermountain's distribution systems are broken into 6 models for ease of use and to reduce the time requirements during a model run analysis.

Synergi can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time; which more closely simulates real life operation utilizing gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this integrated resource plan Intermountain can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost-effective methods of enhancing the constrained location.

4.2.1 Model Building Process

Intermountain's models are rebuilt every three years and are regularly maintained between rebuilds. To rebuild the models, Intermountain exports current GIS data to create the spatial models and exports historical billing data from CC&B to bring into the Customer Management Module (CMM) to create an updated demands file. Intermountain's models were rebuilt in 2025.

4.2.2 Usage Per Customer

The IRP planning process utilizes customer usage as an essential calculation to translate current and future customer counts into estimated demands on the distribution system and total demand for gas supply and interstate transportation planning. The calculated usage per customer is dependent upon weather and geographic location.

Intermountain utilizes a Customer Management Module (CMM) software product, provided by DNV as part of their Synergi Gas product line, to analyze natural gas usage data and to predict usage patterns on the individual customer level.

The first step in operating CMM is extensive data gathering from the Company's Customer Information System (CIS), CC&B. CC&B houses historical monthly meter read data for each of Intermountain's customers, along with daily historical weather and the physical location of each customer. The temperature data is associated with each customer based on location and then related to each customer's monthly meter read according to the date range of usage.

After the correct temperature information has been correlated to each meter read, a base load and temperature dependent load are calculated for each customer through regression analysis over the historical usage period. DNV GL states that it uses a "standard least-squares-fit on ordered pairs of usage and degree day" regression. The result is a customer specific base load that is weather independent, and a heat load that is multiplied by a weather variable, to create a custom regression equation.

Should insufficient data exist to adequately predict a customer's usage factors, then CMM will perform factor substitution. Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute load factor data for a customer which lacks sufficient information for independent analysis.

With all the structural shifts in historical data, and the significantly increased quantity of data utilized for regression, Intermountain has selected a five-year time series to develop the usage per customer equations for model rebuilds. The selected time series is aligned with the recommended time study from DNV.

The Company recognizes that there could be significant differences in the way its customers use natural gas throughout its geographically and economically diverse service territory. Being sensitive to areas that may require capital improvements to keep pace with demand growth, Intermountain separates customers by districts and then determined specific usages per customer for each.

4.2.3 Fixed Network

Over the past couple of years Intermountain has been expanding it's fixed network system. Intermountain' s fixed network will allow for real time data of customer demand/usage at the meter. The fixed network will be another resource to check peak day loading and usage per customer.

Intermountain started installing fixed network in 2021, currently Intermountain' s fixed network system covers 82% of ERT meters and the devices are still being added to the fixed network system.

In 2021 CMM data was compared to a small set (100 data points) of available fixed network loads resulting in a 12% difference between the two systems. In 2023 the comparison was made again with a much larger set (892 data points) of available fixed network loads on a cold weather day in early 2023. The most recent comparison shows a 2% difference between the fixed network data and the calculated CMM loads. The percent difference improvement between the 2021 and 2023 comparisons can be largely attributed to the availability of a larger fixed network data set from across the entire state versus a smaller set of data available for only one area. Overall, the fixed network data comparison agreed with CMM usage per customer loading based on the heating degree day providing confidence in CMM's usage per customer predictions.

4.2.4 Model Validation

To check the usage per customer, Intermountain validates the models for a specific temperature event. To validate the model, Intermountain will gather all pressures and flow data available on its system for a specific date and time and will then set the model to the temperature experienced to see how the model is performing. During model validation pressures and flows in the model are compared to actual pressure and flow data. Comparing the model results to actuals pressures and flows allow the Company to validate the model and have confidence that the usage per customer from CMM is accurate when compared to temperature and flow data in each geographic area.

Once a model is validated it is then ramped up to its peak degree day, based on 30 years of historical temperature data, to create a design day model. Intermountain's peak heating degree days by district are shown in Figure 41.

District	HDD	Avg Daily Temperature (^{o}F)
Boise	75	-10
Nampa	68	-3
New Plymouth & Payette	78	-13
Pocatello	82	-17
Idaho Falls	88	-23
Twin Falls	77	-12
Ketchum	82	-17

Figure 41: Peak Heating Degree Day

As can see from Figure 41, Intermountain operates in diverse regions that range from mountain to desert, which is why the models are broken down by district. Intermountain heating degree day calculations are based on customers turning on their heat when temperatures drop below 65 degrees Fahrenheit. The heating degree day is calculated by subtracting the average daily temperature from 65 degrees Fahrenheit.

4.2.5 Distribution System Planning Process

Intermountain spends significant time and resources on building and maintaining its design day models. Intermountain uses its design day models to review large customer requests, model renewable natural gas injection onto Intermountain's systems, design and size pipe and non-pipe facilities, long term planning, model growth predictions, identify system deficits, determine system reliability, generate emergency plans during large system outages and line breaks, optimize enhancement options and support cold weather action plans.

A system deficit is defined as a critical system that has reached or exceeded the capacity to serve customer demands. Critical system examples that are limiting capacity include pipeline diameter restrictions (bottlenecks), below minimum inlet pressure to a regulator station or high pressure system to meet a downstream operating pressure, not meeting a required customer delivery pressure, or a physical component that is limiting capacity like a regulator which has a rated flow capacity for the specific conditions that the regulator is operating under as published by the manufacturer.

As part of the IRP process, Intermountain completes a comprehensive review of the Company's distribution system models to ensure that the Company can maintain reliable service to customers during design day events. Intermountain also completes annual reviews of its distribution system models as part of the annual budgeting process and continually updates the five-year budget, as needed, based upon new information that impacts the five-year plan. If a deficit is predicted, the system is evaluated, and reinforcement options are reviewed, with an optimized reinforcement selected. The selected reinforcement will then be placed into the capital budget based on the timing needs of the predicted deficit.

The Engineering services department works closely with Field Operations coordinators, Energy Services representatives, Gas Supply, and district management to assure the system is safe and reliable. As towns develop, the need for pipeline expansions and reinforcements increase. The expansions are historically driven by new city developments or new housing plats. Before expansions and installation can be constructed to serve these new customers, engineering analysis is performed. As new groups of customers seek natural gas service, the models help engineers determine how best to serve them reliably.

4.2.6 Distribution System Enhancements

Once a deficit has been identified, Engineering will propose enhancement solutions to address the deficit. Each of Intermountain's systems are unique in pipeline dynamics and will be optimized using different enhancement solutions.
Distribution enhancements typically include:

- Pipeline reinforcement such as replacements
- Pipeline loops and/or back feeds
- Operating pressure increase
- Uprates
- Facility upgrades,
- Additional regulator station feeds or gate station supply
- Compressor stations
- Demand side management strategies

Pipeline looping is the most common method of increasing capacity in an existing distribution system. It involves installing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit flow capacities downstream of the constraint creating inadequate pressures downstream during periods of high demand. When the parallel line connects to the system, this alternative path allows natural gas flow to bypass the original constraint and bolsters downstream pressures. Looping can also involve connecting previously unconnected mains. The feasibility of looping a pipeline depends upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, environmentally sensitive areas, and steep or rocky terrain can increase the cost to a point where alternative solutions are more cost effective.

Pipeline replacement involves replacing existing pipe with a larger diameter pipe. The increased pipe diameter relative to surface area results in less friction, larger flow capacity, and therefore, a lower pressure drop. This option is usually pursued when a pipe is damaged or has integrity issues. If the existing pipe is otherwise in satisfactory condition, the pipeline looping option is typically optimal, as it continues to utilize existing pipe.

Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system instead of constructing more costly additional facilities. However, safety considerations and pipe regulations may prohibit the feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage, creating costly repairs, or prohibiting the proposed uprate altogether. A thorough facility review is conducted to ensure pipeline integrity before an uprate is conducted.

Pressure regulators or regulator stations reduce pipeline pressure at various stages in the distribution system. Regulation provides a specified and constant outlet pressure before natural gas continues its downstream travel to a city's distribution system, a customer's property, or a natural gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of pressure fluctuations upstream of the regulator. Regulators are at gate stations, district regulator stations, high pressure service sets, farm taps, and customer meters. Utilization and strategic positioning of new stations can be very helpful in increasing system reliability and capacity

Compressor stations present a capacity enhancing option for pipelines with significant natural gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline will boosts downstream pressure, which will increase the downstream capacity of the pipeline.

A second option is the installation of smaller compressors located close together or strategically placed along a pipeline. Multiple compressors accommodate a large flow range and use smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace, so that purchasing and installing these less expensive compressors over time allow a pipeline to serve growing customer demand into the future.

Compressors can be a cost-effective option to resolving system constraints; however, land constraints, regulatory and environmental approvals to install a station, along with engineering and construction time, can be significant deterrents. Adding compressor stations typically involves considerable capital expenditure and long-term operations and maintenance costs for the life of the facility.

4.2.7 Distribution System Enhancement Considerations

Each distribution system enhancement option is analyzed during the selection process with consideration to scope, cost, timing, system benefits, long term planning and feasibility. For any project over 1 million dollars there is a more robust analysis for the project and supporting documentation, and engineers work collaboratively with management and directors to examine pipeline alternatives to ensure all alternatives were considered.

4.2.8 Distribution System Enhancement Selection Guidelines

Engineers work collaboratively with the manager and directors to select the most favorable enhancement solution to address the deficit. Engineering uses the following criteria to select distribution system enhancements:

- Non pipe alternatives including:
  - Pressure Increases/Uprates if feasible
  - Compressor Stations if permitting (emission/zoning, etc.) is favorable and land is available and cost effective for project.

Pipe Options:

- The shortest segment(s) of pipe that addresses the deficit.
- The segment of pipe with the most favorable construction conditions that supports long term operations and maintenance activities.
- Route selection that minimizes environmental concerns, i.e. avoid water crossings, wetlands and environmentally sensitive areas.
- Route selection that minimizes impacts to the community, i.e. road closures or city road moratoriums.
- Route selection that provides opportunity to add additional customers.
- Total construction costs including restoration.

4.2.9 Capital Budget Process

Intermountain annually goes through the capital budget process to approve a five-year capital budget. Intermountain's annual budget process begins in June and will typically go through three to five revisions before it is accepted and approved in late November by the board of directors. Engineers support the capital budgeting process by submitting distribution system enhancement projects to the budget. Engineers will work collaboratively with managers and directors to prioritize projects in the budget based on predicted timing needs with the goal of minimizing risk to ensure that the Company can continue to provide safe and reliable service to Cascade's customers. Figure 42 provides a schematic representation of the distribution system selection process to the capital budget.

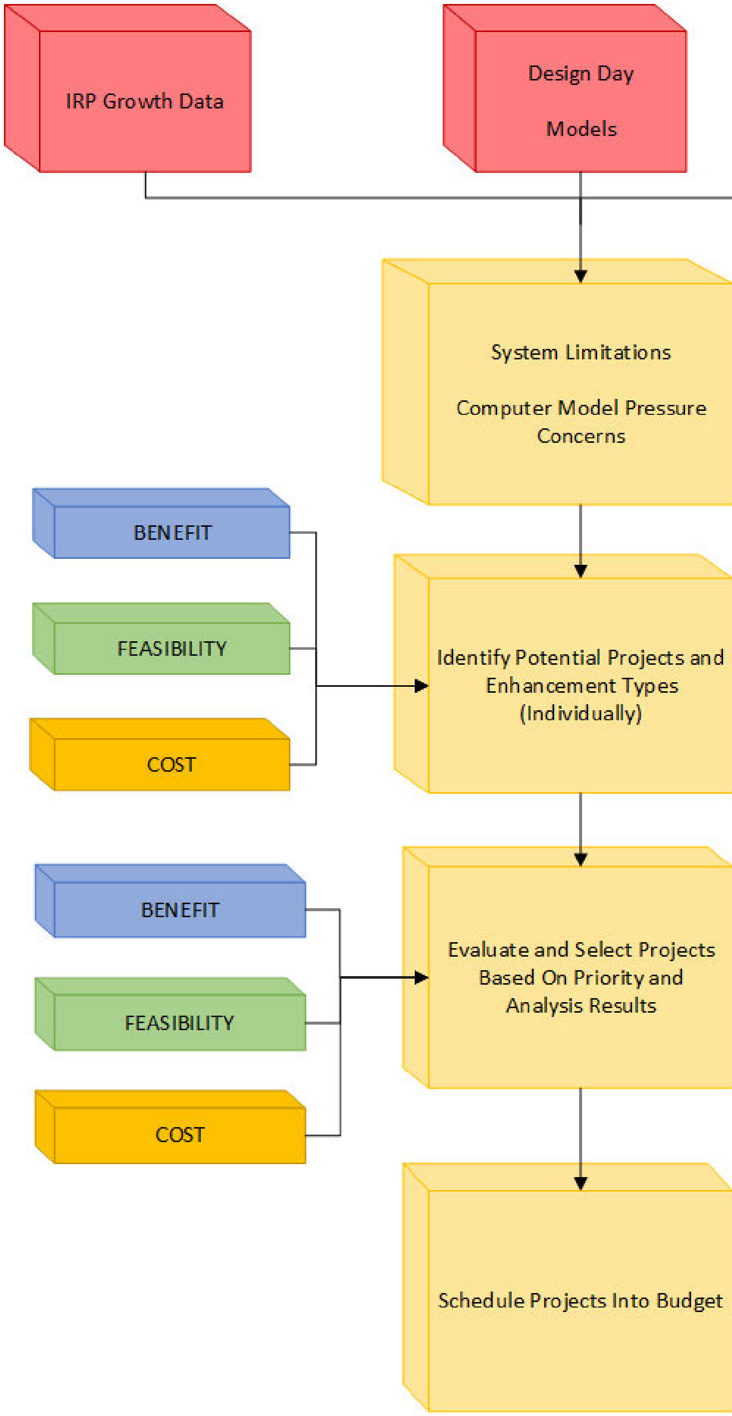

Figure 42: Distribution System Planning Process Flow

Intermountain's budget goes through several revisions and reviews at all levels in the organization to make sure that projects are properly justified and necessary. Every year as part of the capital budget process Intermountain projects are re-reviewed and revisions will be made to the projects, as needed, as new information becomes available as part of an iterative IRP process.

4.2.10 Conclusion

Intermountain's goal is to maintain a reliable natural gas distribution system in order to cost-effectively deliver natural gas to every core customer. This goal relies on Intermountain being proactive in addressing current and future system deficits. Intermountain's five year capital budgeting process allows time for projects to go through alternative analysis considerations and allows extended design and construction timelines required for large projects. The iterative process of Intermountain's IRP and capital budgeting process will allow Intermountain the ability to adapt to the changing dynamics of the natural gas industry. These dynamics include renewable natural gas coming onto Intermountain's systems, building code changes, energy efficiency programs and hydrogen blending.

4.3 Capacity Enhancements

4.3.1 Overview

Throughout previous sections of the IRP, it has been shown that projected growth throughout Intermountain gas' distribution systems could possibly create capacity deficits in the future. Using a gas modeling system that incorporates total customer loads, existing pipe and system configurations along with current distribution system capacities, each potential deficit has been defined with respect to timing and magnitude. If any such deficit occurs then the system capacity enhancements is evaluated, capacity enhancement alternatives are compared in the optimization model, and a final capacity enhancement is selected with consideration to cost, capacity increase and long-term planning. After the capacity enhancement has been selected it is budgeted into Intermountain gas's 5-year budget based on when the capacity enhancement needs to occur to avoid capacity deficiencies.

The five identified Areas of Interest (AOI) that were analyzed under specific design conditions are: Canyon County, State Street Lateral, Central Ada County, Sun Valley Lateral and the Idaho Falls Lateral. Each of these areas are unique in their customers served and their pipeline characteristics, and the optimization of each requires different enhancement solutions.

As part of the IRP capacity review for each AOI the following items are summarized below by AOI:

- AOI Summary/System Dynamics
- Capacity Limiter
- Capacity Enhancement Alternatives Considered
    - Details/Scope
    - Benefits
    - Additional Considerations
    - Cost
        - Direct Cost
        - Net Present Value Cost[1]
    - Capacity
- Table Summary of Capacity Enhancement Alternatives Considered
- Capacity Enhancement Selected
    - Reasoning
    - Timing
- 2023 IRP Updates (as applicable)

Included at the end of the AOI Summaries is a summary with Intermountain Gas's five-year planning and timing of all the capacity enhancement selected and corresponding capacity increases for the AOIs.

[1] See Exhibit 6 – NPV Analysis for information on the Company's net present value cost evaluation. To determine net present cost IGC pulled various O&M cost for the alternatives proposed based on actual O&M costs over the last three years and then calculated the three-year average cost. O&M cost details are shown in the tab with the O&M cost label.

4.3.2 Canyon County

AOI Summary/System Dynamics

The Canyon County area of interest consists of an interconnected system of high-pressure (HP) pipelines that serve communities from Star Road west to Highway 95. The system originally serving Nampa and Caldwell was continually extended west to additional towns and industrial customers. In 2013 the Canyon County system was connected to, and back fed from, a new pipeline installed to the town of Parma. This Parma Lateral 6-inch HP pipeline project provides a secondary feed to the Canyon County area. The next large system enhancements occurred in 2018, 2021 and 2024 with the 12-inch Ustick Phases 1-3 pipeline projects installed on the east side of Caldwell, which was required to remove pipeline flow restrictions through a bottleneck area.

Capacity Limiter

Due to the significant amount of capital investment in Canyon County over the last couple of years no reinforcements are needed to meet 2030 growth predictions.

4.3.3 Central Ada County

AOI Summary/System Dynamics

Central Ada County AOI consists of high pressure and distribution pressure systems in an area of Ada County that has historically experienced high levels of growth and development. The system currently has high pressure supplied from Chinden Boulevard on the north side of the defined area and high pressure supplied from Victory Road on the south side of the defined area. Initially the continued growth demands between these two separate systems taxed the Chinden high pressure pipeline and the branch lines supplied from Chinden. In 2016 an 8-inch high pressure pipeline was installed on Cloverdale Road connected the Victory system to a branch of the Chinden system, which alleviated the excess demand supplied from the Chinden pipeline. The connection between the two systems was an initial step in the long-term plan, and while the project successfully increased capacity in the area, the two systems are operating at different pressures and are currently disconnected through system valving. In 2023 the South Boise Loop project was completed which further reinforced the Boise high pressure system from the Kuna Gate Upgrade to Cloverdale and Victory to supply an additional pressure source to the Victory high pressure system served by the Meridian Gate to increase capacity to Boise and connect the Chinden high pressure system to the South Boise Loop.

Capacity Limiter

Due to the significant amount of capital investment in the Ada County AOI with the 12-inch South Boise Loop (12-inch Cloverdale high pressure) and Kuna Gate upgrade completed in 2023 no reinforcements are needed to meet 2030 growth predictions.

4.3.4 State Street Lateral

AOI Summary/System Dynamics

The State Street Lateral is a sixteen mile stretch of high pressure, large diameter main that begins in Middleton and runs east along State Street serving the towns of Star, north Meridian, Eagle and into northern Boise. The lateral is fed directly from a gate station along with a back feed from another high-pressure pipeline from the south. Much of the pipeline is closely surrounded by residential and commercial structures that create a difficult situation for construction and/or large land acquisition, thus making a compressor station or Liquified Natural Gas (LNG) equipment less favorable.

Capacity Limiter

Due to explosive growth in Boise and north towards Eagle this AOI requires a capacity enhancement by 2026 to meet IRP growth. The current capacity limiter to this AOI is a 12-inch HP bottleneck on State Street and a 4-inch HP bottleneck on Linder Rd as shown in yellow in Figure 43.

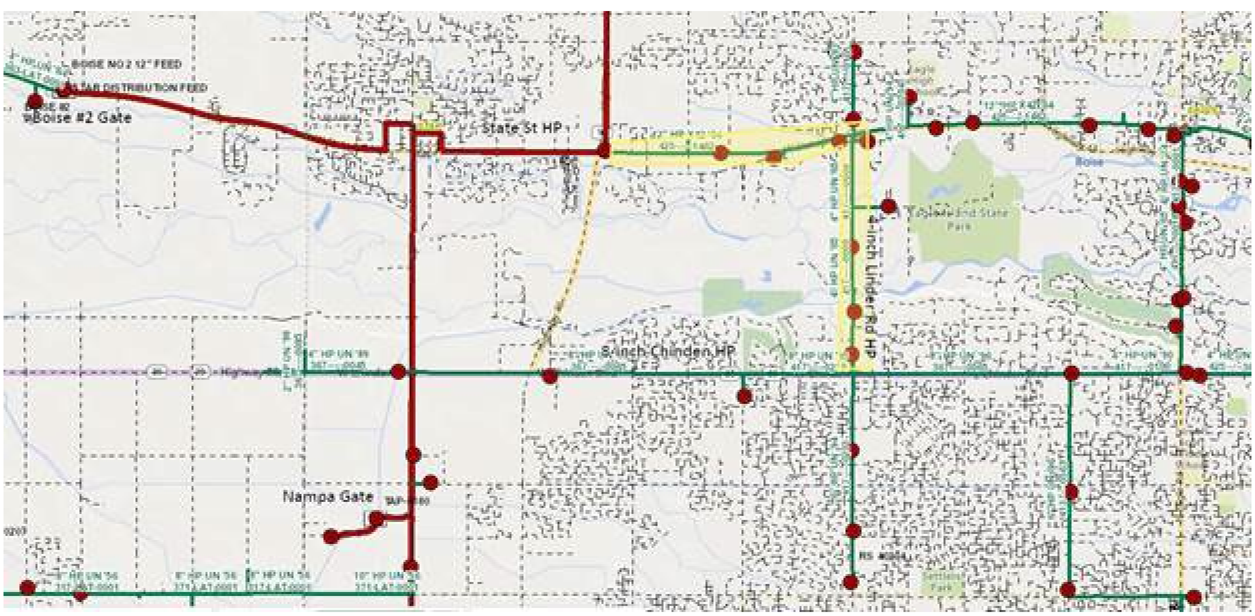

Figure 43: State Street Lateral Capacity Limiter

Capacity Enhancement Alternatives

Two alternatives were considered in the 2021 IRP. Those alternatives included the State Street Phase II uprate and replacing the 12-inch on State Street and 4-inch HP on Linder Road. The State Street Phase II uprate was chosen in 2021 as the lowest cost alternative.

Capacity Enhancement Selected

The State Street Phase II uprate consists of pressure testing and then uprating 12,000 feet of 12-inch HP on State Street and 10,500 feet of 4-inch HP on Linder Road to certify a 500 psig MAOP. In addition to the uprate work a new regulator station would be installed and several existing regulator stations would be retired along with a PE trunk line to support the uprate activities. The State Street Phase II uprate is shown in Figure 44.

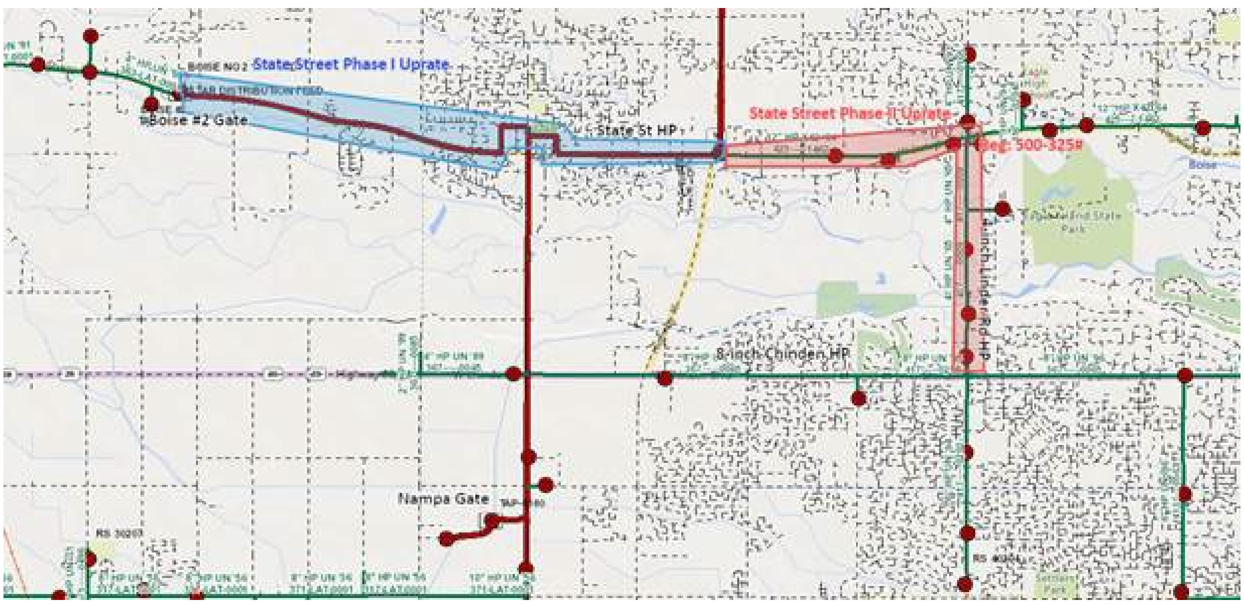

Figure 44: State Street Lateral Phase II Uprate

This enhancement brings lateral capacity to 950,000 therms per day which will meet predicted growth through 2030. The State Street Phase II Uprate is budgeted for 2026 and is estimated to cost $1,200,000 direct and $1,085,641 in net present value cost.

4.3.5 Sun Valley Lateral

AOI Summary/System Dynamics

The Sun Valley Lateral (SVL) is a 68-mile-long, 8-inch high pressure pipeline that has almost its entire demand at the far end of the lateral away from the source of gas. Obtaining land near this customer load center is either expensive or simply unobtainable. In addition, long sections of the pipeline are installed in rock that impose construction obstacles for pipeline looping and expensive construction costs to trench in rock. Throughout the years Intermountain has uprated and upgraded this existing lateral, installed the Jerome Compressor Station towards the south end of the lateral and most recently installed the Shoshone Compressor Station to further boosts pressure and required flows down the lateral to meet the end of line demands on the lateral. The Shoshone Compressor station was completed in 2023 and is located at mile post 32 which is approximately 23 miles north of the Jerome Compressor Station.

Capacity Limiter

Due to the significant amount of capital investment with the Shoshone compressor station the Sun Valley AOI requires no reinforcements to meet 2030 growth predictions.

4.3.6 Idaho Falls Lateral

AOI Summary/System Dynamics

The Idaho Falls Lateral (IFL) began as a 52 mile, 10-inch pipeline that originated just south of Pocatello and ended at the city of Idaho Falls. The IFL was later expanded farther to the north extending an additional 52 miles with 8-inch pipe to serve the growing towns of Rigby, Lewisville, Rexburg, Sugar City and Saint Anthony. As demand has continually increased along the IFL, Intermountain Gas has been completing capacity enhancements for the past 25 years; including compression (now retired), a satellite LNG facility, 40 miles of 12-inch pipeline loop, and 50.5 miles of 16-inch pipeline loops.

Capacity Limiter 2026

Due to continued growth, the IFL AOI requires capacity enhancements by 2026 and 2030 to meet IRP growth predictions. The current capacity limiter for this AOI is the end of line pressure on the lateral to St. Anthony's as shown in yellow in Figure 45.

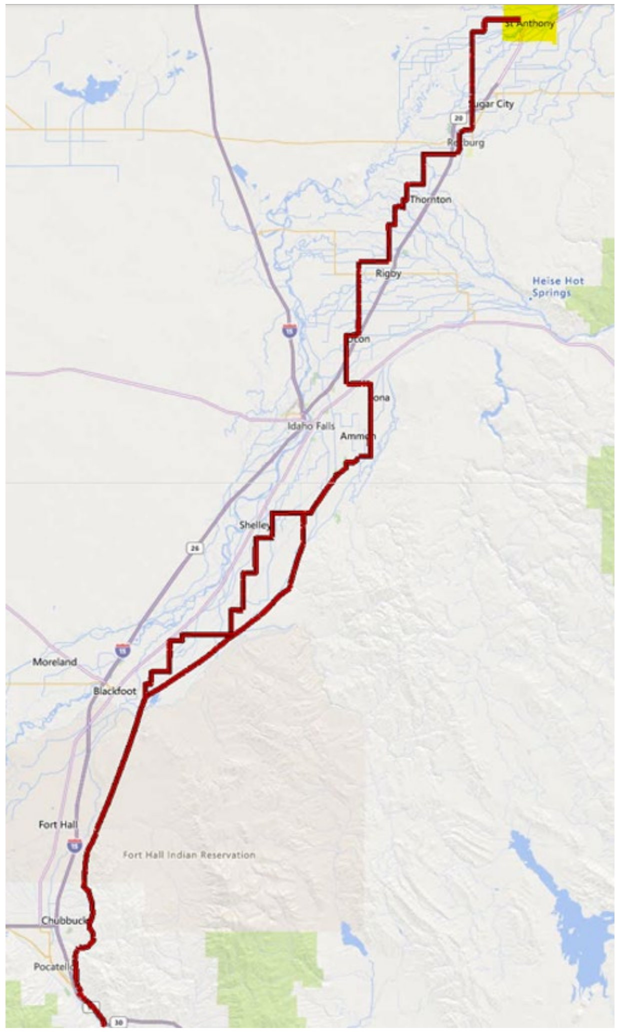

Figure 45: Idaho Falls Lateral Capacity Limiter

Capacity Enhancement Alternatives 2026

Two alternatives were considered in the 2021 and 2023 IRPs to address the 2026 predicted deficit. Those alternatives included a Blackfoot Compressor Station (now called the Wapello Compressor Station) or a Phase VI 16-inch Pipeline with an additional LNG Tank in Rexburg. The Wapello Compressor station was chosen in both previous IRPs as the lowest cost option per therm/day of capacity gained to the lateral.

Capacity Enhancement Selected 2026

The Wapello Compressor enhancement consists of installing a compressor station near Blackfoot, ID on the Idaho Falls lateral as shown in Figure 46.

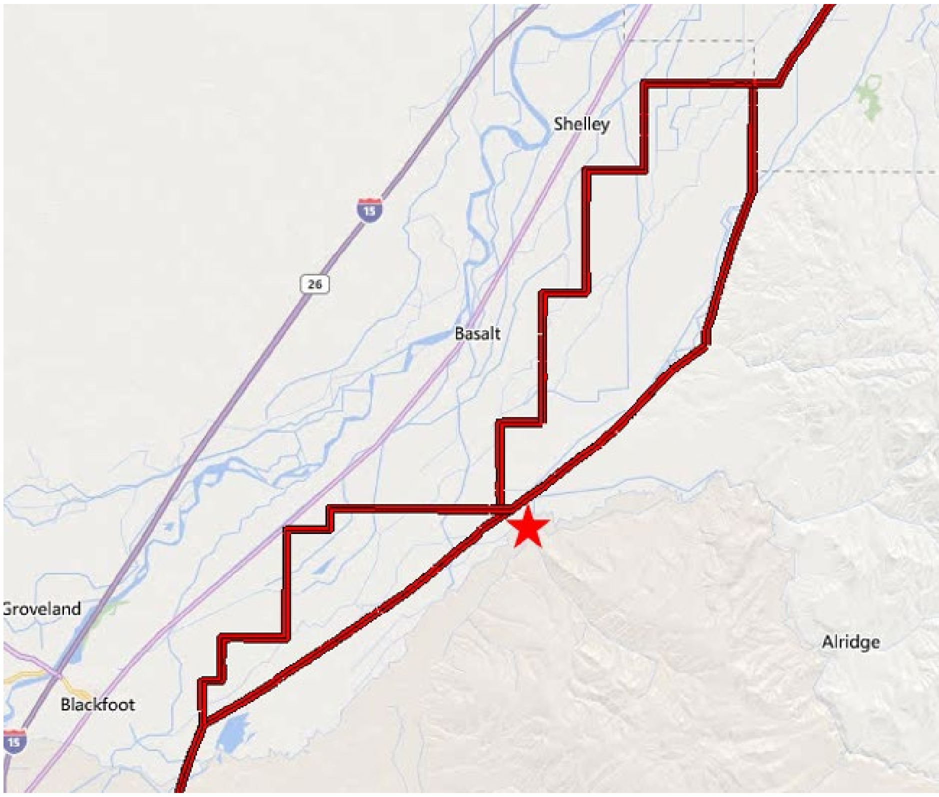

Figure 46: Idaho Falls Lateral Blackfoot Compressor

The selected enhancement brings lateral capacity to 1,037,000 therms per day which would meet predicted growth through 2029. The compressor has been purchased, and site construction started in 2025 with planned completion in 2026. Costs are estimated to be $32,520,992 in direct costs and $34,783,486 in net present value cost.[2]

Capacity Limiter 2030

Once the Wapello compressor station near Blackfoot is operational, the Idaho Falls Lateral (IFL) will see increased capacity and pressure downstream of the station. However, modeled growth predicts that the compressor station's inlet pressures (suction pressures) will drop below operating parameters in 2030. These lower inlet pressures to the compressor station will reduce the available gas capacity through the station as it will be operating outside of its design parameters. The limiting capacity factor on the IFL then becomes the inlet/suction pressures to the Blackfoot compressor station in 2030.

[2] inflated 3.99% each year over the 20-year life of the analysis and a real discount rate of 2.68% was used in the analysis based on the Company's avoided cost model presented in Exhibit 5 – Avoided Cost Model.

Capacity Enhancement Alternatives 2030

Two alternatives were considered to resolve the pressure deficit to the inlet/suction side pressure to the Wapello compressor. A separate compressor could be installed further upstream on the lateral to boost pressures to the Wapello compressor or a pipeline loop upstream of the compressor could be installed to bring available pressure and capacity to the Wapello compressor.

The first alternative considered was a second compressor on the Idaho Falls Lateral which would be similar in design and scope to the Wapello compressor with similar costs adjusted for inflation. The compressor would need to be installed approximately 20 miles south of the existing compressor near Fort Hall, ID as shown in Figure 47.

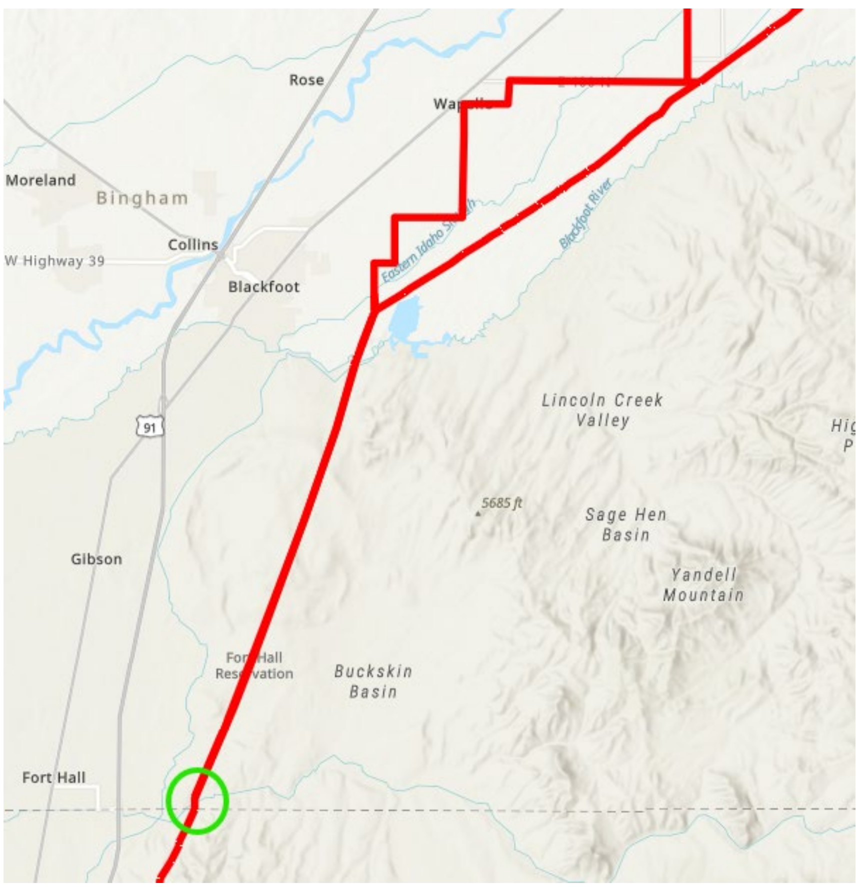

Figure 47: Idaho Falls Lateral Proposed Compressor Location

When comparing a compressor to a pipeline, the compressor station will require higher annual maintenance and operations costs. Examples of these costs would be a compressor operator, oil to run the compressor, and all the wear parts that will need to be replaced over time. These O&M costs are included in the NPV cost. A second compressor station would bring lateral capacity to 1,122,000 therms per day at a cost of $46,732,645 in 2030, which has a net present value cost of $48,359,768.

The second alternative is an 8.5 mile long 16-inch pipeline loop immediately upstream of the Wapello Compressor, as shown in Figure 48.

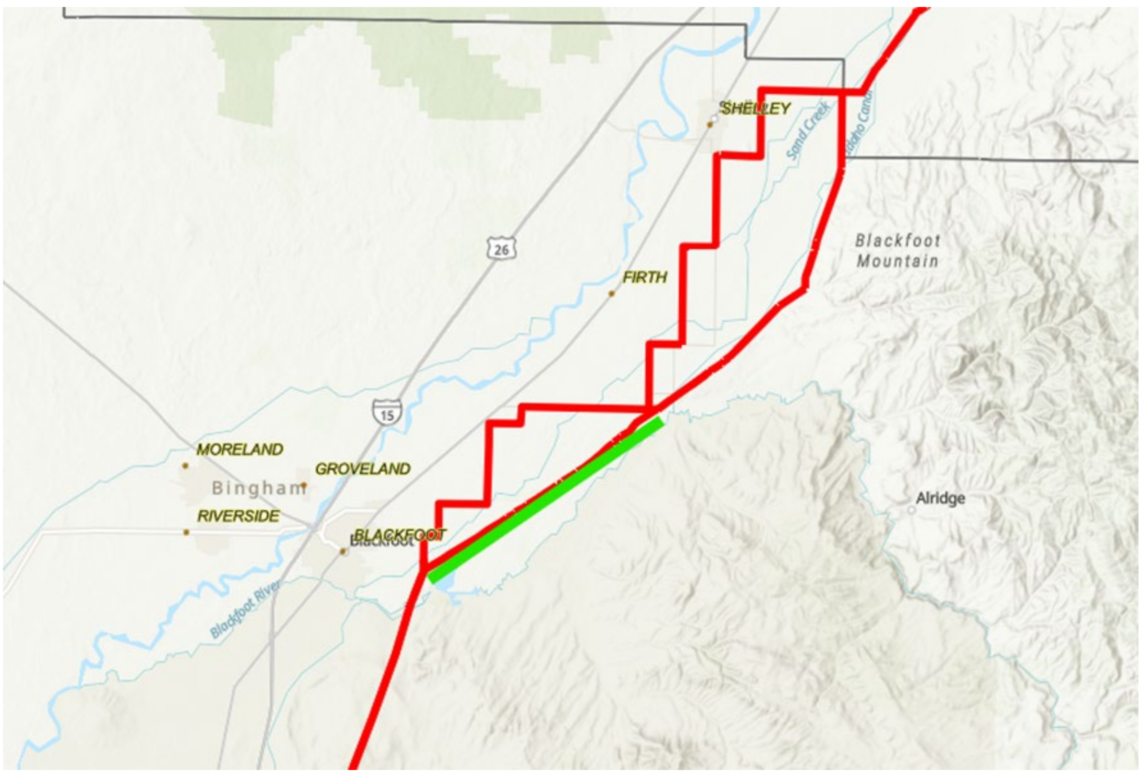

Figure 48: Idaho Falls Lateral Compressor Suction Proposed Pipeline

This pipeline would bring already available pressure and capacity directly to the suction side of the new Wapello Compressor. This pipeline loop will bring the capacity of the lateral to 1,122,000 therms per day meeting growth predictions beyond 2030. This alternative will allow the Wapello compressor to operate within its operational parameters and provide adequate capacity along the IFL, while avoiding ongoing maintenance and operation costs associated with an additional compressor station. Costs are estimated to be $42,000,000 in direct costs and $40,240,248 in net present value cost for this alternative.

Capacity Enhancement Selected 2030

Intermountain is considering alternative 2 for the 8 miles of 16-inch pipeline due to lowest cost alternative when comparing direct and net present value. As discussed above, the operations and maintenance costs associated with having a second compressor station on the IFL make the pipeline loop more favorable to meet growth predictions and eliminates the possibility of having a second compressor station go down during a peak event which could impact the Wapello compressor station and total IFL capacity.

4.3.7 Other AOI

AOI Summary/System Dynamics

The other AOI is defined as areas outside of IGC's established AOI's. For this IRP IGC has two gate upgrades that are needed to support core growth and a significant distribution reinforcement. The two gate upgrades are the State Penn (a.k.a. Boise #3) Gate Upgrade and the New Plymouth Gate Upgrade. The distribution reinforcement is in Caldwell and will consist of installing approximately 5 miles of 6-inch plastic pipe on HWY 20 from Prescott Lane (near Can Ada) to Middleton Road in collaboration with an Idaho Department of Transportation project to widen Highway 20 to five lanes with several large developments and grocery stores and strip malls planned for the area. Intermountain will be able to loop its distribution systems and bring gas to an area that did not have gas with reduced construction costs since the gas line will be installed in the expanded right of way with minimal restoration and traffic control costs.

Capacity Limiter

Once a gate approaches the physical capacity, its capacity will be limited by undersized piping and components that will need to be upgraded to increase the capacity of the gate to allow the gate to be able to meet core growth demand requirements.

Installing infrastructure to a developing area will help offset future deficits since the infrastructure will be in place and sized for the development expected.

Capacity Enhancement Alternatives

No alternatives to consider for gate upgrades in the small town of New Plymouth. For larger towns a secondary gate or back feed could be considered as a redundant feed to the town in comparison to upgrading the existing gate. No alternatives to consider for the State Penn gate upgrade since only the gate needs to be updated, the surrounding Boise Loop Transmission infrastructure meets the five year growth demands and does not require reinforcement. Adding an additional gate would be higher cost since it would also require a pipeline to effectively tie into the existing high pressure system which would have additional cost to secure land for a new gate. The higher cost of the pipeline and land considerations justify upgrading the existing gate.

No comparable alternatives to consider for a core growth project to loop the distribution system in an expanding area that needs gas infrastructure with the opportunity for reduced construction and traffic control cost due to the IDT widening project.

Capacity Enhancement Selected

The New Plymouth Gate upgrade needs to be completed by 2027 to meet core growth needs to avoid a capacity deficit. The New Plymouth Gate Upgrade is estimated to cost $3,640,000 in direct and $3,477,264 in net present value cost. The State Penn Gate upgrade needs to be completed by 2027 to meet core growth needs to avoid a capacity deficit. The capacity gained for these gate upgrades will depend on the amount contracted in the facility agreement with Williams Northwest Pipeline. The State Penn Gate Upgrade is estimated to cost $2,980,000 in direct cost and $2,846,771 in net present value cost. Since the upgraded gate has the same operations and maintenance costs as the current gate there is not much difference in direct and net present value since there is no operations and maintenance cost change.

The Caldwell reinforcement will be completed in 2027 based on IDT's construction schedule. The capacity gained for Caldwell reinforcement is 18,720 therms/day. The Caldwell reinforcement is estimated at $3,650,000 in direct cost and $3,572,905 in net present value cost.

4.3.8 Five-Year Planning and Timing of Capacity Enhancements

To summarize the AOI capacity enhancements below in Table 10 is a capacity summary showing the capacity enhancement selected from the Company's alternative analysis and corresponding capacity increases.

AOI →	Ada County		State Street Lateral		Canyon County		Sun Valley Lateral		Idaho Falls Lateral	
Year ↓	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected
2026	870,000	None	950,000	State Street Uprate	1,390,000	None	247,500	None	1,037,000	Wapello Compressor Station
2027	870,000	None	950,000	None	1,390,000	None	247,500	None	1,037,000	None
2028	870,000	None	950,000	None	1,390,000	None	247,500	None	1,037,000	None
2029	870,000	None	950,000	None	1,390,000	None	247,500	None	1,037,000	None
2030	870,000	None	950,000	None	1,390,000	None	247,500	None	1,122,000	IFL Compressor Suction Reinforcement

Table 10: AOI Capacity Summary and Timing

As can be seen from table 10, five years is enough time to identify, budget, plan, design and construct projects to address capacity deficits. As part of the IRP process, Intermountain will check the five-year plan deficits and alternatives considered for capacity enhancement in the next IRP filing in 2027 and adjust the Company's plans as needed to ensure reliable service to customers based on the next round of IRP growth predictions. This will be an ongoing iterative process as part of Intermountain's two-year IRP filing.

4.4 Load Demand Curves

4.4.1 Overview

The demand forecasting process brings together several key components to create a comprehensive view of future natural gas needs. This includes customer growth projections, weather modeling, usage patterns, and demand-side management strategies. Together, these elements form the foundation of the Load Demand Curve (LDC), which is central to the Integrated Resource Plan (IRP). The customer forecast extends through Planning Year (PY) 2030 and provides daily projections for the entire Company. It also includes detailed forecasts for five specific Areas of Interest (AOIs) within the distribution system. Each AOI forecast was developed under three growth scenarios, low, base case, and high, to account for a range of possible futures.

To model how weather impacts demand, the Company developed a design weather curve that includes the coldest expected conditions across the service areas. This curve helps estimate daily usage for residential and commercial customers under peak weather conditions. By combining this with the customer forecast, Intermountain generates a daily core market load projection through 2030, both Company-wide and for each AOI. Intermountain also modeled demand under normal weather conditions for comparison. In addition to residential and commercial customers, the Company's forecast includes large volume users, those with contract demand that affect both interstate and local distribution capacity. These figures are integrated with the core market data to produce a total daily forecast for gas supply and capacity needs, again broken down by AOI. It's worth noting that the Company's core customers include residential, commercial, and industrial customers.

The Company then evaluated peak day usage under each growth scenario against current capacity to identify potential delivery shortfalls. This analysis assists in understanding when and where constraints might occur, both at the Total Company level and within individual AOIs. Once the demand forecasts are finalized, the data is then input into PLEXOS®, the optimization software used by the Company, to support IRP modeling. The LDC captures all relevant factors influencing future demand and serves as the primary input for long-term planning.

It's important to emphasize that the Load Demand Curves reflect both existing resources and those confirmed to be available during the forecast period. Their purpose is to highlight potential capacity constraints and guide strategic planning. Any identified deficits and proposed solutions will be addressed in the Planning Results section of this report.

4.4.2 Customer Growth Summary Observations – Design Weather – All Scenarios

Canyon County Area

Under the low growth scenario, the customer forecast for the Canyon County Area projects an increase of 11,247 customers, representing a compound annual growth rate (CAGR) of 2.63%. The base case scenario anticipates an increase of 14,065 customers (3.24% CAGR), while the high growth scenario projects an increase of 16,970 customers (3.85% CAGR).

Central Ada County

The low growth scenario for Central Ada County forecasts an increase of 5,148 customers, with a CAGR of 1.34%. The base case projects growth of 7,070 customers (1.82% CAGR), and the high growth scenario estimates an increase of 9,039 customers (2.30% CAGR).

Sun Valley Lateral

Customer growth in the Sun Valley Lateral under the low growth scenario is projected at 823 customers (1.00% CAGR). The base case scenario forecasts an increase of 1,127 customers (1.36% CAGR), while the high growth scenario anticipates 1,438 additional customers (1.72% CAGR).

Idaho Falls Lateral

The Idaho Falls Lateral low growth scenario projects an increase of 5,882 customers, reflecting a CAGR of 1.48%. The base case scenario forecasts growth of 8,641 customers (2.14% CAGR), and the high growth scenario projects an increase of 11,509 customers (2.80% CAGR).

State Street Lateral

For the State Street Lateral, the low growth scenario forecasts an increase of 5,132 customers (1.34% CAGR). The base case scenario projects growth of 7,043 customers (1.82% CAGR), while the high growth scenario anticipates an increase of 9,000 customers (2.29% CAGR).

Total Company

Across the entire service territory, the low growth scenario projects an increase of 37,453 customers, representing a CAGR of 1.42%. The base case scenario forecasts growth of 52,361 customers (1.96% CAGR), and the high growth scenario anticipates an increase of 67,712 customers (2.50% CAGR). These totals include all Areas of Interest (AOIs) as well as customers located outside of the AOIs.

The use of Load Demand Curve (LDC) analyses enables the Company to anticipate changes in future demand and plan accordingly for the utilization of existing resources and the timely acquisition of additional capacity. This approach supports long-term reliability and ensures that infrastructure planning aligns with projected customer growth across all scenarios.

4.4.3 Core Distribution Usage Summary – Design and Normal Weather – All Scenarios

Canyon County Area

Canyon County Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	9,126,430	9,382,173	9,603,624	9,864,594	10,021,419	10,225,076
Base	9,128,807	9,431,977	9,714,578	10,040,639	10,263,525	10,529,881
High	9,131,170	9,481,762	9,826,252	10,218,781	10,510,634	10,857,701

Table 11: Canyon County Design Weather Annual Usage

Canyon County Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	7,203,482	7,402,757	7,575,229	7,779,100	7,902,431	8,062,755
Base	7,205,250	7,441,584	7,661,685	7,916,252	8,091,081	8,305,928
High	7,207,000	7,480,358	7,748,708	8,055,034	8,283,614	8,555,655

Table 12: Canyon County Normal Weather Annual Usage

Central Ada County

Central Ada Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	8,624,132	8,752,153	8,827,092	8,956,541	9,026,646	9,134,273
Base	8,625,808	8,787,311	8,904,219	9,077,385	9,191,614	9,345,101
High	8,627,479	8,822,437	8,981,745	9,199,433	9,359,063	9,560,341

Table 13: Central Ada Design Weather Annual Usage

Central Ada Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	6,804,917	6,904,541	6,963,206	7,063,274	7,118,983	7,202,943
Base	6,806,154	6,931,893	7,023,229	7,157,303	7,247,373	7,367,029
High	6,807,391	6,959,226	7,083,561	7,252,275	7,377,697	7,534,545

Table 14: Central Ada Normal Weather Annual Usage

Sun Valley Lateral

Sun Valley Lateral Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	2,662,285	2,683,948	2,703,638	2,737,314	2,742,888	2,762,692
Base	2,662,860	2,694,135	2,725,728	2,771,424	2,788,868	2,820,997
High	2,663,470	2,704,337	2,747,700	2,805,872	2,835,715	2,880,627

Table 15: Sun Valley Lateral Design Weather Annual Usage

Sun Valley Lateral Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	2,268,361	2,286,586	2,303,129	2,330,316	2,336,105	2,352,741
Base	2,268,821	2,295,196	2,321,849	2,359,236	2,375,125	2,402,223
High	2,269,298	2,303,815	2,340,471	2,388,436	2,414,871	2,452,831

Table 16: Sun Valley Lateral Normal Weather Annual Usage

Idaho Falls Lateral

Idaho Falls Lateral Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	9,259,159	9,379,303	9,490,022	9,648,006	9,707,113	9,811,125
Base	9,262,382	9,437,748	9,617,474	9,847,674	9,979,185	10,158,768
High	9,265,643	9,496,037	9,745,908	10,050,920	10,258,645	10,519,037

Table 17: Idaho Falls Lateral Design Weather Annual Usage

Idaho Falls Lateral Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	8,145,753	8,249,900	8,346,202	8,479,886	8,534,958	8,625,383
Base	8,148,652	8,301,066	8,457,454	8,653,957	8,772,206	8,928,473
High	8,151,578	8,352,049	8,569,583	8,831,177	9,015,898	9,242,549

Table 18: Idaho Falls Lateral Normal Weather Annual Usage

N. of State Street Lateral

N. of State Street Lateral Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	8,724,715	8,855,421	8,933,661	9,066,966	9,139,106	9,249,526
Base	8,726,430	8,891,197	9,012,117	9,189,883	9,306,886	9,463,920
High	8,728,141	8,926,937	9,090,984	9,314,021	9,477,171	9,682,781

Table 19: N. of State Street Lateral Design Weather Annual Usage

N. of State Street Lateral Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	6,853,813	6,955,629	7,016,960	7,120,011	7,177,515	7,263,746
Base	6,855,083	6,983,490	7,078,076	7,215,742	7,308,212	7,430,757
High	6,856,354	7,011,330	7,139,510	7,312,429	7,440,864	7,601,243

Table 20: N. of State Street Lateral Normal Weather Annual Usage

Total Company

Total Company Design Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	61,337,023	62,202,500	62,842,356	63,815,062	64,235,964	64,942,077
Base	61,352,608	62,508,305	63,512,390	64,864,574	65,666,460	66,761,430
High	61,368,264	62,813,946	64,186,553	65,928,323	67,126,374	68,646,400

Table 21: Total Company Design Weather Annual Usage

Total Company Normal Weather - Annual Core Market Distribution Usage (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	50,342,560	51,042,762	51,560,865	52,340,833	52,689,865	53,262,400
Base	50,354,834	51,291,129	52,104,753	53,192,410	53,850,764	54,744,689
High	50,367,142	51,539,274	52,651,980	54,055,590	55,035,525	56,268,357

Table 22: Total Company Normal Weather Annual Usage

4.4.4 Projected Capacity Deficits – Design Weather – All Scenarios

Over the planning horizon, peak day load on Intermountain's system is projected to grow at a compound annual growth rate (CAGR) of 1.12% under the low growth scenario, 1.46% in the base case, and 1.86% under the high growth scenario. The following section outlines anticipated capacity deficits across each Area of Interest (AOI) and for the company as a whole.

Canyon County Area LDC Study

Forecasted peak day usage for the Canyon County Area remains within the maximum physical deliverability of 139,000 dekatherms (Dth) across all customer growth scenarios. No peak day deficits are projected, indicating that available capacity is sufficient to meet anticipated demand throughout the forecast period.

Canyon County Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	0	0	0	0
Base	0	0	0	0	0	0
High	0	0	0	0	0	0

Table 23: Canyon County Design Day Deficit

Central Ada County LDC Study

Forecasted peak day usage for Central Ada County remains within the maximum physical deliverability of 87,000 dekatherms (Dth) across all customer growth scenarios. No peak day deficits are projected, indicating that available infrastructure is sufficient to meet anticipated demand throughout the forecast horizon.

Central Ada Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	0	0	0	0
Base	0	0	0	0	0	0
High	0	0	0	0	0	0

Table 24: Central Ada Design Day Deficit

Sun Valley Lateral LDC Study

Forecasted peak day usage on the Sun Valley Lateral remains within the maximum physical deliverability of 24,750 dekatherms (Dth) under all customer growth scenarios. As a result, no peak day deficits are projected for this lateral, indicating sufficient capacity to meet anticipated demand across the forecast period.

Sun Valley Lateral Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	0	0	0	0
Base	0	0	0	0	0	0
High	0	0	0	0	0	0

Table 25: Sun Valley Lateral Design Day Deficit

Idaho Falls Lateral LDC Study

When forecasted peak day usage in the Idaho Falls Lateral is compared to the maximum physical deliverability of 103,700 dekatherms (Dth), no peak day deficits are projected under any of the customer growth scenarios. This outcome is attributed to the planned upgrade of the Wapello Compressor Station, which is expected to be operational in 2026. The enhancement ensures sufficient capacity to meet anticipated demand across all modeled scenarios.

Idaho Falls Lateral Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	0	0	0	0
Base	0	0	0	0	0	0
High	0	0	0	0	0	0

Table 26: Idaho Falls Lateral Design Day Deficit

N. of State Street Lateral LDC Study

Forecasted peak day usage for the State Street Lateral remains within the maximum physical deliverability of 95,000 dekatherms (Dth) across all scenarios due to planned upgrades. These planned infrastructure upgrades for this AOI are outlined in the Capacity Enhancements section.

N. of State Street Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	0	0	0	0
Base	0	0	0	0	0	0
High	0	0	0	0	0	0

Table 27: N. of State Street Design Day Deficit

Total Company LDC Study

The Total Company perspective reflects the volume of gas that can be delivered to Intermountain through available interstate resources, rather than the capacity of individual laterals or Areas of Interest. Total system deliveries must be sufficient to meet the combined demand—or available distribution capacity, where applicable—across all Areas of Interest. Projected peak day deficits are summarized in the following table, with mitigation strategies discussed in the Upstream Modeling Results section of the Planning Results.

Total Company Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2025	2026	2027	2028	2029	2030
Low	0	0	5,462	11,404	17,858	24,175
Base	0	2,258	11,194	20,466	30,351	40,167
High	0	4,758	16,962	29,642	43,090	56,640

Table 28: Total Company Design Day Deficit

4.4.5 2023 IRP vs. 2025 IRP Common Year Comparisons

This section provides a comparison between the Total Company and each AOI across the three common years included in both the 2023 and 2025 IRP filings. Variations between the two filings may be attributed to several factors, including refinements in modeling techniques and the incorporation of newly available data used to enhance model accuracy and reliability.

Total Company Design Weather Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE
TOTAL COMPANY PEAK DAY USAGE
DESIGN WEATHER – BASE CASE (Dth)

	Core Market	Firm CD[1]	Total
2026	529,083	173,444	702,526
2027	538,019	173,744	711,762
2028	547,271	174,484	721,754

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 29: 2025 IRP Total Company Design Day Peak Usage

2023 IRP LOAD DEMAND CURVE
TOTAL COMPANY PEAK DAY USAGE
DESIGN WEATHER – BASE CASE (Dth)

	Core Market	Firm CD[1]	Total
2026	515,575	151,064	666,639
2027	526,915	151,704	678,619
2028	538,255	151,774	690,029

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 30: 2023 IRP Total Company Design Day Peak Usage

2025 IRP LOAD DEMAND CURVE TOTAL COMPANY PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP			
	Core Market	Firm CD[1]	Total
2026	13,508	22,380	35,887
2027	11,104	22,040	33,143
2028	9,016	22,710	31,725

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 31: 2023 IRP vs. 2025 IRP Total Company Design Day Peak Usage

Total Company Peak Day Deliverability Comparison

2025 IRP PEAK DAY FIRM STORAGE DELIVERABILITY (Dth)			
Maximum Daily Storage Withdrawals:	2026	2027	2028
Nampa LNG	50,000	50,000	50,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	235,512	235,512	235,512
Maximum Deliverability (NWP)	293,893	293,893	293,893
Total Peak Day Deliverability	529,405	529,405	529,405

Table 32: 2025 IRP Total Company Storage Deliverability

2023 IRP PEAK DAY FIRM STORAGE DELIVERABILITY (Dth)			
Maximum Daily Storage Withdrawals:	**2026**	**2027**	**2028**
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	290,893	290,893	290,893
Total Peak Day Deliverability	536,405	536,405	536,405

Table 33: 2023 IRP Total Company Storage Deliverability

2025 IRP PEAK DAY FIRM STORAGE DELIVERY CAPABILITY (Dth) Over/(Under) 2023 IRP			
Maximum Daily Storage Withdrawals:	**2026**	**2027**	**2028**
Nampa LNG	(10,000)	(10,000)	(10,000)
Plymouth LS	0	0	0
Jackson Prairie SGS	0	0	0
Total Storage	(10,000)	(10,000)	(10,000)
Maximum Deliverability (NWP)	3,000	3,000	3,000
Total Peak Day Deliverability	(7,000)	(7,000)	(7,000)

Table 34: 2023 IRP vs. 2025 IRP Total Company Storage Deliverability

Canyon County Area Design Weather/ Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE CANYON COUNTY MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	139,000	83,935	25,160	109,095
2027	139,000	86,567	25,360	111,927
2028	139,000	89,107	25,380	114,487

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 35: 2025 IRP Canyon County Design Weather and Physical Deliverability

2023 IRP LOAD DEMAND CURVE CANYON COUNTY MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	139,000	85,370	25,110	110,480
2027	139,000	88,270	25,110	113,380
2028	139,000	91,171	25,130	116,301

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 36: 2023 IRP Canyon County Design Weather and Physical Deliverability

2025 IRP LOAD DEMAND CURVE CANYON COUNTY MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	-	(1,435)	50	(1,385)
2027	-	(1,703)	250	(1,453)
2028	-	(2,064)	250	(1,814)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 37: 2023 IRP vs. 2025 IRP Canyon County Design Weather and Physical Deliverability

Central Ada County Design Weather/ Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE CENTRAL ADA MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	87,000	78,347	850	79,197
2027	87,000	79,417	850	80,267
2028	87,000	80,622	850	81,472

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 38: 2025 IRP Central Ada Design Weather and Physical Deliverability

2023 IRP LOAD DEMAND CURVE CENTRAL ADA MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	87,000	76,914	850	77,764
2027	87,000	78,501	850	79,351
2028	87,000	80,088	850	80,938

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 39: 2023 IRP Central Ada Design Weather and Physical Deliverability

2025 IRP LOAD DEMAND CURVE CENTRAL ADA MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	-	1,433	-	1,433
2027	-	916	-	916
2028	-	534	-	534

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 40: 2023 IRP vs. 2025 IRP Central Ada Design Weather and Physical Deliverability

Sun Valley Lateral Design Weather/ Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE SUN VALLEY LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	24,750	20,349	1,935	22,284
2027	24,750	20,599	1,935	22,534
2028	24,750	20,848	1,935	22,783

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 41: 2025 IRP Sun Valley Lateral Design Weather and Physical Deliverability

2023 IRP LOAD DEMAND CURVE SUN VALLEY LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	24,750	18,613	1,935	20,548
2027	24,750	18,868	1,935	20,803
2028	24,750	19,123	1,935	21,058

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 42: 2023 IRP Sun Valley Lateral Design Weather and Physical Deliverability

2025 IRP LOAD DEMAND CURVE SUN VALLEY LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	-	1,736	-	1,736
2027	-	1,731	-	1,731
2028	-	1,725	-	1,725

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 43: 2023 IRP vs. 2025 IRP Sun Valley Lateral Design Weather and Physical Deliverability

Idaho Falls Lateral Design Weather/Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE IDAHO FALLS LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	103,700	73,541	20,241	93,782
2027	103,700	75,045	20,341	95,386
2028	103,700	76,566	20,341	96,907

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 44: 2025 IRP Idaho Falls Lateral Design Weather and Physical Deliverability

2023 IRP LOAD DEMAND CURVE IDAHO FALLS LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	109,300	69,823	20,301	90,124
2027	109,300	71,529	20,341	91,870
2028	109,300	73,233	20,341	93,574

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 45: 2023 IRP Idaho Falls Lateral Design Weather and Physical Deliverability

2025 IRP LOAD DEMAND CURVE IDAHO FALLS LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	(5,600)	3,718	(60)	3,658
2027	(5,600)	3,516	-	3,516
2028	(5,600)	3,333	-	3,333

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 46: 2023 IRP vs. 2025 IRP Idaho Falls Lateral Design Weather and Physical Deliverability

N. of State Street Lateral Design Weather/ Base Case Growth Comparison

2025 IRP LOAD DEMAND CURVE N. of STATE STREET LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	95,000	80,657	1,190	81,847
2027	95,000	81,761	1,190	82,951
2028	95,000	82,999	1,190	84,189

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 47: 2025 IRP N. of State Street Lateral Design Weather and Physical Deliverability

2023 IRP LOAD DEMAND CURVE N. of STATE STREET LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth)				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	95,000	79,163	990	80,153
2027	95,000	80,762	990	81,752
2028	95,000	82,362	990	83,352

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 48: 2023 IRP N. of State Street Lateral Design Weather and Physical Deliverability

2025 IRP LOAD DEMAND CURVE N. of STATE STREET LATERAL MAXIMUM PHYSICAL DELIVERABILITY & PEAK DAY USAGE DESIGN WEATHER – BASE CASE (Dth) Over/(Under) 2023 IRP				
		Peak Day Usage		
	Maximum Physical Deliverability	Core Market	Firm CD[1]	Total
2026	-	1,494	200	1,694
2027	-	999	200	1,199
2028	-	637	200	837

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Table 49: 2023 IRP vs. 2025 IRP N. of State Street Lateral Design Weather and Physical Deliverability

4.5 Resource Optimization

4.5.1 Introduction

Intermountain's IRP utilizes an optimization model that selects resource amounts over a pre-determined planning horizon to meet forecasted loads by minimizing the present value of resource costs. The model evaluates and selects the least cost mix of supply and transportation resources utilizing a standard mathematical technique called linear programming. Essentially, the model integrates/coordinates all the individual functional components of the IRP such as demand, supply, demand side management, transport and supply into a least cost mix of resources that meet demands over the IRP planning horizon, 2025 to 2030.

This section of the IRP will describe the functional components of the model, the model structure and its assumptions in general. At the end, model results will be discussed.

4.5.2 Functional Components of the Model

The optimization model has the following functional components:

- Demand Forecast by AOI
- Supply Resources, Storage and Supply, by Area
- Transportation Capacity Resources, Local Laterals and Major Pipelines, Between Areas
- Non-Traditional Resources such as Renewable Natural Gas
- Demand Side Management

Underlying these functional components is a model structure that has gas supply and demand by area of interest with gas transported by major pipelines and local distribution laterals between supply and demand. This model mirrors, in general, how Intermountain's delivery system contractually and operationally functions. In previous IRPs, Intermountain utilized Boris Metrics to perform the optimization modeling. Beginning with the 2023 IRP, the Company is utilizing its in-house expertise to perform the optimization modeling to streamline processes. The optimization modeling results have yielded comparable results.

4.5.3 PLEXOS® Optimization Model

Resource integration is one of the final steps in Intermountain's IRP process. It involves finding the reasonable least cost and least risk mix of reliable demand and supply side resources to serve the forecasted load requirements of the core customers. The tool used to accomplish this task in the IRPs prior to 2023 was a computer optimization model known as SENDOUT®. In this IRP, Intermountain is utilizing PLEXOS®, which is a very similar model to SENDOUT®.

PLEXOS® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources and optimizing their utilization at the lowest net present cost over the entire planning period for a given demand forecast. PLEXOS® permits the Company to develop and analyze a variety of resource portfolios quickly and to determine the type, size, and timing of resources best matched to forecast requirements.

4.5.4 Model Structure

To develop a basic understanding of how gas supply flows from the various receipt points to ultimate delivery to the Company's end-use customers, a graphical representation of Intermountain's system is helpful. Figure 2 (page 6) is a map of the Intermountain system. Generally, gas flows from supply areas such as Canada and the Rockies, and from storage in Washington state and Clay Basin in the Rockies region, across major pipelines to southern Idaho. In southern Idaho, the gas is transported to demand areas by local distribution laterals. The model utilizes a simplified structure of the Figure 2 map.

Figure 58 presents the model of system flows by major pipelines and supply areas. The Figure also shows four major supply receipt areas including Sumas, Stanfield, AECO and Rockies with ultimate delivery to Intermountain in southern Idaho.

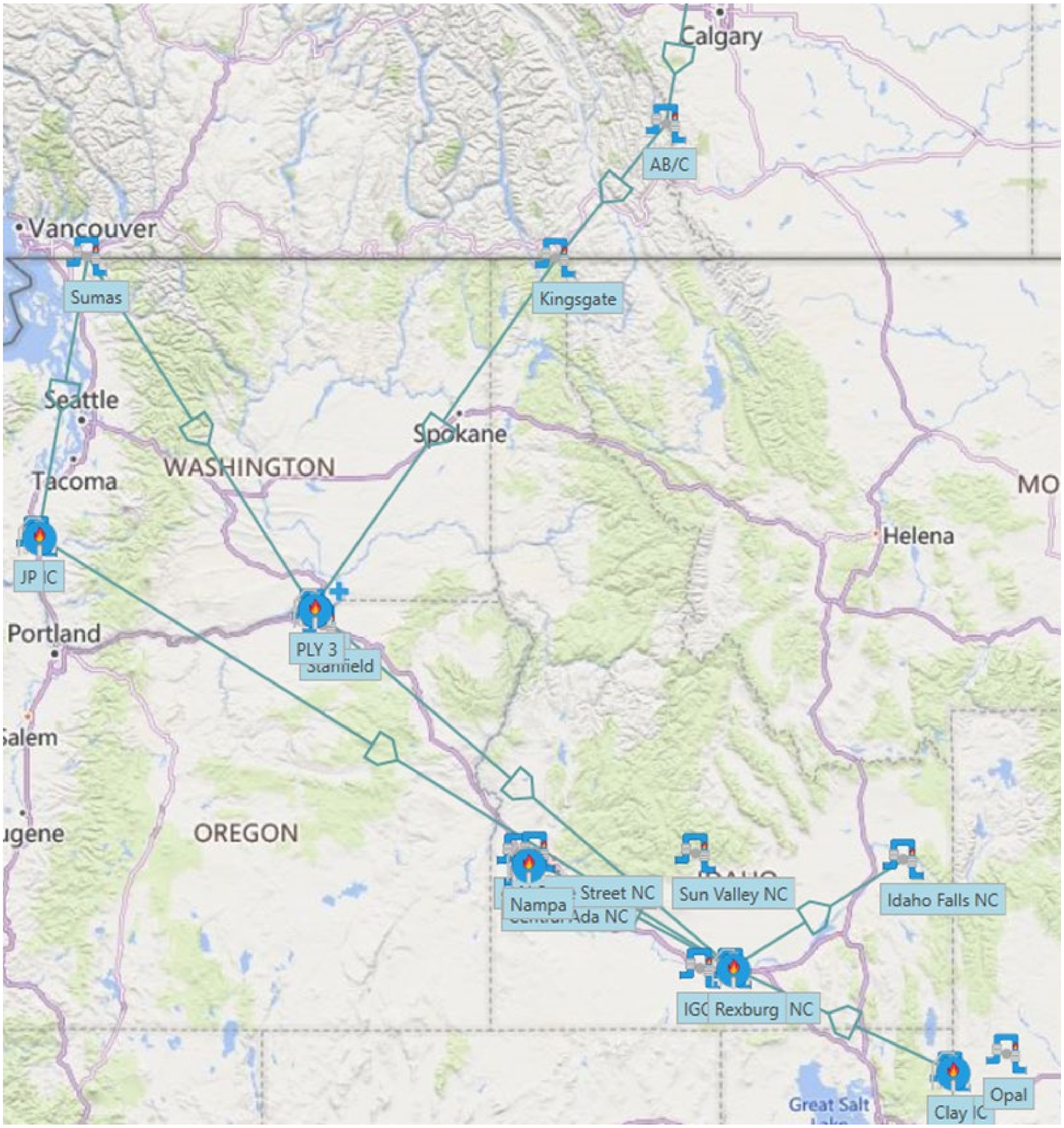

Figure 49: IGC Natural Gas Modeling System Map

Supplies from the supply receipt areas are then delivered and aggregated at the IGC pool (Zone 24) where they are allocated to be delivered to the appropriate demand areas, or AOIs, by local distribution laterals as depicted in Figure 49.

4.5.5 Demand Area Forecasts

As previously discussed in the Load Demand Curves Section, demand is forecasted using a unique load demand curve for each AOI. The sum of all six areas is equal to system gas demand. A map of the AOIs is included at the end of the Executive Summary. Intermountain forecasts peak demand to be 518,606 dth for RS (Residential) and GS (commercial) customers and 161,014 dth for LV-1 and T-4 customers in 2025 and growing to 566,971 dth and 174,484 dth in 2030, respectively.

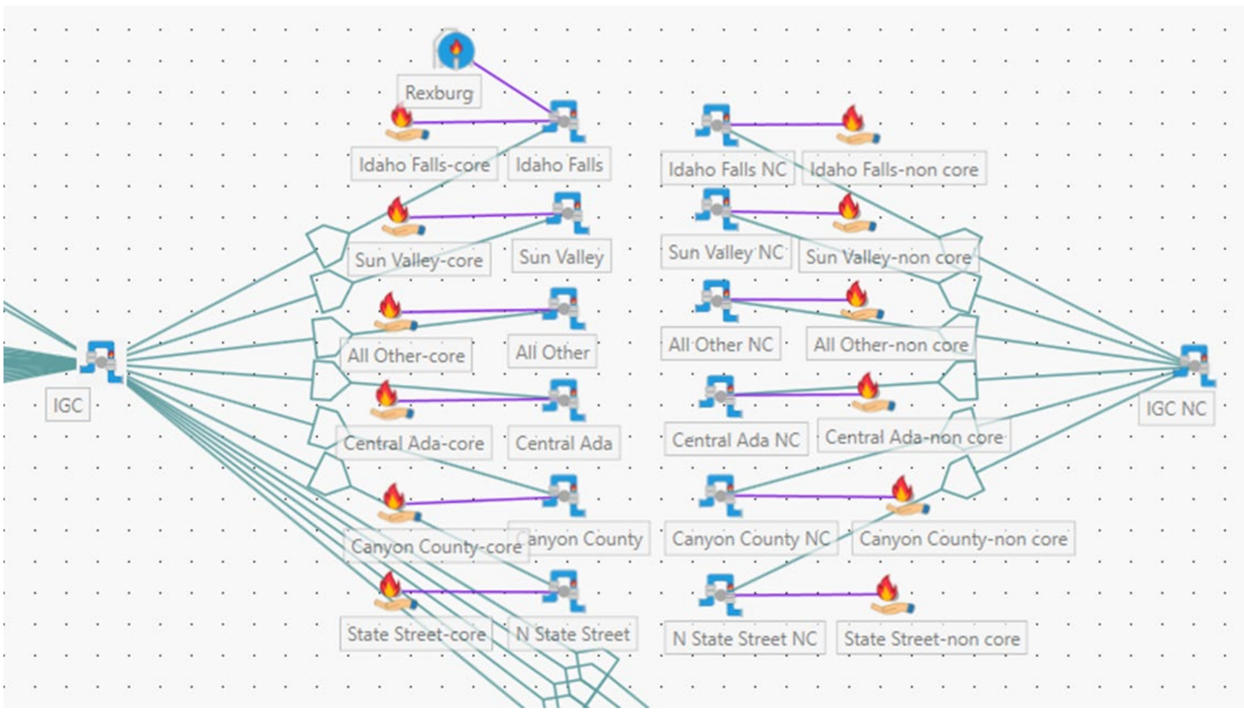

Figure 50: IGC Laterals from Zone 24

The demand areas listed in Figure 50 are:

- Central Ada Area
- State Street Lateral
- Canyon County Region
- Idaho Falls Lateral
- Sun Valley Lateral
- All Other

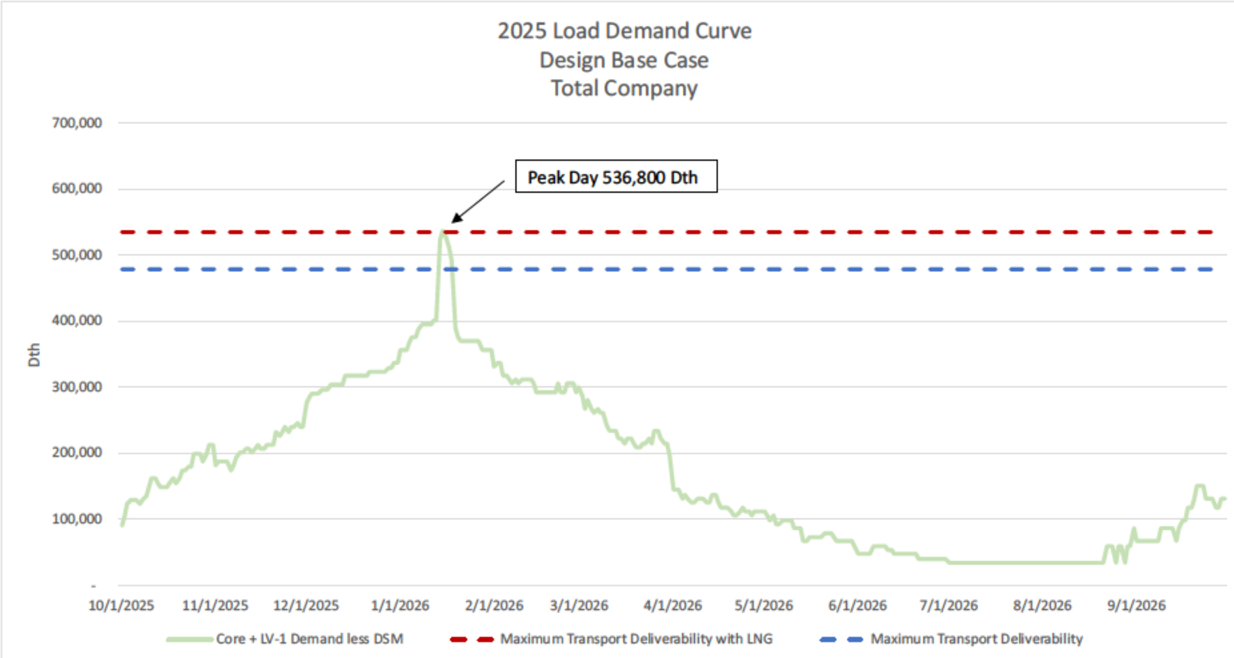

Figure 51: 2025 LDC Total Company Design Weather Base Case

The model is also programmed to recognize that Intermountain must provide gas supply and both interstate and distribution transportation for its core market and LV-1 customers, but only firm distribution capacity for T-4 customers. Figure 51 shows the core market demand with LV-1 customers less DSM, compared to the maximum upstream distribution Intermountain has to serve the demand. T-3 customers are served on an interruptible basis and therefore are not included in the analysis. Because Intermountain is contractually obligated to provide a certain level of firm transport capacity for its firm transporters each day, the industrial demand forecast for these customers is not load-shaped but reflects the aggregate firm industrial CD for each class by specific AOI for each period in the demand curve.

Scenarios for the load demand curves include specific weather and customer growth assumptions which are described elsewhere in this IRP. The weather scenarios are normal weather and design weather. Customer growth is separated into low growth, base case and high growth scenarios. This results in a total of six scenarios. The combination of the design weather and base case scenarios (Design Base) form the critical planning scenario for the IRP and will be reported as the main optimization results. Other scenarios are also available, but all others, except for the combined scenarios of design weather and high growth, would have sufficient resources as long as the Design Base does.

4.5.6 Supply Resources

Resource options for the model are of two types: supply resources and storage contracts, which, from a modeling standpoint, are utilized in a similar manner. All resources have beginning and ending years of availability, periods of availability, must take usage, period and annual flow capability and a peak day capability. Supply resources have price/cost information entered in the model over all points on the load demand curve for the study period. Additionally, information relating to storage resources includes injection period, injection rate, fuel losses and other storage related parameters.

Each resource must be sourced from a specific receipt point or supply area. For example, Figure 52 shows the supply area (in green) providing gas at the AECO interconnect. One advantage of citygate supplies and certain storage withdrawals is that they do not utilize any of Intermountain's existing interstate capacity as the resource is either sited within a demand area or are bundled with their own specific redelivery capacity. Supply resources from British Columbia are delivered into the NWP system at Sumas while Rockies supplies are received from receipt pools known as North of Green River and South of Green River. Alberta supplies are delivered to Northwest's Stanfield interconnect utilizing available upstream capacity - the available quantity at Stanfield is the limiting factor regardless of capacity of any single upstream pipeline. Each supply resource utilizes transport that reaches Zone 24 from its supply receipt node.

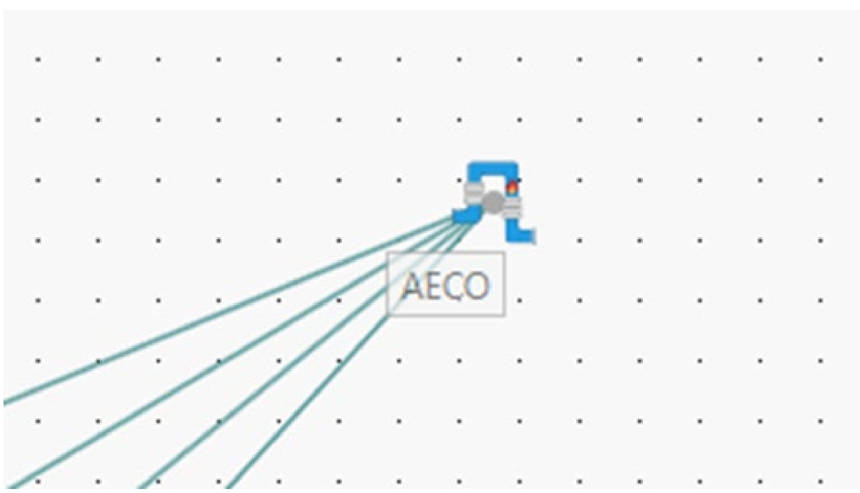

Figure 52: IGC Supply Model Example

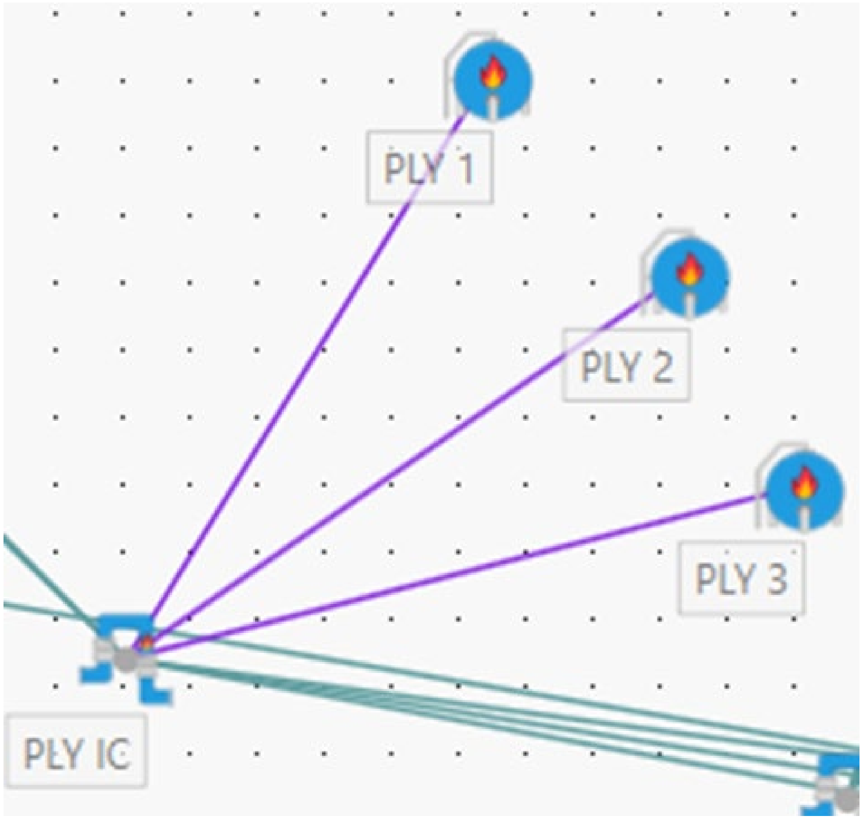

Figure 53: IGC Storage Model Example

Figure 53 shows an example of the PLEXOS modeling perspective of Storage contracts connected to the rest of the system. From a model perspective, the DSM resources are considered a subset of supply resources and fill demand needs on the applicable AOI by offsetting other supply resources when the cost of such is less than other available resources. The DSM applied directly to the AOI. These DSM resources have costs and resource capacity that were determined by a separate DSM analysis as detailed in the Core Market Energy Efficiency Section.

4.5.7 Transport Resources

Transport resources represent the way supplies flow from specific receipt areas to Intermountain's ultimate receipt pool at Zone 24, where all supplies are pooled for ultimate delivery into the Company's various Areas of Interest. Transport resources reflect contracts for interstate capacity, primarily on Northwest Pipeline, but also for the three separate pipelines that deliver gas supplies to Northwest's Stanfield interconnect from AECO. Certain supplies, such as Rexburg LNG, are already located on Intermountain's distribution system on a specific demand lateral and therefore do not require interstate pipeline transportation. The system representation recognizes Northwest's postage stamp pricing and capacity release as well as the per mile rates seen on the transportation contracts from AECO to Stanfield.

Transport resources have a peak day capability and are assumed to be available year-round unless otherwise noted. Transport resources can have different cost and capabilities assigned to them as well as different years of availability. An example of a transportation model is seen in Figure 54.

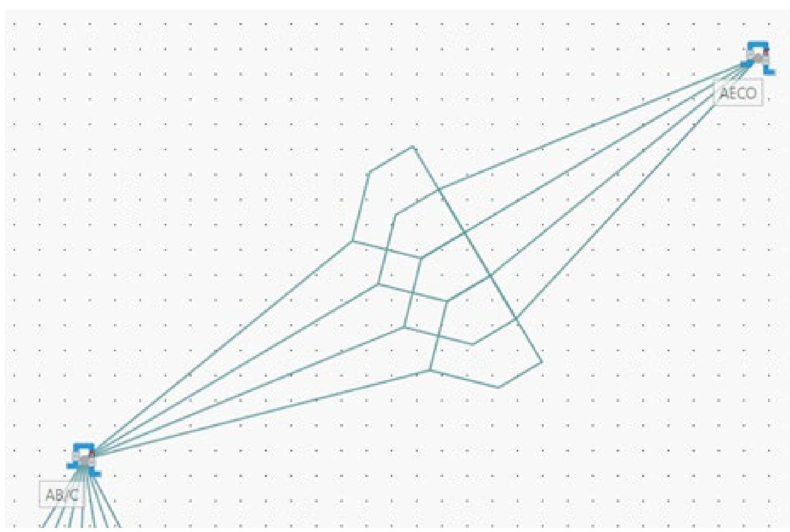

Figure 54: IGC Transport Model Example

4.5.8 Model Operation

The selection of a least cost mix of resources, or resource optimization, is based on the cost, availability and capability of the available resources as compared to the projected loads at each of the AOIs. The model chooses the mix of resources which meet the optimization goal of minimizing the present value cost of delivering gas supply to meet customer demand. The model recognizes contractual take commitments and all resources are evaluated for reasonableness prior to input. Both the fixed and variable costs of transport, storage and supply can be included. The model will exclude resources it deems too expensive compared to other available alternatives.

The model can treat fixed costs as sunk costs for certain resources already under contract. If a fixed cost or annual cost is entered for a resource, the model can include that cost for the resource in the selection process, if directed, which will influence its inclusion vis-à-vis other available resources. If certain resources are committed to and the associated fixed cost will be paid regardless of the level of usage, only the variable cost of that resource is considered during the selection process, but the fixed cost is included in the summary. However, any new resources, which would be additional to the resource mix, will be evaluated using both fixed and variable costs. For cost summary purposes, fixed costs were included, whether sunk or included in the least cost present value optimization, to approximate the expected total costs for transport and supply.

4.5.9 Special Constraints

As stated earlier, the model minimizes cost while satisfying demand and operational constraints. Several constraints specific to Intermountain's system were modeled.

- Nampa LNG storage does not require redelivery transport capacity. Both SGS and LS storage are bundled with firm redelivery capacity; transportation utilization of this capacity matches storage withdrawal from these facilities. SGS, LS and Clay Basin refills are typically injected in the summer.
- All core market and LV-1 sales loads are completely bundled.
- T-4 customer transportation requirements utilize only Intermountain's distribution capacity. The T-4 firm CD is input as a no-cost supply delivered at Zone 24. T-3 customers are served on an interruptible basis and therefore not included in the analysis.
- Traditional resources destined for a specific AOI must be first transported to Zone 24 and then to the AOI.
- Non-traditional resources such as mobile LNG that are designed to serve a specific lateral can only be employed when lateral capacity is otherwise fully utilized.

4.5.10 Model Inputs

The optimization model utilizes these three inputs which do not vary by scenario:

- Transport Resources
- Supply Resources by Year
- Supply Price Format for Supply Resources by Yearly Periods

The model selects the best cost portfolio based on least cost of present value resource costs over the planning horizon. However, the model also has been designed to comply with operational and contractual constraints that exist in the real world (i.e. if the most inexpensive supply is located at Sumas, the model can only take as much as can be transported from that point;

additionally, it will not take inexpensive spot gas until all constraints related to term gas or storage are fulfilled). For the results to provide a reasonable representation of actual operations, all existing resources that have committed must-take contracts are assigned as “must run” resources. The Company’s minimal commitment for summer must-take supplies means that those supplies do not exceed demand. In the real world, having excess summer supplies results in selling those volumes into the market at the then prevailing prices whereas the model only identifies those volumes and related cost. Please note that this level of sales is small relative to total supply.

Another important assumption relates to the supply fill or balancing options. Supply fill resources provide intelligence as to where and how much of any deficit in any existing resource exists. The model treats these resources as economic commodities (i.e. the availability is dynamic up to its maximum capability). The model can select available fill supply at any basin, for any period and in any volume that it needs to help fill capacity constraints. To ensure that the model provides results that mirror reality, these supplies have been aggregated into peak, winter (base and day), summer (base and day) and annual price periods. Base gas is typically a longer-term contract than day gas. Each aggregated group has a different relative price with the peak price being the highest, and the summer price being the lowest. Additionally, since term pricing is normally based on the monthly spot index price, no attempt has been made to develop fixed pricing for fill resources, but each such resource includes a reasonable market premium if applicable.

All transport resources are labeled to specify the pipeline as well as a contract number associated with the transport contract in the Transport table in Exhibit 8. Capability and pricing are included by resource. Figure 55 provides a sample of the input information provided in Exhibit 8. The main inputs for each transportation contract are provided. This includes the Monthly Daily Quantity (MDQ), D1 rate, Transportation Rate, and Fuel percentage. The MDQ is the contract’s specific maximum allowable gas in dekatherms the Company can transport on a given day. The D1 rate is the reservation rate for the transport contract. The transportation rate is the rate charged to the volumes flowed if the pipeline was utilized for the day. The fuel loss percentage is the statutory percent of gas based on the tariff from the pipeline that is lost and unaccounted for from the point of where the gas was purchased to the delivery point.

Transport Name	Property	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25
FTHLS 1	Max Daily Flow (BBtu)	7.105	7.105	7.105	7.105	7.105	7.105
FTHLS 1	Reservation Cost ($/MMBtu)	$ 2.82	$ 2.73	$ 2.82	$ 2.82	$ 2.55	$ 2.82
FTHLS 1	Loss (BBtu)	0.000	0.000	0.000	0.000	0.000	0.000
FTHLS 1	Total Variable Costs ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 2	Max Daily Flow (BBtu)	87.639	87.639	87.639	87.639	87.639	87.639
FTHLS 2	Reservation Cost ($/MMBtu)	$ 2.82	$ 2.73	$ 2.82	$ 2.82	$ 2.55	$ 2.82
FTHLS 2	Loss (BBtu)	0.000	0.000	0.000	0.000	0.000	0.000
FTHLS 2	Total Variable Costs ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 3	Max Daily Flow (BBtu)	0.000	20.941	20.941	20.941	20.941	20.941
FTHLS 3	Reservation Cost ($/MMBtu)	$ -	$ 2.73	$ 2.82	$ 2.82	$ 2.55	$ 2.82
FTHLS 3	Loss (BBtu)	0.000	0.000	0.000	0.000	0.000	0.000
FTHLS 3	Total Variable Costs ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -

Figure 55: Transport Input Summary

The price forecast is provided in the Traditional Supply Resources section.

4.5.11 Model Results

The optimization model results for the design weather, base price and base case scenario for the years 2025 through 2030 are presented and discussed below. The results of the model are summarized, for each scenario using the tables described below:

- Upstream Transportation and Lateral Summary Tables (Exhibit 9)
- Annual Transportation Resources Results (Exhibit 8)
- Annual Supply Resources Results (Exhibit 8)

Model Output for Design Base Scenario

The following provides a description of the information presented by type of output tables in Exhibit 9 and the implication for the Design Base scenario.

Exhibit 9 provides a snapshot by year of whether a specific lateral to an AOI needs an expansion and whether that expansion is a preferred one as opposed to a fill or an alternative lateral resource. Figure 56 shows the first year of the Upstream Transportation and Lateral Summary, for the Design Base scenario.

The “Total Peak Day” is the peak day that includes RS, GS, LV-1, and T-4 customers, since the distribution system must maintain reliability for these customers. The “Existing Capacity” column is the amount of deliverability Intermountain has on the distribution system for each area of interest. The “% of Existing Capacity” is the percentage of total peak day compared to existing capacity. The “Existing + Upgrade Capacity” column is the amount of deliverability Intermountain has on the distribution system for each area of interest after the upgrades discussed in the Capacity Enhancements section take place. The “% of Existing + Upgrade Capacity” is the percentage of total peak day compared to the upgraded capacity. The table for the base year through the final year in the planning horizon displays these conditions for the Design Base scenario (Exhibit 9).

2025	Base Year (Dth)					
Area of Interest	Total Peak Day	Existing Capacity	% of Existing Capacity	Planned Capacity Upgrade	Existing + Upgrade Capacity	% of Existing + Upgrade Capacity
IDAHO FALLS	86,121	90,400	95%	18,900	109,300	79%
SUN VALLEY	19,994	20,000	100%	4,750	24,750	81%
CANYON COUNTY	101,399	103,200	98%	35,800	139,000	73%
STATE STREET	75,346	82,000	92%	-	82,000	92%
CENTRAL ADA	72,996	74,500	98%	12,500	87,000	84%
ALL OTHER	276,942					

Figure 56: Lateral Summary by Year

Figure 57 shows the Annual Traditional Supply Resources Results from Exhibit 8 for the Design Base scenario for the major supply areas. DSM is also provided in Exhibit 8 in a separate table.

Supply Name	Property	Units	2025	2026	2027	2028	2029	2030
AECO Base	Take Quantity	BBtu	12,867	12,907	12,949	13,042	13,058	13,112
AECO Base	Price	$/MMBtu	$ 1.81	$ 2.39	$ 2.52	$ 2.47	$ 2.48	$ 2.56
AECO Base	Commodity Cost	$0	$ 23,350.45	$ 30,811.28	$ 32,642.64	$ 32,275.08	$ 32,406.32	$ 33,512.88
AECO Base W	Take Quantity	BBtu	18,250	18,575	18,851	19,226	19,416	19,718
AECO Base W	Price	$/MMBtu	$ 1.91	$ 2.49	$ 2.62	$ 2.57	$ 2.58	$ 2.66
AECO Base W	Commodity Cost	$0	$ 39,425.40	$ 47,823.07	$ 54,778.30	$ 53,538.87	$ 53,303.12	$ 54,730.14

Figure 57: Annual Traditional Supply Resources Results

The supply resources in the detailed output tables have the following output parameters:

- Total Commodity Cost by year
- Monthly Supply by basin and type of Supply
- Unit Commodity Cost

The total commodity cost is the total dollar amount spent on gas purchased at the supply group location on an annual basis. The monthly supply is the amount of gas purchased at the supply group. The unit commodity cost is the dollar per dekatherm that was spent on purchasing the gas at each supply location. Exhibit 8 also includes the daily purchase amount by supply location for design day.

A sample of the Annual Transportation Resources Results from Exhibit 8 for the Design Base scenario is displayed Figure 58. Exhibit 8 also provides transportation results by month for the planning horizon.

Transport Name	Property	Units	2025	2026	2027	2028	2029	2030	2031
FTHLS 1	Flow Out	BBtu	1,571	1,541	1,330	1,344	1,456	1,023	866
FTHLS 1	Fixed Costs	$0	$ 236.07	$ 236.07	$ 236.07	$ 236.72	$ 236.07	$ 236.07	$ 236.07
FTHLS 1	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 2	Flow Out	BBtu	19,198	19,256	18,772	18,902	16,779	23,095	19,630
FTHLS 2	Fixed Costs	$0	$ 2,913.81	$ 2,913.81	$ 2,913.81	$ 2,921.79	$ 2,913.81	$ 2,913.81	$ 2,913.81
FTHLS 2	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 3	Flow Out	BBtu	2,604	2,706	2,558	2,349	2,326	2,482	2,280
FTHLS 3	Fixed Costs	$0	$ 288.03	$ 288.03	$ 288.03	$ 289.94	$ 288.03	$ 288.03	$ 288.03
FTHLS 3	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 4	Flow Out	BBtu	1,691	1,723	1,447	1,377	1,501	1,421	1,356
FTHLS 4	Fixed Costs	$0	$ 245.44	$ 245.44	$ 245.44	$ 246.11	$ 245.44	$ 245.44	$ 245.44
FTHLS 4	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Figure 58: Annual Transportation Resources Results

The transportation resources in the detailed output tables have the following output parameters:

- D1 Cost
- Outflow
- Transportation Cost

The D1 cost is the total dollars spent on the transportation contracts based on the pipelines. The outflow is the actual amount of gas that flowed on the associated transport group and the transportation costs are the total dollars spent on the transportation rate. Exhibit 8 also includes the outflow on design day.

Other Scenarios

Upstream Transportation and Lateral Summary tables for the high and low customer growth as well as normal weather are provided in Exhibit 10. One notable result from the other scenarios is that even under the most extreme scenario, design weather with high growth, there is still sufficient upstream transportation and distribution system capacity to serve customers through the planning horizon when including the planned solutions for shortfalls in the Planning Results chapter.

4.5.12 Summary

In summary, the optimization model employs utility standard practice method to optimize Intermountain's system via linear programming through PLEXOS®. The optimization includes DSM as a decrement to demand and also optimizes storage injections and withdrawals across seasons. An analysis on lateral expansion is performed as well as an analysis to check for any shortfalls in upstream transportation or supply capacity.

4.6 Planning Results

4.6.1 Overview

Throughout previous sections of the IRP, robust analysis has been performed to determine how the Company will provide safe, reliable, and least cost gas to customers. This section discusses the planning results from distribution system planning after capacity enhancements are applied. After discussing the enhancement solutions for the forecasted capacity deficits, this section will also compare the peak delivery deficits of the total company as well as each AOI during the three common years of the 2025 and 2023 IRP filings. The 2025 IRP is unique compared to previous IRPs, as the 2025 IRP includes a lot of capital investments that have been recently or soon to be completed projects, which have increased the Company's capacity at each AOI. Finally, the planning results for upstream transportation shortfalls are discussed.

4.6.2 Distribution System Planning

Canyon County

In the Capacity Enhancements section, Intermountain mentions that Canyon County has seen significant capital investments at the AOI that provides enough capacity over anticipated growth to 2030.

The following graph (Figure 59) shows no deficit in the final year of the planning horizon under the base case scenario with the completion of the proposed capacity upgrades.

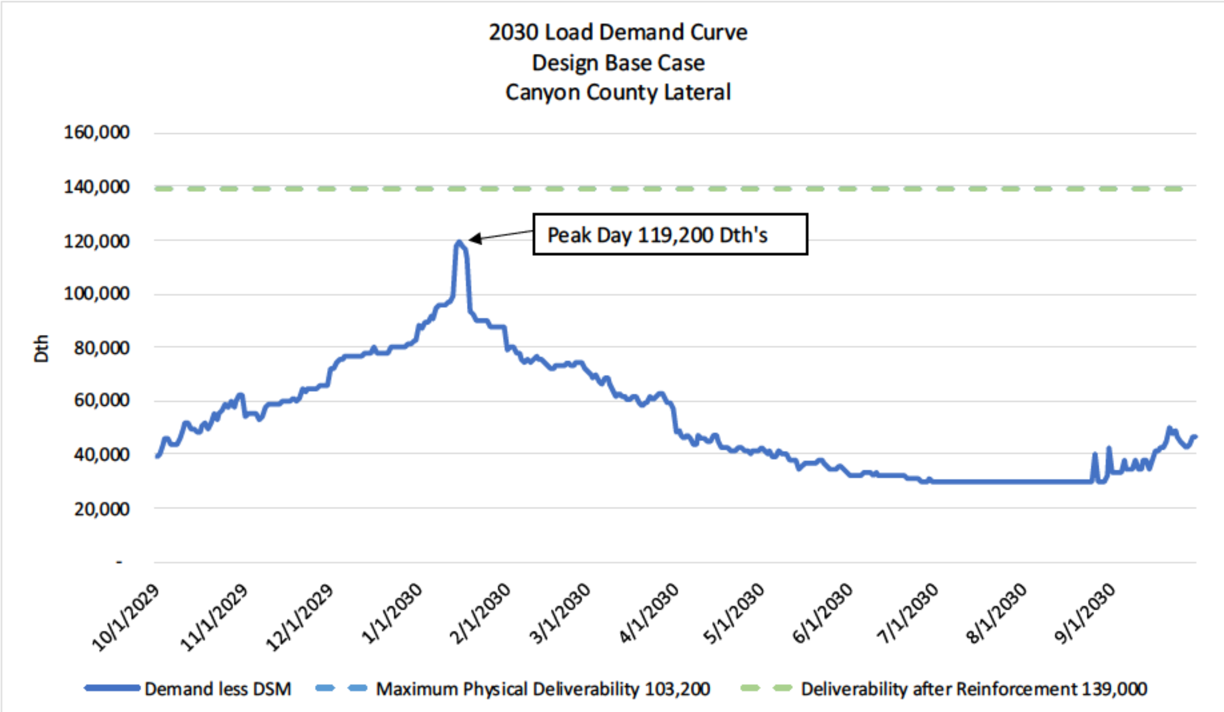

Figure 59: LDC Design Base Case – Canyon County

Central Ada County

In the Capacity Enhancements section, Intermountain mentions that Central Ada has seen significant capital investments at the AOI that provides enough capacity over anticipated growth to 2030.

The following graph (Figure 60) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

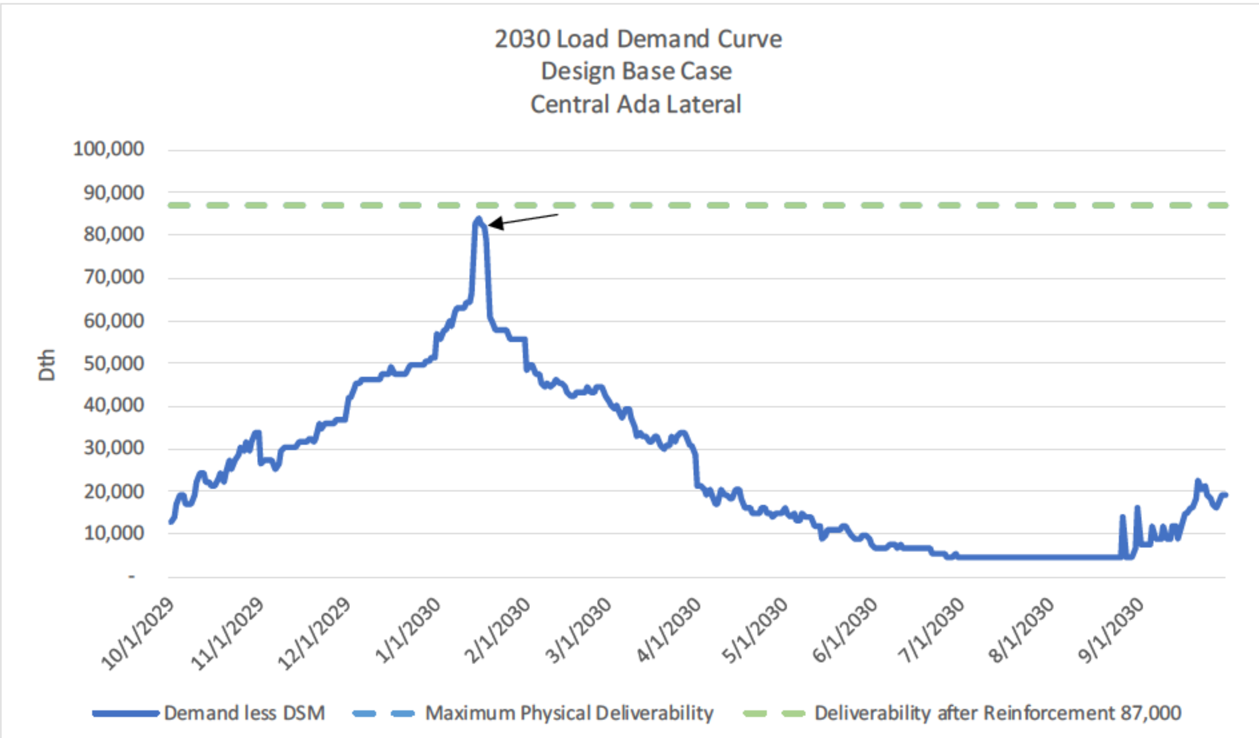

Figure 60: LDC Design Base Case – Central Ada

Sun Valley Lateral

In the Capacity Enhancements section, Intermountain mentions that Sun Valley has seen significant capital investments at the AOI that provides enough capacity over anticipated growth to 2030.

The following graph (Figure 61) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

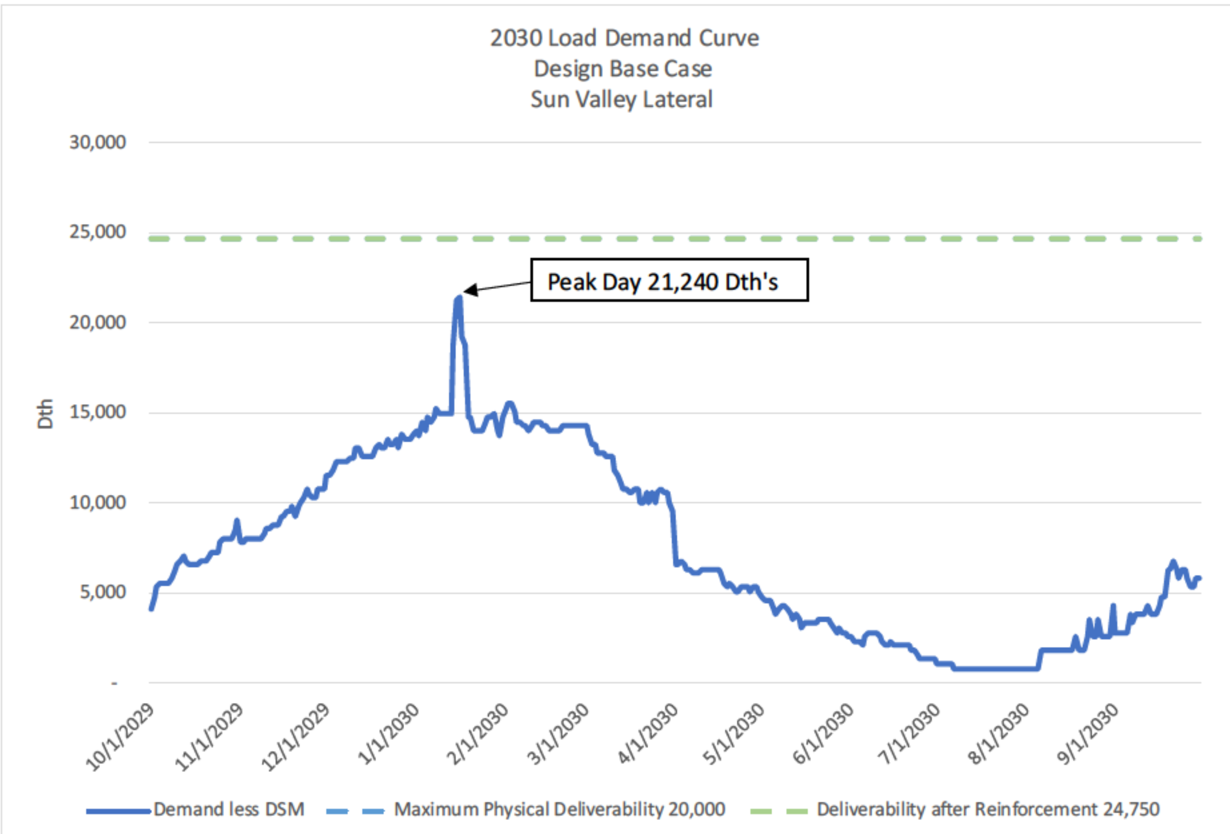

Figure 61: LDC Design Base Case – Sun Valley Lateral

Idaho Falls Lateral

In the Capacity Enhancements section, two options are discussed to meet 2026 capacity needs, the Wapello compressor station or a Phase VI 16-inch pipeline with an additional LNG Tank in Rexburg. The option chosen was the Wapello compressor station. An additional upgrade is needed to meet 2030 capacity needs, in which two options were discussed; a separate compressor station or a pipeline loop. Intermountain is considering the pipeline loop as it is the lowest cost option.

The following graph shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

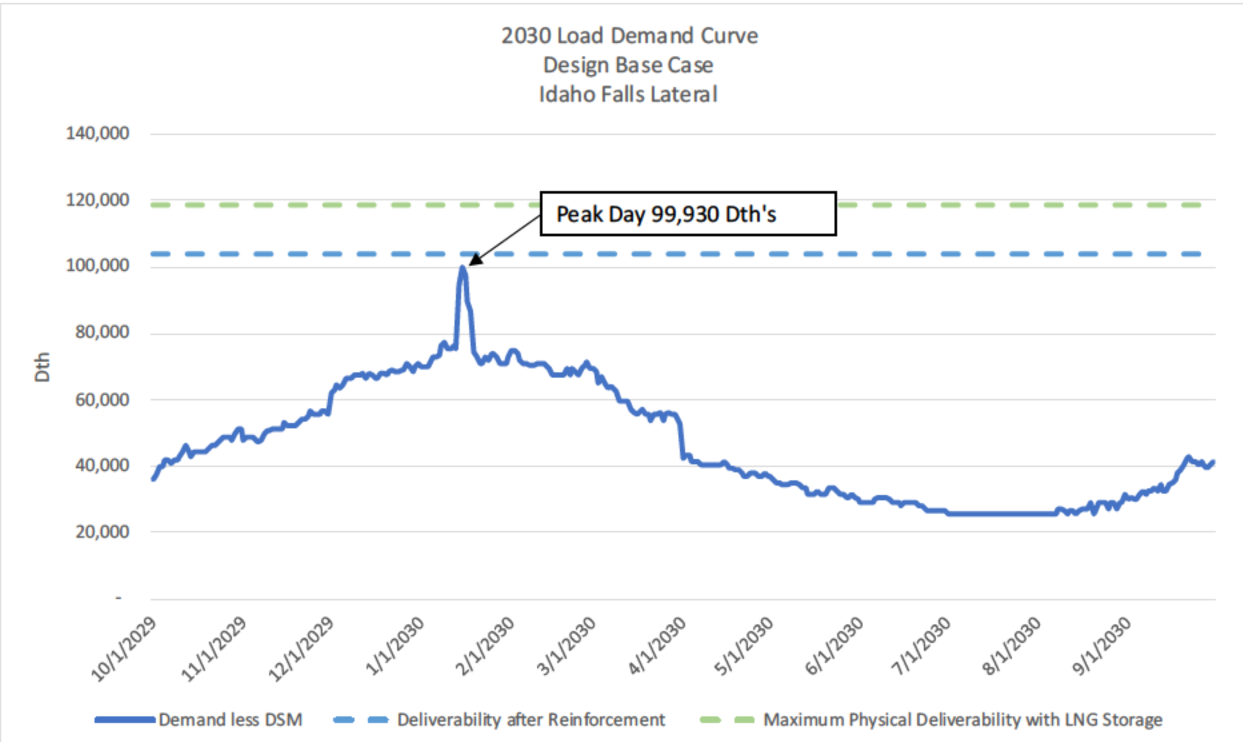

Figure 62: LDC Design Base Case – Idaho Falls Lateral

N. of State Street Lateral

In the Capacity Enhancements section, two options are discussed to determine the best way to solve capacity shortfalls for the State Street Lateral. The option chosen was the State Street Phase II Uprate.

The following graph shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

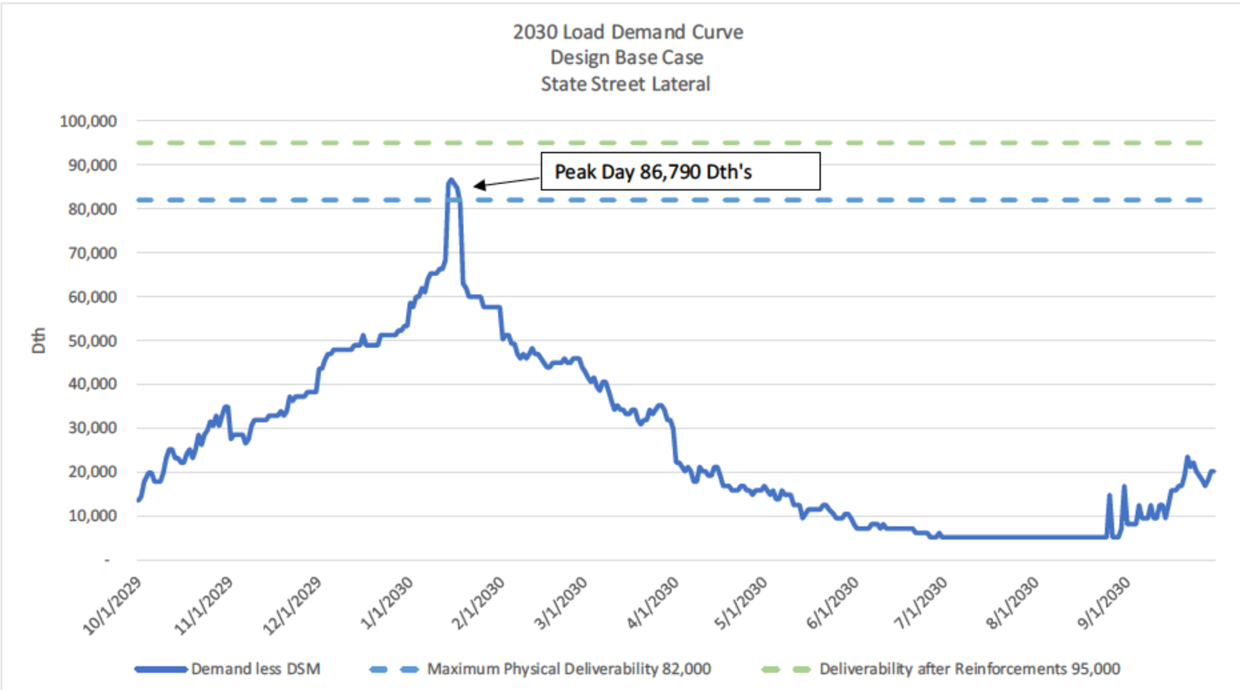

Figure 63: LDC Design Base Case – N. of State Street Lateral

2023 IRP vs. 2025 IRP Common Year Comparisons

This section compares any firm delivery deficits prior to any completed projects after the filing of the IRP for each AOI and the Total Company during the three common years of the 2025 and 2023 IRP filings.

Canyon County Area Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – CANYON COUNTY DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 50: 2025 IRP Canyon County Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – CANYON COUNTY DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 51: 2023 IRP Canyon County Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – CANYON COUNTY DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 52: 2023 IRP vs. 2025 IRP Canyon County Design Weather Delivery Deficit

Central Ada County Firm Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – CENTRAL ADA DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 53: 2025 IRP Central Ada Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – CENTRAL ADA DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 54: 2023 IRP Central Ada Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – CENTRAL ADA DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 55: 2023 IRP vs. 2025 IRP Central Ada Design Weather Delivery Deficit

Sun Valley Lateral Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – SUN VALLEY LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 56: 2025 IRP Sun Valley Lateral Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – SUN VALLEY LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 57: 2023 IRP Sun Valley Lateral Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – SUN VALLEY LATERAL DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 58: 2023 IRP vs. 2025 IRP Sun Valley Lateral Design Weather Delivery Deficit

Idaho Falls Lateral Peak Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – IDAHO FALLS LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 59: 2025 IRP Idaho Falls Lateral Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – IDAHO FALLS LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 60: 2023 IRP Idaho Falls Lateral Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – IDAHO FALLS LATERAL DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0
[1]Equal to the total winter sendout in excess of distribution capacity.			

Table 61: 2023 IRP vs. 2025 IRP Idaho Falls Lateral Design Weather Delivery Deficit

N. of State Street Lateral Firm Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – N. of STATE STREET LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0
[1]Equal to the total winter sendout in excess of distribution capacity.			

Table 62: 2025 IRP N. of State Street Lateral Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – N. of STATE STREET LATERAL DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0
[1]Equal to the total winter sendout in excess of distribution capacity.			

Table 63: 2023 IRP N. of State Street Lateral Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – N. of STATE STREET LATERAL DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 64: 2023 IRP vs. 2025 IRP N. of State Street Lateral Design Weather Delivery Deficit

Total Company Peak Delivery Deficit Comparison

2025 IRP FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	2,258	11,194
Total Winter Deficit[1]	0	2,258	11,194
Days Requiring Additional Resources	0	1	1

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Table 65: 2025 IRP Total Company Design Weather Delivery Deficit

2023 IRP FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE (Dth)			
	2025	2026	2027
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Table 66: 2023 IRP Total Company Design Weather Delivery Deficit

2025 IRP FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE Over/(Under) 2023 (Dth)			
	2025	2026	2027
Peak Day Deficit	0	2,258	11,194
Total Winter Deficit[1]	0	2,258	11,194
Days Requiring Additional Resources	0	1	1

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Table 67: 2023 IRP vs. 2025 IRP Total Company Design Weather Delivery Deficit

4.6.3 Upstream Modeling

Upstream Modeling Results

The upstream modeling results look at the upstream resources to ensure there is sufficient supply, storage, and transportation of gas to Intermountain's distribution system. As mentioned in the Traditional Supply Resources section, supply remains plentiful at the supply basins for the foreseeable future. As Intermountain continues to experience extreme growth, the Company's design capacity begins to hit a shortfall in the planning horizon. Due to this growth, Intermountain shows a shortfall in 2026 and grows throughout the final year of the planning horizon. The following graph (Figure 64) shows the shortfall created by expiring contracts.

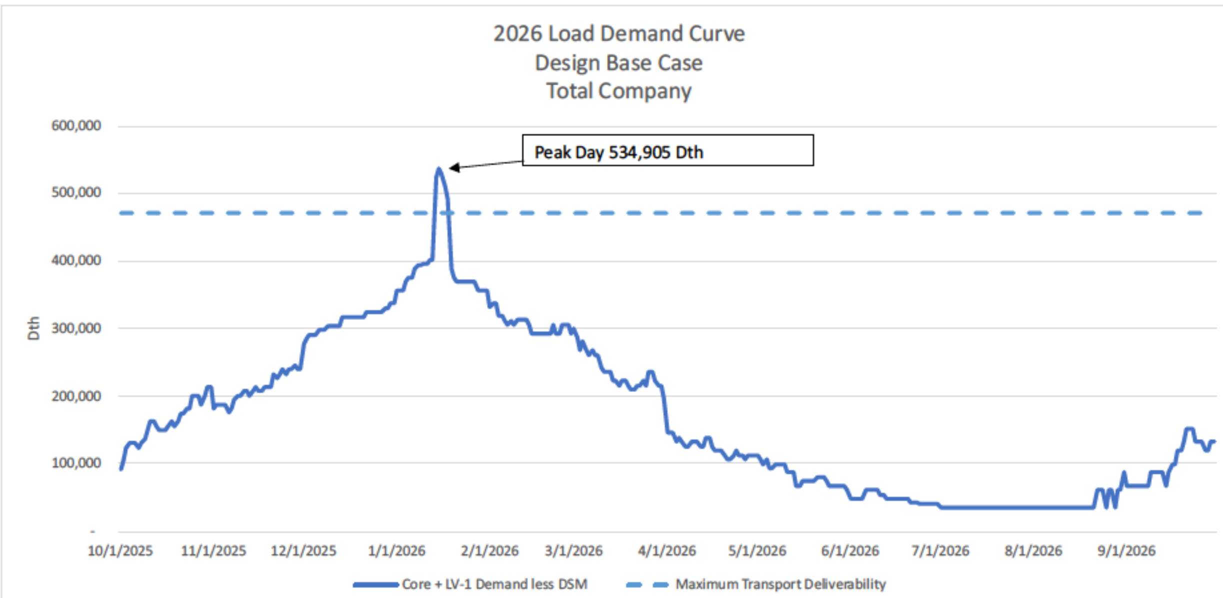

Figure 64: 2026 Design Base Case – Total Company

Solving Upstream Resources Shortfall

The options to solve the transportation shortfall that the Company anticipates happening during the planning horizon are incremental transportation and satellite LNG. As outlined during the IGRAC 4 presentation, Intermountain's most realistic options are the Rockies Connector project and satellite LNG.

The Rockies Connector project is a project put forth by Northwest Pipeline to increase the capacity from the Rockies area flowing north to Stanfield and Sumas. Satellite LNG would consist of adding an additional LNG facility to the Company's distribution system.

Intermountain ultimately selected the Rockies expansion because it provides a strategic balance of reliability and cost efficiency in a shifting energy landscape. The company recognized significant uncertainty surrounding the timing and feasibility of future capacity expansion projects, making it critical to secure near-term solutions. At the same time, LNG project costs are prohibitively high, as outlined in Table 68, limiting their attractiveness as a competitive option. By pursuing the Rockies expansion, Intermountain gains valuable basin diversity between AECO and the Rockies, strengthening supply flexibility and reducing exposure to single-market risks while positioning itself to adapt to evolving infrastructure developments.

Utility	Facility	IRP / Planning Link	Regulatory Filing	Reported Project Cost	Storage Capacity
Puget Sound Energy (WA)[1]	Tacoma LNG	PSE Gas IRP	WA UTC docket UG-230393	~$489 million capital cost (end of 2022)	~9.6 million dth
Pacific NorthWest LNG (BC, canceled)[2]	Lelu Island LNG Export Project	NA (Petronas)	BC EAO, CEAA 2012	Planned $11.4–18 billion investment	~18–20M Dth annually
NW Natural (OR/WA)[3]	Peak-shaving LNG	NW Natural IRP	OPUC docket UG 456	undisclosed	Capacity in PHMSA/permit filings
FortisBC (BC)[4]	Tilbury LNG	BCUC Tilbury LNG CPCN	BCUC Order G-62-23	~$1.14 billion	~25.4 million dth

Table 68: Regional LNG Projects

It is important to remember that the resource optimization model provides information and does not decide the ultimate solution. The resource optimization model results will be provided to Intermountain's Gas Supply Oversight Committee (GSOC. GSOC will need to consider a longer time frame when looking at upstream transportation since those contracts typically are only available for purchase in long-term blocks. Therefore, it may make more sense to do a full renewal. Ultimately, GSOC will make a final decision on the solution to meet the forecasted transportation shortfall.

1 *See:* december12023.pdf, PSE LNG FEIS Cover Pages.pdf

2 *See:* Pacific NorthWest LNG Project, British Columbia - Offshore Technology

3 *See:* lc79has155146.pdf

4 *See:* BCUC Approves FortisBC's Tilbury Liquefied Natural Gas

4.6.4 Conclusion

The distribution system planning results showed that the Company has and continues to need to address capacity shortfalls at each of the Area of Interests. The Capacity Enhancements section describes each solution and the updated capacity values are shown in this section to provide sufficient capacity over the planning horizon. The upstream modeling showed a shortfall due to design day growth. That shortfall will be solved by incremental transportation, with the ultimate decision coming from Intermountain's GSOC.

4.7 Infrastructure Replacement

4.7.1 Overview

Intermountain Gas Company is committed to providing safe and reliable natural gas service to its customers. As part of this commitment, Intermountain proactively monitors its pipeline system utilizing risk management tools and engineering analysis. Additionally, the Company adheres to federal, state and local requirements to replace or improve pipelines and infrastructure as required. Infrastructure that is identified as a potential risk is reviewed and prioritized for replacement or risk mitigation.

During the IRP planning period, Intermountain will address five significant infrastructure replacement projects. These replacement projects are not growth driven.

4.7.2 American Falls Neely Bridge Snake River Crossing

The Neely bridge crossing is a six-inch steel high pressure pipeline above ground crossing over the Snake River where the pipe is hanging on a bridge and is scheduled for replacement in 2026. The pipe has been identified for replacement since it is a suspended crossing installed in 1961 which is difficult to inspect and maintain coating on and has had issues with expansion and contraction of the bridge which has resulted in damage to the facilities.

To address these issues Intermountain is recommending that this above ground crossing be replaced with a below ground crossing under the Snake River using horizontal directional drilling.

4.7.3 Rexburg Snake River Crossing

The Rexburg Snake River crossing is an eight-inch steel transmission pipeline installed under the Snake River southwest of Rexburg which has been identified as an infrastructure replacement project, tentatively scheduled for 2028 design and permitting and 2029 construction. The pipeline was identified for replacement due to risks related to the Snake River and surrounding flood plain. The location of the pipeline under the Snake River and perpendicular to the river along its east bank leave the pipeline susceptible to loss of adequate cover should the river’s rate of flow increase to the point of spilling over the existing bank and/or scouring the existing river bottom.

The Rexburg Snake River crossing has been monitored and has required occasional attention. The riverbank has been rebuilt and reinforced by Intermountain to prevent undermining of the bank and reduce the potential to flood, and the Company has installed engineered scour protection measures over the top of the pipeline to prevent cover loss within the river. These efforts have been successful to date. However, due to the ongoing monitoring and mitigation efforts, along with the ever-present risks associated with this scenario, the Company plans to replace the existing pipeline.

Intermountain's selected replacement method for this existing river crossing is to utilize horizontal directional drilling technology to install a new pipeline much further below the river bottom and surrounding flood area. Horizontal directional drilling will allow the pipeline to be installed much deeper in the ground than conventional installation practices and will avoid any disturbance to the Snake River and the sensitive land surrounding the river. The significant increase in pipeline depth will mitigate the existing risk.

4.7.4 Shoshone Sun Valley Transmission Line Replacement

The Shoshone area is known for rocks due to lava formations. The Sun Valley transmission line has been identified at shallow depth in a field that is farmed and tilled creating a abnormal operating condition, and safety concern and potential excavation risk to the pipeline. 2800 feet of 8-inch transmission line needs to be replaced to get the line back to having acceptable cover. This project is planned for 2026 design and 207 construction.

4.7.5 System Safety and Integrity Program (SSIP)

The System Safety and Integrity Program ("SSIP") is a structured pipe replacement program for replacing early vintage plastic pipe and early vintage steel pipe.

Early vintage plastic pipe includes plastic mains, service lines, and associated fittings installed earlier than January 1, 1995. Early vintage plastic pipe is further divided into Pre-1983 and Post-1982. Pre-1983 includes pipe installed prior to January 1, 1983 that may be susceptible to possible low ductile inner wall characteristics that can result in slow crack growth and slit failures, as documented by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), PHMSA–2004–19856.[1] Post-1982 includes pipe installed between January 1, 1983 and December 31, 1994 and are classified as early vintage plastic pipe to account for different inventory levels and rates of new material adoption throughout Intermountain's operating locations.

Early vintage steel pipe includes steel mains, service lines, and associated fittings installed earlier than January 1, 1970. This pipe presents an increased risk of failure due to external corrosion, material failure, weld or joint failure, and equipment failure.

Intermountain's SSIP utilizes its Distribution Integrity Management Program (DIMP) Risk Model to calculate relative risk scores for Intermountain's distribution system. The DIMP risk model sums up the assigned likelihood scores for each threat and consequence factors for each

[1] *See:* https://www.federalregister.gov/documents/2007/09/06/07-4309/pipeline-safety-updated-notification-of-the-susceptibility-to-premature-brittle-like-cracking-of.

segment of Intermountain's distribution system. The total likelihood factor is then multiplied by the total consequence factor to establish a total relative risk score. The relative risk score is then used to establish a weighted average risk (WAR) score for each town within Idaho. The WAR score is then used to identify towns with increased risk related to early vintage plastic pipe and early vintage steel pipe. Ongoing analysis of early vintage plastic pipe and early vintage steel pipe continues to show that this pipe has a greater likelihood to leak and/or have substandard pipe conditions (corrosion, welds/joints, materials, equipment). These segments of main and service lines have an elevated risk of failure as validated by DIMP risk analysis and are, therefore, prioritized for replacement. Pipeline replacement is typically the most viable option to remediate risks associated with corrosion, material failure, weld/joint failure, equipment failure, and missing data threats. The SSIP program addresses safety, reliability, and operational risks by replacing pipe systematically, where Intermountain has determined that replacement is an appropriate action to reduce risk.

Since 2013, Intermountain has been actively replacing segments of early vintage plastic pipe and early vintage steel pipe within its distribution system.

Intermountain completed SSIP pipe replacement in Boise, Idaho in 2025. The Boise SSIP pipe replacement project is a multi-year project primarily focusing on the replacement of Pre-1983 early vintage plastic main and service lines with MDPE pipe. Boise was identified in 2023 as Intermountain's 2nd highest risk town with early vintage steel pipe and early vintage plastic pipe in the state of Idaho, by Intermountain's SSIP. The Boise SSIP pipe replacement project started in 2023 and will continue through 2027.

Intermountain currently has approximately $4.30 (2026) – $4.95 (2030) million budgeted for SSIP replacement annually, which is used for replacing high risk early vintage plastic pipe and early vintage steel pipe. The SSIP replacement plan will continue through the duration of the IRP.

4.7.6 Transmission Re-Confirmation

PHMSA issued RIN 1 of the Final Rule of Docket No. PHMSA-2011-0023 – Safety of Gas Transmission and Gathering Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments on October 1, 2019. This final rule addressed congressional mandates, National Transportation Safety Board recommendations, and responds to public input. The amendments in this final rule address integrity management requirements and other requirements, and they focus on the actions that must be taken to reconfirm the maximum allowable operating pressure (MAOP) of previously untested transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in populated areas not designated as "high consequence areas," the reporting of exceedances of maximum allowable operating pressure, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.

MAOP reconfirmation requires Intermountain to reconfirm the MAOP of transmission pipeline segments where the records needed to substantiate the MAOP are not traceable, verifiable, and complete (TVC). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location. Pipeline segments with missing records can be reconfirmed using one of six methods which include:

1. Pressure Test
2. Pressure Reduction
3. Engineering Critical Assessment
4. Pipe Replacement
5. Pressure Reduction for Pipeline Segments with Small Potential Impact Radius
6. Alternative Technology

Intermountain currently doesn't have anything budgeted for MAOP reconfirmation pipe replacement. As work continues to reconfirm MAOP, transmission pipeline segments may be identified for replacement where the records needed to substantiate the MAOP are not TVC. MAOP reconfirmation activities will continue through the duration of the IRP.

4.7.7 Shorted Casing Replacement or Abandonment Program (SCRAP)

The Shorted Casing Replacement/Abandonment Program (SCRAP) identifies and replaces shorted casings. A steel carrier pipe installed inside a steel casing is required to be electrically isolated from the steel casing. To determine if a steel carrier is electrically isolated from a steel casing, each casing is tested annually, per Company procedure, to determine if the casing is shorted or electrically isolated. If a casing is determined to be shorted, it must be mitigated or replaced before its status can be resolved as not shorted. Mitigation methods are a short-term remedial action as the metal-to-metal contact may reoccur. Therefore, shorted casing replacement or shorted casing abandonment/removal are the preferred methods to minimize the threat of a shorted casing. Eliminating shorted casings reduces ongoing O&M maintenance costs associated with shorted casings.

Intermountain currently has approximately $494,000 – $701,000 budgeted, for 2026 through 2030, for SCRAP replacement annually, which is used for the replacement of shorted casings. SCRAP will continue through the duration of the IRP.

5. Glossary

Agent (Marketer)

A legal representative of buyers, sellers or shippers of natural gas in negotiation or operations of contractual agreements.

All Other Customers Segment (All Other)

All other segments of the Company's distribution system serving core market customers in Ada County not included in the State Street Lateral or Central Ada County, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties; an Area of Interest for Intermountain.

Area of Interest (AOI)

Distinct segments within Intermountain's current distribution system.

British Thermal Unit (BTU)

The amount of heat that is necessary to raise the temperature of one pound of water by 1 degree Fahrenheit

Bundled Service

Gas sales service and transportation service packaged together in a single transaction in which the utility, on behalf of the customer, buys gas from producers and then transports and delivers it to the customer.

Canyon County Area (CCA)

A distinct segment of Intermountain's distribution system which serves core market customers in Canyon County; an Area of Interest for Intermountain.

Central Ada County (CAC)

Multiple high-pressure pipeline systems which serve core market customers in Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west; an Area of Interest for Intermountain.

Citygate

The points of delivery between the interstate pipelines providing service to the utility or the location(s) at which custody of gas passes from the pipeline to the utility.

Commercial
A customer that is neither a residential nor a contract/large volume customer whose requirements for natural gas service do not exceed 2,000 therms per day. These customers are typically commercial businesses or small manufacturing facilities.

Contract Demand (CD)
The maximum peak day amount of distribution capacity that Intermountain guarantees to reserve for a firm customer each day. The amount is specified in the customer contract. Also see MDFQ.

Core Market
All residential and commercial customers of Intermountain Gas Company. Includes all customers receiving service under the RS and GS tariffs.

Customer Management Module (CMM)
A software product, provided by DNV as part of their Synergi Gas product line, to analyze natural gas usage data and predict usage patterns on an individual customer level.

Delivery (Receipt Point)
Designated points where natural gas is transferred from one party to another. Receipt points are those locations where a local distribution company delivers, and an interstate pipeline receives, gas supplies for re-delivery to the local distribution company's city gates.

Design Year
An estimate of the highest level of annual customer demand that may occur, incorporating extreme cold or peak weather events; a measure used for planning capacity requirements.

Design Weather
Heating degree days that represent the coldest temperatures that may occur in the IGC service territory.

Direct Use
The use of natural gas at the point of final heating energy use, such as natural gas space heating, water heating, cooking, and other heating uses, as opposed to burning natural gas in a power plant to generate electricity to be used at the point(s) of use to for site space heat, water heat, cooking heat and other heat applications. Direct use is a much more efficient use of natural gas.

Demand Side Management (DSM)
Programs implemented by the Company and utilized by its customers to influence the amount and timing of natural gas consumption.

Electronic Bulletin Board (EBB)

A generic name for the system of electronic posting of pipeline transmission information as mandated by FERC.

FERC - Federal Energy Regulatory Commission

The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act. Successor to the Federal Power Commission, the FERC is considered an independent regulatory agency responsible primarily to Congress, but it is housed in the Department of Energy.

Firm Customer

A customer receiving service under rate schedules or contracts designed to provide the customer's gas supply and distribution needs on a continuous basis, even on a peak day.

Firm Service

A service offered to customers under schedules or contracts which anticipate no interruptions.

Fixed Physical

A fixed forward (also known as a fixed price physical contract) is an agreement between two parties to buy or sell a specified amount of natural gas at a certain future time, at a specific price, which is agreed upon at the time the deal is executed. It operates much like the price swap without the margin call risk.

Formation

A formation refers to either a certain layer of the earth's crust, or a certain area of a layer. It often refers to the area of rock where a petroleum or other hydrocarbon reservoir is located. Other related terms are basin or play.

Gas Transmission Northwest (GTN)

A U.S. pipeline which begins at the U.S.-Canadian border near Kingsgate, British Columbia and interconnects with Williams Northwest Pipeline at the Stanfield receipt point in Oregon.

Heating Degree Day (HDD)

An industry-wide standard, measuring how cold the weather is based on the extent to which the daily mean temperature falls below a reference temperature base, which for IGC, is 65 degrees Fahrenheit.

Idaho Falls Lateral (IFL)

A distinct segment of Intermountain’s distribution system which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties; an Area of Interest for Intermountain.

Industrial Customer

For purposes of categorizing large volume customers, any customer utilizing natural gas for vegetable, feedstock or chemical production, equipment fabrication and/or manufacturing or heating load for production purposes.

Institutional Customer

For purposes of categorizing large volume customers, this would include business such as hospitals, schools, and other weather sensitive customers.

Interruptible Customer

A customer receiving service under rate schedules or contracts which permit interruption of service on short notice due to insufficient gas supply or capacity.

Interruptible Service

Lower-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the higher priority claim of firm service customers and other higher priority users. Service is available at any time of the year if distribution capacity and/or pressure is sufficient.

Large Volume Customer

Any customer receiving service under one of the Company's large volume tariffs including LV-1, T-3, and T-4. Such service requires the customer to sign a minimum one-year contract and use at least 200,000 therms per contract year.

Liquefied Natural Gas (LNG)

Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. In volume, it occupies one-six-hundredth of that of the vapor at standard conditions.

Load Demand Curve (LDC)

A forecast of daily gas demand using design or normal temperatures, and predetermined usage per customer.

Local Distribution Company

A retail gas distribution company, utility, that delivers retail natural gas to end users.

Lost and Unaccounted for Natural Gas (LAUF)

The difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers.

Maximum Daily Firm Quantity (MDFQ)

The contractual amount that Intermountain guarantees to deliver to the customer each day. Also see Contract Demand.

Methane

Methane is commonly known as natural gas (or CH_4) and is the most common of the hydrocarbon gases. It is colorless and naturally odorless and burns efficiently without many by products. Natural gas only has an odor when it enters a customer's home because the local distributor adds it as a safety measure.

Normal Weather

Normal weather is comprised of HDD's that represent the average mean temperature for each day of the year. Intermountain's Normal Weather is a 30-year rolling average of NOAA's daily mean temperature.

Northwest Pipeline (Williams Northwest Pipeline, Northwest, NWP)

A 3,900-mile, bi-directional transmission pipeline crossing the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado and the only interstate pipeline which interconnects to Intermountain's distribution system; all gas supply received by the Company is transported by this pipeline.

NYMEX Futures

New York Mercantile Exchange is the world's largest physical commodity futures exchange. Futures are financial contracts obligating the buyer to purchase an asset (or the seller to sell an asset), such as a physical commodity, at a predetermined future date and price. Futures contracts detail the quality and quantity of the underlying asset; they are standardized to facilitate trading on a futures exchange. Some futures contracts may call for physical delivery of the asset, while others are settled in cash.

Peak Shaving

Using sources of energy, such as natural gas from storage, to supplement the normal amounts delivered to customers during peak-use periods. Using these supplemental sources prevents pipelines from having to expand their delivery facilities just to accommodate short periods of extremely high demand.

Peak Day

The coldest day of the design year; a measure used for planning system capacity requirements. For Intermountain, that day is currently January 15 of the design year.

PSIG (Pounds per Square Inch Gauge)

Pressure measured with respect to that of the atmosphere. This is a pressure gauge reading in which the gauge is adjusted to read zero at the surrounding atmospheric pressure. It is commonly called gauge pressure.

Producer

Natural gas producer is generally involved in exploration, drilling, and refinement of natural gas. There are independent producers, as well as integrated producers, which are generally larger companies that produce, transport and distribute natural gas.

Purchased Gas Adjustment or PGA

Intermountain's annual price change to adjust the cost of gas service to its customers, based on deferrals from the prior year and forward-looking cost forecasts.

Residential Customer

Any customer receiving service under the Company's RS Rate Schedule.

SCADA (Supervisory Control and Data Acquisition)

Remote controlled equipment used by pipelines and utilities to operate their gas systems. These computerized networks can acquire immediate data concerning flow, pressure or volumes of gas, as well as control different aspects of gas transmission throughout a pipeline system.

State Street Lateral (SSL)

A distinct segment of Intermountain's distribution system which serves core market customers in Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21; an Area of Interest for Intermountain.

Sun Valley Lateral (SVL)

A distinct segment of Intermountain's distribution system that serves customers in Blaine and Lincoln counties; an Area of Interest for Intermountain.

Therm

A unit of heat energy equal to 100,000 British thermal units (BTU). It is approximately the energy equivalent of burning 100 cubic feet (1 CCF) of natural gas.

Traffic Analysis Zones (TAZ)

An analysis of traffic patterns in certain high traffic areas.

Transportation Tariff

Tariffs that provide for the redelivery of a shipper's natural gas received into an interstate pipeline or Intermountain's distribution system. A transportation customer is responsible for procuring its own supply of natural gas and transporting it on the interstate pipeline system for delivery to Intermountain at one of its citygate locations.

WCSB (Western Canadian Sedimentary Basin)

A vast natural gas producing region encompassing 1,400,000 square kilometers (540,000 sq mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east.