Intermountain Gas Company

Integrated Resource Plan

2023 – 2028

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

In the Community to Serve®

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1 Introduction

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, with a population of roughly 1,404,000. Currently, Intermountain serves approximately 412,500 total customers in 74 communities through a system of over 13,300 miles of transmission, distribution and service lines. In 2020, approximately 755 million therms were delivered to customers and over 260 miles of 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.

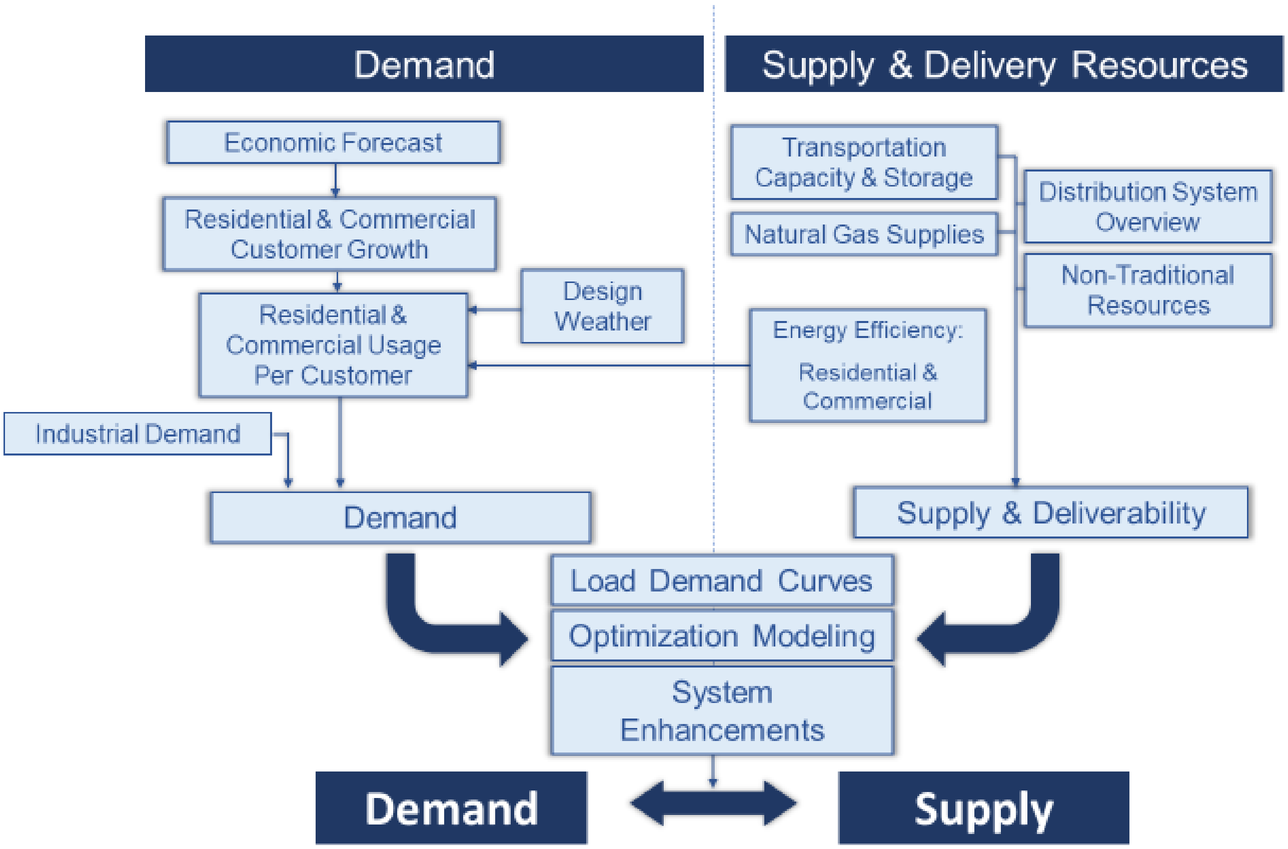


Figure 1: The IRP Process

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, is a sample of the invitation to join the committee. Committee members have varied backgrounds in regulation, economic development, and business.

For this IRP cycle, 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 three virtual meetings were held in 2023 between the months of May and August. Included in Exhibit 1 are sample copies of the presentations from the meetings as well as the meeting minutes. Intermountain also built a website[1] where the Company's meeting schedule, presentation, minutes, and a video recording of each IGRAC meeting can be found.

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.

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* Integrated Resource Plan - Intermountain Gas Company (intgas.com)

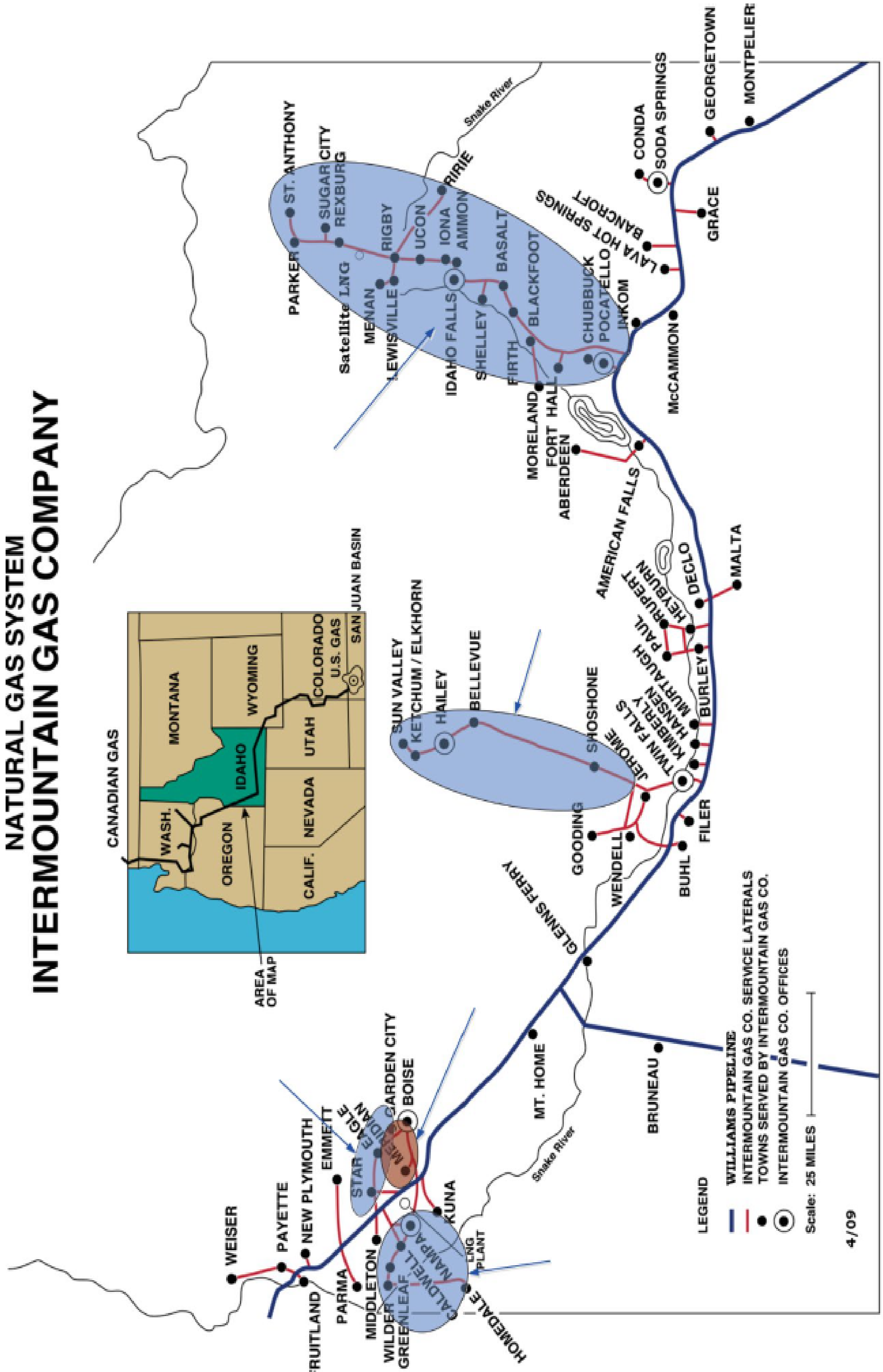


Figure 2: Intermountain Gas System Map

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 is the cleanest fossil fuel. It burns efficiently, producing primarily heat and water vapor. Natural gas has also led U.S. carbon emission reductions to 27-year lows, and the U.S. Energy Information Administration projects that trend will continue.[2] The Environmental Protection Agency's (EPA) "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2021" reveals distribution systems owned and operated by local natural gas utilities emit 8.4 percent of natural gas system CH_4 emissions. These annual emissions declined more than 69 percent from 1990 to 2020, as natural gas utility companies invested an average of $95 million daily in infrastructure upgrades to add more than 815,100 miles of pipelines to serve 22.3 million more customers over that period, increases of 56 percent and 41 percent, respectively.[3] Distribution system CO_2 emissions in 2021 were 70 percent lower than 1990 levels and 1 percent lower than 2020 emissions. Annual CO2 emissions from this segment are less than 0.1 million metric tons of CO_2-equivalent emissions (MMTe) across the time series.[4]

Natural gas pipelines are the safest and most efficient mode of transportation, surpassing rail and truck, according to the U.S. Department of Transportation. Pipeline incidents or disruptions to natural gas service are rare because of the industry's consistent focus on safety and reliability.[5] Intermountain considers safety and reliability at every stage, from pipeline design to construction to ongoing maintenance.

Natural gas is affordable. Since 2008, the price of natural gas has fallen by about 37% (adjusted for inflation). According to the American Gas Association, households that use natural gas for heating, cooking and clothes drying save an average of $1,068 per year compared to homes using electricity for those applications.[6] The American Gas Association also reported that for residential customers, the cost of natural gas has been

[2] https://www.aga.org/wp-content/uploads/2022/12/building-the-value-of-natural-gas-a-fact-base-may-2020.pdf
[3] https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/
[4] https://www.aga.org/wp-content/uploads/2023/08/AGA-Report_Understanding-GHG-Emssions-from-Natural-Gas_2023.pdf
[5] https://www.ingaa.org/File.aspx?id=28478
[6] https://www.aga.org/wp-content/uploads/2023/04/Quick-gas-facts-sheet-2021.pdf

lower than the cost of propane, fuel oil, or electricity since 2010, and is forecasted to stay low through 2040.[7]

According to the American Gas Association, in the United States natural gas currently meets more than 33% of the nation's energy needs, providing energy to almost 77 million residential, commercial and industrial customers.[8] Natural gas is now even more plentiful than ever in North America, with an estimated 86 year supply at current consumption levels.[9] Even with this plentiful supply, however, it remains vital that all natural gas customers use the energy as wisely and as efficiently as possible.

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 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 roughly 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

[7] https://www.aga.org/natural-gas/affordable/
[8] https://www.aga.org/wp-content/uploads/2023/04/Quick-gas-facts-sheet-2021.pdf
[9] https://www.eia.gov/tools/faqs/faq.php?id=58&t=8

region, which according to Idaho Power's 2020 annual report is approximately 5,463,000 MWh. 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 Plan 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.

Under the Company's current RNG Facilitation Plan, Intermountain's customers are completely insulated from any risk that may be inherent in the developing industry. RNG producers pay all of the upfront costs of constructing the facilities to interconnect the RNG production facilities with Intermountain's distribution system. RNG producers also pay a monthly O&M fee that covers all O&M costs that are incurred in providing transportation service to the RNG facilities. Insulating customers from potential risk, while helping to grow an industry that could provide a supply resource in the future creates significant benefits to all parties involved.

2 Demand

2.1 Demand Forecast Overview

The first step in resource planning is forecasting future load requirements. Three essential components of the load forecast include projecting the number of customers requiring service, forecasting the weather sensitive customers' response to temperatures and estimating the weather those customers may experience. To complete the demand forecast, contracted maximum deliveries to industrial customers are also included.

Intermountain's long range demand forecast incorporates various factors including divergent customer forecasts, statistically based gas usage per customer calculations, and varied weather profiles, all of which are discussed later in this document. Using various combinations of these factors results in six separate and diverse demand forecast scenarios for the weather sensitive core market customers.

Combining those projections with the large volume market forecast provides Intermountain with six total company demand scenarios that envelop a wide range of potential outcomes. These forecasts not only project monthly and annual loads but also predict daily usage including peak demand events. The inclusion of all this detail allows Intermountain to evaluate the adequacy of its supply arrangements and delivery under a wide range of demand scenarios.

Intermountain's resource planning looks at distinct segments (i.e., Areas of Interest (AOIs)) within its current distribution system as depicted in Figure 2 on page 6. After analyzing resource requirements at the segment level, the data is aggregated to provide a total company perspective. The AOIs for planning purposes are as follows:

- The Canyon County Area (CCA), which serves core market customers in Canyon County.
- The Sun Valley Lateral (SVL), which serves core market customers in Blaine and Lincoln counties.
- The Idaho Falls Lateral (IFL), which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties.
- The Central Ada County (CAC), which serves core market customers in the area of Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west.

- The State Street Lateral (SSL), which serves core market customers in the area of 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.

The All Other segment, which serves core market customers in Ada County not included in the State Street Lateral and 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 2023 through 2028. This forecast provides the anticipated magnitude and direction of Intermountain's residential and commercial customer growth by the identified Areas of Interest 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 ARIMA model which incorporates population and employment forecasts as an explanatory variable for the residential and commercial customer forecasts, respectively. An ARIMA model is an autoregressive integrated moving average model that is used on time series data to better predict future points. The population data measures actual and forecasted population growth in Intermountain's service territory by county. The employment data measures actual and forecasted full- and part-time jobs by place of work. Generally, when population increases, residential customer counts are also increasing, thus, the reason for including population as an explanatory variable. Similarly, when employment is increasing, commercial customer counts are also increasing, thus, the reason for including employment as an explanatory variable. Each County in Intermountain's service territory is modeled separately.

The residential customer forecast model is as follows:

$$R_{County} = \alpha_0 + \alpha_1 Pop^{County} + ARIMA\epsilon(p, d, q)$$

Where:

- $R_{County} = Residential\ Customers\ by\ County$

- $Pop^{County} = Population\ by\ County$
- $ARIMA\epsilon(p, d, q) =$
  $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d$
  $difference\ terms, and\ q\ moving\ average\ terms$

The commercial customer forecast model is as follows:

$$C_{County} = \alpha_0 + \alpha_1 Emp^{County} + ARIMA\epsilon(p, d, q)$$

Where:

- $C_{County} = Commercial\ Customers\ by\ County$
- $Emp^{County} = Employment\ by\ County$
- $ARIMA\epsilon(p, d, q) =$
  $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d$
  $difference\ terms, and\ q\ moving\ average\ terms$

Exhibit 2 shows the Company's residential and commercial customer forecast.

Similar to the 2021 IRP, which demonstrated a continued resurgence in the housing market Intermountain's growth projections continue to stay strong. The following graph (Figure 3) depicts the relationship, or shape, of customer additions by AOI:

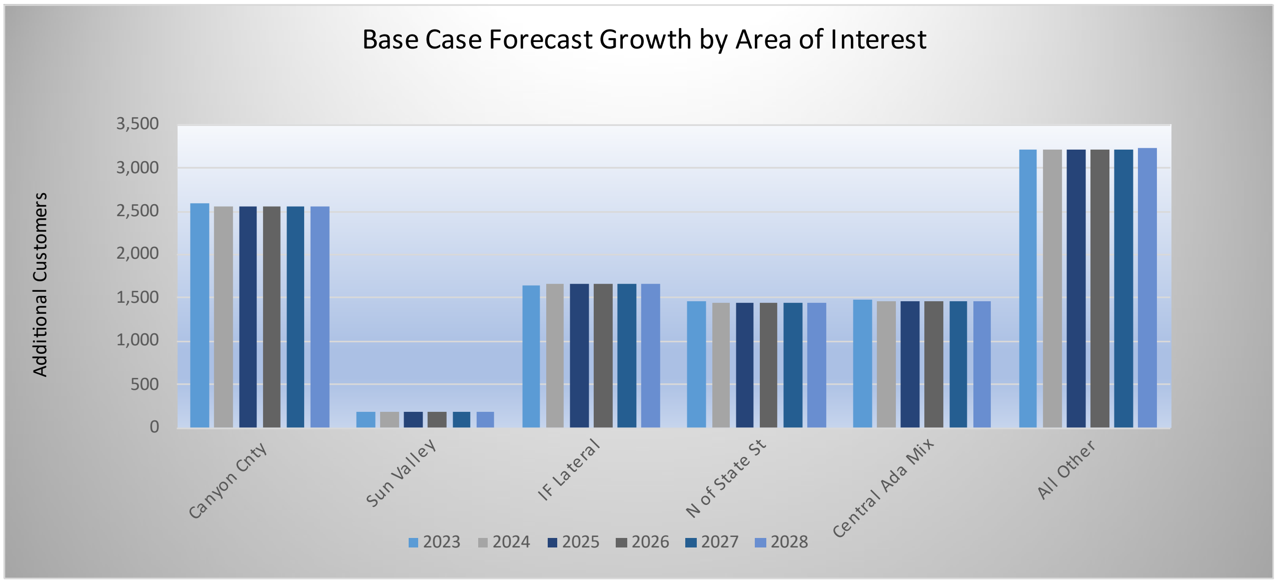


Figure 3: Base Case Forecast Growth by Area of Interest

The forecast contains three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model and has developed three five-year core market customer growth forecasts. The following graph (Figure 4) shows the annual additional customer forecast for each of the three economic scenarios.

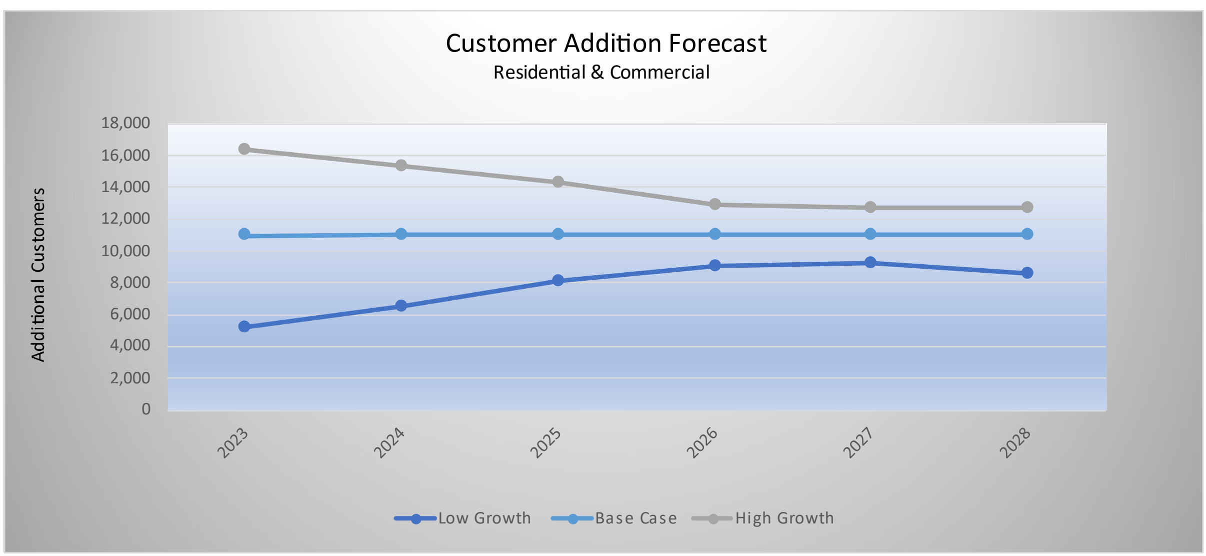


Figure 4: Customer Addition Forecast - Residential & Commercial

The following graph (Figure 5) shows the difference in base case annual additional customers between the 2021 and 2023 IRP forecast years common to both studies:

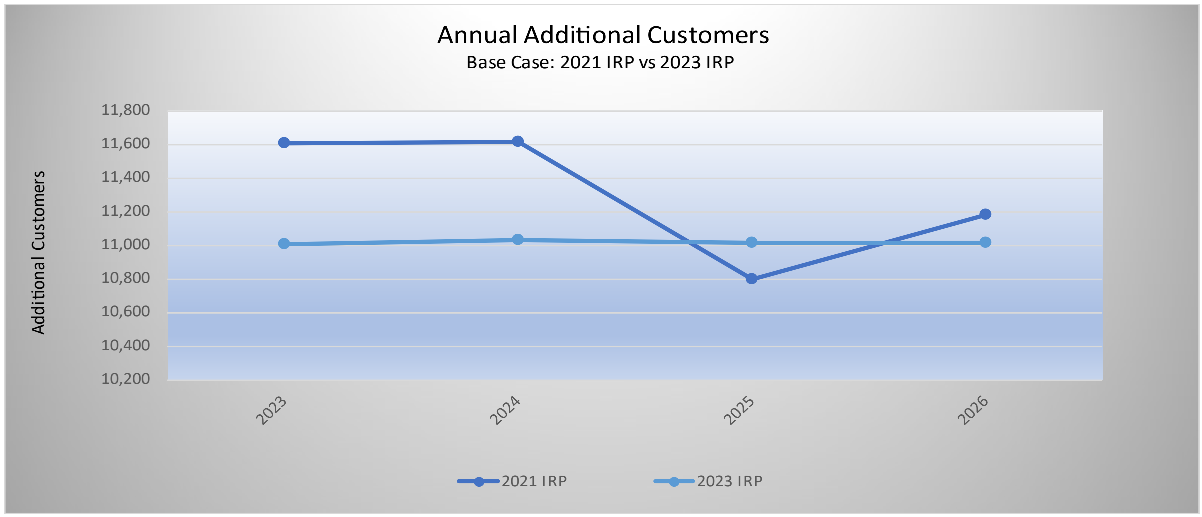


Figure 5: Annual Additional Customers - Base Case: 2019 IRP vs 2021 IRP

The following tables show the results from the five-year customer growth model for each scenario for the annual additional or incremental customers and total customers at each year- end.

Table 1: Forecast New Customers

Forecast New Customers						
	2023	2024	2025	2026	2027	2028
LOW GROWTH	5,229	6,557	8,156	9,077	9,229	8,557
BASE CASE	11,004	11,030	11,018	11,011	11,020	11,017
HIGH GROWTH	16,418	15,379	14,347	12,911	12,770	12,720

Table 2: Forecast Total Customers

Forecast Total Customers						
	2023	2024	2025	2026	2027	2028
LOW GROWTH	409,167	415,724	423,880	432,957	442,185	450,742
BASE CASE	414,942	425,972	436,990	448,001	459,021	470,038
HIGH GROWTH	420,356	435,735	450,082	462,994	475,763	488,484

The following sections explore more fully the different components of the customer forecast, including the '22 Forecast, market penetration and conversion rates, and commercial customer growth.

2.2.1 The Base Case Economic Growth Scenario

Intermountain utilized the 2022 Woods & Poole (W&P) State and County Projections for the base case economic growth scenario. W&P projected that Idaho will continue to be an attractive environment for future economic, population and household growth. In the decade of the 1990s Idaho's population increased at a strong annual average rate of 2.5 percent per year. The Great Recession of 2008 caused a significant slowing in Idaho's economy. The 2008 recession caused Idaho's nonagricultural employment to contract by nearly 51,500 jobs (7.9%) in the years 2008 through 2010.

As the recession took hold in Idaho the state did not immediately experience a slowdown in population growth which averaged 1.9% per year over the 2000 to 2010 period. Nevertheless, population growth slowed to a pace of less than 1.0% per year in 2011 and 2012.

Nonagricultural employment in Idaho regained its upward momentum in 2011 with an annual average increase of 1.2% - 7,200 jobs. In the years 2012 – 2019 Idaho's nonagricultural employment gains were strong with an annual average increase of 2.9% per year, a gain of 137,500 jobs over the 7-year period.

In 2020 the COVID-19 pandemic brought Idaho's economic growth to a halt. Nonagricultural employment in Idaho declined 74,000 jobs between February 2020 and April 2020. However, in the following months Idaho regained many of those jobs that were lost. So much so that the state's November 2020 total employment numbers were down only 7,200 jobs from year earlier levels. While the November 2020 number of persons unemployed in Idaho was nearly 25,000 above year earlier levels the sum of the number of employed plus the unemployed is indicative of an economy that continues to exhibit an underlying upward momentum and future growth.

While Idaho's economy may not post the gains seen in the 2015 to 2019 period in 2021 and 2022 it is forecasted to continue its economic gains over the longer term 2023 to 2045 forecast period.

Total non-agricultural employment in the State is projected to increase by 393,000 (an annual average increase of 1.4 percent per year) over the 2023 to 2045 period. Ada and

Canyon counties are projected to capture the majority of the non-ag employment gains with a projected increase of 226,400 non-ag jobs in the two counties, an annual average increase of 1.8 percent per year over the 2023 to 2045 period. During those twenty-five years Ada and Canyon counties are projected to account for nearly 57.6 percent of the projected total non-ag employment gains statewide. Other areas of projected employment growth are in Bannock, Bonneville, Jefferson, and Madison counties of Eastern Idaho. Over the 2023 to 2045 forecast period non-ag employment in these the Eastern Idaho counties is projected to increase by 55,100 jobs, a 1.3 percent annual average increase.

As has been the case over the last two decades, employment and population growth in the state is projected to be concentrated in the few, more urban, counties. Ada and Canyon counties will continue to capture over 60 percent of the state's projected future employment and population growth. In second place Kootenai and Bonner counties in North Idaho are projected to capture nearly 20% of the 2023 to 2045 employment and population growth. And the Eastern Idaho counties along Intermountain Gas Company's Idaho Falls Lateral (Bannock, Bingham, Bonneville, Butte, Fremont, Jefferson, Madison, and Power counties) are projected to account for nearly 12 percent of future employment and population gains in the state.

Idaho's manufacturing industries will not be the driver of future economic growth in the state. In the years 2000 to 2010 manufacturing employment in Idaho decreased by nearly 17,200 jobs. In what can only be considered as a somewhat remarkable turnaround in the years since 2010, and through mid-year 2020 Idaho regained nearly 14,000 manufacturing jobs. In the 2023 to 2045 forecast period, manufacturing employment is projected to increase by only 9,200 jobs.

Employment in Idaho's forestry, fishing, and related activities sector slipped in the 2008 Great Recession. It has not recovered and its unlikely that it will recover with the possible exception of the production of higher value-added processed wood products. Future job gains in the forestry, fishing, and related activities sector is projected to be minimal over the 2023 to 2045 forecast period.

Statewide employment in the Transportation, Trade, and Utilities industries is projected to increase by nearly 35,000 jobs over the 2023 to 2045 forecast period; an annual average increase 0of nearly 1.0 percent per year. In general, employment in Transportation, Trade, and Utilities is projected to increase at a pace that is slower than the forecasted rate of population and household growth statewide. In Ada and Canyon counties Transportation, Trade, and Utilities employment is projected to increase by 23,100 over the forecast period, representing 66.0 percent of the projected statewide employment gains in the sector.

The service industries in Idaho have been the fastest growing in terms of employment gains over the last twenty years. In the last 10 years, accommodation and food services employment has increased about 20,000 jobs in Idaho, even with a large disruption due to the COVID-19 pandemic. Accommodation and food services industries are the largest part of the leisure and hospitality sector and given Idaho's population and increased tourism, employment will continue to rise. In the 2023 to 2045 forecast period, accommodation and food services employment is projected to increase by 37,000 jobs in Idaho. Idaho employment in the Professional and Technical Services sector increased by nearly 26,000 jobs over the last 20 years; an annual average increase of 2.4 percent per year. Ada and Canyon counties captured nearly 66.7 percent of the State's Professional and Business Services employment growth from that time period. In the 2020 to 2045 forecast period Professional and Business Services employment is projected to increase by 41,300; an annual average compound rate of 2.1 percent per year. Historically the Professional and Technical Services sector in Idaho has posted employment gains and losses that could be considered volatile. This has been due to the business classification of subcontractors utilized by the US Department of Energy at the Idaho National Laboratory (INL). Changes in INL subcontractors have caused Professional and Business Services employment in the state to change rapidly in the past and they may change in the future.

Idaho employment in Educational and Health Services increased by nearly 67,000 jobs over the previous 20 years; an annual average increase of 3.2 percent per year. Ada and Canyon counties captured 31,900, nearly 47.6 percent, of the state's Educational and Health Services employment growth over the previous 20 years. In the 2023 to 2045 forecast period Educational and Health Services employment is projected to increase by 118,500; an annual average compound rate of 2.7 percent per year. Jobs in Idaho's Educational and Health Services sector are more spatially diverse that the Professional and Business Services sector. Almost every county in Idaho is projected to post an increase in employment over the 2023 to 2045 forecast period. In the counties along Intermountain Gas Company's Idaho Falls Lateral the Educational and Health Services sector is projected add 19,800 jobs over the 2023 to 2045 forecast period.

Idaho employment in Arts, Entertainment, & Recreation sector added 10,300 jobs over the last 20 years; an annual average increase of 2.7 percent per year. Ada and Canyon counties captured 5,700, nearly 55.6 percent, of the state's Arts, Entertainment, & Recreation employment growth. In the 2023 to 2045 forecast period Leisure and Hospitality Services employment is projected to increase by 15,300; an annual average compound rate of 2.1 percent per year.

Employment in the Government sector increased by 16,700 jobs over the last 20 years; an annual average increase of 0.8 percent per year. Government employment gained 10,500 jobs in Ada and Canyon counties over that same time period, a reflection of the faster than average population and household growth in the two counties which has caused significant increases in local government employment. In the 2023 to 2045 forecast period Government employment is projected to increase by 20,100; an annual average compound rate of 0.7 percent per year. No specific growth assumptions are made concerning government future employment at Idaho's two largest government facilities – Mountain Home Air Force Base and the INL.

2.2.2 Population and Household Growth

US Census Bureau population estimates indicate that Idaho has experienced a significant increase in population growth since the end of the 2008 Great Recession. Over the years 2014 through 2019, population growth in Idaho was twice ranked as the fastest growing in the nation, and in every year of the last five years Idaho was always ranked one of the fastest growing states in the country. The COVID – 19 pandemic did not slow down Idaho's population growth. Per the US Census Bureau, Idaho was ranked as the fastest growing state in the nation during 2020. This has only continued into 2021 and 2022, as Idaho's population grew 2.98% and 1.82%, respectively. Idaho was the fastest growing state in 2020 and 2021, and the second fastest growing state in 2022.

Total population in Idaho has increased at a robust pace since 2010. Through 2019 the US Census Bureau estimates that Idaho's population increased by 219,500 (14.0% - a annual average increase of 2.0% per year over the 2010 to 2019 period). These increases are overwhelmingly due to a robust in-migration to Idaho. A 2.0% annual average rate of population growth, minus a natural population growth rate of 0.42% per year, leaves an annual average population increase of 1.58% per year (about 28,000 persons per year) due to in-migration.

In five years after the effects of the 2008 Great Recession (2014 – 2019), Idaho's population increased by 136,000, an overall increase of 8.2 percent. Ada and Canyon counties accounted for 53.6 percent of the state's population growth over those five years. Idaho's population growth over the 2014 through 2019 period was very concentrated. If population growth in the Eastern Idaho counties of Bannock, Bonneville, Jefferson, and Madison are included these six counties represent 66.4 percent of the state's population growth. Add in the population growth in Twin Falls County and that share increases to 70.2 percent. Lastly, adding in the population growth that occurred in Kootenai and Bonner counties in North Idaho and these nine counties accounted for 85.3 percent of the state's population growth over the 2014 to 2019 period. That concentration of the state's population growth is projected to continue in the forecast period.

It is projected that during the 2023 to 2045 forecast period Idaho's population will increase by 500,000 reaching a total population of 2,444,700 by the year 2045, an annual average pace of 1 percent per year. The number of households in the state is expected to increase by approximately 186,200 over the 2023 to 2045 forecast period.

Ada and Canyon counties are projected to capture the majority of Idaho's population growth over the forecast period. Population in Ada and Canyon counties are projected to reach 718,400 and 349,300, respectively, by the year 2045. This represents an increase of 190,300 in Ada County population and a 97,900 increase in Canyon County population over the 2023 to 2045 forecast period. In total, population growth in Ada and Canyon counties are projected to account for 57.6 percent of the 2023 to 2045 projected population growth in the state.

In Eastern Idaho, Bonneville, Madison, Bannock, and Jefferson counties are expected to see increases in population of 33,600, 16,600, 8,900 and 10,200, respectively, a total population increase for the four counties of 69,400 over the 2023 to 2045 forecast period. These four Eastern Idaho counties are projected to account for 13.9 percent of the state's population growth over the forecast period.

2.2.3 The High and Low Economic Growth Scenarios

The high growth and low growth scenarios utilize the confidence intervals for each model to build the high and low customer growth scenarios. The confidence intervals capture the high and low historical economic growth, and the impact it has to customer growth through the regression models and provides an output in the case of a high and low economic pathway.

2.2.4 Residential Customer Forecast

The following graphs show the forecasted residential customer counts based on the low growth, base case and high growth scenarios for each AOI and Total Company using the methodology explained previously.

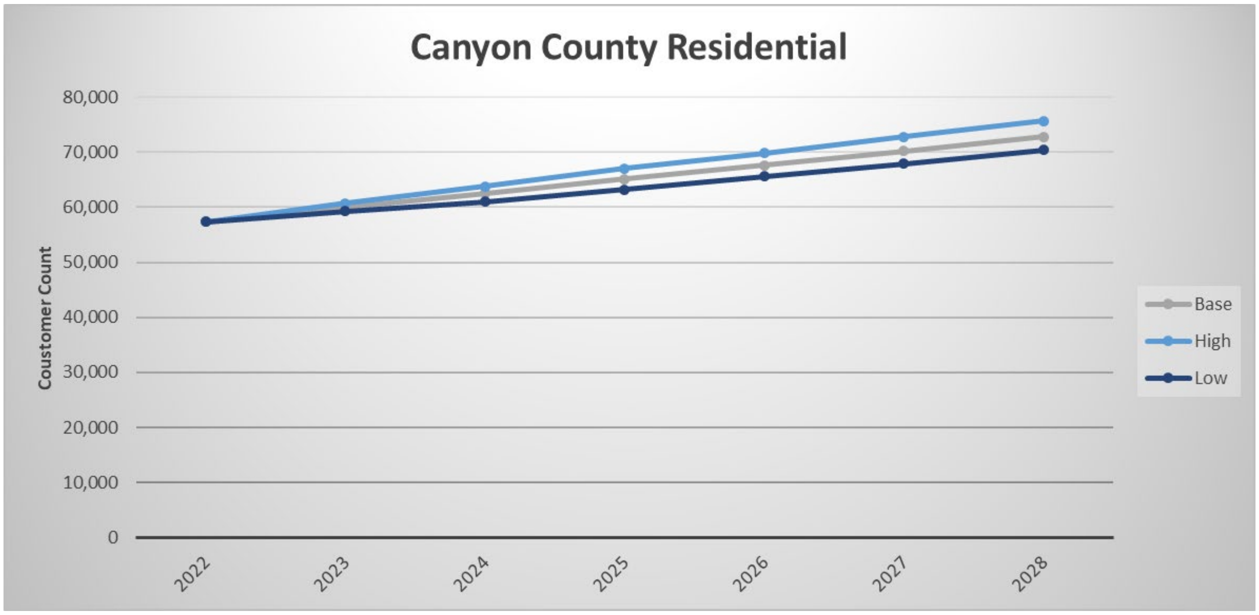


Figure 6: Forecasted Canyon County Residential Customers

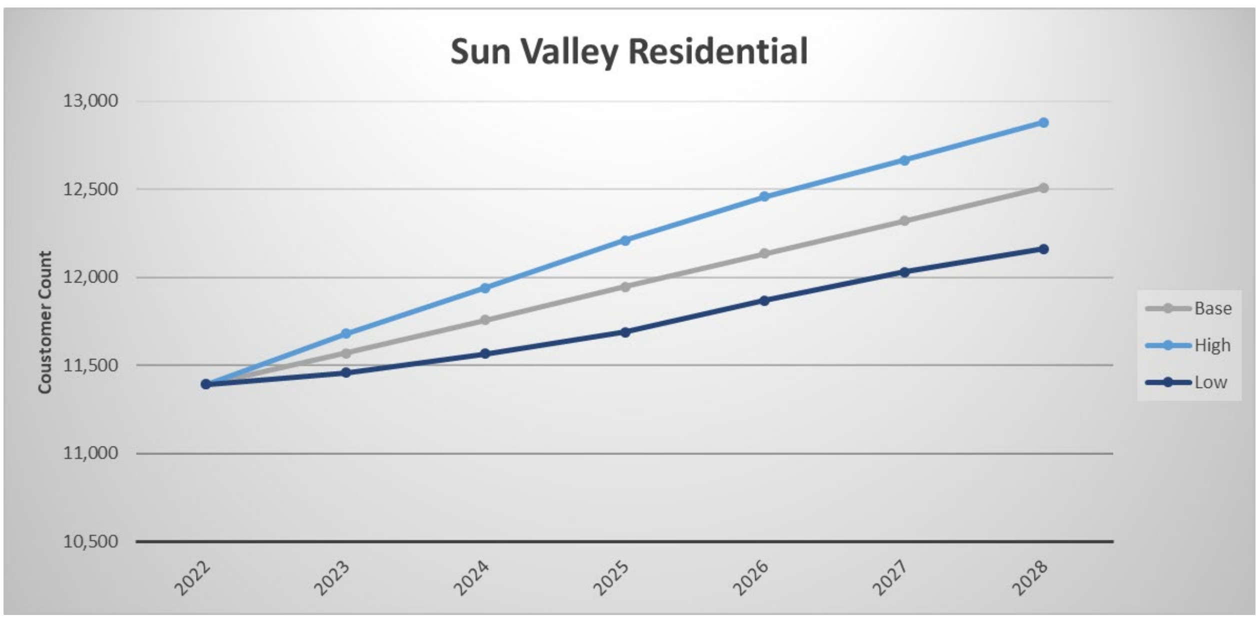


Figure 7: Forecasted Sun Valley Residential Customers

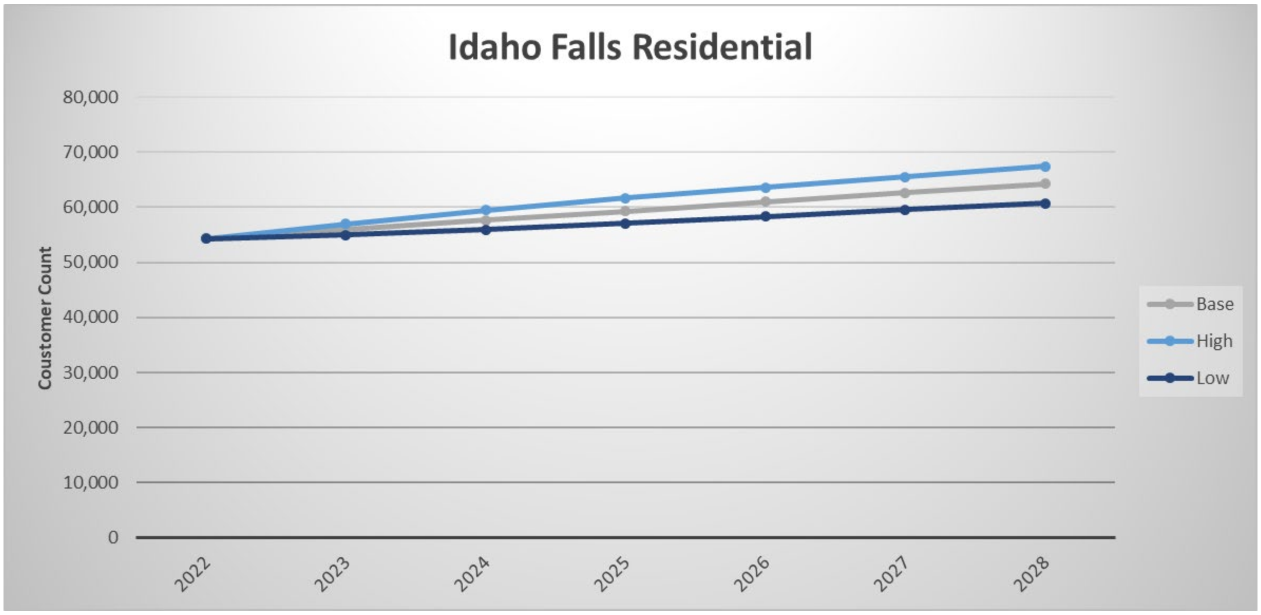


Figure 8: Forecasted Idaho Falls Residential Customers

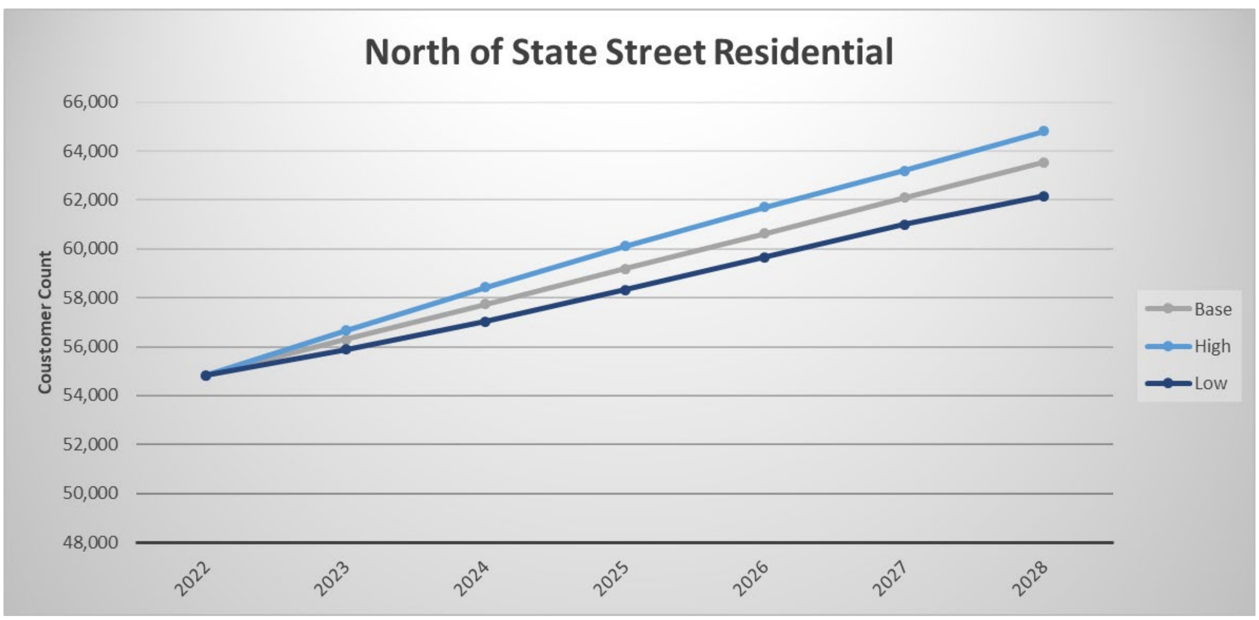


Figure 9: Forecasted North of State St Residential Customers

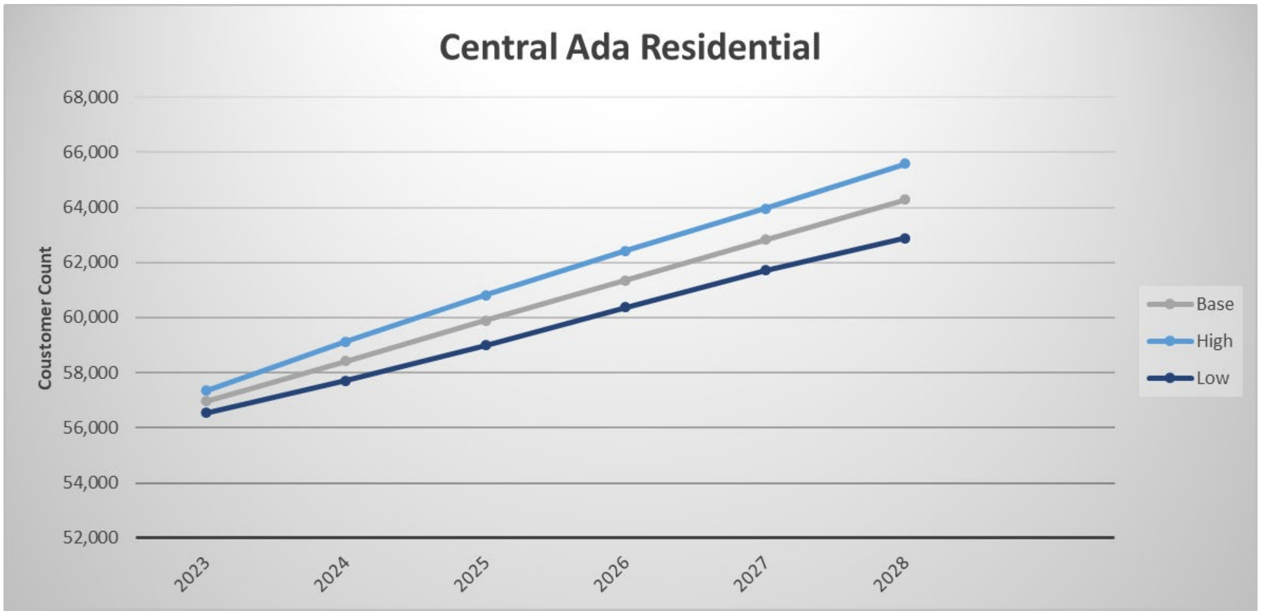


Figure 10: Forecasted Central Ada Residential Customers

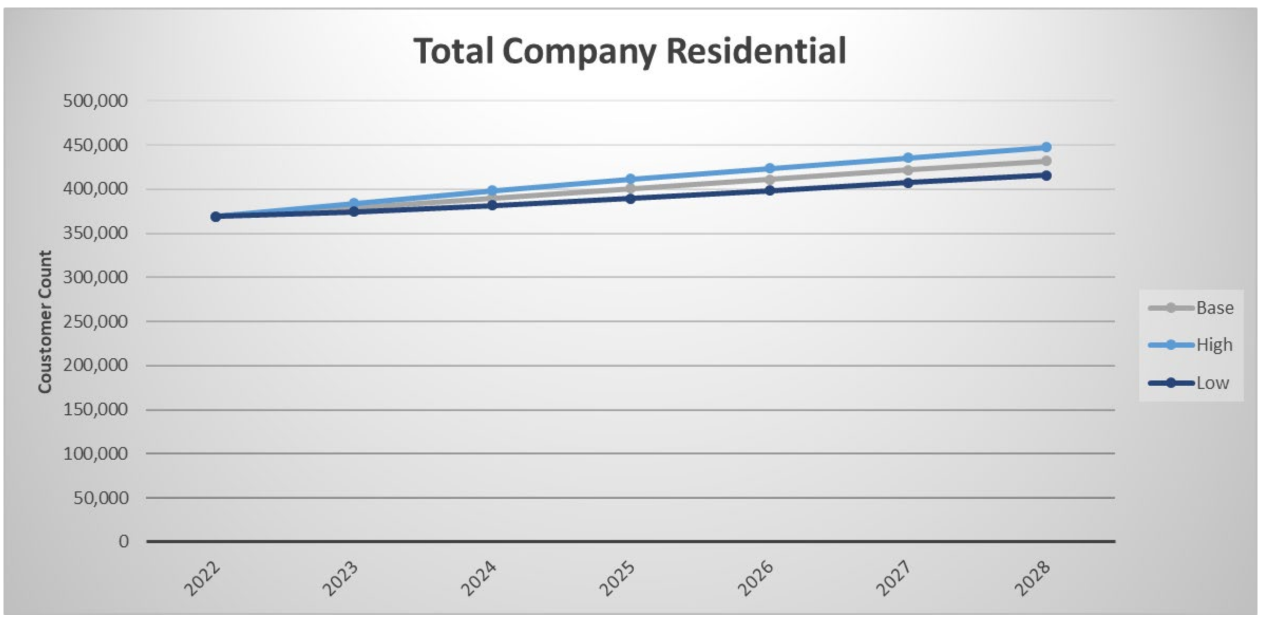


Figure 11: Forecasted Total Company Residential Customers

2.2.5 Commercial Customer Forecast

The following graphs show the forecasted commercial customer counts based on the low growth, base case and high growth scenarios for each AOI and Total Company using the methodology explained previously.

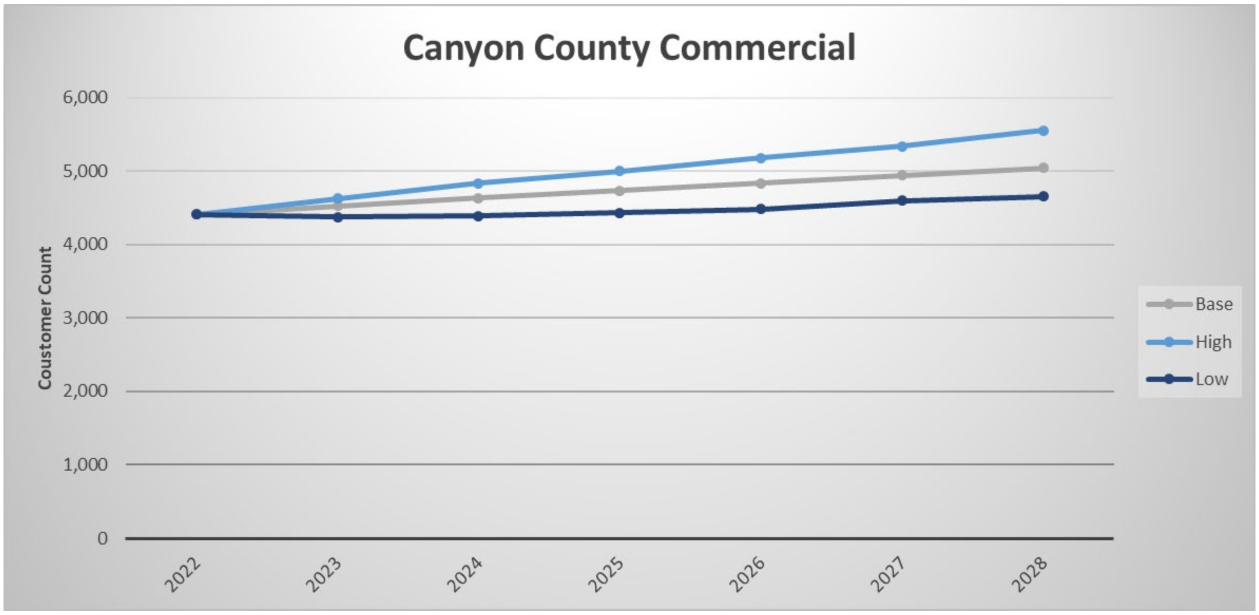


Figure 12: Forecasted Canyon County Commercial Customers

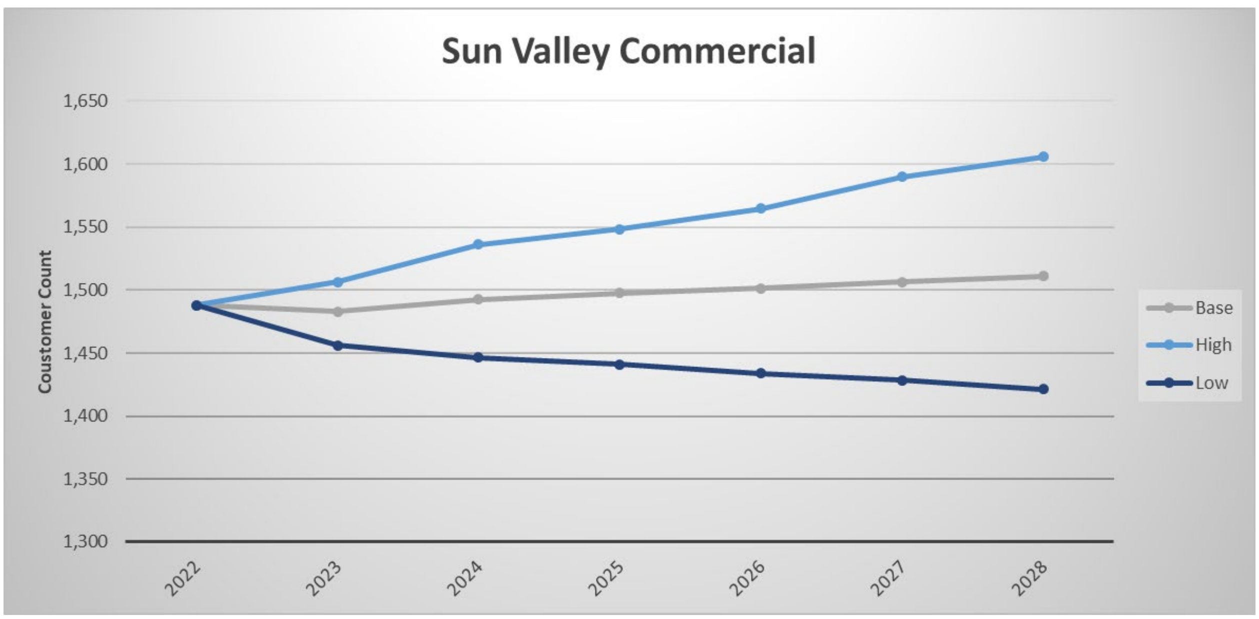


Figure 13: Forecasted Sun Valley Commercial Customers

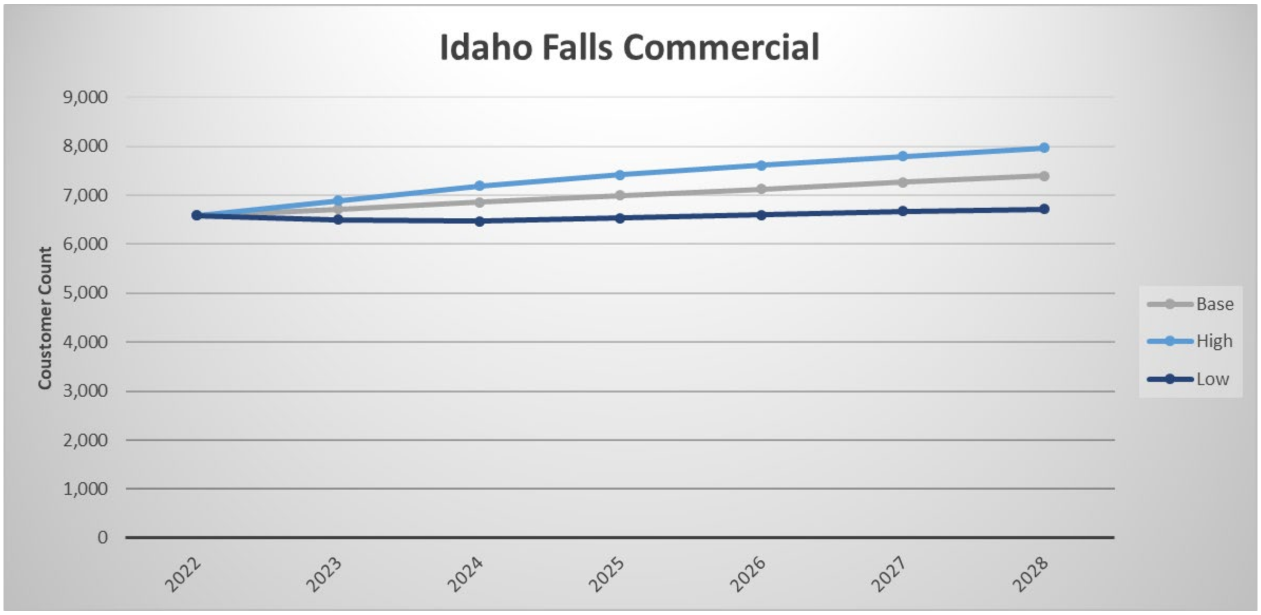


Figure 14: Forecasted Idaho Falls Commercial Customers

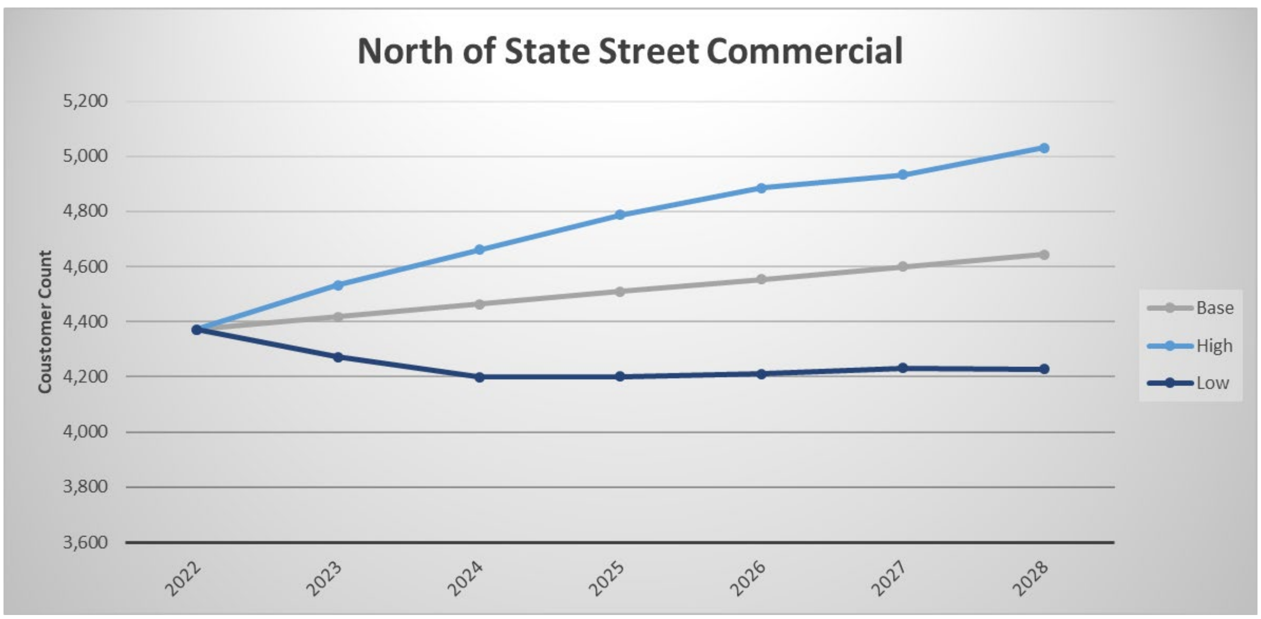


Figure 15: Forecasted North of State St Commercial Customers

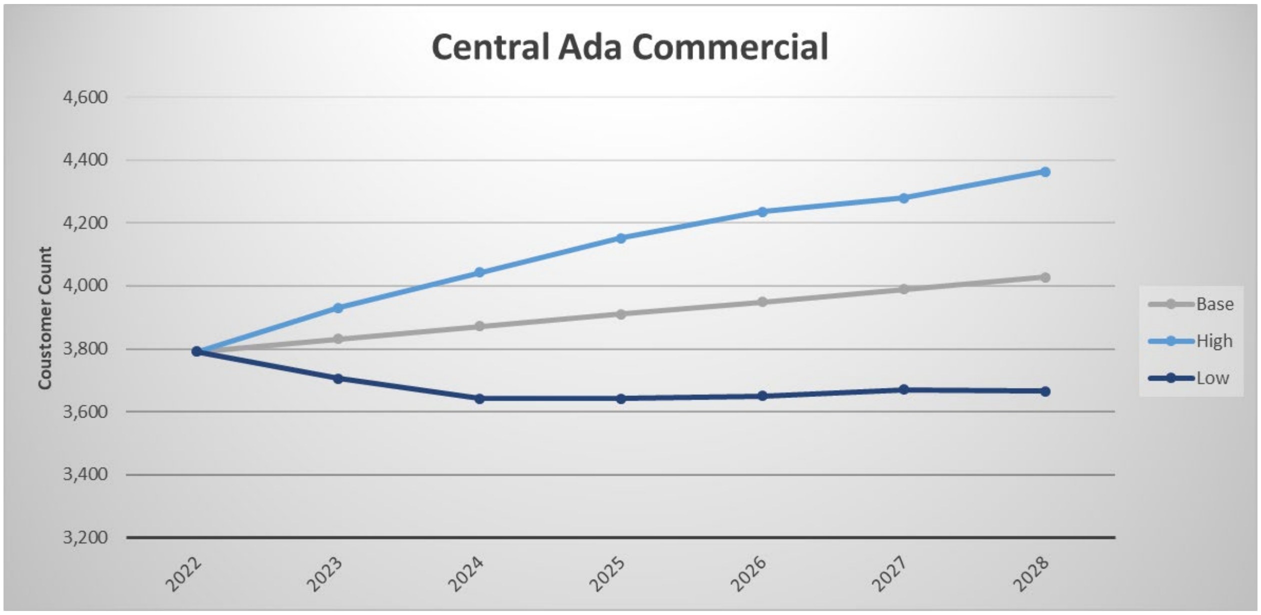


Figure 16: Forecasted Central Ada Commercial Customers

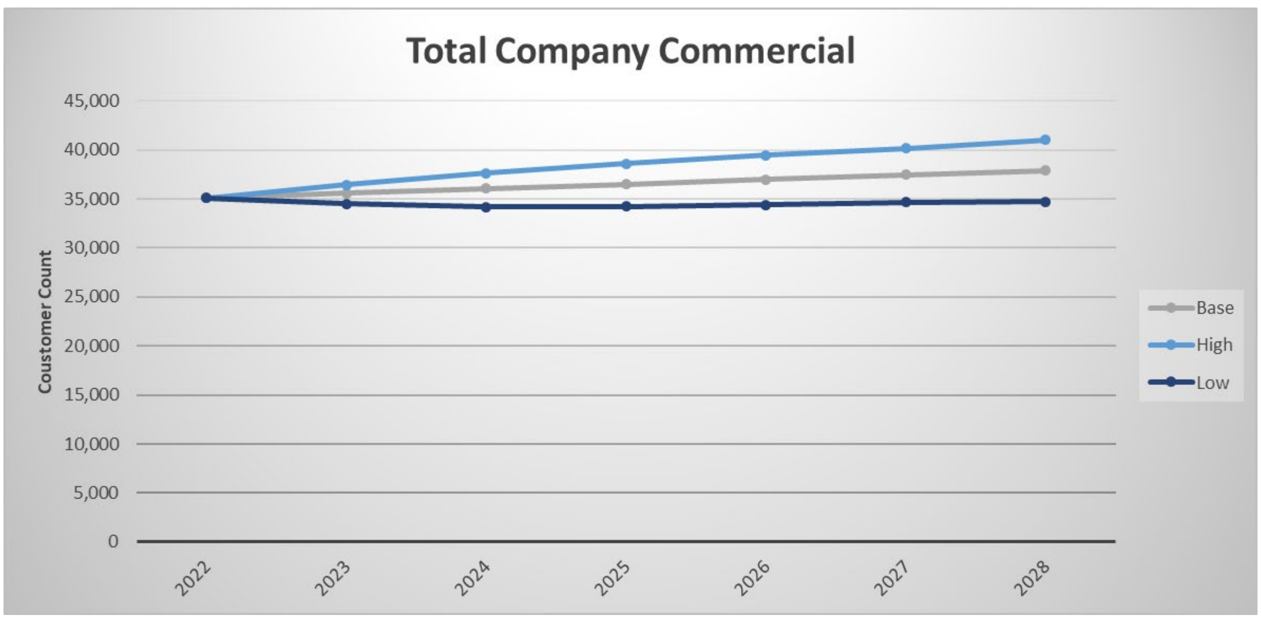


Figure 17: Forecasted Total Company Commercial Customers

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 2022. 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 overusing 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 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, some 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 five-day moving average of the temperatures for the past thirty-year period to select the five 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 four 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 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. Therefore Intermountain does not 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 on following page). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.

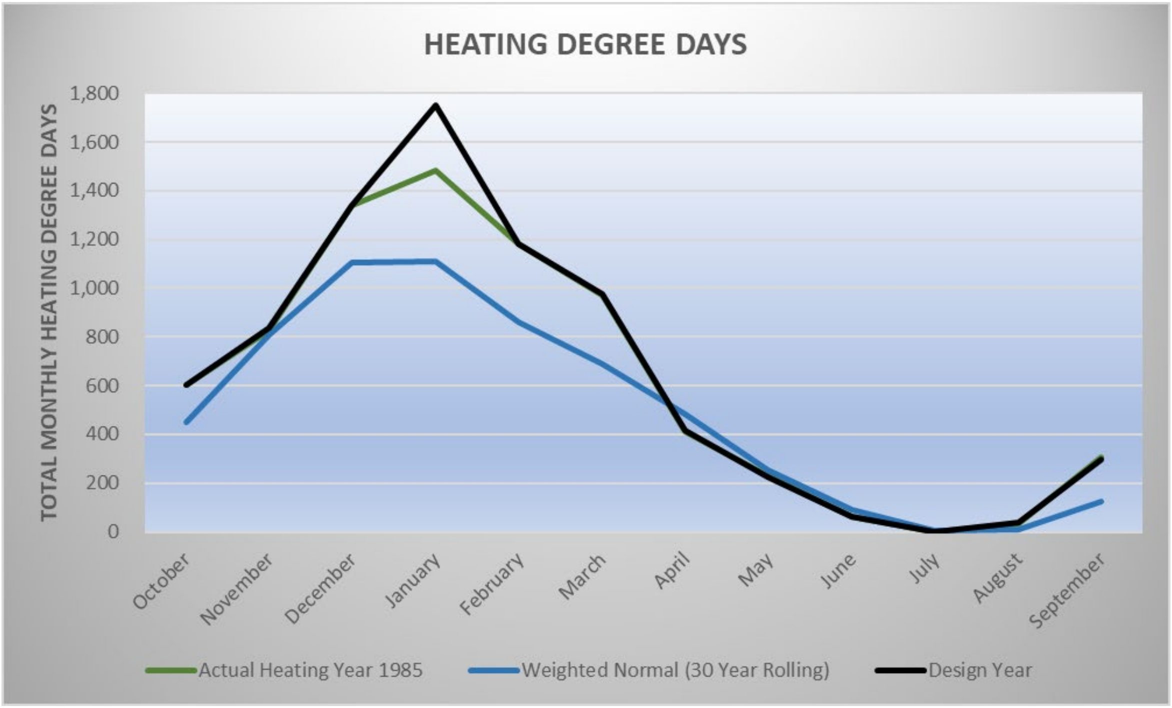


Figure 18: Design Heating Degree Days

The resulting Normal, Base Year (1985), and Design Year degree days by month are outlined in Table 3 below:

Table 3: Monthly Heating Degree Days

Monthly Heating Degree Days			
	Actual Heating Year 1985	Weighted Normal (30 Year Rolling)	Design Year
October	604	452	603
November	827	809	836
December	1,338	1,103	1,338
January	1,483	1,109	1,749
February	1,180	861	1,180
March	972	688	974
April	413	484	414
May	231	253	226
June	62	91	63
July	0	3	0
August	36	10	39
September	306	123	299
Total	7,452	5,986	7,721

2.3.5 Area Specific Degree Days

As noted earlier in this IRP, Intermountain has identified certain Areas of Interest (AOI). 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. 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 149 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 47% of Intermountain's 2022 annual throughput and 24% of the projected 2023 design Base Case peak day. Nearly 97% of 2022 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. The chart below (Figure 19) shows a comparison of total actual LV therm use against base case forecast therm use from the 2021 IRP for the years 2021 – 2023.

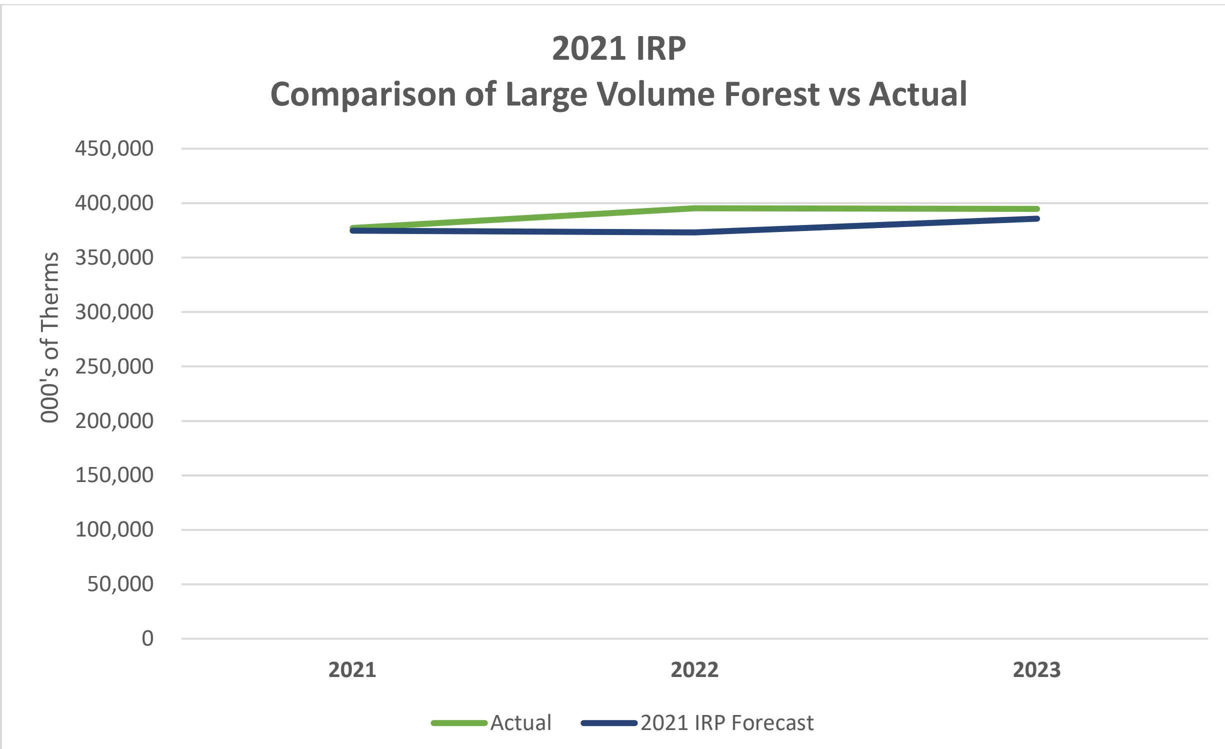


Figure 19: LV Therms - 2021 IRP Forecast vs Actuals

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 149 existing and up to ten projected new customers (per the High Growth scenario) were combined into six homogeneous market segments:

2023 Customers by Market Segment:

- 18 potato processors
- 49 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, 2023, for the beginning point for Base Case CDs.

While many LV customers are predicted to increase their annual usage requirements through 2028, 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 Areas 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 but 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 importance, 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 2022 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 20 million therms (or an annualized rate of 1.0%) as seen in Table 4 below. The rate of projected annualized growth remains strong compared to the last IRP largely due to growth in Other Food, Meat, Dairy and Agriculture.

Table 4: Large Volume Therm Forecast - Base Case Scenario

Large Volume Therm Forecast - Base Case Scenario by Market Segment (Thousands of Therms)							
	2023	2024	2025	2026	2027	2028	Rate of Growth
Potato (A)	105,634	110,634	110,874	111,120	111,372	111,631	1.1%
Other Food (B)	119,798	121,107	122,555	123,219	123,901	124,599	0.8%
Meat, Dairy and Ag (C)	60,467	63,518	63,688	64,862	65,041	65,224	1.5%
Chemical/Fertilizer (D)	33,955	34,925	34,925	34,925	34,925	34,925	0.6%
Manufacturing (E)	26,203	26,412	26,255	26,276	26,284	26,292	0.1%
Institutional (F)	25,569	25,697	25,697	25,947	25,947	25,947	0.3%
Other (G)	18,252	20,863	21,363	21,363	21,363	21,363	3.2%
Total Base Case	389,878	403,156	405,357	407,712	408,833	409,981	1.0%

A. The Potato Processors group is projected to slightly increase over the forecast period. One plant expansion is driving the increase. 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 projected to see some growth over the forecast period. The growth is largely due to strong growth in sugar production and one new plant in the forecast.

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

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

E. The Manufacturing companies' usage is expected to remain relatively flat over the forecast period.

F. The Institutional group is projected to have relatively flat growth, with the addition of a new hospital in the forecast.

G. The usage in the Other group is projected to see some strong growth largely due to customers using 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 trended at a lower rate than that experienced in the past eighteen months and the economy has continued growth. The scenario assumes very competitive natural gas prices compared to other alternatives. Projected sales in year 2024 of the High Growth forecast of 418.1 million therms is approximately 3.7% above Base Case. By 2028 the High Growth scenario's annual sales grow to 438.3 million therms an increase of 28.3 million therms (6.9%) over 2028 Base Case. The following table summarizes the High Growth changes over the forecast period:

Table 5: Large Volume Therm Forecast - High Growth Scenario

Large Volume Therm Forecast – High Growth Scenario by Market Segment (Thousands of Therms)							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Rate of Growth**
Potato (A)	105,634	110,869	111,361	111,878	112,421	112,991	1.4%
Other Food (B)	119,798	133,958	138,147	140,183	142,321	144,566	3.8%
Meat, Dairy and Ag (C)	60,467	65,483	65,832	69,698	70,082	70,485	3.1%
Chemical/Fertilizer (D)	33,955	34,925	34,925	34,925	34,925	34,925	0.6%
Manufacturing (E)	26,203	26,454	27,395	27,438	27,483	27,530	1.0%
Institutional (F)	25,569	25,697	25,697	25,947	25,947	25,947	0.3%
Other (G)	18,252	20,763	21,863	21,863	21,863	21,863	3.7%
Total Base Case	389,878	418,149	425,220	431,932	435,042	438,307	2.4%

A. The Potato Processors group is projected to slightly increase over the forecast period. One plant expansion is driving the increase. No new plants are assumed in the 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. Other Food Processors growth is projected to be strong as demand for sugar, frozen foods and other vegetable continues to grow. This scenario assumes 2 new customers will come online during the forecast period.

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

D. The Chemical/Fertilizer group's gas usage is anticipated to increase only slightly over the five-year period.

E. The Manufacturing group is projected to have a slight growth over the forecast period reflecting increases in electronics and building-related industries. This scenario 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 in 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. Declines are expected in manufacturing and the Other segment is expected to fall as the renewable fuels market declines and compressed natural gas (CNG) markets are replaced by electric vehicles (EVs) as well as ethanol production decreases. Projected sales in year 2024 of the Low Growth Scenario are approximately 3.4% below the Base Case but by 2028 are projected sales are 21.6 million therms (5.2%) under Base Case. The following table summarizes the Low Growth changes over the forecast period:

Table 6: Large Volume Therm Forecast - Low Growth Scenario

Large Volume Therm Forecast - Low Growth Scenario by Market Segment (Thousands of Therms)							
	2023	2024	2025	2026	2027	2028	Rate of Growth
Potato (A)	105,634	108,106	108,106	108,106	108,106	108,106	0.5%
Other Food (B)	119,798	120,704	120,704	120,704	120,704	120,704	0.2%
Meat, Dairy and Ag (C)	60,467	63,280	62,964	63,006	63,049	63,093	0.9%
Chemical/Fertilizer (D)	33,955	34,621	34,621	34,621	34,621	34,621	0.4%
Manufacturing (E)	26,203	26,355	26,055	26,076	26,084	26,092	-0.1%
Institutional (F)	25,569	25,697	25,697	25,697	25,697	25,697	0.1%
Other (G)	18,252	10,309	10,117	10,117	10,117	10,117	-11.1%
Total Base Case	389,878	389,072	388,264	388,327	388,378	388,430	-0.1%

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. The Other Food Processor group is expected to remain steady. Existing facilities will remain flat.

C. The Meat and Dairy group is projected to increase over the period as demand for meat and dairy is expected to grow.

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

E. The Manufacturing group is also projected to slightly decrease over the period by 0.1% reflecting some strength in the high tech/electronics.

F. The institutional group is projected to also show slowing growth that would lead to a small increase in annual gas use.

G. At least one very large fuels facility in the Other group is projected to go out of business and other customers using natural gas to power fleets of vehicles are assumed to begin the move to electric fleets as well as no new renewable natural gas facilities forecasted to come on.

3 Supply and Delivery Resources

3.1 Overview

Once future load requirements have been forecast, 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 Areas of Interest (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, beginning on page **Error! Bookmark not defined.**, demand and capacity are compared to 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 our homes, powering businesses, moving vehicles, and serving as a key component in many of our 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 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).

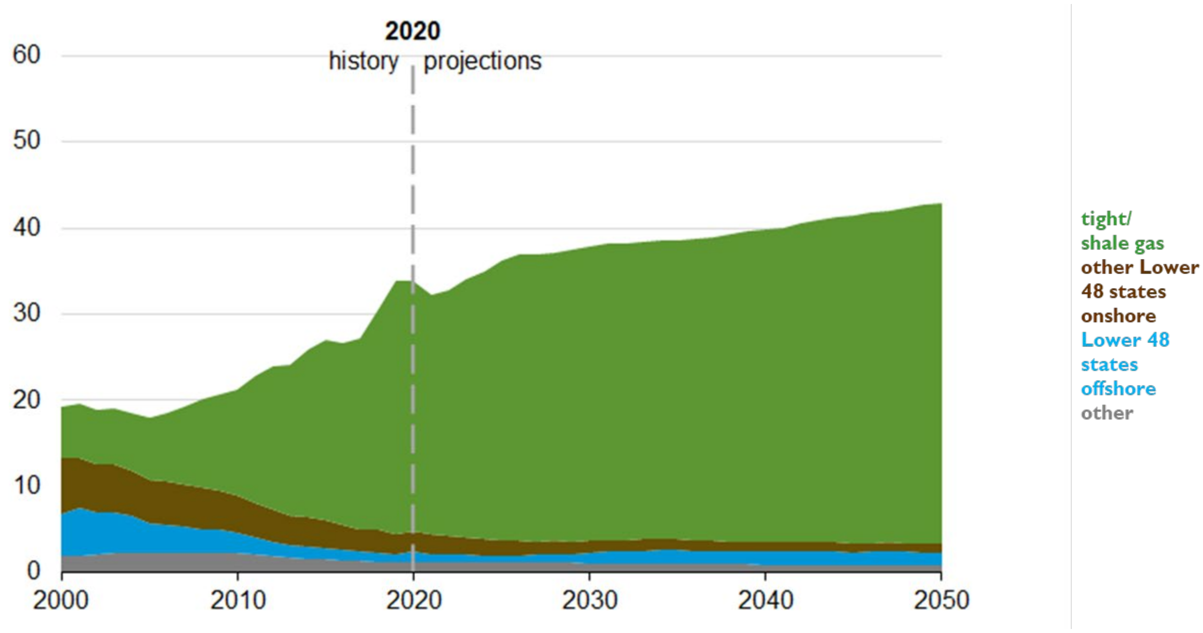


Figure 20: Natural Gas Sources

Source: EIA AEO2021

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 on the following page for consumption by sector, 2000-2050.

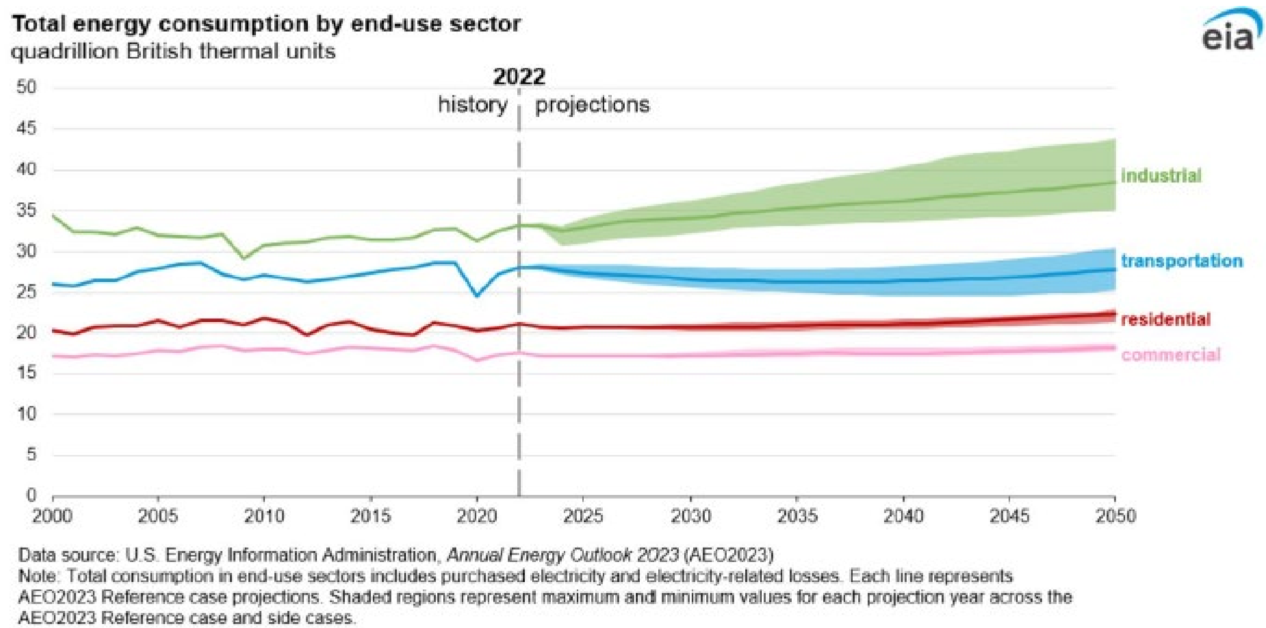


Figure 21: Natural Gas Consumption by Sector

Source: EIA AEO2023

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 through 2050.

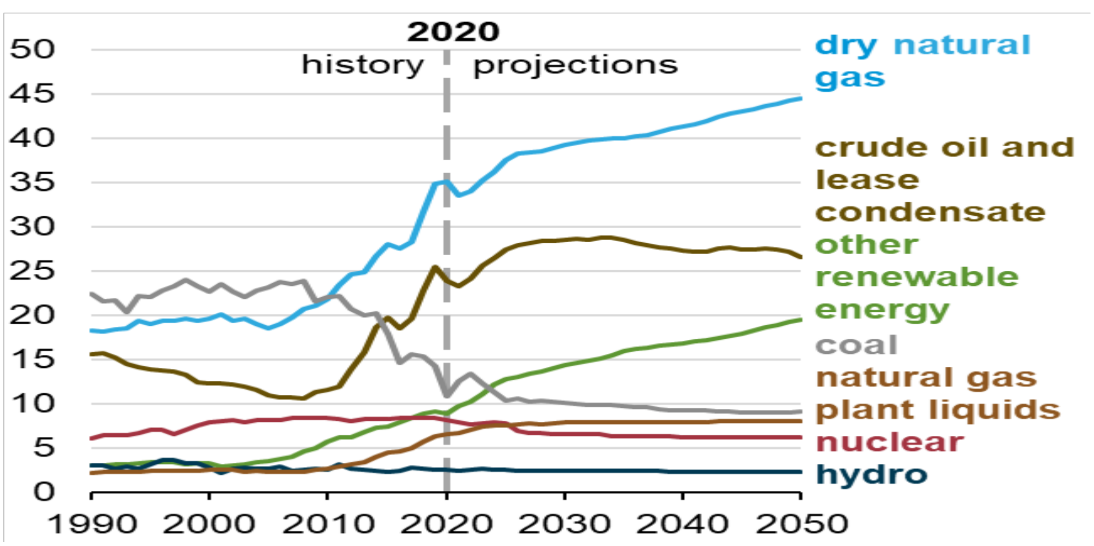


Figure 22: Shale Gas Production Trend

Source: EIA AEO2021

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 tend 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 on the following page identifies the shale plays in the lower 48 states.

Per the EIA, the portion of U.S. energy consumption supplied by domestic production decreased in 2020[10], in large part due to responses to the COVID-19 pandemic. "Demand for energy delivered to the four U.S. end-use sectors (residential, commercial, transportation, and industrial) decreased to 90% of its 2019 level in 2020; a steeper decline

[10] https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

than seen in real GDP. Compared with the financial crisis of 2008, the COVID-19-related decline in the total demand for delivered energy is about 70% larger. In the AEO2021 Reference case, EIA projects that U.S. energy demand takes until 2029 to return to 2019 levels."

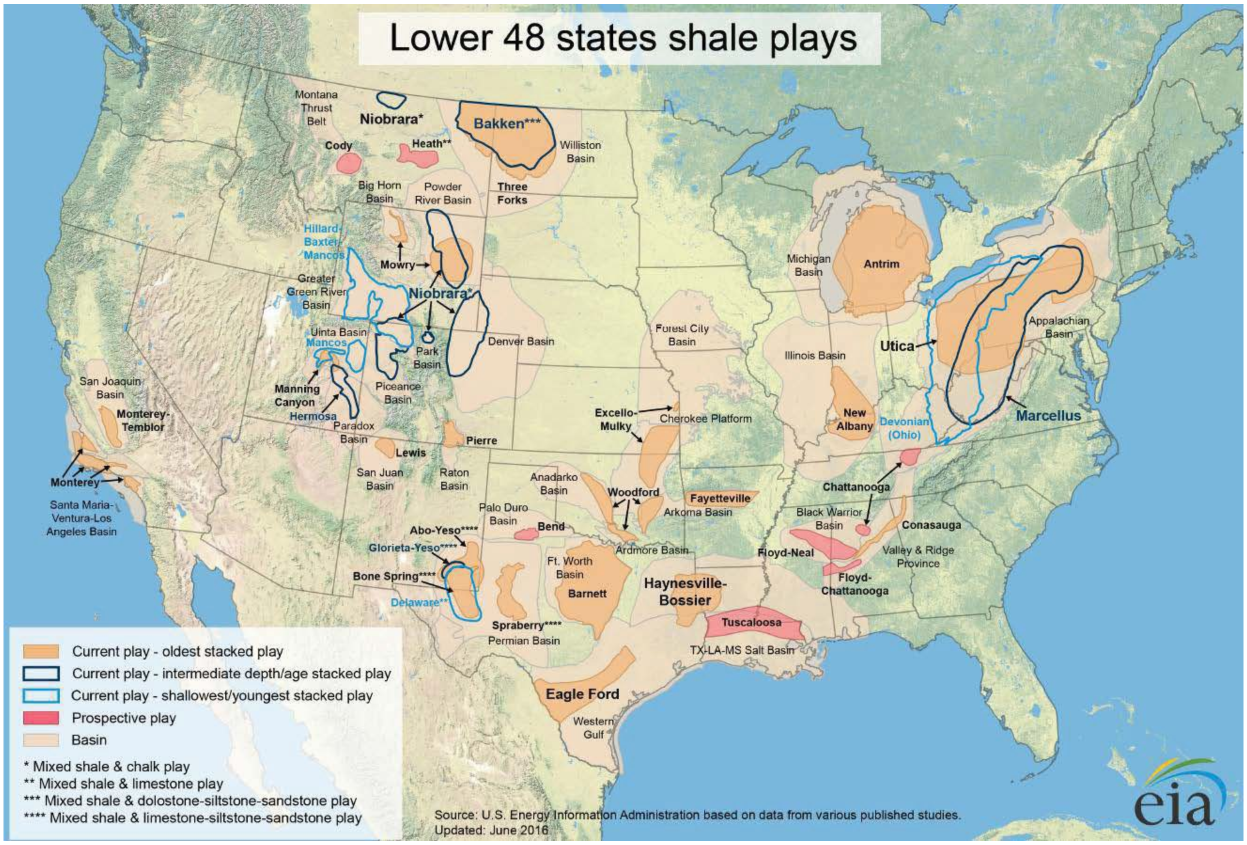


Figure 23: US Lower 48 States Shale Plays

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

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.

3.2.5.1 Alberta

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

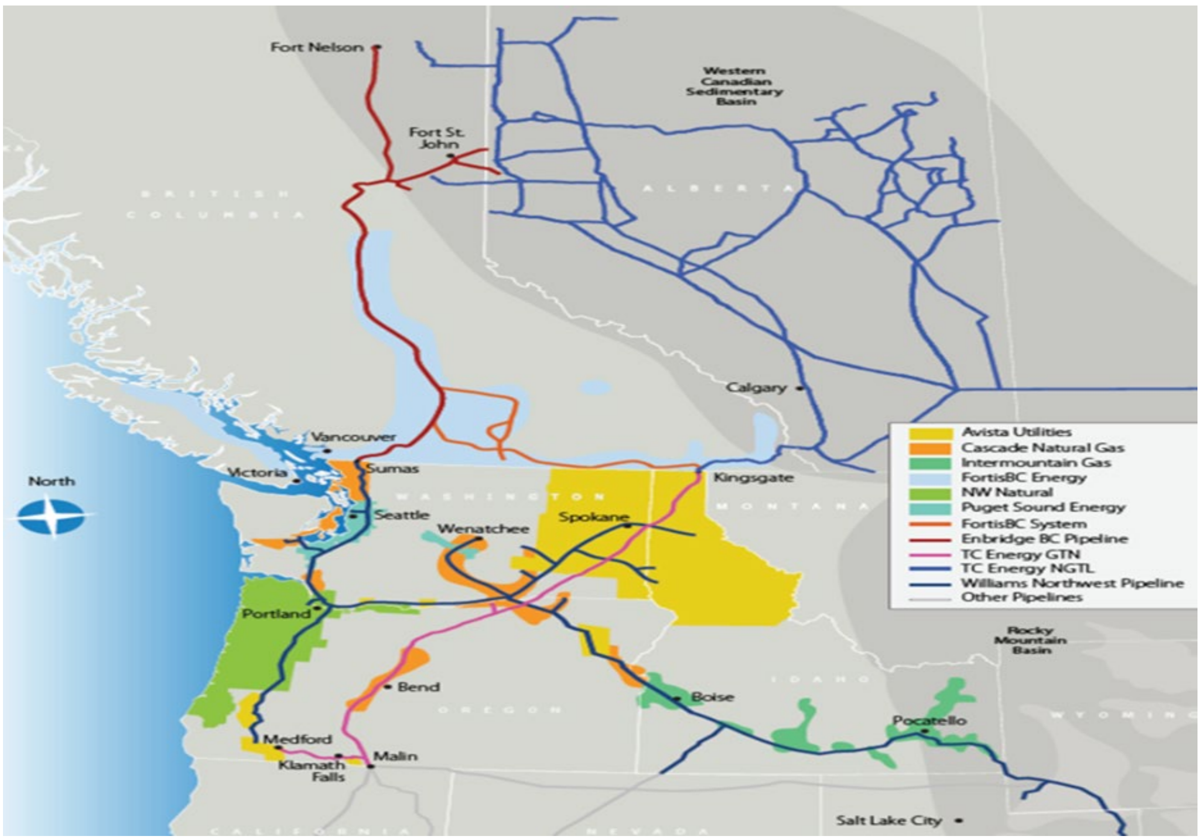


Figure 24: Supply Pipeline Map

Source: Northwest Gas Association 2020 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.

3.2.5.2 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[11] 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. In recent history BC pricing has risen dramatically, and it is no longer one of the lowest basins in the nation. Front of month prices spiked to $45.25 for January of 2023, while day gas prices exceeded $100/dth on some days. This was the result of a number of coinciding forces, including the geopolitical turmoil in the Ukraine, inflationary economic pressure domestically, and an extreme polar system landing in the pacific northwest in the days before the end of 2022. In recent weeks there has been a dramatic fall from 2022 pricing highs, led by what some are calling a correction to market overreaction to the forces described above, a projected El Nino weather pattern contributing to warm heating season forecasts, and higher than expected storage levels.

3.2.5.3 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

[11] 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.

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 chosen today and for the foreseeable future to purchase the predominance of its annual supply needs out of Alberta due to the lower cost environment from that supply basin. 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.

3.2.5.4 Export LNG

Growth in North American natural gas supplies (see Shale Gas above) have 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.

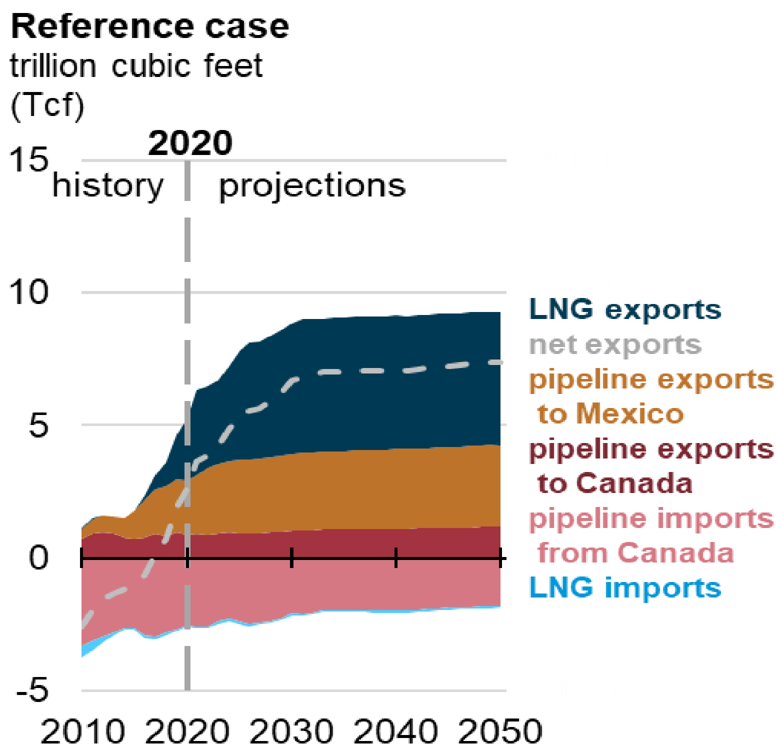


Figure 25: Natural Gas Trade

Source: EIA AEO2021

3.2.5.5 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.

3.2.5.6 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.

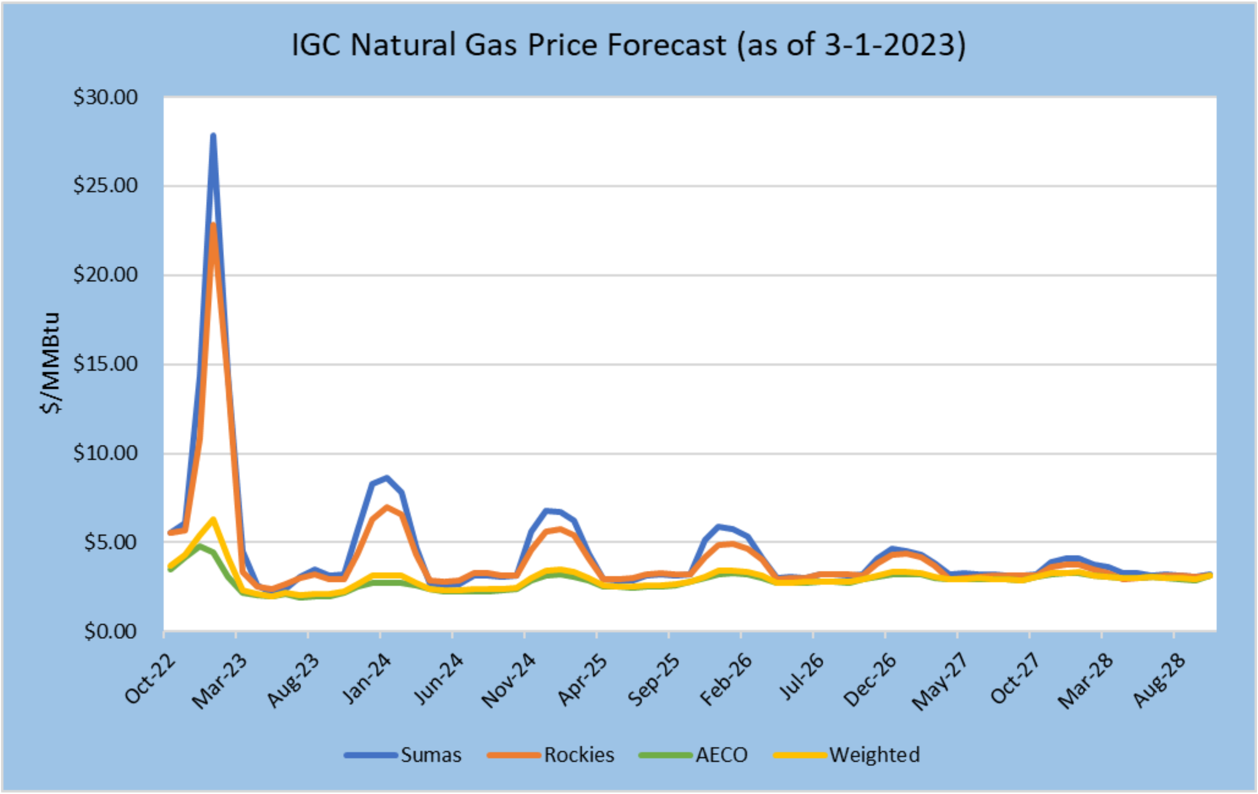


Figure 26: Intermountain Price Forecast as of 03/1/2023

3.2.5.7 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 (see page **Error! Bookmark not defined.**), 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 on following page). 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.

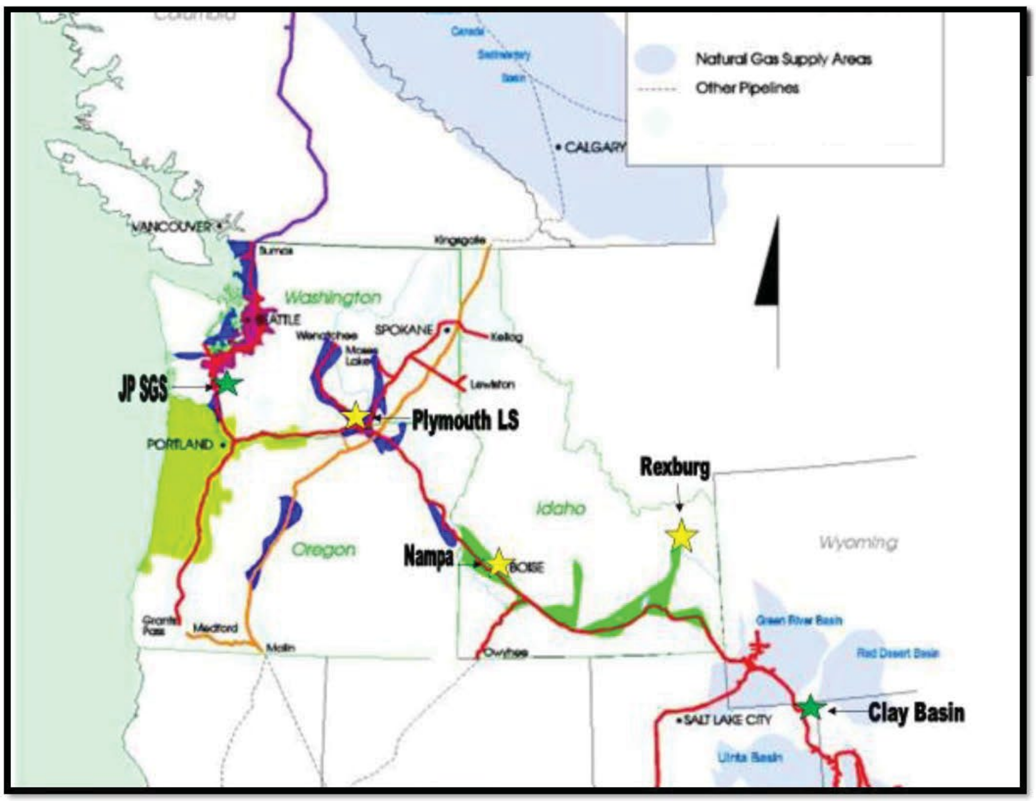


Figure 27: Intermountain Storage Facilities

3.2.5.7.1.1 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.

3.2.5.7.2 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.

Table 7: Storage Resources

Facility	Seasonal Capacity	Daily Withdrawal (Dth) Max Vol	% of 2023 Peak	Daily Injection (Dth) Max Vol	# of Days	Redelivery Capacity
Nampa	610,000	60,000	12%	60,000	166	None
Plymouth	1,475,135	155,175	32%	155,175	213	TF-2
Subtotal Liquid	2,085,135	215,175	44%	215,175		
Jackson Prairie	1,092,099	30,337	6%	30,337	36	TF-2
Clay Basin	8,413,500	70,114	14%	70,114	120	TF-1
Subtotal Underground	9,505,599	100,451	21%	100,451		
Grand Total	11,590,734	315,626	64%	315,626		

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 every-day transport capacity and term gas supplies during those off-peak months when the core market loads are lower.

3.2.5.7.3 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 60 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.

3.2.5.7.4 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.

3.2.6 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 on the following page 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 NOVA 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.

Table 8: Northwest Pipeline Transport Capacity

City Gate Delivery Quantity (MMBtu per day)	2023	2024	2025	2026	2027	2028
TF-1 Capacity -						
Sumas Base Capacity	90,941	90,941	90,941	90,941	90,941	90,941
Sumas Segmentation and Capacity Release	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)
Sumas Winter Only Capacity	-	-	-	-	-	-
Stanfield Base Capacity	109,624	109,624	109,624	109,624	109,624	109,624
Stanfield Segmentation and Capacity Release	111,941	111,941	111,941	111,941	111,941	111,941
Rockies	106,478	106,478	106,478	59,328	59,328	59,328
Total TF-1 Capacity	338,043	338,043	338,043	280,893	280,893	280,893
City Gate Supply	10,000	10,000	10,000	10,000	10,000	10,000
Total City Gate Delivery Before TF-2	348,043	348,043	348,043	290,893	290,893	290,893
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	-	-	-
Total TF-2 Capacity	185,512	185,512	185,512	155,175	155,175	155,175
Nampa LNG (does not include Rexburg)	60,000	60,000	60,000	60,000	60,000	60,000
Total City Gate Delivery	593,555	593,555	593,555	506,068	506,068	506,068

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).

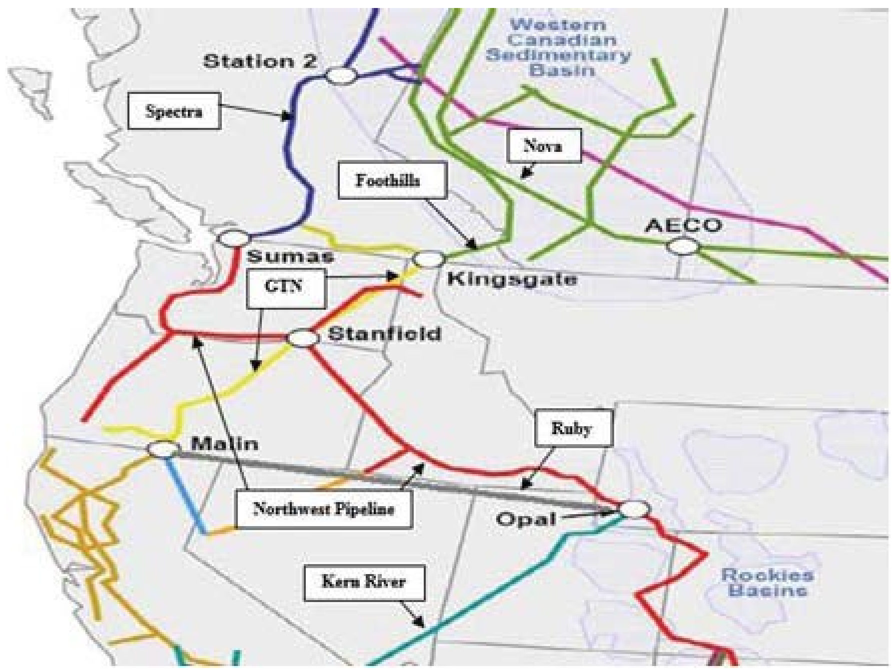


Figure 28: Pacific Northwest Pipelines Map

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 are in an increasingly mega-regional marketplace where market conditions across the continent - including pipeline capacities - can, and often do, affect regional supply availability and pricing dynamics. According to the EIA, "In October, the natural gas spot price at Henry Hub averaged \$5.51 per million British thermal units (MMBtu), which was up from the September average of \$5.16/MMBtu and up from an average of \$3.25/MMBtu in the first half of 2021. The rising natural gas prices in recent months reflect U.S. natural gas inventory levels that are below the five-year (2016–20) average. Despite high prices demand for natural gas for electric power generation has remained relatively high, which along with strong global demand for U.S. liquefied natural gas (LNG) has limited downward natural gas price pressures."[12]

3.2.7 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

[12] https://www.eia.gov/outlooks/steo

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 Model Section beginning on page **Error! Bookmark not defined.**).

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 needed and is willing to pay for new infrastructure. However, a more fully utilized pipeline can also mean existing shippers have less operational flexibility.

Key Points

- Capacity release allows shippers to offer unused capacity in an auction to other shippers.
- Intermountain is an active participant in capacity releases, utilizing IGI Resources to market the capacity to other customers.
- 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.

Intermountain has been 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 are 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:

<u>Non-Traditional Supply Resources</u>

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 BTUs 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 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 three RNG producers on Intermountain's distribution system. All three 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. None of the RNG currently being injected into Intermountain's distribution system is being purchased for the Company's end use customers because of its expense relative to traditional natural gas.

However, 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 $15/MMBtu, which was based on an American Gas Foundation report that states "…many landfill gas projects are estimated to produce RNG at a cost of $10-20/MMBtu, and dairy manure projects may produce RNG at a cost of closer to $40/MMBtu."[13] However, the report goes on to discuss an ICF report that describes substantial RNG production volumes at prices lower than $20/MMBtu. Intermountain is assuming the price of this renewable resource will continue to fall as the technology becomes more mature, and thus settled on a price within the range of current landfill gas projects for all RNG. Results of the RNG analysis are discussed in the Planning Results section.

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."[14] 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
- Gray hydrogen: Hydrogen produced using natural gas to create steam without capturing CO2;

"Green hydrogen, (which is considered one of the cleaner forms of hydrogen), produced with renewable resources costs between about $3/kg and $6.55/kg, according to the European Commission's July 2020 hydrogen strategy."[15] With a conversion rate for kg per

[13] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
[14] https://www.nrel.gov/docs/fy21osti/77610.pdf
[15] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/experts-explain-why-green-hydrogen-costs-have-fallen-and-will-keep-falling-63037203

MMBtu at 7.5, hydrogen prices range from about $22.5/dth to $49.12/dth. 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").[16] 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.

3.5 Lost and Unaccounted For Natural Gas Monitoring

Intermountain Gas Company 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 Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers. Intermountain is consistently one of the best performing companies in the industry with a LAUF percentage of -0.48% over the period of July 2021 to June of 2022.

Intermountain 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 conducts billing audits to identify irregular usage with each billing cycle. Intermountain 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.

[16] https://www.energy.gov/eere/fuelcells/hydrogen-shot

Intermountain 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.

Table 9: 2020 - 2022 Billing and Meter Audit Results

Billing and Meter Audit Results			
	2020	2021	2022
Dead Meters	184	174	164
Drive Rate Errors	2	0	2
Pressure Errors	14	24	14
Totals	200	198	197

3.5.2 Meter Rotation and Testing

Meter rotations are also an important tool in keeping LAUF levels low. Intermountain 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, Intermountain also identifies the potential for incorrectly sized and/or type of meter in use by our larger industrial customers. Intermountain 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, Intermountain technicians check Intermountain'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 our 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. 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.

Out recent efforts are aimed at educating the affected public and excavation contractors on the importance of calling 811 prior to any type of digging. Intermountain Gas has participated in a variety of informational activities, including sponsored events, general awareness mailings, and multi-media advertising, as well 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 Intermountain Gas facilities is still from excavation contractors or individuals not submitting a locate request with the state one call center before digging. Intermountain Gas will continue to focus our public awareness and damage prevention efforts on working with all excavation parties to increase awareness of the importance to submit 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 Intermountain Gas underground facilities. Figure 29 shows the damage rate per 1,000 locates, Figure 30 shows locate requests by region and Figure 31 shows the total locates for 2020 through 2022.

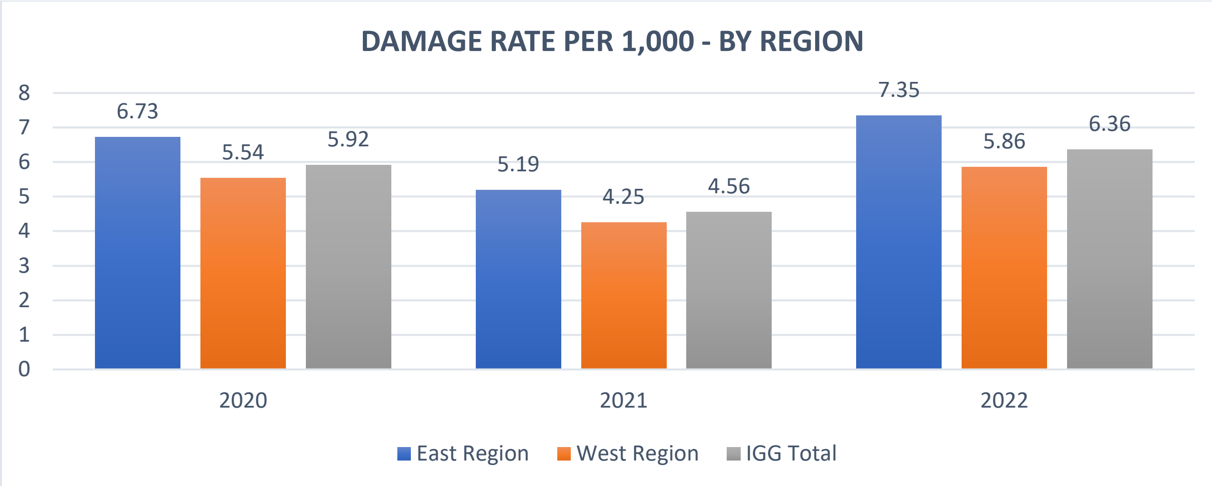


Figure 29: Damage Rates per 1,000 Locates by Region:

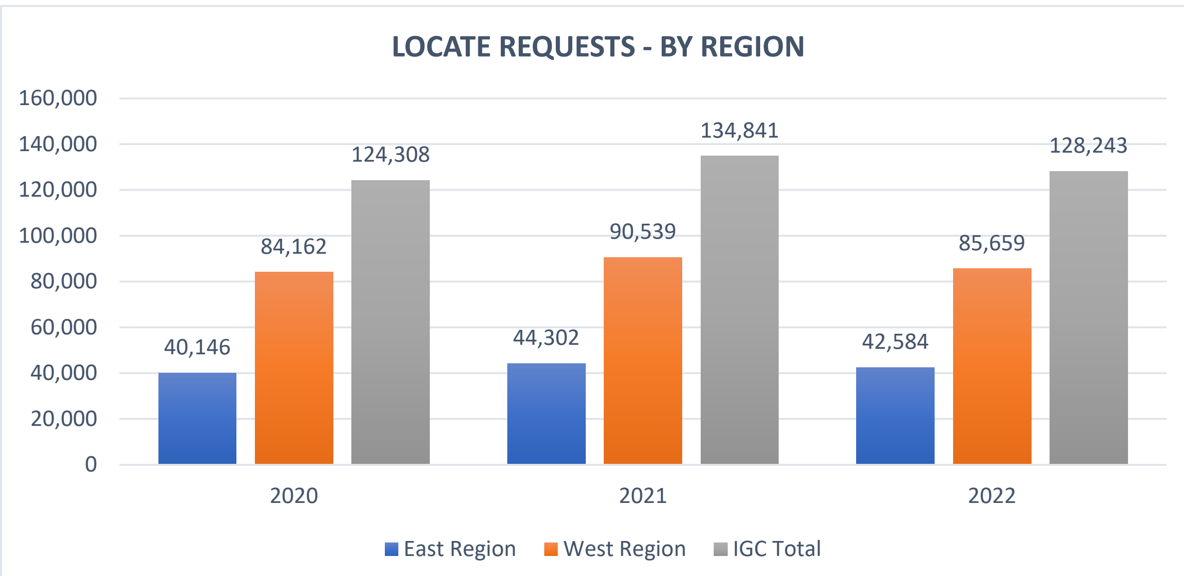


Figure 30: Intermountain Locate Requests by Region

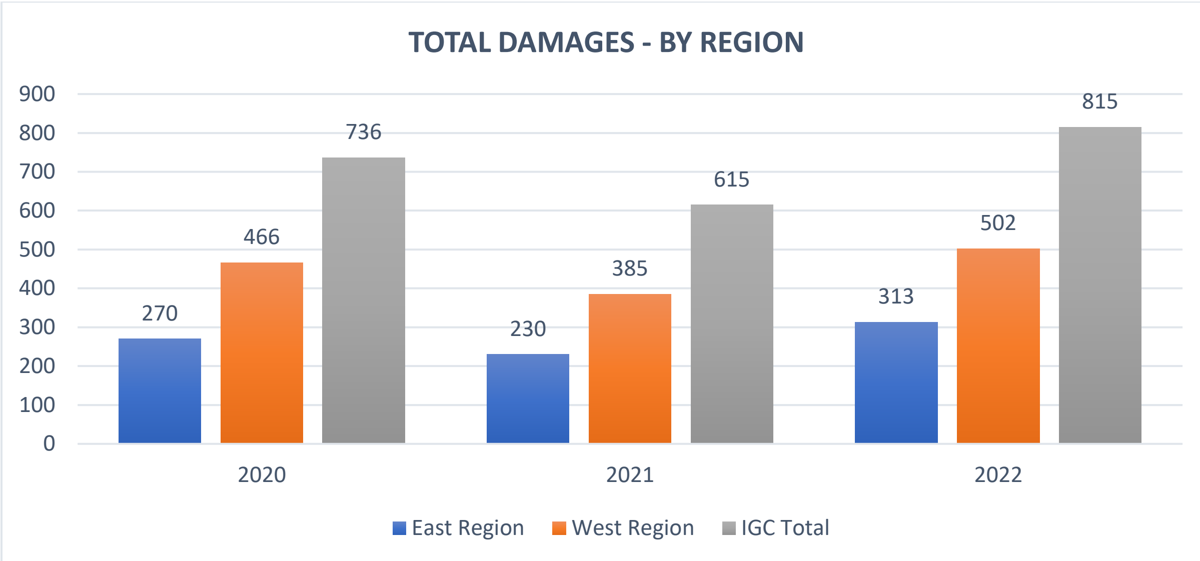


Figure 31: Intermountain Total Damages by Region

3.5.5 Weather and Temperature Monitoring

Intermountain 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, Intermountain utilizes hourly temperatures for a 24-hour period, averaged into 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

Gas can be lost physically or on the Company's records. For large line breaks as well as relief valves that are open for an extended period of time, the volume of gas that is lost is calculated. Gas is also released from the system and lost on small line breaks, venting reliefs that don't vent for an extended period, and during some maintenance activities, such as installing new meters. Additionally, meter accuracies aren't always 100% accurate and the volume of gas that is measured at customer meters will never be the exact same as the volume of gas measured at custody transfer meters. For gas lost, a line break charge is applied based on the effective rate at the time of the break (WACOG + Gas Transportation Costs. Intermountain 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.

Key Points

- Energy efficiency programs acquire cost-effective demand side resources in order to save customers energy and money.
- In its 2023 IRP, the Company estimated DSM therm savings based on the Conservation Potential Assessment (CPA) commissioned by Intermountain.
- The business as usual (BAU) model is the model used for the 2023 IRP base case. The BAU scenario is most closely aligned and calibrated with historic program activity based on program accomplishments.
- Intermountain has modeled three additional scenarios; Unconstrained Historical Budget, Medium Adoption, and High Adoption, High Incentive scenario.
- Cumulatively, Intermountain projects the BAU case to save customers 8.1 million therms in 2028.

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 allow Intermountain to displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcement 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.

3.6.2 Conservation Potential Assessment

In its 2023 IRP, the Company estimated DSM therm savings based on the Conservation Potential Assessment (CPA), found in Exhibit 4, 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.

3.6.3 Market and Measure Characterization

As a first step to the study, Guidehouse conducted a market and baseline characterization which is the collection and analysis of information pertaining to the size and characteristics of Intermountain's customer population. Market characterization forms the basis for scaling up energy efficiency potential from a measure level to utility-wide level. This information is referred to as global inputs and includes the following: building stock, gas sales, avoided costs, retail rate, inflation rate, discount rate and building stock demolition rate.

Additional study indices help define the breadth and scope of the study. Intermountain study indices included two climate zones in Intermountain's territory, climate Zone 5 and Zone 6, and two sectors, residential and commercial. Climate Zones are a national designation to categorize climate types for purposes of such studies. Within each sector, customer segments were identified. In the residential sector there were two segments, single family, and multi-family. Nine customer segments were identified in the commercial sector, education, food service, healthcare, lodging, manufacturing/industrial, office, other, retail and a new segment called light/converted commercial. Based on feedback from customers and Energy Services Representatives, Intermountain requested Guidehouse explore this segment of commercial customers who are on the commercial rate but have smaller energy usage and utilize residential-sized equipment. An example would be a law office or medical office that operates in a residential building that has been converted to a commercial business.

For the measure characterization, which is the categorization of energy efficiency measures applicable to Intermountain's residential and commercial sectors, measures were prioritized for inclusion based on likelihood to have high savings, current market availability and cost-effectiveness. In total, Guidehouse characterized 31 measures for the residential sector and 55 measures for the commercial sector. Guidehouse considered the following in developing the final measure list: existing measures offered by Intermountain, measures that are not currently offered but were analyzed in the previous CPA, input from Intermountain staff on additional measures of interest and other measures commonly offered in other jurisdictions or commonly included in potential studies. Measure characterization also included defining replacement types. Types identified for Intermountain were new construction, replace on burnout or normal replacement, and retrofit, which could be either an equipment add-on or accelerated replacement. Characterization also specified parameters for each technology to calculate potential, such as: measure description, replacement type, applicability, unit basis, energy consumption and savings, costs, measure density and saturation, measure lifetime and net-to-gross ratio.

To characterize key inputs such as unit basis, energy consumption and savings, and cost inputs for each measure, Guidehouse utilized a range of Technical Reference Manuals (TRMs). Guidehouse prioritized the TRMs used in Intermountain's CPA based on the following criteria:

- Climate zone – TRMs from states with similar IECC climate zones,
- Codes and Standards – TRMs that do not set appliance standards beyond Federal code requirements to avoid differing baseline efficiency levels when compared to Idaho,
- Data Format – TRMs with deemed savings values were prioritized over TRMs that only contained engineering algorithms and equations. Deemed savings are agreed-upon savings resulting from installation of specified measures, not requiring customized analysis after-the-fact. The advantage of using deemed values is the ability to incorporate technical measure parameters and variables that have been vetted and approved by the regulatory bodies and experts who maintain TRMs. In addition, leveraging publicly available sources increases transparency and creates less reliance on assumptions of key measure parameters by Guidehouse.

Additionally, basing savings in potential studies on previous realized program results is an industry best practice. Guidehouse utilized the findings from Intermountain's 2020 Impact Evaluation, Verification and Measurement (EM&V) for the furnace measure to inform measure assumptions and account for realized program results in the characterization of measure savings.

Guidehouse also developed density and saturation inputs. Density represents the prevalence of a particular measure among the building stock, or number of units per building. Saturation represents the percentage of a specific measure that is efficient or not. Where applicable, density and saturation assumption that were documented in the 2019 CPA were also referenced.

3.6.4 Energy Efficiency Potential

The primary objective of the CPA was to develop an estimate of the potential for natural gas energy efficiency in Intermountain's service territory over a twenty-year horizon. Three categories of potential savings, technical, economic, and achievable energy savings, depicted in Figure 32, were calculated by Guidehouse. 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 the energy efficiency savings that could be expected in response to specific levels of program incentives and assumptions about existing policies, market influences and barriers.

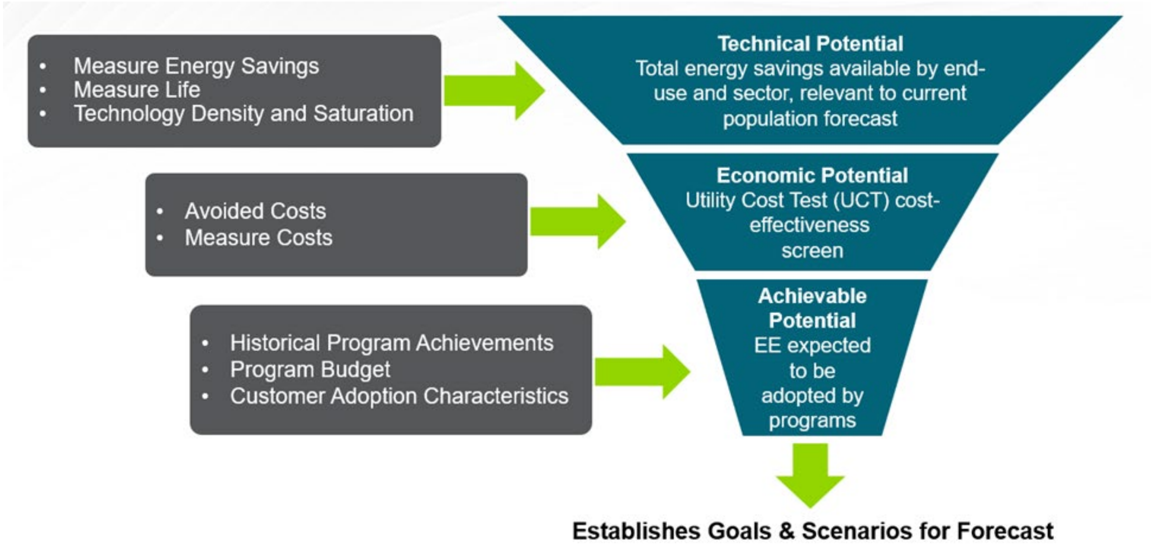


Figure 32: Guidehouse Categories of Potential Savings

Guidehouse tested the reasonableness of the model results by comparing historic program performance and incentive spending with the modeled forecast. The modeled program net savings potential was compared to the 2019-2021 historic program savings values by sector and end-use. In addition, due to the year-over-year variations in program achievements, rather than calibrating the model to a single point estimate like savings achieved in 2020, Guidehouse looked at the savings trend over the past three years of program achievements. The model was then calibrated to match the overall historical data. Guidehouse adjusted model parameters to ensure the forecast net potential was grounded against real-world results. To align adoption rates with historic program savings, a payback adder was applied to most measures. A positive adder slows down adoption rates, while a negative payback adder speeds up the adoption rate. Since the modeled level of adoption overstated the 2019-2021 historic program performance, a payback adder was used to calibrate measures. Payback analysis is a standard approach to energy efficiency adoption by customers. For measures with no historical data, the model was calibrated so these measures would have very little achievable potential compared to measures with historical data.

With the model aligned as closely as possible with historic actual program achievements, different model inputs (or a tuning of "levers" such as awareness and adoption) were used to create alternative scenarios to examine how future achievable potential may vary depending on variables both within Intermountain's influence and external to it. Guidehouse modeled achievable potential for 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.

The BAU scenario is most closely aligned and calibrated with historic program activity based on program accomplishments. Incentive levels are defined as 50% of measure incremental cost, with the exception of residential furnaces which were set at 40% of incremental cost. This was done to ensure the largest potential measure was cost effective throughout the study period. This scenario assumes future program budgets are closely correlated with historic EE spending.

The three additional scenarios explored were: increased customer adoption of energy efficiency through increased program activity, achieved without constraining program spending at historic levels; a scenario of increased customer awareness and willingness to adopt energy efficiency technologies; and increased customer awareness and willingness to adopt combined with increased incentives. Figure 33 provides a synopsis of each scenario. The cumulative net achievable potential for each scenario is illustrated in Figure 34. As budgets, customer awareness and willingness to adopt increase so, too, does net achievable potential of each scenario.

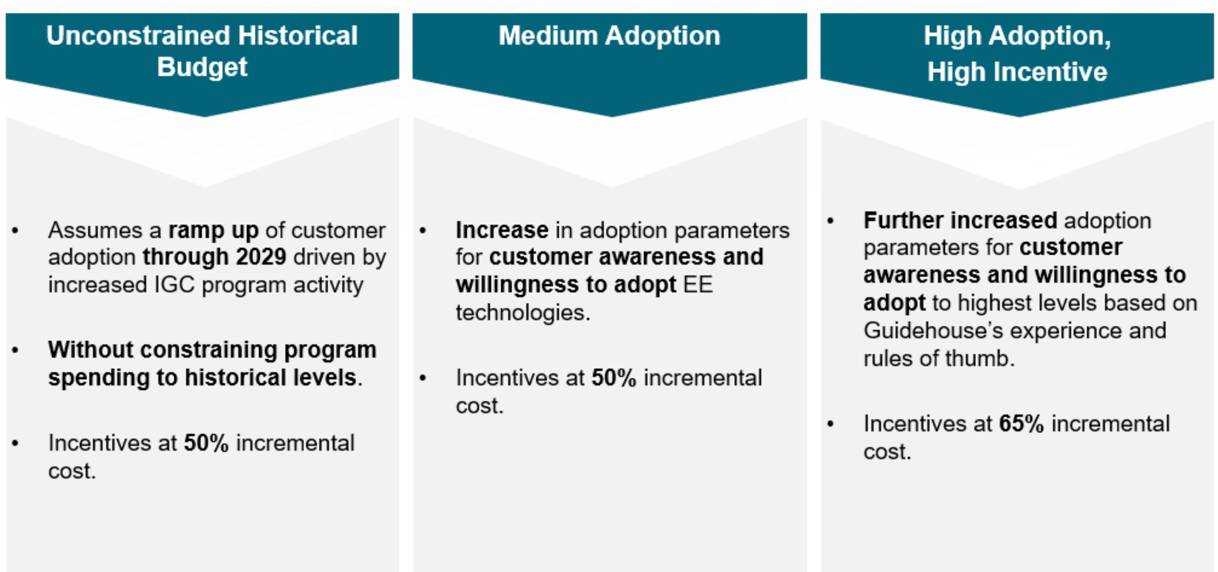
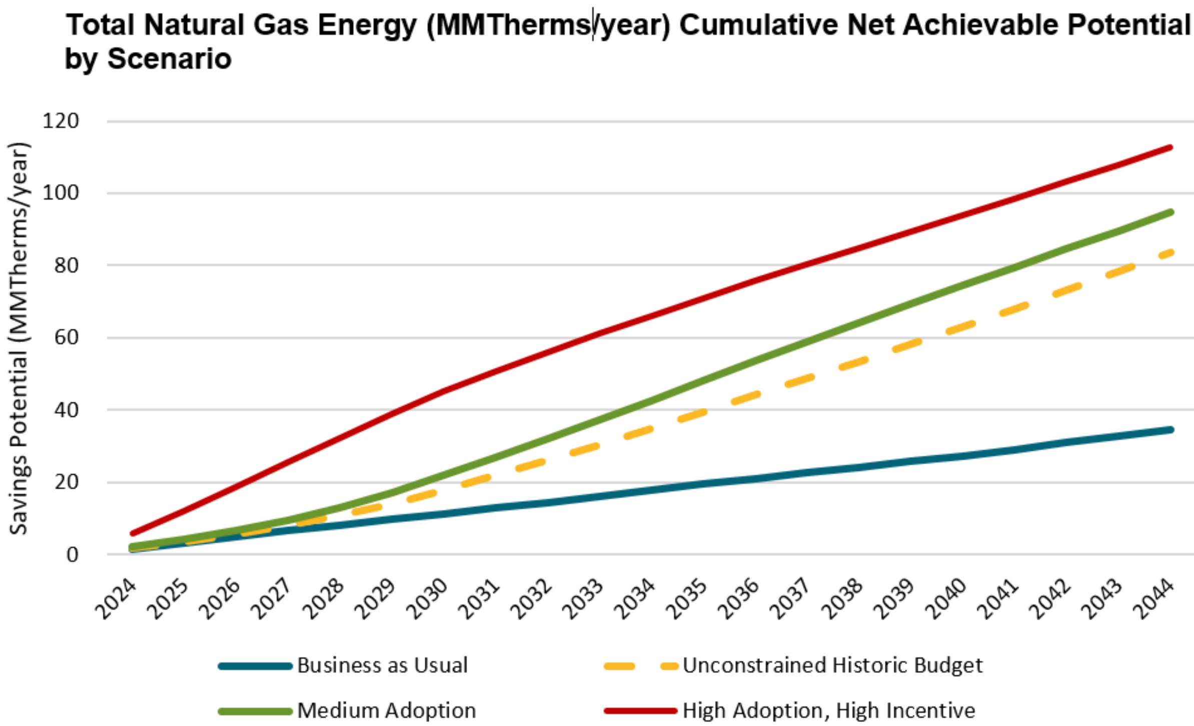


Figure 33: Cumulative Net Achievable Potential Synopsis

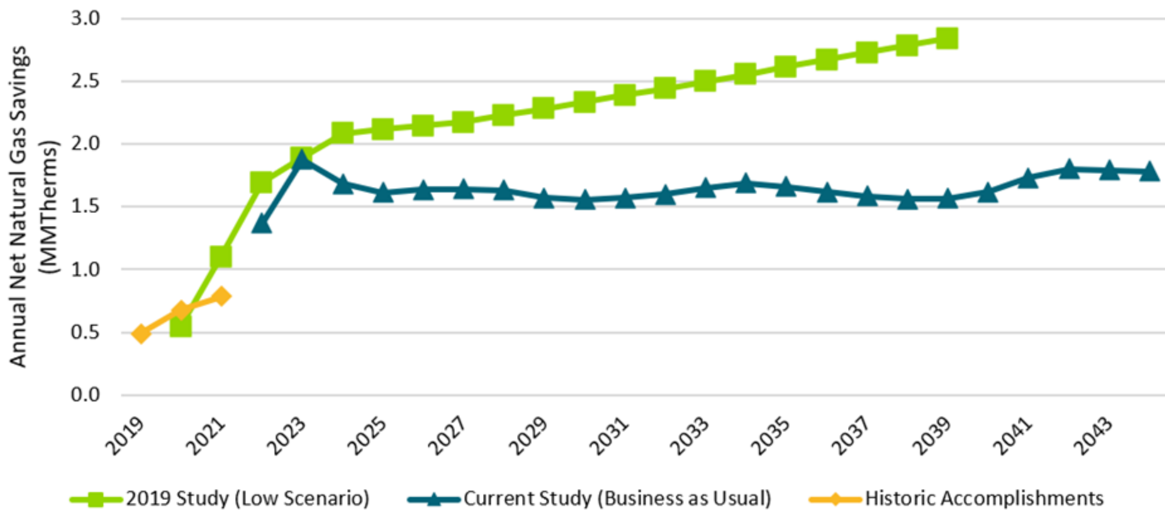


Source: Guidehouse analysis 2023

Figure 34 Cumulative Net Achievable Potential by Scenario

Guidehouse compared Intermountain's historic accomplishments to the achievable potential estimated in the past and current CPA, illustrated in Figure 35, The Low Scenario of the previous study had similar incremental achievable potential to the BAU scenario of this study. The 2019 CPA included the commercial sector savings potential, but Intermountain did not launch a commercial program until April 2021.

Natural Gas Historic Accomplishments Compared to Past and Current Study Achievable Potential Low Scenario Results (Annual Net Gas Savings MMTherms)



Source: Guidehouse analysis 2023

Figure 35 Natural Gas Historic Accomplishments Compared to Past and Current Study Achievable

Given the comparison of historical achievements to the past and current studies, using the BAU scenario to inform the IRP would be the most conservative approach. Net achievable potential, by sector, for the BAU scenario is illustrated in Figure 38.

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.

Usage data is useful in tracking and evaluating energy saving measures, new production procedures and/or usage characteristics of new equipment. To deploy this tool, Intermountain installs SCADA units 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.

Figure 36: Large Volume Website Login

In order to provide our customers with access to this data, Intermountain has designed and hosts a Large Volume website, which is pictured in Figure 36. 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 37. 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.

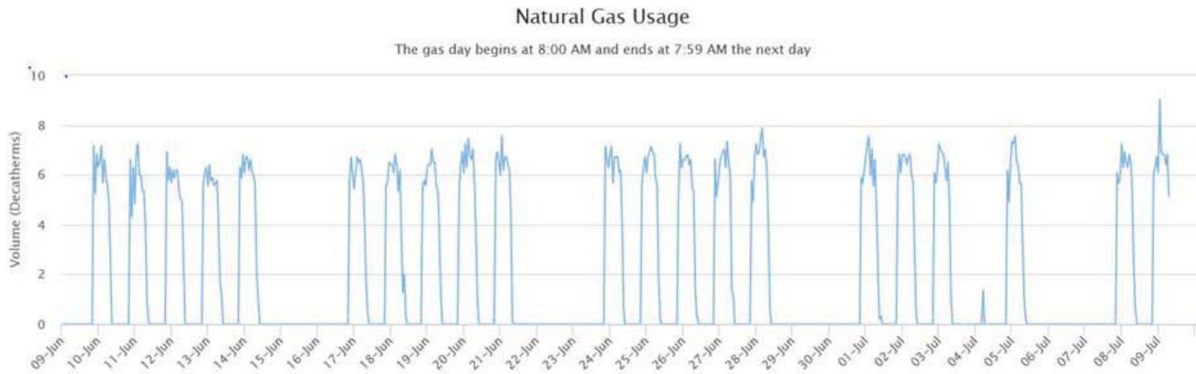


Figure 37: Natural Gas Usage History

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.

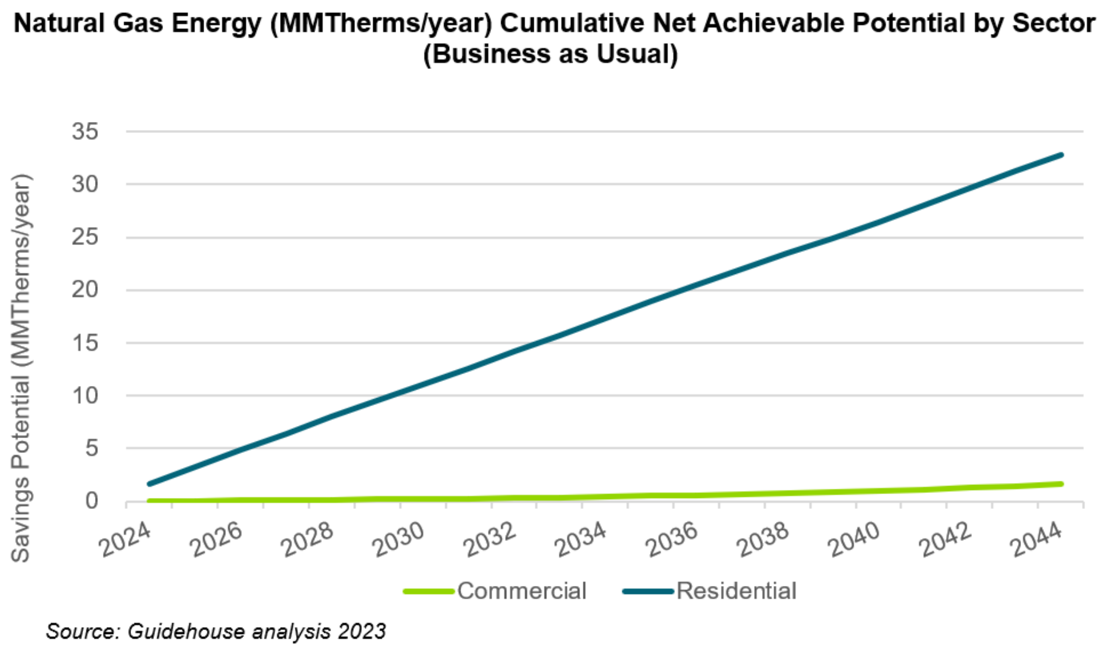


Figure 38: Cumulative Net Achievable Potential by Sector

3.8 Avoided Costs

Key Points

- Avoided cost forecasting serves as a primary input for determining energy efficiency targets.
- Intermountain's avoided costs include transportation costs, commodity costs, and variable distribution costs.
- The discount rate is derived using Intermountain's tax-effected cost of capital.
- 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.

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 2.0%. (Inflation was updated to 3.15% 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

3.8.3.1 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.

3.8.3.2 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's inflation rate of 3.15%. (2% is typically used). 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.

3.8.3.3 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 this cost-benefit ratio may be intuitively apparent, the Company and its Stakeholder group quantify these savings. Currently, Intermountain included distribution system costs in the avoided cost as a scenario and ran the energy efficiency model to produce demand side savings based on a higher avoided cost. The result did not remove or delay any of the distribution system projects. Therefore, the Company is using a placeholder value of zero for this component.

4 Optimization

4.1 Distribution System Overview

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

Key Points

- Distribution system network design fundamentals anticipate demand requirements and identify potential constraints.
- Cascade utilizes its internal GIS environment and other input data to create system models through the use of Synergi® software.
- Distribution system enhancements include analyses of pipelines, regulators, and compressor stations.
- Impacts of proposed conservation resources on anticipated distribution constraints are reviewed.
- Analyses are performed on every system at design day conditions to identify areas where potential outages may occur.

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

4.1.1 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 7,155 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 begin at a city gate station connected to an interstate pipeline. At gate stations Intermountain takes custody of the gas and regulates and odorizes the gas to serve its distribution and transmission pipelines. Typically, high pressure or transmission pipelines are downstream of the gate to transport gas to regulator stations or large volume industrial customers. Regulator station reduce pressure to serve residential or commercial customers.

4.1.2 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 maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment.

Due to the nature of fluid mechanics, there is a finite amount of natural gas that can flow through a pipe of a certain size 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.

In order 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. 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 anticipated 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 GL, 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 and compressor stations and 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 five 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. 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 completely rebuilt every three years and are maintained between rebuilds. To rebuild the models, Intermountain exports current GIS data to create the spatial models and exports historical billing data from Customer Care and Billing (CC&B) to bring into the Customer Management Module (CMM) to create an updated demands file. Intermountain's models were rebuilt in 2020 and are scheduled for rebuild in 2023.

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 CMM software product, provided by DNV GL 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 weather 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 weather information has been correlated to each meter read, a base load and weather 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 GL.

The Company recognizes 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 its 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 with the goal of installing fixed network coverage on 90% of its system. Currently Intermountain' s fixed network system covers 61% of ERT meters and the fixed network installation is expected to be completed by the end of 2023.

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 time and day and will then set the model to the temperature experienced to see how the model is performing to determine if the usage per custom is reasonable. 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 us 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 weather data, to create a design day model. Intermountain's peak heating degree days by district are shown in Figure 39.

District	HDD	Avg Daily Temperature (ºF)
Boise	75	-10
Nampa	68	-3
Pocatello	82	-17
Idaho Falls	88	-23
Twin Falls	77	-12
Ketchum	82	-17

Figure 39: Peak Heating Degree Day

As shown in Figure 2, 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

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 sizing of pipe and facilities, long term planning, model growth predictions, identify system deficits, determine system reliability, 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 bottleneck, 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 its distribution system models every two years to ensure that the Company can maintain reliable service to our customers during design day events. Intermountain also completes annual reviews of its distribution system models as part of its annual budgeting process and will update the five-year budget as needed based upon new information that impacts Intermountain's five-year planning. If a deficit is predicted the system is evaluated and a reinforcement will be proposed and selected based on alternative analysis criteria. 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, and district management to assure the system is safe and reliable. As towns develop, the need for pipeline expansions and reinforcements increases. 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 on a system Engineering will propose enhancement solutions to address the deficit. Distribution enhancements can include:

- pipeline reinforcement such as replacements
- pipeline loops and back feeds
- pressure increases
- uprates
- facility upgrades
- additional regulator station feeds

- compressor stations
- demand side management strategies

Each of Intermountain's systems are unique in pipeline dynamics and will be optimized using different enhancement solutions.

Pipeline solutions consist of looping, upsizing, and uprating. 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 loss down the pipeline 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 upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area results in less friction, larger flow capacity, and therefore, a lower pressure drop. This option is considered for older vintage pipelines. If the existing pipe is otherwise in satisfactory condition, looping augments existing pipe, which remains in use.

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 and or may not reach the proposed uprate pressure. 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 city gate stations, district regulator stations, farm taps, and customer services. Regulator station provide additional capacity to an area since regulator stations are fed by high pressure laterals than can deliver more gas to the distribution system. 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 a significant deterrent. 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 alternative selection process with consideration to scope, cost, timing, system benefits/long term planning and feasibility. For any project over one 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 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.

- 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, i.e., access, existing easements or traffic issues.
- Minimizes environmental concerns, i.e., avoid water crossings, wetlands and environmental sensitive areas.
- Minimizes impacts to the community., i.e., road closures or city road moratoriums.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, engineering, field operations, or energy services representatives begin a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, permitting concerns, etc., resulting in another iteration of the above project/reinforcement selection criteria.

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 timings needs with the goal of minimizing risk to ensure that we can continue to provide safe and reliable service to our customers. Figure 40 provides a schematic representation of the distribution system selection process to the capital budget.

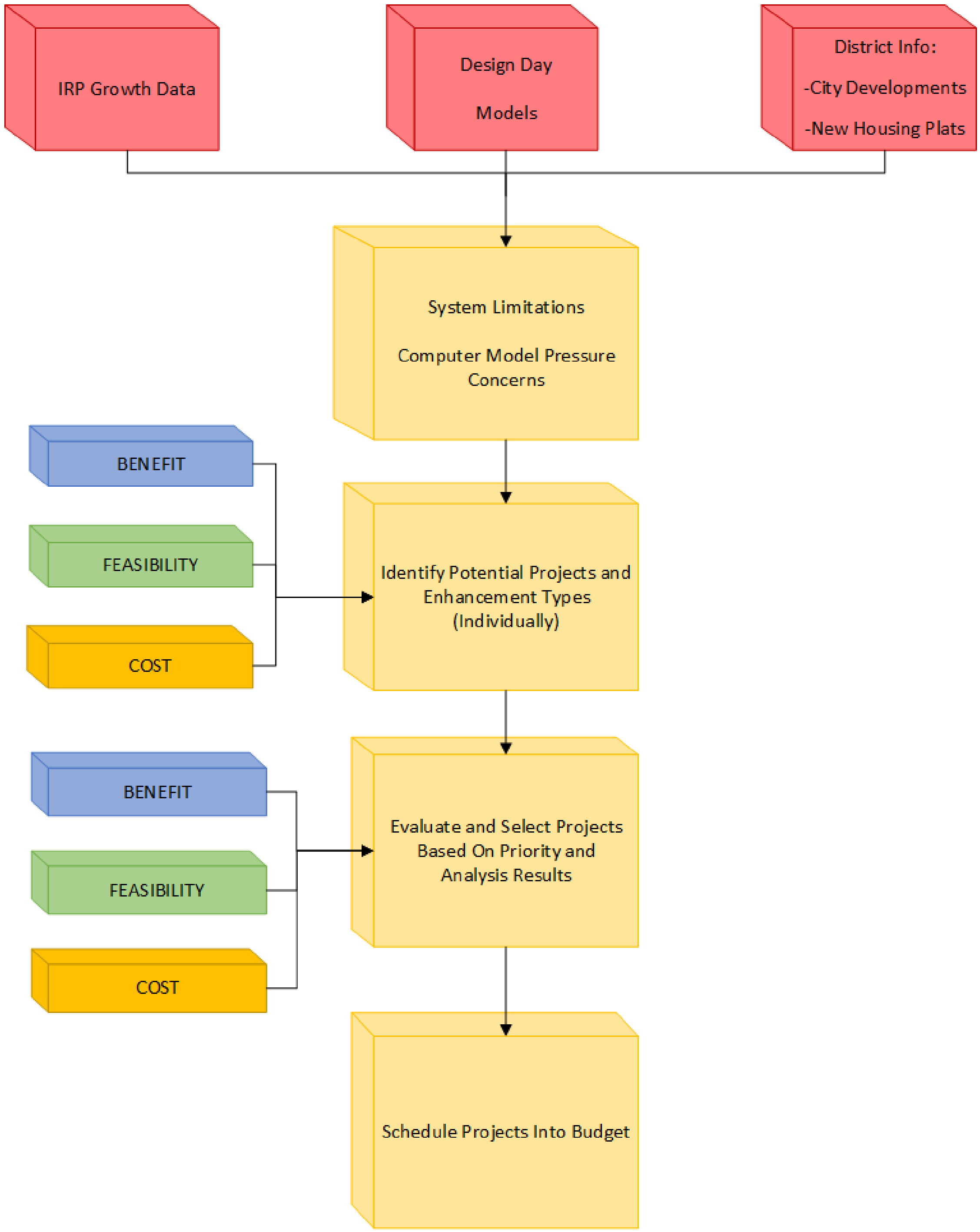


Figure 40: Distribution System Planning Process Flow

Intermountain's budget goes through several revisions and reviews at all levels in the organization to assure projects are properly justified and necessary. Every year as part of the capital budget process Intermountain projects are re-reviewed and revisions made to the projects as needed as new information becomes available as part of Intermountain's 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 time for projects to be designed and constructed to address deficits in time. 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

> **Key Points**
>
> - Capacity Enhancement chapter provides an evaluation of distribution system projects by each Area of Interest.
> - Each evaluation provides capacity enhancement options, timing, cost, and the final capacity option chosen.
> - Ada County, Canyon County, and Sun Valley Lateral are showing immediate needs for capacity upgrades. Idaho Falls and State Street Laterals are showing needs for capacity upgrades in 2024 and 2025, respectively.

4.3.1 Overview

Previous sections of this IRP show projected growth throughout Intermountain gas's 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 five-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[17]

[17] Included with this filing is a spreadsheet (in Exhibit 6) showing Intermountain's net present value cost evaluation. To determine net present cost, IGC pulled various O&M cost for the alternatives proposed based

        - Capacity
    - Table Summary of Capacity Enhancement Alternatives Considered
    - Capacity Enhancement Selected
        - Reasoning
        - Timing
    - 2021 IRP Updates (as applicable)

At the end of the AOI summaries, a summary is included with Intermountain Gas's five-year planning and timing of all the capacity enhancement selected and corresponding capacity increases for the AOIs.

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 and 2021 with the 12-inch Ustick Phase I and Phase II 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 significant growth in Nampa and surrounding communities this AOI requires a capacity enhancement by 2023 to meet IRP growth. This AOI's capacity is currently limited by 8-inch and 10-inch HP on Ustick Road which is experiencing high flow rates and causing high pressure to drop in this section and is compromising pressures down the line which impacts the line's capacity. The 8-inch and 10-inch HP is creating a bottleneck in the system, which is limiting its capacity, the bottleneck is shown below in Figure 41 in yellow.

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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. O&M costs were inflated 2% each year over the 20-year life of the analysis and a real discount rate of 4.68% was used in the analysis based on the Company's avoided cost model presented in Exhibit 5.

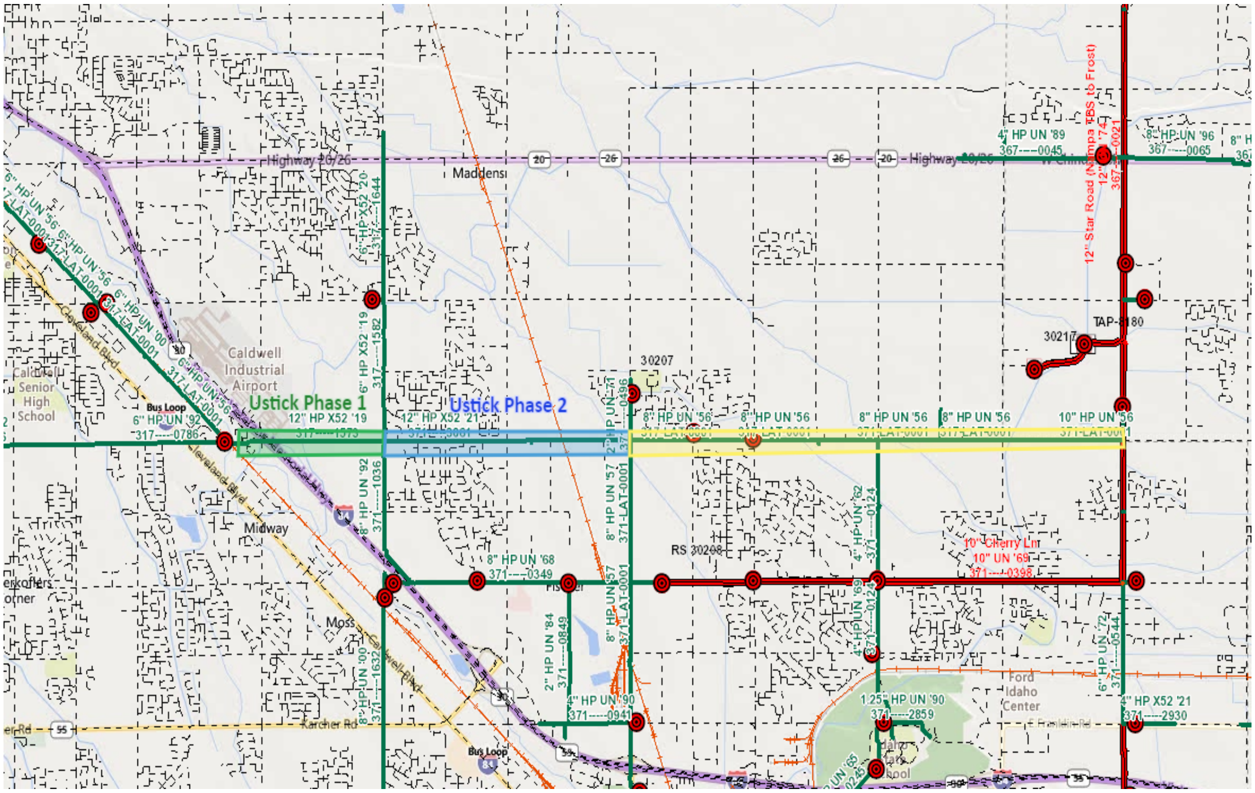

Figure 41: Canyon County Limiter

Capacity Enhancement Alternatives Considered

Three alternatives were considered in the 2021 IRP. These alternatives include Ustick Phase III, Ustick Uprate and an 8-inch High Pressure Extension north of Ustick. Ustick Phase III was chosen in 2021 as the largest capacity increasing alternative.

Capacity Enhancement Selected

Ustick Phase III consists of installing 4.1 miles of HP Steel on Ustick Road with 4 regulators stations to reduce pressure from 500 psig to 330 psig as shown in Figure 42.

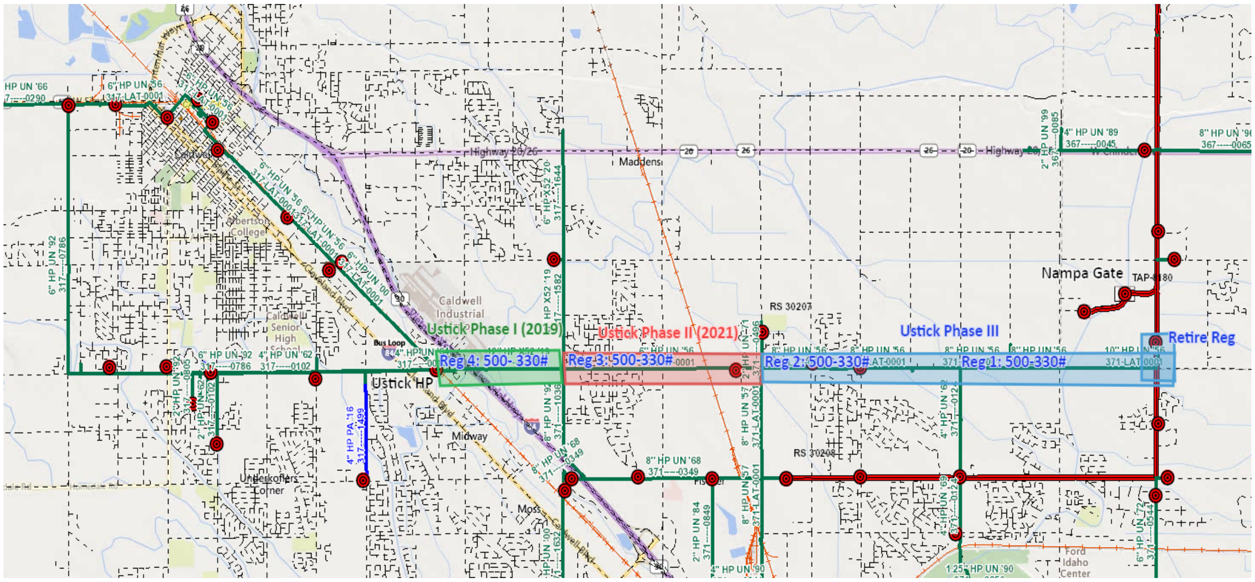

Figure 42: Ustick Phase III

This enhancement brings the lateral capacity to 1,390,000 therms per day which meets the predicted growth through 2028. Ustick Phase III construction has been delayed due to conflicting city/county projects in the area and is expected to start this fall and is estimated to cost $12,800,000 direct and $12,057,698 in net present value cost.

2021 IRP Updates

8-inch Happy Valley Extension- No longer required for this IRP since we are doing Ustick Phase III instead, this could be a future IRP project.

12-inch Ustick Phase II- Was completed in 2021.

4.3.3 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 significant growth in Boise and north of Boise this AOI requires a capacity enhancement by 2023 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.

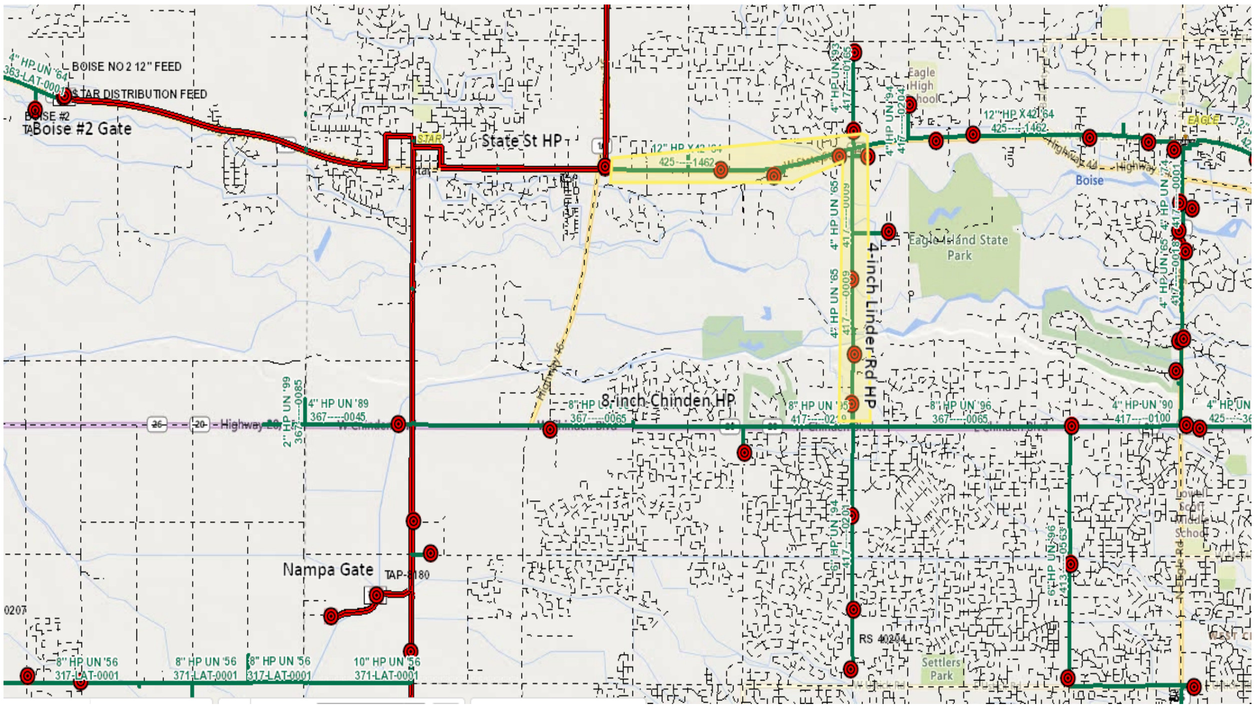

Figure 43: State Street Capacity Limiter

Capacity Enhancement Alternatives

Two alternatives were considered in the 2021 IRP. These alternatives include 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.

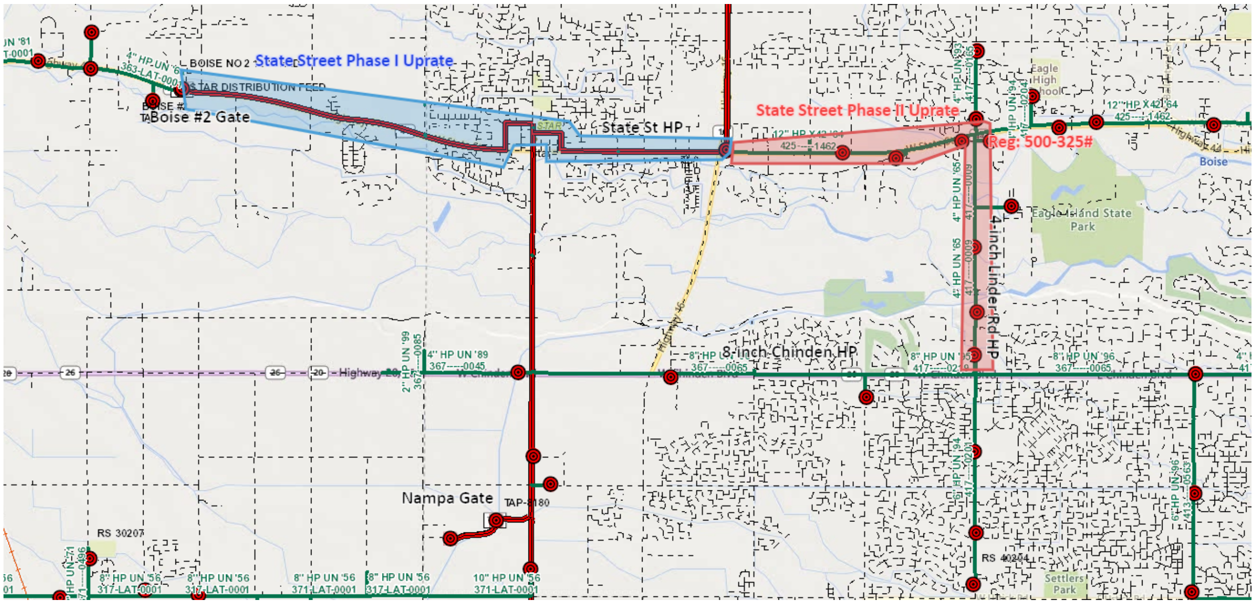

Figure 44: State Street Phase II Update

This enhancement brings lateral capacity to 950,000 therms per day which will meet predicted growth through 2028. The State Street Phase II Uprate is budgeted for 2024 and is estimated to cost $902,000 direct and $800,964 in net present value cost. The State Street lateral also requires the State Penn Gate to be upgraded. No alternative analysis was considered since the physical capacity of the gate is limiting capacity and needs to be rebuilt in place with larger piping and components. The State Penn gate upgrade is budgeted for 2025 design and 2026 construction and is estimated to cost $2,730,000 direct. Net present value cost is not applicable for gate upgrades since the upgraded gate has the same operations and maintenance costs as the current gate.

4.3.4 Central Ada County

AOI Summary/System Dynamics

The 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 that 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.

Capacity Limiter

Due to significant growth in Boise the Central Ada County AOI requires a capacity enhancement by 2023 to meet IRP growth. The current capacity limiter for this AOI is a 10-inch and 8-inch HP bottleneck on Meridian Road and Victory Road directly downstream of the Meridian Gate as shown in yellow in Figure 45.

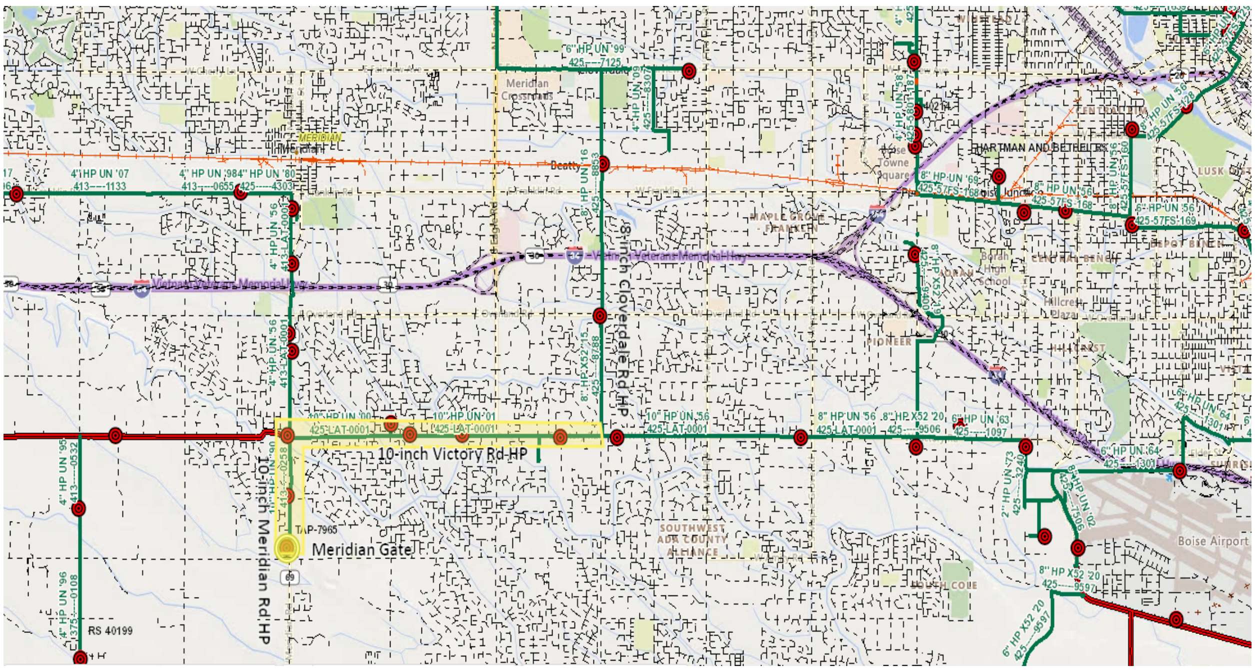

Figure 45: Central Ada County Capacity Limiter

Capacity Enhancement Alternatives

Three alternatives were considered in the 2021 IRP. These alternatives include the 12-inch South Boise Loop, uprating the 10-inch HP on Meridian Road and Victory Road or installing a compressor station. The 12-inch South Boise Loop was chosen in 2021 as the lowest cost option with the most capacity gained.

Capacity Enhancement Selected

The 12-inch South Boise Loop enhancement consists of installing 3.73 miles of 12-inch HP Steel, a Kuna gate upgrade and a regulator station on Cloverdale Road near Victory Road as shown in Figure 46.

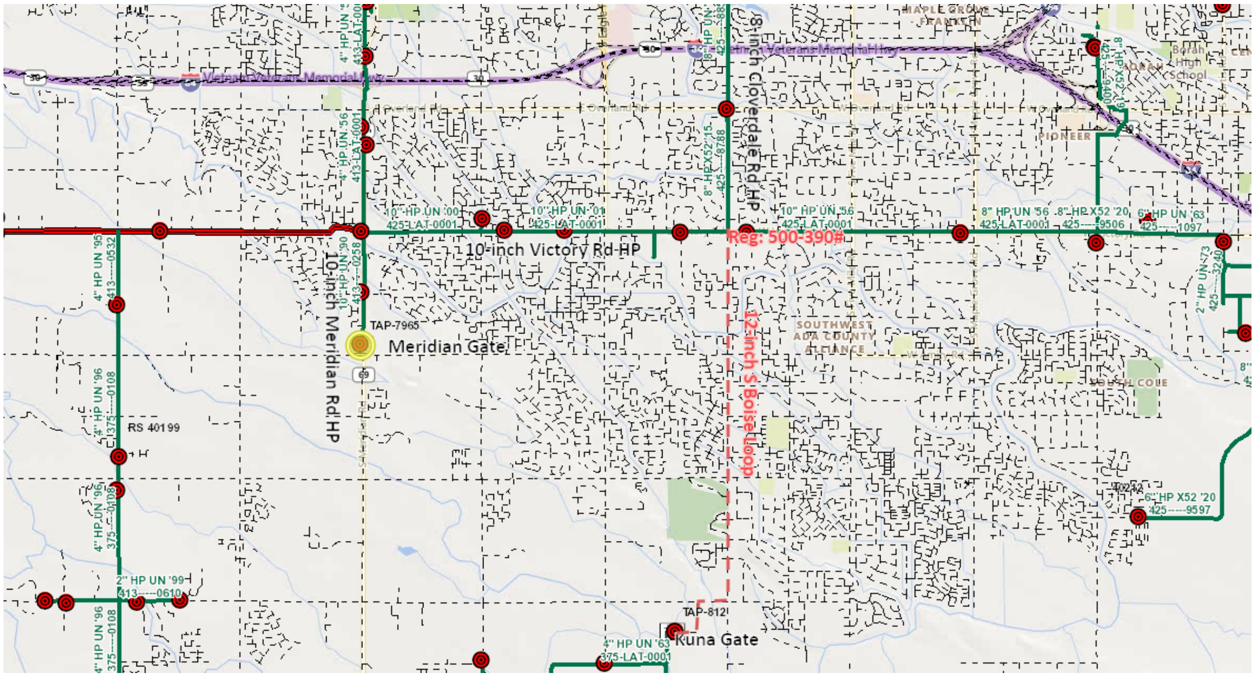

Figure 46: 12-inch South Boise Loop

This enhancement brings the lateral capacity to 870,000 therms per day which meets predicted growth through 2028. The 12-inch Cloverdale project is completed. The Kuna Gate is installed and is waiting on some regulator station parts to come in. The Victory and Cloverdale regulator is in fabrication and will be installed this fall. This project will be online this fall and is estimated to cost $17,900,000 direct and $17,254,430 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 most of its entire demand at the 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. Throughout the years Intermountain has uprated and upgraded this existing lateral, and most recently installed the Jerome Compressor Station towards the south end of the lateral to maintain capacity and increase flow toward the north end of the system.

Capacity Limiter

Due to growth in Sun Valley this AOI requires a capacity enhancement by 2023 to meet IRP growth. The current capacity limiter for this AOI is the end of line pressure on the lateral to the Ketchum area as shown in yellow in Figure 47.

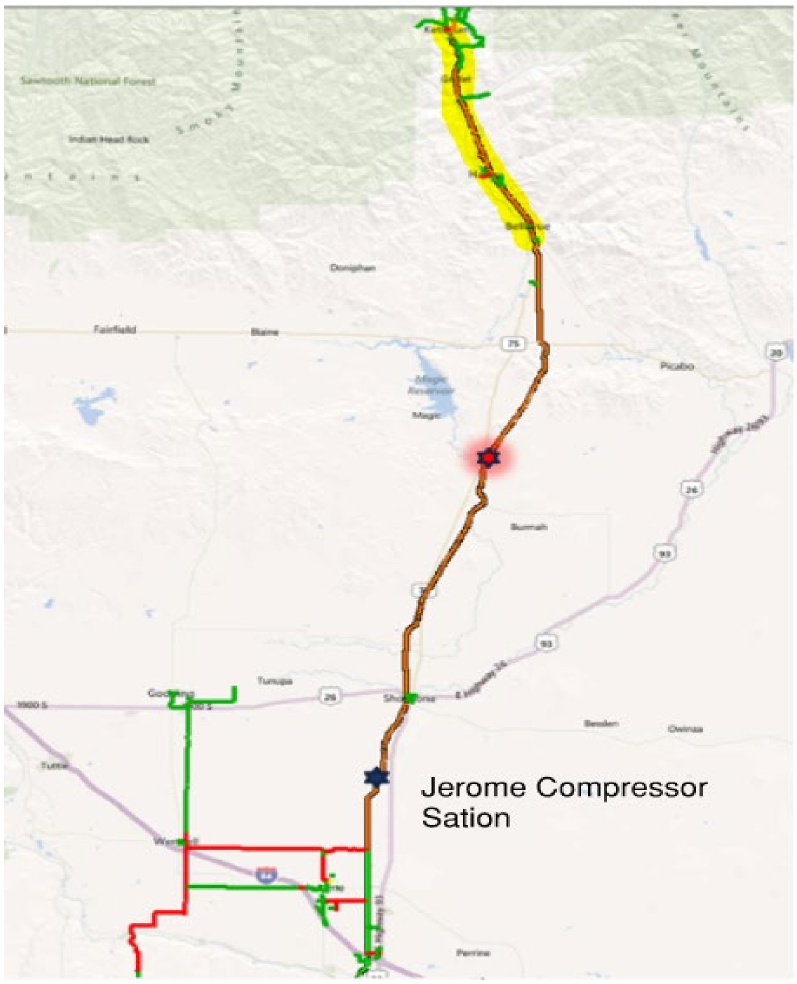

Figure 47: Sun Valley Lateral Capacity Limiter

Capacity Enhancement Alternatives

The Shoshone compressor station was selected in the 2019 IRP. Since 2019, the IGC IRP has been improved and expanded. Alternative analysis discussion in the capacity enhancement section started in the 2021 IRP filing.

Capacity Enhancement Selected

The Shoshone Compressor enhancement consists of installing a compressor station near Shoshone, ID (Mile Post 32) on the Sun Valley lateral as shown in Figure 48.

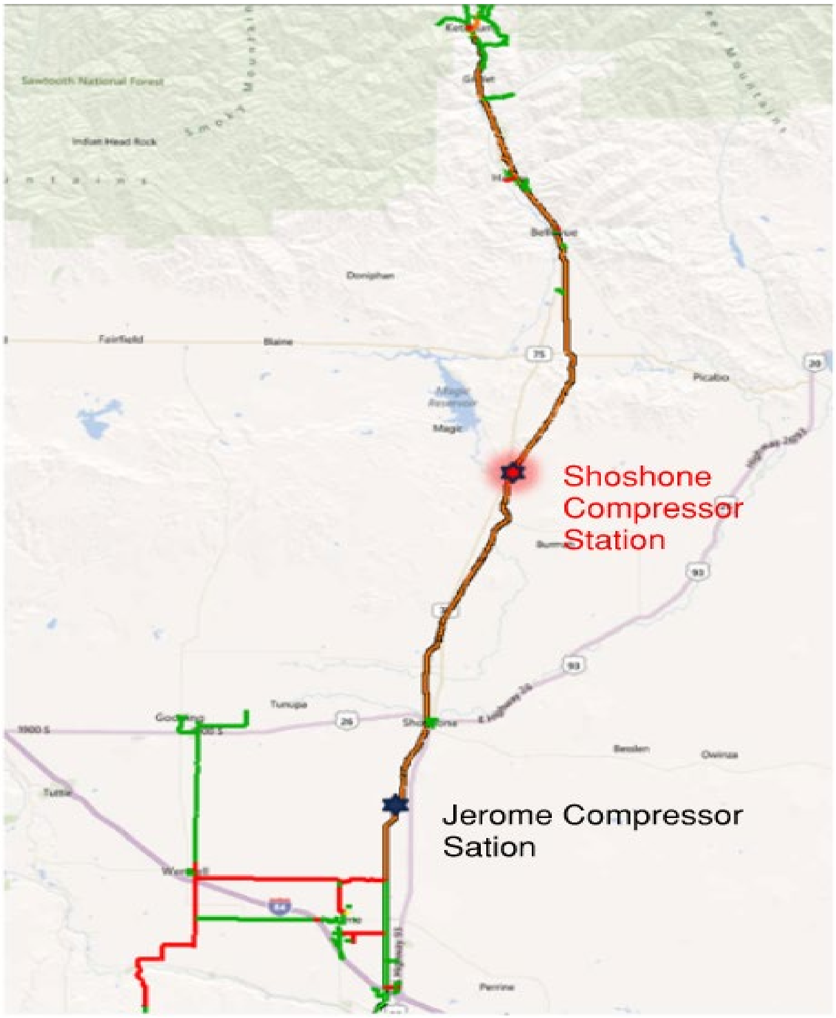

Figure 48: Shoshone Compressor Station

This enhancement brings lateral capacity to 247,500 therms per day which will meet predicted growth through 2028. The compressor is installed onsite and will be commissioned this September to allow the compressor to be online for winter demand. The compressor station is estimated to cost at $6,700,000 direct and $8,769,994 in net present value costs.

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

Due to growth in Idaho Falls this AOI requires a capacity enhancement by 2024 to meet IRP growth. 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 49.

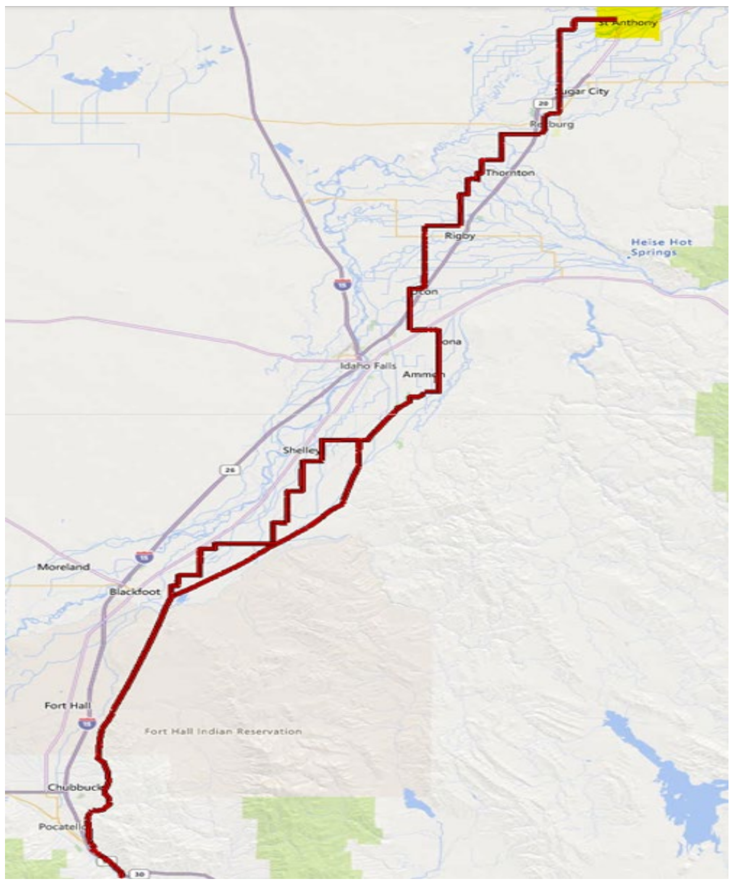

Figure 49: Idaho Falls Lateral Capacity Limiter

Capacity Enhancement Alternatives

Two alternatives were considered in the 2021 IRP. Those alternatives included a Blackfoot Compressor Station or a Phase IV Pipeline with an additional LNG Tank in Rexburg. The Blackfoot Compressor station was chosen in the 2021 IRP as the lowest cost option that provided the largest capacity to the lateral.

Capacity Enhancement Selected

The Blackfoot Compressor enhancement consists of installing a compressor station near Blackfoot, ID on the Idaho Falls lateral as shown in Figure 50.

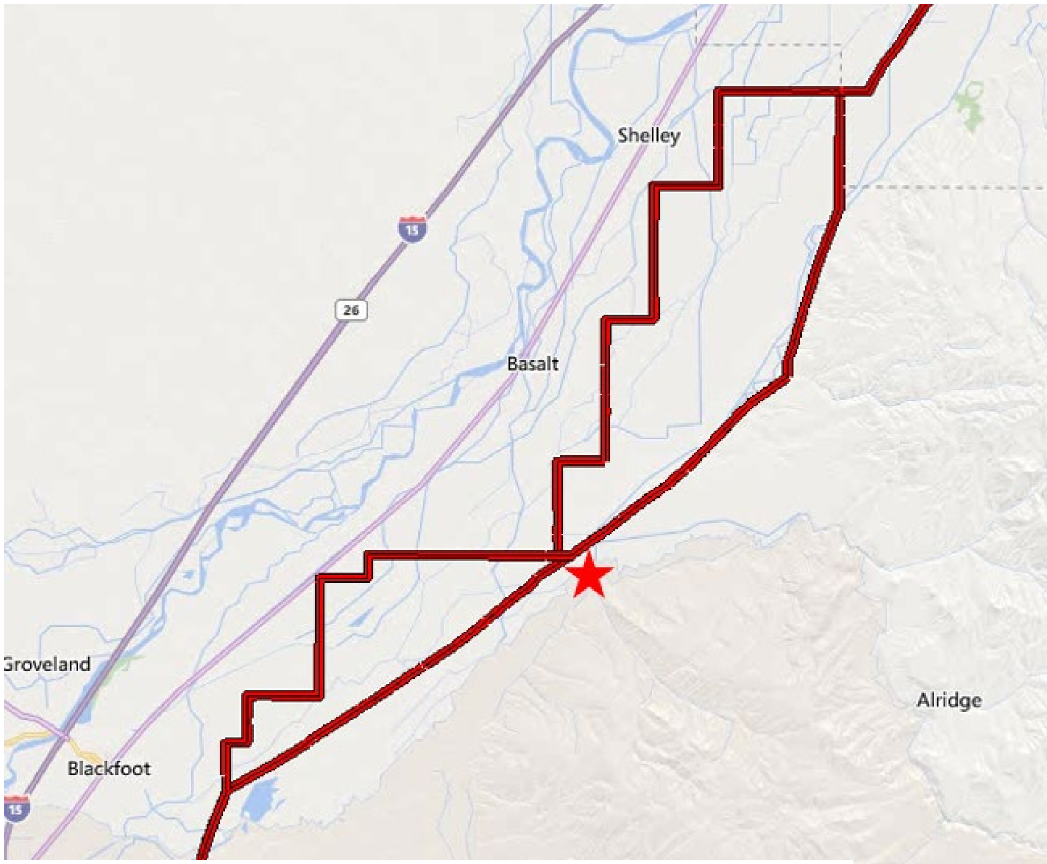

Figure 50: Idaho Falls Lateral Blackfoot Compressor

This enhancement brings lateral capacity to 1,093,000 therms per day (assumes Rexburg LNG is offline) which would meet predicted growth through 2028. The compressor has been ordered with land acquisition and required permit applications ongoing. Construction is planned to commence in 2024 with costs estimated at $20,000,000 in direct and $22,822,278 in net present value cost.

With the decision of adding the Blackfoot compressor station, Intermountain will need to keep the Rexburg satellite LNG facility as a peak shaving facility until 2024 when the Blackfoot compressor station comes online. After 2024, Intermountain plans to keep the Rexburg satellite LNG facility as an emergency backup to provide additional system reliability to the Idaho Falls lateral.

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, the Payette Gate Upgrade and the New Plymouth Gate Upgrade.

Capacity Limiter

Once a gate approaches its 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.

Capacity Enhancement Alternatives

No alternatives to consider for gate upgrades in the small towns of Payette and 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.

Capacity Enhancement Selected

The Payette Gate upgrade and New Plymouth Gate upgrade both need to be completed by 2024 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 Payette Gate Upgrade is estimated to cost $3,490,000 in direct costs and the New Plymouth Gate Upgrade is estimated to cost $2,760,000 in direct costs. Net present value cost is not applicable for gate upgrades since the upgraded gate has the same operations and maintenance costs as the current gate.

4.3.7 Summary

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

Table 10: Five-Year Planning and Timing of Capacity Enhancements Selected

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
2023	870,000	12-inch S Boise Loop	820,000	None	1,390,000	12-inch Ustick Phase III	247,500	Shoshone Compressor Station	904,000	None
2024	870,000	None	820,000	None	1,390,000	None	247,500	None	1,093,000	IFL Compressor Station
2025	870,000	None	950,000	State Street Uprate	1,390,000	None	247,500	None	1,093,000	None
2026	870,000	None	950,000	State Penn Gate Upgrade	1,390,000	None	247,500	None	10,930,000	None
2027	870,000	None	950,000	None	1,390,000	None	247,500	None	10,930,000	None
2028	870,000	None	950,000	None	1,390,000	None	247,500	None	1,093,000	None

As is shown in Table 10, five years is sufficient time to identify, budget, plan, design and construct projects to address capacity deficits. As part of the IRP process, IGC will check its five-year plan deficits and alternatives considered for capacity enhancement in the next IRP filling in 2025 and adjust the Company's plan as needed to ensure reliable service to Intermountain's customers based on the next round of IRP growth predictions. This will be an ongoing iterative process as part of IGC's two-year IRP filing.

4.4 Load Demand Curves

Key Points

- Load Demand Curves (LDC) calculates Intermountain's projected usage during the planning horizon.
- Intermountain does a base, high, and low LDC for each area of interest and for the total company.
- Intermountain expects the Company to increase by increase of 69,894 customers, or 2.8% per year, over the planning horizon.
- Under expected customer growth and normal weather, Intermountain expects usage to grow to 50 million therms by 2028.
- Due to this growth, Intermountain anticipates distribution system shortfalls at each area of interest, requiring distribution system upgrades.

The culmination of the demand forecasting process is aggregating the information discussed in the previous sections into a forecast of future load requirements. As the previous sections illustrate, the customer forecast, design weather, core market usage per customer data, large volume usage forecast, and demand side management are all key drivers in the development of the Load Demand Curves (LDC).

The IRP customer forecast provides a total Company daily projection through Planning Year (PY) 2028 and includes a forecast for each of the five AOIs of the distribution system. Each forecast was developed under each of three different customer growth scenarios: low growth, base case, and high growth.

The development of a design weather curve – which reflects the coldest anticipated weather patterns across the Company's service area – provides a means to distribute the core market's heat sensitive portion of Intermountain's load on a daily basis. Applying design weather to the residential and small commercial usage per customer forecast creates core market usage per customer under design weather conditions. That combined with the applicable customer forecast yields a daily core market load projection through PY28 for the entire company, as well as for each AOI. Similar to the above, normal weather scenario modeling was also completed.

As discussed in the Large Volume Customer Forecast Section, the forecast also incorporates the large volume Contract Demand from both a Company-wide perspective (interstate capacity) as well as from an AOI perspective (distribution capacity). When added to the core market figures, the result is a grand total daily forecast for both gas supply and capacity requirements including a break-out by AOI.

Peak day send-out under each of these customer growth scenarios was measured against the currently available capacity to project the magnitude, frequency and timing of potential delivery deficits, both from a Company perspective and an AOI perspective.

Once the demand forecasts were finished and the evaluation complete, the data was input into SENDOUT®, the Company's optimization model, for IRP modeling. The LDC incorporates all the factors that will impact Intermountain's future loads. The LDC is the basic tool used to reflect demand in the IRP Optimization Model.

It is important to note that the Load Demand Curves, found in Exhibit 7, represent existing resources and are intended to identify potential capacity constraints and to assist in the long-term planning process. Plans to address any identified deficits will be discussed in the Planning Results Section of this report.

4.4.1 Customer Growth Summary Observations – Design Weather – All Scenarios

Idaho Falls Lateral

The Idaho Falls Lateral low growth scenario projects an increase in customers of 6,542 PY23 through PY28 (Jan 1, 2023 to Dec 31, 2028) which corresponds to an annualized growth rate of 1.72%. In the base case scenario customers are forecasted to increase by 10,786 (2.75% annualized growth rate), while the high growth scenario forecasts an increase of 14,473 customers (3.62% annualized growth rate).

Sun Valley Lateral

The Sun Valley Lateral low growth scenario (PY23 – PY28) projects an increase of 705 customers (0.89% annualized growth rate). In the base case scenario customers are projected to increase by 1,142 (1.43% annualized growth rate), while the high growth scenario shows an increase of 1,607 customers (1.98% annualized growth rate).

Canyon County Area

The low growth customer forecast (PY23 – PY28) for Canyon County Area reflects an increase of 13,221 customers (3.28% annualized growth rate). In the base case scenario customers are forecasted to increase by 16,011 (3.92% annualized growth rate), while the high growth scenario projects an increase of 19,414 customers (4.66% annualized growth rate).

State Street Lateral

The low growth customer forecast (PY23 – PY28) for the State Street Lateral reflects an increase of 7,175 customers (1.92% annualized growth rate). The base case scenario projects an increase of 8,980 customers (2.38% annualized growth rate), while the high growth scenario forecasts an increase of 10,640 customers (2.79% annualized growth rate).

Central Ada County

The low growth customer forecast (PY23 – PY28) for the Central Ada County reflects an increase of 7,281 customers (1.95% annualized growth rate). In the base case scenario customers are forecasted to increase by 9,048 (2.40% annualized growth rate), while the high growth scenario projects an increase of 10,671 customers (2.80% annualized growth rate).

Total Company

The Total Company (TC) low growth customer forecast (PY23 – PY28) projects an increase of 46,805 customers (1.84% annualized growth rate). The base case scenario forecasts an increase of 66,100 customers (2.56% annualized growth rate), while the high growth scenario projects an increase of 84,546 customers (3.22% annualized growth rate). Please note that the TC forecasts include the AOIs mentioned above as well as all other customers not located in a particular AOI.

Using the LDC analyses allows Intermountain to anticipate changes in future demand requirements and plan for the use of existing resources and the timely acquisition of additional resources.

4.4.2 Core Customer Distribution Sendout Summary – Design and Normal Weather – All Scenarios

Idaho Falls Area

Table 11: Idaho Falls Lateral Design Weather – Annual Core + LV-1 Market Distribution Sendout (Dth)

Idaho Falls Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	8,109,610	8,136,524	8,188,219	8,297,228	8,400,679	8,531,564
Base	8,181,825	8,402,905	8,538,387	8,711,484	8,881,916	9,095,710
High	8,240,256	8,654,492	8,902,000	9,142,439	9,345,331	9,599,938

Table 12: Idaho Falls Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Idaho Falls Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	7,105,271	7,123,585	7,168,588	7,259,255	7,345,857	7,450,820
Base	7,169,715	7,355,295	7,472,846	7,619,274	7,762,969	7,940,232
High	7,220,835	7,573,359	7,787,819	7,992,798	8,164,839	8,376,848

Sun Valley Area

Table 13: Sun Valley Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Sun Valley Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	2,339,468	2,356,144	2,358,636	2,377,920	2,400,107	2,427,796
Base	2,350,870	2,392,856	2,409,577	2,436,944	2,463,497	2,502,063
High	2,360,063	2,430,295	2,458,404	2,504,628	2,538,271	2,584,974

Sun Valley Area (cont.)

Table 14: Sun Valley Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Sun Valley Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	1,989,354	2,001,835	2,004,423	2,019,854	2,037,659	2,058,973
Base	1,999,014	2,032,984	2,047,585	2,069,943	2,091,440	2,121,814
High	2,006,607	2,064,524	2,088,846	2,127,168	2,154,794	2,192,114

Canyon County Area

Table 15: Canyon County Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Canyon County Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	8,587,798	8,740,367	8,881,047	9,174,525	9,409,297	9,741,969
Base	8,650,142	8,967,484	9,205,257	9,547,643	9,830,009	10,168,730
High	8,694,642	9,184,905	9,508,604	9,932,948	10,280,995	10,700,503

Table 16: Canyon County Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Canyon County Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	6,778,360	6,887,336	6,990,835	7,224,280	7,400,912	7,654,100
Base	6,828,816	7,066,567	7,245,086	7,518,174	7,731,250	7,989,193
High	6,863,981	7,237,655	7,483,465	7,820,823	8,085,852	8,408,690

State Street Lateral

Table 17: State Street Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

State Street Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	7,962,950	8,006,760	8,041,609	8,140,414	8,265,408	8,379,593
Base	8,011,559	8,182,741	8,279,803	8,414,827	8,550,398	8,727,951
High	8,047,006	8,338,892	8,497,203	8,699,947	8,837,401	9,041,741

Table 18: State Street Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

State Street Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	6,201,390	6,224,348	6,244,440	6,311,800	6,401,176	6,480,463
Base	6,240,172	6,363,348	6,431,634	6,528,324	6,625,572	6,754,413
High	6,268,456	6,486,020	6,602,340	6,752,408	6,851,519	7,001,523

Central Ada County

Table 19: Central Ada Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Central Ada Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	7,918,054	7,970,001	8,008,307	8,108,882	8,231,921	8,347,829
Base	7,962,390	8,130,951	8,226,587	8,359,609	8,493,183	8,668,143
High	7,994,970	8,274,665	8,427,177	8,622,055	8,757,408	8,957,541

Central Ada County (cont.)

Table 20: Central Ada Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Central Ada Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	6,206,215	6,235,675	6,258,153	6,326,867	6,414,542	6,495,230
Base	6,241,521	6,362,628	6,429,498	6,524,465	6,619,996	6,746,799
High	6,267,453	6,475,382	6,586,766	6,730,450	6,827,733	6,974,402

Total Company

Table 21: Total Company Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Total Company Design Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	55,917,129	56,240,941	56,502,397	57,281,905	58,129,130	59,107,231
Base	56,313,064	57,667,418	58,452,537	59,591,309	60,671,553	62,056,494
High	56,617,857	59,011,480	60,349,924	61,950,883	63,244,041	64,949,121

Table 22: Total Company Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)

Total Company Normal Weather - Annual Core + LV-1 Market Distribution Sendout (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	45,707,995	45,923,649	46,103,886	46,705,306	47,356,583	48,101,759
Base	46,035,614	47,085,442	47,687,152	48,583,343	49,420,351	50,495,942
High	46,284,345	48,175,848	49,226,704	50,497,575	51,509,277	52,844,927

4.4.3 Projected Capacity Deficits – Design Weather – All Scenarios

Residential, commercial, and industrial peak day load growth on Intermountain's system is forecast over the six-year period to grow at an average annual rate of 1.14% (low growth), 2.18% (base case) and 3.10% (high growth), highlighting the need for long-term planning. The next section illustrates the projected capacity deficits by AOI during the IRP planning horizon.

Idaho Falls Lateral LDC Study

When forecast peak day send-out on the Idaho Falls Lateral is matched against the existing peak day distribution capacity (90,400), peak day delivery deficit occurs under the base case scenario beginning in PY27.

Table 23: Idaho Falls Design Weather - Peak Day Deficit Under Existing Resources (Dth)

Idaho Falls Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	0	0	0	0	0	0
Base	0	0	0	0	1,211	2,830
High	0	0	950	3,136	5,112	7,057

Sun Valley Lateral LDC Study

When forecasted peak day send out on the Sun Valley Lateral is matched against the existing peak day distribution capacity (20,000 Dth), peak day delivery deficits occur in PY24 under the base case scenario.

Table 24: Sun Valley Design Weather - Peak Day Deficit Under Existing Resources (Dth)

Sun Valley Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	0	0	0	57	275	424
Base	0	34	281	522	762	999
High	0	324	636	1,045	1,339	1,623

Canyon County Area LDC Study

When forecasted peak day send out for the Canyon County Area is matched against the existing peak day distribution capacity (103,200 Dth), peak day delivery deficits occur beginning in PY24 under the base case scenario.

Table 25: Canyon County Design Weather - Peak Day Deficit Under Existing Resources (Dth)

Canyon County Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	0	0	1,083	3,677	5,939	8,853
Base	0	1,021	4,041	7,037	9,868	12,726
High	0	2,936	6,733	10,503	13,919	17,353

State Street Lateral LDC Study

When forecasted peak day send out for the State Street Lateral is matched against the existing peak day distribution capacity (82,000 Dth), a peak day delivery deficit occurs in PY28 under the base case scenario.

Table 26: State Street Design Weather - Peak Day Deficit Under Existing Resources (Dth)

State Street Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	0	0	0	0	0	0
Base	0	0	0	0	0	892
High	0	0	0	419	1,950	3,624

Central Ada County LDC Study

Table 27: Central Ada Design Weather - Peak Day Deficit Under Existing Resources (Dth)

Central Ada Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	0	0	0	729	2,124	3,090
Base	0	0	1,484	2,978	4,474	5,973
High	0	1,248	3,260	5,334	6,846	8,499

When forecasted peak day send out for the Central Ada County is matched against the existing peak day distribution capacity (74,500 Dth), peak day delivery deficits occur in PY25 under the base case scenario.

Total Company LDC Study

The Total Company perspective differs from the laterals in that it reflects the amount of gas that can be delivered to Intermountain via the various resources on the interstate system. Hence, total system deliveries should provide at least the net sum demand – or the total available distribution capacity where applicable - of all the laterals/AOIs on the distribution system. The following table shows peak day deficits. The solution for this shortfall is discussed further in the Upstream Modeling Results portion of the Planning Results section.

Table 28: Total Company Design Weather - Peak Day SENDOUT (Core+LV-1) Deficit Under Existing Resources (Dth)

Total Company Design Weather - Peak Day SENDOUT (Core+LV-1) Deficit Under Existing Resources (Dth)						
Growth Scenario	2023	2024	2025	2026	2027	2028
Low	38,567	38,509	44,487	52,999	62,255	69,796
Base	40,534	50,639	61,793	73,234	84,764	95,734
High	41,972	62,003	78,164	93,901	107,305	120,830

4.4.4 2021 IRP vs. 2023 IRP Common Year Comparisons

This section compares the Total Company and each AOI during the three common years of the 2023 and 2021 IRP filings. In some cases, the distribution transportation capacity may be forecasting lower in the 2023 IRP than it was in the 2021 IRP. This is the result of differences in, or fine tuning of, planned capacity upgrades.

Total Company Design Weather/ Base Case Growth Comparison

Table 29: 2023 IRP Load Demand Curve – TC Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2024	492,900	150,254	643,154
2025	504,275	150,474	654,749
2026	515,575	151,064	666,639

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

Table 30: 2021 IRP Load Demand Curve – TC Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2024	498,202	140,364	638,566
2025	510,868	140,779	651,647
2026	522,487	141,379	663,866

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

Table 31: 2023 IRP Load Demand Curve – TC Usage Design Base Case

2023 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE Over/(Under) 2021 IRP (Dth)			
		Peak Day Sendout	
	Core Market	Firm CD[1]	Total
2024	(5,303)	9,890	4,587
2025	(6,593)	9,695	3,102
2026	(6,912)	9,685	2,773

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

Total Company Peak Day Deliverability Comparison

Table 32: 2023 IRP Peak Day Firm Delivery Capability (Dth)

2023 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)	2024	2025	2026
Maximum Daily Storage Withdrawals:			
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)	341,043	338,043	338,043
Total Peak Day Deliverability	586,555	583,555	583,555

Table 33: 2021 IRP Peak Day Firm Delivery Capability (Dth)

2021 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2024	2025	2026
Maximum Daily Storage Withdrawals:			
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)	332,043	332,043	332,043
Total Peak Day Deliverability	577,555	577,555	577,555

Table 34: 2023 IRP Peak Day Firm Delivery Capability

2023 IRP PEAK DAY FIRM DELIVERY CAPABILITY Over/(Under) 2021 (Dth)			
	2021	2022	2023
Maximum Daily Storage Withdrawals:			
Nampa LNG	0	0	0
Plymouth LS	0	0	0
Jackson Prairie SGS	0	0	0
Total Storage	0	0	0
Maximum Deliverability (NWP)	9,000	6,000	6,000
Total Peak Day Deliverability	9,000	6,000	6,000

Idaho Falls Lateral Design Weather/Base Case Growth Comparison

Table 35: 2023 IRP Load Demand Curve – IFL Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	109,300	66,408	20,201	86,609
2025	109,300	68,122	20,301	88,423
2026	109,300	69,823	20,301	90,124

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

Table 36: 2021 IRP Load Demand Curve – IFL Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	109,300	68,029	21,331	89,360
2025	109,300	69,448	21,331	90,779
2026	109,300	70,825	21,381	92,206

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

Table 37: 2023 IRP Load Demand Curve – IFL Usage Design Base Case Over/(Under) 2021 IRP (Dth)

2023 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE Over/(Under) 2021 IRP (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	0	(1,621)	(1,130)	(2,751)
2025	0	(1,326)	(1,030)	(2,356)
2026	0	(1,002)	(1,080)	(2,082)

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

Sun Valley Lateral Design Weather/ Base Case Growth Comparison

Table 38: 2023 IRP Load Demand Curve – SVL Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – SVL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	24,750	18,105	1,935	20,040
2025	24,750	18,361	1,935	20,296
2026	24,750	18,613	1,935	20,548

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

Table 39: 2021 IRP Load Demand Curve –SVL Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE (Dth)				
			Peak Day Sendout	
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	24,750	19,360	1,935	21,295
2025	24,750	19,634	1,935	21,569
2026	24,750	19,830	1,935	21,765

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

Table 40: 2021 IRP Load Demand Curve –SVL Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE Over/(Under) 2021 (Dth)				
			Peak Day Sendout	
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	0	(1,255)	0	(1,255)
2025	0	(1,273)	0	(1,273)
2026	0	(1,217)	0	(1,217)

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

Canyon County Area Design Weather/ Base Case Growth Comparison

Table 41: 2023 IRP Load Demand Curve – CCA Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	139,000	79,570	24,740	104,310
2025	139,000	82,469	24,940	107,409
2026	139,000	85,370	25,110	110,480

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

Table 42: 2021 IRP Load Demand Curve – CCA Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	139,000	78,588	24,790	103,378
2025	139,000	81,553	24,790	106,343
2026	139,000	83,917	24,790	108,707

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

Table 43: 2023 IRP Load Demand Curve – CCA Usage Design Base Case Over/(Under) 2021 (Dth)

2023 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE Over/(Under) 2021 (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	0	982	(50)	932
2025	0	916	150	1,066
2026	0	1,453	320	1,773

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

State Street Lateral Design Weather/ Base Case Growth Comparison

Table 44: 2023 IRP Load Demand Curve – SSL Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	82,000	75,961	990	76,951
2025	95,000	77,563	990	78,553
2026	95,000	79,163	990	80,153

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

Table 45: 2021 IRP Load Demand Curve – SSL Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	95,000	76,823	990	77,813
2025	95,000	79,183	990	80,173
2026	95,000	81,614	990	82,604

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

Table 46: 2023 IRP Load Demand Curve – SSL Usage Design Base Case Over/(Under) 2021 (Dth)

2023 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE Over/(Under) 2021 (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	(13,000)	(862)	0	(862)
2025	0	(1,620)	0	(1,620)
2026	0	(2,451)	0	(2,451)

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

Central Ada County Design Weather/ Base Case Growth Comparison

Table 47: 2023 IRP Load Demand Curve – CAC Usage Design Base Case (Dth)

2023 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	87,000	73,738	850	74,588
2025	87,000	75,327	850	76,177
2026	87,000	76,914	850	77,764

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

Table 48: 2021 IRP Load Demand Curve – CAC Usage Design Base Case (Dth)

2021 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	87,000	73,634	950	74,584
2025	87,000	74,812	950	75,762
2026	87,000	76,002	950	76,952

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

Table 49: 2023 IRP Load Demand Curve – CAC Usage Design Base Case Over/(Under) 2021 (Dth)

2023 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE Over/(Under) 2021 (Dth)				
			Peak Day Sendout	
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2024	0	104	(100)	4
2025	0	515	(100)	415
2026	0	912	(100)	812

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

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, 2023 to 2028.

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 Areas of Interest (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 this 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 previous IRP 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 51 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.

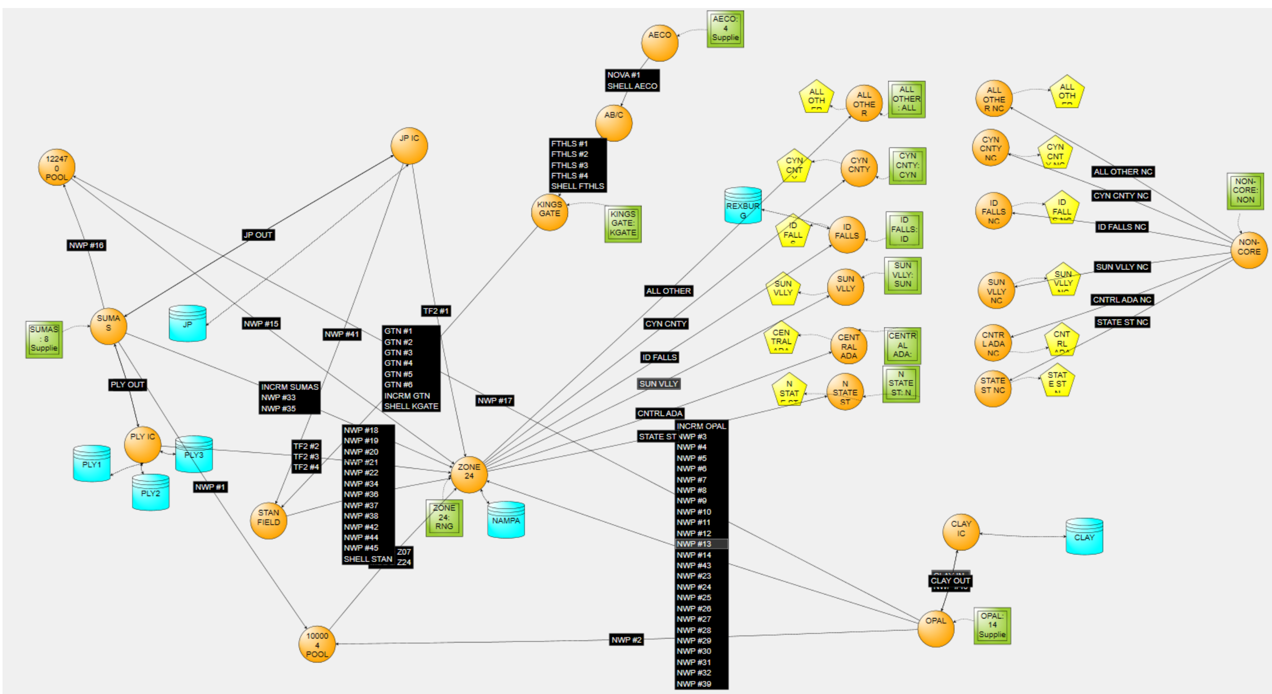

Figure 51: IGC Natural Gas Modeling System Map

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 51.

4.5.5 Demand Area Forecasts

As previously discussed in the Load Demand Curves Section beginning on page **Error! Bookmark not defined.**, 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 Section on page 6. Intermountain forecasts peak demand to be 481,535 dth for RS (Residential) and GS (commercial) customers and 151,054 dth for LV-1 and T-4 customers in 2023 and growing to 538,255 dth and 151,774 dth in 2028, respectively.

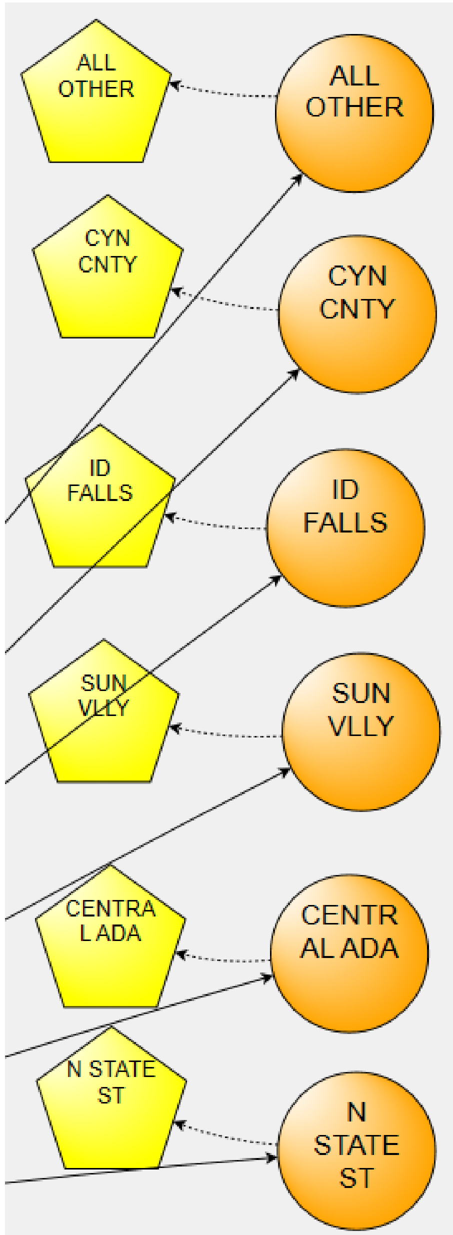

Figure 52: IGC Laterals from Zone 24

The demand areas listed in Figure 52 are:

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

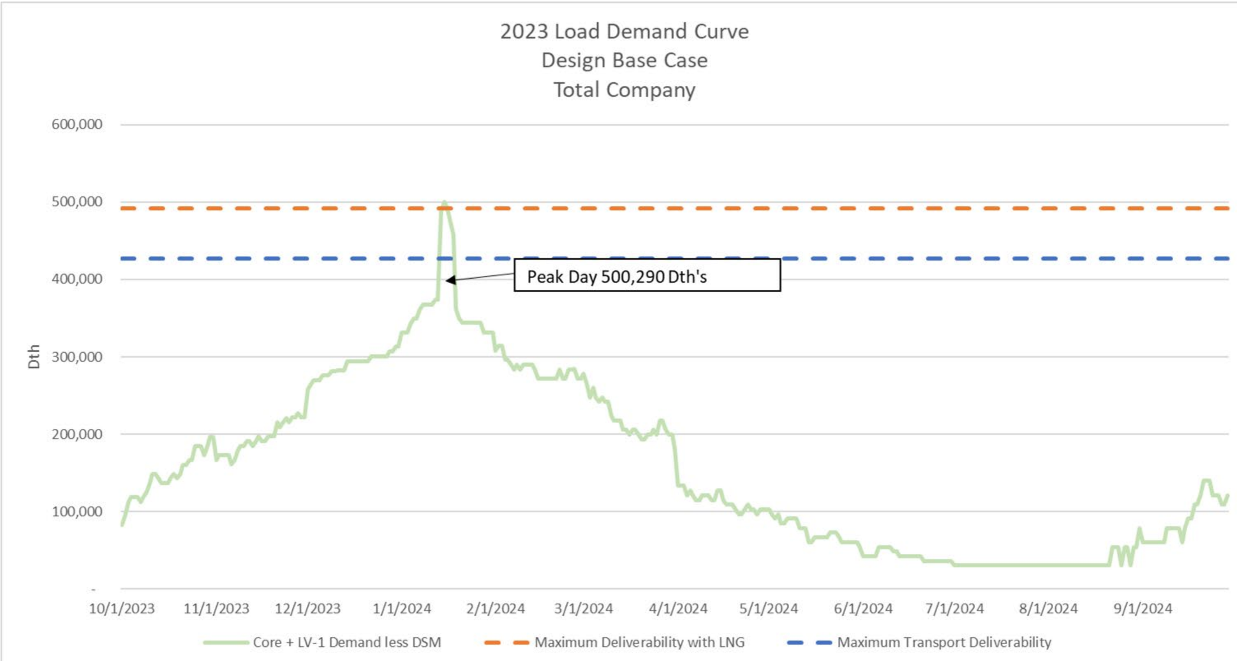

Figure 53: Total Company Design Base 2023

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 53 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 54 shows the supply area (in green) providing gas at the Opal 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.

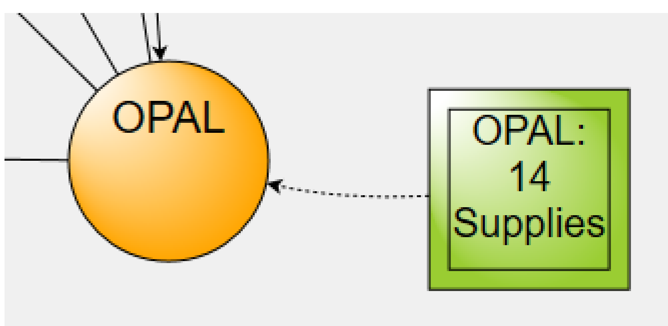

Figure 54: IGC Supply Model Example

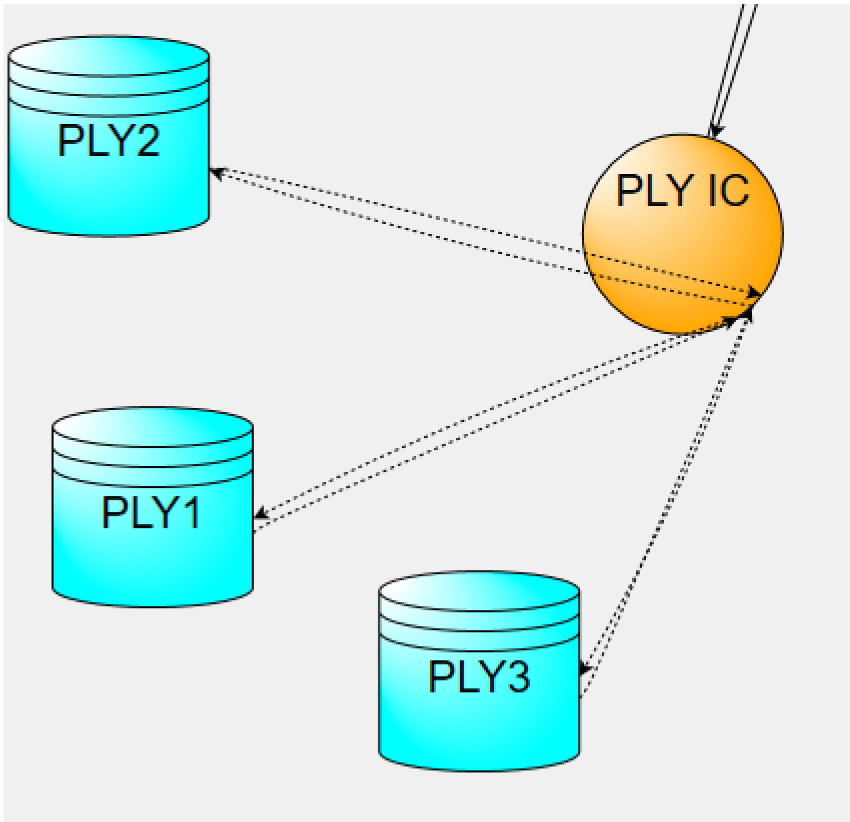

Figure 55: IGC Storage Model Example

Figure 55 shows an example of the SENDOUT 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. Figure 56 shows 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 (starting on page **Error! Bookmark not defined.**).

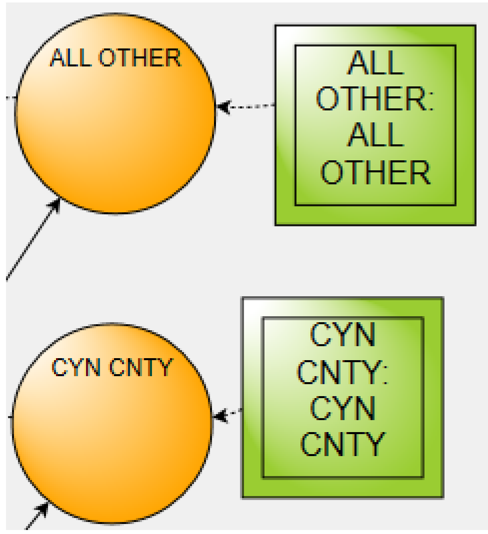

Figure 56: IGC DSM Model Example

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 our transportation model is seen in Figure 57.

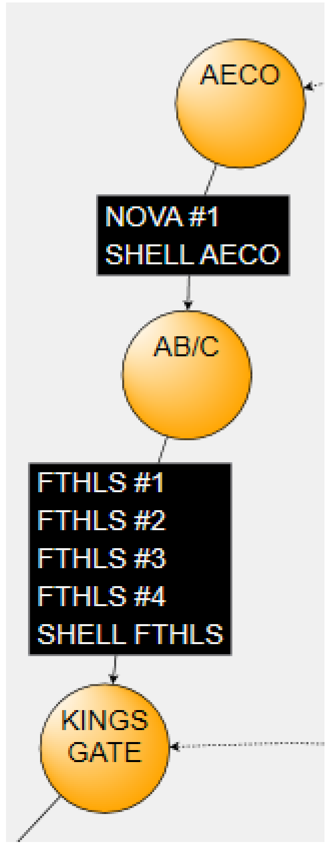

Figure 57: IGC Transport Model Example

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. Table 50 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.

Table 50: Transport Input Summary

Transport	Property	Units	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23
FTHLS 1	Max Daily Flow	BBtu	7.105	7.105	7.105	7.105	7.105	7.105
FTHLS 1	Fixed Costs	$0	$ 20.05	$ 19.40	$ 20.05	$ 20.05	$ 18.11	$ 20.05
FTHLS 1	Reservation Cost	$0	$ 20.05	$ 19.40	$ 20.05	$ 20.05	$ 18.11	$ 20.05
FTHLS 1	Loss	BBtu	0	0	0	0	0	0
FTHLS 2	Max Daily Flow	BBtu	87.639	87.639	87.639	87.639	87.639	87.639
FTHLS 2	Fixed Costs	$0	$ 247.47	$ 239.49	$ 247.47	$ 247.47	$ 223.53	$ 247.47
FTHLS 2	Reservation Cost	$0	$ 247.47	$ 239.49	$ 247.47	$ 247.47	$ 223.53	$ 247.47
FTHLS 2	Loss	BBtu	0	0	0	0	0	0
FTHLS 3	Max Daily Flow	BBtu	0	20.941	20.941	20.941	20.941	20.941
FTHLS 3	Fixed Costs	$0	$ -	$ 57.23	$ 59.13	$ 59.13	$ 53.41	$ 59.13
FTHLS 3	Reservation Cost	$0	$ -	$ 57.23	$ 59.13	$ 59.13	$ 53.41	$ 59.13
FTHLS 3	Loss	BBtu	0	0	0	0	0	0

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 2023 through 2028 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. Table 51 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).

Table 51: Lateral Summary by Year

2023	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%	-	90,400	95%
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					

Table 52 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.

Table 52: Annual Traditional Supply Resources Results

Supply Name	Property	Units	2023	2024	2025	2026	2027	2028
AECO Base	Take Quantity	BBtu	14,900	14,951	14,895	14,968	14,981	15,044
AECO Base	Price	$/MMBtu	$ 4.58	$ 3.22	$ 2.70	$ 2.54	$ 2.44	$ 2.47
AECO Base	Commodity Cost	$0	$ 68,192.68	$ 48,075.99	$ 40,264.14	$38,049.20	$36,598.60	$37,165.78
AECO Day S	Take Quantity	BBtu	1,072	1,076	1,081	1,085	1,089	670
AECO Day S	Price	$/MMBtu	$ 4.78	$ 3.42	$ 2.90	$ 2.74	$ 2.64	$ 2.67
AECO Day S	Commodity Cost	$0	$ 4,080.25	$ 3,185.06	$ 2,910.84	$ 2,841.80	$ 2,785.54	$ 1,739.90
AECO Day W	Take Quantity	BBtu	1,820	1,830	1,820	1,820	1,820	1,830
AECO Day W	Price	$/MMBtu	$ 4.83	$ 3.47	$ 2.95	$ 2.79	$ 2.69	$ 2.72
AECO Day W	Commodity Cost	$0	$ 10,636.41	$ 7,209.32	$ 5,747.10	$ 5,302.77	$ 5,052.09	$ 5,097.71

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 Table 53. Exhibit 8 also provides transportation results by month for the planning horizon.

Table 53: Annual Transportation Resources Results

Transport Name	Property	Units	2023	2024	2025	2026	2027	2028
FTHLS 1	Flow Out	BBtu	2,188	1,812	1,822	1,385	2,030	2,146
FTHLS 1	Fixed Costs	$0	$ 236.07	$ 236.72	$ 236.07	$ 236.07	$ 236.07	$ 236.72
FTHLS 1	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 2	Flow Out	BBtu	24,088	23,769	24,053	23,209	19,054	16,424
FTHLS 2	Fixed Costs	$0	$ 2,913.81	$ 2,921.79	$ 2,913.81	$ 2,913.81	$ 2,913.81	$ 2,921.79
FTHLS 2	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 3	Flow Out	BBtu	3,162	3,183	3,162	3,162	3,075	3,183
FTHLS 3	Fixed Costs	$0	$ 288.03	$ 289.94	$ 288.03	$ 288.03	$ 288.03	$ 289.94
FTHLS 3	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -
FTHLS 4	Flow Out	BBtu	2,236	1,907	1,871	1,688	2,163	2,216
FTHLS 4	Fixed Costs	$0	$ 245.44	$ 246.11	$ 245.44	$ 245.44	$ 245.44	$ 246.11
FTHLS 4	Total Variable Costs	$0	$ -	$ -	$ -	$ -	$ -	$ -

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 2023 and 2021 IRP filings. Finally, the planning results for upstream transportation shortfalls are discussed.

4.6.2 Distribution System Planning

Canyon County

In the Capacity Enhancements section, four options are discussed to determine the best way to solve capacity shortfalls for the Canyon County AOI. The option chosen was the Ustick Phase III enhancements.

The following graph (Figure 58) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrades.

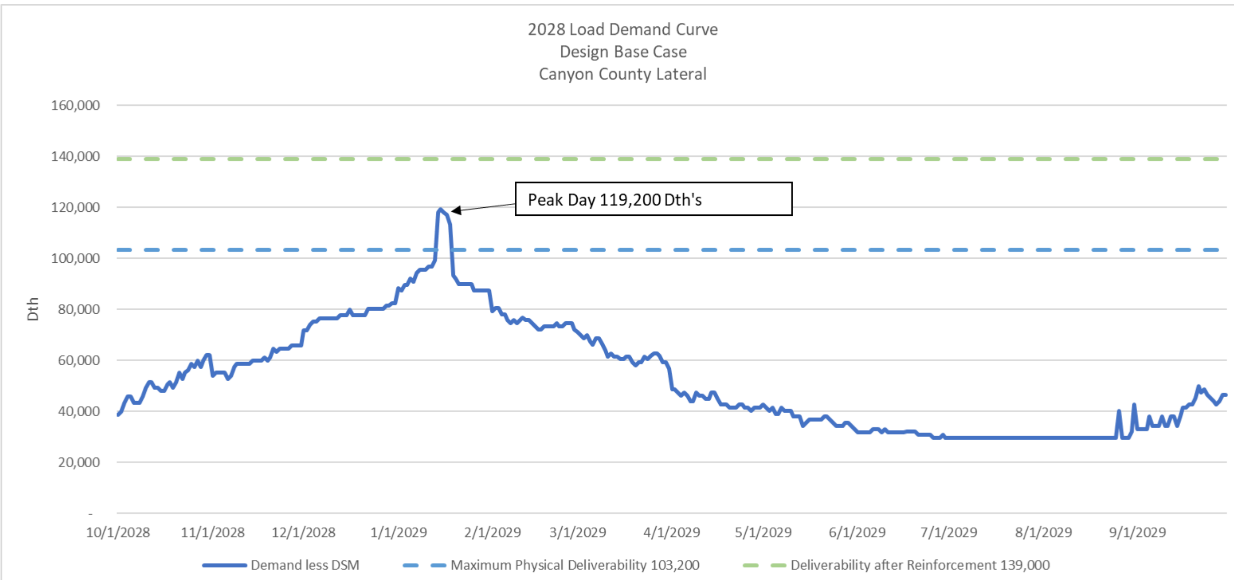

Figure 58: LDC Design Base Case – Canyon County Lateral

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 (Figure 59) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

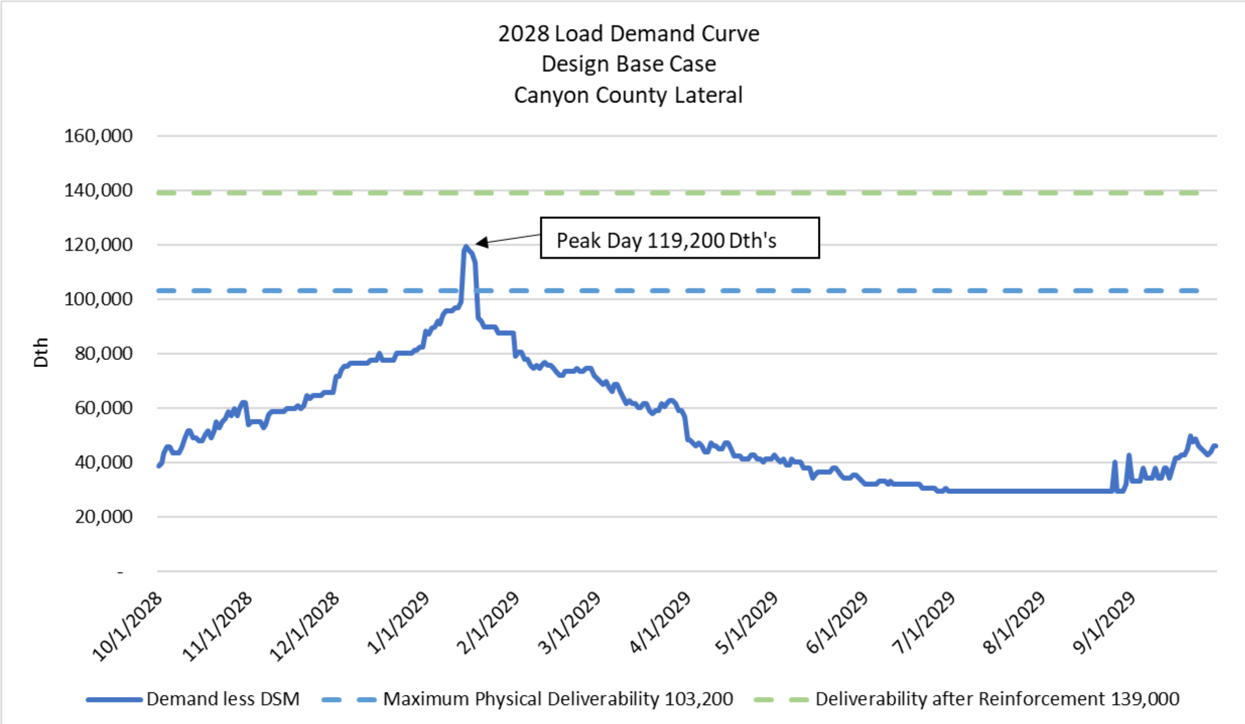

Figure 59: LDC Design Base Case – State Street Lateral

Central Ada County

In the Capacity Enhancements section, three options are discussed to determine the best way to solve capacity shortfalls for the Central Ada County AOI. The option chosen was the 12-inch South Boise Loop upgrade.

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.

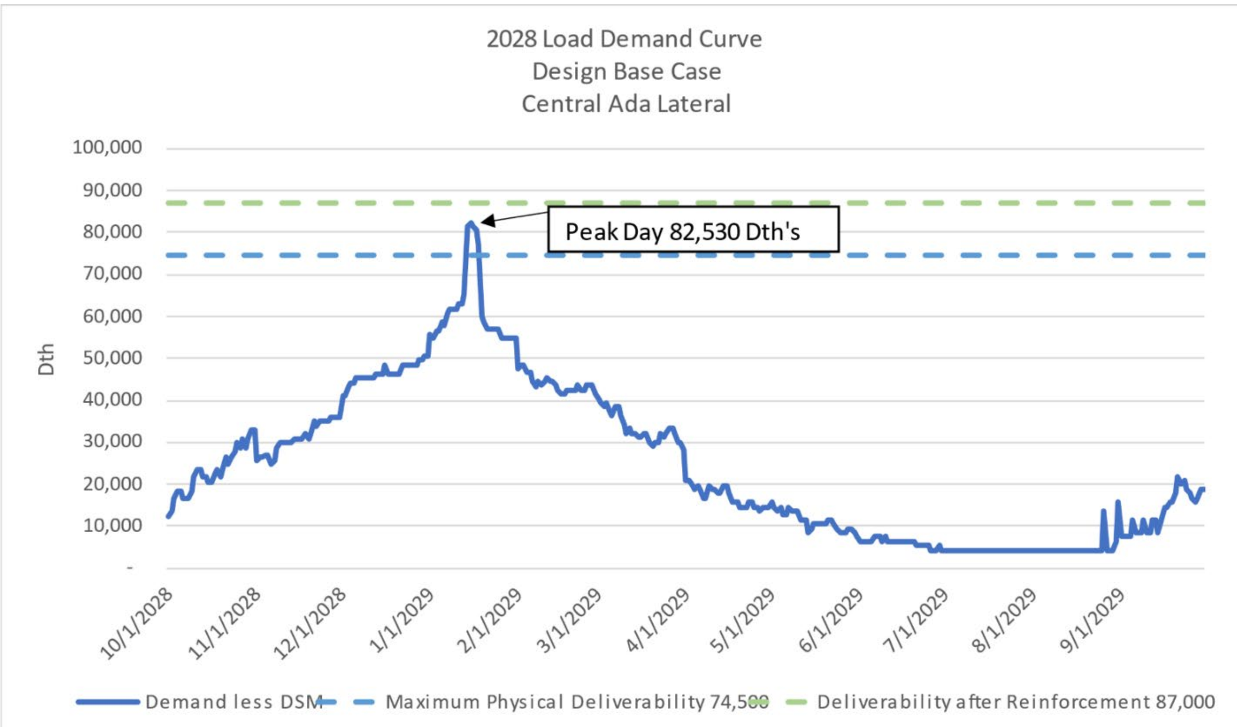

Figure 60: LDC Design Base Case – Central Ada Lateral

Sun Valley Lateral

In the Capacity Enhancements section, one option was identified in the 2019 IRP as the best way to solve capacity shortfalls for the Sun Valley Lateral: Shoshone Compressor Station. The Shoshone compressor station was planned to be installed by the end of 2021 but due to land acquisition delays will not be completed until summer of 2022. To address potential shortfalls during a cold weather event on the Sun Valley Lateral until the Shoshone compressor station comes online, Intermountain has developed a plan for the 2021-2022 winter. The plan for this lateral consists of communicating with downstream customers to turn off their snow melt equipment, running the Jerome compressor station ahead of a severe weather event to pack the lateral, bypassing critical regulator stations as needed to maintain service and to keep pressure on the lateral as high as possible and communicating with large volume customers to adhere to their contract demands during the cold weather event. Because the identified deficit is relatively small, Intermountain believes these measures will keep customers adequately supplied should a cold weather event occur.

The following graph (Figure 62) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

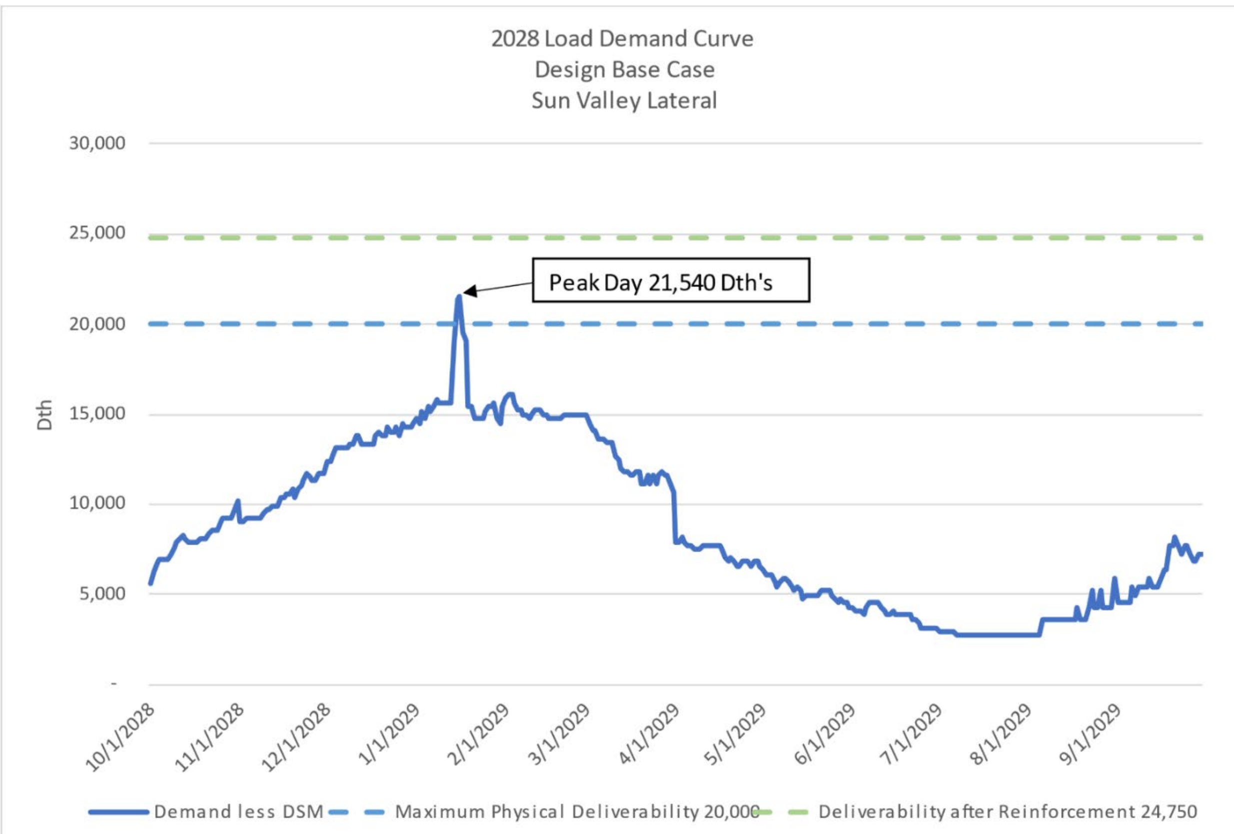

Figure 61: LDC Design Base Case – Sun Valley Lateral

Idaho Falls Lateral

In the Capacity Enhancements section, two options are discussed to determine the best way to solve capacity shortfalls for the Idaho Falls Lateral. The option chosen was the Idaho Falls Lateral Compressor Station.

The following graph (Figure 63) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

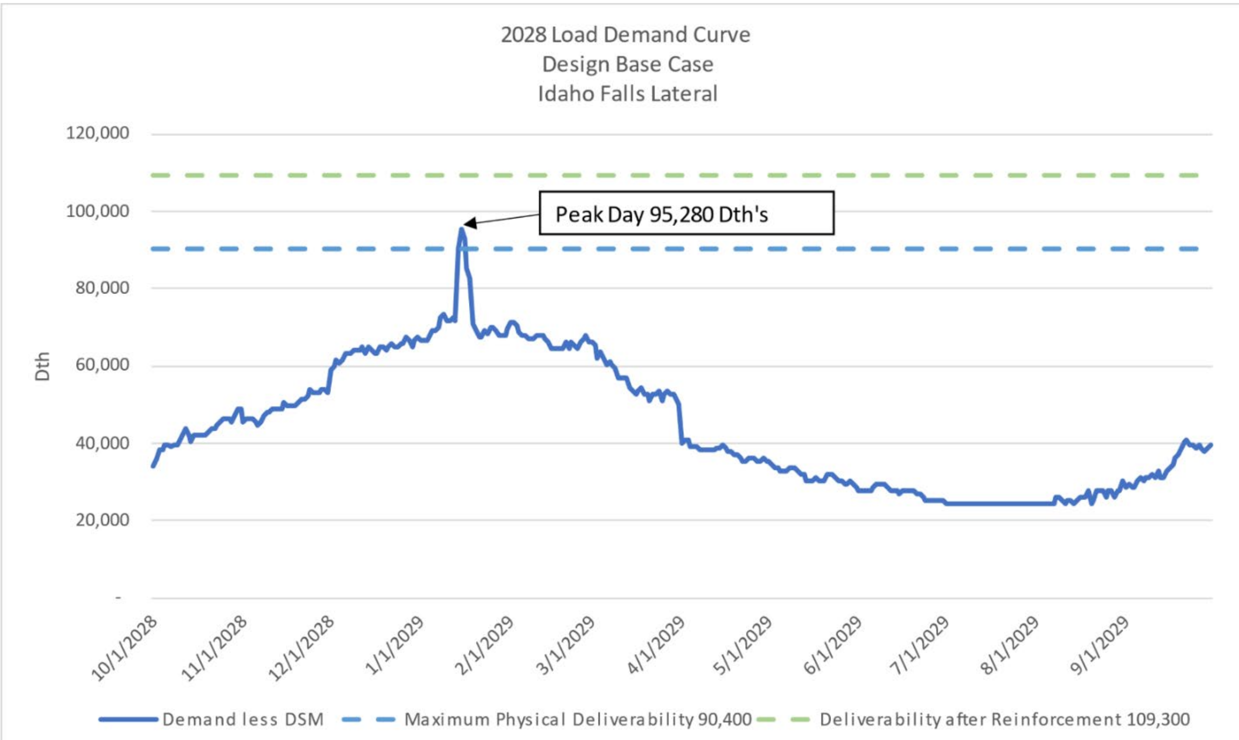

Figure 62: LDC Design Base Case – Idaho Falls Lateral

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 indicated in Table 9 on page 64, total citygate delivery declines beginning in 2023 as upstream transportation contracts begin to expire. Also, due to the segmentation of Sumas capacity, Intermountain has a shortage of capacity getting gas to Stanfield. Due to expiring contracts and the need for more capacity to GTN, Intermountain does show a shortfall in the final year of the planning horizon, where Intermountain anticipate will be served through incremental transport. The following graph (Figure 64) shows the shortfall created by expiring contracts (blue line).

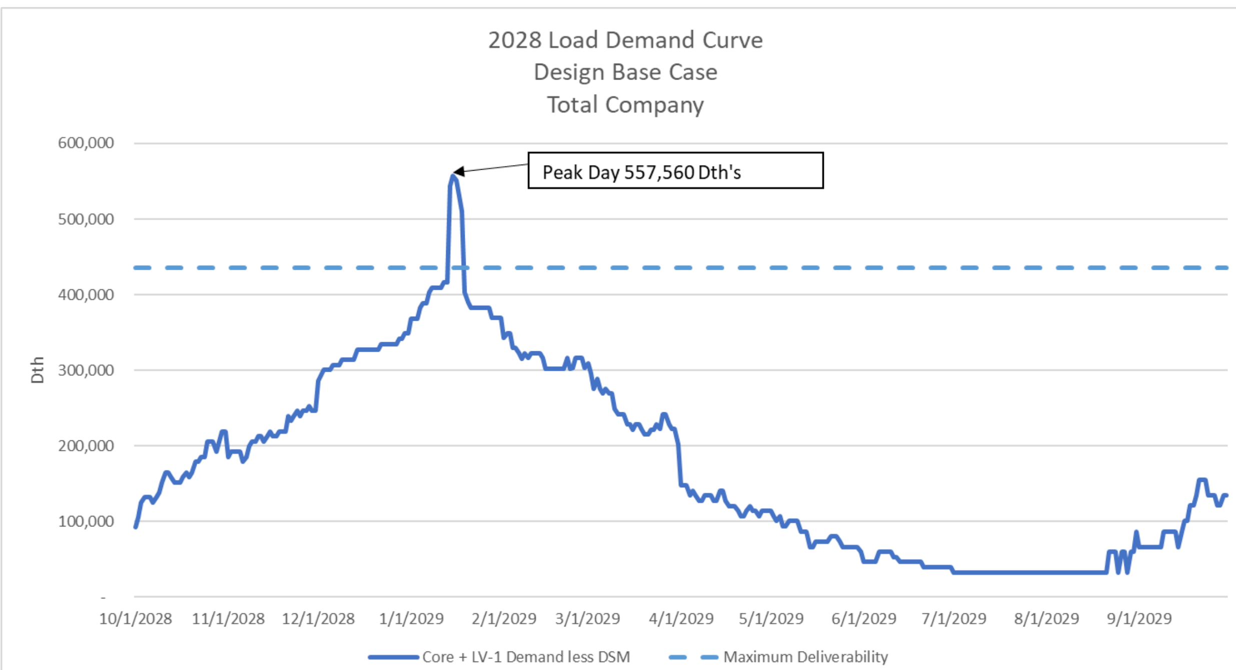

Figure 63: 2028 Design Base Case – Total Company

Solving Upstream Resources Shortfall

The options to solve the current transportation shortfall are contract renewal, alternative transportation uptake, and RNG. Under the contract renewal option, the contracts that will expire will be evergreened, or auto renewed, which provides Intermountain with sufficient transportation to meet load. Under the alternative transportation uptake, the model has the option to choose an alternative transportation rather than renewing. An example of this would be picking up more GTN rather than renewing a contract that moves gas from Sumas to Stanfield. In the RNG option, Intermountain models potentially decreasing the need of upstream transportation by giving the resource optimization model the option to take RNG.

The results in Exhibit 8 show that the options chosen to solve the shortfall are contract renewal and alternative transportation uptake. Currently, due to the high price of RNG, it was not selected to meet the shortfall solve as it would not have been the least-cost option. The resource optimization model has chosen to renew several of the expiring contracts while also choosing incremental GTN, which Intermountain will solve with GTN Xpress. With that said, the model also indicates that Intermountain must add 20,000 to 30,000 dth/day of incremental transportation in the final year of the planning horizon.

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. Figure 65 shows the final year of the planning horizon along with the Company's solutions to meet upstream shortfalls.

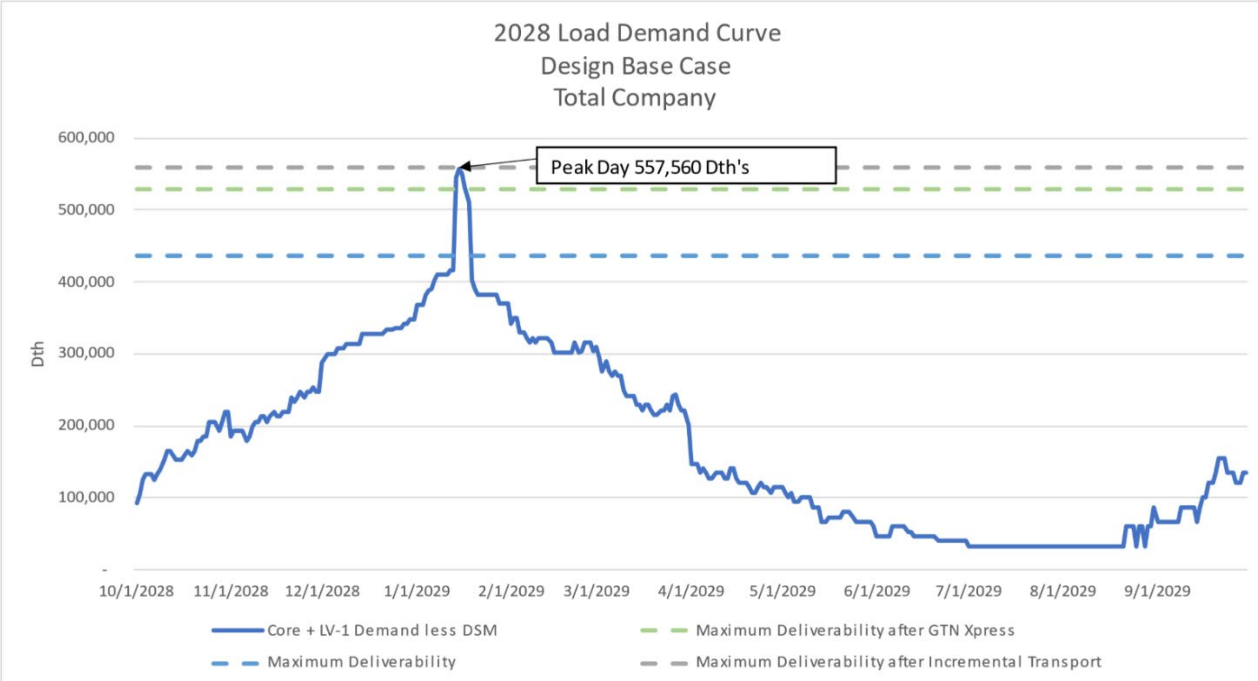

Figure 64: 2028 Design Base Case Shortfall Solution – Total Company

4.6.4 Conclusion

The distribution system planning results showed that the Company needs 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 expiring transportation contracts. That shortfall will be solved by taking either renewed or alternative transportation contracts, with the ultimate decision coming from Intermountain's GSOC.

4.7 Non-Utility LNG Forecast

4.7.1 Introduction

Since 1974, Intermountain has operated its Nampa Liquid Natural Gas (LNG) facility as a winter peaking supply source. The plant is designed to liquefy natural gas into LNG, store it in an onsite tank and vaporize it for injection into the Company's distribution system. The plant design includes a 50,000 gallon per day liquefaction train, a seven million-gallon storage tank and two water-bath vaporization units. The Nampa facility is utilized as the top of the Company's supply stack, or in other words, the last supply source that is used in the event of very cold weather or extraordinary system constraints.

In 2012 Intermountain began an efficiency review that focused on how it might better utilize its Nampa asset. Utilizing the then current IRP forecast, Intermountain determined how many gallons were projected to be withdrawn each winter season. That analysis showed that even under design weather assumptions, an excess of LNG supply would likely be available in each winter season.

Concurrent with the efficiency study, Intermountain began a study to determine the status of the regional LNG supply market relative to providing LNG to the Company's remote LNG facility near Rexburg, Idaho. Intermountain contacted several producing and marketing entities in the area who were then engaged in the non-utility LNG business to gauge future supply as well as the potential to enter the market as a supplier of LNG. It was discovered that due to already existing firm commitment during the heating season, it would be difficult to guarantee that an LNG supply would be available to Intermountain's Rexburg facility during the peak winter months.

4.7.2 History

LNG is a clean burning fuel that has the advantages of easy storage and transport under the right conditions. The two biggest markets for regional LNG are trucking fleets and remote-site heat and/or power applications. Though in relative infancy in the United States – particularly in the Pacific Northwest – LNG from a global perspective has a longer track record and continues to be in high demand in energy import areas like Asia.

As a direct result of the LNG supply study, Intermountain received an emergency supply request in late January 2013 to supply LNG to a small LNG-based distribution utility located in southwestern Wyoming that temporarily had lost its supply of LNG. The Idaho Public Utilities Commission (Commission) immediately granted emergency authority for Intermountain to supply the needed LNG pursuant to Case No. INT-G-13-01. Based on the efficiency review, the market study and the experience gained from supplying the emergency LNG, the Company filed Case No. INT-G-13-02 to request on-going authority from the Commission to sell "excess" LNG to non-utility customers.

4.7.3 Method of Forecasting

Intermountain utilized the results of the supply study (see Load Demand Curves starting on page **Error! Bookmark not defined.**) in this IRP to determine how much Nampa LNG would be needed for the core market during each year under the design weather/high growth scenario. To determine the annual amount of "excess" LNG, Intermountain begins with the annual core market withdrawal requirement and adds 1.2 million gallons of annual boiloff gas (boiloff naturally occurs with the warming of

LNG), 300,000 gallons to maintain operational and training requirements at the Nampa and Rexburg LNG facilities, and 500,000 gallons of "permanent" inventory to ensure that all LNG does not boiloff. After summing those potential needs for each year in the forecast, the remaining capacity is assumed to be available for non-utility LNG sales customers. Table 72 shows the annual amount of Nampa LNG assumed to be available for non-utility sales over the IRP period. For planning purposes, Intermountain will not allow the tank inventory level to drop below the Net Utility Requirements shown below at any time during December – February of any year since this is the peak demand season for the Company's distribution system. Further, should the need arise, all volumes in the tank are always available to serve the core market. It should be noted that the amount shown as "Available for Non-utility Sales" is a point-in-time figure.

Table 54: Nampa LNG Inventory Available for Non-Utility Sales

Nampa LNG Inventory Available for Non-Utility Sales					
Gallons	2022	2023	2024	2025	2026
Projected Withdrawal (High Growth)	681,818	681,818	681,818	681,818	681,818
Annual Boil-off	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Permanent Inventory	500,000	500,000	500,000	500,000	500,000
Nampa & Rexburg Requirements	300,000	300,000	300,000	300,000	300,000
Net Utility Requirement	3,318,182	3,318,182	3,318,182	3,318,182	3,318,182
Available for Non-utility Sales	3,681,818	3,681,818	3,681,818	3,681,818	3,681,818

4.7.4 Benefits to Customers

Intermountain's customers benefit from Intermountain's LNG sales activities in several different ways. First, as authorized in Order No. 35836 (Case No. INT-G-22-07) Intermountain continues to defer 3.0¢ per gallon sold into a capital account and utilizes that balance as it identifies capital costs that were accelerated due to increased use of the Nampa LNG facility. That procedure directly reduces both rate base and depreciation expense. Intermountain also continues to pass back to customers in its annual PGA filing a credit to offset increased operating and maintenance costs as a result of non-utility sales. That credit was previously 2.5¢ per gallon sold, but Order no. 35836 authorized the Company to increase the credit to 4.0¢ per gallon sold. Customers should see this increased benefit beginning with the 2024-2025 PGA to be filed in the fall of 2024. Finally, Intermountain's customers also benefit from the current margin sharing mechanism which offsets gas purchase costs in the Company's annual PGA.

Since April 2013, Intermountain has sold approximately 44 million gallons of LNG to non-utility customers. These sales have provided approximately $1.1 million to offset increased capital costs. Additionally, through its PGA the Company has credited to its utility customers approximately $1.1 million to offset increased O&M costs and approximately $6.5 million from the margin sharing mechanism. Further, the PGA passback has reduced Intermountain's gas costs every year since the PGA filed in August 2013.

Another benefit comes from the fact that the Company has been selling much of its LNG to markets which utilize it in Idaho. The sales primarily provide fuel to trucks that formerly burned diesel as a fuel. LNG sales have increased economic growth in the state and have also provided cleaner air benefits. The markets Intermountain sells LNG to have expressed appreciation for a local, reliable, competitively priced fuel. Further, many of the truck drivers have expressed a preference to load at Nampa as the design and operations allow for more convenient and quicker trailer fills.

4.7.5 2021 Plant Downtime

During a maintenance review in early 2021, Intermountain discovered corrosion along a welded seam in the outer steel tank. Because repairs could not occur with methane in the tank, the facility was shut down in early May 2021 and the remaining LNG was vaporized or allowed to boiloff. When the tank was completely empty and purged or all remaining methane, the corrosion repairs were started. Repairs have been completed and liquefaction is scheduled to begin in early January 2022. The first 2 million gallons of liquefaction will be designated as utility LNG. Due to the limited liquefaction window, non-utility liquefaction may not begin until several months into 2022 meaning that non-utility sales may not begin again until the second quarter of 2022. The plant downtime greatly minimized 2021 non-utility sales and will have a similar effect on 2022 sales.

4.7.6 On-Going Challenges

Since one of the biggest potential target markets for Intermountain's non-utility sales is "big rig" diesel fuel replacement, the price differential between LNG and diesel is important. Low diesel prices tighten the cost differential between diesel and LNG and consequently the Company has had little ability to increase sales prices. In recent years a comparatively low price differential has slowed growth in the LNG-based trucking market.

A further challenge has been the lack of available large displacement LNG engines. Because of the frequency and magnitude of roadway inclines, the mountain west trucking industry prefers to rely on 15-liter engines. However, manufacturers do not produce a 15-liter LNG engine, resulting in a challenge to utilize natural gas-powered engines to haul the heaviest loads. Thus, lower diesel prices combined with the lack of a 15-liter, LNG-powered engine has hampered growth in LNG sales demand. These challenges have limited revenue growth in Intermountain's non-utility LNG sales. As the economy enters into a period of higher oil and gas prices, Intermountain will watch the market for opportunity to grow non-utility sales.

The good news is that continuing efforts to work with existing LNG markets while also marketing to new entities has resulted in Intermountain growing its sales every year since 2013 until the temporary plant shutdown in 2021. Further, Intermountain looks for opportunities to manage its inventory cost which has helped to support average sales margins.

4.7.7 Safeguards

As described above, Intermountain takes steps to ensure that it maintains enough LNG in the tank to provide for all projected customer withdrawal needs. This insulates the core market from the risk of having no LNG should the need for needle peak withdrawals arise. Intermountain has also committed to the Commission that all volumes in the tank, regardless of the intended market, would always be available to serve the core market should the need arise. Additionally, while the Company shares LNG margins with its customers through the PGA, it also insulates its end-use customers from any risk of loss due to non-utility sales.

4.7.8 Future

Intermountain continues to see growth in non-utility LNG sales and may even reach a point where annual liquefaction levels are maximized. As the market continues to look for ways to satisfy ever more stringent emissions standards, it is believed that LNG will generate more interest. Looking to the future, the energy market has seen extremes in supply and pricing. Current forecasts predict strong increases in oil and natural gas prices which could have a short-term effect on margins once the tank is back in service.

Barring major variances in price differentials or LNG demand destruction, the Company expects that future sales volumes and margins will likely return to results seen in 2020.

One advantage the Company has is the ability to store large amounts of LNG which would last for an extended period of time for vaporization purposes. Because of its storage capability, some markets look to Nampa as a backstop supplier when other facilities might experience outages or planned downtime. Should the non-utility sales market continue to show strong growth, the Company would likely not need more storage capacity, but could address the need for more day- to-day sales volumes by adding to or upgrading its liquefaction train in order to increase the daily production of LNG.

The biggest disadvantage of the Nampa plant relates to the cost of liquefaction. Stand-alone commercial LNG production facilities do not need large storage tanks, vaporizers or other equipment designed to support peak shaving withdrawals and can therefore operate at a lower cost. In addition, newer facilities utilize more recent technology that can simply liquefy more efficiently than older facilities. A potential risk to Intermountain's LNG sales would be the construction of new commercial LNG facilities in the region that would have lower operating costs which could result in the loss of customers currently served by the Nampa facility or lower sales margins.

4.7.9 Recommendation

Notwithstanding the plant shutdown, challenges relating to growth in sales volumes and a market facing flat margin growth will remain. A longer-term increase in diesel prices vis-à-vis natural gas prices would provide more opportunity to grow both non-utility LNG sales and margins. Intermountain's Nampa LNG facility is located in an area without direct competitors and the Company continues to build brand loyalty. Based on the benefits to Intermountain and its utility customers, the lack of risk to its customers and the ability to make more efficient use of the Nampa LNG assets, Intermountain recommends that it continue to sell excess LNG to non-utility customers.

4.8 Infrastructure Replacement

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 three significant infrastructure replacement projects. These replacement projects are not growth driven.

Key Points

- Intermountain proactively monitors its pipeline system utilizing risk management tools and engineering analysis.
- Intermountain has identified two crossings of high risk where pipeline replacement is needed.
- Intermountain utilizes an Integrity Management Program to identify, analyze and monitor risks related to the distribution system, and to create programs that will reduce or remove risks.
- Intermountain uses a risk score and risk ratio to prioritize high risk systems for replacement.
- Intermountain also plans for Transmission Re-Confirmation and Shorted Casing Replacement or Abandonment Program (SCRAP).

4.8.1 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 2025. 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.

4.8.2 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 planning year 2024. 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.

4.8.3 System Safety and Integrity Program (SSIP)

Intermountain utilizes an Integrity Management Program to identify, analyze and monitor risks related to the distribution system, and to create programs that will reduce or remove risks. In order to identify risks on the system, Intermountain utilizes system knowledge based on known distribution systems characteristics, historical maintenance information, available outside source information, and the use of subject matter experts (SMEs) who are knowledgeable in operation, maintenance, design and construction. From this information a risk model is used to manage and assess the risk and to assign appropriate likelihood and consequence factors based on known system knowledge and threats to the Company's distribution system.

- Likelihood factors represent the possibility of a specific threat occurring on the distribution system.
- Consequence factors are numerical weighting factors to represent consequences that may be anticipated in case of an integrity issue.

Intermountain uses a GIS-based risk model to calculate relative risk scores for facilities. The risk model sums the assigned likelihood scores for each threat to calculate a total likelihood factor within a 50-foot grid (raster). The same summing calculation is also done for each of the assigned consequence factors within the same 50-foot grid. The total likelihood factor is then multiplied by the total consequence factor to establish a total relative risk score for the grid.

Risk Score = Likelihood Factor x Consequence Factor

Beginning in 2020, a System Safety and Integrity Program (SSIP) was implemented to rank each distribution system utilizing a weighted average of the risk score per foot of pipe. This weighted average is called the Risk Ratio and is used to prioritize high risk systems for replacement.

Risk Ratio = ∑ (Total Relative Risk Score x Pipe Length) / ∑ Pipe Length

Results of the replacement projects on system Risk Ratios are trended and reviewed as part of Intermountain's Distribution Integrity Management Program (DIMP) Performance Management program to ensure that integrity management activities are having the desired effect of mitigating risks.

High risk pipeline segments that are targeted for replacement include:

- Early Vintage Plastic Pipe (EVPP) – Plastic mains, service lines, and associated fittings installed earlier than 1/1/1995.
  - Pre-1983 (i.e., Adyl-A): These pipelines include pipe installed prior to 1/1/1983 that may be susceptible to possible Low Ductile Inner Wall (LDIW) characteristics that can result in slow crack growth and slit failures, as documented by PHMSA–2004–19856.
  - Post-1982: These pipelines were installed between 1/1/1983 and 12/31/1994 and are classified as EVPP to account for different inventory levels and rates of new material adoption.
- Early Vintage Steel Pipe (EVSP) – Steel mains, service lines, and associated fittings installed earlier than 1/1/1970. EVSP includes aging and/or obsolete pipeline segments, bare steel or poorly coated pipe, pipe with unknown attributes

or missing data, gas meters located indoors, and/or pipeline segments with mechanical couplings and fittings.

Since 2013, Intermountain has been actively replacing segments of EVPP and EVSP within its distribution system. In 2020 Intermountain started SSIP replacement in St. Anthony, ID which was completed in 2022.Also in 2022, Intermountain completed replacement in Sugar City, ID. in 2023, Intermountain completed replacement in Parker, ID and is currently working on replacement in Boise, ID. SSIP replacement in Boise is currently planned through 2027. Intermountain currently has approximately $3.87 (2023) – $4.59 (2028) million budgeted for SSIP replacement annually, which is used for replacing high risk distribution main and services. The SSIP replacement plan will continue through the duration of the IRP.

4.8.4 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 has approximately $1.42 (2024) – $2.45 (2028) million budgeted for MAOP reconfirmation pipe replacement annually, which will be used for replacing transmission pipeline segments where the records needed to substantiate the MAOP are not TVC. MAOP reconfirmation replacement will continue through the duration of the IRP.

4.8.5 Shorted Casing Replacement or Abandonment Program (SCRAP)

A steel carrier 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 to determine if the casing is shorted or electrically isolated. Once a casing is determined to be shorted the casing's status remains shorted until the shorted casing is mitigated and/or the casing is determined to be not shorted. Shorted casings are required to be mitigated using one of the following methods:

1. Maintenance
2. Replacement
3. Abandonment/Removal

Intermountain currently has approximately $446,000 – $604,000 budgeted, from 2024 through 2028, 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, which 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

A 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.

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.