ENBRIDGE GAS UTAH

INTEGRATED RESOURCE PLAN

Docket No. 24-057-04

(Plan Year: June 1, 2024 to May 31, 2025)

Submitted: June 14, 2024

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This Integrated Resource Plan (IRP) is submitted by Questar Gas Company dba Enbridge Gas Utah. For purposes of this document, we refer to Enbridge Gas Utah as “Enbridge Gas” or “Company.” The Company became part of the Enbridge, Inc. family of companies on June 1, 2024. This IRP was prepared in a manner consistent with the Company’s historic IRP process.

The Company files this IRP with the Utah Public Service Commission (Utah Commission) and the Public Service Commission of Wyoming (Wyoming Commission), for its natural gas distribution operations that are subject to the respective jurisdiction of each regulatory body. The Company continues to experience strong customer growth in its Utah, Wyoming, and Idaho natural gas service territories of approximately 2% per year.

Since the early 1990s, the Company has engaged in an annual IRP process as part of its commitment to providing safe, reliable, affordable, and sustainable natural gas service to its customers. This process results in a planning document that is used as a guide in meeting the natural gas requirements of the Company’s customers for the ensuing year. As a fundamental part of the IRP process, the Company conducts an assessment of available resources through the utilization of a cost-minimizing linear-programming computer model. Open dialogue with regulatory agencies and interested stakeholders is an overarching principle of the IRP process.

The IRP process this year has resulted in the following key findings:

1. The Company forecasts Design Day firm sales demand of approximately 1.28 MMDth at the city gates for the 2024-2025 heating season.

2. The Company forecasts a 2024-2025 IRP-year cost-of-service gas production level of approximately 58.9 MMDth assuming the completion of new development drilling projects (47.3% of forecasted demand).

3. The Company forecasts a 2024-2025 IRP-year balanced portfolio of gas purchases of approximately 66.7 MMDth.

4. The Company will maintain flexibility in purchase decisions pursuant to the planning guidelines listed herein, because actual weather and load conditions will vary from assumed conditions in the modeling simulation.

5. The Company will review its hedging practices on an annual basis due to increased volatility in the natural gas markets. The Company may purchase additional contracts for fixed-price baseload supply for December 2024 through February 2025 to protect against high-pricing events similar to those that occurred during the past few heating seasons.

6. The Company will continue to monitor and manage producer imbalances.

7. The Company will continue to promote cost-effective energy-efficiency measures.

8. The Company will enter into contracts to serve peak-hour requirements and to secure needed storage and transportation capacity.

9. The Company has completed construction and testing of the Magna Liquified Natural Gas (LNG) facility and plans to have the facility filled and ready for withdrawals for the 2024-2025 heating season.

10. The Company is focused on programs aimed at reducing methane emissions as well as evaluation of options for sustainable gas supplies.

As its customer base continues to grow, the Company conducts an annual analysis to ensure that its system can continue to meet customer needs. The Company’s system will be capable of meeting the demands of the 2024-2025 heating season with adequate supplies and pressures in the system. This system capacity assessment is based on the fact that the gate stations have adequate capacity, the supply contracts are adequate, and system models show that pressures are sufficient to meet demand.

This report is organized into the following sections: 1) Executive Summary; 2) Industry Overview; 3) Customer and Gas Demand Forecast; 4) System Capabilities and Constraints; 5) Distribution System Action Plan (DNG Action Plan); 6) Integrity Management; 7) Environmental Review; 8) Purchased Gas; 9) Cost-of-Service Gas; 10) Gathering, Transportation, and Storage; 11) Supply Reliability; 12) Sustainability; 13) Energy-Efficiency Programs; 14) Final Modeling Results; 15) General IRP Guidelines/Goals, and 16) a Glossary.

The preparation of this planning document is dependent on information from many sources. The Company acknowledges the contributions of all who have participated in the IRP process this year. In the event there are questions, comments, or requests for additional information, please direct them to:

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INDUSTRY OVERVIEW

This planning document pertains to the natural gas distribution operations of the Company that are subject to the jurisdictions of the Utah and Wyoming Commissions. The Company receives its natural gas supplies from interstate pipelines with most of the supply coming from basins in Utah, Wyoming, and Colorado. These interstate pipelines and supplies are subject to regulation by the Federal Energy Regulatory Commission (FERC) and are affected by industry changes and events that occur throughout the world including weather.

This section includes discussion regarding major regulatory factors impacting the industry in the last year, including changes at the FERC, clean energy regulation, power generation impacts on the natural gas industry, and trends regarding pricing, production, storage, and natural gas infrastructure. This section also contains a summary of the Wyoming and Utah IRP processes and a review of the prior heating season.

FEDERAL ENERGY REGULATORY COMMISSION UPDATE

The FERC regulates, among other things, the interstate natural gas pipeline system used to deliver natural gas to local distribution companies in the U.S., including those upstream pipelines that deliver supplies to the Company. The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate. By rule, not more than three members of the FERC may come from the President's party. All have an equal vote, and the President selects the Chairman. The FERC requires at least three members to operate as a quorum. Commissioners serve five-year terms.

President Biden promoted Willie L. Phillips from Acting Chairman to Chairman on February 9, 2024. His term ends June 20, 2026. He is joined by Commissioner Allison Clements whose term lasts until June 30, 2024, and Commissioner Mark Christie whose term lasts until June 30, 2025. The fourth and fifth seats are currently empty.

On February 29, 2024, President Biden announced his nomination of three individuals to serve as commissioners on the FERC: Judy W. Chang, David Rosner, and Lindsay S. See. The nominees testified before the Senate Energy and Natural Resources Committee on March 21, 2024. If approved, these nominees will replace the outgoing Commissioner Clements and fill the two vacancies.

On February 17, 2022, the FERC issued two policy statements that will provide guidance for review of natural gas projects. The two policies were the Updated Certificate Policy Statement (PL18-1) and the interim greenhouse gas (GHG) Policy Statement (PL21-3). The purpose of the policies is to provide "an analytical framework for many need [sic], environmental and public interest issues that arise when companies seek to build new natural gas facilities" and to "improve the legal durability of the Commission's natural gas certificate and LNG decisions".

The Updated Certificate Policy Statement is an update to the 1999 policy statement. This update focuses on "consideration of the effects of such projects on affected communities, the treatment of precedent agreements in determining the need for a project, and the scope of the Commission's environmental review, including an analysis of the impact of a project's greenhouse gas emissions". It also states that those applicants will need to "provide more than just precedent agreements, to help explain why a project is needed, such as the intended end use of the gas." The policy also states that "the Commission may consider other evidence of need, including demand projections, estimated capacity utilization rates, potential cost savings to customers, regional assessments and statements from state regulators or local utilities."

The interim GHG Policy explains how the FERC "will assess the impacts of natural gas infrastructure projects on climate change in its reviews under the National Environmental Policy Act and the Natural Gas Act." This policy has a threshold of 100,000 metric tons per year of GHG emissions. The FERC commission requested comment on this interim policy. Comments were due April 25, 2022, and the FERC has made no new announcements regarding this process.[1]

In July 2022, FERC along with the North American Electric Reliability Corporation (NERC) came together to encourage the North American Energy Standards Board (NAESB) to bring together a forum "to identify solutions to the reliability challenges facing the nation's natural gas system and bulk electric system".[2] NAESB responded by scheduling a Gas-Electric Harmonization (GEH) forum, where interested parties and industry organizations can discuss those challenges and issues. The Company is an active participant in meetings and surveys.

POWER GENERATION IMPACT ON NATURAL GAS

In January 2024, the U.S. Energy Information Association (EIA) forecasted that natural gas generation will hold steady from last year and continue to be the largest source of U.S. electricity generation with about 1.7 billion kWh of annual generation. The Short-Term Energy Outlook also predicts that wind and solar energy will lead growth in U.S. power generation for the next two years and that coal power generation will drop 18% (665 billion kWh to 548 billion kWh) from 2023 to 2025[3]. U.S. electric power generation capacity by source is shown in Figure 2.1 below.[4]

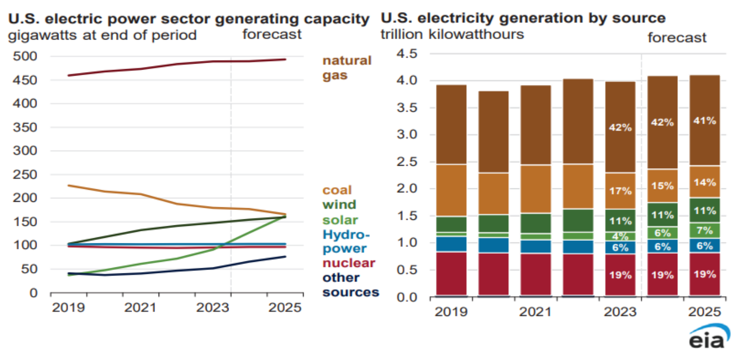

Figure 2.1: U.S. Power Generation by Source

[1] FERC Updates Policies to Guide Natural Gas Project Certifications, February 17, 2022.
[2] "FERC, NERC encourage NAESB to convene gas-electric forum to address reliability challenges", FERC, July 29, 2022.
[3] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* January 2024.
[3] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* May 2024.
[4] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* May 2024.

DATA CENTERS

Across the U.S. the need for electricity continues to grow. One of the key drivers of this growth is the addition of data centers. Data centers are facilities that house many networked computers that process, store, and share data. Data centers are very intensive energy users. These facilities can use as much as 50 times the energy used by a similar typical commercial building. The electric demand for these facilities can use as much as 100 MW to 300 MW.

Power utilities in some states are expressing that they are unable to meet the increased demand for these data centers. "For example, Portland General Electric in Oregon adjusted its estimates and doubled its previous forecast for the next five years due to more industrial growth, including data centers. The company told one group of data center developers that it would need to assess whether it could provide their facility with 60 MW of power, enough to power 45,000 homes. The developers came up with a solution: off-the-grid, high-tech fuel cells that turn natural gas into lower-emissions electricity, supplemented by the power grid." [5]

In Utah, data center developers are facing similar challenges. In response, the Company has received multiple requests to serve direct power generation at specific data center locations.

PRICING TRENDS

In the April 2024 Short-Term Energy Outlook, the Henry Hub spot price for natural gas averaged $2.50 per MMBtu in 2023 compared to a forecasted $2.20 in 2024, which is a $0.30 per MMbtu decrease. EIA explained the decrease was due to storage inventories 39% above the five-year average, steady production, and reduced demand driven by a mild winter with lower-than-normal residential and commercial demand.[6]

The Short-Term Energy Outlook forecast for May 2024 anticipates that the Henry Hub spot price will average about $3.10per MMBtu in 2025 due to expected production decreases resulting from the current low prices.[7]

However, the pricing trends for the western U.S. in recent years have shown a significant variance from the rest of the U.S. This trend is shown in the year-over-year pricing shown in Figure 2.2[8] and Figure 2.3[9] below.

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[5] "Storm-Storm Front – As Data Centers Proliferate, Utilities Turn To Gas-Fired Power To Meet Demand", *RBN Energy, Storm Front - As Data Centers Proliferate, Utilities Turn to Gas-Fired Power to Meet Demand | RBN Energy, 14 May 2024*

[6] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* April 2024

[7] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* May 2024.

[8] S&P Global – Platts Gas Daily

[9] S&P Global – Platts Gas Daily Price Guide

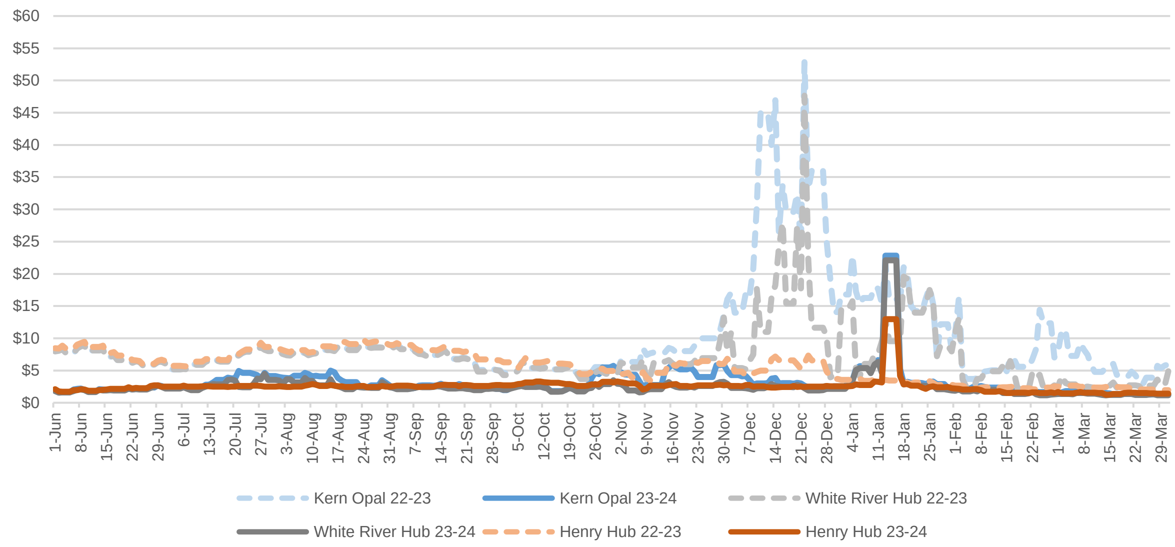

Figure 2.2: 2022-2023 vs 2023-2024 Year-over-Year Daily Pricing

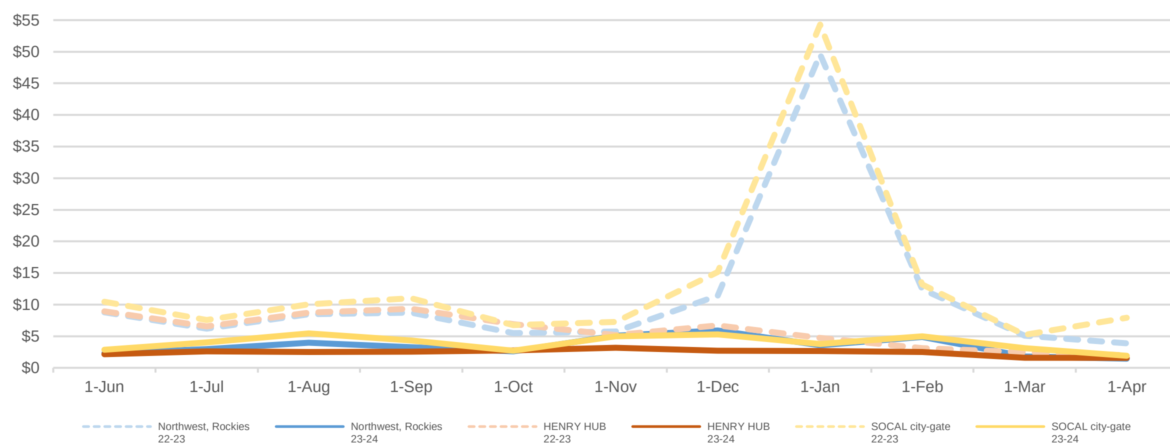

Figure 2.3: 2022-2023 vs 2023-2024 Year-over-Year Monthly Pricing

The high pricing during the 2022-2023 heating season resulted in a significant increase in under collection in the Company’s 191 balancing account. This under collection increased to over $538 million in February 2023. Lower pricing through the remainder of 2023 and 2024 has resulted in steady recovery of this under collection amount. Through April 2024, the under collection had reduced to $5 million and is forecasted to be fully recovered in the spring of 2024. The balance of the 191 balancing account is shown in Figure 2.4 below.

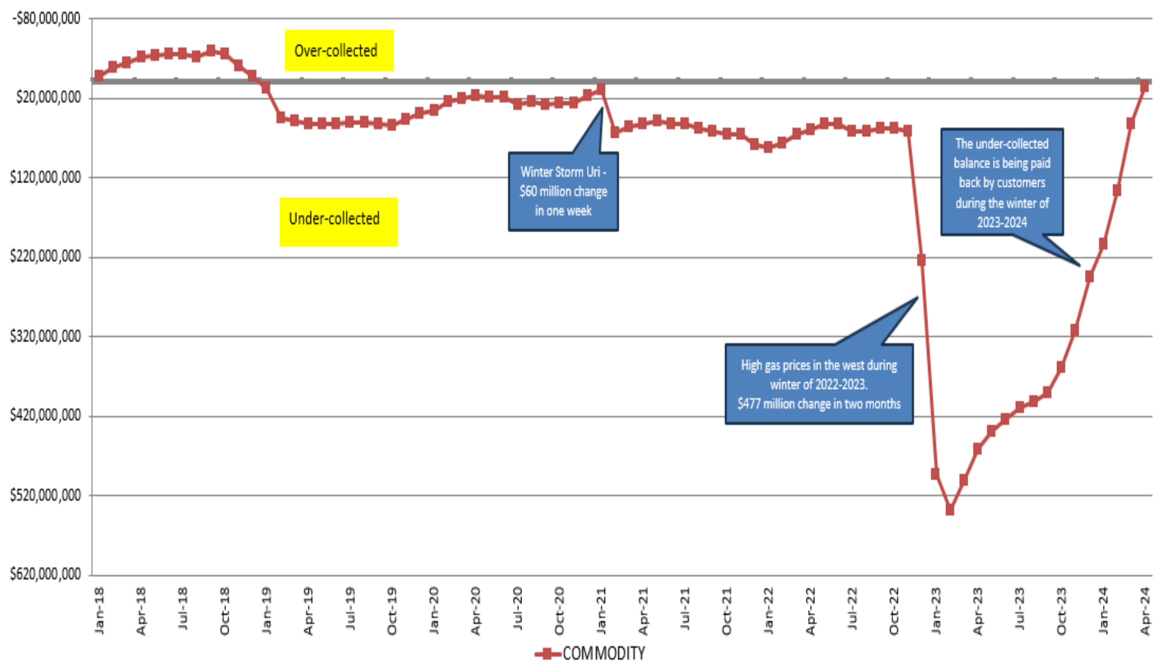

Figure 2.4: Historical Commodity and Supplier Non-Gas (SNG) Costs in 191 Account

Historically, the Company had used a combination of two forecasts from PIRA and IHS CERA to predict pricing. In 2016 S&P Global Platts purchased PIRA Energy group.[10] In 2022 S&P Global completed a merger with IHS Markit which produced the IHS CERA North American Natural Gas Short-Term Outlook.[11] With the consolidation, the two forecasts used were no longer differentiated.

The Company analyzed a few alternatives for predicting pricing including using NYMEX forward curves (Forward Curves) and other forecasts. Through this analysis the Company determined that using an average of the S&P Global forecast and the forward curves provided the best predictions of actual pricing.

PRODUCTION TRENDS

According to the EIA U.S. dry gas production for 2023 was 103.8 Bcf/d and the forecast is for it to drop slightly to 103.58 Bcf/d in 2024[12]

The oil field services company, Baker Hughes, monitors and publishes drilling rig data. Since Baker Hughes began tracking rig data in 1987, the highest weekly gas-directed rotary rig count for North America occurred during August and September of 2008 when the peak reached 1,606 rigs on two occasions. On two other separate occasions during August of

[10] "S&P Global Platts Acquires PIRA Energy Group" *https://www.spglobal.com/commodityinsights/en/about-commodityinsights/media-center/press-releases/2016/080416-acquires-pira-energy-group*, August 2016.
[11] "S&P Global Completes Merger with IHS Markit, Creating a Global Leader to power the Markets of the Future *https://investor.spglobal.com/news-releases/news-details/2022/SP-Global-Completes-Merger-with-IHS-Markit-Creating-a-Global-Leader-to-Power-the-Markets-of-the-Future/,* February 2022.
[12] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* April 2024.

2016, the gas-directed rig count dropped to a low of 81 rigs. By January 2019, the gas-direct rig count had recovered to a level of 202 rigs. However, by July 24, 2020, there were only 68 gas-directed rigs. As of late-April 2024, the number of gas-direct rigs was 105 compared to 161 for the same week last year.[13]

On April 29, 2024, the EIA released its annual report on natural gas proved reserves for the 2022 calendar year. The EIA reported that U.S. proved reserves of natural gas at year-end 2022 increased to a record high of 691.0 up from 625.4 Tcf at year end 2021.[14] In 2023, U.S. natural gas production grew by 4%. This was similar to the growth experienced in 2022. The production growth by region is shown in Figure 2.5 and Figure 2.6 below.[15]

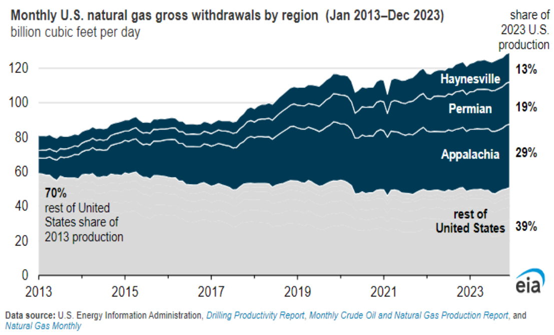

Figure 2.5: U.S. Production by Region

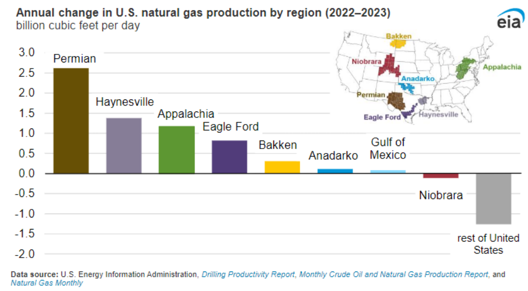

Figure 2.6: U.S. Production by Region

President Biden signed the Inflation Reduction Act into law on August 16, 2022. The act is intended to ensure that the U.S. "remains the global leader in clean energy technology, manufacturing, and innovation". It is designed to "lower energy costs for families and small businesses, accelerate private investment in clean energy solutions in every sector of the economy, and every corner of the country, strengthen supply chains for everything from critical minerals to efficient electric appliances, and create good-paying jobs and new economic opportunities for workers".[16]

The Inflation Reduction Act is focused on providing incentives for clean energy in order to reduce overall U.S. emissions. The act "locks renewables and fossil fuels together" by requiring the administration to offer new oil and gas leases in order to lease federal lands and waters for renewable energy. Andrew Gillick, with Enverus, an energy industry data analytics company, said, "to the industry, the new law signals Democrats are willing to work with them and to abandon the notion fossil fuels could soon be rendered obsolete" and "the

[13] "North America Rig Count Current Week Data." *Baker Hughes*, 24 April 2024, http://rigcount.bakerhughes.com
[14] "U.S. Crude Oil and Natural Gas Proved Reserves, Year-End 2022." *Energy Information Administration,* 29 April 2024, https://www.eia.gov/naturalgas/crudeoilreserves/
[15] "Today in Energy" *U.S. natural gas production grew by 4% in 2023, similar to 2022 - U.S. Energy Information Administration*, 27 March 2024
[16] "Inflation Reduction Act Guidebook." *The Whitehouse*, https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/

folks that think oil and gas will be gone in 10 years may not be thinking through what this means. Both supply and demand will increase over the next decades”.[17]

STORAGE TRENDS

The EIA generally uses two metrics for assessing underground working natural gas storage capacity, design capacity and demonstrated peak capacity. Design capacity is the theoretical limit on the total amount of natural gas that can be stored. This is calculated based on the physical limits of the reservoirs and equipment associated with active storage fields in the lower 48 states. The demonstrated peak capacity is the sum of all the maximum volumes withdrawn from each of the fields during the most recent five-year period. Demonstrated peak capacity rose by 3% or 124 Bcf as of November 2023. This ends a three-year streak of capacity decreases. A big driver of this was a change at Aliso Canyon in California. Regulators eased up on some of the restrictions put in place after the gas leak in 2015. As a result of the regulatory change, the working gas capacity at Aliso Canyon was increased 67% to 68.6 Bcf in August of 2023.[18]

The most relevant metric relating to storage and the impact of storage on the industry is the measure of current working gas in underground storage. This metric indicates that working gas in underground storage is on the high end compared to the five-year history as shown in Figure 2.7 below. Working gas in storage was 2,425 Bcf as of Friday April 19, 2024. Current volumes are 439 Bcf higher than the measure at this time last year, and 655 Bcf above the five-year average.[19]

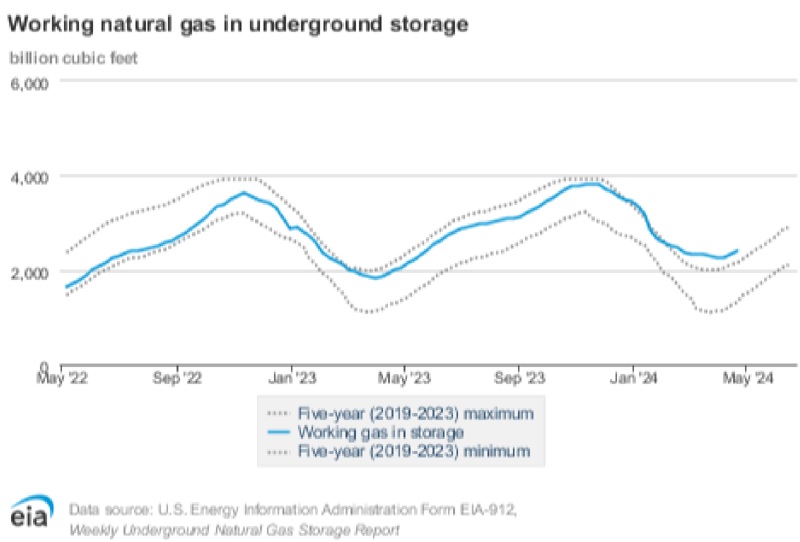

Figure 2.7: Working Natural Gas in Underground Storage as of April 24, 2024

[17] “Climate bill’s unlikely beneficiary: U.S. oil and gas industry”, *AP News*, August 18, 2022, https://apnews.com/article/biden-technology-science-oil-and-gas-industry-climate-environment-28df40ad9ebb33f4447815b6593673b3

[18] “Underground natural gas working storage capacity” *Energy Information Administration, https://www.eia.gov/naturalgas/storagecapacity/.* 30 April 2024.

[19] “Natural Gas Weekly Update.” *Energy Information Administration, https://www.eia.gov/naturalgas/weekly/*, 24 April 2024.

The Company discusses its use of natural gas storage facilities in the Gathering, Transportation, and Storage section of this report.

LNG EXPORTS

The U.S. has been a net exporter of natural gas since 2016. The U.S. exports natural gas to Canada and Mexico by pipeline, and to more than 30 countries as LNG. The EIA forecasts U.S LNG exports to exceed 12.2 Bcf/d this year and to increase by 18% (2.1 Bcf/d) in 2025 when some LNG export projects under construction are expected to be operating.[20]

On January 26, The U.S. Department of Energy (DOE) announced a temporary pause in reviewing applications to export LNG to non-free-trade-agreement (non-FTA) countries. The pause is to allow the DOE to update the economic and environmental analysis metrics used to determine if a project is in the public interest. This pause will not add risk to global supplies as it will “not affect current or near-to-medium-term planned supply”. The U.S. has become the top global exporter of gas recently surpassing Qatar and Australia. There is currently 12 Bcf/d of LNG export capacity under construction and over 20 Bcf/d already authorized but not yet under construction. These projects will not be impacted by the pause.[21] The impact of the projects under construction on current capacity is shown in Figure 2.8 below. [22]

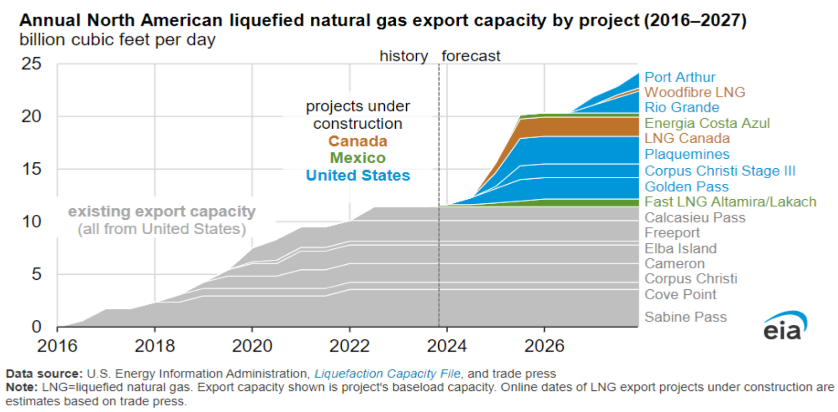

Figure 2.8: LNG Export Projects

SUSTAINABILITY TRENDS

Throughout the country, companies across the natural gas value chain are taking actions to reduce methane emissions. Many of the companies focused on these goals have joined a coalition, One Future, committed to the reduction of methane emissions. The coalition includes production, gathering, processing, transmission and storage, and distribution companies now representing approximately 20% of the U.S. natural gas value chain.

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[20] “U.S. natural gas trade will continue to grow with the startup of new LNG export projects” *Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=61863#,* April 17, 2024.

[21] “The temporary pause on review of pending applications to export liquified natural gas” *U.S. Department of Energy https://www.energy.gov/fecm/articles/temporary-pause-review-pending-applications-export-liquefied-natural-gas* February 23, 2024.

[22] “Today in Energy” *https://www.eia.gov/todayinenergy/detail.php?id=60944, November 13, 2023*

Participating companies include: Antero Resources, Apache, Arsenal Resources, Ascent Resources, Atmos Energy, Berkshire Hathaway Pipeline Group, BKV Corporation, Black Bear Transmission, Black Hills Energy, , Boardwalk Pipeline Partners, LP, ConEdison, Dominion Energy, DT Midstream, DTE Energy, Duke Energy, Enbridge Inc., Encino Acquisition Partners, Enstor, EQT, Equitrans Midstream Corporation, Flywheel Energy, Hess, Jonah Energy, Kinder Morgan, Kinetik, National Fuel, National Grid, NiSource, New Jersey Natural Gas, Northeast Natural Energy, NW Natural, ONE Gas, Inc., ONEOK, Roanoke Gas, Sheridan Production, Southern Company Gas, Southern Star Central Gas Pipeline, Southwestern Energy, Spire, Summit Utilities, Targa, TC Energy, Terra Energy Partners, WBI Energy, Western Midstream, WhiteWater, Williams, WTG and Xcel Energy.

One Future's focus is on "demonstrating an innovative, performance and science-based approach to the management of methane emissions directed toward a concrete goal: to achieve an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total (gross) natural gas production and delivery. ".[23]

The members of One Future had a total 2022 methane intensity listed at 0.421%, according to the One Future 2023 Methane Intensity Report. Methane Intensity is the amount of methane emissions divided by the total amount of methane produced or delivered. This was a 10% reduction from the previous year. The member distribution companies reported a methane intensity of only 0.095%. This beat the stated goal of 0.225% by 58%.[24]

A discussion of the Company's current sustainability efforts is included in the Sustainability section of this report.

Responsibly Sourced Natural Gas (RSG)/Certified Natural Gas

The natural gas industry has an increased focus on reducing methane emissions and many companies have begun offering RSG, also referred to as certified natural gas. RSG or certified natural gas is natural gas that has been certified as being produced using responsible practices. Responsible practices include limiting emissions, water use, and land and community impacts. There are a number of third-party certification companies that review and certify production including Project Canary Trustwell, MiQ, and Equitable Origin.

The RSG market is developing and trading processes and certification standards are developing as well. Currently natural gas is a very liquid trading commodity with electronic trading platforms available to manage the transactions. Once guidelines for certification standards are established to compare similar products for trading purposes, trading of RSG is expected to be similar.

Renewable Natural Gas (RNG)

The natural gas industry also has an increased focus on Renewable Natural Gas. RNG is pipeline quality gas derived from waste sources such as wastewater, animal waste, food waste, and other organic waste. As shown in Figure 2.9, RNG is obtained by capturing and utilizing the methane that would normally be emitted from these waste streams.

[23] https://onefuture.us/faqs/
[24] https://onefuture.us/2023-annual-report/

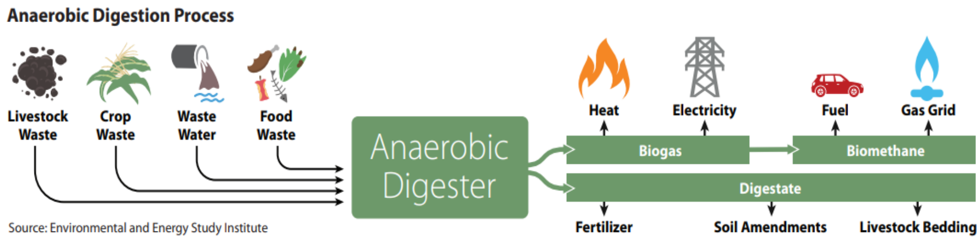

Figure 2.9: RNG

According to a study presented by the Kem C. Gardner Policy Institute, “generation of RNG avoids emissions of methane, a greenhouse gas with warming potential 25–34 times greater than carbon dioxide”. Utah currently has the potential to produce about 4% of Utah’s natural gas demand through RNG. Figure 2.10 shows the potential Utah production by feedstock.[25]

Source		Annual RNG Feedstocks	Potential Renewable Natural Gas (billion cubic feet/yr)	Range of Feedstock Carbon Intensity (g CO_2e/MJ)
Animal Manure	Swine – 1MM	1.2MM tons manure	3.7	**(525)–(150)**
	Cows – 95,000	2.6MM tons manure		
Landfill Gas	8 landfills	2.6 billion ft³ biogas	1.0	**40–80**
Wastewater	2 facilities	92,000 gallons sludge	0.7	**10–40**
Food Waste	Wasatch RR	1MM ton food waste	2.7	**(25)–0**
Total Utah RNG Production			**8.1**	
Utah Natural Gas Demand in 2020			**211.6**	

Source: American Biogas Council, Utah Geological Survey, World Resources Institute, Utah State Agricultural Review

Figure 2.10: Utah RNG by Feedstock

States throughout the country are advancing policies and programs that promote the use of RNG as a renewable source of supply. Most focus on establishing procurement programs and tariff standards for interconnects.

Hydrogen

The natural gas industry is also developing the ability to utilize hydrogen as an energy source. According to the U.S. Energy Information Administration, hydrogen is “useful as an energy source/fuel because it has a high energy content per unit of weight…” While hydrogen is not currently widely used as a fuel, it has potential for increased usage in the future.[26]

Hydrogen is abundant but can only be produced from other sources of energy. When combined with oxygen in a fuel cell, it produces heat and electricity with only one byproduct – water.[27] Hydrogen can be used to store, move, and deliver energy produced from other sources. Currently, hydrogen fuel can be produced through thermal processes, such as

[25] Renewable Natural Gas: A Sustainable Approach to the Energy Transition, January 2022. Renewable Natural Gas: A Sustainable Approach to the Energy Transition (utah.edu)
[26] “Hydrogen explained.” 20 January 2022. https://www.eia.gov/energyexplained/hydrogen/#:~:text=However%2C%20hydrogen%20is%20useful%20as,greater%20use%20in%20the%20future.
[27] “Hydrogen Basics.” May 2022. https://www.nrel.gov/research/eds-hydrogen.html

natural gas reforming, electrolysis, solar-driven processes, and biological processes. About 95% of all hydrogen fuel produced today is through steam reforming of natural gas.[28]

As shown in Figure 2.11, there are different classifications for hydrogen based on the methods used to produce it. Hydrogen produced from natural gas in a process that creates carbon waste is called grey hydrogen. Brown hydrogen is created through coal gasification. Blue hydrogen is created using carbon capture and sequestration for the greenhouse gases created in the production process. Green hydrogen is produced using renewable energy. This is considered the "ultimate clean hydrogen resource".[29]

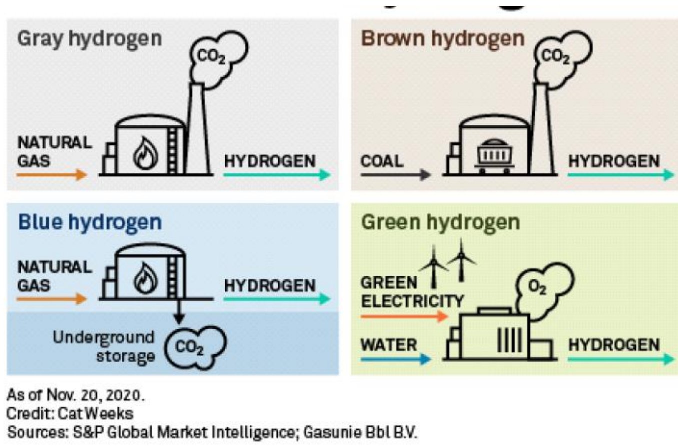

Figure 2.11: The Colors of Hydrogen

Today, hydrogen is mainly used as a fuel for petroleum refining, treating metals, producing fertilizer, and processing foods. It is also used for fueling spacecraft due to its light weight. In the future it may also be used for transportation and power generation. In addition to the Company, SoCalGas, ATCO Gas, Enbridge Gas, Pacific Gas & Electric, and other distribution companies are all studying the blending of hydrogen into their distribution systems as a way of reducing emissions for their customers. This is further discussed in the Sustainability section of this report.

Interest in hydrogen fuel cell vehicles is limited but growing. While hydrogen fuel cell vehicles do exist, the high cost of fuel cells and the limited availability of refueling stations are currently limiting the application for vehicles.

Interest in the use of hydrogen for producing electricity is also growing. As of December 2022, there were about 205 fuel cell electric generators operating in the United States. These smaller units have a total production capacity of 350 megawatts. Several larger power plants have also announced plans to convert to burn hydrogen to produce electricity. These include the Long Ridge Energy Generation Project in Ohio and the Intermountain Power Agency in Utah. These projects plan to burn hydrogen produced from renewable

[28] "Hydrogen Fuel Basics." https://www.energy.gov/eere/fuelcells/hydrogen-fuel-basics
[29] "The Colors of Hydrogen – Brown, Grey, Blue and Green – Think About It." 27 October 2020. https://utilityanalytics.com/2020/10/the-colors-of-hydrogen-brown-grey-blue-and-green-think-about-it/

resources.[30] Figure 2.12 provides an overview of some of the hydrogen projects underway across the country. This figure is based on the "H2 Matchmaker" interactive map provided by the U.S. Department of Energy (DOE) with the intent to provide a resource for users and suppliers on hydrogen to coordinate.[31] These projects represent different parts of the hydrogen value chain.

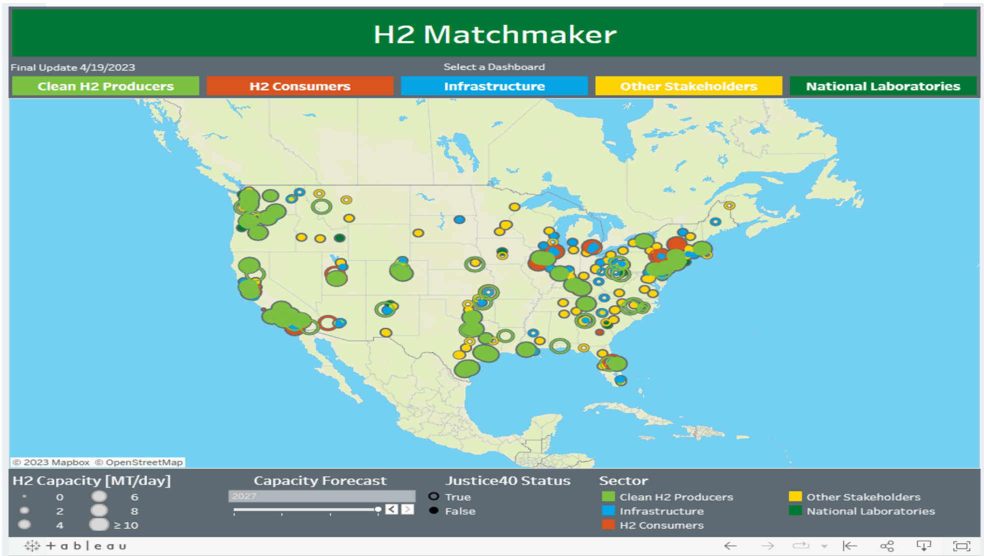

Figure 2.12: U.S. Hydrogen Projects – DOE "H2 Matchmaker" Map

The Advanced Clean Energy Storage Project, a joint development between Magnum Development, Mitsubishi Power Americas and others is a project designed to provide a green hydrogen hub in Delta, Utah. "The green hydrogen hub at the Advanced Clean Energy Storage Project would interconnect green hydrogen production, storage, and distribution in the West. Green hydrogen — which is hydrogen produced from renewable energy sources — will support decarbonizing multiple industries including power, transportation, and manufacturing." If built, the project would include 1,000 megawatts of electrolysis facilities. The hydrogen would be stored in two underground salt caverns each capable of holding 150 gigawatts of carbon-free dispatchable energy production. For comparison, the total U.S. battery storage is at 1.2 gigawatts as of 2020.[32]

In order to prepare for the infrastructure needs that may arise due to the development of hydrogen as a fuel source, the states of Utah, Colorado, New Mexico, and Wyoming signed a Memorandum of Understating (MOU) to coordinate the development of a clean hydrogen hub. This will allow the states to work together to compete for a portion of $8 billion allocated for regional hydrogen hubs in the 2021 Infrastructure Investment and Jobs Act.[33]

[30] "Hydrogen explained." 23 June 2023. https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php
[31] "H2 Matchmaker", https://www.energy.gov/eere/fuelcells/h2-matchmaker
[32] "Advanced Clean Energy Storage Project Invited to Submit Part II Application for up to $595 Million Financing from U.S. Department of Energy for Proposed Hydrogen Hub and Long-duration Renewable Energy Storage Project." 11 May 2021, https://power.mhi.com/regions/amer/news/20210511.html
[33] "Mountain West States Sign MOU to Develop Clean Hydrogen Hub." 24 February 2022.

In January 2023 the regional hydrogen hub proposal received an “Encouraged” recommendation from the DOE. This was a positive step for the concept proposed by Western Interstate Hydrogen Hub (WISHH). The term “regional clean hydrogen hub” is defined by the Bipartisan Infrastructure Law as “a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity.” The plan will include “all elements critical to a regional clean hydrogen hub: comprising production, end-uses, and connective infrastructure; demonstrating capabilities to execute a project plan or to attract and hire such capabilities; planning to deploy proven technologies; and indicating commitments to clean hydrogen and meaningful community benefits.”[34]

In April 2023, WISHH applied for a $1.25 billion grant from the DOE to advance the project and grow the hydrogen economy in the participating states. The grant submission was in response to a DOE Regional Clean Hydrogen Hubs (H2Hubs) Funding Opportunity Announcement (FOA). The projects included in the application included:

- AVANGRID will produce hydrogen in New Mexico.
- AVF Energy will produce renewable natural gas/clean hydrogen from biomass collected In Utah as part of environmental restoration and fire mitigation (Duchesne, Iron and Sevier counties).
- The Company’s ThermH2 project blends hydrogen into the high-pressure natural gas system in Utah (Juab and Utah counties).
- Libertad Power will produce clean hydrogen in New Mexico to serve power generation/storage and heavy haul-transportation customers in the Southwest (San Juan and Lea counties).
- Navajo Agricultural Product Industries (NAPI), a commercial farm owned by the Navajo Nation, will attempt to become energy self-sufficient while raising produce in greenhouses for the benefit of Tribal members and San Juan County, New Mexico.
- Tallgrass Energy will produce clean hydrogen through its eH2Power Front Range Hydrogen projects in New Mexico, Colorado and Wyoming to serve power, transportation, and other industrial markets.
- Xcel Energy Colorado will use wind and solar to produce hydrogen in eastern Colorado to support hydrogen use in the electric sector and hard-to-decarbonize segments of the economy.

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https://energy.utah.gov/2022/02/24/hydrogen-hub-mou/

[34] “Western Interstate Hydrogen Hub concept paper receives positive recommendation from U.S. DoE”, *H2Bulletin*, January 3, 2023, https://www.h2bulletin.com/western-interstate-hydrogen-hub-concept-paper-receives-positive-recommendation-from-us-doe/

WYOMING IRP PROCESS

The Company has been involved in Integrated Resource Planning in the state of Wyoming since the early 1990s. In 1992, the Wyoming Commission ordered the Company to prepare and file Integrated Resource Plans.[35] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to Integrated Resource Planning. The Wyoming Commission proposed the rule to "...give the Wyoming Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[36] On May 12, 2009, the Wyoming Commission approved Chapter 3, Section 33 of the Wyoming Commission rules and on January 24, 2011, the Wyoming Commission approved the natural gas IRP guidelines.[37]

The Company filed its 2023-2025 IRP on June 13, 2023, with the Wyoming Commission. Commission Staff placed Notice of the IRP on the Wyoming Commission's website and Open Meeting Agendas. Pursuant to these notices, the Wyoming Commission required the submission of written comments prior to September 15, 2023. The Wyoming Commission addressed the IRP at its Open Meeting on January 30, 2024. On February 26, 2024, the Wyoming Commission issued a Letter Order placing the IRP in the Wyoming Commission's files.

UTAH IRP PROCESS

Over the previous decade, the Utah Commission has promulgated new IRP standards and guidelines. This implementation process has included numerous discussions between IRP stakeholders in public meetings and the submission of extensive comments.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Guidelines) to be effective starting with the Company's 2010 IRP.[38] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[39]

On June 13, 2023, the Company filed its IRP for the plan year, June 1, 2023, to May 31, 2024 (2023-2024 IRP). A technical conference was held on July 11, 2023, to discuss the 2023-2024 IRP with regulatory agencies and interested stakeholders. On August 24, 2023,

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[35] "In the Matter of the Application of Mountain Fuel Supply Company to File its Integrated Resource Plan as Directed by the Commission in Docket No. 30010-GI-90-8," Findings, Conclusions and Order, Docket No. 30010-GI-91-14, May 21, 1992.

[36] Before the Public Service Commission of Wyoming, "In the Matter of the Proposed Adoption of Chapter 2, Section 253 of the Commission Procedural Rules and Special Regulations Regarding Integrated Resource Planning," Order Initiating Rulemaking, Docket No. 90000-107-XO-09 (Record No. 12032, February 3, 2009).

[37] Correspondence from the Public Service Commission of Wyoming; Alan B. Minier, Chairman, Steve Oxley, Deputy Chairman, and Kathleen "Cindy" Lewis, Commissioner, To All Wyoming Natural Gas Utilities, dated January 24, 2011.

[38] "In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines," Report and Order on Standards and Guidelines for Questar Gas Company, Docket No. 08-057-02, Issued: March 31, 2009.

[39] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Report and Order, Docket No. 09-057-07, Issued: March 22, 2010.

the Utah Office of Consumer Services (Office) filed its IRP comments.[40] The Utah Division of Public Utilities (Division) also submitted its report and recommendation on August 24, 2023.[41]

On December 14, 2023, the Utah Commission issued its Report and Order on the 2022-2023 IRP (Commission Order). The Utah Commission found that “the 2023 IRP as filed generally complies with the Standards and Guidelines.”[42]

On January 23, 2024, the Company met with Division and Office Staff to discuss IRP-related issues. This meeting was attended by representatives from the Company, the Division and the Office. The general purpose of this meeting is to review the most recent Commission Order and address any remaining concerns. The participants discussed just a few issues of concern including the following.

- The parties discussed how to incorporate more robust long-term planning into its IRP process, specifically in reference to price stabilization, supply reliability, and storage.

- The Company agreed to diligently ensure that all data and analyses presented in technical conferences also be in included the IRP documentation.

- The Company agreed to continue to include LNG facility status updates in the Quarterly Variance Reports, along with the potential cost impacts of filling to the end of November 2023 and during any filling season when the Company experiences natural gas price volatility.

- The Company agreed to provide ownership status updates on the MountainWest pipeline and possible Joint Operating Agreement implications in its Quarterly Variance Reports, until all issues related to the transfer of ownership of MountainWest pipeline to Williams Companies are resolved.

- The Company discussed the plan to include location of purchase in the IRP going forward.

- The Company discussed the conversion from SENDOUT to PLEXOS as discussed in the Final Modeling Results section of this report.

Periodically, technical conferences are held in the IRP process to respond to specific issues, as ordered by the Utah Commission, to receive input for the IRP process or report on the progress of the Company’s planning effort.

[40] Memorandum titled, “In the Matter of: Dominion Energy Utah’s Integrated Resource Plan (IRP) for Plan Year: June 1, 2023 to May 31, 2024,” To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Bela Vastag, Utility Analyst, Alex Ware, Utility Analyst, Jacob Zachary, Utility Analyst, August 24, 2023.
[41] Memorandum titled “Docket No. 23-057-02, Dominion Energy Utah’s Integrated Resource Plan (IRP) for Plan Year: June 1, 2023 to May 31, 2024,”, To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Brenda Salter, Assistant Director, Doug Wheelwright, Utility Technical Consultant Supervisor, Eric Orton, Utility Technical Consultant, Date: August 23, 2023.
[42] Commission Order

On February 15, 2024, the Utah Commission held an IRP technical conference in conjunction with the development of the 2024-2025 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission's 2023 IRP Order
- Pricing Update/Under-collection (Industry Overview section)
- Supply Sourcing – Volumes and Locations (Purchased Gas and Cost-of-Service Gas sections)

The Utah Commission held another technical conference on March 19, 2024. The attendees discussed the following topics:

- System Integrity (Integrity Management section)
- Rural Expansion Update (Distribution Action Plan section)
- Transportation and Storage Planning (Gathering, Transportation, and Storage section)
- Supply Modeling Update (Final Model Results section)

The Utah Commission held another technical conference on April 23, 2024. The attendees discussed the following topics:

- Heating Season Review (See below for a review of the 2023-2024 heating season)
- Gas Supply Hedging and LNG Update (Purchased Gas and Gathering, Transportation, and Storage sections)
- IRP Project Detail Discussion (Distribution Action Plan section)

The Utah Commission held another technical conference on May 1, 2024, where the following non-confidential topic was discussed:

- Long-Term Planning Update (System Capabilities and Constraints section)

Part of the May 1, 2024, technical conference was confidential. During the confidential part of the meeting, the following topics were discussed:

- Wexpro Matters (Cost-of-Service section)
- Annual Supply Request for Proposal (RFP) (Purchased Gas section)

The Company welcomes discussion and open dialogue and will schedule additional technical conferences to answer questions and resolve any remaining issues. The Utah Commission has scheduled a technical conference for July 8, 2024, to discuss the 2024-2025 IRP with Utah regulatory agencies and interested stakeholders.

During the course of the IRP process, the Company has maintained the following goals and objectives:

1. To project future customer requirements and analyze alternatives for meeting those requirements from a distribution system standpoint, an integrity management

standpoint, an environmental standpoint, a gas-supply source standpoint, an upstream capacity standpoint (including taking into consideration the inter-day load profile of each source), a reliability standpoint, and a sustainability standpoint;

2. To provide present and future customers with the lowest-reasonable cost alternatives for the provision of natural gas energy services, over the long term, that are consistent with safe and reliable service, stable prices, and are within the constraints of the physical system and available gas supply resources; and

3. To use the guidelines derived from the IRP process as a basis for creating a flexible framework for guiding day-to-day, as well as longer-term gas supply decisions, including decisions associated with cost-of-service gas, purchased gas, gathering, processing, upstream transportation, and storage.

The Company utilizes a number of models as part of its IRP processes. The complexity of the systems being analyzed necessitates the use of computer-based tools. Modeling tools are an integral part of the forecasting, gas network analysis, energy-efficiency analysis, and resource selection processes. In each section of this report where the Company has referred to modeling tools, the IRP contains a description of the functions of each model and the version utilized. The IRP also contains discussion of any material changes (logic and data) from the previous year's IRP including the reasons for those changes.

An annual IRP process coincides well with the natural cycles of the gas industry. Some of the end-of-calendar-year data is not available and fully analyzed for IRP purposes until mid-April. The utilization of this information ensures the Company is including the most current and relevant information in its IRP. The required data input assumptions utilized in IRP models are voluminous. Nevertheless, the intent of this IRP is to summarize, in a readable fashion, the Company's planning processes.

2023-2024 HEATING SEASON REVIEW

The 2023-2024 heating season saw continued price volatility in the fall, which peaked in January with natural gas pricing over $20 in the region during the holiday weekend of January 8 to 15, 2024. During the middle part of January 2024, a winter storm impacted much of the U.S. which resulted in January 16, 2024 experiencing the highest U.S. natural gas consumption on record in the lower 48 states.[43] However, after that weekend both demand and pricing declined over the remainder of the heating season as shown in Figure 2.13 and 2.14 below. The period between October 1, 2023 and March, 31 2024 was almost 10% warmer-than-normal.

[43] "U.S. natural gas consumption established a new daily record in January 2024", *https://www.eia.gov/todayinenergy/detail.php?id=61383*, 6 February 2024

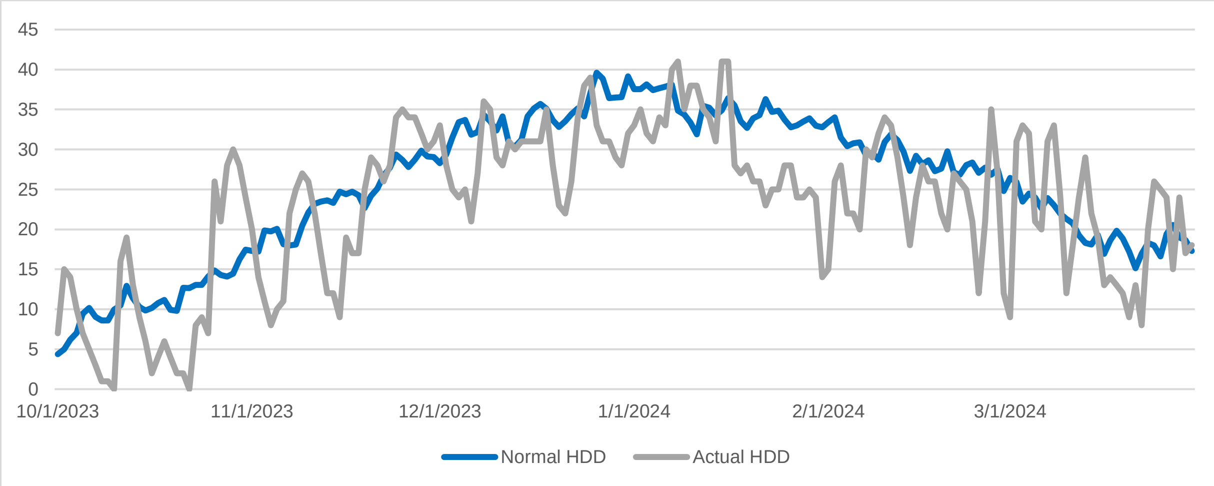


Figure 2.13: October 2023 – March 2024 HDD

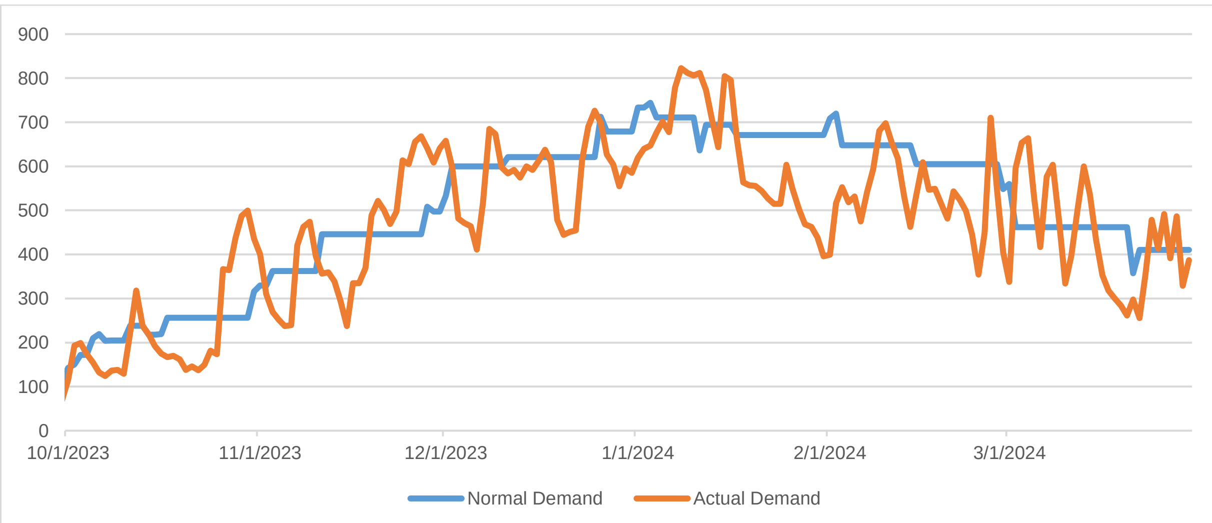


Figure 2.14: October 2023 – March 2024 Demand (1,000 Dth)

The heating season had very few cold events, the most significant event was during January 8 to 11, 2024. This period saw the Company's 17th, 18th, 23rd, and 24th highest total demand days in history. The highest total demand day of the heating season, January 11, 2024, was the Company's 66th highest Sales demand day on record.

Reduced demand and pricing occurred nationwide following the winter storm in mid-January. The impact of this on daily pricing is shown in Figure 2.15 below.[44]

[44] S&P Global – Platts Gas Daily

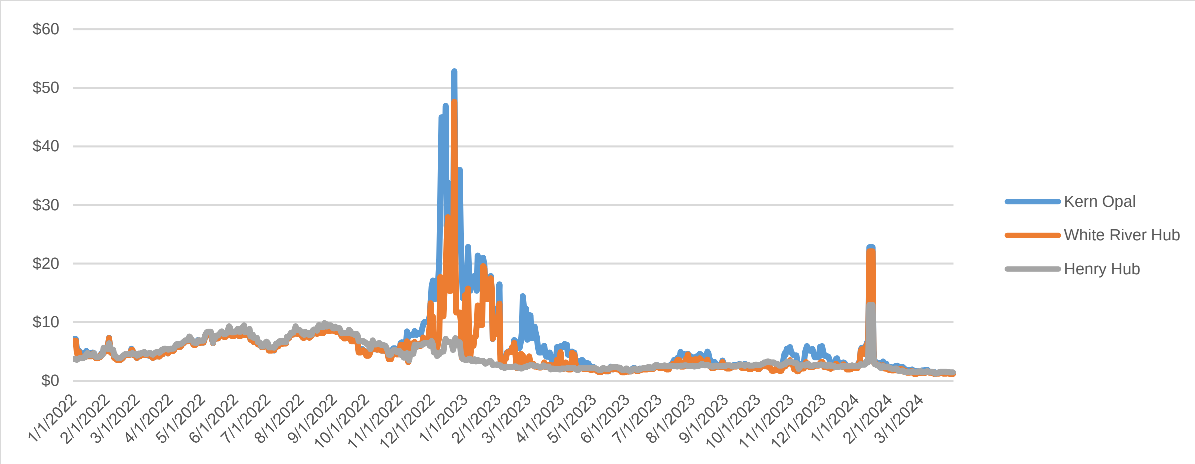


Figure 2.15: January 2022 – March 2024 Daily Pricing

The impact on monthly pricing is shown in Figure 2.16 below. [45]

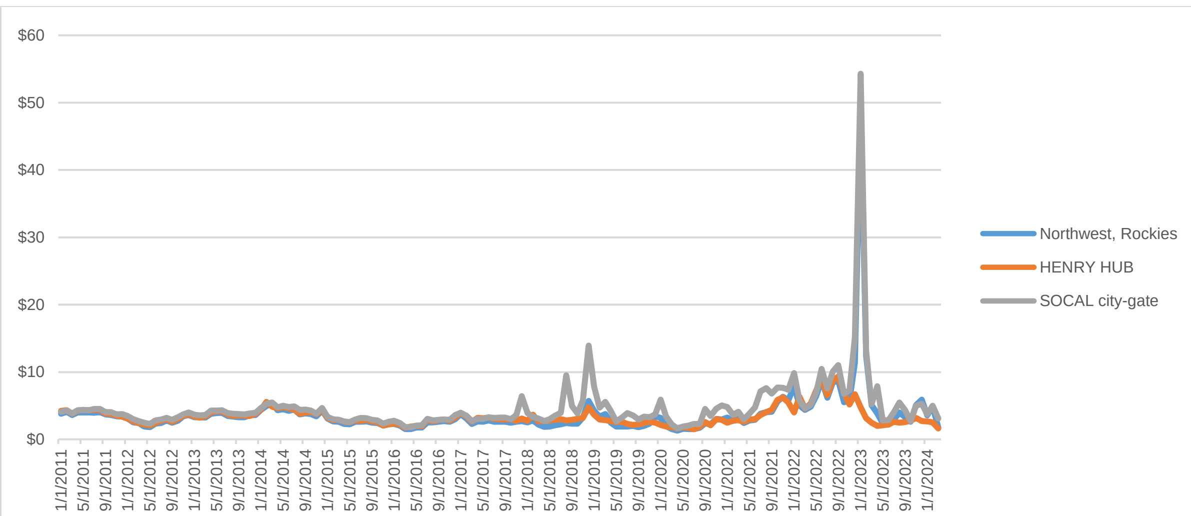


Figure 2.16: January 2011 – March 2024 Monthly Pricing

The reduced demand and lower prices resulted in reduced withdrawals from the Company's storage facilities as described in the Gathering, Transportation, and Storage section of this report. This has also had a similar impact on storage throughout the U.S. Storage reports for the U.S. lower 48, mountain region and pacific region all show strong storage positions as of April 2024 as shown in Figure 2.17, Figure 2.18, and 2.19 respectively below.[46]

[45] S&P Global – Platts Gas Daily Price Guide
[46] "Natural Gas Storage Dashboard" *Natural Gas Storage Dashboard (eia.gov),* April 25, 2024

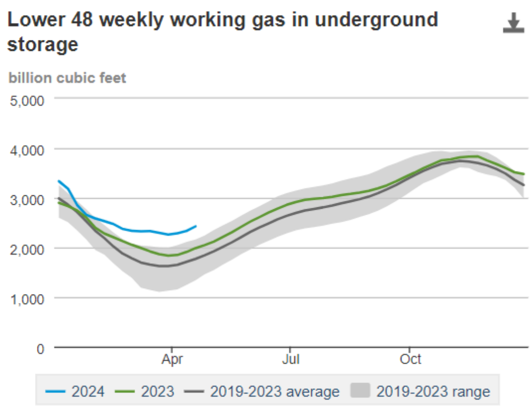


Figure 2.17: U.S. Lower 48 Storage

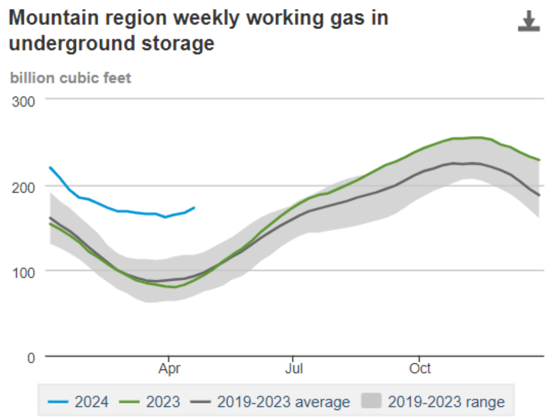


Figure 2.18: Mountain Region Storage

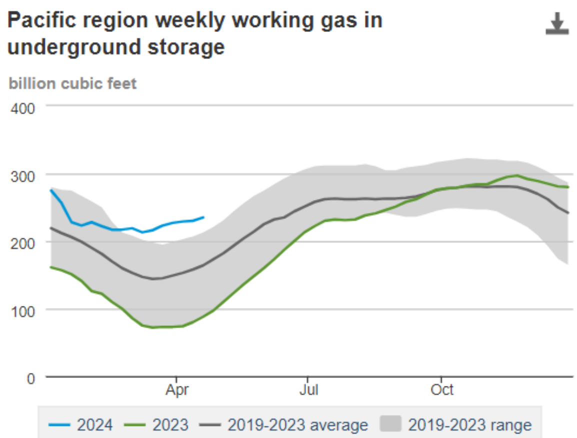


Figure 2.19: Pacific Region Storage

CUSTOMER AND GAS DEMAND FORECAST

SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2023-2024 IRP AND ACTUAL RESULTS

On a temperature-adjusted basis, the Company's estimated natural gas sales through the IRP year ending May 2024 is 124.1 MMDth. The Company forecasted a total of 123.1 MMDth for the period in last year's IRP. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2023-2024 IRP year at 225.4 MMDth. Last year's IRP projected 228.0 MMDth for the same period.

TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2024-2025 IRP YEAR

The forecasted level of sales demand for the 2024-2025 IRP year is 124.6 MMDth, a net increase of about 0.4%. resulting from continued growth in the GS customer base, both residential and commercial, and the departure of about 150 sales customers to transportation service in July of 2024. The pace of residential growth in the single-family dwelling sector continues to slow in response to high interest rates and home prices, but housing demand in Utah is not retreating, and the inventory shortage will perpetuate residential construction and year-to-year growth in the customer base and gas demand. Sales demand is projected to reach 138.2 MMDth in the 2033-2034 IRP year (see Exhibit 3.10).

As noted, around 150 sales customers had notified the Company of intent to shift to transportation service in 2024. On a temperature-adjusted basis, the net effect is an annual sales demand decrease of approximately 800,000 Dth. This year's forecast does not assume further shifting beyond the 2024-2025 IRP year.

The 2024-2025 IRP sales forecast of 124.6 MMDth will be the denominator used in the calculation of the percentage of sales supplied by cost-of-service production per the Trail Unit Settlement Stipulation. The numerator will be the actual cost-of-service quantity as reported at the wellhead.

The Company is forecasting 1.22 million GS customers at the end of the 2024-2025 IRP year and 1.44 million GS customers by the end of the 2033-2034 IRP year (see Exhibit 3.1). The Company forecasts annual Utah GS usage per customer at 99.6 Dth in the 2024-2025 IRP year and 93.9 Dth by end of the 2033-2034 IRP year (see Exhibit 3.2). Annual Wyoming GS usage per customer is projected to be 119.5 Dth in the 2024-2025 IRP year and 116.6 Dth at in the 2033-2034 IRP year (see Exhibit 3.5).

The Company forecasts system total throughput in this year's forecast to increase from 228.4 MMDth during the 2024-2025 IRP year to 242.0 MMDth by end of the 2033-2034 IRP year (see Exhibit 3.10).

RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

Utah

Current housing economics throughout the Company's service territory lead to a forecast of continuing growth in the customer base, though at a slower pace. The 30-year fixed mortgage rate remains above 6% and the ongoing housing inventory shortage, particularly in the high-growth counties of Utah, maintains upward pressure on home prices, deterring homeowners from upgrading and pricing many first-time buyers out. The unit shortage extends to the multi-family sector and continues to fuel a high level of construction of apartments, condominiums, and townhomes. Nearly half of the Company's new residential service agreements in Utah (47%) established during 2023 were multi-family unit connections.

The Company is forecasting moderated but consistent growth through the forecast horizon as the surge in the single-family home market that was fueled by low interest rates and high demand has ended. Demand for both single-family and multi-family units is expected to remain strong, however, as Utah's household formation rate and in-migration keep demand ahead of supply. The Company projects about 21,000 new additions through the next two IRP years with moderate improvement that reaches a level of about 23,500 per year from 2029 onward. Multi-family units are expected to occupy a high percentage of new residential additions, an average of 40% throughout the forecasted period.

Actual temperature-adjusted residential usage per customer for the 12 months ending December 2023 was 79.1 Dth. The Company forecasts an average of about 78.0 Dth through the 2024-2025 IRP year. The overall downward trend in average consumption is expected to continue through the 2033-2034 IRP year as the appliance and shell efficiencies improve and smaller residential dwellings begin to occupy a greater share of the overall dwelling mix (see Exhibit 3.3).

The Company employs several statistical methods to analyze and forecast residential gas demand. These methods include univariate and multivariate time series modeling of demand and such explanatory variables as demand history, customer growth, and the rate of natural gas service per unit of consumption. SAS Enterprise Time Series 14.1 is the software tool used for the statistical time series modeling.

The Company also examines residential consumption by end uses such as space heating and water heating and estimates the effect of increases in the share of high efficiency appliances for those end uses. Effects of increases in the share of smart thermostats and smaller living spaces are also examined. These compartmentalized analyses make extensive use of data collected by the Company's Energy Efficiency Experts as they conduct in-home energy audits through the Energy Efficiency Program. They are important tools that inform long-term forecast development.

Wyoming

Through 2023, the Wyoming residential customer base added 47 new service agreements. The Company forecasts just under 50 new additions through the two IRP years. Moderate growth of about 120 additions per year is expected thereafter as housing affordability challenges and uncertainty in the natural resources sector of the region's economy restrains higher growth.

The average annual usage per residential customer in Wyoming was 82.6 Dth in calendar year 2023. The Company forecasts an average of 82.4 Dth during the 2024-2025 IRP year and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. The 2033-2034 IRP year ends at 79.6 Dth (see Exhibit 3.6).

SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

Utah

The average temperature-adjusted usage among Utah GS commercial customers ended 2023 at 436.0 Dth. Last year also saw healthy growth in Utah's commercial GS base with a net gain of 1,200 service agreements.

This year's forecast projects continued customer and demand growth in this sector with just over 900 net additions through the 2024-2025 IRP year and about 950 the following year.

At the time the forecast was prepared, about 140 commercial GS customers had given notice of intent to shift to transportation service beginning in July of this year. That shift will lead to a net reduction of about 730,000 Dth annually in total GS demand and has been assumed in the forecast. No further shifting beyond 2024 has been assumed.

Wyoming

Temperature-adjusted usage among commercial GS customers in Wyoming for the 12 months ended December 2022 averaged 426.9 Dth, a decrease of about 10 Dth from the end of 2022. The customer base saw a net loss of 23 customers through 2023.

The Company projects mild growth in the commercial sector with about 10 net additions through the next three IRP year and then an increase to about 10 per year through the remainder of the forecast horizon. Average annual usage in the coming IRP year is projected at 433.5 Dth, edging higher to 433.9 the following year, and ending the forecast horizon in the 2033/2034 IRP year at 431.2 Dth.

NON-GS COMMERCIAL, INDUSTRIAL, AND ELECTRIC GENERATION GAS DEMAND

The Company projects demand in the non-GS commercial and industrial sectors at 54.3 MMDth in the 2024-2025 IRP year. The subsequent years will hold steady after a net transfer of just over 800,000 Dth annually from sales to transportation service, with 89% of that volume transferring from the GS commercial class. No shifting after the 2024-2025 IRP year is assumed in this forecast (see Exhibit 3.8).

Electric generation demand is forecasted to hold at a level of about 53.0 MMDth annually through the forecast period. It is a midpoint of the range that seems reasonable given usage levels over the past two years. Demand at some plants comes from generation used to meet peaking load and can vary considerably over time. In addition, baseload generation can be supplemented with open-market procurement, making a forecast of ongoing demand levels difficult.

FIRM CUSTOMER DESIGN DAY GAS DEMAND

The Design Day firm customer demand projection is based on a gas day when the mean temperature is –5 degrees Fahrenheit at the Salt Lake Airport weather station.

Heating degree days, wind speed, the day of the week, and prior day demand are significant factors in the prediction of daily gas sales during the winter heating season. Note that the Design Day demand projection distinguishes between firm sales and firm transportation demand for gas supply and system capacity planning purposes.

Exhibit 3.9 shows actual firm sales and firm transportation demand that occurred on the highest sendout day of each heating season from 2019-2020 through 2023-2024. Design Day conditions did not occur during those periods; however, January 30, 2023 saw the highest total sendout on record. The highest firm sales sendout of the last heating season occurred on January 11, 2024.

The firm sales Design Day gas supply projection for the 2024-2025 heating season is 1.28 MMDth and grows to 1.42 MMDth in the winter of 2033-2034. This estimate is based upon the following Design Day scenario: 70 heating degree days in Salt Lake region; mean daily wind speed of 9.5 mph as measured at the Salt Lake City Airport weather station; the day is not a Friday, Saturday, or Sunday, and it is not a winter holiday. Note that the assumed level of wind speed was observed on the December 22-23 gas day of 1990 when the mean temperature was -4.7 degrees Fahrenheit.

SOURCE DATA

The Company has obtained economic, demographic, and other data from the University of Utah’s Kem C. Gardner Policy Institute and S&P Global (formerly IHS Markit).

ALTERNATIVES TO NATURAL GAS

The Company’s customers have alternatives to using natural gas for virtually every application. Some customer end-use applications are dominated by other energy sources (cooking and clothes drying) while others are dominated by natural gas (space and water heating). A material shift in available competitive energy options would affect future demand and load profiles.

The Company is also aware of efforts throughout the country, mainly at the municipal government level, to ban natural gas infrastructure in new construction projects. Most of these efforts have failed. In 2021, the Utah legislature passed HB 17 and the Wyoming legislature passed SF0152. These bills prevent local governments from enacting ordinances or resolutions that would prohibit the connection of an energy utility service including natural gas utility service. As a result, these efforts have had little to no impact on the Company’s customer usage of natural gas. The Company will continue to monitor these efforts and report on results in future iterations of the IRP.

Solar

The Company does not currently anticipate that solar-powered space or water heat will have a significant impact in the Company’s natural gas service territory. However, as battery technology improves and solar panels become more affordable with lower material cost and continued federal and state tax credits, their application may become more prevalent in the residential and commercial markets.

The Company will continue to monitor this issue and participate in studies with the Gas Technology Institute (GTI), NYSEARCH, and the American Gas Association (AGA) and will report any impacts on the service territory in future IRPs.

Heat Pumps

In the 2021 energy efficiency budget filing (Docket No. 20-057-20), the Company proposed, and the Commission approved, rebates in the ThermWise® Appliance, Builder, and Business programs for customers who purchase and install dual-fuel heating systems. These systems combine electric heat pumps, which can achieve levels of efficiency as high as 300% at optimal ambient air temperatures, with a high efficiency furnace of $\geq$ 95% annual fuel utilization efficiency (AFUE). The Company designed this rebate measure with the heat pump performing heating operations at or above 40°F outside air temperature and the high efficiency furnace providing heat when outside air temperatures drop below that set point.

The Company believes that a dual-fuel system offers benefits for its customers versus a stand-alone electric heat pump. As outside air temperatures drop, the electric heat pump quickly begins to lose efficiency and becomes more costly for customers to operate. This is where the natural gas side of the dual-fuel system is designed to take over (about 39°F outside air temperature and below) and ensure heating at a level of 95% efficiency or greater. The dual-fuel system switches between its two components depending on which is more efficient for the circumstances, which reduces energy use and ultimately saves customers money. An additional benefit of a dual-fuel system is that it offers customers resiliency for home heating in case one component of the system fails during the heating season.

The Company forecasts that a typical customer (using 70 dekatherms annually for space and water heat) who installs a dual-fuel system would reduce annual natural gas usage by 29 dekatherms or 41%. The Company rebated over 3,000 dual-fuel heating systems in 2023 and expects to rebate over 3,500 in 2024. The Company expects participation to continue growing in future years as the heating, ventilation, and cooling trades become more familiar with these technologies.

GAS LOST AND UNACCOUNTED FOR

The Company estimates gas that is lost and unaccounted for (LAUF) by taking the difference between gas volume received into the Company's distribution system and the sum of volumes accounted for through customer billing, Company use, line pack, and loss from tear-outs or flaring. Each year data is collected for the 12-month period ending in June of the current year to calculate the variance. The estimation approach the Company employs has been in place for years and has been refined over time to incorporate additional data and to eliminate unnecessary sources of estimation error.

It is important to understand that a LAUF percentage is not simply an estimate of gas quantity that has escaped the system. It is the calculation of a difference between gas volume received into the system and gas volume accounted for. In addition to gas physically lost from the system through leaks, theft, or damage, variance also arises from other sources. These additional sources are not unique to the Company but are common to most local distribution companies (LDCs).

One of these contributing factors is measurement variance. This is variation in the measurement of gas volume and heat content on the same quantity of gas as it passes through different elevation and temperature zones and is delivered to customers at various regulating pressures. Compensations at the meter level must be made for temperatures and pressures that deviate from the NAESB standard values used to calculate volume and heat content. Differences in the sophistication of meter-level compensation used at system receipt points and that of customer meters or billing system compensation is also a source of variance.

Timing is an additional source of variance. Gas volume and heat content is measured throughout the day at the system receipt points using highly sophisticated equipment. But end-use consumption of that volume is calculated for customer billing through monthly meter reads. Because most billing is done on a cycle basis that includes portions of two consecutive months, some estimation is required to convert portions of billing cycle data to the calendar-month format in which receipt point data are collected. This can also introduce error.

In recent years, the Company has reduced measurement variance by implementing more granular temperature and elevation correction of customer meter reads when the meter does not have built-in compensation. This has reduced the average estimate from around 1.5% to less than 1%. This billing-system compensation was introduced in the Company's Utah/Idaho service regions in 2009 and in its Wyoming regions in 2010. Further, when older meters need to be replaced, a meter with built-in temperature compensation is installed in its place. The Company has also modified the calculation process to minimize the estimation that must be done to render billing cycle data into a calendar-month form for comparison with system receipt data.

Gas that is lost and unaccounted for is chiefly a gas measurement and accounting issue. Nevertheless, some gas is physically lost through leaks, theft, and damage to the Company's pipe by third parties. The Company is taking numerous steps to minimize the volume of gas lost from the distribution system as part of its methane emissions program. This is discussed in detail in the Sustainability section of this report.

The important metric in tracking LAUF across time is the percentage, not the estimated quantity. Estimated quantity can vary considerably from year to year, and there is no sure way to isolate all sources and assign a share of the LAUF portion to them. However, the Company's estimated percentage has remained stable and well below 1% since the implementation of temperature and elevation compensation by the billing system. Estimates by other LDCs provided to the EIA vary considerably across the industry and range from negative percentages to some at 30% or higher.[47]Negative estimates do not suggest that an LDC is making gas inside of its distribution system. Unusually high percentages do not necessarily indicate that an LDC is losing a high portion of the gas it takes in. Instead, such a range of estimates underscores the imprecise nature of comparing measurements of gas

[47] American Gas Association (2014, February), *Lost and Unaccounted for* Gas

volumes taken at different times from a multitude of locations, equipment, and estimated data sources.

The Company calculates the portion of gas that is lost or unaccounted for using a moving three-year average of annual proportions. These proportions are derived by dividing the total of system receipts for the twelve-month period ending June 30 into the sum of Company use gas (accounts 810 and 812); loss from tear-outs, flaring and line pack; and volumes that are unaccounted for during the same period. The updated average is 0.733%.

The current calculation for the most recent three years is included in Table 3.1 below.

Table 3.1: Three-Year Rolling Average of Estimated Use and Calculation of Gas Lost and Unaccounted for (Dth)

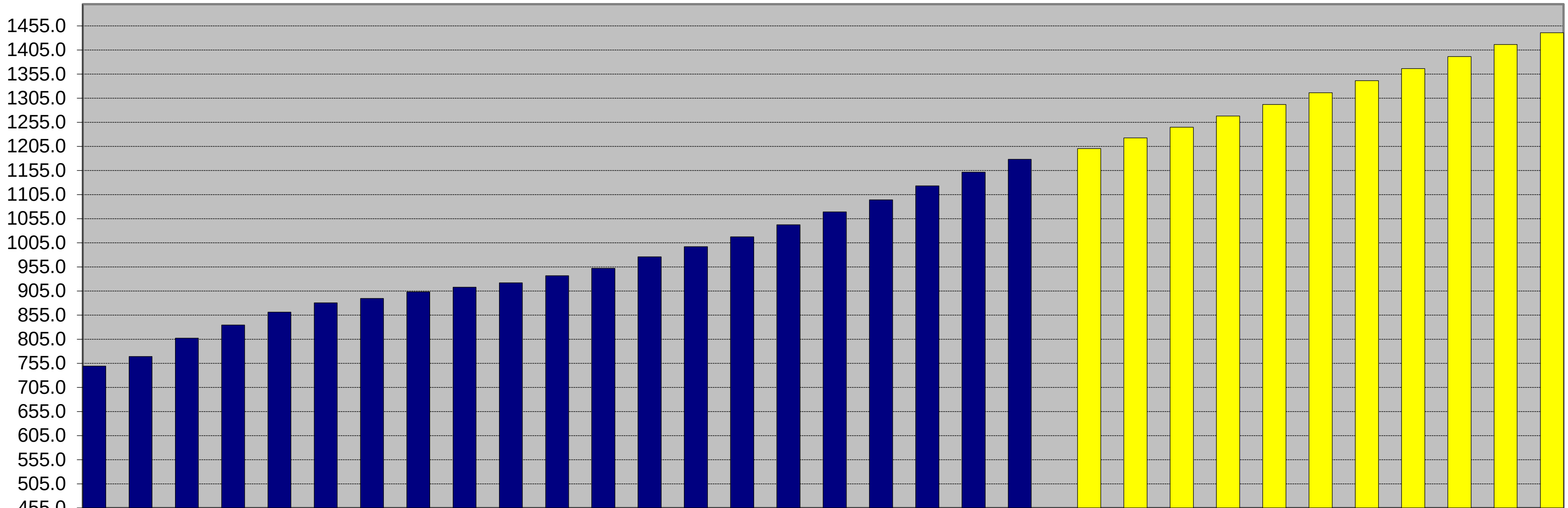
Year	Customer Sales	Customer Transport.	Total Receipts	Sales & Transportation	Use Acct. 810&812	Loss Due to Tearouts	Lost & Unaccounted for Gas	Total Sales, Transport, Company Usage and L&U
2020-2021	112,902,810	101,541,751	214,444,561	212,919,155	56,999	28,487	1,439,920	214,444,561
2021-2022	115,777,808	104,561,512	220,339,320	218,637,215	43,158	33,829	1,625,118	220,339,320
2022-2023	130,322,240	105,249,929	235,572,169	233,886,393	48,209	26,349	1,611,217	235,572,169
Total	**359,002,858**	**311,353,192**	**670,356,050**	**665,442,763**	**148,366**	**88,665**	**4,676,255**	**670,356,050**
	Lost-&-Unaccounted-For-Gas %		0.698%		Company Use and Lost-&-Unaccounted-For-Gas %		0.733%	

FORECAST EXHIBITS

The following charts summarize the 10-year customer and gas demand forecast. All charts contain temperature-adjusted data with forecast horizons summarized on an IRP-year basis (June 1 – May 31).

SYSTEM GS CUSTOMERS

Customers (Thousands)

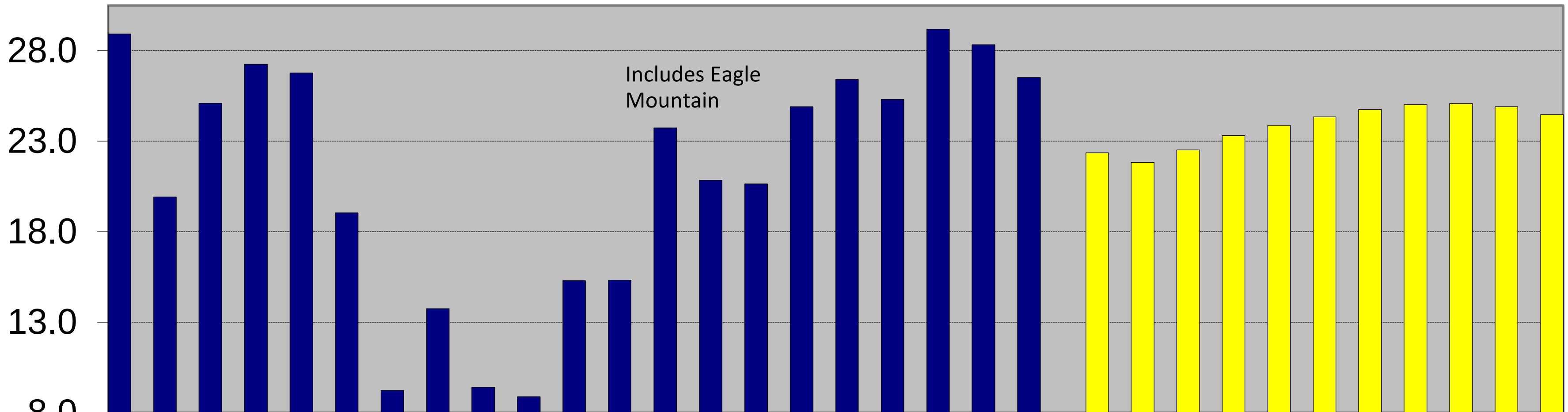


	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
ACTUAL	749.4	769.3	807.4	834.7	861.4	880.5	889.7	903.5	912.8	921.7	937.0	952.4	976.1	996.9	1017.6	1042.5
FORECAST																

	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
ACTUAL	1068.9	1094.2	1123.4	1151.7	1178.2											
FORECAST						1200.6	1222.4	1244.9	1268.2	1292.1	1316.5	1341.2	1366.2	1391.3	1416.2	1440.7

SYSTEM GS ADDITIONS

Customers (Thousands)



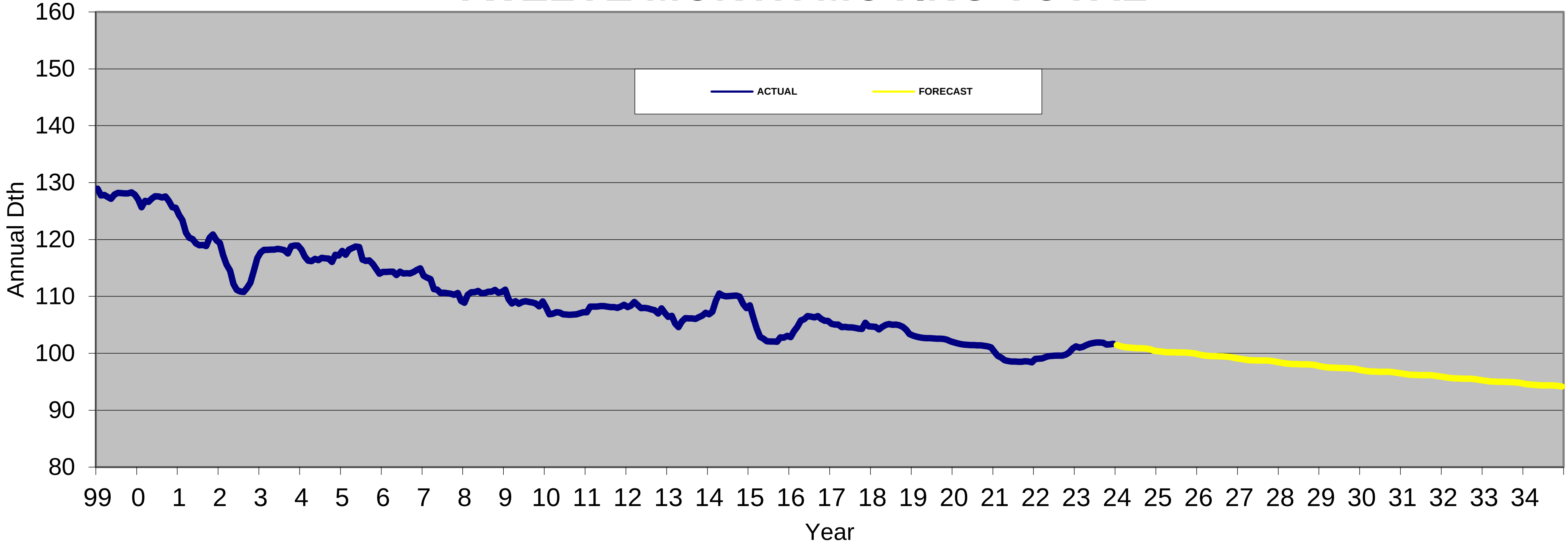
	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
ACTUAL	28.9	19.9	25.1	27.3	26.8	19.0	9.2	13.7	9.4	8.9	15.3	15.3	23.7	20.8	20.6	24.9
FORECAST																

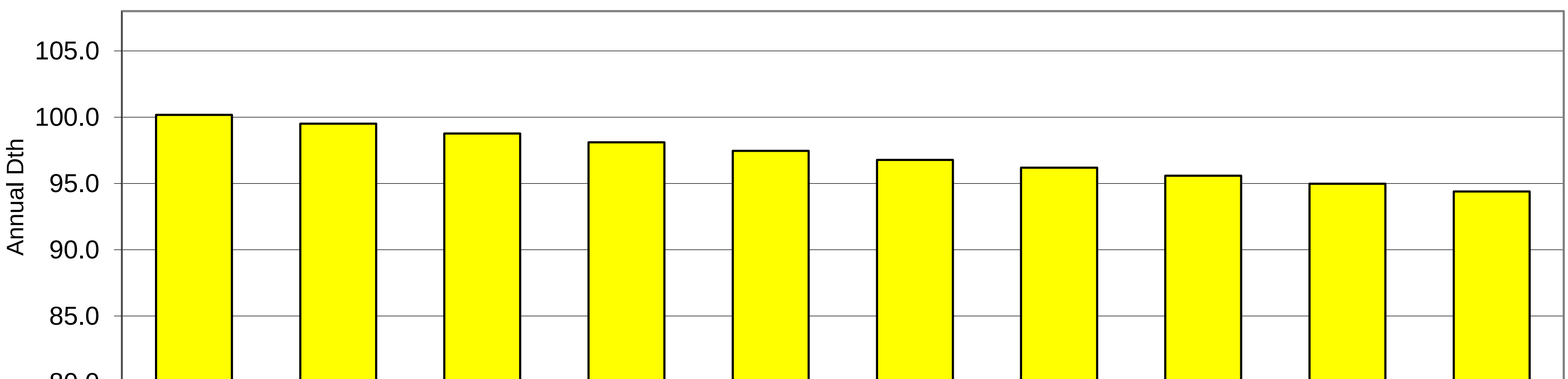
	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
ACTUAL	26.4	25.3	29.2	28.3	26.5											
FORECAST						22.4	21.8	22.5	23.3	23.9	24.4	24.8	25.0	25.1	24.9	24.5

Exhibit 3.1

UTAH GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





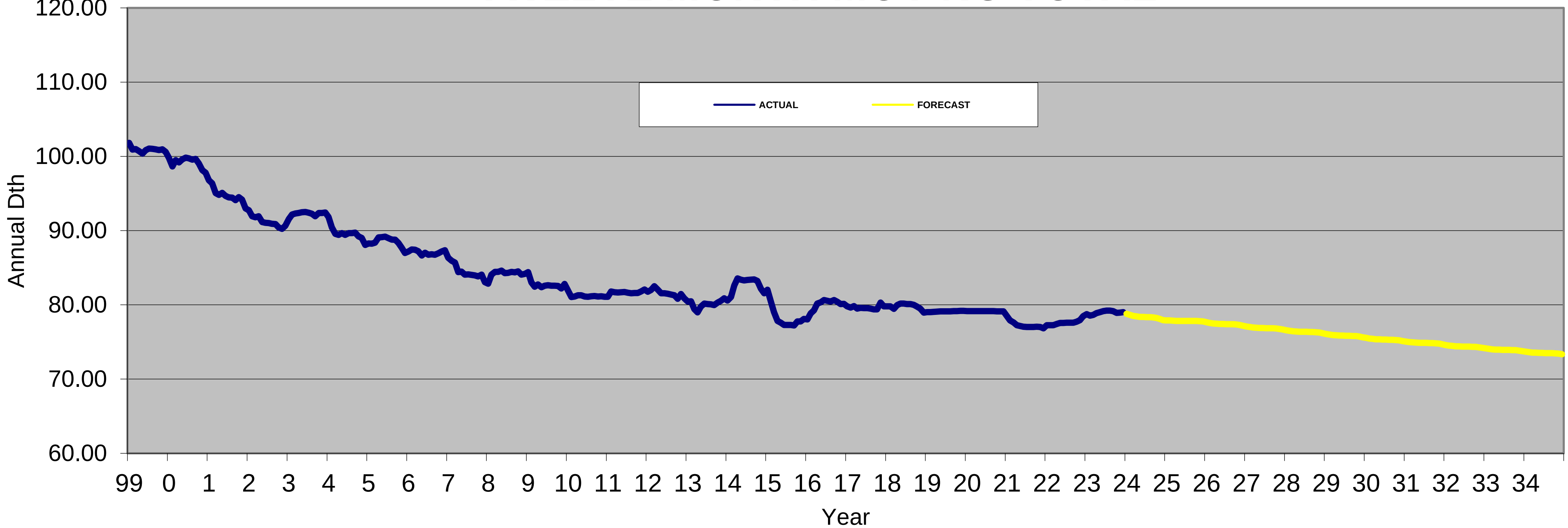
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
FORECAST	100.2	99.5	98.8	98.1	97.5	96.8	96.2	95.6	95.0	94.4

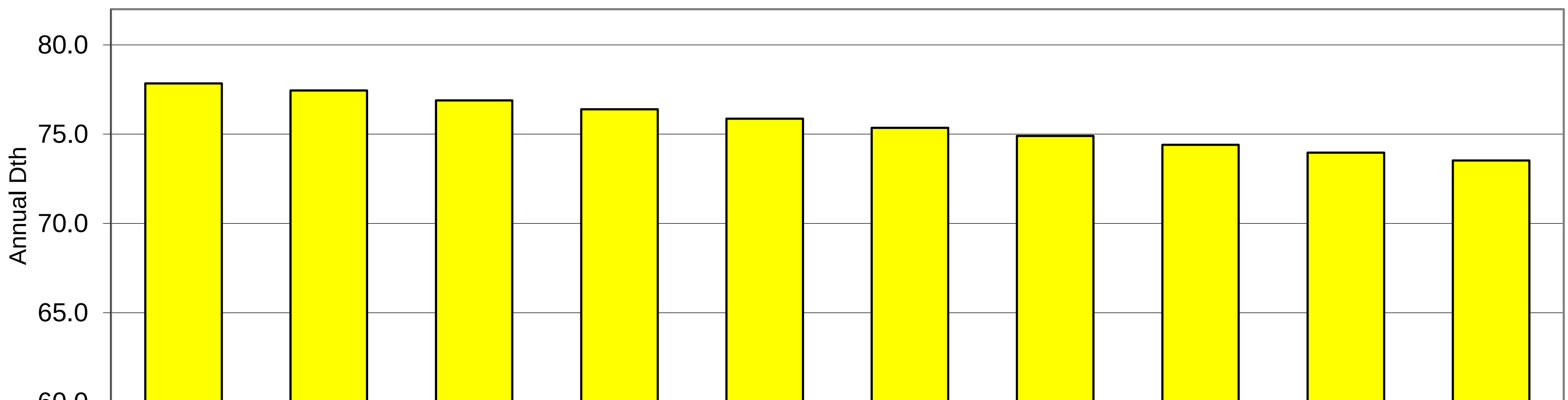
IRP Year

Exhibit 3.2

UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





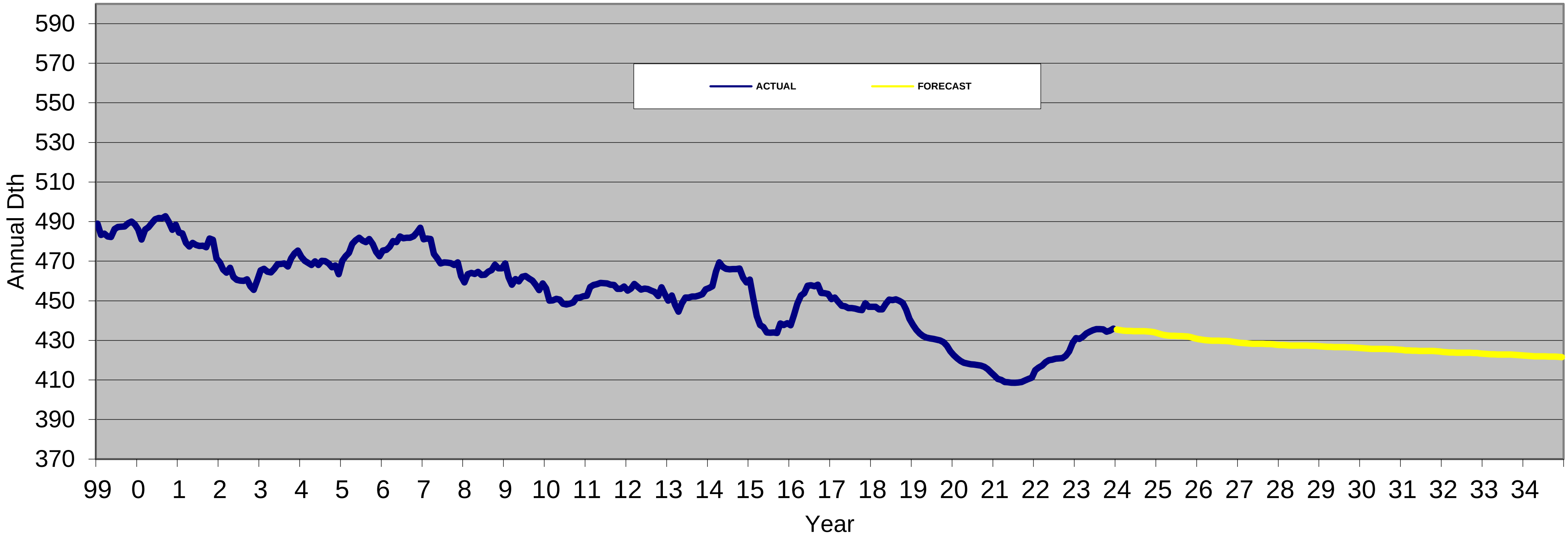
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
FORECAST	77.8	77.4	76.9	76.4	75.9	75.4	74.9	74.4	74.0	73.5

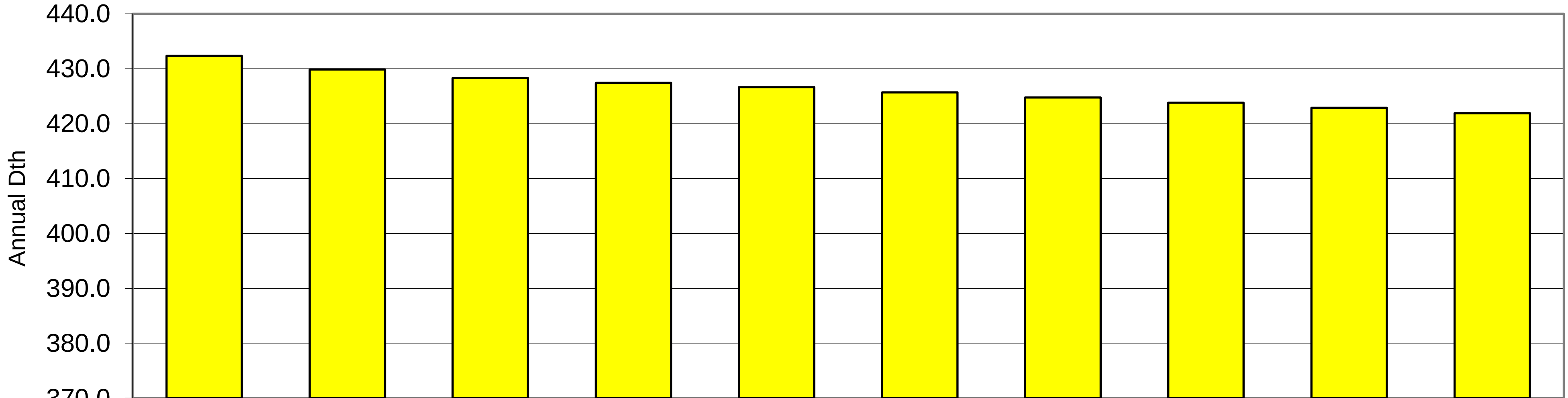
IRP Year

Exhibit 3.3

UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





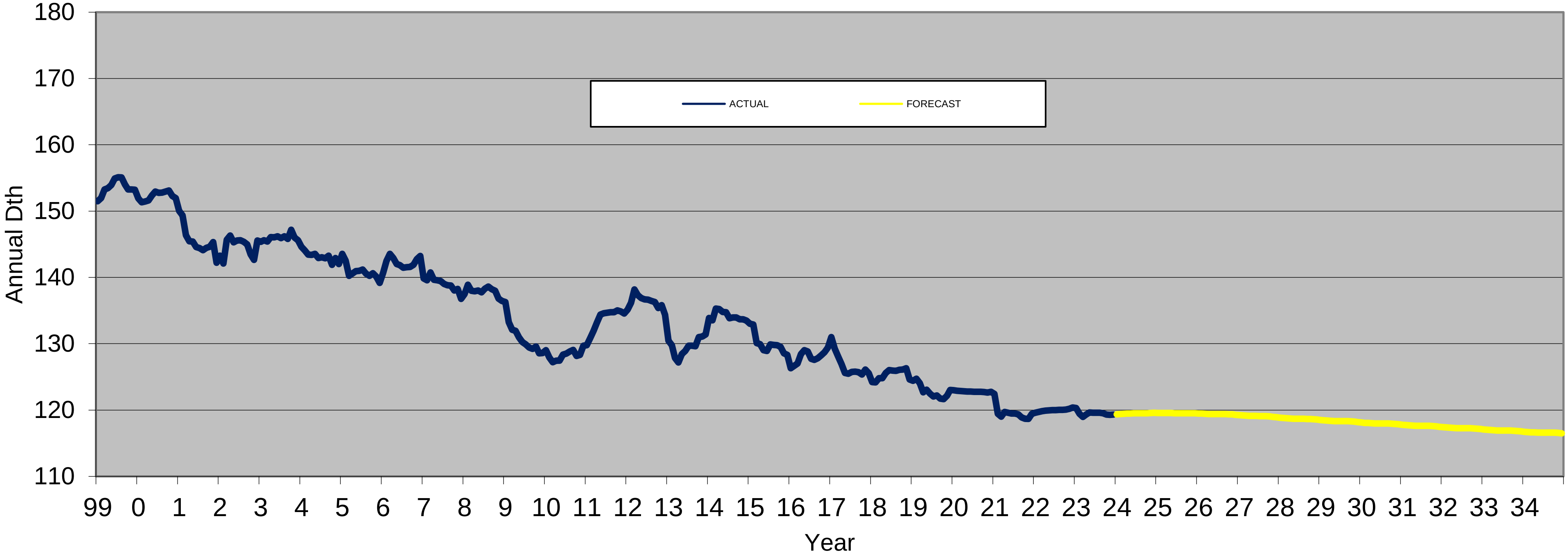
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
FORECAST	432.3	429.9	428.3	427.4	426.6	425.7	424.7	423.8	422.9	421.9

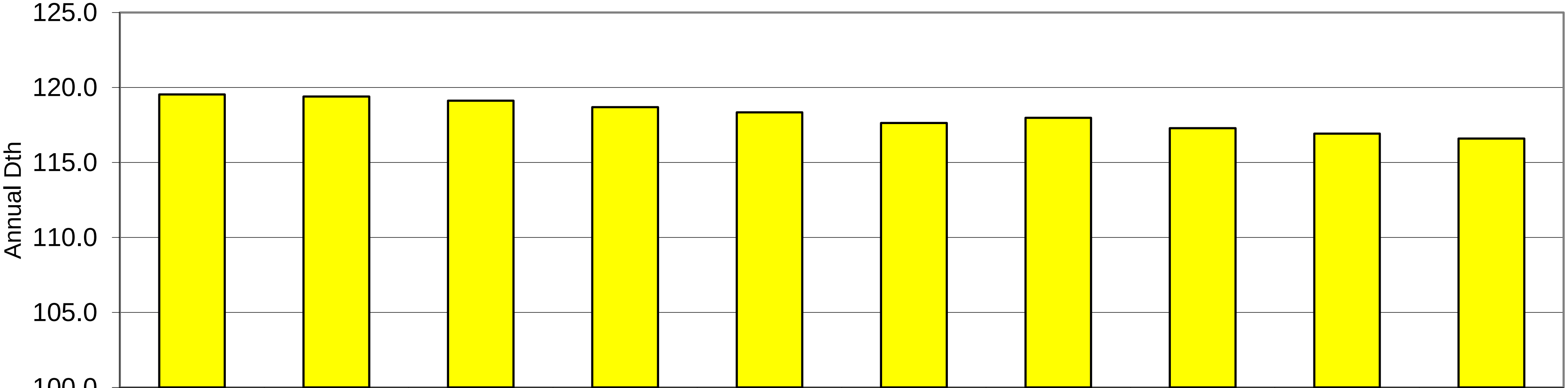
IRP Year

Exhibit 3.4

WYOMING GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



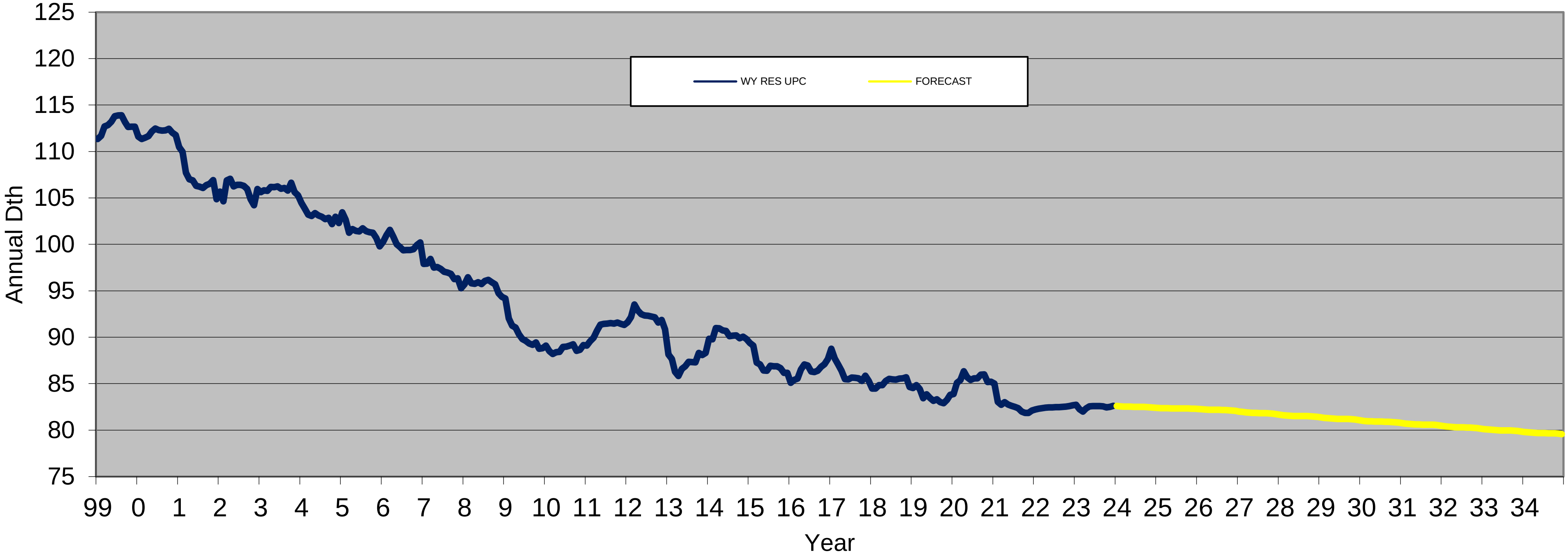


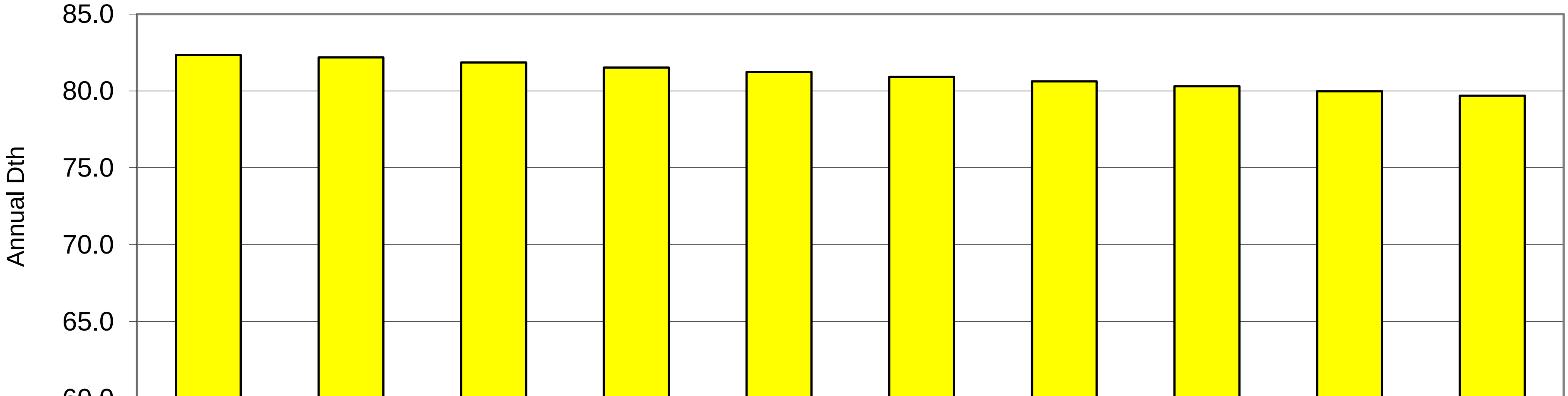
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
WY GS	119.5	119.4	119.1	118.7	118.4	117.6	118.0	117.3	116.9	116.6

IRP Year

Exhibit 3.5

WYOMING GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



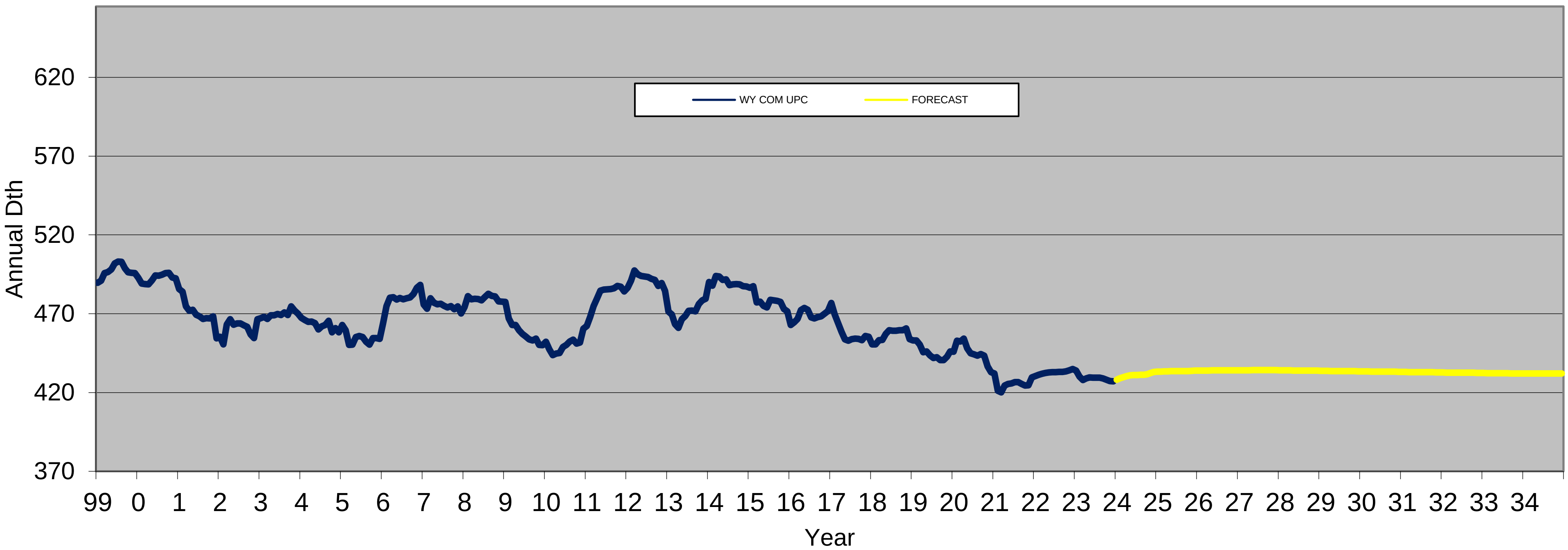


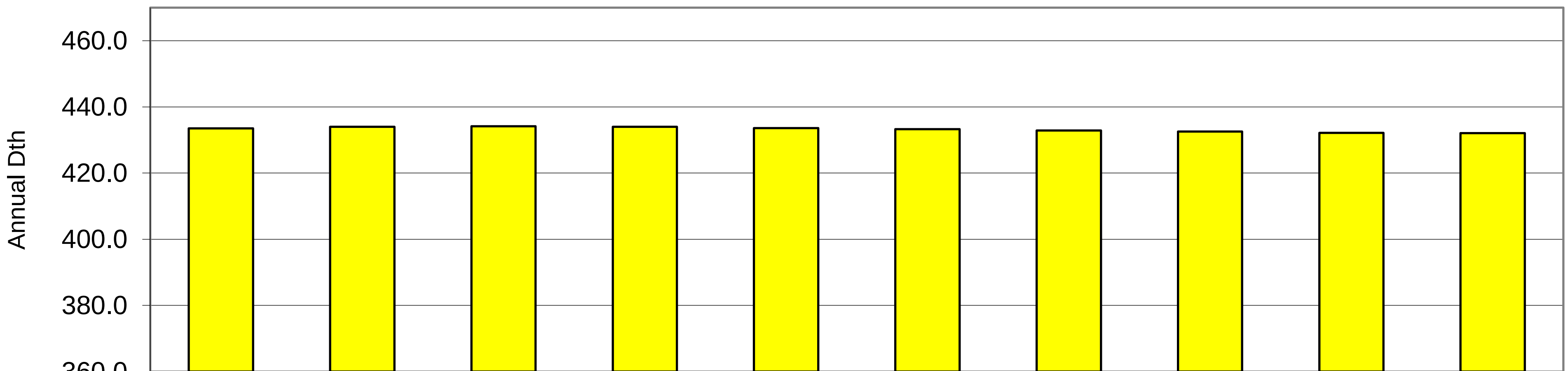
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
WY GS RES UPC	82.3	82.2	81.9	81.5	81.2	80.9	80.6	80.3	80.0	79.7

IRP Year

Exhibit 3.6

WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



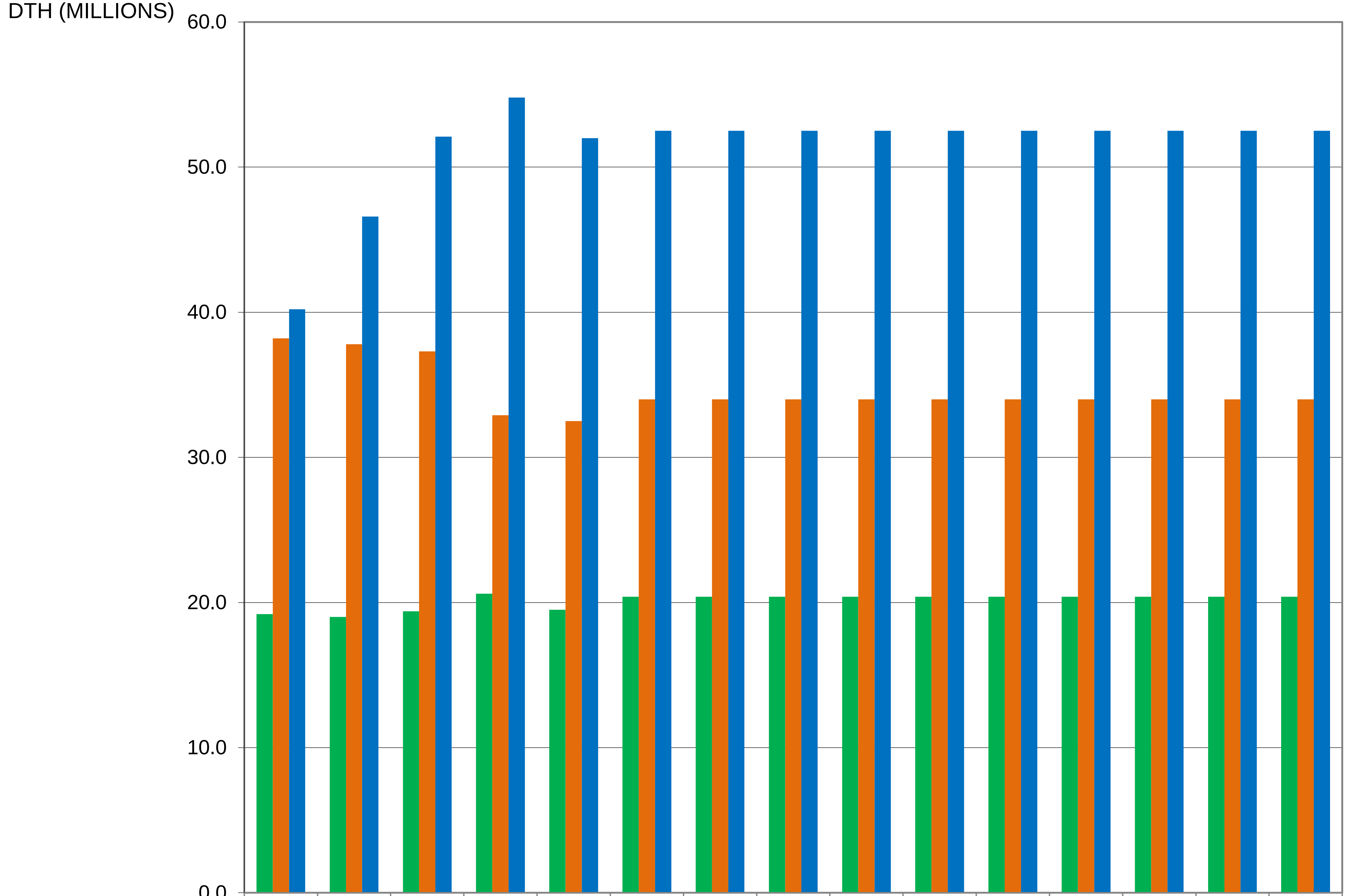


	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
WY GS COM UPC	433.5	434.0	434.2	434.0	433.6	433.3	432.9	432.6	432.2	432.0

IRP Year

Exhibit 3.7

SYSTEM NON-GS DEMAND

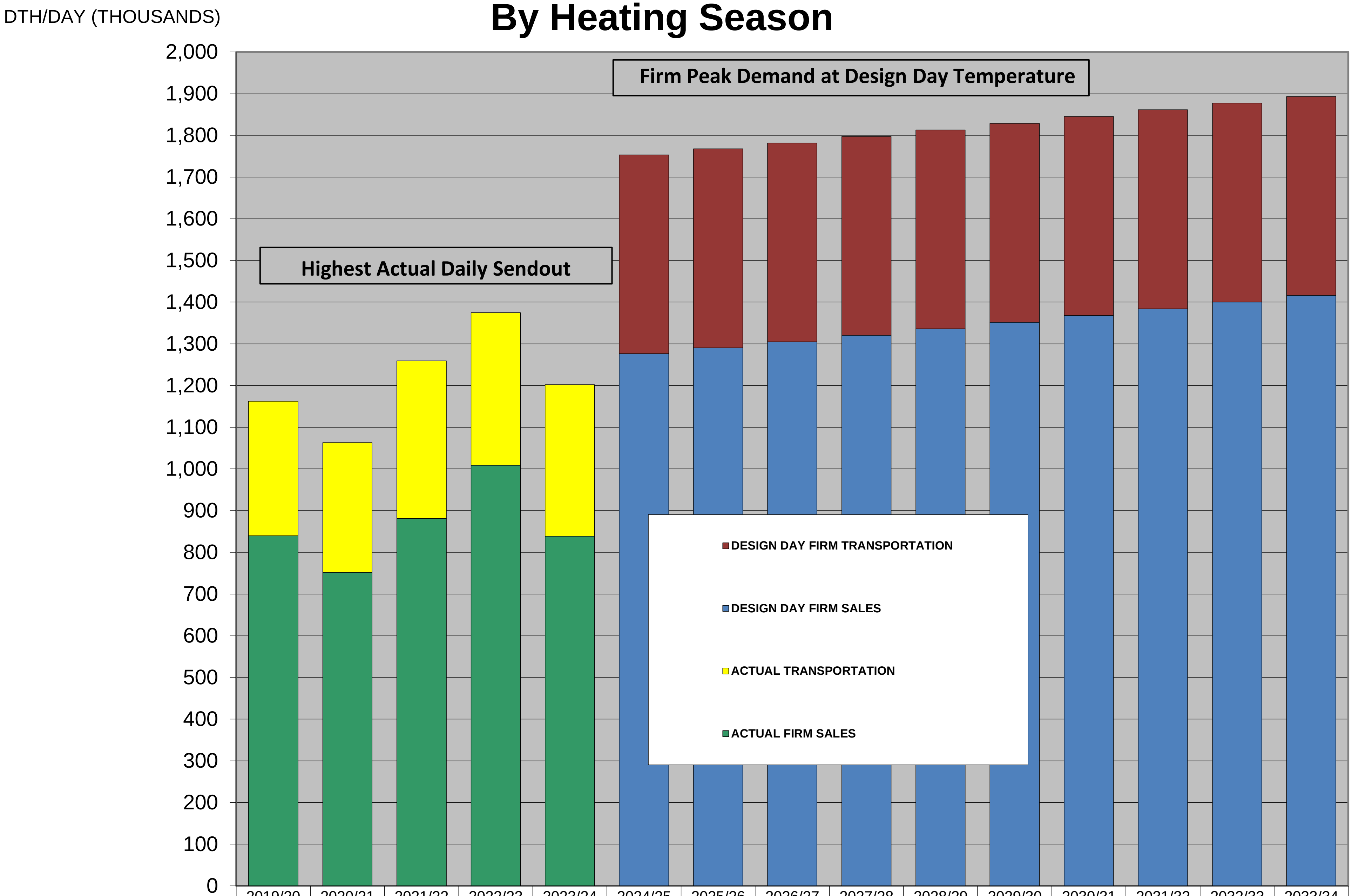


	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
LARGE COMMERCIAL DEMAND	19.2	19.0	19.4	20.6	19.5	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
INDUSTRIAL DEMAND	38.2	37.8	37.3	32.9	32.5	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
ELECTRIC GENERATION	40.2	46.6	52.1	54.8	52.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5

Exhibit 3.8

DESIGN PEAK-DAY DEMAND FORECAST

By Heating Season

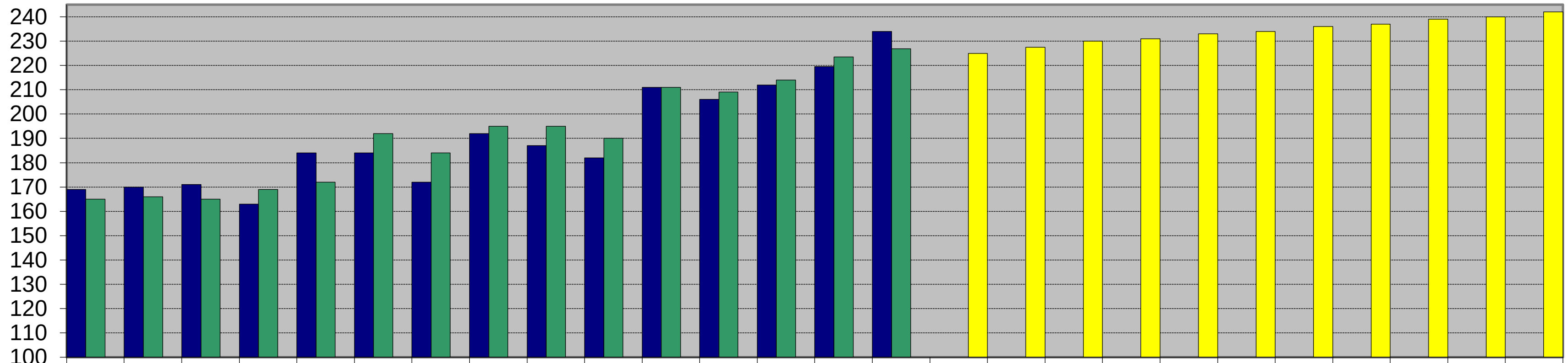


	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
DESIGN DAY FIRM TRANSPORTATION						477	477	477	477	477	477	477	477	477	477
DESIGN DAY FIRM SALES						1276	1291	1305	1321	1336	1352	1368	1384	1400	1416
ACTUAL TRANSPORTATION	323	311	378	366	364										
ACTUAL FIRM SALES	840	752	881	1009	839										

Exhibit 3.9

SYSTEM DTH THROUGHPUT

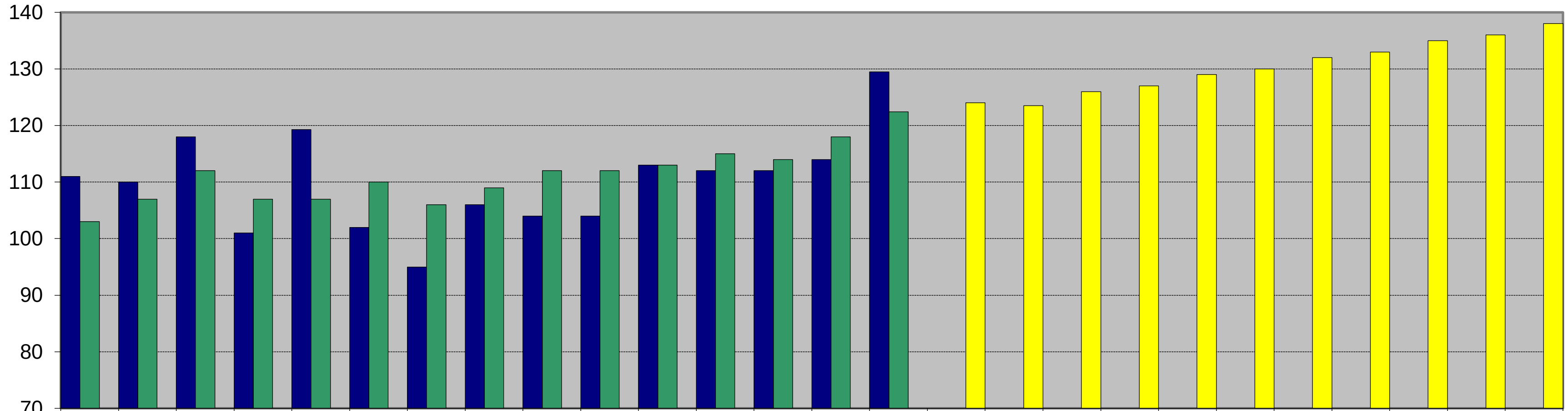
Dth (millions)



	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
ACTUAL	169	170	171	163	184	184	172	192	187	182	211	206	212	220	234											
TEMP ADJUSTED	165	166	165	169	172	192	184	195	195	190	211	209	214	224	227											
FORECAST																225	228	230	231	233	234	236	237	239	240	242

SYSTEM DTH SALES

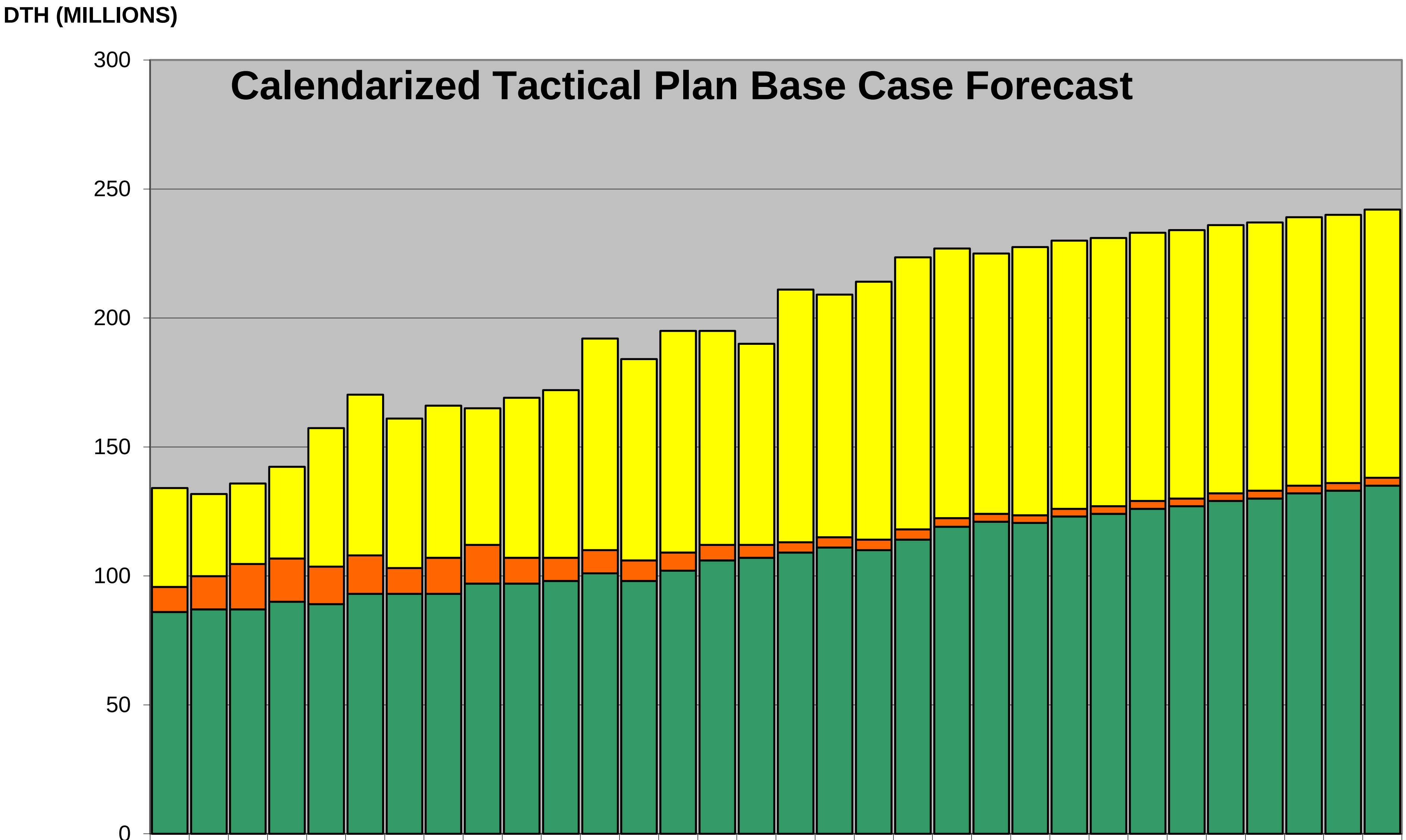
Dth (millions)



	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
ACTUAL	111	110	118	101	119	102	95	106	104	104	113	112	112	114	130											
TEMP ADJUSTED	103	107	112	107	107	110	106	109	112	112	113	115	114	118	122											
FORECAST																124	124	126	127	129	130	132	133	135	136	138

Exhibit 3.10

TEMP ADJUSTED THROUGHPUT



	03	04	05	06	07	08	09	10	11	12	13	14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21	21/ 22	22/ 23	23/ 24	24/ 25	25/ 26	26/ 27	27/ 28	28/ 29	29/ 30	30/ 31	31/ 32	32/ 33	33/ 34
TRANS	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	94	100	106	105	101	104	104	104	104	104	104	104	104	104	104
NON-GS SALES	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
SYSTEM GS	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	111	110	114	119	121	121	123	124	126	127	129	130	132	133	135

Exhibit 3.11

SYSTEM CAPABILITIES AND CONSTRAINTS

SYSTEM OVERVIEW

The Company's system currently consists of approximately 21,967 miles of distribution and transmission mains serving more than 1,201,212 customers. The system operates at pressures that range up to 1,000 psig and is separated into many subsystems in order to deliver the pressures and volumes that customers require. The Company builds system models annually to determine when and to what extent system improvements will be required. Figure 4.1 shows the Company's high-pressure (HP) system, its service area, connecting interstate pipelines, and adjacent producing basins.

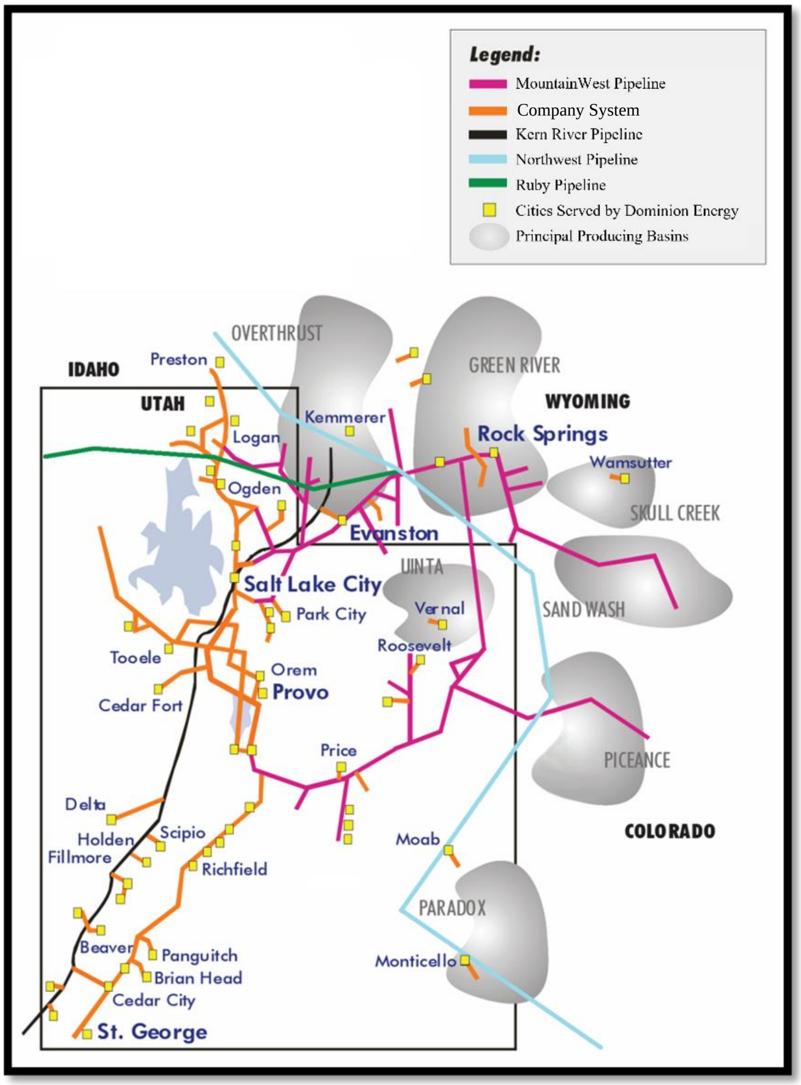


Figure 4.1: High Pressure System

ONGOING AND FUTURE SYSTEM ANALYSIS PROJECTS

Master Planning Models

The Company creates gas network analysis (GNA) master planning models to more accurately predict impacts of system growth. The models are created using global growth projections as well as anticipated growth from specific planned developments in each area. The benefit of using this data is that the resulting system pressures will reflect the impact of the specific growth centers and provide improved projections of system impacts during a peak event.

System Supply and Firm Peaking Analysis (FPA)

The Company analyzes its gas supply contracts each year to determine if they will meet the coming year's demands. The Company carefully considers the upstream (interstate transmission pipelines) constraints and capabilities as well as the ability to acquire gas to deliver to its system on a Design Day. The purpose of this analysis is to determine the amount of gas required on a Design Day, and if the current contracts (sales and transportation) facilitate this required delivery.

In previous years, the Company and MountainWest Pipeline (MWP) have worked together each year to update a Joint Operations Agreement (JOA) as part of this analysis. The JOA included details regarding the pressures and flows available at the jointly operated gate stations, as well as operational and facilities responsibilities. One objective of this agreement was to ensure that the Company receives adequate inlet pressures to these stations in order to maintain system reliability. This complicated process requires detailed collaboration because the flows at these stations fluctuate through the day to match the changing demands on the Company's system. While the Company is currently focusing on a new interconnect agreement to replace the JOA moving forward, the system supply and firm peaking analysis which is completed annually between the two companies will remain the same.

Updating the details regarding the pressures and flows available at the jointly operated gate stations is a necessary practice for ensuring customers receive safe and reliable service. The Company's transportation contracts with MWP permit delivery to multiple gate stations. As a result, the Company enjoys a great deal of flexibility. However, because each gate station delivers supply to the system at different pressures, engineering analysis is required to ensure that pressures and flows across the system are balanced, that the operation of that system does not cause deliveries to exceed contractual maximums, and that gas is flowing at adequate operational system pressures on a Design Day. The Company need not engage in such analysis with other pipelines because those entities do not have such a complex network of interconnects with the Company's system, and contracts for each interconnect are more limited and rigid.

MWP and the Company have engaged in the FPA process consistently for several years, including for the 2024-2025 heating season. The Company is working with MWP on an interconnect agreement to ensure a similar process is performed annually into the future.

Interruption Analysis

A number of customers on the Company's system have chosen to purchase interruptible service and to thereby utilize any available system capacity. Because the Company's system is not designed to provide continuous service for these customers, and because these customers use system capacity on an "as available" basis, it is important to understand the temperatures at which an interruption could become more likely to occur. Accordingly, the Company performs an annual interruption analysis. The interruption analysis divides the system into interruption zones and estimates the Zone Monitoring Temperature (ZMT), or the temperature at which each zone is likely to experience curtailment of interruptible customers in order to ensure reliable service to the surrounding firm service customers. The recent interruption analysis ZMTs for the HP interruption zones are shown below in Table 4.1.

Table 4.1: HP Interruption Zone Information

Zone Code	Location Description	2023 ZMT (°F)
HP-CARB	Carbon County, UT	-9
HP-CEDA	Garfield, Iron, & Northwestern Washington Counties, UT	-7
HP-CENT	Southern Salt Lake & Utah Counties, UT	-6
HP-EVAN	Uinta County, WY	-25
HP-GRAN	Grand County, UT	1
HP-MIDC	Davis, Northern Salt Lake, & Southern Weber Counties, UT	-6
HP-MILL	Juab & Millard Counties, UT	-7
HP-MORG	Morgan County, UT	-15
HP-NORT	Eastern Box Elder, Cache, & Northern Weber Counties, UT; Franklin County, ID	10
HP-SSPG[48]	Sanpete, Sevier, Piute, & Garfield Counties UT	-11
HP-STGE	St George, UT (majority of Washington County)	22
HP-SUMM	Summit County, UT	-13
HP-SWEE	Sweetwater County, WY	-25
HP-UINT	Uintah County, UT	-21
HP-WASA	Wasatch County, UT	-5
HP-WEST	Western Box Elder & Tooele Counties, UT	-6

Operational Models

The Company prepares for planned maintenance and construction work as well as unforeseen events that impact system capabilities by developing and maintaining operational models of the system. The Company maintains these models to represent current conditions that exist in the system. The Company's engineers review these models on an ongoing basis with the Company's Gas Control, Gas Supply, Marketing, Operations,

[48] HP-SSPG was formerly named HP-FILL and was changed this year to better reflect the location and reduce potential ambiguities.

and Measurement and Control departments in order to inform them of expected system conditions.

SYSTEM MODELING AND REINFORCEMENT

The Company utilizes steady-state Intermediate High Pressure (IHP) gas network computer models to determine the required system improvements needed to maintain required operational pressures throughout the distribution system. The Company uses these models to identify the required locations and sizing of new mains and/or regulator stations. The Company also uses the models to compare the required flow from the regulator stations to the maximum delivery capacity of the existing regulator stations. This analysis provides the Company with the information necessary to determine which reinforcements the Company should construct each year. Based on the modeling results, the Company constructs a number of IHP mains, new regulator stations, and upgrades to existing regulator stations.

The HP system models have more variables than the IHP system models and are also used to design for customer demand and growth. Engineers consider gate station capacities, existing supply contracts, supply availability, line pack and the piping system in conducting HP analysis. Because HP projects typically take longer to complete than IHP projects, the Company must identify the need for HP improvements earlier than would be required for IHP projects. The Company and the interstate pipeline companies that supply its system collaborate to identify potential constraints to ensure that the Company's supply needs can be met.

MODEL VERIFICATION

The Company verifies the accuracy of the steady-state (24-hour period) GNA models using recorded pressure data and calculated demands. The Company's engineers built steady-state models to represent the system conditions that were present on Tuesday, January 16, 2024, using actual data from that day. Model settings were adjusted to match the actual temperatures and other conditions for this day. The model pressures were compared to actual pressures at 420 verification points. Each of these points were found to be within 7% of the actual pressures on that day. Four hundred sixteen of the pressures in the verification model were within 5% of the actual pressure. Based on this analysis, the Company has determined that the loads and infrastructure utilized in the GNA models are accurate, and that the Company can rely upon the models for their intended purpose.

The Company verifies the unsteady-state (hourly results for a 24-hour period) models in the same manner as the steady-state models. The temperatures and the gate station flows and pressures are matched as closely as possible. The Central and Northern Regions are the largest of the Company's connected HP systems with ten gate stations and two primary maximum allowable operating pressure (MAOP) zones. There are other smaller isolated systems which also require unsteady-state model analysis included in the results (Figures 4.3 – 4.8). The unsteady-state model minimum pressures were found to be within 7% of the actual minimum pressures at four hundred twenty verification points on that day. Four hundred fourteen of the pressures in the verification model were within 5% of the actual pressure. The results of these comparisons confirm the accuracy of the unsteady-state models.

GATE STATION FLOWS VS. CAPACITY

The Company's system models must accurately emulate the physical pressure and flow limitations of each specific station. To ensure this, The Company completes a capacity review each year for each of the gate stations on the system. The Company calculates hourly and daily flow capacities for each station based on facility limitations, set pressures, and inlet pressures provided by the upstream pipelines. Some stations have specific minimum pressures based on contractual volumes. Other stations have fluctuating inlet pressures based on the changing flow on the Company's system. For the stations with changing inlet pressures, this analysis was based on the inlet pressures included in the update to the FPA.

Table 4.2 shows a list of gate stations with an expected maximum Design Day flow rate greater than 5 MMcfd in descending order in terms of percent utilization. Some gate stations are at or near 100% utilization while others have a wider margin. When a station reaches 80% utilization, further analysis is carried out to estimate when it should be upgraded based on expected system growth rates, system interconnectivity, and downstream takeaway. If the in-depth review supports a near-term upgrade, the Company schedules the work. If a station operates above 80% utilization but does not require an upgrade within 5 years, the Company's engineering department will conduct the in-depth review for that station each year until it requires upgrade or replacement.

Table 4.2: FPA Gate Stations Nearing Capacity (in descending order)

Station	2024-2025 Max Flow (MMcfd)	Station Capacity (MMcfd)	% Utilization
Central Tap	57.9	57.9	100%
Riverton	192.7	200.0	96%
Evanston South	8.1	8.8	92%
Rockport	14.9	16.7	89%
Sunset	80.0	92.8	86%
Dog Valley	5.8	6.9	84%
Hunter Park	320.0	400.0	80%
Hyrum	206.6	262.0	79%
Kanda	11.0	14.0	79%
Porter Lane	103.0	136.7	75%
Payson (FL26)	232.0	320.3	72%
Bluebell (Vernal)	7.1	10.0	71%
Green River Border	5.6	7.9	71%
Jeremy Ranch	20.0	28.7	70%
Wecco	22.5	32.6	69%
Mountain Green	8.4	13.0	64%
Saratoga Tap	137.8	219.0	63%
Little Mountain (FL4)	147.0	238.0	62%
Ioka Lane	5.1	8.4	60%
Payson (FL42)	41.5	70.0	59%
Island Park	7.4	12.8	58%
Promontory	49.4	89.4	55%
Westport	19.7	36.2	54%
Gordon Creek	11.1	22.1	50%

Station	2024-2025 Max Flow (MMcfd)	Station Capacity (MMcfd)	% Utilization
Central Tap	57.9	57.9	100%
Little Mountain (FL21)	125.0	272.0	46%
Eagle Mountain	8.5	25.4	33%
Rock Springs Foothill Dr	10.9	40.0	27%
Rose Park	105.0	400.0	26%

The Central Tap is currently listed at full utilization, but its capacity can increase dynamically depending on its compressor's available suction and desired discharge pressures. Due to the smaller diameter size of FL 81, which is downstream of the compressor, a higher discharge pressure of up to 1,000 psig is required to deliver required volumes against pressure losses along FL 81. As the Southern Expansion project adds larger diameter pipe parallel to FL 81, this problem will be resolved and the higher discharge pressures from the compressor will no longer be needed. This will effectively raise the capacity of the Central Tap. Further details regarding the Southern Expansion project are provided in the Distribution Action Plan.

The Riverton gate station has been operating at or near capacity for almost a decade. It currently does not require a capacity upgrade due to other nearby gate stations with adequate capacity which also supply gas into the same HP system.

The Evanston South, Rockport, Sunset, and Dog Valley gate stations are also at or above 80% utilization. However, the Evanston South station is not expected to require an upgrade within the next 5 years due to the low growth rates. The Dog Valley station is in the process of being upgraded in order to meet increasing demand requirements of a customer in the area.

The Rockport gate station is a MWP station. The Company is currently conducting analysis to determine the capacity it requires at the Rockport gate station and working with MWP to ensure that the station upgrade is completed. The Company expects that MWP will upgrade the station in 2026 or 2027.

The Sunset gate station capacity is limited not by the facility, but due to upstream limitations on MWP's system. Thus, upgrading the Sunset gate station will have little effect if the upstream capacity constraints are not addressed. As a result, additional capacity to serve the area will need to come from other stations serving the area.

The Northern HP system continues to grow. The addition of the Kern River Gas Transmission (KRGT) Rose Park gate station, three years ago, improves the ability to supply additional firm gas to the Wasatch Front. While new gas supply options are limited along the northern end of the Wasatch Front, one additional option would be to construct a Ruby Pipeline tap near Brigham City, which is discussed later. The Company will continue to monitor the available gas supply to this area.

The Saratoga Tap requires a remodel to meet growing demand. Saratoga Springs, Lehi, and Eagle Mountain are some of the fastest growing communities in the Company's service territory. The Saratoga gate station is designed to serve these communities. The Saratoga gate station, while not at capacity on a Design Day, requires a remodel due to operational concerns. Therefore, the Company will upgrade this station by 2026. This project is discussed in greater detail in the Distribution Action Plan section of this report.

SYSTEM PRESSURES

Once the Company verifies the GNA models and properly sets contractual obligations and station capacities, it uses the models to analyze the gas distribution system to verify that it has adequate pressures in order to supply customers. The Company uses Design Day models for this analysis. Design Day models include firm loads for sales and transport customers. The Company uses the daily contract limits for applicable customers and assumes that interruptible demands are curtailed during the Design Day.

Northern

The Northern Region includes the distribution system throughout Salt Lake City and northern Utah, including Box Elder, Cache, Davis, Morgan, Salt Lake, Summit, Tooele, Utah, Wasatch, and Weber counties. The Company serves this region through interconnects with MWP at Meter Allocation Point (MAP) 164 using the Hyrum, Little Mountain, Payson, Porter's Lane, and Sunset stations. The Company also serves the region through Payson gate station from MWP's Main Line 104 (MAP 332), multiple smaller taps from MWP (MAP 162) and KRGT at Eagle Mountain, Lake Side, Hunter Park, Riverton, Westport, and Rose Park gate stations.

In the steady-state model, the calculated low point in the main portion of the northern system is 205 psig, in Orem. The lowest steady-state pressure in the Summit/Wasatch system is in Woodland, which is 282 psig. These pressures remain higher than the Company's minimum allowable design pressure of 125 psig.

The steady-state pressures at some of the key locations in the Company's system are shown in Table 4.3

The locations on the system are shown in Figure 4.2. The Company models these pressures on a Design Day at system endpoints and low points in the area and important intersections. The Company builds steady-state models using average daily flows that most closely represent average pressures for the Design Day. The unsteady-state GNA models profile demands throughout the day and represent the pressure fluctuations throughout the Design Day.

Table 4.3: High Pressure System Steady-State Design Day Pressures

Location	Pressure (psig)
Endpoint of FL 29 – Plymouth	255
Endpoint of FL 36 – West Jordan	273
Endpoint of FL 48 – Stockton	303
Endpoint of FL 51 – Plain City	283
Endpoint of FL 54 – Park City	347
Endpoint of FL 62 – Alta	258
Endpoint of FL 63 – West Desert	303
Endpoint of FL 70 – Promontory	253
Endpoint of FL 74 – Preston	248
Endpoint of FL 106 – Bear River City	277
Intersection of FL 29 & FL 127 – Brigham City	336

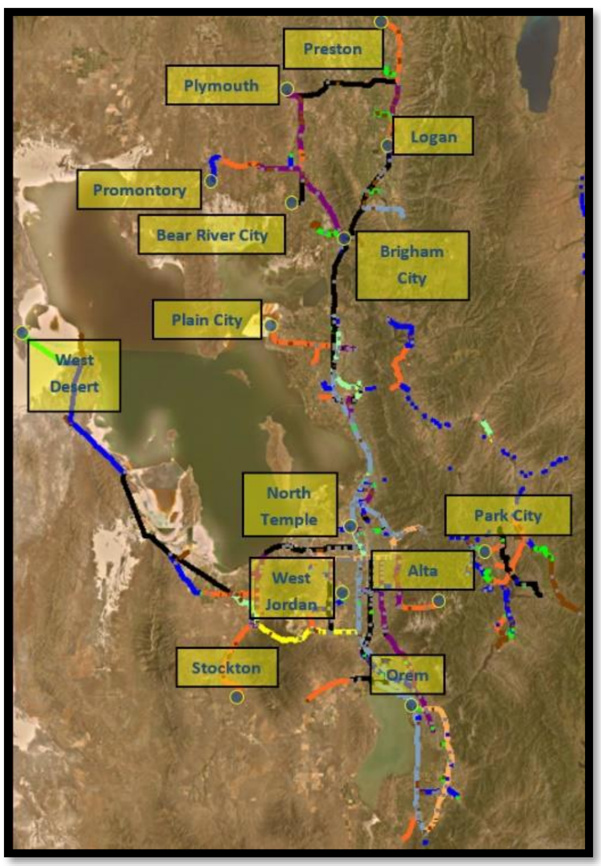


Figure 4.2: Northern Region Key Pressure Locations

The curves shown in, Figure 4.3, Figure 4.4, and Figure 4.5 are the expected Design Day pressures for the Northern Region HP system. In the projected unsteady-state models, the low point in the Northern Region is Orem at 165 psig. The lowest predicted pressure in the Summit/Wasatch subsystem is at the Woodland regulator station with 193 psig during the peak hour of Design Day. In the HP system north of the Flyer Way station, the minimum pressure occurs at Preston with a minimum pressure of 178 psig.

Feeder Line (FL) 13 currently supplies gas between Magna and Salt Lake City and is currently being replaced as part of the Feeder Line replacement program. FL 13 is planned to have an MAOP of 720 psig and be a part of the Company's 720 psig corridor when completed. Last year, a HP station was installed on the east end of FL 13 to facilitate the MAOP zone's operability. FL 13 and this project will be discussed in greater detail in the Distribution Action Plan section of this report.

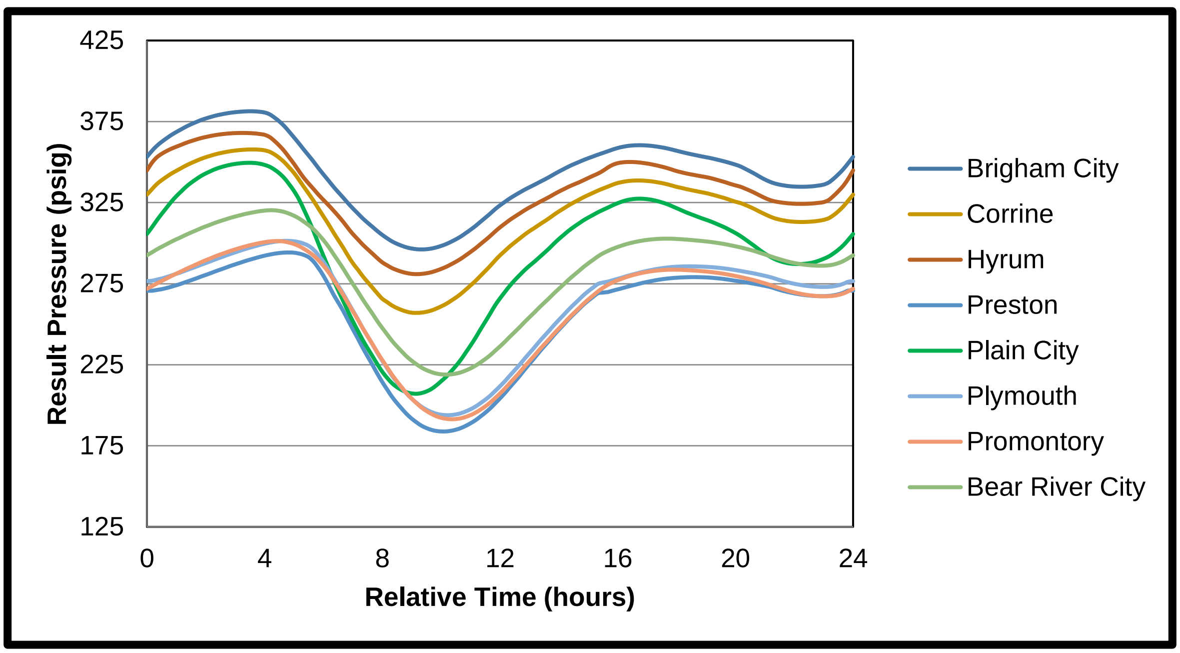


Figure 4.3: 2024-2025 Northern Unsteady-State Design Day Pressures (North of Flyer Way)

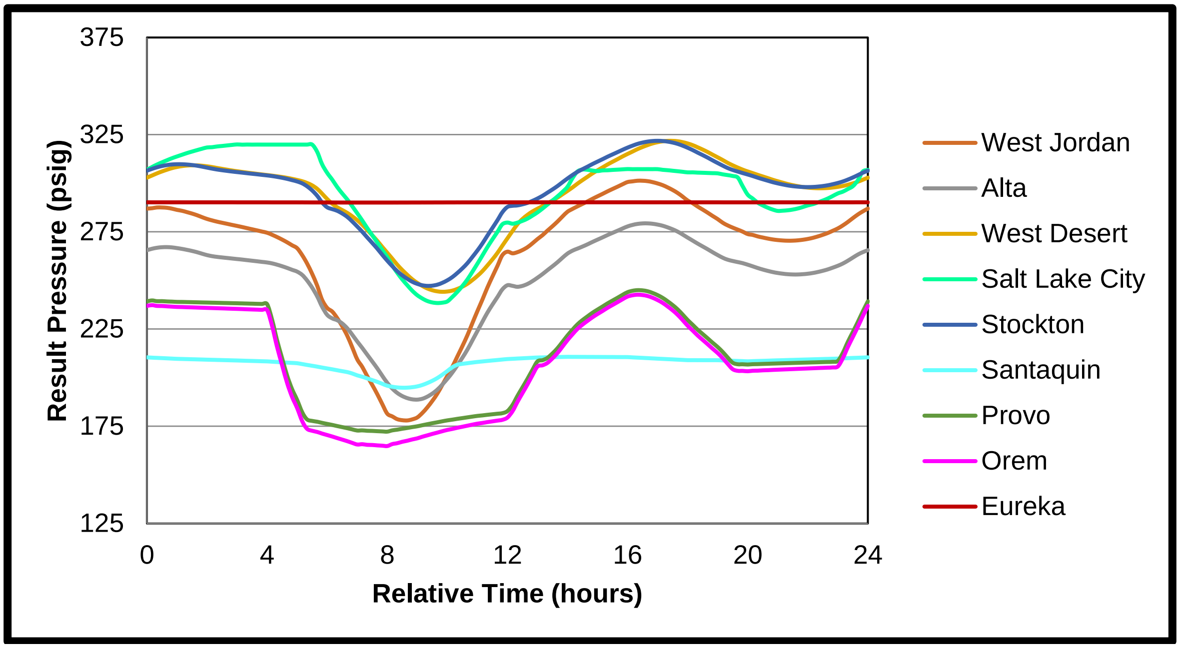


Figure 4.4: 2024-2025 Northern Unsteady-State Design Day Pressures (South of Flyer Way)

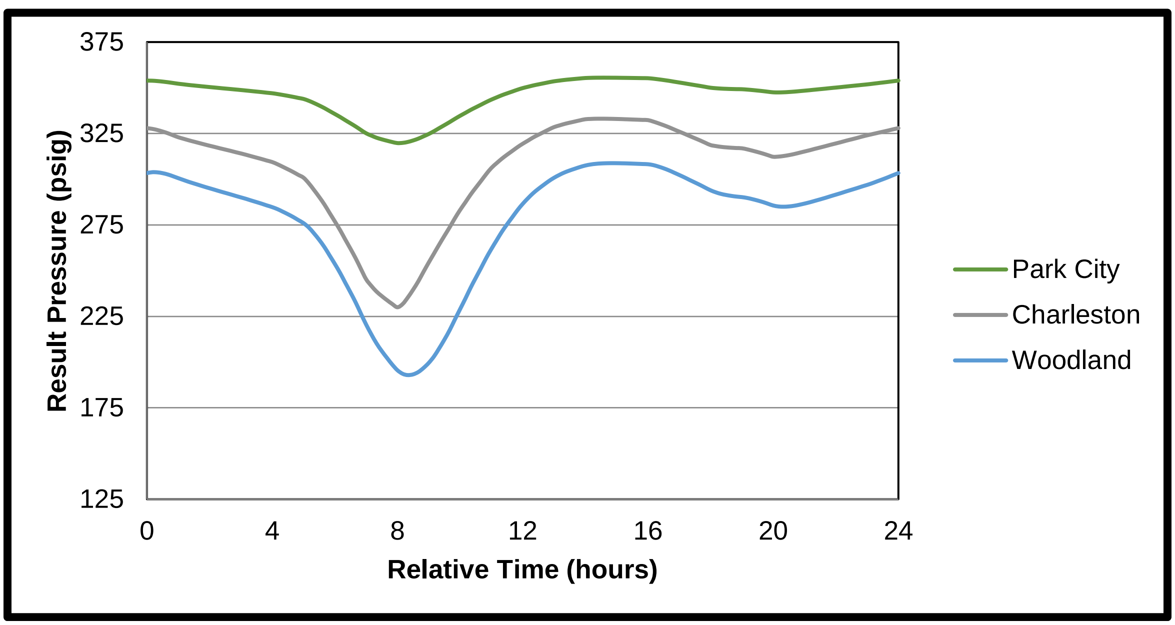


Figure 4.5: 2024-2025 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)

Eastern (North)

The Eastern (North) Region includes Duchesne, Uintah, Carbon, and Emery counties, including the cities of Price and Vernal. The Vernal area is served from MWP by two gate stations through MAP 456 and MAP 334. Minimum pressures in the Vernal system reach a minimum of 197 psig at West Vernal.

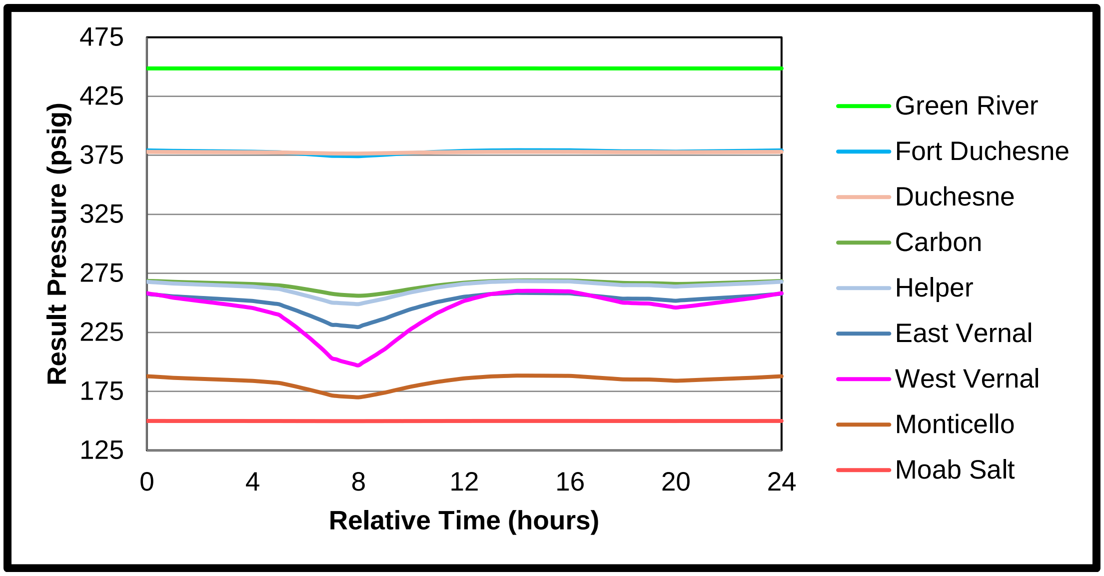


Figure 4.6: 2024-2025 Eastern (North) Unsteady-State Design-Day Pressures

Eastern (Northwest Pipeline)

The Eastern (Northwest Pipeline) Region includes the cities of Moab, Monticello and Dutch John. The Company serves these areas from Northwest Pipeline with three stations in Moab, one of which is the new station to Green River, one station in Monticello, and one station in Dutch John.

The system in this area is comprised of separate subsystems with individual gate stations connected to Northwest Pipeline. All of the segments in this area have adequate pressures, and mostly do not require any improvements to meet the demand for the 2024-2025 heating season. The Monticello gate station will require an upgrade in 2024 to continue to provide gas supply to the downstream system. This project is further discussed in the Distribution Action Plan section of this report. Another project that will eventually be required, is an upgrade of Northwest Pipeline facilities at MO0001 in Moab to increase station capacity. Discussions are currently underway with Northwest Pipeline regarding timelines and potential costs. As the information becomes available, it will be added in the future to the Distribution Action Plan.

Southern (Main System)

The Southern (Main System) Region encompasses the areas served by the Indianola, Wecco and Central gate stations including Richfield, Cedar City, and St. George. The Company serves these areas from MWP at Indianola station through MAP 166 and from KRGT at Central and Wecco stations.

Using the unsteady-state model, the lowest modeled pressure on a Design Day is 340 psig in Brian Head. All segments in this area have adequate pressures, and do not require any improvement to meet the existing demand.

The Southern System will continue substantial upgrades in the next few years. The Company has been closely monitoring the Southern System growth since the Central Compressor station was installed. In order to maintain system growth, FL 81 will need to continue to be looped with 20-inch pipe (FL135) to increase gas flow from the Central tap to St. George as part of the Southern System Expansion. This project is described in greater detail in the Distribution Action Plan section of this report.

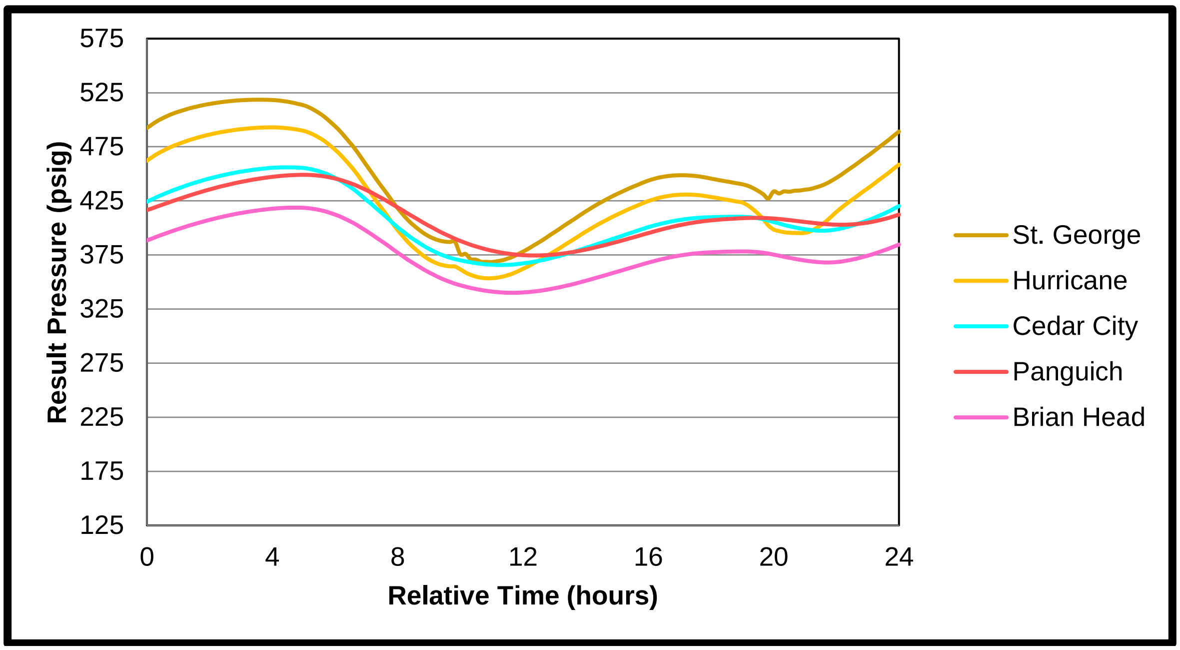


Figure 4.7: 2024-2025 Southern Unsteady-State Design Day Pressures

Southern (KRGT Taps)

The Southern Region includes towns in Juab, Millard, Beaver, Iron, and Washington counties. This includes all towns south of the Payson Gate Station that are not part of the Indianola/Wecco/Central system). These areas are all single feed systems served by KRGT.

The system in this area is comprised of separate subsystems with individual taps off KRGT. All segments in this area have adequate pressures and do not require any improvement to meet the existing demand.

Wyoming

The Wyoming Region includes Rock Springs, Evanston, Lyman, Kemmerer, Baggs, and Granger. The Company serves these areas from MWP through MAP 168, MAP 169, MAP 177, MAP 345, from CIG at Wamsutter and Rock Springs, and from Williams Field Services (WFS) at La Barge and Big Piney.

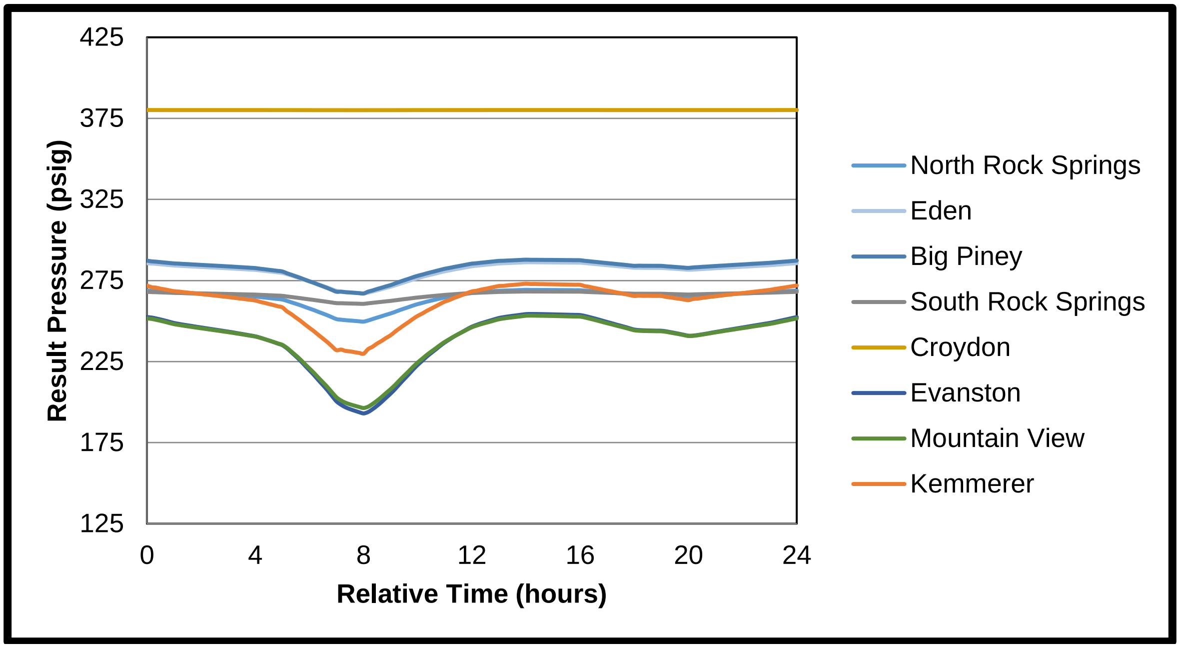


Figure 4.8: 2024-2025 Wyoming Unsteady-State Design Day Pressures

LONG-TERM PLANNING

The Company's modeled Design Day and customer growth for the past 5 years is shown in Table 4.4.

Table 4.4: Modeled historical total system design day growth and customer growth

	2020	2021	2022	2023	2024
Design Day Growth	2.5%	1.7%	1.7%	1.1%	1.3%
Customer Growth	2.3%	2.5%	2.6%	2.5%	1.9%

The average design day growth and customer growth per year over the past 5 years have been about 1.3% and 2.4%, respectively. Using long-term growth projections, it is expected that by 2060, the population across the Company's territory will have large net increases as shown in Table 4.5.

Table 4.5: Projected increases in population of top six counties by 2060 in descending order

County, State	Increase in Population by 2060
Utah, UT	574,000
Salt Lake, UT	423,000
Washington, UT	240,000
Davis, UT	195,000
Weber, UT	118,000
Cache, UT	76,000

With a steady customer demand and growth rate expected to continue, long term plans and options must be considered to maintain the existing and growing system. The Company is considering a number of methods to maintain the level of service with the increased demand as well as sustainability. The Company has identified a number of projects that could contribute to a long-term solution.

First, the Company is considering increasing the size of FL 85, that runs from the Saratoga KRGT gate station to the Central HP system, to increase supply. Doing so will increase the takeaway capacity downstream of the KRGT gate station at Saratoga Springs and will increase flows to the Central HP system. On the other end of FL 85, plans are in place to extend southward from Cedar Fort next year in order to support the west end of Eagle Mountain's booming growth as mentioned in the Distribution Action Plan section of this report.

The Company is also in the long-term design phase for extension of the 720 psig MAOP corridor from Vineyard (it's current termination point) to Hyrum. Replacement of FL 34 as part of the Feeder Line Replacement program will be designed and tested to establish a 720 psig MAOP but will not operate at that level until the corridor is complete. When complete, the 720 psig MAOP corridor will create a line-pack reservoir and will help offset upstream swings in deliverable pressures onto the Company's system. Establishing a 720 psig MAOP corridor is part of the Company's long-term plan. Establishing this corridor will require significant capital investment such as pipe replacement, in-line inspection facilities, heaters, pressure cut stations, etc.

In the long-term, the Company will require investment in upstream pipeline systems to increase capacity and supply availability to the Wasatch Front.

The Company is considering constructing a new Ruby Pipeline gate station near Brigham City. The Ruby Pipeline can be tapped in the future and could provide additional supply to the northernmost area of the Company's system. While this option has not been economically feasible in the past, it remains a potential option for the future.

The Company will continue to assess long-term challenges as they are discovered and will conduct analysis to identify options to address the challenges in future years. Long-term Supply Issues

Currently, the Company is able to buy enough supply to meet demand. As demand on the system continues to grow, the supply requirements of the system will also increase. The Company assumes that the local natural gas availability will continue to grow to meet demand. For example, MWP is currently working towards offering an additional 99,000 Dth/d of transport capacity at Payson station to be available in late 2027. There is currently enough potential production and transportation capacity to meet the demand. However, the Company is committed to following this situation as it progresses. As discussed in more detail in the Industry Overview section of this report, U.S. dry natural gas production is expected to continue to increase to record levels by the end of the year.

The Company is also continuing to assess the need for storage to manage supply. The Company is currently evaluating options for future storage needs based on cost savings and specific operational needs. These needs may change as demand increase. This is discussed in more detail in the Gathering, Transportation, and Storage section of this report.

Another important trend the Company will be following is the increased focus in the industry on sustainable supply. Producers are increasingly offering more sustainable products such as RSG, also called certified natural gas. As more production is certified and offered as RSG, this could reduce the availability of supply that is not certified. This is also a trend the Company will be following and reporting on in the Industry Overview section of this report.

SYSTEM CAPACITY CONCLUSIONS

The Company's HP system is capable of meeting the current Design Day demands. The Company bases this assessment on GNA modeling that indicates that the gate stations and feeder line systems have adequate capacity to meet average daily (on a Design Day) and peak hourly demands and the supply contracts are adequate. All system models show that pressures do not drop below the design minimum of 125 psig. As the Distribution System Action Plan section of this report discusses, the Company has plans to address any areas with projected pressures near the 125-psig minimum. The system will continue to grow along with the demand, and the Company will conduct an analysis annually and address concerns to ensure that the system continues to meet the Design Day needs.

In the Distribution Action Plan section of this IRP, the Company will discuss the following projects that are identified in this section:

- FL135, Central 20-inch Loop
- FL85 Extension
- Rockport Gate Station
- Saratoga (TG0005) Gate Station
- Monticello Gate Station (MZ0003)

DISTRIBUTION SYSTEM ACTION PLAN

The Company is currently planning, designing, and constructing several reinforcement and replacement projects on its system. The following is a brief description of the major planned projects for 2024 and beyond.

HIGH PRESSURE PROJECTS:

Station Projects:

1. WA1602 New FL 13 East HP Regulator Station, District Regulator Station, and In-Line Inspection (ILI) Facilities, Salt Lake City, UT: When the Company replaced FL 13 as part of the Feeder Line Replacement Program, it installed and tested FL 13 to establish an MAOP of 720 psig and to be part of the 720 psig MAOP corridor. This new station will separate the MAOP zones of FL 13 at 720 psig MAOP from the rest of the Central HP system which currently operates with a 354 psig MAOP. The site will still also include two in-line inspection (ILI) receiver barrels and one launcher barrel. This will allow for the required ILI inspections of FL 12 (both north and south of this location) and FL 13. The Company has acquired property on the SW corner of the 2100 S 900 W intersection in Salt Lake City, UT. Additionally, the site will house a new IHP regulator station with a gas heater.

   Feeder Line 13 currently extends only an additional 0.3 miles east of the Surplus Canal along 2100 S until it ends at the intersect with FL 12. The Company looked for property for the new end facility and FL 12/FL 13 crossover within a 0.5-mile radius of the existing crossover. FL 12 also runs through the property.

   The project design is complete and permitting finalized with South Salt Lake City at the end of 2023. The project started construction at the end of March 2024 and is currently in progress. The Company estimates the total cost of the regulator station project (including property acquisition) to be $2,800,000. The first-year revenue requirement is $330,120. The Company first discussed this project on page 5-3 of the 2021-2022 IRP.

2. WA1596 District Regulator Station, South Salt Lake City, UT: Construction on this project has started. This high-capacity regulator station will replace WA0866 in South Salt Lake City. The capacity of the existing station needs to be increased to support the growth in South Salt Lake near 3300 S and 300 W. The project is currently in the design stage and the Company is preparing the site for construction at 334 W Archard Drive. The 4-inch tap line for the new station will be approximately 1,000 lf and will extend from FL 4.

   In searching for property for the relocated regulator station, the Company approached several property owners within a half-mile radius of the existing regulator station. The selected location was the closest to the existing regulator station, available, and was competitively priced.

   The next best alternative to installing a replacement station would be retiring WA0866 and running over 2 miles of large diameter steel main (16-inch) that would connect this area to two other regulator stations. The cost would be in excess of $3,000,000. Additionally, the installation would be much more difficult as the alignment would nearly be entirely along 3300 south and would cross the I-15 corridor. Reliability and service quality of the system in a critical light-industrial manufacturing and commercial area of South Salt Lake would decrease due to the absence of WA1596/WA0866. These factors resulted in the current project selection.

The project started construction in April 2024 and is planned to complete in the summer of 2024. The Company estimates the total cost of the project (including acquiring the property) at $1,500,000. The first-year revenue requirement is $176,850. The Company first discussed this project on page 5-2 of the 2021-2022 IRP.

3. WA1617 – New Regulator Station on Sheep Lane, Grantsville, Utah: The area around the Utah Motorsports Campus is quickly growing, and numerous commercial customers are building facilities nearby. The existing IHP system is not adequate to provide natural gas service as the area grows. A developer in the area provided the Company with a parcel for a regulator station at a location proximate to its high-pressure facilities. The project includes installation of approximately 1-mile 8-inch tap line and the construction of a new district regulator station.

   The project started construction in March 2024 and is expected to complete in the summer of 2024 in conjunction with the installation of FL 147. The Company estimates that the project will cost $750,000 for the regulator station. The first-year revenue requirement is $86,250. The Company first discussed this project on page 5-2 of the 2023-2024 IRP.

4. MZ0003 – Remodel of Monticello Gate Station, Monticello, Utah: The existing equipment at MZ0003 has been identified as needing replacement due to inadequate odorization capacity, end of service life, and the need to improve reliability. Equipment to be replaced includes the meter, regulators, and odorizing equipment. Currently, the gate station is located within the Williams Northwest Pipeline property. To properly update and modernize the equipment, the project will require expanding the existing footprint of the site. To do so, the Company is working to purchase a new parcel adjacent to the Williams Northwest Pipeline property.

   The project is currently in late-stage design and the property has been purchased. The Company anticipates construction of this project to commence in the summer of 2024. Estimates for the remodel are $1,500,000. The first-year revenue requirements will be $171,750. The Company first discussed this project on page 5-3 of the 2023-2024 IRP.

5. EG0007 – Eagle Mountain District Regulator Station, near 4000 N and Hwy 73 in Eagle Mountain, UT: Growth between Highway 73 and Eagle Mountain is accelerating, requiring construction of a new IHP regulator station. Growth in the area includes large commercial and industrial customers. The IHP system was recently extended into the area but will not be able to sustain the growth long-term without additional capacity from a regulator station. The Company will need to acquire property for the station.

The property purchase was finalized at the end of 2023 and the project is currently finalizing design. The Company is targeting constructing the project in the summer of 2024. Estimates for the district regulator station are $750,000. The first-year revenue requirement is $88,425. The Company first discussed this project on page 5-5 of the 2021-2022 IRP.

6. MO0001 and MO0003 – Gate Station and District Regulator Station Remodel in Moab, UT: Moab and the surrounding area is growing rapidly. The existing property contains both the gate station (MO0001) and the district regulator station (MO0003) and is large enough to accommodate the remodel of both. Growth in the surrounding area means additional capacity is required for the distribution system. This will require that both the gate station and district regulator station are remodeled to increase capacity. The gate station will not only be able to supply the adjacent district regulator station with more capacity but will offer additional flexibility along FL 97 in moving gas through Moab.

   The project is currently under construction and is anticipated to be finished in the Fall of 2024. The Company estimates this project at $1,250,000. The first-year revenue requirement is $143,125. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

7. WA1604 – Replace WA0441, West Valley City, UT: WA0441 was installed in 1973. Given its age, and the increasing gas demand in the area it serves, it requires replacement. WA0441 is currently located on the side of the road in public utility easement (PUE) and cannot be expanded in its current location (1300 W and Meadow Brook Parkway).

   The Company is currently in the process of finalizing a property purchase along the Meadow Brook Parkway on the east and west sides of the river. The project is currently in preliminary design and expected to be constructed in 2025. The Company estimates the cost of property and construction at approximately $1,000,000. The first-year revenue requirement is $117,900. The Company first discussed this project on page 5-5 of the 2022-2023 IRP.

8. Black Desert Station in Ivins, UT: Due to significant construction ongoing in the Ivins and Santa Clara area, additional capacity is required for the distribution system to continue supporting the growth in the area. The Company was able to work with developers in the area to secure property for the future station, which will place it directly to the developing area that will need the capacity the most in the near future. FL 071 is also immediately adjacent to chosen property and the station will only require a short tap line which will minimize costs.

   The project is currently in the design phase. The Washington County area also has an extensive permitting process for utility stations and the project is currently in the review phase for approval. Construction is anticipated to start early 2025. This is possible due to the extended construction season in Southern Utah. The Company estimates the cost of the project at $1,000,000. The first-year revenue requirement is $117,900. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

9. AF0014 – New District Regulator Station West of I-15 in American Fork, UT: The area between Utah Lake and I-15 in American Fork is not only growing quickly but is a somewhat isolated IHP distribution system due to the freeway and railway in the area. Because of this isolation from the larger system, a district regulator station is required in the area to sustain the existing growth. The Company is in talks with several property owners with locations next to FL 104. If successful in these negotiations, this would minimize any need for lengthy tap lines or feeder line extensions.

   The project is currently in the planning phase while property is secured. Construction is anticipated to begin in the spring of 2025. The Company estimates the cost of the project at $850,000. The first-year revenue requirement is $97,325. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

10. New District Regulator Station in the Northwest Quadrant (Inland Port) of Salt Lake City, UT: The Inland Port continues to develop, and the newest developments are near 700 N and 8000 W. This location is currently served by the IHP system but there is not enough capacity to sustain additional growth. The nearest regulator station is over a mile away and already nearing capacity due to other load growth in the area. In order to continue serving the growing area, a new station will need to be installed. Additionally, at least a 1-mile FL extension will be required which will extend into the area. The Company is currently in talks with the developers to secure a station property in the heart of the development.

    The project is in the planning stages pending the finalization of acquiring property in the area. Construction is anticipated to start in the summer of 2025. The Company estimates the cost of the station project at $850,000. The first-year revenue requirement is $97,325. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

11. South Bluffdale District Regulator Station, Bluffdale, Utah: As the Bluffdale area continues to grow, the Company's IHP distribution system has extended southward. Currently, the Company's IHP system is served by regulator stations located in the north end of Bluffdale. The Company's system planning models show that IHP pressures will decline to below 25 psig in the near future at the anticipated current growth rate. To avoid this, the Company must construct a new IHP regulator station closer to the load center in order to maintain reliable operational pressures to the area. Constructing additional IHP main or upsizing current IHP main is not a viable solution for resolving the future low-pressure concerns in this area.

    The Company is identifying available property and will be analyzing different routes in the near future. Based on development rates and load growth, the Company anticipates construction of this project to commence in 2025. As the Company establishes viable route options and refines the cost estimate, it will provide updates as part of the IRP variance report process. Current estimates for the regulator station, including property, are $750,000. The first-year revenue requirement is $88,425. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

12. SY0002 Syracuse District Regulator Station, Syracuse, Utah: This regulator station is required to meet the residential growth in the west side of Davis County. Due to growth, the IHP system continues to be extended away from existing regulator stations. This has limited the capability of the existing regulator stations ability to effectively serve the IHP system in this area. SY0002 will provide an additional source of supply and increase pressure in this area of growth. The Company has evaluated increasing the diameter of the IHP piping in the area but determined that construction of a new regulator station as the most viable solution to resolve low IHP pressures in the area. The Company purchased property at 2700 S 3000 W, Syracuse, UT for this project. FL 47 will be extended from SY0001 to supply the new regulator station.

    The project was split into phases during 2022 due to conflicts with city and Utah Department of Transportation (UDOT) projects and moratoriums. Approximately 5,800 lf was installed in 2022-2023 from SY0001 to a location for a temporary station to support the IHP system through future heating seasons until the project can be completed. Phase 2 will be the balance of the project, approximately 8,400 lf and the SY0002 station.

    The station design is complete, and construction will commence upon completion of the associated feeder line construction. The feeder line has been delayed due to roadway moratorium and other conflicts. The Company estimates that the regulator station will cost $750,000. The feeder line extension to serve the regulator station will be discussed below. The Company plans to begin construction by July 2026. The first-year revenue requirement will be $85,875. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

13. St. George – River Road District Regulator Station, St George, Utah: The area of St. George between the Southern Parkway and Enterprise Drive is growing quickly and the system needs additional capacity to support that growth. In order to serve this area, the Company must extend its HP system approximately 2 miles south from the current GE0017 station located near Venture Drive and River Road and install a full capacity IHP regulator station. A property has not yet been procured. As more information becomes available the Company will provide updates to the future IRP or variance reports.

    The project is still in the planning phase, awaiting finalization of a property purchase. At this time, the Company anticipates commencing construction in 2026, if property is procured in an appropriate timeframe. The Company estimates the total cost of the regulator station project (including property acquisition) to be $750,000. The first-year revenue requirement is $88,425. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

14. Rockport Gate Station, Park City, UT: Due to the continual development of the Park City/Heber areas, additional capacity is needed in the HP system. In particular, the Rockport area has been identified as an area that requires additional capacity to meet the growing gas demand in the area. The company is conducting an analysis to determine the required capacity of the remodeled Rockport Gate Station. This project is still in the early planning phase and is tentatively planned for construction in 2026

or 2027 . The Company will provide an update on the project scope and costs in a future IRP as they become available. The Company first discussed this project on page 5-4 of the 2022-2023 IRP.

15. SL0114 Remodel, Salt Lake City, UT: SL0114, located approximately 200 S and 1300 E in Salt Lake City, UT, is the only full-size IHP regulator station that is located near the downtown area of Salt Lake City. As such, it plays a vital role is supporting the Company's IHP Belt Line System. SL0114 was originally installed in 1967 and, although it has undergone some updates, it now needs to be completely remodeled. The Company has been searching for property to expand the site but has thus far been unsuccessful. Expansion would simplify the design and construction of this station, due to its increased size and capacity. If expansion is not possible, the Company will attempt to produce a design to remodel the regulator station on the existing footprint. This design will require extensive shoring, and likely multiple floors within the footprint. This decision on the best path forward will be made during 2024.

    This project is in the early planning phases and the Company is targeting construction in 2026. The Company will provide an update on the project scope and costs in a future IRP as they become available. The Company first discussed this project on page 5-5 of the 2022-2023 IRP.

16. TG0005, Saratoga KRGT Gate Station, Saratoga Springs, Utah: This station is a major gate station with KRGT and delivers gas into FL 85, FL 112, and FL 116. Gas from this gate station serves some of the fastest-growing communities in the Company's service territory, including Lehi, Eagle Mountain, and Saratoga Springs. Though the Saratoga Gate Station is not at full capacity on a Design Day, it requires a remodel to reinforce the overpressure protection, to improve gas measurement and flow control, and to serve the anticipated capacity demands from the quickly growing area. Currently, the gate station has a capacity of 220 MMcfd, and preliminary analysis from the Company's System Planning department suggests that the remodel should include an increase of 100 MMcfd.

    This project is currently in the planning stage. The Company is considering expanding at the existing site and discussions are ongoing with KRGT on costs to increase the existing gate station footprint and provide additional capacity. The Company anticipates constructing this facility in 2026 or 2027. Total project costs are estimated to be at least $5,000,000 depending on the most feasible method of increasing supply from KRGT. Based on this estimate, the first-year revenue requirement will be at least $589,500. The Company first discussed this project on page 5-3 of the 2019-2020 IRP.

    One alternative would involve constructing a new KRGT gate station somewhere along the KRGT pipeline closer to the load center. The Company estimates a new gate station at KRGT, with a design load of 100 MMcfd, would have an estimated cost of approximately $15,000,000+. Additional project costs to construct a feeder line extension from the new gate station to the Company's current high-pressure system (similar scope and cost to alternative one) would prevent this project option from being cost competitive with the selected option discussed above.

17. Salem District Regulator Station, Salem, UT: Southern Utah County continues to grow quickly. Salem is growing towards the east and away from the existing stations supplying the system. To maintain the desired pressures and capacities in the area, the need for an additional regulator station has been identified. The Company is currently working with developers on the east side of the city to secure a property that will help support the expanded IHP system.

    The project is currently in the early planning phase. The anticipated location of the station is about ¾ of a mile away from FL 026, depending on the property. Construction is anticipated for the summer of 2026. The Company estimates the cost of the station project at $850,000. The first-year revenue requirement is $97,325. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

18. Payson District Regulator Station to the West of I-15, Payson, UT: The west side of Payson is growing and specifically the industrial park area is requiring additional natural gas as companies come into the area. I-15 is a natural barrier to the IHP system and district regulator stations are in the area to support the continued growth. Several IHP projects have brought more capacity from the east side into the area but will no longer be sufficient in the near future. The company is looking for property along FL 114 to minimize any FL extension required to support the station.

    The project is currently in the early planning phase. Construction is anticipated to begin in the summer of 2026. The Company estimates the cost of the project at $1,000,000. The first-year revenue requirement is $114,500. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

19. EG0001 – Eagle Mountain Gate Station Remodel, Eagle Mountain, UT: Eagle Mountain is one of the fastest growing cities in the Company’s footprint. Along with residential growth, there is a large industrial area that has started to be developed also promoted by the EDCU. The Company is continually evaluating the area to determine how best to support and be ahead of growth in the area. This evaluation showed that remodeling EG0001, the gate station at the south end of Eagle Mountain and FL 116 needed to be remodeled to increase capacity coming into FL 116, and support other long-term plans of supplying new feeder lines into the area.

    The project is in the early planning phases and the existing property is being evaluated for supporting the future remodel. Construction is targeted for 2027 or 2028. The Company will provide an update on the project scope and costs in a future IRP as they become available. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

20. Hurricane District Regulator Station, Hurricane, UT: The areas to the south of the City of Hurricane continue to grow and expand, requiring the Company’s system to extend accordingly. Currently there are no regulator stations in the area near 3000 South and Sand Hollow Road. The existing capacity in the area is not sufficient to meet anticipated growth, and the Company needs to construct an IHP regulator station to reinforce existing system pressures. Existing pressures in the area are projected to drop below 25 psig if current growth rates continue into 2026.

The Company is identifying available property for the regulator station and analyzing different routes for the HP extension. Unfortunately, UDOT and area property owners are engaged in litigation about property rights, and this dispute is complicating the Company's ability to secure the property rights required to construct the facilities. Based on the current development rates, the Company anticipates construction of this project to commence in 2027, but this schedule is dependent upon the Company's ability to secure those property rights. The Company will provide additional updates and refined estimates when it has identified the route options and a location for the regulator station, in a future IRP or variance report. Current preliminary estimates with the cost of property and potential civil work are approximately $750,000. The first-year revenue requirement is $88,425. The Company first discussed this project on page 5-4 of the 2022-2023 IRP.

21. Washington Fields District Regulator Station, City of Washington, UT: The City of Washington is another quickly expanding area of Southern Utah. The southeastern portion of the city is somewhat isolated from other parts of the IHP system because of the Virgin River. And to support the expansion of the IHP system, an additional district regulator station has been identified as needed by 2028. The Company is currently looking for property adjacent to FL 121 to minimize costs by not requiring a lengthy FL extension.

    The project is in the early planning stages while the property search begins. Construction is currently anticipated to be needed in 2028. The Company estimates the station will cost $1,000,000. The first-year revenue requirement is $114,500. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

Feeder Line Projects:

1. FL 147 – 1 Mile of 8-inch pipe for New Regulator Station on Sheep Lane, Grantsville, Utah: This project is required to support the new District Regulator Station on Sheep Lane, previously identified as WA1617. This new line will connect to FL 38 at Sheep Lane and Erda Way. As noted above, the area around the Utah Motorsports Campus is growing, and a number of large industrial customers are building in the area. This growth results in a significant increase in demand. The existing IHP system cannot meet this demand. The Company acquired a parcel of property for the regulator station at a location that minimizes the length of this line.

    The Company evaluated other potential tap locations off of FL 52. However, all those locations would result in longer tap lines and would require much more extensive right-of-way acquisition. The chosen route is in existing city and UDOT right-of-way and is the shortest route to the station property, which minimizes costs.

    The project is currently under construction. The Company anticipates construction to finish in the summer of 2024. The estimated costs for FL 147 are $2,000,000. The first-year revenue requirement is $230,000. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP.

2. FL 85 Extension for New Eagle Mountain District Regulator Station, Eagle Mountain, UT: The Company plans to extend FL 85 to support a new IHP regulator station on the west side of Eagle Mountain. The Eagle Mountain area is growing rapidly and is

seeing new industrial and commercial customers in addition to large residential growth. The shortest route for FL 85 from WA1519 in Cedar Fort south to the property north of the intersection of 4000 N and Hwy 73 is down Hwy 73 itself. The Company will avoid the cost associated with obtaining private rights-of-way by following the UDOT right-of-way. The feeder line extension is approximately 8,000 LF. The size of the pipe will be 20-inch to support future long-term planning of the growth expected in the area of the next several decades.

The Company evaluated another alternative to tap off of FL 116 in Eagle Mountain and extend to the growth area. The extension would be approximately 4 miles long and be twice as long as the preferred option. Additionally, the diameter of FL 116 is only 6-inches, whereas FL 85 is 8-inches in diameter. Extending FL 85 would give the Company the ability to bring more gas to the area.

The project is currently finalizing design. Construction is expected to begin late Summer 2024 and complete before the end of the year. The estimated costs for the FL extension are $3,500,000. The first-year revenue requirement is $400,750. The Company first discussed this project on page 5-5 of the 2021-2022 IRP.

3. <u>FL 71 AC Mitigation, Washington County, UT:</u> FL 71 was evaluated for the need of alternating current (AC) mitigation due to the high voltage powerlines that parallel and cross this feeder line. A detailed study in 2023 showed the need for 43 horizontal groundings for a total length of 22,266 feet (approximately 4.5 miles) and another 38 decoupling devices. In addition, 12 remote monitoring AC test stations were also recommended for future data collection. This AC mitigation, which will be bare copper grounding wire, is needed in order to preserve the life of FL 71 and prevent any potential AC corrosion that could occur because of the proximity to the high voltage power lines. FL 71 does not currently have any AC mitigation.

   The project is currently in design. Construction is scheduled to begin in the Fall of 2024 and take advantage of the extended construction season in southern Utah. Cost estimates for the project are approximately $10 million. The first-year revenue requirement is $1,145,000. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

4. <u>FL Extension for WA1604, West Valley City:</u> The Company plans to construct a feeder line extension to the proposed IHP regulator station, WA1604, from FL 34 at approximately 4000 S and 1300 W in West Valley City. The Company is finalizing property on the east side of the Jordan River on Meadow Brook Parkway. The most direct route for the proposed feeder line will be approximately 3,200 lf of 8-inch pipe running from FL 34 along 1300 W.

   The next alternative route would run south from FL 4 at 3300 S and 700 W to Meadow Brook Parkway, and then west to the proposed site with an approximate length of 6,600 lf. The final routing will depend, in part, on analysis that will determine whether a directional drill across the Jordan River is a viable option, or if the Company must construct the longer alternative route that does not cross the river.

   The project is still in the planning stages. Once a site is secured for the new regulator station, the Company will evaluate the best routing options for the feeder line extension. The Company will provide an update on the project scope and costs as they become available. The Company is planning to commence construction in 2025. If the Company can pursue the shorter route with the directional drill under the Jordan, River, it estimates the cost of the project to be $3,000,000. If the direction drill is prohibitive, the Company will pursue the longer route at an estimated cost of $4,000,000. The first-year revenue requirement for the directional drill option would be $353,700. The first-year revenue requirement for the longer route would be $460,000. The Company first discussed this project on page 5-2 of the 2021-2022 IRP.

5. SLC NW Quadrant FL Extension, Salt Lake City, UT: The Inland Port continues to develop, and the newest developments are near 700 N and 8000 W. The Company plans on installing a district regulator station near this intersection to support the demand. A feeder line extension of approximately 1 mile will be required to supply the station. Two potential routes are being considered while the Company finalizes the property for the station. Once the property is finalized, the lowest cost alignment for the feeder line will be selected. Not only will the feeder line extension support the district regulator station supplying gas to the IHP system, but it will also allow large industrial customers to move into the area come directly off of the HP system, as needed.

   This project is currently in the early planning stages, awaiting the purchase of the station property. The Company estimates the cost of the feeder line extension at $3,000,000. The first-year revenue requirement is $343,500. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

6. FL Extension for South Bluffdale District Regulator Station, Bluffdale, UT: The Company plans to extend FL 35 approximately 17,000 lf south to serve growth in Bluffdale. Bluffdale is growing to the south, away from existing regulator stations. This extension would serve this growth as far south as Porter Rockwell Boulevard and Redwood Road.

   This project is still in the early planning stages. Once a site is selected for the new regulator station, the Company will evaluate the routing options for the feeder line extension and determine the appropriate sizing for the pipe. The Company will provide an update in a future IRP on the project scope and costs as they become available. Depending on where the property is secured, FL 118 at HR0002, FL 35 at Redwood Road, and FL 34 near 1300 West and Bangerter Highway are all potential options from which to start the extension.

   The Company is planning to commence construction in 2026. Current preliminary estimates based on the 17,000 feet extension from FL 35 on Redwood Road are approximately $6,500,000. The first-year revenue requirement is $766,350. The Company will provide an update on the project scope and costs in a future IRP as they become available. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

7. FL 47 Extension for the SY0002 Station, Syracuse, UT: The Company plans to construct a feeder line from the SY0001 station to the new SY0002 location, which

will supply additional capacity to the growing area. The Company purchased property at 2700 S 3000 W, Syracuse, UT. Feeder line 47 will extend from SY0001 west on SR193, south on 3000 W to the new property, approximately 2.7 miles of 8-inch-high-pressure pipe. This is the shortest route to the new station location, and it follows existing roads. Following any other alignment through city streets would have increased the overall length and cost of the extension.

The project was split into phases during 2022 due to conflicts with city and UDOT projects and moratoriums. Approximately 5,800 lf was installed in 2022-2023 from SY0001 to a location for a temporary station to support the IHP system through future heating seasons until this project is completed. Phase 2 will be the balance of the project, approximately 8,400 lf and the SY0002 station.

Phase 2 of the project is currently in the design phase. The Company is working with Syracuse City and UDOT to address moratorium concerns, which have delayed the final phase of construction. The Company estimates that phase 2 of the feeder line extension will cost approximately $4,000,000. The Company plans to begin and finish construction in 2026. The first-year revenue requirement will be $458,000. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

8. <u>FL 71-5 Extension for the South St. George – River Road District Regulator Station, St. George, UT</u>: This project is intended to support the continued growth in St. George. The Company proposes to construct approximately 12,000 lf of 8-inch diameter pipe from FL 71-5 from Enterprise Drive (near Deseret Power) directly south along River Road to a proposed development. This extension will supply a new regulator station in South St. George to support the quickly growing area. The proposed route follows the alignment of the existing River Road to the proposed station property. Deviating from existing road right-of-way would either conflict with existing conservation areas or interrupt existing development and add substantial costs.

   The project is currently in the early planning stages as the Company finalizes property options. Once a site is secured, the Company will provide an update on the project scope and costs as they become available. The Company is planning to commence construction in 2026, provided it can acquire the required property. Current preliminary estimates based on the potential property location are approximately $4,000,000. The first-year revenue requirement is $471,600. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

9. <u>FL 21-10 Replacement, North Salt Lake, UT</u>: The Company plans to replace approximately 6,800 lf of FL 21-10 to accommodate in-line inspection. The section of pipe to be replaced is located between 2200 W and Redwood Road in North Salt Lake. The Company will replace a 16-inch section of pipe with 24-inch diameter pipe. This section is scheduled for replacement in 2026.

   The project is still in the early planning stages. The Company anticipates that construction will commence in 2026. The current preliminary estimate, based on the 6,800 lf replacement, is $3,000,000 to $5,000,000. The first-year revenue requirement is $353,700+. The Company first discussed this project on page 5-8 of the 2022-2023 IRP.

10. Salem FL Extension for New District Regulator Station, Salem, UT: Southern Utah County continues to grow quickly. The proposed district regulator station to support growth in the area will require approximately ¾ of a mile FL extension of 8-inch diameter pipe to supply the gas. The Company is currently working with developers on the east side of the city to secure a property that will help support the expanded IHP system. The expected alignment will come off FL 26 and head east using city roads and franchise to minimize cost.

    The project is in the early planning stages and waiting on finalizing the location of the property to progress. Construction is anticipated in 2026. The Company estimates the extension at $2,000,000. The first-year revenue requirement is $229,000. This inclusion in the 2024-2025 IRP is the first mention of the project in an IRP.

11. FL Extension for Hurricane District Regulator Station, Hurricane, UT: The Company plans to construct approximately 18,000 lf of 8-inch diameter pipe to the Hurricane Station (described above), which will support the growth of the city. This regulator station will be located near 3000 S and Sand Hollow Road. This location is approximately 18,000 lf south of FL 71, which runs along Hwy 9. The Company is working with the city to procure easements from Hwy 9, near HC0007 to the Sand Hollow Road to the south for the pipeline as well as property for the regulator station.

    The project is still in the early planning stages. Once a site is selected for the new regulator station, the Company will evaluate the routing. The Company will provide an update on the project scope and costs as they become available. The Company is planning to commence construction in 2027. Current preliminary estimates based on the 18,000 lf extension from FL 71 are approximately $6,500,000. The first-year revenue requirement is $766,350. The Company first discussed this project on page 5-4 of the 2022-2023 IRP.

12. Feeder Line Replacement Program: Pursuant to the Utah Commission's Order approving the Settlement Stipulation in Docket No. 09-057-16, on November 15, 2015, the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information. The Company currently estimates that the program will not be complete until 2037 or later.

Southern System Expansion:

The southern system around St. George has been one of the fastest growing systems in the Company's service territory and the Company has been working to reinforce the infrastructure in the area over the last several years.

This system is currently served by two pipelines: FL71, an 8-inch HP pipeline coming from Cedar City and FL81, an 8-inch HP pipeline, coming from Central Gate Station. The Company's southern system is served by three gate stations which include Indianola, Central and Wecco (Cedar City). Both the Central and Wecco Gate Stations are served by KRGT. The original FL 71 and 81 were not adequate to serve the growth in the area. The

Company considered multiple options for reinforcing the infrastructure. The three most viable options were:

1. Tie FL 81 to FL 71 with a 12-inch pipe across St. George. (Completed in 2020)

2. Loop FL 81 with a 20-inch pipe to increase deliverability to St. George from the Central Gate Station. (In progress)

3. Install a new gate station at the Shivwits reservation along with a new 20-inch pipeline to feed into St. George. (Not selected)

These options are shown in Figure 5.1 below:

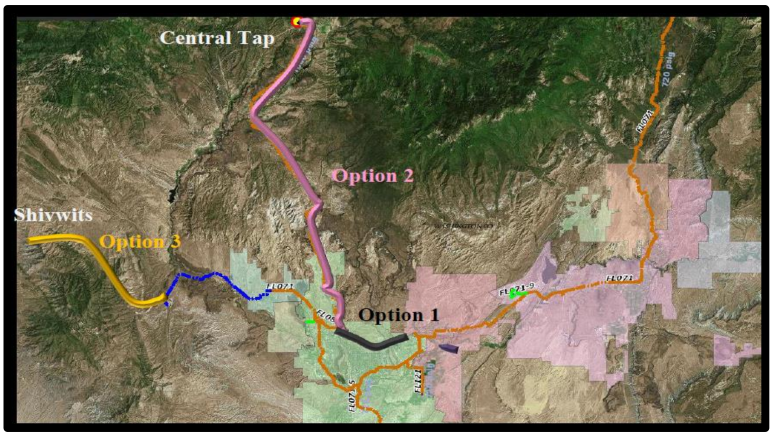


Figure 5.1: Southern System Options

The Company ultimately selected a combination of options 1 and 2, executing them in a four-step phased approach as load growth demanded. Option 3 was deemed infeasible due to permitting roadblocks with the Shivwits Band of Paiutes of Utah (Shivwits), right-of-way challenges, costs associated with building a new gate station and constructability of the pipeline. All of these challenges combined made the Shivwits gate station option more expensive and have more risk than options 1 and 2. The Company has completed the FL 133 extension (Option 1) and will continue efforts to completing the remaining work.

1. FL135, Central 20-inch loop, St. George, Utah: In order to meet the long-term demand needs of the growing St. George community, the Company is planning to construct a 24 mile, 20-inch pipeline reinforcement between the Central Gate Station and the WH0030 Bluff Street high-pressure regulator station in St. George. This new pipeline will allow the Company to bring more gas from the Central Gate Station, where FL 81 taps into KRGT, and deliver it to the St George high-pressure system. The new pipeline will "loop" the Company's existing FL 81 by running parallel to the 8-inch pipeline along Hwy 18.

   The construction of this project is being executed in three phases, the timing of which will depend on the actual growth in the area. Phase 1, approximately 9 miles, was completed at the end of 2022. Currently the Company is planning and designing Phase 2, approximately 10 miles of pipeline running from Dameron Valley to the Ledges. Phase 2 is expected to start construction late 2024 and be constructed in

2025 with an estimated cost of about $45,000,000. Phase 3, the final phase of this project, the Ledges to Bluff Street, is expected to be constructed in 2028. Phase 3 is approximately 5 miles. Actualized load growth in the area will play a role in adjusting the phase lengths and construction years. The Company anticipates the total cost of this project, including all phases, will cost between $100 and $125 million. The Company will provide updates on the timing and estimated costs of Phase 3 in future IRP's.

The Company first discussed this project on page 5-6 of the 2018-2019 IRP. Additional project justification is given on page 4-13 of the System Capabilities and Constraints section of this report.

Preliminary Timeline Summary:

Table 5.1:High Pressure Project Summary Table (Excluding Feeder Line Replacement)

Year	Project	Estimated Cost	Revenue Requirement
2024	WA1602 FL 13 East HP Station, District Regulator Station, and ILI Facilities, Salt Lake City, UT	$2,800,000	$330,120
2024	WA1596 – Replace WA0866 with High-Capacity District Regulator Station for South Salt Lake City, UT	$1,500,000	$176,850
2024	WA1617 – New Reg Station Grantsville on Sheep Lane	$750,000	$86,250
2024	FL147 – 1 Mile of 8-inch for New Reg Station on Sheep Lane	$2,000,000	$230,000
2024	MZ0003 – Remodel of Monticello Gate Station	$1,500,000	$171,750
2024	EG0007 - Eagle Mountain District Regulator Station, near 4000 N and Hwy 73	$750,000	$88,425
2024	FL85 Extension for Eagle Mountain District Regulator Station	$3,500,000	$400,750
2024	MO0001 Gate Station Remodel in Moab	$1,250,000	$143,125
2025	FL71 AC Mitigation – Approx 4.5 miles	$10,000,000	$1,145,000
2025	WA1604 – Replace WA0441	$1,000,000	$117,900

Year	Project	Estimated Cost	Revenue Requirement
2025	FL Extension for WA1604 Across Jordan River	$3,000,000	$353,700
2025	Black Desert Station in Ivins	$1,000,000	$114,500
2025	AF0014	$850,000	$97,325
2025	SLC NW Quadrant Station	$750,000	$85,875
2025	FL Extension for SLC NW Quad – Approx 1 mile	$3,000,000	$343,500
2025	Central 20-inch Loop (Phase 2) – Approximately 10 miles	$45,000,000	$5,152,500
2026	South Bluffdale District Regulator Station	$750,000	$88,425
2026	FL Extension for Bluffdale Station	$6,500,000	$766,350
2026	SY0002 Syracuse District Regulator Station	$750,000	$85,875
2026	FL47 Phase 2 Extension for SY0002 Syracuse District Regulator Station	$4,000,000	$458,000
2026	South St. George – River Road District Regulator Station	$750,000	$88,425
2026	FL71-5 Extension for South St. George DR Station – River Road	$4,000,000	$471,600
2026 or 2027	Rockport Gate Station	TBD	TDB
2026	SL0114 Remodel	TBD	TBD
2026	FL21-10 – 6,800 LF Replacement	$3,000,000 to $5,000,000	$353,700+
2026 or 2027	TG0005 Saratoga KRGT Gate Station	$5,000,000+	$589,500+
2026	Salem Utah Station	$850,000	$97,325

Year	Project	Estimated Cost	Revenue Requirement
2026	FL Extension for Salem Utah Station – 0.75 Miles 8-inch	$2,000,000	$229,000
2026	New Payson UT Station (West of I-15)	$1,000,000	$114,500
2027 or 2028	EG0001 – Gate Station Capacity Increase	TBD	TBD
2027	South Hurricane District Regulator Station	$750,000	$88,425
2027	FL Extension for South Hurricane Station	$6,500,000	$766,350
2028	Central 20-inch Feeder Line Loop (Phase 3) – Approximately 5 Miles	TBD	TBD
2028	Washington Fields Station	$1,000,000	$114,500
2028	FL Ext for Washington Fields – 2,000 LF	$1,000,000	$114,500

INTERMEDIATE HIGH PRESSURE PROJECTS:

1. Belt Main Replacement Program: The Company continues its Belt Main Replacement program in 2024. Pursuant to the Settlement Stipulation of the Utah Commission's Order Approving the Settlement Stipulation, in Docket No. 13-057-05, on November 15, 2015, the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information.

2. Aging IHP Infrastructure Replacement (Not Included in the Infrastructure Rate Adjustment Tracker): The Company is reviewing the replacement rate of its aging infrastructure relative to its expected life and may propose to accelerate replacement in the future. At the end of 2022 there was approximately 4,056 miles of pre-regulatory (pre-1971) steel main and service lines that are less than 8-inch diameter and not considered part of the Infrastructure Rate Adjustment Tracker. Some of this pipe dates back to 1929. The Company is currently working towards replacing all 58 miles of its 1929 – 1939 steel IHP main that is not part of the Infrastructure Rate Adjustment Tracker.

   The Company also has approximately 7,000 miles of Aldyl-A pipe, which is early vintage plastic that has a higher susceptibility to leaking. Because of the potential higher leak rate, many utilities have targeted programs to replace this type of pipe. The Company is evaluating the best approach to replace this pipe in the future.

3. Genola IHP Expansion under the Rural Expansion Program: Genola was approved under the Rural Expansion Program to bring natural gas into the city in Docket No. 23-057-13. There are over 500 residences and business that would be eligible for service in the area. The Company evaluated two options of bringing gas into this area.

   The first option was an IHP only expansion extending IHP main from stations SQ0003 and WA1582 capable of supplying the required load. Construction would require over 30 miles of IHP main (11,500 feet of 8-inch, 7,000 feet of 6-inch, and 38,650 feet of 4-inch, and 115,000 feet of 2-inch). In addition to the main, an additional 79,000 feet of service lines would be installed. This option estimate is $24,135,888. Option 1 was selected, as it was the low-cost alternative.

   The second option required extending HP main into the area constructing a district regulator station. While this slightly decreased the amount of IHP main required to be installed, the additional costs associated with construction of a station and the HP main extension made this the highest cost alternative at over $27,000,000. While this slightly decreased the amount of IHP main required to be installed, the additional costs associated with construction of a station and the HP main extension made this the highest cost alternative at over $27,000,000.

   This project is currently under construction and the IHP mains portion of the work is expected to be completed by the start of the 2024-2025 heating season. Service lines will be constructed between 2024 and 2026. The Genola project was first mentioned briefly on page 5-16 of the 2023-2024 IRP. The estimated revenue requirement for the project is $2.8 million.

MASTER METERS

The Company currently has 2,600 master meters on its system. The Company is currently evaluating potential changes regarding masters going forward.

MOUNTAINWEST PIPELINE TRANSITION

The Company and MountainWest Pipeline are continuing to review the ownership and operation of interconnecting facilities to determine the most efficient structure going forward. Contract negotiations are underway, and as of May 2024, the Company is waiting to receive asset book values and property rights information from MountainWest Pipeline for the contemplated purchases. Since any asset sale by MountainWest Pipeline will require FERC approval, closing of these agreements is not anticipated to take place until early 2025. The Company will provide further updates as definitive information becomes available.

RURAL EXPANSION

In 2017, Utah lawmakers amended Utah Code Ann. §§ 54-17-401, 402, and 403 to encourage the expansion of natural gas service to rural communities. These statutes allow the costs of extending service to rural communities to be spread amongst all customers, with spending caps in place to prevent large swings in customer bills. In 2020, the Utah Legislature passed HB 129, which allows the Company to purchase existing assets to aid in providing gas service to rural communities. Since the inception of the program, the

Company has requested and received approval from the Utah Commission to construct expansions to Eureka, Goshen/Elberta, Green River, and Genola. Table 5.2 Below is a summary of the status of each of the expansion projects that are in service. Genola is currently in the construction phase.

Table 5.2: Rural Expansion Project Status

	Services Signed Up	Services Installed	Meters Installed
Eureka	285	283	253
Goshen/Elberta	314	309	183
Green River	311	299	68

Utah Code Ann §54-17-403(1)(c) outlines spending caps that are in place to prevent large spikes in customer bills due to rural expansion. The spending caps are calculated based on the annual revenue requirement in the Company's most recent general rate case. The three-year cap that is outlined in Utah Code Ann §54-17-403(1)(c)(i) allows the Company to spend about $88.7 million in a rolling three-year period while the aggregate cap in Utah Code Ann §54-17-403(1)(c)(ii) allows the Company to spend about $221.6 million on rural expansion projects. To date, the Company has received rate recovery for investments of $70.5 million through the rural expansion tracker mechanism.

The Company continues to explore options for extending service to other rural communities within Utah. Table 5.3 below shows a list of communities the Company is currently considering for rural expansion. The list was determined by Company personnel and is based on several factors such as number of potential customers, total cost, geographic location, and distance to needed facilities, potential growth in the area, and the spending caps discussed above.

Table 5.3: Rural Expansion Potential Communities

Communities Under Current Evaluation	Estimated Population	Gas Supply Type
Portage	289	High Pressure
Fairfield	161	High Pressure
Rush Valley	467	High Pressure
Miller	270	High Pressure
Lawrence	175	Intermediate High Pressure
Emery	288	High Pressure
Jensen	412	Intermediate High Pressure
Manilla	324	High Pressure
Howell	237	High Pressure
Sutherland	165	High Pressure
Laketown/Garden City	838	High Pressure

INTEGRITY MANAGEMENT

ACTIVITIES AND ASSOCIATED COSTS FOR TRANSMISSION LINES AND DISTRIBUTION SYSTEMS

Transmission Integrity Overview

The Company continues to implement integrity activities defined in its Transmission Integrity Management Plan for transmission lines as originally mandated by the "Pipeline Safety Improvement Act of 2002" and later codified in the Federal Regulations (49 CFR Part 192, Subpart O). The transmission integrity management regulations require the Company to identify all high consequence areas (HCA) along the segments of feeder lines that are defined as transmission lines.[49]

Once the Company identified these HCAs, it calculated a risk score for each segment located in the HCA. These risk scores established the initial priority for when the Company initially assessed each HCA. The Company verifies HCAs in the year prior to performing integrity assessments for the feeder line the segment is a part of and calculates the risk score on an annual basis. Subsequent to this initial assessment, federal regulations require the Company to reassess each HCA at intervals not to exceed seven calendar years from the initial or previous assessment, or sooner based on results of the previous assessment.

Additionally, the Company is required by the transmission integrity rules to conduct additional ongoing preventive and mitigative measures on feeder lines in HCAs and in class 3 and 4 locations.[50] These additional measures include monitoring excavations (excavation standby) near these feeder lines and performing semi-annual leak surveys.

Distribution Integrity Overview

On December 4, 2009, Pipeline Hazardous Materials and Safety Administration (PHMSA) issued its final rule titled: "Integrity Management Program for Gas Distribution Pipelines." This final rule became effective on February 12, 2010, with implementation required by August 2, 2011.

The distribution integrity management rule requires the Company to develop, write and implement a Distribution Integrity Management Program (DIMP) with the following elements: 1) knowledge; 2) identify threats; 3) evaluate and rank risks; 4) identify and implement measures to address risks; 5) measure performance, monitor results, and evaluate effectiveness; 5) periodically evaluate and improve program; and 6) report results.

The Company continues to implement activities defined in its Distribution Integrity Management Plan for the distribution system. It implements the activities to mitigate the threats that are identified in the plan.

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[49] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operation Pressure at or above a pressure that produces a hoop stress of 20% of Specified Minimum Yield Strength (SMYS)).
[50] Class location as defined by 49 CFR Part 192 (§192.5).

TRANSMISSION INTEGRITY MANAGEMENT

Costs

Exhibit 6.1 details the anticipated costs associated with transmission integrity management.

Baseline Assessment Plan

The Baseline Assessment Plan prescribes the methods that the Company will use to assess the integrity of each HCA. The Company determines these methods based upon the known or anticipated threats to these segments. The most common threats on the pipeline include corrosion and third-party damage. The Company has used multiple assessment methods in the past to address these threats, including external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), direct visual examination, pressure testing, and inline inspection. The Company has completed the Baseline Assessment Plan for all segments of pipe.

External Corrosion Direct Assessment

ECDA is an assessment method that evaluates the integrity of the pipeline segments for the threat of external corrosion, including segments of cased gas transmission pipelines. Refer to Figure 6.1 for an overview of the ECDA process.

The ECDA methodology is a four-step process. The four steps of the process include:

- Pre-Assessment - This step utilizes historic and current data to determine whether ECDA is feasible, identifies appropriate indirect inspection tools, and defines ECDA regions. ECDA regions are areas along the pipeline that have similar characteristics. There may be multiple regions along a single pipeline segment. Examples of ECDA regions include segments in casings or segments with different types of external coatings.

- Indirect Inspection - This step utilizes above-ground inspection methods such as close interval survey, pipeline current mapper or DC voltage gradient survey, to identify, and quantify the severity of coating faults and areas of diminished cathodic protection. The analysis of this data can help identify areas along the pipeline segment where corrosion may have occurred or may be occurring. The Company uses a minimum of two indirect inspection tools over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. The Company categorizes indications from indirect inspections according to severity. A third indirect inspection tool is required for initial assessments of the segment.

- Direct Examination - This step includes excavations of the pipe for direct examination to determine if there is corrosion occurring on the pipeline. For initial assessments (i.e., first-time assessments for an HCA), a minimum of two excavations are required for each ECDA region and a minimum of four excavations in total for the ECDA project. The ECDA project may contain more than one pipeline and more than one ECDA region. Reassessments require a minimum of one excavation per ECDA region and a minimum of two excavations in total for the ECDA project. The Company selects excavation sites based on a review of the data collected during the pre-assessment and the indirect surveys.

The Company uses this information to identify the areas on the pipeline within each region where external corrosion is most likely. The Company must also excavate at a location where it has not identified any indications. The Company uses the information gathered at this site to help validate the effectiveness of the ECDA process. When corrosion or other pipeline damage or coating damage is found during the direct examination step, the Company repairs the pipe or coating. The Company may select additional sites for examination based on the findings of the required direct examinations.

- Post-Assessment - This step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals and provide feedback for continuous improvement.

Figure 6.1: ECDA Process Overview

Internal Corrosion Direct Assessment

ICDA is a process used to predict the most likely areas of internal corrosion, including those caused by chemical and microbiologically induced corrosion. ICDA focuses on directly examining locations at which internal corrosion is most likely to occur.

The basis of ICDA is the detailed examination of the most susceptible locations along a pipeline where liquids, if any, would first accumulate in the pipeline. If the locations most likely to accumulate liquids have no indications of internal corrosion, all other locations further downstream are considered to be free from internal corrosion. ICDA relies on the ability to identify locations most likely to accumulate liquids.

The ICDA methodology is a four-step process that is intended to assess the threat of internal corrosion in pipelines and assist in verifying pipeline integrity.

The initial baseline assessment plan, completed on May 20, 2013, included ICDA. The Company was able to eliminate internal corrosion as a threat of concern going forward based on the fact that internal corrosion was not found at the conclusion of completing ICDA on the entire pipeline system as well as the implementation of the Company's ongoing internal corrosion plan.

Visual Examination of Aboveground Pipe and Pipe in Vaults

The Company assesses aboveground piping (e.g., spans and valve assemblies) and piping in vaults by visual examination when the piping is located in a HCA, and the Company cannot assess the pipe utilizing other methods.

Inline Inspection

When a pipeline has been constructed and configured or retrofitted in such a way to allow for inline inspection, the Company assesses the pipe using inline inspection tools commonly called "smart pigs." These tools are equipped with sensors that collect data as the tool travels through the pipeline and can reveal areas of wall loss and dents that may require repair or cutout. The Company has 420.387 miles of transmission piping (52.9% of the Company's transmission system) that can be inspected using smart pigs. As the Company replaces aging infrastructure, it designs and builds the new pipelines to accommodate inline inspection tools. Advancements in technology allow some limited application of inline inspection tools for non-piggable pipelines. The Company has helped fund these advancements through its research and development program. The Company has used these advanced tools to assess locations of its system that it previously could not.

The inline inspection tools provide specific data on the condition of the pipeline segment being inspected. The Company analyzes data that it collects along the pipeline segment for defects and areas of concern (e.g., wall loss or dents) and excavates for further evaluation and repair, or cut out, if necessary.

High Consequence Area Validation

Each year, the Company conducts a field survey of all transmission line segments where integrity management assessment will be performed the following year, to validate the current HCA as well as identify any new potential sites that may trigger a new HCA. Sites that may trigger a new HCA include the following: office buildings, businesses, community centers, churches, day care centers, retirement centers, hospitals, and prisons.

The Company maintains this information in its mapping system and uses it to calculate HCAs on an annual basis.

DISTRIBUTION INTEGRITY MANAGEMENT

Costs

Exhibit 6.2 details the anticipated costs associated with distribution integrity management.

Implementation

The Company implemented its written Distribution Integrity Management Plan in August of 2011. Implementation included identifying the threats associated with the distribution system within each operating region as well as calculating a risk score for each identified threat. The Company utilizes industry knowledge, known infrastructure data, leak history, and subject matter experts (SME) to identify threats, and calculate risk scores for each threat, in each operating region. The threats and the associated risk scores are validated by comparison to a second geographic information system (GIS) risk model. Once the Company identifies the threats and calculates the risk scores for each threat, each operating region identifies possible measures that could be implemented or are currently being implemented that would help mitigate the risks on the distribution system. The process of identifying threats and calculating the risk for each threat is ongoing and is evaluated on an annual basis.

COST SUMMARY

Table 6.1 shows the total costs for the transmission and distribution integrity management programs.

Table 6.1: Integrity Management Costs

	2024	2025	2026
Transmission Integrity Management Program	9,774	11,197	9,629
Distribution Integrity Management Program	1,325	1,235	1,085
Total Integrity Management Cost ($ Thousands)	11,099	12,432	10,714

KEY PERFORMANCE INTEGRITY METRICS

Table 6.2 details specific performance metrics associated with the transmission integrity management program.

Table 6.2: Miles Assessed/Anomalies Repaired

YEAR	TRANSMISSION MILES ASSESSED	HCA MILES ASSESSED	ANOMALIES REPAIRED
2012	34.430	26.470	28
2013	93.391	50.367	27
2014	80.049	54.555*	20
2015	15.903	11.040	2
2016	62.575	37.226	4
2017	49.555	12.935	8
2018	76.327	30.212	9
2019	111.383	25.571	3
2020	188.832	54.624**	8
2021	118.389	11.066	11
2022	55.35	4.512**	4
2023	81.11	8.803	17

NOTE: *Approximately 17 miles of HCA were assessed in 2014 that were originally planned to be completed in 2015. Due to favorable circumstances for completing the direct examinations these assessments were completed early.

** FL026, scheduled for ILI in 2022, was assessed early, in 2020, due to a leak identified that year.

ADDITIONAL REGULATIONS

The following regulations may have significant impact on the Company:

SAFETY OF GAS TRANSMISSION AND GATHERING LINES (MEGA RULE)

Transmission lines: Assessments outside of high consequence areas

The company has implemented integrity activities for transmission lines outside of high consequence areas as mandated by the "Safety of Gas Transmission Pipelines: MAOP reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (aka Mega Rule) and codified in (49 CFR Part 192.710) published October 1, 2019.

PHMSA initially published an advanced notice of proposed rulemaking (ANPRM) for the Safety of Gas Transmission and Gathering Lines, aka Mega Rule on August 25, 2011. On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) in the Federal Register. The Mega Rule is intended to increase the level of safety associated with the transportation of gas by imposing regulations to prevent failures like those involved in recent industry incidents. The Mega Rule also seeks to clarify and enhance some existing requirements and address certain statutory mandates and National Transportation Safety Board (NTSB) recommendations.

PHSMA broke the rule up into 3 rulemakings to address: i) issues contained in the Congressional mandates; ii) topics outside the Congressional mandates; and iii) issues related to gathering lines, which are not applicable to the Company. On October 1, 2019, PHMSA published part one of the rule. Among other topics, this rulemaking addressed MAOP reconfirmation, assessments of pipelines outside of HCAs, in-line inspection, launcher and receiver safety, expanded records requirements, and a moderate consequence area definition. On August 23, 2022, PHMSA published part two of the rule. Among other topics, this rulemaking addressed repair criteria, integrity management improvements, cathodic protection, management of change, and other related amendments.

Part 1, “Safety of Gas Transmission Pipelines: MAOP reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments”, includes requirements that impact the Company’s integrity management program, including the addition of pipeline integrity management measures for pipelines that are not in HCAs, as well as clarifications and selected enhancements to integrity management activities related to pipelines within HCAs, and the opportunistic collection of pipeline material specifications.

Part 2, “Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments”, includes requirements that impact the Company’s integrity management program, a summary of the more significant changes includes management of change, threat identification and data integration, repair requirements and schedules, and preventative and mitigative measures. These changes are effective, February 24, 2024. Other significant changes included in the rule making that do not directly impact the integrity program, are extreme weather event requirements, coating quality control requirements and cathodic protection interference remedial requirements. Extreme weather events requirements and coating quality controls will be in effect May 24, 2023.

Part 3 of the Mega Rule impacts operators with gathering lines (e.g., Wexpro) and does not have an impact on the Company otherwise. The amendments in this final rule extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. The effective date for this final rule was May 16, 2022.

VALVE INSTALLATION AND MINIMUM RUPTURE DETECTION STANDARDS RULE

On November 16, 2018, PHMSA published a Notice of Proposed Rule Making on February 6, 2020. The proposed rule sets forth installation requirements pertaining to automatic or remote-controlled shut-off valves, or equivalent technology on newly constructed or fully replaced transmission pipelines that are greater-than-or-equal to 6 inches in diameter. The objective of the rule is to improve response time to large-volume, uncontrolled release events to reduce the consequence of these events.

PHMSA published the valve Installation and Minimum Rupture Detection Standards Rule in the Code of Federal Regulations on March 31, 2022, and became effective Oct 5, 2022.

PIPES ACT 2020 - SAFETY OF GAS DISTRIBUTION PIPELINES

PHMSA is planning to publish a Notice of Proposed Rule Making later this year as part of the Congressional Pipes Act 2020. Of the proposed changes those noted below are expected to have varying levels of impact on the Integrity Management programs.

The proposed rule provides that threats to the integrity of the pipeline system with a low probability can only be determined to be of “no potential consequence” when supported by engineering analysis or operational knowledge. This is expected to have minimal impact and may only require minimum updates to the Distribution Integrity Management Plan.

The rule contains a requirement to develop a detailed procedure for management of change process, which ensures that relevant qualified personnel, such as an engineer with a professional engineer licensure, subject matter expert, or other employee who possess the necessary knowledge, experience, and skills regarding natural gas distribution systems, review and certify construction plans for accuracy, completeness, and correctness. A robust management of change process is already in use. The proposed rule while requiring modifications to the existing management-of-change (MOC) process is expected to have a minimal impact on resources.

The proposed rule requires distribution system records critical to ensuring proper pressure controls will be required to be traceable, reliable, and complete, including maps and other drawings. These records must be accessible to all personnel responsible for performing or overseeing relevant construction or engineering work. The Company’s ability to determine the impact of this requirement is limited until the proposed rule is published and the exact requirements can be evaluated.

The proposed rule includes a change to the requirements for station design to have secondary or backup pressure-relieving or overpressure-protection safety technology. If the station has a monitor and control regulator design, the operator is to eliminate the common mode of failure or provide backup protection capable of either shutting the flow of gas, relieving gas to atmosphere, or technology in place to eliminate the common mode of failure. The impact of these changes could reduce risk in the system by reducing the consequence of failure. Updates to the integrity risk model to account for these changes would be needed to account for the impact to risk.

Once the Noticed Proposed Rule Making is published it will be possible to do an evaluation of the potential impacts of the changes.

INDUSTRY AND COMPANY BEST PRACTICES

Interstate Natural Gas Association of America (INGAA) Integrity Management Continuous Improvement Initiative (IMCI)

The Company has adopted an industry and Company best practices for transmission pipelines that align with the direction and intent of PHMSA's proposed Mega Rule. INGAA's IMCI extends the application of Integrity Management from HCAs to 90% of the population living adjacent to transmission pipeline corridors, with a first-time assessment to be complete by the end of 2020. The Company achieved the 2020 requirement with over 91% of the population living adjacent to a transmission pipeline corridor having been assessed by Integrity Management practices. The Company will continue to extend the application of Integrity Management completing a first-time assessment for the remaining population as we start to apply Integrity Management in Class 3 and 4 areas and moderate consequence areas (MCA) per Mega Rule requirements. The Company estimates that it will be able to maintain average year-over-year costs level as it completes this commitment and the Mega Rule's expansion of Integrity Management Part One starts.

Close Interval Survey (CIS)

The Company has initiated an internal best practice to conduct CIS on its transmission pipelines cathodic protection systems. The goal is to complete this initial survey of all transmission cathodic protection systems by 2024. As a result of this initiative, CIS inspection costs were added in 2018, and will vary from year to year depending on the mileage of the lines needing to be surveyed. 2024 and beyond CIS work outside of the ECDA program will be conducted on new transmission pipelines and other transmission pipeline segments needing this assessment as identified by cathodic protection system SMEs.

Probabilistic Risk

The Company is evaluating probabilistic risk models considering recommendations from PHMSA's Report, "Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation" and plans to choose and implement a solution within the next year.

Transmission Integrity Management Costs

Activity	2024	2025	2026
ECDA			
Pre-Assessment			
2024 - (FL012, 22, 33, 46, 51, 53) (14.54 HCA miles; 2.12 §192.710 miles@ $4.5k/FL)	27		
2025 - (FL018, 21, 29, 70, 122) (27 HCA miles; 1.89, §192.710 miles @ $4.5K/FL)		22.5	
2026 - (FL023, 28, 71, 71-5, 74, 125, 19, 127 (15.2 HCA miles; 5.95, §192.710 miles @ $4.5K/FL)			36
Indirect Inspections			
2024 - (FL012, 22, 33, 46,51, 53) (14.54 HCA miles; 2.12 §192.710 miles @ $16K/mile)	255		
2025 - (FL018, 21, 29, 70, 122) (27 HCA miles; 1.89 §192.710 miles @ $16K/mile)		462	
2026 - (FL023, 28, 71, 71-5, 74, 125, 19, 127 (15.2 HCA miles; 5.95, §192.710 miles @ $16K/mile)			339
Direct Examinations			
2023 - (FL34, 103, 11, 26, 85) (10 excavations @ $34.5 K ea.)	345		
2023 - (FL34, 103, 11, 26, 85) (Pipetel 2 sites, 2 casings @ $150 K/site)	300		
2024 - (FL012, 22, 33, 46, 51, 53) (6 excavations @ $34.5 K ea.)		207	
2024 - (FL012, 22, 33, 46, 51, 53) (Pipetel 2 sites, 2 casings @ $165 K/site)		330	
2025 - (FL018, 21, 29, 70, 122) (6 excavations @ $34.5 K ea.)			207
2025 - (FL018, 21, 29, 70, 122) (Pipetel 2 sites, 2 casings @ $165 K/site)			330
Post Assessment			
2023 - (FL34, 103, 11, 26, 85) (19.91 HCA miles; 0.03 §192.710; 10.2 CA miles @ $1.75K/FL)	8.75		
2024 - (FL012, 22, 33, 46, 51, 53) (14.54 HCA miles; 2.12 §192.710 miles @ $1.75K/FL)		10.5	
2025 - (FL018, 21, 29, 70, 122) (27 HCA miles; 1.89 §192.710 miles @ $1.75K/FL)			8.75
CIS			
Indirect Inspections			
2024 - (FL012, 22, 33, 46, 51, 53, 104, 25, 22, 19) (29.56 miles @ $6.5K/mile)	192		
2025 - (FL018, 21, 29, 70, 122, 4, 81, 68, 85) (101 miles @ $6.5K/mile)		657	
2026 - (FL023, 28, 71, 71-5, 74, 125, 19, 127) (75.4 miles @ $6.5K/mile)			490
Reports			
No additional cost under current contract			
ACCDA			
Pre-Assessment			
2024 - (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles; Fixed)	6.4		
2025 - (FL018, 21, 29, 70, 122) (15.21 HCA miles; Fixed)		6.4	
2026 - (FL0 28, 71, 71-5, 74, 19, 127) (12.5 HCA miles; Fixed)			6.4
Indirect Inspections			
2024 - (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles @ $19K/mile)	26		
2025 - (FL018, 21, 29, 70, 122) (15.21 HCA miles @ $19K/mile)		287	
2026 - (FL0 28, 71, 71-5, 74, 19, 127) (12.5 HCA miles @ $19K/mile)			238
Direct Examinations			
2023 - (FL11, 26, 85, 103) (2 excavations @ $34.5 K ea.)	69		
2024 - (FL012, 22, 33, 46, 51, 53) (2 excavations @ $34.5 K ea.)		69	
2025 - (FL018, 21, 29, 70, 122) (2 excavations @ $34.5 K ea.)			69
Post Assessment			
2023 - (FL11, 26, 85, 103) (3.01 HCA miles; Fixed)	6		
2024 - (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles; Fixed)		6	
2025 - (FL018, 21, 29, 70, 122) (15.21 HCA miles; Fixed)			6
ICDA			
ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan).			
Inline Inspection			
2023 - Excavations/ Validations Digs/ Remediation (9 excavations @ $34.5 K ea)	311		
2024 - (FL068)	520		
2024 - (FL104)	340		
2024 - (FL022/53/19)	540		
2024 - (FL019)	370		
2024 - (FL64/65)	520		
2024 - Excavations/ Validations Digs/ Remediation (17 excavations @ $34.5 K ea)		587	
2025 - (FL004)		370	
2025 - (FL081)		450	
2025 - (FL072)		450	
2025 - (FL085)		370	
2025 - (FL085) East		500	
2025 - (FL125)		875	
2025 - Excavations/ Validations Digs/ Remediation (18 excavations @ $34.5 K ea)			621
2026 - (FL071)			450
2026 - (FL026)			370
2026 - (FL065)			450
2026 - (FL127)			370
Direct Examination (Spans and Vaults)			
2024 - Vaults (6 @ $3.5 K/vault)	21		
2024 - Spans Reassessment (4 @ $10 K/span)	40		
2024 - Spans First Time (2 @ $75 K/span)	150		
2025 - Vaults (6 @ $3.5 K/vault)		21	
2025 - Spans Reassessment (4 @ $10 K/span)		40	
2025 - Spans First Time (2 @ $75 K/span)		150	
2026 - Vaults (6 @ $3.5 K/vault)			21
2026 - Spans Reassessment (4 @ $10 K/span)			40
2026 - Spans First Time (2 @ $75 K/span)			150

Transmission Integrity Management Costs

Activity	2024	2025	2026
Pressure Test Assessment			
2024 - 1 pipeline segments @ $200 K/segment	200		
2025 - 1 pipeline segments @ $200 K/segment		200	
2026 - 1 pipeline segments @ $200 K/segment			200
Material Verification			
2024 - 8 Opportunistic Samples @ $4 K/sample, 2 Opportunistic Samples @ $20K	72		
2025 - 8 Opportunistic Samples @ $4 K/sample, 2 Opportunistic Samples @ $20K		72	
2026 - 8 Opportunistic Samples @ $4 K/sample, 2 Opportunistic Samples @ $20K			72
MAOP Verification MAOP, for MAOP established in accordance with §192.619(c)			
2022 - HYDRO Test (FL011)	200		
2024 - HYDRO Test (FL046)	200		
Risk			
Probabilistic TIMP Model			100
Excavation Standby			
Distribution Tech (5 employees (2080 hrs. x $75/hr.))	780	780	780
Contractors (4 x 312 days x 4 x $580/day)	724	724	724
Additional Leak Survey			
Leak Survey Tech (3 employees (2,080 hrs. x 3 x $79/hr.))	493	493	493
Additional Cathodic Protection Survey			
Corrosion Tech (2 employees (2,080 hrs. x 3 x $63/hr.)	260	260	260
Administration			
Distribution Tech (4 employees (2080 hrs. x 4 x $75/hr.))	624	624	624
Data Integration Specialists (2 employees (2080 hrs. x 2 x $82/hr.))	341	341	341
Construction Records Tech (2080 hrs. x $45/hr.)	93.6	93.6	93.6
Supervisor (2080 hrs. x $127/hr.)	264	264	264
Engineer (3 employees (2080 hrs. x $92/hr.))	574	574	574
Engineer Tech (2080 hrs. x $ 55/hr.)	114	114	114
Damage Prevention Tech (4 employees (2080 hrs. x $74/hr.))	616	616	616
Cathodic Protection Tech (2080 hrs. x 1 x $63/hr.)	131	131	131
Training (IM and Engineering personnel)	40	40	40
Transmission Integrity Management Total ($ Thousands)	9,774	11,197	9,629

Distribution Integrity Management Costs

Activity	2024	2025	2026
NOTE: The costs estimated here are based on additional and accelerated actions initiated based on the threats identified. The costs also reflect the administration costs associated with this new regulation.			
Additional and Accelerated Actions			
Stray Current Surveys (UTA Reimbursed)	85	85	85
Damage Prevention (IHP Standby)	900	900	900
Cross Bore Inspections	250	250	
Direct Assessments			
ILI			
2022 ILI digs (FL006, FL024) (3 excavations @ 34.5K ea	90		
Administration			
Probabilistic DIMP Risk Model			100
Distribution Integrity Management Total ($ Thousands)	1,325	1,235	1,085

ENVIRONMENTAL REVIEW

The Company is fully committed to meeting the energy needs of our customers in an environmentally responsible manner. Protecting natural and cultural resources is our duty, and it is also good business practice. Our commitment is always to comply with laws and regulations and to act consistently with our core values. While we always strive to meet our legal and regulatory obligations, we set our sights higher. The information provided below, along with additional information provided in the Sustainability section of this report, describes some of the actions we take to meet or exceed our compliance obligations as well as to ensure protection of human health and the environment.

The Company is subject to substantial laws, regulations, and compliance costs with respect to environmental matters. Some of the laws and regulations with which the Company must comply include the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, the Toxic Substance Control Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Emergency Planning, and Community Right to Know Act, the Oil Pollution Act, and the National Historic Preservation Act, as well as similar state and local laws and regulations that can be more strict than their federal counterparts.

These laws and regulations affect future planning and existing operations as a result of compliance, permit, remediation, containment and monitoring obligations and requirements. For example, the U.S. Fish and Wildlife Service may designate critical habitat areas to protect certain threatened and endangered species. A critical habitat designation for a protected species, such as the desert tortoise, can result in restrictions to federal and state land use. Species protections such as these may restrict Company activities to certain times of year. Project modifications may be necessary to avoid harm, or a permit may be needed for unavoidable taking of the species. These requirements and time of year restrictions can result in delays or adverse impacts to project plans and schedules as the Company's infrastructure crosses many miles of federal and state lands that include the critical habitat of protected plant and animal species.

The Clean Water Act and similar state laws and regulations regulate discharges of storm water, hydrostatic test water, wastewater, and other pollutants to surface water bodies such as lakes, rivers, wetlands, and streams. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of penalties for noncompliance, including fines, injunctive relief, and other sanctions.

The Company is subject to various federal and state laws and implementing regulations governing the management, storage, treatment, reuse and disposal of waste materials and hazardous substances that can affect the Company's operations and construction activities. One of these laws, CERCLA, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment. CERCLA also authorizes the U.S. government to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform and pay for cleanup, or voluntarily do so by beginning a site investigation and site remediation under state oversight.

As a result of these laws and regulations, the Company must determine soil disposition prior to construction (when presence of the contamination is suspected), properly train employees, equip employees with protective equipment, and invoke proper disposal and decontamination procedures. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of penalties for noncompliance, including fines, injunctive relief, and other sanctions.

The Company reviews proposed projects for adverse effects on historic resources in compliance with Section 106 of the National Historic Preservation Act. This often includes intensive field surveys to identify archaeological and architectural sites of potential historic significance (e.g., sites eligible for listing on the National Register of Historic Places). Once identified, the project's effects on eligible sites are reviewed and can include the need for additional historic resource surveys (Phase II) or mitigation plans (resource protection, view shed mitigation, or Phase III data recovery). In most cases this requires consultation with State Historic Preservation Offices and Tribal Historic Preservation Offices.

The Company embraces the tenets of environmental justice to create meaningful involvement and fair treatment for all people regardless of race, color, national origin, or income. As such, the Company has formalized its ongoing commitment to environmental justice by adopting a corporate policy establishing the framework whereby specific environmental justice considerations and increased public outreach is incorporated early in project planning.

New and revised environmental policies to address climate change, energy use, and development could impact the Company in the future.

The Company reports certain indirect emissions upstream and downstream of the Company's operations, including Scope 2 emissions and Scope 3 emissions including fuel purchased for the Company's gas distribution systems and consumption of sales gas by natural gas customers.[51] As discussed in the Sustainability section of this report, the Company is taking action to reduce emissions and exploring new technologies to accelerate future emissions reductions.

In 2010, the EPA adopted Greenhouse Gas Reporting Regulations requiring LDCs selling more than 460 MMcf of natural gas annually to report total natural gas receipts so the EPA can account for the downstream GHG emissions associated with customer use of the sold natural gas.

[51] Upstream emissions from fuel for gas distribution systems refers to gas for which the Company takes title.

Since 2011, the EPA has also required measurement and reporting of direct GHG emissions from LDC operations from various source categories such as combustion emissions from large stationary combustion sources and fugitive leaks from natural gas pipelines and equipment components.

In addition to EPA reporting, the Company also maintains a comprehensive GHG inventory, which follows methodologies for calculating emissions as specified in the EPA's GHG Reporting Rule as well as other, more refined industry protocols (e.g. ONE Future) and company specific methodologies. The annual GHG inventory includes carbon dioxide, methane, and nitrous oxide emissions from all assets (i.e. emission sources, stations, and segments), regardless of whether the asset is subject to EPA's GHG Reporting Program. Examples of additional assets not subject to EPA reporting include, auxiliary combustion equipment, meters, pipeline dig-ins, etc. As a result, the Company's reported GHG emissions in its GHG inventory are a more accurate and comprehensive accounting of actual emissions from operations than what is reported to the EPA.

In 2022, the Company reported a total of 163 thousand metric tons of direct CO2e emissions.[52] Table 7.1[53] shows the Company's direct CO2e emission rate per million BTU (greenhouse gas intensity) over the last three years.

Table 7.1: Greenhouse (CO2e) Gas Intensity

Reporting Year	CO2e Intensity (MT CO2e/MMBtu)
2019	0.0008
2020	0.0009
2021	0.0011
2022	0.0007

The Company is a Founding Partner with the EPA in the Methane Challenge Program, committing to voluntary practices that have reduced methane emissions. EPA has announced that it is sunsetting the Methane Challenge program at the end of 2024 in light of new regulatory requirements established by the Inflation Reduction Act and additional regulation of methane under the Clean Air Act. EPA acknowledged the success of the program in reduction methane emissions from the industry. The Company is also a member of the One Future Coalition, which is a group of more than 50 natural gas companies working together voluntarily to reduce menthane emissions across the value chain.

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[52] Starting with the 2023-2024 IRP, CO2e emissions and intensities reported reflect the most recent third party audited CO2e emissions.

[53] Starting with the 2023-2024 IRP and going forward, CO2e intensity is reported for DEUWI Scope 1 direct emissions. Previous IRPs reflected Scope 3 downstream emissions from customer use of sold natural gas.

The Company expects that greater awareness regarding the benefits of natural gas for high-efficiency residential, commercial, transportation, industrial, and electricity generation purposes will result in the advancement of these applications and increased utilization of natural gas-fueled equipment. Greater utilization of natural gas should result in significantly lower U.S. greenhouse gas emissions in comparison with more carbon intensive fuels. For a more detailed discussion about full fuel-cycle efficiency, refer to the Customer and Gas Demand Forecast section of this report.

Reduction in methane emissions will continue to have a positive environmental impact. For example, the Company estimates annual savings of nearly 1.05 million Dth of natural gas in 2023 through the ThermWise programs. The savings represents the equivalent of over 55 thousand metric tons of CO2e or more than 13 thousand passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime natural gas savings attributable to the 2023 ThermWise® programs equates to reductions of nearly 860 thousand metric tons of CO2e or the equivalent of more than 204 thousand passenger vehicles each driven for one year.

The Company remains committed to meeting reduction goals and maintaining compliance with all laws and regulations while continuing to reliably meet the energy needs of our customers in an affordable and environmentally responsible manner.

PURCHASED GAS

LOCAL MARKET ENVIRONMENT

Local prices during the 2023 calendar year averaged $8.28 per Dth. This was higher than the 2022 average price of $6.95 per Dth, an increase of $1.33 per Dth or about 19.1%. This increase was mostly driven by the high pricing in January and February of 2023. The 2022 and 2023 monthly index prices are provided in Table 8.1 below.

Table 8.1: NPC First-of-Month (FOM) Index Price per Dth

Month	2022	2023	Difference
Jan	$7.87	$49.57	$41.70
Feb	$5.04	$12.44	$7.40
Mar	$4.38	$5.07	$0.69
Apr	$4.86	$3.87	($0.99)
May	$6.40	$2.36	($4.04)
Jun	$8.80	$2.32	($6.48)
Jul	$6.18	$2.95	($3.23)
Aug	$8.45	$3.98	($4.47)
Sep	$8.73	$3.26	($5.47)
Oct	$5.51	$2.60	($2.91)
Nov	$5.73	$5.09	($0.64)
Dec	$11.39	$5.90	($5.49)
Average	$6.95	$8.28	$1.33

The local market price for natural gas during the 2023-2024 heating season (November-March) averaged $4.24 per Dth compared to an average price of $16.84 per Dth during the 2022-2023 heating season, a decrease of $12.60 or about 75%. The monthly-index prices for the two heating seasons are provided in Table 8.2 below.

Table 8.2: NPC FOM Index Price per Dth - Heating Season

Month	2022-2023	2023-2024	Difference
Nov	$5.73	$5.09	($0.64)
Dec	$11.39	$5.90	($5.49)
Jan	$49.57	$3.56	($46.01)
Feb	$12.44	$4.88	($7.56)
Mar	$5.07	$1.78	($3.29)
Average	$16.84	$4.24	($12.60)

March 2024 IHS Markit North American Natural Gas Short-Term Outlook (formerly IHS Energy - CERA) forecasts of Rockies indices reflect an average price of approximately $2.08 per Dth through October 2024. Prices for the 2024-2025 heating season are forecasted to be approximately $3.65 per Dth.

ANNUAL GAS SUPPLY REQUEST FOR PROPOSAL (RFP)

One of the fundamental results of the IRP modeling is the selection of the portfolio of natural gas purchase contracts for the coming year. The Company expects that a significant portion (up to 55%) of the annual gas supply needs of the Company's sales customers will be met with cost-of-service supplies provided under the Wexpro I and II Agreements (see Cost-of-Service Gas section of this report). Supply needs not met by cost-of-service gas must be purchased from natural gas providers. Accordingly, the Company issues an RFP to potential suppliers each year.

On February 20, 2024, the Company sent its RFP to 50 prospective suppliers. The RFP sought proposals for both baseload and peaking supplies on the two major interstate pipeline systems interconnected with the Company's system; MWP and KRGT. The Company requested heating season proposals on both pipelines with terms ranging from one to five years. The Company also sought proposals for peaking supplies on both pipeline systems with supply availability of two to four months to meet customer demands during the coldest winter heating season months. The Company specified needs at specific locations such as MAP 285 (Overthrust), MAP 421 (Chipeta), MAP 420 (Spire – Bell Butte), and other locations that were determined to be operational needs.

Reliability of supplies is a critical issue for the Company. The Company thoroughly reviews creditworthiness of all counterparties and includes contract language specifying the minimum advance notice before nomination deadlines for gas flow.

As part of the RFP this year, the Company requested offers for RSG. These offers were evaluated along with the rest of the RFP responses. None of these offers were selected this year.

Responses to the purchased-gas RFP were due on March 7, 2024. The Company received proposals for 184 gas supply packages from 18 potential suppliers. As part of the RFP requirements, submissions must specify if the same gas supply is offered under multiple proposals. This year, supplies offered under baseload proposals totaled 715,450 Dth/D, up from the 640,500 Dth/D offered last year. Peaking supplies offered on the MWP system totaled 167,000 Dth/D, up from the 75,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 175,000 Dth/D, up from last year's level of 150,000 Dth/D.

Each spring, following the receipt of all the proposals, the Company reviews all the packages offered and extracts the parameters needed as data inputs to the PLEXOS model.[54] The Company must identify the pricing mechanisms utilized for each package and link each to the appropriate index price in the model. Also, the Company must resolve the

[54] The SENDOUT model and the Monte Carlo method are described in more detail in the Final Modeling Results Section of this report.

availability of receipt and delivery point capacity on the interstate pipeline system. To the extent that the same underlying gas supplies have been offered under different price and term packages, the Company must identify each to prevent the purchasing of more gas than is actually available. This year, the PLEXOS model evaluated 184 supply packages.

After the Company enters these purchased-gas packages into the PLEXOS model, it allows the model to find an optimal linear-programming solution for any one or all of the packages of natural gas. During this optimization process, the PLEXOS model only incurs costs for a package of gas if it elects to include that package. This gives the model freedom to look at all packages and optimize them in a way that results in the least-cost combination of resources.

This year the model evaluated 1,200 Monte Carlo draws during the modeling process. At the conclusion of the modeling, the Company analyzed the draws to see which were preferred. The Company used a procedure to plot the draws based on Design Day and annual demand as shown in Exhibit 8.1. This year, instead of grouping the draws, the Company plotted each individual draw. The resulting plot shows annual demand on the X axis of the graph, and Design Day on the Y axis. This plot shows how the PLEXOS model met high or low demand during Design Day events.

The Company then selected the draws that most closely met the forecasted Design Day for the coming year while also meeting the forecasted annual demand. The preferred draws are highlighted in Exhibit 8.2. The packages of gas to purchase were selected from these preferred draws. The Company examined the preferred draws looking at the number of times a given package of gas was chosen and the volume of that package most often.

The Company also reviewed the original packages in order to verify that the Company did not entrust too much of its purchased gas to one vendor, that peaking versus baseload contracts seemed reasonable, that packages were within the transportation limits of both KRGT and MWP and verified that a cluster combined with cost-of-service, storage, and spot purchases would meet Design Day requirements. Once this screening was completed, the most often used packages emerged from the RFP process and were then finalized with suppliers.

The levels of purchased-gas packages selected from the PLEXOS modeling process this year are shown in the Final Modeling Results section of this report. The median purchased-gas volumes from the Monte Carlo simulation for the upcoming gas-supply year are shown by month in Exhibits 14.29 to 14.40 along with each probability distribution. The model scenario based on a 20-year normal heating degree day period, spanning 20 years ending December 31, 2018 (Normal Weather) is called the (Normal Case). Individual packages of purchased-gas supplies for the Normal Case are shown for the first two plan years in Exhibits 14.62 and 14.66.

Of the 18 companies submitting proposals this year, 9 had at least one package selected by the modeling process. The total volumes offered was 715,450 Dth per day of baseload supply, 165,000 Dth per day of peaking supply on MountainWest Pipeline, and 175,000 Dth per day of peaking supply on Kern River Gas Transmission Pipeline.

The Company selected new contracts to provide 141,000 Dth per day of baseload supply during the peak winter period. This is in addition to an existing multi-year deal for 30,000 Dth per day of baseload supply. It also includes a contract that will provide 10,000 Dth per day of supply that is year-round. The Company also selected contracts for 110,000 Dth per day of peaking supply from MountainWest Pipeline and 116,000 Dth per day of peaking supply from Kern River Gas Transmission Pipeline. The Company made commitments to purchase from the selected suppliers starting on May 2, 2024.

PRICE STABILIZATION

On May 31, 2001, the Utah Commission approved a Stipulation submitted May 1, 2001, in Docket Nos. 00-057-08 and 00-057-10 proposing that the Company use stabilization measures in conjunction with natural gas purchases during the winter months (October – March). Pursuant to the Stipulation, the Company hedged portions of its baseload winter natural gas portfolio.

In Wyoming Docket No. 30010-GP-01-62, the Company sought to include costs to reduce price volatility, like those that occurred during the winter of 2000-2001. In its October 30, 2001, Order, the Wyoming Commission approved the Company's request to include stabilization costs in the 191 Account. The Company does not engage in any speculative hedging transactions by limiting these price stabilization efforts to contracts that fix or cap prices for gas supplies that are contractually committed to the Company's system for delivery to end-use retail customers.

In 2023, the Company analyzed its exposure to daily-price risk and planned to utilize a diverse portfolio of price stabilization mechanisms for the 2023-2024 heating season. The Company planned to continue to work with Wexpro to increase cost-of-service production, utilize storage withdrawals while also exploring additional storage options, utilize physical baseload contracts while reducing exposure to monthly pricing indexes and diversifying pricing index locations, and secure reliable supply at key locations.

On October 2, 2023, forward curves at the Northwest Pipeline Rocky Mountains index reflected pricing of $7.65, $7.86, and $6.74 for December 2023, January 2024, and February 2024 respectively. The resulting average expected pricing for the Dec-Feb timeframe was $7.42. The Company was able to purchase 84,000 Dth per day of fixed-price baseload supply for this period at an average price of $7.35. This was a similar volume compared to the 77,000 Dth per day of fixed-price baseload supply purchased for the same period in 2022-2023. The Company purchased this supply by converting some of the deals selected in the RFP for 2023-2024 supply to fixed prices, purchasing fixed-price supply at specific key locations with limited availability, and through specific fixed-price RFPs. The total cost of these contracts was $56,187,9500. A comparison of the 2022-2023 and 2023-2024 supply hedging portfolios is shown in Table 8.3 below.

Table 8.3: 2022-2023 vs 2023-2024 Supply Hedging Portfolio

	2022-2023 Heating Season		2023-2024 Heating Season		Difference	Percent Difference
Fixed Price	77,000	29%	84,000	31%	7,000	3%
Daily Index	2,950	1%	45,450	17%	42,500	16%
Monthly Index	174,000	65%	140,000	52%	(34,000)	-13%
NWRx Index	104,000	39%	55,000	20%	(49,000)	-18%
SoCal Index	70,000	26%	30,000	11%	(40,000)	-15%
CIG Index	0	0%	55,000	20%	55,000	20%
Baseload Total	**253,950**		**269,450**		**15,500**	**6%**
Peaking	**310,000**		**143,542**		**166,458**	
Total	***563,950***		***412,992***		***181,958***	

These additional contracts reduced the Company's exposure to daily price risk to 33% of supply on a cold winter day and 50% on a Design Day. The Company still also has 19% exposure to monthly indexes on a cold winter day and 11% on a Design Day. These amounts are shown in Table 8.4 below.

Table 8.4: 2023-2024 Supply Hedging Portfolio

	Design Peak Day		Cold Winter Day	
Spot	445	35%	53	7.1%
Peak	144	11%	144	19.3%
Base Daily Index	45	4%	45	6.1%
Base FOM	140	11%	140	18.8%
Storage	246	19%	111	14.9%
Base Fixed	84	7%	84	11.3%
Wexpro	167	13%	167	22.4%
	1,271	**100%**	**744**	**100%**

Hedge	637	50%	502	67%
Daily Index	634	50%	242	33%

The contracts selected provide price stability but also ensure reliability through securing supply through the heating season that otherwise would be subject to volatile spot-market pricing and availability.

Natural gas daily pricing in the western markets was volatile in the beginning of the heating season with pricing at Kern Opal daily index reaching $22.82 for the weekend of January 13-16, 2024. However, weather moderated after that with pricing continuing to decline through the rest of the heating season. As a result, the fixed-price contracts' pricing cost customers $26,666,990 compared to the actual daily indexed pricing of the spot market during the heating season. This is shown in Figure 8.1 below.

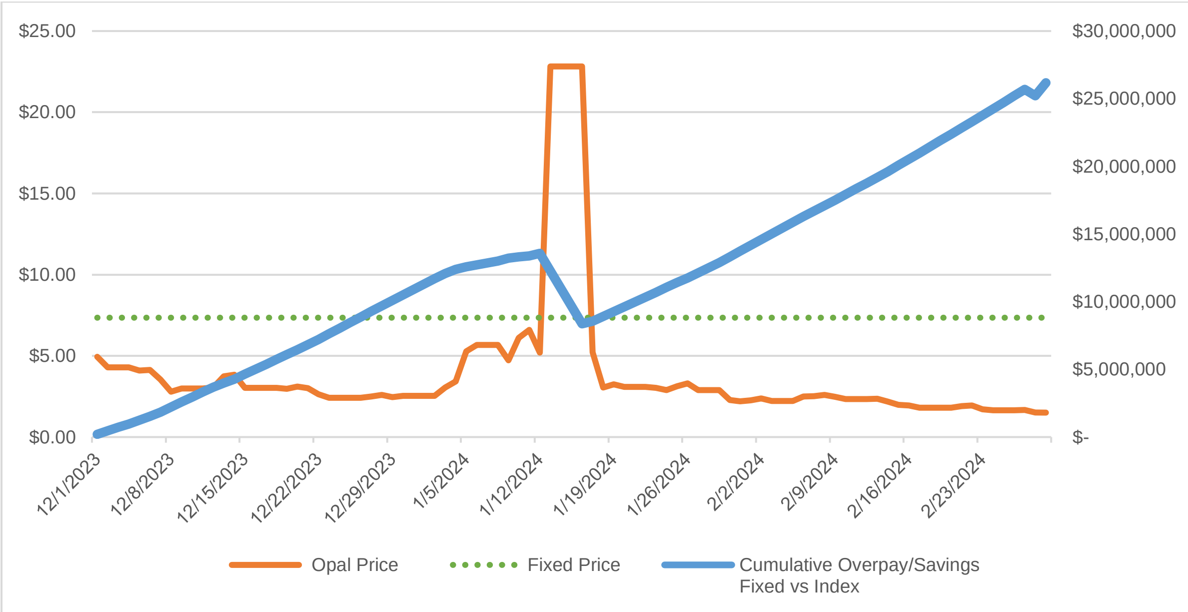


Figure 8.1: 2023-2024 Fixed Price vs. Kern Opal Index

As of April 19, 2024, forward curves at the Northwest Pipeline Rocky Mountains index reflected pricing of $6.91, $6.97, and $5.89 for December 2024, January 2025, and February 20254 respectively. The resulting average expected pricing for the Dec-Feb timeframe was $6.59. The Company also expects the increase in natural gas price volatility will continue in the near term and will continue to review the same alternatives for additional price stabilization options for the 2024-2025 heating season and beyond. The factors impacting pricing are discussed in the Pricing Trends subsection in the Industry Overview Section of this report.

The Company's review of potential alternatives will include tracking the availability of additional storage, determining if it may be beneficial to convert any of the monthly-index priced baseload contracts to fixed-price contracts and considering whether to add additional fixed-price baseload contracts through a separate RFP. As discussed in the Gathering, Transportation, and Storage section of this report, the Company will continue to explore alternatives for potential additional storage and for utilizing pipeline transportation to access diverse supply sources. In addition to price stabilization, baseload supply deals, and physical storage also help to secure the reliability of supply.

PURCHASE LOCATION AND VOLUMES

Location of purchases is important to both cost and reliability of supply. As discussed in the Gathering, Transportation, and Storage section of this report, the Company contracts for firm transportation capacity to provide access to locations with adequate availability of supply. The historic locations, amounts, and average cost per Dth of purchased gas from 2021 to April 2024 are shown in Table 8.5 below.

Table 8.5: 2021-2024 Purchase Locations, Amount, and Cost

		2021-2022			2022-2023			2023-2024 (Through April 18)		
Location	State	Amount (Dth)	Cost	Cost Per Dth	Amount (Dth)	Cost	Cost Per Dth	Amount (Dth)	Cost	Cost Per Dth
ALTAMONT MM	UT				603,344	$6,593,530	$10.93	584,100	$1,874,651	$3.21
BIG PINEY EXCHANGE	WY	92,451	$500,549	$5.41	131,228	$1,475,898	$11.25	99,579	$371,531	$3.73
BLUE FOREST TAP	WY	3,292,969	$18,421,766	$5.59	3,721,977	$33,246,872	$8.93	182,000	$546,116	$3.00
CHIPETA PLANT (REC)	UT	126,000	$635,493	$5.04	1,720,528	$20,199,579	$11.74	2,669,020	$11,009,658	$4.12
CLAY BASIN QPC WD	UT	3,626,211	$19,503,324	$5.38	4,597,795	$67,999,315	$14.79	1,819,989	$6,988,759	$3.84
CLAY BASIN RESERVOIR	UT	100,000	$371,000	$3.71	1,320,000	$8,634,500	$6.54	56,500	$140,000	$2.48
DRIPPING ROCK	WY				357,588	$5,715,017	$15.98			
FT GOSHEN POOL	UT	6,371,964	$37,488,818	$5.88	3,825,469	$78,237,812	$20.45	3,630,000	$20,337,600	$5.60
FT MUDDY CREEK POOL	WY	13,216,646	$72,517,046	$5.49	17,962,537	$263,961,179	$14.70	13,264,814	$70,936,626	$5.35
HUNTER PARK - QUESTAR GAS	UT							1,977,421	$13,746,762	$6.95
KANDA/COL CIG DEL	WY				1,244,188	$12,428,964	$9.99	1,138,176	$4,383,817	$3.85
KANDA/COL CIG REC	WY	4,142,648	$24,219,672	$5.85	2,377,634	$26,697,454	$11.23	1,499,000	$5,198,053	$3.47
KANDA/COL OTPL DEL	WY	915,240	$4,850,486	$5.30	4,226,845	$56,662,710	$13.41	4,743,060	$15,512,578	$3.27
LABARGE EXCHANGE	WY	21,069	$112,440	$5.34	27,381	$327,478	$11.96	19,167	$73,811	$3.85
OPAL PLANT TO QPC/WTNY	WY	267,255	$1,353,534	$5.06	207,084	$1,380,014	$6.66	510,000	$3,674,725	$7.21
OTPL TO QPC X016 REC	WY	880,000	$5,751,500	$6.54	929,440	$22,792,279	$24.52	964,918	$4,660,512	$4.83
OVERTHRUST JL 36 MS	WY	3,933,701	$25,687,999	$6.53	6,992,041	$154,833,776	$22.14	6,789,145	$45,800,143	$6.75
QGC WASATCH FRONT	UT							2,000	$7,500	$3.75
QGC/104	UT	10,000	$53,350	$5.34	280,000	$5,842,800	$20.87	40,000	$916,800	$22.92
RED WASH - FIDLAR	UT	314,600	$1,633,858	$5.19	865,753	$10,061,704	$11.62	763,000	$2,790,160	$3.66
RIVERTON - QUESTAR GAS	UT	704,584	$4,817,330	$6.84	885,876	$7,918,858	$8.94	40,000	$912,800	$22.82
ROBERSON CREEK RCPT	WY	80,000	$375,300	$4.69						
SHUTE CREEK MM	WY	4,478,115	$24,797,393	$5.54	4,122,105	$30,973,464	$7.51	2,616,148	$9,363,781	$3.58
VERMILLION PLT OUT	WY				67,680	$238,348	$3.52	6,000	$12,830	$2.14
WHITE RIVER HUB (R)	CO	14,024,991	$74,786,858	$5.33	17,952,009	$140,864,398	$7.85	16,246,217	$41,110,966	$2.53
WIC WAMSUTTER TO QPC	WY	852,636	$4,283,695	$5.02	1,333,375	$24,016,457	$18.01	873,312	$6,803,064	$7.79
XO-16 NWP REC	WY	2,013,517	$11,736,147	$5.83	5,569,491	$51,747,872	$9.29	2,952,019	$16,096,009	$5.45

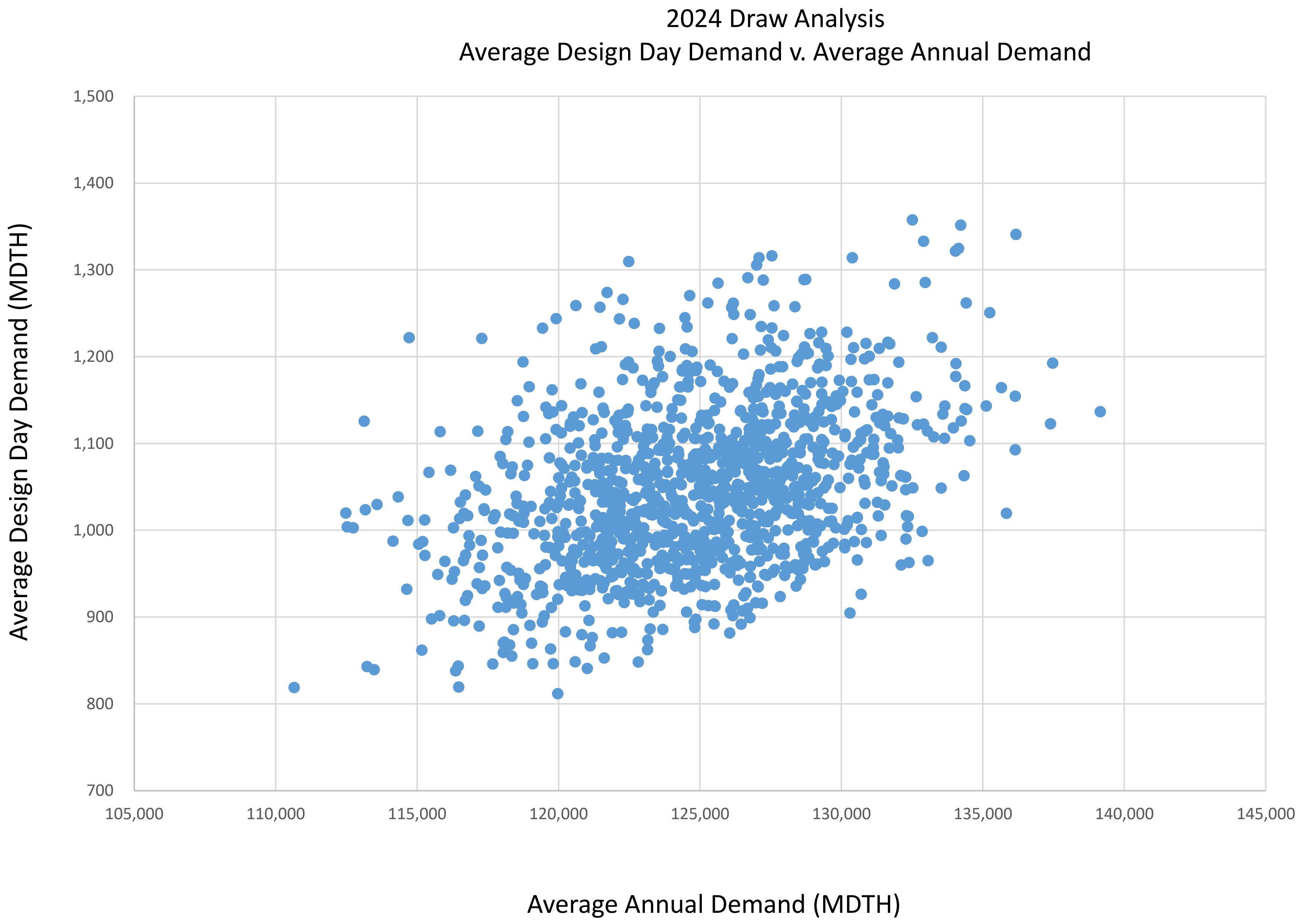

2024 Draw Analysis
Average Design Day Demand v. Average Annual Demand
Average Design Day Demand (MDTH)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
105,000
110,000
115,000
120,000
125,000
130,000
135,000
140,000
145,000
Average Annual Demand (MDTH)

Exhibit 8.1

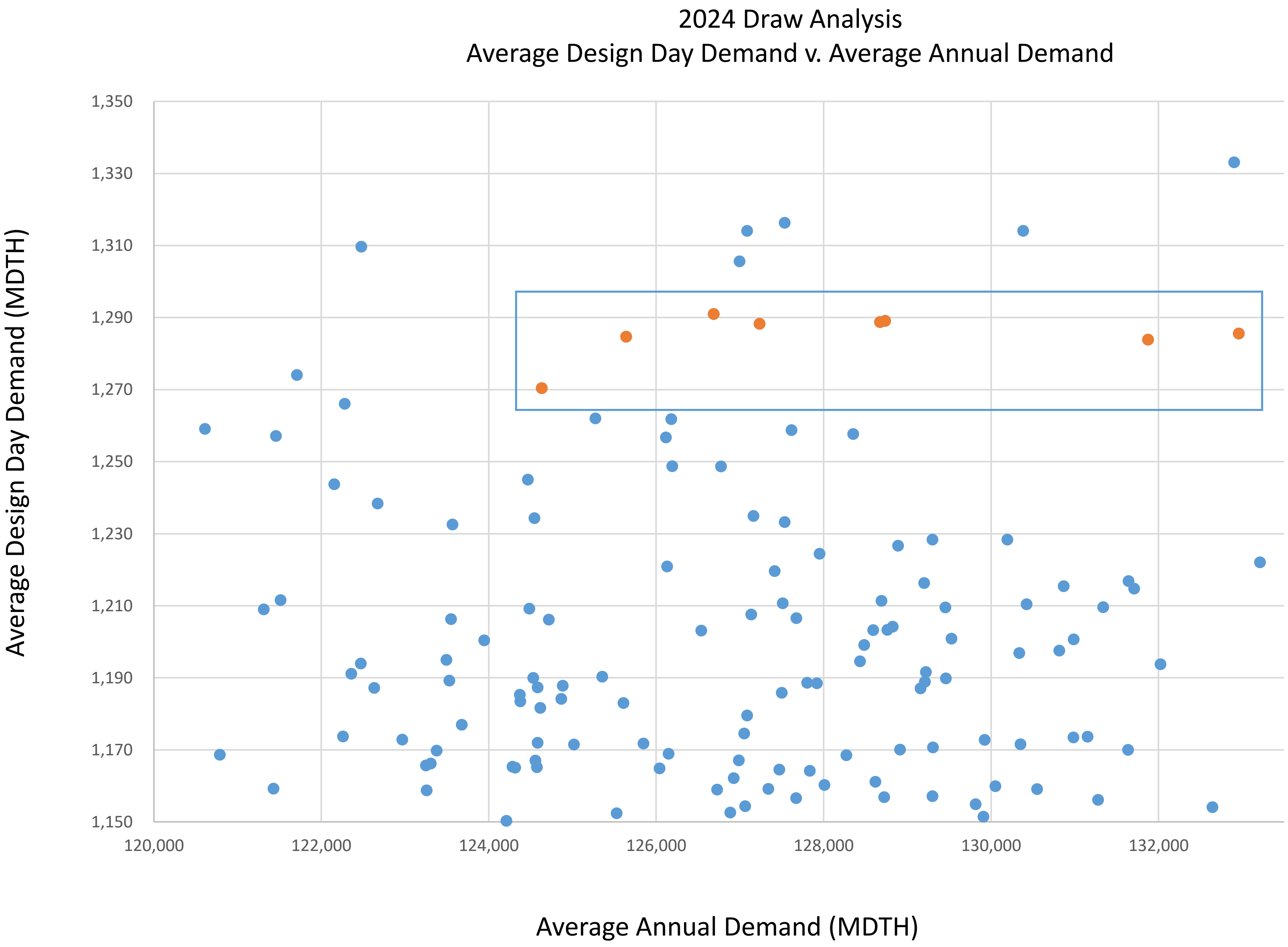

2024 Draw Analysis
Average Design Day Demand v. Average Annual Demand
Average Design Day Demand (MDTH)
1,350
1,330
1,310
1,290
1,270
1,250
1,230
1,210
1,190
1,170
1,150
120,000
122,000
124,000
126,000
128,000
130,000
132,000
Average Annual Demand (MDTH)

Exhibit 8.2

THE COST-OF-SERVICE GAS

COST-OF-SERVICE MODELING FACTORS

The Wexpro Agreement, signed in 1981, defines the relationship between Wexpro and the Company. Under this agreement, Wexpro manages and develops natural gas reserves within a limited and previously established group of properties. Production from these reserves is delivered to the Company at cost-of-service. Since its inception, the Company's customers have received a net benefit from natural gas produced pursuant to the Wexpro Agreement. In recent years, natural gas supplies provided pursuant to the Wexpro Agreement have exceeded one half of the total annual supplies required to meet the needs of Company customers.

During 2013, both the Utah and the Wyoming Commissions approved the Wexpro II Agreement. This agreement was designed to continue the delivery of cost-of-service natural-gas supplies to the customers of the Company through the acquisition of oil and gas properties or undeveloped leases.

In January of 2014, the Utah and Wyoming Commissions approved the Trail Unit Acquisition as a Wexpro II Property. As part of this approval, Wexpro was required to manage cost-of-service production to less than 65% of the forecasted demand for the Company's sales customers each IRP year. In calculating the production percentage, pursuant to the Trail Stipulation, the total wellhead volume of cost-of-service production received as part of the Wexpro I and Wexpro II Agreements will be divided by the total forecasted demand for the Company's sales customers as provided in each year's IRP (see Exhibit 3.10). Wexpro may also sell cost-of-service production in order to manage to the specified level. Under the terms of the Trail Settlement Stipulation, any production sold will be credited to the Company at the greater of the sales price or the cost-of-service price.

In November of 2015 the Utah and Wyoming Commissions approved the Canyon Creek Unit Acquisition as a Wexpro II Property. As part of this approval, the Company, Wexpro, the Division, the Office, and the Wyoming Office of Consumer Advocates (WY OCA), submitted the Canyon Creek Stipulation to the Wyoming and Utah Commissions in their respective dockets. On November 17, 2015, the Utah Commission approved the Canyon Creek Stipulation, and on November 24, 2015, the Wyoming Commission issued its approval of the Stipulation.

In addition to adding the Canyon Creek acquisition as a cost-of-service property under the Wexpro II Agreement, the Canyon Creek Stipulation included certain requirements as follows:

- Wexpro will design its annual drilling program or drilling programs that are more frequent than the annual cycle to provide cost-of-service production that is, at the time Wexpro incurs an obligation in connection with a drilling program, on average, at or below the 5-Year Forward Curve price that was agreed to in the Trail Settlement Stipulation.

- The rate of return on post-2015 Wexpro I and Wexpro II development drilling, or any other capital investment, will be the Commission-Allowed Rate of Return as defined in the Wexpro II Agreement. The return is currently 7.18% as a result of the Company's return on equity (ROE) in its general rate case (Docket No. 19-057-02). The pre-2016 investment base and returns will not be affected.

- Wexpro reduced the cost-of-service gas supply to the Company from 65% of annual demand to 55% beginning in the 2020 IRP Year.

- Post 2015 dry-hole and non-commercial well costs will be expensed and shared on a 50/50 basis between utility customers and Wexpro.

- When the annual weighted average price of cost-of-service gas produced under both Wexpro agreements is less than the current market price, then the annual savings on post-2015 development will be shared on a 50/50 basis between utility customers and Wexpro. When shared savings occurs, Wexpro's return will be capped at the Base Rate of Return + 8%.

In 2022, the Utah and Wyoming Commissions approved the settlement stipulation in the Company's request to modify the Wexpro production cap in Docket Nos. 22-057-04 and 30010-203-GA-22 (Settlement Stipulation), respectively. As a result, the Company may petition each Commission for permission to exceed the 55% production limitation, up to 65%, for a defined period of time. Specifically, the Settlement Stipulation provides that Wexpro may be permitted to manage combined cost-of-service production from Wexpro I and Wexpro II properties to exceed the 55% threshold if Wexpro files a plan that:

- Shows that planned production will be provided at a cost lower than the five-year forecast curve together with shut-in costs;

- The planned production does not exceed 65% of the Company's annual forecasted demand as identified in its IRP, or 65% of the Minimum Threshold as defined in the Trail Settlement Stipulation;

- Includes the date by which Wexpro I and Wexpro II production are reduced to below 55% of the Company's annual IRP forecast or the Minimum Threshold; and

- Each Commission finds the plan to be in the public interest, considering a variety of factors set forth in the Settlement Stipulation.

The Company and Wexpro have not yet sought to advance a plan pursuant to the Settlement Stipulation, and production continues to be planned not to exceed 55% of the Company's IRP forecast. However, the Settlement Stipulation enhances the Company's ability to utilize cost-of-service gas as a hedge against price increases.

During calendar year 2023, Wexpro produced 55.3 MMDth of cost-of-service supplies measured at the wellhead, down from the 56.5 MMDth level produced during calendar year 2022. As development drilling continues to occur, Wexpro anticipates that there will be many more years of production from these sources, due in part to technological improvements in drilling and production methods.

Wexpro continues to look for opportunities to add new properties to the Wexpro II Agreement. The company received approval on June 10, 2022, in Utah and on July 25, 2022, in Wyoming, to include Alkali Gulch wells into the agreement. The company also received approval on April 1, 2024, in Utah and on April 25, 2024, in Wyoming to include the Horseshoe Bend acquisition. The Horseshoe Bend acquisition was a farmout agreement with the owner of a working interest in two federal leases located in Uinta County, Utah.

From calendar year 2022 to 2023, the total costs, net of credits and overriding royalties, for cost-of-service production decreased by approximately 1.4%. This decrease was caused by reduced customer sharing income costs. In 2023, Wexpro incurred $4.1M of customer sharing income costs whereas in 2022, $26.6M was incurred, a $22.5M reduction. These costs are incurred when market prices are greater than Wexpro’s cost-of-service price and Wexpro is allowed to share in 50% of the savings up to a limit on the post-2015 gas development investment base. Additionally, this reduction was offset by higher operator service fees led by higher O&M costs. More information on Wexpro’s planned development drilling programs are contained in the Future Resources discussion later in this section.

One of the important results of the PLEXOS modeling process is a determination of the appropriate production profiles for the cost-of-service gas. This year, the Company modeled 138 categories of cost-of-service production. Last year, it modeled 158 categories. The Company used a modeling time horizon of 25 years for the base case scenario. A relatively long time-horizon better reflects the fact that cost-of-service gas is a long-term resource.

The Company created these categories of cost-of-service gas to naturally group wells which have common attributes including factors such as geography, economics, and operational constraints. A large amount of data must be compiled to provide the inputs to the PLEXOS modeling process. The Company has relied on the expertise of Wexpro personnel in assembling the data elements needed to model each category. Some of those data elements are reserve estimates, production decline parameters, depreciation, and amortization rates, carrying costs, general and administrative costs, operating and maintenance costs, production taxes, royalties, income taxes, and oil revenue credits. The Final Modeling Results section of this document contains the probability curves and median levels of production for cost-of-service gas resulting from the PLEXOS modeling process this year.

The Utah Commission, in its Report and Order issued October 22, 2013, and concerning the Company’s 2013 IRP, required the Company to provide a scenario analysis in future IRPs.[55]

[55] In the Matter of Questar Gas Company’s Integrated Resource Plan for Plan Year: June 1, 2013, to May 31, 2014, The Public Service Commission of Utah, Report and Order, Docket No. 13-057-04, Issued: October 22, 2013.

The IRPs should contain an analysis consisting of the results from multiple PLEXOS modeling scenarios. These scenarios should include varying percentages of cost-of-service gas with varying levels of Company demand (e.g., low, normal, and high). For each scenario, the Company should provide expected management actions, such as projected well shut-ins. Scenario results should include the impacts of those management actions on overall costs. The requested scenario analysis is included at the end of the Final Modeling Results section of this IRP.

Since the late 1990s, the Company has submitted confidential quarterly variance reports to Utah regulatory agencies, as required under the Utah Commission's IRP standards and guidelines. These reports detail the material deviations between planned performance and actual performance of cost-of-service natural gas supplies. Under the 2009 IRP Standards, that process will continue into the future.

There are many reasons the confidential quarterly variance reports often show variance between anticipated volumes and actual production. As part of the IRP modeling process, Wexpro and the Company are required to anticipate the production capability of approximately 2,106 wells. Some of these wells have not been drilled yet but are included in the planning process. Forecasting production from existing wells is not a precise science and forecasting for wells not yet drilled involves even more uncertainty. New wells can be, and occasionally are, dry holes. Production from new wells can vary from non-commercial quantities to levels several times that anticipated during the planning process. Fortunately, non-commercial wells occur very rarely.

Unanticipated delays during the partner approval process can also postpone planned production. Delays during permitting, drilling, and completion can also affect the timing of production volumes. An unexpected archeological find on a drill site can either cause extensive delays for all the wells planned for the site or cause the wells not to be drilled at all. Even small delays can cause schedules to conflict with environmental windows for the migration, mating, and/or nesting of local species, resulting in greater delays. Pad drilling, with all its inherent cost efficiencies can also create delays. Since all the wells on a pad are typically connected to a single gathering system, any delay in one well affects the production timing of all the pad wells.

For existing wells, a number of geotechnical factors can affect production levels. Although reservoir engineers are skilled in the utilization of sophisticated techniques to forecast future production decline rates, precisely predicting the performance of reservoirs, many thousands of feet deep, is complex and uncertain. The fact that the pressures of the connected gathering lines are constantly changing due to fluctuating supplies into, and demands from, the local gathering system further complicates the production process (a phenomenon often totally out of the control of the producers). New wells drilled by any party typically come in at very high pressures and, in the short term, can "pressure-off" old wells temporarily reducing existing production levels from a field. While compression can remedy such problems, those costs must be factored into the overall economics of the production stream. Also, the design and construction of compression facilities takes additional time to complete. There are many reasons for variances between planned and actual cost-of-service gas volumes.

PRODUCER IMBALANCES

In most cost-of-service wells, there are multiple working interest partners. Each of these partners generally has the right to nominate its legal entitlements from a well subject to restrictions as defined in the operating agreement and/or gas balancing agreement governing that well. As the individual owners in a well each nominate supplies to meet their various marketing commitments, imbalances between the various owners are created. Imbalances are a natural occurrence in wells with multiple working interest owners. There are no fields or wells with multiple owners having individual marketing arrangements where an imbalance does not exist. No individual working interest owner can control, in the short term, the level of producer imbalances associated with a well because it does not have control over the volumes that the other working interest owners are nominating.

Anytime allocated wellhead volumes differ from legal entitlements for any one party, an imbalance is created for all the parties in the well. The fact that it is not uncommon for the market of a working interest owner to be lost unexpectedly, either in part or in full, for a variety of reasons, further complicates matters. This can happen without the knowledge of the other parties for a significant period of time and will contribute to an imbalance.

For some wells with multiple working interest owners, contract-based producer-balancing provisions exist. These provisions generally allow for parties that are under-produced to nominate recoupment volumes from parties that are over-produced. Given the time lag in the accounting flow of imbalance information, delays of several months can occur. The process becomes more complicated because several weeks' advance notice is typically necessary before imbalance recoupment nominations can occur.

Over the past year, producer-imbalance recoupment has taken place in several areas where the Company is entitled to cost-of-service supplies. Exhibit 9.1 shows the monthly volumes nominated in these areas for recoupment during calendar year 2023 and for the first three months of 2024. The Company has been taking recoupment in the Church Buttes and Moxa Arch areas for most of the January 2023 through March 2024 period.

As can be seen in Exhibit 9.1, other parties have been recouping gas from the Company. Recoupment from the Company also occurred in the Church Buttes and Moxa Arch areas throughout the period.

As of December 31, 2023, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of 355.8 MMcf.[56] By way of comparison, the total net producer imbalance level for December 31, 2022, was 727.0 MMCF. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its

[56] A positive imbalance means volumes are owed to other parties.

responsibilities. In the most recent audit report, the Hydrocarbon Monitor did not express any concerns about the total producer imbalance levels.[57] Wexpro has not yet received the audit report for 2024.

FUTURE RESOURCES

The current market price of natural gas coupled with future price expectations directly drives the level of drilling in the U.S. Multiple other factors also play into the drilling decision. For example, it may make sense to drill when prices are low because drilling costs are generally lower. By the time a well is drilled and turned to production, prices may have rebounded.

In many situations, lease obligations and drilling permits dictate that leases must be developed within a specified period of time. Lease obligations may require that a property be developed within 5-10 years, or the leases may be lost. Drilling permits typically expire after 2 years. Allowing drilling permits to expire would result in additional costs by requiring the process to start over. These provisions generally prevent exploration and production companies from holding leases indefinitely without creating value for royalty owners. In the current price environment, a substantial portion of drilling in shale-gas plays continues in order to hold leases.

Wexpro's focus is to maintain its long-term drilling plans, thereby continuing to benefit the Company's customers. For calendar year 2024, Wexpro plans on completing to production, approximately 44.1 net wells with a capital budget for those wells of approximately $96.3 million.[58] Assuming market prices don't deviate dramatically from current expectations for the years 2024 through 2028, the total planned net wells are approximately 44.1, 38.4, 35.9, 33.4, and 23.0 respectively, with total annual investments in the range of $62.9 to $96.3 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2024 will focus on the Trail, Canyon Creek, Island, and Alkali Gulch.

Plans, forecasts, and budgets for drilling development wells under the Wexpro Agreements are always subject to change. Many factors including economic conditions, ongoing success rates, partner approval, availability of resources (rigs, crews, and services), access issues associated with environmentally sensitive areas, re-completion requirements, drainage issues, and demand letters all have an impact on drilling and capital budget projections.

PRODUCTION SHUT-INS

The Company utilizes the PLEXOS model to optimize the use of cost-of-service production. The PLEXOS model will choose to shut in the production when it determines this is the most optimal solution considering gas costs, storage availability, and demand. The Company creates operational model updates on a weekly basis to incorporate near-term weather

[57] Wexpro Hydrocarbon Monitor 2023 Spring Semi-annual Review, Wilcox Consulting Company, June 2023.
[58] "Net wells" are the summation of working interests (total and partial ownership).

forecasts, updated pricing forecasts, and/or production forecast changes. The Company uses these updated models to make operational decisions regarding production shut-ins, storage use, and purchases on a day-to-day basis. However, since the model optimizes based only on cost, the Company may override the model guidance due to other factors. These factors can include operational activities such as testing or well, pipeline, or storage maintenance.

Based on the 2023 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 0 MDth of cost-of-service production shut-in for June 2023 through October 2023. As shown in Table 9.1Table 9.1, the Company did not shut in any production due to pricing in 2023.

Table 9.1: 2023 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth	**0 Dth**
Actual Shut-in Production	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth

Based on the 2024 forecast for production provided by Wexpro and normal weather, the model determined that no cost-of-service production should be shut-in for June 2024 through October 2024.

Table 9.2: 2024 Forecasted Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth	**0 Dth**

9.5 RECEIPT LOCATIONS AND VOLUMES

Wexpro production is gathered and delivered into pipelines. The Company transports most of the cost-of-service production on MountainWest Pipeline. The receipt locations of this supply are summarized in Table 9.3 below.

Table 9.3: 2023 Production Locations

Location	State	2021-2022 (Dth)	2022-2023 (Dth)	2023-2024 (Dth)
Powder Wash	CO	2,551,466	2,190,097	1,297,762
Hiawatha	CO	163,510	531,082	328,786
Clay Basin Frontier	UT	715,349	747,794	449,797
Blue Forest / Granger	WY	65,785	67,575	34,074
Blacks Fork	WY	18,267,455	14,609,387	8,449,765
Vermillion	WY	30,816,885	33,650,076	18,536,394
No. Baxter	WY	40,137	27,735	40,664
Red Wash	UT	593,164	667,682	554,932
Opal	WY	1,012,315	1,020,926	620,334
Wamsutter	WY	127,103	39,893	18,260
Grand Total		**54,353,169**	**53,552,247**	**30,330,768**

Exhibit 9.1

Recoupment Nominations (Dth per month by Field) To Dominion Energy		
	Church Buttes	**Moxa**
23-Jan	1,953	12,741
23-Feb	1,848	10,752
23-Mar	2,232	0
23-Apr	1,530	11,880
23-May	341	12,555
23-Jun	3,720	11,760
23-Jul	3,565	11,408
23-Aug	2,201	10,633
23-Sep	2,130	10,950
23-Oct	2,821	0
23-Nov	0	0
23-Dec	1,984	0
24-Jan	2,263	0
24-Feb	2,523	0
24-Mar	0	0
Total	29,111	92,679

Recoupment Nominations (Dth per month by Field) To Other Parties		
	Church Buttes	**Moxa**
23-Jan	-	2,015
23-Feb	-	1,708
23-Mar	-	1,581
23-Apr	-	1,500
23-May	-	1,798
23-Jun	-	2,040
23-Jul	-	3,875
23-Aug	-	2,945
23-Sep	-	3,900
23-Oct	-	16,647
23-Nov	18,420	59,520
23-Dec	-	1,519
24-Jan	-	1,147
24-Feb	-	1,769
24-Mar	-	1,178
Total	18420	103142

GATHERING, TRANSPORTATION, AND STORAGE

GATHERING AND PROCESSING SERVICES

The Company acquires a substantial portion of its natural gas supplies each year pursuant to the Wexpro Agreements. In many situations, gathering and/or processing services are required for these supplies before they can enter the interstate pipeline system to travel to the Company's city gates. Therefore, the Company has several gathering and processing agreements.

The Company has gathering agreements with Williams Field Services (J88, K07, L116, R06 and L39) and Western Midstream (WGR #6236). However, the majority of the cost-of-service production is gathered under agreements between the Company and Marathon Petroleum Logistics (MPLX). These agreements include the #163 contract, commonly known as the System Wide Gathering Agreement (SWGA), the #4485 contract, the #2091 contract, and the #683 contract.

The Company includes cost data for the gathering and processing functions each year in the supply modeling process. The supply model uses a logical gas supply network to define the relationships between modeling variables. Exhibit 10.1 illustrates those logical relationships for the gathering, processing, and transportation functions as utilized by the model.

TRANSPORTATION SERVICES

The Company evaluates all transportation options using assumptions that ensure the Company provides safe, reliable, diverse, and cost-effective service to its customers. As customer demand grows, the Company continues to review options for firm transportation capacity to ensure reliable deliverability of gas supplies. The Company bases contracting decisions on current and forecasted needs, as well as current and projected capacity availability, to ensure supply diversity and reasonable cost. The Company holds firm transportation contracts on MWP, MountainWest Overthrust Pipeline (MWOP), KRGT, Northwest Pipeline, and Colorado Interstate Gas (CIG).

MountainWest Pipeline

The Company has four firm transportation contracts with MWP: (1) Contract #241 for 798,902 Dth/D, (2) Contract #2945 for 12,000 to 87,000 Dth/D (volume changes seasonally), (3) Contract #2361 for 30,000 Dth/D and (4) Contract #6136 for an additional 100,000 Dth/D. These contracts provide capacity from multiple receipt points, including Clay Basin, Vermillion Plant, Blacks Fork Plant, Kanda, and interconnects with Northwest Pipeline, Overthrust Pipeline, and White River Hub.

Contract #241 currently has a term expiration of June 30, 2027. This contract provides access to storage facilities, useful purchases location, such as Kanda, Clay Basin, Blue Forest, Shute

Creek XO-16 with NWP, Spire Storage, Red Wash, Chipeta, and White River Hub. It also serves to Wexpro production from Blacks Fork, Vermillion, Powder Wash, and Red Wash.

Contract #6136 is a contract for additional capacity associated with the Hyrum gate station expansion. This contract also has a term expiration of June 30, 2027, which coincides with the term expiration of Contract #241. Contract #6136 has a receipt point of MWP Whitney Canyon which allows for purchasing gas from Overthrust Pipeline or Spire Storage West.

Contract #2945 has a term expiration of March 31, 2027. This contract provides seasonal capacity with access to valuable receipt points including Vermillion, Blacks Fork, and interconnects with Wyoming Interstate Company, L.L.C (WIC).

Contract #2361 has a term expiration of October 31, 2027. This contract provides capacity to serve the southern portion of the Company's system through the Indianola gate station. This is important capacity to provide year-round supply from Clay Basin to the Company's customers in southern Utah. Without this capacity the Company would have to purchase additional supply from receipt points on KRGT to serve the area. Having contracts with MWP and KRGT also provides additional reliability through a diversification of transportation contracts.

No-Notice Transportation Service

The Company has a contract with MWP for No-Notice Transportation (NNT) service for 203,542 Dth/day. This contract has a term expiration of June 30, 2027. MWP provides NNT service pursuant to its FERC Gas Tariff and the NNT Service Agreement, as amended, between MWP and the Company. MWP's NNT service is offered as an enhanced service to supplement its firm transportation service. NNT service utilizes the contracted reserved daily capacity (RDC) of the underlying firm transportation service (T-1) and offers additional flexibility in intraday variation of the supply and demand of that transportation. Specifically, NNT service allows the Company's level of supply to adjust in real time, subject to certain constraints as described herein, to accommodate the increases or decreases in demand throughout the gas day.

NNT provides for the reservation of firm transportation capacity in excess of a shipper's nomination up to the level of service specified in the NNT contract, not to exceed the RDC of the associated firm contract. NNT supplements firm transportation services with no-notice service, to allow MWP to adjust a shipper's supply in order to accommodate daily demand, which may vary from nominations within the level of service stated in the NNT contract and where total deliveries do not exceed the level of service in the associated T-1 contract. Hourly adjustments above the RDC associated with the firm contract require MWP Firm Peaking Service to assure firm deliveries.

NNT allows MWP to utilize the Company's available storage injection or withdrawal service, together with the Company's available firm transportation service, to balance supply in order to meet actual demand, and to adjust nominations to reflect the change in supply and demand. This enables MWP to automatically adjust the Delivery and Receipt Point nomination(s). When the quantity of gas delivered at Primary Delivery Points specified is less than the quantity of gas nominated for delivery at such points, MWP will automatically inject the difference into storage, subject to available injection allocation capacity. When the quantity of gas delivered at Primary Delivery Points specified is greater than the quantity of gas nominated for delivery at such points, MWP will automatically withdraw the difference from storage, subject to available withdrawal capacity. While no-notice service is “firm up to the RDC,” adjustments above the RDC are subject to actual physical constraints on the pipeline and contractual constraints.

The Company relies on the use of NNT service on a daily basis for delivery in response to non-forecasted demand swings, with adjusted gas day nominations resulting on 356 days during the 2023-2024 IRP year. Different drivers affect the need for the NNT service between summer and winter seasons. In winter, NNT allows the Company to adjust to cold-weather-driven demand changes, while in summer, NNT service provides the Company the flexibility to adjust to demand changes based on changes in customer usage.

The Company used NNT service 194 days during the 2023-2024 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 162 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 132,897 Dth with an average daily supply reduction to the city gate of 26,158 Dth. The maximum daily supply increase to the city gates was 203,542 Dth with an average daily increase to the city gate of 42,730 Dth. The NNT usage for the 2023-2024 IRP year is shown in Figure 10.1 below.

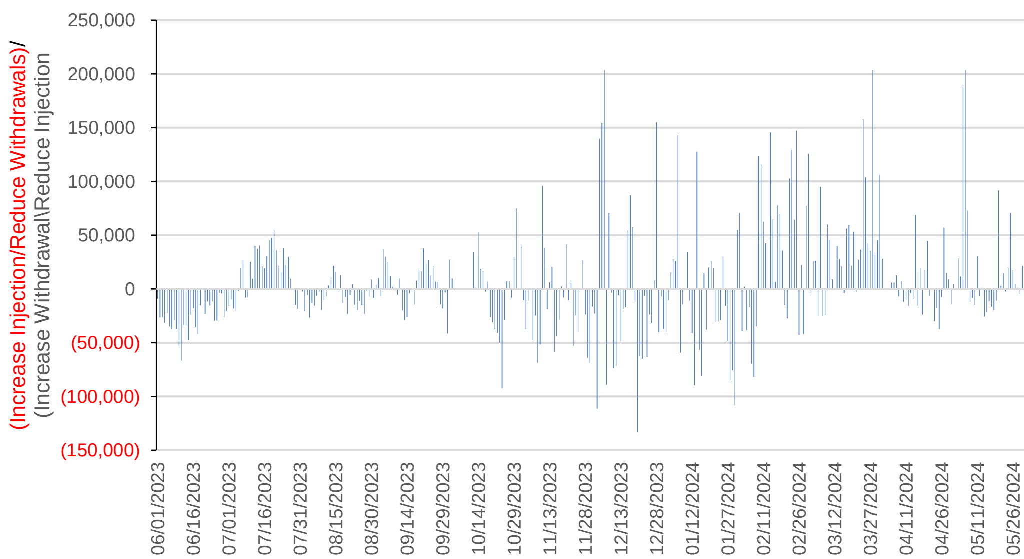


Figure 10.1: NNT Usage – 2023-2024 IRP Year

As part of NNT service, MWP's tariff allows delivery of volumes that exceed the Company's RDC for short periods of time on an operationally available or interruptible basis. The Company and MWP regularly model their systems to quantify this ability to deliver gas at rates that exceed the Company's RDC to ensure that the systems can meet peak-hour demand and peak-flow requirements. While this process quantifies the ability to meet Design Day requirements, the service is only provided on a best-efforts basis and could be interrupted unless MWP Firm Peaking Service is utilized.

MountainWest Overthrust Pipeline

The Company has a firm transportation contract with MWOP for 8,542 Dth/day. Contract #6546 has a term that began on June 1, 2021, and ends on June 30, 2027, in order to coincide with the termination date for MWP Contract #6136. This capacity provides receipt and delivery points that give the Company access to more liquid supply locations for supply to transport on MWP Contract #6136.

Kern River Gas Transmission

The Company has two existing firm transportation contracts with KRGT: (1) Contract #20029 for 83,000 Dth/D, and (2) Contract #20039 for 1,885 Dth/D. Contract #20029 is a 10-year contract at the Alternative Period Two rate with an expiration of April 30, 2028. Of that capacity associated with contract #20029, 33,000 Dth/day of the capacity is available all year. The remaining 50,000 Dth on this contract is only available from November 1st through March 31st each year.

Contract #20039 began on November 1, 2020, under the Alternative Period Two firm transportation service for a Period 2A term of 10 years. The current term expiration for Contract #20039 is November 1, 2030.

To meet growing customer demand and ensure access to reliable supply sources, the Company also contracted for released capacity on KRGT. This long-term seasonal release contract provides firm transportation capacity that will allow the Company to purchase gas at locations with available supply and transport the gas to the Company's city gate stations.

The contract for seasonal release of capacity on KRGT consists of a release of 27,000 Dth/D for the months of November through the succeeding March with a term of November 1, 2017, through March 31, 2032. It also includes a release of 56,925 Dth/D for the months of December through the succeeding February, and 6,000 Dth/D for November and March with a term of November 1, 2017, through March 31, 2031. This capacity has a path from Opal/Muddy Creek to Goshen with full segmentation rights. This effectively allows the Company to use this as 167,850 Dth/D of firm capacity to serve the Company's system.

Northwest Pipeline

The Company has a contract with Northwest Pipeline for 4,311 Dth/D of transportation capacity with a term expiration of April 30, 2029. This contract has a unilateral cancellation provision under which the Company can terminate the agreement by providing 5 years advanced notice. Unless the contract is terminated, each year the contract is extended for an additional year. Northwest Pipeline cannot terminate the contract. The Company uses this contract to serve the towns of Moab, Monticello, and Dutch John. This contract is segmented in order to provide additional capacity to serve these towns. The Company releases capacity to two contracts that were both renewed through April 30, 2025, on May 1, 2022. These segmentation contracts allow for the segmentation of 2,016 Dth/D of this capacity. This allows for a total effective capacity on this contract of 6,327 Dth/D.

In May 2023, Northwest Pipeline commenced and open season for capacity associated with a project referred to as its proposed Ryckman Creek Loop Project (RCL Project). While the primary focus of the project is to provide increased withdrawal capacity from the Spire Storage West storage facility, it is also including access to southbound capacity from the Stanfield, OR receipt points to delivery points that could provide supply to the Company. The open season stated the project could provide up to 44,591 Dth/day of primary firm transportation service between the Stanfield receipt point and the following delivery points: 1) Kern River Muddy Creek, or 2) Overthrust, or 3) Ignacio, or 4) LaPlata, or 5) other delivery points south of Muddy Creek.

The open season required “anchor shipper” bids to have a minimum capacity request of 25,500 Dth/day at the max rate of $0.3725 per Dth/day at a term of no less than 15 years. They also allowed bids for “non-anchor shipper” capacity at lesser volumes at a negotiated rate of $0.30 and a term of no less than 10 years. Bids were due by June 21, 2023. [59]

The Company submitted a non-anchor shipper bid for 25,000 Dth/day for a 10-year period with a receipt point of Stanfield, OR and a delivery to XO-16, an interconnect with MWP. This bid was accepted, and a Precedent Agreement for Firm Transportation was entered into on August 4, 2023. The availability of the capacity is expected to be either December 1, 2025, or December 1, 2026, dependent on the type of permitting required for the project. The 10-year term of the agreement will begin with the availability of the capacity.

Colorado Interstate Gas

The Company has a contract with CIG for 400 Dth/D of transportation capacity with a term expiration of October 31, 2025. The Company uses this capacity to serve the town of Wamsutter, Wyoming. The Company also uses the Foothill gate station to serve Rock Springs, Wyoming from CIG with purchases at the city gate.

FIRM PEAKING SERVICES

Most customers do not use natural gas evenly throughout the day. Usage rates are typically higher in the morning hours. The apex of these periodic increases in instantaneous flow is the peak-hour demand. Hourly demand exceeds the average daily demand for a few hours each day (see Figure 10.2). As the Company’s customer base and associated demand has grown,

[59] “Binding Open Season and Reverse Open Season for Northwest Pipeline LLC’s Ryckman Creek Loop Project”, May 2023.

the Company has seen a corresponding increase in peak-hour demand. It is important to note that transportation capacity is scheduled on a daily basis, not hourly.

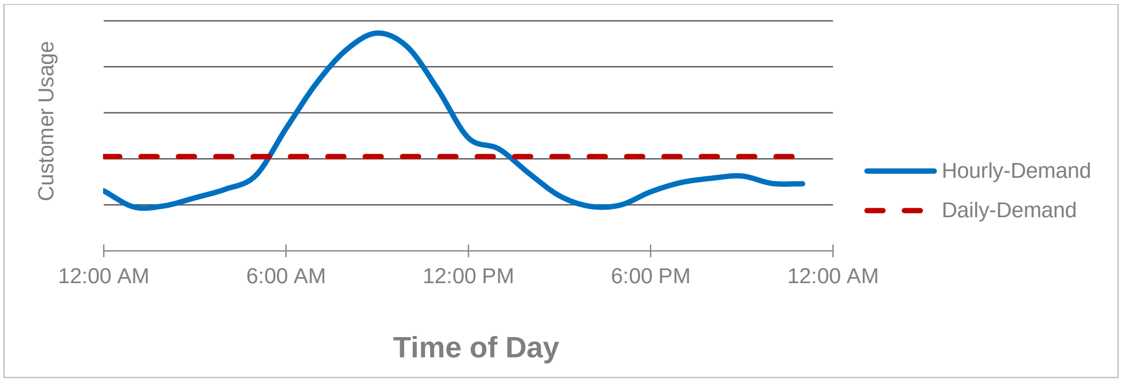


Figure 10.2: Hourly vs. Daily Demand

As shown in Figure 10.3, the Company forecasts that projected peak-hour demand across the system will materially exceed the Company's total firm capacity on a Design Day for each of the next ten heating seasons. This excess peak-hour demand is forecasted to increase from 320,638 Dth/day during the 2024-2025 heating season to 355,742 Dth/day during the 2033-2034 heating season.

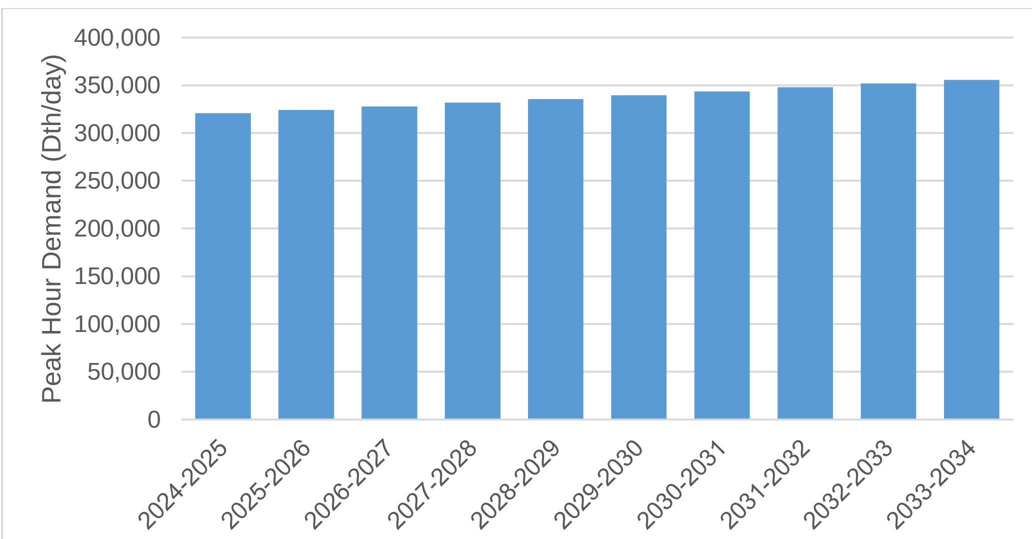


Figure 10.3: Peak-Hour Demand Requirements Above Firm Capacity

The Company continues to evaluate options for meeting the peak-hour demand requirements. The Company has determined that Firm Peaking Services offered by both KRGT and MWP are still the most cost-effective and reliable solution. The Company identified that there is a need for the Firm Peaking Services earlier in December and later in February. Going forward, the term of these contracts may be extended to include the full months of November and February. The Company will continue to review available options for meeting peak-hour demand requirements in order to determine the most cost-effective and reliable solution for future heating seasons.

Kern River Gas Transmission

In February 2024, the Company extended the contract with KRGT for 28,752 Dth of Firm Peaking Service (Contract #1692) for November 1, 2024, through February 28, 2025, November 1, 2025, through February 28, 2026, November 1, 2026, through February 14, 2027, November 1, 2027, through February 29, 2028, and November 1, 2028, through February 28, 2029.

The KRGT Firm Peaking Service for 28,752 Dth allows the Company to flow 4,792 Dth/hr during the 6 peak hours (28,752/6 = 4,792). In order to get the same 4,792 Dth/hr flow on a standard transportation capacity contract, the contract would need to be for 115,008 Dth/day (4,792 x 24 = 115,008). This contract was cost effective because it allowed the Company to pay for capacity during the peak hours when the service was needed instead of paying for the capacity all day. This Firm Peaking Service cost the Company less than the equivalent Firm Transportation Service on KRGT for the same period making the Firm Peaking Service the most cost-effective solution.

MountainWest Pipeline

In November 2021, the Company entered into firm peaking contracts with MWP for 170,000 Dth/day of maximum flow rate with delivery to MAP 164 and 54,000 Dth/day of maximum flow rate to other Company delivery points on the MWP system for November 15, 2021 through February 14, 2022, November 15, 2022 through February 14, 2023, and November 15, 2023 through February 14, 2024. The additional volumes account for the growth in demand on the system.

The Company is currently working with MWP to extend this contract for up to 5 years starting on November 1, 2024.

STORAGE SERVICES

The Company holds firm contracts for storage services with MWP at four underground gas storage fields to respond to seasonal winter and Design Day demands. This includes the Leroy, Coalville, and Chalk Creek aquifer facilities (Aquifers). In 2024, MWP made a change to their tariff to allow them to operate the three aquifers as one facility for nominations/scheduling purposes. Going forward the Company will discuss these all as one facility. The Company also holds contracts for storage at the Clay Basin storage facility. The Company also recently commenced a new Firm Storage Service (FSS) agreement with Spire Storage West which began on April 1, 2024.

MWP owns the Aquifers and the Company utilizes them primarily for short-term peaking needs. The Company is the only shipper at the Aquifers. The Company reviewed these storage resources as part of its planning process and in 2023, extended these contracts through August 2028.

MWP also owns Clay Basin, a depleted dry gas reservoir, and its shippers utilize the facility for both baseload and peaking purposes. The Company's contracted inventory for storage facilities is outlined in Table 10.1 below:

Table 10.1: Contracted Storage Inventory

Facility	Maximum Inventory (MDth)
Clay Basin	13,419
Aquifers	1,928
Spire Storage West	2,000

Clay Basin Storage

The Clay Basin storage facility is located in the northeast corner of Utah, roughly 50 miles from Rock Springs, Wyoming. The Clay Basin field has two producing sandstone formations, the Frontier and the Dakota. The Frontier formation is still producing natural gas today and the Dakota formation is used for storing gas. The Dakota formation was largely depleted in 1976 when construction of the storage facilities began. Today, the Clay Basin reservoir has the largest capacity of any underground storage facility in the Rocky Mountain Region.

The Company receives storage service at Clay Basin under rate schedule FSS. Billing under rate schedule FSS consists of two monthly reservation charges and separate per unit usage fees for injection and withdrawal. The first reservation charge is based on each shipper's minimum required deliverability (MRD) as stated in each shipper's storage service agreement. The second monthly reservation fee is an inventory capacity charge based on each shipper's annual working gas quantity.

The tariff provisions governing Clay Basin ensure that customers will receive their MRD, at a minimum. To the extent that shippers have inventory in excess of their MRD, additional deliverability is available for allocation according to predetermined formulas. The Company exceeds its contract MRD regularly throughout the heating season, but, for purposes of Design Day analysis, the Company assumes that only its MRD will be available during a Design Day.

The Company currently has three FSS storage contracts at Clay Basin. Contract #997 has an inventory capacity of 3,727,500 Dth and withdrawal capacity of 31,063 Dth/day. The current term expiration for this contract is March 31, 2025. This contract has a renewal term of 180 days, so analysis of the renewal of this contract will occur in spring/summer 2024. Contract #988 contract has an inventory capacity of 3,727,500 Dth and withdrawal capacity of 31,063 Dth/day. The current term expiration for this contract is April 30, 2027. Contract #935 contract has an inventory capacity of 5,964,000 Dth and withdrawal capacity of 49,700 Dth/day. After modeling the cost effectiveness using the supply planning model and completing an operational evaluation of this contract, the Company extended the term of Contract #935 for five years in the fall of 2023. The current term expiration for this contract is now April 30, 2029.

2023-2024 Clay Basin Usage

Clay Basin storage is generally used for injection during the non-heating season months (Injection Season) and withdrawals during the heating season (Withdrawal Season). However, there are times, especially on weekends where demand fluctuates to the point that the Company will withdraw during Injection Season or inject during Withdrawal Season. This is an operation benefit of storage, especially when combined with NNT service.

The Company utilizes weekly updates to the PLEXOS model in order to plan and manage the use of storage. The weekly updates include updates to actual storage inventories, production forecasts, and pricing forecasts. These updated models are reviewed to determine the injection withdrawal plans through the year. Variances from the plan based on the original annual plan are discussed in the quarterly variance reports.

Between October 1, 2023, and April 30, 2024, the Company utilized the Clay Basin storage facility to provide more than 8,577 MDth of supply to meet customer demand. This included 35 days with withdrawals that exceeded100 MDth and 9 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 84 days of injection during this period.

The Company usage during the heating season is shown in Figure 10.4 below.

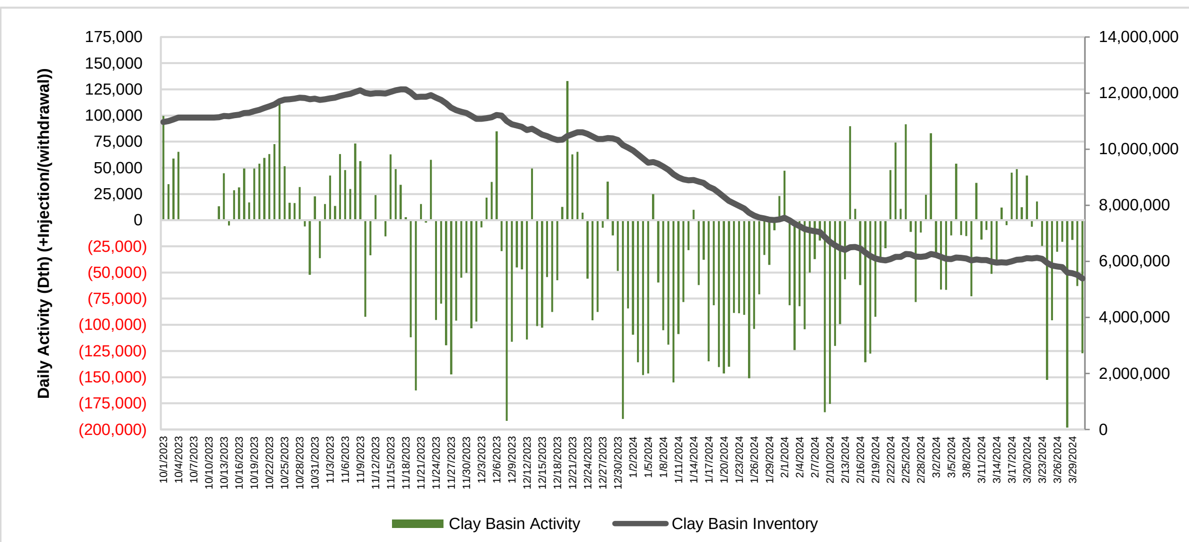


Figure 10.4: Clay Basin Usage 2023-2024 Heating Season (Oct 2023 through April 2024)

Aquifer Storage

The Company had a Peaking Storage (PKS) (Contract #985) for 886,996 Dth of inventory capacity and 79,540 Dth/day of withdrawal capacity at the Leroy aquifer facility, a PKS Contract #986 for 720,372 Dth of inventory capacity and 67,635 Dth/day of withdrawal capacity at the Coalville aquifer facility, and a PKS (Contract #984) for 321,000 Dth of inventory capacity and 37,450 Dth/day of withdrawal capacity at the Chalk Creek aquifer facility. These contracts are now combined into one Aquifers PKS (Contract #7507) which has the same terms as all of the previous combined contracts.

Historically, the Company needed to rely on MWP for guidance as to how to nominate each facility in order to most effectively manage the capabilities of each facility. Going forward, MWP will have the flexibility to operate each individual facility in a manner that will optimize all three facilities based on just one total nominations. The Company will continue to work closely with MWP to guide these operations. However, the nominations process will be simplified for the Company by combining the three facilities into only one required nomination location. Inventory will also now be reported as a combined total inventory.

Following the end of the withdrawal season, the inventories in the Leroy and Coalville facilities have maintained a working gas inventory of approximately 30–50% of maximum capacity through the summer months. Previous practice was to completely deplete the facilities each year at the end of the withdrawal season. The advantages of this revised mode of operation are as follows:

- Wells in the Leroy and Coalville facilities are not “watered out” at the end of the withdrawal cycle, which improves well efficiency when storage injections are initiated in the fall.
- Injection compression fuel gas requirements are reduced (only 50-70% of the working capacity needs to be injected in the fall to fill the reservoir).
- A shorter, more predictable, and easily managed withdrawal/depletion schedule occurs at the end of the heating season.
- A shorter injection season for reservoir refill is required in the fall.

With the Leroy and Coalville inventories at 50%, the flexibility exists to inject significant volumes due to gas displacing water in the reservoir.

In general, operating practices at both the Leroy and Coalville facilities have been as follows:

- Injections into the reservoirs commence in August or September from an initial inventory of approximately 45-55% of maximum working inventory. Injections continue until an inventory of approximately 75% of maximum is reached by early October. Injections follow a specific schedule determined by well and reservoir characteristics which minimizes the potential for “fingering” (gas being trapped behind water in the aquifer and resulting in gas loss).

- In early October, scheduled injections are halted to facilitate MWP’s testing conducted at the Clay Basin storage facility. The testing requires two days of injection at a controlled rate followed by a 7-day no flow period for pressure stabilization. Depending upon system demand and the gas supply situation during the no flow period, the 75% inventory at Leroy and Coalville affords the flexibility to either inject or withdraw to help meet system balancing requirements.

- Following the Clay Basin test, controlled injections again commence in Coalville and Leroy and they typically reach maximum inventory by early November.

- The Company utilizes both Coalville and Leroy to meet peak-load requirements through the heating season, to manage the morning and evening load swings and to offset the cost of purchased gas during a high-pricing event. During periods of lower winter demand, the Company refills the reservoirs to maximum inventory when possible.

- During March, when the need for peaking withdrawals has passed, the Company partially draws down the reservoirs to inventories of approximately 50-70% in preparation for Clay Basin testing (conducted during April). The April Clay Basin test consists of a few days of a withdrawal period followed by 2 days of controlled withdrawal. Following the withdrawal period, MWP shuts Clay Basin in for pressure stabilization. Maintaining Coalville and Leroy at the indicated inventory range during this period provides the flexibility to either inject or withdraw based upon system balancing needs.

- At the end of the spring Clay Basin test, the Company draws Leroy and Coalville down to inventory levels of approximately 45–55% and then maintains both at that level until refill commences in the fall. Periodically, the Company will completely draw down one aquifer when necessary to conduct an inventory volume verification analysis.

Chalk Creek has been utilized differently than the Leroy and Coalville facilities. This facility has more restrictive injection requirements but still provides high deliverability. Due to the nature of the Chalk Creek storage formation and in order to minimize losses, MWP does not currently practice partial inventory maintenance during the summer. Operation at Chalk Creek is as follows:

- By mid-December, the reservoir reaches maximum inventory.

- The Company utilizes Chalk Creek to meet peak-load requirements through the heating season, to manage the morning and evening load swings and to offset the cost of purchased gas during a high-pricing event. During periods of lower winter demand, the Company refills the reservoir to maximum inventory when possible.

- In early March, gas in the reservoir is withdrawn in a controlled manner and it remains empty until refill injections commence in the fall.

2023-2024 Aquifer Usage

The Company uses the Aquifers to provide supply during periods of cold temperatures and/or high pricing during the heating season. The deliverability of each of the Aquifers is impacted by the current inventory and recent usage. During high Aquifer usage periods, the Company works closely with reservoir engineers from MWP to determine real-time injection and withdrawal capabilities. On a Design Day, the Aquifer's deliverability will be required to provide about 135 MDth of supply. This will require the Aquifers to be near full inventory during such an event. The Company continuously monitors weather and demand forecasts and plan to have the Aquifers prepared for a Design Day event.

In order to continue to provide operational flexibility during the Clay Basin testing periods in October 2023 and April 2024, the Company injected into inventory at the Aquifers. The Company adjusted the inventory in the Aquifers to provide maximum flexibility prior to each of the Clay Basin tests.

The Company usage during the heating season and the utilization during the Clay Basin tests are shown in Figure 10.5 below. This flexibility is critical to operations when Clay Basin is not available.

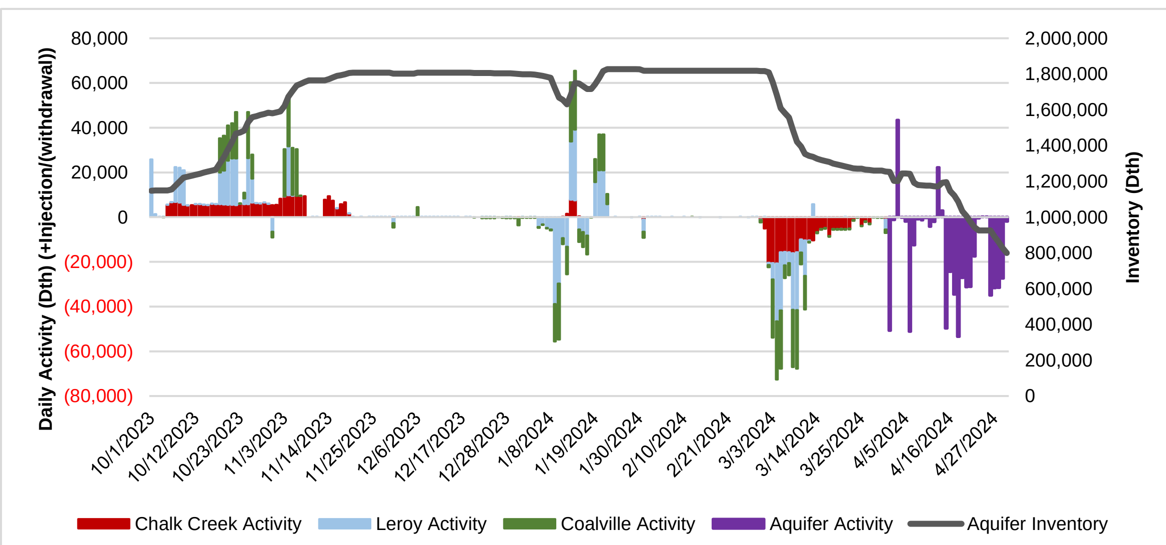


Figure 10.5: Aquifer Usage 2023-2024 Heating Season (Oct 2023 through April 2024)

Spire Storage West

The Spire Storage West LLC (Spire) storage facility involves the utilization of a partially depleted oil and gas field, now referred to as the Belle Butte facility, located approximately 25 miles southwest of the Opal Hub in southwestern Wyoming. The facility interconnects with KRGT, MWP, Northwest Pipeline, MWOP, and Ruby Pipeline.

In April 2024, the Company started a new contract (QUES02342S) for 2 MMDth of inventory capacity with 22,000 Dth/day of withdrawal capacity and 18,000 Dth/day of injection capacity. The injection and withdrawal capacities have ratchets that adjust based on inventory levels. The withdrawal capacity will reduce to 4,400 Dth/day when the Company's inventory drops below 30%. The injection capacity will reduce to 9,000 Dth/day when the inventory is above 50%. The new contract has a term of April 1, 2024, through March 31, 2029. The Company began injection into the facility on April 1, 2024.

The Company will continue to work with Spire to review any additional storage availability at this facility.

Magna LNG Storage

The Magna LNG facility commenced operation in the fall of 2022. The facility is designed to store 15,000,000 gallons (1.2 Bcf) of LNG, has liquefaction capacity of about 100,000 gal/day, and has re-vaporization capacity of 150,000 Dth per day. The Company liquefied gas (injected) to fill the storage tank to the 12 ft tank level (2,400,000 gallons) in December 2022. This inventory allowed for a successful test of the vaporization system. The Company successfully tested and commissioned all plant systems in December 2022. However, additional liquefaction was postponed due to high natural gas pricing through the winter.

The Company began liquefaction again in the summer of 2023. The facility reached 75% of capacity in December 2023 in preparation for the heating season. This reduced as expected through the heating season due to boil-off gas that was captured and sent in the distribution system. After redesign work on the LNG pumps, additional vaporization testing and system tuning was completed in January through March of 2024. These tests ranged in duration from 2 to 24 hours and included testing through the full range of sendout. The successful testing concluded that the facility is fully operational.

When planning liquefaction, the Company will consider both gas pricing and electric costs in order to minimize the cost to customers. Liquefaction resumed in April 2024, with the tank near 50% full. With natural gas pricing low, liquefaction is planned to continue through the summer months in order to have the tank full prior to the 2024-2025 heating season. Some additional testing may be conducted prior to the heating season to ensure readiness. Inventory levels and activity at the facility are shown in Figure 10.6 below. Going forward, this facility will be planned for use as a supply reliability resource as described in the Supply Reliability section of this report.

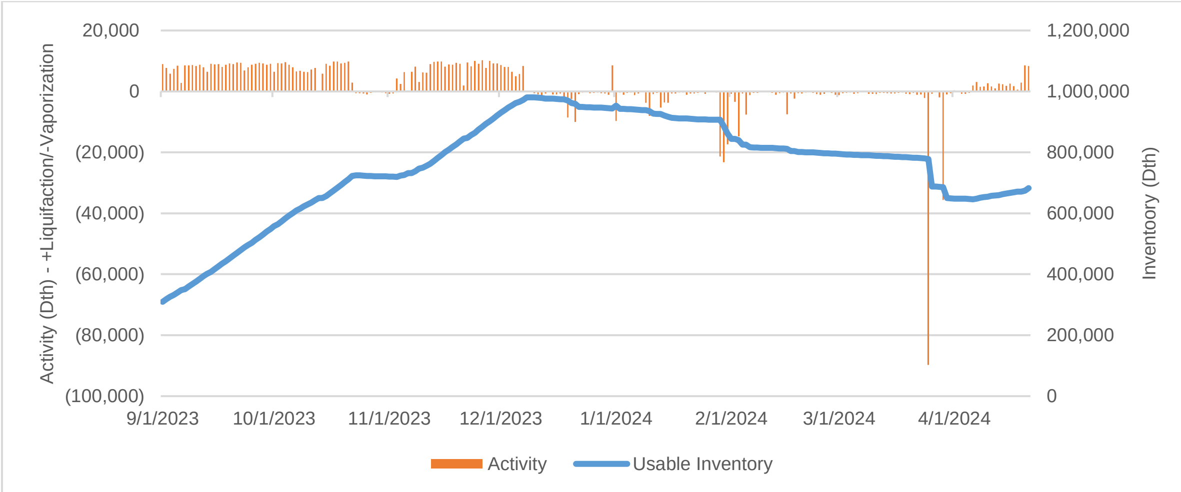
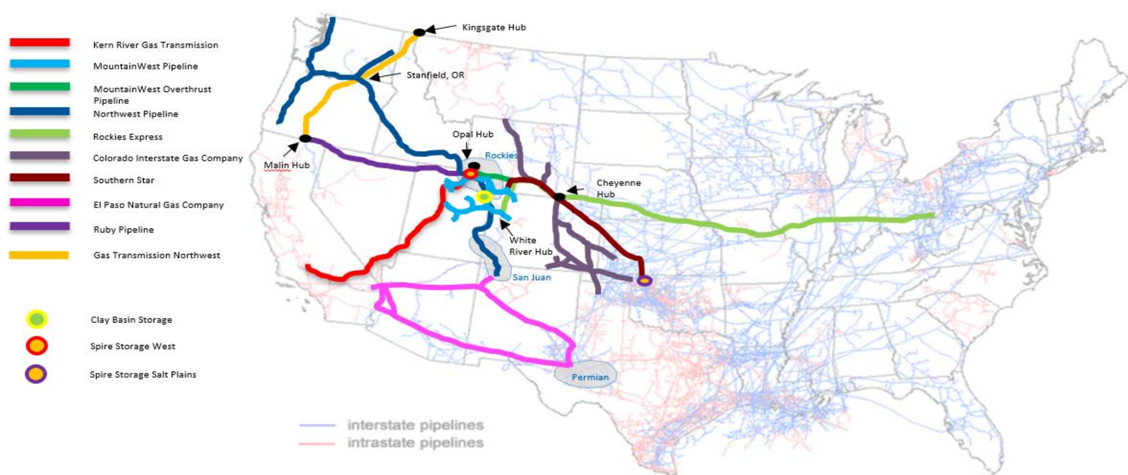


Figure 10.6: LNG Usage 2023-2024 (September 2023 through April 2024)

LONG-TERM PLANNING

The Company is continuously working to evaluate options to ensure the availability of supply that is both cost effective and reliable. The Company plans to utilize firm transportation capacity with access to diverse supply sources. It also plans to utilize storage services to provide physical supply. These storage services along with other hedging options also serve to reduce price risk associated with potential high-pricing events. The Company's hedging program is described in more detail in the Purchased Gas section of this report. An overview of the pipelines and storage facilities that could impact the Company's supply are shown in Figure 10.7 below.



Source: U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines*

Figure 10.7: Regional Pipelines and Storage Facilities

Transportation Planning

Due to high pricing and increased volatility in the local supply market, the Company is exploring options to source supply from geographically diverse locations. In order to obtain supply in other areas, the Company is exploring the availability of additional transportation capacity options to access other market areas.

In the past year, there have been significant basis differentials between the local pricing hubs and most other pricing hubs outside of the Company's geographic region, such as Cheyenne Hub. Access to geographically differentiated supply sources could protect the Company from isolated events such as storms or regional high pricing, like that experienced in February 2021 and throughout the 2022-2023 heating season.

To gain access to supply in these other areas, the Company is exploring transportation capacity options on existing pipelines as well as pipelines outside of the current counterparty footprint. Some of the options the Company is currently evaluating include additional capacity on Northwest Pipeline and MountainWest Pipeline or new capacity on Ruby Pipeline and Rockies Express Pipeline (REX).

The Company recently contracted for additional capacity on Northwest Pipeline to access supply at Stanfield, Oregon, as described above. The Company will continue to explore similar options as they become available.

At a recent customer meeting, MWP announced a possible expansion to provide incremental firm capacity from Uinta Basin to Goshen. The Uinta basin has the potential for significant production growth. This capacity could provide the opportunity to move this gas to the Company's system at Payson Gate Station. This could also provide benefits to the distribution system by bringing gas into the 720-psig line from Payson Gate Station. This has been noticed as a "potential project" with a possible in-service date of 2027. The Company will continue to explore this option going forward.[60]

Ruby Pipeline and Rex pipelines are both owned and operated by Tallgrass Energy, LP (Tallgrass). The Company does not currently interconnect with either of these pipelines.

Access to REX could provide access to supply in the eastern United States. This would provide a great amount of diversity from our current supply portfolio. However, availability is currently limited on the pipeline, and it would also require the use of existing or expanded capacity on MWP or MWOP which is also limited. The Company will continue to explore opportunities to utilize opportunities on REX.

Access to Ruby Pipeline was considered prior to the construction of the pipeline. While the Company did not subscribe to any capacity or install a station, it was still considered as an

[60] 2024 MountainWest Pipeline Customer Meeting, *mwpipe.com/Marketing/MarketingPresentations/2024_MountainWest_Pipeline_Customer_Meeting.pdf.* March 2024

option for the future since it does cross the Company's existing system. The Company made preliminary arrangements with Ruby Pipeline to allow for a possible interconnect during construction of the pipeline and is now working with Tallgrass to get estimates for a potential station. The maximum rate on Ruby Pipeline is $1.137 per Dth per day. However, the pipeline currently has an abundant amount of available capacity. The Company will work with Tallgrass to explore options for negotiating a rate lower than this for potential future capacity.

Storage Planning

The recent price volatility and supply concerns may make additional storage capacity a cost-effect option, as well as helping provide increased operational flexibility and supply reliability. Accordingly, the Company continues to evaluate additional storage options including the Magnum Gas Storage LLC (Magnum) storage facility, the Spire Salt Plains Storage (Spire Salt Plains) facility, a potential deliverability expansion project at the existing Aquifers, Jackson Prairie Storage, and a possible expansion of the Magna LNG facility. The Company will consider both the cost of these options and their operational advantages.

Spire Storage West

The Company recently started injections into a new storage contract at Spire Storage West. Along with this contract, the Company will continue to explore opportunities to acquire more capacity at this facility. The location of this facility works well with the Company's takeaway capacity on MWP.

Spire noticed an Open Season for additional capacity at this facility in February 2024. The Company explored this option. Unfortunately, the details of the open season required deliveries into Ruby Pipeline or KRGT only. As described above, the Company does not currently have access to Ruby Pipeline. The receipt location on KRGT required capacity on a lateral that is not currently provided on the Company's current KRGT contracts. These limitations prevented the Company from bidding on this open season. However, the Company will continue to review future opportunities for capacity at this facility.

Spire Salt Plains Storage

Spire purchased its Salt Plains facility on April 1, 2023.The facility is located in Manchester, Oklahoma. It is a depleted reservoir storage facility and has a working gas capacity of 13 Bcf. The facility interconnects with Southern Star and ONEOK Gas Transmission. In order to utilize capacity at the Spire Salt Plains facility, the Company would need transportation capacity on Southern Star and MWP. The Company's review of this storage option is in the preliminary stages, however, the constraints between this facility and the MWP system may limit the potential for this option.

Magnum Gas Storage

The Magnum facility is a salt-cavern storage facility under development near Delta, Utah. The current plans for the facility can provide a total working-gas capacity of 20,000,000 Dth in two salt caverns with additional expansion possible. The project can provide access to KRGT or

MWP at Goshen. Though FERC has approved construction of this natural gas storage project, the capacity is not under contract and construction has not begun. The permitting is currently valid until 2025 at which point Magnum would need to work with the FERC to try to extend.

The Company is in discussions with Magnum regarding the availability of natural gas storage. Discussions have focused on the transportation aspect of the project and the challenges associated with transporting the gas to the facility and delivering it to the Company's distribution system. The Company will continue these discussions going forward.

MWP Aquifer Expansion

In the fall of 2021, MWP conducted deliverability testing. As a result of this testing, MWP has approached The Company with an option that would provide additional deliverability at the existing Aquifers. This deliverability would not increase the working gas capacity in the reservoirs. Increased withdrawals will only provide additional gas for a few days while reducing the number of days that the Aquifers will be able to provide supply during an event. This short-term benefit will add cost without increasing the amount of available storage inventory. At this point, this is not an option the Company is pursuing.

However, the Company will continue to work with MWP evaluate other potential options at the Aquifers, along with other available storage facilities.

Jackson Prairie

Jackson Prairie is a storage facility located in Washington. The Company could access this facility using capacity on Northwest Pipeline. Unfortunately, this facility is fully subscribed. The company will continue to monitor the availability at this facility and may be interested if capacity would become available.

LNG Storage Expansion

The Company completed construction of the Magna LNG facility in 2022. The LNG Facility will provide the Company with a reliable supply for use in the event of supply disruption or at times when supply is otherwise not available. The Company could expand the LNG facility in the future to provide additional storage capacity by adding another tank. Other facilities at the site, such as piping, the control room, employees, etc. could be utilized to reduce the cost of the expansion compared to the original project.

Storage Modeling in PLEXOS

The Company models the costs, contractual terms, and operating parameters for each of its contracts with storage facilities. The Company also needs a forecast of the storage inventory available at the beginning of the first gas-supply year for each storage facility for the supply modeling process. When the Company modeled storage and inventory, it expected that the inventory at Clay Basin on June 1, 2024, would be approximately 2,700,000 MDth.

RELATED ISSUES

Gas Quality/Interchangeability

Almost all of the gas delivered to the Company's system comes from interstate pipelines (MWP, KRGT, CIG, and Northwest Pipeline). Each of these interstate pipelines manages gas quality to limits defined in its tariff. These limits have been effective in equitably meeting the delivery needs of shippers and downstream customers.

The most prevalent measure of fuel gas interchangeability in the U.S. is the Wobbe Index.[61] Natural gas appliances are rated to operate safely and efficiently within a specific Wobbe Index range. The Company used a consulting firm to establish the Wobbe operating ranges for its service areas. Exhibit 10.2 shows the upper and lower Wobbe operating limits and the specific gravity and BTU values measured for gas delivered to the Utah Wasatch Front (North) region during 2023. The daily averages for 2023 for other Utah regions can be seen in Exhibits 10.3 and 10.4. Exhibit 10.5 shows the most recent quarterly data reported to the Public Service Commission of Wyoming in accordance with Chapter 3, Section 30 of the Public Service Commission Rules. The green dots indicate volume-weighted Wobbe values for each distribution area within ± 4% of the Wobbe set point. Should Wobbe values become a concern in the future at any point delivering gas to the Company, there are a number of tools that the Company can use to manage gas interchangeability including injecting inert gases (or air) in the gas stream, injecting propane or hydrogen, and blending supplies from various sources.

It is difficult to predict the interchangeability of future gas streams. The Company may need to arrange for additional processing or blending in the event it is required to ensure that the gas received from the transmission systems of any of its upstream pipelines are compatible with the needs of the Company's customers. The Company will evaluate this on an ongoing basis as it bears the burden of processing pipeline-quality gas to meet its specific requirements.

The Company has been contacted by parties with renewable gas supplies, such as biomethane producers, interested in delivering gas directly into the Company's system. In response to these requests, the Company set gas quality requirements for non-interstate-pipeline supplies and allow for the delivery of biomethane into the Company's system. The Company began accepting injection of biomethane into its distribution system in December 2020. Equipment and testing are in place to ensure that the gas quality of these supplies meets Company requirements.

[61] The Wobbe Index number consists of the higher heating value of a fuel gas divided by the square root of the specific gravity (relative to air) of the fuel gas. Fuel gases with the same index number generate the same heat output over time from a burner given constant pressure and orifice size.

System Diagram 2024

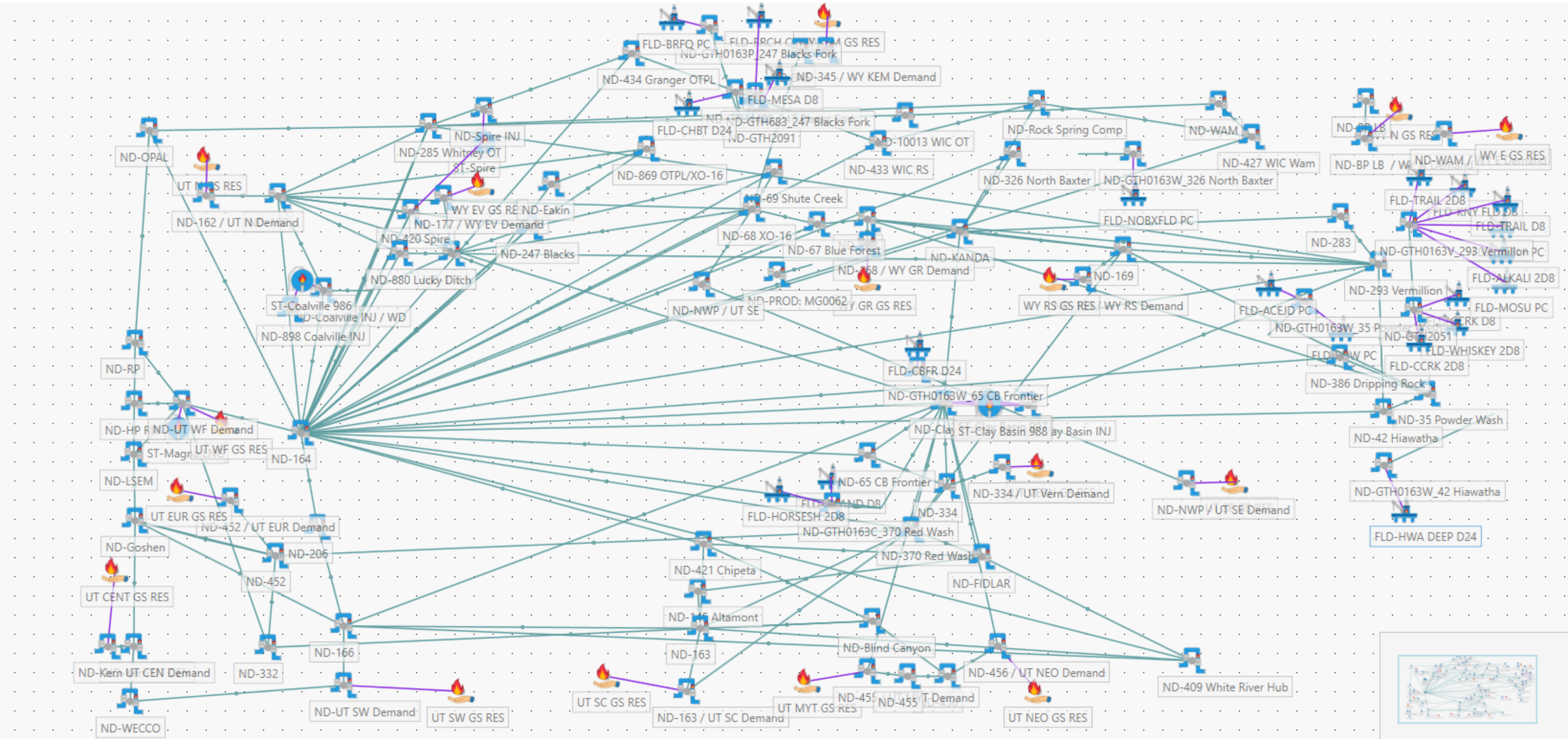


Exhibit 10.1

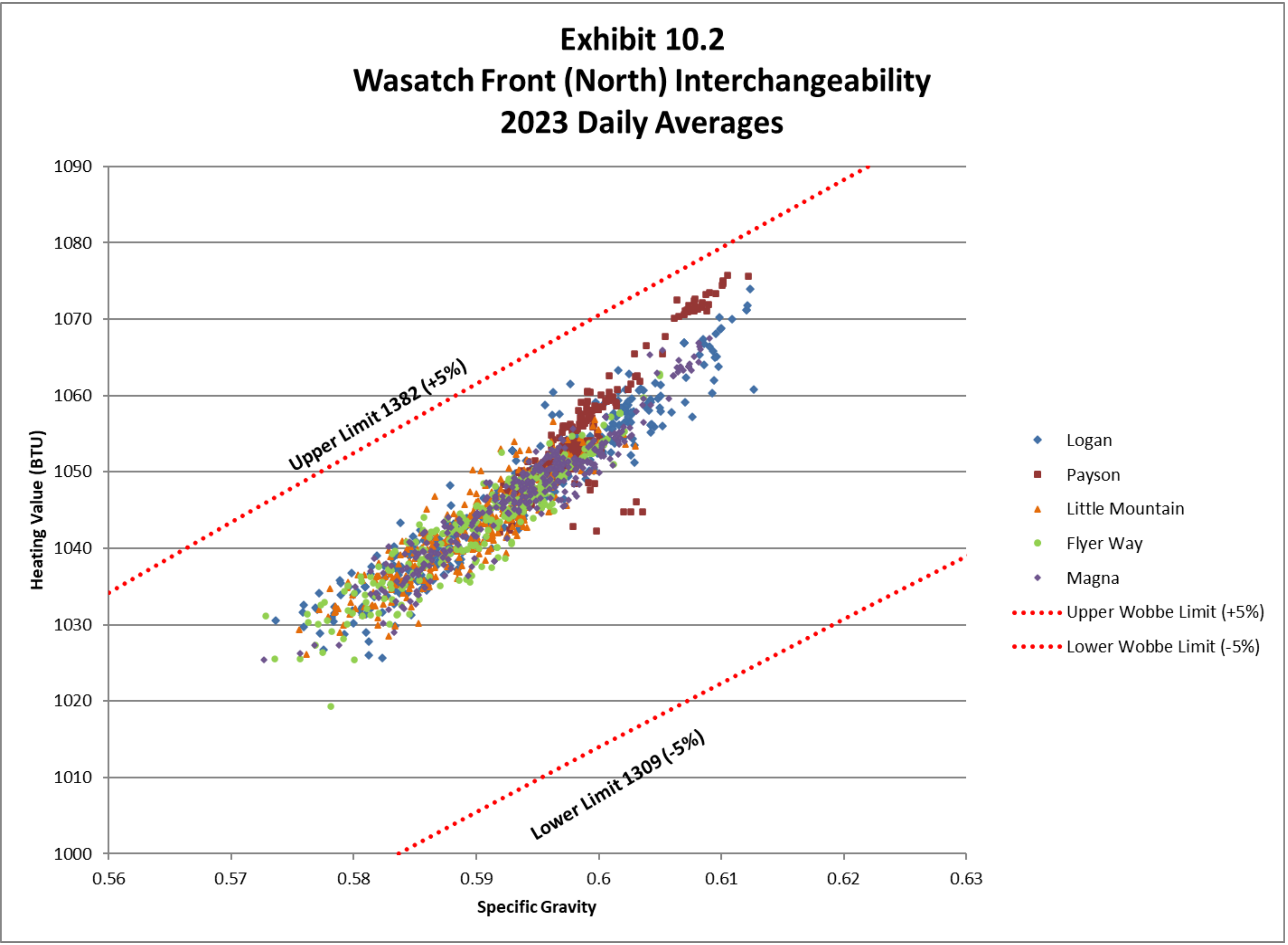


Exhibit 10.2
Wasatch Front (North) Interchangeability
2023 Daily Averages
Upper Limit 1382 (+5%)
Lower Limit 1309 (-5%)
Heating Value (BTU)
Specific Gravity
1090
1080
1070
1060
1050
1040
1030
1020
1010
1000
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
Logan
Payson
Little Mountain
Flyer Way
Magna
Upper Wobbe Limit (+5%)
Lower Wobbe Limit (-5%)

Exhibit 10.2

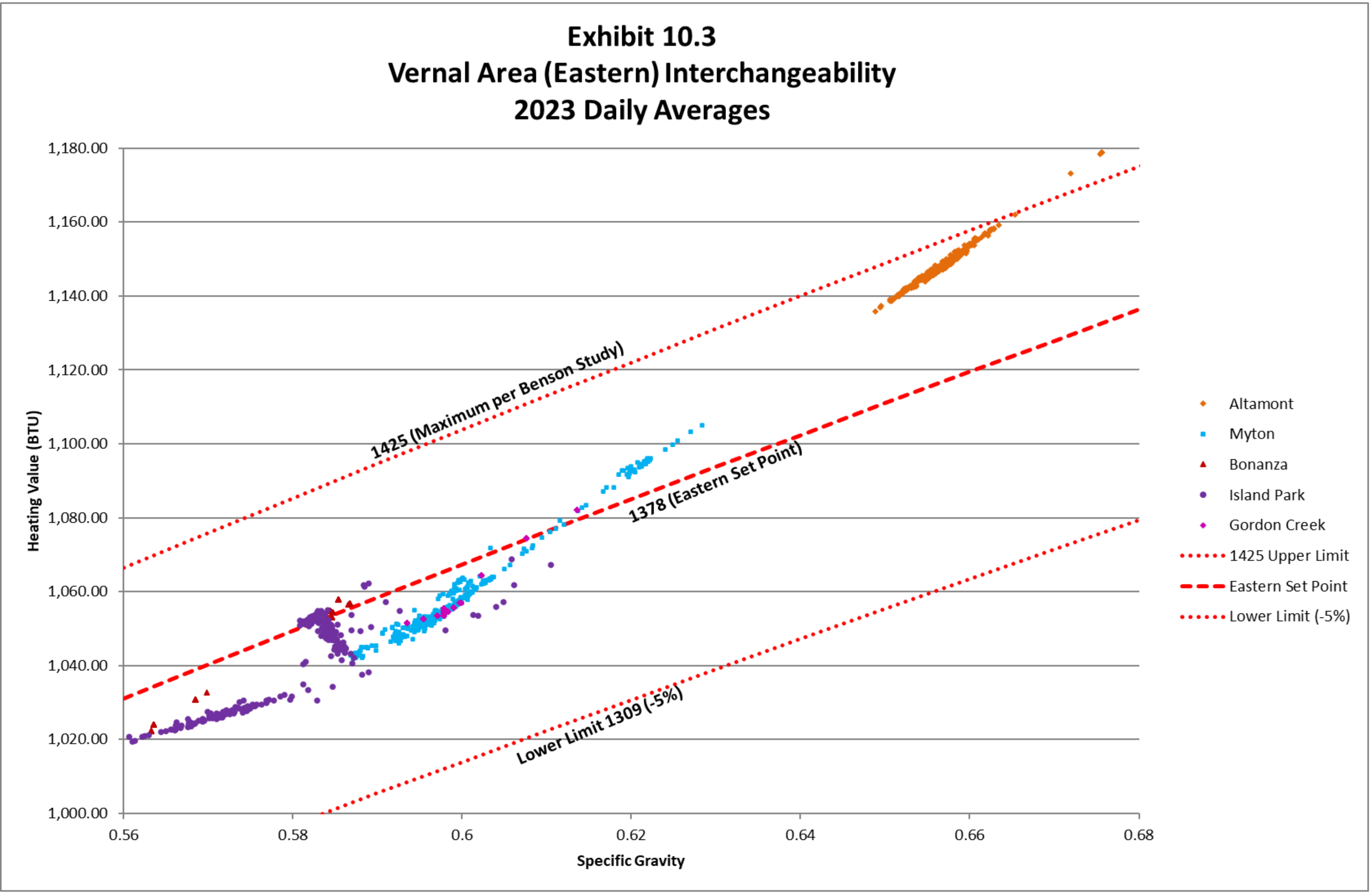


Exhibit 10.3
Vernal Area (Eastern) Interchangeability
2023 Daily Averages
1,180.00
1,160.00
1,140.00
1,120.00
1,100.00
1,080.00
1,060.00
1,040.00
1,020.00
1,000.00
Heating Value (BTU)
0.56
0.58
0.6
0.62
0.64
0.66
0.68
Specific Gravity
1425 (Maximum per Benson Study)
1378 (Eastern Set Point)
Lower Limit 1309 (-5%)
Altamont
Myton
Bonanza
Island Park
Gordon Creek
1425 Upper Limit
Eastern Set Point
Lower Limit (-5%)

Exhibit 10.3

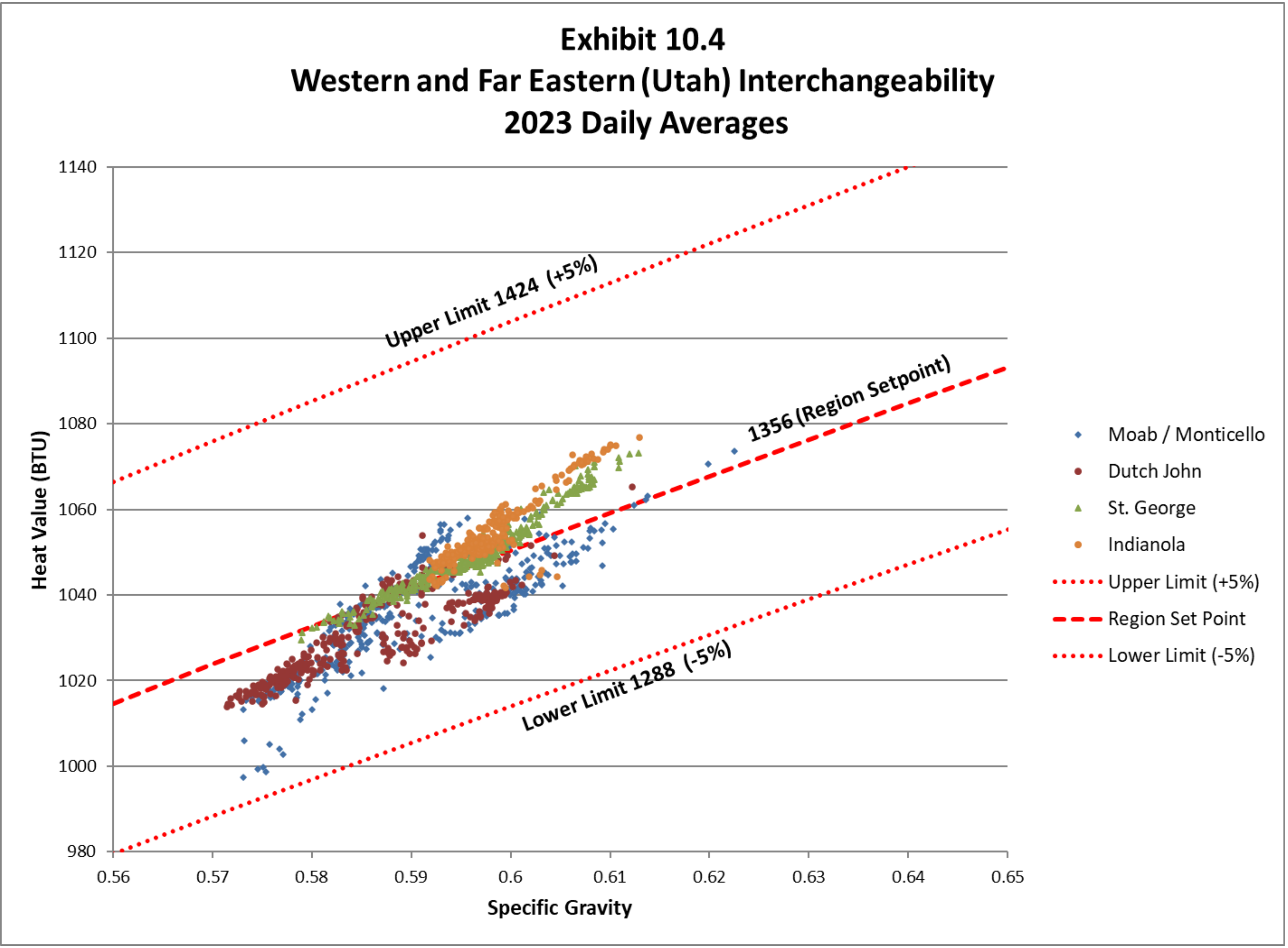


Exhibit 10.4
Western and Far Eastern (Utah) Interchangeability
2023 Daily Averages
Heat Value (BTU)
1140
1120
1100
1080
1060
1040
1020
1000
980
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
0.64
0.65
Specific Gravity
Upper Limit 1424 (+5%)
1356 (Region Setpoint)
Lower Limit 1288 (-5%)
Moab / Monticello
Dutch John
St. George
Indianola
Upper Limit (+5%)
Region Set Point
Lower Limit (-5%)

Exhibit 10.4

System BTU Report MAP
Quarter 1 2024

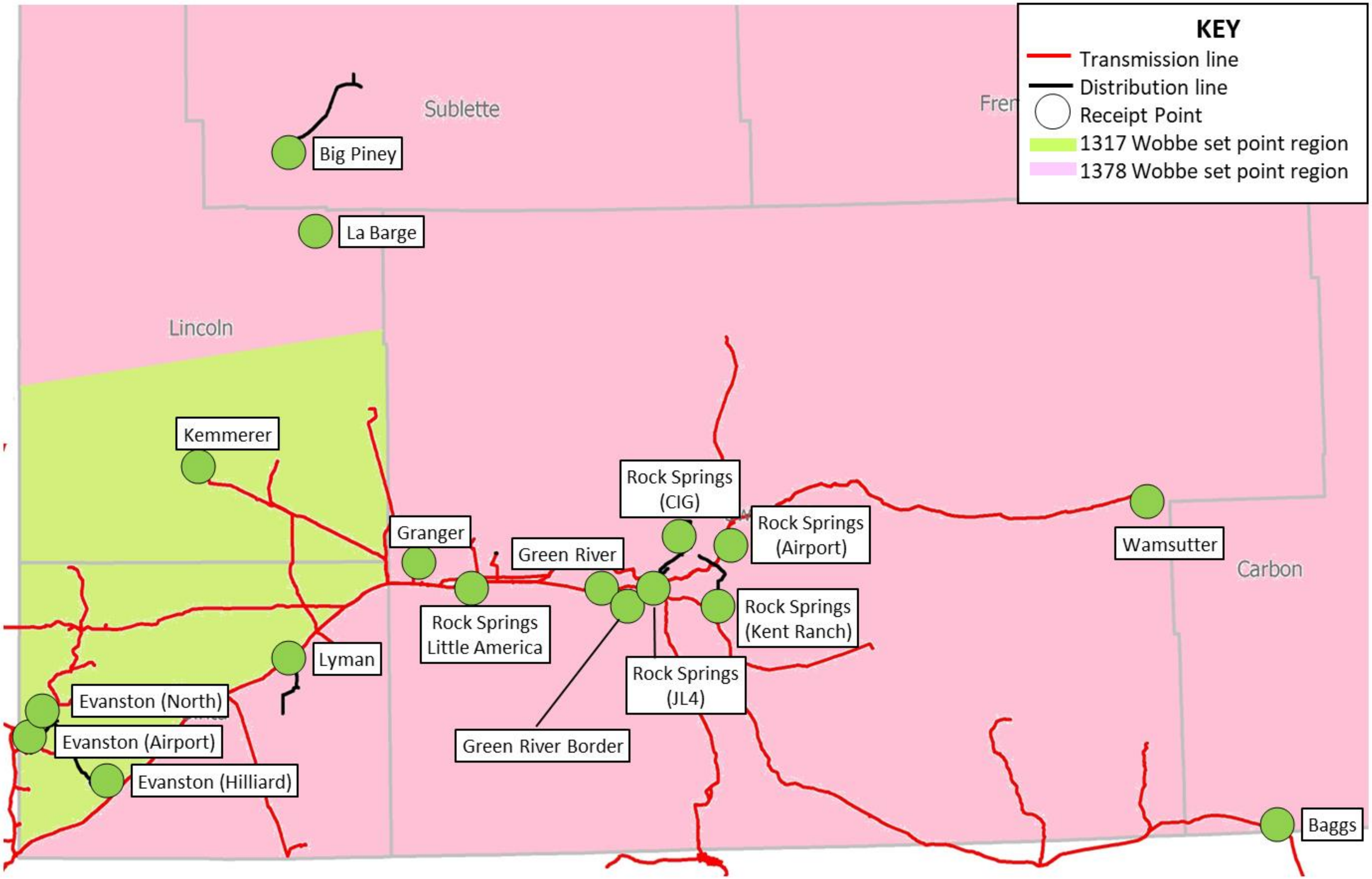


Exhibit 10.5

SUPPLY RELIABILITY

Beginning in 2017, the Company became concerned about the reliability of its upstream supply. That year, several local distribution companies in other states experienced significant supply shortfalls due to upstream well freeze-offs, interstate pipeline transportation disruptions and other causes. In February 2021, similar events occurred in Texas and the midcontinent resulting in widespread supply shortages. The Company sought to ensure that its customers do not experience similar outages. After conducting extended review of possible solutions to the supply reliability concerns, The Company determined that the best available long-term supply reliability solution to address future supply shortfalls would be to construct an LNG facility with liquefaction near the center of the Company's demand center – near Salt Lake City, Utah. The Company sought and received Utah Commission approval to build the facility in Docket No. 19-057-13.

Events similar to the February 2021 event have happened within the U.S. over the past few heating seasons. Fortunately, these events occurred in other areas of the country and did not have a major impact on the Company's physical supply. However, the Company remains confident that the Magna LNG facility would be adequate to mitigate similar issues if they were to occur locally.

LNG FACILITY UPDATE

Construction commenced on the Magna LNG facility, located near Magna, Utah, in July of 2020. The facility is designed to liquify natural gas at a rate of 100,000 gallons per day and re-vaporize it at a rate of 150,000 Dth per day. The LNG storage tank is designed with a net storage capacity of 15,000,000 gallons. The Company completed construction of the plant in September 2022. It performed commissioning activities from September to December of 2022, including intermittent liquefaction to support commissioning the LNG tank and LNG pumps.

Liquefaction was planned for the summer months in 2023. After starting liquefaction, the plant experienced a malfunction with critical equipment in late April 2023. The equipment was under warranty and the Company worked with the manufacturer to remedy the situation. Once the issues were resolved, liquefaction resumed in summer 2023 and the tank was approximately 75% full and available for withdrawals during the 2023-2024 heating season. Additional vaporization testing and system tuning was completed in January through March of 2024. These tests ranged in duration from 2 to 24 hours and included testing through the full range of sendout. Liquefaction resumed in April 2024, with the tank near 50% full. Liquefaction is planned to continue through the summer months in order to have the tank full prior to the 2024-2025 heating season. Some additional testing may be conducted prior to the heating season to ensure readiness.

The facility will normally be kept substantially full during the heating season to have the full operational capacity in the event of supply disruptions. However, the facility may also be available to offset significant gas price increases. Factors such as time of year, expected length of the event, and ability to refill will factor into any decision to use the facility to offset pricing concerns. For example, the facility could be used to offset purchases during a high-price event towards the end of the heating season.

ADDITIONAL RELIABIILITY OPTIONS

As discussed in the Purchased Gas section of this report, the Company is evaluating options for additional hedging resources to mitigate the price and reliability risk associated with the events that occurred in February 2021. The options for increased cost-of-service production, increased storage capacity, geographic diversification of supply and additional baseload contracts may provide additional supply-reliability benefit. Additional on-system storage facilities such as small satellite LNG facilities located in remote or centralized areas of the system could also provide additional supply reliability in the future.

As discussed in the Gathering, Transportation, and Storage section of this report, the Company is working with upstream pipelines to identify transportation paths that may provide access to supply areas outside of the Company's current markets. This approach could help avoid or mitigate geographically isolated price increases or supply availability shortfalls. Because weather events often result in supply reductions in specific geographic areas, geographic diversity of supply can also provide access to supply that may not be as impacted by certain weather events.

All of these options would increase the amount of supply that is already contracted for by the Company during the period of time most likely to experience extreme cold weather events. In the event of limited supply availability in the market, having gas contracted or available from storage would reduce the availability risk of supply purchases.

SUSTAINABILITY

At Enbridge, we're taking a practical approach to the energy transition by providing the energy needed today while simultaneously advancing solutions for tomorrow. We're bridging to a cleaner energy future by innovating across our value chain. Every part of our business is engaged in our emissions reduction goals and targets. By investing in our conventional business, we are supporting reliable energy delivery, lowering our emissions and meeting our customers' needs — and by expanding North American export infrastructure, we are playing a key role in lowering global emissions. We're also ramping up our efforts in lower-carbon solutions, including renewables, carbon capture, hydrogen, and renewable natural gas.

SCOPE 1 SUSTAINABILITY INITIATIVES

The Company is committed to providing, safe affordable, sustainable energy to its customers. Its efforts thus far to achieve these goals are described below.

Methane Emissions Reduction Program

The Company implemented a Methane Emissions Reduction Program in Utah, Wyoming and Idaho that includes:

- Replacing Aging Infrastructure – continuing the ongoing program of replacing parts of the Company's aging distribution system.

- Hot Taps – continuing to use hot taps, the process of tying into a live gas main without blowing down the pressure completely first, to reduce the amount of methane required to be blown down during maintenance operations.

- Leak Survey, Detection, and Repair – regularly conducting leak surveys and performing system maintenance as required. The Company conducts additional leak surveys in Class 3 and Class 4 locations. In 2023 approximately 21.2 million feet of main and 207,600 services were surveyed, resulting in the discovery of 749 leaks, all of which were substantially repaired.

- Reduce Third-Party Damages – continuing on-going programs focused on reducing 3rd party damages to Company facilities. Programs include excavator outreach, stand-by on excavations, participation in state-wide damage prevention seminars, and educational materials mailed to residents along the pipeline rights-of-way and our customers. The Company currently has four damage prevention specialists and has implemented risk modeling software to identify high-risk excavations. This software helps identify tickets with the highest potential of damage. When those are identified, the Company sends personnel from both its locating contractor and a damage prevention specialist to meet with the excavator to discuss the safest approach to digging around the Company's facilities. Depending on the facility type and size, The Company is often also able to schedule onsite monitoring while the excavation takes place. As a result of these efforts, the Company has seen the damage rate drop from 2.95 in 2020 to 2.35 damages per 1,000 locate tickets in 2023.

Wexpro Sustainability Initiatives

Since 2010, Wexpro has reduced its methane emissions by over 90%. First, in 2012 and 2013, Wexpro replaced all of the high bleed pneumatic devices at its production locations with low bleed intermittent controllers. In 2017 Wexpro removed all pneumatic pumps on production locations and installed electric driven units. In 2019 Wexpro optimized all tank burners to match the heat output of the heater to current production levels. In 2023 Wexpro installed Venthawk's on the majority of remaining pneumatic controllers deeming those controllers as non-emitting. Wexpro is evaluating a few other options to further reduce methane emissions.

Well Certification Program

Wexpro's well certification program utilizes an extensive scoring system to certify wells as responsibly-produced with low methane emissions. A third-party, independent company then audited this process by reviewing 25 of these wells at random. The audit evaluated conformance with regulatory criteria in environmental, safety, downhole, and operations, as well as criteria beyond regulatory requirements. Overall, the audit results showed Wexpro's operational management systems and dedication to regulatory compliance to be outstanding and identified a few opportunities for improvement. In addition, performance exceeded regulatory requirements. Wexpro has completed the self-certification of all Wexpro-operated wells. The program is ongoing and is continuing to reevaluate existing wells and any new wells in the area.

Pneumatic Controller Replacement

In 2023 Wexpro completed a project to install Venthawks on the majority of pneumatic devices which allows the vented gas to be captured and used as fuel to be burned in heaters on site. With the Venthawks being installed and capturing the gas, it deems the pneumatic controllers as non-emitting and thereby reduced Wexpro Methane emissions by 80% as compared to 2022 levels. This project was completed in lieu of the replacement of pneumatic controllers as it was a lower cost option and was more feasible to get completed by the end of 2023.

Air Quality Initiatives

To reduce emissions, Wexpro has committed to the following:

- Replace or repair high emitting pneumatic devices with low or no-bleed devices.
- Switch natural gas-powered pneumatic devices to devices that use alternative power.
- Replace natural gas-powered chemical injection pumps with pumps that use alternate power.
- Conduct voluntary leak surveys and repair programs at above-ground production sites.
- Reduce gas well liquids unloading emissions.
- Replace compressor rod packing either every 26,000 hours or every 3 years.

Instrument Air Systems

Wexpro has also advanced emission reductions by installing instrument air systems (air compressors and air dryers) to 31 end devices at Canyon Creek and Church Buttes, eliminating 46,000 MCF of gas lost and related emissions.

SCOPE 3 SUSTAINABILITY INITIATIVES

One Future

The Company is a member of One Future. "The One Future Coalition is a group of more than 50 Natural Gas companies working together to voluntarily reduce methane emissions across the Natural Gas value chain to 1% (or less) by 2025."[62] This coalition includes member companies across the natural gas supply chain, including natural gas production, gathering and processing, transmission and storage, and distribution. This coalition of companies actually exceeded this 1% goal in 2021, registering a methane intensity score of 0.462% as described in the Industry Overview section of this report.[63]

The distribution segment of One Future includes 20 local distribution companies delivering 47% of the total US natural gas. The members of this segment reported a methane intensity of 0.113%, beating the goal of 0.225% by 50%.[64]

Responsibly Sourced Natural Gas

As part of the annual RFP for natural gas supply for 2024-2025 and beyond, the Company included a request for responsibly sourced natural gas from respondents. The Company received multiple offers from a few different counterparties. These offers were provided with additional cost premium to the traditional supply. However, it is important to note that the premium over non-RSG supplies has reduced over previous years. The Company considered these options in its analysis and stated it would select a responsibly sourced option over a traditional option if costs were equivalent. No offers for RSG were selected this year through the RFP. Multiple counterparties have offered to negotiate for RSG supply outside of the annual RFP as available RSG volumes continue to increase. Wexpro also provides low-methane emission natural gas through the well certification program described above.

As the premium continues to be reduced and more RSG volumes become available, the Company believes it would be in the best interest of customers to begin to include RSG as a part of the overall supply portfolio for customers. As the certification of wells continues to increase through the methane emission programs being incorporated by producers, the volume of non-RSG supply may also decrease. This could also drive the Company to need to purchase RSG supplies going forward.

[62] https://onefuture.us/
[63] https://onefuture.us/
[64] https://onefuture.us/2022-methane-emissions-intensity-report/

Renewable Natural Gas

Renewable Natural Gas is pipeline quality gas derived from waste sources such as wastewater, animal waste, food waste, and other organic waste. If left in place, these waste sources emit methane, CO_2, and other constituents over time to the atmosphere. By capturing, processing, and injecting this renewable natural gas, these harmful emissions can be eliminated and put to use as energy in homes, buildings, and vehicles throughout the Company's service territory.

Section 7.07 of the Company's Utah Natural Gas Tariff No. 500 allows for RNG to be delivered directly into the Company's system. As discussed in the Gathering, Transportation, and Storage section of this report, The Company began accepting injection of RNG into the distribution system in December 2020.

The Company is currently evaluating ways to include RNG in its own natural gas portfolio. It will report on these efforts in future IRPs.

Renewable Natural Gas for CNG Vehicle Sales Customers

In 2022 and 2023, and in coordination with Anew Climate, LLC (an RNG supplier), we supplied RNG clean air attributes to 100% of public volumes sold. When RNG is used for transportation refueling purpose, those volumes qualify for high-value Renewable Identification Number (RIN) credits. The use of RNG did not increase the cost of the fuel. Because of the RIN credit share agreement, the cost per gallon was reduced for all transportation customers. [65] The amount of RNG to be distributed in 2024 will be largely dependent on availability of RNG supply.

ThermWise® – Energy Efficiency Programs

In its Order dated January 16, 2007, in Docket No. 05-057-T01, the Utah Public Service Commission approved the Company's proposal to create natural gas focused energy efficiency programs with an initial budget of $6.9 million. The Company branded its energy efficiency programs as ThermWise® and launched a comprehensive suite of Utah customer-focused rebates for the purchase and installation of high efficiency natural gas equipment in early 2007. The Wyoming ThermWise® programs followed in 2009 (Docket No. 30010-94-GR-08) with a Wyoming Public Service Commission-approved first-year budget of $388 thousand. Interest and participation in the Utah and Wyoming ThermWise® programs have remained strong since they were introduced, with nearly 50% of eligible customers having participated in at least one program or rebate measure. Specific details of 2023 ThermWise® results and 2024 program changes, budgets, and cost effectiveness ratios can be found in the Energy Efficiency section of this report.

[65] Through March 2023, the Bluesource partnership has generated $730,941 in RIN credits to the Company that have reduced the CNG commodity rate to sales customers.

GreenTherm® – Voluntary Renewable Natural Gas Program

In Docket No. 19-057-T04, filed on March 29, 2019, the Company applied for approval to create a voluntary RNG program called GreenTherm®. This program was approved on July 30, 2019, and the Company began taking customer subscriptions in early 2020. This program allows customers to purchase renewable natural gas attributes for their own usage. The Company sold 39,052 Dth of RNG green attributes to over 3,000 GreenTherm® participants in 2023.

CarbonRight™ – Carbon Offset Program

In October of 2020, the Utah Commission approved the voluntary carbon offset program – now known as CarbonRight™.[66] This program was approved on October 20, 2021, and allows customers to subscribe to monthly purchases of carbon offsets. A carbon offset represents a quantified reduction in GHG emissions by a mitigating activity. The Company officially launched this new program in March of 2022. In 2023, the Company sold 6,482 metric tons of carbon offsets to over 1,100 CarbonRight™ participating customers.

The initial tranche of offset supply for the CarbonRight™ program came from three different projects located in the United States. The Trans-Jordan landfill, located in South Jordan Utah (75% of CarbonRight™ supply), supports GHG reductions by capturing naturally occurring emissions before they enter the atmosphere. This is accomplished through a network of pipes, running throughout the ground in the landfill, that gathers the naturally occurring methane. Once the methane is gathered and cleaned, it is used to generate on-site electricity. These offsets are part of the Climate Action Reserve registry.

The Maple Hill landfill, located in Macon Missouri (15% of offset supply), collects naturally occurring methane in a similar way to the Trans-Jordan landfill. However, GHG reductions are achieved by flaring (burning) the methane before it is allowed to enter the atmosphere. The emissions from burning the methane are much less potent than if the methane was allowed to escape to the atmosphere. These offsets are part of the Climate Action Reserve registry.

The Blandin Native American Hardwoods Conservation & Carbon Sequestration project is located in Grand Rapids Minnesota (10% of offset supply). This project manages a 75-mile radius of mixed native hardwood forest, which is managed with sustainable practices and will always remain forest through a conservation easement. This preservation allows for improved carbon dioxide sequestration as the trees remove carbon dioxide from the air. These offsets are registered with the American Carbon Registry.

In 2022, the Company sold 2,678 metric tons of carbon offsets to CarbonRight™ participants. In late 2022, the Company recognized that growing customer demand for the CarbonRight™ program would likely exhaust the existing balance of offset supply. As a result, the Company began the internal processes necessary to acquire a new tranche of carbon offset supply.

[66] Order Approving Settlement Stipulation, issued October 20, 2021, Docket No. 21-057-14.

The Company published a competitive request for bid (RFB) to fifty (50) potential suppliers on February 21, 2023. Ultimately, the Company received five (5) bids, selected a package of 30,000 metric tons of offsets, and completed contracting with two (2) suppliers in late April 2023. The Company expects that, at the early 2024 growth rate of the CarbonRight™ program, the second tranche of offsets will be enough supply for approximately four years of program operation.

The second tranche of offset supply for the CarbonRight™ program comes from four different projects located within the United States. The Davis Landfill Gas Offset Project, located in Layton Utah (27% of CarbonRight™ supply), supports GHG reductions by capturing naturally occurring emissions before they enter the atmosphere. This is accomplished through a network of pipes, running throughout the ground in the landfill, that gathers the naturally occurring methane. Once the methane is gathered and cleaned, it is used to generate on-site electricity. These offsets are part of the Climate Action Reserve registry.

The South Jordan Landfill, located in South Jordan Utah (23% of CarbonRight™ supply) is similar to the offsets described above in the Davis Landfill project. These offsets are also part of the Climate Action Reserve registry.

The Spray Foam Alpha project, located in Arizona (47% of CarbonRight™ supply), achieves carbon reductions by replacing a high-Global Warming Potential (GWP) blowing agent (BA), namely Pentafluoropropane (HFC-245fa), with a new blowing agent (Project BA) in the production and use of foam. The BA is also non-ozone depleting and will replace high-GWP BAs formerly used. Blowing agents are a key ingredient in the production of foam products which are used in, among other things, the insulation of homes and other weatherization applications. These offsets are part of the American Carbon Registry.

The 18 Reserves Forest Carbon Registry, located in Ohio (3% of CarbonRight™ supply), is composed of 8,961 acres of mixed hardwood forest that is managed for the purpose of increased carbon sequestration by foregoing significant timber harvesting and maintaining mature forest cover. This project also has other objectives, such as improving ecosystem resilience, increasing wildlife habitat, reducing invasive species presence, and growing research and monitoring of natural systems. Cleveland Metroparks' (CMP) forest holdings contain many valuable ecological, educational, open space, and scenic resource conservation values. These offsets are also part of the American Carbon Registry.

Hydrogen Programs

Research and Development

The Company is participating in the International HyReady study which evaluates the potential to blend renewable hydrogen into natural gas systems. The Company is participating in twenty-five other hydrogen and RNG related research projects with the Gas Technology Institute (GTI) and NYSEARCH.

Hydrogen Pilot Program

The Company is exploring the benefits of blending hydrogen with natural gas in a project coined ThermH_2. The project is verfying existing research on blending as well as gain operational experience within the Company's system.

The first phase was initial testing of hydrogen blending at the Company's Salt Lake Operations Training Facility, which contains an isolated, but representative, subsystem of piping and residential customer appliances. The first phase of the ThermH_2 project sought to validate research in four areas: residential end-use appliances, leak survey capabilities, materials compatibility, and gas quality. Starting in the second quarter of 2021 the Company's research and development group conducted several tests, including: the gas quality effects of adding hydrogen to the gas stream, the effects of hydrogen on current leak survey equipment, any impacts on odorant, burner tip effects along with any changes in emissions and appliance safety, and impacts on materials at IHP pressures with a 5% blend. The test results support that a 5% hydrogen blended gas stream will not adversely impact system or customer safety. This phase was completed in the fall of 2021.

Phase two of the ThermH_2 project involves introducing hydrogen into the Company's system in Delta, Utah. Delta was selected because it is a subsystem with a single main injection point, with a large percentage of modern plastic pipe, and no public CNG stations. Delta has about 1,800 meters. This phase of the pilot will allow the Company to build on the experience from the first phase on a larger scale. In 2023, the Company began introducing up to 5% blend of renewable (green) hydrogen into the distribution system in Delta. This phase includes an electrolyzer, allowing the Company to generate its own renewable hydrogen on-site and on-demand. To ensure safety, the Company is taking extra precautions at the injection site through continuous monitoring through on-site sensors and regular in-person inspections. The Company also regularly monitors gas quality and checks for consistent odorant levels throughout the Delta distribution system. This phase of the project will run through the end of 2024.

The Company is committed to expanding our knowledge and experience with hydrogen and hydrogen blending. Future work with hydrogen may include expanding blending efforts to other parts of the distribution system or high-pressure system, which would allow for more expansive blending to occur. The Company expects the role of hydrogen will continue to play a role within its operations and the gas industry as a whole.

SUSTAINABILITY LEGISLATION

The Company is committed to investing in clean air solutions using natural gas, renewable natural gas, and other innovative technologies.

On December 31, 2019, the Company filed an application seeking approval to fund the Intermountain Industrial Assessment Center (IIAC) at the University of Utah. On August 31, 2020, the Commission issued an order in Docket 19-057-33 approving a two-year pilot program to fund the IIAC at a level of $500,000 annually. On February 6, 2023 (Order, Docket No. 22-057-24) the Commission approved a third and final year of funding for the IIAC pilot program at the same level of the previous two years. The approval of this final year of the IIAC program will bring total funding to $1.5 million over three years. This funding has allowed the IIAC to expand energy assessments of commercial and industrial energy users and provide data-driven recommendations to help improve air quality.

In the 2023 program year, the IIAC completed 20 energy and 40 clean air assessments using STEP funds. These assessments identified 192 potential projects that, if completed by the participating businesses, would result in a reduction of over 30 tons in annual criteria pollutants and more than 42,700 tons of annual CO_2 emissions. The identified potential projects would also result in reduced annual natural gas usage of nearly 300,000 Dth which is equivalent to the usage of over 4,200 homes. This program completed in May 2024.

In 2023 the Company supported Utah Senate Bill 62 (SB 62), which Governor Cox signed on March 14th, 2023. SB 62 provides a template for hydrogen development in Utah and establishes a hydrogen advisory council within the Office of Energy Development.

From 2021 through 2023, The Company participated in the Green Hydrogen Coalition (GHC). The purpose of the GHC is to advance green hydrogen and a carbon free energy system. The five focus areas of GHC are: educating the public, coalition building, developing the market, developing hydrogen-supportive policies, and commercialization. There has been significant effort tracking and providing input into legislation that may affect the trajectory of green hydrogen adoption.

COMMUNITY PROGRAMS

In 2023, the Dominion Energy Charitable Foundation awarded over $1.2 million dollars in environmental stewardship grants to support 118 community organizations across our entire footprint, with $190,000 going to 13 organizations in Utah, Idaho, and Wyoming. These grants were awarded to programs focused on promoting conservation and a cleaner environment through preservation and education efforts. Organizations such as Ducks Unlimited, The Nature Conservancy, and Utah Clean Air Partnership (UCAIR) used the money to tackle important local issues such as a collaborative Great Salt Lake restoration initiative and improving air quality among the Wasatch Front. Red Butte Gardens, The Leonardo Museum, Youth Garden Project, the Jordan River Foundation and The Living Planet funds went toward teaching children from elementary school to high school about water conservation, sustainable gardening, healthy meals, and conservation of a variety of ecosystems through engaging educational programming. Other grants supported organizations such as Grand Staircase Escalante Partners, Canyonlands Fields Institute, Summit Land Conservancy, and Friends of Arches and Canyonland to focus on supporting conservation and education initiatives to maintain the beauty and integrity of our national parks.

ENERGY-EFFICIENCY PROGRAMS

UTAH ENERGY-EFFICIENCY RESULTS 2023

The Company's 2023 Commission-approved ThermWise® energy-efficiency programs and measures were similar to programs in 2022, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. ThermWise® results for 2023 were strong. While participation was lower than projected (78% of budget), gross natural gas savings reached 82% of the 2023 budget projection. Spending for the 2023 program year totaled $26.6 million or 95% of the $28.1 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for 83% of the total ThermWise® spending in 2023 (77% in 2023 budget) and resulted in gross annual natural gas savings of more than 1.05 million Dth.

Utah ThermWise® Appliance Rebates

The Company continued this program in 2023 with the addition of new tiers of rebate-qualifying smart thermostats and dual-fuel heating systems. The Company first proposed to add smart thermostats to the mix of rebate eligible equipment in the 2015 program year (Docket No. 14-057-25). At the time, the Company proposed to limit rebate eligibility to smart thermostats that had a specific onboard technology known as an occupancy sensor. This was done to ensure natural gas savings could be achieved, without any required action by the homeowner, by cycling the furnace off when the home's occupants hadn't walked past the thermostat (thereby triggering the sensor) after a certain amount of time.

The other predominant smart thermostat technology that existed at the time, that the Company proposed to exclude from rebate eligibility, was something known as geofencing. Geofencing is defined as a virtual perimeter covering a geographic area. In the case of smart thermostats, geofencing is required to be enabled and configured by the homeowner to establish the boundaries of the home. Natural gas savings are achieved through geofencing technology when the customer, or more accurately the customer's cell phone, leaves the boundaries of the home and the furnace then cycles off after a certain amount of time.

The Company proposed a tiered rebate structure with tier 1 smart thermostats, equipped with qualifying geofencing technology, eligible for a $50 rebate per device. Tier 2 smart thermostats, equipped with qualifying occupancy sensor technology, were proposed to be eligible for a $75 rebate per device.

The Company also introduced a tiered rebate structure for dual-fuel heating systems beginning in 2023. The Company first proposed adding dual-fuel heating systems as a rebate eligible measure as part of the 2021 energy efficiency budget filing (Docket No. 20-057-20). At the time, the Company proposed to define rebate qualifying dual-fuel systems as a heat pump coupled with high efficiency natural gas combustion backup. Specifically, that meant a >95% annual fuel utilization efficiency (AFUE) natural gas backup paired with an ENERGY STAR® certified ducted heat pump with a heating seasonal performance factor (HSPF) of >9.0 and seasonal energy efficiency ratio (SEER) >14. The Company continued incentivizing this equipment in 2023 as the Tier 1 dual-fuel heating system and at a rebate amount of $1,000 for single family residences and $500 for multifamily residences, which was an increase of $200 and $100 respectively over 2022 levels.

Additionally, the Company introduced a Tier 2 dual-fuel heating system rebate in 2023, at an incentive level of $1,200 for single family residences and $600 for multifamily residences, for a system that includes >97.5% AFUE natural gas backup paired with a minimum 18 SEER, 10 HSPF, and 11.5 energy efficiency ratio (EER) heat pump. This Tier 2 rebate was designed to align with equipment specifications contained within the Inflation Reduction Act (IRA) which was passed by the United States Congress and signed into law by the President on August 16, 2022. The energy efficiency provisions of the IRA allow homeowners to receive a federal tax credit of up to $2,000, for installing a system like the proposed Tier 2 dual-fuel heating system rebate, for equipment installed after December 31, 2022.

The Company continued to perform outreach and marketing work in-house in 2023. Resource Innovations continued to provide technical assistance and rebate processing work for the Appliance program in 2023.

Utah ThermWise® Builder Rebates

The Company continued this program in 2023 with the addition of tiered rebates for smart thermostats and dual-fuel heating systems for the same reasons as described in the Appliance Program discussion. The Company also added a $200 bonus to the single and multifamily Pay-for-Performance rebate measures for new construction projects which install a qualifying dual-fuel heating system while also meeting the existing minimum efficiency standards. This change made the maximum allowable rebate for the Pay-for-Performance measure $1,600 for single family homes ($1,400 Pay for Performance + $200 dual-fuel heating system bonus) and $1,000 for multifamily units ($800 Pay for Performance + $200 dual-fuel heating system + $200 bonus) in 2023.

The Company continued to perform outreach and marketing work in-house in 2023. Resource Innovations provided technical assistance and continued to perform rebate processing work for this program in 2023.

Utah ThermWise® Business Rebates

The Company continued this program in 2023 with the addition of High-Performance New Construction rebate measure. This measure is similar to the existing Pay-for-Performance rebate measure in the ThermWise® Builder Program in the sense that rather than paying out rebates on prescriptive pieces of high efficiency equipment, the rebate a customer qualifies for would be determined by evaluating the entire expected natural gas savings in the building to include an analysis of the space heating, domestic hot water, and the building envelope. Construction drawings are required to be provided by the customer and reviewed by the Company. Specific equipment and building shell performance are input into simplified energy modeling software to estimate the level of natural gas savings and compared to the appropriate energy code baseline.

The Company introduced this measure at a rebate of $2.50 per Dth saved. In addition to the High-Performance New Construction measure, the Company also added tiered rebates for dual-fuel heating systems in 2023 for the same reasons as described in the Appliance Program discussion.

In addition to the new measures, the Company made several minor Tariff changes for purposes of accuracy. Resource Innovations will continue to perform rebate processing and assist with design, outreach, marketing, and technical assistance for this program in 2023.

Utah ThermWise® Weatherization Rebates

The Company continued this program in 2023 with no major changes. Resource Innovations performed rebate processing and provided technical assistance for this program in 2023.

Utah ThermWise® Home Energy Plan

The ThermWise® Home Energy Plan program is offered and administered by the Company with periodic consulting and assistance from Resource Innovations. In 2023, the Company continued to offer virtual, mail-in, and in-home Home Energy Plan assessments.

Utah Low-Income Efficiency Program

The Company funded the Low-Income Efficiency Program in 2023 at $500,000 coming from the energy-efficiency budget ($750,000 total Company funding). The Company disbursed $250,000 every six months, with the disbursements occurring in January and July of 2023. The Company also added the tiered dual-fuel heating system and smart thermostat rebate structures, previously described in the Appliance Program discussion, beginning in 2023.

Utah ThermWise® Energy Comparison Report

In 2022 the Company sent the Energy Comparison Report (ECR or Comparison Report) to more than 230,000 of its customers. As of the end of September 2023, the Comparison Report had been generated over 373,000 times online by over 140,000 unique customers.

The Company increased delivery of the Comparison Report to 280,000 customers in 2023 or 23% above the 2022 level. This increase was realized by adding a new customer distribution group (Group K) of over 50,000 customers.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2023 budget filing is shown in Table 13.1.

Table 13.1 - Utah 2023 Projected & Actual B/C ratios by program and California Standard Practice Test

Program	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	2023 Projected B/C	2023 Actual B/C	2023 Projected B/C	2023 Actual B/C	2023 Projected B/C	2023 Actual B/C	2023 Projected B/C	2023 Actual B/C
ThermWise® Appliance Rebate	1.58	1.73	3.83	5.89	1.66	1.63	0.84	0.80
ThermWise® Builder Rebates	1.87	2.54	3.72	7.06	2.49	2.44	1.03	1.01
ThermWise® Business Rebates	1.38	1.09	3.37	3.37	2.29	3.20	0.98	1.19
ThermWise® Weatherization Rebates	1.24	1.16	2.86	3.58	1.46	1.44	0.81	0.80
ThermWise® Home Energy Plan	2.14	2.73	57.96	92.02	2.11	2.68	0.95	0.95
Low Income Efficiency Program	1.83	0.82	9.33	7.15	1.88	0.89	0.89	0.58
Energy Comparison Report	4.62	2.69	6.22	9.98	4.62	2.69	1.72	0.82
Market Transformation Initiative	0	0	N/A	N/A	0	0	0	0
Totals	1.55	1.58	3.61	5.27	1.91	1.90	0.92	0.90

Actual benefit/cost results for 2023 mirrored corresponding budget projections. The ThermWise® programs passed the Total Resource, Participant, and Utility Cost tests. Actual cost-effectiveness results varied slightly in comparison to projected benefit/cost results due to several factors such as changing avoided gas costs, rebate measure mix, interest rates, and lower than expected participation than were forecasted in cost-effectiveness modeling for the 2023 ThermWise® budget filing (Docket No. 22-057-18).

ThermWise® program results for 2023 (54,897 actual rebates paid) finished the year at 78% of the Company's original 2023 estimate (70,568). The Weatherization program had the highest total number of participants (22,126) and finished at 72% of the 2023 goal.

The DSM Advisory Group continued to meet semi-annually to discuss the Company's energy-efficiency initiatives. Meetings were held at the Company's Utah Center on April 27 and September 21 in 2023.

WYOMING ENERGY-EFFICIENCY RESULTS FOR 2023

The Company filed for approval (Docket No. 30010-211-GT-22) of the of the 2023 Wyoming ThermWise® programs on October 31, 2022. The Wyoming Public Service Commission held an Open Meeting on December 29, 2022, concerning the Company's Application for the proposed 2023 Wyoming ThermWise® programs. The 2023 Wyoming programs were modified to closely align with the 2023 Utah ThermWise® programs to achieve cost savings for both states while also taking current energy-efficiency and equipment standards into account. The Wyoming Public Service Commission approved the 2023 programs (May 26, 2023, Order) and ordered the changes be effective January 1, 2023.

The Wyoming energy-efficiency programs (Appliance, Builder, Business, Home Energy Plan, and Weatherization) have seen good participation and interest from customers since the Company launched the programs on July 1, 2009. In the 2023 program year (January through December 2023) the Wyoming ThermWise® programs had 178 participants or over 1% of the Company's December 31, 2023, Wyoming GS customer base.

UTAH ENERGY-EFFICIENCY PLAN FOR 2024

Based on work with the DSM Advisory Group, Utah-based trade allies, program administrators, and other energy-efficiency stakeholders, the Company proposed, and the Utah Public Service Commission approved, the continuation of seven energy-efficiency programs for 2024 as well as the ThermWise® Market Transformation Initiative. The ThermWise® energy-efficiency programs continuing in 2024 are: 1) the ThermWise® Appliance Rebates Program; 2) the ThermWise® Builder Rebates Program; 3) the ThermWise® Business Rebates Program; 4) the ThermWise® Weatherization Rebates Program; 5) the ThermWise® Home Energy Plan Program; 6) funding of $500,000 for the Low-Income Efficiency Program administered by the Utah Department of Workforce Services; and 7) the ThermWise® Energy Comparison Report.

Utah ThermWise® Appliance Rebates

The Company continues this program in 2024 with the elimination of the residential heating ventilation and air conditioning (HVAC) monitoring and diagnostic systems as a rebate eligible measure. The Company first proposed to add HVAC monitoring and diagnostic systems to the mix of rebate-eligible equipment in the 2022 program year (Docket No. 21-057-25). The Company determined, through industry feedback in 2023, that most smart thermostats can now perform the functions of dedicated monitoring and diagnostic systems and that a stand-alone rebate is no longer necessary.

The Company also sought approval to move system specifications for dual-fuel heating systems from the Company's Utah Natural Gas Tariff No. 600 (Tariff) to ThermWise.com (thermwise.com/equipment-specs/dual-fuel) beginning in 2024. In previous years the Company's Tariff for the Appliance Program specified that rebate-qualifying Tier 1 dual-fuel systems must consist of a >95% annual fuel utilization efficiency (AFUE) natural gas backup paired with an ENERGY STAR® certified ducted heat pump with a heating seasonal performance factor (HSPF) of >9.0 and seasonal energy efficiency ratio (SEER) >14. Rebate-qualifying Tier 2 systems were required to have a >97.5% AFUE natural gas backup paired with a minimum 18 SEER, 10 HSPF, and 11.5 energy efficiency ratio (EER) heat pump.

This change was made in order to be responsive to anticipated system specification changes in coming years due to the dynamic and rapidly advancing nature of this type of equipment, to be responsive to rebate-qualifying dual-fuel specification changes associated with the inflation reduction act (IRA), and to maintain alignment with Rocky Mountain Power's dual-fuel heating rebate specifications. Accordingly, like Rocky Mountain Power, the Company proposed to place such changes on its website and in its program documents to afford the Company to make such changes mid-year without need of seeking specific Commission approval.

The Company will continue to perform outreach and marketing work in-house in 2024. Resource Innovations will provide technical assistance and continue to perform rebate processing work for this program in 2024.

Utah ThermWise® Builder Rebates

Th Company continues this program in 2024 with the elimination of the HVAC monitoring and diagnostic systems rebate and implementation of the dual-fuel heating systems Tariff changes in 2024 for the same reasons as described in the Appliance Program discussion.

The Company will continue to perform outreach and marketing work in-house in 2024. Resource Innovations will provide technical assistance and continue to perform rebate processing work for this program in 2024.

Utah ThermWise® Business Rebates

The Company continues this program in 2024 with the addition of a rebate for variable refrigerant flow (VRF) systems that include a natural gas dedicated outdoor air system (DOAS). VRF with natural gas DOAS systems provide ultra-efficient space heat, using a refrigerant and compression process, which is employed after pre-heating incoming outside air to a pre-determined setpoint. The high efficiency natural gas-fueled DOAS pre-heats incoming outside air, to typically between 65° and 70° in the Utah climate zones, after which the VRF unit delivers heated air to the thermostatically controlled conditioned spaces in a building. VRF with natural gas DOAS systems can achieve between 300% and 400% efficiency levels. These systems obtain their high efficiency by using inverter compressors. Inverter systems allow the compressor to ramp up or down based on the needs within each conditioned space. In VRF with natural gas DOAS systems, the refrigerant passes through condenser units to indoor units, cutting down on the need for extensive ductwork. The smaller pipes make it easier to retrofit in older buildings than traditional HVAC systems. Removing ducts from the equation is part of the increased energy efficiency.

The U.S. Department of Energy's Energy Saver reports that more than 30% of energy consumption could be due to losses of cool air through ducts. Additionally, the Company estimates that natural gas usage from the DOAS pre-heat unit can be reduced by an additional 30%, or 6.86 Dth per ton, annually in comparison to typical natural gas HVAC solutions. The Company established the rebate amount for dual fuel VRF systems at $150 per ton in 2024.

In addition to the new measures, the Company made several minor Tariff changes for purposes of accuracy. Resource Innovations will continue to perform rebate processing and assist with design, outreach, marketing, and technical assistance for this program in 2024.

Utah ThermWise® Weatherization Rebates

The Company continues this program in 2024 with no major changes. Resource Innovations will continue to perform rebate processing and assist with technical assistance for this program in 2024.

Utah ThermWise® Home Energy Plan

As described above, the Company offers the ThermWise® Home Energy Plan program with periodic consulting and assistance from Resource Innovations. In 2024, the Company will continue to offer virtual, mail-in, and in-home energy plans.

Utah Low-Income Efficiency Program

The Company will continue funding the Low-Income Efficiency Program in 2024 at $500,000 coming from the energy-efficiency budget ($750,000 total Company funding). The Company will disburse $250,000 every six months, with the disbursements occurring in January and July of 2024. The Company will also eliminate the HVAC monitoring and diagnostic systems rebate and implement the dual-fuel heating systems Tariff changes previously described in the Appliance Program discussion, beginning in 2024.

Utah ThermWise® Energy Comparison Report

As of the end of September 2023, the Energy Comparison Report had been generated over 376,000 times online by over 141,000 unique customers.

The Company will decrease delivery of the Comparison Report to 220,000 customers in 2024 or 21% below the 2023 level. This decrease is realized by discontinuing distribution of the comparison report to participant groups (Groups C, E, and L) of over 60,000 customers.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2024 budget filing is shown in Table 13.2 below.

Table 13.2 - Utah 2024 projected NPV & Benefit/Cost ratios by program and California Standard Practice Test

2024 Projections	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	NPV	B/C	NPV	B/C	NPV	B/C	NPV	B/C
ThermWise® Appliance Rebate	$3.32	1.69	$24.32	6.17	$3.16	1.64	-$1.93	0.81
ThermWise® Builder Rebates	$8.78	1.83	$50.70	5.13	$11.23	2.38	-$0.12	0.99
ThermWise® Business Rebates	$0.70	1.17	$11.75	4.55	$2.10	1.78	-$0.44	0.92
ThermWise® Weatherization Rebates	$1.36	1.17	$20.79	3.72	$2.47	1.37	-$2.63	0.78
ThermWise® Home Energy Plan	$0.57	2.06	$3.81	79.15	$0.56	2.02	-$0.19	0.86
Low Income Efficiency Program	$0.63	1.81	$3.61	12.49	$0.65	1.85	-$0.22	0.87
Energy Comparison Report	$0.54	2.04	$3.54	8.53	$0.54	2.04	-$0.35	0.75
Market Transformation Initiative	-$1.32	0	$0	N/A	-$1.32	0	-$1.32	0
Totals	**$14.59**	**1.48**	**$118.54**	**5.12**	**$19.39**	**1.76**	**-$7.19**	**0.86**

*Shown in millions

Table 13.3 shows the Utah cost-effectiveness results using the projections included in the budget filing updated to include the gas cost forward curve used in the PLEXOS model.

Table 13.3 - Utah 2024 NPV & Benefit/Cost ratios using gas cost forward curve from PLEXOS model

2024 IRP Forward Curve	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	NPV	B/C	NPV	B/C	NPV	B/C	NPV	B/C
ThermWise® Appliance Rebate	$3.37	1.70	$23.50	6.00	$3.21	1.65	-$1.51	0.84
ThermWise® Builder Rebates	$8.75	1.82	$48.89	4.98	$11.20	2.37	$0.66	1.04
ThermWise® Business Rebates	$0.50	1.12	$11.35	4.43	$1.90	1.71	-$0.45	0.91
ThermWise® Weatherization Rebates	$1.56	1.20	$20.04	3.63	$2.67	1.40	-$2.06	0.82
ThermWise® Home Energy Plan	$0.49	1.91	$3.70	76.93	$0.48	1.88	-$0.21	0.83
Low Income Efficiency Program	$0.67	1.86	$3.49	12.10	$0.69	1.90	-$0.12	0.93
Energy Comparison Report	$0.82	2.57	$3.43	8.29	$0.82	2.57	-$0.01	0.99
Market Transformation Initiative	-$1.32	0.00	$0.00	N/A	-$1.32	0.00	-$1.32	0.00
Totals	$14.84	1.49	$114.39	4.98	$19.64	1.77	-$5.03	0.90

*Shown in millions

WYOMING ENERGY-EFFICIENCY PLAN FOR 2024

The Company expects 2024 participation in the portfolio of Wyoming ThermWise® programs to reach 387 customers.

PLEXOS MODEL RESULTS FOR 2024

The Company entered projections from the approved 2024 energy-efficiency budget into the PLEXOS model in response to the Utah Commission's request. Data entries for the 2024 energy-efficiency programs included participants and associated deemed lifetime Dth savings per program measure. The Company also incorporated incentive (variable) and administration (fixed) costs for each program measure into the PLEXOS model.

The PLEXOS model used the projected 2024 participation and administration costs as the baseline for its analysis of each program. For each program, the model examined what would happen if participation was reduced to 25% or increased to 150% of the 2024 projection. The model also examined different scenarios involving the escalation of annual administration costs per program. In these scenarios, administration costs per program were increased to 150% and 200% of the 2024 projection. PLEXOS then made the judgment as to whether a program should be "accepted" (100% on the included graph) or "rejected" (0% on the included graph) based on a given level of participation and administration costs. Please see Exhibit 13.1 for the PLEXOS results in a table format.

The model accepted the 2024 ThermWise® Builder and Home Energy Plan programs at 50% of 2024 projected participation if administration costs were increased to 200% of the 2024 budget projection. The model accepted the Appliance, Business, and Energy Comparison Report programs at 75% of participation and 200% of the 2024 budget projection. The model accepted the Low Income and Weatherization programs at 100% of 2024 projected participation if administration costs were increased to 200% of the 2024 budget projection.

Another way to view the results of the PLEXOS model is to analyze how much administration costs could increase and still be accepted if participation was held at 100% of the 2024 projection. In this scenario, the administration costs for the Builder and Home Energy Plan programs could increase by four times the 2024 budget projection and still be accepted. The Appliance, Business, and Energy Comparison Report programs could increase projected administration costs by over two times and still be accepted. The Low Income and Weatherization programs could increase projected administration costs by two times and still be accepted.

In summary, the PLEXOS model results indicate that as a gas supply resource at the approved budget and participation levels, the 2024 energy-efficiency programs are accepted as qualifying and cost-effective resources when compared to other available resources. Furthermore, this holds true when participation rates are held constant, and program administrative costs are increased.

The PLEXOS model is a comprehensive resource planning and evaluation tool. In comparison, the Company developed its Energy-Efficiency Model in-house, with assistance of the Company's DSM Advisory Group and the Utah Commission's review. The Company uses its Energy-Efficiency Model for the sole purpose of modeling the Company's energy-efficiency programs. To this end, the Company relies on the Energy-Efficiency Model for energy-efficiency program planning purposes and more importantly energy-efficiency program cost effectiveness (based on the California Standard Practices Manual).

Using the Energy-Efficiency Model, the Company analyzed the approved 2024 energy-efficiency programs at a “break-even” benefit / cost ratio (B/C = 1.00) by holding participation (and incentive payments) constant and increasing all other costs in a linear manner. The analysis is based on projected natural gas savings of 911,884 Dth in 2024. This analysis resulted in a projected potential total energy-efficiency spending limit of $45.3 million per year using the Utility Cost Test. The currently-approved $25.66 million per year is well below this threshold. This analysis indicates that the maximum potential spending on energy-efficiency is directly related to the cost-effectiveness of realizing each Dth saved. Therefore, as long as the Company’s energy-efficiency programs are determined cost-effective in the Energy-Efficiency Model, accepted by the PLEXOS model when compared to other available resources, and do not negatively impact company operations, energy-efficiency programs are an appropriate resource.

AVOIDED COSTS RESULTING FROM ENERGY EFFICIENCY

The ThermWise® Cost-Effectiveness Model calculates the avoided cost of gas purchases as the sole benefit of the energy-efficiency programs. In 2023, the avoided gas cost attributable to energy-efficiency was calculated to be $61.6 million. For 2024, the avoided gas cost attributable to energy-efficiency was calculated to be $45.3 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

Exhibit 13.1

2024 Energy-Efficiency Modeling Results from PLEXOS

Program @ <u>100%</u> of 2024 Budget $	% of 2024 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Low Income Efficiency					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by PLEXOS Model as a resource =

Not Accepted by PLEXOS Model as a resource =

Program @ <u>150%</u> of 2024 Budget $	% of 2024 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Low Income Efficiency					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by PLEXOS Model as a resource =

Not Accepted by PLEXOS Model as a resource =

Program @ <u>200%</u> of 2024 Budget $	% of 2024 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Low Income Efficiency					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by PLEXOS Model as a resource =

Not Accepted by PLEXOS Model as a resource =

FINAL MODELING RESULTS

LINEAR PROGRAMMING OPTIMIZATION MODEL

The Company uses a computer-based linear-programming optimization model to evaluate both supply-side and demand-side resources. Beginning with this IRP the company is now using a new software package called PLEXOS. PLEXOS is an energy market simulation platform owned by Energy Exemplar. This software provides similar and enhanced analysis and reporting functionality to SENDOUT that has been used up until this IRP.

In setting up and evaluating the new PLEXOS model, the Company ran a comparison model with SENDOUT that was based on the base model used in the 2023-2024 IRP. Figure 14.1 below shows the Normal Case model results with Normal Weather demand. This example includes comparison of HDD's, Demand, Wexpro Production, and Clay Basin Inventory. Table 14.1 shows a comparison of Total System Costs between the two models.

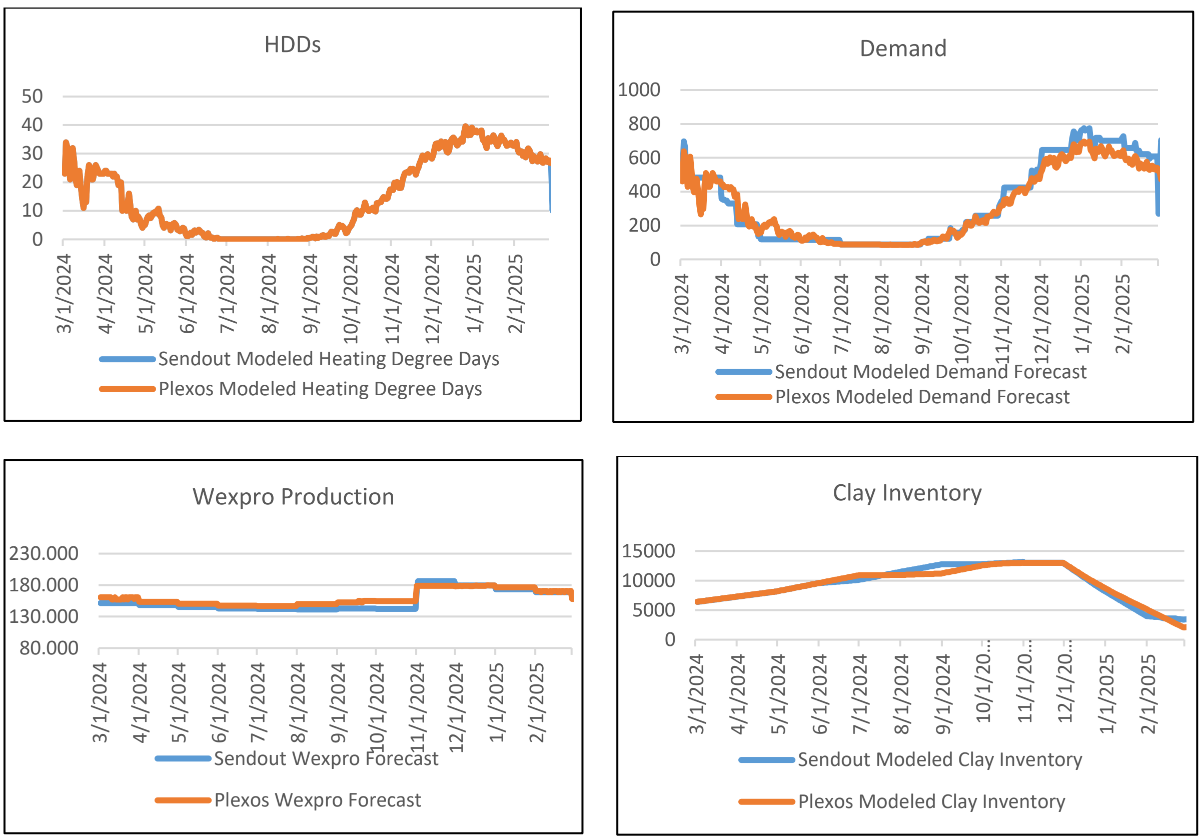


Figure 14.1: 2024-2025 Normal Case Model Results

Table 14.1: PLEXOS/SENDOUT 1 Year Total System Cost Comparison

	Plexos Total	SENDOUT Total	Difference
Total System Costs	$424.7 million	$428.6 million	Less than 1%
Wexpro Production	56.1 MMDth	56.5 MMdth	Less than 1%

CONSTRAINTS AND LINEAR PROGRAMMING

While the concepts of linear programming date back to the early 19th century, it was not until the middle of the 20th century that this approach began to be more widely accepted as a method for achieving optimal solutions in practical applications. In summary, linear programming problems involve the optimization of a linear objective function subject to linear constraints.

Constraints are necessary in determining a maximum or minimum solution. Constraints must be linear functions that represent either equalities or inequalities. An example of an inequality constraint in the natural gas business would be the quantity of natural gas that is physically transported over a certain segment of an interstate pipeline must be "less than or equal to" a certain level of transportation previously contracted for with that pipeline company. Another example of an inequality constraint would be the forecast production available from a group of cost-of-service wells. The amount this resource can be taken can never exceed the forecast maximum level available as production naturally declines over time. All resources are defined by constraints.

Constraints must accurately reflect the problem being solved. The arbitrary removal of required constraints results is an unacceptable solution. For example, if the Company removed the constraint on how quickly it filled Clay Basin, the model would assume that it could be done instantaneously, resulting in an unrealistic solution. The removal of all constraints in a linear programming problem would result in no solution ever being able to be reached.

The Company will periodically reevaluate the constraints in its PLEXOS model to determine if they accurately reflect the realities of the problem being solved. For the 2024-2025 IRP model, the Company maintained the same constraints used in the previous SENDOUT model.

MODEL IMPROVEMENTS

With the implementation of the PLEXOS model, the Company made changes to utilize some new capabilities. This includes splitting the demand into geographical areas, improved modeling of Wexpro functionality, and access to more detailed results. PLEXOS is also a much faster working software with reduced software functionality concerns.

The discount rate used in the model was adjusted to 5.35.% to reflect the Carrying Charge stated in the Tariff.

MONTE CARLO METHOD FOR STRESS TESTING MODEL

To have a meaningful Monte Carlo simulation, it is important to have a sufficient number of draws (typically hundreds). Each draw consists of one deterministic linear programming computer run. The Monte Carlo simulation developed by the Company this year utilized 1,000 draws. Each draw has different inputs for pricing and weather. No other variables have a more profound impact on the cost minimization problem being solved by PLEXOS.

The output reports generated from the PLEXOS modeling results consist primarily of data and graphs. Many of the numerical-data reports show probability distributions for key variables in a simulation run. The heading “max” in these reports refers to the value of the draw in a simulation with the highest quantity. The heading “min” refers to the value of the draw in a simulation with the lowest quantity. The heading “med” refers to the median draw (or the draw in the middle of all draws).

The Company believes that the mean and median values are good indicators of likely occurrence, given the underlying assumptions in a simulation. Many exhibits in this report also include a Normal Case number to show how the Normal Case compares to the mean and median. The Company will discuss the Normal Case in more detail later in this section. Also, in these reports are the headings “p95,” “p90,” “p10,” and “p5.” The label “p95” on report means, based on input assumptions, that a 95% confidence exists that the resulting variable will be less than or equal to that number. Likewise, a “p10” number suggests that there is a 10% likelihood that a variable will be less than or equal to that number. These statistics, and/or the shape of a frequency curve, define the range of potential outcomes.

NATURAL GAS PRICES

It is extremely difficult to accurately model future natural gas prices. Most of the Company’s natural gas purchases are tied contractually to one or more of ten price indices. Two of those indices are published first-of-month prices for deliveries to the interstate pipeline systems of Northwest Pipeline and CIG. The remaining eight are published daily indices.

With the implementation of the PLEXOS model and changes to gas forecasts the method the Company uses to input pricing information is different beginning with the 2024-2025 IRP. As explained in the Industry Overview section, pricing inputs to the model are now the average of the S&P Global forecast and the most recent NYMEX forward curves (Predicted Prices).

In order to set up the model for Monte Carlo analysis on gas pricing PLEXOS requires an input called the “Error Standard Deviation”. This is a calculation comparing how far from the Predicted Price the actual value may be. To calculate this number, the Company compares historical prices with the Predicted Prices and calculates the error for each month going back two years. These monthly data points are grouped into “Winter” and “Non-winter” groups. Winter is defined as December-February. For each price index in the model a winter and non-winter Error Standard Deviation is used when calculating the price ranges during Monte Carlo sampling.

WEATHER AND DEMAND

Weather-induced demand is the single most unpredictable variable in natural gas resource modeling. The Company enters the Normal Weather for each day of the year into the PLEXOS model. This data comes from the rate case model. When forecasting future demands, the Company uses the weather heating degree days input, along with usage-per-customer-per-degree-day and the number of customers, to calculate the customer demand profile used by the model.

The Monte Carlo sampling on weather takes the Normal Weather by day and varies that for the 1,000 draws. Exhibits 14.13 through 14.25 show the annual and the monthly demand distribution curve for the first year of the base simulation. Exhibit 14.26 shows the annual heating-degree-day distribution.

DESIGN DAY AND BASELOAD PURCHASE CONTRACTS

Another important consideration in the modeling process is the need to have adequate resources sufficient to meet a Design Day. The sales-demand Design Day for the 2024-2025 heating season is approximately 1.28 MMDth per day at the city gates. The most likely day for a Design Day to occur is on December 26 although, the probability of a Design Day occurring on any day between mid-December and mid-February is relatively the same.

After executing the RFP process, The Company then executes a series of deterministic PLEXOS scenarios, removing the unused RFP packages, and leaving the base load and peaking packages that were selected. One of the purposes of these runs is to verify that adequate purchased gas resources, at the lowest cost, will be available in the event that a Design Day were to occur. The optimizing nature of the PLEXOS model helps to make this happen. This year, of the 1,000 draws generated in this process, 7 draws included days with demand that met or exceeded the Design Day requirement of 1.28 MMDth. In other words, these scenarios have enough resources to meet a Design Day event.

All of the seasonal baseload purchased-gas resources were committed prior to the beginning of the IRP year. Storage, daily spot gas, and cost-of-service gas supply do not need to be committed to before the IRP year begins. This modeling approach also lends itself to performing operational analysis during the year as natural gas prices change.

Exhibit 14.27 shows the resources utilized to meet the Design Day. Exhibit 14.28 shows the firm Design Day demand distribution for the base simulation for the first plan year. As expected, the Design Day for the Company is in the upper portion of the curve.

NORMAL TEMPERATURE CASE

In this document, the Normal Case scenario can be seen in Exhibits 14.59 through 14.68. These show additional planning detail for the first two years of the Normal Case. The Company lists monthly data for each category of cost-of-service gas and each purchase-gas package. The Company also includes planned injections and withdrawals for each of the storage facilities currently under contract. Although no actual gas-supply year will ever perfectly mirror the plan, these exhibits are among the most useful products of the IRP process. They are used extensively in making monthly and day-to-day nomination decisions.

Figure 14.2 below shows the model results with Normal Weather demand and a potential supply mix to meet this demand. This example includes forecasted cost-of-service production, baseload supply, and a supply mix of storage, peaking supply, and spot purchases. When supply is greater than demand, gas will be injected into storage.

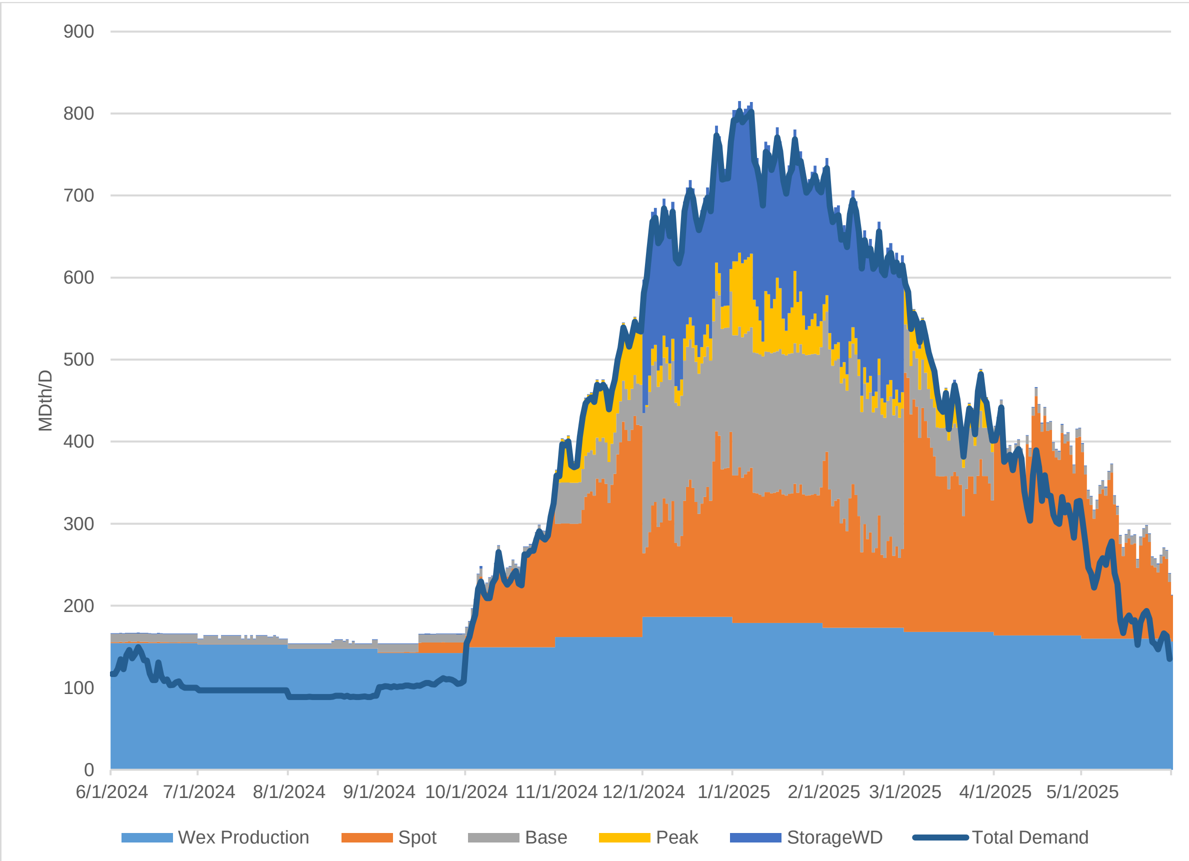


Figure 14.2: 2024-2025 Normal Case Supply and Demand

PURCHASED GAS RESOURCES

Exhibits 14.29 through 14.40 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 14.41 shows the annual distribution from the simulation. Exhibit 14.42 shows the numerical monthly data with confidence limits. Gas purchased for the first plan year under the Normal Case is approximately 66.7 MMDth. The Company is confident that, for a colder-than-normal year, sufficient purchased gas resources will be available in the market. Likewise, the Company is confident that in the event of a warmer-than-normal year, it has not contracted for too much gas.

COST-OF-SERVICE GAS

Another important output from the PLEXOS modeling exercise each year is a determination of the level of cost-of-service gas to be produced during the upcoming gas-supply year.

Exhibits 14.43 through 14.54 show the distributions for cost-of-service gas for each month of the first plan year from the base simulation. Exhibit 14.55 shows the annual distribution from the simulation. Exhibit 14.56 shows the numerical monthly data with confidence limits. Cost-of-service production for the first plan year from the Normal Case is approximately 58.9 MMDth.

FIRST YEAR AND TOTAL SYSTEM COSTS

The linear-programming objective function for the PLEXOS model is the minimization of variable cost. A distribution curve for first-year total cost from the Normal Case simulation is shown in Exhibit 14.57. The similar curve for the total 25-year modeling time horizon is shown in Exhibit 14.58. The Normal Case cost for the full 25-year time period is approximately $15.2 billion.

GAS SUPPLY/DEMAND BALANCE

Exhibits 14.67 and 14.68 show monthly natural gas supply and demand broken out by geographical area, residential, commercial and the non-GS categories of commercial, industrial and electric generation.

This report is available in PLEXOS and is titled “Required vs. Supply”. The data in these exhibits represent the Normal Case. The Company slightly adapted the PLEXOS report to show geographical areas and lost-and-unaccounted-for gas. Because the Company measures demand at the customer meter and modeling occurs at the city gate, in years past the Company grossed-up demand by the estimated lost-and-unaccounted-for volume to model natural gas demand at the city gate.[67] The Company models lost-and-unaccounted-for gas as a percent of the other demand classes and lists it as its own specific demand class.

Exhibit 14.67 of the report shows the requirements of the system. Those are specifically demand, fuel consumed, and storage injection. This results in a total requirement of 124.6 MMDth for the Normal Case. Exhibit 14.68 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the 124.6MMDth demand for the Normal Case.

SHUT-IN SCENARIO ANALYSIS

The Utah Commission, in its Report and Order issued October 22, 2013, concerning the Company’s 2013 IRP, required the Company to provide a scenario analysis for future IRPs that includes varying percentages of cost-of-service gas with varying levels of the Company demand (e.g., low, normal and high).[68]

The tables below illustrate different scenarios that may occur with differing levels of cost-of-service gas and demand. Table 14.1 shows the estimated annual volume of cost-of-service

[67] Also included are compressor fuel, Company use, and gas loss due to tear outs.

[68] In the Matter of Questar Gas Company’s Integrated Resource Plan for Plan Year: June 1, 2013, to May 31, 2014, The Public Service Commission of Utah, Report and Order, Docket No. 13-057-04, Issued: October 22, 2013.

gas that would be shut in under different scenarios. Table 14.2 shows the anticipated total annual costs under different scenarios. The cost differences are, in part, a result of estimated shut-in costs when cost-of-service gas exceeds demand as well as the cost of having to replace cost-of-service gas (with purchased gas) when demand exceeds the amount of cost-of-service gas available.

Table 14.1: Annual Shut-In Production (MDth)

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	0.00	0.00	0.00
	IRP Forecast	0.00	0.00	0.00
	High 10%	0.00	0.00	0.00

Table 14.2: Total Annual System Costs ($ million)

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	531.77	544.95	570.23
	IRP Forecast	533.47	545.04	568.94
	High 10%	535.42	544.87	566.94

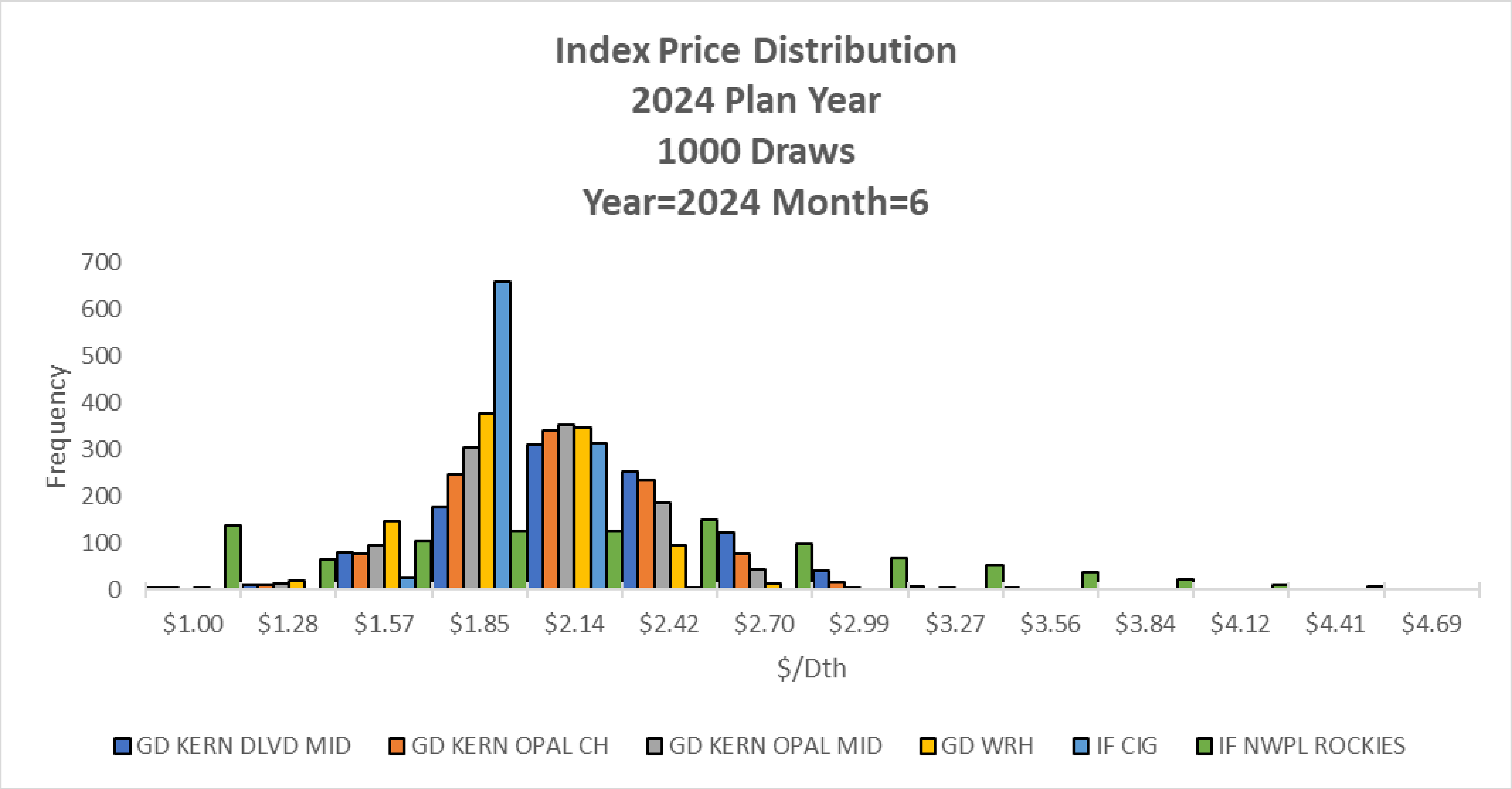


Exhibit 14.01

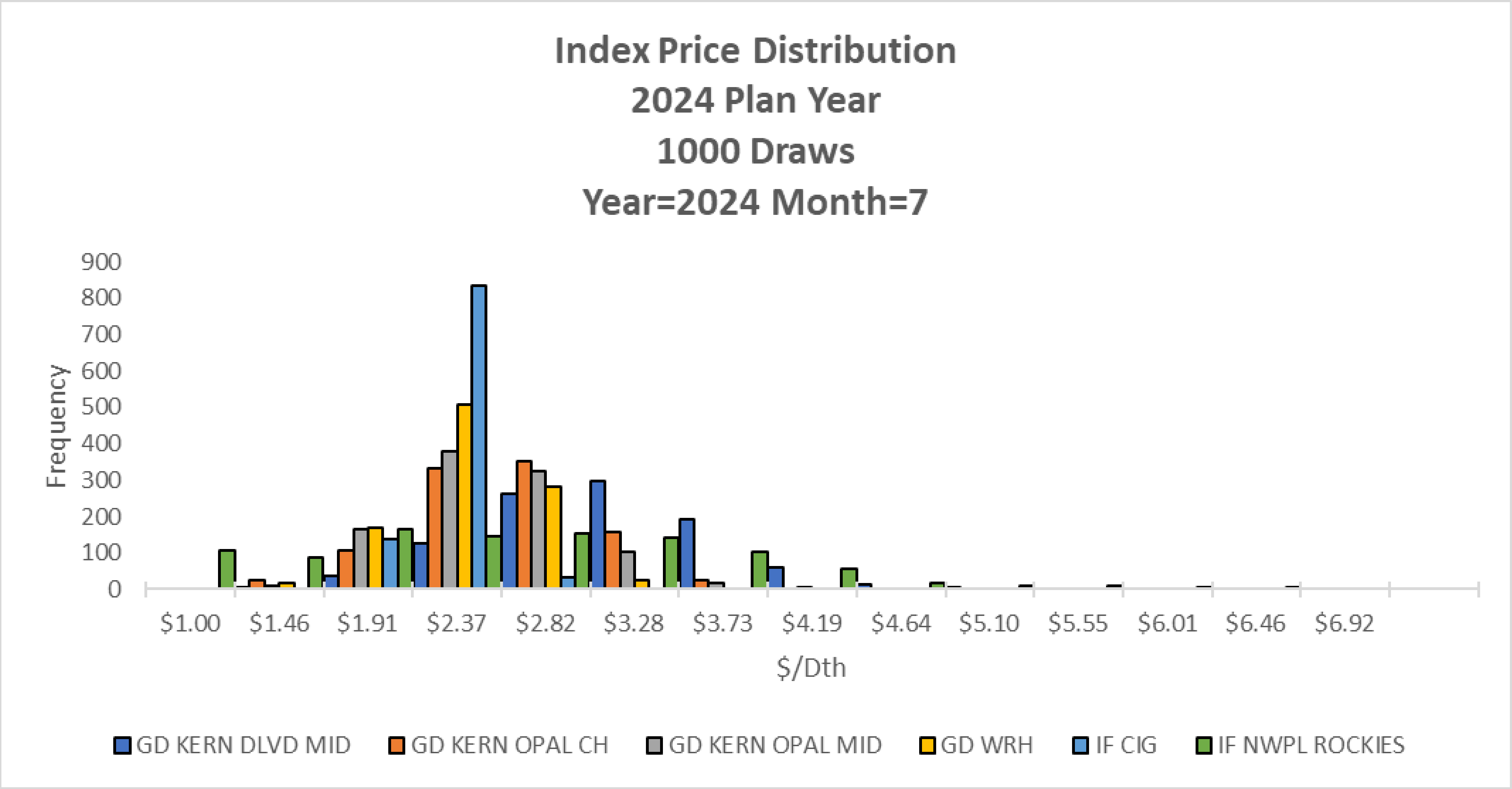
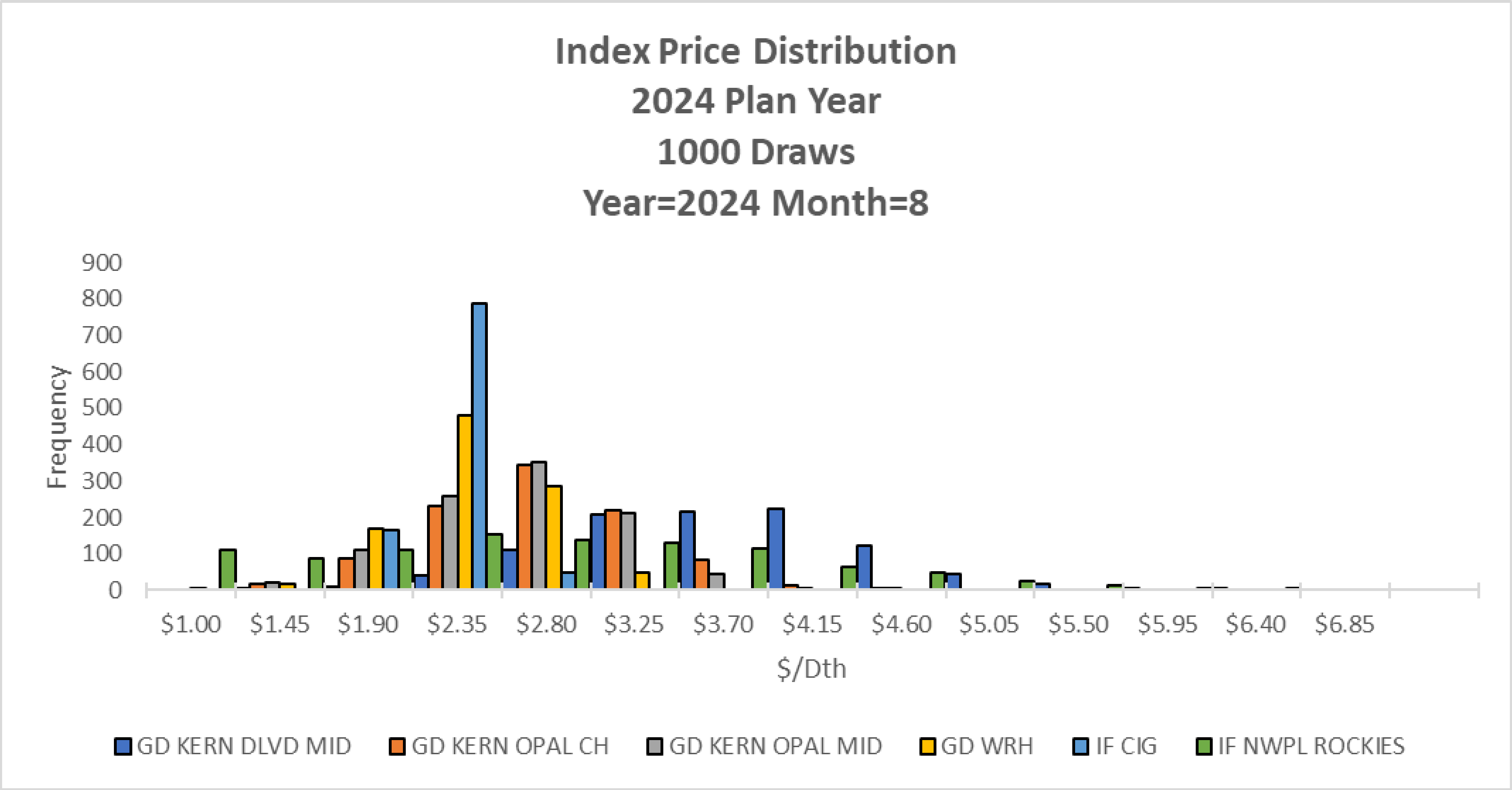


Exhibit 14.02



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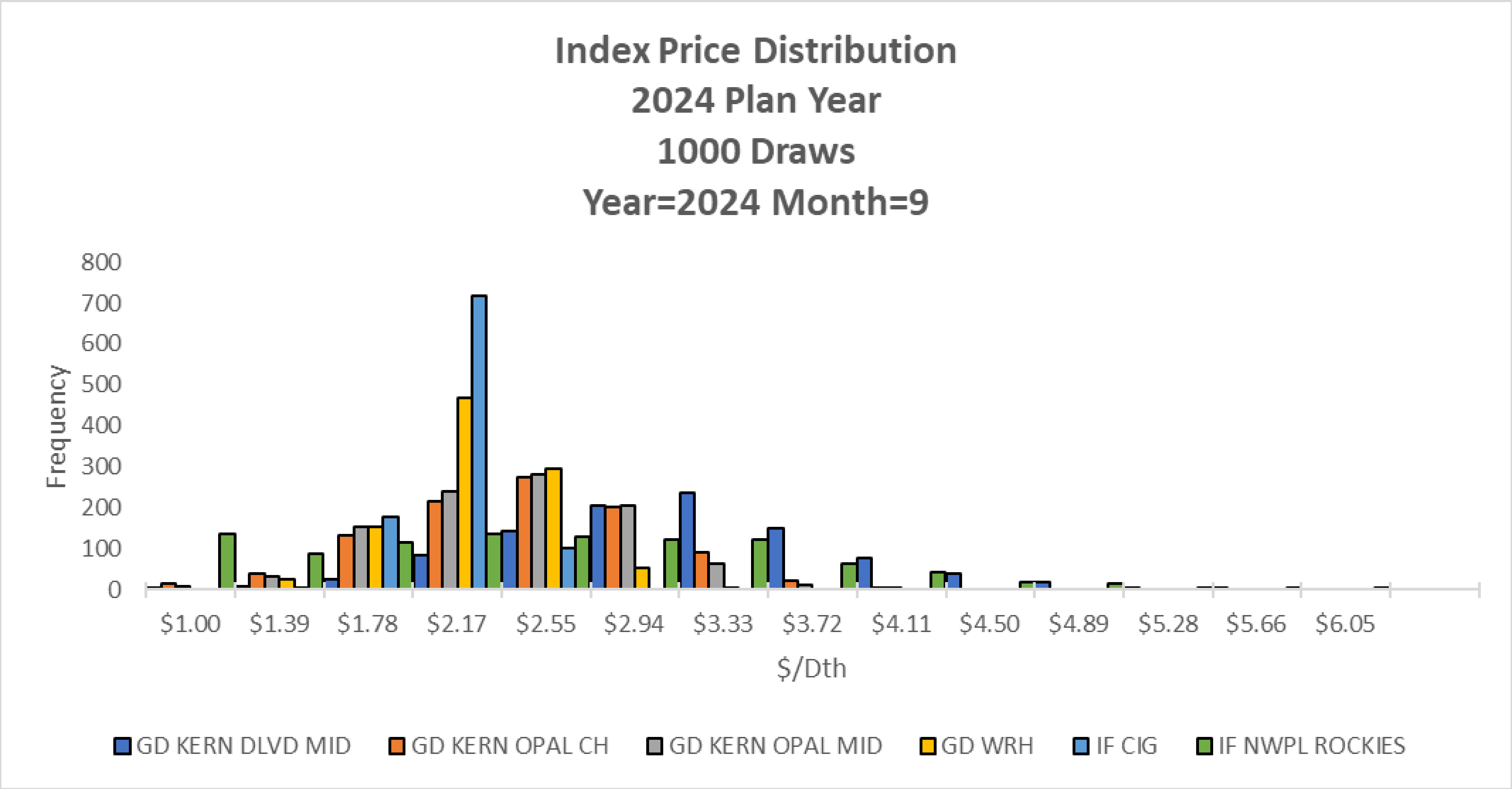

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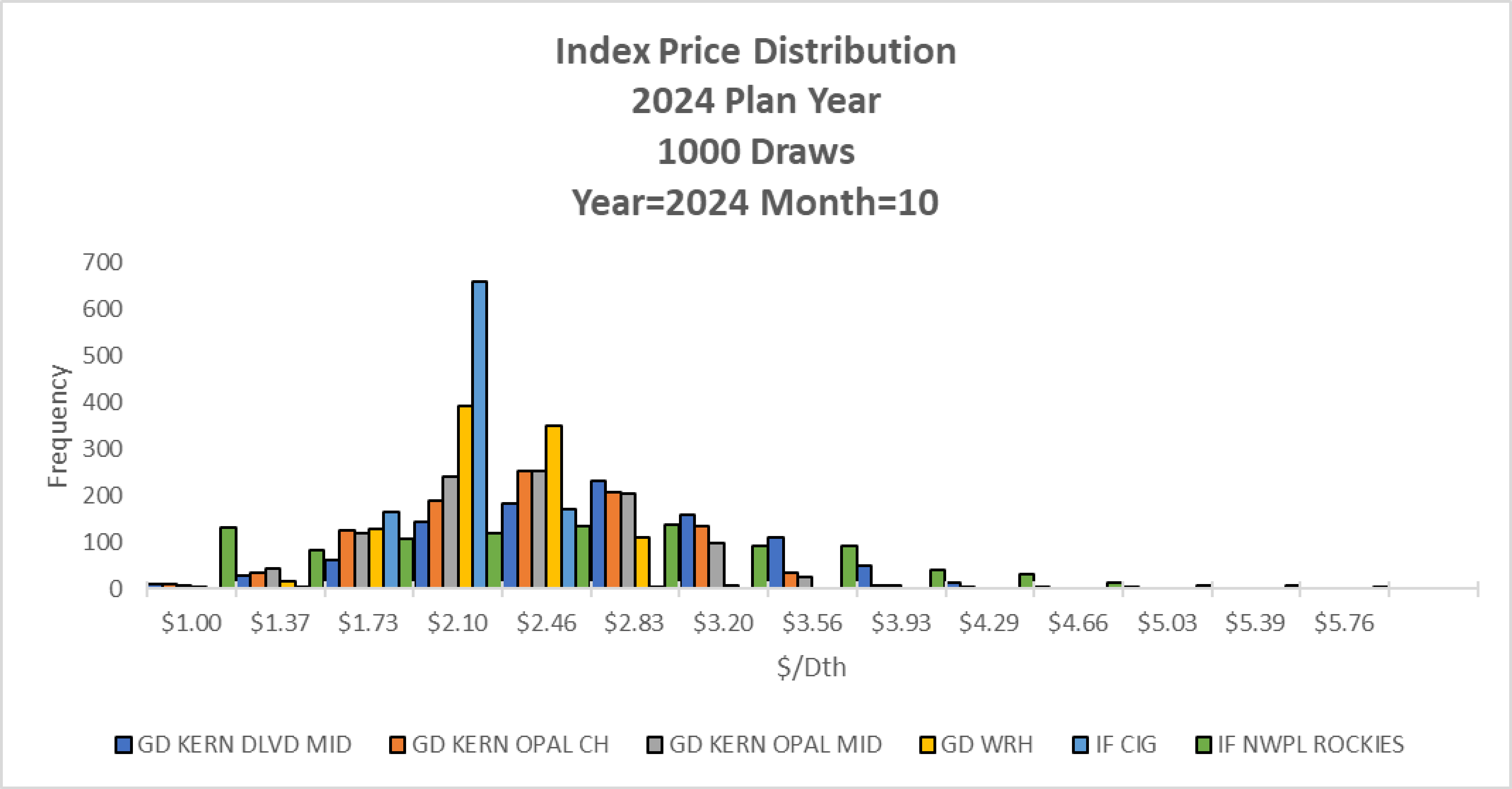

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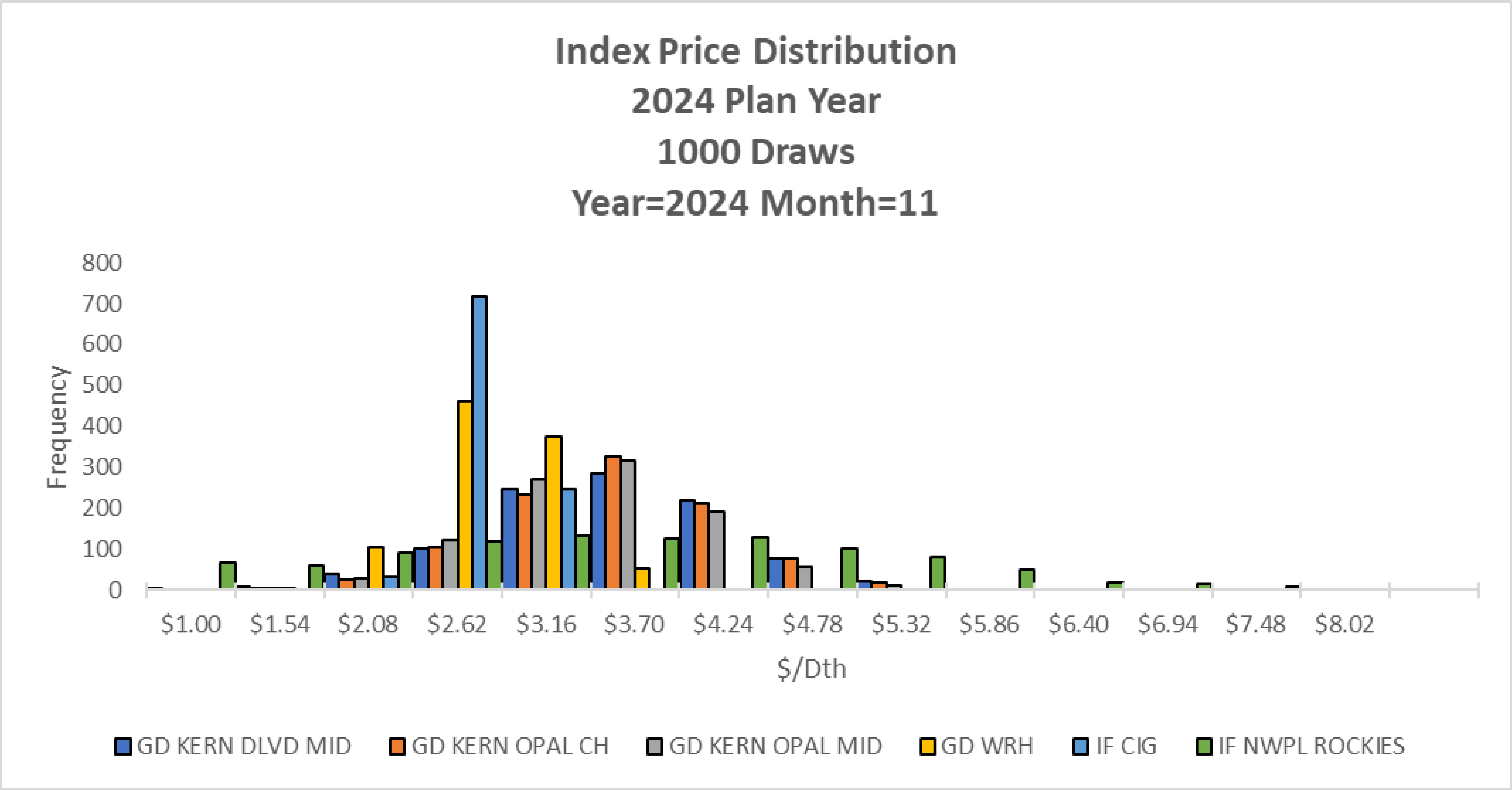

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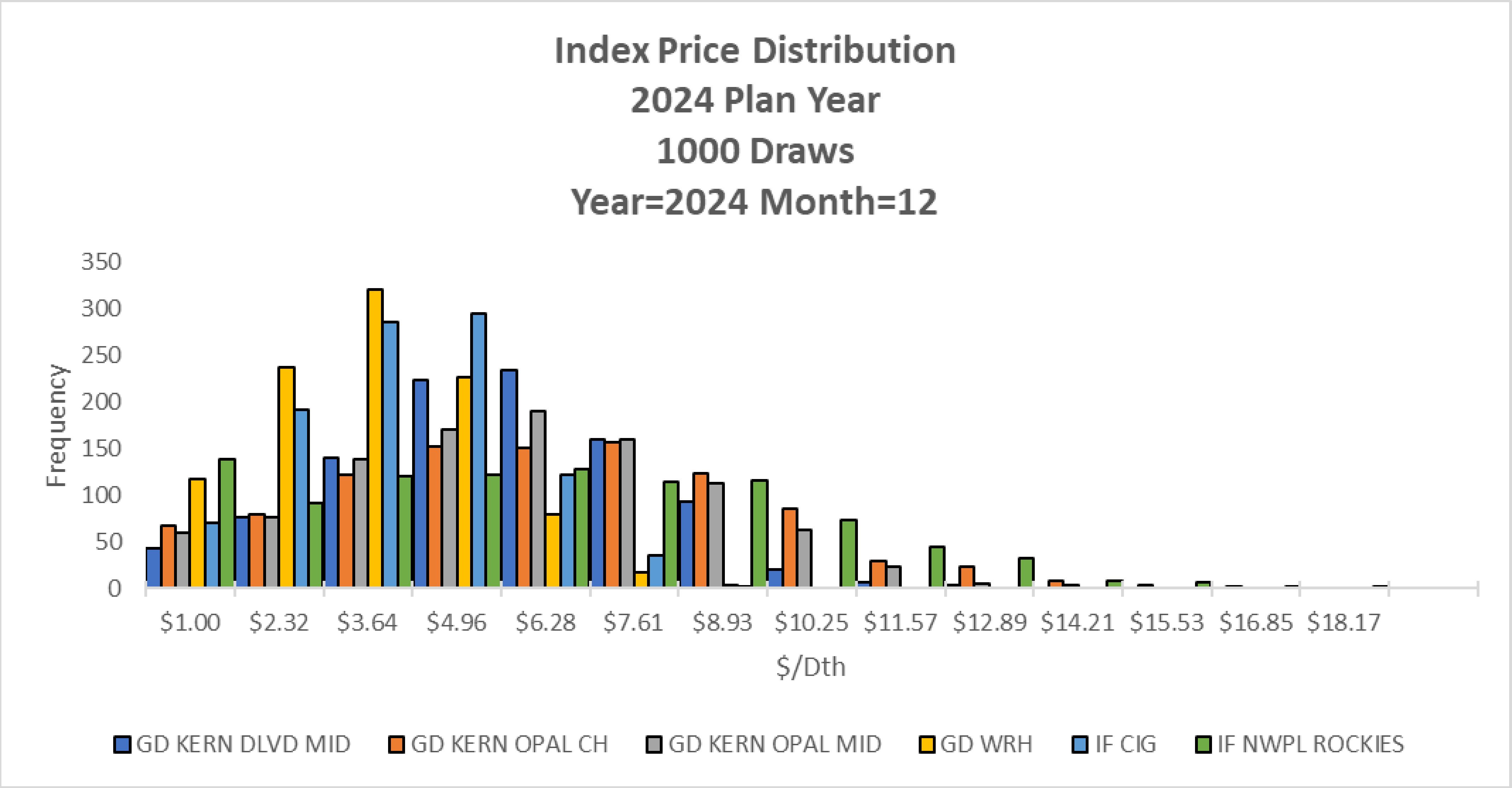

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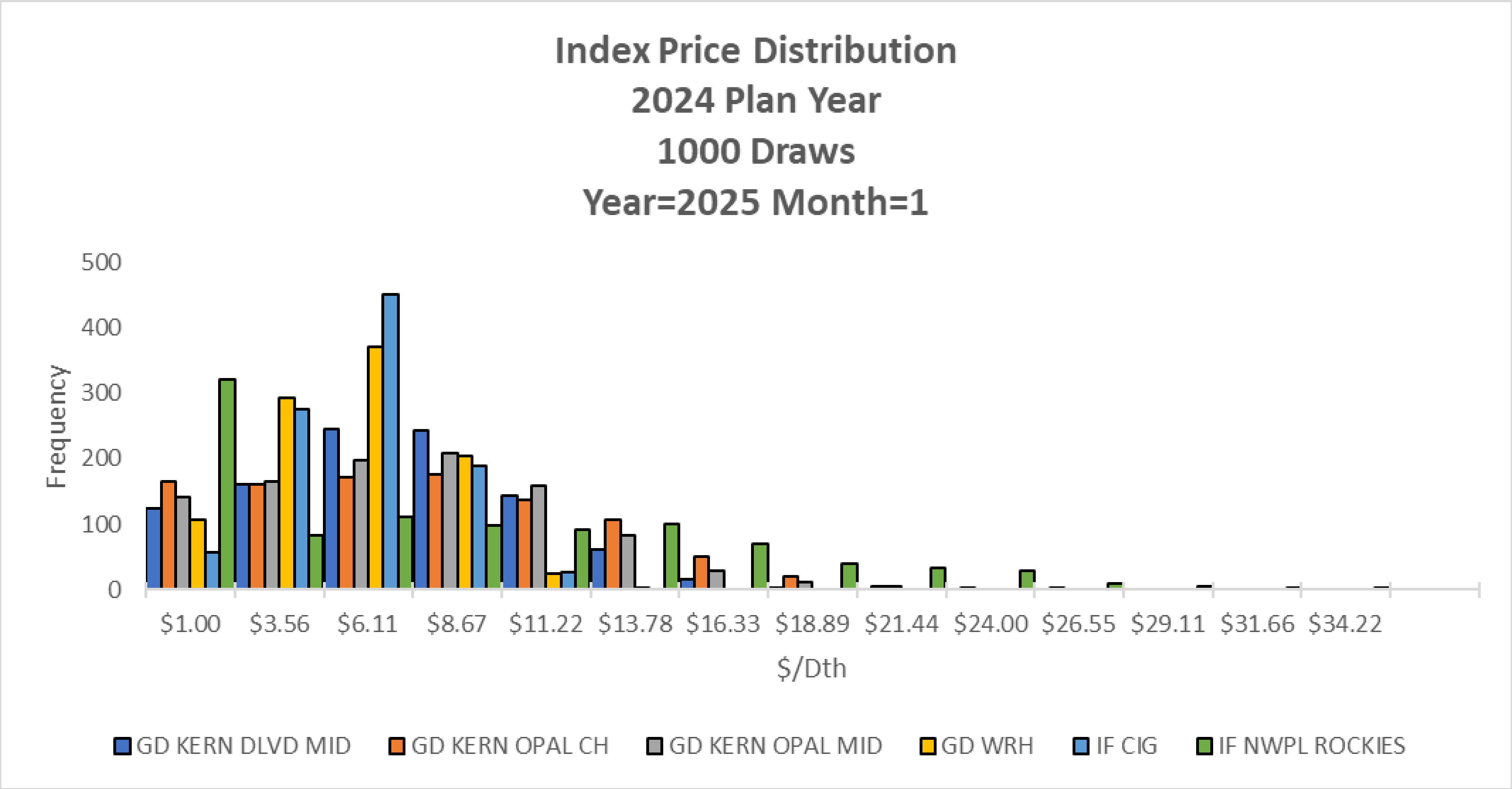

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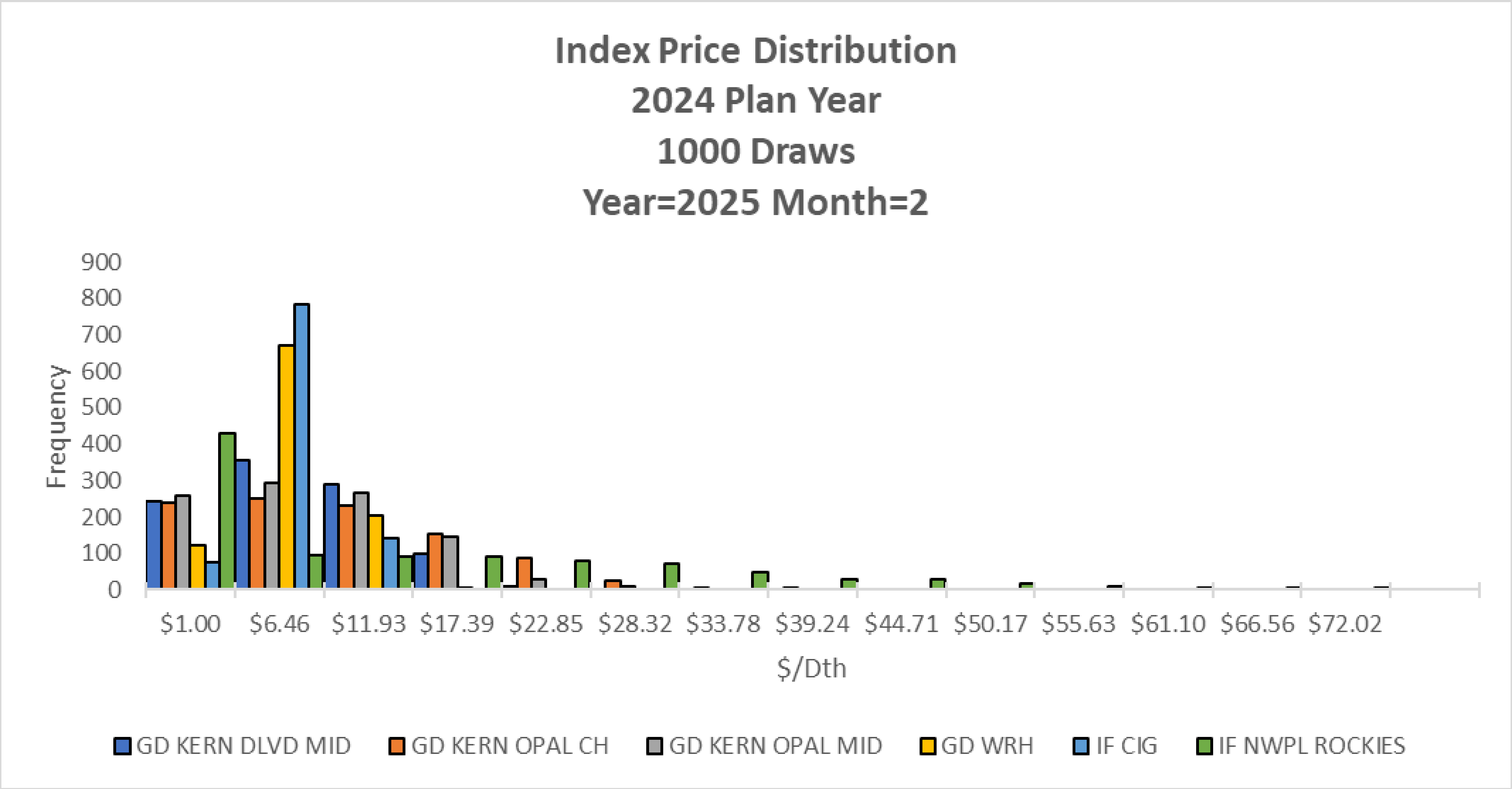

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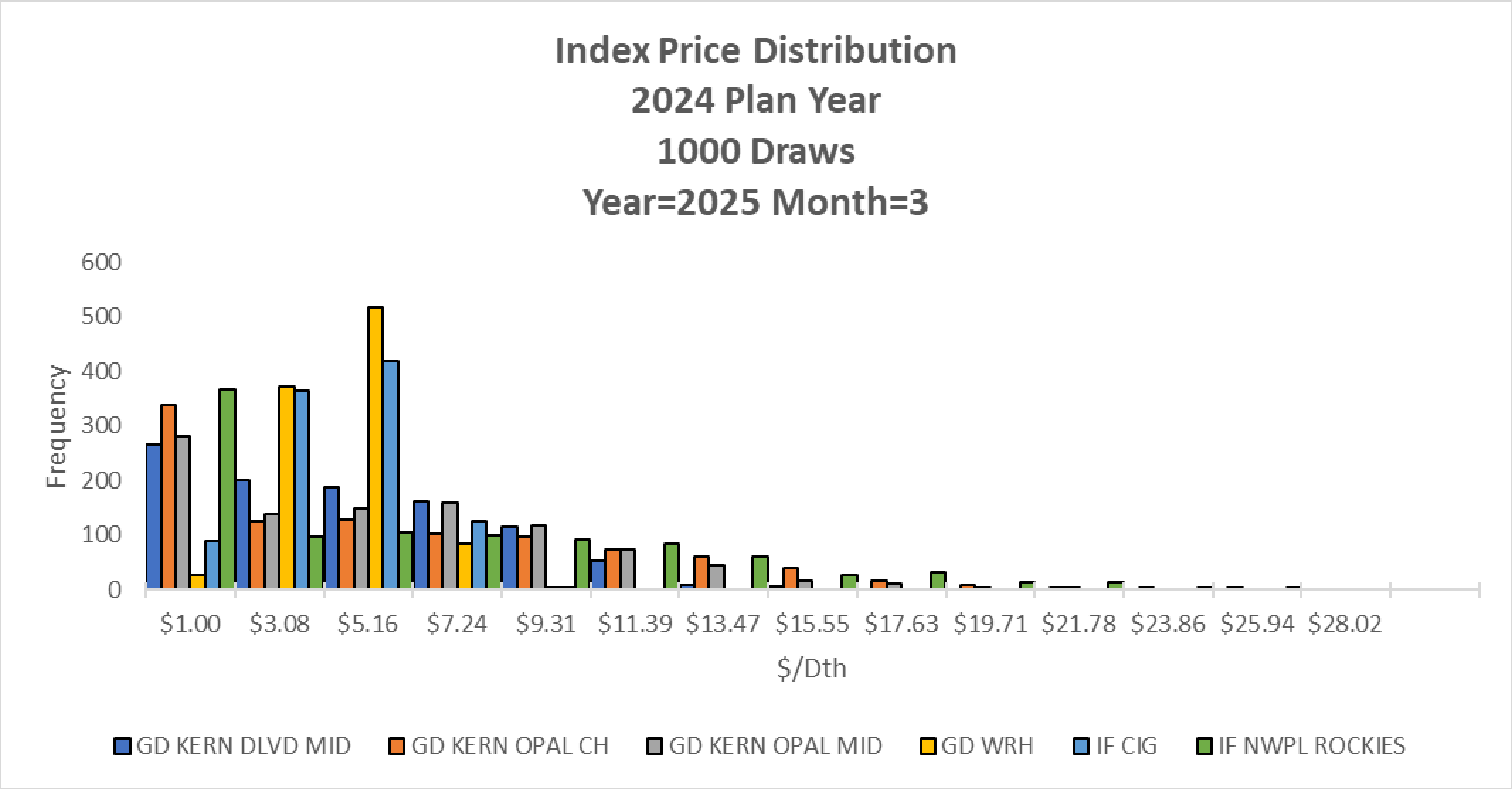

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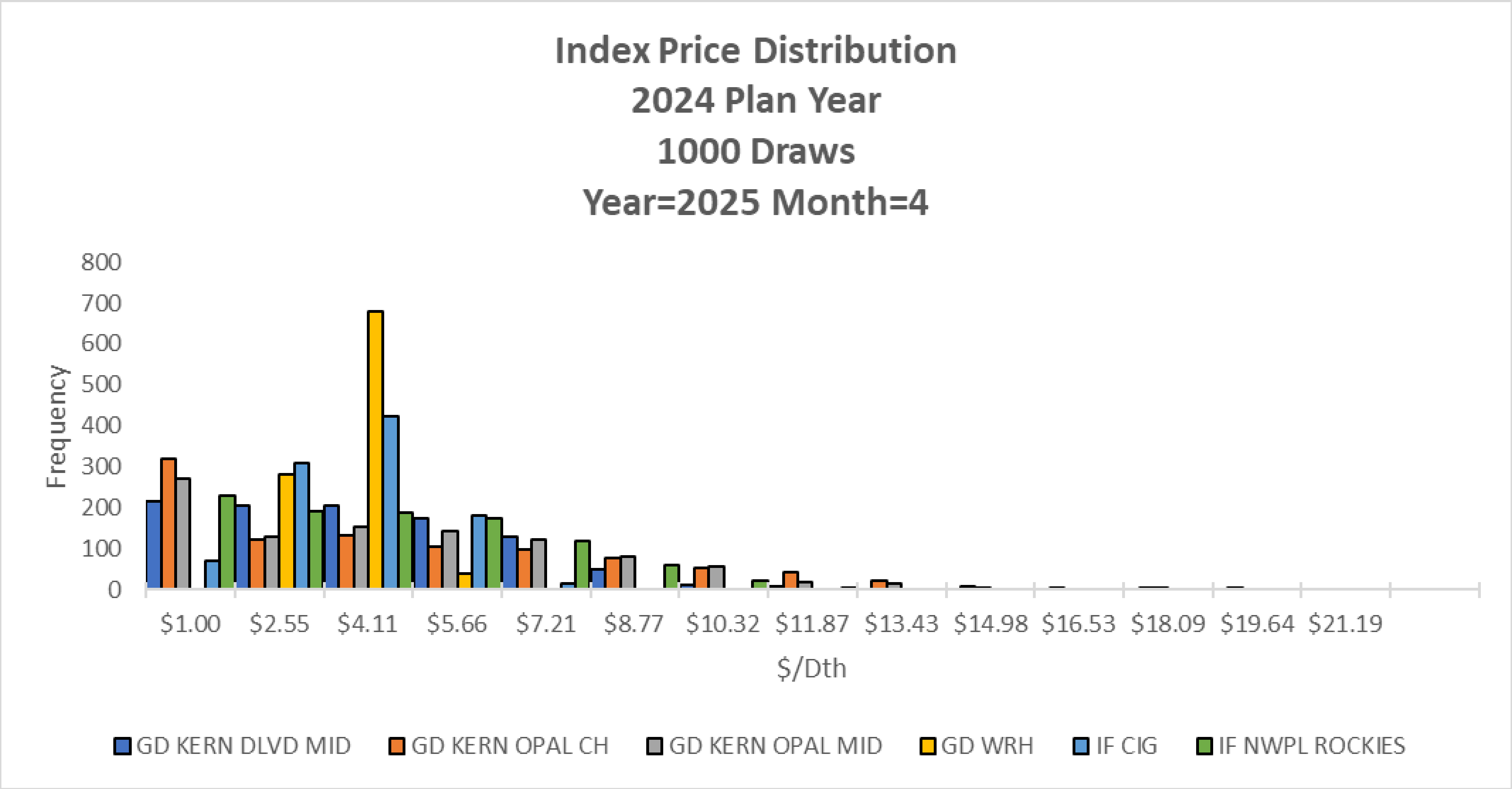

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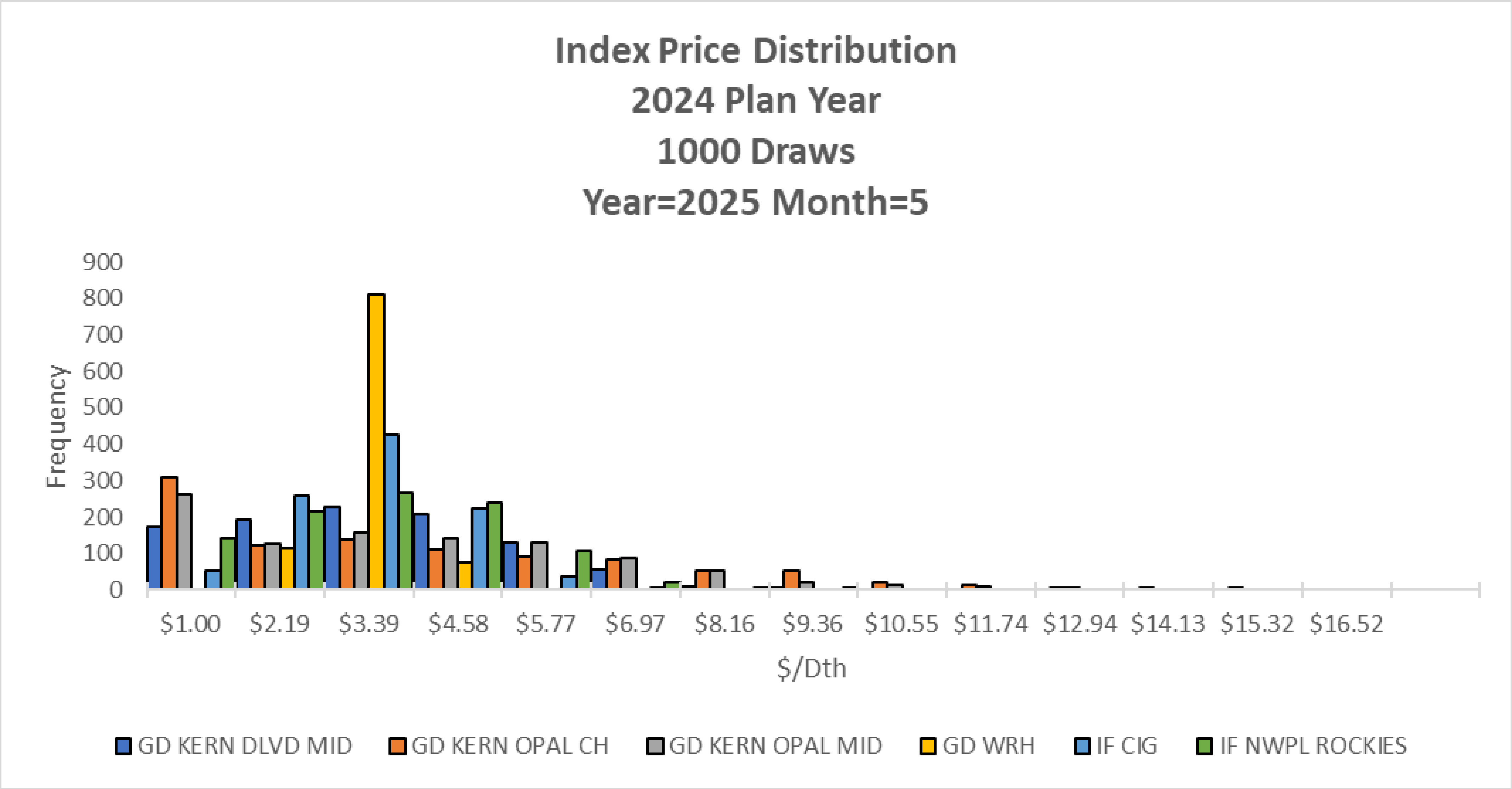

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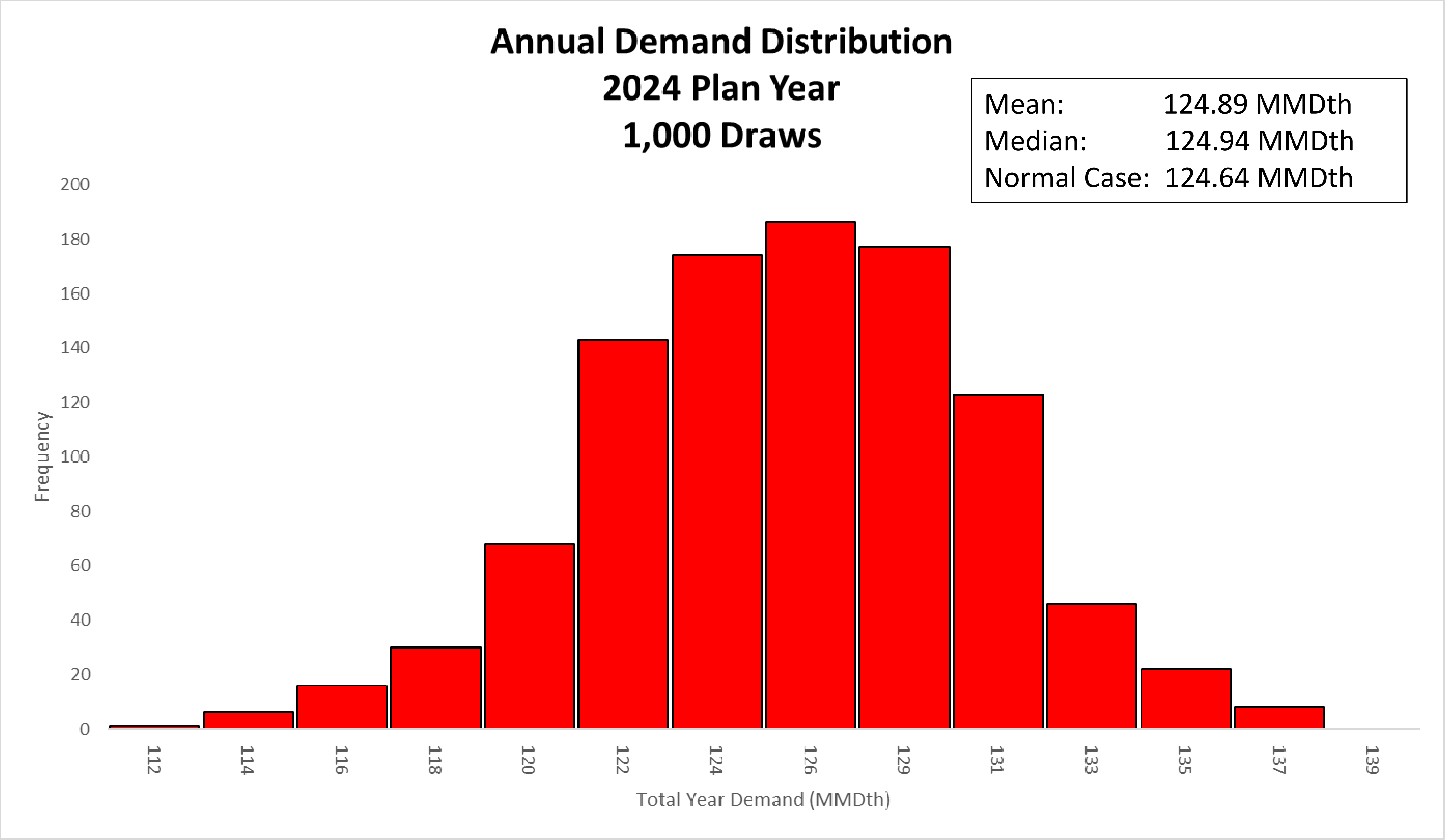
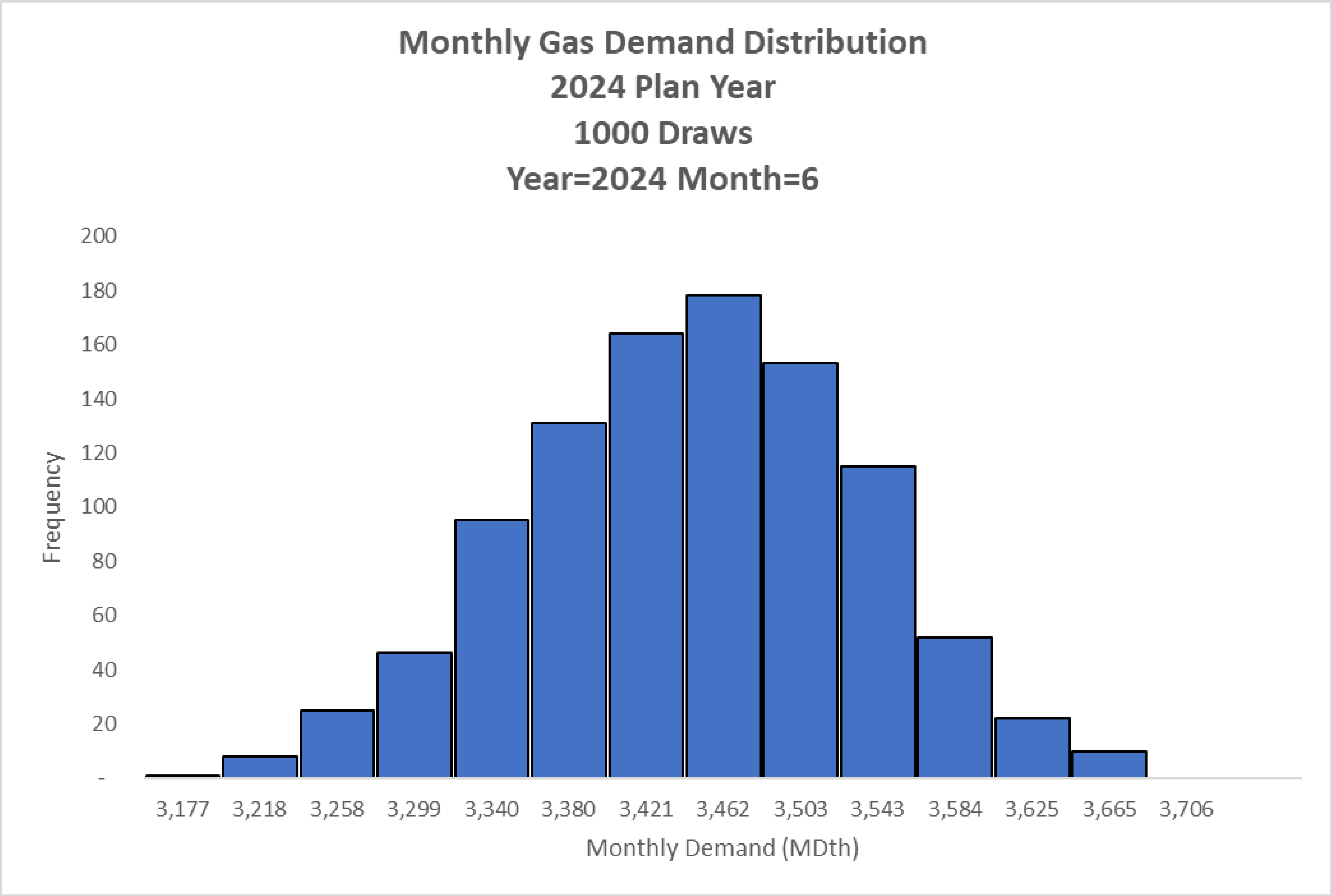


Exhibit 14.13



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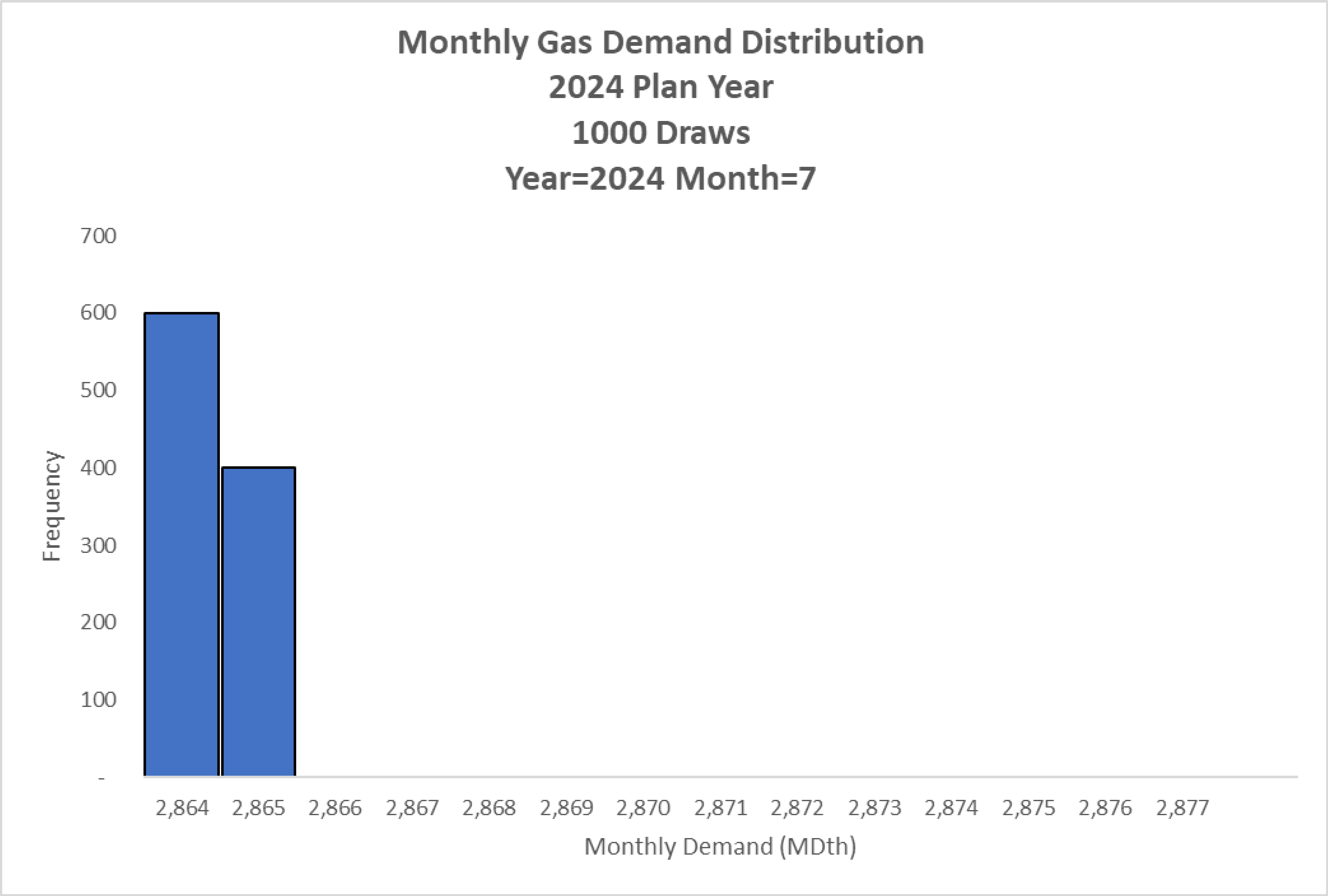

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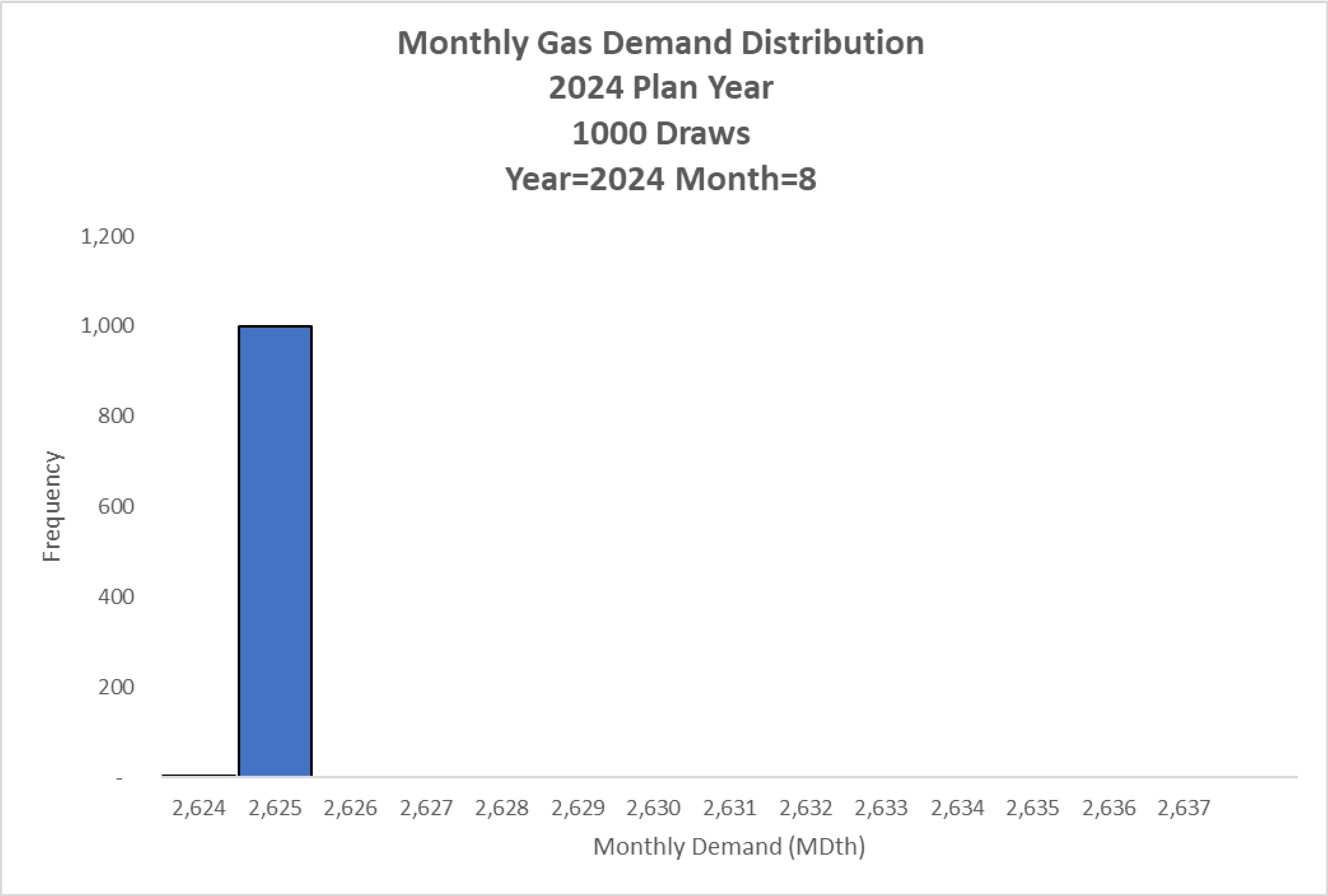

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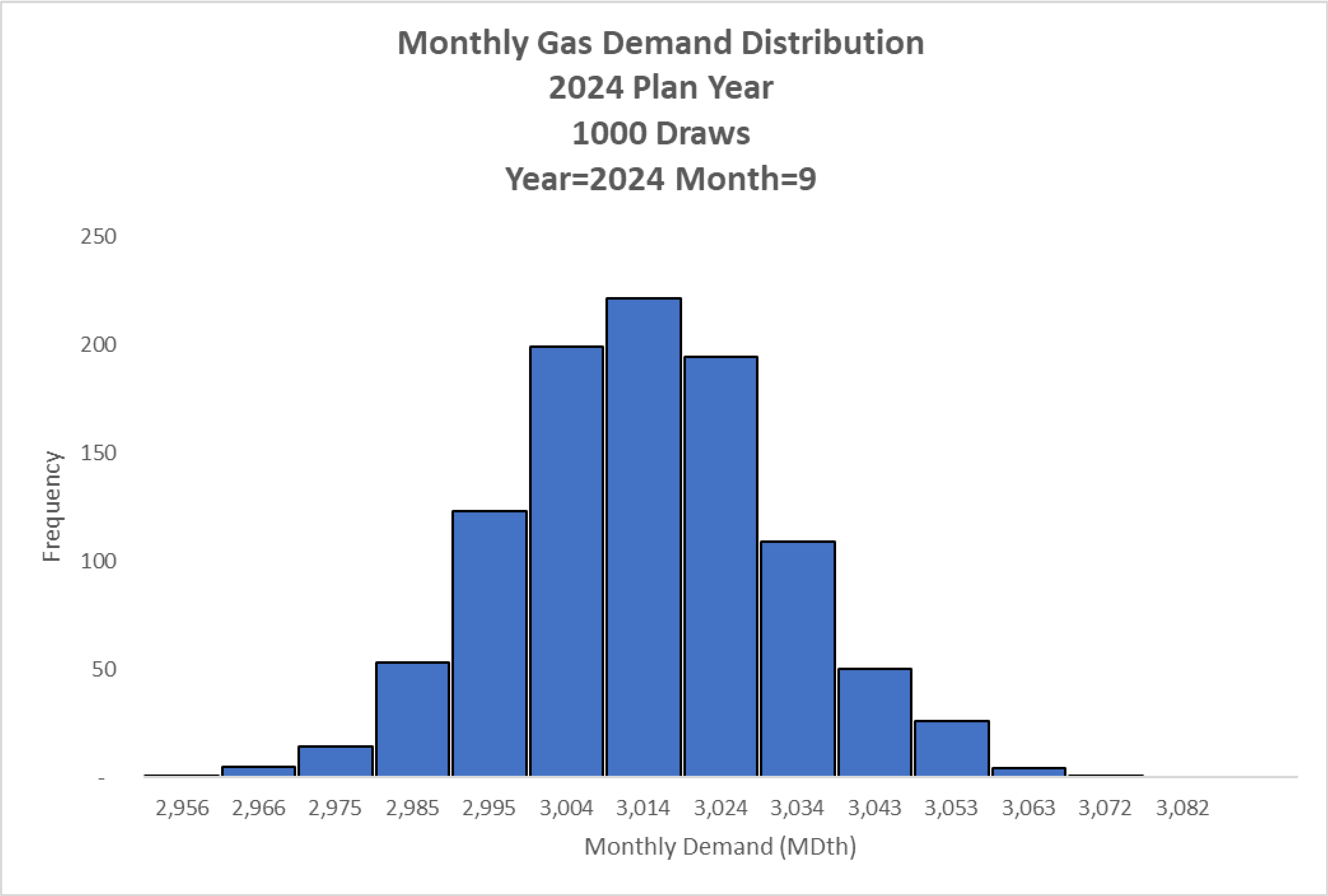

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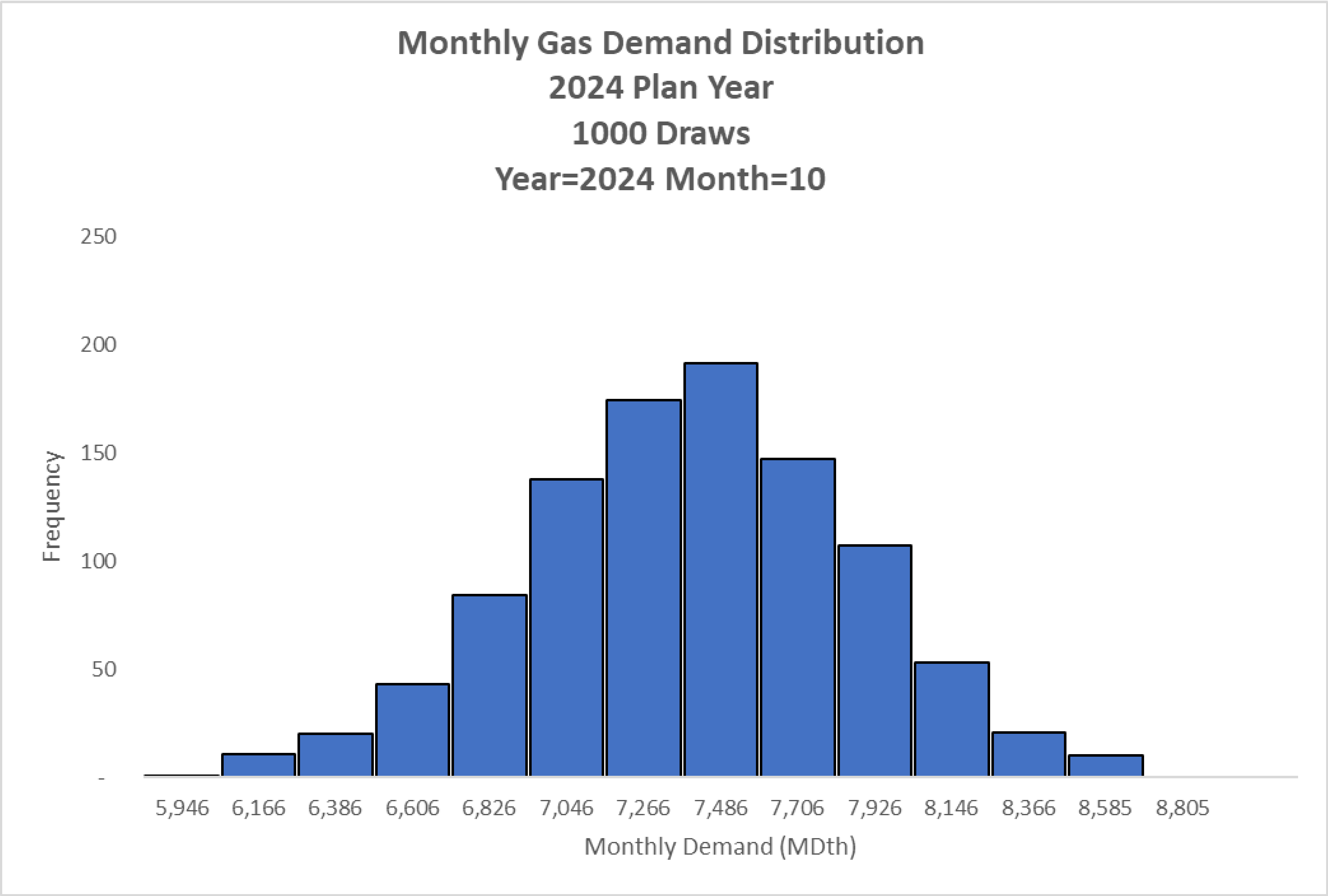

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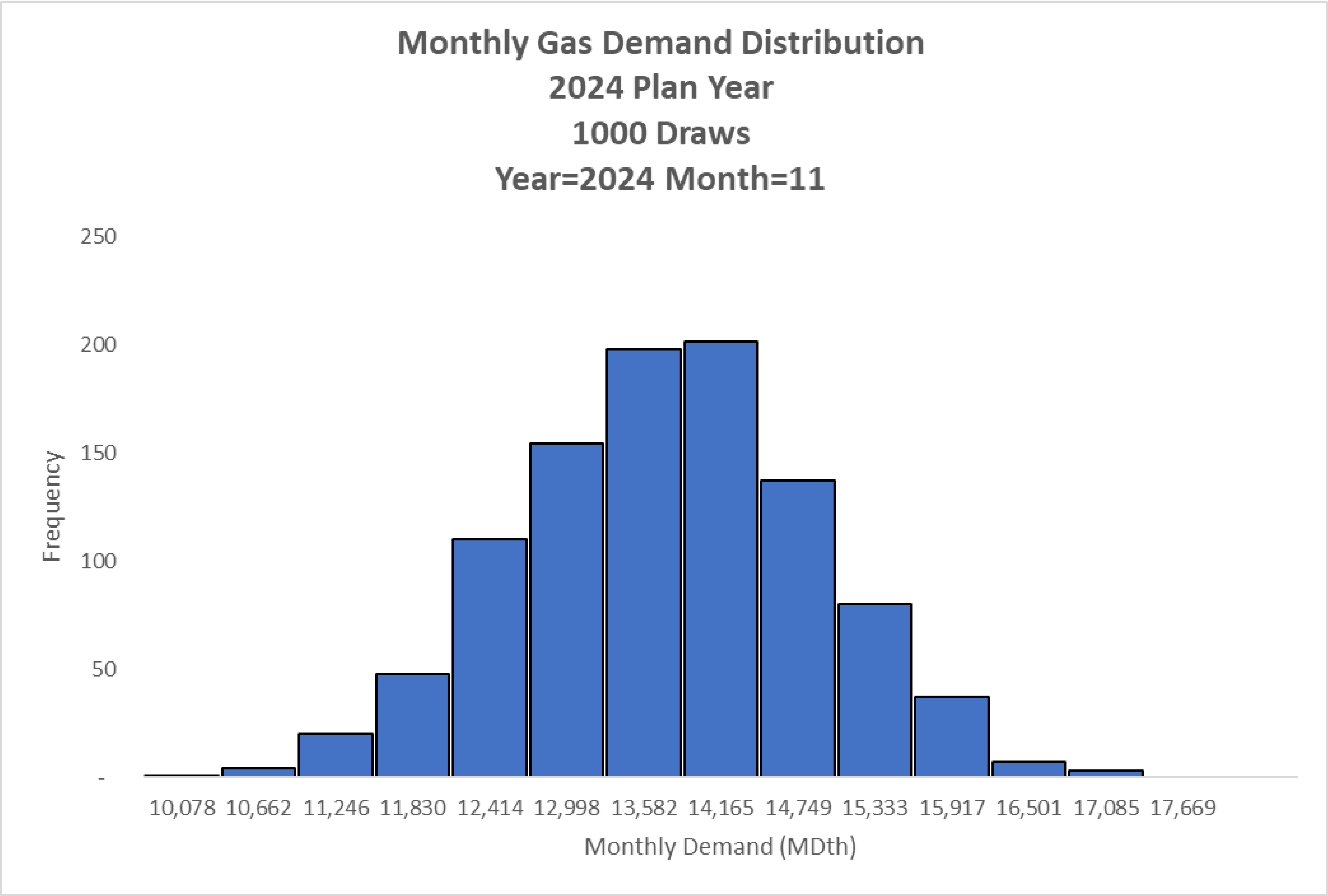

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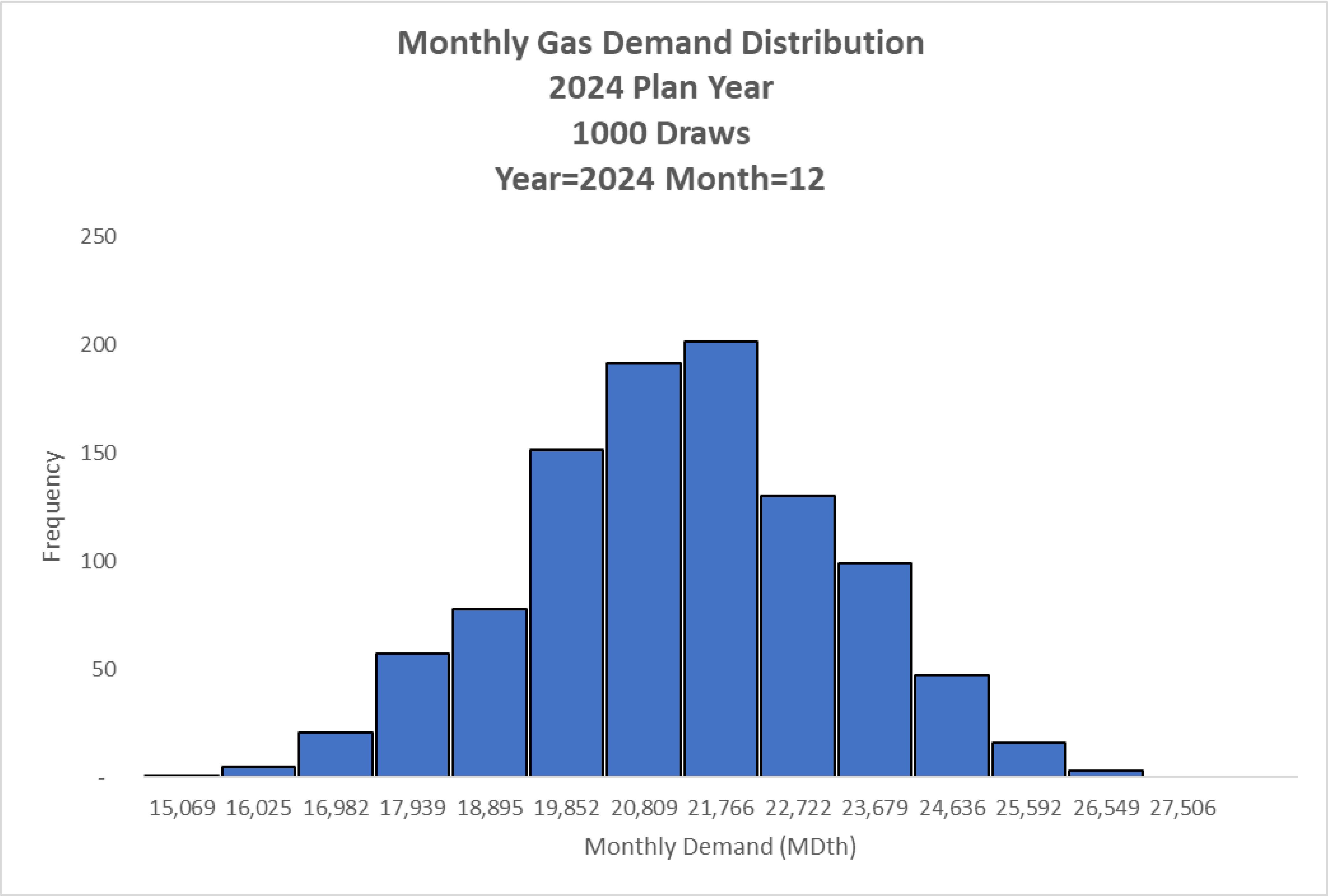

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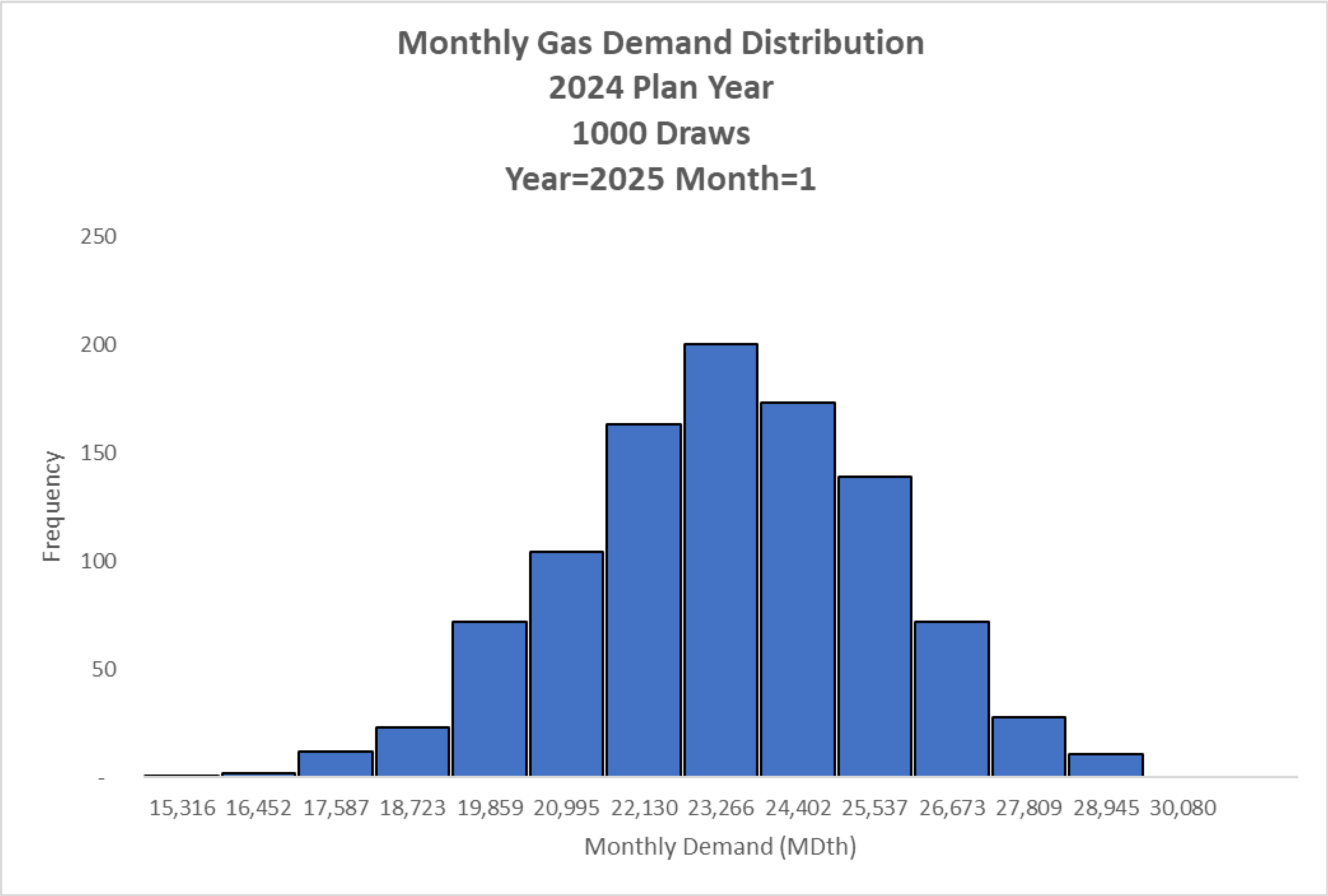

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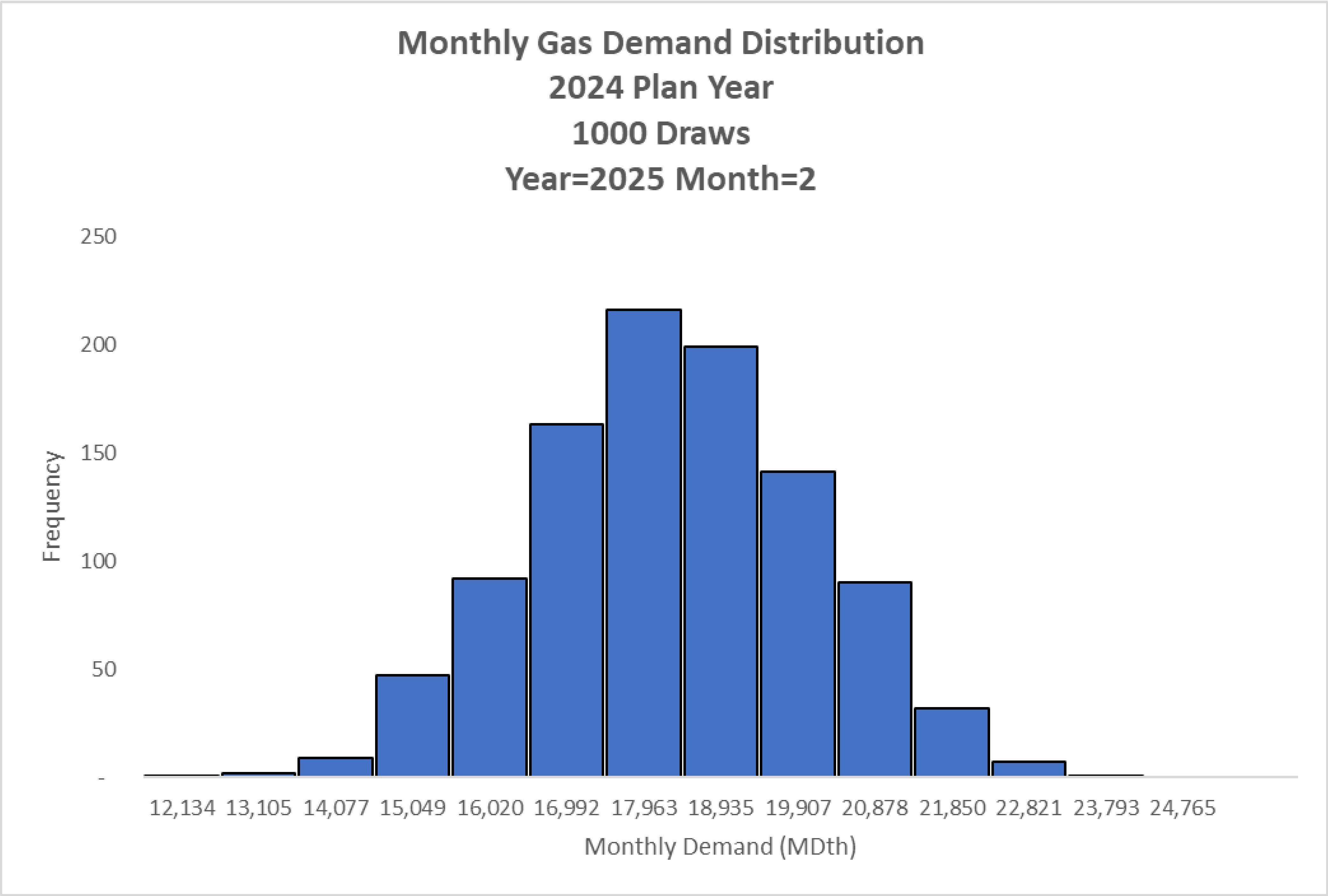


Exhibit 14.22

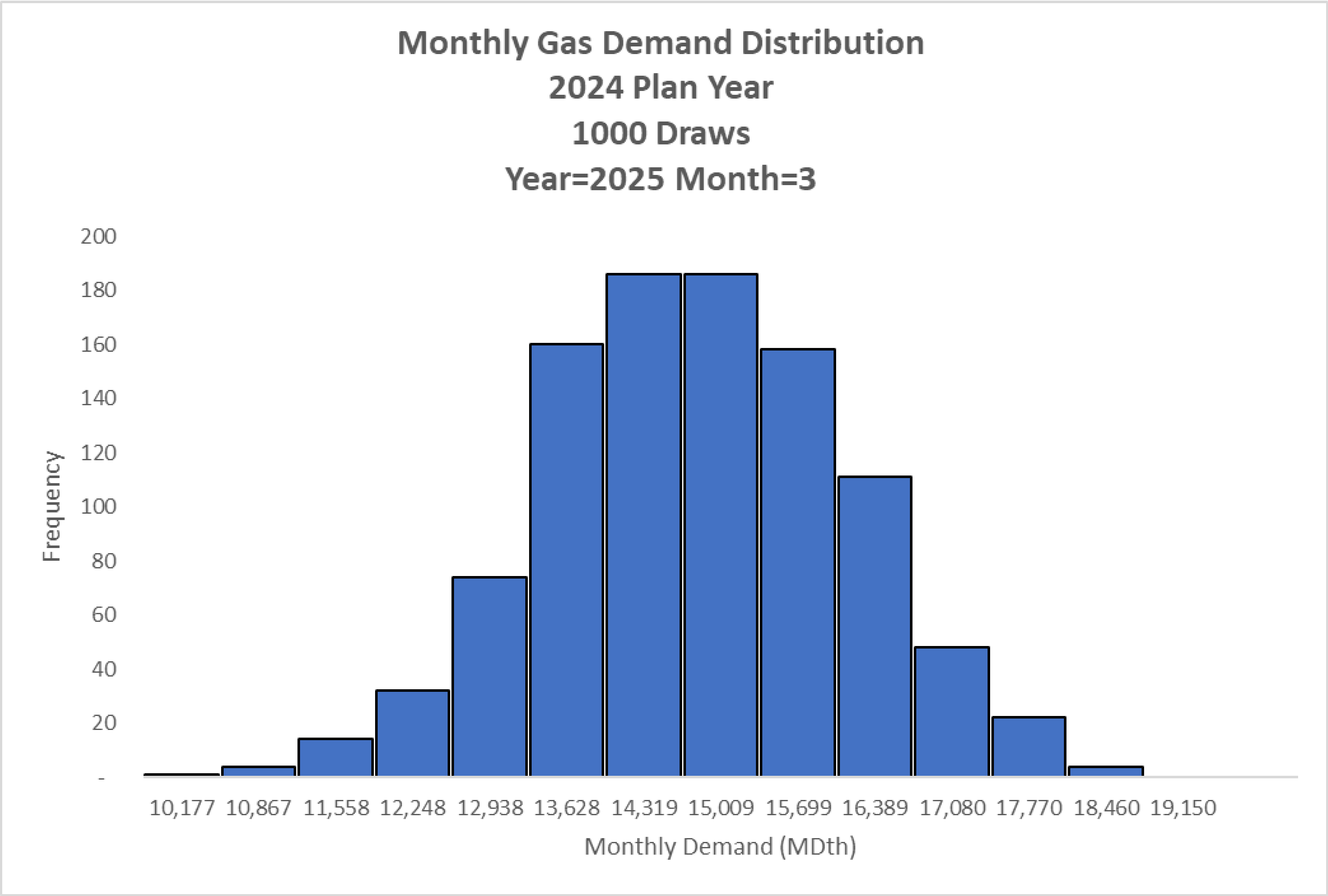
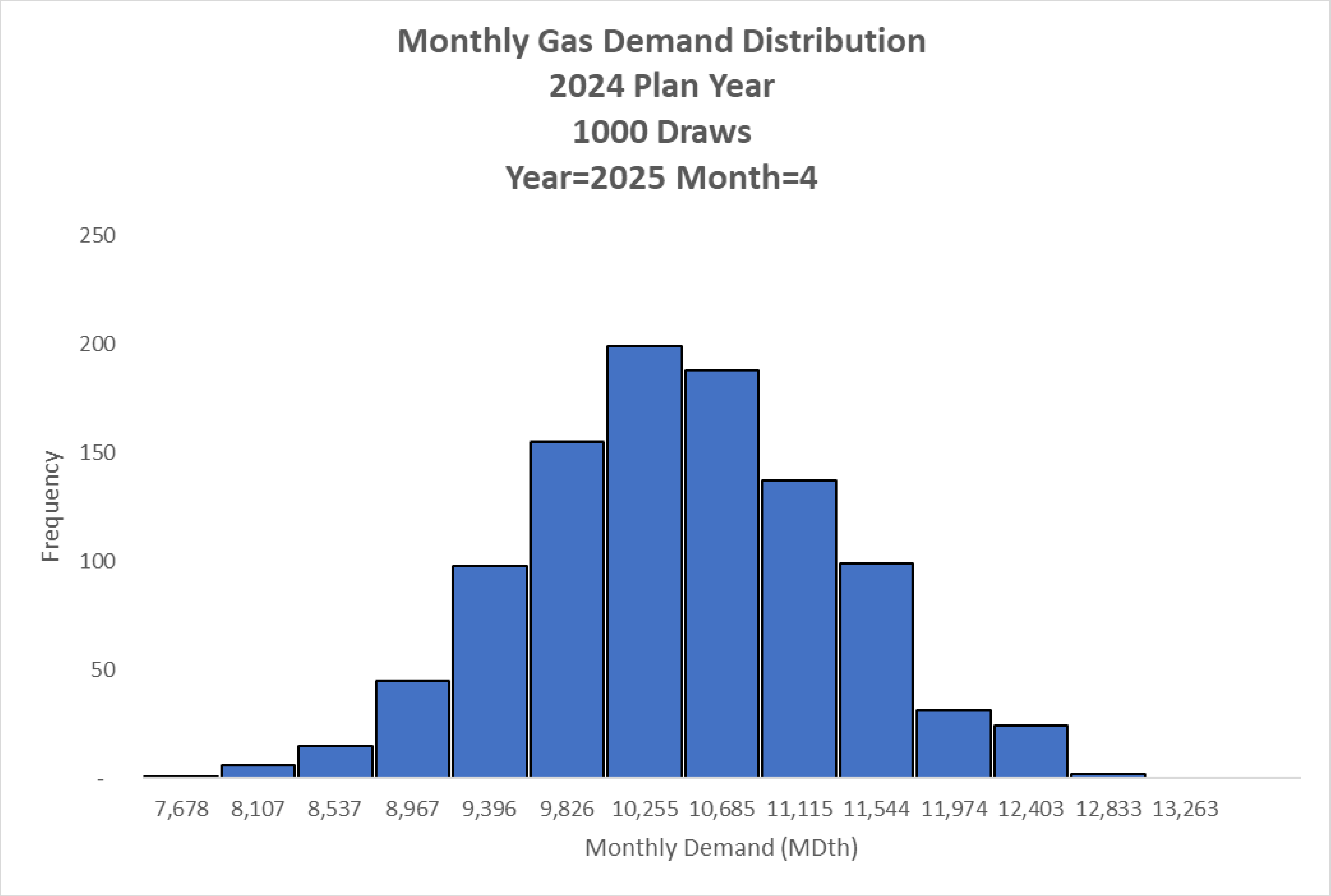


Exhibit 14.23



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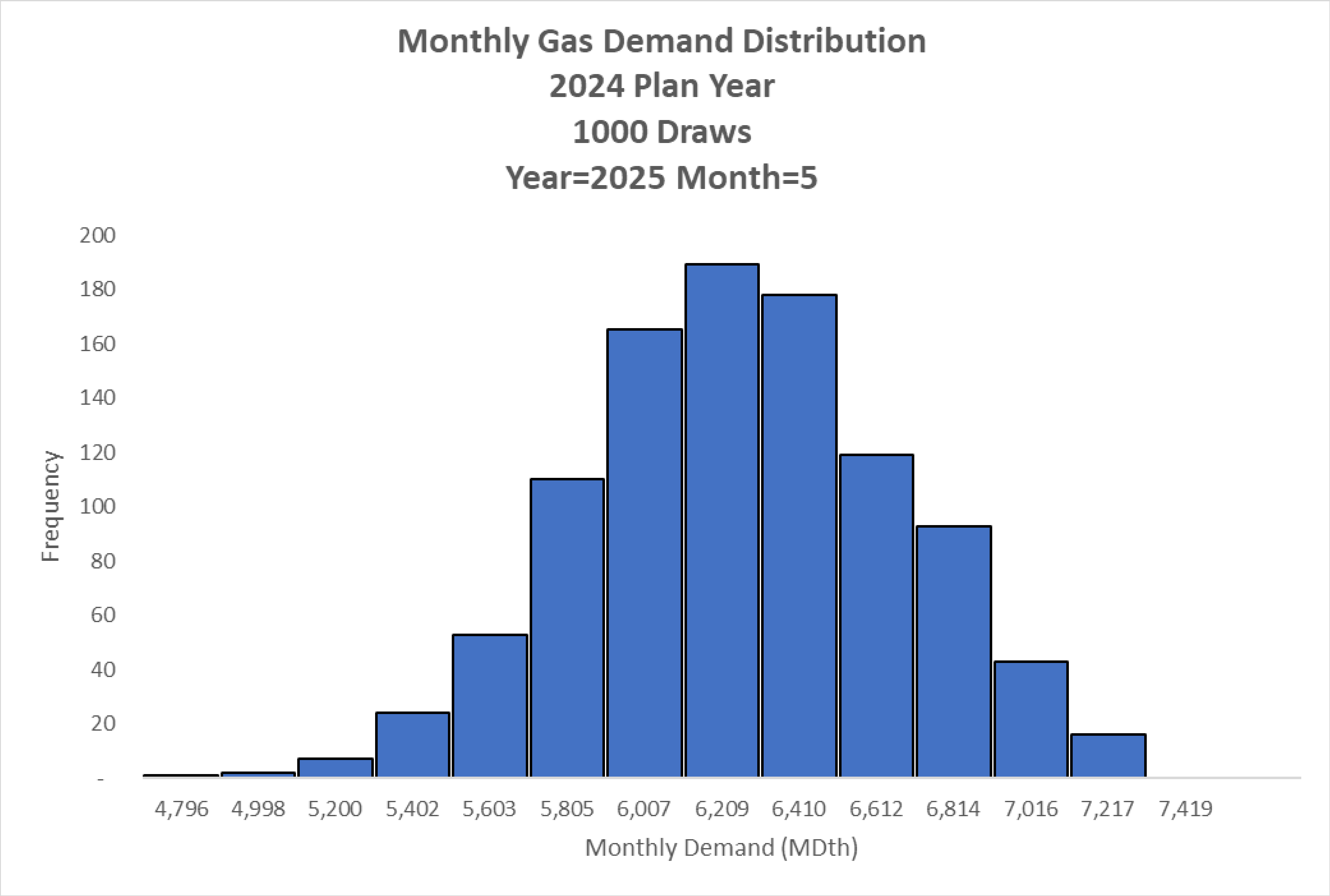

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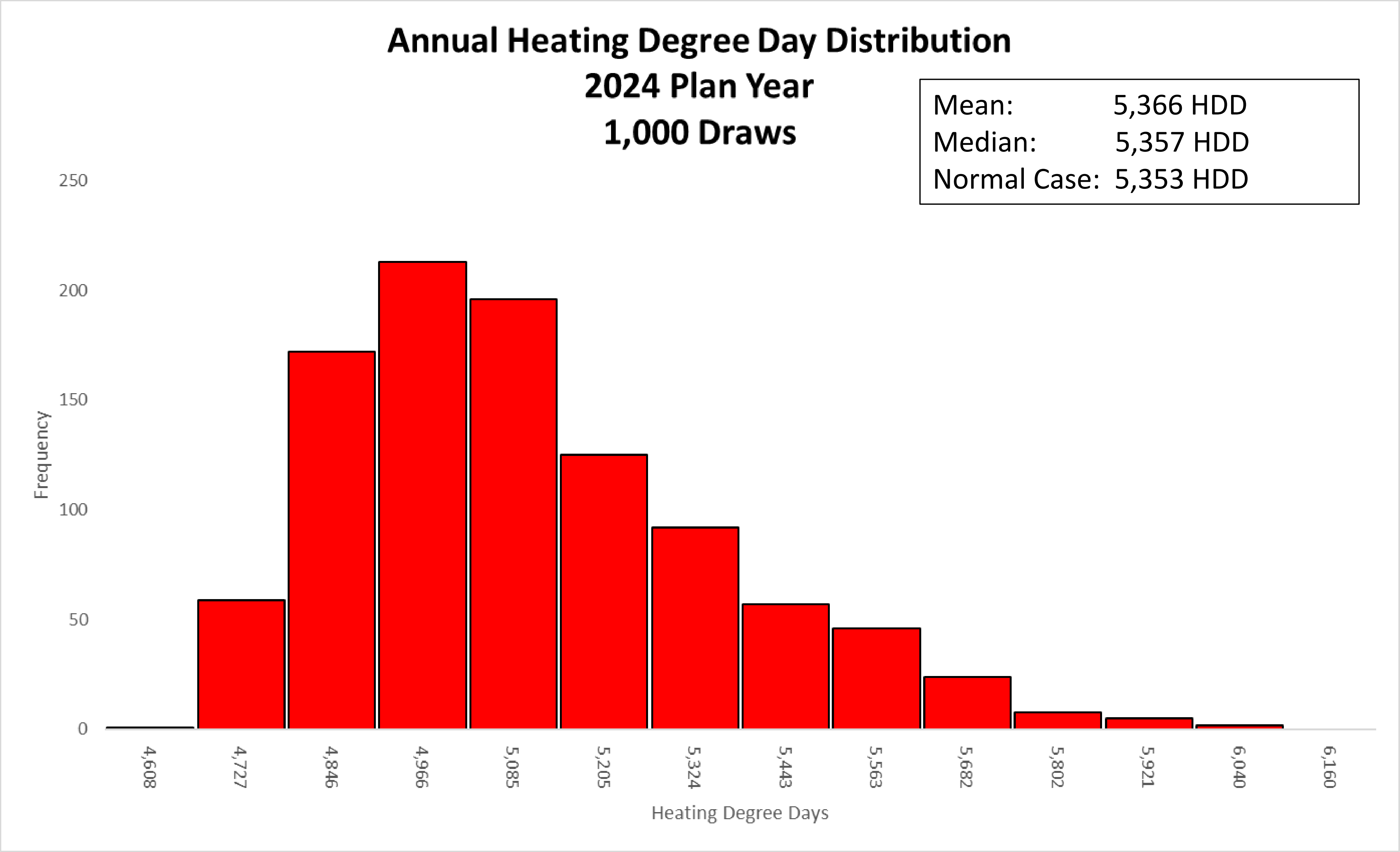

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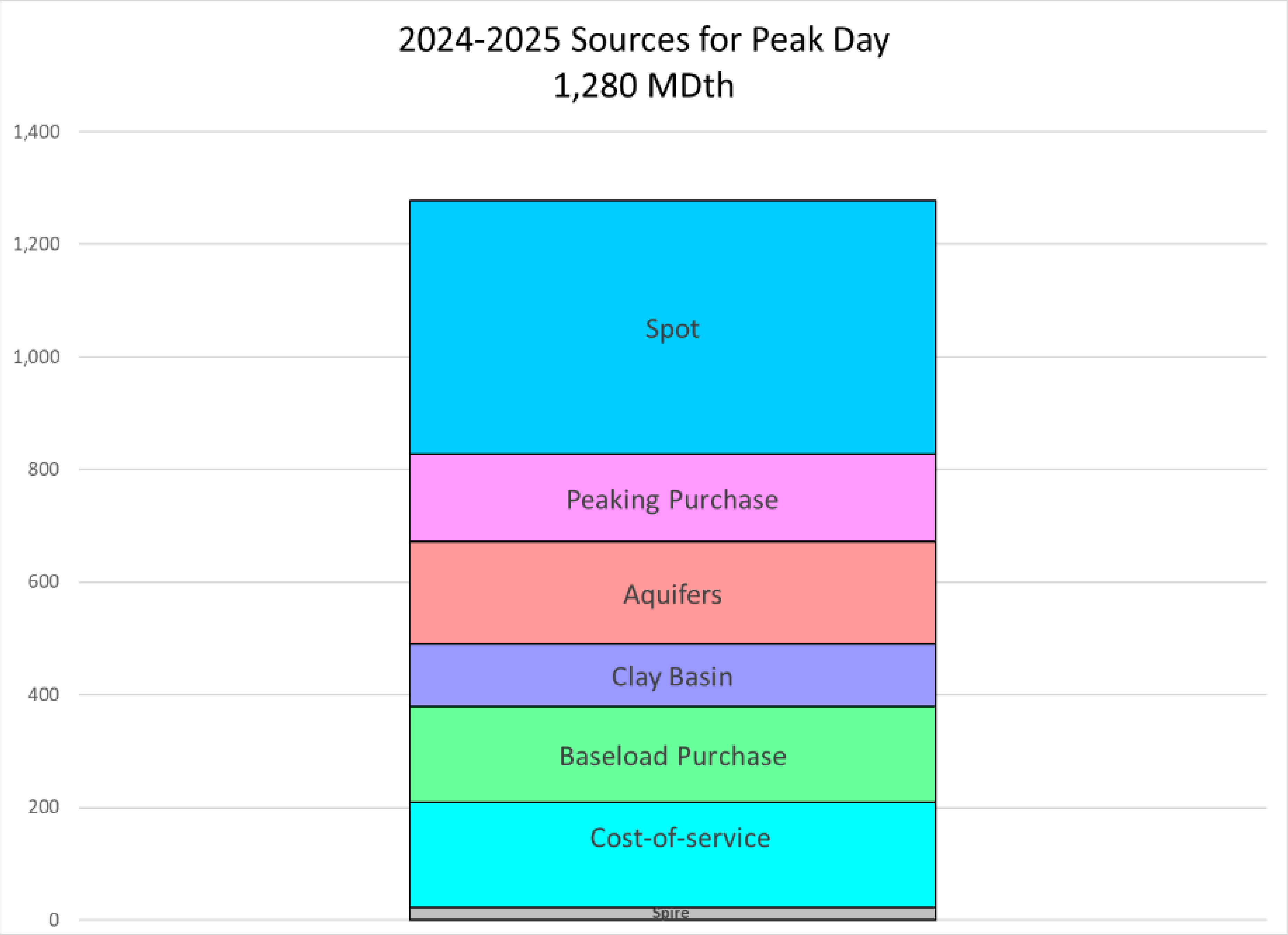

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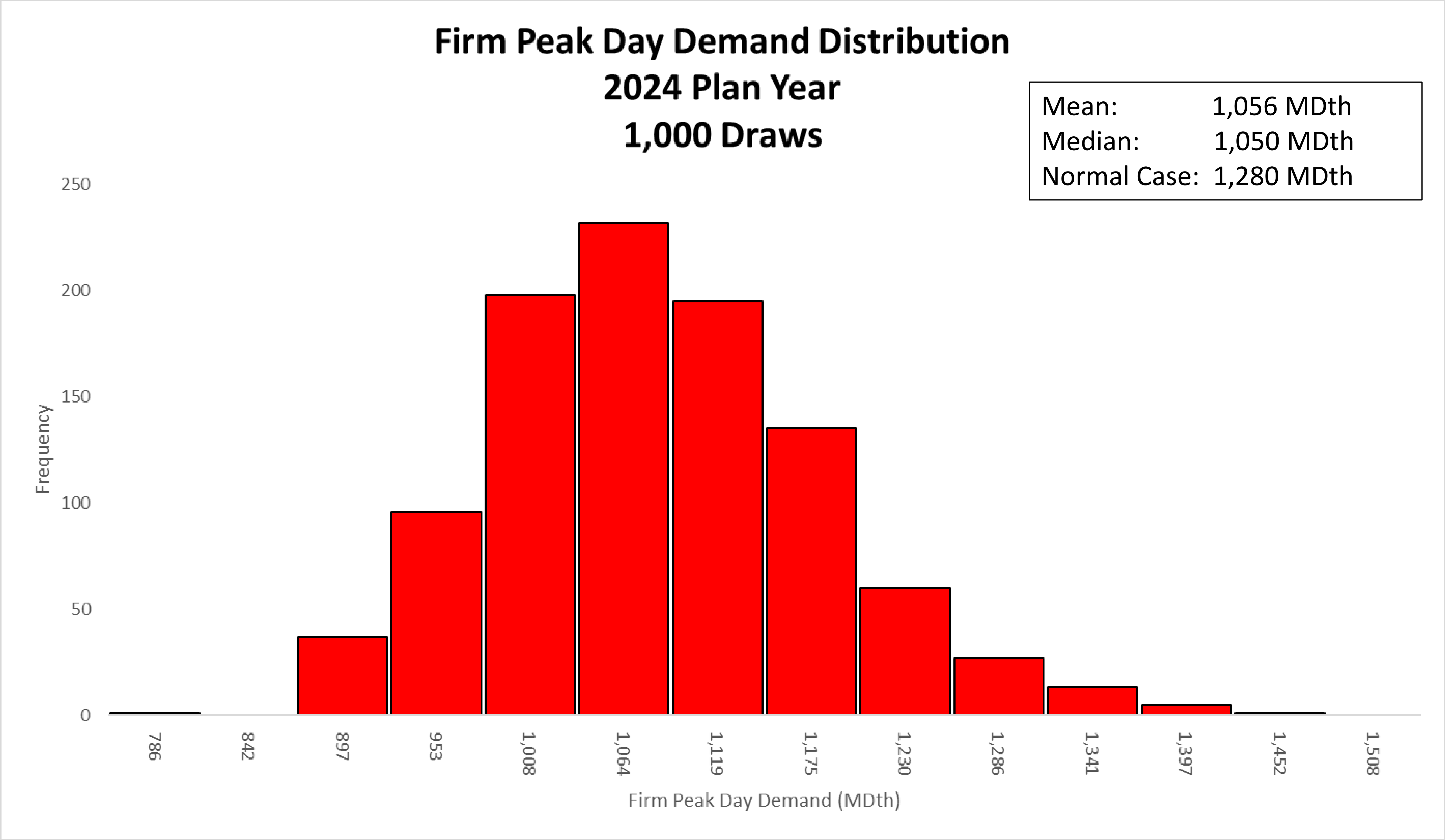

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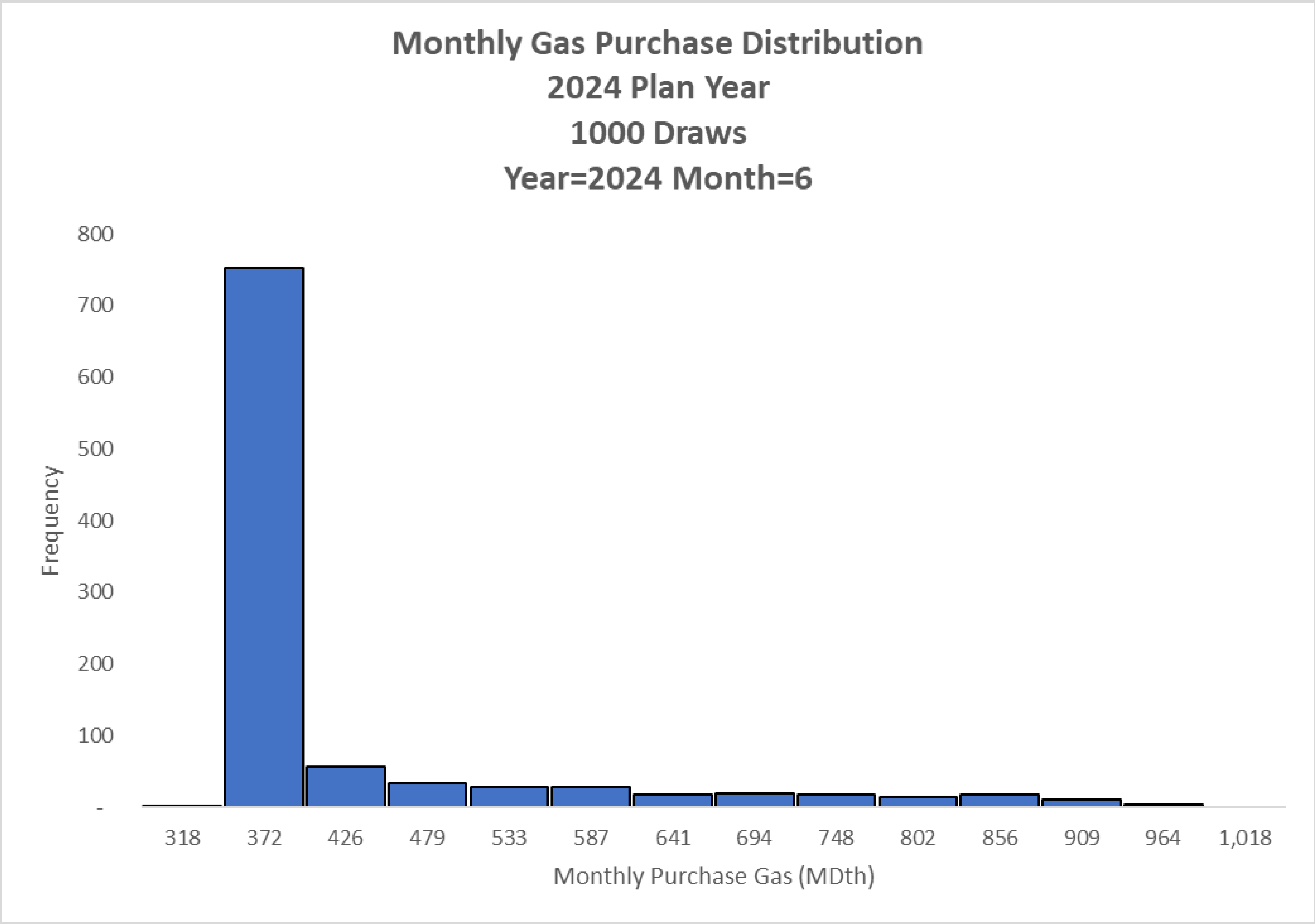

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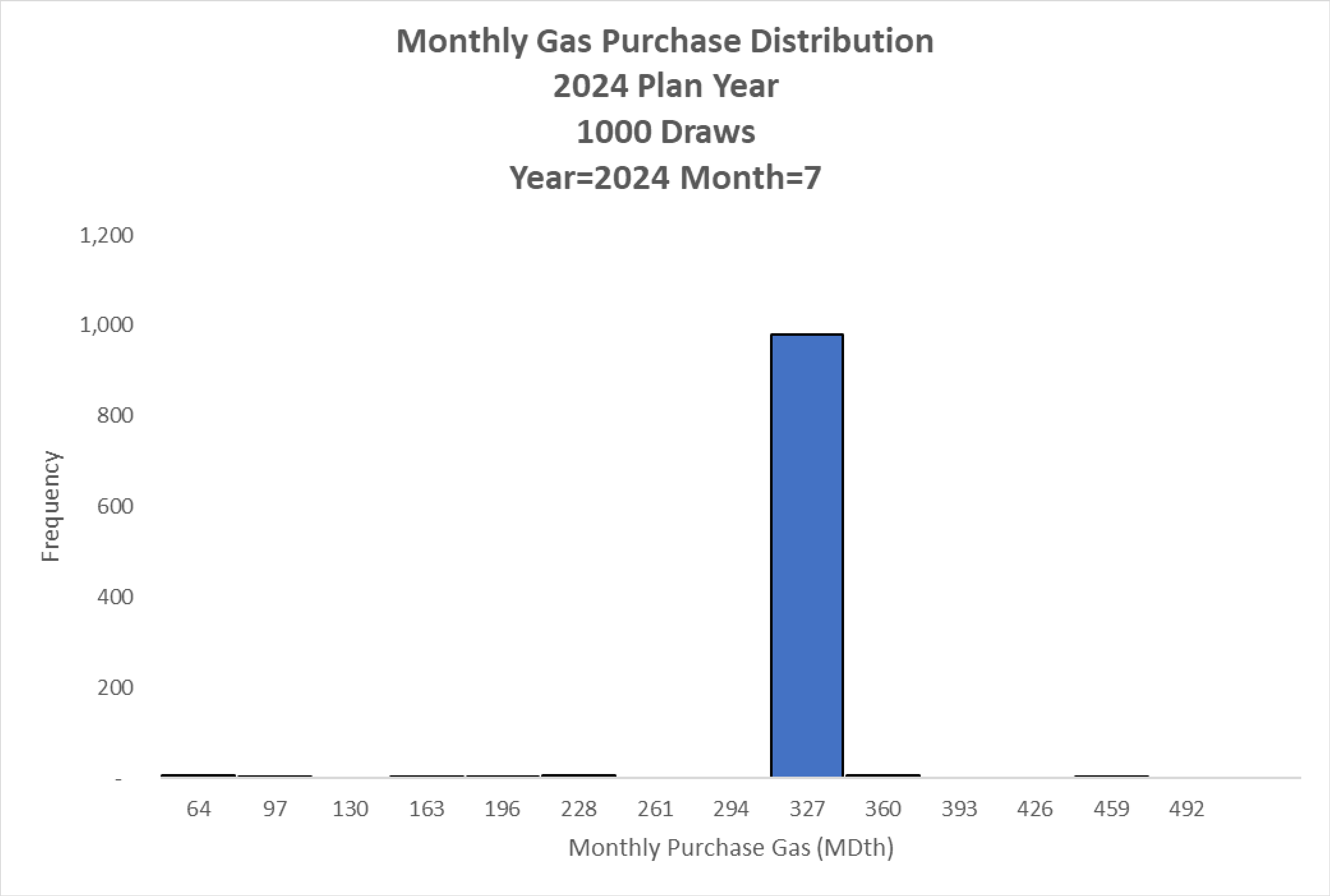


Exhibit 14.30

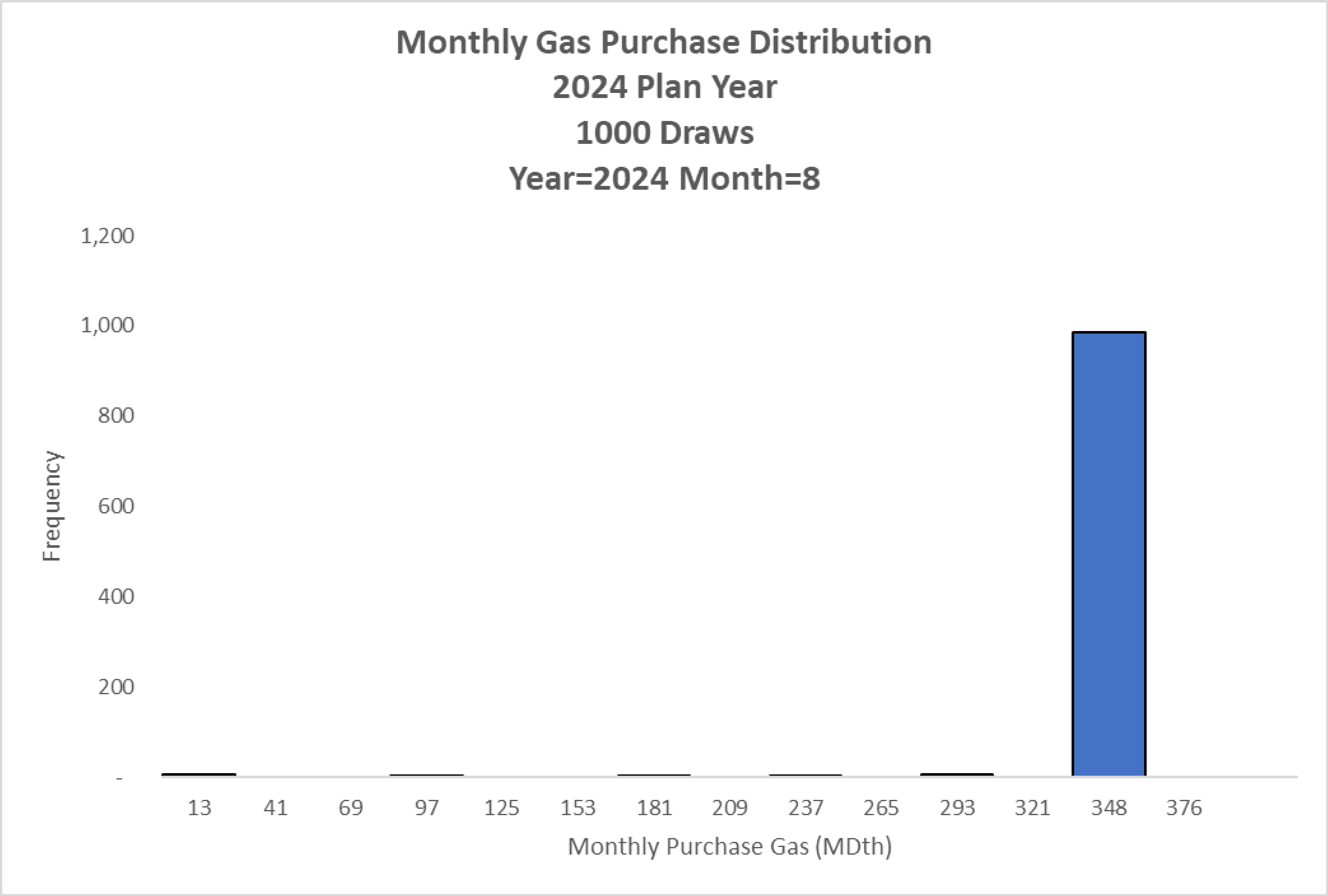
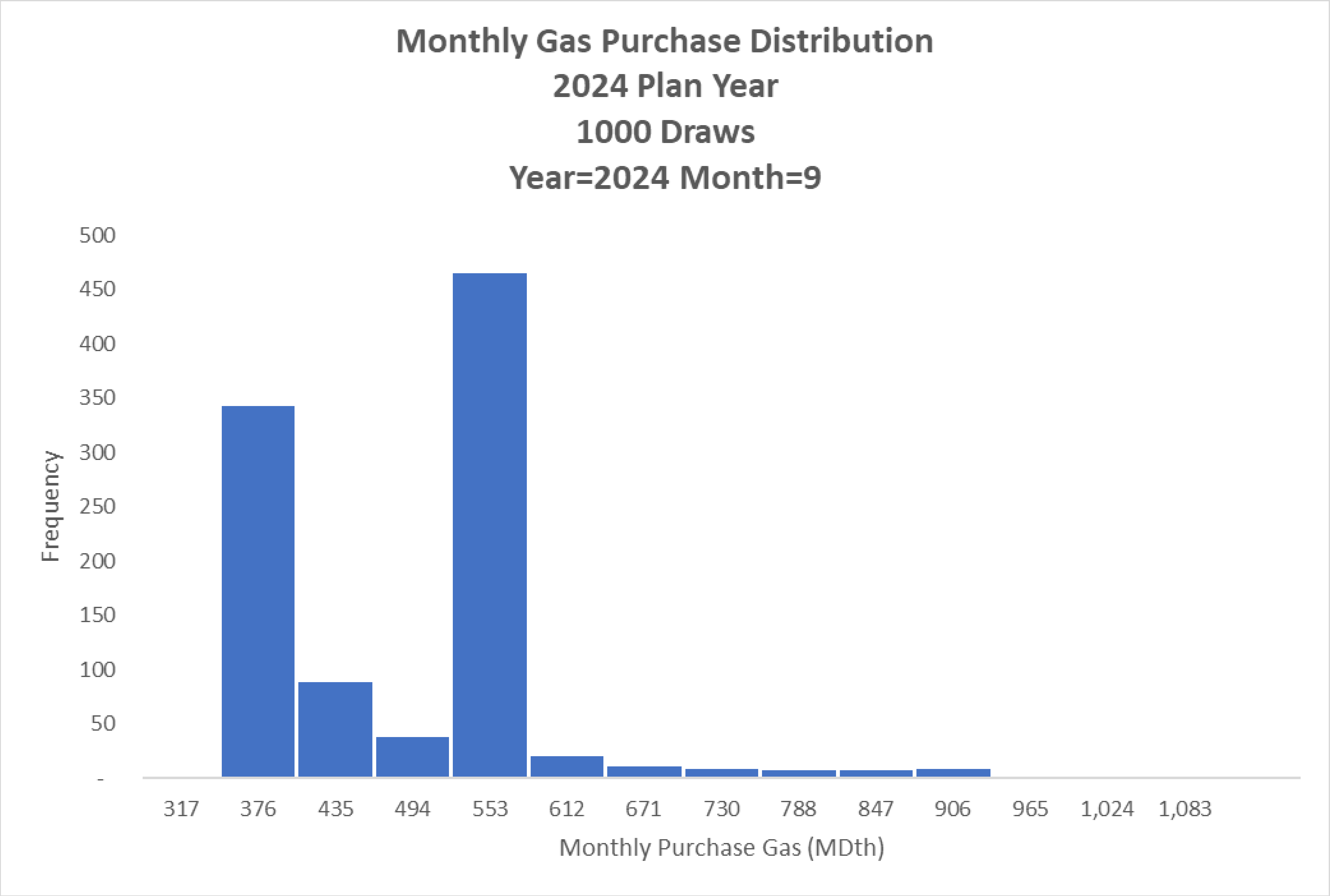


Exhibit 14.31



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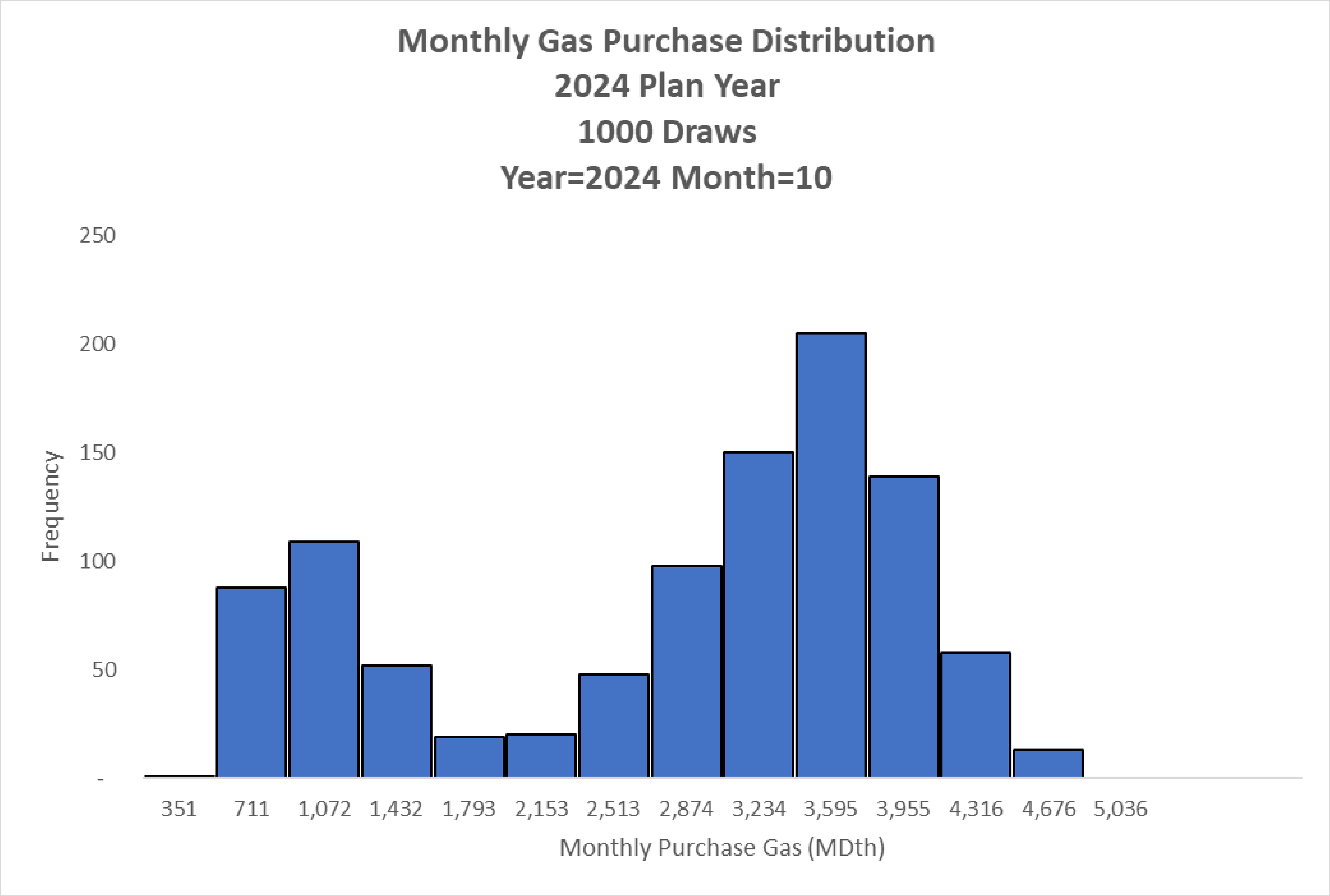

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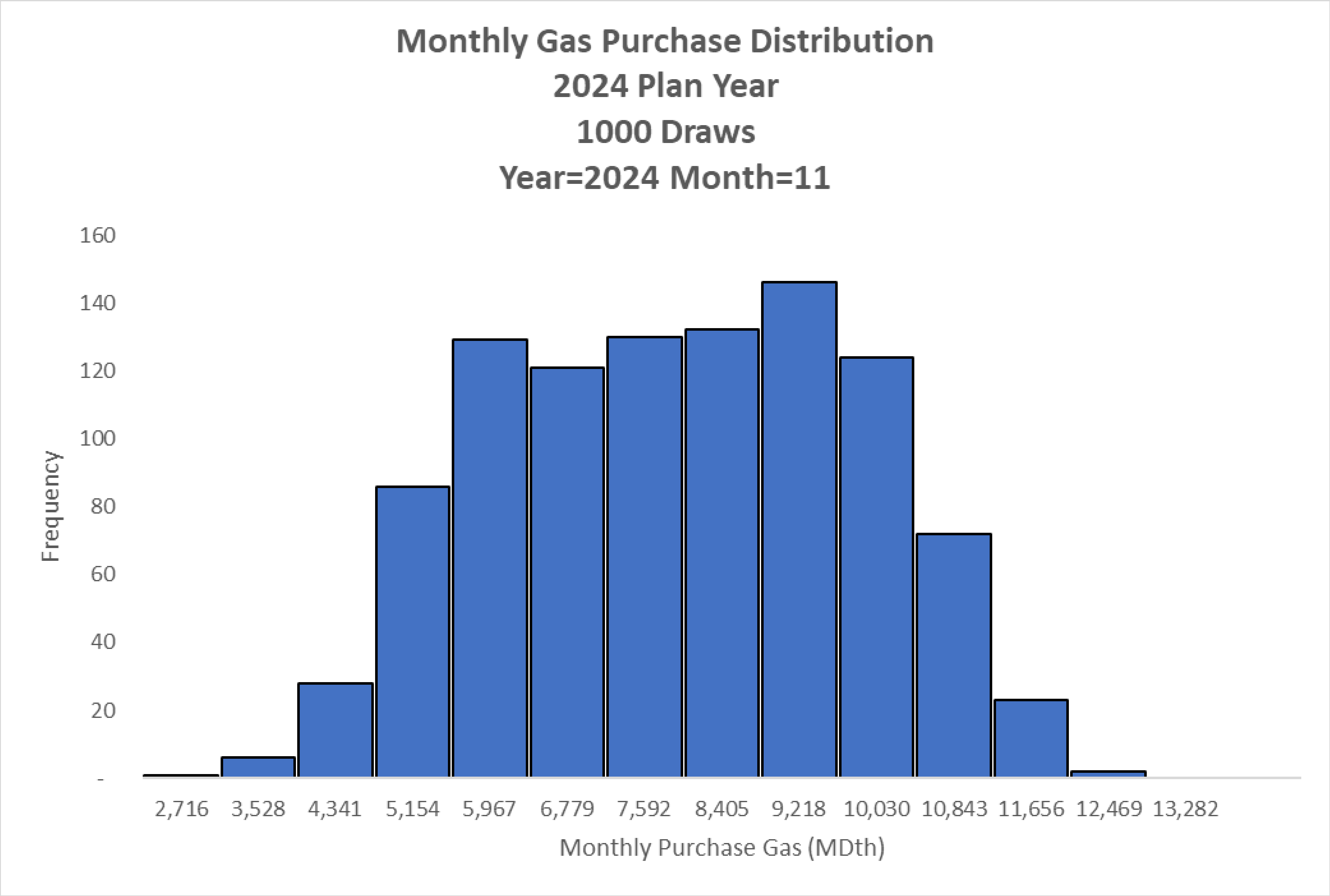
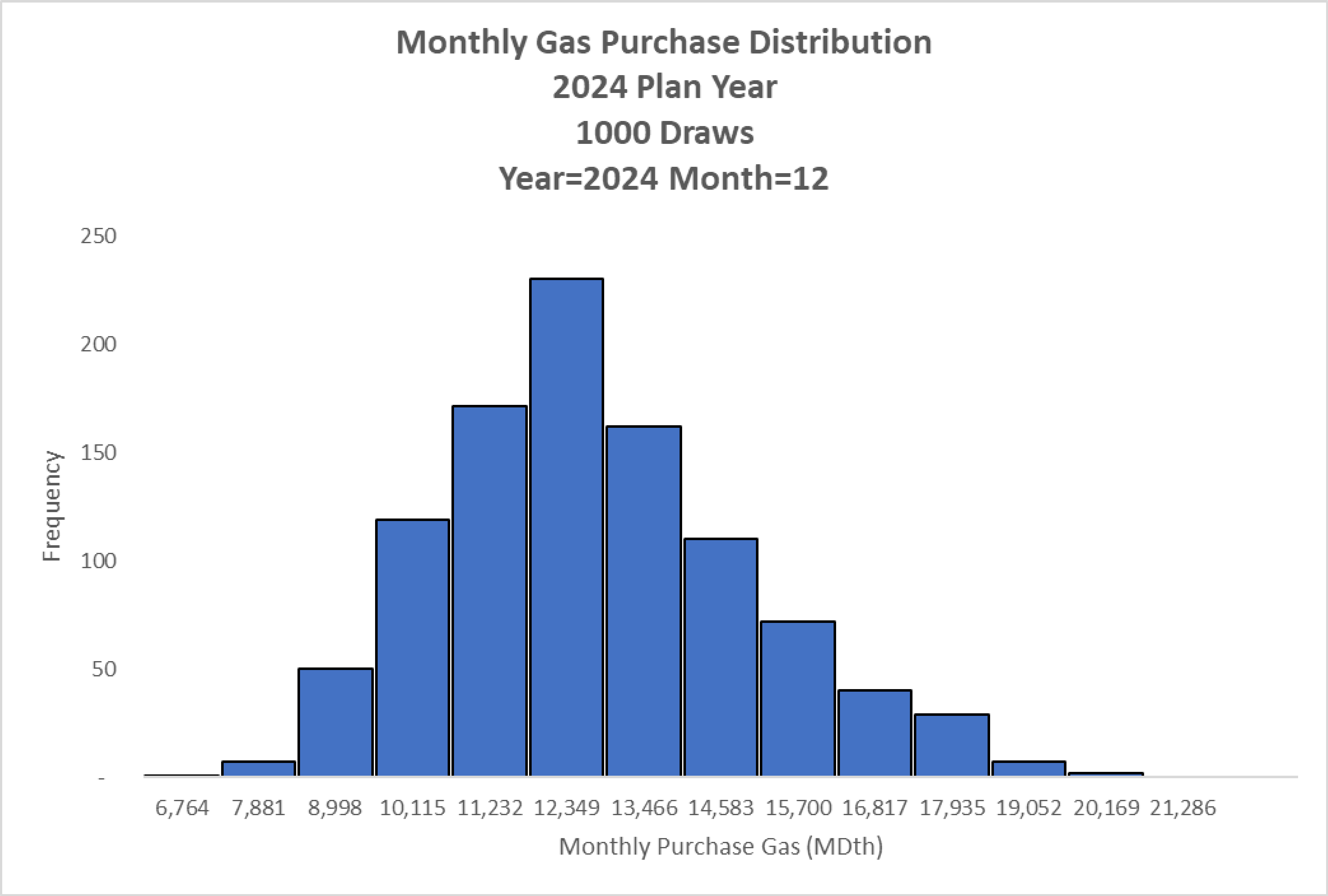


Exhibit 14.34



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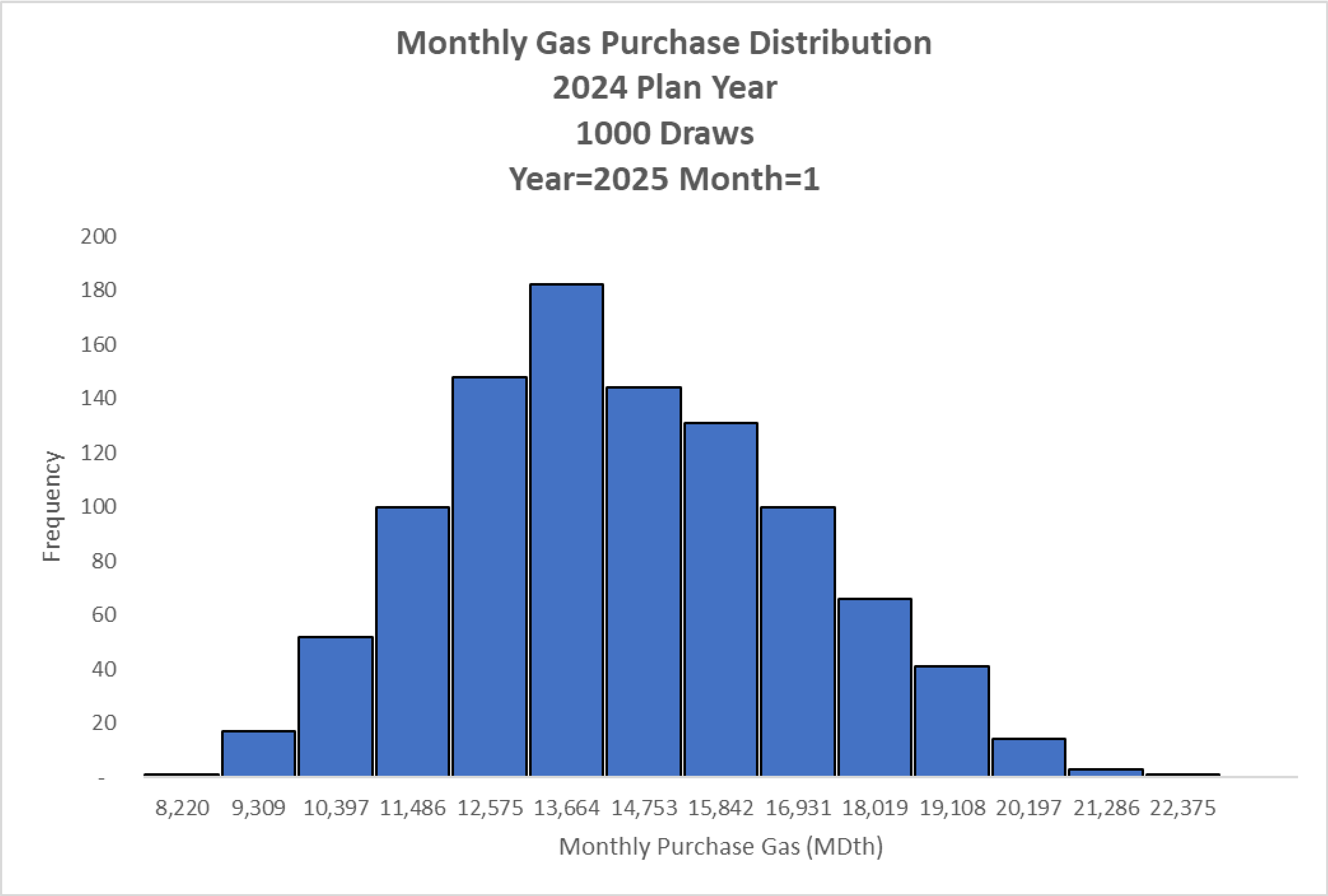

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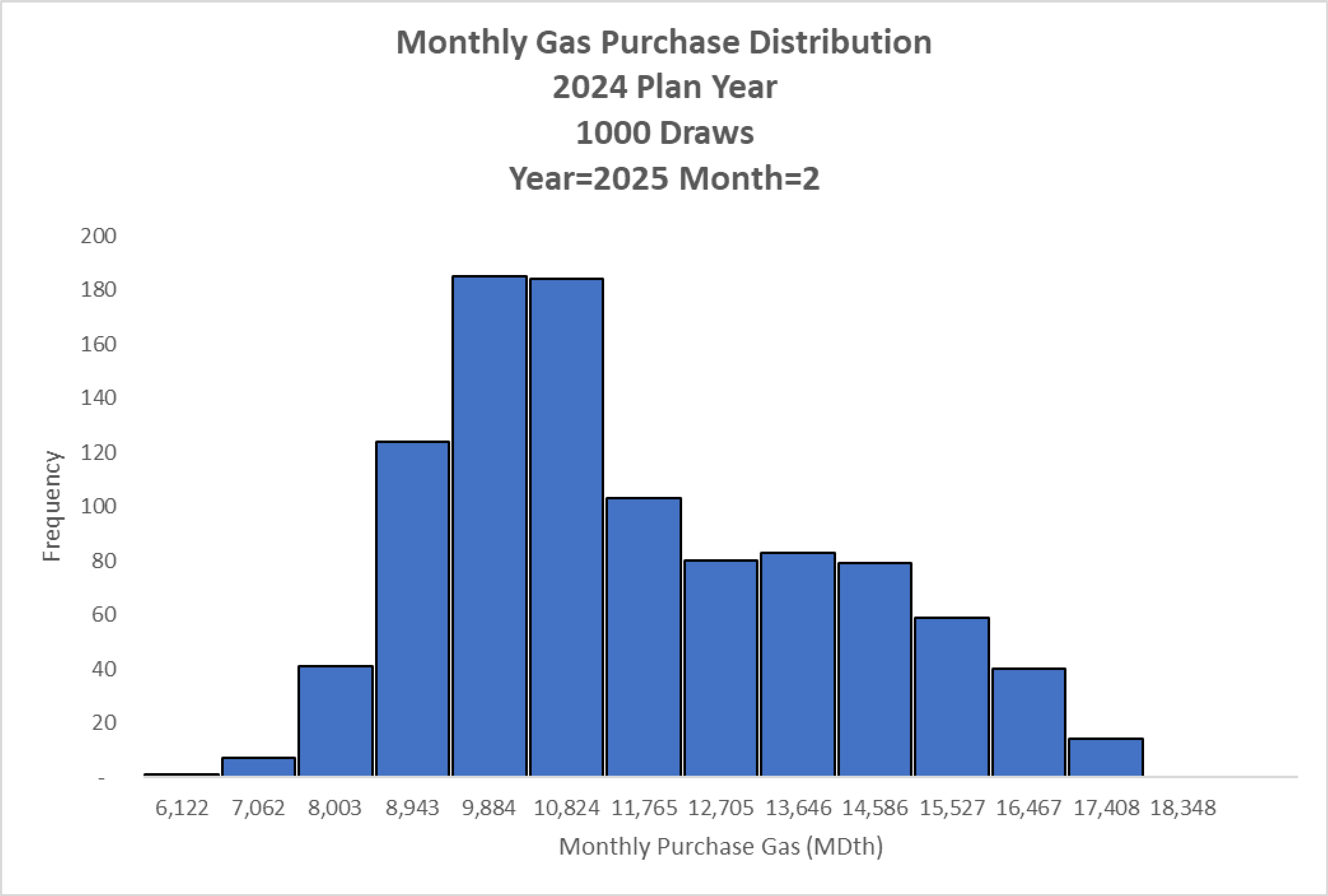

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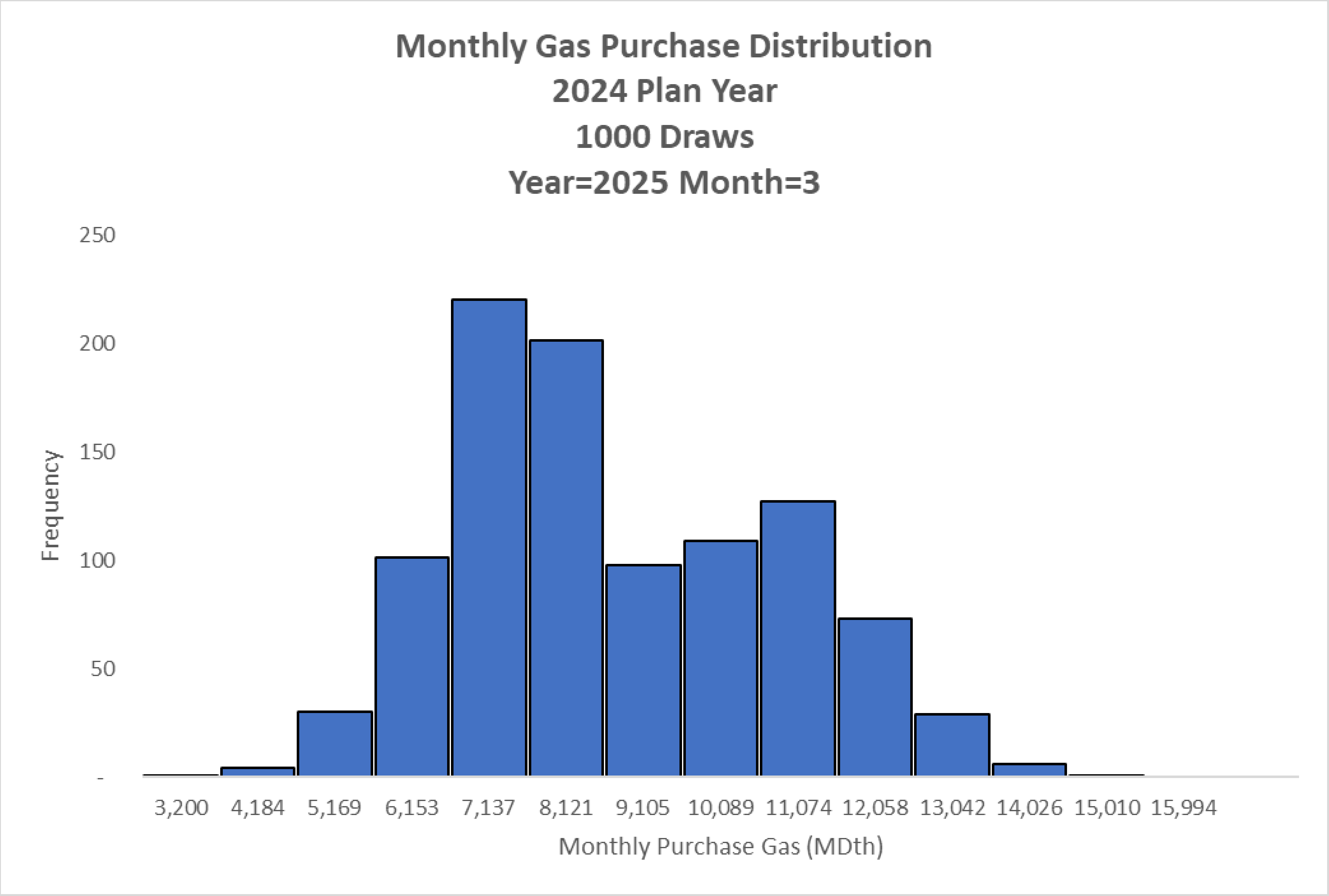
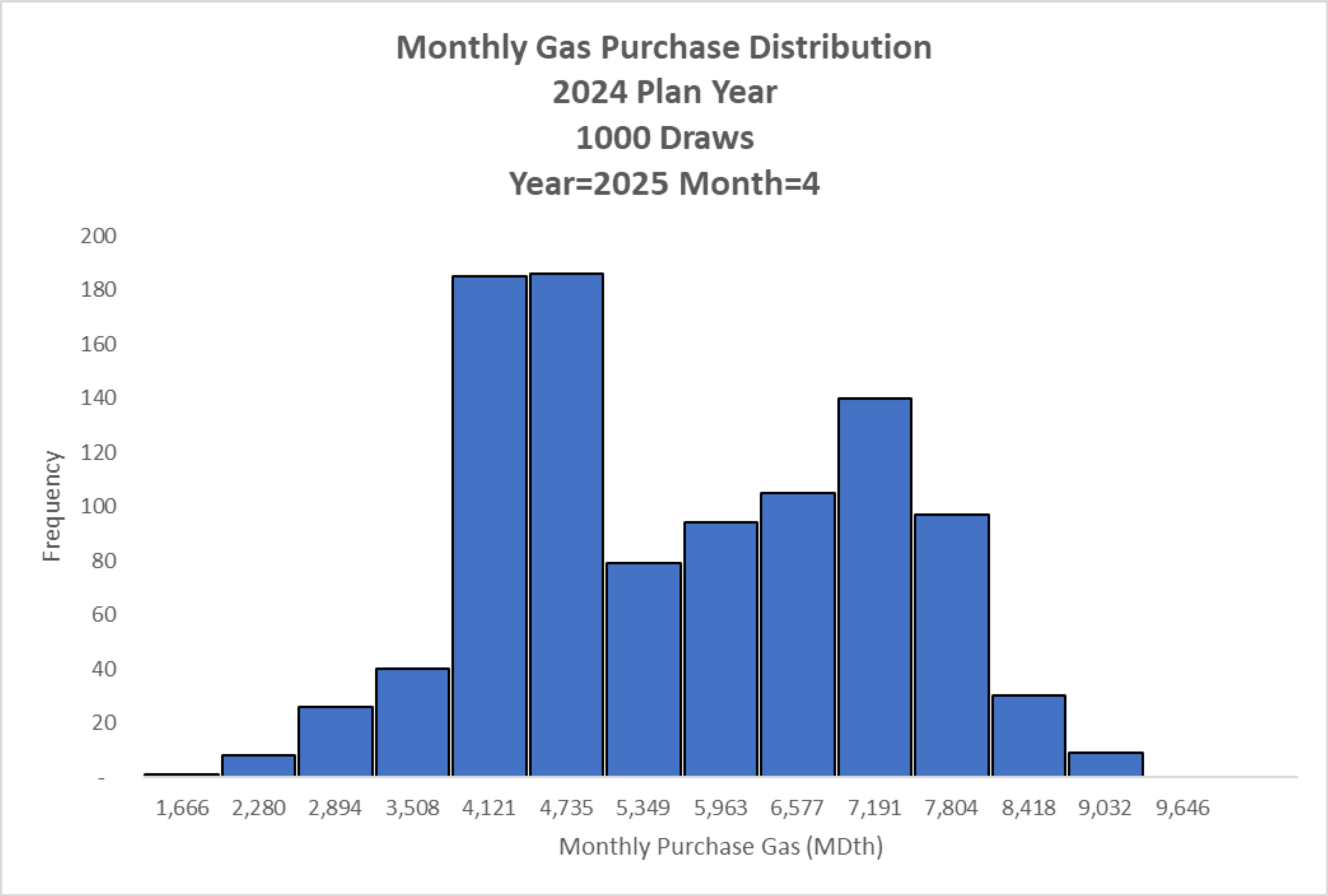


Exhibit 14.38



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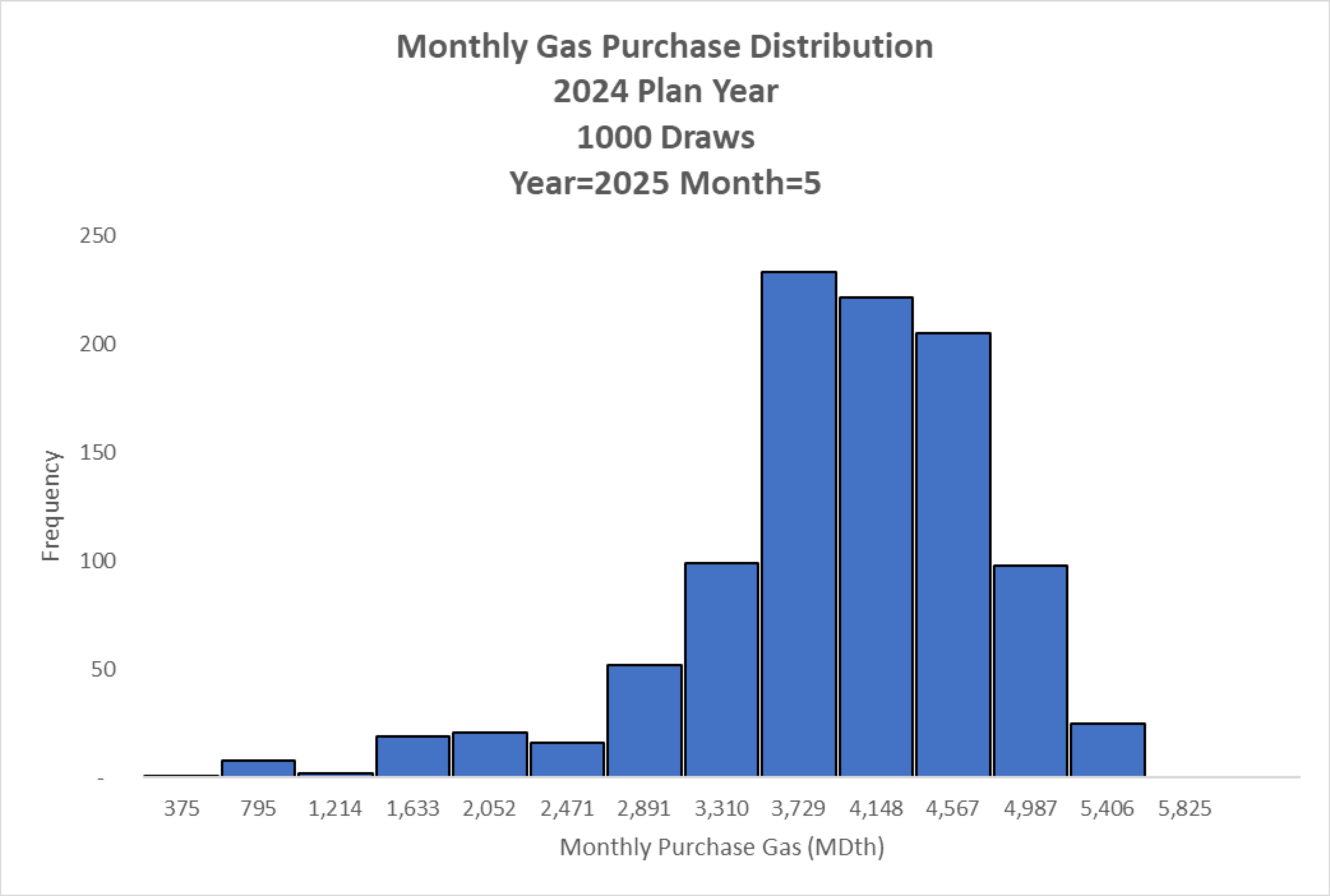

Exhibit 14.40

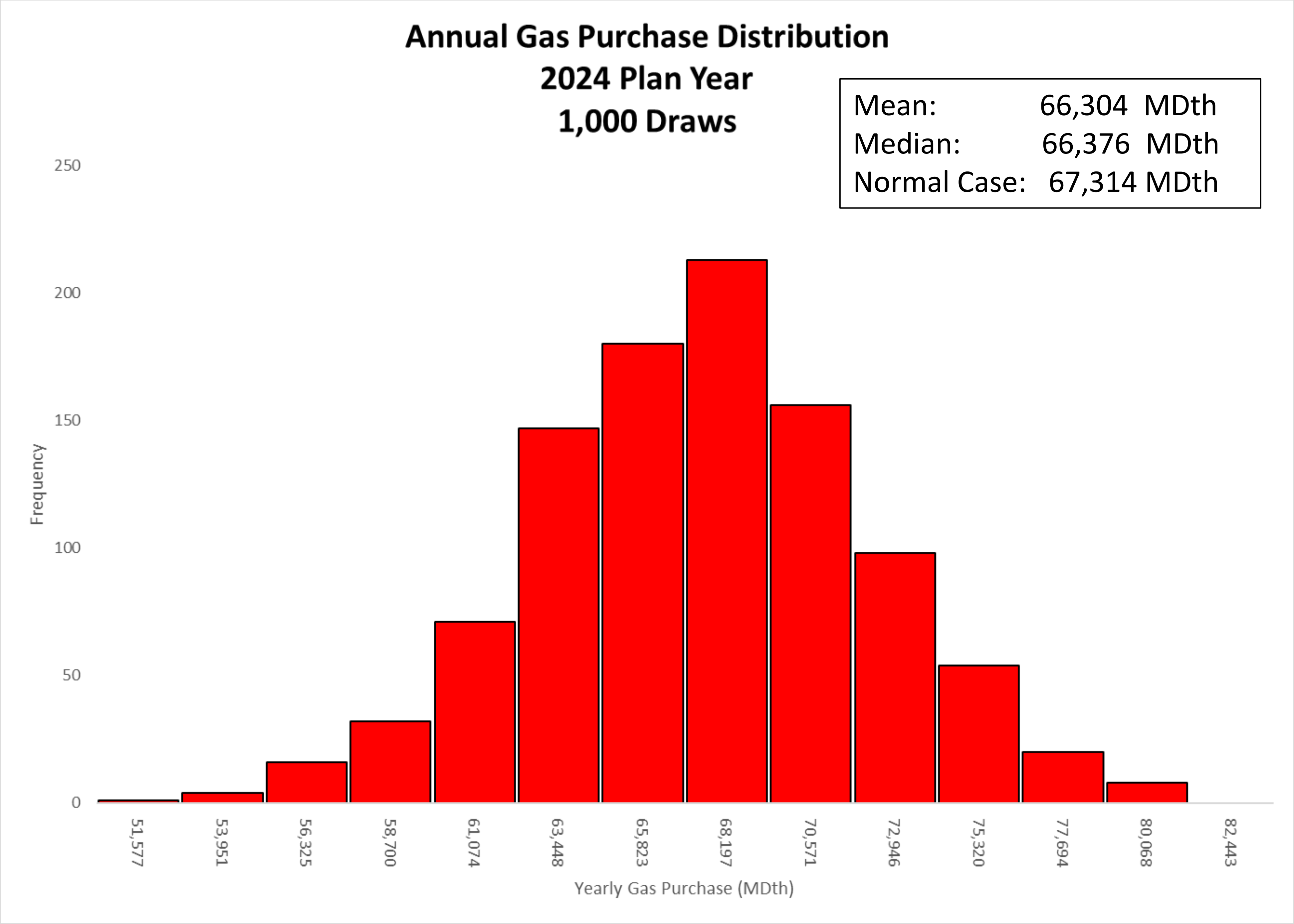

Exhibit 14.41

Monthly Purchase Gas (MDth)

2024 Plan Year

1000 Draws

year	2024	2024	2024	2024	2024	2024	2024	2025	2025	2025	2025	2025
month	6	7	8	9	10	11	12	1	2	3	4	5
mean	395	321	321	454	2,632	7,532	12,217	13,912	11,166	8,255	5,359	3,740
max	963	459	348	1,024	4,676	12,469	20,169	21,286	17,408	15,010	9,032	5,406
p95	735	324	323	596	4,024	10,394	16,508	18,143	15,571	11,838	7,705	4,841
p90	583	324	323	523	3,850	9,984	15,285	17,279	14,766	11,169	7,396	4,625
med	340	324	323	519	3,058	7,584	11,981	13,665	10,581	7,786	5,172	3,831
p10	322	324	323	319	752	4,997	9,553	10,821	8,404	5,809	3,869	2,746
p5	321	324	323	319	598	4,533	8,860	10,124	8,004	5,376	3,174	1,987
min	318	64	13	317	351	2,716	6,764	8,220	6,122	3,200	1,666	375

Exhibit 14.42

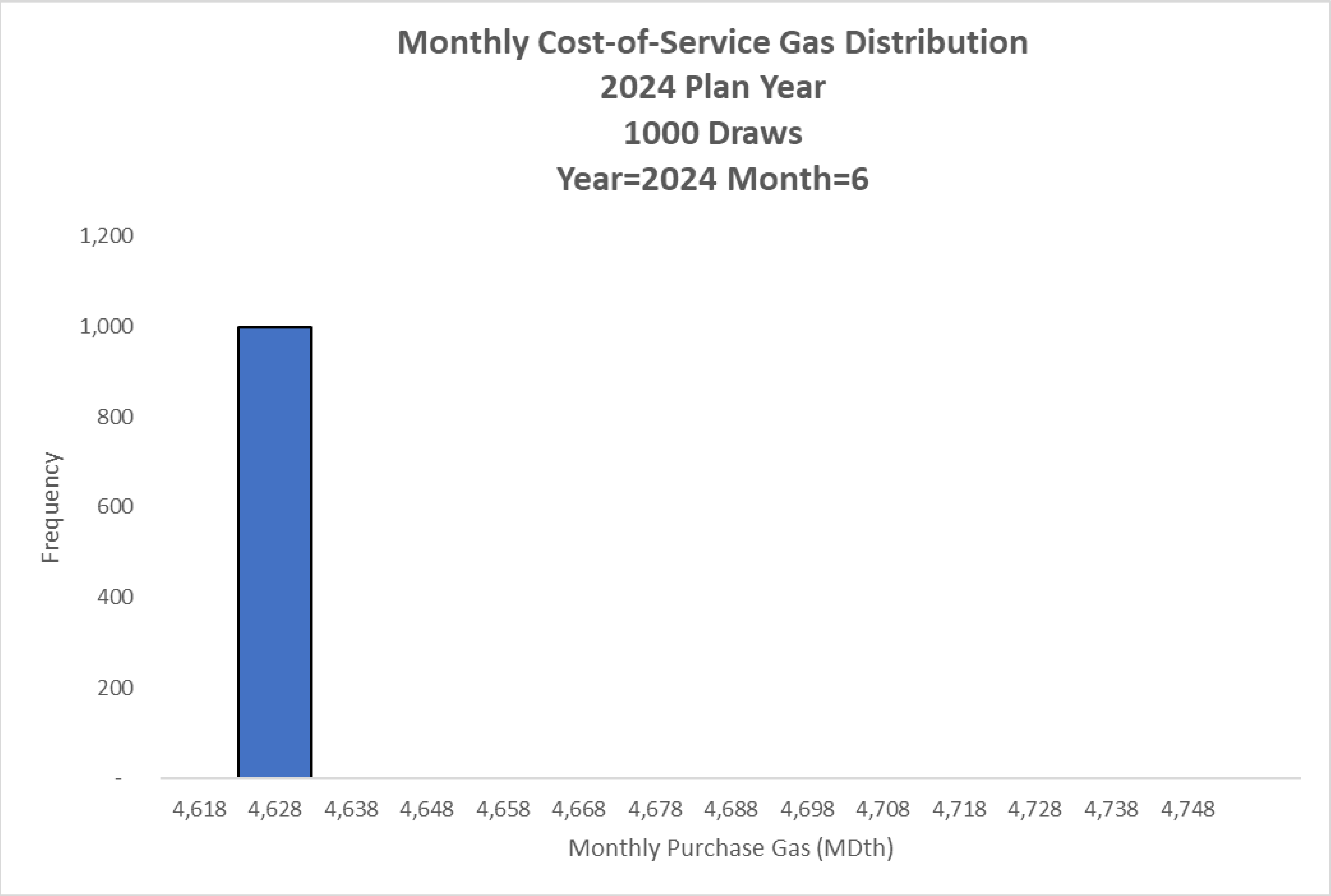

Exhibit 14.43

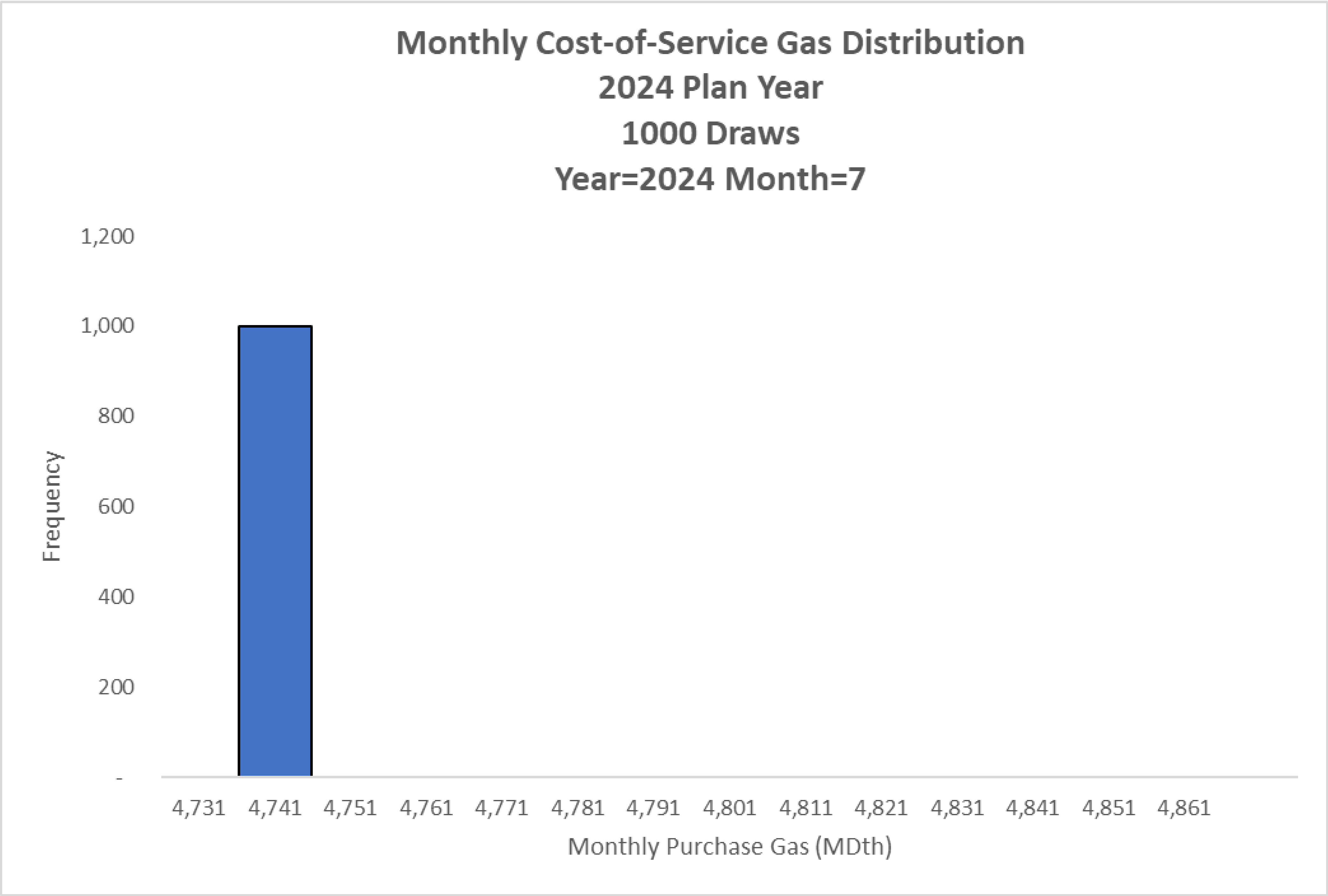

Exhibit 14.44

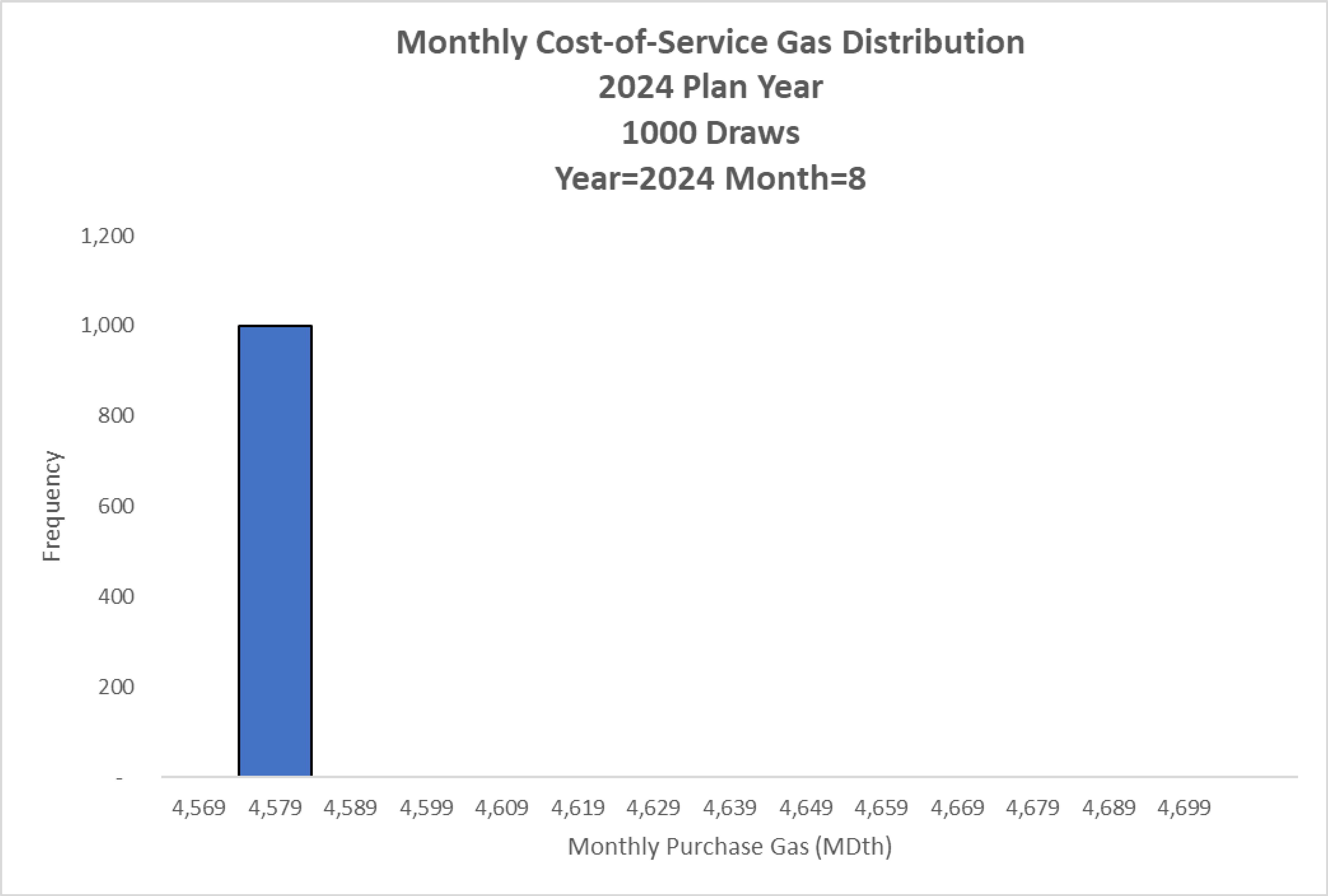

Exhibit 14.45

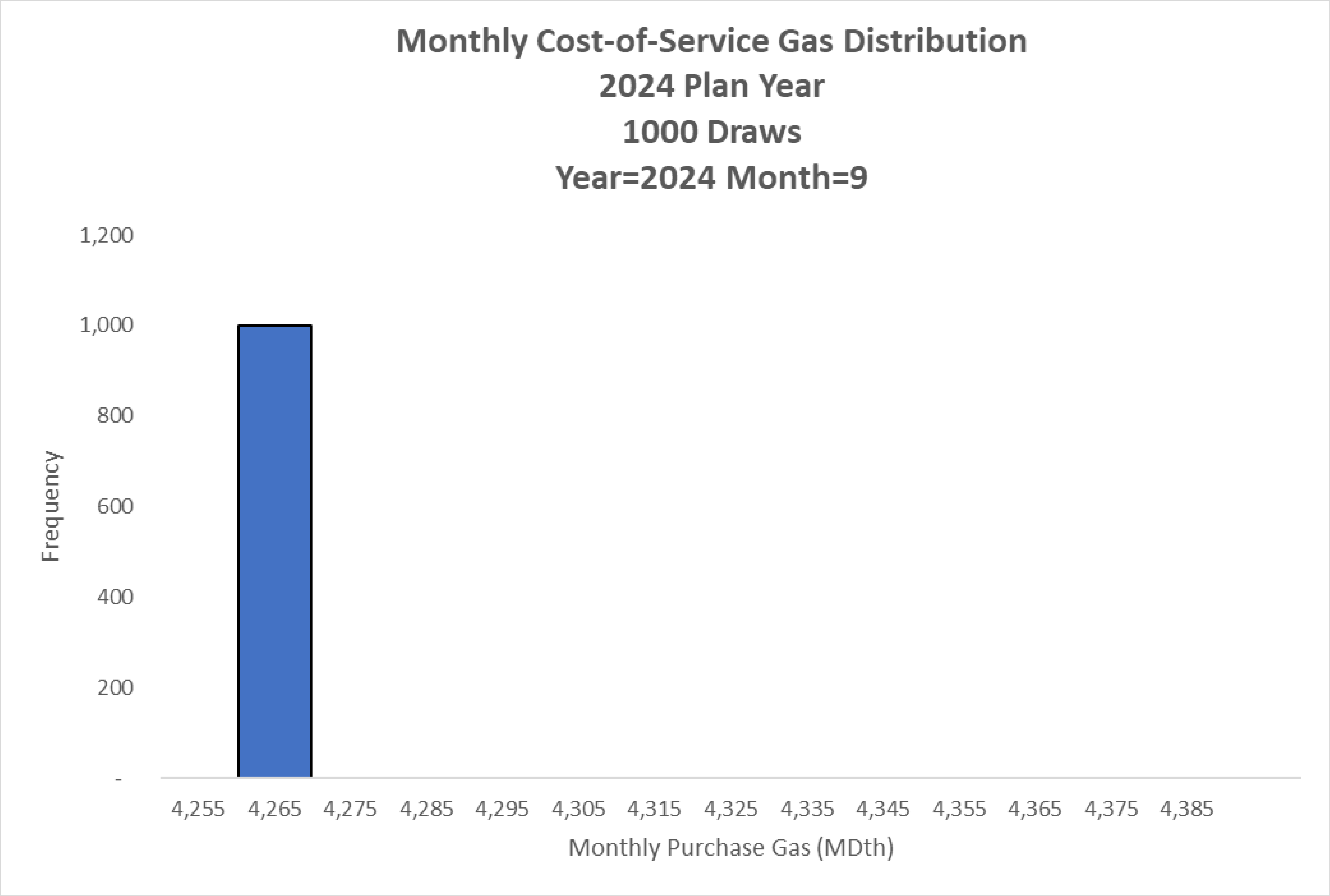

Exhibit 14.46

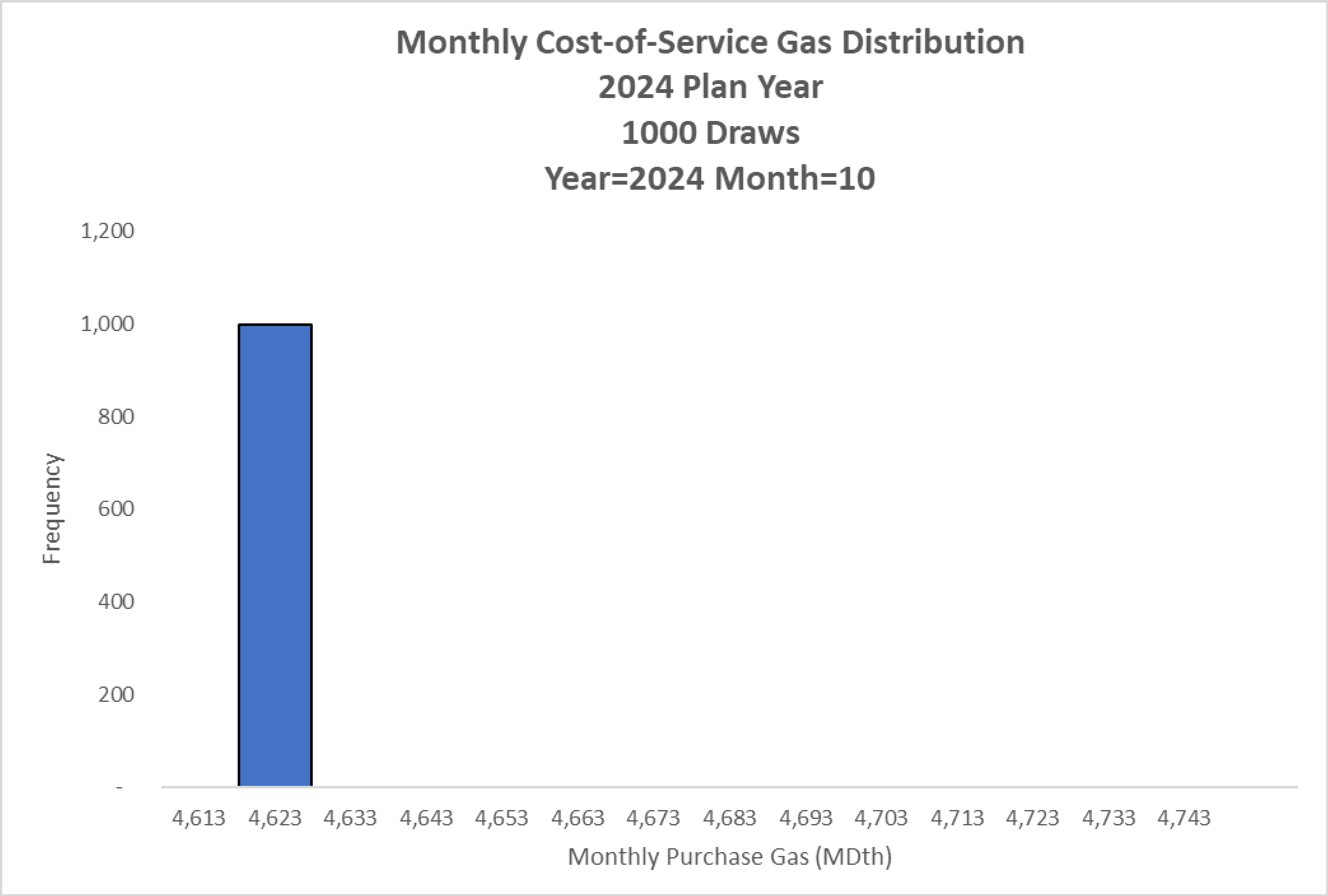

Exhibit 14.47

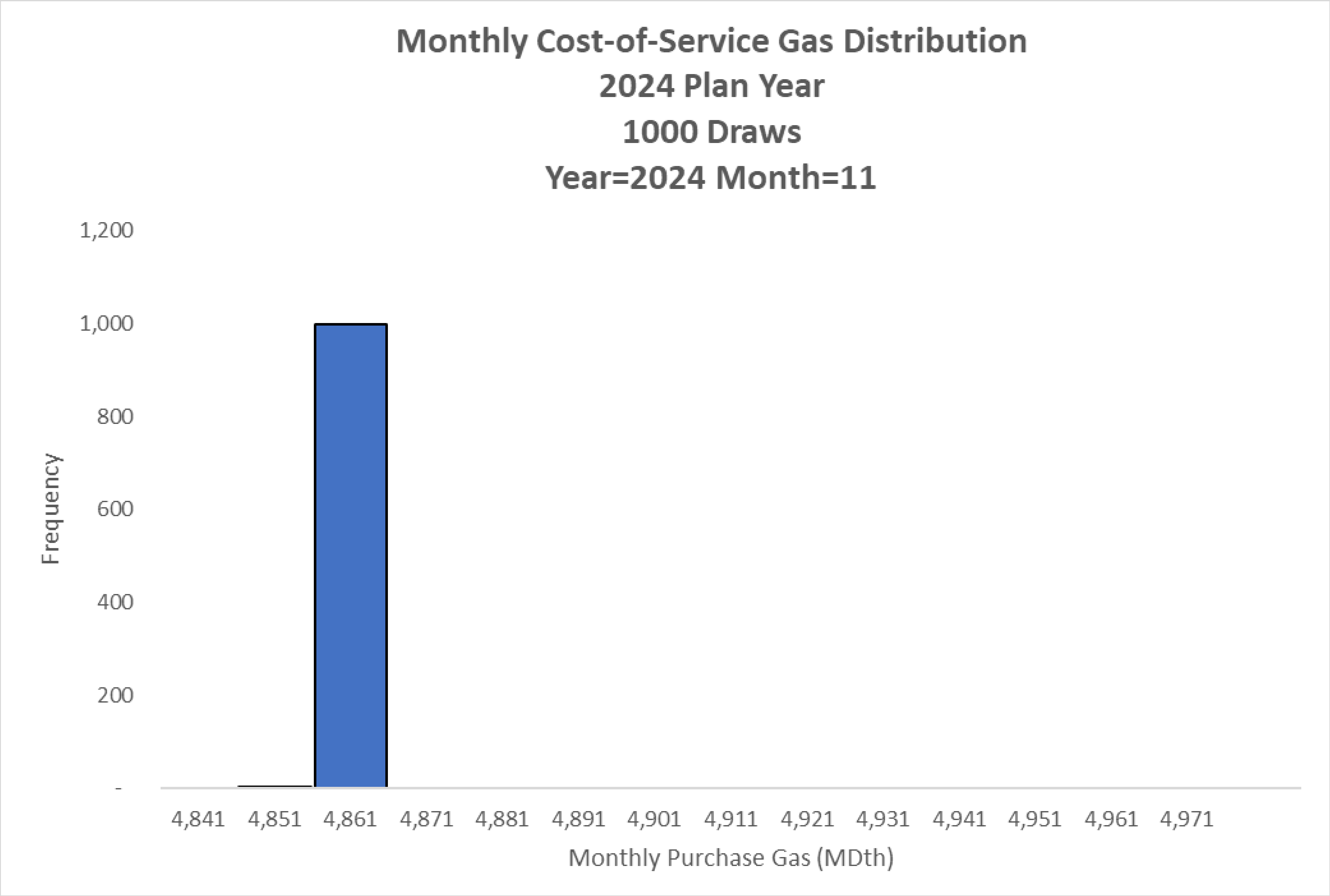

Exhibit 14.48

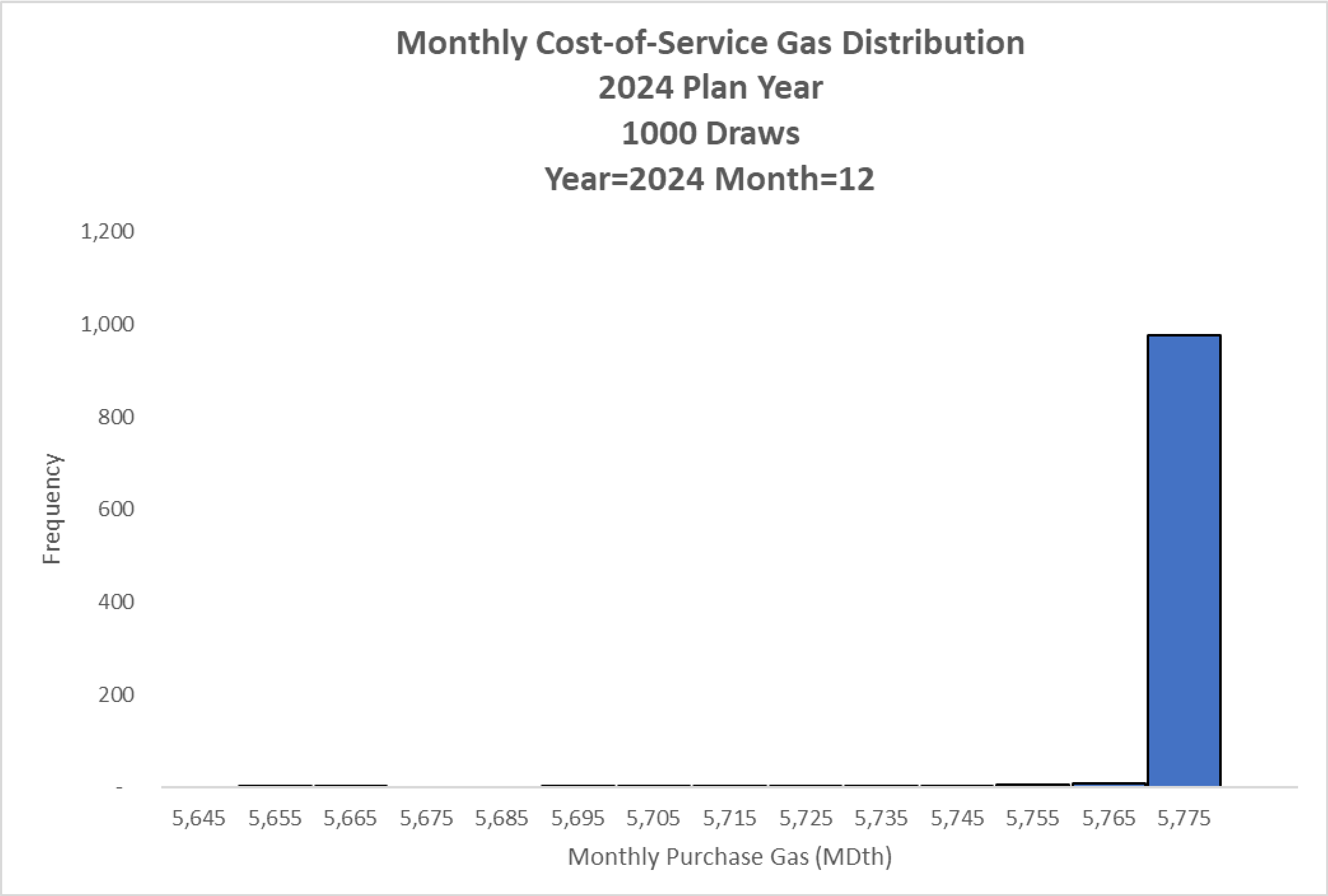

Exhibit 14.49

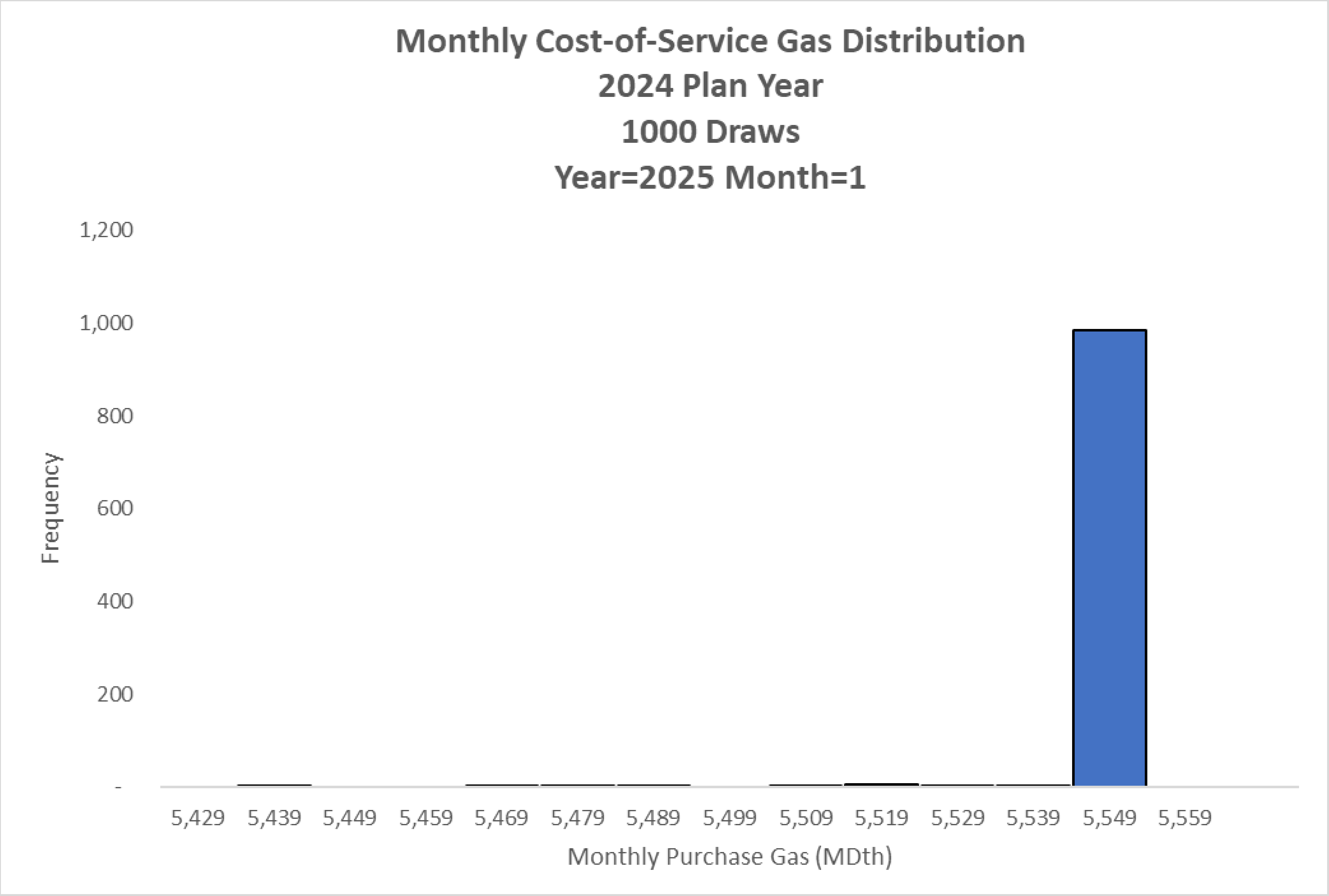

Exhibit 14.50

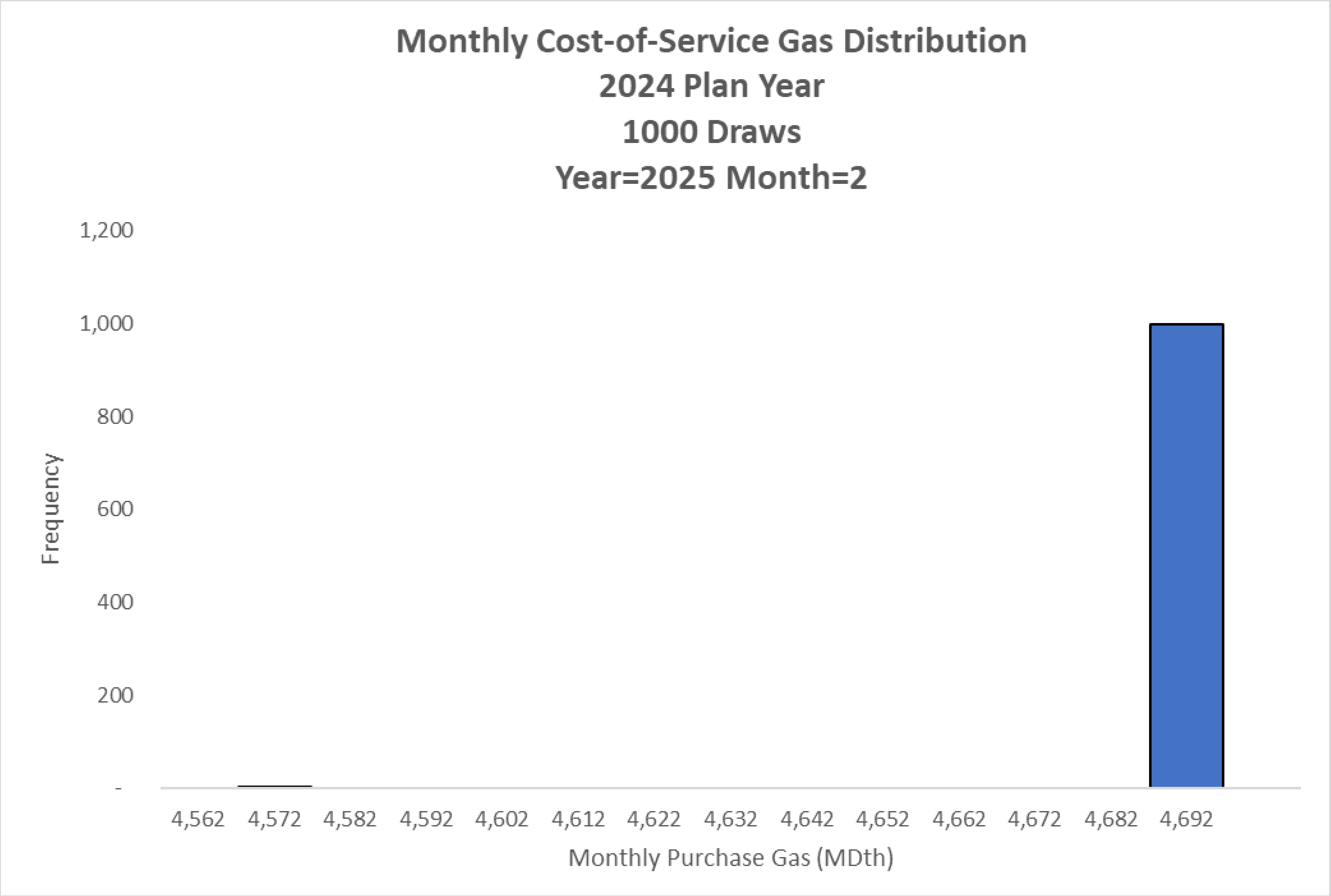

Exhibit 14.51

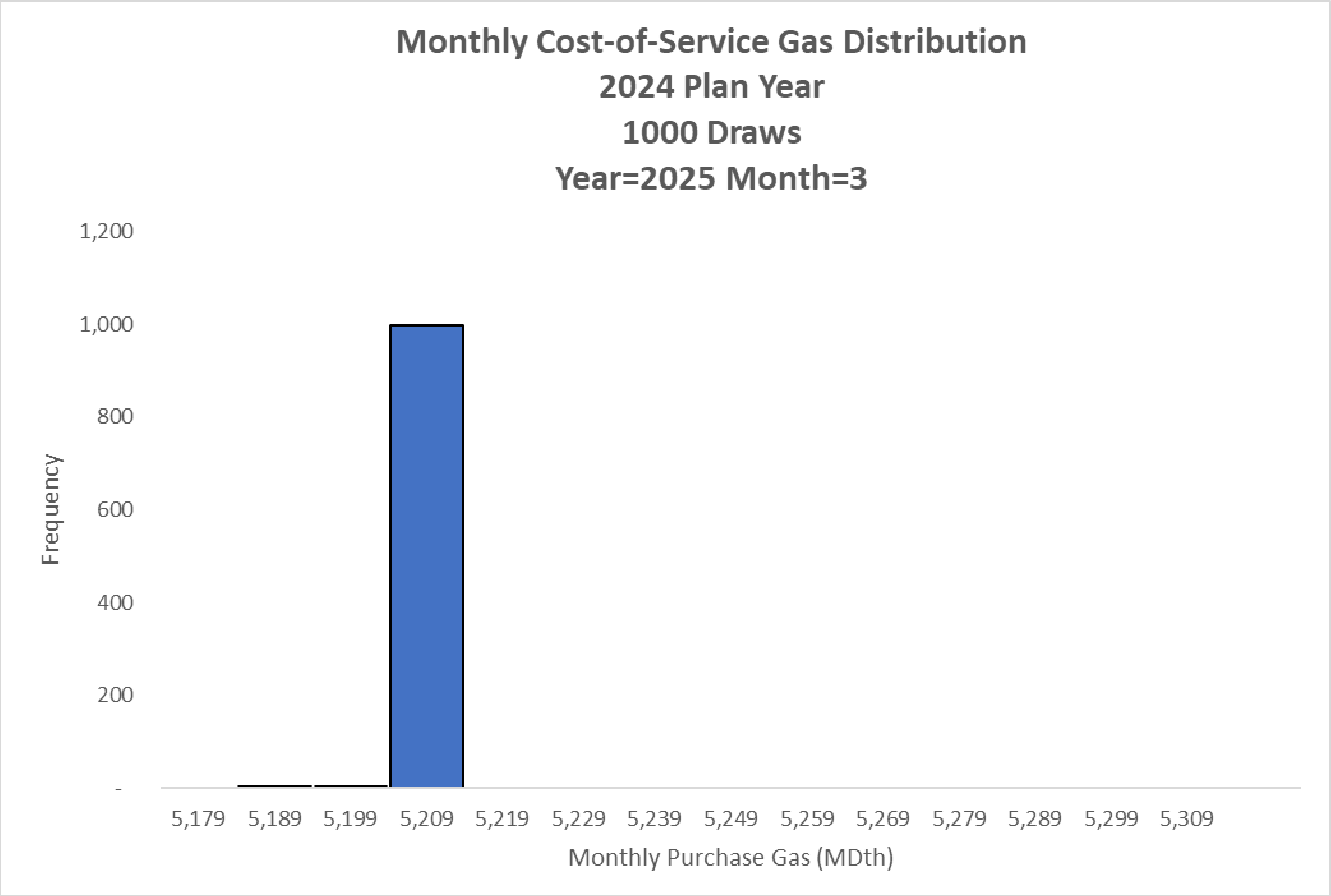

Exhibit 14.52

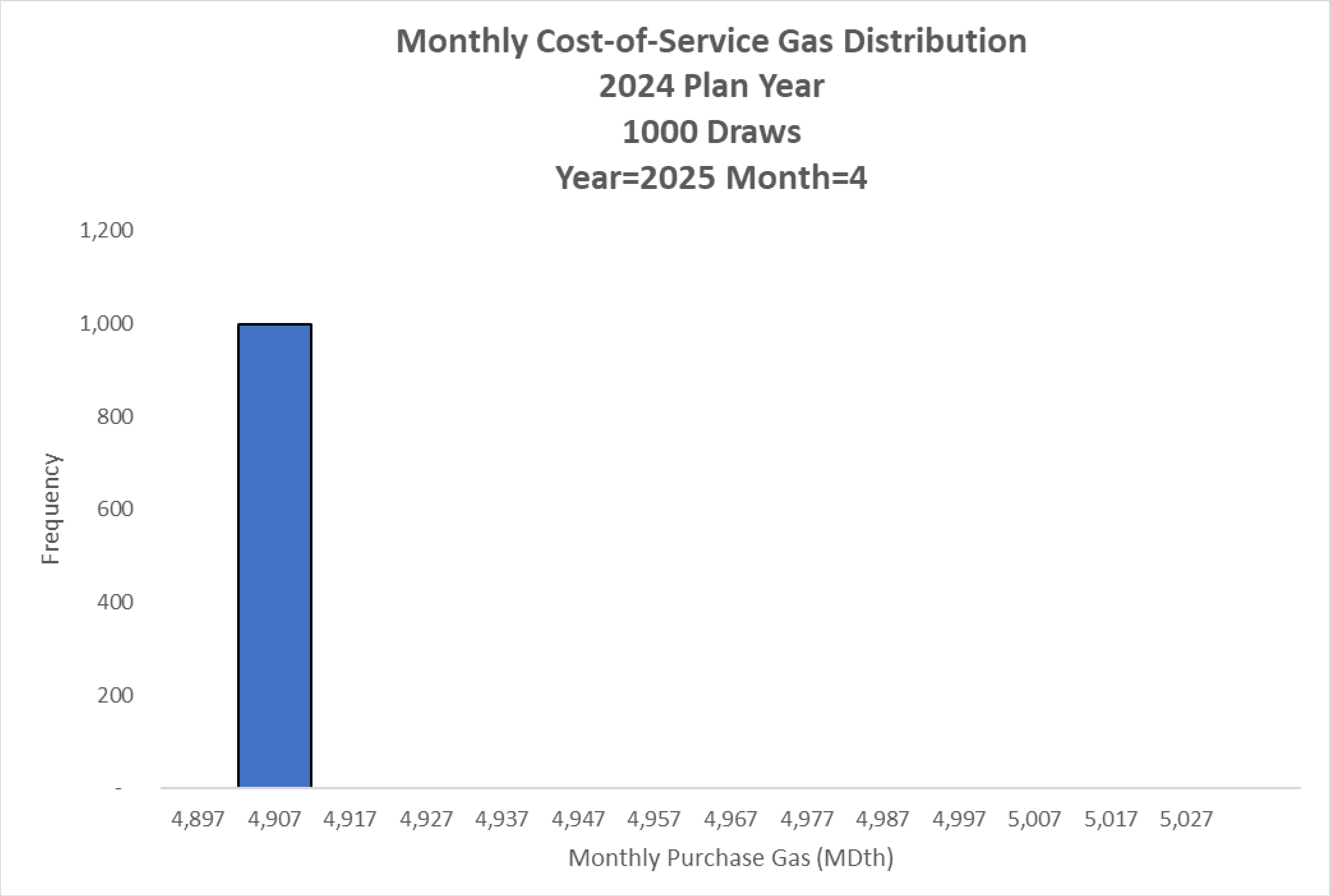

Exhibit 14.53

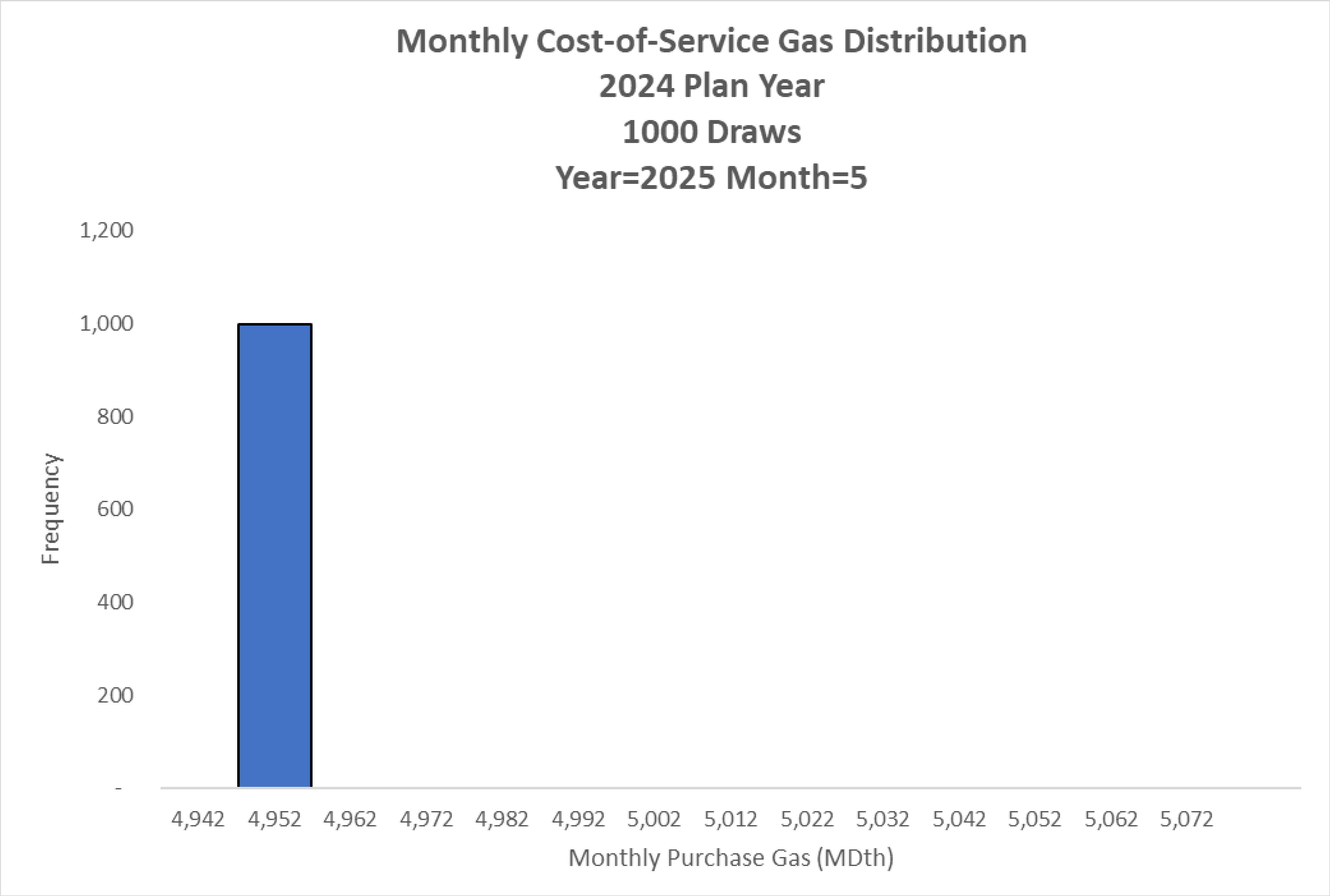

Exhibit 14.54

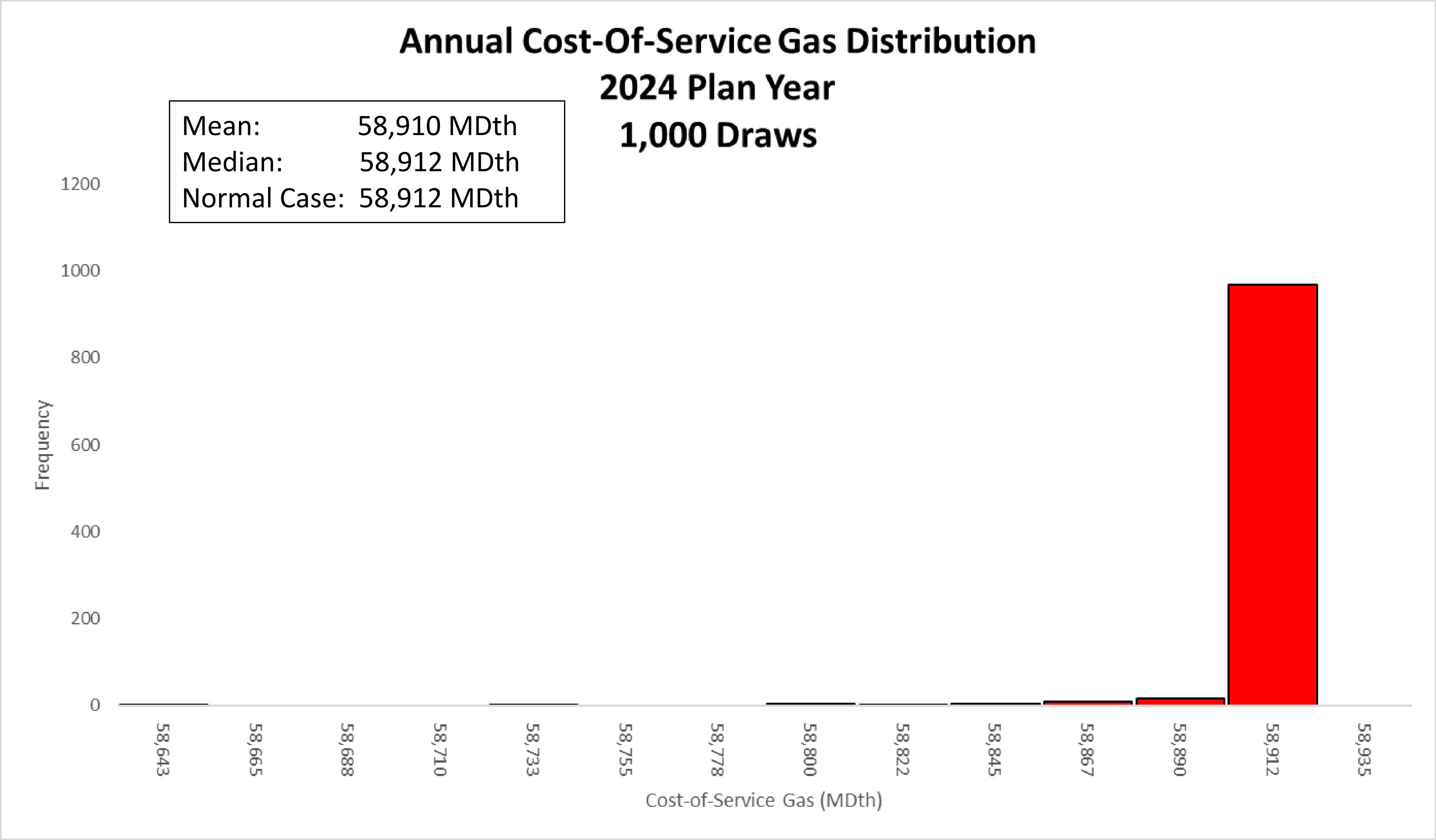

Exhibit 14.55

Monthly Cost-of-Service Gas (MDth)

2024 Plan Year

1000 Draws

year	2024	2024	2024	2024	2024	2024	2024	2025	2025	2025	2025	2025
month	6	7	8	9	10	11	12	1	2	3	4	5
mean	4,628	4,741	4,579	4,265	4,623	4,851	5,773	5,544	4,841	5,205	4,907	4,952
max	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
p95	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
p90	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
med	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
p10	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
p5	4,628	4,741	4,579	4,265	4,623	4,851	5,774	5,545	4,842	5,205	4,907	4,952
min	4,628	4,741	4,579	4,265	4,623	4,851	5,655	5,439	4,572	5,189	4,907	4,952

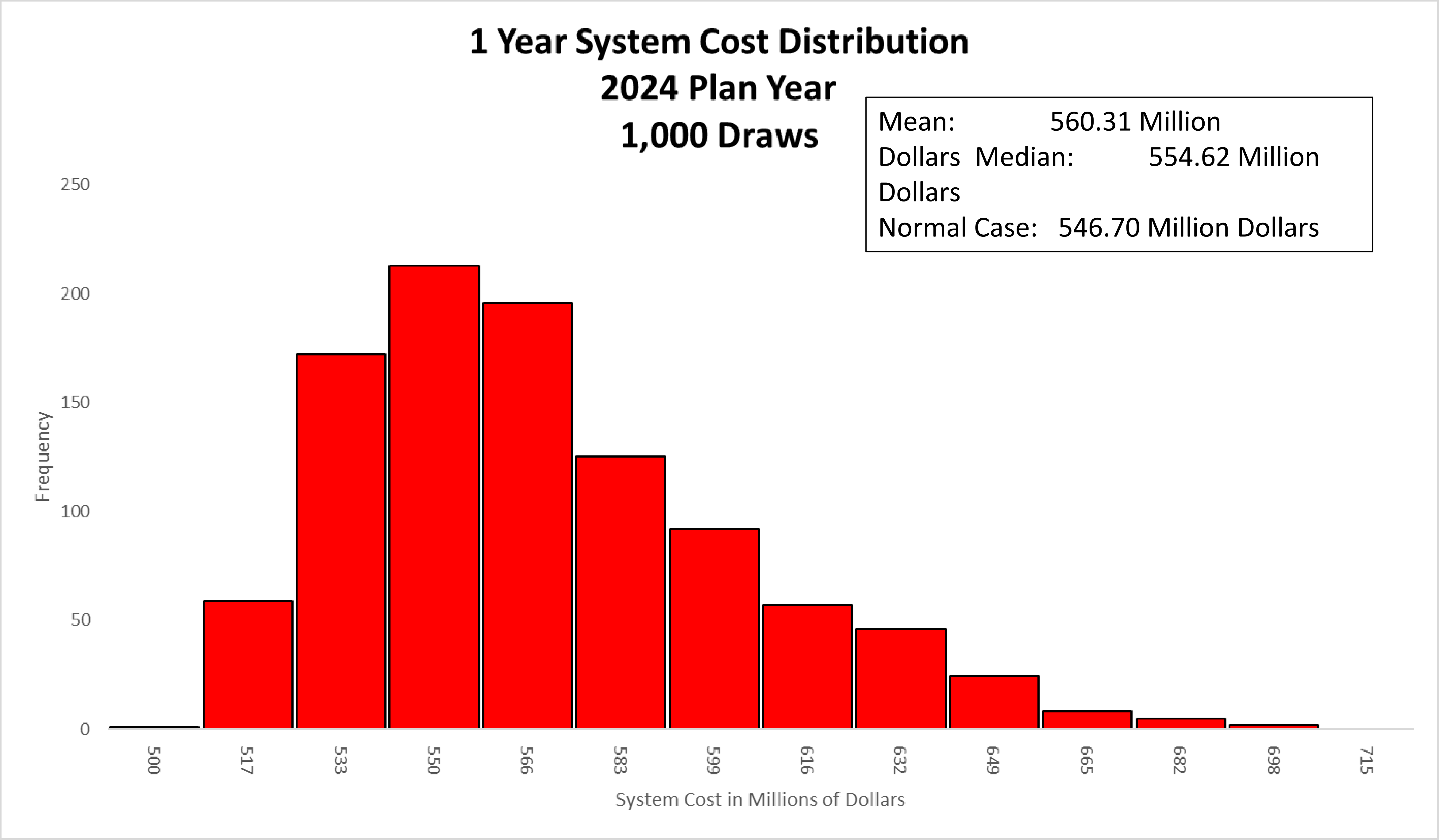

Exhibit 14.57

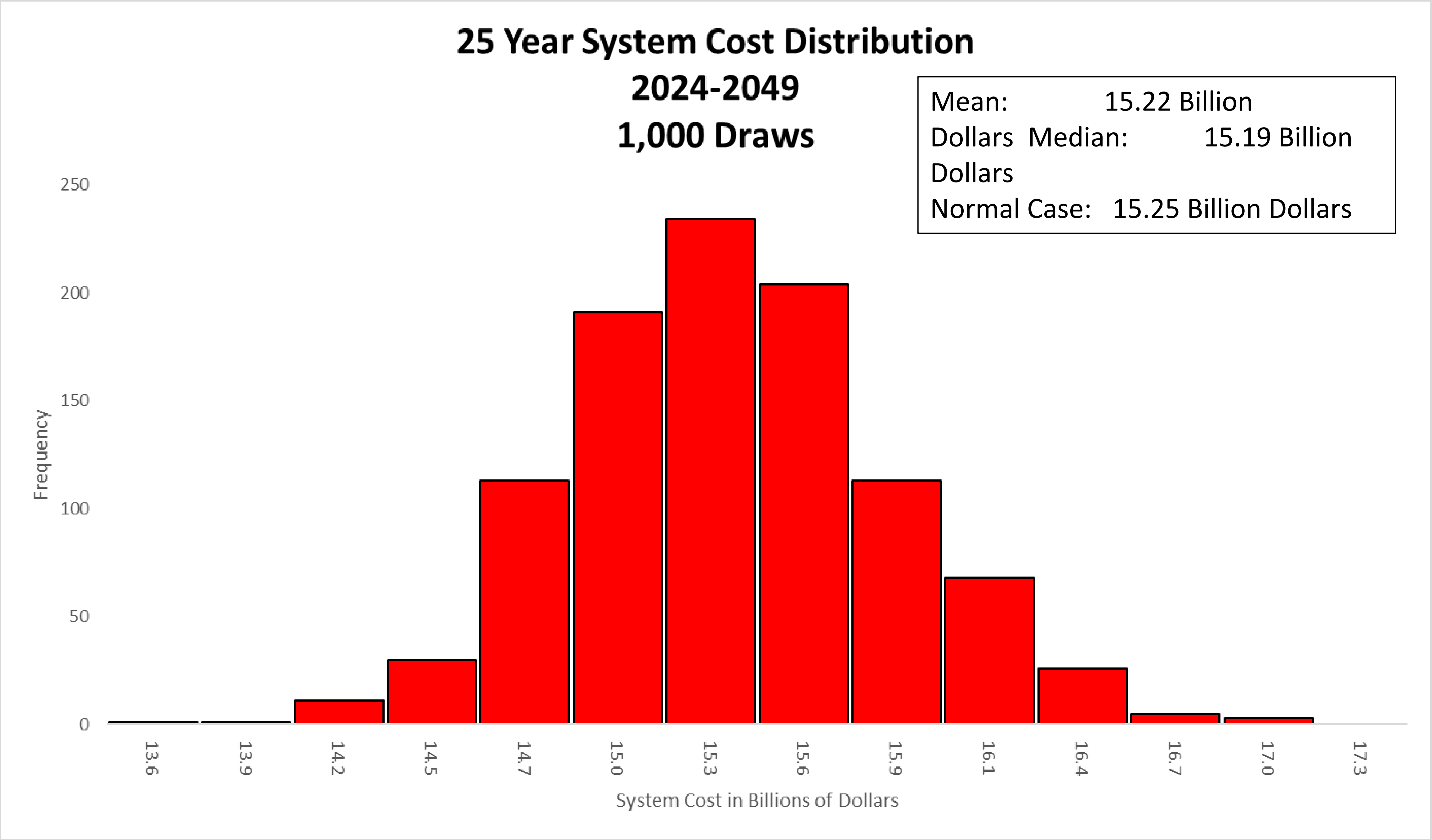

Exhibit 14.58

Normal Temperatue Case: Plan Year 1
MDth

	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	Total
D24													
FLD-ACEJD D24	9.71324	9.96679	9.89705	9.51077	9.75903229	9.37814373	9.62294366	9.55561	8.57049	9.42236	9.05462	9.29097	113.742
FLD-BRCH CRK D24	90.4737	92.9447	92.4043	88.9045	91.3358603	87.8784782	90.2836218	89.7634	80.6101	88.7343	85.3793	87.7199	1066.43
FLD-BRFM D24	1.92065	1.97275	1.96091	1.88626	1.93743298	1.86367781	1.91423749	1.90274	1.70829	1.87996	1.8084	1.85746	22.6128
FLD-BRFQ D24	114.178	117.196	116.418	111.54	114.503488	110.088178	113.020455	112.291	100.772	110.855	106.595	109.448	1336.91
FLD-BRFW D24	44.6988	45.9013	45.6159	43.8701	44.8998758	43.1835202	44.3479781	44.0749	39.5646	43.5343	41.8711	43.0011	524.563
FLD-CBFR D24	11.8153	12.1328	12.0569	11.595	11.9065963	11.4504641	11.7581644	11.6846	10.4879	11.539	11.097	11.3952	138.919
FLD-CCRK D24	300.009	307.576	305.175	274.882	263.979961	267.06303	296.484899	294.166	263.678	289.718	278.258	285.374	3426.36
FLD-CHBT D24	12.3942	12.7351	12.6632	12.1855	12.5206406	12.0483566	12.379694	12.3098	11.0558	12.1712	11.7121	12.0342	146.21
FLD-CHBTBUFF D24	0.63588	0.65353	0.64999	0.62563	0.64299149	0.61889036	0.63606832	0.63264	0.56833	0.62583	0.60238	0.6191	7.51125
FLD-CHBTC2 D24	71.1963	73.0619	72.5584	69.7344	71.5632538	68.7789603	70.5838153	70.0999	62.8824	69.1434	66.4557	68.202	834.26
FLD-CHBTC3 D24	133.641	137.167	136.251	130.98	134.451221	129.257736	132.690421	131.823	118.29	130.112	125.098	128.431	1568.19
FLD-DRYPINY6 D24	0.70289	0.72195	0.71761	0.69028	0.7090047	0.68200836	0.70050516	0.69629	0.62513	0.68795	0.66176	0.67971	8.27509
FLD-DRYPINYU D24	4.53541	4.64656	4.607	4.42053	4.52921804	4.34612383	4.45320479	4.41584	3.95514	4.34237	4.16734	4.27054	52.6893
FLD-HWA DEEP D24	13.2509	13.6329	13.5736	13.0785	13.455623	12.964888	13.3387427	13.2807	11.9433	13.1654	12.6853	13.0511	157.421
FLD-HWPL1&3 D24	67.81	69.479	68.8933	66.1095	67.7383952	65.0023066	66.6050309	66.0463	59.1547	64.9443	62.3235	63.8627	787.969
FLD-HWPL2 D24	4.04416	4.14175	4.10494	3.9373	4.0325515	3.86802129	3.9617515	3.92693	3.51578	3.85837	3.70124	3.79122	46.884
FLD-ISLAND D24	43.8665	45.0215	44.7175	42.9838	44.1187321	42.4100844	43.2815075	42.9936	38.5754	42.4259	40.7863	41.8683	513.049
FLD-JNSNRDG D24	1.38942	1.42942	1.42314	1.37117	1.41064949	1.35914166	1.39827069	1.39212	1.25187	1.37991	1.32952	1.3678	16.5024
FLD-JRDG WFS D24	1.85685	1.90719	1.89571	1.82351	1.87294917	1.80162122	1.85047021	1.83933	1.65134	1.81726	1.74806	1.79546	21.8598
FLD-KNY FLD D24	8.89381	9.14292	9.09584	8.75712	9.00248432	8.6672985	8.91019851	8.86445	7.96552	8.77374	8.4472	8.68406	105.205
FLD-MESA D24	431.548	438.981	432.247	411.961	419.310678	399.765761	407.02011	400.998	356.978	389.589	371.67	378.622	4838.69
FLD-MOSU D24	0.95616	0.97929	0.97063	0.93101	0.95353754	0.91461768	0.93674682	0.92846	0.8312	0.91211	0.87488	0.89605	11.0847
FLD-PDW D24	116.059	118.741	117.942	113.37	116.364231	111.857249	114.813944	114.048	102.078	111.914	107.584	110.433	1355.21
FLD-PDW1A1B D24	0.34891	0.35825	0.35597	0.34229	0.35144474	0.33794124	0.34698134	0.34477	0.30942	0.34039	0.32731	0.33607	4.09975
FLD-PDWCUT D24	0.81695	0.84058	0.837	0.80655	0.82988409	0.799692	0.82282808	0.81932	0.73688	0.81236	0.7828	0.80545	9.71029
FLD-PDWPLT2 D24	2.78023	2.8569	2.84101	2.73408	2.80952791	2.70380942	2.77844401	2.76305	2.48184	2.73256	2.6298	2.70245	32.8137
FLD-SGRLF D24	10.685	10.946	10.8517	10.4111	10.6654682	10.2324853	10.4824633	10.3921	9.30559	10.2139	9.79923	10.0386	124.024
FLD-TRAIL D24	228.622	230.893	214.953	204.105	219.414056	214.727471	228.688104	226.736	203.065	222.943	213.967	219.287	2627.4
FLD-WHLA D24	28.2226	28.9456	28.7295	27.5952	28.3021831	26.9621045	27.6528226	27.4464	24.6052	27.0382	25.9708	26.6362	328.107
FLD-WWILSON D24	0.8133	0.83511	0.82984	0.79801	0.81941051	0.78798306	0.80912265	0.80403	0.72165	0.79395	0.76351	0.784	9.55991
Total	1757.88	1795.81	1765.24	1671.94	1704.19038	1651.80004	1722.57355	1707.04	1527.94	1676.42	1608.15	1647.28	20236.3
D21													
FLD-BRCH CRK D21	0.19915	0.20528	0.20478	0.19769	0.20377359	0.19671555	0.20277322	0.20228	0.18225	0.20128	0.19431	0.2003	2.39058
FLD-PDW1A1B D21	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0.19915	0.20528	0.20478	0.19769	0.20377359	0.19671555	0.20277322	0.20228	0.18225	0.20128	0.19431	0.2003	2.39058
PW													
FLD-BRCH CRK PW	0.2531	0.26014	0.25875	0.24906	0.2559899	0.24640916	0.2532638	0.25191	0.22632	0.24923	0.23991	0.24659	2.99069
FLD-DRYPINYU PW	0.29502	0.30381	0.30277	0.292	0.30070563	0.29001411	0.29866137	0.29765	0.26793	0.29563	0.28512	0.29363	3.52294
FLD-MOSU PW	0.33464	0.34426	0.34273	0.3302	0.33969279	0.32727403	0.33668026	0.33518	0.3014	0.33221	0.32007	0.32927	3.97362
Total	0.88276	0.90821	0.90425	0.87127	0.89638832	0.8636973	0.88860543	0.88474	0.79565	0.87708	0.8451	0.86949	10.4872
Q50													
FLD-BRCH CRK Q50	0.53068	0.54315	0.53804	0.51583	0.52811076	0.50640379	0.5185456	0.51389	0.46003	0.50483	0.48428	0.41496	6.05877
FLD-CCRK Q50	0.1458	0.14966	0.14867	0.14291	0.14669531	0.14101951	0.14475151	0.14379	0.12901	0.14188	0.13639	0.14	1.71059
FLD-TRAIL Q50	0.68131	0.45419	0	0.28938	0.69319203	0.66593891	0.68317999	0.67832	0.60837	0.66887	0.64281	0.65964	6.72519
Total	1.35779	1.147	0.68671	0.94812	1.3679981	1.31336221	1.3464771	1.336	1.19741	1.31558	1.26348	1.2146	14.4945

Normal Temperatue Case: Plan Year 1

MDth

Exhibit 14.60

PC

FLD-ACEJD PC	3.06136	3.14861	3.13388	3.01861	3.10463836	2.99043716	3.07566659	3.06128	2.7521	3.03272	2.92116	3.00442	36.3049
FLD-BRCH CRK PC	11.4678	11.7932	11.7366	11.3034	11.6241638	11.1952028	11.5128642	11.4576	10.2992	11.348	10.9292	11.2394	135.907
FLD-BRFQ PC	15.2982	15.7221	15.6366	15.05	15.467268	14.887175	15.3000945	15.2173	13.6704	15.0533	14.4891	14.8913	180.683
FLD-BRFW PC	8.17007	8.39986	8.35754	8.0472	8.27355989	7.96634925	8.19044395	8.14921	7.32352	8.06738	7.76785	7.98639	96.6994
FLD-CBFR PC	44.2509	45.4697	45.215	43.5115	44.7102404	43.0258894	44.2114167	43.9642	39.4877	43.4742	41.8369	42.99	522.148
FLD-CCRK PC	47.0069	48.2352	47.9006	40.994	37.1253964	40.1040717	46.7774793	46.4577	41.6761	45.8284	44.0503	45.2122	531.368
FLD-CHBTC1 PC	51.858	53.2632	52.9419	50.9252	52.3055566	50.3133418	51.6773819	51.3663	46.1163	50.7502	48.8179	50.1421	610.477
FLD-CHBTC2 PC	6.30204	6.47237	6.4329	6.18744	6.35473808	6.11229989	6.27760365	6.23942	5.60134	6.1638	5.92874	6.08917	74.1619
FLD-DRYPINYU PC	10.5947	10.8845	10.8216	10.4122	10.6974101	10.29296	10.5751999	10.5148	9.44319	10.3955	10.0032	10.2781	124.913
FLD-FOGARTY PC	0.28609	0.29373	0.29185	0.28063	0.28812352	0.27704314	0.28444412	0.28262	0.25364	0.27901	0.26828	0.27545	3.36091
FLD-HWA DEEP PC	0.12732	0.12963	0.12772	0.12179	0.12399398	0.11822939	0.12037358	0.1186	0.10555	0.11514	0.10979	0.11178	1.42991
FLD-HWPL1&3 PC	49.9955	51.3749	51.0894	49.1666	50.5233164	48.6220038	49.9637803	49.6864	44.629	49.1366	47.2877	48.593	590.068
FLD-HWPL2 PC	0.7239	0.74484	0.74166	0.71467	0.735343	0.70858464	0.72907865	0.72597	0.65291	0.71978	0.69359	0.71365	8.60399
FLD-ISLAND PC	0.4454	0.45739	0.45455	0.43716	0.44892905	0.43175184	0.44337534	0.44062	0.39551	0.43517	0.41852	0.42979	5.23818
FLD-JNSNRDG PC	1.26449	1.30113	1.29565	1.24857	1.28475529	1.23807568	1.27395828	1.2686	1.14101	1.25794	1.21224	1.24738	15.0338
FLD-KNY FLD PC	2.97394	3.06097	3.04891	2.93894	3.02494247	2.91583463	3.00116257	2.98934	2.68942	2.96584	2.85887	2.94253	35.4107
FLD-MDBXCOMP PC	0	0	0	0	0	0	0	0	0	0	0	0	0
FLD-MESA PC	0	0	0	0	0	0	0	0	0	0	0	0	0
FLD-MOSU PC	5.66811	5.82112	5.78552	5.56477	5.71532365	5.49745746	5.6464051	5.61242	5.03886	5.54536	5.33446	5.47949	66.7093
FLD-NBXCAMP PC	2.24248	2.30784	2.29849	2.21534	2.27991024	2.19742772	2.26147817	2.25232	2.02611	2.23411	2.15329	2.21605	26.6849
FLD-NOBXFLD PC	2.01589	2.07238	2.06172	1.98495	2.04056685	1.96458604	2.0196315	2.00924	1.80547	1.98863	1.91458	1.96823	23.8459
FLD-PDW PC	23.987	24.6521	24.5184	23.5989	24.2294881	22.7671745	23.4001575	23.2749	20.9101	23.0266	22.1646	22.781	279.31
FLD-PDW1A1B PC	3.80908	3.9175	3.89906	3.75551	3.86242267	3.72022999	3.82614032	3.80813	3.42341	3.77237	3.63351	3.73696	45.1643
FLD-PDWCUT PC	0.54839	0.56474	0.56282	0.54281	0.55899653	0.53912475	0.55520115	0.55331	0.49807	0.54956	0.53002	0.54582	6.54886
FLD-PDWPLT2 PC	3.88023	3.99268	3.97587	3.83141	3.94244999	3.79934764	3.30442085	3.2621	2.93471	3.23623	3.11939	3.21056	42.4894
FLD-PDWPLT3 PC	2.82502	2.90371	2.88832	2.78034	2.85780044	2.75097037	2.82762139	2.81266	2.52702	2.78298	2.67896	2.75363	33.389
FLD-SBXSWEET PC	0.10887	0.11189	0.11129	0.10711	0.11008544	0.10595797	0.10889759	0.10831	0.0973	0.10714	0.10312	0.10598	1.28596
FLD-SGRLF PC	27.3693	28.1322	27.9836	26.9379	27.6888563	26.6542235	27.3973404	27.2528	24.4856	26.966	25.9586	26.6824	323.509
FLD-TRAIL PC	2.48496	2.38267	1.78473	2.08352	2.64372424	2.5383227	2.60248677	2.58237	2.31459	2.54311	2.44252	2.50507	28.9081
FLD-WWILSON PC	5.79742	5.95372	5.91702	5.69085	5.84430726	5.6209361	5.77252436	5.73698	5.14988	5.66656	5.45002	5.59704	68.1973
Total	334.563	343.564	341.013	323.451	327.866307	319.355009	333.136629	331.206	297.448	327.442	315.076	323.729	3917.85

Wexpro I

FLD-CCRK D8	401.42	401.371	388.857	362.341	361.244266	343.48788	350.030719	342.239	302.589	328.268	311.571	316.026	4209.44
FLD-ISLAND D8	32.4763	67.5702	63.7056	55.9749	58.0815082	55.398114	55.0685177	53.0483	46.2122	49.3989	46.2072	46.1986	629.34
FLD-KNY FLD D8	34.7044	35.6915	35.5275	34.2373	35.2346728	33.9704664	34.9752773	34.2659	29.4867	30.7643	28.2152	27.7632	394.836
FLD-MESA D8	223.013	226.868	223.393	212.921	216.73676	206.657463	210.441826	207.42	184.69	201.613	192.407	196.098	2502.26
FLD-TRAIL D8	381.657	363.439	320.16	303.172	342.199744	325.226966	333.828153	324.739	285.763	308.648	291.738	294.755	3875.33
Total	1073.27	1094.94	1031.64	968.645	1013.49695	964.740889	984.344493	961.713	848.741	918.692	870.137	880.841	11611.2

Wexpro I New Drill

FLD-Z24 CCRK D8	0	0	0	0	0	0	165.732385	143.592	115.213	115.318	102.21	97.7067	739.772
FLD-Z24 ISLAND D8	0	0	0	0	0	217.038258	201.417148	182.652	150.821	153.703	137.724	132.444	1175.8
FLD-Z24 KNY FLD D8	0	0	0	0	0	30.9008954	27.5537909	24.4394	19.9508	20.2387	18.1335	17.4912	158.708
FLD-Z24 TRAIL D8	0	0	15.2295	12.7179	11.6563617	84.4738205	270.581375	235.993	190.414	191.496	170.427	163.501	1346.49
Total	0	0	15.2295	12.7179	11.6563617	332.412974	665.284699	586.676	476.399	480.756	428.494	411.143	3420.77

Normal Temperatue Case: Plan Year 1
MDth

Exhibit 14.61

Wexpro II

FLD-ALKALI 2ACQ	147.207	151.022	147.165	115.013	91.9880619	91.8955762	167.170183	165.564	148.376	162.939	156.459	160.467	1705.27
FLD-ALKALI 2D8	150.69	140.071	127.927	99.8979	82.6540774	77.7798417	101.129121	95.6172	82.0248	86.581	80.1467	79.4465	1203.96
FLD-CC SH 2ACQ	2.38784	2.45425	2.44115	2.3498	2.41518476	2.32482429	2.38953032	2.37682	2.1354	2.35163	2.26369	2.32674	28.2169
FLD-CCRK 2ACQ	174.592	179.017	177.64	158.816	151.275189	154.430185	172.702527	171.374	153.629	168.819	162.158	166.322	1990.77
FLD-CCRK 2D8	201.328	201.303	195.027	181.728	181.177892	172.272383	175.553865	171.646	151.76	164.639	156.265	158.499	2111.2
FLD-CCRK 2Q50	0.74569	0.52306	0.07355	0.35678	0.757875	0.7281241	0.74701522	0.74173	0.66527	0.73145	0.70297	0.72139	7.4949
FLD-TRAIL 2ACQ	228.826	230.978	214.624	204.181	219.878426	215.125535	228.996873	227.044	203.342	223.249	214.261	219.59	2630.1
FLD-TRAIL 2D8	415.007	397.705	354.391	339.169	384.184899	366.540577	379.662646	369.386	325.129	351.271	332.135	335.689	4350.27
FLD-WHISKEY 2ACQ	17.1789	17.6325	17.5148	14.5609	12.4519298	12.4873203	17.1343893	17.0218	15.2739	16.8003	16.1528	16.5833	190.793
FLD-WHISKEY 2D8	121.837	122.023	118.625	111.869	112.868593	106.82182	108.105361	106.004	93.9788	102.218	97.2574	98.8781	1300.49
Total	1459.8	1442.73	1355.43	1227.94	1239.65213	1200.40619	1353.59151	1326.78	1176.31	1279.6	1217.8	1238.52	15518.6

Wexpro II New Drill

FLD-Z24 ALKALAI 2D	0	62.1757	53.6526	46.0531	312.480233	296.601465	376.193882	336.348	276.414	281.966	253.818	245.798	2541.5
FLD-Z24 CCRK 2D8	0	0	0	0	0	0	68.9163365	59.7095	47.9089	47.9527	42.502	40.6293	307.619
FLD-Z24 TRAIL 2D8	0	0	15.0578	12.5745	11.5249369	83.5213857	267.530591	233.332	188.267	189.337	168.505	161.658	1331.31
Total	0	62.1757	68.7103	58.6275	324.00517	380.12285	712.64081	629.39	512.59	519.256	464.825	448.085	4180.43

Normal Temperatue Case: Plan Year 1
MDth

Exhibit 14.62

Inject

	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	Total
Clay Bsn 93	670.302	620	620	501.674	0	0	0	0	0	0	644.1	1050.9	4106.98
Clay Bsn 98	348.499	387.5	387.5	346.981	0	0	0	0	0	0	410.4	669.6	2550.48
Clay Bsn 99	375.286	387.5	387.5	320.194	0	0	0	0	0	0	410.4	669.6	2550.48
Aquifers	0	0	0	372.114	410.7333174	200.598374	0	0	0	200.237	0	0	1183.68
MagnaLNG	0	188.885	242.966	25.83	26.691	0	0	0	0	0	0	171.9	656.272
Spire	41.073	434.292	436.553	113.723	1.948976383	0	0	0	0	0	342.244	558	1927.83
Total	1435.16	2018.18	2074.52	1680.51	439.3732937	200.598374	0	0	0	200.237	1807.14	3120	12975.7

Withdrawl

	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	Total
Clay Bsn 93	0	0	0	0	0	0	1581	1581	1428	389.557	0	0	4979.56
Clay Bsn 98	0	0	0	0	0	0	930	930	840	432.775	0	0	3132.77
Clay Bsn 99	0	0	0	0	0	0	930	930	840	432.775	0	0	3132.77
Aquifers	0	0	0	0	0	0	0	414.874	0	0	0	0	414.874
MagnaLNG	25.83	26.691	26.691	25.83	26.691	25.83	30.861	31	28	26.691	25.83	26.691	326.636
Spire	0	0	0	0	1.900251973	0	682	682	616	20	0	0	2001.9
Total	25.83	26.691	26.691	25.83	28.59125197	25.83	4153.861	4568.87	3752	1301.8	25.83	26.691	13988.5

Purchase Gas

	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	Total
Spot	0	0	0	0	26.10249923	183.0704503	0	0	0	0	402.505	99.2913	710.97
Spot	0	0	0	0	0	188.7338728	0	0	0	0	0	0	188.734
Spot	0	0	0	0	3.681234006	168.5380788	58.99101303	511.31	32.0168	17.816	58.5086	6.43177	857.293
Spot	0	0	0	0	0	15.46791027	21.21086924	31	28	22.3467	6.83947	0.09877	124.964
Spot	0	0	0	0	607.8170949	1800	727.7957583	1860	1287.24	1716.59	1681.7	968.876	10650
Spot	0	0	0	0	0	124.0456042	0	0	0	0	0	0	124.046
Spot	0	0	0	0	0	0	1354.827938	355.57	328.059	1550	0	0	3588.46
Spot	0	0	0	0	1.968243176	151.5058126	0	0	0	0	1088.91	282.248	1524.63
Spot	3.17255	1.99395	1.97275	2.82846	6.960645803	14.09485393	21.17961646	21.4117	17.781	15.1937	12.0777	7.84662	126.514
Spot	0	0	0	0	0	0	0	0	0	0	11.9524	0	11.9524
Spot	0	0	0	160	165.7830201	89.65062103	146.7169888	15.8021	130.471	2.47189	270	181.519	1162.42
Spot	0	0	0	0	5.679377892	134.4308564	0	0	0	0	530.888	43.1935	714.192
Spot	18.431	11.583	11.461	16.433	40.43499998	81.87799898	123.0330025	124.387	103.293	88.264	70.166	45.582	734.946
Spot	0	0	0	0	0	0	0	0	0	0	30.8734	186	216.873
Spot	0	0	0	0	0	123.8193062	0	0	0	0	0	0	123.819
Spot	0	0	0	0	0	135	0	0	0	0	0	0	135
Spot	0	0	0	0	1963.683339	2160	2232	2232	2016	2232	2160	2213.04	17208.7
Spot	17.8315	0	0	42.2832	123.0038149	289.8091226	286.0000709	140.378	202.754	152.493	729.453	148.51	2132.52
Peak	0	0	0	0	0	0	154.144925	0	0	0	0	0	154.145
Peak	0	0	0	0	0	0	606.3763844	620	560	620	0	0	2406.38
Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	0	0	0	0	0	1.342000002	0	1.83	0.122	0	0	0	3.294
Peak	0	0	0	0	0	1110.347216	0	812.28	0	0	0	0	1922.63
Peak	0	0	0	0	0	692.1538717	65.97038952	918.668	17.6698	99.923	0	0	1794.38
Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	930	930	840	0	0	0	2700
Base	0	0	0	0	0	1050	1085	1085	980	1085	0	0	5285
Base	0	0	0	0	0	0	620	620	560	0	0	0	1800
Base	300	238.266	220.247	300	310	300	310	310	280	310	300	310	3488.51
Base	0	0	0	0	0	0	930	930	840	0	0	0	2700
Base	0	0	0	0	0	0	620	620	560	0	0	0	1800
Base	0	0	0	0	0	0	279	279	252	279	0	0	1089
Base	0	0	0	0	0	0	372	372	336	0	0	0	1080
Base	0	0	0	0	0	150	155	155	140	155	0	0	755
Total	339.435	251.843	233.681	521.545	3255.114269	8963.887575	11099.24696	12945.6	9511.41	8346.1	7353.88	4492.63	67314.4

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.63

D24

	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	Total
FLD-ACEJD D24	8.92835459	9.16141538	9.09731673	8.74225845	8.97046309	8.62035657	8.84537998	8.78349441	7.87797378	8.66102088	8.32299336	8.54025596	104.551
FLD-BRCH CRK D24	84.4046545	86.7198955	86.2251218	82.9681714	85.2458133	82.0269549	84.167176	83.6898598	75.1626147	82.7448157	79.6229147	81.8123077	994.79
FLD-BRFM D24	1.786746	1.83521893	1.82420013	1.75475574	1.80236076	1.7337477	1.78078289	1.7700911	1.58919269	1.74889972	1.68232209	1.7279621	21.0363
FLD-BRFQ D24	105.246134	108.067231	107.386403	103.269369	106.042912	101.980595	104.722651	104.070896	93.4157358	102.783544	98.8526427	101.517023	1237.36
FLD-BRFW D24	41.3585366	42.4750433	42.2147053	40.6027005	41.6992826	40.107259	41.1907626	40.9390542	36.7513781	40.4406645	38.8973765	39.9488853	486.626
FLD-CBFR D24	10.958634	11.2531297	11.1827823	10.7543962	11.043409	10.6203659	10.9057799	10.837612	9.72762642	10.7025569	10.2925786	10.5691918	128.848
FLD-CCRK D24	274.102686	281.128802	279.041709	268.042931	274.936269	264.113192	270.919279	268.942976	241.149965	265.052311	254.648852	261.241463	3203.32
FLD-CHBT D24	11.5802928	11.8987596	11.8315973	11.385304	11.6984094	11.2571396	11.5667198	11.5014333	10.3297553	11.3719628	10.9430076	11.2439492	136.608
FLD-CHBTBUFF D24	0.59590141	0.61244765	0.60914923	0.5863253	0.60260835	0.58003124	0.59614115	0.59293491	0.53267458	0.58657673	0.56460437	0.58029013	7.03969
FLD-CHBTC2 D24	65.5516962	67.2751854	66.8172278	64.222108	65.9120048	63.3529107	65.0208232	64.5804195	57.9360025	63.7098292	61.2383052	62.8526556	768.469
FLD-CHBTC3 D24	123.484342	126.777045	125.960154	121.112572	124.345412	119.561894	122.755177	121.968963	109.460626	119.704389	115.10371	118.182119	1448.42
FLD-DRYPINY6 D24	0.65382669	0.67156144	0.66752669	0.64211286	0.65953081	0.63442186	0.65163194	0.64771852	0.58152279	0.63996292	0.61560037	0.63230132	7.69772
FLD-DRYPINYU D24	4.09860271	4.20029538	4.16575282	3.99831157	4.09779835	3.93326916	4.03132135	3.99862166	3.58244161	3.93427603	3.77672941	3.87130446	47.6887
FLD-HWA DEEP D24	12.5752023	12.9378823	12.8816438	12.4119282	12.769925	12.304298	12.6592077	12.6042211	11.3350171	12.49499	12.0394261	12.3310283	149.345
FLD-HWPL1&3 D24	61.2864861	62.8009624	62.2774151	59.7664634	61.2446962	58.776211	60.2307937	59.730771	53.5028516	58.7443337	56.3785375	57.7757209	712.515
FLD-HWPL2 D24	3.63694251	3.72546652	3.6930971	3.54296232	3.6293545	3.48190958	3.56691341	3.53617087	3.16647664	3.47562288	3.33465435	3.41629827	42.2059
FLD-ISLAND D24	40.2514848	41.3205017	41.0501458	39.4665376	40.2171923	38.6665258	39.6957934	39.438305	35.3910169	38.9295778	36.8347228	37.8168769	469.079
FLD-JNSNRDG D24	1.3178552	1.35579598	1.34983462	1.30054792	1.33799055	1.28913643	1.32625067	1.32041951	1.18739331	1.30883414	1.26104486	1.2973506	15.6525
FLD-JRDG WFS D24	1.72709497	1.7739308	1.76326244	1.69612183	1.74212085	1.6757873	1.72123687	1.71089055	1.53603247	1.69038702	1.62602816	1.67013324	20.333
FLD-KNY FLD D24	8.36090505	8.59539876	8.55144817	8.23330464	8.46429763	8.1494448	8.37813508	8.33542134	7.49040635	8.2507201	7.94393191	8.1669781	98.9204
FLD-MESA D24	361.317135	368.215063	363.179345	346.692292	353.419098	337.439196	344.049253	339.500876	302.615456	330.659369	315.832609	322.040156	4084.96
FLD-MOSU D24	0.85947879	0.88027393	0.87248917	0.83687747	0.85712574	0.82214096	0.84203269	0.8345861	0.74715331	0.81989007	0.7864252	0.80545277	9.96393
FLD-PDW D24	105.903198	108.353432	107.497981	102.956752	105.684258	101.5983	104.290543	103.601099	92.9568438	102.236708	98.2854689	100.891292	1234.26
FLD-PDW1A1B D24	0.32315644	0.33180107	0.32968737	0.31701984	0.32550017	0.3129935	0.32136622	0.31931905	0.28657985	0.31526343	0.30314997	0.31125931	3.7971
FLD-PDWCUT D24	0.77614566	0.79860005	0.79519799	0.76626791	0.78843694	0.75975317	0.78173343	0.77840302	0.70007852	0.77178491	0.74370649	0.76522231	9.22533
FLD-PDWPLT2 D24	2.60084725	2.67272697	2.65800584	2.55810769	2.628843	2.53006376	2.60004725	2.58578564	2.32274846	2.55753271	2.46149014	2.52963483	30.7058
FLD-SGRLF D24	9.63112707	9.86643927	9.78145635	9.38439585	9.61369157	9.22344767	9.44881767	9.36744973	8.38806429	9.20681965	8.83310856	9.04895721	111.794
FLD-TRAIL D24	210.490011	215.755867	214.034388	205.491211	210.67442	202.290823	207.417881	205.825353	184.488724	202.707093	194.690135	199.672349	2453.54
FLD-WHLA D24	25.5846752	26.2402957	26.044591	25.0164896	25.6576277	24.6448514	25.2765166	25.0881269	22.4913763	24.7156246	23.7401502	24.3487493	298.849
FLD-WWILSON D24	0.7539487	0.77419046	0.76933347	0.73984753	0.7597171	0.73060372	0.75022926	0.74553301	0.66917125	0.73623462	0.70803101	0.72706023	8.8639
Total	1580.1461	1618.47466	1604.55297	1539.25844	1576.87057	1513.21762	1550.51038	1537.6468	1377.3729	1511.7016	1450.36426	1486.33423	18346.5

D21

FLD-BRCH CRK D21	0.19335878	0.19931387	0.19882497	0.19193939	0.19785108	0.19099942	0.19688235	0.19639994	0.17695896	0.19543903	0.18867144	0.19448321	2.32112
FLD-PDW1A1B D21	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0.19335878	0.19931387	0.19882497	0.19193939	0.19785108	0.19099942	0.19688235	0.19639994	0.17695896	0.19543903	0.18867144	0.19448321	2.32112

PW

FLD-BRCH CRK PW	0.2373647	0.2439731	0.24267705	0.23360191	0.24010782	0.23113022	0.23756882	0.23631054	0.21231194	0.23381614	0.22507736	0.23135103	2.80529
FLD-DRYPINYU PW	0.28319912	0.29165124	0.29066771	0.2803438	0.2887139	0.27846145	0.28677749	0.28581585	0.25729146	0.28390518	0.27382865	0.28201163	3.38267
FLD-MOSU PW	0.31722785	0.32634539	0.32489508	0.31301735	0.32201385	0.31024138	0.3191581	0.31773974	0.28571534	0.31492194	0.30340876	0.3121291	3.76681
Total	0.83779167	0.86196973	0.85823984	0.82696306	0.85083557	0.81983305	0.84350441	0.83986613	0.75531873	0.83264327	0.80231476	0.82549176	9.95477

Q50

FLD-BRCH CRK Q50	0.39833346	0.40830905	0.40505596	0.38888773	0.39869185	0.38281761	0.39250854	0.38948173	0.34909377	0.38355218	0.3683684	0.37778116	4.64288
FLD-CCRK Q50	0.13458702	0.13814878	0.13723045	0.13192088	0.13541208	0.13017285	0.13361779	0.13272959	0.11908786	0.13097084	0.12590344	0.12923539	1.57902
FLD-TRAIL Q50	0.63393747	0.65053272	0.6460282	0.6208595	0.63711244	0.61229118	0.62831971	0.62396907	0.55968252	0.61535773	0.59138394	0.60686529	7.42634
Total	1.16685796	1.19699054	1.18831461	1.14166811	1.17121637	1.12528164	1.15444604	1.14618039	1.02786415	1.12988076	1.08565579	1.11388183	13.6482

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.64

PC

FLD-ACEJD PC	2.89390076	2.97637907	2.96245911	2.85348797	2.93481416	0.72044312	2.90742731	2.89383026	2.60155823	2.86682582	2.76137268	2.84007361	32.2126
FLD-BRCH CRK PC	10.8246696	11.1318675	11.0785071	10.6697511	10.9725736	10.5677398	10.8676805	10.8156212	9.72215802	10.7122696	10.317073	10.6099329	128.29
FLD-BRFQ PC	14.3333092	14.7313533	14.652112	14.1032502	14.4950876	13.9522208	14.3399754	14.263126	12.8138313	14.1108179	13.5825982	13.9603384	169.338
FLD-BRFW PC	7.68988279	7.90624113	7.86647677	7.57443665	7.78756336	7.49846368	7.70946376	7.67071645	6.89357214	7.59382089	7.31193937	7.51771747	91.0203
FLD-CBFR PC	41.3710485	42.5115572	42.274443	40.6826457	41.8044178	40.2304732	41.3399385	41.1097573	36.9247165	40.6534667	39.1232335	40.2025516	488.228
FLD-CCRK PC	43.460194	44.6085956	44.3113442	42.5971388	43.7256463	42.0359044	43.1513405	42.8683366	38.4666135	42.3104018	40.6793394	41.7627669	509.978
FLD-CHBTC1 PC	48.2331269	49.5416815	49.2443878	47.3700086	48.6555248	46.8038018	48.0742058	47.7863468	42.9035239	47.2161534	45.4198031	46.6532534	567.902
FLD-CHBTC2 PC	5.85699515	6.01552608	5.97906528	5.75113884	5.90685999	5.68172232	5.83559941	5.80031906	5.20734073	5.73045007	5.51212069	5.66149211	68.9386
FLD-DRYPINYU PC	9.89037973	10.1624475	10.1052927	9.72442629	9.9922835	9.61587513	9.88093637	9.82588357	8.82563391	9.67845113	9.30012019	9.55854818	116.56
FLD-FOGARTY PC	0.26485695	0.27193238	0.27019047	0.25979976	0.26674011	0.25648205	0.26333377	0.26164696	0.23481248	0.25830568	0.24837203	0.25500711	3.11148
FLD-HWA DEEP PC	0.1065817	0.10851466	0.10691871	0.10194798	0.10379689	0.09897129	0.10076622	0.09928424	0.08835719	0.09638533	0	0	1.01152
FLD-HWPL1&3 PC	46.7647638	48.0557272	47.7894109	45.9915804	47.2613863	45.4835371	46.7394329	46.480716	41.7502481	45.9677475	44.2388497	45.4606752	551.984
FLD-HWPL2 PC	0.68768109	0.70757046	0.7045501	0.67891224	0.69854809	0.67312856	0.69259712	0.68964061	0.62024227	0.68376557	0.65888402	0.67794055	8.17346
FLD-ISLAND PC	0.4133449	0.42447288	0.42183912	0.40569844	0.41662057	0.40067954	0.41146652	0.4089135	0.36704954	0.40385481	0.38840224	0.3988587	4.8612
FLD-JNSNRDG PC	1.2020627	1.23690812	1.23170776	1.18696469	1.22137532	1.17700938	1.21113318	1.20604576	1.08475668	1.19593765	1.1525001	1.18591788	14.2923
FLD-KNY FLD PC	2.83639317	2.91939632	2.90789849	2.80301261	2.88503887	2.7809773	2.86235912	2.85108605	2.56503267	2.82867323	2.72664453	2.80643621	33.7729
FLD-MDBXCOMP PC	0	0	0	0	0	0	0	0	0	0	0	0	0
FLD-MESA PC	0	0	0	0	0	0	0	0	0	0	0	0	0
FLD-MOSU PC	5.27128887	5.41479166	5.38286775	5.17860312	5.31985355	5.1181508	5.25792631	5.22736067	4.69411547	5.16700969	4.97150034	5.10767489	62.1111
FLD-NBXCAMP PC	2.13588382	2.19814296	2.18924265	2.11004374	2.17155066	2.0929926	2.15400329	2.14528337	1.92983146	2.12795039	2.05097116	2.11075871	25.4167
FLD-NOBXFLD PC	1.89494066	1.94803485	1.93801607	1.86585366	1.9181329	1.84671089	1.89845363	1.88868982	1.69713985	1.86931274	1.79970853	1.85013442	22.4151
FLD-PDW PC	21.9282485	22.3214635	21.7868667	20.9720377	21.5559862	20.7498391	21.327645	21.214422	19.0597109	20.9898411	20.2049749	20.7677185	252.879
FLD-PDW1A1B PC	3.59939851	3.70188469	3.68447142	3.54884643	3.6498957	3.51554649	3.61565067	3.59865245	3.23511504	3.56489424	3.43368279	3.53146463	42.6795
FLD-PDWCUT PC	0.52642073	0.54211837	0.5402748	0.52106843	0.53660615	0.51753007	0.53296266	0.5311504	0.47811734	0.52754403	0.50879015	0.52396171	6.28654
FLD-PDWPLT2 PC	3.09464389	3.18508966	3.17243196	3.05789486	3.147267	3.03363875	3.12230235	3.10989482	2.79777388	3.08522578	2.97383641	3.06075149	36.8408
FLD-PDWPLT3 PC	2.65072101	2.72460727	2.7102184	2.60894474	2.68168013	2.58147948	2.65345733	2.63946399	2.37146145	2.61170793	2.51413965	2.58426125	31.3321
FLD-SBXSWEET PC	0.1020101	0.10484019	0.10427305	0.10036351	0.10314792	0.09928058	0.10203495	0.10148296	0.09116617	0.10038795	0.09662407	0.09930476	1.20492
FLD-SGRLF PC	25.6856065	26.4019263	26.2628254	25.2817606	25.986904	25.0162023	25.7139962	25.578662	22.9817378	25.3102087	24.3649186	25.0446832	303.629
FLD-TRAIL PC	2.40627829	2.4681873	2.45016221	2.35393758	2.414904	2.32031366	2.38065881	2.36390011	2.12021158	2.33106765	2.24024554	2.29889771	28.1488
FLD-WWILSON PC	5.38317958	5.52841257	5.49442563	5.28450482	5.42709998	5.2197667	5.36063141	5.32771494	4.78258812	5.26251041	5.06150306	5.19813516	63.3305
Total	311.507811	319.84967	317.62268	305.638059	314.041305	300.088881	310.507379	308.757948	277.308416	305.254987	293.642148	301.729257	3665.95

Wexpro I

FLD-CCRK D8	300.421277	305.149425	300.138393	285.848267	290.841582	277.27164	282.3766	278.415412	248.040472	270.964829	258.82295	264.063472	3362.35
FLD-ISLAND D8	43.2968795	43.3658573	42.0713381	39.5289254	39.6859525	37.3437383	37.5461489	36.5544367	32.1656505	34.7146237	32.7657683	33.0403763	452.08
FLD-KNY FLD D8	25.6836479	25.4564006	24.4860592	22.8507653	22.8187123	21.3823356	21.4302979	20.8182333	18.2916205	19.7258357	18.6146252	18.7765874	260.335
FLD-MESA D8	187.202692	190.852326	188.323941	179.859979	183.444201	175.246869	178.786066	176.53525	157.463155	172.181274	164.588555	168.013379	2122.5
FLD-TRAIL D8	279.166823	282.567199	277.000775	262.973981	266.755512	253.570711	259.840525	255.511285	227.050793	247.424499	235.778905	240.006683	3087.65
Total	835.77132	847.391209	832.020505	791.061917	803.54596	764.815294	779.979638	767.834617	683.011691	745.011062	710.570803	723.900497	9284.91

Wexpro I New Drill

FLD-Z24 CCRK D8	88.1722549	85.5137839	80.6931477	74.0231302	72.7886562	67.2567034	66.5518494	63.8946538	55.5340767	59.2857538	55.4237193	55.4170862	824.555
FLD-Z24 ISLAND D8	119.814782	116.193577	109.429865	100.048836	97.9481966	90.0349042	88.5761314	84.5094055	72.9686135	77.3665858	71.8200926	71.2993519	1100.01
FLD-Z24 KNY FLD D8	15.9056206	15.5285042	14.7385341	13.5902717	13.4257266	12.4575554	12.3742991	11.922082	10.3957837	11.131577	10.435707	10.4619219	152.368
FLD-Z24 TRAIL D8	148.014079	143.957462	136.188535	125.220635	123.393129	114.237433	113.244054	108.904856	94.8028609	101.355842	94.8839673	94.9960776	1399.2
FLD-Z25 CCRK D8	0	0	0	0	0	0	62.1496443	53.8468373	43.2048798	43.2443581	38.3288734	36.640012	277.415
FLD-Z25 CHBT D8	0	0	0	0	0	18.1066624	53.2985267	45.678885	36.4200866	36.3100722	32.1007926	30.6346476	252.55
FLD-Z25 ISLAND D8	0	0	134.56372	247.174847	320.150928	280.98081	265.471246	244.402915	204.432682	210.677229	190.62461	184.897508	2283.38
FLD-Z25 PDW D8	0	0	0	0	36.2566682	99.9707753	88.5895144	78.2321868	63.6482711	64.3887699	57.556771	55.4057367	544.049
FLD-Z25 TRAIL D8	0	0	0	0	131.848896	205.424026	224.575876	200.099336	163.861309	166.583323	149.474168	144.319948	1386.19
Total	371.906736	361.193327	475.613802	560.057719	795.8122	888.46887	974.831141	891.491158	745.268563	770.34351	700.648701	684.07229	8219.71

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.65

Wexpro II

FLD-ALKALI 2ACQ	154.168248	158.188057	157.103177	151.015398	155.02199	149.051058	153.038564	152.078171	136.51009	150.211746	144.298159	148.103217	1808.79
FLD-ALKALI 2D8	73.9393161	73.6427281	71.1231559	66.5922348	66.6828133	62.6261313	62.8860542	61.1843032	53.8277774	58.1077053	54.8825069	55.3982649	760.893
FLD-CC SH 2ACQ	2.23975524	2.30215759	2.2899756	2.20438827	2.26583299	2.18116462	2.24197964	2.23016105	2.00372734	2.20673526	2.12431844	2.1835916	26.4738
FLD-CCRK 2ACQ	159.768772	163.88074	162.680451	156.266582	160.092215	153.806069	157.785911	156.651005	140.476805	154.41634	148.370423	152.226921	1866.42
FLD-CCRK 2D8	150.67282	153.044171	150.530944	143.363896	145.868236	139.062387	141.622722	139.636034	124.401833	135.899279	129.809659	132.437983	1686.35
FLD-CCRK 2Q50	0.69330462	0.71147303	0.70656548	0.67905655	0.69685164	0.66972094	0.68727132	0.6825308	0.6122271	0.67314742	0.64693953	0.66389305	8.12298
FLD-TRAIL 2ACQ	210.781847	216.056239	214.333586	205.779627	210.971299	202.57703	207.712522	206.118916	184.752934	202.998589	194.971212	199.961695	2457.02
FLD-TRAIL 2D8	318.05343	322.049131	315.825488	299.94736	304.376377	289.441195	296.352783	291.521059	259.142061	282.494366	269.290695	274.21178	3522.71
FLD-WHISKEY 2ACQ	15.9447727	16.3702443	16.2651825	15.6396859	16.0575184	15.4400281	15.8525314	15.751023	14.1356327	15.5499553	14.7623551	14.7425198	186.511
FLD-WHISKEY 2D8	94.2038646	95.8879221	94.5021068	90.1741896	91.9159651	87.7809614	89.5474784	88.4320828	78.9034575	86.3204938	82.566532	84.349808	1064.58
Total	1180.46613	1202.13286	1185.36063	1131.66242	1153.9491	1102.63575	1127.72782	1114.28528	994.766546	1088.87836	1041.7228	1064.27967	13387.9

Wexpro II New Drill

FLD-Z24 ALKALAI 2D8	224.273659	219.598526	208.960652	193.11483	191.157701	177.688821	176.783663	170.569076	148.927151	159.658202	149.840862	150.367871	2170.94
FLD-Z24 CCRK 2D8	36.6645809	35.5591105	33.5545514	30.780966	30.2676348	27.9672877	27.6741905	26.5692512	23.09268	24.6527364	23.0467902	23.0440309	342.874
FLD-Z24 TRAIL 2D8	146.345231	142.334351	134.653016	123.808782	122.001883	112.949415	111.967237	107.676962	93.7339675	100.213064	93.8141583	93.9250045	1383.42
FLD-Z25 ALKALAI 2D8	0	0	0	0	0	66.8690783	128.724033	112.512384	90.9415968	91.595124	81.6240541	78.3994478	650.666
FLD-Z25 CCRK 2D8	0	0	0	0	0	0	174.35482	150.544142	120.63352	120.715668	107.032143	102.386517	775.667
FLD-Z25 TRAIL 2D8	0	0	0	0	130.362306	203.107889	219.529959	195.673985	160.27593	162.966141	146.246914	141.217558	1359.38
Total	407.283471	397.491987	377.168219	347.704579	473.789525	588.582491	839.033902	763.5458	637.604845	659.800935	601.604921	589.340429	6682.95

Exhibit 14.66

Normal Temperature Case : Plan Year 2
MDth

	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	Total
Inject													
Clay Bsn 935	908.49	826.646	826.646	699.99	72.51909241	0	0	0	0	0	0	5.433275626	3339.72
Clay Bsn 988	574.005	516.677	516.677	437.505	39.2	0	0	0	0	0	0	0	2084.06
Clay Bsn 997	574.005	516.677	516.677	437.505	39.2	0	0	0	0	0	0	15.20064428	2099.26
Aquifers	0	0	0	151.0631787	266.7525968	0	0	0	0	200.1340297	0	0	617.95
MagnaLNG	48.833	26.691	18.212	0	0	0	0	0	0	0	0	0	93.736
Spire	540	298.1265471	312.9116122	0	0	0	0	0	0	0	0	0	1151.04
Total	2645.333	2184.817547	2191.123612	1726.063179	417.6716892	0	0	0	0	200.1340297	0	20.63391991	9385.78
Withdrawl													
Clay Bsn 935	0	0	0	0	0	0	1581	1581	1428	1187.778	0	5.379546507	5783.16
Clay Bsn 988	0	0	0	0	0	0	930	930	840	911.111	0	0	3611.11
Clay Bsn 997	0	0	0	0	0	0	930	930	840	911.111	0	15.05032663	3626.16
Aquifers	0	0	0	0	0	0	0	0	1373.0896	0	0	0	1373.09
MagnaLNG	25.83	26.691	26.691	25.83	26.691	30	31	31	28	31	30	30.861	343.594
Spire	0	0	0	0	0	0	682	682	616	20	0	0	2000
Total	25.83	26.691	26.691	25.83	26.691	30	4154	4154	5125.0896	3061	30	51.29087314	16737.1
Purchase Gas													
Spot	0	0	0	0	15	270	418.6014318	453.4907471	261.3875855	51.32193585	269.3403421	113.5457611	1852.69
Spot	0	0	0	0	0	565.1997758	1043.199402	1173.417663	195.5657078	7.176425066	0	0	2984.56
Spot	0	0	0	0	2.979112026	331.2807301	558.2856381	553.6284369	384.4327328	75.30651375	40.75529431	43.69564815	1990.36
Spot	0	0	0	0	0	0	2.393203941	8.580343255	6.127312722	0.737147592	0	0	17.838
Spot	2.665435285	0	0	0	581.1887091	1800	1860	1860	1680	1860	1685.428368	899.2924978	12228.6
Spot	0	0	0	0	0	310.0678271	493.7006017	505.820671	267.2065291	20.20785595	0	0	1597
Spot	0	0	0	0	0	0	195.861104	1550	1400	964.9762864	0	0	4110.84
Spot	0	0	0	0	0	486.2792903	866.1577515	1150.622008	149.0028352	68.26695328	422.3553054	143.3083129	3285.99
Spot	3.170534804	1.998990911	1.975782039	2.833501522	6.974772857	14.11604421	21.20585259	21.43188722	17.78910199	15.20787086	12.10494434	7.856710313	126.666
Spot	0	0	0	0	0	0	16.49985664	297.0823704	0	0	0.581997646	0	314.164
Spot	70.70240392	0	0	0	17.87306034	270.7433499	242.9141832	290	200	53.26567368	235.9302565	104.6425299	1486.07
Spot	0	0	0	0	25.9287947	461.9714605	765.7451368	731.8126357	115.3983193	34.40084607	391.2813044	60.16241596	2586.7
Spot	18.41700008	11.61200007	11.48299999	16.46099985	40.51799963	82.0029987	123.1940021	124.498998	103.3370012	88.34899952	70.32100043	45.64500021	735.839
Spot	180	0	0	0	0	0	64.19382346	88.1834728	0	0	8.542	0	340.919
Spot	0	0	0	0	0	140.0588373	217	196	146.9320083	15.81053278	0	0	715.801
Spot	0	0	0	0	0	163.0222993	279	252	198	12.60669186	0	0	904.629
Spot	1204.283004	440.432373	159.5682122	169.0260858	2073.462718	2160	2232	2232	2016	2232	2160	0	17078.8
Spot	53.50241371	14.17722281	13.11900628	42.46276756	111.6328993	542.3047862	1085.54124	1168.501195	349.3478344	295.3757531	465.8492815	146.1703592	4287.98
Base	0	0	0	0	0	1050	1085	1085	980	1085	0	0	5285
Total	1532.740792	468.2205868	186.1460005	230.7833547	2875.558066	8647.047399	11570.49323	13742.07043	8470.526968	6880.009486	5762.490095	1564.319236	61930.4

Required vs. Supply

Area	Class	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	Total
UT CENT	UT CENT GS COM	8.770	7.250	6.580	7.480	18.790	35.080	54.520	59.820	46.800	37.640	26.590	15.720	325.040
UT CENT	UT CENT GS RES	23.400	19.790	18.000	20.530	51.470	96.020	148.920	164.010	128.150	103.090	72.920	43.170	889.470
UT EUR	UT EUR GS COM	0.280	0.230	0.210	0.240	0.610	1.130	1.760	1.930	1.510	1.210	0.860	0.510	10.480
UT EUR	UT EUR GS RES	0.750	0.640	0.580	0.660	1.660	3.100	4.810	5.290	4.140	3.330	2.350	1.390	28.700
UT MYT	UT MYT GS COM	2.250	1.860	1.690	1.920	4.840	9.020	14.030	15.390	12.040	9.680	6.840	4.040	83.600
UT MYT	UT MYT GS RES	6.020	5.090	4.630	5.280	13.240	24.700	38.310	42.190	32.970	26.520	18.760	11.110	228.820
UT N	UT N GS COM	51.330	42.430	38.500	43.800	110.030	205.380	319.230	350.210	273.990	220.380	155.670	92.010	1902.960
UT N	UT N GS RES	136.970	115.860	105.390	120.210	301.360	562.180	871.870	960.240	750.280	603.580	426.930	252.740	5207.610
UT NEO	UT NEO GS COM	6.170	5.100	4.630	5.270	13.230	24.690	38.380	42.100	32.940	26.490	18.710	11.060	228.770
UT NEO	UT NEO GS RES	16.470	13.930	12.670	14.450	36.230	67.580	104.810	115.440	90.200	72.560	51.320	30.380	626.040
UT SC	UT SC GS COM	16.940	14.000	12.700	14.450	36.310	67.770	105.340	115.560	90.410	72.720	51.370	30.360	627.930
UT SC	UT SC GS RES	45.200	38.230	34.780	39.670	99.440	185.500	287.690	316.850	247.570	199.160	140.870	83.400	1718.360
UT SE	UT SE GS COM	3.560	2.940	2.670	3.040	7.630	14.240	22.130	24.280	19.000	15.280	10.790	6.380	131.940
UT SE	UT SE GS RES	9.500	8.030	7.310	8.340	20.900	38.980	60.450	66.580	52.020	41.850	29.600	17.520	361.080
UT SW	UT SW GS COM	51.960	42.960	38.970	44.340	111.370	207.900	323.140	354.500	277.350	223.080	157.580	93.140	1926.290
UT SW	UT SW GS RES	138.650	117.280	106.680	121.690	305.060	569.060	882.550	972.000	759.470	610.980	432.160	255.840	5271.420
UT VERN	UT VERN GS COM	2.980	2.460	2.240	2.540	6.390	11.930	18.550	20.350	15.920	12.800	9.040	5.350	110.550
UT VERN	UT VERN GS RES	7.960	6.730	6.120	6.980	17.510	32.660	50.650	55.790	43.590	35.070	24.800	14.680	302.540
UT WF	UT WF FS COM	124.100	110.810	109.240	128.260	172.970	156.300	191.190	205.880	186.150	172.200	147.460	136.120	1840.680
UT WF	UT WF FS IND	34.560	31.600	31.160	36.580	49.330	44.580	54.530	58.720	53.090	49.110	42.050	38.820	524.130
UT WF	UT WF GS COM	708.530	585.740	531.370	604.620	1518.730	2834.940	4406.430	4834.080	3782.010	3042.020	2148.770	1270.100	26267.340
UT WF	UT WF GS RES	1890.650	1599.290	1454.690	1659.350	4159.800	7759.870	12034.620	13254.420	10356.280	8331.420	5893.020	3488.650	71882.060
UT WF	UT WF IS COM	6.930	4.620	4.230	6.170	9.860	17.080	24.030	27.540	23.520	21.880	15.480	10.310	171.650
UT WF	UT WF IS IND	7.040	6.790	6.290	7.020	7.470	10.660	10.910	11.270	11.310	12.840	10.950	9.560	112.110
UT WF	UT WF NGV IND	19.570	15.710	18.130	16.430	15.400	14.750	14.880	15.000	15.000	17.460	18.370	18.260	198.960
WY E	WY E GS COM	7.060	4.450	4.400	6.310	15.530	31.380	47.190	47.820	39.730	33.940	26.960	17.520	282.290
WY E	WY E GS RES	11.370	7.130	7.060	10.120	24.900	50.500	75.850	76.560	63.560	54.330	43.210	28.060	452.650
WY EV	WY EV FS COM	6.070	5.360	5.540	6.520	7.380	11.490	12.710	12.490	12.030	11.840	8.890	6.270	106.590
WY EV	WY EV GS COM	8.360	5.280	5.210	7.480	18.400	37.170	55.890	56.650	47.060	40.200	31.940	20.750	334.390
WY EV	WY EV GS RES	13.470	8.440	8.360	11.990	29.490	59.810	89.840	90.690	75.290	64.350	51.180	33.240	536.150
WY EV	WY EV IS COM	1.970	0.320	0.500	0.690	1.700	3.800	4.980	6.230	5.790	6.610	4.760	1.870	39.220
WY GR	WY GR GS COM	5.240	3.300	3.260	4.680	11.520	23.280	35.000	35.470	29.470	25.170	20.000	13.000	209.390
WY GR	WY GR GS RES	8.430	5.290	5.240	7.510	18.470	37.450	56.250	56.780	47.140	40.290	32.040	20.810	335.700
WY KEM	WY KEM GS COM	1.770	1.120	1.100	1.580	3.890	7.870	11.830	11.980	9.960	8.500	6.760	4.390	70.750
WY KEM	WY KEM GS RES	2.850	1.790	1.770	2.540	6.240	12.660	19.010	19.190	15.930	13.620	10.830	7.030	113.460
WY N	WY N GS COM	1.200	0.760	0.750	1.080	2.650	5.350	8.050	8.160	6.780	5.790	4.600	2.990	48.160
WY N	WY N GS RES	1.940	1.220	1.200	1.730	4.250	8.610	12.940	13.060	10.840	9.270	7.370	4.790	77.220
WY RS	WY RS FS COM	6.070	5.360	5.540	6.520	7.380	11.490	12.710	12.490	12.030	11.840	8.890	6.270	106.590
WY RS	WY RS GS COM	8.690	5.480	5.420	7.770	19.120	38.640	58.090	58.880	48.910	41.780	33.190	21.570	347.540
WY RS	WY RS GS RES	14.000	8.770	8.690	12.460	30.660	62.170	93.380	94.260	78.250	66.880	53.190	34.550	557.260
WY RS	WY RS IS COM	1.970	0.320	0.500	0.690	1.710	3.800	4.980	6.230	5.790	6.610	4.760	1.870	39.230
WY RS	WY RS IS IND	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
WY RS	WY RS NGV IND	0.450	0.300	0.270	0.240	0.220	0.270	0.270	0.180	0.260	0.430	0.500	0.340	3.730
	Total	3421.450	2864.060	2624.270	3009.230	7293.140	13400.840	20682.700	22696.560	17814.530	14403.800	10262.330	6165.940	124638.850

Exhibit 14.67

Required vs. Supply

Fuel	Transport & Gathering	136.590	137.700	130.090	122.980	174.510	239.490	361.020	336.340	273.710	241.980	217.030	185.290	2556.730
Fuel	Withdrawal	0.000	0.000	0.000	0.000	0.000	0.000	17.630	26.840	15.920	6.430	0.000	0.000	66.820
	Total Fuel	136.590	137.700	130.090	122.980	174.510	239.490	378.650	363.180	289.630	248.410	217.030	185.290	2623.550

Inject	Clay Basin	1394.086	1395.000	1395.000	1168.848	0.000	0.000	0.000	0.000	0.000	0.000	1464.900	2390.100	9207.935
Inject	Aquifers	0.000	0.000	0.000	372.114	410.733	200.598	0.000	0.000	0.000	200.237	0.000	0.000	1183.682
Inject	Magna LNG	0.000	188.885	242.966	25.830	26.691	0.000	0.000	0.000	0.000	0.000	0.000	171.900	656.272
Inject	Spire	41.073	434.292	436.553	113.723	1.949	0.000	0.000	0.000	0.000	0.000	342.244	558.000	1927.834
	Total Injection	1435.159	2018.177	2074.519	1680.515	439.373	200.598	0.000	0.000	0.000	200.237	1807.144	3120.000	12975.723

Total Required	4993.199	5019.937	4828.879	4812.725	7907.023	13840.928	21061.350	23059.740	18104.160	14852.447	12286.504	9471.230	140238.123

Area	Class	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	
Supply	Spot	39.435	13.577	13.434	221.545	2945.114	5660.044	4971.755	5291.859	4145.615	5797.173	7053.879	4182.634	40336.064
Supply	Peak	0.000	0.000	0.000	0.000	0.000	1803.843	826.492	2352.778	577.792	719.923	0.000	0.000	6280.827
Supply	Base	300.000	238.266	220.247	300.000	310.000	1500.000	5301.000	5301.000	4788.000	1829.000	300.000	310.000	20697.514
	Total Take	339.435	251.843	233.681	521.545	3255.114	8963.888	11099.247	12945.637	9511.407	8346.096	7353.879	4492.634	67314.405

Withdrawl	Clay Basin	0.000	0.000	0.000	0.000	0.000	0.000	3441.000	3441.000	3108.000	1255.107	0.000	0.000	11245.107
Withdrawl	Aquifers	0.000	0.000	0.000	0.000	0.000	0.000	0.000	414.874	0.000	0.000	0.000	0.000	414.874
Withdrawl	Magna LNG	25.830	26.691	26.691	25.830	26.691	25.830	30.861	31.000	28.000	26.691	25.830	26.691	326.636
Withdrawl	Spire	0.000	0.000	0.000	0.000	1.900	0.000	682.000	682.000	616.000	20.000	0.000	0.000	2001.900
Production	Company	2094.880	2141.632	2108.044	1997.408	2034.525	1973.529	2058.148	2040.669	1827.562	2006.256	1925.530	1973.298	24181.483
Production	Wexpro I	1073.270	1094.939	1046.873	981.363	1025.153	1297.154	1649.629	1548.389	1325.140	1399.448	1298.632	1291.984	15031.975
Production	Wexpro II	1459.800	1504.904	1424.138	1286.569	1563.657	1580.529	2066.232	1956.165	1688.904	1798.854	1682.625	1686.608	19698.986
	Total	4653.780	4768.166	4605.747	4291.170	4651.927	4877.042	9927.871	10114.096	8593.606	6506.357	4932.618	4978.581	72900.960

Total Supply	4993.215	5020.009	4839.428	4812.715	7907.041	13840.929	21027.118	23059.733	18105.013	14852.453	12286.496	9471.215	140215.365

Exhibit 14.68

GENERAL IRP GUIDELINES/GOALS FOR GAS SUPPLY AND ENERGY EFFICIENCY RESOURCES

The Company has compiled a list of general guidelines to help direct the Company's daily decision-making processes with regard to gas supply and energy-efficiency resources. While some of these guidelines incorporate specific numeric targets from the PLEXOS modeling process this year, all are general and flexible in nature to accommodate the potential for variability in weather, markets, and operating conditions. Many are similar to those of previous years and have evolved from years of operating experience. When substantial changes in operating and/or market conditions occur, the Company uses the PLEXOS model to help assess the appropriate mix of market resources. The guidelines for the 2024-2025 gas-supply year are as follows:

- Produce approximately 58.9 MMDth of cost-of-service gas, recognizing the uncertainties associated with demand, operating conditions, and gas well productivity.
- Execute Distribution System Action Plan to ensure distribution system is adequate to serve firm customers.
- Produce the categories of cost-of-service gas as determined this year in the modeling exercise as contained in Exhibits 14.59 through 14.61, and also, subject to demand, operating conditions, gas well productivity, and the terms of the Trail Unit, Canyon Creek, and Vermillion Settlement Stipulations.
- Purchase a balanced portfolio of gas of approximately 66.7 MMDth.
- Continue to monitor and manage producer imbalances.
- Override the PLEXOS model utilization profiles when producer-imbalance considerations dictate.
- Maintain flexibility in purchase decisions since actual conditions will vary from the normal-case conditions in the modeling simulation.
- Review options for additional price stabilization to determine whether such measures are appropriate.
- Continue to promote cost-effective energy-efficiency measures in Utah and Wyoming.
- Contract to resolve peak-hour issues and to secure needed storage and transportation capacity.
- Continue operation of an on-system LNG facility to help provide system reliability for sales customers.

GLOSSARY

This Glossary is intended for convenience and reference use only. The operational provisions of the Tariff are controlling in any case where there is an inconsistency.

A

Aquifers

The three DEQP aquifer storage facilities at which the Company has Peaking Storage (PKS) contracts. The facilities are Leroy, Coalville, and Chalk Creek.

AFUE

Annual fuel utilization efficiency is the ratio of annual heat output of a furnace or boiler compared to the total energy consumed by a furnace or boiler. An AFUE of 90% means that 90% of the energy in the fuel becomes heat for the home or business.

ARC

Advanced rooftop controls are digital system that allow remote monitoring, and enables control of fan speed, economizer functions, and a thermostat, making it easier to maintain occupant comfort and system efficiency in commercial buildings.

B

base load

Gas required for non-seasonal purposes, such as water heating and cooking.

Bcf

One billion cubic feet

Bcf/D

One billion cubic feet per day

blowdown

The process of reducing pressure in a pipeline.

Btu

A British thermal unit, equivalent to the amount of heat required to raise the temperature of one pound of water one-degree Fahrenheit.

C

cf

Cubic feet

CIG

Colorado Interstate Gas, an interstate pipeline serving the Company.

class location unit

An onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometer) length of pipeline.

Close Interval Survey (CIS)

An inspection technique that includes a series of above ground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e., 2-100 feet) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

Company

Questar Gas Company

Compressed Natural Gas (CNG)

Natural gas that has been compressed to a high-pressure to increase the amount of gas that can be stored and transported in a vessel. Typical pressures are between 2,900-3,600 psig. CNG is generally used to describe the fuel that takes the place of gasoline or diesel fuel in a vehicle.

cost-of-service production

Production managed by Wexpro that is provided to the Company on cost-based rates.

D

degree-day (heating)

Heating degree day is a term that refers to a measurement of how far the average temperature extends below the base temperature of 65º Fahrenheit. The time period measured is normally a 24-hour day. It is a measurement that is used to calculate weather normalized usage. The heating degree day measurement is calculated by taking the difference between 65º Fahrenheit and average temperature for the period. Any positive difference means that the average temperature was below the base, and this difference is the heating degree days measurement for the period.

Any negative difference means that the average temperature was above the base; in this case, the heating degree days measurement is zero.

dekatherm (Dth)

A unit of heat equal to 1,000,000 British thermal units (Btu).

Design Day

A day with a daily mean temperature of -5 degrees Fahrenheit or lower in the Salt Lake valley.

DNG

Distribution Non-Gas

dry hole well

A well that is determined to not be productive based on a commercial test.

dry natural gas

Natural gas production not associated with any other liquid hydrocarbons.

Dth

Dekatherm

Dth/D

Dekatherms per day

E

ECM

Electrically commutated motors are ultra-high efficiency, programmable, brushless direct current motors typically in heating, ventilation, and cooling applications.

end devices

Electronic devices such as pressure transmitters on the tubing or casing. These can be temperature transmitters, pressure switches, high level switches, etc.

ERV

Energy Recovery Ventilation are devices which are used to recover energy contained in normally-exhausted building or space air and is then used to treat (or precondition) the incoming outdoor ventilation air in residential and commercial heating, ventilation, and cooling systems.

External Corrosion Direct Assessment (ECDA)

A four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline [§192.925 and NACE SP 0502-2008 Pipeline External Corrosion Direct Assessment Methodology].

Excess Flow Valve (EFV)

A small valve that automatically reduces the flow of gas if a customer or contractor accidentally breaks the service line while digging on the property.

F

Fitness for Service (FFS)

The pipeline’s ability to operate in a manner that ensures the safety of the people that live and work near pipelines, protects the environment, while dependably transporting natural gas from sources to markets. INGAA designed their FFS program to address previously untested pre-regulation pipeline, or pipelines built prior to federal regulations established March 12, 1970. The FFS program establishes a starting point for evaluation and remediation of pre-regulation pipeline in High Consequence Areas (HCAs) that lack traceable, verifiable and complete test records. Further, the FFS process defines a priority-based process, and includes a timeline for analysis, implementation and completion of the program.

firm

Firm service. The is priority distribution service from the utility that will not be curtailed in the event of a supply shortfall until all interruptible service has been curtailed.

FL

Feeder Line

fugitive methane emissions

Emissions of methane that are not captured and therefore are released to the atmosphere.

FOM

First of month as it refers to pricing indexes for gas supply purchasing.

G

gathering Lines

A pipeline that transports gas from a current production facility to a transmission line or main.

Type A

Gathering lines in class 2, 3, or 4 locations; and any of the following: metallic and the MAOP produces a hoop stress of 20% SMYS or more, the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part, or non-metallic and the MAOP is more than 125 psig.

Type B

Gathering lines in class 3 or 4 location, or class 2 location determined by methods described in CFR §192.8 and any of the following: metallic and the MAOP produces a hoop stress level less than 20% SMYS, or non-metallic and the MAOP is 125 psig or less.

Type C

Gathering lines in class 1 location with outside diameter greater than or equal to 8.625 inches and any of the following: metallic and the MAOP produces a hoop stress of 20% SMYS or more, the stress level is unknown segment is metallic and the MAOP is more than 125 psig, or Non-metallic and the MAOP is more than 125 psig.

Type R

Gathering lines in a class 1 or 2 location all other onshore gathering lines.

GHG Policy

Interim Greenhouse Gas (GHG) Emissions Policy Statement (PL21-3) released by the FERC on February 17, 2022.

Global Positioning System (GPS)

A system used to identify the latitude and longitude of locations using GPS satellites.

GNA

Gas Network Analysis, which refers to the types of engineering models used by the Company’s System Planning department to model pressures and flows throughout the entire system.

Gas Pipeline Advisory Committee (GPAC)

A committee of government, industry, and public representatives appointed by the Secretary of Transportation to advise PHMSA on rulemaking.

GS

The General Service rate schedule.

GW

Gigawatt

H

High Consequence Area (HCA)

An area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy.

HP

High Pressure. The distribution system that is connected to Gate Stations and moves gas to District Regulator Stations and High-Pressure customers. This system operates at or above 125 psig and the material mainly used for pipe is steel.

hydrostatic test

A method of pressure testing a pipe or fitting using water.

I

indications

An irregularity of the pipeline that may be the location of corrosion, 3rd party damage, or some other type of defect that may reduce the pipeline's strength, and has not been directly examined.

Internal Corrosion Direct Assessment (ICDA)

A process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas [§192.927].

IHP

Intermediate-High Pressure. This system is downstream of District Regulator stations and operates between 15 psig and 45 psig with an MAOP of 60 psig. The majority of DEUWI customers are connected to the IHP system by a network of steel and plastic pipe.

Integrity Management Continuous Improvement (IMCI)

A systematic process developed by INGAA and its members to improve the integrity of the interstate natural gas transmission system. The overall goal of the IMCI process is zero incidents. To achieve that goal, INGAA and its members have instituted a system for reassessing individual processes, ranking them in priority, and applying management system methodologies to improve performance. In general, IMCI extends IM processes and FFS to transmission pipelines outside of HCAs.

Interstate Natural Gas Association of America (INGAA)

A trade organization that advocates regulatory and legislative positions of importance to the natural gas pipeline industry in North America. INGAA is comprised of 27 members, representing the vast majority of the interstate natural gas transmission pipeline companies in the U.S. and Canada. INGAA members operate almost 200,000 miles of pipeline.

interruption

Period when gas service is unavailable to interruptible customers; or period when emergency sales restrictions apply to customers because of a major disaster or pipeline break.

J

JOA

Joint Operations Agreement, which refers to the document outlining maintenance responsibilities and operating conditions on a peak day at interconnect points (gate stations) between the Company and DEQP.

K

Kern River Gas Transmission (KRGT)

Interstate pipeline serving the DEUWI system.

kWh

Kilowatt hours

L

lf

linear feet.

liquefaction

The process of changing a substance, such as natural gas, to a liquid state.

LAUF

Gas volume that is lost and unaccounted for.

LNG

Liquified Natural Gas

loop

Any pipe that is meant to reinforce an existing area without replacing older or smaller pipelines.

M

MAOP

Maximum Allowable Operating Pressure, the maximum rated pressure at which a given Feeder Line is allowed to operate.

MAP

Meter Allocation Point. A receipt or delivery point on a pipeline.

MBCx

Monitoring-based commissioning is an evolution of the energy efficiency industry standard measure, known as retrocommissioning, whereby major building components and equipment are tuned up after a period of time in order to achieve efficiency gains. The difference between retrocommissioning and MBCx is that MBCx introduces software and analytics into the process to provide actionable information that can be used to optimize facility operations.

meter purge

Removing any air from the meter after any work has been performed (i.e. new meter, service replacement)

Mcf

One thousand cubic feet

Mcfd

One thousand cubic feet per day

Mcfh

One thousand cubic feet per hour

MDth

One thousand dekatherms

MDth/D

One thousand dekatherms per day

Mega Rule

Industry name given to PHMSA’s Rule making, “Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments”.

methane intensity

The amount of methane emissions divided by the total amount of methane produced or delivered.

MMBtu

One million British thermal units

MMcf

One million cubic feet

MMCfd

One million cubic feet per day

MMDth

One million dekatherms

MW

Megawatt

MWP

MountainWest Pipeline, an interstate pipeline serving the Company's system.

MWOP

MountainWest Overthrust Pipeline, an interstate pipeline utilized to flow gas to the Company's system.

N

Net Zero

A commitment to net zero carbon and methane emissions, which includes the following carbon and methane emissions: Scope 1 emissions are those directly from Dominion Energy's electric and natural gas operations. Scope 2 emissions are those emitted from electricity consumed but not generated. Scope 3 emissions include those from three material categories: electricity purchased to power the grid, fuel purchased for power stations and gas distribution systems, and consumption of sales gas by natural gas customers. Upstream emissions from fuel for power stations refers to natural gas, oil, and coal. Upstream emissions from fuel for gas distribution systems refers to gas for which the Company takes title.

non-GS

Includes all rate schedules other than GS (General Service).

Normal Case

A model scenario based on Normal Weather.

Normal Weather

20-year normal heating degree day period, spanning 20 years ending December 31, 2018, was approved by the Utah Public Service Commission in its order on docket number 19-057-02 dated, February 25, 2020.

NOx

Oxides of nitrogen, especially as atmospheric pollutants

NTSB

National Transportation Safety Board

O

operator service fee

The fees charged by Wexpro under the Wexpro under the Wexpro I and Wexpro II Agreements

opportunistic

Verification of material properties and attributes. If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following **opportunities**: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service.

P

pad drilling

The process of drilling multiple, directional wells from a single site of disturbance. Each well that is drilled from the pad is drilled during the time that the rig is at the pad location. Pad drilling drastically cuts down on the amount of land that would have to be disturbed as well as reduces the number of drill rigs needed for an operation. A typical multi-well pad can have 2 to more than 20 wells depending on various factors.

pigging

A pipeline inspection technique that uses devices known in the industry as smart pigs. These devices run inside the pipe and provide indications of metal loss, deformation and other defects. Also referred to as In-line inspection (ILI).

pneumatic device

Any tool or instrument that uses pneumatic power (either compressed air, or natural gas from the wellhead) to open/close a valve or controller.

Predicted Price

The average of the S&P Global forecast (North American Gas Regional Short-Term Forecast - 67 months) and the most recent NYMEX forward curves.

psi

Pounds per square inch

psia

Pounds per square inch absolute

psig

Pounds per square inch gauge

PHMSA

The Pipeline Hazardous Materials Safety Administration

purge procedure

The procedures that must be followed to remove air from the existing pipeline facilities.

Q

R

Remote Methane Leak Detection (RMLD)

A methane detection device that can detect methane and identify leaks up to 100 feet away from the gas source.

receipt point

The point at which measured gas enters the Company’s distribution system.

Reserved Daily Capacity (RDC)

The quantity of Natural Gas in Dth per day that MountainWest Pipeline is obligated to receive, transport and deliver to Shipper on a firm basis.

RNG

Renewable Natural Gas, which refers to recovered methane that is injected and blended into the Company’s system.

RSG

Responsibly Sourced Natural Gas is natural gas that has been certified as being produced using responsible practices including limiting emissions, water use, and land and community impacts.

S

Sales

Demand by customers receiving firm or interruptible sales service from the utility.

scraper facility

A vessel at a predetermined location that traps contaminates from the pipeline that have been removed by a pig (i.e. scraper). Contaminated fluids are then pumped from this vessel to a tanker truck for shipment to a treatment facility.

sphere facilities

Storage tanks for compressed natural gas or liquefied natural gas, that are spherical.

sendout

The volume of gas that enters the distribution system.

segmentation rights

The rights of a shipper to be able to utilize separate sections of a pipeline under a single contract.

span

A section of pipe that crosses an obstruction, such as a river, above ground.

stack-tested

When the exhaust stack on any burner or engine undergoes testing to verify its emissions are within the permitted limit.

steady-state models

These are gas network analysis models that are indicative of conditions at a particular moment in time due to conditions.

SWGA

System Wide Gathering Agreement. A gathering contract between Marathon Petroleum Corp and to the Company for Marathon Petroleum Corp to perform gathering and processing services for cost-of-service production.

T

Tap line

A high-pressure line extending from a feeder line to specifically serve a district regulator station or industrial customer. No other district regulator station or customer will be on this line.

Tariff

The published volume of rate schedules, conditions of service and billing provisions under which natural gas will be supplied to customers by the Company.

Tcf

One trillion cubic feet

temperature-adjusted

Gas demand that has been adjusted to a baseline of long-run average heating degree days.

token relief valve

A low-capacity relief valve intended to provide limited overpressure protection while reducing gas released to the atmosphere and providing an audible alert to an increase in downstream pressure beyond the regulator set point.

throughput

The total demand across the distribution system by customers of all service classes.

transportation

Demand by customer receiving transportation service from the utility.

U

unsteady-state models

These are gas network analysis models that are indicative of conditions over a period due to conditions.

upstream

This references the location on a pipeline based on the direction of flow. Gas flows from upstream to downstream.

UT Commission

Public Service Commission of Utah

V

W

well pads

A temporary site that is constructed for the use of a drilling rig during drilling operations. Well pads are generally constructed of local materials, such as gravel, and are reclaimed almost entirely after drilling operations. Depending on the number of wells to be drilled from a pad, they can range in size from less than an acre to over 5 acres.

WFS

Williams Field Services, an interstate pipeline serving the Company's system.

X

Y

Z