DOMINION ENERGY UTAH

INTEGRATED RESOURCE PLAN

Docket No. 23-057-02

(Plan Year: June 1, 2023 to May 31, 2024)

Submitted: June 13, 2023

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This Integrated Resource Plan (IRP) is submitted by Questar Gas Company dba Dominion Energy Utah in Utah, and dba Dominion Energy Wyoming in Wyoming. For purposes of this document, we refer to Dominion Energy Utah and Dominion Energy Wyoming collectively as “DEUWI” or “Company.” The Company is a subsidiary of Dominion Energy, Inc. (Dominion Energy) – one of the nation’s largest producers and transporters of energy, energizing the homes and businesses of nearly seven million customers in 16 states with electricity or natural gas.

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 over 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 1.27 MMDth at the city gates for the 2023-2024 heating season.

2. The Company forecasts a 2023-2024 IRP-year cost-of-service gas production level of approximately 56.5 MMDth assuming the completion of new development drilling projects (46% of forecasted demand).

3. The Company forecasts a 2023-2024 IRP-year balanced portfolio of gas purchases of approximately 65.6 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 2023 through February 2024 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 of the Magna Liquified Natural Gas (LNG) facility and plans to have the facility ready for withdrawals for the 2023-2024 heating season.

10. DEUWI is focusing on methane emission reduction programs and renewable natural gas projects as part of Dominion Energy's commitment to net zero carbon and methane emissions across its nationwide electric generation and natural gas operations by 2050 (Net Zero).[1] This program includes methane emissions programs 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 DEUWI system will be capable of meeting the demands of the 2023-2024 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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[1] Reference to Dominion Energy's commitment to Net Zero emissions by 2050 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 Dominion Energy consumes but does not generate. Scope 3 emissions include those from three material categories: electricity purchased to power the grid, fuel purchased for Dominion Energy's 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 Dominion Energy takes title.

INDUSTRY OVERVIEW

This planning document pertains to the natural gas distribution operations of Dominion Energy 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 and 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.

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.

The FERC Chairman Richard Glick's term ended January 2023. Willie L. Phillips was named Acting Chairman by President Biden. He is joined by Commissioner James Danly, Commissioner Allison Clements, and Commissioner Mark Christie. The seat of the fifth Commissioner is currently vacant.

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 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.[2]

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".[3] 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 May 2022, the US Energy Information Association (EIA) forecasted that the rising generation from wind and solar would reduce the generation from natural gas and coal power plants over the next two years. It projected that the share of generation from natural gas will fall from 37% in 2021 to 34% by 2023.[4]

In the more recent short-term energy outlook, the EIA reported that in 2022, Natural Gas accounted for 39% of U.S. electricity generation and now estimates that it will remain at 39% for 2023[5]. This is 5% higher than what it estimated for 2023 a year ago.

The report shows renewables will move from 20% in 2022 to 24% in 2023. The share of coal generation will drop from 20% to 17%, and nuclear generation will make up the rest at 19% in 2022 and 20% in 2023. It appears that EIA expects the percentage of gas fired generation to remain steady, and the increase in renewables to offset the decrease in coal production.

PRICING TRENDS

On May 5, 2022 the Henry Hub spot price for natural gas averaged $8.78 per MMBtu which was $3.06 per MMbtu higher than April 1, 2022.[6] In the May 2022 Short-Term Energy Outlook, the EIA explained that higher pricing was due to storage inventories below the five-year average, steady demand, driven by high LNG export levels, high electric power demand, and higher-than-normal residential and commercial demand due to a cool spring.

The Short-Term energy forecast for April 2023 anticipates that the Henry Hub spot price will average about $2.65 per MMBtu. Storage inventories have recovered and now sit above the

[2] FERC Updates Policies to Guide Natural Gas Project Certifications, February 17, 2022,

[3] "FERC, NERC encourage NAESB to convene gas-electric forum to address reliability challenges", FERC, July 29, 2022.

[4] "New renewable power plants are reducing U.S. electricity generation from natural gas", *U.S. Energy Information Administration*, 18 January, 2022.

[5] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* April 2023.

[6] "Short-Term Energy Outlook" U.S. Energy Information Administration, May 2022.

five-year average. The report indicates that natural gas prices will average less than $3.00 per MMBtu for the remainder of 2023, more than a 50% decrease from last year.[7]

However, the pricing trends for the western US have shown a significant variance from the rest of the US from October 2022 through the most recent heating season. Pricing in the western US was significantly higher throughout the heating season due to a low regional storage position, high demand due to increased natural gas power generation, and colder-than-average temperatures. Limited supply into southern California as a result of the El Paso Natural Gas Pipeline Line 2000 outage also contributed to high natural gas pricing in the area.[8]

PRODUCTION TRENDS

According to the EIA forecasts, U.S. dry natural gas production will reach 100-101 Bcf/d for the year 2023. This would represent an increase of approximately 2% from 2022.[9]

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 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 mid-April 2023, the number of gas-direct rigs was 159 compared to just 144 a year earlier.[10]

On January 30, 2023, the EIA released its annual report on natural gas proved reserves for the 2021 calendar year. The EIA reported that U.S. proved reserves of natural gas at year-end 2021 increased to a record high of 625.4 Tcf. Five states set record highs in proven reserves in 2021, including Alaska, which nearly tripled its proved reserves in 2021.[11]

President Joe Biden signed the Inflation Reduction Act into law on August 16, 2022. The act is intended to ensure that the US "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".[12]

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[7] "Short-Term Energy Outlook" *U.S. Energy Information Administration,* April 2023.

[8] "Kinder sees blast-damaged part of Arizona natgas pipe down for months", December 2023. https://www.reuters.com/markets/commodities/kinder-sees-blast-damaged-part-arizona-natgas-pipe-down-months-2021-12-01/

[9] "U.S. dry natural gas production set monthly records in 2022; we forecast annual record." *Energy Information Administration*, 9 December, 2022, https://www.eia.gov/todayinenergy/

[10] "North America Rig Count Current Week Data." *Baker Hughes*, 21 April,2023, http://rigcount.bakerhughes.com

[11] "Proved Reserves of Natural Gas Increased 32% in the United States during 2021." *Energy Information Administration,* 30 January 2023, https://www.eia.gov/todayinenergy/detail.php?id=55339

[12] "Inflation Reduction Act Guidebook." *The Whitehouse*, https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/

The Inflation Reduction Act is focused on providing incentives for clean energy in order to reduce overall US 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 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."[13]

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. Natural gas design capacity was lower in 2021, primarily due to Pacific Gas and Electric reclassifying a significant amount of its gas as base or "cushion" gas rather than working gas. Demonstrated peak capacity decreased in each of the regions in the lower forty-eight states. Demonstrated peak capacity fell 0.8% or 57 Bcf as of the November 2021 report period compared with the November 2020 report period.[14] The report with the November 2022 data has not yet been released.

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 2.1 below. Working gas in storage was 1.930 Bcf as of Friday April 14, 2023. Current volumes are 488 Bcf higher than the measure at this time last year, and 329 Bcf above the five-year average.[15]

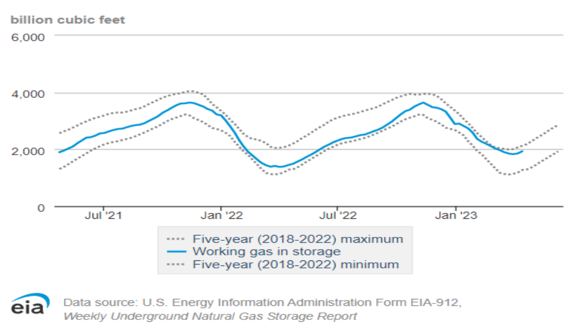

Figure 2.1: Working Natural Gas in Underground Storage as of April 14, 2023

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[13] "Climate bill's unlikely beneficiary: US oil and gas industry", *AP News*, August 18, 2022, https://apnews.com/article/biden-technology-science-oil-and-gas-industry-climate-environment-28df40ad9ebb33f4447815b6593673b3

[14] "Underground natural gas working storage capacity" *Energy Information Administration, https://www.eia.gov/naturalgas/storagecapacity/*. 31 August 2022.

[15] "Natural Gas Weekly Update." *Energy Information Administration, https://www.eia.gov/naturalgas/weekly/*, 20 April 2023.

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. U.S. LNG exports peaked in March of 2022 at 11.7 Bcf/d. Freeport LNG terminal shut down due to a fire in June 2022 which reduced exports to 10.0 Bcf/d from June 2022 through December. The EIA forecasts U.S LNG exports to exceed 12 Bcf/d this year and to increase to approximately 14 Bcf/d by December 2024 when some LNG export projects under construction are expected to be operating[16].

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 more than 20% of the U.S. natural gas value chain. Participating companies include: Antero Resources, Apache, Arsenal Resources, Ascent Resources, Atmos Energy, Berkshire Hathaway Pipeline Group, BKV Corporation, Black Bear Transmission, Black Hills Energy, Blue Racer Midstream, Boardwalk Pipeline Partners, LP, Caerus Oil and Gas, ConEdison, Crestwood, Dominion Energy, DT Midstream, DTE Energy, Duke Energy, Enbridge Inc., Encino Acquisition Partners, Enstor, Equitrans Midstream Corporation, EQT, Flywheel Energy, Forge Energy II, 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, Sempra Energy, Sheridan Production, Southern Company Gas, Southern Star Central Gas Pipeline, Southwestern Energy, Spire, Summit Utilities, Targa, TC Energy, Terra Energy Partners, UGI Utilities, Inc., WBI Energy, Western Midstream, WhiteWater, Williams, WTG and Xcel Energy.

One Future's mission is to "reduce member company methane emissions across the value chain to 1% (or less) by 2025". This will preserve "the future of natural gas as a long-term sustainable fuel. This mission will help to preserve the industry's leadership in energy production and reduction of emissions".[17]

The members of One Future had a total 2021 methane intensity listed at 0.462%, according to the One Future 2022 Methane Intensity Report. Methane Intensity is the amount of methane emissions divided by the total amount of methane produced or delivered. This means that "members are 99.54% efficient in delivering a molecule of gas from the rig to the burner tip." The member distribution companies reported a methane intensity of only 0.113%. This beat the stated goal of 0.225% by 50%.[18]

[16] "Liquefied natural gas will continue to lead growth in U.S. natural gas exports" *Energy Information Administration, https:/eia.gov/todayinenergy/detail.php?id-55741,* 8 March, 2023.

[17] https://onefuture.us/who-is-one-future/

[18] https://onefuture.us/2022-methane-emissions-intensity-report/

Dominion Energy has a stated vision to become the most sustainable energy company in the country. A discussion of the Company's current sustainability efforts is included in the Sustainability section of this report.

Responsibly Sourced Natural Gas (RSG)

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 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 2.2, RNG is obtained by capturing and utilizing the methane that would normally be emitted from these waste streams.

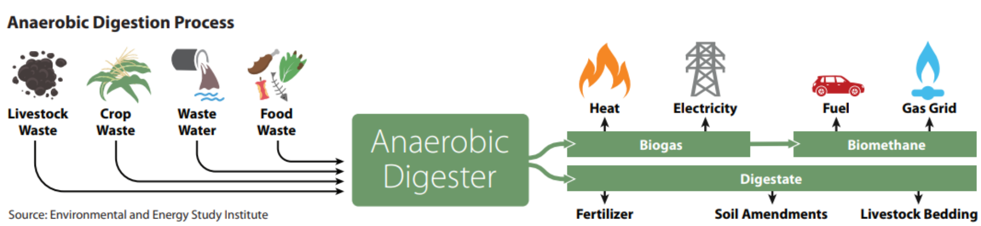


Figure 2.2: RNG

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 2.3 shows the potential Utah production by feedstock.[19]

[19] Renewable Natural Gas: A Sustainable Approach to the Energy Transition, January 2022. Renewable Natural Gas: A Sustainable Approach to the Energy Transition (utah.edu)

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 2.3: 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.[20]

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.[21] 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 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.[22]

As shown in Figure 2.4, 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".[23]

[20] "Hydrogen explained." 20 January, 2022. https://www.eia.gov/energyexplained/hydrogen/#:~:text=However%2C%20hydrogen%20is%20useful%20as,greater%20use%20in%20the%20future.
[21] "Hydrogen Basics." May 2022. https://www.nrel.gov/research/eds-hydrogen.html
[22] "Hydrogen Fuel Basics." https://www.energy.gov/eere/fuelcells/hydrogen-fuel-basics
[23] "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/

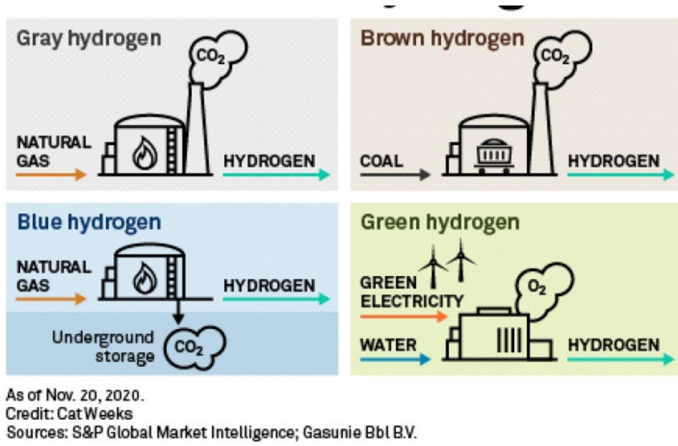


Figure 2.4: The Colors of Hydrogen

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. Dominion Energy, 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 October 2021, there were about 166 fuel cell electric generators operating in the United States. These smaller units have a total production capacity of 260 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 resources.[24] Figure 2.5 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 US Department of Energy (DOE) with the intent to provide a resource to for users and suppliers on hydrogen to coordinate.[25] These projects represent different parts of the hydrogen value chain.

[24] “Hydrogen explained.” 20 January, 2022. https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php
[25] “H2 Matchmaker”, https://www.energy.gov/eere/fuelcells/h2-matchmaker

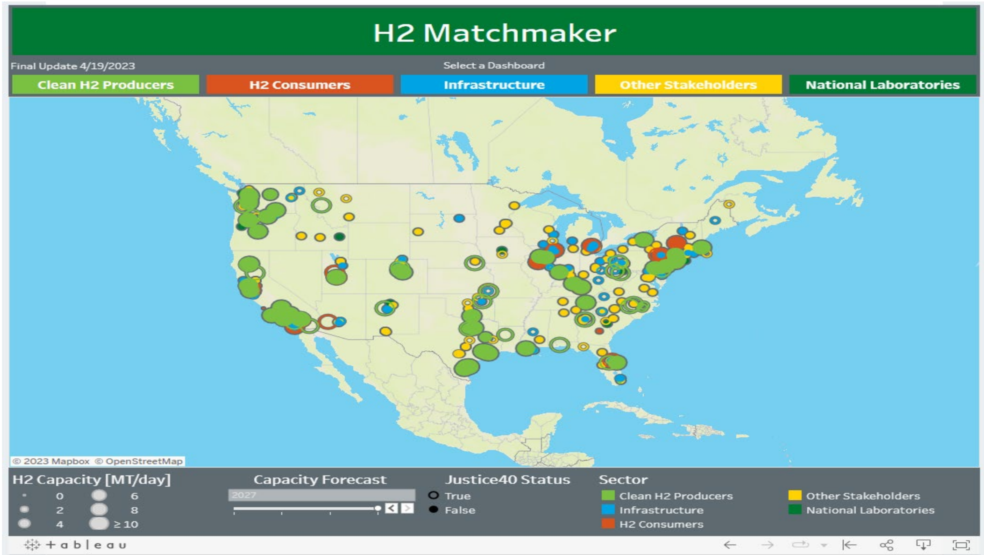


Figure 2.5: U.S. Hydrogen Projects – DOE "H2 Matchmaker" Map

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.[26]

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.[27]

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

[26] "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
[27] "Mountain West States Sign MOU to Develop Clean Hydrogen Hub." 24 February, 2022. https://energy.utah.gov/2022/02/24/hydrogen-hub-mou/

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."[28]

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)
- DEUWI'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

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.[29] 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

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

[29] "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.

reviewing such plans."[30] 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.[31]

The Company filed its 2022-2023 IRP on June 15, 2022, with the Wyoming Commission. Commission Staff solicited written public comments on the IRP filing by noticing the matter on the Wyoming Commission's open meeting agendas indicating that comments on the IRP were due on November 10, 2022, and that reply comments were due on December 13, 2022. No public comments were received.

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.[32] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[33]

On June 15, 2022, the Company filed its IRP for the plan year, June 1, 2022, to May 31, 2023 (2022-2023 IRP). A technical conference was held on June 28, 2022, to discuss the 2022-2023 IRP with regulatory agencies and interested stakeholders. On September 1, 2022, the Utah Office of Consumer Services (Office) filed its IRP comments.[34] The Utah Division of Public Utilities (Division) also submitted its report and recommendation on September 1, 2022.[35]

On January 6, 2023, the Utah Commission issued its Report and Order on the 2022-2023 IRP (Commission Order). The Utah Commission found that "the 2022 IRP generally complies with the Standards and Guidelines." The Commission acknowledged that the

[30] 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).

[31] 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.

[32] "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.

[33] "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.

[34] Memorandum titled, "In the Matter of: Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2022 to May 31, 2023," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Bela Vastag, Utility Analyst, Alex Ware, Utility Analyst, September 1, 2022.

[35] Memorandum titled "Docket No. 22-057-02, Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2022 to May 31, 2023,", To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Artie Powell, Manager, Doug Wheelwright, Utility Technical Consultant Supervisor, Eric Orton, Utility Technical Consultant, Date: September 1, 2022.

2022-2023 IRP met the Standards and Guidelines without additional comments or requirements.

On January 9, 2023, 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. With no outstanding concerns resulting from the Commission Order, the participants discussed just a few issues of concern including the following.

- The parties discussed how usage at the Lakeside Power Plant is reported in the IRP. The Company clarified that usage for the facility is included as “Electric Generation” in the Customer and Gas Demand section of the IRP.

- The Company confirmed that an update on the operations of the LNG facility would be included in the 2023-2024 IRP and presented as a topic in an IRP Technical Conference.

- The Company confirmed that a discussion on the supply/pricing situation that occurred during the heating season would be included in the 2023-2024 IRP and presented as a topic in an IRP Technical Conference.

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.

On January 24, 2023, the Utah Commission held an IRP technical conference in conjunction with the development of the 2023-2024 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission’s 2022 IRP Order
- Pricing Update

The Utah Commission held another technical conference on April 4, 2023. The attendees discussed the following topics:

- System Integrity (See in the Integrity Management section of this report)
- Rural Expansion Update (See the Distribution Action Plan section of this report)

Part of the April 4, 2023, technical conference was confidential. During the confidential part of the meeting, the following topics were discussed:

- Wexpro Matters (See the Cost-of-Service section of this report)

The Utah Commission held another technical conference on April 25, 2023, where the following topics were discussed:

- Heating Season Review (See below for a review of the 2021-2022 heating season)
- Gas Supply Hedging (*S*ee the Purchased Gas section of this report)

- Transportation and Storage Planning (See Gathering, Transportation and Storage section of this report)
- LNG Operations Update (See Gathering, Transportation and Storage and Supply Reliability sections of this report)

The Utah Commission held another technical conference on May 2, 2023, where the following topics were discussed:

- IRP Project Detail Discussion (See the Distribution Action Plan section of this report).
- Long-Term Planning Update (See the System Capabilities and Constraints section of this report).
- Sustainability Update (See the Sustainability section of this report).

Part of the May 2, 2023, technical conference was confidential. During the confidential part of the meeting, the following topics were discussed:

- Annual Supply Request for Proposal (RFP) (See the Purchased Gas section of this report)

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 11, 2023, to discuss the 2023-2024 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;

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; and

4. To provide the framework by which the Company will become the most sustainable natural gas company in the country.

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.

2022-2023 HEATING SEASON REVIEW

The 2022-2023 heating season was a period of high demand, increased price volatility and high natural gas costs. The period between October 1, 2022 and March, 31 2023 was over 4% colder-than-normal. Most of the days in that period were colder-than-normal with just a short period of warmer-than-normal temperatures in late December and Early January. The demand during this period was more than 10% above normal.

While this time period had a number of cold events, the most significant was during January 30 to February 1, 2023. January 30 and 31, 2023 were the Company's two highest demand days in history. In all, the Company experienced seven of the 20 highest historical total demand days on the DEUWI system during this period.

The other major development through the heating season was increased volatility in the natural gas markets. During the summer of 2022, pricing throughout the country was also elevated because demand outpaced production, primarily due to increased LNG production and high global pricing resulting from the war in the Ukraine. Natural Gas price volatility increased significantly during the 2022-2023 heating season with daily pricing at the Kern, Opal index reaching above $50 for one day and above $30 for multiple days. Local monthly indexes for January were also near $50.

While temperatures in the eastern U.S. and much of the world became more moderate and the associated volatility and high pricing subsided, the opposite occurred in the western U.S. Storage inventory in the western and pacific regions were low as a result of any factors including high pricing, a change in storage operations in California, a continued outage on a major pipeline supplying southern California, and resultant reduced supply to that market. The western U.S. concurrently experienced a cold winter with increased demand. These factors, together, resulted in increased price volatility and high prices in the western natural gas markets. In December, 2022, daily prices at the Kern, Opal index exceeded $52 per Dth. This daily volatility and the forecast of extended cold temperatures also resulted in monthly indexes for January 2023 reaching near $50.

The Company expects this volatility to continue in the near future and is proposing to continue with additional hedging as a result. This is discussed in more detail in the Purchased Gas section of this report.

CUSTOMER AND GAS DEMAND FORECAST

EFFECTS OF COVID-19

The decline in demand within the non-residential class of customers that resulted from the COVID-19 pandemic has been largely reversed. Total demand by the commercial class during the November/ December 2022 billing cycles was 10% higher than the same period in 2021. At that point usage had begun to recover from the trough period observed in March 2021. Annual usage per customer among the largest subset of commercial customers, the commercial GS class, was at 429 Dth at the end of 2022; that is three Dth above the level in March 2020 when the effects of the halt in public activity were nascent, and it is 26 Dth higher than the trough period average that was observed one year later. Industrial demand is 6% lower than its 2020 level. It seems unlikely, however, that the sustained reduction is attributable to some lingering effect of pandemic-induced economic trauma; that shock has generally faded with the resumption of normal commercial and industrial operations that were temporarily suspended.

Overall residential demand did not negatively respond to the pandemic; rather, it has seen a 7% increase since the end of 2019 with the addition of 85,000 new service agreements during that three-year span.

The Company believes that the demand response to the temporary shock from COVID-19 has faded and expects overall demand to sustain its growth as the residential customer base expands and new commercial establishments follow. Given this expectation, a segment highlighting potential COVID-19 demand response will not be included in coming versions of the IRP document. Should any alteration in the long-run trajectory of demand become evident, it will be addressed in subsequent segments of this section.

SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2022-2023 IRP AND ACTUAL RESULTS

On a temperature-adjusted basis, the Company’s estimated natural gas sales through the IRP year ending May 2023 is 121.2 MMDth. The Company forecasted a total of 118.3 MMDth for the period in last year’s IRP. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2022-2023 IRP year at 225.8 MMDth. Last year’s IRP projected 219.9 MMDth for the same period.

TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2023-2024 IRP YEAR

The forecasted level of sales demand for the 2023-2024 IRP year is 123.1 MMDth, an increase of about 1.5%, resulting chiefly from continued growth in the GS customer base, both residential and commercial. The pace of residential growth in the single-family dwelling sector is slowing as high interest rates and home prices force many would-be buyers to delay. But Utah is still facing a housing inventory shortage that will perpetuate year-to-year growth in the customer base and gas demand. Sales demand is projected to reach 135.4 MMDth in the 2032-2033 IRP year (see Exhibit 3.10).

When this forecast was completed, six sales customers had notified the Company of intent to shift to transportation service in 2023, and about 50 transportation service customers had given notice of intent to return to sales service at the same time. On a temperature-adjusted basis, the net effect is an annual sales demand increase of approximately 461,000 Dth. This year's forecast does not assume further shifting beyond the 2023-2024 IRP year.

The 2023-2024 IRP sales forecast of 123.1 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 1.2 million GS customers at the end of the 2023-2024 IRP year and 1.4 million GS customers by the end of the 2032-2033 IRP year (see Exhibit 3.1). The Company forecasts annual Utah GS usage per customer at 99.5 Dth in the 2023-2024 IRP year and 92.4 Dth by end of the 2032-2033 IRP year (see Exhibit 3.2). Annual Wyoming GS usage per customer is projected to be 120.8 Dth in the 2023-2024 IRP year and 117.1 Dth at in the 2032-2033 IRP year (see Exhibit 3.5).

The Company forecasts system total throughput in this year's forecast to increase from 228.0 MMDth during the 2023-2024 IRP year to 240.4 MMDth by end of the 2032-2033 IRP year (see Exhibit 3.10).

RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

Utah

The Company's residential customer base in Utah saw its third consecutive year of strong growth with 27,364 net additions through the 12 months ending December 2022. Higher mortgage rates coupled with high home prices are slowing activity in the single-family housing market. But overall housing demand in Utah continues to exceed supply and is fueling ongoing investment in new multi-unit housing. Nearly half of the Company's new residential service agreements in Utah (45%) established during 2022 were multi-family unit connections.

The Company is forecasting healthy growth through the forecast horizon, albeit at a decelerated pace as the surge in the single-family home market that was fueled by low interest rates and high demand continues to dissipate. 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 just over 23,000 new additions through the 2023-2024 IRP year and about 22,000 through the following year. The rate of growth is anticipated to stabilize from 2025 onward with around 24,000 additions per year. Multi-family units are expected to occupy a comparatively high percentage of new residential additions, an average of 40%, throughout the forecasted period, with the first two years realizing the highest percentage – approximately 50%.

Actual temperature-adjusted residential usage per customer for the 12 months ending December 2022 was 78.6 Dth. The Company projects an average of 77.2 Dth through the 2023-2024 IRP year. The overall downward trend in average consumption is expected to continue through the 2032-2033 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 2022 the Wyoming residential customer base added 106 new service agreements. The Company forecasts just under 100 new additions through the 2023-2024 IRP year and about 120 the following year. Moderate growth of 120 to 140 additions per year is expected thereafter as uncertainty in the natural resources sector of the region's economy restrains higher growth.

The average annual usage per residential customer in Wyoming was 82.7 Dth in calendar year 2022. The Company forecasts an average of 81.8 Dth during the 2023-2024 IRP year and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. The 2032-2033 IRP year ends at 78.6 Dth (see Exhibit 3.6).

SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

Utah

The average temperature-adjusted usage among Utah GS commercial customers ended 2022 at 428.8 Dth, an increase of 18 Dth over 2021 and 25 Dth above the March 2021 low point following the onset of the Covid-19 pandemic. Last year also saw healthy growth in Utah's commercial GS base with a net gain of 1,300 service agreements.

This year's forecast assumes that the usage recovery is sustained and that further long-term decline in average usage is attributable to efficiency improvements. Total demand will increase as the customer base continues to grow. The Company forecasts just over 900 net additions through the 2023-2024 IRP year and about 850 the following year. About 50 of this year's additions are existing transportation service customers that will shift to GS service in July. That shift will add over 300,000 Dth annually to commercial GS demand. No further shifting beyond 2023 is assumed in this forecast.

Wyoming

Temperature-adjusted usage among commercial GS customers in Wyoming for the 12 months ended December 2022 averaged 434.9 Dth, an increase of nearly 6 Dth from the end of 2021 and 15 Dth above the low point in March of that year. As in Utah, this increase in average usage suggests that the commercial demand response to the economic shock from COVID-19 has played out. The customer base added just under eight service agreements through 2022.

The Company forecasts about 10 customer additions per year through the forecast horizon. Average annual usage in the coming IRP year is expected to continue to climb to a pre-pandemic level of about 446 Dth during the 2023-2024 IRP year and remain there through the following year.

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

The Company projects demand in the non-GS commercial and industrial sectors at 55.8 MMDth in the 2023-2024 IRP year. The subsequent years will hold steady after a net transfer of just under 330,000 Dth annually from transportation service to the GS commercial class. No shifting after the 2023-2024 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. A marked increase in baseload generation observed in 2022 has been carried forward through the forecast horizon.

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 2018-2019 through 2022-2023. Design Day conditions did not occur during those periods; however, January 30, 2023 saw the highest total sendout on record.

The firm sales Design Day gas supply projection for the 2023-2024 heating season is 1.27 MMDth and grows to 1.40 MMDth in the winter of 2032-2033. 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 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 ≥ 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 2,000 dual-fuel heating systems in 2022 and expects to rebate over 3,000 in 2023. 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 are 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 DEUWI 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 North American Energy Standards Board (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.[36]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 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, and volumes that are unaccounted for during the same period. The updated average is 0.678% and reflects meter-level compensation for temperature and elevation in the Utah service territory that began in August of 2010 and in the Wyoming service territory in October of 2012.

The current calculation for the most recent three years is included in

Table 3.1.

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

Year	DEUWI Customer Sales	DEUWI Customer Transport.	Total Receipts	DEUWI Sales & Transportation	DEUWI Use Acct. 810&812	DEUWI Loss Due to Tearouts	DEUWI Lost & Unaccounted for Gas	Total Sales, Transport, Company Usage and L&U
2019-2020	113,189,937	93,799,591	206,989,528	205,868,216	90,617	44,984	985,712	206,989,528
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
Total	**341,870,555**	**299,902,854**	**641,773,409**	**637,424,586**	**190,773**	**107,300**	**4,050,750**	**641,773,409**

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

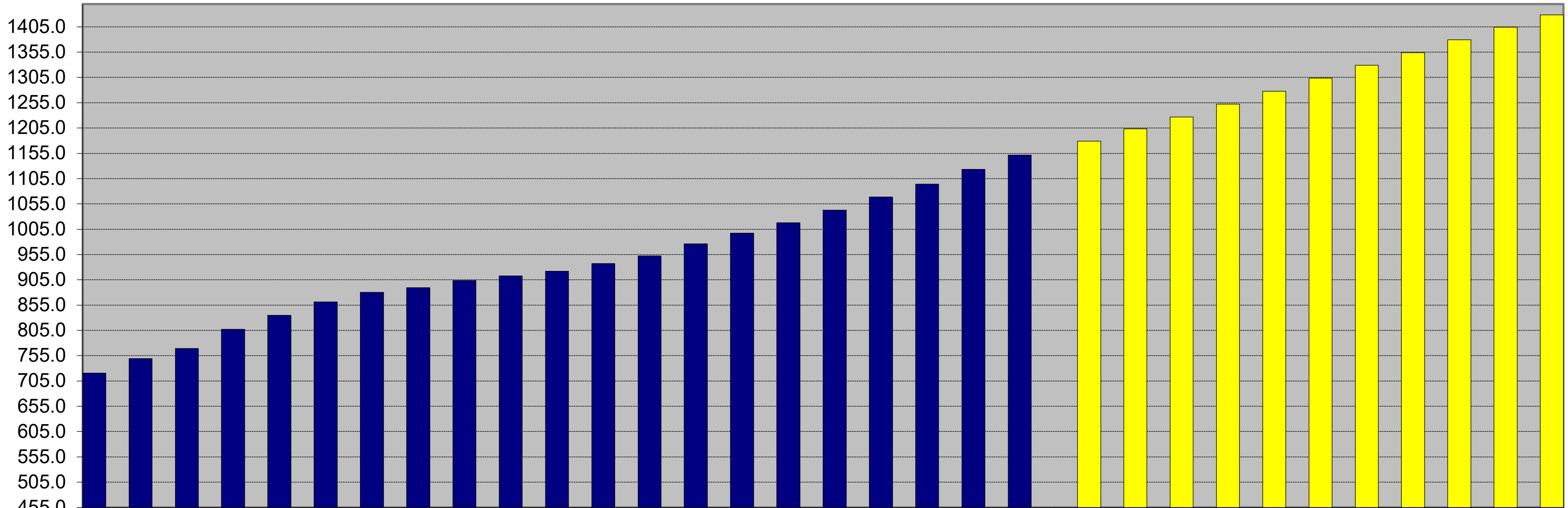
Lost-&-Unaccounted-For-Gas %	0.631%	Company Use and Lost-&-Unaccounted-For-Gas %	0.678%

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)

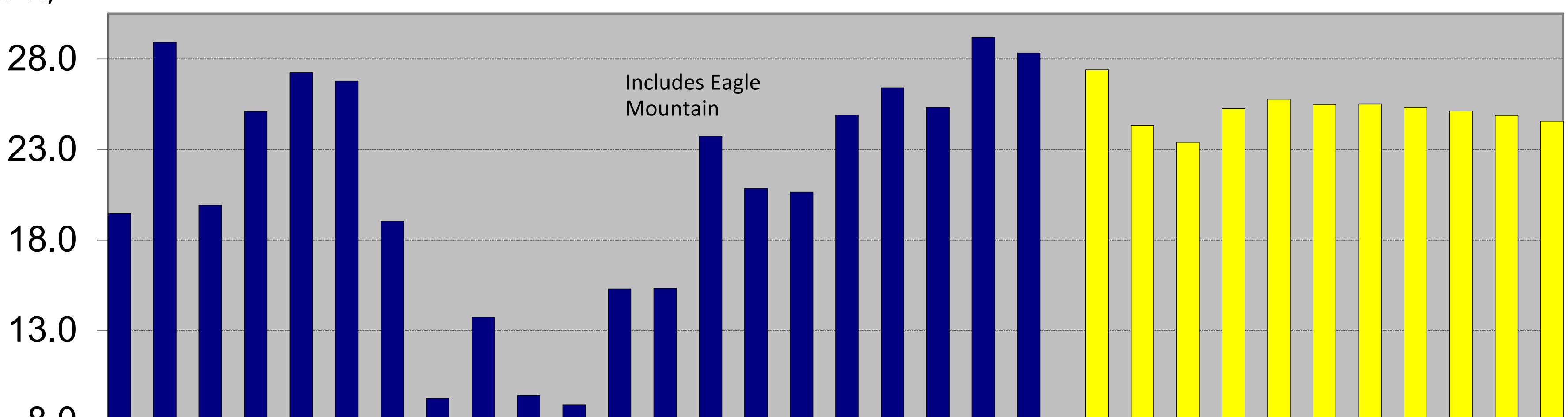


	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
ACTUAL	720.5	749.4	769.3	807.4	834.7	861.4	880.5	889.7	903.5	912.8	921.7	937.0	952.4	976.1	996.9	1017.6
FORECAST																

	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
ACTUAL	1042.5	1068.9	1094.2	1123.4	1151.7											
FORECAST						1179.1	1203.5	1226.8	1252.1	1277.9	1303.4	1328.9	1354.2	1379.3	1404.2	1428.7

SYSTEM GS ADDITIONS

Customers (Thousands)



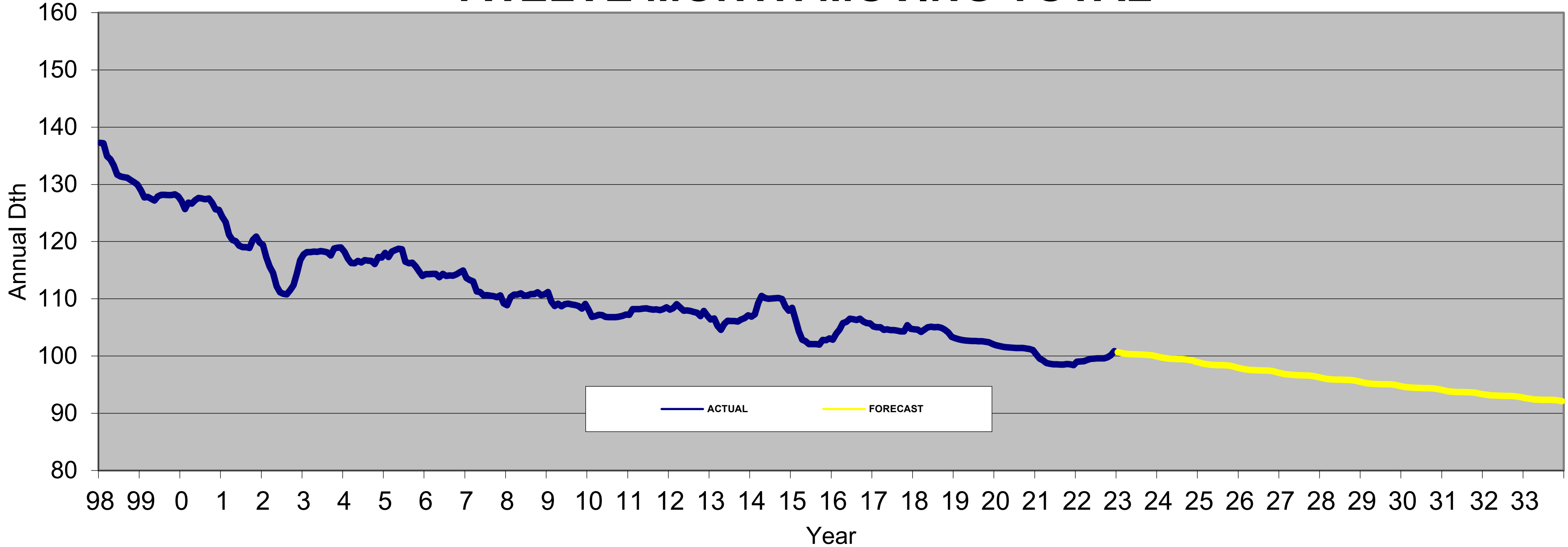
	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
ACTUAL	19.5	28.9	19.9	25.1	27.3	26.8	19.0	9.2	13.7	9.4	8.9	15.3	15.3	23.7	20.8	20.6
FORECAST																

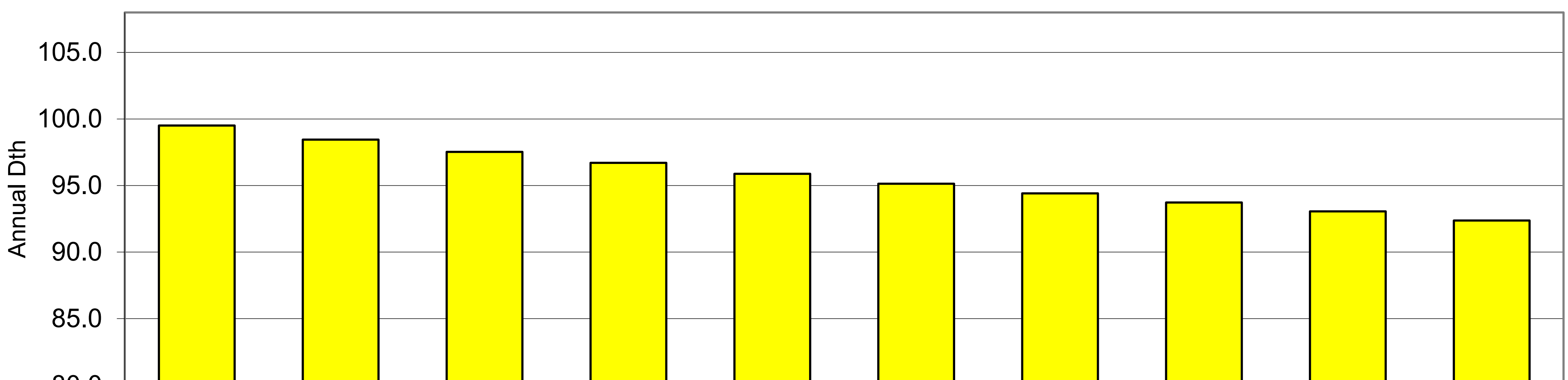
	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33
ACTUAL	24.9	26.4	25.3	29.2	28.3											
FORECAST						27.4	24.3	23.4	25.2	25.8	25.5	25.5	25.3	25.1	24.9	24.6

Exhibit 3.1

UTAH GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





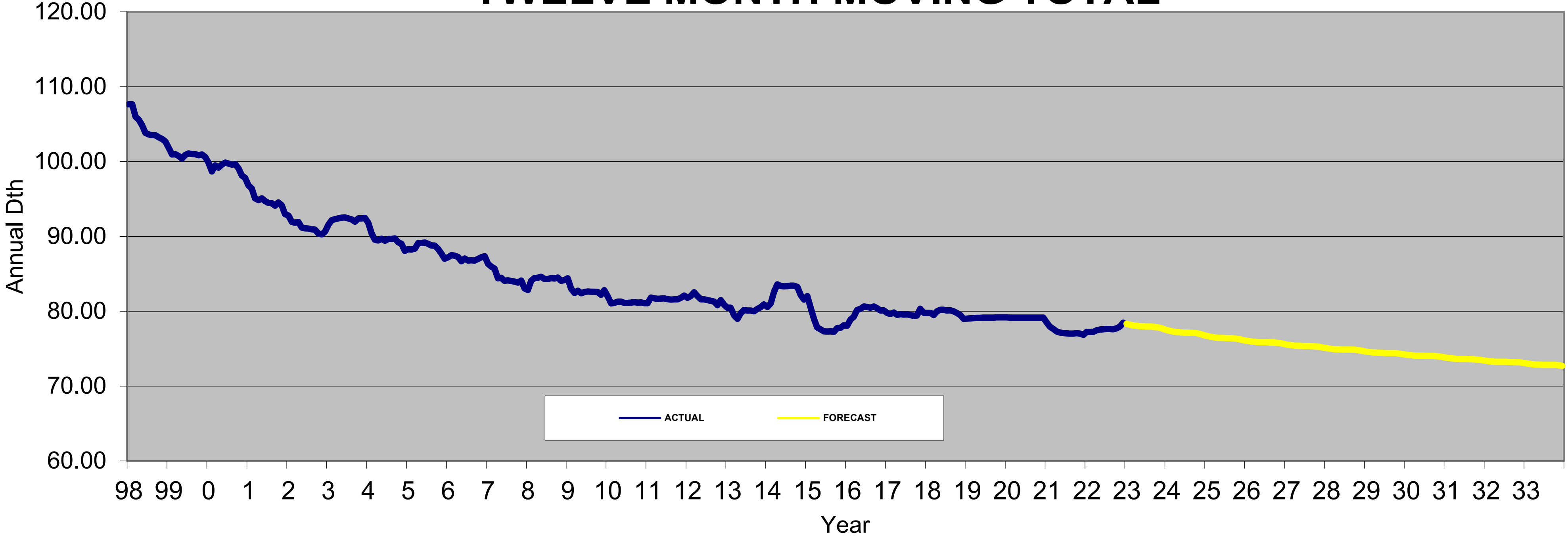
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
FORECAST	99.5	98.5	97.5	96.7	95.9	95.1	94.4	93.7	93.1	92.4

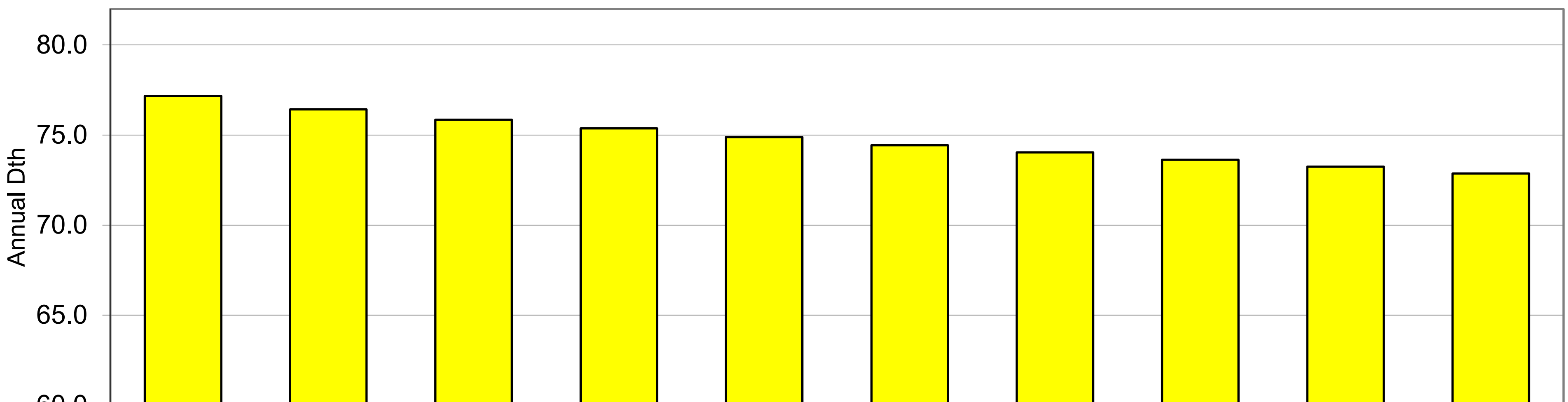
IRP Year

Exhibit 3.2

UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





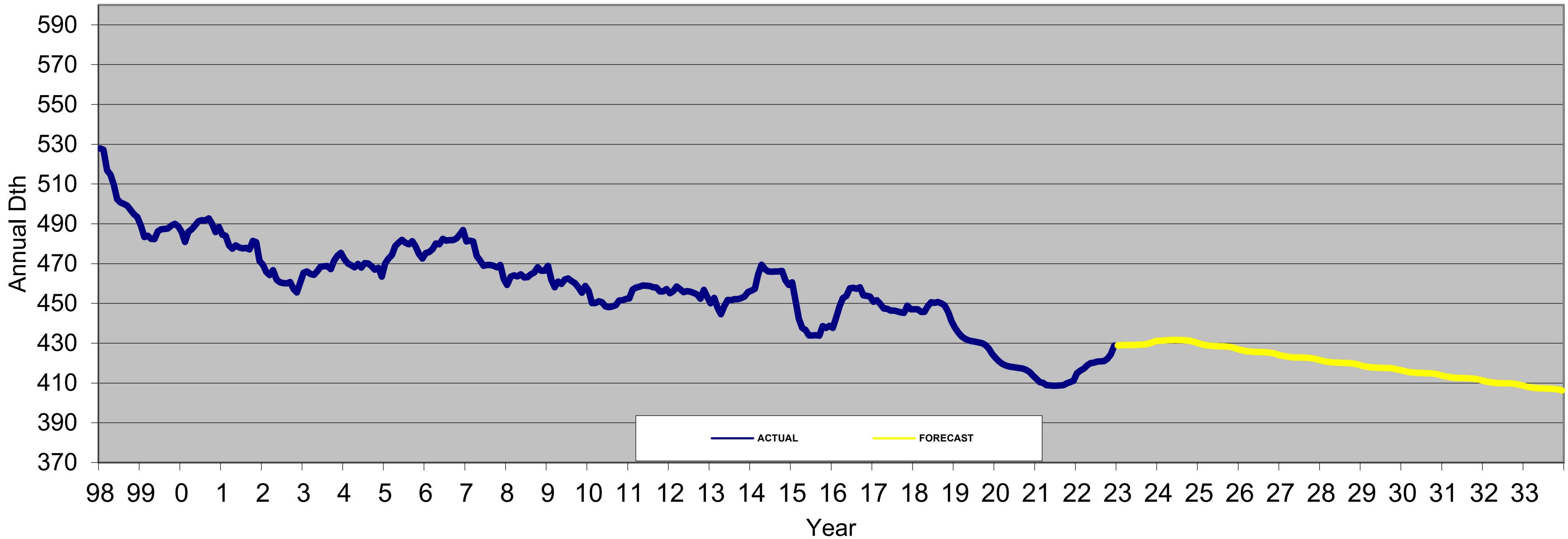
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
FORECAST	77.2	76.4	75.9	75.4	74.9	74.4	74.0	73.6	73.2	72.9

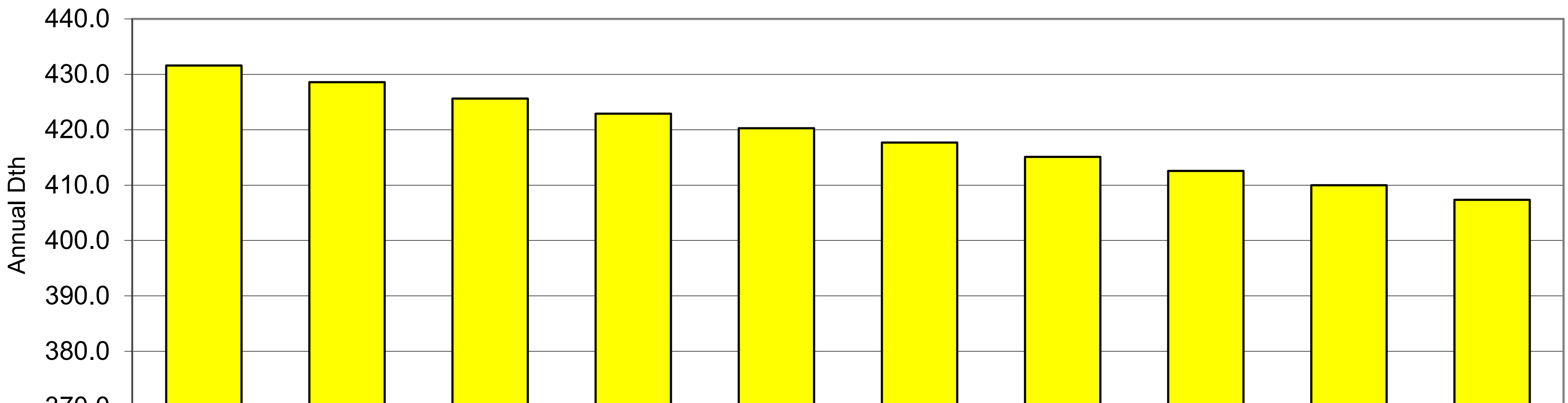
IRP Year

Exhibit 3.3

UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





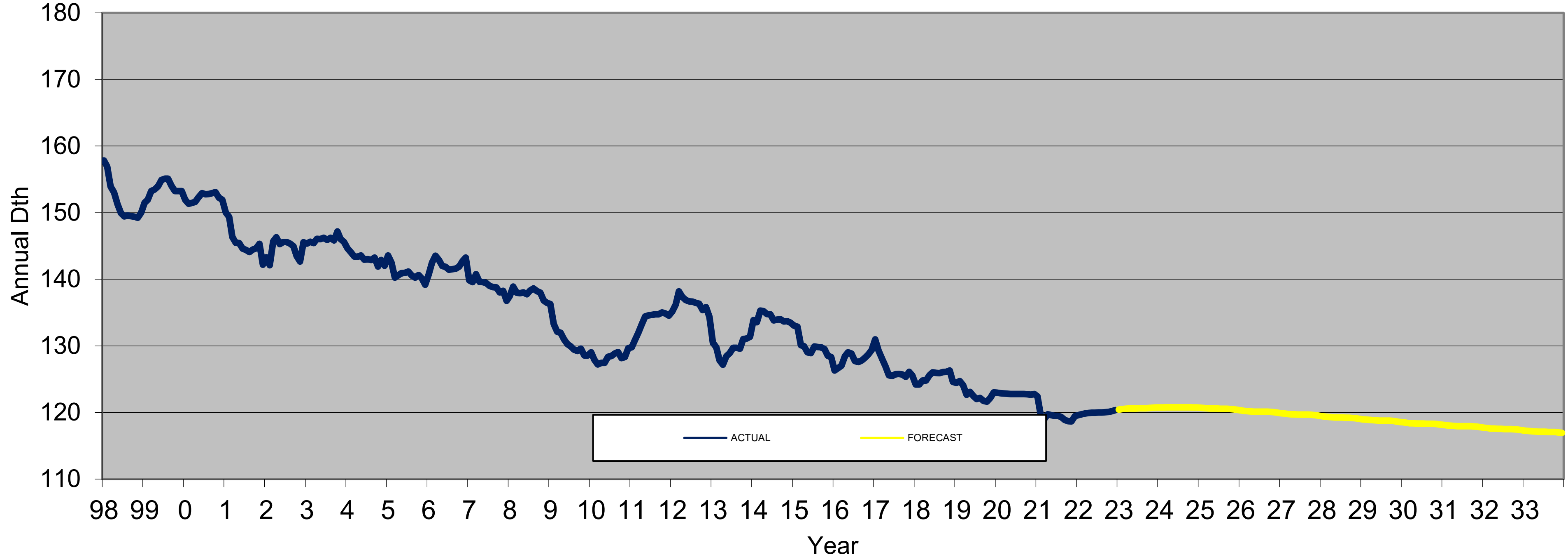
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
FORECAST	431.6	428.6	425.6	422.9	420.3	417.7	415.1	412.6	410.0	407.4

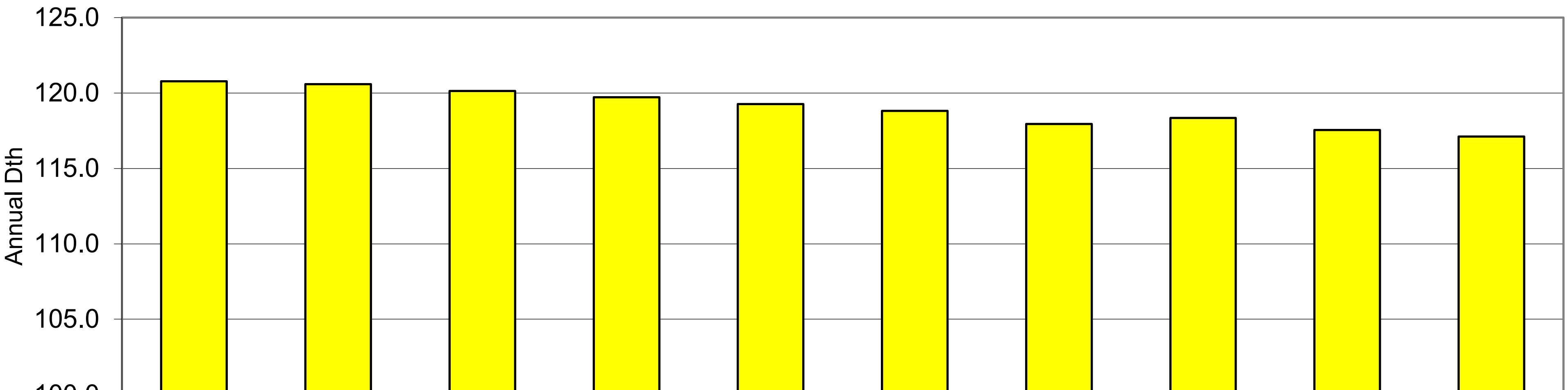
IRP Year

Exhibit 3.4

WYOMING GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



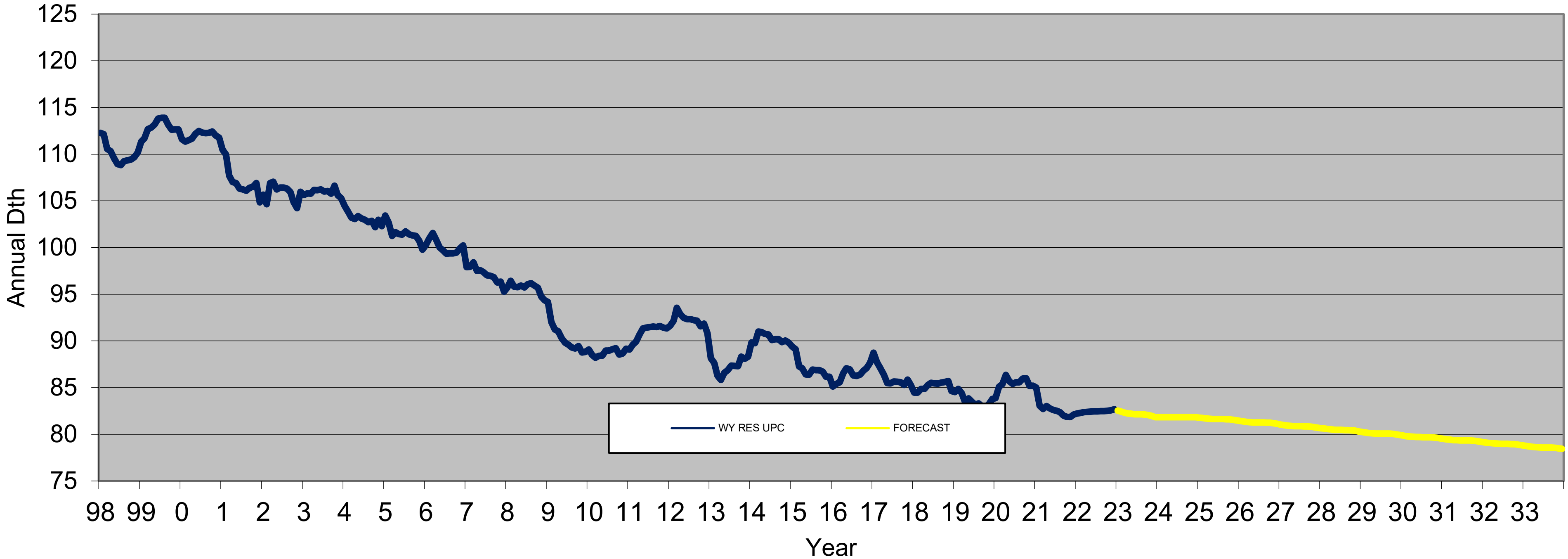


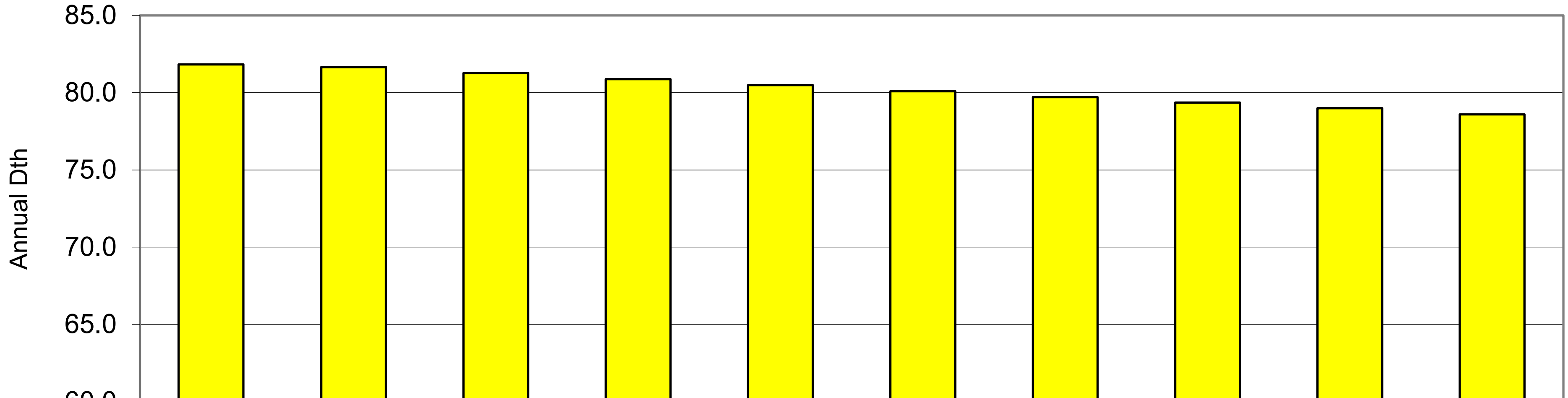
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
WY GS	120.8	120.6	120.1	119.7	119.3	118.8	118.0	118.3	117.5	117.1

IRP Year

Exhibit 3.5

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



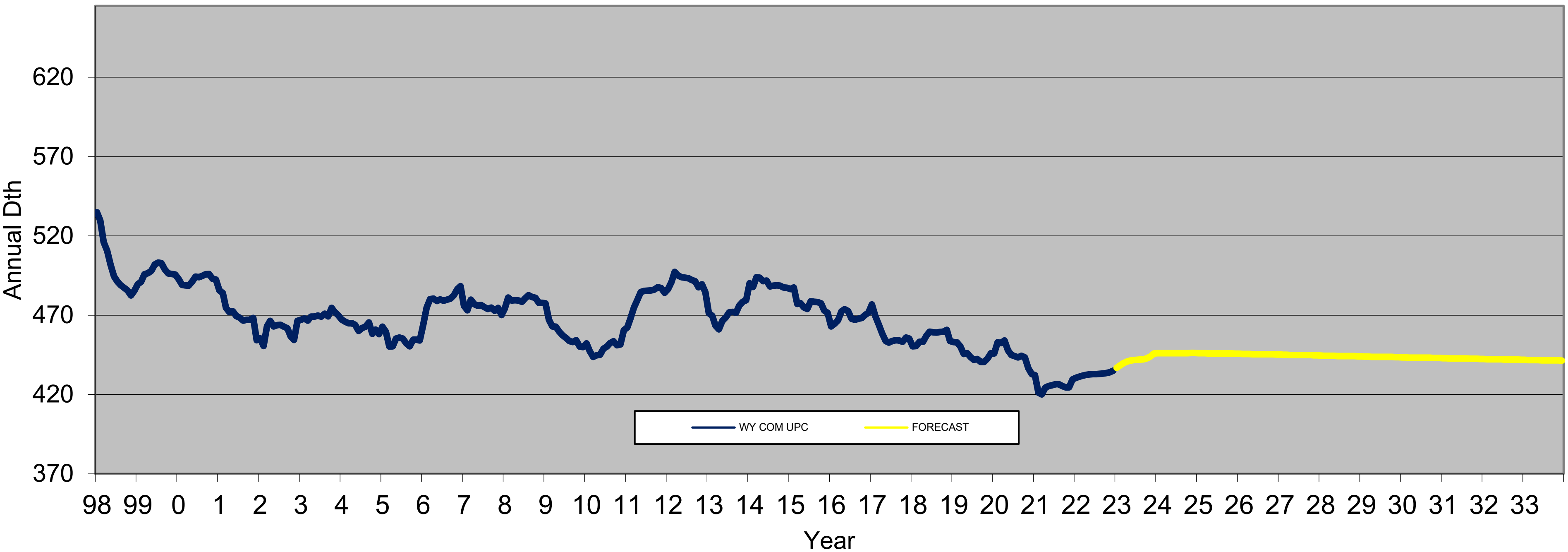


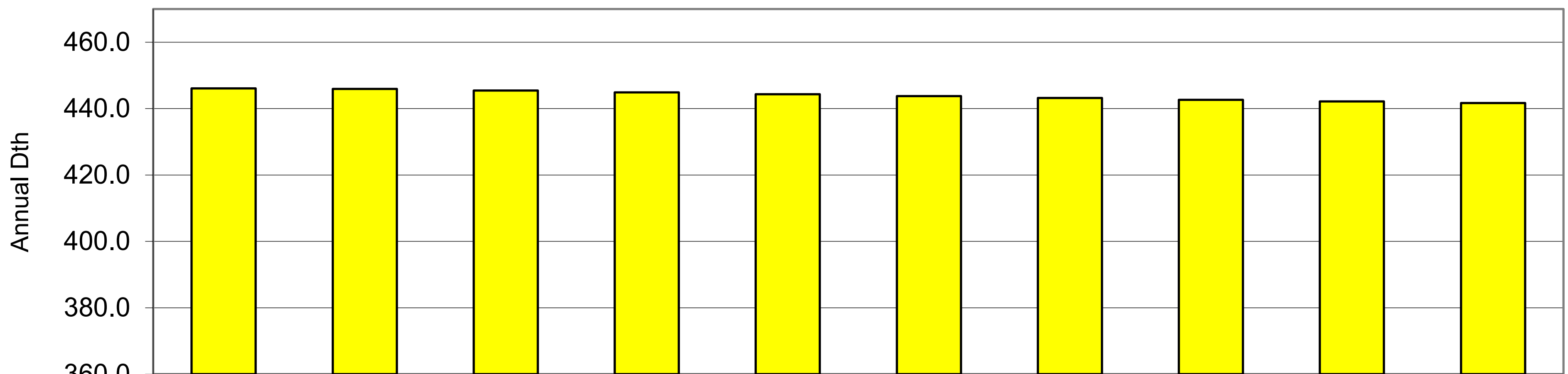
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
WY GS RES UPC	81.8	81.7	81.3	80.9	80.5	80.1	79.7	79.4	79.0	78.6

IRP Year

Exibit 3.6

WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



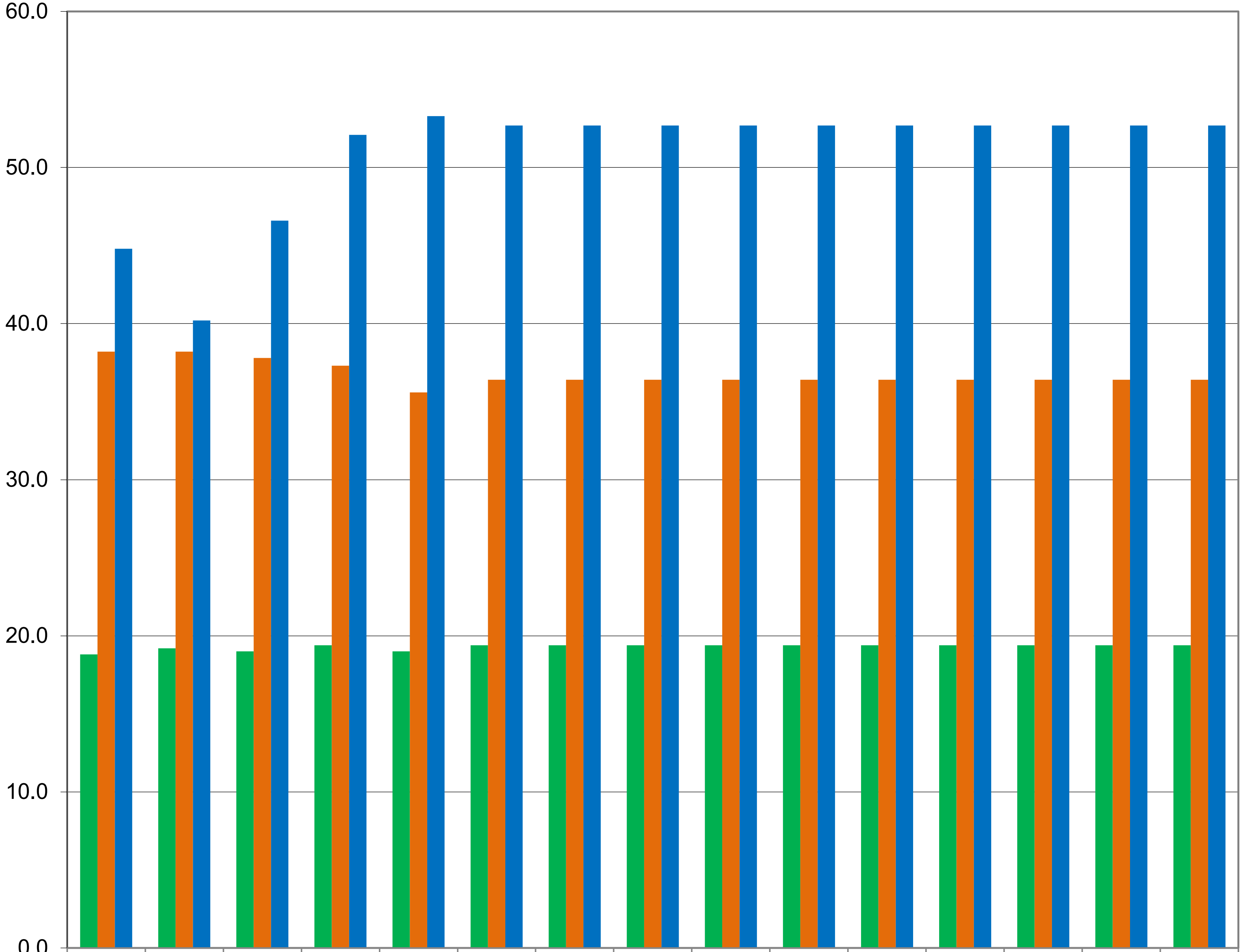


	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
WY GS COM UPC	446.1	445.9	445.5	444.9	444.3	443.8	443.2	442.7	442.2	441.7

IRP Year

Exhibit 3.7

SYSTEM NON-GS DEMAND

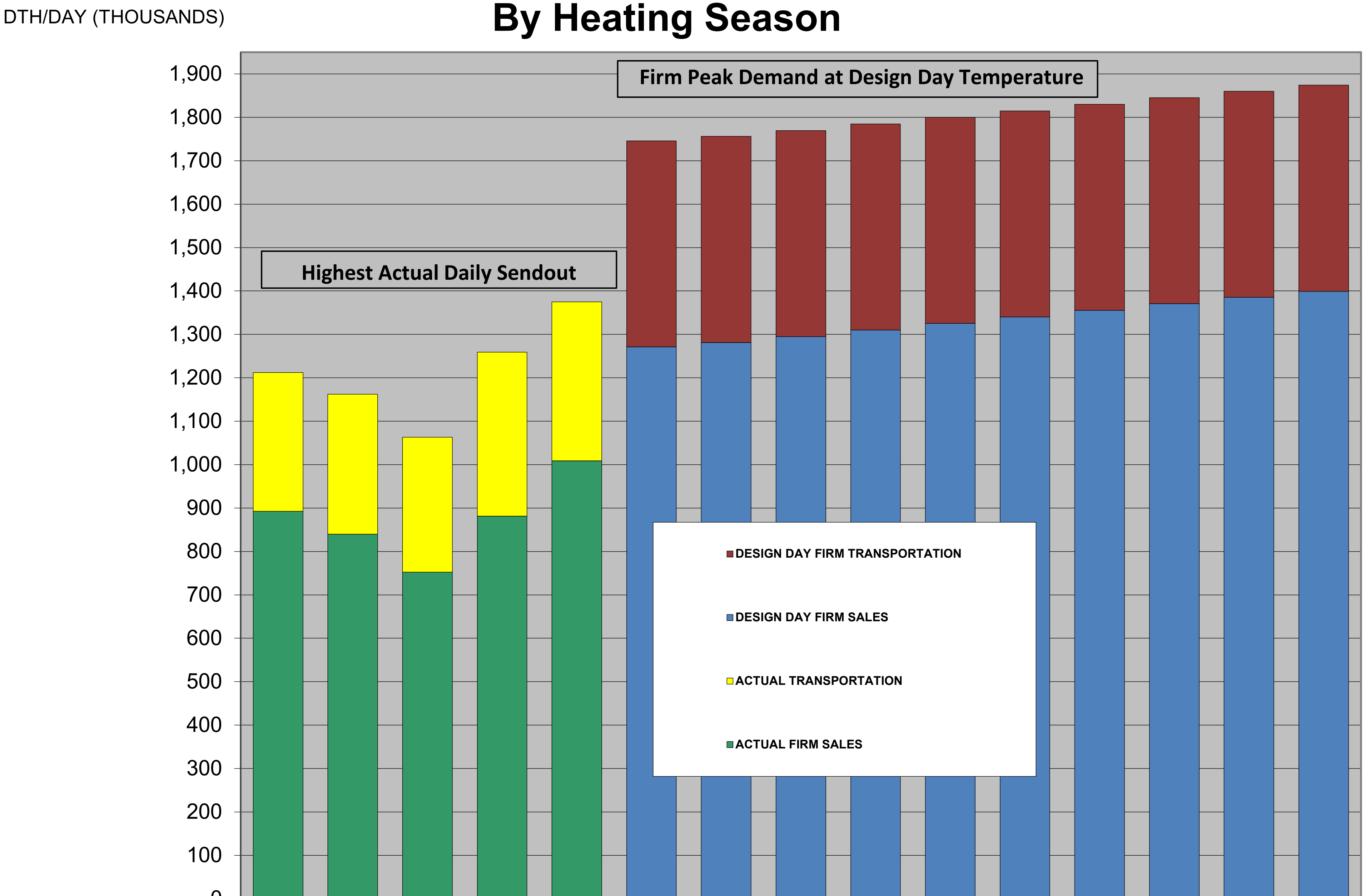


	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
LARGE COMMERCIAL DEMAND	18.8	19.2	19.0	19.4	19.0	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
INDUSTRIAL DEMAND	38.2	38.2	37.8	37.3	35.6	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4
ELECTRIC GENERATION	44.8	40.2	46.6	52.1	53.3	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7

Exhibit 3.8

DESIGN PEAK-DAY DEMAND FORECAST

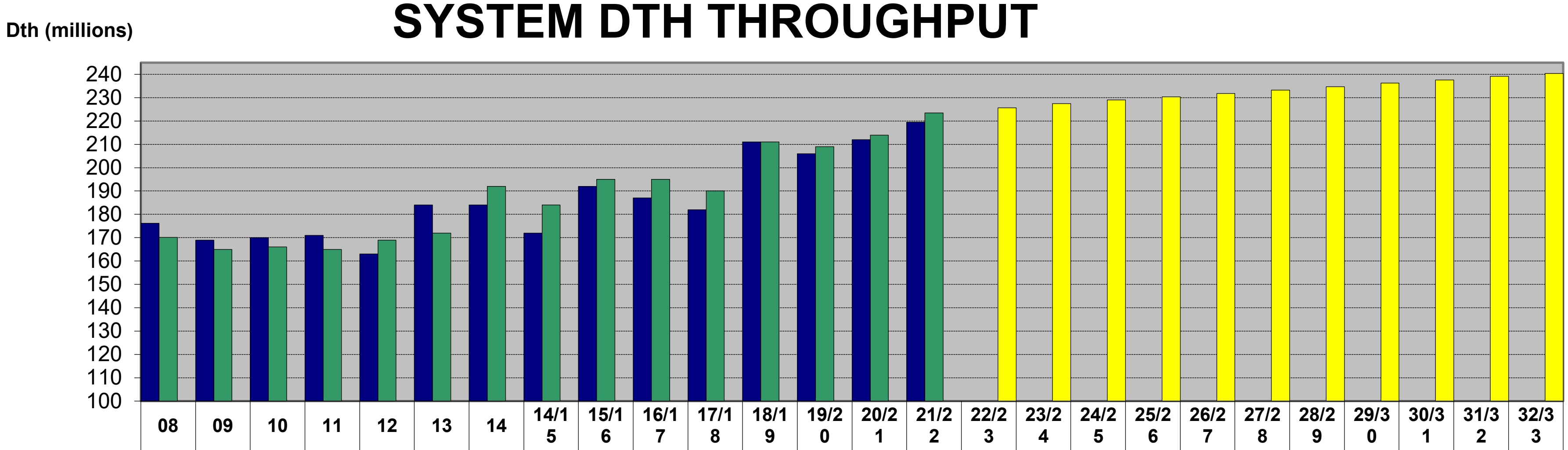
By Heating Season



	2018/19	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
DESIGN DAY FIRM TRANSPORTATION						475	475	475	475	475	475	475	475	475	475
DESIGN DAY FIRM SALES						1271	1281	1295	1310	1325	1340	1355	1371	1385	1399
ACTUAL TRANSPORTATION	320	323	311	378	366										
ACTUAL FIRM SALES	892	840	752	881	1009										

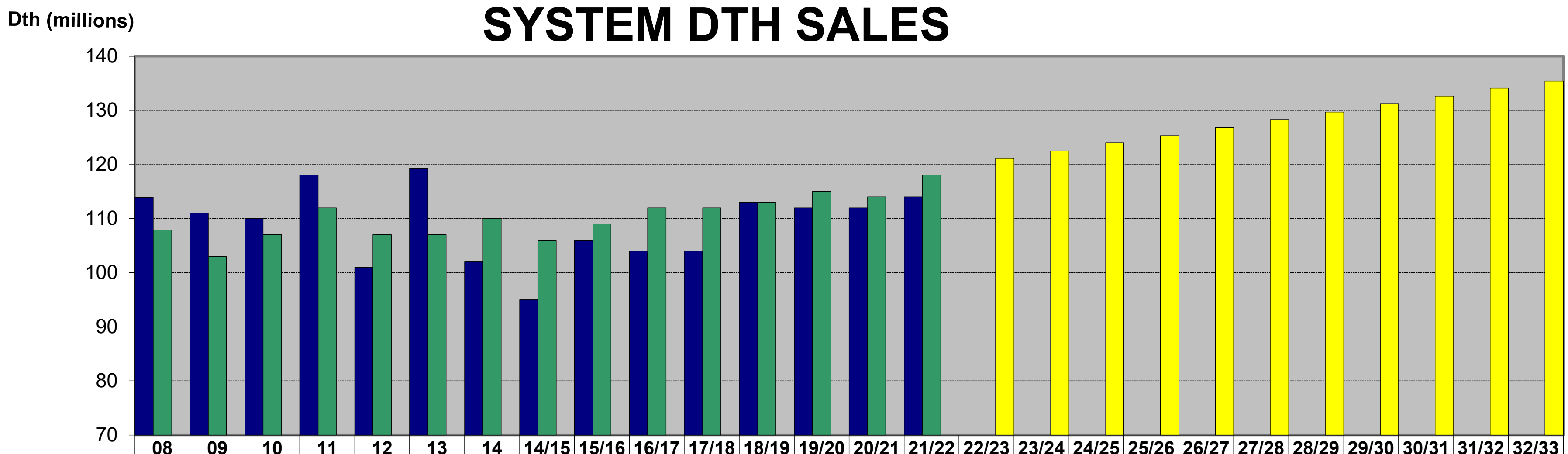
Exhibit 3.9

SYSTEM DTH THROUGHPUT



	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
ACTUAL	176	169	170	171	163	184	184	172	192	187	182	211	206	212	220											
TEMP ADJUSTED	170	165	166	165	169	172	192	184	195	195	190	211	209	214	224											
FORECAST																226	228	229	230	232	233	235	236	238	239	240

SYSTEM DTH SALES

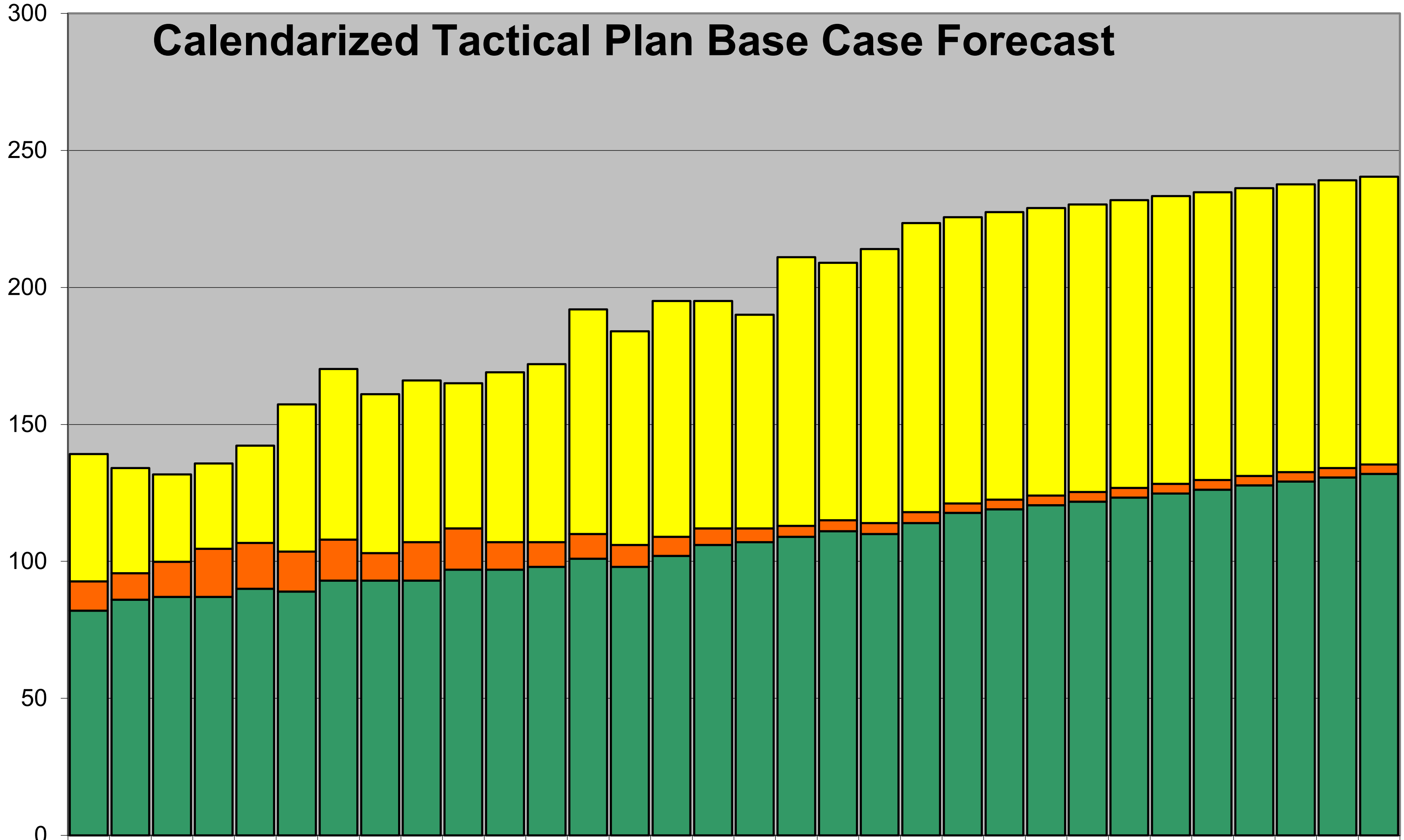


	08	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33
ACTUAL	114	111	110	118	101	119	102	95	106	104	104	113	112	112	114											
TEMP ADJUSTED	108	103	107	112	107	107	110	106	109	112	112	113	115	114	118											
FORECAST																121	123	124	125	127	128	130	131	133	134	135

Exhibit 3.10

TEMP ADJUSTED THROUGHPUT

DTH (MILLIONS)



	02	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
TRANS	46	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	94	100	106	105	105	105	105	105	105	105	105	105	105	105
NON-GS SALES	11	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	4	4	3	4	4	4	4	4	4	4	4	4	4
SYSTEM GS	82	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	111	110	114	118	119	121	122	123	125	126	128	129	131	132

Exhibit 3.11

SYSTEM CAPABILITIES AND CONSTRAINTS

DEUWI SYSTEM OVERVIEW

The Company's system currently consists of approximately 21,566 miles of distribution and transmission mains serving more than 1,180,399 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.

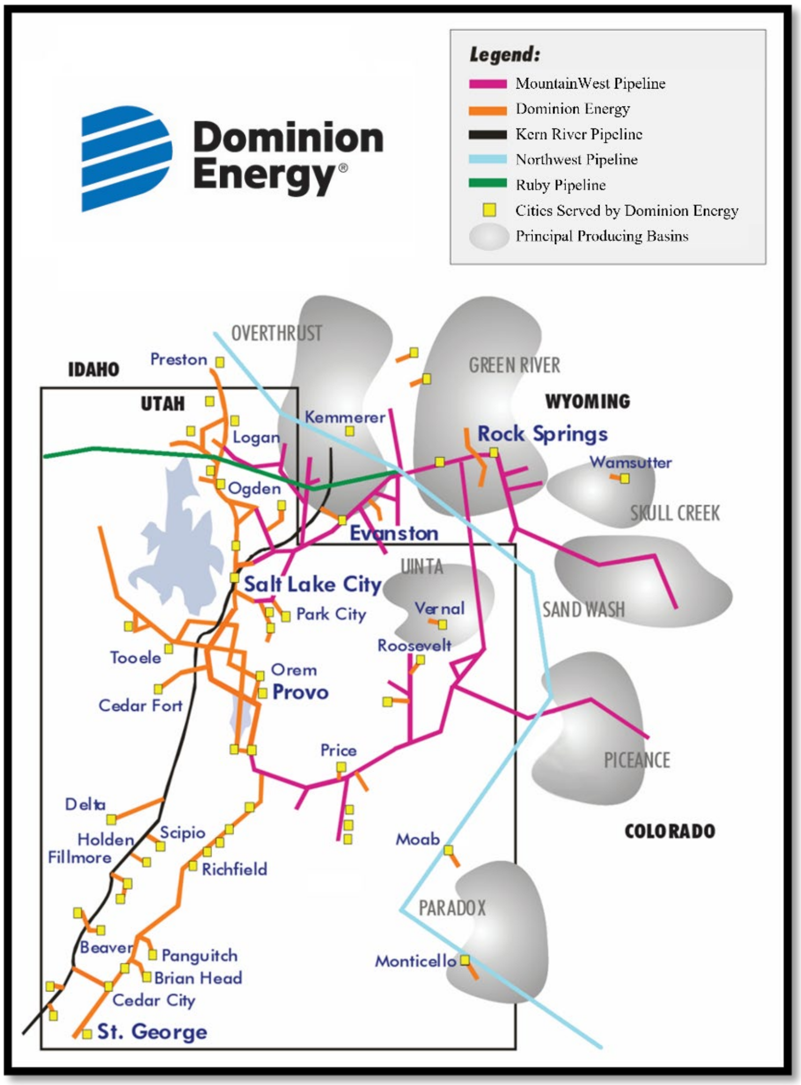


Figure 4.1: DEUWI High Pressure System

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 Analysis and Joint Operating Agreement (JOA)

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.

The Company and Mountain West Pipeline (MWP) work together each year to update a JOA as part of this analysis. The JOA includes 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 is to ensure that the Company receives adequate inlet pressures to these stations in order to maintain system reliability. This is a complicated process that requires detailed collaboration because the flows at these stations fluctuate through the day to match the changing demands on the Company's system.

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. DEUWI's transportation contracts with MWP permit delivery to multiple gate stations. As a result, DEUWI enjoys a great deal of flexibility. However, because each gate station delivers supply to DEUWI's system at different pressures, engineering analysis is required to ensure that pressures and flows across DEUWI's 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. DEUWI need not engage in such analysis with other pipelines because those entities do not have such a complex network of interconnects with DEUWI's system, and contracts for each interconnect are more limited and rigid.

MWP and DEUWI have engaged in the JOA process consistently for several years. Notwithstanding the sale of MWP to Williams Pipeline, that same process is under way in 2023. DEUWI 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 DEUWI'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	2022 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	-2
HP-EVAN	Uinta County, WY	-25
HP-FILL	Beaver, Piute, Sanpete, & Sevier Counties, UT	-11
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	15
HP-STGE	St George, UT (majority of Washington County)	15
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	5

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, 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 31, 2023, 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 385 verification points. Each of these points were found to be within 7% of the actual pressures on that day. Three hundred and seventy-six 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 three hundred and seventy-seven verification points on that day. Three hundred and fifty-five 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 JOA.

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 more comfortable 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: JOA Gate Stations Nearing Capacity (in descending order)

Station	2023-2024 Max Flow (MMcfd)	Station Capacity (MMcfd)	% Utilization
Central Tap	62.8	62.8	100%
Riverton	192.7	200.0	96%
Evanston South	8.1	8.8	88%
Sunset	80.0	92.8	86%
Dog Valley	5.9	6.9	86%
Rockport	14.1	16.7	84%
Hunter Park	320.0	400.0	80%
Payson (FL26)	245.2	320.3	77%
Kanda	10.7	14.0	76%
Hyrum	197.5	262.0	75%
Green River Border	5.6	7.9	71%
Bluebell (Vernal)	7.1	10.0	71%
Porter Lane	95.0	136.7	69%
Jeremy Ranch	19.5	28.7	68%
Little Mountain (FL4)	150.0	238.0	63%
Saratoga Tap	137.1	219.0	63%
Mountain Green	8.0	13.0	62%
Payson (FL42)	41.5	70.0	59%
Island Park	7.3	12.8	57%
Wecco	18.5	32.6	57%
Little Mountain (FL21)	147.0	272.0	54%
Promontory	47.2	89.4	53%
Westport	19.1	36.2	53%
Gordon Creek	10.5	22.1	47%
Indianola	28.2	61.9	45%
Eagle Mountain	9.2	25.4	36%
Rock Springs Foothill Dr	10.9	40.0	27%
Rose Park	96.3	400.0	24%

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 FL81, 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 FL81. As the Southern Expansion project adds larger diameter pipe parallel to FL81, 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, Dog Valley, Sunset, and Rockport gate stations are also at or above 80% utilization. However, the Evanston South and Dog Valley stations are not expected to require an upgrade within the next 5 years due to the low growth rates of the areas they supply.

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 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 2024

The Northern HP system continues to grow. The addition of the Kern River Gas Transmission (KRGT) Rose Park gate station, two 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 of 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 DEU'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 228 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: DEUWI High Pressure System Steady-State Design Day Pressures

Location	Pressure (psig)
Endpoint of FL 29 – Plymouth	266
Endpoint of FL 36 – West Jordan	262
Endpoint of FL 48 – Stockton	303
Endpoint of FL 51 – Plain City	284
Endpoint of FL 54 – Park City	348
Endpoint of FL 62 – Alta	273
Endpoint of FL 63 – West Desert	291
Endpoint of FL 70 – Promontory	263
Endpoint of FL 74 – Preston	258
Endpoint of FL 106 – Bear River City	284
Intersection of FL 29 & FL 127 – Brigham City	344

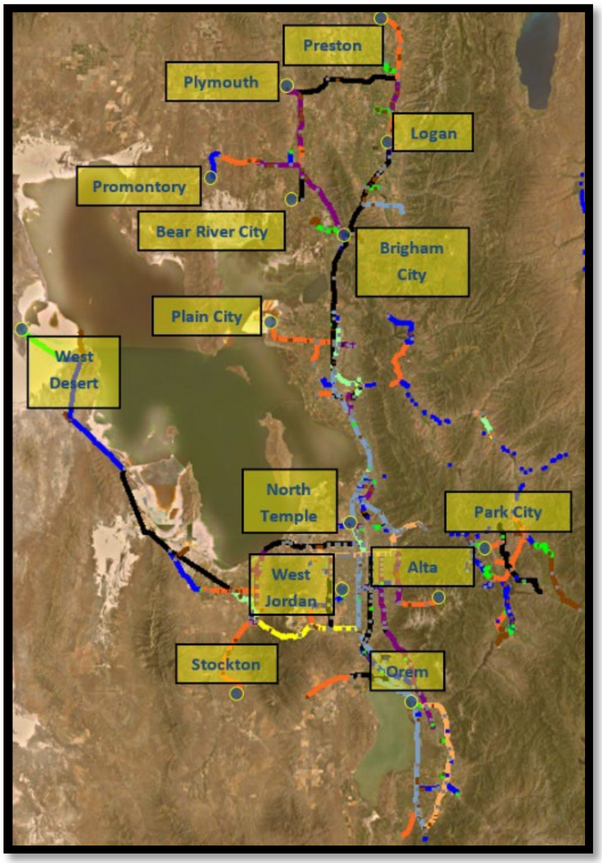


Figure 4.2: Northern Region Key Pressure Locations

The curves shown in, 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 West Jordan at 153 psig. The lowest predicted pressure in the Summit/Wasatch subsystem is at the Woodland regulator station with 201 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 194 psig.

Feeder Line 13 currently supplies gas between Magna and Salt Lake City and is currently being replaced as part of the Feeder Line replacement program. FL13 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 west end of FL13, but the east end still requires a station to properly regulate pressures between MAOP zones. FL13 and this project will be discussed in greater detail in the Distribution Action Plan section of this report.

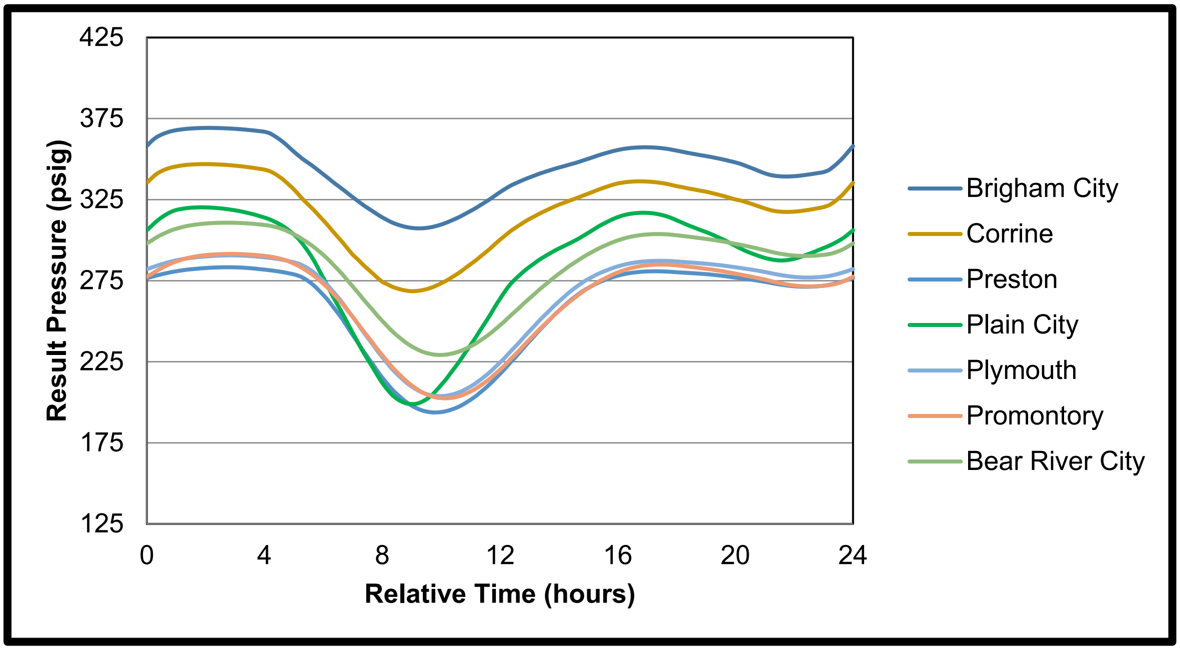


Figure 4.3: 2023-2024 Northern Unsteady-State Design Day Pressures (North of Flyer Way)

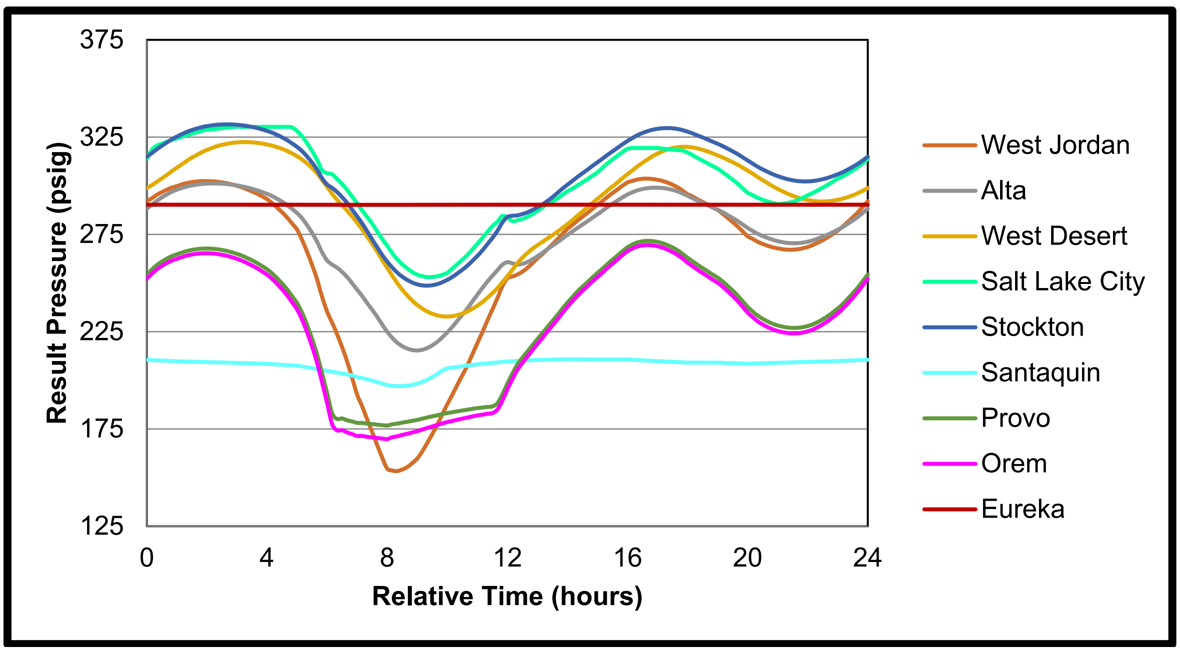


Figure 4.4: 2023-2024 Northern Unsteady-State Design Day Pressures (South of Flyer Way)

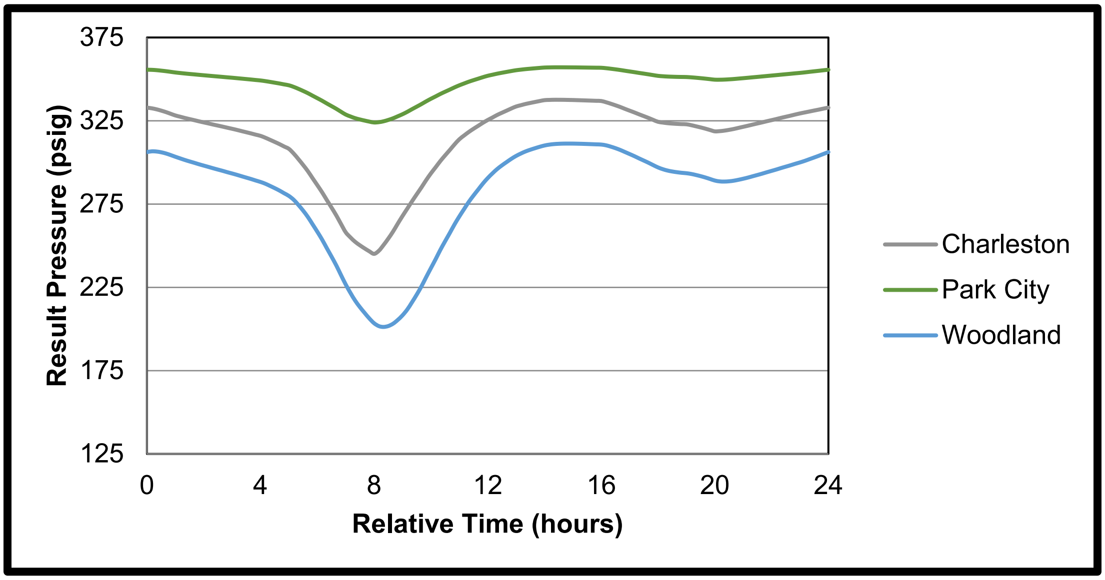


Figure 4.5: 2023-2024 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)

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 199 psig at West Vernal.

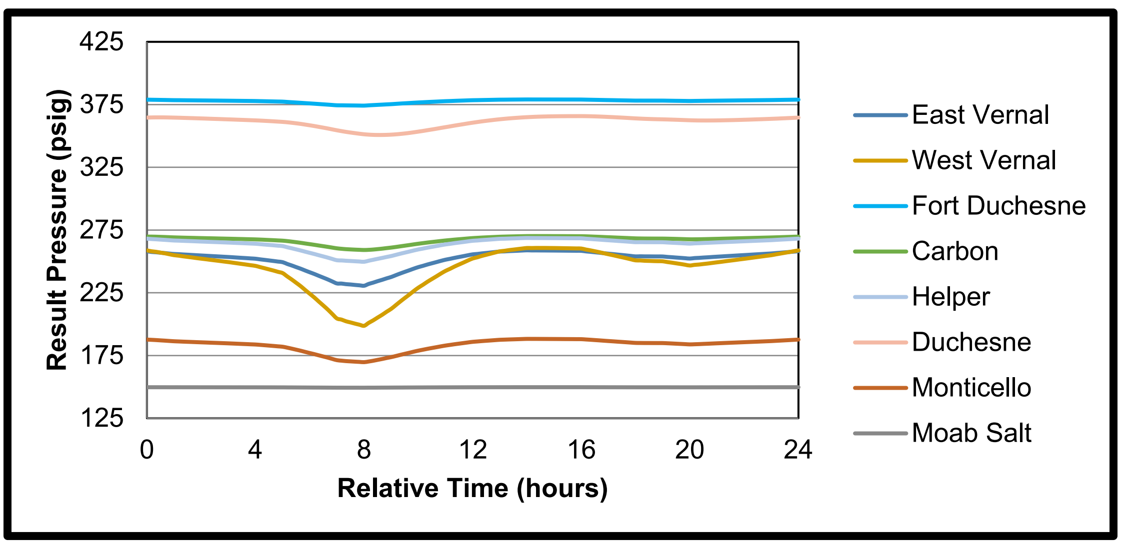


Figure 4.6: 2023-2024 Eastern (North) Unsteady-State Design-Day Pressures

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 two stations in Moab, 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 2023-2024 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 403 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, FL81 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.

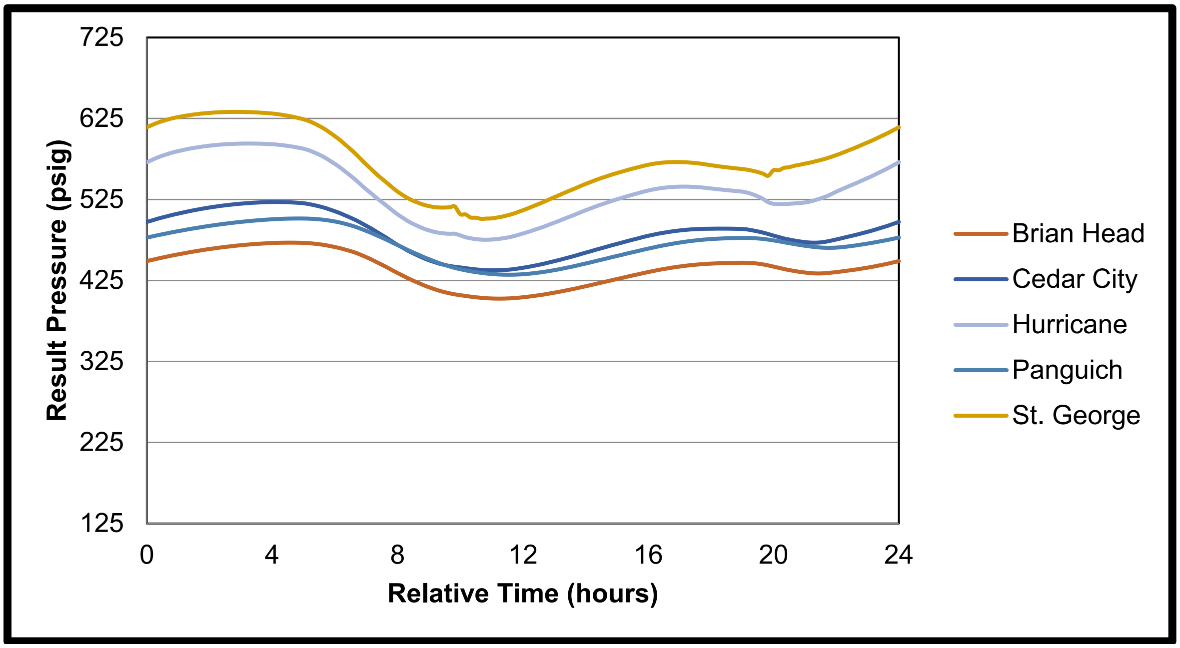


Figure 4.7: 2023-2024 Southern Unsteady-State Design Day Pressures

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.

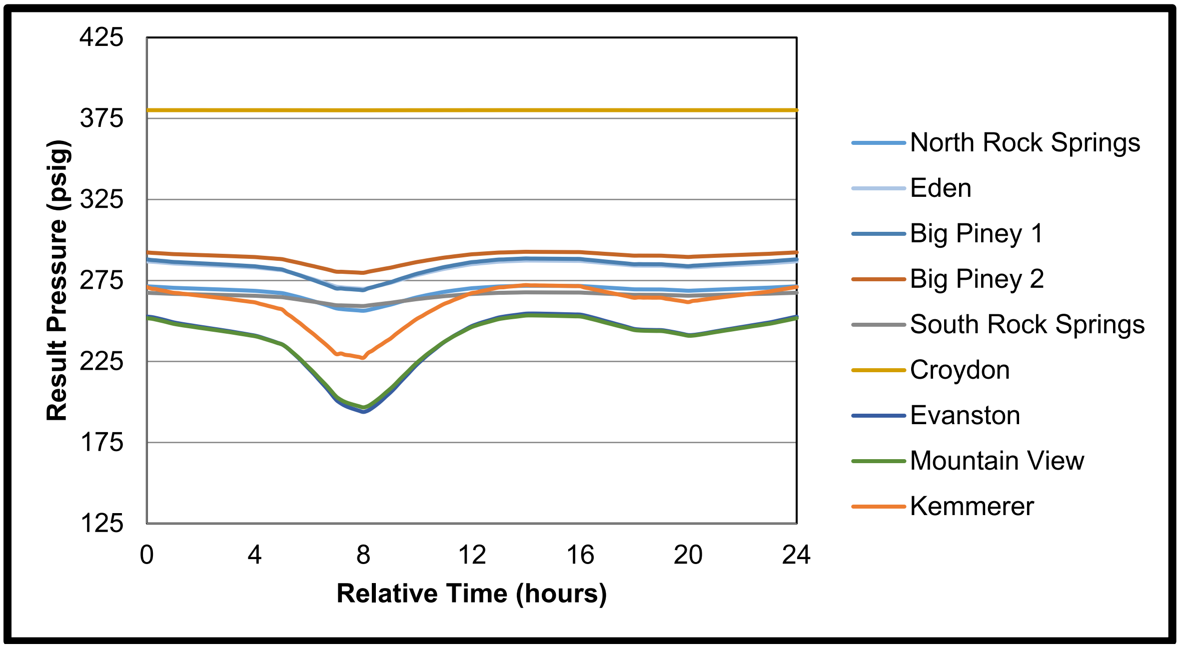


Figure 4.8: 2023-2024 Wyoming Unsteady-State Design Day Pressures

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

	2019	2020	2021	2022	2023
Design Day Growth	3.0%	2.5.%	1.7%	1.7%	1.1%
Customer Growth	2.6%	2.3%	2.5%	2.6%	2.5%

The average design day growth and customer growth per year over the past 5 years have been about 1.6% and 2.5%, respectively. 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 FL85, 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 FL85, 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 FL34 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, and such pressures are needed. 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 to the Wasatch Front.

The Company could also consider constructing modular LNG sites throughout its system. Such facilities could boost pressures in areas that otherwise have lower pressures and are without other supply reliability options.

The Company is also considering constructing RNG sites as possible supply resources that would both provide renewable natural gas on the Company's system and could address system concerns as well.

The Company is considering constructing a new Ruby Pipeline gate station near Brigham City. The Ruby Pipeline can easily 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 is also working towards a sustainable future through a hydrogen pilot program which looks at the benefits of blending hydrogen with natural gas. The hydrogen pilot program is discussed in further detail in the Sustainability section of this report.

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. The Company is also evaluating the possibility of expanding service into previously unserved or underserved rural areas including Genola, Bear Lake, Kanab, Rockville/Springdale, and East Wendover, Utah.

Long-term Supply Issues

Currently, the Company is able to buy enough supply to meet demand. However, 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. There is currently enough potential production and transportation capacity to increase production 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, US 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 Responsibly Sourced Natural Gas (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 to Eagle Mountain
- Rockport Gate Station
- FL13 East HP 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 2023 and beyond.

HIGH PRESSURE PROJECTS:

Station Projects:

1. WA1602 New FL13 East HP Regulator Station, District Regulator Station, and ILI Facilities, Salt Lake City, UT: When FL13 is replaced as part of the Feeder Line Replacement Program, FL13 will have an MAOP of 720 psig and be part of the 720 psig MAOP corridor. This new station will separate the MAOP zones of FL13 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 ILI receiver barrels and one launcher barrel. This will allow for the required ILI inspections of FL12 (both north and south of this location) and FL13. Property has been acquired 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 FL12. The Company looked for property for the new end facility and FL12/FL13 crossover within a 0.5-mile radius of the existing crossover. FL12 also runs through the property.

   The project design is complete and the Company is working through permitting with South Salt Lake City. The project's construction is anticipated to commence by summer 2023. 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 $322,000. 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: This high-capacity regulator station will replace WA0866 in South Salt Lake City. The capacity 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 currently preparing the site for construction at 334 W Archard Drive. The 4-inch tap line will be approximately 1,000 lf and will extend from FL4.

   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 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 approximately $3,000,000. The installation would be much more difficult as the alignment would nearly be entirely along 3300 south and crossing the I-15 corridor. Reliability and service quality of the system would decrease due to the absence of WA1596/WA0866 in a critical light manufacturing and commercial area of South Salt Lake. These factors resulted in the current project selection.

The project is currently in the design phase and finalizing Conditional Use Permitting with South Salt Lake City before the design is issued for construction. The Company estimates the total cost of the project (including acquiring the property) at $1,500,000. The Company plans to begin construction in 2023. The first-year revenue requirement is $172,500. 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 the high-pressure facilities.

   The project design is complete, and the project will be constructed in conjunction with the installation of FL147. The Company estimates that the project will cost $750,000 for the regulator station. The Company expects construction to commence in the summer of 2023. The first-year revenue requirement is $86,250. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP.

4. WA1609 – Replacement of WA0045 at North Temple and I-215, SLC, UT: This regulator station needs to be replaced due to its age, and the work necessary to advance the Company's planned 720 MAOP Corridor. This project will include improvement of existing cathodic protection, and the retirement of a brick building that is susceptible to earthquakes. The Company plans to install a new, larger station, and to construct a 720 MAOP corridor crossover between FL 12 and FL55, which is currently only rated for 354 psig.

   The project is utilizing the same location as the existing WA0045. First the existing station will need to be demolished to provide the space for the future facilities. The Company will install a new high-capacity regulator station to support the surrounding belt line system, and a HP regulator station for the crossover between FL55 and FL12 at this station.

   The project design has been issued for construction. The Company estimates the cost of the project at $3,000,000. The first-year revenue requirement is $345,000. The Company expects construction to commence by the summer 2023 and to be complete in time for the 2023-2024 heating season. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP.

5. 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 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. FL47 will extend from SY0001 to supply the regulator station.

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 the 2023-2024 heating season. 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 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 2023 and to finish construction before the 2023-2024 heating season. The first-year revenue requirement will be $86,250. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

6. 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 needs include 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 property.

   The project is currently in the planning stage. The Company is identifying potential property locations nearby or adjacent to the existing MZ0003 property to properly remodel and update MZ0003. The Company anticipates construction of this project to commence in 2024. As the Company establishes location of the remodeled facilities and further defines the project scope, it will provide updated estimates in a future IRP. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP.

7. 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 project is currently in the planning stages and the Company is looking at the available property options. The Company is targeting constructing the project in 2024. Preliminary estimates for the district regulator station are $750,000. The first-year revenue requirement is $86,250. The Company first discussed this project on page 5-5 of the 2021-2022 IRP.

8. <u>South Bluffdale District Regulator Station, Bluffdale, Utah:</u> 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 current growth rate. The Company must construct a new IHP regulator station closer to the growing load in order to maintain reliable operational pressures to the area. Constructing additional IHP main or upsizing current IHP main would not be adequate or cost-effective for resolving the future low-pressure concerns.

   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 process. Current estimates for the regulator station, including property, are $750,000. The first-year revenue requirement is $86,250. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

9. <u>St. George – River Road District Regulator Station, St George, Utah:</u> The area of St. George between the Southern Parkway and Enterprise Drive is growing quickly and 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. The Company is in the planning phase for this project. A property has not yet been procured. As more information becomes available the Company will provide updates to the future IRP or variance reports.

   At this time, the Company anticipates commencing construction in 2025, 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 $86,250. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

10. <u>WA1604 – Replace WA0441, West Valley City, UT:</u> 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 identifying potential property locations nearby, along the Meadow Brook Parkway on the east and west sides of the river. The Company anticipates construction of this project to commence in 2025. As the Company establishes the location of the new regulator station and further defines the project scope, it will provide updated estimates, as well as a comparison with the next-best alternative, in a future IRP or in a variance report. Current estimates with the cost of property and potential civil work are approximately $1,000,000. The first-year revenue requirement is $115,000. The Company first discussed this project on page 5-5 of the 2022-2023 IRP.

11. 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 2026, 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 $86,250. The Company first discussed this project on page 5-4 of the 2022-2023 IRP.

12. 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. This project is still in the early planning phase and is currently planned for construction in 2024 by MWP. 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.

13. 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 summer of 2023.

    This project is in the early planning phases and the Company is targeting construction in 2025. 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.

14. TG0005, Saratoga KRGT Gate Station, Saratoga Springs, Utah: This station is a major gate station with KRGT and delivers gas into FL85, FL112, and FL116. Gas from this gate station serves some of the fastest-growing communities in DEUWI'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 address concerns with 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. 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 $575,000.

    One alternative to this project would be to increase capacity at the existing Eagle Mountain KRGT gate stations to the south. This option would require replacement of approximately 9 miles of 6-inch HP pipe with 12-inch pipe, at a cost of approximately $29,000,000. This is not a viable alternative due to cost. The Company first discussed this project on page 5-3 of the 2019-2020 IRP.

    A second 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 $7,000,000. 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.

Feeder Line Projects:

1. FL147 – 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 FL38 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 FL52. 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 in the design phase. The Company anticipates construction beginning in the summer of 2023. The estimated costs for FL147 are $2,000,000. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP. The first-year revenue requirement is $230,000.

2. FL36 – 2.6 miles of AC Mitigation in West Jordan and South Jordan, Utah: The DEUWI high-pressure feeder line system includes several pipelines that co-locate and cross overhead alternating current power lines. These power lines can interfere with pipelines and cause corrosion and/or other safety concerns. The Company conducted a detailed assessment on FL36 and developed a mitigation strategy based on that assessment. This strategy includes grounding the AC voltage off the pipeline through decoupling devices to ground and installing zinc ribbon adjacent to the existing pipe and tying it to Polarization Cell Replacement (PCR) stations.

   The project is currently under construction. Estimated costs for the AC Mitigation are $1,700,000. This inclusion in the 2023-2024 IRP is the first mention of the project in an IRP. The first-year revenue requirement is $195,500.

3. FL47 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. FL47 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 the 2023-2024 heating season. 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. 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 2024. The first-year revenue requirement will be $460,000. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

4. FL85 Extension for New Eagle Mountain District Regulator Station, Eagle Mountain, UT: The Company plans to extend FL85 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 to the growth area is to extend FL85 from WA1519 in Cedar Fort south to the 4000 N and Hwy 73 intersection. 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 expected to be approximately 2 miles long and 8-inches in diameter. The final location will depend on how the developments in the area are designed, and on the availability of property.

The Company evaluated another alternative to tap off of FL116 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 FL116 is only 6-inches, whereas FL85 is 8-inches in diameter. Extending FL85 would give the Company the ability to bring more gas to the area.

The project is currently in the early planning stages and the Company is looking at the available property options. Once a site has been selected, the Company will provide an update on the project scope and costs as they become available. The Company anticipates commencing construction in 2024. 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 2021-2022 IRP.

5. 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, FL118 at HR0002, FL35 at Redwood Road, and FL34 near 1300 West and Bangerter Highway are all potential options from which to start the extension.

   The Company is planning to commence construction in 2025. Current preliminary estimates based on the 17,000 lf extension from FL35 on Redwood Road are approximately $6,500,000. The first-year revenue requirement is $747,500. 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.

6. FL71-5 Extension for the South St. George – River Road District Regulator Station, St. George, UT: 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 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 2023, 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 $460,000. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

7. FL Extension for WA1604, West Valley City: The Company plans to construct a feeder line extension to the proposed IHP regulator station, WA1604, from FL34 at approximately 4000 S and 1300 W in West Valley City. The Company is working to procure 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 FL34 along 1300 W.

   The next alternative route would run south from FL4 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 early 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 $345,000. 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.

8. 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 FL71, 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 2024. Current preliminary estimates based on the 18,000 lf extension from FL71 are approximately $6,500,000. The first-year revenue requirement is $747,500. The Company first discussed this project on page 5-4 of the 2022-2023 IRP.

9. FL21-10 Replacement, North Salt Lake, UT: The Company plans to replace approximately 6,800 lf of FL21-10 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 2025.

The project is still in the early planning stages. The Company anticipates that construction will commence in 2025. The current preliminary estimate, based on the 6,800 lf replacement, is $3,000,000 - $5,000,000. The first-year revenue requirement is $345,000 – $575,000. The Company first discussed this project on page 5-8 of the 2022-2023 IRP.

10. 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 current feeder line infrastructure will not support the growing demand. For the past 10 years, the Company has been considering different options to reinforce this area. 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 8-inch feeder lines, which extend from the KRGT gate stations do not have enough capacity to meet the growing demand. The three most viable options were:

1) Tie FL81 to FL71 with a 12-inch pipe across St. George. (Completed in 2020)
2) Loop FL81 with a 20-inch pipe to increase deliverability to St. George from the Central gate station.
3) Install a new gate station at the Shivwits reservation along with a new 20-inch pipeline to feed into St. George.

These options are shown in Figure 5.1 below:

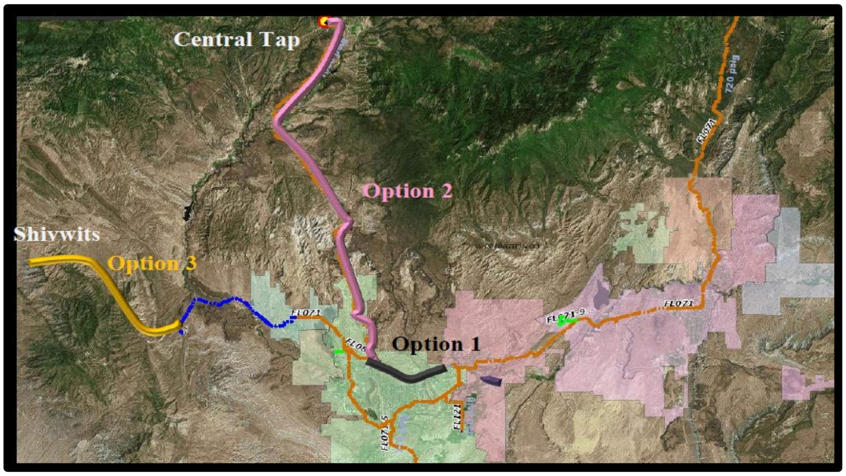


Figure 5.1: Southern System Options

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 FL133 extension (Option 1) and will continue efforts to completing the remaining work.

1. <u>FL135, Central 20-inch loop, St. George, Utah:</u> 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 FL81 taps into KRGT, and deliver it to the St George high-pressure system. The new pipeline will "loop" the Company's existing FL81 by running parallel to the 8-inch pipeline along Hwy 18.

   The construction of this project will be 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 Veyo to Diamond Valley. Phase 2 is expected to be constructed between 2024 and 2025 with an estimated cost of about $45,000,000. Phase 3, the final phase of this project, Diamond Valley to Bluff Street, is expected to be constructed between 2027 and 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 $120 and $150 million. The Company will provide updates on the timing and estimated costs of Phase 2 and 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
2023	WA1602 FL13 East HP Station, District Regulator Station, and ILI Facilities, Salt Lake City, UT	$2,800,000	$322,000
2023	WA1596 – Replace WA0866 with High-Capacity District Regulator Station for South Salt Lake City, UT	$1,500,000	$172,500
2023	WA1617 – New Reg Station Grantsville on Sheep Lane	$750,000	$86,250
2023	FL147 – 1 Mile of 8-inch for New Reg Station on Sheep Lane	$2,000,000	$230,000
2023	WA1609 – Replacement of WA0045 North Temple and I-215 Station	$3,000,000	$345,000
2023	AC Mitigation 2.6 Miles on FL36	$1,700,000	$195,500
2024	SY0002 Syracuse District Regulator Station	$750,000	$86,250
2024	FL47 Phase 2 Extension for SY0002 Syracuse District Regulator Station	$4,000,000	$460,000
2024	MZ0003 – Remodel of Monticello Gate Station	TBD	TBD
2024	Eagle Mountain District Regulator Station, near 4000 N and Hwy 73	$750,000	$86,250

Year	Project	Estimated Cost	Revenue Requirement
2024	FL85 Extension for Eagle Mountain District Regulator Station	TBD	TBD
2025	South Bluffdale District Regulator Station	$750,000	$86,250
2025	FL Extension for Bluffdale Station	$6,500,000	$747,500
2025	South St. George – River Road District Regulator Station	$750,000	$86,250
2025	FL71-5 Extension for South St. George DR Station – River Road	$4,000,000	$460,000
2025	Central 20-inch Loop (Phase 2) – Approximately 10 miles	$45,000,000	$5,715,000
2025	WA1604 – Replace WA0441	$1,000,000	$115,000
2025	FL Extension for WA1604 Across Jordan River	$3,000,000 to $4,000,000	$345,000 to $460,000
2026	South Hurricane District Regulator Station	$750,000	$86,250
2026	FL Extension for South Hurricane Station	$6,500,000	$747,500
2026	Rockport Gate Station	TBD	TDB

Year	Project	Estimated Cost	Revenue Requirement
2026	SL0114 Remodel	TBD	TBD
2026	FL21-10 – 6,800 LF Replacement	$3,000,000 to $5,000,000	$345,000 to 575,000
2026	TG0005 Saratoga KRGT Gate Station	$5,000,000+	$575,000+
2028	Central 20-inch Feeder Line Loop (Phase 3) – Approximately 5 Miles	TBD	TBD

INTERMEDIATE HIGH PRESSURE PROJECTS:

1. Belt Main Replacement Program: The Company continues its Belt Main Replacement program in 2023. 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.

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 currently reviewing the ownership and operation of interconnecting facilities to determine the most efficient structure going forward. Contract negotiations are currently underway. Since any asset sales by MountainWest Pipeline will require FERC approval, closing of these agreements is not anticipated to take place until early 2024. The Company will provide further updates as definitive information becomes available.

RURAL EXPANSION

In addition to the projects discussed above, the Company continues to construct facilities to serve previously unserved rural communities. 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.

In late 2019, the Company requested approval from the Utah Commission to construct of its first rural expansion project to Eureka, Utah. In August of 2020, the Utah Commission granted approval for the Eureka project. Since then, the Company has requested and received permission to construct two additional expansion projects; Goshen/Elberta in 2021 and Green River in 2022. Below is a summary of the status of each of these expansion projects.

Eureka Expansion Project

The Eureka expansion project was put into service in November of 2021. The project consisted of the installation of approximately 8.4 miles of 6-in HP pipeline, a new gate station/interconnect with Mountain West Pipeline, a new regulator station, and IHP main and services within the town. The Company is installing service lines to homes and businesses in the town. To date, approximately 306 customers have signed up for a service line and the Company has installed 297 of those service lines. Prospective customers have until November of 2023 to sign up for a service line. The Company believes the project will be completed very close to the approved budget amount of $22.19 million but will provide further details when it completes installation of the remaining service lines.

Goshen/Elberta Expansion Project

The Goshen/Elberta project was put into service in November of 2022. The project consisted of the installation of approximately 4.2 miles of 6-in HP pipeline, three regulator stations, and the installation of IHP main and service lines in the towns of Elberta and Goshen. The Company is currently installing service lines in both towns. To date 273 Customers in Goshen and 48 customers in Elberta have signed up for service lines. The Company has installed 253 service lines in Goshen and another 46 service lines in Elberta. While the sign-up period for service lines in these communities does not end until November 2024, the Company's current projections show the project being completed at or below the Commission-approved budget of $13.3 million.

Green River Expansion Project

In August of 2021, the Company filed an application seeking Commission pre-approval to construct facilities to serve Green River, Utah. To serve Green River, the Company proposed to purchase an approximately 21.2 mile long gathering line. The Company also proposed to construct approximately 17 miles of 6-in HP pipeline, two district regulator stations, and the IHP facilities required to serve Green River. On January 19, 2022, the Utah Commission approved the Company's proposed expansion to Green River at a cost of $33.7 million. The Company has completed a significant portion of the installation of HP and IHP main lines.

Since the time the Company initially filed the request for pre-approval of the project, the anticipated costs associated with the project have increased by approximately $11 million. The cost increase is attributable to inflationary pressures on material prices and labor, unanticipated additional length of service lines, and other causes beyond the Company's control. On April 14, 2023, the Company filed a Request for Review and Consideration of a Notice to Proceed in Docket No. 21-057-12, seeking the issuance of a Notice to Proceed with the project.

Next Steps

The Company continues to explore options for extending service to other communities within Utah. The Company conducted outreach to the League of Cities and Towns and the Utah Association of Counties to identify other communities with interest in receiving natural gas service. The Company has evaluated its list of those communities that do not yet have natural gas service, and has identified Genola, Utah as the next community it will seek permission to serve. The Company is currently scheduling community meetings, scoping the project and compiling cost estimates. The Company hopes to submit an application for pre-approval of the project this summer. If approved, the Company anticipates construction of the project would commence in 2024.

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.[37]

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.[38] 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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[37] 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)).
[38] 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 412.906 miles of transmission piping (53.5% 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

	2023	2024	2025
Transmission Integrity Management Program	8,709	8,616	9,537
Distribution Integrity Management Program	2,385	1,089	985
Total Integrity Management Cost ($ Thousands)	11,094	9,705	10,531

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

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.

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 DEUWI. 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 has had a minor impact on Wexpro. The Mega Rule divided Wexpro gas gathering lines into two parts; Type C and Type R. All existing Wexpro Type C gathering lines that are 12.75 inch outside diameter (OD) or less, not located within a potential impact radius containing a BIHO or other impacted site and are not located within a class location unit containing a BIHO or other impacted site are exempt from corrosion control and leakage surveys. Annual reporting, leak and repair tracking were required by 2023. Type R gathering lines, 6 inch OD or less, require annual reporting, leak and repair tracking, and incident reporting.

New or replaced composite and metallic pipe must be in compliance with DOT part 192.9 safety standards and Type C gathering must have protective coating and add cathodic protection in areas where corrosion is found and will be reevaluated not less than every 3 years. These changes will not impact the current Wexpro operating standards and practices.

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, depending on the language in the requirement some updates may be needed.

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 MCAs per Mega Rule requirements. DEUWI 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 of its cathodic protection system. The goal is to complete this initial survey 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.

Transmission Integrity Management Costs

Activity	2023	2024	2025
ECDA			
Pre-Assessment			
2023 (FL34, 103, 11, 26, 85) (19.91 HCA miles; 0.03 §192.710; 10.2 CA miles @ $4K/FL)	22.5		
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
Indirect Inspections			
2023 (FL34, 103, 11, 26, 85) (19.91 HCA miles; 0.03 §192.710; 10.2 CA miles @ $16K/mile)	477		
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
Direct Examinations			
2022 (FL10, 14, 48, 52, 88) (8 excavations @ $34.5 K ea.)	276		
2022 (FL10, 14, 48, 52, 88) (Pipetel 1 sites, 1 casings @ $150 K/site)	150		
2023 (FL34, 103, 11, 26, 85) (6 excavations @ $34.5 K ea.)		207	
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 @ $150 K/site)			300
Post Assessment			
2022 (FL10, 14, 48, 52, 88) (4.05 HCA miles; 5.67 CA miles @ $1.5K/FL)	7.5		
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
CIS			
Indirect Inspections			
2023 (FL068, 71, 35, 41, 10, 34, 103, 11, 4, 26, 85) (67.74 miles @ $6.5K/mile)	440		
2024 (FL012, 22, 33, 46, 51, 53, 104, 25, 22, 19) (66.93 miles @ $6.5K/mile)		435	
2025 (FL018, 21, 29, 70, 122, 4, 81, 68, 85) (101 miles @ $6.5K/mile)			657
Reports			
No additional cost under current contract			
ACCDA			
Pre-Assessment			
2023 (FL11, 26, 85, 103) (3.01 HCA miles; Fixed)	5		
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
Indirect Inspections			
2023 (FL11, 26, 85, 103) (3.01 HCA miles @ $14K/mile)	42		
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
Direct Examinations			
2022 (FL10, 88) (2 excavations @ $34.5 K ea.)	69		
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
Post Assessment			
2022 (FL10, 88) (0.31 HCA miles; Fixed)	6		
2023 (FL11, 26, 85, 103) (3.01 HCA miles; Fixed)		6	
2024 (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles; Fixed)			6
ICDA			
ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan).			
Inline Inspection			
2022 Excavations/ Validations Digs/ Remediation (13 excavations @ $34.5 K ea.)	449		
2023 (FL068, FL071)	350		
2023 (FL035/41)	500		
2023 (FL010)	500		
2023 Excavations/ Validations Digs/ Remediation (15 excavations @ $34.5 K ea.)	69	449	
2024 (FL104)		350	
2024 (FL022/53/19)		500	
2024 (FL019)		350	
2024 (FL125)		500	
2024 Excavations/ Validations Digs/ Remediation (14 excavations @ $34.5 K ea.)			483
2025 (FL004)			350
2025 (FL081)			350
2025 (FL068)			350
2025 (FL085)			350
2025 (FL085) East			500
Direct Examination (Spans and Vaults)			
2023 - Vaults (10 @ $3.5 K/vault)	35		
2023 - Spans Reassessment (7 @ $10 K/span)	70		
2023 - Spans First Time (2 @ $75 K/span)	150	21	
2024 - Vaults (6 @ $3.5 K/vault)		40	
2024 - Spans Reassessment (4 @ $10 K/span)		150	
2024 - Spans First Time (2 @ $75 K/span)			21
2025 - Vaults (6 @ $3.5 K/vault)			40
2025 - Spans Reassessment (4 @ $10 K/span)			150
2025 - Spans First Time (2 @ $75 K/span)			

Transmission Integrity Management Costs

Activity	2023	2024	2025
Pressure Test Assessment			
2023 - 0 pipeline segments @ $200 K/segment			
2024 - 1 pipeline segments @ $200 K/segment		200	
2025 - 1 pipeline segments @ $200 K/segment			200
Material Verification			
2023 - 8 Opportunistic Samples @ $4 K/sample, 2 Opportunistic Samples @ $20K	72		
2024 - 8 Opportunistic Samples @ $4 K/sample, 2 Opportunistic Samples @ $20K		72	
2025 - 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 (FL11)	375		
Excavation Standby			
Distribution Tech (5 employees (2080 hrs.. x $75/hr.))	780	780	780
Contractors (4 x 312 days x 4 x $580/day)	729	729	729
Additional Leak Survey			
Leak Survey Tech (3 employees (2,080 hrs.. x 3 x $65/hr.))	406	406	406
Additional Cathodic Protection Survey			
Corrosion Tech (2 employees (2,080 hrs.. x 3 x $62.50/hr.)	260	260	260
Administration			
Project Coordination (5 employees (2080 hrs. x 5 x $75/hr.))	780	780	780
Data Integration Specialists (2 employees (2080 hrs. x 2 x $75/hr.))	312	312	312
Construction Records Tech (2080 hrs. x $45/hr.)	94	94	94
Supervisor (2080 hrs. x $85/hr.)	177	177	177
Engineer (3 employees (2080 hrs. x $85/hr.))	530	530	530
Engineer Tech (2080 hrs. x $ 65/hr.)	135	135	135
Damage Prevention Tech (3 employees (2080 hrs. x $65/hr.))	406	406	406
Training (IM personnel)	35	35	35
Transmission Integrity Management Total ($ Thousands)	8,709	8,616	9,537

Distribution Integrity Management Costs

Activity	2023	2024	2025
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	1050		
Direct Assessments			
ILI			
2022 (FL006, FL024)	350		
2022 ILI digs (FL006, FL024) (3 excavations @ 34.5K ea		103.5	
Administration			
Consultant - 3rd Party Plan Review			
Distribution Integrity Management Total ($ Thousands)	2,385	1,089	985

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.

For more than a decade the Company has been committed to reporting and reducing its Greenhouse Gas (GHG) emissions. In 2020, Dominion Energy announced that by 2050, it will achieve Net Zero carbon and methane direct (Scope 1) emissions across its electric and natural gas operations nationwide. In February 2022, Dominion Energy expanded this commitment to include certain indirect emissions upstream and downstream of Dominion Energy's operations, including Scope 2 emissions and the following three material categories of Scope 3 emissions: electricity purchased to power the grid, fuel purchased for Dominion Energy's power stations and gas distribution systems, and consumption of sales gas by natural gas customers.[39] As discussed in the Sustainability section of this report, DEUWI is taking action to reduce emissions and exploring new technologies to accelerate future emissions reductions.

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[39] 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 Dominion Energy takes title.

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.

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 Dominion Energy also maintains a comprehensive Corporate 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 Corporate 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, Dominion Energy's reported GHG emissions in its Corporate GHG inventory are a more accurate and comprehensive accounting of actual emissions from operations than what is reported to the EPA.

In 2021, the Company reported a total of 223 thousand metric tons of direct CO2e emissions.[40] Table 7.1[41] shows the Company's direct CO2e emission rate per million BTU (greenhouse gas intensity) over the last three years.

Table 7.1: DEUWI Greenhouse (CO2e) Gas Intensity

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

In March 2016, Dominion Energy became a Founding Partner with the EPA in the Methane Challenge Program, committing to voluntary practices that will reduce methane emissions. Dominion Energy is continuing to renew this commitment for reporting year 2023. Additionally, Dominion Energy joined the One Future Coalition in 2018, which is a group of more than 50

[40] Starting with the 2023-2024 IRP, CO2e emissions reported reflect the most recent third party audited CO2e emissions. Also note that the intensity table was calculated using 2021 audited data.
[41] Starting with the 2023-2023 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.

natural gas companies working together voluntarily to reduce menthane emissions across the value chain.

Dominion Energy 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 950,000 Dth of natural gas in 2022 through the ThermWise programs. The savings represents the equivalent of over 50 thousand metric tons of CO2e or more than 11 thousand passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime natural gas savings attributable to the 2022 ThermWise® programs equates to reductions of nearly 850 thousand metric tons of CO2e or the equivalent of more than 189 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 2022 calendar year averaged $6.95 per Dth. This was higher than the 2021 average price of $3.90 per Dth, an increase of $3.05per Dth or about 78.2%. The 2021 and 2022 monthly index prices are provided in Table 8.1 below.

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

Month	2021	2022	Difference
Jan	$3.23	$7.87	$4.64
Feb	$2.75	$5.04	$2.29
Mar	$3.04	$4.38	$1.34
Apr	$2.41	$4.86	$2.45
May	$2.80	$6.40	$3.60
Jun	$2.91	$8.80	$5.89
Jul	$3.79	$6.18	$2.39
Aug	$4.04	$8.45	$4.41
Sep	$4.09	$8.73	$4.64
Oct	$5.60	$5.51	($0.09)
Nov	$6.34	$5.73	($0.61)
Dec	$5.78	$11.39	$5.61
Average	$3.90	$6.95	$3.05

The local market price for natural gas during the 2022-2023 heating season (November-March) averaged $16.84 per Dth compared to an average price of $5.88 per Dth during the 2021-2022 heating season, an increase of $10.96 or about 186%. 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	2021-2022	2022-2023	Difference
Nov	$6.34	$5.73	($0.61)
Dec	$5.78	$11.39	$5.61
Jan	$7.87	$49.57	$41.70
Feb	$5.04	$12.44	$7.40
Mar	$4.38	$5.07	$0.69
Average	$5.88	$16.84	$10.96

March 2023 S&P Global North American Gas Regional Short-Term Forecast (formerly PIRA Energy Group - PIRA) and IHS Markit North American Natural Gas Short-Term Outlook (formerly IHS Energy - CERA) forecasts of Rockies indices reflect an average price of approximately $4.34 per Dth through October 2023. Prices for the 2023-2024 heating season are forecasted to be approximately $5.39 per Dth.

ANNUAL GAS SUPPLY REQUEST FOR PROPOSAL

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 16, 2023, the Company sent its RFP to 56 prospective suppliers. The RFP sought proposals for both baseload and peaking supplies on the two major interstate pipeline systems interconnected with the Company; 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 3, 2023. The Company received proposals for 131 gas supply packages from 16 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 640,500 Dth/D, up from the 629,500 Dth/D offered last year. Peaking supplies offered on the MWP system totaled 75,000 Dth/D, down from the 105,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 150,000 Dth/D, down from last year's level of 250,000 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 SENDOUT model.[42] The Company must identify the pricing mechanisms utilized for each package and

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

link each to the appropriate index price in the model. Also, the Company must resolve the 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 SENDOUT model evaluated 131 supply packages.

After the Company enters these purchased-gas packages into the SENDOUT 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 SENDOUT 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 924 Monte Carlo draws during the modeling process. At the conclusion of the modeling, the Company analyzed the draws to see which were preferred. Using a statistical analysis package, the Company used a procedure to group (or cluster) optimized draws in similar ways. Clustering is the assignment of a set of observations into subsets so that observations in the same cluster are similar. The Company performs the clustering for Design Day and annual demand.

The Company then used a follow-up statistical procedure to split clusters at cluster designed levels as shown in Exhibit 8.1. This year, as in other years, the Company broke the cluster analysis into 30 groups and plotted them as representations of optimized solutions. A point on the graph represents a cluster and a cluster represents like draws. The resulting plot shows demand on the X axis of the graph, and Design Day on the Y axis. This plot shows how the SENDOUT model met high or low demand during Design Day events.

The Company then selected the clusters that most closely met the forecasted annual demand for the coming year. The Company examined the preferred draws that make up the clusters looking at the number of times a given package of gas was chosen and the volume of that package most often used.

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 SENDOUT 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 13.53 to 13.64 along with each probability distribution. Individual packages of purchased-gas supplies for the normal case are shown for the first two plan years in Exhibits 13.85 and 13.88. Of the 16 companies submitting proposals this year, 8 had at least one package selected by the modeling process. The Company made commitments to purchase from the selected suppliers starting on May 3, 2023.

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.

For the 2022-2023 heating season, the Company did not financially hedge the price of any of its baseload purchased gas supplies. However, the Company continues to utilize other alternatives to offset the potential risk of price increases such as cost-of-service production from Wexpro, storage withdrawals, and physical baseload contracts with fixed price and monthly-indexed pricing.

In 2023, the Company analyzed its exposure to daily-price risk based on the price stabilization mechanisms in place for the 2022-2023 heating season. The results of this evaluation showed that based on the contracts in place, on a typical winter day, the Company would have about 36% of supply purchases exposed to daily-price risk. On a Design Day, that exposure increases to 54%.

The Company considered options for additional resources including additional storage capacity, additional monthly-index based supply contracts, financial hedges, and additional fixed-price baseload contracts. The Company also continues to work with Wexpro to review any opportunities for increasing cost-of-service production.

As a result of this analysis, the Company contracted for 77,000 Dth/day of fixed price baseload supply for December 2022 through February 2023 to minimize this exposure on high demand days. The total cost of these contracts was $55,451,700. These contracts were the result of a separate RFP process conducted in July of 2022. These additional contracts reduced the Company's exposure to daily price risk to 25% of supply on a typical winter day and 48% on a Design Day.

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 relatively high throughout the 2022-2023 heating season. The fixed-price contracts' pricing saved customers $43,970,360 compared to the actual daily indexed pricing of the spot market during this period.

Unfortunately, the natural gas monthly indexes also experienced unusually high volatility in the west during the 2022-2023 heating season. The monthly indexes used in the Company's baseload contracts settled near $50 for the month of January 2023 resulting in significant costs. To mitigate a similar impact in February 2023, the Company converted 84,000 Dth of monthly-index baseload contracts for February to fixed price contracts prior to the settlement of the February monthly indexes.

The Company expects the increase is 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 2023-2024 heating season and beyond. This review will include determining if it may be beneficial to convert any of the monthly-index priced baseload contracts to fixed-price contracts. It will also consider whether to add any additional fixed-price baseload contracts through a separate RFP.

2023 Cluster Analysis
Average Design Day Demand v. Average Annual Demand

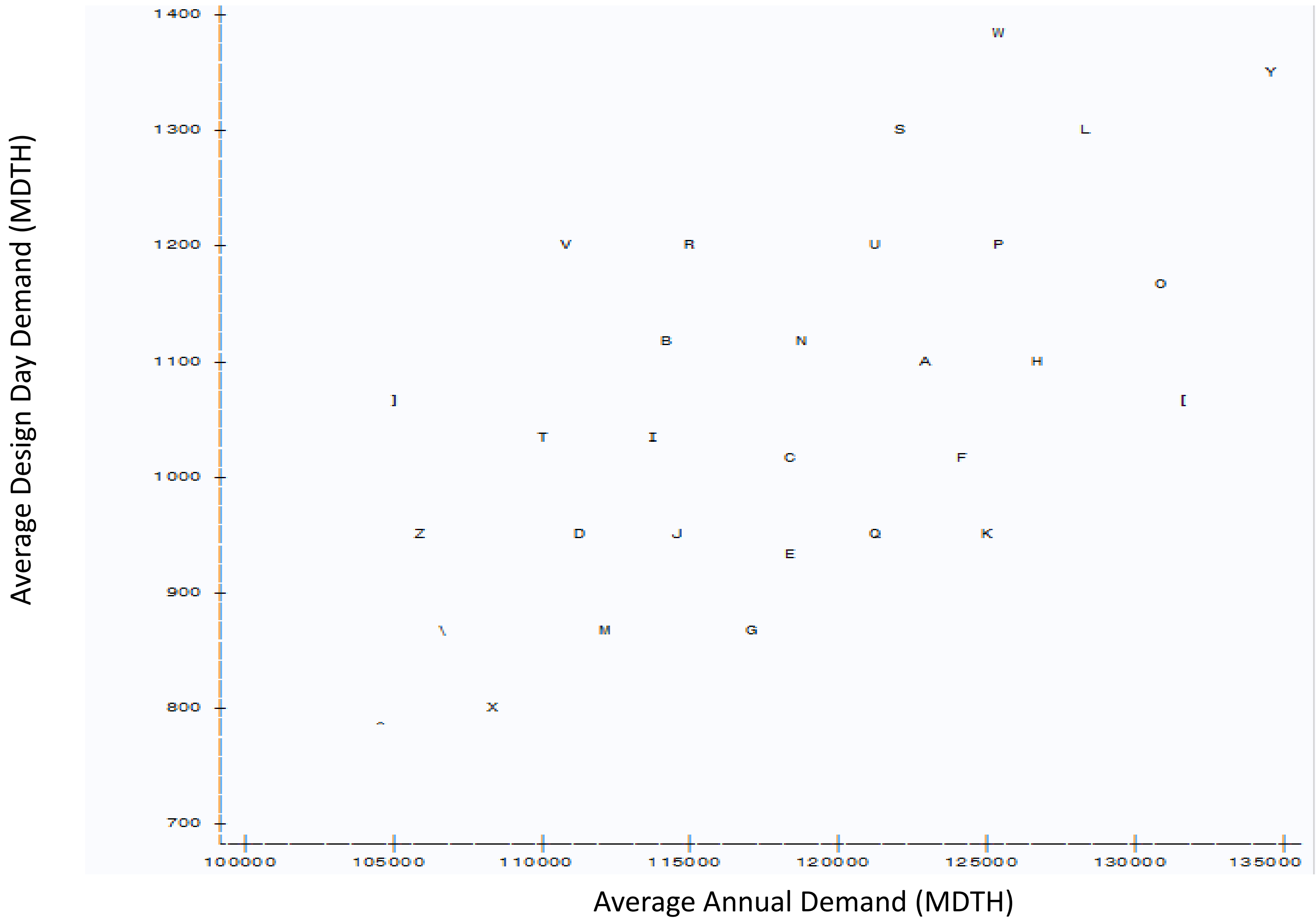


Exhibit 8.1

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 DEU's 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 DEUWI'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 DEUWI'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 2022, Wexpro produced 56.5 MMDth of cost-of-service supplies measured at the wellhead, down from the 59.2 MMDth level produced during calendar year 2021. 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.

From calendar year 2021 to 2022, the total costs, net of credits and overriding royalties, for cost-of-service production increased by approximately 3.7%. This increase was caused by a 72% increase in royalties due to higher gas prices throughout 2022. Additionally, Wexpro incurred $26.6 million of customer sharing income costs in 2022 where there was $0 in 2021. 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. 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 SENDOUT modeling process is a determination of the appropriate production profiles for the cost-of-service gas. This year, the Company modeled 158 categories of cost-of-service production. Last year, it modeled 138 categories. Both years, the Company used a modeling time horizon of 31 years for the base case scenarios. 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 SENDOUT 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 SENDOUT 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.[43] The IRPs should contain an analysis consisting of the results from multiple SENDOUT 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.

[43] 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 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 1,852 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 2022 and for the first three months of 2023. The Company has been taking recoupment in the Church Buttes, Hiawatha and Moxa Arch areas for most of the January 2022 through March 2023 period.

As can be seen in Exhibit 9.1, other parties have been recouping gas from the Company. A working interest partner in the Hiawatha Deep wells has been recouping gas from the Company since May 2019 through the end of the period. Recoupment from the Company also occurred in the Church Buttes and Dry Piney areas throughout the period.

As of December 31, 2022, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of 727.0 MMcf.[44] By way of comparison, the total net producer imbalance level for December 31, 2021, was 523.5 MMCF. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its

[44] 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.[45]

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 2023, Wexpro plans on completing to production, approximately 38.8 net wells with a capital budget for those wells of approximately $79.8 million.[46] Assuming market prices don't deviate dramatically from current expectations for the years 2024 through 2028, the total planned net wells are approximately 37.8, 37, 37.4, 37.5, and 27.5 respectively, with total annual investments in the range of $59.8 to $83.1 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2023 will focus on the Trail, Canyon Creek, 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 SENDOUT model to optimize the use of cost-of-service production. The SENDOUT 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 forecasts, updated pricing forecasts, and/or production forecast changes. The Company uses

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

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 2022 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 257 MDth of cost-of-service production shut-in for June 2022 through October 2022. As shown in Table 9.1, the Company did not shut in any production due to actual prices that were higher than forecast through the summer compared to the IRP modeled price forecast and cooler weather in the fall that resulted in increased demand.

Table 9.1: 2022 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	50,955 Dth	52,386 Dth	52,120 Dth	50,184 Dth	51,596 Dth	**257,242 Dth**
Actual Shut-in Production	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth	0 Dth

Based on the 2023 forecast for production provided by Wexpro and normal weather, the model determined that no cost-of-service production should be shut-in for June 2023 through October 2023.

Table 9.2: 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**

Exhibit 9.1

Recoupment Nominations (Dth per month by Field) To Other Parties			
	Church Buttes	**Hiawatha**	**Moxa**
22-Jan	1271	403	1240
22-Feb	1148	364	1176
22-Mar	1426	403	1147
22-Apr	1380	150	1020
22-May	1178	0	2976
22-Jun	1080	360	1200
22-Jul	1426	248	744
22-Aug	1519	372	1240
22-Sep	1470	330	840
22-Oct	1488	93	899
22-Nov	1410	90	1080
22-Dec	1302	0	2728
23-Jan	1240	0	1953
23-Feb	924	0	1848
23-Mar	930	0	2232
Total	19,192	2,813	22,323

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 QEPM Gathering I, LLC (QEPM). Andeavor Logistics LP (formerly Tesoro Logistics LP) acquired these midstream assets from QEP Resources Inc. in December of 2014. On October 1, 2018, Marathon Petroleum Corp (Marathon) and Andeavor Logistics LP closed on their merger. The combined company is known as Marathon Petroleum Corp. These agreements are managed by 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 SENDOUT modeling process. The SENDOUT 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).

On February 14, 2023, the Williams Companies, Inc. (Williams) officially closed on the purchase of MountainWest Pipelines Holding Company. This acquisition included the assets associated with MWP and MWOP included pipelines and storage.[47] This change in ownership will have no impact on the Company.

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.

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. 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.

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 was extended in October 2022 and now has a term expiration of October 31, 2027. This contract provides capacity to serve the southern portion of the DEUWI 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 was extended in May 2022 and now 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

[47] Williams (February 14, 2023) Williams Closes Acquisition of MountainWest Natural Gas Transmission and Storage Business [Press Release], https://investor.williams.com/press-releases/press-release-details/2023/Williams-Closes-Acquisition-of-MountainWest-Natural-Gas-Transmission-and-Storage-Business

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 348 days during the 2022-2023 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 189 days during the 2022-2023 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 159 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 106,511 Dth with an average daily supply reduction to the city gate of 28,231 Dth. The maximum daily supply increase to the city gates was 180,000 Dth with an average daily increase to the city gate of 40,254 Dth. The NNT usage for the 2022-20232 IRP year is shown in Figure 10.1 below.

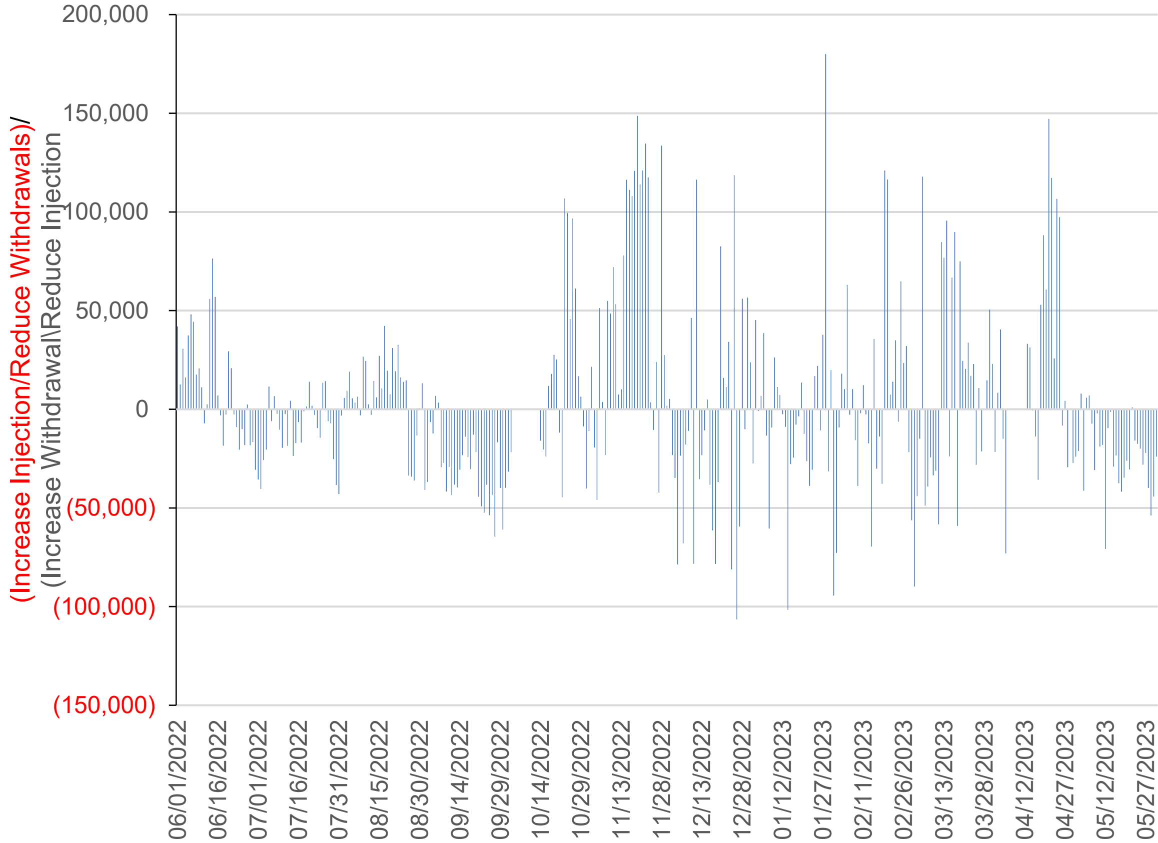


Figure 10.1: NNT Usage – 2022-2023 IRP Year

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 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, 2028. 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 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.

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.

Additional Transportation Options

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 pipelines outside of the current counterparty footprint. Some of the options the Company is currently evaluating include Ruby Pipeline, Rockies Express Pipeline (REX), and Southern Star Central Gas Pipeline (Southern Star). Ruby Pipeline and REX are both owned and operated by Tallgrass Energy, LP (Tallgrass).

The Company does not currently interconnect with any of these pipelines. However, the Company previously explored a connection with Ruby Pipeline which does cross existing Company facilities. The Company made preliminary arrangements with Ruby Pipeline to allow for a possible interconnect during construction of the pipeline. Access to REX and Southern Star would require the use of existing or expanded capacity on MWP or MWOP.

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, 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.

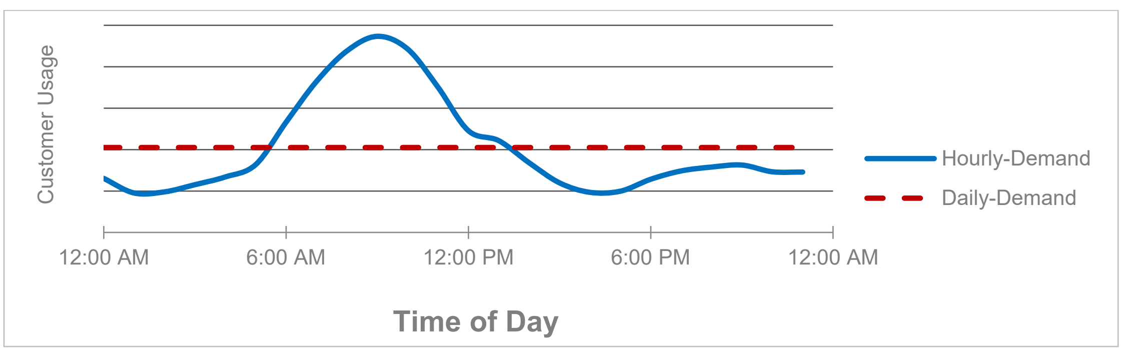


Figure 10.2: Hourly vs. Daily Demand

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 326,880 Dth/day during the 2023-2024 heating season to 359,882 Dth/day during the 2032-2033 heating season.

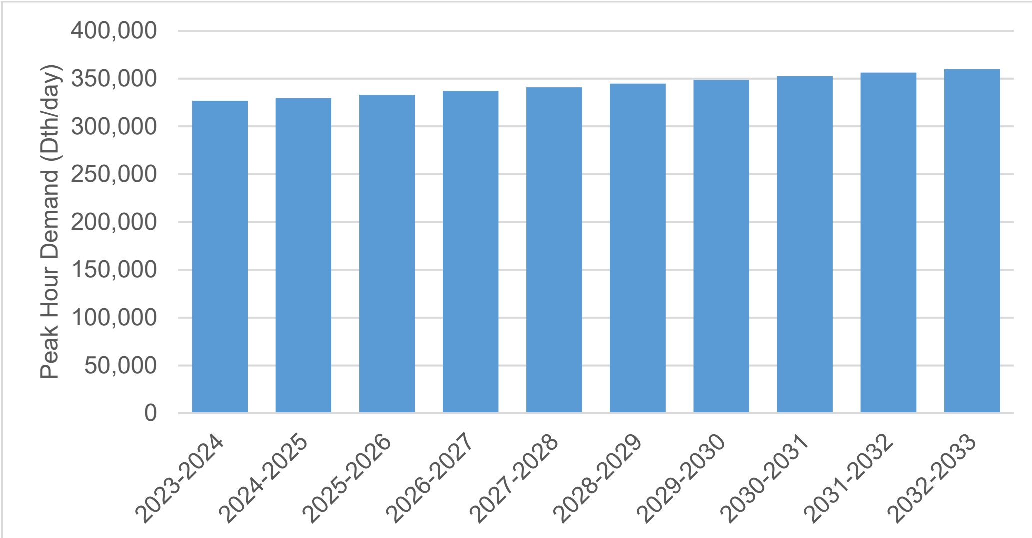


Figure 10.3: Peak-Hour Demand Requirements Above Firm Capacity

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 has also now 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 December 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 October 2021, the Company extended the contract with KRGT for 28,752 Dth of Firm Peaking Service (Contract #1692) for November 15, 2021 through February 14, 2022, November 15, 2022, through February 14, 2023, and November 15, 2023, through February 14, 2024.

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 DEUWI 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.

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). 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 will begin on April 1, 2024.

MWP owns the Aquifers and the Company utilizes them primarily for short-term peaking needs. The Company fully subscribes the Aquifer facilities. The Company has reviewed these storage resources as part of its planning process and plans to 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
Leroy	886
Coalville	720
Chalk Creek	321
Spire Storage West (Starting April 1, 2024)	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. Contract #935 contract has an inventory capacity of 5,964,000 Dth and withdrawal capacity of 49,700 Dth/day. The current term expiration for this contract is April 30, 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. After modeling the cost effectiveness using the SENDOUT model and completing an operational evaluation of this contract, the Company recently extended the term of Contract #988 for five years.

2022-2023 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 SENDOUT 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, 2022, and April 30, 2023, the Company utilized the Clay Basin storage facility to provide more than 11,837 MDth of supply to meet customer demand. This included 56 days with withdrawals that exceeded100 MDth and 9 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 56 days of injection during this period.

Leroy and Coalville Storage

The Company has 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. The Company also has PKS Contract #986 for 720,372 Dth of inventory capacity and 67,635 Dth/day of withdrawal capacity at the Coalville aquifer facility.

Following the end of the withdrawal season, the inventories in these 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, current operating practices at both the Leroy and Coalville facilities are 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 Storage

The Company also has 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.

Chalk Creek is 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:

- Historically, injections weren't allowed in the Chalk Creek facility until November. Injections may now commence in September following a controlled injection profile. This is an operational change, that MWP requested, and the FERC approved in 2018.

- 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.

2022-2023 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 2022 and April 2023, the Company withdrew inventory from 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

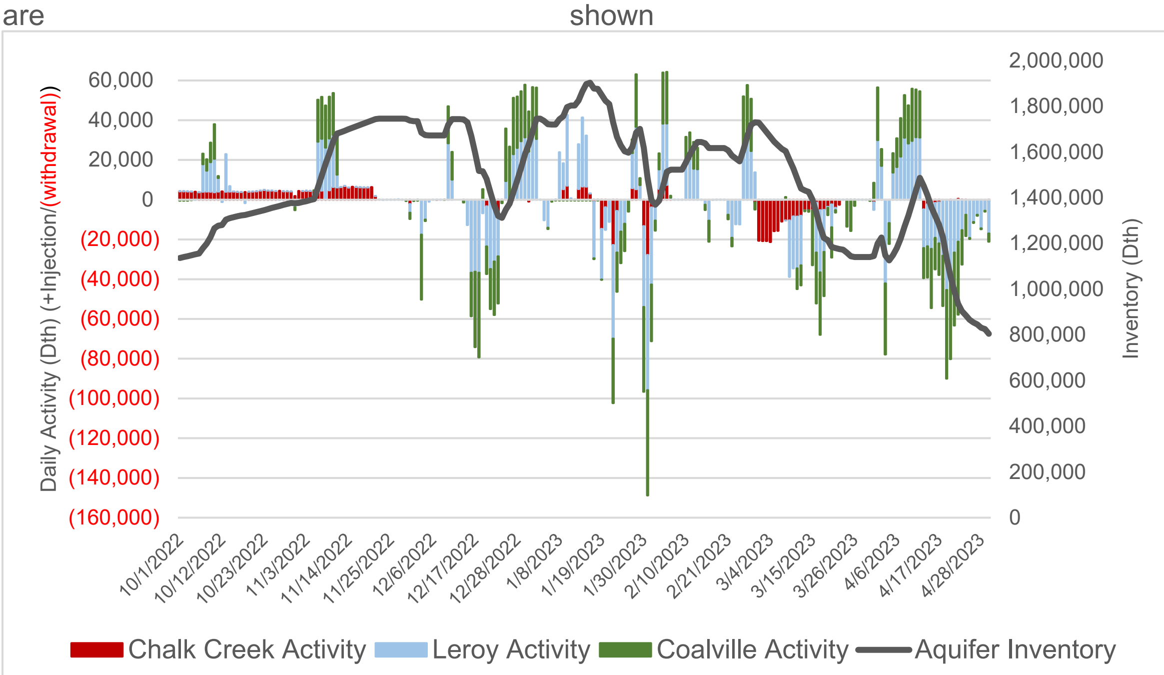


Figure 10.4 below. This flexibility is critical to operations when Clay Basin is not available.

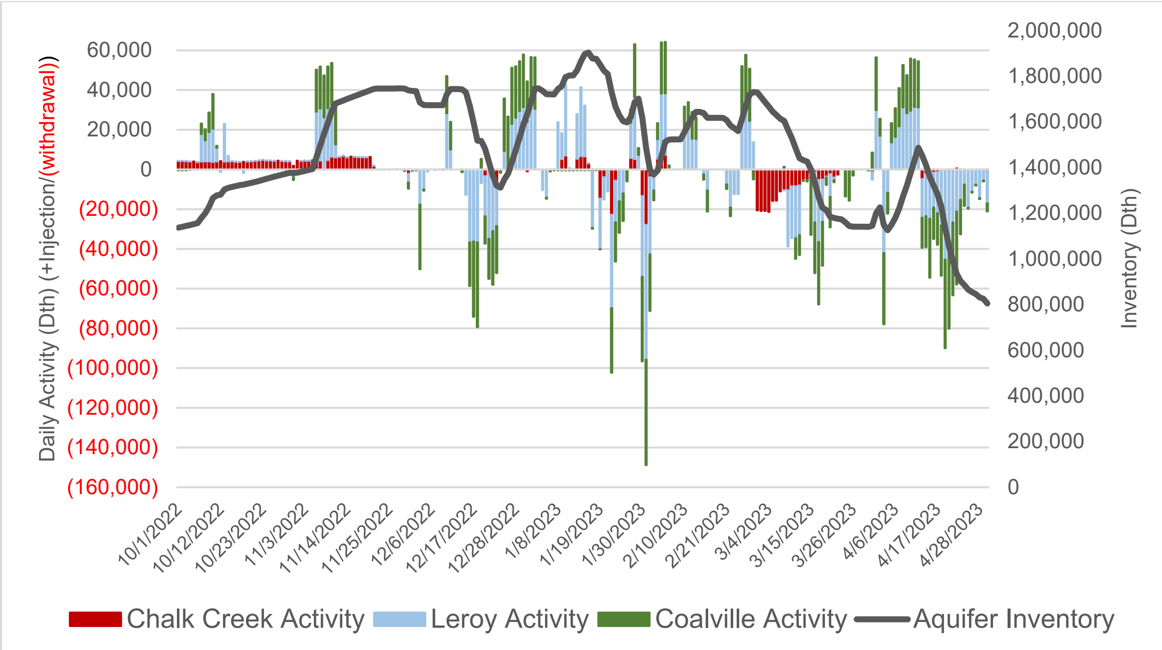


Figure 10.4: Aquifer Usage 2022-2023 Heating Season (Oct 2022 through April 2023)

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, Overthrust Pipeline, and Ruby Pipeline.

The Company previously held a FSS storage contract at this facility prior to March 31, 2021. The Company opted not to renew the contract going forward. The decision not to renew that contract was made prior to the high pricing event that occurred in February 2021, and prior to the increased pricing volatility of the more recent heating season. These events and the increased market volatility has changed the market for natural gas storage.

In April 2023, the Company responded to Spire Storage West's open season for firm storage capacity. The Company bid on storage capacity, and was offered, and accepted, a contract 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 DEUWI inventory drops below 30%.The injection capacity will reduce to 9,000 Dth/day when the inventory is above 50%. The new FSS contract will have a term of April 1, 2024, through March 31, 2029.

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. 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 is under warranty and the Company is working with the manufacturer to remedy the situation as quickly as possible. Currently, liquefaction is expected to resume in summer 2023 and the tank is expected to be approximately 80% full and available for withdrawals during the 2023-2024 heating season. If weather and commodity pricing are conducive, liquefaction could continue into the heating season, further increasing usable inventory.

Additional Storage Options

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, and a possible expansion of the Magna LNG facility. The Company will consider both the cost of these options and their operational advantages.

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, and its ability to contract for storage there is contingent upon cost and availability of transportation capacity for both delivery to the facility, and delivery from the facility to the Company’s distribution system.

Magnum Gas Storage

The Magnum Gas Storage (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. If Magnum fails to obtain contracts or begin construction by 2023 or 2024, its FERC certificate may expire.

The Company has been in discussions with Magnum regarding the availability of natural gas storage.

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. The Company will continue to evaluate this option, along with other available storage options, however at this point, this is not an option the Company is pursuing.

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 SENDOUT

The Company models the costs, contractual terms, and operating parameters for each of its contracts with storage facilities in SENDOUT. 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 SENDOUT modeling process. When the Company modeled storage and inventory, it expected that the inventory at Clay Basin on June 1, 2023, would be approximately 2,462,468 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.[48] 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 2022. The daily averages for 2022 for other Utah regions can be seen in Exhibits 10.3 and 10.4. In previous IRPs the Company utilized gas chromatograph data from MWP. This year, the company utilized data from new sources as a way of better representing the overall picture of gas quality on the DEUWI system. 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

[48] 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.

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.

System Diagram 2023

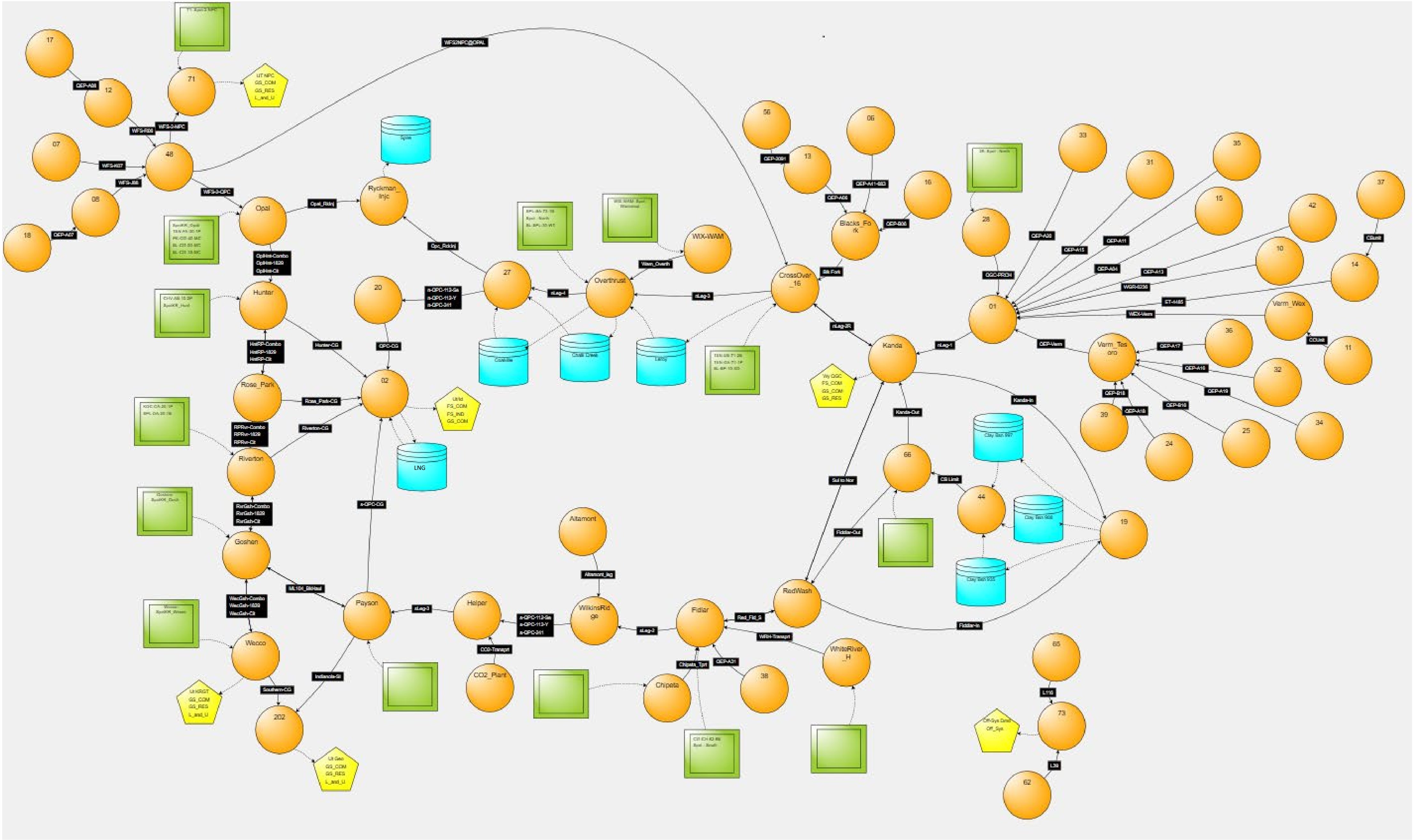


Exhibit 10.1

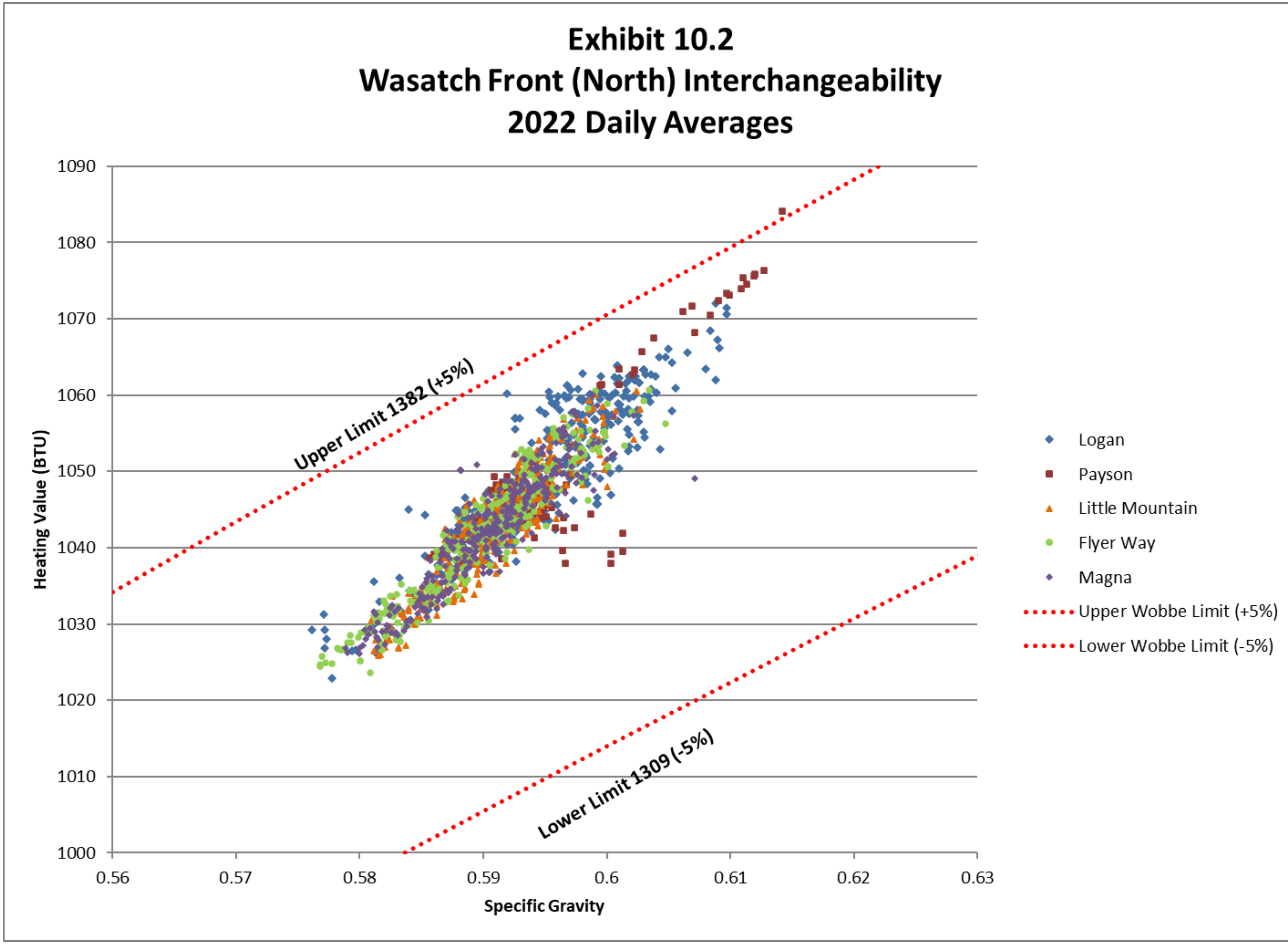


Exhibit 10.2
Wasatch Front (North) Interchangeability
2022 Daily Averages
Heating Value (BTU)
Specific Gravity
1090
1080
1070
1060
1050
1040
1030
1020
1010
1000
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
Upper Limit 1382 (+5%)
Lower Limit 1309 (-5%)
Logan
Payson
Little Mountain
Flyer Way
Magna
Upper Wobbe Limit (+5%)
Lower Wobbe Limit (-5%)

Exhibit 10.2

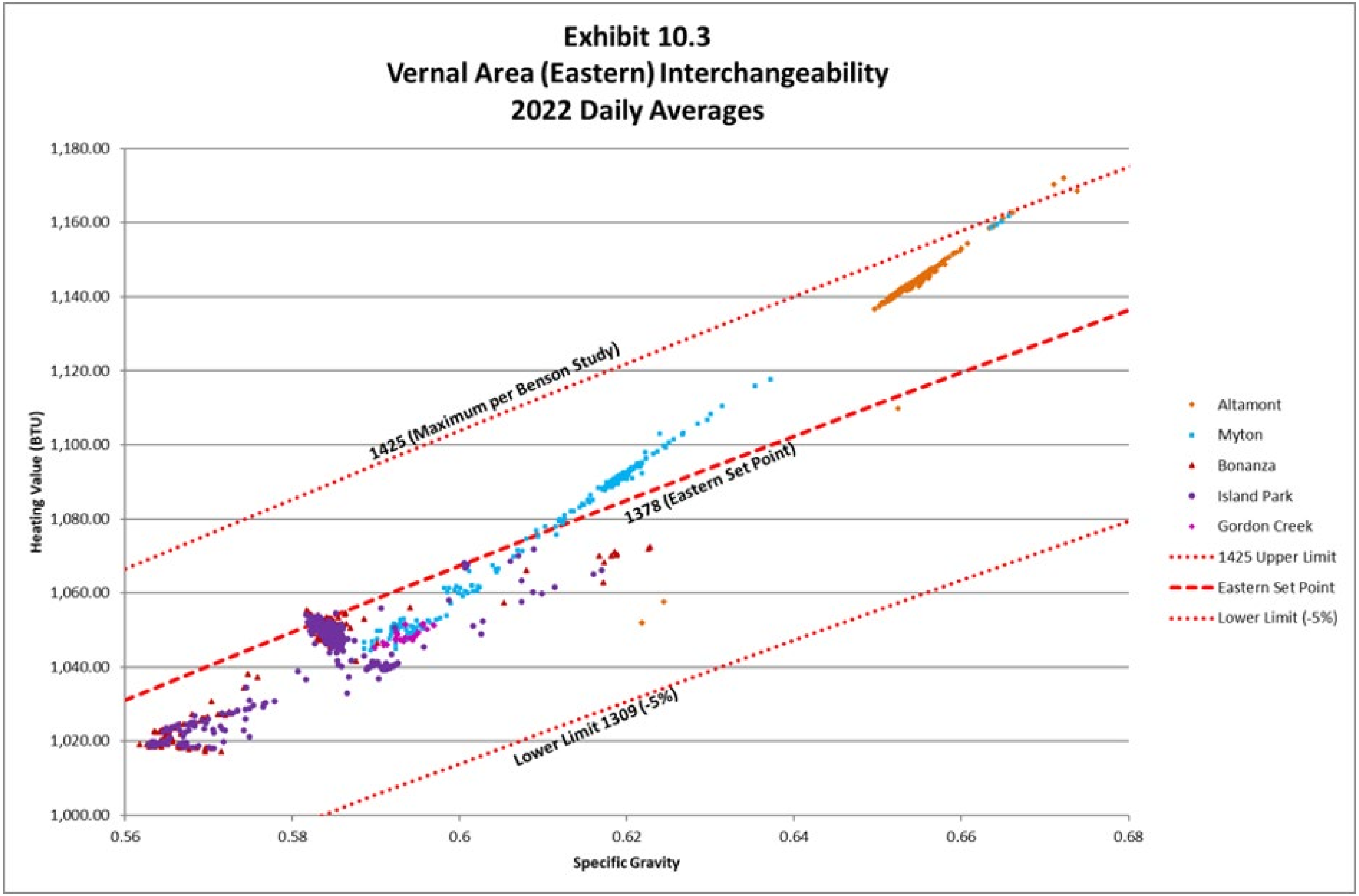


Exhibit 10.3
Vernal Area (Eastern) Interchangeability
2022 Daily Averages
1425 (Maximum per Benson Study)
1378 (Eastern Set Point)
Lower Limit 1309 (-5%)
Heating Value (BTU)
Specific Gravity
1,180.00
1,160.00
1,140.00
1,120.00
1,100.00
1,080.00
1,060.00
1,040.00
1,020.00
1,000.00
0.56
0.58
0.6
0.62
0.64
0.66
0.68
Altamont
Myton
Bonanza
Island Park
Gordon Creek
1425 Upper Limit
Eastern Set Point
Lower Limit (-5%)

Exhibit 10.3

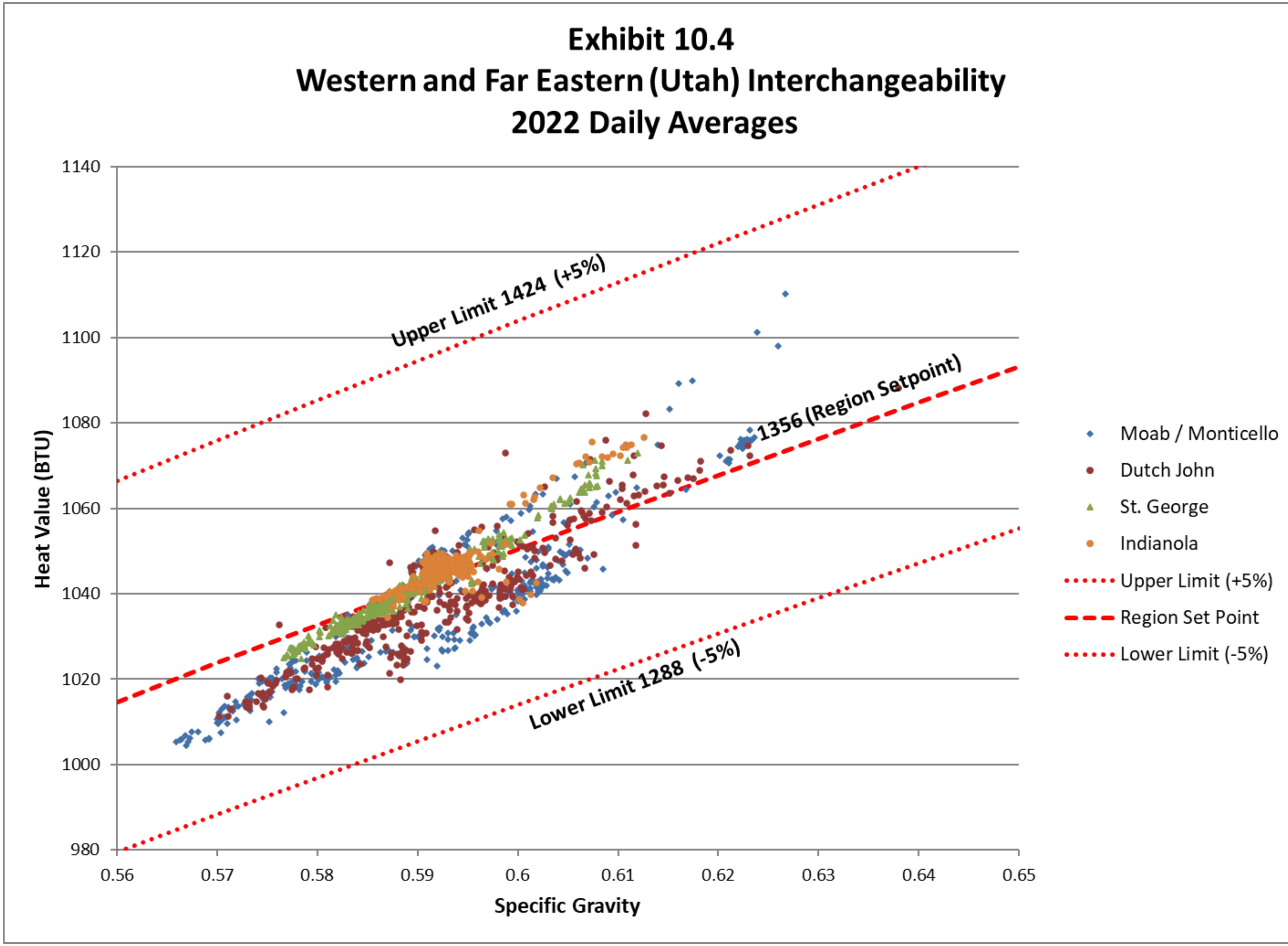


Exhibit 10.4
Western and Far Eastern (Utah) Interchangeability
2022 Daily Averages
Heat Value (BTU)
Specific Gravity
Upper Limit 1424 (+5%)
1356 (Region Setpoint)
Lower Limit 1288 (-5%)
Moab / Monticello
Dutch John
St. George
Indianola
Upper Limit (+5%)
Region Set Point
Lower Limit (-5%)
1140
1120
1100
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

Exhibit 10.4

DEW System BTU Report MAP
Quarter 1 2023

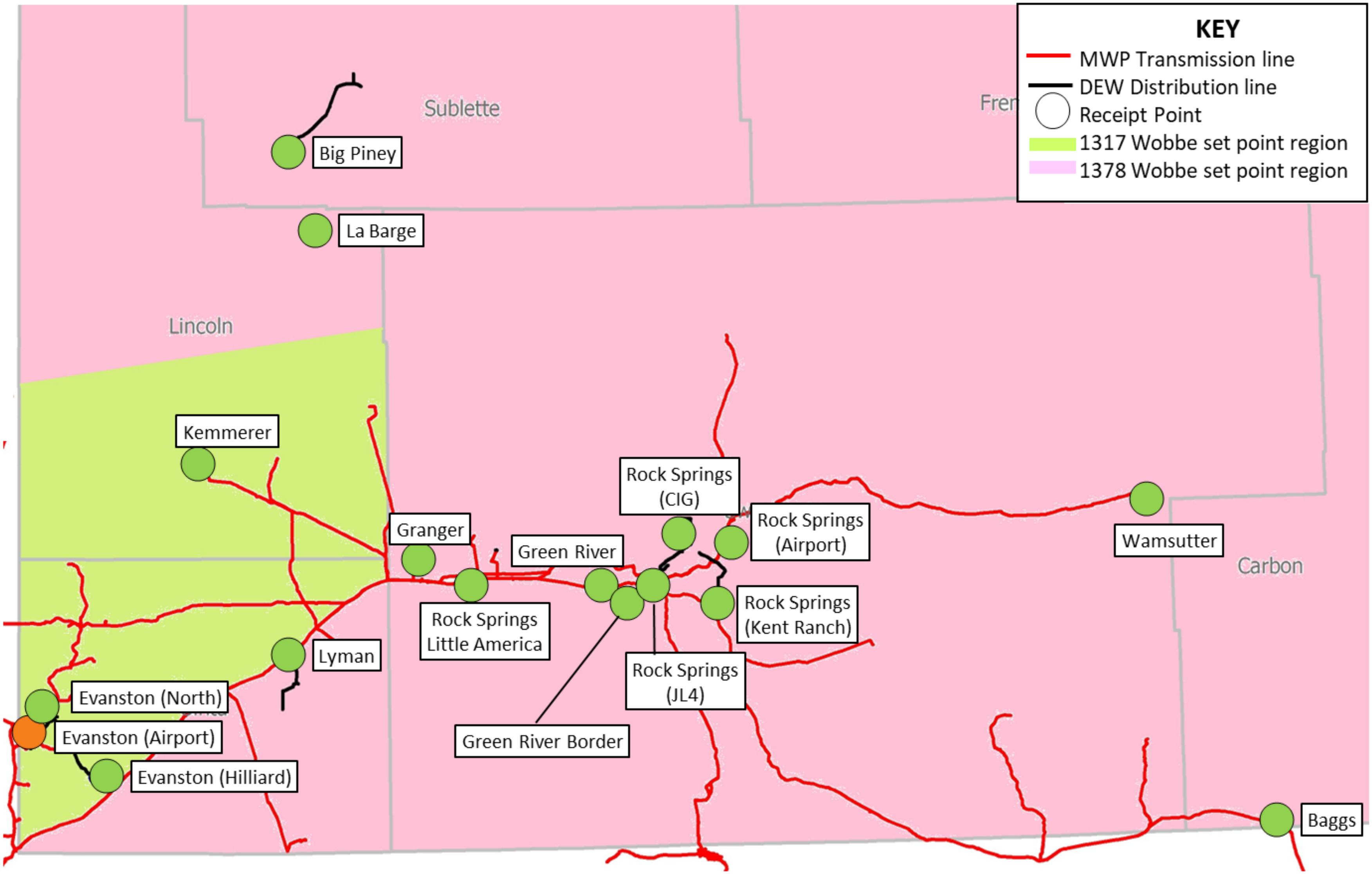


Exhibit 10.5

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.

Construction commenced on the facility, located near Magna, Utah, in July of 2020. That facility is now commissioned and will be a supply reliability resource for the 2023-2024 heating season. 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 is under warranty and the Company is working with the manufacturer to remedy the situation as quickly as possible. Currently, liquefaction is expected to resume in summer 2023 and the tank is expected to be approximately 80% full and available for withdrawals during the 2023-2024 heating season. If weather and commodity pricing are conducive, liquefaction could continue into the heating season, further increasing usable inventory.

LNG FACILITY UPDATE

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. The Company plans to liquify gas through the summer and fall of 2023 in preparation to provide supply reliability support during the 2023-2024 heating season.

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 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.

STORAGE ADDITION

As discussed in the Gathering, Transportation and Storage section of this report, the Company added 2,000,000 Dth of new firm storage service at the Spire Storage West facility in Wyoming beginning April 1, 2024. The withdrawal capability associated with this contract will help reduce the amount of supply the Company will need to purchase during high-demand events. Storage has been a reliable source of supply during these events in the past.

SUSTAINABILITY

DOMINION ENERGY'S COMPANY-WIDE SUSTAINABILITY COMMITMENTS

Across every part of the company, Dominion Energy is committed to safely providing reliable, affordable, and sustainable energy and to achieving Net Zero carbon and methane emissions for Scopes 1, 2, and material categories of Scope 3 by 2050. Dominion Energy provides details of this commitment in its 2022 Climate Report.[49]

In 2020, Dominion Energy announced its commitment to Net Zero carbon and methane emissions, from both its electric and gas businesses, by 2050. In addition to covering carbon and methane emissions within its direct control (known as Scope 1 emissions), in February 2022, Dominion Energy broadened its Net Zero commitment to encompass emissions outside of its direct operations (known as Scope 2 and Scope 3 emissions). Scope 2 emissions are those emitted from electricity the company consumes but does not generate. The Scope 3 portion of the commitment includes emissions from three material categories: electricity purchased to power the grid, fuel for power stations and gas distribution systems, and consumption of sales gas by natural gas customers like DEUWI's customers. Figure 12.1 below represents examples of each of these scopes of emissions, and their position upstream and downstream from DEUWI's operations.

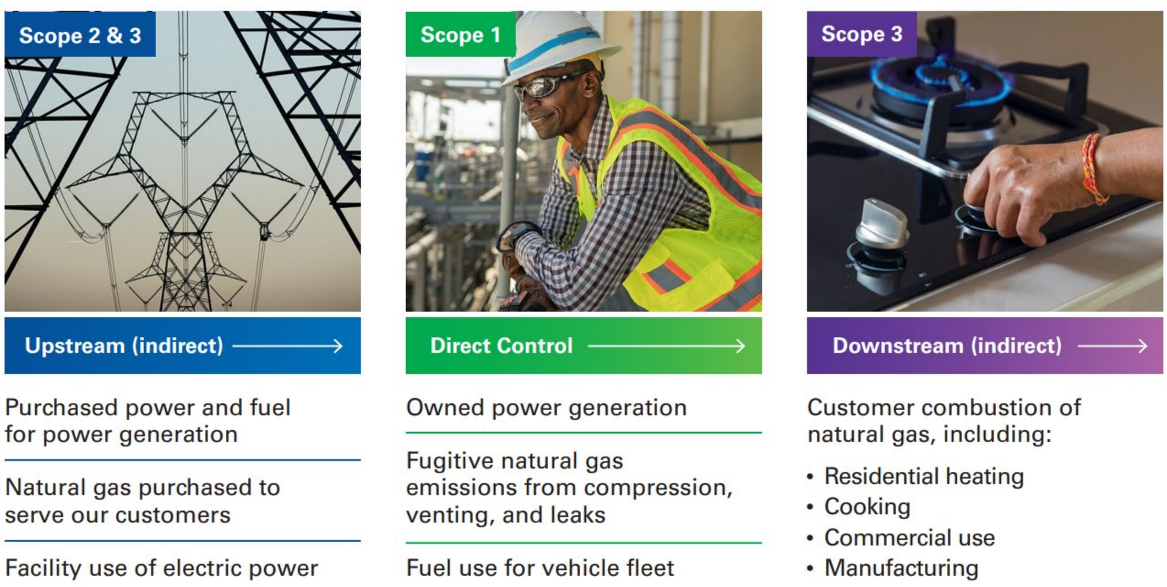
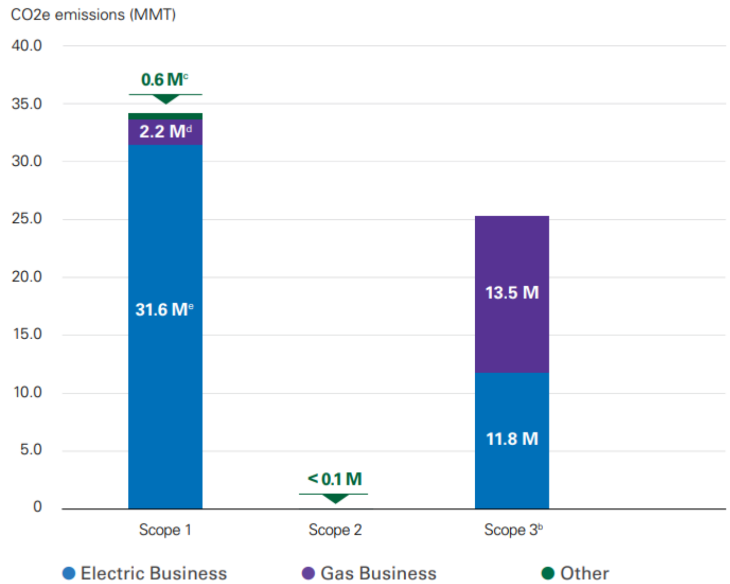


Figure 12.1: Emissions Categories

49 Dominion Energy 2022 Climate Report, 2022, https://www.dominionenergy.com/-/media/pdfs/global/company/esg/2022-climate-report.pdf

Figure 12.2 shows the majority of the emissions related to the Dominion Energy gas business are Scope 3 emissions, with a smaller portion of emissions being categorized as Scope 1.



[a] Excludes emissions from recently divested Dominion Energy Questar Pipeline (DEQP) and Dominion Energy West Virginia (DEWV) assets.

[b] Scope 3 emissions for the electric business include upstream emissions from electricity purchased to power the grid and fuels purchased for our power stations. Upstream emissions from fuel for our power stations refers to natural gas, oil, and coal. Scope 3 emissions for our gas business include upstream emissions from fuel purchased for our gas distribution systems and downstream emissions from consumption of sales gas by our natural gas customers. Upstream emissions from fuel for our gas distribution systems refers to gas for which the company takes title.

[c] Includes emissions on an equity share basis from Cove Point.

[d] Approximately 63% (1.4 MMT) of gas business CO2e emissions are from emissions of methane.

[e] Approximately 99% (31.3 MMT) of electric business CO2e emissions are from emissions of carbon dioxide.

Figure 12.2: Emissions Across Dominion Energy Value Chain

Achieving Net Zero emissions by 2050 — not only for Scope 1 electric and gas operations, but for Scope 2 and certain material Scope 3 categories — lies at the heart of Dominion Energy's long-term business strategy. This strategy aims to leverage all decarbonization alternatives and maintain optionality going forward to adjust plans based on advancements and evolving circumstances. In doing so, Dominion Energy, and all of its subsidiaries, remain committed to maintaining customer reliability and affordability and mindful that many of these approaches will require legislative and regulatory support. Dominion Energy is pursuing several pathways to meet this Net Zero commitment:

- rapidly expanding its portfolio of renewable energy and storage
- extending the licenses of its zero-carbon nuclear stations
- investing in system resiliency and modernization
- advancing zero-carbon or carbon-beneficial technologies, including RNG, hydrogen, SMRs, energy storage, and more

Natural gas is part of Dominion Energy's long-term vision and consistent with its Net Zero commitment. Natural gas plays a key role in delivering clean energy by providing fuel to power the electric grid as intermittent renewable energy sources are brought online. DEUWI is committed to efforts that reduce upstream and downstream emissions, as well as continued investment in its gas infrastructure to support integration of RNG and hydrogen on its system.

Dominion Energy is committed to making near-term progress toward its Net Zero commitment. Dominion Energy expects to reduce Scope 1 methane emissions from its natural gas business 65% by 2030 and 80% by 2040 (from 2010 levels). Figure 12.3 below shows the Dominion Energy company-wide Net Zero commitment targets. [50]

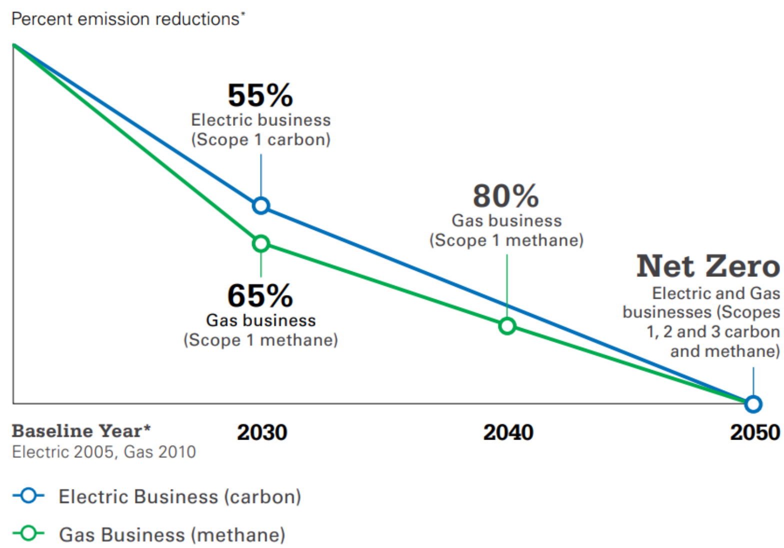


Figure 12.3: Dominion Energy Company-Wide Net Zero Commitment Targets

Dominion Energy in Utah, Wyoming, and Idaho will play a key role in meeting these goals. Dominion Energy is also working to make all of the natural gas distribution systems "Future Ready." The Company is committed to promoting renewable natural gas and blending increasing quantities of it into its local distribution systems. The Company is also preparing for hydrogen blending in the distribution system. As discussed more fully below, DEUWI's systems will be prepared to receive up to 5 percent hydrogen by 2030.

DEUWI SCOPE 1 SUSTAINABILITY INITIATIVES

DEUWI shares Dominion Energy's goals. Its efforts thus far to achieve these goals are described below.

[50] Dominion Energy 2022 Climate Report, 2022, https://www.dominionenergy.com/-/media/pdfs/global/company/esg/2022-climate-report.pdf

DEUWI 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 DEUWI'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 2022 approximately 21 million feet of pipeline and 210,500 services were surveyed, resulting in the discovery of 846 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. In 2020 the Company implemented a process for fining excavators who do not call 811 before digging and damaging a DEUWI facility. The fine is remitted to the State of Utah as outlined in the 811 law. 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, Dominion Energy 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 a low of 2.20 damages per 1,000 locate tickets in 2022.

Wexpro Sustainability Initiatives

Since 2010, Wexpro has reduced its methane emissions by over 50%. 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. Wexpro now has a number of programs ongoing to 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 Dominion

Energy 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

Wexpro continues to work toward removing the largest remaining methane emissions source, pneumatic controllers. Pneumatic controllers constituted 92% of Wexpro's methane emissions in 2021. Wexpro has replaced some of its pneumatic controllers with electric controllers, and it has installed a solar powered air compressor to drive the existing pneumatic controllers on some well locations. Both systems were proven successful during the winter of 2020-2021 and appear to be viable options. Unfortunately, due to supply chain issues Wexpro was not able to convert the targeted 225 wells over the past year. However, a new solution has been identified that will allow Wexpro to convert all feasible Wexpro operated sites to non-emitting controllers by the end of 2023. This new solution will collect all vented gas and route it to a pilot light to be burned as a fuel gas rather than being vented to the atmosphere.

Air Quality Initiatives

Beginning in 2019, all Wexpro-operated production unit and tank burners, which are used to heat the natural gas, produced water, and condensate to assist in separation, were lowered in BTU output to better match the demand of the declined production. The burners were originally sized for higher initial production rates and as the production declines the required heat input (BTU) to obtain separation is reduced. This project better matched the equipment BTU rating to the declined production rates. Once the burner ratings were reduced, all units were stack tested via an analyzer to further optimize and ensure complete combustion.

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.

DEUWI SCOPE 3 SUSTAINABILITY INITIATIVES

One Future

Dominion Energy 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."[51] 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.[52]

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%.[53]

Responsibly Sourced Natural Gas

As part of the annual RFP for natural gas supply for 2023-2024 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.

[51] https://onefuture.us/
[52] https://onefuture.us/
[53] 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 DEUWI 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.

DEUWI 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 2019, the Company partnered with Anew Climate, LLC (formerly Bluesource, LLC), an RNG supplier, to provide renewable natural gas to its CNG refueling customers. Because RNG qualifies for high-value RIN credits when used as transportation fuel, this RNG did not increase the cost of gas to customers.[54] In 2022, renewable natural gas made up every gallon sold to CNG sales customers. The amount of RNG to be distributed in 2023 will largely depend on the 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 2022 ThermWise® results and 2023 program changes, budgets, and cost effectiveness ratios can be found in the Energy Efficiency section of this report.

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

[54] Through March 2021, the Bluesource partnership has generated $198,049 in RIN credits to Dominion Energy that have reduced the CNG commodity rate to sales customers.

program allows customers to purchase renewable natural gas attributes for their own usage. The Company sold 32,784 Dth of RNG green attributes to over 3,000 GreenTherm® participants in 2022.

CarbonRight™ – Carbon Offset Program

In October of 2020, the Utah Commission approved the voluntary carbon offset program – now known as CarbonRight™.[55] 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. During the first year of the CarbonRight™ program, the Company sold 2,678 metric tons of carbon offsets to over 1,100 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. 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 2023 growth rate of the CarbonRight™

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

program, the second tranche of offsets will be enough supply for approximately five 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, 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 (BAs) 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. DEUWI is participating in twenty-one other hydrogen and RNG related research projects with GTI (Gas Technology Institute) and NYSEARCH.

DEUWI Hydrogen Pilot Program

DEUWI is exploring the benefits of blending hydrogen with natural gas in a project coined ThermH_2. The project is taking place in four Phases to verify existing research on blending as well as gain operational experience within the DEUWI 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 DEUWI'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. In March 2023, the Company began introducing up to 5% blend of hydrogen into the distribution system in Delta. This phase of the pilot will allow the Company to build on the experience from the first phase on a larger scale. This phase includes an electrolyzer, allowing the Company to generate its own renewable hydrogen. To ensure safety, the Company is taking extra precautions at the injection site through frequent 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.

Phase three will introduce a hydrogen blend into a high-pressure natural gas system to gain operational experience on a more expansive basis. This phase will pave the way for the Company to have experience blending into larger and more complex systems than the earlier phases.

The final phase of testing will introduce the methanation process, which is the conversion of hydrogen and carbon dioxide to methane. Current technologies for methanation often involve using bacteria to create the methane. Ideally the Company will be able to use captured carbon dioxide and renewable hydrogen to create another source of carbon neutral methane.

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 2022 program year, the IIAC completed 20 energy and 40 clean air assessments using STEP funds. These assessments identified 263 potential projects that, if completed by the participating businesses, would result in a reduction of over 149 tons in annual criteria pollutants and more than 72,800 tons of annual CO_2 emissions. The identified potential projects would also result in reduced annual natural gas usage of nearly 970,000 Dth which is equivalent to the usage of over 12,000 homes.

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. The Company is active in the effort to advance the Hydrogen Hub in Utah and the west.

Since 2021, The Company has 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 2022, the Dominion Energy Charitable Foundation awarded $1.3 million dollars in environmental stewardship grants to support 97 community organizations across our entire footprint, with $190,000 going to 11 organizations in Utah, Idaho, and Wyoming. These grants were awarded to organizations 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. Compost Utah, Youth Garden Project, and the Thanksgiving Point Institute funds went toward teaching children from elementary school to high school about composting, sustainable gardening, healthy meals, and water conservation with hydroponic gardening techniques. Other grants supported organizations such as Grand Staircase Escalante Partners, Summit Land Conservancy, and Tracey Aviary to focus on river restoration projects and supporting conservation and education initiatives to maintain the beauty and integrity of our national parks.

ENERGY-EFFICIENCY PROGRAMS

UTAH ENERGY-EFFICIENCY RESULTS 2022

The Company's 2022 Commission-approved ThermWise® energy-efficiency programs and measures were similar to programs in 2021, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. ThermWise® results for 2022 were strong. While participation was lower than projected (64% of budget), gross natural gas savings reached 82% of the 2022 budget projection. Spending for the 2022 program year totaled $24.9 million or 82% of the $30.2 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for 81% of the total ThermWise® spending in 2022 (79% in 2022 budget) and resulted in gross annual natural gas savings of more than 940,000 Dth.

Utah ThermWise® Appliance Rebates

The Company continued this program in 2022 with the addition of residential heating ventilation and air conditioning (HVAC) monitoring and diagnostic systems to the mix of rebate-eligible equipment. The Company added a $50 rebate for both single and multifamily customers who purchase and install a qualifying residential HVAC monitoring and diagnostic system. A residential HVAC monitoring and diagnostic system is a small device that can be added to a customer's new or existing furnace to provide real time performance monitoring. System performance is monitored through a subscription-based service offered by the installing HVAC contractor or device manufacturer, to ensure optimal system efficiency. If a fault in furnace performance is detected by the system, the homeowner will be contacted by the monitoring company to correct the issue.

The Company continued to perform outreach and marketing work in-house in 2022. Resource Innovations continued to provide technical assistance and rebate processing work for the Appliance program in 2022.

Utah ThermWise® Builder Rebates

The Company continued this program with the addition of the residential HVAC monitoring and diagnostic system as a rebate eligible measure in 2022 for the same reasons as described in the Appliance Program discussion. The Company also added rigid foam exterior insulation as a rebate-eligible measure in 2022. Rigid foam exterior insulation is a relatively new product which is intended to minimize heat loss through wood framing and improve moisture and airflow control in buildings. The Company proposes a $200 single family and $150 multifamily rebate per home/unit for builders who install qualifying rigid foam exterior insulation. In order to qualify, builders must install products which achieve > R-5 insulation value, the product must not be required by state and local building/energy efficiency codes, single and multifamily properties must have natural gas space heating, and the installation must comply with the ventilation requirements outlined in the applicable International Mechanical Code.

In addition to the new measures, the Company made several minor Tariff changes for purposes of accuracy. Also, the Company adjusted the per-saved-therm rebate amount from $3 to $4, but left the existing $800 rebate maximum in place, for the multifamily pay-for-performance measure in 2022.

The Company continued to perform outreach and marketing work in-house in 2022. Resource Innovations provided technical assistance and continued to perform rebate processing work for this program in 2022.

Utah ThermWise® Business Rebates

The Company continued this program in 2022 with the addition of rebates for two categories of advanced boiler control systems. The two systems, linkageless controls and O2 trim controls, have seen significant customer participation in recent years through the Business Custom rebate option. Due to the nature of the Business Custom measure, where equipment is installed and actual natural gas savings are monitored over time, the Company had the necessary experience and evidence to support inclusion of both systems as prescriptive rebate measures.

Linkageless controls are a retrofit improvement intended to increase combustion efficiency on older boilers. Baseline boilers with linked controls have a single mechanical actuator that controls (“links”) both the fuel valve and the combustion air damper together. They are tuned to deliver the recommended 10% excess air (EA) at high fire conditions, but do not maintain this ideal EA ratio at other firing conditions because the linked actuators cannot respond independently. Linkageless controls retrofit the boiler by separating actuators on the combustion and damper lines, allowing dynamic adjustment of air supply to the burner which enables higher combustion efficiency at a wider range of operating conditions. To be eligible for a rebate, customers were required to replace existing mechanically linked combustion air and fuel valve mechanisms with a digital linkageless control. Additionally, only natural gas boilers could qualify for a rebate and the linkageless control was not allowed to be required by state and local building/energy efficiency codes. The Company introduced this measure at a rebate amount of $0.50 per thousand British Thermal Unit (kBtu) of the boiler in which the linkageless control was installed.

O2 trim control systems work in tandem with linkageless controls to optimize combustion efficiency in boilers. O2 trim control systems consist of an O2 sensor and a pressure gauge on the stack, which monitors flue gas EA. The system feeds this information to a controller, which adjusts the fuel flow and combustion dampers to optimize combustion efficiency. Trim controllers can maintain tighter EA ratios across all firing conditions. To be eligible for a rebate, O2 controls must be capable of reducing excess air by < 10%. Additionally, only natural gas boilers qualified for a rebate and the O2 trim control was only eligible if it was not required by state and local building/energy efficiency codes. The Company introduced this measure at a rebate amount of $0.20 per kBtu of the boiler in which the O2 trim control was installed.

In addition to the new measures, the Company made several minor Tariff changes for purposes of accuracy. Resource Innovations continued to perform rebate processing and assisted with design, outreach, marketing, and technical assistance for this program in 2022.

Utah ThermWise® Weatherization Rebates

The Company continued this program with the addition of the rigid foam exterior insulation rebate, previously described in the Builder Program discussion. The Company further added a $0.40 rebate per square foot (maximum rebate of $800 single family / $400 multifamily) for customers who installed qualifying rigid foam exterior insulation.

Resource Innovations continued to perform rebate processing and assist with technical assistance for this program in 2022.

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. After briefly pausing in-home Home Energy Plan assessments and commencing a virtual Home Energy Plan assessment in 2020, the Company resumed the in-home option and opted to continue the virtual option. In 2022, the Company continued to offer virtual and in-home Home Energy Plan assessments.

Utah Low-Income Efficiency Program

The Company continued funding the Low-Income Efficiency Program in 2022 at $500,000, which was disbursed from the energy-efficiency budget ($750,000 total Company funding). The Company issued checks of $250,000 every six months in 2022, with the issuances occurring in January and July of the year. The Company also added the rigid foam exterior insulation rebate, previously described in the 2022 Builder Program discussion. The rebate was introduced at $0.40 per square foot for both qualifying single and multifamily properties that install qualifying rigid foam exterior insulation.

Utah ThermWise® Energy Comparison Report

In 2022 the Company sent the ThermWise energy comparison report (ECR or comparison report) to more than 228,000 customers. As of the end of September 2021, the Comparison Report had been generated over 368,000 times online by over 138,000 unique customers.

The Company increased delivery of the Comparison Report to 228,000 customers in 2022. Data shows that customers not only change behaviors to save natural gas as a result of the Comparison Report, but they are also more likely to participate in other ThermWise® Programs if they have received the report.

Program participants increased slightly over 2021 (less than 1%). Natural gas savings per customer also increased from 2021, by 1.6% per customer, in 2022. Given the program's maturity (in its seventh year in 2022) the Company moved the savings methodology to a deemed savings of 1.28 Dth per recipient for 2022 and future program years.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2022 budget filing is shown in Table 13.1.

Table 3.1 - Utah 2022 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	
	2022 Projected B/C	2022Actual B/C	2022 Projected B/C	2022 Actual B/C	2022Projected B/C	2022 Actual B/C	2022Projected B/C	2022 Actual B/C
ThermWise® Appliance Rebate	1.85	1.94	4.86	4.63	1.80	1.91	0.82	0.89
ThermWise® Builder Rebates	1.81	2.75	3.64	5.43	2.62	2.65	1.03	1.07
ThermWise® Business Rebates	1.30	1.46	3.52	3.87	2.13	2.26	0.89	0.97
ThermWise® Weatherization Rebates	1.23	1.23	2.86	2.80	1.45	1.54	0.81	0.84
ThermWise® Home Energy Plan	1.79	3.42	60.55	65.71	1.76	3.35	0.78	1.14
Low Income Efficiency Program	1.68	1.02	8.91	6.46	1.73	1.10	0.82	0.67
Energy Comparison Report	1.71	4.33	5.24	5.45	1.71	4.33	0.72	1.68
Market Transformation Initiative	0	0.00	N/A	N/A	0	0.00	0	0.00
Totals	1.53	1.86		4.38	1.92	2.05	0.89	0.96

Actual benefit/cost results for 2022 mirrored corresponding budget projections. The ThermWise® programs as a whole passed the Total Resource, Participant, and Utility Cost tests. Actual cost-effectiveness results were higher than projected primarily due to greater than expected participation in high-savings energy-efficiency measures and higher than forecasted avoided natural gas costs than were used in cost-effectiveness modeling for the 2022 ThermWise® budget filing (Docket No.21-057-25).

ThermWise® program results for 2022 (53,429 actual rebates paid) finished the year at 64% of the Company's original 2022 estimate (83,370). The Weatherization program had the highest total number of participants (21,110) and finished at 65% of the 2022 goal.

The DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Three meetings were held in 2022 on the following dates: April 13, August 18, and September 27.

WYOMING ENERGY-EFFICIENCY RESULTS FOR 2022

The Company filed for approval (Docket No. 30010-201-GT-21) of the of the 2022 Wyoming ThermWise® programs on October 29, 2021. The Wyoming Public Service Commission held an Open Meeting on December 30, 2021 concerning the Company's Application for the proposed 2022 Wyoming ThermWise® programs. The 2022 Wyoming programs were modified to closely align with the 2022 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 2022 programs (January 25, 2022, Order) and ordered the changes be effective January 1, 2022.

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 2022 program year (January through December 2022) the Wyoming ThermWise® programs had 224 participants or 1.01% of the Company's December 31, 2022, Wyoming GS customer base.

UTAH ENERGY-EFFICIENCY PLAN FOR 2023

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 2023 as well as the ThermWise® Market Transformation Initiative. The ThermWise® energy-efficiency programs continuing in 2023 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 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.

Though the Company has not previously recommended offering a rebate for geofencing-enabled smart thermostats, it has continued to monitor and track research on their energy savings capabilities since 2015. As a result, the Company believes that natural gas savings can be achieved through geofencing-enabled smart thermostats, at a lower level than occupancy sensor thermostats, and proposes to add them to the rebate mix beginning in 2023. The Company proposes 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, are proposed to be eligible for a $75 rebate per device beginning in 2023.

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 will continue to perform outreach and marketing work in-house in 2023. Resource Innovations will provide technical assistance and continue to perform rebate processing work for this program in 2023.

Utah ThermWise® Builder Rebates

Th Company continues this program in 2023 with the addition of the 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 will continue to perform outreach and marketing work in-house in 2023. Resource Innovations will provide technical assistance and continue to perform rebate processing work for this program in 2023.

Utah ThermWise® Business Rebates

The Company continues this program in 2023 with the addition of High-Performance New Construction rebate measure in 2023. 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 Dekatherm saved. In addition to the High-Performance New Construction measure, the Company also added the 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 continues this program in 2023 with no major changes. Resource Innovations will continue to perform rebate processing and assist with technical assistance for this program in 2023.

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 2023, 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 2023 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 2023. The Company will add 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 2023 the Company will send the ECR to more than 280,000 of its customers. As of the end of September 2022, the Comparison Report had been generated over 373,000 times online by over 140,000 unique customers.

The Company will increase delivery of the Comparison Report to 280,000 customers in 2023 or 23% above the 2022 level. This increase is 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 13.2 below.

Table 3.2 - Utah 2023 projected NPV & BC ratios by program and California Standard Practice Test

2023 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	$3.58	1.58	$18.57	3.83	$3.86	1.66	($1.91)	0.84
ThermWise® Builder Rebates	$9.56	1.87	$35.08	3.72	$12.28	2.49	$0.69	1.03
ThermWise® Business Rebates	$2.00	1.38	$11.40	3.37	$4.13	2.29	($0.17)	0.98
ThermWise® Weatherization Rebates	$2.14	1.24	$16.83	2.86	$3.51	1.46	($2.58)	0.81
ThermWise® Home Energy Plan	$0.59	2.14	$2.29	57.96	$0.58	2.11	($0.05)	0.95
Low Income Efficiency Program	$0.62	1.83	$2.36	9.33	$0.64	1.88	($0.16)	0.89
Energy Comparison Report	$1.99	4.62	$2.61	6.22	$1.99	4.62	$1.06	1.72
Market Transformation Initiative	($1.32)	0.00	$0.00	N/A	($1.32)	0.00	($1.32)	0.00
Totals	$19.16	1.55	$89.14	3.61	$25.68	1.91	($4.45)	0.92

*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 SENDOUT model.

Table 13.3 - Utah 2023 NPV & B/C ratios using gas cost forward curve from SENDOUT model

2022 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	$4.89	1.79	$18.57	3.83	$5.18	1.88	($0.60)	0.95
ThermWise® Builder Rebates	$12.91	2.18	$35.08	3.72	$15.63	2.89	$4.04	1.20
ThermWise® Business Rebates	$2.82	1.53	$11.40	3.37	$4.95	2.55	$0.65	1.09
ThermWise® Weatherization Rebates	$4.20	1.46	$16.83	2.86	$5.57	1.72	($0.52)	0.96
ThermWise® Home Energy Plan	$0.64	2.24	$2.29	57.96	$0.63	2.21	$0.00	1.00
Low Income Efficiency Program	$0.83	2.10	$2.36	9.33	$0.85	2.16	$0.04	1.03
Energy Comparison Report	$1.96	4.56	$2.61	6.22	$1.96	4.56	$1.03	1.70
Market Transformation Initiative	-$1.32	0.00	$0.00	N/A	-$1.32	0.00	($1.32)	0.00
Totals	$26.93	1.78	$89.14	3.61	$33.44	2.19	$3.32	1.06

*Shown in millions

WYOMING ENERGY-EFFICIENCY PLAN FOR 2023

The Company expects 2023 participation in the portfolio of Wyoming ThermWise® programs to reach 464 customers.

SENDOUT MODEL RESULTS FOR 2023

The Company entered projections from the approved 2023 energy-efficiency budget into the SENDOUT model in response to the Utah Commission's request. Data entries for the 2022 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 SENDOUT model.

The SENDOUT model used the projected 2023 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 2023 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 2023 projection. SENDOUT 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 SENDOUT results in a table format.

The model accepted the 2023 ThermWise® Appliance, Builder, Business, Home Energy Plan, and Weatherization programs at 25% of 2023 projected participation if administration costs were increased to 200% of the 2023 budget projection. The model accepted the Energy Comparison Report at 75% of participation and 100% of the 2023 budget projection.

Another way to view the results of the SENDOUT model is to analyze how much administration costs could increase and still be accepted if participation was held at 100% of the 2023 projection. In this scenario, the administration costs for the Appliance, Builder, Business, Home Energy Plan, and Weatherization programs could increase by eight times the 2023 budget projection and still be accepted. The Energy Comparison Report could increase projected administration costs by 25% and still be accepted.

In summary, the SENDOUT model results indicate that as a gas supply resource at the approved budget and participation levels, the 2023 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 SENDOUT model is a comprehensive resource planning and evaluation tool. In comparison, the Company developed its Energy-Efficiency Model in-house, with the 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 2023 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 1,094,835 Dth in 2023. This analysis resulted in a projected potential total energy-efficiency spending limit of $61.6 million per year using the Utility Cost Test. The currently-approved $28.1 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 SENDOUT 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 2022, the avoided gas cost attributable to energy-efficiency was calculated to be $58.6 million. For 2023, the avoided gas cost attributable to energy-efficiency was calculated to be $61.6 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

2023 Energy-Efficiency Modeling Results from SENDOUT

Program @ <u>100%</u> of 2023 Budget $	% of 2023 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT Model as a resource =

Program @ <u>150%</u> of 2023 Budget $	% of 2023 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT Model as a resource =

Program @ <u>200%</u> of 2023 Budget $	% of 2023 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT 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. Ventyx maintains this software product and markets it under the name of "SENDOUT." Ventyx was owned by ABB Ltd, a global power and automation technology group headquartered in Zurich, Switzerland with approximately 132,000 employees. On July 1, 2020, Hitachi Ltd announced the purchase of ABB Power Grids (ABB).[56] On July 1, 2021, Hitachi ABB Power Grids announced they would become Hitachi Energy starting October 2021.[57] SENDOUT is now a product of Hitachi Energy.

SENDOUT has the capability of performing Monte Carlo simulations thereby facilitating risk analysis. The Monte Carlo method utilizes repeated random sampling to generate probabilistic results. It is best applied where relative frequency distributions of key variables can be developed or where draws can be made from historic data. Because of the need for numerous random draws, the availability of high-speed computer technology helps facilitate this process. This year, due to software issues, the Company was only able to use a time horizon of 15 years for the Monte Carlo analysis.

The Company is using Version 14.3 of the SENDOUT modeling software. In performing gas supply modeling, the Company works closely with a consultant from Hitachi Energy. The consultant is very familiar with the gas-supply modeling conceptual approach of the Company and they are comfortable with how the Company utilizes and configures the SENDOUT model.

Due to ongoing software issues such as the inability to run longer time horizons for the Monte Carlo analysis, concerns regarding availability of updates, and support for the SENDOUT software in the future (no updates are currently planned), the Company plans to start using an alternate software package for its supply portfolio optimization, called Plexos. Plexos is an energy market simulation platform owned by Energy Exemplar. This software will provide similar and enhanced analysis and reporting functionality to SENDOUT. The Company plans to begin using Plexos in compiling the 2024-2025 IRP. The Company is currently working to set up the new model and reporting tools.

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

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[56] Hitachi Ltd (July 1, 2020), *Hitachi Completes Acquisition of ABB's Power Grids Business; Hitachi ABB Power Grids Begins Operation.* [Press Release]. https://www.hitachi.com/New/cnews/month/2020/07/f_200701.pdf

[57] Hitachi ABB Power Grid (July 1, 2021), *Hitachi ABB Power Grids is evolving to become Hitachi Energy and broadens commitment to a sustainable energy future.* [Press Release]. https://www.hitachi.com/New/cnews/month/2021/07/210701c.html

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 periodically reevaluates the constraints in its SENDOUT model to determine if they accurately reflect the realities of the problem being solved. For the 2022-2023 IRP model, The Company added a constraint to prohibit the model from fully emptying the inventory in the Clay Basin storage contracts prior to April 1. The Company has determined there are operational needs and benefits to maintaining at least 1 Bcf in Clay Basin through March.

MODEL IMPROVEMENTS

The Company made one additional modification to the SENDOUT model for the 2023-2024 IRP. The discount rate used in the model was adjusted to 4.58.% to reflect the Carrying Charge stated in the Tariff.

MONTE CARLO METHOD

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. With the complexity of the Company’s modeling approach, one simulation can take as long as several days to run. The Monte Carlo simulation developed by the Company this year utilized 809 draws.

When the developers of SENDOUT incorporated the Monte Carlo methodology, they limited the number of variables for which stochastic analysis can be applied to avoid excessive computer run times. The two variables determined necessary are price and weather (within SENDOUT, demand is modeled as a function of weather). No other variables have a more profound impact on the cost minimization problem being solved by SENDOUT.

The output reports generated from the SENDOUT modeling results consist primarily of data and graphs. Most of the graphs are frequency distribution profiles from a Monte Carlo simulation. 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 and likelihood 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 four price indices. Two of those indices are published first-of-month prices for deliveries to the interstate pipeline systems of Kern River and Northwest Pipeline. The remaining two are published daily indices for Kern River and one basket containing a combination of two additional Kern River indices.

To develop a future probability distribution, the Company assembles historical data and determines the means and standard deviations associated with each price index. The Company then uses the average of two price forecasts developed by S&P Global (North American Gas Regional Short-Term Forecast - 67 months) and IHS Markit (North American Natural Gas Short-Term Outlook - 271 months) as the basis for projecting the stochastic modeling inputs. Both price forecasts are provided by S&P Global. The Company adjusts forecasted standard deviations pro rata based on the historical prices to more accurately mirror reality. Exhibits 14.01 through 14.36 show, for the first model year, the resulting monthly price distribution curves for the first-of-month prices and the daily prices for each of the price indices used in the base simulation.

Given the extreme pricing scenario in February 2021, the standard deviations calculated as inputs to the Monte Carlo continue to be higher than normal and as such the simulations continued to include high price spikes in February.

WEATHER AND DEMAND

Weather-induced demand is the single most unpredictable variable in natural gas resource modeling. The Company provides 89 years of weather data to the SENDOUT model. When forecasting future demands, heating degree days are stochastic with a mean and standard deviation by month. The Company uses this number, along with usage-per-customer-per-degree-day and the number of customers, to calculate the customer demand profile used by the model.

The stochastic nature of the heating-degree-days creates a normal plot for degree days based on the 809 draws. For each month of simulation, the model randomly selects a monthly-degree-day standard-deviation multiplier to create a draw-specific monthly-degree-day total. It scans through 89 years of monthly data to find the closest matching month. Then the model allocates daily degree-day values according to the degree-days in this historic month pattern. Exhibits 14.37 through 14.49 show the annual and the monthly demand distribution curve for the first year of the base simulation. Exhibit 14.50 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 2023-2024 heating season is approximately 1.27 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.

Selecting a draw from a Monte Carlo simulation that utilizes, on the maximum demand day, a level of resources approximately equaling the Design Day has proven to be problematic in that it results in the SENDOUT model selecting too much baseload purchased gas for a typical weather year. The draws which have a Design Day occurrence also tend to be much colder than normal throughout the entire year. The solution to this dilemma is to perform a statistical clustering analysis of all the Monte Carlo draws for first-year Design Day demand versus the median level of first-year annual demand.[58] The result of this clustering exercise is a scatter plot that shows groups of draws. These cluster points or groups represent draws that are most closely alike in terms of Design Day requirements and annual demand. The Company then chooses a cluster point that it believes will meet annual demand without falling short on Design Day.

The Company then executes a series of deterministic SENDOUT scenarios, removing the unused RFP packages, and leaving those “cluster point” packages. 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 SENDOUT model helps to make this happen. This year, of the 809 draws generated in this process, 20 draws included days with demand that met or exceeded the Design Day requirement of 1.27MMDth. 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.

[58] See the cluster analysis discussion in the Modeling Issues subsection of the Purchased Gas section of this report.

Exhibit 14.51 shows the resources utilized to meet the Design Day. Exhibit 14.52 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 temperature scenario can be seen in Exhibits 14.83 through 14.92. 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.

PURCHASED GAS RESOURCES

Exhibits 14.53 through 14.64 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 14.65 shows the annual distribution from the simulation. Exhibit 14.66 shows the numerical monthly data with confidence limits. Gas purchased for the first plan year under the normal case is approximately 65.6 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 SENDOUT 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 14.67 through 14.78 show the distributions for cost-of-service gas for each month of the first plan year from the base simulation. Exhibit 14.79 shows the annual distribution from the simulation. Exhibit 14.80 shows the numerical monthly data with confidence limits. Cost-of-service production for the first plan year from the normal case is approximately 56.5 MMDth.

FIRST YEAR AND TOTAL SYSTEM COSTS

The linear-programming objective function for the SENDOUT model is the minimization of variable cost. A distribution curve for first-year total cost from the base simulation is shown in Exhibit 14.81. The first-year total cost from the normal case is approximately $428.6 million. Because the Monte Carlo analysis was limited to 15 years, a similar curve for the total 15-year modeling time horizon is shown in Exhibit 14.82. The normal case cost for the full 31- year time period is approximately $13.9 billion.

GAS SUPPLY/DEMAND BALANCE

Exhibits 14.89 and 14.90 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 SENDOUT and is titled "Required vs. Supply." The data in these exhibits represent the normal case. The Company slightly adapted the SENDOUT 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.[59] 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 14.91 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 137 MMDth for the normal case. Exhibit 14.92 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the MMDth 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).[60]

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 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)

[59] Also included are compressor fuel, Company use, and gas loss due to tear outs.

[60] 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.

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	0.00	0.00	0.00
	IRP Forecast	106.70	0.00	0.00
	High 10%	698.40	280.90	203.50

Table 14.2: Total Annual System Costs ($ million)

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	349	441	541
	IRP Forecast	337	430	530
	High 10%	331	419	520

Monthly FOM Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=6

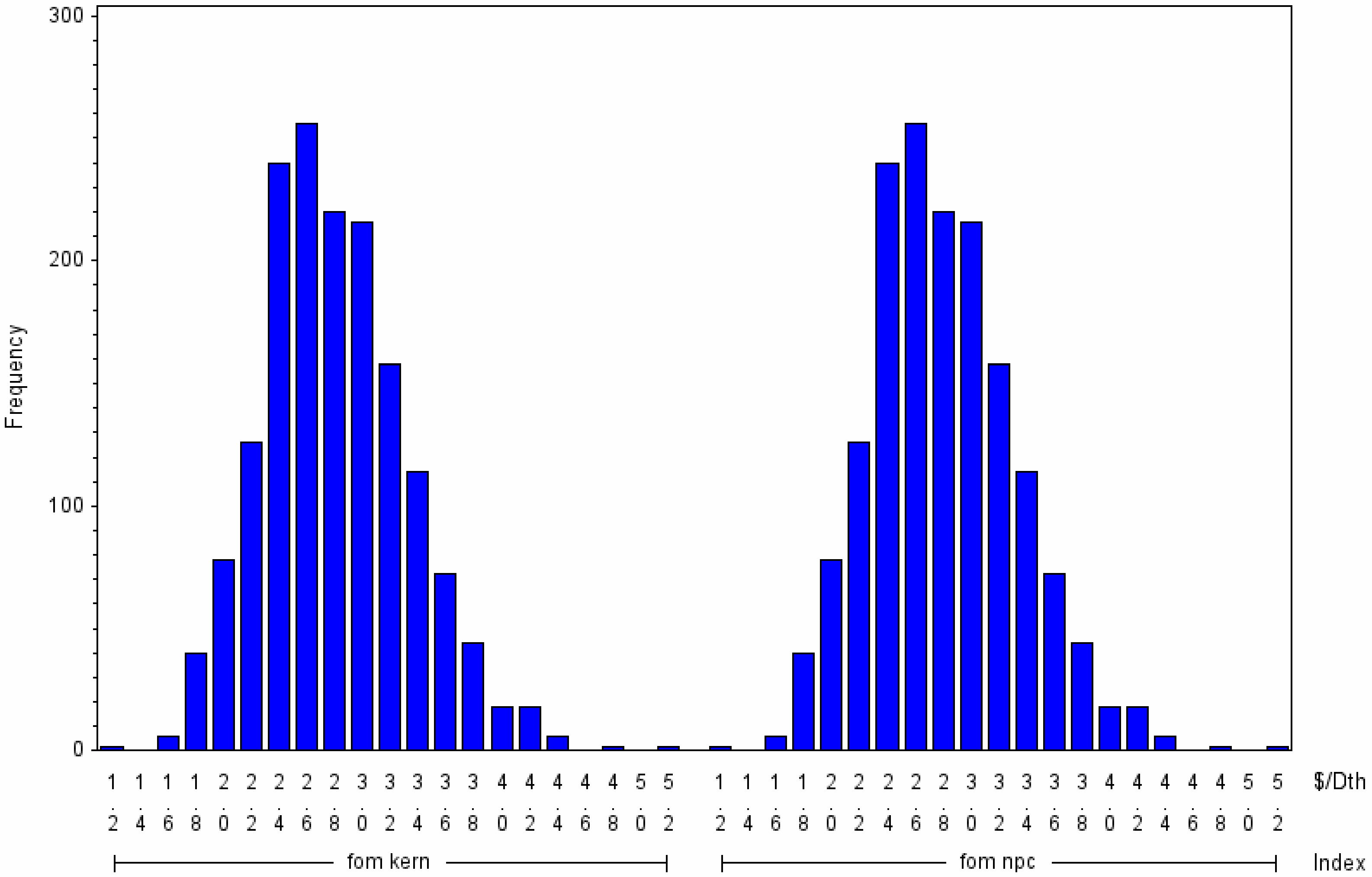
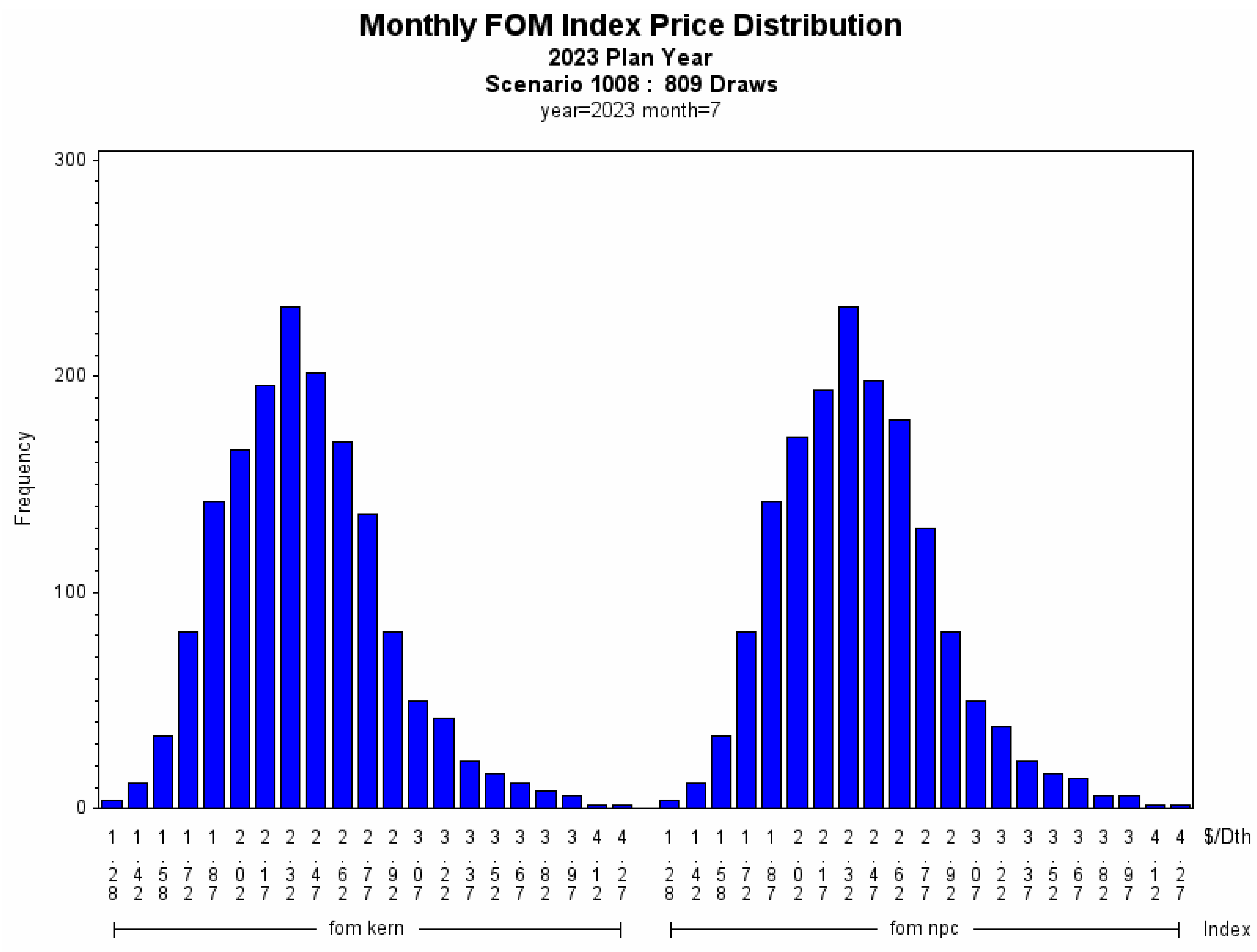


Exhibit 14.01



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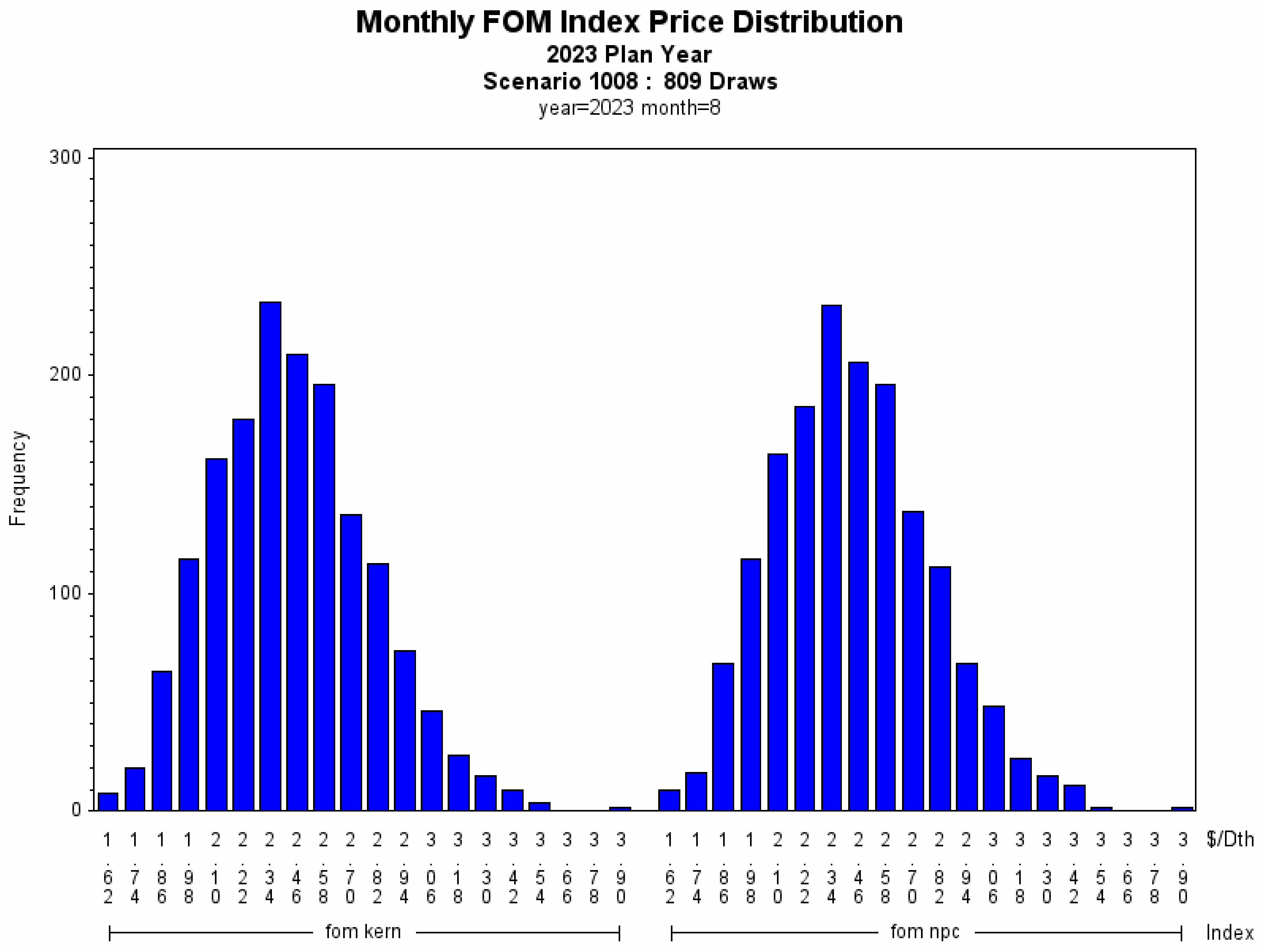

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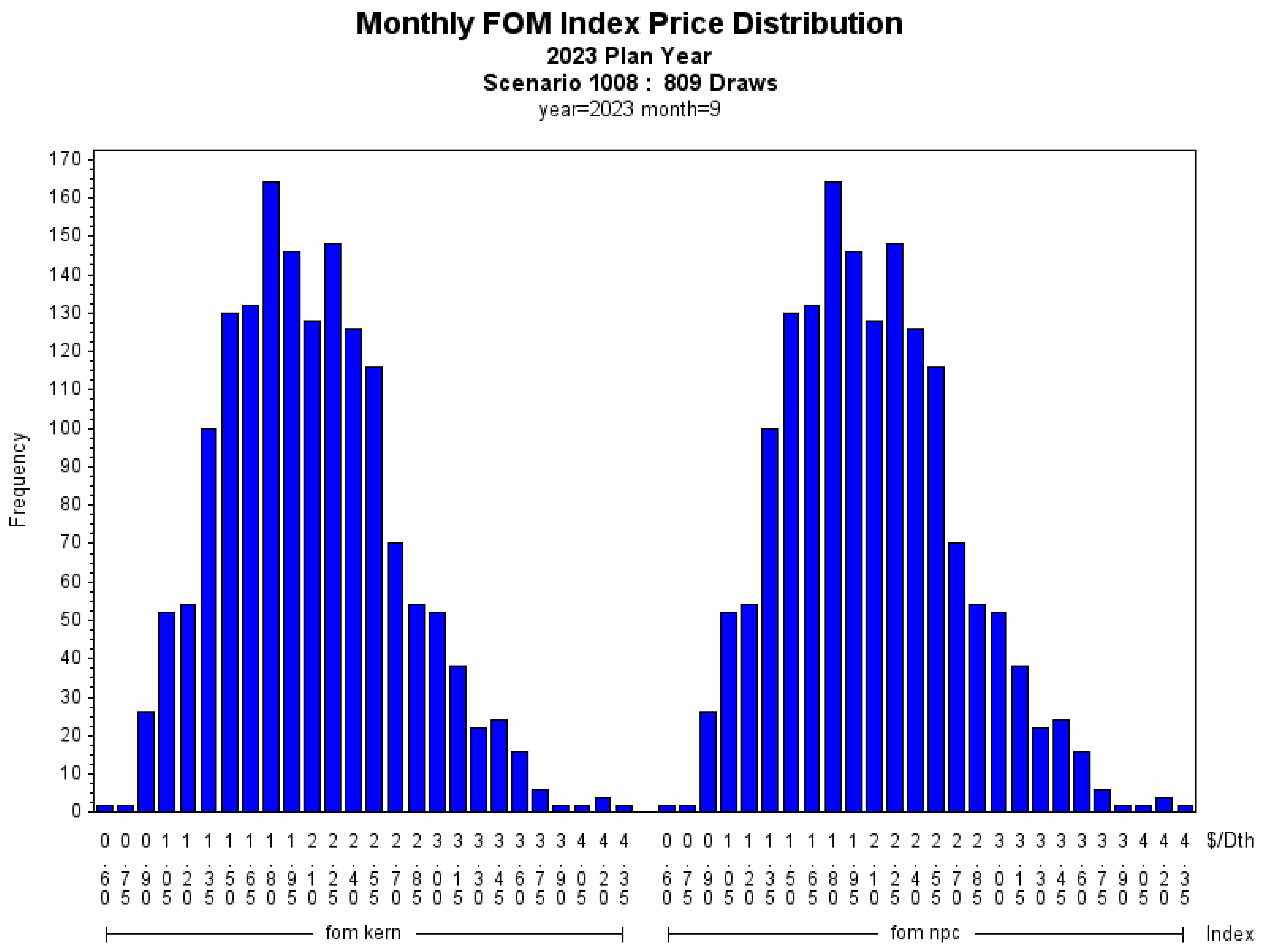

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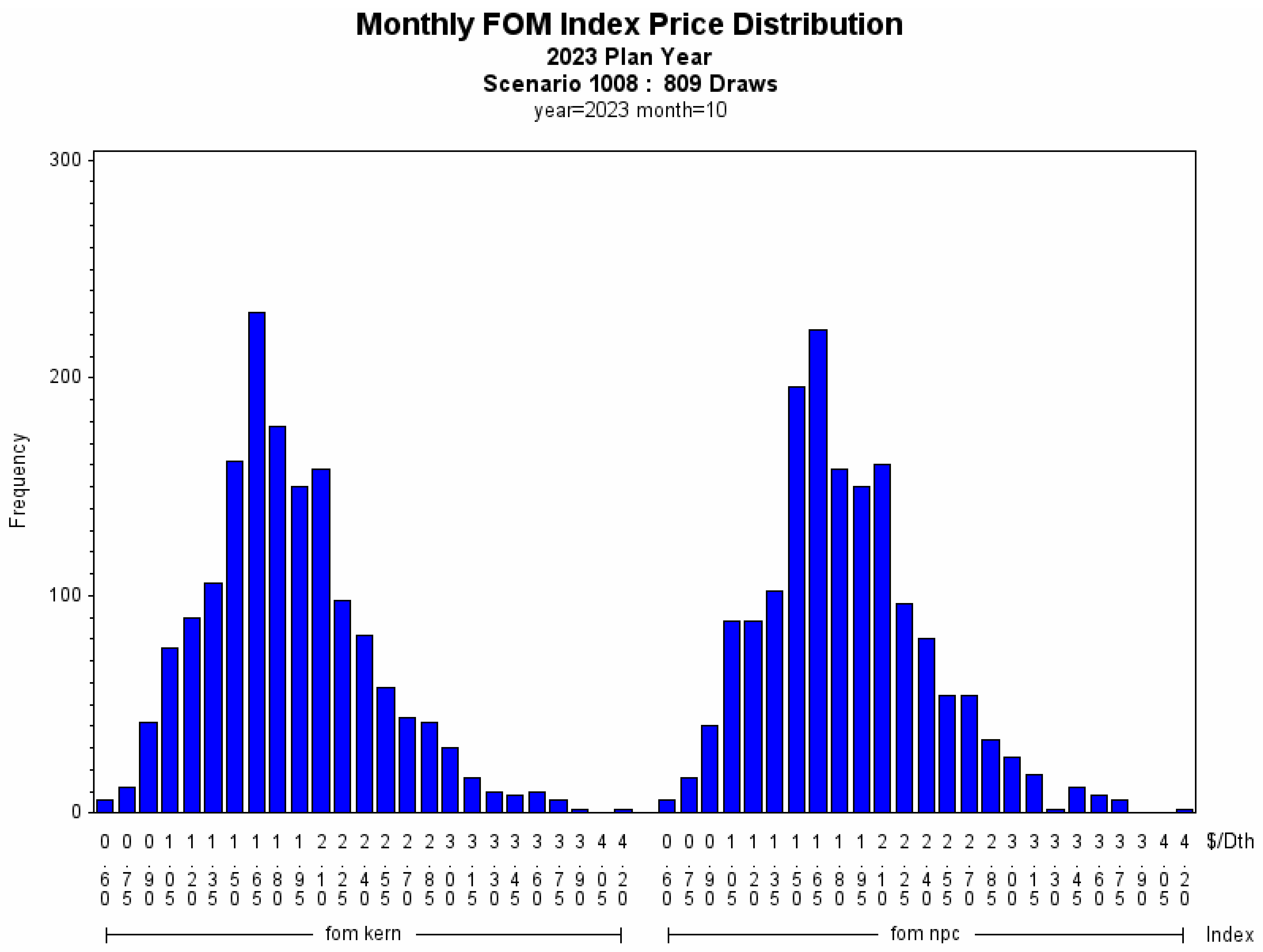

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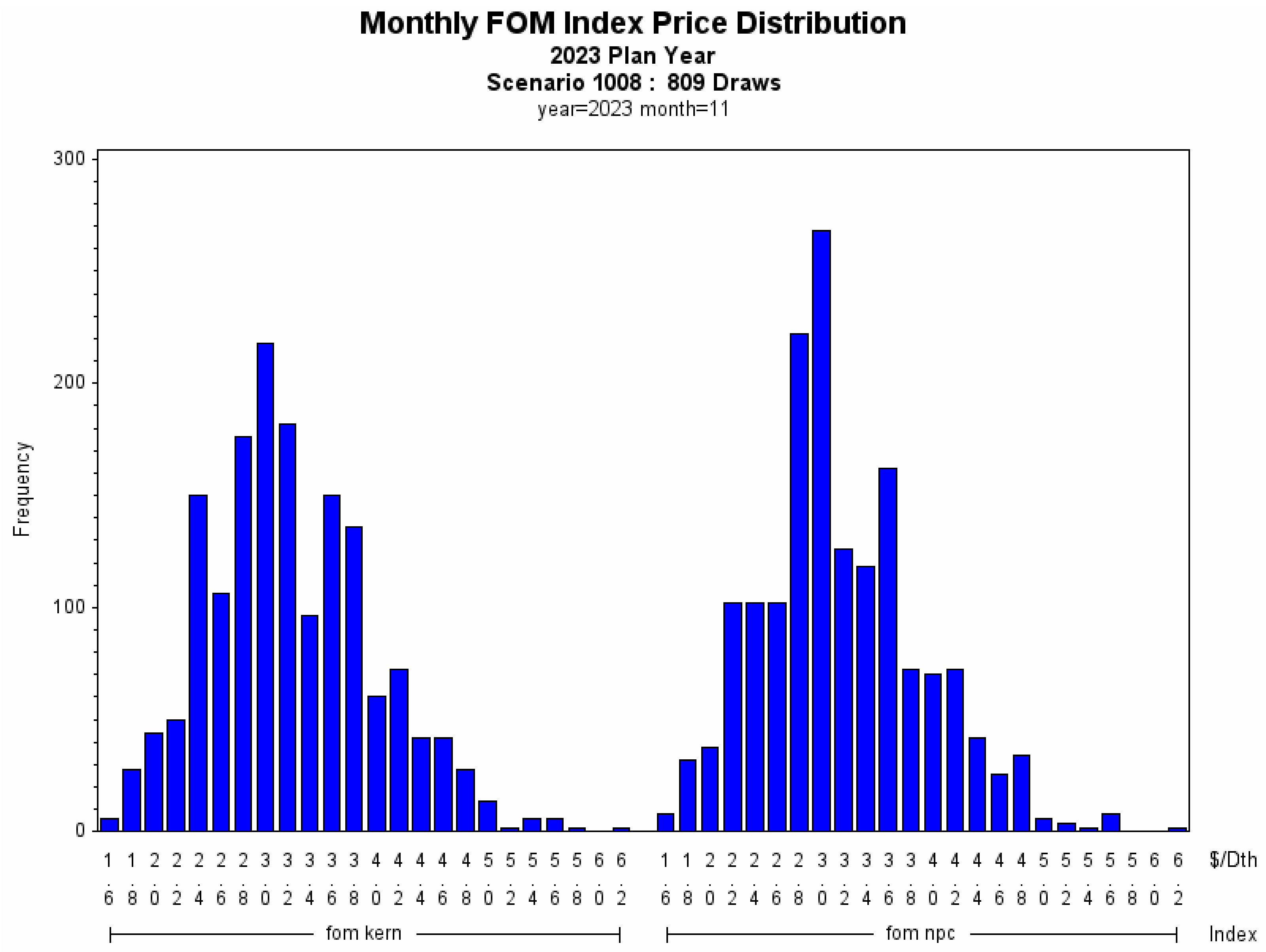

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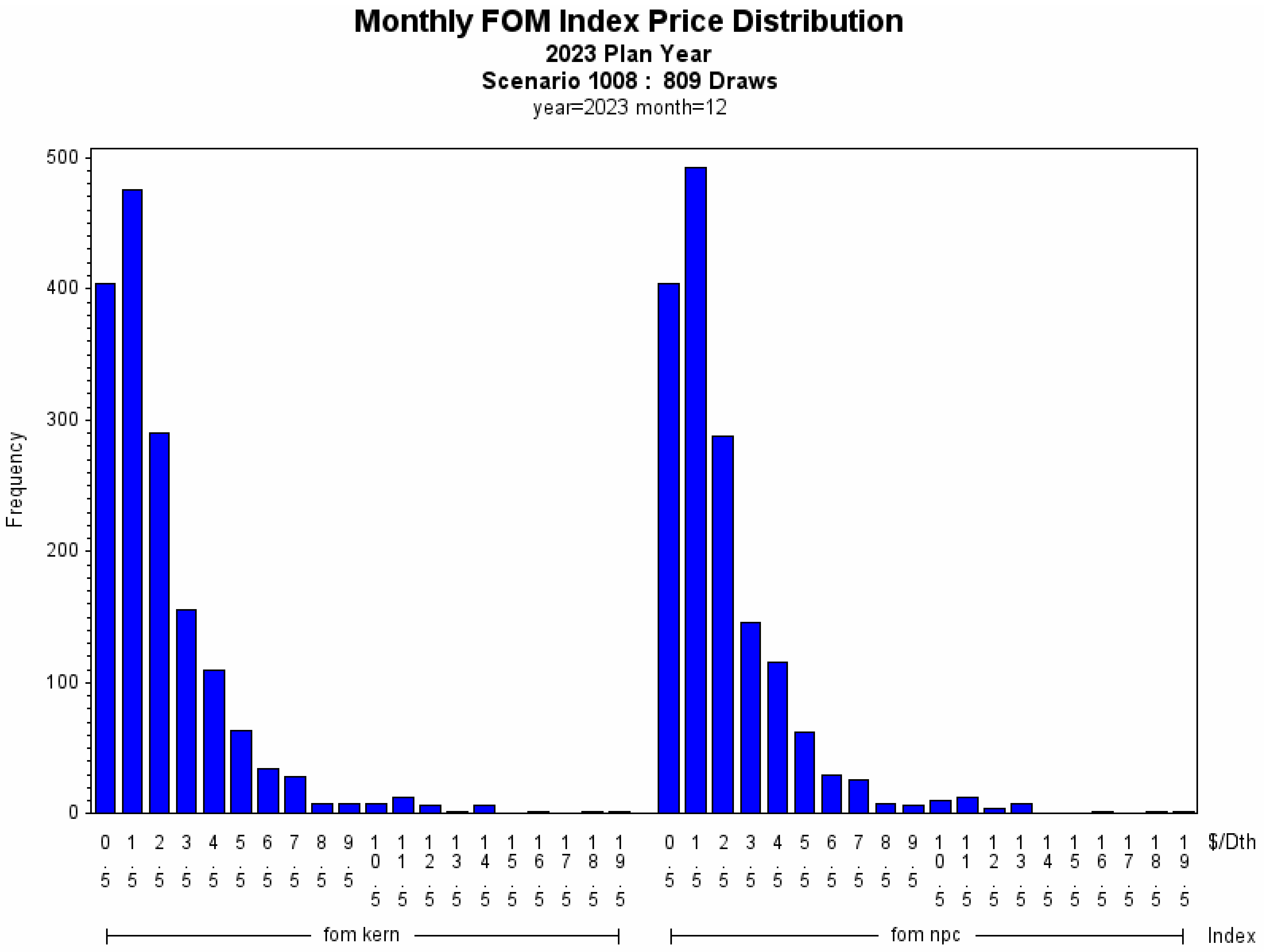

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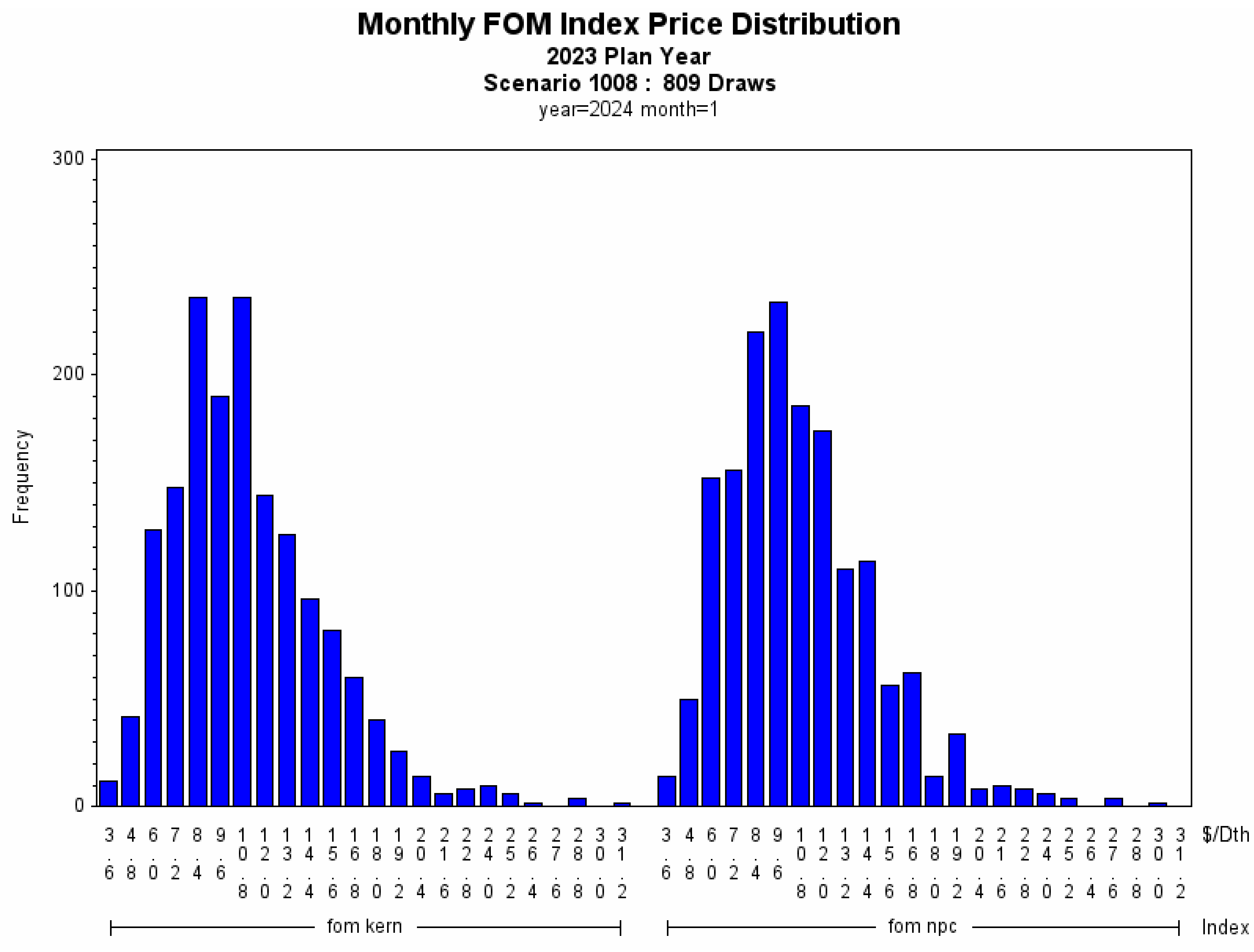

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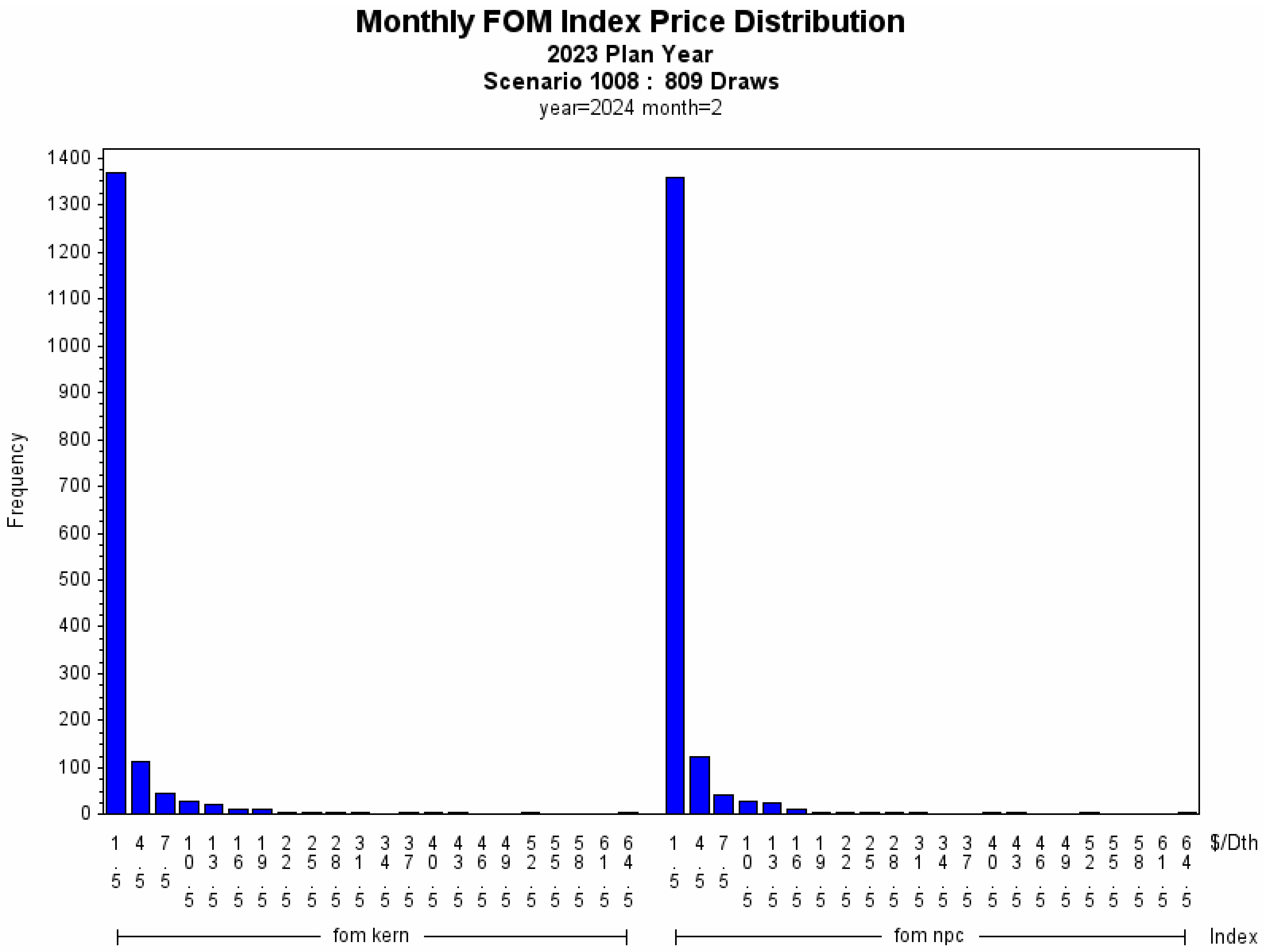


Exhibit 14.09

Monthly FOM Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=3

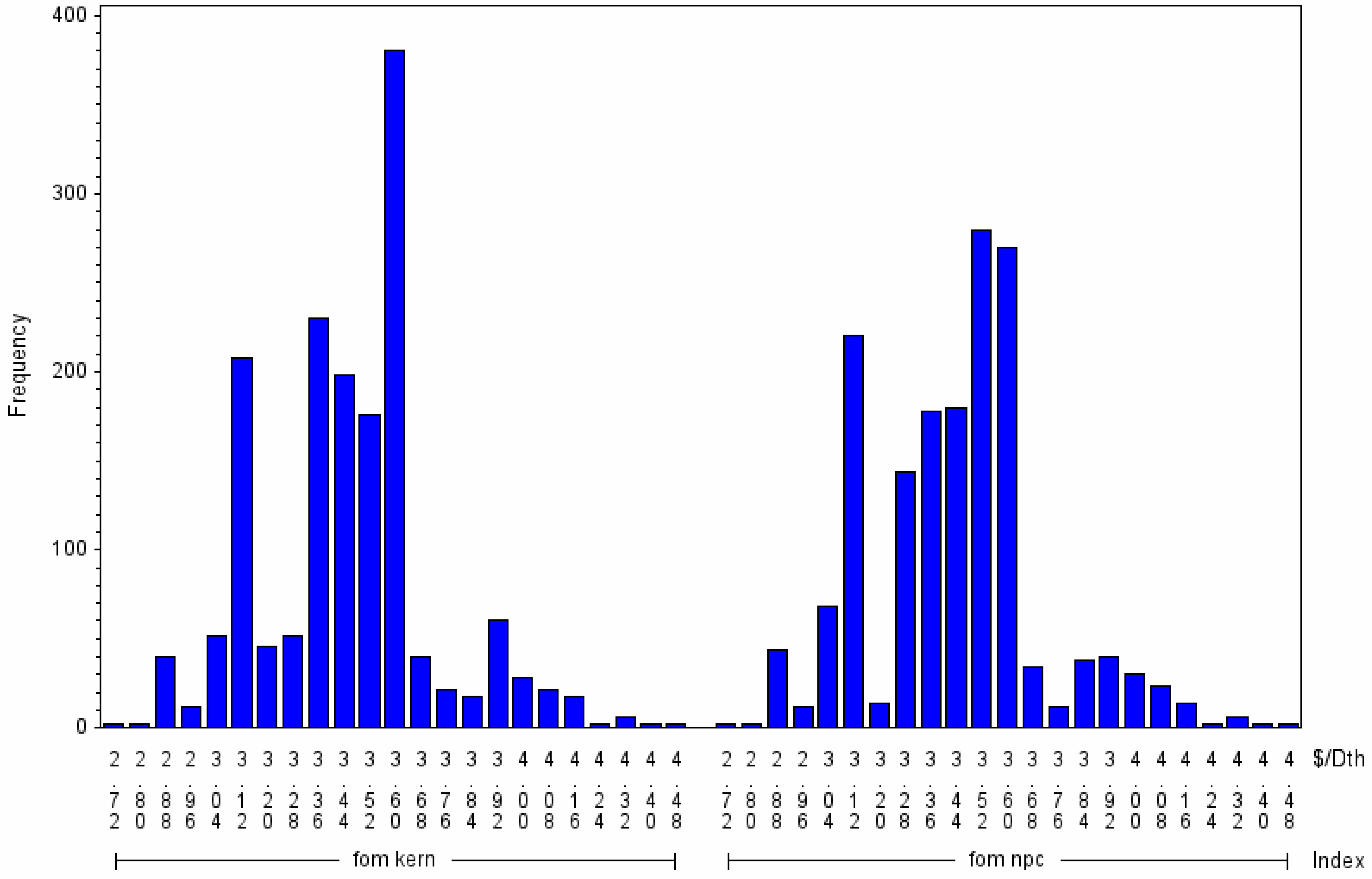


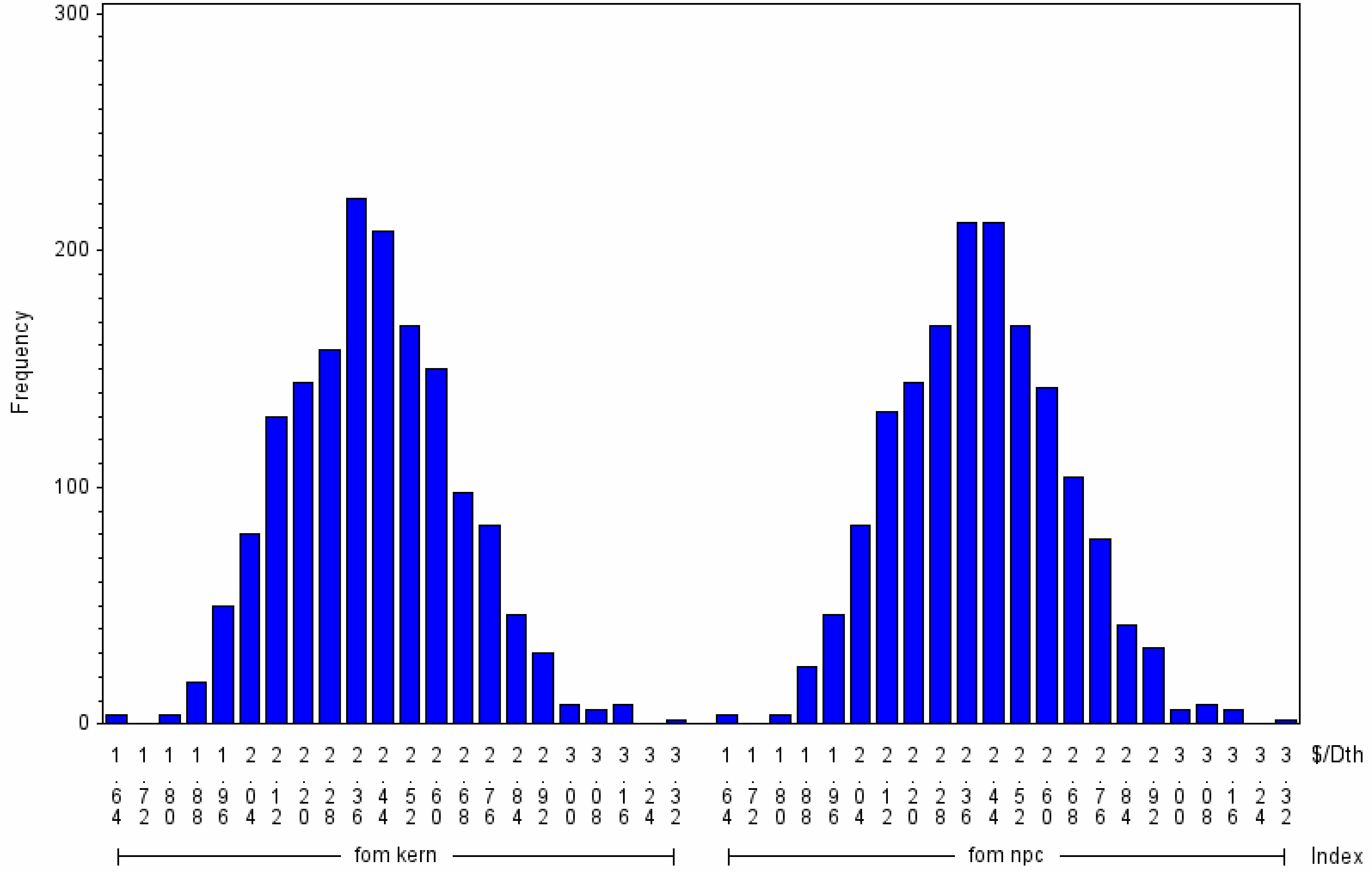
Exhibit 14.10

Monthly FOM Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=4



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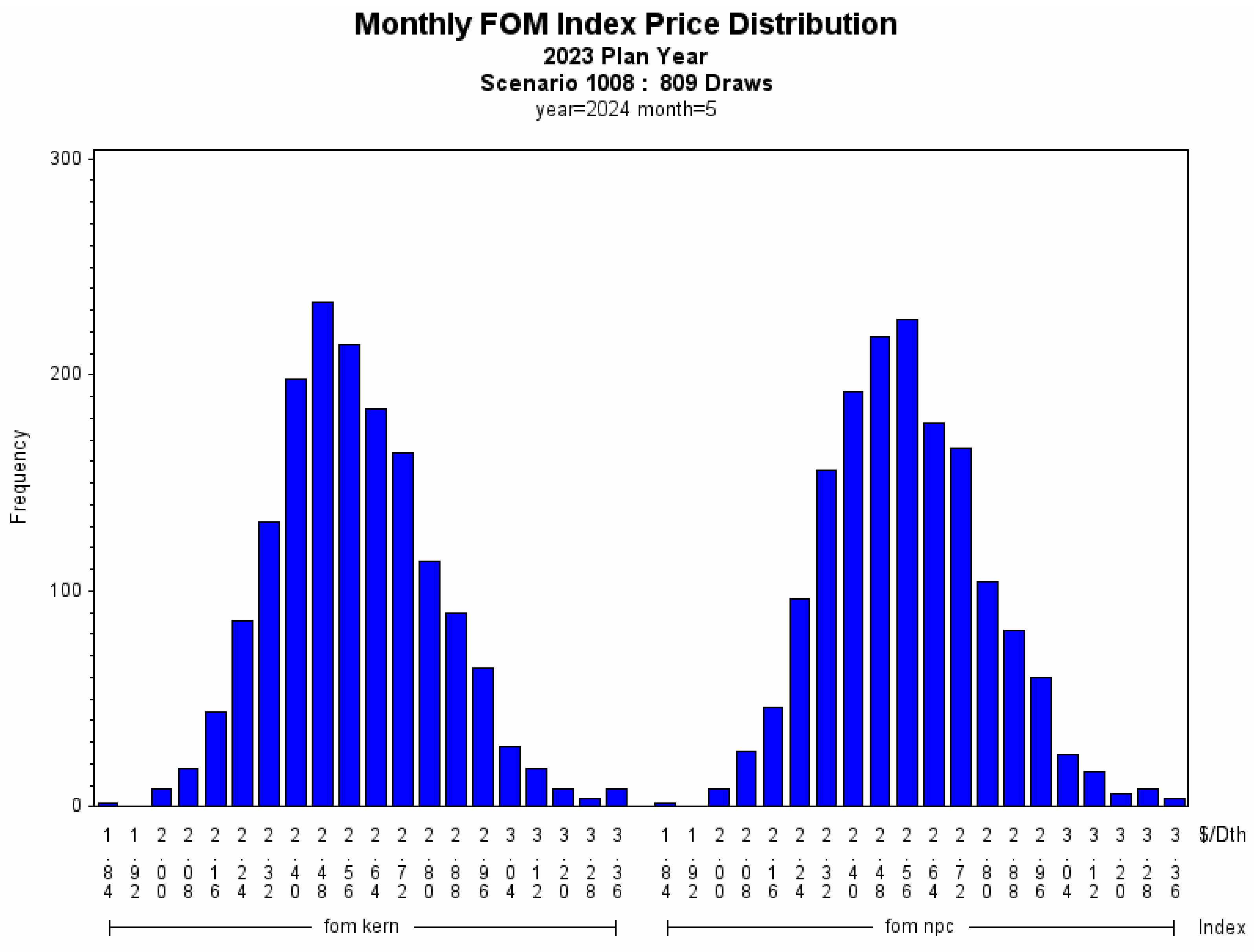


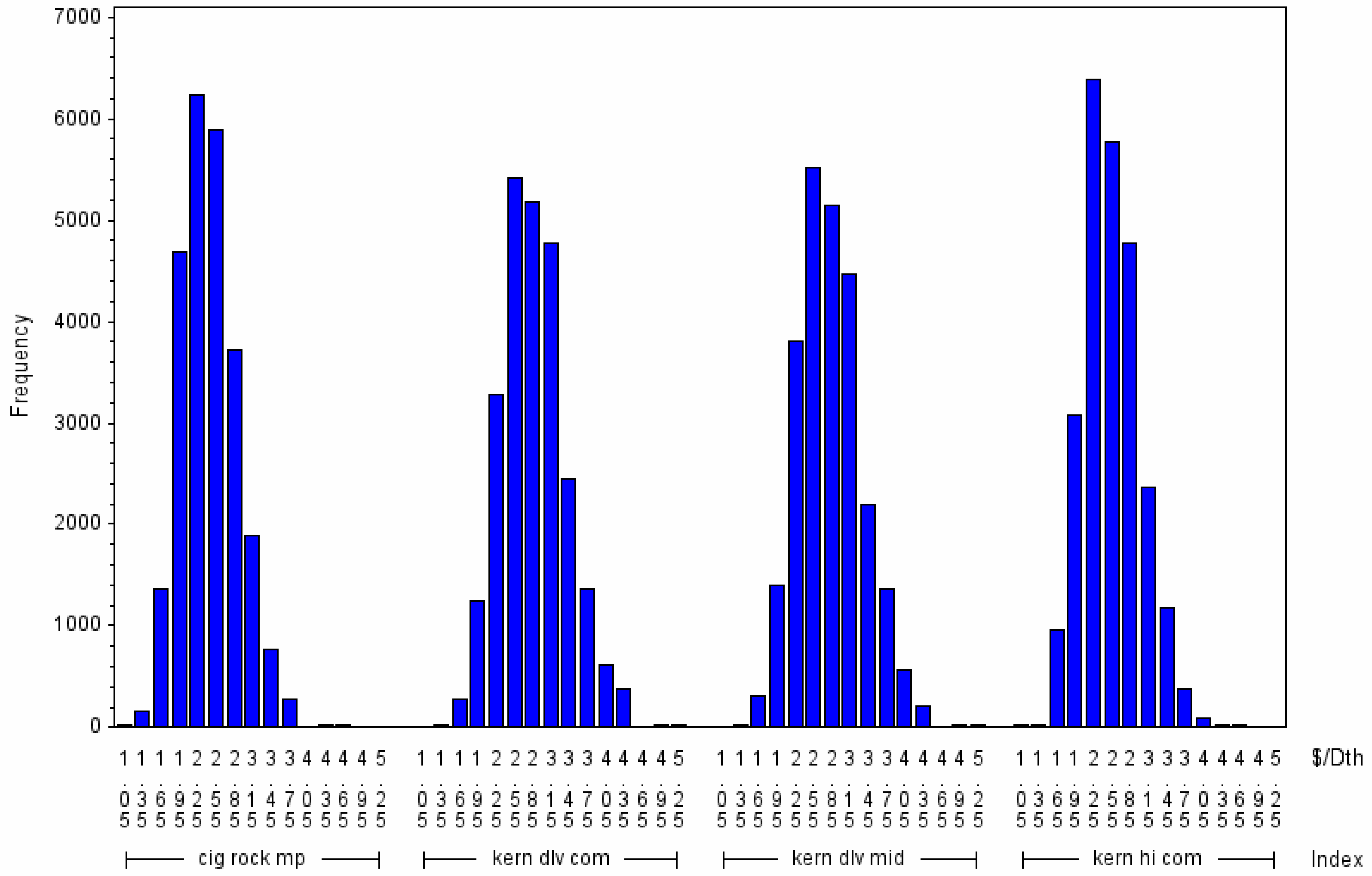
Exhibit 14.12

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=6



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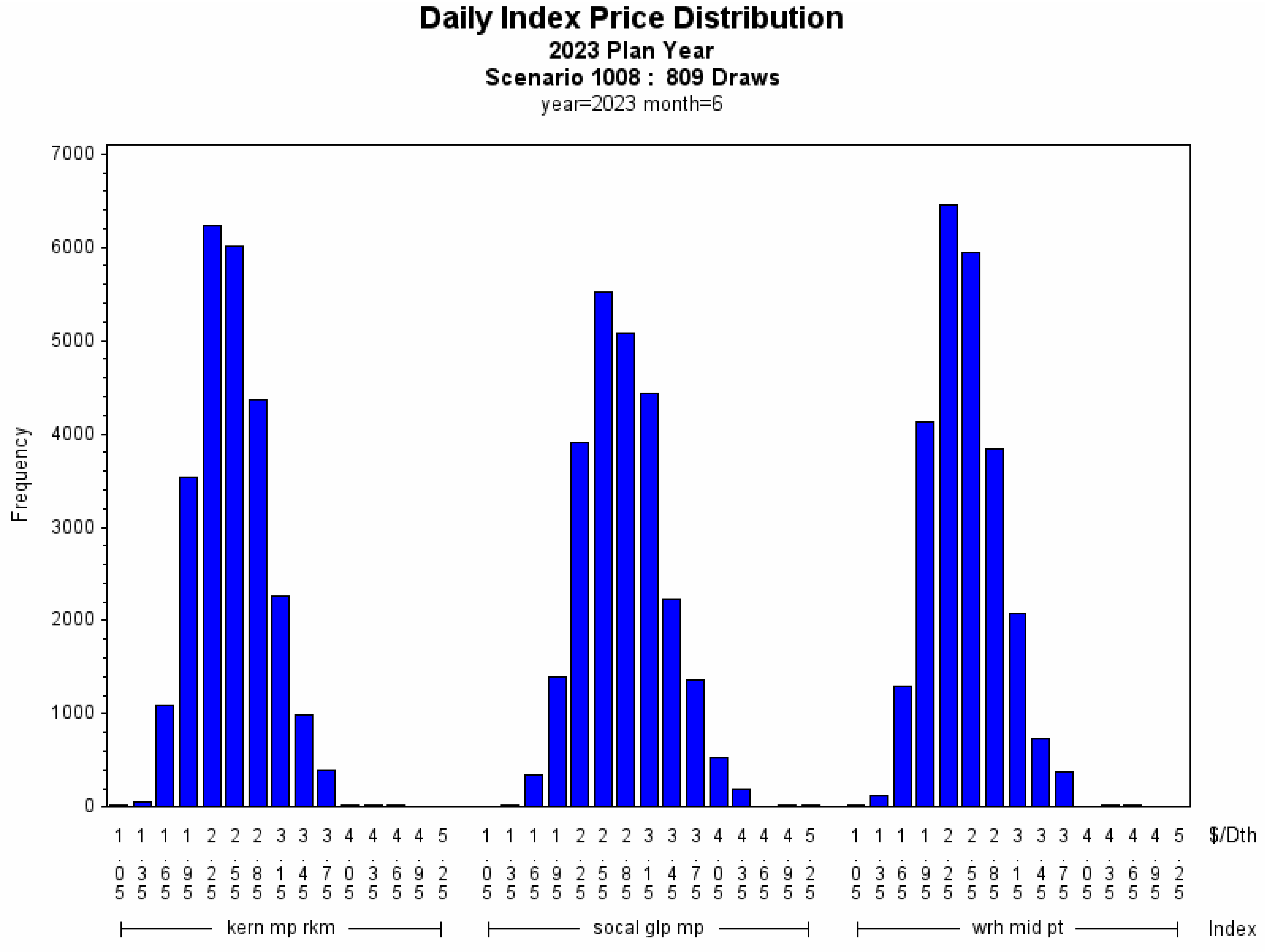


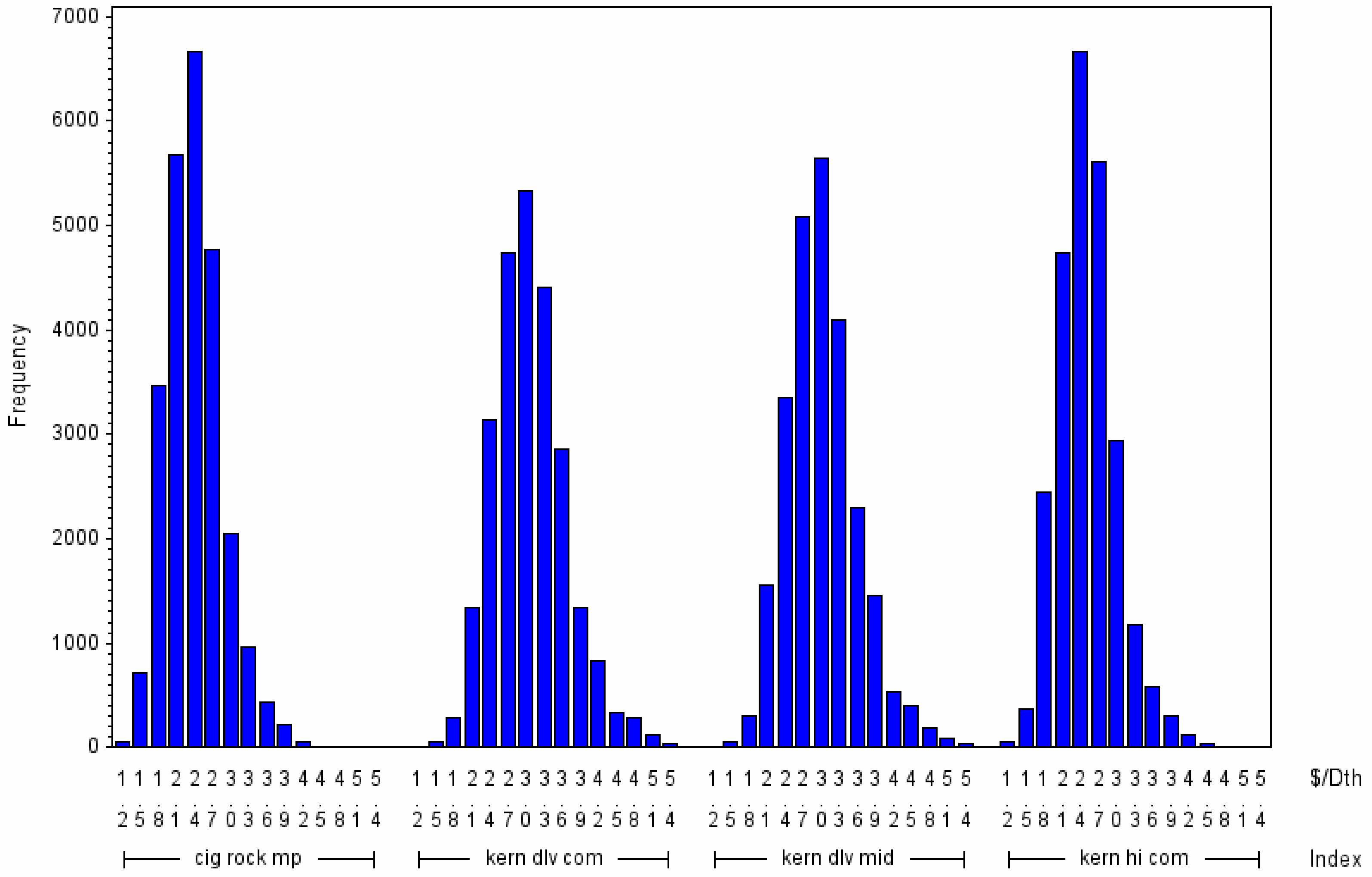
Exhibit 14.14

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=7



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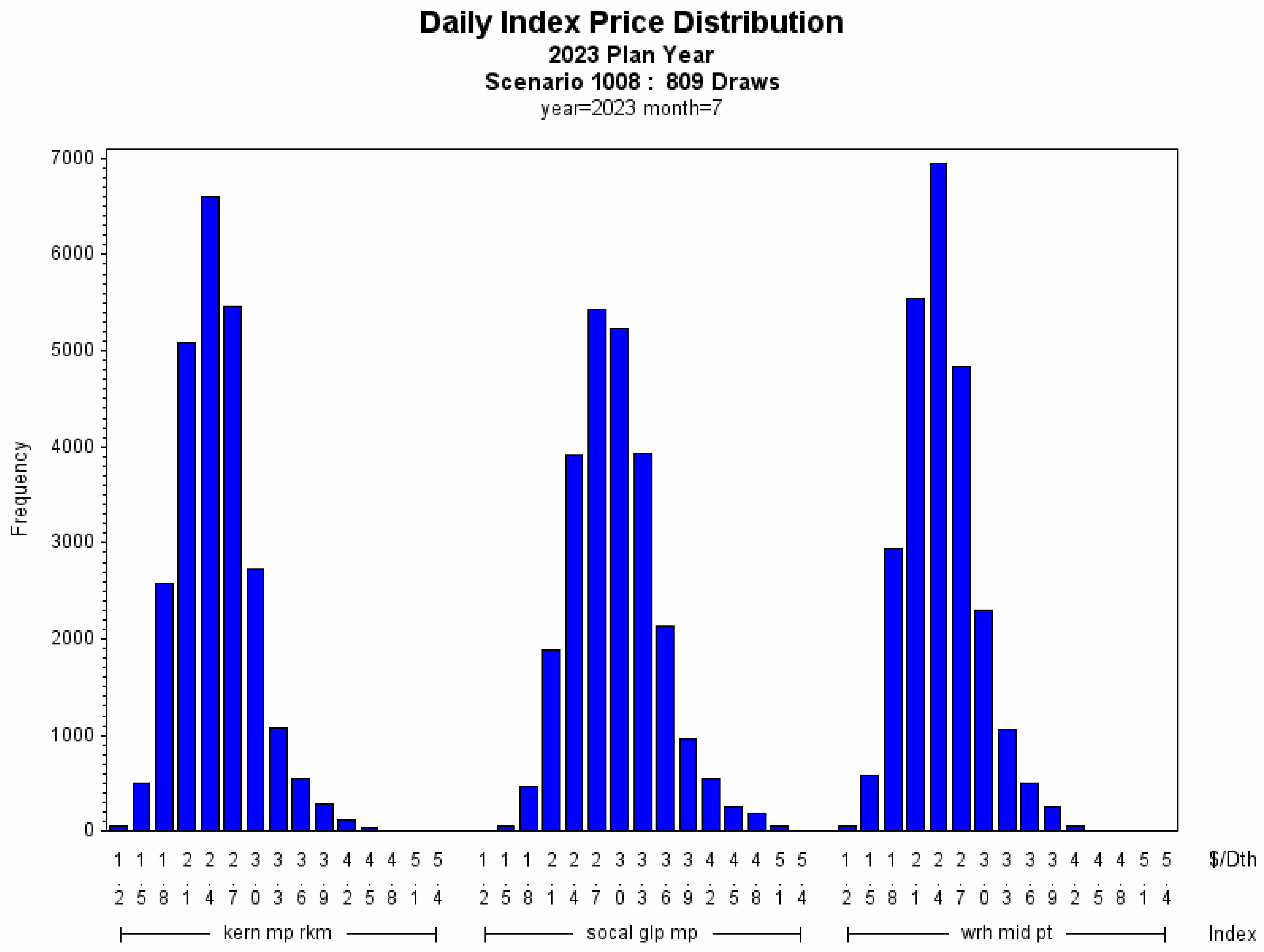

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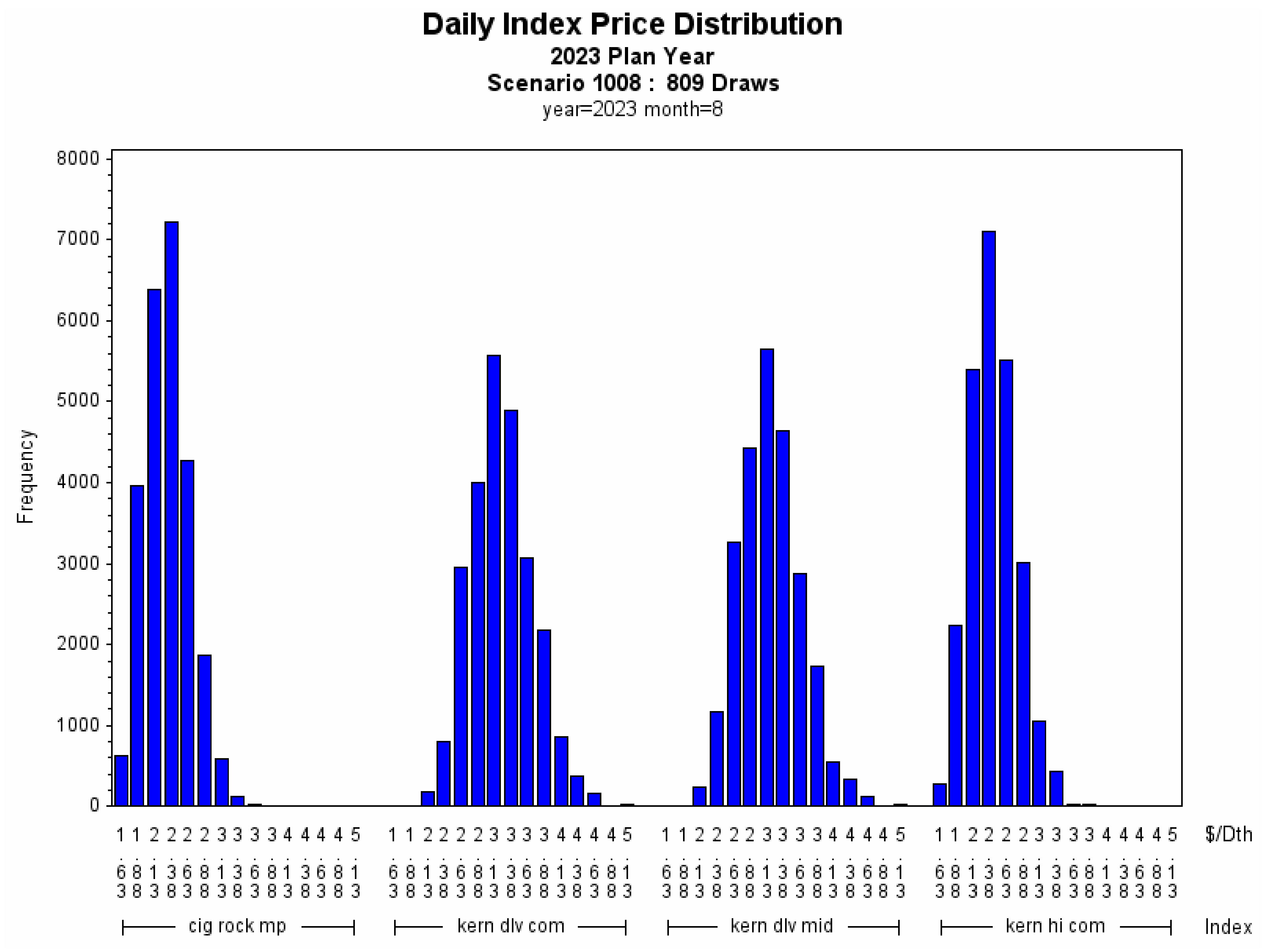


Exhibit 14.17

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=8

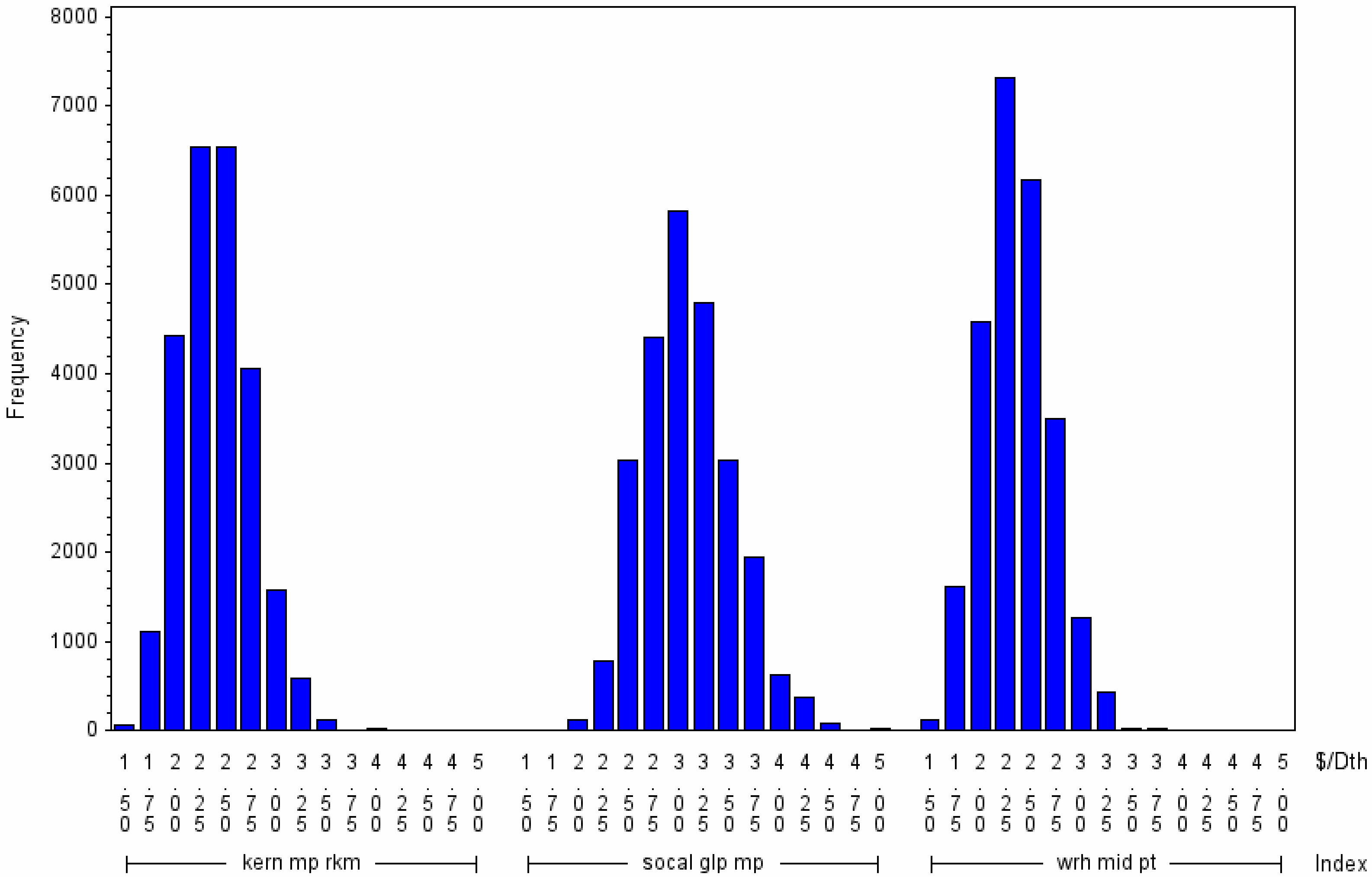


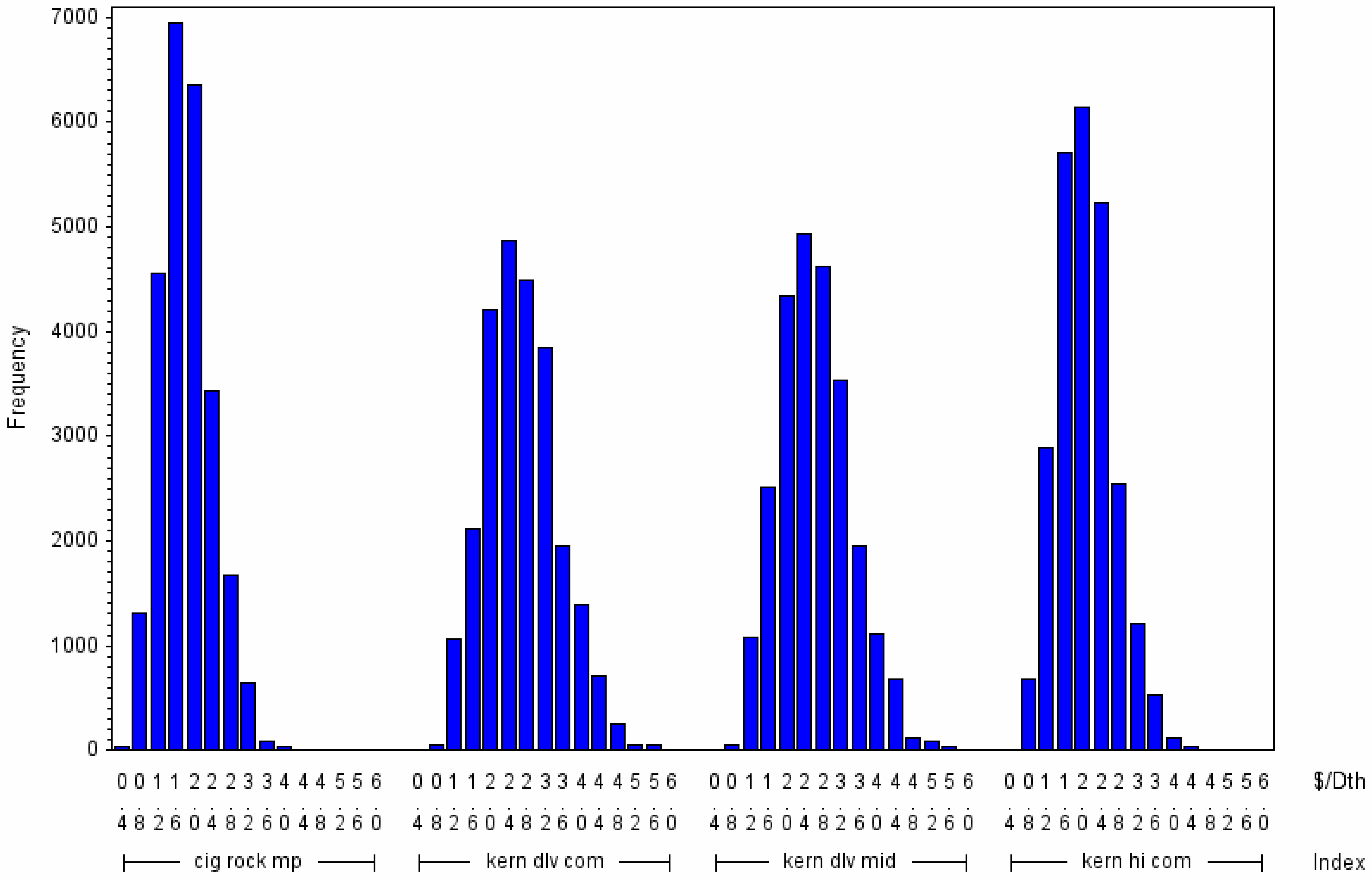
Exhibit 14.18

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=9



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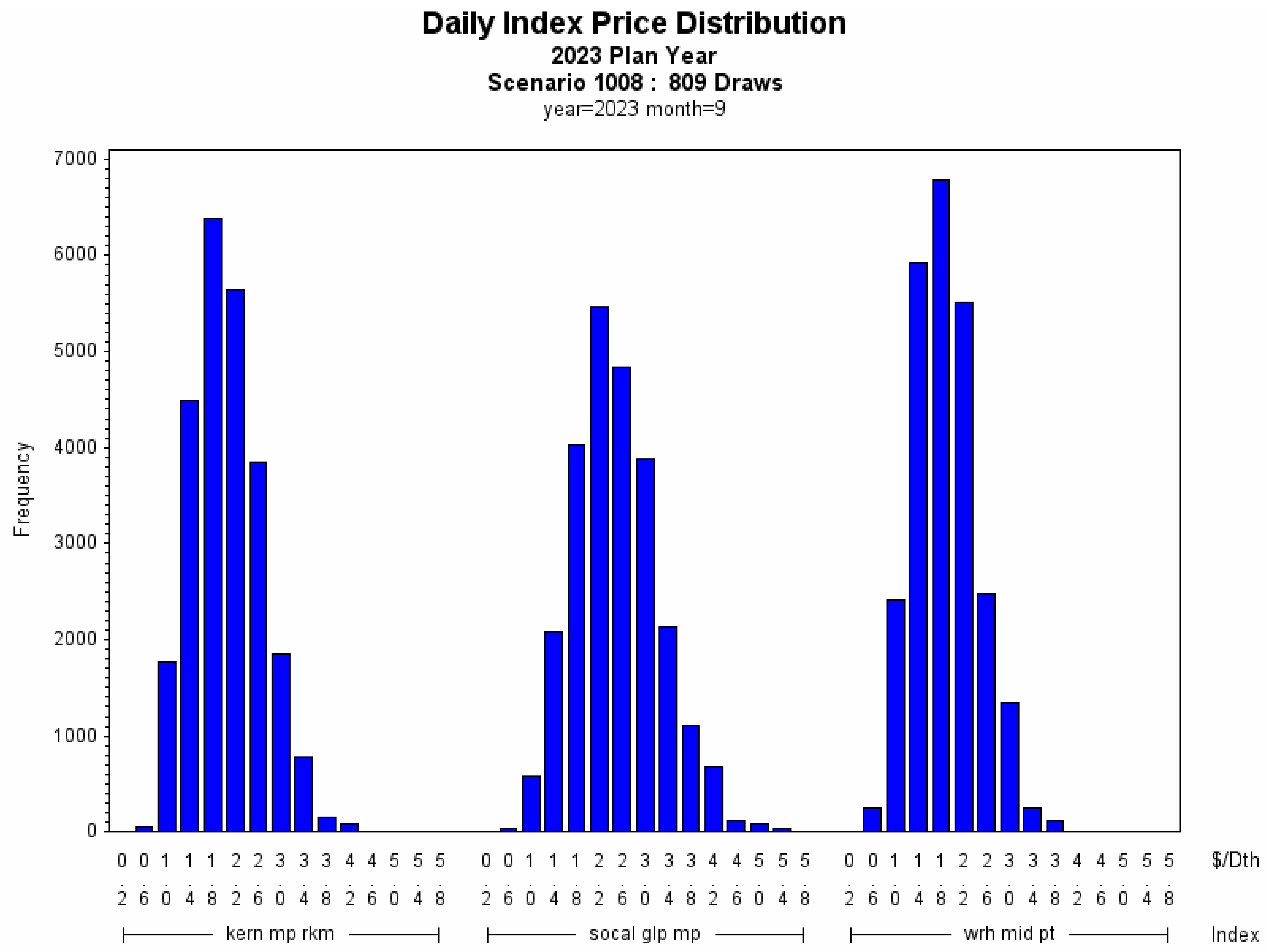

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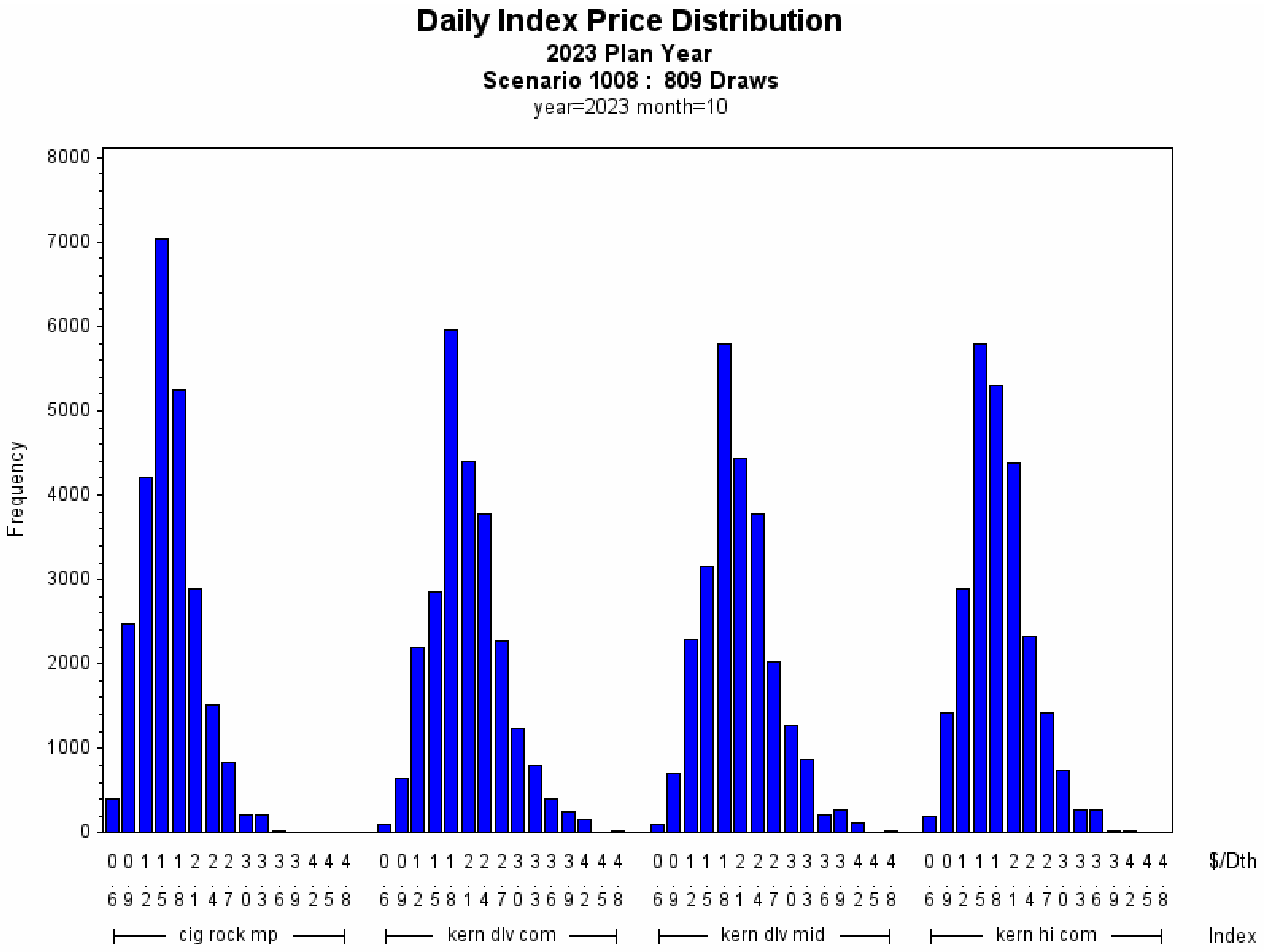
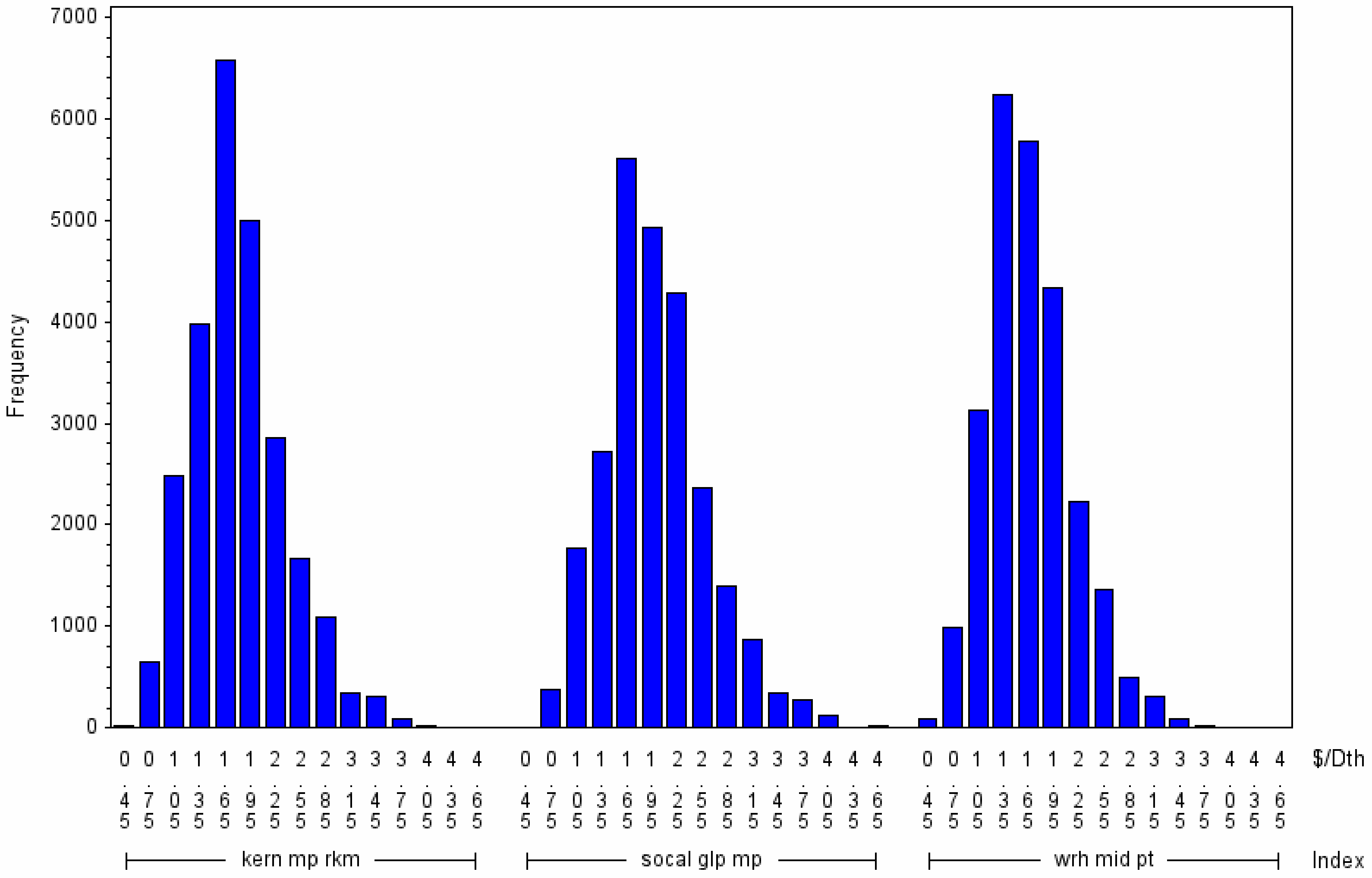


Exhibit 14.21

Daily Index Price Distribution
2023 Plan Year
Scenario 1008 : 809 Draws
year=2023 month=10



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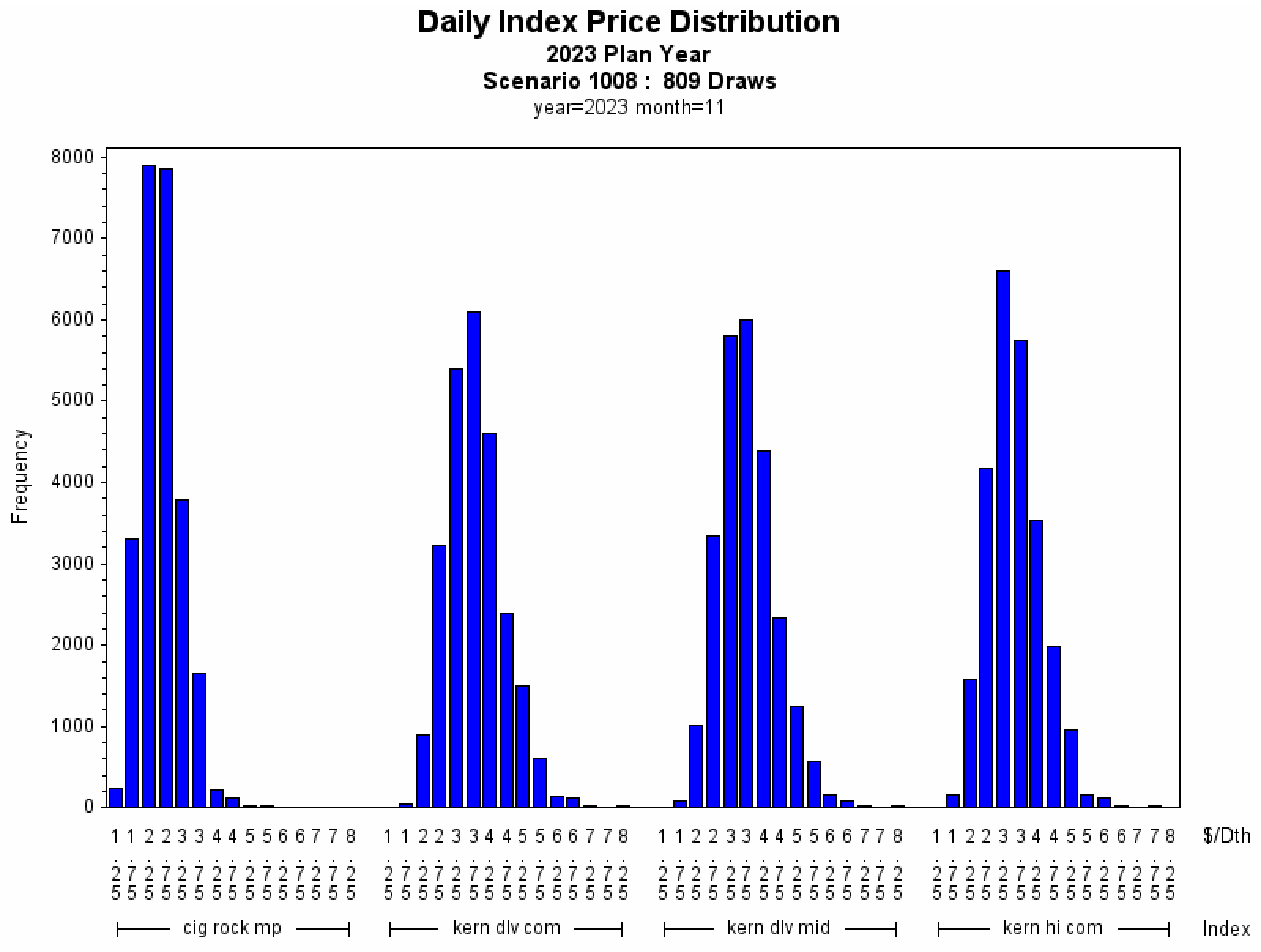

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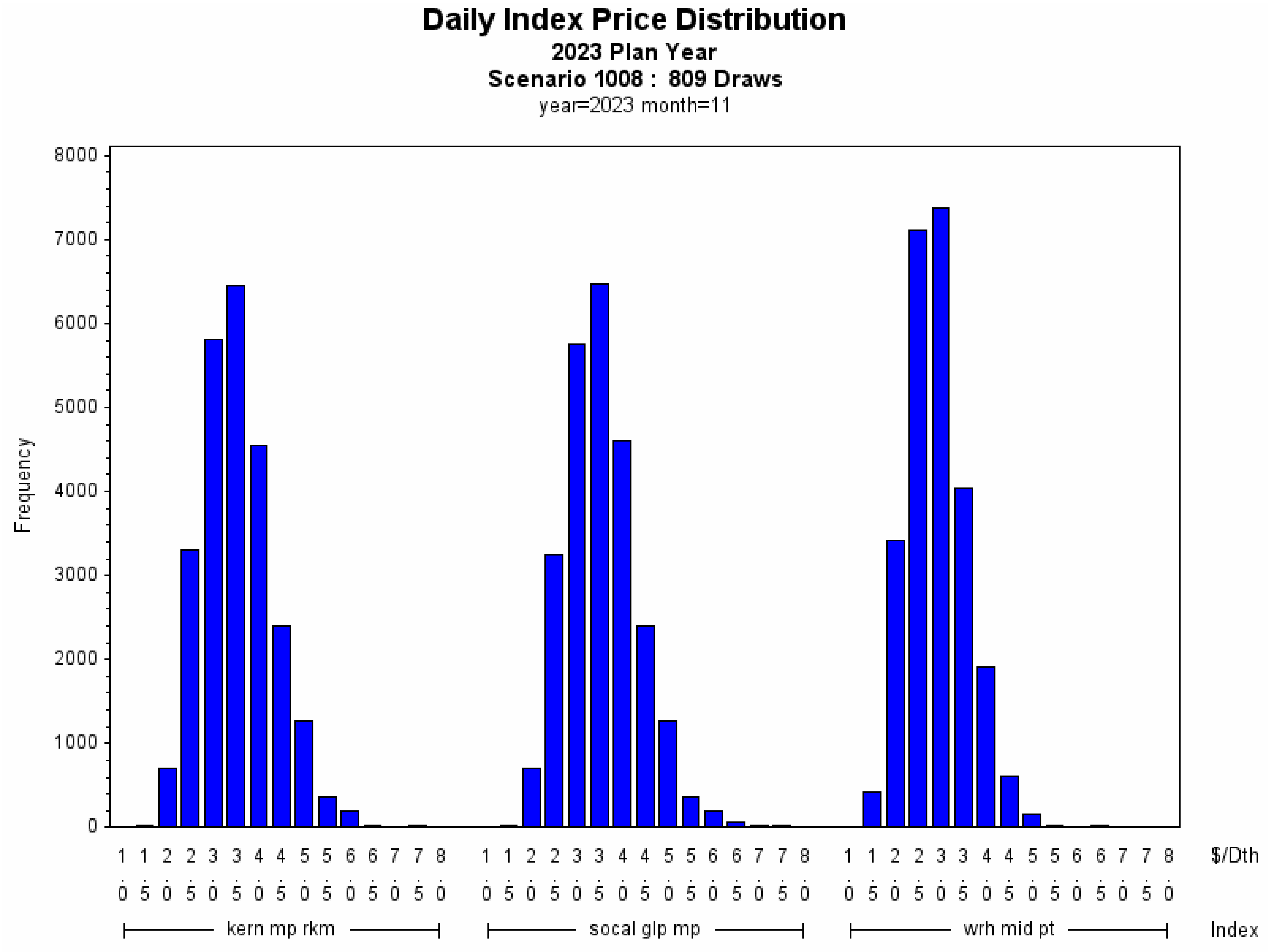

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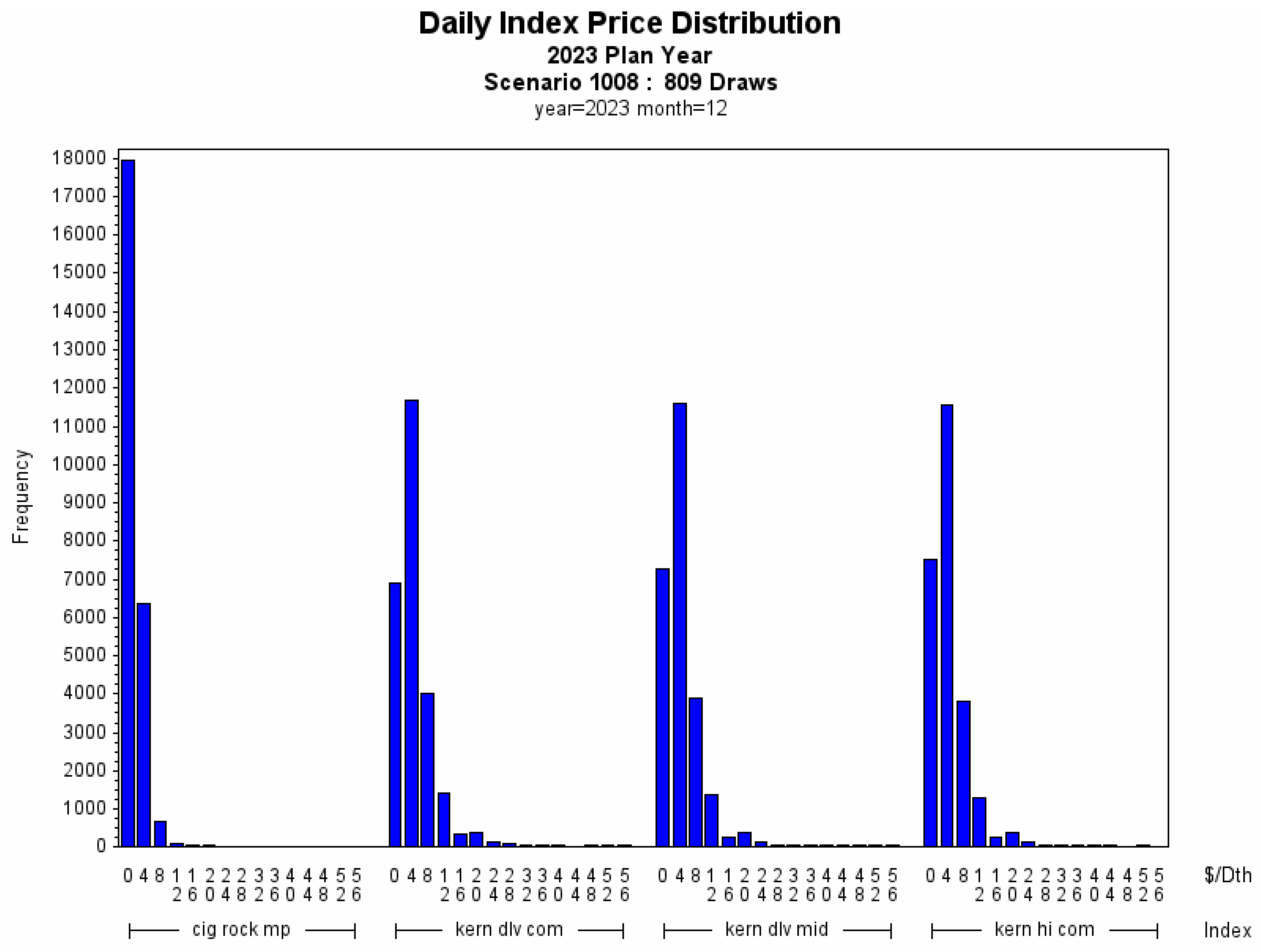

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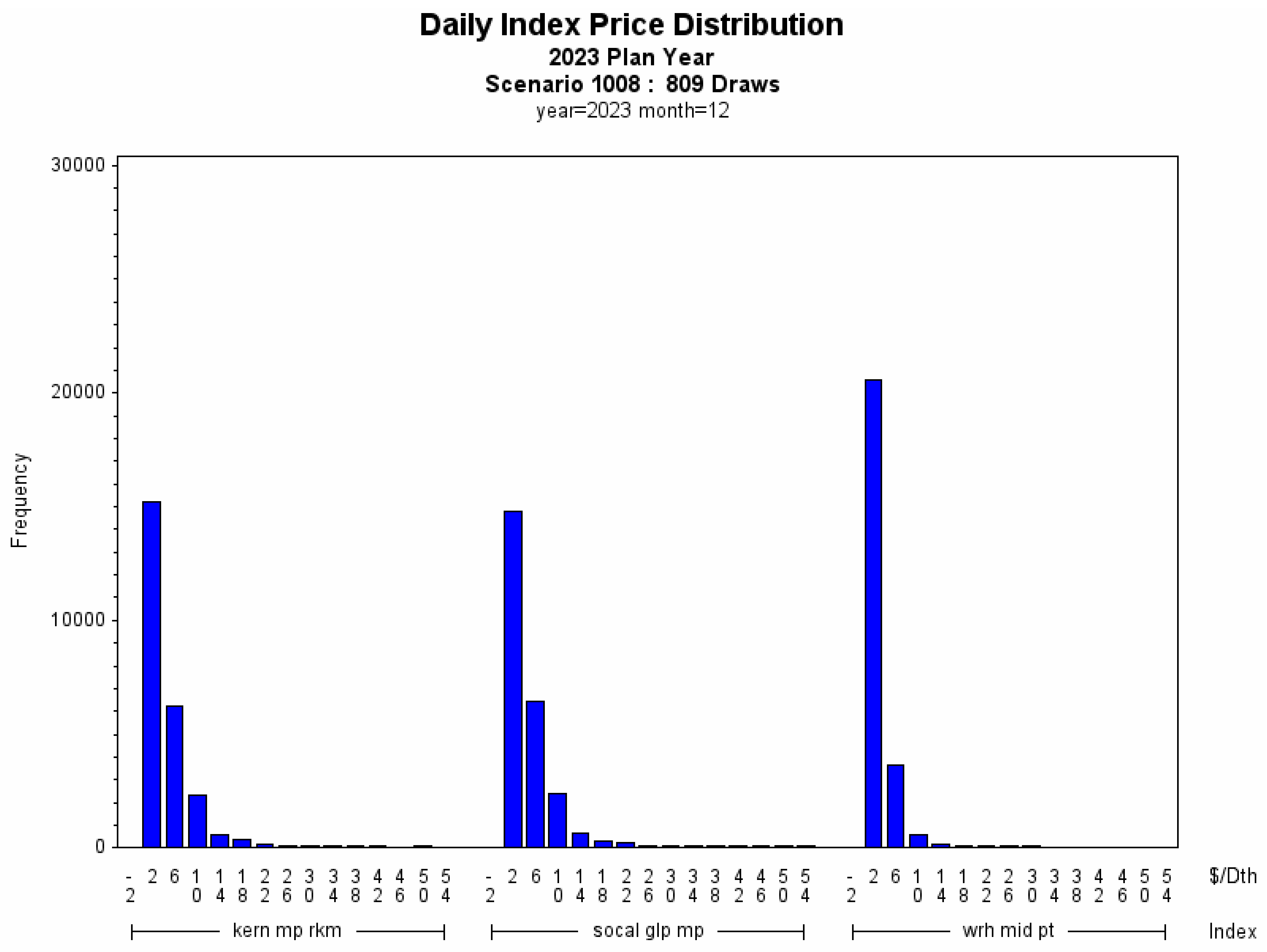


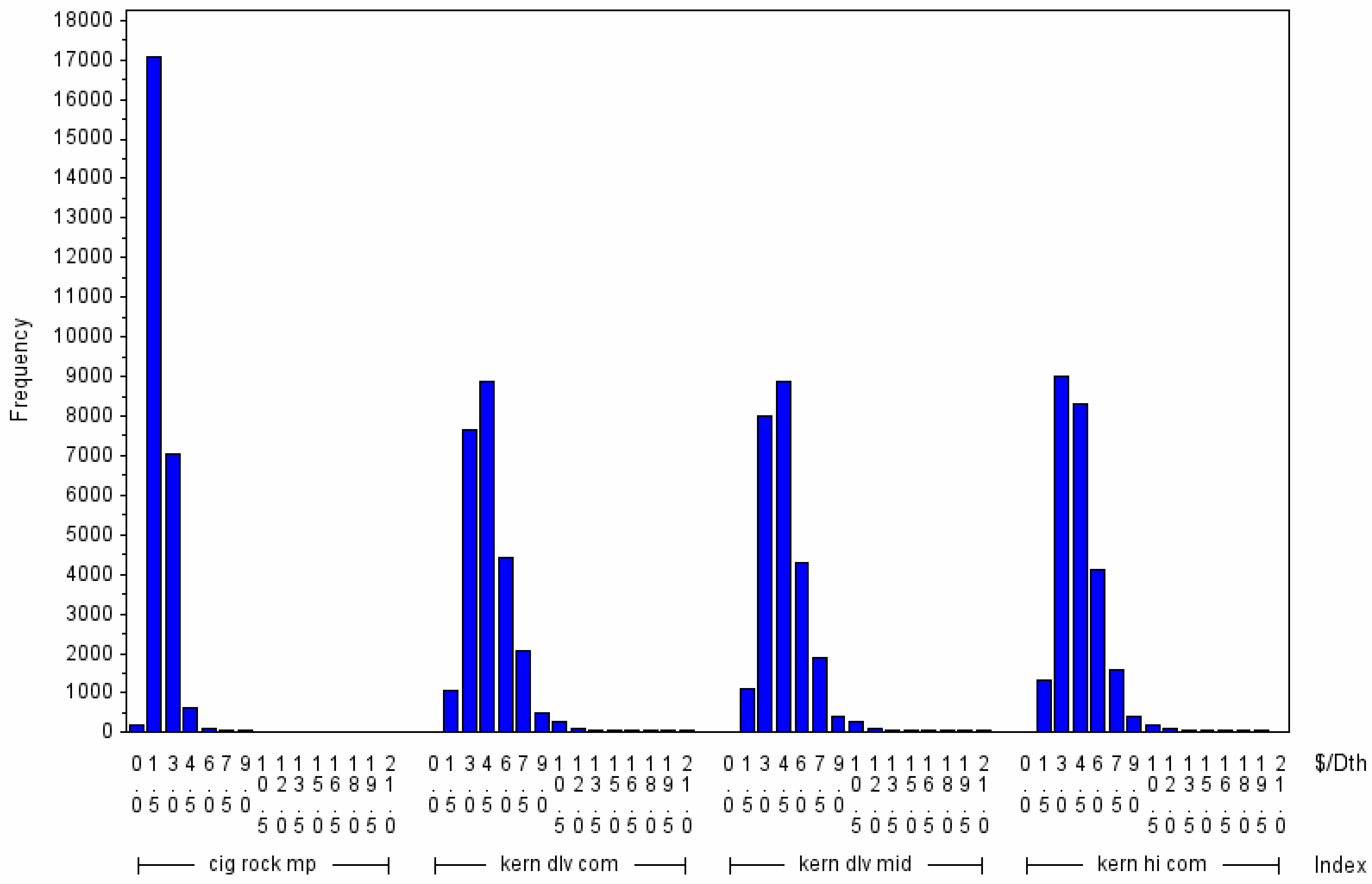
Exhibit 14.26

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=1



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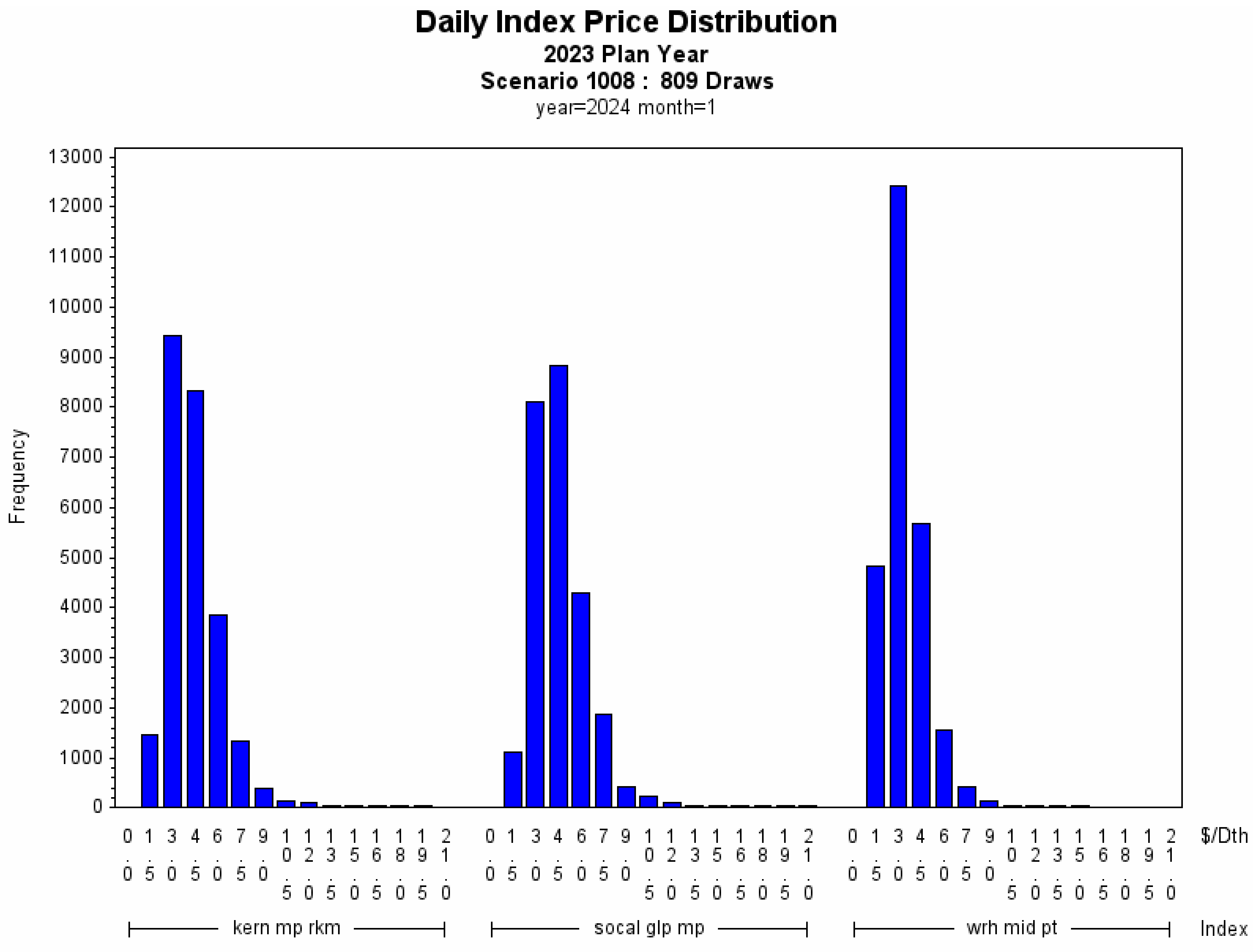


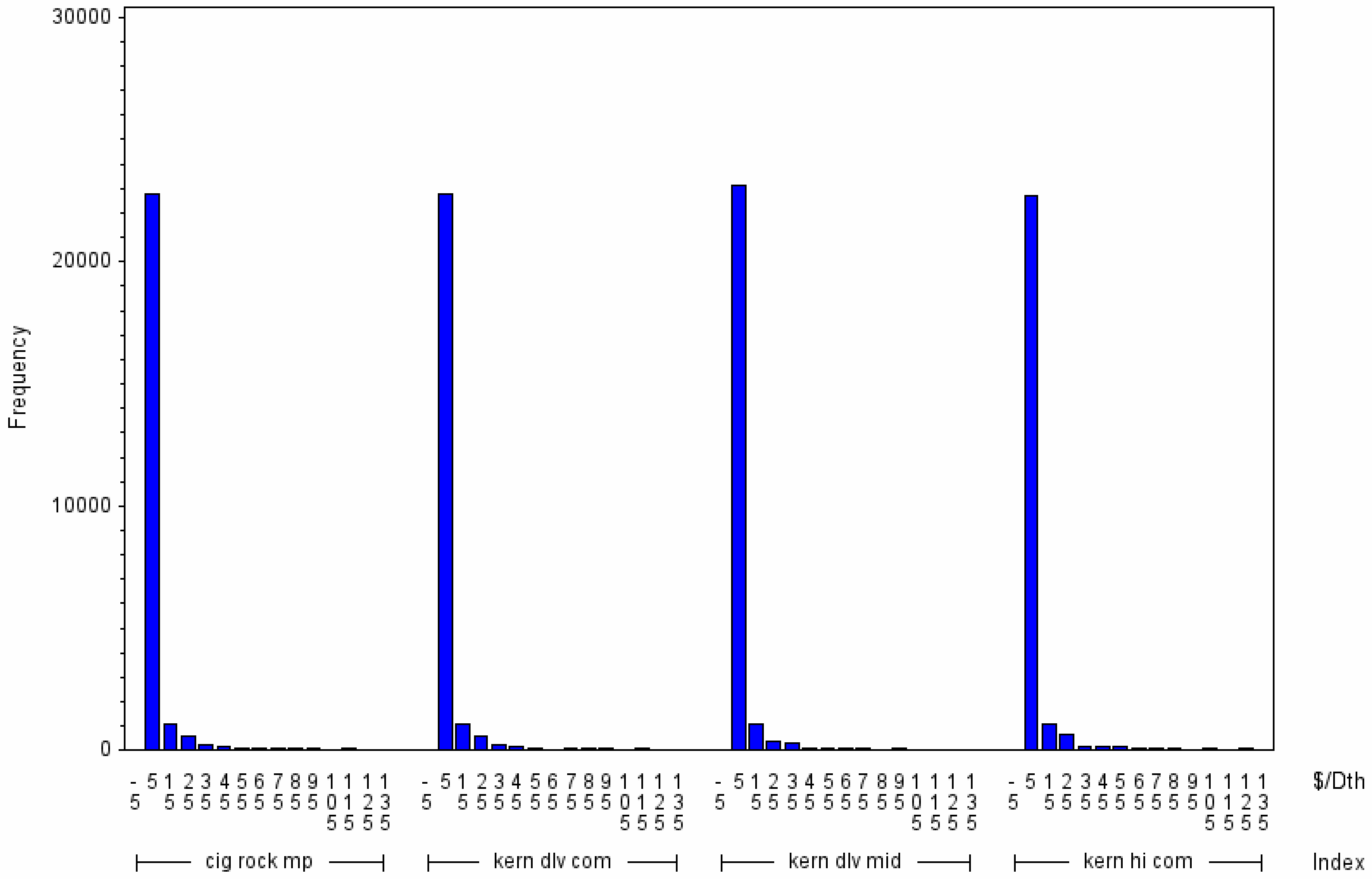
Exhibit 14.28

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=2



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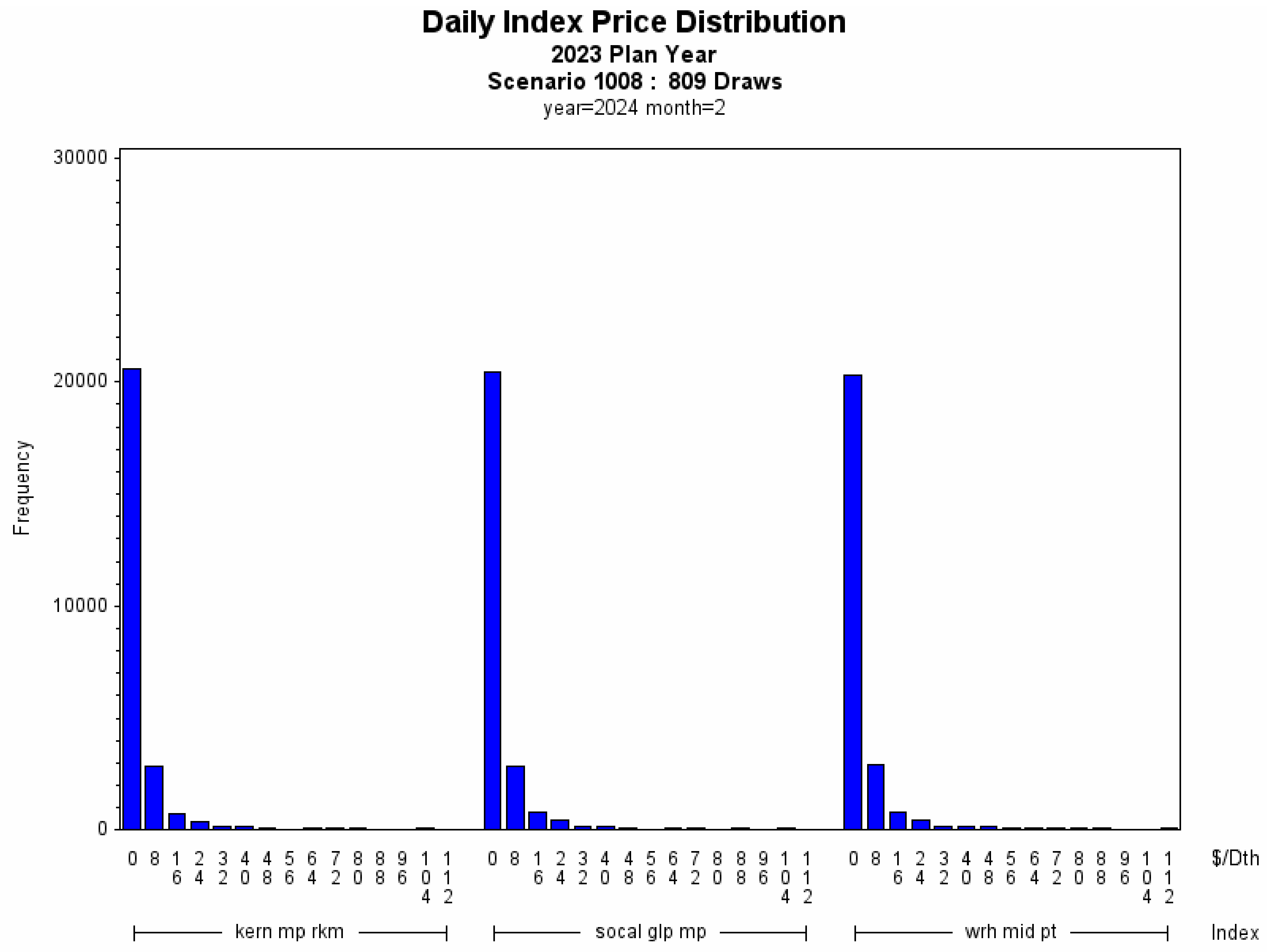


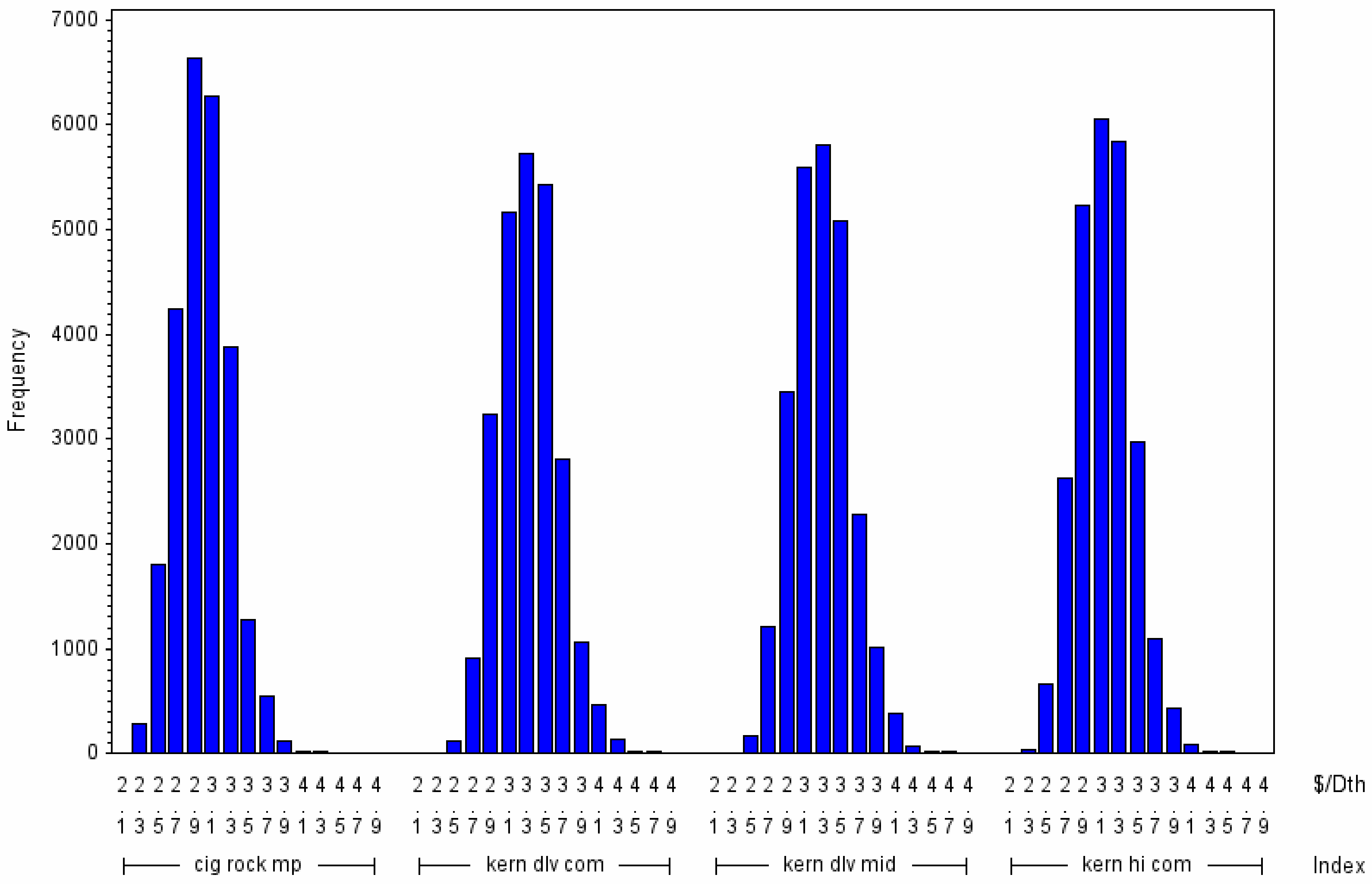
Exhibit 14.30

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=3



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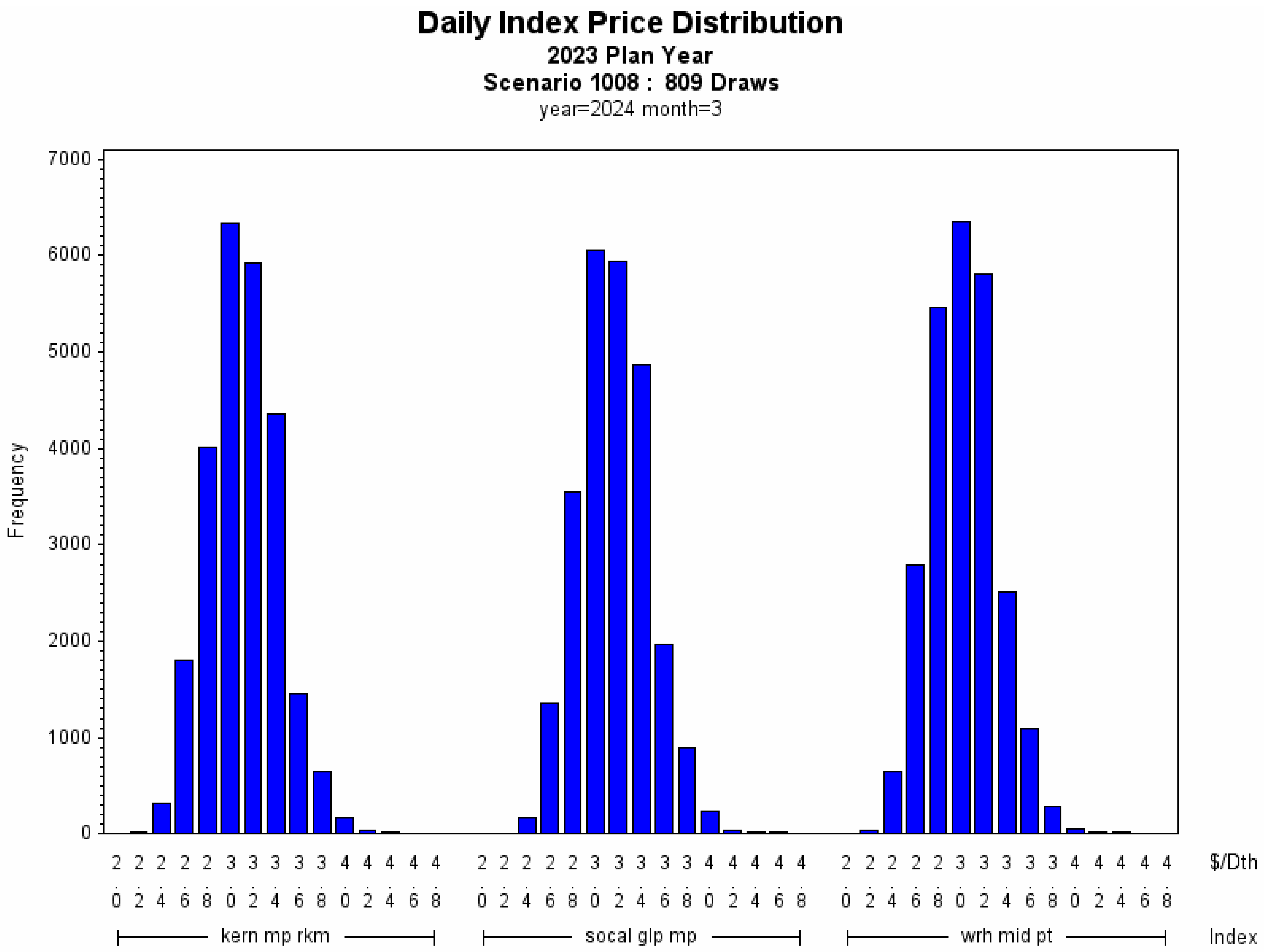

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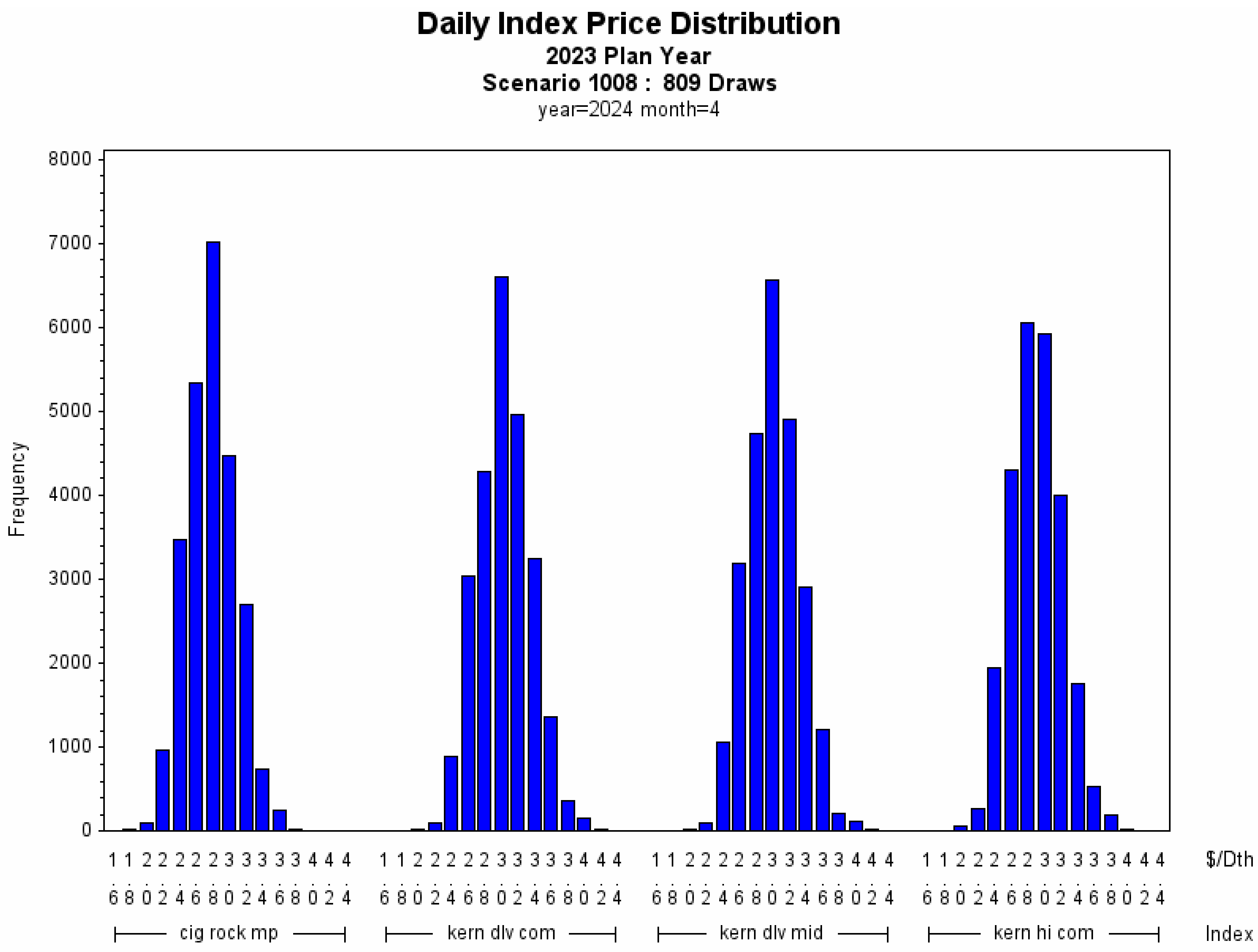

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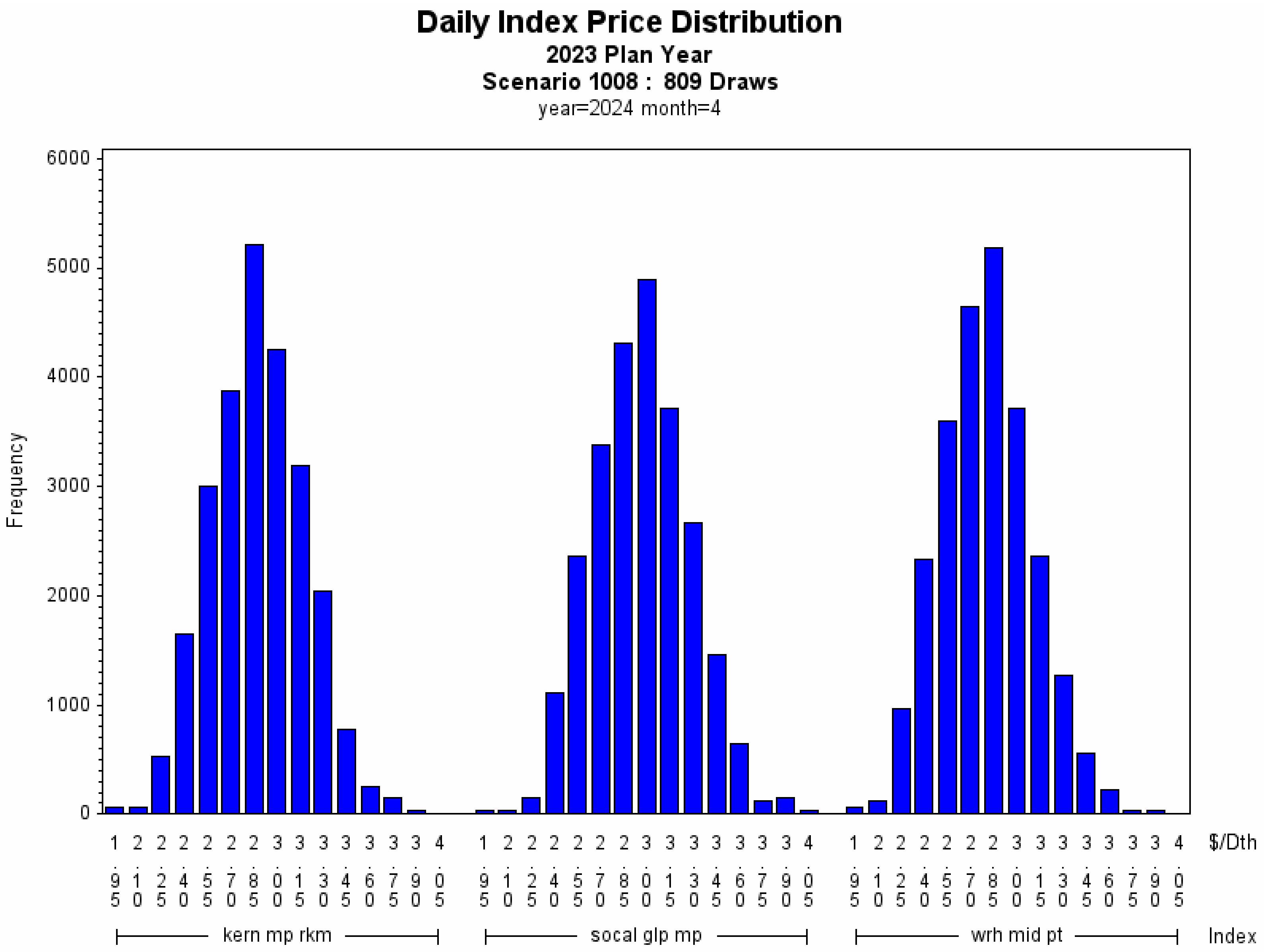


Exhibit 14.34

Daily Index Price Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=5

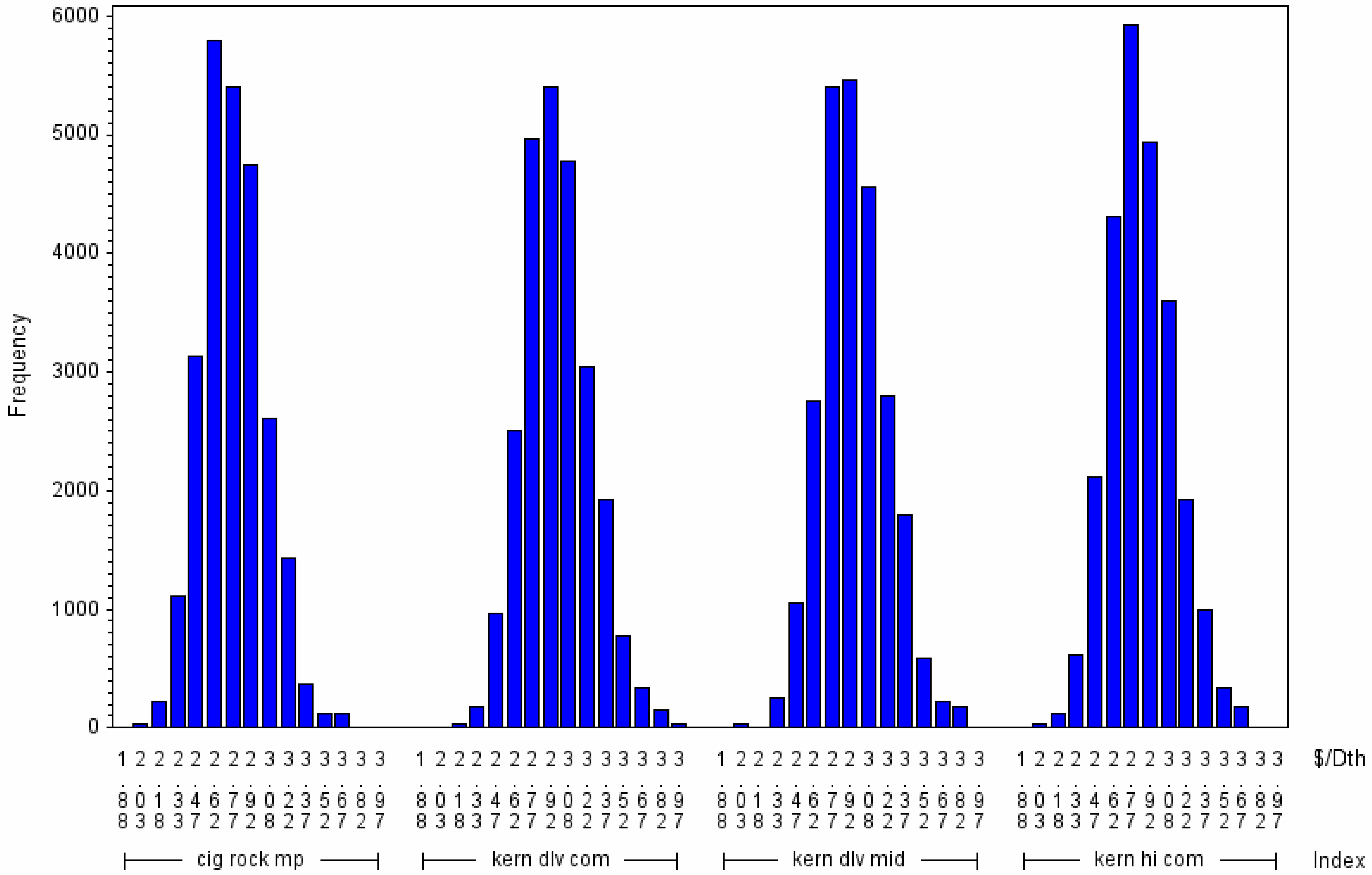
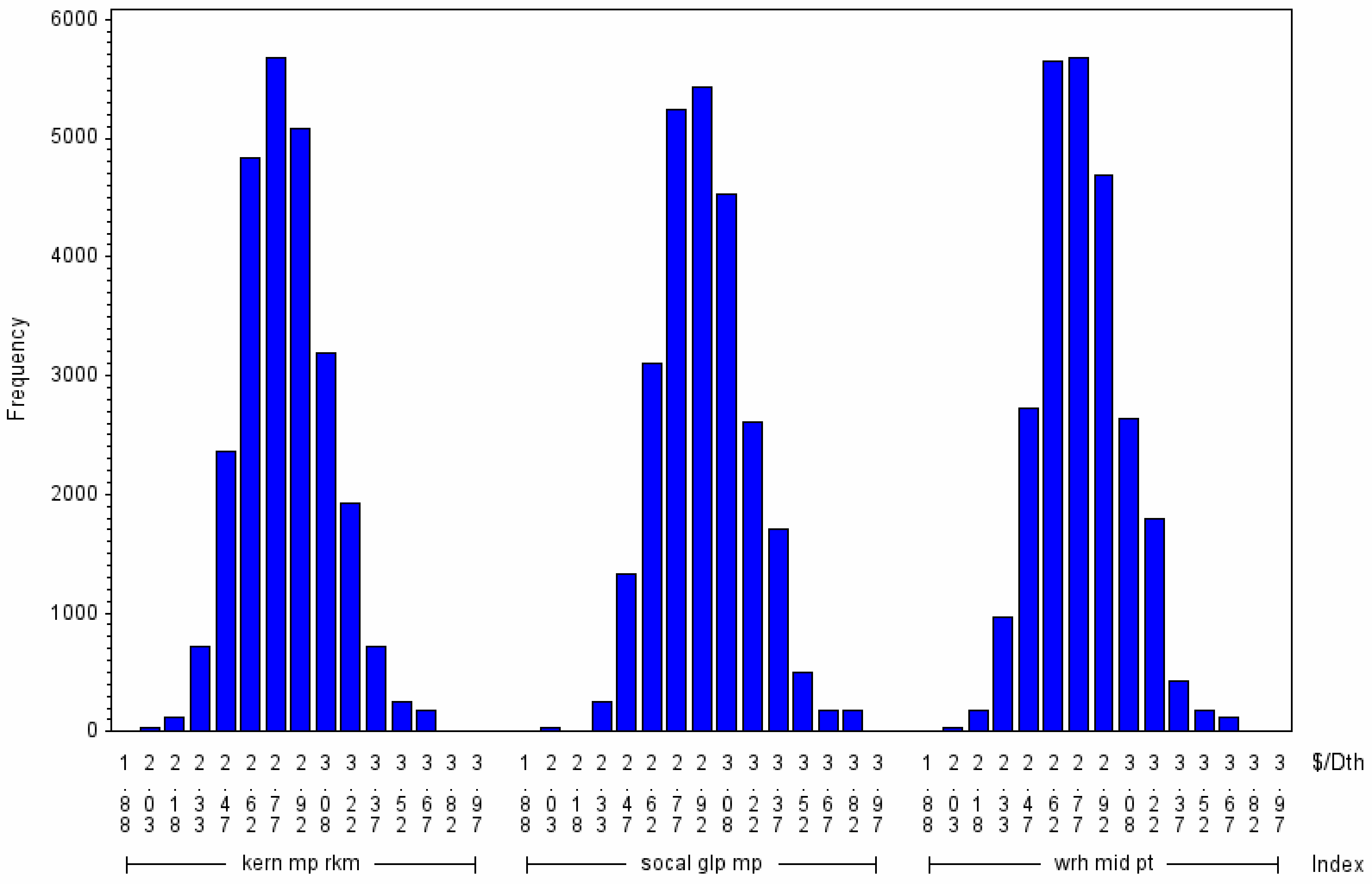


Exhibit 14.35

Daily Index Price Distribution
2023 Plan Year
Scenario 1008 : 809 Draws
year=2024 month=5



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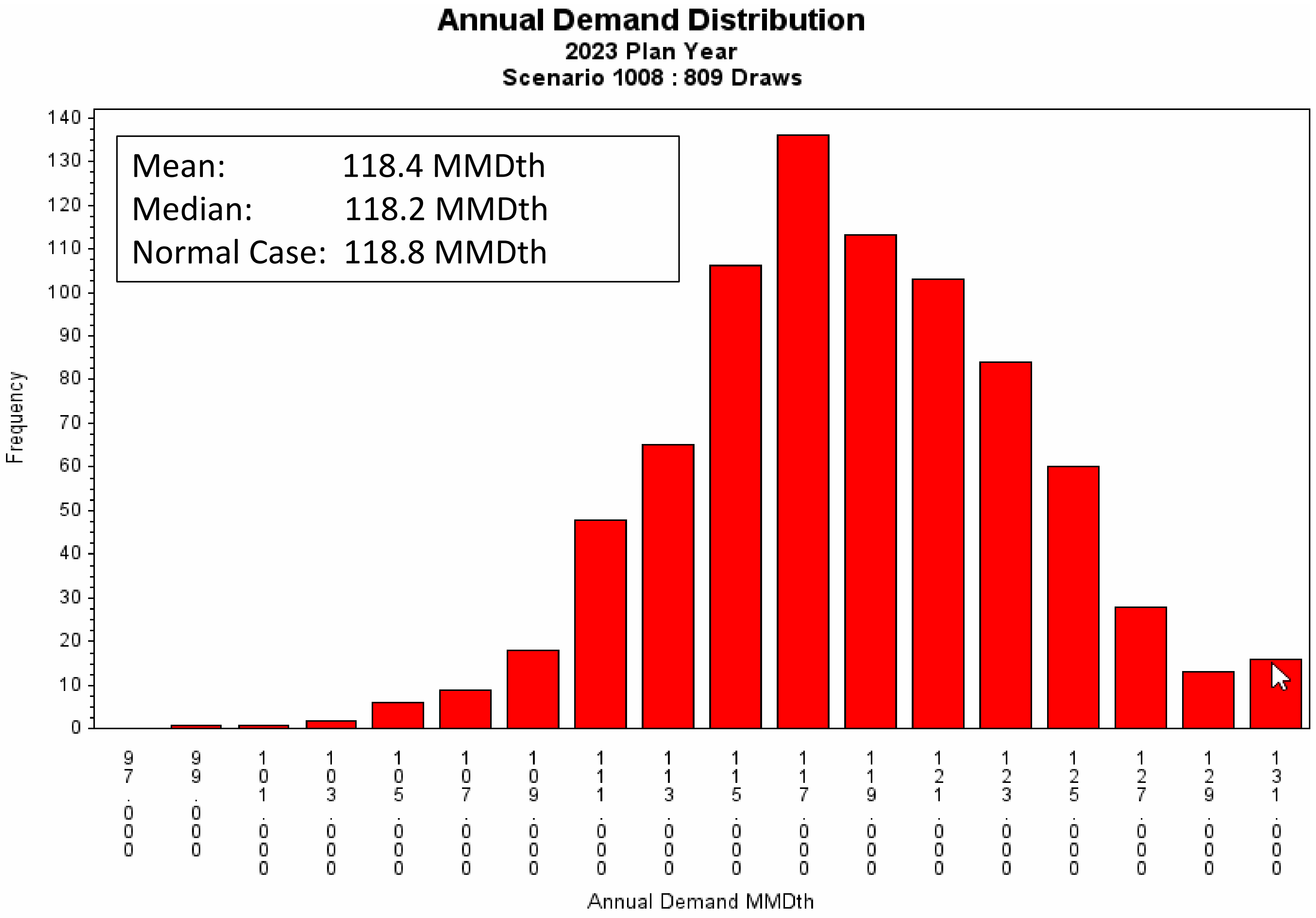

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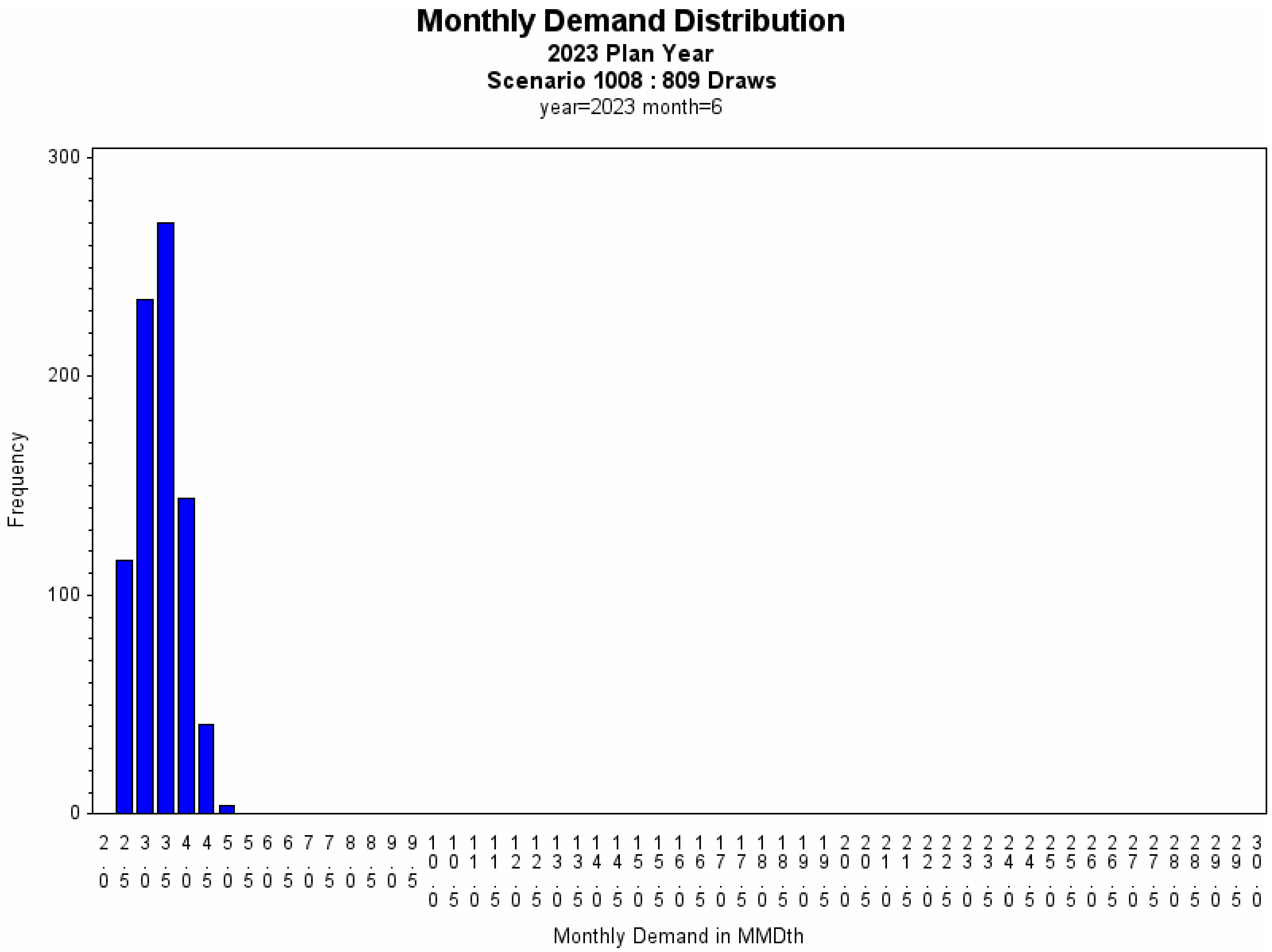

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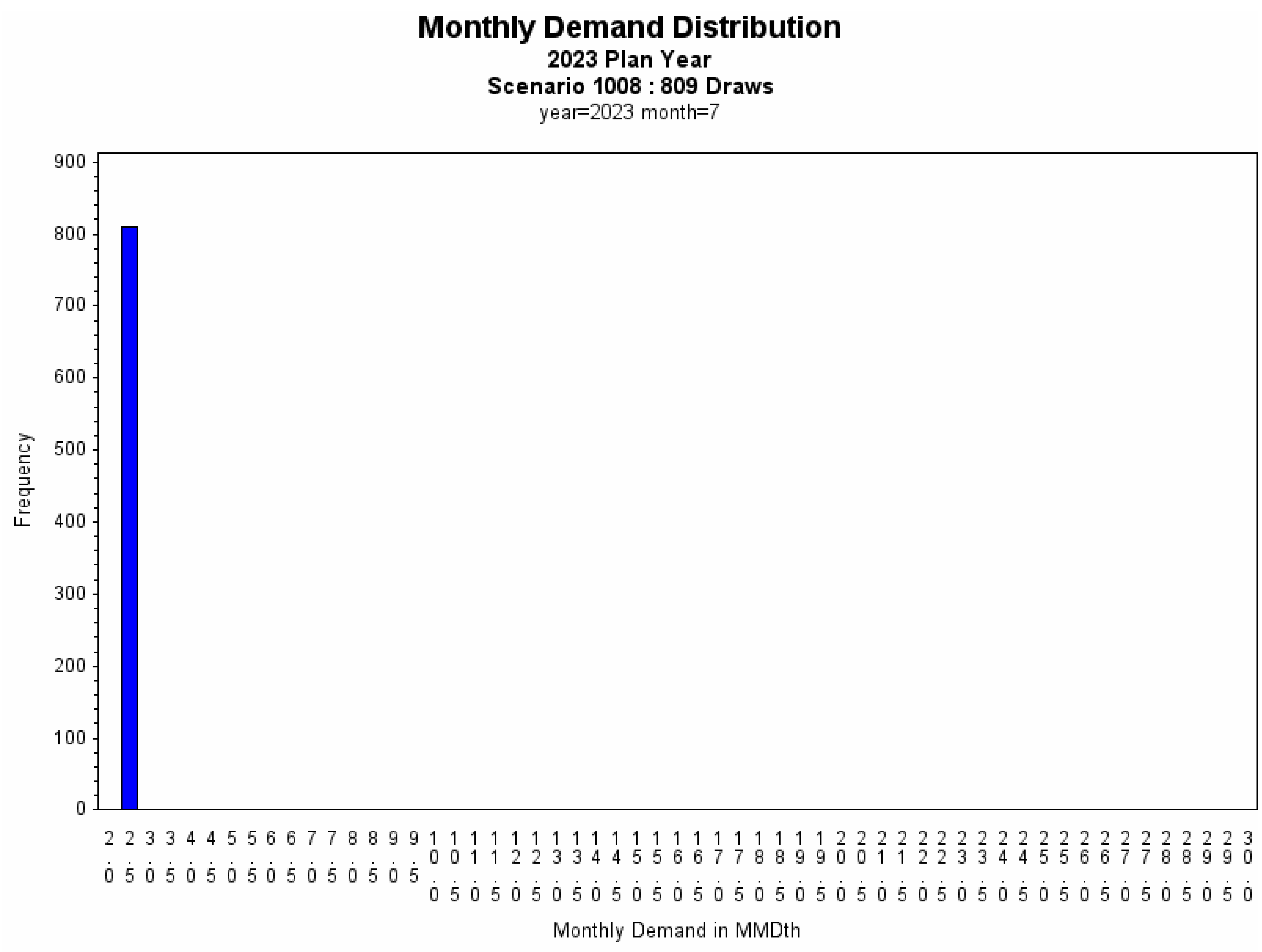

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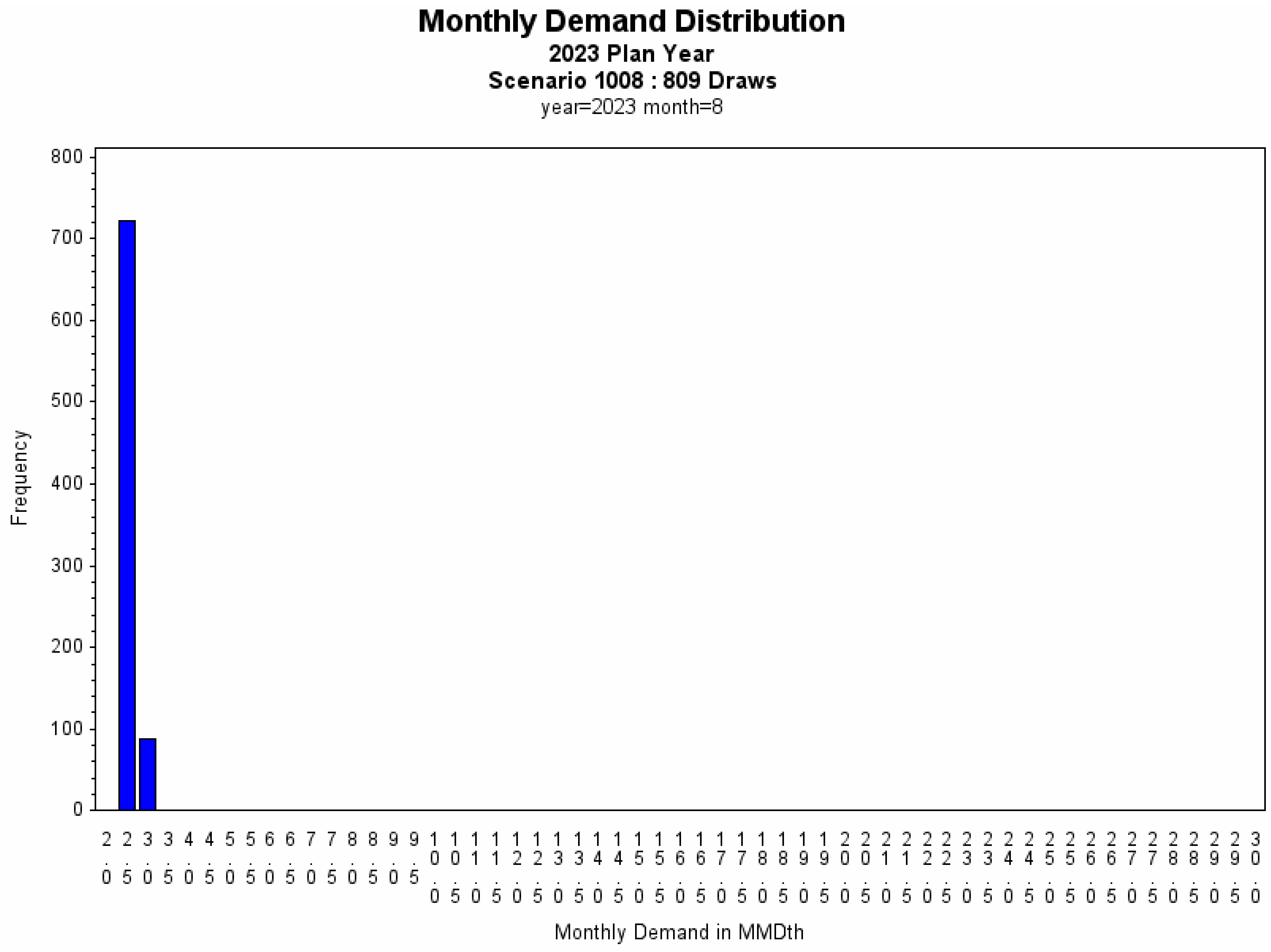

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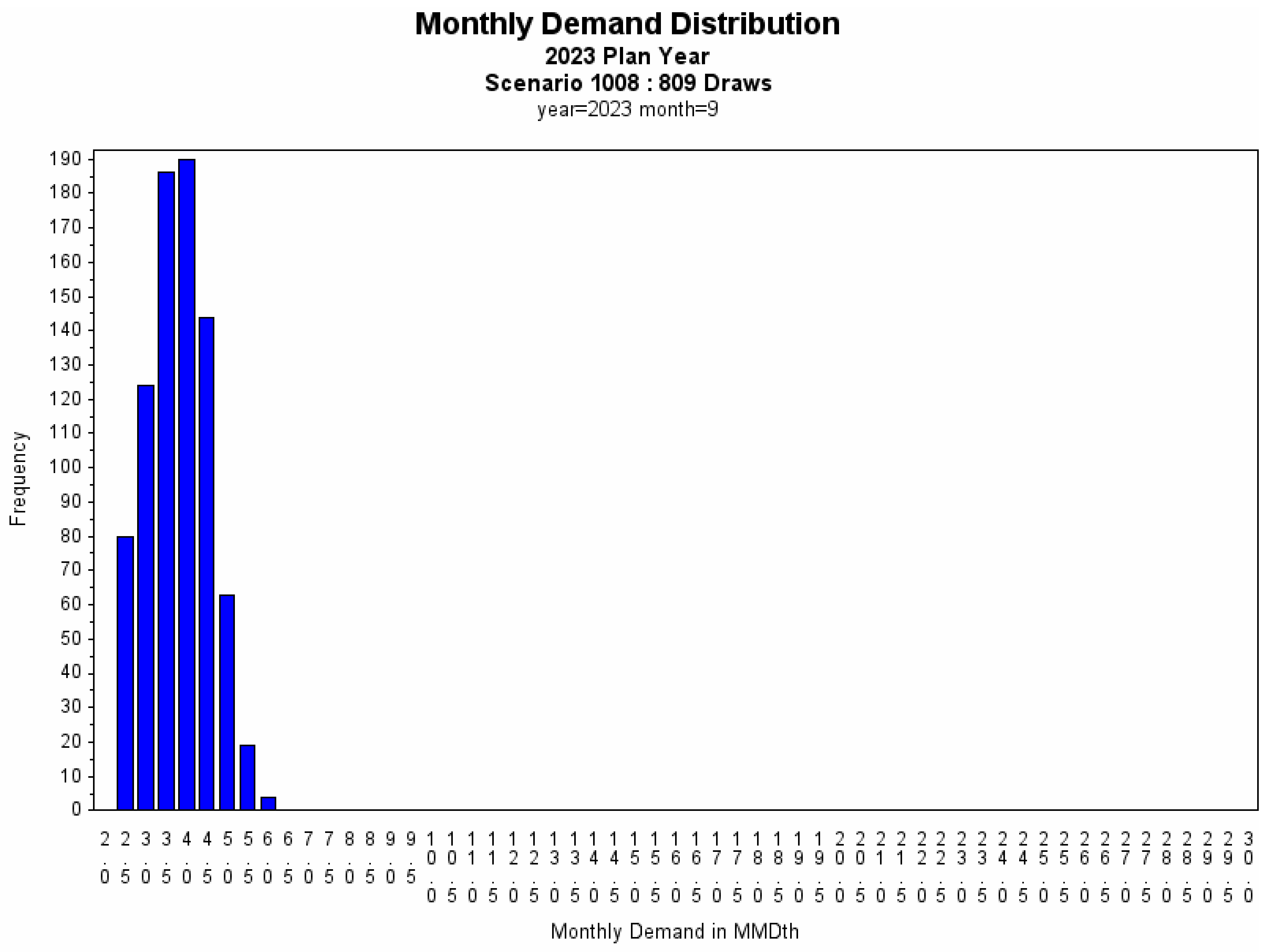

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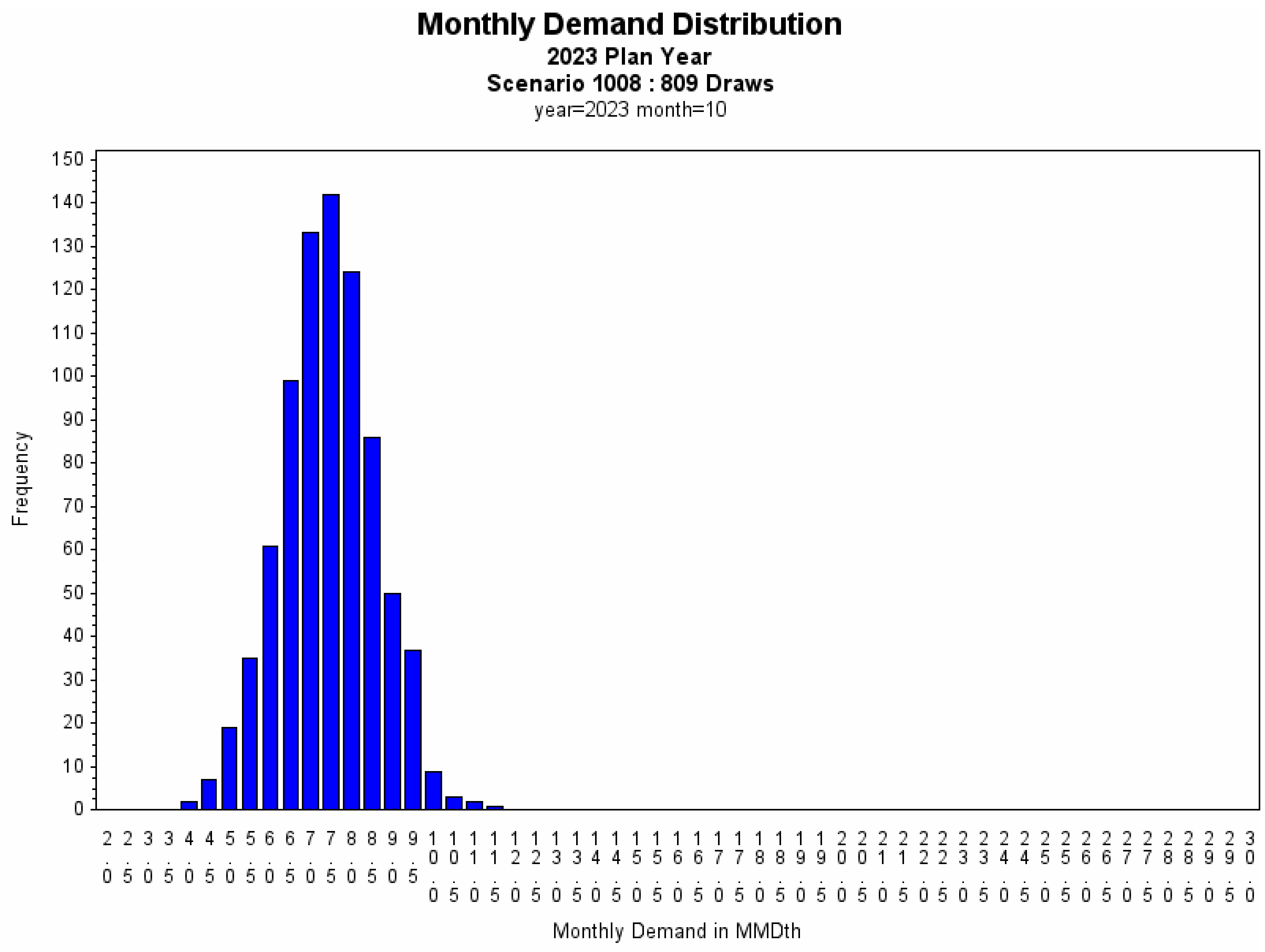


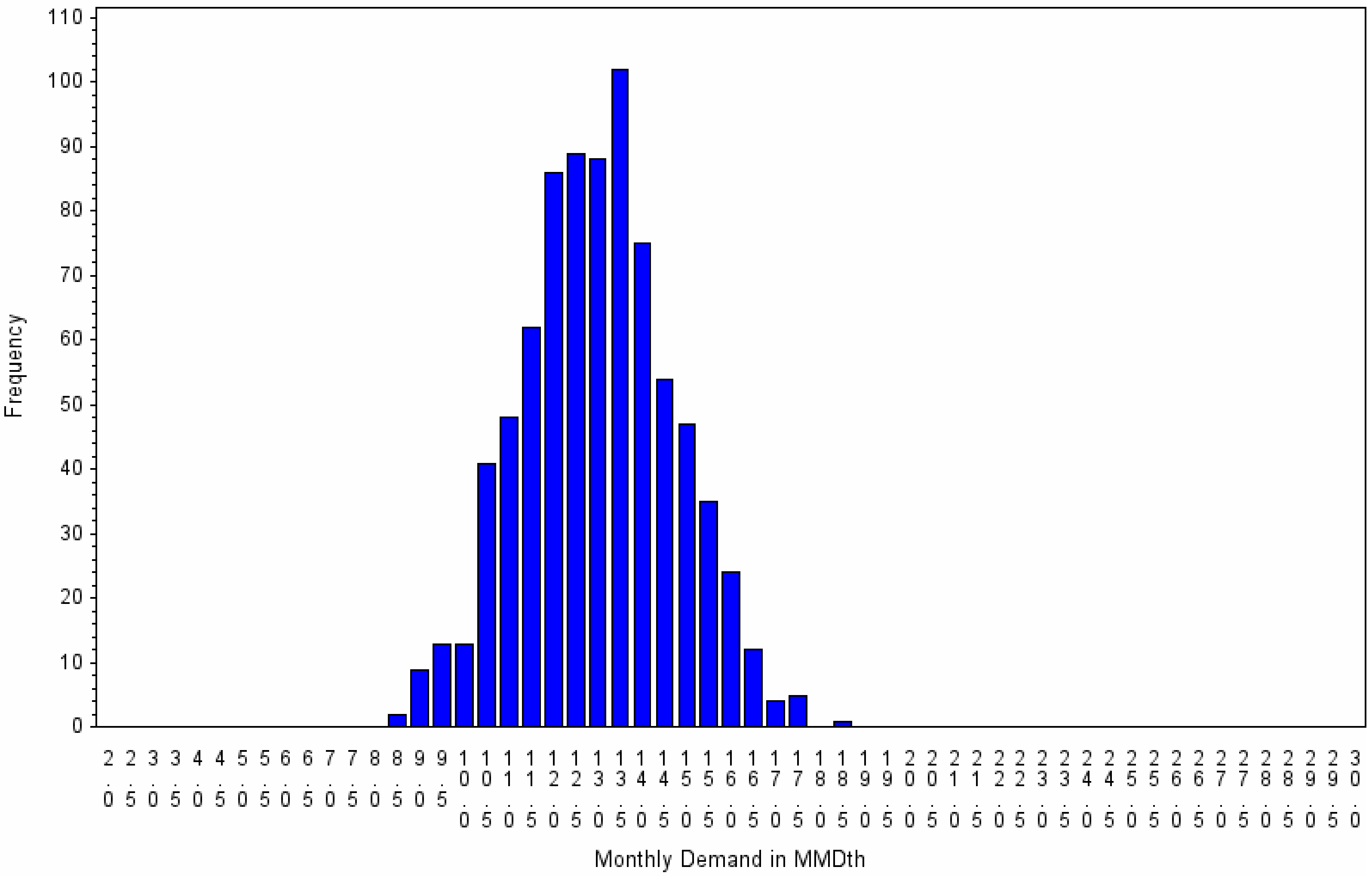
Exhibit 14.42

Monthly Demand Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=11



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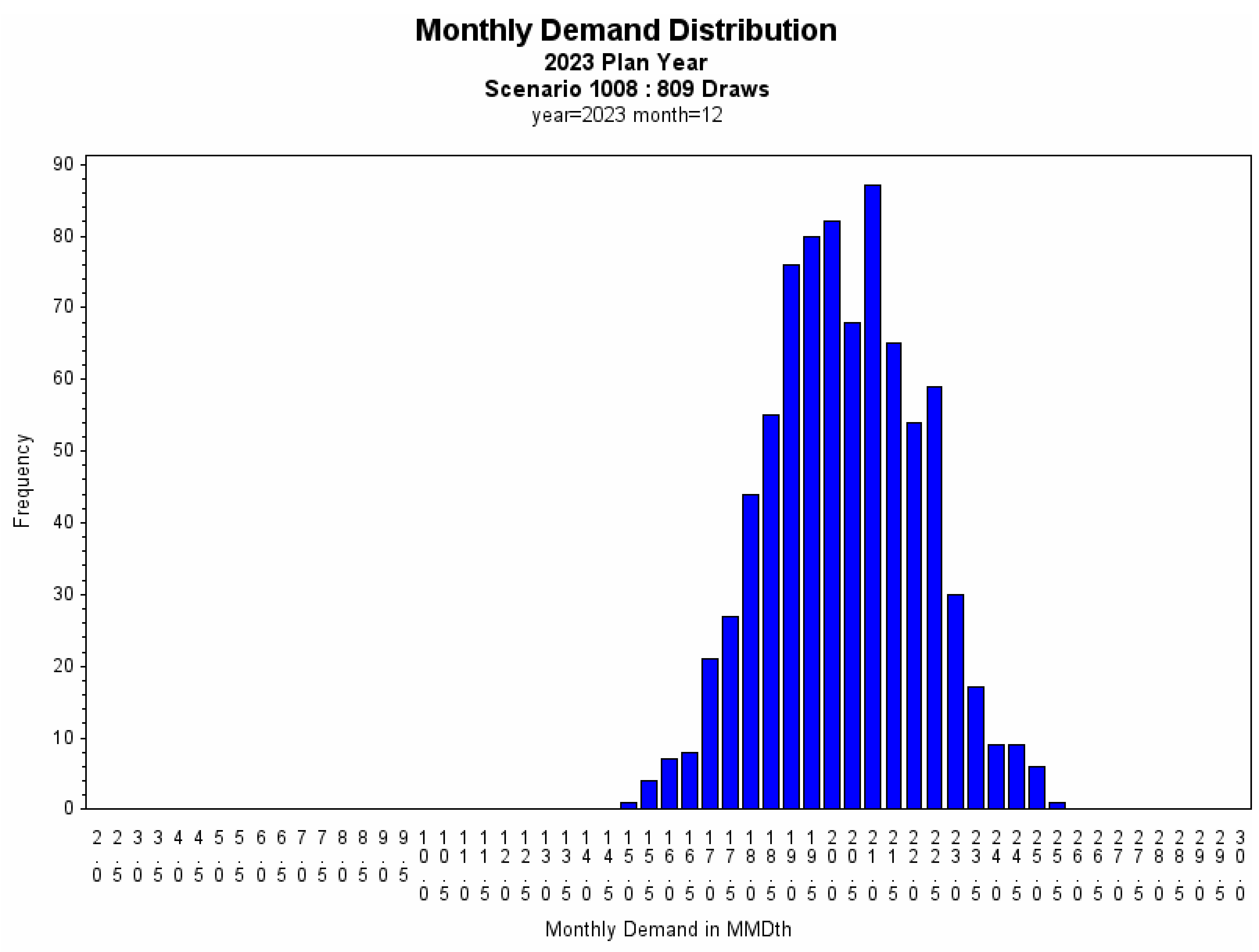

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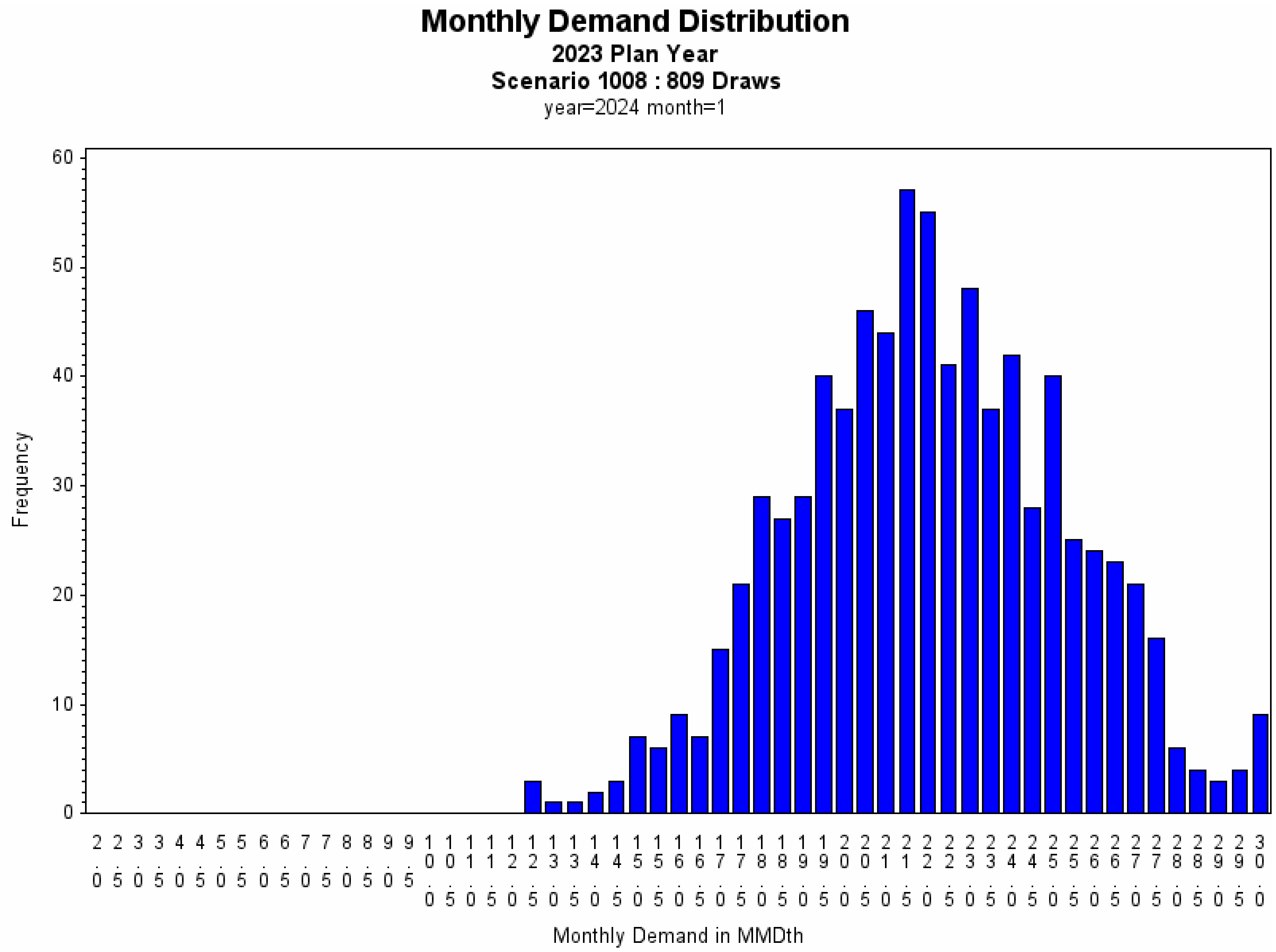

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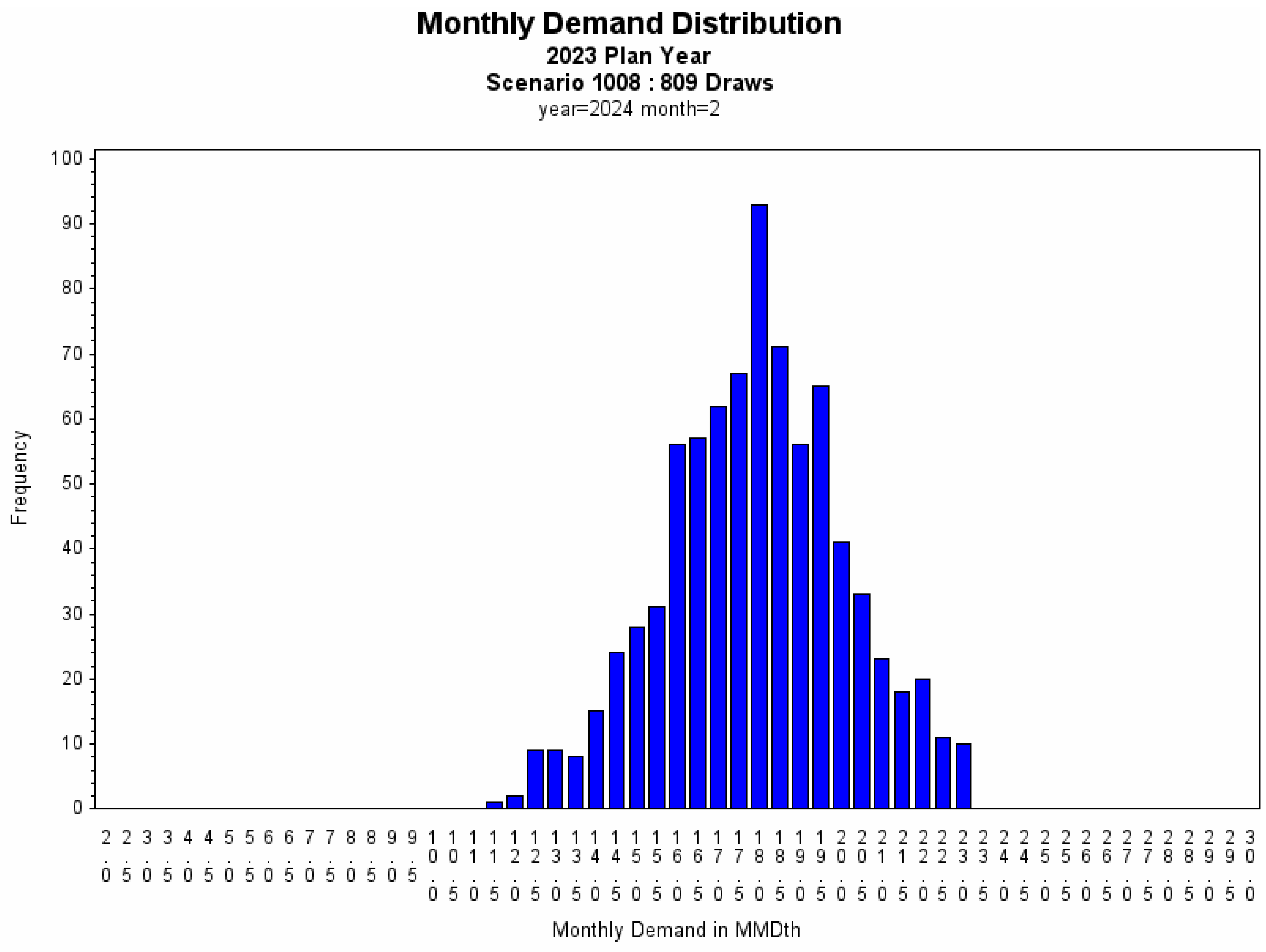

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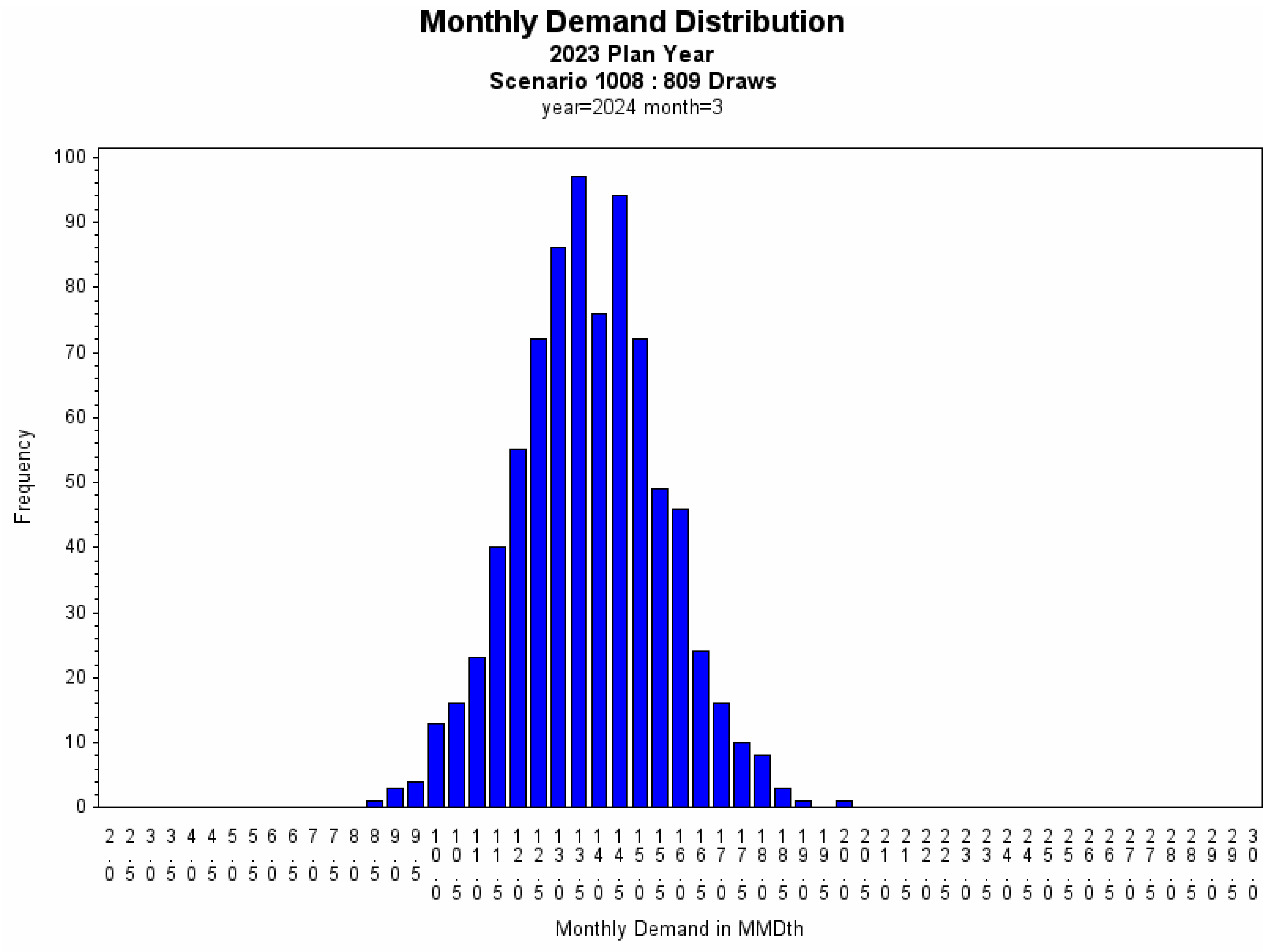

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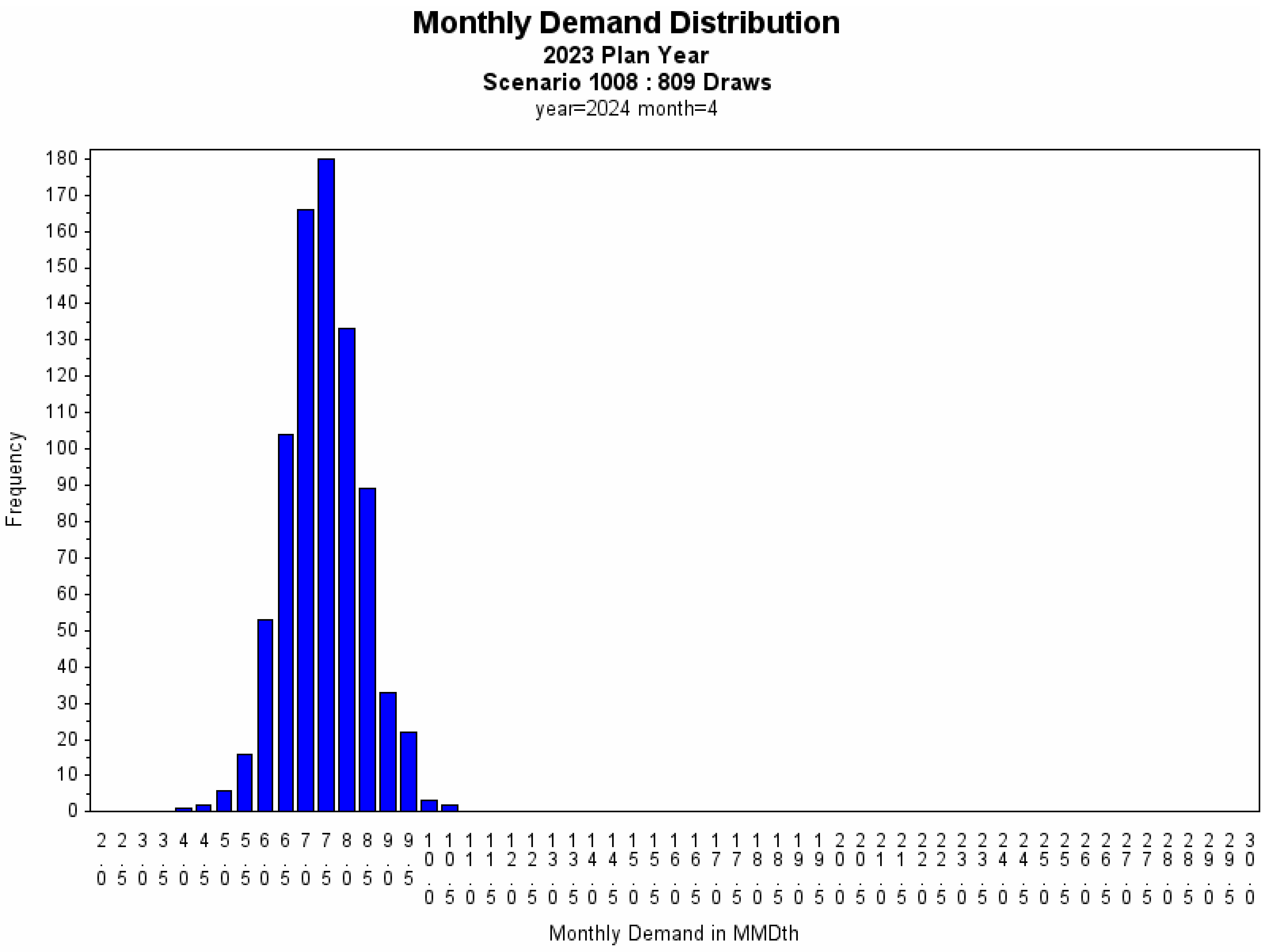


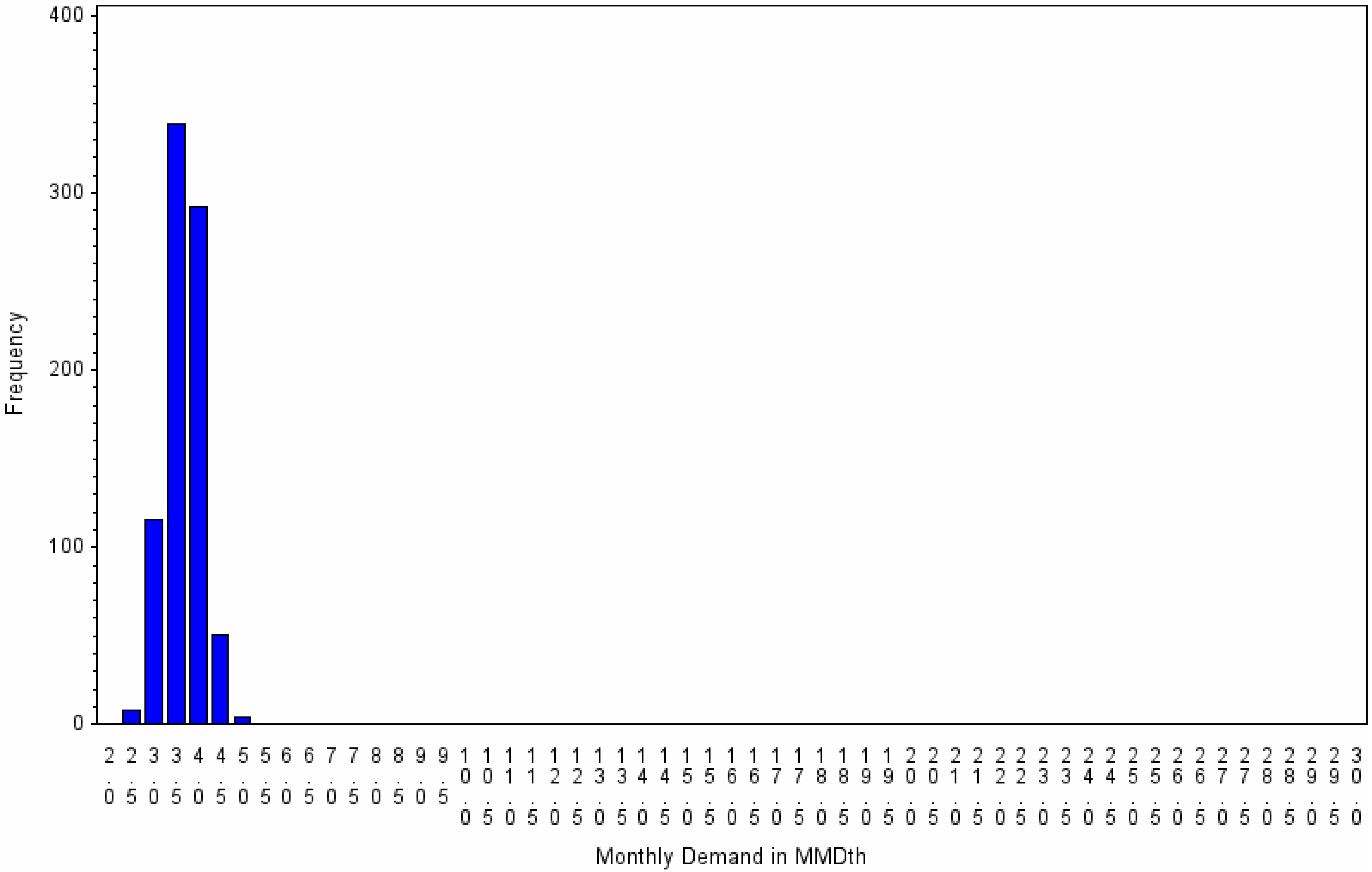
Exhibit 14.48

Monthly Demand Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=5



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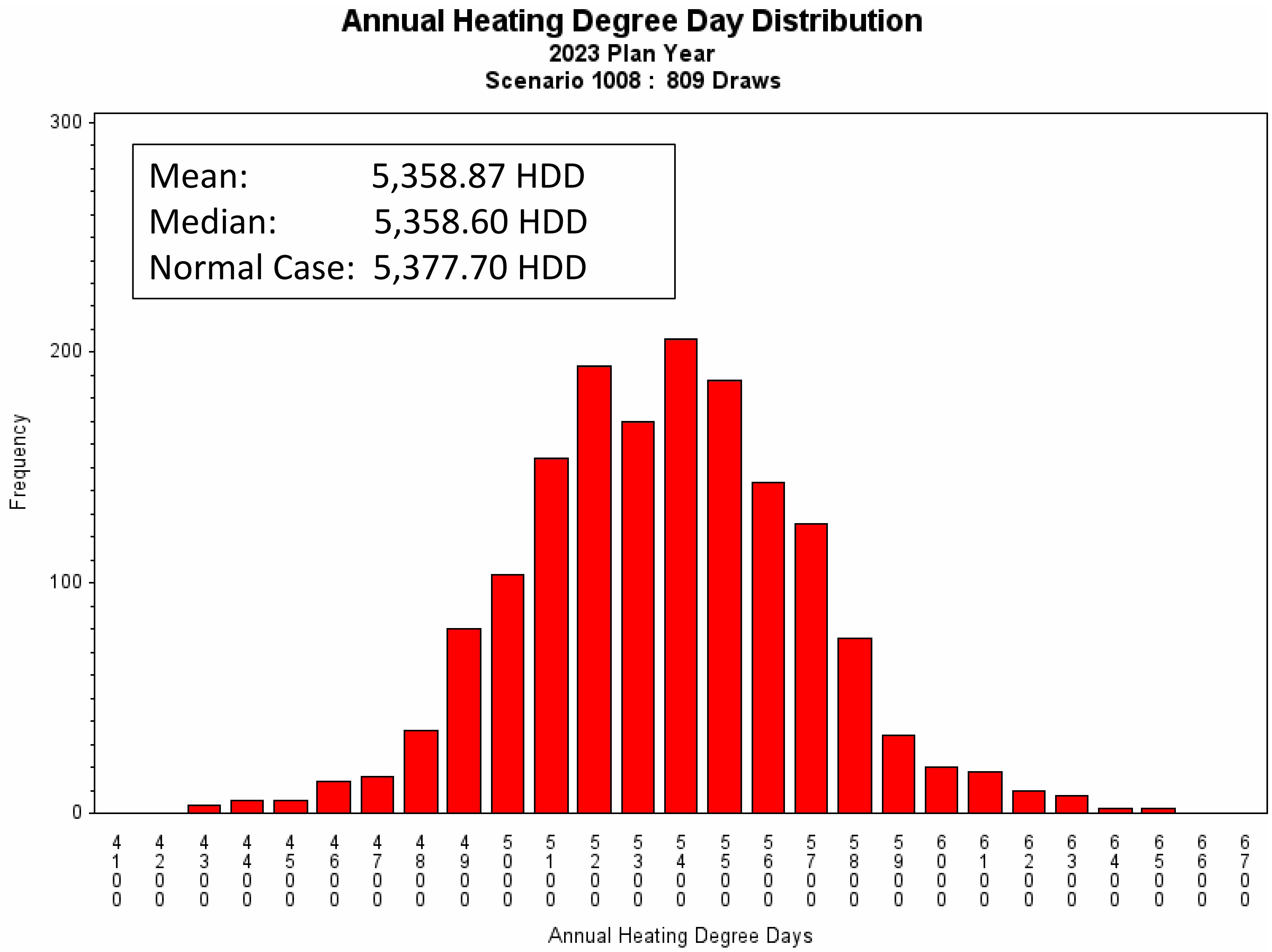

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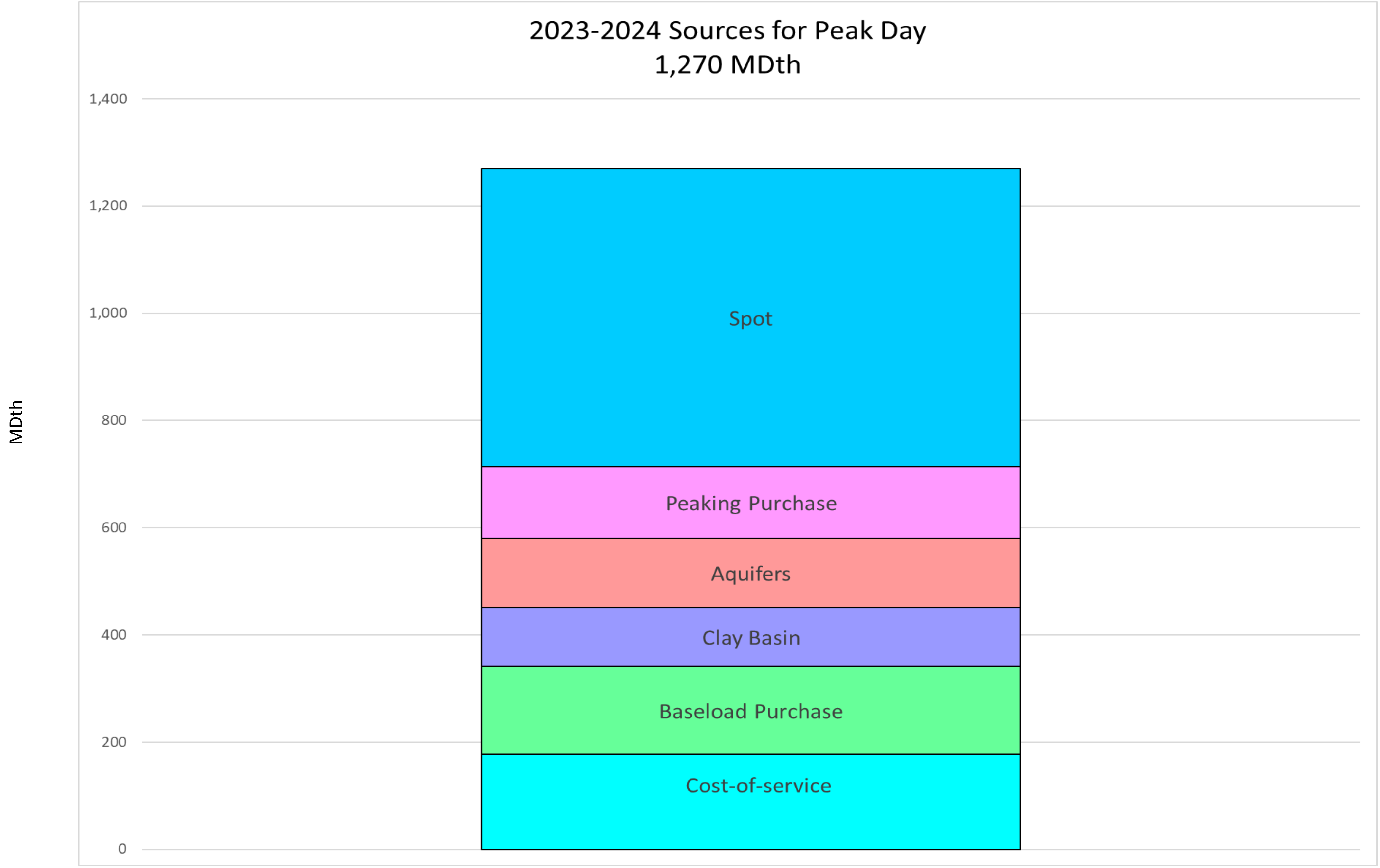

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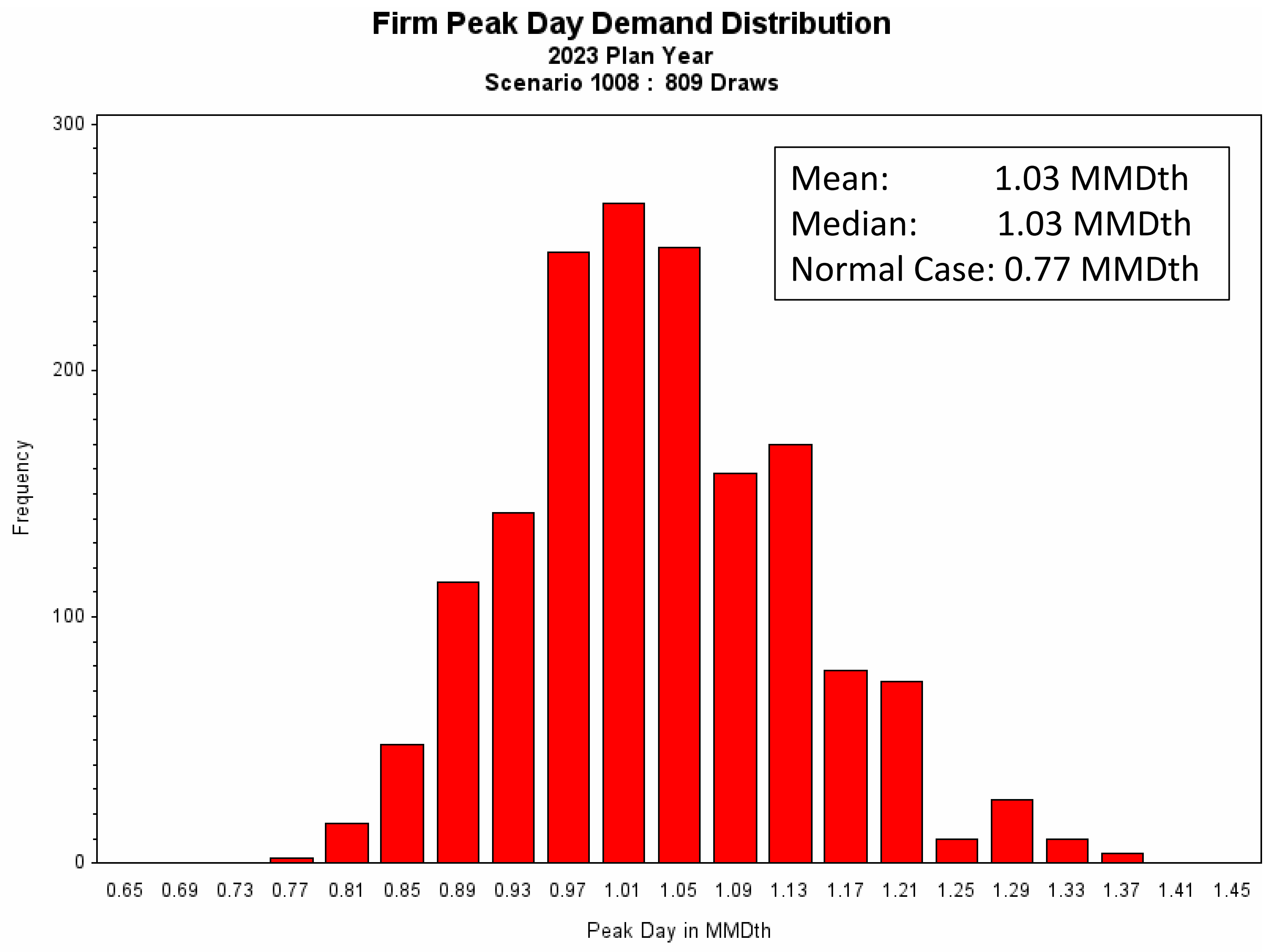

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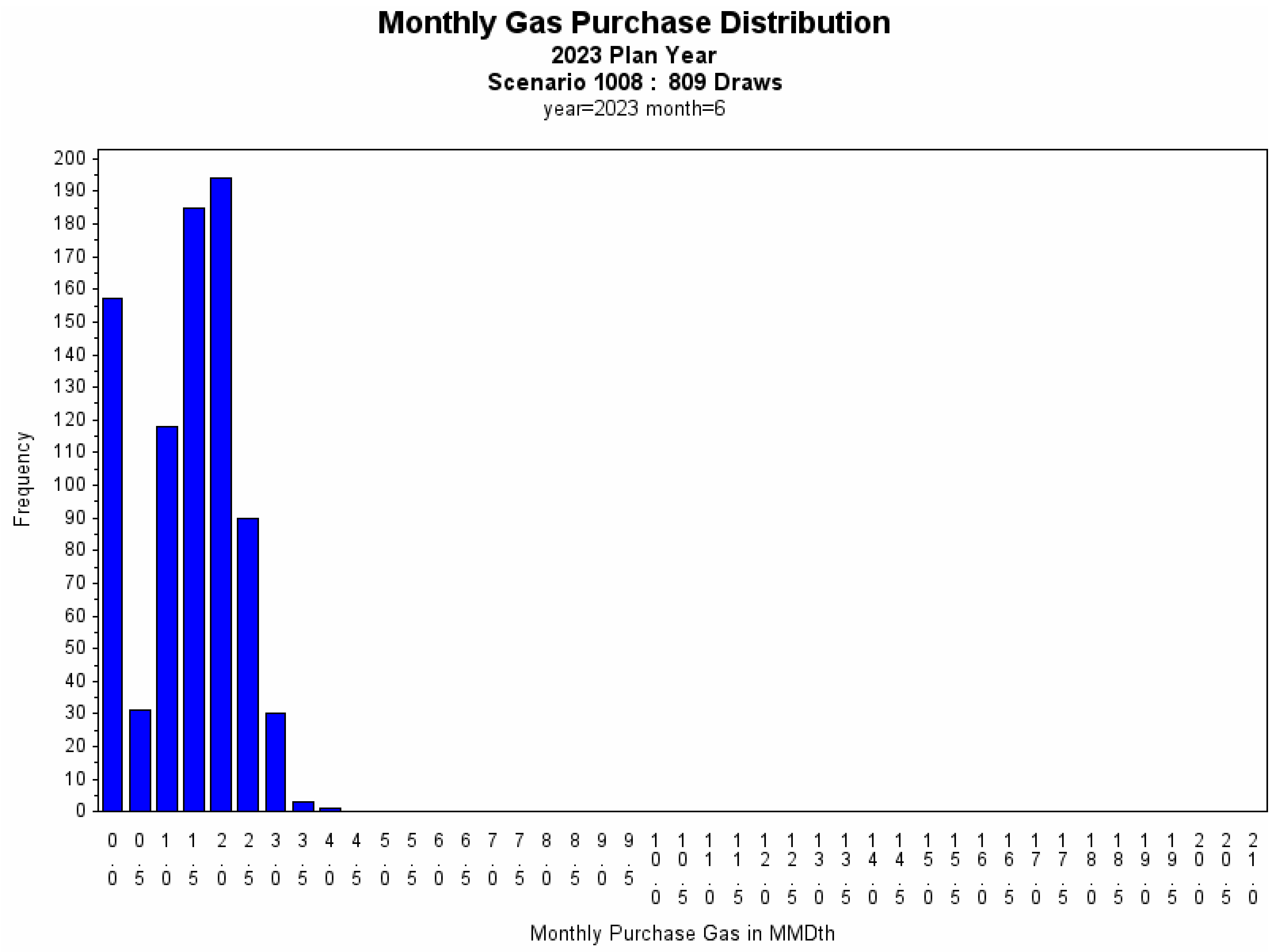

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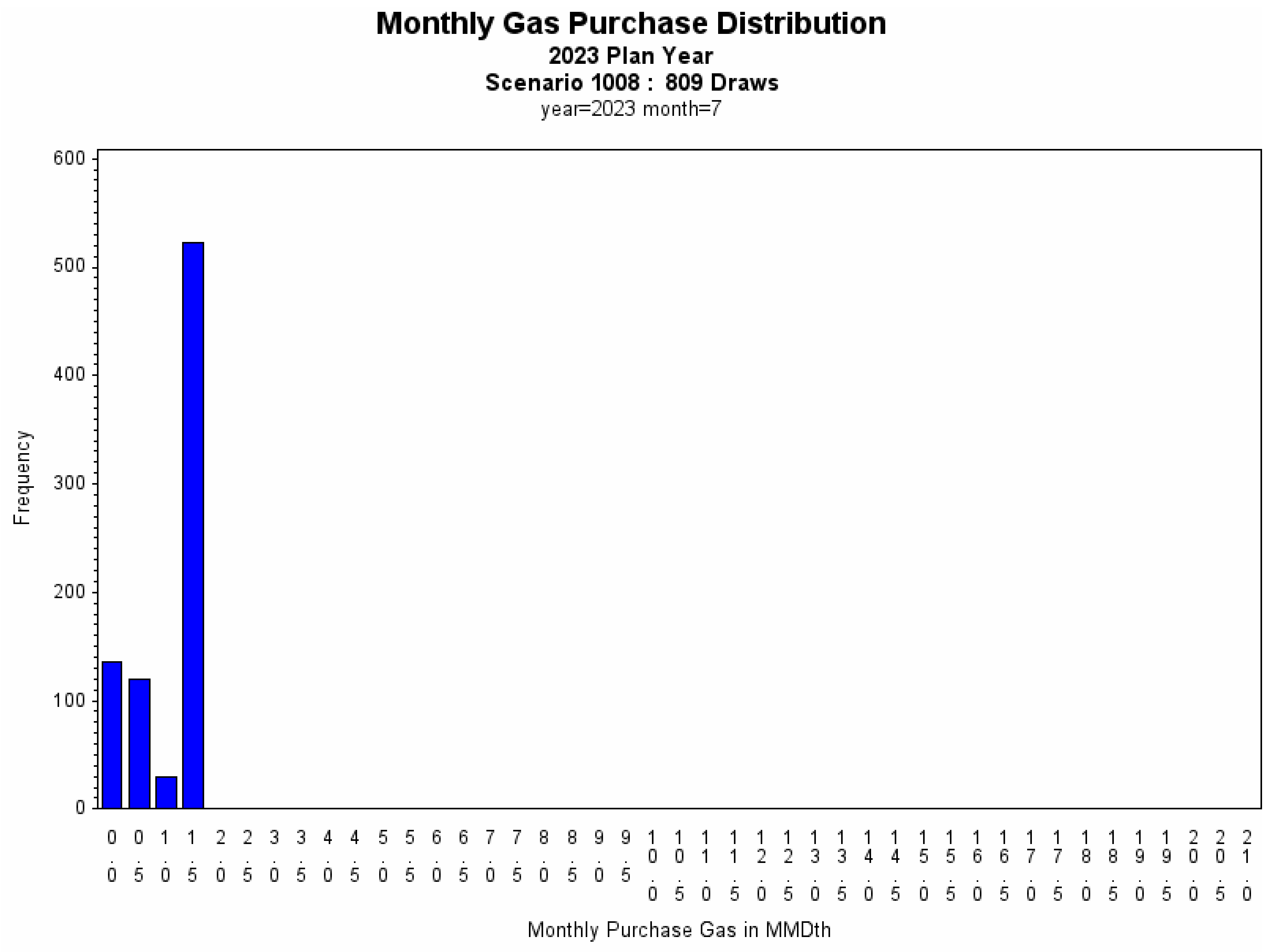

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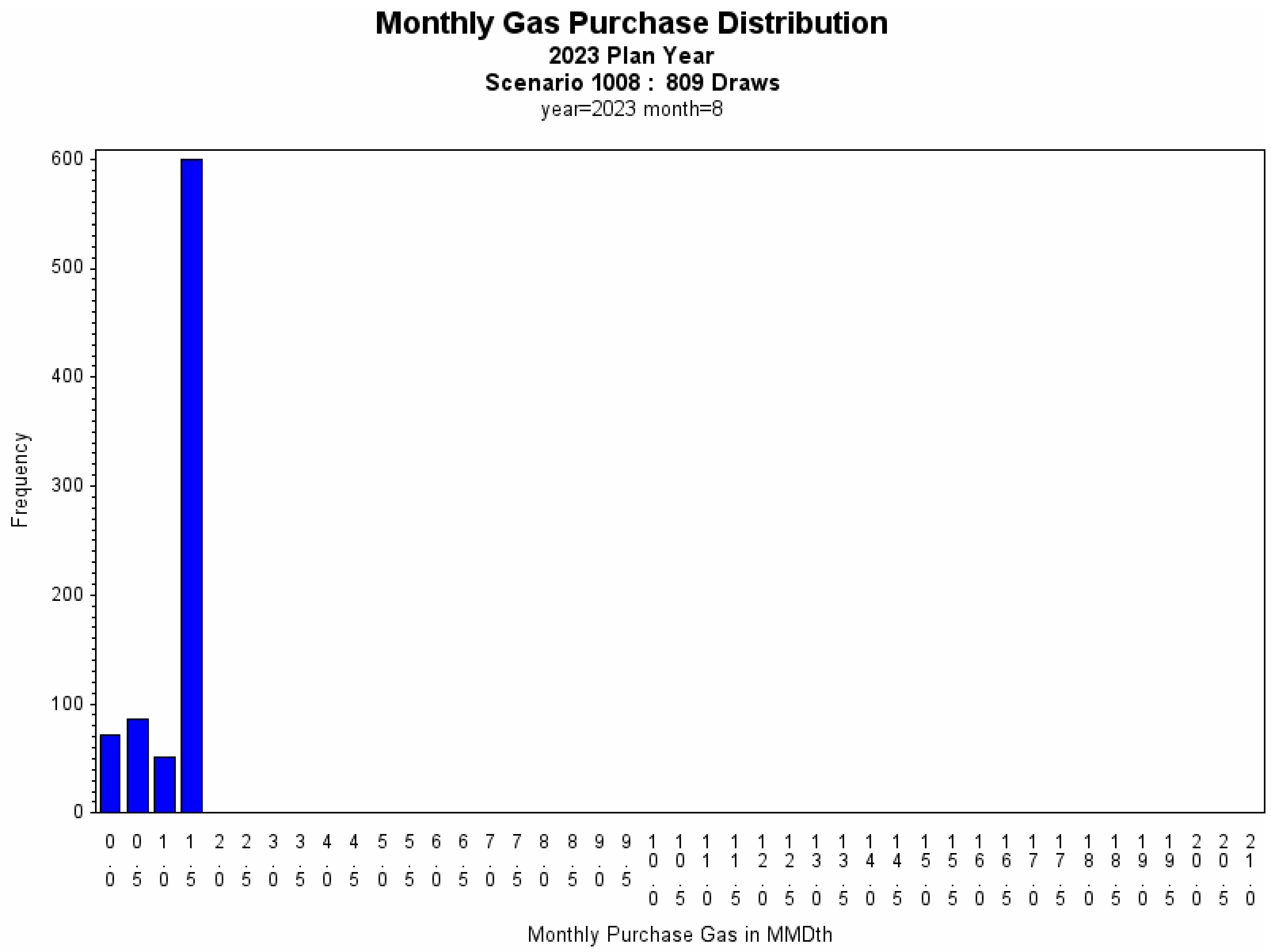

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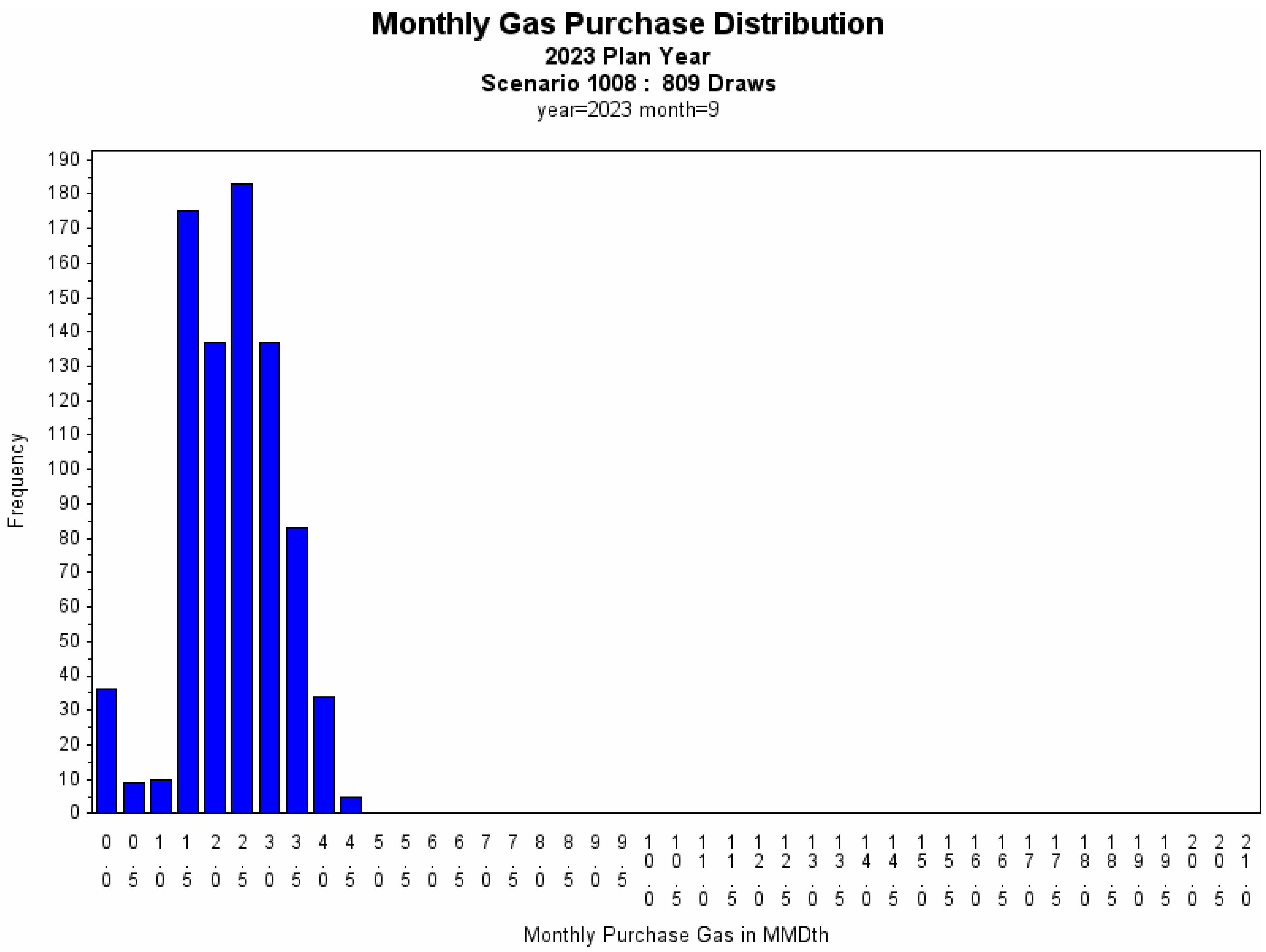

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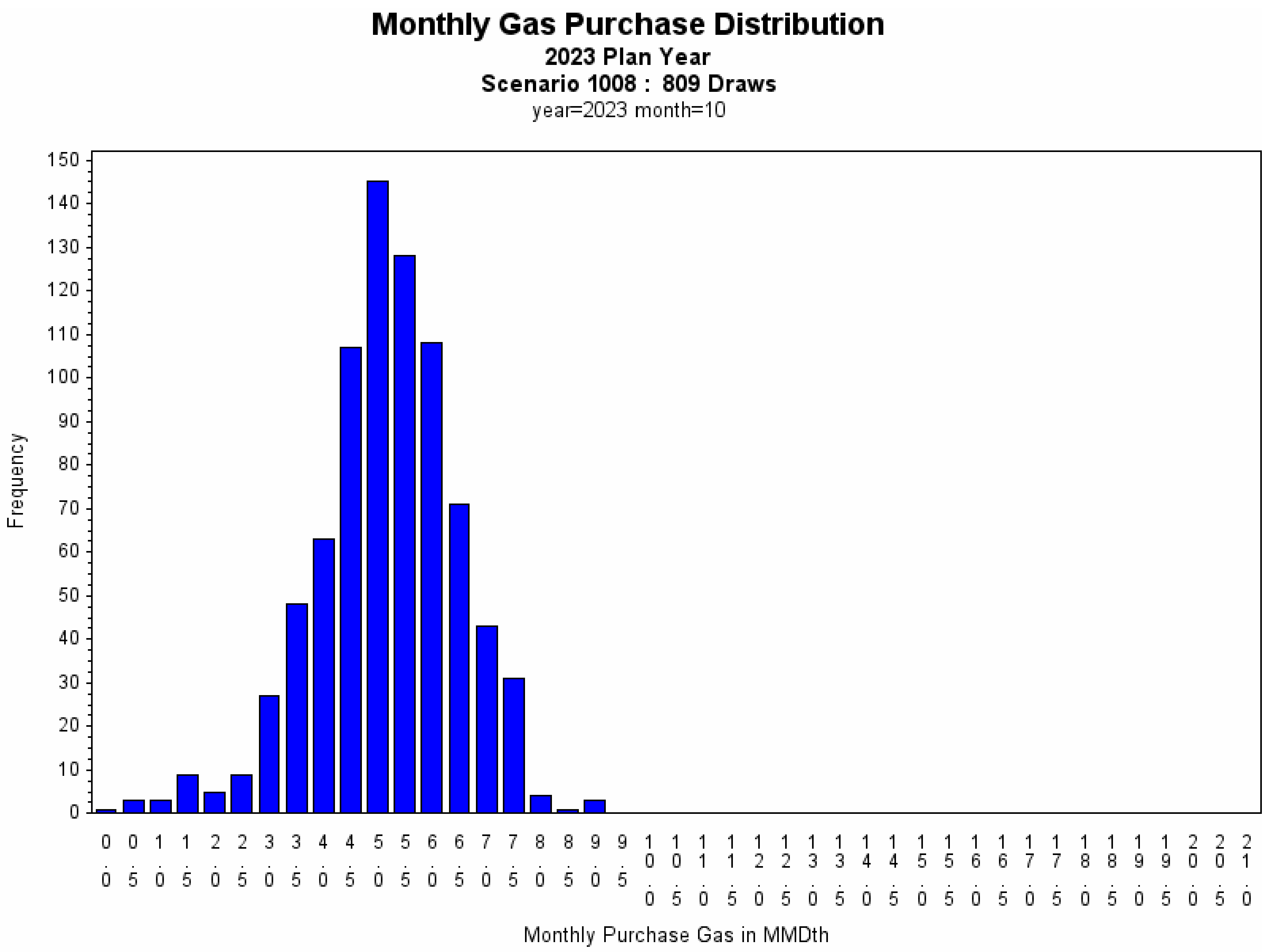

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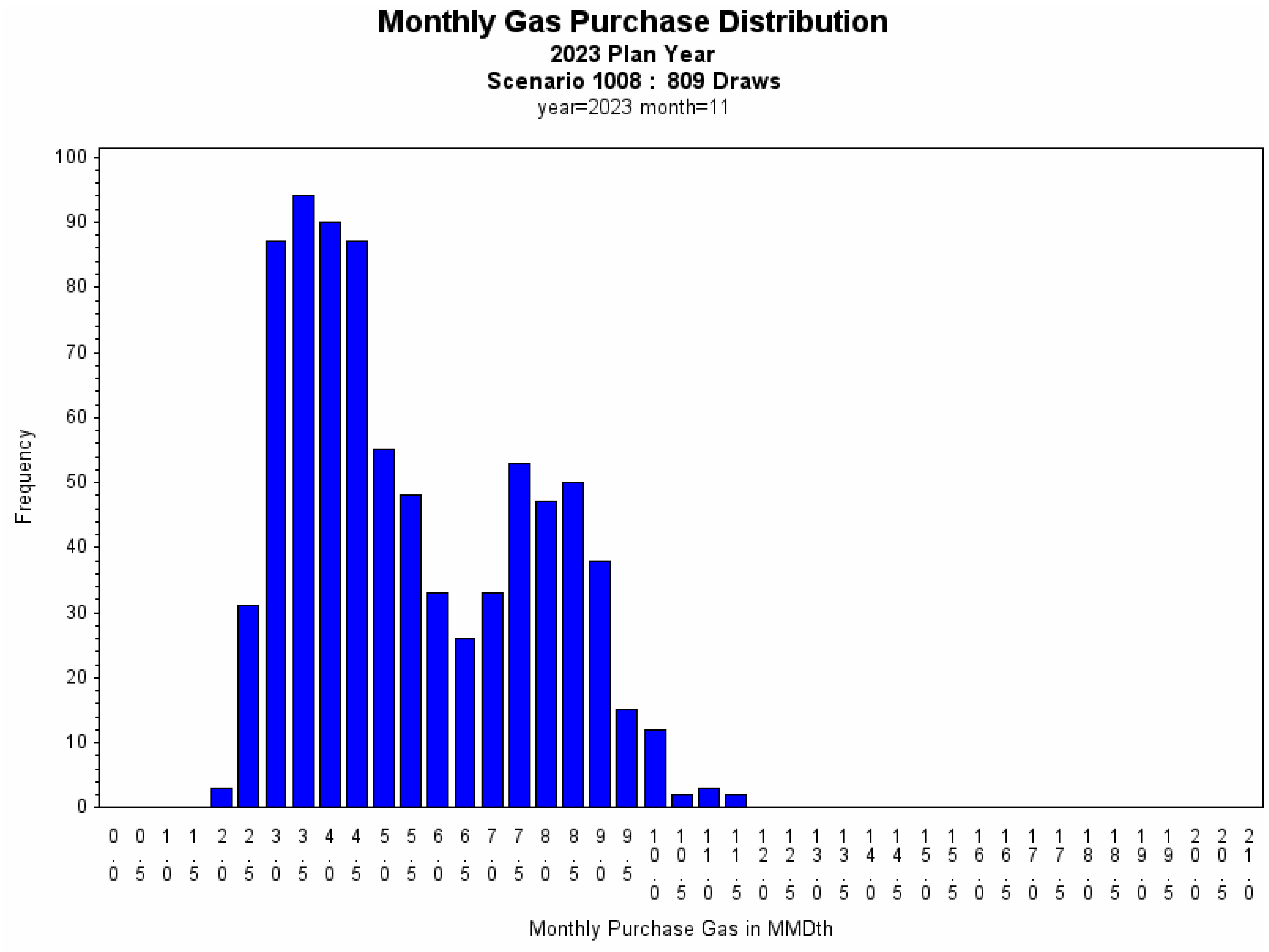

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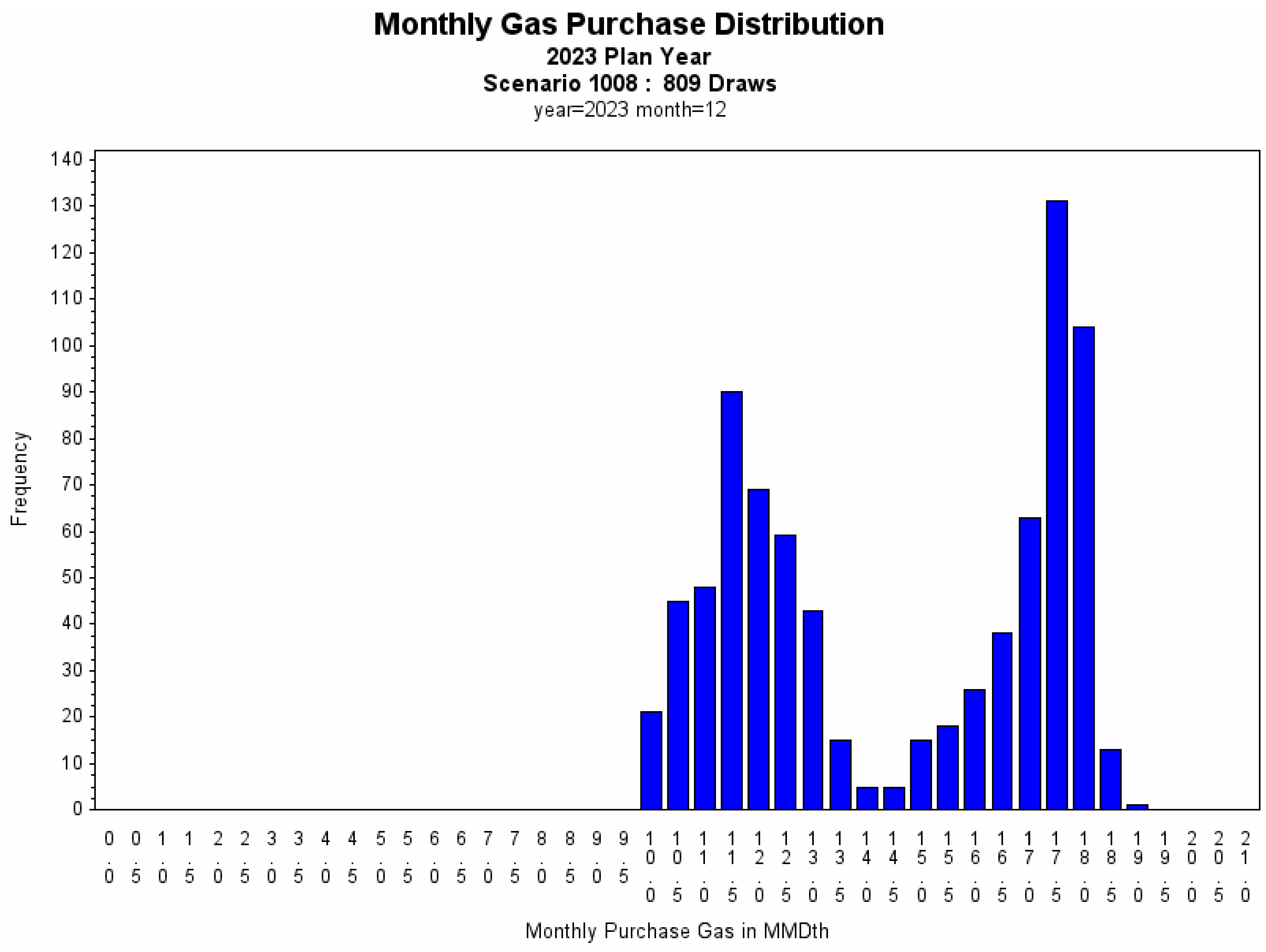

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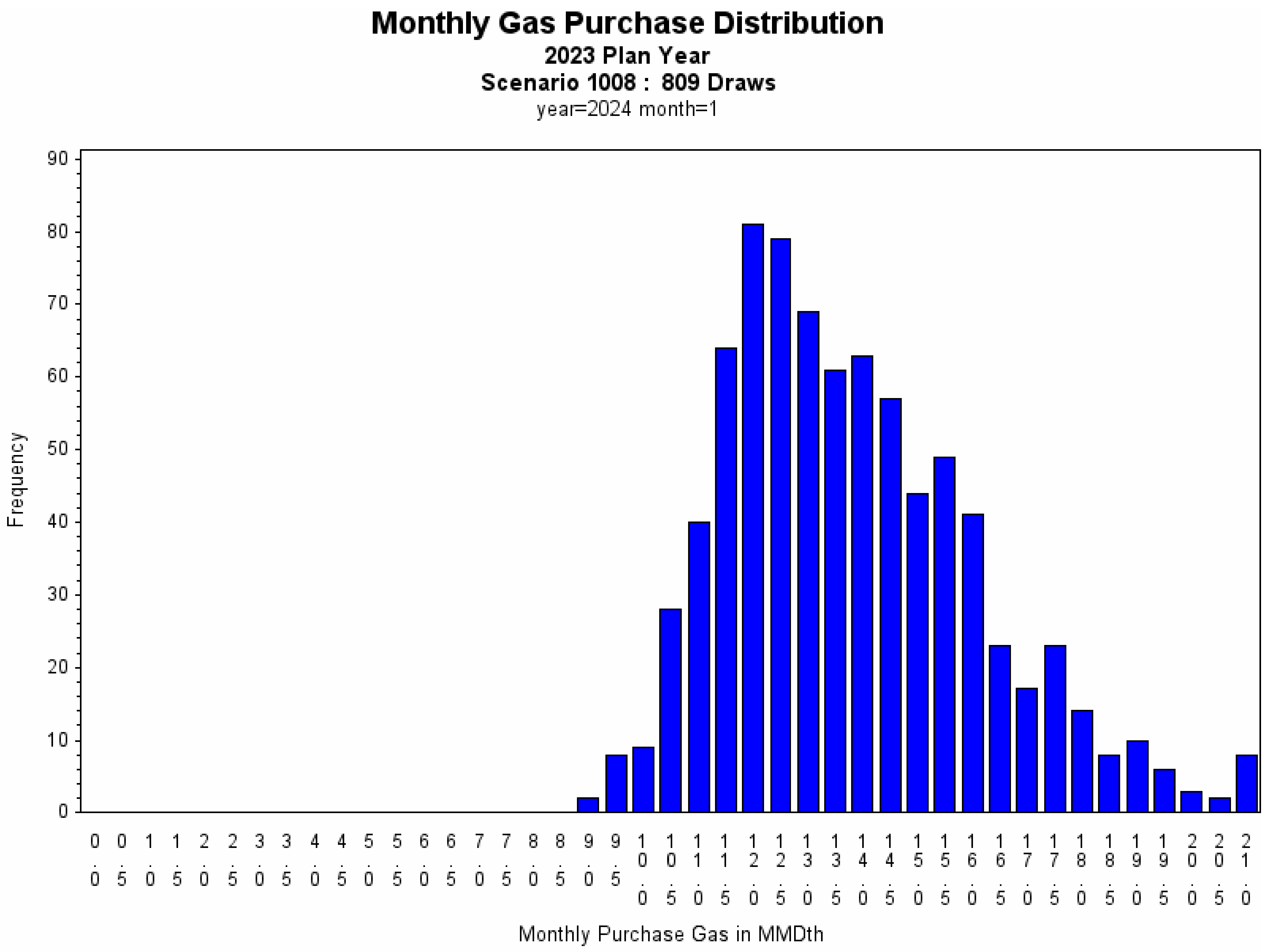

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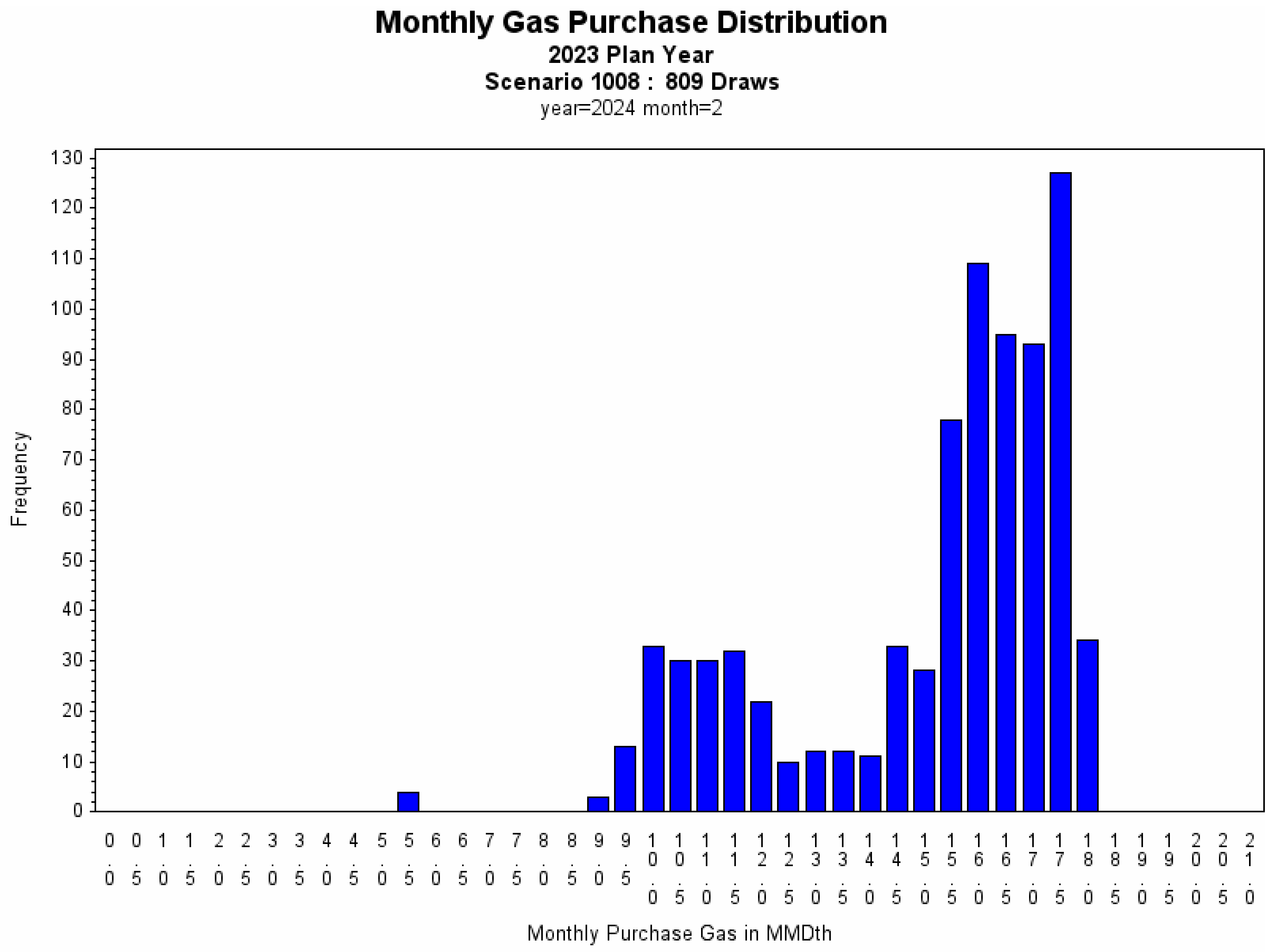

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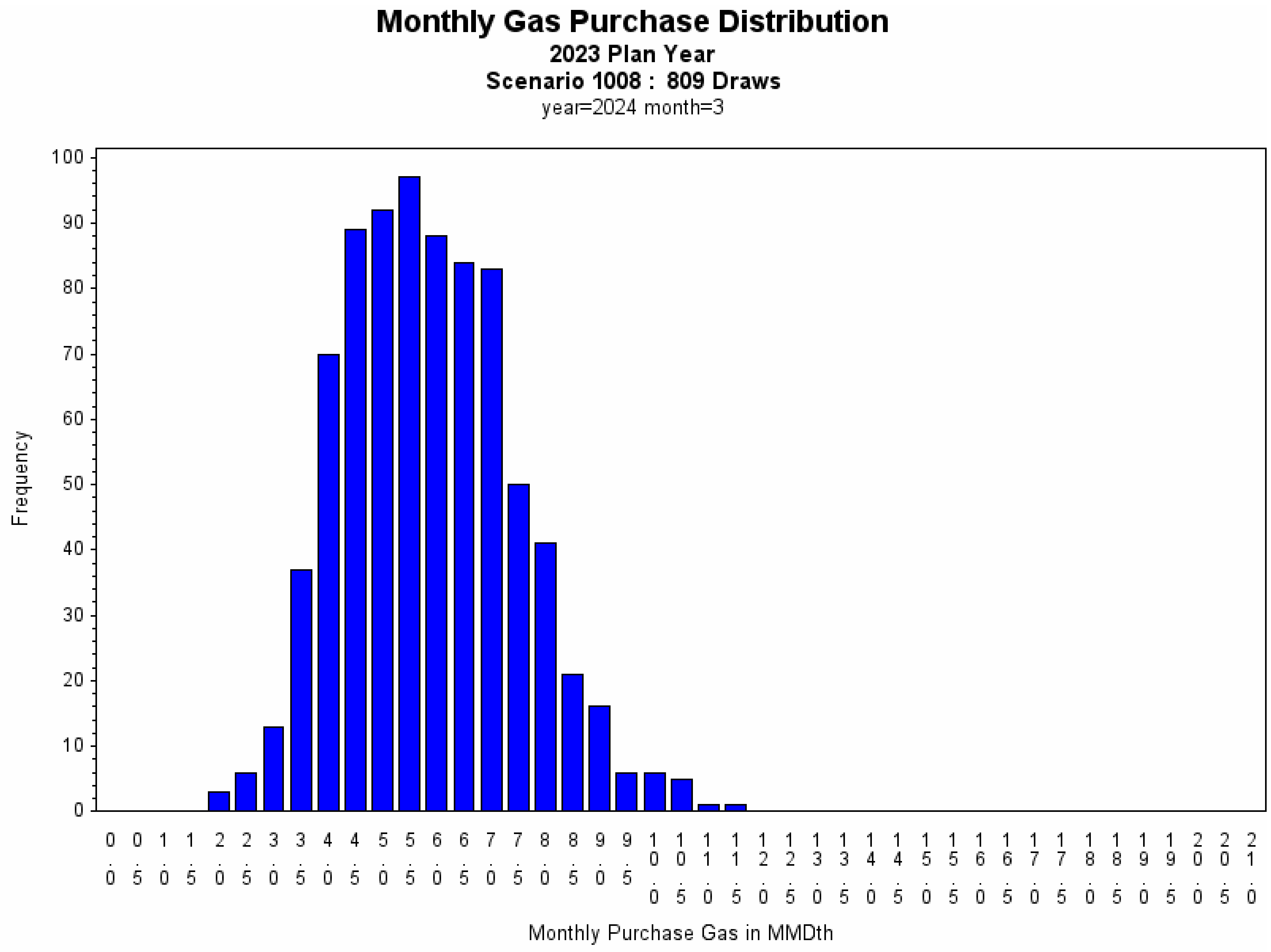

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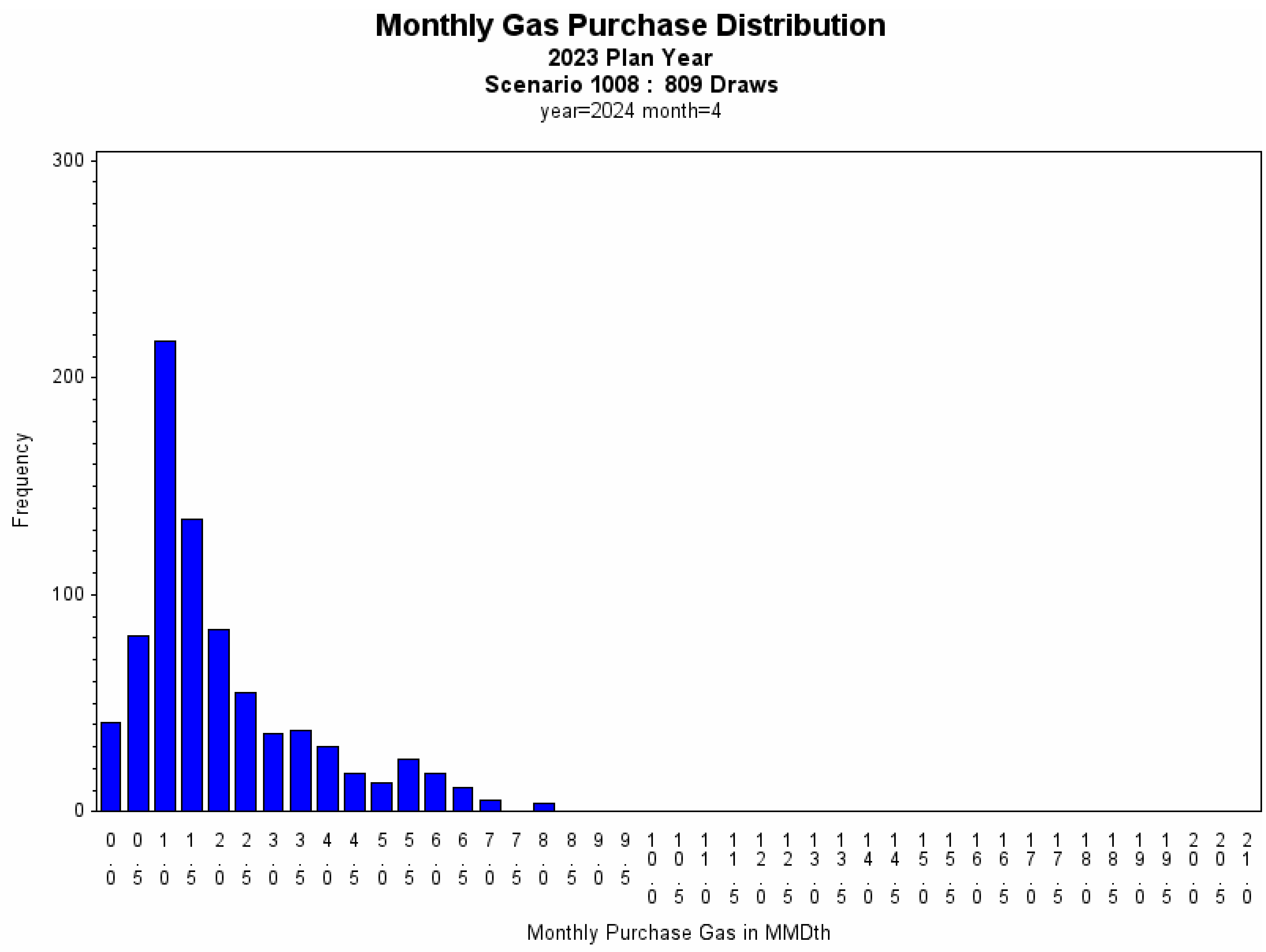

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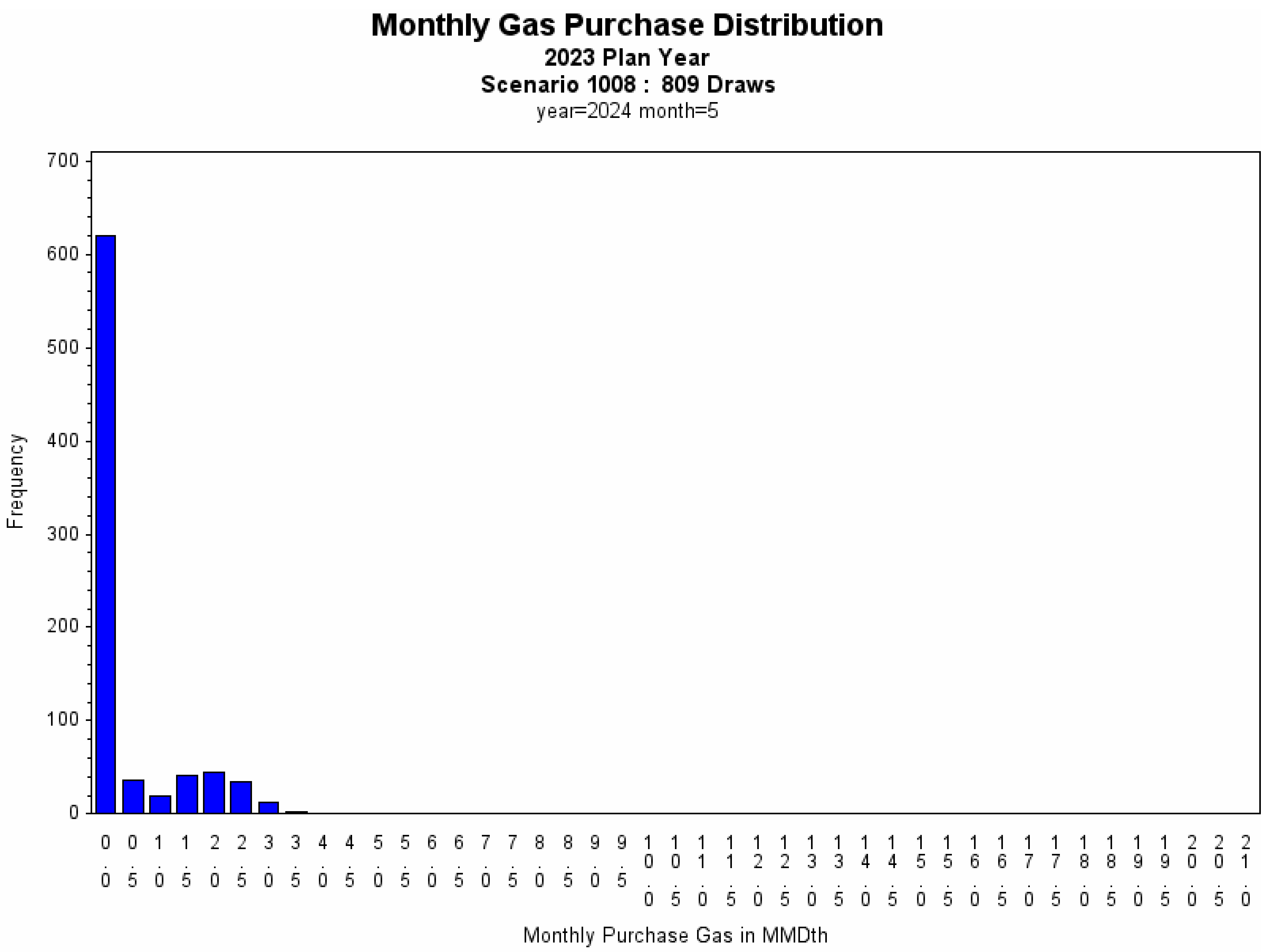

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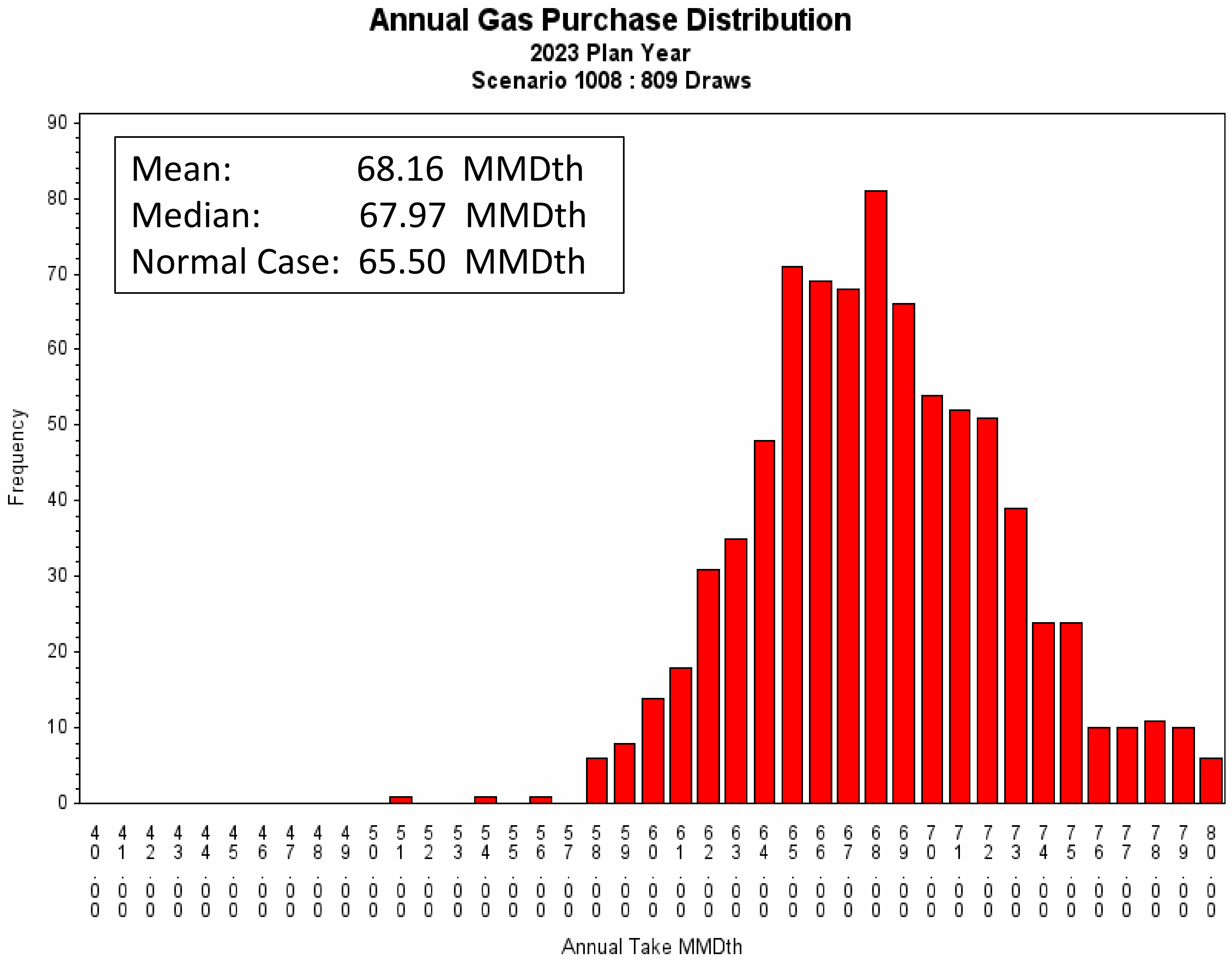

Exhibit 14.65

Monthly Purchase Gas Distribution in Mdth
2023 Plan Year
Scenario 1008 : 809 Draws

year	month	mean	max	p95	p90	med	p10	p5	min
2023	6	1.41	3.75	2.67	2.43	1.51	0.01	0.01	0.01
2023	7	0.97	1.3	1.3	1.3	1.3	0.01	0.01	0.01
2023	8	1.11	1.52	1.42	1.4	1.29	0.52	0.01	0.01
2023	9	2.3	4.64	3.74	3.43	2.35	1.38	0.43	0.01
2023	10	5.15	9.15	7.19	6.75	5.18	3.53	2.91	0.24
2023	11	5.49	11.47	9.12	8..67	4.91	3.05	2.83	2.13
2023	12	14.54	19.16	18.05	17.91	14.91	10.94	10.55	9.78
2024	1	13.81	23.05	18.19	17	13.51	11.2	10.69	9.1
2024	2	15.98	18.2	17.72	17.53	16.03	10.68	9.97	5.37
2024	3	5.86	11.33	8.65	7.94	5.74	3.91	3.52	1.76
2024	4	2.02	8.21	5.68	4.57	1.42	0.57	0.21	0.01
2024	5	0.4	3.68	2.36	1.96	0.01	0.01	0.01	0.01

Exhibit 14.66

Monthly Cost-of-Service Gas Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2023 month=6

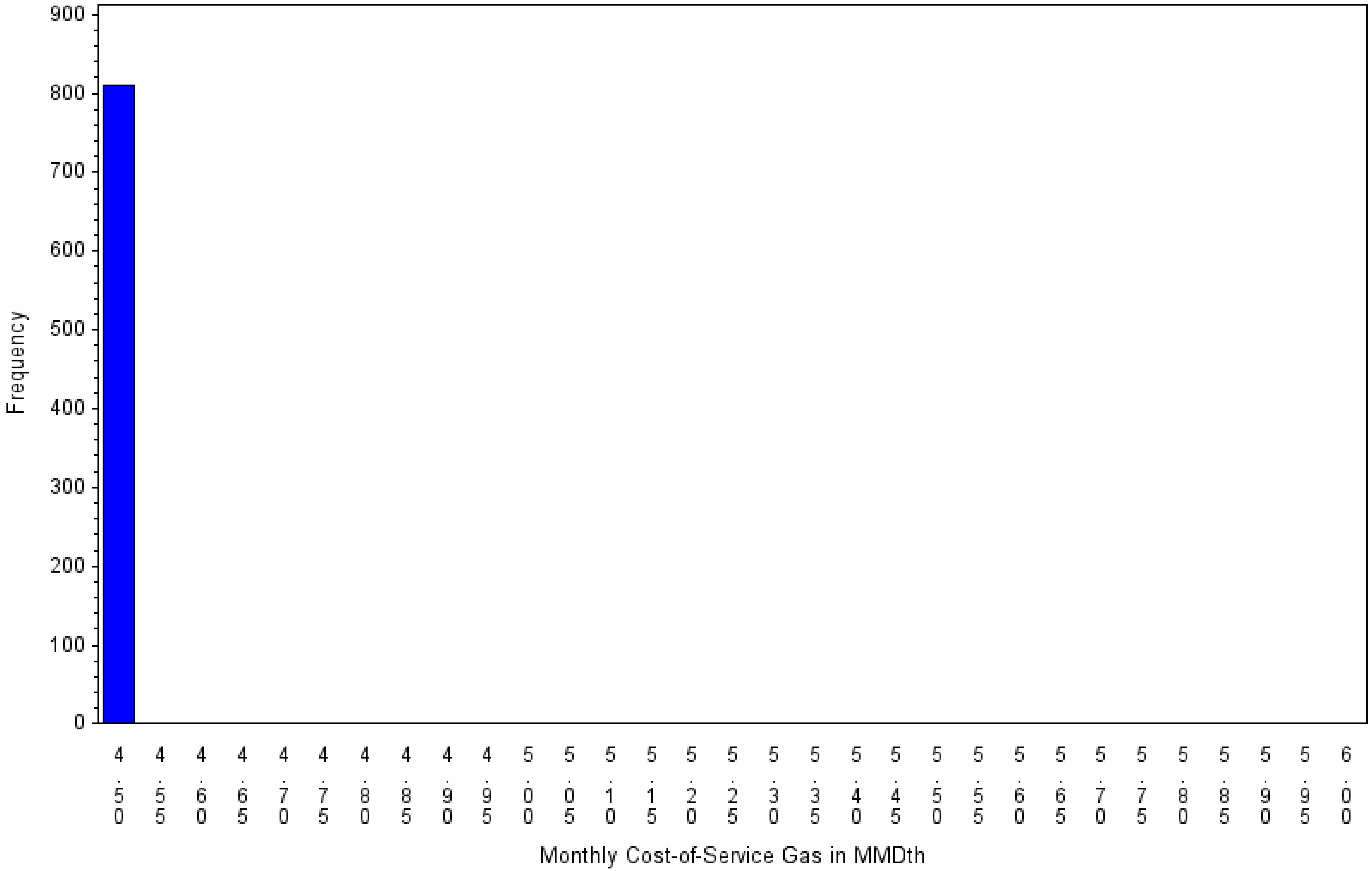

Exhibit 14.67

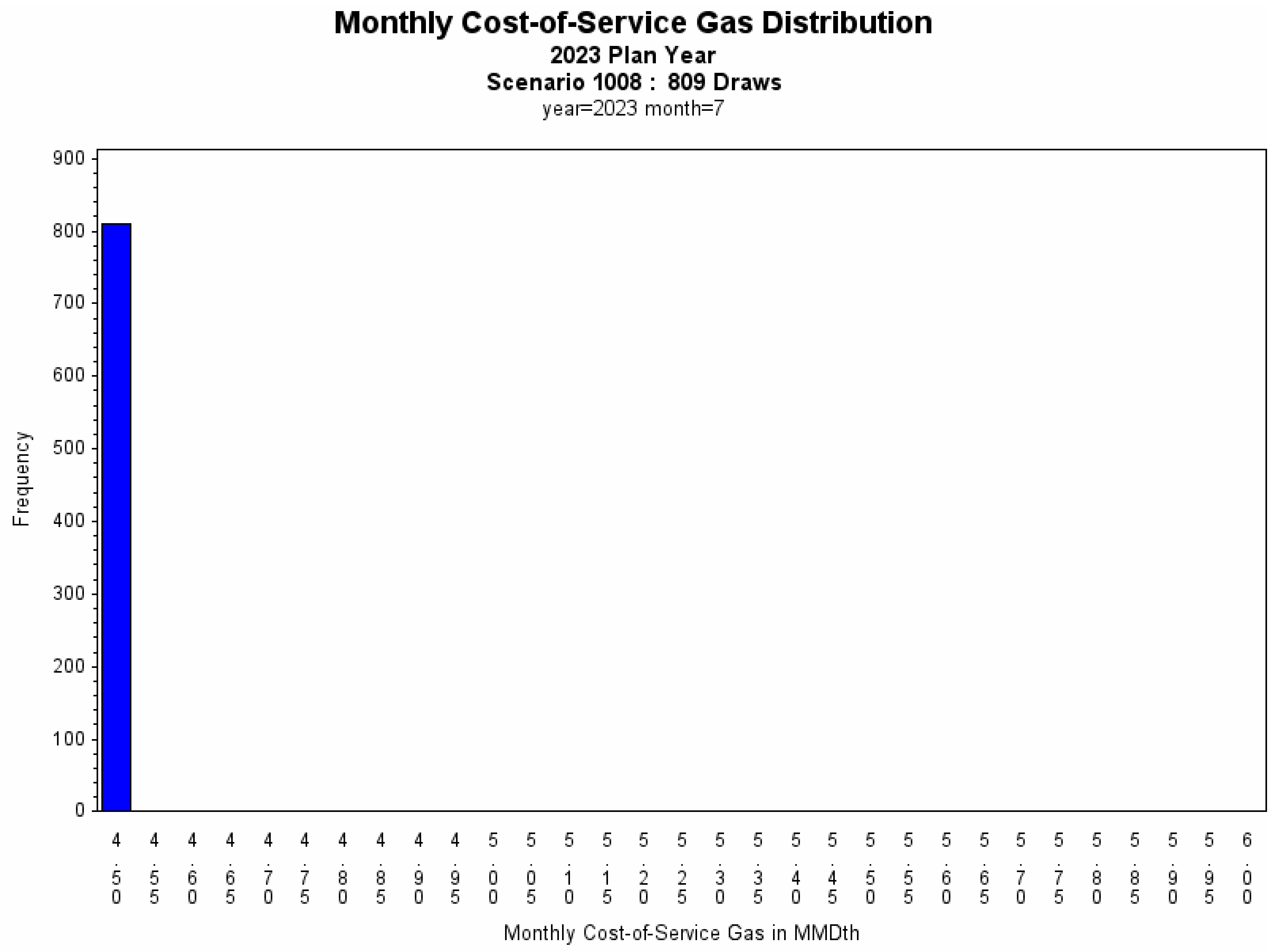

Exhibit 14.68

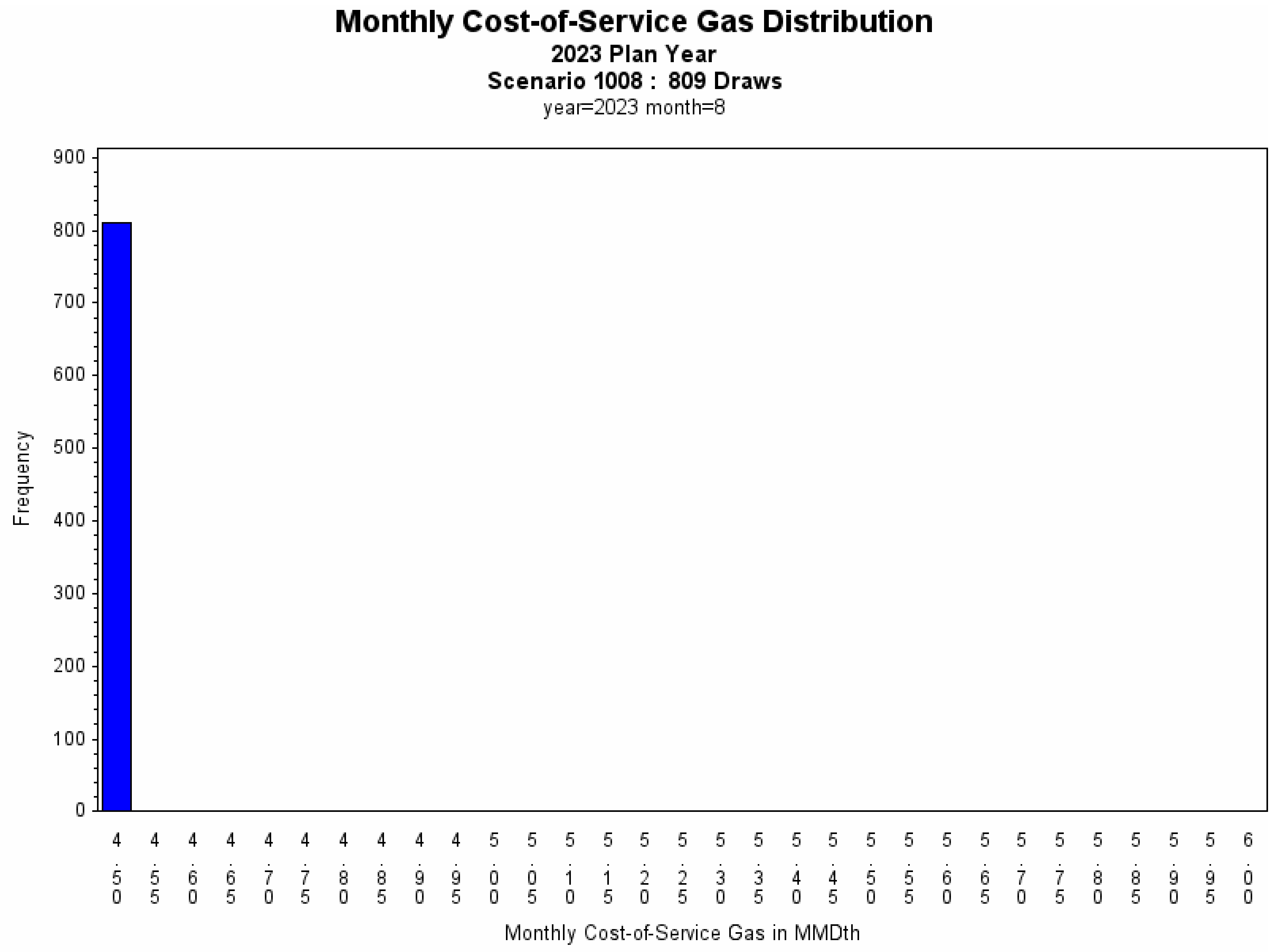

Exhibit 14.69

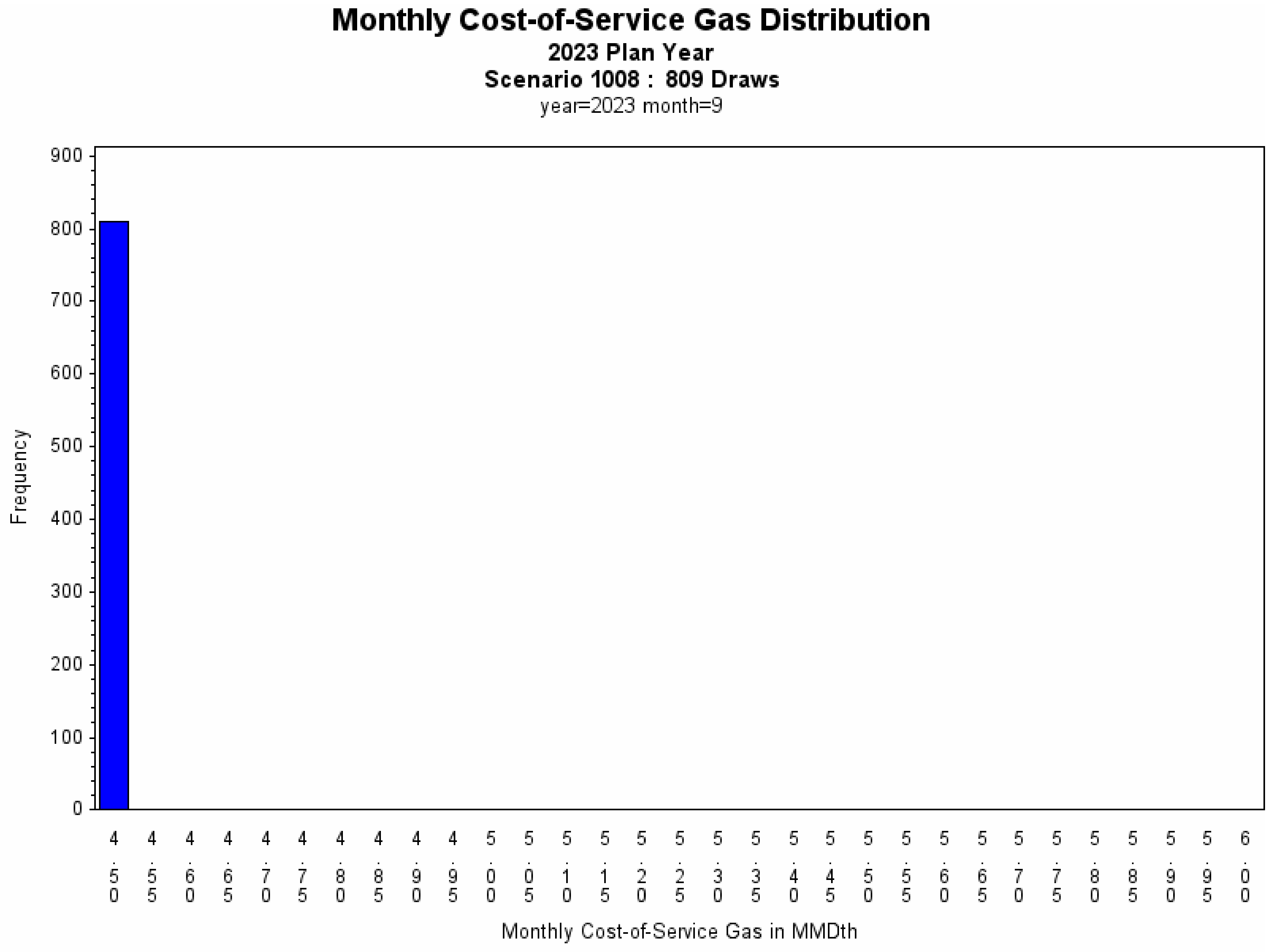

Exhibit 14.70

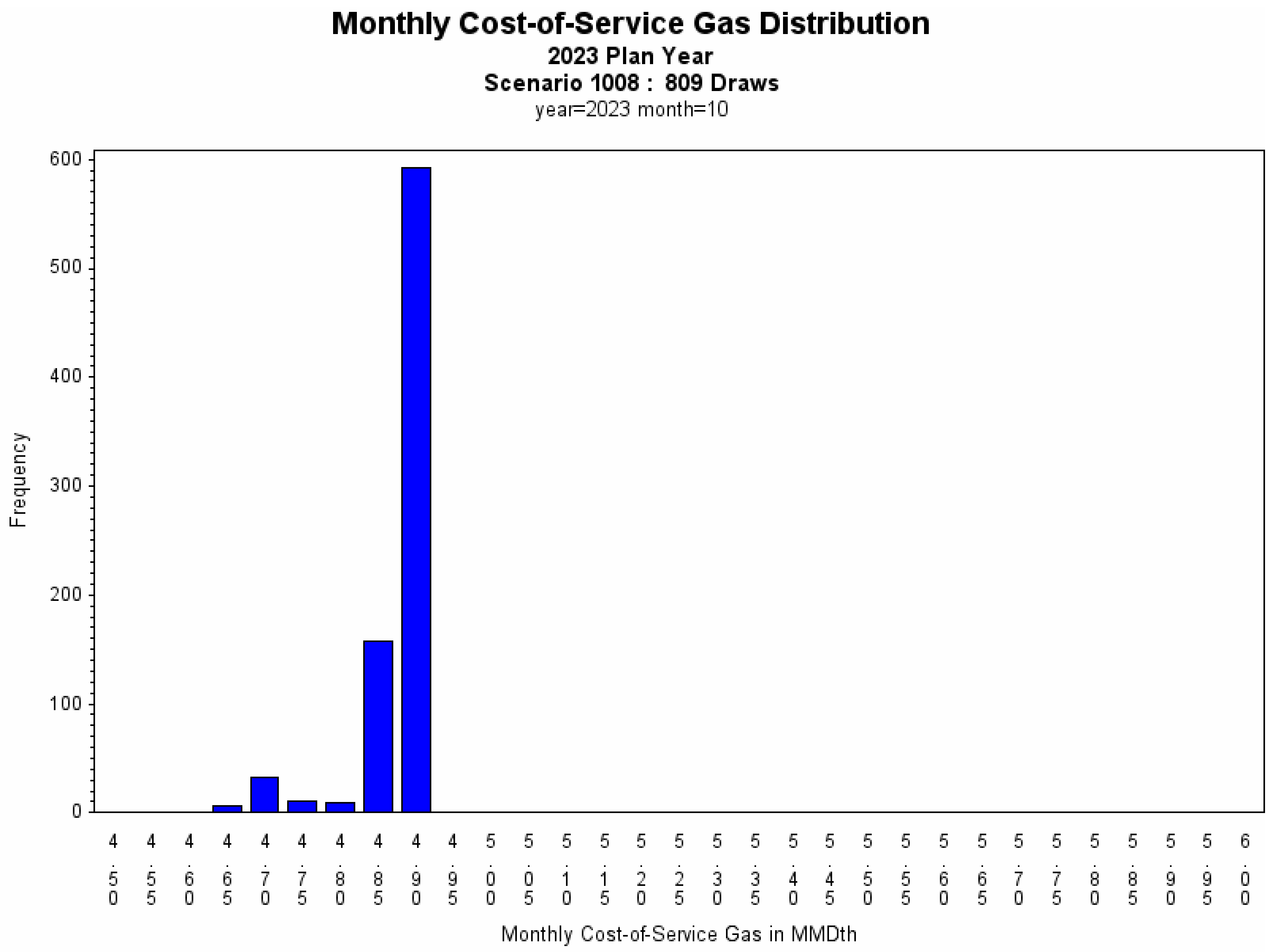

Exhibit 14.71

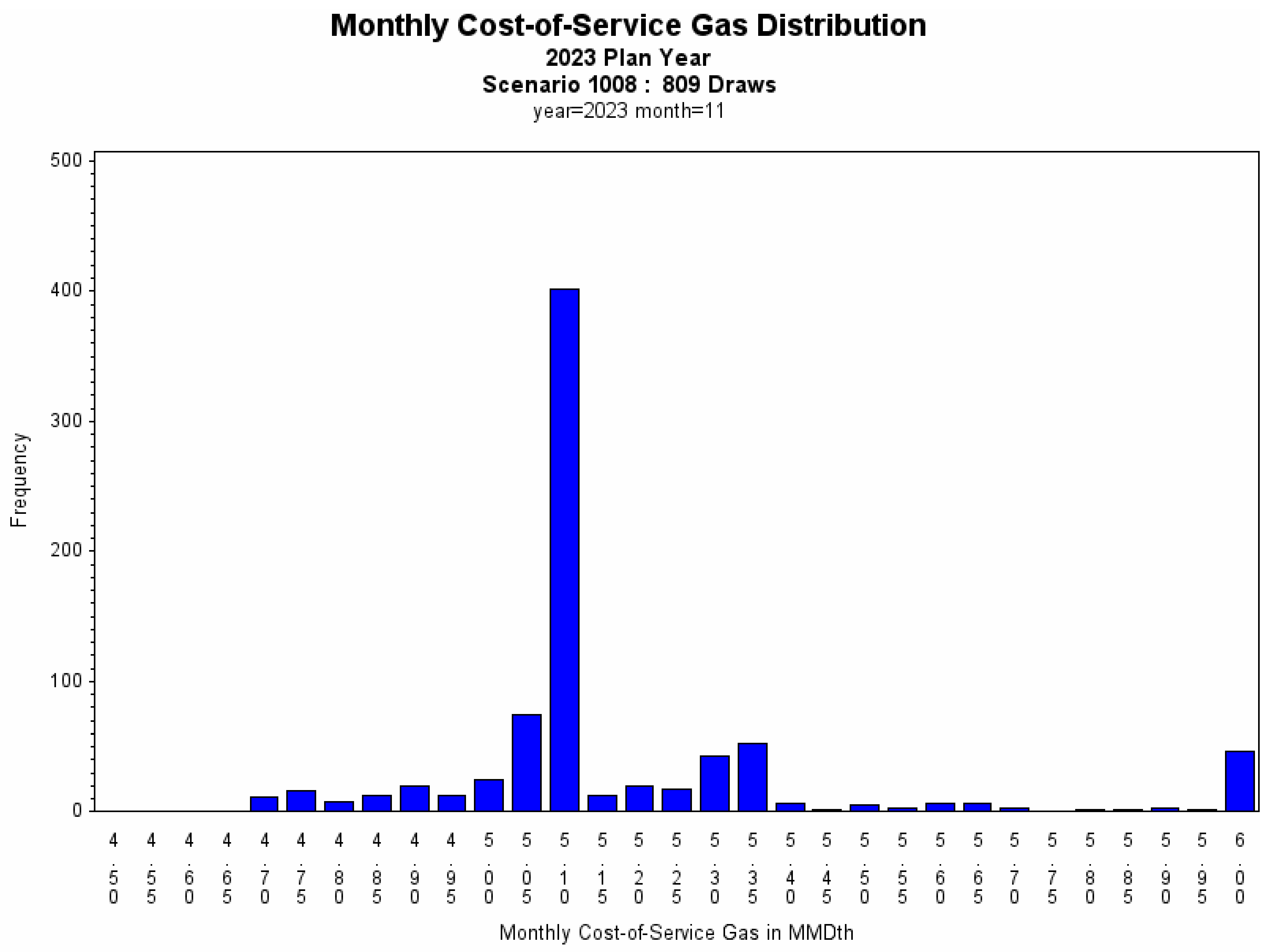

Exhibit 14.72

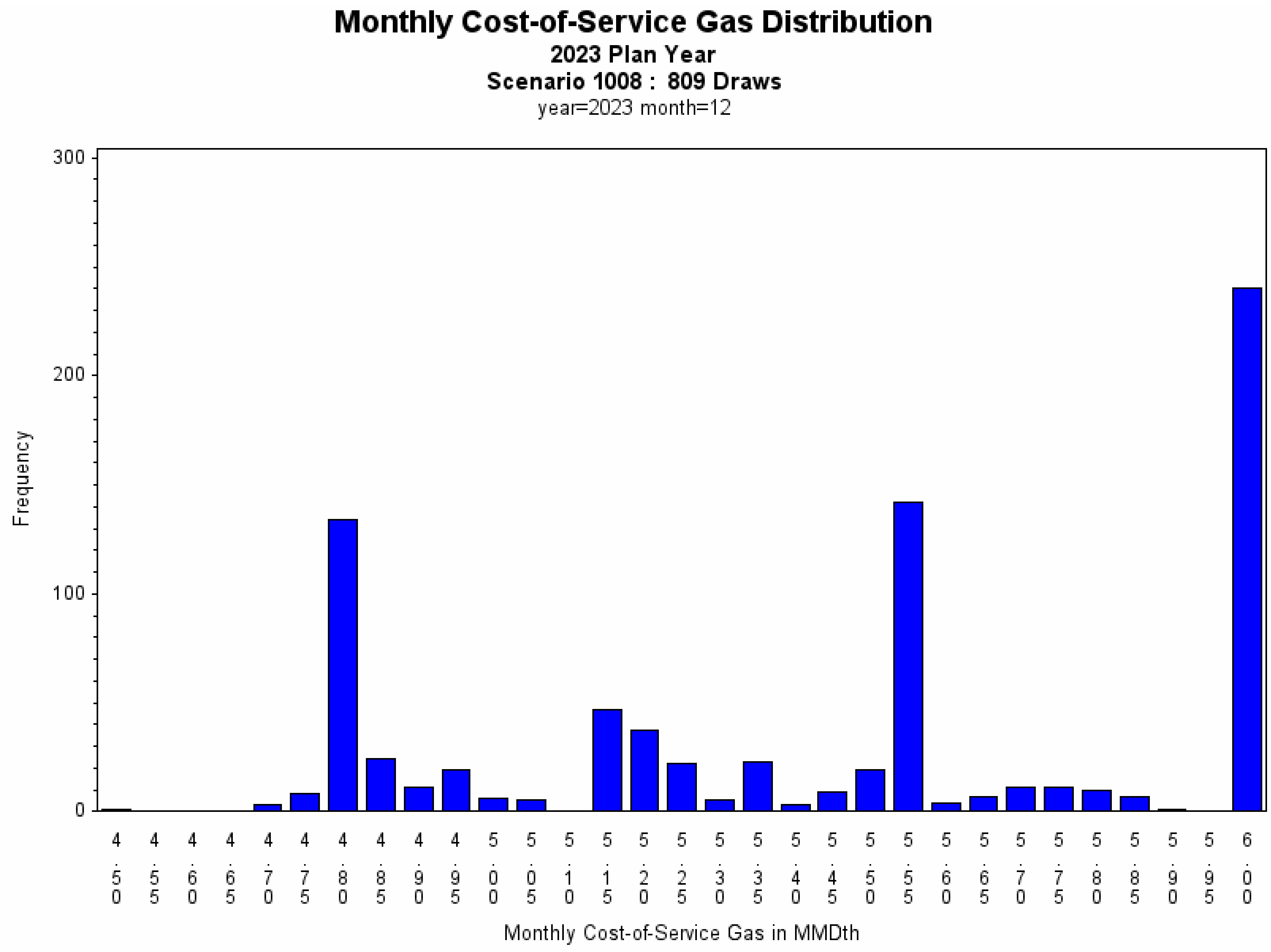

Exhibit 14.73

Monthly Cost-of-Service Gas Distribution

2023 Plan Year

Scenario 1008 : 809 Draws

year=2024 month=1

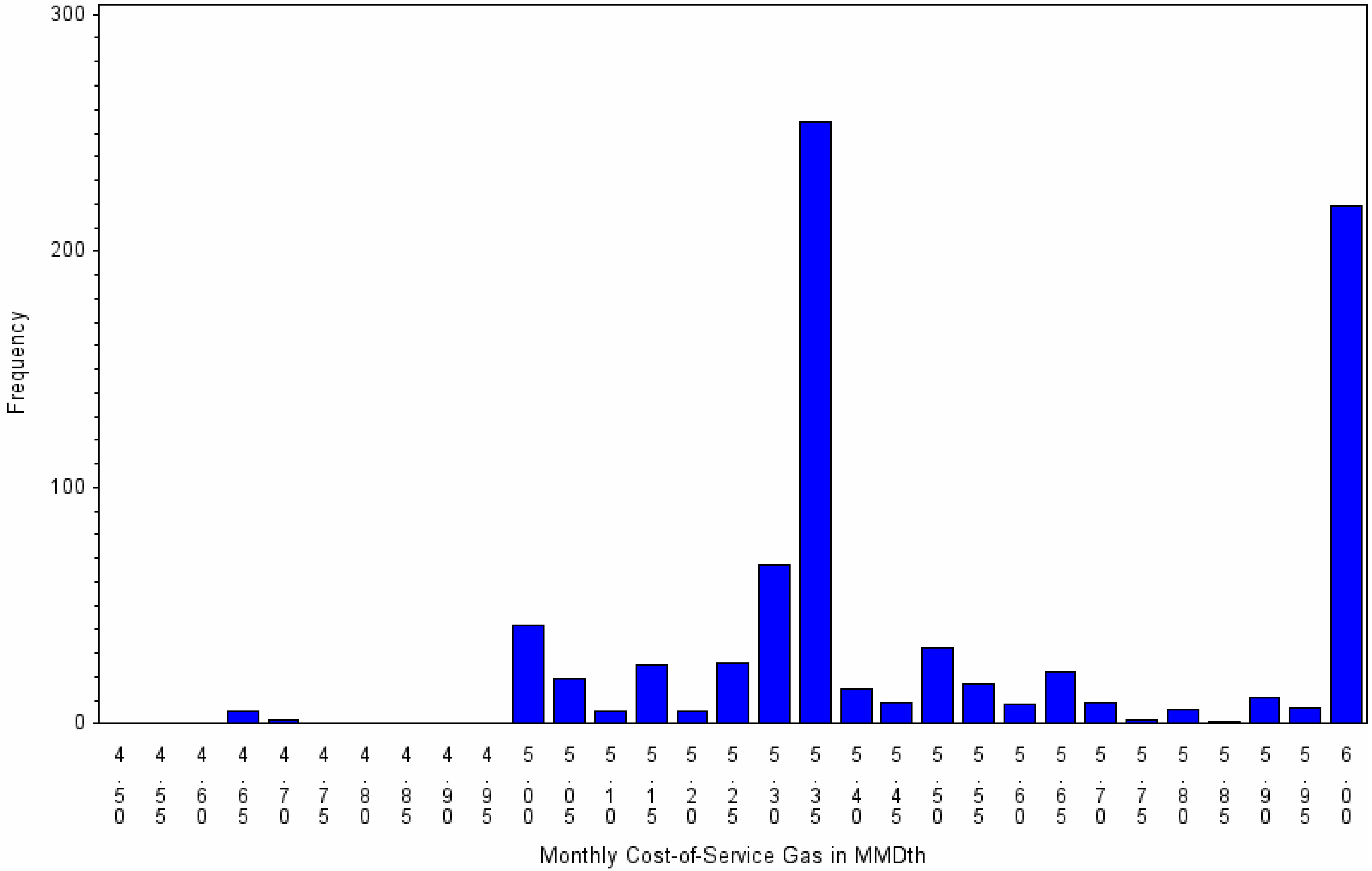

Exhibit 14.74

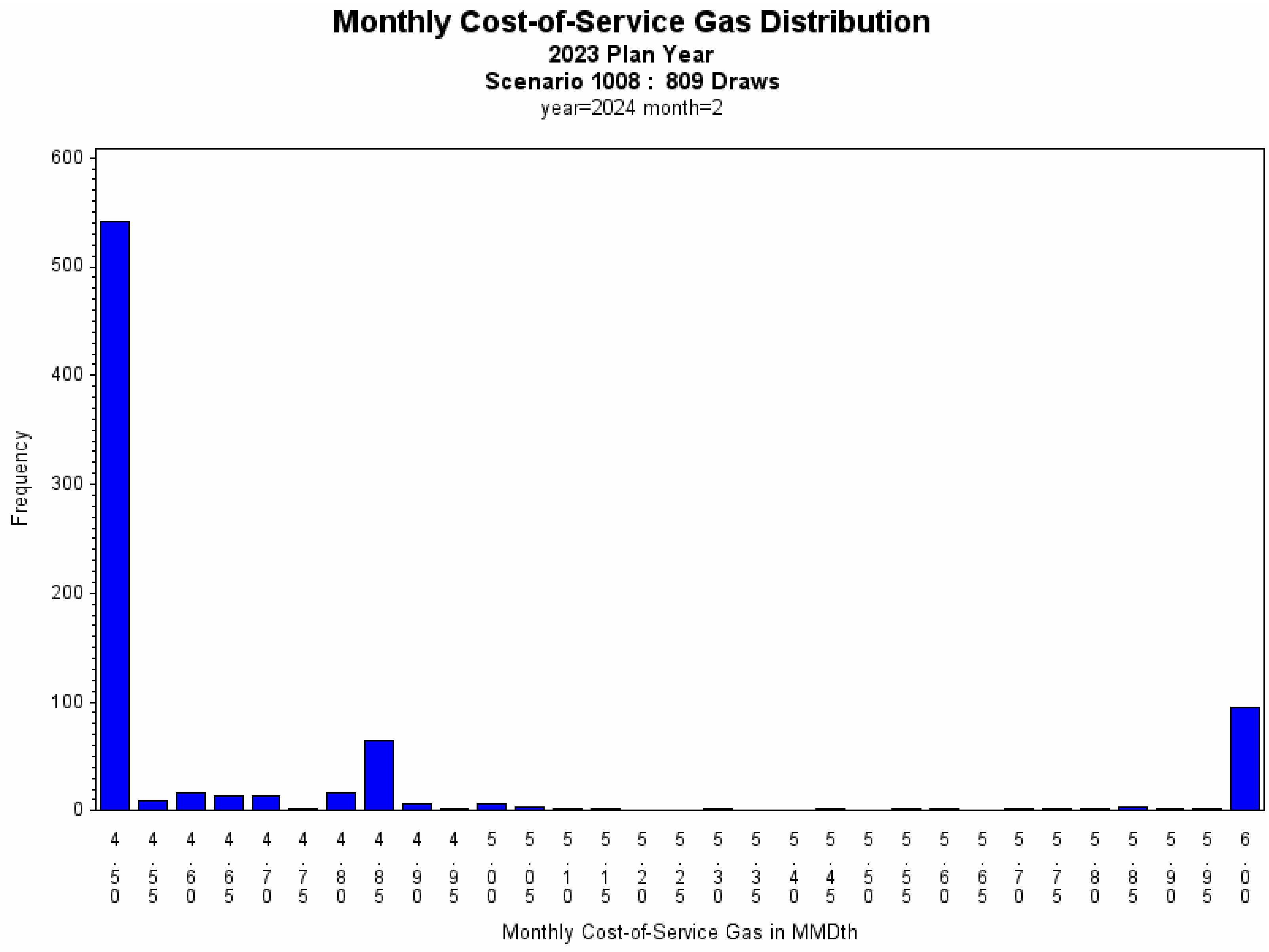

Exhibit 14.75

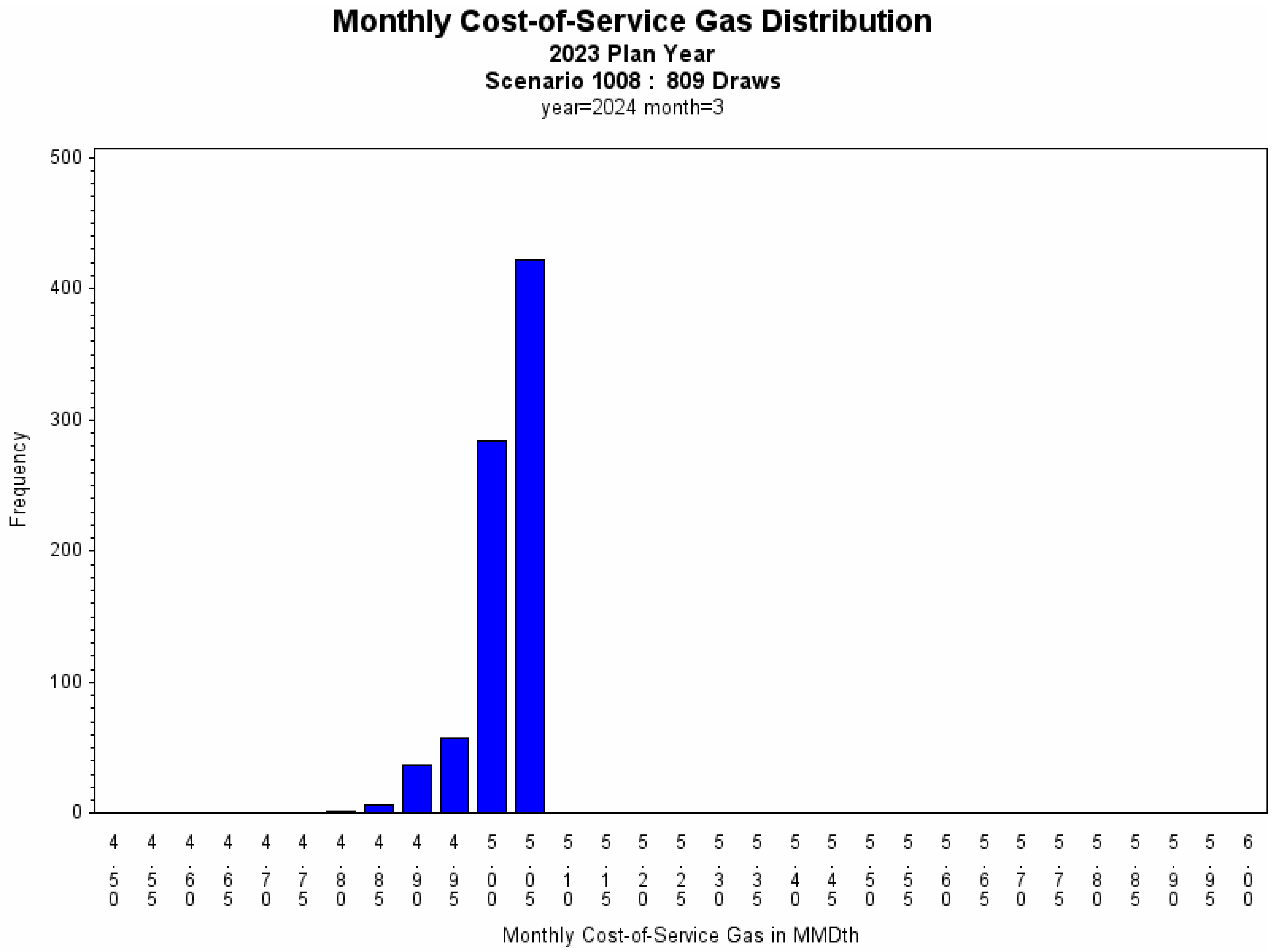

Exhibit 14.76

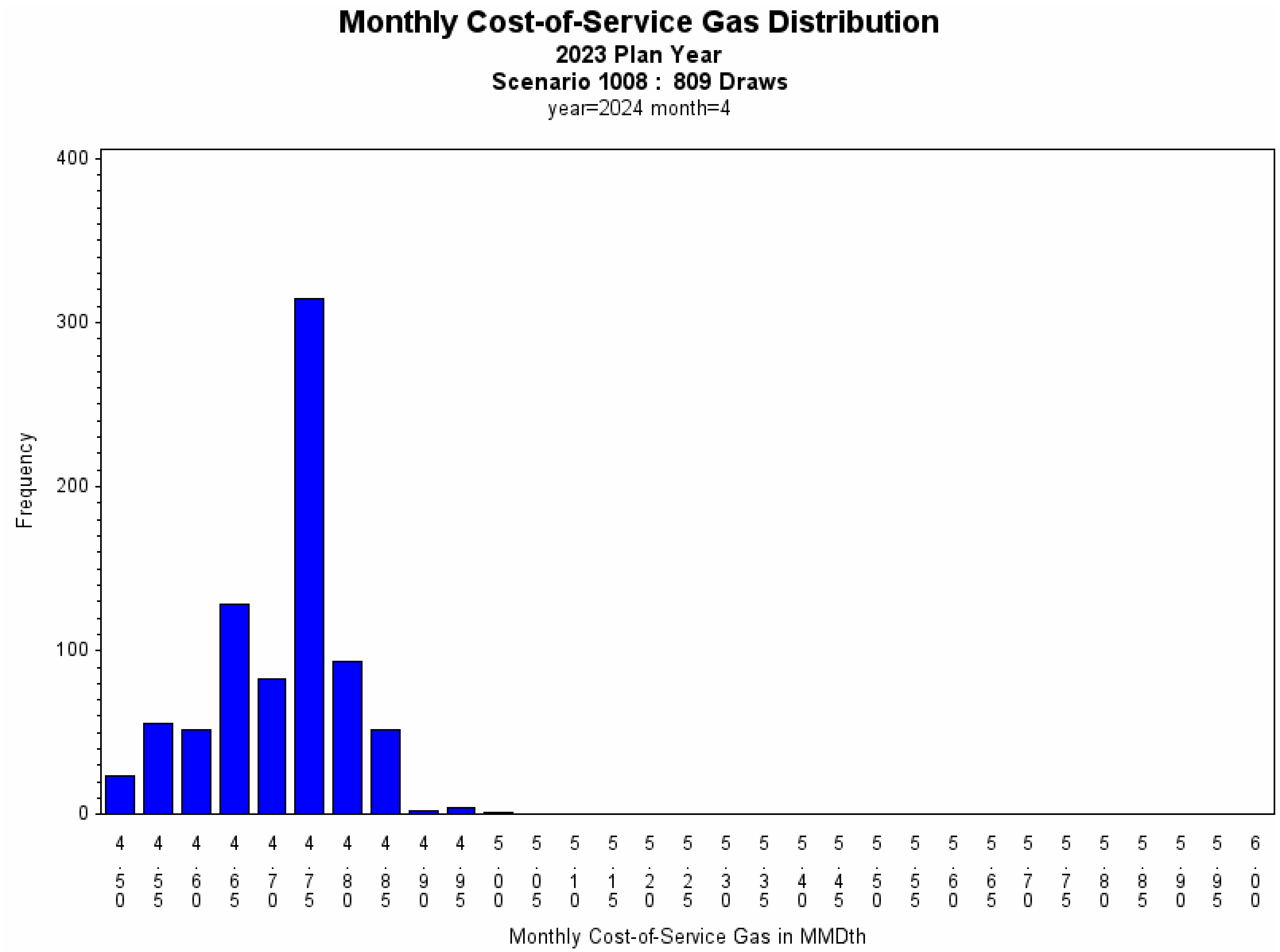

Exhibit 14.77

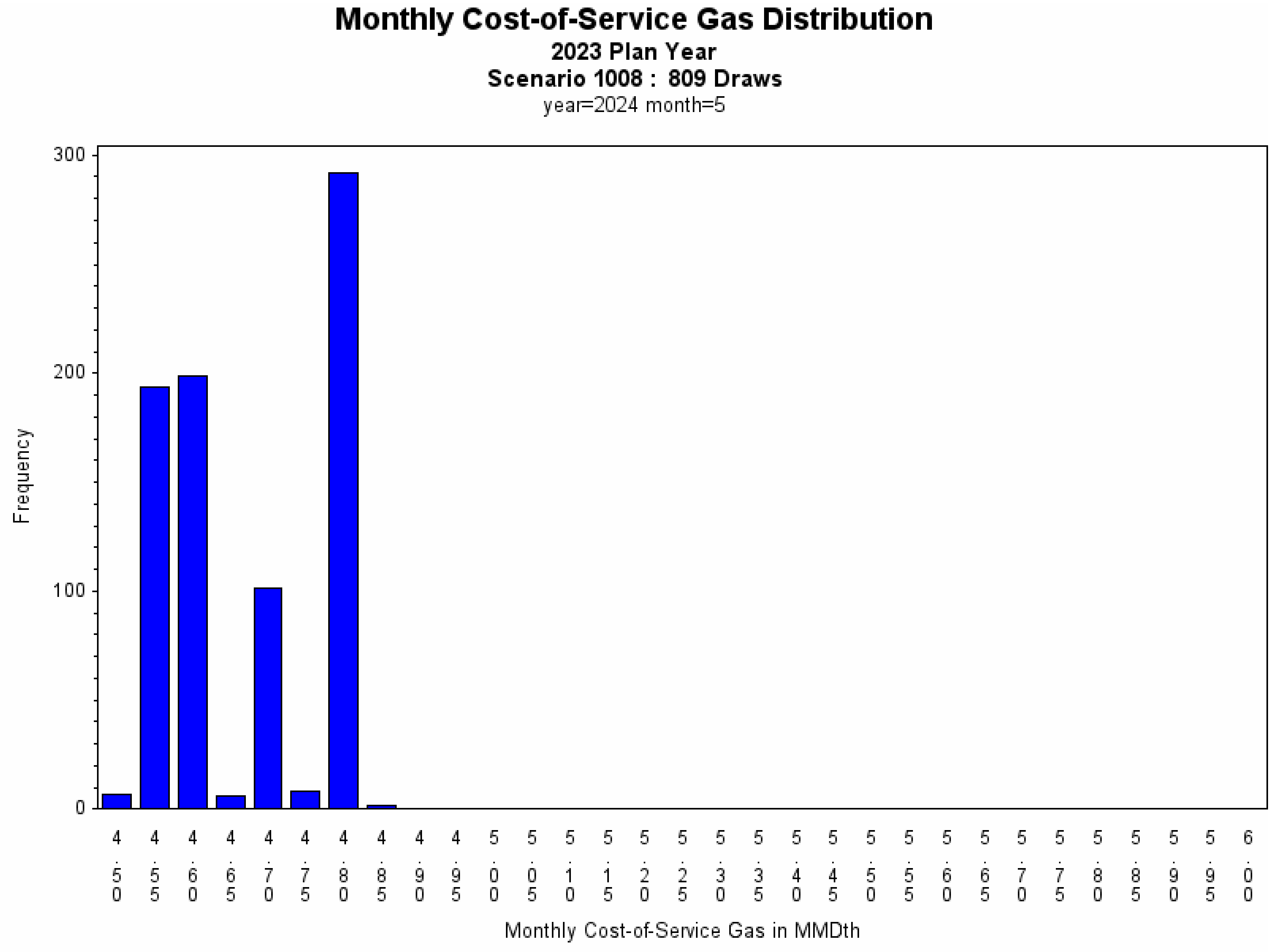

Exhibit 14.78

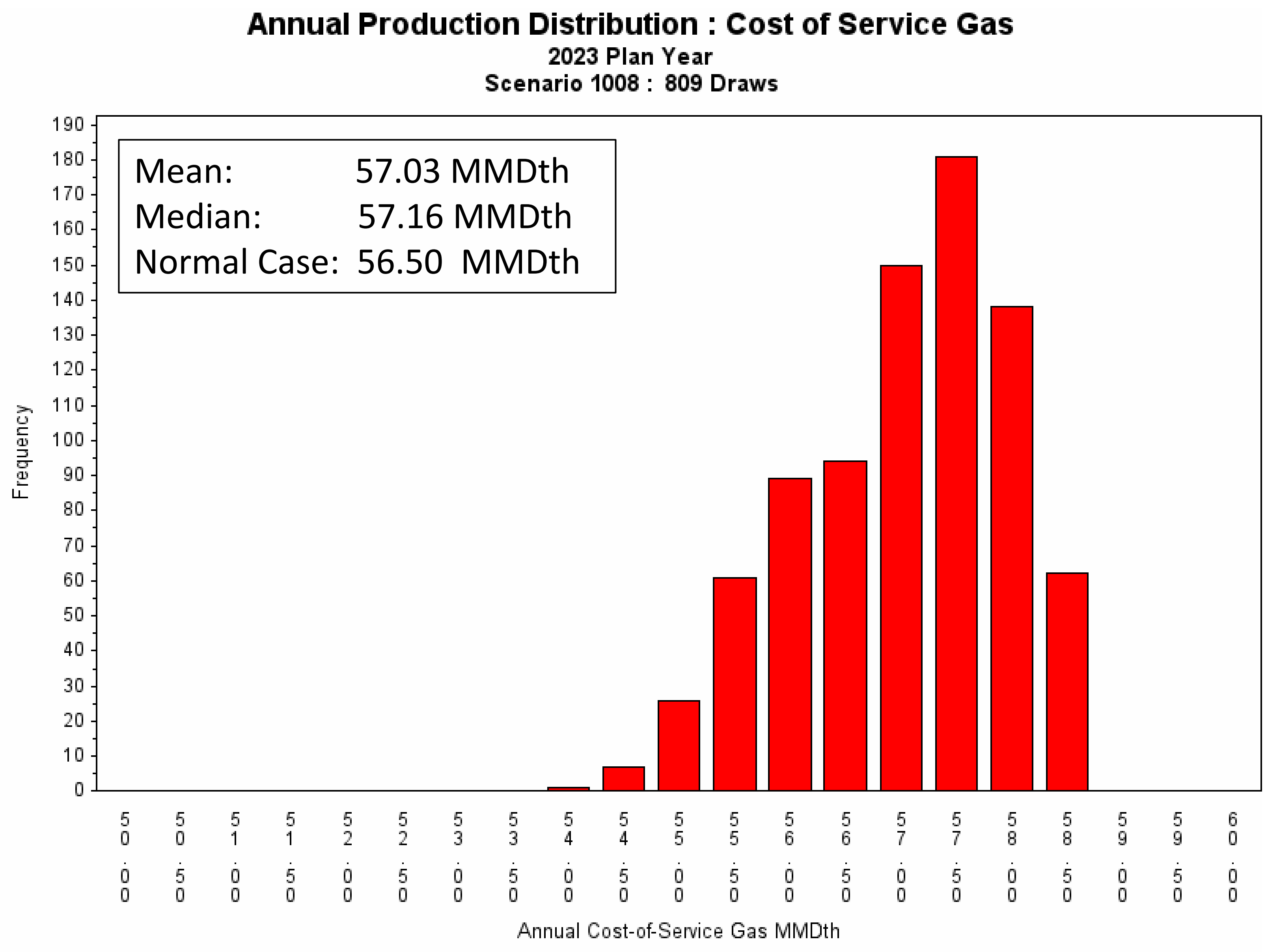

Exhibit 14.79

Monthly Cost-of-Service Gas Distribution in Mdth

2023 Plan Year

Scenario 1008 : 809 Draws

year	month	mean	max	p95	p90	med	p10	p5	min
2023	6	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24
2023	7	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
2023	8	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21
2023	9	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
2023	10	4.89	4.92	4.92	4.92	4.91	4.85	4.73	4.63
2023	11	5.18	6.3	6.09	5.39	5.08	4.98	4.87	4.69
2023	12	5.65	6.81	6.76	6.74	5.53	4.8	4.79	4.24
2024	1	5.65	6.62	6.54	5.54	5.33	5.14	5.01	4.67
2024	2	4.39	6.1	6.04	6.03	4.27	3.45	2.9	2.49
2024	3	5.01	5.03	5.03	5.03	5.03	4.94	4.92	4.78
2024	4	4.71	4.98	4.84	4.82	4.75	4.59	4.54	4.41
2024	5	4.68	4.86	4.8	4.8	4.67	4.57	4.57	4.32

Exhibit 14.80

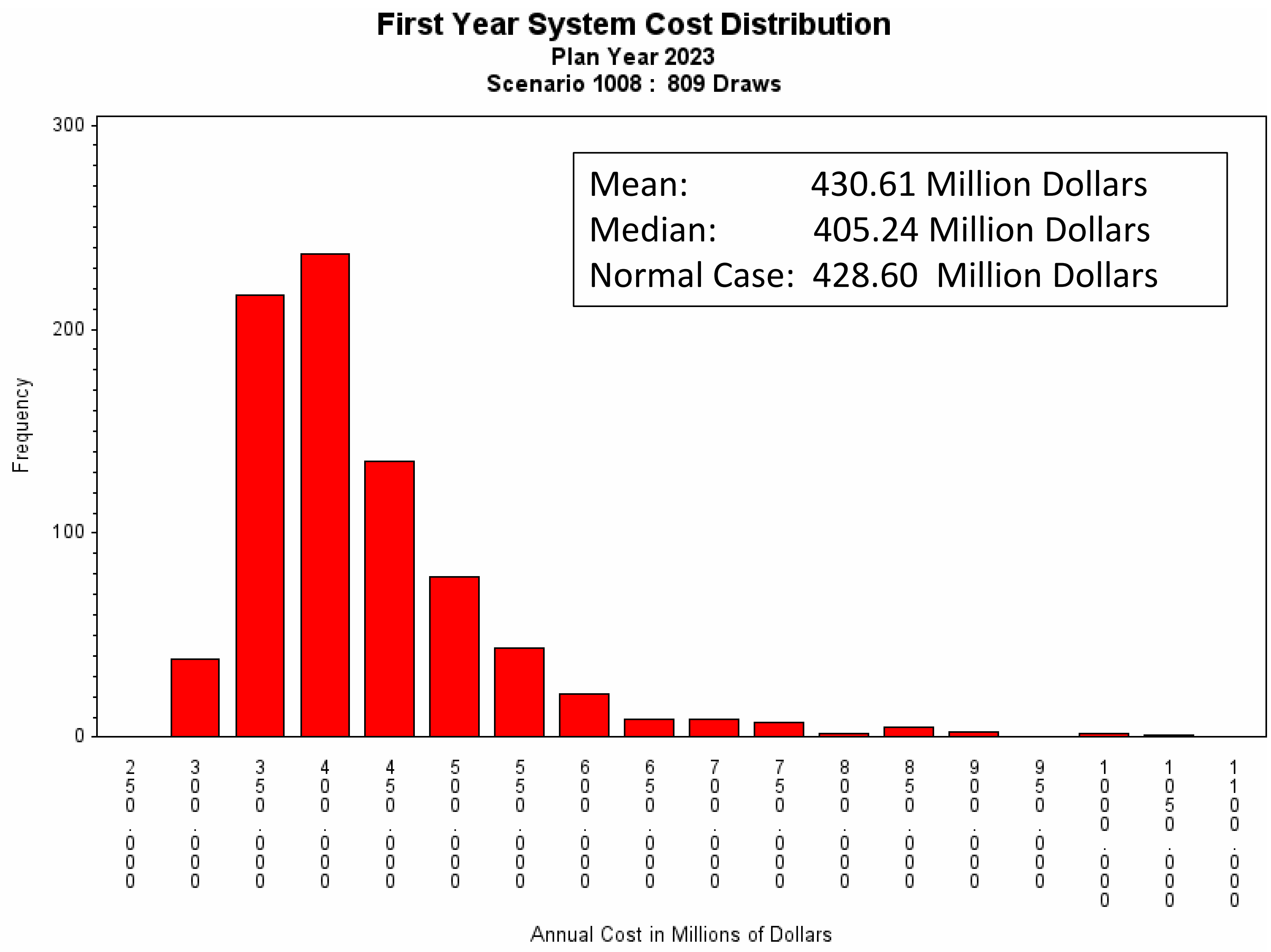

Exhibit 14.81

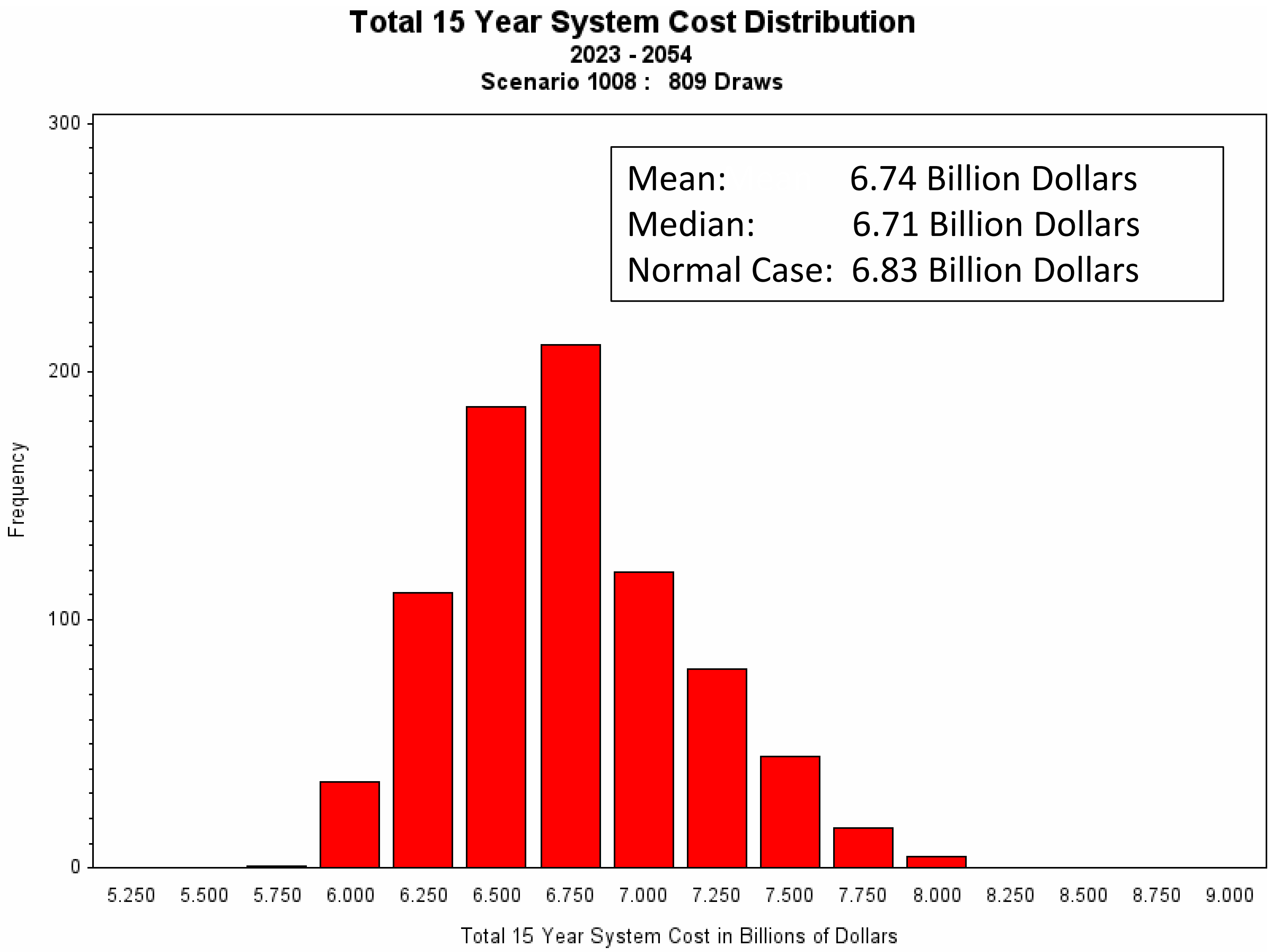

Exhibit 14.82

Exhibit 14.83

Normal Temperatue Case: Plan Year 1

MDth

	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	Total
D24													
ACEJDMT D24	9.361	9.596	9.52	9.14	9.369	8.995	9.221	9.148	8.49	9.004	8.644	8.862	109.35
BRCH CRK D24	95.527	98.13	97.553	93.852	96.412	92.756	95.288	94.621	88.002	93.524	89.983	92.444	1128.092
BRFM D24	1.829	1.879	1.868	1.797	1.845	1.775	1.823	1.812	1.685	1.791	1.722	1.769	21.595
BRFQ D24	120.813	124.026	123.219	118.469	121.62	116.926	120.034	118.543	110.172	117.004	112.494	115.49	1418.81
BRFQMT D24	2.45	2.518	2.505	2.412	2.48	2.388	2.455	2.442	2.273	2.417	2.327	2.393	29.06
BRFW D24	46.707	47.951	47.641	45.806	47.026	45.213	46.268	45.969	42.726	45.378	43.631	44.795	549.111
CBFR D24	12.493	12.804	12.7	12.19	12.493	11.991	12.29	12.19	11.31	11.992	11.51	11.797	145.76
CCRUNIT D24	300.42	283.34	264.881	257.83	292.631	302.964	310.505	307.985	285.79	303.049	290.934	298.246	3498.575
CCRUNITMTD24	29.786	30.512	29.741	28.066	29.049	28.572	29.279	29.038	26.943	28.568	27.425	28.113	345.092
CHBT MT	12.728	13.078	13.004	12.513	12.857	12.372	12.713	12.641	11.759	12.499	12.027	12.358	150.549
CHBTBUFF D24	0.623	0.64	0.636	0.612	0.629	0.606	0.623	0.619	0.576	0.612	0.589	0.606	7.371
CHBTCAT2 D24	70.976	72.823	72.309	69.483	71.293	68.507	70.293	69.8	64.839	68.825	66.139	67.866	833.153
CHBTCAT3 D24	132.768	136.305	135.422	130.205	133.674	128.525	131.951	131.098	121.847	129.409	124.426	127.744	1563.374
DRY PINY MT	4.189	4.296	4.264	4.096	4.201	4.036	4.14	4.11	3.817	4.051	3.892	3.993	49.085
DRYPINY6 D24	0.825	0.848	0.843	0.811	0.832	0.801	0.823	0.818	0.76	0.808	0.777	0.798	9.744
DRYPINYU D24	1.413	1.452	1.444	1.389	1.428	1.374	1.412	1.404	1.306	1.389	1.337	1.373	16.721
HWA DEEP D24	0.21	0.214	0.212	0.202	0.206	0.197	0.201	0.199	0.184	0.194	0.185	0.189	2.393
HWADEEPMTD24	13.265	13.649	13.591	13.096	13.475	12.985	13.36	13.303	12.392	13.19	12.71	13.078	158.094
HWPL1&3MTD24	8.096	8.317	8.268	7.954	8.17	7.86	8.074	8.026	7.464	7.932	7.63	7.838	95.629
HWPLT1&3 D24	62.89	64.437	63.894	61.311	62.821	60.282	61.767	61.247	56.813	60.221	57.788	59.213	732.684
HWPLT2 D24	4.663	4.779	4.74	4.551	4.665	4.479	4.593	4.558	4.232	4.49	4.314	4.425	54.489
HWPLT2MT D24	1.089	1.115	1.105	1.06	1.086	1.042	1.067	1.058	0.981	1.039	0.997	1.021	12.66
ISLAND D24	51.34	52.665	52.285	50.236	51.542	49.528	50.82	50.466	46.883	49.771	47.835	49.092	602.463
JNSNRDG D24	1.343	1.382	1.377	1.327	1.366	1.316	1.355	1.35	1.257	1.339	1.291	1.328	16.031
JRDG WFS D24	1.904	1.956	1.946	1.873	1.925	1.852	1.904	1.893	1.762	1.873	1.802	1.852	22.542
KNY FLD D24	7.827	8.038	7.989	7.685	7.892	7.591	7.796	7.749	7.205	7.655	7.363	7.562	92.352
MESA D24	407.468	416.701	412.399	394.977	403.934	386.874	395.652	391.577	362.544	383.56	367.371	375.715	4698.772
MOSUMT D24	0.931	0.953	0.945	0.906	0.928	0.89	0.912	0.904	0.838	0.888	0.852	0.872	10.819
PDW MT	125.19	128.602	127.845	122.994	126.346	121.551	124.864	124.13	115.439	122.675	118.02	121.237	1478.893
PDW1A1B D24	0.29	0.297	0.296	0.284	0.292	0.281	0.289	0.287	0.267	0.284	0.273	0.28	3.42
PDWCUT D24	0.803	0.826	0.823	0.793	0.816	0.787	0.81	0.807	0.752	0.8	0.771	0.794	9.582
PDWMT D24	14.871	15.271	15.176	14.595	14.988	14.414	14.802	14.71	13.675	14.527	13.971	14.152	175.152
PDWPLT2 D24	3.279	3.372	3.355	3.231	3.322	3.199	3.29	3.273	3.047	3.241	3.121	3.21	38.94
SGRLF D24	1.225	1.257	1.249	1.201	1.233	1.185	1.216	1.208	1.123	1.193	1.146	1.177	14.413
SGRLFMT D24	10.638	10.9	10.809	10.373	10.628	10.199	10.451	10.363	9.613	10.19	9.779	10.02	123.963
TRAIL D24	212.618	203.171	187.336	203.068	208.959	201.644	208.009	205.98	190.841	202.071	193.729	198.345	2415.771
TRAILMT D24	33.635	29.487	24.409	31.64	34.005	32.628	33.43	33.149	30.752	32.602	31.292	32.072	379.101
WHLA D24	22.077	22.65	22.489	21.609	22.17	21.302	21.856	21.7	20.156	21.393	20.555	21.09	259.047
WWILSON D24	0.916	0.941	0.936	0.9	0.925	0.89	0.914	0.909	0.846	0.899	0.865	0.888	10.829
Total	1829.476	1831.178	1781.024	1744.537	1819.533	1770.777	1816.55	1801.084	1671.361	1772.347	1701.517	1744.097	21283.48
D21													
BRCH CRK D21	0.485	0.495	0.489	0.467	0.477	0.456	0.466	0.46	0.426	0.45	0.43	0.44	5.541
PDW1A1B D21	0.376	0.386	0.384	0.369	0.379	0.365	0.375	0.372	0.346	0.368	0.354	0.364	4.438
Total	0.861	0.881	0.873	0.836	0.856	0.821	0.841	0.832	0.772	0.818	0.784	0.804	9.979
PW													
BRCH CRK PW	0.303	0.31	0.307	0.294	0.301	0.289	0.296	0.293	0.272	0.288	0.277	0.283	3.513
MOSU MT	0.356	0.366	0.365	0.351	0.361	0.348	0.358	0.357	0.332	0.353	0.34	0.35	4.237
Total	0.659	0.676	0.672	0.645	0.662	0.637	0.654	0.65	0.604	0.641	0.617	0.633	7.75
Off-System													
OFF SYS D24	25.24	25.946	25.811	24.849	25.544	24.591	25.279	25.149	23.404	24.889	23.962	24.633	299.297
OFF SYS PC	7.131	7.339	7.31	7.045	7.251	6.989	7.193	7.164	6.674	7.106	6.849	7.049	85.1
OFF SYS PW	0.086	0.089	0.089	0.085	0.088	0.085	0.088	0.087	0.081	0.087	0.084	0.086	1.035
Total	32.457	33.374	33.21	31.979	32.883	31.665	32.56	32.4	30.159	32.082	30.895	31.768	385.432
Q50													
BRCH CRK Q50	0.542	0.551	0.543	0.517	0.526	0.502	0.511	0.503	0.464	0.489	0.467	0.476	6.091
TRAIL Q50	1.445	1.48	0.726	0	0.09	1.457	1.493	1.48	1.373	1.456	1.398	1.433	13.831
Total	1.987	2.031	1.269	0.517	0.616	1.959	2.004	1.983	1.837	1.945	1.865	1.909	19.922

Normal Temperatue Case: Plan Year 1

MDth

Exhibit 14.84

PC

ACEJDMT PC	3.05	3.137	3.122	3.007	3.093	2.979	3.064	3.05	2.84	3.021	2.91	2.993	36.266
BRCH CRK PC	11.247	11.558	11.495	11.064	11.37	10.944	11.248	11.188	10.411	11.069	10.656	10.953	133.203
BRFM PC	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0	0.001	0	0.001	0.01
BRFQ PC	11.48	11.795	11.728	11.285	11.594	11.154	11.458	11.39	10.593	11.257	10.831	11.126	135.691
BRFQMT PC	2.507	2.573	2.555	2.456	2.52	2.422	2.485	2.468	2.293	2.434	2.339	2.4	29.452
BRFW PC	8.748	8.992	8.945	8.611	8.851	8.521	8.759	8.713	8.108	8.622	8.3	8.532	103.702
BRUFF MT PC	5.102	5.244	5.216	5.021	5.161	4.967	5.106	5.078	4.726	5.024	4.836	4.971	60.452
CBFR PC	44.446	45.594	45.263	43.485	44.608	42.856	43.964	43.645	40.533	43.014	41.325	42.393	521.126
CCRUNIT MT	30.016	30.708	27.549	23.774	25.981	28.814	29.494	29.22	27.083	28.689	27.514	28.18	337.022
CCRUNIT PC	42.641	43.713	43.369	41.642	42.697	41.003	42.047	41.728	38.743	41.106	39.485	40.501	498.675
CCRUNITMT PC	13.809	14.178	13.837	13.074	13.569	13.39	13.748	13.66	12.697	13.486	12.968	13.314	161.73
CHBTC1 MT PC	25.023	25.674	25.492	24.495	25.132	24.149	24.777	24.602	22.852	24.255	23.306	23.913	293.67
CHBTCAT1 PC	28.313	29.105	28.953	27.873	28.653	27.584	28.355	28.208	26.251	27.916	26.875	27.627	335.713
CHBTCAT2 PC	5.314	5.447	5.404	5.189	5.321	5.11	5.24	5.2	4.828	5.122	4.92	5.046	62.141
DRYPINY6 PC	0.868	0.894	0.89	0.858	0.883	0.851	0.876	0.872	0.813	0.865	0.834	0.858	10.362
DRYPINYU PC	9.762	10.033	9.979	9.605	9.872	9.502	9.766	9.714	9.038	9.61	9.25	9.507	115.638
FOGARTY PC	0.33	0.339	0.336	0.324	0.332	0.319	0.328	0.326	0.303	0.322	0.309	0.318	3.886
HWA DEEP PC	0.229	0.233	0.23	0.219	0.223	0.213	0.217	0.214	0.197	0.207	0.198	0.201	2.581
HWPL1&3MTPC	5.749	5.905	5.871	5.648	5.802	5.582	5.734	5.701	5.302	5.634	5.42	5.568	67.916
HWPLT1&3 PC	44.111	45.331	45.083	43.39	44.591	42.917	44.105	43.864	40.81	43.386	41.757	42.914	522.259
HWPLT2 PC	0.766	0.788	0.784	0.756	0.778	0.749	0.771	0.768	0.715	0.761	0.734	0.755	9.125
ISLAND PC	0.516	0.529	0.526	0.506	0.52	0.5	0.513	0.51	0.474	0.504	0.484	0.497	6.079
JNSNRDG PC	1.202	1.237	1.233	1.188	1.223	1.179	1.214	1.209	1.127	1.2	1.157	1.191	14.36
KNY FLD PC	2.548	2.624	2.614	2.521	2.596	2.503	2.578	2.568	2.394	2.55	2.459	2.532	30.487
MOSUMT PC	6.518	6.691	6.647	6.391	6.561	6.308	6.476	6.434	5.981	6.352	6.108	6.271	76.738
NBXCAMP PC	2.152	2.192	2.162	2.064	2.105	2.012	2.054	2.03	1.878	1.985	1.9	1.943	24.477
NOBXFLD PC	1.511	1.554	1.546	1.488	1.53	1.473	1.514	1.506	1.402	1.491	1.435	1.476	17.926
PDW1A1B MTPC	3.182	3.275	3.262	3.143	3.235	3.118	3.209	3.195	2.977	3.169	3.055	3.143	37.963
PDW1A1B PC	0.565	0.58	0.577	0.555	0.57	0.548	0.563	0.56	0.521	0.553	0.532	0.547	6.671
PDWCUT PC	0.531	0.547	0.545	0.526	0.542	0.523	0.539	0.537	0.501	0.533	0.515	0.53	6.369
PDWPLT2 PC	4.245	4.368	4.349	4.19	4.311	4.154	4.274	4.255	3.963	4.218	4.064	4.181	50.572
PDWPLT3 PC	3.559	3.659	3.642	3.507	3.607	3.474	3.572	3.555	3.31	3.521	3.391	3.487	42.284
SBXSWEET PC	0.111	0.114	0.114	0.109	0.112	0.108	0.111	0.111	0.103	0.11	0.106	0.108	1.317
SGRLF PC	27.131	27.872	27.711	26.661	27.39	26.353	27.074	26.918	25.036	26.608	25.601	26.302	320.657
TRAIL PC	7.195	6.175	6.286	7.167	7.394	7.028	7.137	7.018	6.458	6.795	6.474	6.59	81.717
WHLA PC	3.998	4.103	4.075	3.917	4.02	3.864	3.965	3.938	3.659	3.885	3.734	3.832	46.99
WWILSON PC	6.429	6.602	6.562	6.311	6.481	6.233	6.401	6.361	5.914	6.283	6.042	6.205	75.824
Total	364.905	373.364	367.953	352.021	363.229	353.405	362.737	360.315	334.834	355.558	341.824	350.906	4281.051

Wexpro I

CCRK D8	29.396	28.551	26.976	24.774	24.387	22.554	22.337	21.462	19.333	19.941	18.653	18.661	277.025
CCRUNIT D8	186.417	183.31	175.095	163.09	177.153	178.904	182.198	179.645	165.769	174.856	167.036	170.436	2103.909
KNY FLD D8	16.745	16.574	15.927	14.849	14.814	13.867	13.886	13.477	12.253	12.747	12.021	12.118	169.278
MESA D8	243.32	247.408	243.52	232.024	236.118	225.089	229.175	225.863	208.284	219.53	209.517	213.561	2733.409
TRAIL D8	285.279	284.77	339.919	345.583	353.036	327.786	328.107	316.145	285.522	295.37	277.198	278.277	3716.992
Total	761.157	760.613	801.437	780.32	805.508	768.2	775.703	756.592	691.161	722.444	684.425	693.053	9000.613

Wexpro I New Drill

z23 CCRK D8	0	0	0	0	0	20.048	141.081	122.523	102.021	98.758	87.657	83.9	655.988
z23 ISL D8	0	0	0	114.457	106.219	93.216	206.331	187.275	160.318	157.904	141.627	136.326	1303.673
z23 KNY D8	0	0	0	0	0	0	31.949	27.569	22.876	22.101	19.597	18.749	142.841
z23 TRL D8	0	0	0	0	0	152.213	153.739	135.991	114.746	112.204	100.396	96.726	866.015
Total	0	0	0	114.457	106.219	265.477	533.1	473.358	399.961	390.967	349.277	335.701	2968.517

Normal Temperatue Case: Plan Year 1

MDth

Exhibit 14.85

Wexpro II

ACE 2D8	1.304	1.338	1.328	1.276	1.309	1.258	1.291	1.282	1.19	1.264	1.214	1.246	15.3
ALKALI 2D8	91.674	93.975	75.173	43.096	55.346	75.123	91.32	90.628	84.145	89.279	85.763	87.975	963.497
CCOPA 2E	3.06	3.143	3.123	3.004	3.085	2.967	3.048	3.029	2.816	2.992	2.878	2.956	36.101
CCRK 2D8	6.125	5.93	5.588	5.12	5.029	4.642	4.59	4.403	3.961	4.08	3.813	3.81	57.091
CCRUNIT 2D8	63.69	61.868	60.707	58.19	61.755	62.771	64.071	63.308	58.534	61.86	59.199	60.506	736.459
CCRUNIT 2E	235.93	228.478	215.342	205.84	228.059	230.722	235.966	233.482	216.158	228.836	219.354	224.551	2702.718
CCRUNIT 2EMT	21.865	22.414	21.856	20.633	21.374	21.045	21.58	21.415	19.881	21.092	20.258	20.777	254.19
CCRUNIT 2MT	15.054	15.401	13.817	11.923	13.031	14.451	14.792	14.655	13.583	14.388	13.799	14.133	169.027
HWA DEEP 2D8	28.445	29.257	29.121	28.051	28.851	27.791	28.584	28.452	26.493	28.189	27.154	27.929	338.317
KNY FLD 2D8	9.604	9.683	9.467	8.97	9.086	8.629	8.759	8.612	7.927	8.344	7.956	8.105	105.142
TRAIL 2D8	313.531	313.204	366.899	365.662	372.862	346.779	347.476	335.267	303.166	313.96	294.921	296.313	3970.04
TRAIL 2E	250.987	241.56	225.812	246.014	253.355	243.959	251.116	248.533	230.163	243.618	233.488	238.99	2907.595
TRAIL 2E MT	30.374	26.219	21.239	28.518	30.801	29.565	30.303	30.06	27.896	29.584	28.404	29.121	342.084
WHISKEY MT	19.548	19.99	19.785	18.954	19.391	18.582	19.015	18.834	17.454	18.484	17.724	18.15	225.911
WHISKEYC 2E	133.603	133.509	129.514	104.84	116.214	113.794	117.68	115.215	105.651	110.82	105.334	106.994	1393.168
Total	1224.794	1205.969	1198.771	1150.091	1219.548	1202.078	1239.591	1217.175	1119.018	1176.79	1121.259	1141.556	14216.64

Wexpro II New Drill

z23 AKG 2D8	0	0	0	0	483.624	403.866	370.157	334.549	286.757	283.804	256.375	248.936	2668.068
z23 AKGL 2D8	0	0	0	0	69.85	58.33	53.462	48.319	41.416	40.99	37.028	35.954	385.349
z23 CCRK 2D8	0	0	0	0	0	8.337	115.211	99.742	82.91	80.182	71.134	68.07	525.586
z23 TRL 2D8	0	0	0	0	0	150.497	165.819	146.377	123.342	120.495	107.737	103.741	918.008
z23 WSKY 2D8	0	0	0	0	0	46.008	41.025	36.388	30.766	30.133	26.999	26.043	237.362
Total	0	0	0	0	553.474	667.038	745.674	665.375	565.191	555.604	499.273	482.744	4734.373

Normal Temperatue Case: Plan Year 1

MDth

Exhibit 14.86

	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	Total
Inject													
Clay Bsn 935	1039.988	1074.654	882.847	1039.988	816.3	0	0	0	0	0	0	890.936	5744.713
Clay Bsn 988	650.006	671.673	541.229	650.006	510.198	0	0	0	0	0	0	233.906	3257.018
Clay Bsn 997	650.006	671.673	541.229	650.006	510.198	0	0	0	0	0	0	233.906	3257.018
Coalville	0	0	0	42	280.8	37.386	0	0	170	348.75	0	0	878.936
Chalk Creek	0	0	0	40	123	90	0	0	44.31	0	0	0	297.31
Leroy	0	0	0	47.5	45	300	49.998	0	146.8	376.152	0	0	965.45
Spire	0	0	0	0	0	0	0	0	0	0	0	224.824	224.824
MagnaLNG	270	279	133.969	270	279	10.125	0	0	0	0	0	0	1242.094
Total	2610	2697	2099.274	2739.5	2564.496	437.511	49.998	0	361.11	724.902	0	1583.572	15867.36
Withdrawl													
Clay Bsn 935	0	0	0	0	0	1875.071	1522.688	1515.578	387.321	119.28	0	0	5419.938
Clay Bsn 988	0	0	0	0	0	1307.404	951.68	947.236	106.591	74.55	0	0	3387.461
Clay Bsn 997	0	0	0	0	0	1322.327	951.68	947.236	91.668	74.55	0	0	3387.461
Coalville	0	0	0	0	0	0	60.079	350.107	468.75	0	0	0	878.936
Chalk Creek	0	0	0	0	0	0	0.436	79.556	110.25	98.4	0	0	288.642
Leroy	0	0	0	0	0	0	78.943	391.355	496.152	0	0	0	966.45
Spire	0	0	0	0	0	0	0	0	0	0	0	0	0
MagnaLNG	20.22	20.894	20.894	20.22	20.894	20.25	20.925	20.925	19.575	20.894	20.22	20.894	246.805
Total	20.22	20.894	20.894	20.22	20.894	4525.052	3586.431	4251.993	1680.307	387.674	20.22	20.894	14575.69
Purchase Gas													
Spot	389.395	0	0	1013.245	3674.572	1656.78	3531.734	4664.895	1339.135	7360.43	1339.359	0	24969.55
Spot	1500	1290.026	705.593	1497.36	1550	1500	1550	1550	0	1550	1500	625.114	14818.09
Spot	0	0	0	0	0	0	0	0	2320	0	0	0	2320
Spot	0	0	0	0	0	0	0	0	2123.08	0	0	0	2123.08
Spot	0	0	0	0	0	0	0	0	870	0	0	0	870
Spot	0	0	0	0	0	0	0	0	0	156.522	0	0	156.522
Spot	0	0	0	0	0	0	6.211	84.069	3.284	35.338	0	0	128.902
Spot	6.564	6.935	7.087	7.004	7.388	7.294	7.685	7.832	7.464	8.125	8.003	8.414	89.795
Peak	0	0	0	0	0	750	775	775	0	0	0	0	2300
Peak	0	0	0	0	0	0	620	620	580	0	0	0	1820
Peak	0	0	0	0	0	0	0	0	271.961	0	0	0	271.961
Base	0	0	0	0	0	0	930	930	870	0	0	0	2730
Base	0	0	0	0	0	0	930	930	870	0	0	0	2730
Base	0	0	0	0	0	0	620	620	580	0	0	0	1820
Base	0	0	0	0	0	0	620	620	580	0	0	0	1820
Base	0	0	0	0	0	300	310	310	290	310	0	0	1520
Base	0	0	0	0	0	0	465	465	435	0	0	0	1365
Base	0	0	0	0	0	0	465	465	435	0	0	0	1365
Base	0	0	0	0	0	0	310	310	290	0	0	0	910
Base	0	0	0	0	0	0	310	310	290	0	0	0	910
Base	0	0	0	0	0	0	155	155	145	0	0	0	455
Total	1895.959	1296.961	712.68	2517.609	5231.96	4214.074	11605.63	12816.8	12299.92	9420.415	2847.362	633.528	65492.9

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.87

	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													
ACEJDMT D24	8.508	8.722	8.653	8.307	8.516	8.176	8.382	8.316	7.452	8.185	7.858	8.056	99.132
BRCH CRK D24	88.944	91.378	90.851	87.414	89.808	86.095	88.455	87.949	78.983	86.946	83.509	85.801	1046.134
BRFM D24	1.702	1.748	1.738	1.671	1.717	1.651	1.696	1.686	1.513	1.666	1.602	1.645	20.035
BRFQ D24	111.04	113.997	113.257	108.893	111.793	107.487	110.351	109.638	98.388	108.227	102.914	105.659	1301.643
BRFQMT D24	2.304	2.368	2.356	2.269	2.332	2.246	2.309	2.297	2.064	2.273	2.189	2.25	27.257
BRFW D24	43.071	44.221	43.937	42.247	43.375	41.707	42.82	42.546	38.183	42.003	40.388	41.468	505.968
CBFR D24	11.323	11.605	11.51	11.048	11.323	10.869	11.139	11.049	9.898	10.869	10.433	10.693	131.759
CCRUNIT D24	286.345	293.564	291.266	279.674	286.754	275.359	282.346	280.181	251.133	275.923	264.997	271.76	3339.303
CCRUNITMTD24	26.991	27.672	27.457	26.365	27.035	25.963	26.625	26.424	23.688	26.03	25.004	25.648	314.901
CHBT MT	11.892	12.215	12.138	11.672	11.985	11.525	11.834	11.759	10.554	11.612	11.166	11.465	139.817
CHBTBUFF D24	0.583	0.599	0.596	0.574	0.59	0.567	0.583	0.58	0.521	0.574	0.552	0.567	6.886
CHBTCAT2 D24	65.218	66.922	66.456	63.865	65.536	62.981	64.63	64.182	57.57	63.298	60.834	62.428	763.921
CHBTCAT3 D24	122.486	127.703	126.859	121.957	125.192	120.356	123.551	122.394	109.826	120.799	116.14	119.229	1456.493
DRY PINY MT	3.837	3.937	3.909	3.757	3.855	3.705	3.802	3.776	3.388	3.725	3.581	3.675	44.948
DRYPINY6 D24	0.768	0.789	0.784	0.754	0.775	0.745	0.765	0.761	0.683	0.752	0.723	0.743	9.04
DRYPINYU D24	1.322	1.358	1.351	1.3	1.336	1.286	1.321	1.314	1.18	1.299	1.251	1.285	15.603
HWA DEEP D24	0.181	0.184	0.182	0.174	0.177	0.17	0.173	0.171	0.152	0.167	0.159	0.162	2.052
HWADEEPMTD24	12.602	12.966	12.911	12.441	12.801	12.335	12.692	12.638	11.366	12.531	12.075	12.424	149.783
HWPL1&3MTD24	7.541	7.746	7.7	7.408	7.61	7.321	7.52	7.476	6.712	7.388	7.107	7.301	88.829
HWPLT1&3 D24	56.822	58.223	57.734	55.403	56.77	54.478	55.823	55.355	49.58	54.433	52.237	53.527	660.385
HWPLT2 D24	4.252	4.362	4.332	4.163	4.272	4.107	4.215	4.187	3.757	4.131	3.971	4.077	49.826
HWPLT2MT D24	0.98	1.004	0.995	0.954	0.978	0.938	0.96	0.952	0.852	0.936	0.897	0.919	11.365
ISLAND D24	47.185	48.427	48.1	46.235	47.456	45.618	46.551	46.241	41.489	45.631	43.867	45.031	551.831
JNSNRDG D24	1.28	1.318	1.313	1.265	1.302	1.255	1.292	1.287	1.158	1.277	1.231	1.267	15.245
JRDG WFS D24	1.783	1.832	1.822	1.754	1.802	1.735	1.783	1.773	1.593	1.754	1.688	1.735	21.054
KNY FLD D24	7.273	7.47	7.424	7.141	7.334	7.054	7.245	7.201	6.464	7.113	6.842	7.027	85.59
MESA D24	359.86	368.037	364.205	348.827	356.758	341.591	349.287	345.711	309.059	338.672	324.396	331.724	4138.127
MOSUMT D24	0.837	0.857	0.849	0.815	0.834	0.8	0.82	0.812	0.727	0.798	0.765	0.784	9.699
PDW MT	116.637	119.817	119.113	114.594	117.719	113.252	116.34	115.658	103.852	114.304	109.968	112.967	1374.221
PDW1A1B D24	0.27	0.277	0.275	0.265	0.272	0.262	0.269	0.267	0.24	0.264	0.254	0.261	3.178
PDWCUT D24	0.765	0.788	0.785	0.756	0.779	0.75	0.772	0.769	0.692	0.763	0.736	0.757	9.114
PDWMT D24	12.666	13.007	12.926	12.431	12.765	12.276	12.606	12.527	11.245	12.372	11.898	11.985	148.702
PDWPLT2 D24	3.091	3.178	3.163	3.046	3.132	3.016	3.102	3.087	2.774	3.057	2.944	3.027	36.618
SGRLF D24	1.131	1.161	1.154	1.109	1.139	1.095	1.124	1.116	1.002	1.102	1.059	1.087	13.28
SGRLFMT D24	9.615	9.853	9.77	9.375	9.607	9.219	9.446	9.367	8.39	9.211	8.839	9.057	111.748
TRAIL D24	190.204	194.783	193.06	185.199	189.719	182.03	186.509	184.951	165.671	181.92	174.625	178.997	2207.67
TRAILMT D24	30.787	31.558	31.307	30.058	30.816	29.59	30.339	30.104	26.982	29.644	28.47	29.196	358.852
WHLA D24	20.264	20.791	20.643	19.835	20.351	19.554	20.063	19.92	17.864	19.638	18.87	19.36	237.153
WWILSON D24	0.855	0.878	0.873	0.84	0.863	0.83	0.853	0.848	0.762	0.838	0.807	0.829	10.075
D21													
BRCH CRK D21	0.421	0.43	0.426	0.407	0.417	0.399	0.408	0.404	0.361	0.396	0.379	0.388	4.836
PDW1A1B D21	0.35	0.359	0.357	0.344	0.353	0.34	0.349	0.347	0.312	0.343	0.33	0.339	4.122
Total	0.771	0.789	0.783	0.751	0.77	0.739	0.757	0.751	0.673	0.739	0.709	0.727	8.959
PW													
BRCH CRK PW	0.272	0.279	0.277	0.265	0.272	0.261	0.268	0.266	0.238	0.261	0.251	0.257	3.167
MOSU MT	0.337	0.347	0.346	0.333	0.343	0.33	0.339	0.338	0.304	0.335	0.323	0.332	4.007
Total	0.609	0.626	0.623	0.598	0.615	0.591	0.607	0.604	0.542	0.596	0.574	0.589	7.174
Off System													
OFF SYS D24	23.715	24.379	24.254	23.35	24.004	23.111	23.758	23.636	21.239	23.394	22.515	23.146	280.501
OFF SYS PC	6.794	6.992	6.964	6.712	6.908	6.658	6.853	6.825	6.14	6.77	6.525	6.716	80.857
OFF SYS PW	0.083	0.086	0.086	0.083	0.085	0.082	0.085	0.084	0.076	0.084	0.081	0.084	0.999
Total	30.592	31.457	31.304	30.145	30.997	29.851	30.696	30.545	27.455	30.248	29.121	29.946	362.357
Q50													
BRCH CRK Q50	0.454	0.463	0.457	0.436	0.445	0.425	0.434	0.429	0.383	0.418	0.4	0.409	5.154
TRAIL Q50	1.375	1.41	1.399	1.344	1.379	1.324	1.358	1.349	1.209	1.33	1.278	1.311	16.068
Total	1.829	1.873	1.856	1.78	1.824	1.749	1.792	1.778	1.592	1.748	1.678	1.72	21.219

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.88

PC

ACEJDMT PC	2.883	2.965	2.951	2.843	2.924	2.816	2.897	2.883	2.592	2.856	2.751	2.83	34.192
BRCH CRK PC	10.544	10.838	10.781	10.379	10.669	10.271	10.559	10.335	9.287	10.229	9.849	10.125	123.866
BRFM PC	0	0	0	0	0	0	0	0	0	0	0	0	0.006
BRFQ PC	10.705	10.997	10.933	10.519	10.807	10.398	10.683	10.621	9.538	10.499	10.102	10.379	126.181
BRFQMT PC	2.307	2.367	2.351	2.259	2.318	2.228	2.286	2.27	2.037	2.239	2.152	2.208	27.022
BRFW PC	8.214	8.443	8.399	8.085	8.311	8.001	8.225	8.182	7.351	8.096	7.794	8.012	97.114
BRUFF MT PC	4.785	4.918	4.892	4.709	4.84	4.659	4.788	4.763	4.279	4.712	4.536	4.662	56.544
CBFR PC	40.729	41.781	41.479	39.851	40.881	39.276	40.292	40.001	35.869	39.425	37.878	38.858	476.319
CCRUNIT MT	27.032	27.691	27.455	26.344	26.994	25.906	26.55	26.334	23.593	25.912	24.877	25.504	314.192
CCRUNIT PC	38.908	39.912	39.623	38.069	39.057	37.527	38.503	38.232	34.29	37.698	36.228	37.176	455.224
CCRUNITMT PC	12.802	13.145	13.061	12.559	12.894	12.399	12.73	12.649	11.352	12.488	12.008	12.329	150.414
CHBTC1 MT PC	22.978	23.576	23.409	22.494	23.079	22.177	22.755	22.594	20.263	22.276	21.405	21.963	268.969
CHBTCAT1 PC	26.597	27.341	27.199	26.186	26.918	25.915	26.64	26.503	23.814	26.229	25.252	25.959	314.555
CHBTCAT2 PC	4.848	4.973	4.937	4.743	4.866	4.675	4.797	4.763	4.272	4.697	4.513	4.632	56.716
DRYPINY6 PC	0.827	0.851	0.848	0.817	0.841	0.811	0.834	0.831	0.747	0.824	0.794	0.817	9.843
DRYPINYU PC	9.151	9.405	9.355	9.004	9.255	8.908	9.156	9.107	8.182	9.01	8.673	8.914	108.119
FOGARTY PC	0.305	0.313	0.311	0.3	0.308	0.296	0.304	0.302	0.271	0.298	0.286	0.294	3.587
HWA DEEP PC	0.192	0.195	0.193	0.184	0.187	0.178	0.181	0.179	0.159	0.174	0.166	0.169	2.156
HWPL1&3MTPC	5.357	5.503	5.47	5.263	5.406	5.201	5.343	5.312	4.77	5.25	5.051	5.188	63.114
HWPLT1&3 PC	41.303	42.447	42.215	40.63	41.756	40.189	41.302	41.077	36.9	40.631	39.106	40.19	487.745
HWPLT2 PC	0.727	0.748	0.745	0.718	0.739	0.712	0.733	0.729	0.656	0.723	0.697	0.717	8.645
ISLAND PC	0.478	0.491	0.488	0.47	0.482	0.464	0.476	0.473	0.425	0.467	0.45	0.462	5.627
JNSNRDG PC	1.148	1.182	1.178	1.135	1.169	1.127	1.16	1.156	1.04	1.147	1.106	1.138	13.685
KNY FLD PC	2.442	2.514	2.505	2.416	2.488	2.399	2.47	2.461	2.215	2.444	2.357	2.427	29.137
MOSUMT PC	6.03	6.192	6.152	5.916	6.075	5.842	5.999	5.962	5.351	5.888	5.662	5.815	70.884
NBXCAMP PC	1.861	1.904	1.886	1.807	1.85	1.775	1.817	1.802	1.613	1.771	1.7	1.743	21.53
NOBXFLD PC	1.421	1.46	1.453	1.399	1.438	1.385	1.423	1.416	1.272	1.401	1.349	1.387	16.805
PDW1A1B MTPC	3.03	3.118	3.105	2.993	3.08	2.968	3.055	3.042	2.736	3.017	2.908	2.993	36.043
PDW1A1B PC	0.526	0.54	0.537	0.517	0.531	0.511	0.525	0.522	0.468	0.515	0.496	0.509	6.198
PDWCUT PC	0.511	0.527	0.525	0.507	0.522	0.503	0.519	0.517	0.465	0.514	0.496	0.511	6.116
PDWPLT2 PC	4.029	4.145	4.127	3.976	4.091	3.942	4.056	4.038	3.631	4.003	3.857	3.968	47.863
PDWPLT3 PC	3.358	3.454	3.437	3.31	3.404	3.279	3.372	3.356	3.016	3.324	3.201	3.292	39.803
SBXSWEET PC	0.104	0.107	0.107	0.103	0.106	0.102	0.105	0.104	0.094	0.103	0.099	0.102	1.235
SGRLF PC	25.307	25.421	25.206	24.26	24.931	23.994	24.658	24.523	22.028	24.255	23.344	23.99	291.917
TRAIL PC	6.284	6.401	6.312	6.025	6.143	5.867	5.985	5.911	5.273	5.768	5.516	5.634	71.119
WHLA PC	3.683	3.78	3.754	3.608	3.703	3.559	3.652	3.628	3.254	3.578	3.439	3.53	43.167
WWILSON PC	5.968	6.129	6.091	5.858	6.016	5.786	5.942	5.905	5.301	5.833	5.61	5.761	70.199
Total	337.374	345.774	343.47	330.256	339.079	326.046	334.772	332.483	298.404	328.294	315.708	324.188	3955.848

Wexpro I

CCRK D8	17.509	17.566	17.076	16.081	16.188	15.277	15.407	15.05	13.288	14.393	13.635	13.802	185.273
CCRUNIT D8	162.918	166.336	164.391	157.268	160.691	153.801	157.218	155.559	139.05	152.382	145.992	149.375	1864.98
KNY FLD D8	11.452	11.566	11.314	10.718	10.851	10.294	10.436	10.244	9.088	9.888	9.408	9.562	124.819
MESA D8	203.906	207.923	205.219	196.052	200.025	191.157	195.096	192.726	171.987	188.159	179.961	183.812	2316.022
TRAIL D8	262.043	263.851	257.424	243.326	245.839	232.827	235.649	230.989	204.656	222.409	211.397	214.671	2825.08
Total	657.828	667.242	655.424	623.445	633.594	603.356	613.806	604.568	538.069	587.231	560.393	571.222	7316.178

Wexpro I New Drill

z23 CCRK D8	75.796	73.583	69.496	63.803	62.785	58.052	57.48	55.217	48.018	51.288	47.97	47.986	711.47
z23 ISL D8	123.439	119.812	112.929	103.328	101.232	93.117	91.667	87.511	75.604	80.204	74.492	73.987	1137.321
z23 KNY D8	16.937	16.445	15.537	14.271	14.051	13	12.88	12.381	10.774	11.516	10.779	10.79	159.362
z23 TRL D8	87.866	85.703	81.274	74.884	73.924	68.548	68.048	65.523	57.103	61.113	57.264	57.381	838.63
z24 CCRK D8	0	0	0	0	0	283.819	254.1	225.725	184.319	186.9	167.324	161.231	1463.418
z24 CHBT D8	0	0	0	0	0	28.988	40.398	35	28.109	28.169	25	23.931	209.595
z24 ISL D8	0	59.136	189.712	189.868	202.06	200.702	212.536	217.004	199.722	224.928	221.091	231.75	2148.509
z24 PDW D8	0	0	0	0	43.544	56.855	50.928	45.298	37.044	37.62	33.73	32.548	337.565
Total	304.038	354.679	468.948	446.154	497.596	803.081	788.037	743.659	640.693	681.738	637.65	639.604	7005.877

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.89

Wexpro II

ACE 2D8	1.197	1.228	1.219	1.172	1.202	1.155	1.185	1.177	1.055	1.16	1.115	1.144	14.009
ALKALI 2D8	84.521	86.71	86.091	82.722	84.877	81.564	83.696	83.116	74.554	81.975	78.787	80.856	989.468
CCOPA 2E	2.843	2.92	2.902	2.791	2.867	2.758	2.832	2.815	2.528	2.781	2.676	2.748	33.462
CCRK 2D8	3.572	3.58	3.477	3.272	3.292	3.104	3.129	3.054	2.695	2.918	2.763	2.796	37.652
CCRUNIT 2D8	57.93	59.235	58.627	56.164	57.462	55.067	56.357	55.826	49.955	54.802	52.556	53.825	667.804
CCRUNIT 2E	215.31	220.47	218.498	209.581	214.675	205.451	209.982	208.205	186.48	204.745	196.508	201.399	2491.304
CCRUNIT 2EMT	19.958	20.471	20.321	19.522	20.026	19.24	19.738	19.596	17.574	19.318	18.563	19.047	233.373
CCRUNIT 2MT	13.558	13.888	13.769	13.213	13.539	12.993	13.316	13.207	11.833	12.996	12.477	12.791	157.58
HWA DEEP 2D8	26.904	27.672	27.545	26.534	27.292	26.29	27.042	26.917	24.201	26.671	25.692	26.427	319.186
KNY FLD 2D8	7.737	7.889	7.788	7.444	7.599	7.268	7.425	7.342	6.56	7.185	6.881	7.038	88.157
TRAIL 2D8	279.227	281.332	274.632	259.719	262.515	248.717	251.817	246.913	218.823	237.862	226.135	229.682	3017.374
TRAIL 2E	229.133	234.607	232.497	223.003	228.422	219.147	224.523	222.634	199.415	218.963	210.173	215.426	2657.942
TRAIL 2E MT	27.963	28.671	28.451	27.323	28.019	26.91	27.597	27.389	24.554	26.982	25.917	26.583	326.358
WHISKEY MT	17.408	17.83	17.675	16.958	17.375	16.674	17.087	16.947	15.184	16.676	16.011	16.416	202.239
WHISKEYC 2E	101.857	103.609	102.054	97.333	99.174	94.679	96.556	95.331	85.044	93.025	88.969	90.881	1148.511
Total	1089.118	1110.112	1095.546	1046.751	1068.336	1021.017	1042.282	1030.469	920.455	1008.059	965.223	987.059	12384.43

Wexpro II New Drill

z23 AKG 2D8	227.607	223.229	212.699	196.786	194.971	181.374	180.571	174.324	152.282	163.327	153.344	153.937	2214.451
z23 AKGL 2D8	32.873	32.241	30.72	28.422	28.16	26.196	26.08	25.178	21.994	23.589	22.147	22.233	319.833
z23 CCRK 2D8	61.493	59.703	56.397	51.789	50.976	47.148	46.698	44.874	39.036	41.709	39.024	39.05	577.897
z23 TRL 2D8	94.198	91.846	87.075	80.21	79.166	73.396	72.849	70.137	61.117	65.403	61.279	61.399	898.075
z23 WSKY 2D8	23.682	23.12	21.944	20.235	19.99	18.548	18.424	17.751	15.478	16.574	15.538	15.577	226.86
z24 AKG 2D8	0	0	0	0	0	374.418	333.862	296.125	241.739	245.227	219.719	211.937	1923.028
z24 AKGL 2D8	0	0	0	0	0	33.798	30.137	26.731	21.821	22.136	19.834	19.131	173.589
z24 CCRK 2D8	0	0	0	0	0	118.02	105.662	93.863	76.645	77.719	69.578	67.044	608.532
z24 TRL 2D8	0	0	0	0	0	173.686	155.222	137.796	112.505	114.102	102.187	98.511	894.009
Total	439.853	430.139	408.835	377.442	373.263	1046.584	969.505	886.779	742.617	769.786	702.65	688.819	7836.272

Normal Temperature Case : Plan Year 2
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
Inject													
Clay Bsn 935	1039.988	1074.654	558.071	1039.988	816.3	0	0	0	0	732.608	0.915	1074.654	6337.178
Clay Bsn 988	650.006	671.673	671.673	650.006	510.198	0	0	0	0	457.393	0	671.673	4282.622
Clay Bsn 997	650.006	671.673	671.673	650.006	510.198	0	0	0	0	551.452	0	671.673	4376.681
Coalville	0	0	0	42	280.8	37.386	0	0	170	317.5	0	0	847.686
Chalk Creek	0	0	0	40	114	90	44.9	0	44.31	0	0	0	333.21
Leroy	0	0	0	47.5	45	300	50.998	0	146.8	343.075	0	0	933.373
Spire	160.926	544.05	0	298.35	272.025	70.959	0	0	0	0	0	544.05	1890.36
MagnaLNG	0	0	0	9	227.68	10.125	0	0	0	0	0	0	246.805
Total	2500.926	2962.05	1901.417	2776.85	2776.201	508.47	95.898	0	361.11	2402.028	0.915	2962.05	19247.92
Withdrawl													
Clay Bsn 935	0	0	0	0	0	2170.74	1515.578	1515.578	575.883	0	0	0	5777.779
Clay Bsn 988	0	0	0	0	0	1351.259	947.236	947.236	365.38	0	0	0	3611.111
Clay Bsn 997	0	0	0	0	0	1276.646	951.68	947.236	352.053	0	0	0	3527.615
Coalville	0	0	0	0	0	0	60.079	350.107	437.5	0	0	0	847.686
Chalk Creek	0	0	0	0	0	0	45.004	79.556	128.625	14.7	65.325	0	333.21
Leroy	0	0	0	0	0	0	78.943	391.355	463.075	0	0	0	933.373
Spire	0	0	0	0	0	207.134	682	682	0	0	0	0	1571.134
MagnaLNG	20.22	20.894	20.894	20.22	20.894	20.25	20.925	20.925	18.9	20.894	20.22	20.894	246.13
Total	20.22	20.894	20.894	20.22	20.894	5026.029	4301.445	4933.993	2341.416	35.594	85.545	20.894	16848.04
Purchase Gas													
Spot	0	0	0	777.869	4236.155	1826.666	7698.839	7750	5574.72	7750	1201.041	348.563	37163.85
Spot	1500	1145.379	0	1496.744	1550	1500	1550	1550	0	1550	1500	1550	14892.12
Spot	0	0	0	0	0	0	1115.557	2189.995	72.175	2056.354	0	0	5434.081
Spot	0	0	0	0	0	0	0	0	2240	0	0	0	2240
Spot	0	0	0	0	0	0	0	0	2100	0	0	0	2100
Spot	0	0	0	0	0	0	9.95	32.797	840	21.709	0	0	904.456
Spot	0	0	0	0	0	0	11.598	84.891	8.664	52.686	0	0	157.839
Spot	8.281	8.7	8.842	8.693	9.123	8.964	9.402	9.54	8.74	9.814	9.636	10.092	109.827
Spot	0	0	0	0	0	0	0	0	0	17	0	0	17
Base	0	0	0	0	0	0	620	620	560	0	0	0	1800
	1508.281	1154.079	8.842	2283.306	5795.278	3335.63	11015.346	12237.22	11404.3	11457.56	2710.677	1908.655	64819.18

Required vs. Supply

Area	Class	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	Total
Off-Sys Dmd	Off_Sys	36.388	37.601	37.601	36.388	37.601	36.388	37.601	37.601	35.176	37.601	36.388	37.601	443.935
Ut/Id	L_and_U	20.413	16.265	16.232	23.071	44.72	78.903	122.603	133.068	109.655	83.195	44.642	22.3	715.067
Wy QGC	L_and_U	0.583	0.432	0.44	0.678	1.365	2.722	4.029	4.121	3.671	3.008	1.672	0.764	23.485
Ut KRGT	L_and_U	0.127	0.1	0.1	0.144	0.282	0.511	0.796	0.863	0.71	0.536	0.285	0.139	4.593
UT NPC	L_and_U	0.083	0.066	0.065	0.094	0.185	0.335	0.522	0.566	0.466	0.352	0.187	0.091	3.012
Ut/Id	FS_COM	137.74	127.229	127.754	144.471	223.262	174.62	233.527	262.875	242.479	224.809	166.903	140.184	2205.853
Ut/Id	FS_IND	31.642	29.991	30.073	32.693	54.764	41.184	58.065	65.922	60.177	54.693	39.562	32.866	531.632
Ut/Id	GS_COM	773.236	610.567	606.75	876.091	1715.089	3104.526	4848.883	5278.268	4343.79	3278.168	1736.368	844.672	28016.408
Ut/Id	GS_RES	2055.543	1619.335	1617.844	2336.587	4584.247	8290.177	12909.3	13979.08	11493.96	8682.338	4618.546	2256.622	74443.579
Ut/Id	IS_COM	5.738	5.363	5.355	5.977	10.755	16.698	24.705	27.139	21.883	19.755	13.146	7.207	163.721
Ut/Id	IS_IND	6.831	6.538	6.308	7.017	7.74	10.407	8.536	13.306	11	10.882	9.844	7.51	105.919
Wy QGC	FS_COM	10.883	10.07	10.111	11.401	14.164	23.558	26.406	23.918	25.1	23.51	14.944	10.963	205.028
Wy QGC	GS_COM	28.829	20.448	20.865	34.12	71.307	144.662	218.925	224.201	198.309	160.199	87.997	38.527	1248.389
Wy QGC	GS_RES	44.311	31.437	32.077	52.417	109.616	222.532	335.969	343.528	303.542	244.973	134.79	59.157	1914.349
Wy QGC	IS_COM	1.92	1.807	1.813	1.992	5.585	9.08	11.797	16.229	14.536	15.033	8.672	3.573	92.037
Wy QGC	IS_IND	0.038	0	0.002	0.061	0.722	1.613	1.199	0	0	0.011	0.162	0.536	4.344
Ut KRGT	GS_COM	5.105	4.039	4.014	5.794	11.335	20.518	32.066	34.905	28.733	21.663	11.482	5.59	185.244
Ut KRGT	GS_RES	13.595	10.71	10.7	15.454	30.32	54.829	85.385	92.454	76.018	57.421	30.545	14.925	492.356
UT NPC	GS_COM	3.346	2.641	2.633	3.802	7.446	13.464	21.044	22.882	18.858	14.218	7.534	3.658	121.526
UT NPC	GS_RES	8.915	7.024	7.016	10.134	19.884	35.958	55.983	60.621	49.853	37.657	20.029	9.786	322.86
Ut Geo	GS_COM	56.673	44.75	44.471	64.218	125.708	227.545	355.378	386.898	318.362	240.265	127.254	61.905	2053.427
Ut Geo	GS_RES	150.662	118.69	118.579	171.26	336.004	607.63	946.19	1024.602	842.455	636.37	338.516	165.399	5456.357
Ut Geo	L_and_U	1.406	1.108	1.105	1.597	3.13	5.662	8.825	9.57	7.87	5.944	3.158	1.541	50.916
	Total	3394.007	2706.211	2701.908	3835.461	7415.231	13123.522	20347.734	22042.617	18206.603	13852.601	7452.626	3725.516	118804.04

Fuel	Transport	105.435	98.928	98.246	112.932	151.911	214.868	287.547	305.341	193.434	221.843	146.695	109.362	2046.542
Fuel	Injection	23.036	23.804	19.347	25.338	23.745	10.427	1.52	0	6.761	15.241	0	19.141	168.36
Fuel	Withdrawal	0	0	0	0	0	14.86	14.664	30.59	27.22	2.696	0	0	90.03
	Total Fuel	128.471	122.732	117.593	138.27	175.656	240.155	303.731	335.931	227.415	239.78	146.695	128.503	2304.932

Inject	a_Clay Basin	2340	2418	1965.304	2340	1836.696	0	0	0	0	0	0	1358.748	12258.748
Inject	Aquifer	0	0	0	129.5	448.8	427.386	49.998	0	361.11	724.902	0	0	2141.696
Inject	Spire	0	0	0	0	0	0	0	0	0	0	0	224.824	224.824
Inject	LNG	270	279	133.969	270	279	10.125	0	0	0	0	0	0	1242.094
	Total Injection	2610	2697	2099.273	2739.5	2564.496	437.511	49.998	0	361.11	724.902	0	1583.572	15867.362

Total Required	6132.476	5525.944	4918.774	6713.233	10155.38	13801.49	20704.55	22378.55	18794.82	14817.28	7599.321	5509.591	137051.41

Exhibit 14.91

Required vs. Supply

Area	Class	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	Total
Supply	Spot	1895.959	1296.961	712.68	2517.61	5231.96	3164.074	5095.63	6306.796	6662.964	9110.414	2847.362	633.528	45475.938
Supply	Peak	0	0	0	0	0	750	1395	1395	851.961	0	0	0	4391.961
Supply	Base	0	0	0	0	0	300	5115	5115	4785	310	0	0	15625
	Total Take	1895.959	1296.961	712.68	2517.609	5231.96	4214.074	11605.63	12816.796	12299.924	9420.415	2847.362	633.528	65492.898
Withdrawal	Clay Basin	0	0	0	0	0	4504.802	3426.048	3410.05	585.58	268.38	0	0	12194.86
Withdrawal	Aquifer	0	0	0	0	0	0	139.458	821.018	1075.152	98.4	0	0	2134.028
Withdrawal	LNG	20.22	20.894	20.894	20.22	20.894	20.25	20.925	20.925	19.575	20.894	20.22	20.894	246.805
Production	Company	2197.887	2208.134	2151.784	2098.556	2184.9	2127.601	2182.782	2164.866	2009.406	2131.309	2046.608	2098.347	25602.18
Production	Wexpro I	761.158	760.613	801.436	894.777	911.725	1033.679	1308.802	1229.95	1091.121	1113.41	1033.702	1028.754	11969.127
Production	Wexpro II	1224.795	1205.968	1198.771	1150.09	1773.023	1869.119	1985.266	1882.551	1684.211	1732.395	1620.534	1624.3	18951.023
	Total	4204.06	4195.609	4172.885	4163.643	4890.542	9555.451	9063.281	9529.36	6465.045	5364.788	4721.064	4772.295	71098.023
Off_System	Off System	32.458	33.374	33.209	31.979	32.883	31.665	32.56	32.4	30.16	32.082	30.895	31.768	385.433
		32.458	33.374	33.209	31.979	32.883	31.665	32.56	32.4	30.16	32.082	30.895	31.768	385.432
Total Supply		6132.476	5525.944	4918.774	6713.233	10155.38	13801.49	20704.55	22378.55	18794.82	14817.28	7599.321	5509.591	137051.41

Exhibit 14.92

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 SENDOUT 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 SENDOUT model to help assess the appropriate mix of market resources. The guidelines for the 2023-2024 gas-supply year are as follows:

- Produce approximately 56.5 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 15.83 and 15.84, 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 65.6 MMDth.
- Continue to monitor and manage producer imbalances.
- Override the SENDOUT 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.
- Work to contribute to Dominion Energy's commitment to achieve Net Zero by 2050.

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 dba Dominion Energy Utah.

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.

DEU

Dominion Energy Utah, the Utah region of the Company.

DEUWI

Dominion Energy Utah, Wyoming, and Idaho, also known as the Company.

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.

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.

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 (formerly Dominion Energy Questar Pipeline), an interstate pipeline serving the DEUWI system.

MWOP

MountainWest Overthrust Pipeline (formerly Dominion Energy Overthrust Pipeline), an interstate pipeline utilized to flow gas to the DEUWI system.

N

Net Zero

Dominion Energy's commitment to net zero carbon and methane emissions across its nationwide electric generation and natural gas operations by 2050, 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 Dominion Energy consumes but does not generate. Scope 3 emissions include those from three material categories: electricity purchased to power the grid, fuel purchased for Dominion Energy's 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 Dominion Energy takes title.

non-GS

Includes all rate schedules other than GS (General Service).

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.

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 Dominion Energy Utah to 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.

Wexpro

Dominion Energy Wexpro

WFS

Williams Field Services, an interstate pipeline serving the Company's system.

X

Y

Z