DOMINION ENERGY UTAH

INTEGRATED RESOURCE PLAN

Docket No. 22-057-02

(Plan Year: June 1, 2022 to May 31, 2023)

Submitted: June 15, 2022

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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 13 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 1.25 MMDth at the city gates for the 2022-2023 heating season.

2. The Company forecasts a 2022-2023 IRP-year cost-of-service gas production level of approximately 54.35 MMDth assuming the completion of new development drilling projects (45 % of forecasted demand).

3. The Company forecasts a 2022-2023 IRP-year balanced portfolio of gas purchases of approximately 66.6 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 is reviewing 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 2022 through February 2023 to protect against extreme price increases similar to what occurred during February 2021.

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 is on schedule for the Magna LNG facility to be operational and have approximately 9-11 million gallons of LNG available for vaporization by the middle of the 2022 – 2023 heating season. In subsequent heating seasons the full 15 million gallons will be available for vaporization.

10. DEUWI is focusing on methane 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 infrastructure operations by 2050. This program includes methane emissions programs as well as evaluation of options for sustainable 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 2022-2023 heating season with adequate supplies and pressures in the system. This system capacity assessment is based on the fact that the gate stations have adequate capacity, the supply contracts are adequate, and system models show that pressures are sufficient to meet demand.

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

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

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INDUSTRY OVERVIEW

This planning document pertains to the natural gas distribution operations of 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 commission consists of Chairman Richard Glick, Commissioner James Danly, Commissioner Allison Clements, Commissioner Mark Christie, and Commissioner Willie L. Phillips.

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 is seeking comment on this interim policy.[1]

POWER GENERATION IMPACT ON NATURAL GAS

Solar generation is expected to make up the largest share of power generation capacity additions in 2022. The U.S. Energy Information Administration (EIA) expects 46.1 gigawatts (GW) of new capacity to be added in 2022. Solar is expected to account for 46% of this new generation capacity, wind is expected to account for 17%, and natural gas is expected to account for 21% or 9.6 GW.

The 9.6 GW is projected to come from 8.1 GW of combined-cycle plants and 1.4 GW of combustion-turbine plants.[2] The EIA is forecasting that the rising generation from wind and solar will reduce the generation from natural gas and coal power plants over the next two years. They project that the share of generation from natural gas will fall from 37% in 2021 to 34% by 2023.[3]

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 the April 1, 2022. In the May 2022 Short-Term Energy Outlook, the EIA explains that higher pricing is 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.

Currently, the EIA forecasts that natural gas spot prices at Henry Hub will average $8.34 per MMBtu from the second quarter of 2022 through the end of the year. However, with expectations of limited gas-to-coal switching for power generation, "this dynamic creates conditions for natural gas prices to rise significantly above forecast levels, particularly if summer temperatures are hotter than assumed in this forecast and lead to higher-than-expected levels of electricity demand". The EIA is forecasting supply production to outpace demand starting in early 2023 as production increases in response to this high-priced market. This should decrease the cost of gas going forward.[4]

PRODUCTION TRENDS

According to the EIA, U.S. dry natural gas production will reach 97.5 Bcf/d in by December 2022 which would be a new monthly record high. This production forecast is trending up to potentially exceed the previous monthly record of 97.2 Bcf/d set in November 2019. Due to

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

[2] "Solar power will account for nearly half of new U.S. electric generating capacity in 2022", *U.S. Energy Information Administration*, 10 January, 2022.

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

[4] "Short-Term Energy Outlook." *Energy Information Administration,* 10 May, 2022, https://www.eia.gov/outlooks/steo/marketreview/natgas.php

the COVID-19 pandemic production hit a recent low of 87.3 Bcf/d in May 2020, since then production has risen over the long term.[5]

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 2022, the number of gas-direct rigs was 144 compared to just 94 a year earlier.[6]

On January 13, 2022, the EIA released its annual report on natural gas proved reserves for the 2020 calendar year. The EIA reported that U.S. proved reserves of natural gas at year-end 2020 decreased to 473.3 Tcf. This level was a 4% decrease from the previous level of 495.4 Tcf set in 2019. This was the second decrease in a row.

Higher prices typically increase reserve estimates because operators consider a larger portion of the natural gas economically producible. In 2020, the annual average spot price for natural gas decreased 24% at Henry Hub. Alaska saw the largest increase in reserve volume increasing by 27 Tcf in 2020. The largest decreases in reserve volumes came from Texas and Pennsylvania with decrease of 11 Tcf and 9.6 Tcf respectively[7].

On January 27, 2021, President Biden issued an executive order that implemented a moratorium on new oil and gas leases on federal lands and waters. This is expected to have a long-term impact on production. President Biden said, “We’re going to review and reset the oil and gas leasing program”, but he also clearly stated “we’re not going to ban fracking”.[8]

The moratorium is continuing and is not expected to have a near-term impact on production because existing leases and production are not impacted and because of the existing stockpile of leases by the industry. The industry already owns “millions of acres of leases” and is “sitting on approximately 7,700 unused, approved permits to drill”, according to the Department of Interior. However, this could shift the industry away from federally controlled regions. Sixty percent of shale gas production in Utah comes from federal lands.

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

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[5] “EIA forecasts U.S. natural gas production will establish a new monthly record high in 2022.” *Energy Information Administration*, 16 December, 2021, https://www.eia.gov/todayinenergy/

[6] “North America Rig Count Current Week Data.” *Baker Hughes*, 22 April, 2022, http://rigcount.bakerhughes.com

[7] “U.S. Crude Oil and Natural Gas Proved Reserves, Year end 2020.” *Energy Information Administration*, 13 January, 2022, https://www.eia.gov/naturalgas/crudeoilreserves/index.php

[8] “Biden issues broad moratorium on oil, gas leases on federal lands, waters.” *Gas Daily, S&P Global Platts, 28 January, 2021.*

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. Unfortunately, as of June 7, 2022, the annual EIA update on design capacity and demonstrated peak capacity has not been released for 2021.

The storage metric that currently provides the most relevant information regarding storage and the impact on the industry is the current working gas in underground storage. This metric indicates that working gas in underground storage is on the low end compared to the five-year history as shown in Figure 2.1 below. Low storage inventories are the primary indicator that production is outpacing demand. Net storage withdrawals in the winter of 2021-2022 totaled 2,264 Bcf. This was the highest winter net withdrawal since the winter of 2017-2018. The large withdrawal this winter occurred due to record average U.S winter demand of 119.2 Bcf/d despite a record average supply of 104.3 Bcf/d.[9] This supply deficit is the driver for the current high price of natural gas.

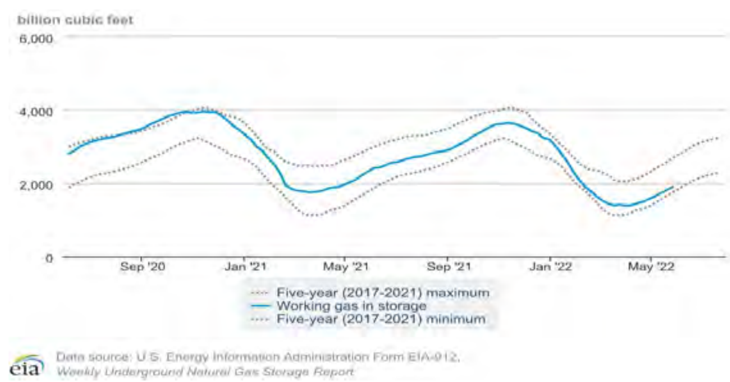

Figure 2.1: Working Natural Gas in Underground Storage as of June 1, 2022

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. The U.S. now also exports natural gas to over 30 countries as LNG. In March 2022, the EIA reports that U.S. exports of LNG set a record high in 2021, averaging 9.7 BCF/d. These increases are due to all six U.S. LNG export facilities operating near full design capacity. Higher international LNG demand in Europe and Asia have been driving these increases.[10] Geopolitical tensions in eastern Europe indicate that the demand for LNG in Europe will not diminish for some time.

The proposed Jordan Cove LNG export facility on the Oregon coast was of particular interest to the Company because the addition of this facility could impact prices in the Rockies. After years of work and the ultimate inability to gain state and federal approvals

[9] "Natural Gas Weekly Update." *Energy Information Administration, https://www.eia.gov/naturalgas/weekly/*, 1 June, 2022.

[10] "U.S. exported record amounts of liquified natural gas in 2021." Today in Energy, *Energy Information Administration*, 28 March, 2022.

Pembina Pipeline Corporation (Pembina), the developer of Jordan Cove, announced in December 2021 that they were abandoning this project.[11]

The EIA projects that increased LNG capacity in the U.S. will be driven by facilities that are currently under construction in Texas and Louisiana. These include additional trains in Texas at Golden Pass and in Louisiana at Sabine Pass and Calcasieu Pass.[12]

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, 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, DTE Energy, Duke Energy, Enbridge Inc., Encino Acquisition Partners, Enstor, Equitrans Midstream Corporation, EQT, Flywheel Energy, Hess, HRM Resources, Jonah Energy, Kinder Morgan, Kinetik, National Fuel, National Grid, New Jersey Natural Gas, Northeast Natural Energy, NW Natural, ONE Gas, Inc., ONEOK, Roanoke Gas, Sempra Energy, Sheridan, Southern Company Gas, Southern Star, Southwestern Energy, Spire, Summit Utilities, Targa, TC Energy, Terra Energy Partners, Tug Hill Operating, UGI Utilities, Inc., WTG, Western Midstream, Williams, and Xcel Energy.

The mission of One Future is to "reduce member company methane emissions 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."[13]

Based on the One Future 2021 Methane Intensity Report, the members' total 2020 methane intensity is listed at 0.424%. Methane Intensity is the amount of methane emissions divided by the total amount of methane produced or delivered. This means that "members are 99.58% efficient in delivering a molecule of gas from the rig to the burner tip." The member distribution companies reported a methane intensity of only 0.118%. This is below the stated goal of 0.225%.[14]

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.

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[11] "Pembina nixes Jordan Cove LNG plant project in Oregon." 1 December, 2021, https://www.reuters.com/markets/commodities/pembina-nixes-jordan-cove-lng-plant-project-oregon-2021-12-01/

[12] "EIA expects U.S. natural gas production to rise as demand for exports grows." *Energy Information Administration*, 9 March, 2022.

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

[14] https://onefuture.us/2021-methane-emissions-intensity-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. 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, MiQ, and Equitable Origins.

The RSG market is developing quickly, 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.

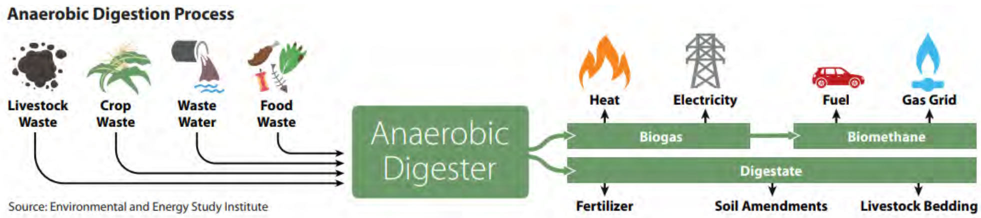

Figure 2.2: RNG

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.[15]

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

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

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.[16]

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.[17] 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.[18]

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”.[19]

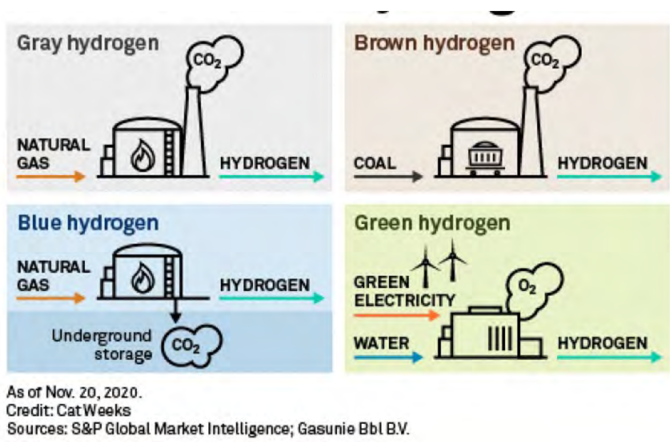

Figure 2.4: The Colors of Hydrogen

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16 “Hydrogen explained.” 20 January, 2022. https://www.eia.gov/energyexplained/hydrogen/#:~:text=However%2C%20hydrogen%20is%20useful%20as,greater%20use%20in%20the%20future.

17 “Hydrogen Basics.” May 2022. https://www.nrel.gov/research/eds-hydrogen.html

18 “Hydrogen Fuel Basics.” https://www.energy.gov/eere/fuelcells/hydrogen-fuel-basics

19 “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/

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.

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.[20] Figure 2.5 provides an overview of some of the hydrogen projects underway across the country. These projects represent different parts of the hydrogen value chain.

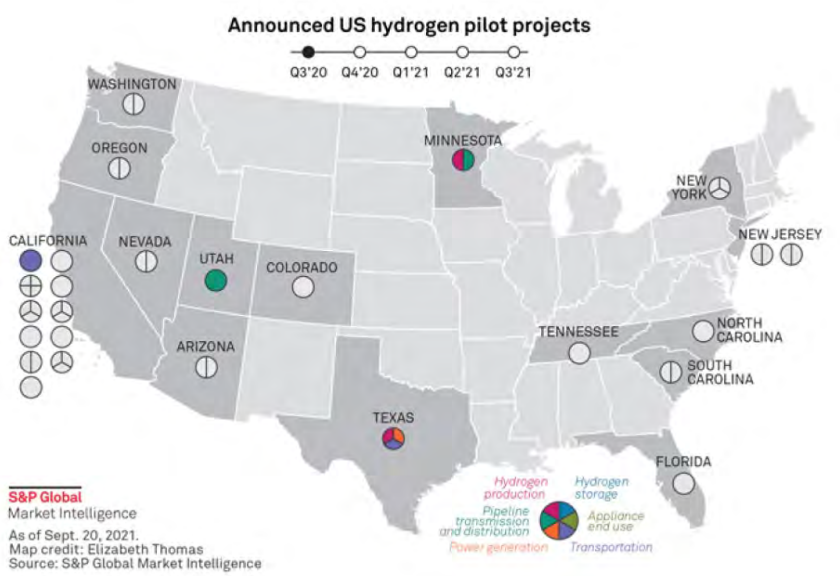

Figure 2.5: U.S. Hydrogen Projects

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.[21]

The Advanced Clean Energy Storage Project, a joint development between Magnum Development, Mitsubishi Power Americas and others is a project designed to provide a

[20] "Hydrogen explained." 20 January, 2022. https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php
[21] "Mountain West States Sign MOU to Develop Clean Hydrogen Hub." 24 February, 2022. https://energy.utah.gov/2022/02/24/hydrogen-hub-mou/

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.[22]

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.[23] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to Integrated Resource Planning. The Wyoming Commission proposed the rule to "...give the Wyoming Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[24] 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.[25]

The Company filed its 2021-2022 IRP on June 16, 2021, 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 15, 2021, and that a hearing would occur after December 15, 2021. 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

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[22] "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

[23] "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.

[24] 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).

[25] 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.

Company's 2010 IRP.[26] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[27]

On June 14, 2021, the Company filed its IRP for the plan year, June 1, 2021, to May 31, 2022 (2021-2022 IRP). A technical conference was held on June 22, 2021, to discuss the 2021-2022 IRP with regulatory agencies and interested stakeholders. On October 1, 2021, the Utah Office of Consumer Services (Office) filed its IRP comments.[28] The Utah Division of Public Utilities (Division) also submitted its report and recommendation on October 1, 2021.[29]

On January 7, 2022, the Utah Commission issued its Report and Order on the 2021-2022 IRP. The Utah Commission found that "the 2021-2022 IRP generally complies with the applicable IRP guidelines and PSC orders." The Commission adopted the Company's commitment to include additional information in the future regarding any management decision to override the SENDOUT model, the long-term planning section, information provided in technical conferences and hedging discussions.

On February 10, 2022, the Company met with Division and Office Staff to discuss IRP related issues. This meeting was attended by representatives from Dominion Energy, the Division and the Office. The general purpose of this meeting is to review the most recent Commission Order and address any remaining concerns. The participants discussed a number of topics including:

- Variances from the IRP plan outlined by the SENDOUT modeling arising in response to operational concerns. The SENDOUT model is a cost-optimization tool that can be influenced by operational requirements. Sometimes, these requirements arise after the IRP has been filed. The Company discusses these variances its quarterly Variance Reports.

- A SENDOUT model overview, including changes to the model. The Final Model Results section of this report addresses the SENDOUT model in greater detail.

- A discussion about usage of existing storage facilities. The Gathering, Transportation, and Storage section of this report includes additional detail related to the Company's use of storage facilities.

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[26] "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.

[27] "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.

[28] Memorandum titled, "In the Matter of: Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2021 to May 31, 2022," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Bela Vastag, Utility Analyst, Alex Ware, Utility Analyst, October 1, 2021.

[29] Action Request Response, To: Utah Public Service Commission, From: Division of Public Utilities; Artie Powell, Director, Doug Wheelwright, Utility Technical Consultant Supervisor, Eric Orton, Utility Technical Consultant, Russ Crazier, Utility Analyst, Tyler McIntosh, Utility Analyst, Vana Venjimuri, Utility Analyst, Subject: Action Request Docket No. 21-057-01, Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2021 to May 31, 2022 , Recommendation (Acknowledge), Date: October 1, 2021.

- A discussion about planned LNG facility usage. The Supply Reliability section of this report contains additional information about the Company's plans for utilizing its Magna LNG facility.

- A discussion about the Company's Long-term planning. The Company explained that because many of its long-term plans are conceptual and preliminary, there is generally little specific information available. The Company agreed to include a discussion on supply planning in this section as well. The System Capabilities and Constraints section of this report discusses the Company's long-term plans in greater detail.

- A discussion of the activities related to the sale of Dominion Energy Questar Pipeline. In December of 2021, Dominion Energy, Inc. sold the Dominion Energy Questar Pipeline subsidiaries to SouthWest Gas. Those assets have been rebranded as MountainWest Pipeline. The participants in this meeting discussed how the sale would impact the Company, including plans for the Joint Operating Agreement (JOA) between the Company and MountainWest Pipeline and the need to separate the gas control function for each entity, these matters are discussed in greater detail in the Gathering, Transportation, and Storage and the System Capabilities and Constraints sections of this report.

- A discussion about the Company's annual interruption analysis. The Company agreed to provide more detail about this analysis as part of the annual IRP. The System Capabilities and Constraints section of this report contains this detail.

- A discussion about Lost and Unaccounted for Gas. As a result of this discussion, the Company will include 2^{nd} party losses in the Sustainability section of this report.

- A discussion about IRP Technical Conferences. As a result of this discussion, the Company agreed to include information provided in IRP technical conferences in its IRP document.

- An update about the Company's efforts to increase hedging during 2021-2022 heating season. As a result of this discussion, the Company agreed include greater detail about its hedging activities, and hedging options in future IRPs. This detail appears in the Purchase Gas section of this report.

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

On February 17, 2022, the Utah Commission held an IRP technical conference in conjunction with the development of the 2020-2021 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission's 2021 IRP Order
- LNG Project Update (See the Distribution Action Plan and Supply Reliability sections of this report)

- Dominion Energy Questar Pipelines Sale Update and Contract Discussion – (See the Gathering, Transportation, and Storage section of this report).

The Utah Commission held another technical conference on April 19, 2022. The attendees discussed the following topics:

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

Part of the April 19, 2022, 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).
- Annual Supply Request for Proposal (RFP) (See the Purchased Gas section of this report).

The Utah Commission held another technical conference on May 17, 2022, where the following topics were discussed:

- Rural Expansion Update (See the Distribution Action Plan section of this report).
- 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).
- System Integrity (See in the Integrity Management 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 June 28, 2022, to discuss the 2022-2023 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.

2021-2022 HEATING SEASON REVIEW

The 2021-2022 heating season had three cold events that occurred in January and February. During these cold events of 2022 the Company experienced seven of the 20 highest historical total demand days on the DEUWI system. The high total system demand was driven by coincident high power generation demand. The temperatures and associated sales demand were not records for these days.

The other major development through the heating season was increased volatility in the natural gas markets. The natural gas market pricing was volatile throughout the heating season. The pricing at the Kern, Opal index reached above $7 multiple times. The Company expects this 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 usage decline among the commercial class of customers that was observed during the height of the pandemic appears to be reversing. Since March of 2021, overall demand within the class has increased by just over 6%. Commercial GS customers – the largest segment of the commercial class – averaged 416 Dth of temperature-adjusted usage through the 12-month period ending in March 2022. That is well below the 425 Dth level observed in March of 2020, but it suggests a notable recovery from the low of 403 Dth seen in March 2021.

The industrial demand has not followed the commercial path into positive territory; rather, it declined by 1% through the same 12-month period.

Residential demand did not seem to alter from its long-run path during the pandemic; it has increased by nearly 2% annually through March of 2022, driven by the considerable acceleration in growth that began in 2020 and persisted through 2021.

The Company expects commercial demand to sustain its growth as a growing population brings new commercial establishments and restrictions on commercial activity continue to ease. However, it is premature to anticipate a permanent change in the use of office space and how any such evolution might affect gas consumption in the commercial sector. If such a shift is occurring, it will become clearer as communities settle into a new normal in the coming months and years.

SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2021-2022 IRP AND ACTUAL RESULTS

On a temperature-adjusted basis, the Company's estimated natural gas sales through the IRP year ending May 2022 is 116.5 MMDth. The Company forecasted a total of 117.8MMDth for the period in last year's IRP. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2021-2022 IRP year at 220.7 MMDth. Last year's IRP projected 215.5 MMDth for the same period.

TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2022-2023 IRP YEAR

The forecasted level of sales demand for the 2022-2023 IRP year is 118.3 MMDth, an increase of about 1.6% resulting from the continuing high level of residential construction throughout the state. Though the pace of construction is expected to slow as interest rates rise, economic and demographic factors will continue to fuel growth in housing stock and commercial facilities, and sales demand will continue to rise. The Company forecasts that level to reach 132.0 MMDth in the 2031-2032 IRP year (see Exhibit 3.10).

When this forecast was completed, about 20 sales customers had notified the Company of intent to shift to transportation service in 2022.On a temperature-adjusted basis, those customers collectively burn approximately 150,000 Dth annually. This year's forecast does not assume further shifting beyond the 2022-2023 IRP year.

The 2022-2023 IRP sales forecast of 118.3 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.

This year's forecast of GS customer growth projects 1.18 million customers at the end of the 2022-2023 IRP year and 1.41 million GS customers by the end of the 2031-2032 IRP year (see Exhibit 3.1). The Company forecasts annual Utah GS usage per customer at 97.6 Dth in the 2022-2023 IRP year and 90.9 Dth by end of the 2031-2032 IRP year (see Exhibit 3.2). Annual Wyoming GS usage per customer is projected to be 120.7 Dth in the 2022-2023 IRP year and 117.5 Dth at in the 2031-2032 IRP year (see Exhibit 3.5).

The Company forecasts system total throughput in this year's forecast to increase from 219.9 MMDth during the 2022-2023 IRP year to 233.5 MMDth by end of the 2031-2032 IRP year (see Exhibit 3.10).

RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

Utah

Utah residential GS customer additions through the 12 months ending December 2021 totaled 27,064. About 40% of those additions were multi-family units. The inventory of existing homes for sale remains below average, and while interest rates are rising, that low inventory, coupled with demographic and economic factors, will continue to fuel strong demand for new housing through the 2022-2023 IRP year. Apartments and other multifamily housing options will continue to occupy a large share of new housing stock, especially along Utah's Wasatch Front, as the median price of a single-family home remains high.

The Company is forecasting about 27,000 residential additions through the 2022-2023 IRP year and just under 26,000 the following year. This high growth follows from the momentum of the current surge in demand for new housing. After that, the Company expects high growth to continue but at a decelerating pace as the economic recovery becomes firm and interest rates continue to rise in the face of elevated housing prices.

Actual temperature-adjusted residential usage per customer for the 12 months ending December 2021 was 76.9 Dth. The Company projects an average of 76.1 Dth for the 2022-2023 IRP year. The overall downward trend in average consumption is expected to continue through the 2031-2032 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 commodity price. 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 the long-term forecast development.

Wyoming

Through 2021, the Wyoming residential customer base realized a net increase of 14 service agreements. The Company projects about 65 new additions through the 2022-2023 IRP year and about 90 the following year. This relatively moderate growth is expected to continue as the five counties in the Company's Wyoming service territory grapple with the volatile natural resources sector of the State's economy.

The average annual usage per residential customer in Wyoming was 82.1 Dth in calendar year 2021. The Company forecasts an average of 82.8 Dth during the 2022-2023 IRP year which is a slight increase and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. The 2031-2032 IRP year ends at 80.1 Dth (see Exhibit 3.6).

SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

Utah

The average temperature-adjusted usage among Utah GS commercial customers ended a volatile year in 2021 at 411.2 Dth, a decline of 2.6 Dth per customer. It reached a low of 403.5 Dth in March of that year, but it has since rebounded to 415.9 Dth through the end of March 2022.

This year's forecast assumes that the rebound is long-term. It is unclear at this point if an evolution in the use of commercial office space is underway and how such an evolution might alter space heating by that sector. The Company will continue to analyze commercial usage and identify evidence of any long-term effects of the pandemic.

This year's forecast also incorporates the expectation of about 20 GS customers shifting to transportation service in July with a temperature-adjusted Dth transition of approximately 150,000 Dth annually. No further shifting beyond 2022 is assumed.

About 930 new Utah GS commercial customers were added in 2021. The Company forecasts about the same year-to-year absolute growth through the forecast period.

Wyoming

Temperature-adjusted usage among commercial GS customers in Wyoming for the 12 months ended December 2021 averaged 429.2 Dth, a decline of 3.7 Dth from 2021. With such a small base of customers and varying usage patterns, total and average usage in this sector can be volatile. However, as with the Utah service territory, the Company expects the decline in usage brought about by pandemic restrictions to be reversed in the coming IRP year, at least to some extent. Average annual usage of 436.1 Dth is forecasted for the 2022-2023 IRP year and 436.6 Dth through the following IRP year.

There was a net loss of four commercial GS service agreements through 2021. Some growth in this sector is expected, though it will likely be moderate. About five to ten new agreements per year have been forecasted for the next three IRP years with a slightly higher level per year through the remaining years of the 10-year forecast horizon.

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

The Company forecasts demand in the non-GS commercial and industrial sectors to hold at about 57.9 MMDth in the 2022-2023 IRP year and beyond. A modest degree of shifting from the GS class to transportation service is assumed through the 2022-2023 IRP year, but no further shifting is assumed beyond that point in this forecast. At this time, major additions or departures within this class are not anticipated (see Exhibit 3.8).

This year's forecast of electric generation demand holds a steady level of about 47.1 MMDth per year. 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 has been frequently supplemented with open-market procurement in recent years, making a forecast of ongoing demand levels difficult. A marked increase in baseload generation observed in 2021 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 2017-2018 through 2021-2022. Design Day conditions did not occur during those periods; however, February 23, 2022 saw the 2nd highest total sendout on record.

The firm sales Design Day gas supply projection for the 2022-2023 heating season is 1.25 MMDth and grows to 1.39 MMDth in the winter of 2031-2032. 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 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.

Full Fuel-Cycle Efficiency

Natural gas remains the most efficient and least expensive form of energy for use in space heating, water heating, cooking, and clothes drying applications. This is particularly evident when compared to electricity through a full fuel-cycle analysis. Full fuel-cycle analysis looks at the journey of different forms of energy, and their associated losses, from the point of production to the point at which the customer receives and uses the energy. Figure 3.1 shows that for each 100 MMBtu of natural gas extracted, 91 MMBtu are delivered to the customer for direct use. Conversely, for each 100 MMBtu of other energy sources extracted for conversion to electricity, 36 MMBtu are ultimately delivered to the customer for direct use. In other words, converting any fossil fuel source into electricity to power comparable electric end-use products only maintains 36% of usable energy.

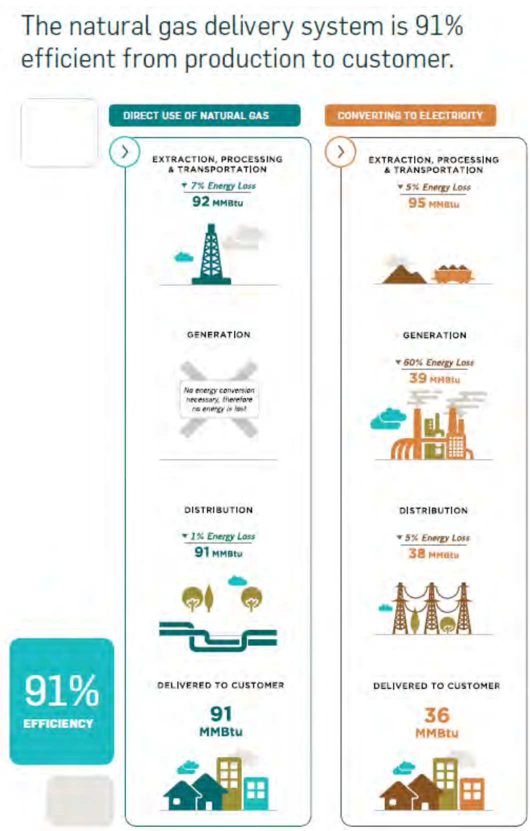


Figure 3.1: Full Fuel-Cycle Analysis
(Source American Gas Association 2022 Playbook)

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 will 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 $\geq$ 95% annual fuel utilization efficiency (AFUE). The Company designed this rebate measure with the heat pump performing heating operations at or above 40°F outside air temperature and the high efficiency furnace providing heat when outside air temperatures drop below that set point.

The Company believes that a dual-fuel system is the best option for 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 80 dekatherms annually for space and water heat) who installs a dual-fuel system would reduce annual natural gas usage by 29 dekatherms or 36%. The Company rebated over 1,200 dual-fuel heating systems in 2021 and expects to rebate over 2,000 in 2022. The Company expects participation to continue growing in future years as the heating, ventilation, and cooling trades become more familiar with these technologies.

GAS LOST AND UNACCOUNTED FOR

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

It is important to understand that a LAUF percentage is not simply an estimate of gas quantity that has escaped the system. It is the calculation of a difference between gas volume received into the system and gas volume accounted for. In addition to gas physically lost from the system through leaks, theft, or damage, variance also arises from other sources. These additional sources are not unique to DEUWI but are common to most 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 about 0.4% to 0.5%. 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 measurement and gas 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 year to year 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[30].

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

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 0.559% 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
2018-2019	115,015,137	99,051,746	214,066,883	213,164,268	169,345	31,627	701,643	214,066,883
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
Total	**341,107,884**	**294,393,088**	**635,500,972**	**631,951,638**	**316,961**	**105,098**	**3,127,275**	**635,500,972**
	Lost-&-Unaccounted-For-Gas %		0.492%		Company Use and Lost-&-Unaccounted-For-Gas %		0.559%	

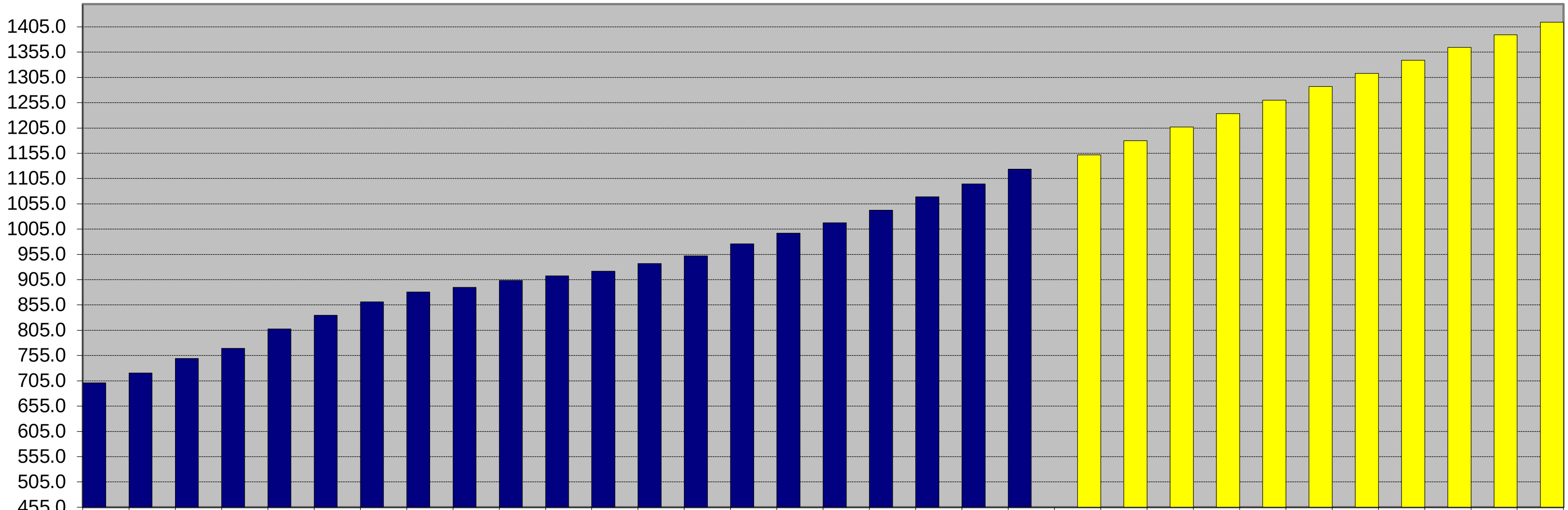
FORECAST EXHIBITS

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).

Exhibit 3.1

SYSTEM GS CUSTOMERS

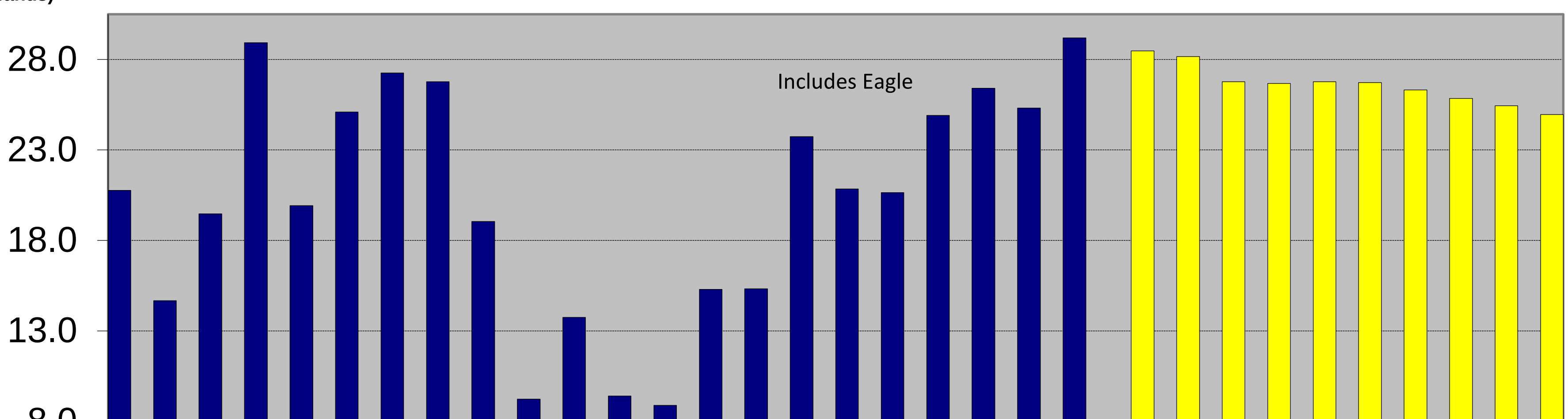
Customers (Thousands)



	00/01	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	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
ACTUAL	701.0	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	1042.5	1068.9	1094.2	1123.4											
FORECAST																						1151.9	1180.0	1206.8	1233.5	1260.2	1287.0	1313.3	1339.1	1364.6	1389.5	1414.1

SYSTEM GS ADDITIONS

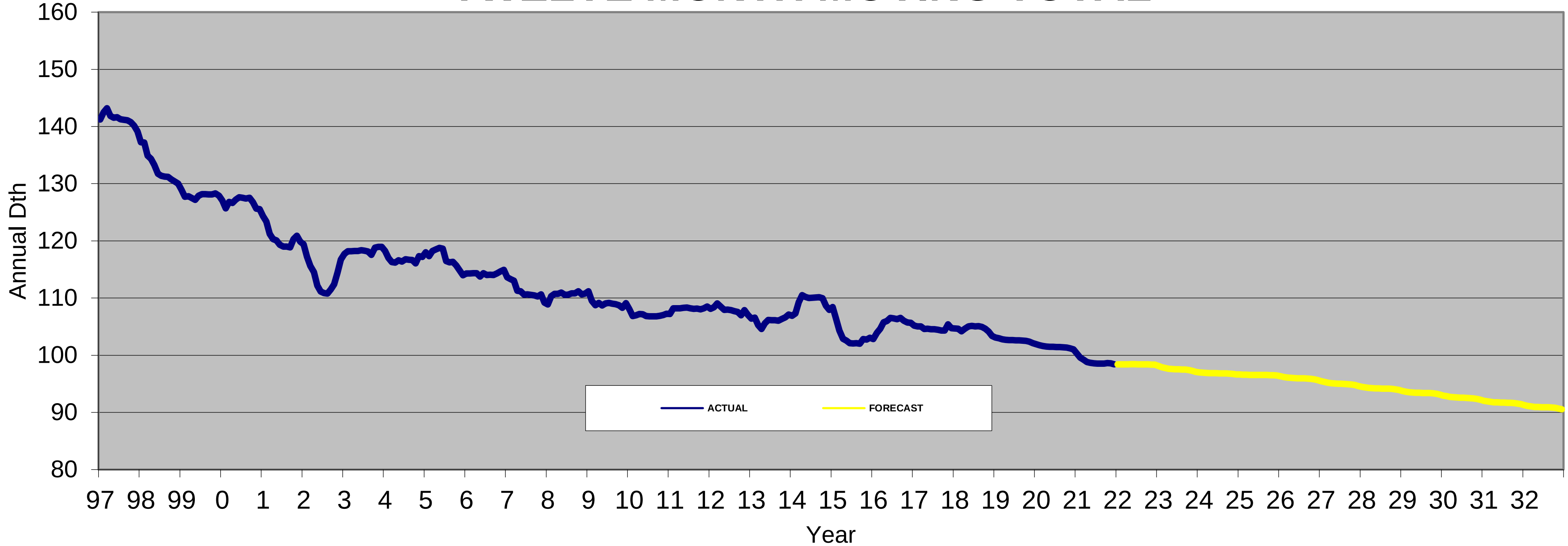
Customers (Thousands)

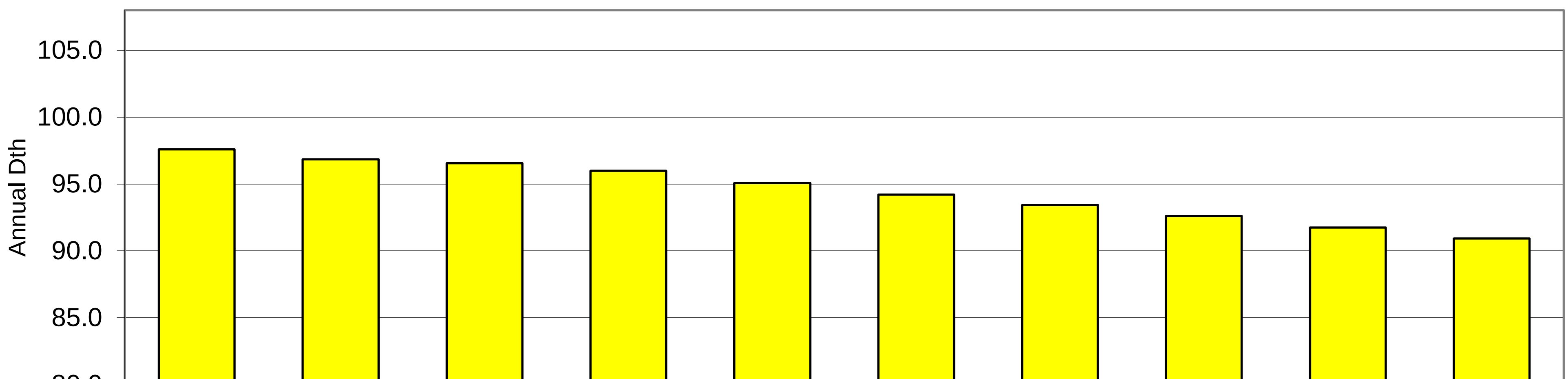


	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
ACTUAL	20.8	14.7	19.5	28.9	19.9	25.1	27.3	26.8	19.0	9.2	13.7	9.4	8.9	15.3	15.3	23.7	20.8	20.6	24.9	26.4	25.3	29.2										
FORECAST																							28.5	28.2	26.8	26.7	26.8	26.7	26.3	25.8	25.4	25.0

UTAH GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





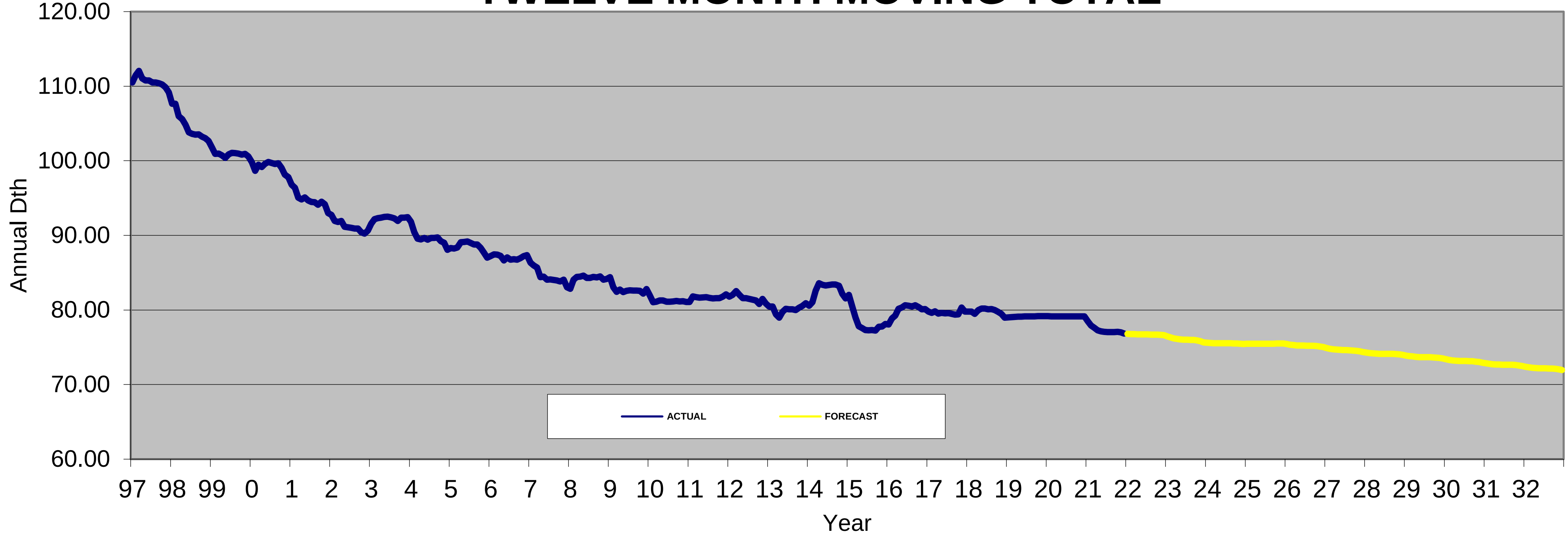
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
FORECAST	97.6	96.8	96.6	96.0	95.1	94.2	93.4	92.6	91.7	90.9

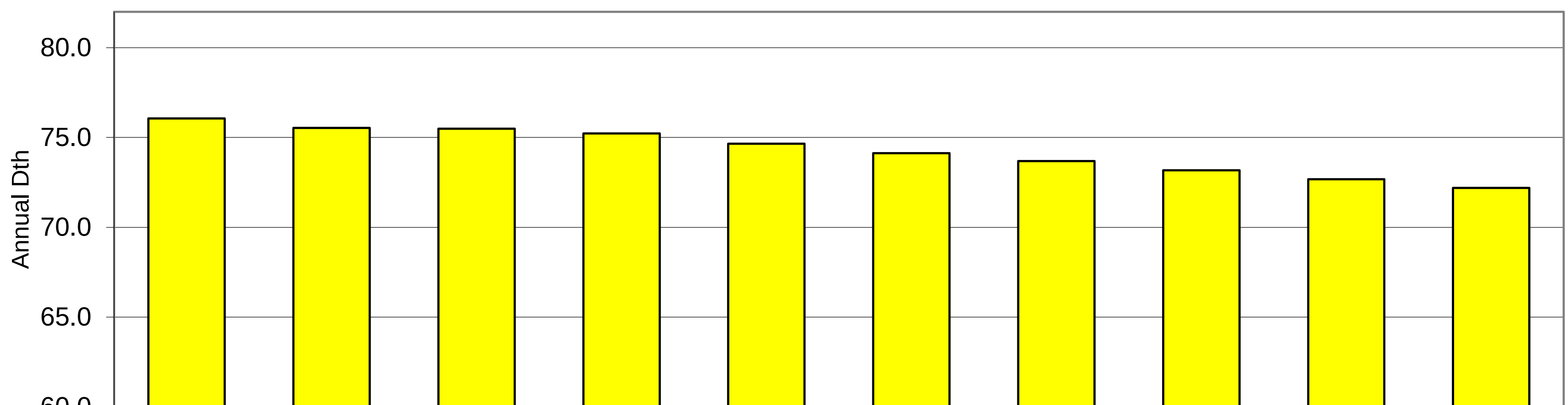
IRP Year

Exhibit 3.2

UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



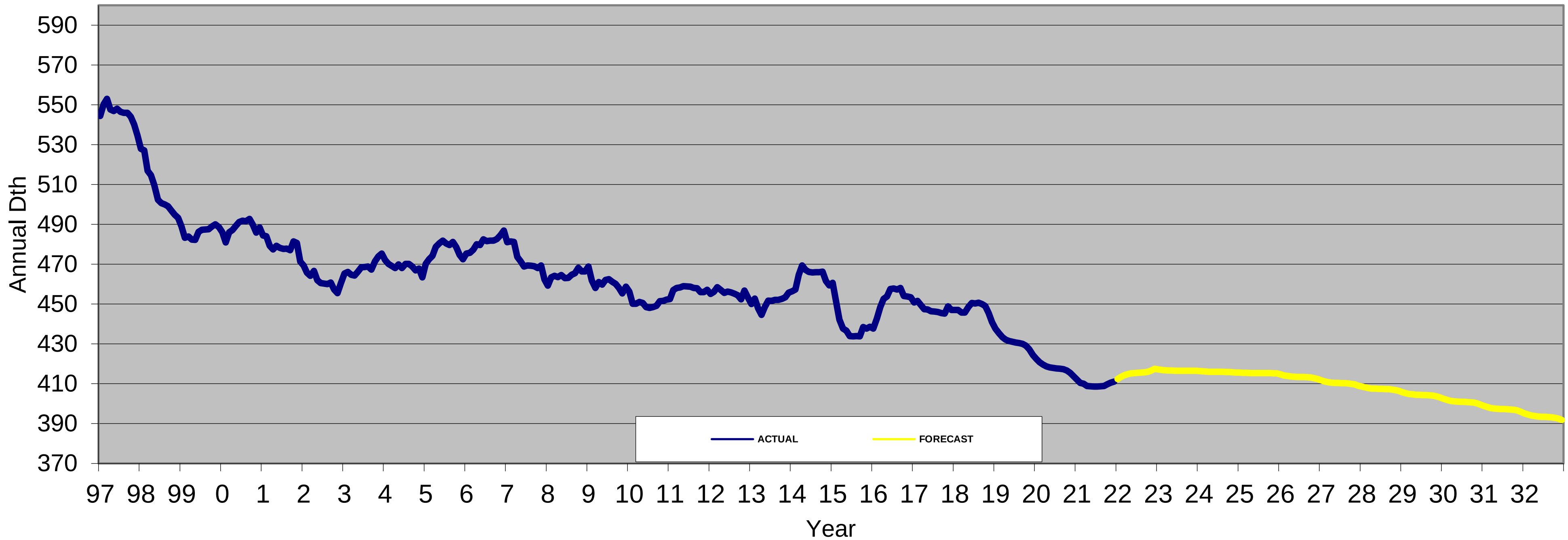


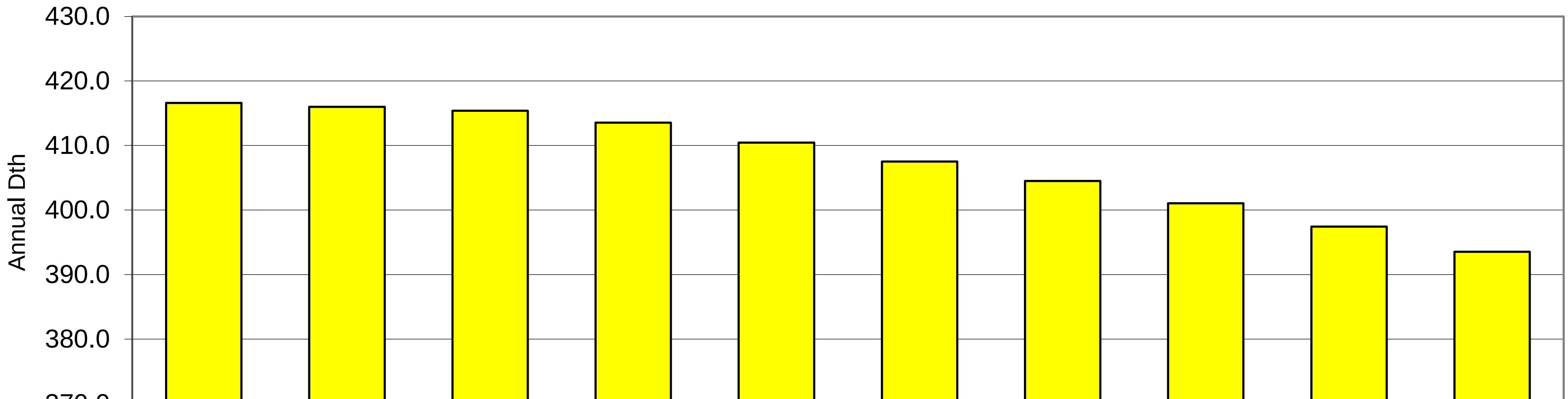
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
FORECAST	76.1	75.5	75.5	75.2	74.7	74.1	73.7	73.2	72.7	72.2

Exhibit 3.3

UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





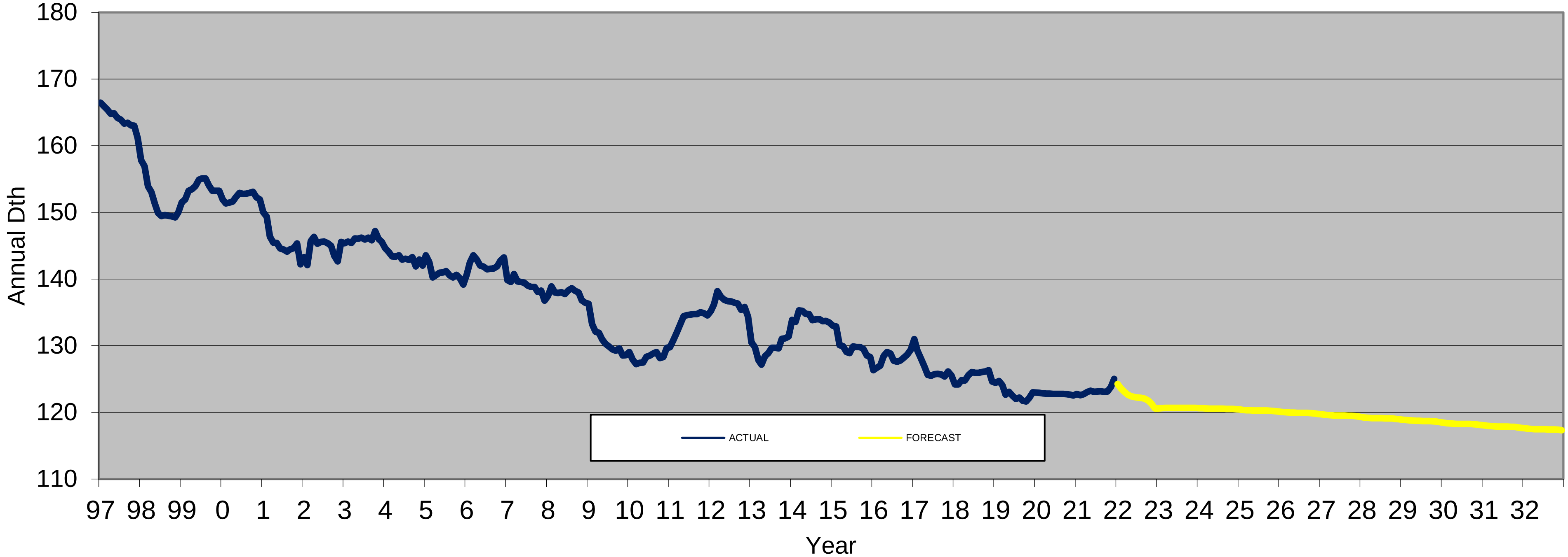
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
FORECAST	416.6	416.0	415.4	413.6	410.5	407.5	404.5	401.1	397.4	393.6

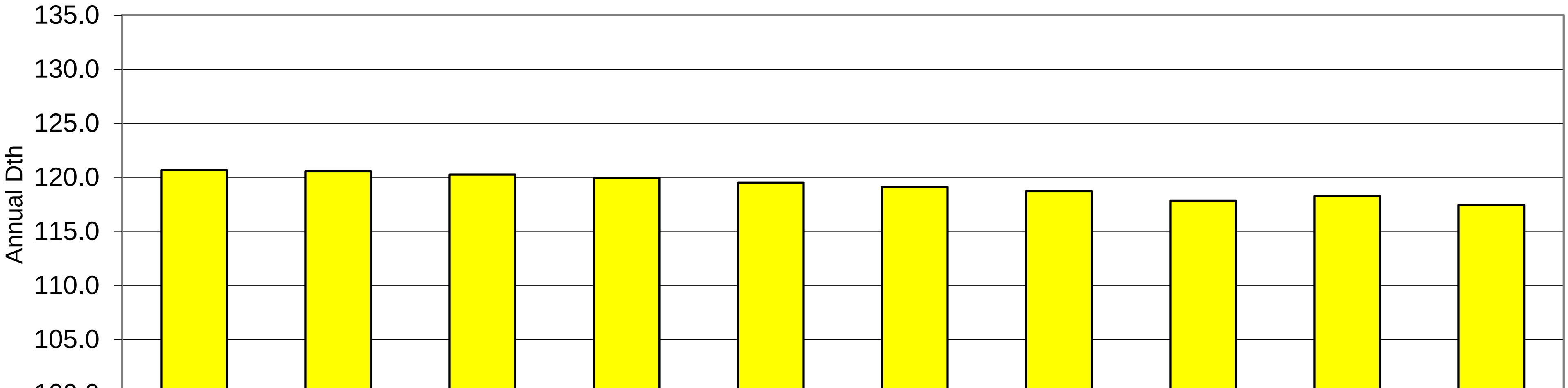
IRP Year

Exhibit 3.4

WYOMING GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL

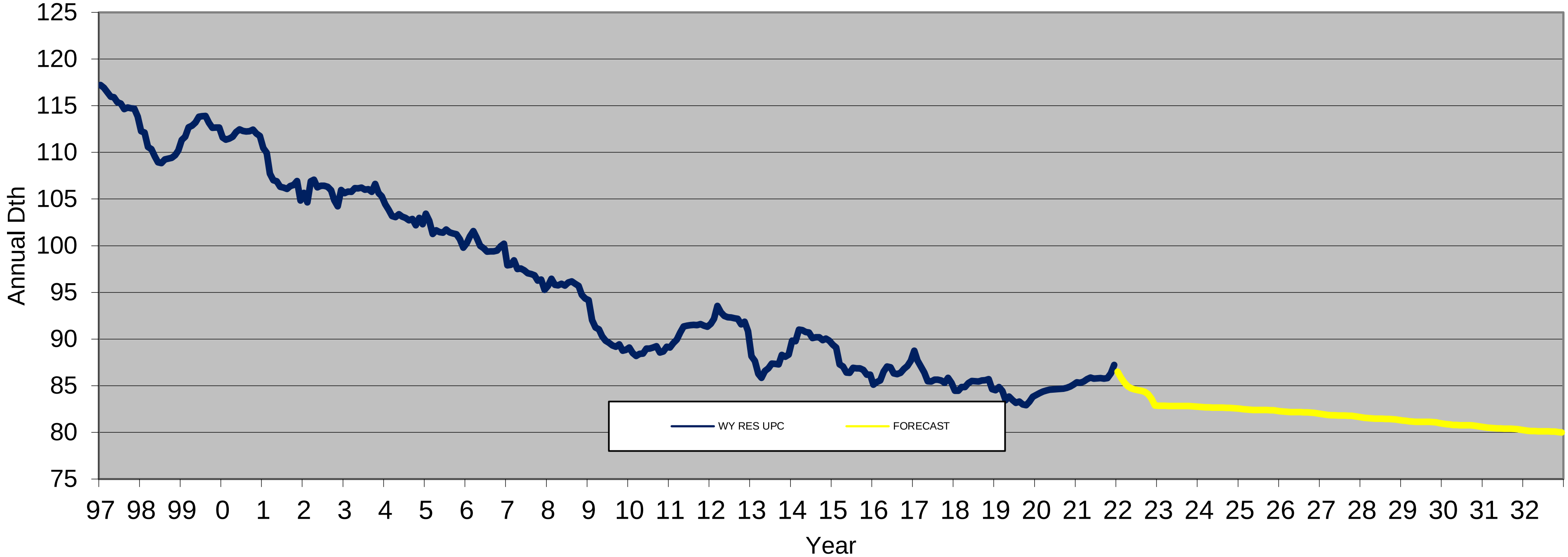


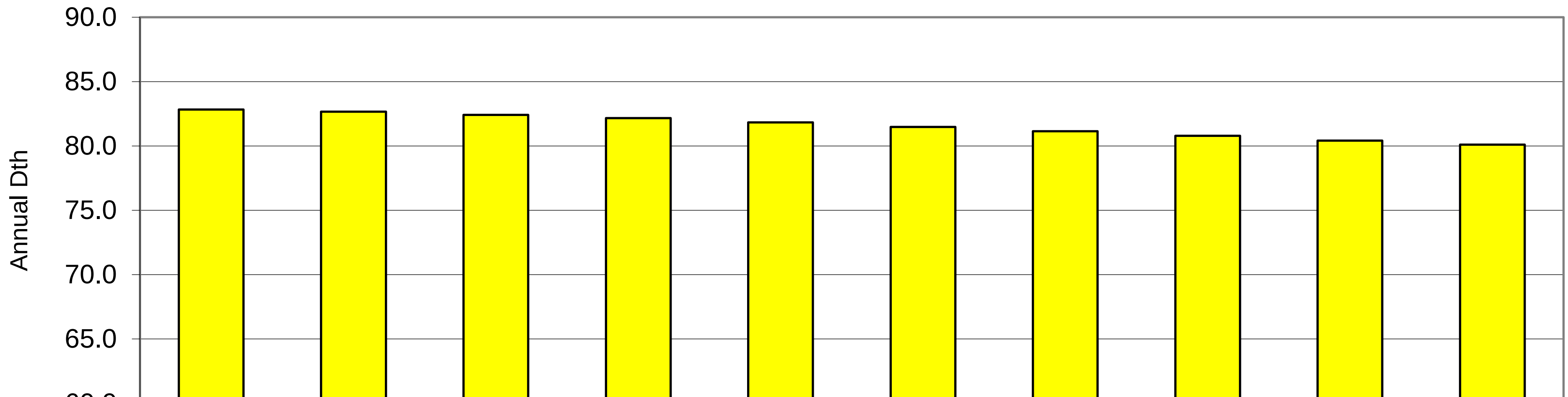


	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
WY GS	120.7	120.6	120.3	120.0	119.5	119.1	118.7	117.9	118.3	117.5

Exhibit 3.5

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



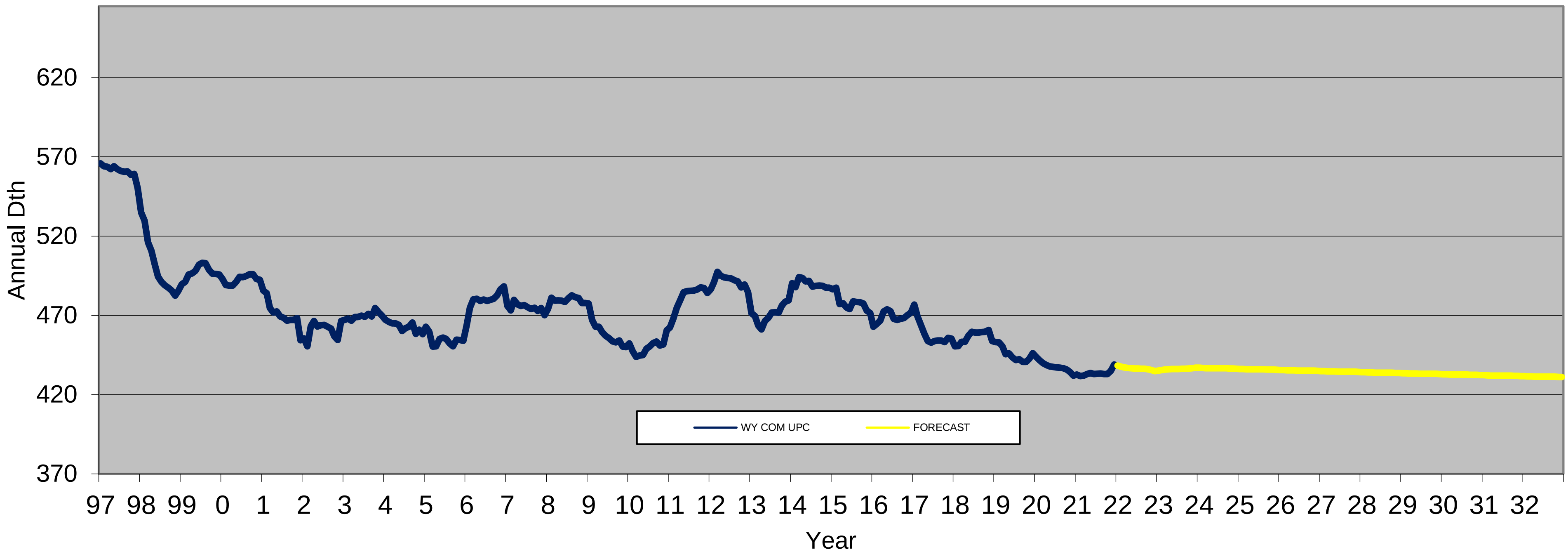


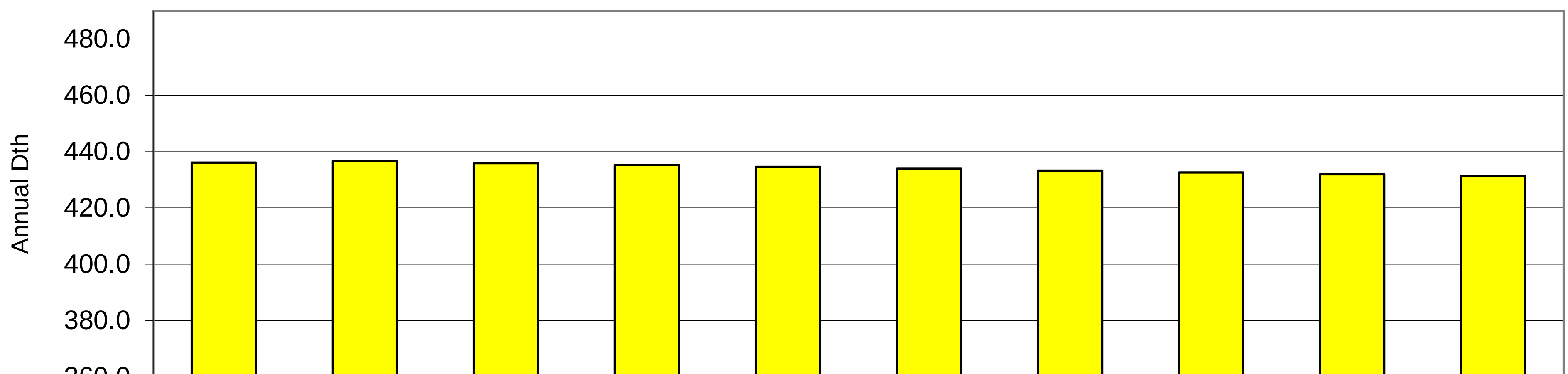
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
WY GS RES UPC	82.8	82.7	82.4	82.2	81.8	81.5	81.1	80.8	80.4	80.1

IRP Year

Exibit 3.6

WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



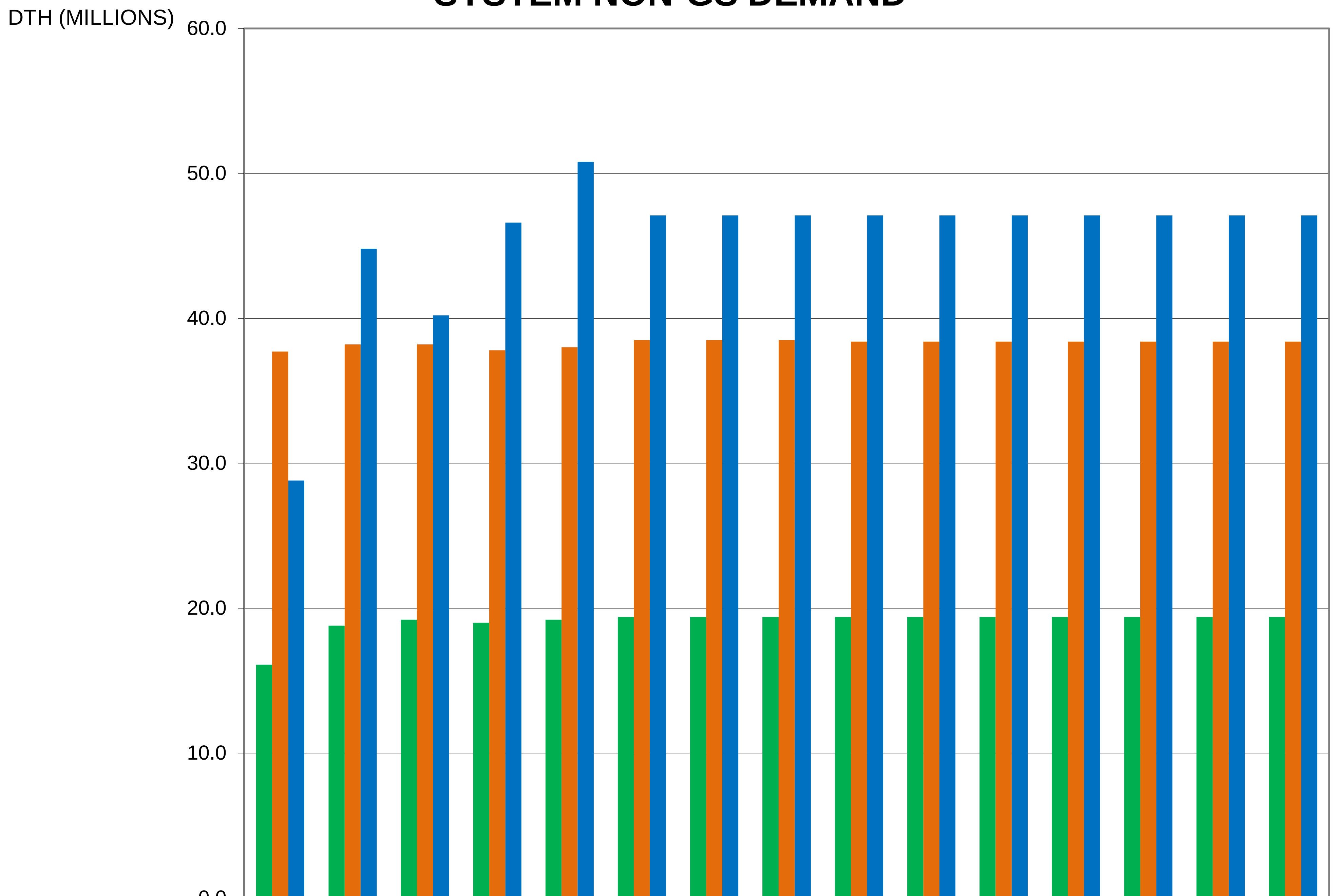


	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
WY GS COM UPC	436.1	436.6	435.9	435.2	434.6	433.9	433.2	432.6	432.0	431.4

IRP Year

Exhibit 3.7

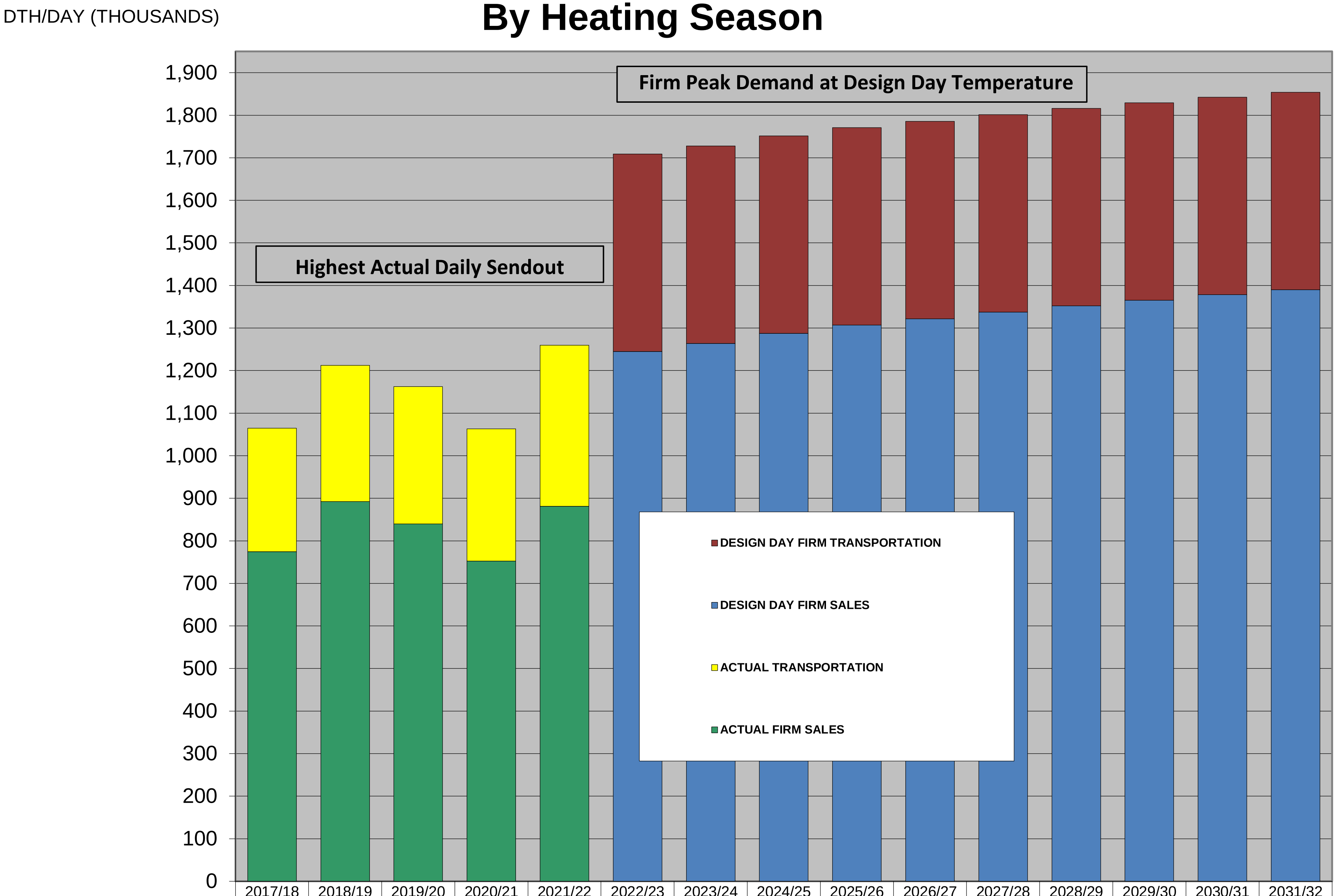
SYSTEM NON-GS DEMAND



	2017/18	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
LARGE COMMERCIAL DEMAND	16.1	18.8	19.2	19.0	19.2	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
INDUSTRIAL DEMAND	37.7	38.2	38.2	37.8	38.0	38.5	38.5	38.5	38.4	38.4	38.4	38.4	38.4	38.4	38.4
ELECTRIC GENERATION	28.8	44.8	40.2	46.6	50.8	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1

Exhibit 3.8

DESIGN PEAK-DAY DEMAND FORECAST
By Heating Season

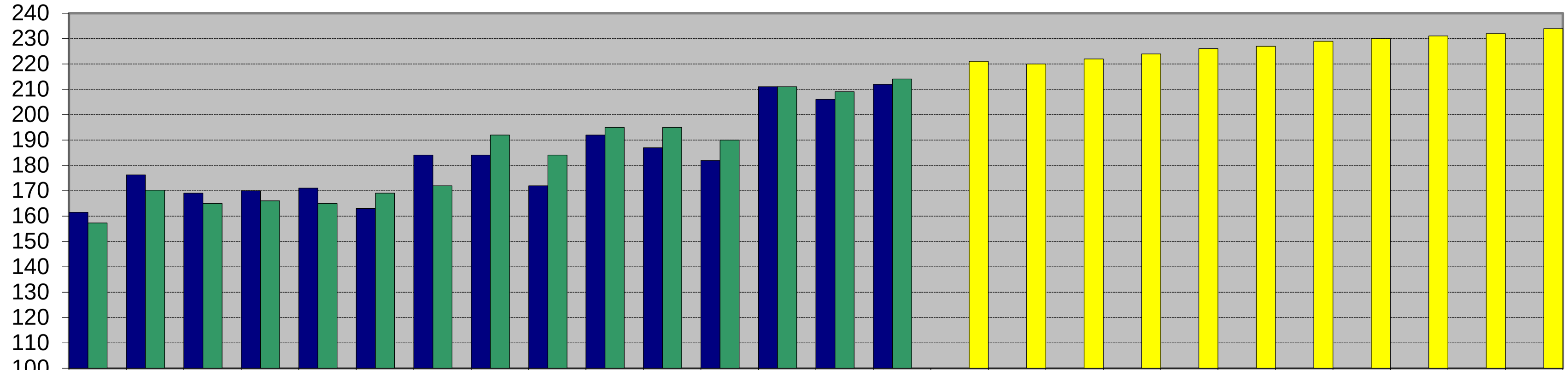


	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
DESIGN DAY FIRM TRANSPORTATION						464	464	464	464	464	464	464	464	464	464
DESIGN DAY FIRM SALES						1245	1264	1287	1307	1322	1337	1352	1365	1378	1390
ACTUAL TRANSPORTATION	290	320	323	311	378										
ACTUAL FIRM SALES	775	892	840	752	881										

Exhibit 3.9

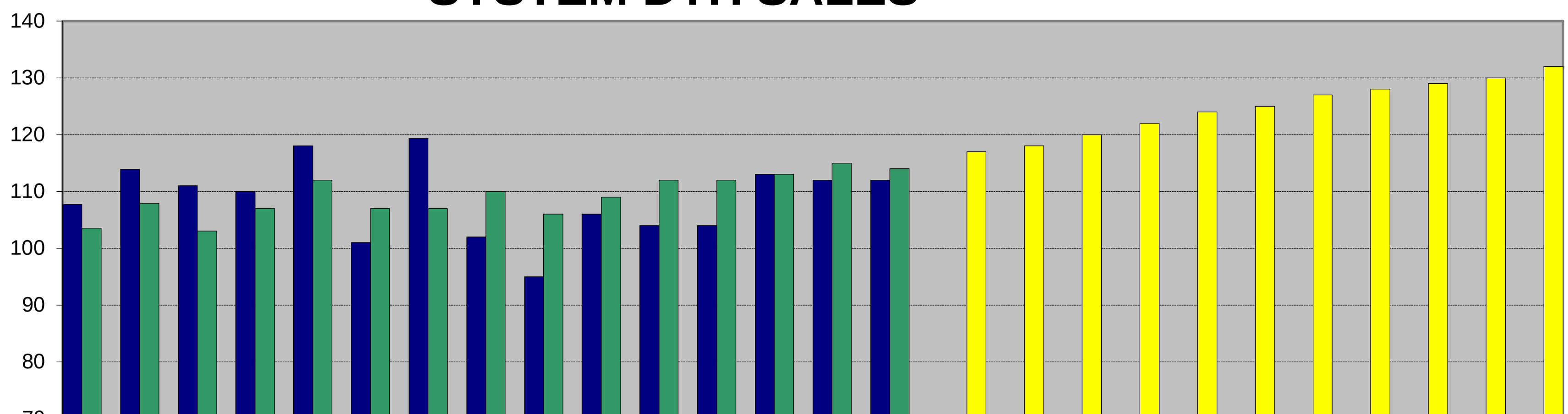
Exhibit 3.10

SYSTEM DTH THROUGHPUT



	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
ACTUAL	162	176	169	170	171	163	184	184	172	192	187	182	211	206	212											
TEMP ADJUSTED	157	170	165	166	165	169	172	192	184	195	195	190	211	209	214											
FORECAST																221	220	222	224	226	227	229	230	231	232	234

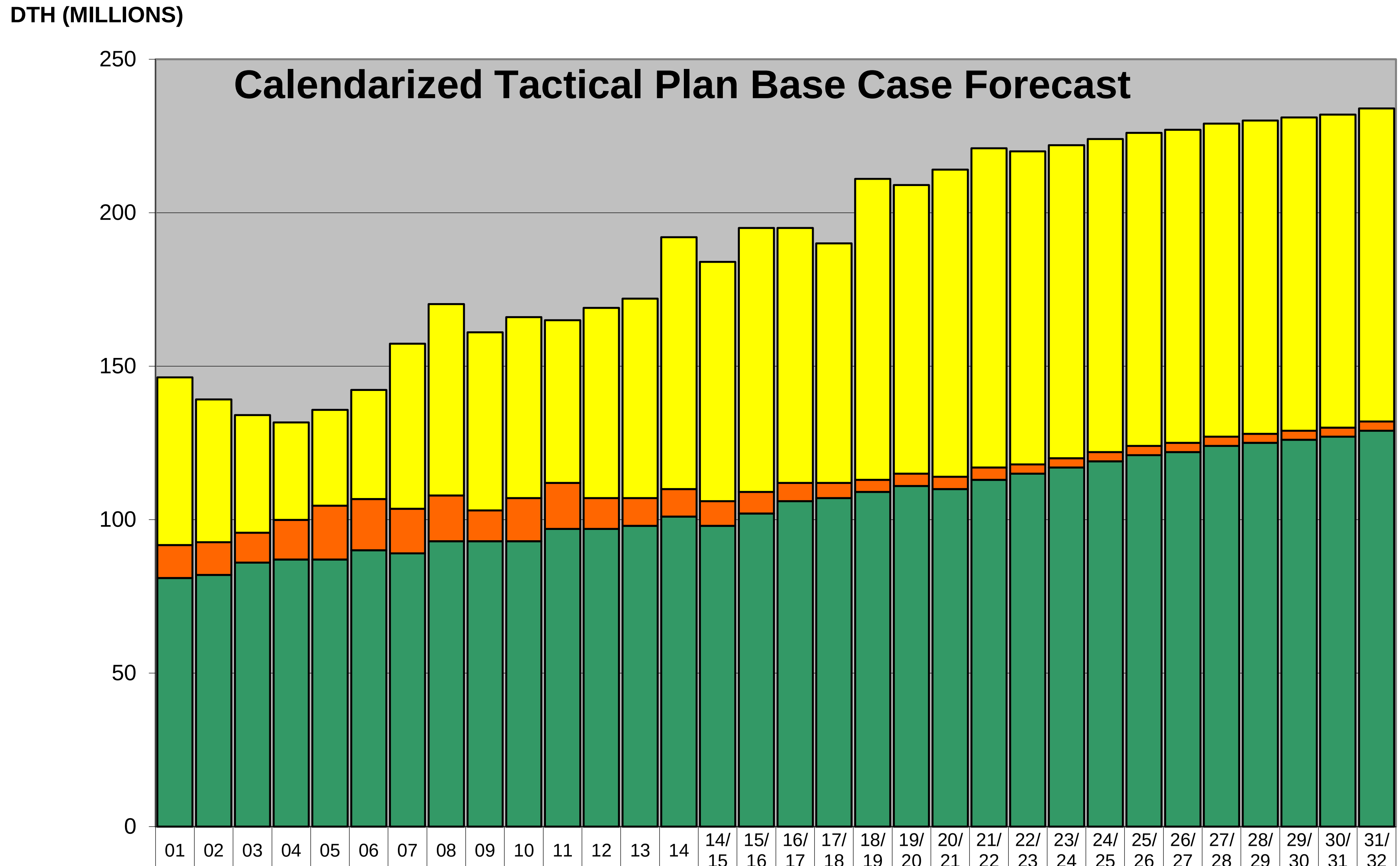
SYSTEM DTH SALES



	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
ACTUAL	108	114	111	110	118	101	119	102	95	106	104	104	113	112	112											
TEMP ADJUSTED	104	108	103	107	112	107	107	110	106	109	112	112	113	115	114											
FORECAST																117	118	120	122	124	125	127	128	129	130	132

Exhibit 3.11

TEMP ADJUSTED THROUGHPUT



	01	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
TRANS	55	46	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	94	100	104	102	102	102	102	102	102	102	102	102	102
NON-GS SALES	11	11	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	4	4	3	3	3	3	3	3	3	3	3	3
SYSTEM GS	81	82	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	111	110	113	115	117	119	121	122	124	125	126	127	129

SYSTEM CAPABILITIES AND CONSTRAINTS

DEUWI SYSTEM OVERVIEW

The Company's system currently consists of approximately 21,069 miles of distribution and transmission mains serving more than 1,152,000 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.

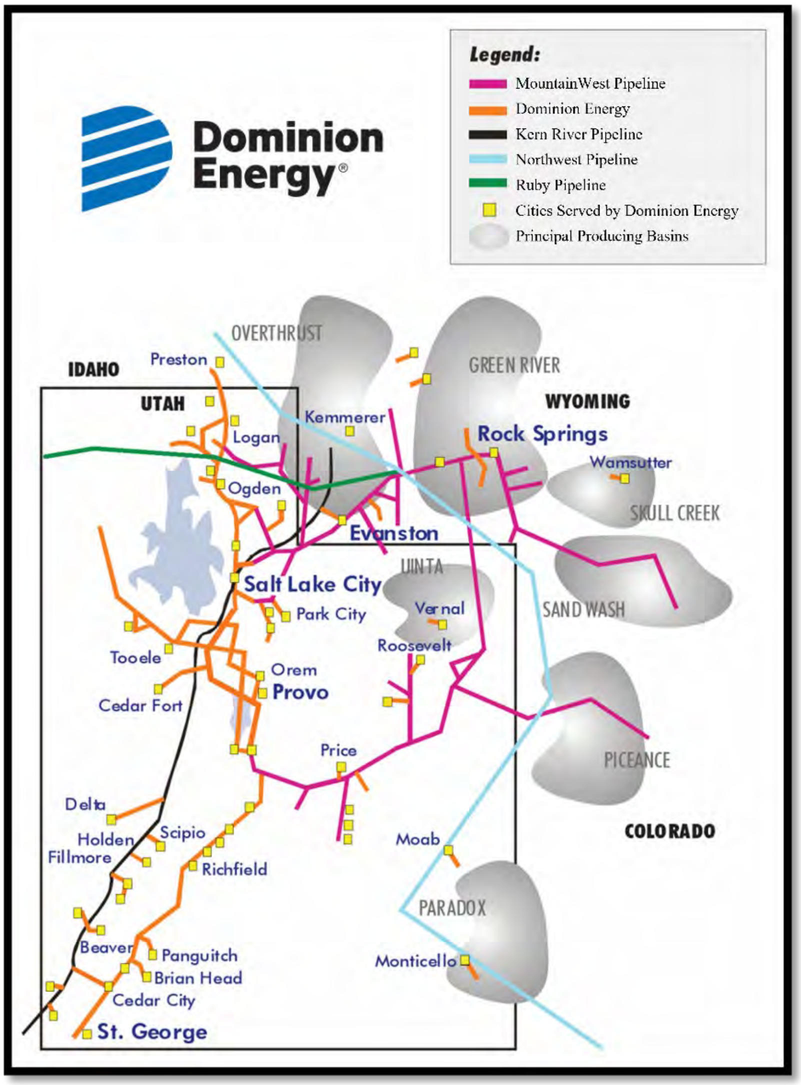


Figure 4.1: DEUWI High Pressure System

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

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 MountainWest 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 Southwest Gas Holdings, that same process is under way in 2022. DEUWI is working with MWP to determine how to address these issues going forward.

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	2021 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	-6
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 Wednesday, February 3, 2022, 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 407 verification points. Each of these points were found to be within 7% of the actual pressures on that day. Three hundred and ninety-nine 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 all verification points on that day. Three hundred and ninety-eight 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 that station each year until it requires upgrade or replacement.

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

Station	2022-2023 Max Flow (MMcfd)	Station Capacity (MMcfd)	% Utilization
Central Tap	51.0	51.0	100%
Riverton	192.7	200.0	96%
Evanston South	7.8	8.8	88%
Sunset	80.0	92.8	86%
Dog Valley	5.9	6.9	86%
Hunter Park	330.0	400.0	83%
Rockport	13.4	16.7	80%
Island Park	7.1	9.2	77%
Kanda	10.5	14.0	75%
Payson (FL26)	229.2	320.3	72%
Bluebell (Vernal)	7.0	10.0	70%
Green River Border	5.5	7.9	70%
Hyrum	179.0	262.0	68%
Wecco	22.0	32.6	67%
Jeremy Ranch	19.1	28.7	66%
Little Mountain (FL4)	148.0	238.0	62%
Saratoga Tap	133.7	219.0	61%
Mountain Green	7.8	13.0	60%
Payson (FL42)	41.5	70.0	59%
Promontory	45.0	75.9	59%
Westport	20.0	36.2	55%
Porter Lane	75.0	136.7	55%
Little Mountain (FL21)	147.0	272.0	54%
Gordon Creek	10.5	22.1	47%
Indianola	28.7	61.9	46%
Eagle Mountain	8.4	25.4	33%
Kent Ranch	5.0	17.0	30%
Rock Springs Foothill Dr	10.8	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 1000 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 higher discharge pressures 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.

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 last year improves the ability to supply additional firm gas to the Wasatch Front. In addition, last year's FL23 replacement project has allowed for additional capacity to be available to the Wasatch Front through the Hyrum gate station. 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 2023. This project is discussed in greater detail in the Distribution Action Plan section of this report.

SYSTEM PRESSURES

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

Northern

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

162) and KRGT at Eagle Mountain, Lake Side, Hunter Park, Riverton, Westport, and Rose Park gate stations.

In the steady-state model, the calculated low point in the main portion of the northern system is 205 psig, in Orem. The lowest steady-state pressure in the Summit/Wasatch system is in Woodland, which is 286 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	262
Endpoint of FL 36 – West Jordan	245
Endpoint of FL 48 – Stockton	281
Endpoint of FL 51 – Plain City	296
Endpoint of FL 54 – Park City	351
Endpoint of FL 62 – Alta	237
Endpoint of FL 63 – West Desert	267
Endpoint of FL 70 – Promontory	260
Endpoint of FL 74 – Preston	254
Endpoint of FL 106 – Bear River City	281
Intersection of FL 29 & FL 127 – Brigham City	342

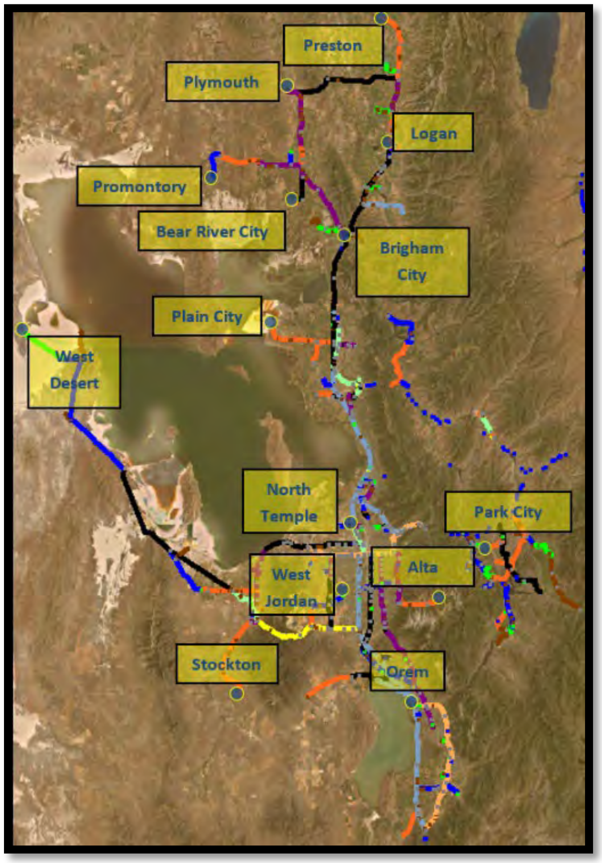


Figure 4.2: Northern Region Key Pressure Locations

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 165 psig. The lowest predicted pressure in the Summit/Wasatch subsystem is at the Woodland regulator station with 211 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 180 psig.

One of the HP regulator stations that supplies gas from the 720 psig MAOP of FL26 into the 354 psig MAOP northward is the Lindon station (RE0027). This station requires capacity upgrades to continue to improve supply reliability during potential outages northward. This project will be discussed in greater detail in the Distribution Action Plan section of this report.

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. HP stations will need to be installed on the east and west ends of FL13 to continue to properly regulate pressures between MAOP zones. These projects will be discussed in greater detail in the Distribution Action Plan section of this report.

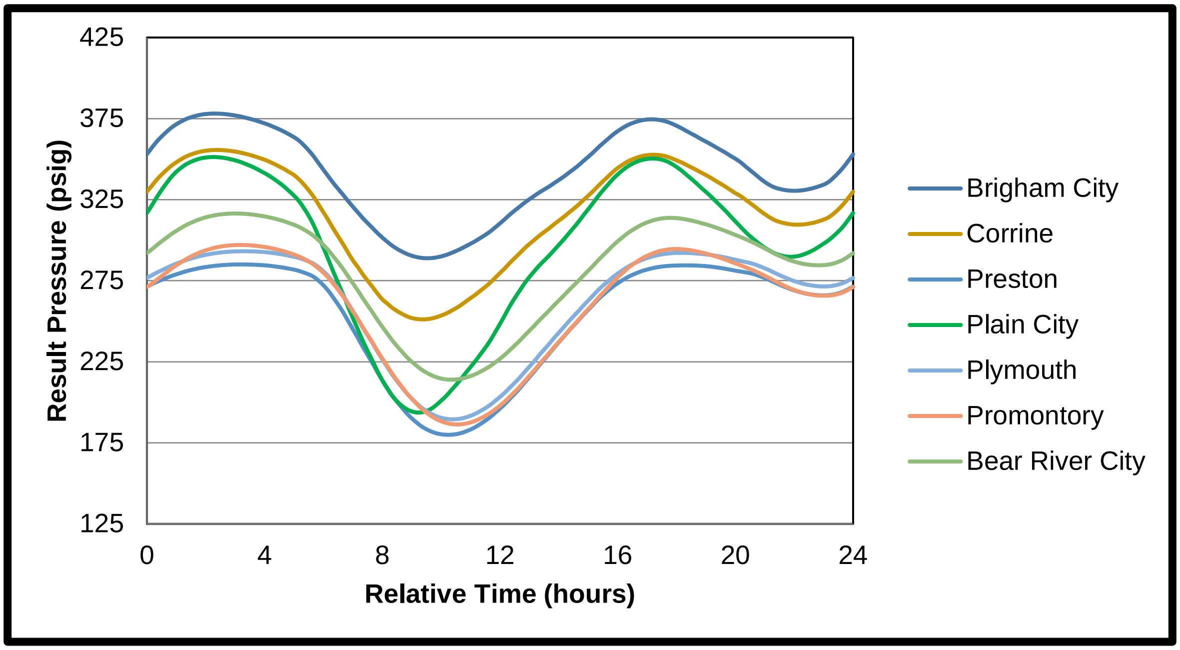


Figure 4.3: 2022-2023 Northern Unsteady-State Design Day Pressures (North of Flyer Way)

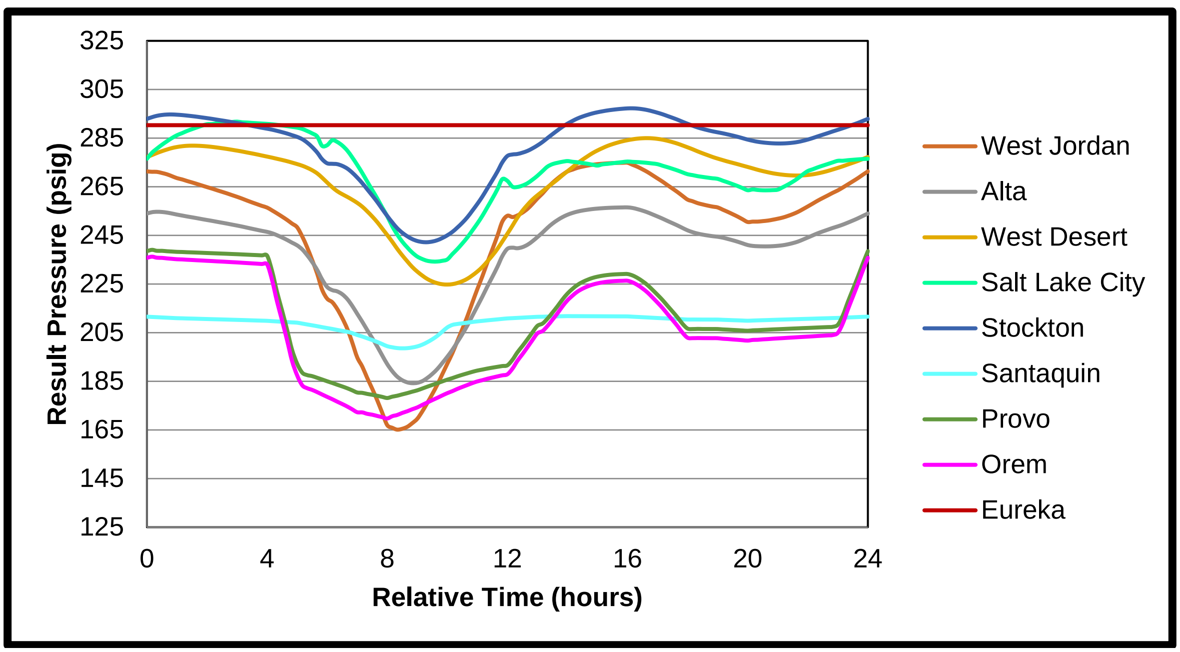


Figure 4.4: 2022-2023 Northern Unsteady-State Design Day Pressures (South of Flyer Way)

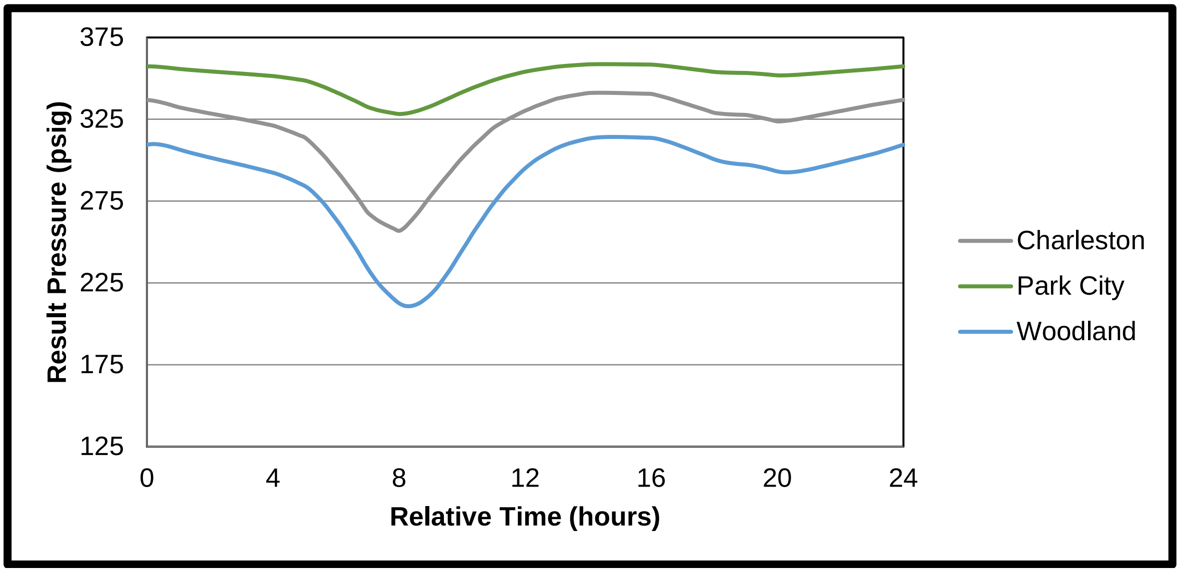


Figure 4.5: 2022-2023 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)

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 163 and MAP 334. Minimum pressures in the Vernal system reach a minimum of 203 psig at West Vernal.

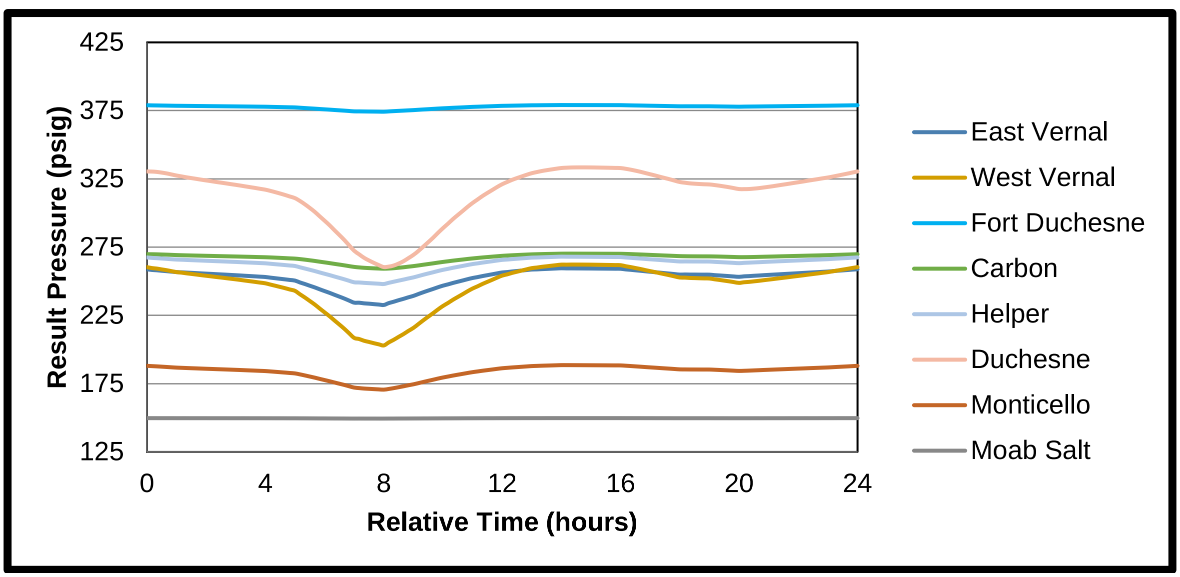


Figure 4.6: 2022-2023 Eastern (North) Unsteady-State Design-Day Pressures

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 do not require any improvements to meet the demand for the 2022-2023 heating season.

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 376 psig in Hurricane. All segments in this area have adequate pressures, and do not require any improvement to meet the existing demand.

The Southern System will require substantial upgrades within 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 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.

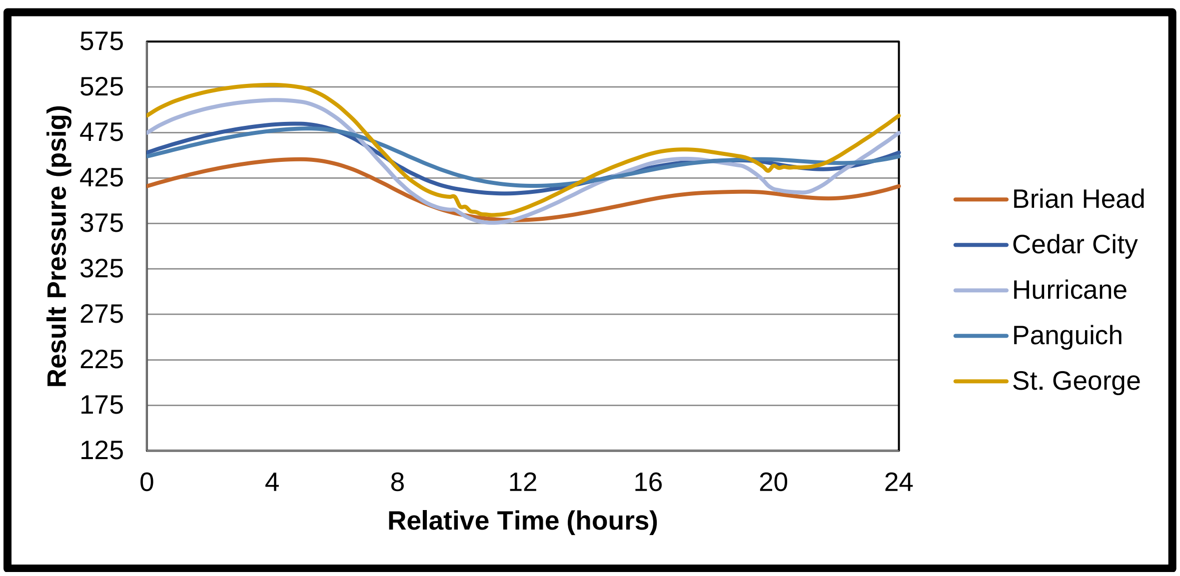


Figure 4.7: 2022-2023 Southern Unsteady-State Design Day Pressures

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, from CIG at Wamsutter and Rock Springs, and from Williams Field Services (WFS) at La Barge and Big Piney.

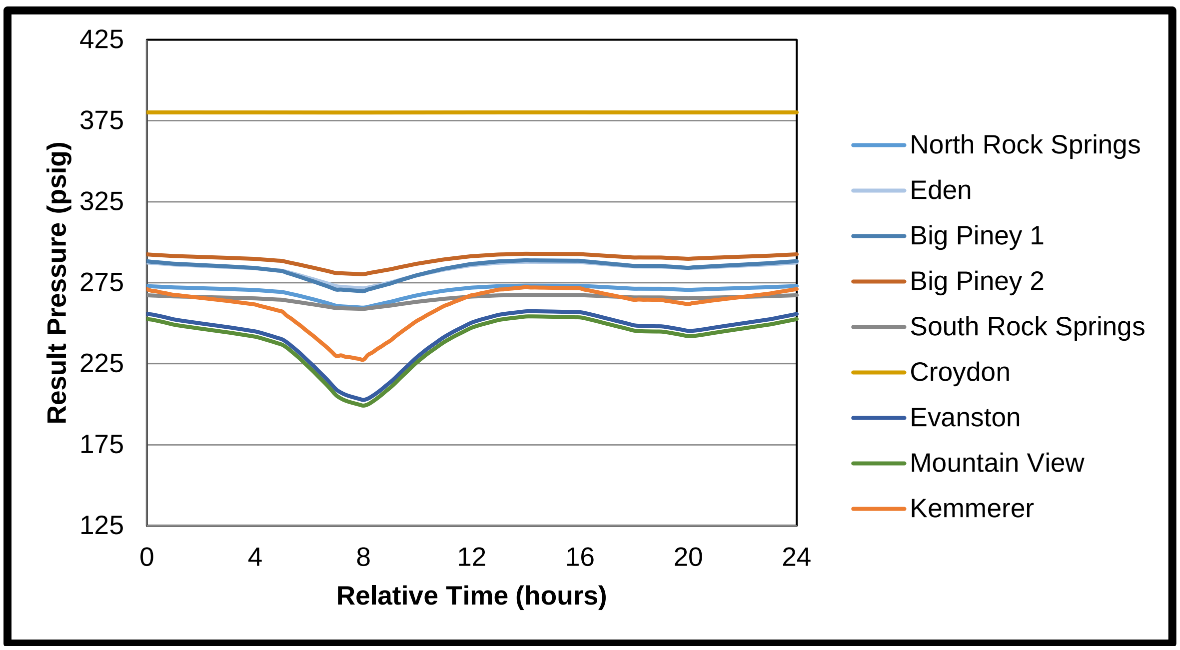


Figure 4.8: 2022-2023 Wyoming Unsteady-State Design Day Pressures

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 peak day growth and customer growth

	2018	2019	2020	2021	2022
Peak Day Growth	1.83%	3.03%	0.64%[31]	1.66%	1.77%
Customer Growth	2.28%	2.60%	2.35%	2.45%	2.63%

The average system growth and customer growth per year over the past 5 years have been about 1.8% 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 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. 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 his long-term plan. Establishing this corridor will require significant capital investment.

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

[31] Lower peak day demand growth in 2020 was mainly due to a reduction in contracted industrial demand.

The Company is considering 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.

Finally, 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 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. Currently these needs are based on cost savings as opposed to a specific operational need. This need could change as demand increase. This is discussed in more detail in the Gathering, Transportation, and Storage section of this report.

Another important trend the Company will be following is the increased focus in the industry on sustainable supply. Producers are increasingly offering more sustainable products such as RSG. 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
- Lindon (RE0027) HP Regulator Station
- Rockport Gate Station
- FL13 East and West HP Stations
- Saratoga (TG0005) Gate Station

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 2022 and beyond.

HIGH PRESSURE PROJECTS:

Station Projects:

1. LE0021 – District Regulator Station for American Fork and Lehi: The southwest side of American Fork, between I-15 and Utah Lake, is developing rapidly, and the Company needs to construct a new regulator station in the area to support the growth. The Company is attempting to acquire property near its low-capacity regulator station LE0017 and adjacent to FL85. The tap line will be approximately 70 lf and 6-inch in diameter. The Company has considered multiple options and selected the lowest cost alternative. Other options would require longer tap lines and horizontal directional drilling installation of pipe under Pioneer Crossing, thus significantly increasing costs.

   The Company is working to obtain the necessary property and will commence construction when the property has been secured. The Company anticipates completion during 2022. The estimated capital cost for this project is $750,000 with a revenue requirement of $88,425.

2. 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 size 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 Company first discussed this project on page 5-3 of the 2018-2019 IRP.

   Project is currently in the design phase. The Company estimates that the regulator station will cost $500,000. The Feeder Line extension to serve the regulator station will be discussed below. The Company plans to begin construction by July 2022 and finish construction before the 2022 heating season. The first-year revenue requirement will be $58,950.

3. WA1605 - New FL13 West HP Regulator Station and In-line Inspection (ILI) Facilities in Expanded WA 0027Site Near 8000 W and SR-201, Magna, 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 also include all the

connections necessary for an ILI launcher barrel. The Company purchased additional property near the existing WA0027 station, located at 2900 S 8000 W, Magna, UT. This site will now be the new connection between FL13 and FL11 and was the closest location for the new FL13/FL11 tie.

The project is currently in the design stage and is anticipated to be constructed in 2022. The Company estimates the total cost of the regulator station project (including property acquisition) to be $900,000. The first-year revenue requirement is $106,110.

4. <u>WA1602 New FL13 East HP Regulator Station, District Regulator Station and ILI Facilities, Salt Lake City, UT:</u> 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.

   No other site alternatives were feasible. FL13 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. The seller of the purchased property was the only willing seller with a reasonable purchase price. FL12 also runs through the property.

   The project is currently in the design stages. The project's construction is anticipated in 2022. The Company estimates the total cost of the regulator station project (including property acquisition) to be $2,800,000. The first-year revenue requirement is $330,120.

5. <u>WA1596 District Regulator Station, South Salt Lake City, UT:</u> 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. None were willing to sell property to the Company at a price that was competitive with market value. The selected location was the closest to the existing regulator station and was competitively priced.

   The project is currently in the design phase. 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 $176,850.

6. St. George – River Road District Regulator Station, St George, Utah: The area of St. George between the Southern Parkway and Enterprise Drive is growing quickly and 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 on 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 is currently procured to serve the area. 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 2023. The Company first discussed this project on page 5-4 of the 2018-2019 IRP. The Company estimates the total cost of the regulator station project (including property acquisition) to be $750,000. The first-year revenue requirement is $88,425.

7. 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 several Utah County communities including Lehi, Eagle Mountain, and Saratoga Springs. These communities are some of the fastest growing communities in DEUWI's service territory. The Saratoga gate station, while not at capacity on a Design Day, requires a remodel to address concerns with overpressure protection and anticipating future capacity demands from the quickly growing area. Currently the gate station has a capacity of 220 MMcfd. The Company's System Planning department is analyzing if additional capacity should be constructed as part of this project. Initial analysis indicates an increase of 100 MMcfd may be warranted. Other required improvements include gas measurement to allow flow control and improved overpressure protection.

   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., As mentioned above, the Company's System Planning department would provide requirements of any additional capacity increase. The Company anticipates constructing this facility in 2023. Total project costs are estimated to be between $2,000,000 and $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 between $235,800 and $589,500.

   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.

   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 off KRGT, with a design load of 100 MMcfd, would have an estimated cost of approximately $6,000,000. Additional project costs to construct a feeder line extension from the new gate station to the Company's current high-pressure system would prevent this project option from being cost competitive with the selected option discussed above.

8. Eagle Mountain District Regulator Station, near 4000 N and Hwy 73 in Eagle Mountain, UT: Growth between Highway 73 and Eagle Mountain to the east is accelerating, requiring construction of a new IHP regulator station. Large commercial and industrial areas are starting to develop, and additional capacity will be needed. 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. Property will need to be acquired 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 2023. Preliminary estimates for the district regulator station are $750,000. The first-year revenue requirement is $88,425.

9. South Bluffdale District Regulator Station, Bluffdale, Utah: As the Bluffdale area continues to grow, the Company's IHP distribution system has extended southward. Currently, the Company's IHP system is served by regulator stations located in the north end of Bluffdale. The Company's system planning models show that IHP pressures will decline to below 25 psig in the near future at the 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 in 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 2024. As the Company establishes viable route options and refines the cost estimate, it will provide updates as part of the IRP process in the future. Current estimates for the regulator station, including property, are $750,000. The first-year revenue requirement is $88,425.

10. 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 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 2024.

    The Company is identifying available property for the regulator station and analyzing different routes for the HP extension. Based on the current development rates, the Company anticipates construction of this project to commence in 2024. As the Company establishes viable route options for the HP extension and suitable locations for the IHP regulator station., Additional updates and refined estimates will be provided for this project in a future IRP. Current preliminary estimates with the cost of property and potential civil work are approximately $750,000. The first-year revenue requirement is $88,425.

11. 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. As the Company establishes viable design options, refined project scope and estimates will be provided in a future IRP.

12. 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 been unsuccessful. If expansion is not possible, the remodeled regulator station will be designed to fit within the existing footprint. This decision on the best path forward will be made during summer of 2022.

    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.

13. WA1604 – Replace WA0441, West Valley City, UT: WA0441 was installed in 1973. Given its age, and the increasing gas demand in the area it serves, it requires replacement. WA0441 is currently located on the side of the road in public utility easement (PUE) and cannot be expanded in its current location. WA0441 is located at 1300 W and Meadow Brook Parkway (approx. 4000 S).

    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 location of the new regulator station and further defines the project scope, it will provide updated estimates in a future IRP. Current estimates with the cost of property and potential civil work are approximately $1,000,000. The first-year revenue requirement is $118,900.

14. RE0027 FL26 HP Regulator Station, Lindon Utah: This is an existing HP regulator station in Lindon, Utah that separates the MAOP zones and reduces pressure on FL26 from 720 psig in the south to 354 psig in the north. Currently the regulator station has a capacity of 120 MMcfd and will eventually need to be increased to 200 MMcfd. FL26 is a 20-inch pipeline that leaves this regulator station and extends north into Bluffdale, bringing gas into the Salt Lake valley. Given that RE0027 is an existing station and this project's scope is to increase the capacity, there are no other alternatives to this project.

    The project is currently in the early planning phases The Company will provide updates to this project in a future IRP as details become available.

Feeder Line Projects:

1. 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.

   Project is currently in the design phase. The Company estimates that feeder line extension will cost approximately $5,500,000. The Company plans to begin and finish construction in 2022. The first-year revenue requirement will be $648,450.

2. FL71-5 Extension for the South St. George – River Road District Regulator Station, St. George, UT: The shortest route to the proposed property is extending FL71-5 from Enterprise Drive (near Deseret Power) directly south along River Road to the proposed developer site (subject to change). Estimated footage would be 12,000 lf of 8-inch diameter pipe. The extended FL71-5 will supply the new regulator station in South St. George to support the quickly growing area. The feeder line route will be the alignment of the existing River Road down to the station property. Deviating from existing road ROW will either conflict with existing conservation areas or interrupt existing development and add substantial costs. This alignment is directly south along River Road from where FL71-5 currently ends.

   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 on starting construction in 2023 (pending property). Current preliminary estimates based on the potential property location are approximately $4,000,000. The first-year revenue requirement is $471,600.

3. FL85 Extension for New Eagle Mountain District Regulator Station, Eagle Mountain, UT: This extension of FL85 will be to support a new IHP regulator station on the west side of Eagle Mountain. The Eagle Mountain area is fast growing with 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. By following the UDOT ROW, the need for acquiring additional easement on private land will be avoided and save costs. The feeder line extension is expected to be approximately 2 miles long and 8-inches in diameter. Final location will depend on build out of the area and available property.

   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 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.

4. FL Extension for South Bluffdale District Regulator Station, Eagle Mountain, UT: The extension of the feeder line system to support this new station could go as far south as Porter Rockwell Blvd and Redwood Rd. This station would serve the growth of Bluffdale that is continually moving south away from existing regulator stations. The anticipated feeder line extension is approximately 17,000 lf of pipe extending from FL 35. The project is still in the early planning stages and the size of pipe has yet to be selected, though it will be a minimum of 8-inches in diameter. Once a site is selected for the new regulator station, the Company will evaluate the routing options for the feeder line extension. 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 2024. 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 $766,350.

5. 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 $766,350.

6. 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 shortest 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 a longer route (6,600 lf) 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 is able to pursue the shorter route with the directional drill under the Jordan, River, it estimates the cost of the project to be $3,000,000. If the direction drill is prohibitive, the Company will pursue the longer route at an estimated cost of $4,000,000. The first-year revenue requirement for the directional drill option would be $353,700. The first-year revenue requirement for the longer route would be $471,600.

7. FL21-10 Replacement, North Salt Lake, UT: The Company plans to replace approximately 6,800 lf of FL21-10 in order 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. Current preliminary estimates based for the 6,800 lf replacement is $3,000,000 - 5,000,000. The first-year revenue requirement is $353,700 – $589,500.

8. 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 had 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. Currently, Phase 1 is under construction and will be complete by the end of 2022. Phase 1 has an estimated cost of $32,813,000. The first-year revenue requirement is $3.9 million. Phase 2, Veyo to Diamond Valley, is expected to be constructed between 2024 and 2025 and the final phase of this project, Diamond Valley to Bluff Street, is expected to be constructed between 2027 and 2028. 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
2022	LE0021 District Regulator Station for American Fork and Lehi	$750,000	$88,425
	Central 20-inch Feeder Line Loop (Phase 1)	$32,813,000	$3,868,653
	SY0002 Syracuse District Regulator Station	$500,000	$58,950
	FL47 Extension for SY0002 Syracuse District Regulator Station	$5,500,000	$648,450
	WA1605 - FL13 West HP Station and ILI Facilities, Magna, UT	$900,000	$106,110
	WA1602 FL13 East HP Station, District Regulator Station, and ILI Facilities, Salt Lake City, UT	$2,800,000	$330,120
2023	WA1596 – Replace WA0866 with High-Capacity District Regulator Station for South Salt Lake City, UT	$1,500,000	$176,850
	South St. George – River Road District Regulator Station	$750,000	$88,425
	FL71-5 Extension for South St. George DR Station – River Road	$4,000,000	$471,600
	TG0005 Saratoga KRGT Gate Station	$2,000,000 to $5,000,000	$235,800 to $589,500
	Eagle Mountain District Regulator Station, near 4000 N and Hwy 73	$750,000	$88,425
	FL85 Extension for Eagle Mountain District Regulator Station	$3,000,000	$353,700
2024	South Bluffdale District Regulator Station	$750,000	$88,425
	FL Extension for Bluffdale Station	$6,500,000	$766,350
	South Hurricane District Regulator Station	$750,000	$88,425

Year	Project	Estimated Cost	Revenue Requirement
	FL Extension for South Hurricane Station	$6,500,000	$766,350
	Rockport Gate Station	TBD	TDB
2025	Central 20-inch Loop (Phase 2)	TBD	TBD
	SL0114 Remodel	TBD	TBD
	WA1604 – Replace WA0441	$1,000,000	$117,900
	FL Extension for WA1604 Across Jordan River	$3,000,000 to $4,000,000	$353,700 to $471,600
	FL21-10 – 6,800 LF Replacement	$3,000,000 to $5,000,000	$353,700+
2028	Central 20-inch Feeder Line Loop (Phase 3)	TBD	TBD
TBD	RE0027 - Lindon HP Station Capacity Upgrade	TBD	TBD

PLANT PROJECTS:

1. On-System LNG Facility: The Commission approved the construction of an on-system LNG facility located in Magna, Utah in Docket No. 19-057-13. As discussed in greater detail in the "Supply Reliability" section of this report and in the application and accompanying testimony and exhibits in Docket No. 19-057-13, supply disruptions upstream of the Company's system have become an increasing concern. The Company is also concerned that, in the event of a significant supply disruption, it would be unable to provide reliable service to its customers. The Company determined it would be prudent to have a reliable supply source that the Company can call upon in the event of unanticipated supply disruption, line damage, or events caused by forces of nature.

   The Company set forth a detailed analysis of alternatives evaluated, and all required information set forth in the 2009 IRP Guidelines and the Report and Order in the 2017-2018 IRP process (Docket No. 17-057-12) in the Application accompanying testimony and exhibits in Docket No. 18-057-03 and Docket No. 19-057-13. On October 25, 2019, the Commission approved the Company's application, including its selected alternative to address the supply reliability concerns. 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 original projected cost of the facility was $211,000,000. Due to Covid-19-related commodity cost increases, and supply chain delays these costs are now projected to be $218,563,414. The cost recovery of the project will be determined in the Company's general rate case in Docket 22-057-03.

An update on the status of this project is included in the Supply Reliability section of this report.

INTERMEDIATE HIGH PRESSURE PROJECTS:

1. Belt Main Replacement Program: The Company continues its Belt Main Replacement program in 2022. 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 2019 there was approximately 4,130 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 tariff prohibits new master meter installations at mobile home parks and discourages them at other locations unless it is determined by the Company that a master meter is the only feasible method of providing gas service.

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. The Company will provide further updates as information becomes available.

RURAL EXPANSION

In addition to the reinforcement projects discussed above, the Company has been exploring options to expand into new communities within its service territory. There are many factors influencing which communities are best suited for an expansion including: 1) cost of expansion; 2) number of potential new customers; 3) impact on current operations; 4) impact on the current system; and 5) risk of low customer growth in expansion areas.

Utah

During Utah's 2017 legislative session, lawmakers amended Utah Code Ann. §§ 54-17-401, 402, and 403 to encourage expansion of natural gas service to rural communities. The referenced statutes, as amended, allow the costs of main extensions to rural communities to be spread among all customers with spending caps in place to prevent large swings to customer bills. During the 2020 legislative session, lawmakers passed HB129, which allows for the Company to purchase existing assets to aid in providing gas service to rural communities.

Eureka Expansion Project

On December 3, 2019, the Company filed an Application in Docket No. 19-057-31 seeking approval to extend natural gas service to Eureka. The original application was amended on April 15, 2020, to include service lines in the proposed program. The Amended Application included a discussion of the alternatives for serving Eureka. The Commission approved the Amended Application, including the selected alternative for providing that service, on August 27, 2020. The project includes the following: 8.4 miles of feeder line installation, district regulator station, HP gate station, and IHP main installation for the town. This project was put in service in 2021. Customer sign-ups are ongoing and as of the end of April 2022, over 235 residents have signed up to have a service line installed.

Goshen/Elberta Expansion Project

On April 5, 2021, the Company filed an Application in Docket No. 21-057-06 seeking Commission approval to expand its natural gas distribution system to the communities of Goshen and Elberta, Utah. The Commission approved the Application on August 17, 2021. Construction is scheduled to start June 2022 and be completed by November 2022 for heating season. The project includes the following: 6-inch feeder line approximately 22,000 lf, three regulator stations, and IHP main installation. Construction is planned to start in June 2022.

Green River Expansion Project

On August 5, 2021, the Company filed an Application in Docket No. 21-057-12 seeking Commission approval to expand its natural gas distribution system to the Community of Green River, Utah. The Commission approved the Application on January 19, 2022. The Company is in the planning phase of this project and anticipates beginning construction in early 2023. The project should be completed before the beginning of the 2023-2024 heating season. The project includes the following: conversion of 21 miles of 16-inch PEMC pipeline, install additional 17 miles of 6-inch steel feeder line, two regulator stations, and IHP main.

The Company is continuing the feasibility evaluation of expanding to several other interested communities including Kanab, Genola, the Bear Lake valley, and Rockville/Springdale. The Company will continue working with each of these communities and will work to identify additional candidates for expansion. The Company will provide an update on the project scope and costs as they become available.

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.[32]

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.[33] 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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[32] 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)).
[33] 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.

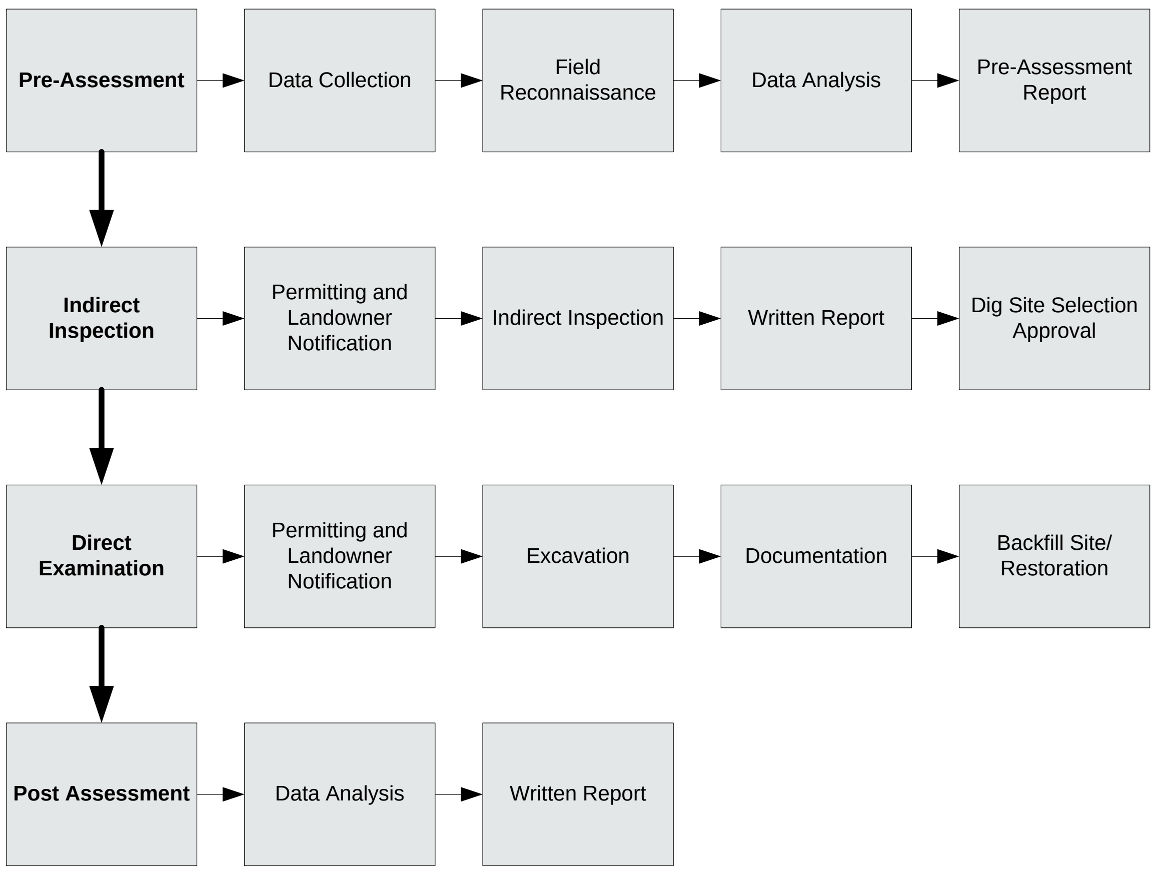

Figure 6.1: ECDA Process Overview

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 294.5 miles of transmission piping (38% 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 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

	2022	2023	2024
Transmission Integrity Management Program	6,639	7,266	7,478
Distribution Integrity Management Program	2,189	1,843	1,408
Total Integrity Management Cost ($ Thousands)	8,828	9,109	8,886

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

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. HCA Miles Assessed are a subset of Transmission Miles Assessed.

NEW 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.

The Trump administration delayed the publication of the Mega Rule regulation. In March 2018 PHMSA's Gas Pipeline Advisory Committee (GPAC) gathered to continue its work on developing the proposed rule for Transmission and Gathering Pipelines. PHSMA outlined that it intended to break 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. 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.

Part 1 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.

PHMSA is expected to publish the second part of the Mega Rule in the summer of 2022. This rulemaking would amend the pipeline safety regulations to gas transmission pipelines by adjusting the repair criteria in high consequence areas. It would also create new criteria for non-high consequence areas, require the inspection of pipelines following extreme events, require safety features on in-line inspection tool launchers and receivers, update and bolster pipeline corrosion control, codify a management of change process, clarify certain integrity management provisions, and strengthen integrity management assessment requirements.

PHMSA published the third part of the Mega Rule November 15, 2021. This part of the Mega Rule applies to gas gathering lines and has no application to assets operated by the Company.

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 will be effective 180 days from the date of publication.

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.

Interstate Natural Gas Association of America (INGAA) Fitness for Service (FFS)

The Company has adopted industry and Company best practices for transmission pipelines that align with the direction and intent of PHMSA's proposed Mega Rule. INGAA's FFS applies current pressure testing requirements to transmission pipelines constructed prior to the pipeline safety regulation publication in 1970, exceeding current PHMSA requirements for pre-regulatory transmission pipelines and meeting proposed Mega Rule requirements. This will assess potential integrity construction defect threats and improve the Company's knowledge of these pipelines. The FFS practices were adopted during the delayed implementation of the Mega Rule. Part One of the Mega Rule is now in effect, including the MAOP reconfirmation requirements. Therefore, the FFS will stop and DEUWI will transition resources to activities directed at compliance with Part One of the Mega Rule.

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	2022	2023	2024
ECDA			
Pre-Assessment			
2022 (FL10, 14, 48, 52, 88) (4.05 HCA miles; 5.67 CA miles @ $4K/FL)	24		
2023 (FL34, 103, 11, 26, 85) (19.91 HCA miles; 9.93 CA miles @ $4K/FL)		20	
2024 (FL012, 22, 33, 46, 51, 53) (14.54 HCA miles; 10.85 CA miles @ $4K/FL)			24
Indirect Inspections			
2022 (FL10, 14, 48, 52, 88) (4.05 HCA miles; 5.67 CA miles @ $16K/mile)	156		
2023 (FL34, 103, 11, 26, 85) (19.91 HCA miles; 9.93 CA miles @ $16K/mile)		475	
2024 (FL012, 22, 33, 46, 51, 53) (14.54 HCA miles; 10.85 CA miles @ $16K/mile)			406
Direct Examinations			
2021 (FL68-4, 69, 83, 84, 99, 104) (6 excavations @ 34.5K ea.)	207		
2021 (FL68-4, 69, 83, 84, 99, 104) (Pipetel 0 sites, 0 casings @ 150K/site)			
2022 (FL10, 14, 48, 52, 88) (6 excavations @ 34.5K ea.)		207	
2022 (FL10, 14, 48, 52, 88) (Pipetel 2 sites, 2 casings @ 150K/site)		300	
2023 (FL34, 103, 11, 26, 85) (6 excavations @ 34.5K ea.)			207
2023 (FL34, 103, 11, 26, 85) (Pipetel 2 sites, 2 casings @ 150K/site)			300
Post Assessment			
2021 (FL 68-4, 69, 83, 84, 99, 104) (2.19 HCA miles; 7.13 CA miles @ $1.5K/FL)	9		
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; 9.93 CA miles @ $1.5K/FL)			7.5
CIS			
Indirect Inspections			
2022 (66, 67, 68, 23,10, 14, 48, 52, 88) (85.36 miles @ 6.5 K/mile)	555		
2023 (FL068, 71, 35, 41,10, 34, 103, 11, 4, 26, 85) (67.74 miles @ 6.5K/mile)		440.3	
2024 (FL012, 22, 33, 46, 51, 53,104, 25, 22,19) (66.93 miles @ 6.5K/mile)			435
Reports			
No additional cost under current contract			
ACCDA			
Pre-Assessment			
2022 (FL10, 88) (0.31 HCA miles; Fixed)	2.5		
2023 (FL11, 26, 85, 103) (6.18 HCA miles; Fixed)		5	
2024 (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles; Fixed)			2
Indirect Inspections			
2022 (FL10, 88) (0.31 HCA miles; @ 32K/mile)	9.9		
2023 (FL11, 26, 85, 103) (6.18 HCA miles; @ 14K/mile)		86.5	
2024 (FL012, 22, 33, 46, 51, 53) (1.37 HCA miles @ $24K/mile)			33
Direct Examinations			
2021 (FL68, 69, 83, 84, 99, 104) (2 excavations @ 34.5K ea.)	69		
2022 (FL10, 88) (2 excavations @ 34.5K ea.)		69	
2023 (FL11, 26, 85, 103)(4 excavations @ 34.5K ea.)			138
Post Assessment			
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; Fixed)	3		
2022 (FL10, 88) (.31 HCA miles: Fixed)		6	
2023 (FL11, 26, 85, 103) (6.18 HCA miles; Fixed)			6
ICDA			
ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan).			
Inline Inspection			
2021 Excavations/ Validations Digs/ Remediation (12 excavations @ 34.5 K ea)	207		
2022 (FL023)	600		
2022 (FL066, FL067, FL068)	400		
2022 Excavations/ Validations Digs/ Remediation (12 excavations @ 34.5 K ea)	138	276	
2023 (FL068, FL071)		300	
2023 (FL035/41)		400	
2023 (FL010)		400	
2023 (PEMC)			
2023 Excavations/ Validations Digs/ Remediation (15 excavations @ 34.5 K ea)			345
2024 (FL104)			300
2024 (FL026)			300
2024 (FL022/53/19)			400
2024 (FL019)			300
Direct Examination (Spans and Vaults)			
2022 - Vaults (3 @ 3.5 K/ vault)	10.5		
2022 - Spans Reassessment (1 @ 10 K/ span)	10		
2023 - Vaults (6 @ 3.5 K/ vault)		21	
2023 - Spans Reassessment (4 @ 10 K/ span)		40	
2023 - Spans First Time (2 @ 75 K/ span)		150	
2024 - Vaults (6 @ 3.5 K/ vault)			21
2024 - Spans Reassessment (4 @ 10 K/ span)			40
2024 - Spans First Time (2 @ 75 K/ span)			150

Transmission Integrity Management Costs

Activity	2022	2023	2024
Pressure Test Assessment			
2022 - 0 pipeline segments @ 200 K/segment			
2023 - 1 pipeline segments @ 200 K/segment		200	
2024 - 1 pipeline segments @ 200 K/segment			200
Material Verification			
2022 - 8 Opportunistic Samples @ 4 K/sample, 2 Opportunistic Samples @ 20K	72		
2023 - 8 Opportunistic Samples @ 4 K/sample, 2 Opportunistic Samples @ 20K		72	
2024 - 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 $70/hr))	728	728	728
Contractors (3 x 312 days x 3 x $580/day)	543	543	543
Additional Leak Survey			
Leak Survey Tech (3 employees (2,080 hrs x 3 x $50/hr))	312	312	312
Additional Cathodic Protection Survey			
Corrosion Tech (2 employees (2,080 hrs x 3 x $62/hr)	258	258	258
Administration			
Project Coordination (5 employees (2080 hrs x 5 x $60/hr))	676	676	676
Data Integration Specialists (2 employees (2080 hrs x 2 x $60/hr))	250	250	250
Construstion Records Tech (2080 hrs x $45/hr)	94	94	94
Supervisor (2080 hrs x $65/hr)	146	146	146
Engineer (3 employees (2080 hrs x $60/hr))	374	374	374
Engineer Tech (2080 hrs x $ 45/hr)	94	94	94
Damage Prevention Tech (3 employees (2080 hrs x $45/hr))	281	281	281
Training (IM personnel)	35	35	35
Transmission Integrity Management Total ($ Thousands)	6,639	7,266	7,478

Distribution Integrity Management Costs

Activity	2022	2023	2024
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)	1,323	1,323	1,323
Meter Paints	281	281	
Direct Assessments			
ILI			
2022 (FL006, FL024)	500		
2022 ILI digs (FL006, FL024) (3 excavations @ 34.5K ea		103.5	
Administration			
Consultant - 3rd Party Plan Review		50	
Distribution Integrity Management Total ($ Thousands)	2,189	1,843	1,408

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 GHG emissions across its electric and natural gas operations nationwide where Dominion Energy and its subsidiaries do business. In February 2022, Dominion Energy expanded this commitment to cover direct emissions from operation sources and indirect emissions from upstream and downstream sources not owned by Dominion Energy. As discussed in the Sustainability section of this report, DEUWI is taking immediate action to reduce emissions and exploring new technologies to accelerate future emissions reductions.

In 2010, the EPA adopted Greenhouse Gas Reporting Regulations requiring the measurement and reporting of carbon dioxide equivalent (CO2e) emissions emitted from combustion at large facilities (emitting more than 25 thousand metric tons/year of CO2e). Although the Company does not have any single facilities that exceed that threshold, local distribution companies are required to account for the GHG emissions of their customers (residential, commercial, and industrial customers using less than 460 MMcf per year of natural gas) annually.

In 2011, the EPA expanded reporting under this regulation to include measurement and reporting of GHG emissions attributed to fugitive methane emissions, requiring on-going measurement and monitoring of methane emissions at the Company's regulator and gate-stations. In2021, the Company reported a total of 7.29 million metric tons of CO_2e emissions in Utah and 260 thousand metric tons of CO_2e emissions in Wyoming. The Company also reported approximately 3,800 metric tons attributed to fugitive methane sources in Utah and approximately 120 metric tons of fugitive methane emissions in Wyoming. Figure 7.1 shows the Company's CO_2 emission rate per million BTU (greenhouse gas intensity) over the last seven years.

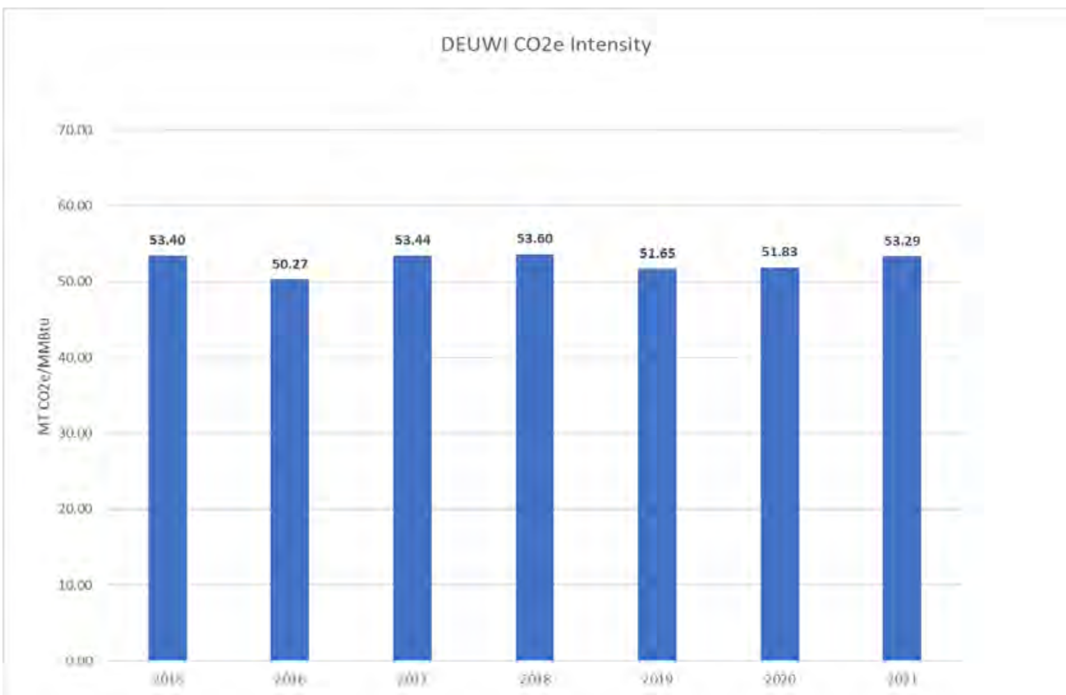

Figure 7.1: Greenhouse Gas Intensity

In March 2016, the Company became a Founding Partner with the EPA in the Methane Challenge Program, committing to voluntary practices that will reduce methane emissions. Additionally, the Company joined the One Future Coalition in 2018, which commits the Company to limit methane emissions to below 1% of gas throughput across the Company.

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

Reduction in methane emissions will continue to have a positive environmental impact. For example, the Company estimates annual savings of nearly 950,000 Dth of natural gas in 2021 through the ThermWise program. The savings represents the equivalent of over 50 thousand metric tons of CO2e or nearly 11 thousand passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime savings attributable to the ThermWise® program totals nearly 545 thousand metric tons of CO2e or the equivalent of more than 117 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 meet the energy needs of our customers in an environmentally responsible manner.

PURCHASED GAS

LOCAL MARKET ENVIRONMENT

Local prices during the 2021 calendar year averaged $3.90 per Dth. This was higher than the 2020 average price of $2.07 per Dth, an increase of $1.83 per Dth or about 88.4%. The 2020 and 2021 monthly index prices are provided in Table 8.1 below.

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

Month	2020	2021	Difference
Jan	$3.16	$3.23	$0.07
Feb	$1.95	$2.75	$0.80
Mar	$1.54	$3.04	$1.50
Apr	$1.29	$2.41	$1.12
May	$1.59	$2.80	$1.21
Jun	$1.54	$2.91	$1.37
Jul	$1.53	$3.79	$2.26
Aug	$1.69	$4.04	$2.35
Sep	$2.39	$4.09	$1.70
Oct	$2.23	$5.60	$3.37
Nov	$3.03	$6.34	$3.31
Dec	$2.94	$5.78	$2.84
Average	$2.07	$3.90	$1.83

The local market price for natural gas during the 2021-2022 heating season (November-March) averaged $5.88 per Dth compared to an average price of $3.00 per Dth during the 2020-2021 heating season, an increase of $2.88 or about 96%. 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	2020-2021	2021-2022	Difference
Nov	$3.03	$6.34	$3.31
Dec	$2.94	$5.78	$2.84
Jan	$3.23	$7.87	$4.64
Feb	$2.75	$5.04	$2.29
Mar	$3.04	$4.38	$1.34
Average	$3.00	$5.88	$2.88

April 2022 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 $5.81 per Dth through October 2022. Prices for the 2022-2023 heating season are forecasted to be approximately $6.20 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 17, 2022, the Company sent its RFP to 59 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, 2022. The Company received proposals for 153 gas supply packages from 14 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 629,500 Dth/D, up from the 596,000 Dth/D offered last year. Peaking supplies offered on the MWP system totaled 105,000 Dth/D, down from the 137,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 250,000 Dth/D, up from last year's level of 175,000 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.[34] The Company must identify the pricing mechanisms utilized for each package and

[34] 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 153 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 857 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 14 companies submitting proposals this year, 10 had at least one package selected by the modeling process. The Company made commitments to purchase from the selected suppliers starting on April 21, 2022.

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 2020-2021 heating season, the Company did not financially hedge the price of any of its baseload purchased gas supplies. 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 baseload contracts with FOM pricing.

In 2021, the Company analyzed its exposure to daily price risk based on its existing price stabilization techniques. The results of this evaluation showed that based on 2020-2021 contracts, on a typical winter day, the Company has about 44% of supply purchases exposed to daily price risk. On a Design Day, that exposure increases to 69%.

This situation was highlighted during the high-pricing event that occurred in February 2021. Fortunately, the Company was able to utilize cost-of-service production and high storage withdrawals to minimize gas purchases which would have been exposed to record-high pricing. Had this event also corresponded with a high demand event in the DEUWI service territory, any additional supply would have been purchased at extremely high cost.

The Company considered options for additional resources including additional storage capacity, additional FOM 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 80,000 Dth/day of fixed price baseload supply for December 2021 through February 2022 to minimize this exposure on high demand days. The total cost of these contracts was $42,048,000. These contracts were the result of a separate RFP process conducted in September of 2021. The RFP process was closely Coordinated with both the Utah Office of Consumer Services and the Utah Division of Public Utilities. These additional contracts reduced the Company's exposure to daily price risk to 80% of supply on a typical winter day and 49% 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. Fortunately, the 2021-2022 heating season market did not experience a day like the February 2021 event. These fixed-price contracts' pricing was $35,126,000 higher than the price of gas during the season, based on the actual daily indexed pricing of the spot market during this period.

The Company will continue to review the same alternatives for additional price stabilization options for the 2022-2023 heating season and beyond. For the 2022-2023 heating season the Company is planning to contract for additional fixed-price baseload supply contracts through a separate RFP.

2022 Cluster Analysis
Average Design Day Demand v. Average Annual Demand

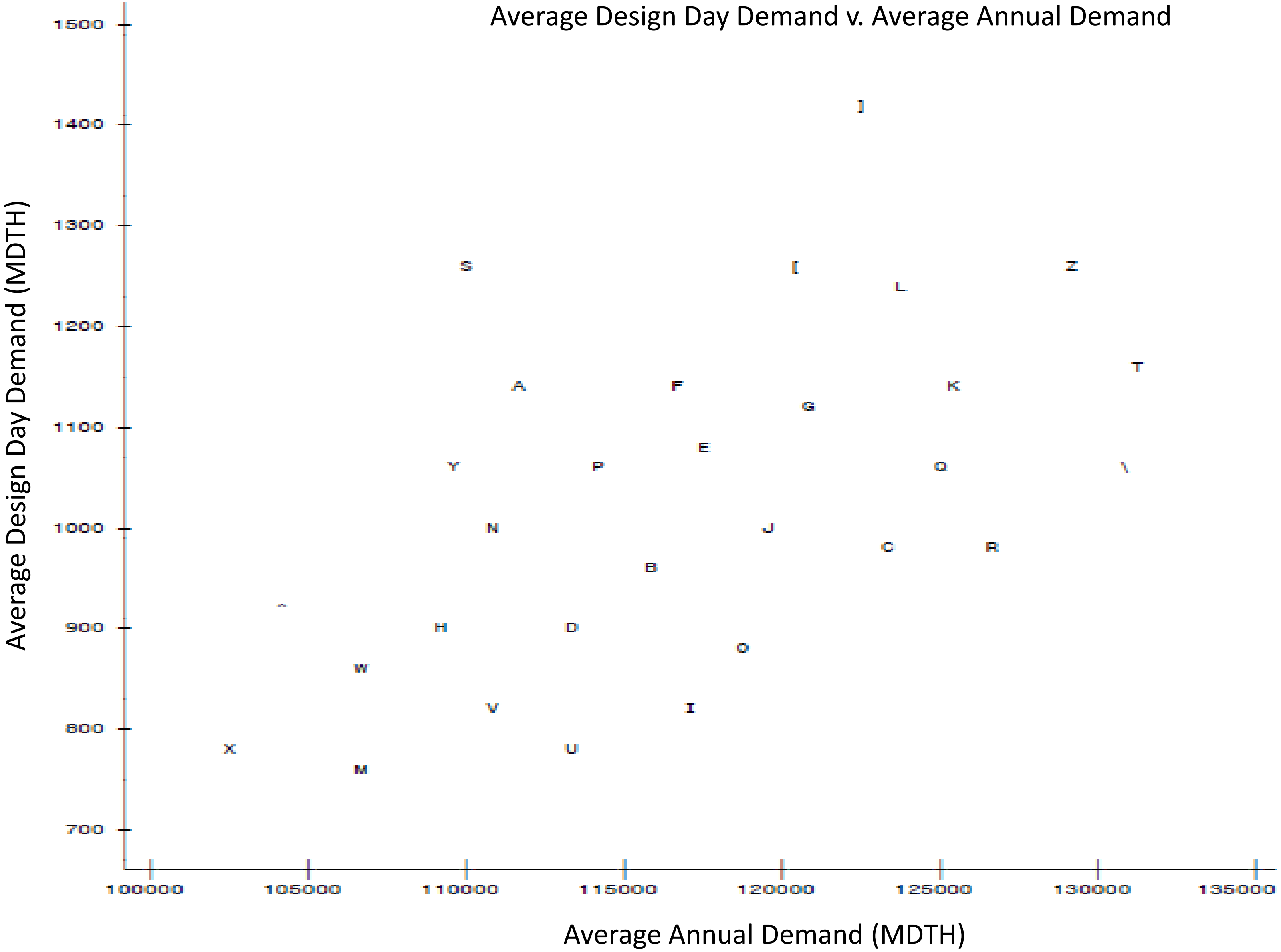

Exhibit 8.1

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 must manage cost-of-service production to less than 55% of the forecasted demand for the Company's sales customers each IRP year, beginning with the 2020-2021 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 55% 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 7.19% 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 Dominion Energy'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 Dominion Energy'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.

Dominion Energy 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 2021, Wexpro produced 59.2 MMDth of cost-of-service supplies measured at the wellhead, down from the 65.0 MMDth level produced during calendar year 2020. 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 2020 to 2021, the total costs, net of credits and overriding royalties, for cost-of-service production declined by approximately 6.0% (the seventh consecutive year of declining net costs). This decrease was caused by an 8% reduction in the Wexpro operating service fee. This was partially offset by higher oil and gas prices increasing royalties. 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 138 categories of cost-of-service production. Last year, it modeled 120 categories. Both years, the Company used a modeling time horizon of 31 years. 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, concerning the Company's 2013 IRP, required the Company to provide a scenario analysis in future IRPs.[35] 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. 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

[35] 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.

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 1,683 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 2021 and for the first two months of 2022. The Company has been taking recoupment in the Canyon Creek, Pinedale and Moxa Arch areas for most of the January 2020 through February 2021 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, Dry Piney, and Pinedale areas throughout the period.

As of December 31, 2021, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of 523.5 MMcf.[36] By way of comparison, the total net producer imbalance level for December 31, 2020, was a negative 56.5 MMCF. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In the most recent audit report, the Hydrocarbon Monitor did not express any concerns about the total producer imbalance levels.[37]

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.

[36] A positive imbalance means volumes are owed to other parties.
[37] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, May 2022.

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 2022, Wexpro plans on completing to production, approximately 19 net wells with a capital budget for those wells of approximately $36 million.[38] Assuming market prices don't deviate dramatically from current expectations for the years 2023 through 2027, the total planned net wells are approximately 24, 31, 32, 32, 24 respectively, with total annual investments in the range of $36 to $60 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2022 will focus on the Trail, Canyon Creek and Whiskey Canyon.

Wexpro II drilling plans for 2022 through 2027, broken out from the totals stated above, are approximately 16, 16, 14, 15, and 23 net wells respectively to be drilled with total annual capital costs ranging from approximately $25 million to $38 million.

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 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 2021 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 707 MDth of cost-of-service production shut-

[38] "Net wells" are the summation of working interests (total and partial ownership).

in for June 2021 through October 2021. As shown in Table 9.1, the Company shut in significantly less than forecasted 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: 2021 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	214,743 Dth	220,679 Dth	58,243 Dth	138,608 Dth	74,717 Dth	**706,991 Dth**
Actual Shut-in Production	174,679 Dth	135,204 Dth	57,334 Dth	0 Dth	0 Dth	**367,217, Dth**

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.

Table 9.2: 2022 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	50,955 Dth (1,699 Dth/day)	52,386 Dth (1,689 Dth/day)	52,120 Dth (1,681 Dth/day)	50,184 Dth (1,673 Dth/day)	51,596 Dth (1,664 Dth/day)	**257,242 Dth (1,681 Dth/day)**

Exhibit 9.1

Recoupment Nominations (Dth per month by Field) Dominion Energy				
	Moxa	Canyon Creek	Pinedale	Dry Piney
Jan-21	3,565	12,741	1,440	0
Feb-21	3,136	10,752	1,376	0
Mar-21	3,813	0	593	0
Apr-21	3,540	11,880	593	0
May-21	3,503	12,555	585	0
Jun-21	3,150	11,760	587	0
Jul-21	3,348	11,408	588	0
Aug-21	3,317	10,633	588	2,232
Sep-21	3,150	10,950	588	2,190
Oct-21	1,829	0	0	2,201
Nov-21	1,740	0	0	2,070
Dec-21	1,767	0	0	2,232
Jan-22	1,674	0	0	2,232
Feb-22	1,484	0	0	1,316
Total	39,016	92,679	6,938	14,473

Recoupment Nominations (Dth per month by Field) Other Parties				
	Hiawatha Deep	Pinedale	Church Buttes	Dry Piney
Jan-21	372	5,741	1,302	0
Feb-21	336	5,680	1,316	0
Mar-21	372	5,625	992	0
Apr-21	300	5,539	990	0
May-21	217	5,718	1,798	0
Jun-21	150	5,679	1,200	0
Jul-21	155	5,679	1,643	0
Aug-21	155	5,511	1,395	5,704
Sep-21	150	5,511	1,350	5,730
Oct-21	434	0	1,395	5,797
Nov-21	420	0	1,350	5,760
Dec-21	434	0	38,998	5,797
Jan-22	403	0	34,689	5,673
Feb-22	364	0	31,276	5,264
Total	4,262	50,683	119,694	39,725

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 Occidental Petroleum (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.

In 2020, Wexpro assumed operations for a portion of the gathering and processing services. The cost for these services is included in the operator service fee. In November 2021, Wexpro also purchased the gathering system in the Trail area. Wexpro has successfully transitioned operations and administration to Wexpro personnel. This transition will provide better operational control while also providing significant savings.

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, KRGT, Northwest Pipeline, and Colorado Interstate Gas (CIG).

On July 5, 2020 Dominion Energy announced an agreement to sell substantially all of its Gas Transmission and Storage assets to Berkshire Hathaway Energy (BHE)[39]. The sale of all of the assets, other than the assets in the west including MWP and MWOP, closed on November 2, 2020.[40]

On July 12, 2021 Dominion Energy and Berkshire Hathaway Energy announced that effective July 9, 2021 the sale of the Questar Pipelines to Berkshire Hathaway Energy had been terminated due to "ongoing uncertainty associated with achieving clearance from the Federal Trade Commission."[41] Subsequently, on October 5, 2021, Dominion Energy announced an agreement to sell Questar Pipelines to Southwest Gas Holdings, Inc.[42] On December 31, 2021, Dominion Energy announced the closing of the sale of Questar Pipelines to Southwest Gas Holdings, Inc.[43] In April 2022 Questar Pipelines were rebranded to MountainWest Pipeline. [44]

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 the contract for the additional capacity associated with the Hyrum gate station expansion. This contract

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39 Dominion Energy, (July 5, 2020), *Dominion Energy Agrees to Sell Gas Transmission, Storage Assets to Berkshire Hathaway Energy-- Strategic Repositioning Toward 'Pure-Play' State-Regulated, Sustainability-Focused Utility Operations* [Press Release]. https://news.dominionenergy.com/2020-07-05-Dominion-Energy-Agrees-to-Sell-Gas-Transmission-Storage-Assets-to-Berkshire-Hathaway-Energy-Strategic-Repositioning-Toward-Pure-Play-State-Regulated-Sustainability-Focused-Utility-Operations

40 Dominion Energy, (November 2, 2020), *Dominion Energy Closes on Sale of Majority of Gas Transmission & Storage Assets* [Press Release]. https://news.dominionenergy.com/2020-11-02-Dominion-Energy-Closes-on-Sale-of-Majority-of-Gas-Transmission-Storage-Assets

41 Dominion Energy (July 12, 2021), Dominion Energy and Berkshire Hathaway Energy Agree to Terminate Sale of Questar Pipelines; Dominion Energy Commencing Competitive Sale Process. [Press Release]. https://news.dominionenergy.com/2021-07-12-Dominion-Energy-and-Berkshire-Hathaway-Energy-Agree-to-Terminate-Sale-of-Questar-Pipelines-Dominion-Energy-Commencing-Competitive-Sale-Process

42 Dominion Energy (October 5, 2021), *Dominion Energy Announces Agreement to Sell Questar Pipelines to Southwest Gas* [Press Release]. https://news.dominionenergy.com/2021-10-05-Dominion-Energy-Announces-Agreement-to-Sell-Questar-Pipelines-to-Southwest-Gas

43 Dominion Energy (December 31, 2021), Dominion Energy Announces Closing of Sale of Questar Pipelines to Southwest Gas [Press Release]. https://news.dominionenergy.com/2021-12-31-Dominion-Energy-Announces-Closing-of-Sale-of-Questar-Pipelines-to-Southwest-Gas

44 Southwest Gas Holdings (April 1, 2022) Southwest Gas Holdings Completes Rebranding of Subsidiary MountainWest Pipelines [Press Release], https://investors.swgasholdings.com/news-releases/news-release-details/southwest-gas-holdings-*completes*-rebranding-subsidiary

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.

The #2945 contract is very beneficial because it provides seasonal capacity with valuable receipt points. However, on November 1, 2021, its initial term expired, and it went into a year-to-year evergreen renewal term. The Company sought to extend this contract because MWP uses leased capacity on the Overthrust pipeline to manage this contract and that capacity is in high demand. The Company successfully extended this contract effective April 1, 2022. The new contract term will extend to March 31, 2027. The remaining contract terms remain unchanged.

The #2361 contract is currently in year-to-year evergreen with a current expiration of November 10, 2022. This contract is necessary because it 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 MWP 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. The Company is working to extend the term of this contract for an additional five years.

No-Notice Transportation Service

The Company has a contract with MWP for No-Notice Transportation (NNT) service for 203,542 Dth/day. This contract is in an annual evergreen. 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. MWP updated its NNT rate schedule in its Tariff effective November 1, 2019. This update intended to clarify the NNT service. NNT service utilizes the contracted reserved daily capacity (RDC) of the underlying firm transportation service (T-1) and offers additional flexibility in intraday variation of the supply and demand of that transportation. Specifically, NNT service allows the Company's level of supply to adjust in real time, subject to certain constraints as described herein, to accommodate the increases or decreases in demand throughout the Gas Day.

NNT provides for the reservation of firm transportation capacity in excess of 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. Adjustments above the RDC associated with the firm contract MWP Firm Peaking Service is required to assure firm deliveries.

NNT allows MWP to utilize Shipper's available Storage injection or withdrawal service, together with Shipper'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 in 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 349 days during the 2021-2022 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 196 days during the 2021-2022 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 153 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 108,367 Dth with an average daily supply reduction to the city gate of 29,116 Dth. The maximum daily supply increase to the city gates was 190,842 Dth with an average daily increase to the city gate of 35,025 Dth. The NNT usage for the 2021-2022 IRP year is shown in Figure 10.1 below.

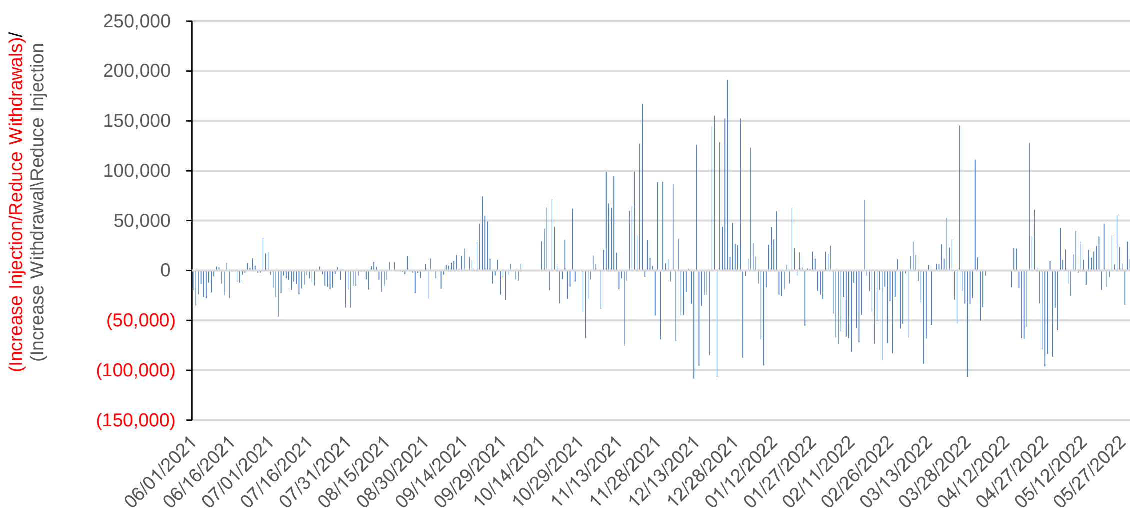


Figure 10.1: NNT Usage – 2021-2022 IRP Year

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.

Based on the value of the service described above, the Company extended this contract for an additional 5 years in May 2022.

MountainWest Overthrust Pipeline

The Company has a firm transportation contract with MountainWest Overthrust Pipeline (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 under 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 is the new contract number for the extension of Contract #1829. This contract 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, 2027. 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 April 28, 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.

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.

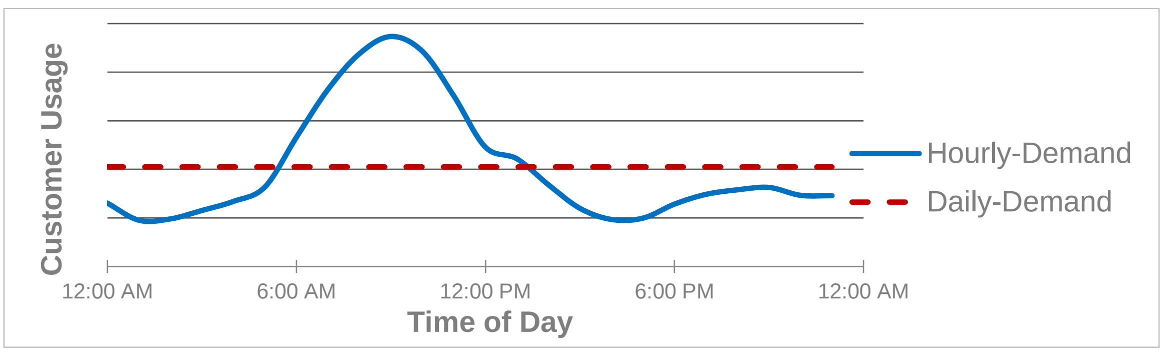


Figure 10.2: Hourly vs. Daily Demand

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 309,240 Dth/day during the 2022-2023 heating season to 345,226 Dth/day during the 2031-2032 heating season.

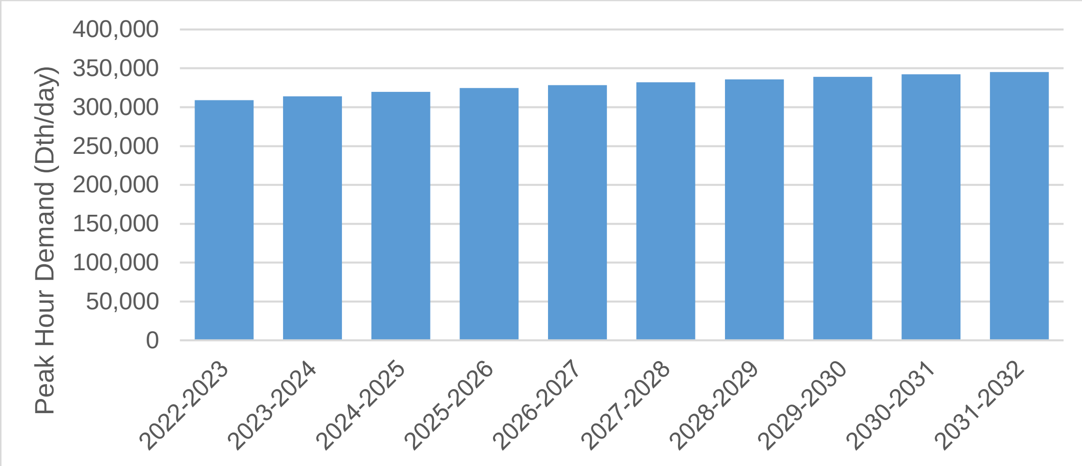


Figure 10.3: Peak-Hour Demand Requirements Above Firm Capacity

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 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, 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 the Clay Basin storage facility. The Company commenced service on its negotiated Firm Storage Service (FSS) agreement with what is now Spire Storage West on April 1, 2017.

MWP owns the Aquifers and the Company utilizes them primarily for short-term peaking needs. The Company fully subscribes the Aquifer facilities. The Company reviewed these storage resources as part of its planning process and extended these contracts through August 2023.

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	2,500

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 extended the term for five years.

2021-2022 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, 2021, and April 30, 2022, the Company utilized the Clay Basin storage facility to provide more than 10,293 MDth of supply to meet customer demand. This included 59 days with withdrawals that exceeded 100 MDth and 12 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 50 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.

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

2021-2022 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 MountainWest Pipeline to determine real-time injection and withdrawal capabilities. All of the Aquifer's deliverability will be required to provide about 135 MDth of supply on a Design Day. 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.

During the 2021-2022 heating season, the Company used Aquifer withdrawals for withdrawal testing associated with a possible expansion project and during periods in January and February with high demand and pricing.

Also, in order to continue to provide operational flexibility during the Clay Basin testing periods in October 2021 and April 2022, 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 January, the February events, and the utilization for both injection and withdrawal during the Clay Basin test are shown in

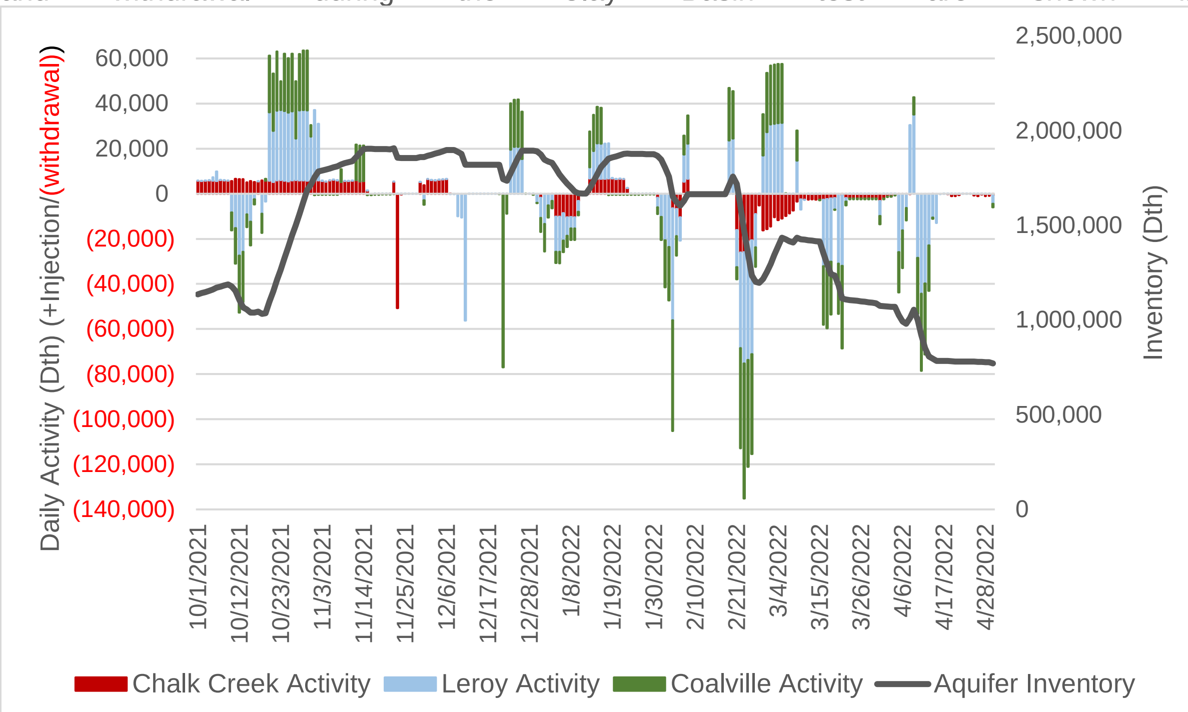


Figure 10.4 below. This flexibility is critical to operations when Clay Basin is not available.

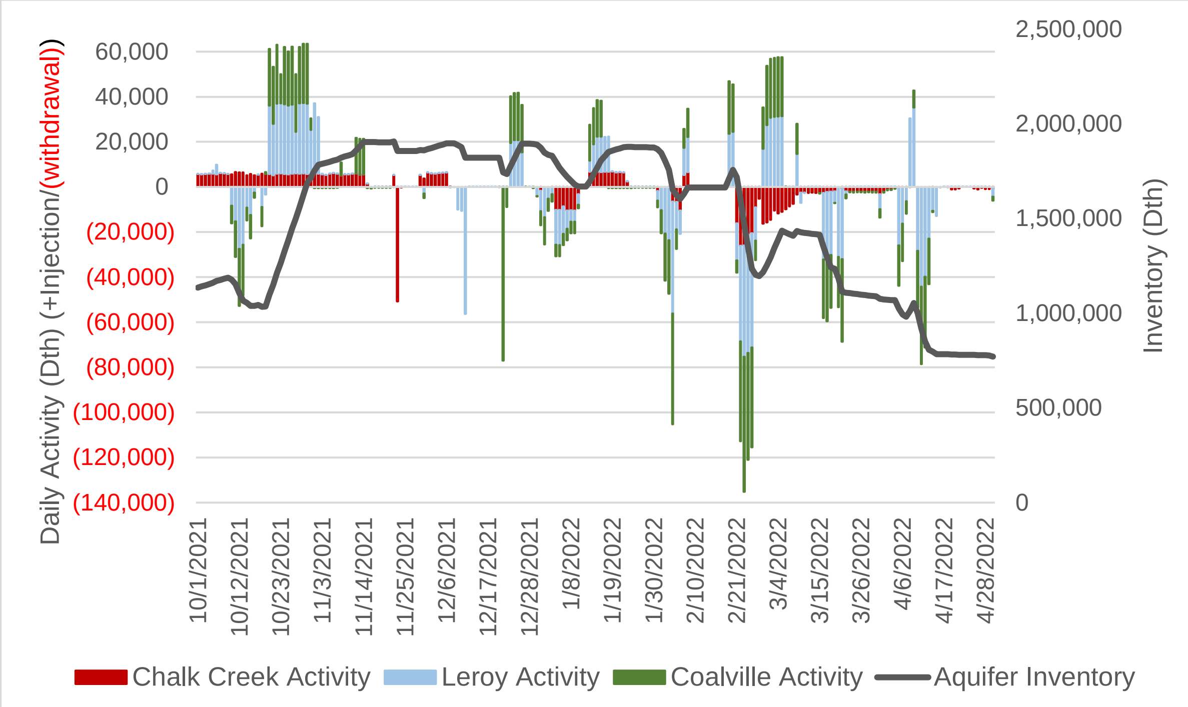


Figure 10.4: Aquifer Usage 2021-20221 Heating Season (Oct 2021 through April 2022)

Magna LNG Storage

The Magna LNG facility is expected to be available for injection in the fall of 2022. The Company intends to liquefy gas (inject) to fill the storage as soon as possible in order to have the facility available for supply reliability purposes through the heating season.

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 Spire Storage West LLC (Spire) storage facility, the Magnum Gas Storage LLC (Magnum) storage facility, a potential deliverability expansion project at the existing Aquifers, and a possible expansion of the LNG facility now in construction. The Company will consider both the cost of these options, and their operational advantages.

Spire Storage West

The 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 the Ruby Pipeline.

The Company held a firm storage contract with Spire for 2.5 MMDth of inventory capacity and 16,600 Dth/day of withdrawal capacity until March 31, 2021. After evaluating the cost and operational utility of this contract, the Company opted not to renew the contract going forward. This analysis was conducted, and notice was given prior to the high pricing event that occurred in February 2021 and prior to the increased volatility that is now being experienced in the natural gas markets.

There is currently no additional firm capacity available at this facility. In the fall of 2020, Spire submitted for approval from the FERC to expand the Clear Creek facility. The proposed expansion would increase injection/withdrawal capability by tenfold. In March 2022, the FERC issued an Environmental Impact Statement for the project. The statement concludes that with the mitigation methods proposed there would be no significant impacts and the greenhouse gas emissions would fall below the threshold for significant climate change impacts. This is a significant step toward the awarding of certificates for construction and operation of the expansion project. The project could move forward as early as July 2022.

If options for capacity become available, the Company will review these options and contract if analysis shows the decision to be prudent.

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 is currently working with Magnum to complete an analysis of costs on this project. This evaluation should be completed in summer 2022.

MWP Aquifer Expansion

In the fall of 2021, MWP conducted deliverability testing. As a result of this testing, MWP has approached Dominion Energy with an option that would provide additional deliverability at the existing Aquifers. This deliverability would not increase the working gas capacity in the reservoirs. The Company will continue to evaluate this along with other available storage options.

LNG Storage Expansion

The Company's Magna LNG facility is currently under construction. 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, 2022, would be approximately 810,000 MDth.

RELATED ISSUES

Gas Quality/Interchangeability

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

The most prevalent measure of fuel gas interchangeability in the U.S. is the Wobbe Index.[45] 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 2020. The daily averages for 2021 for other Utah regions can be seen in Exhibits 10.3 and 10.4. Exhibit 10.5 shows the most recent quarterly data reported to the Public Service Commission of Wyoming in accordance with Chapter 3, Section 30 of the Public Service Commission Rules. The green dots indicate volume-weighted Wobbe values for each distribution area within ± 4% of the Wobbe set point. Should Wobbe values become a concern in the future at any point delivering gas to the Company, there are a number of tools that the Company can use to manage gas interchangeability including injecting inert gases (or air) in the gas stream, injecting propane or hydrogen, and blending supplies from various sources.

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

[45] 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 2022

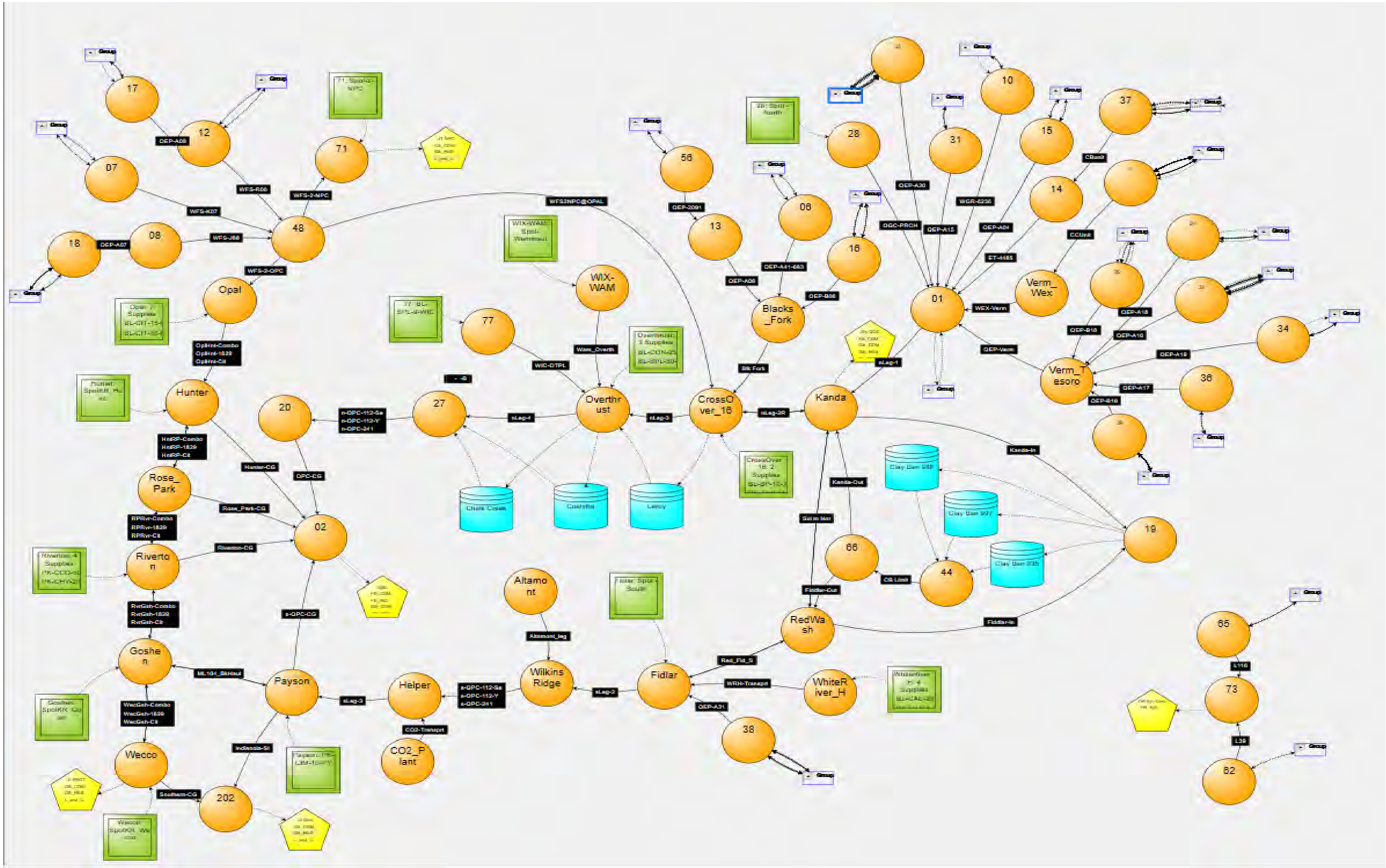


Exhibit 10.1

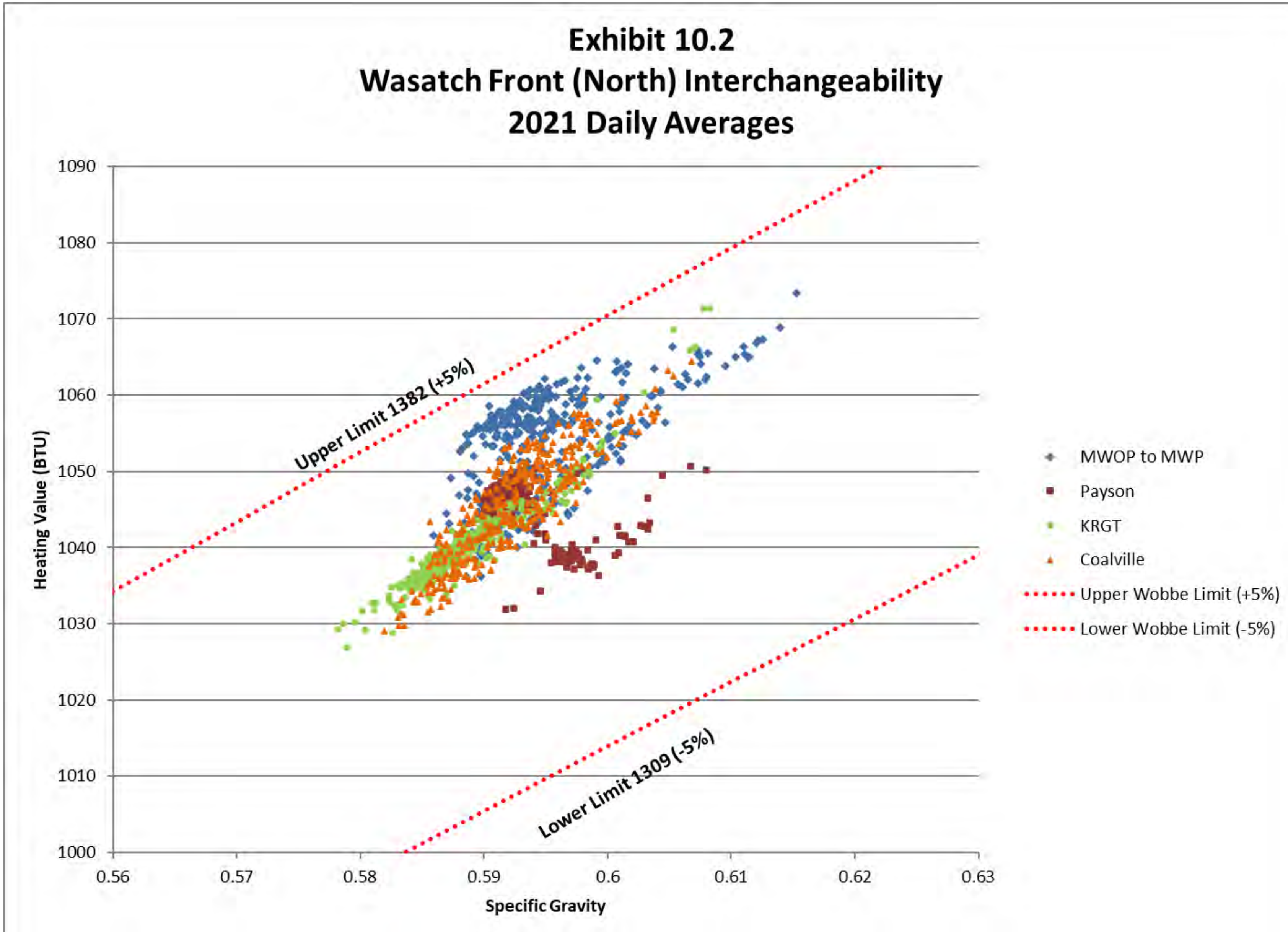


Exhibit 10.2
Wasatch Front (North) Interchangeability
2021 Daily Averages
Heating Value (BTU)
1090
1080
1070
1060
1050
1040
1030
1020
1010
1000
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
Specific Gravity
Upper Limit 1382 (+5%)
Lower Limit 1309 (-5%)
MWOP to MWP
Payson
KRGT
Coalville
Upper Wobbe Limit (+5%)
Lower Wobbe Limit (-5%)

Exhibit 10.2

Vernal Area (Eastern) Interchangeability
2021 Daily Averages

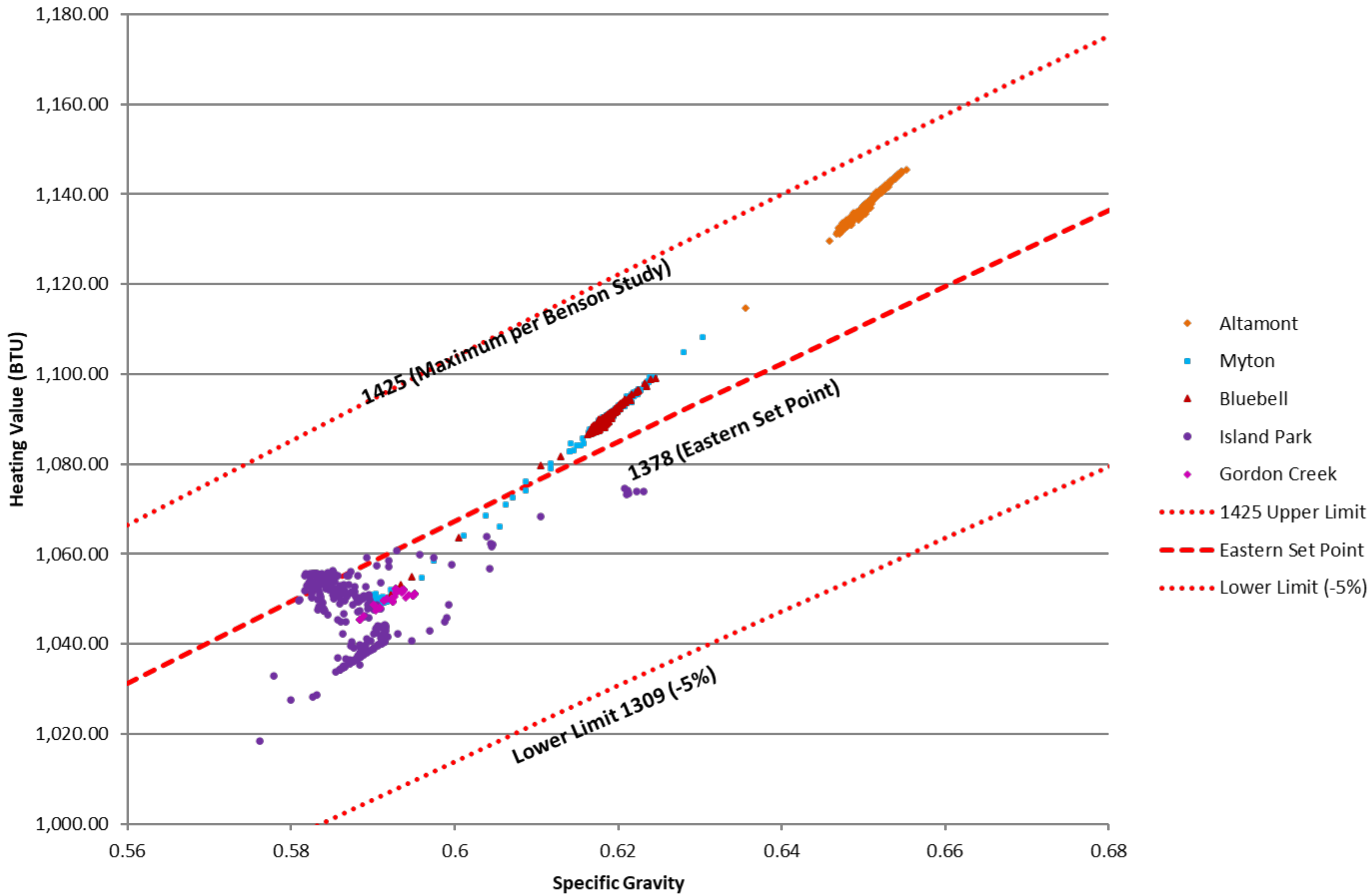
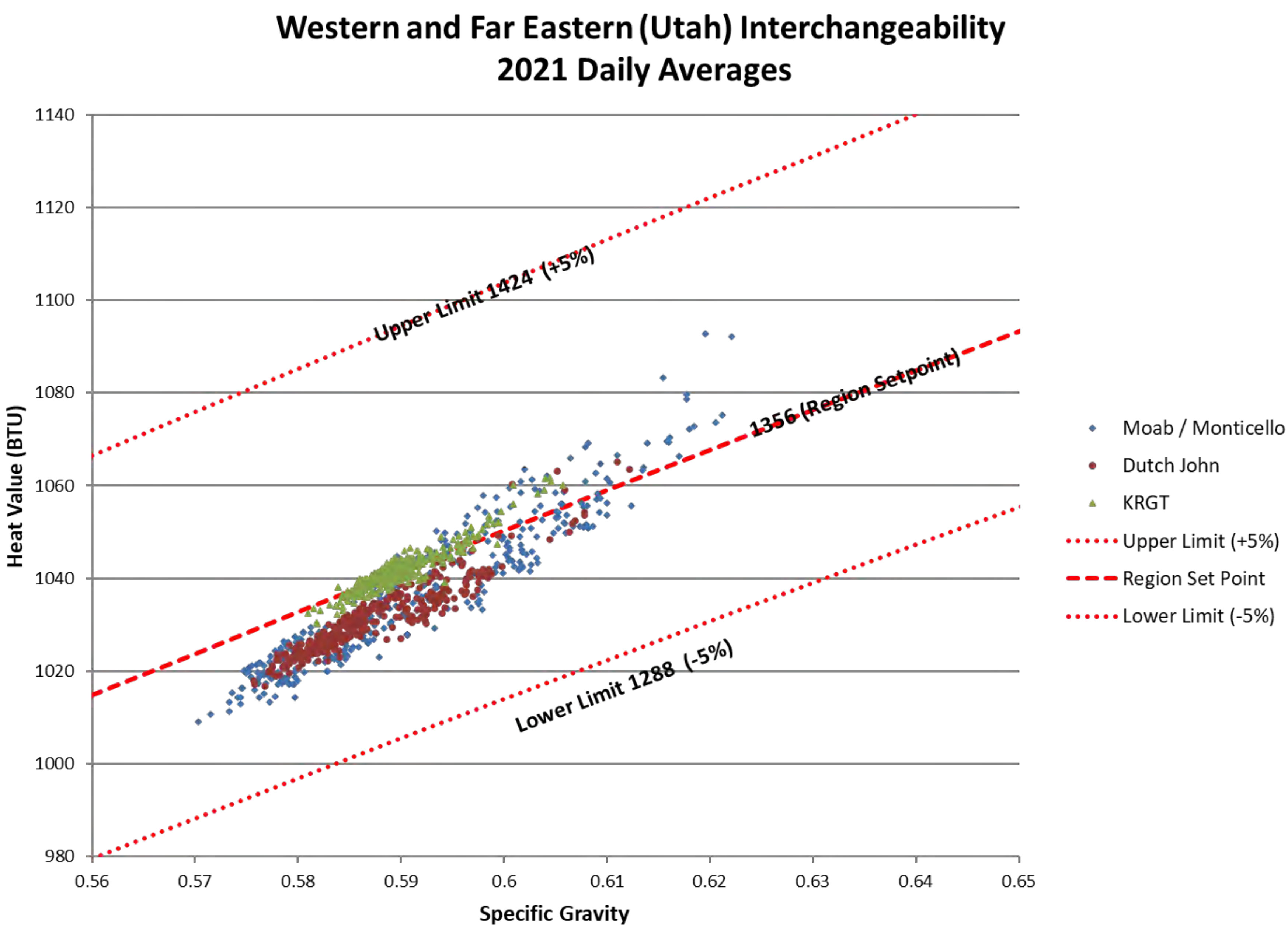


Exhibit 10.3



Western and Far Eastern (Utah) Interchangeability
2021 Daily Averages
Heat Value (BTU)
Specific Gravity
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
Upper Limit 1424 (+5%)
1356 (Region Setpoint)
Lower Limit 1288 (-5%)
Moab / Monticello
Dutch John
KRGT
Upper Limit (+5%)
Region Set Point
Lower Limit (-5%)

Exhibit 10.4

DEW Pipeline System BTU Report MAP
Quarter 1 2022

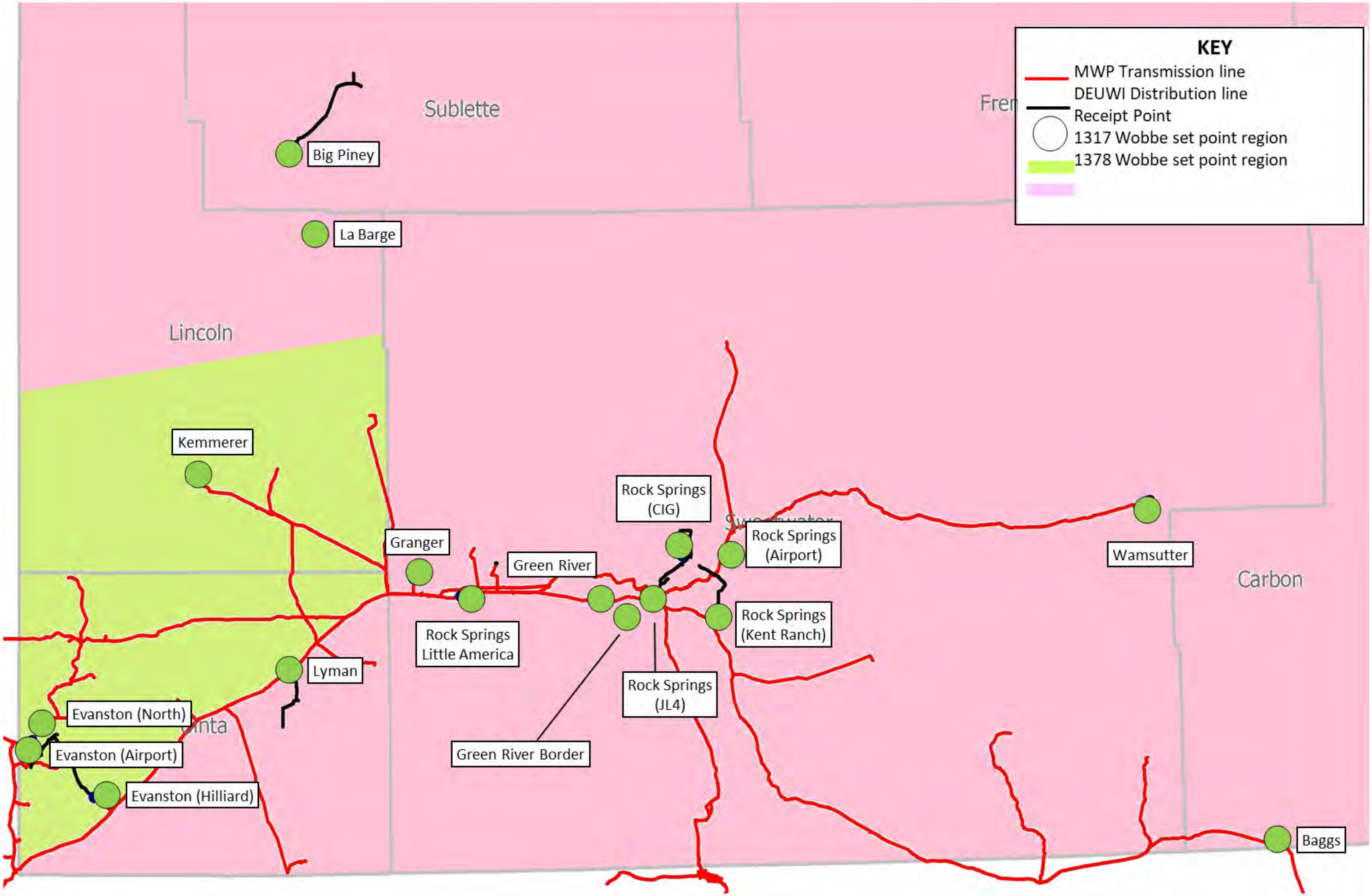


Exhibit 10.5

SUPPLY RELIABILITY

Beginning in 2017, Dominion Energy Utah 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. Dominion Energy Utah sought to ensure that its customers do not experience similar outages. After conducting extended review of possible solutions to the supply reliability concerns, Dominion Energy Utah 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.

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.

In July of 2020, the Company commenced construction of the LNG facility. Since that time the Company has made substantial progress on construction. The LNG tank’s outer wall is complete, and the roof was raised into place in May 2021. The LNG tank’s inner cryogenic wall and hydrotest was completed in March 2022.

Aside from the LNG tank, construction progress has progressed on the balance of plant as well. The site has been grubbed, brought to rough grade and perimeter fences and gates installed. Construction of ground improvements (aggregate columns and helical piles required to support equipment and buildings) were completed be in August 2021. Construction of concrete foundations and equipment placement began were completed in December 2021. The main pipe rack erection was completed in August 2021. All buildings were erected and complete by March 2022. Since breaking ground in July of 2020, significant progress has been made on the project. The Company and its contractors have had strong safety performance throughout the construction process.

The facility is near completion, and commissioning activities are under way. The Company expects to begin filling the LNG tanks at the facility in the fall of 2022, and that it will be available for use middle of in the 2022-2023 heating season. Engineering and procurement are complete, and construction is progressing toward mechanical completion in Q3 of 2022. Commissioning will take place during Q3 and Q4 of 2022, with a goal of having 9,000,000 gallons of LNG in the tank by the end of the year.

Significant milestones over the last year include ground improvements completion in 2021, the LNG tank hydrotest in April 2022, pipe racks and structural steel complete, all major foundations and concrete work complete, all major equipment delivered and installed, all pre-engineered metal buildings erected, transformers and switchgear energized, cable tray and process piping nearing completion, and wiring and instrumentation currently underway.

The facility is scheduled to be in service in October 2022 in time for the 2022-2023 heating season. The facility is expected to reach full inventory by the middle of the heating season. Once completed this facility will be used to ensure supply reliability on the DEUWI system. The facility will normally be kept full during the heating season in order 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 risk associated with the dramatic price volatility like that seen in February 2021. The options for increased cost-of-service production, increased storage capacity, and additional baseload contracts would all provide this additional supply-reliability benefit. Additional on-system storage facilities such as small satellite LNG facilities that could be located in remote or centralized areas of the system could also provide additional supply reliability. All of these options would increase the amount of supply that is already contracted for by the Company during the period of time most likely to experience extreme cold weather events. In the event of limited supply availability in the market, having gas contracted or available from storage would reduce the availability risk of supply purchases.

SUSTAINABILITY

DOMINION ENERGY'S COMPANY-WIDE SUSTAINABILITY COMMITMENTS

Across every part of the company, Dominion Energy is transforming the way we do business to build a more sustainable future for the planet, our customers, our employees, and our industry. This includes a commitment to achieve net zero emissions by 2050. The Company provides details of this commitment in its 2021 Climate Report.[46]

This goal covers carbon dioxide and methane emissions, the dominant greenhouse gases from electricity generation and gas infrastructure operations. This strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions consistent with the findings of the United Nations' Intergovernmental Panel on Climate Change. It is also a recognition of the increased expectations and interest among customers, as well as employees, in building a clean energy future.

In February 2022, Dominion Energy expanded our net zero commitment to include not only our direct emissions from operations, known as Scope 1 emissions, but also Scope 2 emissions, and the following material categories of Scope 3 emissions: natural gas customer use, upstream fuel production and delivery, and electric power market purchases by suppliers.

Reducing emissions as fast as possible, and achieving net zero emissions, requires immediate and direct action. That is why Dominion Energy is moving to extend licenses for its zero-carbon nuclear generation fleet, promoting customer energy efficiency programs, and investing in wind and solar power, lower-carbon natural gas, and carbon-beneficial renewable natural gas. Over the long-term, achieving this goal will also require supportive legislative and regulatory policies, technological advancements, and broader investments across the economy. This includes support for the testing and deployment of such technologies as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture, all of which have the potential to significantly reduce greenhouse gas emissions.

As part of these goals, Dominion Energy has committed to reduce Scope 1 methane emissions from its natural gas businesses by 65 percent by 2030 and 80% by 2040[47]. 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." DEUWI is committed to promoting renewable natural gas and blending increasing quantities of it into our 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.

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[46] Dominion Energy 2021 Climate Report, 2021, https://www.dominionenergy.com/-/media/pdfs/global/company/esg/2021-climate-report.pdf

[47] Methane emission reductions are in reference to 2010 baseline levels.

Categorizing Emissions

Emissions are categorized as direct (Scope 1) or indirect (Scope 2 and 3). These scope categories are explained in Figure 12.1. The breakdown of emissions across the Dominion Energy value chain are shown in Figure 12.2. 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.[48]

Emissions by Scope | **Emissions Source**

Scope 1: Direct emissions from operations in sources owned or controlled by Dominion Energy.

- Electric generation: on-site combustion at power plants.
- Transmission and distribution: fugitive emissions from the use of sulfur hexafluoride and line losses.
- Natural gas operations: on-site combustion and fugitive methane emissions from compressor stations, delivery of natural gas, and production.
- Company-owned aircraft and vehicle fleet: combustion of fuels.
- Buildings: on-site combustion of fuels for building heat.

Scope 2: Indirect emissions from purchased electricity (third-party generation) for use in Dominion Energy facilities.

Buildings: electricity used in facilities outside of Dominion Energy's service territory.

Scope 3: Indirect emissions from upstream and downstream emissions sources not owned or controlled by Dominion Energy that result from company operations.

Fuel and energy-related emissions:

- Purchased power for consumer use (market transactions, power purchase agreements), including transmission losses.
- Customer end-use of natural gas (burner-tip) that is owned and sold by Dominion Energy.
- Upstream emissions from natural gas extraction, processing, and transportation (well-head).
- Upstream emissions from extraction, processing, and transportation of fuels used in electricity generation.
- Capital goods (e.g., upstream emissions from manufacturing and transportation of solar panels and wind turbines purchased in a given year).

[2]Additional Scope 3 sources of emissions that occur but are not examined in this analysis include: Capital goods (e.g., upstream emissions from manufacturing and transportation of other capital assets purchased in a given year), Purchased goods and services (supply chain), Employee commuting, Business travel, Waste generated in operations and disposed of off-site, Transmission and distribution losses from wheeled power. We are in the process of gathering the inventory of emissions on these sources which are not material to Scope 3.

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[48] Dominion Energy 2021 Climate Report, 2021, https://www.dominionenergy.com/-/media/pdfs/global/company/esg/2021-climate-report.pdf

Figure 12.1: Emissions Categories

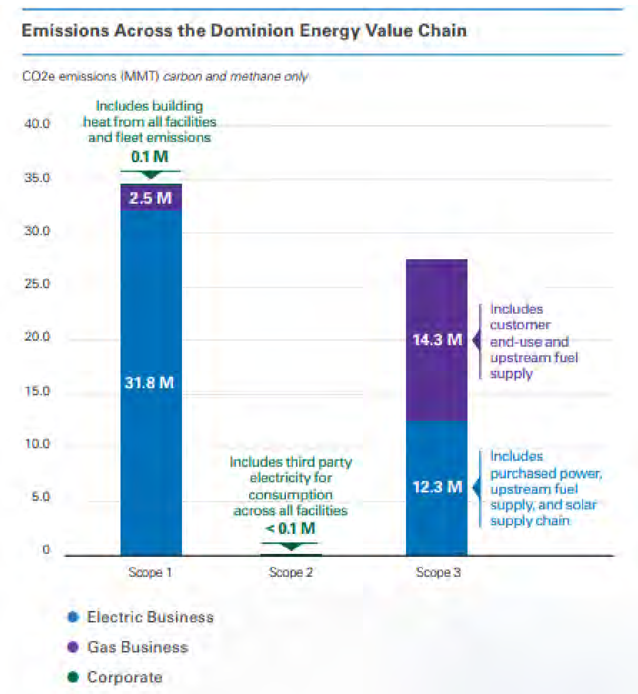


Figure 12.2: Emissions Across Dominion Energy Value Chain

DEUWI SCOPE 1 SUSTAINABILITY INITIATIVES

DEUWI shares these same goals. Its efforts thus far to achieve these goals are described below.

DEUWI Methane Emissions Reduction Program

Dominion Energy 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 2021 more than 21 million feet of pipeline and 204,000 services were surveyed. Resulting in the discovery of 542 leaks, all of which were fixed.

- 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 consequently hit a line. The fine is remitted to the State of Utah as outlined in the 811 law. In recent months the Company has hired additional damage prevention specialists and implemented a risk modeling software to identify high-risk excavations. Once identified the Company sends personnel to monitor the excavations. As a result of these efforts, the damage rate achieved in 2021 hit a record low of 2.31.

- The Company acknowledges that there can be first-party (Company crews), and second-party (contractors hired by the Company) damages to facilities. In the 2021 calendar year, first-party damages made up 0.15% of all damages, while second-party damages accounted for an additional 2.55%. The Company is focusing effort is with first and second parties on education regarding safe excavation practices.

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.

Well Certification Program

The well certification program utilizes an extensive scoring system to certify wells as responsibly-produced. 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 has now moved to reevaluate the initial 250 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 73% of Wexpro's methane emissions in 2019. 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 a well location. Both systems were proven successful during the winter of 2020-2021 and appear to be viable options. Based on the evaluation of these options Wexpro will be installing the electronic controllers going forward. Wexpro is scheduled to convert approximately 225 wells per year over the next two years and to finish the conversion by the end of 2024.

Trailer Mounted Combustor

Wexpro is also evaluating trailer mounted combustors for use during well liquid unloading events. Currently, producing wells will load up with liquids in the wellbore and require periodic unloading, during which the well is opened to the atmosphere to bring the fluid in the wellbore to surface. The associated natural gas (methane) that is brought to surface is vented to atmosphere. After completing an evaluation of the trailer mounted combustors Wexpro has decided not to move forward with trailer mounted combustors to combust the natural gas that would otherwise vent to the atmosphere. Instead, Wexpro is now evaluating the use of Zevac units to capture the natural gas emissions rather than venting it 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 Dominion Energy's overall goal of 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 40 Natural Gas companies working together to voluntarily reduce methane emissions across the Natural Gas value chain to 1% (or less) by 2025.” 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 2020, registering a methane intensity score of .424% as described in the Industry Overview section of this report. Currently the Dominion Energy methane intensity score for operations in the west is also below the 1% goal.[49]

Responsibly Sourced Natural Gas

As part of the annual RFP for natural gas supply for 2022-2023 and beyond, the Company included a request for responsibly sourced natural gas from respondents. The Company received multiple offers from two 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 does provide responsibly sourced 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 increase. This could also drive the Company to need to purchase RSG supplies going forward.

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,

[49] https://onefuture.us/

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, Dominion Energy Utah partnered with 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.[50] In 2021, renewable natural gas made up over half of the gallons sold to CNG sales customers. The amount of RNG to be distributed in 2022 will largely depend on the availability of RNG supply.

GreenTherm® – Voluntary Renewable Natural Gas Program –

In Docket No. 19-057-T04, filed on March 29, 2019, the Company applied for approval to create a voluntary RNG program called GreenTherm®. This program was approved on July 30, 2019, and the Company began taking customer subscriptions in early 2020. This program allows customers to purchase renewable natural gas attributes for their own usage. In 2021, the Company sold approximately 19,150 Dth of RNG green attributes to GreenTherm® participants.

CarbonRight™ – Carbon Offset Program In October of 2020, the Utah Commission approved the voluntary carbon offset program – now known as CarbonRight™.[51] This program was approved on October 20, 2021. This program 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. The projects supported by CarbonRight™ may change over time depending on the availability of carbon offsets.

The initial tranche of offset supply for the CarbonRight™ program come 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 (Project ID: CAR400).

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.

[50] 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.
[51] Order Approving Settlement Stipulation, issued October 20, 2021, Docket No. 21-057-14.

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 (Project ID: CAR521).

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 (Project ID: ACR212).

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 participated in seventeen other RNG research projects with GTI 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 determine if there are any impacts on 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 plastic pipe, and no public CNG stations. Delta has 1,812 meters. The Company will introduce a 5% blend of hydrogen to the distribution system. This phase of the pilot will allow the Company to build on the experience from the first phase on a larger scale. To ensure safety, extra precautions will be taken at the injection site including monitoring the blend and overall quality of the gas. The Company will also be regularly monitoring gas quality and checking for consistent odorant throughout the Delta distribution system. This phase of the project will last 2 years and has a projected cost of $1.9 million.

Phase three involves introducing hydrogen into a high-pressure natural gas system in order to gain operational experience on a more expansive basis. This phase will pave the way for the Company to have better blending control over larger systems, where the gas can enter the distribution system at multiple points, than can be experienced in Delta or the Training Facility.

The final phase of testing will introduce the methanation process, 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. The Company participated in the 2019 legislative session and supported Utah House Bill 107 (HB 107). This bill was signed into law by the Governor of Utah on April 22, 2019.

HB107 modified the Sustainable Transportation Energy Plan Act (STEP), Utah Code Ann. §54-20-105, to allow DEUWI to invest in sustainable solutions that include clean-air initiatives, subject to Utah Commission approval. In addition, HB107 introduced the Natural Gas Clean Air Program (NGCAP). This program modified the Utah Code Ann. §54-4-13.1 and is designed to improve air quality through increased use of natural gas and renewable natural gas. Any project under this legislation is subject to approval by the Commission.

The STEP program will benefit Utah customers by reducing emissions and improving air quality. With Commission approval, the Company can advance programs and projects that reduce emissions and improve air quality. The Company could advance a variety of projects including projects that would incentivize the use of compressed natural gas (CNG) combined with RNG production in natural gas vehicle fleets. The Company could propose to fund research and development of new efficiency technologies that would reduce NOx, carbon, and greenhouse gas emissions. The Company has already begun work on programs that will improve air quality and reduce greenhouse gases.

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. This funding allows the IIAC to expand energy assessments of commercial and industrial energy users and provide data-driven recommendations to help improve air quality. In 2021, the IIAC completed 20 energy and clean air assessments using STEP funds. Additionally, the IIAC completed 20 STEP funded air quality assessments as part of 20 U.S. Department of Energy (DOE) funded energy assessments. The 20 STEP funded energy and 40 air quality assessments identified 234 potential projects that, if completed by the participating businesses, would result in a reduction of over 64 tons in annual criteria pollutants and more than 55,000 tons of annual CO_2 emissions. The identified potential projects would also result in reduced annual natural gas usage of over 900,000 Dth.

COMMUNITY PROGRAMS

In 2021, the Dominion Energy Charitable Foundation awarded $1.5 million dollars in environmental stewardship grants to support 115 community organizations across our entire footprint, with about $180,000 going to seven organizations in Utah, Idaho and Wyoming. These grants were awarded to organizations that focus on promoting conservation and a cleaner environment through preservation and education efforts. Organizations such as The Nature Conservancy and Sageland Collaborative used the money to focus on river restorations projects, improving water quality and revitalizing habitats for reptiles, fish and other wildlife. Additional grants supported the conservation and education to visitors to some of our national parks. Organizations such as Friends of Arches and Canyonlands Parks and Grand Staircase of Escalante Partners were able to use the grants to continue stewardship programs, repair damage, and improve visitation and preservation practices to maintain the beauty of these national parks for future generations.

ENERGY-EFFICIENCY PROGRAMS

UTAH ENERGY-EFFICIENCY RESULTS 2021

The Company's 2021 Commission-approved ThermWise® energy-efficiency programs and measures were similar to programs in 2020, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. ThermWise® results for 2021 were strong. While participation was lower than projected (76% of budget), gross natural gas savings reached 93% of the 2021 budget projection. Spending for the 2021 program year totaled $25.03 million or 93% of the $27.06 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for nearly 81% of the total ThermWise® spending in 2021 (85% in 2021 budget) and resulted in gross annual natural gas savings of more than 930,000 Dth.

Utah ThermWise® Appliance Rebates

The Company continued this program in 2021 with the addition of dual-fuel heating systems to the mix of rebate-eligible equipment. The Company added an $800 rebate for single family homes and a $450 rebate for multifamily properties that purchase and install a qualifying air source (also referred to as air-to-air) dual-fuel heating system beginning in 2021. A dual-fuel heating system is defined as a heat pump coupled with high efficiency natural gas combustion backup. For the purposes of the rebate, the Company defined qualifying dual-fuel systems as an ENERGY STAR® Certified ducted heat pump, heating seasonal performance factor (HSPF) > 9.0, and seasonal energy efficiency ratio (SEER) > 14. Further, the customer is required to purchase and install an ENERGY STAR® Certified natural gas heating system to provide heat at low ambient outside air temperatures.

While heat pumps can provide both space heating and cooling, for the purposes of the ThermWise® programs and natural gas savings, the Company is solely focused on the high efficiency performance of the heating operations. Operating in heating mode, an air source heat pump can deliver space heat at efficiency levels nearing 300% under the right conditions. This is accomplished by stripping heat from the ambient air outside of a building's envelope and, using the basic refrigeration cycle with a reversing valve, deliver heat to condition the inside of a home.

Because of the process by which air source heat pumps generate heat, heating capacity and efficiency performance are greatly impacted by the temperature of outside air. As the outside air temperature drops, the heating capacity and efficiency performance of the typical air source system also drops because it cannot remove as much heat from the air. If the outside air temperature drops enough, the typical air source heat pump loses capacity to provide a structure's necessary heating load. For this reason, typical air source heat pumps have auxiliary heating systems, usually provided by electric strip heaters, at a certain outside air temperature. This type of auxiliary heating is inefficient, particularly in Utah's climate zones, and can be especially costly to operate in the coldest months of the year. For this reason, air source heat pumps with auxiliary electric heat have traditionally seen the greatest uptake in the United States in climate zones 3-5 where heating degree days average less than 5,500 annually. For contrast, the majority of Utah is situated in climate zones 1 and 2 (with only

Washington County located in climate zone 4) where heating degree days ranged between 5,500 and more than 8,600 in 2019.

The Company also added energy recovery ventilation (ERV) to the mix of rebate-eligible equipment in 2021. ERVs 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 HVAC systems. The Company's first experience with ERVs was as a Business Custom measure for several years. This gave the Company a chance to evaluate performance and observe natural gas savings before it introduced the ERV as a prescriptive rebate measure in the Business Program (Docket No. 18-057-20). The Company introduced ERVs in 2021 based on observations and supporting data that there is potential for natural gas savings from the installation and use of these systems.

Additionally, the Company changed the rebate efficiency standard for the fireplace rebate measure from annual fuel utilization efficiency (AFUE), used in 2020 and earlier program years, to fireplace efficiency (FE) in 2021. FE is a Canadian standard that was established in mid-2020 and has gained greater market adoption by manufacturers and other utility efficiency programs throughout the country since introduction.

The Company continued to perform outreach and marketing work in-house in 2021. In May 2021, Nexant, Inc. merged with Resource Innovations. The newly formed company, continuing services as Resource Innovations, continued to provide technical assistance and rebate processing work for the Appliance and other ThermWise® programs in 2021.

Utah ThermWise® Builder Rebates

The Company continued this program with the addition of the dual-fuel heating system and ERV rebates for the reasons outlined in the 2021 Appliance Program discussion. The Company also eliminated the builder rebate credit, first proposed in the 2014 ThermWise® budget (Docket No. 13-057-14). The builder rebate credit was introduced as a new streamlined rebate method that was intended to replace a large percentage of traditional paper rebate applications. This rebate method has been successful over the years and has seen good participation. However, beginning in 2019, the Company began to encourage builders to shift from receiving rebates through the rebate credit to participation in pay-for-performance measures. The pay-for-performance measures have a higher requirement for documentation and testing by builders that does not function well with the builder rebate credit. The pay-for-performance model has seen good market uptake to this point, and the Company sees this as the future direction, in 2021 and beyond, for the Builder Program.

The Company continued to perform outreach and marketing work in-house in 2021. Resource Innovations provided technical assistance and continued to perform rebate processing work for this program in 2021.

Utah ThermWise® Business Rebates

The Company continued this program with the addition of the dual-fuel heating system rebate for the reasons outlined in the 2021 Appliance Program discussion.

The Company also added Advanced Rooftop Controls (ARCs) as a new rebate measure in the 2021 Business Program. ARCs are a digital system that allows 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. ARC rebates are divided into three tiers: 1) Advanced Rooftop Control ≥ 5 tons and ≤ 10 tons; 2) Advanced Rooftop Control > 10 tons and ≤ 15 tons; 3) Advanced Rooftop Control < 15 tons. The proposed rebate and expected annual natural gas savings are $500 and 34 Dth for ARC tier 1; $650 and 42 Dth for ARC tier 2; and $800 and 76 Dth for ARC tier 3.

Additionally, the Company added Monitoring Based Commissioning (MBCx) to the list of simplified analysis rebates as part of the Business Custom measure. Monitoring-Based Commissioning (MBCx) 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. For example, the software might identify a fan in an HVAC system that is cycling defectively and notify the customer of the performance issue. The customer would then remedy the issue and achieve efficiency gains. The Company limited MBCx eligibility to large facilities (>150k square feet) and facilities that have savings potential ≥ 1,000 Dth per year. Additional MCBx participation requirements are kept in the Business Custom Program Manual, available at ThermWise.com.

Resource Innovations continued to perform rebate processing and assisted with design, outreach, marketing, and technical assistance for this program in 2021.

Utah ThermWise® Weatherization Rebates

The Company continued this program in 2021 by moving the direct-install program, first approved by the Commission as a three-year pilot in Docket No. 16-057-15, from pilot status to an ongoing initiative. This change in status is made based on the findings of an evaluation of the pilot initiative conducted in 2020. At a summary level, the evaluation found that the natural gas savings achieved by the sample of direct-install program participant was 77.81% of the Company’s estimated savings. At this savings level, the direct-install initiative is cost effective. The Company adjusted natural gas savings in its 2021 cost effectiveness model to match the realization rate found in the evaluation.

Resource Innovations continued to perform rebate processing and technical assistance for this program in 2021.

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. The Company offers in-home Home Energy Plans, as well as a virtual, on-line Home Energy Plan option. In Docket No. 20-057-T03, the Commission granted DEUWI permission in 2020 to temporarily suspend in-home Home Energy Plans in response to the COVID-19 pandemic. The Company instituted virtual home energy assessments as a replacement to the in-home option, beginning in March of 2020. The Company continued virtual assessments throughout 2021. In a letter, dated June 4, 2021 (Docket No. 20-057-T03), the Company notified the Commission that it would resume in-home energy plans beginning July 1, 2021, and that it will continue to offer the virtual Home Energy Plan assessment as well.

Utah Low-Income Efficiency Program

The Company continued funding the Low-Income Efficiency Program in 2021 at $500,000 coming from the energy-efficiency budget ($750,000 total Company funding). The Company disbursed $250,000 to the State Weatherization Agency in January and July of 2021.

Utah ThermWise® Energy Comparison Report

The ThermWise® Energy Comparison Report allows customers to compare their natural gas usage with neighboring homes that are similarly sized and situated. The Comparison Report encourages customers to employ energy efficiency measures and behaviors. The Company developed the Comparison Report and first offered it to customers in November 2011.

In 2021 the Company sent the ECR to more than 226,000 of its customers. As of the end of September 2020, the Comparison Report had been generated over 355,000 times online by over 135,000 unique customers.

The Company decreased delivery of the Comparison Report to 226,000 in 2021. The Company realized this total number by discontinuing Group B and Group D, while adding Group J which will be delivered to 50,000 additional customers in 2021. For Group J, some customers from previously discontinued groups may be considered in the selection process.

While proposed program participants decrease from 2020, natural gas savings per customer increases moderately by 4% in 2021. The Company conducted a study in 2020 that focused savings analysis on all current recipients of the report (Groups E and F). As a result, the Company updated the natural gas savings number from 1.21 Dth/year in the 2020 Model, to 1.26 Dth/year in the 2021 Model. Throughout the life of the ECR Program, the Company has observed that peak dekatherm savings occur approximately in years two through four, and then slightly decrease and moderate.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2021 budget filing is shown in Table 13.1.

Table 3.1 - Utah 2021 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	
	2021 Projected B/C	2021Actual B/C	2021 Projected B/C	2021 Actual B/C	2021 Projected B/C	2021 Actual B/C	2021Projected B/C	2021 Actual B/C
ThermWise® Appliance Rebate	1.86	1.77	5.26	4.68	1.74	1.75	0.77	0.81
ThermWise® Builder Rebates	1.56	1.77	3.6	3.60	1.77	2.37	0.83	1.00
ThermWise® Business Rebates	1.22	1.12	3.11	3.48	2.04	1.58	0.98	0.78
ThermWise® Weatherization Rebates	1.26	1.52	2.95	3.35	1.48	1.66	0.79	0.86
ThermWise® Home Energy Plan	1.76	2.26	60.25	132.27	1.73	2.24	0.74	0.87
Low Income Efficiency Program	1.70	0.97	8.55	6.73	1.72	1.05	0.78	0.63
Energy Comparison Report	1.79	1.84	5.36	5.20	1.79	1.84	0.71	0.74
Market Transformation Initiative	0	0	N/A	N/A	0	0	0	0
Totals	1.40	1.54	3.73	3.79	1.63	1.82	0.80	0.87

Actual benefit/cost results for 2021 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 (with the exception of the Participant Test) 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 2021 ThermWise® budget filing (Docket No. 20-057-20).

ThermWise® program results for 2021 (57,768 actual rebates paid) finished the year at 76% of the Company's original 2021 estimate (75,542). Actual participation surpassed estimated participation in the Builder (30,963) and Weatherization (36,793) programs. The Weatherization program had the highest total number of participants and finished at 115% of the 2020 goal.

The DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Three meetings were held in 2021 on the following dates: April 14, August 26, and September 28.

ENERGY EFFICIENCY EFFECTS ON DESIGN DAY & DEMAND RESPONSE

Beginning in Docket No. 13-057-04 the Commission ordered the Company to discuss the "…effect of energy efficiency programs on peak demand and the need for new infrastructure and how energy efficiency programs could reduce or offset the need for future capital projects" in both a DSM Advisory Group and IRP public input meeting. (Report and Order dated October 22, 2013, Docket No. 13-057-04.) The Company has since addressed this topic in various DSM Advisory Group meetings in 2014, 2015, 2016, 2017, and 2018. Additionally, the Company has addressed this issue in Dockets 14-057-15, 15-057-07, 16-057-08, 16-057-15.

In 2017, the Company began to explore opportunities for DSM pilot programs that might alleviate peak demand. As part of these efforts, the Company contacted natural gas utilities who might have demand response programs, searched utility websites, reviewed industry conference papers, contacted large demand response vendors, and contacted national energy efficiency organizations. The Company also began a study of water heaters with the purpose of reducing peak demand in 2017. The study, which relied on the Company's system data from 2012-2016 paired with actual five-minute usage data from 7,000 electric storage water heaters taken over a three-month period, showed water heaters (both tankless and storage) peaking roughly 2 to 3 hours earlier than the hours when peaking risk for the Company's system is highest.

In recent years, the Company's efforts on energy efficiency programs and peak demand reduction have focused on studying emerging natural gas demand response programs, administered in customer homes through smart thermostats, throughout the country. The most prominent of these programs began as a pilot in 2017 with SoCalGas and was limited to 500 participants. A third-party evaluation on the impacts of the SoCalGas demand response program was performed and published August 14, 2018. The evaluation concluded that while the demand response program had reduced natural gas usage during the targeted window in time, overall usage for the entire day was not impacted in a statistically significant way. The study theorized that the lack of daily natural gas savings may have been caused by the post event "snap back", when a customer's preferred temperature settings are restored. Ultimately, the evaluation stated that, "without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective."[52]

The Company has explored natural gas demand response programs, including receiving proposals from three different program administrators, in 2019 and early 2020. The Company reviewed the 2019 proposals and ultimately determined that the estimated natural gas savings and system benefits did not justify proposing inclusion in the 2020, 2021, or 2022 ThermWise® programs.

WYOMING ENERGY-EFFICIENCY RESULTS FOR 2021

The Company filed for approval (Docket No. 30010-194-GT-20) of the twelfth year of the Wyoming ThermWise® programs on October 29, 2020. The 2021Wyoming programs were modified to closely align with the 2021 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 2021 programs (January 7, 2021, Order) and ordered the changes be effective January 1, 2021.

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 twelfth full program year (January

[52] SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation, August 14, 2018, Nexant, Inc.

through December 2021) the Wyoming ThermWise® programs had 285 participants or 1.02% of the Company's December 31, 2021, Wyoming GS customer base.

UTAH ENERGY-EFFICIENCY PLAN FOR 2022

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 2022 as well as the ThermWise® Market Transformation Initiative. The ThermWise® energy-efficiency programs continuing in 2022 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 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 systems. 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 in order to correct the issue.

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

Utah ThermWise® Builder Rebates

The Company continues 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 will continue to perform outreach and marketing work in-house in 2022. Resource Innovations will provide technical assistance and continue to perform rebate processing work for this program in 2022.

Utah ThermWise® Business Rebates

The Company continues 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 must replace existing mechanically linked combustion air and fuel valve mechanisms with a digital linkageless control. Additionally, only natural gas boilers qualify for a rebate and the linkageless control must not be required by state and local building/energy efficiency codes. The Company proposes to rebate this measure at $0.50 per thousand British Thermal Unit (kBtu) of the boiler in which the linkageless control is 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 qualify for a rebate and the O2 trim control must not be required by state and local building/energy efficiency codes. The Company proposes to rebate this measure at $0.20 per kBtu of the boiler in which the O2 trim control is installed.

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 2022.

Utah ThermWise® Weatherization Rebates

The Company continues 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 $800 single family / $400 multifamily) for customers who install qualifying rigid foam exterior insulation.

Resource Innovations will continue to perform rebate processing and assist with technical assistance for this program in 2021.

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. 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 has opted to continue the virtual option. In 2022, the Company will continue to offer virtual and in-home Home Energy Plan.

Utah Low-Income Efficiency Program

The Company will continue funding the Low-Income Efficiency Program in 2022 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 2022. The Company will add the rigid foam exterior insulation rebate, previously described in the 2022 Builder Program discussion. The rebate will be $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 will send the ECR to more than 228,000 of its 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 will increase delivery of the Comparison Report to 228,000 customers in 2022. The Company reaches this total number by restarting Group E, discontinuing Group F, restarting Group E in November 2022, and adding Group K which will be delivered to 35,000 additional customers in late 2022. For Group K, some customers from previously discontinued groups may be considered in the selection process. 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 will increase slightly over 2021. Natural gas savings per customer will also increase from 2021, by 1.6% per customer, in 2022. Given the program’s maturity, now in its seventh year, the Company will move 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 13.2 below.

Table 3.2 - Utah 2022 projected NPV & BC ratios by program and California Standard Practice Test

2022 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	$5.09	1.85	$24.64	4.86	$4.92	1.80	-$2.44	0.82
ThermWise® Builder Rebates	$11.15	1.81	$43.20	3.64	$15.38	2.62	$0.84	1.03
ThermWise® Business Rebates	$1.64	1.30	$12.80	3.52	$3.81	2.13	-$0.93	0.89
ThermWise® Weatherization Rebates	$2.19	1.23	$17.64	2.86	$3.61	1.45	-$2.77	0.81
ThermWise® Home Energy Plan	$0.39	1.79	$2.29	60.55	$0.39	1.76	-$0.25	0.78
Low Income Efficiency Program	$0.52	1.68	$2.47	8.91	$0.55	1.73	-$0.29	0.82
Energy Comparison Report	$0.39	1.71	$2.13	5.24	$0.39	1.71	-$0.37	0.72
Market Transformation Initiative	-$1.32	0	$0.00	N/A	-$1.32	0	-$1.32	0
Totals	$20.07	1.53	$105.17	3.76	$27.72	1.92	-$7.52	0.89

*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 2022 NPV & B/C ratios using gas cost forward curve from SENDOUT model

2021 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	$5.60	1.93	$24.64	4.86	$5.43	1.88	-$1.93	0.86
ThermWise® Builder Rebates	$10.67	1.78	$43.20	3.64	$14.89	2.57	$0.35	1.01
ThermWise® Business Rebates	$2.01	1.36	$12.80	3.52	$4.17	2.24	-$0.56	0.93
ThermWise® Weatherization Rebates	$1.68	1.18	$17.64	2.86	$3.10	1.39	-$3.27	0.77
ThermWise® Home Energy Plan	$0.52	2.04	$2.29	60.55	$0.52	2.01	-$0.12	0.90
Low Income Efficiency Program	$0.57	1.73	$2.47	8.91	$0.59	1.79	-$0.25	0.84
Energy Comparison Report	$1.02	2.88	$2.13	5.24	$1.02	2.88	$0.27	1.21
Market Transformation Initiative	-$1.32	0.00	$0.00	0.00	-$1.32	0.00	-$1.32	0.00
Totals	$20.76	1.55	$105.17	3.76	$28.41	1.94	-$6.83	0.90

*Shown in millions

WYOMING ENERGY-EFFICIENCY PLAN FOR 2022

The Company expects 2022 participation in the portfolio of Wyoming ThermWise® programs to reach 501 customers which would be an increase of 76% from the 2021 actual participation levels.

SENDOUT MODEL RESULTS FOR 2022

The Company entered projections from the approved 2022 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 2022 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 2022 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 2022 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 2022 ThermWise® Appliance, Builder, Business, Weatherization, and Energy Comparison Report programs at 25% of 2022 projected participation if administration costs were increased to 200% of the 2022 budget projection. The model accepted the Home Energy Plan program at 50% of participation and 200% of the 2022 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 2022 projection. In this scenario, the administration costs for the Appliance, Builder, Business, Weatherization, and Energy Comparison Report programs could increase by eight times the 2022 budget projection and still be accepted. The Home Energy Plan program could increase projected administration costs by four times 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 2022 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 2022 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 1,146,149 Dth in 2022. This analysis resulted in a projected potential total energy-efficiency spending limit of $58.6 million per year using the Utility Cost Test. The currently-approved $30.2 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 2021, the avoided gas cost attributable to energy-efficiency was calculated to be $41.5 million. For 2022, the avoided gas cost attributable to energy-efficiency was calculated to be $58.6 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

Exhibit 13.1

2022 Energy-Efficiency Modeling Results from SENDOUT

Program @ <u>100%</u> of 2022 Budget $	**% of 2022 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 2022 Budget $	**% of 2022 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 2022 Budget $	**% of 2022 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)[53]. On July 1, 2021, Hitachi ABB Power Grids announced they would become Hitachi Energy starting October 2021[54]. SENDOUT is now a product of Hitachi Energy. Roughly 100 utilities use SENDOUT for gas supply planning and portfolio optimization.

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.

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. The Company does have concerns regarding future support for the SENDOUT software as no updates are currently planned. As a result, the Company is evaluating potential alternatives with enhanced support and longevity. One potential alternative is a market simulation platform called Plexos which is owned by Energy Exemplar.

CONSTRAINTS AND LINEAR PROGRAMMING

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

Constraints are necessary in determining a maximum or minimum solution. Constraints must be linear functions that represent either equalities or inequalities. An example of an

[53]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

[54]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

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. No adjustments were made to the constraints for the 2022-2023 IRP model.

MODEL IMPROVEMENTS

The Company made one modification to the SENDOUT model for the 2020-2021 IRP. The discount rate used in the model was adjusted to 3.05% 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 base Monte Carlo simulation developed by the Company this year utilized 932 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 are two 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. 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 were significantly higher than normal and as such the simulations had very 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 932 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 2022-2023 heating season is approximately 1.25 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.[55] 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 932 draws generated in this process, seven draws would exceed the Design Day requirement of 1.25MMDth. In other words, these scenarios have enough resources to meet a Design Day event. Most of the seasonal baseload purchased-gas resources are committed prior to the beginning of the IRP year. Storage, daily spot gas, and cost-of-service gas supply do not need to be committed to before the IRP year begins. This modeling approach also lends itself to performing operational analysis during the year as natural gas prices change.

Exhibit 14.51 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 14.88. 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.

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

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 66.6 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 54.35 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 $747 million. A similar curve for the total 31-year modeling time horizon is shown in Exhibit 14.82. The normal case cost for this time period is approximately $16.29 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.[56] 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 14.89 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 133

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

MMDth for the normal case. Exhibit 14.90 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the 133 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).[57]

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)

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	651.6	651.8	654.2
	IRP Forecast	726.9	724.2	729.2
	High 10%	1,282.0	1,014.3	956.2

Table 14.2: Total Annual System Costs ($ million)

		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	600.1	762.6	933.7
	IRP Forecast	585.1	747.0	918.0
	High 10%	571.0	732.9	902.9

[57] 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.

Monthly FOM Index Price Distribution
2022 Plan Year
Scenario 1005 : 932 Draws
year=2022 month=6

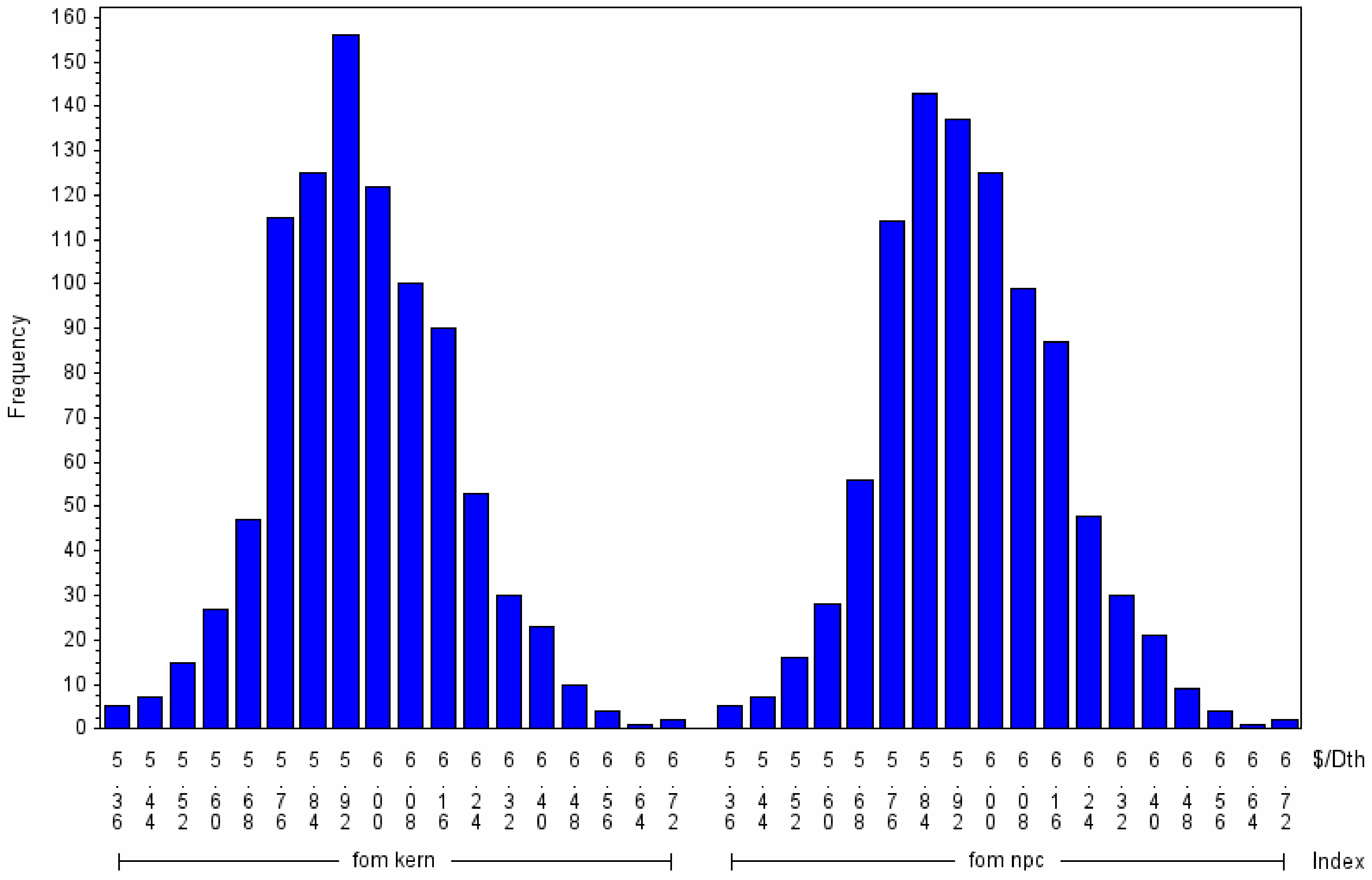
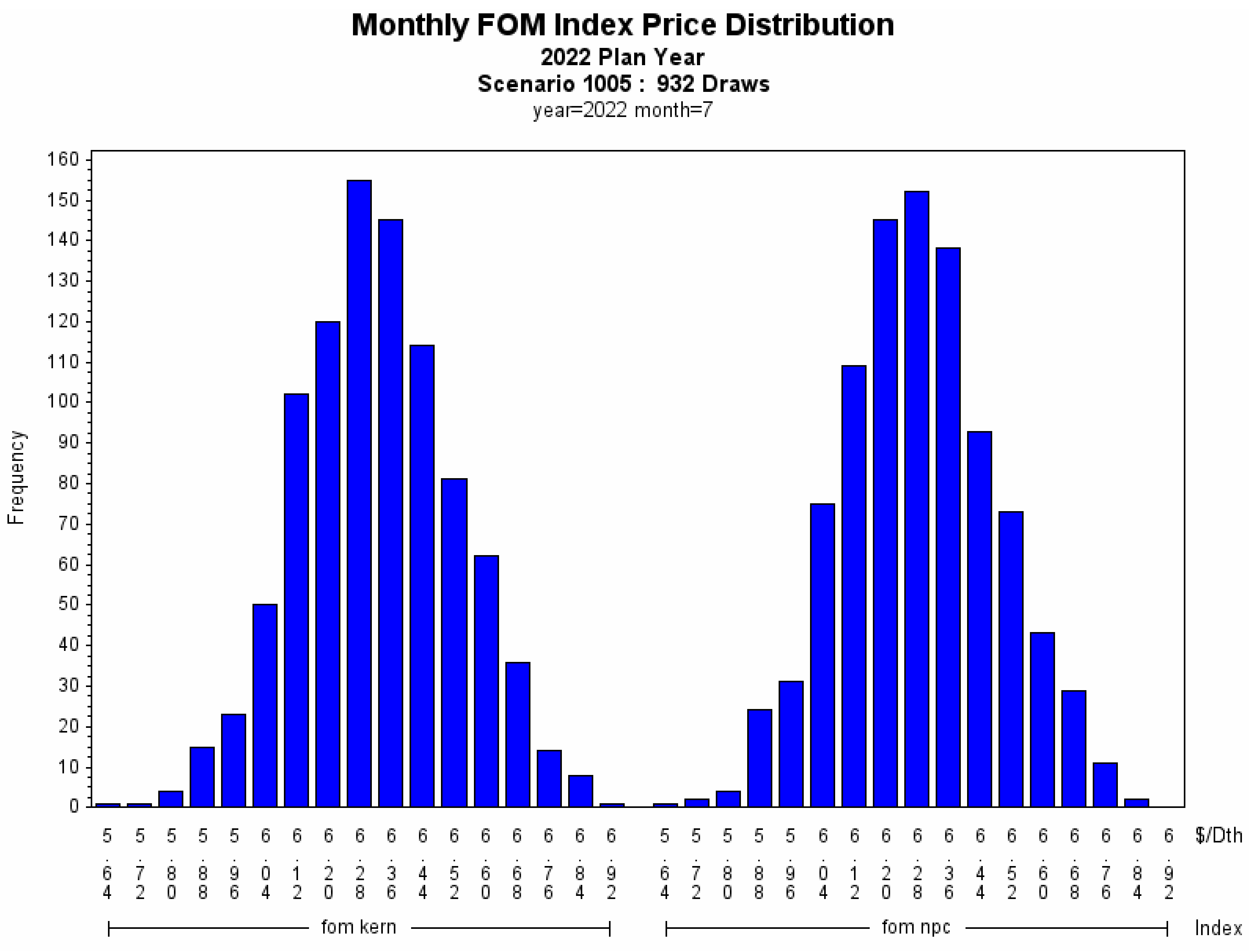


Exhibit 14.01



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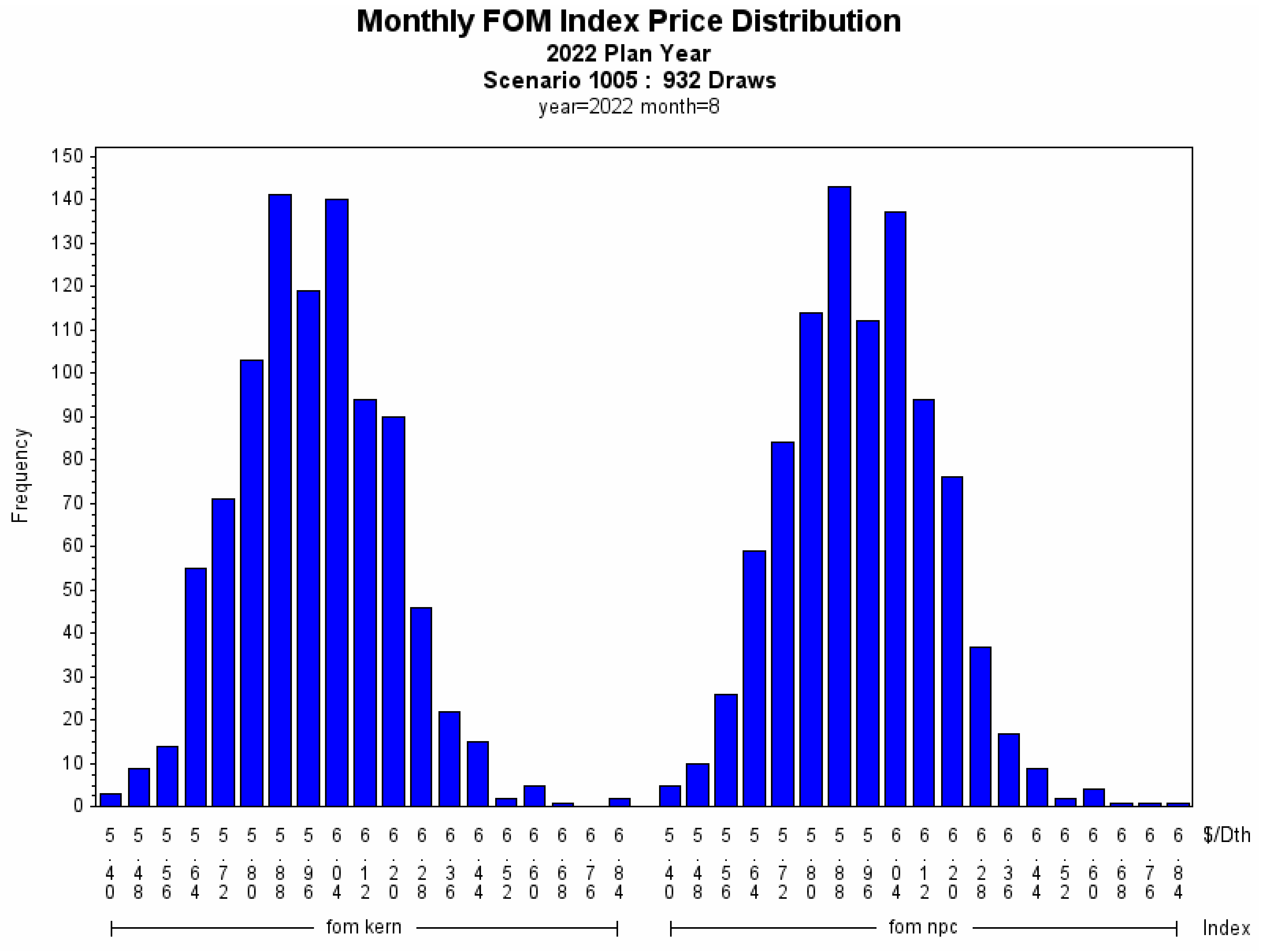

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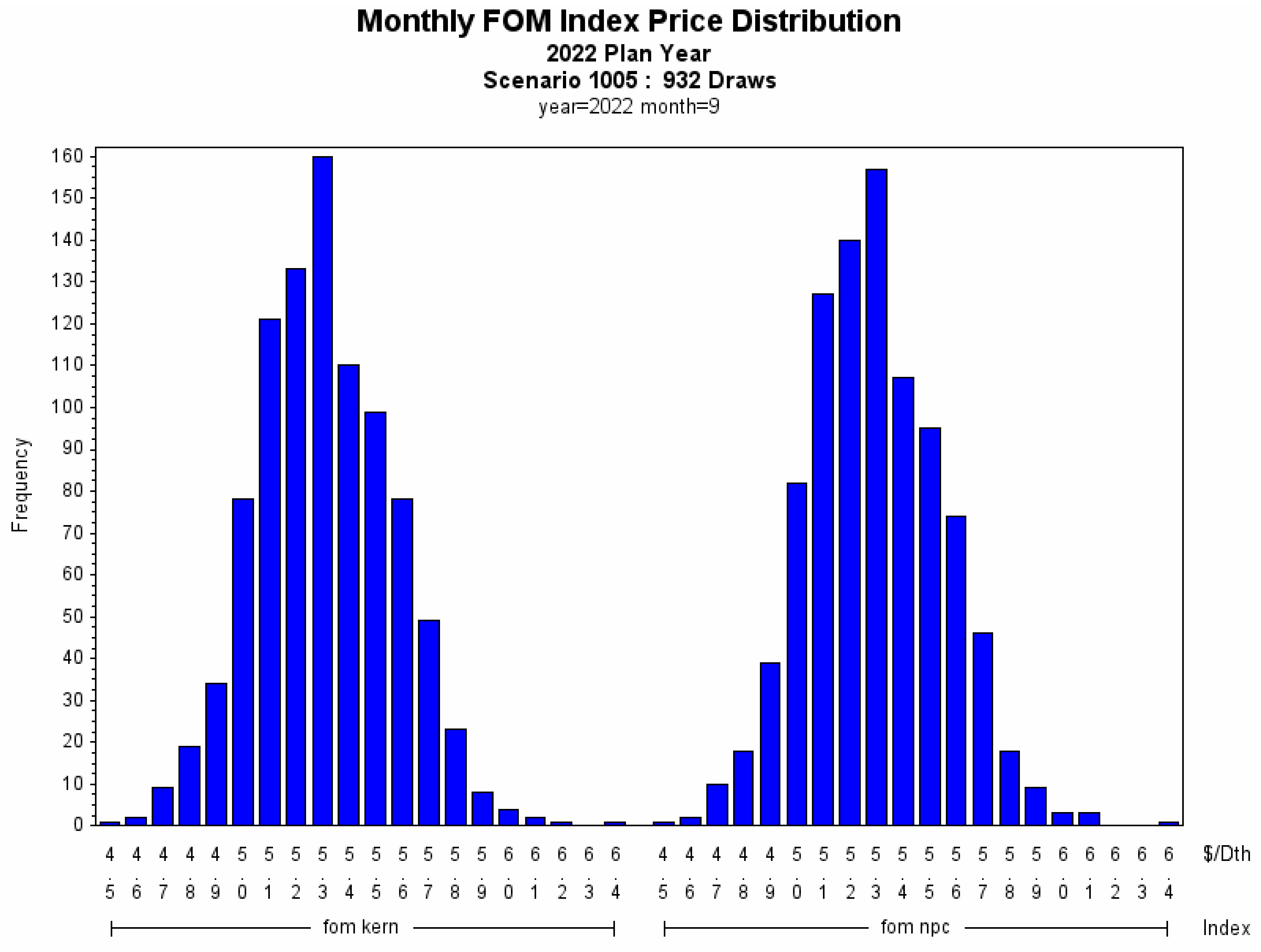
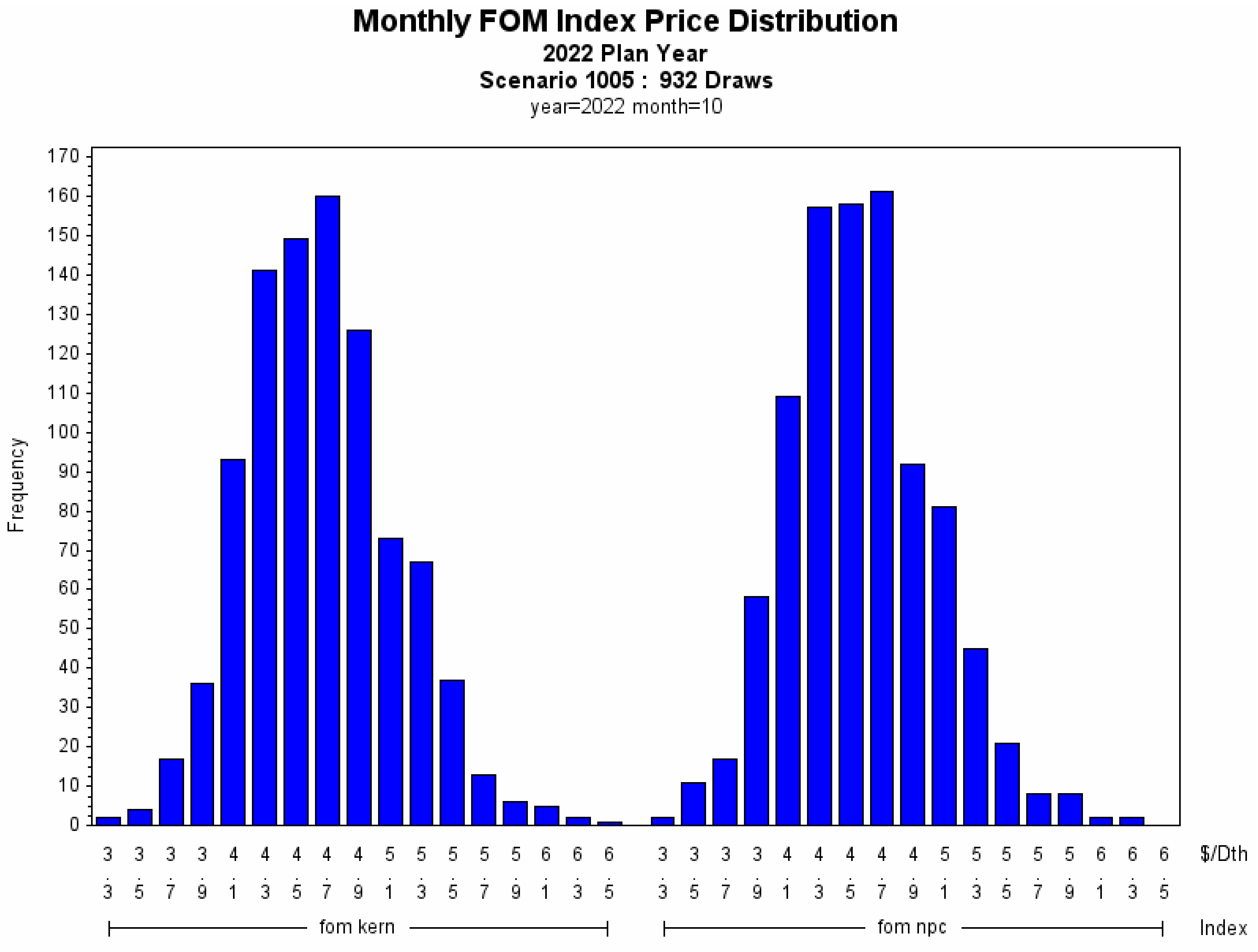


Exhibit 14.04



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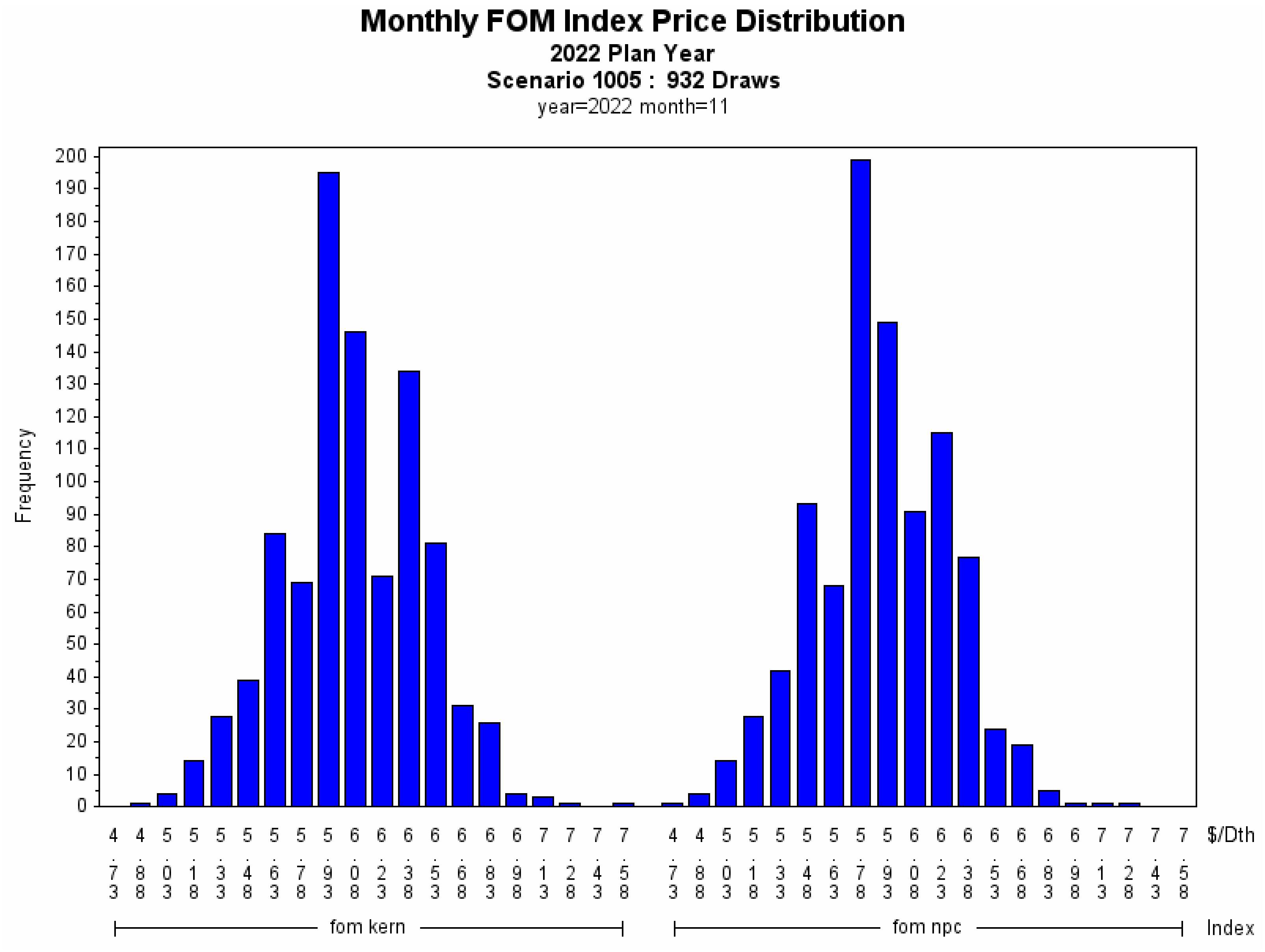

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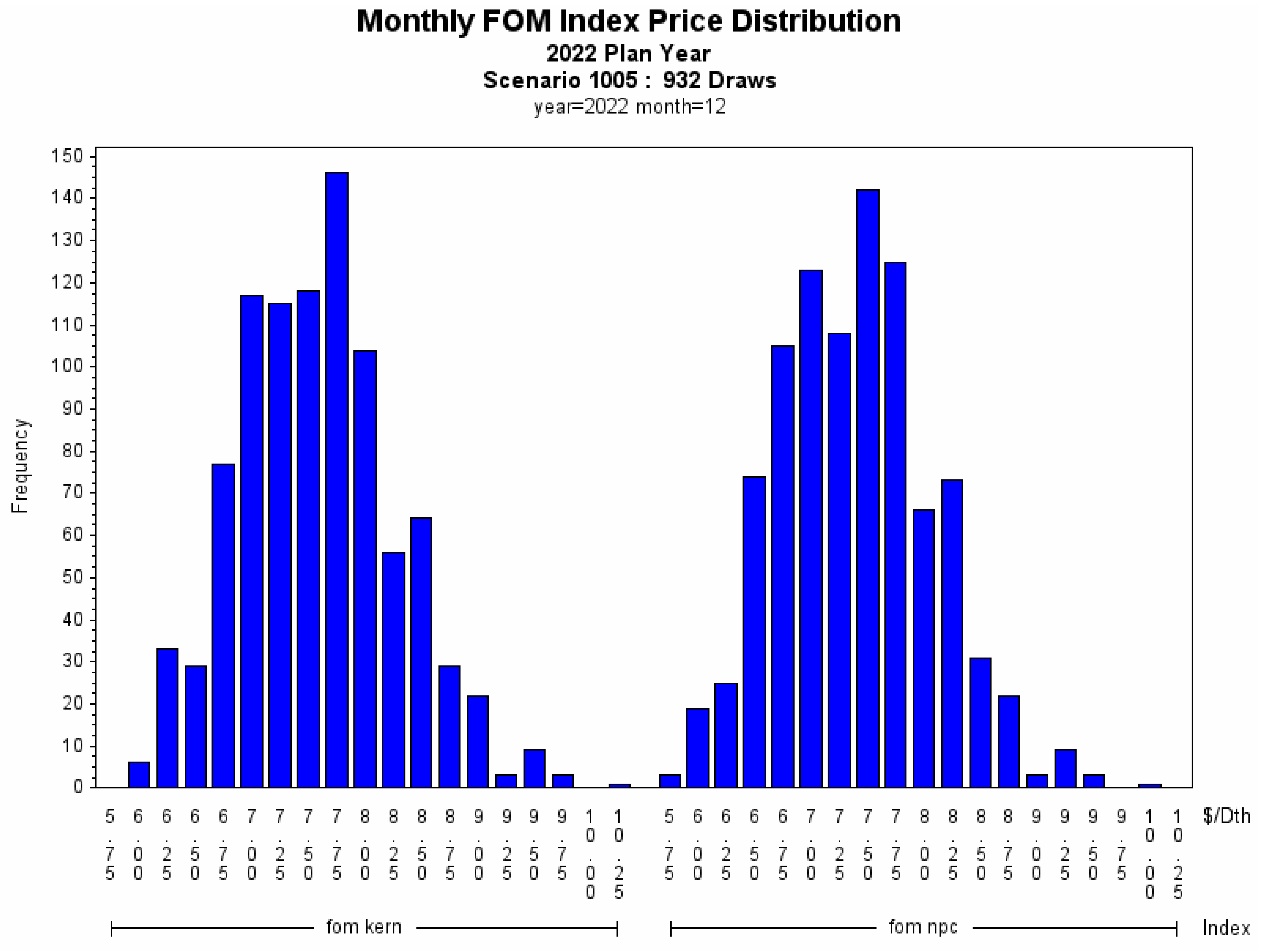

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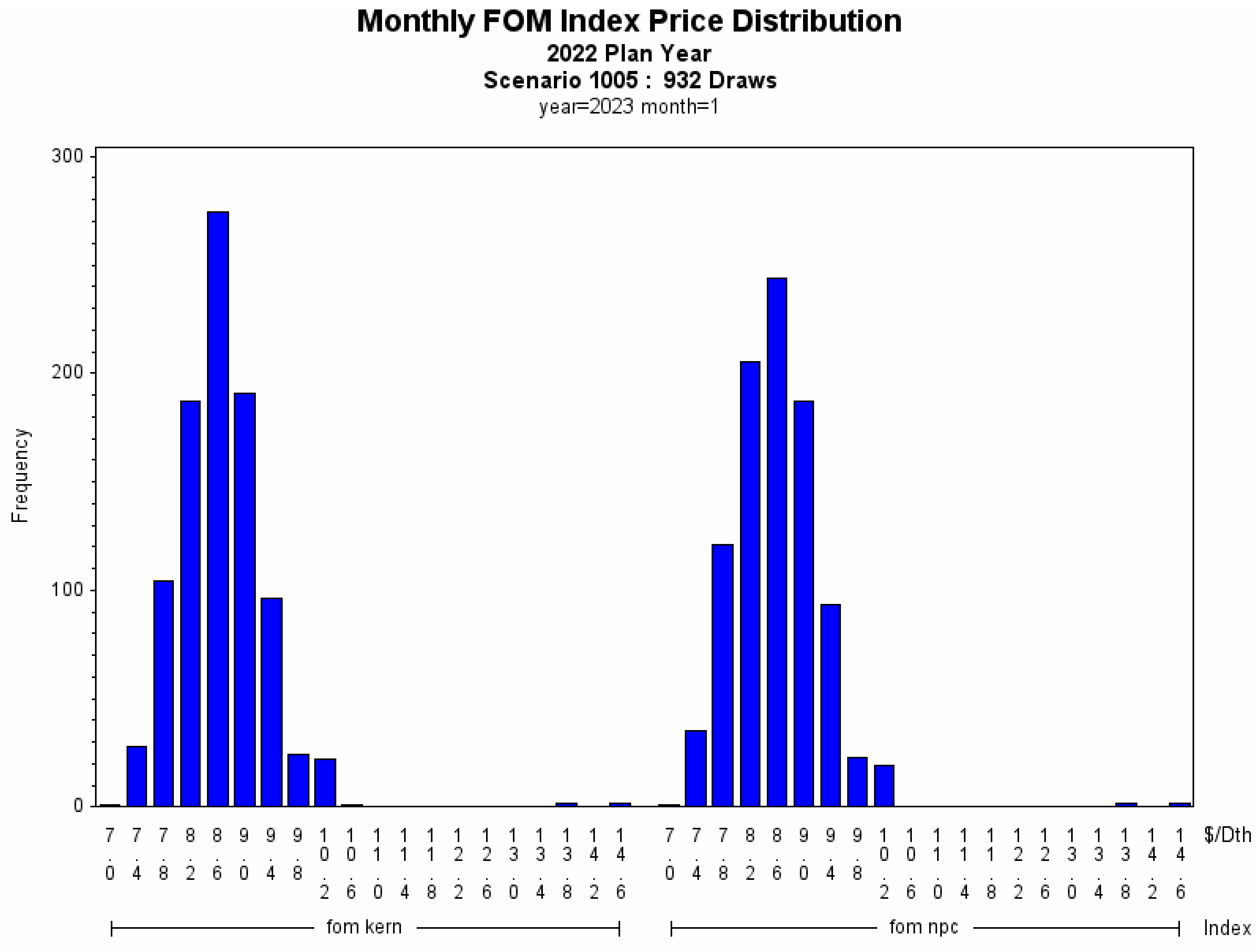

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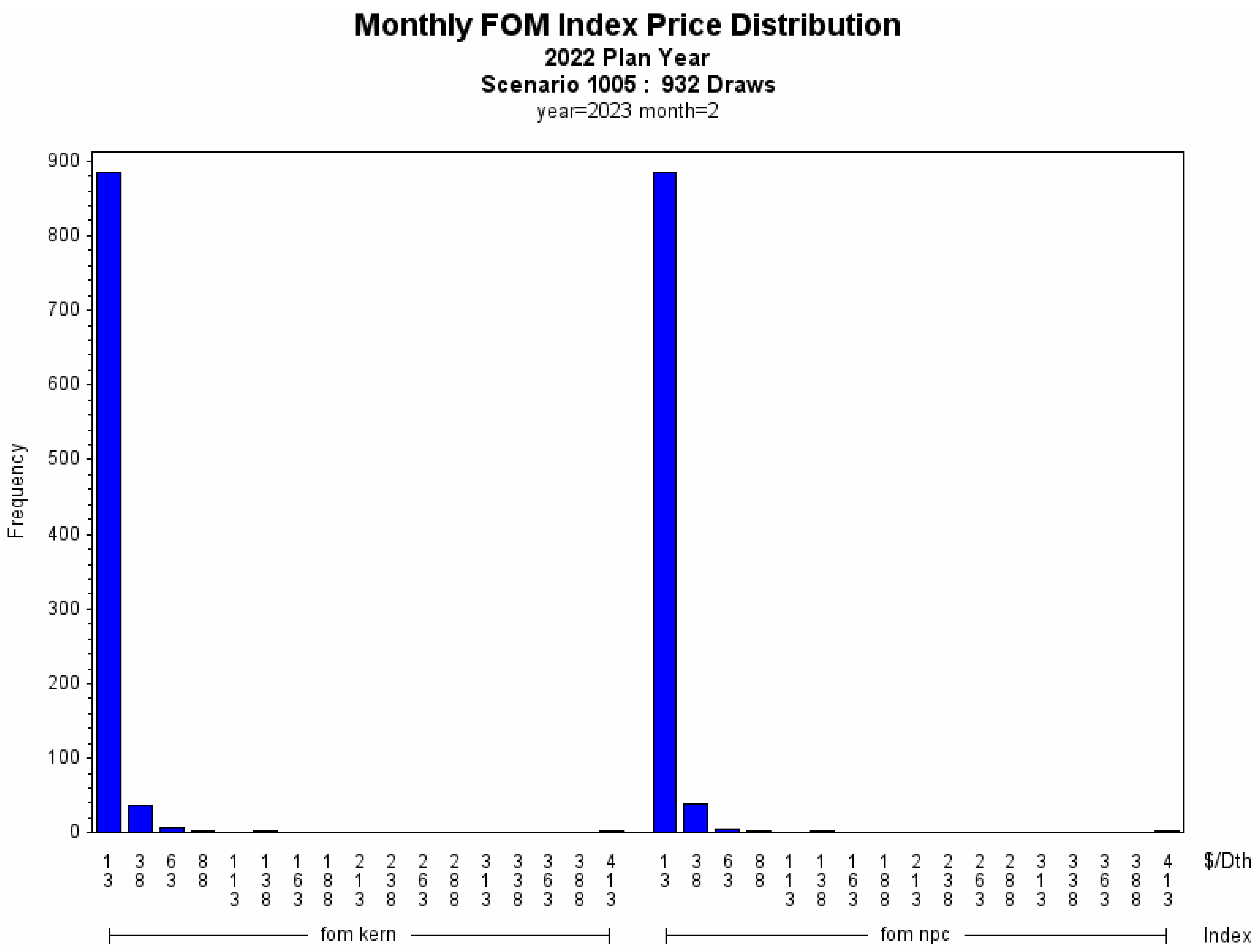

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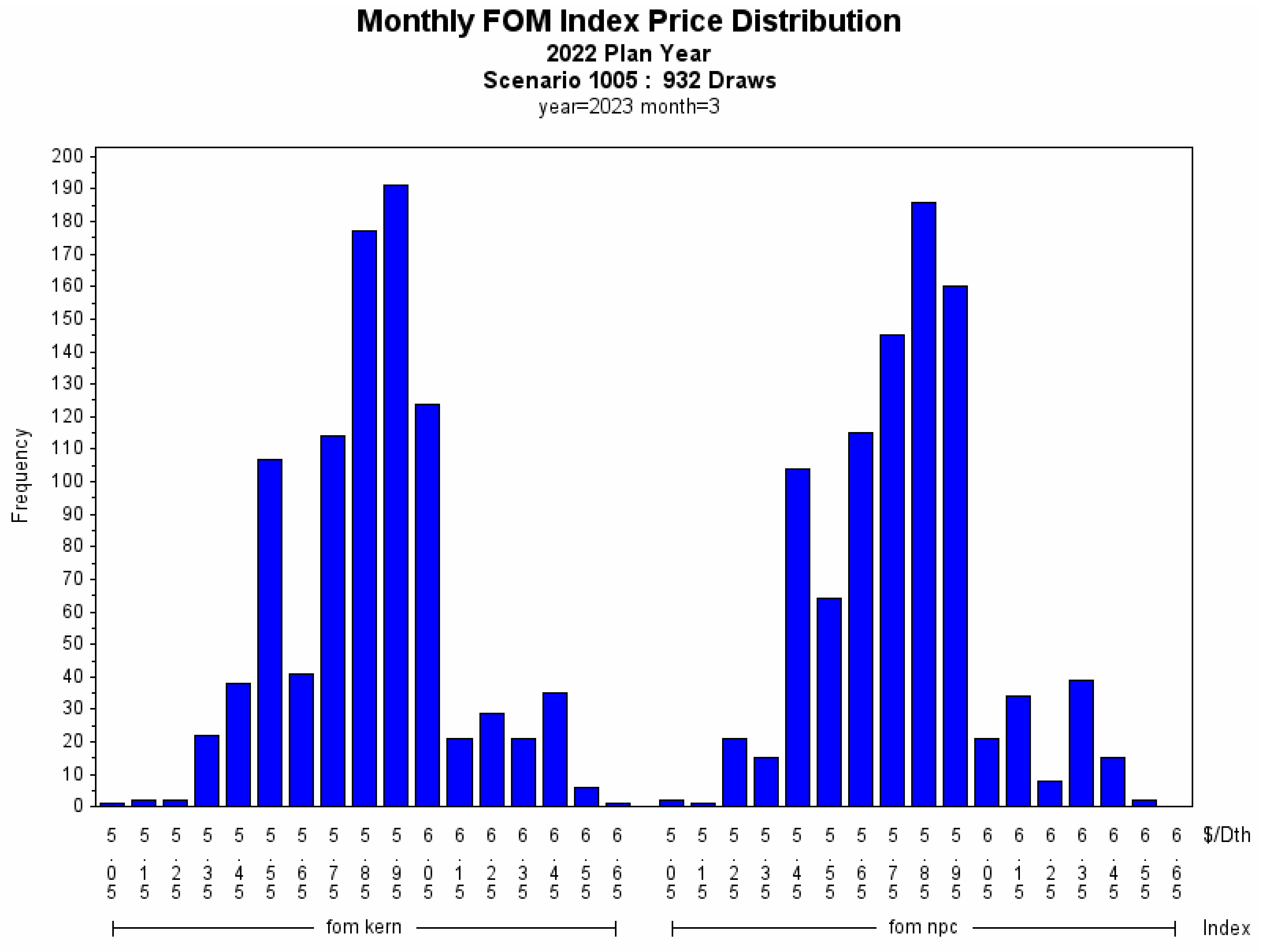


Exhibit 14.10

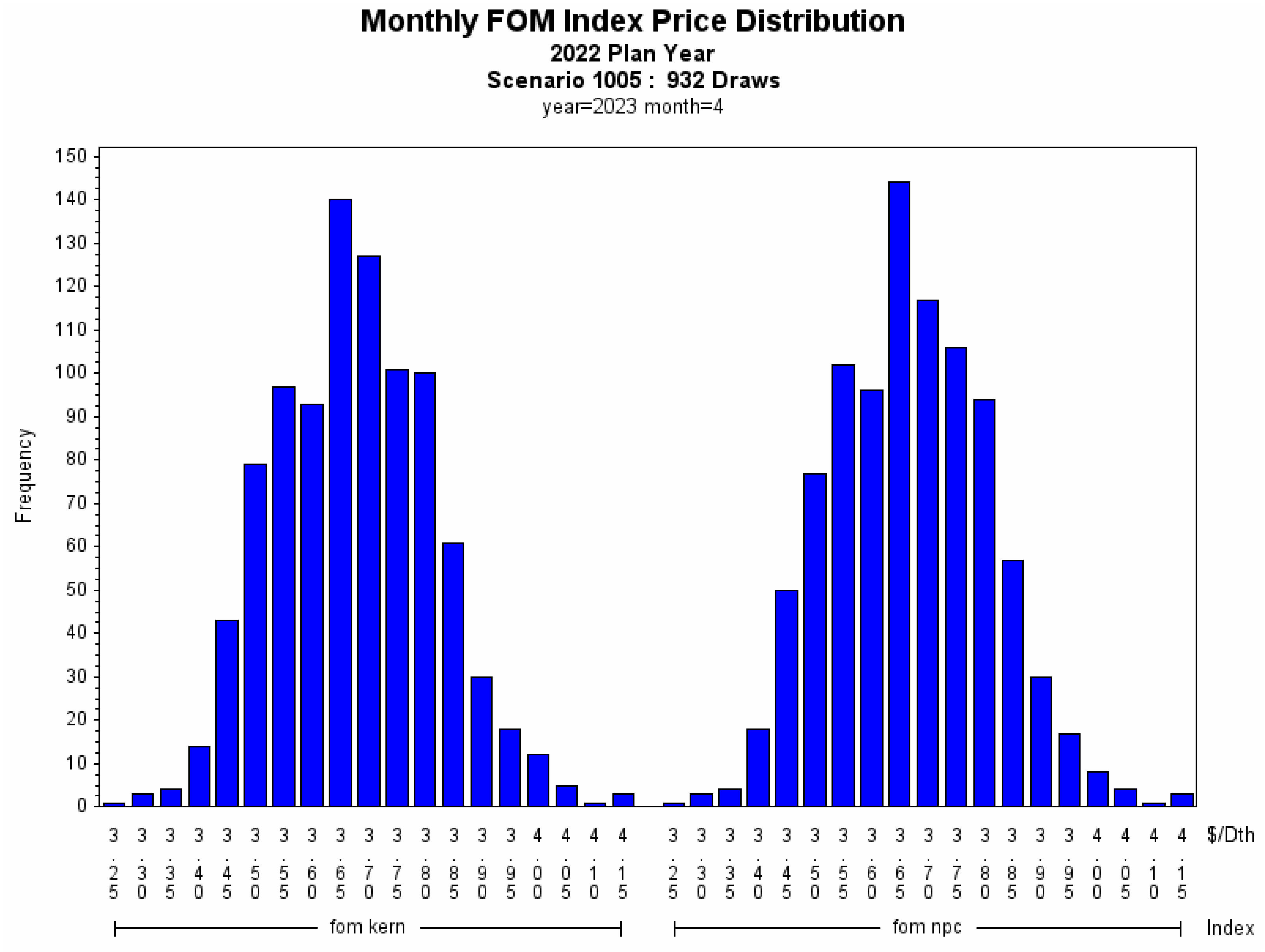


Exhibit 14.11

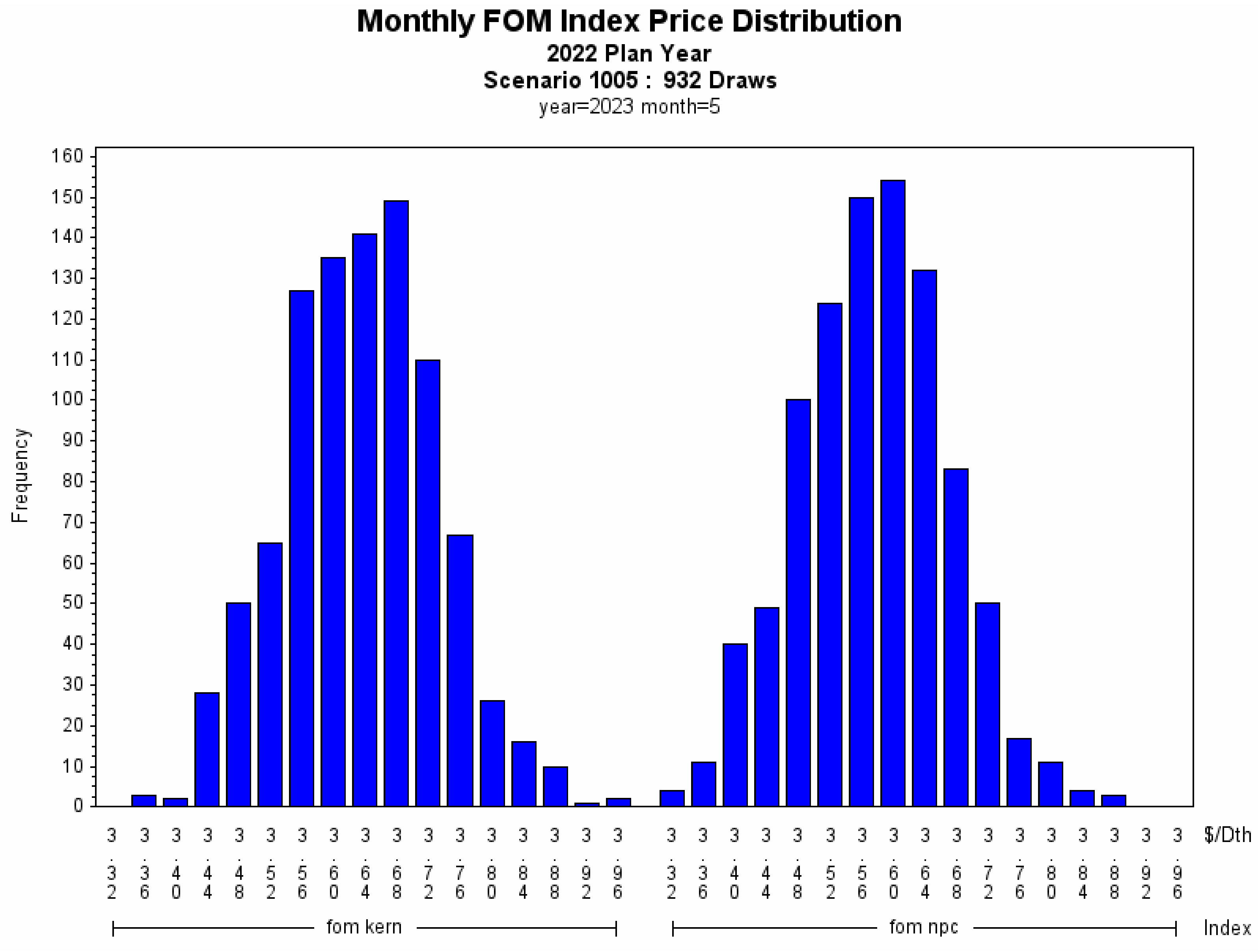


Exhibit 14.12

Exhibit 14.13

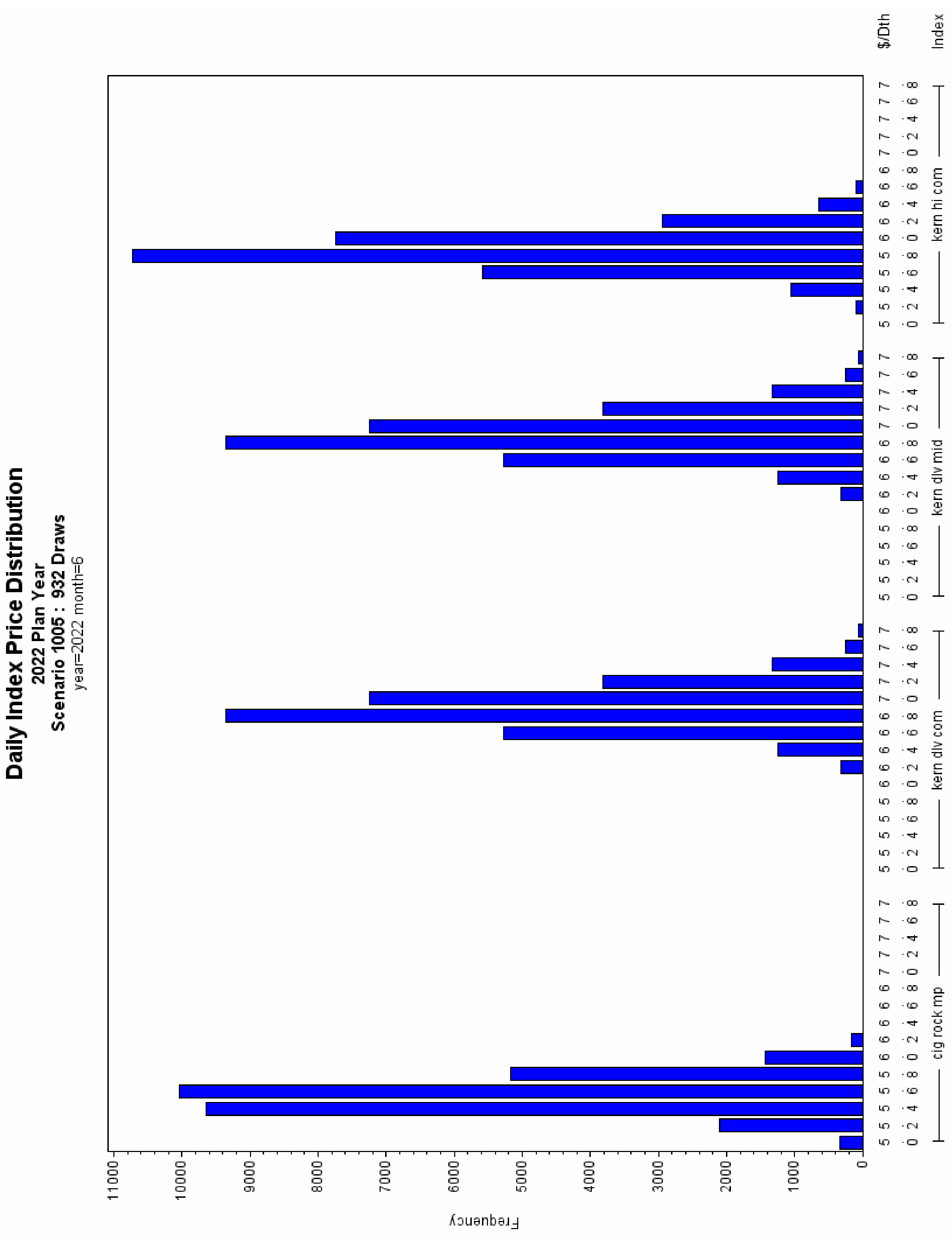


Exhibit 14.14

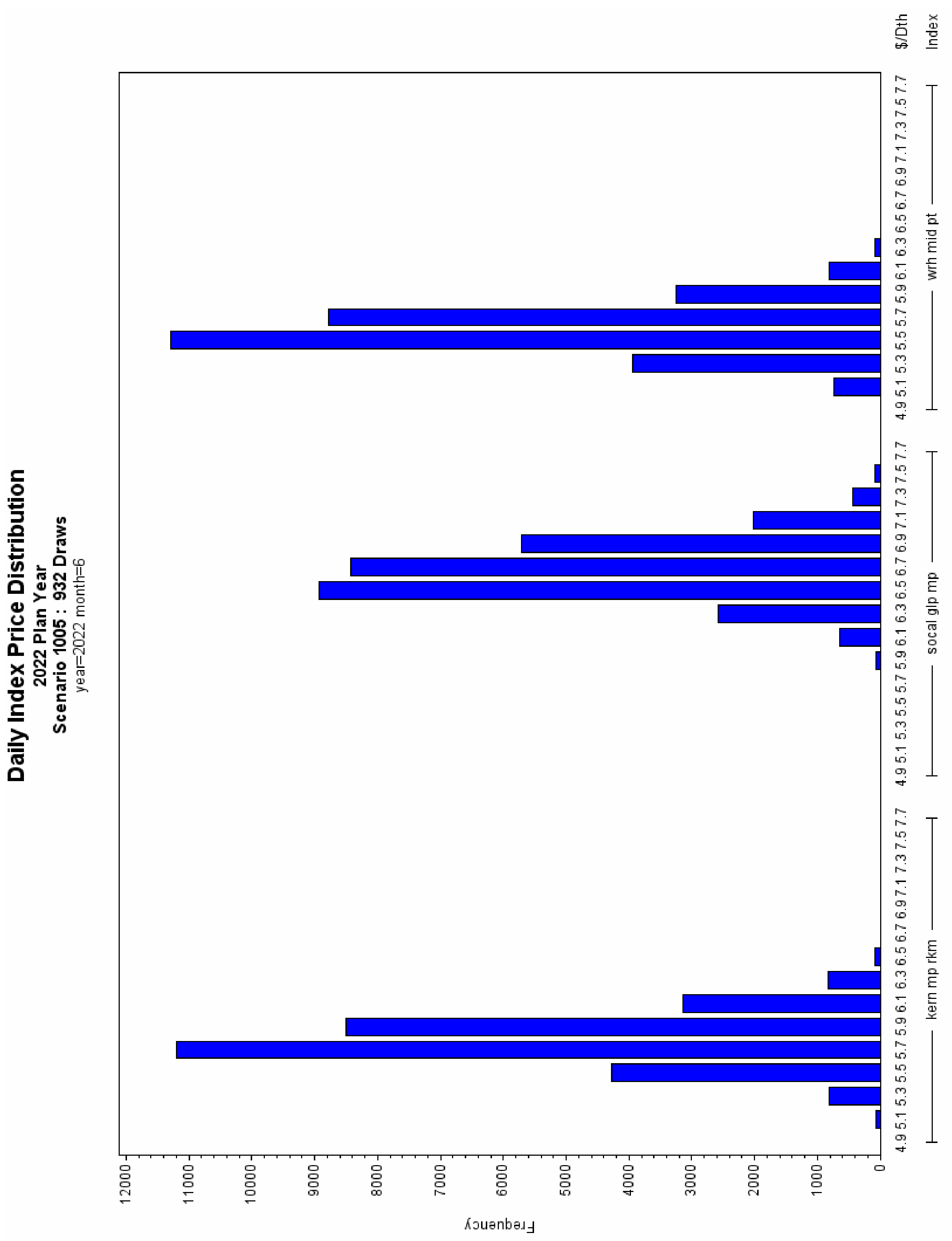


Exhibit 14.15

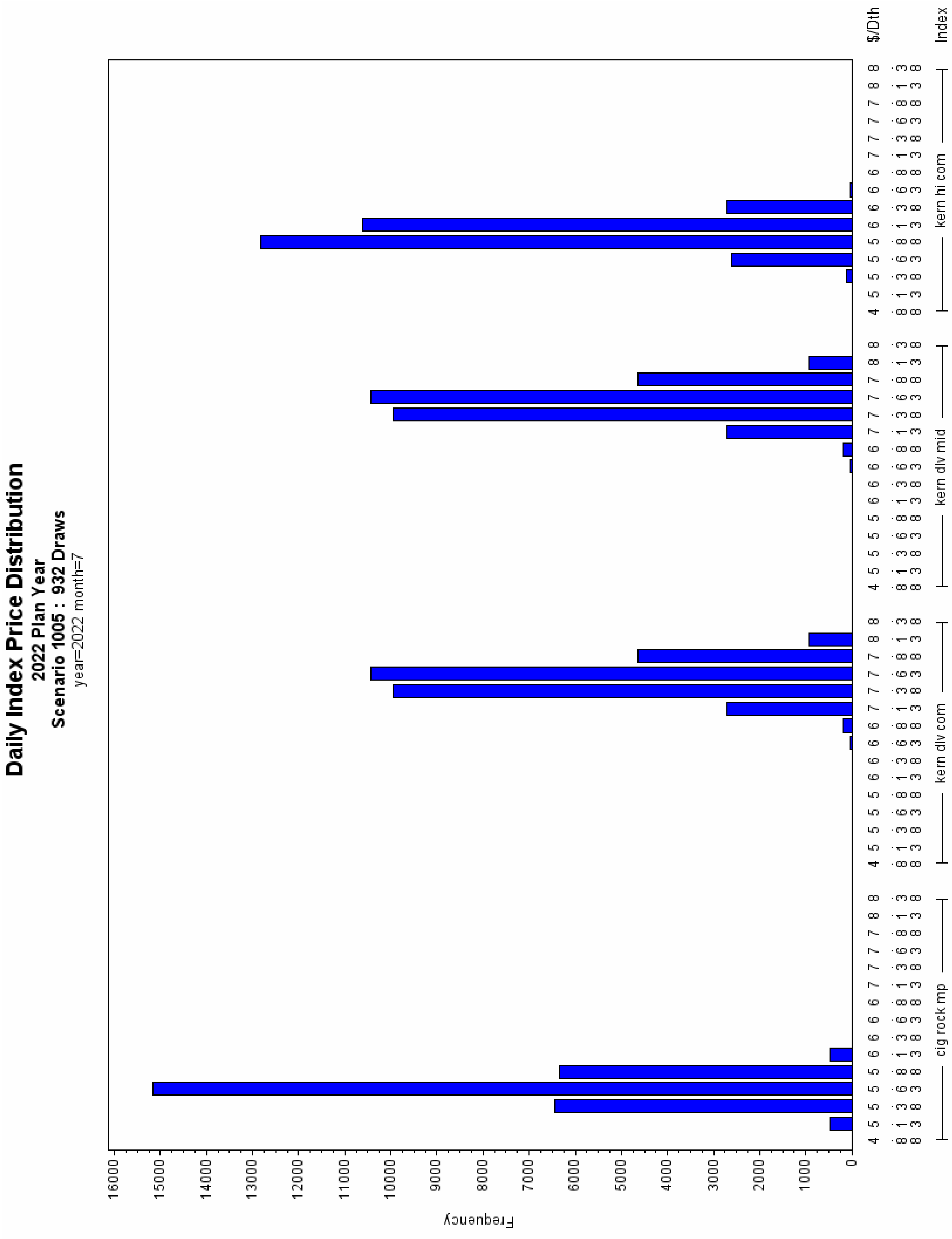
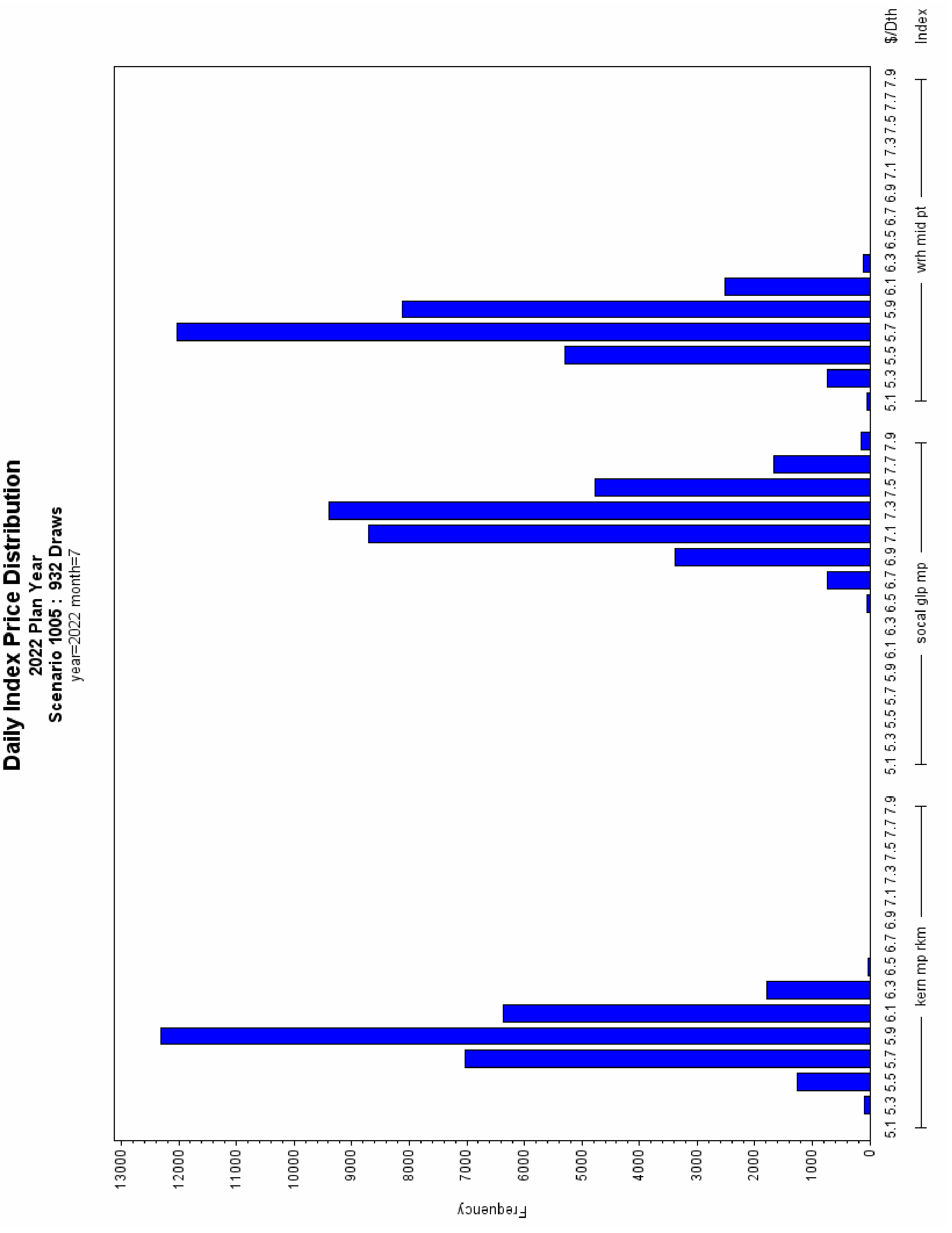


Exhibit 14.16



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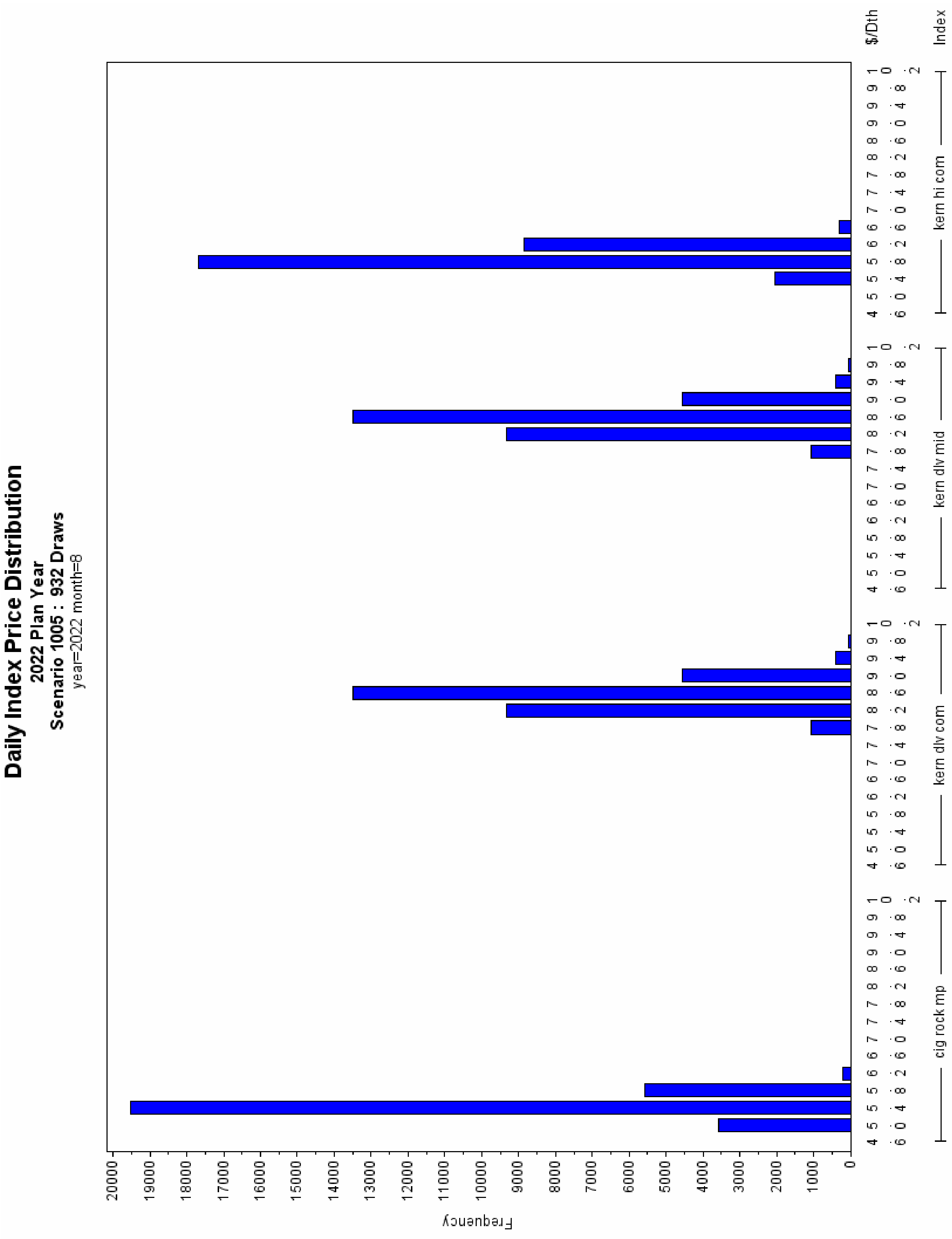

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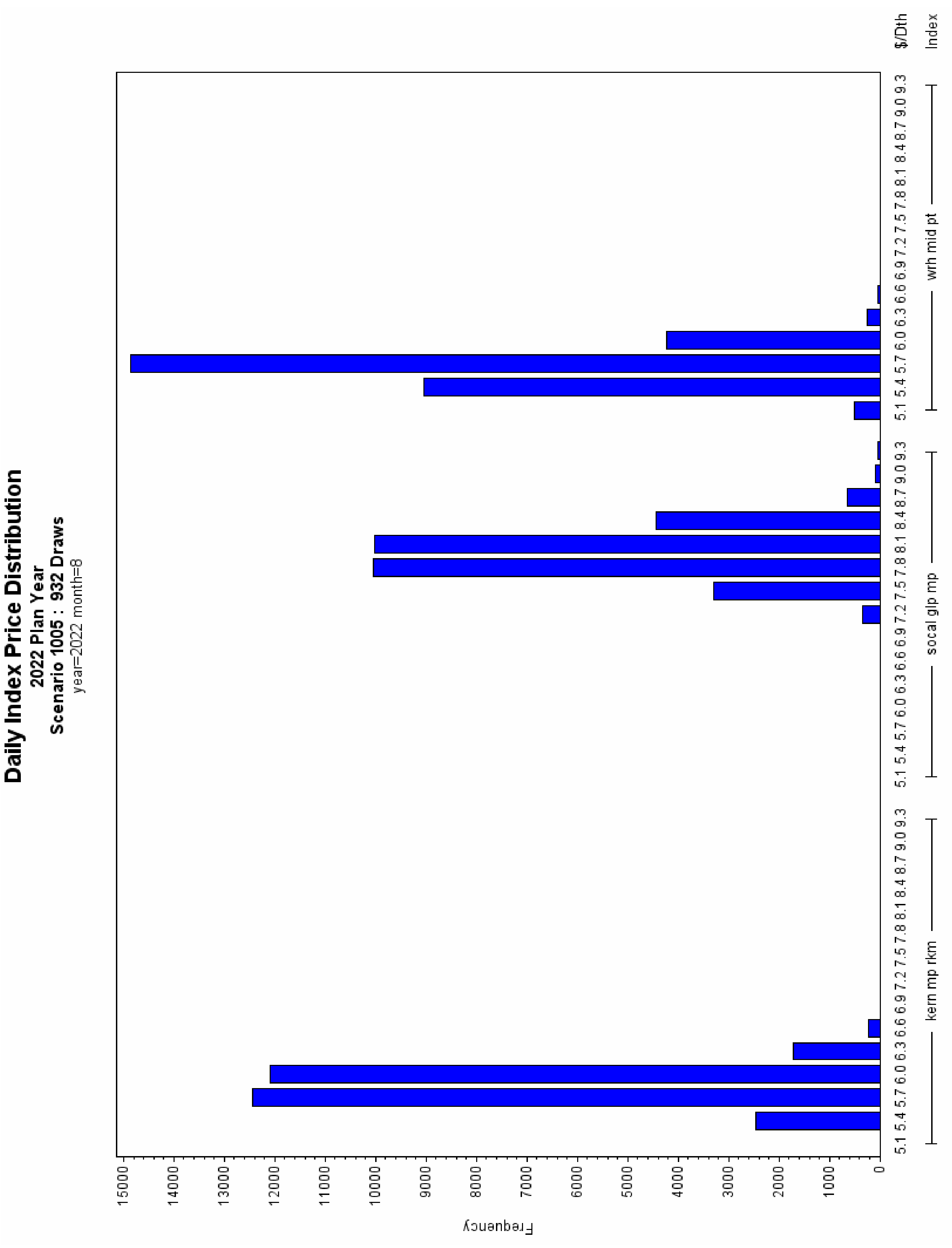


Exhibit 14.19

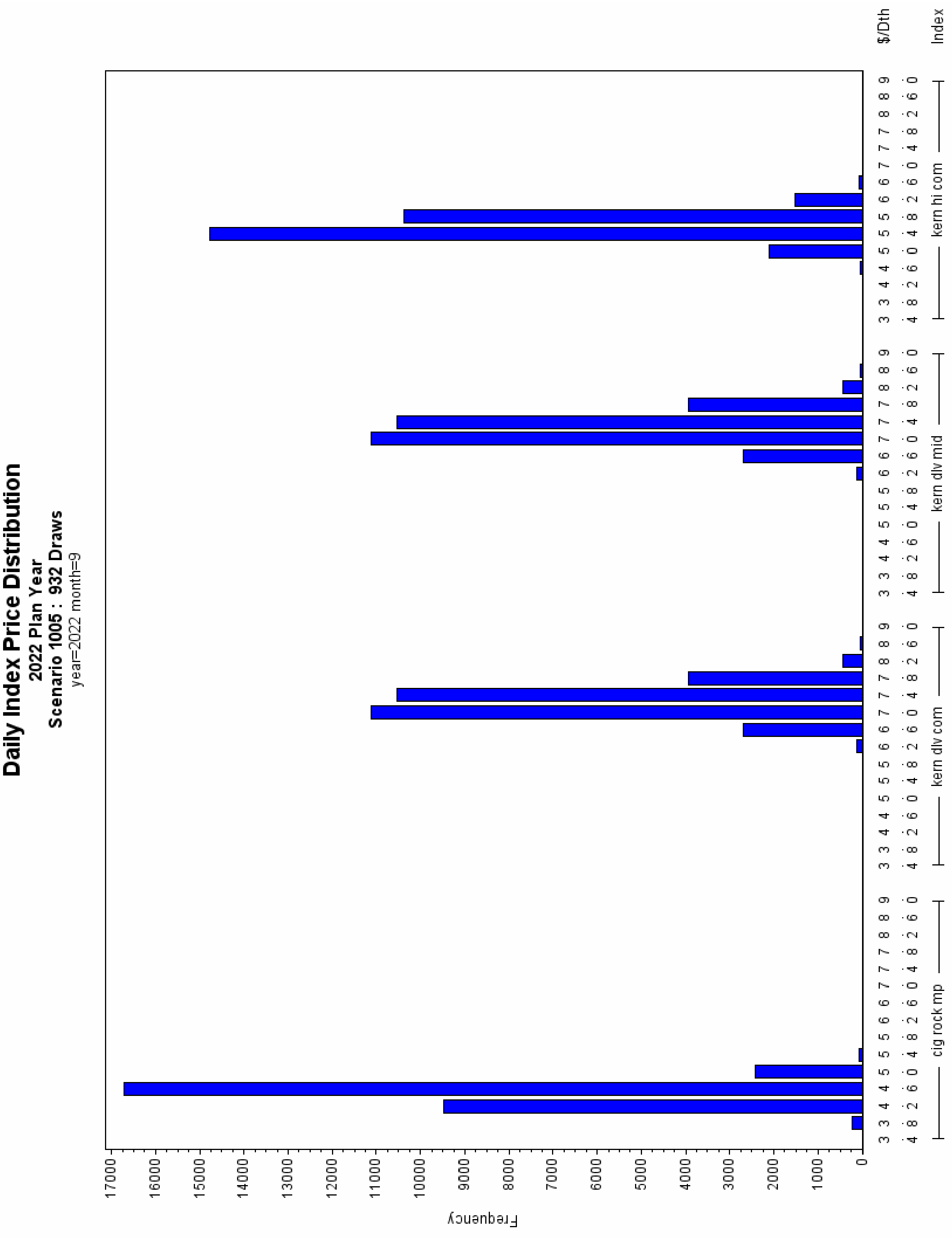


Exhibit 14.20

Daily Index Price Distribution

2022 Plan Year

Scenario 1005 : 932 Draws

year=2022 month=9

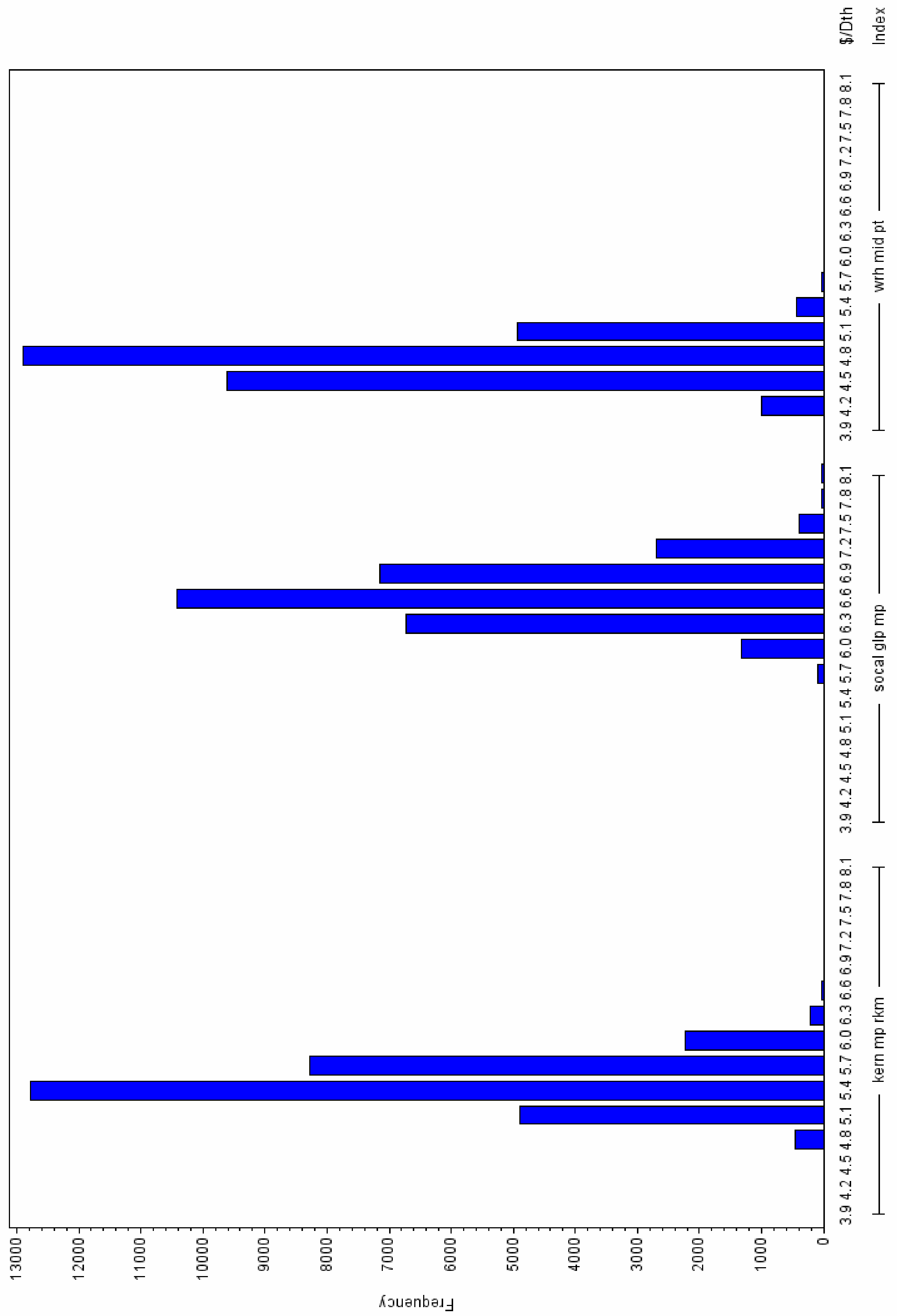


Exhibit 14.21

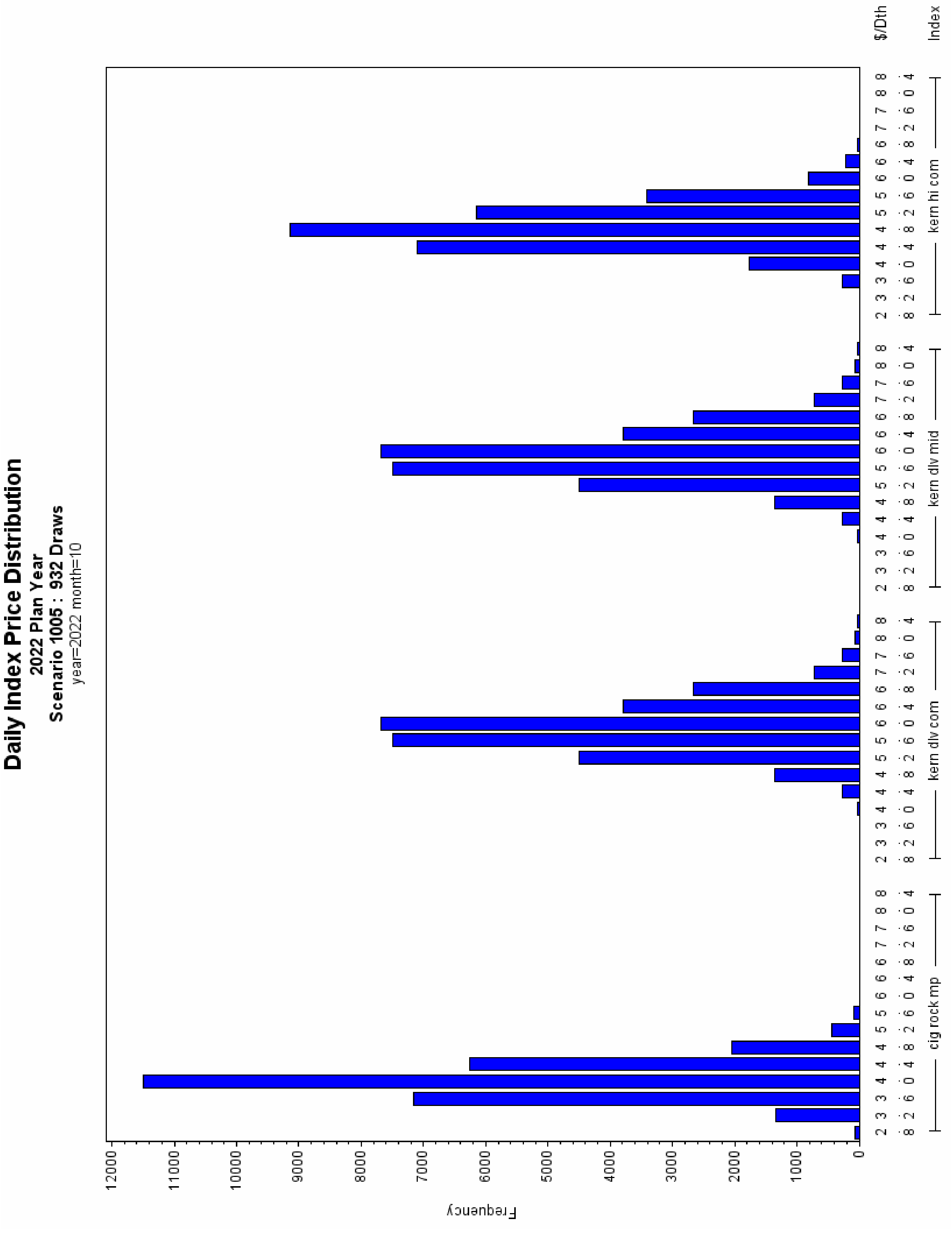


Exhibit 14.22

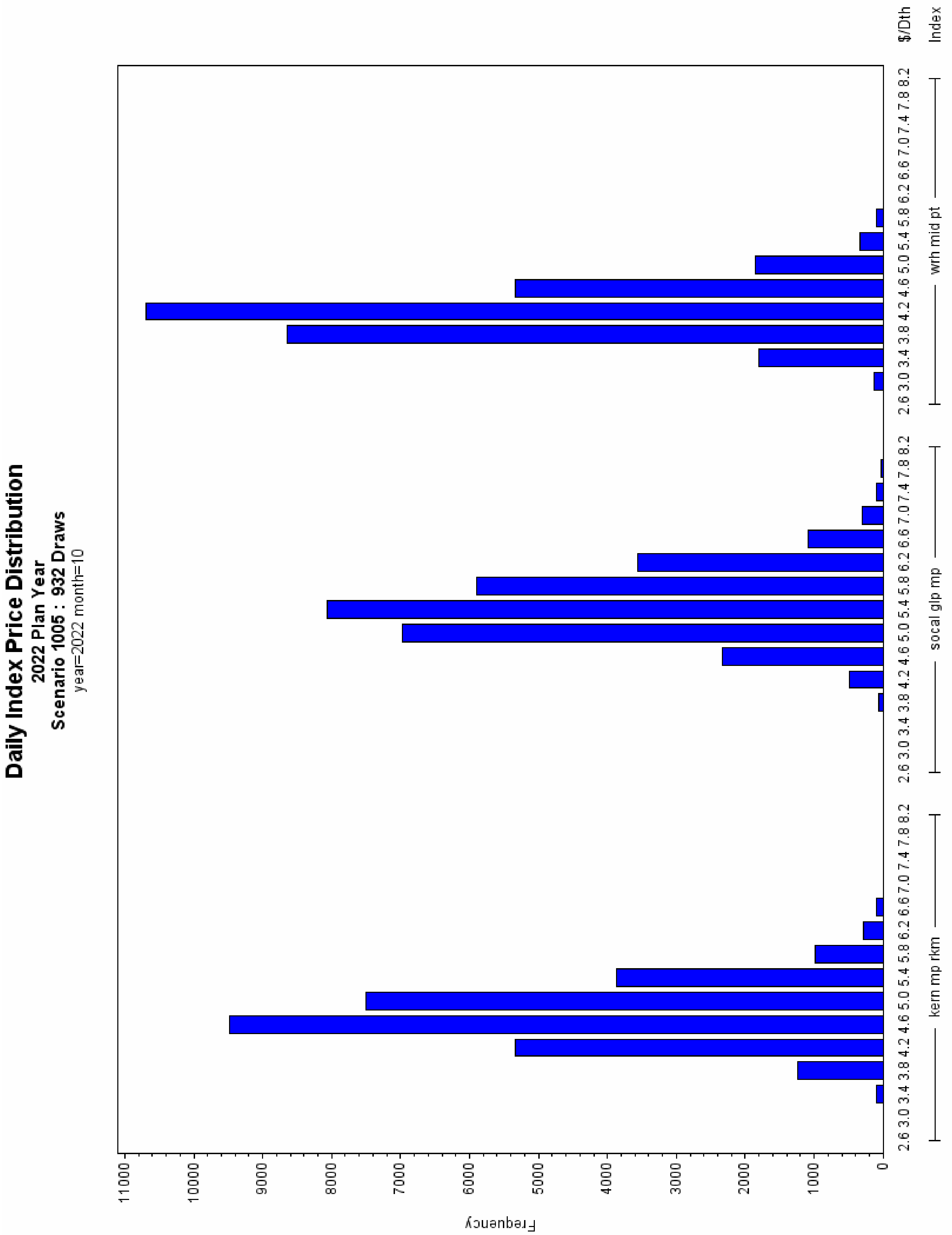


Exhibit 14.23

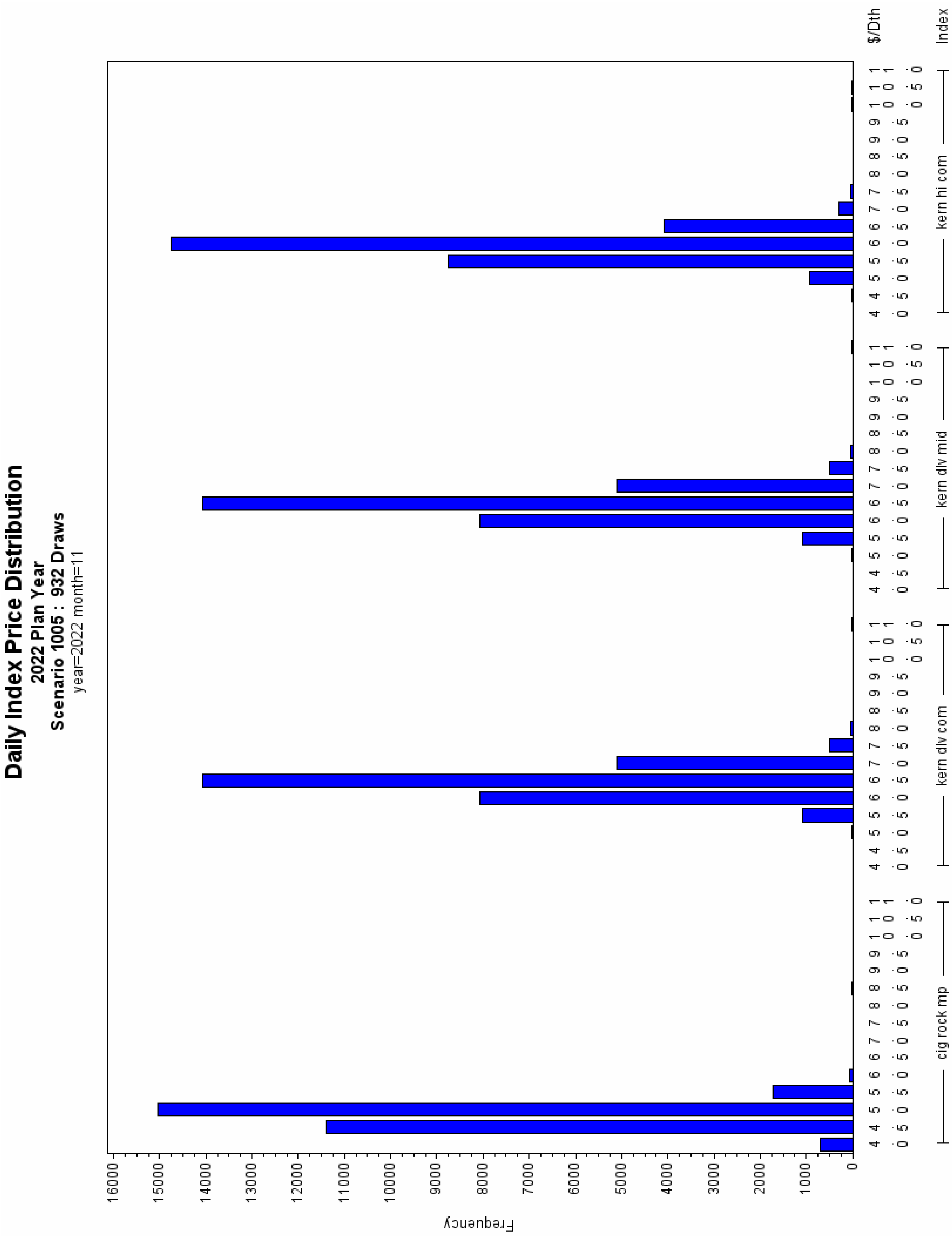


Exhibit 14.24

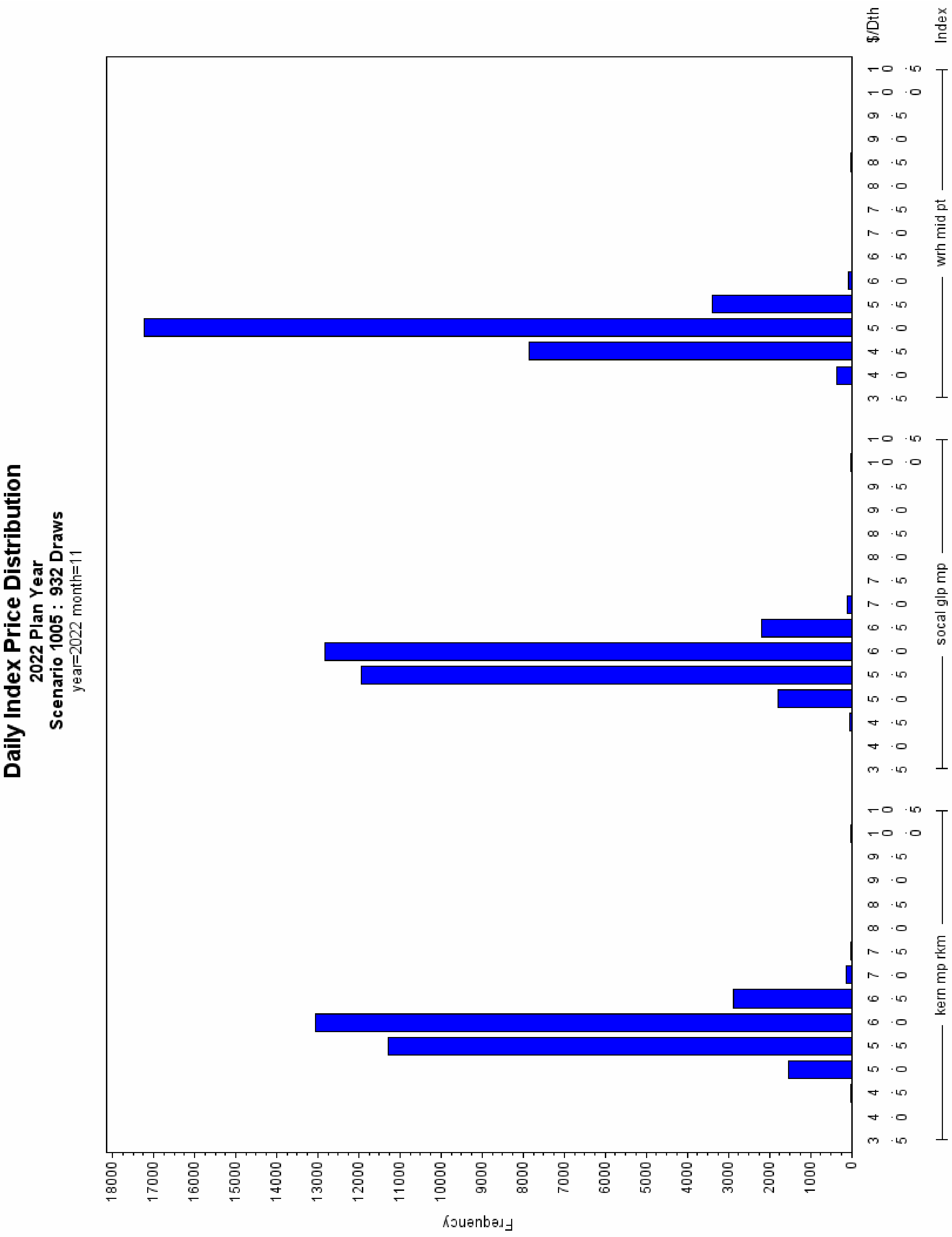


Exhibit 14.25

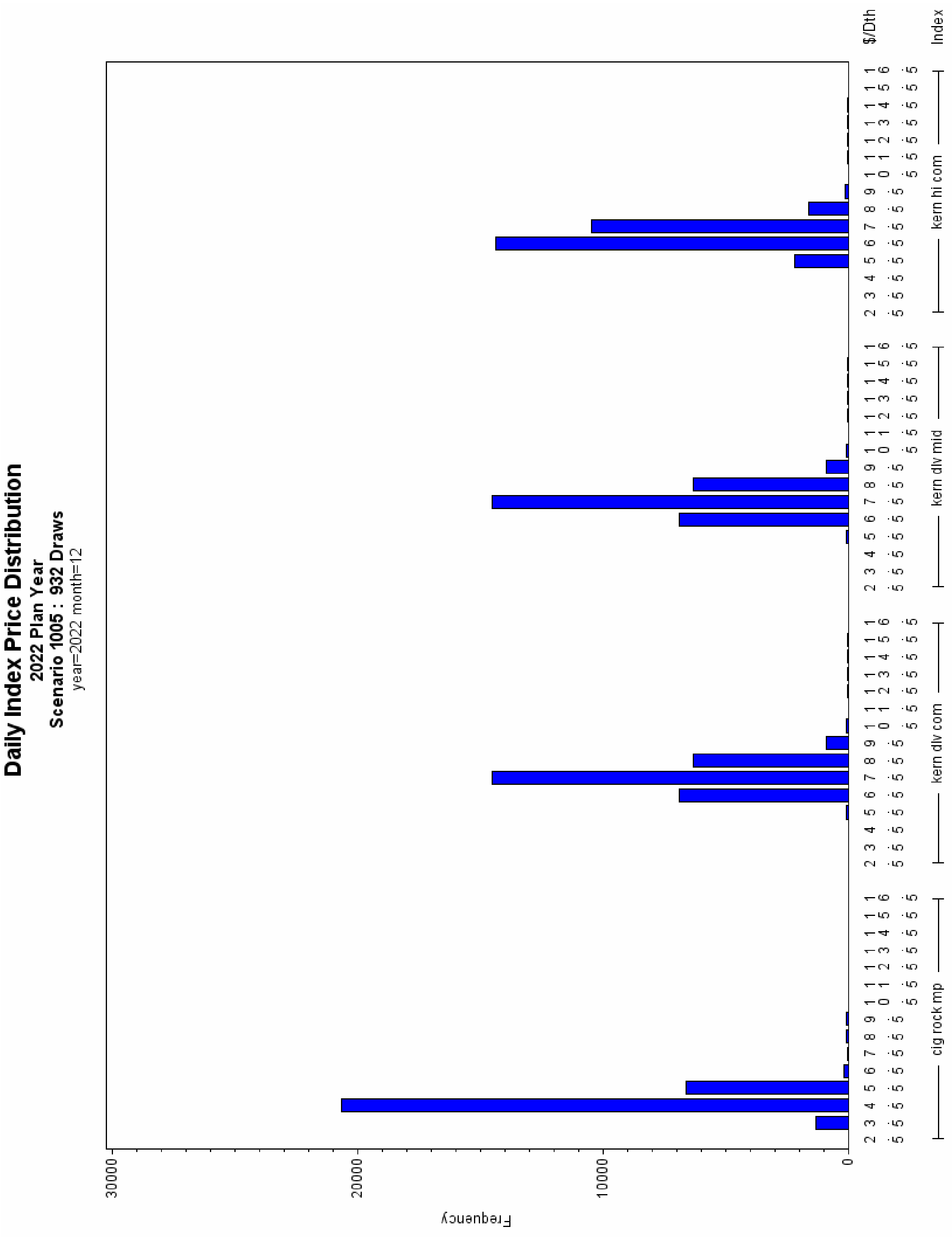


Exhibit 14.26

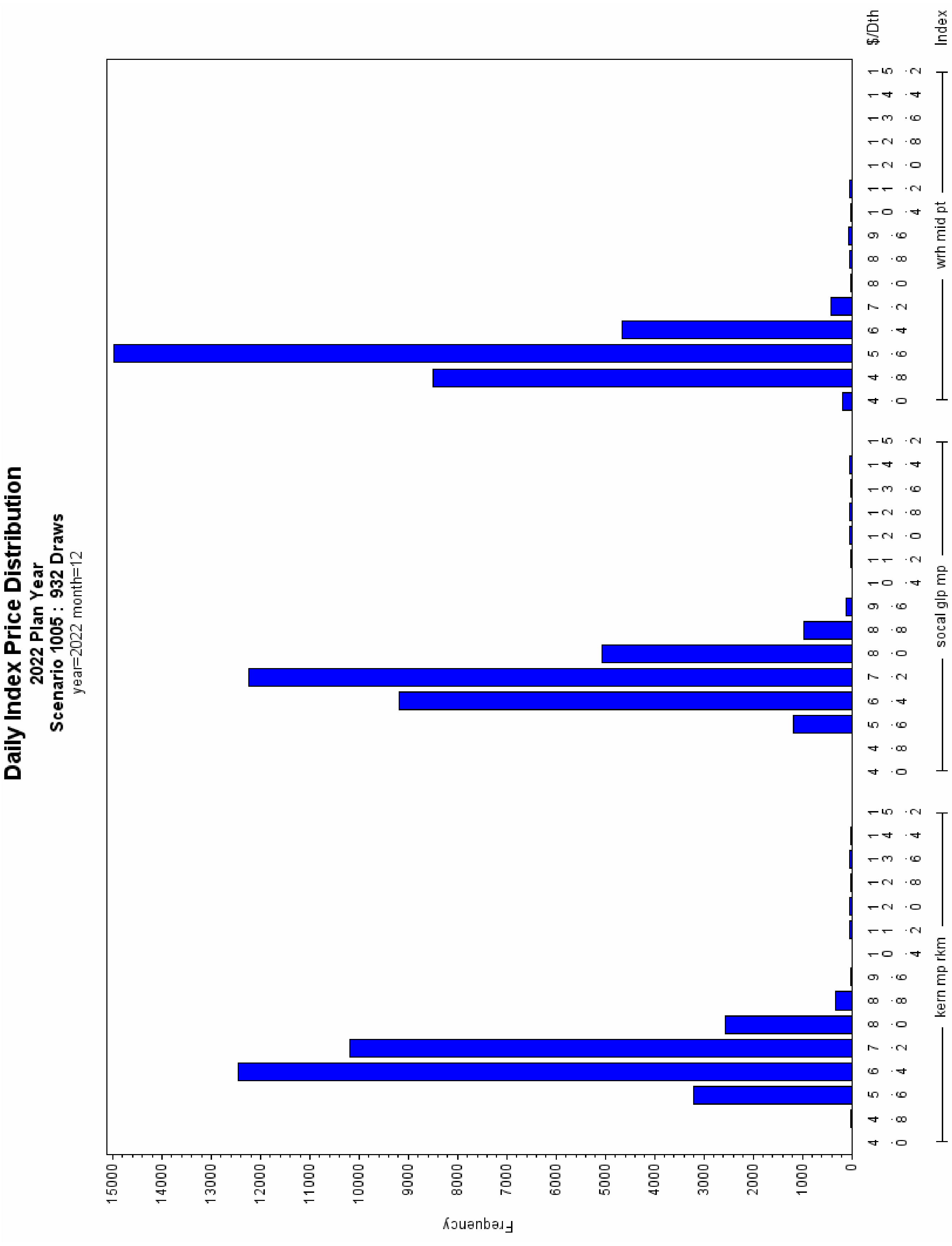


Exhibit 14.27

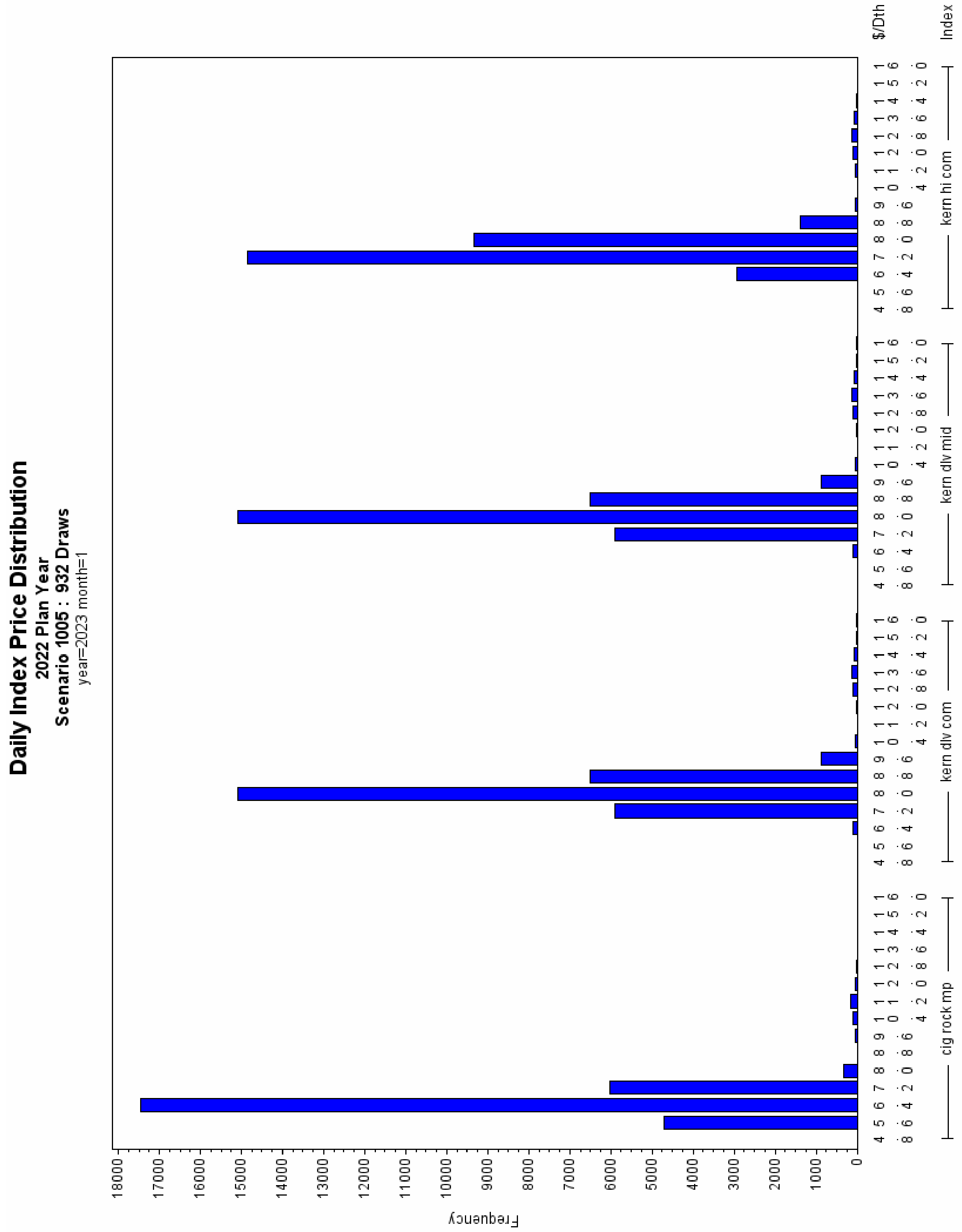


Exhibit 14.28

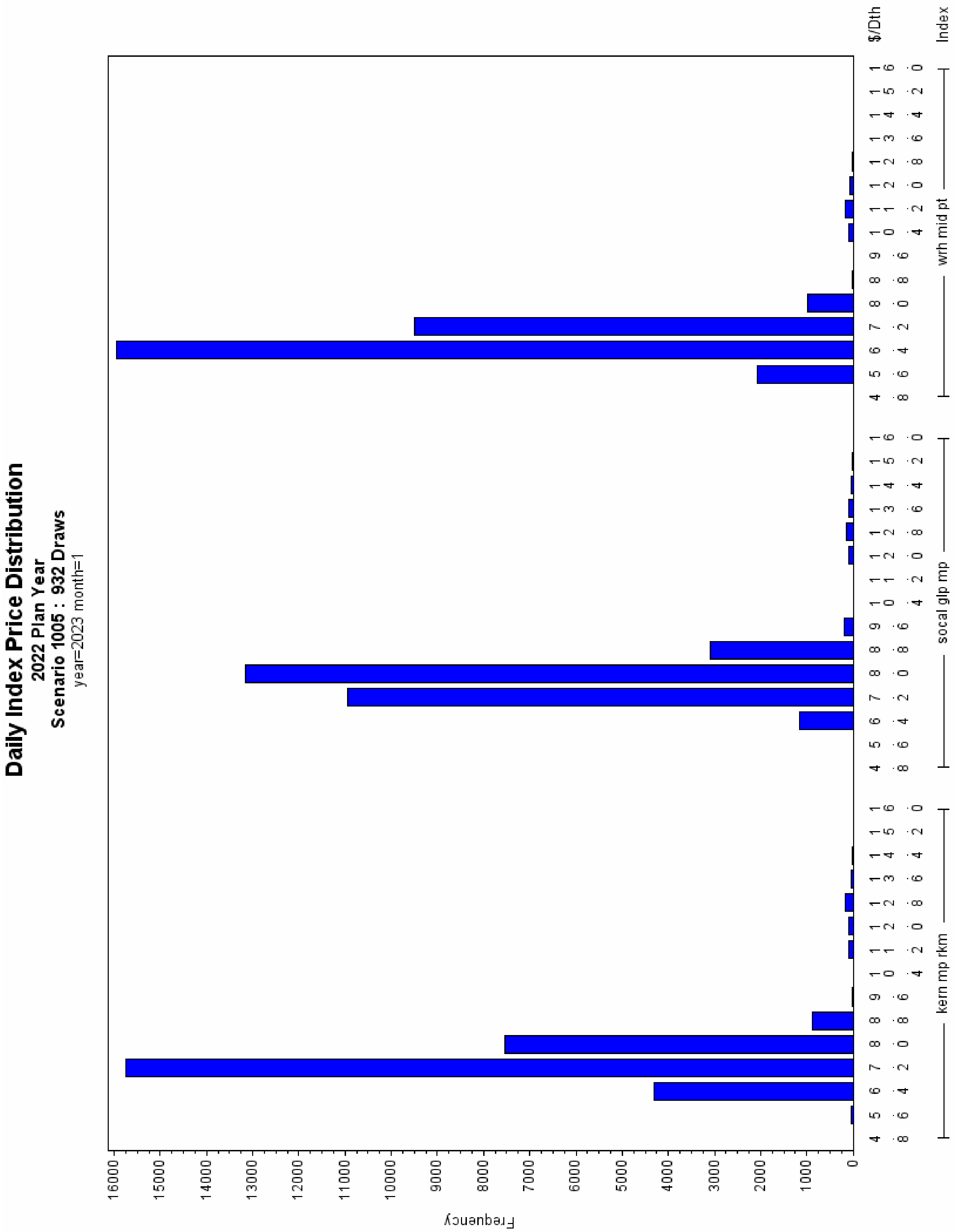


Exhibit 14.29

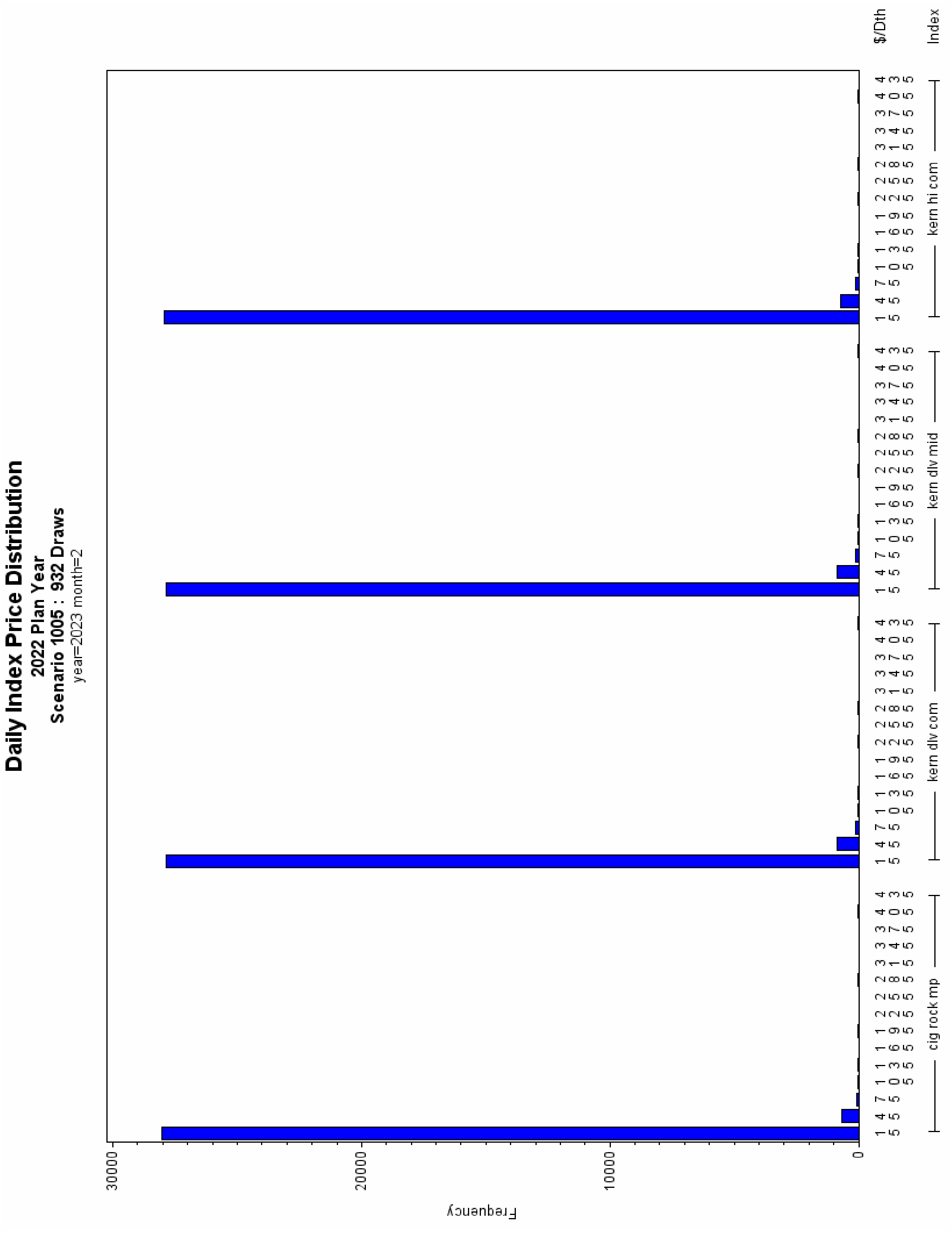


Exhibit 14.30

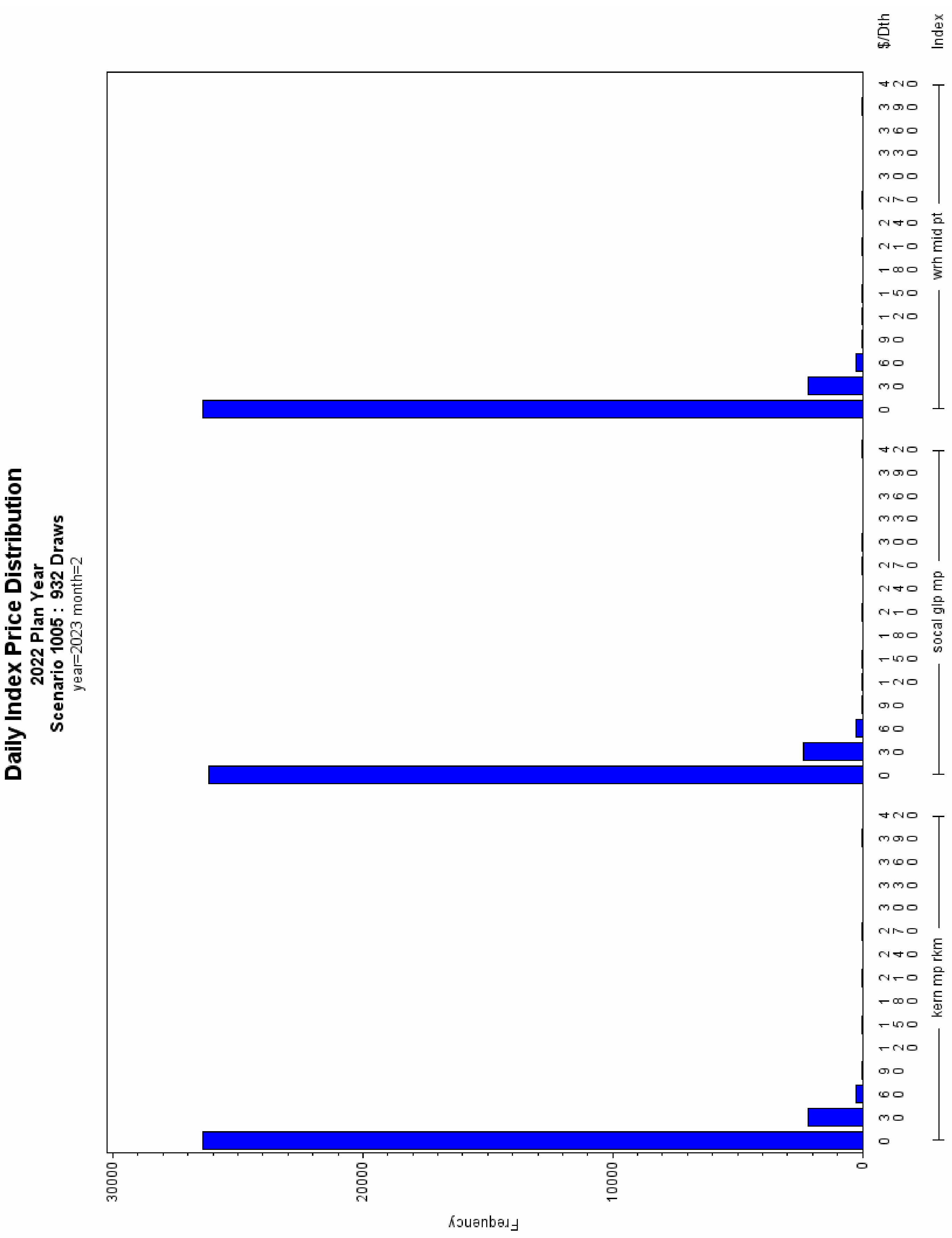


Exhibit 14.31

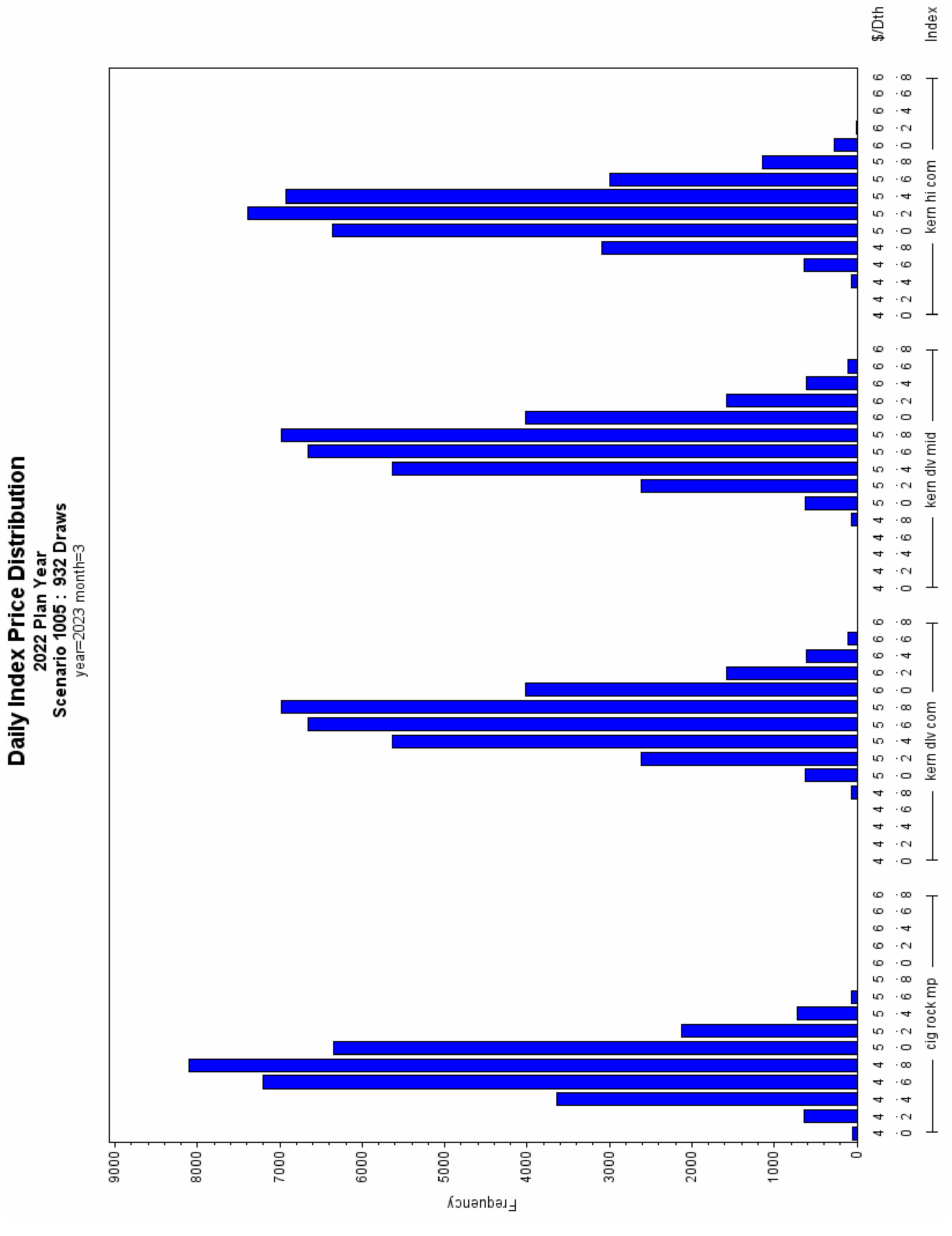
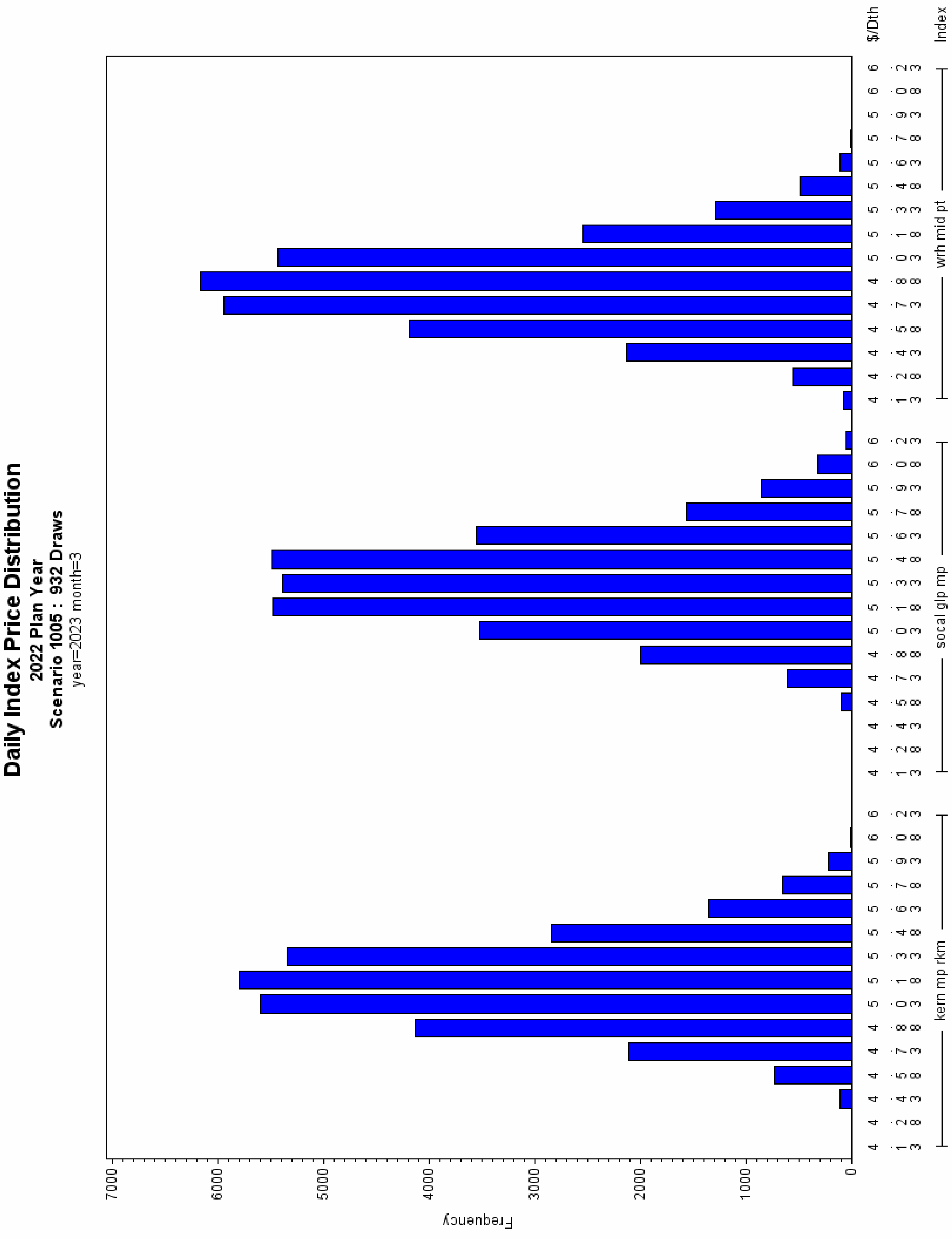


Exhibit 14.32



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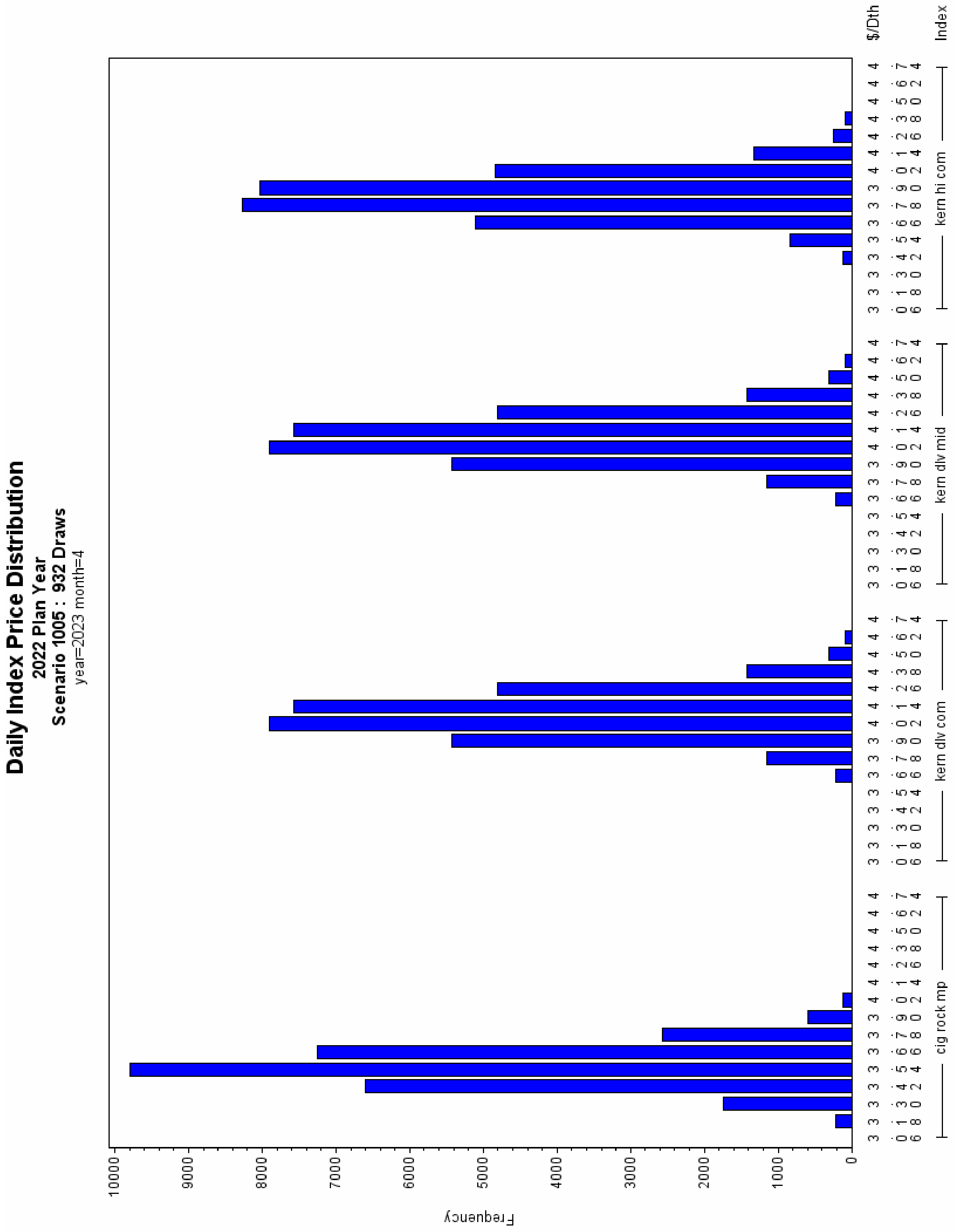

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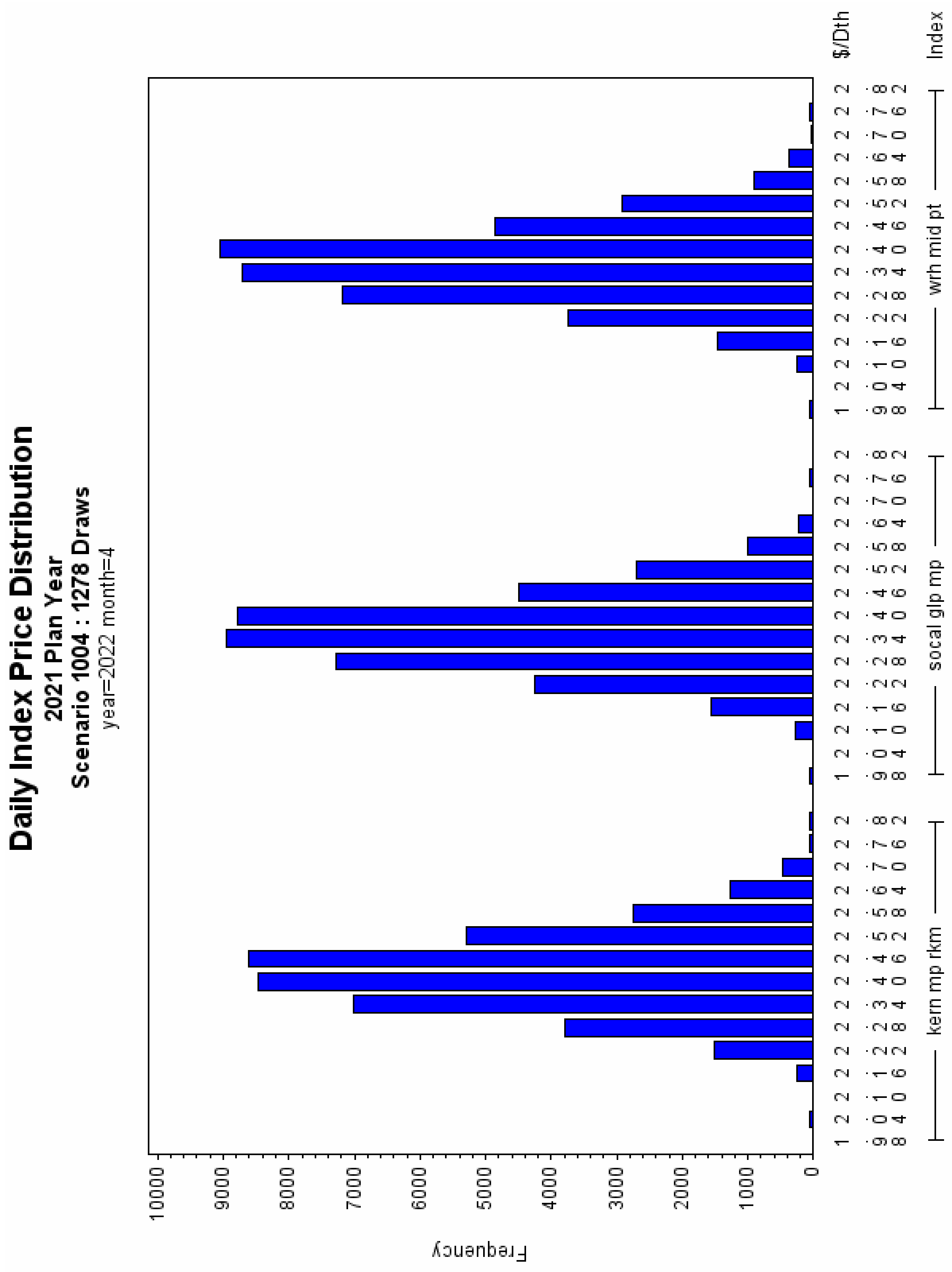
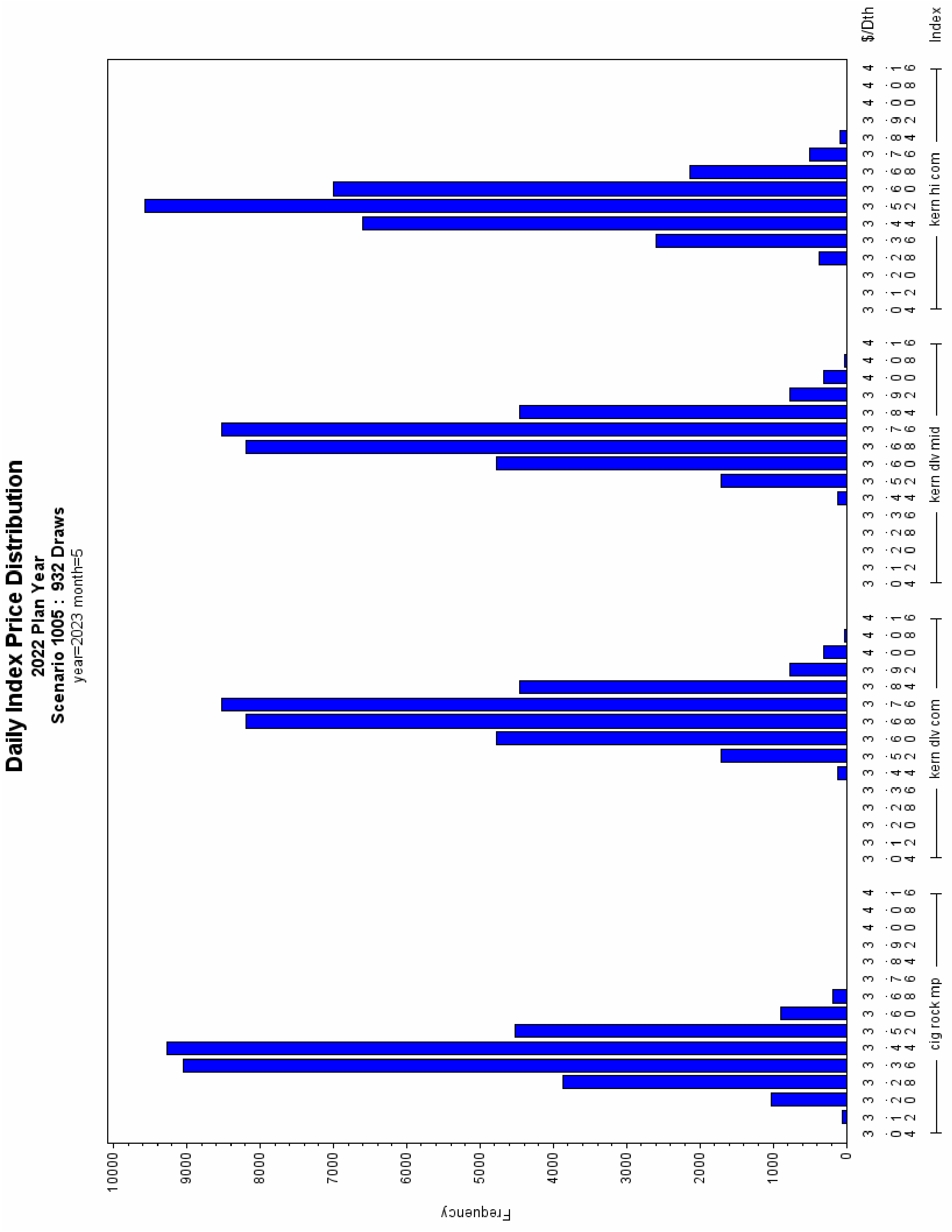


Exhibit 14.35



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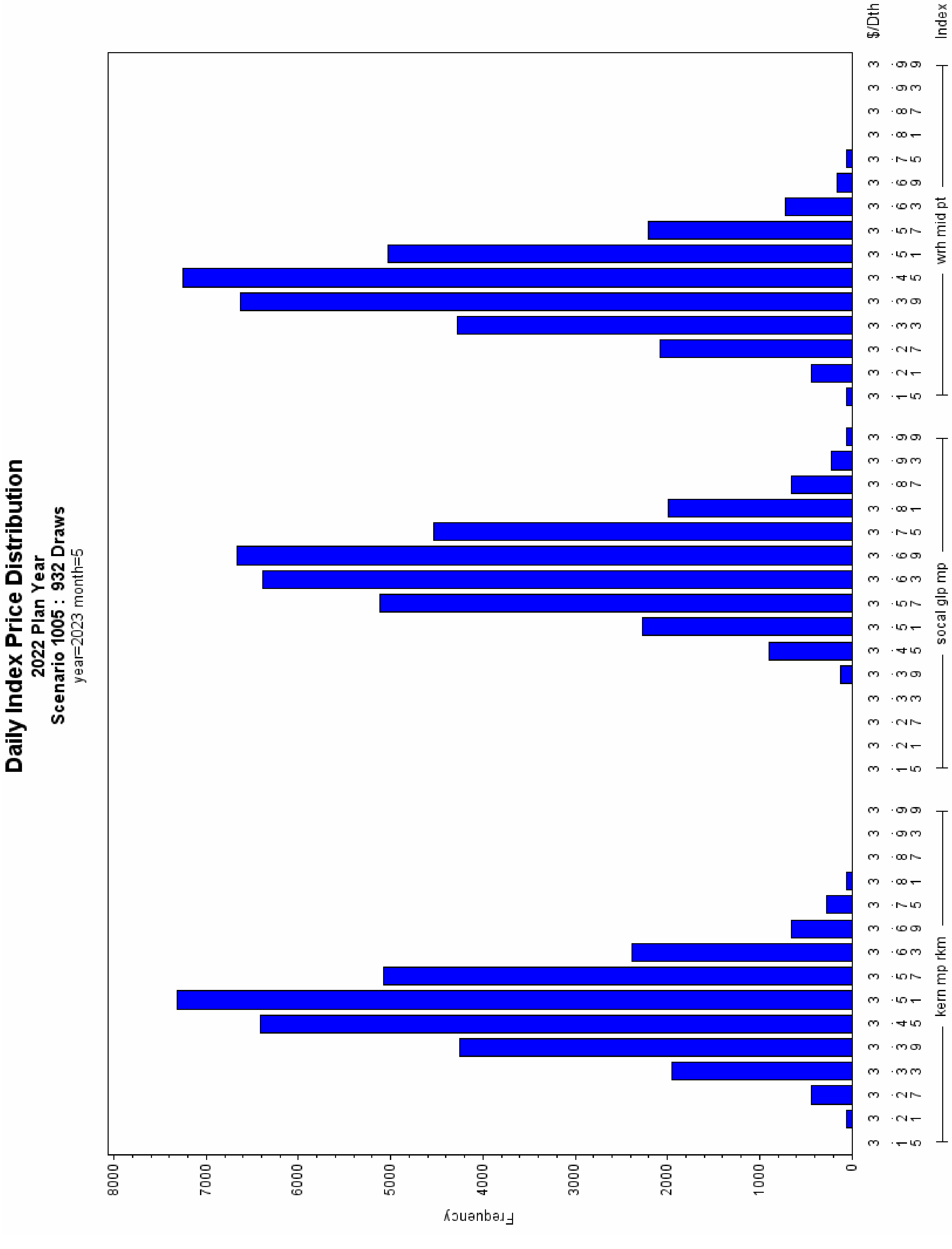


Exhibit 14.37

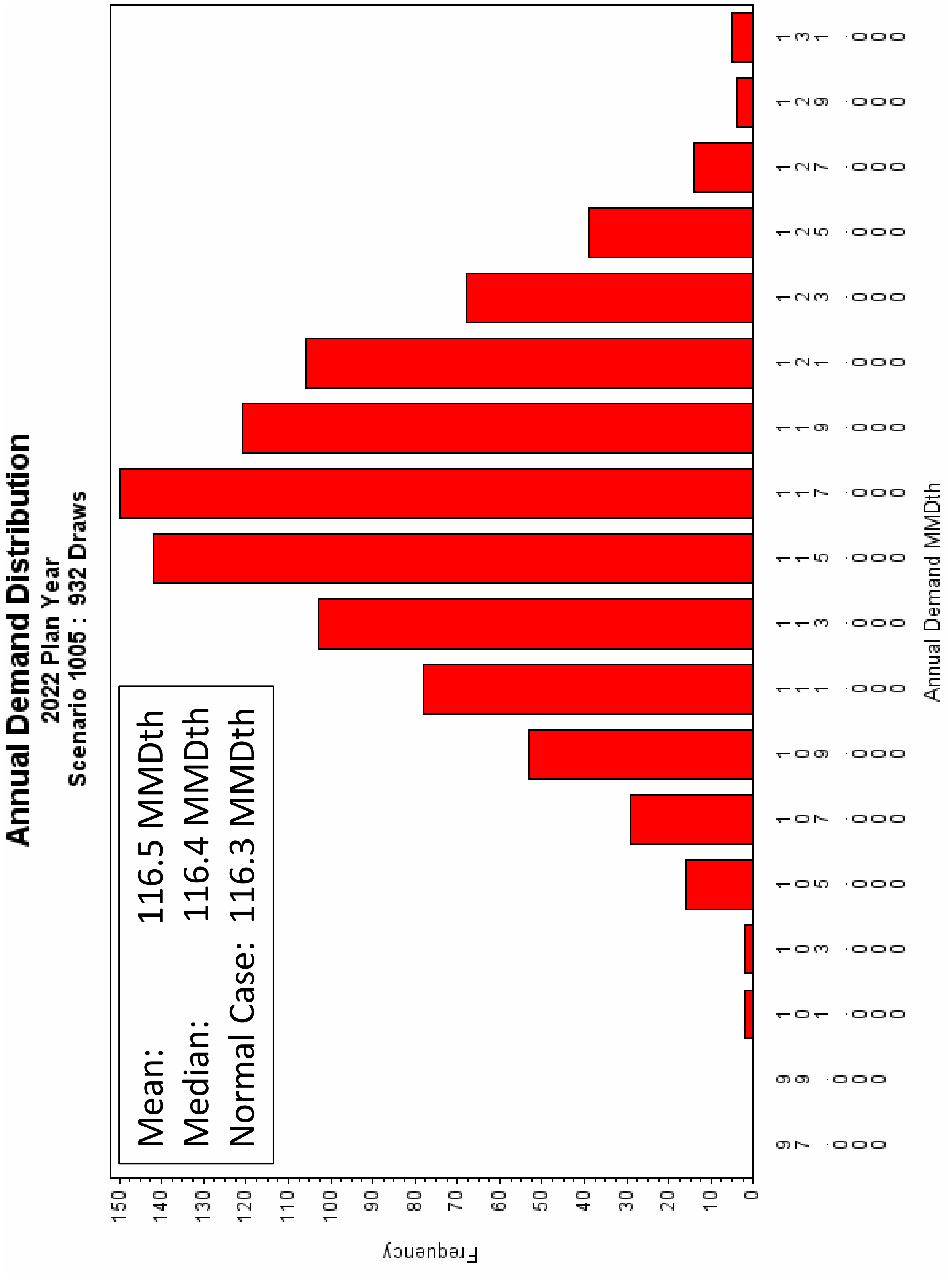
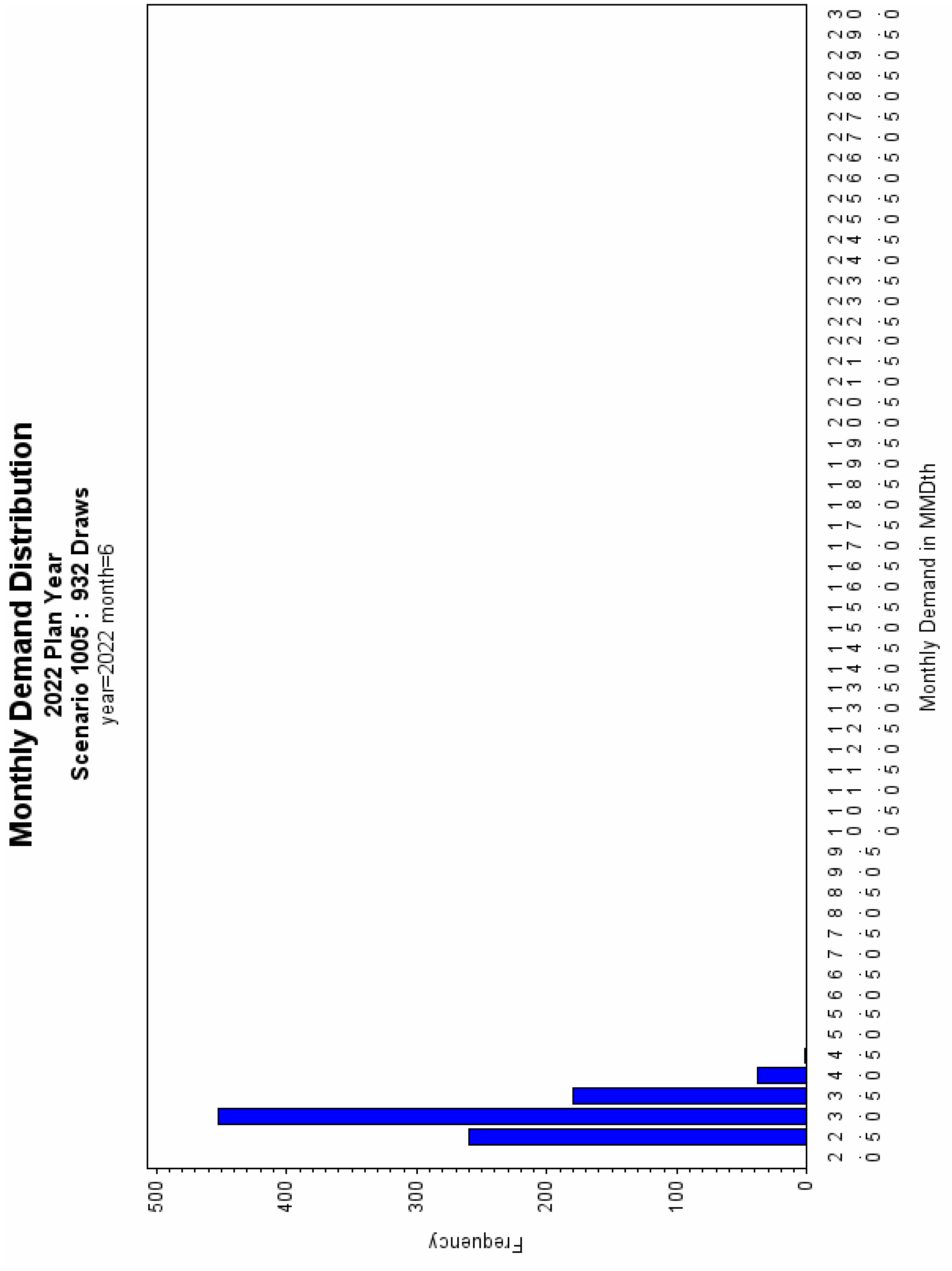


Exhibit 14.38



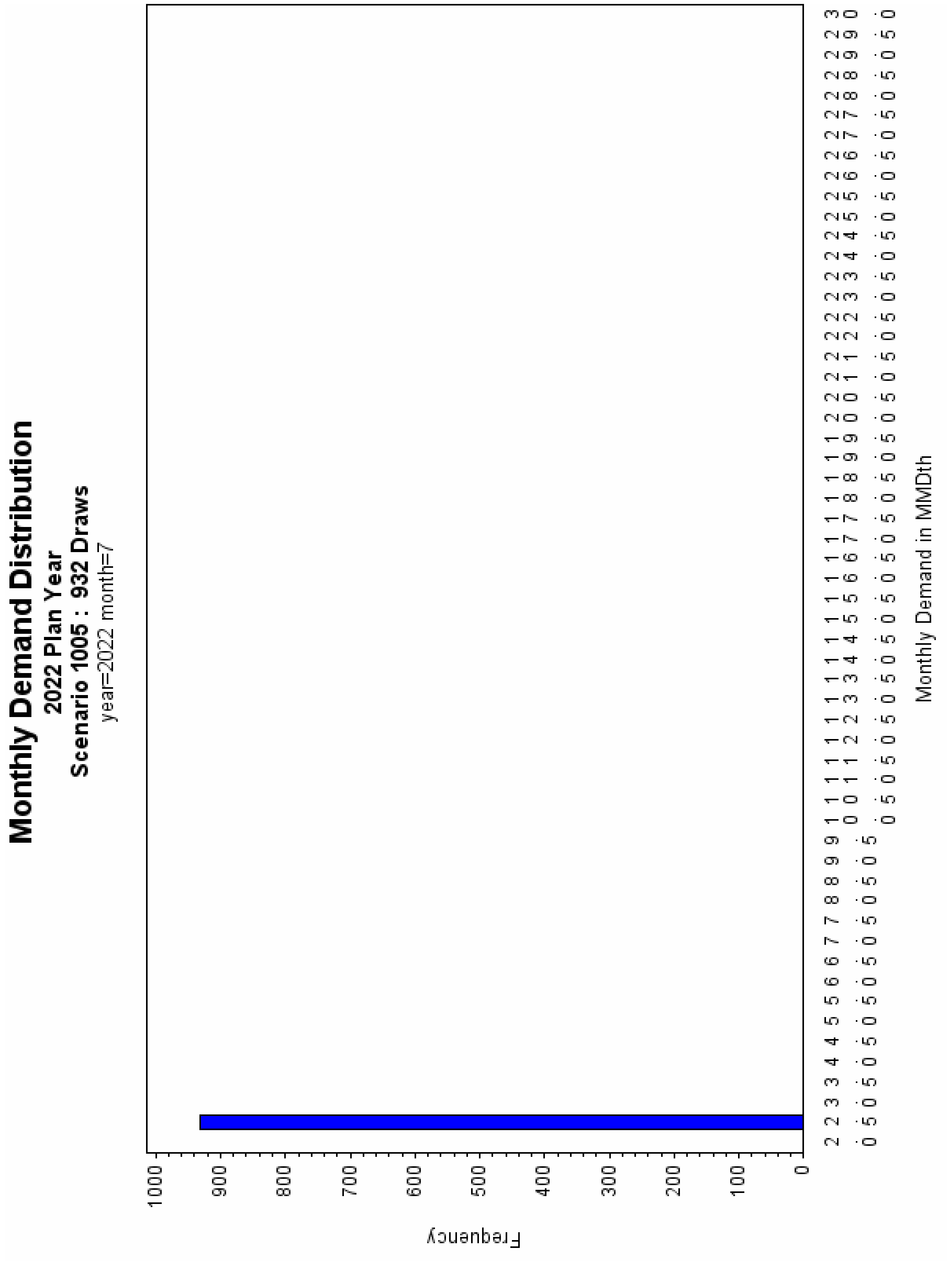

Monthly Demand Distribution
2022 Plan Year
Scenario 1005 : 932 Draws
year=2022 month=7
Frequency
1000
900
800
700
600
500
400
300
200
100
0
Monthly Demand in MMDth

Exhibit 14.40

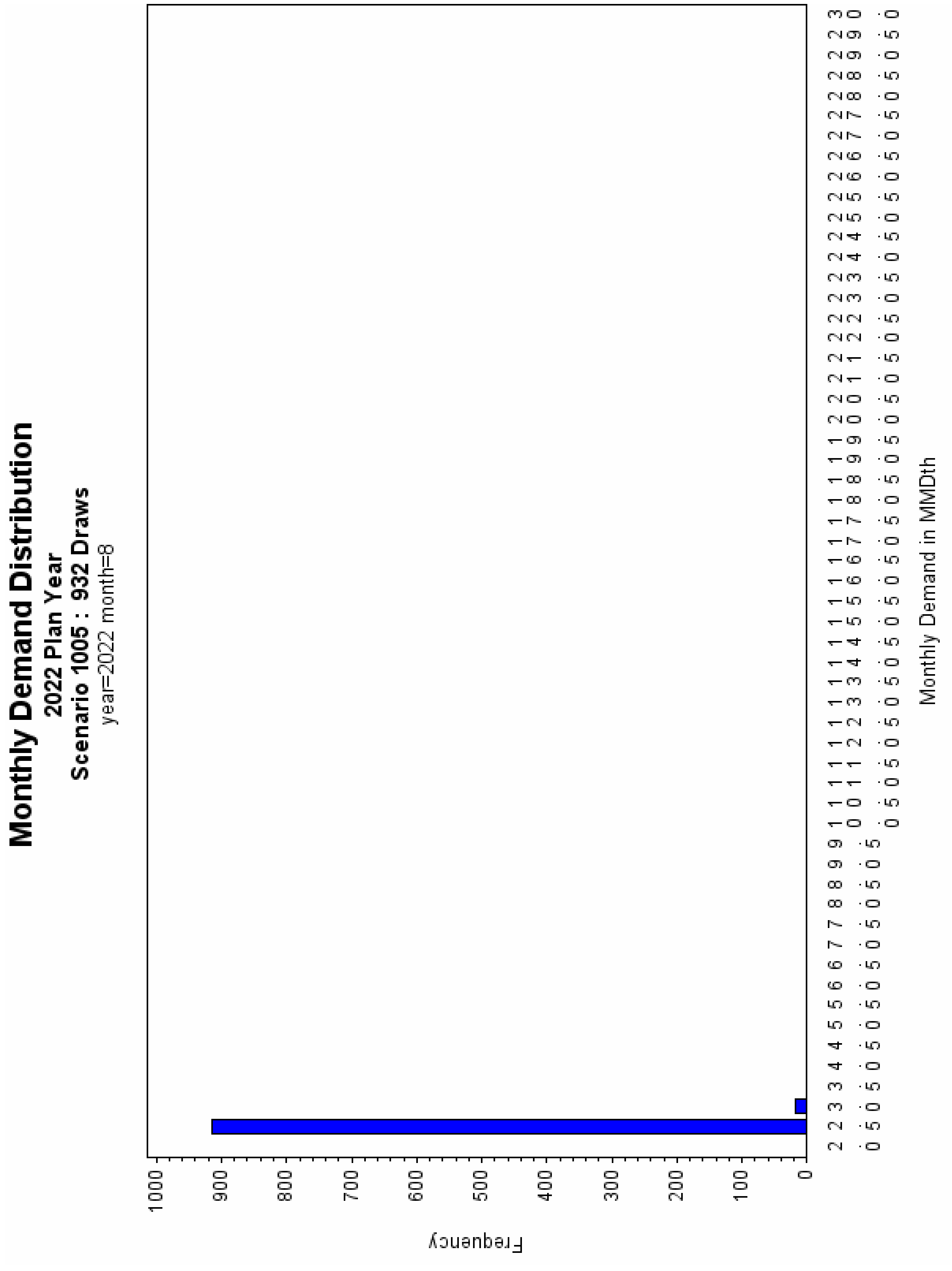


Exhibit 14.41

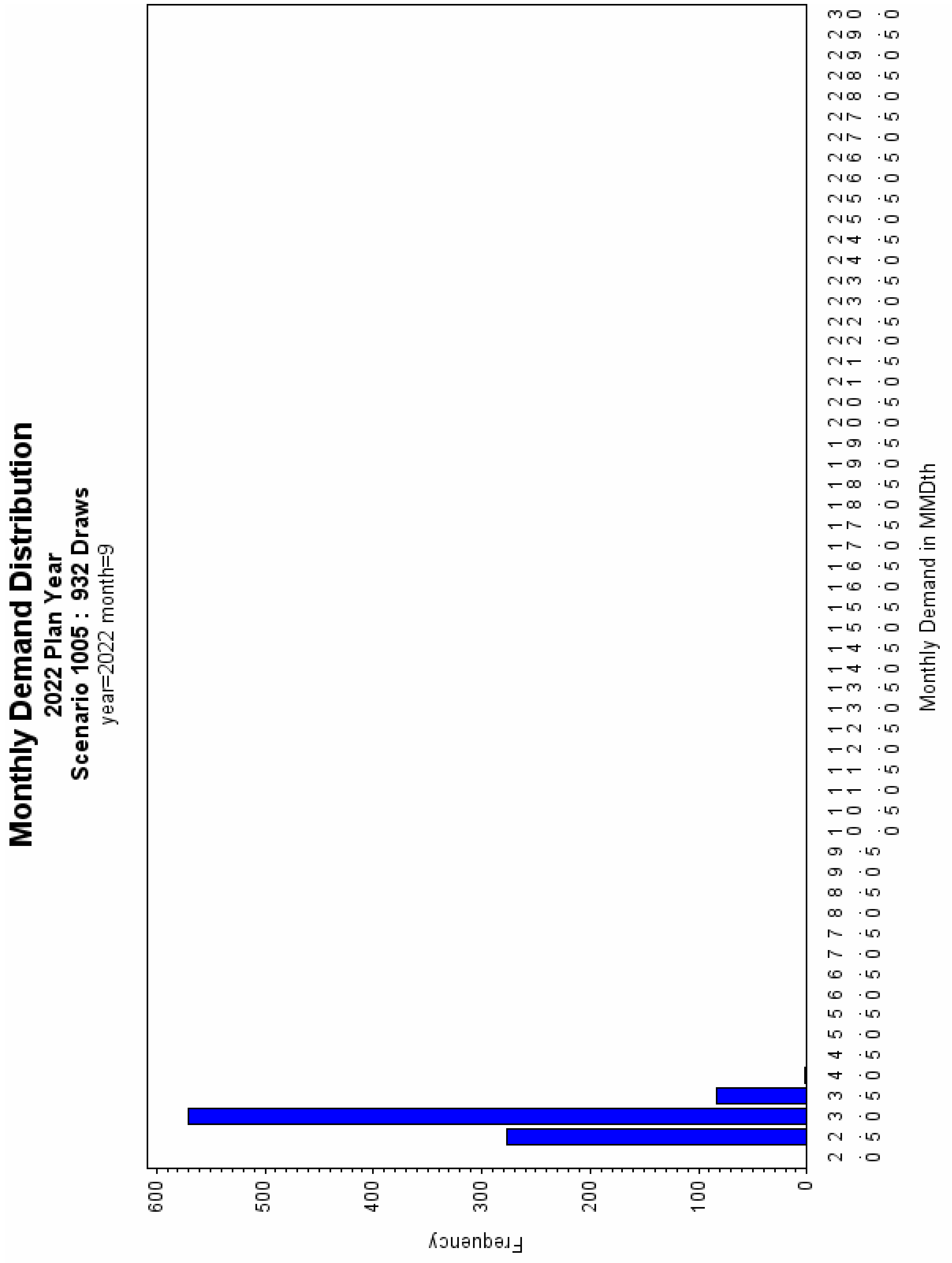


Exhibit 14.42

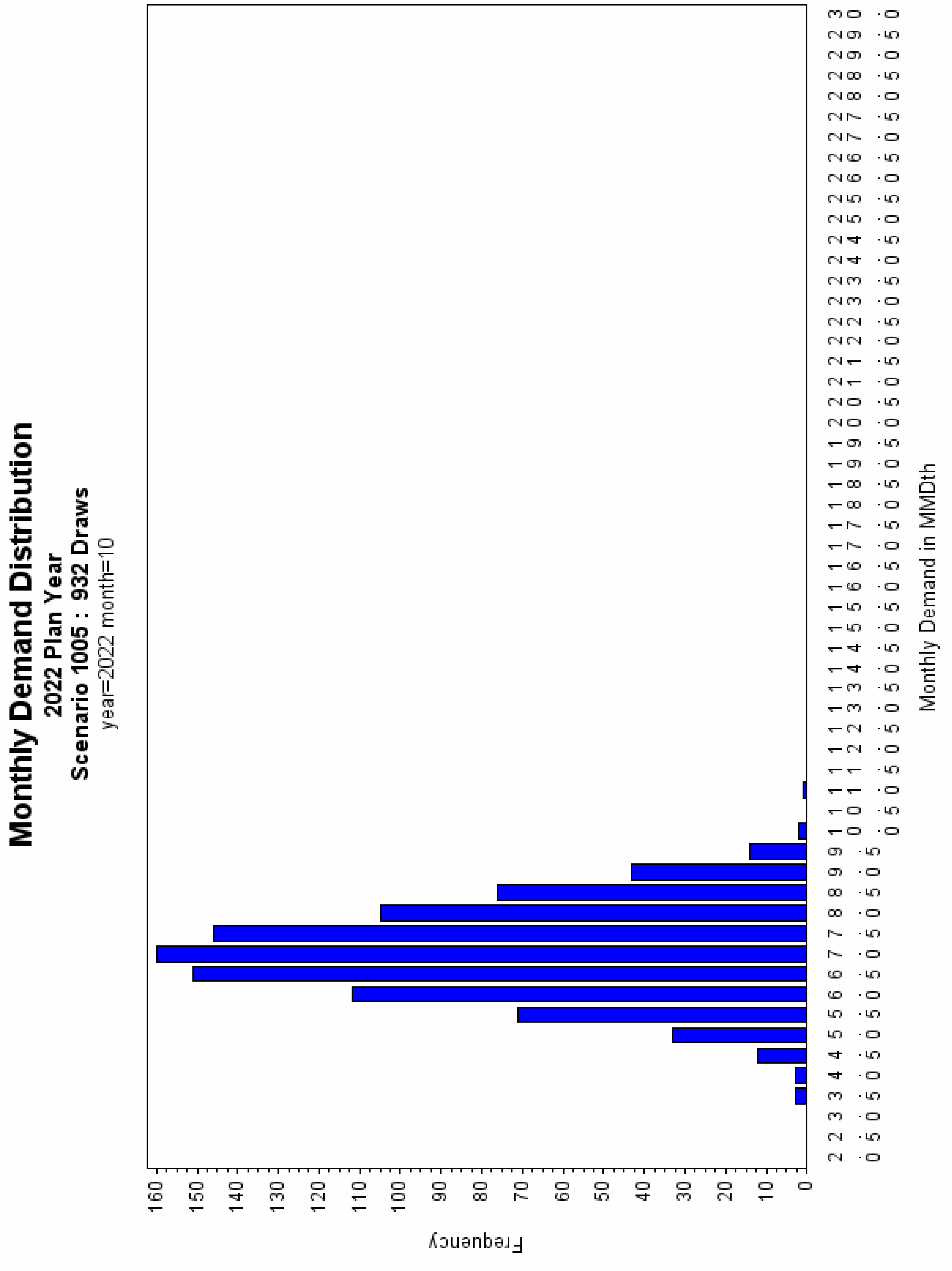


Exhibit 14.43

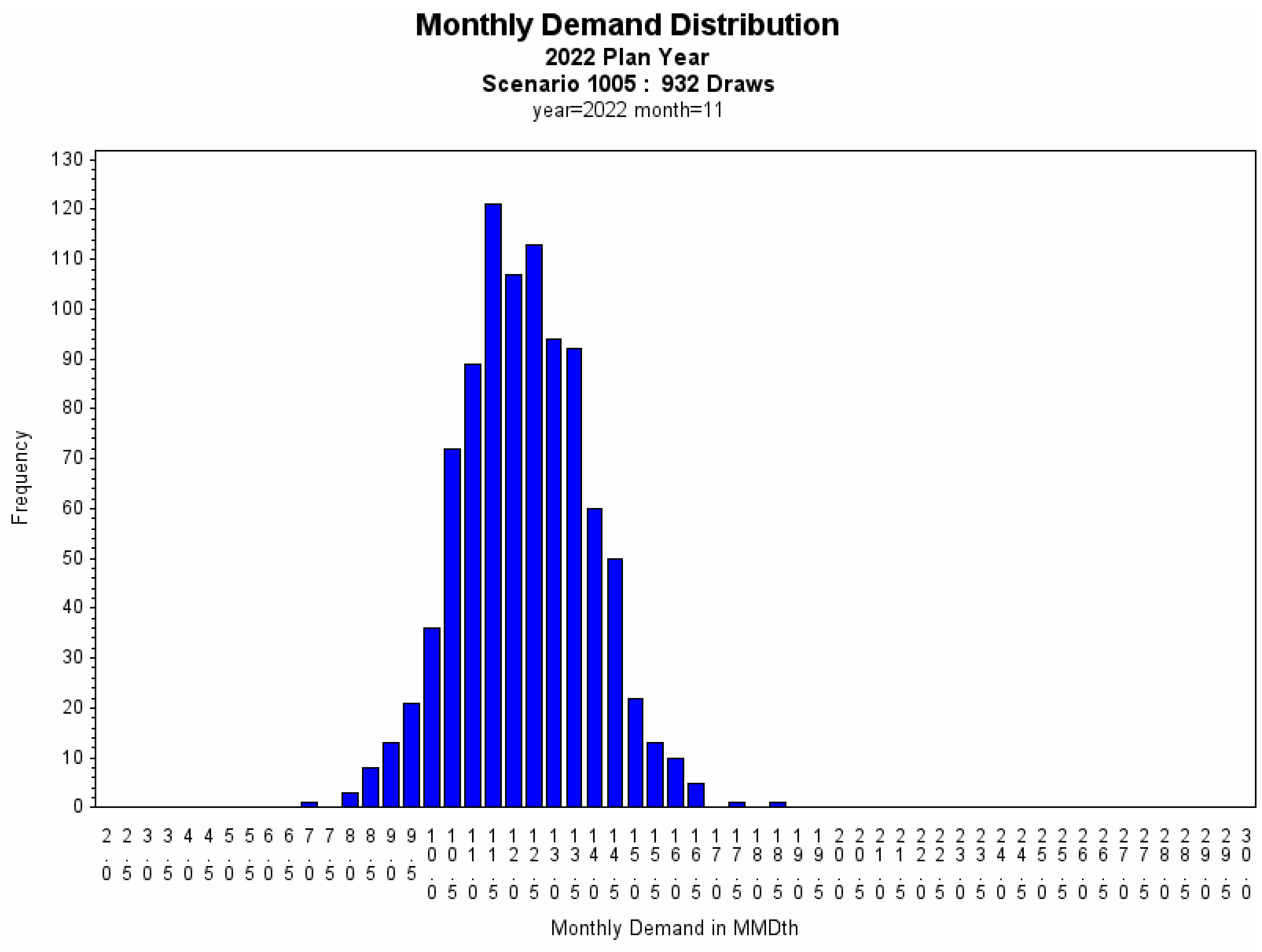


Exhibit 14.44

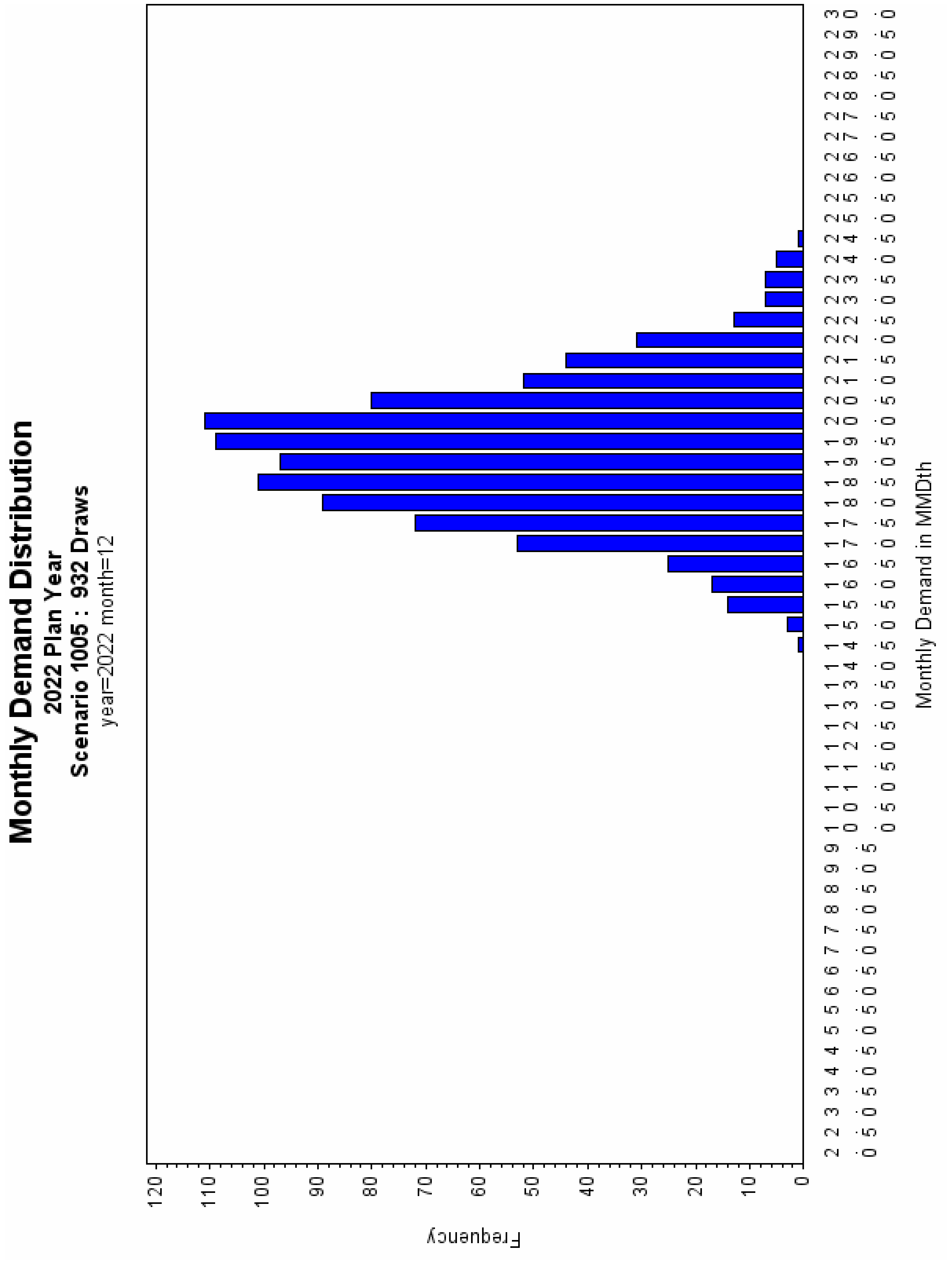


Exhibit 14.45

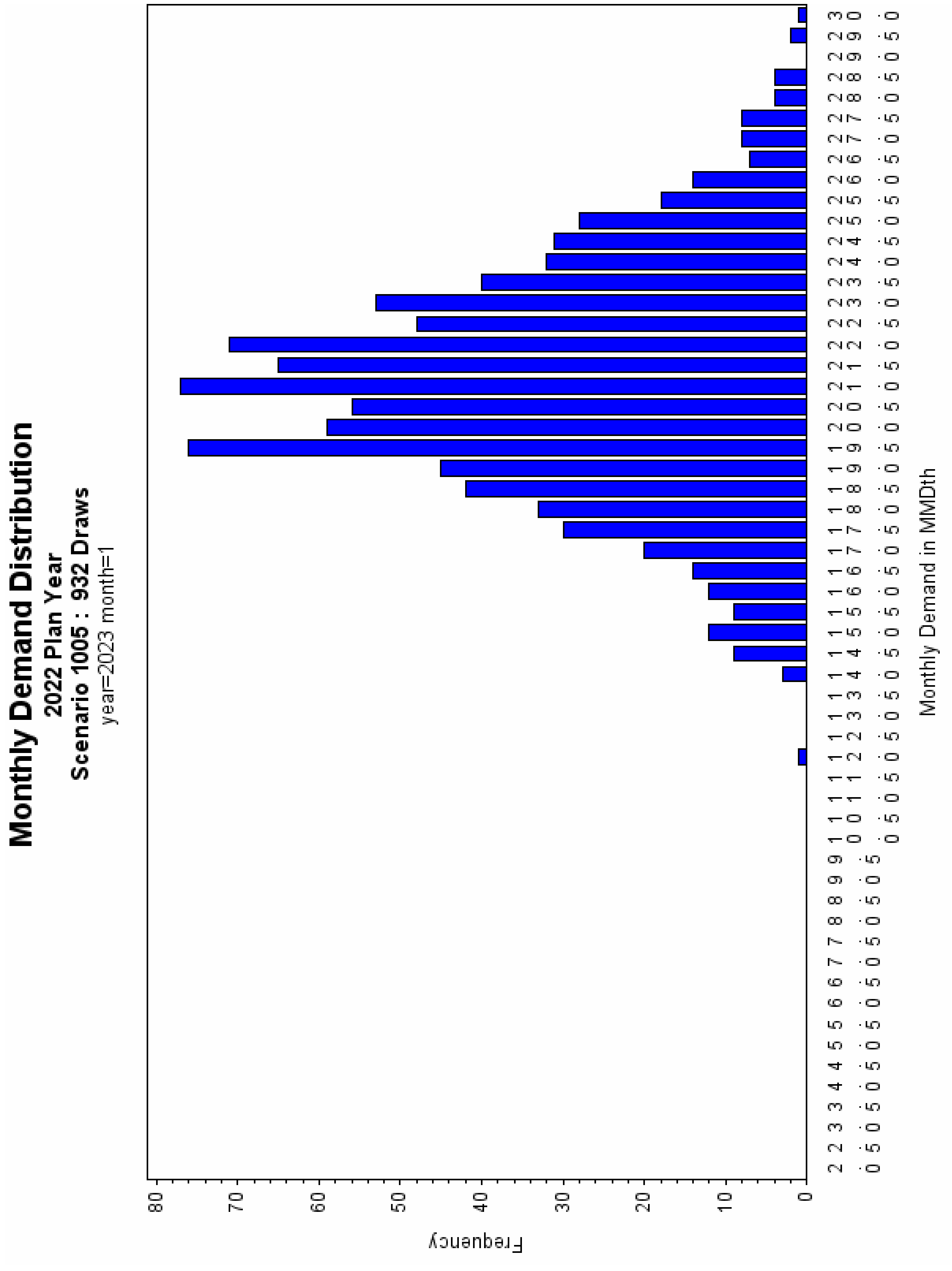


Exhibit 14.46

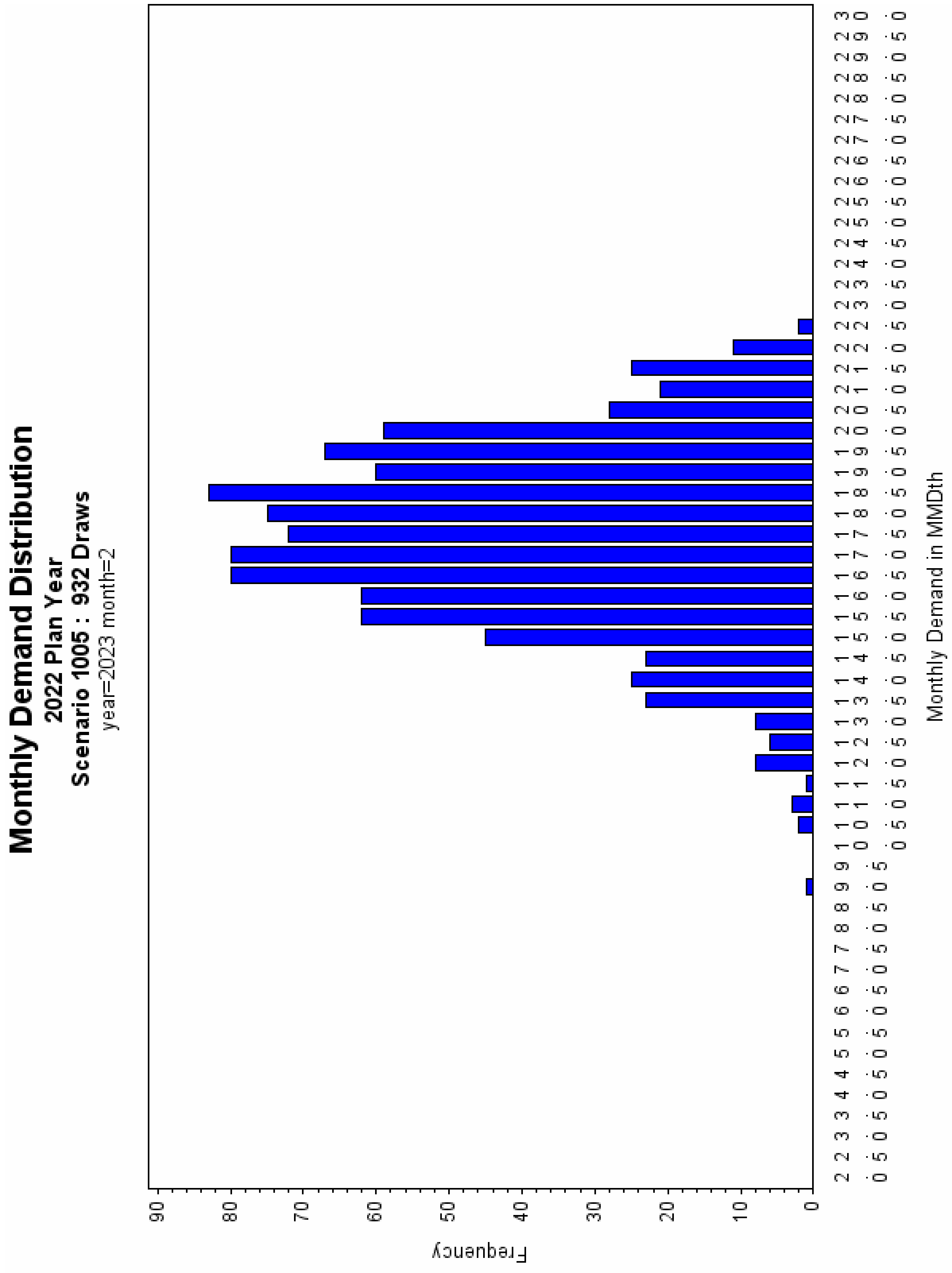


Exhibit 14.47

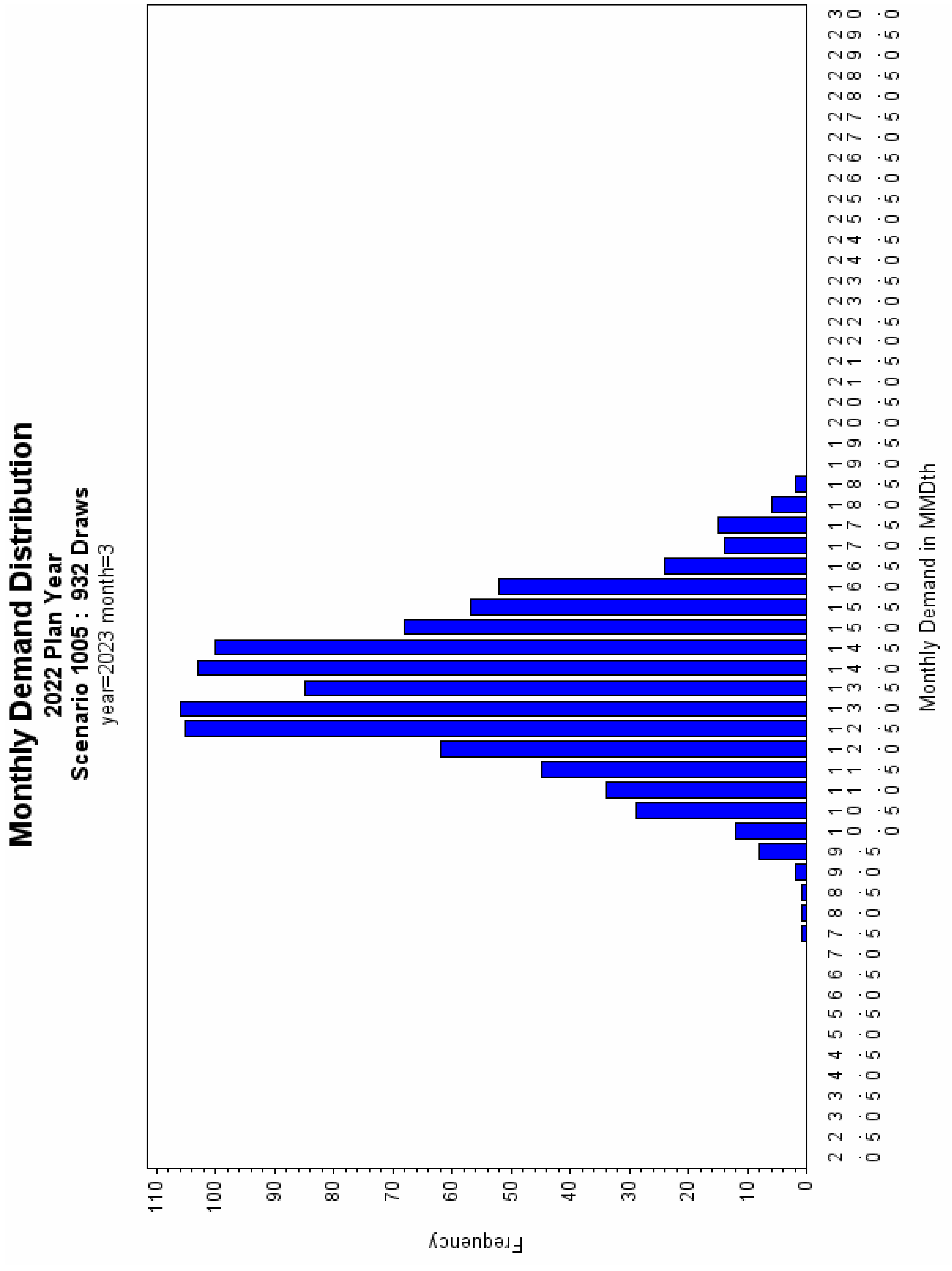


Exhibit 14.48

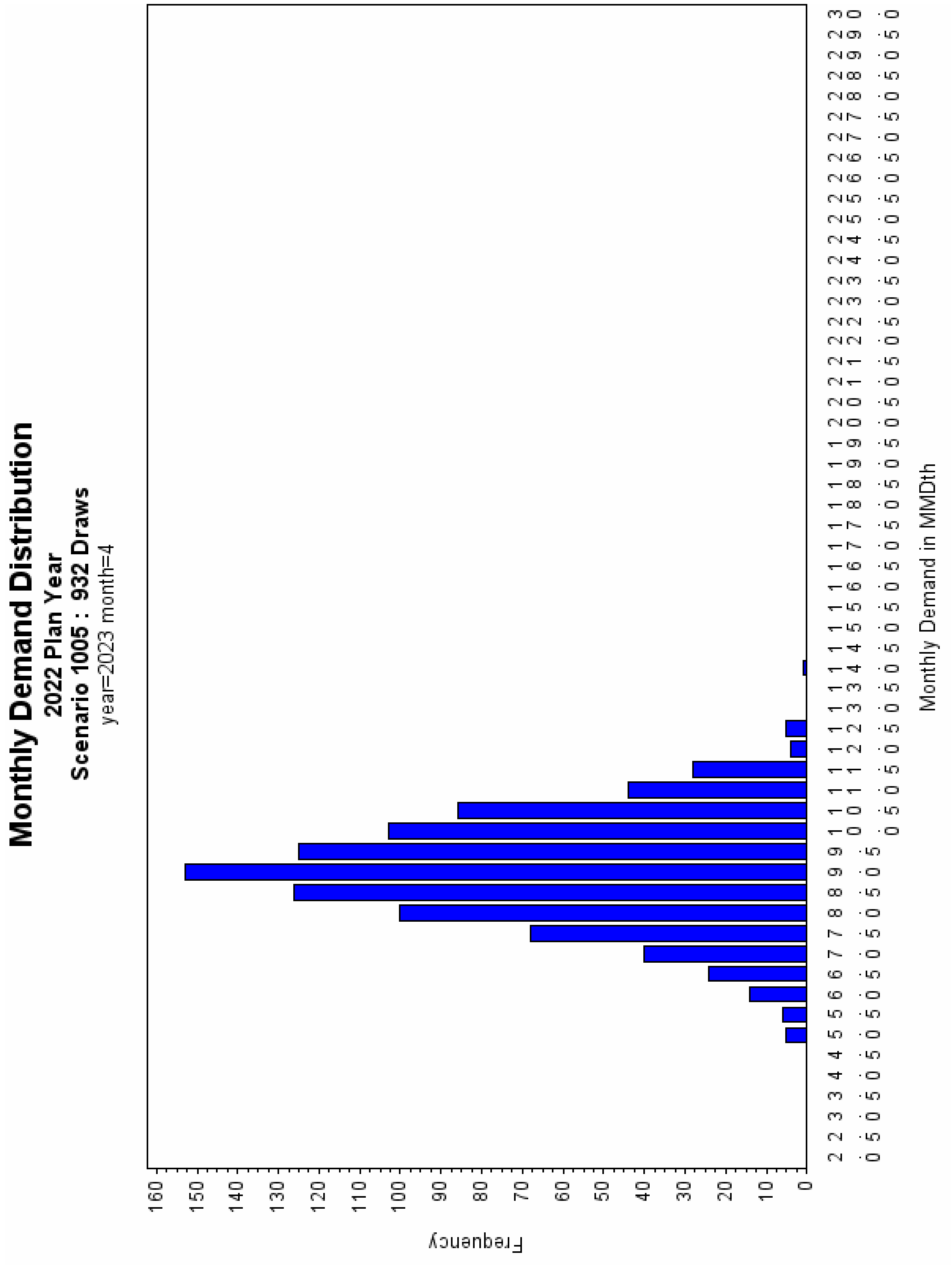
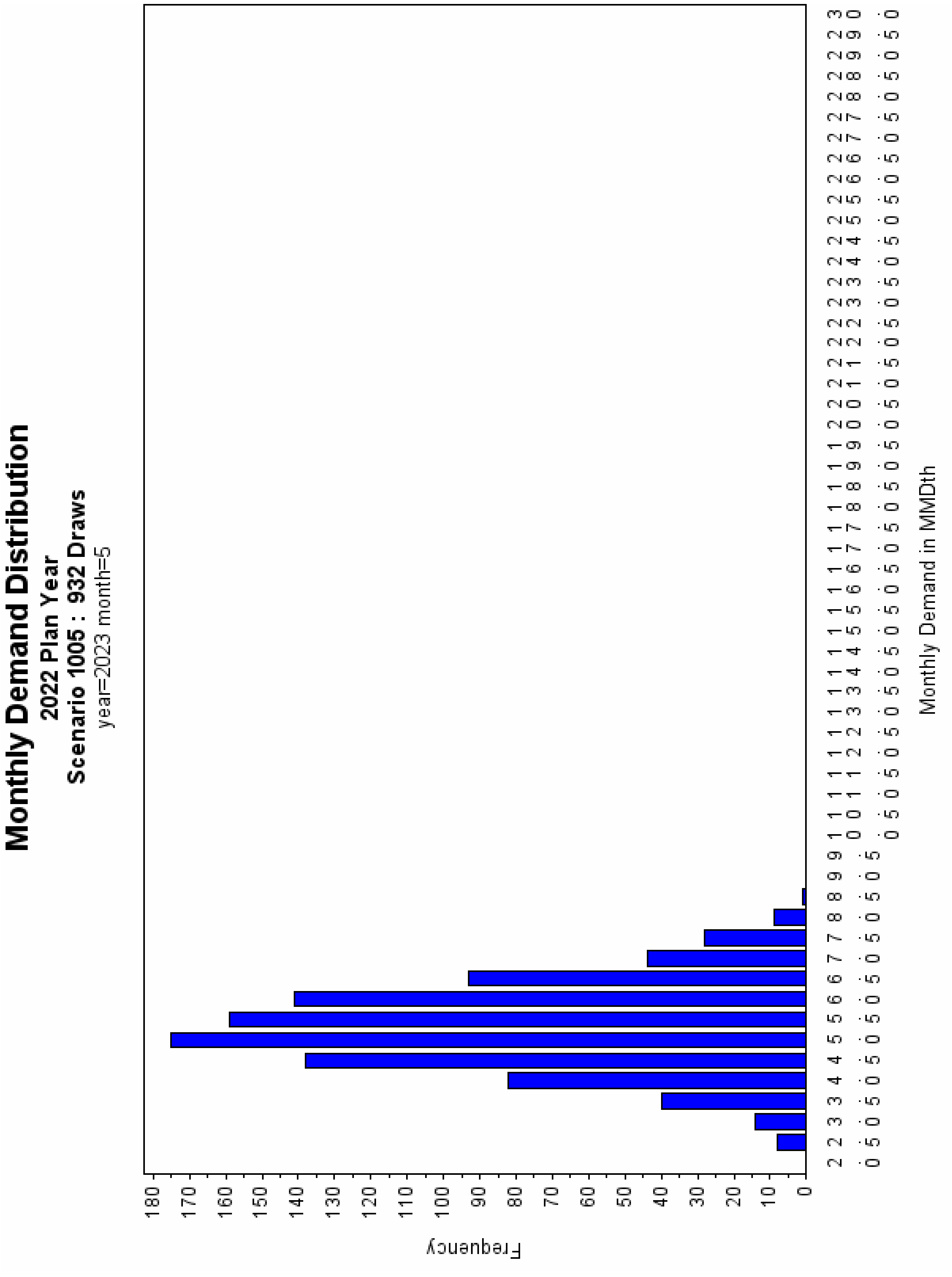
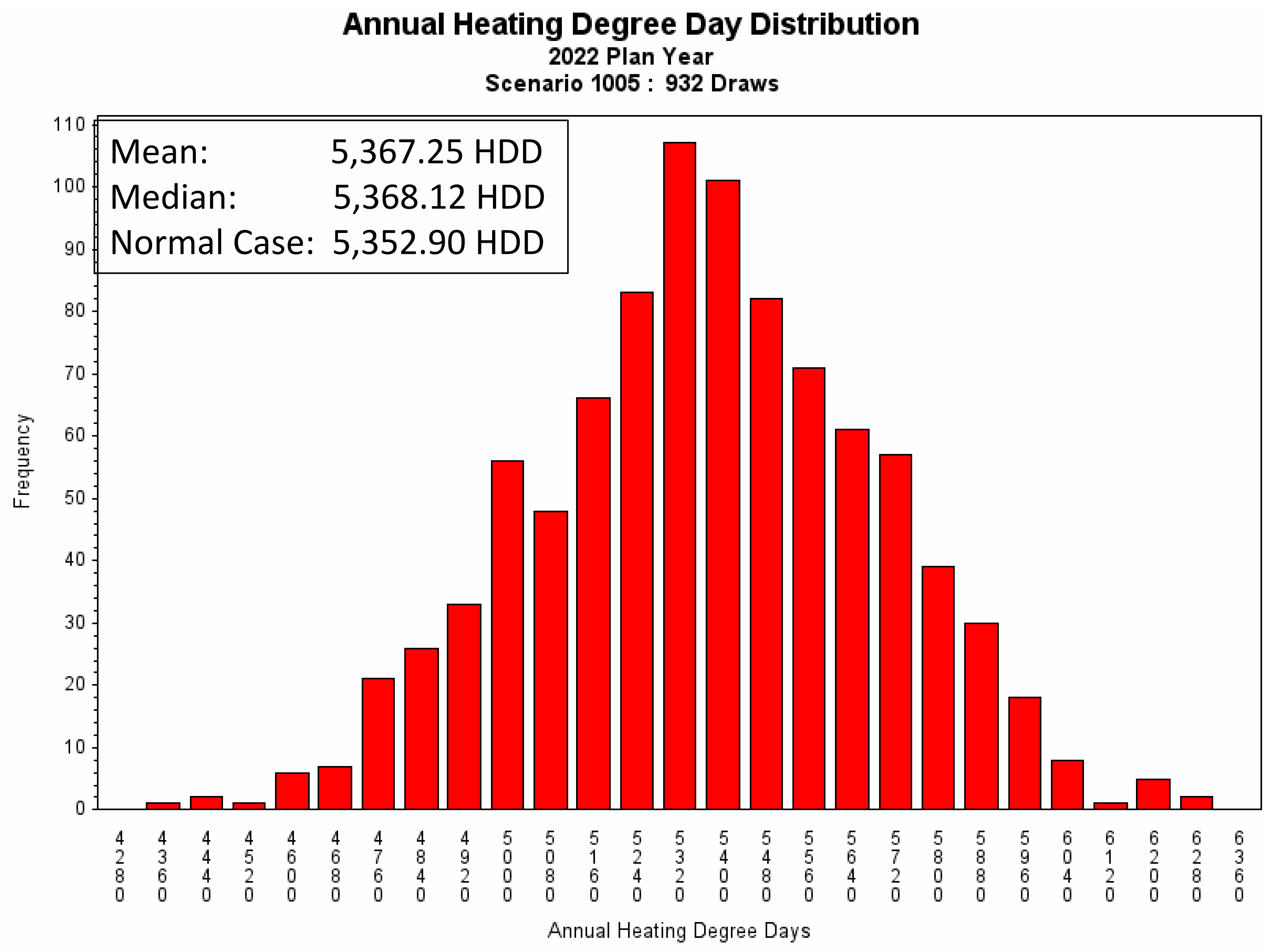


Exhibit 14.49





Annual Heating Degree Day Distribution
2022 Plan Year
Scenario 1005 : 932 Draws
Mean: 5,367.25 HDD
Median: 5,368.12 HDD
Normal Case: 5,352.90 HDD
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
4280
4360
4440
4520
4600
4680
4760
4840
4920
5000
5080
5160
5240
5320
5400
5480
5560
5640
5720
5800
5880
5960
6040
6120
6200
6280
6360
Annual Heating Degree Days

Exhibit 14.51

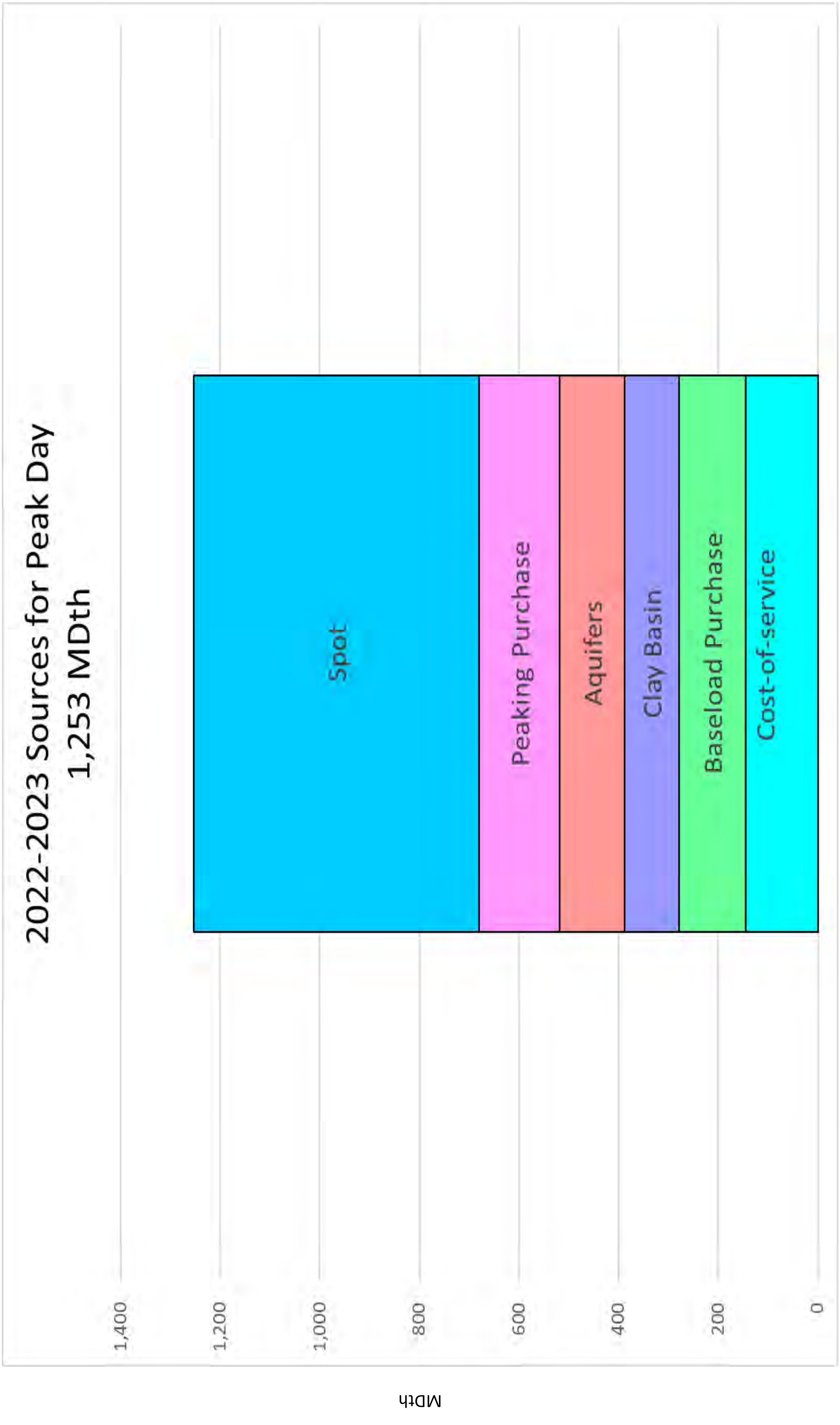


Exhibit 14.52

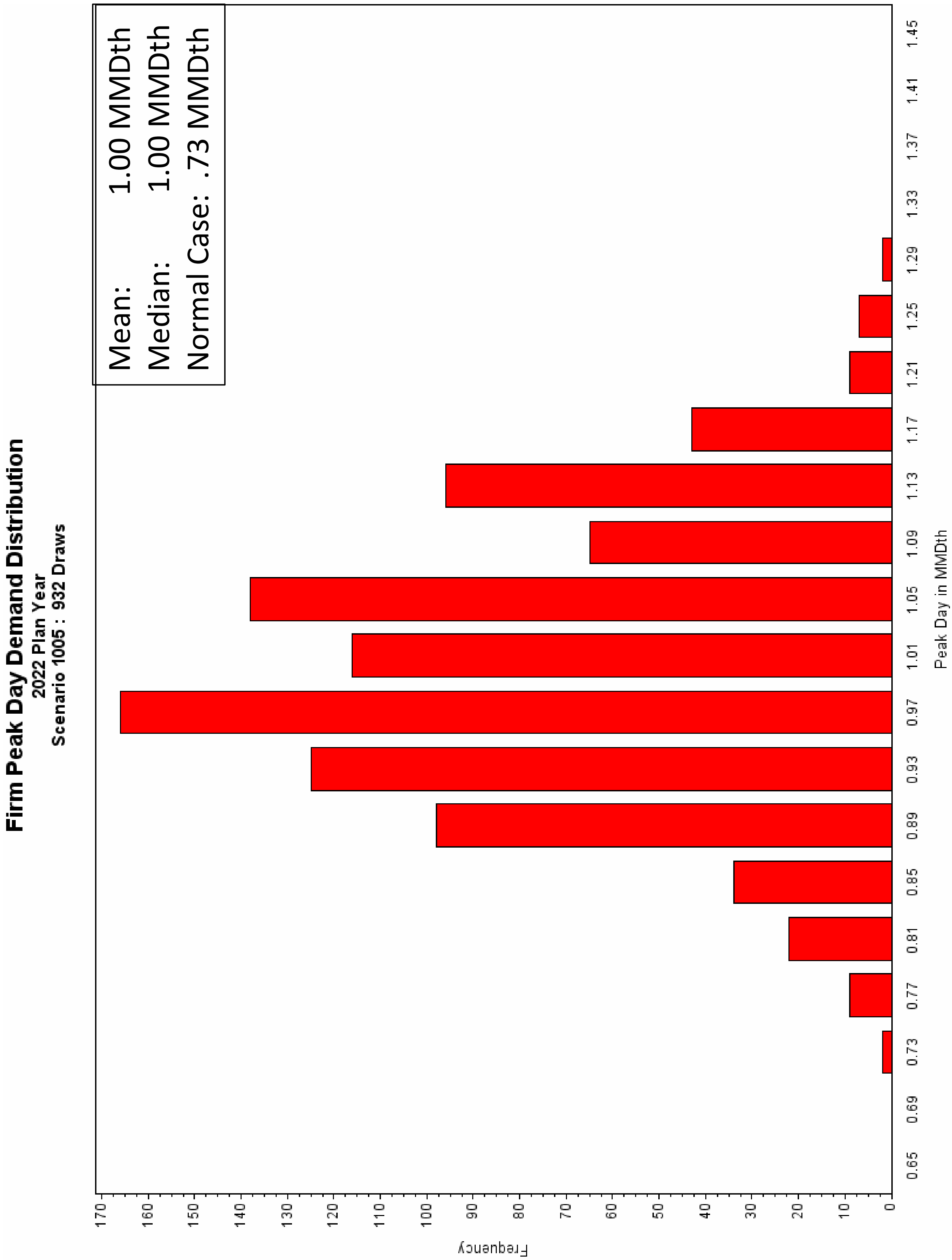


Exhibit 14.53

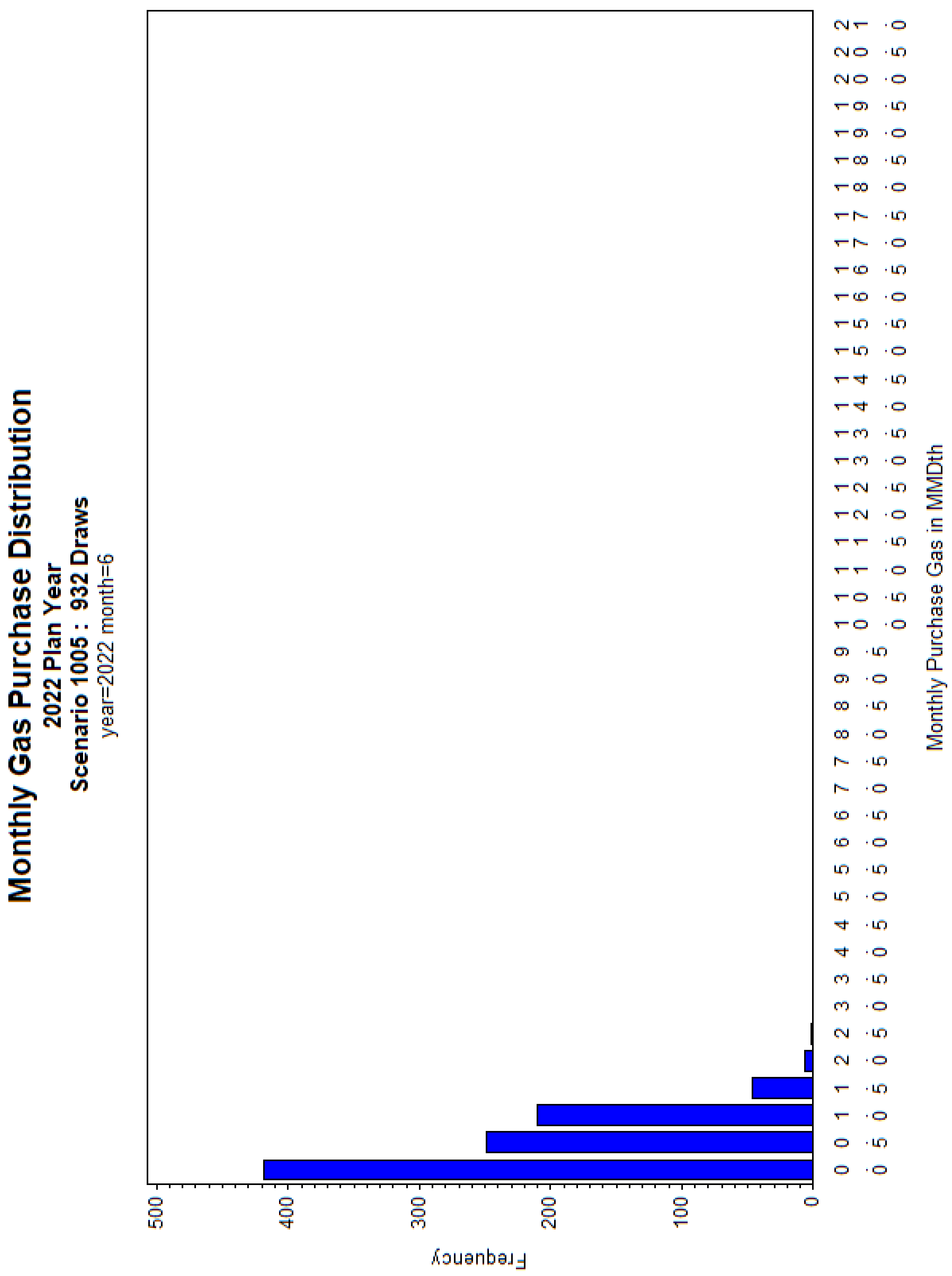


Exhibit 14.54

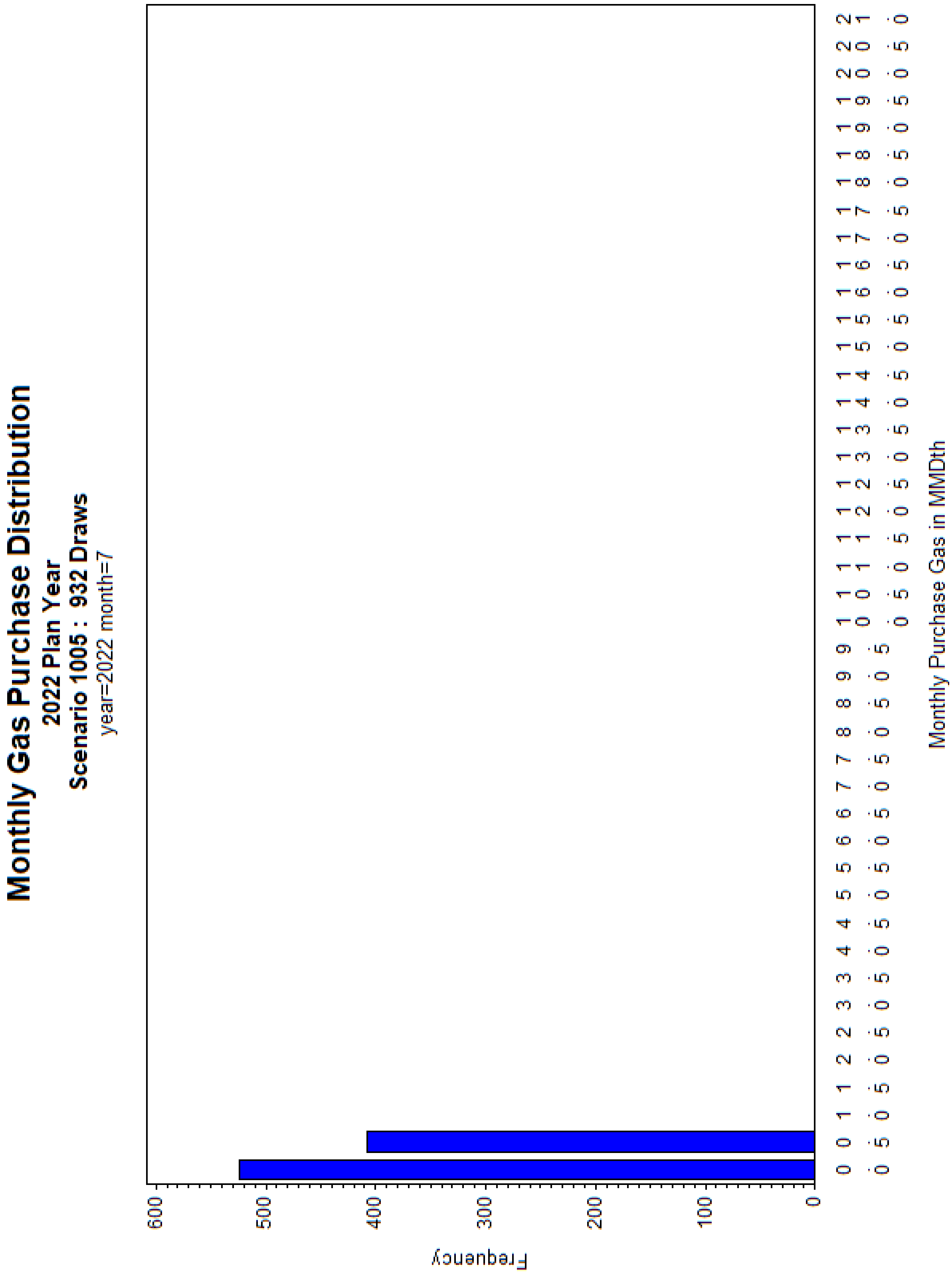


Exhibit 14.55

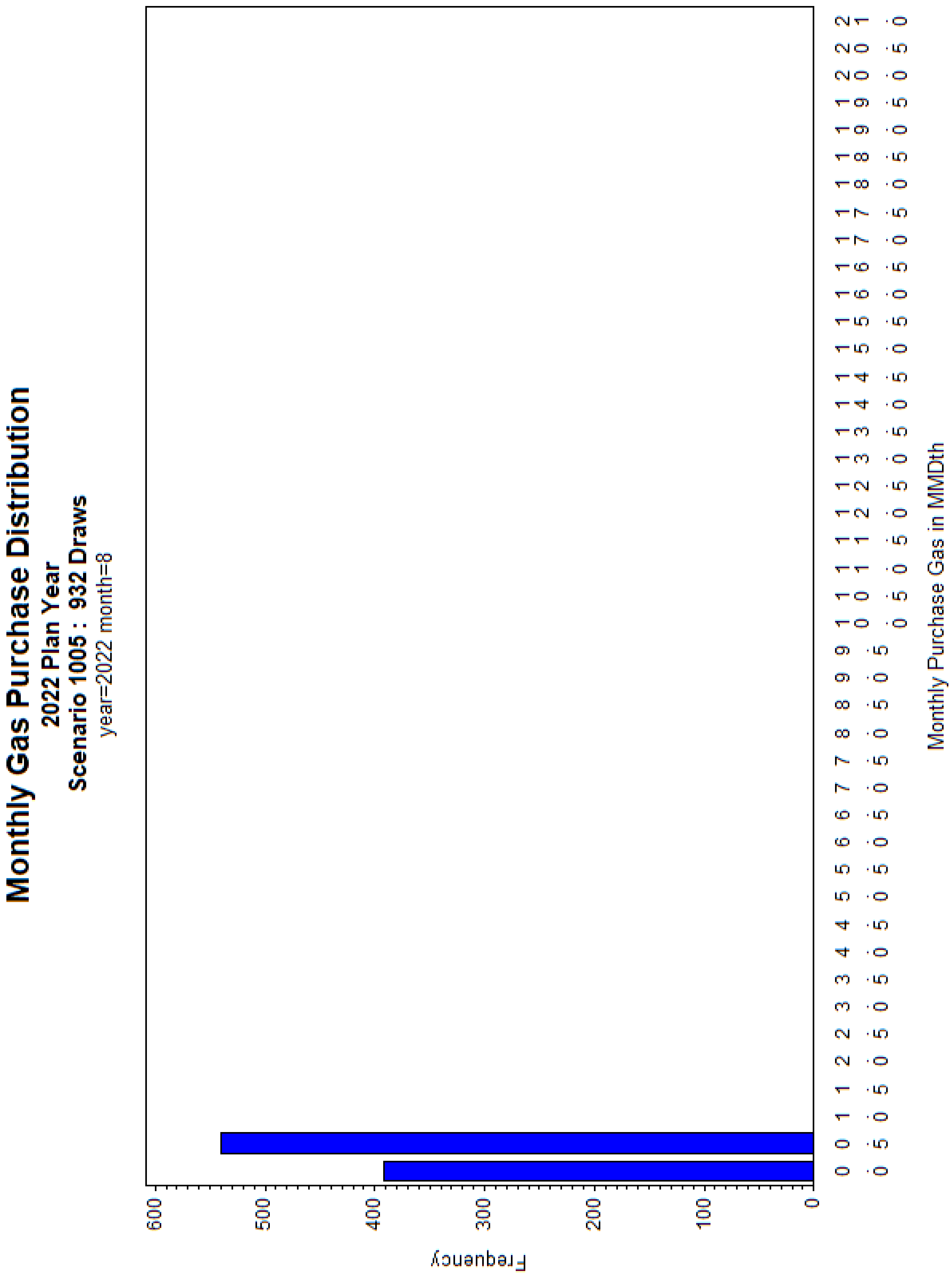


Exhibit 14.56

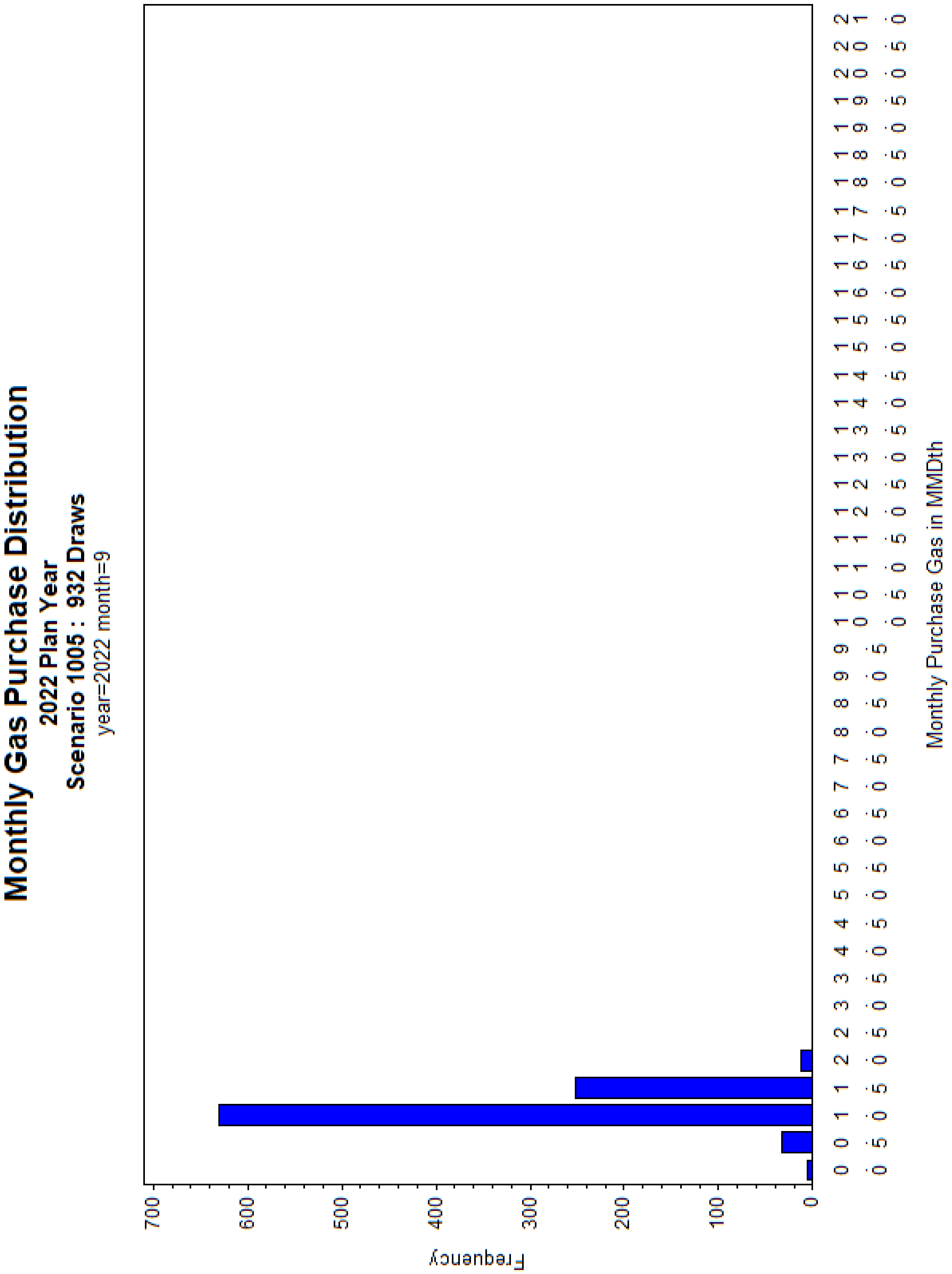


Exhibit 14.57

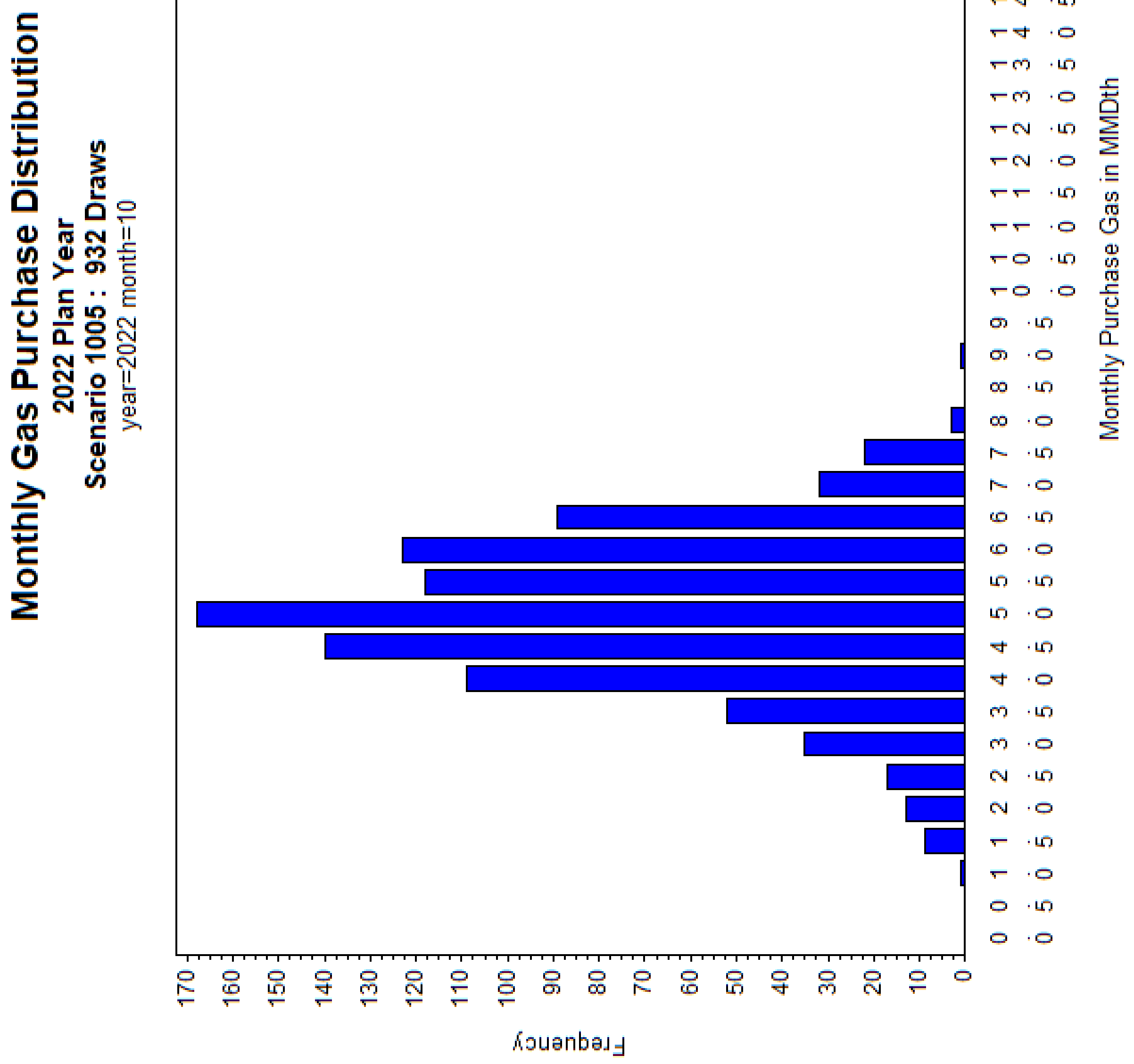


Exhibit 14.58

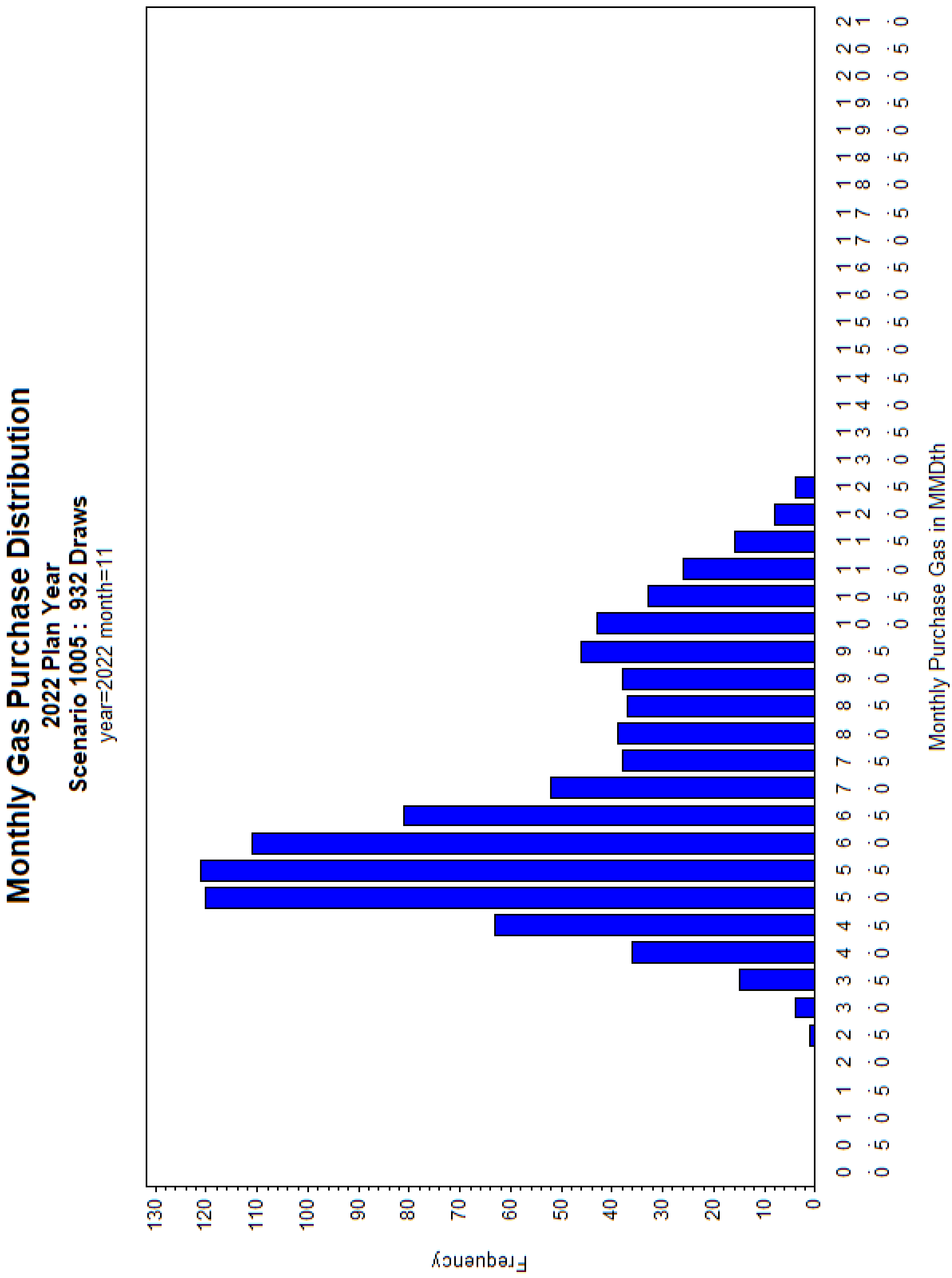


Exhibit 14.59

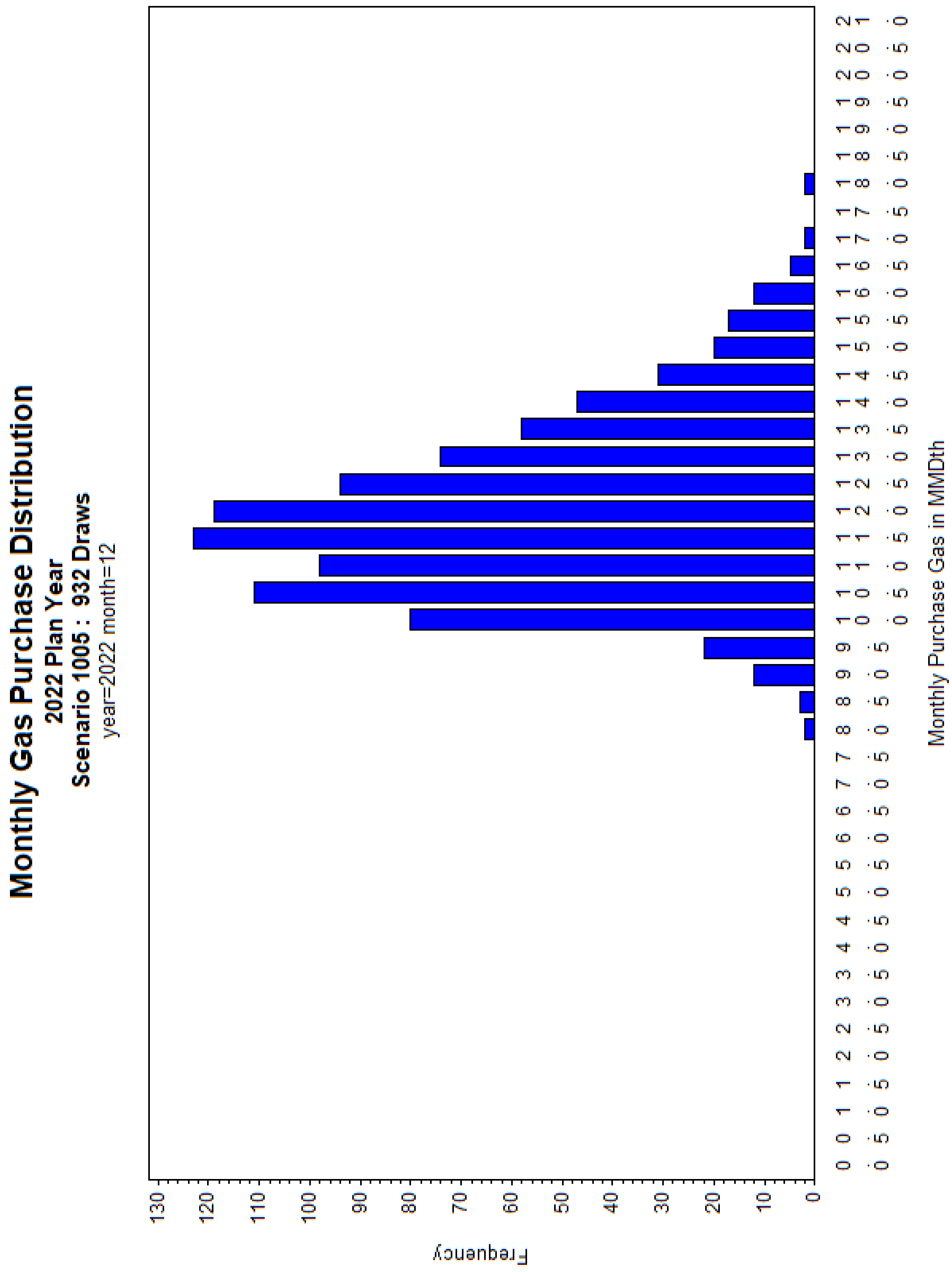
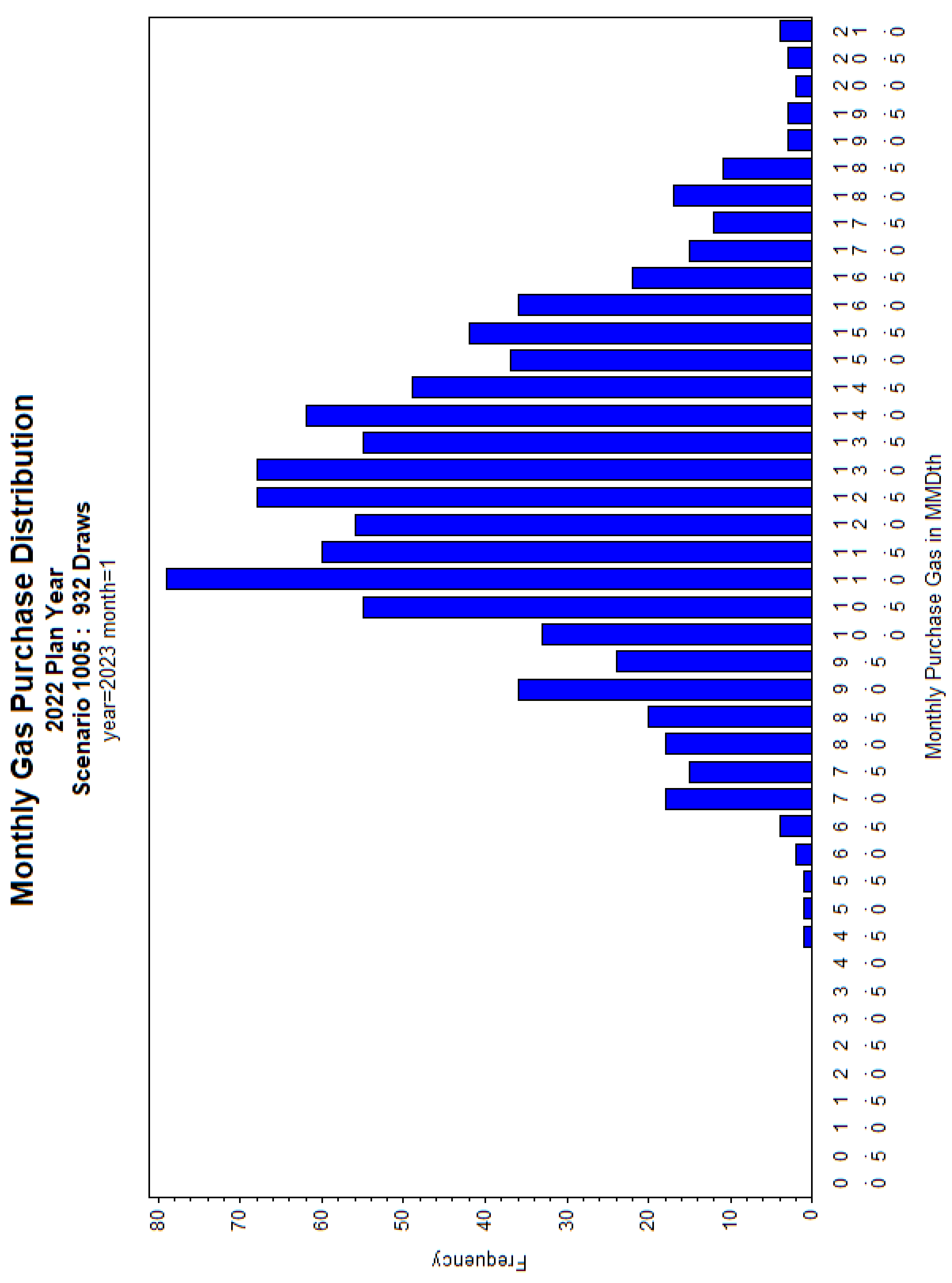


Exhibit 14.60



Monthly Gas Purchase Distribution

2022 Plan Year

Scenario 1005 : 932 Draws

year=2023 month=2

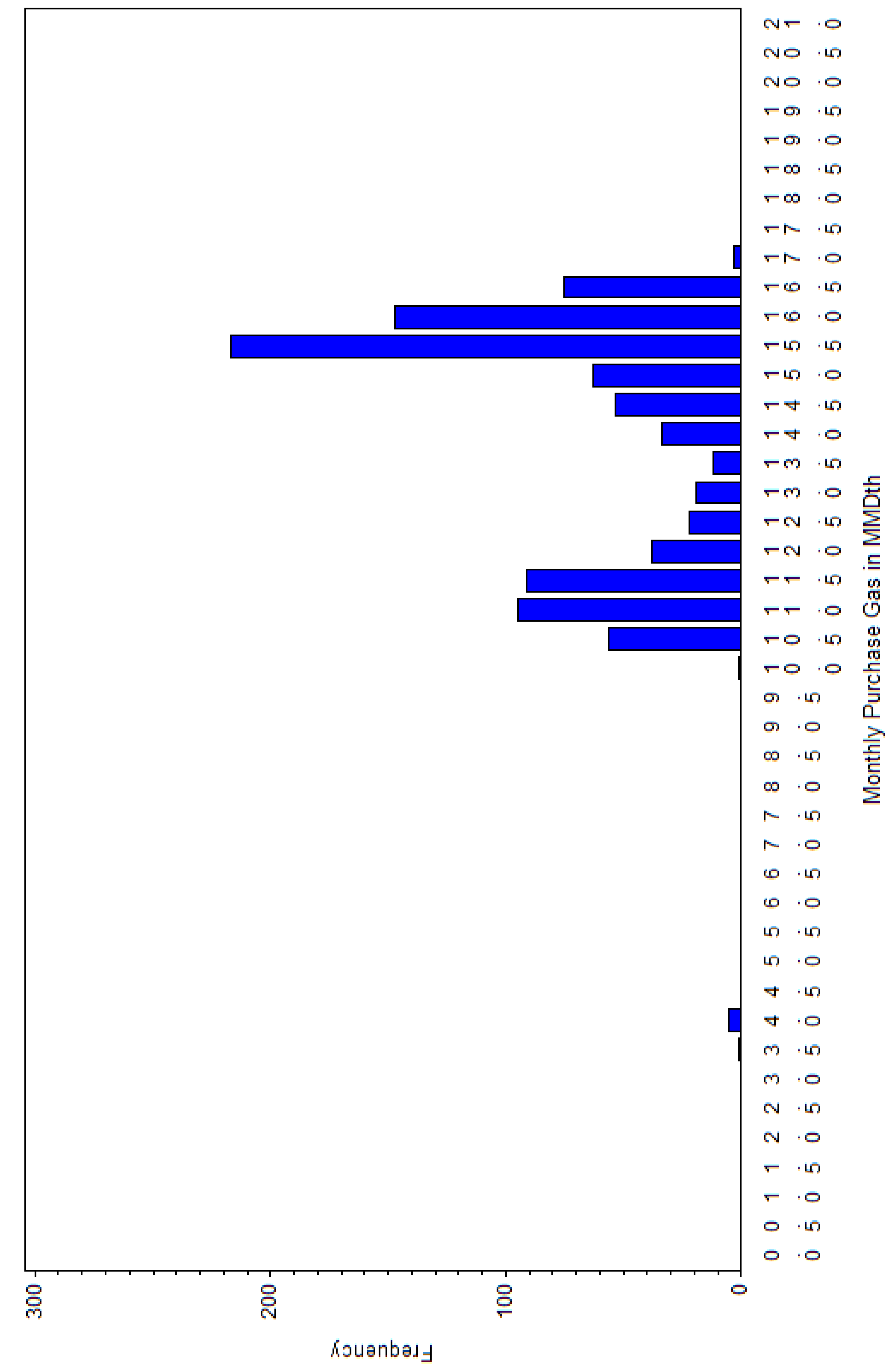


Exhibit 14.62

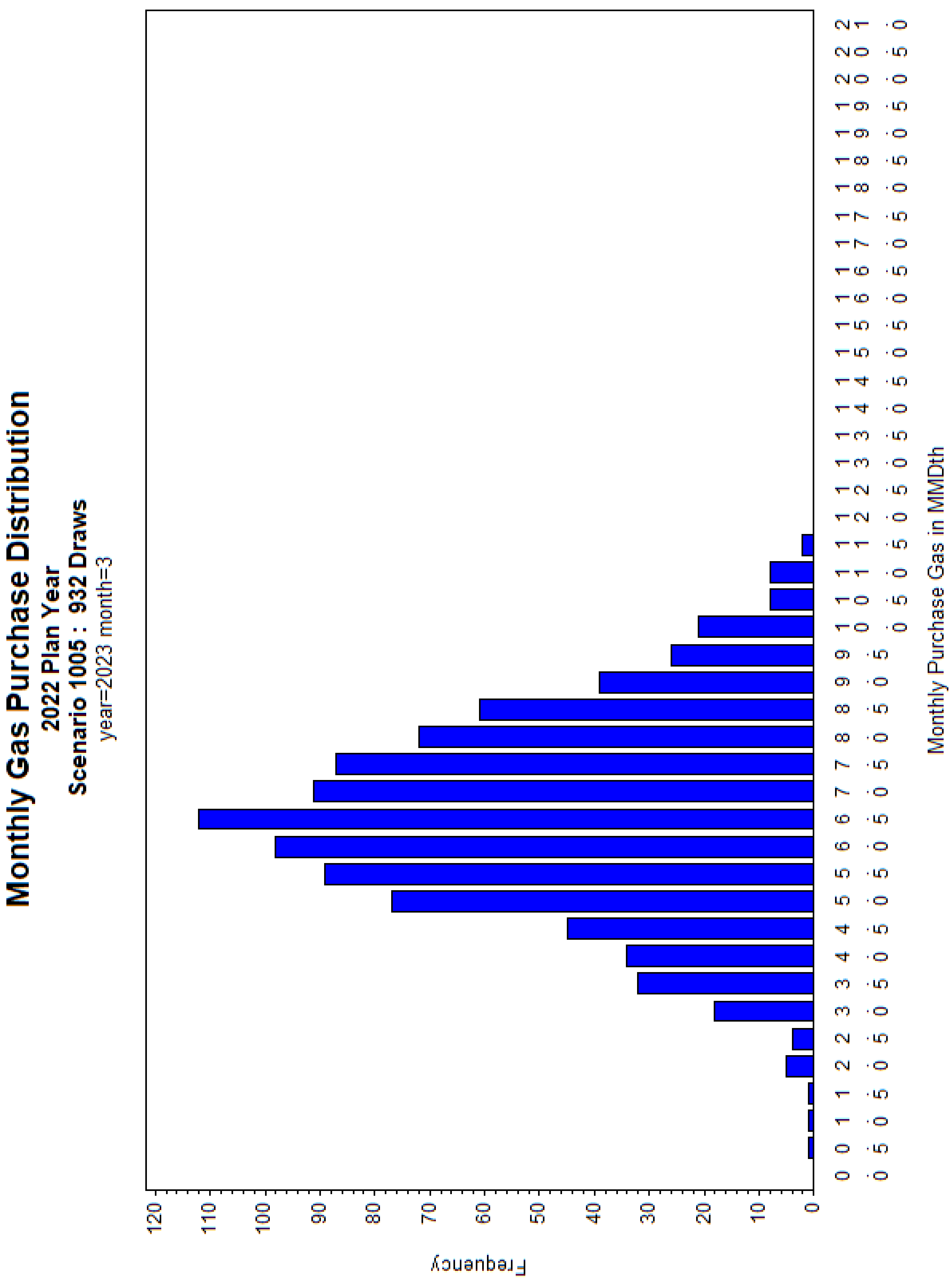


Exhibit 14.63

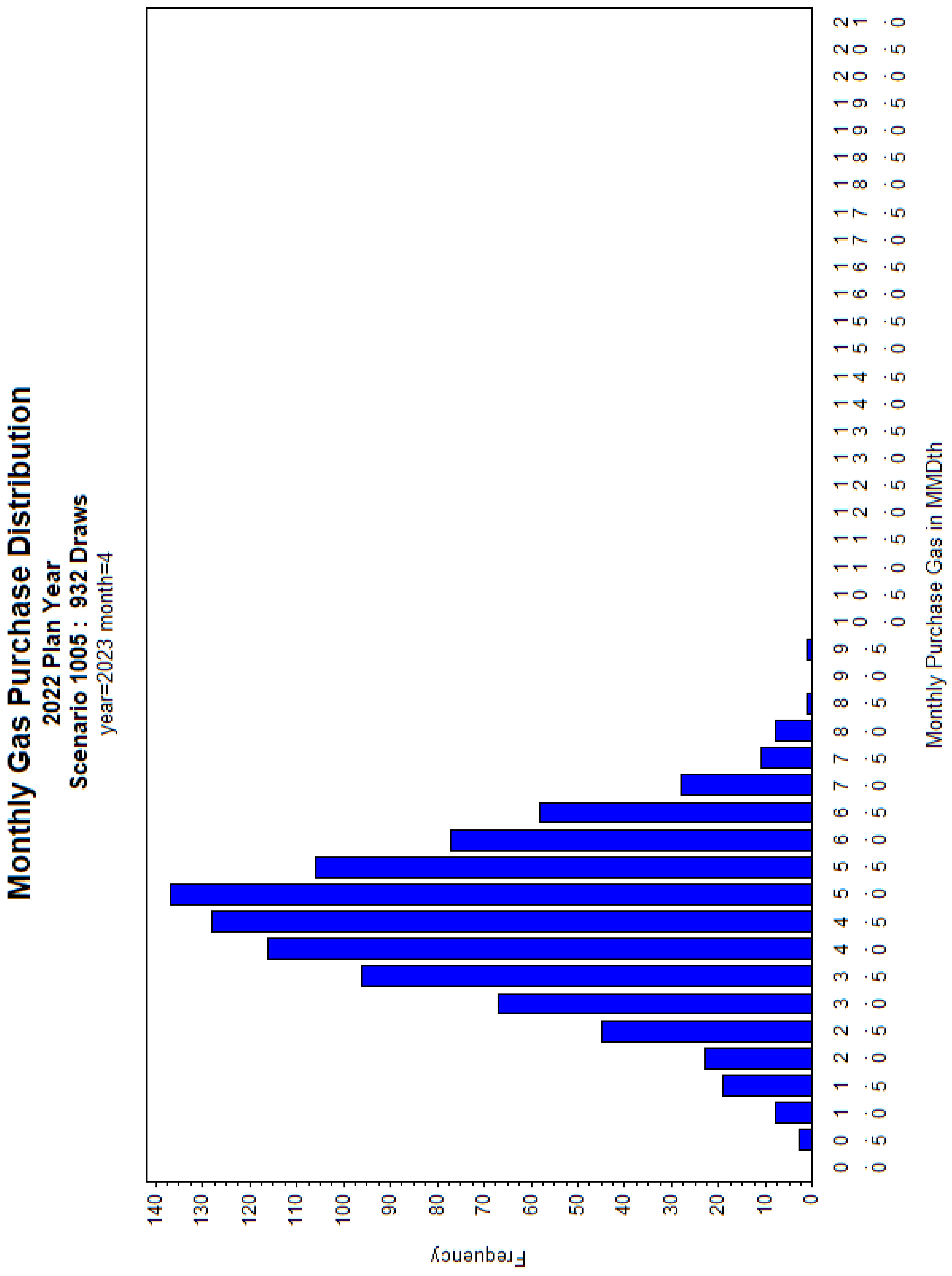


Exhibit 14.64

Monthly Gas Purchase Distribution

2022 Plan Year

Scenario 1005 : 932 Draws

year=2023 month=5

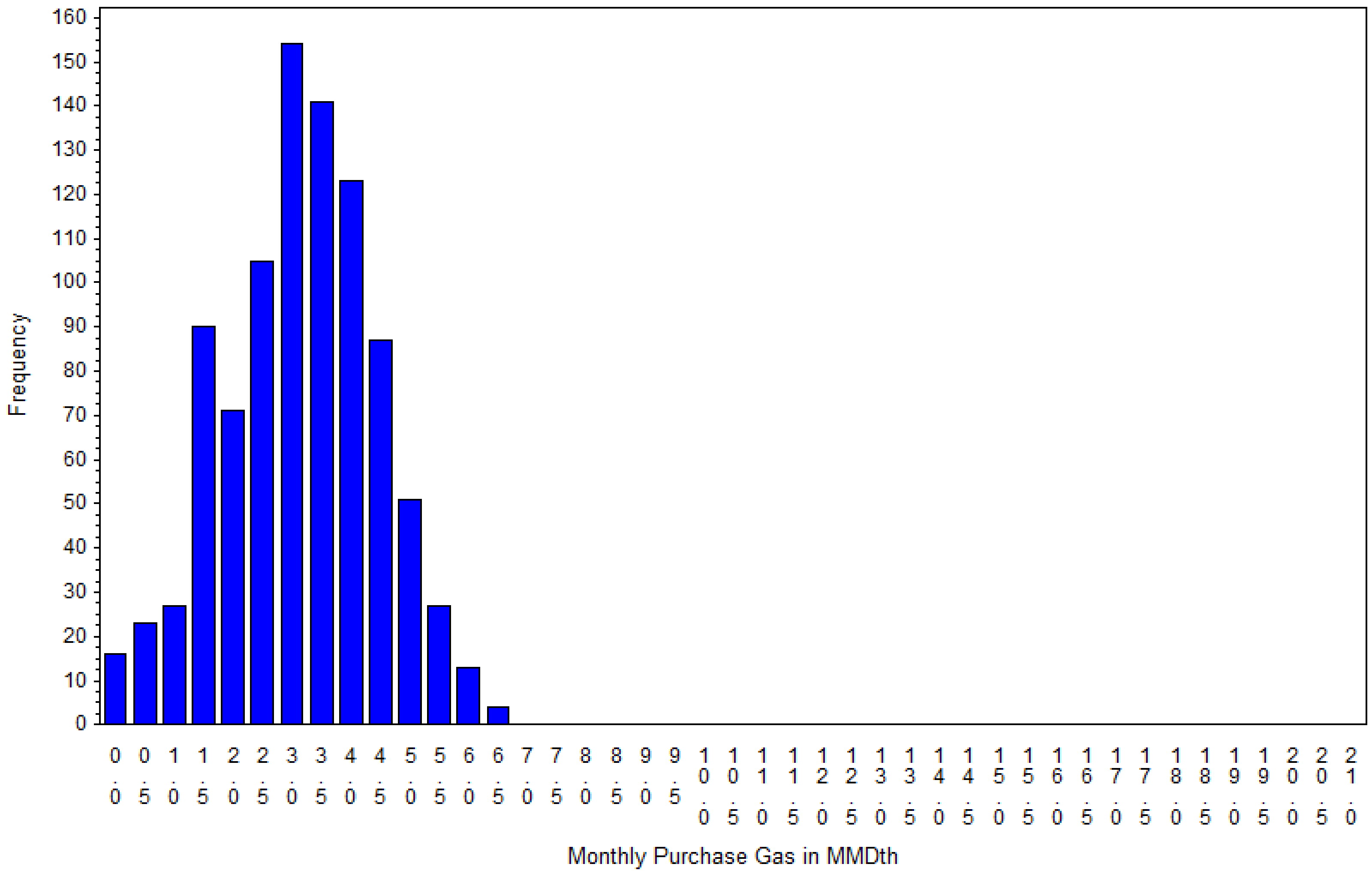
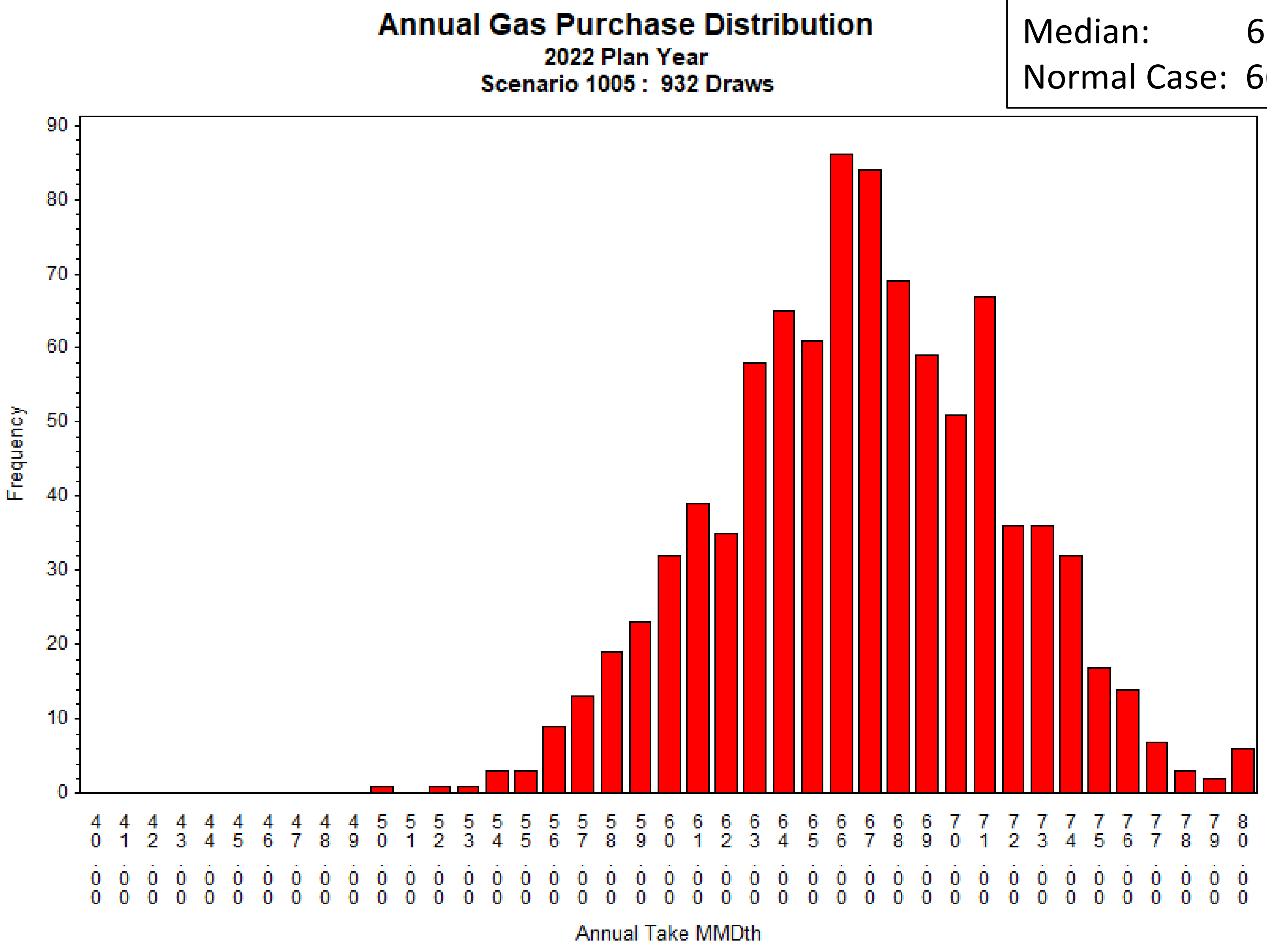


Exhibit 14.65

Mean:	66.71 MMDth
Median:	66.69 MMDth
Normal Case:	66.62 MMDth



Monthly Purchase Gas Distribution in Mdth
2022 Plan Year
Scenario 1005 : 932 Draws

year	month	mean	max	p95	p90	med	p10	p5	min
2022	6	0.46	2.35	1.27	1.12	0.38	0.00	0.00	0.00
2022	7	0.13	0.28	0.28	0.28	0.00	0.00	0.00	0.00
2022	8	0.22	0.58	0.46	0.43	0.33	0.00	0.00	0.00
2022	9	1.13	2.07	1.57	1.47	1.14	0.81	0.77	0.00
2022	10	5.02	9.13	6.83	6.61	5.11	3.45	2.88	1.02
2022	11	6.86	12.52	10.84	10.18	6.21	4.57	4.19	2.63
2022	12	11.99	17.99	15.03	14.20	11.82	10.11	9.82	8.08
2023	1	12.63	23.32	17.60	16.22	12.54	8.96	7.87	4.46
2023	2	14.00	16.81	16.43	16.17	15.07	11.03	10.68	3.67
2023	3	6.56	11.47	9.58	8.86	6.54	4.24	3.55	0.71
2023	4	4.55	9.38	6.81	6.34	4.60	2.70	2.03	0.28
2023	5	3.14	6.58	5.17	4.77	3.20	1.52	0.93	0.00

Exhibit 14.67

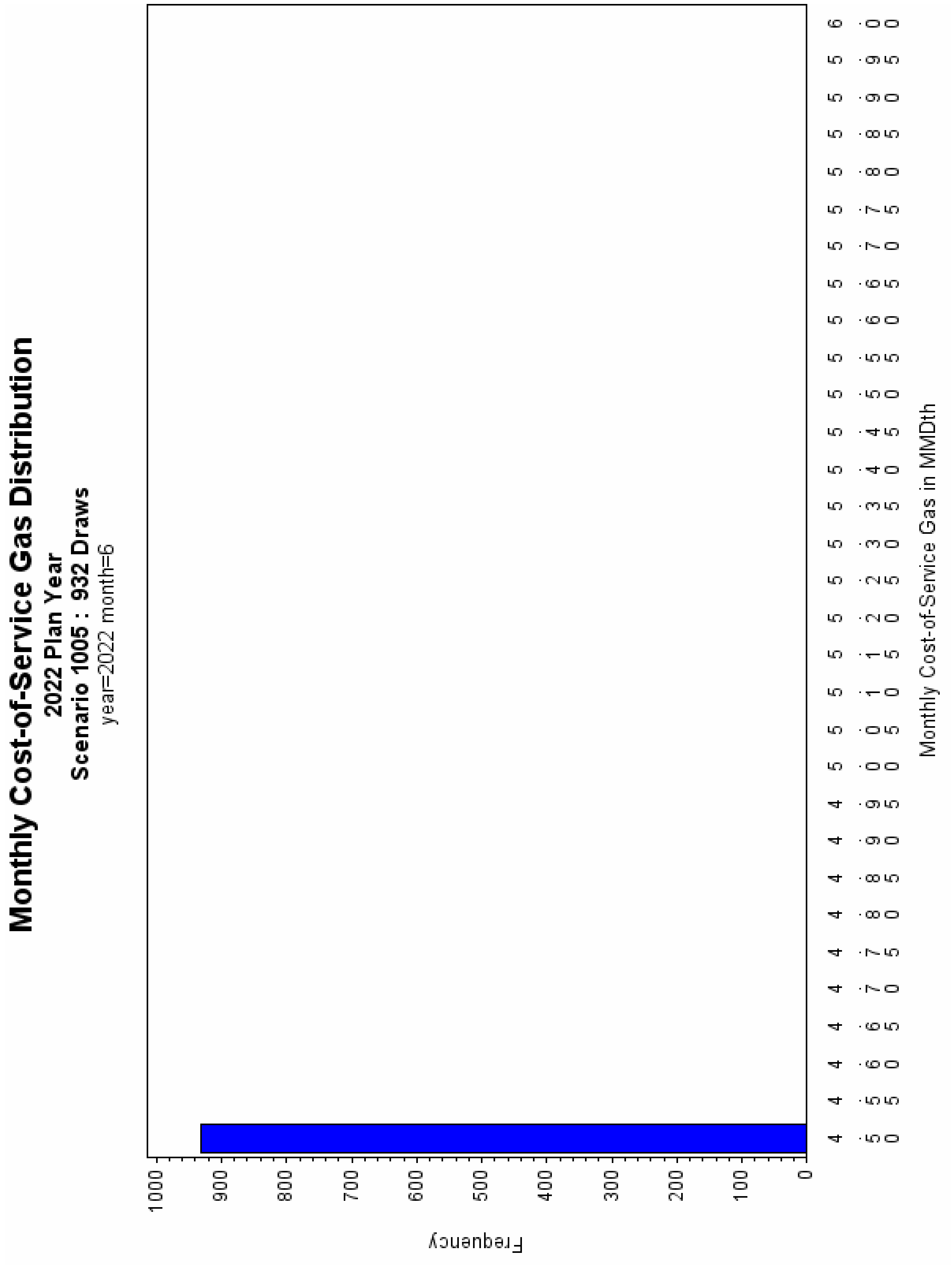


Exhibit 14.68

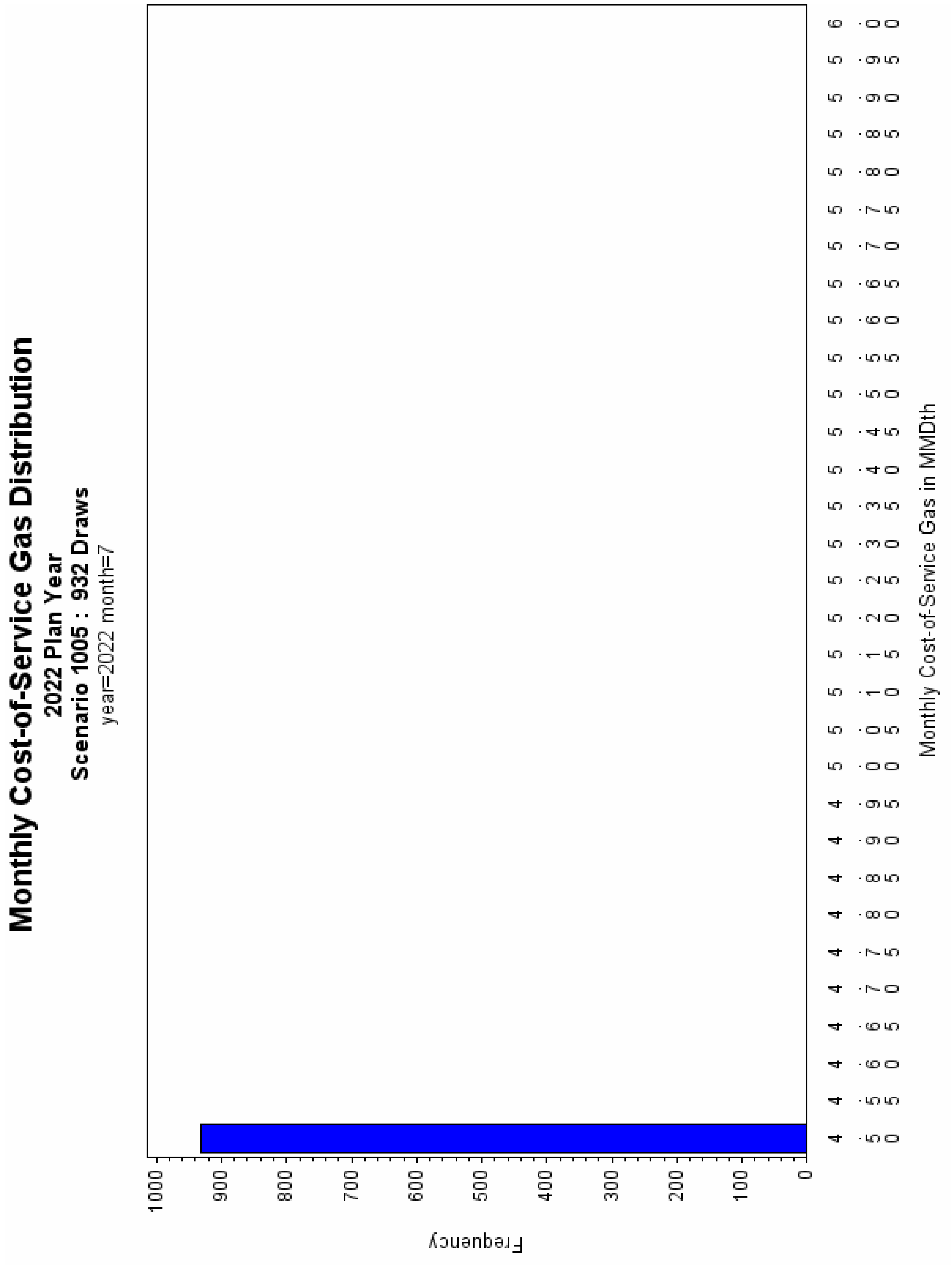


Exhibit 14.69

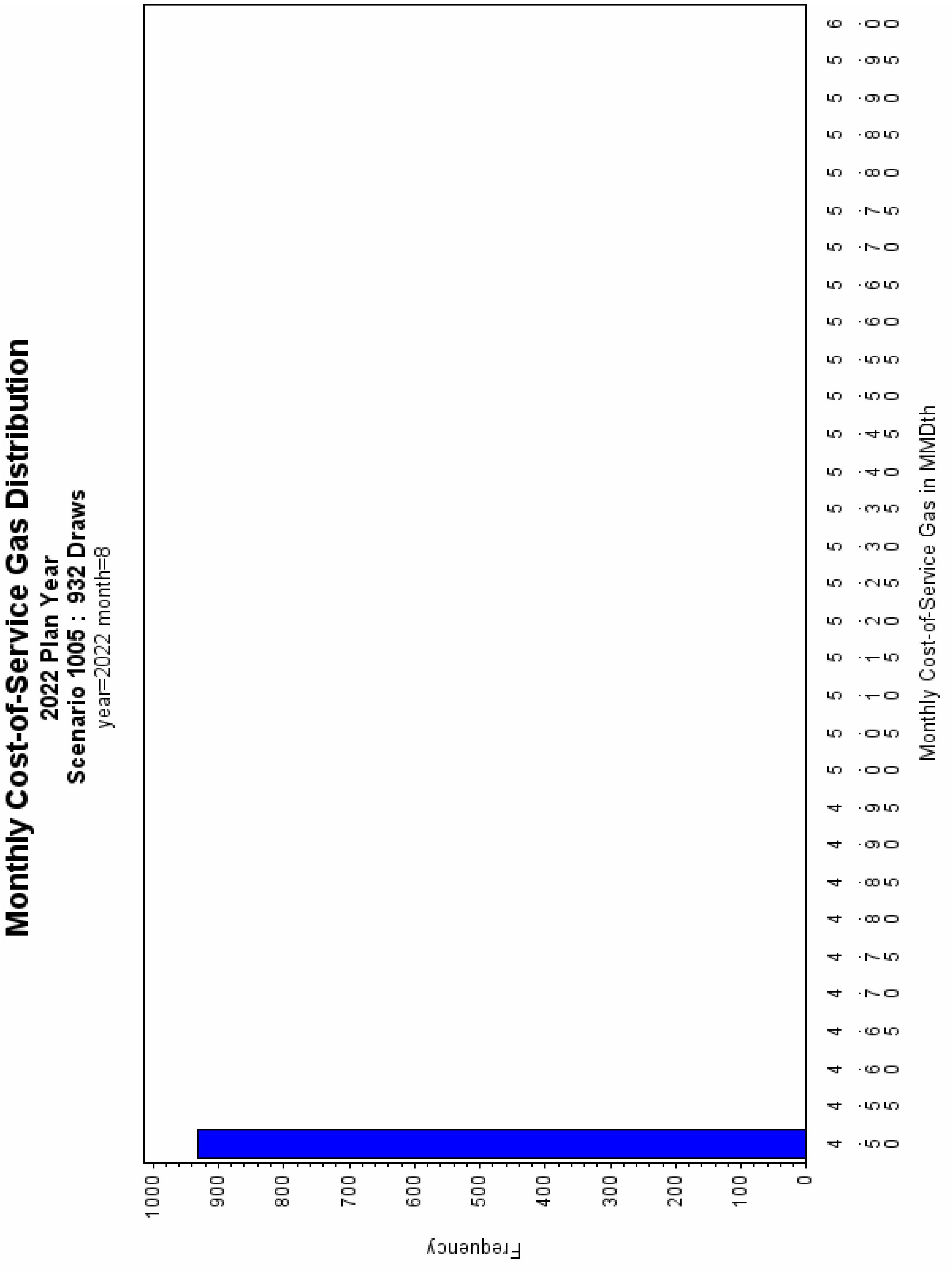


Exhibit 14.70

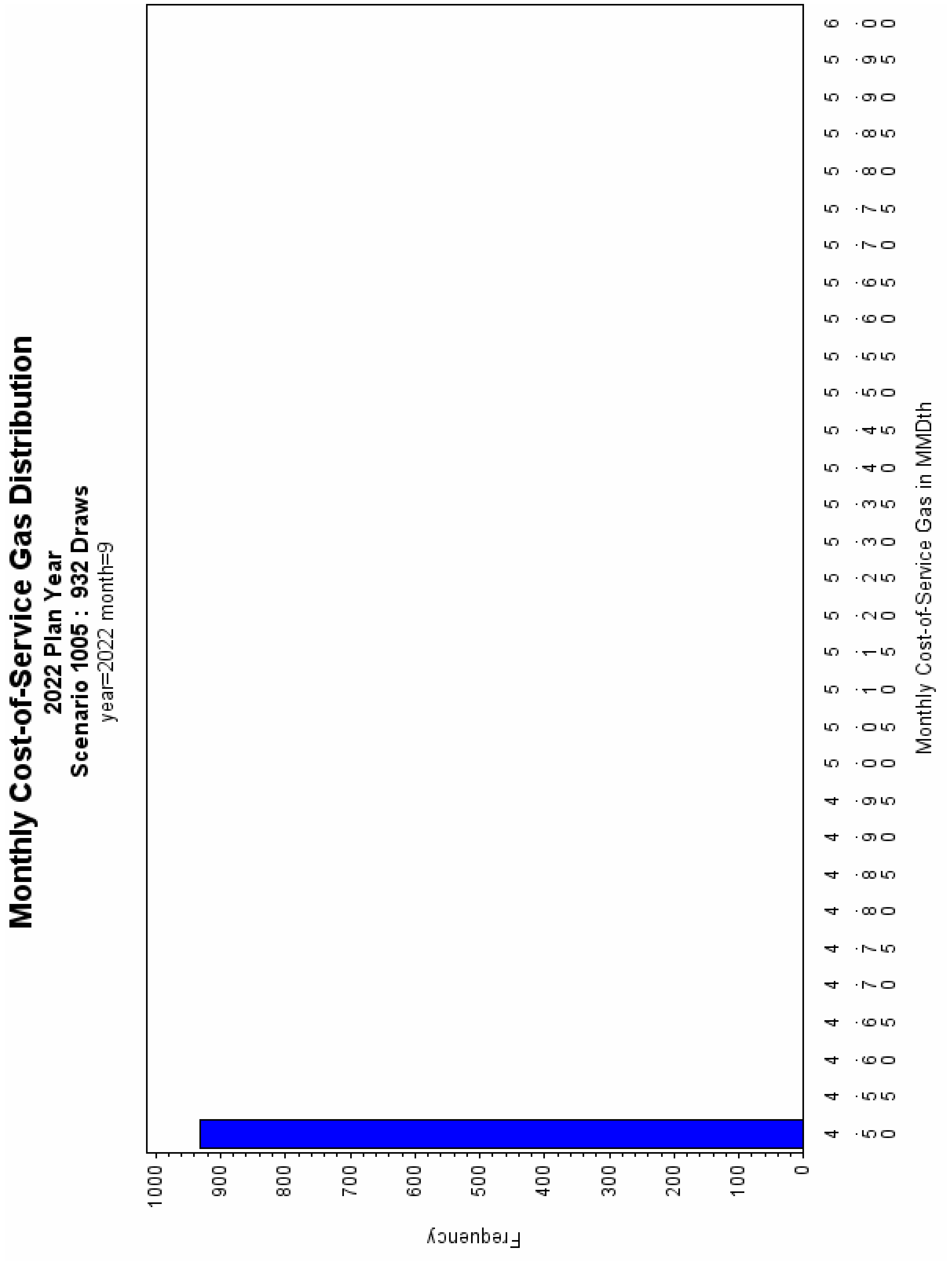


Exhibit 14.71

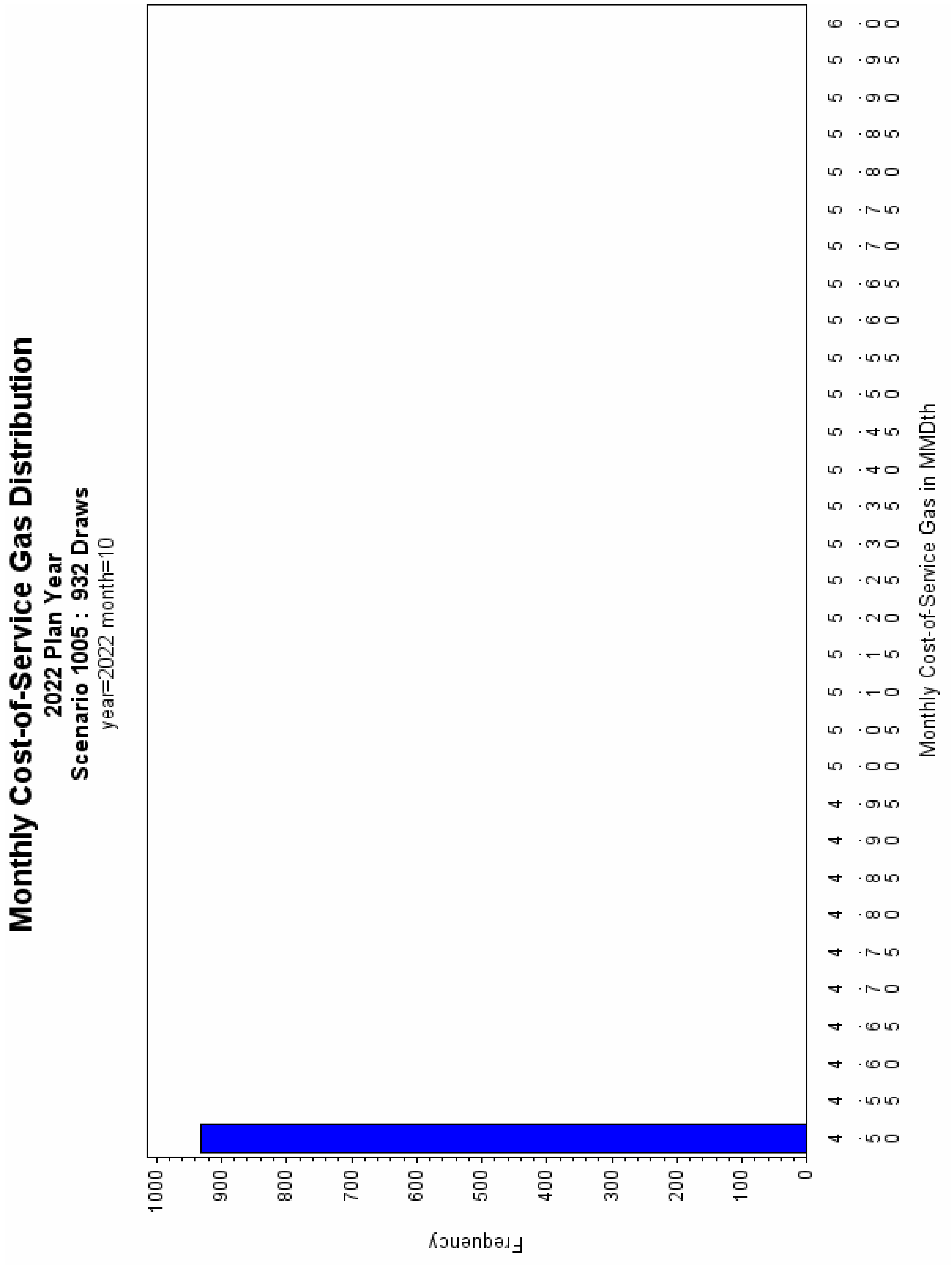


Exhibit 14.72

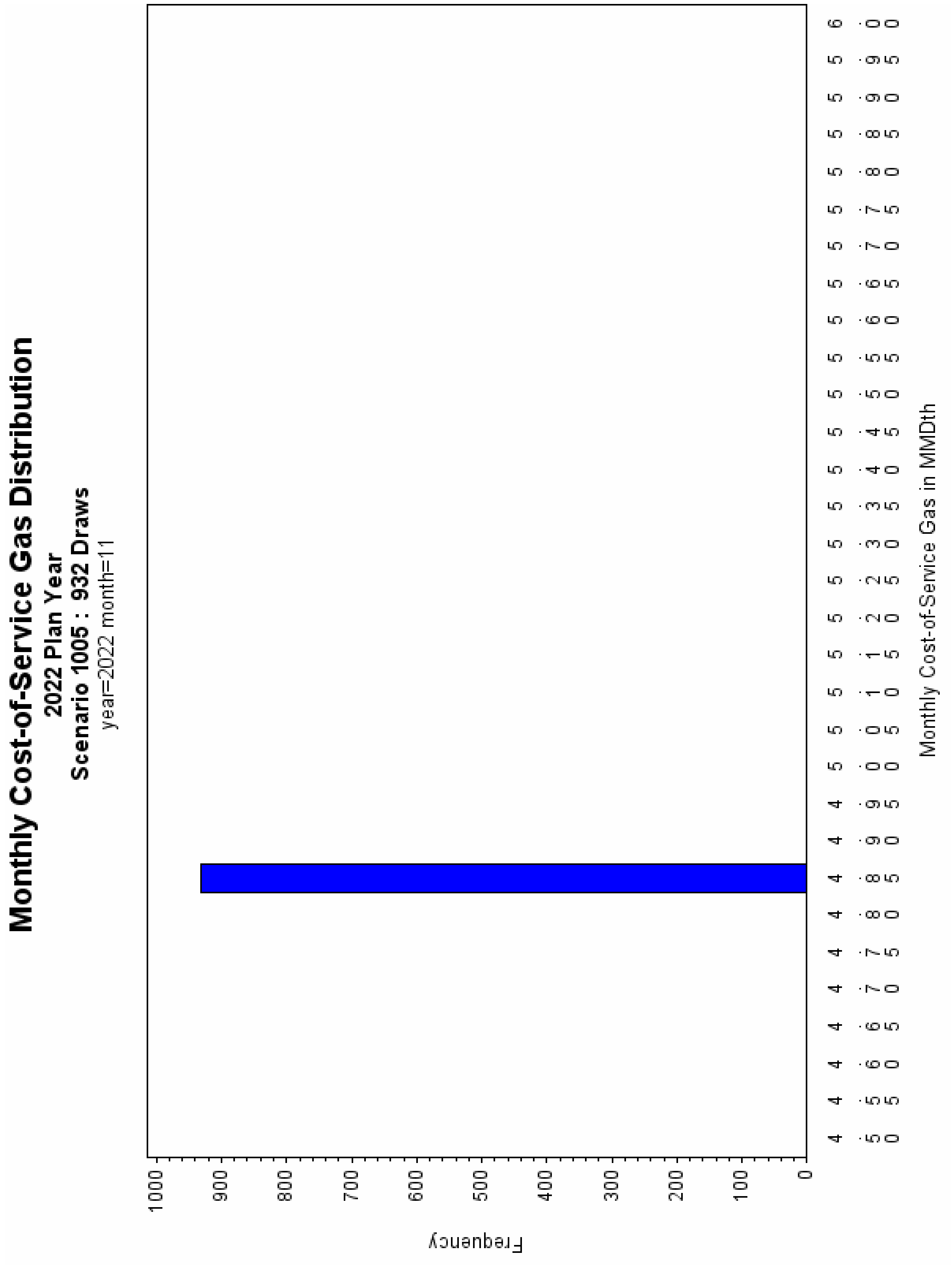


Exhibit 14.73

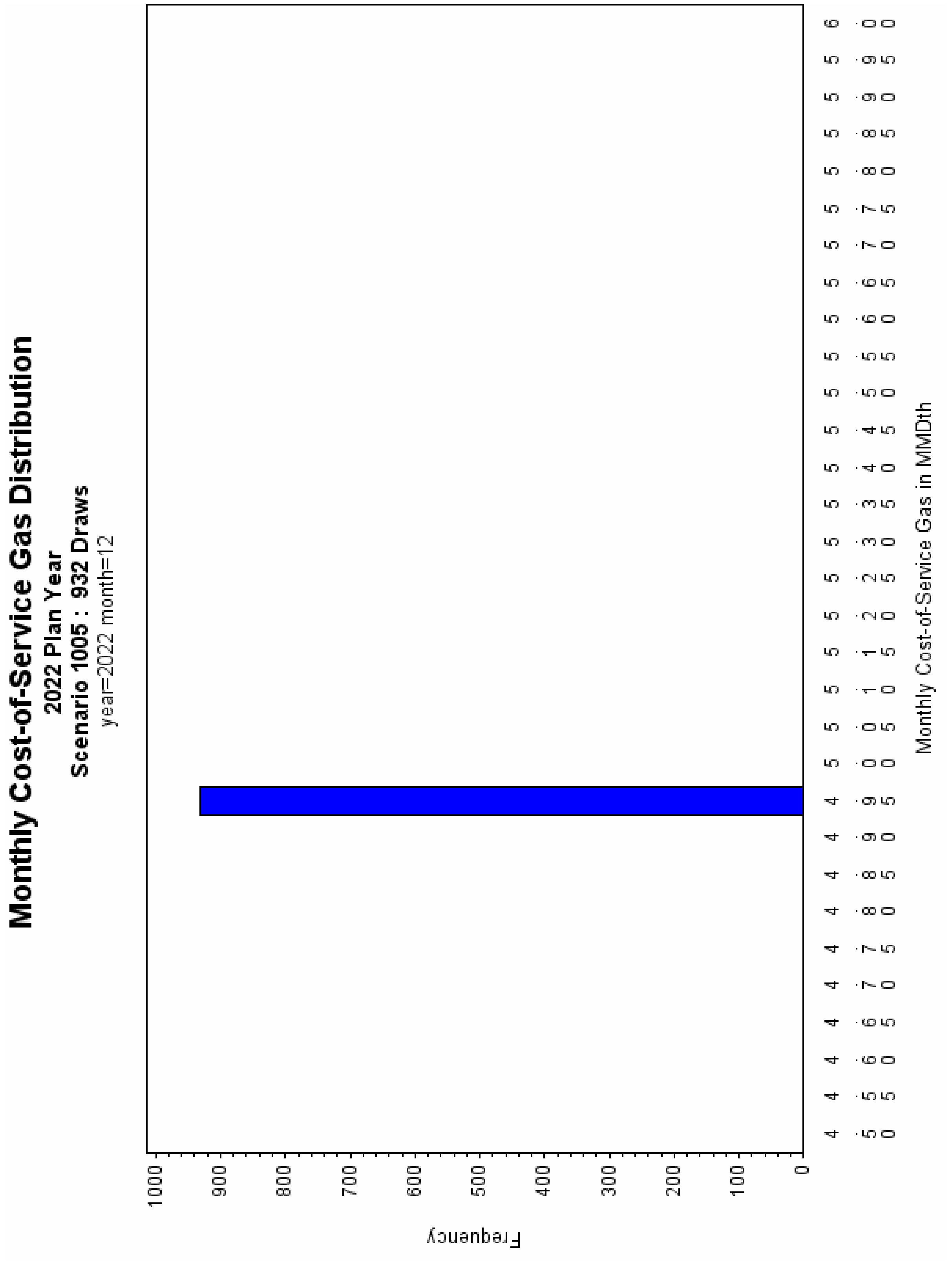


Exhibit 14.74

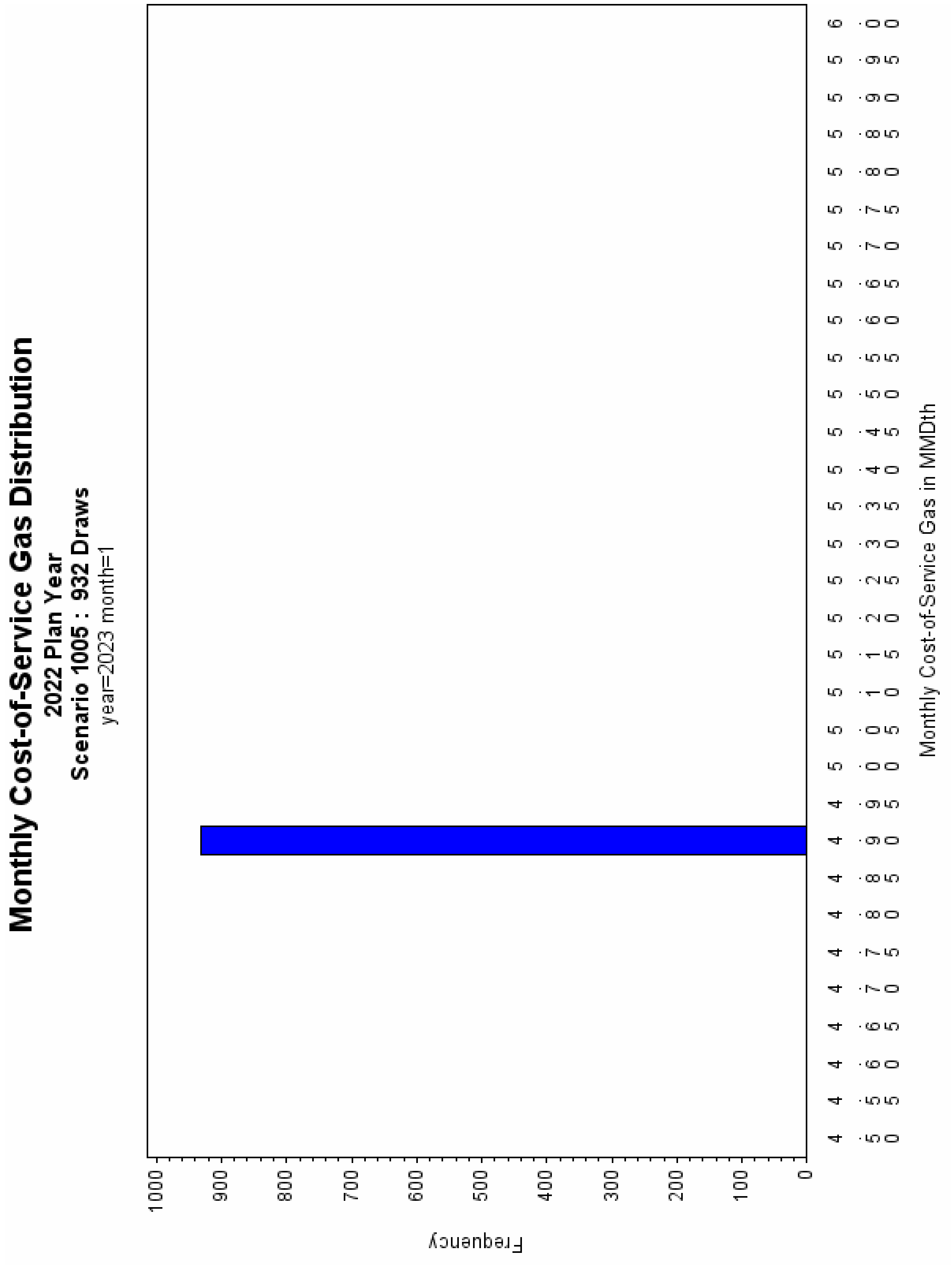


Exhibit 14.75

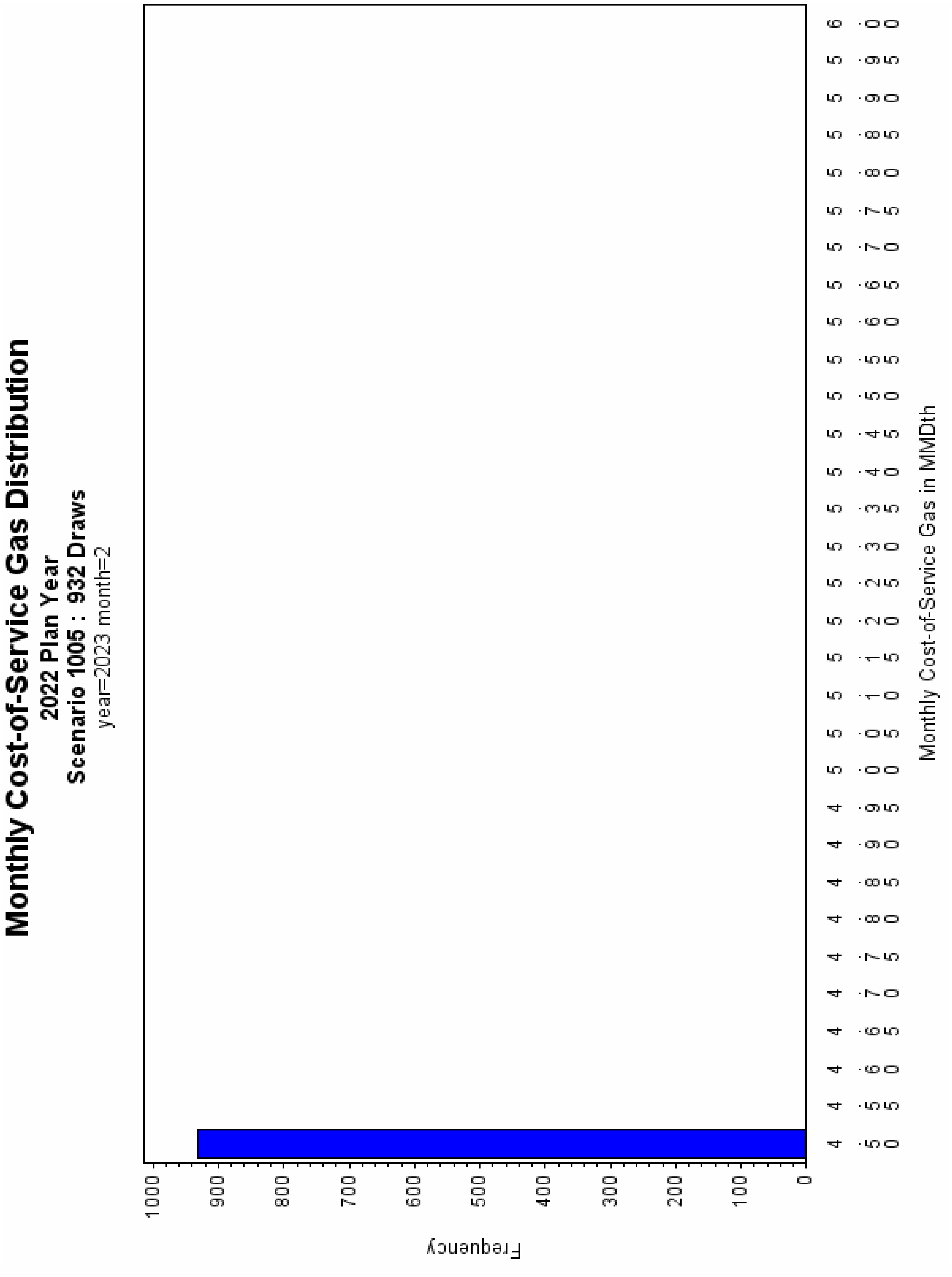
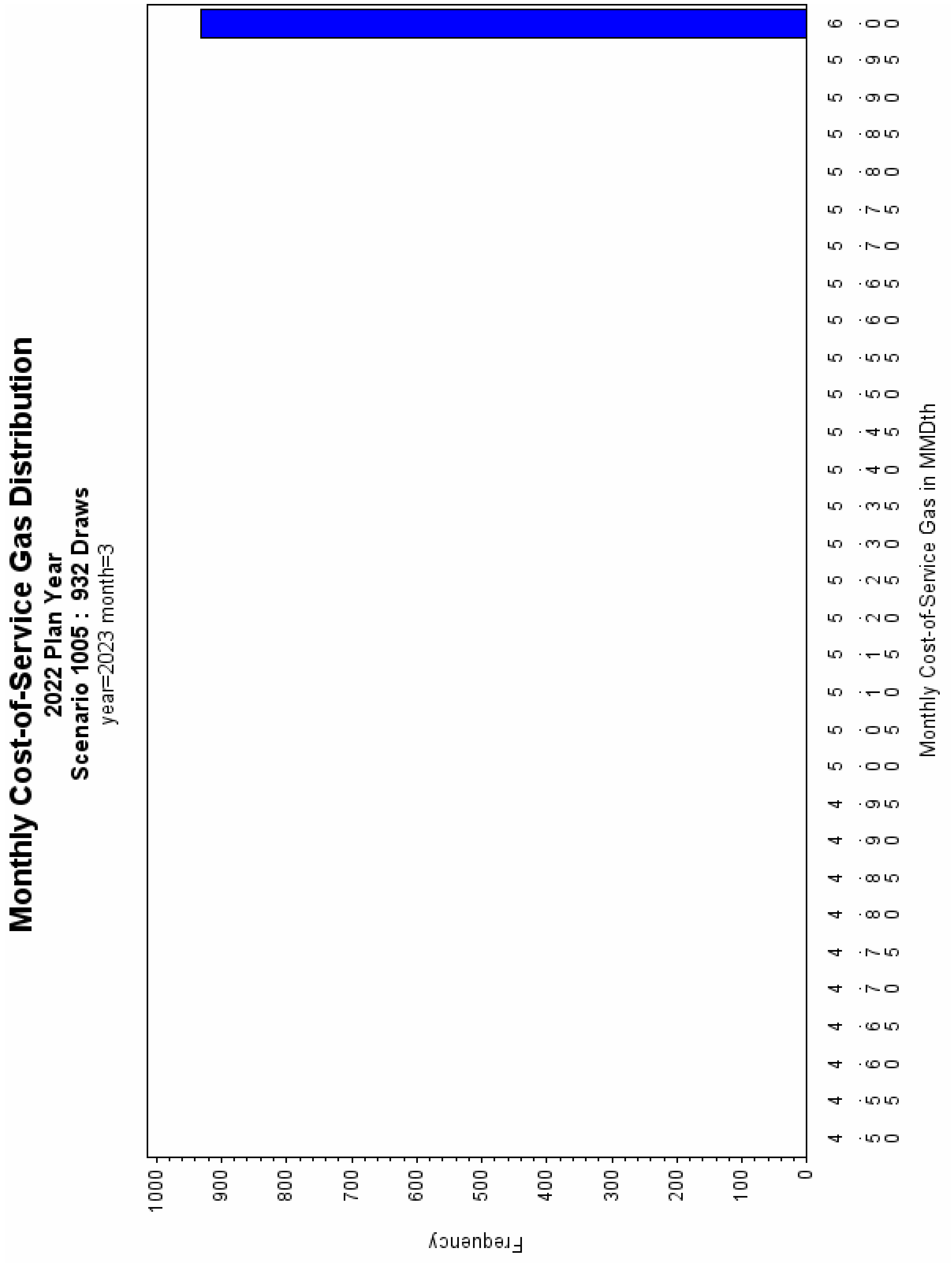


Exhibit 14.76



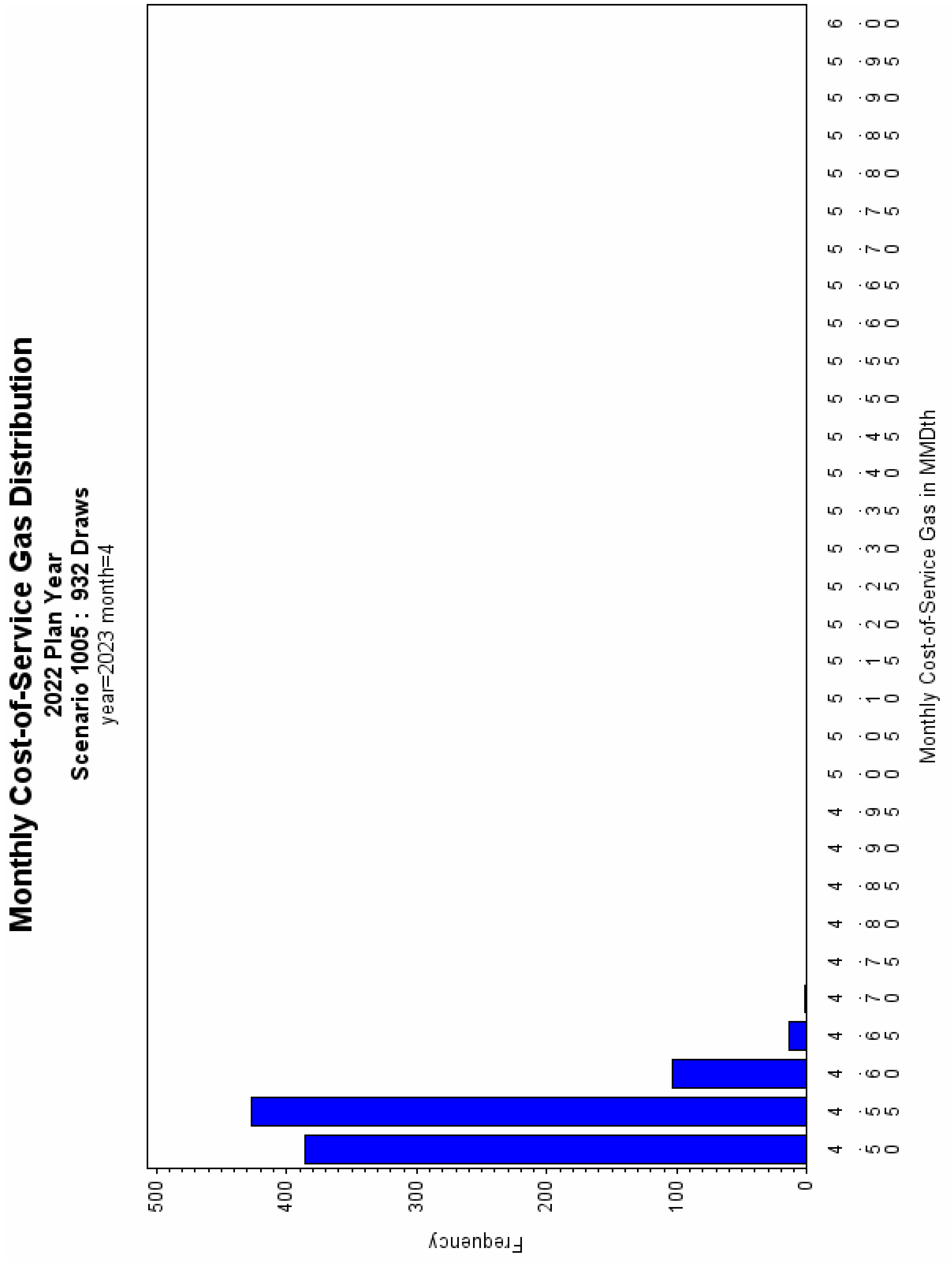
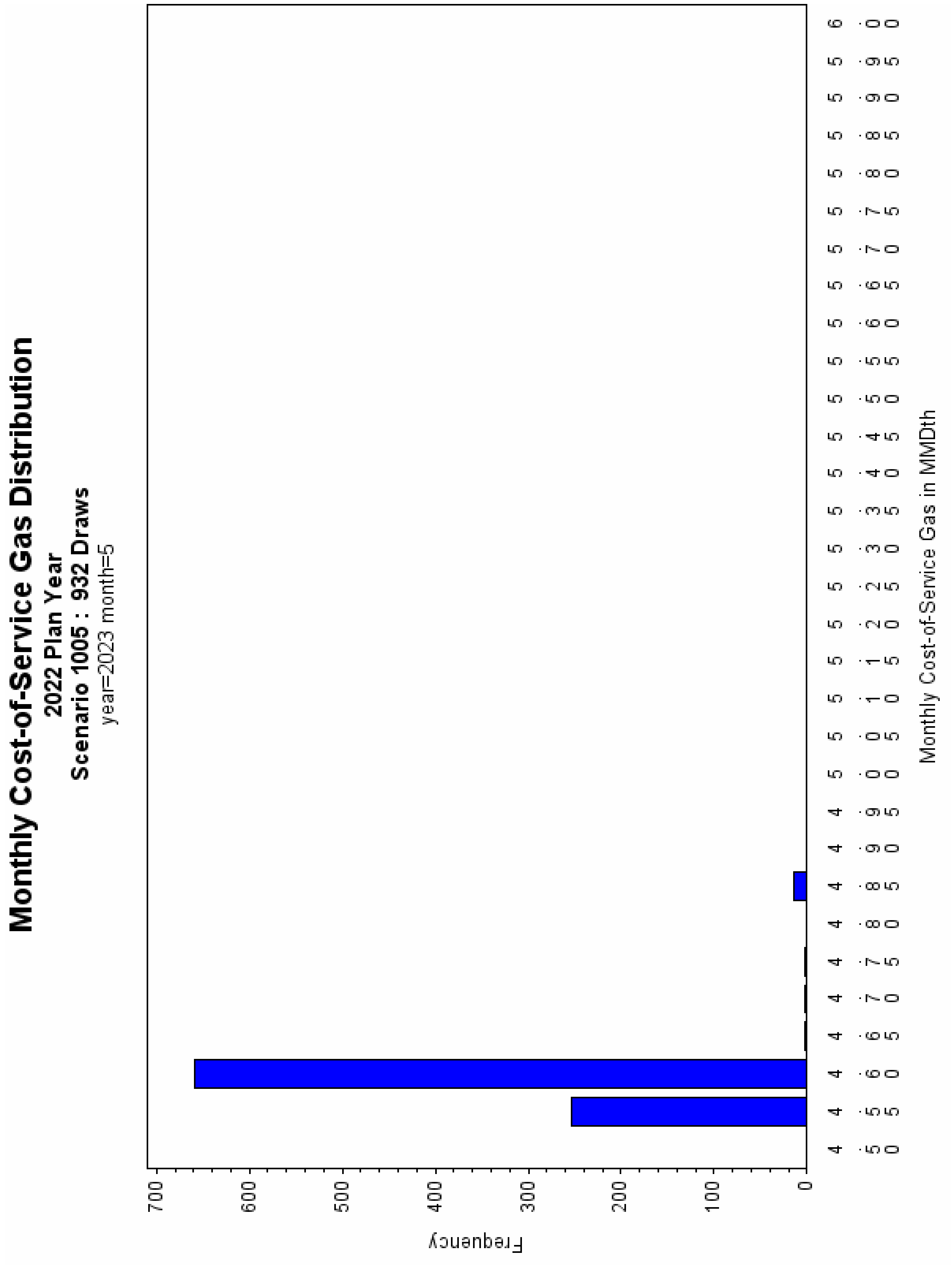
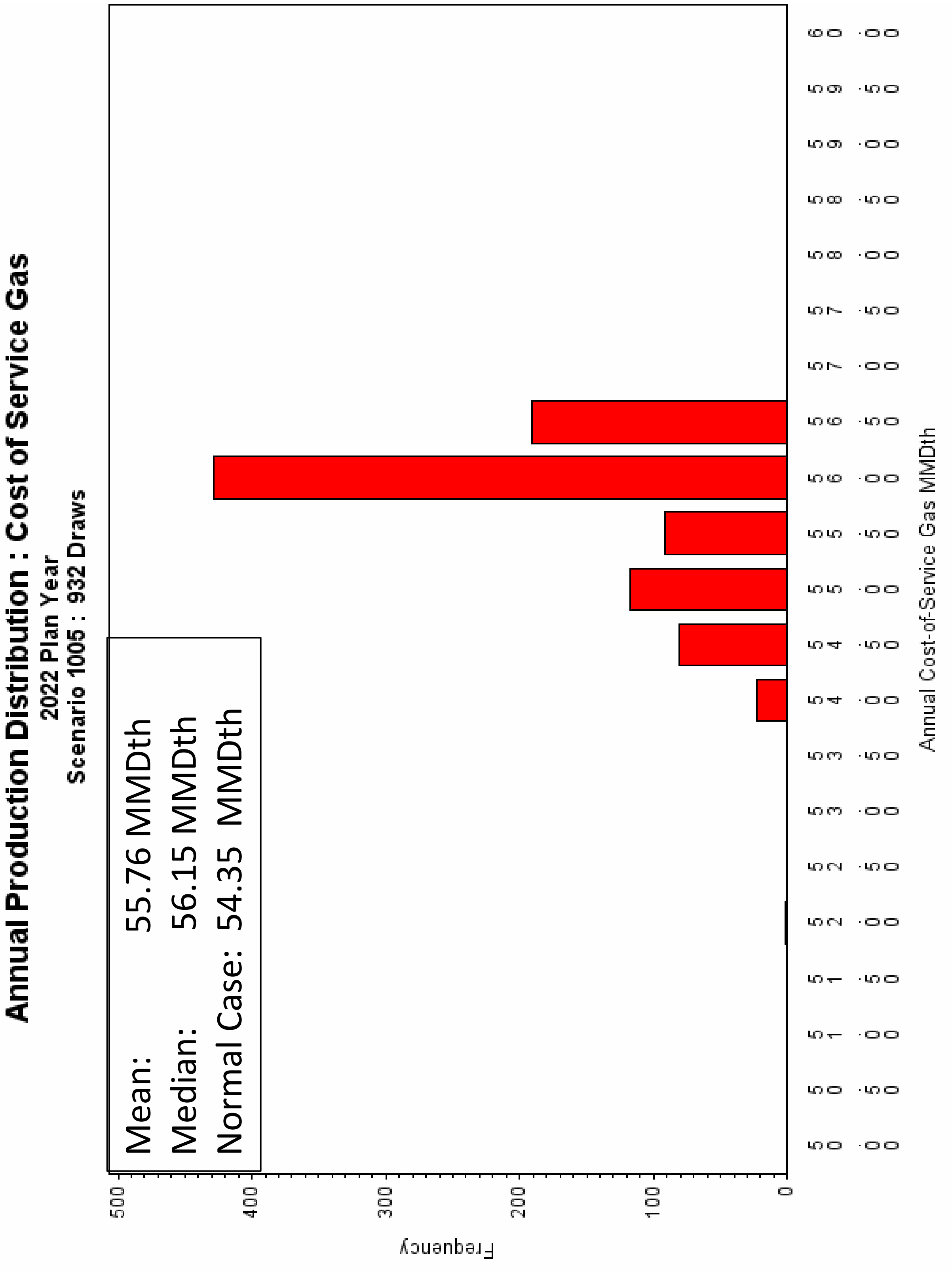

Monthly Cost-of-Service Gas Distribution
2022 Plan Year
Scenario 1005 : 932 Draws
year=2023 month=4
Frequency
0
100
200
300
400
500
4.50
4.55
4.60
4.65
4.70
4.75
4.80
4.85
4.90
4.95
5.00
5.05
5.10
5.15
5.20
5.25
5.30
5.35
5.40
5.45
5.50
5.55
5.60
5.65
5.70
5.75
5.80
5.85
5.90
5.95
6.00
Monthly Cost-of-Service Gas in MMDth

Exhibit 14.78





Annual Production Distribution : Cost of Service Gas
2022 Plan Year
Scenario 1005 : 932 Draws
Mean: 55.76 MMDth
Median: 56.15 MMDth
Normal Case: 54.35 MMDth
Frequency
0
100
200
300
400
500
50.00
50.50
51.00
51.50
52.00
52.50
53.00
53.50
54.00
54.50
55.00
55.50
56.00
56.50
57.00
57.50
58.00
58.50
59.00
59.50
60.00
Annual Cost-of-Service Gas MMDth

Exhibit 14.80

Monthly Cost-of-Service Gas Distribution
2022 Plan Year
Scenario 1005 : 932 Draws

year	month	mean	max	p95	P90	med	p10	p5	min
2022	6	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39
2022	7	4.49	4.49	4.49	4.49	4.49	4.49	4.49	4.49
2022	8	4.44	4.44	4.44	4.44	4.44	4.44	4.44	4.44
2022	9	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26
2022	10	4.34	4.36	4.36	4.36	4.35	4.31	4.23	4.18
2022	11	4.84	4.85	4.84	4.84	4.84	4.84	4.84	4.84
2022	12	4.95	4.97	4.96	4.96	4.95	4.95	4.95	4.95
2023	1	4.89	4.91	4.90	4.89	4.89	4.89	4.89	4.89
2023	2	3.92	4.42	4.42	4.42	4.36	2.88	2.68	0.04
2023	3	6.13	6.16	6.16	6.15	6.13	6.08	6.07	5.98
2023	4	4.53	4.69	4.60	4.58	4.53	4.50	4.48	4.43
2023	5	4.58	4.85	4.59	4.58	4.58	4.57	4.57	4.57

Exhibit 14.81

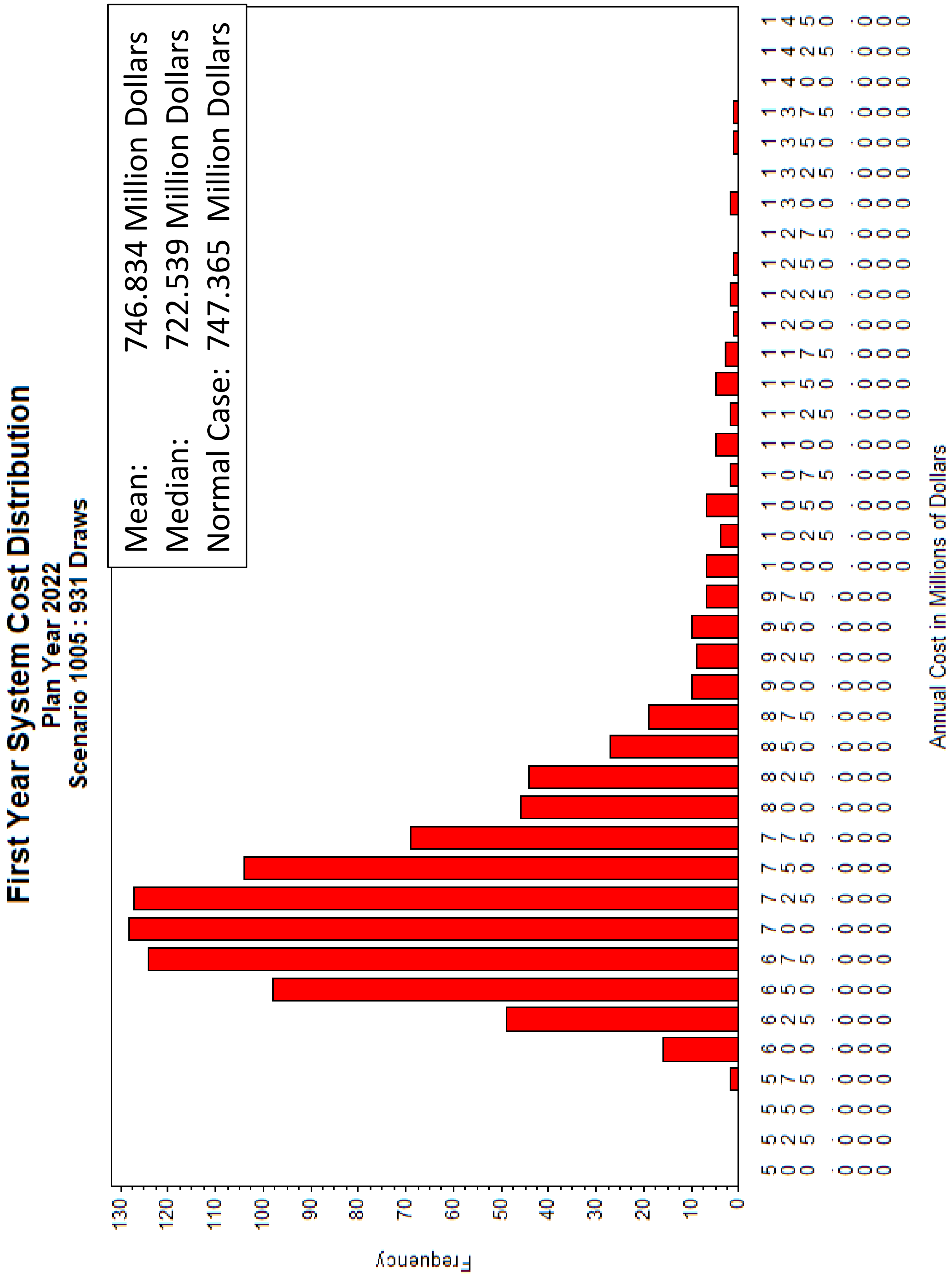


Exhibit 14.82

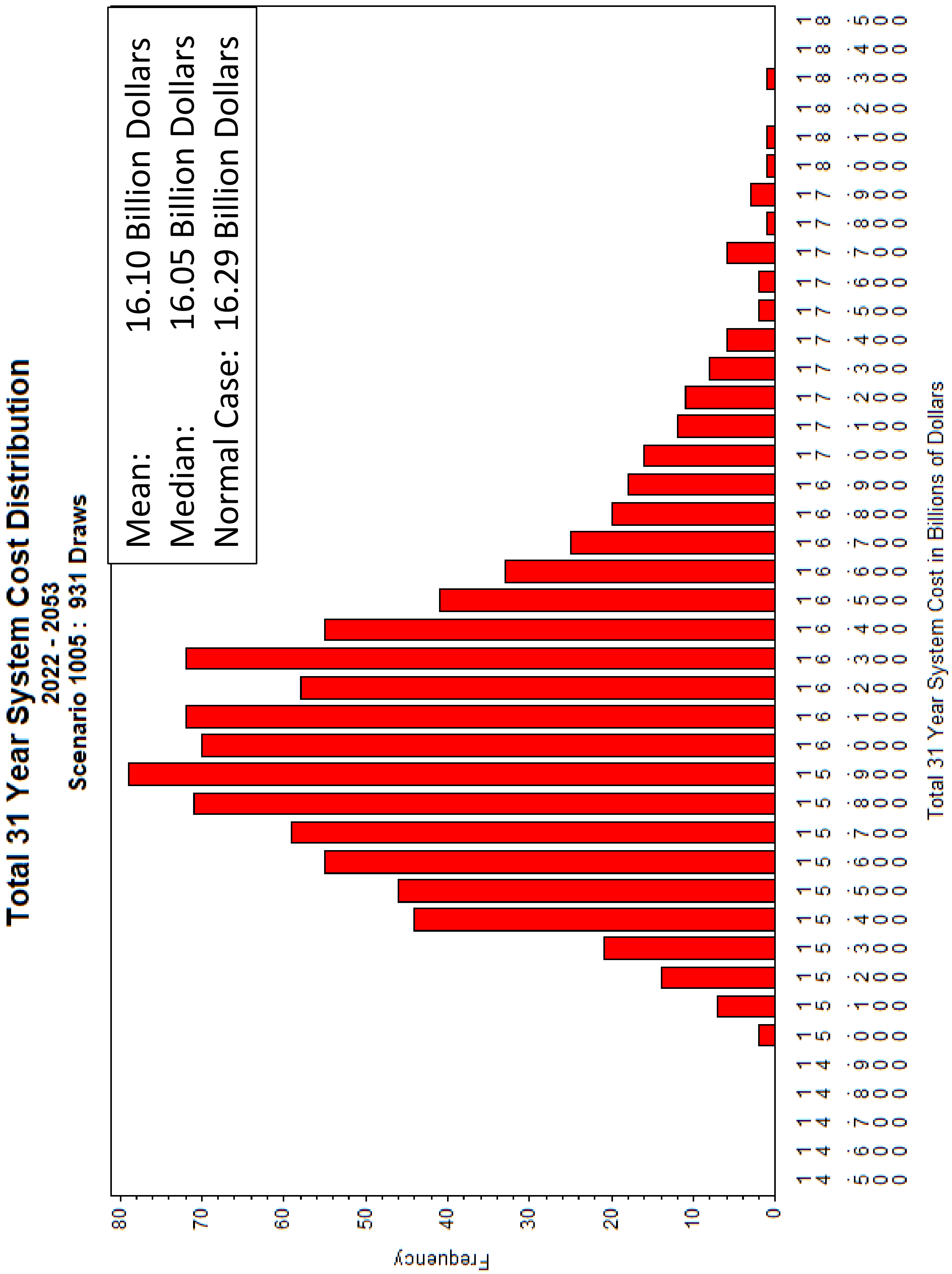


Exhibit 14.83

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
Birch Creek													
BIRCH CREEK	101.625	104.414	103.822	99.903	102.65	98.772	101.485	100.911	97.22	99.77	96.009	98.648	1205.23
Total	101.625	104.414	103.822	99.903	102.65	98.772	101.485	100.911	97.22	99.77	96.009	98.648	1205.23
D24													
ACEJDMT D24	7.176	7.359	7.304	7.014	7.192	6.909	7.087	7.031	6.763	6.925	6.654	6.823	84.237
BRFM D24	1.938	1.996	1.99	1.92	1.975	1.905	1.962	1.956	1.888	1.941	1.872	1.928	23.271
BRFQ D24	120.942	124.239	123.513	118.83	122.072	117.447	120.655	119.951	115.548	118.566	114.078	117.202	1433.042
BRFQMT D24	2.904	2.985	2.97	2.859	2.942	2.832	2.911	2.895	2.793	2.868	2.76	2.837	34.555
BRFW D24	48.894	50.242	49.96	48.078	49.405	47.544	48.856	48.583	46.812	48.047	46.233	47.511	580.163
CBFR D24	14.424	14.83	14.753	14.202	14.601	14.055	14.449	14.375	13.856	14.226	13.698	14.08	171.549
CCRUNIT D24	388.299	399.956	397.212	381.771	391.806	376.59	386.508	383.898	369.451	378.752	364.08	373.702	4592.025
CCRUNITMTD24	35.532	36.496	36.279	34.899	35.848	34.485	35.421	35.21	33.913	34.791	33.468	34.379	420.721
CHBT MT	18.576	18.91	18.653	17.82	18.197	17.412	17.803	17.623	16.913	17.295	16.59	16.997	212.789
CHBTBUFF D24	0	0	0	0	0	0	0	0	0	0	0	0	0
CHBTCAT2 D24	82.227	84.497	84.032	80.874	83.108	79.983	82.193	81.738	78.761	80.842	77.802	79.946	976.002
CHBTCAT3 D24	134.967	138.753	138.043	132.906	136.632	131.544	135.228	134.534	129.676	133.151	128.193	131.784	1605.412
DRY PINY MT	4.488	4.607	4.576	4.398	4.511	4.335	4.452	4.421	4.254	4.359	4.191	4.3	52.89
DRYPINY6 D24	0.462	0.474	0.471	0.453	0.465	0.45	0.462	0.459	0.441	0.453	0.438	0.45	5.477
DRYPINYU D24	1.542	1.584	1.575	1.515	1.556	1.5	1.541	1.531	1.473	1.513	1.455	1.494	18.279
HWA DEEP D24	0.093	0.093	0.093	0.09	0.093	0.087	0.09	0.09	0.087	0.09	0.084	0.087	1.076
HWA MT	0	2.688	2.672	0	2.303	2.547	2.616	2.604	2.511	2.576	0	0	20.518
HWADEEPMTD24	11.58	11.904	11.842	11.4	11.718	11.283	11.597	11.538	11.121	11.417	10.992	11.3	137.693
HWPL1&3MTD24	6.756	6.95	6.916	6.66	6.851	6.597	6.783	6.752	6.51	6.687	6.441	6.625	80.528
HWPLT1&3 D24	63.924	65.574	65.097	62.538	64.155	61.635	63.228	62.769	60.378	61.867	59.439	60.977	751.58
HWPLT2 D24	3.75	3.838	3.804	3.648	3.736	3.585	3.673	3.643	3.5	3.581	3.438	3.525	43.72
HWPLT2MT D24	0	0	0	0	2.179	2.496	2.561	2.545	2.448	2.508	0	0	14.736
ISLAND D24	45.051	46.261	45.97	44.208	45.396	43.659	44.832	44.55	42.897	43.995	42.312	43.45	532.581
JNSNRDG D24	1.668	1.714	1.708	1.644	1.693	1.632	1.677	1.671	1.612	1.655	1.596	1.64	19.911
JRDG WFS D24	2.184	2.241	2.229	2.142	2.201	2.118	2.173	2.161	2.082	2.136	2.052	2.108	25.827
KNY FLD D24	9.816	10.075	10.004	9.615	9.867	9.483	9.731	9.663	9.297	9.529	9.159	9.396	115.636
MESA D24	480.351	491.297	486.151	465.69	476.337	456.306	466.752	462.043	443.161	452.783	433.773	443.471	5558.113
MOSUMT D24	0.915	0.942	0.936	0.9	0.924	0.888	0.911	0.908	0.873	0.896	0.861	0.884	10.838
PDW MT	155.4	159.228	157.902	151.545	155.319	149.091	152.824	151.609	145.731	149.228	143.289	146.915	1818.08
PDW1A1B D24	0.267	0.273	0.273	0.261	0.27	0.258	0.264	0.264	0.252	0.26	0.249	0.257	3.147
PDWCUT D24	1.113	1.144	1.138	1.098	1.128	1.086	1.119	1.113	1.073	1.104	1.062	1.091	13.269
PDWMT D24	18.738	19.223	19.084	18.333	18.808	18.069	18.538	18.405	17.702	18.138	17.427	17.878	220.342
PDWPLT2 D24	0	0	0	0	0	0	0	0	0	0	0	0	0
SGRLF D24	1.209	1.24	1.231	1.182	1.215	1.167	1.197	1.19	1.145	1.172	1.128	1.156	14.233
SGRLFMT D24	10.644	10.921	10.847	10.425	10.698	10.281	10.549	10.475	10.08	10.332	9.93	10.19	125.373
TRAIL D24	246.795	252.563	250.17	239.844	245.57	256.536	262.923	260.809	249.365	253.05	241.293	246.031	3004.95
TRAILMT D24	37.623	38.629	38.384	36.912	37.907	36.462	37.451	37.228	35.859	36.797	35.382	36.354	444.987
WHLA D24	26.691	27.388	27.196	26.136	26.815	25.767	26.44	26.251	25.256	25.882	24.87	25.519	314.212
WWILSON D24	3.087	3.174	3.156	3.039	3.122	3.006	2.722	2.709	2.61	2.681	2.583	2.654	34.543
Total	1990.026	2044.288	2028.134	1944.849	1998.615	1941.03	1990.179	1975.195	1898.092	1942.093	1858.872	1904.941	23516.31
D21													
PDW1A1B D21	0.444	0.456	0.453	0.435	0.446	0.429	0.44	0.437	0.421	0.431	0.414	0.425	5.23
Total	0.444	0.456	0.453	0.435	0.446	0.429	0.44	0.437	0.421	0.431	0.414	0.425	5.23
PW													
MOSU MT	0	0	0	0	0	0	5.67	5.568	5.298	0	0	0	16.536
Total	0	0	0	0	0	0	5.67	5.568	5.298	0	0	0	16.536
Off-System													
OFF SYS D24	31.857	32.758	32.6	31.353	32.243	31.05	31.93	31.778	30.641	31.471	30.309	31.17	379.161
OFF SYS PC	6.873	7.068	7.037	6.78	6.972	6.717	6.91	6.879	6.635	6.817	6.567	6.755	82.01
OFF SYS PW	0.069	0.071	0.071	0.066	0.068	0.066	0.068	0.068	0.067	0.068	0.066	0.068	0.817
Total	38.799	39.897	39.708	38.199	39.283	37.833	38.908	38.725	37.343	38.356	36.942	37.993	461.988
Q50													
BRCH CRK Q50	0.582	0.592	0.583	0.555	0.567	0.54	0.552	0.542	0.519	0.53	0.507	0.515	6.584
TRAIL Q50	0.942	0.967	0.958	0.918	0.942	0.903	0.927	0.921	0.884	0.905	0.87	0.893	11.031
Total	1.524	1.559	1.541	1.473	1.509	1.443	1.479	1.463	1.403	1.435	1.377	1.408	17.615

Normal Temperatue Case: Plan Year 1
MDth

Exhibit 14.84

PC

ACEJDMT PC	3.279	3.373	3.357	3.234	3.326	3.204	3.295	3.28	2.948	3.249	3.129	3.218	38.893
BRFM PC	0.144	0.149	0.146	0.141	0.146	0.141	0.143	0.143	0.129	0.143	0.138	0.139	1.7
BRFQ PC	10.056	10.342	10.295	9.918	10.202	9.828	10.109	10.063	9.047	9.97	9.606	9.88	119.315
BRFQMT PC	3.111	3.199	3.184	3.066	3.156	3.039	3.125	3.109	2.794	3.078	2.964	3.05	36.876
BRFW PC	8.715	8.962	8.919	8.589	8.835	8.508	8.748	8.708	7.826	8.624	8.307	8.541	103.282
BRUFF MT	4.509	4.634	4.61	4.437	4.56	4.389	4.51	4.486	4.032	4.439	4.272	4.393	53.271
CBFR PC	55.47	57.012	56.708	54.585	56.101	54	55.502	55.205	49.594	54.613	52.569	54.03	655.388
CCRUNIT MT	38.415	39.243	38.8	37.134	37.953	36.333	37.147	36.76	32.864	36.016	34.503	35.303	440.47
CCRUNIT PC	0	0	0	0	0	0	0	0	0	0	0	0	0
CCRUNITMT PC	15.129	15.565	15.497	14.931	15.36	14.799	15.224	15.159	13.63	15.026	14.475	14.892	179.688
CHBTC1 MT PC	22.23	22.875	22.776	21.948	22.58	21.759	22.388	22.292	20.048	22.103	21.297	21.914	264.21
CHBTCAT1 PC	41.697	42.802	42.52	40.878	41.965	40.347	41.419	41.152	36.929	40.622	39.063	40.105	489.499
CHBTCAT2 PC	1.818	1.863	1.848	1.773	1.817	1.743	1.786	1.77	1.585	1.739	1.668	1.708	21.117
DRYPINY6 PC	0.996	1.026	1.02	0.984	1.011	0.975	1.004	0.998	0.899	0.992	0.954	0.983	11.842
DRYPINYU PC	9.783	10.044	9.982	9.6	9.858	9.48	9.734	9.672	8.68	9.551	9.183	9.43	114.997
FOGARTY PC	0.522	0.536	0.533	0.513	0.527	0.507	0.518	0.515	0.462	0.508	0.489	0.502	6.132
HWA DEEP PC	0.504	0.518	0.515	0.495	0.508	0.489	0.502	0.499	0.448	0.493	0.474	0.487	5.932
HWPL1&3MTPC	5.847	6.011	5.977	5.751	5.909	5.685	5.844	5.809	5.219	5.744	5.529	5.682	69.007
HWPLT1&3 PC	49.824	51.2	50.918	49.005	50.359	48.465	49.805	49.532	44.492	48.986	47.145	48.45	588.18
HWPLT2 PC	0.804	0.825	0.822	0.789	0.812	0.783	0.803	0.8	0.72	0.79	0.762	0.784	9.493
ISLAND PC	0.525	0.539	0.536	0.516	0.53	0.51	0.524	0.521	0.468	0.515	0.495	0.508	6.187
JNSNRDG PC	1.914	1.969	1.959	1.89	1.944	1.875	1.928	1.922	1.728	1.903	1.836	1.888	22.755
KNY FLD PC	3.096	3.187	3.174	3.06	3.15	3.036	3.125	3.112	2.8	3.088	2.976	3.063	36.866
MOSUMT PC	10.167	10.435	10.363	9.963	10.227	9.831	10.091	10.022	8.991	9.889	9.504	9.756	119.238
NBXCAMP PC	0	0	0	0	0	0	0	0	0	0	0	0	0
NOBXFLD PC	0	0	0	0	0	0	0	0	0	0	0	0	0
PDW1A1B PC	0.738	0.756	0.753	0.723	0.741	0.714	0.732	0.725	0.652	0.722	0.699	0.722	8.679
PDW1AB MT PC	3.129	3.218	3.202	3.084	3.171	3.054	3.14	3.125	2.808	3.094	2.979	3.066	37.071
PDWCUT PC	0.654	0.676	0.673	0.648	0.666	0.642	0.663	0.66	0.594	0.654	0.63	0.651	7.811
PDWPLT2 PC	4.842	4.979	4.957	4.773	4.91	4.731	4.864	4.842	4.351	4.796	4.62	4.752	57.417
PDWPLT3 PC	4.806	4.938	4.907	4.722	4.852	4.668	4.796	4.768	4.281	4.712	4.533	4.659	56.642
SBXSWEET PC	0	0	0	0	0	0	0	0	0	0	0	0	0
SGRLF PC	33.171	34.066	33.858	32.568	33.449	32.172	33.043	32.845	29.484	32.445	31.209	32.054	390.363
TRAIL PC	1.125	1.153	1.144	1.101	1.128	1.086	1.113	1.107	0.991	1.091	1.047	1.076	13.162
WHLA PC	8.844	9.086	9.033	8.691	8.928	8.592	8.826	8.773	7.879	8.674	8.343	8.572	104.241
WWILSON PC	9.672	9.929	9.864	9.483	9.737	9.363	9.613	9.551	8.571	9.427	9.063	9.306	113.58
Total	355.536	365.11	362.85	348.993	358.418	344.748	354.064	351.925	315.944	347.696	334.461	343.564	4183.304

Wexpro I

CCRUNIT D8	149.496	152.34	150.282	143.514	146.382	139.872	142.749	141.022	125.866	137.733	131.772	134.642	1695.67
KNY FLD D8	19.614	19.843	19.44	18.441	18.69	17.748	18.005	17.686	15.697	17.084	16.257	16.529	215.033
MESA D8	440.418	446.955	439.23	417.96	423.581	402.552	408.766	401.921	357.143	387.897	368.766	374.57	4869.758
TRAIL D8	83.643	85.008	83.654	79.713	81.146	77.394	78.858	77.785	69.328	75.767	72.405	73.904	938.604
Total	693.171	704.146	692.606	659.628	669.799	637.566	648.378	638.414	568.034	618.481	589.2	599.645	7719.065

Wexpro I New Drill

z22 CCRK D8	0	0	0	0	0	195.879	202.408	202.408	182.82	178.244	153.963	144.336	1260.059
z22 ISLND D8	0	0	0	0	0	0	0	0	0	0	0	0	0
z22 TRAIL D8	0	0	0	0	0	128.469	132.751	132.751	119.904	132.751	126.486	123.179	896.292
Total	0	0	0	0	0	324.348	335.159	335.159	302.724	310.995	280.449	267.515	2156.351

Wexpro II

CCOPA 2E	3.603	3.705	3.686	3.552	3.652	3.519	3.618	3.602	3.237	3.568	3.438	3.534	42.713
CCRUNIT 2D8	60.444	61.585	60.741	57.996	59.145	56.505	57.657	56.953	50.823	55.608	53.193	54.346	684.996
CCRUNIT 2E	238.647	244.339	242.15	232.281	237.953	228.324	233.966	232.041	207.886	228.315	219.204	224.738	2769.844
CCRUNIT 2EMT	22.179	22.788	22.661	21.81	22.41	21.567	22.162	22.038	19.796	21.793	20.973	21.554	261.731
TRAIL 2D8	226.473	228.206	222.884	210.951	212.136	200.304	202.21	197.774	174.896	188.474	178.011	179.722	2422.042
TRAIL 2E	294.117	300.585	297.355	284.733	291.189	278.946	285.38	282.596	252.798	277.239	265.803	272.149	3382.891
TRAIL 2E MT	39.426	40.337	39.947	38.286	39.265	37.719	38.694	38.421	34.462	37.894	36.429	37.395	458.276
WHISKEY MT	23.418	23.929	23.672	22.665	23.176	22.197	22.708	22.481	20.107	22.05	21.138	21.638	269.178
WHISKEYC 2E	72.825	74.44	73.653	70.533	72.137	69.105	70.702	70.01	62.625	68.677	65.841	67.41	837.958
Total	981.132	999.914	986.749	942.807	961.063	918.186	937.097	925.916	826.63	903.618	864.03	882.486	11129.63

Wexpro II New Drill

z22 CCRK 2D8	0	0	0	0	0	81.453	84.168	84.168	76.023	74.118	64.023	60.019	523.972
z22 TRAIL2D8	0	0	0	0	0	124.209	128.349	128.349	115.928	128.349	122.322	119.251	866.758
z22 WSKY 2D8	0	0	0	0	0	142.347	140.269	118.621	93.85	93.108	82.047	78.126	748.369
Total	0	0	0	0	0	348.009	352.786	331.138	285.801	295.575	268.392	257.396	2139.099

Normal Temperatue Case: Plan Year 1

MDth

Exhibit 14.85

	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Inject													
Clay Bsn 935	880	680.069	911.927	867.293	700.816	0	0	0	0	357.84	60.685	1074.667	5533.296
Clay Bsn 988	550	516.965	508.742	507.419	438.019	3.921	0	0	0	223.65	37.896	671.667	3458.279
Clay Bsn 997	550	568.333	266.485	551.58	438.019	150.649	0	0	0	223.65	37.896	671.667	3458.279
Chalk Creek	0	0	0	40	132	90	53.593	0	44.31	0	0	0	359.903
Coalville	0	0	0	18	280.8	99.904	0	0	170	317.5	0	0	886.204
Leroy	0	0	0	47.5	45	300	45.573	0	146.8	0	0	0	584.873
Magna LNG	0	0	0	270	279	270	279	132	0	0	0	279	1509
Total	1980	1765.367	1687.154	2301.792	2313.654	914.474	378.166	132	361.11	1122.64	136.477	2697.001	15789.83
Withdraw													
Clay Bsn 935	0	0	0	0	0	0	1515.578	1515.578	1368.909	0	0	0	4400.064
Clay Bsn 988	0	0	0	0	0	0	947.236	947.236	855.568	0	0	0	2750.04
Clay Bsn 997	0	0	0	0	0	0	947.236	947.236	855.568	0	0	0	2750.04
Chalk Creek	0	0	0	0	0	0	0	124.56	128.625	112.125	0	0	365.31
Coalville	0	0	0	0	0	0	0	410.186	437.5	0	0	0	847.686
Leroy	0	0	0	0	0	0	0	470.298	120	0	0	0	590.298
MagnaLNG	0	0	0	0	0	0	0	0	0	1230	0	0	1230
Total	0	0	0	0	0	0	3410.05	4415.094	3766.17	1342.125	0	0	12933.44
Purchase Gas													
Spot	0	0	0	0	2626.615	4564.547	3450.881	3636.472	4771.384	3101.981	1843.416	2066.48	26061.78
Spot	721.841	0	0	1093.547	1550	1500	1550	1550	0	1550	1500	1550	12565.39
Spot	0	0	0	0	1028.496	2250	1156.263	1156.72	1184.277	2325	0	0	9100.756
Spot	0	0	0	0	0	49.832	76.392	83.859	5.605	0	36.194	21.305	273.186
Spot	0	0	0	0	0	0	2.277	27.551	4.159	0	0	0	33.988
Peak	0	0	0	0	0	0	680	1240	0	1550	1500	0	4970
Peak	0	0	0	0	0	0	170	310	140	0	0	0	620
Peak	0	0	0	0	0	150	70	0	0	0	0	0	220
Peak	0	0	0	0	0	0	140	0	0	0	0	0	140
Peak	0	0	0	0	0	0	0	0	24.413	0	0	0	24.413
Peak	0	0	0	0	0	0	0	0	4.619	0	0	0	4.619
Base	0	0	0	0	0	0	930	930	840	0	0	0	2700
Base	0	0	0	0	0	0	930	930	840	0	0	0	2700
Base	0	0	0	0	0	0	775	775	700	0	0	0	2250
Base	0	0	0	0	0	0	775	775	700	0	0	0	2250
Base	0	0	0	0	0	270	279	279	252	279	0	0	1359
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Total	721.841	0	0	1093.547	5205.111	8784.379	11449.81	12158.6	9886.457	8805.981	4879.61	3637.785	66623.12

Exhibit 14.86

Normal Temperature Case : Plan Year 2
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
Birch Creek													
BIRCH CREEK	101.625	104.414	103.822	99.903	102.65	98.772	101.485	100.911	97.22	99.77	96.009	98.648	1205.23
Total	101.625	104.414	103.822	99.903	102.65	98.772	101.485	100.911	97.22	99.77	96.009	98.648	1205.23
D24													
ACEJDMT D24	7.176	7.359	7.304	7.014	7.192	6.909	7.087	7.031	6.763	6.925	6.654	6.823	84.237
BRFM D24	1.938	1.996	1.99	1.92	1.975	1.905	1.962	1.956	1.888	1.941	1.872	1.928	23.271
BRFQ D24	120.942	124.239	123.513	118.83	122.072	117.447	120.655	119.951	115.548	118.566	114.078	117.202	1433.042
BRFQMT D24	2.904	2.985	2.97	2.859	2.942	2.832	2.911	2.895	2.793	2.868	2.76	2.837	34.555
BRFW D24	48.894	50.242	49.96	48.078	49.405	47.544	48.856	48.583	46.812	48.047	46.233	47.511	580.163
CBFR D24	14.424	14.83	14.753	14.202	14.601	14.055	14.449	14.375	13.856	14.226	13.698	14.08	171.549
CCRUNIT D24	388.299	399.956	397.212	381.771	391.806	376.59	386.508	383.898	369.451	378.752	364.08	373.702	4592.025
CCRUNITMTD24	35.532	36.496	36.279	34.899	35.848	34.485	35.421	35.21	33.913	34.791	33.468	34.379	420.721
CHBT MT	18.576	18.91	18.653	17.82	18.197	17.412	17.803	17.623	16.913	17.295	16.59	16.997	212.789
CHBTBUFF D24	0	0	0	0	0	0	0	0	0	0	0	0	0
CHBTCAT2 D24	82.227	84.497	84.032	80.874	83.108	79.983	82.193	81.738	78.761	80.842	77.802	79.946	976.002
CHBTCAT3 D24	134.967	138.753	138.043	132.906	136.632	131.544	135.228	134.534	129.676	133.151	128.193	131.784	1605.412
DRY PINY MT	4.488	4.607	4.576	4.398	4.511	4.335	4.452	4.421	4.254	4.359	4.191	4.3	52.89
DRYPINY6 D24	0.462	0.474	0.471	0.453	0.465	0.45	0.462	0.459	0.441	0.453	0.438	0.45	5.477
DRYPINYU D24	1.542	1.584	1.575	1.515	1.556	1.5	1.541	1.531	1.473	1.513	1.455	1.494	18.279
HWA DEEP D24	0.093	0.093	0.093	0.09	0.093	0.087	0.09	0.09	0.087	0.09	0.084	0.087	1.076
HWA MT	0	2.688	2.672	0	2.303	2.547	2.616	2.604	2.511	2.576	0	0	20.518
HWADEEPMTD24	11.58	11.904	11.842	11.4	11.718	11.283	11.597	11.538	11.121	11.417	10.992	11.3	137.693
HWPL1&3MTD24	6.756	6.95	6.916	6.66	6.851	6.597	6.783	6.752	6.51	6.687	6.441	6.625	80.528
HWPLT1&3 D24	63.924	65.574	65.097	62.538	64.155	61.635	63.228	62.769	60.378	61.867	59.439	60.977	751.58
HWPLT2 D24	3.75	3.838	3.804	3.648	3.736	3.585	3.673	3.643	3.5	3.581	3.438	3.525	43.72
HWPLT2MT D24	0	0	0	0	2.179	2.496	2.561	2.545	2.448	2.508	0	0	14.736
ISLAND D24	45.051	46.261	45.97	44.208	45.396	43.659	44.832	44.55	42.897	43.995	42.312	43.45	532.581
JNSNRDG D24	1.668	1.714	1.708	1.644	1.693	1.632	1.677	1.671	1.612	1.655	1.596	1.64	19.911
JRDG WFS D24	2.184	2.241	2.229	2.142	2.201	2.118	2.173	2.161	2.082	2.136	2.052	2.108	25.827
KNY FLD D24	9.816	10.075	10.004	9.615	9.867	9.483	9.731	9.663	9.297	9.529	9.159	9.396	115.636
MESA D24	480.351	491.297	486.151	465.69	476.337	456.306	466.752	462.043	443.161	452.783	433.773	443.471	5558.113
MOSUMT D24	0.915	0.942	0.936	0.9	0.924	0.888	0.911	0.908	0.873	0.896	0.861	0.884	10.838
PDW MT	155.4	159.228	157.902	151.545	155.319	149.091	152.824	151.609	145.731	149.228	143.289	146.915	1818.08
PDW1A1B D24	0.267	0.273	0.273	0.261	0.27	0.258	0.264	0.264	0.252	0.26	0.249	0.257	3.147
PDWCUT D24	1.113	1.144	1.138	1.098	1.128	1.086	1.119	1.113	1.073	1.104	1.062	1.091	13.269
PDWMT D24	18.738	19.223	19.084	18.333	18.808	18.069	18.538	18.405	17.702	18.138	17.427	17.878	220.342
PDWPLT2 D24	0	0	0	0	0	0	0	0	0	0	0	0	0
SGRLF D24	1.209	1.24	1.231	1.182	1.215	1.167	1.197	1.19	1.145	1.172	1.128	1.156	14.233
SGRLFMT D24	10.644	10.921	10.847	10.425	10.698	10.281	10.549	10.475	10.08	10.332	9.93	10.19	125.373
TRAIL D24	246.795	252.563	250.17	239.844	245.57	256.536	262.923	260.809	249.365	253.05	241.293	246.031	3004.95
TRAILMT D24	37.623	38.629	38.384	36.912	37.907	36.462	37.451	37.228	35.859	36.797	35.382	36.354	444.987
WHLA D24	26.691	27.388	27.196	26.136	26.815	25.767	26.44	26.251	25.256	25.882	24.87	25.519	314.212
WWILSON D24	3.087	3.174	3.156	3.039	3.122	3.006	2.722	2.709	2.61	2.681	2.583	2.654	34.543
Total	1990.026	2044.288	2028.134	1944.849	1998.615	1941.03	1990.179	1975.195	1898.092	1942.093	1858.872	1904.941	23516.31
D21													
PDW1A1B D21	0.444	0.456	0.453	0.435	0.446	0.429	0.44	0.437	0.421	0.431	0.414	0.425	5.23
Total	0.444	0.456	0.453	0.435	0.446	0.429	0.44	0.437	0.421	0.431	0.414	0.425	5.23
PW													
MOSU MT	0	0	0	0	0	0	5.67	5.568	5.298	0	0	0	16.536
Total	0	0	0	0	0	0	5.67	5.568	5.298	0	0	0	16.536
Off-System													
OFF SYS D24	31.857	32.758	32.6	31.353	32.243	31.05	31.93	31.778	30.641	31.471	30.309	31.17	379.161
OFF SYS PC	6.873	7.068	7.037	6.78	6.972	6.717	6.91	6.879	6.635	6.817	6.567	6.755	82.01
OFF SYS PW	0.069	0.071	0.071	0.066	0.068	0.066	0.068	0.068	0.067	0.068	0.066	0.068	0.817
Total	38.799	39.897	39.708	38.199	39.283	37.833	38.908	38.725	37.343	38.356	36.942	37.993	461.988
Q50													
BRCH CRK Q50	0.582	0.592	0.583	0.555	0.567	0.54	0.552	0.542	0.519	0.53	0.507	0.515	6.584
TRAIL Q50	0.942	0.967	0.958	0.918	0.942	0.903	0.927	0.921	0.884	0.905	0.87	0.893	11.031
Total	1.524	1.559	1.541	1.473	1.509	1.443	1.479	1.463	1.403	1.435	1.377	1.408	17.615

Normal Temperature Case : Plan Year 2
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Exhibit 14.87

PC

ACEJDMT PC	3.099	3.19	3.174	3.057	3.143	3.03	3.116	3.1	2.99	3.072	2.958	3.044	36.973
BRFM PC	0.135	0.139	0.139	0.132	0.136	0.132	0.136	0.136	0.131	0.133	0.129	0.133	1.613
BRFQ PC	9.516	9.79	9.743	9.387	9.657	9.3	9.567	9.52	9.181	9.433	9.084	9.343	113.521
BRFQMT PC	2.937	3.019	3.004	2.895	2.976	2.865	2.948	2.933	2.828	2.905	2.796	2.877	34.982
BRFW PC	8.226	8.46	8.42	8.109	8.339	8.031	8.262	8.221	7.926	8.144	7.842	8.063	98.042
BRUFF MT	4.227	4.343	4.321	4.161	4.275	4.116	4.228	4.207	4.054	4.163	4.005	4.117	50.218
CBFR PC	52.008	53.453	53.165	51.177	52.598	50.628	52.037	51.758	49.88	51.206	49.287	50.657	617.853
CCRUNIT MT	33.831	34.621	34.289	32.871	33.651	32.265	33.037	32.739	31.439	32.163	30.852	31.608	393.364
CCRUNIT PC	0	0	0	0	0	0	0	0	0	0	0	0	0
CCRUNITMT PC	14.349	14.762	14.697	14.16	14.567	14.034	14.44	14.375	13.868	14.248	13.728	14.124	171.351
CHBTC1 MT PC	21.117	21.728	21.635	20.847	21.449	20.667	21.266	21.173	20.428	20.993	20.229	20.813	252.345
CHBTCAT1 PC	38.565	39.599	39.348	37.839	38.855	37.365	38.372	38.133	36.717	37.662	36.222	37.2	455.878
CHBTCAT2 PC	1.638	1.68	1.665	1.596	1.637	1.569	1.609	1.593	1.531	1.566	1.503	1.541	19.127
DRYPINY6 PC	0.945	0.973	0.97	0.933	0.961	0.927	0.952	0.949	0.916	0.942	0.906	0.933	11.308
DRYPINYU PC	9.069	9.312	9.253	8.901	9.139	8.79	9.024	8.968	8.636	8.857	8.517	8.745	107.212
FOGARTY PC	0.483	0.496	0.493	0.474	0.487	0.468	0.481	0.477	0.458	0.471	0.453	0.465	5.706
HWA DEEP PC	0.468	0.481	0.477	0.459	0.471	0.453	0.465	0.462	0.444	0.456	0.438	0.45	5.523
HWPL1&3MTPC	5.466	5.617	5.586	5.376	5.524	5.316	5.462	5.431	5.232	5.369	5.169	5.31	64.859
HWPLT1&3 PC	46.629	47.917	47.653	45.864	47.132	45.36	46.615	46.361	44.672	45.852	44.13	45.35	553.534
HWPLT2 PC	0.753	0.775	0.772	0.741	0.763	0.735	0.756	0.75	0.725	0.744	0.717	0.735	8.966
ISLAND PC	0.489	0.502	0.499	0.48	0.493	0.474	0.487	0.484	0.464	0.477	0.459	0.471	5.779
JNSNRDG PC	1.821	1.872	1.866	1.797	1.851	1.782	1.835	1.829	1.763	1.814	1.746	1.798	21.774
KNY FLD PC	2.952	3.038	3.029	2.919	3.004	2.895	2.979	2.97	2.865	2.945	2.838	2.923	35.357
MOSUMT PC	9.378	9.626	9.564	9.192	9.436	9.072	9.309	9.247	8.903	9.126	8.772	9.006	110.631
NBXCAMP PC	0	0	0	0	0	0	0	0	0	0	0	0	0
NOBXFLD PC	0	0	0	0	0	0	0	0	0	0	0	0	0
PDW1A1B PC	0.699	0.722	0.722	0.699	0.722	0.699	0.722	0.722	0.676	0.722	0	0	7.106
PDW1AB MT PC	2.952	3.035	3.019	2.91	2.992	2.88	2.964	2.948	2.842	2.92	2.814	2.892	35.168
PDWCUT PC	0.627	0.645	0.642	0.621	0.639	0.615	0.632	0.632	0.609	0.626	0.603	0.623	7.514
PDWPLT2 PC	4.575	4.706	4.684	4.512	4.641	4.47	4.597	4.576	4.414	4.532	4.365	4.492	54.563
PDWPLT3 PC	4.482	4.603	4.579	4.404	4.526	4.353	4.473	4.445	4.283	4.396	4.23	4.346	53.121
SBXSWEET PC	0	0	0	0	0	0	0	0	0	0	0	0	0
SGRLF PC	30.831	31.667	31.474	30.273	31.093	29.907	30.718	30.532	29.403	30.163	29.013	29.797	364.871
TRAIL PC	1.035	1.06	1.054	1.011	1.038	0.999	1.023	1.017	0.98	1.004	0.963	0.989	12.174
WHLA PC	8.247	8.472	8.423	8.106	8.327	8.01	8.231	8.184	7.882	8.088	7.782	7.995	97.746
WWILSON PC	8.949	9.188	9.13	8.778	9.012	8.664	8.897	8.841	8.512	8.727	8.391	8.618	105.706
Total	330.498	339.491	337.489	324.681	333.534	320.871	329.64	327.713	315.652	323.919	310.941	319.458	3913.885

Wexpro I

CCRUNIT D8	128.871	131.731	130.34	124.824	127.667	122.307	125.135	123.919	118.915	121.576	116.565	119.347	1491.196
KNY FLD D8	15.741	16.015	15.773	15.036	15.311	14.607	14.883	14.679	14.033	14.291	13.65	13.925	177.943
MESA D8	356.511	362.505	356.875	340.146	346.31	330.33	336.561	331.957	317.33	323.231	308.796	315.081	4025.633
TRAIL D8	70.665	72.168	71.343	68.271	69.778	66.804	68.305	67.605	64.841	66.259	63.501	64.988	814.529
z22 CCRK D8	128.28	122.893	114.799	104.424	101.95	93.621	92.144	88.049	81.751	81.059	75.525	67.787	1152.283
z22 ISLND D8	0	0	0	0	0	0	0	0	0	0	0	0	0
z22 TRAIL D8	113.526	112.576	106.321	95.778	92.761	84.615	82.807	78.74	72.799	71.911	66.78	66.377	1044.991
Total	813.594	817.888	795.451	748.479	753.777	712.284	719.835	704.949	669.669	678.327	644.817	647.505	8706.575

Wexpro I New Drill

z23 ISLND D8	0	0	0	0	0	23.271	24.047	24.047	23.299	21.176	18.291	17.149	151.279
z23 PDW D8	0	0	0	0	0	0	0	0	0	0	0	0	0
z23 TRAIL D8	0	0	0	0	0	179.139	183.092	176.694	161.666	147.951	129.084	121.982	1099.608
Total	0	0	0	0	0	202.41	207.139	200.741	184.965	169.127	147.375	139.131	1250.887

Wexpro II

CCOPA 2E	3.405	3.503	3.484	3.357	3.453	3.327	3.422	3.407	3.286	3.373	3.249	3.342	40.608
CCRUNIT 2D8	52.008	53.159	52.588	50.358	51.5	49.335	50.471	49.975	47.954	49.023	46.998	48.118	601.489
CCRUNIT 2E	215.805	222.909	221.222	212.481	217.933	209.349	214.743	213.187	205.068	210.137	201.915	207.173	2551.921
CCRUNIT 2EMT	20.742	21.316	21.198	20.4	20.965	20.175	20.733	20.618	19.868	20.392	19.626	20.169	246.201
TRAIL 2D8	170.097	172.053	168.553	159.921	162.124	174.819	177.825	175.141	165.894	166.501	157.206	158.856	2008.991
TRAIL 2E	260.991	267.288	264.942	254.169	260.394	249.861	256.032	253.915	244.009	249.807	239.814	245.846	3047.067
TRAIL 2E MT	35.955	36.918	36.685	35.283	36.236	34.857	35.805	35.597	34.29	35.188	33.861	34.791	425.466

Normal Temperature Case : Plan Year 2
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
Inject													
Clay Bsn 935	880	909.333	911.927	882.51	700.816	0	0	0	0	0	60.685	1074.667	5419.938
Clay Bsn 988	550	568.333	569.966	551.58	438.019	0	0	0	0	0	37.896	671.667	3387.461
Clay Bsn 997	550	568.333	569.966	551.58	438.019	0	0	0	0	0	37.896	671.667	3387.461
Chalk Creek	0	0	0	40	132	90	59	0	44.31	0	0	0	365.31
Coalville	0	0	0	42	280.8	37.386	0	0	170	325	0	0	855.186
Leroy	0	0	0	47.5	45	300	50.998	0	146.8	0	0	0	590.298
Magna LNG	270	279	125.779	270	42.221	0	0	0	135	0	0	0	1122
Total	2250	2324.999	2177.638	2385.17	2076.875	427.386	109.998	0	496.11	325	136.477	2418.001	15127.65
Withdraw													
Clay Bsn 935	0	0	0	0	0	215.378	1816	1536.909	1417.798	433.853	0	0	5419.938
Clay Bsn 988	0	0	0	0	0	134.611	1135	960.568	886.124	271.158	0	0	3387.461
Clay Bsn 997	0	0	0	0	0	134.611	1135	960.568	886.124	271.158	0	0	3387.461
Chalk Creek	0	0	0	0	0	0	0	124.56	110.25	120.1	0	0	354.91
Coalville	0	0	0	0	0	0	0	410.186	445	0	0	0	855.186
Leroy	0	0	0	0	0	0	0	470.298	120	0	0	0	590.298
MagnaLNG	0	0	0	0	0	0	0	0	0	1230	0	0	1230
Total	0	0	0	0	0	484.6	4086	4463.089	3865.296	2326.269	0	0	15225.25
Purchase Gas													
Spot	0	0	0	0	2018.583	4987.616	5274.21	6886.319	7004.368	4327.226	2176.334	2058.2	34732.86
Spot	1056.279	640.018	586.617	125.095	1550	1500	1550	1550	188.795	1550	1500	1550	13346.8
Spot	0	0	0	0	0	0	8.861	0	1050	0	0	0	1058.861
Spot	0	0	0	0	0	0	77.271	85.267	36.749	0	36.844	21.655	257.786
Spot	0	0	0	0	0	0	4.864	40.8	5.949	0	0	0	51.613
Spot	0	0	0	0	0	0	0	0	0	0	0	0	0
Spot	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	0	0	0	1176.355	1537.818	1500	1550	1550	0	1550	1500	0	10364.17
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	465	465	435	0	0	0	1365
Total	1056.279	640.018	586.617	1301.45	5106.401	7987.616	10790.21	12437.39	10460.86	7427.226	5213.178	3629.855	66637.09

Required vs. Supply

Area	Class	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Ut/Id	FS_COM	121.422	115.715	116.023	126.146	195.444	143.461	206.655	226.478	204.491	191.562	154.899	136.127	1938.423
Wy QGC	FS_COM	8.81	8.365	8.39	9.207	13.035	18.508	21.983	20.428	21.145	19.85	14.543	11.682	175.946
Ut/Id	FS_IND	36.699	35.213	35.261	36.87	59.474	43.655	62.885	68.919	62.227	58.293	47.135	41.424	588.056
Ut/Id	GS_COM	666.461	572.742	578.881	640.143	1597.218	2897.124	4471.048	4969.277	4099.21	3174.395	2103.092	1211.94	26981.53
Wy QGC	GS_COM	29.035	20.143	20.416	27.935	74.269	145.823	210.572	216.063	188.281	154.142	111.663	70.404	1268.748
Ut KRGT	GS_COM	4.914	4.21	4.251	4.713	11.439	20.253	31.109	34.559	28.606	22.268	14.886	8.732	189.939
UT NPC	GS_COM	3.225	2.759	2.783	3.093	7.489	13.291	20.414	22.684	18.733	14.631	9.749	5.731	124.584
Ut Geo	GS_COM	54.419	46.64	47.099	52.289	126.68	224.59	345.102	382.736	316.828	246.869	164.982	96.759	2104.992
Ut/Id	GS_RES	1802.238	1554.571	1576.371	1752.659	4370.446	7906.07	12166.16	13323.15	10982.58	8511.555	5650.667	3272.701	72869.19
Wy QGC	GS_RES	46.135	32.022	32.477	44.43	118.348	231.91	334.729	340.755	296.355	243.11	176.029	111.189	2007.489
Ut KRGT	GS_RES	13.28	11.424	11.574	12.917	31.279	55.306	84.712	92.583	76.584	59.719	40.018	23.57	512.965
Ut Geo	GS_RES	147.184	126.599	128.255	143.172	346.631	612.878	938.761	1026.124	848.78	661.793	443.456	261.206	5684.84
UT NPC	GS_RES	8.709	7.49	7.59	8.472	20.512	36.264	55.553	60.709	50.23	39.161	26.243	15.455	336.387
Ut/Id	IS_COM	5.046	4.813	4.826	5.259	11.705	16.152	21.927	25.995	20.597	18.956	15.61	9.818	160.704
Wy QGC	IS_COM	3.52	3.512	3.513	3.573	9.196	12.185	14.73	18.484	16.517	17.028	14.23	9.365	125.854
Ut/Id	IS_IND	5.638	5.501	5.509	5.8	7.022	9.302	8.955	13.13	10.761	9.468	10.363	7.645	99.094
Wy QGC	IS_IND	0.038	0	0.002	0.061	0.966	1.794	1.008	1.083	0.82	0.62	0.192	1.269	7.853
Ut/Id	L_and_U	14.744	12.793	12.951	14.349	34.889	61.578	94.681	104.125	85.974	66.88	44.618	26.159	573.741
Wy QGC	L_and_U	0.489	0.358	0.362	0.476	1.206	2.293	3.259	3.336	2.924	2.43	1.77	1.14	20.045
Ut KRGT	L_and_U	0.102	0.087	0.088	0.099	0.239	0.422	0.647	0.711	0.588	0.458	0.307	0.181	3.929
UT NPC	L_and_U	0.067	0.057	0.058	0.065	0.157	0.277	0.425	0.466	0.386	0.301	0.201	0.118	2.577
Ut Geo	L_and_U	1.127	0.968	0.98	1.093	2.646	4.681	7.177	7.876	6.516	5.079	3.401	2.001	43.545
Off-Sys Dmd	Off_Sys	36.388	37.601	37.601	36.388	37.601	36.388	37.601	37.601	33.963	37.601	36.389	37.483	442.608
	Total	3009.69	2603.583	2635.261	2929.209	7077.891	12494.21	19140.09	20997.27	17373.1	13556.17	9084.443	5362.099	116263
Fuel	Transport	104.343	101.909	101.474	104.575	146.886	205.438	280.206	297.341	250.078	200.98	165.22	130.702	2089.153
Fuel	Injection	20.315	18.113	17.31	21.804	21.932	12.696	1.921	0	6.761	11.727	1.4	24.809	158.789
Fuel	Withdrawal	0	0	0	0	0	0	12.503	36.026	27.032	2.063	0	0	77.624
	Total Fuel	124.658	120.022	118.784	126.379	168.818	218.134	294.63	333.367	283.871	214.77	166.62	155.511	2325.566
Inject	Clay Basin	1980	1765.367	1687.154	1926.292	1576.854	154.57	0	0	0	805.14	136.477	2418.001	12449.85
Inject	Aquifer	0	0	0	105.5	457.8	489.904	99.166	0	361.11	317.5	0	0	1830.98
Inject	LNG	0	0	0	270	279	270	279	132	0	0	0	279	1509
	Total Inject	1980	1765.367	1687.154	2301.792	2313.654	914.474	378.166	132	361.11	1122.64	136.477	2697.001	15789.83
Total Required		5114.348	4488.972	4441.199	5357.38	9560.363	13626.81	19812.89	21462.64	18018.08	14893.58	9387.54	8214.611	134378.4

Exhibit 14.90

Required vs. Supply

Area	Class	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Supply	Spot	721.841	0	0	1093.547	5205.111	8364.379	6235.813	6454.603	5965.425	6976.981	3379.61	3637.784	48035.09
Supply	Peak	0	0	0	0	0		1060	1550	169.032	1550	150	0	5979.032
Supply	Base	0	0	0	0	0	270	4154	4154	3752	279	0	0	12609
	Total	721.841	0	0	1093.547	5205.111	8634.379	11449.81	12158.6	9886.457	8805.981	3529.61	3637.784	66623.13
Withdrawal	Clay Basin	0	0	0	0	0	0	3410.05	3410.05	3080.045	0	0	0	9900.145
Withdrawal	Aquifer	0	0	0	0	0	0	0	1005.044	686.125	112.125	0	0	1803.294
Withdrawal	LNG	0	0	0	0	0	0	0	0	0	1230	0	0	1230
Production	Company	2679.102	2744.505	2721.44	2622.294	2683.983	2575.221	2639.201	2617.912	2345.771	2576.394	2466.756	2529.501	31202.08
Production	Wexpro I	693.171	704.146	692.605	659.628	669.798	961.914	983.537	973.574	870.758	929.476	869.649	867.16	9875.416
Production	Wexpro II	981.132	999.914	986.749	942.807	961.062	1266.195	1289.882	1257.056	1112.432	1199.195	1132.422	1139.882	13268.73
	Total	4353.405	4448.565	4400.794	4224.729	4314.843	4803.33	8322.67	9263.636	8095.131	6047.19	4468.827	4536.543	67279.66
Off_System	Off System	39.105	40.408	40.408	39.105	40.408	39.105	40.409	40.409	36.498	40.409	39.106	40.281	475.651
	Total	39.105	40.408	40.408	39.105	40.408	39.105	40.409	40.409	36.498	40.409	39.106	40.281	475.651
Total Supply		5114.351	4488.973	4441.202	5357.381	9560.362	13476.81	19812.89	21462.65	18018.09	14893.58	8037.543	8214.608	134378.4

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 2022-2023 gas-supply year are as follows:

- Produce approximately 54.35 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 66.6 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 construction of an on-system LNG facility to help ensure system reliability for sales customers.
- Work to contribute to Dominion Energy's commitment to achieve net zero carbon and methane emissions across Dominion Energy's nationwide electric generation and natural gas infrastructure operations 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.

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

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

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 Dominion Energy Questar 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

tapline

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