Dominion Energy®

# DOMINION ENERGY UTAH / WYOMING

# INTEGRATED RESOURCE PLAN

(Plan Year: June 1, 2019 to May 31, 2020)

Submitted: June 13, 2019

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# EXECUTIVE SUMMARY

This integrated resource plan (IRP) is filed 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 "Dominion Energy" or "Company." Dominion Energy 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 jurisdictions of these regulatory bodies. The Company continues to experience strong 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. 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[1] firm sales demand of approximately 1.220 MMDth at the city gates for the 2019-2020 heating season.

2. The Company forecasts a 2019-2020 IRP-year cost-of-service gas production level of approximately 65.9 MMDth[2] assuming the completion of new development drilling projects (56% of forecast demand).

3. The Company forecasts a 2019-2020 IRP-year balanced portfolio of gas purchases of approximately 56.7 MMDth.

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

5. There is not a current need for any additional price stabilization, but the Company will review this on an annual basis to determine whether such measures are appropriate in the future.

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[1] Design Day is a day with a daily mean temperature of -5 degree Fahrenheit or lower in the Salt Lake valley.

[2] Throughout this report, "Dth" refers to dekatherms, "Mcfh" refers to thousand cubic feet per hour, "MDth" refers to thousands of dekatherms, "MMDth" refers to millions of dekatherms, "Dth/D" refers to dekatherms per day, "MDth/D" refers to thousands of dekatherms per day, "Btu" refers to British thermal units, "MMBtu" refers to millions of British thermal units, "cf" refers to cubic feet, "cfh" refers to cubic feet per hour, "Mcf" refers to thousands of cubic feet, "MMcf" refers to millions of cubic feet, "Bcf" refers to billions of cubic feet, "Bcf/D" refers to billions of cubic feet per day, "Tcf" refers to trillions of cubic feet, "Mcfd" refers to thousands of cubic feet per day, "MMcfd" refers to millions of cubic feet per day, "psi" refers to pounds per square inch, "psig" refers to pounds per square inch gauge, "GW" refers to gigawatts, "MW" refers to megawatts, "Kwh" refers to kilowatt hours, "lf" refers to linear feet, and "FL" refers to feeder line.

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 will take the necessary steps to obtain required approvals for the design and construction of an on-system liquefied natural gas (LNG) facility to ensure system reliability for customers.

10. The Company is fully committed to meeting its customers' energy needs in an environmentally responsible and proactive manner. It is the Company's duty to protect natural and cultural resources – and a good business practice. The Company aims to do what's right for the communities it serves by meeting or going beyond basic obligations to comply with applicable environmental laws and regulations.

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 Dominion Energy system will be capable of meeting the demands of the 2019-2020 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; and 15) General IRP Guidelines/Goals.

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, Inc. that are subject to the jurisdictions of the Utah and Wyoming Commissions. The Company receives its natural gas supplies from interstate pipelines with the majority of 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 country including weather.

Major regulatory factors impacting the industry in the last year, including changes at the FERC and clean energy regulation, are discussed below. Also discussed are power generation impacts on the natural gas industry and trends regarding pricing, production, storage, and natural gas infrastructure. The Wyoming and Utah IRP process is also summarized.

## 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.

On June 28, 2018 Commissioner Robert Powelson declared his intent to resign from the FERC effective mid-August.[1] Meanwhile, Chairman Kevin McIntyre was suffering from health concerns and on October 24, 2018 he withdrew as Chairman of the FERC. President Trump appointed Commissioner Neil Chatterjee to replace Chairman McIntyre.[2]

President Trump nominated Bernard L. McNamee to replace Commissioner Powelson, and on December 6, 2018 the Senate confirmed him in a split 50-49 vote. His confirmation completed the FERC, with two Democrat and three Republican nominees.[3] Less than a month later, the FERC announced the passing of Chairman McIntyre on January 3, 2019.[4] Chairman McIntyre's passing left the FERC split between Republicans and Democrats and President Trump has not yet nominated a replacement.

In a surprise move, on March 15, 2018 the FERC issued a Revised Policy Statement that eliminates a Master Limited Partnership's (MLP) ability to recover an income tax allowance

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[1] "Commissioner Robert F. Powelson Statement," Headlines, Federal Energy Regulatory Commission, June 28, 2018.
[2] "President Donald J. Trump Announces his Designation and Intent to Nominate Individuals to Key Administration Posts," The White House, Office of the Press Secretary, October 24, 2018.
[3] "Senate Votes to Confirm McNamee to FERC," News Release, Federal Energy Regulatory Commission, December 6, 2018.
[4] "FERC Announces Passing of Chairman Kevin J. McIntyre," News Releases, Federal Energy Regulatory Commission, January 3, 2019.

in its cost of service. In response to this change, along with the new tax rates in the Tax Cuts and Jobs Act, the FERC required interstate pipelines to file a one-time informational report showing a calculation of the hypothetical impact of the federal income tax rate change on 2017 financial results (FERC Form No. 501-G). Pipelines were to choose one of four options: (1) take no action; (2) file a statement explaining why a rate adjustment is not needed; (3) file a Natural Gas Act limited Section 4 filing to reduce rates; or (4) make a commitment to file a general Section 4 rate case in the near future. If a pipeline chose not to reduce rates, the FERC would consider ordering the pipeline into a section 5 rate case, requiring the pipeline to either reduce its rates or explain why it should not be required to do so.[5]

Dominion Energy Questar Pipeline (DEQP) chose option 2 and was not required to reduce rates. Kern River Gas Transmission Company (KRGT) chose option 2, but ultimately filed a Stipulation and Agreement of Settlement. For more details, see the Gathering, Transportation, and Storage section of this report.

Also on March 15, 2018, Dominion Energy Overthrust Pipeline, LLC (Overthrust) was called into a Section 5 rate case. The FERC calculated Overthrust's return on equity (ROE) for years 2015 and 2016 to be 23.4 and 19.9 percent respectively. Excluding an income tax allowance, the recalculated ROEs would have been 36.4 and 30.9 percent, respectively. Based on these findings, the FERC initiated an investigation to examine the justness and reasonableness of Overthrust's rates.[6] On October 5, 2018, Overthrust filed an Offer of Settlement with the FERC which reduced the FT Systemwide Reservation Charge from $2.031/Dth to $1.68/Dth. The settlement also eliminated the Wamsutter Expansion Reservation Charge and updated other rate schedules and charges. The FERC accepted the settlement agreement on January 25, 2019.[7]

## CLEAN ENERGY REGULATION

On March 28, 2017, the Trump Administration issued an executive order beginning the process of rescinding some of the climate-change policies of the previous administration. The order, entitled "Presidential Executive Order on Promoting Energy Independence and Economic Growth," promotes clean and safe development of U.S. energy resources. The order required all executive departments and agencies to immediately begin reviewing existing regulations that burden the development of domestic energy resources beyond the degree necessary to protect the public interest and comply with the law. Of particular interest to the energy industry is the specific requirement in the order for the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan for consistency with the presidential order.

The Clean Power Plan may have been the most ambitious initiative ever undertaken by the EPA. Regardless of the outcome of the plan, however, it is apparent that fundamental changes in the mix of power generating fuels have been taking place and will continue to

[5] "Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate," 162 FERC ¶ 61,226, Federal Energy Regulatory Commission, March, 15 2018.
[6] "Order Instituting Investigation and Setting Matter for Hearing Procedures Pursuant to Section Five of the Natural Gas Act," 162 FERC ¶ 61,218, Federal Energy Regulatory Commission, March, 15 2018.
[7] "Dominion Energy Overthrust Pipeline, LLC," 166 FERC ¶ 61,050 (2019), January 25, 2019.

take place in the U.S. That shift will move the industry generally away from the use of coal towards more environmental-friendly fuel sources.

On October 10, 2017, the EPA proposed to repeal the Clean Power Plan and a change in the legal interpretation of section 111(d) of the Clean Air Act, on which the Clean Power Plan was based. The EPA accepted comments on the proposed repeal until April 26, 2018, generating nearly 2 million comments.[8]

In a separate but related action to the proposed repeal of the Clean Power Plan, the EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) to solicit public input about a potential future rulemaking to limit greenhouse gas emissions from existing power plants. The ANPRM sought information on the roles and responsibilities of States and the EPA in regulating existing power plants for greenhouse gas emissions. It also sought information on how to best define the “Best System of Emission Reduction” and develop emission guidelines for existing power plants.[9]

Following public comment on the ANPRM, on August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) rule which establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE rule replaces the Clean Power Plan in lieu of the total repeal discussed above. The rule includes a determination of the best system of emission reduction for coal-fired power plants, a list of technologies states can consider when developing their plans, an applicability test for determining if a change to a power plant triggers a New Source Review, and implementation regulations. A public hearing was held on October 1, 2018 and the public comment period closed October 30, 2018. Following the EPA’s review of public comments, the Final Rule will be implemented sometime later this year.[10]

## POWER GENERATION IMPACT ON NATURAL GAS

During 2018, 31.3 gigawatts (GW) of electric generating capacity were added to the U.S. power grid. Capacity retirements during 2018 totaled approximately 18.7 GW leaving a net gain of approximately 12.6 GW. The top three 2018 electric-capacity additions consisted of natural gas (19.3 GW), wind (6.6 GW) and solar (4.9 GW).[11]

In 2018, natural-gas-fired generation continued to exceed coal-fired generation in the U.S. on an annual basis. As a percentage of all energy sources, natural gas comprised 35.1% and coal comprised 27.4%.[12] The U.S. Energy Information Administration (EIA) expects that

[8] “Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,” 82 Fed. Reg. 48,035, U.S. Environmental Protection Agency, Docket EPA-HQ-OAR-2017-0355, October 10, 2017.

[9] “State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,” 82 Fed. Reg. 61,507, U.S. Environmental Protection Agency, Docket EPA-HQ-OAR-2017-0545, December 18, 2017.

[10] “Greenhouse Gas Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,” 83 Fed. Reg. 44,746, U.S. Environmental Protection Agency, Docket EPA-HQ-OAR-2017-0355, August 31, 2018.

[11] “ More than 60% of electric generating capacity installed in 2018 was fueled by natural gas,” Today in Energy, U.S. Energy Information Administration, March 11, 2019.

[12] “Table ES1.B. Total Electric Power Industry Summary Statistics, Year-to-Date 2018 and 2017,” Electric Power Monthly with Data for December 2018, U.S. Energy Information Administration, Department of Energy, February 2019.

additions of utility-scale natural-gas-fired generating capacity to the power grid during 2019 will total more than 17.7 GW.[13]

Recent EIA data indicates that energy-related $CO_2$ emissions in the U.S., during calendar year 2018, totaled 5.29 billion metric tons, an increase of 2.8% from the 2017 level. This is the largest increase since 2010. Weather conditions and continued economic growth were the primary factors in increasing energy consumption and emission in 2018.[14]

## PRICING TRENDS

During 2018, natural gas spot prices averaged $3.16 per Dth at Henry Hub, about 15 cents higher than 2017. Prices increased gradually through the year with significant increases during October and November. Increased production and low winter temperatures contributed to increased natural gas consumption through 2018. In addition, increases in exports to Mexico and additional LNG export capacity resulted in the U.S. exporting more natural gas than it imported for the second year in a row.[15]

Regional prices at the Opal, Wyoming hub were even more volatile than Henry Hub during 2018, with an average of $2.75 per Dth. Prices at this location during the 2018-2019 heating season reached a peak of $17.51 per Dth on February 8, 2018 due to cold weather in the Northwest United States. The high winter prices at Opal can mainly be attributed to the rupture of a 36-inch pipeline in Canada. The pipeline is a major import pipeline for Canadian gas into the Northwest U.S. The rupture resulted in reduced imports of approximately 1.3 Bcfd from Canada. The majority of this reduction was made up by gas coming from Opal. On May 16, 2018, the average daily mid-point price at Opal was $1.790 per Dth.

Going forward, EIA forecasts the Henry Hub natural gas futures forward curve to remain relatively flat near the average price of $2.90/Dth. The forward curve is projected to swing seasonally for the next two years from the high $2.00 per Dth range during the summers to the mid $3.00 per Dth range during the winters.[16]

## PRODUCTION TRENDS

According to the EIA, U.S. natural gas production increased in 2018 due to higher prices. Total production averaged 101.3 Bcf/d in 2018, an 11% increase from 2017. This increase surpassed the all-time natural gas production record set in 2017.[17]

The recent increase in natural gas prices has had an impact on the rig count. 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

[13] “Electric Generating Capacity, Annual Energy Outlook 2019,” U.S. Energy Information Administration, January 24, 2019.

[14] “ U.S. energy-related CO2 emissions increased in 2018 but will likely fall in 2019 and 2020,” Today in Energy, U.S. Energy Information Administration, U.S. Department of Energy, Released: January 28, 2019.

[15] “Natural gas prices, production, and exports increased in 2018,” Today in Energy, Energy Information Administration, U.S. Department of Energy, January 7, 2019.

[16] “ EIA expects relatively flat natural gas prices, continued record production through 2020,” Today in Energy, Energy Information Administration, U.S. Department of Energy, January 17, 2019.

[17] “ U.S. natural gas production hit a new record high in 2018,” Today in Energy, Energy Information Administration, U.S. Department of Energy, March 14, 2019.

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 an all-time low of 81 rigs. By May 3, 2019, the gas-direct rig count had recovered to a level of 183. Due to the greater economic interest in oil, the gas directed rig count at this point in time is only about 19% of the total rigs in operation[18]

In Colorado, on April 16, 2019, Democratic Governor Jared Polis signed into law Senate Bill 181, which fundamentally changes the nature of how the state regulates the oil and gas industry. Historically, the Colorado Oil and Gas Conservation Commission had authority over drilling plans. Under the new law, local governments have more equal footing with state regulators when it comes to approving drilling permits. Cities and counties could make the process for new development more difficult. The ultimate impact of the new law will require many complicated regulator rulemakings at both the state and local levels, which could take years to complete.[19]

According to the law firm of Haynes and Boone, from the beginning of 2015 through January 7, 2019, 167 North American oil and gas producers filed for bankruptcy. These cases involve approximately $96 billion in cumulative secured and unsecured debt. During 2015, 44 oil and gas producers filed for bankruptcy, during 2016, 70 filed for bankruptcy, during 2017, 24 filed for bankruptcy, and 29 more companies filed during 2018.[20]

In November of 2018, the EIA released its annual report on natural gas proved reserves for the 2017 calendar year. On November 29, 2018, the EIA reported that U.S. proved reserves of natural gas at year-end 2017 set a new record of 464.3 Tcf. This level was 123.2 Tcf higher than the 2016 level, an increase of approximately 36%, surpassing the previous record of 388.8 Tcf set in 2014. Increasing prices typically increase reserve estimates because operators consider a larger portion of the natural gas economically producible. In 2017, the annual average spot price for natural gas increased 21% at Henry Hub. The majority of the increase in 2017 reserves was due to increased reserves in shale formations, including the Wolfcamp/Bone Spring in the Permian Basin, Marcellus, Utica, and Haynesville/Bossier shales. Proved reserves are estimated volumes of natural gas from known reservoirs that geologic and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions.[21]

Total U.S. discoveries during 2017 totaled 70.8 Tcf, primarily extensions to existing natural gas fields. By source, the 70.8 Tcf discovered in 2017, can be broken down as 60.9 Tcf from shale formations (86%) and 9.9 Tcf from conventional and other tight formations (14%). Texas continues to have the largest proved natural gas reserves, followed by Pennsylvania,

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[18] "North America Rig Count Current Week Data," Baker Hughes, http://www.bhge.com/, May 3, 2019.
[19] "Colorado governor declares end to 'oil and gas wars' after signing controversial bill." Gas Daily, Platts McGraw Hill Financial, April 18, 2019, pages 8 and 9.
[20] "Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, January 7, 2019.
[21] " U.S. crude oil and natural gas proved reserves set new records in 2017," Today in Energy, Energy Information Administration, U.S. Department of Energy, November 29, 2018.

Oklahoma, West Virginia, and Ohio. During 2016, Pennsylvania added 28.1 Tcf as a result of development in the Marcellus shale play, the largest increase of any state.[22]

## STORAGE TRENDS

Each year, the EIA tracks, throughout the country, the design capacity of natural gas storage facilities at the beginning of the traditional injection season. The total working-gas design capacity in the Lower 48 states during the period from November 2017 to November 2018 decreased slightly from 4,725 Bcf to 4,712 Bcf. Since November 2013, total working-gas design capacity has been relatively flat. For the fourth consecutive year, no new underground storage facilities initiated operations in the U.S. The majority of the capacity decrease was due to reductions at existing facilities in Texas (12 Bcf). The East Cheyenne Field in Wyoming also expanded its capacity by 4 Bcf by reclassifying base gas to working gas, increasing the total mountain region capacity to 471 Bcf.[23]

The 2018 storage injection season began in April with 1,391 Bcf in working gas storage. By the end of the traditional injection season at the end of October, national working gas storage volumes were 3,237 Bcf. The traditional 2018 injection season had net injections of 1,846 Bcf. By comparison, net injections for the 2017 traditional injection season totaled 1,753 Bcf.[24] By the end of the 2018-2019 traditional withdrawal season, on March 29, 2019, the lower-48 inventory level stood at 1,130 Bcf. This level was 228 Bcf lower than the same time last year and was 505 Bcf or 30.9% below the five year average.[25]

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

## LNG EXPORTS

In 2017, the U.S. became a net exporter of natural gas for the first time. This trend was reinforced by the rebound of natural gas production in 2017. The EIA expects exports to continue to increase through the 2020s as more LNG export terminals come online.[26] By the end of 2018, export capacity from the Lower 48 states increased to 4.9 billion cubic feet per day (Bcf/d) following the completion of the fifth liquefaction train at the Sabine Pass facility near the Texas/Louisiana border and Cheniere Energy's Corpus Christi LNG Train 1. Three additional LNG export facilities – Cameron LNG in Louisiana (three trains), Freeport LNG in Texas (two trains) and Elba Island (ten small modular trains) – are expected to be fully operational by the end of 2019, bringing total LNG capacity to 8.9 BCF/d. Other LNG facilities currently under construction are: Freeport Train 3 and Corpus Christi Train 3. Four additional export terminals and the sixth train at Sabine Pass have been approved and are

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[22] "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2017," U.S. Energy Information Administration, U.S. Department of Energy, November, 2018. Components may not add to totals due to independent rounding.
[23] "Underground Natural Gas Working Storage Capacity," Energy Information Administration, U.S. Department of Energy, Release Date: March 29, 2019.
[24] "Table 9. Underground natural gas storage – by season, 2017 – 2019," Natural Gas Monthly, Energy Information Administration, U.S. Department of Energy, March 2019.
[25] "Weekly Natural Gas Storage Report," Energy Information Administration, U.S. Department of Energy, For the week ending March 29, 2019, Released April 4, 2019.
[26] "U.S. Natural Gas Production and Consumption increase in Nearly All AEO 2018 Cases," Today in Energy, Energy Information Administration, U.S. Department of Energy, April 16, 2018.

expected to make final investment decisions soon. These four proposed projects represent an additional 7.6 Bcf/d combined.[27] As of April 2019, 17 U.S. LNG export facilities had been proposed to the FERC. Of those proposals, 12 are pending applications and 5 are projects in the pre-filing phase.[28]

The proposed Jordan Cove LNG export facility on the Oregon coast is of particular interest to the Company because the addition of this facility could impact prices in the Rockies. Pembina Pipeline Corporation (Pembina), the developer of Jordan Cove, acquired a 50% interest in the Ruby Pipeline in 2014. The Ruby Pipeline extends from the Opal Hub in Wyoming to the Malin Hub in Oregon and crosses the Company's northern service territory. The Company regularly purchases natural gas at the Opal Hub. The Ruby Pipeline provides direct access to the Jordan Cove LNG facility through the proposed Pacific Connector Gas Pipeline.

On March 11, 2016, the FERC rejected the Pacific Connector pipeline and consequently the Jordan Cove LNG project on the grounds that the applicant had not adequately demonstrated a market need. The FERC specified that its decision was issued without prejudice and that the developers could submit a new application to construct the facilities in the future if they are able to show a market need for the project.[29] Less than two weeks after the FERC Order, Pembina announced that it had signed a long-term capacity agreement for the Jordan Cove facility with a Tokyo-based electric utility joint venture. The agreement includes the purchase of approximately one quarter of the 6 million-tons-per-annum liquefaction capacity of the facility.[30]

On September 21, 2017, Pembina filed its applications requesting the FERC issue a Final Environmental Impact Statement by August 2018 and authorizations and waivers by November 2018 in order to meet a planned fourth quarter 2022 in-service date.[31] The Draft Environmental Impact Statement (DEIS) was issued by the FERC on March 29, 2019. Public comments for the DEIS are due by July 5, 2019.[32]

## 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

[27] " U.S. liquefied natural gas export capacity to more than double by the end of 2019," Today in Energy, Energy Information Administration, U.S. Department of Energy, December 10, 2018.
[28] "Proposed North American LNG Export Terminals: As of March 20, 2019," Federal Energy Regulatory Commission, Natural Gas Industry.
[29] "Order Denying Applications for Certificate and Section 3 Authorization," Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P., Docket No. CP13-483-000, Pacific Connector Gas Pipeline, Docket No. CP13-492-000, Issued March 11, 2016.
[30] "Jordan Cove in offtake deal with JERA," Gas Daily, Platts McGraw Hill Financial, March 24, 2016, Pages 6 and 7.
[31] "Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity," Before the Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP, Docket No. CP17-494-000, CP17-495-000, September 21, 2017.
[32] "Draft Environmental Impact Statement for the Jordan Cove Energy Project (CP17-494-000 and CP17-495-000)," Federal Energy Regulatory Commission, Issued March 29, 2019.

and file integrated resource plans.[33] 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."[34] 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.[35]

The Company filed its 2018-2019 IRP on June 14, 2018, 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. No public comments were received. On December 18, 2018, Wyoming Commission Staff issued a report on its review of the 2018-2019 IRP. Wyoming Commission Staff found no areas of concern with the results and projections in the 2018-2019 IRP, and concluded, ". . . it is evident that the Company is actively identifying, evaluating, and executing projects and plans to meet its obligation to maintain Wyoming services at safe and reliable levels."[36]

The Wyoming Commission noticed the Company's 2018-2019 IRP on its Open Meeting Agendas from June 21, 2018 through December 20, 2018 and received no comments or protests. At its regularly scheduled Open Meeting on December 20, 2018, the Wyoming Commission received a presentation from representatives of the Company which provided a summary of the sections of the 2018-2019 IRP. On January 3, 2019, the Wyoming Commission issued a letter order directing the 2018-2019 IRP be placed in the Commission's files with no further action being taken and closed the matter.[37]

## 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

[33] "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.

[34] 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).

[35] 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.

[36] Memorandum from Michelle Bohanan and John Burbridge to Chairman Russell, Deputy Chair Brighton Fornstrom and Commissioner Sessions Cooley; Re: Docket No. 30010-175-GA-18 (Record No. 15028) In the matter of the application of Questar Gas Company D/B/A Dominion Energy Wyoming Integrated Resource Plan for Year June 1, 2018 to May 31, 2019; December 14, 2018; Page 24.

[37] Letter Order, To: Jenniffer Nelson Clark, Corporate Counsel, Dominion Energy Wyoming, From: John S. Burbridge, Assistant Secretary Wyoming Public Service Commission, Re: The Matter of the Filing of Questar Gas Company d/b/a Dominion Energy Wyoming's Integrated Resource Plan For Plan Year June 1, 2018 to May 31, 2019 - Docket No. 30010-l 75-GA-18 (Record No. 15028), Issued: January 3, 2019.

Company's 2010 IRP.[38] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[39]

On June 14, 2018, the Company filed its IRP for the plan year, June 1, 2018 to May 31, 2019 (2018-2019 IRP). A technical conference was held on June 26, 2018, to discuss the 2018-2019 IRP with regulatory agencies and interested stakeholders. On September 14, 2018, the Utah Office of Consumer Services (Office) filed its IRP comments.[40] The Utah Division of Public Utilities (Division) submitted its report and recommendation on September 14, 2018.[41] On October 12, 2018, the Company filed its Reply Comments.[42]

On November 19, 2018, the Utah Commission issued its Report and Order on the 2018-2019 IRP.[43] The Utah Commission found that "the 2018 IRP as filed generally complies with the requirements of the 2009 Standards and Guidelines." The Company committed to provide complete information in future documents, rather than incorporating information by reference and to providing confidential information through the discovery process or by using the provisions of Utah Admin. Code R746-1-601 *et seq.* The Commission adopted the Company's commitments set forth in its reply comments and ordered the Company to "convene a stakeholder meeting prior to the initiation of the 2019 IRP docket to discuss how it can address the OCS's concerns regarding the insufficiency of certain information in the IRP." On December 17, 2018, the Company met with Division and Office Staff to discuss the Office's concerns.

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 20, 2019, the Utah Commission held an IRP technical conference in conjunction with the development of the 2019-2020 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission's 2018 IRP Order

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

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

[40] Memorandum titled, "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2018 to May 31, 2019," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Alex Ware, Utility Analyst, September 14, 2018.

[41] Action Request Response, To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Artie Powell, Manager, Energy Section, Doug Wheelwright, Technical Consultant, Eric Orton, Technical Consultant, Carolyn Roll, Technical Consultant, Subject: Action Request Docket No. 18-057-01, Dominion Energy Utah 2018-19 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: September 14, 2018.

[42] "In the Matter of Dominion Energy Utah's Integrated Resource Plan for Plan Year: June 1, 2018 to May 31, 2019," Before the Public Service Commission of Utah, Dominion Energy Utah's Reply Comments, Docket No. 18-057-01, October 12, 2018.

[43] "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2018 to May 31, 2019," The Public Service Commission of Utah, Report and Order, Docket No. 18-057-01, Issued: November 19, 2018.

- Proposed 2019-2020 IRP Outline
- Renewable Natural Gas Update
- Wexpro Well Freeze-offs

On February 25, 2019, the Company sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 8, 2019.

The Utah Commission held another technical conference on March 20, 2019. The attendees discussed the following topics:

- Heating Season Review
- Long Term Planning
- Normal Heating Degree Days Update
- Rural Expansion
- Rate Case Preview

On April 25, 2019, the Utah Commission held a confidential technical conference where the following topics were discussed:

- RFP Recommendations
- Supply Reliability Results

The Utah Commission held another technical conference on May 29, 2019 where the following topics were discussed:

- Wexpro Matters (Confidential)
- Integrity Management Update

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 20, 2019, to discuss the 2019-2020 IRP with Utah regulatory agencies and interested stakeholders.

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

1. To project future customer requirements and analyze alternatives for meeting those requirements from a distribution system standpoint, an integrity management standpoint, an environmental standpoint, a gas-supply source standpoint, an upstream capacity standpoint (including taking into consideration the inter-day load profile of each source), a reliability standpoint, and a sustainability standpoint.

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

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

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.

# CUSTOMER AND GAS DEMAND FORECAST

## SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2018-2019 IRP AND ACTUAL RESULTS

On a weather-normalized basis, the Company's natural gas sales through the IRP year ending May, 2019 is estimated at 116.6 MMDth. The Company projected a total of 115.2 MMDth in last year's IRP for the same time period. Average usage per system-wide General Service (GS) customer for the IRP year is estimated at 105.6 Dth. The 2018-2019 IRP projected an average of 105.2 Dth. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2018-2019 IRP year at 211.1 MMDth. Last year's IRP projected 202.7 MMDth for the same period. While actual sales were 1% higher than projected, variance is primarily in the electric generation sector where usage in 2018 increased about 43% from the prior year.

## TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2019-2020 IRP YEAR

The sales demand for the 2019-2020 IRP year is forecasted to be 117.4 MMDth, driven largely by robust growth in the residential sector. About 150 sales customers receiving service on the GS, FS, and IS rate schedules will shift to the TS rate schedule in July of this year. The effect on sales demand is a reduction of about 1.2 MMDth annually. The forecast assumes about the same number of customers and annual Dth moving the TS class in the 2020-2021 IRP year, but no further shifting is assumed beyond that point. Steady growth in the GS class, the result of healthy growth in households and strong economics, is forecasted to bring sales demand to 128.4 MMDth for the 2028-2029 IRP year (see Exhibit 3.10).

The 2019-2020 IRP sales forecast of 117.4 MMDth will be the denominator used in the calculation of the percentage of sales supplied by cost-of-service production per the Trail Unit Settlement Stipulation. The numerator will be the actual cost-of-service quantity as reported at the wellhead.

The forecast projects GS customer growth from 1.09 million customers at the end of the 2019-2020 IRP year to more than 1.3 million GS customers by the end of the 2028-2029 IRP year (see Exhibit 3.1). The Company projects that the annual Utah GS usage per customer will be 104.5 Dth in the 2019-2020 IRP year and decline to 95.8 Dth by end of the 2028-2029 IRP year (see Exhibit 3.2). Annual Wyoming GS usage per customer is projected to be 130.4 Dth in the 2019-2020 IRP year and decline to 122.0 by the end of the 2028-2029 IRP year (see Exhibit 3.5).

The Company projects annual usage per Utah residential customer to be 80.5 in the 2019-2020 IRP year and decline to 73.8 Dth (see Exhibit 3.3) by the end of the 2028-2029 IRP year. The Company projects the average annual usage per Utah GS commercial customer to be 442.3 Dth in the 2019-2020 IRP year and 413.3 Dth by the end of the 2028-2029 IRP year (see Exhibit 3.4). The Company projects annual usage per Wyoming residential customer to be at 87.6 Dth in the 2019-2020 IRP year and 80.1 Dth by the end of the 2028-2029 IRP year (see Exhibit 3.6). The Company projects annual usage per Wyoming GS commercial customer to be 483.6 Dth in the 2019-2020 IRP year and 469.8 Dth by the end of the 2028-2029 IRP year (see Exhibit 3.7).

The Company expects system total throughput in this year's forecast to increase from 208.5 MMDth during the 2019-2020 IRP year to 220.8 MMDth by end of the 2028-2029 IRP year (see Exhibit 3.10).

The Company is projecting strong customer growth in Utah driven by a strong economy, tight labor market, rising personal income, and a household formation rate that is exceeding the supply of homes. GS demand in both the residential and commercial classes will continue to grow as a result. Non-GS commercial and industrial consumption will continue to grow modestly.

Moderate growth is projected in the Wyoming territory as the natural resources sector of the economy begins to stabilize from the energy market drop in 2016.

## RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

### *Utah*

Utah residential GS customer additions through the twelve months ending December 2018 totaled 25,631. Over 40% of those additions were in the multi-family sector. Strong housing demand is expected to continue but will be somewhat tempered in the single-family sector by rising interest rates and affordability challenges. Growth in multi-family structures is expected to remain strong as the rental market remains tight and homebuyers search for a more affordable alternative to a single-family home. The Company is forecasting about 22,588 residential additions in the 2019-2020 IRP year and about 22,100 in the 2020-2021 IRP year.

Actual temperature-adjusted residential usage per customer for the twelve months ending December 2018 was 80.9 Dth. The Company projects an average of 80.5 for the 2019-2020 IRP year. The overall downward trend in average consumption is expected to continue through the 2028-2029 IRP year as the pace of new dwelling construction increases and energy efficiency programs continue to incentivize greater efficiency (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 STAT 14.1 and SAS Enterprise Time Series 14.1 are the software tools used for the statistical time series modeling.

The Company also studies residential consumption by end use such as space heating, water heating and cooking with respect to dwelling size, region, appliance efficiencies, and other such variables. This end use analysis makes extensive use of data collected by the Company's Energy Efficiency Experts as they conduct in-home energy audits through the Energy Efficiency Program.

### *Wyoming*

During the twelve months ending December, 2018, the Wyoming residential customer base grew by 18 service agreements. The Company is forecasting moderate growth and projects about 50 new additions in the 2019-2020 IRP year and 80 in the 2020-2021 IRP year.

The average annual usage per residential customer in Wyoming was 88.0 Dth in calendar year 2018, a decrease of 0.7 Dth from the year prior. The Company forecasts an average of 87.6 Dth during the 2019-2020 IRP year and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. This long-run decline brings the average to 80.1 in the 2028-2029 IRP year (see Exhibit 3.6).

## SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

### *Utah*

Temperature-adjusted Utah GS commercial usage per customer for the twelve months ended December 2018 was 451.1 Dth. This year's forecast incorporates the anticipation of a number of GS commercial customers shifting to transportation service rate schedules over the next two IRP years. An average of 442.3 Dth by the end of the 2019-2020 IRP year is projected, followed by 430.9 Dth average in the 2020-2021 IRP year (see Exhibit 3.4).

Utah GS commercial customer additions are expected to increase along with the residential level. The Company forecasts approximately 1,300 additions per year through the next two IRP years (see Exhibit 3.7).

### *Wyoming*

Usage among commercial GS customers in Wyoming for the twelve months ended December 2018 averaged 472.0 Dth. With such a small base of customers and varying usage patterns, total and average usage in this sector can be volatile. But the Company a long-run decline in average usage that ends the 2028-2029 IRP year at 469.8 Dth.

There are 5 additions forecasted in the 2019-2020 IRP year and about double that amount in the following IRP year.

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

As shown in Exhibit 3.8, annual gas demand among non-GS commercial customers and industrial customers is growing with the continued shifting of some commercial GS customers to transportation service. The Company expects demand in that sector to grow from 57.8 MMDth in the 2019-2020 IRP year to 58.7 MMDth in the 2028-2029 IRP year.

Annual demand among electric generation customers decreased over the prior year by about 43% in 2018. 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. This year's forecast assumes a steady electric generation demand at the current level of about 37 MMDth per year – an average of generation demand over the last three years. This is a midpoint of the range of electric generation demand over that period of time.

## 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.

As shown in Exhibit 3.9, the firm sales and firm transportation demand for the heating seasons of 2014-2015 through 2018-2019 show actual firm sendout for the coldest day in each season. Design Day conditions did not occur during those time periods. However, January 2017 represented the 2$^{nd}$ highest total sendout month for the Company and included the 2$^{nd}$ and 3$^{rd}$ highest total sendout days on record.

The firm sales Design Day gas supply projection for the 2019-2020 heating season is 1.220 MMDth and grows to 1.34 MMDth in the winter of 2028-2029. 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 Dec 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.

## UTAH AND WYOMING ECONOMIC OUTLOOK

Table 3.1 and Table 3.2 below show the recent history and the current economic outlook for Utah and Wyoming:

**Table 3.1: Summary of Utah Economy**
**Annual Percentage Change**

| Description | 2013 – 2018 | 2018 - 2019 | 2018 - 2023 | 2018 – 2026 |
|---|---|---|---|---|
| Population | 1.8% | 1.8% | 1.6% | 1.5% |
| Personal Income | 6.1% | 4.9% | 5.2% | 5.2% |
| Construction Employment | 7.2% | 1.8% | 3.9% | 4.2% |
| Manufacturing Employment | 2.3% | 2.5% | 0.1% | 0.2% |
| Non-Manufacturing Employment | 3.4% | 2.6% | 1.9% | 1.6% |
| Total Employment | 3.3% | 2.6% | 1.7% | 1.5% |
| Average Housing Starts | 20,216 | 23,835 | 23,114 | 23,269 |

Source: Spring 2019 Long-term Forecasts by IHS

**Table 3.2: Summary of Wyoming Economy**
**Annual Percentage Change**

| Description | 2013 – 2018 | 2018 - 2019 | 2018 - 2023 | 2018 – 2026 |
|---|---|---|---|---|
| Population | -0.1% | -0.1% | 0.1% | 0.1% |
| Personal Income | 2.3% | 3.9% | 4.3% | 4.2% |
| Construction Employment | -1.6% | 7.6% | 2.2% | 2.0% |
| Manufacturing Employment | 0.5% | 3.6% | 0.6% | 0.5% |
| Non-Manufacturing Employment | -0.6% | 1.6% | 0.7% | 0.5% |
| Total Employment | -0.6% | 1.7% | 0.7% | 0.5% |
| Average Housing Starts | 1,831 | 1,548 | 1,531 | 1,557 |

Source: Spring 2019 Long-term Forecasts by IHS

## U.S. ECONOMIC OUTLOOK

Table 3.3 is a review of recent history and shows the consensus economic outlook:

**Table 3.3: U.S. Macroeconomic Forecast**
**Source: IHS Review of the U.S. Economy – March, 2019**

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|
| Real Gross Domestic Product 1/ | 1.8 | 2.5 | 2.9 | 1.6 | 2.2 | 2.9 | 2.4 |
| GDP Price Index - Chain Wt. 1/ | 1.8 | 1.9 | 1.0 | 1.1 | 1.9 | 2.2 | 2.1 |
| CPIU 1/ | 1.5 | 1.6 | 0.1 | 1.3 | 2.1 | 2.4 | 2.0 |
| Real Disposable Income 1/ | -1.3 | 4.0 | 4.1 | 1.7 | 2.6 | 2.9 | 2.5 |
| Pre-tax Profits 1/ | 0.7 | 5.4 | -2.9 | -1.1 | 3.2 | 7.4 | 2.2 |
| Unemployment Rate 3/ | 7.4 | 6.2 | 5.3 | 4.9 | 4.4 | 3.9 | 3.6 |
| Housing Starts 4/ | 0.9 | 1.0 | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 |
| 3-month Treasury Bills 3/ | 0.06 | 0.03 | 0.05 | 0.32 | 0.93 | 1.94 | 2.53 |
| 30-Year Fixed Mortgage Rate 3/ | 4.0 | 4.2 | 3.9 | 3.7 | 4.0 | 4.5 | 4.6 |
| Trade Balance 2/ | -349 | -365 | -408 | -433 | -449 | -483 | -588 |
| Vehicle Sales – Total 4/ | 15.5 | 16.5 | 17.4 | 17.5 | 17.1 | 17.2 | 16.8 |
| Real Non-Res Fixed Investment 1/ | 4.1 | 6.9 | 1.8 | 0.5 | 5.3 | 7.0 | 4.2 |
| Industrial Production 1/ | 2.0 | 3.1 | -1.0 | -1.9 | 1.6 | 4.0 | 2.6 |

1/ Annual Rate of Change (Percent)
2/ Billions of 1996 chained dollars
3/ Percent
4/ Million Units

**Table 3.4: Long-term U.S. Economic Outlook**
**Source: IHS Global Insight Review of the U.S. Economy – March, 2019**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| Real Gross Domestic Product 1/ | 2.1 | 1.8 | 1.7 | 1.6 | 1.6 | 1.6 | 1.8 |
| GDP Price Index - Chain Wt. 1/ | 2.3 | 2.5 | 2.5 | 2.4 | 2.3 | 2.3 | 2.3 |
| CPIU 1/ | 2.1 | 2.3 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |
| Real Disposable Income 1/ | 2.4 | 2.2 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 |
| Pre-tax Profits 1/ | 2.6 | 3.2 | 2.3 | 1.7 | 2.8 | 3.9 | 4.1 |
| Unemployment Rate 3/ | 3.6 | 3.8 | 4.0 | 4.2 | 4.4 | 4.5 | 4.6 |
| Housing Starts 4/ | 1.2 | 1.3 | 1.4 | 1.3 | 1.3 | 1.3 | 1.3 |
| 3-month Treasury Bills 3/ | 2.69 | 2.68 | 2.67 | 2.54 | 2.43 | 2.43 | 2.43 |
| 30-Year Fixed Mortgage Rate 3/ | 4.8 | 4.9 | 5.0 | 5.0 | 5.0 | 5.0 | 4.9 |
| Trade Balance 2/ | -642 | -698 | -786 | -839 | -833 | -772 | -708 |
| Vehicle Sales - Total 4/ | 16.6 | 16.5 | 16.4 | 16.5 | 16.7 | 16.7 | 16.8 |
| Real Non-Res Fixed Investment 1/ | 3.0 | 2.7 | 2.6 | 2.6 | 2.4 | 2.3 | 2.3 |
| Industrial Production 1/ | 1.7 | 1.4 | 1.3 | 1.5 | 1.9 | 2.2 | 2.4 |

1/ Annual Rate of Change (Percent)
2/ Billions of 1996 chained dollars
3/ Percent
4/ Million Units

## 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.

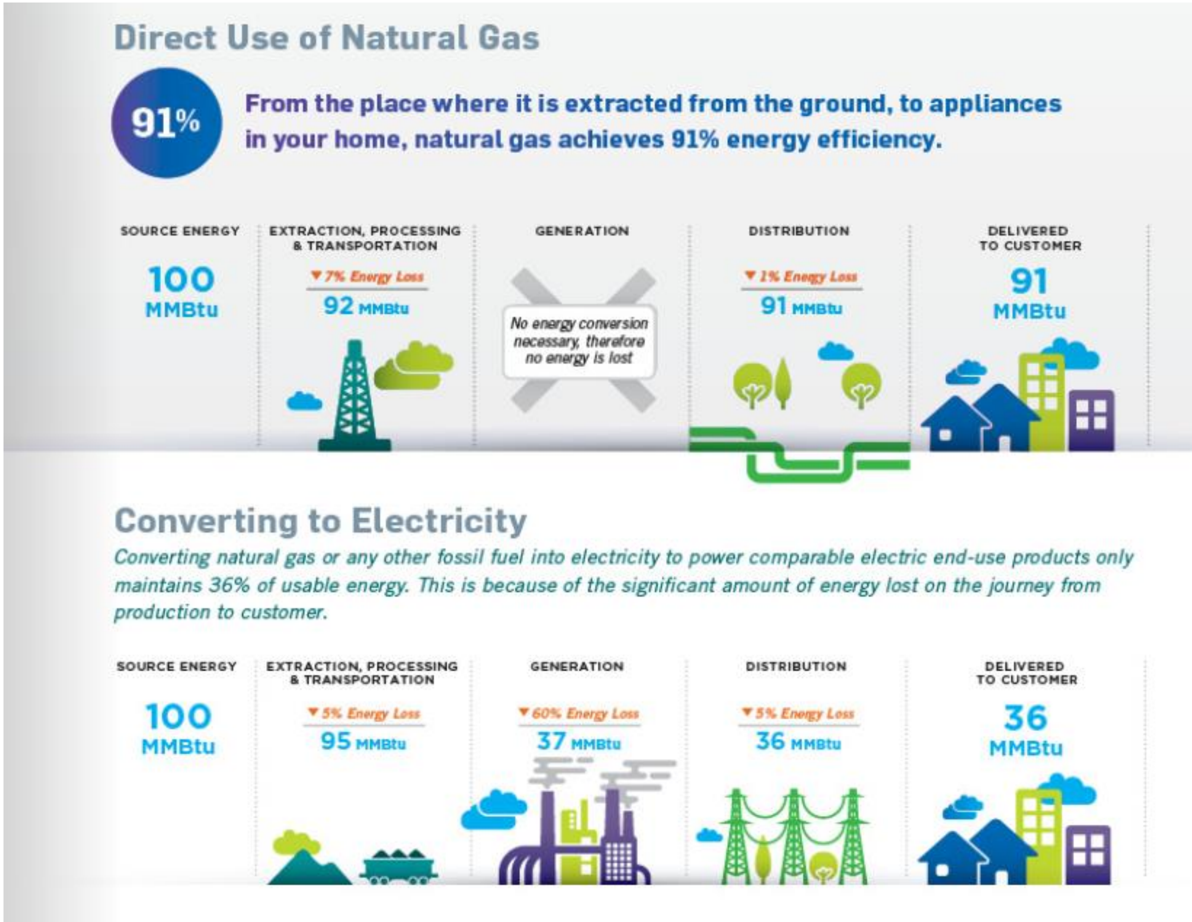



**Figure 3.1: Full Fuel-Cycle Analysis**
**(Source American Gas Association 2019 Playbook)**

## *Solar*

Although solar penetration is a significant issue for electric utilities, 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 2016-2017 IRP, the Company provided information and presented the results of a study on potential regulatory issues related to heat pumps. That study can be found in pages 9 through 16 of the Customer and Gas Demand Forecast section in Docket No. 16-057-08. The Company has seen no substantial changes in this area since the publishing of the study.

## GAS LOST AND UNACCOUNTED FOR

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 0.495% 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 3.5.

**Table 3.5: 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 |
|---|---|---|---|---|---|---|---|---|
| 2015-2016 | 106,441,947 | 86,054,640 | 192,496,587 | 192,108,233 | 102,160 | 30,991 | 255,203 | 192,496,587 |
| 2016-2017 | 104,715,760 | 81,800,370 | 186,516,130 | 185,610,886 | 181,865 | 30,744 | 692,635 | 186,516,130 |
| 2017-2018 | 105,266,225 | 78,050,010 | 183,316,235 | 181,824,568 | 170,188 | 30,771 | 1,290,708 | 183,316,235 |
| **Total** | **316,423,932** | **245,905,020** | **562,328,952** | **559,543,688** | **454,213** | **92,506** | **2,238,545** | **562,328,952** |
| | Lost-&-Unaccounted-For-Gas % | | 0.398% | | Company Use and Lost-&-Unaccounted-For-Gas % | | 0.495% | |

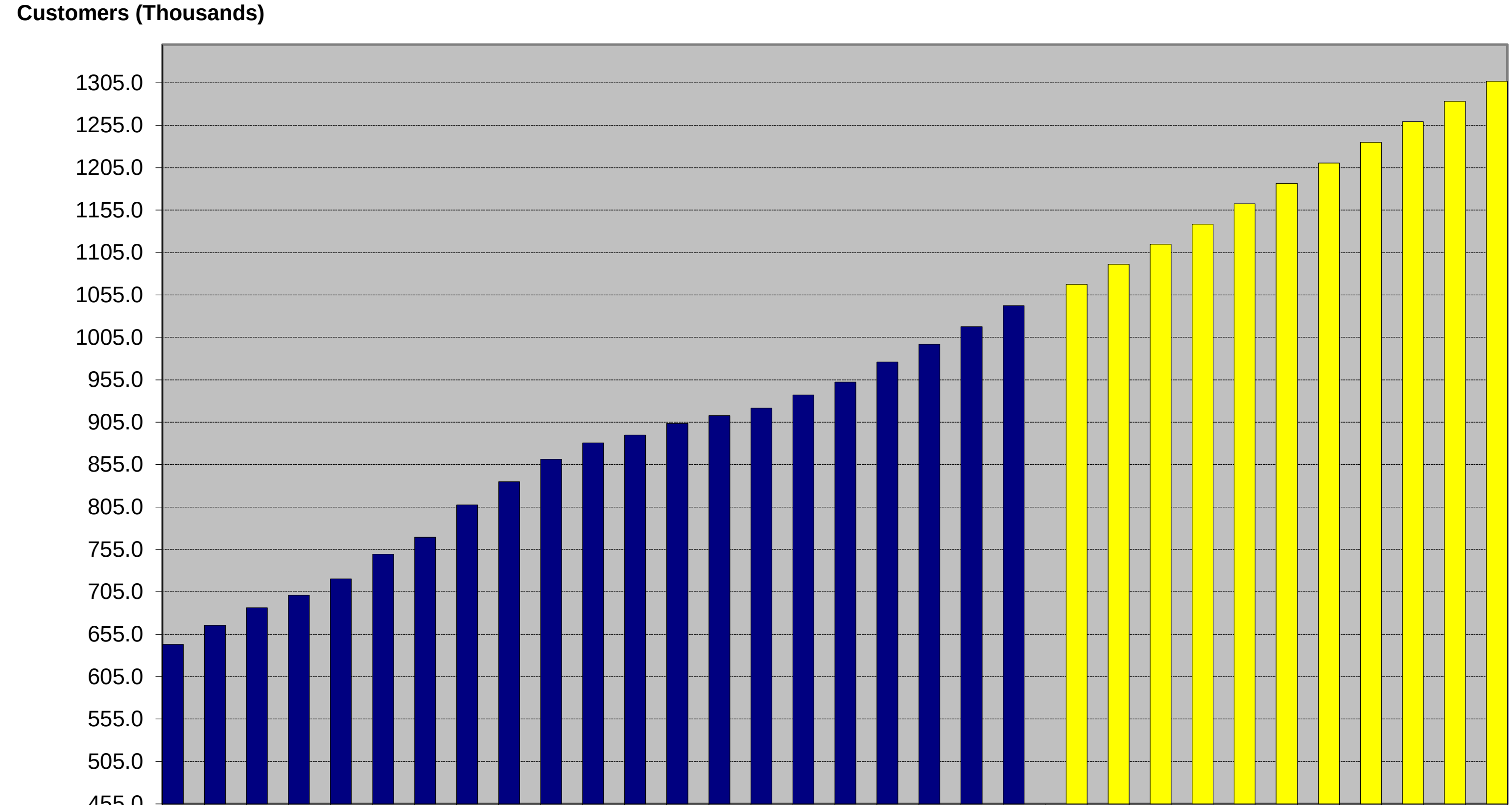
The Company is taking numerous steps to minimize the volume of lost or unaccounted for gas as part of its methane emissions program. This is discussed in detail in the Sustainability section of this report.

## 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).

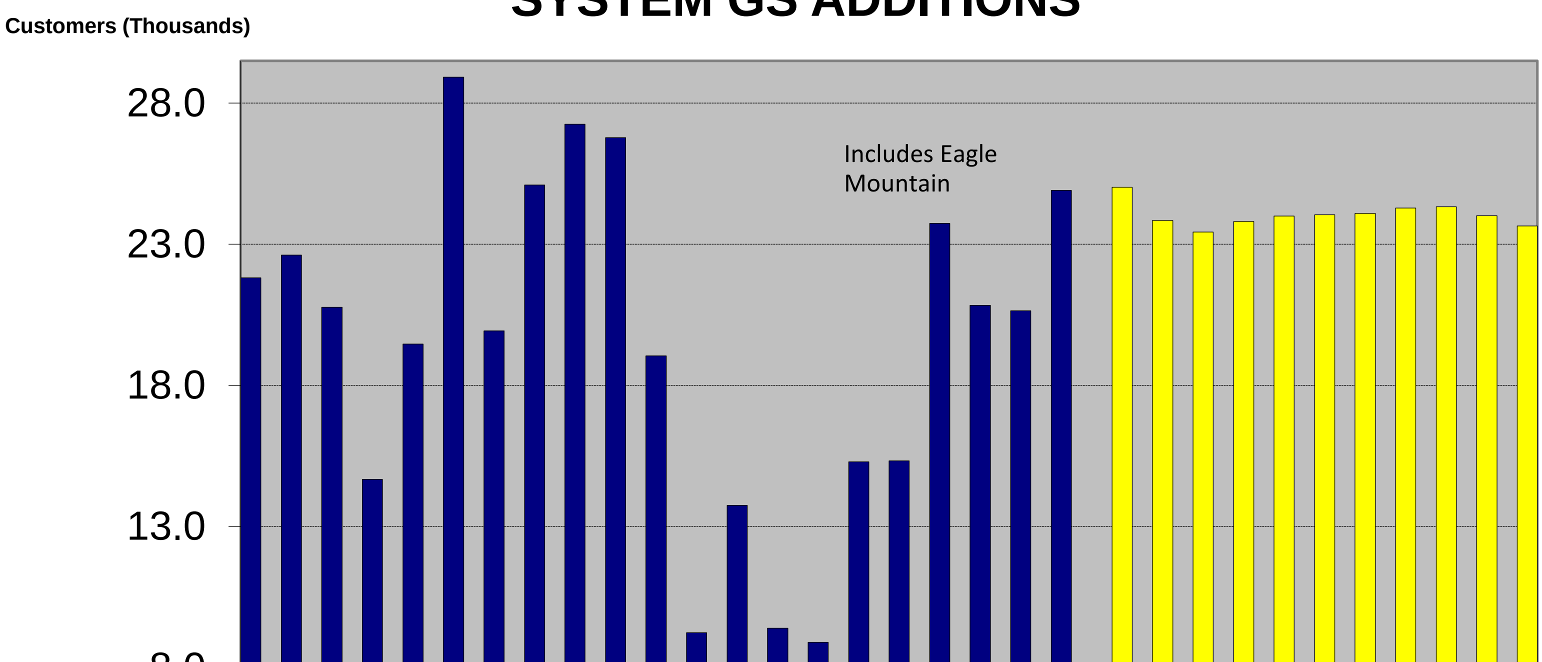
Exhibit 3.1

# SYSTEM GS CUSTOMERS




| | 97/98 | 98/99 | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 643.0 | 665.6 | 686.3 | 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 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | | | | | | | 1067.5 | 1091.3 | 1114.8 | 1138.6 | 1162.6 | 1186.6 | 1210.7 | 1235.0 | 1259.3 | 1283.3 | 1307.0 |

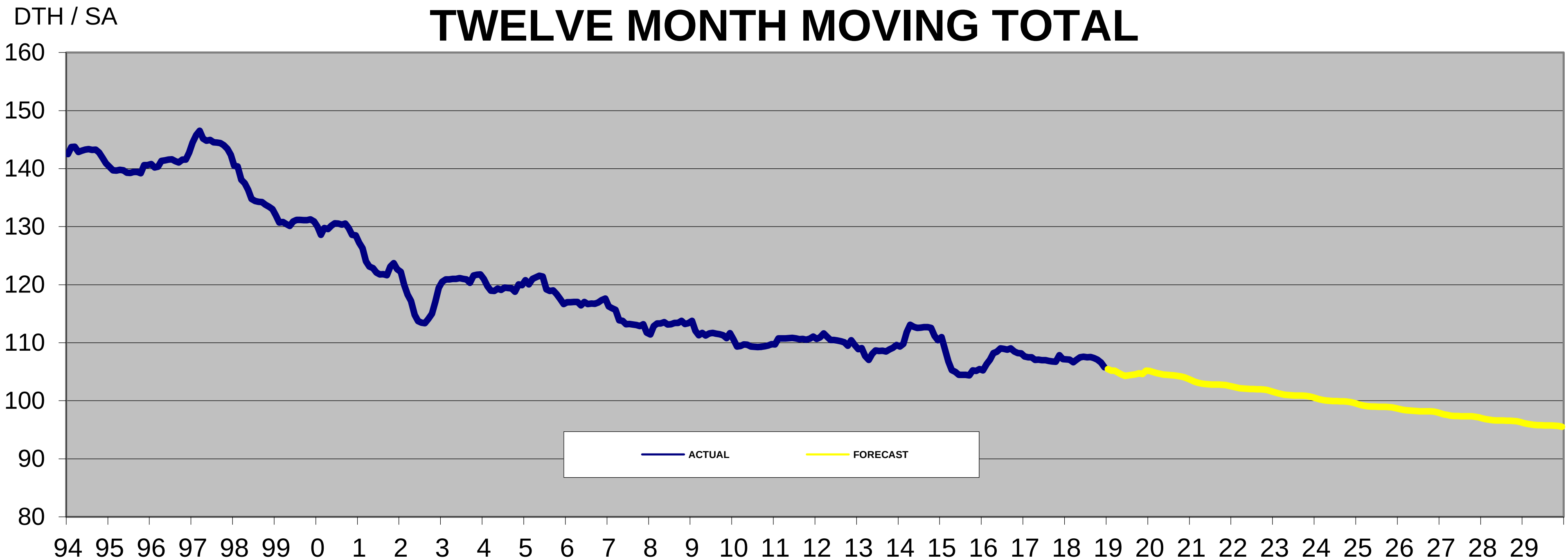
# SYSTEM GS ADDITIONS

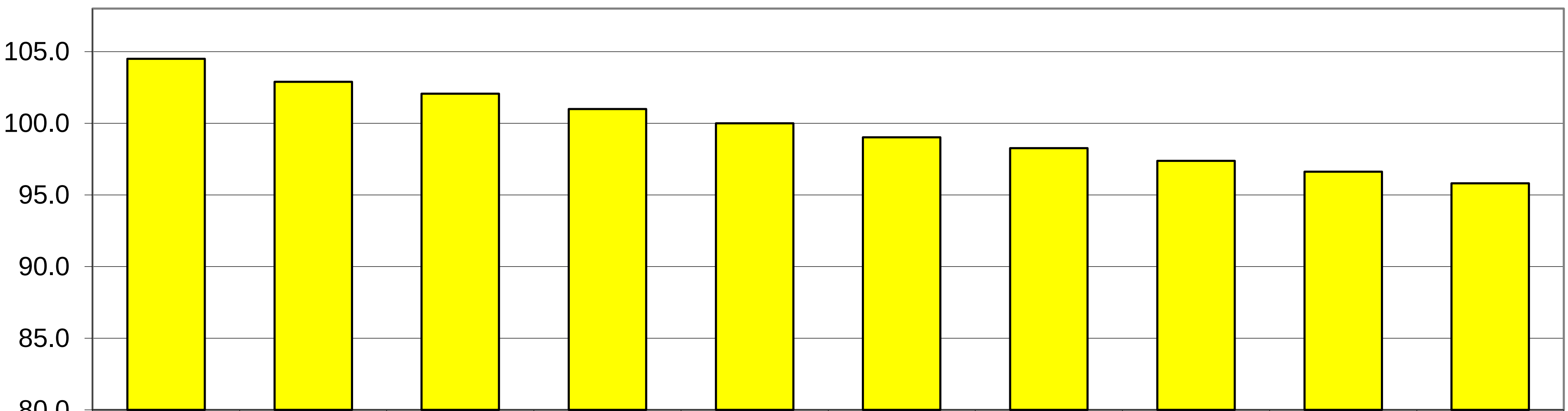



| | 97/98 | 98/99 | 99/00 | 00/01 | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 21.8 | 22.6 | 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 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | | | | | | | 25.0 | 23.8 | 23.4 | 23.8 | 24.0 | 24.0 | 24.1 | 24.3 | 24.3 | 24.0 | 23.7 |

# UTAH GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



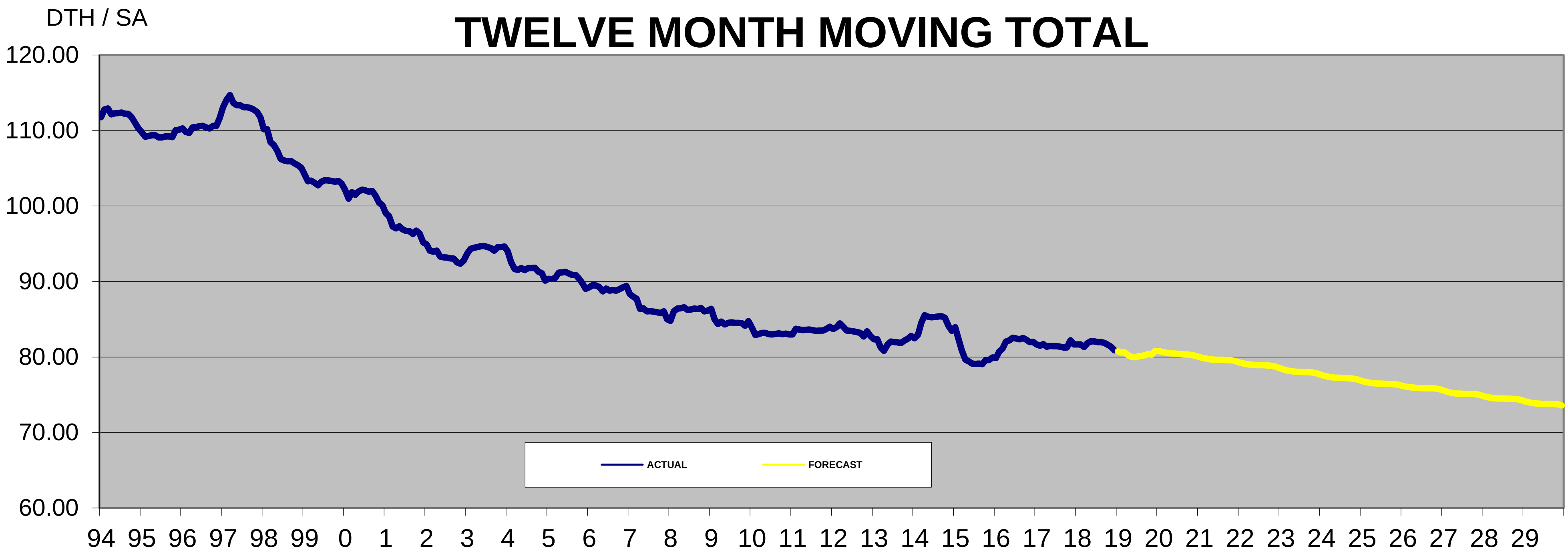



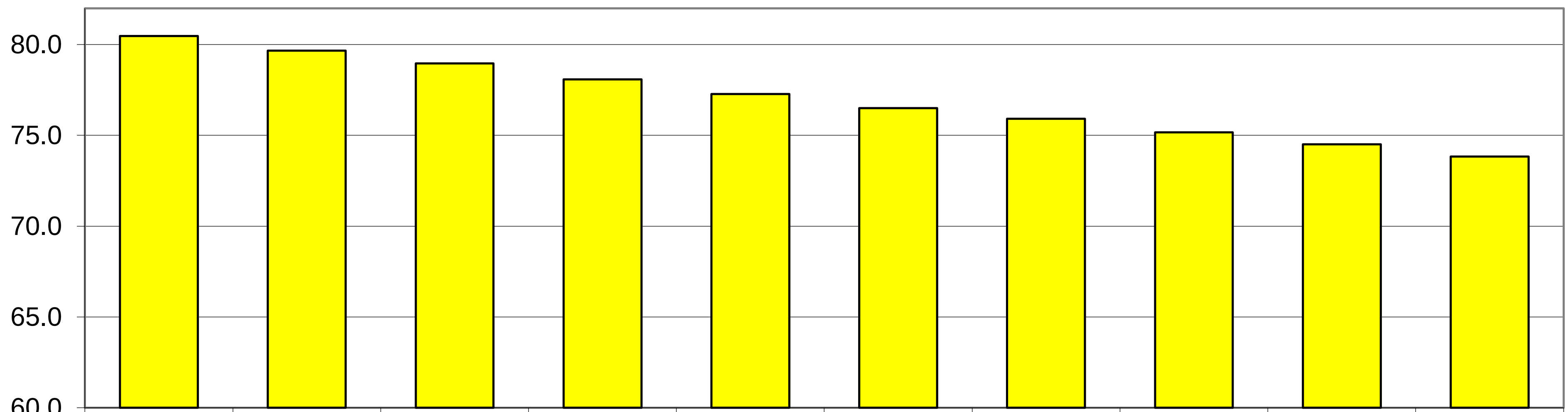

| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 104.5 | 102.9 | 102.1 | 101.0 | 100.0 | 99.0 | 98.3 | 97.4 | 96.6 | 95.8 |

Exhibit 3.2

# UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



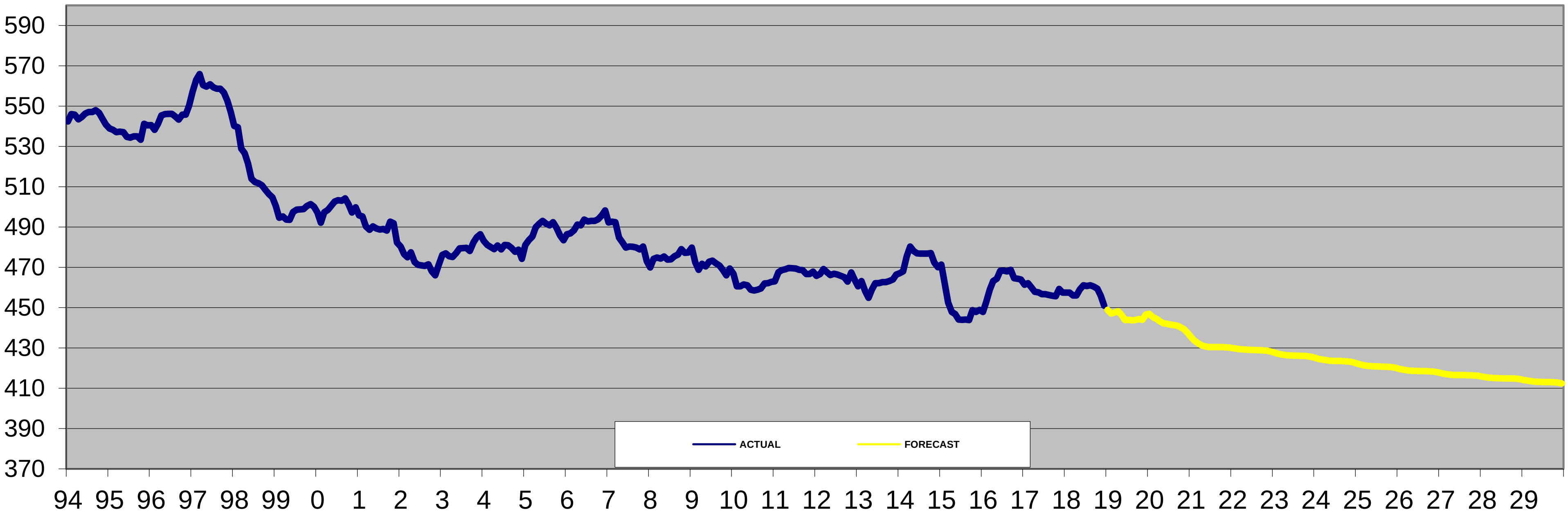



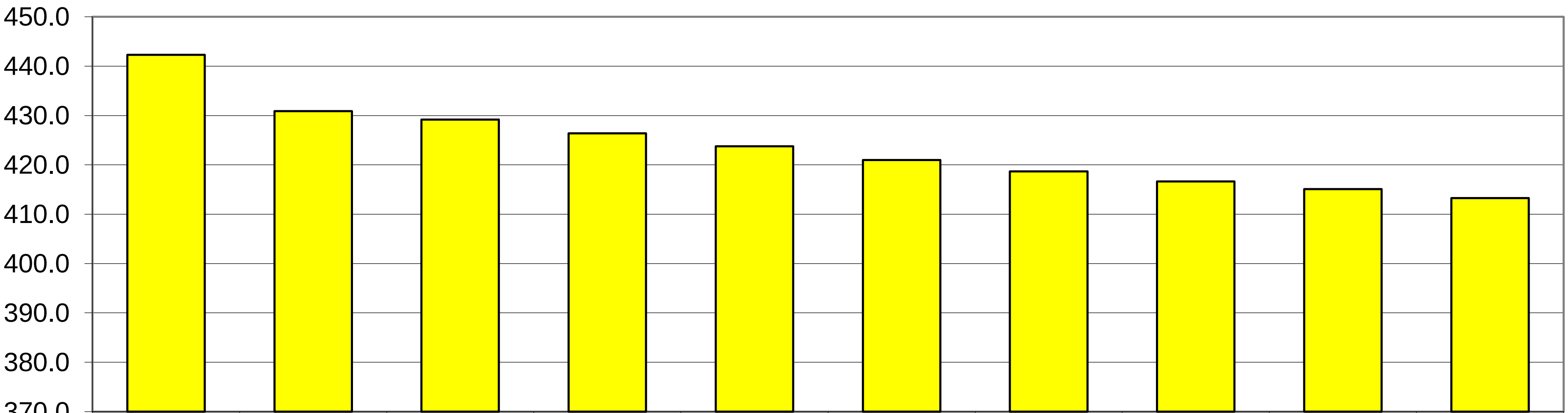

| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 80.5 | 79.7 | 79.0 | 78.1 | 77.3 | 76.5 | 75.9 | 75.2 | 74.5 | 73.8 |

Exhibit 3.3

# UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



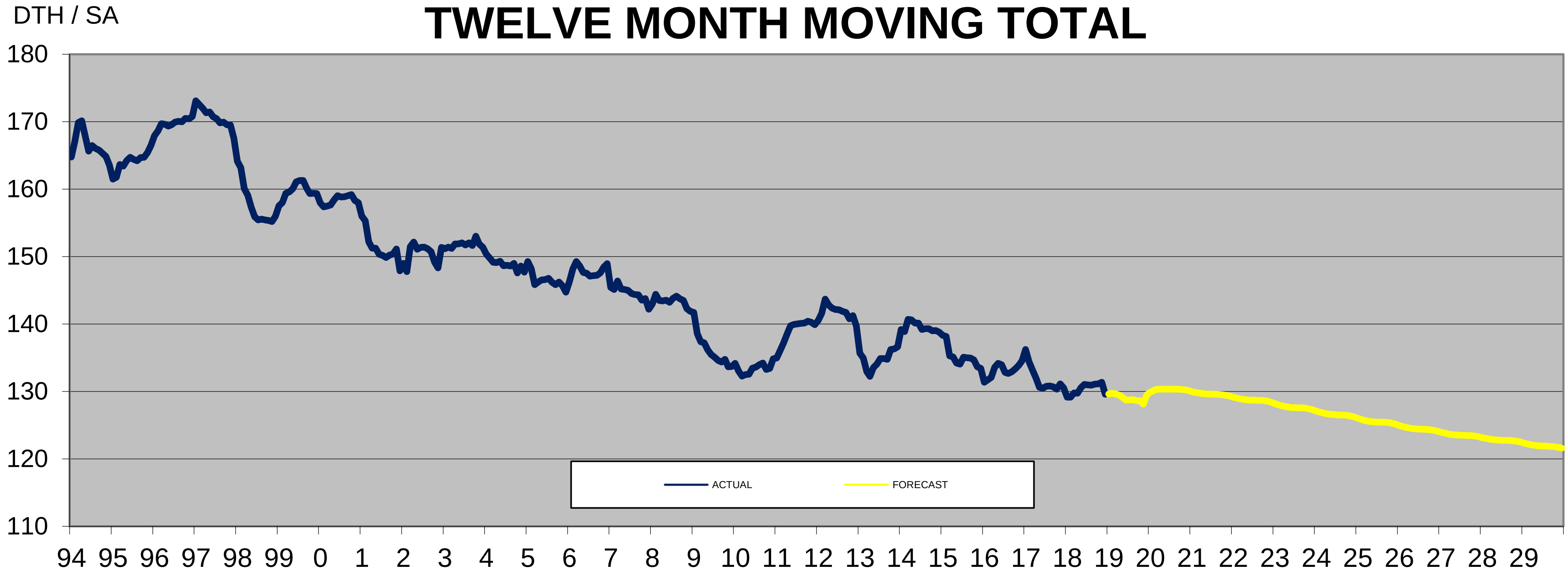



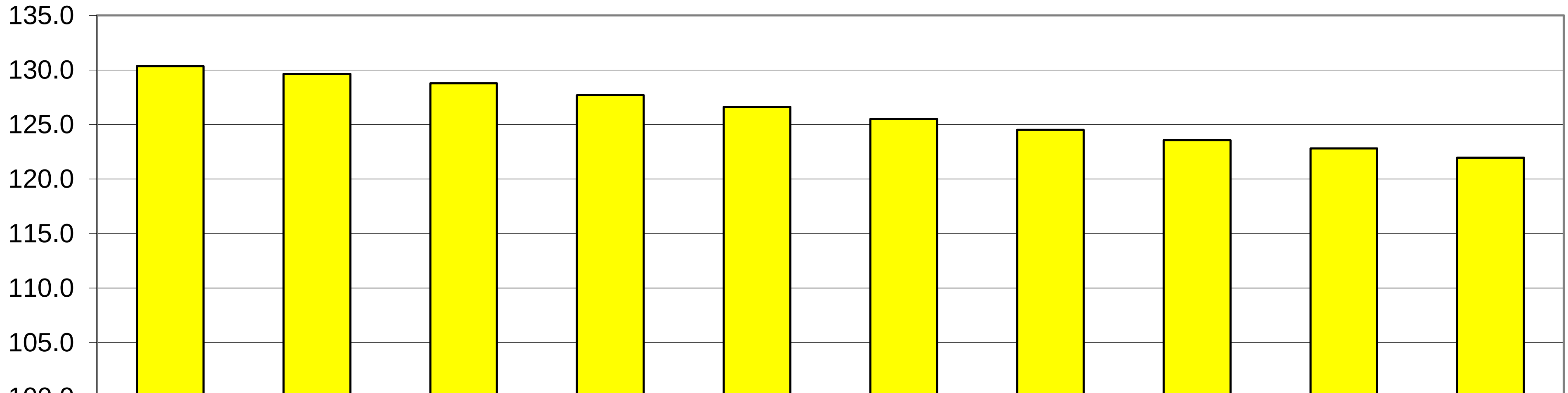

| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 442.3 | 430.9 | 429.2 | 426.4 | 423.8 | 421.0 | 418.7 | 416.7 | 415.1 | 413.3 |

Exhibit 3.4

# WYOMING GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL

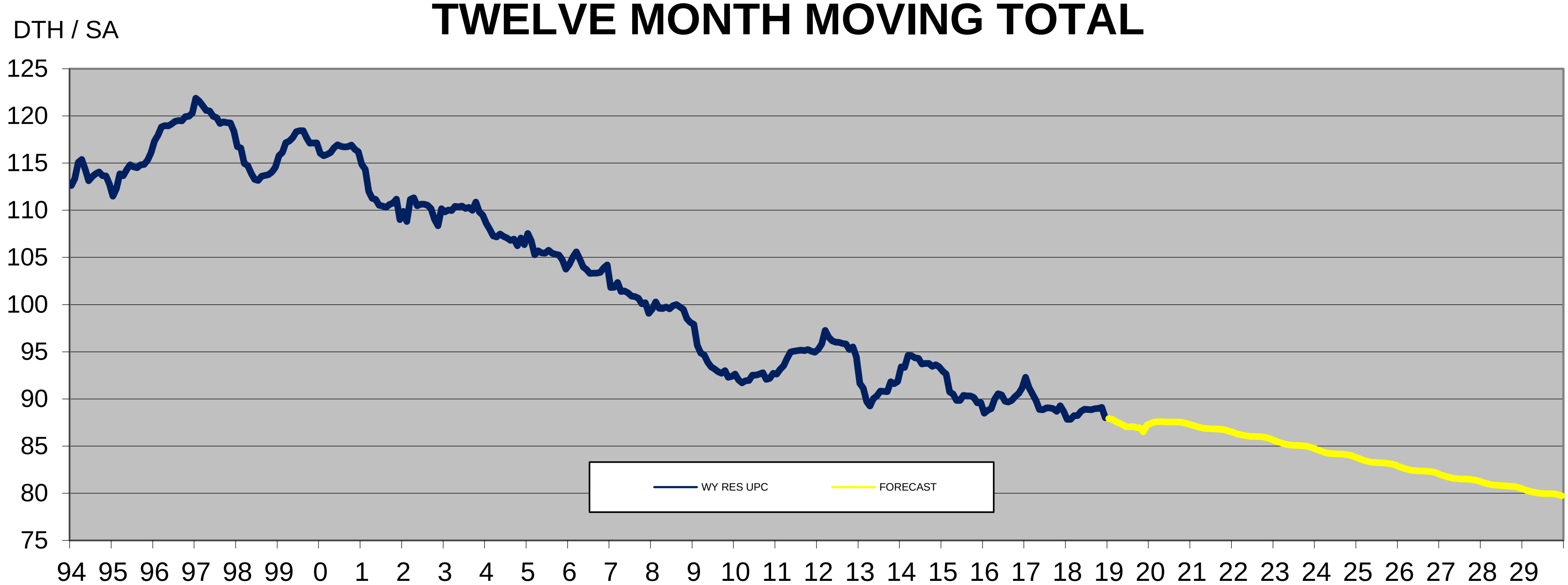


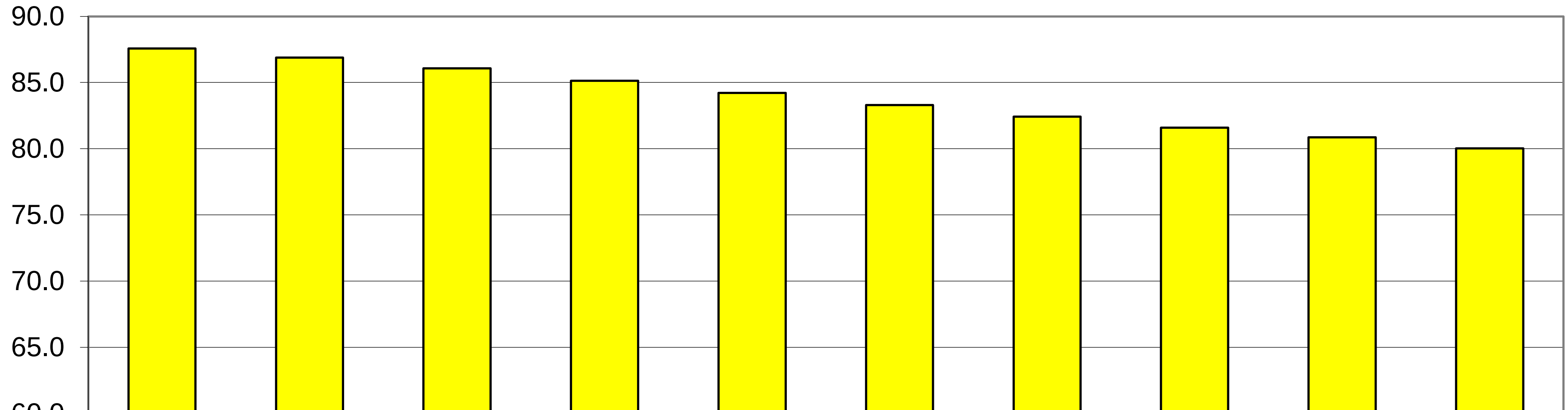



| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| WY GS | 130.4 | 129.6 | 128.8 | 127.7 | 126.6 | 125.5 | 124.5 | 123.6 | 122.8 | 122.0 |

Exhibit 3.5

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

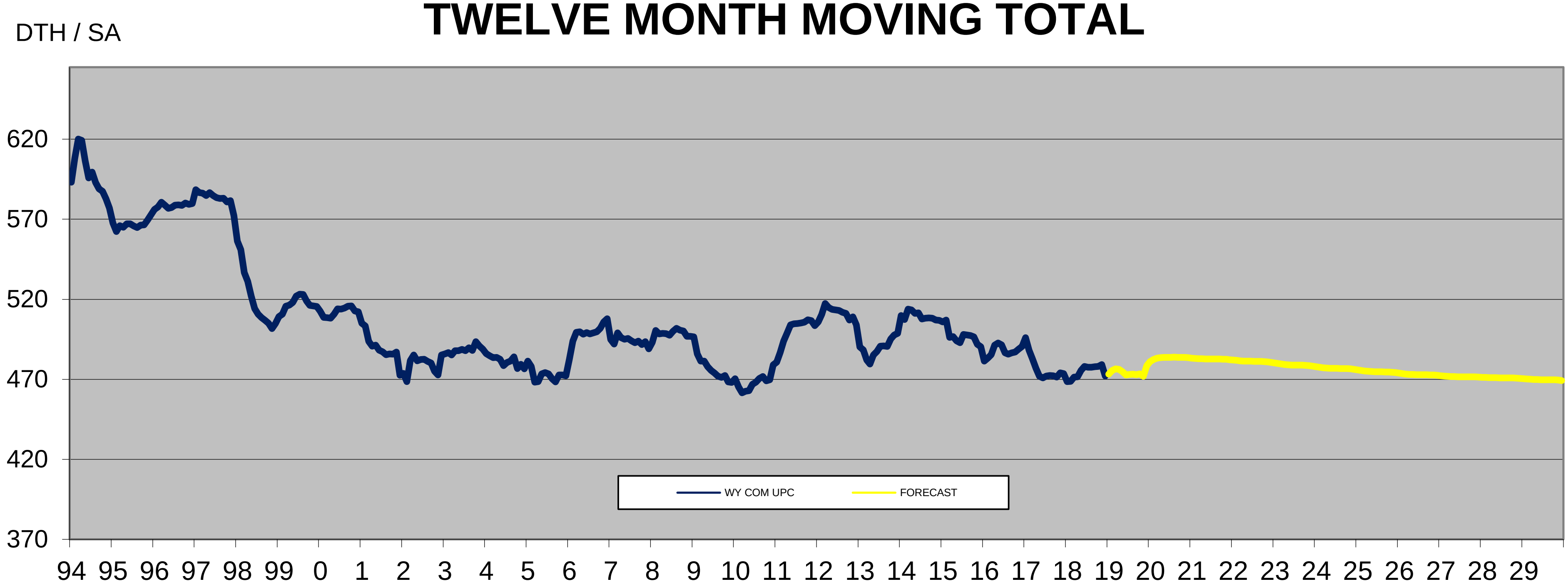


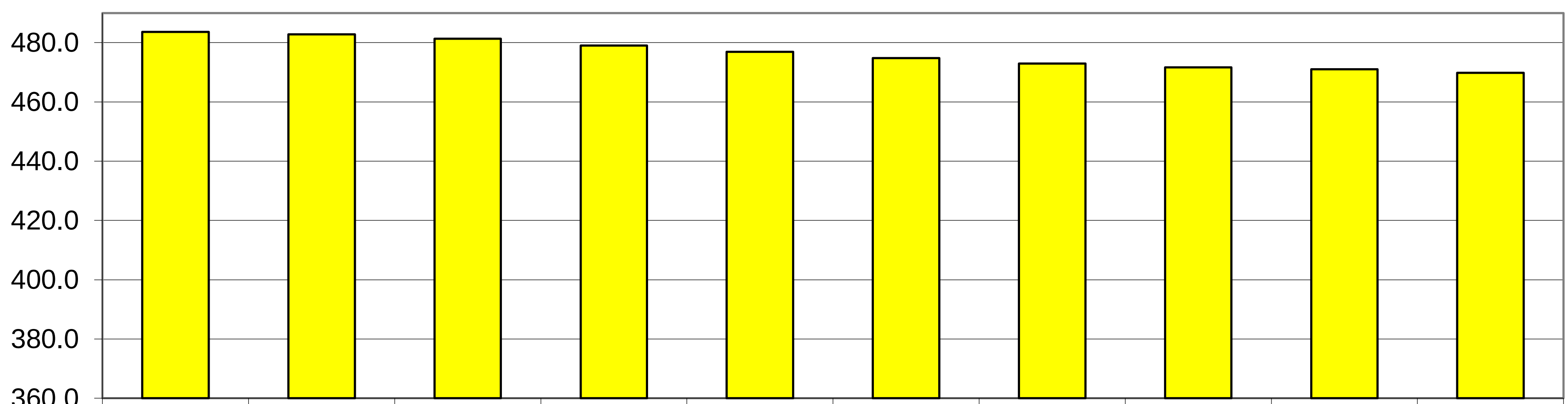




| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| WY GS RES UPC | 87.6 | 86.9 | 86.1 | 85.1 | 84.2 | 83.3 | 82.4 | 81.6 | 80.9 | 80.0 |

Exhibit 3.6

# WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
# TWELVE MONTH MOVING TOTAL

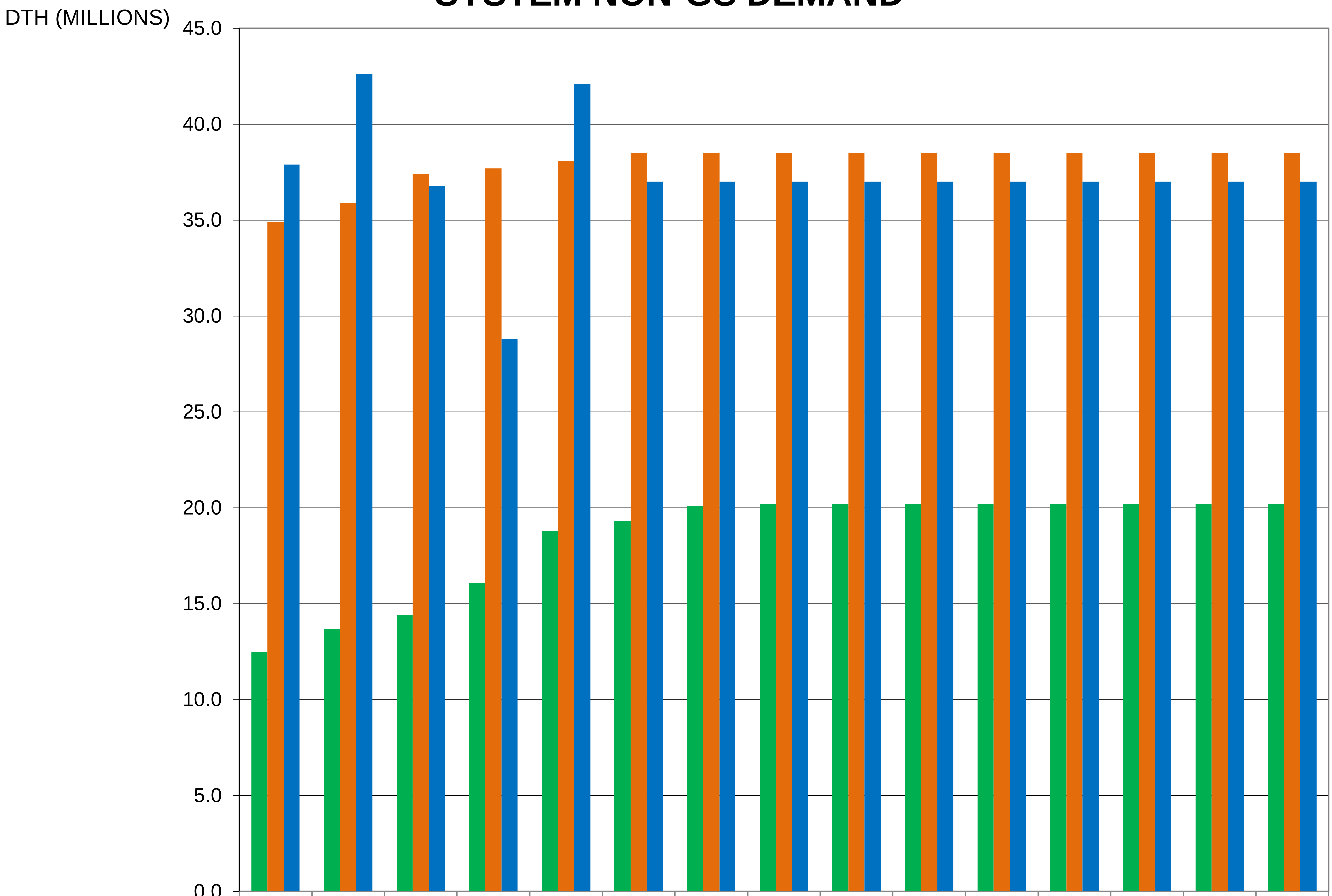



| | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|
| WY GS COM UPC | 483.6 | 482.8 | 481.3 | 479.0 | 476.9 | 474.8 | 473.0 | 471.7 | 471.0 | 469.8 |

Exhibit 3.7

# SYSTEM NON-GS DEMAND

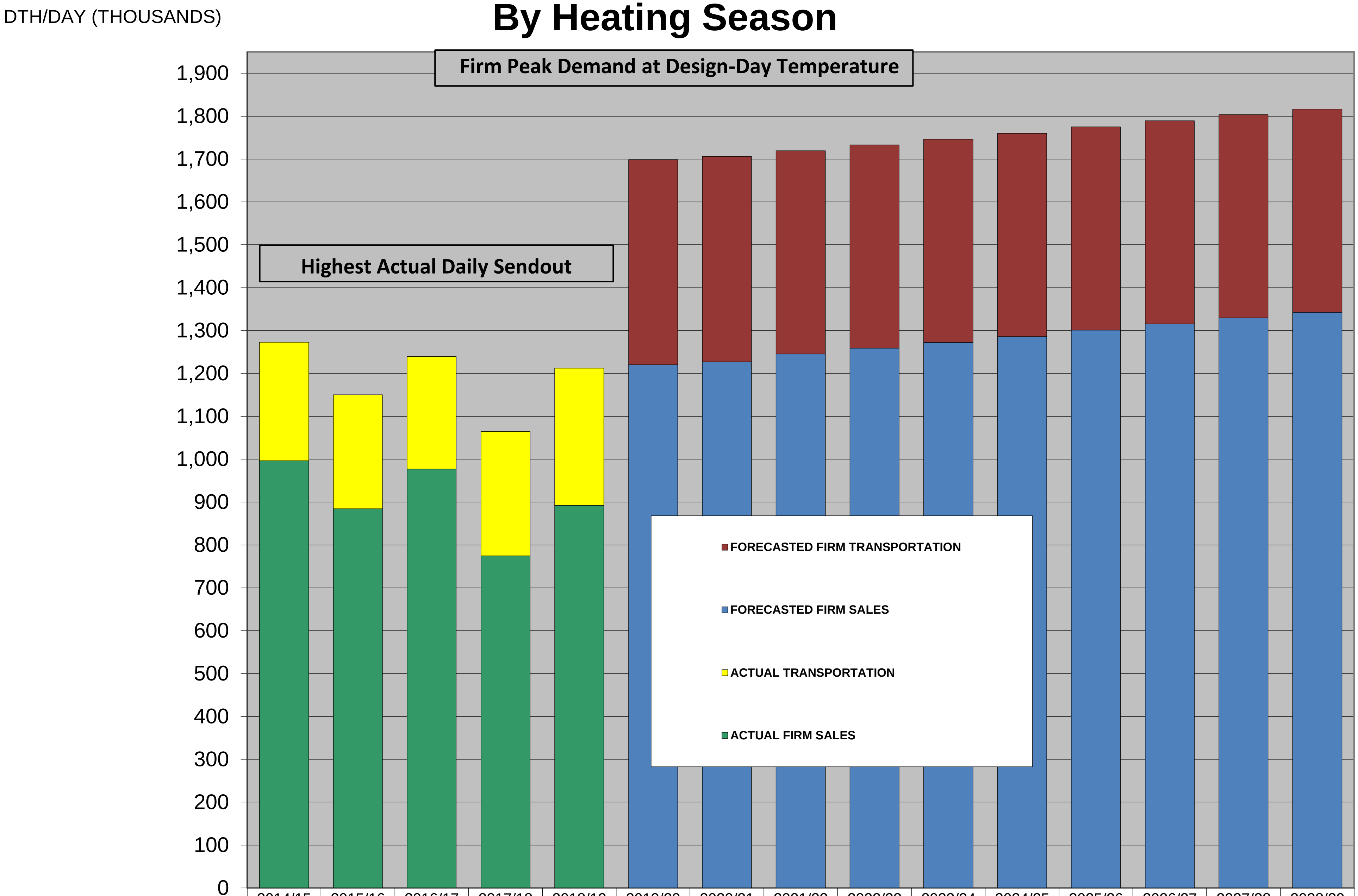



| | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LARGE COMMERCIAL DEMAND | 12.5 | 13.7 | 14.4 | 16.1 | 18.8 | 19.3 | 20.1 | 20.2 | 20.2 | 20.2 | 20.2 | 20.2 | 20.2 | 20.2 | 20.2 |
| INDUSTRIAL DEMAND | 34.9 | 35.9 | 37.4 | 37.7 | 38.1 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 |
| ELECTRIC GENERATION | 37.9 | 42.6 | 36.8 | 28.8 | 42.1 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 |

Exhibit 3.8

# DESIGN PEAK-DAY DEMAND FORECAST

## By Heating Season

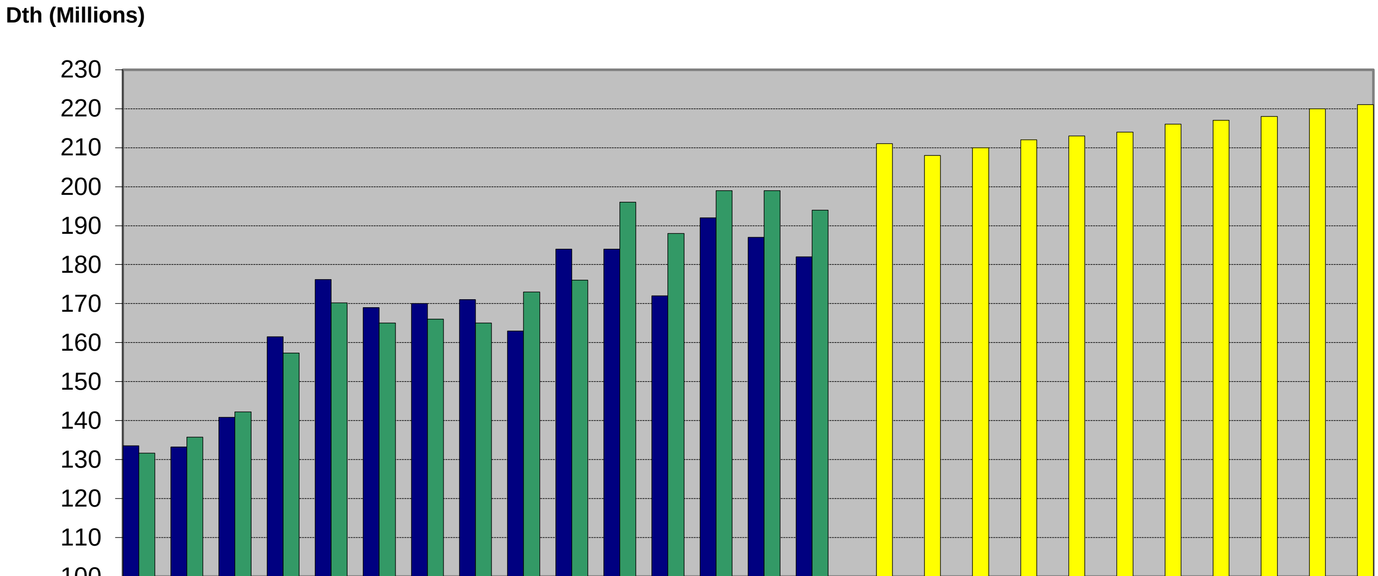



| | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FORECASTED FIRM TRANSPORTATION | | | | | | 478 | 479 | 474 | 474 | 474 | 474 | 474 | 474 | 474 | 474 |
| FORECASTED FIRM SALES | | | | | | 1220 | 1227 | 1246 | 1259 | 1272 | 1286 | 1301 | 1315 | 1329 | 1342 |
| ACTUAL TRANSPORTATION | 276 | 266 | 262 | 290 | 320 | | | | | | | | | | |
| ACTUAL FIRM SALES | 996 | 884 | 977 | 775 | 892 | | | | | | | | | | |

Exhibit 3.9

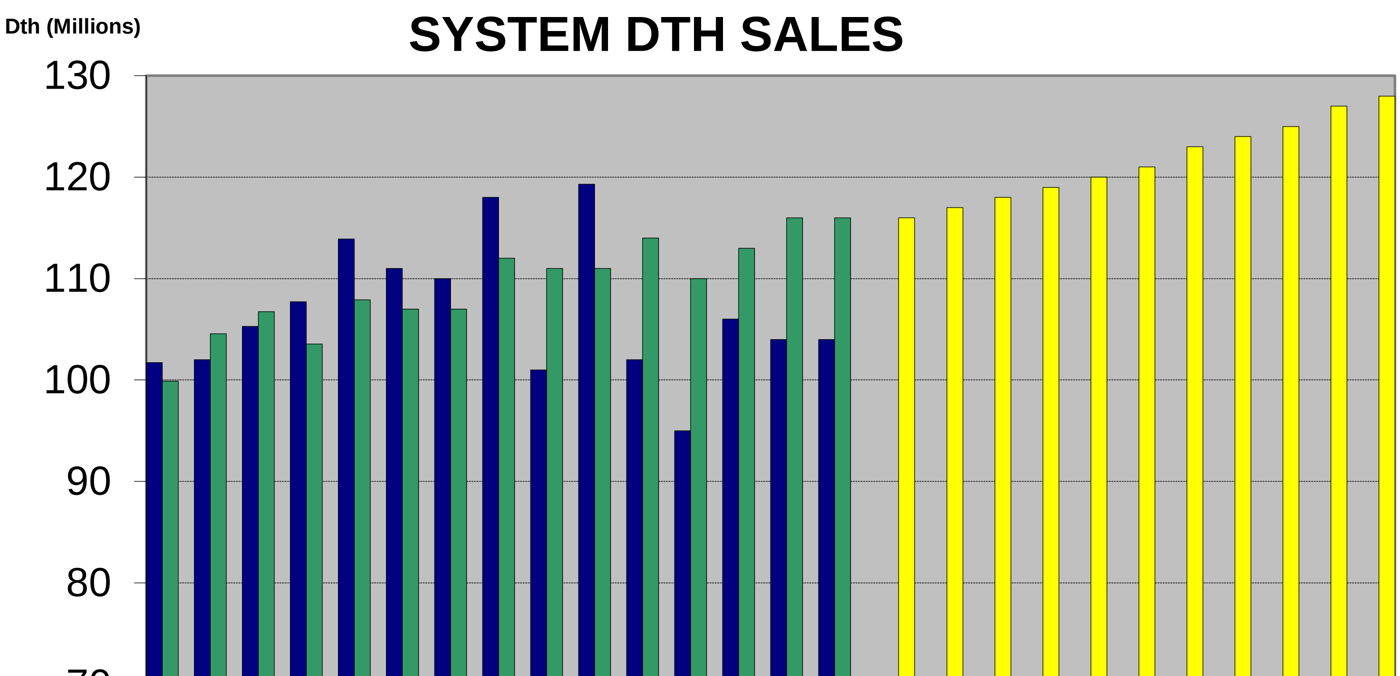
Exhibit 3.10

# SYSTEM DTH THROUGHPUT



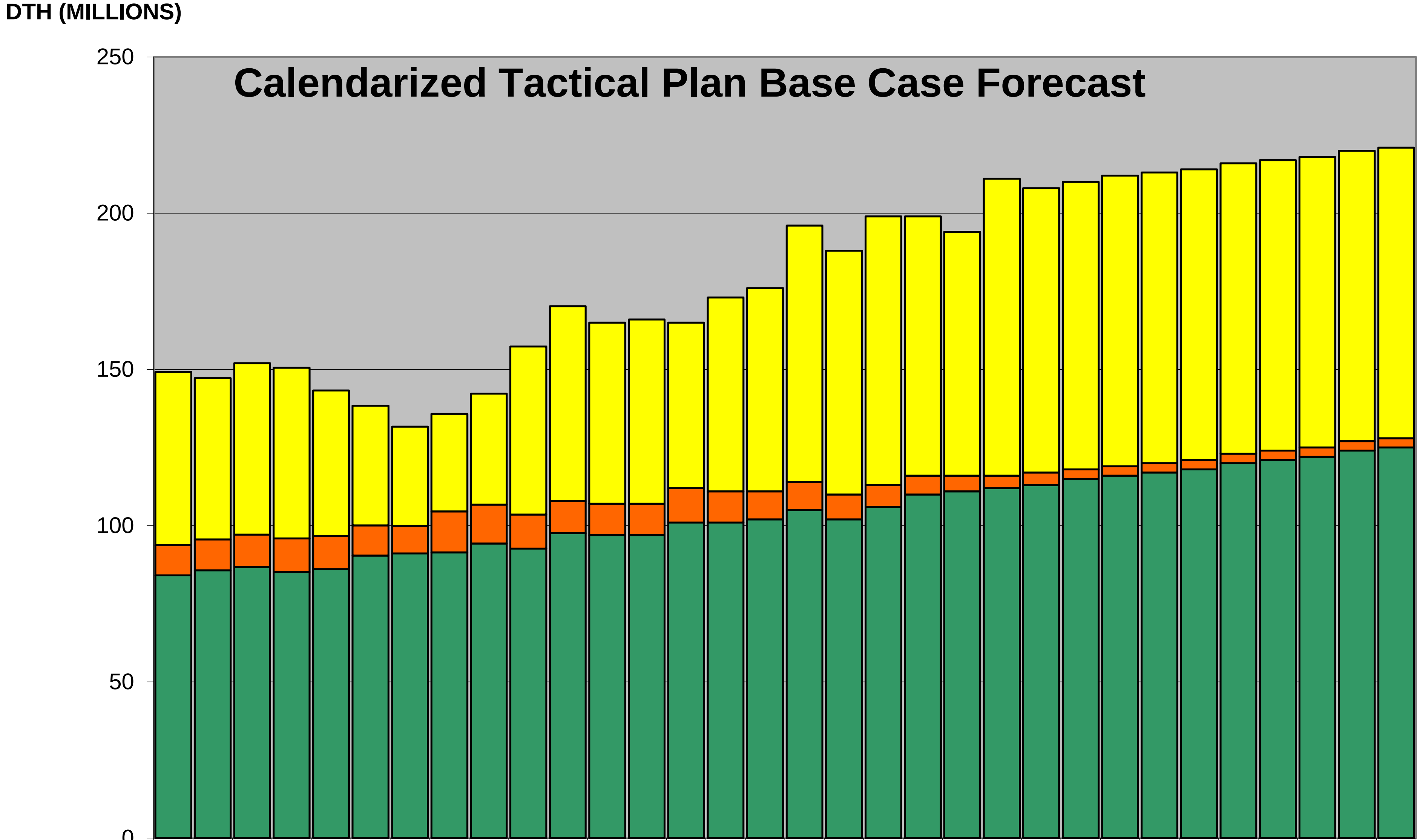

| | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 14/ 15 | 15/ 16 | 16/ 17 | 17/ 18 | 18/ 19 | 19/ 20 | 20/ 21 | 21/ 22 | 22/ 23 | 23/ 24 | 24/ 25 | 25/ 26 | 26/ 27 | 27/ 28 | 28/ 29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 134 | 133 | 141 | 162 | 176 | 169 | 170 | 171 | 163 | 184 | 184 | 172 | 192 | 187 | 182 | | | | | | | | | | | |
| TEMP ADJUSTED | 132 | 136 | 142 | 157 | 170 | 165 | 166 | 165 | 173 | 176 | 196 | 188 | 199 | 199 | 194 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | 211 | 208 | 210 | 212 | 213 | 214 | 216 | 217 | 218 | 220 | 221 |

# SYSTEM DTH SALES




| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 102 | 102 | 105 | 108 | 114 | 111 | 110 | 118 | 101 | 119 | 102 | 95 | 106 | 104 | 104 | | | | | | | | | | | |
| TEMP ADJUSTED | 100 | 105 | 107 | 104 | 108 | 107 | 107 | 112 | 111 | 111 | 114 | 110 | 113 | 116 | 116 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | 116 | 117 | 118 | 119 | 120 | 121 | 123 | 124 | 125 | 127 | 128 |

# TEMP ADJUSTED THROUGHPUT




| | 98 | 99 | 00 | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TRANS | 55 | 52 | 55 | 55 | 46 | 38 | 32 | 31 | 36 | 54 | 62 | 58 | 59 | 53 | 62 | 65 | 82 | 78 | 86 | 83 | 78 | 95 | 91 | 92 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 |
| NON-GS SALES | 10 | 10 | 10 | 11 | 11 | 10 | 9 | 13 | 12 | 11 | 10 | 10 | 10 | 11 | 10 | 9 | 9 | 8 | 7 | 6 | 5 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| SYSTEM GS | 84 | 86 | 87 | 85 | 86 | 90 | 91 | 91 | 94 | 93 | 98 | 97 | 97 | 101 | 101 | 102 | 105 | 102 | 106 | 110 | 111 | 112 | 113 | 115 | 116 | 117 | 118 | 120 | 121 | 122 | 124 | 125 |

Exhibit 3.11

# SYSTEM CAPABILITIES AND CONSTRAINTS

## DOMINION ENERGY SYSTEM OVERVIEW

The Company's system currently consists of approximately 19,775 miles of distribution and transmission mains serving more than 1,050,000 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.

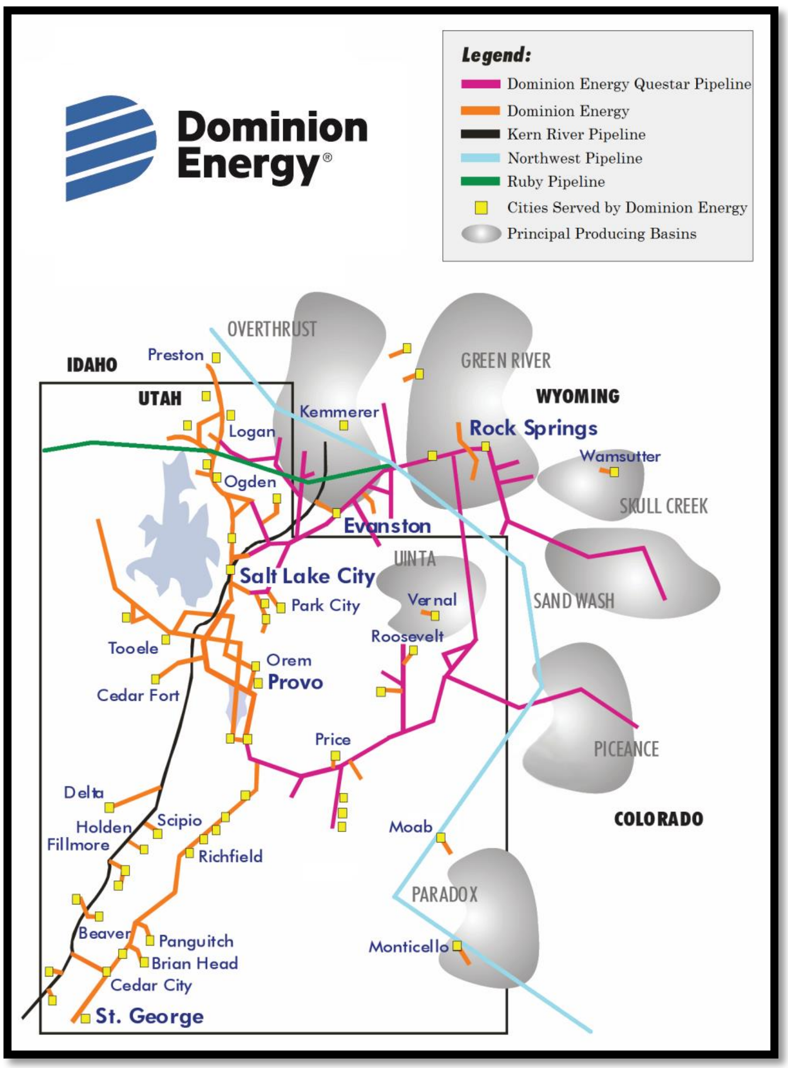



Figure 4.1: Dominion Energy High Pressure System

## 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 Dominion Energy Questar Pipeline (DEQP) work together each year to update a Joint Operating Agreement (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 due to the fact that the flows at these stations fluctuate through the day to match the changing demands on the Company's system.

### *Interruption Analysis*

A number of customers on the Company's system have chosen to purchase service on an interruptible rate utilizing any available system capacity. Because the system is not designed for these customers, it is important to understand the temperatures at which an interruption would be expected. The Company performs an interruption analysis on an annual basis. The interruption analysis divides the system into interruption zones and determines the temperature at which interruption of a specific zone is appropriate to ensure reliable service to the surrounding firm customers.

### *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, January 2, 2019 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 155 verification points. One hundred and fifty-four of these points were found to be within 7% of the actual pressures on that day. One hundred and forty-one of the pressures in the verification model were within 5% of the actual pressure. Based on this analysis, the Company has deemed the loads and infrastructure utilized in the GNA models are accurate, and the models can confidently be used 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 seven 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 140 verification points on that day. One hundred and forty 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 study each year for each of the gate stations on the system. The Company calculated 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 JOA.

There are a number of other gate stations that are near 100% utilization shown in Table 4.1. These stations will be upgraded as necessary in the coming years in order to accommodate their respective required flows. Each of these stations is either flowing at capacity in last year's JOA or is nearing the physical capacity of the station. Stations at or near capacity that do not have associated projects may not be a concern due to the fact that multiple gate stations feed the same HP subsystem.

**Table 4.1: Gate Stations Nearing Capacity in the JOA**

| Station | 2019-2020 (MMcfd) | Station Capacity (MMcfd) | % Utilization | Upgrade Year |
|---|---|---|---|---|
| Riverton | 200 | 200 | 100% | - |
| Myton | 7.885 | 7.885 | 100% | - |
| Evanston South | 8.438 | 8.441 | 100% | - |
| Dog Valley | 5.452 | 5.683 | 96% | 2019 |
| Dalton Creek | 0.195 | 0.203 | 96% | 2019 |
| Central Tap | 44.814 | 47.5 | 94% | 2024 |
| Rockport | 14.5 | 15.71 | 92% | 2022 |
| Como Springs | 1.2 | 1.304 | 92% | TBD* |
| Hunter Park | 366.5 | 400 | 92% | - |

In addition to these specific gate stations, the total gate station capacity[1] of the Northern HP system is approaching maximum capacity. Residential and commercial growth in Utah is increasing demand for natural gas along the Wasatch Front. In 2017, The Company determined that the system would benefit from a new gate station, served by KRGT, to feed Northern Utah within the next three years. This new gate station will provide the ability to bring additional firm gas to the Wasatch Front. In addition, when the FL23 replacement project is complete, there will be additional capacity available to the Wasatch Front through the Hyrum gate station.

[1] Reflects station Capacity when combined with gas supply and upstream transportation contracts.

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, past issues, and design inadequacies.  Therefore, the Company will upgrade this station by 2022.

## 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 DEQP 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 DEQP's Main Line 104 (MAP 332), multiple smaller taps from DEQP (MAP 162) and KRGT at Eagle Mountain, Lake Side, Hunter Park, and Riverton stations.

In the steady-state model, the calculated low point in the main portion of northern system is 221 psig, in the West Desert. The lowest steady-state pressure is in the Summit/Wasatch system, in Woodland, which is 278 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 4.2. 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 4.2: Dominion Energy High Pressure System Steady-State Design Day Pressures**

| Location | Pressure (psig) |
|---|---|
| Endpoint of FL 29 – Plymouth | 328 |
| Endpoint of FL 36 – West Jordan | 240 |
| Endpoint of FL 48 – Stockton | 267 |
| Endpoint of FL 51 – Plain City | 377 |
| Endpoint of FL 54 – Park City | 316 |
| Endpoint of FL 62 – Alta | 226 |
| Endpoint of FL 63 – West Desert | 221 |
| Endpoint of FL 70 – Promontory | 327 |
| Endpoint of FL 74 – Preston | 321 |
| Endpoint of FL 106 – Bear River City | 346 |
| Intersection of FL 29 & FL 23 – Brigham City | 406 |

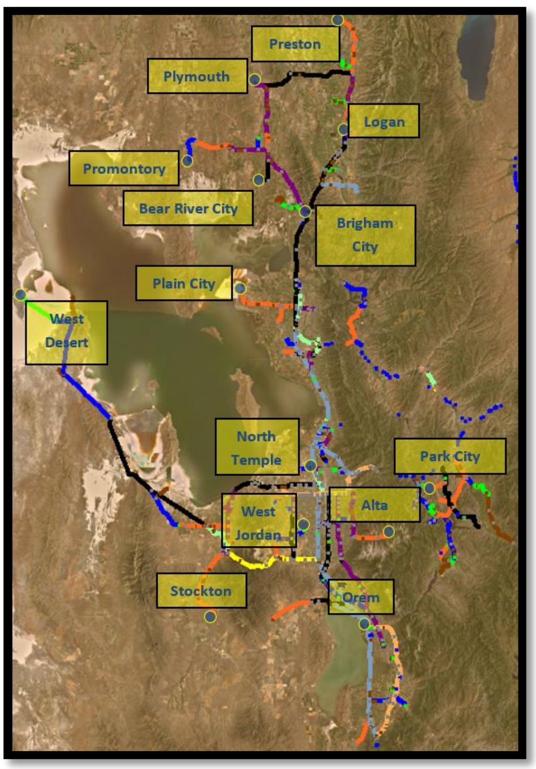



**Figure 4.2: Northern Region Key Pressure Locations**

The curves shown in Figure 4.3, Figure 4.4, and Figure 4.5 are the expected Design Day pressures for the Northern Region HP system. In the projected unsteady-state models, the low point in the Northern Region is West Jordan at 171 psig. The lowest predicted pressure in the Summit Wasatch subsystem is at the Woodland regulator station with 218 psig during the peak hour.

In the HP system north of the North Temple station, the minimum pressure occurs at Plain City with a minimum pressure of 256 psig. While these pressures are well above operational minimums, the gate stations in the North are all expected to reach their maximum capacities on a Design Day. In order to maintain pressures in this area, the Company requires additional gate station capacity and pressure support by 2020. The one existing station in this area that is not at capacity due to upstream constraints is Hyrum Gate Station. However, Hyrum is constrained due to the size of FL23, which is scheduled for replacement as part of the Company's Infrastructure Rate Adjustment Tracker program. Increasing the diameter of FL23 not only increases pressures in the area, it is necessary to allow more gas to flow from Hyrum Gate into the Northern system.

In addition to the locations shown on the chart, system pressures near the Salt Lake International Airport reach 184 psig in the 2019-2020 Design Day model. These results are significant due to the fact that FL55, the 6-inch feeder line supplying gas to this area, is near capacity. In order to maintain operational pressures, FL131 will be extended from the Westport Tap to FL55.

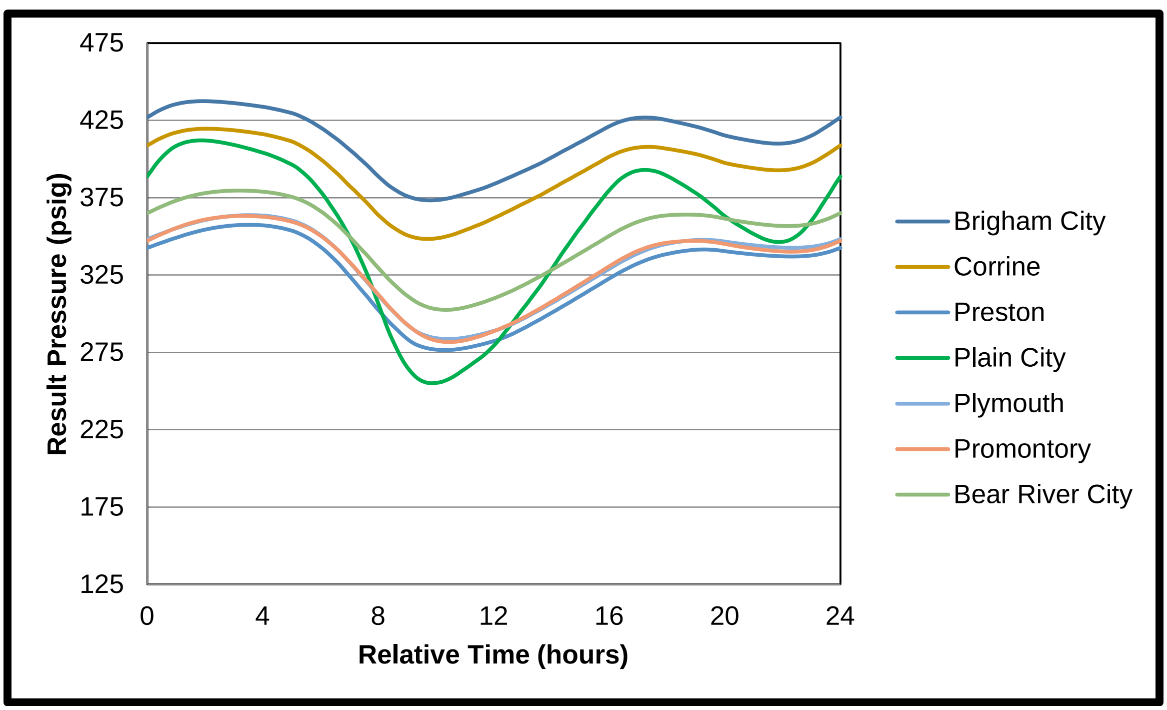



**Figure 4.3: 2019-2020 Northern Unsteady-State Design Day Pressures (North of North Temple)**

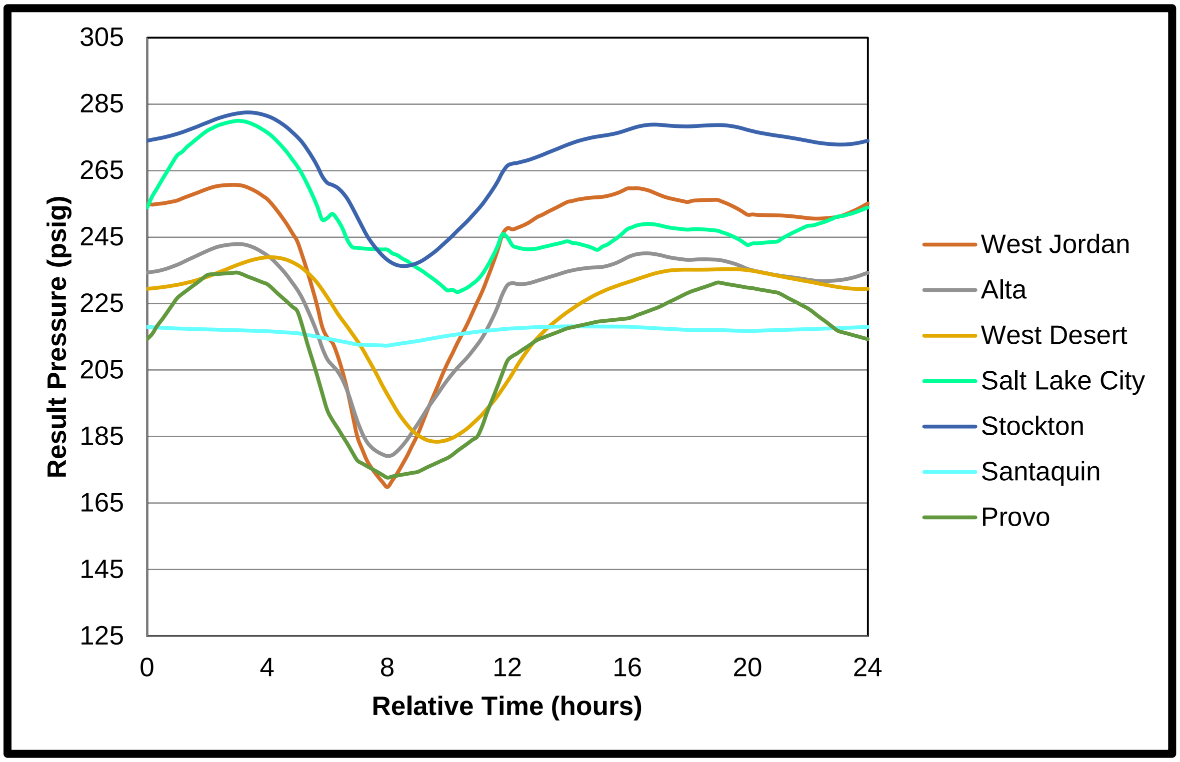



**Figure 4.4: 2019-2020 Northern Unsteady-State Design Day Pressures (South of North Temple)**

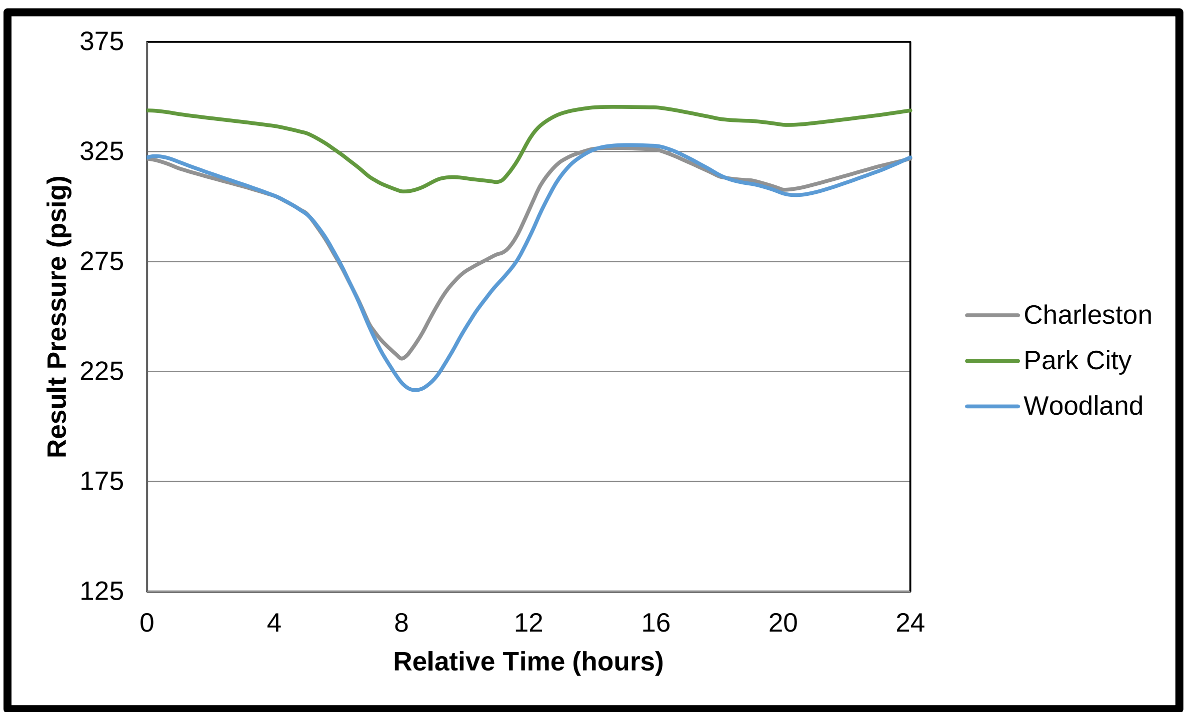



**Figure 4.5: 2019-2020 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)**

## 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 DEQP by two gate stations through MAP 163 and MAP 334. Minimum pressures in the Vernal system reach a minimum of 200 psig.

Pressures are continuing to decline in the Fort Duchesne area. Currently, the minimum pressure at Fort Duchesne is 219 psig. In order to maintain pressures, the Company must loop or replace FL43. The Company plans to install a new gate station in Ioka, which will increase pressures at Fort Duchesne until the line can be replaced. FL43 is identified to be replaced as part of the Infrastructure Rate Adjustment Tracker and will be scheduled for replacement in the next five years.

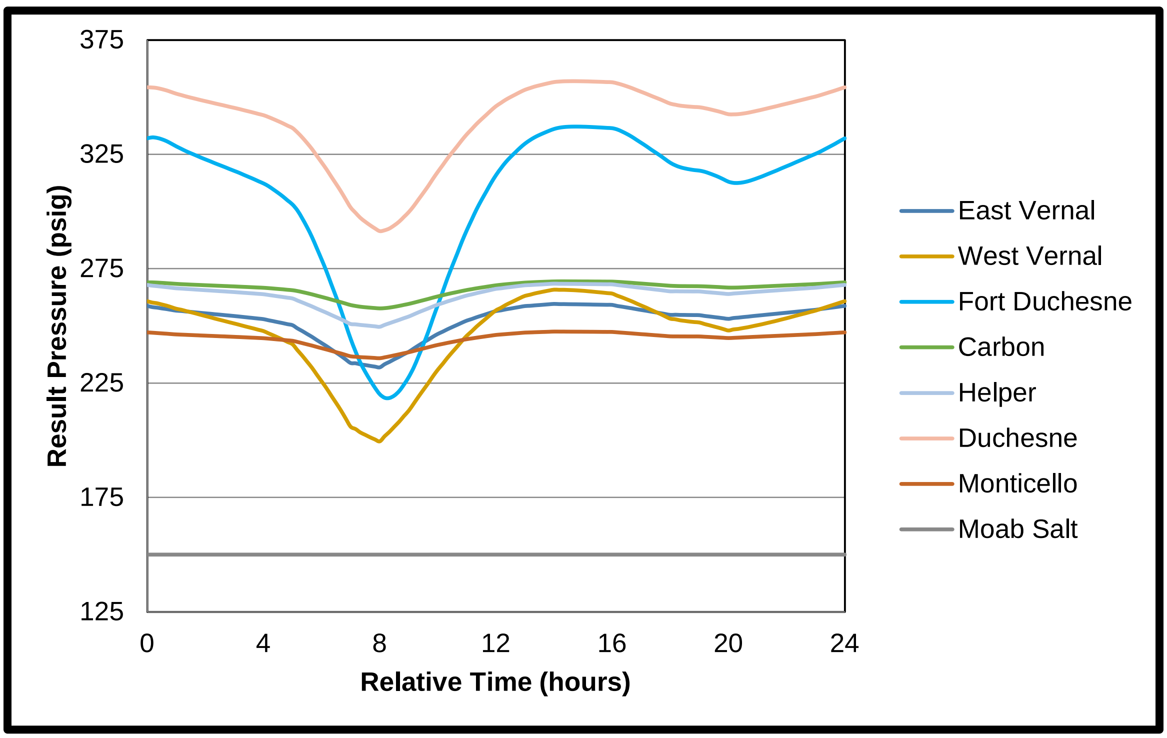



**Figure 4.6: 2019-2020 Eastern (North) Unsteady-State Design-Day Pressures**

## 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 2019-2020 heating season.

## Southern (Main System)

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

Using the steady-state model, the lowest modeled pressure on a Design Day is 425 psig at the Brian Head regulator station. 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 ten years. The Company has monitored the Southern System growth since the Central Compressor station was installed. Based on the current projections, it is estimated that a new feeder line will need to be installed from the Bluff St station east to the Washington 2 tap line prior to the 2020-2021 heating season in order to maintain system pressures. In the years following this tie across the system, FL81 will need to be looped to increase gas flow from the Central tap to St George.

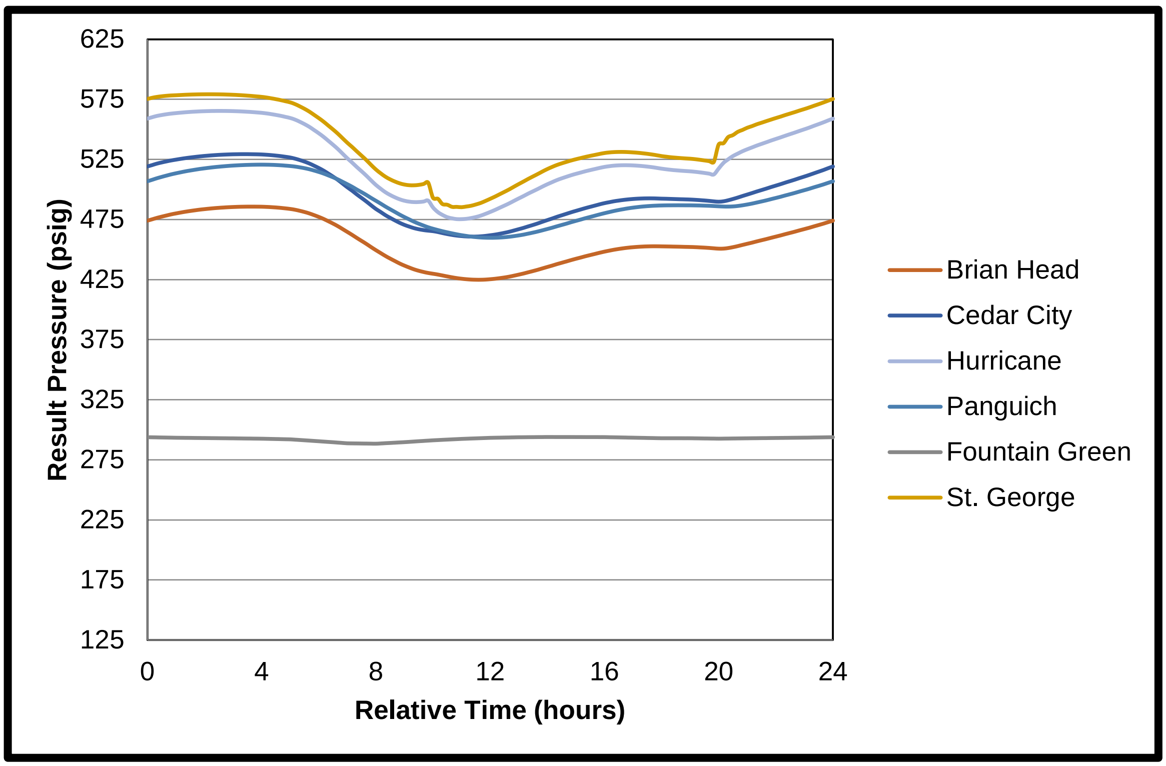



**Figure 4.7: 2019-2020 Southern Unsteady-State Design Day Pressures**

## 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 DEQP 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.

The Rock Springs HP system has two gate stations; the Kanda gate station (fed from DEQP), and the Foothill CIG gate station. While neither station is near its capacity on a Design Day, these stations are meant to be redundant for reliability purposes. Kanda will be incapable of meeting the entire Design Day demand of this sub-system and must be upgraded in 2023.

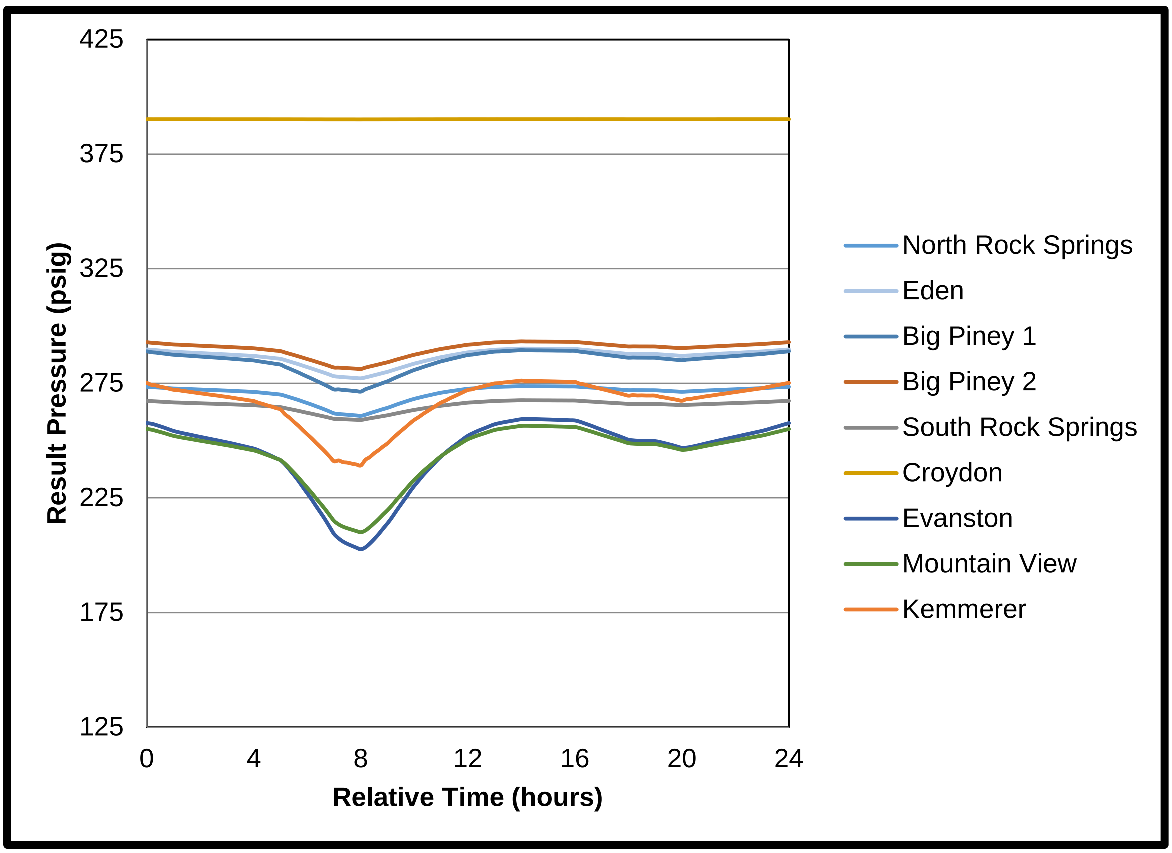



**Figure 4.8: 2019-2020 Wyoming Unsteady-State Design Day Pressures**

## 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 should 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.

The Company will discuss project options in the distribution action plan (DNG Action Plan) for these identified constraints and concerns:

- Increasing demand and limited supply in the Northern and Central Regions
- Low pressures at the endpoint of FL51 near Plain City
- Trending pressures in Fort Duchesne
- Low pressures near Salt Lake International Airport
- Demand growth in the Southern HP System
- Station capacity of the Saratoga Tap

# DISTRIBUTION SYSTEM ACTION PLAN (DNG 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 2019 and beyond.

## HIGH PRESSURE PROJECTS:

### *Station Projects:*

1. LG0012 District Regulator Station, Nibley, Utah: This pressure regulator station is required to alleviate low pressures in the IHP system in Nibley, Utah. The pipeline required to serve the station is 13,200 lf of 8-in diameter pipe. The pipeline begins near U.S. Highway 89 on 3200 S, approximately 3 miles north of Wellsville. The alignment then runs east along 3200 S for approximately 2.5 miles until 3200 S and Main St in Nibley. The Company purchased the property for this station in 2009 in anticipation of a station being required in the area in the future. The pipeline route is a direct line from the tap location on FL23 to the station property. There are, therefore, no other route alternatives to this project.

   The Company first discussed this project on page 4-14 of the 2016-2017 IRP. Over the last year high level design including survey and subsurface utility engineering have allowed the Company to refine the project cost estimate. The project is currently in the design phase, and the Company anticipates construction in 2020. The updated estimated cost for this project is $4,800,000 with a first-year revenue requirement of $475,000.

2. Flyer Way HP Regulator Station, Salt Lake City, Utah: This HP regulator station is a replacement and relocation of the current “North Temple” HP regulator station. The North Temple station needed to be replaced due to antiquated equipment, excessive vibration and inadequate space for a required in-line inspection launcher/receiver facility.

   The station’s primary purpose is to regulate pressures and flows between the 471 psig MAOP zone to the north and the 354 psig MAOP zone to the south. An important design requirement of the station is that it has the ability to flow in either direction. Default flow direction is north to south (from the higher MAOP to the lower MAOP), but in certain system conditions the station needs to be able to flow south to north. For example, if a major gate station or feeder line was out of service in Davis or Weber counties, we may need to be able to flow gas from the Salt Lake County into Davis County. This design will greatly improve the reliability of the Company’s system. The secondary purpose of the station is to house in-line inspection tool launchers and receivers.

   The alternative to this project would be to lower the 471 psig pressure zone to 354 psig and lose the capacity associated with the higher pressure. The Company first discussed this project on page 4-16 of the 2017-2018 IRP. In that report the station number was erroneously identified as WA0085. The correct station ID is WA0045.

Additionally, in 2018 the project name was changed from the North Temple HP regulator station to the Flyer Way HP regulator station. The project is currently in the design phase, and the Company anticipates construction in 2019.

The estimated cost for this project is $6,400,000 with a first-year revenue requirement of $630,000.

3. 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 station has a capacity of 120 MMcfd, and it needs to be increased to 200 MMcfd. Increasing the station capacity is necessary to ensure reliability in the event that other gate stations in the Salt Lake valley are unable to meet demand requirements. FL26 is a 20" pipeline that leaves this 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 aren't any other alternatives to this project.

   The project has an estimated cost of $2,500,000. The Company's facilities related to this project are currently in the design phase, and the Company anticipates construction of those facilities in 2020. The first-year revenue requirement is $245,000.

4. Rose Park Gate Station, Salt Lake City, Utah: This station is a new 400 MMcfd gate station receiving gas off KRGT and delivering it into DEU's FL33 in North Salt Lake. The gate station is required to meet firm sales demand growth in the area. The Company first discussed this project on page 4-17 of the 2017-2018 IRP. Additional project justification is given on page 4-4 of this report. The purpose of the project is to have KRGT gas brought on to the Company's 471 psig MAOP system in Davis County. There are no third-party alternatives to this project that provide the adequate volumes to DEU's North Salt Lake service area. The Company has purchased property for the station at 2700 N and 2200 W in Salt Lake City, where Kern River's pipeline crosses the Company's FL33. This location minimizes the required pipeline extension required to connect KRGT to the Company's system. The Company's facilities related to this project are currently in the design phase, and the Company anticipates construction of those facilities in 2020.

   The estimated cost for this project is $15,800,000 with a first-year revenue requirement of $1,565,000.

5. TG0007 Regulator Station, Saratoga Springs, Utah: This IHP regulator station is required to meet the residential growth in Saratoga Springs. The project will extend the existing HP pipeline that serves Saratoga Springs south another 4.5 miles under the identification of FL112. The route follows the west side of the existing development along the future Mountain View Corridor alignment. The Company considered an alternative route running down Redwood Road, but the construction costs were estimated to be $13,500,000, well above the costs for the selected project, due to required asphalt repair and traffic control. The Company first discussed this project on page 4-18 of the 2017-2018 IRP. The project is currently in the planning phase, and the Company anticipates commissioning the station in 2020.

The estimated cost for this project is $9,300,000 with a first-year revenue requirement of $921,000.

6. Syracuse Regulator Station, Syracuse, Utah: This IHP regulator station is required to meet the residential growth in the west side of developed Davis County. This project is currently in the design phase. The exact station location and pipeline alignment have not yet been established. The pipeline length is anticipated to be approximately 3 miles. At this point in the design phase, it appears as though the pipeline alignment will follow the shortest route on existing roads between the beginning point and the new station location. Constructing the IHP regulator station is the only identified solution to resolving the low IHP pressures in this area. No alternative pipeline routes have been identified at this time. Once the property is purchased and the initial engineering is complete, the Company will provide updated route selection and project costs as part of the IRP Variance Report process. The Company first discussed this project on page 5-3 of the 2018-2019 IRP. The Company currently estimates that the cost will be approximately $5,200,000. The Company plans to begin construction in 2020. The first-year revenue requirement will be $515,000.

7. Jamestown Regulator Station, Jamestown, Wyoming: Jamestown is a small community approximately 2.5 miles northwest of Green River in Wyoming. The Company currently serves the town through a one-way feed of 2 miles of IHP main extending from Green River to Jamestown. The Company plans to construct a regulator station in Jamestown to provide redundant feed. However, at present, all of the regulator stations in the area are fed directly from DEQP and the Company does not have odorized HP pipelines in the area that could be extended to Jamestown. Therefore, in order to provide redundancy in the service to Jamestown, the Company is considering the installation of a new gate station from a nearby transmission line and extending 6,300 lf of IHP main to the town. Another option would be to reinforce the area with a new supply line directly from the distribution system in Green River. The project's construction is anticipated for 2022 or 2023. The Company is in the early stages of planning. When it has completed its initial analysis, the Company will provide updated routing information and estimated project costs as part of the IRP Variance Report process or in future IRPs.

8. White Dome IHP Regulator Station, St George, Utah: A large master-planned residential community called White Dome is under construction at the far south end of St. George, Utah. It will likely take 10 years, or more, to fully develop the planned 10,000 homes and commercial areas. In order to serve this community, the Company must extend its HP system approximately 2 miles south from the current GE0015 station located on River Road and Commerce Drive and install a full capacity high-pressure regulator station. As the Company completes its initial review of the project, and determines the most appropriate location for the station, it will provide updates to the Commission. At this time, the Company anticipates commencing construction in 2022. The Company first discussed this project on page 5-4 of the 2018-2019 IRP.

9. TG0005, Saratoga KRGT Gate Station, Saratoga Springs, Utah: This station is a major gate station receiving gas off KRGT and delivering it primarily into FL85, along with FL112 and FL116. Gas from this station serves the several Utah County

communities including Lehi, Eagle Mountain, and Saratoga Springs. These communities are some of the fastest growing communities in DEU's service territory. The Saratoga gate station, while not at capacity on a Design Day, requires a remodel due to operational concerns. Currently the station has a capacity of 250 MMcfd and the design capacity of the remodel project is 350 MMcfd. Other required improvements include gas measurement to allow flow control and improved overpressure protection.

This project to remodel TG0005 in its existing location is in the early planning stages and is anticipated for construction in 2021. Total project costs are estimated at $2,000,000. Based on this estimate, the first-year revenue requirement will be $198,000.

One alternative to this project would be to increase capacity at the existing Eagle Mountain KRGT gate station 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 $29,000,000, well above the cost of the selected project.

A second alternative would involve constructing a new KRGT gate station somewhere along the KRGT pipeline closer to the load center. Even assuming no feeder line extension would be required to connect the Company's system to the new station, an entirely new gate station with a design load of 100 MMcfd would have an estimated cost of approximately $6,000,000, also well above the cost of the selected option.

10. South Bluffdale IHP 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 district 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 2023. 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. The Company first discussed this project on page 5-4 of the 2018-2019 IRP.

11. American Fork IHP Regulator Station: The southwest side of American Fork, between I-15 and Utah Lake, is developing rapidly, and the Company needs to construct a new IHP regulator station in the area to support the growth. There will be multiple options for bringing a HP tap line to the station as FL26 is located to the north, FL85 to the northwest and FL104 to the south. The location of where the Company finds property for the station will determine in large part how the pipeline alignment is designed. The pipeline will be between 5,000 and 9000 lf and the entire

project is planned for 2021 construction. The total project estimated cost is $3,000,000. Based on this estimate, the first-year revenue requirement will be $297,000.

12. FL43 Extension, Ioka, UT: To meet the load growth demand and provide a redundant gas feed source to the Roosevelt/Fort Duchesne system, an additional gate station and feeder line extension is required. DEQP is designing and constructing the Ioka gate station which will be located at 4000 S and 5000 W. in Ioka, which is near Roosevelt. The Company is designing and constructing the pipeline which will be an 8-inch 5,000 lf extension of FL43. There is only one option for alignment of the pipeline, running it east/west between the station and FL43 along 4000 S.

    The project is currently in the design phase, and construction on both the gate station and the pipeline are expected to be completed by the fall of 2019. Additional project justification is given on page 4-11 of the System Capabilities and Constraints section of this report. Estimated cost for the pipeline is $1,500,000. Based on this estimate, the first-year revenue requirement will be $149,000.

## *Feeder Line Projects:*

1. New Utah State Prison Site, Salt Lake City, Utah: The Utah State Department of Facilities and Construction Management (DFCM) is constructing a new state prison at approximately 7800 west, approximately 3 miles north of I-80 and expects to complete construction in late 2020. The new prison will require natural gas service in 2019. The Company does not currently have any facilities within this area.

    The Company's Engineering department has determined that the minimum system required to serve the new prison would be a 4-inch HP pipeline. In order to provide sufficient capacity to support future growth the Company plans to construct an 8-inch HP pipeline. The Company estimates the cost to construct the minimum system required by the prison facilities is $7,783,000. The State of Utah will pay those minimum system costs. The total cost of the project is $10,645,000. The Company will bear the approximately $2,862,000 difference with a first-year revenue requirement of $283,000.

    The currently proposed route leaves the new Westport gate station (approx. 5700 W 450 S) heads north along 5600 W, under I-80 to Amelia Earhart Dr, then west to John Glen Road, then north for 1/3 of a mile, then west for 1.5 miles. From there the route turns north for a mile and then west for a mile along future roads that have yet to be constructed.

    The Company considered an alternative route running from the Westport gate station north on 5600 W, running west primarily on the north side of I-80 for 2.75 miles, and then running north toward the prison for 2.5 miles. While this route is the most direct route, nearby wetlands and a landfill impair the Company's ability to complete a required bore across I-80. The proposed route has a more feasible I-80 bore than this alternative, and most of the alignment is either in existing roads or future roads. Pipeline footage is comparable on either route. Estimated cost for this alternative route is around $13,000,000, above the estimated cost of the selected option.

Additionally, it carried with it significant risk to budget, schedule and overall feasibility with the wetland permits and soil quality risks.

Approximately 1200 lf of this project was constructed in 2018. The remainder is anticipated to be constructed in 2019 in two phases, with the earlier of the two currently under construction. The Company first discussed this project on page 5-4 of the 2018-2019 IRP

2. FL55 extension, Salt Lake City, UT: Currently the Company's FL55 is a 6-inch high-pressure pipeline extending from 2200 W past the Salt Lake International Airport to 5000 W, and serving multiple IHP regulator stations along the way. Industrial growth is strong in this area, and modeling shows that on a Design-Day, pressures on the pipeline would drop. The 2018 construction of the Westport KRGT Gate Station provided an opportunity to extend FL55 and to provide a two-way feed, thereby boosting the pressures to accommodate the area's growing gas needs. Additionally, the new Utah State Prison HP pipeline (FL131) will reduce the length required for this extension.

   The current design for the pipeline alignment is a 5600 lf route that begins at the current FL55 termination point at SL0118, 5000 W and Douglas Corrigan Way. From there it will run north to Amelia Earhart Drive, and then west to 5600 W where it will connect to the FL131 Utah State Prison pipeline.

   The Company considered two other routes: The first would follow Wiley Post Way from the west until it intersects with Admiral Byrd Rd, and then continue west through 1000' of private property. This option would have reduced the pipeline footage by about 1,800 lf, but property owners were not willing to sell property to the Company. Instead of pursuing condemnation, the Company abandoned this option.

   The second alternate route ran along Amelia Earhart Drive, Wiley Post Way and Admiral Byrd Road. This route would have been the same length, but it would have avoided the heavy vehicle traffic of Amelia Earhart Drive. The Company abandoned this option after Salt Lake City Planning and Engineering departments opposed the route. Salt Lake City personnel were concerned that this route would have a heavy impact to nearby businesses and that the chosen alternative would result in a reduced traffic disruption on Amelia Earhart Drive. Total cost for this option was estimated at $2,400,000.

   The selected project is currently in the design phase and construction is planned for 2021. Additional project justification is given on page 4-9 of the System Capabilities and Constraints section of this report. The total estimated cost for the project is $2,400,000. Based on this estimate, the first-year revenue requirement will be $238,000.

3. 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. When the original high pressure replacement plan was approved in Docket 13-057-05, it was anticipated that the program would be complete in 2028. Currently, the program is taking longer

than anticipated and is currently expected to be complete in approximately 2036. The Company plans to propose to increase the allowed amount of expenditures in the Feeder Line Replacement program in the next General Rate Case.

## *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 HP pipeline 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-in HP pipeline coming from Cedar City and FL81, an 8-in HP pipeline coming from Central gate station. Both lines are fed from Kern River gate stations. The bottleneck in bringing gas to St George is the 8-in HP pipelines. The Company considered several options. The three most viable options were:

1) Tie FL81 to FL71 with a 12-inch pipe across St. George.
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:

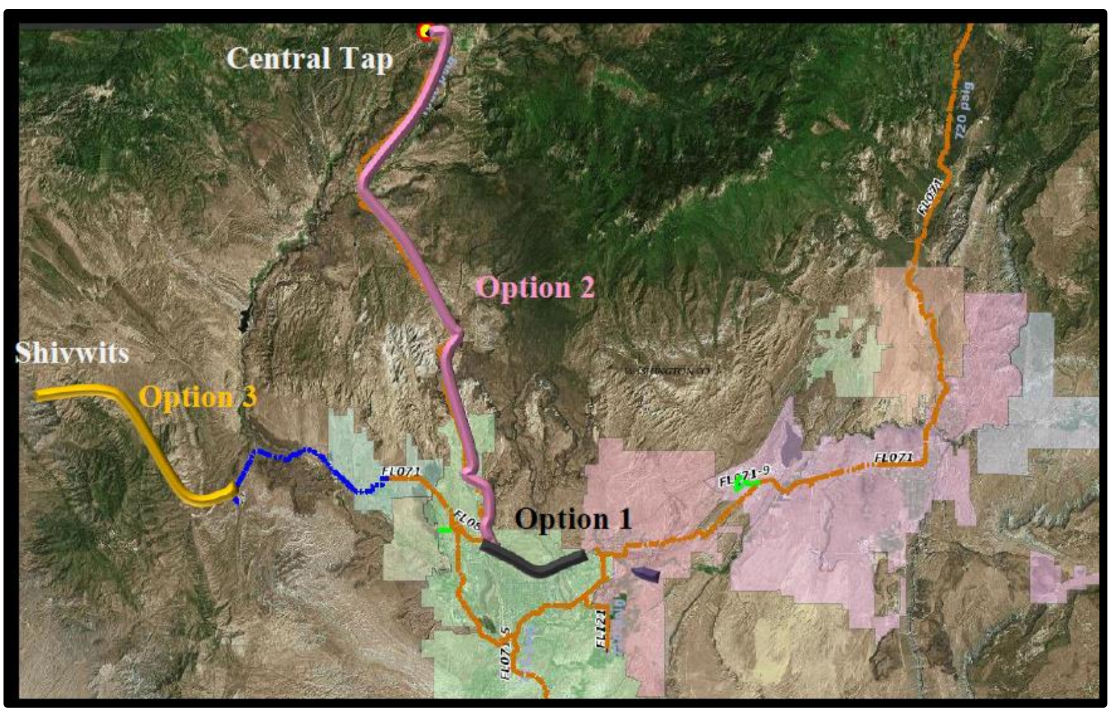



**Figure 5.1: Southern System Options**

The Company ultimately decided to select 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 reservation, right-of-way challenges and construability of the pipeline. All of these challenges combined made the Shivwits gate station option more expensive and carry more risk than options 1 and 2.

1. <u>FL133, St George Reinforcement tie, St George, Utah</u>: In order to reinforce its HP system to meet the growing demands of St George and the surrounding area the Company has determined it necessary to construct a 12-in pipeline through the north end of the city. The pipeline will begin at the HP regulator station WH0030 on Bluff Street and Snow Canyon Drive, will terminate at 3000 E and 450 N, and will be approximately 6.3 miles long. After leaving the WH0030 station, the route will run east on Red Hills parkway until 1680 E, where it will then bore under I-15 and run south to 450 N, then east to 3000 E. The Company will buy property where a pig receiver and interconnect valves with FL71 will be constructed. The total project cost is currently estimated at $21,000,000.

   The Company considered an alternative route that begins at the WH0030 station and runs south on Bluff Street for approximately 1.5 miles. It then turns east on 100 S until River Road, then travels northeast until Mall Drive, then south to 450 N, then east to 3000 E. This alternative route had an approximate cost of $24,000,000, well above the cost of the selected option. Costs are increased for this alternative due to extensive traffic control requirements and asphalt replacement along the entire alignment. Additionally, the City of St. George discouraged this route because it adversely impacted traffic on roads with high traffic volume.

   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. The project is currently in the design phase. The Company anticipates beginning construction in February of 2020 and completing in the fall of 2020. The first-year revenue requirement will be $2,080,000.

2. <u>FL135, Central 20-in 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-in pipeline reinforcement between the Central gate station and the WA0030 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-in 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, the Company plans to construct Phase 1, Central to Veyo, between 2021 and 2022 for an estimated cost of $32,813,000. 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 St, 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. The first-year revenue requirement for Phase 1 will be $3,250,000.

## *Preliminary Timeline Summary:*

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

| Year | Project | Estimated Cost | Revenue Requirement |
|---|---|---|---|
| 2019 | FL43 Ext, Ioka, Utah | $1,500,000 | $149,000 |
| | Flyer Way HP Regulator Station | $6,400,000 | $634,000 |
| | New Utah State Prison Extension | $2,862,000 | $283,000 |
| 2020 | FL55 Extension | $2,400,000 | $238,000 |
| | TG0007 District Regulator Station | $9,300,000 | $921,000 |
| | Rose Park Gate Station | $15,800,000 | $1,565,000 |
| | St George Reinforcement Tie | $21,000,000 | $2,080,000 |
| | Syracuse District Regulator Station | $5,200,000 | $515,000 |
| | LG0012 District Regulator Station | $4,800,000 | $475,000 |
| 2021 | American Fork District Regulator Station | $3,000,000 | $297,000 |
| | TG0005 Saratoga KR Gate Station | $2,000,000 | $198,000 |
| 2021-2022 | Central 20-in Loop (Phase 1) | $32,813,000 | $3,250,000 |
| 2022 | White Dome District Regulator Station | TBD | TBD |
| 2023 | Bluffdale District Regulator Station | TBD | TBD |
| 2024-2025 | Central 20-in Loop (Phase 2) | TBD | TBD |
| 2027-2028 | Central 20-in Loop (Phase 3) | TBD | TBD |

## PLANT PROJECTS:

1. On-System LNG Facility: As discussed in greater detail 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 safe and reliable service to its customers. Accordingly, the Company has proposed the construction of an on-system LNG facility. This facility would provide a reliable supply source that the Company could call upon in the event of unanticipated supply disruption, line damage, or events caused by forces of nature.

   The Company has set forth a detailed analysis of alternatives evaluated, and all of 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. In an effort to avoid inclusion of Highly Confidential information in this IRP, the Company incorporates that analysis by reference. These are also summarized in the Supply Reliability section of this report.

   The Company has obtained an option to purchase property in the western side of the Salt Lake valley and has completed a Front End Engineering and Design (FEED) study for the facility. The proposed facility would include a 15 million gallon LNG storage tank, gas liquefaction capabilities of 8.2 MMcfd, and vaporization capabilities of 150 MMcfd. Detailed information regarding the costs, schedule and comparison with alternatives can be found in the Company's pre-approval application (DEU 19-057-13).

## INTERMEDIATE HIGH PRESSURE PROJECTS:

1. Belt Main Replacement Program: The Company continued its Belt Main Replacement program in 2019. 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 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 2016 there was approximately 4,300 miles of pre-regulatory (pre-1971) steel main and service lines, some dating back to 1929, that are not currently in the Infrastructure Rate Adjustment Tracker. The Company is currently working towards replacing all 58 miles of its 1929 – 1939 steel IHP main as well. The Company is concerned that the current rate of replacement may be inadequate.

   The Company also has approximately 7,000 miles of Aldyl-A pipe, which is early vintage plastic that has a higher than average leak rate. Because of the 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.

## TRANSPONDER REPLACEMENT PROGRAM:

On January 6, 2018, the Company provided information to the Commission and interested parties relating to its transponder replacement program. Beginning in 2012, the Company began to experience challenges related to non-responsive transponders. Battery degradation in Elster transponders was resulting in an unacceptably high failure rate, and an increase in estimated customer bills. In order to address the matter, the Company determined that it should replace the Elster transponders with Itron transponders. The only alternatives would be to either continue to replace the Elster transponders as they fail, or to increase manual meter reading. Because neither option would fully address the problem, the Company opted to replace all of the transponders proactively.

The Company began installing Itron transponders in November of 2015. To date the Company has completed replacements for about 75% of its customers, including customers located in Bluffdale, Tooele, St George, Park City, Moab, Wyoming, Richfield, Cedar City, and Springville. Eagle Mountain customers already had Itron transponders when the Company purchased the system. Bluffdale, Ogden, Salt Lake, Logan, Vernal, and Price remain to be installed. The Company anticipates completing the project by mid-2020 with a total cost of approximately $70 million. Spending on this project was about $6 million in 2018 and is anticipated to be approximately $11.6 million in 2019 and $5 million in 2020 with first-year revenue requirements of $1,150,000 and $495,000, respectively.

## 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. The Company is evaluating the feasibility of expanding to several interested communities including Green River, Eureka, Kanab, and Rockville/Springdale. The Company will work with each of these communities and complete its analysis in the coming months, and anticipates seeking Commission approval for an expansion project in the fourth quarter of 2019. The Company will provide updates on its analysis and any selected project in the IRP variance report process.

### *Wyoming*

The Company is also working to identify communities in Wyoming that are geographically proximate to the Company's existing system and may be candidates for natural gas service. To date, the Company has identified North Rock Springs, Bear River, and Almy as communities that may be candidates for expansion. The Company is conducting preliminary engineering, analysis of customers in each area, cost- savings over propane to identify the best expansion candidate. The Company will update interested stakeholders in Wyoming to provide updates on the Company's analysis, and to discuss regulatory and legal requirements for proceeding for such an expansion.

# 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.[1]

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.[2] 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.

[1] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operation Pressure (MAOP) at or above a pressure that produces a hoop stress of 20% of Specified Minimum Yield Strength (SMYS)).
[2] 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 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 an HCA and the Company cannot assess the pipe utilizing other methods.

## *Inline Inspection*

When a pipeline has been constructed and configured, or retro-fitted 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 143 miles of transmission piping (18% 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.

| | 2019 | 2020 | 2021 |
|---|---|---|---|
| Transmission Integrity Management Program | 8,014 | 9,303 | 8,298 |
| Distribution Integrity Management Program | 2,483 | 1,689 | 1,689 |
| Total Integrity Management Cost ($ Thousands) | 10,497 | 10,992 | 9,987 |

## KEY PERFORMANCE INTEGRITY METRICS

Table 6.1 details specific performance metrics associated with the transmission integrity management program.

**Table 6.1: HCA Miles Assessed/Anomalies Repaired**

| Year | HCA Miles Assessed | Anomalies Repaired |
|---|---|---|
| 2012 | 26.470 | 28 |
| 2013 | 50.367 | 27 |
| 2014 | 54.555 | 20 |
| 2015 | 11.040 | 2 |
| 2016 | 37.226 | 4 |
| 2017 | 12.935 | 8 |
| 2018 | 30.212 | 9 |
| 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. | | |

## NEW REGULATIONS

The following regulations may have significant impact on the Company:

### *Safety of Gas Transmission and Gathering Lines (Mega Rule)*

PHMSA initially published an advanced notice of proposed rulemaking (ANPRM) for the 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 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 new administration has 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. PHMSA is currently focused on finalizing the first rulemaking, which covers key issues within the Congressional mandate such as MAOP reconfirmation and assessments of pipelines outside of HCAs. PHMSA anticipates the first rule making will be published summer 2019.

If adopted, the proposed rule would require additional 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. This could have a substantial impact on the costs in the integrity management program.

The proposed Mega Rule addresses several integrity management topics, including:

- Revision of integrity management repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies and other defects;

- Codifying functional requirements related to the nature and application of risk models consistent with current industry standard;

- Codifying requirements for collecting, validating, and integrating pipeline data models consistent with current industry standards;

- Strengthening requirements for applying knowledge gained through the integrity management program models consistent with current industry standards;

- Strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference;

- Adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; and

- Codifying requirements for management of change consistent with current industry standards.

With respect to non-integrity management requirements, the proposed Mega Rule would impose:

- A new ‘‘moderate consequence area’’ definition;

- Requirements for monitoring gas quality and mitigating internal corrosion;

- Requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys;

- Requirements for management of change, including invoking the requirements of ASME/ ANSI B31.8S, Section 11;

- Repair criteria for pipeline segments located in areas not in an HCA; and

- Requirements for verification of maximum allowable operating pressure (MAOP) and for verification of pipeline material for certain onshore steel gas transmission pipelines including establishing and documenting MAOP if the pipeline MAOP was established in accordance with §192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP.

The proposed Mega Rule also proposes requirements for additional topics that have arisen since issuance of the ANPRM including:

- Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster or other similar event;

- Allowing extension of the 7-year reassessment interval upon written notice;

- Requiring operators to report each instance when the MAOP exceeds the margin (build-up) allowed for operation of pressure limiting or control devices;

- Adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats;

- Adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities; and

- Incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using inline inspection, internal corrosion direct assessment and stress corrosion cracking direct assessment.

### *Plastic Pipe Rule*

PHMSA published this regulation as a final rule on November 11, 2018 with an effective date of January 22, 2019. The rule amends natural and other gas pipeline safety regulations addressing regulatory requirements involving plastic piping systems used in gas service lines. The amendments permit increasing the maximum pressure and diameter for Polyamide-11 (PA-11) pipe and components; allow the use of newer Polyamide-12 (PA-12) pipe and components; impose new standards for risers and more stringent standards for plastic fittings and joints; require stronger mechanical fitting requirements; incorporate by reference certain new or updated consensus standards for pipe, fittings, and other components; update the qualification of procedures and personnel for joining plastic pipe; the installation of plastic pipe; and include a number of additional general provisions.

### *Valve Installation and Minimum Rupture Detection Standards Rule*

On November 16, 2018, PHMSA issued its latest update pertaining to this rule and indicated that it planned to publish this rule as an NPRM in January 2019. However, to date the NPRM has not been published. This rule is expected to cover rupture detection and response time metrics including the integration of automatic shutoff valves and remote control valves on transmission pipelines with an objective to improve overall incident response.

### *Miscellaneous Rule*

PHMSA published this regulation as a final rule on March 11, 2015, with an effective date of October 1, 2015. One component of this rulemaking includes the performance of post-construction inspections and qualification of plastic pipe joiners. New post-construction inspection could have a significant impact on the Company. PHMSA is currently in the process of developing guidance for the interpretation and implementation on the requirements associated with post-construction inspection. PHMSA has indefinitely extended the effective date for the post-construction inspection requirements. The Company anticipates publication of further guidance in the future.

## 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. As a result of this initiative, the indirect inspection costs are expected to increase in 2019 and 2020.

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

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 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 our knowledge of these pipelines. Testing is scheduled to be completed by year end 2021.

### *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 | 2019 | 2020 | 2021 |
|---|---|---|---|
| **ECDA** | | | |
| Pre-Assessment | | | |
| 2019 (FL18, 21, 29, 70) (14.12 HCA Miles; 29.42 CA Miles @ 0.9 K/mile) | 40 | | |
| 2020 (FL19, 23, 28, 71, 73, 74, 125) (6.69 HCA miles; 9.34 CA miles @ 0.9 K/mile) | | 15 | |
| 2021 (FL64, 65, 66, 68, 69, 83, 84, 99, 104, 40, 78) (1.94 HCA miles; 8.16 CA miles @ 0.9 K/mile) | | | 9 |
| Indirect Inspections | | | |
| 2019 (FL18, 21, 29, 70) (14.12 HCA Miles; 29.42 CA Miles @ 20.5 K/mile) | 893 | | |
| 2020 (FL19, 23, 28, 71, 73, 74, 125) (6.69 HCA miles; 9.34 CA miles @ 20.5 K/mile) | | 329 | |
| 2021 (FL64, 65, 66, 68, 69, 83, 84, 99, 104, 40, 78) (1.94 HCA miles; 8.69 CA miles @ 20.5 K/mile) | | | 207 |
| Direct Examinations | | | |
| 2018 (FL12, 13, 22, 33, 46, 51, 53 ) (6 excavations @ 33 K ea.) | 198 | | |
| 2018 (FL12, 13, 22, 33, 46, 51, 53 ) (Pipetel 2 sites, 2 casings @ 150K/site) | 300 | | |
| 2019 (FL18, 21, 29, 70) (6 excavations @ 33 K ea.) | | 198 | |
| 2019 (FL18, 21, 29, 70) (Pipetel 2 sites, 2 casings @ 150K/site) | | 300 | |
| 2020 (FL19, 23, 28, 71, 73, 74, 125) (6 excavations @ 33 K ea.) | | | 198 |
| 2020 (FL19, 23, 28, 71, 73, 74, 125) (Pipetel 2 sites, 2 casings @ 150K/site) | | | 300 |
| Post Assessment | | | |
| 2018 (FL12, 13, 22, 33, 46, 51, 53 ) (14.0 HCA Miles; 12.83 CA Miles @ 0.6 K/mile) | 16 | | |
| 2019 (FL18, 21, 29, 70) (14.12 HCA Miles; 29.42 CA Miles @ 0.6 K) | | 26 | |
| 2020 (FL19, 23, 28, 71, 74, 125) (6.69 HCA miles; 9.34 CA miles @ 0.6K/mile) | | | 10 |
| **CIS** | | | |
| Indirect Inspections | | | |
| 2019 (FL4/11, 81, 61, 122, 18, 47, 21, 29, 70) (134.8 miles @ 3.91K) | 527 | | |
| 2020 (FL85, 65, 28-6, 19, 23, 28, 71, 74, 125) (96.1 miles @ 4.05K) | | 389 | |
| 2021 (FL64, 65, 10, 23, 66, 68, 69, 83, 84, 99, 104, 40, 73, 78, 35, 39, 49, 67) (178.35 miles @ 3.81K) | | | 680 |
| Reports | | | |
| 2019 (122, 18, 47, 21, 29, 70) (134.8 miles @ 6K Fixed) | 6 | | |
| 2020 (FL19, 23, 28, 71, 74, 125)(96.1 miles @ 6K Fixed) | | 6 | |
| 2021 (FL64, 65, 10, 66, 68, 69, 83, 84, 99, 104) (208.1 miles @ 6K Fixed) | | | 6 |
| **ACCDA** | | | |
| Pre-Assessment | | | |
| 2019 (FL21, 51, 29, 70) (14.2 HCA Miles; 2.2 Distribution IM Miles; 1.2 Additional; Fixed) | 7 | | |
| 2020 (FL19, 23, 28, 71,74, 125) (6.69 HCA miles; Fixed) | | 10 | |
| 2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; Fixed) | | | 13 |
| Indirect Inspections | | | |
| 2019 (FL21, 51, 29, 70) (14.2 HCA Miles; 2.2 Distribution IM Miles; 1.2 Additional @ 18.4 K/mile) | 324 | | |
| 2020 (FL19, 23, 28, 71, 74, 125) (6.69 HCA miles; @ 18.4 K/mile) | | 123 | |
| 2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; @ 18.4k/mile) | | | 36 |
| Direct Examinations | | | |
| 2018 (FL22, 46, 53) (2 excavations @ 33 K ea.) | 66 | | |
| 2019 (FL21, 51, 29, 70) (2 excavations @ 33 K ea.) | | 66 | |
| 2020 (FL19, 23, 28, 71, 74, 125) (2 excavations @ 33 K ea.) | | | 66 |
| Post Assessment | | | |
| 2018 (FL22, 46, 53 ) (10.6 HCA Miles Fixed) | 7 | | |
| 2019 (FL21, 51, 29, 70) (14.2 HCA Miles; 2.2 Distribution IM Miles; 1.2 Additional; Fixed) | | 9 | |
| 2020 (FL19, 23 28, 71, 74, 125) (6.69 HCA miles; Fixed) | | | 11 |
| **ICDA** | | | |
| ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan). | | | |
| **Inline Inspection** | | | |
| 2018 Excavations/ Validations Digs/ Remediation (12 excavations @ 33 K ea) | 198 | | |
| 2019 (FL81) | 250 | | |
| 2019 (FL68) | 500 | | |
| 2019 (FL4) | 250 | | |
| 2019 Excavations/ Validations Digs/ Remediation (12 excavations @ 33 K ea) | 198 | 198 | |
| 2020 (FL85) | | 250 | |
| 2020 (FL65) | | 500 | |
| 2020 (FL71) | | 250 | |
| 2020 (FL28-6) | | 500 | |
| 2020 Excavations/ Validations Digs/ Remediation (16 excavations @ 33 K ea) | | 264 | 264 |
| 2021 (FL64) | | | 500 |
| 2021 (FL64/FL65) | | | 500 |
| 2021 (FL23) | | | 250 |
| 2021 (FL10) | | | 250 |
| 2021 Excavations/ Validations Digs/ Remediation (16 excavations @ 33 K ea) | | | 264 |
| **Direct Examination (Spans and Vaults)** | | | |
| 2019 – Vaults (18 @ 3.5 K/ vault) | 63 | | |
| 2019 – Spans (2 @ 75 K/ span) | 50 | | |
| 2019 – Spans Reassessment (4 @ 10 K/ span) | 40 | 25 | |
| 2020 – Vaults (7 @ 3.5 K/ vault) | | 150 | |
| 2020 – Spans (2 @ 75 K/ span) | | 50 | |
| 2020 – Spans Reassessment (5 @ 10 K/ span) | | | 4 |
| 2021 – Vaults (1 @ 3.5 K/ vault) | | | 75 |

## Transmission Integrity Management Costs

| Activity | 2019 | 2020 | 2021 |
|---|---|---|---|
| **Pressure Test Assessment** | | | |
| 2019 – 0 pipeline segments @ $100,000/segment | 0 | | |
| 2020 – 0 pipeline segments @ $100,000/segment | | 0 | |
| 2021 – 0 pipeline segments @ $100,000/segment | | | 0 |
| **Material Verification** | | | |
| 2019 - (FL014, 23, 26, 41, 69, 85) | 189 | | |
| 2020 - (FL014) | | 45 | |
| 2021 - (FL021) | | | 15 |
| **MAOP Verification MAOP, for MAOP established in accordance with §192.619(c)** | | | |
| 2019 - HYDRO Test (FL021) | 220 | | |
| 2019 - Nitrogen Test (FL021, 23) | 200 | | |
| 2020 - HYDRO Test (FL011, 13, 21, 35, 46, 50) | | 900 | |
| 2020 - Nitrogen Test (FL011, 13, 21, 35, 46, 50) | | 1,100 | |
| 2021 - HYDRO Test (FL004, 21) | | | 600 |
| 2021 - Nitrogen Test (FL021) | | | 500 |
| **Excavation Standby** | | | |
| 6 employees (2,080 hrs x 6 x $60/hr) | 749 | 749 | 749 |
| **Additional Leak Survey** | | | |
| 3 employees (2,080 hrs x 3 x $45/hr) | 281 | 281 | 281 |
| **Additional Cathodic Protection Survey** | | | |
| 2 employees (2,080 hrs x 3 x $60/hr) | 250 | | |
| **Administration** | | | |
| Project Coordination (5 employees (2,080 hrs x 5 x $60/hr)) | 624 | 624 | 624 |
| Data Integration Specialists (2 employees (2,080 hrs x 2 x $60/hr)) | 250 | 250 | 250 |
| Construction Records Tech (2,080 x $45/hr) | 94 | 94 | 94 |
| Supervisor (2,080 hrs x $60/hr) | 125 | 125 | 125 |
| Engineer (4 employees (2,080 hrs x 3 x $60/hr)) | 500 | 500 | 500 |
| IM Engineer – Engineer Tech (1 employee (2,080 hrs @ $ 50/hr)) | 104 | 104 | 104 |
| Damage Prevention Tech (1 employees (2,080 hrs x $45/hr)) | 94 | 94 | 94 |
| New Position – Damage Prevention Tech (2 employees (2,080 hrs @ $45/hr) (¾ year 2019)) | 141 | 188 | 188 |
| New Position – Data Integration Specialists (2,080 hrs x $60/hr) | | 125 | 125 |
| Training (for IM and Engineering personnel $4,000 x 13 employees) | 52 | 52 | 52 |
| Consultant – ILI run comparison analysis | 56 | | |
| Consultant – 3rd Party Review | | 60 | |
| **Transmission Integrity Management Total ($ Thousands)** | 8,014 | 9,303 | 8,298 |

## Distribution Integrity Management Costs

| Activity | 2019 | 2020 | 2021 |
|---|---|---|---|
| **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) | 0 | 0 | 0 |
| Additional Leak Survey | 85 | 85 | 85 |
| Damage Prevention (IHP Standby) | 1,323 | 1,323 | 1,323 |
| Meter Paints | 281 | 281 | 281 |
| **CIS/ECDA** | | | |
| Indirect Inspections | | | |
| 2019 (FL97, 98, 110, 42 Tap, FL7 Sandy)(61.9 miles @ 6k fixed) | 743 | | |
| Reporting | | | |
| 2019 (FL97, 98, 110, 42 Tap, FL7 Sandy)(61.9 miles @ 12K) | 6 | | |
| **Administration** | | | |
| Consultant - 3rd Party Plan Review | 45 | | |
| Distribution Integrity Management Total ($ Thousands) | 2,483 | 1,689 | 1,689 |

# ENVIRONMENTAL REVIEW

The Company is committed to compliance with environmental laws and regulations. Some of the 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 that can be more strict than their federal counterparts.

Agencies issuing permits and enforcing these regulations frequently place restrictions on the Company's activities. Requirements are becoming more stringent over time and can affect the location and construction of the Company's infrastructure. When projects impact environmental resources, regulatory agencies require studies, consultations, permit applications, agency review, and public comment periods prior to permit approval. Permit conditions can be rigorous and costly, requiring compliance activities long after project completion. Monitoring may be required during the entirety of installation.

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. Such restrictions can delay or prohibit access to or use of subject land. Because the Company infrastructure crosses many miles of federal and state lands that include the critical habitat of protected plant and animal species, there can be a material impact on the location of pipeline facilities and construction schedules.

The Clean Water Act and similar state laws regulate discharges of storm water, hydrostatic test water, wastewater, and other pollutants to surface water bodies such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges or accidental releases could result in civil and criminal penalties, orders to cease such discharges, corrective actions, and other costs and damages.

Pre-existing conditions complicating project construction include situations where the Company's pipelines, both new and existing, cross contaminated sites owned by third parties. In many cases, these sites have not been reported to regulatory agencies by the prior owner, and in some cases the boundaries of the sites are unknown, resulting in unforeseen construction interruptions as the Company consults with the regulators on proper remedial activities. Where they have been reported, the sites, are usually regulated by the CERCLA or comparable state regulations, and require corrective actions as construction activities proceed.

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. All of these activities result in escalated project costs, and potential route adjustments. Accidental spills and releases requiring cleanup may also occur in the ordinary course of business, requiring remediation. The Company may incur substantial costs to take corrective actions in any of these cases. Failure to comply with these laws and regulations can result in fines as well as significant costs for remedial activities or injunctions.

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 special considerations and public outreach is incorporated into projects during the planning stages.

New and revised environmental policy is affecting the industry and the Company specifically, and will result in additional costs to conduct business. For example, federal and state courts and administrative agencies are addressing claims and demands related to climate change under various laws pertaining to the environment, energy use, and development.

In 2010, the EPA adopted Greenhouse Gas (GHG) Reporting Regulations requiring the measurement and reporting of carbon dioxide equivalent (CO2e) emissions emitted from combustion at large facilities (emitting more than 25,000 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. In 2018, the Company reported a total of 6.7 million metric tons of CO2e emissions in Utah and 233 thousand metric tons of CO2e emissions in Wyoming. The Company also reported approximately 94 thousand metric tons attributed to fugitive methane sources in Utah and zero fugitive methane emissions in Wyoming. Figure 7.1 shows the Company's CO2 emission rate per million BTU (greenhouse gas intensity) over the last five years.

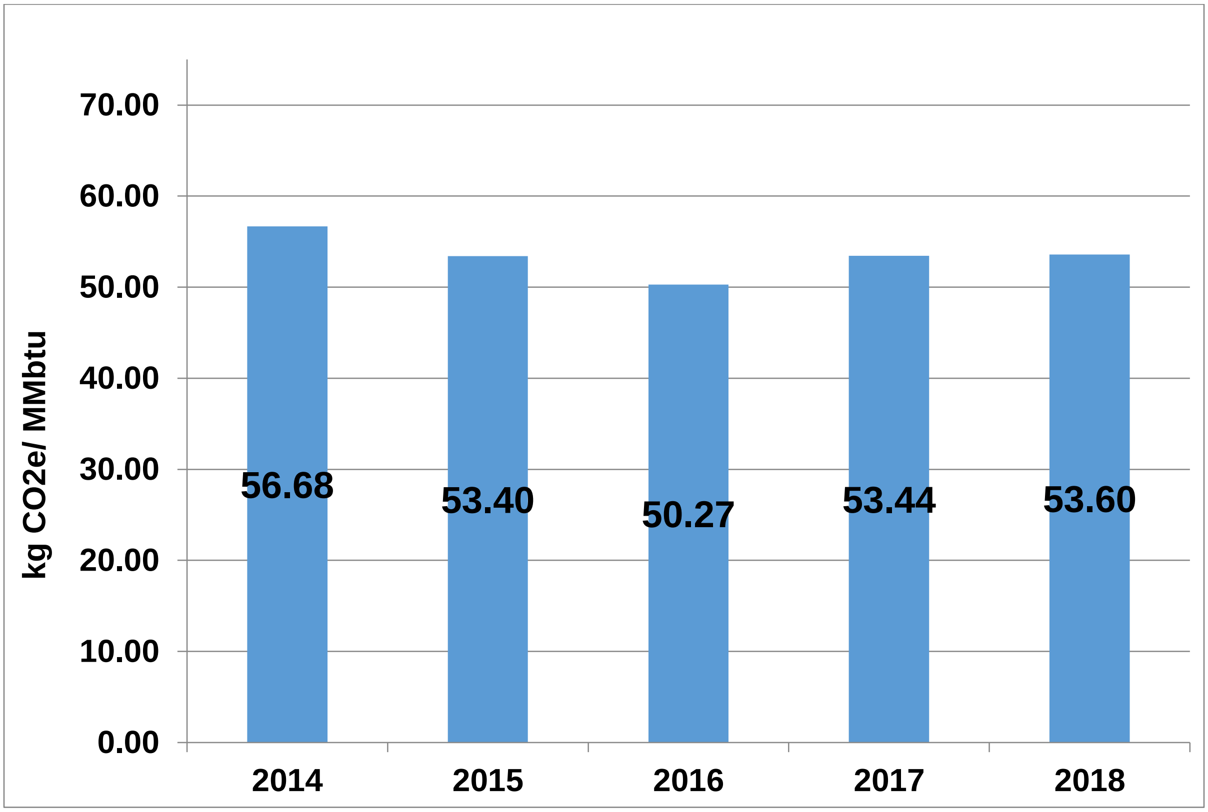



**Figure 7.1: Greenhouse Gas Intensity**

In March 2016, the Company became a Founding Partner with the EPA in the Natural Gas STAR Methane Challenge Program, committing to voluntary practices that will reduce methane emissions.

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.

Conservation efforts will also continue to have a positive environmental impact. For example, the Company estimates annual savings of more than 6 MMDth of natural gas from 2007 to 2017. The savings represents the equivalent of about 318,000 metric tons of $CO_2e$ or 67,541 passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime savings attributable to the ThermWise® program totals more than 3.4 million tons of $CO_2e$ or the equivalent of about 74,300 passenger vehicles each driven for one year.

# PURCHASED GAS

## LOCAL MARKET ENVIRONMENT

Local prices during the 2018 calendar year averaged $2.63 per Dth. This was lower than the 2017 average price of $2.74 per Dth, a decrease of $0.11 per Dth or about 9.6%. The 2017 and 2018 monthly index prices are provided in Table 8.1 below.

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

| Month | 2017 | 2018 | Difference |
|---|---|---|---|
| Jan | $3.73 | $2.50 | ($1.23) |
| Feb | $3.11 | $2.80 | ($0.31) |
| Mar | $2.29 | $2.17 | ($0.12) |
| Apr | $2.64 | $1.85 | ($0.79) |
| May | $2.62 | $1.90 | ($0.72) |
| Jun | $2.79 | $2.09 | ($0.70) |
| Jul | $2.63 | $2.24 | ($0.39) |
| Aug | $2.59 | $2.41 | ($0.18) |
| Sep | $2.59 | $2.32 | ($0.27) |
| Oct | $2.48 | $2.32 | ($0.16) |
| Nov | $2.63 | $3.23 | $0.60 |
| Dec | $2.73 | $5.70 | $2.97 |
| Average | $2.74 | $2.63 | ($0.11) |

The local market price for natural gas during the 2018-2019 heating season (November-March) averaged $4.06 per Dth compared to an average price of $2.57 per Dth during the 2017-2018 heating season, an increase of $1.49 or about 158%. 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 | 2017-2018 | 2018-2019 | Difference |
|---|---|---|---|
| Nov | $2.63 | $3.23 | $0.60 |
| Dec | $2.73 | $5.70 | $2.97 |
| Jan | $2.50 | $4.22 | $1.72 |
| Feb | $2.80 | $3.38 | $0.58 |
| Mar | $2.17 | $3.77 | $1.60 |
| Average | $2.57 | $4.06 | $1.49 |

April 2019 PIRA Energy Group (PIRA) and IHS Energy (IHS) forecasts of Rockies indices reflect an average price of approximately $2.50 per Dth through October 2019. Prices for the 2019-2020 heating season are forecasted to be approximately $2.79 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 (approximately 55-65%) 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 25, 2019, the Company sent its RFP to 58 prospective suppliers. The RFP sought proposals for both baseload and peaking supplies on the two major interstate pipeline systems interconnected with the Company; DEQP 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 (Ryckman), and other locations that were determined to be operational needs.

Reliability of supplies is a critical issue for the Company. In its RFP, the Company required that all seasonal purchase contracts have language specifying liquidated damages of $15.00 per Dth for failure to perform. The Company required all proposals to have language ensuring creditworthiness and language specifying the minimum advance notice before nomination deadlines for gas flow.

Responses to the purchased-gas RFP were due on March 8, 2019. The Company received proposals for 183 gas supply packages from 11 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 380,000 Dth/D, down from the 450,000 Dth/D offered last year. Peaking supplies offered on the DEQP system totaled 130,000 Dth/D, down from the 200,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 390,000 Dth/D, down from last year's level of 445,000 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.[1] The Company must identify the pricing mechanisms utilized for each package and link each to the appropriate index price in the model. Also, the Company must resolve the 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

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

term packages, the Company must identify each to prevent the purchasing of more gas than is actually available. This year, the SENDOUT model evaluated 183 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 1,194 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 DEQP 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.

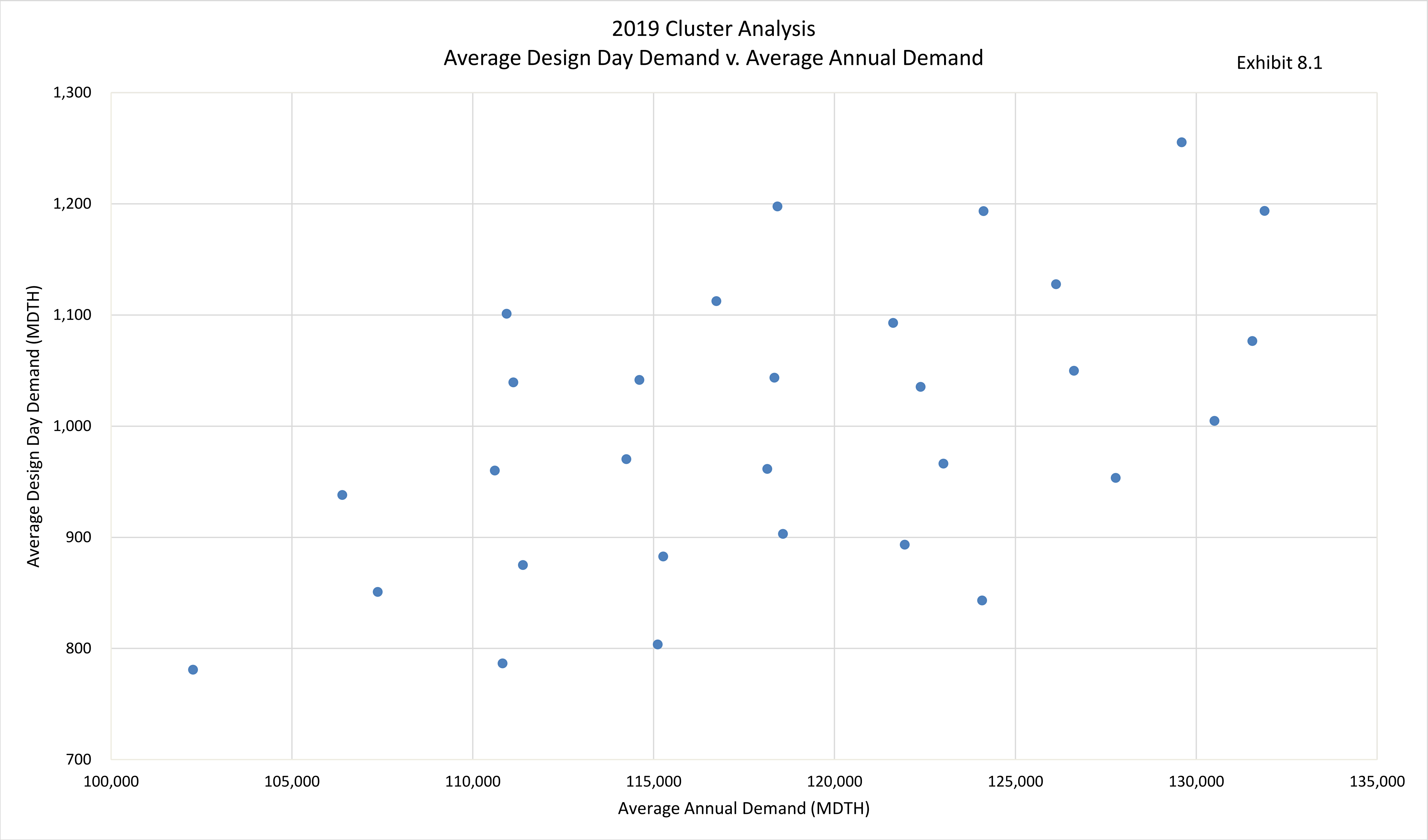
The levels of purchased-gas packages selected from the SENDOUT modeling process this year are shown in the Final Modeling Results section of this report. The median purchased-gas volumes from the Monte Carlo simulation for the upcoming gas-supply year are shown by month in Exhibits 13.53 to 13.64 along 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 11 companies submitting proposals this year, 6 had at least one package selected by the modeling process. The Company made commitments to purchase from the selected suppliers starting on April 28, 2019. The Company is in the process of finalizing the agreements with a few of the counterparties that had packages selected in the RFP. The Company will make purchase commitments for these packages once the agreements are in place.

## 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 October 2018 - March 2019 time period, the Company did not hedge the price of any of its baseload purchased gas supplies because of the forecasted level of cost-of-service gas in the supply portfolio. Given the current forecast for cost-of-service production, the Company does not plan to enter into any fixed-price agreements designed to hedge the price of its baseload purchased gas supplies during the next IRP year, but may do so in the future.


2019 Cluster Analysis
Average Design Day Demand v. Average Annual Demand
Exhibit 8.1
Average Design Day Demand (MDTH)
1,300
1,200
1,100
1,000
900
800
700
100,000
105,000
110,000
115,000
120,000
125,000
130,000
135,000
Average Annual Demand (MDTH)

# 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, which historically has been lower-priced than market-based sources. 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 65% of the forecasted demand for the Company's sales customers each IRP year. In calculating the production percentage, pursuant to the Trail Stipulation, the total wellhead volume of cost-of-service production received as part of the Wexpro I and Wexpro II Agreements will be divided by the total forecasted demand for the Company's sales customers as provided in each year's IRP (see Exhibit 3.10). Wexpro may also sell cost-of-service production in order to manage to the 65% level. 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 (currently 7.64%). The pre-2016 investment base and returns will not be affected.

- Wexpro will reduce 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%.

During calendar year 2018, Wexpro produced 73.3 MMDth of cost-of-service supplies measured at the wellhead, up from the 69.5 MMDth level produced during calendar year 2017. 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 2017 to 2018, the total costs, net of credits and overriding royalties, for cost-of-service production declined by approximately 16.1% (the fourth consecutive year of declining net costs). This decrease was caused primarily by a 19.3% reduction in the Wexpro operating service fee. This was partially offset by two cost components. First, the development-gas cost-of-service component increased by approximately 10.3%. Second, Wexpro’s gathering costs increased by approximately 13.27%. More information on Wexpro’s planned development-drilling programs is 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 123 categories of cost-of-service production. Last year, it modeled 113 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.

As discussed in the Introduction to this report, 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.[1] 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 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 1,635 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 cause extensive delays for all the wells planned for the site, or can 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 multiplicity 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

[1] 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.

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 2018 and for the first two months of 2019. The Company has been taking recoupment in the Canyon Creek and Moxa Arch areas for the entire January 2018 through February 2019 period. The Company also took recoupment from the Church Buttes field the months of January 2018 through March 2018, Pinedale area the months of May 2018 through February 2019, and from one well in the Butcherknife area January 2018 and February 2018.

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 March of 2015, ending in September 2018. Recoupment from the Company occurred in the Canyon Creek field during September and October 2018 and from Pinedale from August 2018 through February 2019. In the Moxa Arch field, recoupment from the Company has been occurring for several years.

As of December 31, 2018, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of a negative 0.7 Bcf.[2] By way of comparison, the total net producer imbalance level for December 31, 2017 was a negative 0.9 Bcf. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In a recent audit report, the Hydrocarbon Monitor did not express any concerns about the total producer imbalance levels.[3]

## FUTURE RESOURCES

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

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

There can be other factors affecting the rate of leasehold development. For example, the Company's customers benefit from the receipt of significant quantities of cost-of-service production from wells in the Pinedale Anticline Project Area (PAPA) in Sublette County, Wyoming. Development in the PAPA is governed by a Record of Decision (ROD), issued by the U.S. Department of Interior, Bureau of Land Management during September of 2008. The ROD was issued in response to certain environmental mitigation measures and operational safeguards proposed by the partners in PAPA.[4]

As a means of minimizing environmental impacts, the Pinedale ROD, in an orderly and systematic way, allows for concentrated development by limiting the number of well pads and requiring the maximum use of existing well pads before constructing new well pads. Operators are required to "stay on a well pad until the well pad is completely drilled out".[5] Drilling is fundamentally sequential with time limitations for development in certain areas.

[2] A positive imbalance means volumes are owed to other parties.
[3] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, May 2019.
[4] Record of Decision for the Supplemental Environmental Impact Statement, Pinedale Anticline Oil and Gas Exploration and Development Project, U.S. Department of the Interior, Bureau of Land Management, Cheyenne Wyoming, September 12, 2008.
[5] Ibid., Summary, Page 20.

Wexpro's focus is to maintain its long-term drilling plans, thereby continuing to benefit the Company's customers. For calendar year 2019, Wexpro plans on completing to production, approximately 4.8 net wells with a capital budget for those wells of approximately $13 million.[6] Assuming market prices don't deviate dramatically from current expectations for the years 2020 through 2024, the total planned net wells are approximately 14, 21, 19, 19, and 19 respectively, with total annual investments in the range of $14 to $29 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2019 is expected to focus in the Mesa/Pinedale area.

Wexpro does not plan to conduct any Wexpro II drilling in 2019. Wexpro II drilling plans for 2020 through 2024, broken out from the total net wells stated above, are for approximately 5, 9, 15, and 11 net wells respectively to be drilled with total annual capital costs ranging from approximately $8 million to $21 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.

Based on the 2018 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 652 MDth of cost-of-service production shut-in for June 2018 through October 2018. As shown in Table 9.1, the Company shut-in approximately 1,678 MDth of cost-of-service production during June 2018 through October 2018.

**Table 9.1: 2018 Production Shut-ins**

| | June | July | August | September | October | Total |
|---|---|---|---|---|---|---|
| Forecasted Shut-in Production | 46, 459 Dth | 334,189 Dth | 233,673 Dth | 46,848 Dth | 0 Dth | **661,169 Dth** |
| Actual Shut-in Production | 190,784 Dth | 474,300 Dth | 474,300 Dth | 459,000 Dth | 79,500 Dth | **1,677,884 Dth** |

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

Based on the 2019 forecast for production provided by Wexpro and normal weather, the model determined that there should be 430 MDth of cost-of-service production shut-in for June 2019 through October 2019.

**Table 9.2: 2019 Production Shut-ins**

| | June | July | August | September | October | Total |
|---|---|---|---|---|---|---|
| Forecasted Shut-in Production | 0 Dth<br>(0 Dth/day) | 0 Dth<br>(0 Dth/day) | 430,170 Dth<br>(13,876 Dth/day) | 0 Dth<br>(0 Dth/day) | 0 Dth<br>(0 Dth/day) | **430,170 Dth**<br>**(13,876 Dth/day)** |

**Exhibit 9.1**

**Recoupment Nominations (Dth per month by Field)**
**Dominion Energy**

| | Moxa | Butcherknife | Church Buttes | Canyon Creek | Pinedale |
|---|---|---|---|---|---|
| Jan-18 | 5,363 | 217 | 49,941 | 15,810 | 0 |
| Feb-18 | 4,844 | 105 | 46,934 | 14,644 | 0 |
| Mar-18 | 5,261 | 0 | 47,020 | 16,335 | 0 |
| Apr-18 | 5,228 | 0 | 0 | 15,355 | 0 |
| May-18 | 4,206 | 0 | 0 | 13,476 | 1,700 |
| Jun-18 | 4,217 | 0 | 0 | 12,902 | 1,700 |
| Jul-18 | 4,030 | 0 | 0 | 13,238 | 1,520 |
| Aug-18 | 3,778 | 0 | 0 | 10,588 | 3,284 |
| Sep-18 | 3,327 | 0 | 0 | 12,326 | 4,301 |
| Oct-18 | 3,791 | 0 | 0 | 12,313 | 6,787 |
| Nov-18 | 3,790 | 0 | 0 | 16,182 | 6,742 |
| Dec-18 | 3,891 | 0 | 0 | 18,270 | 7,423 |
| Jan-19 | 3,816 | 0 | 0 | 16,419 | 7,223 |
| Feb-19 | 1,115 | 0 | 0 | 14,286 | 6,967 |
| Total | 56,657 | 322 | 143,895 | 202,142 | 47,647 |

**Recoupment Nominations (Dth per month by Field)**
**Other Parties**

| | Canyon Creek | Hiawatha Deep | Moxa | Pinedale |
|---|---|---|---|---|
| Jan-18 | 0 | 396 | 6,820 | 0 |
| Feb-18 | 0 | 304 | 3,248 | 0 |
| Mar-18 | 0 | 726 | 4,737 | 0 |
| Apr-18 | 0 | 933 | 4,664 | 0 |
| May-18 | 0 | 964 | 4,300 | 0 |
| Jun-18 | 0 | 467 | 3,233 | 0 |
| Jul-18 | 0 | 482 | 5,403 | 0 |
| Aug-18 | 0 | 482 | 4,705 | 5,083 |
| Sep-18 | 63,567 | 0 | 4,144 | 10,061 |
| Oct-18 | 65,335 | 0 | 3,473 | 14,404 |
| Nov-18 | 0 | 0 | 3,575 | 13,901 |
| Dec-18 | 0 | 0 | 4,050 | 14,855 |
| Jan-19 | 0 | 0 | 3,223 | 15,311 |
| Feb-19 | 0 | 0 | 3,231 | 14,827 |
| Total | 128,902 | 4,755 | 58,806 | 88,442 |

# 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 majority of the cost-of-service production is gathered under the System-Wide Gathering Agreement (SWGA), 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.

The Company includes cost data for the gathering and processing functions each year in the SENDOUT modeling process. The Company used the rates from the amended SWGA in this year's 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 DEQP, KRGT, Northwest Pipeline, and Colorado Interstate Gas (CIG).

### *Dominion Energy Questar Pipeline*

The Company has three transportation contracts with DEQP for 798,902 Dth/D (Contract #241), 12,000/87,000 Dth/D (Contract #2945 – volume changes seasonally) and 30,000 Dth/D (Contract #2361). In March, 2017 the Company extended Contract #241 for 798,902 Dth/D until June 30, 2027. This contract provides capacity from multiple receipt points, including Clay Basin, Vermillion Plant, Blacks Fork Plant, Emigrant Trail Plant, Kanda, and interconnects with Northwest Pipeline, Overthrust Pipeline, and White River Hub. With this extension, the Company also signed a Precedent Agreement to upgrade the Hyrum Gate station and expand the total capacity by 100,000 Dth/D. Simultaneously, the Company and DEQP entered into a Facilities Agreement that obligates DEQP to construct at least

$5,000,000 of delivery point upgrades for the Company. These would normally be paid for by DEU.

The expansion of the Hyrum gate station and associated capacity will provide necessary increased supplies to the northern area of the Company's distribution system. DEQP will complete the upgrades in 2019 and the capacity will be available for the 2019-2020 heating season. The Company is replacing FL23 starting in 2019 which will increase the takeaway capacity from the station and increase pressures in the area as discussed in the System Capabilities and Constraints section of this report.

Contract #2945 entered into year-to-year evergreen on March 31, 2018 and renewed for another year under this evergreen provision again in March 2019. This contract provides seasonal capacity with valuable receipt points. It also provides the summertime capacity necessary to transport supplies to the Spire Storage West (formerly Ryckman Creek) storage facility for injections. Contract #2361 expires on November 1, 2021. This contract provides capacity to serve the Company's southern HP system.

### DEQP Rate Adjustment Filing

In response to the FERC Final Rule to address the impact of the federal Tax Cuts and Jobs Act of 2017,DEQP filed a statement explaining why a rate adjustment is not needed and was not required by the FERC to reduce rates.

### No-Notice Transportation Service

DEQP provides No-Notice Transportation (NNT) service pursuant to its FERC Gas Tariff and the NNT Service Agreement, as amended, between DEQP and the Company. DEQP's NNT Service is offered as an enhanced service to supplement its firm transportation service. NNT service utilizes the contracted reserved daily capacity (RDC) of the underlying firm transportation service (T-1) and offers additional flexibility in intraday variation of the supply and demand of that transportation. Specifically, NNT service allows the Company's level of supply to adjust in real time, subject to certain constraints as described herein, to accommodate the increases or decreases in demand throughout the Gas Day.

Under the NNT rate schedule, the Company may nominate transportation capacity the day before the gas flows to reserve sufficient capacity and provide adequate variable sources of supply to match any change in demand. NNT adjustments for increased demand through the Gas Day, which do not cause flow to exceed the associated T-1 RDC are considered firm; however, NNT adjustments which cause the flow to exceed the T-1 RDC on an hourly basis are only offered subject to pipeline operational capacity availability. 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 358 days during the 2018-2019 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 212 days during the 2018-2019 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 146 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 109,175 Dth with an average daily supply reduction to the city gate of 30,371 Dth. The maximum daily supply increase to the city gates was 203,542 Dth with an average daily increase to the city gate of 47,393 Dth. The NNT usage for the 2018-2019 IRP year is shown in Figure 10.1 below.

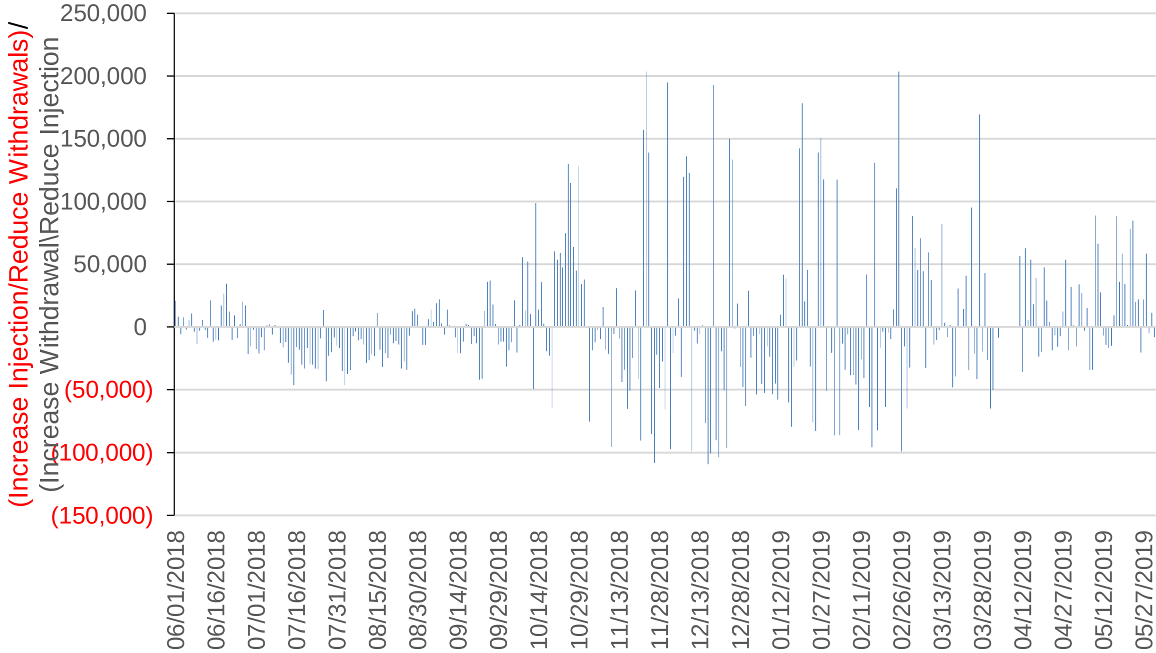



**Figure 10.1: NNT Usage – 2018-2019 IRP Year**

As part of NNT service, DEQP'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 DEQP 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. This analysis is part of the JOA process described in the System Capabilities and Constraints section of this report.

## *Kern River Gas Transmission*

The Company has two existing transportation contracts with KRGT for 83,000 Dth/D (Contract #20029) and 1,885 Dth/D (Contract #1829). 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.

The current term expiration for Contract #1829 is November 1, 2020. Contract renewal requires notice to KRGT one year prior to expiration. This contract will be eligible for renewal for either 10 or 15 years at either Period 2 or Alternate Period 2 rates. The Company plans to evaluate the options to determine the alternative most beneficial to customers and renew this contract prior to October, 31 2019.

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.

### Kern River Gas Transmission Rate Case Settlement

On October 11, 2018, in response to the FERC Final Rule to address the impact of the federal Tax Cuts and Jobs Act of 2017, KRGT filed both its FERC Form No. 501-G and a Stipulation and Agreement of Settlement designed to provide a rate credit against the Maximum Base Tariff Rate for firm service and any one-part rate that includes fixed costs, until a "triggering event" occurs.

In its FERC Form No. 501-G filing, KRGT states that its return on equity (ROE) was 12.5% after adjustments were made to the 21.4% ROE stated in its 501-G form. The 12.5% ROE included adjustments for the impact of levelized rate design and for the removal of Alternate Period Two prior period adjustments. KRGT also stated that "FERC Form No. 501-G does not reflect the change in circumstances on Kern River" due to it being based on 2017 historical data. KRGT indicated that it was not reflective of then-current condition due to the amount of capacity that had not been recontracted on a long-term basis, or at rates differing from the tariff rates. KRGT also claimed increased competition for transportation of natural gas to Southern California and lower market value of capacity on their pipeline as reasons for the difference.[1]

The Stipulation and Agreement of Settlement, proposed an 11% rate reduction in the form of a credit by reflecting a decrease in the federal corporate tax rate for shippers paying the maximum base tariff rate, or any one-part rate that includes fixed costs. This rate reduction would remain in effect until a "triggering event" occurs, meaning either (1) the federal corporate income tax rate is raised above 21 percent, in which case the proposed tax reform credit will be reduced on a pro rata basis by the increase above 21 percent as a percentage of the initial corporate income tax reduction of 14 percent from 35 percent to 21 percent, or

[1] Letter from Kern River Gas Transmission Company to the FERC dated October 11, 2018 Re FERC Form 501-G, Docket No. 19-076-000, page 17.

(2) the Commission initiates an NGA section 5 proceeding against Kern River. All impacted Kern River shippers either supported or did not oppose the Stipulation and Agreement of Settlement.[2] On November 15, 2018, The FERC issued an order approving the settlement.[3]

### 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, 2024. 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 4, 2017. These segmentation contracts have no additional reservation costs, but 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, WY 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.

[2] *Ibid.*
[3] Order Approving Settlement Issued November 15, 2018 Re FERC Form 501-G, Docket No. 19-076-000.

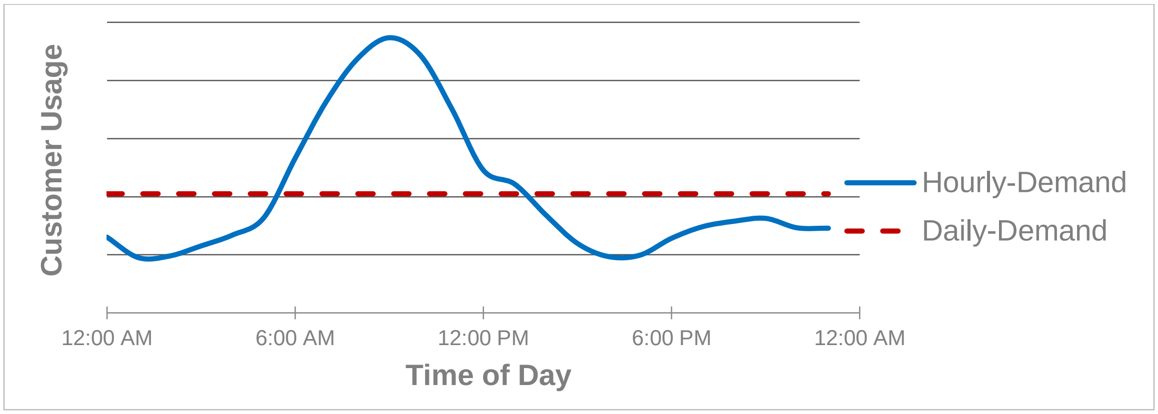



**Figure 10.2: Hourly vs. Daily Demand**

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 315,881 Dth/day during the 2019-2020 heating season to 347,567 Dth/day during the 2028-2029 heating season.

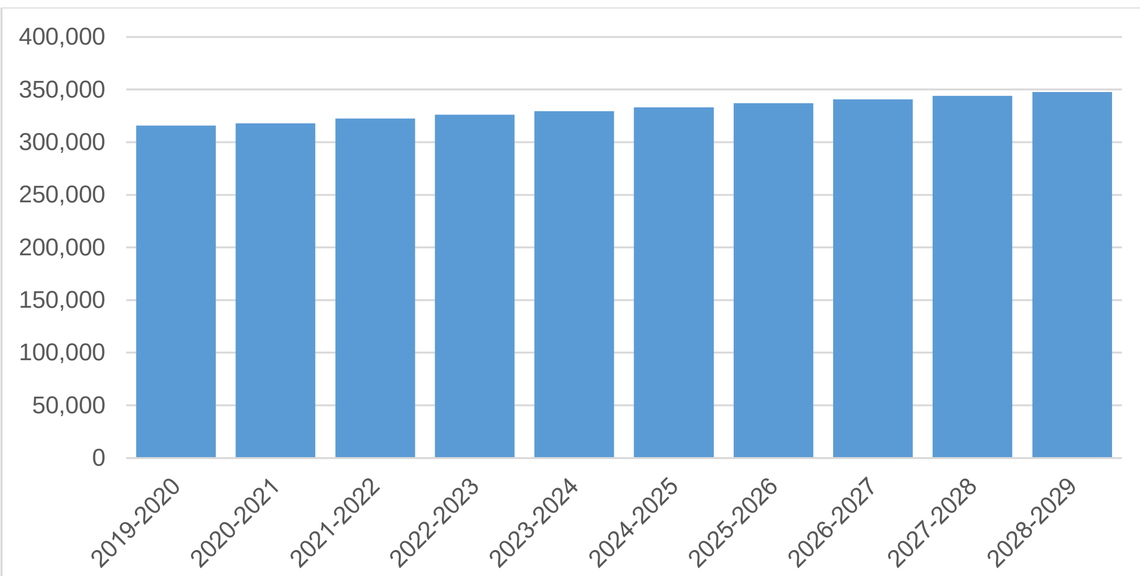



**Figure 10.3: Peak-Hour Demand Requirements above Firm Capacity**

The Company evaluated several options for meeting the peak-hour demand requirements and determined that the Firm Peaking Services offered by both KRGT and DEQP are currently the most cost-effective and reliable solution. The Company believes it has adequate contracts in place to cover its peak hour needs during the 2019-2020 IRP year. In 2019, the Company will again review available options for meeting peak-hour demand requirements in order to determine the most cost-effective and reliable solution going forward in future years.

### *Kern River Gas Transmission*

The Company has a contract with KRGT for 25,002 Dth of Firm Peaking Service for November 15, 2018 to February 14, 2019 and 28,752 Dth of Firm Peaking Service from November 15, 2019 to February 14, 2020. The KRGT Firm Peaking Service for 25,002 Dth allows the Company to flow 4,167 Dth/hr during the 6 peak hours (25,000/6 = 4,167). In order to get the same 4,167 Dth/hr flow on a standard transportation capacity contract, the contract would need to be for 100,008 Dth/day (4,167 x 24 = 100,008). This contract is cost effective because it allows the Company to pay for capacity during the peak hours when it is needed instead of paying for the capacity all day. This Firm Peaking Service for the remaining term of Nov 15, 2019 through Feb 14, 2020 will 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.

### *Dominion Energy Questar Pipeline*

The Company had Peak Hour contracts in place with DEQP for the 2017-2018 heating season which provided 250,000 Dth/day of maximum flow rate during peak hours. Specifically, these contracts allowed for 190,000 Dth/day of maximum flow rate with delivery to MAP 164 and 60,000 Dth/day of maximum flow rate to other DEU delivery points on the DEQP system. In November, 2018 the Company renewed the contract with DEQP for Firm Peaking Service for November 15, 2018 to February 14, 2019 and November 15, 2019 to February 14, 2020, respectively. The extensions were for 150,000 Dth/day of maximum flow rate with delivery to MAP 164 and 49,000 Dth/day of maximum flow rate to other DEU delivery points on the DEQP system for the 2018-2019 heating season, and for 142,000 Dth/day of maximum flow rate with delivery to MAP 164 and 49,000 Dth/day of maximum flow rate to other DEU delivery points on the DEQP system for the 2019-2020 heating season. These contracts have year-to-year evergreen renewal provisions and require 365 days of notice for termination. DEU will reevaluate its Firm Peaking Service options with DEQP prior to November, 2020.

## STORAGE SERVICES

The Company holds firm contracts for storage services with DEQP 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 Ryckman Creek on April 1, 2017.

DEQP 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.

DEQP 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.

Between October 1, 2018 and April 30, 2019, the Company utilized the Clay Basin storage facility to provide more than 11,874 MDth of supply to meet customer demand. This included 56 days with withdrawals that exceeded 100 MDth and 17 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 51 days of injection during this period.

## *Leroy and Coalville Storage*

Since 2000, the operation of the Leroy and Coalville storage facilities have been modified to provide more flexibility and enhance storage efficiency. 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 DEQP’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, DEQP 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*

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, DEQP 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 DEQP requested from the FERC and was 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.

## *2017-2018 Aquifer Usage*

During the 2018-2019 heating season, the Company used the Aquifers to provide supply during periods of cold temperatures in 2018-2019 heating season in October, December, January, and February. All of the Aquifer's deliverability will be required to provide 135 MDth of supply on a Design Day.

In order to continue to provide operational flexibility during the Clay Basin testing period in April 2019, the Company withdrew inventory from the Aquifers in March. The Company adjusted the inventory in the Aquifers in order to provide maximum flexibility during the Clay Basin test in April.

The Company was able to utilize the Aquifers for both injection and withdrawal during this time period as shown in Figure 10.4 below. This flexibility is critical to operations when Clay Basin is not available.

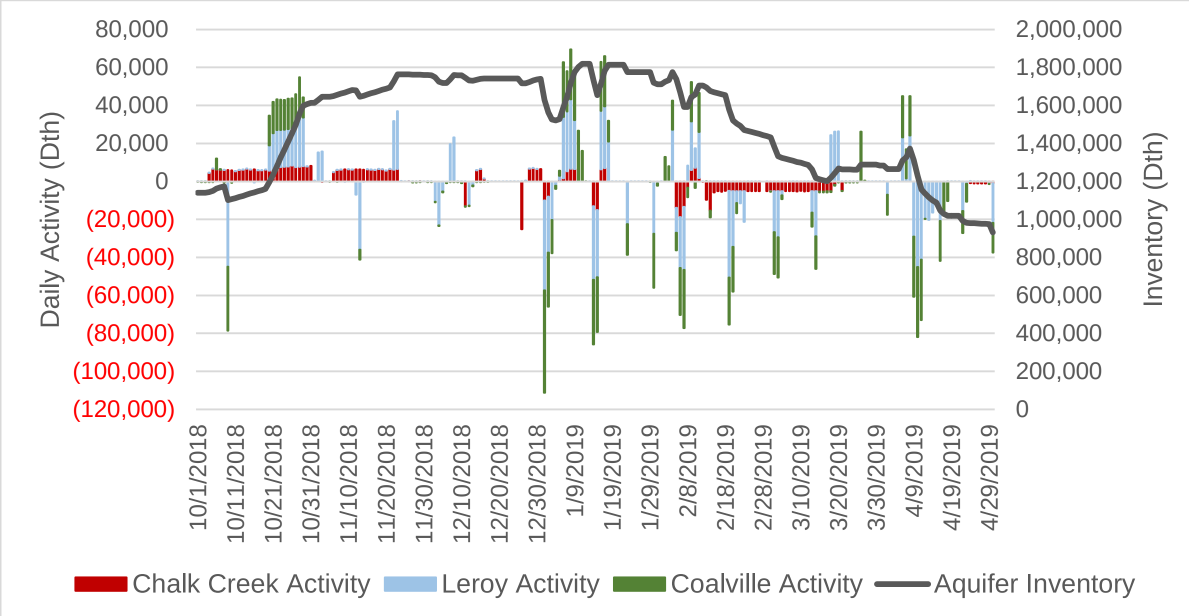



**Figure 10.4: Aquifer Usage 2018-2019 Heating Season (Oct 2018 through April 2019)**

## *Spire Storage West (formerly Ryckman Creek) Gas Storage*

The Spire Storage West storage facility involves the utilization of a partially depleted oil and gas field located approximately 25 miles southwest of the Opal Hub in southwestern Wyoming. The facility interconnects with KRGT, DEQP, Northwest Pipeline, Overthrust Pipeline, and the Ruby Pipeline.

Effective April 18, 2011, the Company entered into a Firm Gas Storage Service Precedent Agreement with Ryckman for 2.5 MMDth of storage capacity.

On December 27, 2017, Belle Butte LLC, an indirect, wholly-owned subsidiary of Spire Inc., acquired a controlling interest in Ryckman Creek Resources, LLC ("Ryckman Creek"). Ryckman Creek subsequently changed its name to Spire Storage West LLC (Spire Storage West). Since taking ownership of the facility, management of Spire Storage West has made a number of changes. One significant change is that the former management of the facility reported the total working gas of capacity at 35 Bcf. Management of Spire Storage West will report the working gas capacity as 19 Bcf until it can confirm additional working gas capacity is available. [4]

Another significant change occurred in May, 2018, when Belle Butte II, LLC, another indirect, wholly-owned subsidiary of Spire, acquired all of the membership interests in Clear Creek, resulting in Spire Storage West and Clear Creek becoming affiliates. Clear Creek

[4] Letter from Spire Storage West to FERC Spire Storage West LLC – Notice Regarding Storage Capacity Development, dated July 26, 2018, Docket No. CP11-24-000.

owns and operates interstate natural gas storage facilities located in Uinta County, Wyoming. Since these two facilities are only about 6 miles apart, and they serve the same markets, Spires Storage West plans to combine the two companies and operate the storage facilities as one integrated facility called Spire Storage West. The combined working gas capacity of the facility will be 39 Bcf with 385 MMcf/D of maximum injection capability and 530 MMcf/D of maximum withdrawal capacity. [5]

Between October 1, 2018 and April 30, 2019, the Company utilized the Spire Storage West storage facility to provide 1,900,775 MDth of supply to meet customer demand. This included 113 days of withdrawals at the contract maximum withdrawal rate of 16.6 MDth. Spire Storage West also supplied operational flexibility by providing 16 days of injection during this period. During this period there were no operational issues at the facility that resulted in an inability to perform.

### *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, 2019 would be approximately 2.00 Bcf.

## RELATED ISSUES

### *Gas Quality/Interchangeability*

Almost all of the gas delivered to the Company's system comes from interstate pipelines (DEQP, 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.[6] 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 2018.The daily averages for 2018 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

[5] Spire Storage West 166 FERC ¶ 62,038 FEDERAL ENERGY REGULATORY COMMISSION
[6] 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.

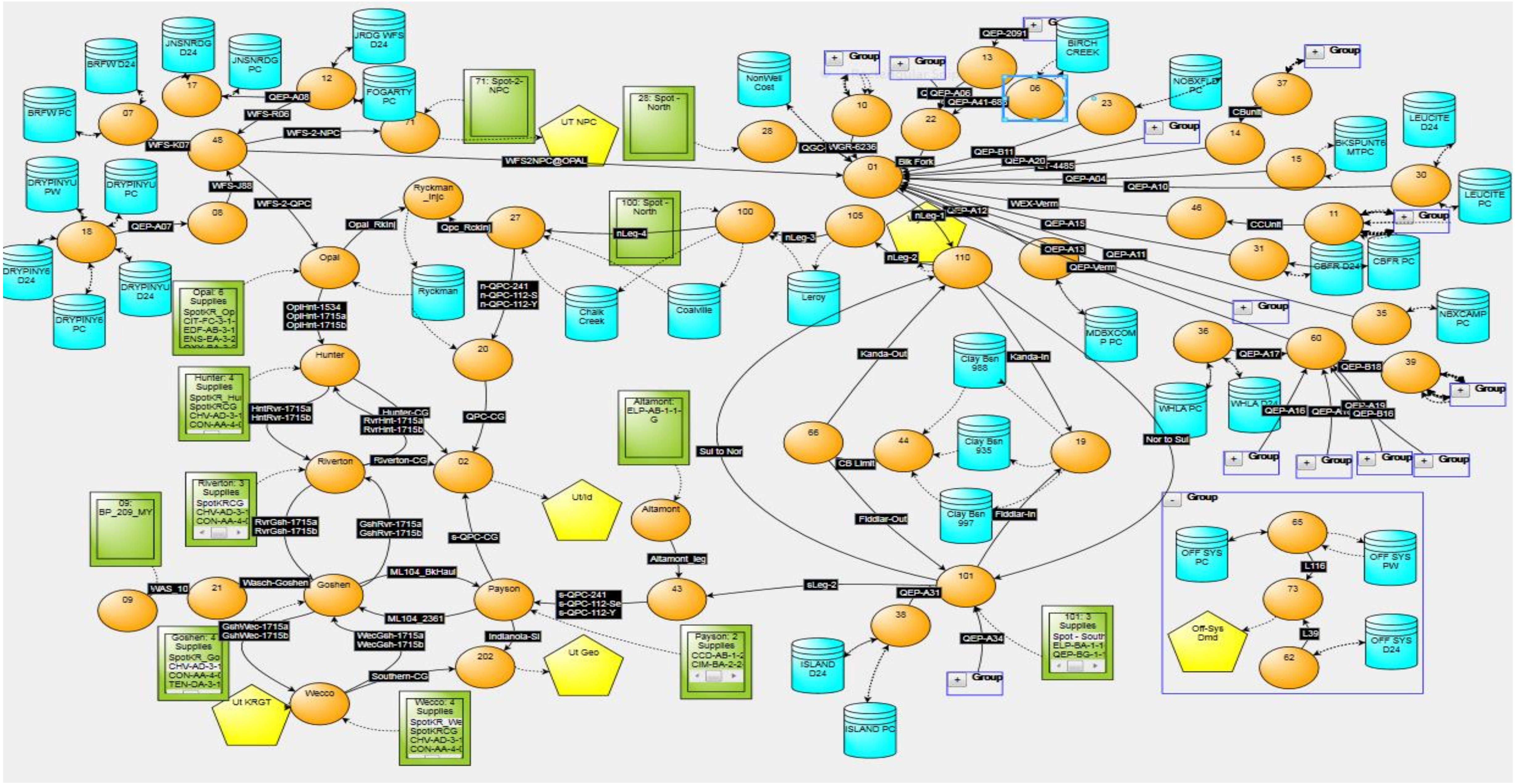
tools that the Company can use to manage gas interchangeability including injecting inert gases (or air) in the gas stream, injecting propane, and blending supplies from various sources.

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

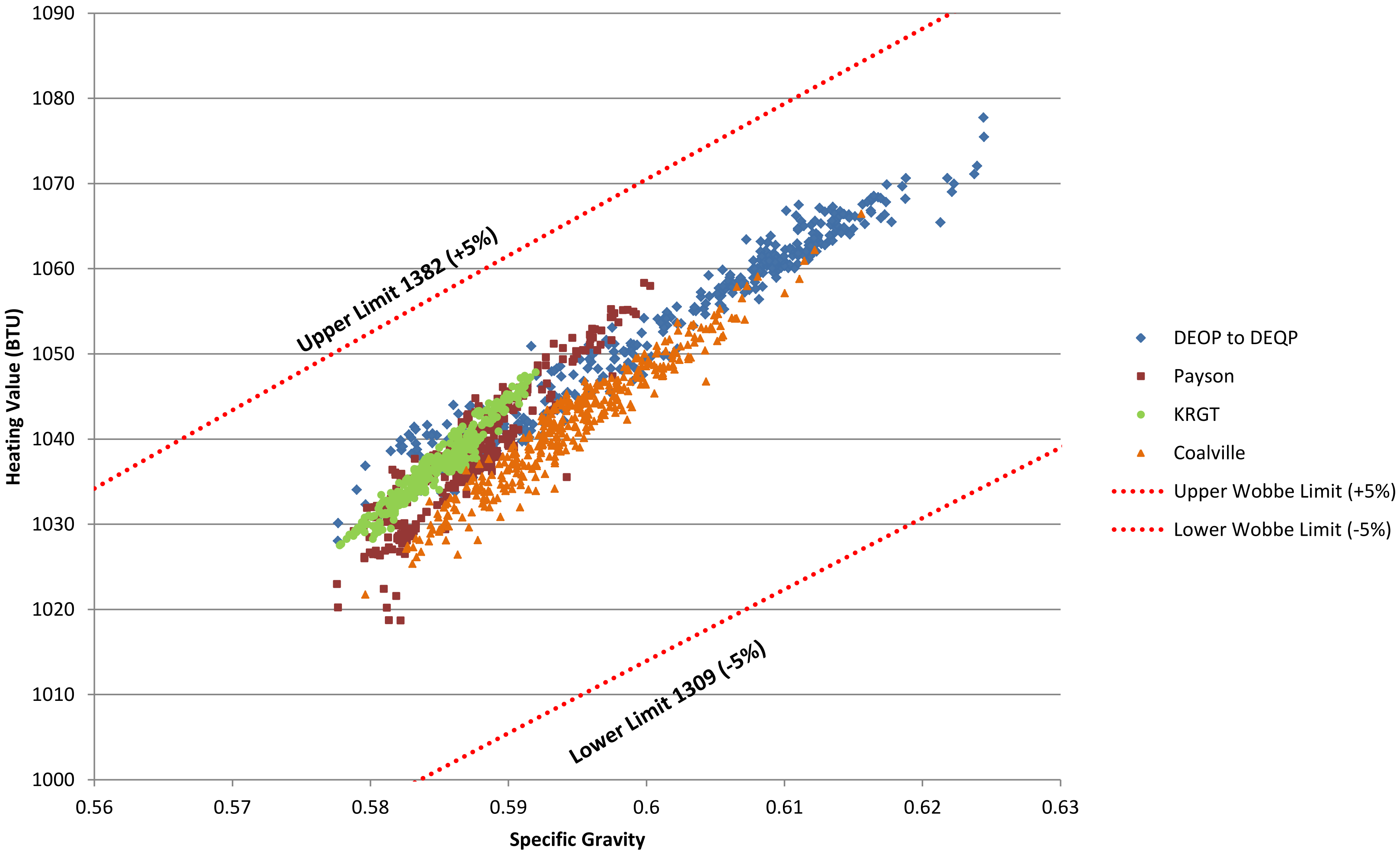
The Company has been contacted by parties with renewable gas supplies, such as biomethane producers, interested in delivering gas directly into the Company's system. In response to these requests, the Company sought Utah Commission approval to implement Section 7.07 that would set gas quality requirements for non-interstate-pipeline supplies, and would permit the delivery of biomethane into the Company's system. The Company expects to see the first biomethane supplies coming into the system during the 3rd quarter of 2019.

# System Diagram 2019

Exhibit 10.1



## Exhibit 10.2
## Wasatch Front (North) Interchangeability
## 2018 Daily Averages



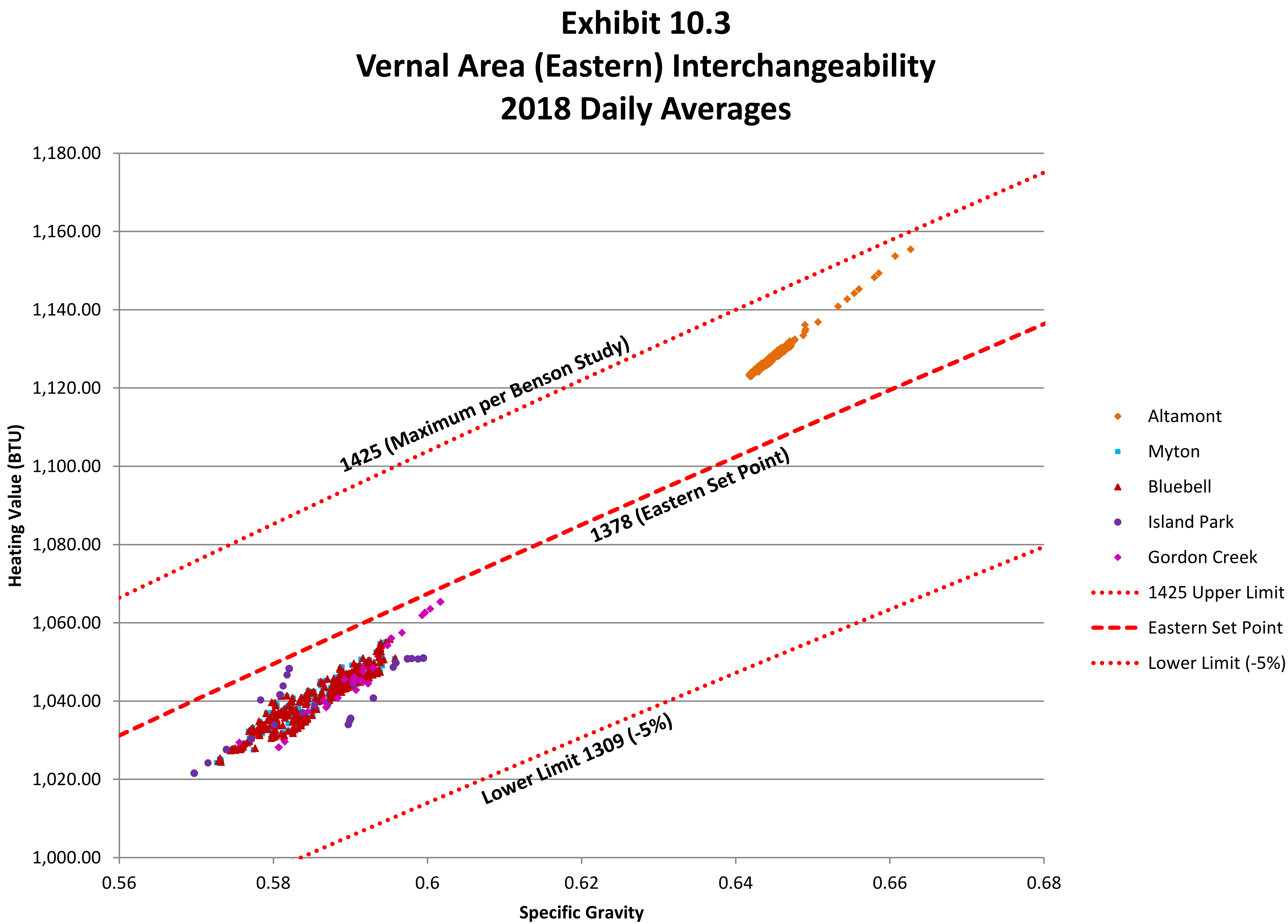
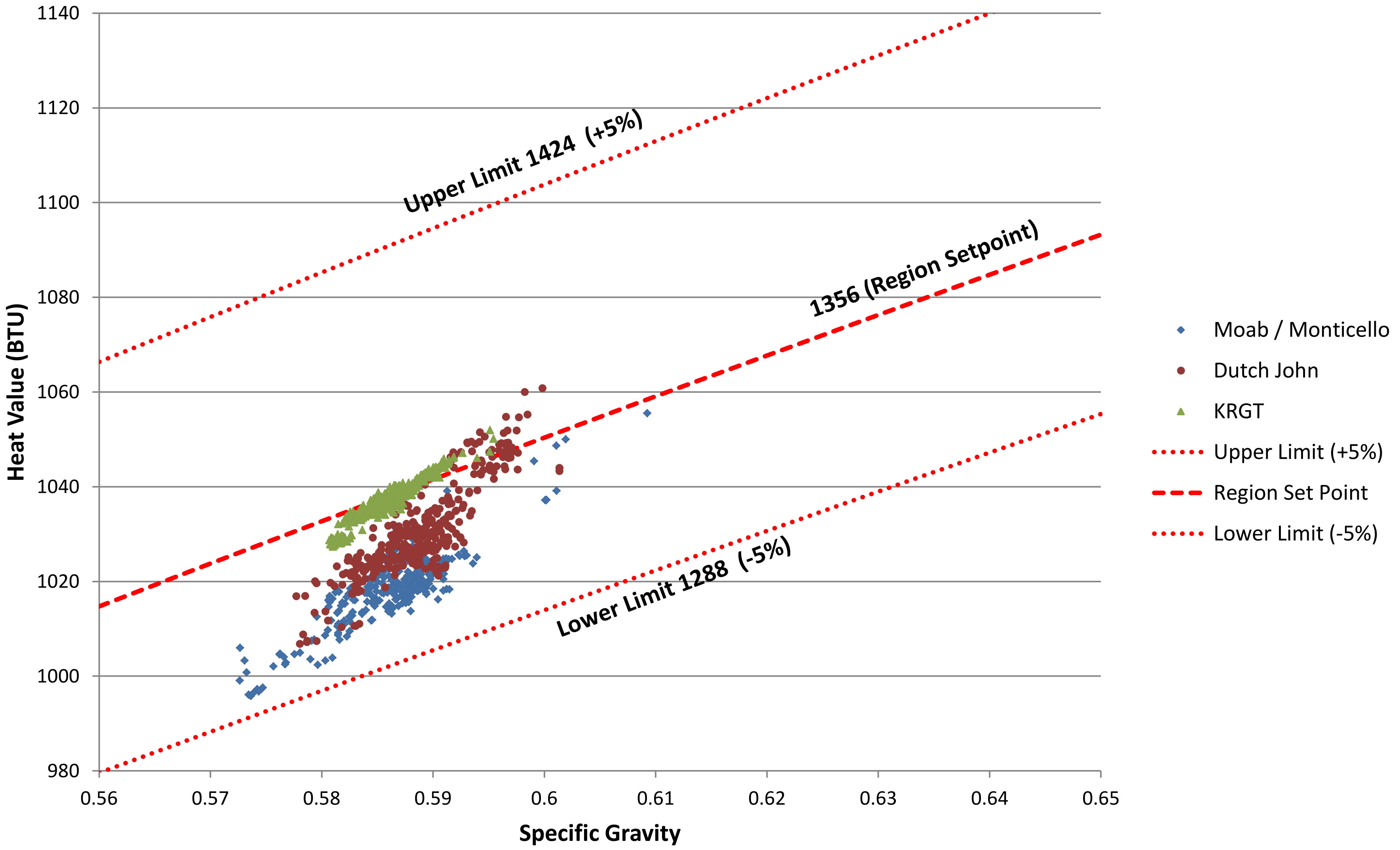
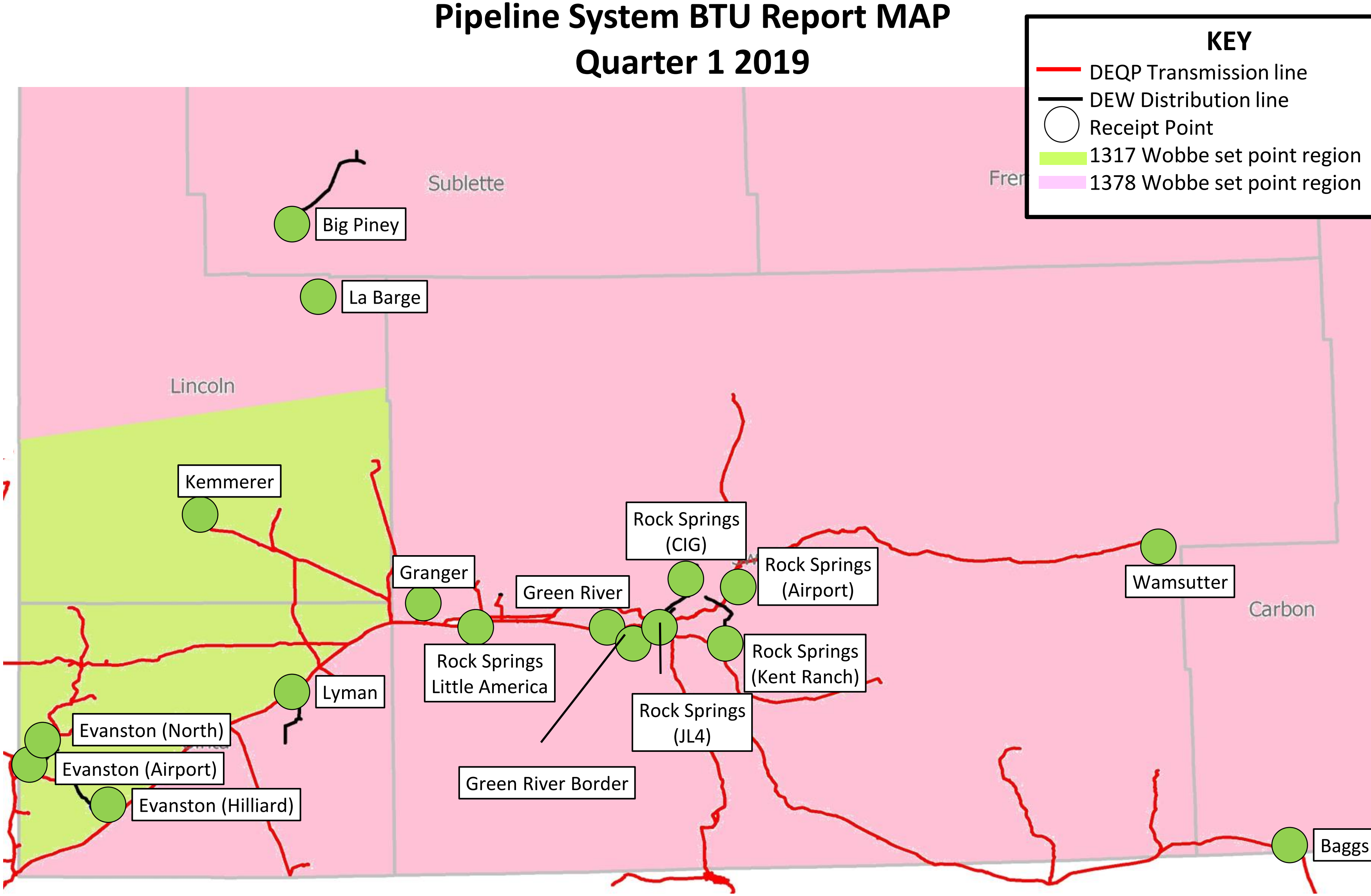


Exhibit 10.3
Vernal Area (Eastern) Interchangeability
2018 Daily Averages
Heating Value (BTU)
1,180.00
1,160.00
1,140.00
1,120.00
1,100.00
1,080.00
1,060.00
1,040.00
1,020.00
1,000.00
0.56
0.58
0.6
0.62
0.64
0.66
0.68
Specific Gravity
1425 (Maximum per Benson Study)
1378 (Eastern Set Point)
Lower Limit 1309 (-5%)
Altamont
Myton
Bluebell
Island Park
Gordon Creek
1425 Upper Limit
Eastern Set Point
Lower Limit (-5%)

# Exhibit 10.4
# Western and Far Eastern (Utah) Interchangeability
# 2018 Daily Averages



# Exhibit 10.5
# Dominion Energy Wyoming (DEW)
# Pipeline System BTU Report MAP
# Quarter 1 2019



# SUPPLY RELIABILITY

## SUPPLY RELIABILITY NEEDS

In recent years, supply shortfalls have occurred during cold weather events. These shortfalls have occurred when temperatures have been well above Design Day conditions. The Company has been subject to a number of events that have occurred upstream of the Dominion Energy system, including production losses (e.g., due to wellhead freeze-offs), processing plant outages, compressor station or gate station failures, transportation pipeline capacity reductions, power outages, plant shut-downs, mechanical failures and force majeure events. All of these events resulted in supply shortfalls.

Failure of contracted gas supplies to be delivered to the Company's system during a Design Day or near Design Day could result in loss of adequate pressure in the distribution system during extreme cold weather events. If this were to occur, the Company would have no recourse but to initiate emergency service interruptions of both interruptible and firm customers, including industrial, commercial, and residential customers. System models show that the types of gas supply shortfalls recently experienced could result in the loss of system pressure in large areas of the Company's system, resulting in a loss of service up to 650,000 customers depending on the delivery point where the shortfall occurs.

Failure of contracted gas supplies to reach the Company's system on a Design Day would result in the interruption of gas service to interruptible industrial customers, firm industrial customers, commercial customers, and residential customers alike. If a loss of service occurs, industrial customers would be without gas for process use and power generation. Businesses would be without natural gas service for heating, water heating and cooking. Critical facilities such as hospitals, health care facilities, senior citizen/ assisted living facilities, day care facilities and schools would be without heat and hot water. Residential customers would also be without natural gas for heating, cooking, and hot water. During cold weather conditions that can reach minus 5º Fahrenheit (ºF) or colder, prolonged exposure would pose a significant risk to the safety, health and property of the Company's residential and commercial customers.

It is important to recognize the differences between restoration of service for electric systems as compared to gas systems. In the restoration of service of electric systems, large blocks of customers can be restored simultaneously with a single flip of a switch. Conversely, once the pressure in an area of a gas system reaches zero psig, the Company must physically shut off each impacted customer meter in that area before gas can be reintroduced to the system and service can be restored to each customer, one by one. Based on the potential for the loss of service to up to 650,000 customers, the Company estimates that it may take weeks to restore service to all affected customers. In the meantime, the Company's customers would be exposed to extreme winter temperatures of minus 5º F or lower which exposes them to serious safety and health consequences.

It is also important to recognize that the loss of upstream supply during extreme cold weather conditions is not a hypothetical event.

In December of 1990, Questar Corporation (Questar Gas and Questar Pipeline) experienced a period of prolonged extreme cold weather. Temperatures during this event were near design day temperatures. The prolonged cold weather and high demand resulted in supply shortfalls to what is now the Company's system. These shortfalls were caused by equipment failures at wellheads resulting in reduced pipeline pressures, compressor mechanical problems and plant shut-downs. At the time, these shortfalls were managed through interruption of customers and the flexibility provided by joint operations with the upstream pipelines. Since most of the Company's transportation customers are not on interruptible contracts, and FERC order 636 requires the Company to be treated equally with all other shippers on upstream pipelines, including DEQP, these options are no longer available.

In more recent examples, during the winter of 2011, there was a major upstream supply shortfall that disrupted natural gas supplies to communities in the states of Arizona and New Mexico with resulting serious impacts on the safety, health, comfort and convenience of a large number of gas customers.

In October 2018, a rupture of a 36-inch Enbridge Pipeline in Canada near the border caused significant supply disruptions for much of the Pacific Northwest. These disruptions resulted in significant price spikes as well as supply shortfalls to downstream distribution companies. FortisBC, the LDC serving Vancouver, BC and surrounding areas was directly impacted.

In January 2019, the Midwest experienced record cold temperatures due to a "polar vortex" event. During this event, there was a fire at a Consumers Energy natural gas compressor station in Michigan. The resulting supply shortages prompted the Michigan governor and utilities including Xcel Energy in Minnesota to request firm customers to reduce their usage. However, firm residential customers in Minnesota lost service due to this supply-shortfall event.

In addition to serious life safety and health implications, the consequences of an event that results in wide-scale supply loss would have dramatic economic consequences for the Company's customers, the communities served by the Company, and the Company itself.

The estimated cost to restore service to the estimated number of affected customers could be up to $100 million. This figure is exclusive of costs for financial and other harm (e.g. property damage) that would be incurred at the state, community, and individual levels, or any financial harm to the Company. The estimated impact on Gross State Product is up to $2.4 billion due to the loss of workforce at Utah businesses.

In order to meet the Company's commitment and statutory obligation to provide safe and reliable service to its customers, the Company's gas supply plan should include sufficient resources to prudently operate and provide uninterrupted service to industrial, commercial, and residential sales customers in the event of supply shortfalls during a cold weather event.

Based on historical supply shortfalls experienced by the Company, the Company determined that it needed to plan to replace approximately 150,000 Dth/day of gas supply. To provide adequate assurance that all cost-effective options to provide supply reliability for the Company's customers were considered, the Company issued a well-advertised public solicitation for proposals (Supply Reliability RFP) to identify any potential resource that may be available. The Company completed an evaluation of all options that were identified to determine the optimum approach to ensure safe, reliable and cost-effective system supply during periods of supply shortfalls.

## SUPPLY RELIABILITY OPTIONS

The Company evaluated the options provided in response to the Supply Reliability RFP to identify the most reliable, safe, and lowest reasonable cost alternative to ensure supply reliability and minimize the potential for service interruptions under cold weather conditions. Those options and the Company's analysis are summarized in DEU Highly Confidential Exhibit 3.03 in Docket No. 19-057-13.

### *Magnum Energy Storage*

Three different options to utilize Magnum Energy Storage were evaluated. These options are Highly Confidential and are described in detail in Docket 18-057-0319-057-13.

### *Prometheus Energy*

Two different options for on-system LNG provided by Prometheus Engineering were evaluated. These options are Highly Confidential and are described in detail in Docket 19-057-13.

### *United Energy Partners*

An option for off-system LNG storage combined with No-Notice Transportation was evaluated. These options are Highly Confidential and are described in detail in Docket 19-057-13.

### *Company Owned On-System LNG Facility*

The Company researched potential storage options that could be located on the Company's system in close proximity to the demand center that would allow the Company to manage and control its supplies on-system in the event of upstream, off-system supply shortfalls. An on-system facility owned and operated by Dominion Energy would provide supply independence and diversity, and would provide a number of significant operational benefits. For purposes of this analysis the only viable on-system storage option that was identified is was an LNG facility. To our knowledge, no other feasible storage options exist near the demand center of the Wasatch Front. Some utilities are located near salt caverns or depleted natural gas reservoirs and can use these geologic formations for on-system storage. There are no known geologic formations on the Company's system near our demand center.

Under this option, the Company would construct an LNG storage facility on its system near its demand center along the Wasatch Front. This "on-system" storage would be an LNG facility with liquefaction/ vaporization capabilities. This facility would be designed to provide up to 150,000 Dth/day of deliverability.

This on-system facility would be owned and operated by the Company, allowing the utility complete operational control over the facility and the deliveries into the Company's system. This option would include liquefaction capabilities, including the ability to liquefy gas throughout the summer months for use during the heating season.

The Company has provided technical analysis and supporting workpapers identifying the costs, benefits, and risks used to determine and support the selection of an LNG facility as the best solution to address the supply-reliability need in Docket No. 18-057-03 and in Docket No. 19-057-13. The Application and accompanying testimony and exhibits discusses these matters, and the other data required by the Commission's 2009 IRP guidelines and its Report and Order in Docket No. 17-057-12. Because this analysis includes Confidential and Highly Confidential information, the Company incorporates the information by reference.

## SUPPLY RELIABILITY CONCLUSIONS

The Company has considered and evaluated all of the proposals provided in response to its RFP for options to meet the Company's commitment and statutory obligation to provide safe and reliable service to its customers. The recommended approach for the Company to ensure safe and reliable service, even during periods of supply shortfalls is to construct, own and operate an on-system LNG storage facility.

The Company-owned LNG Facility provides the lowest-cost option and the highest reliability. This solution also has significant advantages over other options. For example, such a facility would provide supply independence in times of supply shortfall. Withdrawing from the Company-owned LNG Facility would not be subject to NAESB nomination cycle constraints or upstream supply risks that are associated with many of the other alternatives the Company considered as solutions to supply disruptions. The LNG supply could be used to directly match demand on the DEU system in the event of an upstream supply disruption. Withdrawals from the facility would feed directly into the DEU feeder line system and ensure supply reliability with the best system pressures. Additionally, the on-system facility would be owned and operated by the Company, giving it complete control of the facility.

On-system storage provides reliability and flexibility that other supply options cannot match. Reliability is an attribute that cannot be overstated. This alternative provides supply reliability when upstream sources fall short. Gas from on-system storage does not need to be purchased or nominated at the time of need, and may be brought onto the distribution system on short notice. With a 15 million gallon LNG storage tank the Company could vaporize at 150,000 Dth/day and be able to maintain pressure for firm customers in the event of supply shortfalls or other system emergencies. Proximity to the demand center provides immediate system support and is not dependent on long transmission pipelines that are subject to a variety of risks such as land movement, third party excavation damage, forest fires, floods, washouts, corrosion, regulatory shutdowns, and other force majeure events.

The Company-owned LNG Facility option also has additional benefits beyond supply reliability. It could provide peak-hour system support and flexibility to offset purchases when supply is limited. It also could be used to provide natural gas service to remote communities that do not currently have natural gas availability and would be more economically served by satellite LNG than a mainline extension. The availability of on-system LNG would prove advantageous in responding to emergencies.

Based on the above analysis and evaluations, the construction of the Company-owned LNG Facility was recommended as the preferred supply reliability solution.

# SUSTAINABILITY

Dominion Energy, Inc. (DEI) has adopted, and the Company fully supports, an environmental policy statement designed to set clear expectations with regards to compliance with environmental laws and regulations:

> ***"Dominion Energy is fully committed to meeting its customers' energy needs in an environmentally responsible and proactive manner. It is our duty to protect natural and cultural resources – and a good business practice. We aim to do what's right for the communities we serve by meeting or going beyond basic obligations to comply with applicable environmental laws and regulations."***

## SUSTAINABILITY GOALS

DEI has the following natural-gas related sustainability goals for all of its subsidiaries, including the Company:[1]

- DEI commits to reduce methane emissions from its natural gas businesses by 50 percent by 2030 (from 2010 baseline). See Figure 12.1.

- Beginning in 2019, DEI's natural gas companies, including Dominion Energy, plan to install equipment on gas distribution construction projects involving large diameter pipe to minimize the need to blowdown natural gas which will reduce methane emissions.

- DEI has committed to test and pilot new technology to reduce natural gas loss during inline pipe inspections.

- DEI has a zero-landfill policy. Dominion Energy and its affiliates responsibly recycle information technology equipment that is no longer used and plans to improve recycling processes to increase the amount of waste recycled.

- To protect birds near DEI's subsidiaries' gas produced-water evaporation ponds, we use netting or bird deterrents and expect to continue to implement these systems as new facilities are constructed in 2019.

[1] "2017 – 2018 Sustainability & Corporate Responsibility Report." Dominion Energy, https://sustainability.dominionenergy.com/, Accessed May 7, 2019.

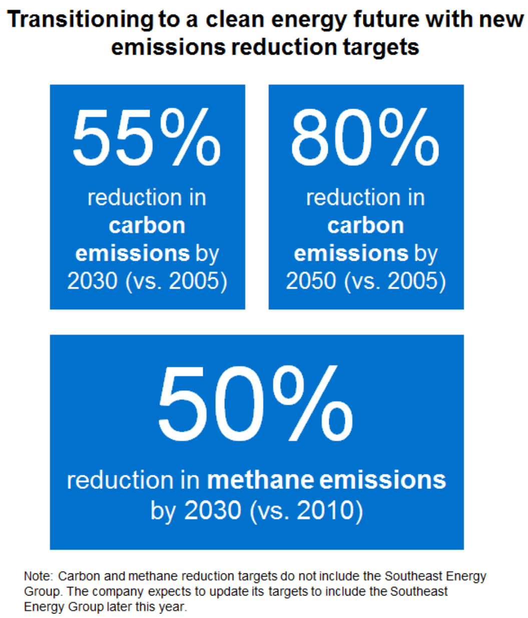



**Figure 12.1: Dominion Energy, Inc. Company-Wide Emissions Reduction Targets**

## SUSTAINABILITY IN THE WEST

### *Methane Reduction Program*

Dominion Energy implemented a Methane Reduction Program in Utah, Wyoming and Idaho that includes:

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

- Hot Taps – continuing to use hot taps, the process of tying in to 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.

- Reducing Emissions from Pigging Projects – implementing a new technology – Zero Emission Vacuum & Compressor (ZEVAC) that will significantly reduce emissions from pigging operations.

- Reducing Pressure During Maintenance Prior to Blow Down – continuing the practice of reducing pressure in gas mains to the lowest possible pressure before completely blowing it down when scheduled maintenance work requires the Company to blow down the main. This minimizes the amount of gas that is blown down to the atmosphere. The Company records or estimates the pressure in order to calculate the amount of gas that it blows down. Additionally, the Company is testing portable compressors to evacuate pipe and eliminate some blowdowns.

- Meter Purge Procedure – implementing new procedure that modifies the purge procedure during meter turn on that reduces the amount of methane released to the atmosphere.

- Leak Detection and Repair (LDAR) Program – implementing a LDAR program focused on regulator stations.

- Pressure Monitoring at Regulator Stations – adding remote pressure monitoring at district regulator stations that takes the place of token relief valves and eliminates the potential release of gas.

- 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.

- Excess Flow Valves – installing Excess Flow Valves (EFVs). Beginning in 2006, the Company proactively began installing EFVs on all new and replaced services to single family residences. In 2008, the PHMSA promulgated a rule requiring installation on all new and replaced service lines to single family residences. Beginning in 2013, the Company proactively began installing EFVs on service lines 2-inches and smaller with usage of 5,000 cfh and under. In 2017, PHMSA enacted a rule requiring, among other things, the installation of EFVs on all services 1,000 cfh and smaller. (49 CFR 192.383 and 49 CFR 192.385). PHMSA regulations also require operators like Dominion Energy to notify all customers in writing or electronically of the availability of EFVS. On April 6, 2017, the Company issued a letter to the Utah and Wyoming Commissions explaining its compliance with the new PHMSA rule related for excess flow valves. On April 7, 2017, the Company began publishing such notice on its website and it included further notice in its Gaslight News in the May, 2017 issue.

- Leak Survey 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.

- Response Time to Leak Calls – continuing to evaluate ways to reduce the response time to gas leak calls through efficiencies in how employees are dispatched to these gas leaks. The Company has implemented a Global Positioning System (GPS) to allow dispatchers the ability to dispatch personnel based on their geographic location with respect to the leak.

- Leak Detection Equipment - utilizing advanced technologies for locating and identifying leaks. Examples include the remote methane leak detection (RMLD) and the Rover and SENSIT gas detector.

- Wellhead Emission Reductions – Wexpro will install 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.

- Research and Development – conducting research. The Company participated in a GTI study to identify factors for fugitive emissions from various types of facilities. Starting in April of 2018, the Research and Development team also began a project to use Global Positioning System (GPS) to track construction equipment in real-time near the Company's pipelines in the Geographic Information System (GIS).

## *Clean Water Initiatives*

In 2018, Wexpro installed a produced water treatment system at the Canyon Creek Unit Produced Water Evaporation Facility. This system should allow an estimated 21 million gallons of water to be reused over the next five years at the Canyon Creek Unit Central facility and operations

## *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 Dominion Energy 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 in the transportation sector. The State of Utah will benefit from the following key objectives of these amendments:

- Reduced emissions and improved air quality through incentivizing compressed natural gas (CNG) combined with renewable natural gas (RNG) production in natural gas vehicle fleets

- Reduced NOx, carbon, and greenhouse gas emissions through research and development of new efficiency technologies

- Advancement of renewable natural gas projects to further reduce methane emission

## *Renewable Natural Gas*

### What is RNG?

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. 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.

### Renewable Natural Gas Transportation Service

In Docket No. 18-057-T05, filed on November 1, 2018, the Company requested changes to its Tariff that would allow RNG suppliers to transport RNG to their own fleet customers through Dominion Energy's CNG stations. The Utah Commission approved this service, and the new Section 5.07 of the Company's Tariff, Renewable Natural Gas Transportation (RNGT) service became effective January 1, 2019. This service will facilitate and support a more robust RNG market within the state of Utah.

On April 11, 2019 Dominion Energy filed an application for approval of a special contract with Fleet Saver, LLC, for RNGT service. If approved, Fleet Saver, LLC will deliver locally-produced RNG to fleets throughout Utah using Dominion Energy's network of NGV stations.

### Voluntary Renewable Natural Gas Program – GreenTherm™

In Docket No. 19-057-T04, filed on March 29, 2019, the Company applied for approval to create a voluntary RNG program. If approved, this program will allow customers to contribute to a program where renewable natural gas attributes are purchased by the Company and assigned to participating customers.

# ENERGY-EFFICIENCY PROGRAMS

## UTAH ENERGY-EFFICIENCY RESULTS 2018

The Company's energy-efficiency efforts have consistently focused on providing all segments of the GS rate class with a comprehensive suite of natural-gas-saving efficiency programs. That focus continued into 2018 as the Company introduced new rebate-qualifying efficiency measures for existing and new homes, multi-family properties, low-income customers and commercial customers. In addition to the new measures, the Company continued to refine the comparison characteristics of the ThermWise® Energy Comparison Report (Comparison Report) and delivered it to over 280,000 customers in 2018.

ThermWise® results for 2018 were strong with participation for all of the programs exceeding 97% of original projections. Spending for the 2018 program year totaled $23.4 million or 95% of the $24.5 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for nearly 78% of total ThermWise® spending in 2018 (73% in 2018 budget) and resulted in annual natural gas savings of more than 600,000 Dth. Actual natural gas savings were nearly 95% of the amount projected in the Company's 2018 budget filing.

### *Utah ThermWise® Appliance Rebates*

The Company continued this program in 2018 and added boiler reset controls and combined space and water heaters to the list of rebate-eligible equipment.

A boiler outside air reset control is an add-on unit used to automatically reduce the boiler supply water temperature at warmer outside air temperatures. This process helps to reduce boiler natural gas consumption. Boiler outside air reset controls are code-required in new homes with boilers. Therefore, the Company added this equipment as a rebate-eligible measure only in the retrofit appliance program.

Combined space and water heating systems provide domestic water and space heating from a single heat source. Qualifying devices use a tankless water heater or boiler and a furnace to provide space heat and are packaged together in a single unit. These devices require less mechanical equipment space and are well suited for small single family and multifamily applications. Eligible units utilize condensing technology, which is more efficient than code-required water and space heating equipment.

The Company also made the following changes to the 2018 Appliance program including: 1) eliminating the tankless tier 1 water heater as a rebate-eligible measure in an effort to align with ENERGY STAR® specifications of > 90% energy factor (EF); 2) reducing the smart thermostat rebate to $50 per device; and 3) reducing the rebate amount by $50 for the 95% annual fuel utilization efficiency (AFUE) furnaces, 95% AFUE furnaces with an electrically commutated motor (ECM), and the 98% AFUE furnace with ECM. The changes in rebate amounts were made to align the Company's rebate offerings with expected 2018 market conditions.

The Company performed outreach and marketing work with in-house staff and Nexant, Inc. (Nexant) provided technical assistance for this program in 2018. The Company was informed by Blackhawk Engagement Solutions in June 2018 that it would cease all utility rebate-processing work by the end of October 2018. The Company sought proposals from firms and ultimately awarded a two-year rebate-processing contract to Nexant beginning in September of 2018.

## *Utah ThermWise® Builder Rebates*

The Company continued this program in 2018 with the addition of a new–construction, multifamily high rise rebate. This measure incentivizes builders, through a $25 per-unit rebate, to seek the ENERGY STAR® Multifamily High Rise (MFHR) designation for buildings of four stories or greater. Buildings that score a 75 or above (on a 1-100 scale), as determined through ENERGY STAR® Portfolio Manager, are eligible to receive the ENERGY STAR® MFHR designation. New construction commercial facilities such as motels/hotels, nursing homes, assisted-living facilities, and dormitories do not qualify for the ENERGY STAR® MFHR designation and, therefore, are ineligible to participate in this rebate measure. The Company anticipates several qualifying multifamily high rise projects in the near future and believes the time is right to move these types of residential developments further down the path of energy efficiency.

The Company also added combined space and water heaters as a rebate-eligible measure, implemented the $50 reduction to specific furnaces and the smart thermostat measures, and eliminated the tier 1 tankless water heater as a rebate-eligible measure. These changes aligned the Company's rebate offerings with expected 2019 market conditions.

The Company performed outreach and marketing work with in-house staff and Nexant provided technical assistance for this program in 2018. The Company was informed by Blackhawk Engagement Solutions in June 2018 that it would cease all utility rebate-processing work by the end of October 2018. The Company sought proposals from firms and ultimately awarded a two-year rebate-processing contract to Nexant beginning in September of 2018.

## *Utah ThermWise® Business Rebates*

The Company continued this program in 2018 with the following changes: 1) introduction of pipe insulation to the current rebate measure mix; 2) elimination of the tankless tier 1 water heater as a rebate-eligible measure; and 3) reduction of the rebate amounts for the 95% AFUE, 95% AFUE with ECM, and 98% AFUE furnace with ECM by $50 in 2018. The rebate amount for smart thermostats was changed in the 2017 Business Program from a fixed amount per device to a rebate based on the square footage serviced by the device. As such, the Company believed the 2017 rebate structure was in harmony with the 2018 market conditions and, therefore, made changes to the Business Program smart thermostat measure in 2018.

The Company performed outreach and marketing work with in-house staff and Nexant provided technical assistance for this program in 2018. The Company was informed by Blackhawk Engagement Solutions in June 2018 that it would cease all utility rebate-processing work by the end of October 2018. The Company sought proposals from firms and ultimately awarded a two-year rebate-processing contract to Nexant beginning in September of 2018.

## *Utah ThermWise® Weatherization Rebates*

In January 2017, the Company introduced the ThermWise® Direct-Install Weatherization Pilot Program. This program was designed to reach communities and customers with historically low participation in weatherization measures. The Company published a request for proposal (RFP), selected two contractors to perform the work, and began marketing efforts in June of 2018. Direct-install work commenced in July, 2017. The Company was pleased with the results of this new initiative in 2018 and has kept the Advisory Group informed as to the early results. Participating contractors also provided positive feedback on the direct-install pilot and have additionally made suggestions intended to help augment natural gas savings. One such suggestion was to establish a rebate for the installation of pipe insulation, on the water supply pipes, in the unconditioned space of homes. After performing an evaluation of potential savings, the Company added a rebate for pipe insulation of $0.50 per linear foot in 2018. The Company additionally recommended that participation in this measure be limited to the Direct-Install pilot, where quality installation can be ensured through the Company's already-established quality assurance/quality control (QA/QC) process.

The Company also launched a three year pilot initiative, through the 2018 Weatherization Program, designed to achieve natural gas savings in both low-income and market rate multifamily properties. This initiative, called the Pilot Multifamily Program, aims to entice multifamily property owners to implement comprehensive energy efficiency retrofits and replace energy systems across the entire property instead of waiting to replace equipment at the point of failure.

The Pilot Multifamily Program is administered by the International Center for Appropriate and Sustainable Technology (ICAST). ICAST seeks to achieve participation by educating multifamily property owners on the ancillary benefits of retrofits including increase in value of their property, increase in net operating income (NOI), access to Fannie, Freddie and FHA green lending initiatives, tax credits and deduction, access to low-cost financing and other incentives. ICAST specializes in developing and administering a one-stop-shop program solely for multifamily customers who are typically underserved and considered hard-to-reach.

ICAST promoted the installation of current rebate measures to both low-income and market rate properties (≈50% low income / 50% market rate) and target first year natural gas savings of 12,500 Dth. ICAST's administrative fees were paid by the Company based on natural gas savings achieved. In other words, ICAST was paid only if and when natural gas savings were realized. In addition to funding, the Company assisted in making introductions between ICAST and Utah's other multifamily stakeholders, developing a marketing plan, and providing marketing collateral in 2018.

The Company performed outreach and marketing work with in-house staff and Nexant provided technical assistance for this program in 2018. The Company was informed by Blackhawk Engagement Solutions in June 2018 that it would cease all utility rebate-processing work by the end of October 2018. The Company sought proposals from firms and ultimately awarded a two-year rebate-processing contract to Nexant beginning in September of 2018.

## *Utah ThermWise® Home Energy Plan*

The Company continued this program in 2018 with no major changes.

## *Utah Low-Income Efficiency Program*

The Company continued funding the Low-Income Efficiency Program in 2018 at $500,000 per year from the energy-efficiency budget ($750,000 total Company funding). The Company disbursed $250,000 every six months, with the disbursements occurring in January and July.

## *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.

The Company initially sent the report to a small group of customers (Group A – 8,000 customers) as a pilot program. The Company has since launched larger pilot groups in 2012 (Group B – 25,000), 2013 (Group C – 100,000), 2014 (Group D – 100,000), and in 2018 (Group F – 50,000). Currently the Company sends the report, via U.S. and electronic mail, to more than 255,000 of its customers. The Company maintains an additional group of nearly 100,000 customers in order to determine natural gas savings achieved from delivery of the Comparison Report. With the exception of the control group, all customers are able to generate and view a copy of their Comparison Report through their online account at www.dominionenergy.com. As of the end of September 2017, the Comparison Report had been generated over 275,000 times online by nearly 110,000 unique customers.

The Company increased delivery of the Comparison Report to 285,000 in 2018. The Company realizes this total number by reintroducing Group B in 2017, pausing Group C beginning September 2017, and adding Group F which was delivered to 50,000 additional customers in 2018. 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. The Company conducted an analysis in 2014 that showed, when contrasted against a control group of non-recipients, customers who had received their Comparison Report were more likely to participate in ThermWise® rebates and/or request a Home Energy Plan. The Company continued to target the Comparison Report to customers with higher usage relative to conditioned square footage in 2018.

While program participants are expected to increase slightly from 2017 levels, natural gas savings are projected to increase by 34% in 2018. The Company expects savings to increase because of the projected expansion of the Comparison Report in 2018 and because of savings persistence. The Company conducted a study in 2017 that focused analysis on all current recipients of the report (Groups B, C, and D). The study showed weather-normalized usage reductions per participant of 1.22 Dth/year. As a result, the Company updated the natural gas savings number from 0.91 Dth/year in the 2017 Model, to 1.22 Dth/year in the 2018 Model.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2018 budget filing is shown in Table 13.1.

**Table 13.1 - Utah 2018 Projected & Actual B/C ratios by program and California Standard Practice Test**

| Program | Total Resource Cost Test | | Participant Test | | Utility Cost Test | | Ratepayer Impact Measure Test | |
|---|---|---|---|---|---|---|---|---|
| | 2018 Projected B/C | 2018 Actual B/C | 2018 Projected B/C | 2018 Actual B/C | 2018 Projected B/C | 2018 Actual B/C | 2018 Projected B/C | 2018 Actual B/C |
| ThermWise® Appliance Program | 1.15 | 1.45 | 3.01 | 3.66 | 1.49 | 1.80 | 0.79 | 0.86 |
| ThermWise® Builder Program | 1.14 | 0.77 | 3.24 | 2.01 | 1.05 | 1.20 | 0.65 | 0.72 |
| ThermWise® Business Program | 1.16 | 1.04 | 3.21 | 3.19 | 1.87 | 1.59 | 1.01 | 0.90 |
| ThermWise® Weatherization Program | 1.11 | 1.05 | 2.69 | 2.87 | 1.22 | 1.03 | 0.74 | 0.66 |
| ThermWise® Home Energy Plan | 1.34 | 2.03 | 50.64 | 66.38 | 1.32 | 1.99 | 0.73 | 0.86 |
| Low-Income Efficiency Program | 1.18 | 0.79 | 5.40 | 2.23 | 1.21 | 0.87 | 0.71 | 0.58 |
| Energy Comparison Report | 1.74 | 1.94 | 5.63 | 6.80 | 1.74 | 1.94 | 0.83 | 0.75 |
| Market Transformation | 0.00 | 0.00 | N/A | N/A | 0.00 | 0.00 | 0.00 | 0.00 |
| **TOTALS** | **1.10** | **1.00** | **3.15** | **2.88** | **1.29** | **1.24** | **0.76** | **0.73** |

Actual benefit/cost results for 2018 mirrored corresponding budget projections. The ThermWise® programs as a whole passed the Total Resource, Participant, and Utility Cost tests. Actual cost-effectiveness results were lower than projected primarily due to higher than expected participation in lower-savings energy-efficiency measures and lower than forecasted avoided natural gas costs than were used in cost-effectiveness modeling for the 2018 ThermWise® budget filing (Docket No. 17-057-22).

Customer participation in the ThermWise® programs remained high in 2018 (78,852 actual rebates paid) finishing the year at 97% of the Company's original 2018 estimate (81,228). Actual participation surpassed estimated participation in the Builder (23.832) program. The Weatherization program had the highest total number of participants (29,321) and finished at 85% of the 2018 goal.

The DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Three meetings were held on the following dates: March 29, 2018, August 23, 2018 and September 26, 2018.

## ENERGY EFFICIENCY EFFECTS ON DESIGN DAY & DEMAND RESPONSE

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 addressed this topic at the DSM Advisory Group meeting held March 19, 2015 and again at the IRP meeting held on April 30, 2015. In both meetings the attendees discussed the ThermWise® programs, the fact that they are designed to reduce over-all energy consumption, and that they do not, necessarily, impact Design-day usage.

In Docket No. 14-057-15 the Commission ordered the Company to "…continue its discussion on peak-day issues in the DSM Advisory Group and in a public input meeting associated with the 2015 IRP." (Report and Order dated October 8, 2015, Docket No. 14-057-15.) The Company continued the discussion of the effects of energy-efficiency on Design Day at the Advisory Group meeting held March 24, 2015 and again at the IRP meeting held on March 25, 2015.

In Docket No. 15-057-07 the Commission ordered the Company to "…address Heat Pumps and the impacts of EE programs on peak demand" in the 2016 IRP. The Company addressed Heat Pumps and continued the discussion of the effects of energy-efficiency on Design Day in the Customer and Gas Demand Forecast section, pages 9 through 16, of the 2016 IRP. Additionally, the Company has continued to study this topic since that time.

The Company also agreed in its 2017 Energy Efficiency budget filing (Letter dated December 7, 2016 in Docket No. 16-057-15) to "…begin development of an analytical framework for evaluating efficiency measure benefits and costs unrelated to natural gas savings" in 2017. The Company, in collaboration with Nexant, began a study of water heaters and development of an analytical framework in June of 2017. The Company presented the results of its study and the resulting analytical framework to representatives of the Division of Public Utilities and the Office of Consumer Services at a meeting held October 10, 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. The final report and analytical framework were published by Nexant on November 21, 2017.

In Docket No. 16-057-08 the Commission ordered the Company and the DSM Advisory Group to collaborate and "…to explore whether opportunities exist for one or more DSM pilot programs that might alleviate peak demand." The Company began to study demand response natural gas programs in the spring of 2017. The methodology used by the Company in this study was to identify and contact natural gas utilities who might have demand response programs, search utility websites, review industry conference papers, contact large demand response vendors, and contact national energy efficiency organizations.

The Company's study found the following potential demand response options: 1) Interruptible rates; 2) fuel-switching; 3) time of use rates; and 4) direct load control. Of the twenty-two natural gas utilities surveyed by the Company, eighteen were determined to have interruptible rates for use during periods of high demand, five had fuel switching incentives for use in extreme weather conditions, and none had implemented or had plans for time of use rates or direct load control programs in the future. Additionally, the four demand response vendors contacted by the Company indicated that they did not have any natural gas-related direct load control programs.

The Company presented the results of this study to the Advisory Group at a meeting held on August 24, 2017. At that meeting, a member of the Advisory Group suggested that SoCalGas had implemented a natural gas demand response program, through the smart thermostat manufacturer Ecobee, during the winter heating season of 2015-2016. The Company contacted Ecobee to discuss the program on September 26, 2017. Through this discussion, the Company was able to determine that the size of the program was small in nature (limited to approximately 500 participants) and that there had been no weather events during that heating season which required adjusting the temperature in participant homes. The Company subsequently updated the Advisory Group of these findings at a meeting held on September 27, 2017.

A third-party evaluation of the SoCalGas demand response program was performed by Nexant and published August 14, 2018. The second-year demand response program, which was expanded to include a second thermostat manufacturer, covered the 2017-2018 winter heating season and the impact on natural gas usage in about 10,000 participating homes. The Nexant 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.” The evaluation concluded with the idea that, “traditional energy efficiency and behavioral conservation based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage.”[1]

## WYOMING ENERGY-EFFICIENCY RESULTS FOR 2018

The Company filed for approval (Docket No. 30010-172-GA-17) of the ninth-year of the Wyoming ThermWise® programs on October 31, 2017. The ninth-year Wyoming programs were modified to closely align with the 2018 Utah ThermWise® programs in an effort 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 ninth-year programs (January 4, 2018 Order) and ordered the changes effective January 1, 2018.

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 ninth full program year (January through December 2018) the Wyoming ThermWise® programs had 468 participants or 1.7% of the Company’s December 31, 2018 Wyoming GS customer base.

## UTAH ENERGY-EFFICIENCY PLAN FOR 2019

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

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

programs for 2019 as well as the ThermWise® Market Transformation initiative. The ThermWise® energy-efficiency programs continuing in 2019 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 2019 with the elimination of the 92% annual fuel utilization efficiency (AFUE) furnace as a rebate-eligible measure. The Company first began to offer a rebate for 92% AFUE furnaces in the 2011 program year (Docket No. 10-057-15). Prior to that time, rebates for furnaces had been set at an efficiency level of 90% AFUE or above. In the 2013 ThermWise® budget filing (Docket No. 12-057-14), the Company proposed eliminating the 92% AFUE furnace as a rebate-eligible measure and setting the minimum efficiency at 95% AFUE for future program years. This change was proposed by the Company in anticipation of a United States Department of Energy (DOE) promulgated rule requiring national minimum efficiency standards for furnaces to be set at 90% AFUE. However, DOE's proposed rule was never implemented and the Company sought Commission approval to reintroduce the 92% AFUE furnace and establish a four-tiered furnace rebate structure (>92<95%, >95%, >95% with electrically commutated motor (ECM), and >98% with ECM) in the 2014 ThermWise® budget filing (Docket No. 13-057-14). In an effort to continue pushing efficiency standards forward, the Company permanently eliminated the 92% AFUE furnace as a rebate-eligible measure in 2019.

The Company also reduced the rebate for tankless water heaters by $50 and made minor changes to Tariff language by setting the definition for rebate-qualifying single family residences at three or fewer and multifamily at four or more residences. The reduction in the tankless water heater rebate from $350 to $300 is a result of the Company's 2018 market research that found a significant reduction in the incremental cost between the base level storage water heater and the high efficient tankless models. These changes in Tariff language align the ThermWise® programs with the Company's internal definitions of single and multifamily properties and also with Rocky Mountain Power's (RMP) Wattsmart programs.

The Company will continue to perform outreach and marketing work in-house in 2019. Nexant will provide technical assistance and continue to perform rebate processing work for this program in 2019.

## *Utah ThermWise® Builder Rebates*

Under this program, the Company offers rebates to residential builders for installing qualifying energy efficiency measures and constructing homes that meet certain whole-home efficiency requirements. The ThermWise® Builder Program is available to all newly constructed residences receiving service on the GS rate schedule. Currently, qualifying single family residences are defined as new structures that have up to four residential dwelling units and multifamily residence as new structures having five or more residential dwelling units. The Company added Tariff language to the Builder Program in 2019 to set the definition for rebate-qualifying single family residences at three or fewer and multifamily at four or more residences. Additionally, the Company eliminated the 92% AFUE furnace as a rebate-eligible measure from the Builder Program and reduced the rebate amount for the tankless rebate measure by $50 in 2019. These changes were made for the reasons outlined in the Appliance Program discussion.

The Company also added Tariff language to the Builder Program in 2019 which defines the version of efficiency rating software that must be used by home energy raters (HERS) and also excludes solar energy as part of the calculation for whole-home single family rebate measures. These changes were made to ensure consistency across the community of HERS raters and establish a baseline for modeling natural gas savings.

Another 2019 Builder Program change is the addition of a pay-for-performance rebate measure for new multifamily properties. The Multifamily Performance measure compares the energy usage of new multifamily properties against a software-designed reference property. The reference property is based on existing Utah building codes. Incentives for this measure are based on the software's calculation of the difference between the natural gas usage of the reference and above-code multifamily properties. The Multifamily Performance measure is similar to the Commission-approved HERS rebates for single family properties offered by the Company beginning in the 2017 ThermWise® program year. The Company added this measure in an effort to be responsive to market conditions and to increase natural gas savings.

The Company will continue to perform outreach and marketing work in-house in 2019. Nexant will provide technical assistance and continue to perform rebate processing work for this program in 2019.

### *Utah ThermWise® Business Rebates*

The Company continued this program in 2019 with the elimination of the 92% AFUE furnace as a rebate-eligible measure for the reasons outlined in the Appliance Program discussion. The Company also increased the incentives for tier 2 and tier 3 boiler tune-ups by $50 in 2019. Under this scenario, tier 2 tune-ups increase to $200 and tier 3 tune-ups to $300. This change was made based on feedback from commercial customers, including several of the State's school districts, that the 2018 incentive amounts were not set at a level that would motivate them to take action triennially. For 2019, the Company also removed previous Tariff language which set a size limitation (<300 kBtu) on the tier 1 boiler tune-up measure. This limitation was erroneously included in the 2015 ThermWise® budget filing (Docket No. 14-057-25).

The Company additionally added six types of used food service equipment (charbroilers, combination ovens, commercial fryers, convection ovens, conveyor ovens, and steam cookers) to the list of rebate-eligible measures in 2019. Used food service equipment accounts for a large percentage of annual sales in the kitchen and restaurant equipment industry. Since used equipment had not historically been rebate-eligible through the Business Rebates Program, the Company believed that a large portion of the restaurant industry was not benefitting from this program and the resulting natural gas savings. The rebate for used food service equipment was made in an effort to encourage kitchens and restaurants to select the efficient models when purchasing used equipment. The rebate amount for each type of used food service equipment is half of the rebate for corresponding new equipment.

Additionally, the Company added the following equipment as rebate-eligible measures in 2019: 1) combined heat and power; 2) direct-fired heaters; 3) prescriptive energy recovery ventilators (ERV); 4) green certified new buildings; (5) boiler O2 trim controls; (6) boiler linkageless controls; (7) commercial find-and-fix $RC_{x;}$ and (8) commercial high performance building envelope.

Nexant will continue to perform rebate processing and assist with design, outreach, marketing, and technical assistance for this program in 2019.

## *Utah ThermWise® Weatherization Rebates*

The Company continued this program in 2019 with changes to the Tariff to align the definition of single and multifamily residences with those outlined in the 2019 Appliance Program discussion. Additionally, the Company changed the structure of the air sealing rebate measure and created a rebate based on building performance in the Pilot Multifamily Program.

The 2018 air sealing rebate measure, originally proposed in Docket No. 11-057-12, was intended to incent customers to seal penetrations in residential structures, thereby reducing the number of air changes per hour and the corresponding heat losses. The incentive for this measure was previously structured to provide a base incentive of $100 per home with an additional $.18 per square foot of area sealed. The measure is capped at a maximum rebate of $850 per single family residence. 2018 market feedback indicated that weatherization contractors were avoiding smaller square footage homes because of the incentive structure at the time. In order to address this issue, the Company changed the structure in 2019 by increasing the base incentive to $200, reduced the per square foot portion of the incentive to $.12, and maintained the maximum rebate limitation at $850 per home. The Company believes these changes will incent weatherization contractors to promote this measure to all homes, regardless of size, while also ensuring positive cost-effectiveness results.

In 2018, the Company launched a three-year pilot initiative, through the Weatherization Program, designed to achieve natural gas savings in both low-income and market rate multifamily properties. This initiative, called the Pilot Multifamily Program, aims to entice multifamily property owners to implement comprehensive energy efficiency retrofits and replace energy systems across the entire property instead of waiting to replace equipment at the point of failure. The Company selected the ICAST to administer the three year pilot initiative. The Pilot Multifamily Program has seen good participation and market uptake since introduction in 2018. However, the Company recognized in 2018 that the existing Tariff limited payment for natural gas savings to the prescriptive rebate measures in the Appliance, Builder, and Weatherization programs. Based on feedback from ICAST, the Company believed that additional natural gas savings could be achieved with a second rebate path. Therefore, the Company added an incentive method that is paid based on the overall performance of existing multifamily properties in 2019. This path is structured, and natural gas savings modeled, similarly to the pay-for-performance measure detailed in the 2019 Builder Program discussion.

Nexant will continue to perform rebate processing and assist with technical assistance for this program in 2019.

## *Utah ThermWise® Home Energy Plan*

The ThermWise® Home Energy Plan program is offered and administered by the Company with periodic consulting and assistance from Nexant. This program includes two primary components: an in-home energy plan performed by trained and experienced Company auditors and a “do-it-yourself” mail-in plan with on-line data input availability. This program will continue to be available to customers in the Company’s Utah service territory in 2019.

## *Utah Low-Income Efficiency Program*

The Company will continue funding the Low-Income Efficiency Program in 2019 at $500,000 per year 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.

The Company eliminated the 92% AFUE furnace as a rebate-eligible measure, for the reasons outlined in the 2019 Appliance Program discussion. The Company also added the smart thermostat as a rebate-eligible measure in the Low-Income Efficiency Program for 2019. Throughout 2018, the Utah Weatherization Assistance Program (Utah WAP), the administrator of the Low-Income assistance funds provided by the Company, studied and tracked the performance of smart thermostats in other areas of the country. Particularly, data from a pilot program in the Colorado Weatherization Assistance Program (Colorado WAP) showed significant natural gas savings had been achieved in low income homes where a smart thermostat had been installed. Utah WAP will begin installing ThermWise-qualifying smart thermostats in 2019. The initial installations will be focused on Home Energy Assistance Target (HEAT) qualified customers in order to achieve maximum natural gas savings impact. An additional benefit of this measure is that rebate funds provided by the Company will be rolled back into Utah WAP’s budget, thereby allowing Utah WAP to complete additional statewide low-income work.

## *Utah ThermWise® Energy Comparison Report*

In 2019 the Company will send the ECR to more than 224,000 of its customers. As of the end of September 2018, the Comparison Report had been generated over 305,000 times online by nearly 120,000 unique customers.

The Company will decrease delivery of the Comparison Report to 224,000 in 2019. The Company realizes this total number by pausing Groups B and D beginning August and December 2018 respectively, and adding Group G which will be delivered to 25,000 additional customers in 2019.

While program participants will decrease from 2018, natural gas savings will increase by 34% in 2019. The Company expects savings to increase because of the expansion of the Comparison Report in 2019 and because of savings persistence. The Company conducted a study in 2018 that focused analysis on the current recipients of the report (Groups B, C, D, and E). The study showed weather-normalized usage reductions per participant of 1.62

Dth/year. As a result, the Company updated the natural gas savings number from 1.22 Dth/year in the 2018 Model, to 1.62 Dth/year in the 2019 Model.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2019 budget filing is shown in Table 13.2 below.

**Table 13.2 - Utah 2019 projected NPV & BC ratios by program and California Standard Practice Test**

| 2019 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 Program | $4.87 | 1.72 | $22.79 | 4.25 | $5.65 | 1.96 | -$0.91 | 0.93 |
| ThermWise® Builder Program | $1.03 | 1.17 | $11.75 | 2.72 | $2.33 | 1.49 | -$1.48 | 0.83 |
| ThermWise® Business Program | $2.00 | 1.35 | $14.58 | 3.60 | $4.08 | 2.13 | $0.71 | 1.10 |
| ThermWise® Weatherization Program | $3.22 | 1.39 | $19.17 | 3.08 | $3.66 | 1.47 | -$2.03 | 0.85 |
| ThermWise® Home Energy Plan Program | $0.28 | 1.42 | $2.80 | 54.58 | $0.27 | 1.40 | -$0.32 | 0.75 |
| Low-Income Efficiency Program | $0.52 | 1.55 | $2.58 | 5.89 | $0.60 | 1.69 | -$0.22 | 0.87 |
| ThermWise® Energy Comparison Report | $0.17 | 1.27 | $2.52 | 5.42 | $0.17 | 1.27 | -$0.52 | 0.61 |
| Market Transformation Initiative | -$1.32 | 0.00 | $0.00 | N/A | -$1.32 | 0.00 | -$1.32 | 0.00 |
| **TOTALS** | **$10.77** | **1.35** | **$76.20** | **3.56** | **$15.44** | **1.60** | **-$6.08** | **0.87** |

*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 2019 NPV & B/C ratios using gas cost forward curve from SENDOUT model**

| 2019 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 Program | $2.43 | 1.36 | $22.79 | 4.25 | $3.21 | 1.54 | -$3.34 | 0.73 |
| ThermWise® Builder Program | -$0.57 | 0.91 | $11.75 | 2.72 | $0.73 | 1.15 | -$3.08 | 0.64 |
| ThermWise® Business Program | $0.37 | 1.06 | $14.58 | 3.60 | $2.45 | 1.68 | -$0.91 | 0.87 |
| ThermWise® Weatherization Program | $0.55 | 1.07 | $19.17 | 3.08 | $0.99 | 1.13 | -$4.70 | 0.65 |
| ThermWise® Home Energy Plan Program | $0.15 | 1.22 | $2.80 | 54.58 | $0.14 | 1.20 | -$0.45 | 0.64 |
| Low-Income Efficiency Program | $0.20 | 1.21 | $2.58 | 5.89 | $0.29 | 1.33 | -$0.53 | 0.68 |
| ThermWise® Energy Comparison Report | $0.32 | 1.50 | $2.52 | 5.42 | $0.32 | 1.50 | -$0.37 | 0.73 |
| Market Transformation Initiative | -$1.32 | 0.00 | $0.00 | N/A | -$1.32 | 0.00 | -$1.32 | 0.00 |
| **TOTALS** | **$2.14** | **1.07** | **$76.20** | **3.56** | **$6.81** | **1.27** | **-$14.71** | **0.69** |

*Shown in millions

## WYOMING ENERGY-EFFICIENCY PLAN FOR 2019

The Company expects tenth-year participation in the portfolio of Wyoming ThermWise® programs to reach 858 customers which would be an increase of 18% from the 2018 budget participation levels.

## SENDOUT MODEL RESULTS FOR 2019

The Company entered projections from the approved 2019 energy-efficiency budget into the SENDOUT model in response to the Utah Commission’s request. Data entries for the 2019 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 2019 participation and administration costs as the baseline for its analysis of each program. For each program, the model examined what would happen if participation reduced to 25% or increased to 150% of the 2019 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 2019 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 12.1 for the SENDOUT results in a table format.

The model accepted the 2019 ThermWise® Appliance and Weatherization programs at 25% of 2019 projected participation if administration costs were increased to 200% of the 2019 budget projection. The model accepted the Builder and Business programs at 50% of participation and 200% of the 2019 budget projection. The model accepted the Energy Comparison Report at 75% of participation and 200% of the 2019 budget projection. The model accepted the Home Energy Plan program at 100% of participation and 200% of the 2019 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 2019 projection. In this scenario, the administration costs for the Appliance and Weatherization programs could increase by eight times the 2019 budget projection and still be accepted. The Builder and Business programs could increase projected administration costs by four times and still be accepted. The Energy Comparison Report could increase projected administration costs by more than two times and still be accepted. The Home Energy Plan could double projected administration costs 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 2019 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 2019 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 1,203,472 Dth in 2019. This analysis resulted in a projected potential total energy-efficiency spending limit of $32.4 million per year using the Utility Cost Test. The currently-approved $25.5 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 2018, the avoided gas cost attributable to energy-efficiency was calculated to be $36.2 million. For 2019, the avoided gas cost attributable to energy efficiency is estimated to be $32.4 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

# 2019 Energy-Efficiency Modeling Results from SENDOUT

| Program @ 100% of 2019 Budget $ | % of 2019 Budget Participation | | | | |
|---|---|---|---|---|---|
| | 25% | 50% | 75% | 100% | 150% |
| ThermWise Appliance Program | | | | | |
| ThermWise Builder Program | | | | | |
| ThermWise Business Program | | | | | |
| ThemWise 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 @ 150% of 2019 Budget $ | % of 2019 Budget Participation | | | | |
|---|---|---|---|---|---|
| | 25% | 50% | 75% | 100% | 150% |
| ThermWise Appliance Program | | | | | |
| ThermWise Builder Program | | | | | |
| ThermWise Business Program | | | | | |
| ThemWise 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 @ 200% of 2019 Budget $ | % of 2019 Budget Participation | | | | |
|---|---|---|---|---|---|
| | 25% | 50% | 75% | 100% | 150% |
| ThermWise Appliance Program | | | | | |
| ThermWise Builder Program | | | | | |
| ThermWise Business Program | | | | | |
| ThemWise 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 is owned by ABB, a global power and automation technology group headquartered in Zurich, Switzerland with approximately 132,000 employees. 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 consultants from Ventyx. The Ventyx consultants are 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.

## 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 more widely accepted as a method for achieving optimal solutions in practical applications. In summary, linear programming problems involve the optimization of a linear objective function subject to linear constraints.

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

Constraints must accurately reflect the problem being solved. The arbitrary removal of required constraints results in 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.

## MODEL IMPROVEMENTS

The Company made one modification to the SENDOUT model for the 2019-2020 IRP. The discount rate used in the model was adjusted to 4.37% 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 1,306 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 PIRA (67 months) and CERA (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.

## 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 1,405 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 2019-2020 heating season is approximately 1.220 MMDth per day at the city gates. The most likely day for a Design Day to occur is on January 2, 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.[1] 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 1,194 draws generated in this process, three draws would exceed the Design Day requirement of 1.220 MMDth. 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-peak-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.

## 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 56.7 MMDth. The Company is confident that, for a colder-than-normal year, sufficient purchased-gas resources will be available in the market. Likewise, the Company is confident that in the event of a warmer-than-normal year, it has not contracted for too much gas.

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

## 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 65.9 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 $640 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 $13.1 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.[2] 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 138 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 138 MMDth demand for the normal case.

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

## 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).[3]

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**

| | | Demand (Thousands of Dths) | | |
|---|---|---|---|---|
| | | One Standard Deviation Warmer | Normal Temperatures | One Standard Deviation Colder |
| Cost-of-service gas | Low 10% | 0.0 | 0.0 | 0.0 |
| | IRP Forecast | 1,041.7 | 506.3 | 1,041.7 |
| | High 10% | 4,031.7 | 1,773.8 | 1,392.0 |

**Table 14.2: Total Annual Production Costs**

| | | Demand (Millions of Dollars) | | |
|---|---|---|---|---|
| | | One Standard Deviation Warmer | Normal Temperatures | One Standard Deviation Colder |
| Cost-of-service gas | Low 10% | $569.9 | $644.7 | $569.9 |
| | IRP Forecast | $566.8 | $639.9 | $566.8 |
| | High 10% | $567.5 | $635.6 | $715.7 |

[3] 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.

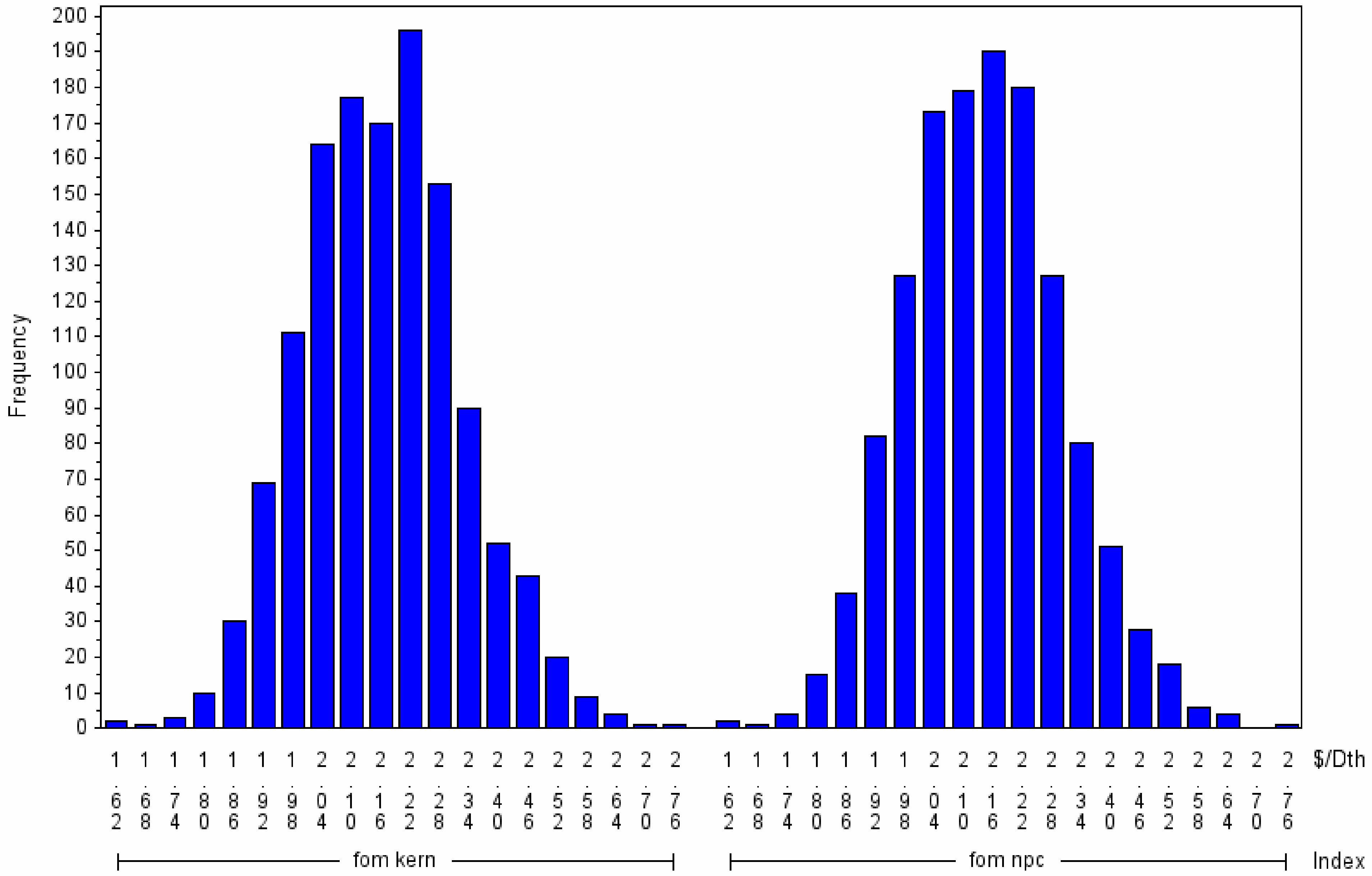
Exhibit 14.01

# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=6



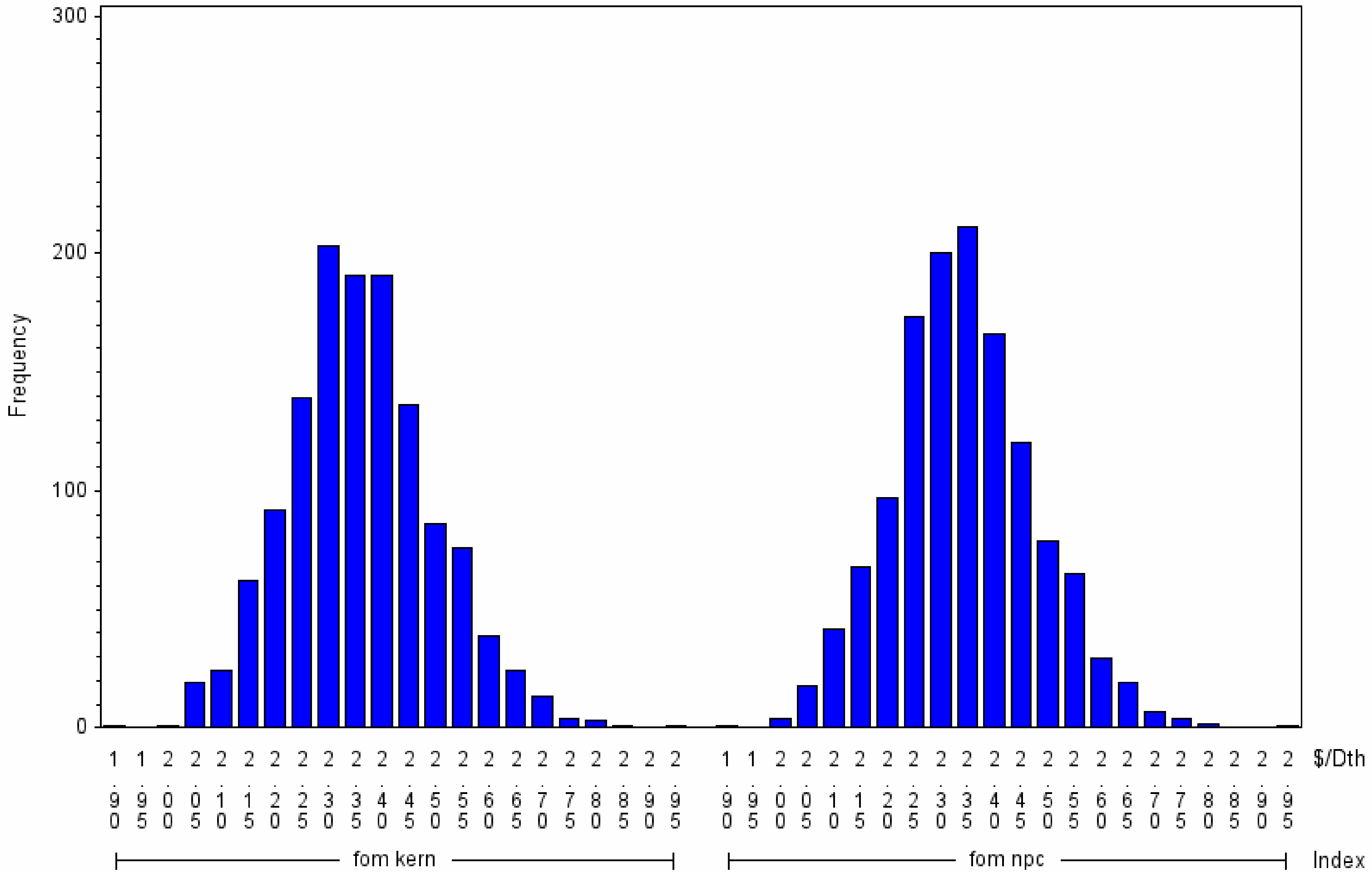
# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=7

Exhibit 14.02



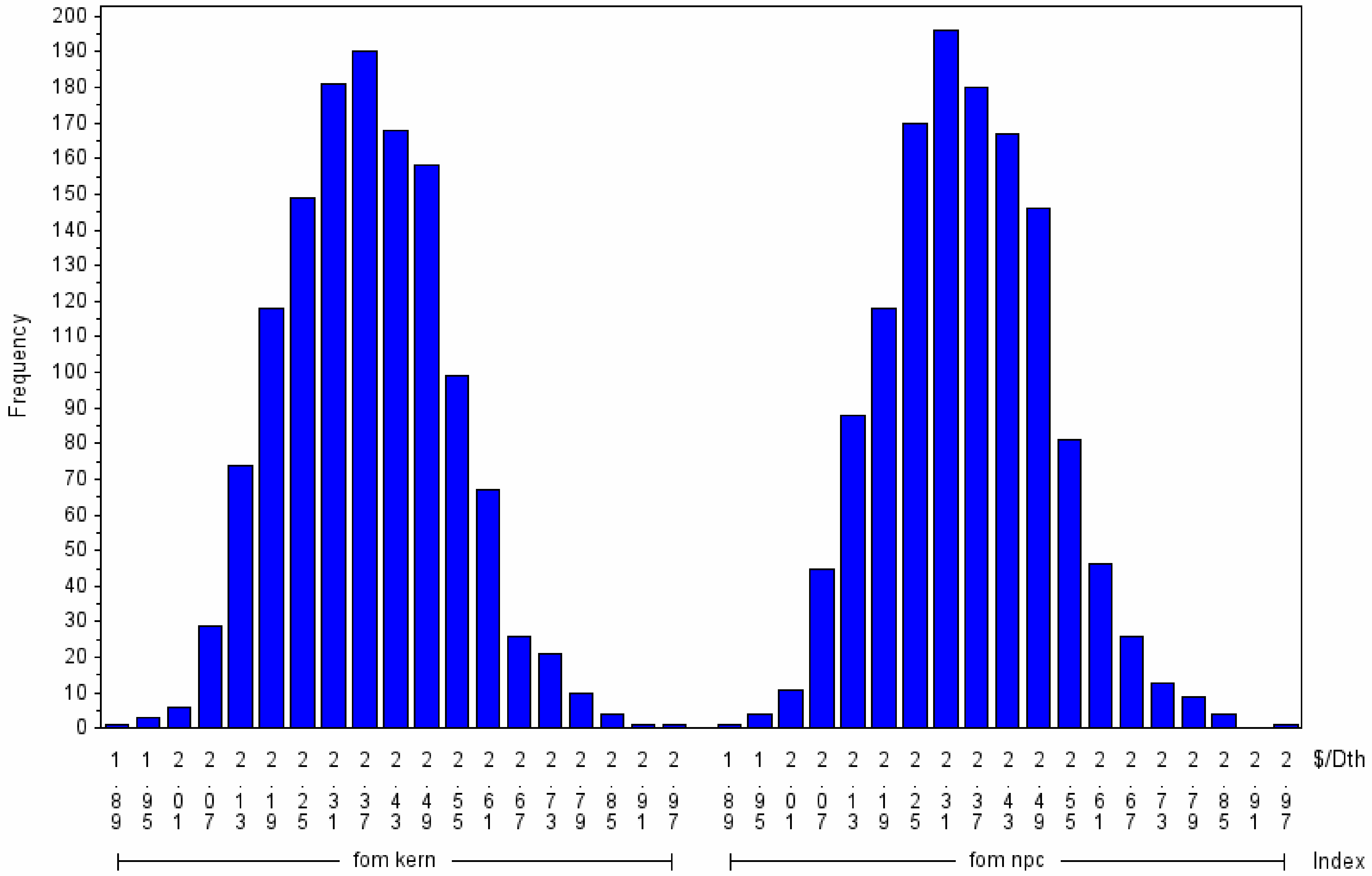
# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=8

Exhibit 14.03



# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=9

Exhibit 14.04

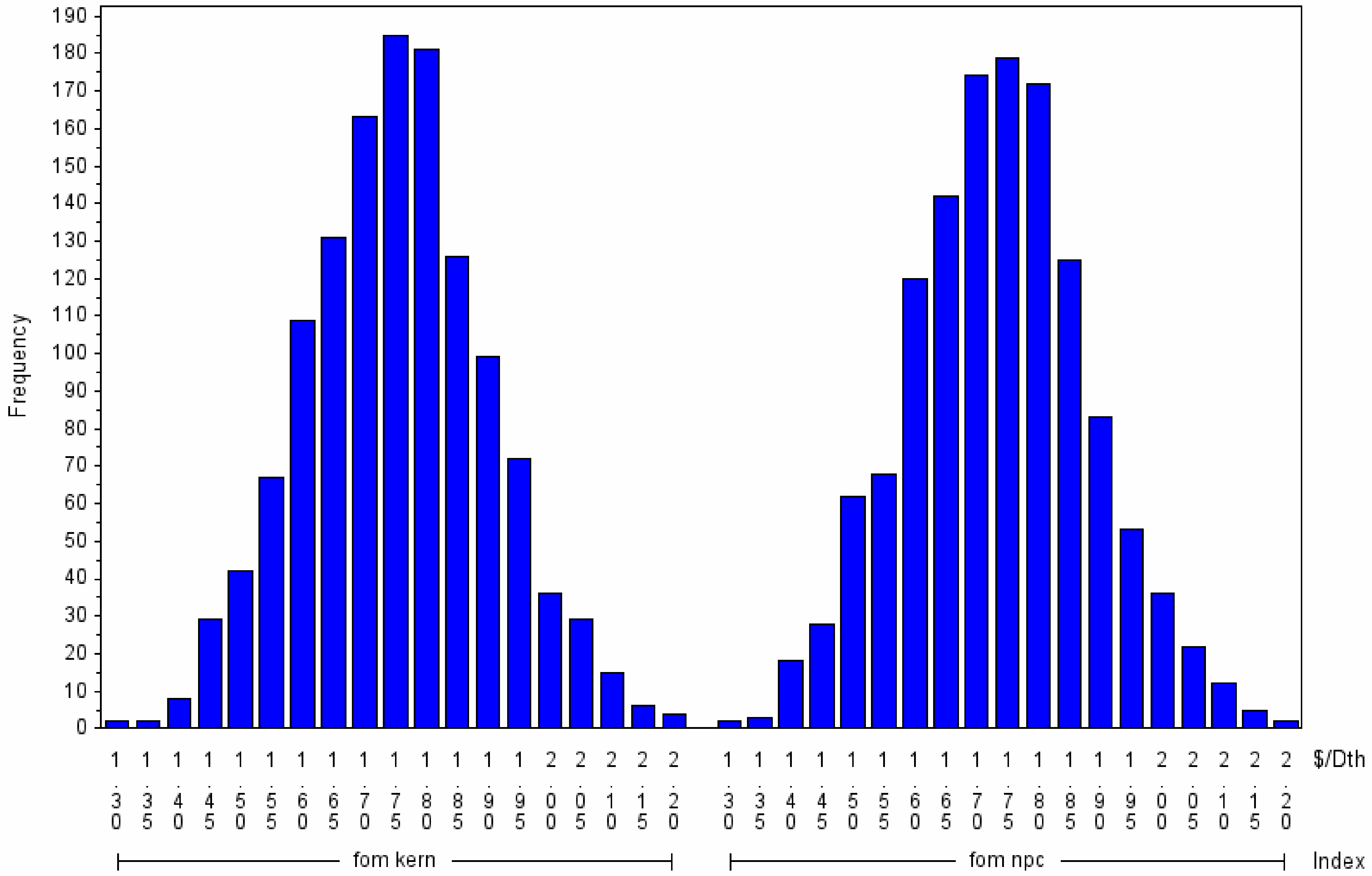


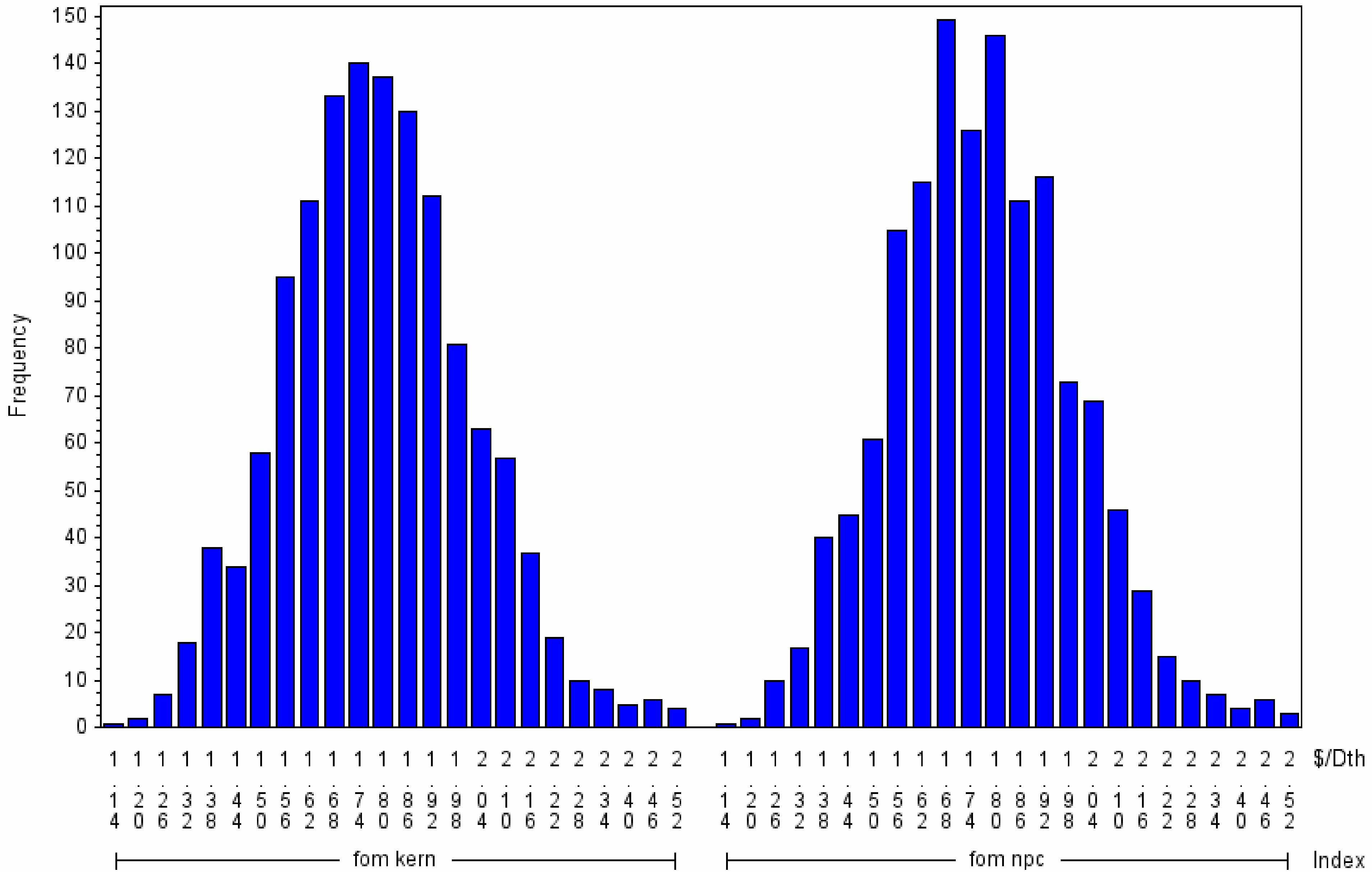
Exhibit 14.05

# Monthly FOM Index Price Distribution

**2019 Plan Year**

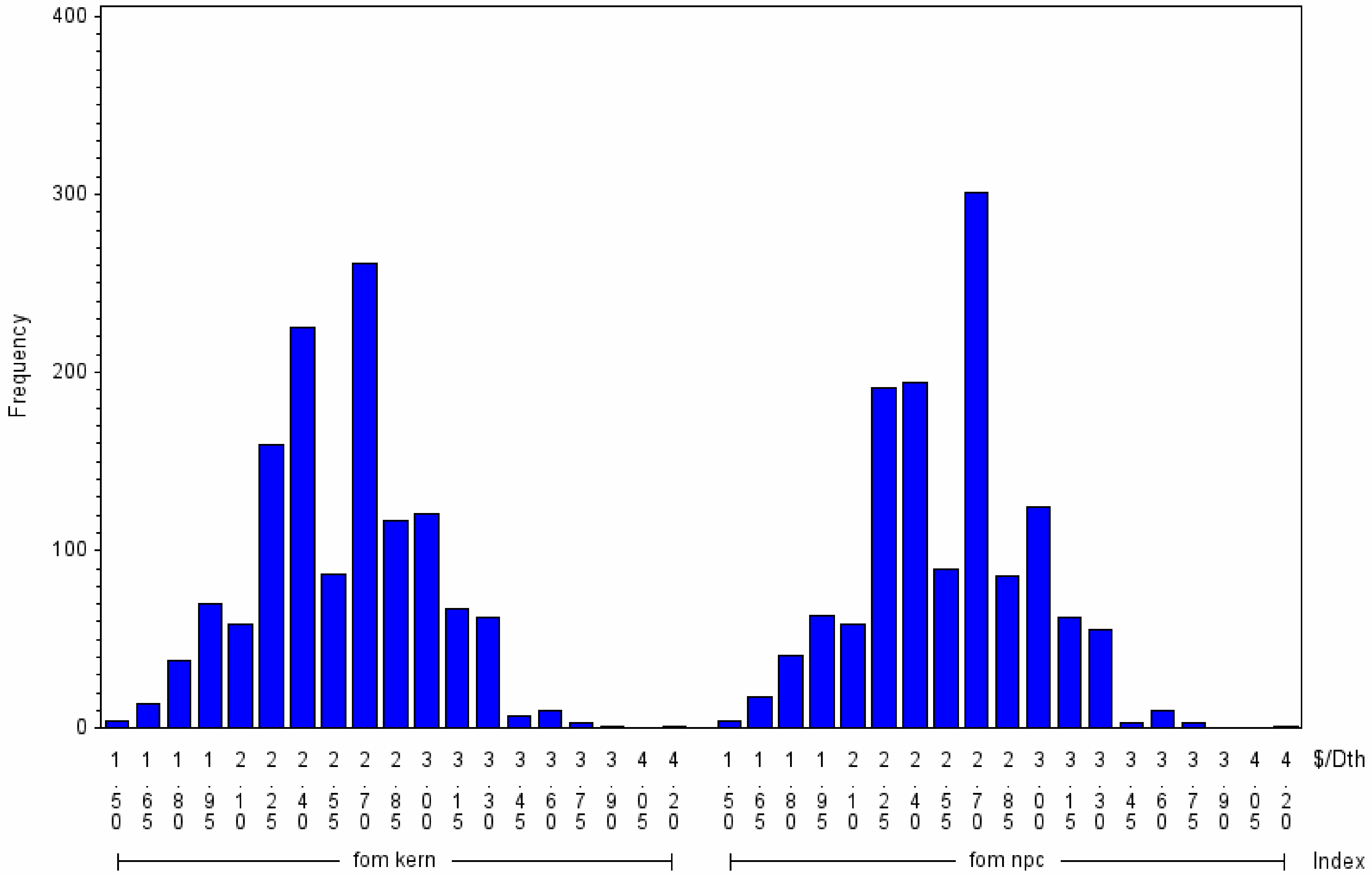
**Scenario 1001 : 1306 Draws**

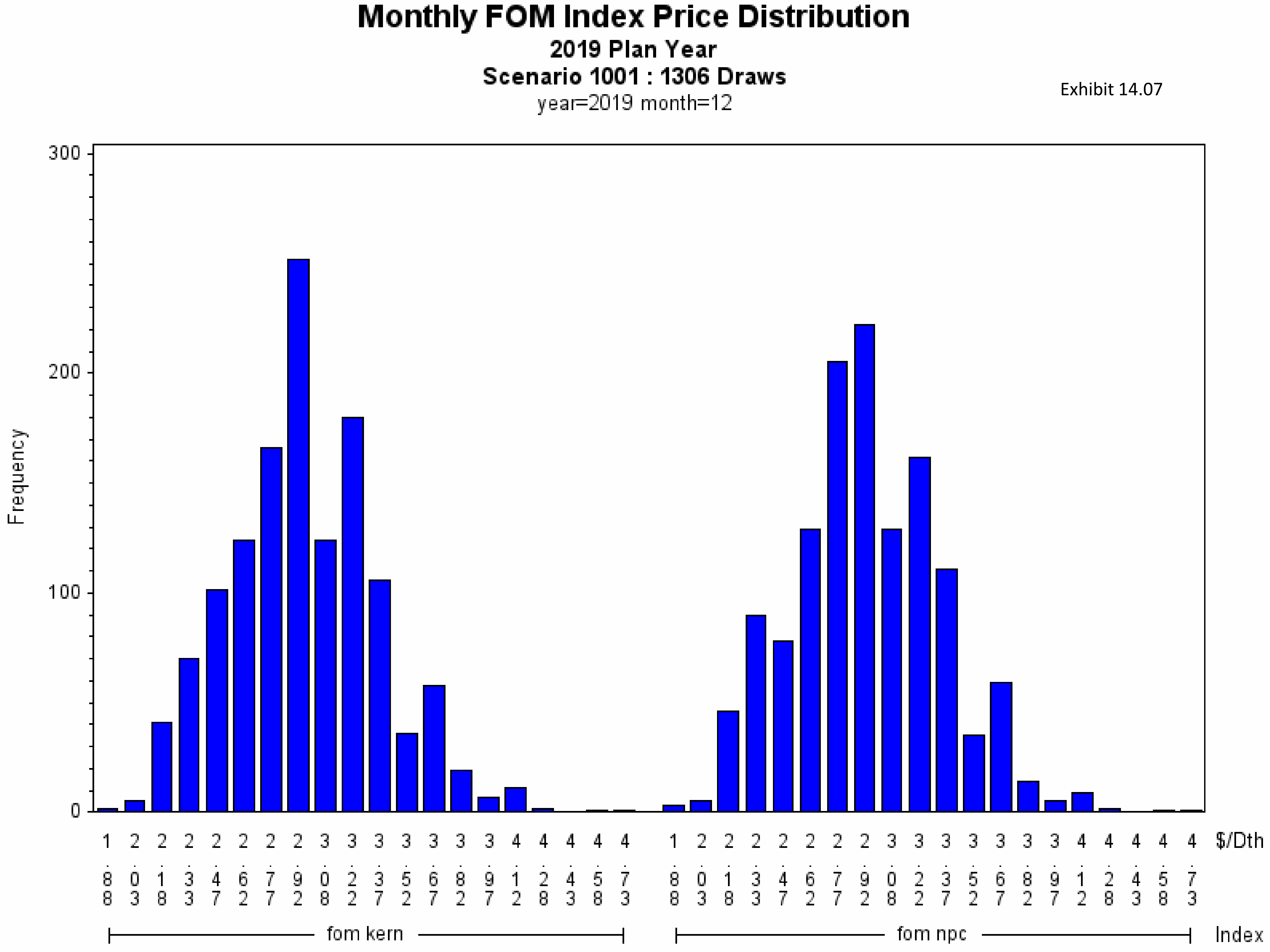
year=2019 month=10



# Monthly FOM Index Price Distribution
## 2019 Plan Year
## Scenario 1001 : 1306 Draws
year=2019 month=11

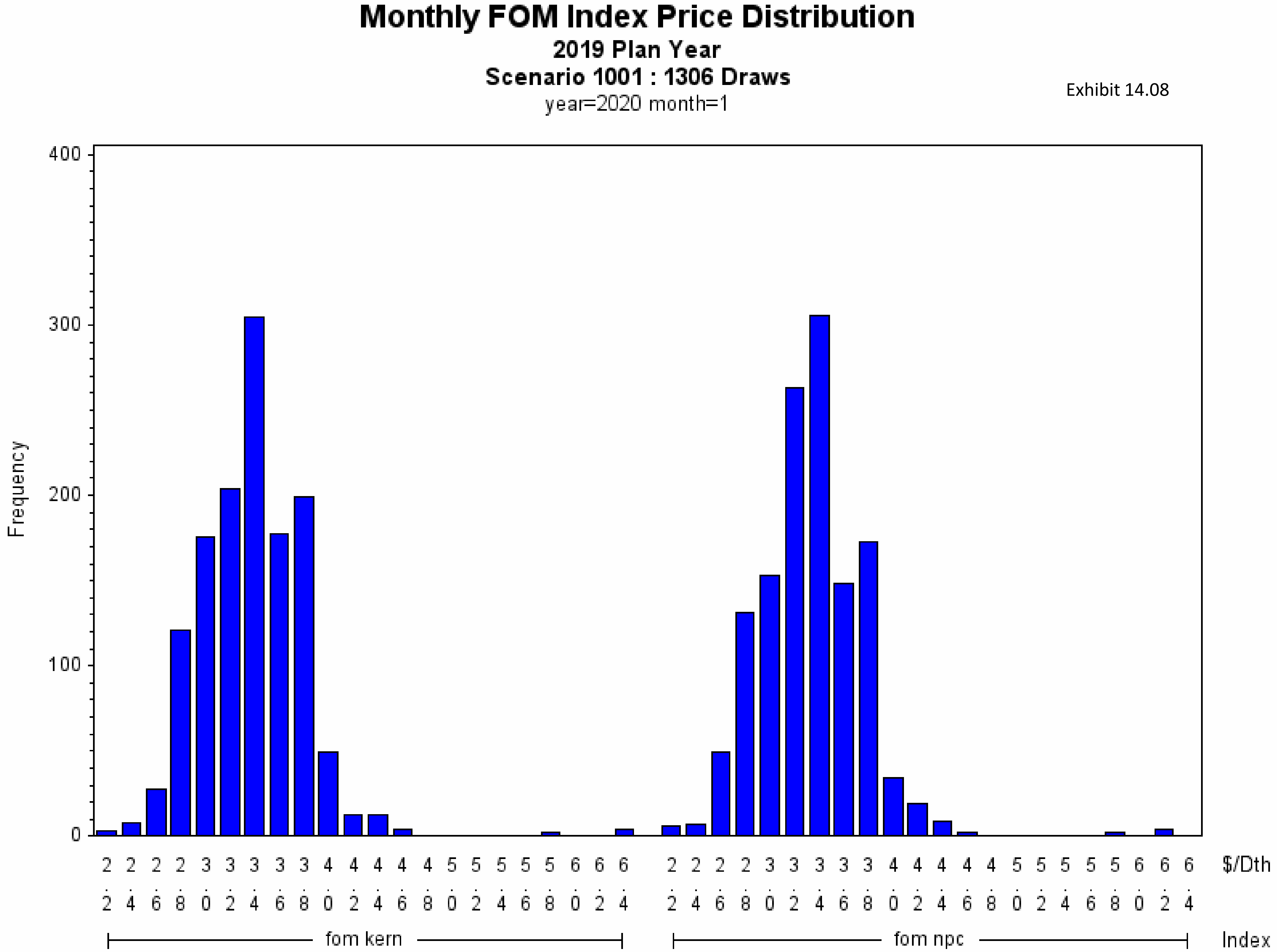
Exhibit 14.06





Monthly FOM Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2019 month=12
Exhibit 14.07
Frequency
300
200
100
0
$/Dth
1.88 2.03 2.18 2.33 2.47 2.62 2.77 2.92 3.08 3.22 3.37 3.52 3.67 3.82 3.97 4.12 4.28 4.43 4.58 4.73
1.88 2.03 2.18 2.33 2.47 2.62 2.77 2.92 3.08 3.22 3.37 3.52 3.67 3.82 3.97 4.12 4.28 4.43 4.58 4.73
fom kern
fom npc
Index

Exhibit 14.08



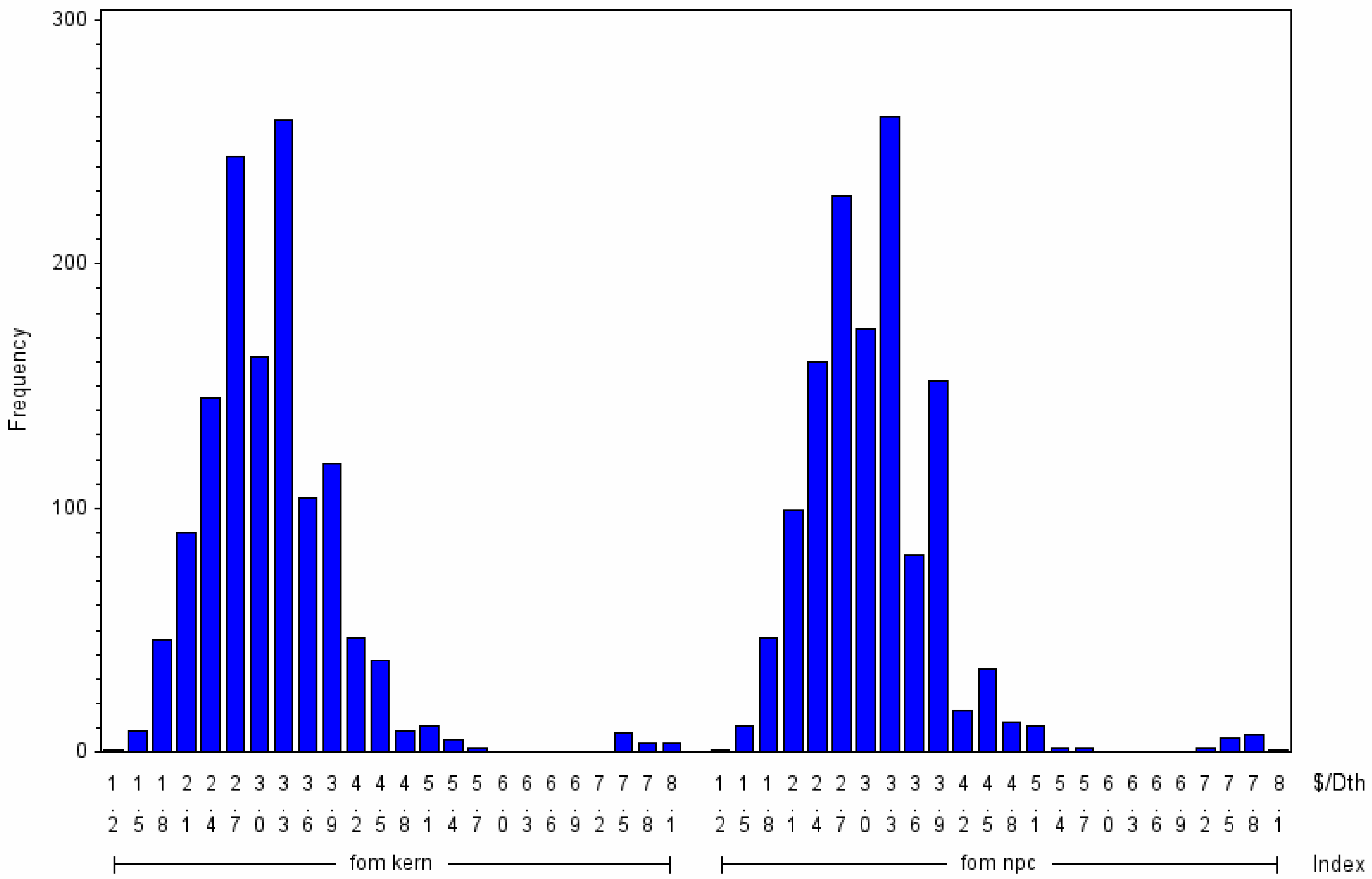
# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=2

Exhibit 14.09



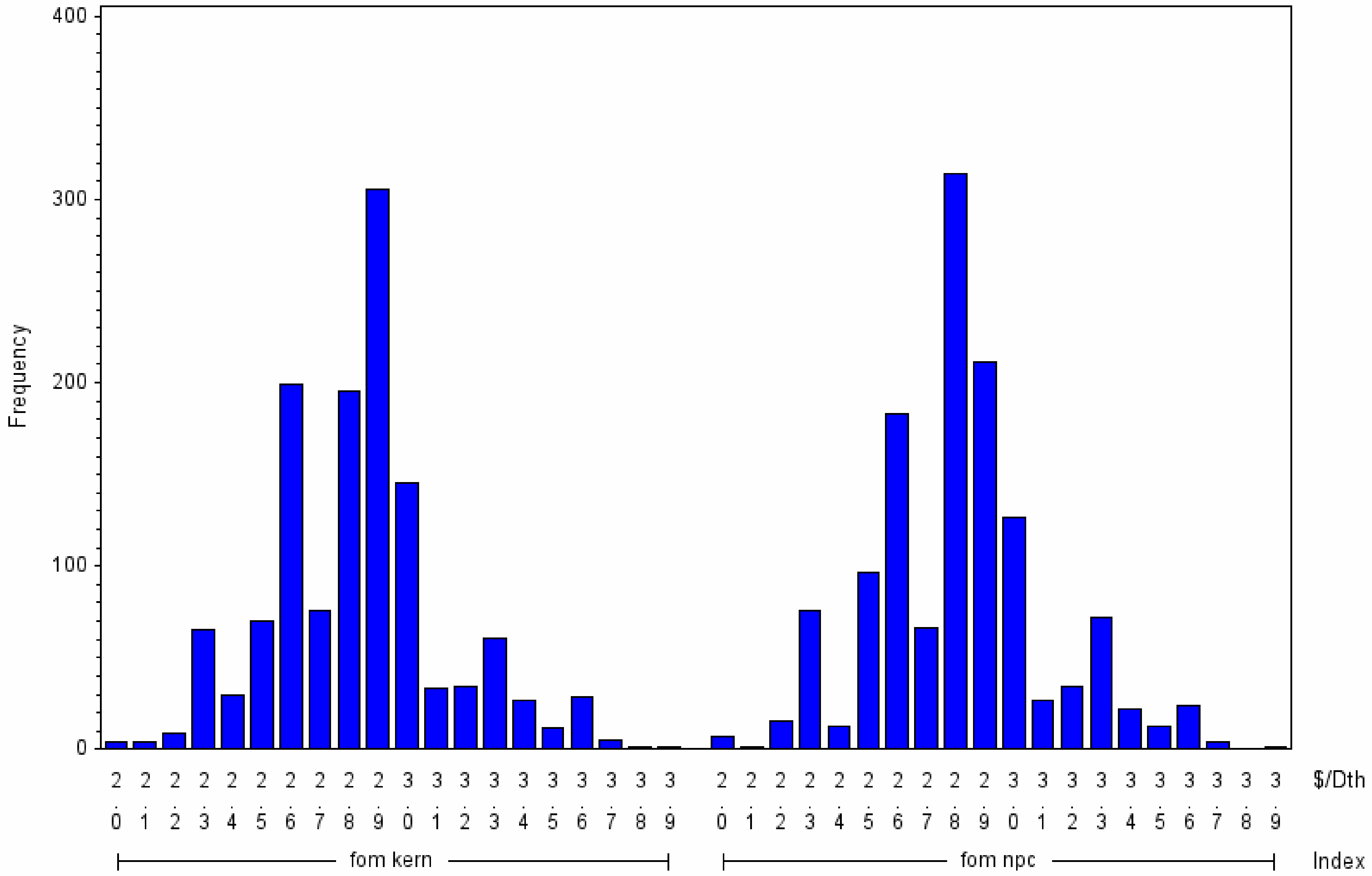
# Monthly FOM Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=3

Exhibit 14.10



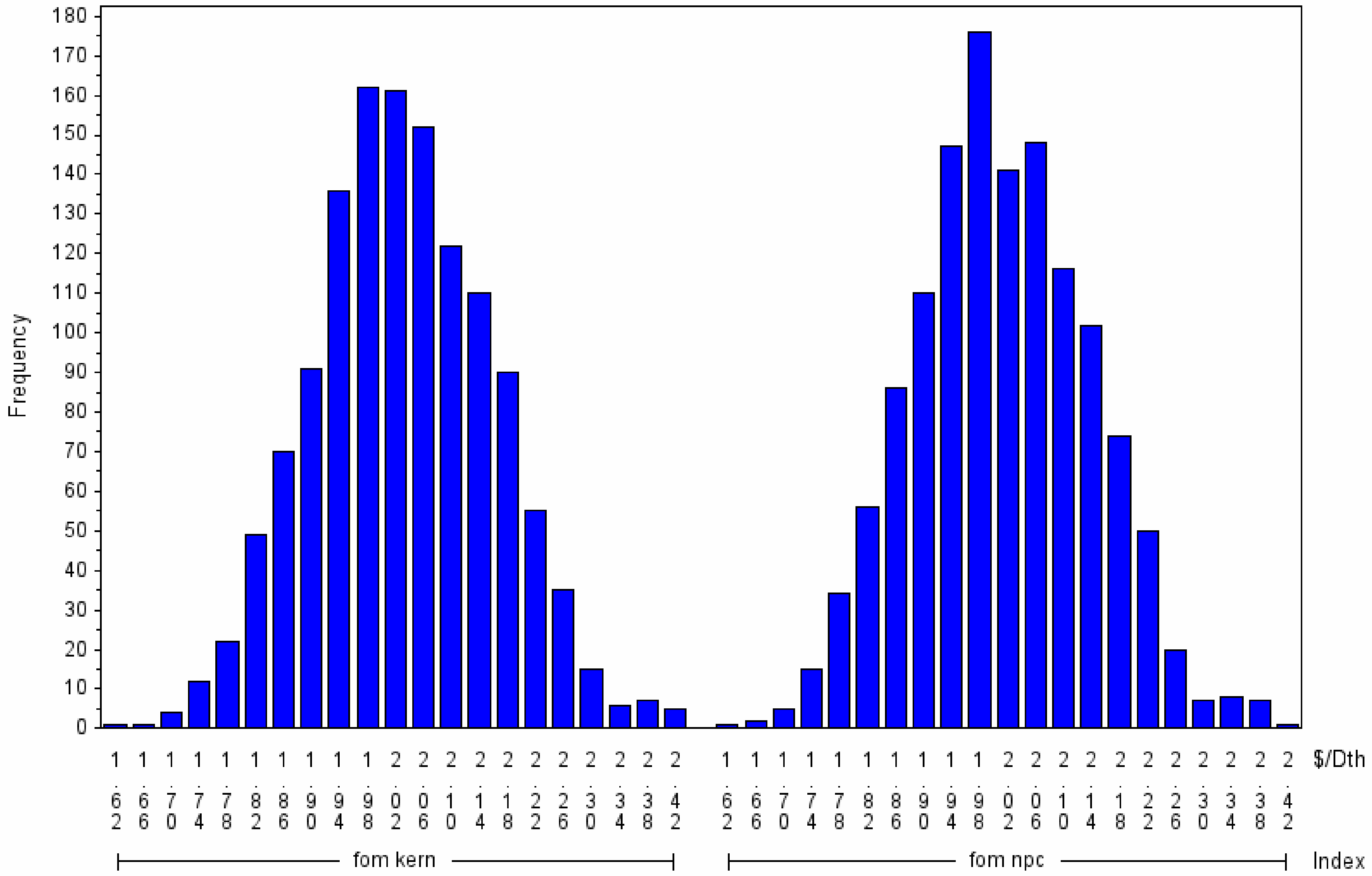
# Monthly FOM Index Price Distribution

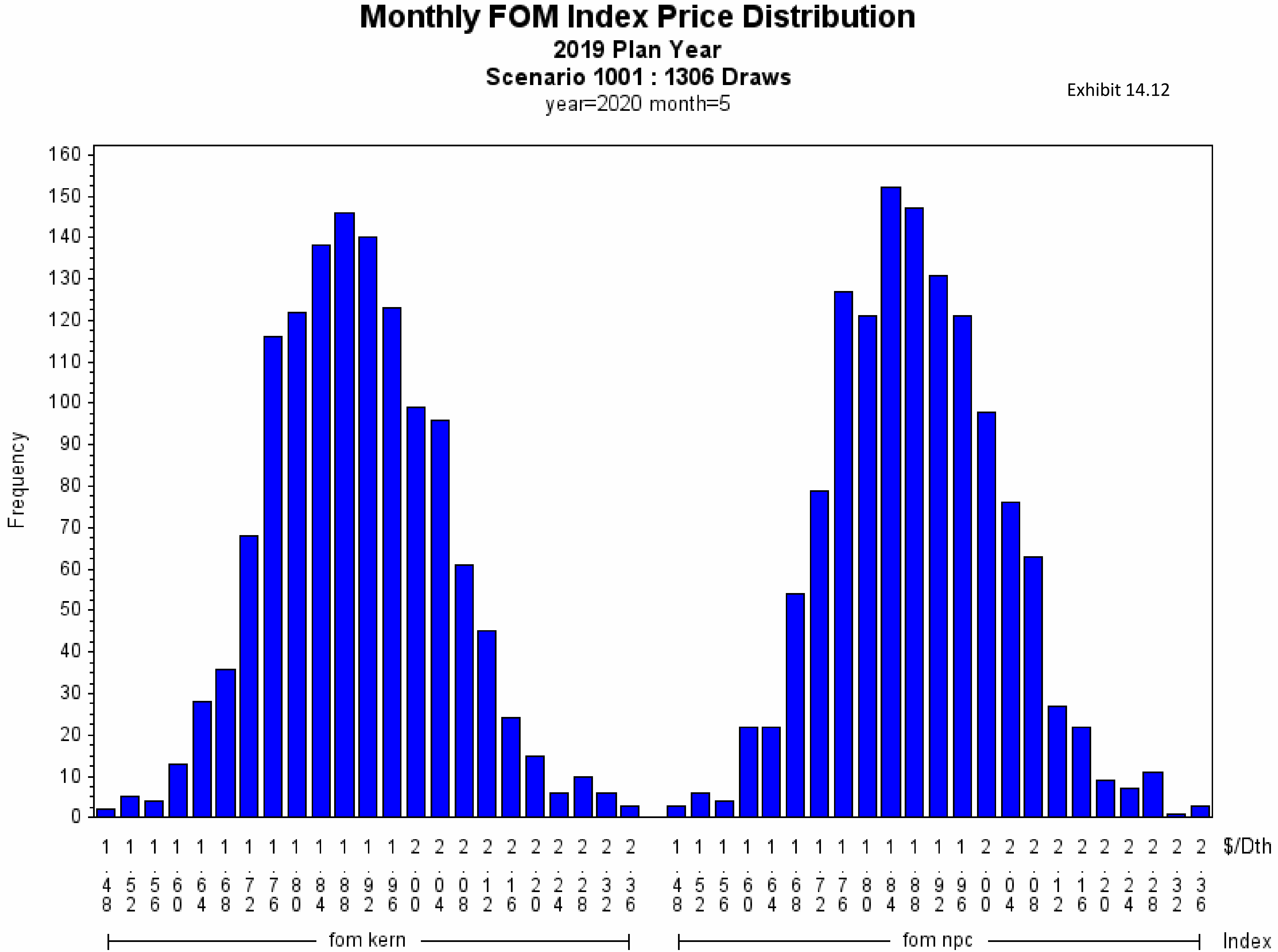
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=4

Exhibit 14.11




Monthly FOM Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=5
Exhibit 14.12
Frequency
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
$/Dth
1.48 1.52 1.56 1.60 1.64 1.68 1.72 1.76 1.80 1.84 1.88 1.92 1.96 2.00 2.04 2.08 2.12 2.16 2.20 2.24 2.28 2.32 2.36
1.48 1.52 1.56 1.60 1.64 1.68 1.72 1.76 1.80 1.84 1.88 1.92 1.96 2.00 2.04 2.08 2.12 2.16 2.20 2.24 2.28 2.32 2.36
fom kern
fom npc
Index

# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=6

Exhibit 14.13

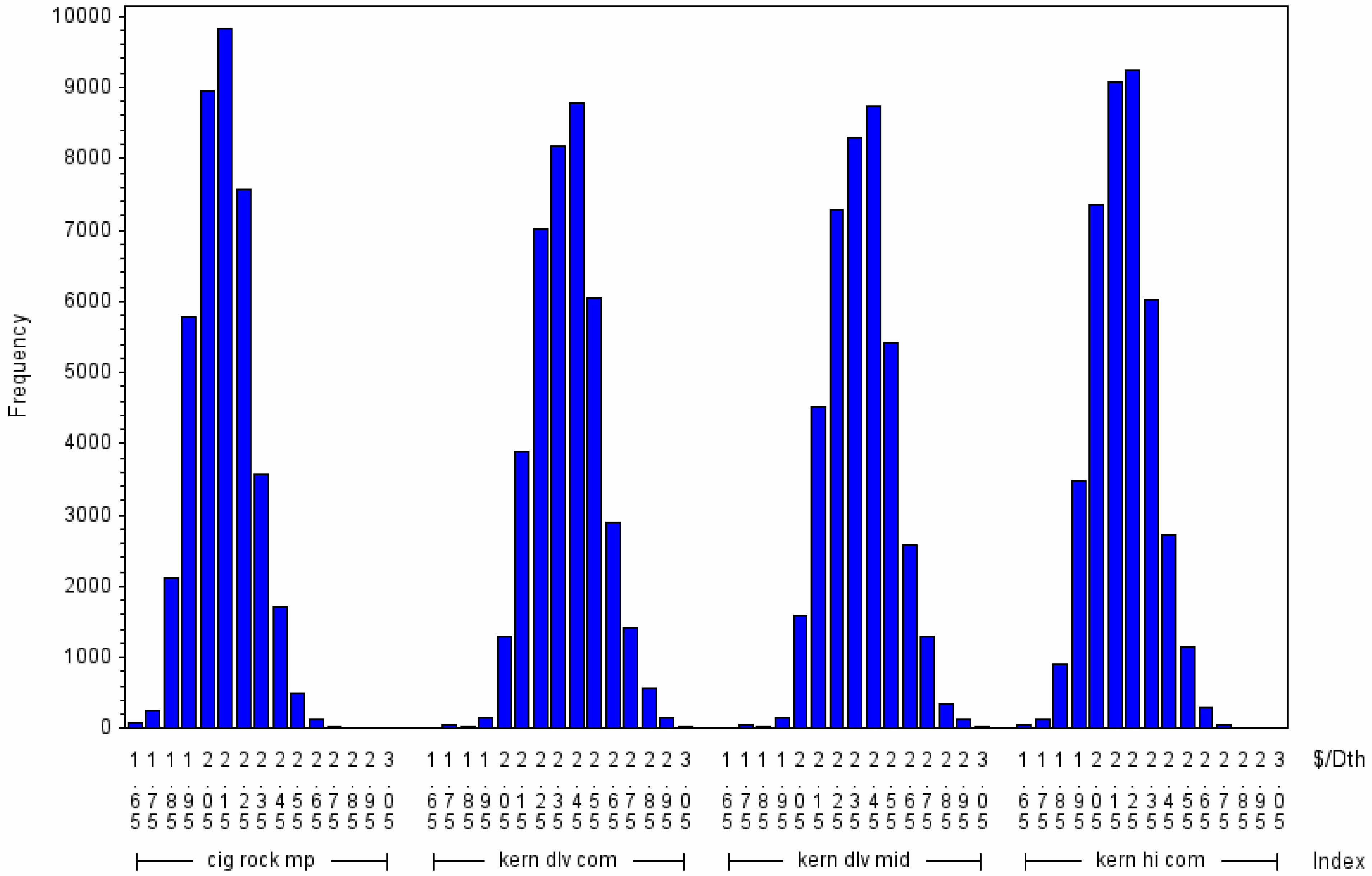
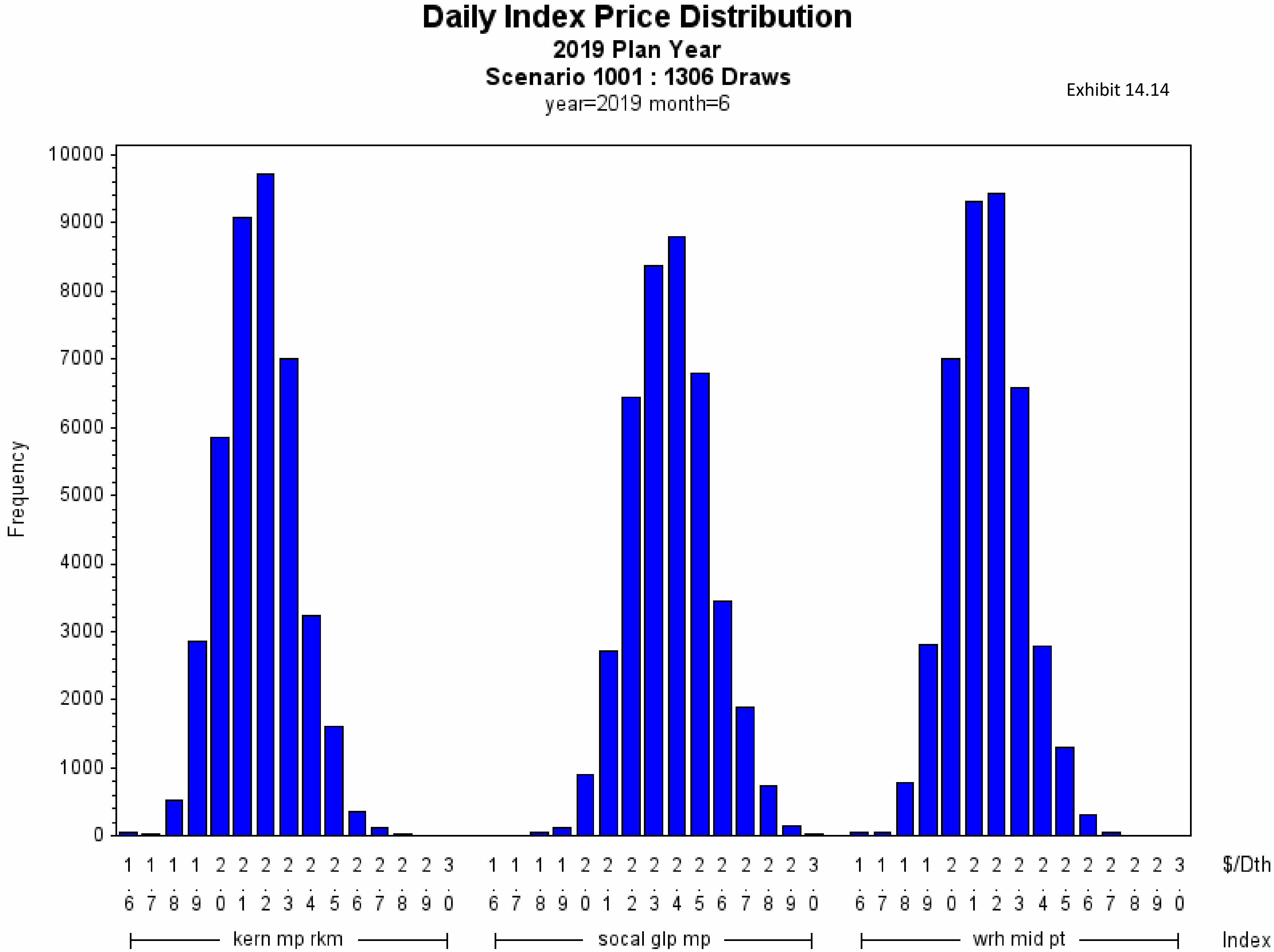


Exhibit 14.14



# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=7

Exhibit 14.15

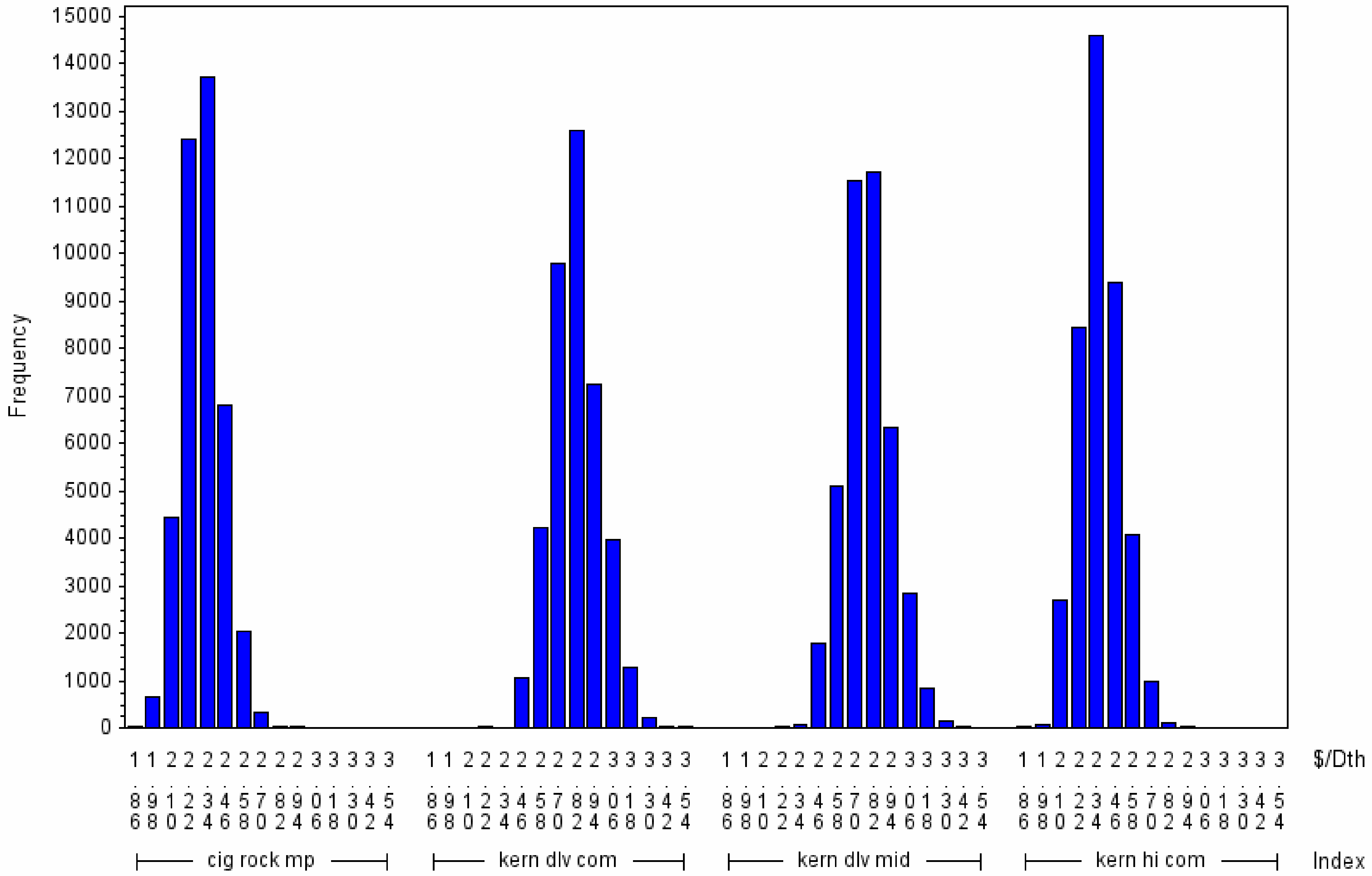


Exhibit 14.16

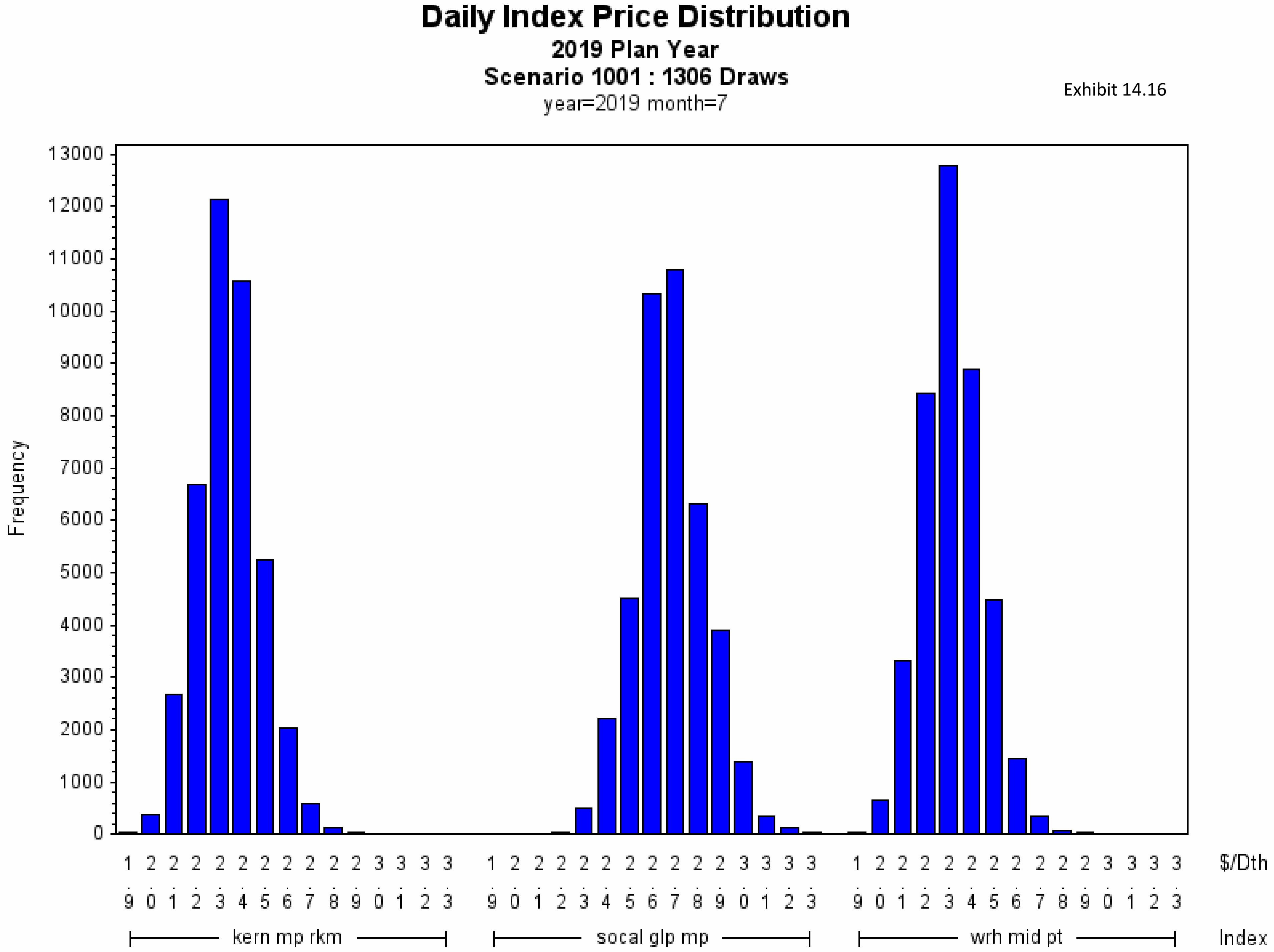


Exhibit 14.17

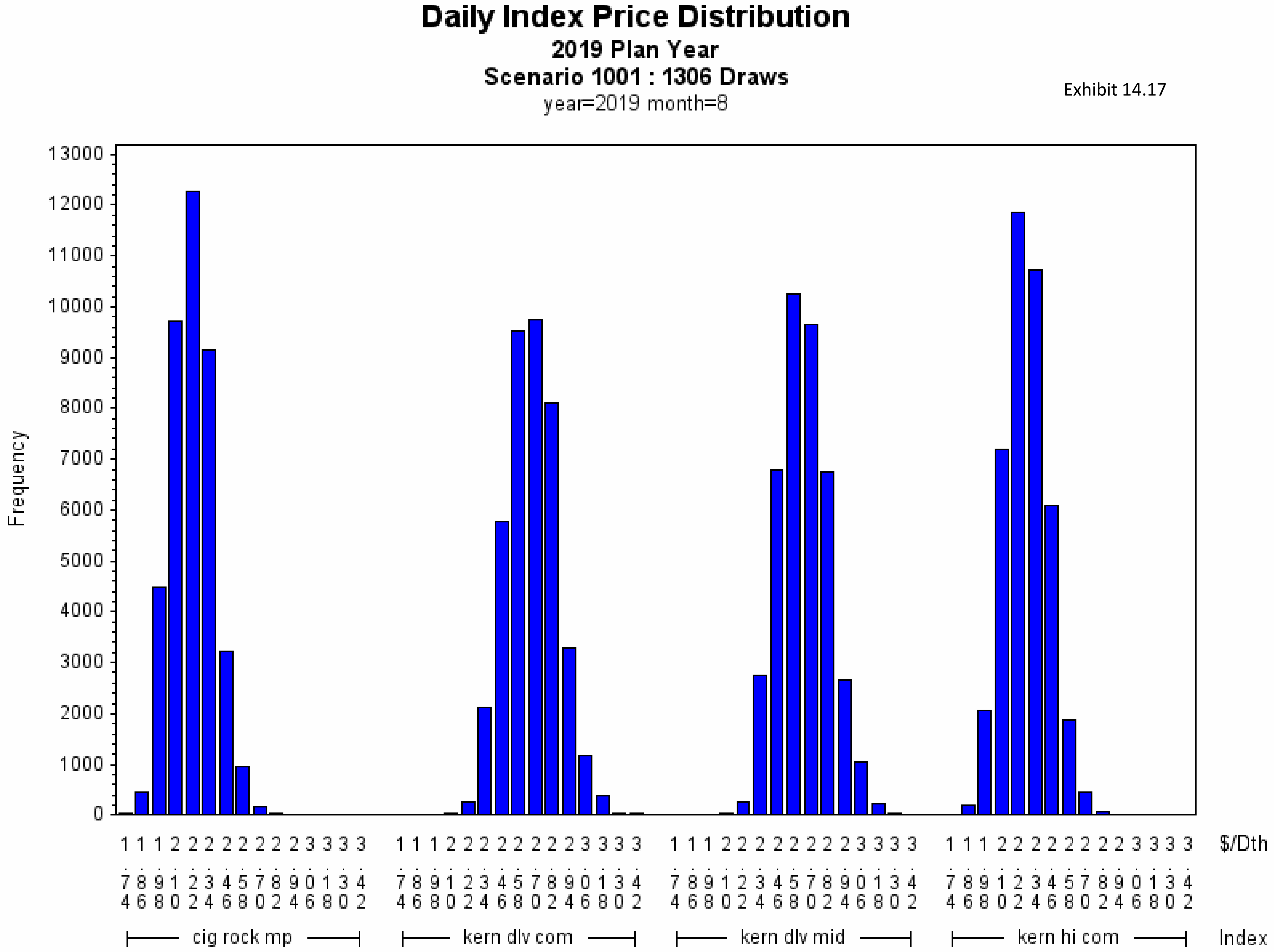


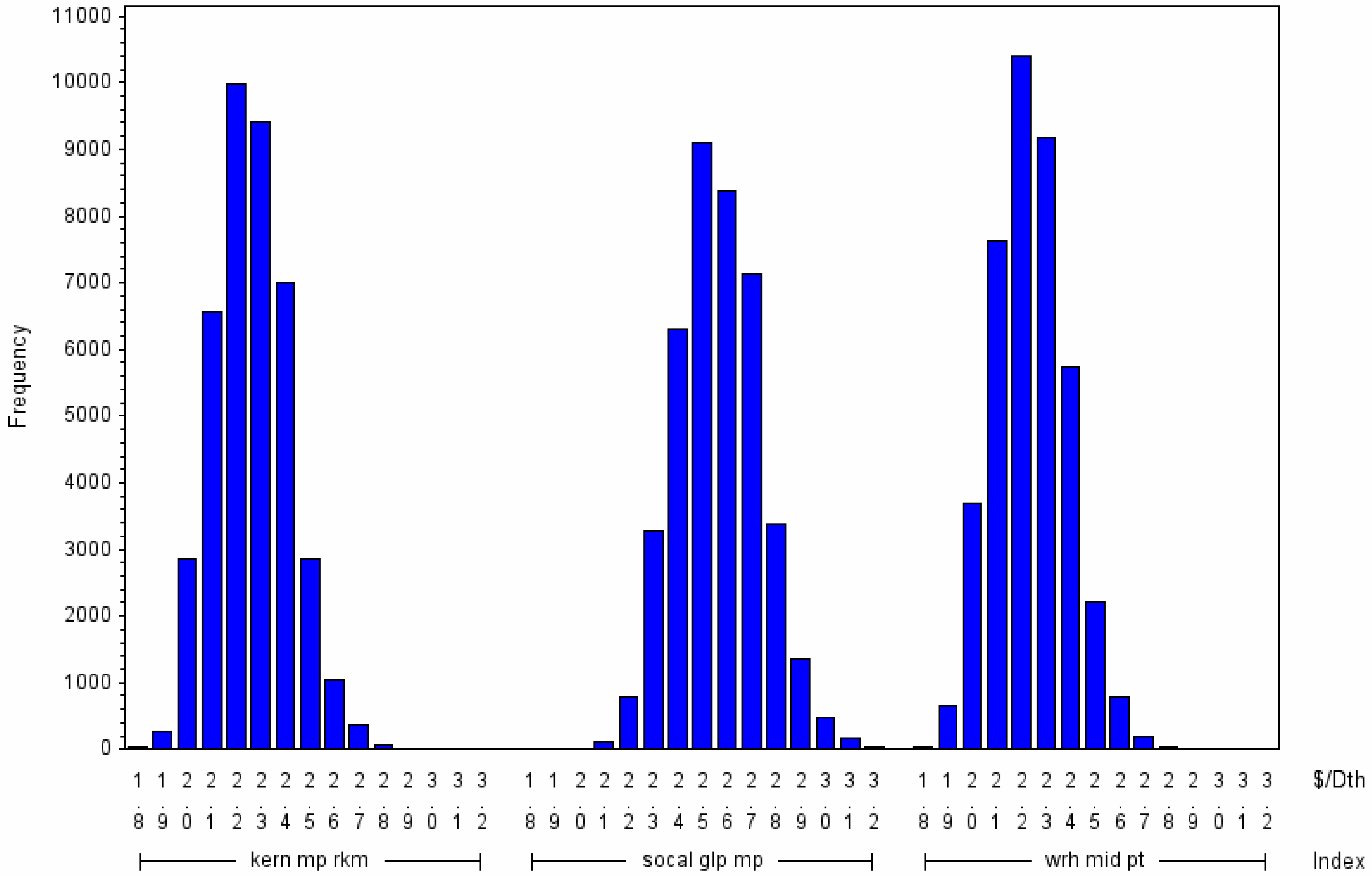
Exhibit 14.18

# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=8



# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=9

Exhibit 14.19

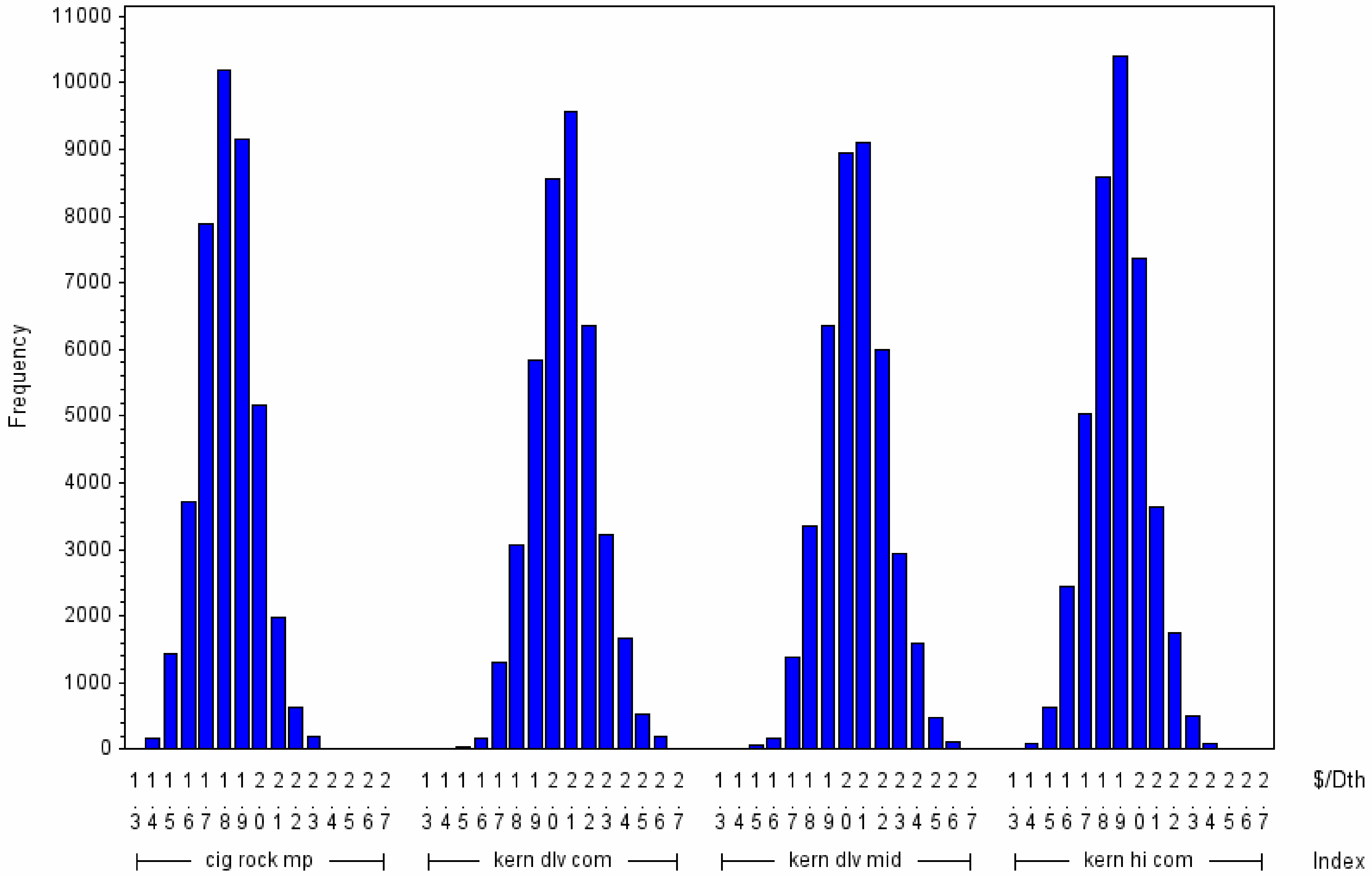


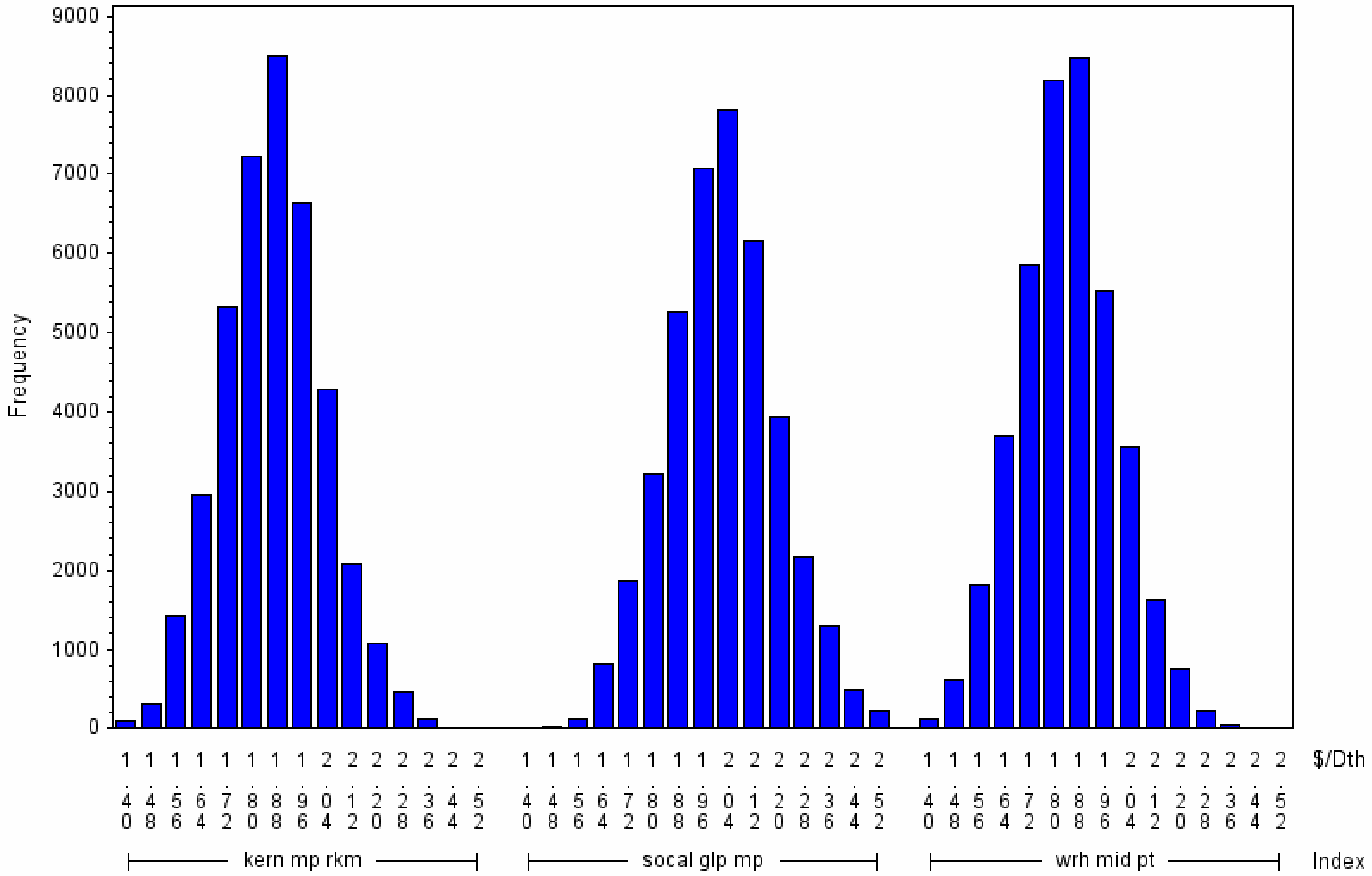
Exhibit 14.20

# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=9



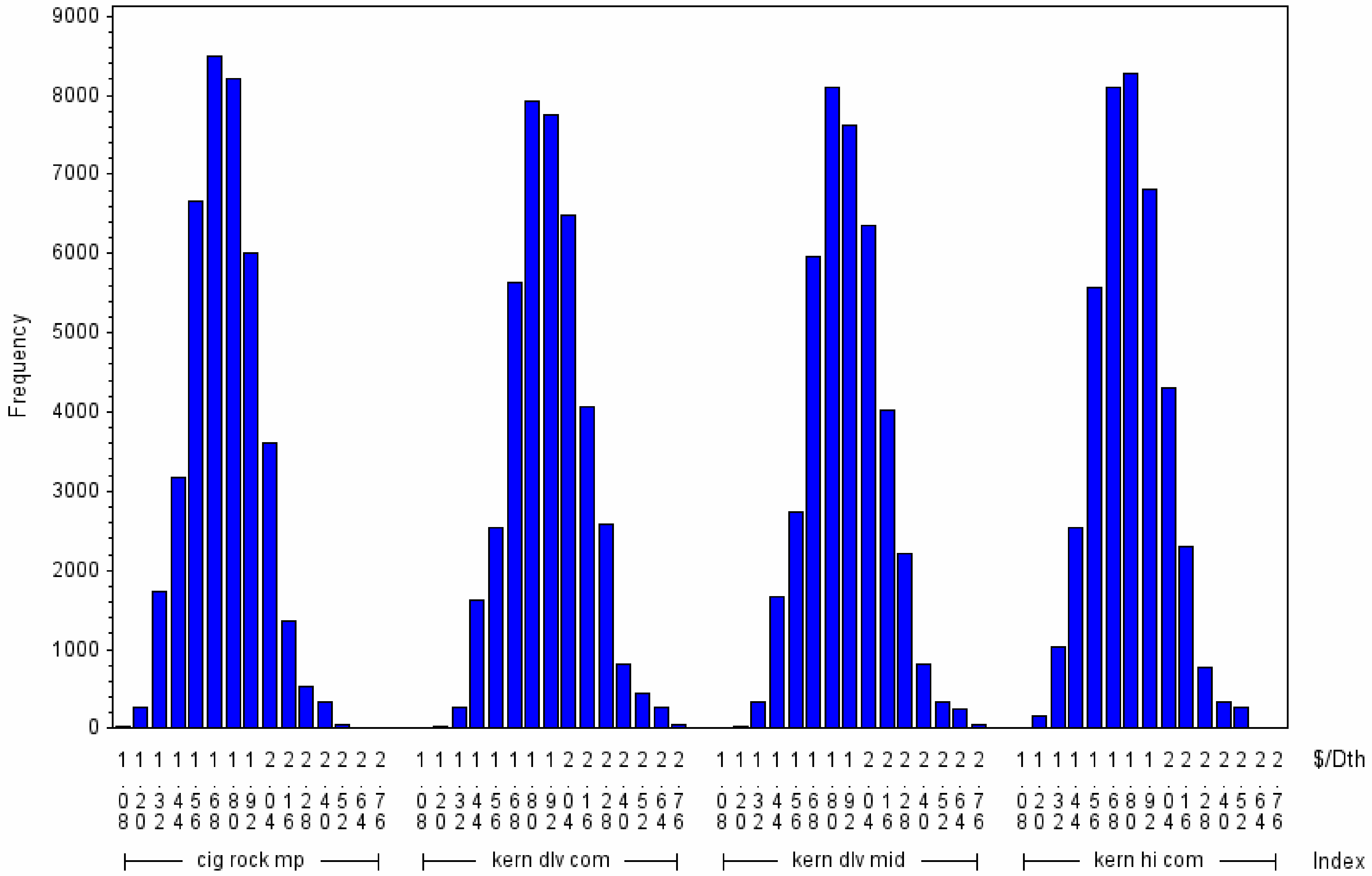
# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=10

Exhibit 14.21



# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=10

Exhibit 14.22

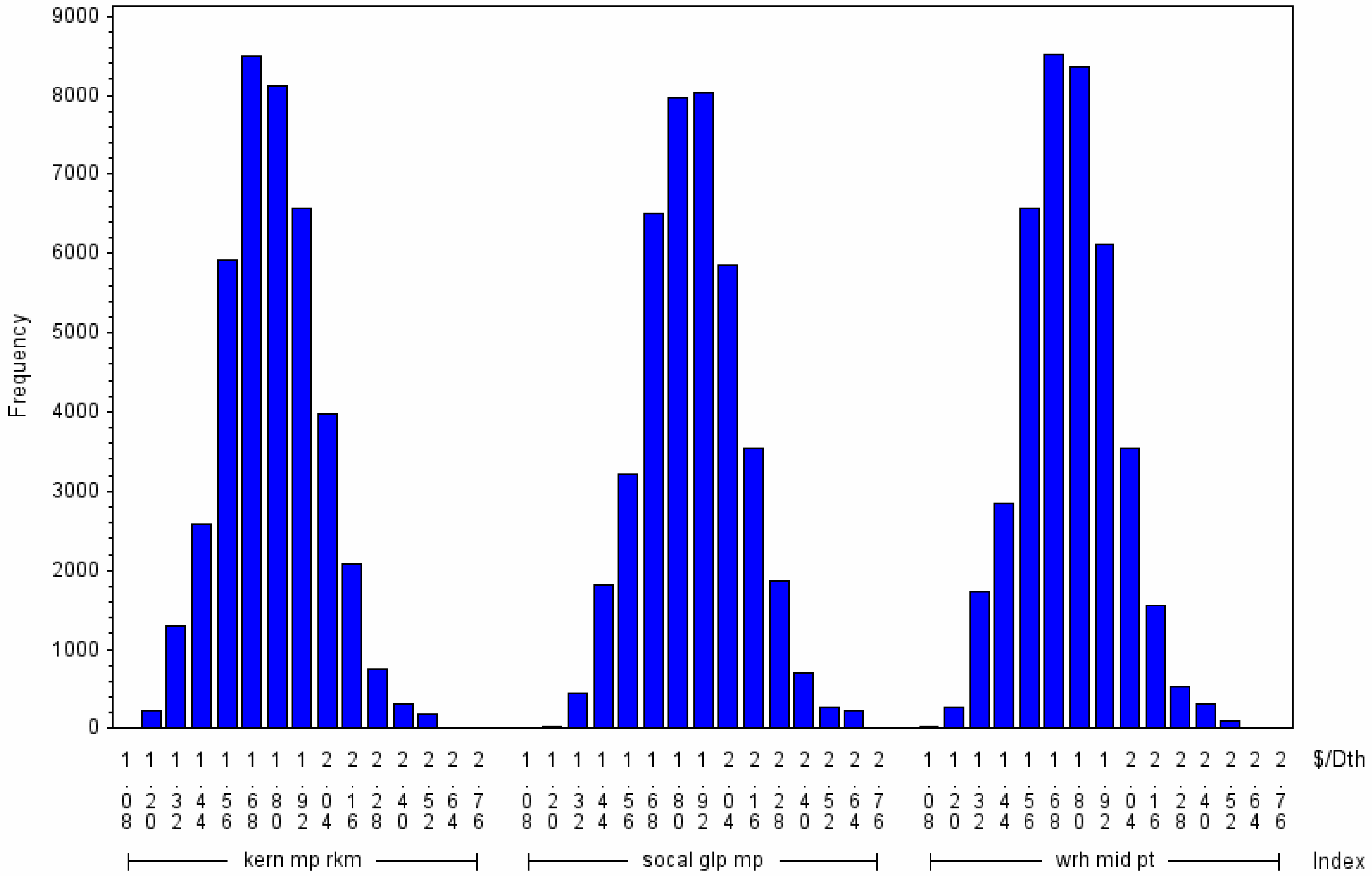
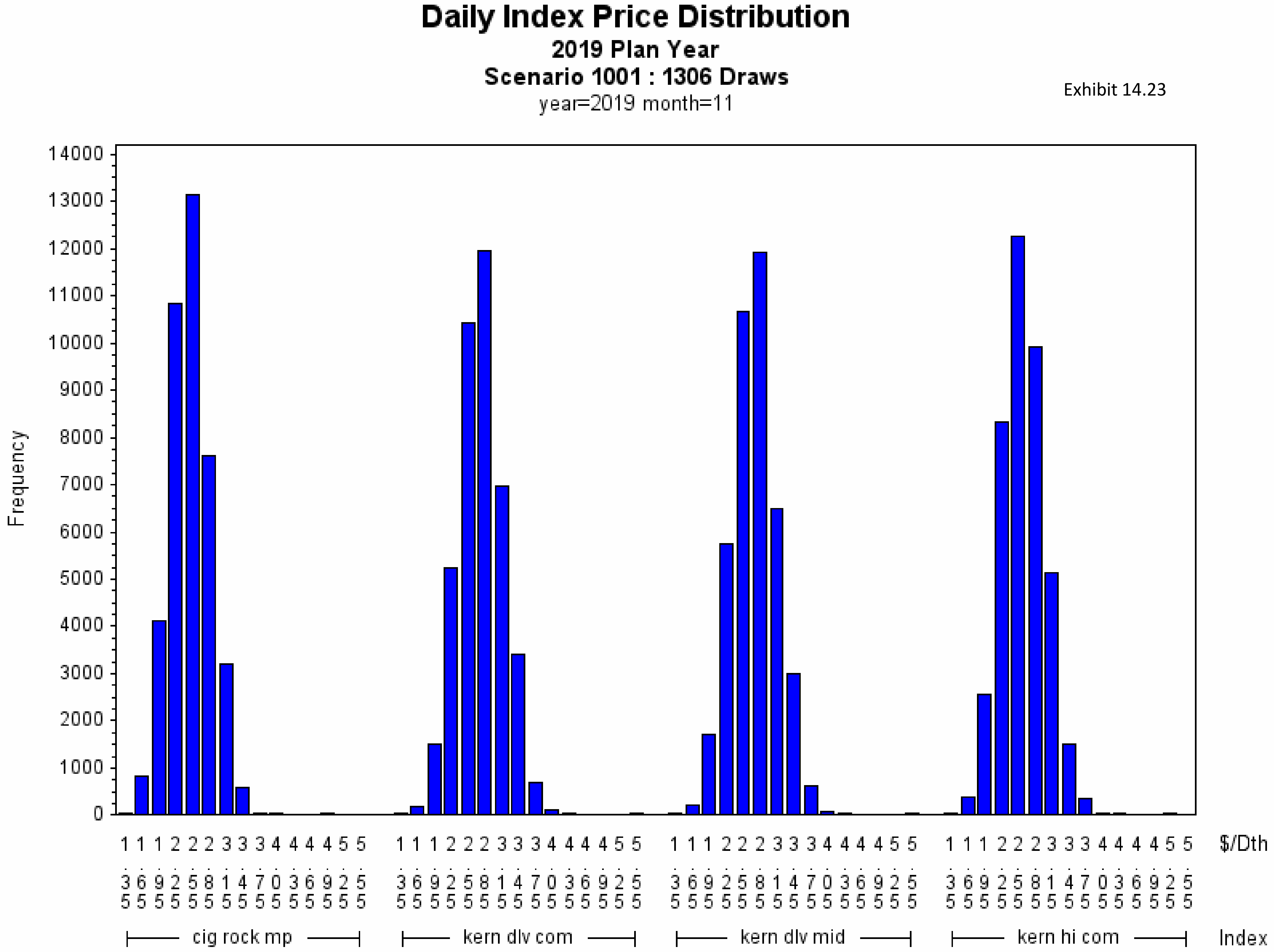


Exhibit 14.23



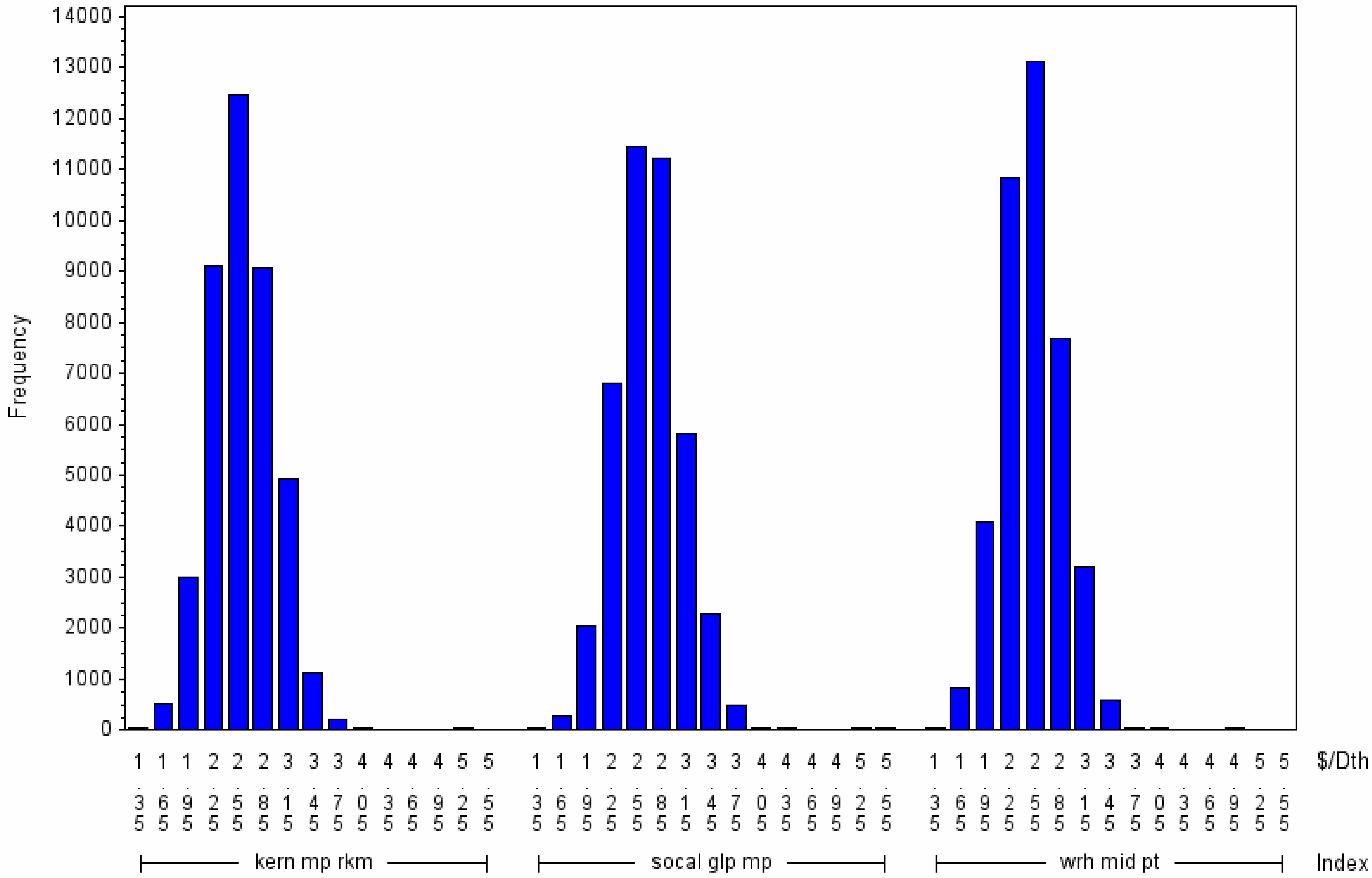
# Daily Index Price Distribution

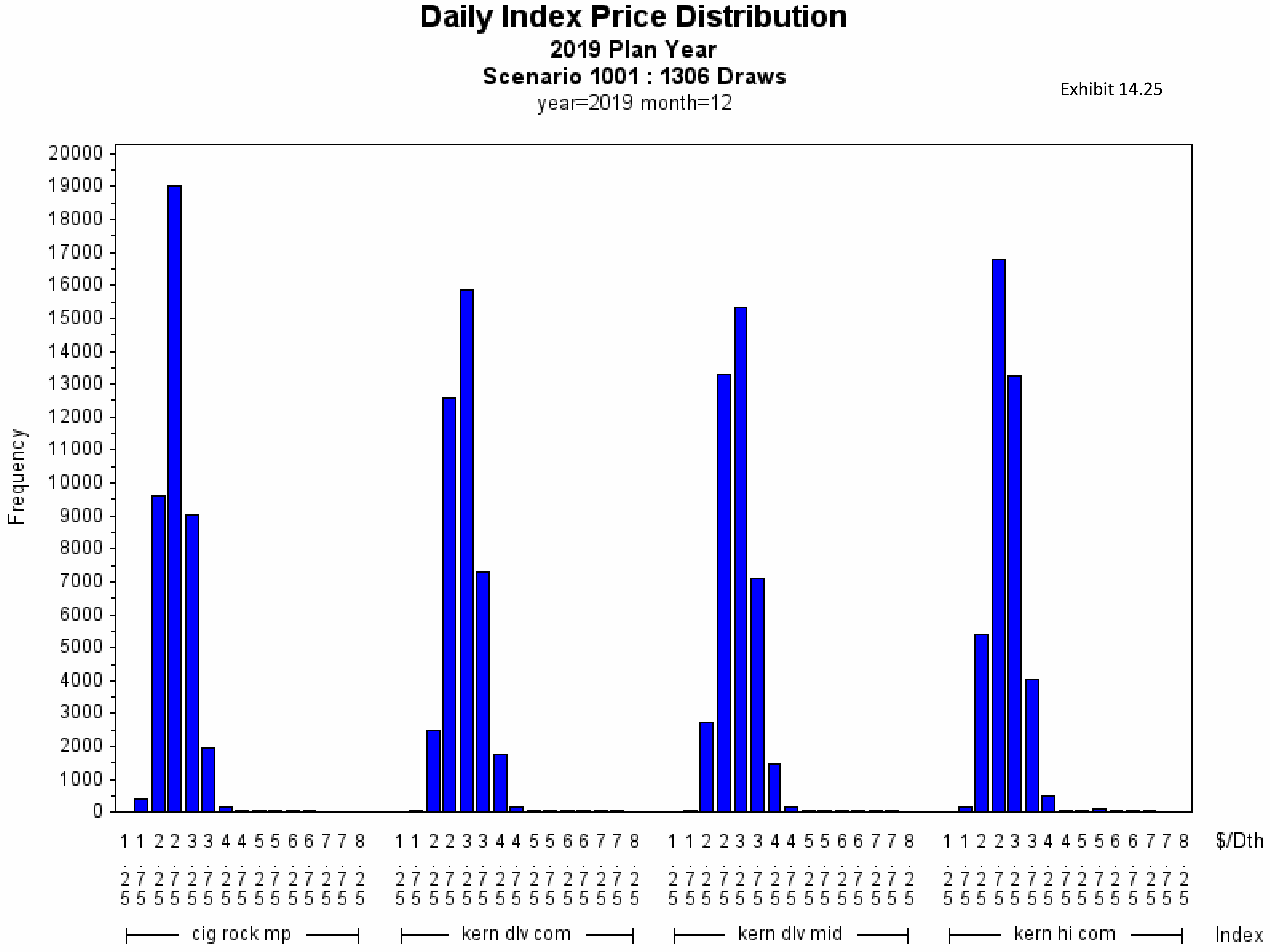
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=11

Exhibit 14.24




Daily Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2019 month=12
Exhibit 14.25
Frequency
20000
19000
18000
17000
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
$/Dth
Index
cig rock mp
kern dlv com
kern dlv mid
kern hi com

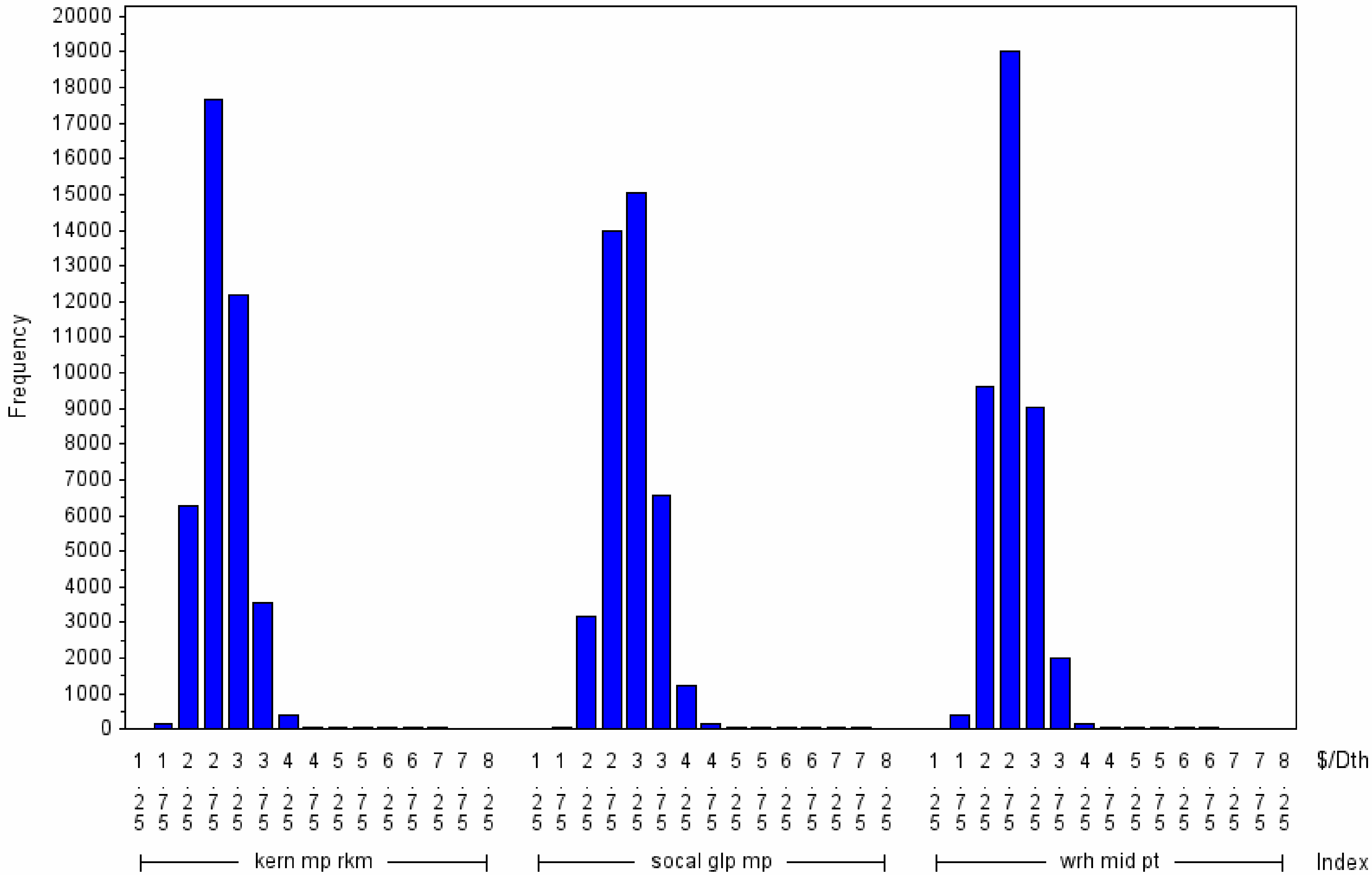
# Daily Index Price Distribution

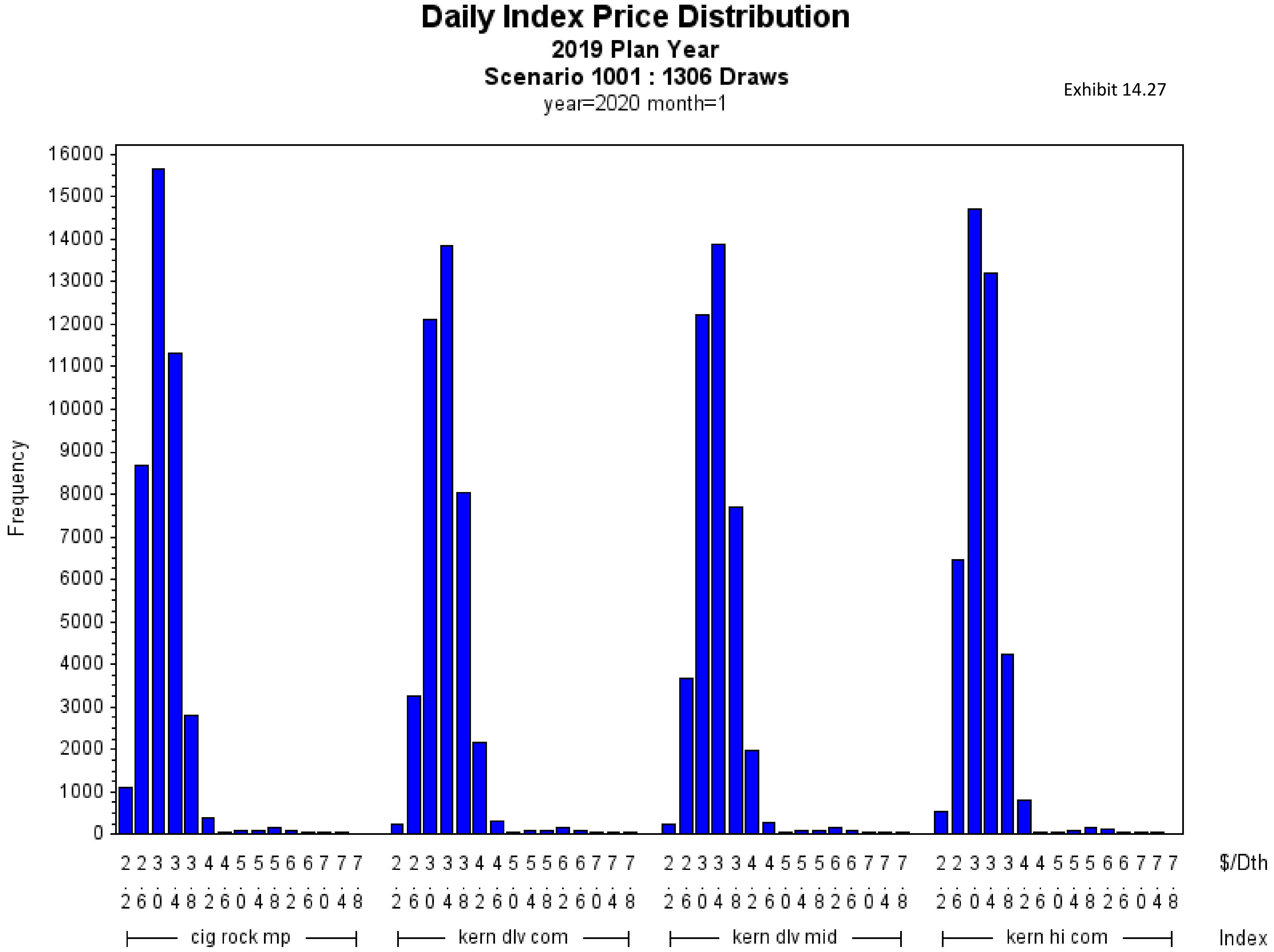
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=12

Exhibit 14.26





Daily Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=1
Exhibit 14.27
Frequency
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
$/Dth
Index
cig rock mp
kern dlv com
kern dlv mid
kern hi com

Exhibit 14.28

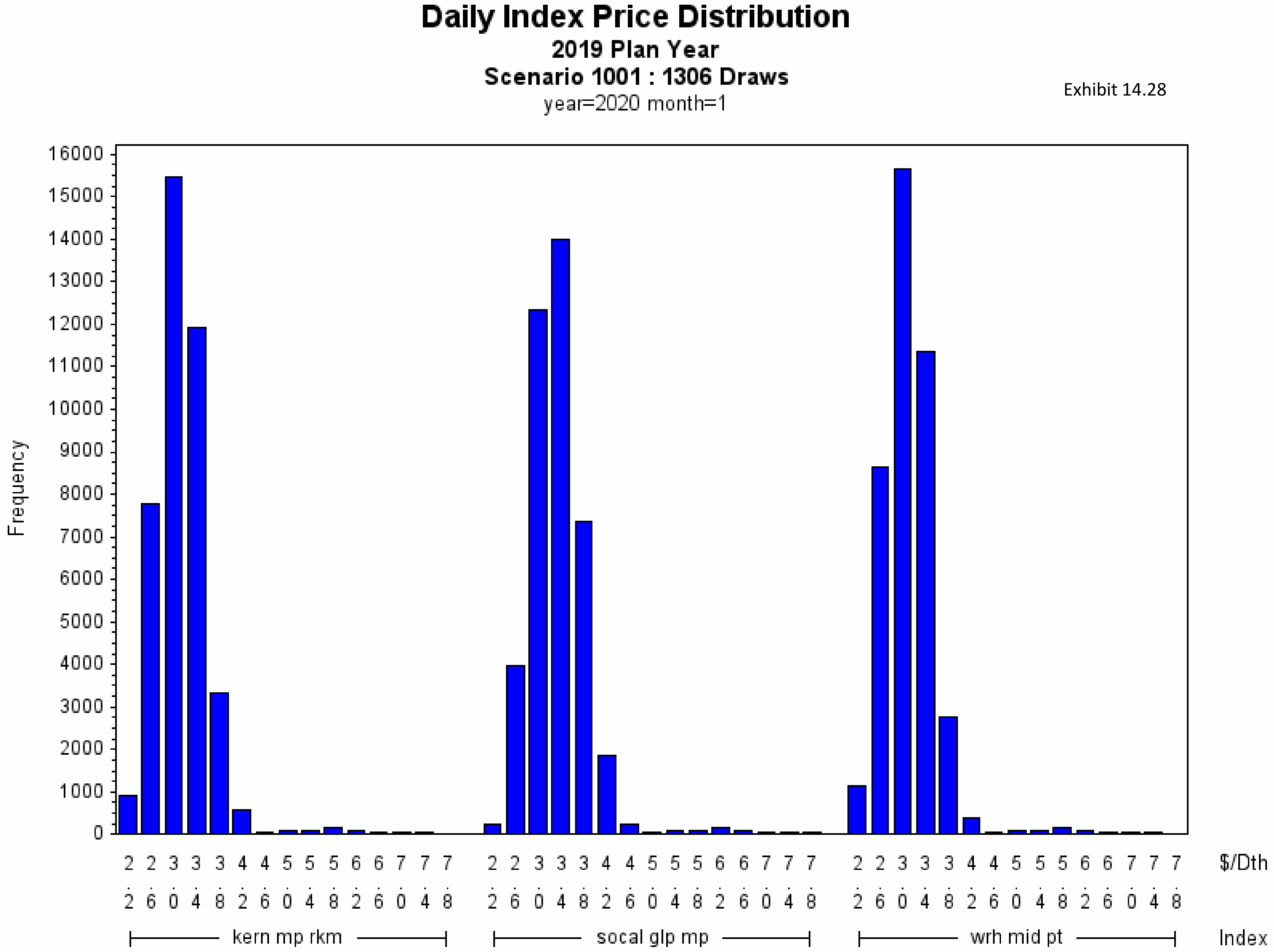


Exhibit 14.29

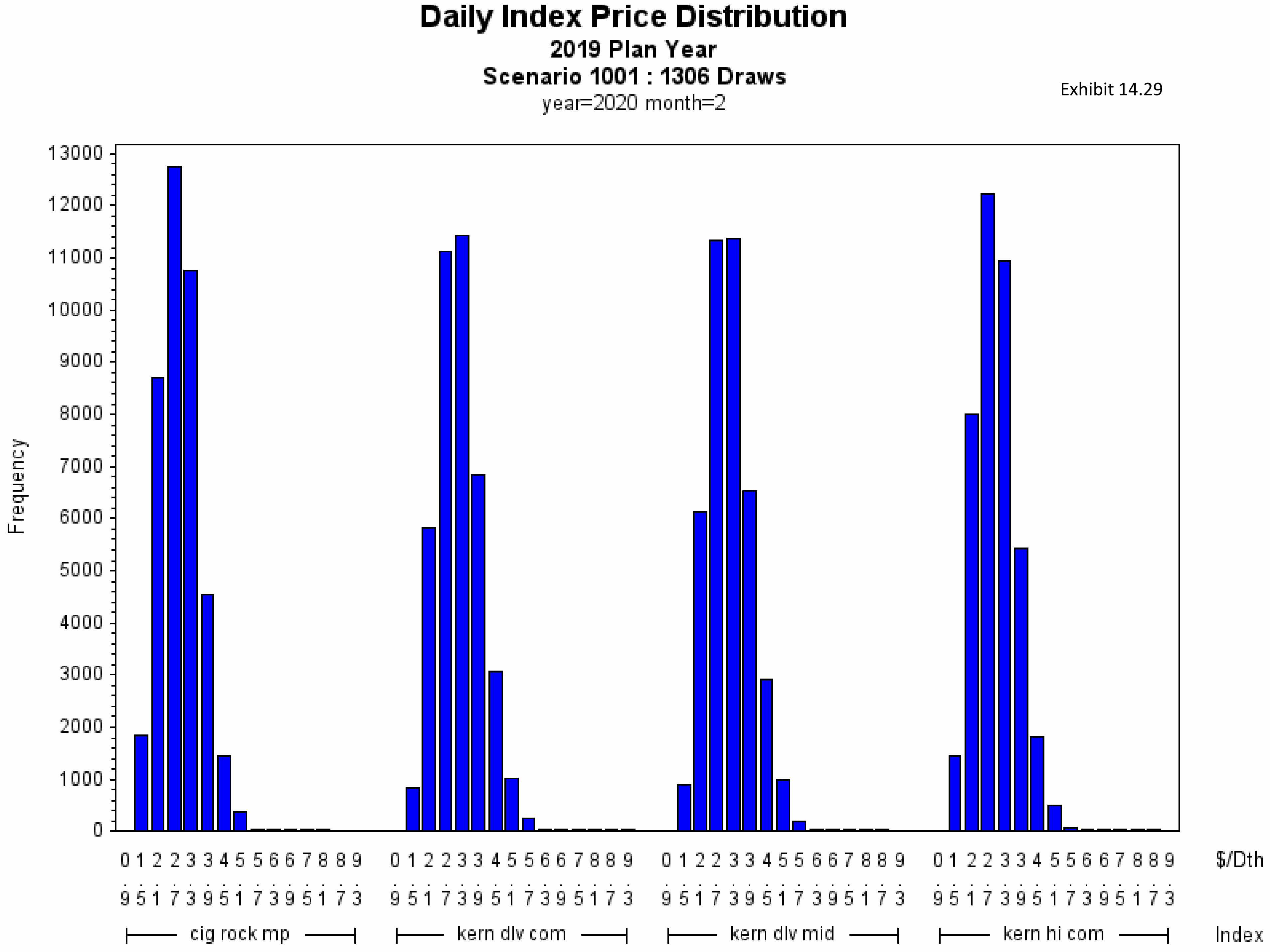
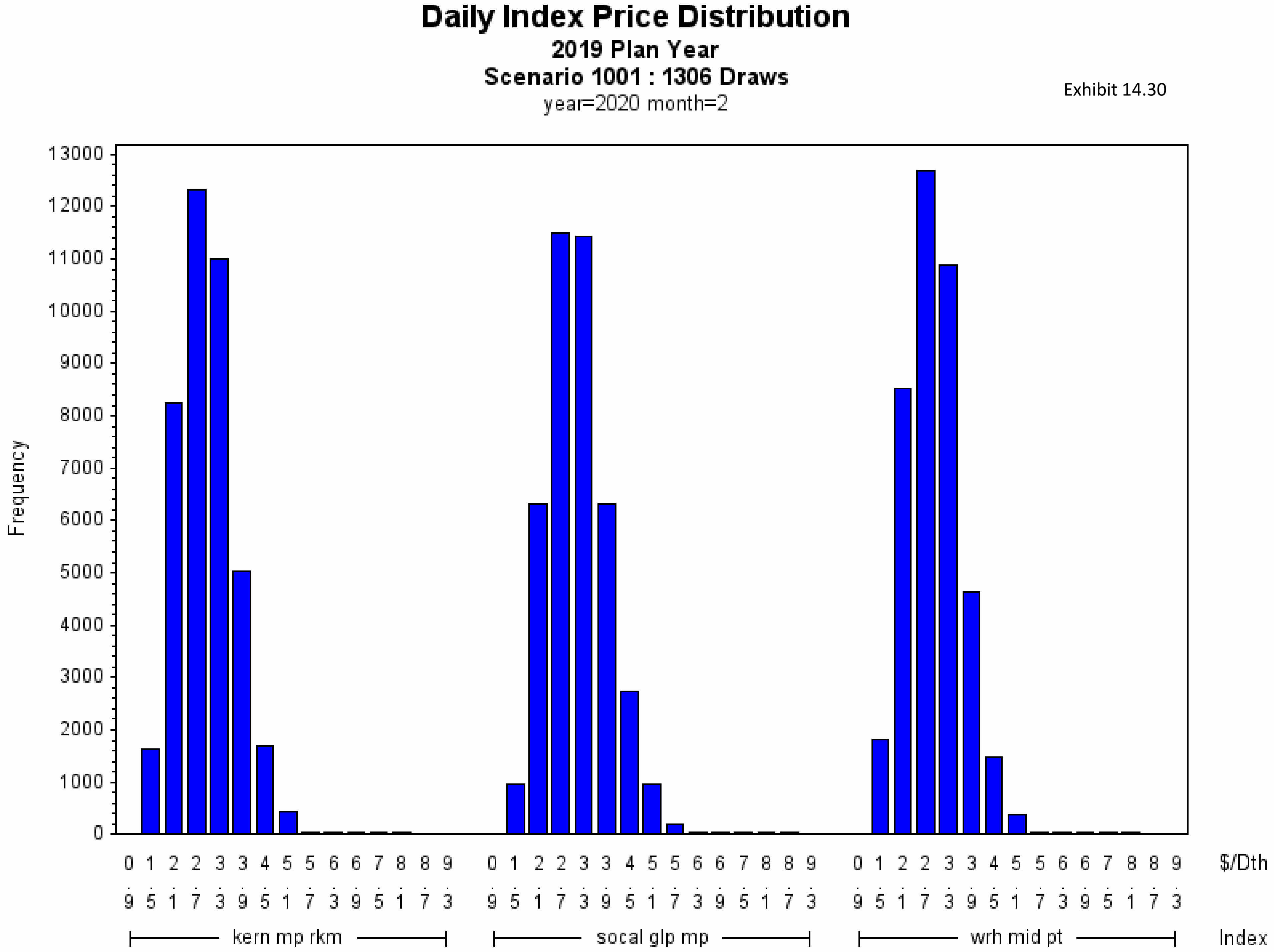


Exhibit 14.30



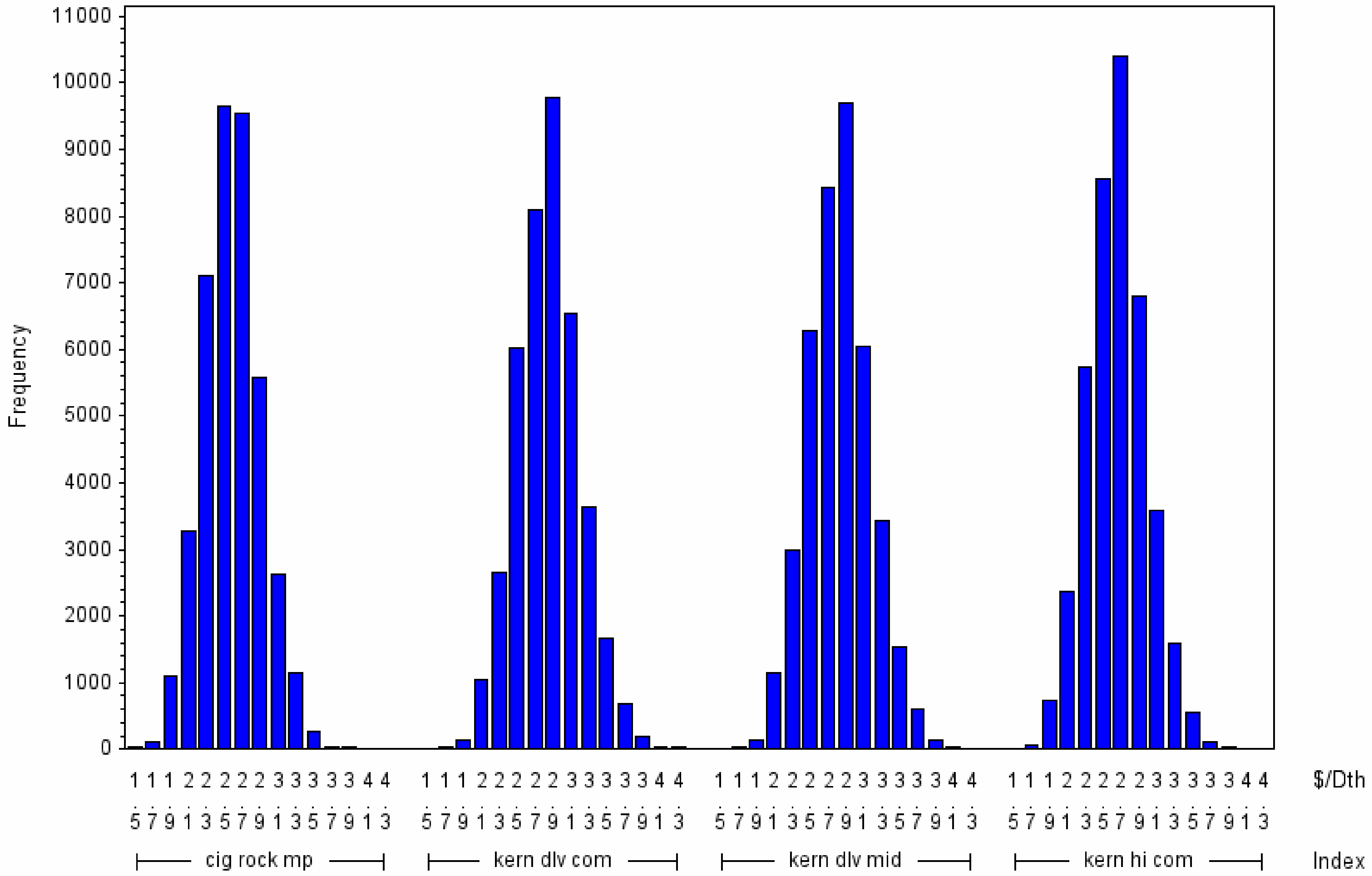
# Daily Index Price Distribution

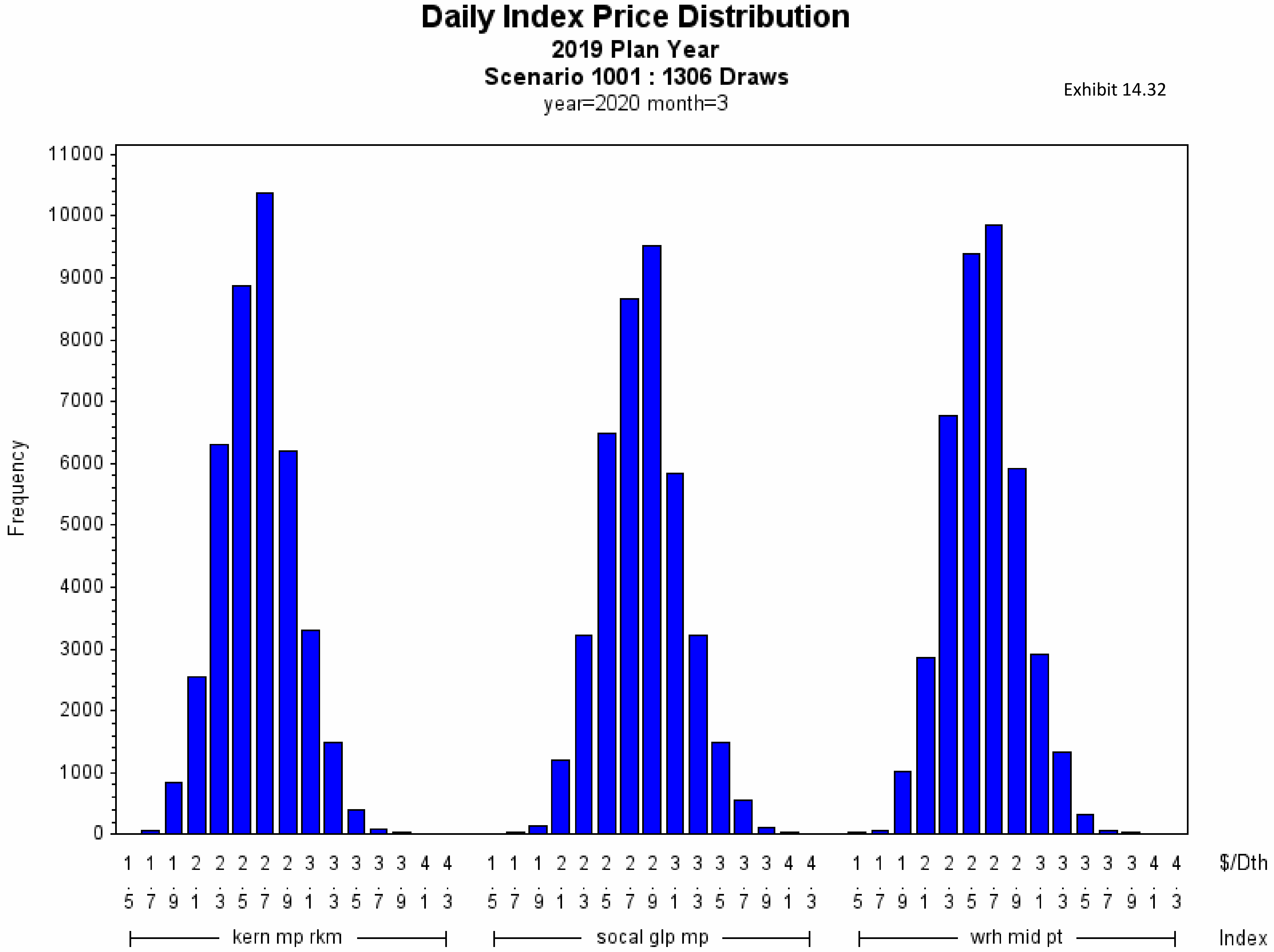
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=3

Exhibit 14.31




Daily Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=3
Exhibit 14.32
Frequency
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1.5 1.7 1.9 2.1 2.3 2.5 2.7 2.9 3.1 3.3 3.5 3.7 3.9 4.1 4.3
$/Dth
kern mp rkm
socal glp mp
wrh mid pt
Index

# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=4

Exhibit 14.33

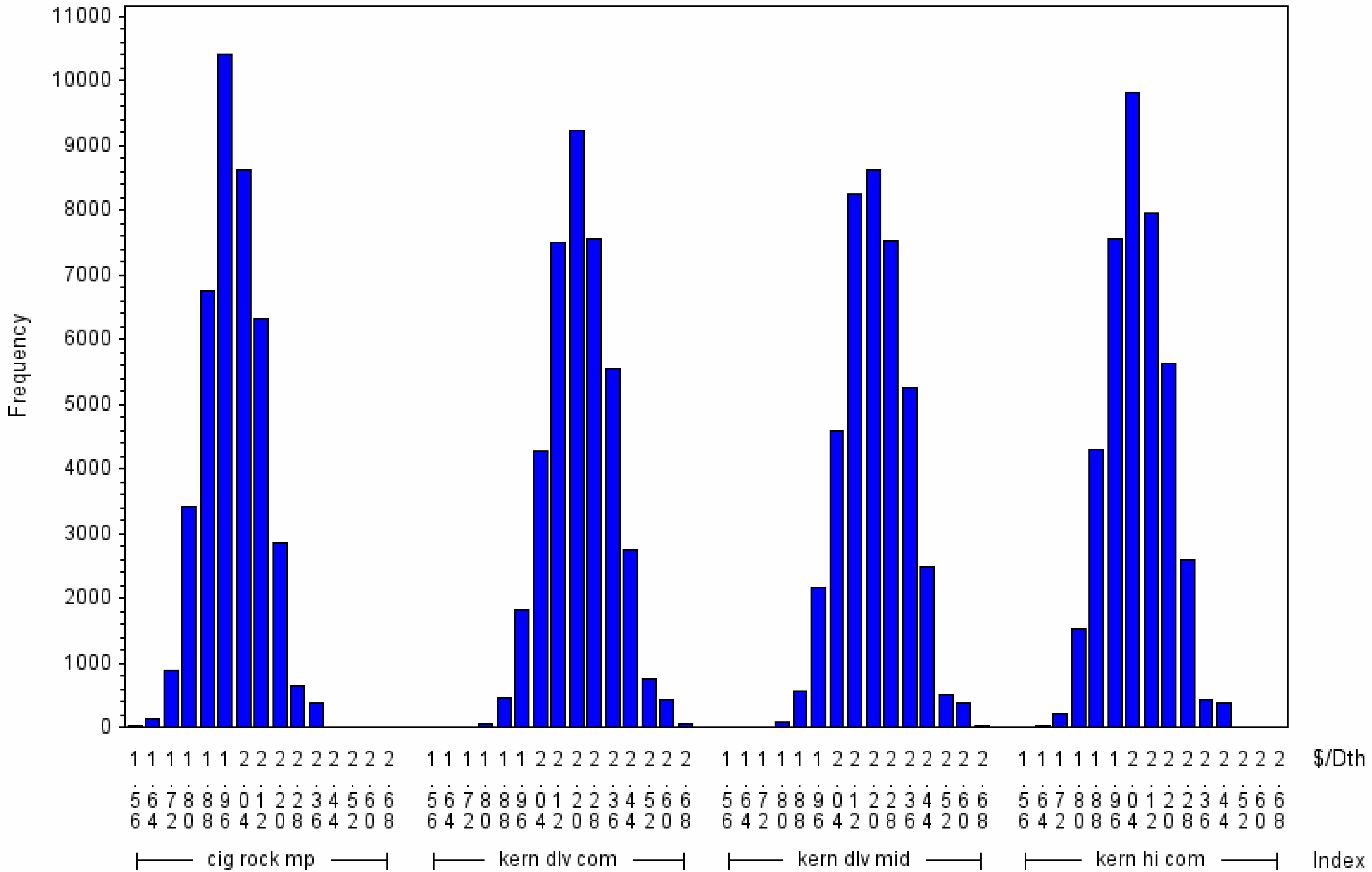
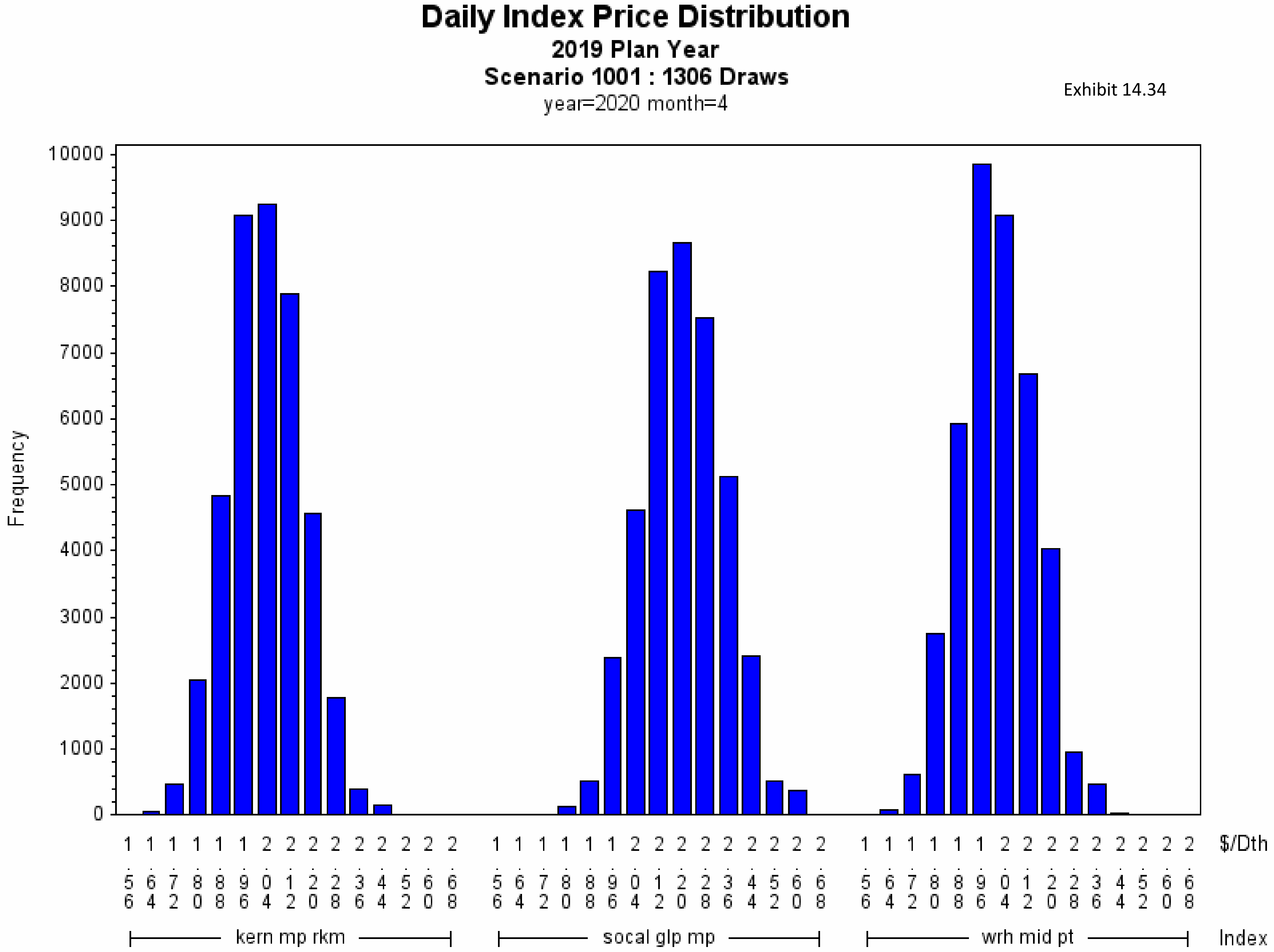
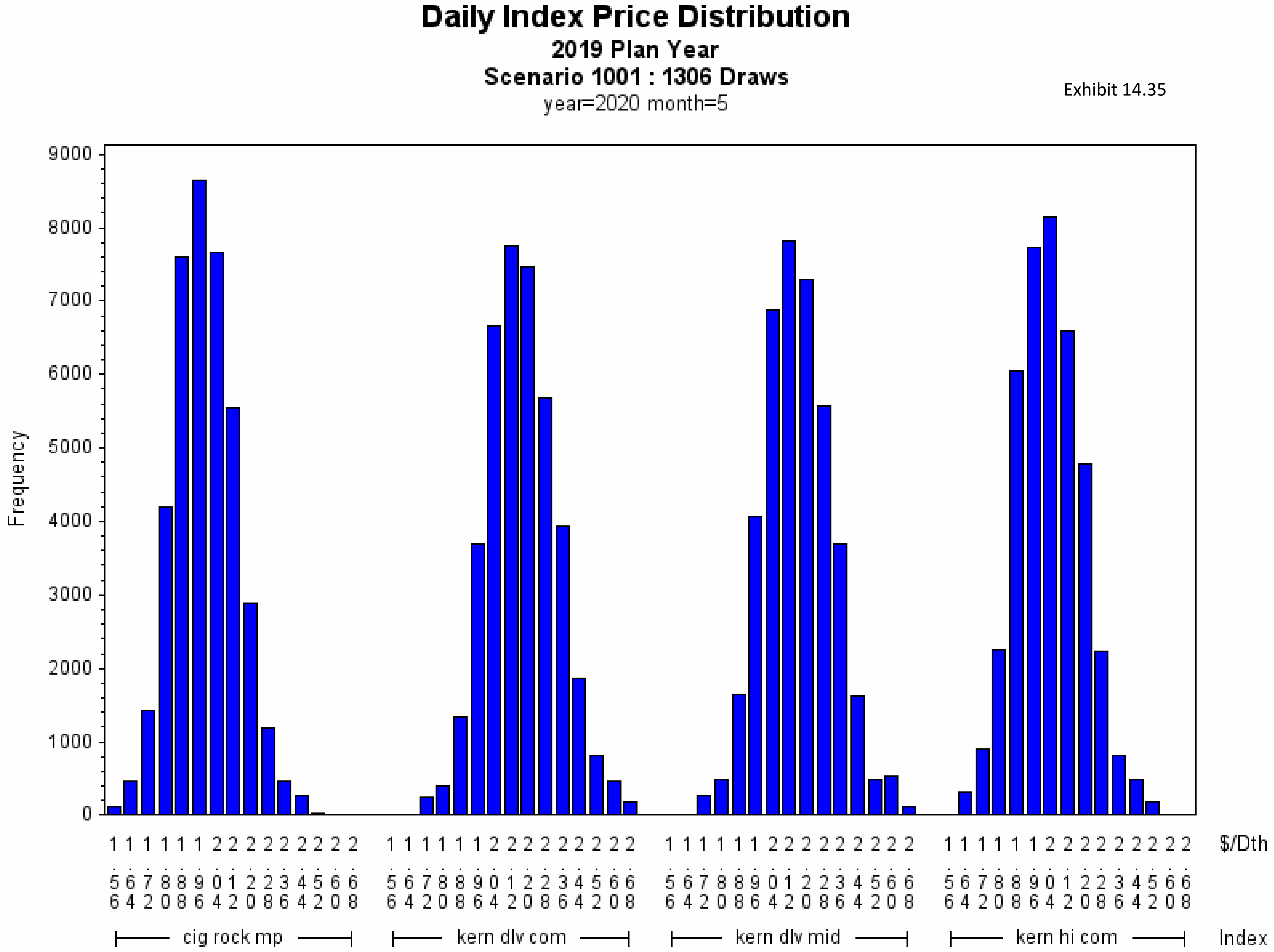


Exhibit 14.34




Daily Index Price Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=5
Exhibit 14.35
Frequency
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
$/Dth
cig rock mp
kern dlv com
kern dlv mid
kern hi com
Index

# Daily Index Price Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=5

Exhibit 14.36

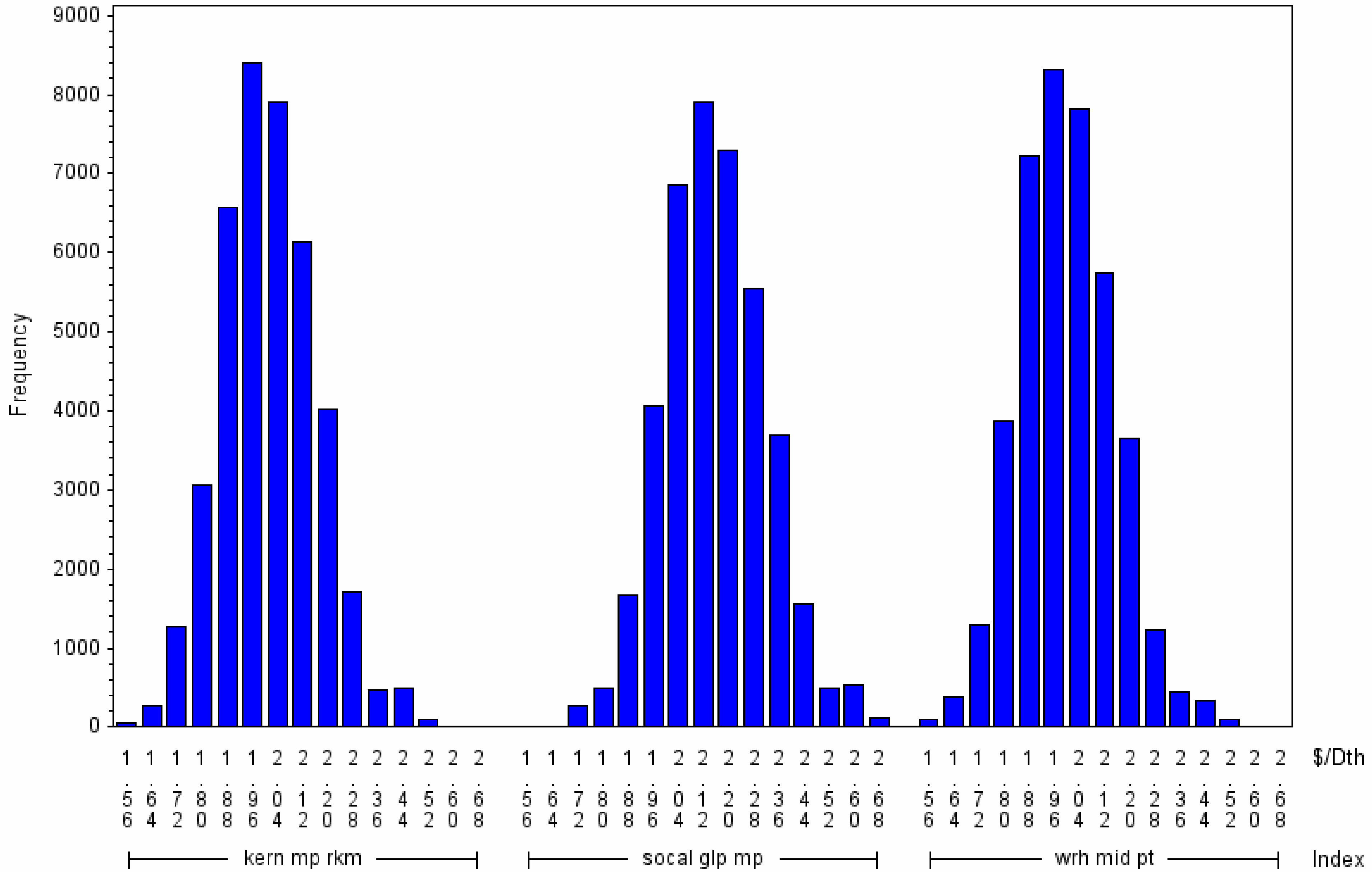


Exhibit 14.37

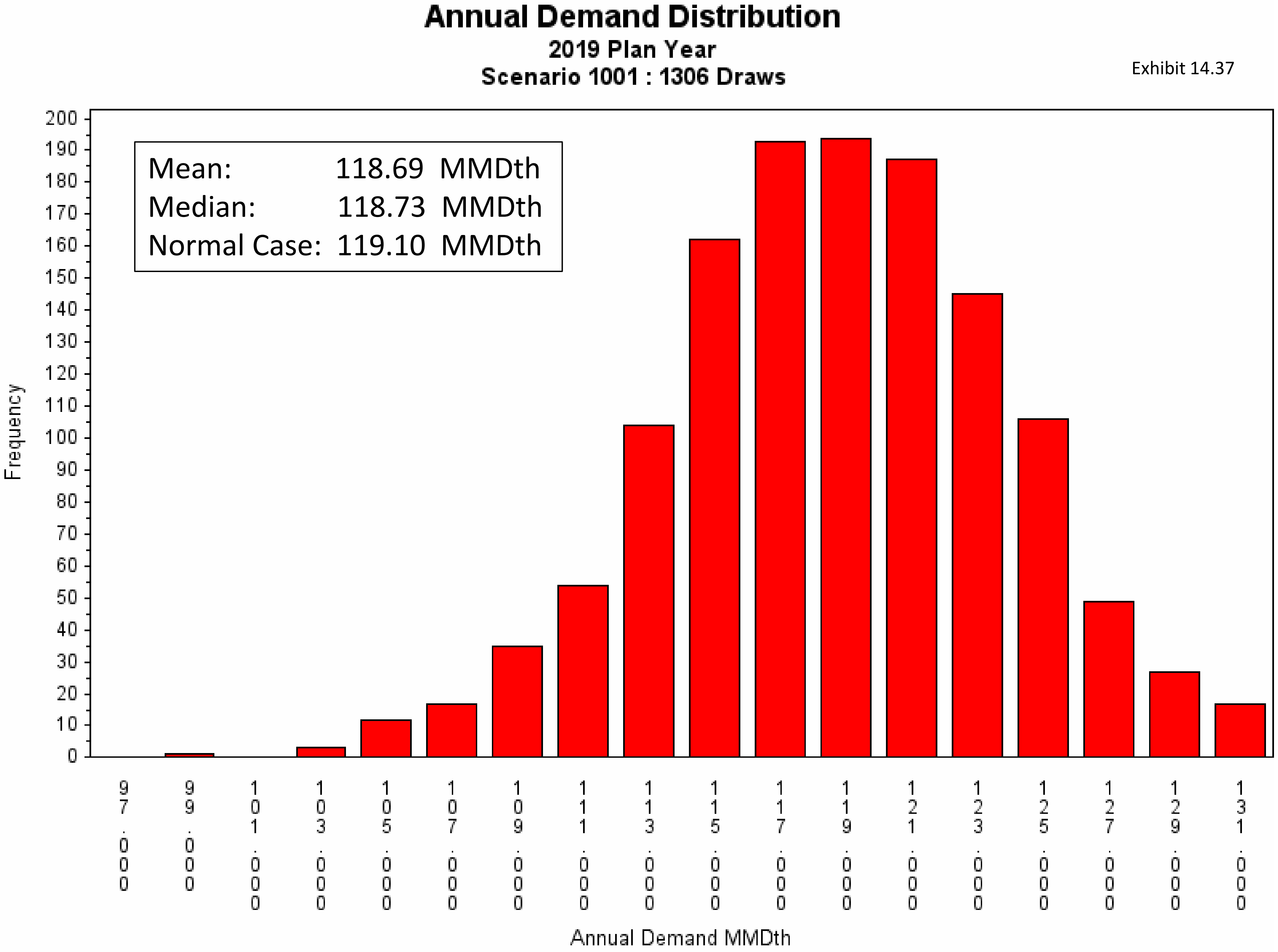


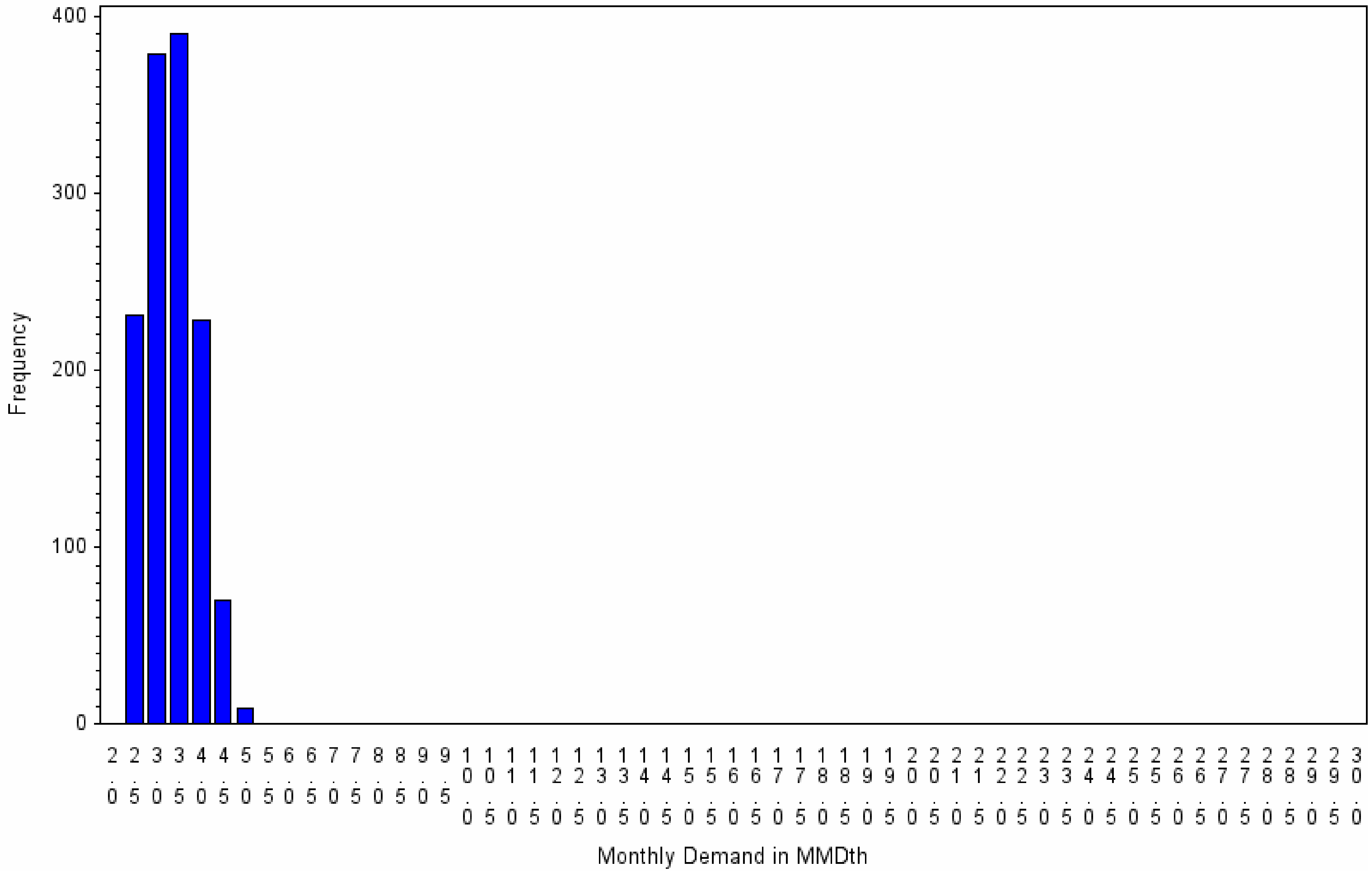
Exhibit 14.38

# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=6



# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=7

Exhibit 14.39

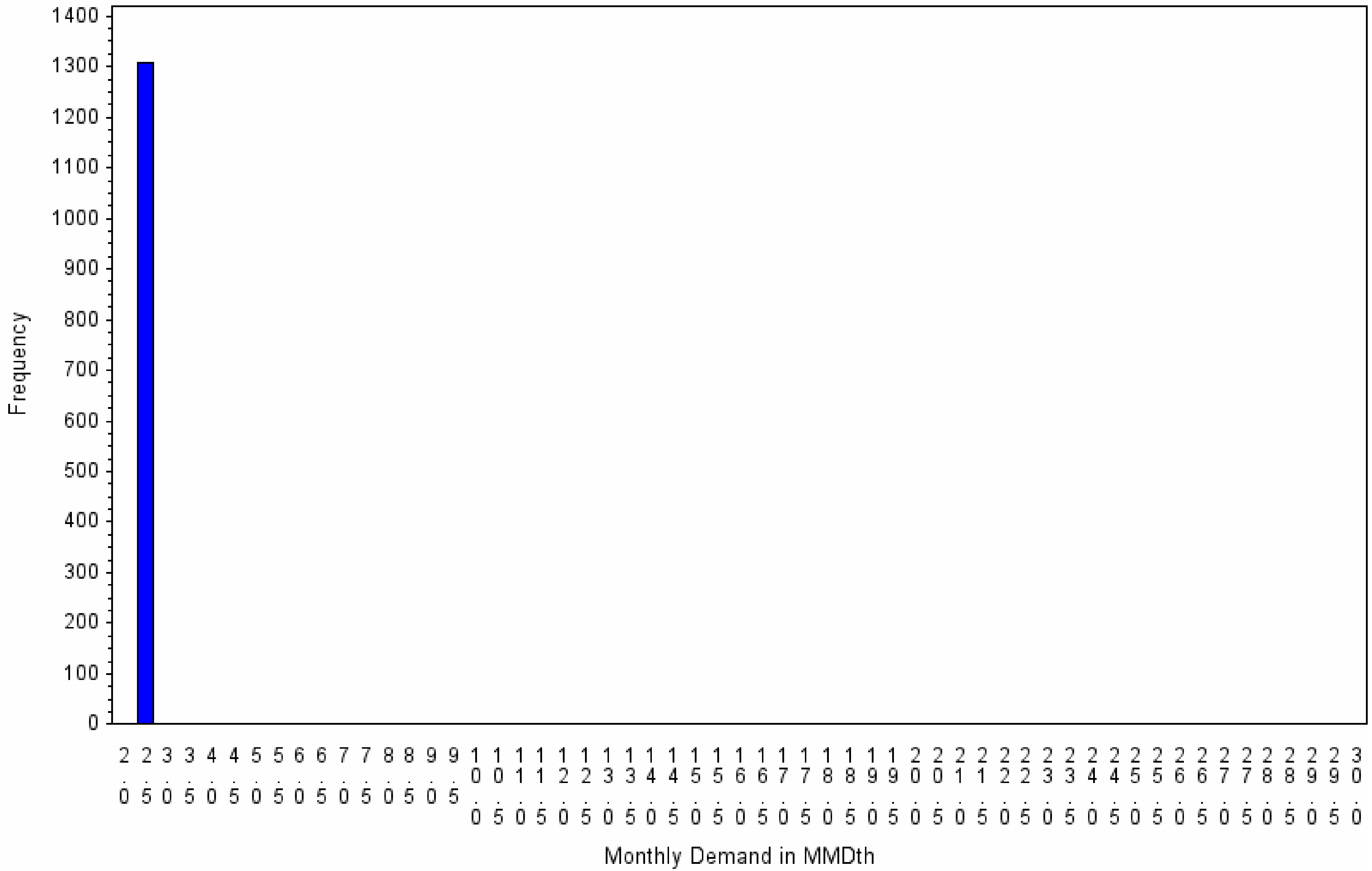


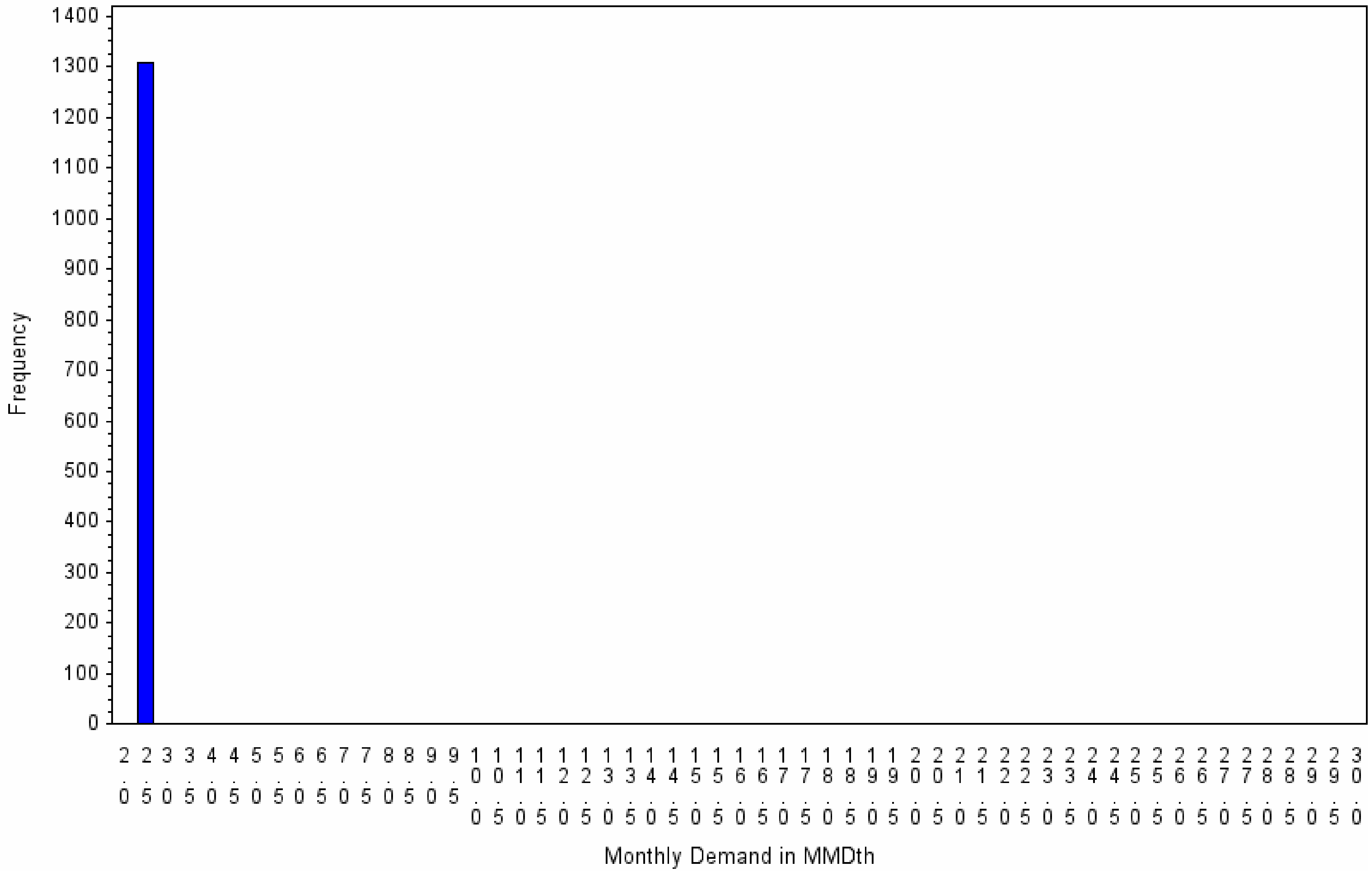
Exhibit 14.40

# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=8



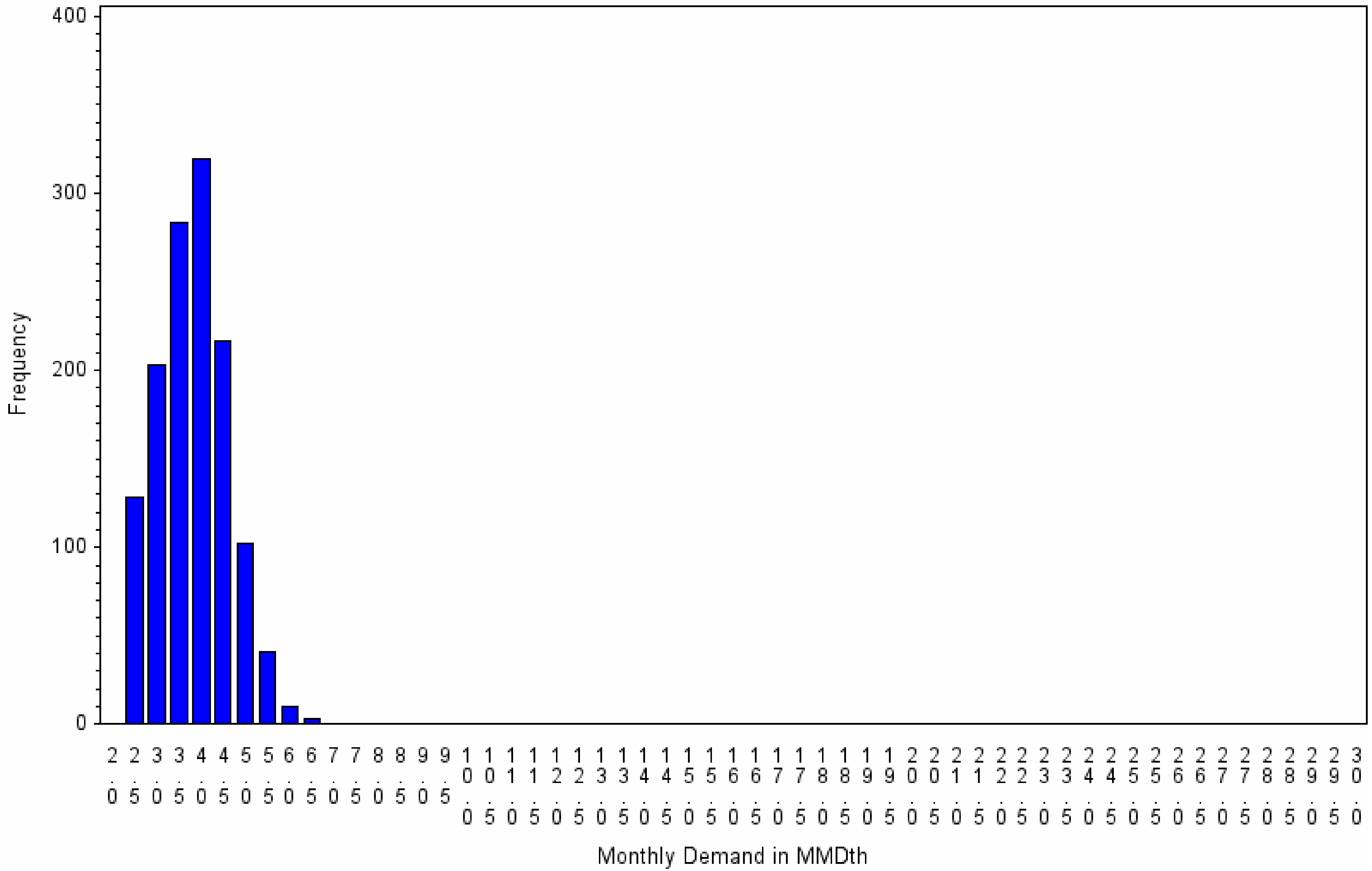
# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=9

Exhibit 14.41



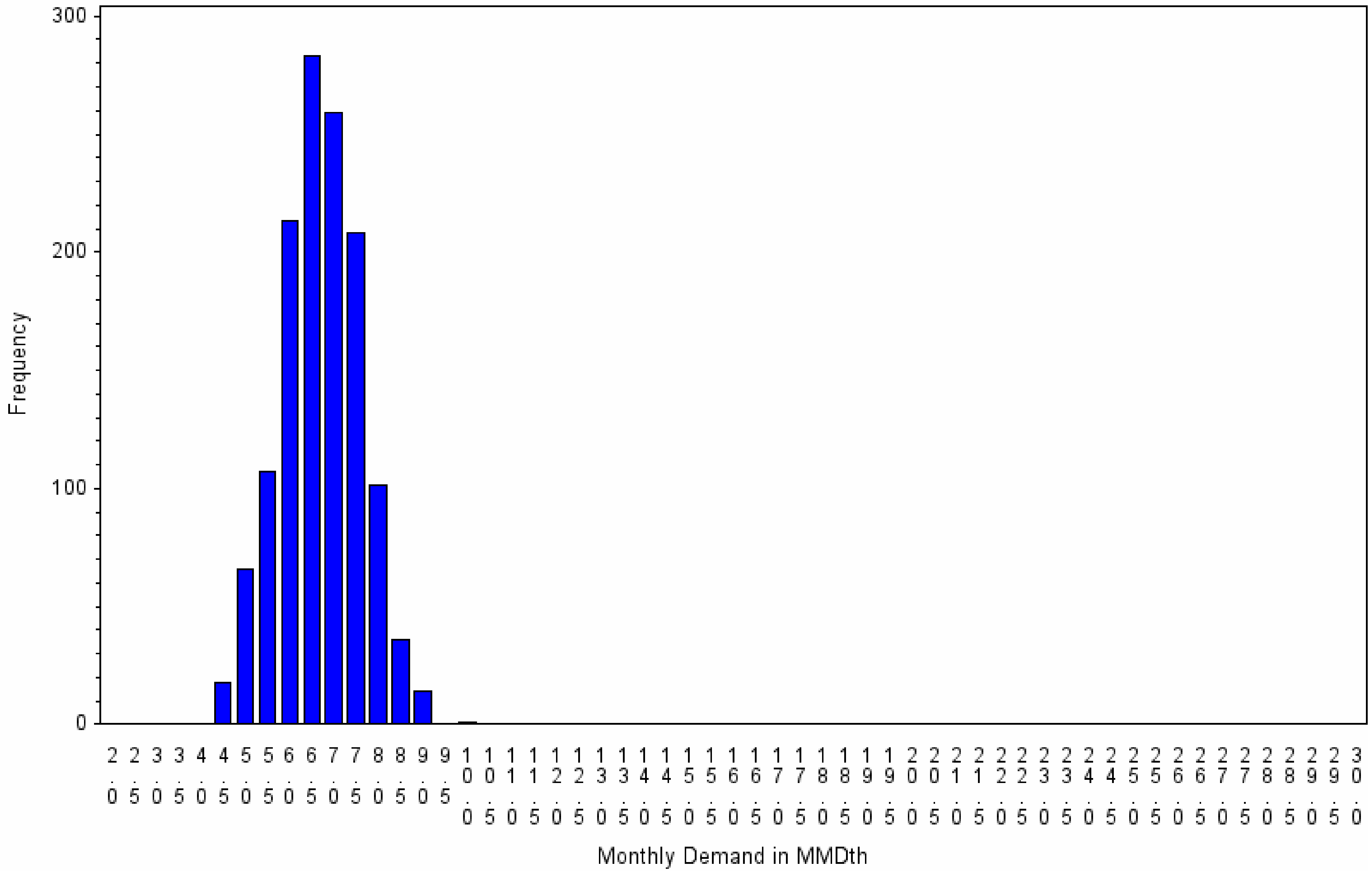
## Monthly Demand Distribution

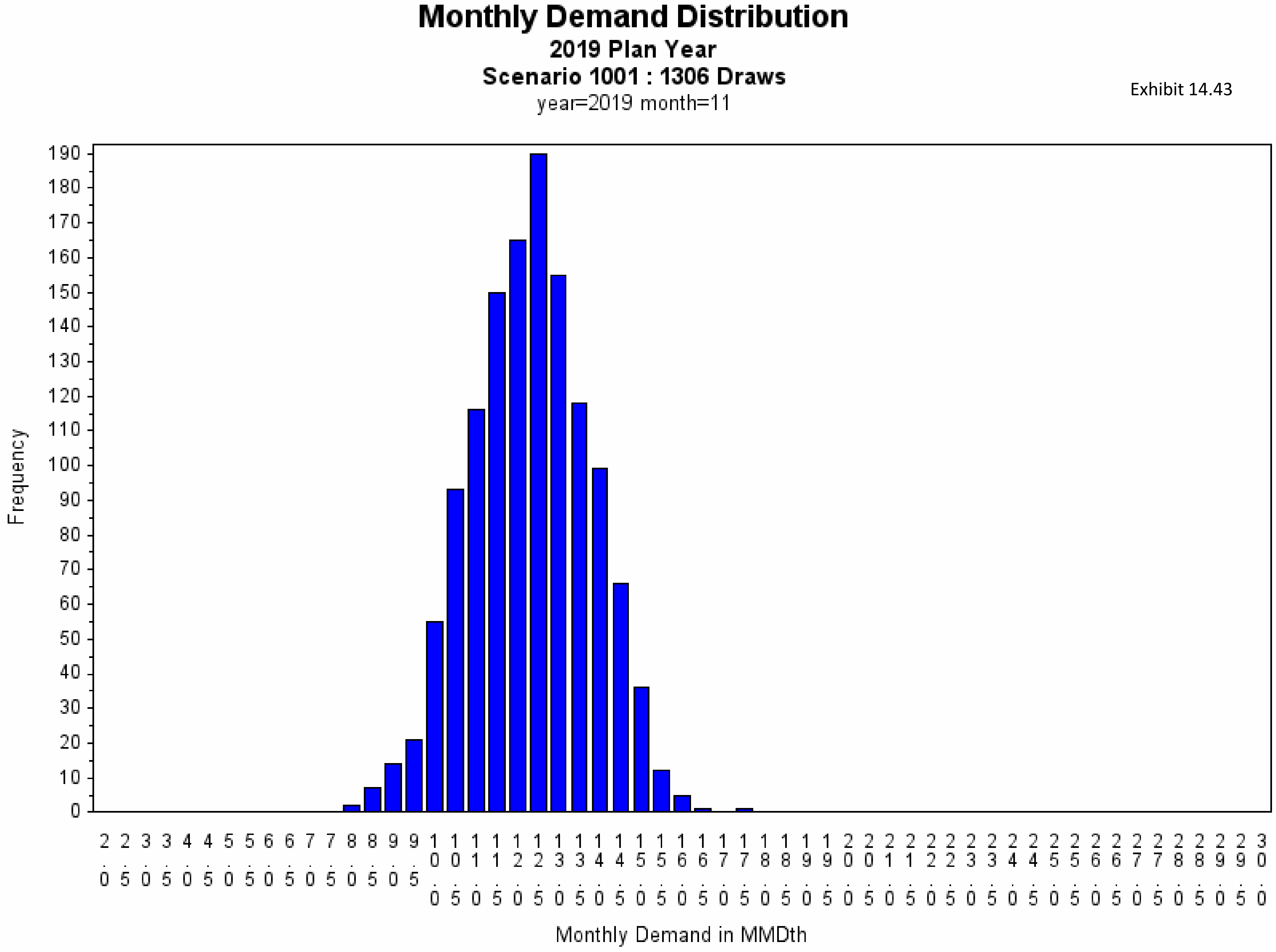
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=10

Exhibit 14.42




Monthly Demand Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2019 month=11
Exhibit 14.43
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100 105 110 115 120 125 130 135 140 145 150 155 160 165 170 175 180 185 190 195 200 205 210 215 220 225 230 235 240 245 250 255 260 265 270 275 280 285 290 295 300
Monthly Demand in MMDth

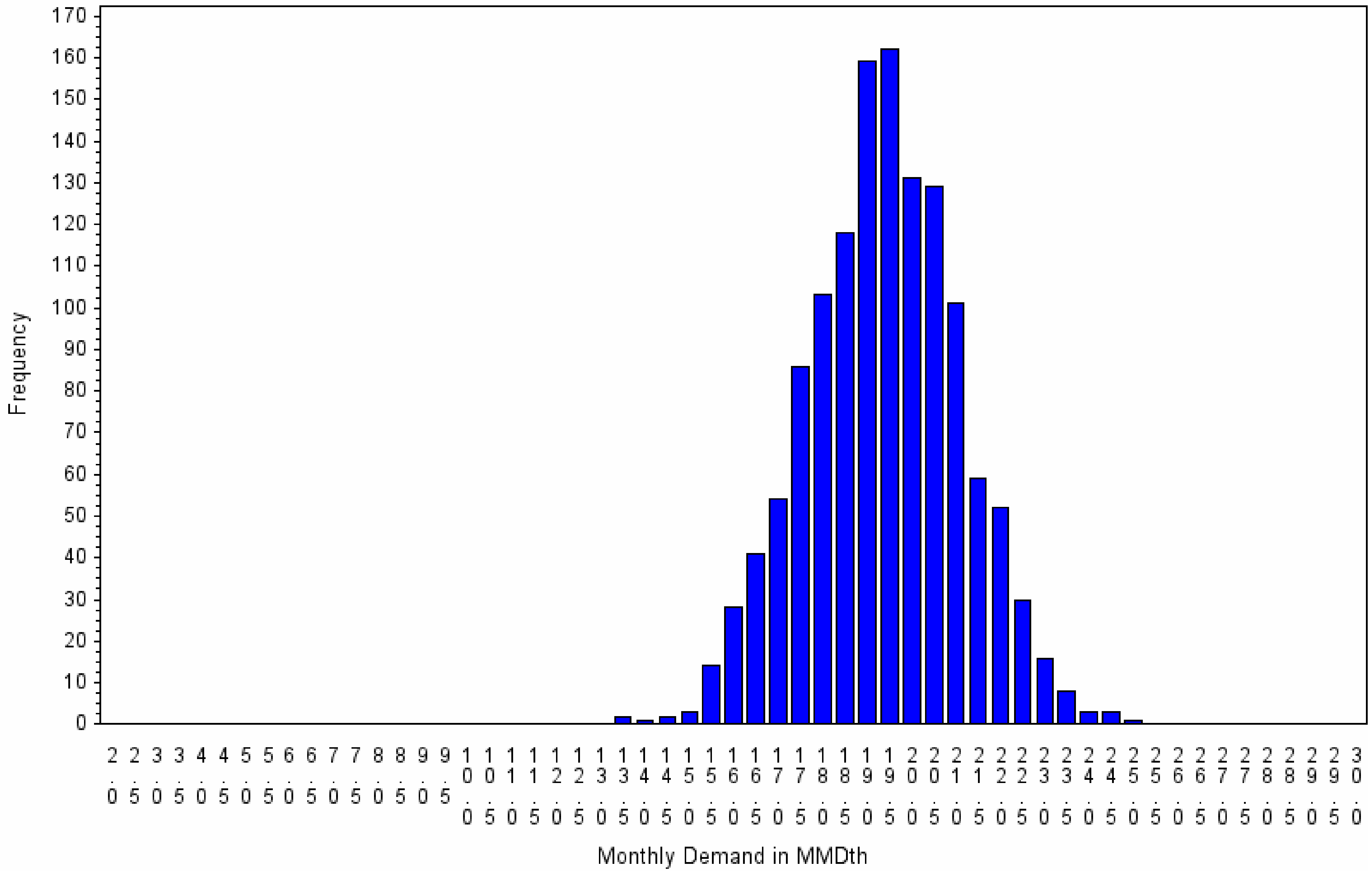
# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=12

Exhibit 14.44



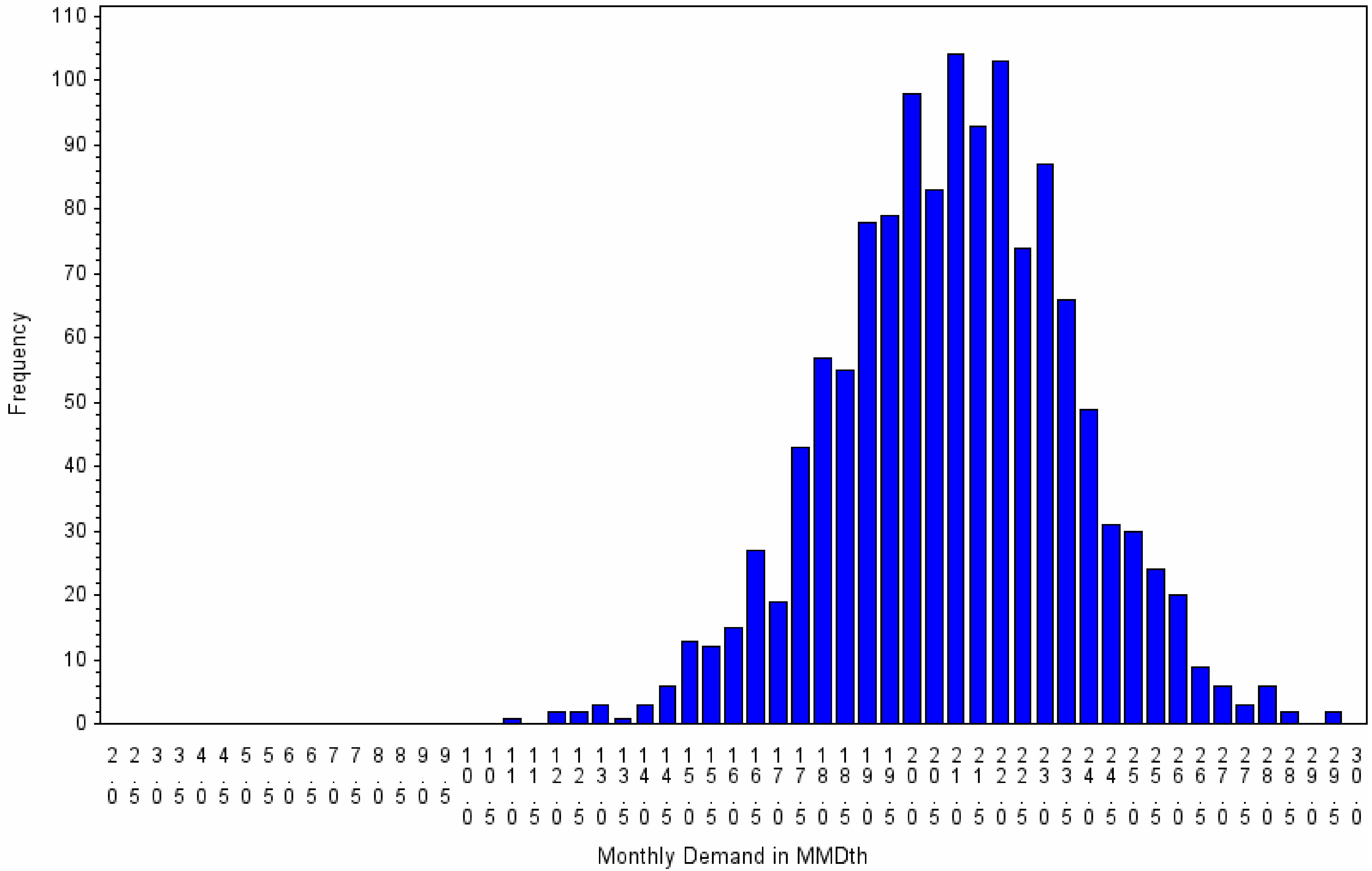
# Monthly Demand Distribution

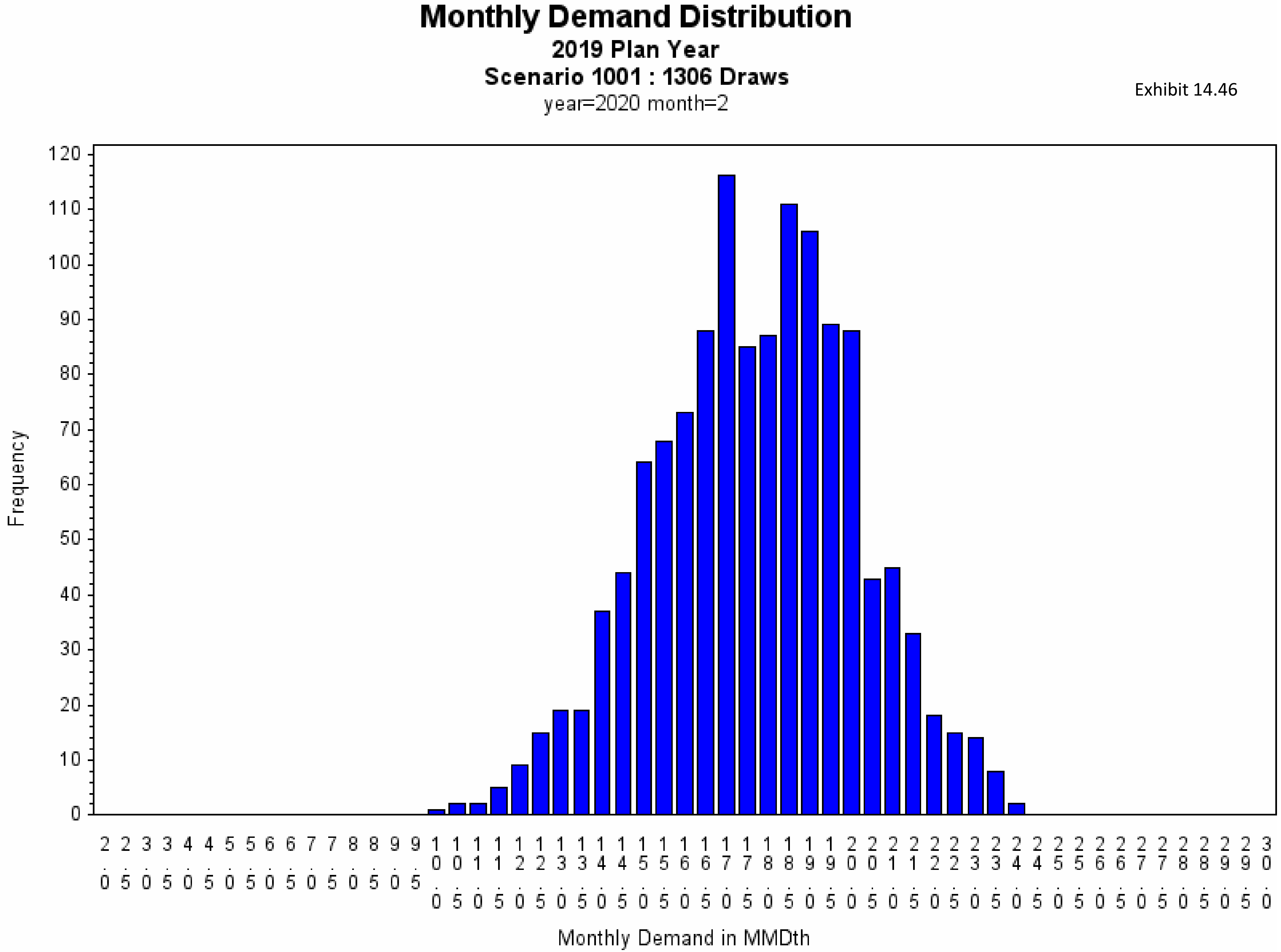
**2019 Plan Year**

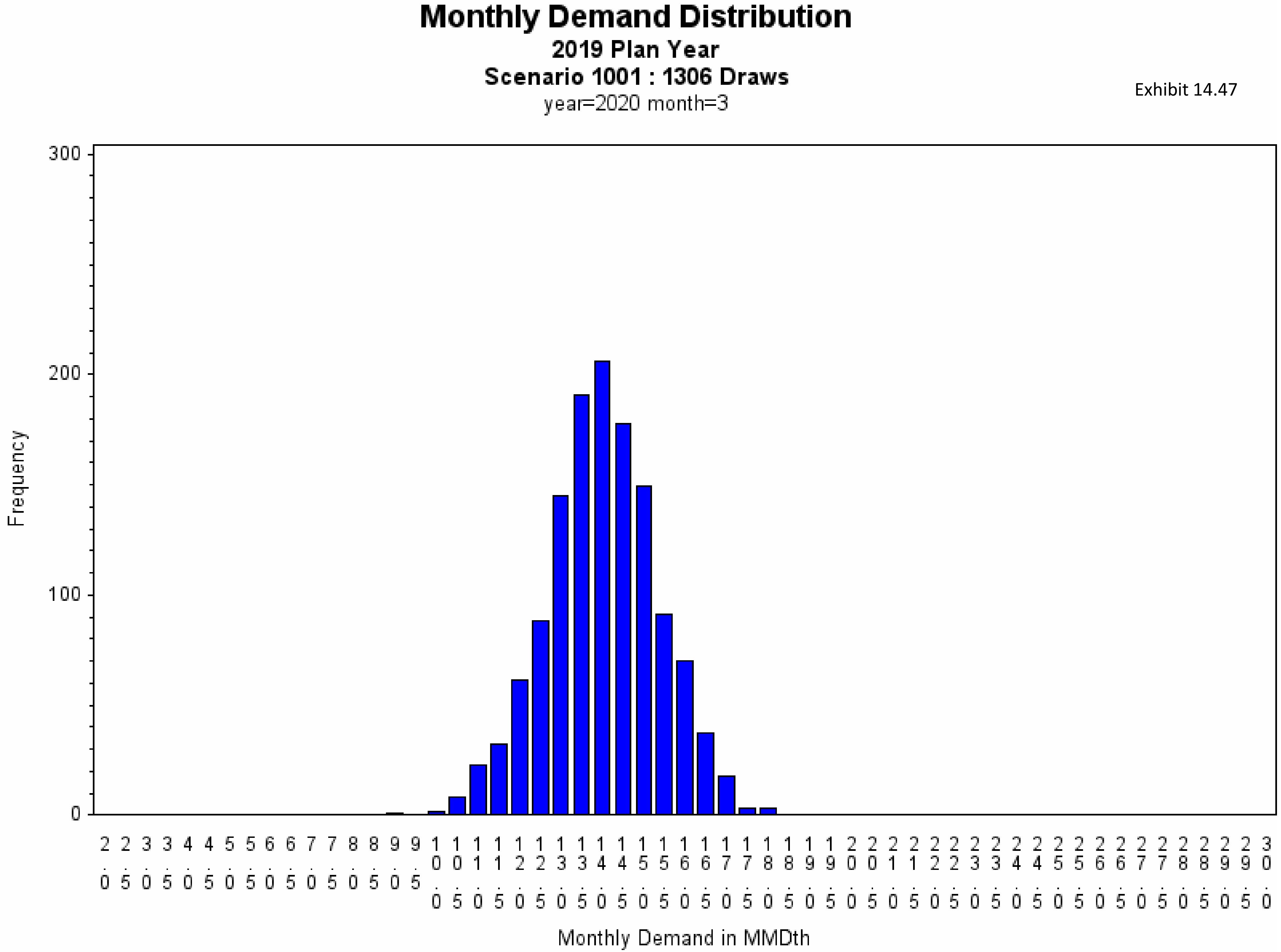
**Scenario 1001 : 1306 Draws**

year=2020 month=1

Exhibit 14.45




Monthly Demand Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=2
Exhibit 14.46
Frequency
Monthly Demand in MMDth



Monthly Demand Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=3
Exhibit 14.47
Frequency
Monthly Demand in MMDth

# Monthly Demand Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=4

Exhibit 14.48

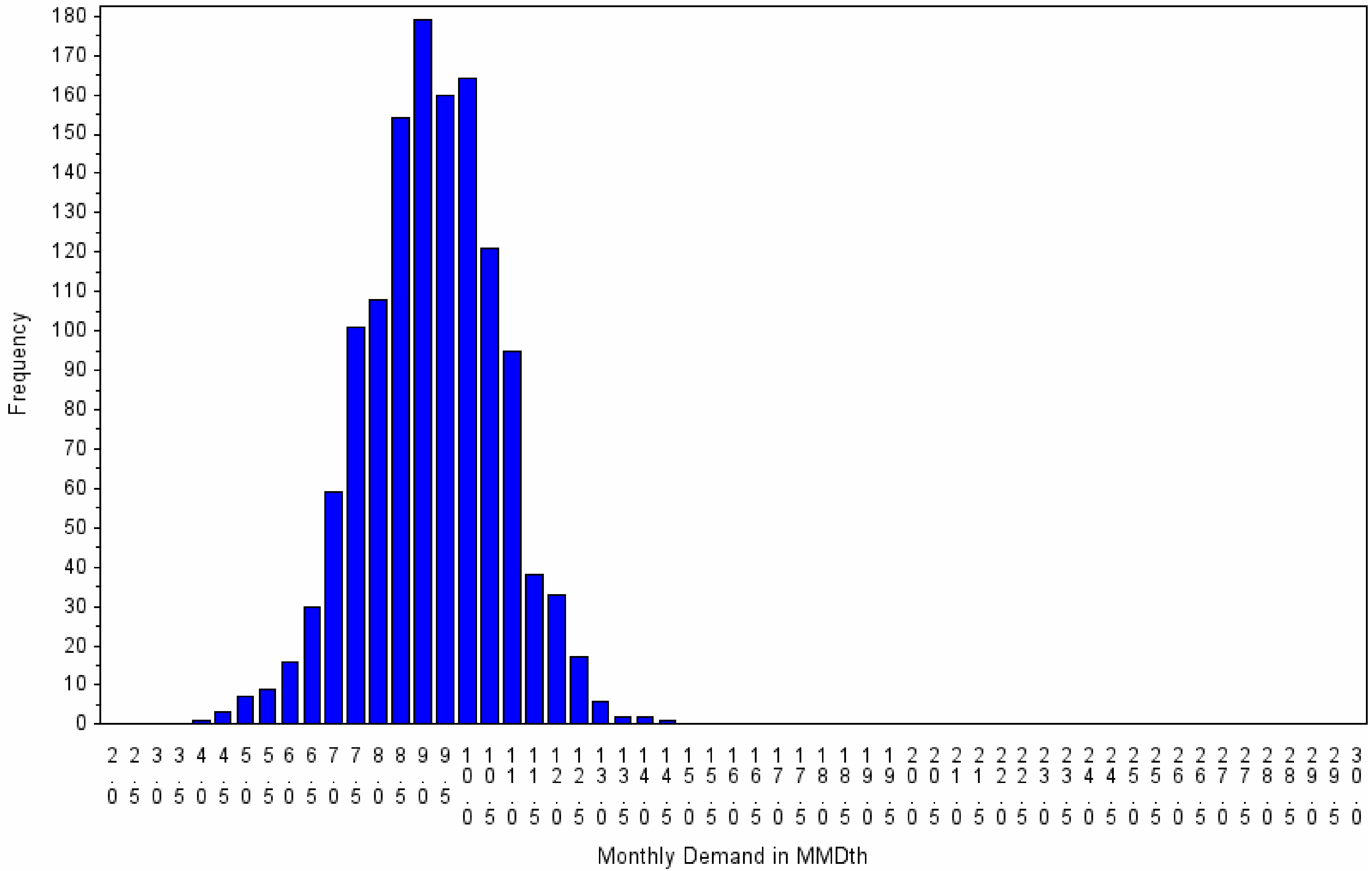
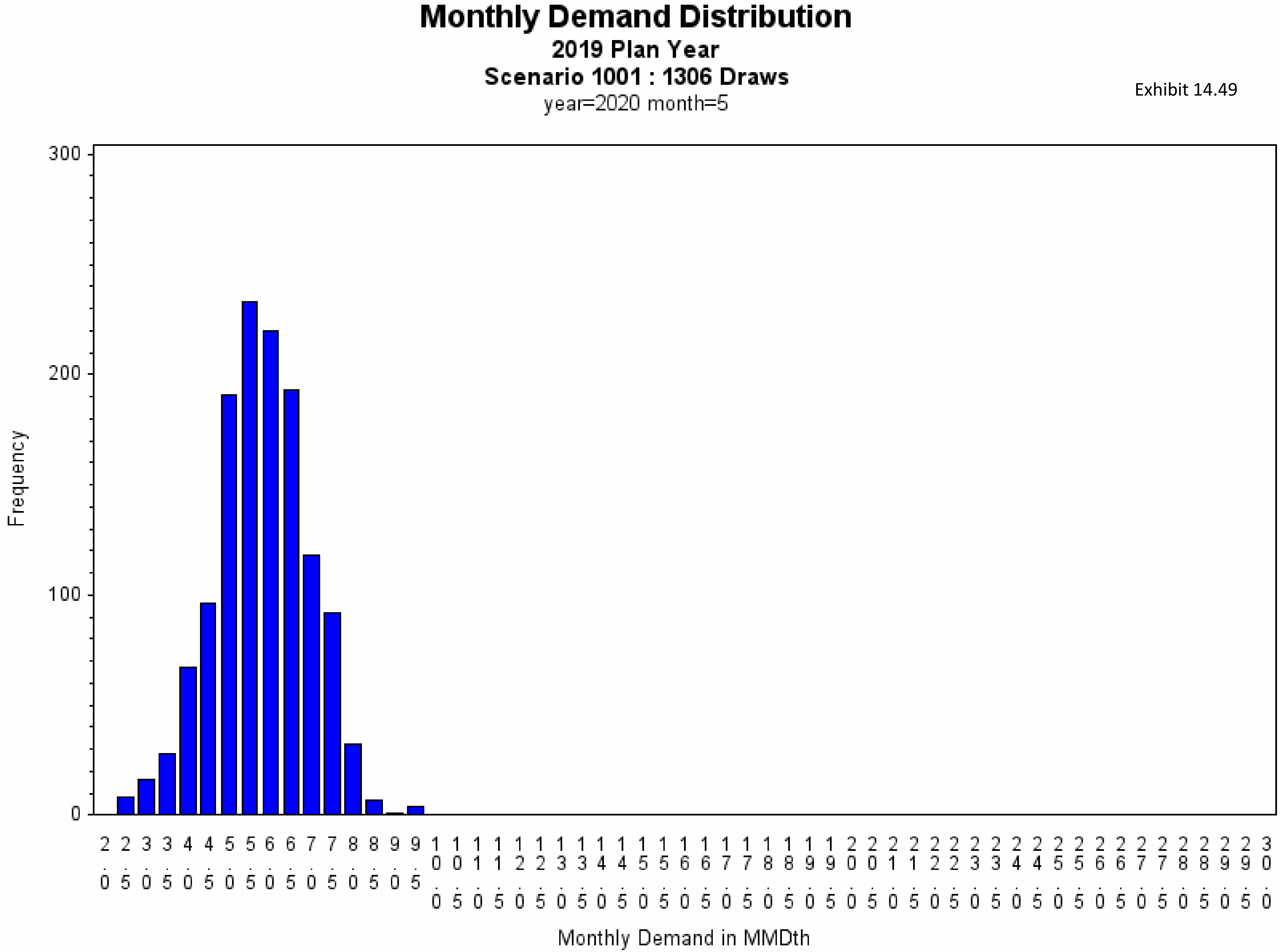


Exhibit 14.49



# Annual Heating Degree Day Distribution

2019 Plan Year

Scenario 1001 : 1306 Draws

Exhibit 14.50

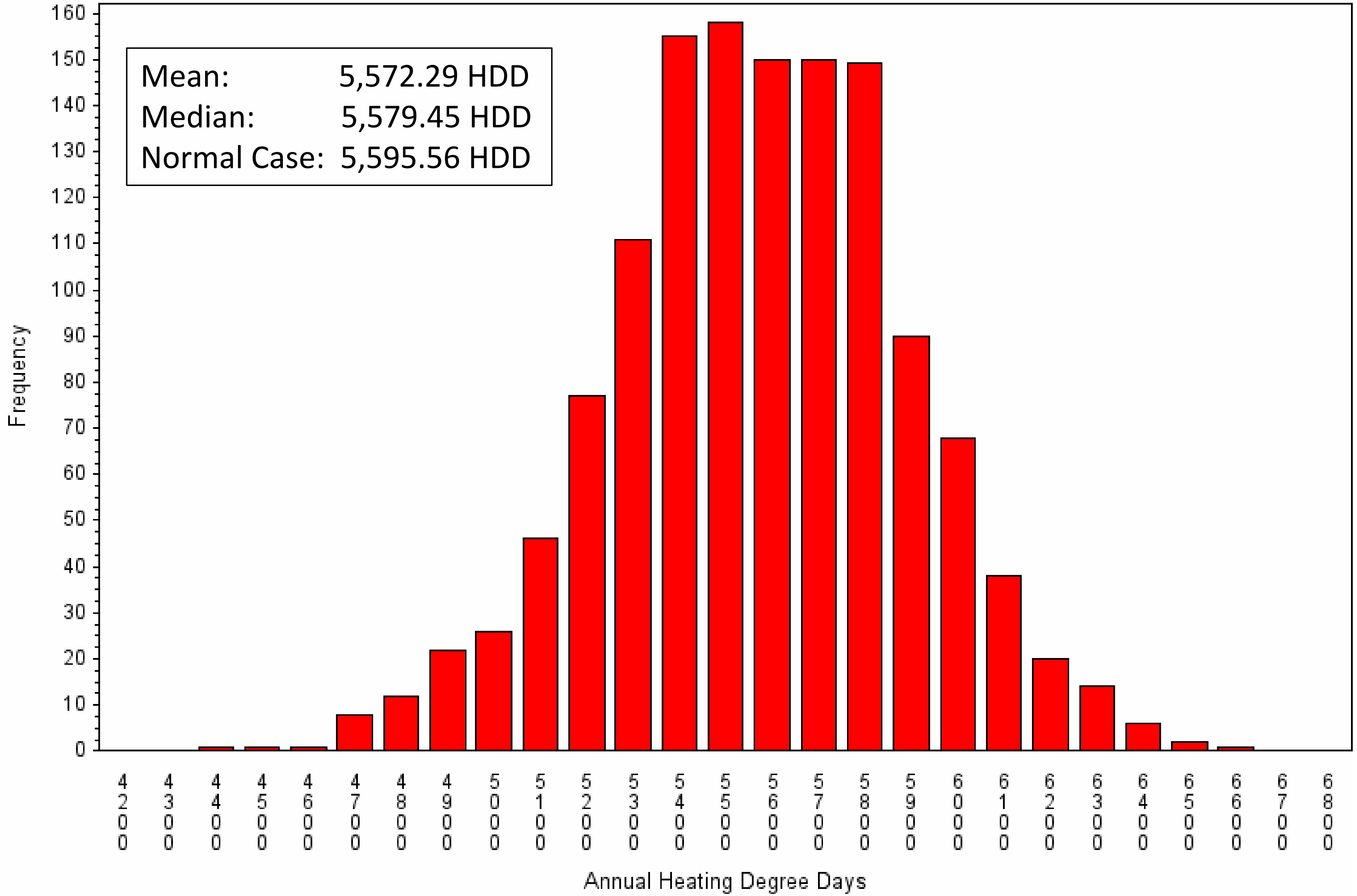


Exhibit 13.51

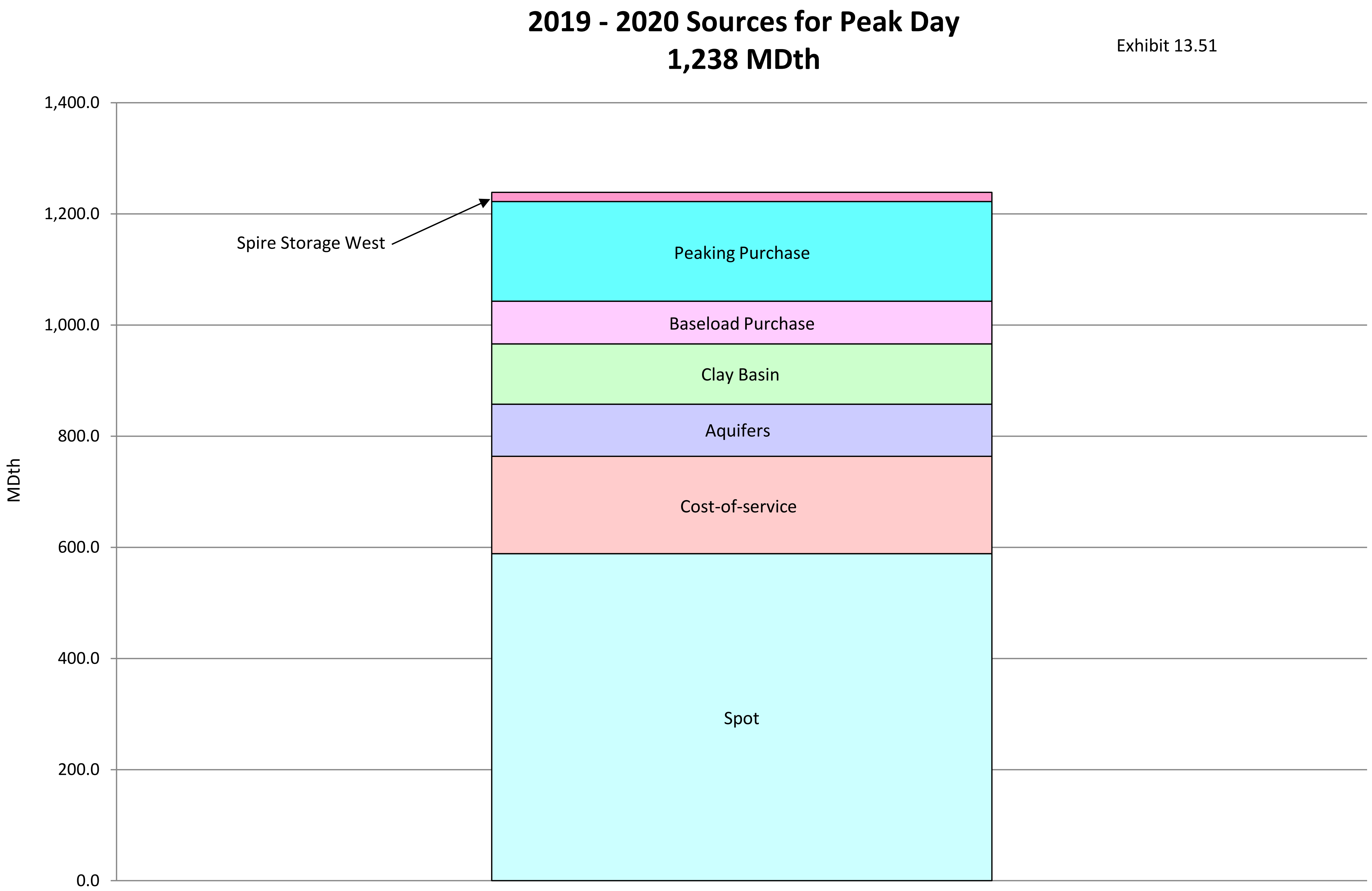


Exhibit 14.52

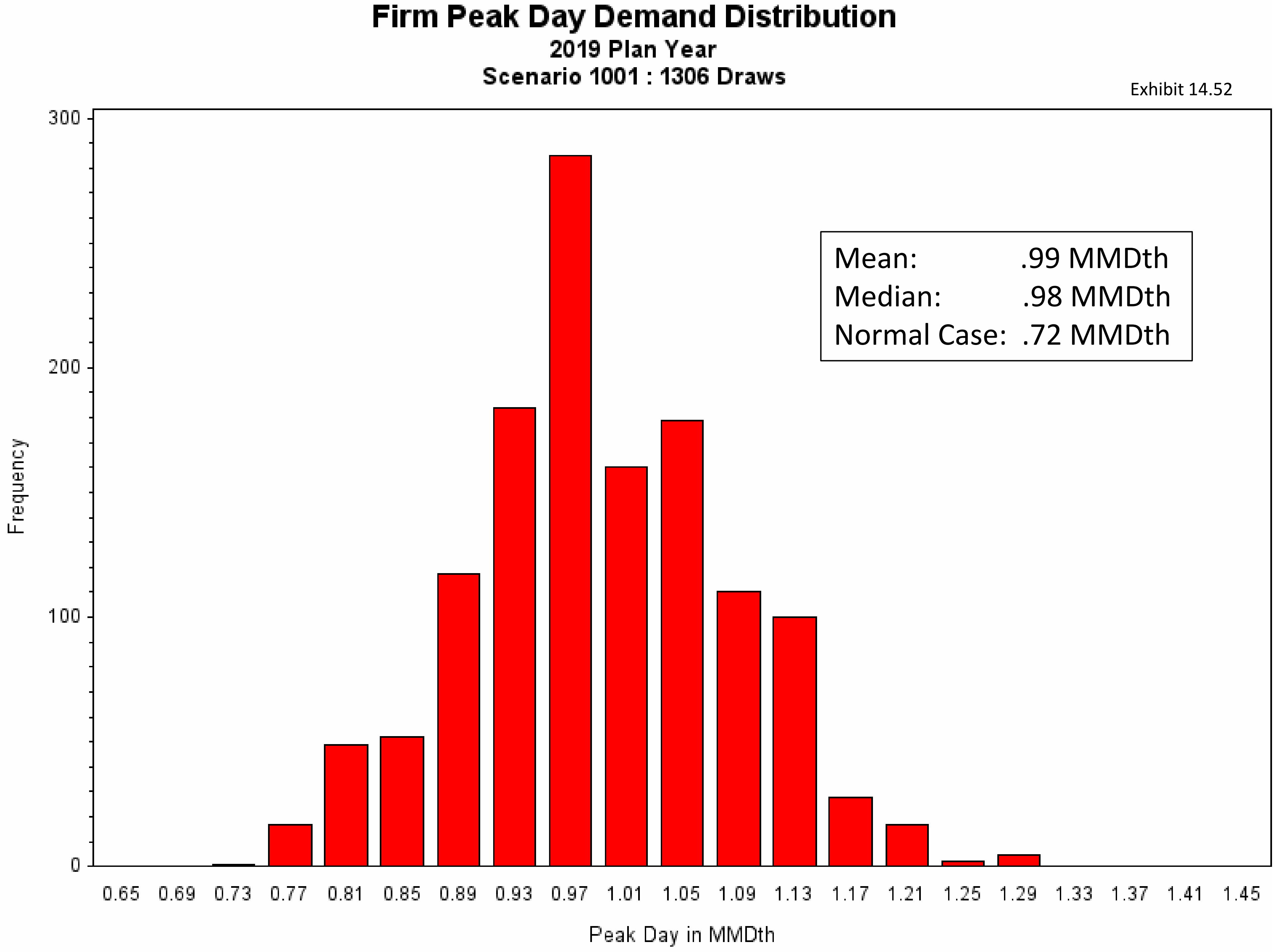
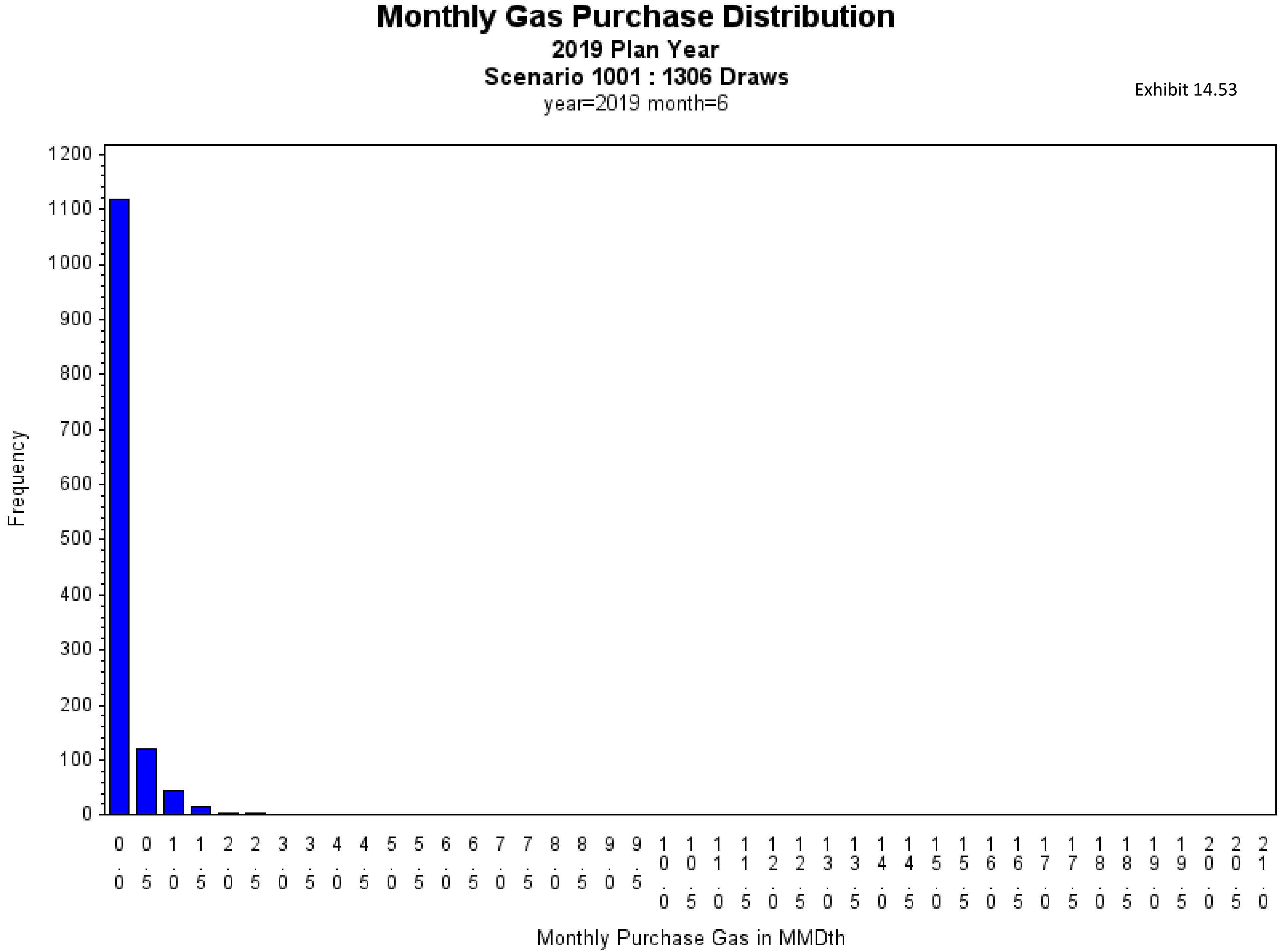


Exhibit 14.53



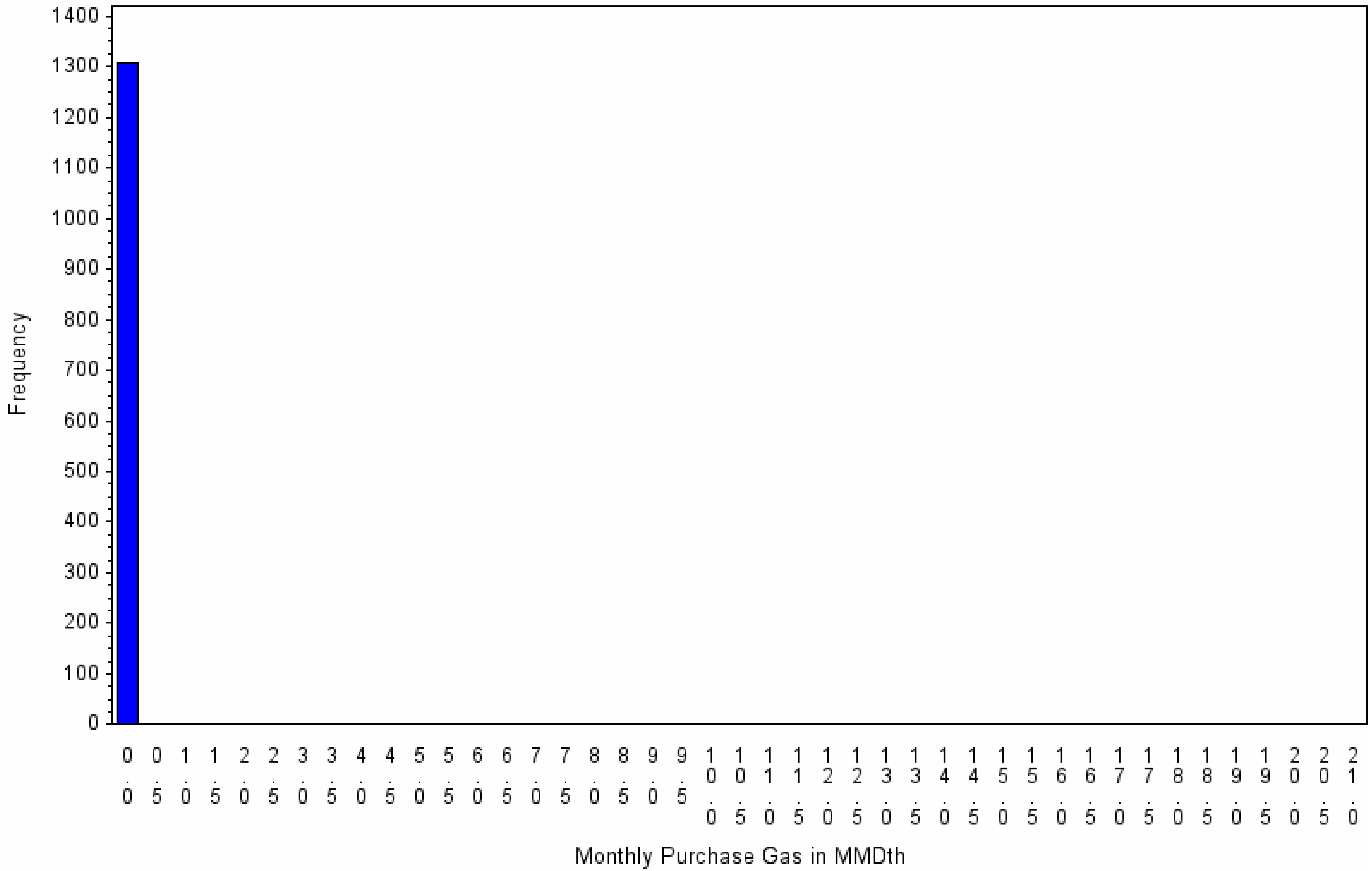
# Monthly Gas Purchase Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=7

Exhibit 14.54



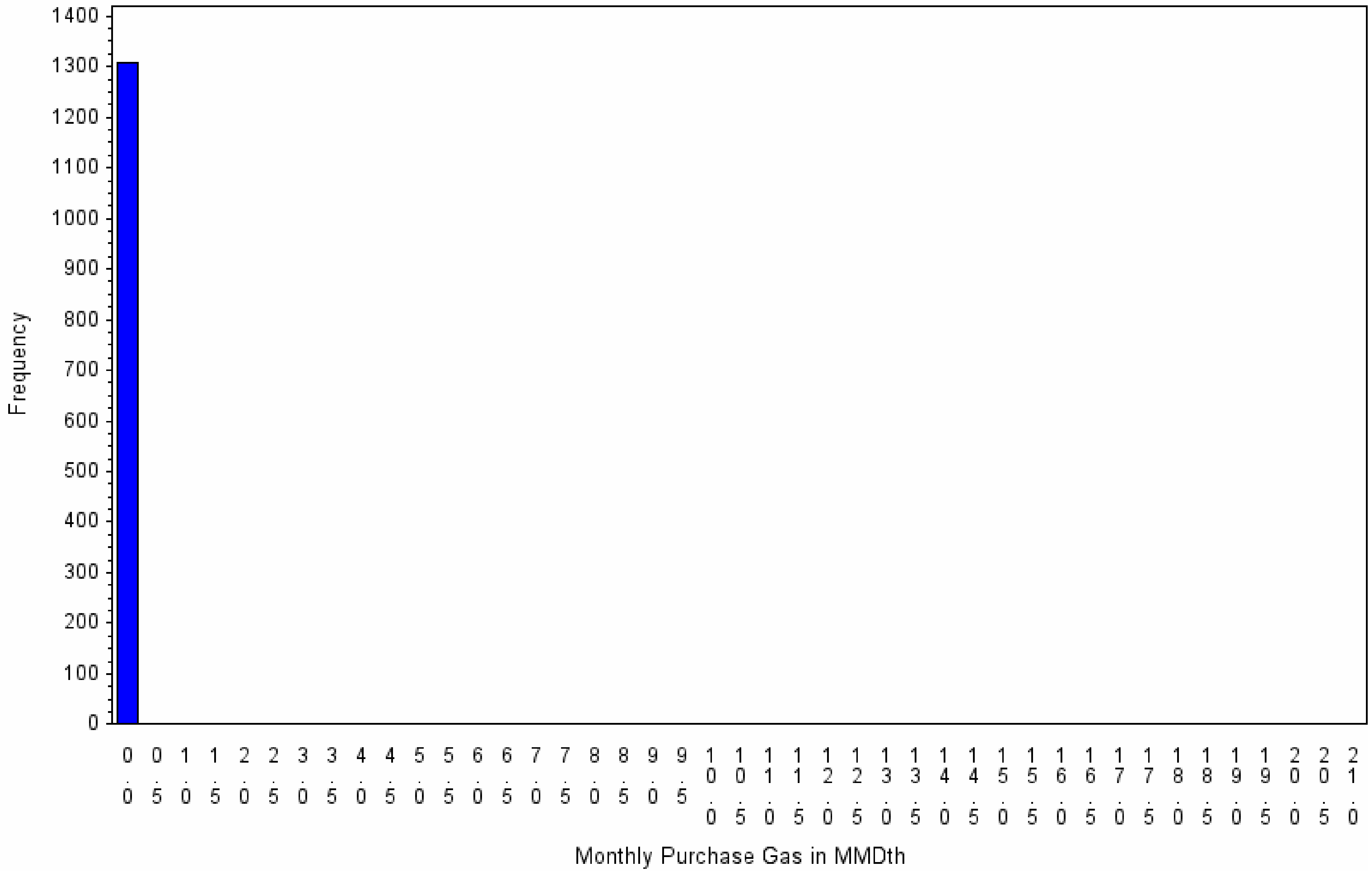
# Monthly Gas Purchase Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=8

Exhibit 14.55



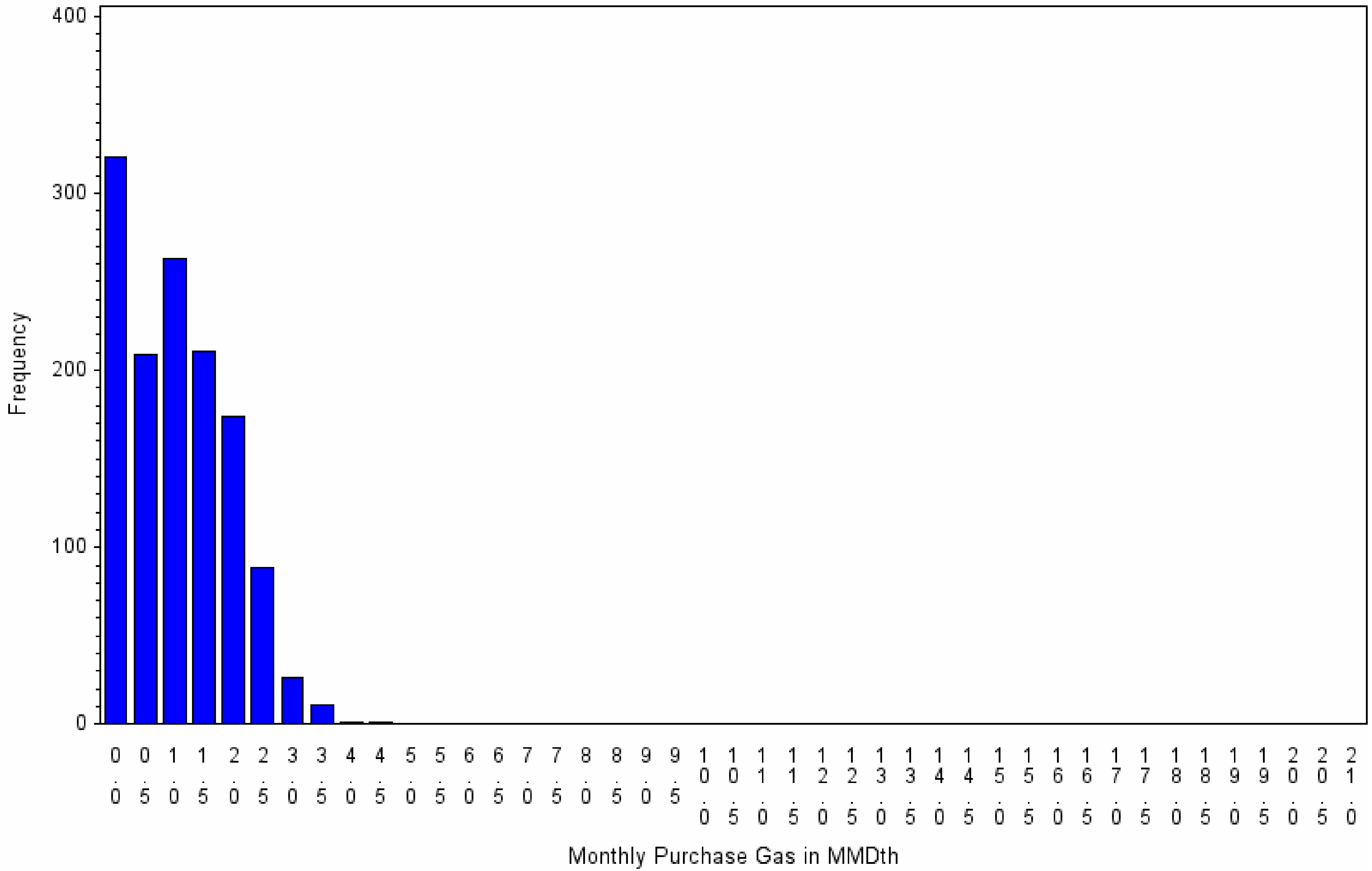
# Monthly Gas Purchase Distribution

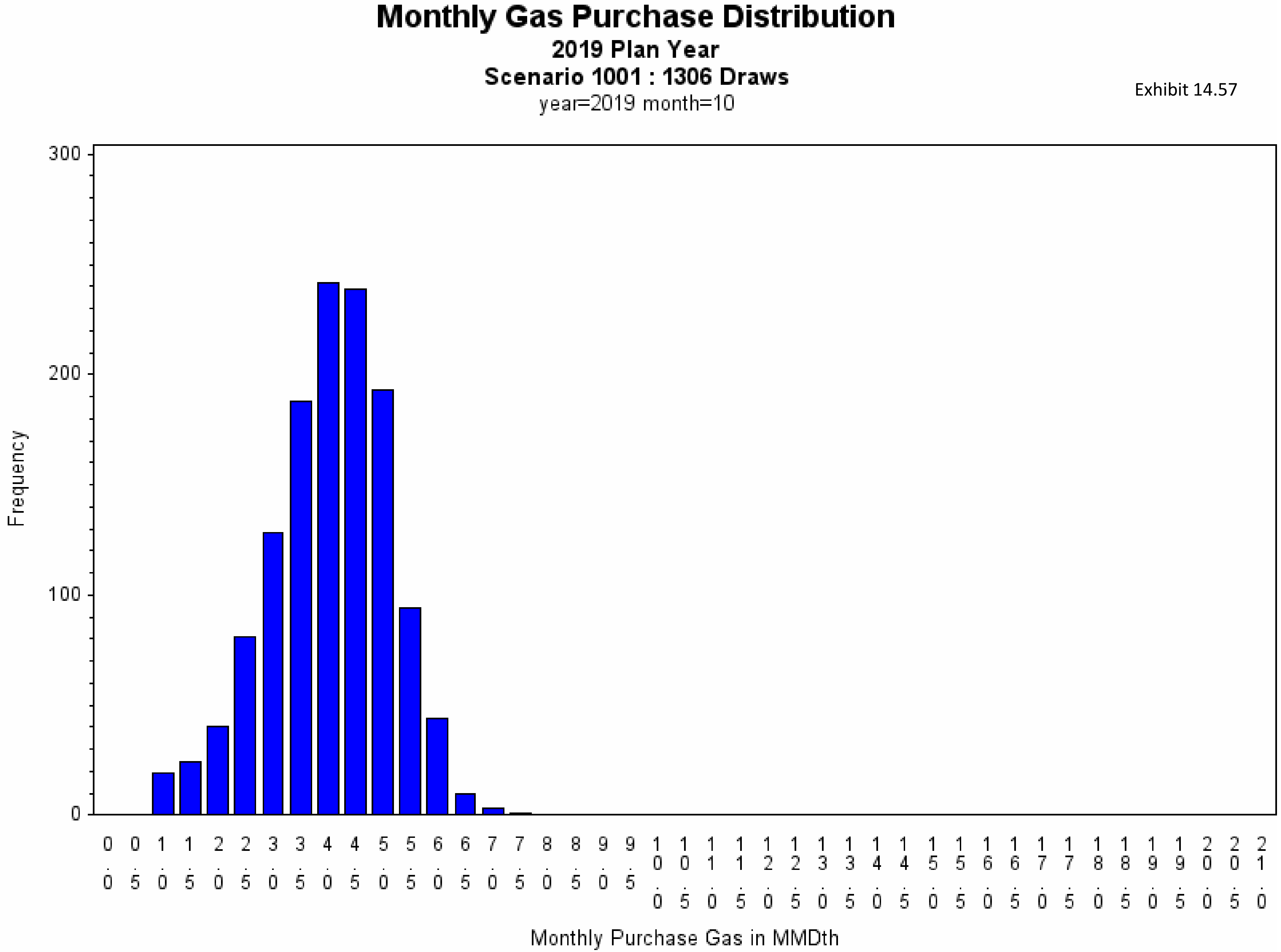
**2019 Plan Year**

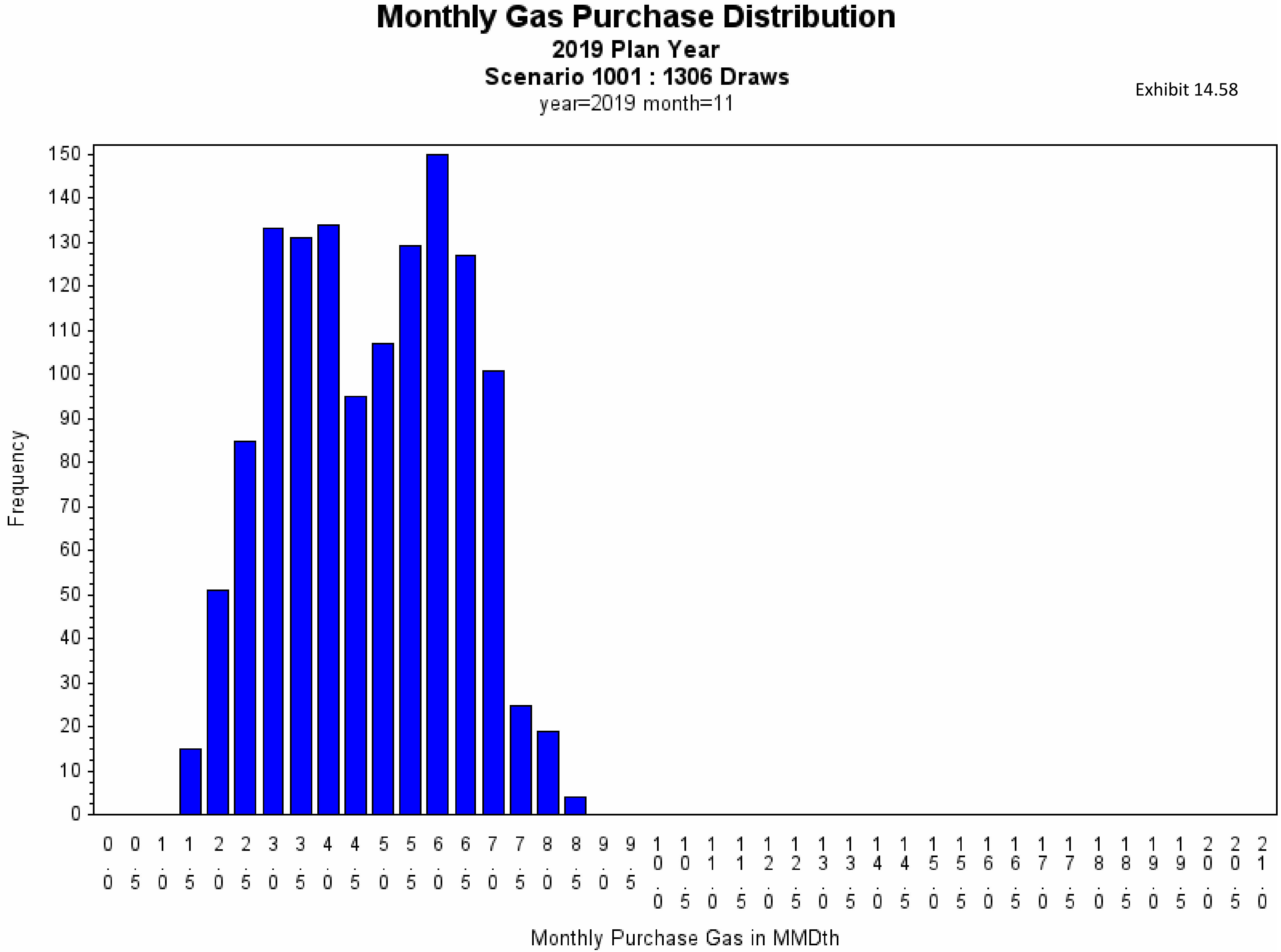
**Scenario 1001 : 1306 Draws**

year=2019 month=9

Exhibit 14.56




Monthly Gas Purchase Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2019 month=10
Exhibit 14.57
Frequency
300
200
100
0
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0 7.5 8.0 8.5 9.0 9.5 10.0 10.5 11.0 11.5 12.0 12.5 13.0 13.5 14.0 14.5 15.0 15.5 16.0 16.5 17.0 17.5 18.0 18.5 19.0 19.5 20.0 20.5 21.0
Monthly Purchase Gas in MMDth


Monthly Gas Purchase Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2019 month=11
Exhibit 14.58
Frequency
Monthly Purchase Gas in MMDth

# Monthly Gas Purchase Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=12

Exhibit 14.59

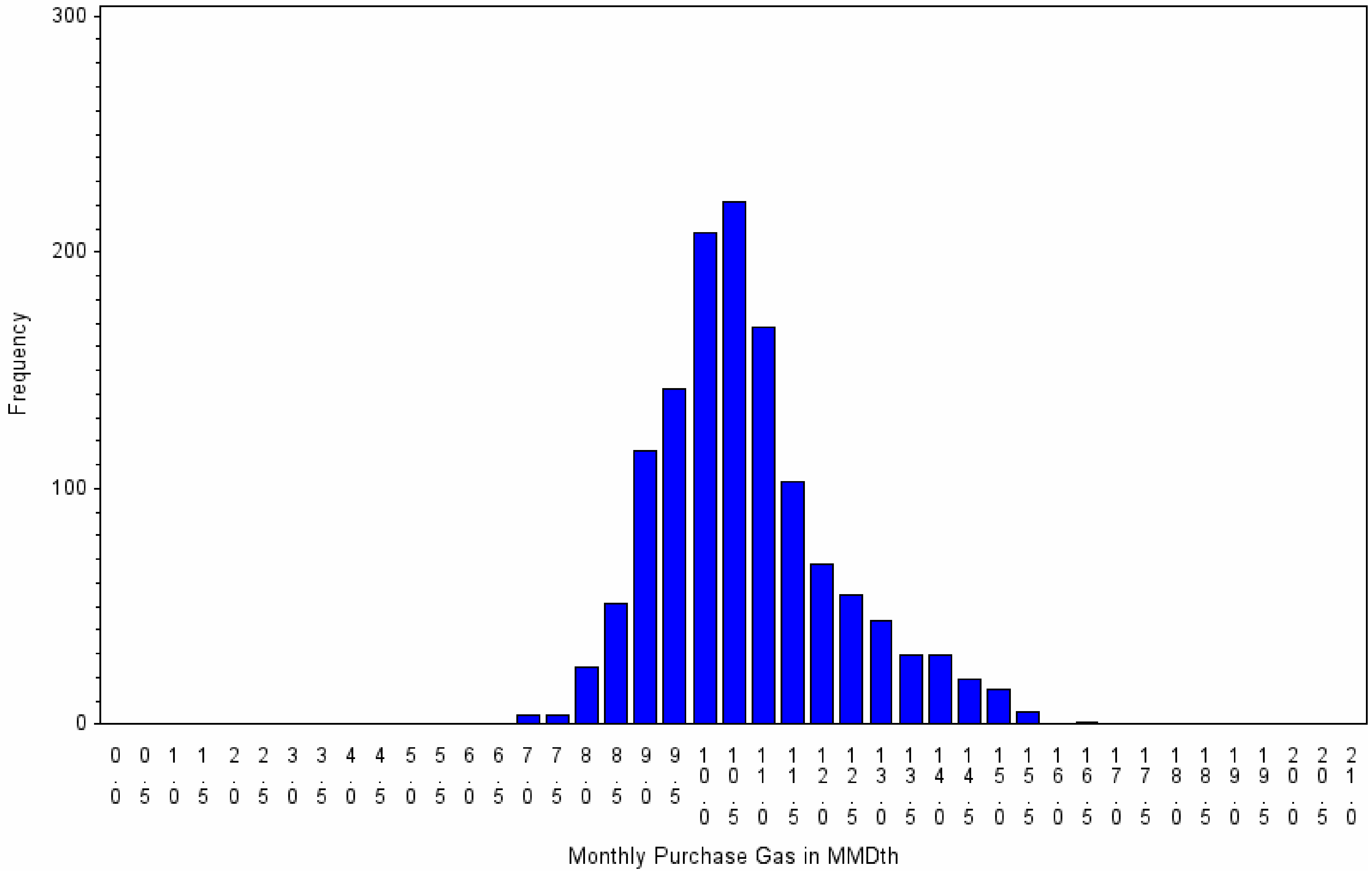


Exhibit 14.60

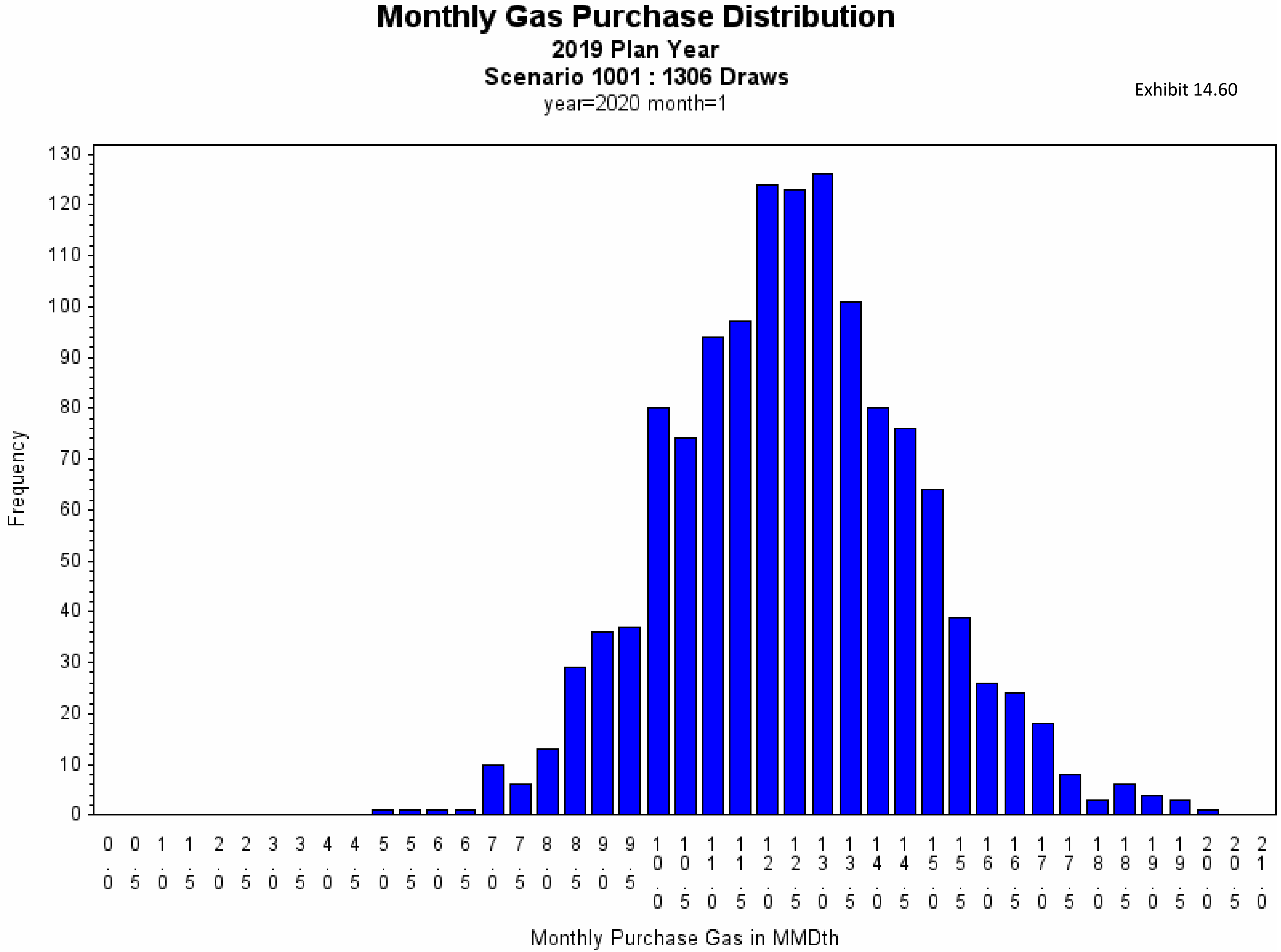
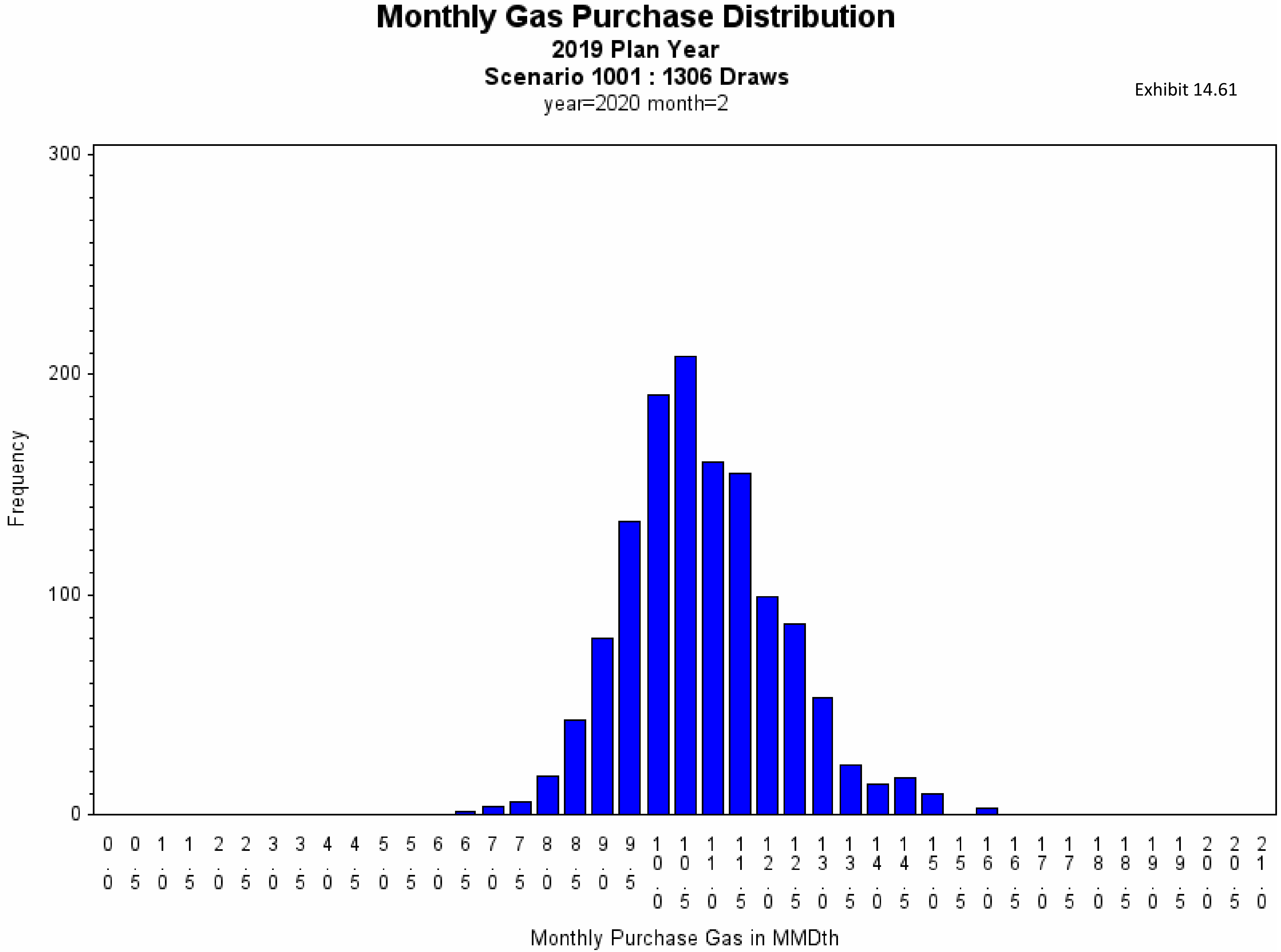
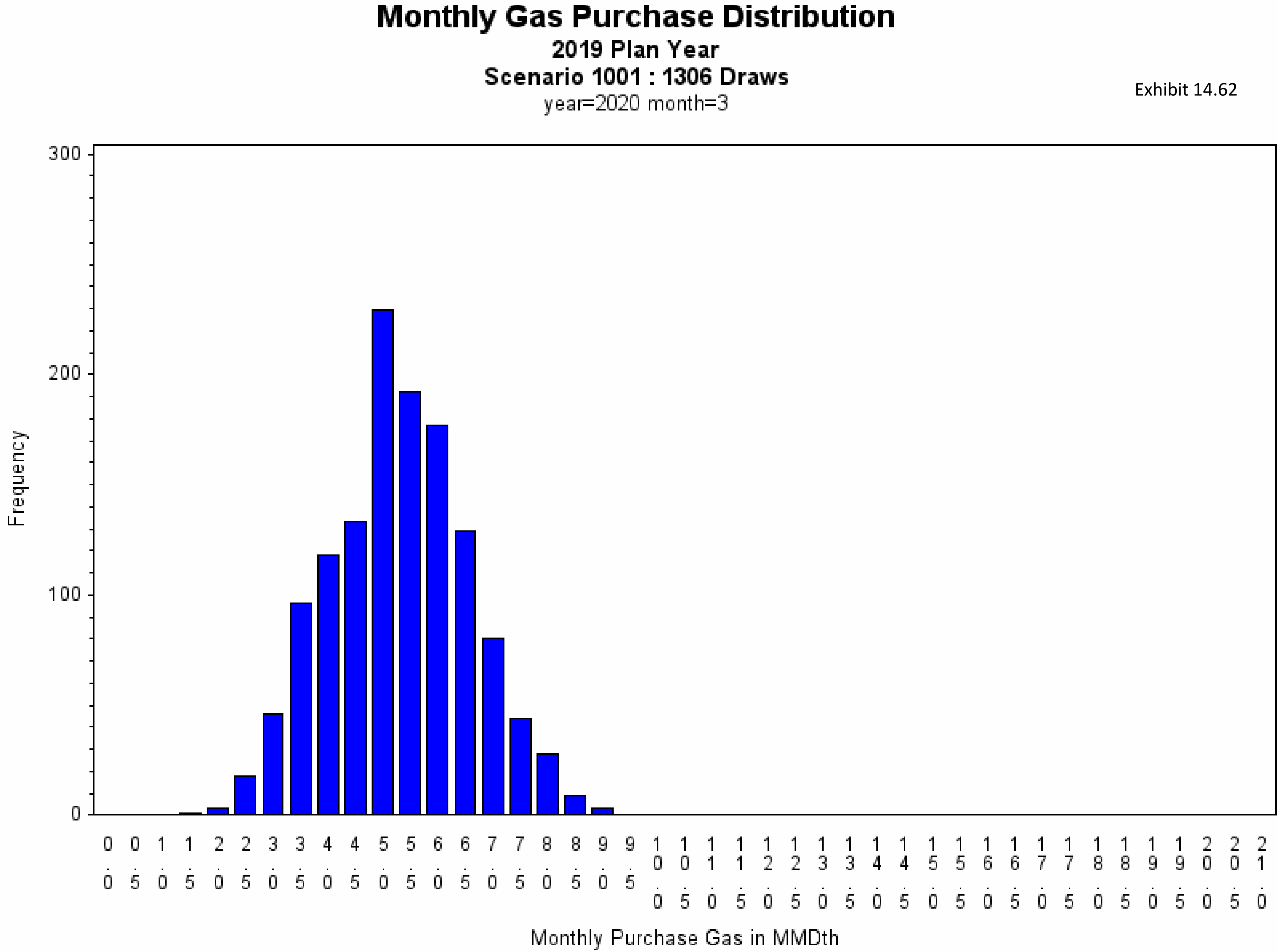


Exhibit 14.61




Monthly Gas Purchase Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
year=2020 month=3
Exhibit 14.62
Frequency
300
200
100
0
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0 7.5 8.0 8.5 9.0 9.5 10.0 10.5 11.0 11.5 12.0 12.5 13.0 13.5 14.0 14.5 15.0 15.5 16.0 16.5 17.0 17.5 18.0 18.5 19.0 19.5 20.0 20.5 21.0
Monthly Purchase Gas in MMDth

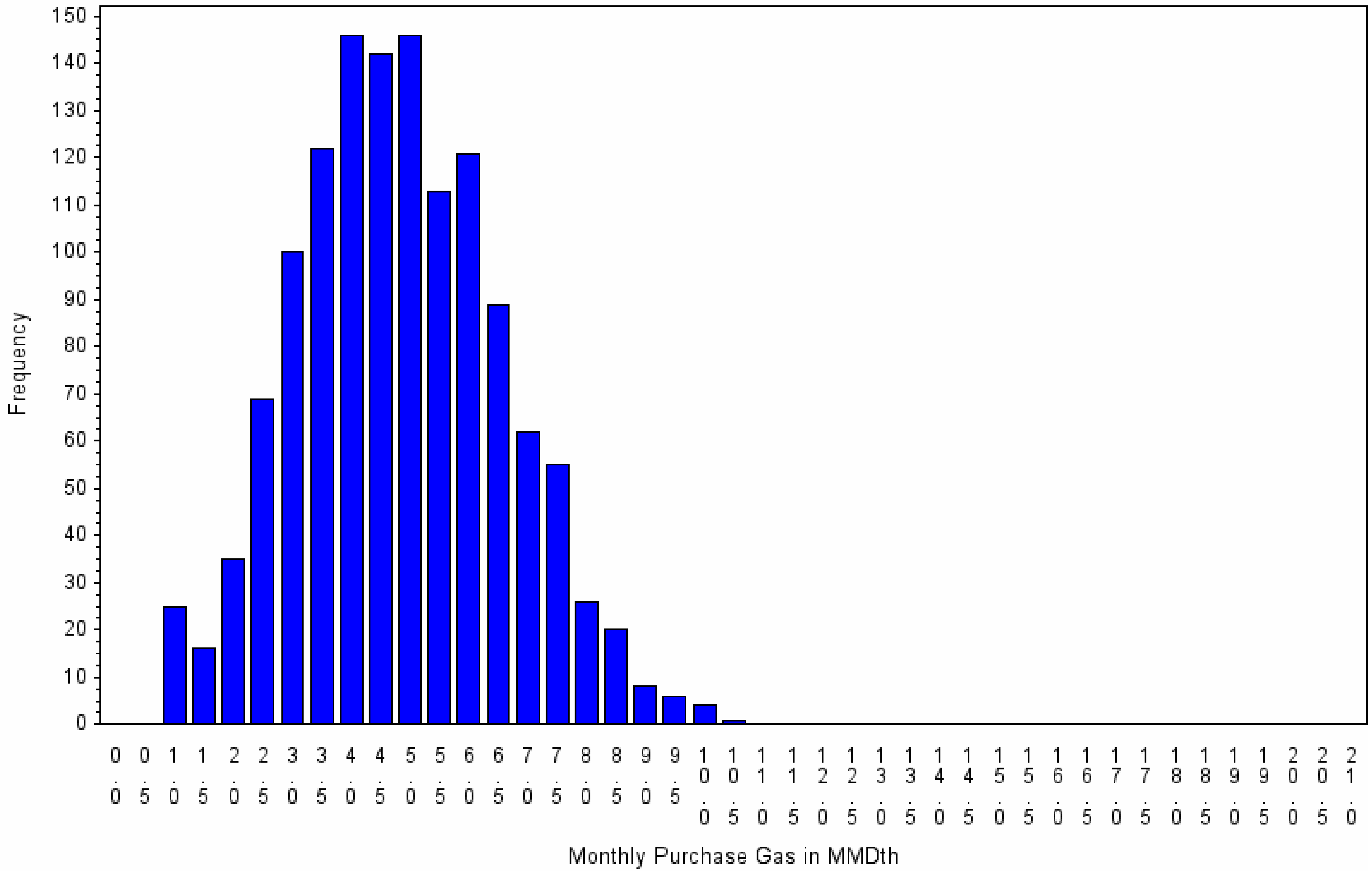
# Monthly Gas Purchase Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=4

Exhibit 14.63



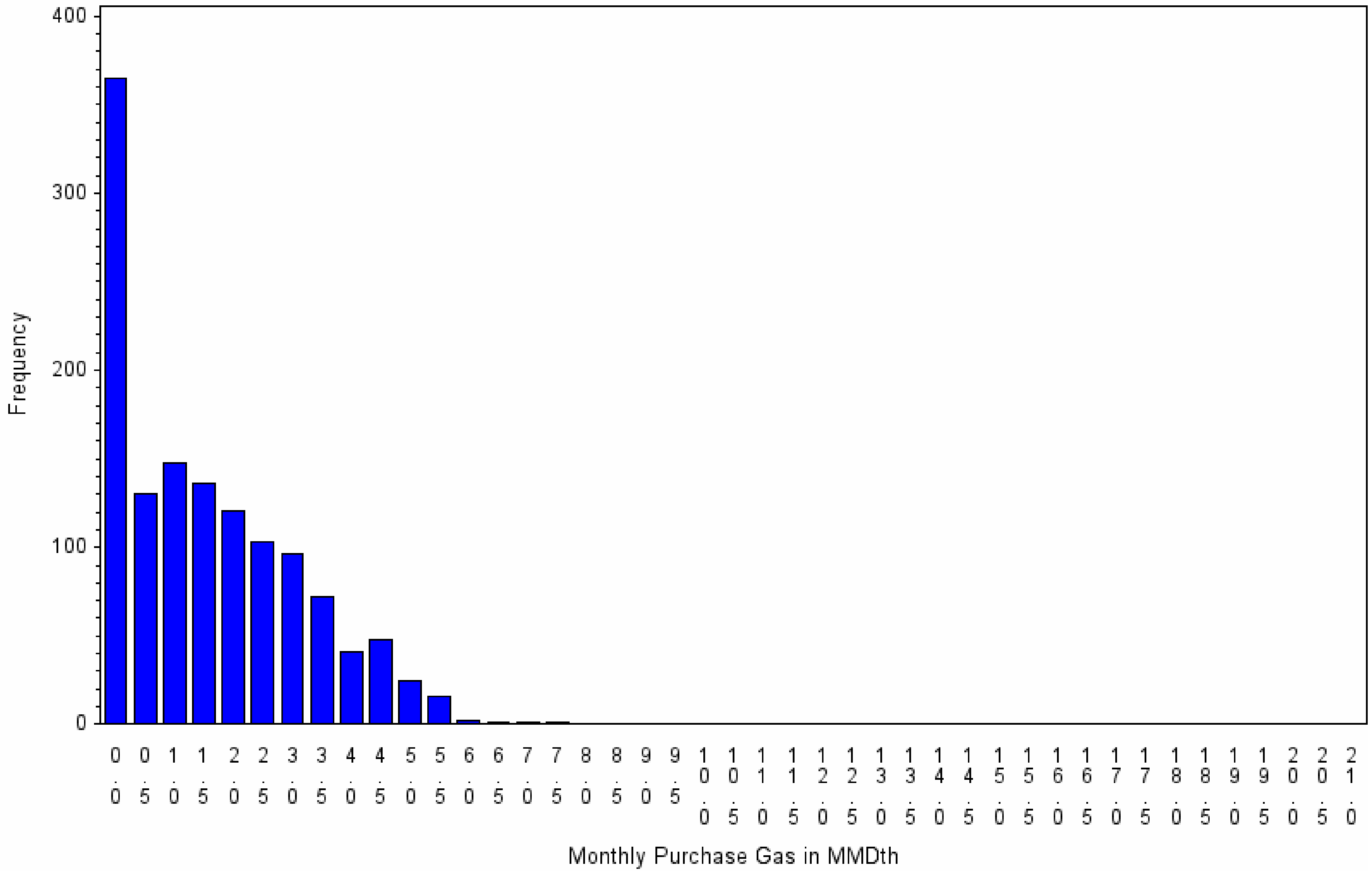
# Monthly Gas Purchase Distribution

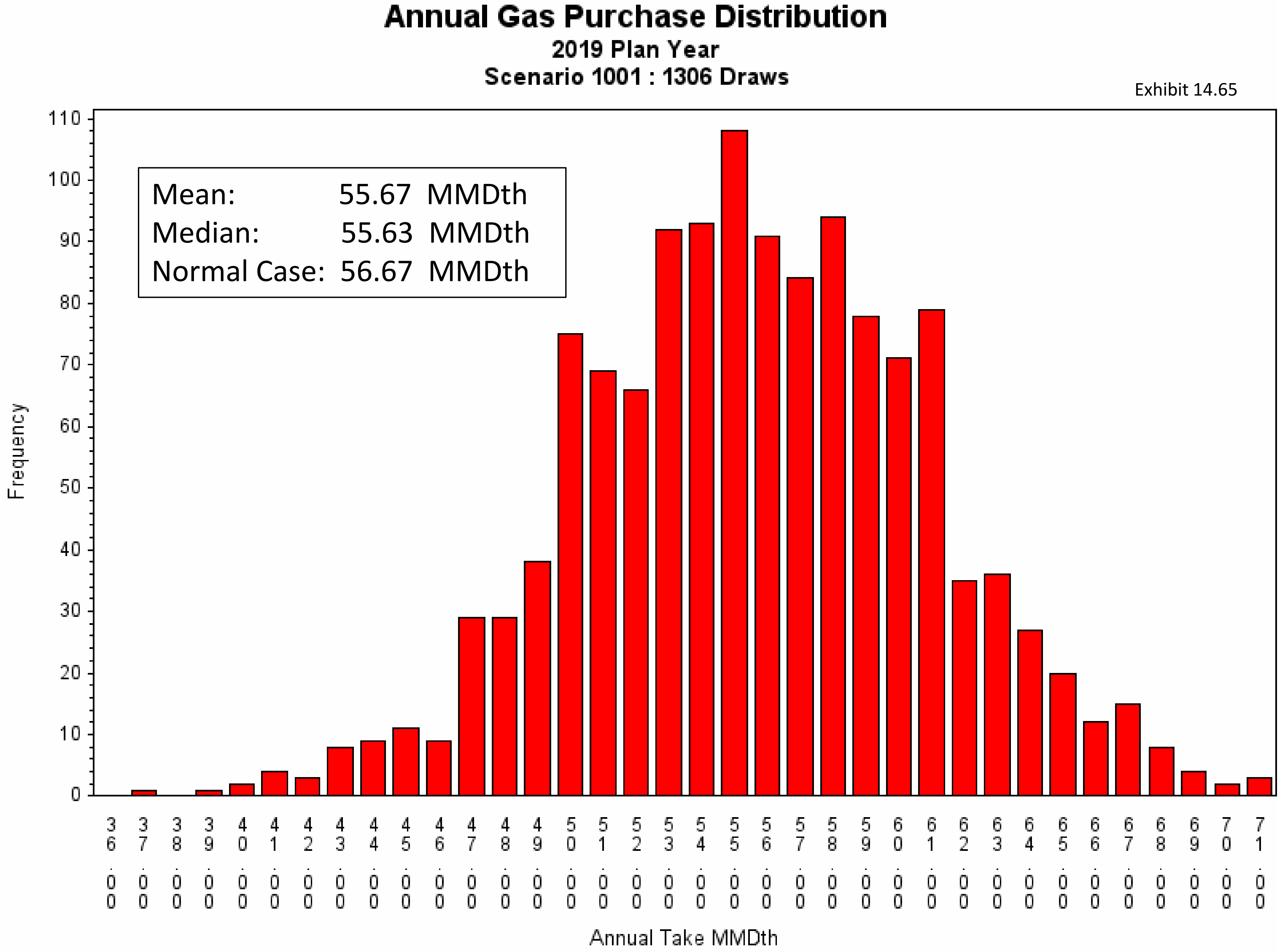
**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=5

Exhibit 14.64





Annual Gas Purchase Distribution
2019 Plan Year
Scenario 1001 : 1306 Draws
Exhibit 14.65
Mean: 55.67 MMDth
Median: 55.63 MMDth
Normal Case: 56.67 MMDth
Frequency
Annual Take MMDth

Exhibit 14.66

# Monthly Purchase Gas Distribution in Mdth
## 2019 Plan Year
## Scenario 1001 : 1306 Draws

| year | month | mean | max | p95 | p90 | med | p10 | p5 | min |
|---|---|---|---|---|---|---|---|---|---|
| 2018 | 6 | 0.11 | 2.29 | 0.76 | 0.46 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 7 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 8 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 9 | 1.07 | 4.30 | 2.60 | 2.23 | 0.99 | 0.00 | 0.00 | 0.00 |
| 2018 | 10 | 4.03 | 7.5 | 5.7 | 5.33 | 4.09 | 2.56 | 2.07 | 0.93 |
| 2018 | 11 | 4.75 | 8.60 | 7.12 | 6.86 | 4.78 | 2.62 | 2.24 | 1.27 |
| 2018 | 12 | 10.70 | 16.45 | 13.79 | 12.84 | 10.48 | 9.00 | 8.66 | 6.99 |
| 2019 | 1 | 12.47 | 19.87 | 16.30 | 15.25 | 12.46 | 9.68 | 8.86 | 5.22 |
| 2019 | 2 | 10.82 | 16.10 | 13.27 | 12.69 | 10.64 | 9.12 | 8.64 | 6.50 |
| 2019 | 3 | 5.30 | 9.02 | 7.37 | 6.92 | 5.28 | 3.66 | 3.23 | 1.40 |
| 2019 | 4 | 4.83 | 10.37 | 7.71 | 7.17 | 4.74 | 2.63 | 2.16 | 0.90 |
| 2019 | 5 | 1.60 | 7.59 | 4.53 | 3.79 | 1.30 | 0.00 | 0.00 | 0.00 |

# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=6

Exhibit 14.67

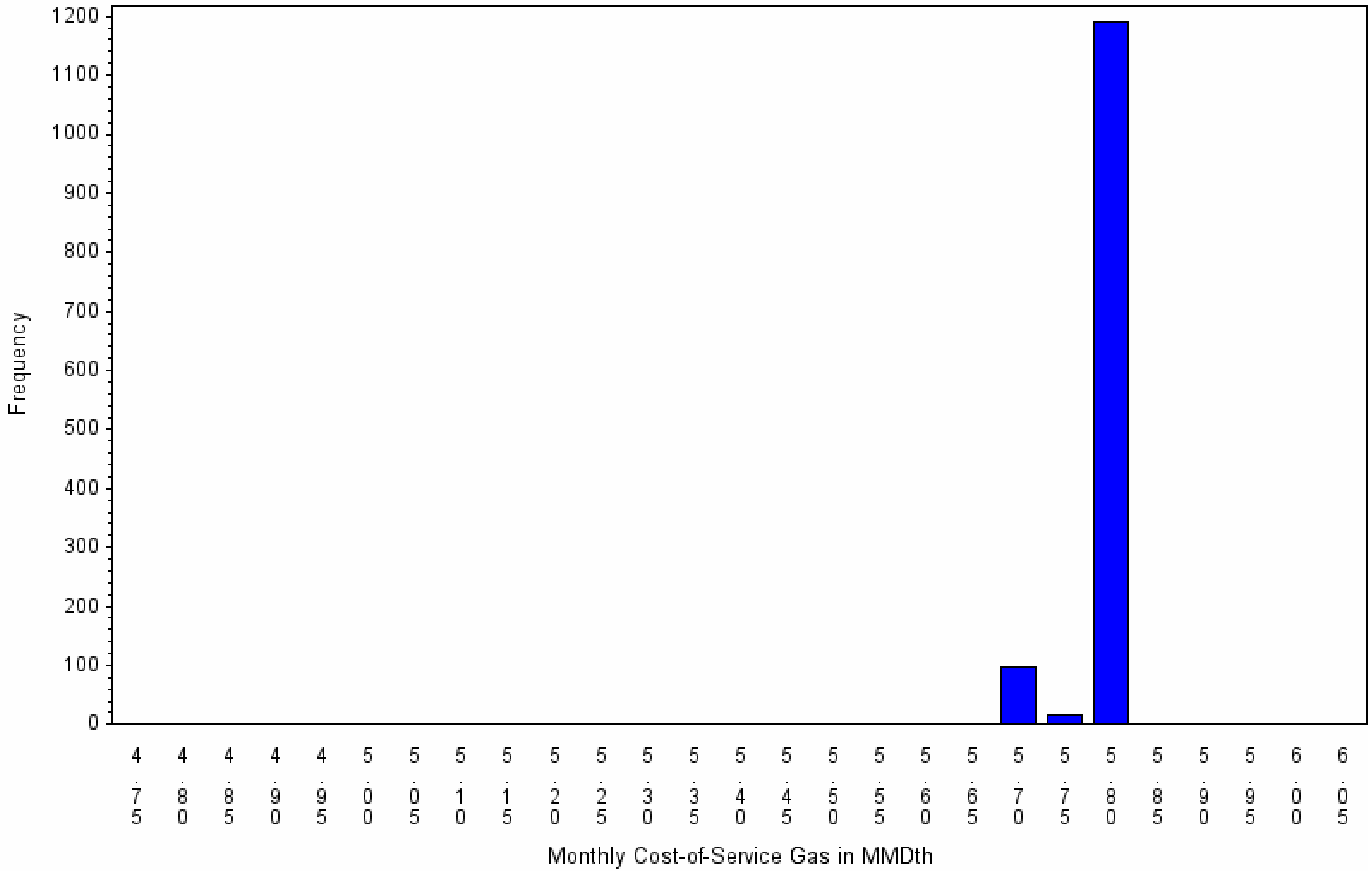


Exhibit 14.68

# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=7

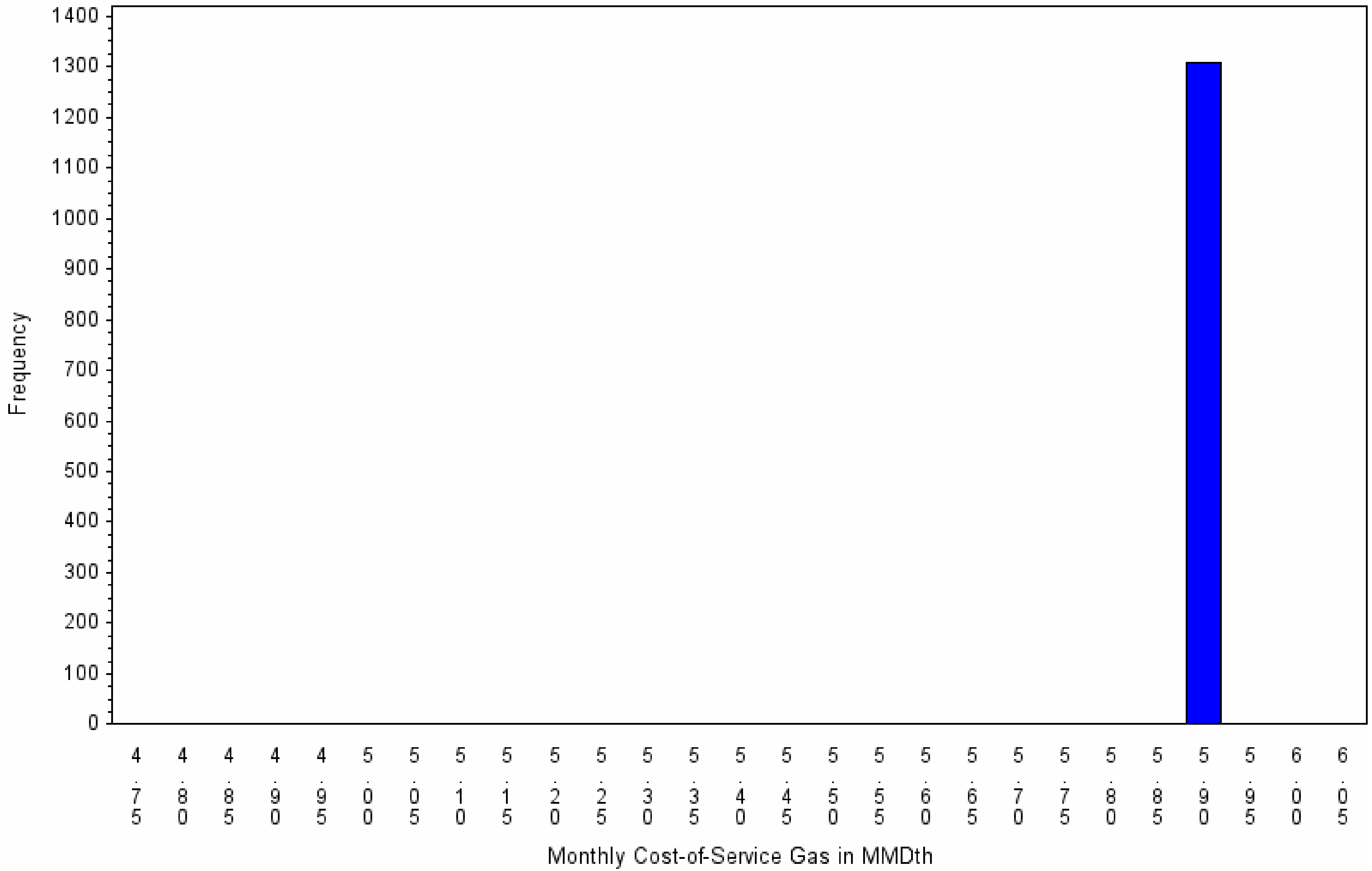
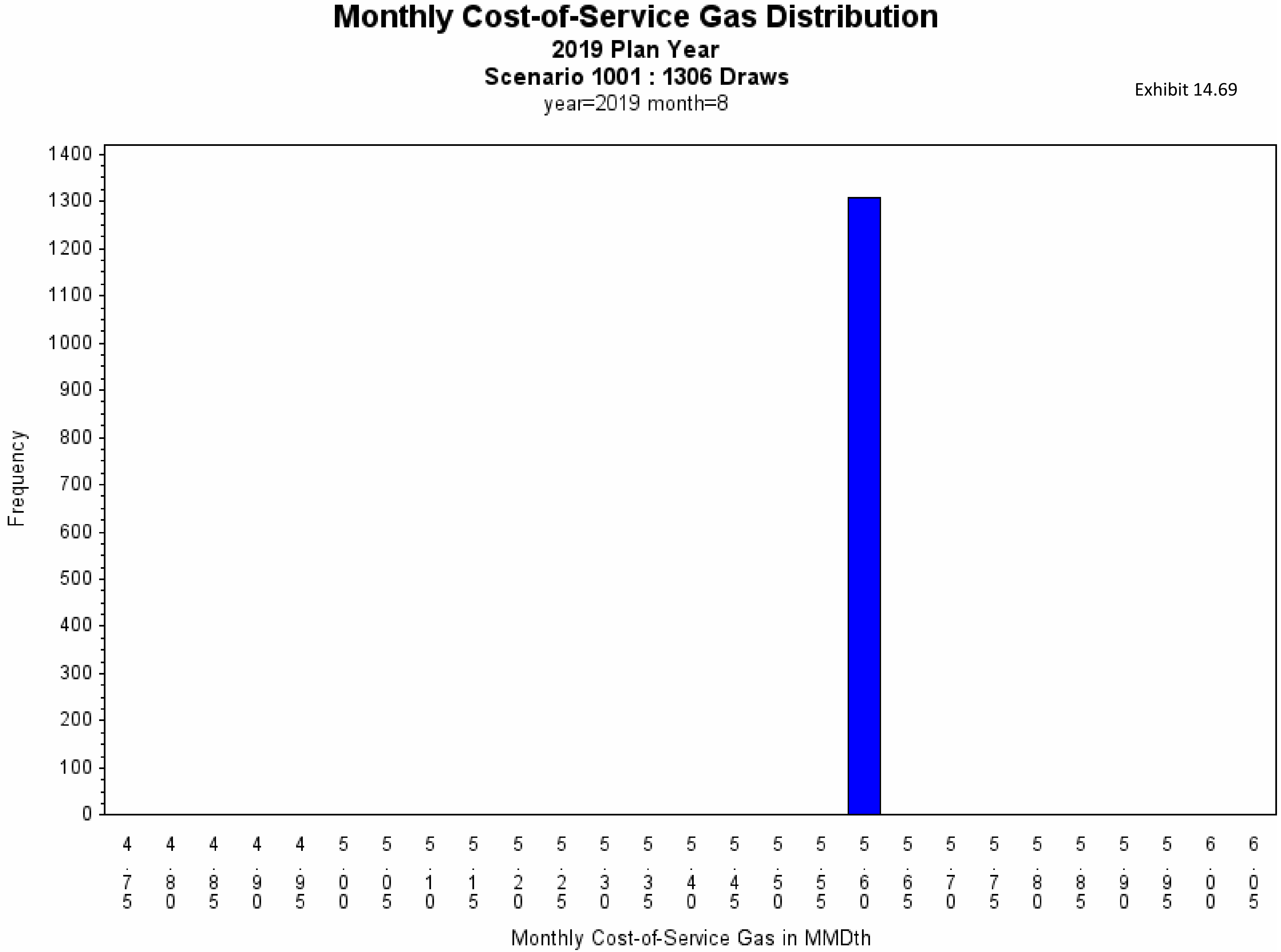


Exhibit 14.69



# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=9

Exhibit 14.70

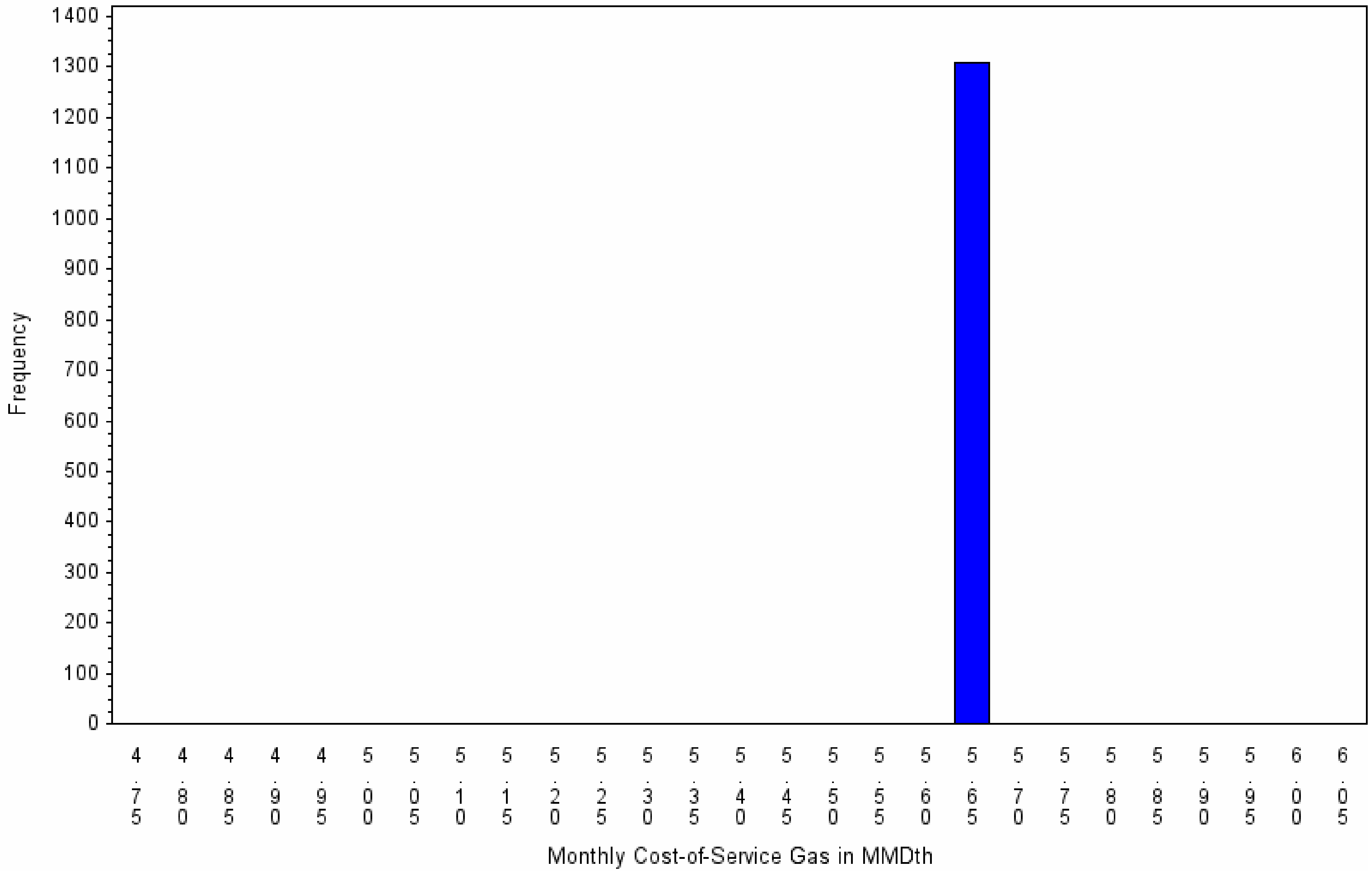


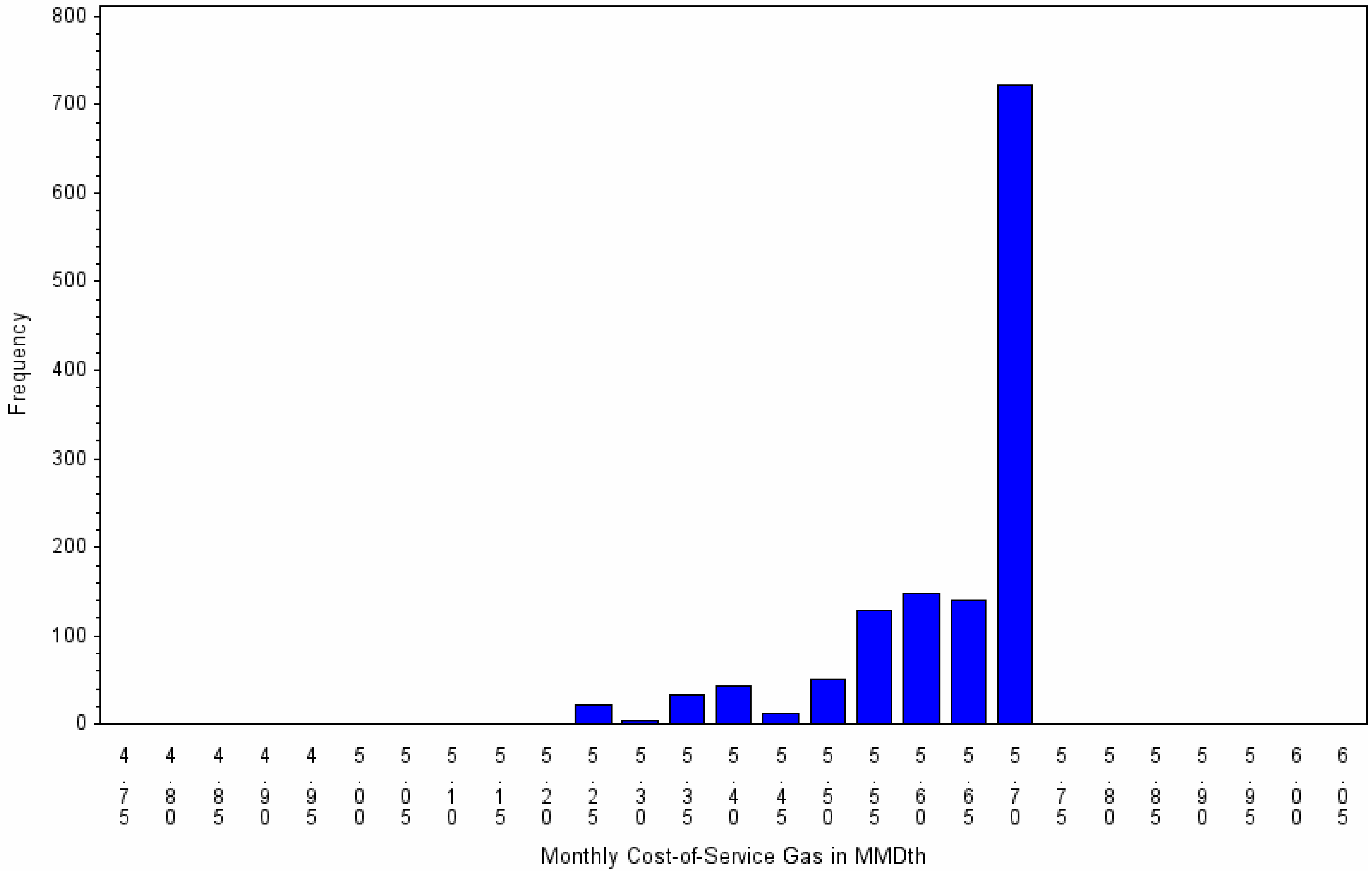
Exhibit 14.71

# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=10



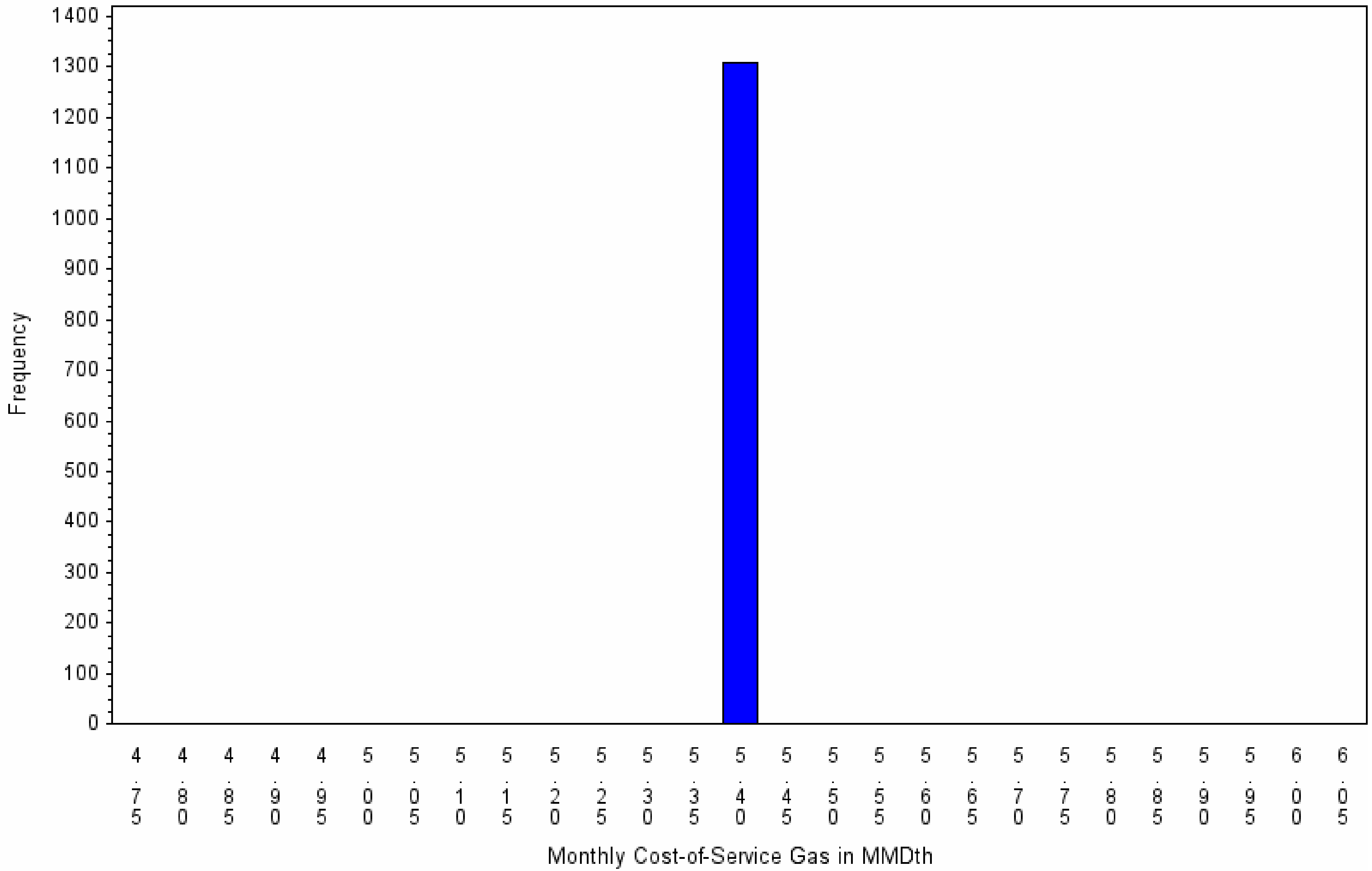
# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=11

Exhibit 14.72



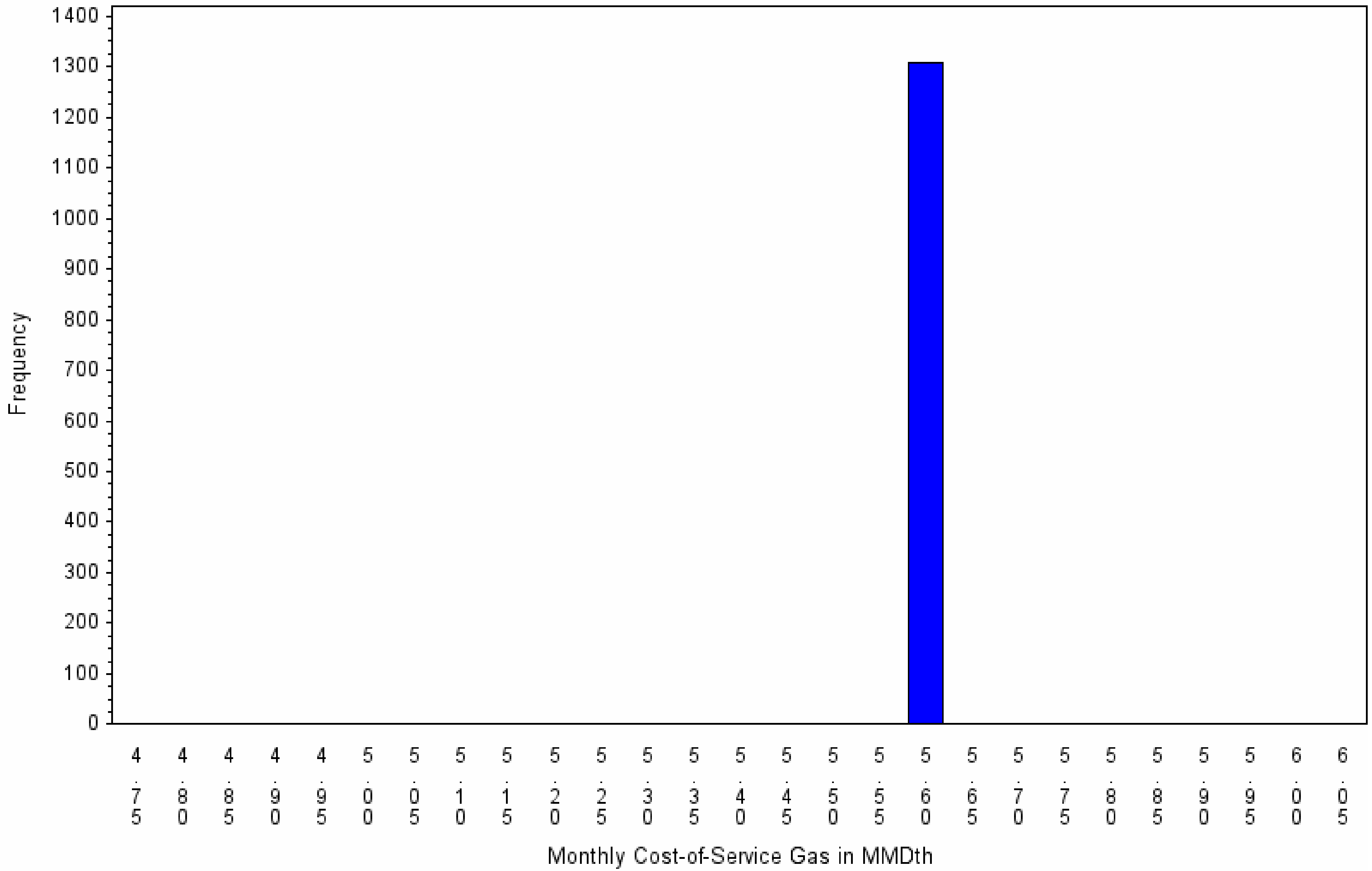
# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2019 month=12

Exhibit 14.73



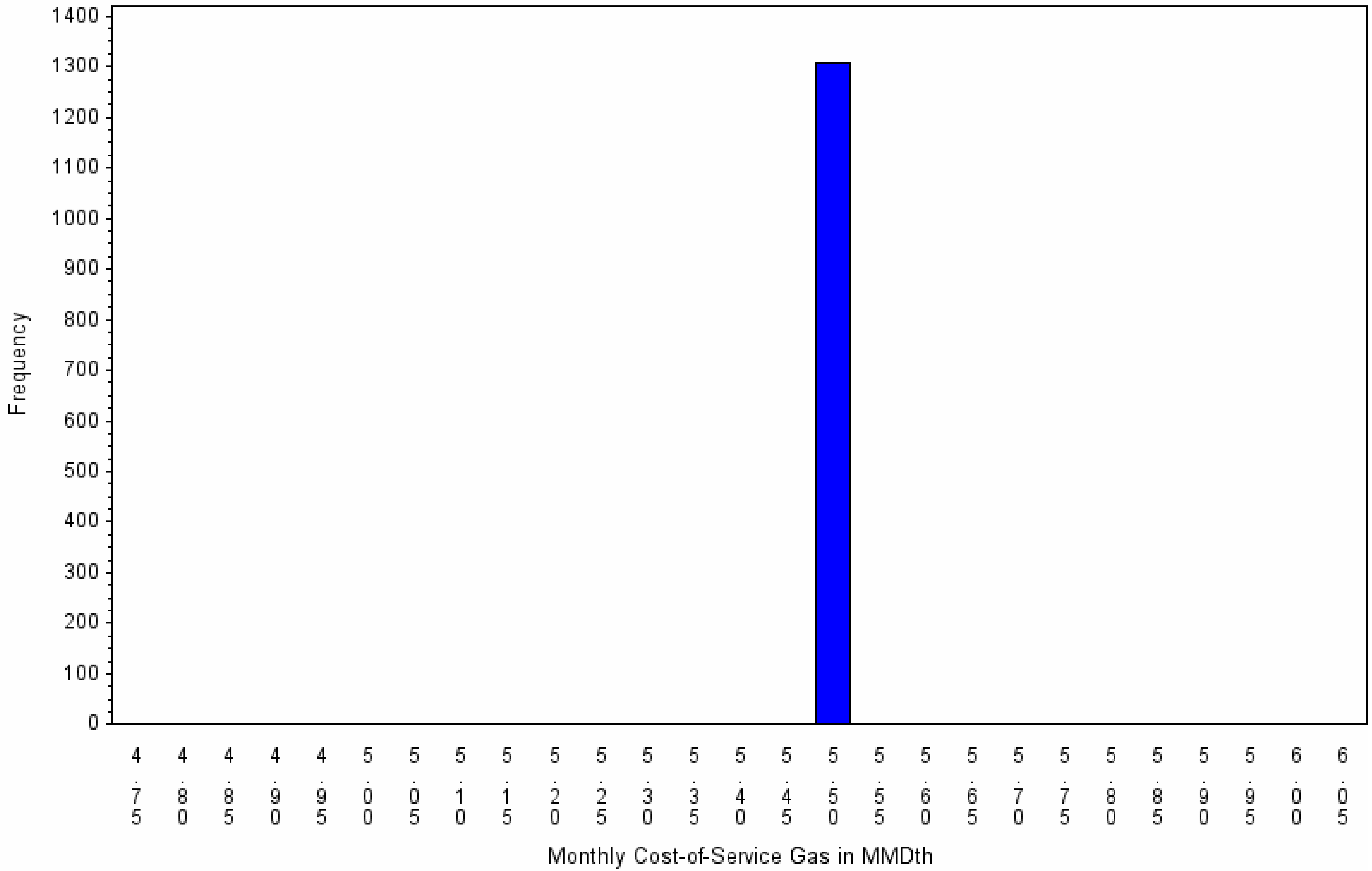
# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=1

Exhibit 14.74



# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=2

Exhibit 14.75

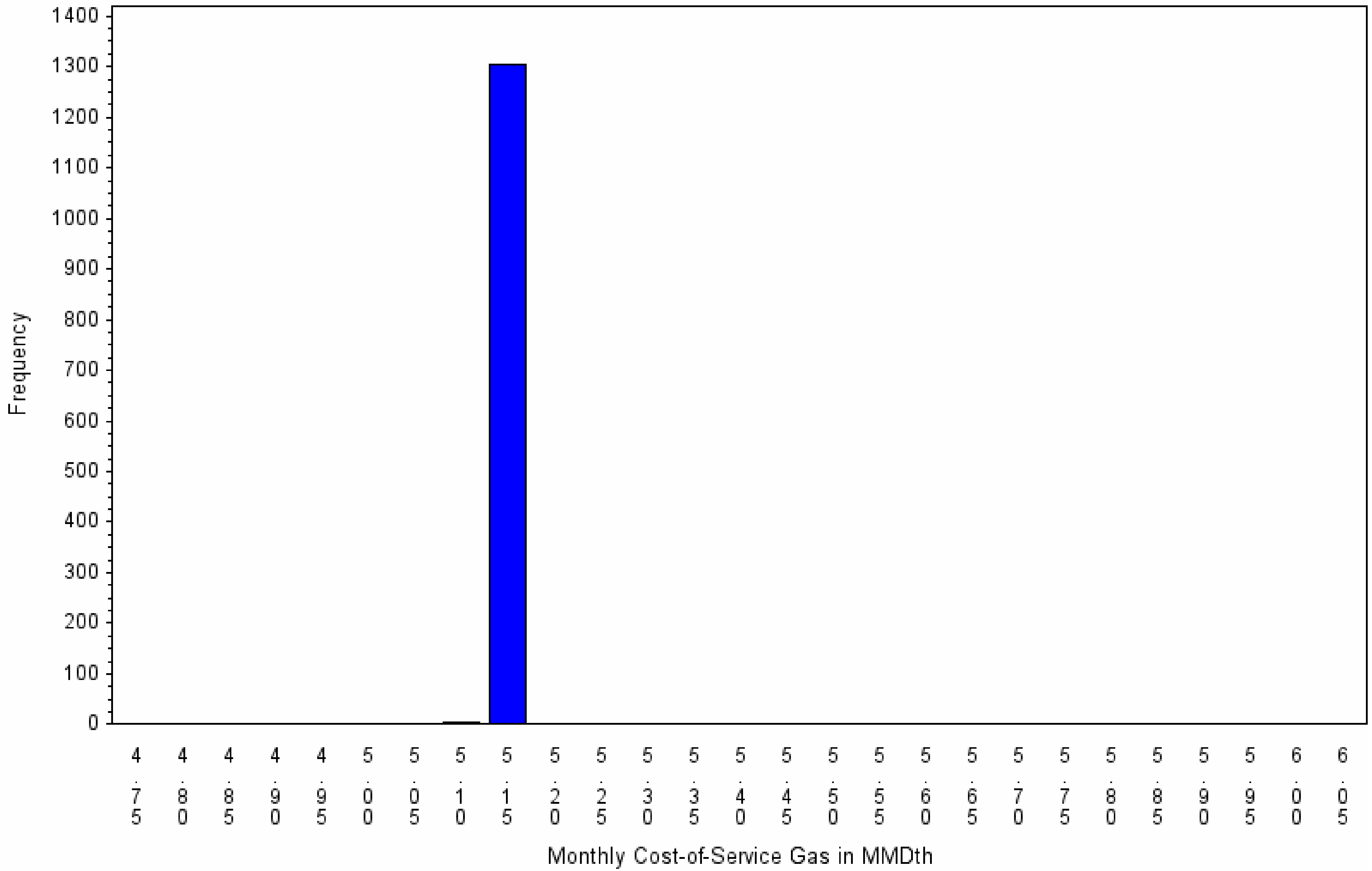


Exhibit 14.76

# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=3

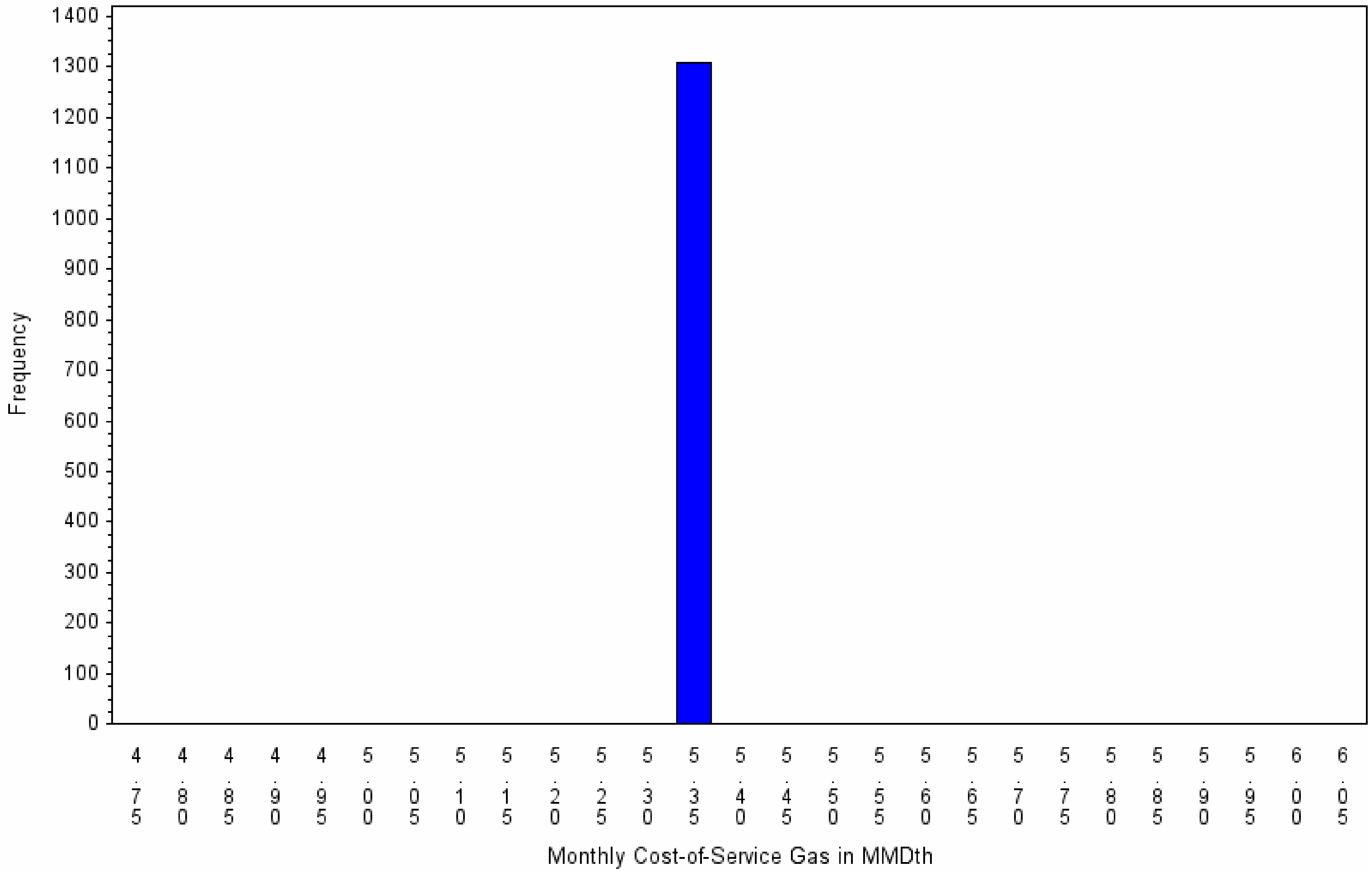
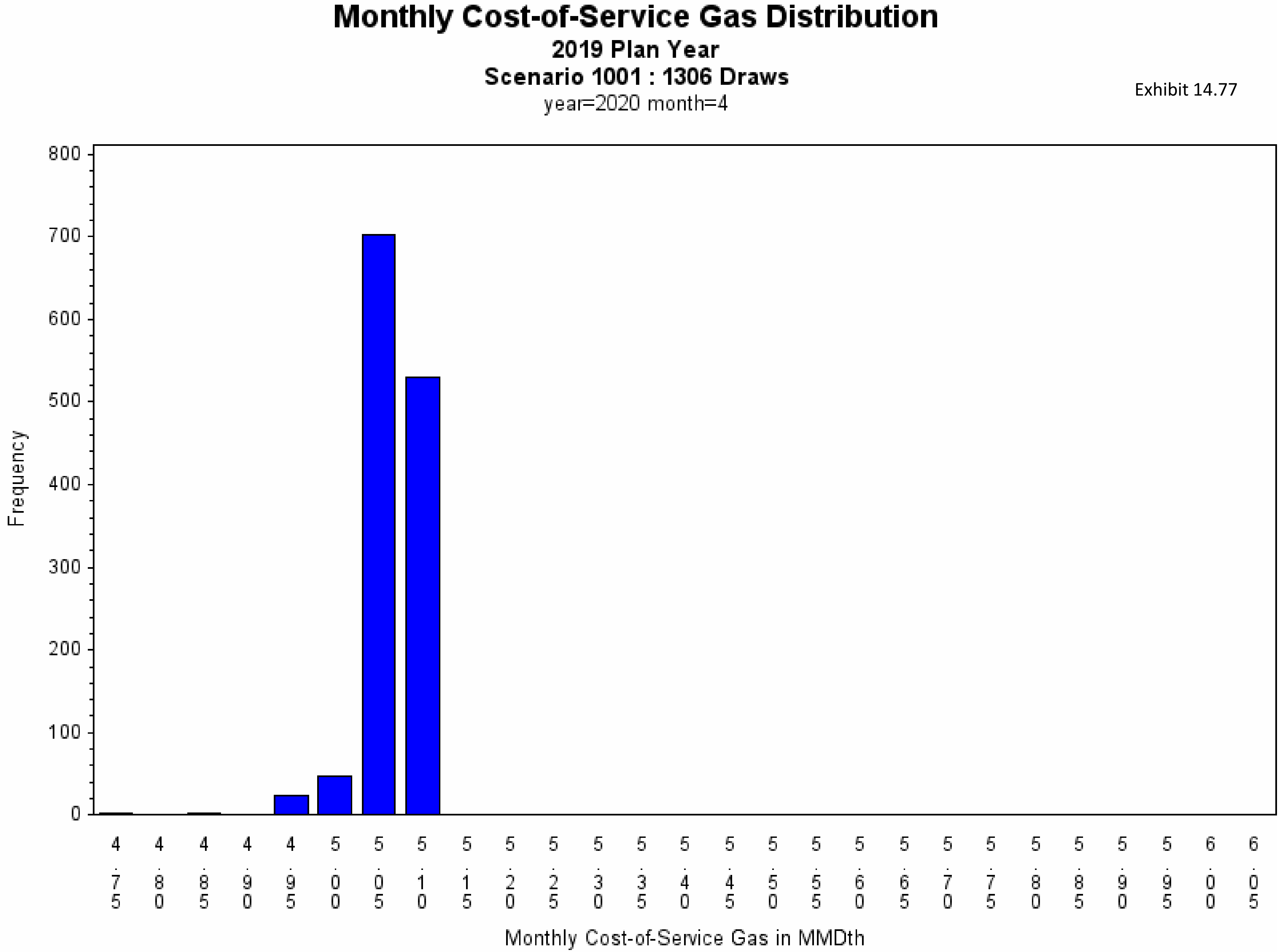


Exhibit 14.77



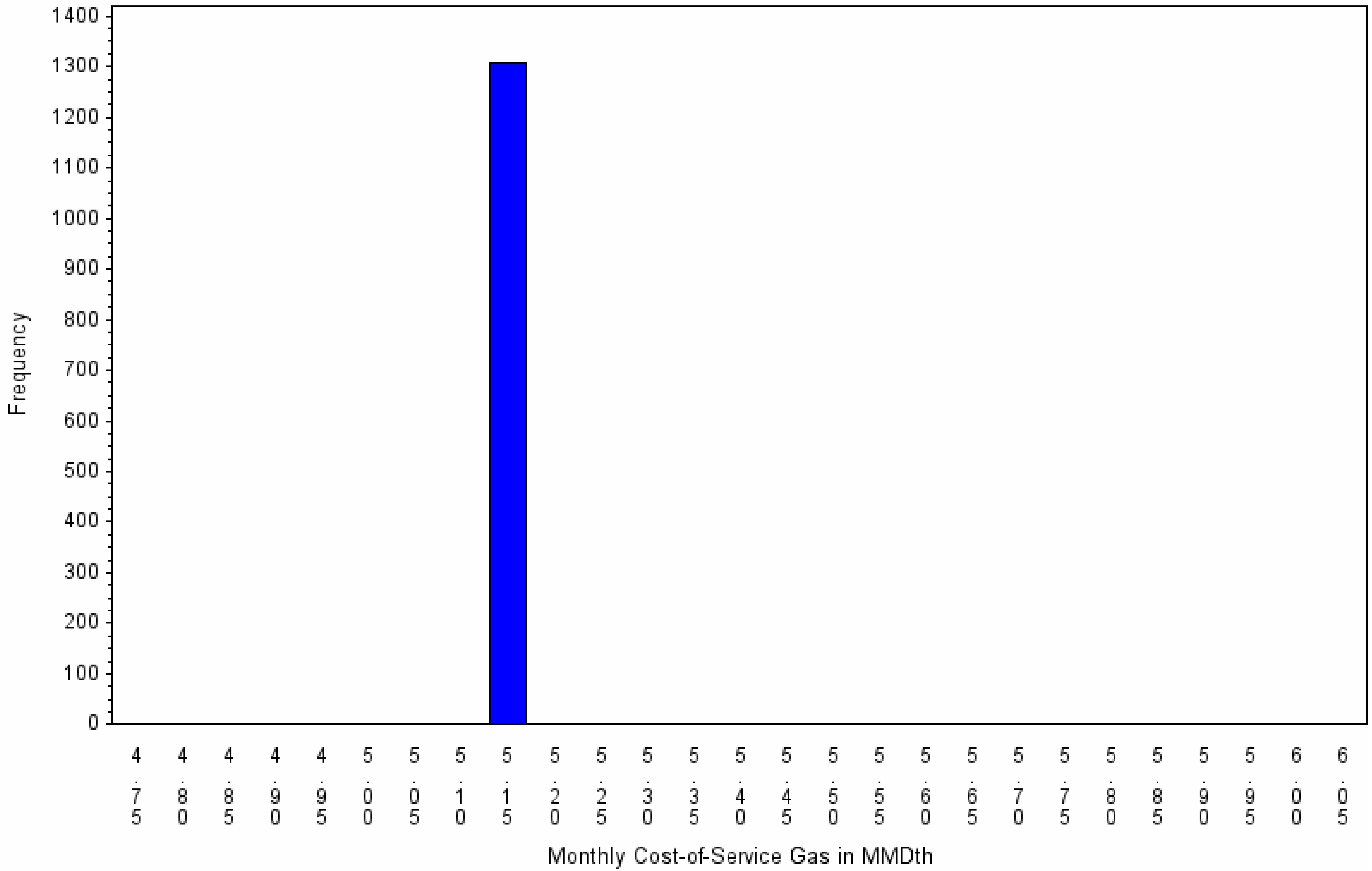
# Monthly Cost-of-Service Gas Distribution

**2019 Plan Year**

**Scenario 1001 : 1306 Draws**

year=2020 month=5

Exhibit 14.78



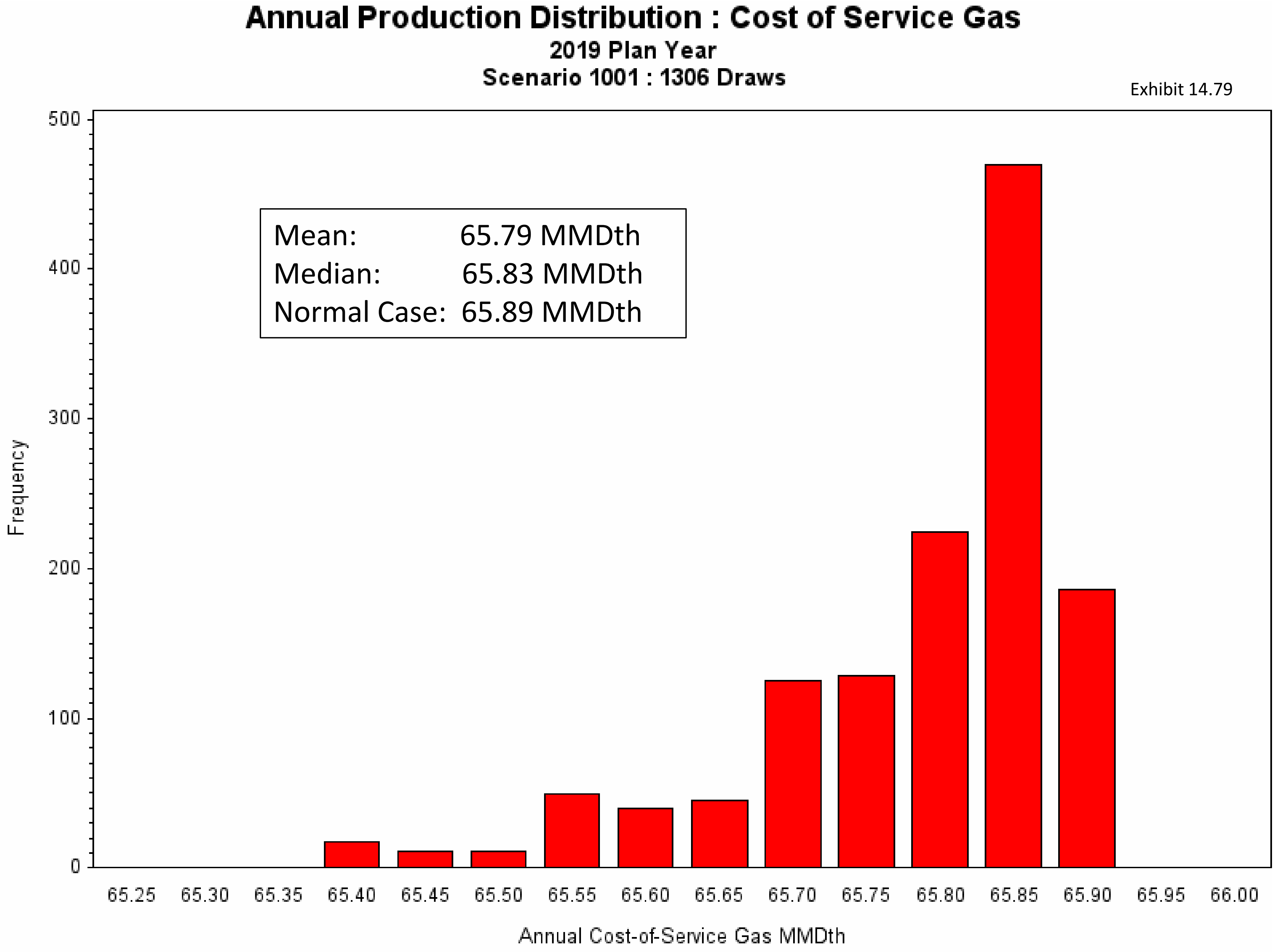

Annual Production Distribution : Cost of Service Gas
2019 Plan Year
Scenario 1001 : 1306 Draws
Exhibit 14.79
Mean: 65.79 MMDth
Median: 65.83 MMDth
Normal Case: 65.89 MMDth
Frequency
500
400
300
200
100
0
65.25
65.30
65.35
65.40
65.45
65.50
65.55
65.60
65.65
65.70
65.75
65.80
65.85
65.90
65.95
66.00
Annual Cost-of-Service Gas MMDth

Exhibit 14.80

# Monthly Cost-of-Service Gas Distribution
## 2019 Plan Year
## Scenario 1001 : 1306 Draws

| year | month | mean | max | p95 | p90 | med | p10 | p5 | min |
|---|---|---|---|---|---|---|---|---|---|
| 2018 | 6 | 5.78 | 5.79 | 5.79 | 5.79 | 5.79 | 5.78 | 5.71 | 5.71 |
| 2018 | 7 | 5.90 | 5.91 | 5.91 | 5.91 | 5.90 | 5.90 | 5.90 | 5.88 |
| 2018 | 8 | 5.60 | 5.60 | 5.60 | 5.60 | 5.60 | 5.60 | 5.60 | 5.60 |
| 2018 | 9 | 5.65 | 5.66 | 5.65 | 5.65 | 5.65 | 5.65 | 5.65 | 5.64 |
| 2018 | 10 | 5.63 | 5.70 | 5.70 | 5.70 | 5.68 | 5.51 | 5.38 | 5.25 |
| 2018 | 11 | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 | 5.38 |
| 2018 | 12 | 5.61 | 5.61 | 5.61 | 5.61 | 5.61 | 5.61 | 5.60 | 5.60 |
| 2019 | 1 | 5.48 | 5.48 | 5.48 | 5.48 | 5.48 | 5.48 | 5.48 | 5.48 |
| 2019 | 2 | 5.14 | 5.14 | 5.14 | 5.14 | 5.14 | 5.14 | 5.13 | 5.12 |
| 2019 | 3 | 5.36 | 5.36 | 5.36 | 5.36 | 5.36 | 5.36 | 5.35 | 5.33 |
| 2019 | 4 | 5.07 | 5.09 | 5.09 | 5.09 | 5.07 | 5.06 | 5.00 | 4.73 |
| 2019 | 5 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 |

**First Year System Cost Distribution**
**Plan Year 2019**
**Scenario 1001 : 1306 Draws**

Exhibit 14.81

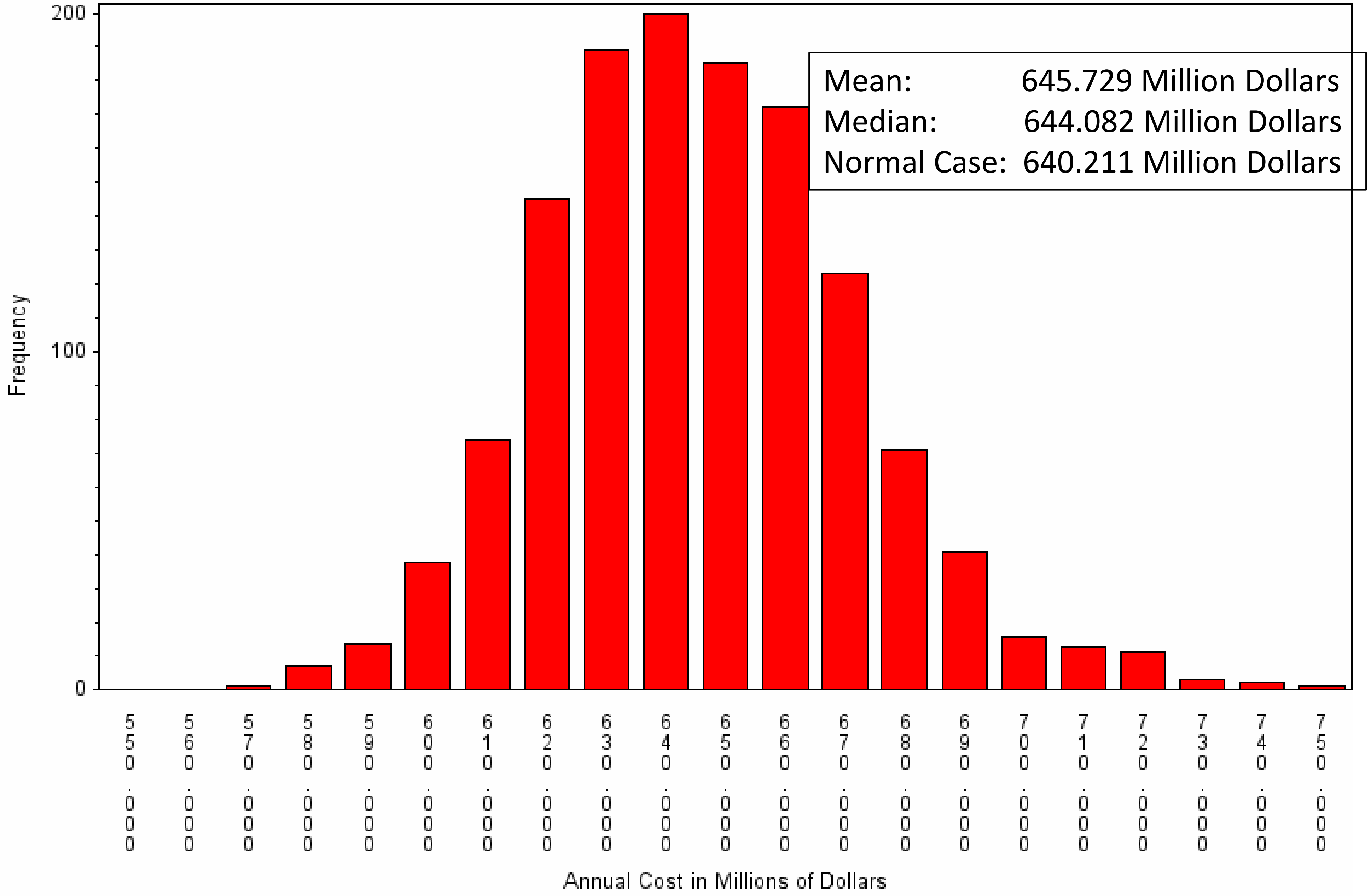
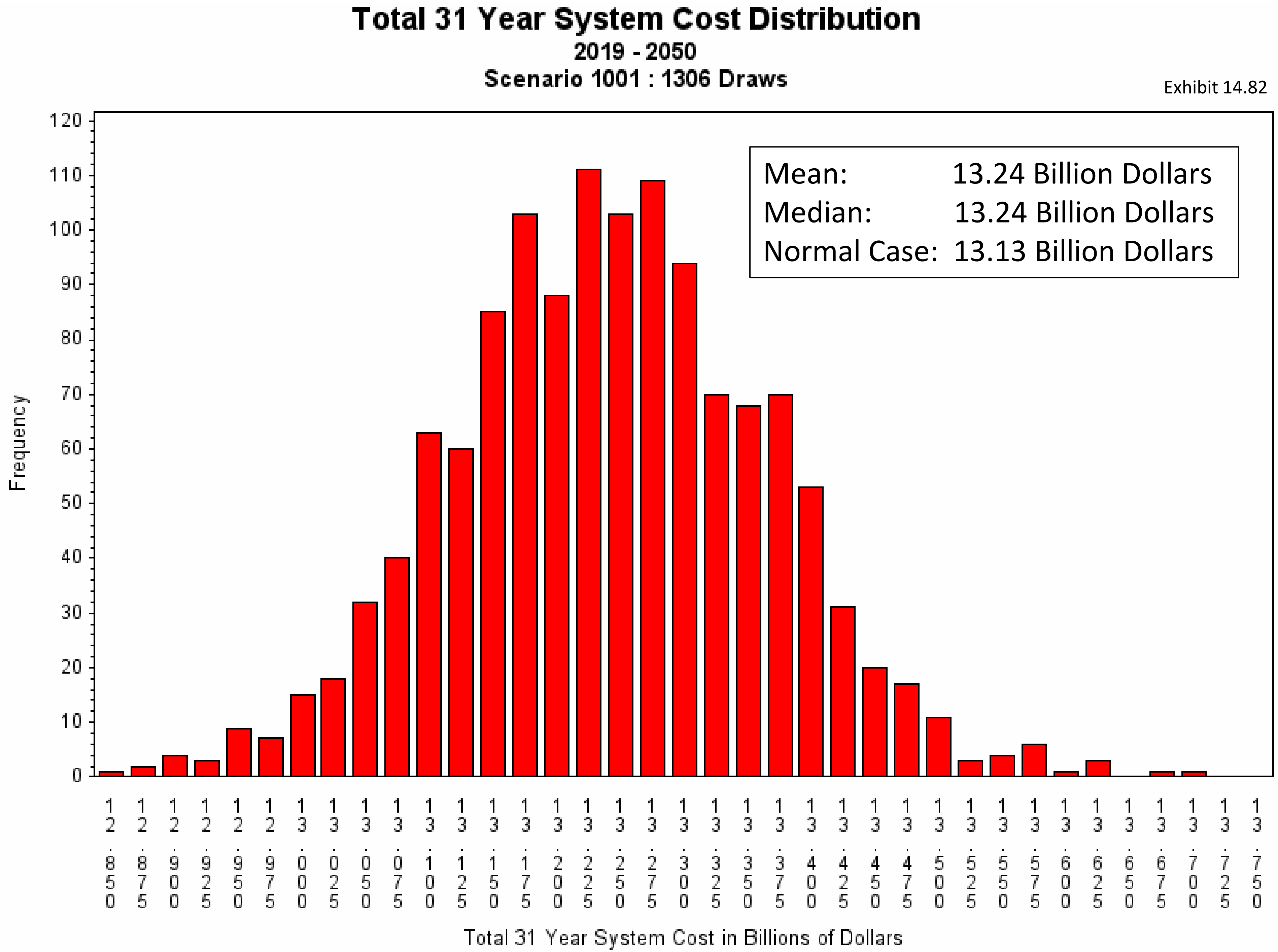


Exhibit 14.82



Normal Temperature Case : Plan Year 1
MDth

Exhibit 14.83

| Nomination Grp | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BIRCH CREEK | 126.669 | 130.070 | 129.251 | 124.296 | 127.630 | 122.739 | 126.034 | 125.243 | 116.426 | 123.675 | 118.935 | 122.131 | 1493.099 |
| Total | 126.669 | 130.070 | 129.251 | 124.296 | 127.630 | 122.739 | 126.034 | 125.243 | 116.426 | 123.675 | 118.935 | 122.131 | 1493.099 |
| | | | | | | | | | | | | | |
| PDW1A1B D21 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.682 | 0.679 | 0.629 | 0.000 | 0.000 | 0.000 | 1.990 |
| Total | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.682 | 0.679 | 0.629 | 0.000 | 0.000 | 0.000 | 1.990 |
| | | | | | | | | | | | | | |
| ACEJDMT D24 | 9.924 | 10.143 | 10.035 | 9.609 | 9.824 | 9.408 | 9.619 | 9.517 | 8.813 | 9.322 | 8.931 | 9.133 | 114.278 |
| BRFM D24 | 1.917 | 1.969 | 0.000 | 1.884 | 1.934 | 1.860 | 1.910 | 1.900 | 1.766 | 1.876 | 1.806 | 1.854 | 20.676 |
| BRFQ D24 | 151.464 | 155.409 | 150.536 | 144.246 | 148.006 | 142.227 | 145.939 | 144.919 | 134.624 | 142.904 | 137.331 | 140.520 | 1738.125 |
| BRFQMT D24 | 5.487 | 5.636 | 5.605 | 5.391 | 5.540 | 5.331 | 5.475 | 5.444 | 5.063 | 5.382 | 5.178 | 5.320 | 64.852 |
| BRFW D24 | 57.342 | 58.807 | 58.367 | 56.061 | 57.496 | 55.224 | 56.637 | 56.215 | 52.197 | 55.382 | 53.196 | 54.560 | 671.484 |
| CBFR D24 | 15.393 | 15.742 | 0.000 | 14.928 | 15.274 | 14.637 | 14.982 | 14.840 | 13.752 | 14.567 | 13.968 | 14.307 | 162.390 |
| CCRUNIT D24 | 528.126 | 540.373 | 535.131 | 512.901 | 524.973 | 503.271 | 515.217 | 510.480 | 473.202 | 501.276 | 480.777 | 492.410 | 6118.137 |
| CCRUNITMTD24 | 44.769 | 45.874 | 45.496 | 43.665 | 44.749 | 42.954 | 44.026 | 43.670 | 40.525 | 42.975 | 41.259 | 42.296 | 522.258 |
| CHBT MT | 16.608 | 17.050 | 16.935 | 16.281 | 16.712 | 16.068 | 16.492 | 16.384 | 15.225 | 16.170 | 15.543 | 15.956 | 195.424 |
| CHBTBUFF D24 | 0.789 | 0.809 | 0.806 | 0.774 | 0.797 | 0.765 | 0.787 | 0.784 | 0.728 | 0.775 | 0.744 | 0.766 | 9.324 |
| CHBTCAT2 D24 | 98.094 | 100.598 | 99.839 | 95.889 | 98.335 | 94.446 | 96.856 | 96.128 | 89.248 | 94.683 | 90.936 | 93.260 | 1148.312 |
| CHBTCAT3 D24 | 166.461 | 167.481 | 166.176 | 155.748 | 159.697 | 153.351 | 157.241 | 156.032 | 144.841 | 153.639 | 147.282 | 151.026 | 1878.975 |
| DRY PINY MT | 5.592 | 5.726 | 0.000 | 5.445 | 5.577 | 5.352 | 5.484 | 5.434 | 5.040 | 5.344 | 5.127 | 5.255 | 59.376 |
| DRYPINY6 D24 | 1.257 | 1.287 | 1.274 | 1.221 | 1.252 | 1.200 | 1.231 | 1.218 | 1.131 | 1.197 | 1.149 | 1.178 | 14.595 |
| DRYPINYU D24 | 1.800 | 1.854 | 1.845 | 1.776 | 1.826 | 1.758 | 1.807 | 1.798 | 1.676 | 1.783 | 1.716 | 1.764 | 21.403 |
| HWA MT | 3.792 | 3.887 | 3.860 | 3.708 | 3.804 | 3.651 | 3.745 | 3.717 | 3.451 | 3.664 | 3.519 | 3.608 | 44.406 |
| HWADEEPMTD24 | 14.040 | 14.390 | 14.272 | 13.701 | 14.046 | 13.485 | 13.829 | 13.721 | 12.740 | 13.516 | 12.984 | 13.318 | 164.042 |
| HWPL1&3MTD24 | 8.133 | 8.355 | 8.305 | 7.989 | 8.209 | 7.896 | 8.113 | 8.063 | 7.499 | 7.970 | 7.665 | 7.874 | 96.071 |
| HWPLT1&3 D24 | 87.543 | 89.404 | 88.359 | 84.513 | 86.316 | 82.563 | 84.326 | 83.353 | 77.076 | 81.443 | 77.913 | 79.586 | 1002.395 |
| HWPLT2 D24 | 5.295 | 5.434 | 5.397 | 5.184 | 5.320 | 5.112 | 5.248 | 5.211 | 4.840 | 5.137 | 4.938 | 5.065 | 62.181 |
| HWPLT2MT D24 | 4.722 | 4.827 | 4.774 | 4.572 | 4.675 | 4.476 | 4.576 | 4.526 | 4.191 | 4.433 | 4.245 | 4.340 | 54.357 |
| ISLAND D24 | 55.746 | 57.214 | 56.829 | 54.042 | 55.468 | 53.319 | 54.724 | 54.359 | 50.509 | 53.630 | 51.552 | 52.914 | 650.306 |
| JNSNRDG D24 | 2.202 | 2.266 | 0.000 | 2.175 | 2.238 | 2.157 | 2.220 | 2.210 | 2.059 | 2.195 | 2.115 | 2.176 | 24.013 |
| JRDG WFS D24 | 2.931 | 3.010 | 0.000 | 2.877 | 2.954 | 2.841 | 2.917 | 2.902 | 2.697 | 2.864 | 2.754 | 2.830 | 31.577 |
| KNY FLD D24 | 17.010 | 17.403 | 17.236 | 16.521 | 16.911 | 16.212 | 16.597 | 16.449 | 15.248 | 16.157 | 15.498 | 15.875 | 197.117 |
| MESA D24 | 845.850 | 864.590 | 855.330 | 817.359 | 835.723 | 800.337 | 818.465 | 810.070 | 750.097 | 793.730 | 760.422 | 777.948 | 9729.921 |
| MOSUMT D24 | 0.975 | 0.989 | 0.000 | 0.924 | 0.936 | 0.888 | 0.902 | 0.887 | 0.812 | 0.853 | 0.810 | 0.822 | 9.798 |
| PDW MT | 207.063 | 212.183 | 210.434 | 201.990 | 207.040 | 198.765 | 203.766 | 202.170 | 187.656 | 199.051 | 191.154 | 196.022 | 2417.294 |
| PDW1A1B D24 | 0.642 | 0.657 | 0.654 | 0.627 | 0.645 | 0.618 | 0.636 | 0.629 | 0.586 | 0.623 | 0.597 | 0.614 | 7.528 |
| PDWCUT D24 | 1.560 | 1.603 | 0.000 | 1.539 | 1.581 | 1.524 | 1.569 | 1.559 | 1.453 | 1.547 | 1.488 | 1.531 | 16.954 |
| PDWMT D24 | 26.805 | 27.482 | 27.271 | 26.187 | 26.852 | 25.788 | 26.446 | 26.248 | 24.369 | 25.854 | 24.834 | 25.473 | 313.609 |
| PDWPLT2 D24 | 5.013 | 5.149 | 5.115 | 4.920 | 5.053 | 4.860 | 4.991 | 4.960 | 4.611 | 4.898 | 4.710 | 4.839 | 59.119 |
| SGRLF D24 | 1.686 | 1.730 | 0.000 | 1.653 | 1.696 | 1.629 | 1.671 | 1.662 | 1.543 | 1.637 | 1.572 | 1.615 | 18.094 |
| SGRLFMT D24 | 10.353 | 10.627 | 10.552 | 10.140 | 10.407 | 10.002 | 10.261 | 10.193 | 9.469 | 10.050 | 9.660 | 9.911 | 121.625 |
| TRAIL D24 | 356.901 | 360.418 | 352.566 | 334.047 | 338.222 | 320.949 | 325.419 | 319.511 | 293.642 | 308.540 | 293.649 | 298.561 | 3902.425 |
| TRAILMT D24 | 63.060 | 63.888 | 62.691 | 59.574 | 60.493 | 57.561 | 58.519 | 57.604 | 53.073 | 55.899 | 53.325 | 54.340 | 700.027 |
| WHLA D24 | 32.106 | 32.466 | 32.231 | 30.960 | 31.760 | 30.510 | 31.295 | 31.065 | 28.849 | 30.613 | 29.406 | 30.163 | 371.424 |
| WWILSON D24 | 3.639 | 3.732 | 0.000 | 3.564 | 3.658 | 3.516 | 3.608 | 3.584 | 3.329 | 3.534 | 3.396 | 3.484 | 39.044 |
| Total | 2862.090 | 2920.462 | 2847.921 | 2754.585 | 2815.999 | 2696.511 | 2757.546 | 2729.416 | 2527.630 | 2675.113 | 2563.149 | 2622.514 | 32772.936 |
| | | | | | | | | | | | | | |
| ACEJDMT PC | 3.882 | 3.993 | 3.974 | 3.828 | 3.937 | 3.792 | 3.900 | 3.881 | 3.616 | 3.847 | 3.705 | 3.810 | 46.165 |
| BKSPUNT6MTPC | 2.421 | 2.489 | 2.480 | 2.388 | 2.455 | 2.367 | 2.434 | 2.421 | 2.256 | 2.399 | 2.313 | 2.378 | 28.801 |
| BRFM PC | 0.150 | 0.152 | 0.000 | 0.147 | 0.149 | 0.144 | 0.149 | 0.146 | 0.136 | 0.146 | 0.138 | 0.143 | 1.600 |
| BRFQ PC | 10.215 | 10.506 | 0.000 | 10.074 | 10.363 | 9.981 | 10.267 | 10.221 | 9.518 | 10.128 | 9.756 | 10.035 | 111.064 |
| BRFQMT PC | 3.432 | 3.525 | 3.500 | 3.363 | 3.450 | 3.315 | 3.404 | 3.379 | 3.141 | 3.333 | 3.204 | 3.286 | 40.332 |
| BRFW PC | 9.885 | 10.159 | 0.000 | 9.720 | 9.988 | 9.615 | 9.880 | 9.827 | 9.144 | 9.719 | 9.354 | 9.613 | 106.904 |
| BRUFF MT | 5.013 | 5.149 | 0.000 | 4.920 | 5.053 | 4.857 | 4.988 | 4.957 | 4.608 | 4.895 | 4.710 | 4.836 | 53.986 |
| CBFR PC | 57.261 | 58.602 | 58.048 | 55.647 | 56.966 | 54.618 | 55.918 | 55.409 | 51.365 | 54.414 | 52.188 | 53.447 | 663.883 |
| CCRUNIT MT | 71.091 | 71.179 | 69.099 | 65.025 | 65.435 | 61.746 | 62.291 | 60.875 | 55.709 | 58.305 | 55.287 | 56.020 | 752.062 |
| CCRUNIT PC | 59.706 | 61.188 | 60.686 | 58.248 | 59.703 | 57.312 | 58.748 | 58.280 | 54.088 | 57.362 | 55.074 | 56.467 | 696.862 |
| CCRUNITMT PC | 13.755 | 14.096 | 13.984 | 13.425 | 13.761 | 13.215 | 13.550 | 13.445 | 12.482 | 13.240 | 12.717 | 13.042 | 160.712 |
| CHBTC1 MT PC | 18.336 | 18.079 | 17.307 | 16.080 | 15.993 | 14.928 | 14.911 | 14.437 | 13.096 | 13.594 | 12.792 | 12.871 | 182.424 |
| CHBTCAT1 PC | 38.598 | 39.612 | 39.345 | 37.818 | 38.812 | 37.305 | 38.288 | 38.028 | 35.334 | 37.516 | 36.060 | 37.008 | 453.724 |
| CHBTCAT2 PC | 0.510 | 0.521 | 0.000 | 0.495 | 0.508 | 0.486 | 0.496 | 0.493 | 0.455 | 0.484 | 0.462 | 0.474 | 5.384 |
| DRYPINY6 PC | 1.056 | 1.088 | 0.000 | 1.044 | 1.073 | 1.035 | 1.063 | 1.060 | 0.986 | 1.051 | 1.011 | 1.042 | 11.509 |
| DRYPINYU PC | 12.999 | 13.349 | 0.000 | 12.762 | 13.107 | 12.606 | 12.946 | 12.865 | 11.963 | 12.710 | 12.225 | 12.555 | 140.087 |
| FOGARTY PC | 0.528 | 0.539 | 0.000 | 0.513 | 0.527 | 0.504 | 0.518 | 0.512 | 0.476 | 0.502 | 0.483 | 0.496 | 5.598 |
| HWA DEEP PC | 1.662 | 1.705 | 1.696 | 1.629 | 1.674 | 1.608 | 1.652 | 1.640 | 1.525 | 1.618 | 1.557 | 1.600 | 19.566 |
| HWPL1&3MTPC | 6.957 | 7.133 | 7.077 | 6.795 | 6.966 | 6.687 | 6.854 | 6.801 | 6.310 | 6.693 | 6.426 | 6.588 | 81.287 |
| HWPLT1&3 PC | 57.915 | 59.381 | 0.000 | 56.577 | 58.017 | 55.716 | 57.136 | 56.705 | 52.647 | 55.856 | 53.652 | 55.028 | 618.630 |
| HWPLT2 PC | 0.831 | 0.849 | 0.843 | 0.807 | 0.828 | 0.795 | 0.812 | 0.806 | 0.745 | 0.791 | 0.759 | 0.778 | 9.644 |
| ISLAND PC | 0.612 | 0.626 | 0.000 | 0.007 | 0.000 | 0.597 | 0.617 | 0.617 | 0.000 | 0.000 | 0.000 | 0.000 | 3.076 |
| JNSNRDG PC | 2.451 | 2.523 | 0.000 | 2.421 | 2.492 | 2.400 | 2.471 | 2.461 | 2.291 | 2.440 | 2.352 | 2.418 | 26.720 |
| KNY FLD PC | 5.334 | 5.478 | 0.000 | 5.235 | 5.375 | 5.169 | 5.310 | 5.276 | 4.904 | 5.211 | 5.013 | 5.146 | 57.451 |
| MDBXCOMP PC | 0.045 | 0.053 | 0.000 | 0.063 | 0.071 | 0.075 | 0.084 | 0.087 | 0.087 | 0.099 | 0.102 | 0.112 | 0.878 |
| MOSUMT PC | 12.891 | 13.218 | 13.116 | 12.597 | 12.918 | 12.405 | 12.719 | 12.623 | 11.719 | 12.431 | 11.940 | 12.242 | 150.819 |
| NBXCAMP PC | 0.000 | 0.000 | 0.000 | 0.000 | 0.074 | 0.147 | 0.226 | 0.304 | 0.354 | 0.453 | 0.510 | 0.605 | 2.673 |

Normal Temperature Case : Plan Year 1
MDth

Exhibit 14.84

| Nomination Grp | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NOBXFLD PC | 0.000 | 0.000 | 0.000 | 0.000 | 0.047 | 0.093 | 0.143 | 0.189 | 0.223 | 0.285 | 0.321 | 0.378 | 1.679 |
| PDW1A1B PC | 1.101 | 1.132 | 0.000 | 1.080 | 1.107 | 1.065 | 1.091 | 1.085 | 1.006 | 1.070 | 1.026 | 1.054 | 11.817 |
| PDW1AB MT PC | 5.208 | 5.354 | 5.329 | 5.133 | 5.279 | 5.082 | 5.227 | 5.202 | 4.843 | 5.152 | 4.962 | 5.103 | 61.874 |
| PDWCUT PC | 0.645 | 0.663 | 0.660 | 0.636 | 0.657 | 0.633 | 0.651 | 0.648 | 0.603 | 0.645 | 0.621 | 0.639 | 7.701 |
| PDWPLT2 PC | 4.467 | 4.594 | 4.573 | 4.404 | 4.529 | 4.362 | 4.486 | 4.464 | 4.156 | 4.424 | 4.260 | 4.380 | 53.099 |
| PDWPLT3 PC | 5.547 | 5.707 | 5.679 | 5.469 | 5.623 | 5.415 | 5.571 | 5.543 | 5.162 | 5.490 | 5.289 | 5.437 | 65.932 |
| SGRLF PC | 36.615 | 37.476 | 37.126 | 35.598 | 36.450 | 34.959 | 35.805 | 35.492 | 32.915 | 34.881 | 33.471 | 34.298 | 425.086 |
| TRAIL PC | 1.326 | 1.361 | 1.352 | 1.299 | 1.333 | 1.281 | 1.314 | 1.305 | 1.212 | 1.287 | 1.236 | 1.268 | 15.574 |
| WHLA PC | 8.055 | 8.231 | 0.000 | 7.788 | 7.958 | 7.617 | 7.784 | 7.700 | 7.125 | 7.536 | 7.215 | 7.378 | 84.387 |
| WWILSON PC | 14.016 | 14.390 | 14.300 | 13.752 | 14.121 | 13.578 | 13.944 | 13.854 | 12.879 | 13.680 | 13.155 | 13.510 | 165.179 |
| Total | 474.516 | 484.100 | 360.174 | 456.787 | 466.799 | 447.510 | 457.648 | 453.038 | 419.079 | 443.687 | 425.346 | 435.485 | 5324.169 |
| | | | | | | | | | | | | | |
| MOSU MT | 0.597 | 0.614 | 0.000 | 0.588 | 0.605 | 0.582 | 0.601 | 0.598 | 0.557 | 0.592 | 0.570 | 0.586 | 6.490 |
| Total | 0.597 | 0.614 | 0.000 | 0.588 | 0.605 | 0.582 | 0.601 | 0.598 | 0.557 | 0.592 | 0.570 | 0.586 | 6.490 |
| | | | | | | | | | | | | | |
| OFF SYS PW | 0.057 | 0.059 | 0.059 | 0.057 | 0.056 | 0.054 | 0.056 | 0.056 | 0.052 | 0.056 | 0.054 | 0.056 | 0.672 |
| OFF SYS PC | 8.904 | 9.161 | 9.120 | 8.790 | 9.043 | 8.712 | 8.965 | 8.925 | 8.314 | 8.847 | 8.526 | 8.770 | 106.077 |
| OFF SYS D24 | 34.725 | 35.628 | 35.404 | 34.042 | 34.926 | 33.583 | 34.475 | 34.251 | 31.828 | 34.064 | 33.001 | 34.141 | 410.068 |
| Total | 43.686 | 44.848 | 44.583 | 42.889 | 44.025 | 42.349 | 43.496 | 43.232 | 40.194 | 42.967 | 41.581 | 42.967 | 516.817 |
| | | | | | | | | | | | | | |
| Wexpro I | | | | | | | | | | | | | |
| CCRUNIT D8 | 197.658 | 194.491 | 186.384 | 173.631 | 173.293 | 162.411 | 162.886 | 158.385 | 144.301 | 150.434 | 142.152 | 143.586 | 1989.612 |
| KNY FLD D8 | 12.903 | 13.094 | 0.000 | 12.240 | 12.440 | 11.844 | 12.050 | 11.867 | 10.936 | 11.523 | 10.992 | 11.203 | 131.092 |
| MESA D8 | 469.473 | 464.895 | 447.116 | 417.375 | 417.049 | 391.095 | 392.330 | 381.477 | 347.487 | 362.142 | 342.060 | 345.346 | 4777.845 |
| TRAIL D8 | 159.480 | 160.543 | 156.851 | 147.159 | 146.717 | 137.709 | 138.524 | 132.023 | 116.078 | 117.847 | 109.071 | 108.336 | 1630.338 |
| Wexpro I New Drill | | | | | | | | | | | | | |
| z19 PINED D8 | 214.347 | 255.970 | 223.128 | 386.985 | 349.534 | 303.342 | 414.430 | 365.437 | 309.978 | 305.372 | 275.349 | 267.239 | 3671.111 |
| z20 PINED D8 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 120.228 | 101.466 | 82.626 | 74.509 | 378.829 |
| Total | 1053.861 | 1088.993 | 1013.479 | 1137.390 | 1099.033 | 1006.401 | 1120.220 | 1049.189 | 1049.008 | 1048.784 | 962.250 | 950.219 | 12578.827 |
| | | | | | | | | | | | | | |
| Wexpro II | | | | | | | | | | | | | |
| CCRUNIT2EMT | 24.336 | 24.940 | 24.732 | 23.739 | 24.332 | 23.355 | 23.941 | 23.749 | 22.043 | 23.377 | 22.446 | 23.011 | 284.001 |
| CCRUNIT MT | 29.562 | 29.599 | 28.734 | 27.039 | 27.209 | 25.677 | 25.904 | 25.315 | 23.165 | 24.245 | 22.989 | 23.297 | 312.735 |
| CCRUNIT 2E | 324.054 | 326.886 | 319.960 | 303.525 | 308.100 | 293.253 | 298.341 | 293.970 | 271.167 | 286.003 | 273.228 | 278.842 | 3577.329 |
| CCRUNIT 2D8 | 80.127 | 78.805 | 75.494 | 70.308 | 70.156 | 65.739 | 65.922 | 64.093 | 58.386 | 60.862 | 57.507 | 58.085 | 805.484 |
| WHISKEYC 2E | 125.298 | 125.296 | 121.520 | 114.273 | 114.933 | 108.417 | 109.343 | 106.848 | 97.774 | 102.334 | 97.047 | 98.351 | 1321.434 |
| WHISKEY MT | 46.275 | 46.339 | 44.975 | 42.306 | 42.551 | 40.128 | 40.452 | 39.503 | 36.122 | 37.774 | 35.793 | 36.239 | 488.457 |
| TRAIL 2E MT | 60.690 | 61.476 | 60.311 | 57.306 | 58.181 | 55.353 | 56.265 | 55.378 | 51.017 | 53.729 | 51.249 | 52.216 | 673.171 |
| TRAIL 2E | 396.561 | 400.343 | 391.502 | 370.833 | 375.370 | 356.109 | 360.983 | 354.349 | 325.589 | 342.042 | 325.467 | 330.851 | 4329.999 |
| TRAIL 2D8 | 143.274 | 142.733 | 138.294 | 128.712 | 127.326 | 118.731 | 118.780 | 112.248 | 97.617 | 98.171 | 90.108 | 88.843 | 1404.837 |
| Total | 1230.177 | 1236.417 | 1205.522 | 1138.041 | 1148.158 | 1086.762 | 1099.931 | 1075.453 | 982.880 | 1028.537 | 975.834 | 989.735 | 13197.447 |
| | | | | | | | | | | | | | |
| Production Total | 5791.596 | 5905.504 | 5600.930 | 5654.576 | 5702.249 | 5402.854 | 5606.158 | 5476.848 | 5136.403 | 5363.355 | 5087.665 | 5163.637 | 65891.775 |

Normal Temperature Case : Plan Year 1

MDth

Exhibit 14.85

| Storage Withdraw | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clay Bsn 935 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1092.146 | 1529.798 | 1515.578 | 1417.798 | 0.000 | 0.000 | 0.000 | 5555.320 |
| Clay Bsn 988 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 682.591 | 956.124 | 947.236 | 886.124 | 0.000 | 0.000 | 0.000 | 3472.075 |
| Clay Bsn 997 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 682.591 | 956.124 | 947.236 | 886.124 | 0.000 | 0.000 | 0.000 | 3472.075 |
| Chalk Creek | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 45.004 | 0.000 | 257.250 | 0.000 | 0.000 | 302.254 |
| Coalville | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 60.079 | 0.000 | 300.107 | 0.000 | 0.000 | 360.186 |
| Leroy | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 78.940 | 0.000 | 364.543 | 0.000 | 0.000 | 443.483 |
| Ryckman | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 498.000 | 514.600 | 514.600 | 481.400 | 0.000 | 0.000 | 0.000 | 2008.600 |
| Total | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2955.328 | 3956.646 | 4108.673 | 3671.446 | 921.900 | 0.000 | 0.000 | 15613.993 |

| Purchase Gas | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spot | 137.716 | 0.000 | 0.000 | 0.000 | 1792.420 | 0.000 | 1544.710 | 3385.600 | 2384.700 | 5114.500 | 2573.790 | 1028.000 | 17961.436 |
| Spot | 627.032 | 0.000 | 0.000 | 0.000 | 1474.200 | 721.462 | 803.300 | 519.910 | 0.000 | 728.720 | 1302.220 | 1550.000 | 7726.844 |
| Spot | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 901.492 | 2325.000 | 2325.000 | 2175.000 | 934.030 | 0.000 | 0.000 | 8660.522 |
| Spot | 12.635 | 0.000 | 0.000 | 0.000 | 26.100 | 48.110 | 75.520 | 81.610 | 70.770 | 54.650 | 36.280 | 22.380 | 428.055 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 765.100 | 775.000 | 695.540 | 0.000 | 0.000 | 0.000 | 2235.640 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 300.000 | 310.000 | 310.000 | 290.000 | 310.000 | 0.000 | 0.000 | 1520.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 600.000 | 620.000 | 620.000 | 580.000 | 0.000 | 0.000 | 0.000 | 2420.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 620.000 | 620.000 | 580.000 | 0.000 | 0.000 | 0.000 | 1820.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 930.000 | 900.000 | 930.000 | 930.000 | 870.000 | 930.000 | 900.000 | 0.000 | 6390.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 750.000 | 775.000 | 775.000 | 725.000 | 0.000 | 0.000 | 0.000 | 3025.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 155.000 | 155.000 | 145.000 | 0.000 | 0.000 | 0.000 | 455.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 210.000 | 217.000 | 217.000 | 203.000 | 0.000 | 0.000 | 0.000 | 847.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 775.000 | 775.000 | 725.000 | 0.000 | 0.000 | 0.000 | 2275.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 310.000 | 310.000 | 290.000 | 0.000 | 0.000 | 0.000 | 910.000 |
| Total | 777.383 | 0.000 | 0.000 | 0.000 | 4222.720 | 4431.064 | 10225.630 | 11799.120 | 9734.010 | 8071.900 | 4812.290 | 2600.380 | 56674.497 |

| Storage Inject | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clay Bsn 935 | 1200.000 | 1240.000 | 1102.240 | 515.744 | 830.909 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 189.768 | 5078.661 |
| Clay Bsn 988 | 750.000 | 775.000 | 688.880 | 322.360 | 519.314 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 533.702 | 3589.256 |
| Clay Bsn 997 | 750.000 | 759.170 | 688.880 | 395.326 | 462.182 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 688.882 | 3744.440 |
| Chalk Creek | 0.000 | 0.000 | 0.000 | 82.400 | 132.000 | 76.600 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 291.000 |
| Coalville | 0.000 | 0.000 | 0.000 | 0.186 | 310.000 | 50.186 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 360.372 |
| Leroy | 0.000 | 0.000 | 0.000 | 0.000 | 443.966 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 443.966 |
| Spire | 341.730 | 353.120 | 353.120 | 340.901 | 238.343 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 335.461 | 353.119 | 2315.794 |
| Total | 3041.730 | 3127.290 | 2833.120 | 1656.917 | 2936.714 | 126.786 | 0.000 | 0.000 | 0.000 | 0.000 | 335.461 | 1765.471 | 15823.489 |

Normal Temperature Case : Plan Year 2

MDth

Exhibit 14.86

| Nomination Grp | 1-Jun-20 | 1-Jul-20 | 1-Aug-20 | 1-Sep-20 | 1-Oct-20 | 1-Nov-20 | 1-Dec-20 | 1-Jan-21 | 1-Feb-21 | 1-Mar-21 | 1-Apr-21 | 1-May-21 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BIRCH CREEK | 117.450 | 120.606 | 119.849 | 115.257 | 118.355 | 113.820 | 116.879 | 116.148 | 104.252 | 114.700 | 109.995 | 112.955 | 1380.266 |
| Total | 117.450 | 120.606 | 119.849 | 115.257 | 118.355 | 113.820 | 116.879 | 116.148 | 104.252 | 114.700 | 109.995 | 112.955 | 1380.266 |
| | | | | | | | | | | | | | |
| ACEJDMT D24 | 8.748 | 8.950 | 8.860 | 8.487 | 8.683 | 8.319 | 8.513 | 8.429 | 7.538 | 8.265 | 7.920 | 8.107 | 100.819 |
| BRFM D24 | 1.785 | 1.832 | 1.820 | 1.752 | 1.798 | 1.731 | 1.776 | 1.767 | 1.585 | 1.745 | 1.680 | 1.724 | 20.995 |
| BRFQ D24 | 135.045 | 138.579 | 137.621 | 132.261 | 135.727 | 130.443 | 133.864 | 132.944 | 119.252 | 131.124 | 126.024 | 129.335 | 1582.219 |
| BRFQMT D24 | 5.118 | 5.258 | 5.227 | 5.028 | 5.168 | 4.971 | 5.106 | 5.078 | 4.558 | 5.019 | 4.830 | 4.960 | 60.321 |
| BRFW D24 | 52.320 | 53.664 | 53.261 | 51.159 | 52.474 | 50.268 | 51.562 | 51.181 | 45.889 | 50.431 | 48.447 | 49.693 | 610.349 |
| CBFR D24 | 13.722 | 14.055 | 13.935 | 13.371 | 13.702 | 13.149 | 13.476 | 13.367 | 11.978 | 13.156 | 12.633 | 12.955 | 159.499 |
| CCRUNIT D24 | 472.350 | 483.857 | 479.694 | 460.257 | 471.575 | 452.532 | 463.723 | 459.891 | 411.981 | 452.411 | 434.280 | 445.157 | 5487.708 |
| CCRUNITMTD24 | 40.608 | 41.633 | 41.308 | 39.666 | 40.669 | 39.054 | 40.043 | 39.736 | 35.616 | 39.131 | 37.581 | 38.539 | 473.584 |
| CHBT MT | 15.339 | 15.745 | 15.640 | 15.036 | 15.435 | 14.838 | 15.230 | 15.128 | 13.574 | 14.930 | 14.352 | 14.731 | 179.978 |
| CHBTBUFF D24 | 0.738 | 0.756 | 0.753 | 0.723 | 0.744 | 0.717 | 0.735 | 0.732 | 0.658 | 0.722 | 0.696 | 0.716 | 8.690 |
| CHBTCAT2 D24 | 89.571 | 91.859 | 91.165 | 87.561 | 89.798 | 86.247 | 88.449 | 87.783 | 78.691 | 86.468 | 83.049 | 85.169 | 1045.810 |
| CHBTCAT3 D24 | 145.038 | 148.729 | 147.591 | 141.741 | 145.350 | 139.587 | 143.143 | 142.054 | 127.330 | 139.212 | 133.698 | 137.107 | 1690.580 |
| DRY PINY MT | 5.043 | 5.168 | 5.124 | 4.917 | 5.041 | 4.836 | 4.957 | 4.917 | 4.404 | 4.836 | 4.644 | 4.759 | 58.646 |
| DRYPINY6 D24 | 1.131 | 1.159 | 1.150 | 1.104 | 1.132 | 1.086 | 1.113 | 1.104 | 0.988 | 1.085 | 1.044 | 1.070 | 13.166 |
| DRYPINYU D24 | 1.698 | 1.748 | 1.739 | 1.674 | 1.724 | 1.659 | 1.705 | 1.699 | 1.526 | 1.680 | 1.620 | 1.665 | 20.137 |
| HWA MT | 3.465 | 3.556 | 3.528 | 3.390 | 3.475 | 3.339 | 3.426 | 3.401 | 3.046 | 3.348 | 3.216 | 3.298 | 40.488 |
| HWADEEPMTD24 | 12.795 | 13.129 | 13.036 | 12.525 | 12.853 | 12.354 | 12.676 | 12.589 | 11.292 | 12.416 | 11.931 | 12.245 | 149.841 |
| HWPL1&3MTD24 | 7.575 | 7.781 | 7.738 | 7.443 | 7.645 | 7.356 | 7.555 | 7.511 | 6.745 | 7.421 | 7.140 | 7.335 | 89.245 |
| HWPLT1&3 D24 | 76.137 | 77.776 | 76.889 | 73.560 | 75.147 | 71.898 | 73.448 | 72.614 | 64.845 | 70.978 | 67.911 | 69.381 | 870.584 |
| HWPLT2 D24 | 4.869 | 4.997 | 4.963 | 4.767 | 4.892 | 4.701 | 4.827 | 4.793 | 4.298 | 4.724 | 4.542 | 4.659 | 57.032 |
| HWPLT2MT D24 | 4.155 | 4.250 | 4.204 | 4.026 | 4.117 | 3.945 | 4.033 | 3.993 | 3.570 | 3.912 | 3.747 | 3.832 | 47.784 |
| ISLAND D24 | 49.647 | 50.341 | 50.006 | 47.463 | 48.723 | 46.839 | 48.081 | 47.126 | 42.286 | 45.288 | 43.539 | 44.696 | 564.035 |
| JNSNRDG D24 | 2.097 | 2.158 | 2.148 | 2.073 | 2.133 | 2.055 | 2.114 | 2.108 | 1.896 | 2.089 | 2.013 | 2.074 | 24.958 |
| JRDG WFS D24 | 2.721 | 2.796 | 2.778 | 2.673 | 2.744 | 2.640 | 2.709 | 2.694 | 2.419 | 2.660 | 2.559 | 2.629 | 32.022 |
| KNY FLD D24 | 15.231 | 15.605 | 15.475 | 14.853 | 15.221 | 14.610 | 14.973 | 14.855 | 13.311 | 14.620 | 14.037 | 14.393 | 177.184 |
| MESA D24 | 745.407 | 762.690 | 755.247 | 723.798 | 740.717 | 709.953 | 726.625 | 719.733 | 643.947 | 706.242 | 677.067 | 693.117 | 8604.543 |
| MOSUMT D24 | 0.780 | 0.794 | 0.440 | 0.738 | 0.000 | 0.711 | 0.722 | 0.710 | 0.641 | 0.710 | 0.000 | 0.000 | 6.246 |
| PDW MT | 188.265 | 193.080 | 191.636 | 184.074 | 188.802 | 181.368 | 186.040 | 184.683 | 165.598 | 182.013 | 174.873 | 179.406 | 2199.838 |
| PDW1A1B D24 | 0.588 | 0.605 | 0.601 | 0.576 | 0.592 | 0.570 | 0.583 | 0.580 | 0.521 | 0.574 | 0.549 | 0.564 | 6.903 |
| PDWCUT D24 | 1.476 | 1.516 | 1.510 | 1.455 | 1.497 | 1.440 | 1.482 | 1.476 | 1.327 | 1.463 | 1.407 | 1.448 | 17.497 |
| PDWMT D24 | 24.471 | 25.101 | 24.918 | 23.937 | 24.555 | 23.592 | 24.202 | 24.028 | 21.549 | 23.687 | 22.758 | 23.349 | 286.147 |
| PDWPLT2 D24 | 4.653 | 4.780 | 4.749 | 4.569 | 4.690 | 4.512 | 4.635 | 4.607 | 4.136 | 4.551 | 4.377 | 4.495 | 54.754 |
| SGRLF D24 | 1.551 | 1.593 | 1.581 | 1.521 | 1.559 | 1.500 | 1.538 | 1.528 | 1.369 | 1.507 | 1.449 | 1.485 | 18.181 |
| SGRLFMT D24 | 9.525 | 9.774 | 9.706 | 9.330 | 9.573 | 9.201 | 9.443 | 9.378 | 8.411 | 9.247 | 8.886 | 9.120 | 111.594 |
| TRAIL D24 | 284.412 | 289.422 | 285.135 | 271.953 | 277.059 | 264.435 | 269.579 | 266.042 | 237.210 | 259.327 | 247.878 | 253.056 | 3205.508 |
| TRAILMT D24 | 51.876 | 52.902 | 52.223 | 49.905 | 50.936 | 48.705 | 49.740 | 49.169 | 43.915 | 48.084 | 46.032 | 47.064 | 590.551 |
| WHLA D24 | 28.977 | 29.723 | 29.506 | 28.344 | 29.075 | 27.930 | 28.650 | 28.443 | 25.500 | 28.027 | 26.922 | 27.618 | 338.715 |
| WWILSON D24 | 3.351 | 3.438 | 3.413 | 3.282 | 3.367 | 3.237 | 3.320 | 3.298 | 2.960 | 3.255 | 3.129 | 3.209 | 39.259 |
| Total | 2512.278 | 2570.799 | 2546.318 | 2440.992 | 2498.392 | 2396.328 | 2453.796 | 2431.169 | 2176.360 | 2386.358 | 2288.460 | 2344.160 | 29045.410 |
| | | | | | | | | | | | | | |
| ACEJDMT PC | 3.669 | 3.776 | 3.757 | 3.618 | 3.723 | 3.585 | 3.689 | 3.670 | 3.298 | 3.636 | 3.501 | 3.602 | 43.524 |
| BKSPUNT6MTPC | 2.289 | 2.356 | 2.344 | 2.259 | 2.322 | 2.238 | 2.303 | 2.291 | 2.061 | 2.269 | 2.187 | 2.251 | 27.170 |
| BRFM PC | 0.138 | 0.140 | 0.140 | 0.135 | 0.136 | 0.132 | 0.136 | 0.136 | 0.120 | 0.133 | 0.129 | 0.130 | 1.605 |
| BRFQ PC | 9.666 | 9.942 | 9.895 | 9.534 | 9.805 | 9.447 | 9.715 | 9.672 | 8.694 | 9.582 | 9.231 | 9.495 | 114.678 |
| BRFQMT PC | 3.159 | 3.243 | 3.218 | 3.093 | 3.174 | 3.051 | 3.131 | 3.109 | 2.789 | 3.066 | 2.946 | 3.023 | 37.002 |
| BRFW PC | 9.252 | 9.511 | 9.458 | 9.102 | 9.356 | 9.003 | 9.254 | 9.204 | 8.268 | 9.105 | 8.763 | 9.006 | 109.282 |
| BRUFF MT | 4.650 | 4.774 | 4.746 | 4.563 | 4.687 | 4.506 | 4.628 | 4.600 | 4.130 | 4.545 | 4.368 | 4.486 | 54.683 |
| CBFR PC | 51.267 | 52.511 | 52.055 | 49.938 | 51.159 | 49.086 | 50.291 | 49.864 | 44.660 | 49.030 | 47.052 | 48.217 | 595.130 |
| CCRUNIT MT | 53.199 | 53.977 | 53.029 | 50.448 | 51.271 | 48.822 | 49.665 | 48.912 | 43.529 | 47.498 | 45.324 | 46.196 | 591.870 |
| CCRUNIT PC | 54.219 | 55.592 | 55.165 | 52.977 | 54.324 | 52.170 | 53.503 | 53.097 | 47.600 | 52.303 | 50.241 | 51.528 | 632.719 |
| CCRUNITMT PC | 12.528 | 12.850 | 12.753 | 12.249 | 12.564 | 12.069 | 12.381 | 12.288 | 11.018 | 12.112 | 11.634 | 11.935 | 146.381 |
| CHBTC1 MT PC | 12.138 | 12.236 | 11.951 | 11.301 | 11.424 | 10.818 | 10.949 | 10.732 | 9.506 | 10.326 | 9.810 | 9.957 | 131.148 |
| CHBTCAT1 PC | 35.571 | 36.509 | 36.261 | 34.854 | 35.774 | 34.386 | 35.290 | 35.052 | 31.447 | 34.581 | 33.237 | 34.116 | 417.078 |
| CHBTCAT2 PC | 0.453 | 0.465 | 0.462 | 0.441 | 0.453 | 0.432 | 0.443 | 0.440 | 0.392 | 0.431 | 0.414 | 0.422 | 5.248 |
| DRYPINY6 PC | 1.005 | 1.032 | 1.029 | 0.990 | 1.020 | 0.981 | 1.011 | 1.008 | 0.904 | 0.998 | 0.963 | 0.989 | 11.930 |
| DRYPINYU PC | 12.075 | 12.400 | 12.326 | 11.856 | 12.177 | 11.712 | 12.028 | 11.954 | 10.732 | 11.808 | 11.358 | 11.665 | 142.091 |
| FOGARTY PC | 0.474 | 0.487 | 0.481 | 0.462 | 0.474 | 0.453 | 0.465 | 0.462 | 0.412 | 0.453 | 0.435 | 0.446 | 5.504 |
| HWA DEEP PC | 1.536 | 1.578 | 1.569 | 1.506 | 1.547 | 1.488 | 1.528 | 1.519 | 1.361 | 1.497 | 1.440 | 1.479 | 18.048 |
| HWPL1&3MTPC | 6.324 | 6.482 | 6.433 | 6.174 | 6.330 | 6.078 | 6.231 | 6.181 | 5.538 | 6.082 | 5.841 | 5.986 | 73.680 |
| HWPLT1&3 PC | 52.860 | 54.219 | 53.819 | 51.702 | 53.038 | 50.952 | 52.269 | 51.894 | 46.533 | 51.150 | 49.146 | 50.422 | 618.004 |
| HWPLT2 PC | 0.747 | 0.763 | 0.756 | 0.726 | 0.744 | 0.714 | 0.698 | 0.694 | 0.622 | 0.682 | 0.657 | 0.673 | 8.476 |
| JNSNRDG PC | 2.331 | 2.399 | 2.390 | 2.301 | 2.368 | 2.283 | 2.350 | 2.341 | 2.103 | 2.319 | 2.235 | 2.300 | 27.720 |
| KNY FLD PC | 4.950 | 5.084 | 5.053 | 4.860 | 4.991 | 4.800 | 4.929 | 4.901 | 4.399 | 4.839 | 4.656 | 4.780 | 58.242 |
| MDBXCOMP PC | 0.114 | 0.121 | 0.127 | 0.129 | 0.140 | 0.141 | 0.152 | 0.155 | 0.146 | 0.167 | 0.168 | 0.177 | 1.737 |
| MOSUMT PC | 11.757 | 12.056 | 11.966 | 11.490 | 11.783 | 11.316 | 11.606 | 11.517 | 10.324 | 11.343 | 10.893 | 11.172 | 137.223 |
| NBXCAMP PC | 0.657 | 0.753 | 0.828 | 0.870 | 0.973 | 1.014 | 1.119 | 1.190 | 1.142 | 1.336 | 1.362 | 1.476 | 12.720 |

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.87

| Nomination Grp | 1-Jun-20 | 1-Jul-20 | 1-Aug-20 | 1-Sep-20 | 1-Oct-20 | 1-Nov-20 | 1-Dec-20 | 1-Jan-21 | 1-Feb-21 | 1-Mar-21 | 1-Apr-21 | 1-May-21 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NOBXFLD PC | 0.411 | 0.471 | 0.518 | 0.546 | 0.608 | 0.633 | 0.698 | 0.741 | 0.708 | 0.831 | 0.843 | 0.915 | 7.923 |
| PDW1A1B PC | 0.636 | 1.039 | 1.032 | 0.993 | 0.000 | 0.978 | 1.004 | 0.998 | 0.893 | 0.983 | 0.000 | 0.000 | 8.556 |
| PDW1AB MT PC | 4.914 | 5.053 | 5.028 | 4.845 | 4.982 | 4.797 | 4.932 | 4.910 | 4.413 | 4.861 | 4.683 | 4.814 | 58.232 |
| PDWCUT PC | 0.615 | 0.636 | 0.632 | 0.609 | 0.626 | 0.606 | 0.623 | 0.620 | 0.557 | 0.617 | 0.594 | 0.611 | 7.346 |
| PDWPLT2 PC | 4.218 | 4.337 | 4.318 | 4.158 | 4.275 | 4.119 | 4.235 | 4.216 | 3.788 | 4.176 | 4.020 | 4.135 | 49.995 |
| PDWPLT3 PC | 5.238 | 5.385 | 5.360 | 5.163 | 5.307 | 5.112 | 5.258 | 5.233 | 4.704 | 5.183 | 4.992 | 5.134 | 62.069 |
| SGRLF PC | 32.916 | 33.734 | 33.461 | 32.121 | 32.925 | 31.611 | 32.411 | 32.156 | 28.820 | 31.663 | 30.408 | 31.186 | 383.412 |
| TRAIL PC | 1.218 | 1.252 | 1.243 | 1.194 | 1.225 | 1.176 | 1.209 | 1.200 | 1.075 | 1.184 | 1.137 | 1.166 | 14.279 |
| WHLA PC | 7.065 | 7.226 | 7.149 | 6.849 | 7.003 | 6.708 | 6.863 | 6.792 | 6.073 | 6.659 | 6.378 | 6.526 | 81.291 |
| WWILSON PC | 12.990 | 13.339 | 13.256 | 12.747 | 13.088 | 12.588 | 12.927 | 12.843 | 11.528 | 12.682 | 12.198 | 12.524 | 152.710 |
| Total | 417.249 | 427.728 | 424.008 | 406.803 | 415.796 | 400.005 | 409.924 | 406.592 | 364.287 | 400.130 | 383.244 | 392.940 | 4848.706 |
| | | | | | | | | | | | | | |
| MOSU MT | 0.564 | 0.580 | 0.577 | 0.555 | 0.570 | 0.552 | 0.567 | 0.564 | 0.507 | 0.558 | 0.537 | 0.552 | 6.683 |
| Total | 0.564 | 0.580 | 0.577 | 0.555 | 0.570 | 0.552 | 0.567 | 0.564 | 0.507 | 0.558 | 0.537 | 0.552 | 6.683 |
| | | | | | | | | | | | | | |
| OFF SYS D24 | 33.079 | 34.219 | 34.256 | 33.229 | 34.374 | 33.301 | 34.448 | 34.485 | 31.182 | 34.560 | 33.481 | 34.634 | 405.248 |
| OFF SYS PC | 8.451 | 8.696 | 8.658 | 8.301 | 8.541 | 8.229 | 8.466 | 8.429 | 7.580 | 8.358 | 8.052 | 8.283 | 100.044 |
| OFF SYS PW | 0.051 | 0.053 | 0.053 | 0.051 | 0.053 | 0.051 | 0.053 | 0.053 | 0.048 | 0.050 | 0.048 | 0.050 | 0.614 |
| Total | 41.581 | 42.968 | 42.967 | 41.581 | 42.968 | 41.581 | 42.967 | 42.967 | 38.810 | 42.968 | 41.581 | 42.967 | 505.906 |
| | | | | | | | | | | | | | |
| Wexpro I | | | | | | | | | | | | | |
| CCRUNIT D8 | 135.963 | 137.594 | 134.859 | 128.010 | 129.831 | 123.402 | 125.311 | 123.213 | 109.483 | 119.300 | 113.685 | 115.723 | 1496.374 |
| KNY FLD D8 | 10.695 | 10.906 | 10.766 | 10.287 | 10.500 | 10.038 | 10.252 | 10.131 | 9.047 | 9.905 | 9.480 | 9.691 | 121.698 |
| MESA D8 | 326.832 | 330.556 | 323.792 | 307.155 | 311.327 | 295.710 | 300.086 | 294.860 | 261.822 | 285.107 | 271.494 | 276.170 | 3584.911 |
| TRAIL D8 | 101.166 | 101.175 | 98.165 | 92.361 | 92.954 | 87.741 | 88.552 | 86.586 | 76.549 | 83.034 | 78.792 | 79.896 | 1066.971 |
| Wexpro I New Drill | | | | | | | | | | | | | |
| z19 PINED D8 | 244.416 | 239.881 | 228.774 | 211.872 | 210.137 | 195.684 | 195.015 | 188.455 | 164.780 | 176.889 | 166.218 | 166.994 | 2389.115 |
| z20 CCRK D8 | 0.000 | 0.000 | 0.000 | 0.000 | 184.466 | 156.042 | 144.544 | 131.828 | 109.962 | 113.507 | 103.179 | 100.756 | 1044.284 |
| z20 ISLND D8 | 0.000 | 0.000 | 0.000 | 0.000 | 40.722 | 32.553 | 29.140 | 25.969 | 21.302 | 21.716 | 19.548 | 18.938 | 209.888 |
| z20 PINED D8 | 64.431 | 60.487 | 55.636 | 49.995 | 48.338 | 44.037 | 43.059 | 40.920 | 35.255 | 37.349 | 34.680 | 34.472 | 548.659 |
| z20 TRAIL D8 | 0.000 | 0.000 | 58.280 | 151.023 | 138.068 | 120.780 | 114.523 | 106.259 | 89.813 | 93.682 | 85.887 | 84.463 | 1042.778 |
| Total | 883.503 | 880.599 | 910.272 | 950.703 | 1166.343 | 1065.987 | 1050.482 | 1008.221 | 878.013 | 940.489 | 882.963 | 887.103 | 11504.678 |
| | | | | | | | | | | | | | |
| Wexpro II | | | | | | | | | | | | | |
| CCRUNIT 2D8 | 54.996 | 55.654 | 54.545 | 51.774 | 52.508 | 49.905 | 50.676 | 49.826 | 44.274 | 48.242 | 45.969 | 46.791 | 605.160 |
| CCRUNIT 2E | 266.616 | 272.304 | 269.232 | 257.682 | 263.413 | 252.240 | 257.973 | 255.375 | 228.385 | 250.399 | 240.012 | 245.684 | 3059.315 |
| CCRUNIT MT | 22.122 | 22.444 | 22.050 | 20.979 | 21.319 | 20.301 | 20.652 | 20.339 | 18.099 | 19.753 | 18.846 | 19.211 | 246.115 |
| CCRUNIT2EMT | 22.095 | 22.655 | 22.481 | 21.588 | 22.137 | 21.258 | 21.799 | 21.635 | 19.393 | 21.309 | 20.466 | 20.990 | 257.806 |
| TRAIL 2D8 | 82.407 | 81.918 | 79.038 | 73.983 | 74.106 | 69.642 | 69.998 | 68.185 | 60.066 | 64.933 | 61.422 | 62.096 | 847.794 |
| TRAIL 2E | 315.120 | 320.618 | 315.819 | 301.173 | 306.785 | 292.767 | 298.425 | 294.469 | 262.528 | 286.973 | 274.272 | 279.973 | 3548.922 |
| TRAIL 2E MT | 49.845 | 50.825 | 50.167 | 47.937 | 48.927 | 46.779 | 47.768 | 47.216 | 42.168 | 46.168 | 44.196 | 45.183 | 567.179 |
| WHISKEY MT | 34.383 | 34.860 | 34.221 | 32.529 | 33.034 | 31.434 | 31.955 | 31.450 | 27.966 | 30.498 | 29.082 | 29.624 | 381.036 |
| WHISKEYC 2E | 93.411 | 94.798 | 93.158 | 88.647 | 90.117 | 85.839 | 87.346 | 86.047 | 76.597 | 83.610 | 79.803 | 81.360 | 1040.733 |
| Wexpro II New Drill | | | | | | | | | | | | | |
| z20 CCRK 2D8 | 0.000 | 0.000 | 0.000 | 0.000 | 76.706 | 64.887 | 60.106 | 54.817 | 45.724 | 47.198 | 42.906 | 41.897 | 434.241 |
| z20 TRAIL2D8 | 0.000 | 0.000 | 57.623 | 0.000 | 0.000 | 0.000 | 113.231 | 105.059 | 0.000 | 0.000 | 0.000 | 0.000 | 275.913 |
| Total | 940.995 | 956.076 | 998.334 | 896.292 | 989.052 | 935.052 | 1059.929 | 1034.418 | 825.200 | 899.083 | 856.974 | 872.809 | 11264.214 |
| | | | | | | | | | | | | | |
| Production Total | 4913.620 | 4999.356 | 5042.325 | 4852.183 | 5231.476 | 4953.325 | 5134.544 | 5040.079 | 4387.429 | 4784.286 | 4563.754 | 4653.486 | 58555.863 |

Normal Temperature Case : Plan Year 2

MDth

Exhibit 14.88

| Storage Withdraw | 1-Jun-20 | 1-Jul-20 | 1-Aug-20 | 1-Sep-20 | 1-Oct-20 | 1-Nov-20 | 1-Dec-20 | 1-Jan-21 | 1-Feb-21 | 1-Mar-21 | 1-Apr-21 | 1-May-21 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clay Bsn 935 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1848.000 | 1536.909 | 1368.909 | 690.925 | 0.000 | 0.000 | 5444.743 |
| Clay Bsn 988 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1155.000 | 960.568 | 855.568 | 431.828 | 0.000 | 0.000 | 3402.964 |
| Clay Bsn 997 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1155.000 | 960.568 | 855.568 | 431.828 | 0.000 | 0.000 | 3402.964 |
| Chalk Creek | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 45.004 | 0.000 | 243.896 | 0.000 | 0.000 | 288.900 |
| Coalville | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 60.079 | 0.000 | 300.107 | 0.000 | 0.000 | 360.186 |
| Leroy | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 78.940 | 0.000 | 364.543 | 0.000 | 0.000 | 443.483 |
| Ryckman | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 491.400 | 514.600 | 514.600 | 464.800 | 514.600 | 0.000 | 0.000 | 2500.000 |
| Total | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 491.400 | 4672.600 | 4156.668 | 3544.845 | 2977.727 | 0.000 | 0.000 | 15843.240 |

| Purchase Gas | 1-Jun-20 | 1-Jul-20 | 1-Aug-20 | 1-Sep-20 | 1-Oct-20 | 1-Nov-20 | 1-Dec-20 | 1-Jan-21 | 1-Feb-21 | 1-Mar-21 | 1-Apr-21 | 1-May-21 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spot | 127.320 | 0.000 | 0.000 | 641.570 | 2412.430 | 3448.680 | 3765.780 | 6308.860 | 4688.890 | 3713.210 | 3077.490 | 2277.970 | 30462.200 |
| Spot | 1500.000 | 0.000 | 0.000 | 1397.630 | 1528.250 | 150.000 | 350.000 | 0.000 | 50.000 | 736.880 | 1013.390 | 1550.000 | 8276.150 |
| Spot | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 308.710 | 180.780 | 193.810 | 175.560 | 941.260 | 0.000 | 0.000 | 1800.120 |
| Spot | 12.630 | 0.000 | 0.000 | 11.240 | 26.210 | 48.390 | 76.020 | 82.160 | 69.110 | 55.010 | 36.470 | 22.450 | 439.690 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 750.000 | 775.000 | 775.000 | 700.000 | 0.000 | 0.000 | 0.000 | 3000.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2325.000 | 2325.000 | 2100.000 | 0.000 | 0.000 | 0.000 | 6750.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 775.000 | 775.000 | 700.000 | 0.000 | 0.000 | 0.000 | 2250.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 300.000 | 310.000 | 310.000 | 280.000 | 310.000 | 0.000 | 0.000 | 1510.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 600.000 | 620.000 | 620.000 | 560.000 | 0.000 | 0.000 | 0.000 | 2400.000 |
| Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 600.000 | 12.470 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 612.470 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 930.000 | 900.000 | 930.000 | 930.000 | 840.000 | 930.000 | 900.000 | 0.000 | 6360.000 |
| Base | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 210.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 210.000 |
| Total | 1639.950 | 0.000 | 0.000 | 2050.440 | 4896.890 | 7315.780 | 10120.050 | 12319.830 | 10163.560 | 6686.360 | 5027.350 | 3850.420 | 64070.630 |

| Storage Inject | 1-Jun-20 | 1-Jul-20 | 1-Aug-20 | 1-Sep-20 | 1-Oct-20 | 1-Nov-20 | 1-Dec-20 | 1-Jan-21 | 1-Feb-21 | 1-Mar-21 | 1-Apr-21 | 1-May-21 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clay Bsn 935 | 1200.000 | 1049.610 | 1102.240 | 1066.680 | 836.450 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1102.240 | 6357.220 |
| Clay Bsn 988 | 750.000 | 775.000 | 154.830 | 666.660 | 522.771 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 688.880 | 3558.141 |
| Clay Bsn 997 | 750.000 | 85.770 | 688.880 | 666.660 | 522.771 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 688.880 | 3402.961 |
| Chalk Creek | 0.000 | 0.000 | 0.000 | 93.650 | 132.000 | 76.600 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 302.250 |
| Coalville | 0.000 | 0.000 | 0.000 | 50.190 | 310.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 360.190 |
| Leroy | 0.000 | 0.000 | 0.000 | 0.000 | 443.483 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 443.483 |
| Spire | 341.730 | 353.120 | 353.120 | 341.730 | 353.119 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1742.819 |
| Total | 3041.730 | 2263.500 | 2299.070 | 2885.570 | 3120.594 | 76.600 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2480.000 | 16167.064 |

Units: MDth

Required v. Supply

Exhibit 14.89

| Area | Class | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ut/Id | FS_COM | 139.574 | 118.613 | 118.571 | 136.618 | 146.781 | 177.211 | 216.835 | 280.342 | 258.122 | 207.564 | 210.103 | 171.963 | 2,182.297 |
| Wy QGC | FS_COM | 9.557 | 8.754 | 8.751 | 10.550 | 18.097 | 16.648 | 21.171 | 21.297 | 19.482 | 16.684 | 14.905 | 14.685 | 180.581 |
| Ut/Id | FS_IND | 48.859 | 45.191 | 45.161 | 48.594 | 62.860 | 59.363 | 69.961 | 74.630 | 75.885 | 67.986 | 64.429 | 60.739 | 723.658 |
| Ut Geo | GS_COM | 44.911 | 34.966 | 35.047 | 40.001 | 92.742 | 171.016 | 268.363 | 286.421 | 248.347 | 191.849 | 127.287 | 78.546 | 1,619.496 |
| Ut KRGT | GS_COM | 6.202 | 4.835 | 4.848 | 5.533 | 12.815 | 23.641 | 37.058 | 39.621 | 34.306 | 26.507 | 17.586 | 10.845 | 223.796 |
| UT NPC | GS_COM | 3.562 | 2.773 | 2.774 | 3.167 | 7.345 | 13.545 | 21.262 | 22.675 | 19.704 | 15.195 | 10.080 | 6.217 | 128.300 |
| Ut/Id | GS_COM | 780.461 | 599.195 | 600.626 | 926.441 | 1,639.055 | 3,076.402 | 4,874.005 | 5,190.749 | 4,486.267 | 3,450.619 | 2,253.258 | 1,367.417 | 29,244.495 |
| Wy QGC | GS_COM | 35.785 | 23.451 | 23.494 | 36.110 | 90.067 | 157.694 | 222.200 | 239.253 | 217.819 | 180.192 | 131.218 | 84.586 | 1,441.870 |
| Ut Geo | GS_RES | 113.746 | 88.629 | 88.810 | 101.367 | 235.090 | 433.341 | 680.140 | 738.716 | 640.209 | 494.693 | 328.445 | 202.623 | 4,145.810 |
| Ut KRGT | GS_RES | 15.722 | 12.249 | 12.273 | 14.010 | 32.494 | 59.892 | 94.008 | 102.099 | 88.492 | 68.377 | 45.370 | 27.994 | 572.980 |
| UT NPC | GS_RES | 9.016 | 7.024 | 7.041 | 8.036 | 18.638 | 34.349 | 53.918 | 58.570 | 50.748 | 39.215 | 26.036 | 16.064 | 328.654 |
| Ut/Id | GS_RES | 1,976.818 | 1,518.394 | 1,521.855 | 2,352.271 | 4,154.154 | 7,796.658 | 12,349.275 | 13,392.765 | 11,570.757 | 8,898.419 | 5,811.707 | 3,526.957 | 74,870.031 |
| Wy QGC | GS_RES | 53.849 | 35.291 | 35.349 | 54.328 | 135.562 | 237.226 | 334.257 | 356.902 | 324.914 | 268.726 | 195.673 | 126.159 | 2,158.237 |
| Ut/Id | IS_COM | 4.503 | 3.591 | 3.589 | 3.927 | 3.887 | 6.655 | 9.236 | 11.245 | 8.151 | 8.930 | 6.311 | 4.728 | 74.753 |
| Wy QGC | IS_COM | 3.251 | 3.214 | 3.212 | 3.336 | 8.183 | 13.508 | 14.117 | 16.875 | 16.017 | 15.752 | 14.153 | 8.982 | 120.600 |
| Ut/Id | IS_IND | 2.901 | 2.704 | 2.703 | 3.098 | 4.585 | 5.178 | 9.395 | 5.845 | 4.335 | 4.649 | 4.668 | 3.566 | 53.626 |
| Wy QGC | IS_IND | 0.046 | 0.002 | 0.002 | 0.080 | 0.536 | 1.494 | 0.527 | 1.096 | 0.885 | 0.658 | 0.149 | 1.927 | 7.403 |
| Ut Geo | L_and_U | 0.714 | 0.556 | 0.557 | 0.636 | 1.475 | 2.720 | 4.268 | 4.613 | 3.999 | 3.089 | 2.051 | 1.265 | 25.944 |
| Ut KRGT | L_and_U | 0.099 | 0.077 | 0.077 | 0.088 | 0.204 | 0.376 | 0.590 | 0.638 | 0.553 | 0.427 | 0.283 | 0.175 | 3.585 |
| UT NPC | L_and_U | 0.057 | 0.044 | 0.044 | 0.050 | 0.117 | 0.216 | 0.338 | 0.366 | 0.317 | 0.245 | 0.163 | 0.100 | 2.056 |
| Ut/Id | L_and_U | 13.289 | 10.295 | 10.316 | 15.619 | 27.051 | 50.047 | 78.879 | 85.300 | 73.816 | 56.872 | 37.577 | 23.109 | 482.170 |
| Wy QGC | L_and_U | 0.461 | 0.318 | 0.319 | 0.470 | 1.136 | 1.920 | 2.665 | 2.859 | 2.606 | 2.169 | 1.602 | 1.064 | 17.589 |
| Off-Sys | Off_Sys | 41.472 | 42.575 | 42.324 | 40.716 | 41.794 | 40.203 | 41.292 | 41.041 | 38.158 | 40.790 | 39.474 | 40.790 | 490.630 |
| | | 3,304.856 | 2,562.743 | 2,567.744 | 3,805.046 | 6,734.667 | 12,379.303 | 19,403.762 | 20,973.920 | 18,183.887 | 14,059.607 | 9,342.528 | 5,780.500 | 119,098.563 |

| | | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Transport | 144.402 | 135.286 | 127.423 | 151.420 | 182.801 | 243.755 | 331.315 | 353.676 | 308.530 | 276.781 | 213.361 | 172.773 | 2,641.524 |
| Fuel | Injection | 77.993 | 80.187 | 72.644 | 41.193 | 70.783 | 1.314 | 0.000 | 0.000 | 0.000 | 0.000 | 8.602 | 45.268 | 397.984 |
| Fuel | Withdrawal | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 38.089 | 53.352 | 57.038 | 49.446 | 20.764 | 0.000 | 0.000 | 218.688 |
| | Total Fuel | 222.395 | 215.473 | 200.067 | 192.614 | 253.584 | 283.158 | 384.667 | 410.714 | 357.976 | 297.546 | 221.962 | 218.041 | 3,258.196 |

| | | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Inject | a_Clay Basin | 2,700.000 | 2,774.166 | 2,480.000 | 1,233.429 | 1,812.404 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1,412.351 | 12,412.350 |
| Inject | Aquifer | 0.000 | 0.000 | 0.000 | 82.586 | 885.966 | 126.786 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1,095.338 |
| Inject | Spire | 341.728 | 353.119 | 353.119 | 340.901 | 238.343 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 335.461 | 353.119 | 2,315.788 |
| | Total | 3,041.728 | 3,127.284 | 2,833.119 | 1,656.916 | 2,936.713 | 126.786 | 0.000 | 0.000 | 0.000 | 0.000 | 335.461 | 1,765.470 | 15,823.477 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Required | | 6,568.979 | 5,905.500 | 5,600.930 | 5,654.576 | 9,924.963 | 12,789.240 | 19,788.420 | 21,384.630 | 18,541.860 | 14,357.150 | 9,899.953 | 7,764.011 | 138,180.230 |

# Required v. Supply

Exhibit 14.90

Units: MDth

| | | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Supply | Spot | 777.383 | 0.000 | 0.000 | 0.000 | 3,292.719 | 1,671.065 | 4,748.529 | 6,312.117 | 4,630.473 | 6,831.903 | 3,912.288 | 2,600.380 | 34,776.856 |
| Supply | Peak | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 1,650.000 | 3,090.099 | 3,100.000 | 2,870.542 | 310.000 | 0.000 | 0.000 | 11,020.641 |
| Supply | Base | 0.000 | 0.000 | 0.000 | 0.000 | 930.000 | 1,110.000 | 2,387.000 | 2,387.000 | 2,233.000 | 930.000 | 900.000 | 0.000 | 10,877.000 |
| | Total | 777.383 | 0.000 | 0.000 | 0.000 | 4,222.719 | 4,431.065 | 10,225.620 | 11,799.110 | 9,734.014 | 8,071.903 | 4,812.288 | 2,600.380 | 56,674.497 |

| | | 1-Jun-19 | 1-Jul-19 | 1-Aug-19 | 1-Sep-19 | 1-Oct-19 | 1-Nov-19 | 1-Dec-19 | 1-Jan-20 | 1-Feb-20 | 1-Mar-20 | 1-Apr-20 | 1-May-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Withdraw | Aquifer | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 184.023 | 0.000 | 921.900 | 0.000 | 0.000 | 1,105.923 |
| Withdraw | Clay Basin | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2,457.329 | 3,442.046 | 3,410.050 | 3,190.046 | 0.000 | 0.000 | 0.000 | 12,499.471 |
| Withdraw | Spire | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 498.000 | 514.600 | 514.600 | 481.400 | 0.000 | 0.000 | 0.000 | 2,008.600 |
| Production | Company | 3,463.872 | 3,535.243 | 3,337.344 | 3,336.256 | 3,411.029 | 3,267.342 | 3,342.510 | 3,308.971 | 3,064.319 | 3,243.062 | 3,108.000 | 3,180.712 | 39,598.663 |
| Production | Wexpro I | 1,053.861 | 1,088.993 | 1,013.479 | 1,137.390 | 1,099.034 | 1,006.401 | 1,120.219 | 1,049.189 | 1,049.008 | 1,048.783 | 962.250 | 950.218 | 12,578.825 |
| Production | Wexpro II | 1,230.177 | 1,236.416 | 1,205.522 | 1,138.041 | 1,148.156 | 1,086.762 | 1,099.930 | 1,075.452 | 982.880 | 1,028.537 | 975.834 | 989.734 | 13,197.440 |
| | | 5,747.910 | 5,860.652 | 5,556.347 | 5,611.687 | 5,658.219 | 8,315.834 | 9,519.305 | 9,542.285 | 8,767.654 | 6,242.281 | 5,046.084 | 5,120.664 | 80,988.921 |
| Production | Off-System | 43.686 | 44.848 | 44.583 | 42.889 | 44.025 | 42.349 | 43.496 | 43.231 | 40.195 | 42.967 | 41.581 | 42.967 | 516.817 |
| Total Supply | | 6,568.979 | 5,905.500 | 5,600.930 | 5,654.576 | 9,924.963 | 12,789.240 | 19,788.420 | 21,384.630 | 18,541.860 | 14,357.150 | 9,899.953 | 7,764.011 | 138,180.230 |

# 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 2019-2020 gas-supply year are as follows:

- Produce approximately 65.1 MMDth of cost-of-service gas, recognizing the uncertainties associated with demand, operating conditions, and gas well productivity.
- Execute Distribution System Action Plan to ensure distribution system is adequate to serve firm customers.
- Produce the categories of cost-of-service gas as determined this year in the modeling exercise as contained in Exhibits 14.83 and 14.84 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 56.7 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 the issue of additional price stabilization on an annual basis 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.
- Obtain required approvals for the design and construction of an on-system LNG facility to help ensure system reliability for sales customers.
- Commit to meeting customers' energy needs in an environmentally responsible and proactive manner.