# QUESTAR GAS COMPANY

# INTEGRATED RESOURCE PLAN

(For Plan Year: June 1, 2010 to May 31, 2011)

Submitted: May 20, 2010

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# EXECUTIVE SUMMARY

Questar Gas Company (Questar Gas or Company) is a regulated natural gas utility company providing retail natural-gas-distribution service to more than 900,000 customers in Utah, southwestern Wyoming and two communities in southeastern Idaho. The Company is regulated by the Utah Public Service Commission (Utah Commission) and the Public Service Commission of Wyoming (Wyoming Commission).

A substantial portion of the service territory of Questar Gas is situated along the Wasatch Mountain Range of Utah and on the high plateaus of southwestern Wyoming where some of the coldest temperatures in the nation can occur, along with some of the widest daily temperature swings. Accordingly, frequent and rigorous planning processes are necessary to provide safe and reliable natural gas service. This report documents the Company's most recent integrated resource planning process.

In recent years, both the Wyoming Commission and the Utah Commission have revisited the rules and guidelines governing integrated resource planning within their jurisdictions (see the Introduction and Background section of this report). Questar Gas submits this planning document, for the operating year extending from June 1, 2010 to May 31, 2011, to the Utah Commission in accordance with the following: 1) the Report and Order issued March 31, 2009 in Docket No. 08-057-02, and 2) the Report and Order issued March 22, 2010 in Docket No. 09-057-07. The first Utah order established new integrated resource planning guidelines and the second Utah order clarified certain planning requirements. The Company agrees with the Commission that this IRP process is "ongoing" and "is expected to evolve over time." Interested parties are continuing to meet, as directed in the March 22, 2010 Order, to "discuss their positions with the goal of reaching a consensus to the extent possible."

This document is also submitted to the Wyoming Commission pursuant to the following: 1) the Order issued May 21, 1992 in Docket No. 30010-GI-14, and 2) the Rule 253 of the Commission Procedural Rules and Special Regulations Regarding Integrated Resource Planning, approved May 12, 2009 by the Wyoming Commission in Docket No. 90000-107-XO-09.

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

1. A design-day firm demand of approximately 1.272 million decatherms (Dth) at the city gates for January 2011;

2. Approximately 67.7 million Dth of cost-of-service natural gas, assuming normal weather conditions, forecasted market prices for purchased gas, and the completion of new development drilling projects;

3. A balanced portfolio of approximately 49.5 million Dth of purchased gas;

4. Questar Gas should 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. Questar Gas should undertake price stabilization measures for purchased gas contracts to help mitigate the risk of volatility in the marketplace;

6. Questar Gas should continue to monitor and manage producer imbalances; and

7. In Utah and Wyoming, Questar Gas should continue to incorporate cost-effective energy-efficiency measures.

The preparation of this planning document is dependent on information from many sources in a variety of formats such as numerical data and qualitative information. Questar Gas acknowledges the contributions of all who have participated in the Integrated Resource Planning (IRP) process this year. In the event there are questions, comments or requests for additional information, please direct them to:

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## INTRODUCTION AND BACKGROUND

Over the previous year, financial markets around the world have generally stabilized, even as they reflect uncertainty at times. While many economists maintain that the U.S. financial crisis is far from over, confidence in credit markets and the overall economy is gradually improving aided primarily by massive governmental monetary stimulus and extraordinarily low interest rates.

The most commonly used indicator of economic health within a country is gross domestic product (GDP), the market value of all final goods and services produced over a period of time. In the U.S., real GDP continued to decline on an annualized basis for the first two quarters of 2009 by 6.4 percent and 0.7 percent, respectively, but grew for the last two quarters at rates of 2.2 percent and 5.6 percent, respectively.[1] The advance estimate for first quarter 2010 real GDP growth from the U.S. Department of Commerce is 3.2 percent.

During March of 2009, the Dow Jones Industrial Average and the Standard and Poor's 500 stock indices reached 12-year lows. Since then, equity markets have improved dramatically, although they are still far below their peaks of early 2008. While employment levels are still weak, and credit is still tight, some economists are seeing encouraging signs that the U.S. economy is swinging slowly towards recovery.

The energy sector and the overall U.S. economy are inextricably connected. Although energy expenditures as a percentage of GDP remain relatively modest, energy continues to be a fundamental driver of economic growth in the U.S. During the 1980's, energy expenditures, as a percentage of GDP, averaged 10.6 percent. During the 1990's, energy expenditures averaged 7.1 percent of the GDP. From 2000 through 2006, the most current data available from the U.S. Department of Energy, Energy Information Administration (EIA), this statistic averaged about 7.4 percent of GDP.[2] By way of comparison, U.S. medical expenditures, as a percentage of GDP from 2000 through 2006, averaged 15.1 percent, more than double that for energy.[3]

Since the advent of interstate long-haul pipelines in the 1930's, natural gas has been a significant source of energy for American homes, industries and businesses. More recently, from 2000 through 2008, natural gas as an energy source provided an annual average of 23 percent of total U.S. energy consumption on a British thermal unit (Btu) equivalent basis.[4] In a study recently conducted by IHS Global Insight, the natural gas industry is estimated to have made a direct economic impact to the U.S. economy of $385 billion in 2008.

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[1]U.S. Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, Gross Domestic Product (GDP), Percent Change From Preceding Period, www.bea.gov/national/gdpchg.xls.
[2]U.S. Department of Energy, Energy Information Administration, Table 1.5 Energy Consumption, Expenditures, and Emissions Indicators, 1949-2008, www.eia.doe.gov/emeu/aer/txt/ptb0105.html.
[3]U.S. Department of Health and Human Services, Centers for Medicare and Medicaid Services, NHE Fact Sheet, www.cms.hhs.gov/NationalHealthExpendData/downloads/tables.pdf.
[4]U.S. Department of Energy, Energy Information Administration, Table 1.3 Primary Energy Consumption by Source, 1949-2008 (Quadrillion Btu), www.eia.doe.gov/emeu/aer/txt/ptb0103.html.

Employment attributable to the natural gas industry, both direct and indirect, is estimated to be approximately 2.8 million jobs.[5]

In recent years, a fundamental shift has occurred in the natural gas industry. In 1990, "unconventional gas" accounted for approximately 10 percent of U.S. production. Unconventional production includes tight-sands gas, coal-bed methane, and shale gas. These unconventional sources are all characterized by low permeability formations. Today, unconventional gas makes up about 40 percent of U.S. production and is continuing to grow.[6] Much of this growth is from shale-gas plays such as the Barnett Shale in Texas, the Marcellus Shale in the Appalachian Basin, and the Hanesville-Bossier Shale in the Texas-Louisiana Salt Basin.

Developments in two technologies, horizontal drilling and hydraulic fracturing, have been instrumental in unlocking the potential of low-permeability formations, particularly shales. Directional drilling within a shale formation maximizes the borehole surface area in contact with the shale resulting in more perforations, greater flows, and much larger reserves. Also, multiple horizontal wells can be drilled from the same pad reducing drilling time and cost. The development of down-hole drilling motors coupled with telemetry techniques have greatly facilitated horizontal drilling.[7]

The second major development in bringing about the shale-gas boom is attributable to improvements in hydraulic fracturing (or "fracing"). Fracing stimulates production from a formation by creating fractures through the application of extremely high fluid pressures. Fractures in a formation are typically maintained by injecting proppant into the formation. The proppant (such as grains of sand or ceramic material) prevents the fissures in the formation from closing when the injection of high pressure fluids is terminated.

Over the last few years, there has been a growing disconnect between the U.S. natural gas rig count and production levels. While the rig count dropped precipitously during 2009, natural gas production only dropped modestly. This disconnect is generally ascribed to the prodigious volumes produced from horizontal wells in shale-gas plays.

The shale-gas boom has had major implications for gas markets. Production from prolific shale-gas plays in the eastern United States, where much of the lower-48-state natural-gas demand exists, has helped facilitate a regional trend towards gas-price parity non-existent previously. For example, the Rockies price basis to Henry Hub a few years ago was several dollars as opposed to approximately 30 cents today. Shale gas has also added to the gas supply bubble which results in downward pressure on the forward price curve. The 18-month Henry Hub forward curve for natural gas currently has monthly prices per decatherm growing, in the near term, from the low-four-dollar range to the mid-five-dollar range in later months.

[5] "The Contributions of the Natural Gas Industry to the U.S. National and State Economies," IHS Global Insight, Lexington, MA, September, 2009.
[6] "America's Natural Gas Revolution," The Wall Street Journal, November 2, 2009.
[7] It is not uncommon for the radius of curvature for a ninety degree bend in a horizontal well to be one quarter of a mile.

The level of interstate natural gas pipeline construction has also been affected by the surge in shale-gas production. Just a few years ago, a number of interstate pipeline companies were looking at capitalizing on the relatively large price basis between producing areas in the Rockies and market areas on both the east and west coasts. The flattening of the natural gas price basis across the country has taken the bloom off most of those projects for the near term. Some interstate pipeline segments may reverse flow direction in the future to accommodate increasing shale-gas volumes or to accommodate volumes displaced by shale gas.

The Rockies Express Pipeline (REX) has also been instrumental in flattening the price basis. The first segment of REX began flowing in February 2006. The final two eastern segments of REX were completed during 2009 with a "fully in service" date of November 12, 2009. REX is one of the largest natural gas delivery systems in the United States extending 1,679 miles from the Rockies to eastern Ohio.[8]

The Ruby Pipeline Project (Ruby) is still actively proceeding. This 42-inch 675-mile interstate pipeline with a capacity of 1.5 million decatherms per day is expected to cost some three billion dollars. The project, extending from Opal, Wyoming to Malin, Oregon, crosses the service territory of Questar Gas in northern Utah. Because of its location, Questar Gas has been involved in discussions with Ruby involving a possible interconnection. The final environmental impact statement for the project has been issued and Ruby is awaiting final regulatory approvals to proceed with construction. Additional information on the Ruby Pipeline Project and other interstate pipelines used by Questar Gas is contained in the Transportation Issues Section of this report.

As the economy and health care have become priority issues at the federal level, climate-change legislation appears to have temporarily taken a back seat. The American Clean Energy and Security Act of 2009 (the Waxman-Markey Bill), passed the House of Representatives on a close vote during late June of 2009, but has since stalled in the Senate. With congressional elections approaching, it is possible no further action could take place this year.

Supporters of the cap and trade concept in the Waxman-Markey Bill believe that the ultimate costs to average households are minimal when weighed against the risks of failing to limit greenhouse gasses. They argue that the incentives inherent in the program will work by pointing to the successes of the cap and trade program for controlling sulfur-dioxide emissions.

Critics of the Waxman-Markey Bill argue that the miniscule impacts on expected future global temperature do not justify the costs, which they believe have been vastly underestimated. Opponents are also critical of the fact that emission allowances in the Waxman-Markey Bill are disproportionately allocated to the worst polluters thus effectively penalizing cleaner sources of energy such as natural gas.

[8] Rockies Express Pipeline, Press Release, "Gov. Freudenthal Commends Rockies Express Pipeline on Full In Service," Cheyenne, Wyoming, November 17, 2009.

On May 12, 2010, Senators Kerry and Lieberman released the details of their proposed energy and climate-change legislation, the American Power Act Bill. Designed to create jobs and promote energy independence, this bill, if enacted, would require carbon emission reductions of 17 percent by 2012 and by over 80 percent in 2050. Like the Waxman-Markey Bill, it is uncertain if any further action will take place on this proposed legislation this year.

Under either a cap-and-trade mechanism, or a direct carbon tax, natural gas would likely become a preferred fuel displacing energy sources that are not as clean. Climate change legislation, depending on how and where it is implemented, could, however, increase costs to natural gas end-use customers.

In recent years, natural gas was thought by many to be a bridge fuel to a world of vastly reduced carbon emissions. With a greater awareness of the potential supplies available at reasonable prices, natural gas is viewed increasingly as a fundamental component of the long-term solution. As the cleanest of the fossil fuels, Questar Gas believes that natural gas, when used in an efficient manner, helps to remediate environmental impacts. This becomes evident by comparing energy sources on the level playing field of pounds-of-air-pollutant-produced per unit-of-energy. When compared on this basis, for example, carbon dioxide emissions from natural gas combustion are slightly more than one half of those associated with coal. Carbon monoxide and nitrogen oxides are approximately 20 percent of that for coal. Sulfur dioxide and particulates are far less than one percent of that emitted by coal.[9]

Questar Corporation's commitment to the environment is reflected in its mission statement; ". . . we respect and protect the environment and we contribute to a better quality of life in the communities where we operate." During July of 2009, the Bureau of Land Management recognized six winners of the "2009 Oil, Gas Geophysical and Geothermal Development Environmental Best Management Practices Awards." Questar Corporation, as one of the winners, was recognized once again for its work in the Pinedale Anticline Field for designing and implementing best management practices in reducing the amount of nitrogen oxides and volatile organic compounds stemming from operations in that area.[10] The customers of Questar Gas benefit from cost-of-service production received from the Pinedale Field pursuant to the Wexpro Agreement (see the "Cost-of-Service Gas" section of this report).

Questar Gas is a stakeholder in the Utah Clean Cities Coalition, an independent non-profit organization comprised of approximately 65 governments and private organizations devoted to clean air quality and the reduction of dependence on foreign oil in the State of Utah. On August 26, 2009, the U.S. Department of Energy announced the selection of up to 25 projects nationwide under the Clean Cities program to receive funding under the American Recovery and Reinvestment Act. The Utah Clean Cities Coalition received $14.9 million for the construction of up to 16 new compressed natural gas (CNG) public fueling facilities, upgrades to 24 existing public CNG fueling facilities, three biodiesel public refueling stations, and an increase in the number of natural gas vehicles operating in Utah by

[9] "Natural Gas 1998: Issues and Trends," Energy Information Administration's Office of Oil and Gas, page 58.
[10] www.blm.gov/wo/st/en/info/newsroom/2009/july/NR_0708_2009.html (July 9, 2009).

678.[11] This initiative is expected to displace some 1.1 million gallons of petroleum annually in the state.[12]

Questar Gas was also recognized recently by the U.S. Environmental Protection Agency (EPA) for its outstanding contributions to reducing greenhouse gas emissions. On March 18, 2010, Questar Gas was presented with a 2010 ENERGY STAR Partner of the Year Award for delivering outstanding information and services to its customers to increase energy efficiency. During 2009, the Company was successful in recruiting 44 production builders to the ENERGY STAR New Homes program raising the total to 91 participants. Ten percent of all new homes constructed during the year qualified as ENERGY STAR Homes.[13] The Energy Efficiency Section of this report contains more information on Questar Gas' efforts in improving its customers' energy efficiency and reducing greenhouse emissions.

On April 21, 2010, Questar Corporation announced that it is considering spinning off its natural gas and oil exploration and production business.[14] If the spinoff is consummated, Questar Pipeline Company, Questar Gas Company, and Wexpro Company would remain as Questar Corporation and the exploration and production business would become a new company. The proposed transaction would not impact the customers of Questar Gas. Natural gas rates will be unaffected, and the benefits of cost-of-service production from Wexpro Company will continue to accrue to the Company's customers. On May 18, 2010, it was announced that the Questar Corporation board of directors had conditionally approved the spinoff.

As national and regional trends affecting the natural gas industry evolve, Questar Gas incorporates, to the extent possible, these factors into its forecasting and planning processes. These processes occur within the Company on a daily, monthly, annual and multi-year basis.

## Wyoming IRP Process

On February 3, 2009, the Public Service Commission of Wyoming issued an order initiating a rulemaking pertaining to integrated resource planning. The rule was proposed to ". . . give the Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[15] The order initiated a formal proceeding to consider promulgating the following rule:

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[11] Jibson, Ron. "Full Speed Ahead," *American Gas: The Monthly Magazine of the American Gas Association*, April 2010, Pages 22-26.

[12] www.eere.energy.gov/cleancities/printable_versions/projects.html (Aug 27, 2009).

[13] www.energystar.gov/index.cfm?fuseaction=pt_awards.showAwardDetails&esa_id=3849 (March 29, 2010)

[14] "Questar Considering Spin-Off of Exploration and Production Business," News Release, Questar Corporation, April 21, 2010.

[15] 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).

> Rule 253: Integrated Resource Planning
>
> Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.[16]

Proposed IRP Guidelines were also issued with the Wyoming Commission Order. These guidelines were not part of Rule 253.

On March 10, 2009, the Wyoming Commission issued a notice for comments and suggestions on Rule 253 to be filed no later than April 27, 2009. A hearing on the proposed rule was held in Cheyenne, Wyoming on May 12, 2009. Questar Gas was represented at the meeting where the Company's position was articulated that it was generally in agreement with Rule 253. Questar Gas has been required to prepare and file integrated resource plans in Wyoming since 1992 under a separate order.[17] After deliberations, the Commission approved Rule 253 as noticed.

Following the filing of Questar Gas's 2009-2010 IRP in Wyoming in early May of 2009, notice was issued by the Wyoming Commission that the document was available for review with written comments to be filed on or before July 27, 2009. During the last quarter of 2009, Questar Gas responded to both written and verbal questions posed by the Wyoming Commission Advisory Staff about both the 2008 and 2009 IRPs.

On December 15, 2009, at the Wyoming Commission's Open Meeting, Questar Gas representatives participated in a discussion regarding the 2008 and 2009 IRPs. A summary of the general processes and inputs used in these documents was provided. Under a Wyoming Commission Letter Order issued January 7, 2010, the Commission ordered that Questar Gas' IRP for May 1, 2008 to April 30, 2009 be placed in the Commissions files with no further action thereby closing the matter.

## Utah IRP Process

Since 2007, new IRP standards and guidelines have been under consideration in the State of Utah. This process has included numerous discussions between IRP stakeholders in public meetings, the submission of extensive comments, and the issuance of draft standards and guidelines by the Utah Commission on April 3, 2008. Comments on these draft standards were instrumental in developing final standards.

[16] Ibid.

[17] "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.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Standards).[18] On May 4, 2009 Questar Gas filed its 2009 IRP. Because the 2009 IRP Standards were issued just weeks before the 2009 IRP was to be filed, the effective date of the 2009 IRP Standards was made June 1, 2009, after the filing of the 2009 IRP. This IRP report (the 2010 IRP) and future IRP reports will be filed in accordance with the 2009 IRP Standards.

Subsequent to the filing of the 2009 IRP, the Utah Commission issued an action request to the Division of Public Utilities (Division) on May 6, 2009, requesting that comments be provided on the adequacy of the 2009 IRP, both the plan and the process. In the action request, the Utah Commission acknowledged the "many changes and enhancements to the information provided" by Questar Gas in the 2009 IRP. This action request also asked for comments on changes, if any, that would be necessary for the 2009 IRP to meet the requirements of the 2009 IRP Standards, as if they had been in effect, thus testing the sufficiency of information going forward.[19] On May 11, 2009, the Utah Commission issued an order broadening the action request by inviting all interested parties to comment on the same matters.[20]

In response to the action request and the broader request for comments, documents were filed by the Division, the Office of Consumer Services (the Office), and the Company. On March 22, 2010, the Utah Commission issued an order providing guidance on Questar Gas' 2009 IRP and clarifying the requirements of the 2009 IRP Standards (Clarification Order).[21]

In the Clarification Order, the Company was commended for its commitment to the IRP process and timely IRP filings. The Utah Commission also recognized the Company's efforts in its 2008 and 2009 IRP filings thereby enhancing the contents of these IRPs as required by the Utah Commission in its December 14, 2007 order.[22] The Utah Commission found the changes valuable and educational for parties interested in the issues and challenges facing the Company. The Utah Commission also made a number of findings thereby clarifying the 2009 IRP Standards. For a number of other issues, the comments filed by parties were so disparate that the Utah Commission directed the Company to include discussions of these matters in 2010 IRP meetings in an attempt to reach a consensus among all interested parties. Questar Gas welcomes such dialogue with the recognition that integrated resource planning is a continually evolving process. Matters not fully resolved in time for the 2010 IRP filing will be addressed and included as required in future filings.

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[18] "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.
[19] "Action Request – Revised," From: Public Service Commission, Subject: Questar IRP; 09-057-07, May 6, 2009.
[20] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Request For Comments, Docket No. 09-057-07, Issued: May 11, 2009.
[21] "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.
[22] "In the Matter of the Filing of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2007 to April 30, 2008," Report and Order, Docket No. 07-057-01, Issued: December 14, 2007, Pages 17-22.

In early November, 2009, representatives of Questar Gas met with representatives of the Division. Among the matters discussed were factors influencing the decision to shut-in cost-of-service production, particularly during periods of time when the prevailing market prices of natural gas are relatively low. Such shut-ins have occurred in the past and most recently, during the summer and fall of 2009. At the conclusion of the early November meeting, the Division requested a report outlining these factors and containing simplified illustrative analyses for several cost-of-service production sources.

Also, during November and December of 2009, discussions took place between representatives of the Company and various Commissioners and/or Commission Staff serving with both the Utah Public Service Commission and the Public Service Commission of Wyoming where similar topics were discussed. In response to these inquiries and discussions, a report titled “Considerations Affecting Production Shut-Ins” has been prepared. Since this report has direct relevance to the IRP process, it is included as Appendix A to this IRP document and is discussed further in the Cost-of-Service Gas section.

Since the last IRP was filed on May 4, 2009, Questar Gas has held a number of planning and reporting meetings on a variety of IRP-related topics in Utah. Meetings were scheduled to provide gas purchase updates and to discuss hedging/price-stabilization issues.

On February 22, 2010, the Utah Commission held a public meeting to discuss the following topics:

- 2010-2011 IRP Schedule
- Purchased Gas request for proposal (RFP)
- IRP standards utilized this year
- IRP topics to be addressed in the report
- Historical gas price profiles
- Short term gas price expectations
- 2009-2010 hedging summary
- Production shut-in report
- Kern River Rate Case

On February 23, 2010, Questar Gas sent out its annual RFP for natural gas purchases. Responses were due on March 8, 2010.

On April 14, 2010, the Utah Commission held a public meeting to discuss:

- Purchased-gas RFP responses
- Purchased-gas modeling results and recommendations
- Ruby Pipeline update
- Magnum salt cavern storage facility update
- Regional natural gas supply and pricing issues
- Scheduling of IRP technical conferences

An IRP public meeting was held on May 4, 2010 where the following matters were presented and discussed:

- Utah IRP History
- IRP goals and objectives
- IRP demand forecast breakout
- Range of forecasts
- Range of weather forecasts
- IRP meeting notice procedures

A public meeting has been scheduled for June 1, 2010, to discuss this IRP and the final IRP modeling results with Utah regulatory agencies and interested stakeholders.

A technical conference has been scheduled for June 22, 2010, to discuss the modeling and planning provisions associated with the high pressure and intermediate high pressure systems of the Company. Another technical conference has been scheduled for September 21, 2010, to familiarize interested parties with the terms and conditions of the Wexpro Agreement.

During the course of the IRP process Questar Gas has maintained four main goals and objectives:

1. To project future customer requirements;

2. To analyze alternatives for meeting customer requirements from a system capacity and gas-supply source standpoint;

3. To develop a plan that will provide customers with the most reasonable costs over the long term that are consistent with reliable service, stable prices, and are within the constraints of the physical system and available gas supply resources; and

4. 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.

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 dovetails well with the natural seasonal 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 that 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 planning processes engaged in by the Company.

This report has been organized into the following sections: 1) Questar Gas's customer and gas demand forecast; 2) the capabilities and constraints of Questar Gas's distribution system; 3) the local market for natural gas, the purchased gas RFP, associated modeling issues, and price stabilization topics; 4) cost-of-service gas including modeling issues, producer imbalances and future development prospects; 5) gathering, transportation and storage; 6) energy-efficiency programs; 7) the final modeling results; and 8) the general planning guidelines to be used in the implementation of the IRP from June of 2010 through May of 2011.[23]

[23] Throughout this report, "Dth" refers to decatherms, "MDth" refers to thousands of decatherms, "Dth/D" refers to decatherms per day, "MDth/D" refers to thousands of decatherms per day, "Btu" refers to British thermal units, "MMBtu" refers to millions of British thermal units, "cf" refers to cubic feet, "Mcf" refers to thousands of cubic feet, "MMcf" refers to millions of cubic feet, "Bcf" refers to billions of cubic feet, "Tcf" refers to trillions of cubic feet, "Mcf/D" refers to thousands of cubic feet per day, "MMcf/D" refers to millions of cubic feet per day, "psi" refers to pounds per square inch, "psig" refers to pounds per square inch gauge, and "lf" refers to linear feet.

# Customer and Gas Demand Forecast

## System Total Temperature-Adjusted Dth Sales and Throughput Comparison – 2009 IRP and Actual Results for 2009

On a weather normalized basis, Questar Gas' actual natural gas sales during 2009 totaled 106.6 million Dth. This compares with the 107.5 million Dth that were projected in last year's IRP. Average usage per Utah General Service (GS) customer on an annual basis declined to 108.3 Dth (see Exhibit 3.2) compared to last year's base case forecast of 108.6 Dth.

Temperature-adjusted system throughput (Dth sales plus Dth transported) was 164.6 million Dth in 2009 compared to last year's IRP forecast of 166.6 million Dth for the same period.

Customer additions are expected to remain low through 2011 as home construction continues to be dampened by the effects of the recession. Usage per customer within the GS class is expected to continue to decline due to lower household income and a continued trend toward greater efficiency consistent with participation in the ThermWise® and other energy efficiency programs. Non-GS commercial and electric generation consumption is forecasted to decrease initially as the effects of the recession on demand in both sectors continues to materialize. Non-GS industrial consumption is expected to begin a slight increase this year, and all three non-GS sectors are projected to resume a steady increase within two to three years.

## Temperature-Adjusted Dth Sales and Throughput Summary – 2010 IRP

This year's forecast of system sales is anticipated to increase from 106.4 million Dth in 2010 to 119.6 million Dth in 2020. This is a less aggressive increase than last year's forecast because of sharper declines in household income, lower square footage in new homes, and lower non-GS gas demand than was anticipated at the end of 2008.

The new forecast projects 1,141,979 (Exhibit 3.1) system GS customers by the end of 2020, with annual Utah GS usage per customer at 96.6 Dth (Exhibit 3.2) and annual Wyoming GS usage per customer at 110.1 Dth (Exhibit 3.5). The annual usage per Utah residential customer is projected to be 71.7 Dth (Exhibit 3.3) at the end of 2020, and average annual usage per Utah GS commercial customer is expected to be 428.0 Dth by the end of 2020 (Exhibit 3.4). The annual usage per Wyoming residential customer is projected to be at 74.9 Dth at the end of 2020 (Exhibit 3.6), and annual usage per Wyoming commercial customer is projected to be at 396.0 (Exhibit 3.7) Dth for the same period.

System throughput in this year's forecast is expected to increase from 168.0 million Dth in 2010 to 200.2 million Dth in 2020 (Exhibit 3.10). The current forecast includes the anticipated throughput for existing electric generation customers.

## Residential Usage and Customer Additions

### *Utah*

Utah residential GS customer additions in 2009 totaled 8,533, a drop of 4,315 additions from 2008. Expectations of a slow recovery in residential construction result in a forecast of about 10,000 residential customer additions in 2010 and 13,300 in 2011. Expected improvements in economic conditions will accelerate additions in 2012, and by 2014 the rate of annual additions is expected to return to pre-recession levels of over 20,000.

Actual temperature-adjusted residential usage per customer for the twelve months ending December 2009 was 82.3 Dth, a decrease of 1.2 Dth from year-end 2008. Residential usage per customer is expected to decline to 80.9 Dth by the end of 2010 (Exhibit 3.3). Factors contributing to this decline include the moderate growth in new housing, sluggish economic conditions that are projected to continue, household income below historical levels, and the continuation of the relatively high level of participation in residential energy efficiency programs.

Residential usage is projected using a model that incorporates estimates of natural gas appliance saturation by efficiency rating throughout the residential customer base, customer growth projections, and projected changes in economic variables that affect use per customer such as the average residential gas bill and household income. Effects on use per customer from the company's energy efficiency programs based on past and projected participation have also been addressed in the model. Time series projections are also utilized in the forecasting process.

### *Wyoming*

Wyoming residential GS customers increased by 378 in 2009, 132 lower than the prior year's additions. Economic conditions driving the slowdown in housing and residential construction are expected to persist through most of 2010, and the forecast of customer additions reflects this slowdown with about 268 additions expected in 2010 and 345 additions in 2011. Expectations of a gradual economic recovery will drive customer additions up to 400 by the end of 2012.

Wyoming residential annual usage per customer was 84.7 Dth at the end of 2009 (Exhibit 3.6). As in Utah, modest growth, tempered increase in household income, and a general trend toward greater appliance efficiency accelerated by participation in the energy efficiency programs is expected to drive an overall decline in usage per customer through the forecasted period.

## Small Commercial Usage and Customer Additions

### *Utah*

The projection of usage per commercial GS customer and customer additions is primarily driven by residential customer growth and class historical trends. Temperature-adjusted Utah GS commercial usage per customer for the twelve months ended December 2009 was 454.7 Dth. This year's forecast reflects a continuation of a general downward trend with average usage projected at 451.0 at the end of 2010 and 449.6 at the end of 2011.

Utah GS commercial customer additions are expected to change in direct proportion to the changes in Utah GS residential customer additions. Historically, the relationship of commercial customers to residential customers has remained stable. As we add residential customers, commercial customers are added to provide services to them. It is anticipated that approximately 569 customers will be added in 2010. The rate of annual additions will follow residential customer additions and gradually increase to 1,500 additions and above per year after 2013.

### *Wyoming*

Usage for commercial GS customers in Wyoming for the twelve months ending December 2009 was 430.5 Dth. This is based on usage that has been normalized using current normal heating degree days. Temperature-adjusted usage per customer for year-end 2010 is forecasted to be 427.4 Dth and is projected to continue a general decline through the forecast period.

During 2009, 43 commercial GS customers were added – down from 63 additions from the prior year. This reflects the general slowdown in commercial construction. The forecast projects a gradual increase toward 50 annual additions after 2011 as economic conditions improve. As with Utah, these projections are driven primarily by residential customer increases.

## Large Commercial, Industrial and Electric Generation Gas Demand

As shown in Exhibit 3.8 annual gas demand among large commercial customers begins the forecasted period with a decline but resumes an increasing trend as the economic recovery gains momentum. Demand is expected to grow from 11.3 million Dth in 2010 to 12.3 million Dth in 2020.

Annual demand among industrial and electric generation customers is projected to grow steadily throughout the forecast period. Industrial growth is driven by eventual regional economic improvements in manufacturing and the ramp-up of a large manufacturing plant in 2010. Industrial demand is expected to grow from 29.6 million Dth in 2010 to 40.91 million by the end of 2020. Electric generation demand is projected to grow from 29.8 million Dth in 2010 to 37.1 million Dth in 2020. Although electric generation demand is expected to decline through 2010 and 2011 due to lingering recessionary effects, this is offset by an increase in activity in 2010 attributable to a large generation plant that experienced an unplanned shutdown for maintenance and repair during 2009. The Company is aware that a large natural gas power plant has the potential of coming on-line in 2014. The usage and peak requirements for that plant have not been included in this IRP. The Company is working with the prospective customer and will include this plant in future plans if the likelihood of its construction becomes more certain.

## Firm Customer Design-Day Gas Demand

As in prior years, the design-day demand projections are based on a one-in-twenty year (five occurrences in 100 years) weather event. More specifically, the design-day firm customer gas demand projection is based on a theoretical day where the mean temperature is –5 degrees Fahrenheit at the Salt Lake Airport weather station and correspondingly design-day temperatures are seen coincidentally across the Company's service territory.

Wind speed, average December, January and February Utah GS sales, and prior days' temperatures and sales are factors that have been statistically significant in predicting daily gas send-out during the winter heating season. The design-day demand projections distinguish between firm sales customers and firm transportation customers for gas supply and system capacity planning purposes.

As shown in Exhibit 3.9, the firm customer design-day gas supply projection for the 2010-2011 heating season is 1.272 million Dth. The design-day projection grows to a level of 1.391 million Dth in the winter of 2019-2020.

## Periods of Interruption

Under peak-day conditions it is estimated that potentially 125,000 Dth, system wide, could be interrupted, 117,000 Dth of interruptible transportation and 8,000 Dth of interruptible sales.

The Utah Questar Gas Tariff states, "At times there may be a need for interruption on an isolated portion of the Company's system." In 2009 the Company performed an analysis to determine if isolation of certain system segments could alleviate pressure concerns while limiting the impact on customers that are neither affected by nor can affect pressures on that segment.

The Company is working to improve its interruption processes to ensure the reliability of service while also limiting the impact upon interruptible customers.

## Source Data

Where available, the Company has obtained economic and demographic information from state and local sources such as the University of Utah (Bureau of Economic and Business Research) and the Utah Governor's Office of Planning and Budget. Where local information was not available, it was obtained from nationally recognized economic forecasting organizations such as IHS Global Insight.

## The Utah and Wyoming Economic Outlook

Below is a review of recent history and the current economic outlook:

**Summary of Utah Economy**
**Annual Percentage Change**

| Description | 2004 – 2009 | 2009 - 2010 | 2009 - 2014 | 2009 – 2017 |
|---|---|---|---|---|
| Population | 2.7% | 2.1% | 2.1% | 2.0% |
| Personal Income | 5.6% | 2.9% | 5.0% | 5.1% |
| Construction Employment | -0.4% | -9.4% | 1.2% | 1.6% |
| Manufacturing Employment | -0.4% | -5.3% | 0.2% | 0.2% |
| Non-Manufacturing Employment | 1.8% | -0.3% | 1.6% | 1.6% |
| Total Employment | 1.5% | -0.8% | 1.5% | 1.5% |
| Average Single-Family & Multi-Family Dwelling units | 19,204 | 9,438 | 18,058 | 20,892 |

Source: Based on Spring, 2010 long-term forecasts by IHS Global Insights.

**Summary of Wyoming Economy**
**Annual Percentage Change**

| Description | 2004 – 2009 | 2009 - 2010 | 2009 - 2014 | 2009 – 2017 |
|---|---|---|---|---|
| Population | 1.6% | 1.8% | 1.0% | 0.8% |
| Personal Income | 6.4% | 2.0% | 4.6% | 4.9% |
| Construction Employment | 4.5% | -11.1% | 1.0% | 1.1% |
| Manufacturing Employment | -0.6% | 1.7% | 1.6% | 1.0% |
| Non-Manufacturing Employment | 2.4% | -2.2% | 0.6% | 0.7% |
| Total Employment | 2.3% | -2.1% | 0.6% | 0.7% |

Source: Based on Spring, 2010 long-term forecasts by IHS Global Insights.

## The U.S. Economic Outlook

Below is a review of recent history and the consensus economic outlook:

**U.S. MACROECONOMIC FORECAST**
**Source: HIS GLOBAL INSIGHT Review of the U.S. Economy – April, 2010**

| | | | | | | Forecast | |
|---|---|---|---|---|---|---|---|
| | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Real Gross Domestic Product 1/ | 3.6 | 3.1 | 2.7 | 2.1 | 0.4 | -2.4 | 3.0 |
| GDP Price Index - Chain Wt. 1/ | 2.8 | 3.3 | 3.3 | 2.9 | 2.1 | 1.2 | 1.0 |
| CPIU 1/ | 2.7 | 3.4 | 3.2 | 2.9 | 3.8 | -.03 | 1.9 |
| Real Disposable Income 1/ | 3.4 | 1.3 | 4.0 | 2.2 | 0.5 | 0.9 | 1.4 |
| Pre-tax Profits 1/ | 27.5 | 16.8 | 10.5 | -4.1 | -11.8 | -3.8 | 15.6 |
| Unemployment Rate 3/ | 5.5 | 5.1 | 4.6 | 4.6 | 5.8 | 9.3 | 9.6 |
| Housing Starts 4/ | 2.0 | 2.1 | 1.8 | 1.3 | 0.9 | 0.6 | 0.7 |
| 3-month Treasury Bills 3/ | 1.4 | 3.1 | 4.7 | 4.4 | 1.4 | 0.2 | 0.4 |
| 30-Year Fixed Mortgage Rate 3/ | 5.8 | 5.9 | 6.4 | 6.3 | 6.0 | 5.0 | 5.2 |
| Trade Balance 2/ | -631 | -749 | -804 | -727 | -706 | -420 | -526 |
| Vehicle Sales – Total 4/ | 16.9 | 17.0 | 16.5 | 16.1 | 13.2 | 10.4 | 11.8 |
| Real Non-Res Fixed Investment 1/ | 6.0 | 6.7 | 7.9 | 6.2 | 1.6 | -17.8 | 1.7 |
| Industrial Production 1/ | 2.5 | 3.3 | 2.3 | 1.5 | -2.2 | -9.7 | 5.1 |

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

**Long-term U.S. Economic Outlook**
Source: **GLOBAL INSIGHT** Review of the U.S. Economy – April, 2010

| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|---|---|
| Real Gross Domestic Product 1/ | 3.0 | 3.3 | 2.7 | 2.8 | 2.7 | 2.7 | 2.5 |
| GDP Price Index - Chain Wt. 1/ | 1.9 | 2.0 | 2.0 | 2.0 | 1.9 | 1.9 | 1.9 |
| CPIU 1/ | 2.0 | 2.3 | 2.2 | 2.1 | 2.1 | 2.1 | 2.0 |
| Real Disposable Income 1/ | 1.9 | 2.1 | 1.7 | 4.2 | 3.5 | 3.4 | 2.9 |
| Pre-tax Profits 1/ | 7.8 | 5.3 | 3.8 | 0.3 | 1.3 | 2.1 | 2.0 |
| Unemployment Rate 3/ | 9.0 | 8.1 | 7.4 | 6.9 | 6.5 | 6.2 | 5.8 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Housing Starts 4/ | 1.2 | 1.6 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 |
| 3-month Treasury Bills 3/ | 2.1 | 3.4 | 3.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| 30-Year Fixed Mortgage Rate 3/ | 5.6 | 6.1 | 6.3 | 7.2 | 7.2 | 7.2 | 7.2 |
| Trade Balance 2/ | -578 | -641 | -604 | -608 | -618 | -631 | -593 |
| Vehicle Sales - Total 4/ | 13.8 | 15.6 | 16.5 | 17.0 | 17.4 | 17.4 | 17.1 |
| Real Non-Res Fixed Investment 1/ | 7.6 | 11.9 | 9.2 | 5.8 | 3.9 | 3.4 | 3.7 |
| Industrial Production 1/ | 4.7 | 3.6 | 3.4 | 3.6 | 2.8 | 2.9 | 2.7 |

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

**Alternatives to Natural Gas**

Questar Gas customers have alternatives to using natural gas for virtually every application. Some energy applications are dominated by another fuel (cooking, clothes drying) while others are dominated by natural gas (space and water heat). A material shift in customer preference would affect future demand and load profiles.

*Solar*

It is not anticipated that solar space or water heat will have a significant impact in the Company's service territory. The large investment required does not allow for an attractive payback, thereby limiting the potential.

*Air-Source Heat Pumps*

Air-source heat pumps are becoming more competitive. There are significant risks to the Company and its customers if these devices proliferate. The loads placed on the system will be substantially lower than a similar customer with conventional natural gas space and water heat, yet the investment to serve the customer will not be any lower. Most air-source heat pumps require a back-up heat source for those times when the outside air temperature is too low for the heat pump to meet the load. Since natural gas is the most economic heat source it is anticipated that natural gas will be selected by most consumers for the back-up role.

The first risk arises because these customers will increase the peak demand on the system. This risk is especially troubling because it will be very difficult to estimate the additional peak requirement caused by these customers. There are only a handful of days each winter when temperatures are too low for these units to operate efficiently. As a result the potential for peak load attributable to these units will not be evident in the load data used to predict peak requirements.

The second risk is more significant for other customers. The cost to serve customers with air-source heat pumps is essentially identical to the cost to serve a similarly situated traditional customer. With the current rate design, the Company will only recover a portion of the cost to serve from air-source heat pump customers. The direct effect of this under collection will be that other customers will be required to make up the difference. This may lead to a material cross subsidy between traditional customers and the air-source heat pump customers. The Company is monitoring the penetration of air-source heat pumps.

*Ground-Source Heat Pumps*

While ground-source heat pumps may have similar risks to the air-source heat pumps, the potential for significant penetration is very low. There is a large capital investment required for these installations. Commercial customers with adequate acreage have begun adopting this technology. The decision to install ground-source heat pump technology is often driven by considerations beyond pure economics.

## Gas Lost and Unaccounted For

The Company use, lost and unaccounted for calculation is based on a three-year rolling average, year-ending June 30. The calculation is performed by dividing Company use (accounts 810 and 812), loss from tearouts and unaccounted for gas by total system receipts as recorded by gas control.

The most recent calculation for year-end June 30, 2009 results in a system Company use, lost and unaccounted for percentage of 2.030%.

The current calculation for the most recent 3 years is included in the following table.

**QGC Estimated Company Use and Lost-and-Unaccounted-For-Gas Calculation**
**Three Year Rolling Average**

| Year | QGC Customer Sales | QGC Customer Transport. | Total Receipts | QGC Sales & Transportation | QGC Use Acct. 810&812 | QGC Loss Due To Tearouts | QGC Loss & Unaccounted For Gas | Total Sales, Transport, Company Usage and L&U |
|---|---|---|---|---|---|---|---|---|
| 2006-2007 | 109,953,006 | 40,592,318 | 150,545,324 | 145,375,914 | 252,128 | 52,683 | 4,864,599 | 150,545,324 |
| 2007-2008 | 118,602,454 | 62,143,455 | 180,745,909 | 177,520,334 | 247,144 | 38,123 | 2,940,308 | 180,745,909 |
| 2008-2009 | 108,824,916 | 62,770,745 | 171,595,661 | 169,781,680 | 271,987 | 24,889 | 1,517,762 | 171,596,318 |
| Total | 337,380,376 | 165,506,518 | 502,886,894 | 492,677,928 | 771,259 | 115,695 | 9,322,669 | 502,887,551 |

Lost-&-Unaccounted-For-Gas % 1.854%    Company Use and Lost-&-Unaccounted-For-Gas % 2.030%

It should be noted that sales and transportation volumes forecasted in this IRP do not include the new temperature and elevation adjustments as approved in Docket No. 09-057-16. In the 2011 IRP, these adjustments will be included and will affect the unaccounted for portion of the Company use, lost and unaccounted for calculation.

Questar Gas has implemented the following activities to minimize lost and unaccounted for gas by reducing natural gas emission during pipeline construction and operations activities:

- **Maintenance work on high pressure feeder lines.** When scheduled maintenance work requires the feeder line to be blown down, the line is allowed to feed down to the lowest possible pressure before being completely blown down. This minimizes the amount of gas that is blown down to the atmosphere. The pressure is recorded to allow the amount of gas that is blown down to be calculated.
- **Feeder line replacement project.** The feeder line replacement project replaces aging infrastructure to ensure the safety and reliability of the distribution system.
- **Hot tapping.** The Company utilizes hot taps when making branch connections on the feeder line system to eliminate the need to blow down sections of the feeder line. The hot tapping process allows this work to be completed while the line remains in service.
- **Excess flow valves.** The Company installs an excess flow valve on any new or replaced service line serving a single-family residence (when commercially available). The excess flow valve is designed to limit the amount of gas lost in the event of the service line being severed (i.e. third party damage).
- **Leak survey and repair.** The Company regularly conducts leak surveys and performs system maintenance as required. Additional leak surveys are conducted in high consequence areas or areas with aging infrastructure.
- **Response time to leak calls.** The Company continues evaluating ways to reduce response time to gas leak calls through efficiencies in how employees are dispatched to these gas leaks. Plans have been approved to implement a GPS system to allow dispatchers the ability to dispatch personnel based on their geographic location with respect to the leak.
- **Leak detection equipment.** The Company utilizes advanced technologies for locating and identifying leaks. Examples include the RMLD (remote methane leak detection) and the Rover (gas detector).
- **Research and Development.** The Company participated in a Gas Technology Institute study to identify factors for fugitive emissions from various types of facilities.

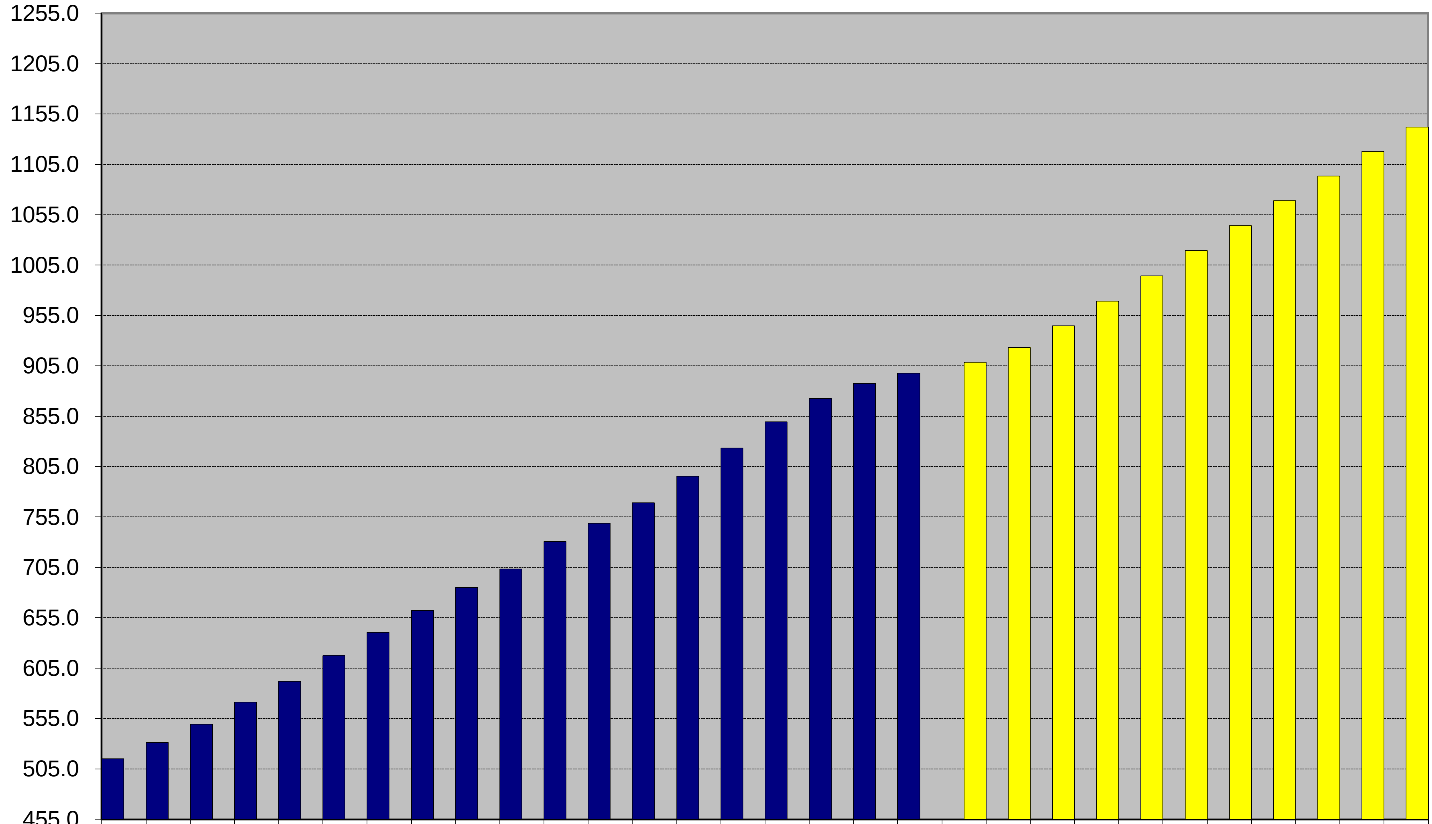
### Forecast Exhibits

The following charts summarize the 10-year customer and gas demand forecast. All charts contain temperature-adjusted data.

Exhibit 3.1

# SYSTEM GS YEAR-END CUSTOMERS

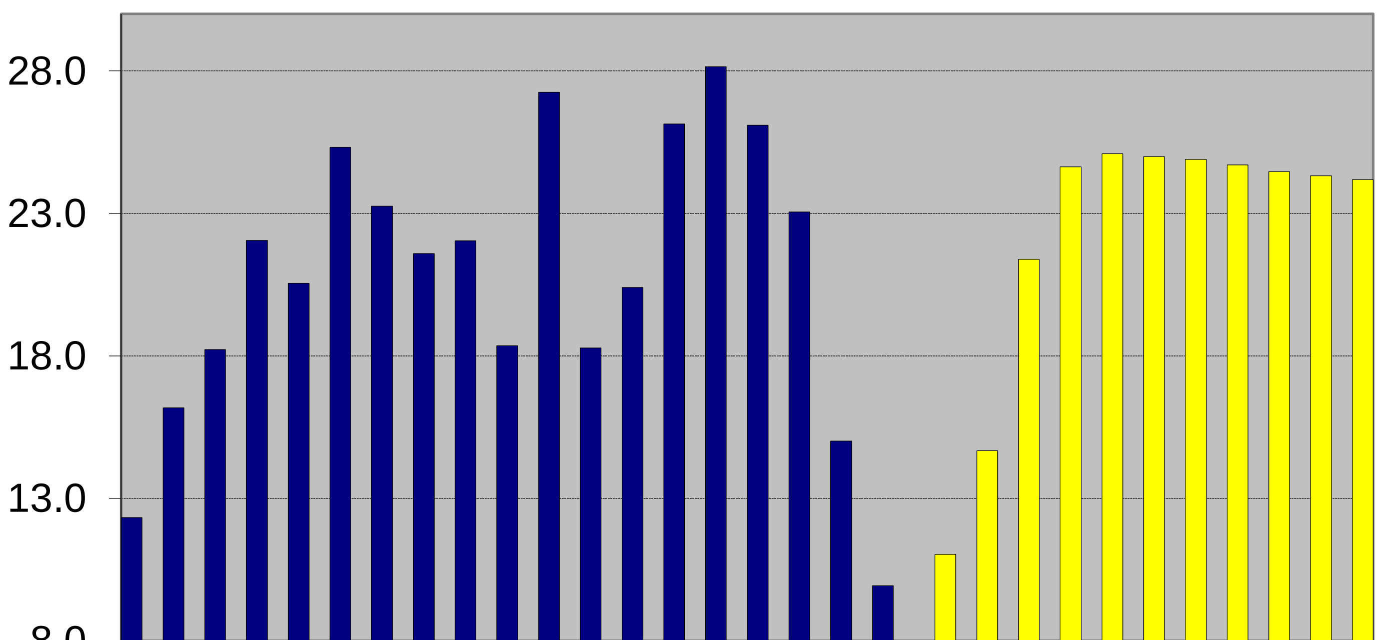
Customers (Thousands)




| | 91 | 92 | 93 | 94 | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 514.9 | 531.1 | 549.3 | 571.4 | 591.9 | 617.2 | 640.5 | 662.1 | 684.9 | 703.3 | 730.6 | 748.8 | 769.2 | 795.4 | 823.5 | 849.6 | 872.7 | 887.7 | 897.6 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | | | | | 908.6 | 923.3 | 944.7 | 969.3 | 994.4 | 1019.4 | 1044.3 | 1069.0 | 1093.5 | 1117.8 | 1142.0 |

# SYSTEM GS YEAR-END ADDITIONS

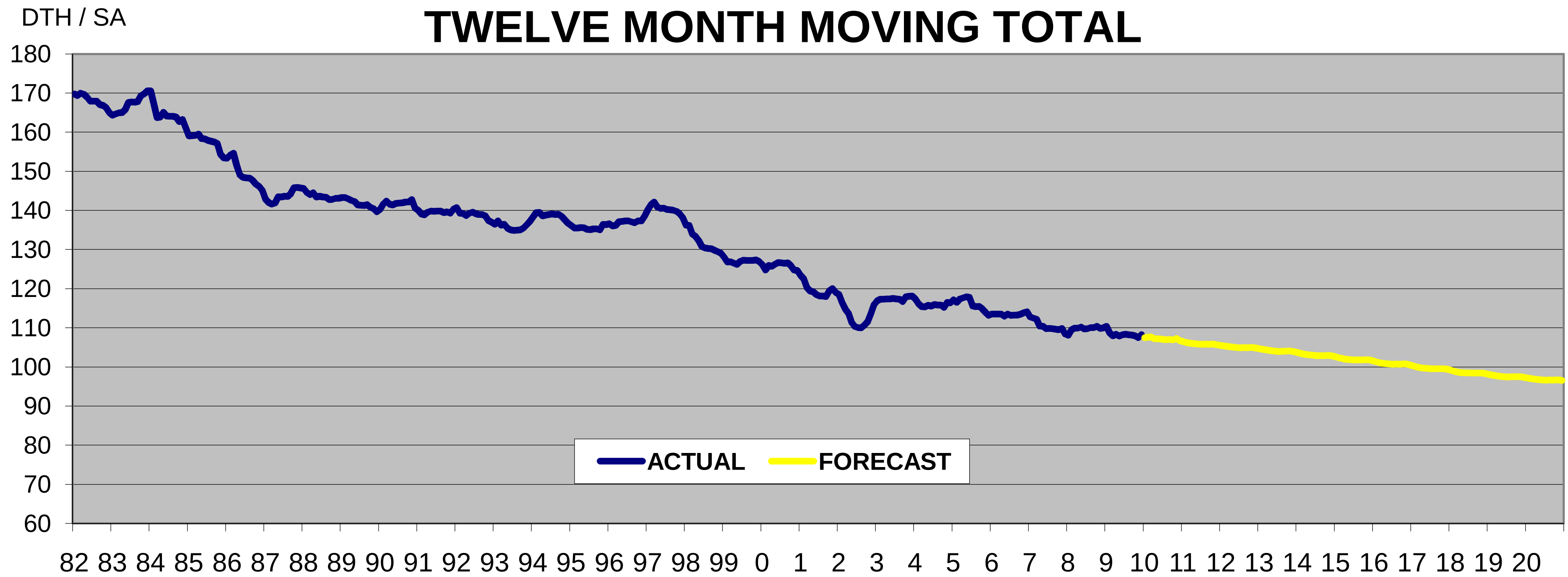
Customers (Thousands)

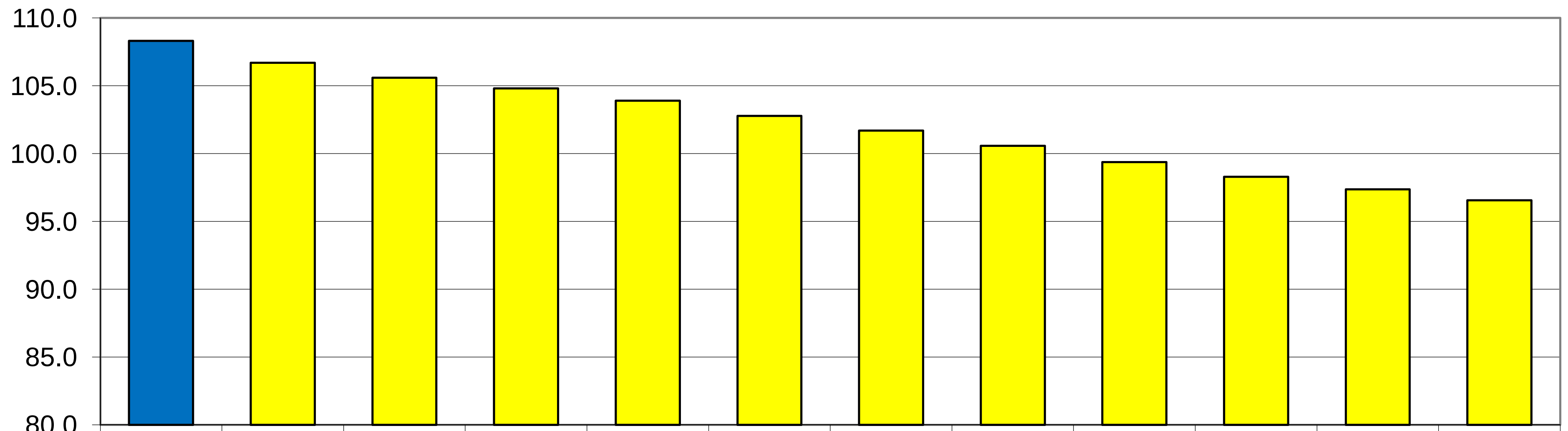



| | 91 | 92 | 93 | 94 | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 12.3 | 16.2 | 18.2 | 22.0 | 20.5 | 25.3 | 23.3 | 21.6 | 22.0 | 18.4 | 27.3 | 18.3 | 20.4 | 26.1 | 28.1 | 26.1 | 23.1 | 15.0 | 9.9 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | | | | | 11.0 | 14.7 | 21.4 | 24.6 | 25.1 | 25.0 | 24.9 | 24.7 | 24.5 | 24.3 | 24.2 |

# UTAH GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



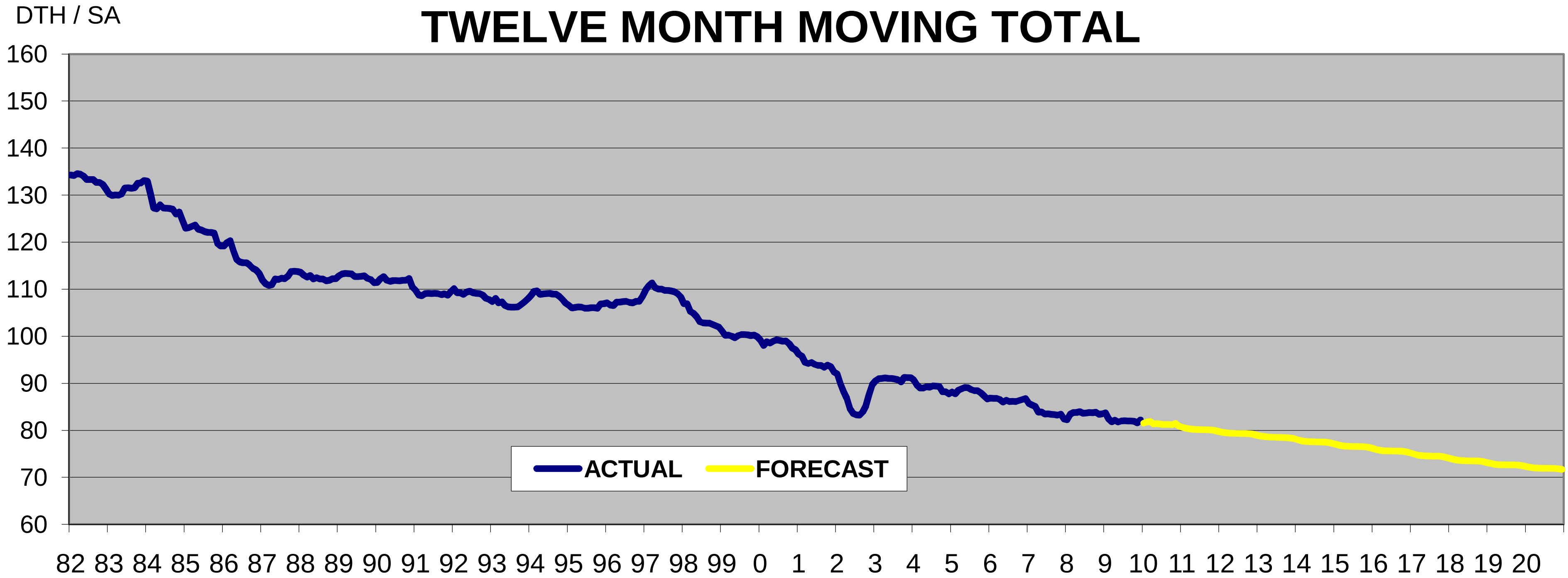



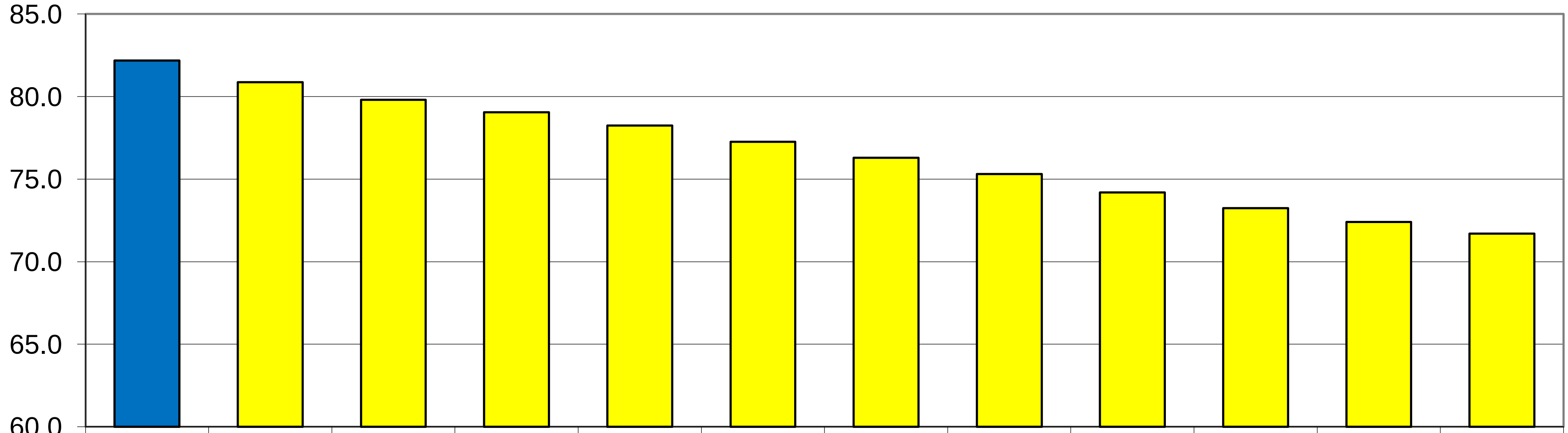

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 108.3 | 106.7 | 105.6 | 104.8 | 103.9 | 102.8 | 101.7 | 100.6 | 99.4 | 98.3 | 97.4 | 96.6 |

Exhibit 3.2

# UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



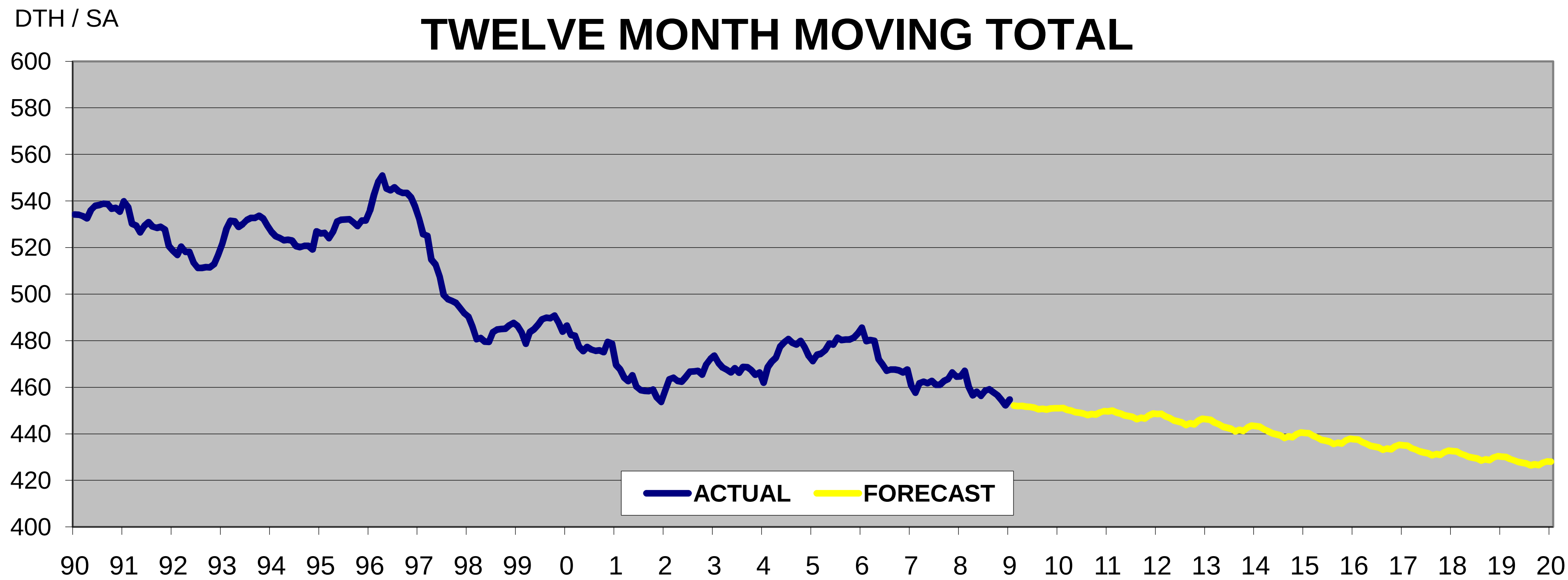



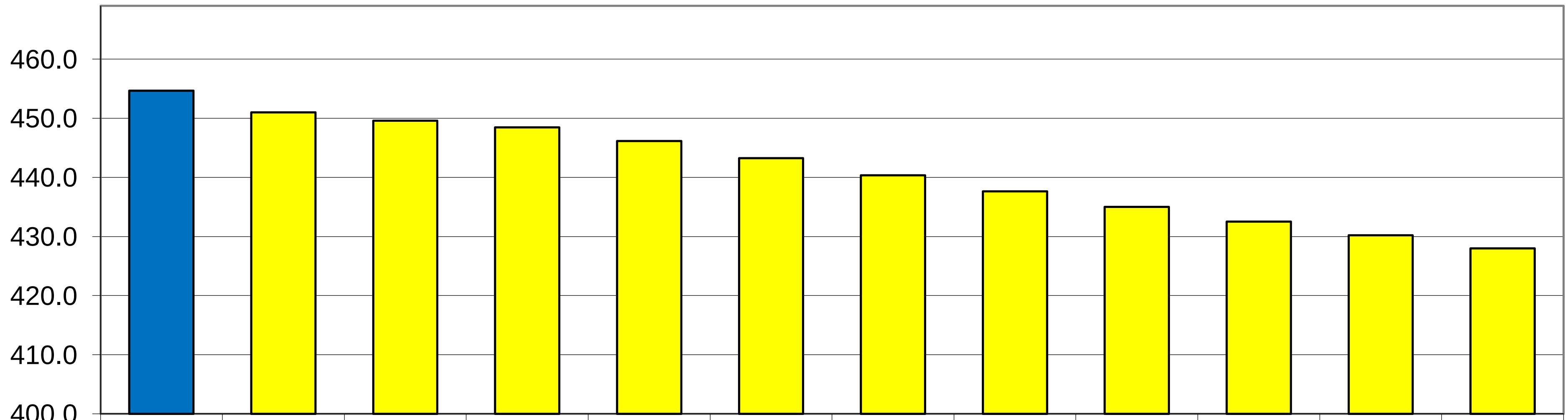

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 82.2 | 80.9 | 79.8 | 79.0 | 78.2 | 77.3 | 76.3 | 75.3 | 74.2 | 73.2 | 72.4 | 71.7 |

Exhibit 3.3

# UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



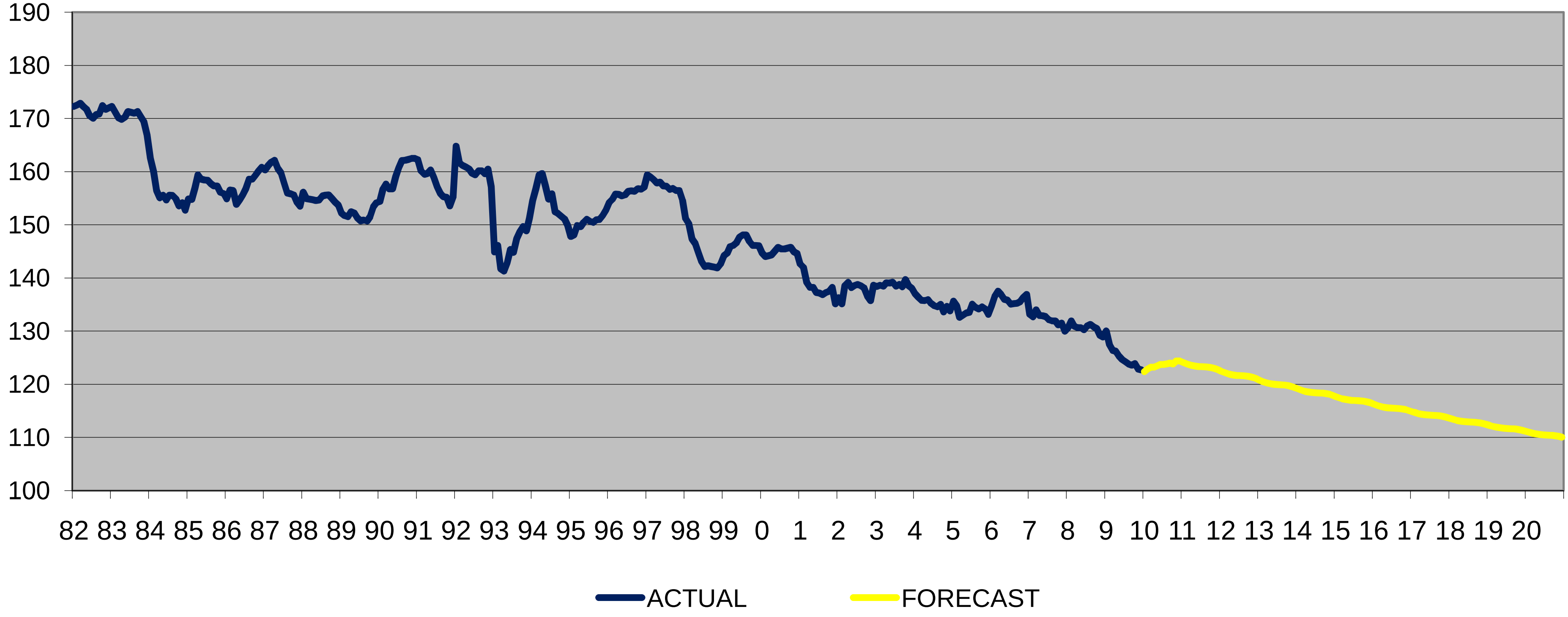



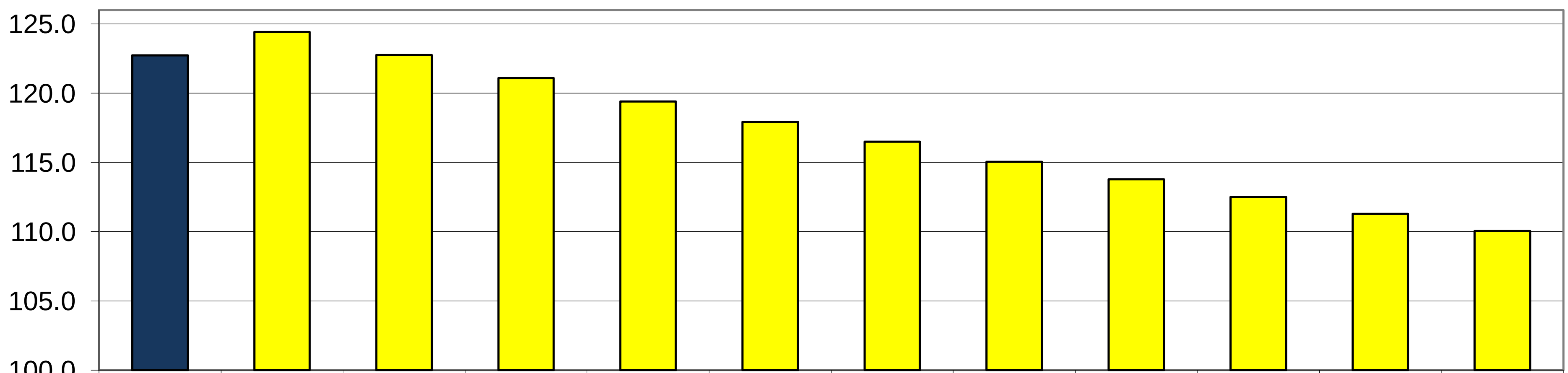

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FORECAST | 454.7 | 451.0 | 449.6 | 448.5 | 446.2 | 443.2 | 440.4 | 437.6 | 435.0 | 432.5 | 430.2 | 428.0 |

Exhibit 3.4

# WYOMING GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



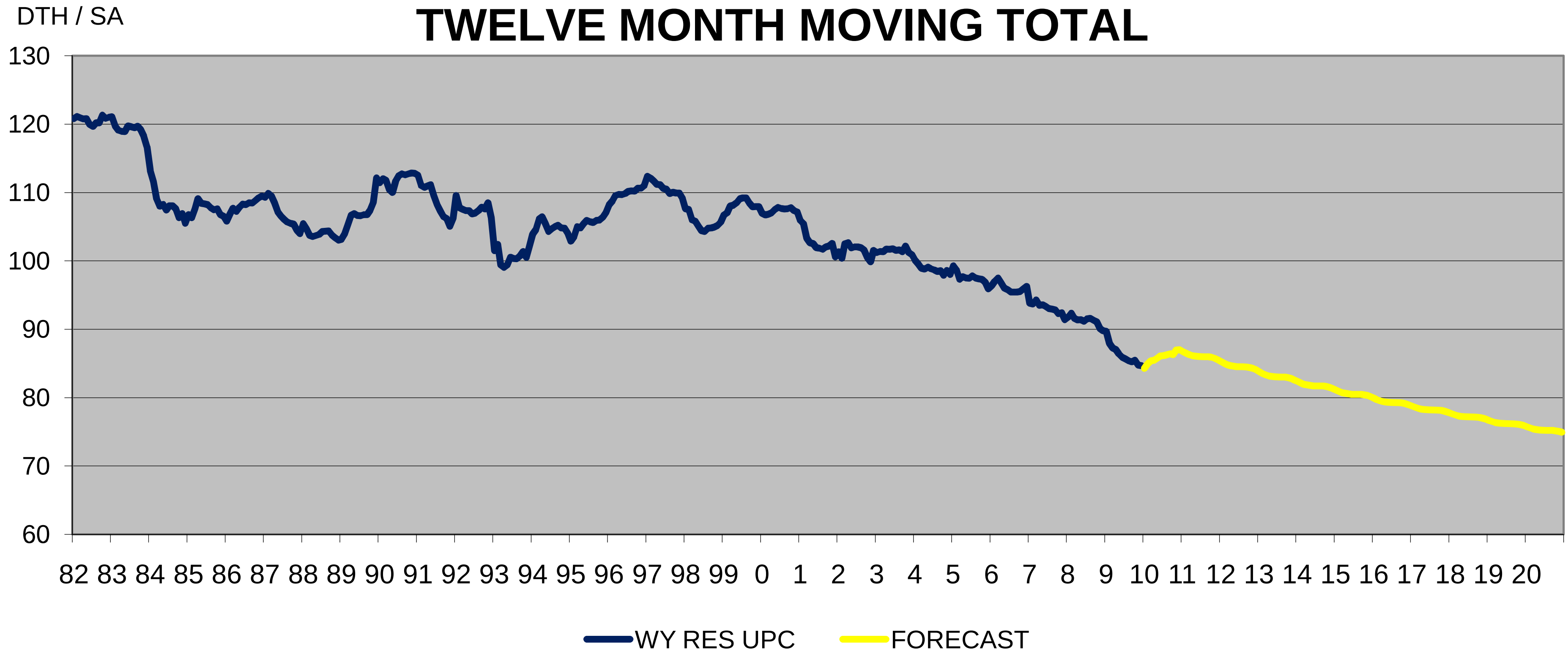



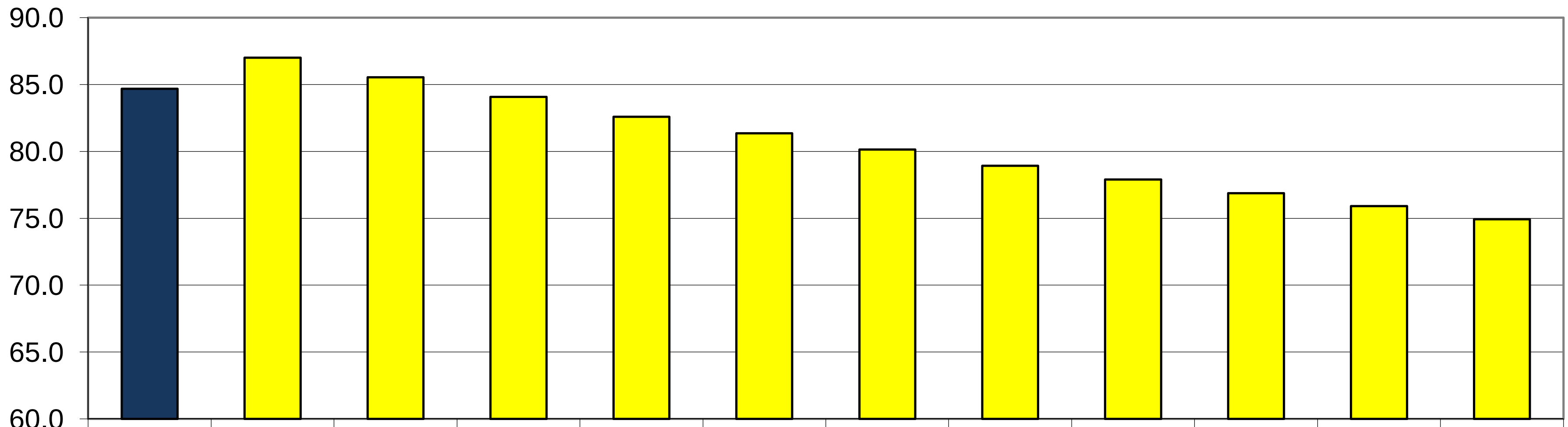

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WY GS | 122.7 | 124.4 | 122.8 | 121.1 | 119.4 | 117.9 | 116.5 | 115.1 | 113.8 | 112.5 | 111.3 | 110.1 |

Exhibit 3.5

# WYOMING GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL



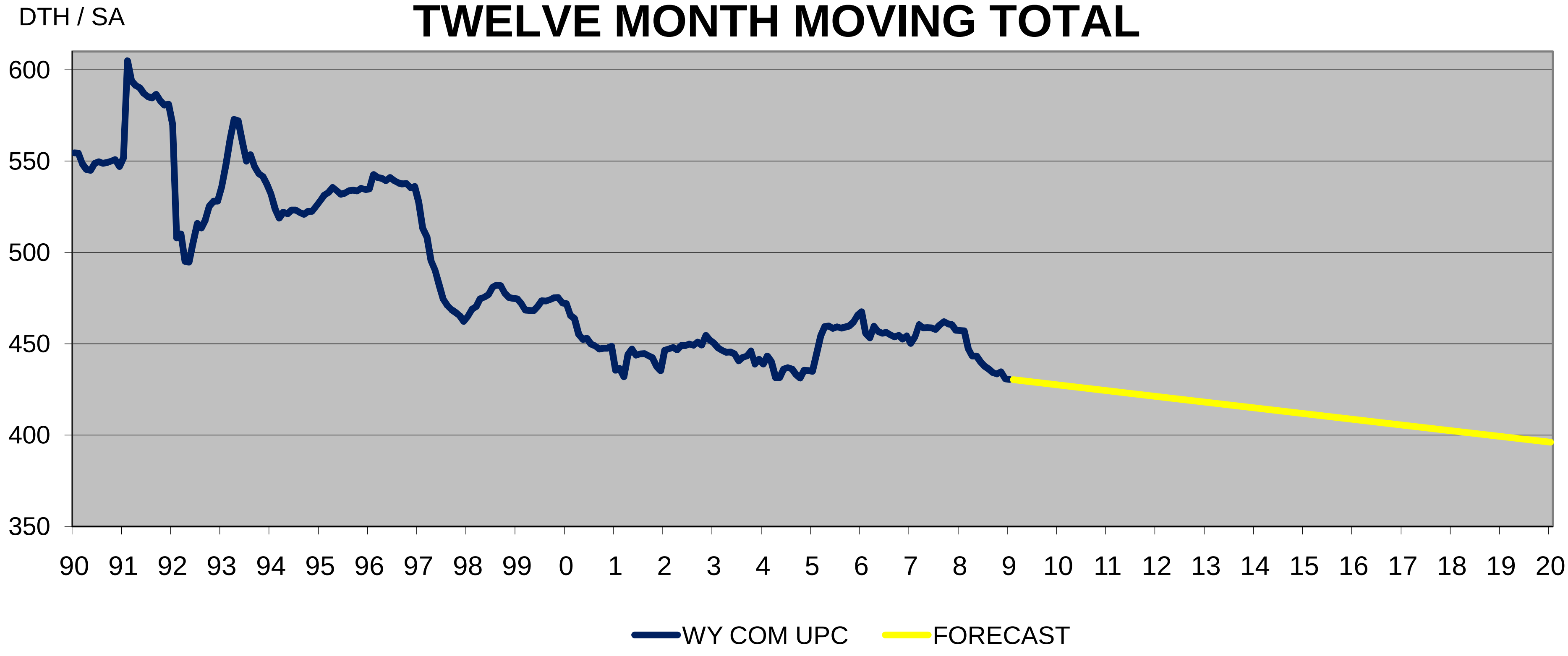



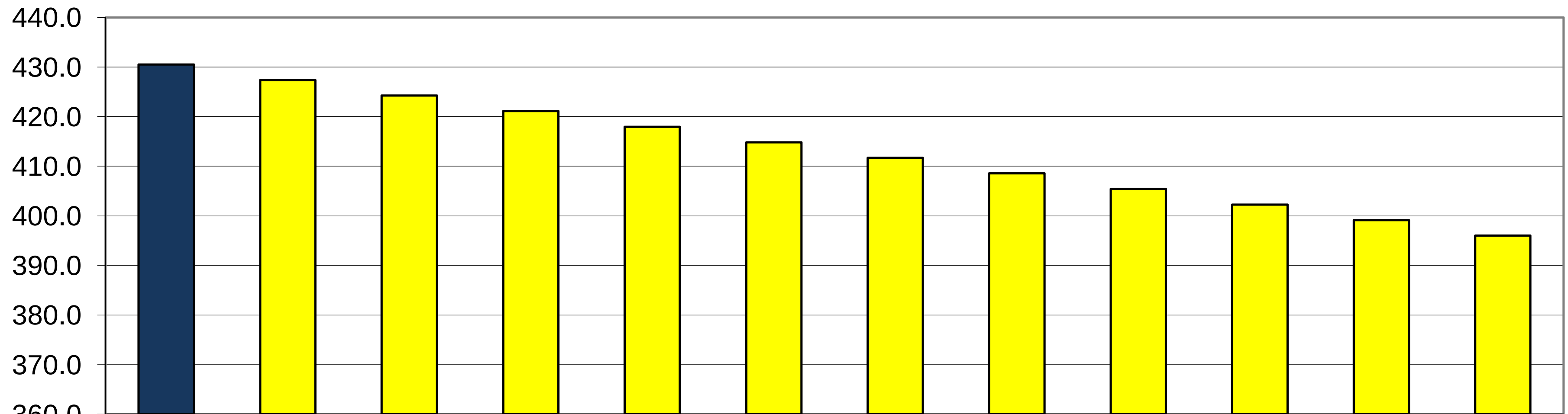

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WY GS RES UPC | 84.7 | 87.0 | 85.5 | 84.1 | 82.6 | 81.4 | 80.1 | 78.9 | 77.9 | 76.9 | 75.9 | 74.9 |

Exibit 3.6

# WYOMING GS TEMP ADJ USAGE PER CUSTOMER

## TWELVE MONTH MOVING TOTAL




| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WY GS COM UPC | 430.5 | 427.4 | 424.2 | 421.1 | 418.0 | 414.8 | 411.7 | 408.6 | 405.4 | 402.3 | 399.2 | 396.0 |

Exhibit 3.7

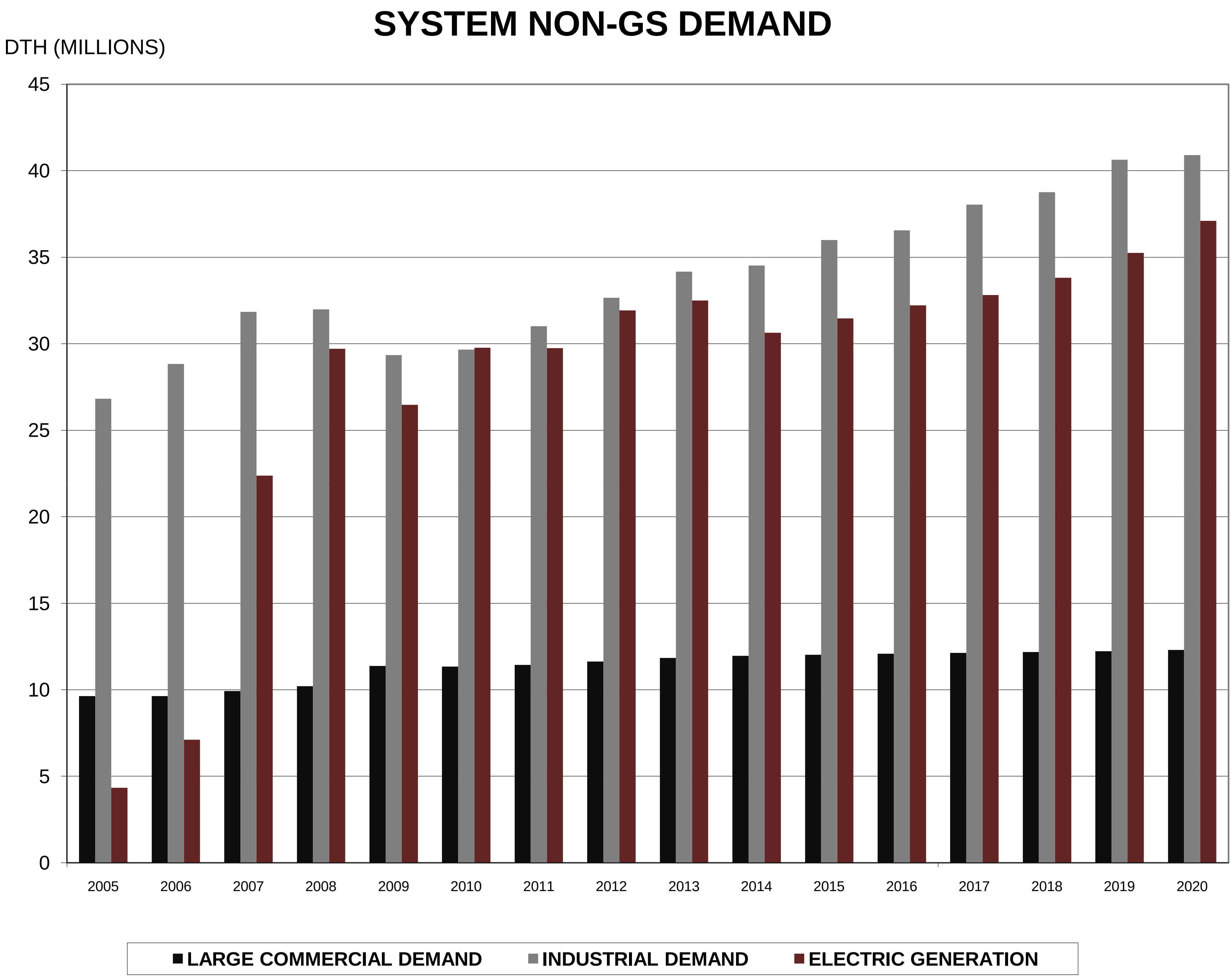
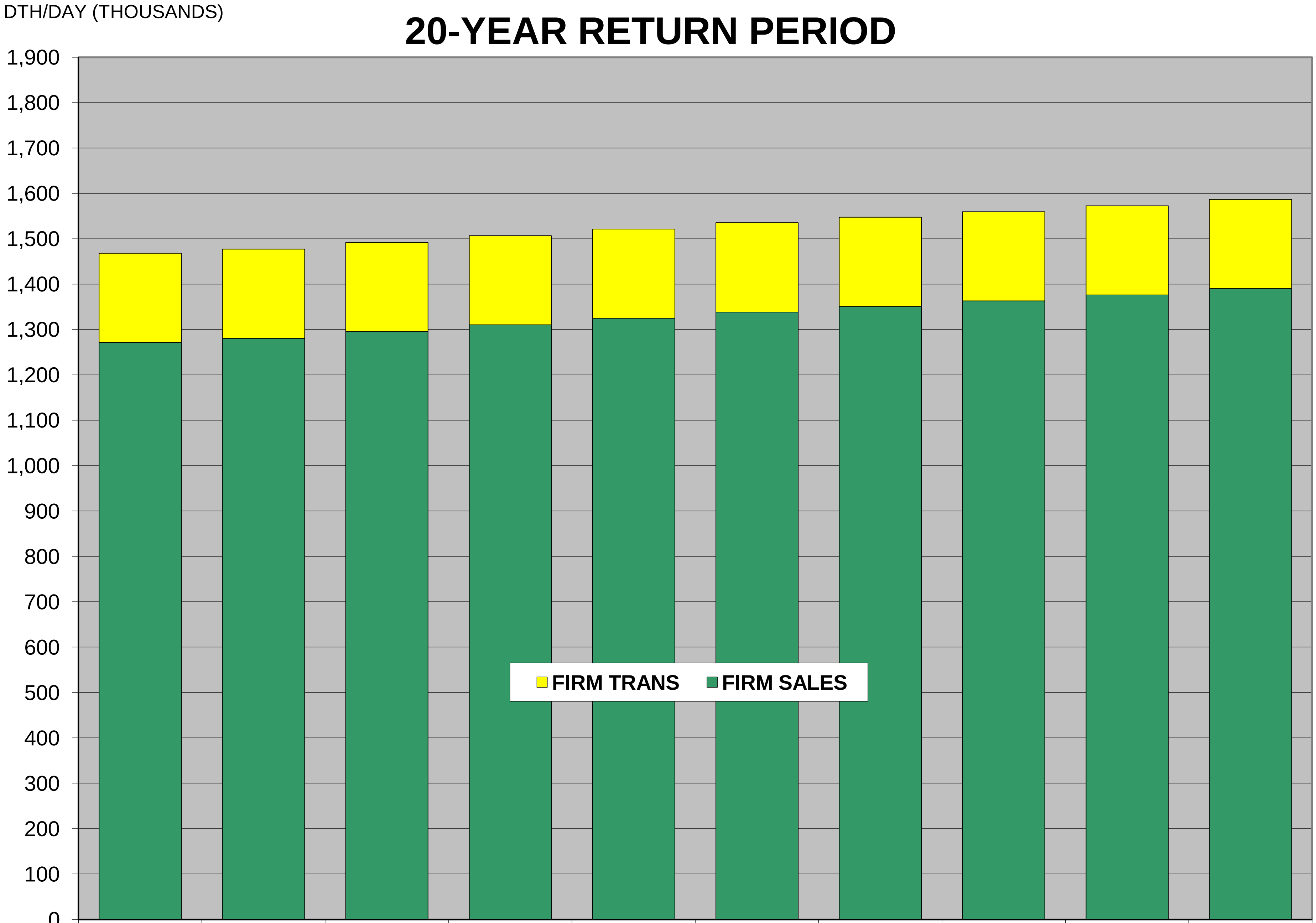

SYSTEM NON-GS DEMAND
DTH (MILLIONS)
45
40
35
30
25
20
15
10
5
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
LARGE COMMERCIAL DEMAND
INDUSTRIAL DEMAND
ELECTRIC GENERATION

Exhibit 3.8

# FIRM PEAK DEMAND FORECAST

## 20-YEAR RETURN PERIOD



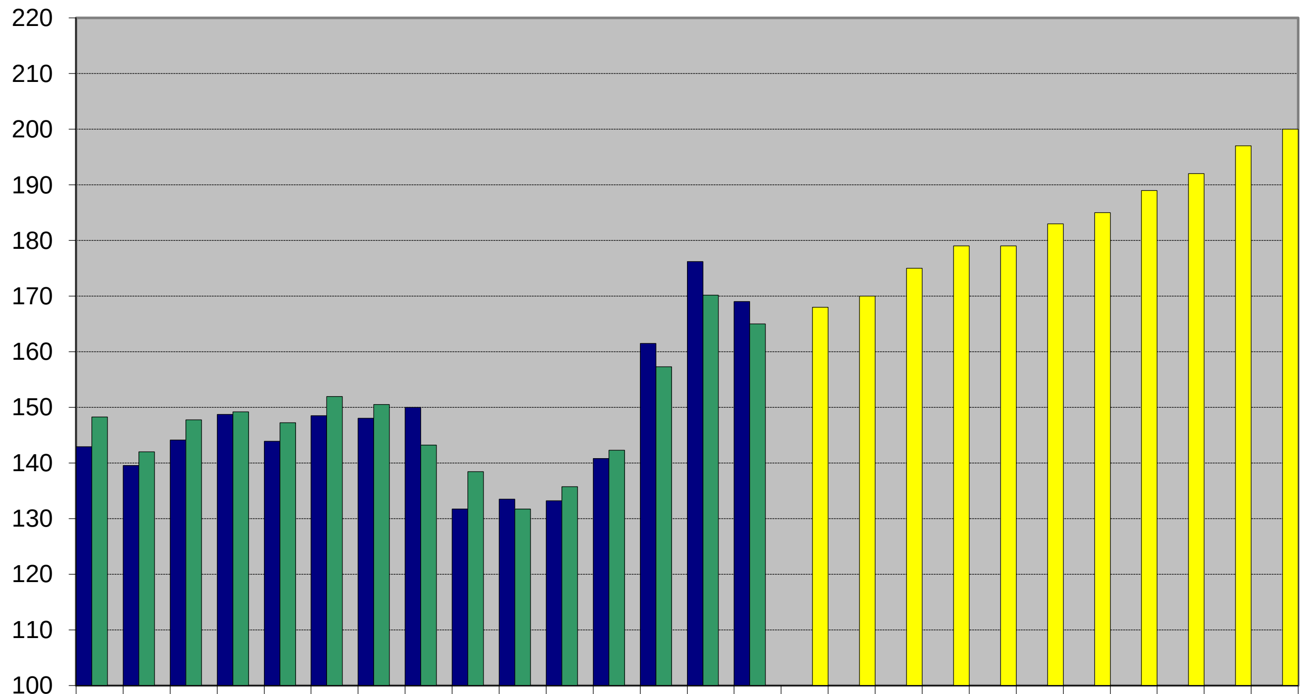

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| FIRM TRANS | 197 | 197 | 197 | 197 | 197 | 197 | 197 | 197 | 197 | 197 |
| FIRM SALES | 1272 | 1281 | 1296 | 1310 | 1325 | 1339 | 1351 | 1363 | 1377 | 1391 |

Exhibit 3.9

Exhibit 3.10

# SYSTEM DTH THROUGHPUT

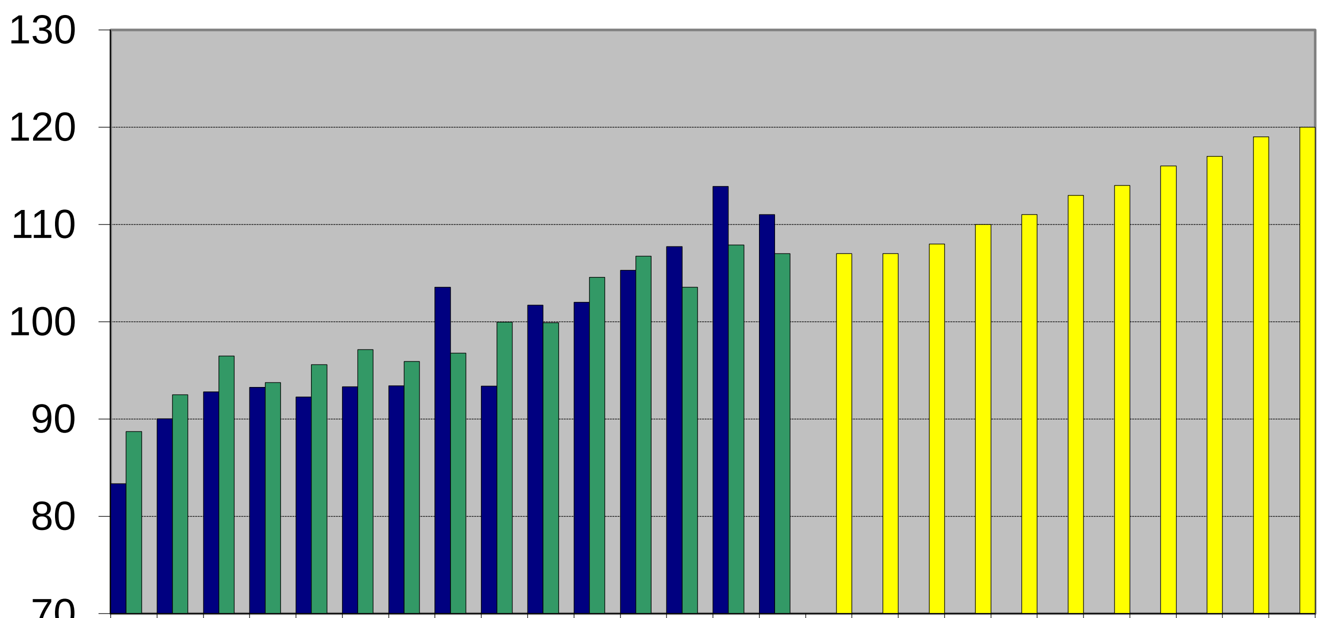
Dth (Millions)



| | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 143 | 140 | 144 | 149 | 144 | 149 | 148 | 150 | 132 | 134 | 133 | 141 | 162 | 176 | 169 | | | | | | | | | | | |
| TEMP ADJUSTED | 148 | 142 | 148 | 149 | 147 | 152 | 151 | 143 | 138 | 132 | 136 | 142 | 157 | 170 | 165 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | 168 | 170 | 175 | 179 | 179 | 183 | 185 | 189 | 192 | 197 | 200 |

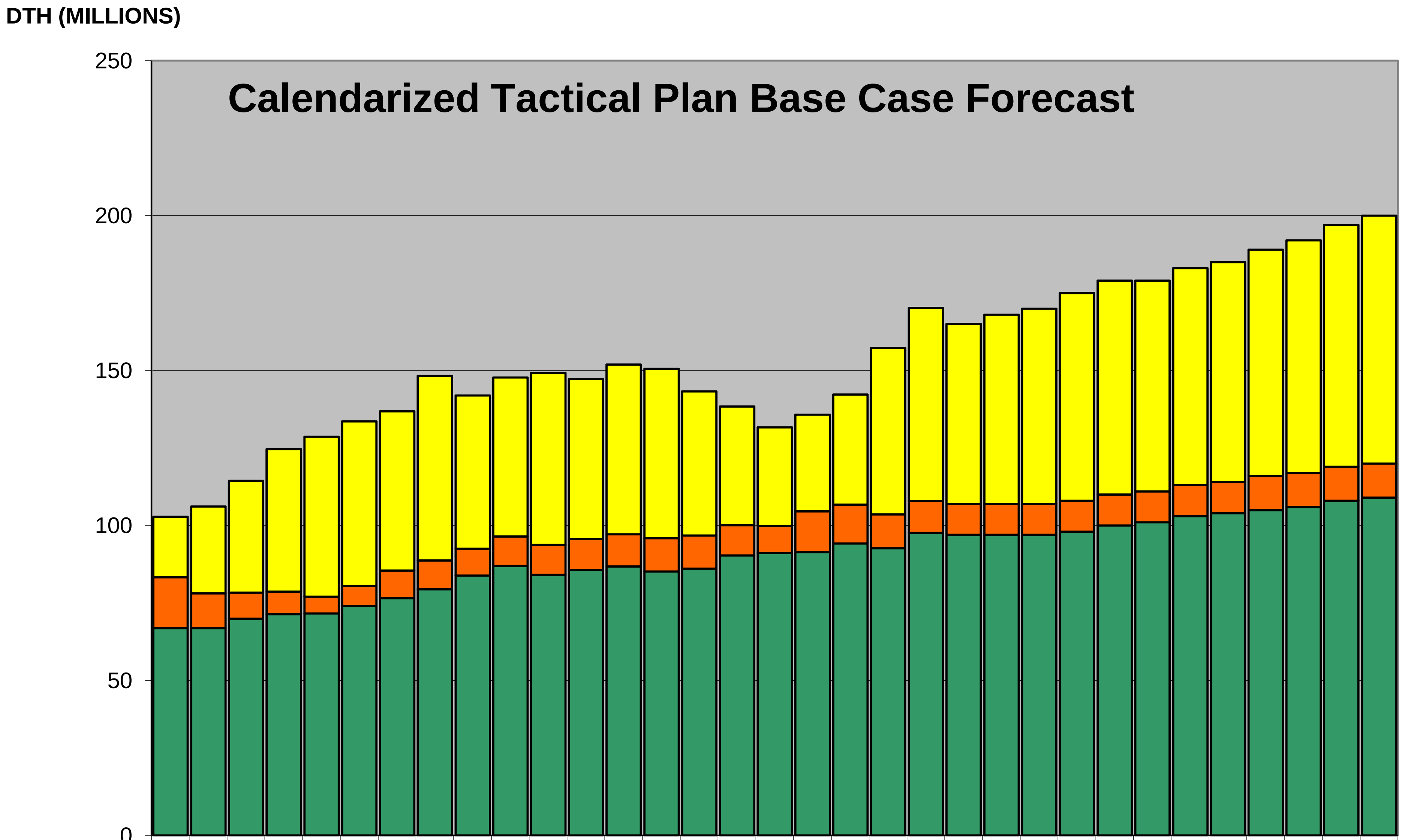
# SYSTEM DTH SALES

Dth (Millions)



| | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | 83 | 90 | 93 | 93 | 92 | 93 | 93 | 104 | 93 | 102 | 102 | 105 | 108 | 114 | 111 | | | | | | | | | | | |
| TEMP ADJUSTED | 89 | 92 | 96 | 94 | 96 | 97 | 96 | 97 | 100 | 100 | 105 | 107 | 104 | 108 | 107 | | | | | | | | | | | |
| FORECAST | | | | | | | | | | | | | | | | 107 | 107 | 108 | 110 | 111 | 113 | 114 | 116 | 117 | 119 | 120 |

# TEMP ADJUSTED THROUGHPUT




| | 88 | 89 | 90 | 91 | 92 | 93 | 94 | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TRANS | 20 | 28 | 36 | 46 | 52 | 53 | 51 | 60 | 49 | 51 | 55 | 52 | 55 | 55 | 46 | 38 | 32 | 31 | 36 | 54 | 62 | 58 | 61 | 63 | 67 | 69 | 68 | 70 | 71 | 73 | 75 | 78 | 80 |
| NON-GS SALES | 16 | 11 | 8 | 7 | 5 | 6 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 11 | 11 | 10 | 9 | 13 | 12 | 11 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 11 | 11 | 11 | 11 |
| SYSTEM GS | 67 | 67 | 70 | 71 | 72 | 74 | 77 | 79 | 84 | 87 | 84 | 86 | 87 | 85 | 86 | 90 | 91 | 91 | 94 | 93 | 98 | 97 | 97 | 97 | 98 | 100 | 101 | 103 | 104 | 105 | 106 | 108 | 109 |

Exhibit 3.11

## SYSTEM CAPABILITIES AND CONSTRAINTS

### Questar Gas System Overview

Gas supply costs are the primary focus of the IRP process because they represent a major portion of the total utility cost of service.[1] Nonetheless, analysis of the physical plant used to deliver the product to the consumer is an important element of natural gas IRPs. The capacity of the system must meet the forecasted load in order to provide reliable service to the customer.

Historically, Questar Gas customers have been served by an integrated transmission and distribution system connecting natural gas fields in Utah, Wyoming and Colorado to the Company's Utah, Wyoming, and Idaho markets. This original integrated system remains intact. Questar Gas' ability to serve its customers is dependent upon gas transmission companies such as Questar Pipeline Company (Questar Pipeline) and Kern River Gas Transmission Company (Kern River). To a much smaller extent, the Company relies on deliveries from Northwest Pipeline Corporation to serve the towns of Moab, Monticello and Dutch John, Williams Field Services to serve the towns of LaBarge and Big Piney in Wyoming, and Colorado Interstate Gas Company to serve the town of Wamsutter. These pipeline systems and costs are part of the modeling process discussed in other IRP sections. This section will concentrate mostly on Questar Gas' local distribution system.

Steady-state and unsteady-state Gas Network Analysis (GNA) system models are built each year to account for changes in piping facilities and customer growth. These models are completed in April of each year and are updated to include facilities and demands as of February of the current year. The models are then adjusted to match the predicted demand for the following year based on the growth projections discussed elsewhere in this report. This report is based on the current 2010-2011 models which were created in April 2010.

These GNA models are used to perform system analysis to ensure future capacity requirements can be met while maintaining system reliability. Each time the models are built they are checked for validity and then reviewed to determine any need for system improvements, supply changes, or contracts revisions. The models can then be expanded to meet any analysis needs including planning analysis and operational analysis. This may include creating models at different temperatures or creating different types of models from the standard system model.

### Ongoing and Future System Analysis Projects

*Intermediate High Pressure Geographic Information System (IGIS) and High Pressure Mapping System – Arc GIS Pipeline Data Model (APDM)*

The changeover to the new IGIS system is complete. This has also changed the way the GNA models are built. The Intermediate High Pressure models are built directly from the new

[1] By comparison, the electric utility industry focuses more on physical plant and control of respective costs.

IGIS. The new process provides for additional attributes to be transferred from the IGIS to the models. As a result, the new models now include elevations. Changes were also made to more accurately convert customer load from Dth/day to MMcf/D. These changes will make the IHP models more accurate and will carry forward to the High Pressure (HP) models as well. Prior to next fall, Questar Gas will begin to build the HP model from the APDM.

*Contingency Planning*

As part of emergency planning, the HP system models are being used to develop contingency plans for potential emergency scenarios. The scenarios are being coordinated with the Company's engineering department and its pipeline compliance group, and incorporated into its emergency plan. Unsteady-State Modeling (USM) helps to determine the system impact and time required to make changes to maintain system integrity or enact emergency procedures. While it may not be possible to model every possible scenario, it will be beneficial to prepare general plans that can be tailored to specific events.

*Develop Operational Models*

Another way to prepare for planned maintenance or unforeseen scenarios is to develop and maintain operational models of the system. These models are being maintained to represent current actual conditions that exist in the system at temperatures that are likely to exist with the system conditions. These models will be reviewed with the Company's Gas Control, Gas Supply, Marketing, Operations and Measurement and Control departments in advance of planned maintenance in order to know what system conditions can be expected.

## System Modeling and Reinforcement

Questar Gas Engineering utilizes steady-state IHP models to analyze the improvements needed to maintain adequate pressures in the IHP systems. These models are used to identify the required location and sizing of new mains and/or regulator stations. The models are also used to compare the required flow from the regulator stations to the maximum flow capacity of the existing stations. This analysis results in a number of IHP mains being installed each year as reinforcements. It also results in the construction of a number of new stations and a few station upgrades each year.

The analysis of the HP system models is much more complex than that of the IHP system. Gate stations, existing supply contracts, supply availability, line pack, and the piping system must all be considered in the HP analysis. The time it takes to complete larger HP projects also requires projects be identified much earlier than with IHP projects.

## Model Validation

The steady-state GNA models are validated for accuracy using pressure validation and demand comparisons. A steady-state high pressure model was built to represent the system conditions on a specific day (December 9, 2009). Settings in the model were all adjusted to match this day. The modeled pressures were compared to actual pressures at key points recorded on this day. The pressures were all found to be within 8.5% and on average were within 0.5%. Based on this, the model is considered accurate.

The Company also validated its model by comparing the modeled demand with the daily recorded sendout for the validation day at the gate stations. The results of this analysis showed that the predicted demand was within 5.5% of the sendout for the verification day. This difference likely occurs because the steady-state model does not include linepack. Actual system flows would provide for some linepack in the system. The results of these comparisons also confirm the accuracy of the steady-state models.

The Company verified the unsteady-state models in the same manner as the steady-state models. The same verification day was reproduced in the model using the weather zone specific heating degree days. Gate station flows and pressures were then matched as closely as possible.

The Central and Northern Regions are the largest connected high pressure systems in the Questar system and, between them, contain 7 gate stations and 2 separate pressure systems. This analysis has 24 pressure verification points as well as the known pressures and flows from the gate stations. None of the pressure differences at any of the verification points have error values higher than 10% when compared to the actual minimum and average pressures. There are three smaller isolated systems which also require a USM analysis: Summit/Wasatch, Eastern, and Southern. The minimum pressure and average daily flow results for the gate stations in each of these systems are very similar to those of the Central and Northern system. The pressures have relatively small differences. The results of the comparisons confirm the accuracy of the unsteady-state models.

## Gate Station Flows vs. Capacity

In order to accurately represent actual system conditions, station settings were adjusted to match supply contracts at each of the meter allocation points (MAPs). This allows for the system to be analyzed based on supply conditions to determine capacity requirements of the gate stations as well as the operational capacity of the piping system.

When setting up the system models, it is also important to stay within the pressure and flow parameters for each of the stations. To achieve this, a capacity study was completed for each of the gate stations. Hourly and daily flow capacities were calculated for each station based on set pressures in the system model and inlet pressures from Questar Pipeline Systems Engineering group and interconnect agreements with other suppliers.

According to this study, Hunter Park will again require upgrades to meet a peak required capacity of 174.36 MMcf/D. Central Station will also require upgrades to meet a peak required capacity of 25.57 MMcf/D. Both of these stations require upgrades to facilities on the Kern River side of the station. The Company has requested that Kern River upgrade these stations prior to the 2010/2011 heating season. The Moab stations are still near capacity and being monitored for possible upgrade scenarios in the near future. Sunset Station also continues to be constrained due to the upstream piping of Main Line 3 (ML 3) on the Questar Pipeline system. This station is therefore held at near 65,000 Dth/D in all models. There is currently no planned capacity upgrade to this line.

**System Pressures**

Once the system models are verified and set up to match the contractual obligations and station capacities, they can be used to analyze the system to ensure adequate pressures to supply all of Questar Gas' customers. Questar Gas uses the peak models for this analysis. The peak models include all firm loads for both sales and transport customers. The daily contract limits are used for customers with signed contracts. The models do not take interruptible volumes into account because those customers would presumably be interrupted in a peak event.

*Northern*

This area consists of the main system around Salt Lake City and northern Utah. This area includes Salt Lake, Tooele, Summit, Utah, Wasatch, Davis, Morgan, Weber, Cache, and Box Elder Counties. This area has gas delivered from Questar Pipeline at MAP 164 through Hyrum, Little Mountain, Payson, Porter's Lane, and Sunset stations. Multiple smaller taps from Questar Pipeline serve the area through MAP 162. It is also served by Kern River at Hunter Park and Riverton stations.

The ability to take gas from both Questar Pipeline and Kern River allows Questar Gas to meet its peak-day obligations to the Northern Region. The gas supply at the two Kern River gate stations make up the difference between Questar Gas' firm obligations and the contracted delivery capacity from Questar Pipeline.

In the steady-state model, the low point in the main northern system is 270 psig at the endpoint of Feeder Line (FL) 62, in Alta. The pressure at this point is just lower than the location usually considered to be the lowest point in the system, the endpoint of FL 36 in West Jordan. The low point at West Jordan is 279 psig. Both of these pressures are substantially higher than the Company's lowest allowable pressure of 125 psig. There is, however, an area of isolated low pressures on the western side of Salt Lake City. The pressures in this area are near 144 psig due to the loads on 3-inch pipe in the area.

The pressures at some of the key locations in the northern system are shown in Table 1 and Figure 1. These are modeled pressures on a peak day at system endpoints, low points in the area or just important intersections.

Table 1 – Key Pressures

| Location | Pressure (psig) |
|---|---|
| North Temple Pressure Station - Outlet | 315 |
| Endpoint of FL 106 – Bear River | 389 |
| Endpoint of FL 48 – Tooele | 325 |
| Endpoint of FL 63 - West Desert | 325 |

| | |
|---|---|
| Endpoint of FL 62 – Alta | 270 |
| Endpoint of FL 36 - West Jordan | 279 |
| Endpoint of FL 74 – Preston | 378 |
| Endpoint of FL 29 – Brigham City | 376 |
| Endpoint of FL 70 – Brigham City | 381 |
| Intersection FL 29 & FL 23 - Brigham City | 419 |

Figure 1 – Key Pressures

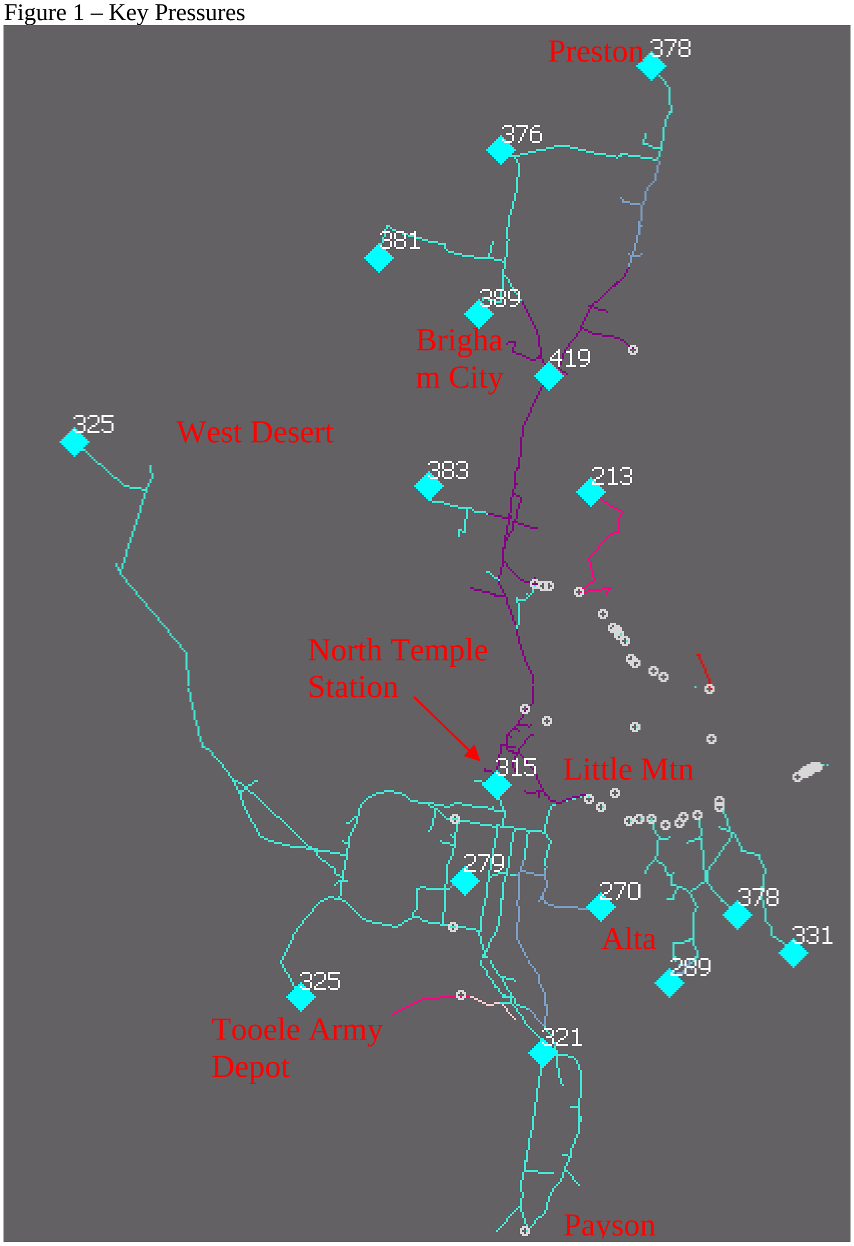
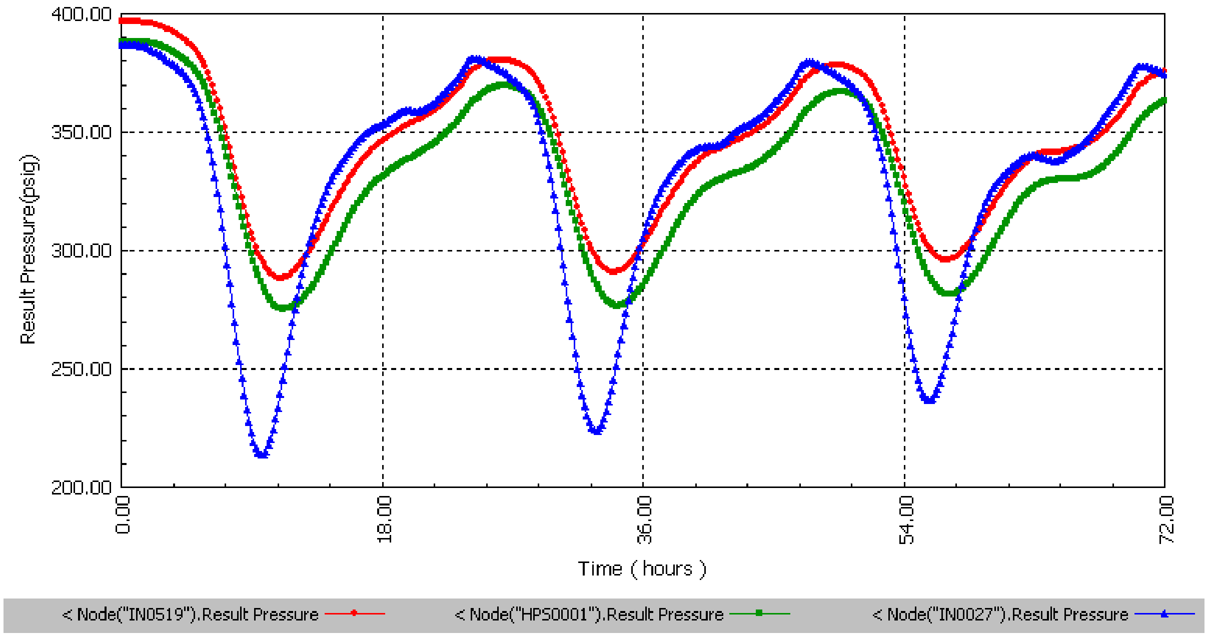



Figure 2 shows the pressure variations at several end points in the northern part of the system using the unsteady-state model. The lowest pressure is 214 psig at the end of FL 50 west of Ogden. This pressure is lower than the steady-state model pressure at this point. However, it is important to remember that the steady-state model calculates an average daily pressure at each point.

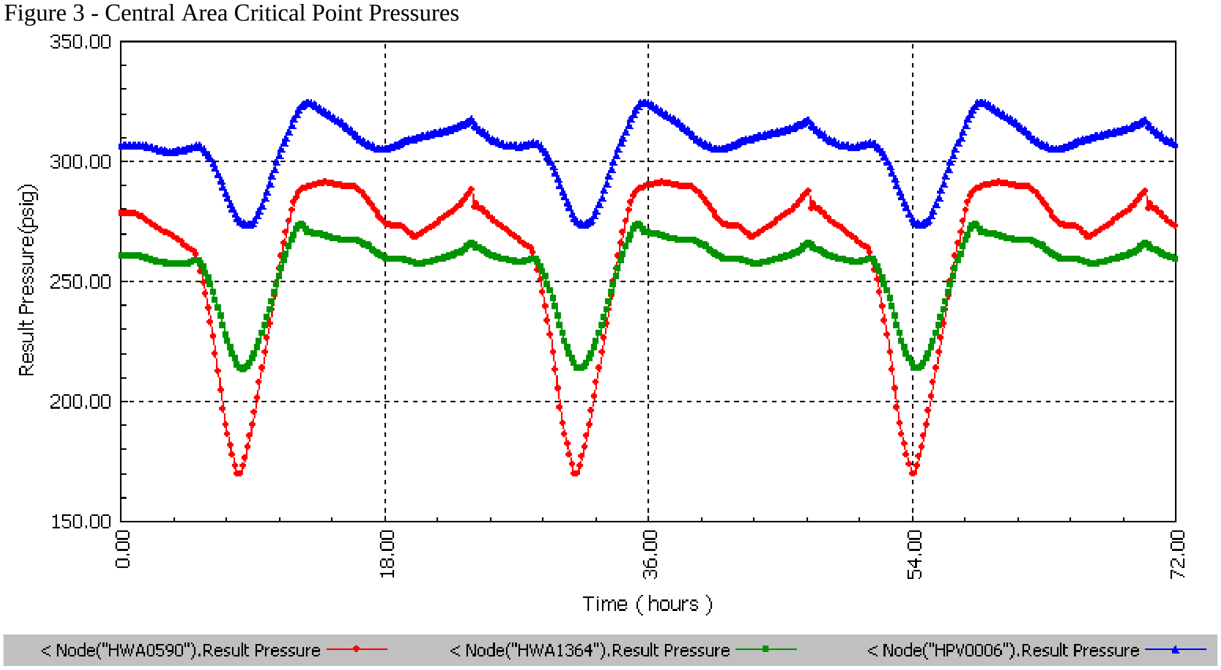
Figures 3 and 4 show the pressures at the end points in the central part of the system and in Summit County. The lowest pressure in the central area is 169 psig at the end of FL 36 in West Jordan. The lowest pressure in the Summit County area is 177 psig in Charleston at the end of FL 56.

Figure 2- Northern Area Critical Point Pressures



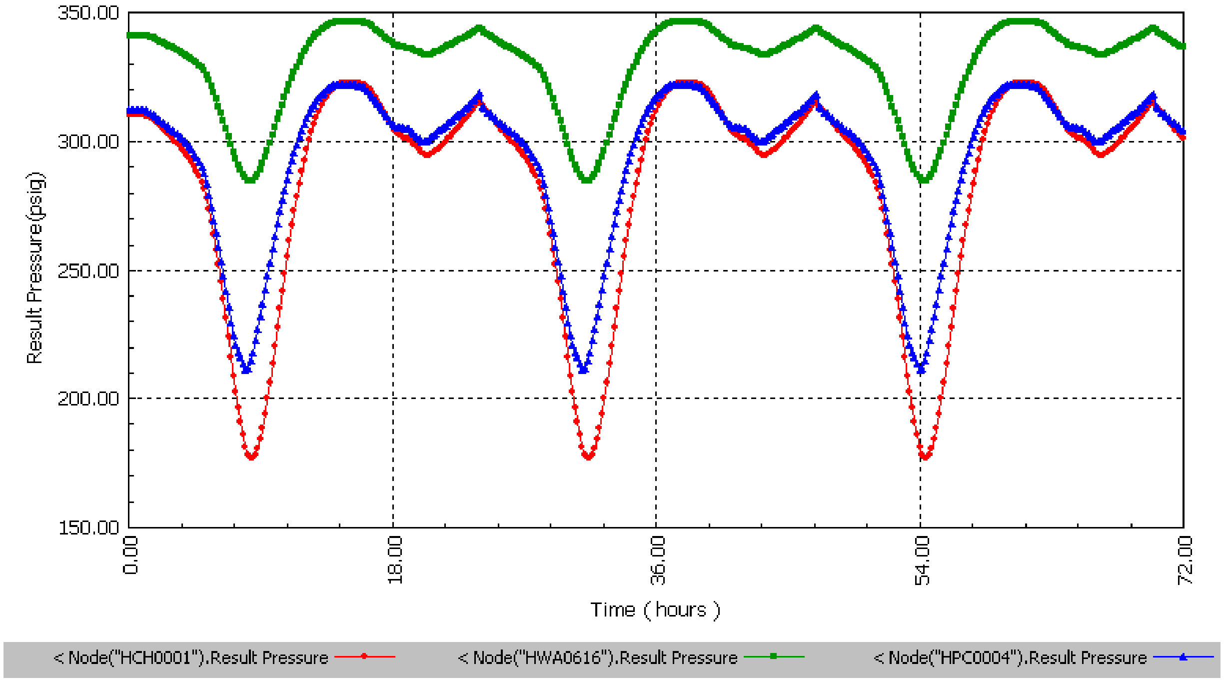

IN0519 = Croyton HPS0001 = Preston, ID IN0027 = West, Ogden

Figure 3 - Central Area Critical Point Pressures




HWA0590 = West Jordan HWA1364 = End of FL 62 (Alta) HPV0006 = Provo

Figure 4 - Summit County Critical Point Pressures



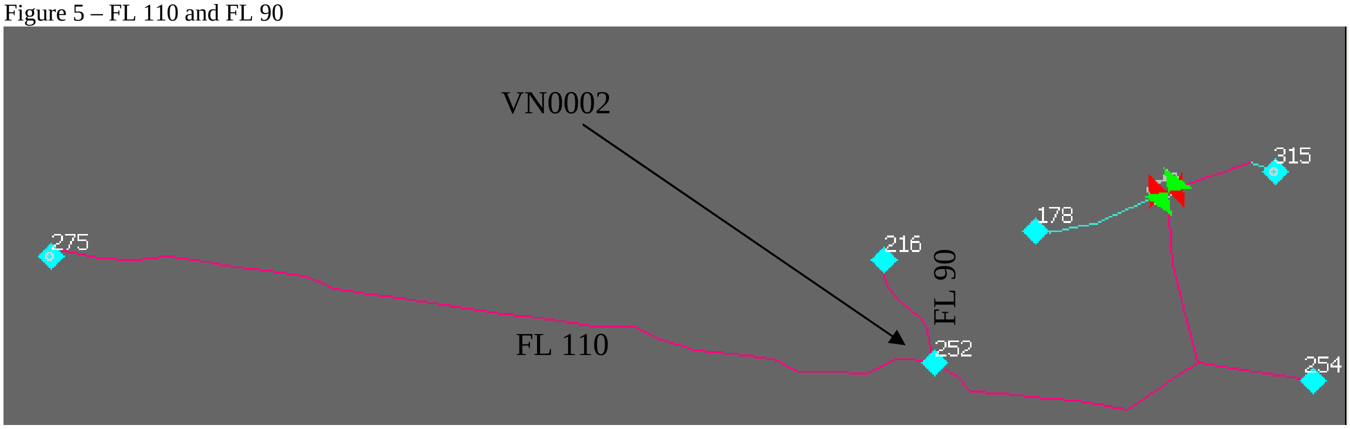

HCH0001 = Charleston  HWA0616 = Kamas  HPC0004 = Park City

*Eastern (North)*

This area consists of Duchesne, Uintah, Carbon, and Emery Counties, including Price and Vernal. The Vernal system is one of the systems that was previously owned by Utah Gas. This area is served from Questar Pipeline by multiple taps through MAP 163.

The systems that make up the Eastern System (North) operate at different pressure levels. The pressure concerns at the end of FL 90 were resolved by removing the pressure regulation cut at VN0002 where FL 90 intersects with Fl 110. Through a pressure uprate process, FL 90 now operates at a 328 psig maximum allowable operating pressure (MAOP). Figure 5 shows the pressures on FL 110 and FL 90 on a peak day.

Figure 5 – FL 110 and FL 90



*Eastern (Northwest Pipeline)*

This area consists of Moab, Monticello and Dutch John. The Moab system is one of the systems that was previously owned by Utah Gas. These areas are all served from Northwest Pipeline by two stations in Moab, one station in Monticello, and one tap in Dutch John.

The Eastern Systems served by Northwest Pipeline are IHP systems. The pressures are regulated to IHP pressure at the Gate Stations with Northwest Pipeline. Improvements are ongoing to ensure the Monticello IHP system has adequate pressures.

*Southern (Main System)*

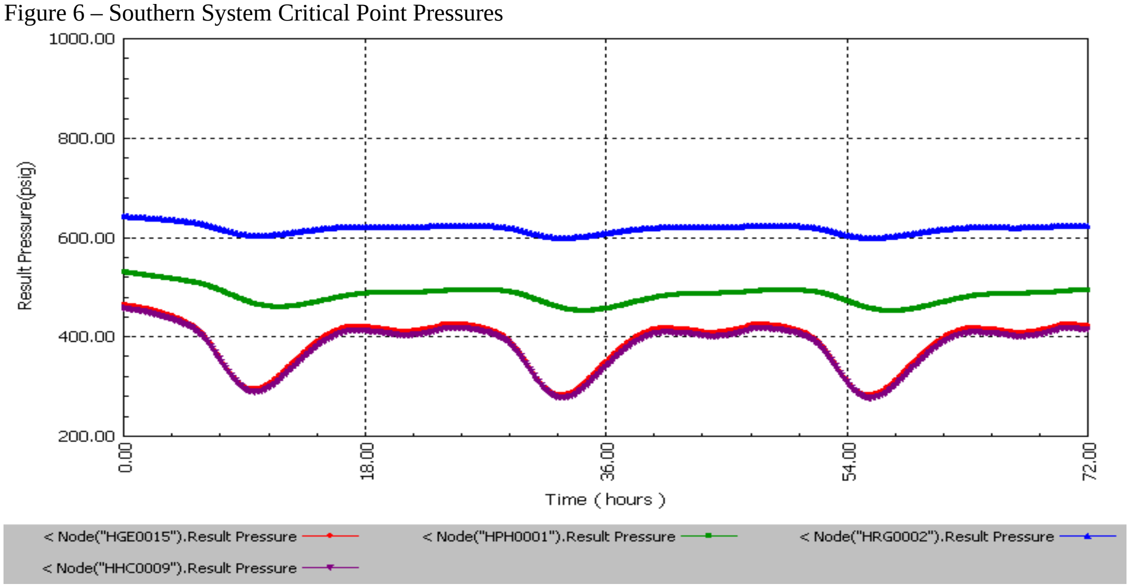
This area consists of the entire Southern Region that is served by the Indianola/Wecco/Central system, including Richfield, Cedar City and St. George. These areas have gas delivered from Questar Pipeline at Indianola station through MAP 166 and from Kern River at Central and Wecco stations.

The lowest point in the main Southern System is on a spur in Hurricane. Using the steady-state model, the lowest pressure on a peak day is 378 psig. While this is still fairly high compared to the pressures in the northern system, it is important to note that this system operates at higher pressures than most of the Questar Gas system. Pressures are near 600-625 psig at the Kern River gate stations and approach 700 psig at Indianola.

The predicted pressure in this area is significantly higher than last year. The higher pressures are based on upgrades to the Kern River facilities at Central Station being completed prior to the heating season. The higher pressures are also a result of changes at Indianola Station. As of last winter, the station is being served by ML 104 rather than ML 41. ML 104 provides higher inlet pressures with more available flow through the station. The result of these changes is more flow through the station with a higher outlet pressure.

Using the unsteady-state model, the lowest pressure in the Southern area is 277 psig in Hurricane. The increase in pressure from last year’s model is due to the changes at Indianola and also increased capacity from Central Station. The Central Station improvements should be completed prior to the 2010-2011 heating season.

Figure 6 – Southern System Critical Point Pressures




HGE0015 = St. George  HPH0001 = Panguitch  HRG0002 = Redmond  HHC0009 = Hurricane

*Southern (Kern River Taps)*

This area consists of all of the towns served south of Payson Station that are not part of the Indianola/Wecco/Central system. This consists of towns in Juab, Millard, Beaver, Iron, and Washington Counties. These areas are all single feed systems served by Kern River.

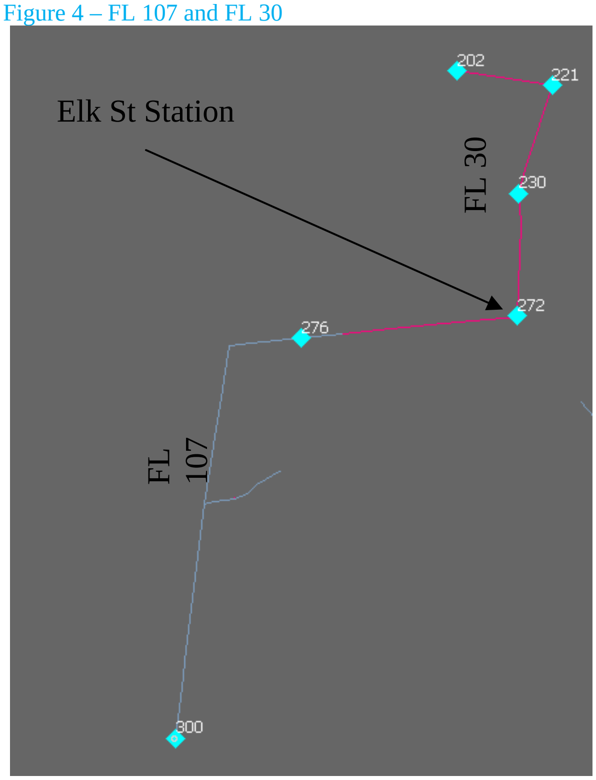
The Southern System Kern River Taps are made up of separate systems with individual taps from Kern River. All of the segments in this area have adequate pressures and do not require any improvement to meet the existing demand.

*Wyoming*

This area consists of all of the towns served in Wyoming. This includes Rock Springs, Evanston, Lyman, Kemmerer, Baggs, and Granger. These areas are served from Questar Pipeline through MAP 168, MAP 169, and MAP 177, from Colorado Interstate Gas (CIG) at Wamsutter and from Williams Field Services (WFS) at LaBarge and Big Piney.

The pressure concerns discussed last year at the end of FL 30 were resolved by removing the pressure regulation at Elk St. This allows FL 30 to operate at the same pressures as FL 107. This required the replacement of a few fittings, however, the MAOP of FL 30 is adequate to support the higher operating pressure. With this improvement all of the pressures in this system are adequate.

Figure 4 – FL 107 and FL 30




**System Capacity Conclusions**

The current assessment of the state of the Questar Gas HP feeder line system is that the system is capable of meeting the current peak day demands 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 both the steady-state and unsteady-state models show that system pressures do not drop below the design minimum of 125 psig. The system will continue to grow along with the demand and this analysis will be completed on an annual basis to ensure that the system continues to meet the peak day needs.

Some of the other issues that are being analyzed for future improvements are as follows:

- Due to gas supply availability issues at the Questar Pipeline gate stations, additional future volume will need to come from Kern River gate stations. As demand increases in areas that are only served by Questar Pipeline, the Questar Gas contracts will need to be amended to supply more gas to those areas. Without increased availability from Questar Pipeline the result of this will be less gas available from Questar Pipeline to the main system (Wasatch Front). In the short term, this reduction, as well as demand growth on the system, will need to be met with additional supplies at Hunter Park and Riverton stations. Upgrades are currently being designed for Hunter Park station to meet the additional supply requirements. The station will be upgraded to at least meet the required capacity of 174.36 MMcf/D. The station will likely also be designed to a higher capacity to meet growth. These upgrades will be made on Questar Gas' system and will be required for the 2010-2011 heating season.

- Additional options will need to be considered in order to meet the long term needs of system growth. Possible options include new stations from Kern River Ruby Pipeline or Questar Pipeline. Upgrades to existing stations with additional supply contracts may also be considered.

- The Southern System is reaching capacity. The only feasible long-term improvement options require additional supply from Kern River near St. George. All of these options include long distances of large HP pipe into St. George. Kern River is the only available supplier nearby and there are a few routes being considered for the reinforcement. Preliminary analysis shows the need for a new 24-inch main to be installed by the heating season of 2013/2014. Additional short-term improvement options, such as compression on the 8-inch main from Indianola Station, are being considered as well. Questar Gas is carefully monitoring growth in St. George and will phase this project based upon the expected growth in the area. The timing of construction is under review and will be based upon growth projections. Engineering and right-of-way work for the project is ongoing.

Maps reflecting peak day flow rates for each of the areas are contained in Exhibits 4.1 through 4.6.

**Questar Gas 2009 High-Pressure (HP) Projects**

In 2009 Questar Gas Company completed several HP projects of note. Typically, such projects are completed for a variety of reasons including: general system reinforcement, relocations and replacements, and system expansion. Each category of work is discussed in greater detail below.

*System Reinforcements:*

Questar Gas did not construct any general reinforcement HP projects in 2009. The 2009 IRP included plans to extend a feeder line in Providence, Utah and reinforce FL 105 in West Haven and FL 16 in Heber. However, slower than expected growth rates in several cities across the state caused these HP projects to be postponed.

The DNG Action Plan, section 4 of this IRP, contains a discussion on the current anticipated schedule of these and other general system reinforcement projects.

*Relocations and Replacements:*

Questar Gas relocated several HP facilities in 2009. The majority of these relocations were required as the result of conflict with Utah Department of Transportation (UDOT) road projects. Questar Gas was reimbursed for a portion of the costs associated with UDOT projects according to Utah Code Ann. § 72-6-116 (2010). In areas where Questar Gas owns facilities located within existing UDOT corridors (i.e.by permit), Questar Gas receives 50% reimbursement on the relocation work. In areas where Questar Gas owns facilities within rights-of-way that it owns, the reimbursement rate is 100%. The major HP relocations were:

1. Pioneer Crossing UDOT relocation, American Fork, Utah: This project included the relocation of approximately 1,180 lf of FL 26 (24" diameter) and 400 lf of FL 104 (24" Diameter). Questar Gas' anticipated share of the costs are $250,000.

2. SR-92 UDOT Reconstruction, Lehi, Utah: This project included the relocation of approximately 7,400 lf of FL 103 (12" diameter) and 375 lf of FL 20 (20" diameter). The project is still under construction but Questar Gas' share of the costs is anticipated to be approximately $400,000.

3. South Layton Interchange, Layton, Utah: This project included the relocation of approximately 2,900 lf of FL 21 (20" diameter) and 860 lf of FL 17 (12" diameter). The project also included the relocation of district regulator stations LY0001 and LY0008. Substantial IHP relocation work was also required. The major relocation work for this project has been completed. Questar Gas' share of the costs is anticipated to be approximately $230,000 for the HP portion of the project and $125,000 for the IHP portion.

4. Feeder Line Replacement Program: Questar Gas continued its Feeder Line replacement program in 2009. The portions of FL 19 in Ogden that were located within High Consequence Areas (HCA) were replaced and some of the pre-design for the replacement of FL 12 took place. The cost of this work was approximately $12,800,000. Approximately 7,800 lf of FL 19 (12" diameter) and 12,700 lf of FL 19 (20" diameter) were replaced.

**DNG Action Plan**

Questar Gas is currently planning and designing several reinforcement projects and replacement projects. Questar Gas also anticipates that several UDOT projects will continue to require substantial relocation projects in the near term. The following is a brief description of the major projects anticipated by Questar Gas in 2010 and beyond.

*2010 Gate Station Projects:*

1. Hunter Park Gate Station: Hunter Park gate station is located at approximately 3500 South, 5800 West in Salt Lake City, Utah. The gate station is one of two interconnects between Questar Gas and Kern River in the Salt Lake Valley. GNA modeling has indicated that, due load growth along the Wasatch Front, the capacity of the gate station needs to be increased to a capacity of at least 250,000 MMcf/D. In 2009 Questar Gas increased capacity on its portion of the facility by

installing a larger control valve (3” to 6”). Questar Gas is currently working with Kern River to increase the capacity of Kern River’s facilities at Hunter Park during 2010. The estimated cost for Kern River to modify their facilities is $750,000. Questar Gas is responsible for 100% of these costs. The first-year revenue requirement for this project is estimated to be $140,000.

In 2011, Questar Gas anticipates further system improvements will be required at Hunter Park. These improvements include: retiring the existing meter building, re-configuring odorization, and re-configuring control valves. The estimated cost for this portion of work is $750,000. The first-year revenue requirement for this project is estimated to be $140,000.

2. Central Gate Station: Central gate station is located near St. George, Utah. It is one of two major interconnects between Questar Gas and Kern River in southern Utah (the other is at Wecco). Like Hunter Park, GNA modeling has indicated that the peak capacity at Central needs to be increased prior to the 2010/2011 heating season. GNA modeling has indicated that the required capacity of the station is 30,000 MMcf/D. Questar Gas’ facilities at Central are adequate to handle this demand. However, Kern River’s facilities do not have the capacity to meet this demand. Consequently, Questar Gas has made a request to Kern River to upgrade its facilities. The first-year revenue requirement for this project is estimated to be $140,000. Like Hunter tap, Questar Gas will be responsible for 100% of the upgrade costs. Questar Gas has budgeted $750,000 for this work.

3. Ruby Pipeline Gate Station: Ruby Pipeline, LLC (Ruby) is planning a new 42-inch interstate pipeline that will cross the Questar Gas service territory. The new pipeline, known as “Ruby Pipeline,” will cross, and in some places parallel, the Questar Gas feeder line system in Brigham City. Ruby contacted Questar Gas to measure interest in obtaining a tap off of the new pipeline. Questar Gas conducted a GNA analysis to determine the impact and benefit adding a new gate station near Brigham City could have on the Questar Gas feeder line system.

   The analysis determined that while a new station is not necessary at this point, there may be a number of benefits to having a station installed in the future. One potential benefit is that a station in Brigham City could be sized large enough to provide 100% load redundancy for Questar Gas’ Hyrum Station. A new station at this location would also be in line with the Company’s plans for a 20-inch “trunk line” running north/south in this area. The trunk line is intended to provide increased flexibility between supply points in this area. An additional supply point, from an additional supplier would add to this flexibility.

   In order to provide the opportunity to install a station in the future, negotiations are in progress to have Ruby agree to install a tap valve as part of its original project design and construction. Ruby estimates that the tap valve will cost approximately $155,000. This valve will be installed during the construction of the Ruby pipeline. Installing the tap valve now is far less expensive than installing the valve after the Ruby Pipeline is in service. The first year revenue requirement for this project is estimated to be $29,000.

*2010 Feeder Line Projects:*

1. St. George Reinforcement: In order to meet the anticipated load growth in the St. George area, a major feeder line system reinforcement is under analysis. The current project plans call for the construction of a new 24-inch diameter feeder line that would extend from a new Kern River gate station into St. George. A number of routes are currently being evaluated for this pipeline. These routes include a “southern route” that would originate in the Jackson Springs area, run through lands owned by the Shivwits Band of Paiute Indians (the Shivwits) and tie-in near Ivins. There are also two northern routes being analyzed. The first of these options would originate at a new gate station off of Kern River near Veyo, while the second “northern” option would originate at a new Kern River gate station near Questar Gas’ existing Central Gate station. Both “northern” options would parallel and tie-into Questar Gas’ existing FL 81.

   There are a number of issues associated with all route options. These include: rights-of-way issues with the Shivwits, BLM environmental permitting concerns, and constructability issues. In addition to the route evaluations, Questar Gas is conducting detailed GNA analysis to determine appropriate sizing, phasing, and schedule requirements for each alternative.

   Current GNA modeling and growth projections show that this improvement would not be needed until at least the 2013/2014 heating season. Additional alternatives are being considered which may help to extend this schedule further into the future. Some of the alternatives being considered include adding compression along the 8” feeder line that extends from the Indianola gate station, adding compression at Central gate station, or potential peak shaving facilities in St. George. All the options will be evaluated for both operational and cost effectiveness.

   Questar Gas has budgeted $2,300,000 in 2010 to conduct the NEPA process (environmental analysis) for the three pipeline routes mentioned above, as well as potential rights-of-way purchases. This process, which could take approximately 2 years, will finalize routing and provide required federal approvals for the project. The estimated cost of Phase 1 of this project is about $46 million, which includes the tap. The first-year revenue requirement for this project is estimated to be $7.9 million.

2. Utah Feeder Line Reinforcements: Questar Gas has budgeted $200,000 in 2010 to evaluate and initiate design on feeder line projects to reinforce Charleston, Utah and Saratoga Springs, Utah.

   GNA system models indicate the potential for low HP system pressures in the Charleston area. Questar Gas is currently considering an approximately 3.9 mile extension of 8-inch HP pipe that would extend from FL 16 in Midway to

Charleston. Questar Gas is analyzing potential routes as well as finalizing pipe size requirements. Construction of this project will likely occur in 2011, prior to the 2011/2012 heating season. The Charleston reinforcement is estimated to cost about $4 million. The first-year revenue requirement is estimated to be about $690,000.

The Saratoga Springs area in Utah County is currently being served by IHP main. The nearest HP facilities are located approximately 9 miles from the extremities of the IHP system. There is currently limited growth in the area, but with approximately 2000 vacant lots already served with existing IHP mains, demand in the area could increase quickly with an improvement in Utah housing market. If this growth does occur, the area will require HP reinforcement. The Saratoga Springs reinforcement is estimated to cost $7-9 million. The first-year revenue requirement is estimated to be between $1.2 and $1.5 million.

Questar Gas is currently conducting preliminary analysis of this project to determine the scope, timing, and potential phasing of HP reinforcement in Saratoga Springs.

3. <u>Heber City HP Reinforcement</u>: Questar Gas has completed the preliminary design for the reinforcement of east Heber, Utah. Currently work is on-going to secure the last of required permitting and rights-of-way. The project was originally scheduled for installation in 2009. However, slow load growth in east Heber area allowed for the project to be delayed. Current load estimates show that the project may be required prior to the 2011/2012 heating season. Consequently, Questar Gas is planning to complete the project in 2011.

   The project consists of 2 miles of 8-inch HP main from FL 16 on the north end of Heber to a proposed regulator station on the east side of Heber. The estimated cost for this project is $2,300,000. The first-year revenue requirement is estimated to be $400,000.

4. <u>Feeder Line Replacement Program</u>: Questar Gas is continuing its Feeder Line replacement program in 2010. Approximately 63,400 lf of FL 19 (20" diameter) will be replaced and approximately 30,000 lf of FL 12 will be replaced. Pursuant to the Settlement Stipulation and the Utah Commission's bench order approving the Settlement Stipulation, in Docket No. 09-057-16, the Company will file an infrastructure replacement plan each fall detailing the planned projects, the anticipated costs and other relevant information.

5. <u>Wyoming HP Reinforcement Projects</u>: Questar Gas has budgeted $200,000 in 2010 to analyze three potential projects in Wyoming: One for the town of LaBarge, one for the town of Big Piney, and one in Rock Springs.

   The town of LaBarge, Wyoming is served by a Williams Field Services gathering line. Pressure in the gathering line is decreasing as production in the area decreases. The pressure is already dropping to about 120 psig, (slightly below

Questar Gas' standard minimum design inlet pressure of 125 psig) and will likely continue to drop over the next few years. The pressure issues can be solved temporarily by removing the regulation at the beginning of the FL 31 and allowing the line to operate at the same pressure as the gathering line. This would require the replacement of some fittings and an uprate of the feeder line to match the upstream MAOP of the gathering line. Analysis will be completed this year to determine other long-term solutions to this issue, such as tapping a different transmission line in the area.

The town of Big Piney, Wyoming is also served by a Williams Field Services gathering line. The pressure in this feeder line is not dropping; however the IHP system demand is growing. Continued growth may require the 12-mile long 3-inch FL 49 to be reinforced. Preliminary analysis work is ongoing to determine the scope and timing for a potential reinforcement. This may include replacing some, or all, of FL 49 in the next few years. It is estimated that a replacement could cost $6 million. The first-year revenue requirement is estimated to be about $1 million.

Lastly, Questar Gas is evaluating options for creating redundancy in feeds to Rock Springs. The city of Rock Springs is currently served from two sources. The first is FL 107, which ties into Questar Pipeline main line at the Kanda/Coleman compressor station. The second source into Rock Springs is FL 37, which ties into the same Questar Pipeline main line at Kent's Ranch. If flow was interrupted on either FL 107, FL 37 or the Questar Pipeline main line, Rock Springs could suffer service interruptions. Questar Gas is currently analyzing ways to provide redundant feed into Rock Springs by extending FL 107 to the east and tieing-in at North Baxter, extending FL 37 to the north to Elk Street, or establishing an interconnect with Colorado Interstate Gas in north Rock Springs. Questar Gas is currently analyzing the scope, phasing and timing of these options. It is likely that the project will be constructed in 2011. Initial cost estimates for this project are about $7 million. The first-year revenue requirement is estimated to be about $1.2 million.

6. <u>UDOT Required Relocations</u>: Questar Gas anticipates the following HP relocations in 2010:

- UDOT's I-15 Core Project will require the relocation of approximately 2200 lf of 20" HP main (FL 26) in American Fork, including the extension of a 24" casing. This relocation is expected to cost: $1,700,000. The first-year revenue requirement is estimated to be about $280,000.
- UDOT's I-15 Core Project will require the relocation of approximately 1250 lf of 4" HP Main (FL 26 tap line) including the extension of 24" casings in Spanish Fork. This relocation is expected to cost $290,000. The first-year revenue requirement is estimated to be about $50,000.

Questar Gas will be responsible for 50% of the costs shown for these projects.

In addition to the I-15 Core project, Questar Gas is working with UDOT to identify possible conflicts associated with the proposed Mountain View Corridor (MVC) project. Questar Gas believes that any relocation work associated with the MVC will occur in 2011 at the earliest.

*Substantial IHP System Projects:*

1. Kemmerer/Diamondville, Wyoming Replacement: Based upon leak survey data, Questar Gas has implemented a replacement program under which major portions of the Kemmerer/Diamondville systems will be replaced.

   The replacement program began in 2008/2009 and Questar Gas replaced 35,142 lf of main and 319 services at a cost of $1,405,000. In 2010, 57,000 lf of main and 308 services will be replaced at a cost of $2,100,000. In 2011/2012 the remaining 114,375 lf of main and 773 services will be replaced at an approximate cost of $5,000,000. The revenue requirements for the three periods are $250,000, $375,000 and $880,000, respectively.

2. Monticello Uprate Project, Utah: Questar Gas is currently in the process of increasing the MAOP (Uprate) of large portions of the IHP system in Monticello, Utah from 25 psig to 60 psig. The Uprate of the IHP lines is necessary to improve delivery pressures within the system. The Uprate is performed by either re-pressure testing the existing lines or replacing the old lines with new, stronger material. To date, approximately 50% of the lines have been re-pressure tested successfully, while the other 50% have had to be replaced.

   The Uprate project began in 2008 and is scheduled to continue through 2012. Annual costs have been approximately $700,000/year. Questar Gas anticipates similar annual costs in 2011 and 2012. The Uprate of the IHP facilities will be approximately 60% complete at the end of 2010.

*2011 and 2012 Projects:*

The following projects are anticipated for 2011 and 2012:

- In 2011, Questar Gas expects to install the Charleston, Utah feeder line reinforcement detailed above.
- In 2011, Questar Gas anticipates paying Kern River a down payment of $300,000 to commence design of a new gate station in anticipation of the St. George project described above. In 2012, Questar Gas anticipates starting installation of the proposed gate station and ordering materials for the 2013 project.
- In 2011, Questar Gas expects to install the Heber reinforcement detailed above.
- In 2011, Questar Gas expects to install the Rock Springs reinforcement detailed above.

- In 2011, Questar Gas expects to commence pre-engineering of HP reinforcement projects in Park City.
- The Feeder Line replacement program will continue in 2011 and 2012.
- The Monticello Uprate Project will continue in 2011 and 2012.

**Integrity Management Plan Activities and Associated Costs**

Questar Gas continues to implement integrity management activities for transmission lines as originally mandated by the "Pipeline Safety Improvement Act of 2002" and later codified in the Federal Regulations (*see* 49 CFR, § 192). The requirements for transmission integrity management require Questar Gas to identify all high consequence areas along the segments of feeder lines that are defined as transmission lines.[2] Once these high consequence areas are defined, a risk score is then calculated for each segment. These risk scores are summed up for each unique feeder line. These risk scores establish the baseline and set the priority and frequency of integrity assessment for each line. Questar Gas verifies these high consequence areas and calculates the risk score for each on an annual basis. Questar Gas has ten years[3] to complete the baseline assessment of all segments in high consequence areas.

Questar Gas is also required by the transmission integrity rule to conduct additional preventive and mitigative measures on feeder lines in high consequence areas and class[4] 3 and 4 locations. These additional measures include monitoring excavations (excavation standby) near the feeder lines and performing semi-annual leak surveys. Other integrity activities include annual high consequence area validation, pipeline centerline survey and the day-to-day administration of the program.

On December 4, 2009, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued the 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 operators to develop, write, and implement a distribution integrity management program.

**Transmission Integrity Management**

*Costs*

See attached table (Table 1- Transmission Integrity Management Costs) for details on the anticipated costs associated with transmission integrity management.

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[2] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. MAOP) at or above 20% SMYS.
[3] The baseline assessment must be completed by 12/17/2012 (49 CFR §192.921 (d)).
[4] Class location as defined by 49 CFR §192.5.

*Baseline Assessment Plan*

The baseline assessment plan prescribes the methods that will be used to assess each high consequence area segment. These methods are determined by the known or anticipated threats to these segments. Currently the threats on the pipeline include external corrosion, internal corrosion, and third party damage. The assessment methods utilized to address these threats are external corrosion direct assessment (ECDA) and internal corrosion direct assessment (ICDA).

*External Corrosion Direct Assessment (ECDA)*

ECDA is intended to evaluate the integrity of pipeline segments for the threat of external corrosion. This includes segments of cased gas transmission pipelines. During the assessment process other types of damage may be identified. In those cases the damage must be documented and other suitable assessment methodologies used to evaluate the integrity of the pipeline segments. Refer to Figure 1 for an overview of the ECDA process.

The ECDA methodology is a four-step process requiring integration of pre-assessment data, data from multiple indirect field inspections, and data from pipe surface examinations. The four steps of the process are:

1. Pre-Assessment - The Pre-Assessment step utilizes historic and recent data to determine whether ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions.

2. Indirect Inspection - The Indirect Inspection step utilizes above ground inspections to identify and define the severity of coating faults, diminished cathodic protection, and areas where corrosion may have occurred or may be occurring. A minimum of two indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way.

3. Direct Examination - The Direct Examination step includes analyses of pre-assessment data and indirect inspection data to prioritize indications based on the likelihood and severity of external corrosion. This step includes excavation of prioritized sites for pipe surface evaluations resulting in validation. During the Direct Examination step, high priority areas with corrosion damage are re-evaluated for further action.

4. Post-Assessment - The Post-Assessment 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.

*Internal Corrosion Direct Assessment (ICDA)*

ICDA is a process 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. Refer to Figure 2 for an overview of the ICDA process.

The basis of ICDA is that detailed examination of locations along a pipeline where liquids would first accumulate provides information about the downstream condition of the pipeline. If the locations most likely to accumulate liquids have not corroded, other downstream locations that are less likely to accumulate liquids may be considered free from 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.

1. Pre-Assessment - The Pre-Assessment step collects and utilizes historic and recent data to determine whether ICDA is feasible and to define ICDA regions.

2. ICDA Region Identification - The ICDA Region Identification step covers flow-modeling techniques, developing a pipeline elevation profile and identifying sites where internal corrosion may be present.

3. Detailed Examination - The Detailed Examination step integrates the pre-assessment data and ICDA Region Identification analyses to select locations for detailed examinations. This step includes excavation of sites to evaluate for the presence of internal corrosion.

4. Post-Assessment - The Post-Assessment step utilizes data collected from the previous three steps to assess the effectiveness of the ICDA process, establish monitoring programs, and determine reassessment intervals.

*Direct Examination of Aboveground Pipe and Pipe in Vaults*

Piping that falls in a high consequence area (HCA) and is aboveground or because of its location is not feasible to be assessed using external corrosion direct assessment methods is assessed by direct examination. This includes spans (e.g. over waterways) and pipe in vaults. This examination typically includes the removal of external coating and checking the pipe for external corrosion and physical defects.

*High Consequence Area (HCA) Validation*

Each year, Questar Gas conducts a survey on all transmission lines to validate the current high consequence areas as well as any new potential sites that may trigger new high consequence areas. This information is captured in Questar Gas' mapping system and is used to evaluate high consequence areas on an annual basis.

**Distribution Integrity Management**

*Costs*

See attached table (Table 2- Distribution Integrity Management Costs) for details on the anticipated costs associated with distribution integrity management.

*Implementation*

Questar Gas is currently in the process of evaluating the details of this newly published rule and has assigned a team to evaluate it. Questar Gas anticipates completing the first phase of implementation, establishing a written plan, in 2010.

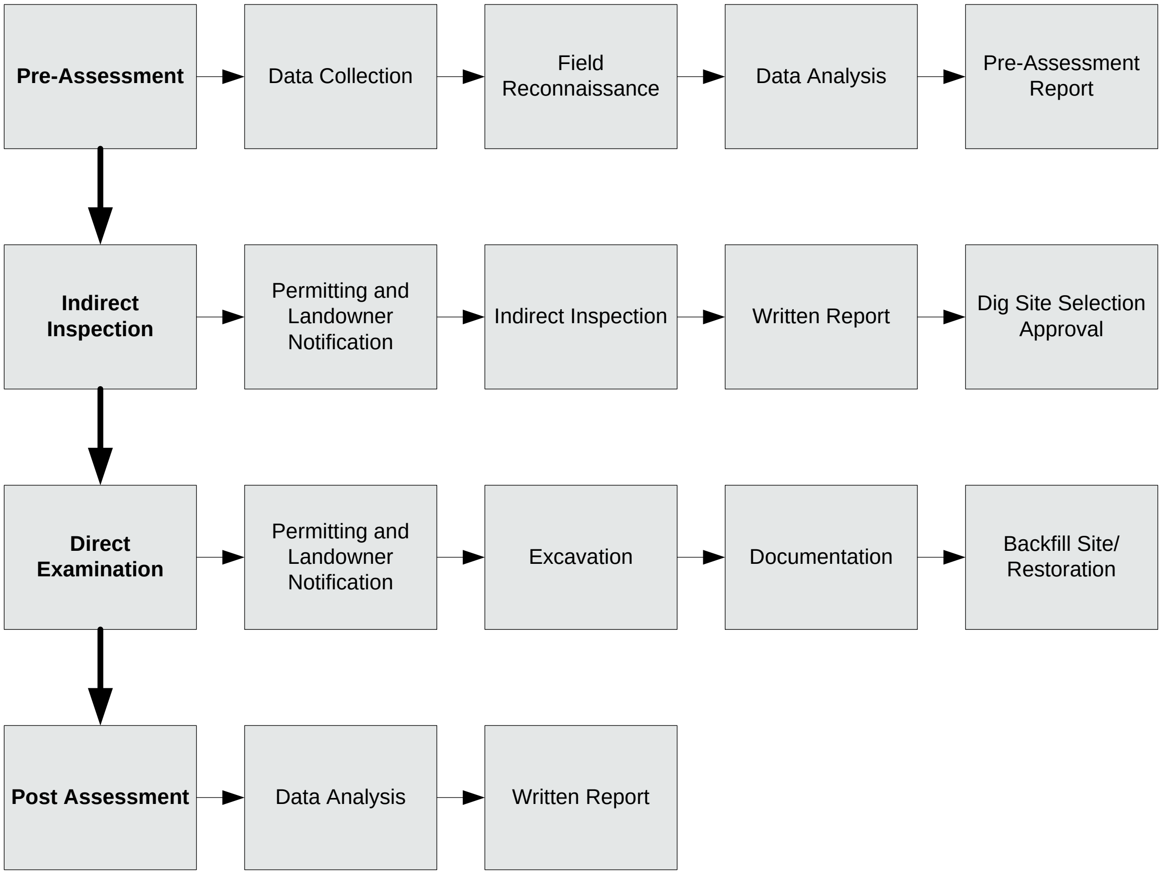



**Figure 1 – ECDA Process Overview**

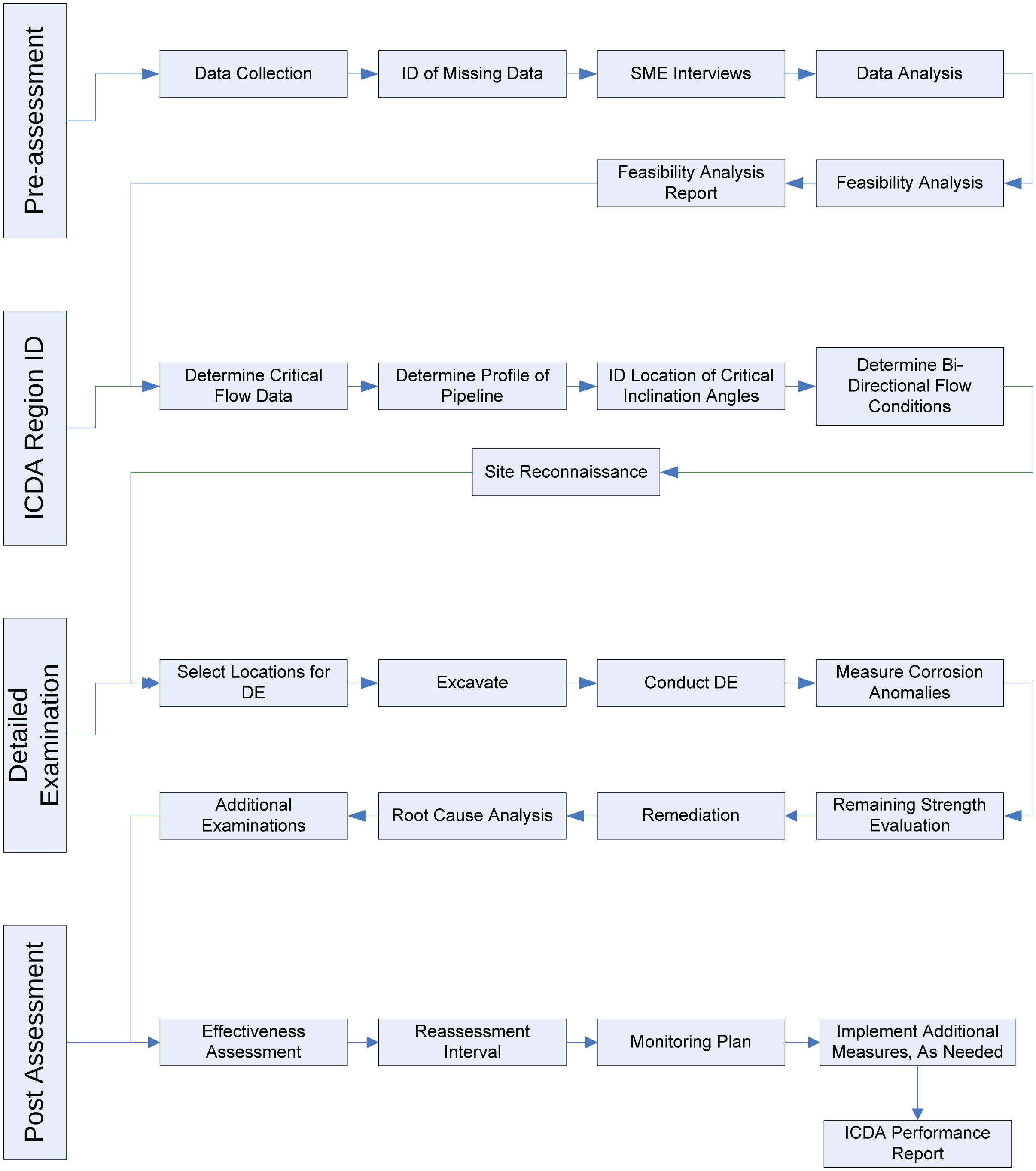



**Figure 2 – ICDA Process Overview**

**Table 1 – Transmission Integrity Management Costs** — **$ Thousands**

| Activity | 2010 | 2011 | 2012 |
|---|---|---|---|
| **Transmission Integrity Management** | | | |
| **ECDA (Utah Only)** | | | |
| Pre-Assessment | | | |
| 2010 (FL41, 64, 65, 66, 68, 69, 72, 81, 84) (20 HCA miles @ 2 K / mile) | 40 | | |
| 2011 (FL10, 14, 35, 41, 48, 52, 85, 88) (12.5 HCA miles @ 2 K / mile) | | 25 | |
| 2012 ( to be determined) (25 HCA miles @ 2 K / mile) | | | 50 |
| Indirect Inspections | | | |
| 2010 (FL41, 64, 65, 66, 68, 69, 72, 81, 84) (20 HCA miles @ 30 K/mile) | 600 | | |
| 2011 (FL10, 14, 35, 41, 48, 52, 85, 88) (12.5 HCA miles @ 30 K / mile) | | 375 | |
| 2012 ( to be determined) (25 HCA miles @ 30 K / mile) | | | 750 |
| Direct Examinations | | | |
| 2010 (FL 16, 46, 62, 51, 53, 54, 55, 56, 87, 51, 53, 70, 83) (29 excavations @ 12 K ea.) | 348 | | |
| 2010 (FL 16, 46, 62, 51, 53, 54, 55, 56, 87, 51, 53, 70, 83) (5 casings @ 100 K ea.) | 500 | | |
| 2011 (FL41, 64, 65, 66, 68, 69, 72, 81, 84) (24 excavations @ 12 K ea.) | | 288 | |
| 2011 (FL41, 64, 65, 66, 68, 69, 72, 81, 84) (4 casings @ 100 K ea.) | | 400 | |
| 2012 (FL10, 14, 35, 41, 48, 52, 85, 88) (20 excavations @ 12 K ea.) | | | 240 |
| 2012 (FL10, 14, 35, 41, 48, 52, 85, 88) (4 casings @ 100 K ea.) | | | 400 |
| Post Assessment | | | |
| 2010 ( FL16, 46, 62, 51, 53, 54, 55, 56, 87, 51, 53, 70, 83) | 43 | | |
| 2011 (FL41, 64, 65, 66, 68, 69, 72, 81, 84) | | 25 | |
| 2012 (FL10, 14, 35, 41, 48, 52, 85, 88) | | | 25 |
| **ICDA (Utah Only)** | | | |
| 2010 (FL83, 99) | 163 | | |
| 2010 Excavations (8 excavations @ 3 K ea.) | 24 | | |
| 2011 (FL14, 41, 48, 52, 88) | | 350 | |
| 2011 Excavations (8 excavations @ 3 K ea.) | | 24 | |

## Table 1 – Transmission Integrity Management Costs

| Activity | 2010 | 2011 | 2012 |
|---|---|---|---|
| | $ Thousands | | |
| **Direct Examination (Utah Only)** | | | |
| 2010 - Spans (2 spans @ 75 K / span) | 150 | | |
| 2010 - Vaults (3 vaults @ 5 K/ vault) | 15 | | |
| 2011 - Spans (2 spans @ 75 K/ span) | | 150 | |
| 2011 - Vaults (3 vaults @ 5 K/ vault) | | 15 | |
| 2012 - Spans (2 spans @ 75 K/ span) | | | 150 |
| 2012 - Vaults (3 vaults @ 5 K/ vault) | | | 15 |
| **HCA Validation** | | | |
| Identified Site Survey ( QPEC - 1200 hrs @ $30.00 / hr) | 36 | 36 | 36 |
| Identified Site Survey (misc. travel expenses 40 days @ $125/day) | 5 | 5 | 5 |
| Data integration/ update HCAs (100 hrs @ $70.00/ hr) | 7 | 7 | 7 |
| **Excavation Standby** | | | |
| 4 employees (2080 hrs x 4 x $70.00/hr) | 582.4 | 582.4 | 582.4 |
| **Additional Leak Survey** | | | |
| 120 hrs @ $70.00/hr | 8.4 | 8.4 | 8.4 |
| **GIS - Pipeline Centerline Mapping Project** | | | |
| 5.75 FTE x 65 days x 8hrs/ day x $70.00/hr | 209.3 | | |
| **Administration** | | | |
| Project Coordination (3 employees (2080 hrs x 3 x $70.00/hr)) | 436.8 | 436.8 | 436.8 |
| Data Integration Specialists (2 employees (2080 hrs x 3 x $70.00/hr)) | 285.6 | 285.6 | 285.6 |
| Data Integration Specialist - QPEC (1500 hrs x $30.00/hr) | 45 | 45 | 45 |
| Supervisor (2080 hrs x $70.00/hr) | 142.8 | 142.8 | 142.8 |
| Engineering (2080 hrs x $70.00/hr) | 142.8 | 142.8 | 142.8 |
| Training (for IM personnel) | 22.45 | 22.45 | 22.45 |
| **Transmission Integrity Management Total ($ Thousands)** | $ 3,807 | $ 3,366 | $ 3,344 |

## Table 2 – Distribution Integrity Management Costs

$ Thousands

| Activity | | 2010 | 2011 | 2012 |
|---|---|---|---|---|
| **Distribution Integrity Management** | | | | |
| **NOTE:** *The following is a detailed description of the costs associated with the new distribution integrity management rule. These numbers are estimates of anticipated system-wide costs (not just Utah).* | | | | |
| **§ 192.383** | **Excess Flow Valve Installation** | | | |
| | Administrative Functions (reporting, procedures, documentation) Year 1 – 110 hrs + 2125 hrs; Year 2 and on – 10 hrs + 2500 hrs @ $70.00/hr | 156.45 | 175.7 | 175.7 |
| **§ 192.1001** | **What definitions apply to this subpart?** | | | |
| | Procedures and training – Year 1- 1080 hrs; Year 2 and on – 0 hrs @ $70.00/hr | 75.6 | | |
| **§ 192.1005** | **What must a gas distribution operator do to implement this subpart?** | | | |
| | Implementation Team – Year 1 – 100 hrs; Year 2 and on – 24 hrs | 7 | 1.68 | 1.68 |
| | Plan Template - $25,000.00 | 25 | | |
| | Plan Prep – Year 1 – 1000 hrs; Year 2 and on – 0 hrs @ $70.00/hr | 70 | | |
| | Plan update/revisions – Year 1 – 0 hrs; Year 2 and on – 250 hrs @ $70.00/hr | | 17.5 | 17.5 |
| | Manage overall program – Year 1 – 1000 hrs; Year 2 and on – 500 hrs @ $70.00/hr | 70 | 35 | 35 |
| **§ 192.1007** | **What are the required elements of an integrity management plan?** | | | |
| | System Knowledge – Year 1 – 1000 hrs; Year 2 and on – 200 hrs @ $70.00/hr | 70 | 14 | 14 |
| | Identify threats – Year 1 – 1000 hrs; Year 2 and on – 0 hrs @ $70.00/hr | 70 | | |
| | Risk Software – Year 1 - $25,000.00; Year 2 and on - $0 @ $70.00/hr | 25 | | |

**Table 2 – Distribution Integrity Management Costs**

| | | $ Thousands | | |
|---|---|---|---|---|
| **Activity** | | **2010** | **2011** | **2012** |
| | Risk Calculations – Year 1 – 0 hrs; Year 2 and on – 250 hrs @ $70.00/hr | | 17.5 | 17.5 |
| | Region Meetings – Year 1 – 0 hrs; Year 2 and on – 240 hrs @ $70.00/hr | | 16.8 | 16.8 |
| | Field Activities – Year 1 - $0; Year 2 and on – $264,000.00 | | 264 | 264 |
| | Measuring performance – Year 1 – 0 hrs; Year 2 and on – 100 hrs @ $70.00/hr | | 7 | 7 |
| | Periodic evaluation – Year 1 – 0 hrs; Year 2 and on – 100 hrs @ $70.00/hr | | 7 | 7 |
| | Reporting – Year 1 – 0 hrs; Year 2 and on – 20 hrs @ $70.00/hr | | 1.4 | 1.4 |
| **§ 192.1009** | **What must an operator report when compression couplings fail?** | | | |
| | Revisions to database/ capture of field data - Year 1 – 100 hrs; Year 2 and on – 20 hrs @ $70.00/hr | 7 | 1.4 | 1.4 |
| **§ 192.1011** | **What records must an operator keep?** | | | |
| | Year 1 – 200 hrs; Year 2 and on – 80 hrs @ $70.00/hr | 14 | 5.6 | 5.6 |
| **Distribution Integrity Management Total ($ Thousands)** | | $ 590.05 | $ 564.58 | $ 564.58 |

**Environmental Issues**

Questar Gas is committed to be part of the climate change solution. Energy efficiency has been part of the natural gas utility business plan since the early 1970's; the average natural gas general service (GS) customer uses 55% less natural gas than in 1972. Questar Gas has placed great emphasis on energy efficiency over the last three years through its ThermWise® program resulting in over 17% of customers participating in the programs by having home energy audits, improving home weatherization and installing more energy efficient appliances.

Natural gas is an abundant domestic fuel and new technologies continue to be developed to find and produce gas. Much of Questar Gas' supply is company owned, and the non-owned supply sources have become more diverse.

Natural gas consumption will be affected, in part, by how climate change regulations address natural gas. If these regulations recognize that use of natural gas in high efficiency residential, commercial, transportation, industrial and electricity generation applications is key to attempts to lower US green house gas emissions, then use of natural gas in these applications should increase. Similarly, natural gas will be essential in ensuring electrical grid reliability as reliance on intermittent renewable energy increases in the future.

Questar Gas is a member of the EPA's Natural Gas STAR program, a flexible, voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Some of the "best management practices" utilized include:

1. Directed Inspection and Maintenance – repair or replacement of valves/components at surface facilities to reduce emissions;
2. Customer Meters –maintenance and replacement program;
3. Pipe Replacement of older feeder lines;
4. Blowdowns – when conducting pipeline maintenance, avoid blowdowns of pressurized lines when possible; and
5. Hot tap technology to reduce gas loss and avoid shut downs.

New environmental policy is affecting industry, in general, and the natural gas industry specifically, and will result in significant additional costs. The following will have particularly dramatic effects on the costs of conducting business:

1. EPA Greenhouse Gas Reporting Rule: EPA's Greenhouse Gas Reporting Rule was promulgated at the end of 2009 and, starting in January, 2010, natural gas distribution companies are required to annually report $CO_2$e combustions emissions greater than 25,000 metric tonnes per year at individual facilities, as well as report $CO_2$e emissions for all residential and commercial customers. Using estimates for 2009, Questar Gas would report 9 million tonnes of $CO_2$e emissions for its customers (QGC individual facility emits more than 25,000 tonnes per year in combustion emissions). On March 23, 2010, a revised Subpart W of the rule was released for comment, which covers fugitive methane

emissions from natural gas operations. The proposed Subpart W now includes fugitive and vented emissions of methane from LDC pipeline systems; this will result in a significant increase in reported $CO_2e$ emissions for QGC.

This rule develops an "inventory" of emissions that will likely be used in the future to determine emissions for cap and trade (or other regulatory) purposes. Any fees charged for carbon emissions (whether allowances, taxes, or regulatory fees) could be assessed for the emissions from the LDC's customers and/or for fugitive/vented methane. At a very roughly estimated 9.5 million metric tonnes (9 million tonnes from emissions from distribution customers and 500,000 tonnes (preliminary estimate) attributable to pipeline system methane fugitives and venting) and a hypothetical $25/metric tonne charge, the LDC could be assessed $237.5 million per year (which does not include costs of condcuting the work to collect data for reporting). Recognizing that the LDC is a regulated retail distributor of natural gas, the LDC would anticipate full recovery of costs incurred (including costs of conducting sampling and analysis, etc.) to meet these climate change obligations. Based on 900,000 customers, that equates to an annual fee of about $264/customer.

2. Endangerment Finding and EPA Tailoring Rule: In April 2009, the EPA announced that greenhouse gases (GHGs) threaten the public health and welfare of the American people. EPA also found that GHG emissions from on-road vehicles contribute to that threat. EPA's final findings respond to the 2007 U.S. Supreme Court decision that GHGs fit within the Clean Air Act definition of air pollutants. The findings do not, in and of themselves, impose any emission reduction requirements but rather allow EPA to finalize the GHG standards for new light-duty vehicles as part of a joint rulemaking with the Department of Transportation. When this light-duty vehicle standard went into effect, greenhouse gases effectively became "regulated pollutants" under the Clean Air Act. That, in turn, will automatically triggers Prevention of Significant Deterioration (PSD) permit requirements for stationary sources that are above the threshold for being "major sources" of regulated pollutants.

The statutory threshold for PSD review was 250 tonnes per year, which would have resulted in the need for many commercial and industrial natural gas customers to apply for a PSD permit, the most stringent air permit under the Clean Air Act. On May 13, 2010, the EPA published the final PSD Tailoring rule that raises the thresholds for green house gas emissions and defines when permits under the PSD and Title V Operating Permit programs of the Clean Air Act are required for new and existing facilities. The rule will be phased in and should intially affect only Questar's largest industrial customers. Although EPA will undertake more rulemaking related to green house gas threshold under this rule, in 2011-2012, they will not regulate sources with greenhouse gas emissions less than 50 tonnes per year, which still only affects large commercial/industrial customers. Finally, by 2016, EPA will determine whether any additional smaller sources need to be regulated. These rulemakings could affect additional commercial facilities and potentially influence them to install electric drives to power equipment, rather than use natural gas, even though life cycle analysis would show that the use of natural gas is much more environmentally sound.

3. National Ambient Air Quality Standards (NAAQS) Reductions: Under the Clean Air Act, the EPA has reduced NAAQS limits for $PM_{10}$ and ozone. Reduction of ozone levels fundamentally results in the need to reduce $NO_x$ and VOC emissions since they are precursors to ozone. Additionally, a new Primary Standard for $NO_2$ (1 hour exposures) and a $PM_{2.5}$ standard recently went into effect. Several Utah counties, particularly along the Wasatch Front, will be affected by these changes. The State will need to revise the Clean Air Act-required State Implementation Plan in order to move the State from non-attainment to attainment of the standards. This could lead to increased use of alternative fuel vehicles, including NGVs (reduced $NO_x$ and $PM_{10}$). It also could lead to installation of cleaner burning appliances and industrial equipment.

4. Questar Gas will continue to comply with existing environmental and safety rules that protect employees, the public, and the environment. Environmental issues are investigated, researched and addressed to minimize impacts. These environmental and safety matters continue to be properly addressed to mitigate the problem while working as efficiently as possible.

Exhibit 4.1

**Northern System – Peak Day – Steady State**

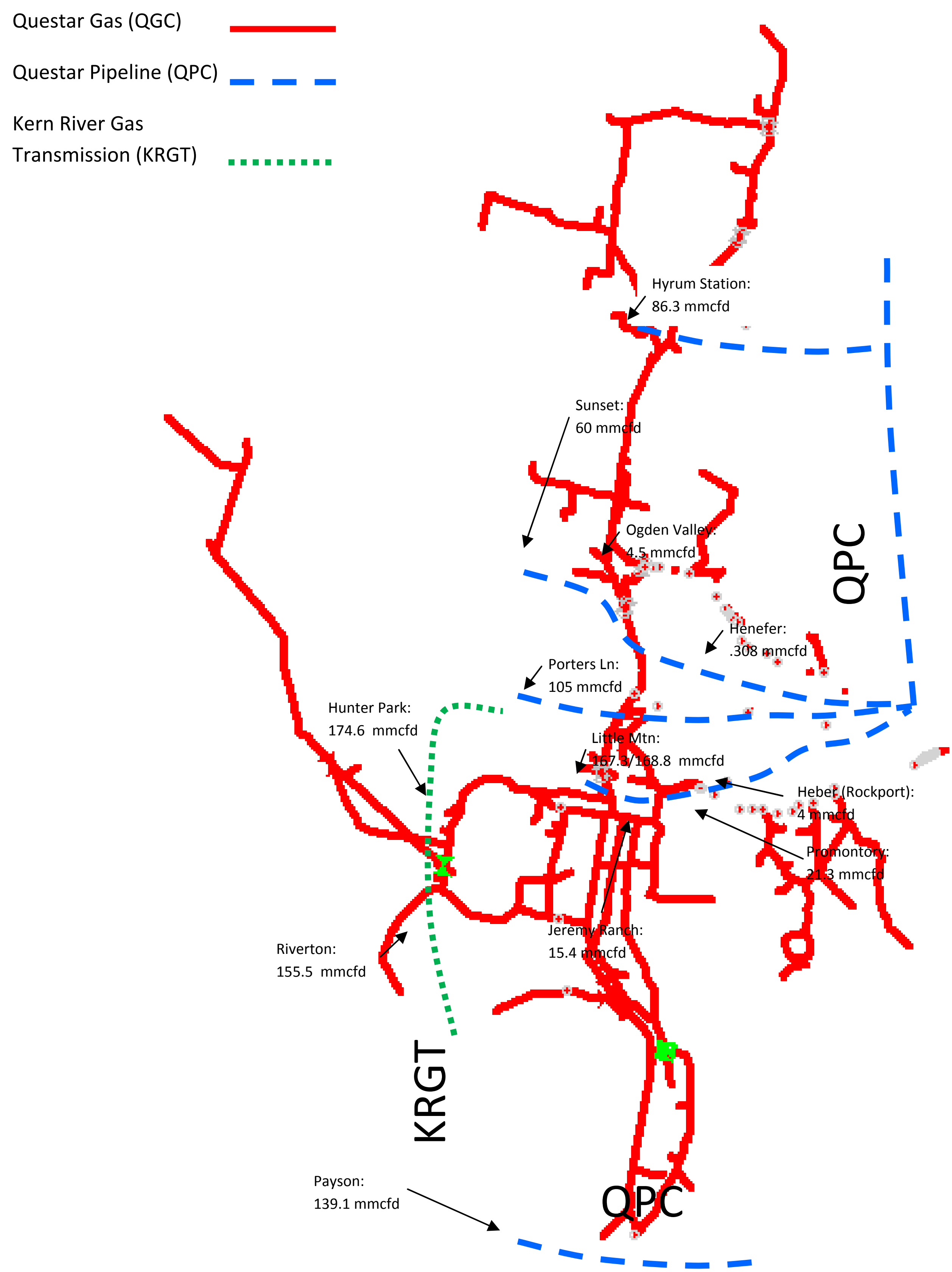


Exhibit 4.2

## Eastern (North) System – Peak Day – Steady State

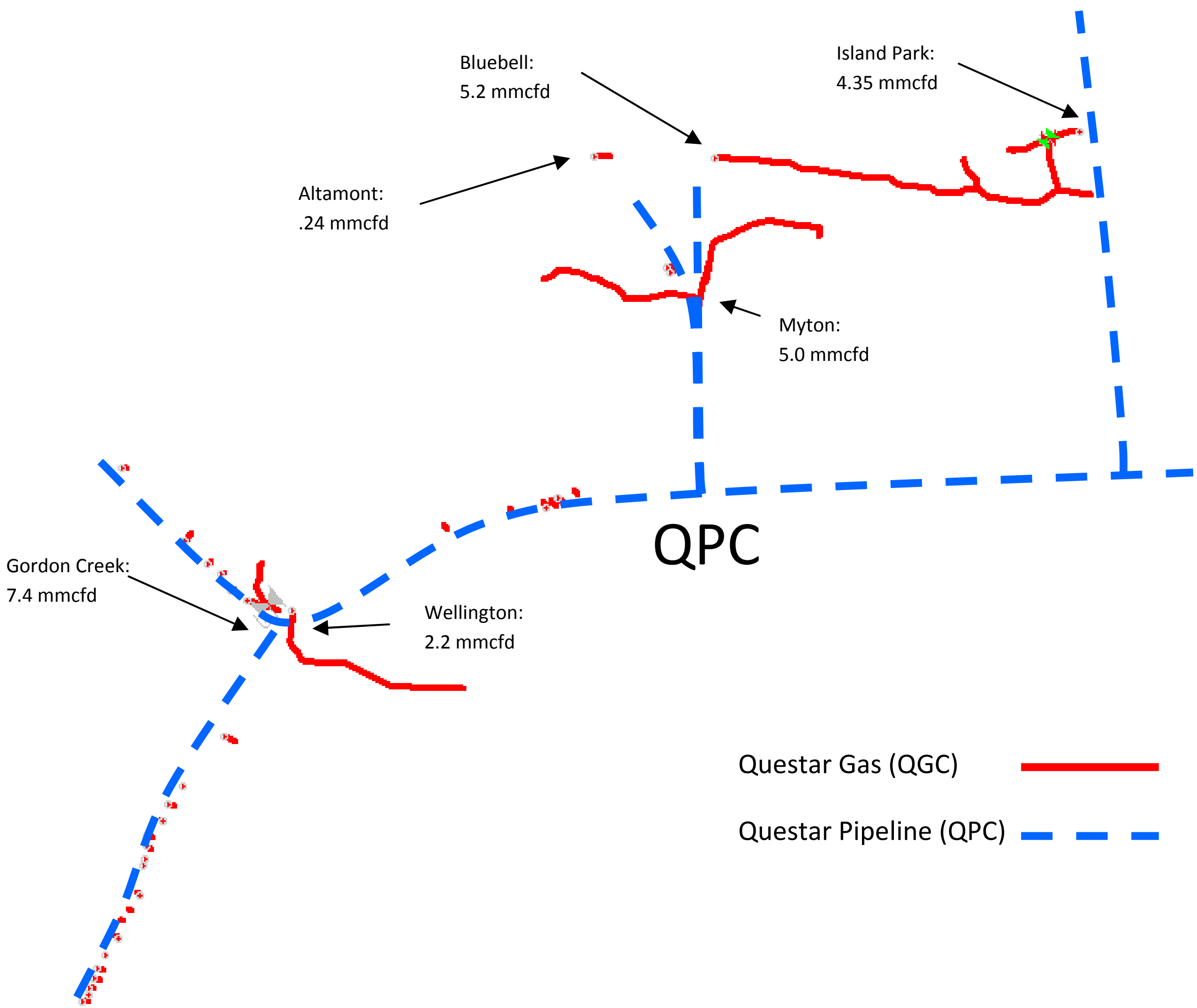


Exhibit 4.3

**Eastern (Northwest Pipeline) System – Peak Day – Steady State**

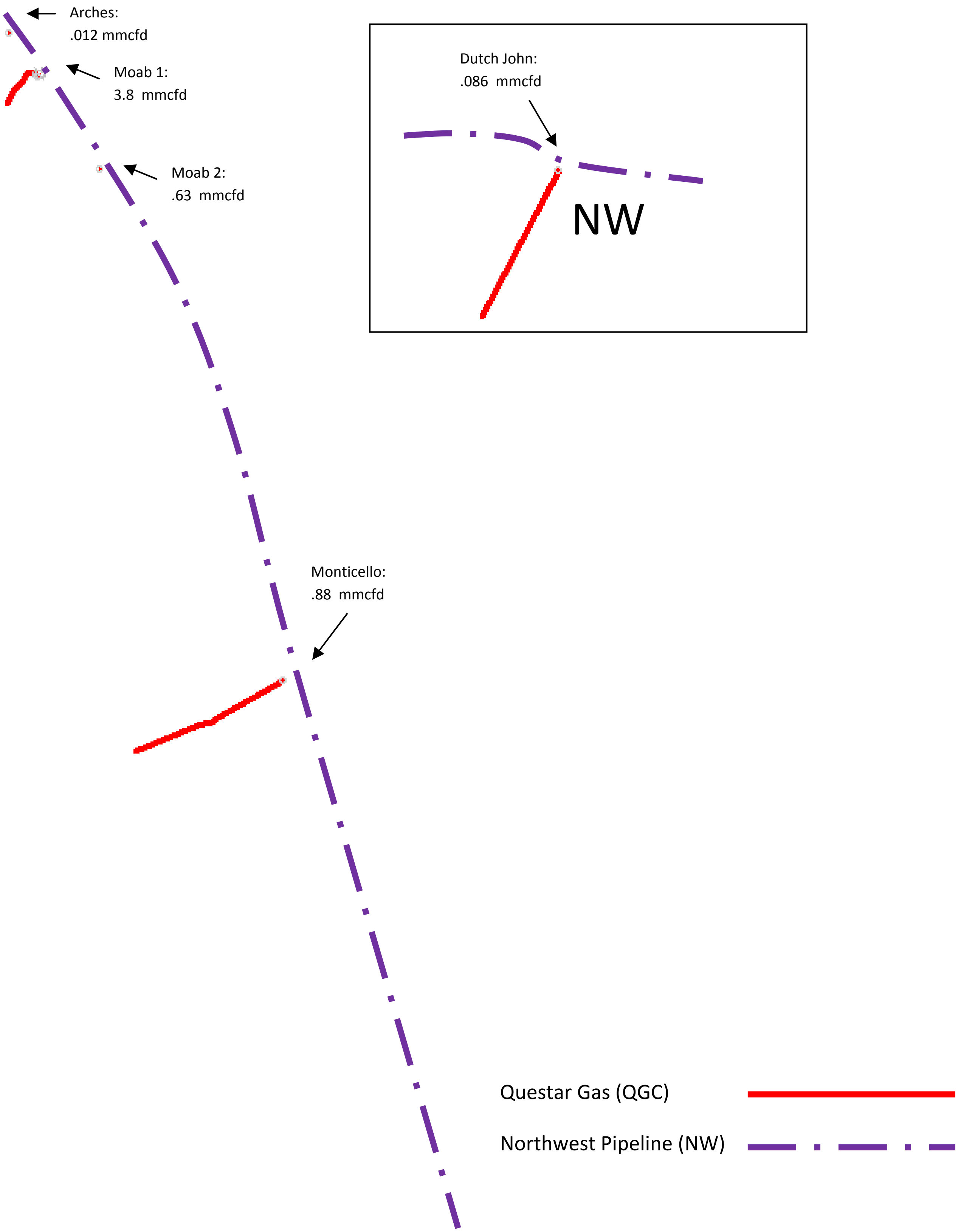


Exhibit 4.4

**Southern (Main) System – Peak Day – Steady State**

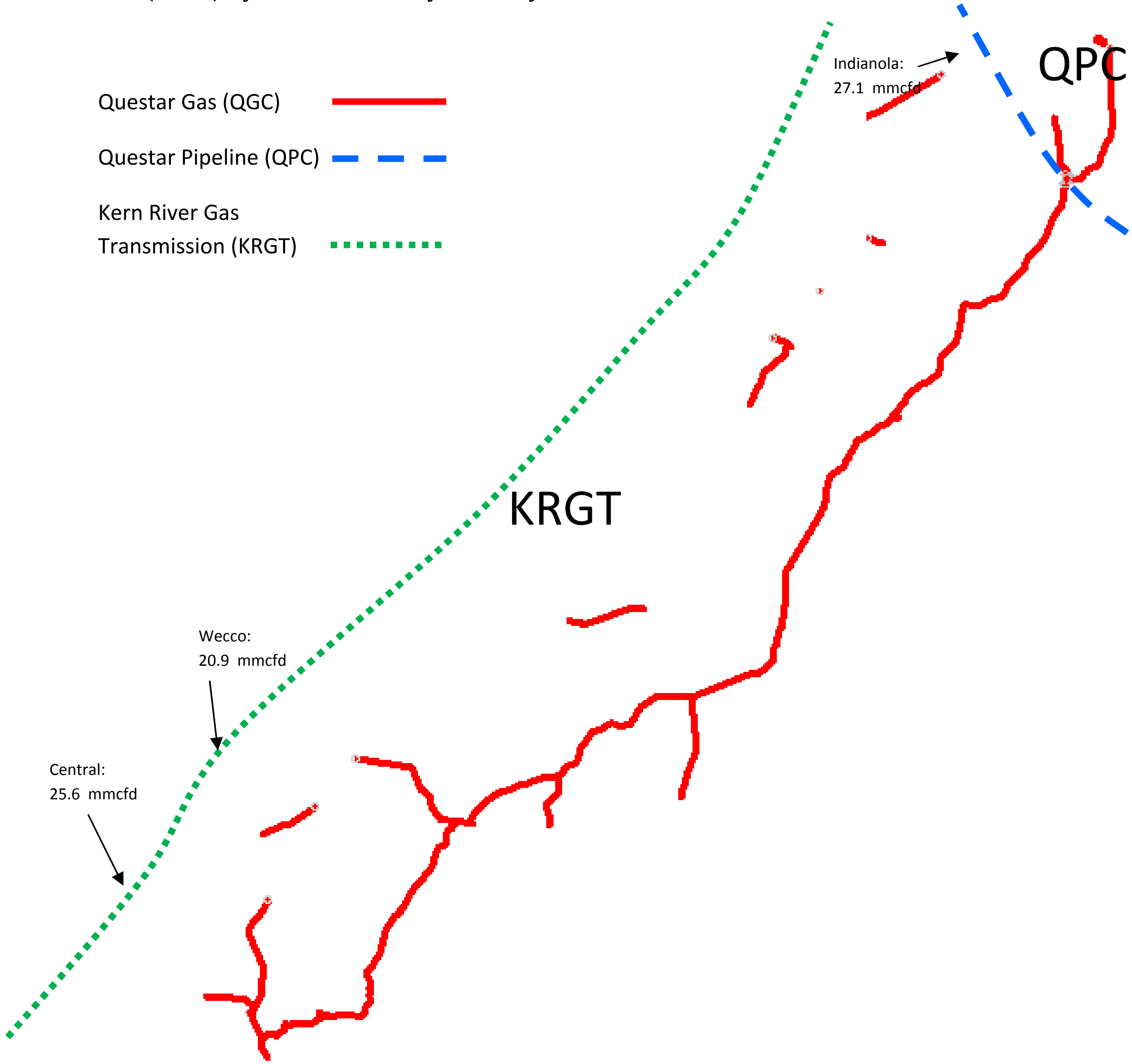


Exhibit 4.5

**Southern System (KRGT Taps) – Peak Day – Steady State**

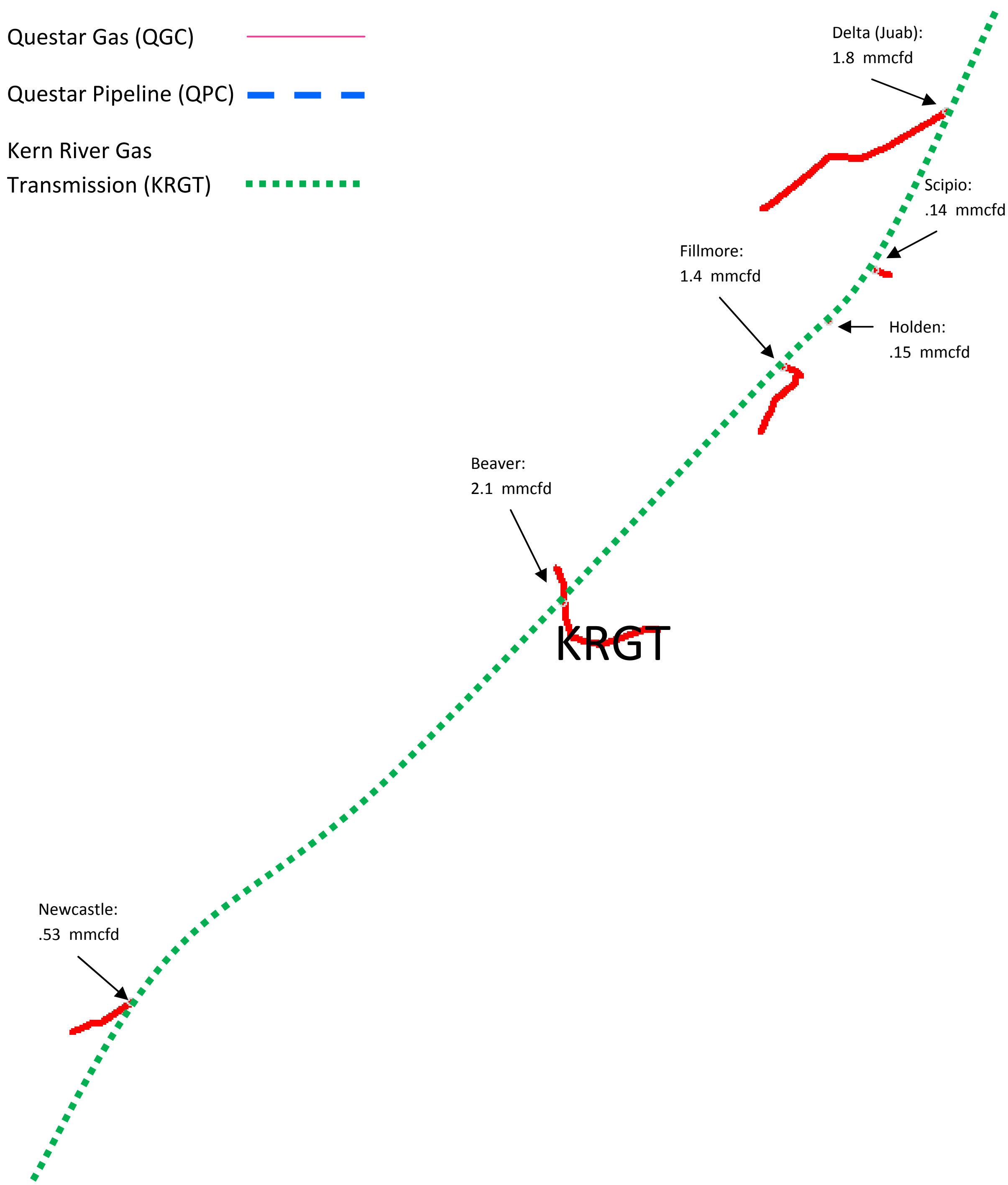
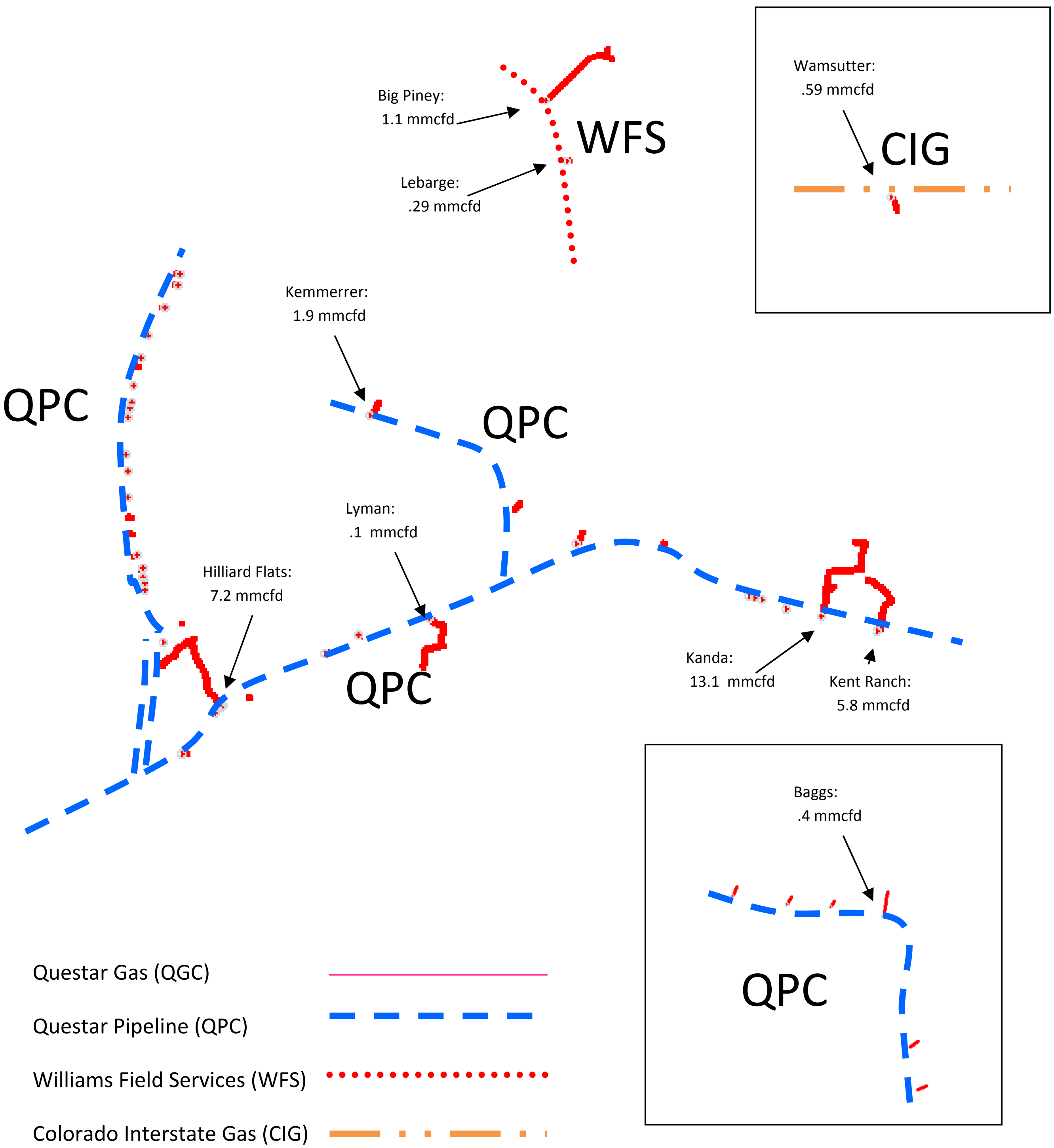


Exhibit 4.6

**Wyoming System – Peak Day – Steady State**



# PURCHASED GAS

## Local Market Environment

Monthly index prices for natural gas delivered into Questar Pipeline's system during the 2009 calendar year averaged $3.02 per Dth. This was substantially lower than the 2008 average price of $6.15 per Dth, a decrease of $3.13 per Dth or 51%. The 2008 and 2009 monthly index prices are provided in Table 5.1 below.

**Table 5.1 Questar Pipeline First-of-Month (FOM) Index Price per Dth**

| Month | 2008 | 2009 | Difference |
|---|---|---|---|
| Jan | $5.89 | $4.21 | ($1.68) |
| Feb | $7.15 | $2.87 | ($4.28) |
| Mar | $7.72 | $2.43 | ($5.29) |
| Apr | $7.75 | $2.28 | ($5.47) |
| May | $8.87 | $2.46 | ($6.41) |
| Jun | $8.91 | $2.40 | ($6.51) |
| Jul | $8.45 | $2.61 | ($5.84) |
| Aug | $6.51 | $2.85 | ($3.66) |
| Sep | $1.77 | $2.39 | $0.62 |
| Oct | $3.36 | $3.30 | ($0.06) |
| Nov | $2.61 | $4.28 | $1.67 |
| Dec | $4.83 | $4.10 | ($0.73) |
| **Average** | **$6.15** | **$3.02** | **($3.13)** |

The price for natural gas delivered on Questar Pipeline's system during the 2008-2009 heating season (November-March) averaged $3.39 per Dth compared to an average price of $4.69 per Dth during the 2009-2010 heating season, an increase of $1.30 or 38%. The monthly index prices for the two heating seasons are provided in Table 5.2 below.

**Table 5.2 Questar Pipeline FOM Index Price per Dth – Heating Season**

| Month | 2008-2009 | 2009-2010 | Difference |
|---|---|---|---|
| Nov | $2.61 | $4.28 | $1.67 |
| Dec | $4.83 | $4.10 | ($0.73) |
| Jan | $4.21 | $5.55 | $1.34 |
| Feb | $2.87 | $5.06 | $2.19 |
| Mar | $2.43 | $4.47 | $2.04 |
| **Average** | **$3.39** | **$4.69** | **$1.30** |

Current forecasts of Rockies indices reflect an average price of approximately $3.80 per Dth through October 2010. Prices for the 2010-2011 heating season are forecasted to be approximately $4.10 per Dth.

**Modeling Issues**

Among the most fundamental outcomes from the IRP modeling process each year is a determination of the characteristics of the portfolio of natural gas purchase contracts to be utilized by Questar Gas. A significant portion of the annual gas supply needs of the customers of Questar Gas are met with cost-of-service supplies provided under the Wexpro Agreement (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 requests for proposals (RFPs) to potential suppliers on upstream interconnecting interstate pipelines each year.

Over the years, Questar Gas has determined that the most favorable time to issue its annual RFP, soliciting proposals for natural gas supplies, is in the late-winter/early-spring time frame. During this time period, sufficient supplies for the upcoming winter heating season are likely to be available and uncommitted. Time is needed for proposals to be developed and submitted by the RFP recipients. Then, the Company needs time to extract all the data, model all the gas supply packages proposed, and complete the contracting process. In the event some of the deals do not materialize for packages selected, ample time remains before the winter heating season begins to remedy any shortfalls.

On February 23, 2010, Questar Gas sent out its RFP to 52 prospective suppliers. The RFP sought proposals for both base load and peaking supplies on the two major interstate pipeline systems interconnected with Questar Gas; Questar Pipeline and Kern River. The RFP required that base load supplies on Questar Pipeline have availabilities of 180, 150, 120 and/or 90 days. Due to the fact that 50,000 Dth/D of the 53,000 Dth/D held on Kern River are only available during the five winter months of November through March, the RFP required base load supplies on Kern River to have availabilities of 150, 120, and/or 90 days. Multi-year winter-heating-season proposals were sought on both pipelines with terms ranging from two to five years. Proposals for peaking supplies were sought on both pipeline systems having availabilities of two to four months to meet customer demands during the coldest winter-heating-season months.

Reliability of supplies is a critical issue for Questar Gas. The RFP required that all purchased gas proposals accepted by Questar Gas have, in the underlying confirmation letters, language specifying a $15.00 per decatherm penalty for failure to perform. All proposals were also required to have language ensuring creditworthiness and language specifying the minimum advance notice required before nomination deadlines for gas flow.

Responses to the purchased-gas RFP were due on March 8, 2010. Proposals for 344 gas supply packages were received from 18 potential suppliers. As part of the RFP requirements, submissions are required to specify if the same gas supply is offered under multiple proposals. This year supplies offered under base-load proposals totaled 569,000 Dth/D, down slightly from the 591,000 Dth/D offered last year. Peaking supplies offered on Questar Pipeline's system totaled 365,000 Dth/D, down from the 420,000 offered last year. Peaking supplies offered on Kern River totaled 540,000 Dth/D, up from last year's level of 470,000 Dth/D.

Each spring, following the receipt of all the proposals, Questar Gas reviews all the purchased-gas packages offered and extracts the parameters needed as data inputs to the SENDOUT model.[1] The pricing mechanisms utilized for each package must be identified and linked to the appropriate index price in the model. Also, the availability of receipt and delivery point capacity on the interstate pipeline system utilized must be resolved. To the extent that the same underlying gas supplies have been offered in different natural-gas price and term packages, they must be identified to prevent the modeling of more gas than is actually available.

Questar Gas includes in its modeling process each year the availability of supplies that can be purchased from the Company's interruptible transportation customers in the State of Utah. As a condition to receiving interruptible transportation service, the Company's Utah Tariff allows for the purchase of these supplies during periods of interruption for the benefit of Questar Gas' firm sales customers. Upon notice by the Company, interruptible transportation customers are required to nominate levels of this resource as specified by the Company. The Company can purchase these supplies at the interconnecting upstream pipeline receipt point and use its own transportation capacity, or the purchase can take place at Questar Gas' city gates. The tariff specifies a predetermined pricing mechanism for payment for these supplies. Questar Gas has planned on the availability of 50,000 Dth/D of this resource for its SENDOUT modeling process this year, for the months of December through February.

The levels of purchased-gas packages selected from the SENDOUT modeling process this year are shown in the 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 9.53 to 9.64 along with each probability distribution. Individual packages of purchased-gas supplies for the base case are shown for the first two plan years in Exhibits 9.84 and 9.86. Commitments to purchase were made with suppliers on April 16, 2010.

**Price Stabilization**

During the winter of 2000-2001, the Office, Division and Utah Commission developed a working depth of knowledge through information provided by the Company and seminars from outside consultants.

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 price stabilization measures be used in conjunction with natural gas purchases during the winter months (October – March).

[1] The SENDOUT model is described in more detail in the Results section of this report.

Pursuant to the Stipulation, the Company proceeded to hedge portions of its natural gas portfolio each winter.

In Wyoming Docket No. 30010-GP-01-62, the Company requested to include costs to reduce price volatility such as 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 or contract amendments that fix or cap prices for gas supplies that are contractually committed to Questar Gas' system for delivery to end-use retail customers.

For the October 2009 – March 2010 time period, the Company hedged 29% of its base load purchased gas supplies. This resulted in 7.17 Bcf being hedged at an average price of $4.76/MMBtu.

The Company plans to continue a hedging program for the 2010 – 2011 winter heating season.

# COST-OF-SERVICE GAS

## COS Modeling Factors

One of the most unique resources available to the customers of Questar Gas is natural gas produced pursuant to the Wexpro Agreement.[1] The Wexpro Agreement, signed in 1981, defines the relationship between Wexpro Company (Wexpro) and Questar Gas. Under this relationship, Wexpro manages and develops natural gas reserves within a limited and previously established group of properties. Production from these reserves is delivered to Questar Gas at cost-of-service, which historically, on average, has been lower-priced than market-based sources. The Wexpro Agreement contractually defines risk sharing among the parties. Wexpro is allowed to earn a return on its investment in commercial wells, but must bear the cost of dry holes.

The Division is entitled to monitor performance under the Wexpro Agreement. To facilitate that process, Wexpro provides routine reports to the Division. Further facilitating the review of performance, according to the Wexpro Agreement, is the establishment of two monitoring entities, 1) an independent certified public accounting firm (Accounting Monitor), and 2) an independent hydrocarbon industry consulting firm (Hydrocarbon Monitor). The Accounting Monitor and Hydrocarbon Monitor are selected by the Division and the Staff of the Wyoming Commission. The fees associated with both monitors are paid by Wexpro.

Questar Gas also submits periodic variance reports as required under integrated resource planning standards and guidelines in the State of Utah since the late 1990s. Under these standards and guidelines, Questar Gas has provided quarterly reports each year to Utah regulatory agencies detailing the material deviations between planned performance and actual performance of cost-of-service natural gas supplies. Under the recently established 2009 IRP Standards, that process will continue into the future.

In early November, 2009, representatives of the Company met with representatives of the Division to discuss factors influencing the decision to shut-in cost-of-service production, particularly during periods when the prevailing market prices of natural gas are relatively low. Such shut-ins have occurred in the past and most recently, during the summer and fall of 2009. At the conclusion of the early November meeting, the Division requested a report outlining these factors and containing simplified illustrative analyses for several cost-of-service production sources.

Also, during November and December of 2009, discussions took place between representatives of the Company and various commissioners and/or commission staff serving with both the Utah Commission and the Wyoming Commission where similar topics were

[1] "The Wexpro Stipulation and Agreement," Executed October 14, 1981, Approved October 28, 1981, by Public Service Commission of Wyoming and December 31, 1981, by Public Service Commission of Utah; Parties: Mountain Fuel Supply Company, Wexpro Company, Utah Department of Business Regulations, Division of Public Utilities, Utah Committee of Consumer Services, and Staff of Wyoming Public Service Commission.

discussed. The Company prepared the report *"Considerations Affecting Production Shut-Ins"*. Because of its relevance to the IRP process, it is attached as Appendix A to this integrated resource plan.

Since its inception in 1981, natural gas supplies provided pursuant to the Wexpro Agreement have amounted to between one third and one half of the total annual supplies needed to meet the needs of the customers of Questar Gas. During 2009, cost-of-service supplies comprised approximately 51 percent of the total. 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.

During 2009, the total costs remitted by Questar Gas through the monthly Wexpro invoice declined slightly from calendar year 2008. Nevertheless, the size and success of recent drilling programs coupled with the anticipated future development programs suggests that substantial future declines in the operator service fee will not likely occur. More information on Wexpro's planned development-drilling programs is contained in the Future Resources section of this report.

Among the most important results of the SENDOUT modeling process each year is a determination of the appropriate production profiles for cost-of-service gas. This year, Questar Gas modeled 51 categories of cost-of-service production. These categories have been created 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. Questar Gas 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 probability curves and median levels of production for cost-of-service gas resulting from the SENDOUT modeling process this year are contained in the Results section of this report.

**Producer Imbalances**

In most of the wells where Questar Gas receives cost-of-service gas, 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 doesn't exist. No individual working interest owner can control, in the short term, the level of producer imbalances associated with a well because they do not have control over the volumes that their partners 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. Further complicating matters is 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. 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 partners, 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. Also complicating the process is the fact that advance notice of several weeks is typically required before imbalance recoupment can begin to be nominated.

Over the past year, producer-imbalance recoupment has taken place in fields where Questar Gas is entitled to receive cost-of-service production. Exhibit 6.1 shows the monthly volumes nominated for recoupment during calendar year 2009 and for the first two months of 2010.

Questar Gas has had an overproduced position in Hiawatha Deep Well No. 1, and an under-produced position in Hiawatha Deep Well No. 3. In early 2008, the Company began nominating recoupment in the Hiawatha Deep Well No. 3 and was recouped against by its working interest partner in Well No. 1. This recoupment has continued through 2009 and early 2010. The net effect is that imbalance levels in both wells will be lessened and the volumes will offset to some extent in the determination of the field total. Exhibit 6.1 shows monthly recoupment volumes for both Hiawatha Deep wells.

Recoupment has also been taking place for wells in the Ace/Jacks Draw area. These volumes are relatively minor as shown in Exhibit 6.1.

Questar Gas has been over-produced in the Mesa/Pinedale, Trail and Moxa fields. For selected wells in these areas, the working interest partners of Questar Gas have nominated imbalance recoupment volumes as can be seen in Exhibit 6.1.

During 2008, the Company recouped imbalance volumes in the Church Buttes Field. Wells in the Church Buttes Field are designated by the pricing category in which they fall under definitions contained in the Natural Gas Policy Act of 1978. This recoupment process resulted in the minimization of imbalance levels in all three pricing categories such that no further recoupment needs to take place. There are wells that fall outside of the Church Buttes Unit which are designated as Church Buttes Buffer Wells in which Questar Gas had an over produced position. During 2009 and early 2010, a working interest partner in the Buffer Wells nominated recoupment against Questar Gas. These volumes are also shown in Exhibit 6.1.

As of December 31, 2009, Questar Gas had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of approximately 2.0 Bcf. By way of comparison, the total net producer imbalance level for December 31, 2008 was approximately 1.2 Bcf. The Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In a recent audit report, the Hydrocarbon Monitor concluded that total producer imbalance levels had been reasonable.[2]

## Future Resources

The current market price of natural gas coupled with future expectations has a direct impact on the levels of drilling in the U.S. but other factors play into the drilling decision. Among the most valued of assets in any energy production company are knowledgeable personnel such as reservoir engineers or geotechnical experts. Staffing-up and staffing-down with short-term swings in market prices generally results in the loss of valuable employees with field-specific knowledge. Plus, a case can be made for drilling when prices are down since drilling costs are generally lower. By the time a well is drilled and turned to production, prices may have rebounded.

In many situations, drilling permits dictate that leases must be developed within a specified period of time, such as two years, or the leases will be lost. 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 taking place in shale gas plays is being done on a non-voluntary basis to hold leases.

There can be other factors affecting the rate of leasehold development. For example, the customers of Questar Gas 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.[3] (See the Introduction and Background section of this report.)

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".[4] Drilling is fundamentally sequential with time limitations for development in certain defined areas.

Given all these factors, the extended focus of Wexpro is to maintain its long-term drilling plans, to the extent possible, thereby continuing to benefit the customers of Questar Gas. Planned net wells for 2010 are up from the projection for 2009. The total projected

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[2] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, April, 2010.
[3] 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.
[4] Ibid., Summary, Page 20.

expenditures for 2010 are down, however, from that forecasted for 2009. Wexpro's preliminary 2010 drilling plan calls for 62 net wells at a cost of approximately $100 million.

Over the next five years, between 50 and 60 net wells are planned to be drilled each year with Wexpro budget amounts ranging from approximately $100 million to $158 million per year. Given the prevailing uncertainty in the financial markets and natural gas markets, these longer-term estimates could vary in the future. Drilling activity in 2010 is expected to occur in the following areas: Church Buttes, Bruff/Moxa Arch, and Mesa/Pinedale. A fair amount of activity is also expected to occur in a number of fields in the Vermillion Basin including Powder Wash, Canyon Creek, Trail, and Sugar Loaf.

Plans, forecasts, and budgets for drilling development wells under the Wexpro Agreement 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.

Exhibit 6.1

Recoupment Nominations (Dth per month by Field)
QGC

| | Ace/Jacks Draw | Hiawatha Deeps |
|---|---|---|
| Jan-09 | 31 | 11,873 |
| Feb-09 | 28 | 10,724 |
| Mar-09 | 0 | 11,873 |
| Apr-09 | 0 | 28,830 |
| May-09 | 0 | 29,791 |
| Jun-09 | 60 | 28,830 |
| Jul-09 | 62 | 29,791 |
| Aug-09 | 62 | 29,791 |
| Sep-09 | 60 | 28,830 |
| Oct-09 | 62 | 29,791 |
| Nov-09 | 60 | 30,630 |
| Dec-09 | 62 | 27,714 |
| Jan-10 | 62 | 27,714 |
| Feb-10 | 56 | 24,136 |
| Total | 605 | 350,318 |

Recoupment Nominations (Dth per month by Field)
Other Parties

| | Hiawatha Deeps | Mesa | Moxa | Trail | Church Buttes Buffer |
|---|---|---|---|---|---|
| Jan-09 | 2,015 | 0 | 341 | 11,253 | 341 |
| Feb-09 | 1,820 | 0 | 308 | 7,980 | 308 |
| Mar-09 | 2,015 | 0 | 279 | 14,229 | 341 |
| Apr-09 | 4,890 | 0 | 270 | 13,830 | 1,200 |
| May-09 | 5,053 | 0 | 279 | 19,995 | 1,240 |
| Jun-09 | 4,890 | 0 | 270 | 5,130 | 1,200 |
| Jul-09 | 5,053 | 0 | 248 | 9,176 | 1,240 |
| Aug-09 | 5,053 | 0 | 248 | 10,602 | 1,240 |
| Sep-09 | 4,890 | 0 | 240 | 10,560 | 1,200 |
| Oct-09 | 5,053 | 0 | 248 | 9,362 | 1,085 |
| Nov-09 | 4,890 | 76,260 | 210 | 4,950 | 300 |
| Dec-09 | 4,495 | 30,938 | 217 | 1,674 | 310 |
| Jan-10 | 4,092 | 31,310 | 217 | 1,674 | 310 |
| Feb-10 | 3,640 | 28,224 | 196 | 0 | 280 |
| Total | 57,849 | 166,732 | 3,571 | 120,415 | 10,595 |

## GATHERING, TRANSPORTATION AND STORAGE

### Gathering and Processing Issues

As discussed in the previous section, Questar Gas is the recipient of supplies pursuant to the Wexpro agreement which are provided to its customers at cost of service. In general, some level of gathering and processing service is required for these supplies to enter the interstate pipeline system where they can be delivered to Questar Gas' city gates. Questar Gas is party to a number of gathering and processing agreements which facilitate these services. None of these agreements were negotiated or amended with either affiliates or third parties during the previous year. Many of these agreements have contractual escalation clauses requiring routine annual adjustments to gathering and processing rates which take place periodically throughout the year.

The most pertinent of all these agreements is the System-Wide Gathering Agreement with Questar Gas Management Company (Gas Management). A substantial portion of the cost-of-service natural gas supplies Questar Gas receives is contractually dedicated to this agreement. This agreement, effective September 1, 1993, incorporates a cost-of-service methodology to determine the reservation and usage rates for gathering services. Each year, new rates are calculated based on the previous-calendar-year costs-of-service allocable to Questar Gas and the previous-calendar-year natural-gas throughput. Costs are allocated based on throughput during five winter heating season months of November through March. New rates are effective each year from September 1 through August 31. As specified in the agreement, sixty percent of the annual cost of service is allocated to the reservation charge and forty percent is allocated to the usage charge.

During the summer of 2009, new rates under the System-Wide Gathering Agreement were established to be effective September 1, 2009. The new monthly reservation charge increased from $852,099 to $955,513, approximately 12 percent. Although the monthly reservation charge went up from the previous year, the commodity charge declined by nearly 20 percent, from $0.22616 per decatherm to $0.18160 per decatherm. The decline in the commodity charge was due to a substantially higher billing determinant based on a greater level of gathered volumes during calendar year 2008 than 2007. During the summer and fall of 2007, some of the cost-of-service supplies Questar Gas is entitled to receive under the Wexpro Agreement were shut in temporarily to take advantage of the availability of low-cost purchased gas.[1]

Questar Gas updates the gathering and processing cost data included in the SENDOUT modeling process each year. A logical gas supply network is utilized by the SENDOUT model to define the relationships between modeling variables. Exhibit 7.1

[1] Billing data for the System-Wide Gathering Agreement is provided on a monthly basis to the Utah Division of Public Utilities in the 191 Account Packet. Copies of the System-Wide Gathering Agreement have been provided as requested to regulatory agencies along with cost-of-service detail.

illustrates those logical relationships for the gathering, processing and transportation functions as utilized by the model this year.

## Transportation Issues

*Questar Pipeline Gas Quality*

As discussed in more detail in previous IRPs, the Federal Energy Regulatory Commission (FERC) issued an order on August 6th 2007, accepting tariff sheets proposed by Questar Pipeline to modify its gas quality provisions.[2] These gas quality provisions established cricondentherm-hydrocarbon-dew-point (CHDP) zones with CHDP limits for each zone effective January 1, 2008.[3] These zones and their limits are shown in Exhibit 7.2. Questar Gas believes that the implementation of these CHDP zones and limits has worked well over the last two years as no major gas quality issues have arisen. These CHDP provisions appear to be an effective long-term solution to equitably resolving gas quality matters. It is difficult to predict the interchangeability of future gas streams received by Questar Gas. 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 either Questar Pipeline or Kern River are compatible with the needs of Questar Gas' customers.

*Questar Pipeline Transmission*

On October 6, 1999, Questar Gas signed a firm transportation service agreement with Questar Pipeline for 50,000 decatherms per day of year-round capacity extending from the outlet of the Price CO2 plant to the Wasatch Front, a pipeline project which came to be known as Main Line 104. The primary term of service for this contract was ten years from the in-service date of these facilities (November of 2001).

Given the upcoming expiration of the primary term of this contract, and, given Questar Pipeline's proposed Main Line (ML) 104 Extension Project, Questar Gas has been in discussions with Questar Pipeline personnel concerning this Southern-System capacity. The proposed ML 104 Extension Project consists of an extension of the existing ML 104 eastward by constructing 23.5 miles of 24-inch diameter pipeline. This line will parallel Questar Pipeline's ML 40 from the Green River Block Valve to the Fidlar Compressor Station allowing for greater access to natural gas supplies in the Uinta Basin. The expected completion date of the ML 104 Extension Project is November of 2011.

On October 27, 2009, Questar Gas amended its ML 104 contract, subject to completion of the ML 104 Extension Project, by extending the primary term of the agreement to November 1, 2021. The amendment also moved the primary receipt point farther east on the Southern System to Clay Basin and changed the maximum daily quantity to 30,000 decatherms per day. The reservation and usage charges for this

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[2] Questar Pipeline Company, Docket No. RP07-457-000, FERC Gas Tariff Filing, May 18, 2007.
[3] Federal Energy Regulatory Commission, Questar Pipeline Company, Docket No. RP07-457-000, "Order Accepting Tariff Sheets," Issued August 6, 2007.

capacity to Questar Gas' city gates remains the maximum system-wide tariff rates for Questar Pipeline. The current reservation charge is $5.28804 per decatherm per month and the current usage charge is $0.00457 per decatherm (including ACA).[4]

*Kern River Gas Transmission Company Rate Case*

There have been some additional developments over the past year in the Kern River rate case. By way of brief background, Questar Gas is a shipper on Kern River's system holding 50,000 decatherms per day of seasonal capacity and 3,000 decatherms per day of year-round capacity made available from Kern River's 2003 Expansion Project. On April 30, 2004, Kern River filed a Section 4 rate case with the FERC. A Presiding Administrative Law Judge (ALJ) issued an initial decision on March 2, 2006, addressing many cost-of-service and rate-design issues.[5]

On October 19, 2006, the FERC issued Opinion No. 486.[6] Requests for rehearing of Opinion No. 486 were addressed in Opinion No. 486-A, issued on April 18, 2008, resolving most issues, with the notable exception of return on equity (ROE).[7]

On January 15, 2009, the FERC issued Opinion No. 486-B.[8] This Opinion articulated, for the first time, the new FERC policy of including master limited partnerships in the rate-of-return proxy group, making this a landmark opinion. Opinion 486-B also established an ROE of 11.55 percent and ordered Kern to file, within 45 days, a compliance filing incorporating that ROE in its rates. Several parties filed for rehearing of Opinion No. 486-B. On December 17, 2009, the FERC issued Opinion No. 486-C denying requests for rehearing of Opinion No. 486-B and accepting subsequently filed tariff sheets, subject to certain conditions, for Kern River's Period One Rates.[9] Period One for each shipper consists of the term of that shipper's initial contract (which for Questar Gas is 15 years from May 1, 2003). Tariff sheets for Period Two rates were rejected by the FERC and Opinion No. 486-C directed the appointment of a settlement judge to facilitate a settlement process on certain Period Two issues. Furthermore, it was ordered that in the event settlement could not be achieved, a trial-type evidentiary hearing would be held to resolve the remaining issues.

[4] ACA refers to the Annual Charge Adjustment assessed and collected by the Federal Energy Regulatory Commission.

[5] Federal Energy Regulatory Commission, Kern River Gas Transportation Company, Docket No. RP04-274-000, Initial Decision, March 2, 2006.

[6] Federal Energy Regulatory Commission, Kern River Gas Transportation Company, Docket No. RP04-274-000, Opinion No. 486, Opinion and Order on Initial Decision, October 19, 2006.

[7] Federal Energy Regulatory Commission, Kern River Gas Transportation Company, Docket No. RP04-274, Opinion No. 486-A, Order on Rehearing Establishing Paper Hearing Procedures, April 18, 2008.

[8] Federal Energy Regulatory Commission, Kern River Gas Transportation Company, Docket No. RP04-274-000, Opinion No. 486-B, Order on Rehearing, Proposed Settlement and Paper Hearing, January 15, 2009.

[9] Federal Energy Regulatory Commission, Kern River Gas Transportation Company, Docket No. RP04-274-000, Opinion No. 486-C, Order on Rehearing and Compliance and Establishing Settlement Judge Procedures and a Hearing, December 17, 2009.

Questar Gas and a number of other shippers were actively involved in the settlement process. On April 8, 2010, the Settlement Judge issued a status report to the FERC recommending that settlement proceedings be terminated due to an impasse over a fundamental issue even though the parties had worked diligently to resolve their differences.[10] It is anticipated that the hearing process will take place later this year and early next year. In the interim, two parties including Kern River have filed for rehearing of FERC Opinion No. 486-C. In addition, Kern River has filed a petition with the United States Court of Appeals for the District of Columbia Circuit to review FERC Opinions Nos. 486, 486-A and 486-C. Questar Gas has been actively involved in Kern River's rate case from the beginning.

*Kern River Gas Transmission Company's 2010 Expansion Project*

On June 20, 2008, Kern River filed with the FERC, pursuant to Section 7(c) of the Natural Gas Act, an application for a certificate of public convenience and necessity authorizing the construction and operation of facilities designed to increase the year-round firm transportation capacity of its system by approximately 145,000 decatherms per day.[11] Because the proposed expansion was expected to be completed during 2010, it became known as the "2010 Expansion Project". This incremental transportation capacity will be achieved through the installation of additional compression and meters at existing sites along Kern River's system, and from raising the certificated maximum allowable operating pressure of the pipeline from 1,200 pounds psig to 1,333 psig. The total cost of the project is expected to be in excess of $60 million.

Prior to the 2010 Expansion Project application, Kern River held open seasons soliciting offers for this increment of new unsubscribed capacity. On Monday, June 2, 2008, Questar Gas submitted a bid for 10,000 decatherms per day. Due to the level of interest in this resource, Questar Gas was allocated 1,885 decatherms per day of year-round ten-year capacity. The rate to be paid will be the maximum recourse rate for the 2003 Expansion Project. Questar Gas believes that this capacity will be beneficial in meeting future customer growth in the Company's service territory served only by Kern River's system. With the ability to segment, this capacity will also be useful for all of Questar Gas's customers including the facilitation of the transportation of cost-of-service supplies available at interconnection points near Opal, Wyoming. The 2010 Expansion Project was placed in service on April 9, 2010.

*Ruby Pipeline Project*

As described in the introductory section, Ruby Pipeline, L.L.C. (Ruby) filed with the FERC, on January 27, 2009, an application, under Section 7(c) of the Natural Gas Act, to obtain a certificate of convenience and public necessity facilitating the

[10] Federal Energy Regulatory Commission, Status Report to the Commission and the Chief Administrative Law Judge Recommending Termination of Settlement Proceedings, Docket Nos. RP04-274-015, RP04-274-016, RP04-274-017, RP04-274-018, RP04-274-019, RP04-274-008, Issued: April 8, 2010.

[11] Federal Energy Regulatory Commission, Kern River Gas Transmission Company, "Kern River 2010 Expansion Project," Abbreviated Application for Certificate of Public Convenience and Necessity, Docket No. CP08-429-000, June 20, 2008.

construction and operation of an interstate pipeline system.[12] The system proposed by Ruby would extend from Opal, Wyoming to Malin, Oregon. The decline in natural gas imports from Canada and anticipated long-term growth in the Pacific Northwest and California have given impetus to this project. The project is comprised of approximately 675 miles of 42-inch diameter natural gas pipeline, four compressor stations, and measurement facilities. The design capacity of the project is approximately 1.5 million decatherms per day and the estimated capital cost is approximately $3 billion.

The planned route of the Ruby pipeline project passes through northern Utah where Questar Gas has natural gas distribution facilities (see Exhibit 7.3). It is expected that the pipeline will cross the southern end of Cache Valley (south of Logan, Utah) as it extends west in a route past Brigham City, Utah in Box Elder County. Because of the proximity to the facilities of Questar Gas, the Company has been considering an interconnection with Ruby just north of Brigham City near Mile Post 109 on the Ruby system (see Exhibits 7.4 and 7.5). Questar Gas has held discussions with Ruby and Ruby is willing to put in a side tap at this location. Discussions are still taking place concerning the size of the tap and valve and the costs associated with other potential interconnection facilities.

It is difficult to know at this juncture what the costs of gas supply resources from Ruby will be when compared with other gas supply options available to the Company. Nevertheless, a northern system interconnection with this independent pipeline could potentially be valuable in terms of enhancing reliability of service for Questar Gas' customers. On February 11, 2009, Questar Gas filed a motion to intervene in the Ruby application and has been afforded full party status in these proceedings.

Since the filing of Ruby's certificate application, a number of milestones have been reached. Survey work has been initiated, environmental and cultural studies have been completed, and on January 8, 2010, the Final Environmental Impact Statement was issued by the FERC and cooperating agencies. On April 5, 2010, the FERC issued a certificate, subject to certain conditions, authorizing the Ruby Pipeline to be constructed, operated and maintained.[13] The project is currently on schedule with an anticipated in-service date of March 2011.

*Sunstone Pipeline Project*

Inquiries have been made with regard to the proposed Sunstone Pipeline Project (Sunstone Project) as a potential source of gas supply for the customers of Questar Gas. The partners of the proposed Sunstone Project are Williams Gas Pipeline Company, LLC and TransCanada Pipeline USA Ltd. The Sunstone Project is designed to transport up to 1.2 billion cubic feet of Rockies natural gas from Opal, Wyoming to an interconnect with TransCanada's Gas Transmission Northwest pipeline system near Stanfield, Oregon. This 602-mile, 42-inch-diameter pipeline is designed to serve higher-priced west coast

[12] Federal Energy Regulatory Commission, "Application of Ruby Pipeline, L.L.C. for a Certificate of Public Convenience and Necessity," Docket No. CP09-54-000, January 27, 2009.
[13] Federal Energy Regulatory Commission, Ruby Pipeline, L.L.C., Docket No. CP09-54-000, "Order Issuing Certificate and Granting in Part and Denying in Part Requests for Rehearing and Clarification," Issued: April 5, 2010.

markets. The proposed pipeline does not intersect the infrastructure of Questar Gas thereby requiring stacked pipeline rates to get supplies to the city gates of the Company. Questar Gas already has access to supplies at Opal without having to pay stacked transportation rates. As the natural gas price basis has flattened across the country, and as the Ruby Pipeline approaches its in-service date, the proposed Sunstone Project has become increasingly less viable, at least in the short term. The partners of the project have indicated that they are currently ". . . re-evaluating the scope and timing of the Sunstone Pipeline Project to meet the needs of our shippers. In the interim, we have decided to temporarily suspend field work, including survey activities. The Sunstone team remains committed to its original objective of providing safe and reliable clean-burning natural gas to markets in the West and Pacific Northwest."[14]

*Overthrust Loop Expansion Project*

Questions have also been raised about the Overthrust Loop Expansion Project as a potential resource for Questar Gas. This project is sponsored by Questar Overthrust Pipeline Company, a wholly-owned subsidiary of Questar Pipeline Company. The existing Overthrust system is in southwestern Wyoming and consists primarily of a 212 mile pipeline with a total daily capacity of nearly 2 million decatherms per day. The Overthrust Loop Expansion Project has been designed to provide an additional 0.8 million decatherms per day of capacity by constructing a 43-mile, 36-inch loop pipeline from the existing Rock Springs Compressor Station to the Cabin 31 Station in Uinta County, Wyoming. This $94 million project has been designed to facilitate deliveries to the Rockies Express, Wyoming Interstate, Kern River and Ruby pipeline systems. Overthrust Pipeline filed their application with the FERC in mid-October of 2009. Transportation to the major Questar Gas city gates from the Overthrust Loop Expansion Project would involve stacked pipeline rates. Although the Overthrust pipeline is near several small Wyoming towns served by Questar Gas, these areas are currently served by Questar Pipeline with existing interconnection facilities and vintage transportation rates.

*No Notice Transportation Service*

An additional resource utilized by Questar Gas is no-notice transportation (NNT) service. This service is essential in meeting the gas supply needs of Questar Gas' customers.[15] Questar Gas, as a transportation customer of Questar Pipeline, was entitled to the provision of NNT service since it had been receiving no-notice, bundled, city-gate, firm sales service from Questar Pipeline prior to FERC Order 636.[16] In its Order 636 restructuring application, Questar Pipeline filed a NNT service rate schedule. In order to receive the same "quality and quantity of transportation service" needed previously,

[14] www.williamsenergy.com/sunstone_pipeline/ (March 24, 2010)

[15] For a more detailed discussion of the need for no-notice transportation service, see Questar Gas Company Integrated Resource Plan, For Plan Year: May 1, 2008 to April 30, 2009, Submitted May 1, 2008, Pages 7-2 to 7-4 and Exhibits 7.2, 7.3 and 7.4.

[16] The FERC, on April 8, 1992, issued Order 636, and later, on August 3, 1992, issued Order No. 636-A. These orders required interstate pipeline companies to unbundle their sales and transportation services ensuring that all natural gas suppliers could receive the same quality of transportation services. Among those services which the FERC required interstate pipeline companies to provide on an unbundled basis, was "no-notice transportation service."

Questar Gas subscribed to this NNT service offered by Questar Pipeline. It was primarily the rationale given by the FERC which necessitated the receipt of this service by Questar Gas . . . “unexpected changes in temperature.”[17]

Within the service area of Questar Gas, temperatures can be among the coldest in the nation. Temperature swings along the Wasatch Front can be large, sudden and difficult to predict. The transient flows resulting from unexpected hourly changes in temperature can be substantial. It was precisely for this purpose that the FERC required that NNT be offered to achieve comparability of service. NNT provides Questar Gas flexibility far beyond what is available under the FERC approved nomination process on Questar Pipeline. Questar Gas uses this NNT flexibility to facilitate withdrawals and injections of gas throughout the day utilizing Clay Basin and the aquifers in order to meet Questar Gas customers’ changing loads (see subsequent Storage Issues Section).

Questar Gas is one of two companies who have contracted for NNT with Questar Pipeline. When Questar Pipeline filed its Order 636 restructuring application, the FERC reviewed and approved not only the tariff language for the provision of this service, but also all the costs which are associated with this service. Questar Gas believes that its NNT service from Questar Pipeline is the most reasonable, physically feasible, and cost-effective way to receive comparable service.

**Storage Issues**

Questar Gas contracts with Questar Pipeline for storage services at four underground gas storage fields to respond to seasonal winter and peak demands. The fields are Leroy, Coalville, Chalk Creek, and Clay Basin. Leroy, Coalville, and Chalk Creek are aquifer-type storage facilities fully subscribed by Questar Gas that are utilized primarily for short term peaking. Clay Basin, utilized by both Questar Gas and other open access storage customers, is a depleted dry gas reservoir used for both seasonal base load and peaking purposes. Questar Gas’ key capacity parameters for these facilities are outlined in the following table:

| Facility | Maximum Inventory (MDth) | Maximum Injection Rate (MDth/D) | Maximum Withdrawal Rate (MDth/D) | Minimum Withdrawal Rate, MRD (MDth/D) | Sustained 3-Day Peak Withdrawal (MDth/D) |
|---|---|---|---|---|---|
| Clay Basin | 13,419 | 75+ | 203 | 112 | n/a |
| Leroy | 886 | 7 to 33 | 84 | n/a | 79 |
| Coalville | 720 | 7 to 21 | 63 | n/a | 53 |
| Chalk Creek | 321 | 6 to 11 | 37 | n/a | 26 |

*Leroy and Coalville Storage*

As was first outlined in the May 1, 2000 IRP, the operation of the Leroy and Coalville storage facilities has been modified from procedures followed historically to provide more flexibility and enhance storage efficiency. Since 2000, following the end

[17] FERC Order No. 636, Final Rule, Docket Nos. RM91-11-000 and RM87-34-065, pages 88-89.

of the withdrawal season, the inventories in these facilities have maintained a working gas capacity of approximately 50% of maximum through the summer months. Previous practice was to completely draw down the facilities each year at the end of the withdrawal season. The advantages of this revised mode of operation are as follows:

- Wells are not "watered out" at the end of the withdrawal cycle, improving well efficiency when refill injections are initiated in the fall.
- Injection compression fuel gas requirements are reduced (only 50% 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 results at the end of the heating season.
- A shorter injection season for reservoir refill is required in the fall.
- The flexibility exists to inject significant volumes if required while the reservoirs are at 50% inventory.

Operating experience has indicated that the above operating advantages result without significantly impacting gas losses.

In general, current operating practices at both the Coalville and Leroy facilities are as follows:

- Refill injections into the reservoirs commence in early September from an initial inventory of approximately 50% of maximum working inventory. Injections continue until an inventory of approximately 70% of maximum is reached by early October. Injections follow a specific well configuration and volume profile to minimize the potential for "fingering" and resulting gas loss.
- In early October, scheduled aquifer injections are halted to allow for the testing program conducted at the Clay Basin storage facility. The testing requires one day 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 70% inventory at Leroy and Coalville affords the flexibility to either inject or withdraw to meet system balancing requirements.
- Following the Clay Basin test, controlled refill injections again commence in Coalville and Leroy with maximum inventory being reached by early November.
- Both Coalville and Leroy are utilized to meet peak load requirements through the heating season. During periods of lower winter demand, the reservoirs are refilled to maximum inventory when possible.
- During March, when the need for peaking withdrawals has passed, the reservoirs are partially drawn down (for use) to inventories ranging from 50–70% in preparation for Clay Basin testing conducted during April. The April Clay Basin test consists of a one week withdrawal only period followed by 2 days of controlled withdrawal. Following the withdrawal period, Clay Basin is shut in for 14 days 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, Leroy and Coalville are then drawn down to inventory levels of approximately 50% and then maintained at that level until refill commences in the fall (unless it is necessary to periodically conduct a complete inventory analysis).

This mode of operation has greatly enhanced the value of the peaking storage service to Questar Gas while not significantly impacting gas losses. Through this mode of operation, seasonal withdrawals during a typical yearly operating season in excess of the maximum working volume have been achieved. For example, during the 2006-2007 season, Leroy withdrawals were 1,074,201 Mcf (1.29 times the maximum working gas inventory of 830,000 Mcf) and Coalville withdrawals were 875,552 Mcf (1.27 times the maximum working gas inventory of 690,000 Mcf).

*Chalk Creek Storage*

Due to the nature of the Chalk Creek storage formation, cycling and partial inventory maintenance during the summer is not practiced at this facility in order to minimize gas losses. Operation at Chalk Creek is as follows:

- Injections from zero working gas inventory commence in early November following a controlled well and injection profile.
- Maximum inventory is reached by mid-December.
- From December through early March, Chalk Creek is typically held in reserve unless very high demand periods are experienced.
- In early March, the reservoir is blown down in a controlled manner to zero working gas inventory and is then shut in until refill injections commence in the fall.

Emphasis is placed upon following the above operating procedures to minimize gas losses and ensure efficient storage facility operation.

*Clay Basin Storage*

The costs, contractual terms and operating parameters for each of the four storage facilities subscribed to by Questar Gas are modeled in SENDOUT. A forecast of the Clay Basin storage inventory (available at the beginning of the first gas-supply year) is also included in the SENDOUT modeling process each year. This year, it is expected that the June 1, 2010 inventory will be between 1.5 and 2.0 Bcf.

The tariff provisions governing Clay Basin assure that customers will receive a minimum withdrawal amount (Minimum Required Deliverability or MRD). To the extent that shippers have inventory in excess of that necessary for their last day of withdrawals, additional deliverability is available for allocation according to predetermined formulas (see the previous table).

*Clay Basin Gas Quality*

During 2007, when Questar Pipeline was resolving CHDP issues on its transmission system, it also remedied CHDP issues at its Clay Basin storage facility. On August 23, 2007, Questar Pipeline filed, with the FERC, revisions to its tariff, Questar Pipeline also filed the "Stipulation and Agreement" negotiated with all of the Clay Basin storage customers. Included with the filing was the "Joint Petition of Questar Pipeline Company and Firm Customers for Approval of Stipulation and Agreement and Request for Expeditious Action."[18] The FERC accepted the revised tariff sheets on November 7, 2007, to be effective on January 1, 2008 and also approved the Stipulation and Petition.[19] As a result of these FERC actions, the Kastler Processing Plant was refunctionalized as a Clay Basin storage asset (previously it was a transmission asset) and additional processing facilities were installed, thus ensuring a total delivery capability of 320,000 decatherms per day to either Northwest Pipeline or Questar Pipeline. This project was completed in December of 2008 at a cost of approximately $12 million. The costs associated with conditioning storage gas, including the installation and operation of these new facilities are expected to be recovered from the sale of natural gas liquids over a 20-year time period. The refunctionalization of the Kastler Plant and the installation of new processing facilities have, at this point in time, effectively resolved the liquids issues at Clay Basin.

*Magnum Storage*

On June 10, 2009, Magnum Gas Storage, LLC (Magnum) announced the start of a non-binding open season for its Magnum Gas Storage Project. This project involves the construction and operation of a high-deliverability, multi-cycle salt cavern storage facility, and a connecting header pipeline to be located in Millard, Juab and Utah Counties, Utah. The proposed project would consist of an underground storage facility consisting of four caverns with a combined storage capacity of 42 Bcf. The storage caverns would be approximately one mile north of the town of Delta, Utah. It is anticipated that the project would be capable of injecting up to 0.3 Bcf per day and withdrawing up to 0.5 Bcf per day. The storage facility would be interconnected with the interstate transmission systems of Kern River and Questar Pipeline near the town of Goshen, Utah with a 61.5-mile, 36-inch diameter header pipeline. A map of Magnum's proposed facilities is shown in Exhibit 7.6.

Magnum invited non-binding expressions of interest in storage-related services associated with the project to be made by July 31, 2009. Questar Gas responded to the open season and is currently waiting to see how the project develops. In the interim, Magnum has filed an application with the FERC, on November 17, 2009, requesting,

[18] Questar Pipeline Company, Docket No. RP07-606-000, FERC Gas Tariff Filing, August 22, 2007; and Questar Pipeline Company, Docket No. RP07-606-001, Amended FERC Gas Tariff Filing, August 30, 2007.

[19] Federal Energy Regulatory Commission, Questar Pipeline Company, Docket Nos. RP07-606-000 and RP07-606-001, Letter Order Accepting Tariff Sheets dated November 7, 2007, "Reference: Stipulation, Petition, and Revised Tariff Sheets."

pursuant to Section 7(c) of the Natural Gas Act, a certificate of public convenience and necessity.[20]

[20]Federal Energy Regulatory Commission, Magnum Gas Storage, LLC, Docket No. CP-10-22, "Abbreviated Application for Certificate of Public Convenience and Necessity Authorizing Construction and Operation of Natural Gas Storage Facility, For Limited Jurisdiction Certificate Authorizing Construction and Operation of Cavern Leaching Facility, For Blanket Certificates and for Approval of Market-Based Rates Under Section 7 of the Natural Gas Act," November 17, 2009.

Exhibit 7.1

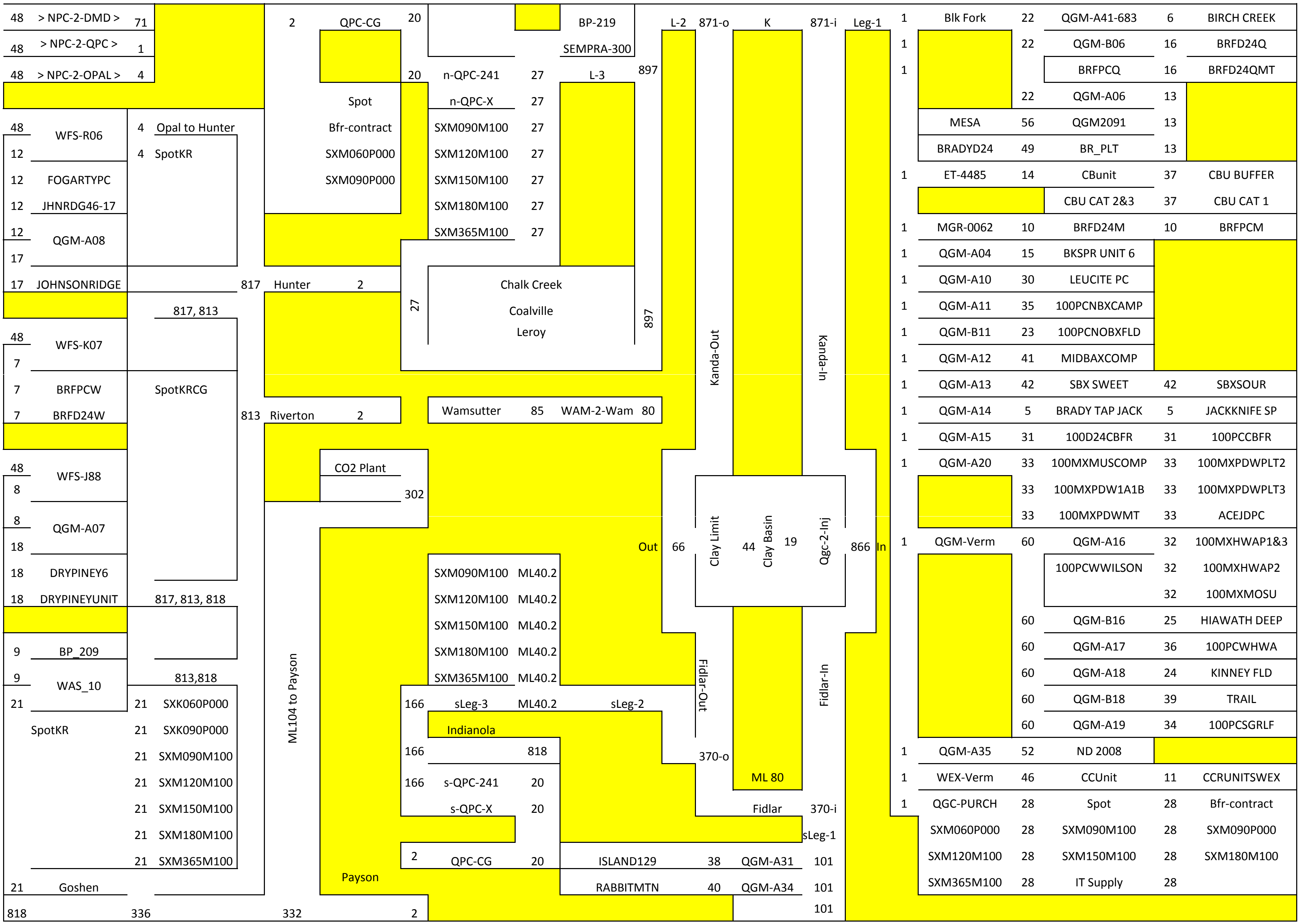
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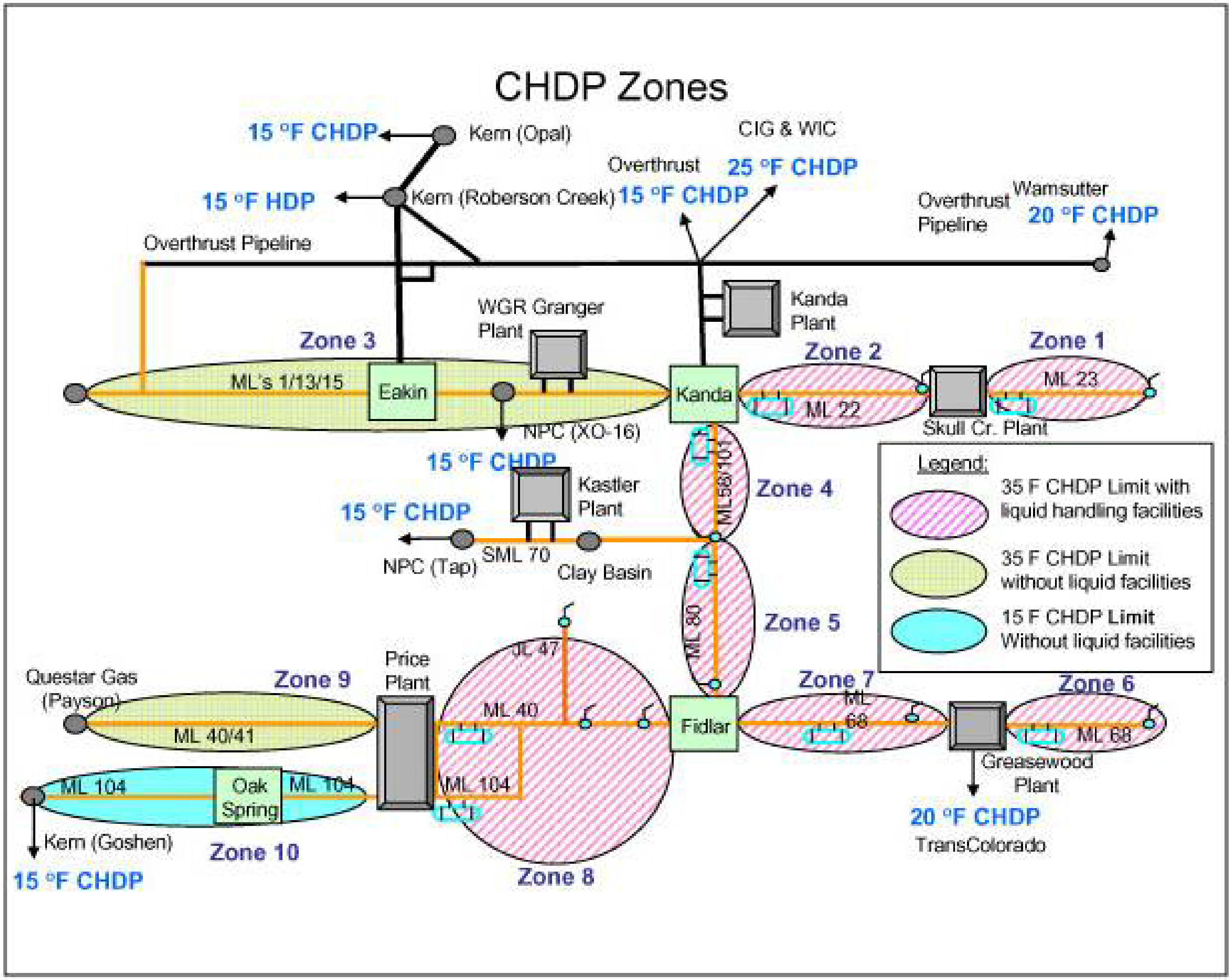
Exhibit 7.2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Overthrust Pipeline
Wamsutter
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Overthrust Pipeline
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WGR Granger Plant
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Zone 2
Zone 1
ML's 1/13/15
Eakin
Kanda
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JL 47
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Zone 9
Price Plant
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Fidlar
Zone 7
ML 68
Zone 6
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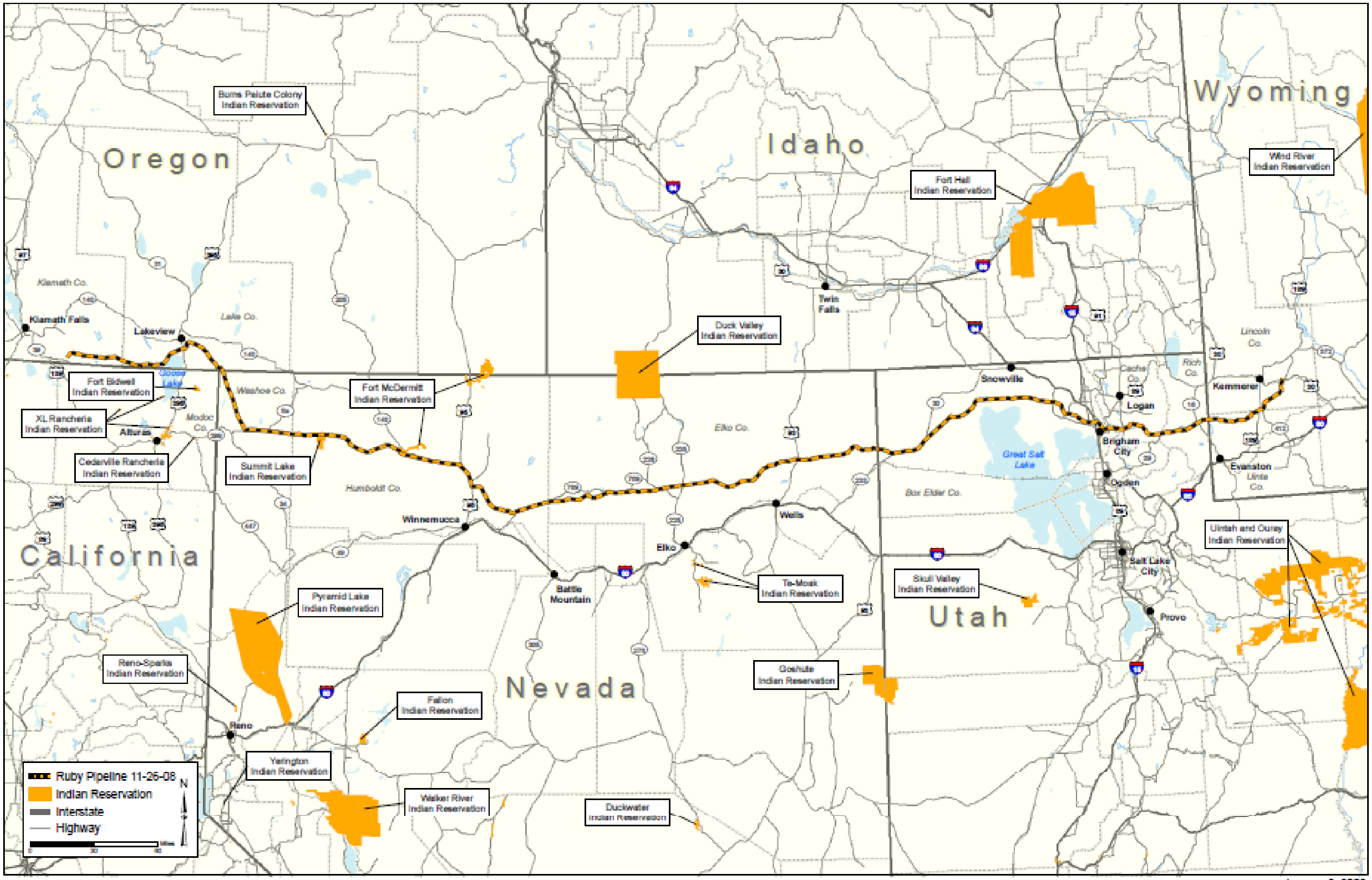
Zone 8




January 6, 2009

Exhibit 7.3

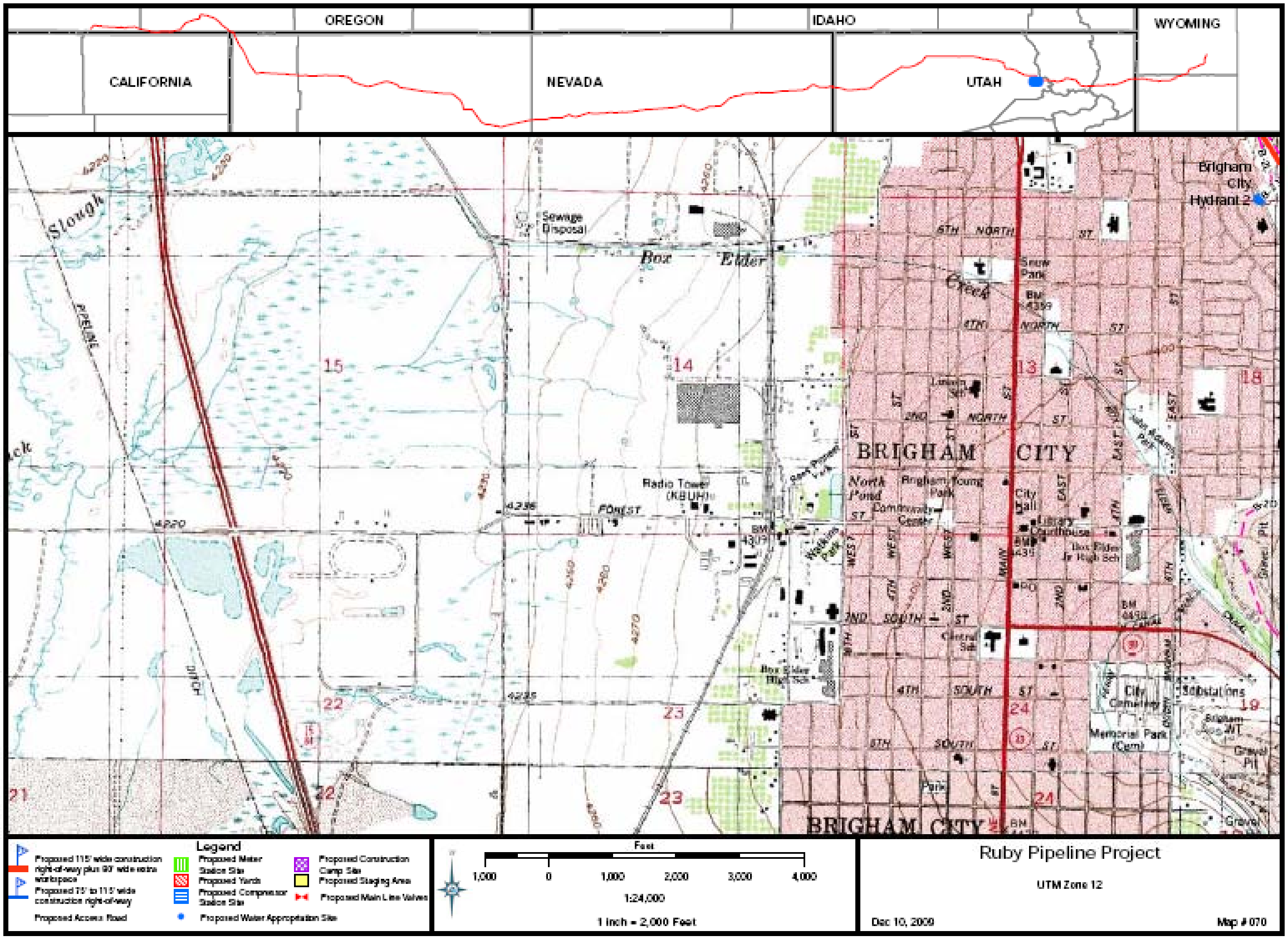

OREGON
IDAHO
WYOMING
CALIFORNIA
NEVADA
UTAH
Brigham City Hydrant 2
Sewage Disposal
Box Elder Creek
Slough
PIPELINE
Radio Tower (KBUH)
FOREST
BRIGHAM CITY
North Pond
Brigham Young Park
Community Center
City Hall
Library
Courthouse
Box Elder Jr High Sch
Box Elder High Sch
Central Sch
City Cemetery
Memorial Park (Cem)
Substations
Gravel Pit
DITCH
Snow Park
6TH NORTH ST
4TH NORTH ST
2ND NORTH ST
2ND SOUTH ST
4TH SOUTH ST
6TH SOUTH ST
MAIN
Legend
Proposed 115' wide construction right-of-way plus 90' wide extra workspace
Proposed 75' to 115' wide construction right-of-way
Proposed Access Road
Proposed Meter Station Site
Proposed Yards
Proposed Compressor Station Site
Proposed Water Appropriation Site
Proposed Construction Camp Site
Proposed Staging Area
Proposed Main Line Valves
Feet
1,000 0 1,000 2,000 3,000 4,000
1:24,000
1 inch = 2,000 Feet
Ruby Pipeline Project
UTM Zone 12
Dec 10, 2009
Map # 070

Exhibit 7.4

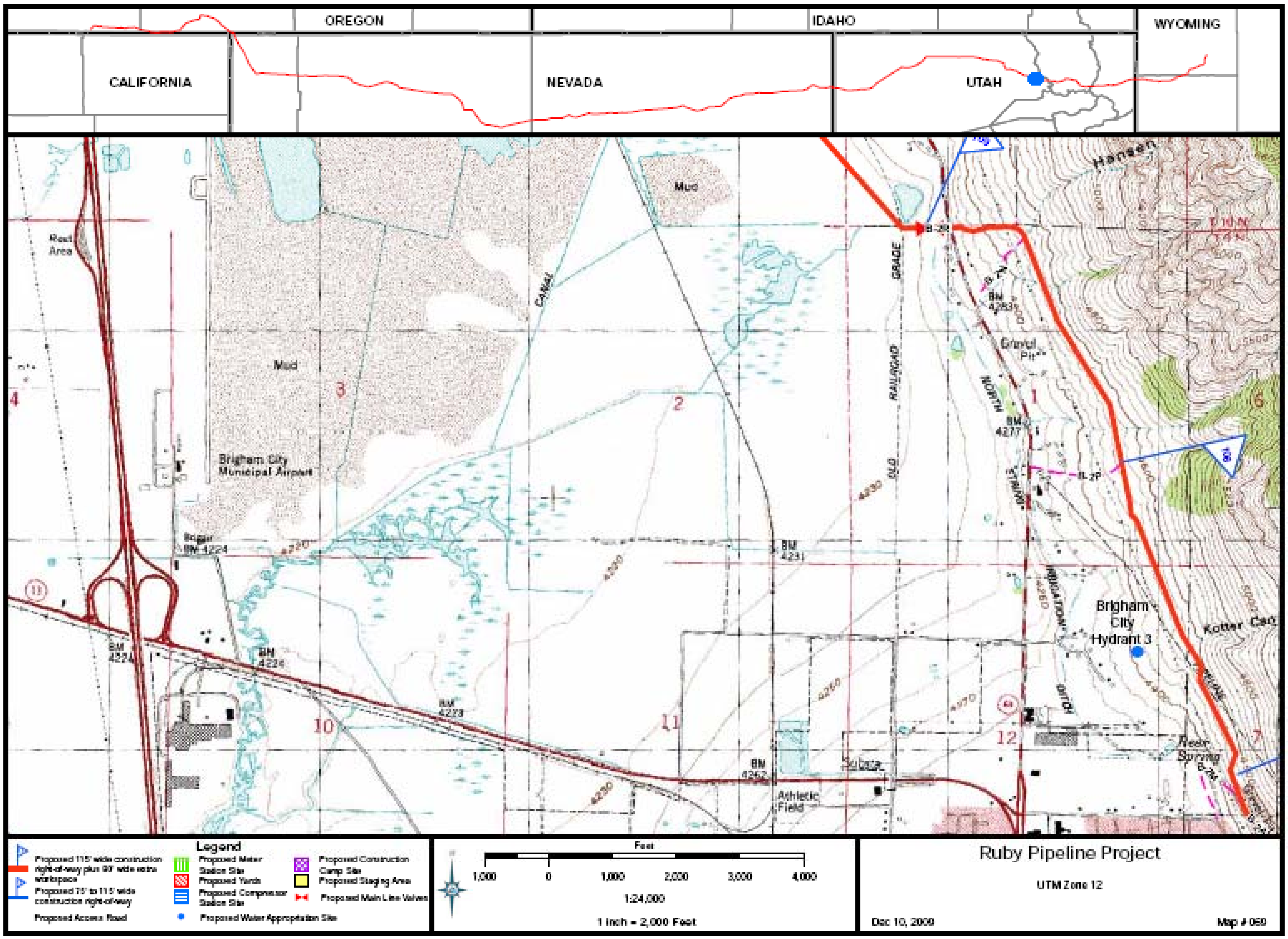
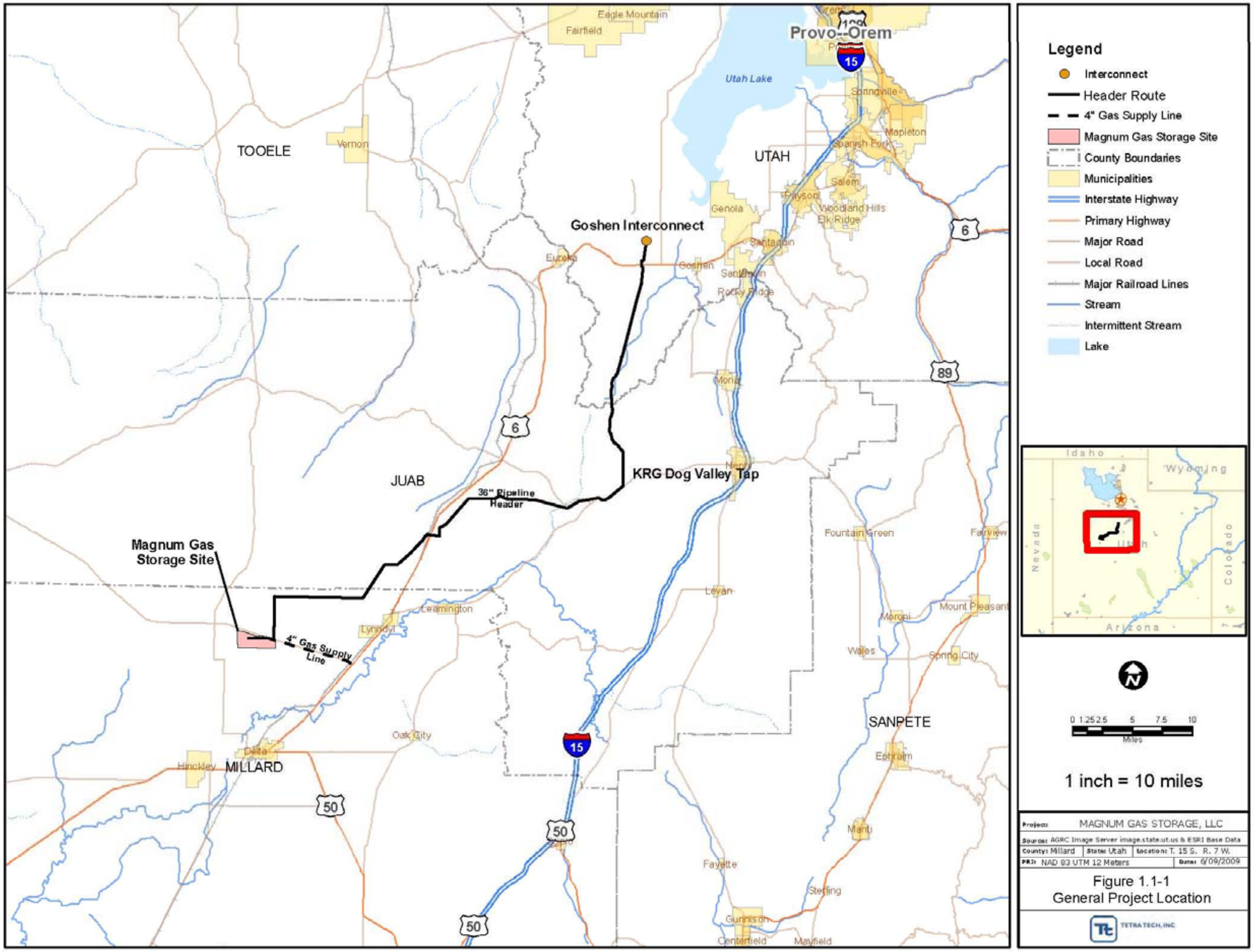

OREGON
IDAHO
WYOMING
CALIFORNIA
NEVADA
UTAH
Mud
Rest Area
Brigham City Municipal Airport
CANAL
GRADE
RAILROAD
OLD
NORTH
Gravel Pit
Hansen
Brigham City Hydrant 3
Kotter Can
Athletic Field
Legend
Proposed 115' wide construction right-of-way plus 90' wide extra workspace
Proposed 75' to 115' wide construction right-of-way
Proposed Access Road
Proposed Meter Station Site
Proposed Yards
Proposed Compressor Station Site
Proposed Water Appropriation Site
Proposed Construction Camp Site
Proposed Staging Area
Proposed Main Line Valves
Feet
1,000 0 1,000 2,000 3,000 4,000
1:24,000
1 inch = 2,000 Feet
Ruby Pipeline Project
UTM Zone 12
Dec 10, 2009
Map # 069

Exhibit 7.5



Provo--Orem
Utah Lake
TOOELE
UTAH
JUAB
MILLARD
SANPETE
Goshen Interconnect
KRG Dog Valley Tap
36" Pipeline Header
Magnum Gas Storage Site
4" Gas Supply Line
Eagle Mountain
Fairfield
Vernon
Springville
Mapleton
Spanish Fork
Salem
Payson
Woodland Hills
Elk Ridge
Genola
Santaquin
Eureka
Goshen
Rocky Ridge
Mona
Nephi
Fountain Green
Fairview
Levan
Moroni
Mount Pleasant
Wales
Spring City
Leamington
Lynndyl
Oak City
Delta
Hinckley
Ephraim
Manti
Fayette
Sterling
Gunnison
Centerfield
Mayfield
Legend
Interconnect
Header Route
4" Gas Supply Line
Magnum Gas Storage Site
County Boundaries
Municipalities
Interstate Highway
Primary Highway
Major Road
Local Road
Major Railroad Lines
Stream
Intermittent Stream
Lake
Idaho
Wyoming
Nevada
Utah
Colorado
Arizona
0 1.25 2.5 5 7.5 10
Miles
1 inch = 10 miles
Project: MAGNUM GAS STORAGE, LLC
Source: AGRC Image Server image.state.ut.us & ESRI Base Data
County: Millard
State: Utah
Location: T. 15 S. R. 7 W.
PRJ: NAD 83 UTM 12 Meters
Date: 6/09/2009
Figure 1.1-1
General Project Location
TETRA TECH, INC


Exhibit 7.6

## ENERGY EFFICIENCY PROGRAMS

### Utah Energy-Efficiency Results 2009

The Company's initial 2009 Commission approved energy-efficiency programs and measures were similar to 2008, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. The major changes to the energy-efficiency programs occurred in March 2009. During that month, the Company filed to reduce the per-square-foot rebate amounts for insulation measures in the ThermWise® Weatherization and Multifamily programs. This filing was in response to changes that the Company recognized were taking place in the cost structure of the insulation marketplace in late 2008 and early 2009. The new measures, changes to qualifying equipment, and changes in rebate levels enhanced customer participation, increased gas savings and improved overall program cost effectiveness.

*ThermWise® Appliance Rebates*

In 2009 the Company continued this program with one minor change to the minimum efficiency qualifications for tier 1 ENERGY STAR clothes washers. Between January 1 and June 30, 2009, ENERGY STAR clothes washers with a Modified Energy Factor (MEF) rating between 1.72 and 1.99 qualified for the ThermWise® tier 1 rebate ($50). In order to qualify for the tier 1 rebate post June 30, 2009, Questar Gas customers were required to purchase and install a clothes washer with an MEF rating between 1.80 and 1.99. This change was made to align the Company's energy efficiency programs with the U.S. Department of Energy's mid-year change to the ENERGY STAR labeling requirements for high efficiency clothes washers.

*ThermWise® Builder Rebate*

The Company continued this program in 2009 with no significant changes.

*ThermWise® Business Rebates*

In 2009 the Company continued this program with several minor changes to eligibility requirements and updated cost-effectiveness inputs. In addition, in 2009 this program made a distinction between pre-fabricated and site-built windows. In order to receive a rebate, prefabricated windows required a U-value of 0.30 or less (glazing only rating) while site-built windows required a U-value of 0.35 or less (entire window assembly rating). The rebate levels for both types of windows remained at $.28 per square foot. This change more closely aligned the program with existing market conditions.

*ThermWise® Weatherization Rebates*

In 2009, initially the Company proposed and received Commission approval to continue this program with no changes. However, due to rapidly changing market conditions beginning the fourth quarter of 2008 and continuing into the first quarter of 2009, the insulation rebates for this program were no longer set at a level that met the design intent of the program. Due to a transformation in the market, in part from the Company's program and in part from a slowing economy, competition for insulation services dramatically increased driving the price to the end-use customer down. This reduction in price caused the insulation rebate amounts being paid in the program to be equal to; and sometimes greater than (especially when other utility rebates were combined); the cost of the insulation service. Full cost coverage from rebates paid in this program was not consistent with the original and approved design of the program and left the Questar Gas customer disengaged from the rebate process. To that end, on March 11, 2009 the Company submitted a tariff change application (Docket No. 09-057-T04) requesting a reduction in insulation rebate amounts by $.15 per square foot. This tariff change application was approved by the Utah Commission and ordered to be effective May 2, 2009. With these approved changes, the cost-effectiveness of this program was improved and Questar Gas customers became more engaged in the rebate process.

*ThermWise® Home Energy Audit*

The Company continued this program in 2009 with no significant changes.

*Low-Income Weatherization Assistance*

In 2009 the Company increased funding of the LIWAP to a level of $500,000 per year from the energy-efficiency budget ($750,000 total Company funding). The Company disbursed $250,000 in January and July of 2009.

*ThermWise® Multi-Family Rebates*

As with the ThermWise® Weatherization program, the Company initially proposed in 2009 and received Commission approval to continue the Multifamily Rebates program with no changes. However, due to rapidly changing market conditions beginning the fourth quarter of 2008 and continuing into the first quarter of 2009, the insulation rebates for this program were no longer set at a level that met the design intent of the program. Due to a transformation in the market, in part from the Company's program and in part from a slowing economy, competition for insulation services dramatically increased driving the price to the end use customer down. This reduction in price caused the insulation rebate amounts being paid in the program to be equal to and sometimes greater than (especially when other utility rebates were combined) the cost of the insulation service. Full cost coverage from rebates paid in this program was not consistent with the original and approved design of the program and left the Questar Gas customer disengaged from the rebate process. To that end, on March 11, 2009 the Company submitted a tariff change application requesting a reduction in insulation rebate amounts by $.15 per square foot. This tariff change application was approved by the Utah Commission to be effective May 2, 2009. With these approved changes, the cost-effectiveness of this program was improved and Questar Gas customers became more engaged in the rebate process.

In addition to the insulation rebate changes, this program also had the minor mid-year change to the minimum efficiency qualifications for tier 1 ENERGY STAR clothes washers. Between January 1 and June 30, 2009, ENERGY STAR clothes washers with a Modified Energy Factor (MEF) rating between 1.72 and 1.99 qualified for the ThermWise tier 1 rebate ($50). In order to qualify for the tier 1 rebate post June 30, 2009, Questar Gas customers were required to purchase and install a clothes washer with an MEF rating between 1.80 and 1.99. This change was made to align the Company's energy efficiency programs with the U.S. Department of Energy's mid-year change to the ENERGY STAR labeling requirements for high efficiency clothes washers.

*ThermWise® Business Custom Rebates*

The Company continued this program in 2009 with no changes. This program targets new and existing Utah GS commercial customers by offering rebates for energy savings resulting from more customized energy system improvements that are not otherwise available through other ThermWise® programs.

A summary of the projected and actual benefit-cost ratios for each of the 2009 ThermWise® programs is shown below.

| **2009 Projected and Actual B/C** | **Total Resource Cost Test** | | **Participant Test** | | **Utility Cost Test** | | **Ratepayer Impact Measure Test** | |
|---|---|---|---|---|---|---|---|---|
| | 2009 Projected B/C | 2009 Actual B/C | 2009 Projected B/C | 2009 Actual B/C | 2009 Projected B/C | 2009 Actual B/C | 2009 Projected B/C | 2009 Actual B/C |
| ThermWise® Appliance Rebates Program | 1.8 | 2.0 | 2.2 | 2.2 | 2.8 | 3.2 | 1.9 | 2.0 |
| ThermWise® Business Rebates Program | 3.0 | 2.4 | 3.4 | 3.0 | 5.0 | 3.7 | 3.2 | 2.6 |
| ThermWise® Builder Rebates Program | 1.7 | 1.9 | 2.3 | 2.4 | 2.6 | 3.0 | 1.8 | 1.9 |
| ThermWise® Weatherization Rebates Program | 2.5 | 2.3 | 2.8 | 2.5 | 2.7 | 3.0 | 1.9 | 2.0 |
| ThermWise® Home Energy Audit Program | 1.0 | 0.8 | 24.5 | 17.2 | 1.0 | 0.8 | 0.8 | 0.7 |
| Low Income Weatherization Program | 1.0 | 2.2 | 0.0 | 0.0 | 1.0 | 2.2 | 0.9 | 1.6 |
| ThermWise® Multi-Family Rebates Program | 1.3 | 1.9 | 2.5 | 2.4 | 1.5 | 2.3 | 1.2 | 1.7 |
| ThermWise® Business Custom Rebates Program | 1.8 | 1.0 | 5.2 | 5.5 | 1.9 | 1.1 | 1.5 | 1.0 |
| Market Transformation | 0.0 | 0.0 | N/A | N/A | 0.0 | 0.0 | 0.0 | 0.0 |
| **TOTALS** | **1.8** | **2.2** | **2.5** | **2.5** | **2.4** | **2.9** | **1.7** | **1.9** |

ThermWise® results for 2009 were better than expected with actual participation surpassing estimated participation by 138%, actual costs surpassing budget by 167%, and achieved net deemed savings surpassing the gross Dth savings goal by 119%. During 2009, the Utah DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Three meetings were held on the following dates: March 5, August 26, and December 1. In addition to overall program performance, the plan and progress on the ThermWise® program evaluation was also a topic of discussion at those meetings.

Work on a two phase program evaluation began in early 2008. The Company published a request for proposal from third-party evaluation firms on February 1, 2008. The request for proposal was solicited by the Company to over forty evaluation firms and posted on an industry website in an effort to obtain strong evaluation plans and competitive bids. One firm and a team of two firms ultimately responded. As the Company conducted analysis of both proposals, it also sought the support and advice of the DSM Advisory Group. Both bids along with Company analysis were presented at the April 1, 2008 Advisory Group meeting. Ultimately, the Company selected the proposal from the team of Cadmus Group, Inc. (Cadmus) (formerly Quantec) and TechMarket Works. Announcement of the winning proposal was made on April 11, 2008.

Cadmus began work on the evaluation plan after contracts were finalized in early June 2008. The plan required the evaluation to be performed in two phases with a deliverable report due to the Company at the end of each phase. The Phase I report was completed and delivered to the Company at the end of November 2008. A summary of the Phase I report was presented to the Company and DSM Advisory Group on November 20, 2008 by Cadmus. The full report was subsequently e-mailed to the DSM Advisory Group, including the Division, Office and the Utah Commission staff for analysis and comment. The ThermWise® team performed an in depth review and analysis of the Phase I evaluation. Results of this review and Company analysis of the results were presented to the DSM Advisory Group on March 5, 2009.

Work on the Phase II evaluation began in late 2009. The Phase II evaluation will be focused on the impact that the energy-efficiency programs have had on customer usage. In order to perform the analysis of the impact of the programs on usage, Cadmus will collect weather-normalized gas usage of ThermWise® participants and compare the pre and post-participation usage against each other. In addition, the analysis will include a comparison of ThermWise® participant usage versus the usage of the non-participant GS population. The Phase II report is contracted to be delivered to the Company by June 30, 2010.

**Wyoming Energy-Efficiency 2009**

On August 18, 2008 Questar Gas filed a general rate case (Docket No. 30010-94-GR-08) with the Wyoming Public Service Commission. Included in the filing was an application to offer Wyoming Questar Gas customers the following five energy-efficiency programs: ThermWise® Appliance Rebates, ThermWise® Builder Rebates, ThermWise® Business Rebates, ThermWise® Weatherization Rebates, and the ThermWise® Home Energy Audits program. In addition to the specific programs, the Company proposed to extend its market transformation education and awareness campaign to Wyoming including partnering with the Wyoming Energy

Council on the Wyoming Home Performance with ENERGY STAR program, as well as extend the advertising campaigns to the Wyoming service territory. A public hearing on the general rate case and the proposed energy-efficiency programs was held in Cheyenne April 1 through April 3, 2009.

A ruling on the general rate case and the proposed energy-efficiency programs (2009 Order) was issued by the Wyoming Public Service Commission on June 17, 2009. In the ruling, the Commission approved the energy-efficiency programs as a three year pilot program and ordered them effective July 1, 2009.

The Wyoming energy-efficiency programs have seen good participation and interest from customers in the third and fourth quarters of 2009. The Company expects participation in Wyoming to increase as customer education and market transformation efforts continue.

*Energy-Efficiency Plan 2010*

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 Commission approved the continuation of the eight energy-efficiency programs and the ThermWise® Market Transformation initiative from 2009. This continuation included the addition of new rebate measures and an update and/or revision of certain program measures to improve customer uptake, program cost effectiveness, and to align the programs with current market conditions.

*ThermWise® Appliance Rebates*

In 2010, the Company is continuing this program by adding a second tier rebate for certain high efficiency gas water heaters. The $100 rebate will apply to Utah Questar Gas customers on the GS rate schedule who purchase and install a gas water heater with a .67 Energy Factor (EF) rating. This additional tier is being added in anticipation of the U.S. Department of Energy moving the ENERGY STAR rating for gas waters from the current rating of .62 EF. This program will continue to be offered to customers in the Company's Utah service territory.

*ThermWise® Builder Rebates*

In 2010, the Company is continuing this program by adding a second tier rebate for certain high efficiency gas water heaters. The $100 rebate will apply to Utah builders who purchase and install a gas water heater, in qualifying new residential construction, with a .67 Energy Factor (EF) rating. This additional tier is being added in anticipation of the U.S. Department of Energy moving the ENERGY STAR rating for gas waters from the current rating of .62 EF. This program will continue to be offered to customers in the Company's Utah service territory and administered by PECI.

*ThermWise® Business Rebates*

The Company is continuing this program in 2010 with several minor changes. In an effort to more closely align the program with current market conditions, the 2010 energy-efficiency efforts will, for the first time, make a distinction between new construction and retrofit commercial building shell measures. Rebates for new construction will be paid to businesses for installing attic ($.04 per sq ft) and wall ($.03 per sq ft) insulation above commercial code levels. In order to receive a rebate for new construction windows, pre-fabricated windows will require a U-value of 0.30 or less (glazing only rating) while site-built windows will require a U-value of 0.35 or less (entire window assembly rating). The rebate for new construction windows will be paid at $.28 per square foot.

Rebates for commercial retrofits will be paid to businesses for installing attic ($.08 per sq ft) and wall ($.06 per sq ft) insulation above commercial code levels. In order to receive a rebate for retrofit windows, pre-fabricated windows will require a U-value of 0.30 or less (glazing only rating) while site-built windows will require a U-value of 0.35 or less (entire window assembly rating). The rebate for retrofit windows will be paid at $.37 per square foot.

In addition to the new building shell measures, the rebate for high efficiency gas water heaters with a rating of .67 EF, outlined in the 2010 Appliance and Builder sections, will also be included as a 2010 Business program rebate measure. This program will continue to be available to GS commercial customers in the Company's Utah service territory.

*ThermWise® Weatherization Rebates*

With input in 2009 from the Advisory Group, the Company proposed and received Commission approval to offer Utah customers a second tier attic insulation rebate in 2010. The purpose of this second tier attic insulation rebate ($.07 per square foot) is to incent customers to bring their homes to the current minimum energy efficiency code (IECC 2006) requirement of R-38. Questar Gas customers seeking to participate in the attic insulation measures in 2010 will be required to first install one increment of R-19. In the case that the homeowner's new R-19 attic insulation plus the pre-existing insulation level are equal to or greater than R-38, the homeowner would not be required to install additional attic insulation and would be eligible for the tier 1 rebate of $.20 per square foot.

In the case where pre-existing and the new tier 1 attic insulation do not reach the required R-38 minimum (pre-existing levels between R-0 and R-18), the homeowner would be required to install an additional minimum increment of R-11 (homeowners with pre-existing levels between R-0 and R-7 would be required to install more than R-11). The homeowner would then be eligible for the tier 1 rebate of $.20 per square foot for the first increment of attic insulation (R-19) and the tier 2 rebate of $.07 per square foot for the second attic insulation increment (R-11).

The design of the tiered rebate structure is such that homeowners must first participate in the tier 1 rebate before they may receive a rebate for tier 2 attic insulation. Also, no rebates will be paid for tier 1 or 2 attic insulation for which a residence's final R-value exceeds R-60. Additionally, beginning in 2010, participation in attic, wall, and floor insulation will be limited to one rebate per measure for the lifetime of the premise. In other words, a customer who received a rebate for attic, wall, or floor insulation for a certain residence in 2007 will not be eligible to receive an additional insulation rebate for that residence in 2010 or beyond. This program will continue to be available to existing residential customers in the Company's Utah service territory.

*ThermWise® Home Energy Audit*

The Company is continuing this program with no significant changes. The ThermWise® Home Energy Audit Program is offered and administered by Questar Gas with periodic consulting and assistance from Nexant. This program includes two primary components: in-home energy audits performed by trained and experienced Questar Gas Auditors and "do-it-yourself" mail-in audits with on-line data input availability. This program will continue to be available to customers in the Company's Utah service territory.

*Low-Income Weatherization Assistance*

In 2010 the Company will continue funding the LIWAP 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.

*ThermWise® Multi-Family Rebates*

The Company is continuing this program in 2010 with several changes. This program will implement the tiered attic insulation rebate structure outlined in the 2010 ThermWise® Weatherization Rebates program above. Also, the tiered high efficiency gas water heater rebates, outlined in the 2010 Appliance and Builder sections, will be implemented in the Multi-Family program.

In addition, the duct sealing and insulation measures, previously only available to residential GS customers, will be extended to qualifying customers in the multi-family market. The qualifications for duct sealing and insulation measures will be the same as in the 2010 Weatherization program and the rebate amounts will be $125 and $150 respectively.

This program will continue to be available to Questar Gas Utah service territory property owners/managers, builders, developers, home owner associations and directly to tenants.

*ThermWise® Business Custom Rebates*

The Company is continuing this program in 2010 with no significant changes. A summary of the cost-effectiveness used in the energy efficiency model for each ThermWise® program based upon the 2010 budget and projections is shown below.

| 2010 Projections | Total Resource Cost Test | | Participant Test | | Utility Cost Test | | Ratepayer Impact Measure Test | |
|---|---|---|---|---|---|---|---|---|
| | 2010 Projected NPV | 2010 Projected B/C | 2010 Projected NPV | 2010 Projected B/C | 2010 Projected NPV | 2010 Projected B/C | 2010 Projected NPV | 2010 Projected B/C |
| ThermWise® Appliance Rebates | $7.3 | 1.9 | $10.7 | 2.2 | $10.2 | 2.8 | $7.4 | 1.9 |
| ThermWise® Business Rebates | $2.5 | 2.6 | $2.8 | 2.9 | $3.1 | 5.0 | $2.7 | 3.0 |
| ThermWise® Builder Rebates | $1.9 | 1.6 | $3.5 | 2.3 | $2.9 | 2.6 | $2.0 | 1.7 |
| ThermWise® Weatherization Rebates | $51.3 | 2.6 | $61.3 | 2.6 | $62.6 | 4.1 | $48.2 | 2.3 |
| ThermWise® Home Energy Audit | $.04 | 1.1 | $.84 | 20.6 | $.03 | 1.0 | -$.12 | .9 |
| Low Income Weatherization | -$.50 | 0.0 | $0 | 0.0 | -$.50 | 0.0 | -$.50 | 0.0 |
| ThermWise® Multifamily Rebates | $.77 | 1.2 | $3.06 | 1.6 | $2.6 | 2.4 | $1.5 | 1.4 |
| ThermWise® Business Custom Rebates | $.29 | 1.7 | $.52 | 5.2 | $.34 | 1.9 | $.25 | 1.6 |
| Market Transformation | -$1.4 | 0.0 | $0 | N/A | -$1.4 | 0.0 | -$1.4 | 0.0 |
| **TOTALS** | **$62.3** | **2.2** | **$82.7** | **2.5** | **$79.9** | **3.2** | **$60.1** | **2.1** |

## SENDOUT Model Results for 2010

Projections from the approved 2010 DSM budget as updated with the insulation rebate changes were entered into the SENDOUT model in response to the Utah Commission's request. Data entries for the 2010 DSM programs included participants and deemed lifetime Dth savings per program measure. Incentive (variable) and non-incentive (fixed) costs for each program measure were also incorporated into the SENDOUT model.

The SENDOUT model used the projected 2010 participation and non-incentive costs as the baseline for its analysis of each program. For each program, the model then examined what would happen if participation was reduced to as low as 25% or increased to as high as 150% of the 2010 projection. The model also examined different scenarios involving the escalation of annual non-incentive costs per program. In these scenarios, non-incentive costs per program were increased to 150% and 200% of the 2010 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 non-incentive costs. Please see Exhibit 8.1 for the SENDOUT results in a table format.

The 2010 ThermWise® Business and Weatherization programs were accepted by the model at 25% of 2010 projected participation if non-incentive costs were increased to 200% of the 2010 budget projection. The Appliance program was accepted by SENDOUT at 25% of projected participation if non-incentive costs were increased to 150% of the projection. The ThermWise® Builder program was accepted by the model at 50% of projected participation if non-incentive costs were increased to 150% of the projection. The Multi-Family program was accepted at 100% of participation and 150% of projected non-incentive costs. The Business Custom program was accepted at 100% of participation and 100% of projected non-incentive costs. The Home Energy Audit program was accepted by the model at 150% of participation and 100% of non-incentive costs.

In summary, the SENDOUT model results indicate that as a gas supply resource at the approved budget and participation levels, the 2010 DSM 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 non-incentive costs are increased by as much as eight times 2010 budget levels.

In comparison to the SENDOUT model which is a comprehensive resource planning and evaluation tool, the Questar Gas energy efficiency model which was developed in-house by the Company with the assistance of the Questar Gas DSM Advisory Group and approved by the Commission, is used for the sole purpose of modeling Questar Gas' energy-efficiency programs. To this end, the Company relies on the Questar Gas energy efficiency model for energy-efficiency program planning purposes and more importantly energy-efficiency program cost effectiveness (based on the California Standard Practices Model).

Using the Questar Gas energy-efficiency model, the Company analyzed the approved 2010 DSM 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. This analysis resulted in a projected potential total energy efficiency spending limit of $63 million per year versus the current approved $36.1 million per year for the 2010 projected natural gas savings which is equal to 978,832 Dth. 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 Questar Gas 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.

Exhibit 8.1

# 2010 Energy-Efficiency Modeling Results from SENDOUT

| Program @ <u>100%</u> of 2010 Budget $ | % of 2010 Budget Participation | | | |
|---|---|---|---|---|
| | 25% | 50% | 100% | 150% |
| ThermWise® Appliance Program | | | | |
| ThermWise® Builder Program | | | | |
| ThermWise® Business Custom Program | | | | |
| ThermWise® Business Program | | | | |
| ThemWise® Home Energy Audit Program | | | | |
| ThermWise® Multi-Family Program | | | | |
| ThermWise® Weatherization Program | | | | |

*Accepted by SENDOUT Model as a resource =*

*Not Accepted by SENDOUT Model as a resource =*

| Program @ <u>150%</u> of 2010 Budget $ | % of 2010 Budget Participation | | | |
|---|---|---|---|---|
| | 25% | 50% | 100% | 150% |
| ThermWise® Appliance Program | | | | |
| ThermWise® Builder Program | | | | |
| ThermWise® Business Custom Program | | | | |
| ThermWise® Business Program | | | | |
| ThemWise® Home Energy Audit Program | | | | |
| ThermWise® Multi-Family Program | | | | |
| ThermWise® Weatherization Program | | | | |

*Accepted by SENDOUT Model as a resource =*

*Not Accepted by SENDOUT Model as a resource =*

| Program @ <u>200%</u> of 2010 Budget $ | % of 2010 Budget Participation | | | |
|---|---|---|---|---|
| | 25% | 50% | 100% | 150% |
| ThermWise® Appliance Program | | | | |
| ThermWise® Builder Program | | | | |
| ThermWise® Business Custom Program | | | | |
| ThermWise® Business Program | | | | |
| ThemWise® Home Energy Audit Program | | | | |
| ThermWise® Multi-Family Program | | | | |
| ThermWise® Weatherization Program | | | | |

*Accepted by SENDOUT Model as a resource =*

*Not Accepted by SENDOUT Model as a resource =*

## FINAL MODELING RESULTS

### Linear Programming Optimization Model

Questar Gas has utilized for a number of years, a computer-based linear-programming optimization (LPO) model to evaluate both supply-side and demand-side resources. This software product, marketed under the name of "SENDOUT," is maintained by Ventyx[1] headquartered in Atlanta, Georgia. SENDOUT is used by more than 100 energy companies 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, this method has been facilitated by the availability of high-speed computer technology.

Questar Gas is using the same release of SENDOUT used last year, Version 12.5.5. This version was installed during March 2009. A new release of SENDOUT is available, Version 13.1.1., that utilizes more powerful database tools, Microsoft SQL Server or SQL Server Express. In previous versions, Microsoft Access was used. SENDOUT Version 13.1.1 also has the capability of defining logical pricing relationships (baskets) within the model. Given the newness of SENDOUT Version 13.1.1, and given that some issues arose during the model validation process using the approach of Questar Gas, a determination was made by the Company to continue with the utilization of SENDOUT Version 12.5.5 this year. Questar Gas will consider migration to the newer version in the future when objective function values can be validated.

In performing gas supply modeling, Questar Gas Company representatives work closely with consultants from Ventyx. The Ventyx consultants are very familiar with the gas supply modeling 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 at least the early 19$^{th}$ century, it was not until the middle of the 20$^{th}$ century that this approach began to be more widely accepted as a method for achieving optimal solutions in practical applications. In a nutshell, linear programming problems involve the optimization of a linear objective function subject

1 On May 5, 2010, Ventyx issued a news release announcing the acquisition of Ventyx by ABB Ltd., headquartered in Zurich, Switzerland. ABB is a global power and automation technology group with approximately 117,000 employees. ABB and Ventyx managements are committed to the continued support of Ventyx products and services. This acquisition is subject to regulatory approvals and is expected to close by mid-year 2010.

to linear constraints. Constraints are necessary in the determination of a maximum or minimum solution. Constraints must be linear functions and can either represent equalities or inequalities. An example of an inequality constraint in the natural gas business would be that the quantity of natural gas that can be transported over a certain segment of an interstate pipeline must be "less than or equal to" a certain level previously contracted for with that pipeline company. Another example of an inequality constraint would be the production available from a group of wells providing cost-of-service natural gas. The levels of this resource that can be taken can never exceed the maximum level available as production naturally declines over time. All resources are defined by constraints including purchased gas. Some peaking contracts have minimum levels that must be taken during an agreed-upon period of time which would be translated into a "greater than or equal to" constraint. Constraints must be carefully defined to accurately reflect the problem being solved. The arbitrary removal of required constraints results in an inaccurate solution. For example, if the constraint on how quickly the Company's capacity at the Clay Basin storage facility can be refilled were to be removed, 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 results in no solution being obtained. Questar Gas periodically reevaluates the constraints in its SENDOUT model to determine if they accurately reflect the realities of the problem being solved.

**Monte Carlo Method**

When performing Monte Carlo analysis, the length of computer run times can become an issue. To have a meaningful 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 usually takes several days to run. The base Monte Carlo simulation developed by the Company this year utilized 1139 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 which they appropriately determined should be included 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 than these two.

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). Questar Gas 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 base case number to show how the base case compares to the mean and median. The base case will be discussed in more detail later in this section. Also in these data reports are the headings “p95,” “p90,” “p10,” and “p5.” The label “p95” on an output report means, based on input assumptions, that a 95 percent 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 percent likelihood that a variable will be less than or equal to that number. These statistics and/or the shape of a frequency curve help define the range and likelihood of potential outcomes.

### Natural Gas Price

The price for which natural gas supplies can be purchased in the future is extremely difficult to model with any level of accuracy. It is not uncommon for the best industry forecasts to be off by more than a factor of two or less than a factor of 0.5. Most of the natural gas purchased by Questar Gas is tied contractually to one or more of eight area price indices. Three of those indices are published first-of-month prices for deliveries to the following interstate pipeline systems; Kern River, Questar Pipeline, and Northwest Pipeline. The remaining five are published daily indices for Kern River (3), Questar Pipeline, and Northwest Pipeline. To develop a future probability distribution, Questar Gas assembled historical data and determined the means and standard deviations associated with each price index. Questar Gas then utilized the average of two long-term price forecasts developed by PIRA[2] and CERA[3] as the basis for projecting the stochastic modeling inputs. Forecasted standard deviations have been scaled up pro rata based on prices to more accurately mirror reality. Exhibits 9.1 through 9.36 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 eight price indices used in the base simulation.

### Weather and Demand

In addition to the price of natural gas, the other single most unpredictable variable in natural gas resource modeling is weather induced demand. Questar Gas makes available to the SENDOUT model 81 years of weather data. It should be noted that when forecasting future demands, heating degree days are stochastic with a mean and standard deviation by month. This number, along with usage-per-customer-per-degree-day and the number of customers, is used 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 1,139 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 then scans through 81 years of monthly data to find the closest match. Then the model allocates daily degree-day values from the draw-specific monthly value. Exhibits 9.37

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[2] PIRA Energy Group, Inc. (PIRA) is an international energy consulting firm with expertise in energy market analysis and intelligence. PIRA’s client base exceeds 550 entities in over 60 countries.
[3] Cambridge Energy Research Associates, Inc. (CERA) is a leading advisor to international energy companies, governments, financial institution, and technology providers. CERA has a staff of 200 employees in nine offices worldwide.

through 9.49 show first the annual and then the monthly demand distribution curves for the first year of the base simulation. Exhibit 9.50 shows the annual heating-degree-day distribution.

In prior years, before Questar Gas utilized Monte Carlo modeling techniques, a high demand and a low demand scenario were modeled as part of a sensitivity analysis. Currently, with the use of a Monte Carlo modeling approach, the wide variability in weather-induced demand resulting from historical weather data is broader than any reasonable range of load growth scenarios. This year there are 1,139 deterministic cases in the Monte Carlo simulation, each with a different demand level, thus obviating the need to model just one high and one low demand case.

**Peak Day and Base Load Purchase Contracts**

An important consideration in the modeling process is the need to have adequate resources sufficient to meet a design-peak day. The design-peak day for the 2010/2011 winter-heating season has been determined to be 1.272 million Dth per day at the city gates. The design-peak day for many years has been defined to be a 1-in-20-year weather occurrence. The most likely day for a design peak to occur is on January 2, although, the probability of a design peak occurring on any day between mid-December and mid-February is relatively flat. Even though it is unlikely that a design-peak day will occur this year, the Company must be prepared to meet such a need should it occur. Selecting a draw from a Monte Carlo simulation that utilizes on the maximum demand day a level of resources approximately equaling the design-peak day has proven to be problematic in that the SENDOUT model selects too much base-load purchased gas for a typical weather year. The draws which have a design-peak-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 peak demand versus the median level of first-year annual demand. 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 peak-day requirements and annual demand. A cluster point is then chosen that we believe will meet both a realistic annual demand and peak day. A second SENDOUT scenario is then executed, with the unused RFP packages removed, and only those "cluster point" packages remaining. One of the purposes of this run is to verify that adequate purchased gas resources at the least cost will be available in the remote event that a design-peak day were to occur. The optimizing nature of the SENDOUT model helps to make this happen. This year, of the 1,139 draws generated in this process, 8 draws would exceed the design peak-day requirement of 1.272 MMDth. In other words, this scenario has enough resources to meet a peak-day event. Most of the base-load purchased-gas resources, with their associated time-availabilities, must be committed to during the springtime, prior to the beginning of the gas supply year, to be ready for cold weather in the fall. Patterns of usage for storage resources, spot gas, and cost-of-service gas do not need to be committed to before the gas year begins. This modeling approach also lends itself to performing operational analysis periodically during the year as natural gas prices change.

Exhibit 9.51 shows the resources utilized to meet the design-peak day. Exhibit 9.52 shows the firm-peak-day demand distribution for the base simulation for the first plan year. Understandably, the design-peak day for Questar Gas is in the upper tail of the curve.

**Base Case Identification**

Whenever one draw of a stochastic analysis is identified as a base case, there is a general tendency to assume that there is a greater likelihood of all the attributes of that draw occurring than actually exists. Nevertheless, it is useful to identify a base case for ease of discussion and to facilitate the measurement of deviations.

In determining a base case, Questar Gas made available to the SENDOUT model, all of the optimal purchase gas resources selected to meet the design-peak day occurrence as described previously. Then, another Monte Carlo simulation was performed. Re-running the simulation allowed the model for each draw, to size the appropriate level of purchased-gas resources from packages which, for the most part, will actually be under contract. Inevitably, when purchased-gas RFP responses are made, a few of the deals will fall through for a variety of reasons. These deals can usually be replaced under fairly similar terms.

There are a number of criteria, however, that could probably be used to determine a base case from the simulation. The draw with the median demand level could be used, for example, but that draw will not be the same as a draw with the median price for any one of the eight price distributions used, and vice versa. Questar Gas developed an algorithm to systematically select its base case. Using the distributions for 21-year total cost, first year demand, first-year purchase gas and first-year cost-of-service gas, each distribution was ordered from least to greatest result value. Then, in the stated order above, starting with the median value, a window of draws was selected centered at the median. Those selected draws were then taken as the starting point to look in the second distribution with the same size matching draws. If matches were found, then those were taken to the third distribution as the starting point. The first draw that was found within the window and that existed in all distributions was selected as the base case. When no match was found from one distribution to the next, the process started over and the bounds of the window were increased to include the next highest and next lowest draws.

**Purchased-Gas Resources**

Exhibits 9.53 through 9.64 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 9.65 shows the annual distribution from the simulation. Exhibit 9.66 shows the numerical monthly data with confidence limits. The sum of the median monthly totals for purchased gas for the first plan year from the base simulation is approximately 49.5 million Dth. Questar Gas is confident that for a colder-than-normal year, sufficient purchased-gas resources will be available in the market. Likewise, Questar Gas is confident that in the event of a warmer-than-normal year, it has not “over-bought” base-load purchase contracts.

**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 9.67 through 9.78 show the distributions for cost of service gas for each month of the first plan year from the base simulation. Exhibit 9.79 shows the annual distribution from the simulation. Exhibit 9.80 shows the numerical monthly data with confidence limits. The sum of the median monthly totals for cost-of-service production for the first plan year from the base simulation is approximately 67.7 million Dth.

**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 9.81. The first year median total from the base simulation is approximately $658.01 million. A similar curve for the total 21-year modeling time horizon is shown in Exhibit 9.82. The median cost for this time period is approximately $9.1 billion.

**Gas Supply Plan**

Exhibits 9.83 through 9.86 show additional planning detail for the first two years of the base case. Monthly data for each category of cost-of-service gas and each purchase-gas package are listed. Also included are injections into and withdrawals from each of the four storage facilities utilized by the Company. 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.

**Gas Supply/Demand Balance**

New to the Results section this year are Exhibits 9.87 through 9.88. These Exhibits 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.

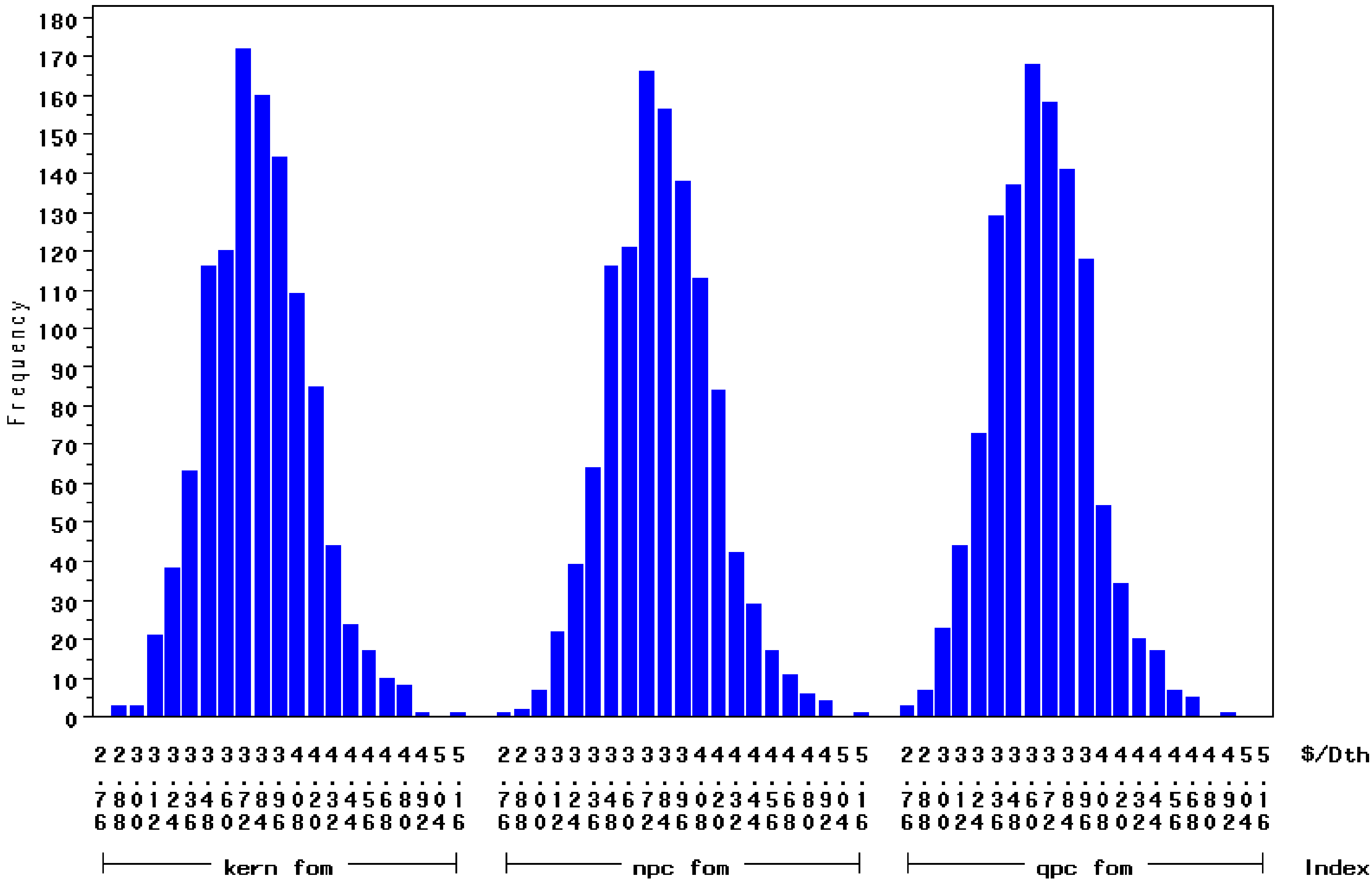
This report is available in SENDOUT and is called “Natural Gas Requirements Versus Supply.” The data in these exhibits represent the selected base case. The SENDOUT report has been slightly adapted to show geographical areas and lost-and-unaccounted-for gas. Because demand is measured at the customer meter and modeling occurs at the city gate, in years past the demand has been grossed up by the lost-and-unaccounted-for amount to model natural gas demand at the city gate. This year lost-and-unaccounted-for gas was modeled as a percent of the other demand classes and is shown as its own specific demand class.

The first of page 9.87 and part of 9.88 of the report show Requirements of the System. Those are specifically Demand, Fuel Consumed, and Storage Injection. This gives the total requirement at 132.43 MMDth for the Base Case. The last of page 9.88 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin, and the Aquifers. The total supply is 132.27 MMDth for the Base Case. The difference is .16 MMDth which is listed as Unsupplied Demand.

# Monthly FOM Index Price Distribution

**2010 Plan Year**
**Scenario 1040 : 1139 Draws**
**year=2010 month=6**

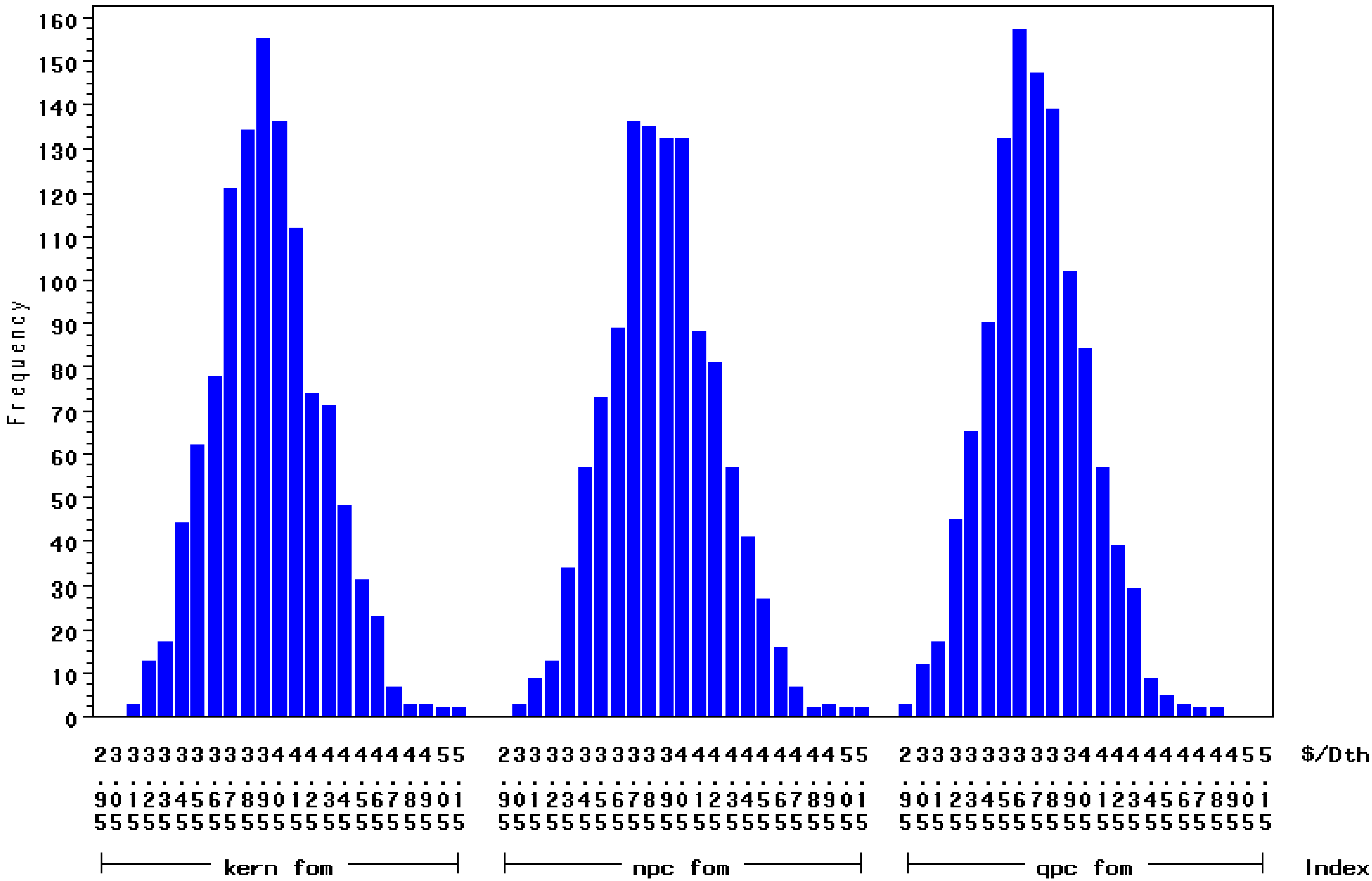
Exhibit 9.01



# Monthly FOM Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7

Exhibit 9.02



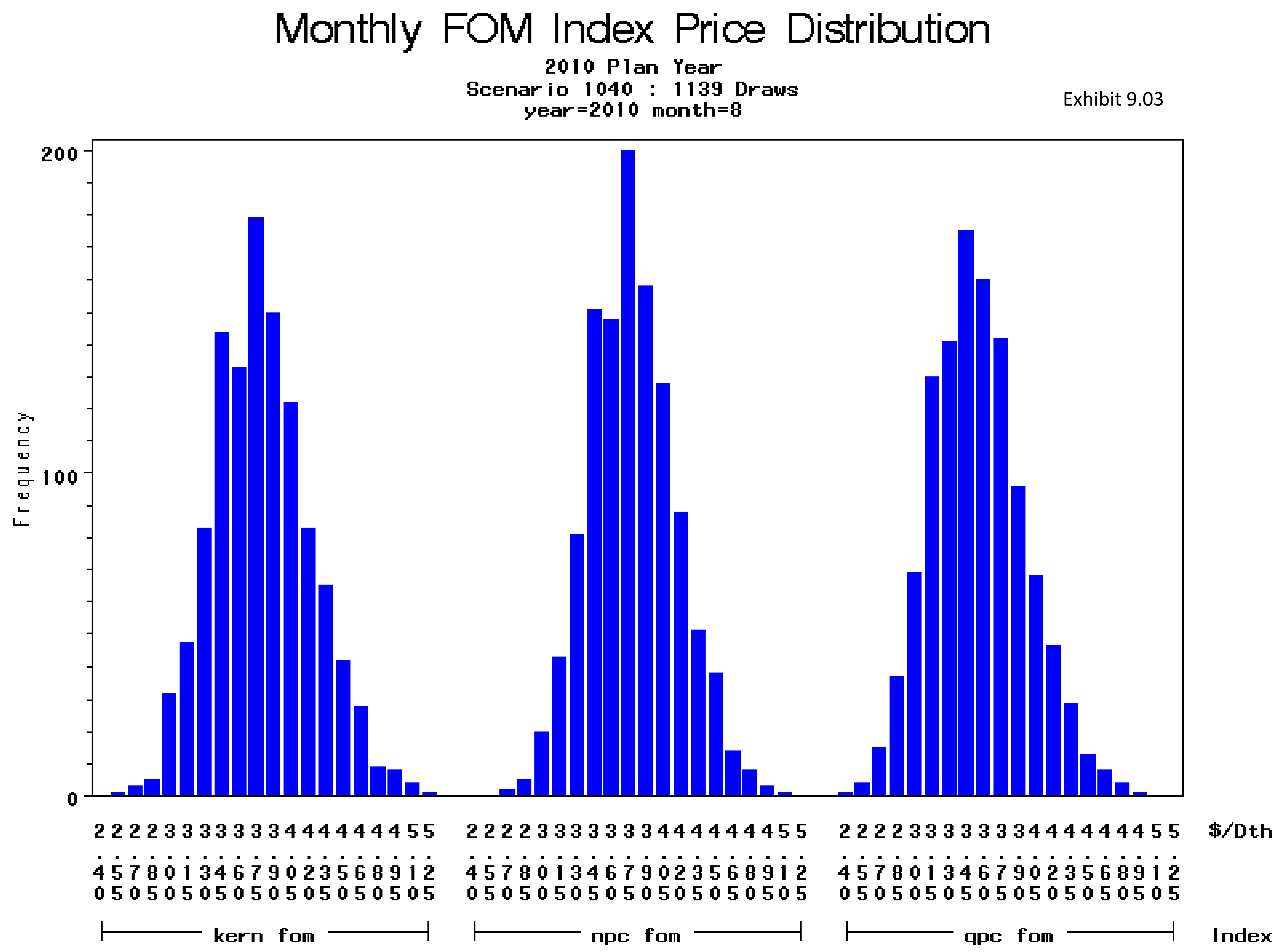

Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8
Exhibit 9.03
Frequency
200
100
0
$/Dth
kern fom
npc fom
qpc fom
Index

Exhibit 9.04

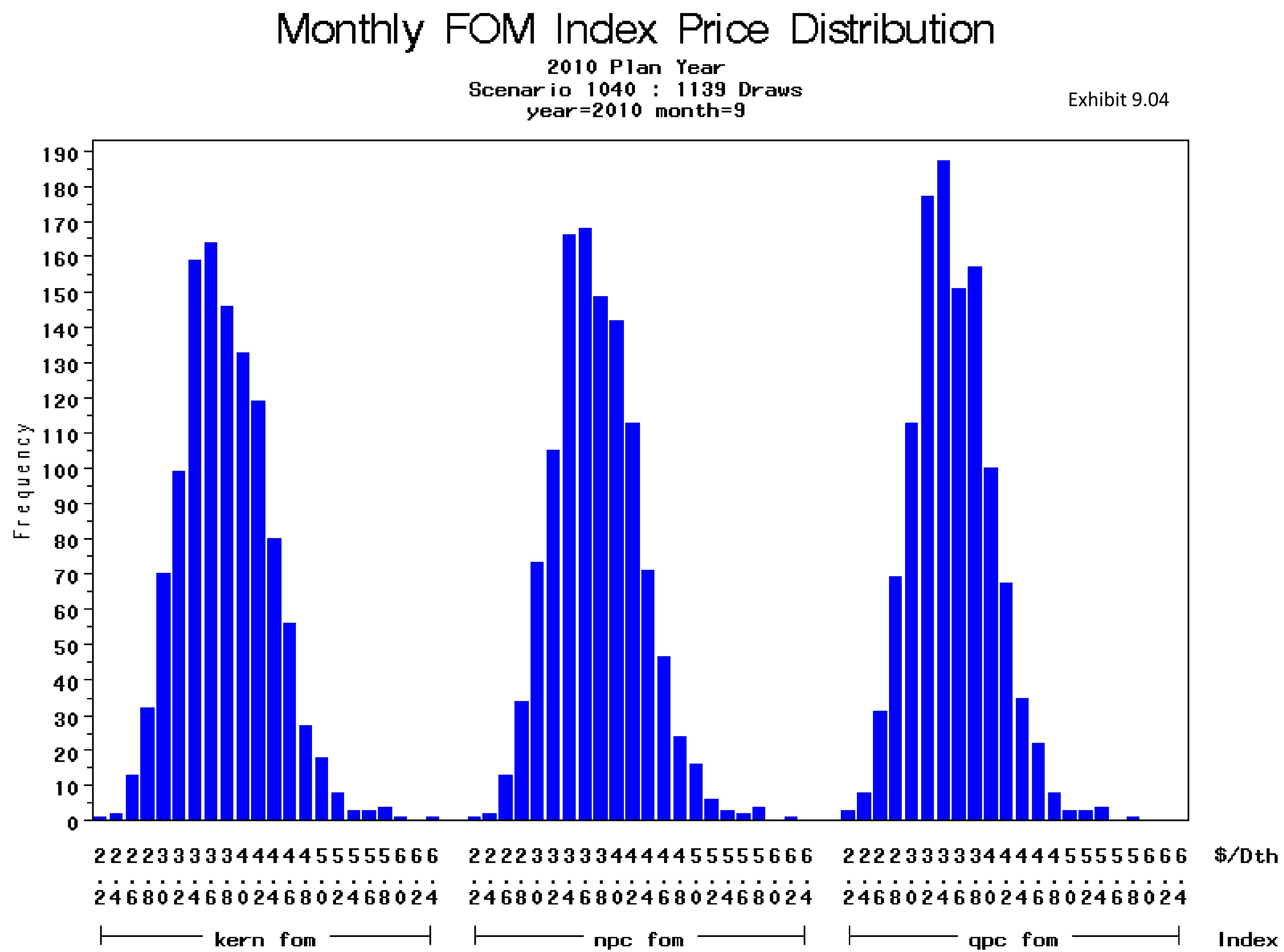

Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=9
Frequency
$/Dth
kern fom
npc fom
qpc fom
Index

Exhibit 9.05

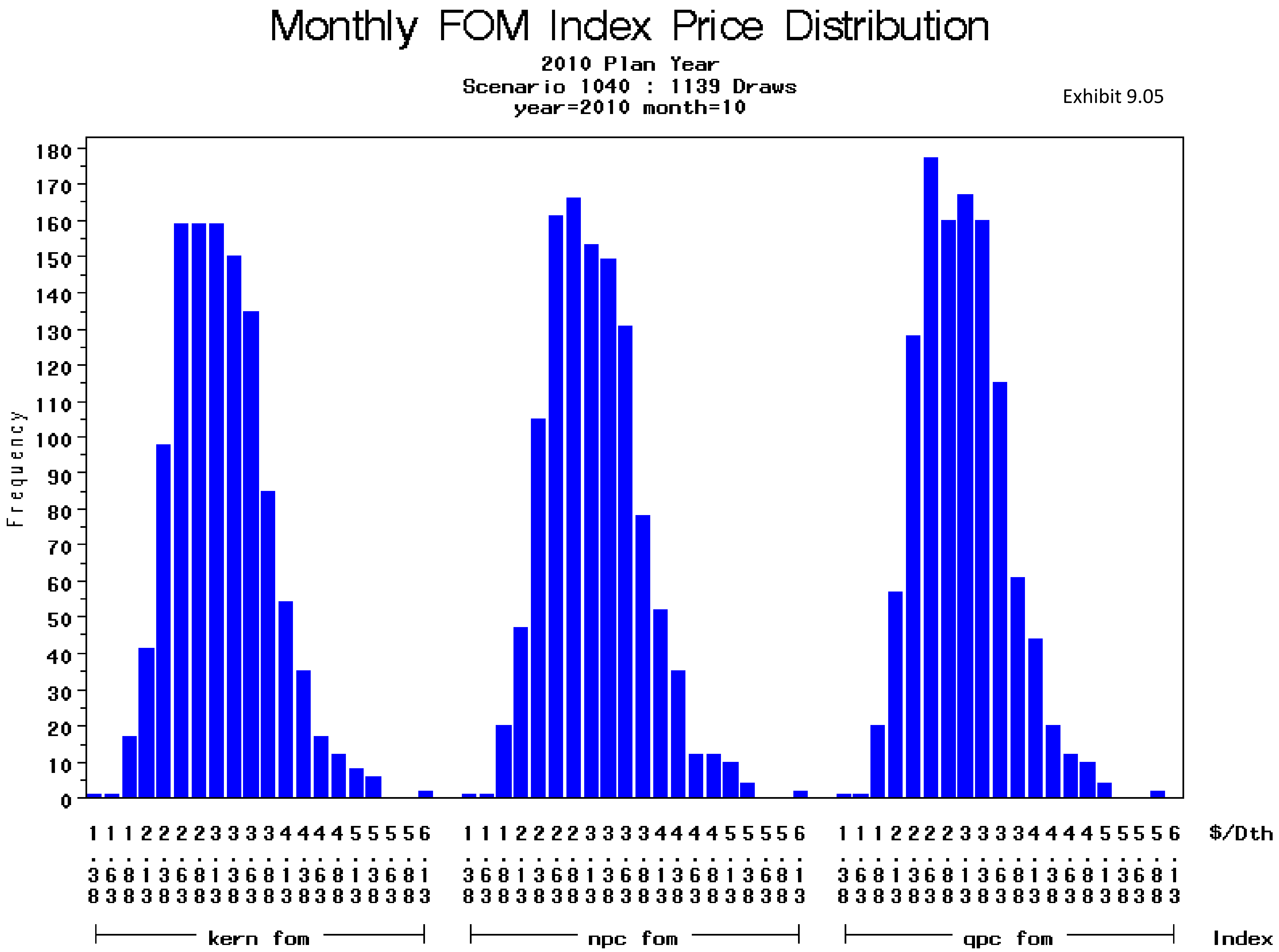
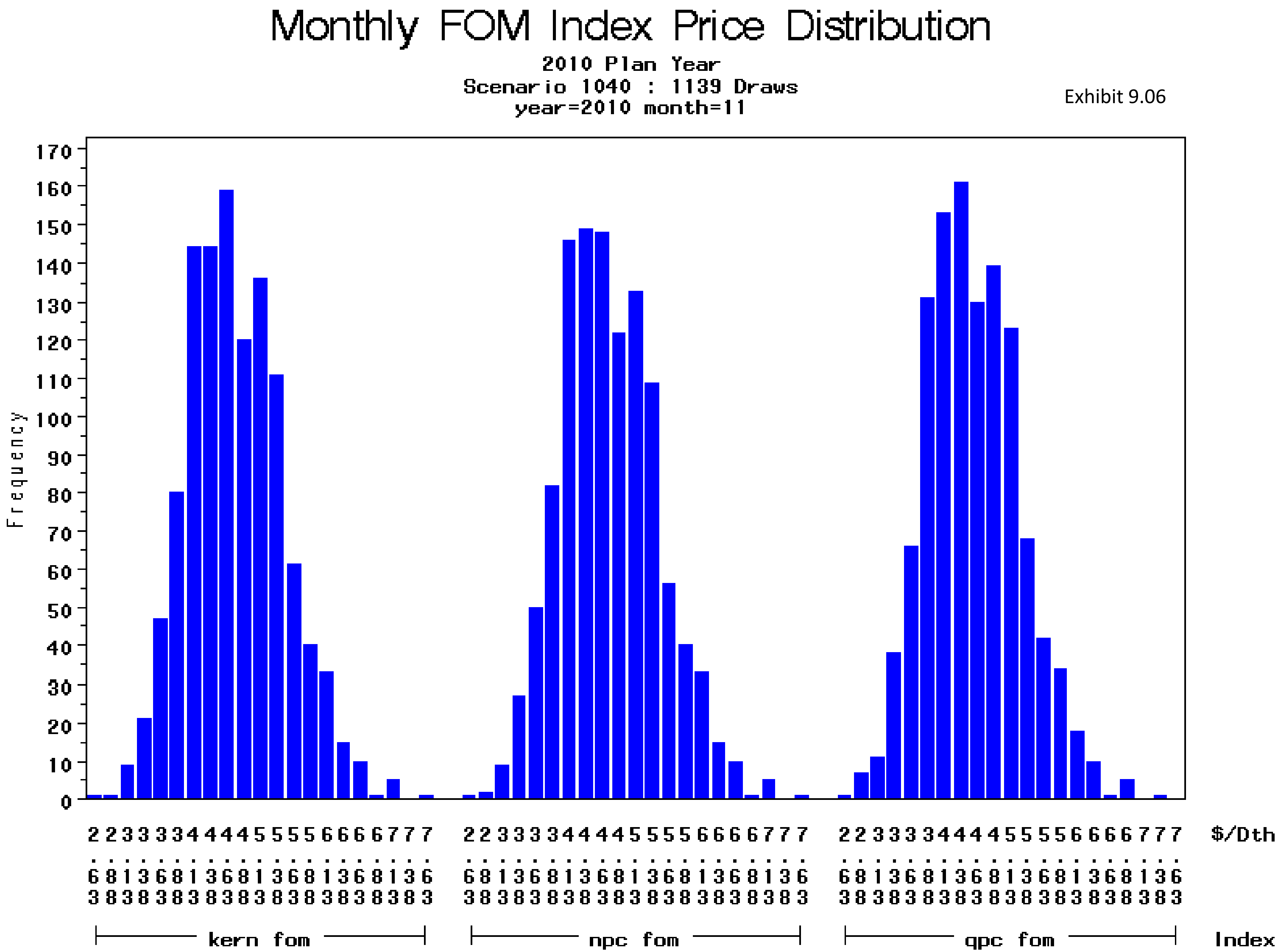

Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10
Frequency
$/Dth
kern fom
npc fom
qpc fom
Index

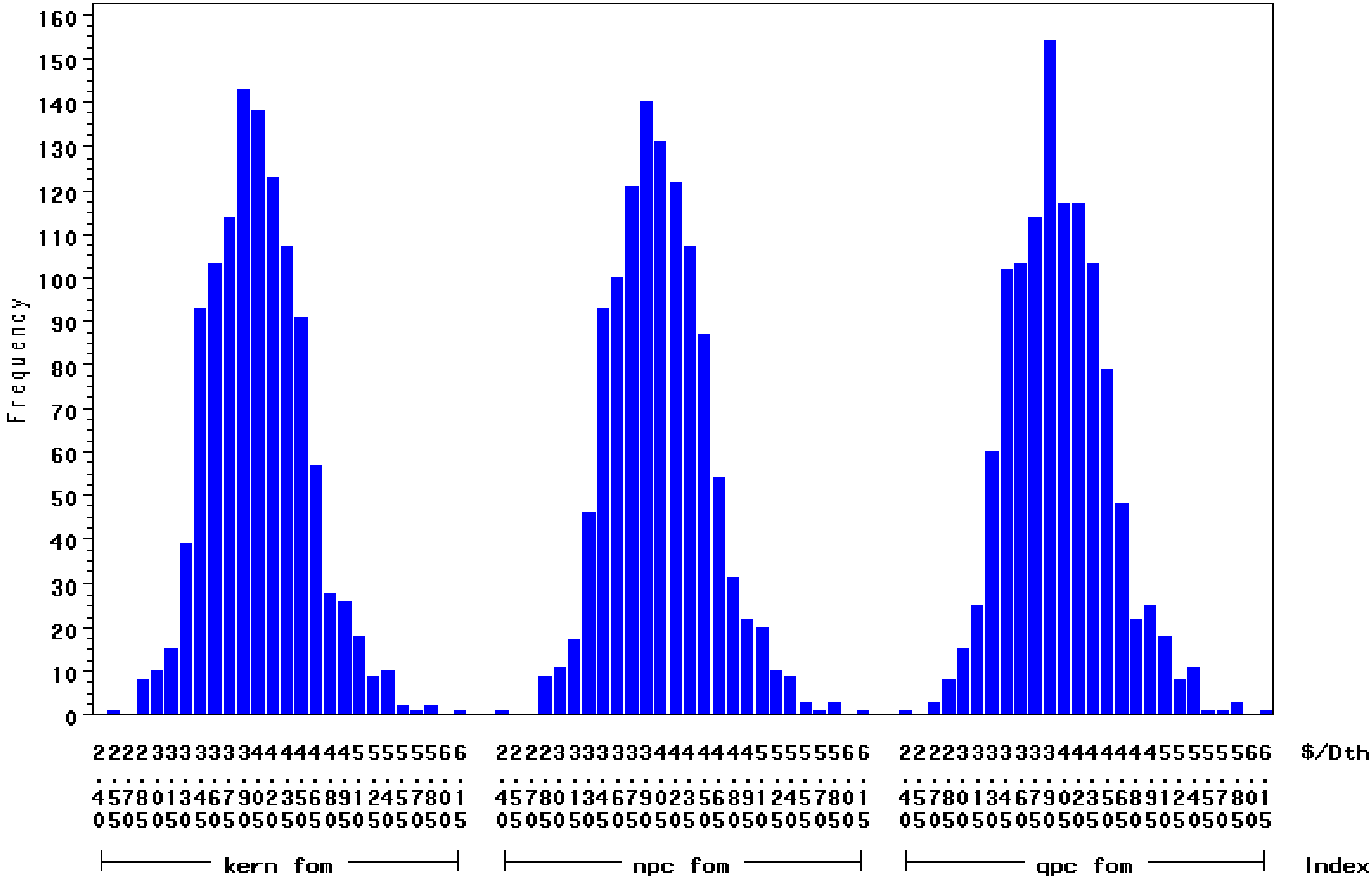
Exhibit 9.06


Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=11
Frequency
$/Dth
kern fom
npc fom
qpc fom
Index

# Monthly FOM Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=12

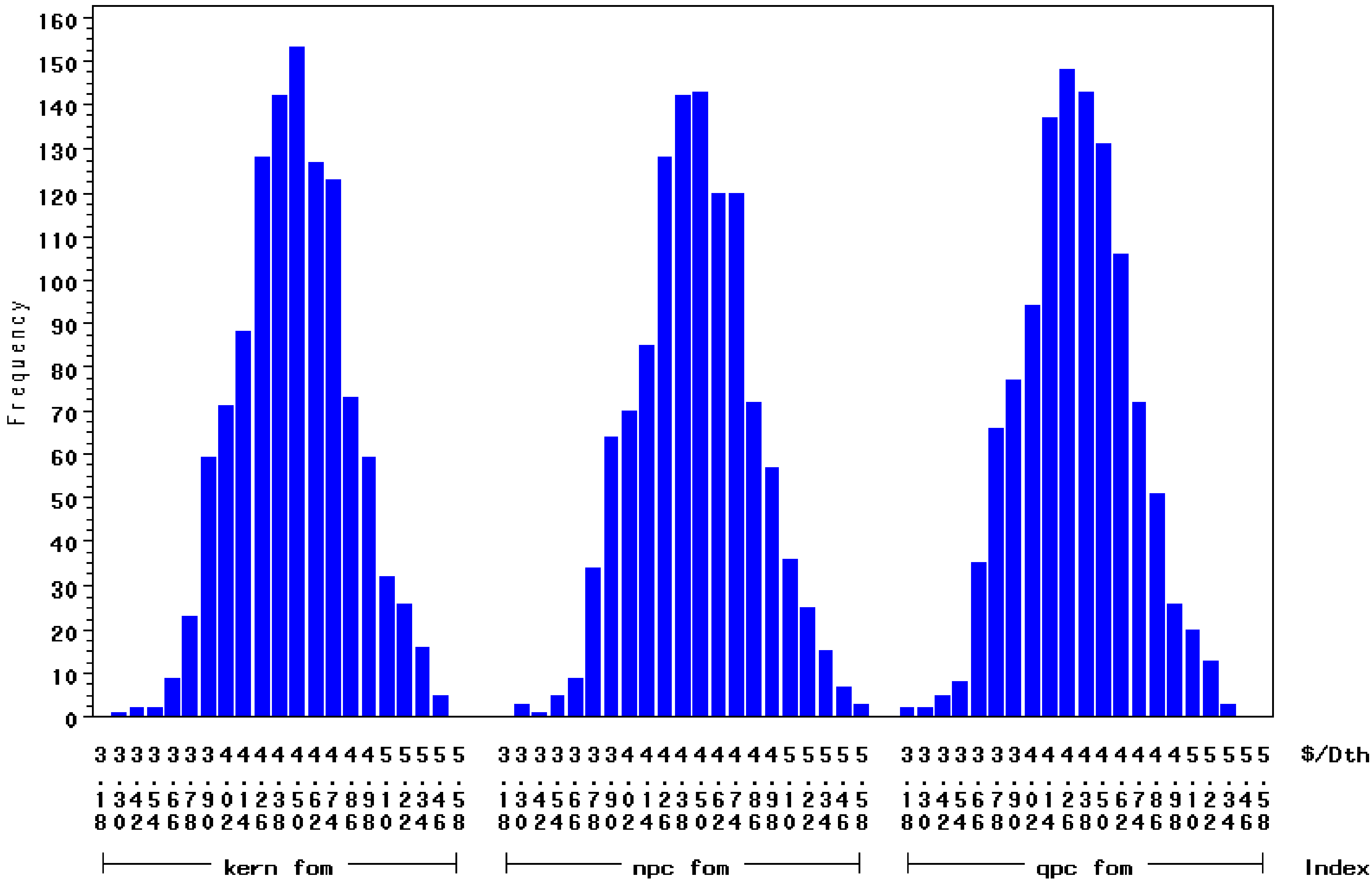
Exhibit 9.07



# Monthly FOM Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1

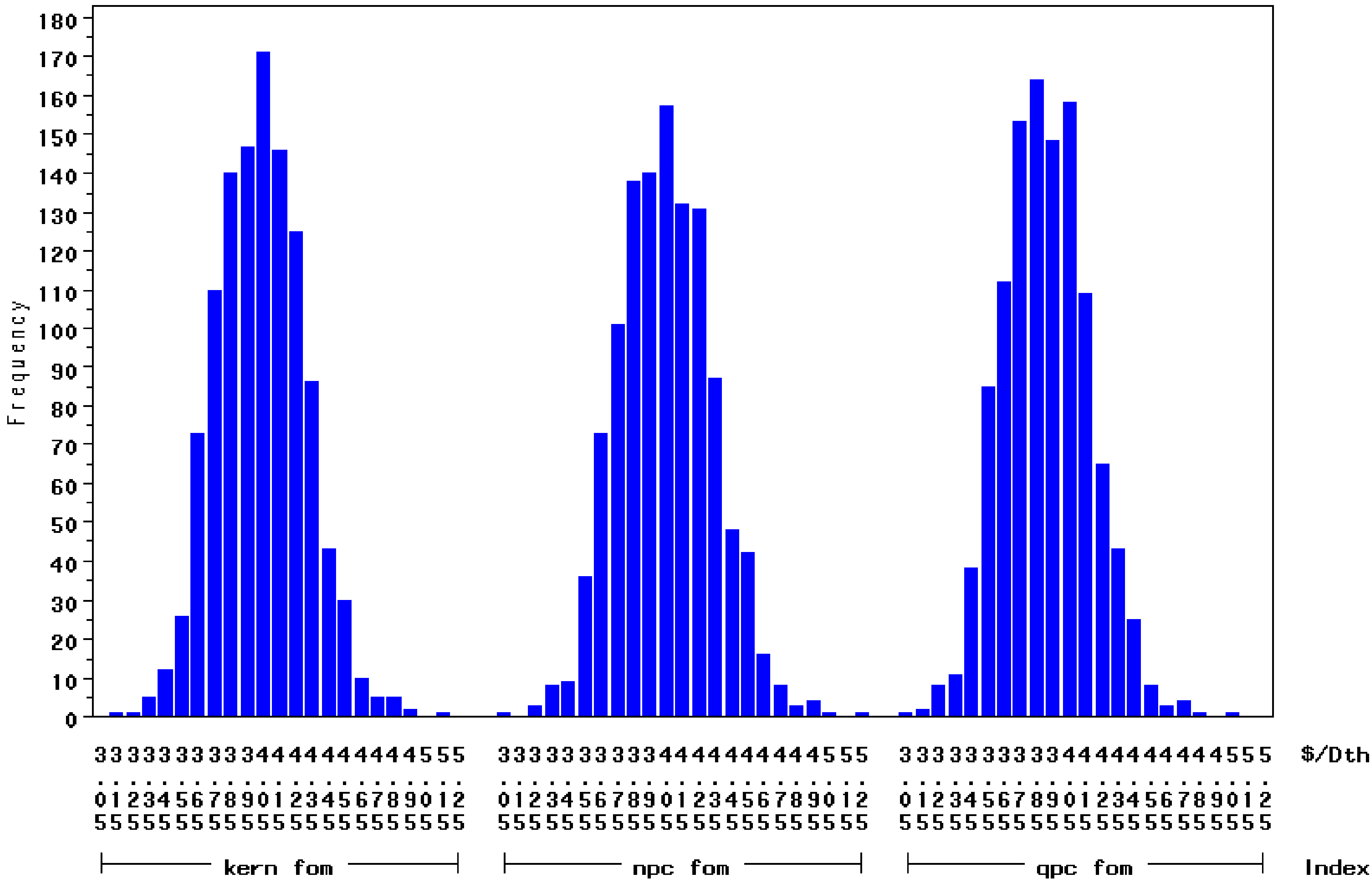
Exhibit 9.08

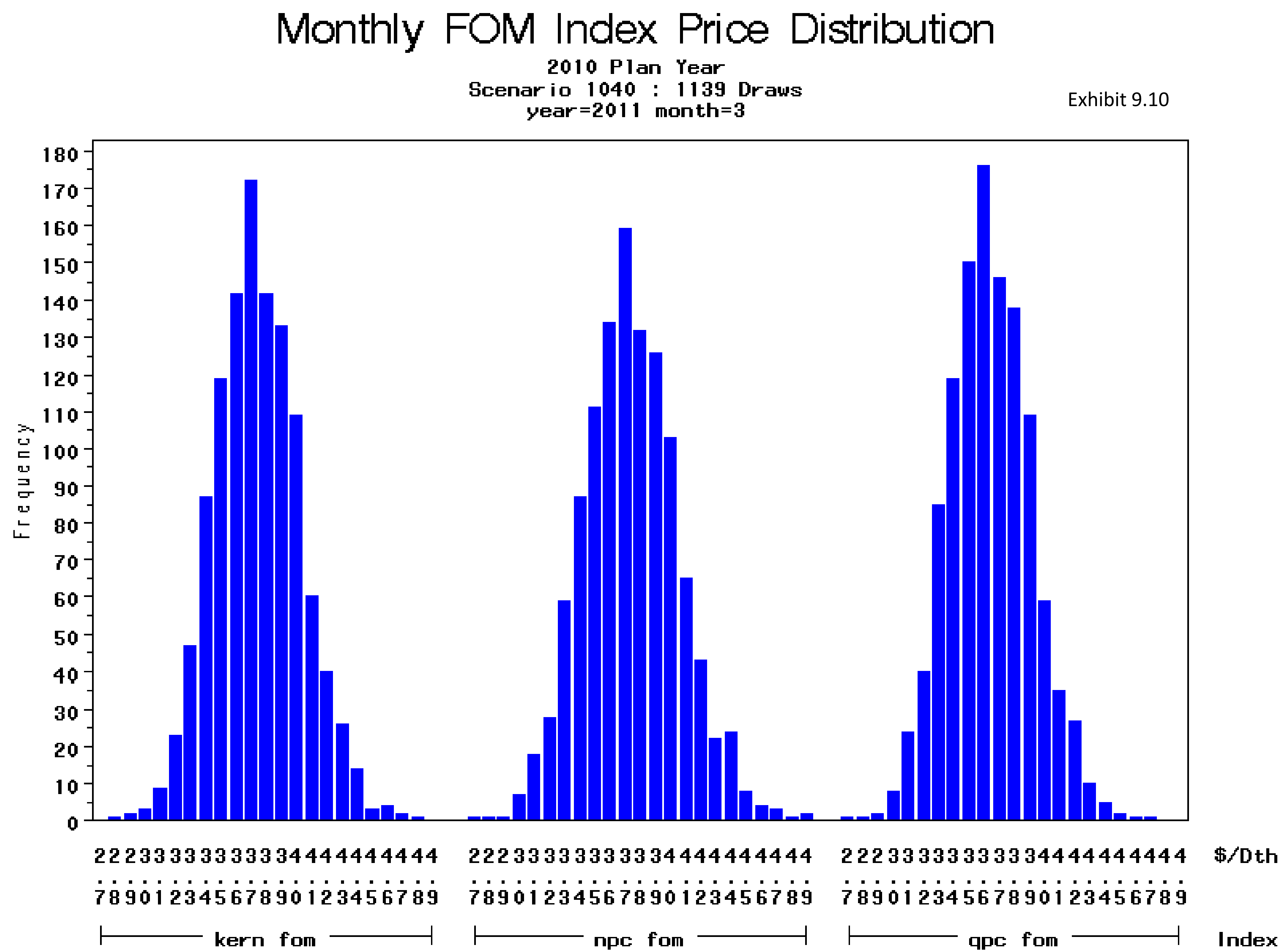


# Monthly FOM Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=2

Exhibit 9.09



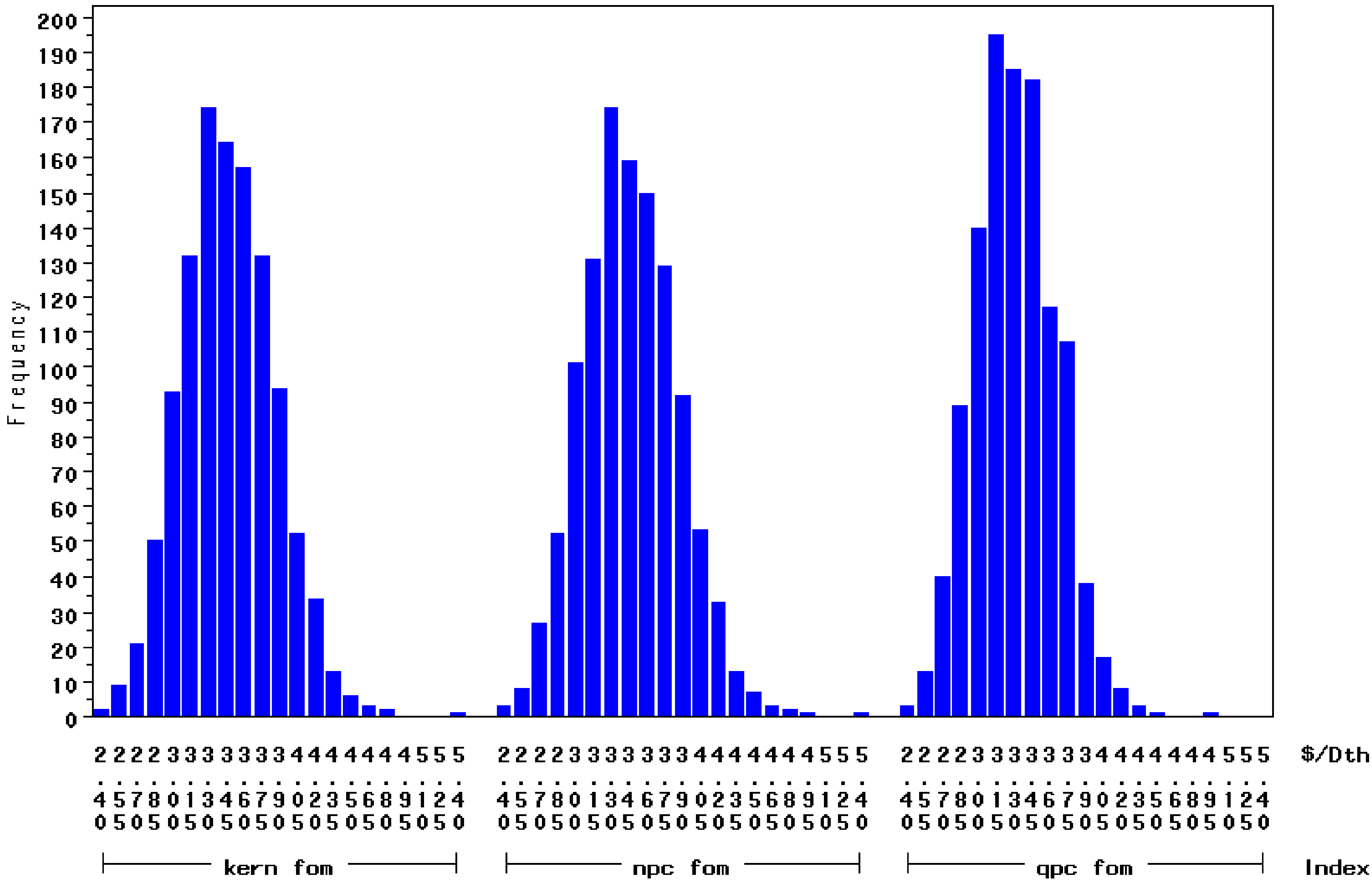


Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3
Exhibit 9.10
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
$/Dth
kern fom
npc fom
qpc fom
Index

Exhibit 9.11

# Monthly FOM Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4



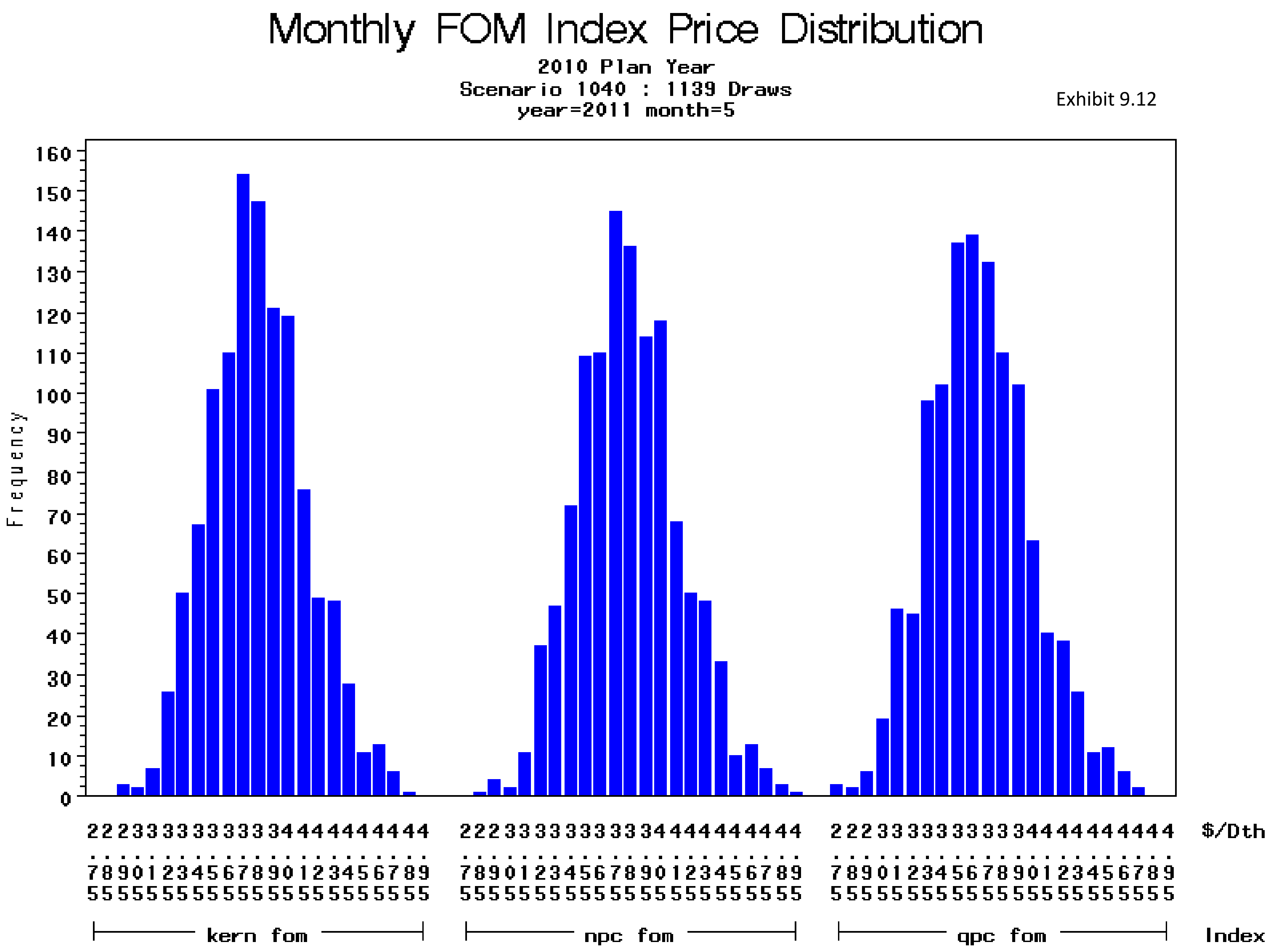
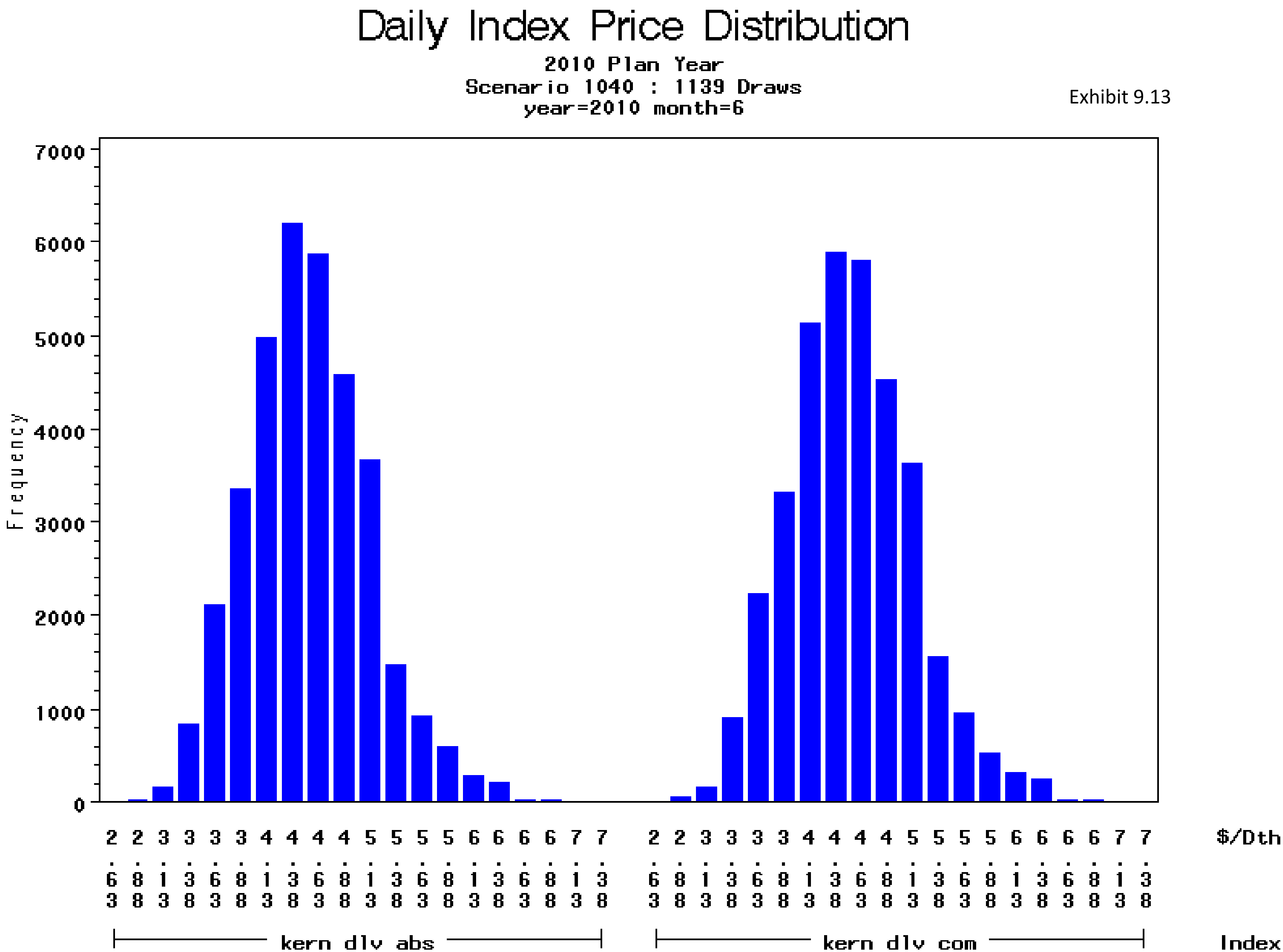

Monthly FOM Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5
Exhibit 9.12
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
$/Dth
kern fom
npc fom
qpc fom
Index

Exhibit 9.13


Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=6
Frequency
0
1000
2000
3000
4000
5000
6000
7000
2.63 2.88 3.13 3.38 3.63 3.88 4.13 4.38 4.63 4.88 5.13 5.38 5.63 5.88 6.13 6.38 6.63 6.88 7.13 7.38
2.63 2.88 3.13 3.38 3.63 3.88 4.13 4.38 4.63 4.88 5.13 5.38 5.63 5.88 6.13 6.38 6.63 6.88 7.13 7.38
$/Dth
kern dlv abs
kern dlv com
Index

# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=6

Exhibit 9.14

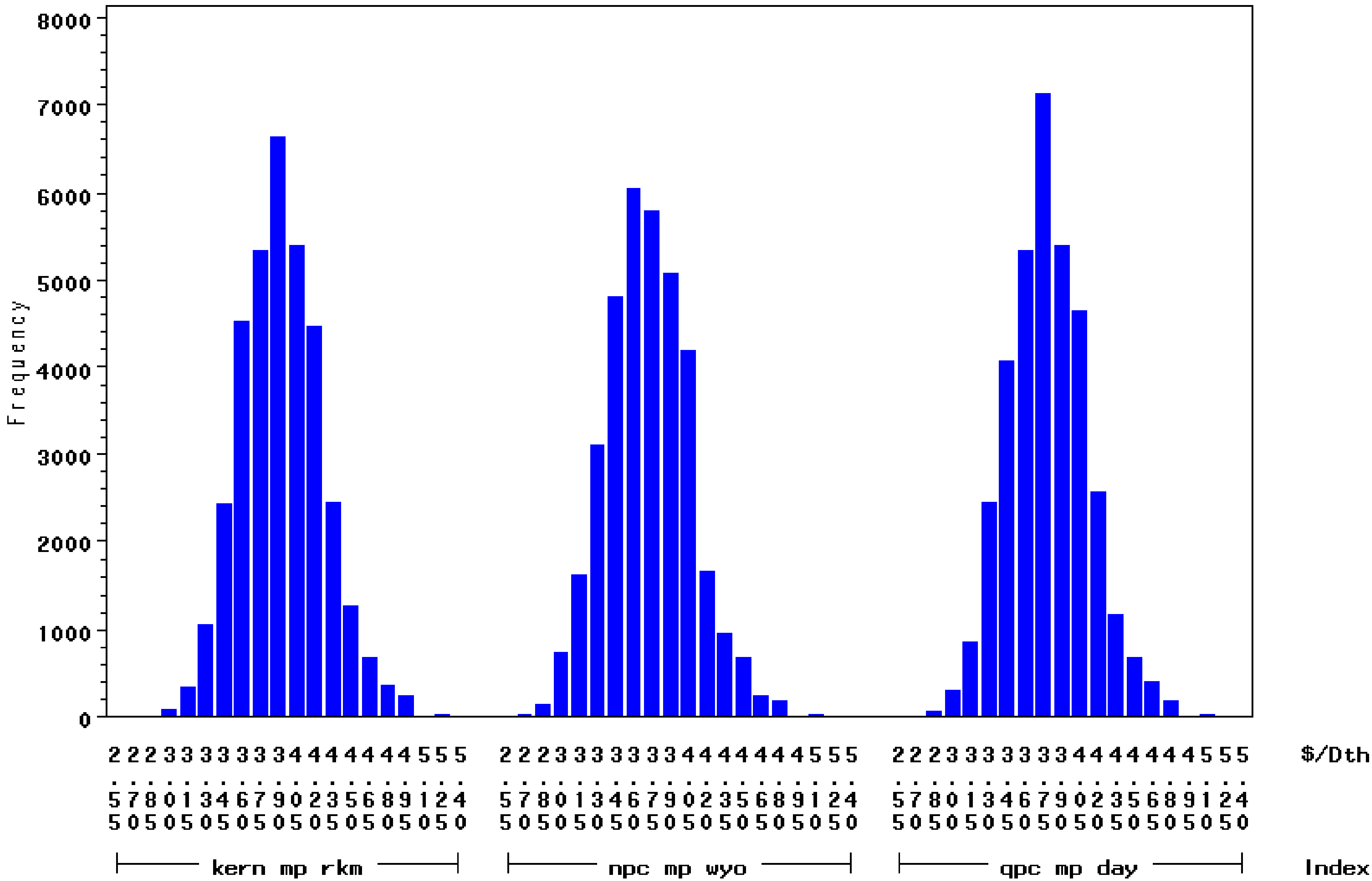


Exhibit 9.15

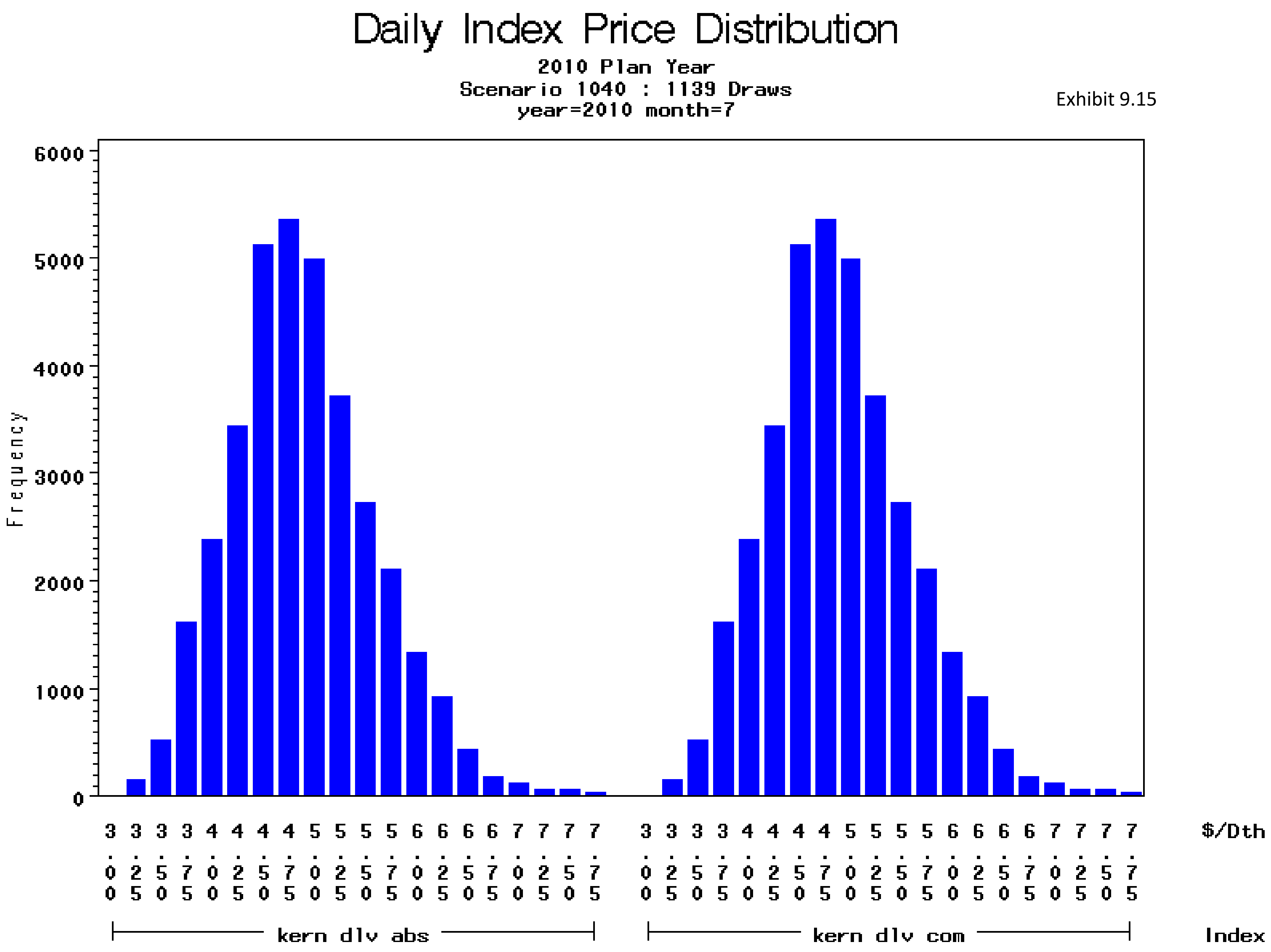
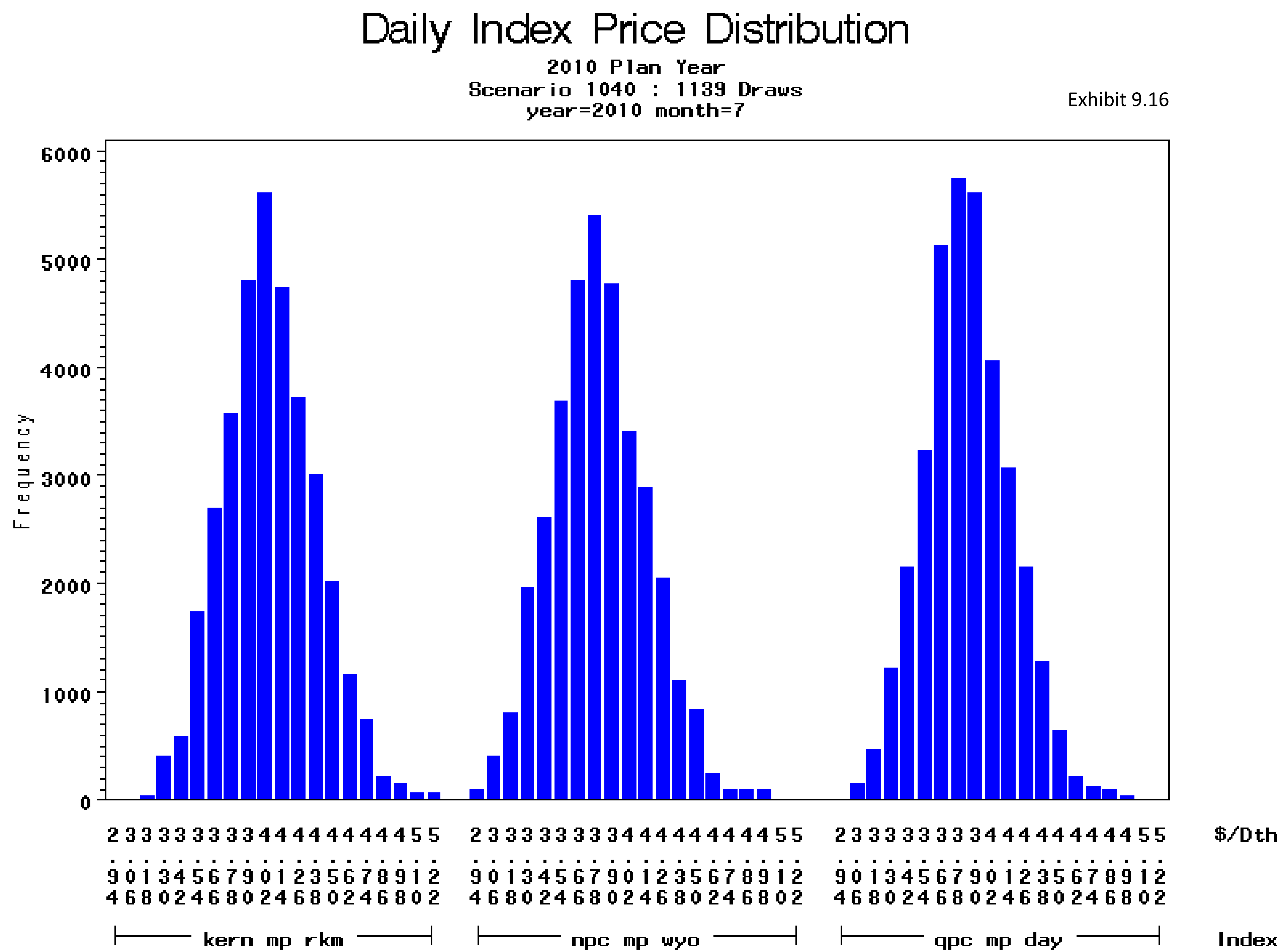
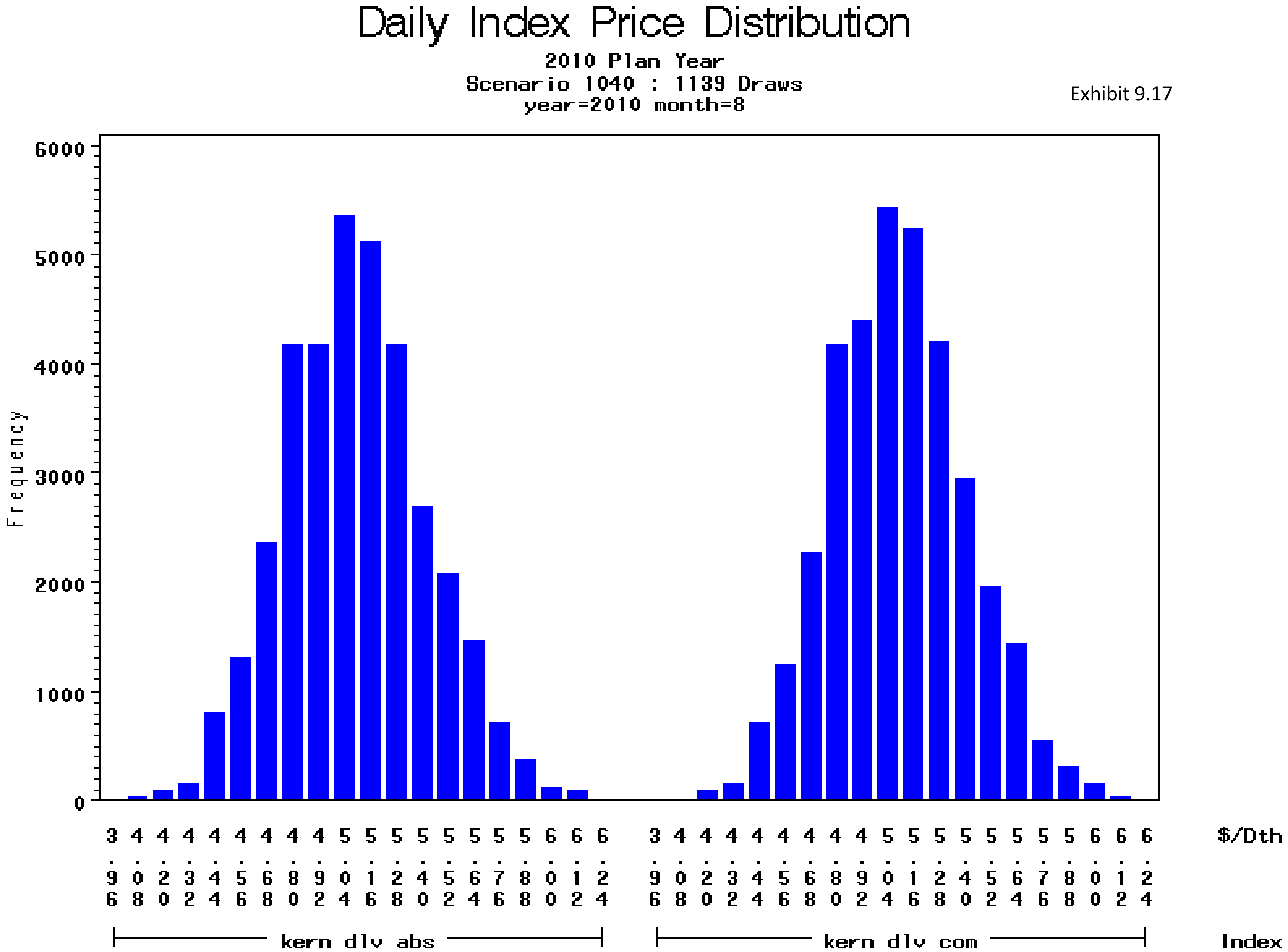

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7
Frequency
6000
5000
4000
3000
2000
1000
0
$/Dth
kern dlv abs
kern dlv com
Index

Exhibit 9.16



Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7
Frequency
6000
5000
4000
3000
2000
1000
0
2.94 3.06 3.18 3.30 3.42 3.54 3.66 3.78 3.90 4.02 4.14 4.26 4.38 4.50 4.62 4.74 4.86 4.98 5.10 5.22
kern mp rkm
2.94 3.06 3.18 3.30 3.42 3.54 3.66 3.78 3.90 4.02 4.14 4.26 4.38 4.50 4.62 4.74 4.86 4.98 5.10 5.22
npc mp wyo
2.94 3.06 3.18 3.30 3.42 3.54 3.66 3.78 3.90 4.02 4.14 4.26 4.38 4.50 4.62 4.74 4.86 4.98 5.10 5.22
qpc mp day
$/Dth
Index

Exhibit 9.17



Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8
Frequency
0
1000
2000
3000
4000
5000
6000
3.96 4.08 4.20 4.32 4.44 4.56 4.68 4.80 4.92 5.04 5.16 5.28 5.40 5.52 5.64 5.76 5.88 6.00 6.12 6.24
kern dlv abs
3.96 4.08 4.20 4.32 4.44 4.56 4.68 4.80 4.92 5.04 5.16 5.28 5.40 5.52 5.64 5.76 5.88 6.00 6.12 6.24
kern dlv com
$/Dth
Index

Exhibit 9.18

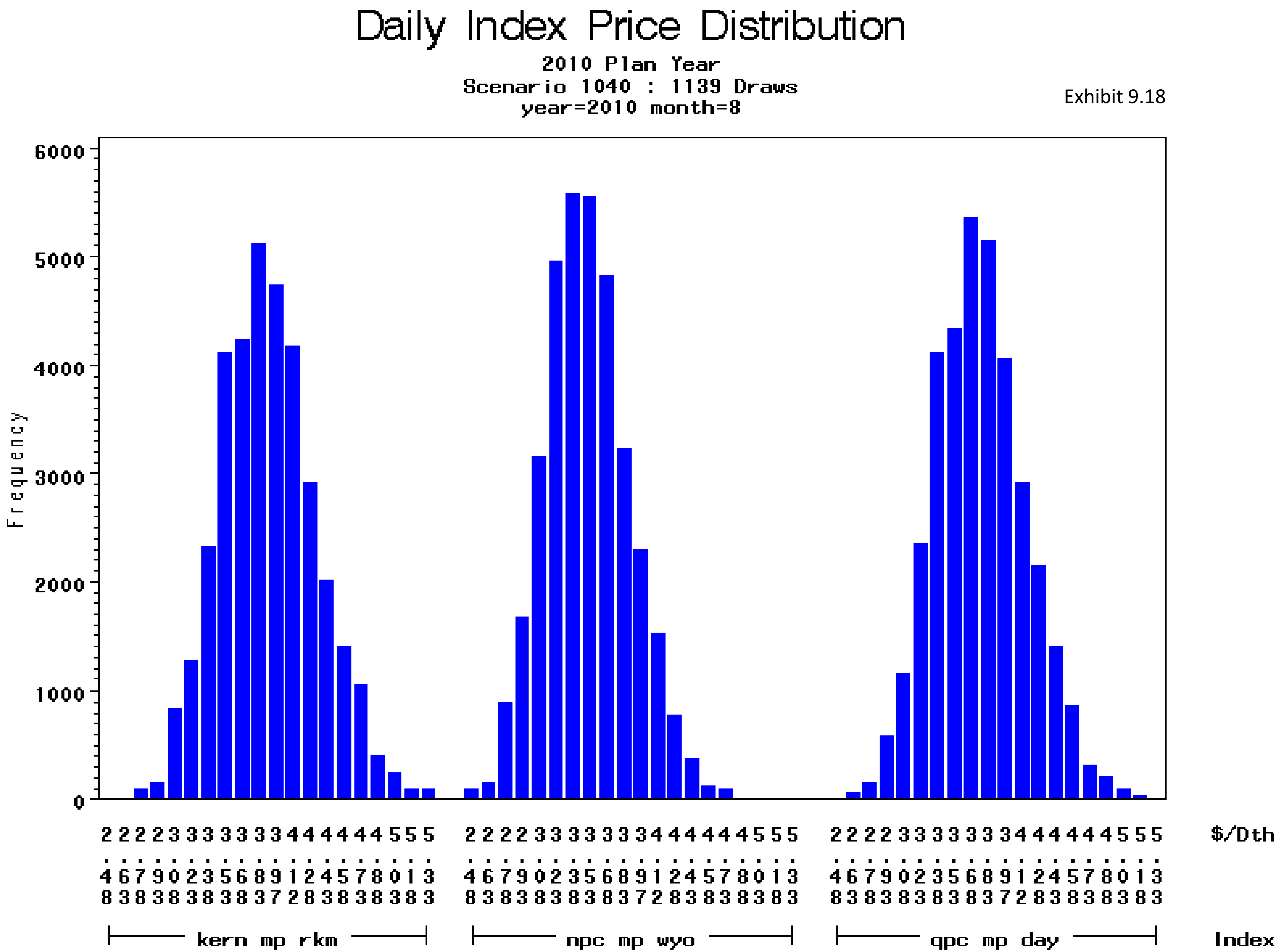
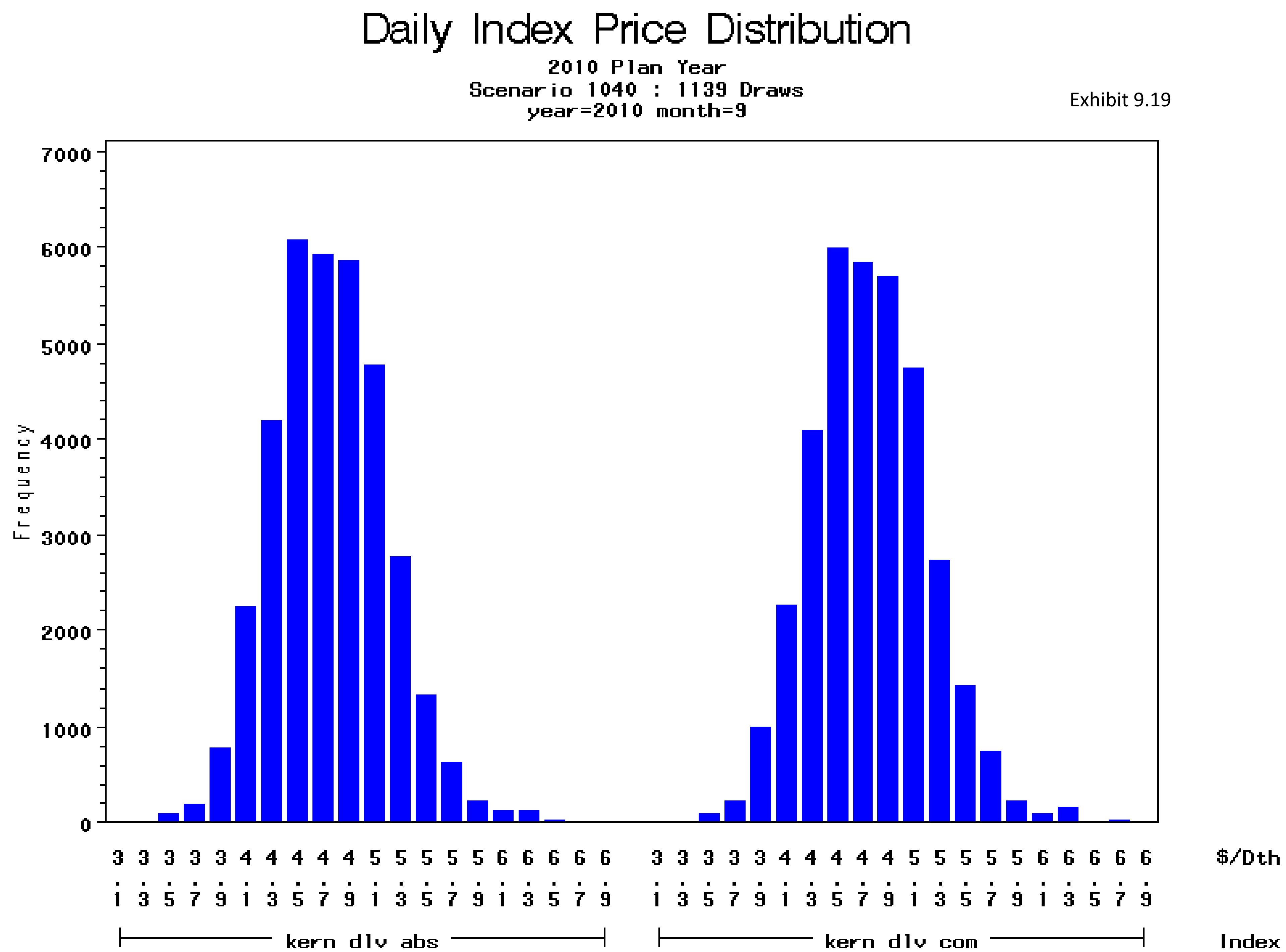

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8
Frequency
0
1000
2000
3000
4000
5000
6000
2.48 2.63 2.78 2.93 3.08 3.23 3.38 3.53 3.68 3.83 3.97 4.12 4.28 4.43 4.58 4.73 4.88 5.03 5.18 5.33
$/Dth
kern mp rkm
npc mp wyo
qpc mp day
Index

Exhibit 9.19



Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=9
Frequency
7000
6000
5000
4000
3000
2000
1000
0
3.1 3.3 3.5 3.7 3.9 4.1 4.3 4.5 4.7 4.9 5.1 5.3 5.5 5.7 5.9 6.1 6.3 6.5 6.7 6.9
kern dlv abs
3.1 3.3 3.5 3.7 3.9 4.1 4.3 4.5 4.7 4.9 5.1 5.3 5.5 5.7 5.9 6.1 6.3 6.5 6.7 6.9
kern dlv com
$/Dth
Index

Exhibit 9.20

# Daily Index Price Distribution

**2010 Plan Year**
**Scenario 1040 : 1139 Draws**
**year=2010 month=9**

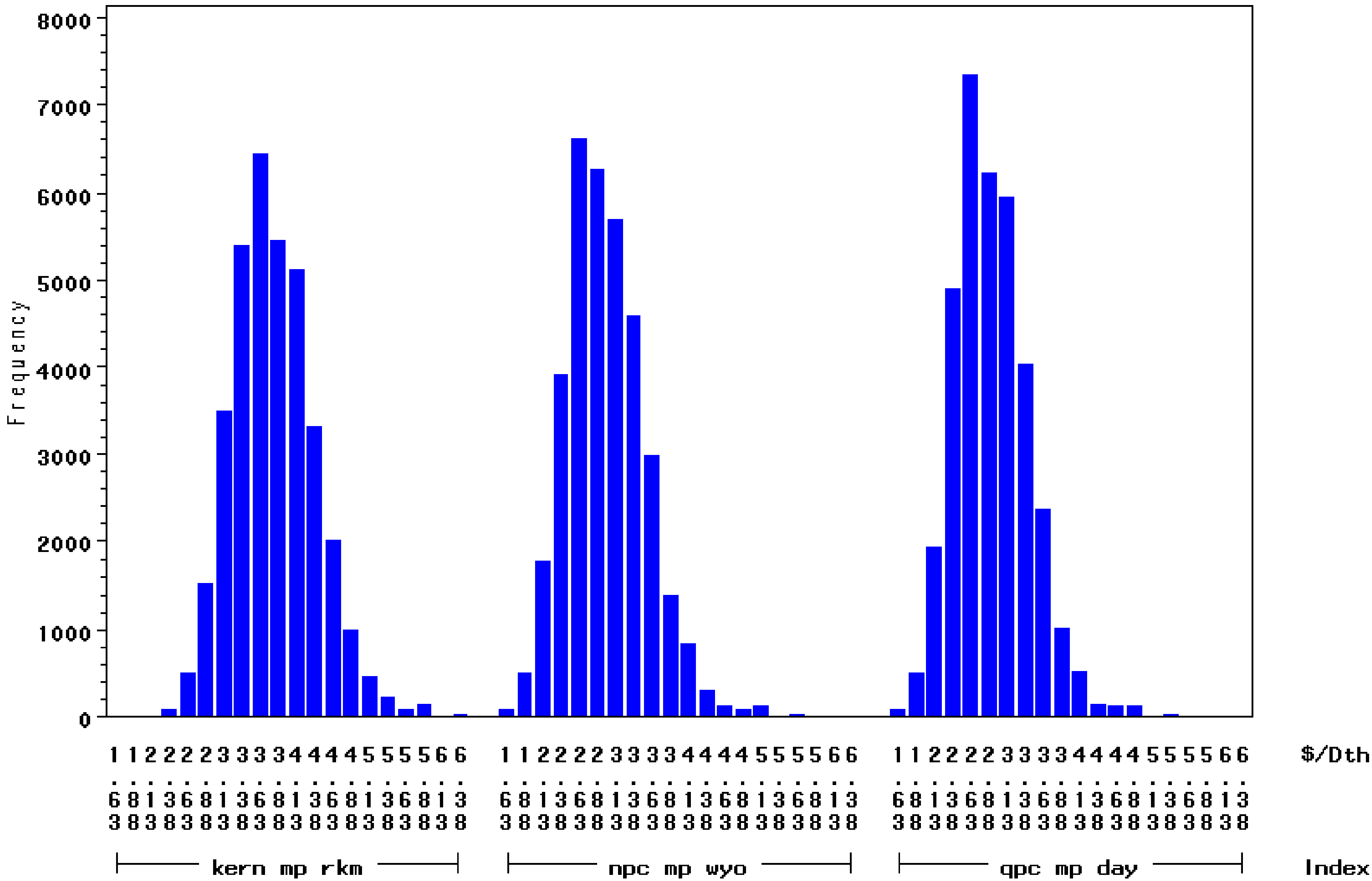
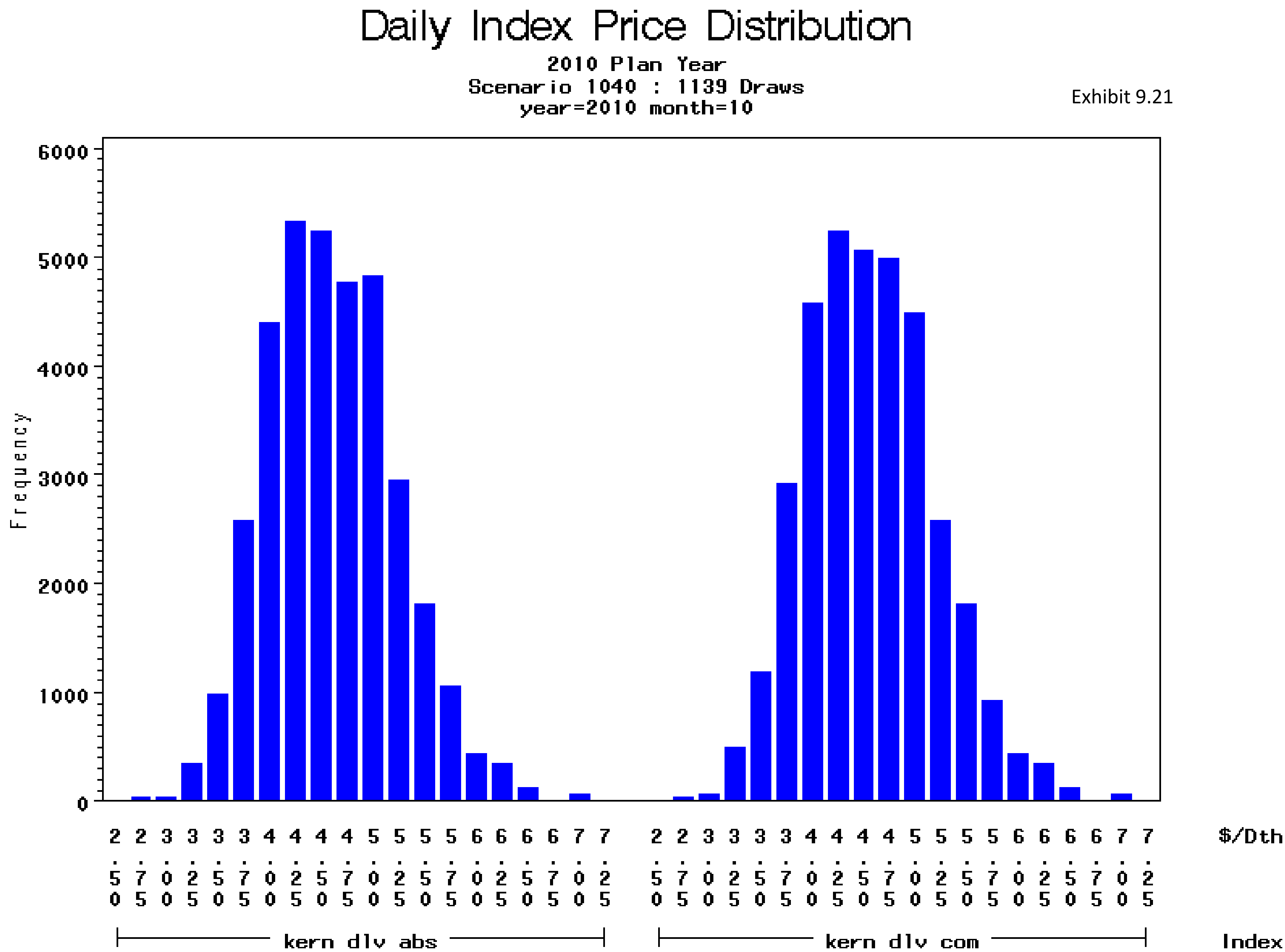


Exhibit 9.21


Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10
Frequency
6000
5000
4000
3000
2000
1000
0
2.50 2.75 3.00 3.25 3.50 3.75 4.00 4.25 4.50 4.75 5.00 5.25 5.50 5.75 6.00 6.25 6.50 6.75 7.00 7.25
2.50 2.75 3.00 3.25 3.50 3.75 4.00 4.25 4.50 4.75 5.00 5.25 5.50 5.75 6.00 6.25 6.50 6.75 7.00 7.25
$/Dth
kern dlv abs
kern dlv com
Index

# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10

Exhibit 9.22

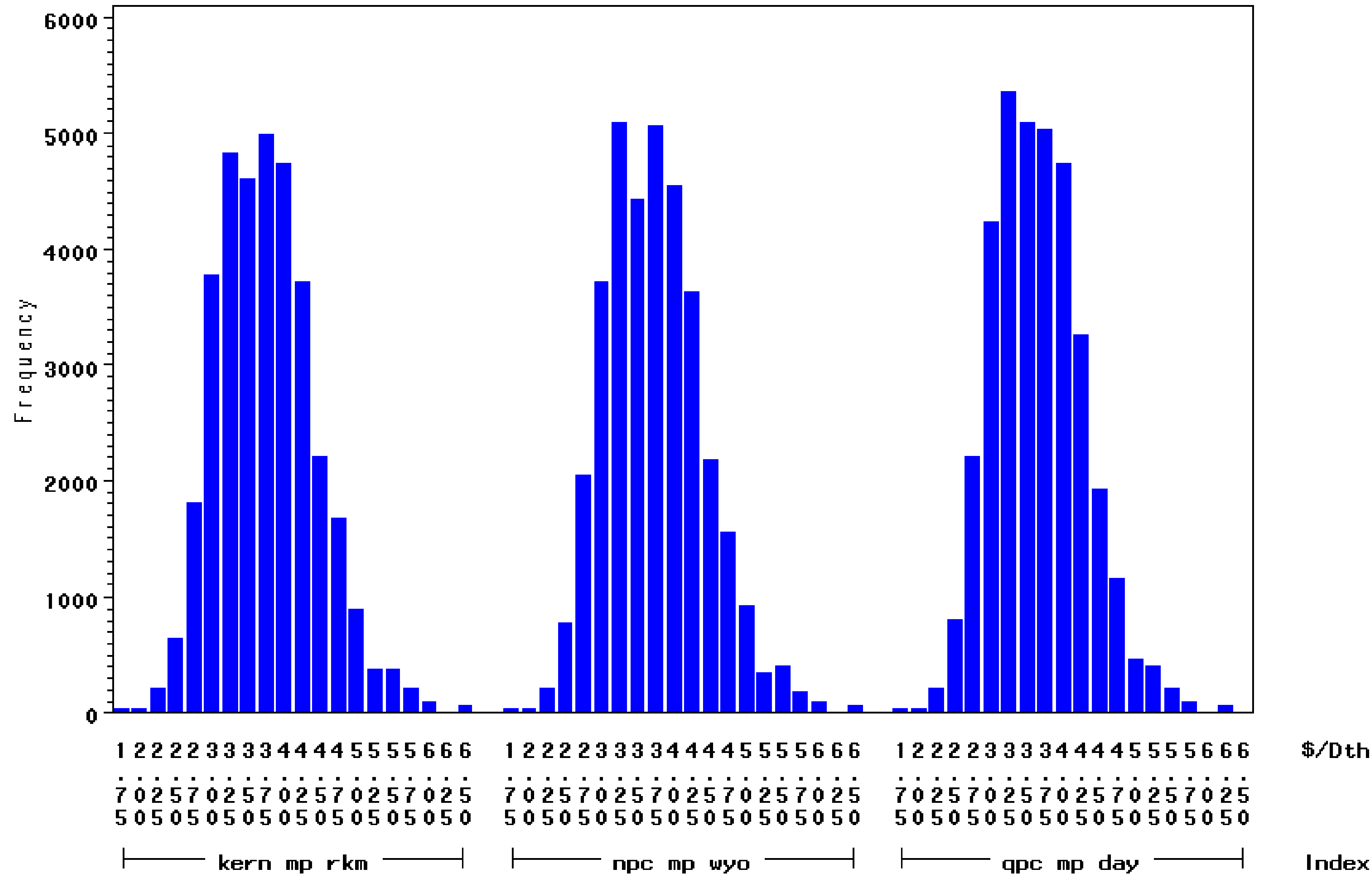
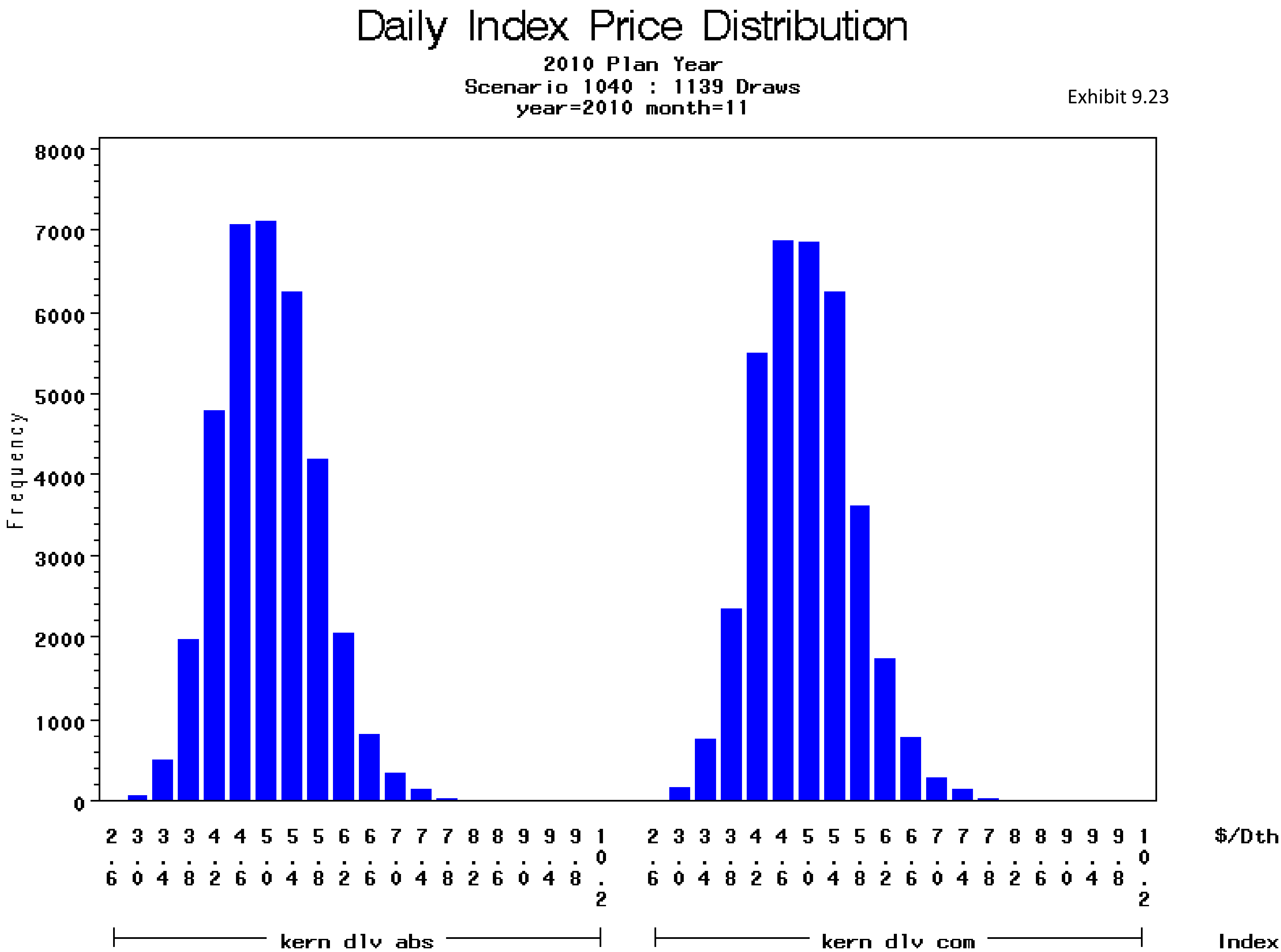


Exhibit 9.23



Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=11
Frequency
8000
7000
6000
5000
4000
3000
2000
1000
0
2.6 3.0 3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2
2.6 3.0 3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2
$/Dth
kern dlv abs
kern dlv com
Index

# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=11

Exhibit 9.24

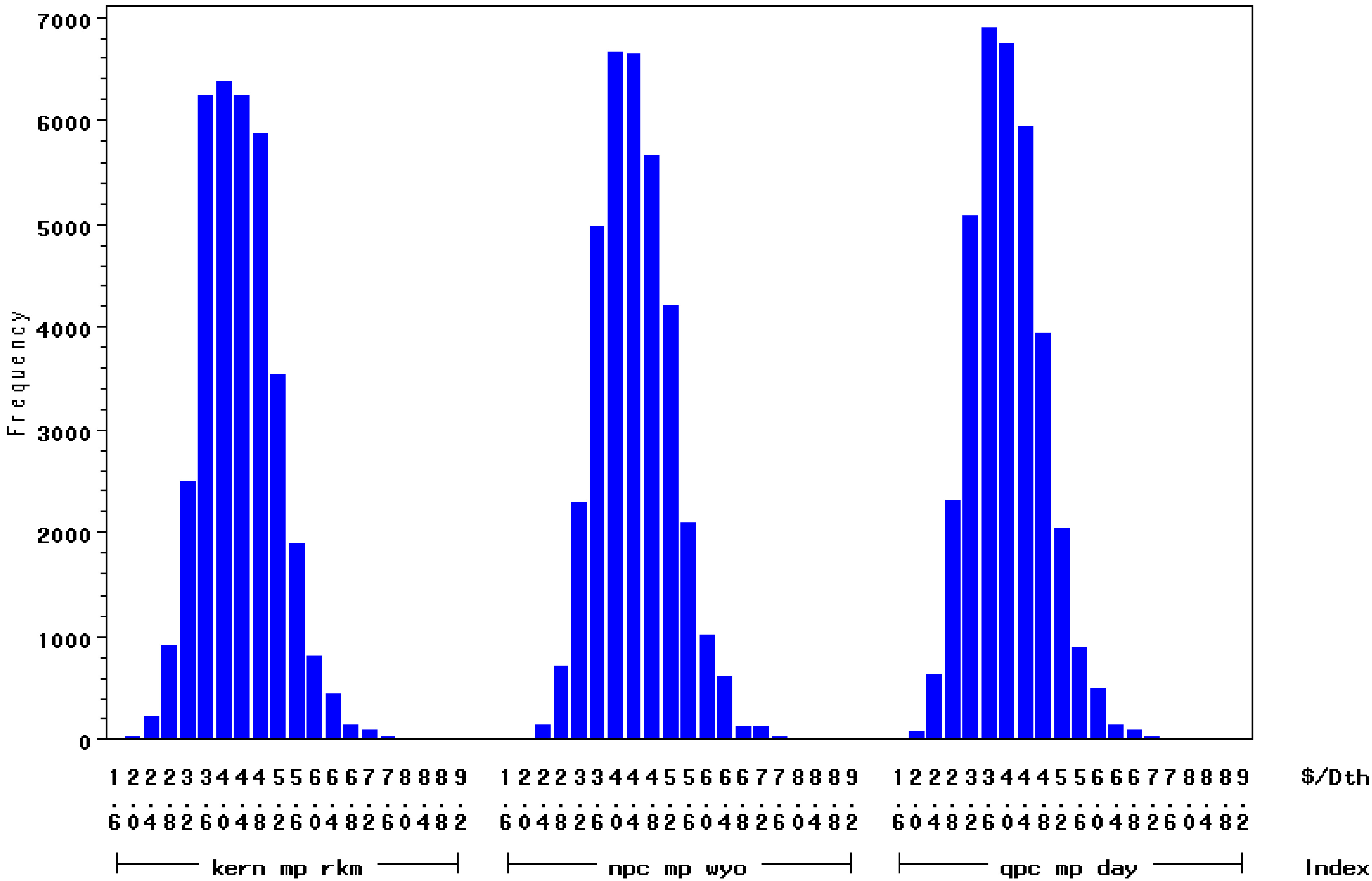
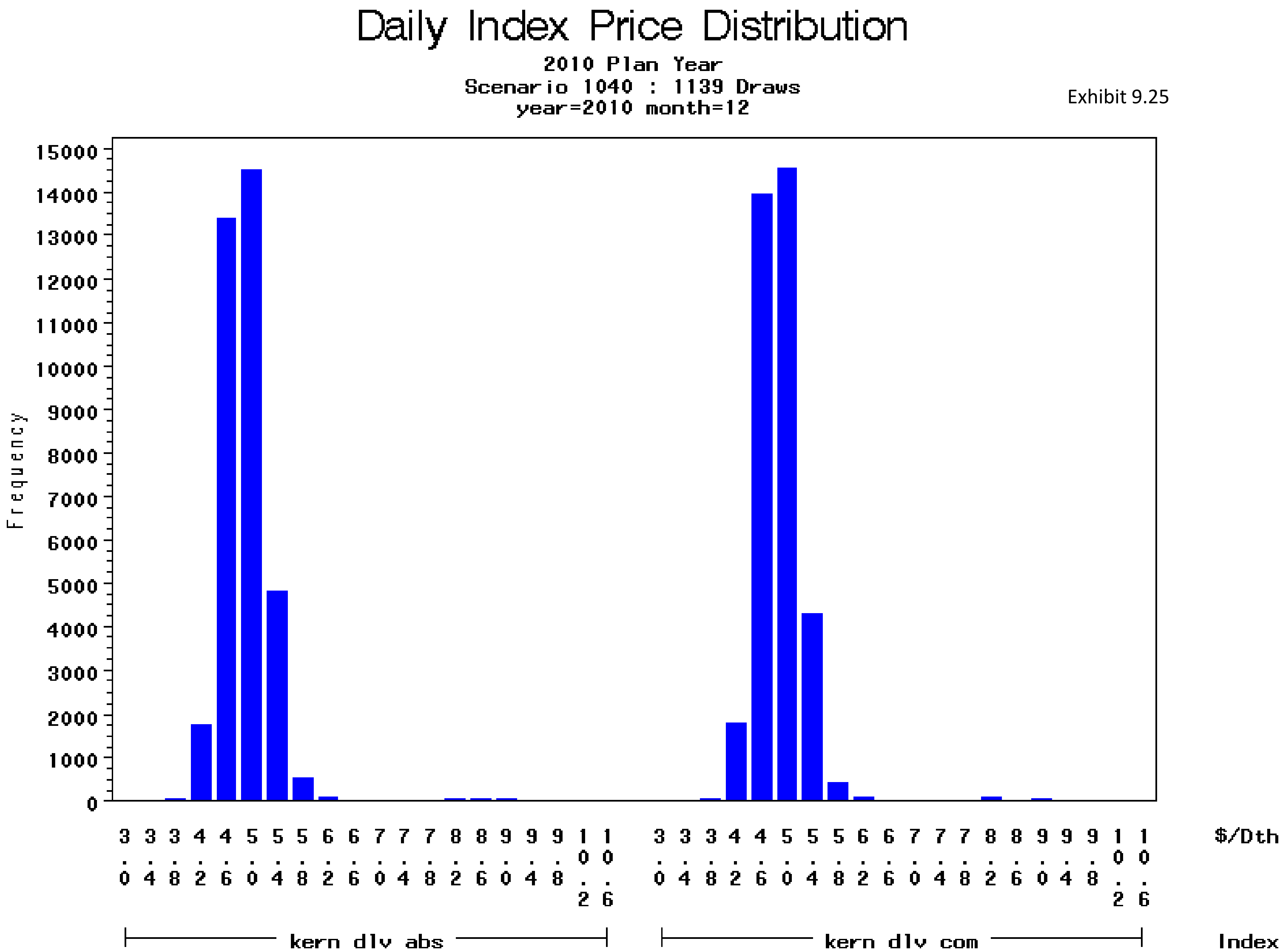


Exhibit 9.25



Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=12
Frequency
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
3.0 3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2 10.6
3.0 3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2 10.6
$/Dth
kern dlv abs
kern dlv com
Index

Exhibit 9.26

# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=12

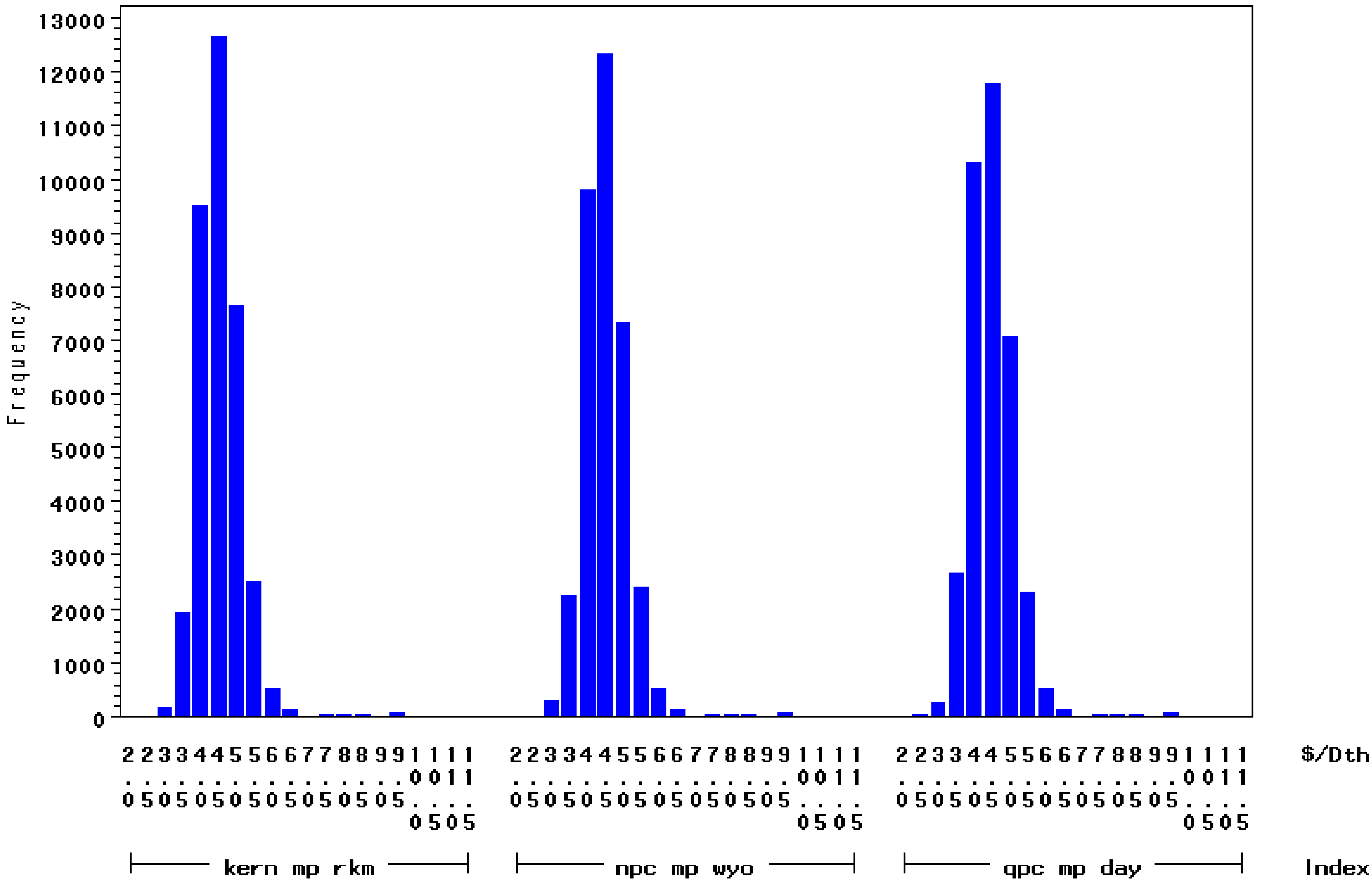


Exhibit 9.27

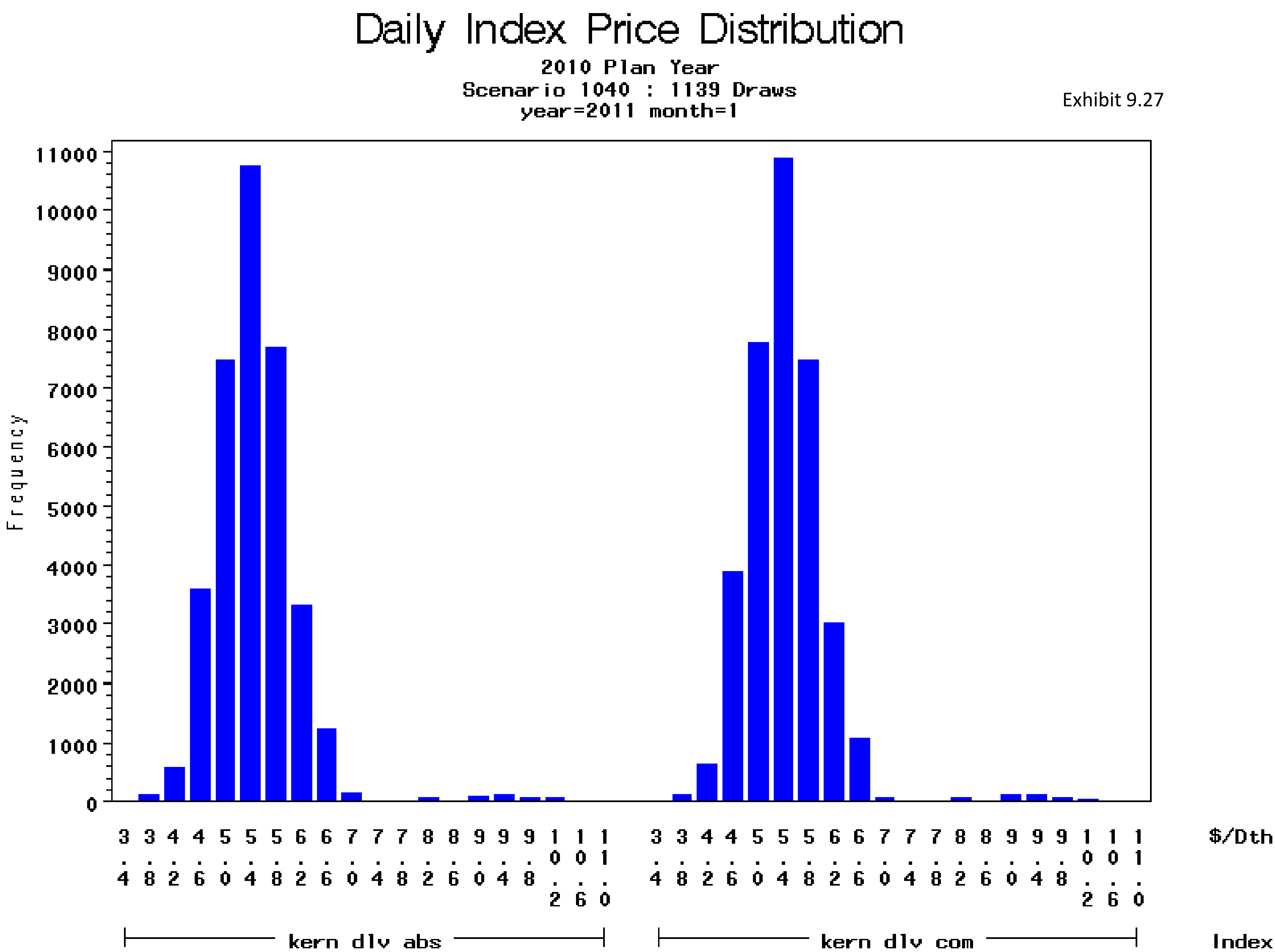
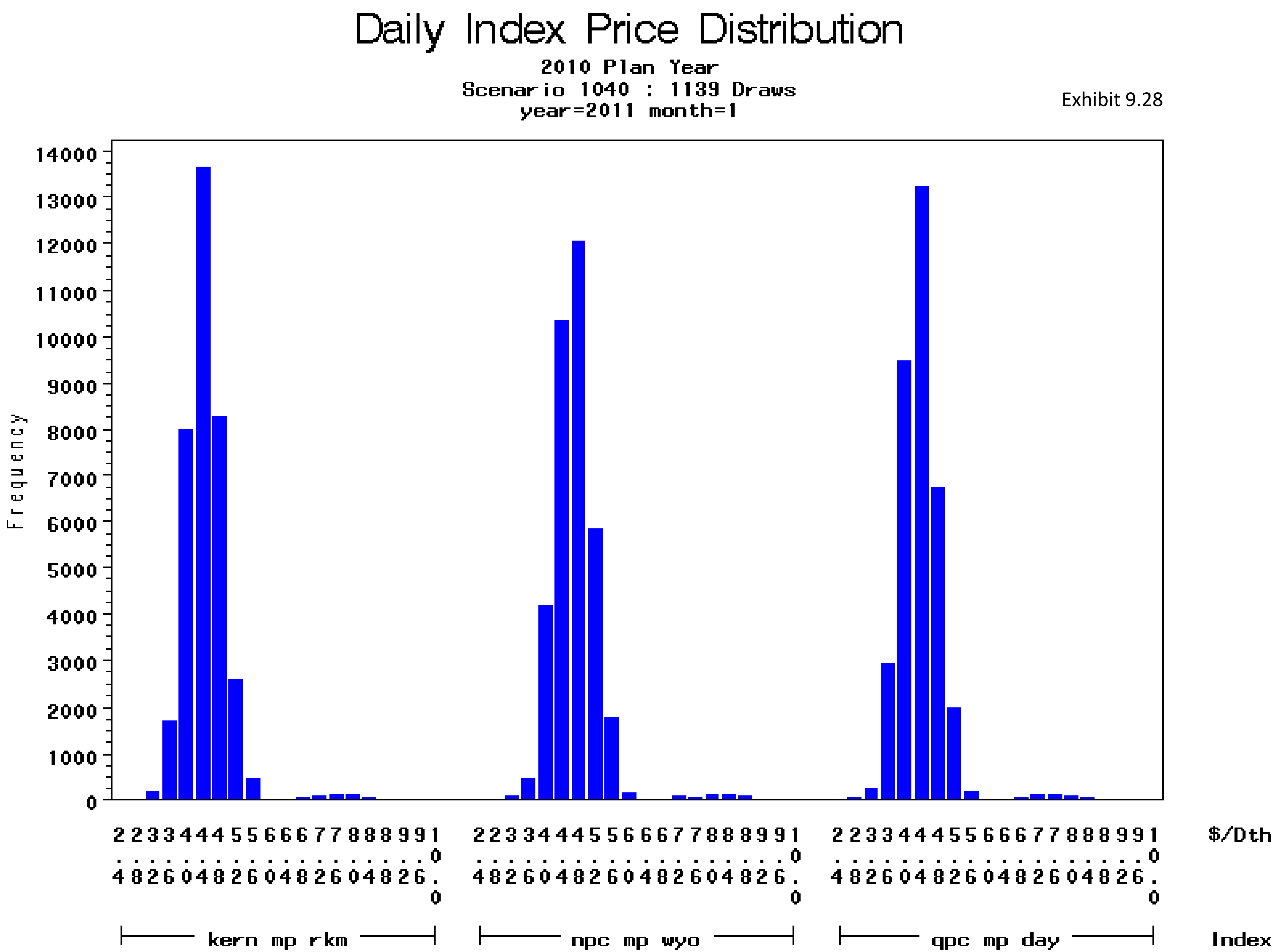
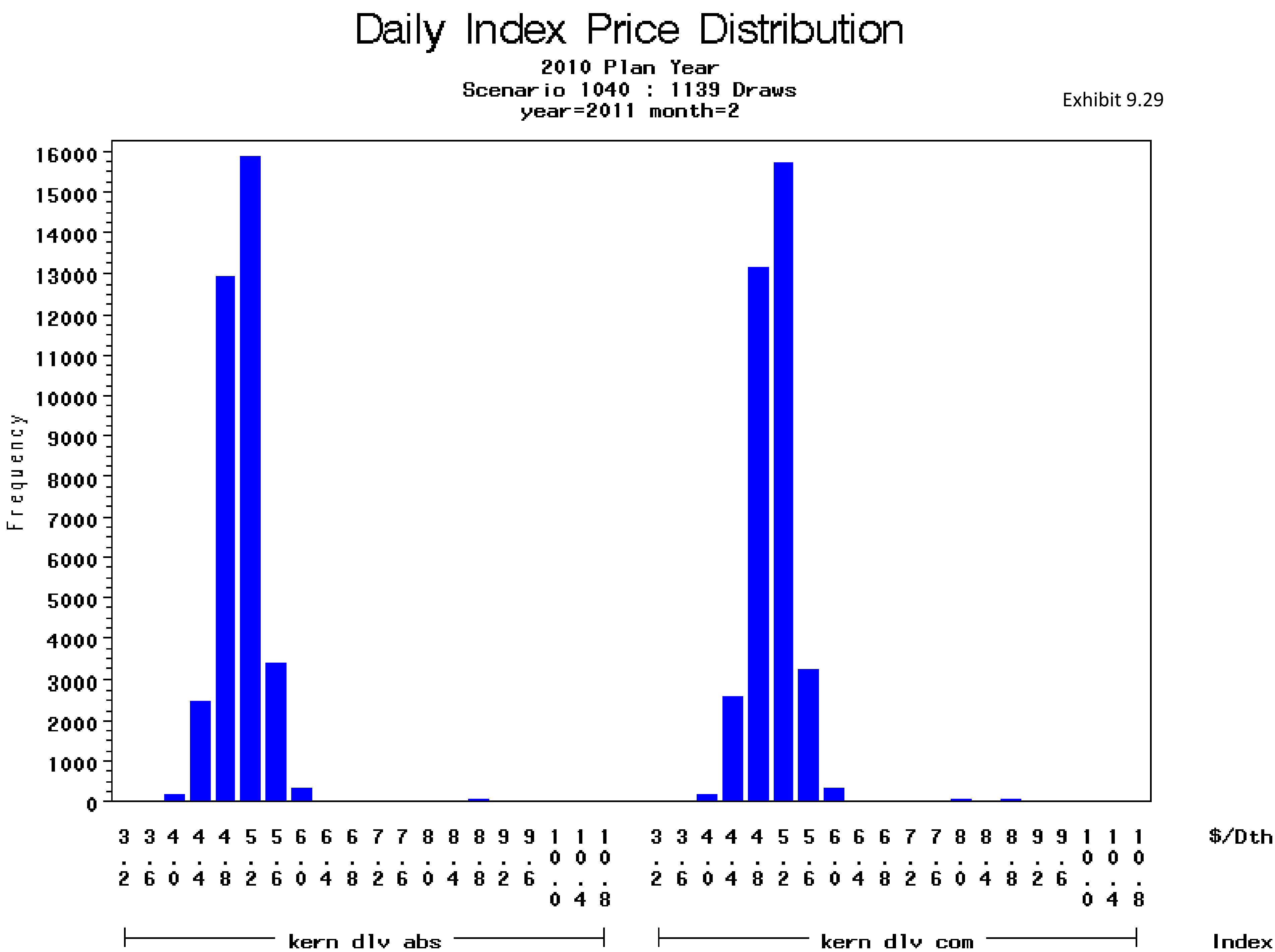

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1
Frequency
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
11000
3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2 10.6 11.0
kern dlv abs
3.4 3.8 4.2 4.6 5.0 5.4 5.8 6.2 6.6 7.0 7.4 7.8 8.2 8.6 9.0 9.4 9.8 10.2 10.6 11.0
kern dlv com
$/Dth
Index

Exhibit 9.28



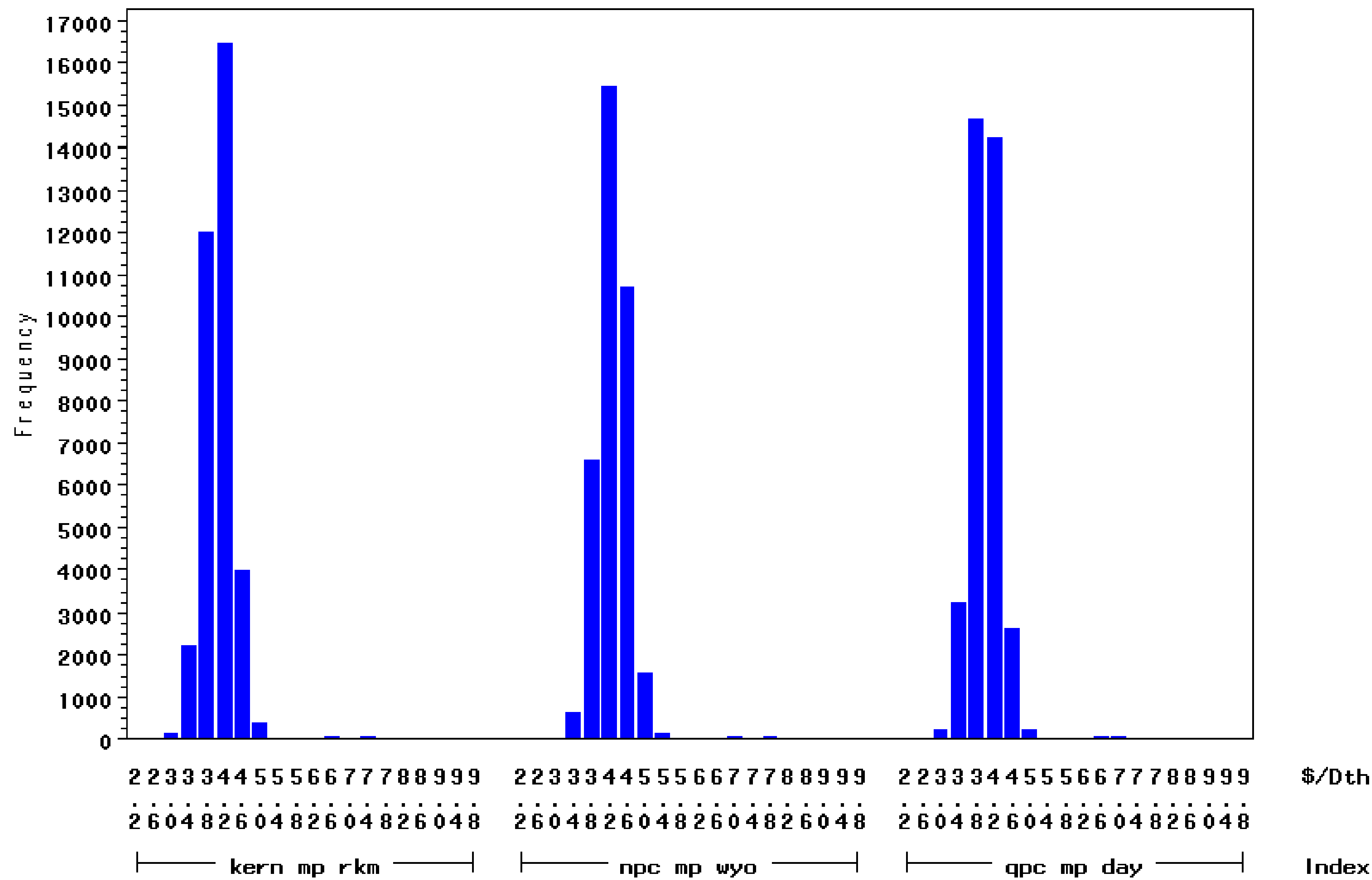
Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1
Frequency
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
$/Dth
kern mp rkm
npc mp wyo
qpc mp day
Index


Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=2
Exhibit 9.29
Frequency
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
3.2 3.6 4.0 4.4 4.8 5.2 5.6 6.0 6.4 6.8 7.2 7.6 8.0 8.4 8.8 9.2 9.6 10.0 10.4 10.8
3.2 3.6 4.0 4.4 4.8 5.2 5.6 6.0 6.4 6.8 7.2 7.6 8.0 8.4 8.8 9.2 9.6 10.0 10.4 10.8
$/Dth
kern dlv abs
kern dlv com
Index

# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=2

Exhibit 9.30



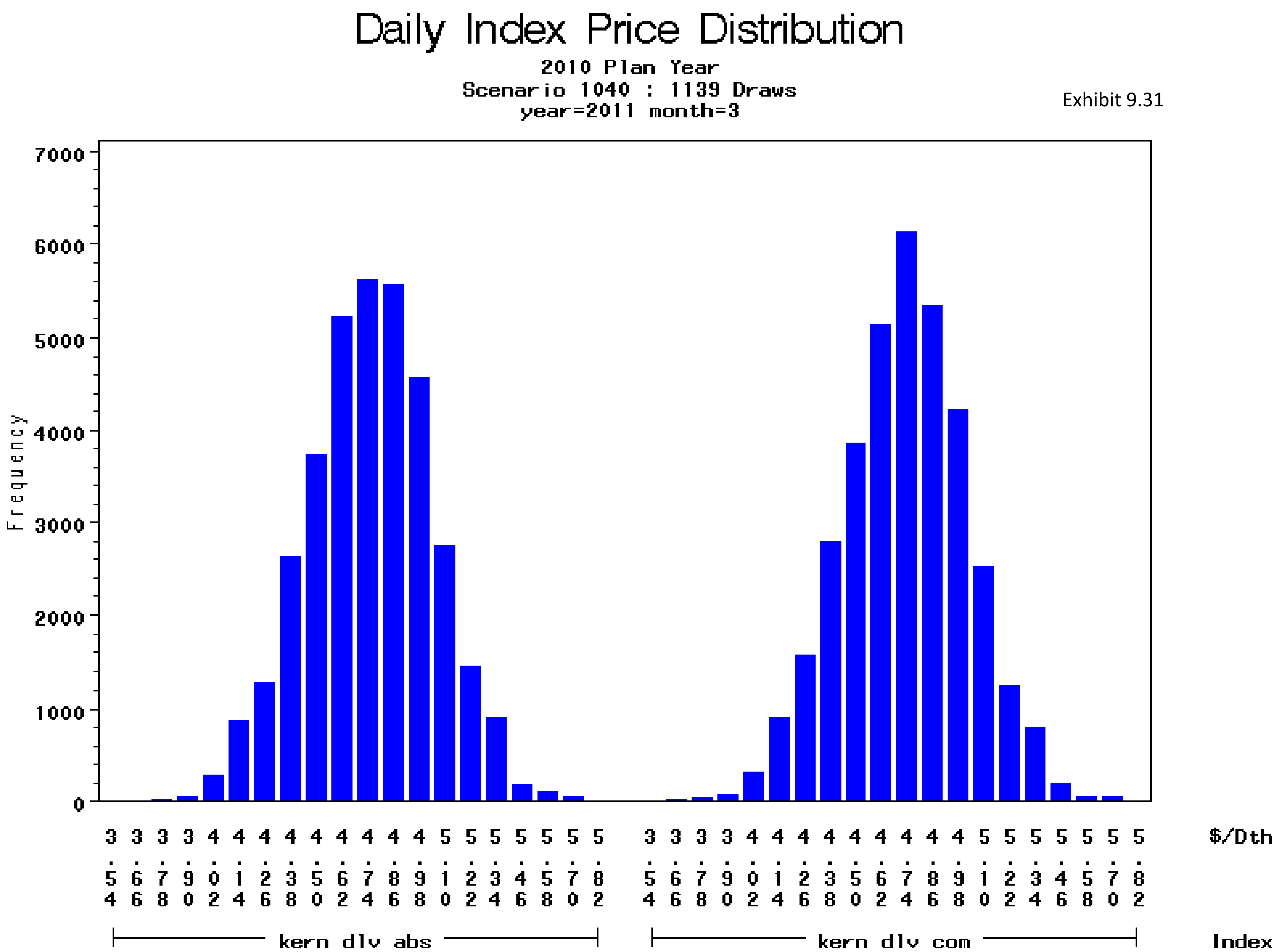

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3
Exhibit 9.31
Frequency
7000
6000
5000
4000
3000
2000
1000
0
3.54 3.66 3.78 3.90 4.02 4.14 4.26 4.38 4.50 4.62 4.74 4.86 4.98 5.10 5.22 5.34 5.46 5.58 5.70 5.82
kern dlv abs
3.54 3.66 3.78 3.90 4.02 4.14 4.26 4.38 4.50 4.62 4.74 4.86 4.98 5.10 5.22 5.34 5.46 5.58 5.70 5.82
kern dlv com
$/Dth
Index

Exhibit 9.32

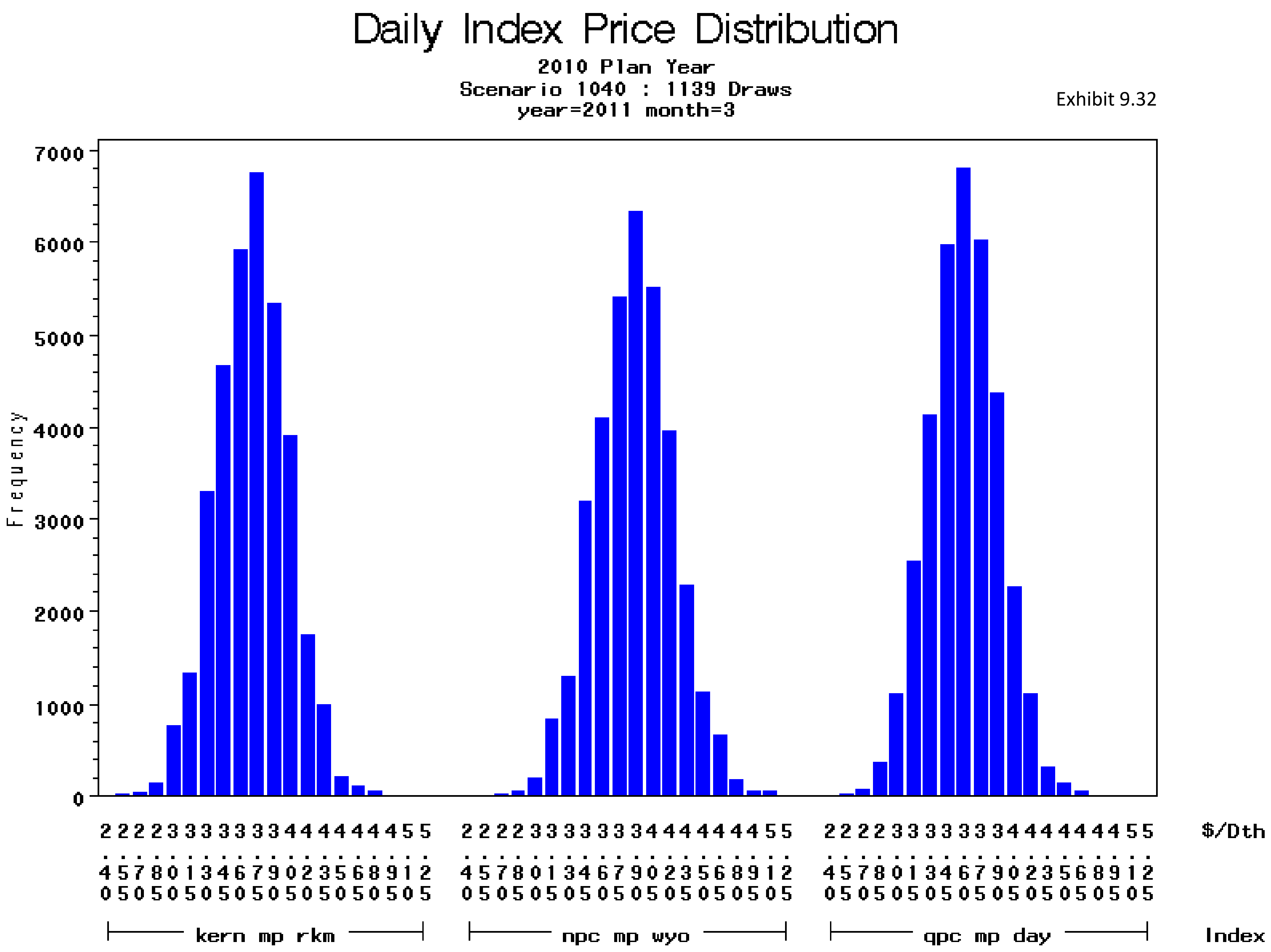

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3
Frequency
7000
6000
5000
4000
3000
2000
1000
0
$/Dth
kern mp rkm
npc mp wyo
qpc mp day
Index

Exhibit 9.33

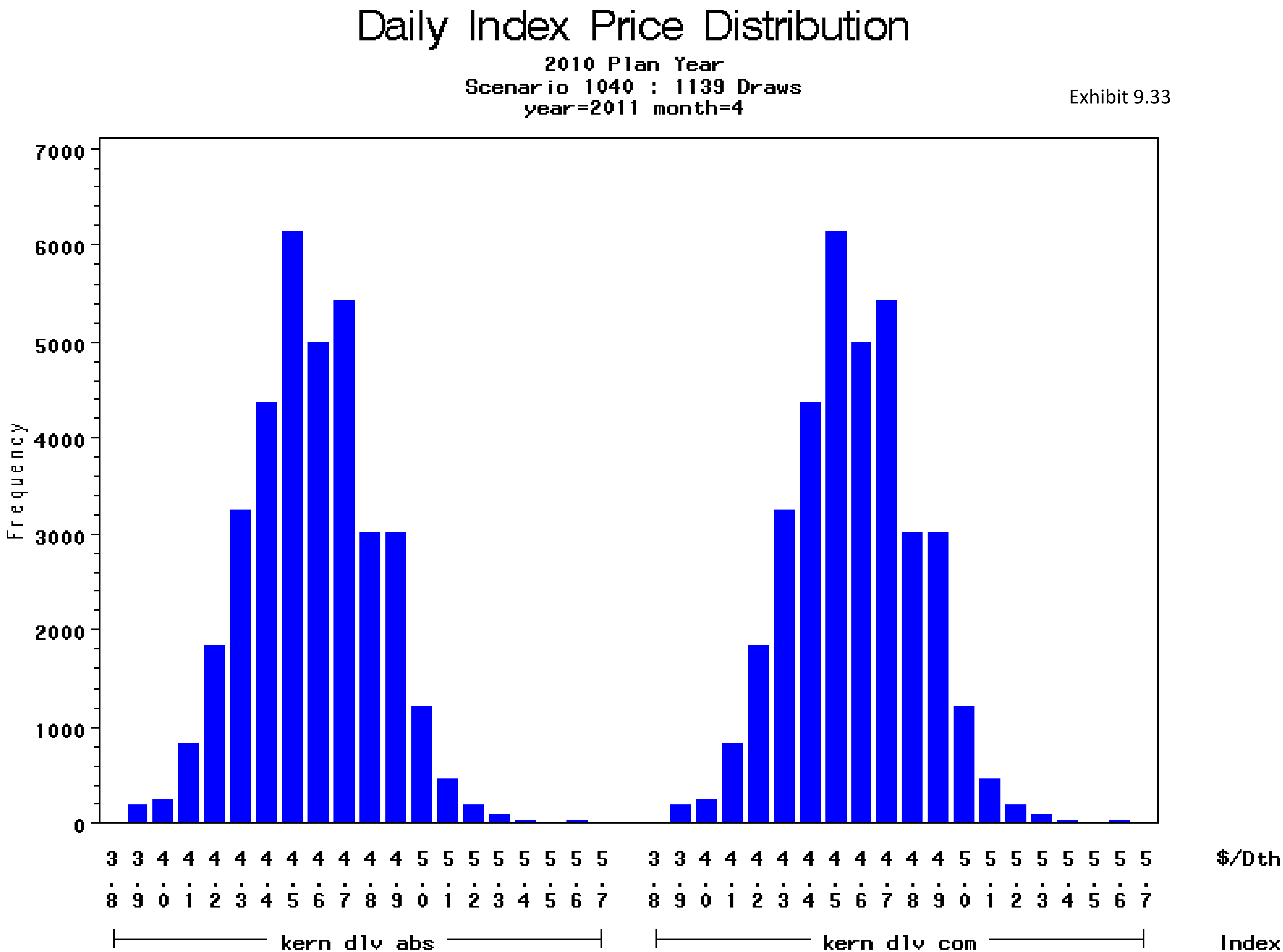
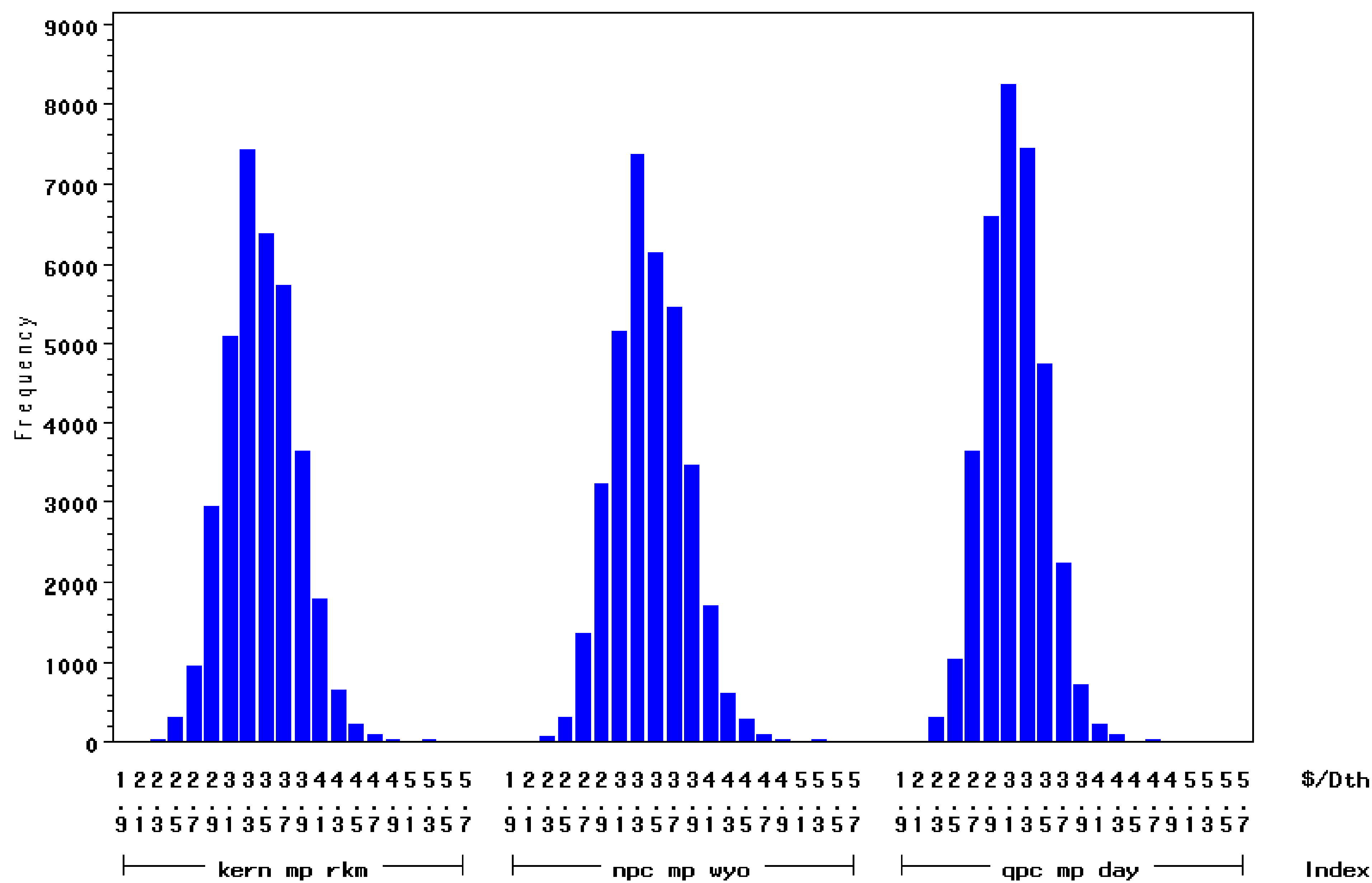

Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4
Frequency
0
1000
2000
3000
4000
5000
6000
7000
3.8 3.9 4.0 4.1 4.2 4.3 4.4 4.5 4.6 4.7 4.8 4.9 5.0 5.1 5.2 5.3 5.4 5.5 5.6 5.7
3.8 3.9 4.0 4.1 4.2 4.3 4.4 4.5 4.6 4.7 4.8 4.9 5.0 5.1 5.2 5.3 5.4 5.5 5.6 5.7
$/Dth
kern dlv abs
kern dlv com
Index

Exhibit 9.34

# Daily Index Price Distribution

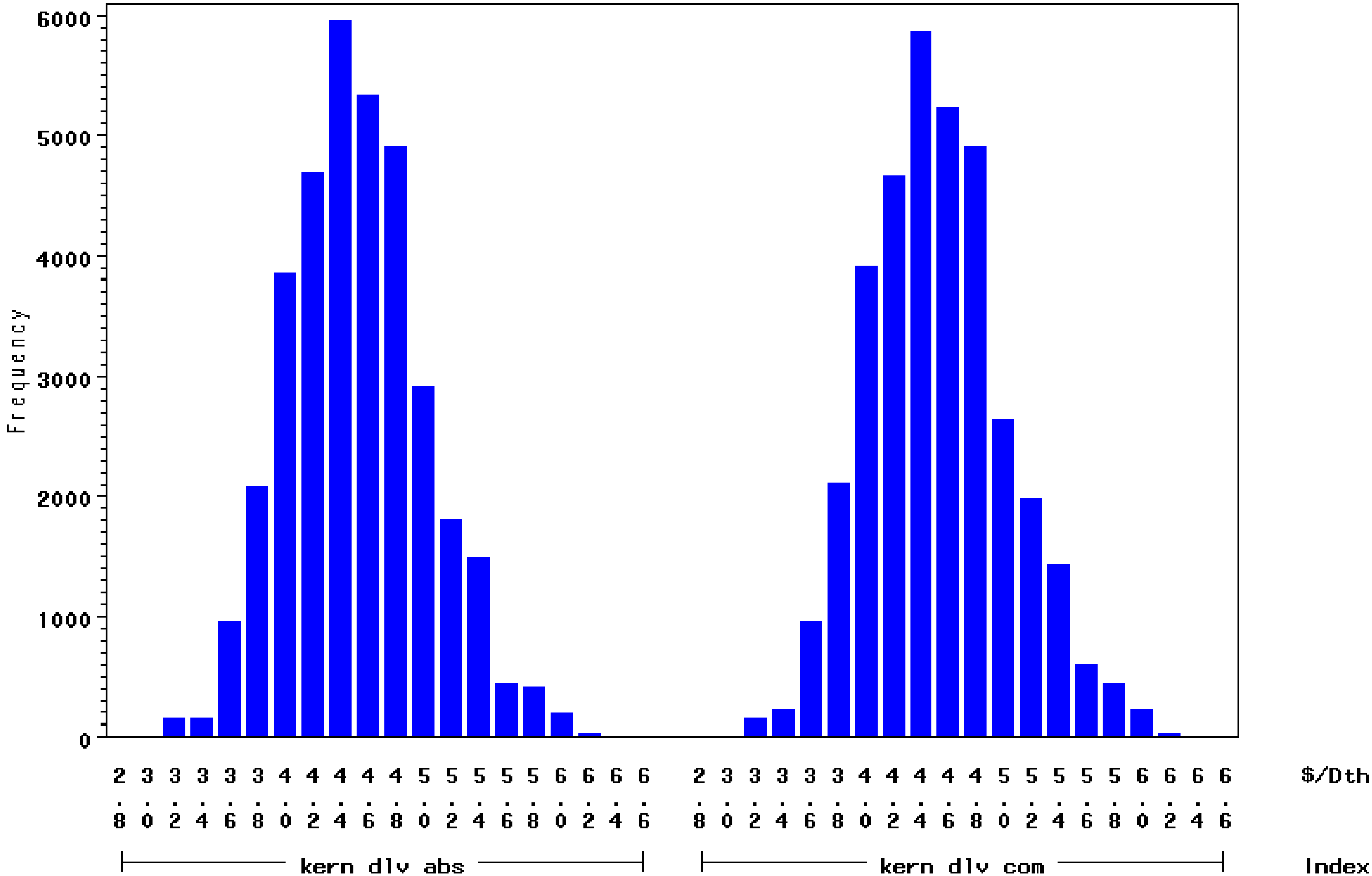
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4

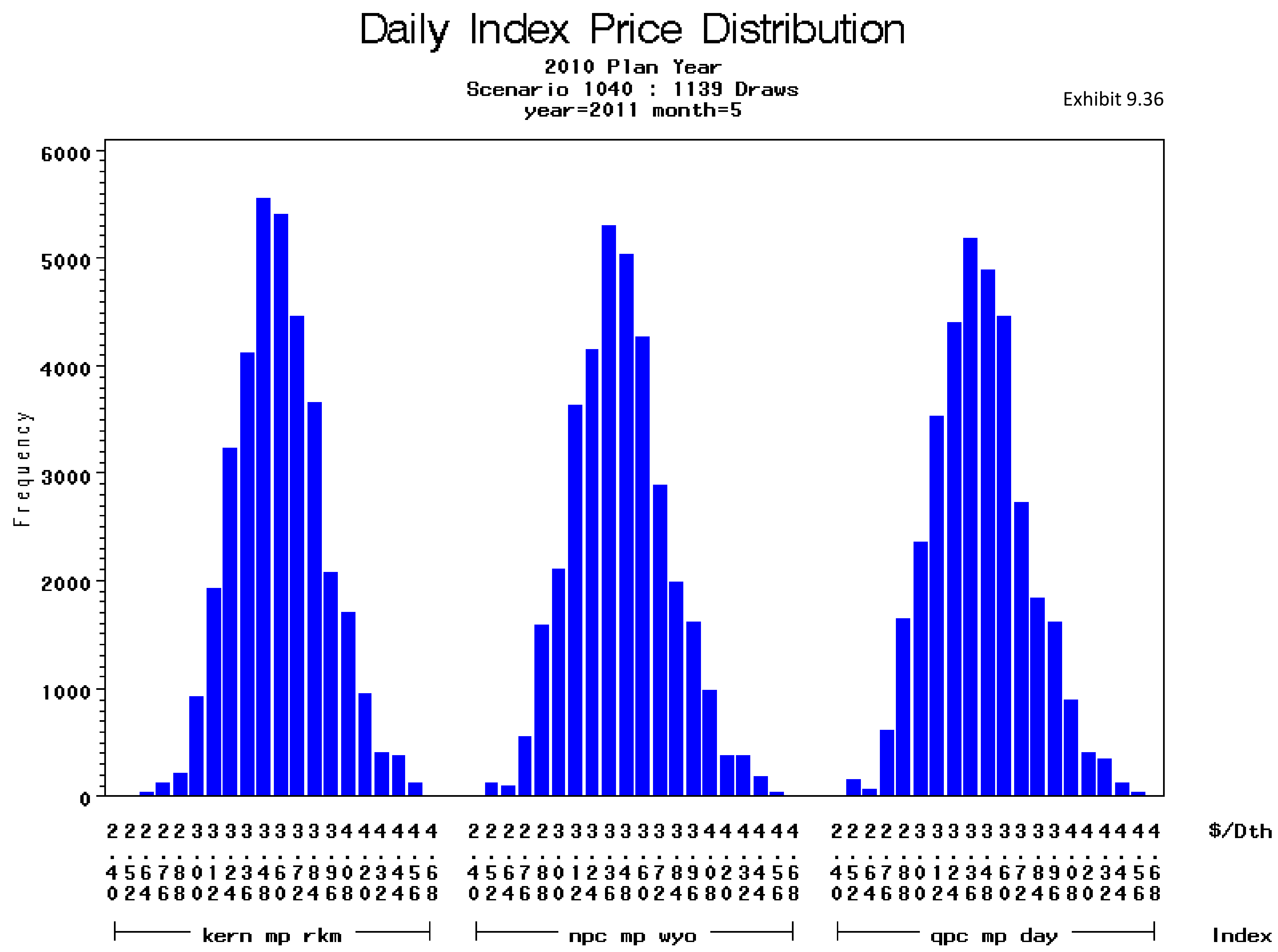


# Daily Index Price Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5

Exhibit 9.35





Daily Index Price Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5
Exhibit 9.36
Frequency
6000
5000
4000
3000
2000
1000
0
$/Dth
kern mp rkm
npc mp wyo
qpc mp day
Index

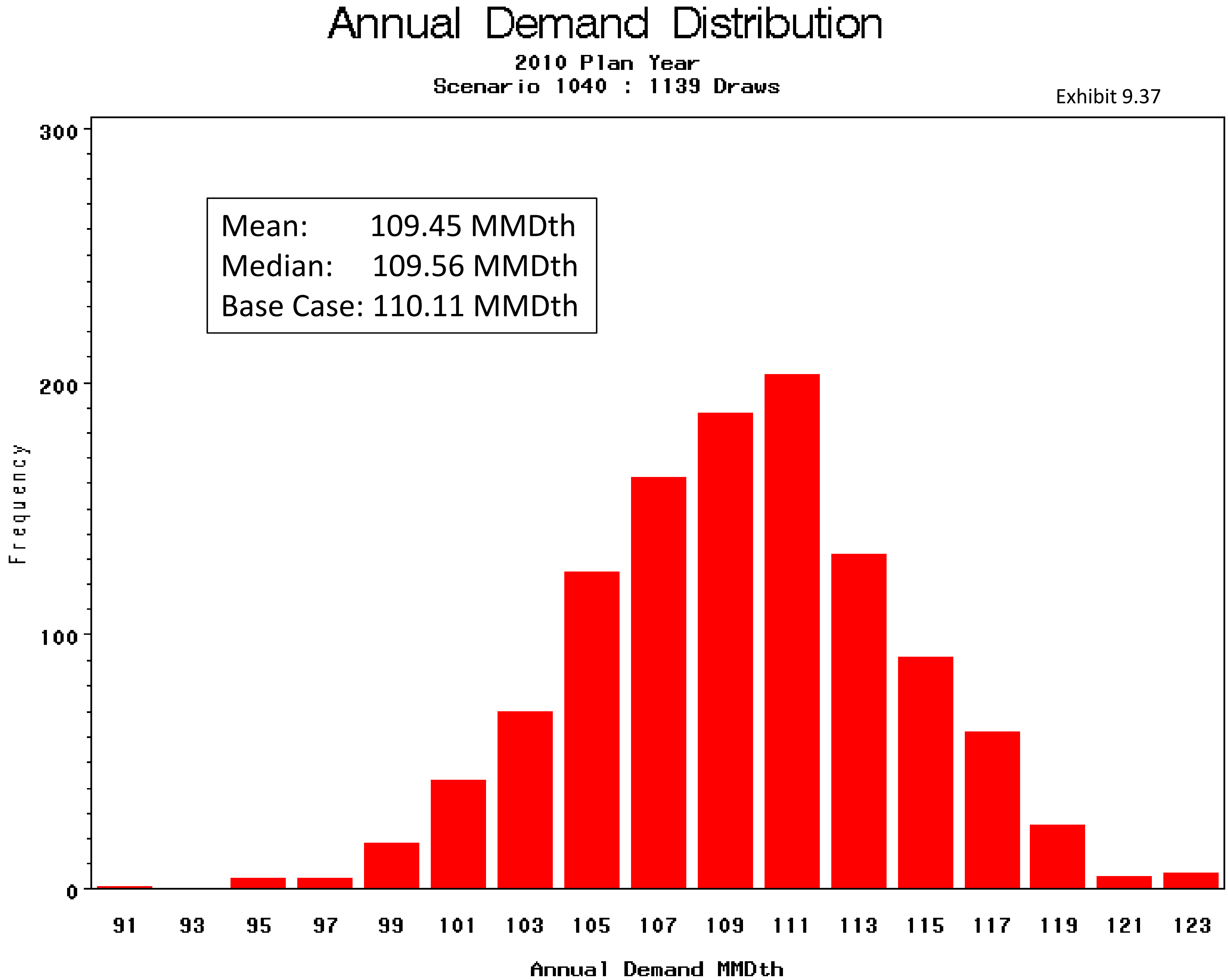
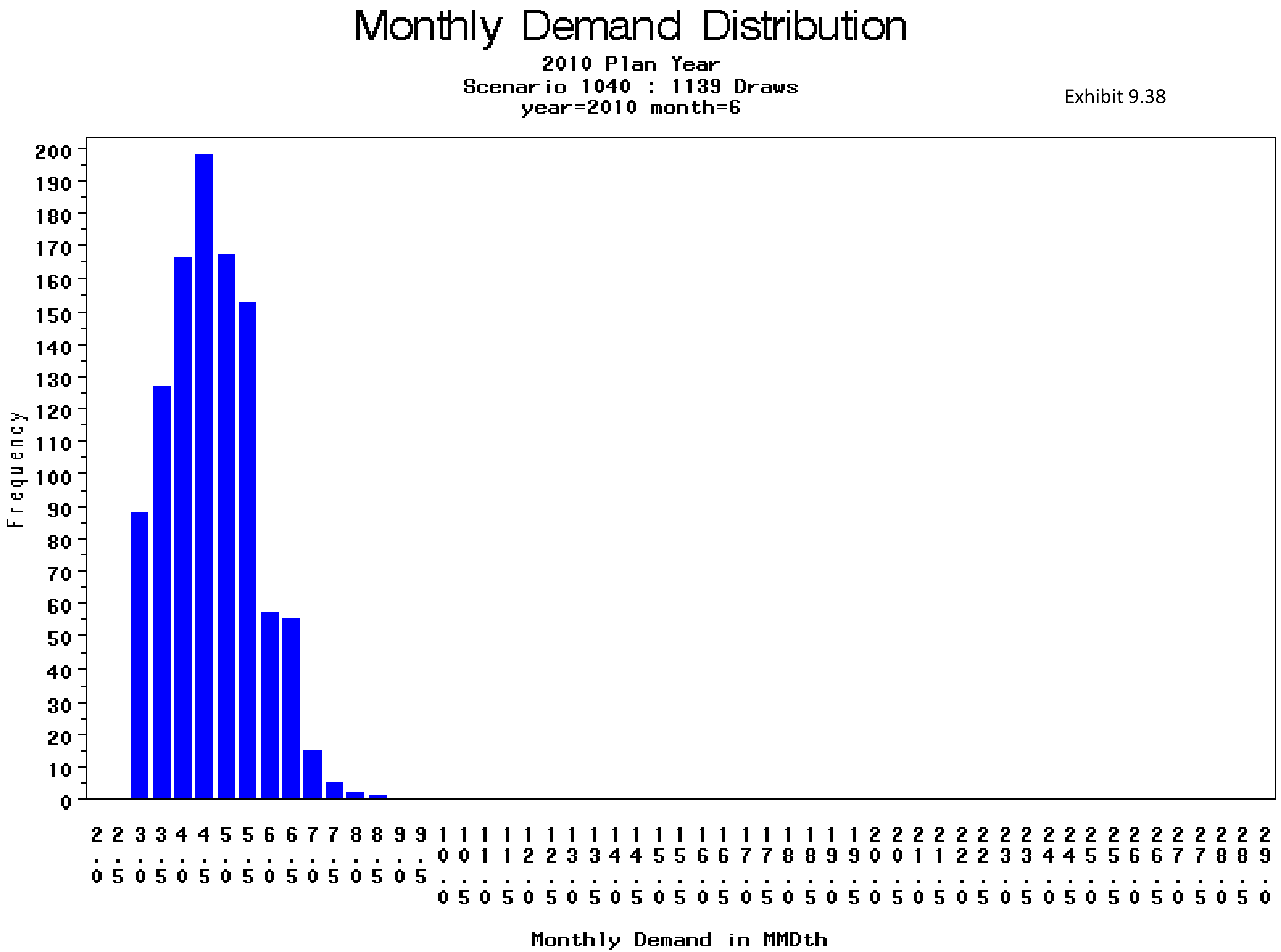

Annual Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
Exhibit 9.37
Mean: 109.45 MMDth
Median: 109.56 MMDth
Base Case: 110.11 MMDth
Frequency
0
100
200
300
91
93
95
97
99
101
103
105
107
109
111
113
115
117
119
121
123
Annual Demand MMDth

Exhibit 9.38



Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=6
Frequency
Monthly Demand in MMDth

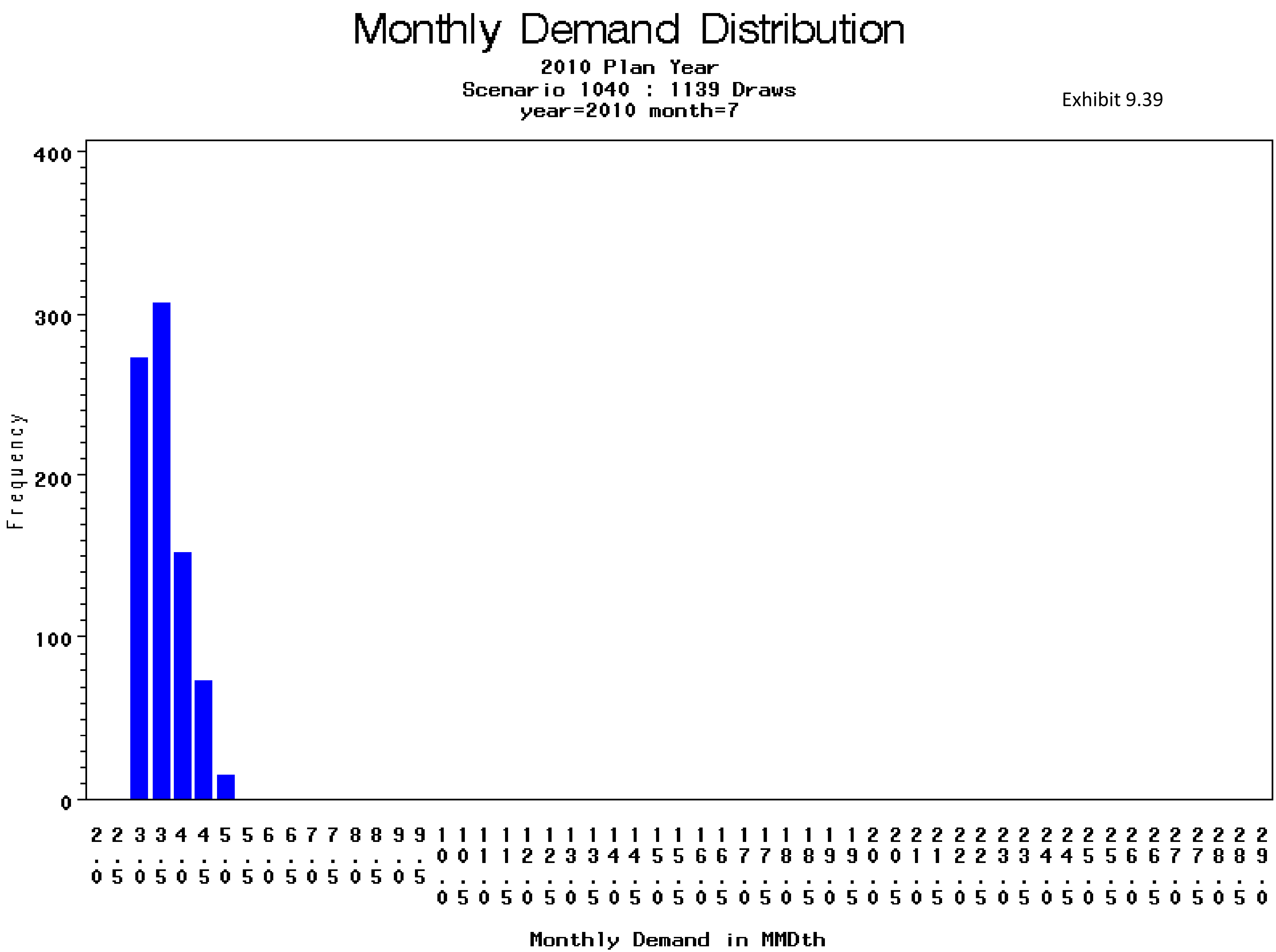
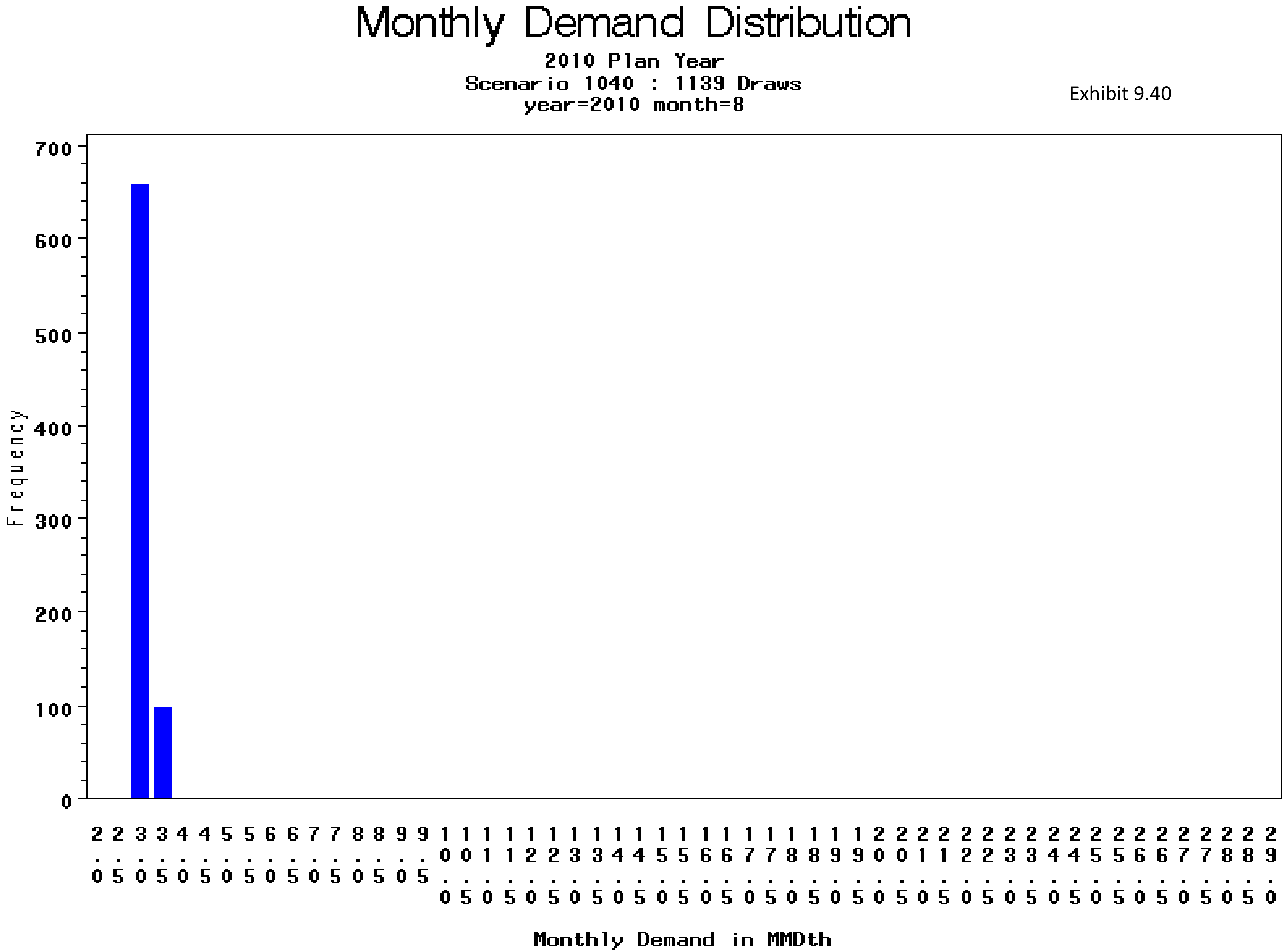

Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7
Exhibit 9.39
Frequency
0
100
200
300
400
Monthly Demand in MMDth
2.0 2.5 3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0 7.5 8.0 8.5 9.0 9.5 10.0 10.5 11.0 11.5 12.0 12.5 13.0 13.5 14.0 14.5 15.0 15.5 16.0 16.5 17.0 17.5 18.0 18.5 19.0 19.5 20.0 20.5 21.0 21.5 22.0 22.5 23.0 23.5 24.0 24.5 25.0 25.5 26.0 26.5 27.0 27.5 28.0 28.5 29.0

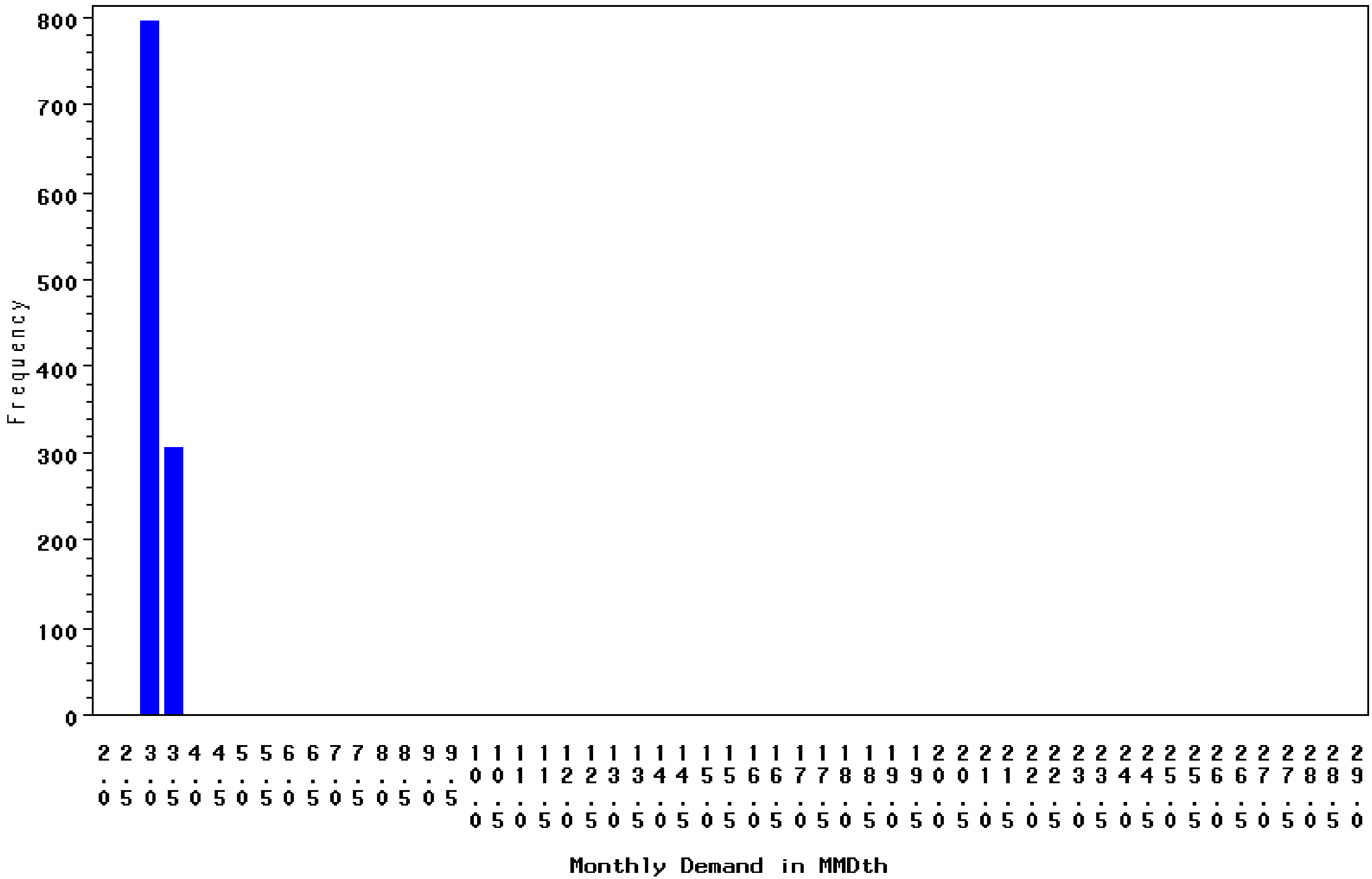
Exhibit 9.40


Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8
Frequency
0
100
200
300
400
500
600
700
Monthly Demand in MMDth

# Monthly Demand Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=9

Exhibit 9.41



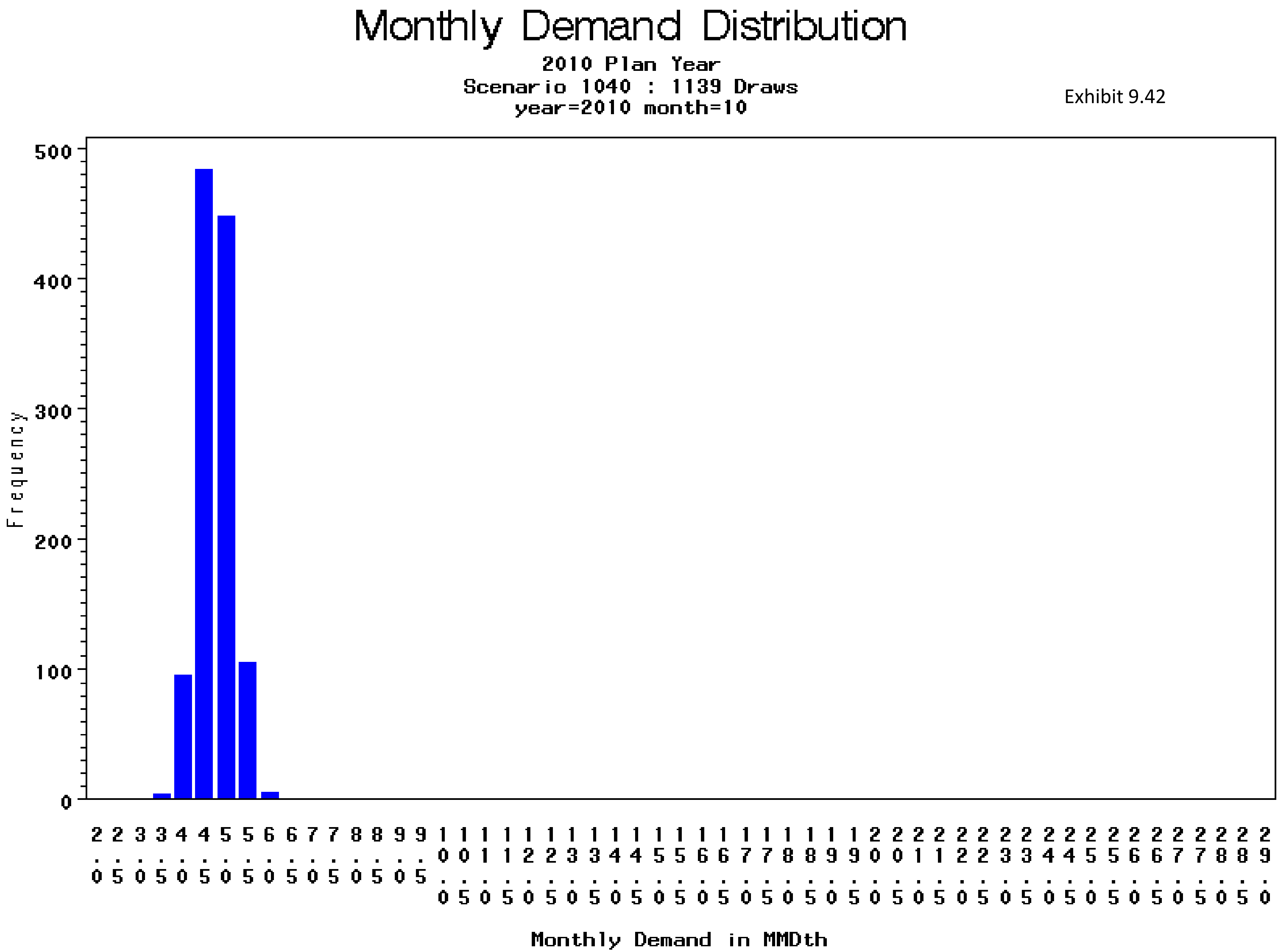
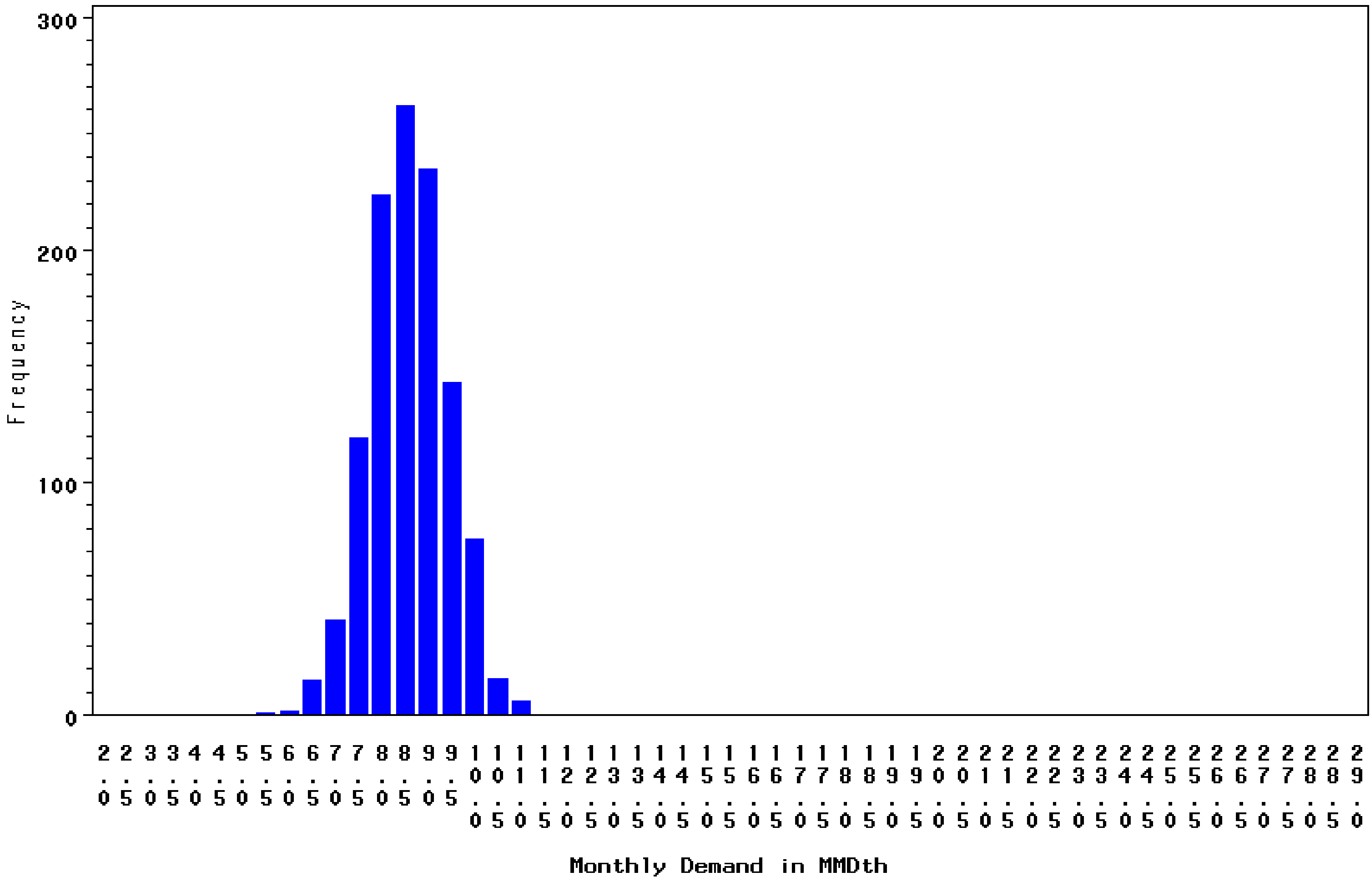

Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10
Frequency
0
100
200
300
400
500
Monthly Demand in MMDth

Exhibit 9.42

# Monthly Demand Distribution

**2010 Plan Year**
**Scenario 1040 : 1139 Draws**
**year=2010 month=11**

Exhibit 9.43



Monthly Demand Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=12

Exhibit 9.44

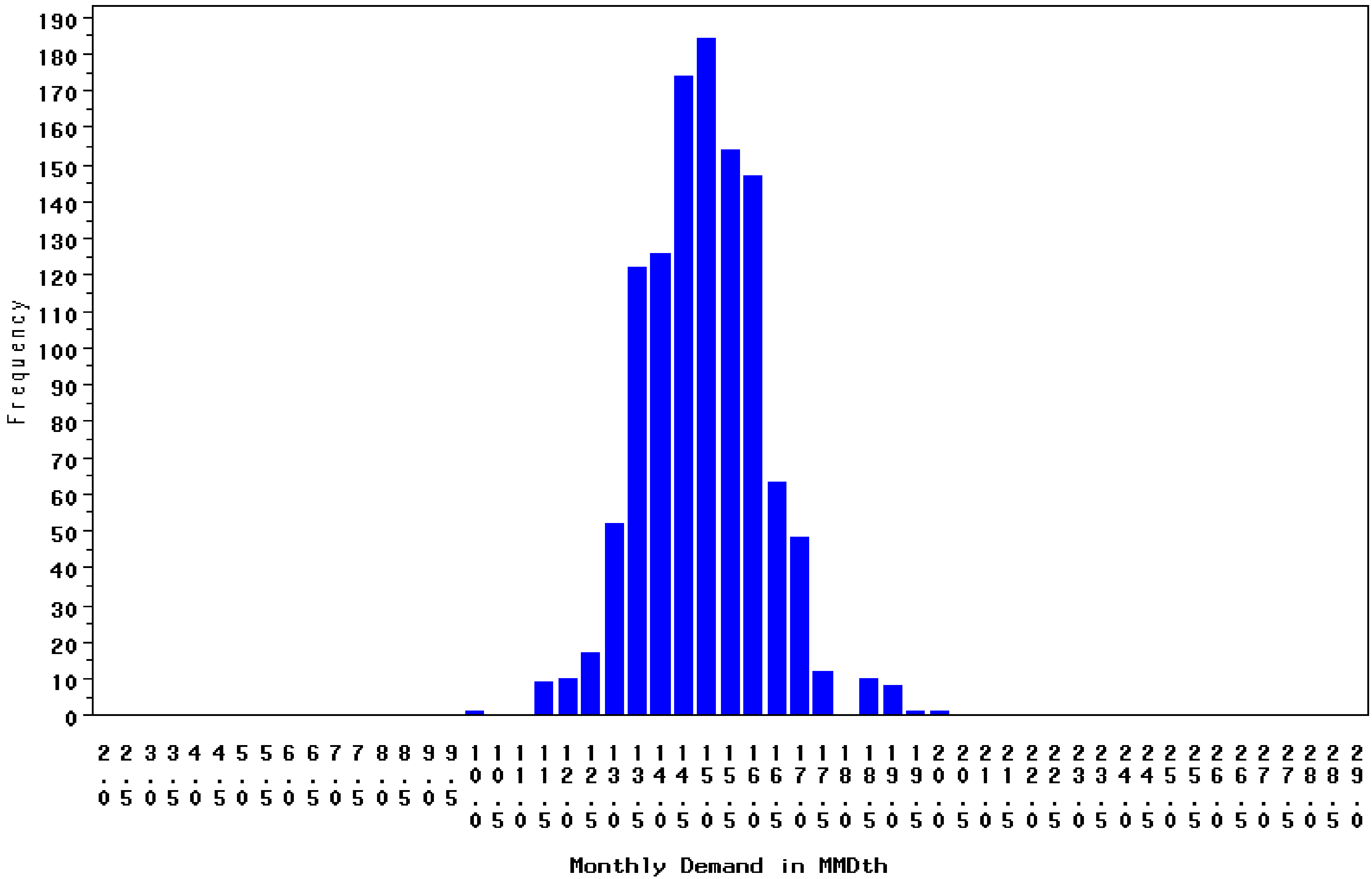


Exhibit 9.45

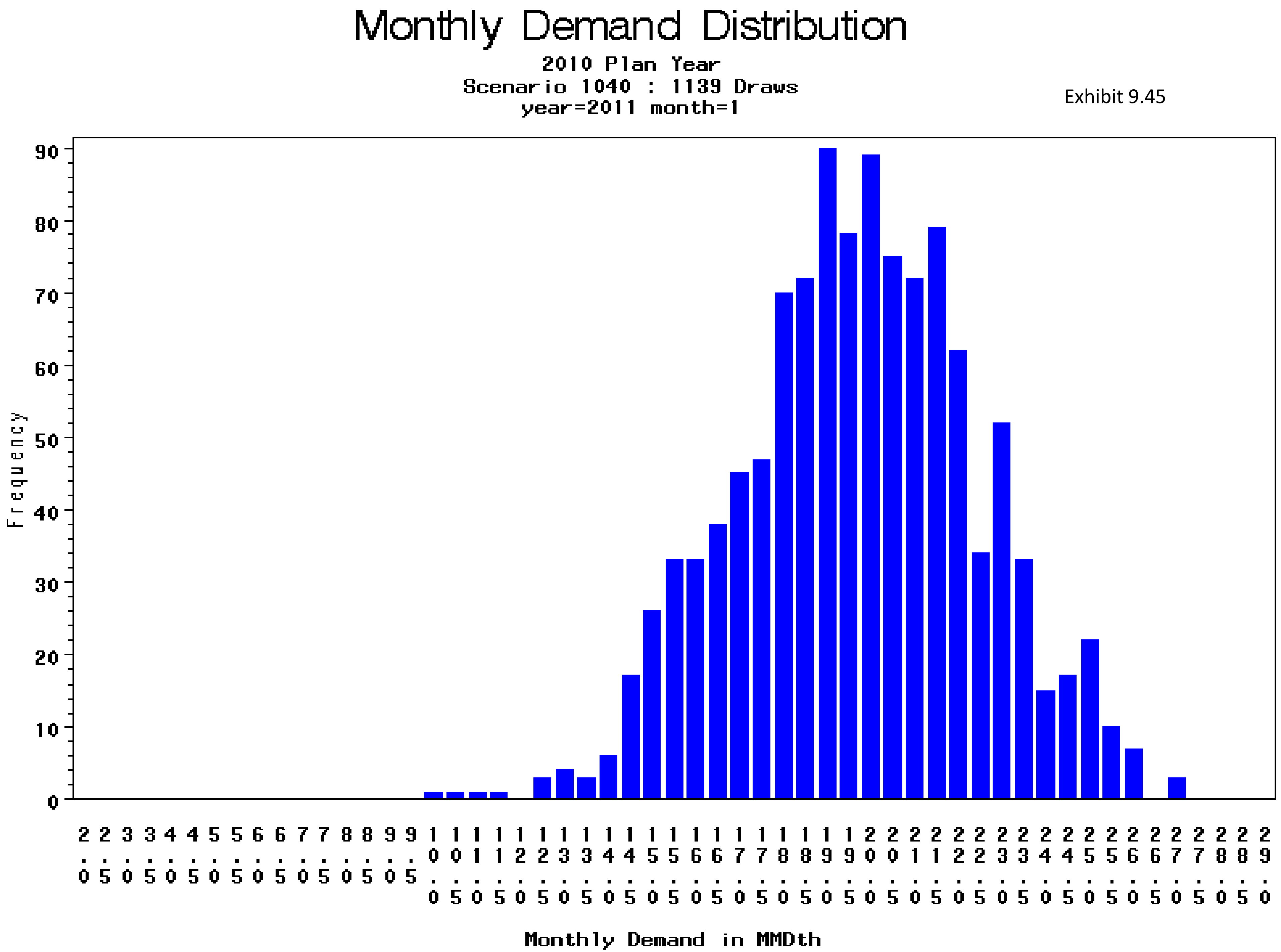

Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1
Frequency
0
10
20
30
40
50
60
70
80
90
Monthly Demand in MMDth

Exhibit 9.46

# Monthly Demand Distribution

**2010 Plan Year**
**Scenario 1040 : 1139 Draws**
**year=2011 month=2**

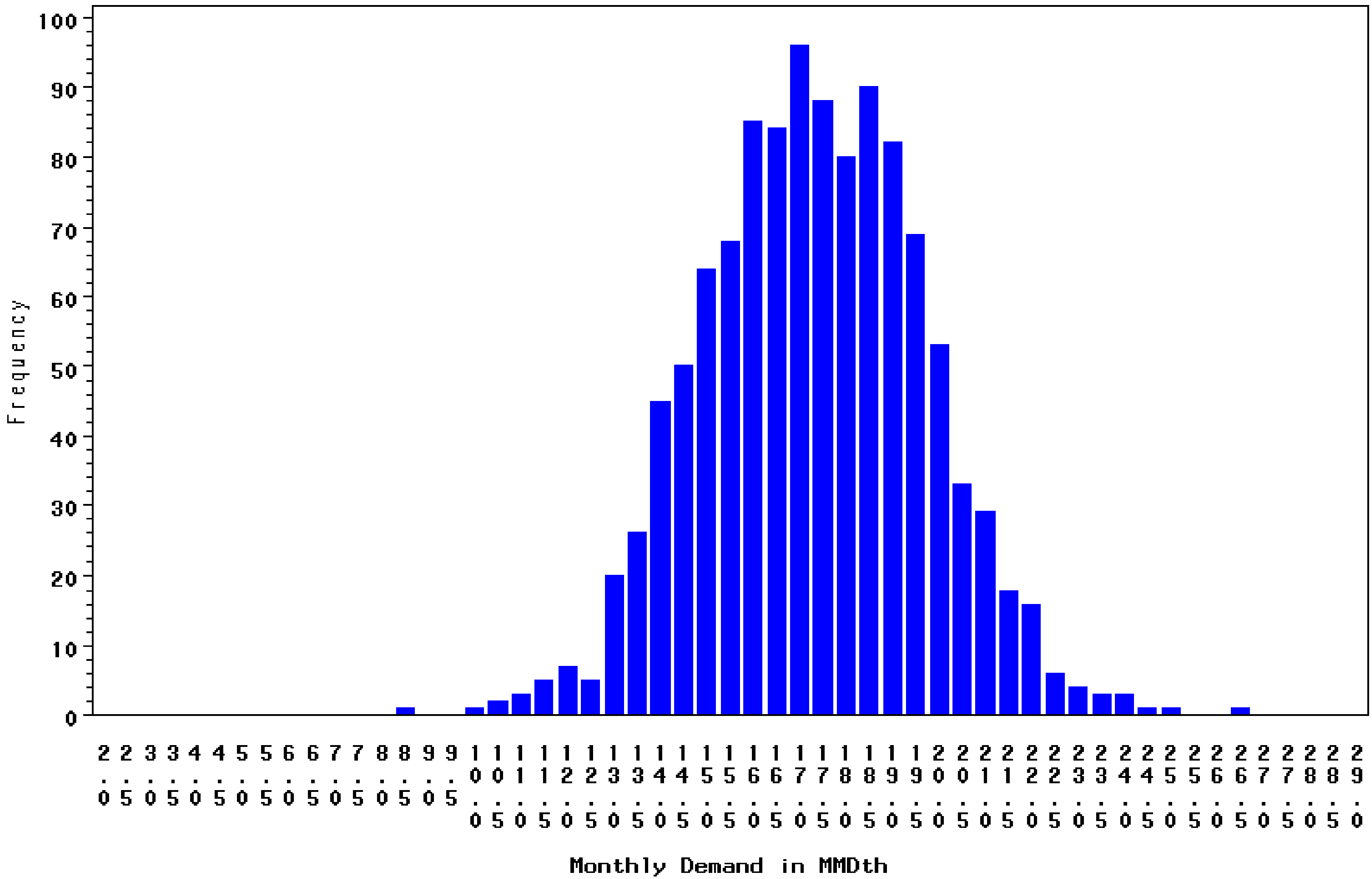


Exhibit 9.47

# Monthly Demand Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3

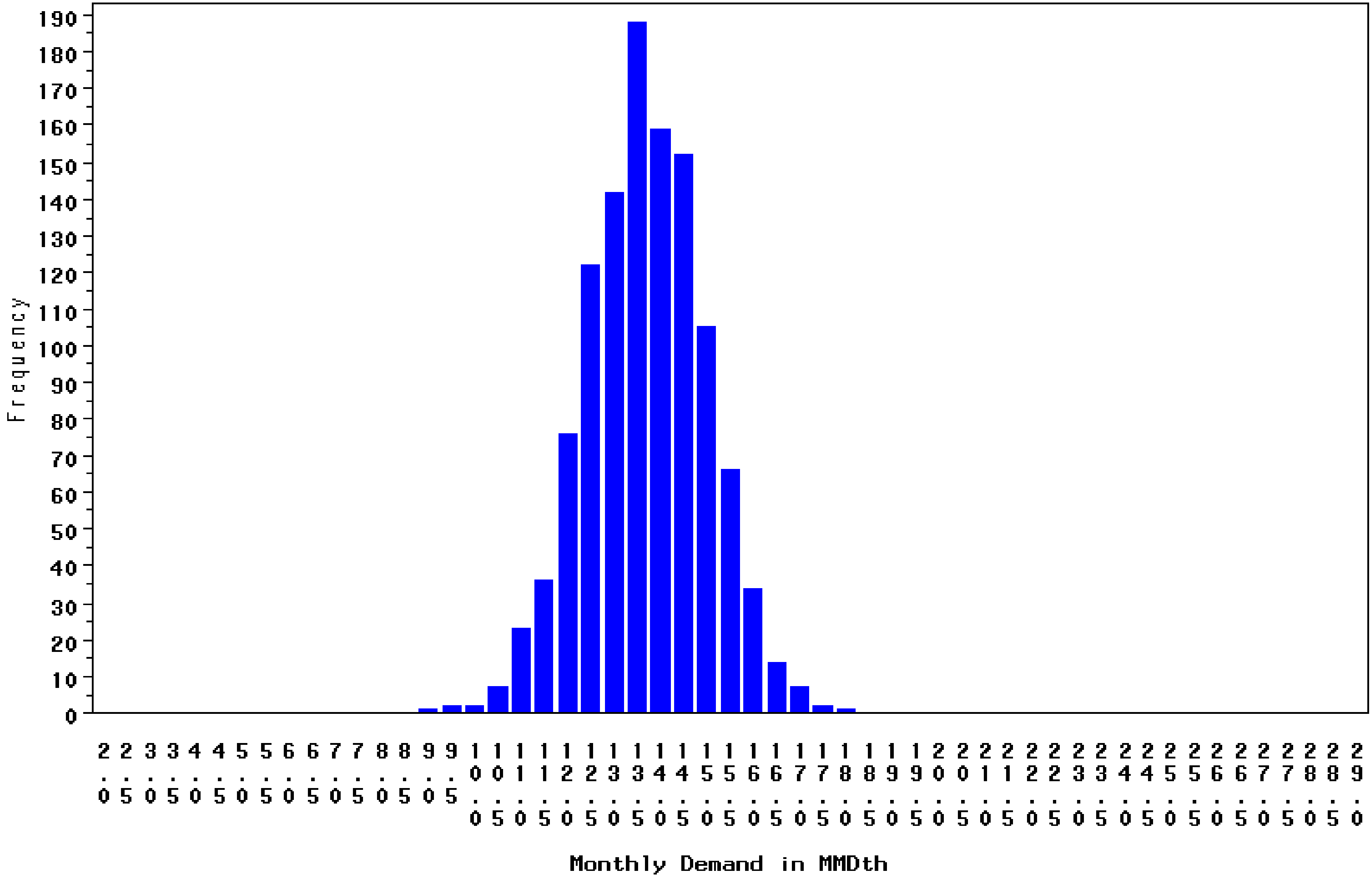


Exhibit 9.48

# Monthly Demand Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5

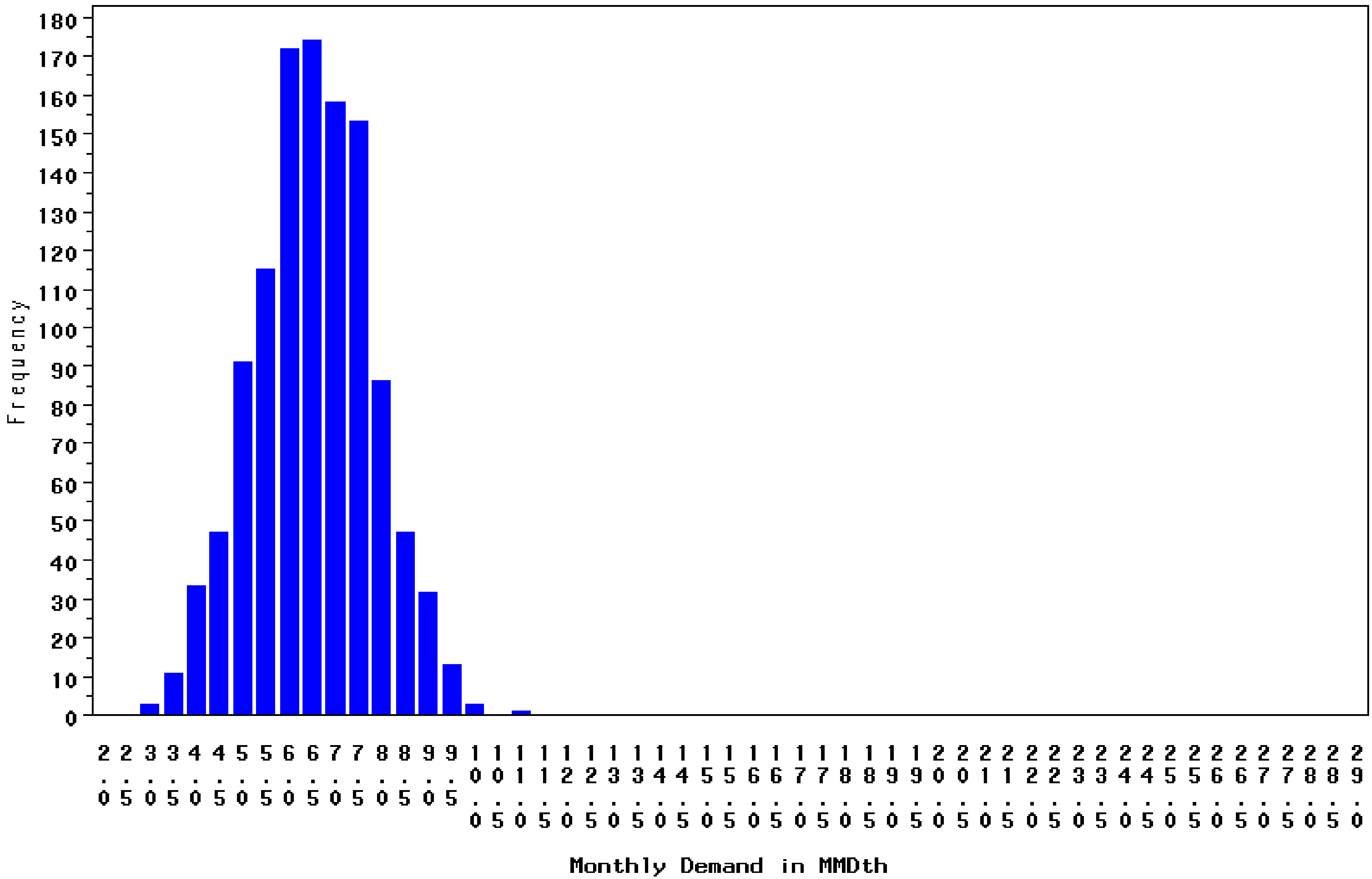
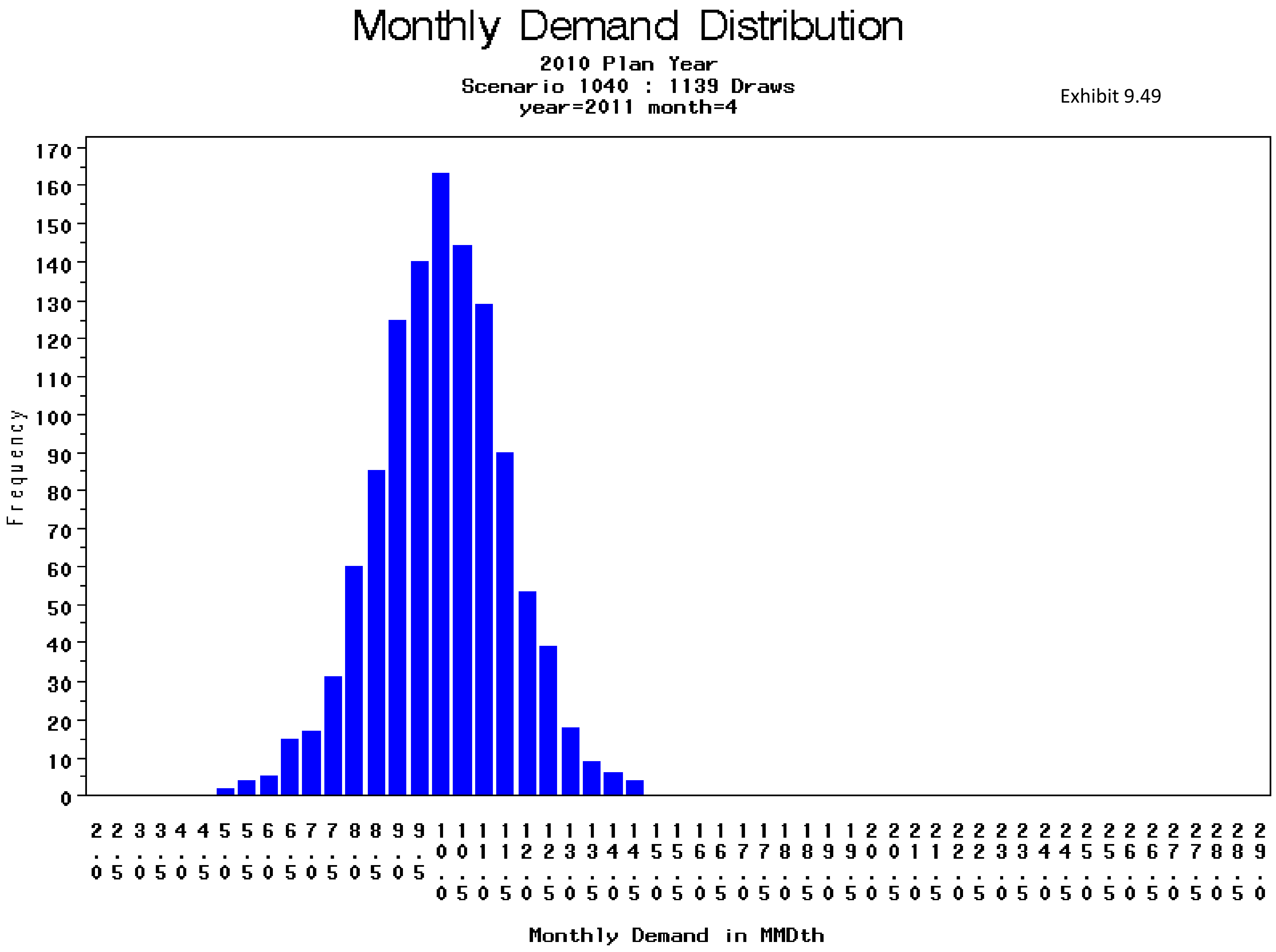
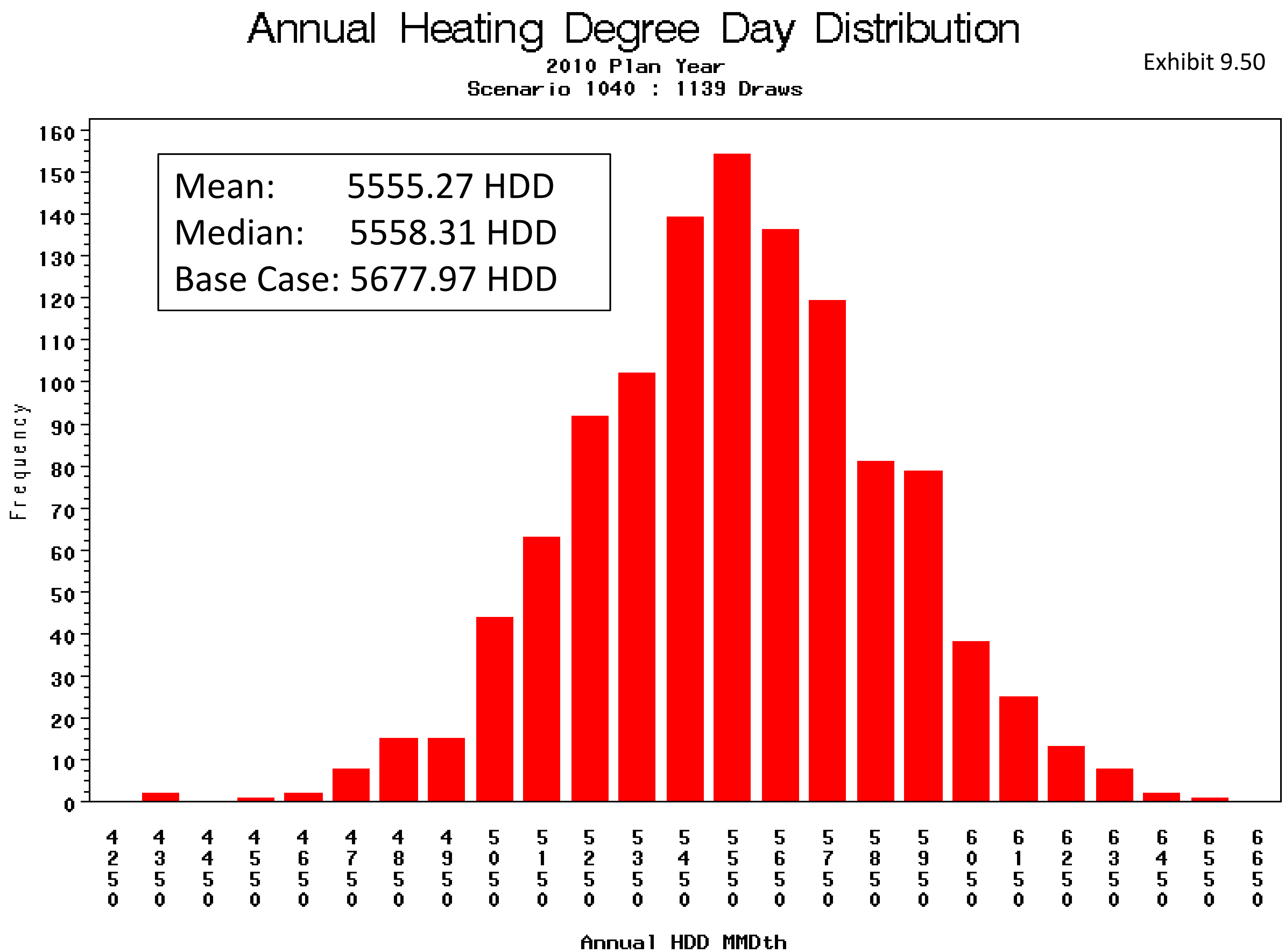


Exhibit 9.49



Monthly Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4
Frequency
Monthly Demand in MMDth

Exhibit 9.50


Annual Heating Degree Day Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
Mean: 5555.27 HDD
Median: 5558.31 HDD
Base Case: 5677.97 HDD
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
4250
4350
4450
4550
4650
4750
4850
4950
5050
5150
5250
5350
5450
5550
5650
5750
5850
5950
6050
6150
6250
6350
6450
6550
6650
Annual HDD MMDth

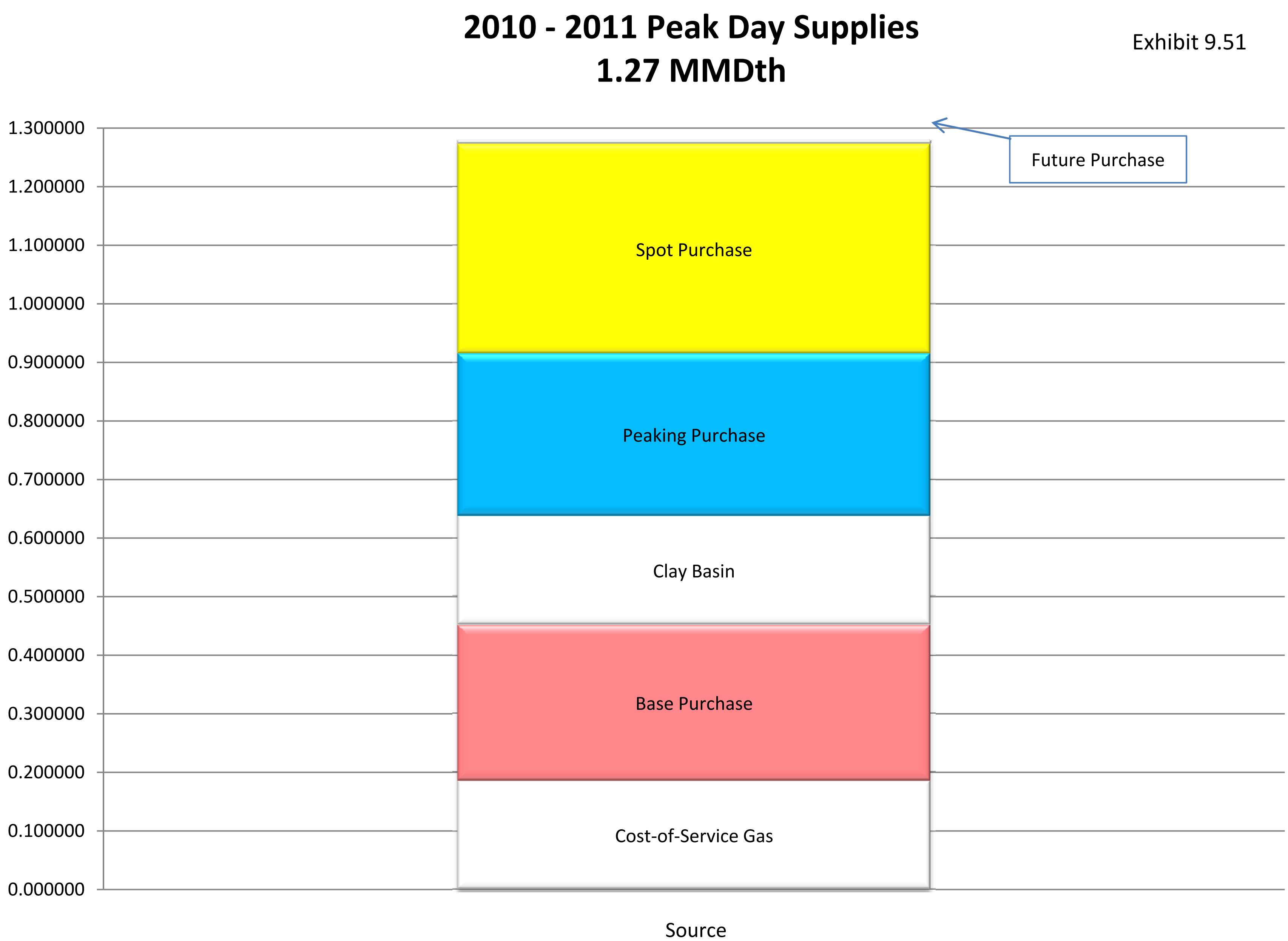

2010 - 2011 Peak Day Supplies
1.27 MMDth
Exhibit 9.51
Future Purchase
Spot Purchase
Peaking Purchase
Clay Basin
Base Purchase
Cost-of-Service Gas
1.300000
1.200000
1.100000
1.000000
0.900000
0.800000
0.700000
0.600000
0.500000
0.400000
0.300000
0.200000
0.100000
0.000000
Source

Exhibit 9.52

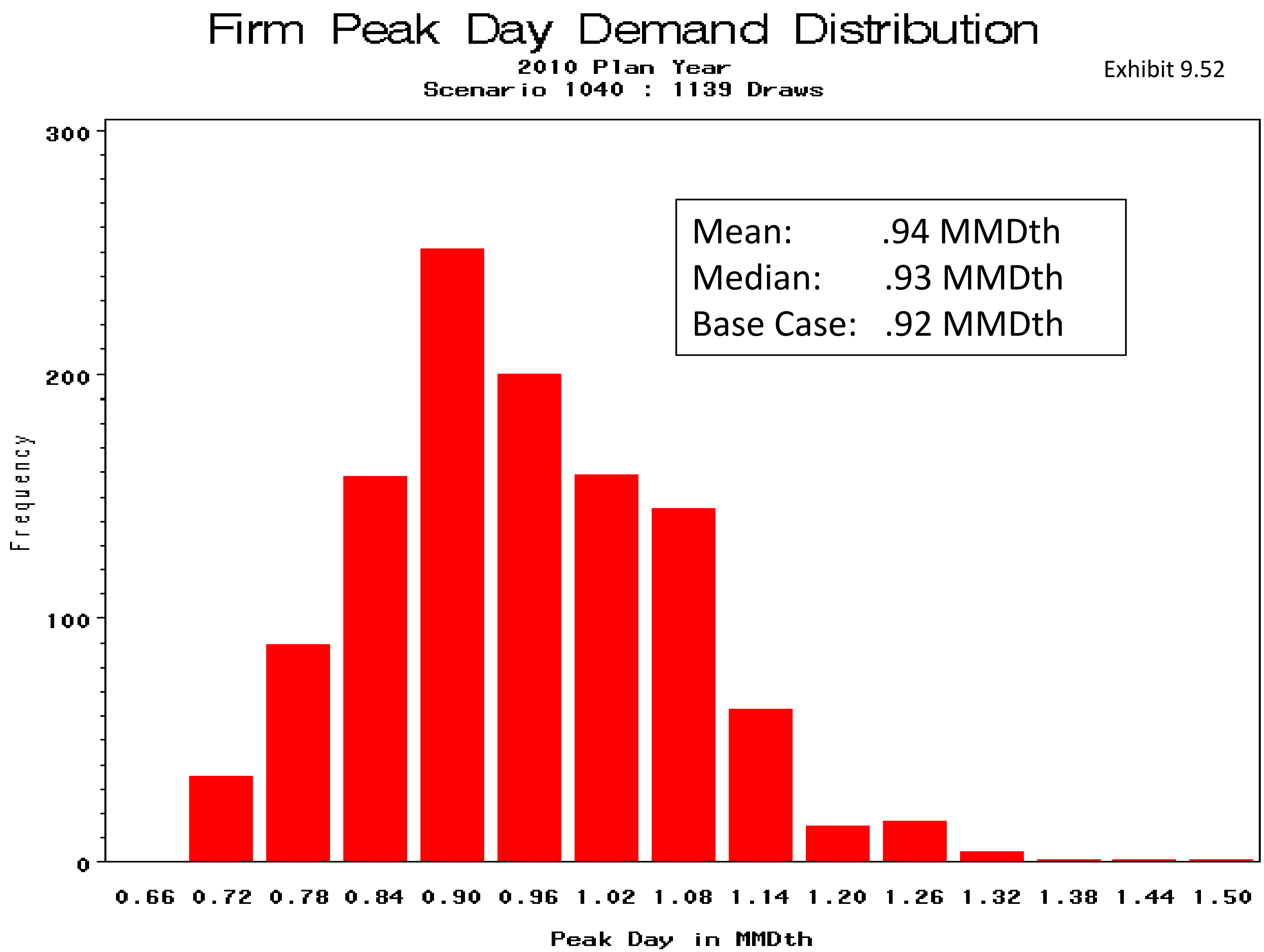
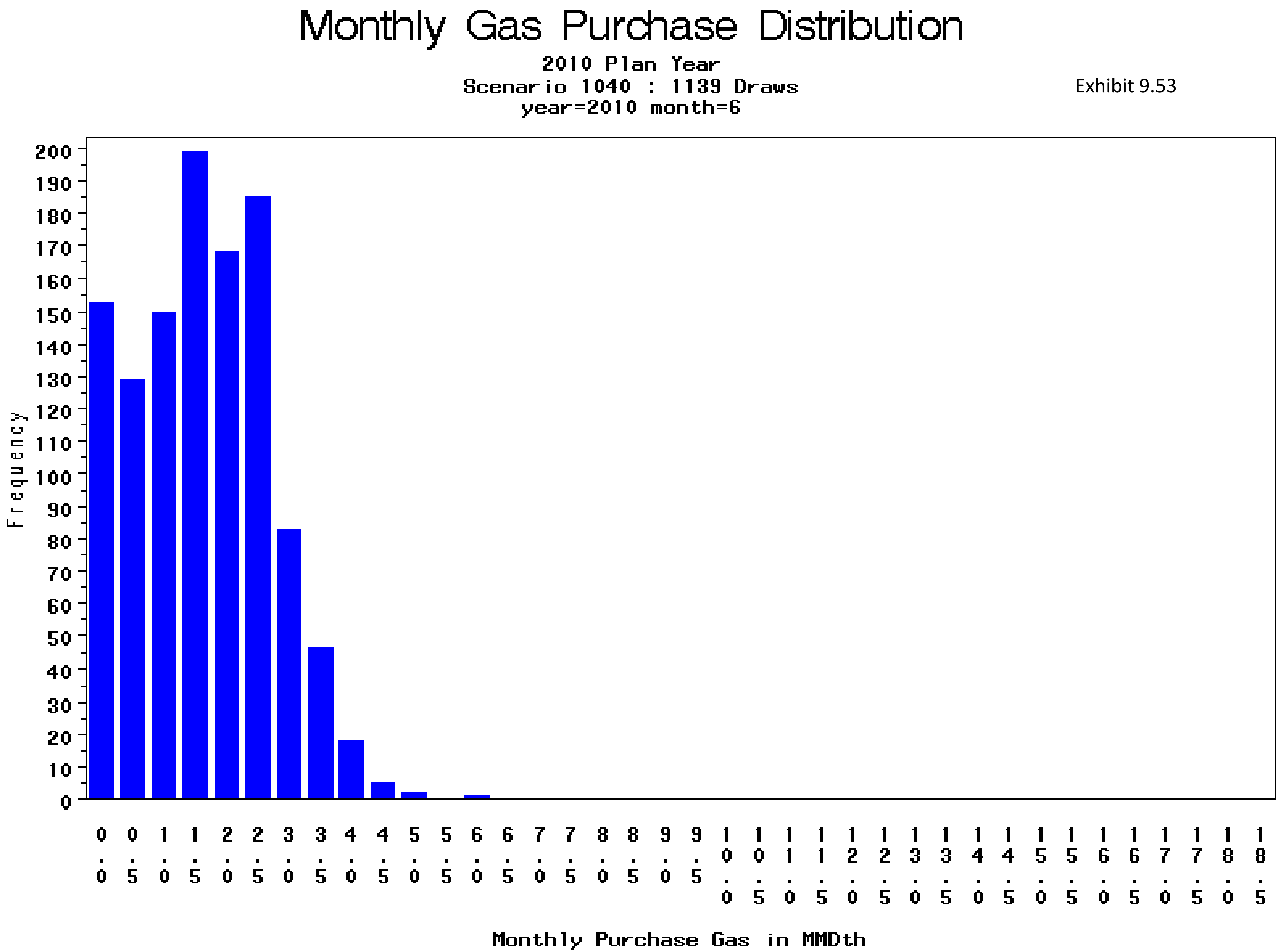

Firm Peak Day Demand Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
Mean: .94 MMDth
Median: .93 MMDth
Base Case: .92 MMDth
Frequency
300
200
100
0
0.66 0.72 0.78 0.84 0.90 0.96 1.02 1.08 1.14 1.20 1.26 1.32 1.38 1.44 1.50
Peak Day in MMDth

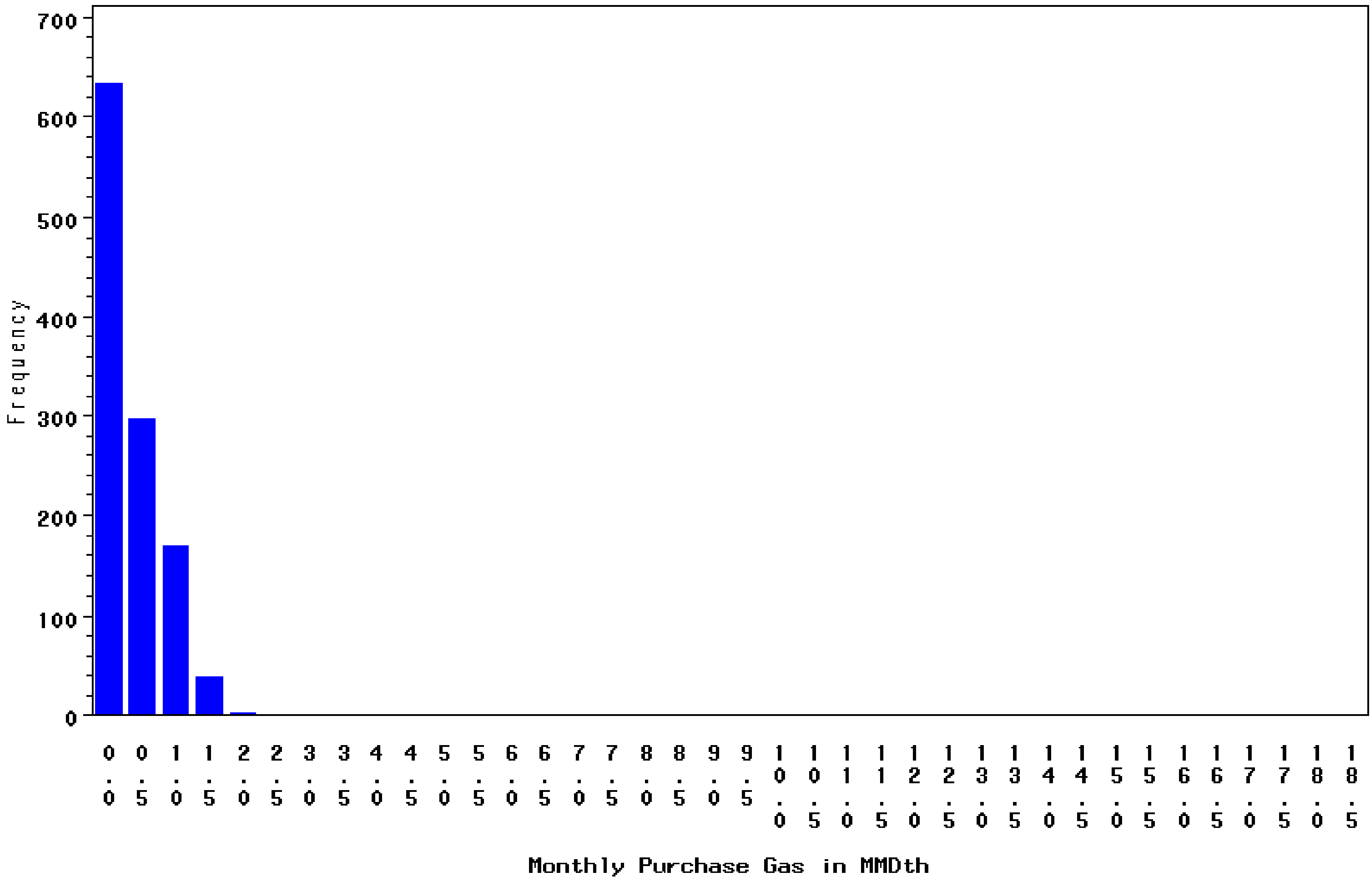
Exhibit 9.53

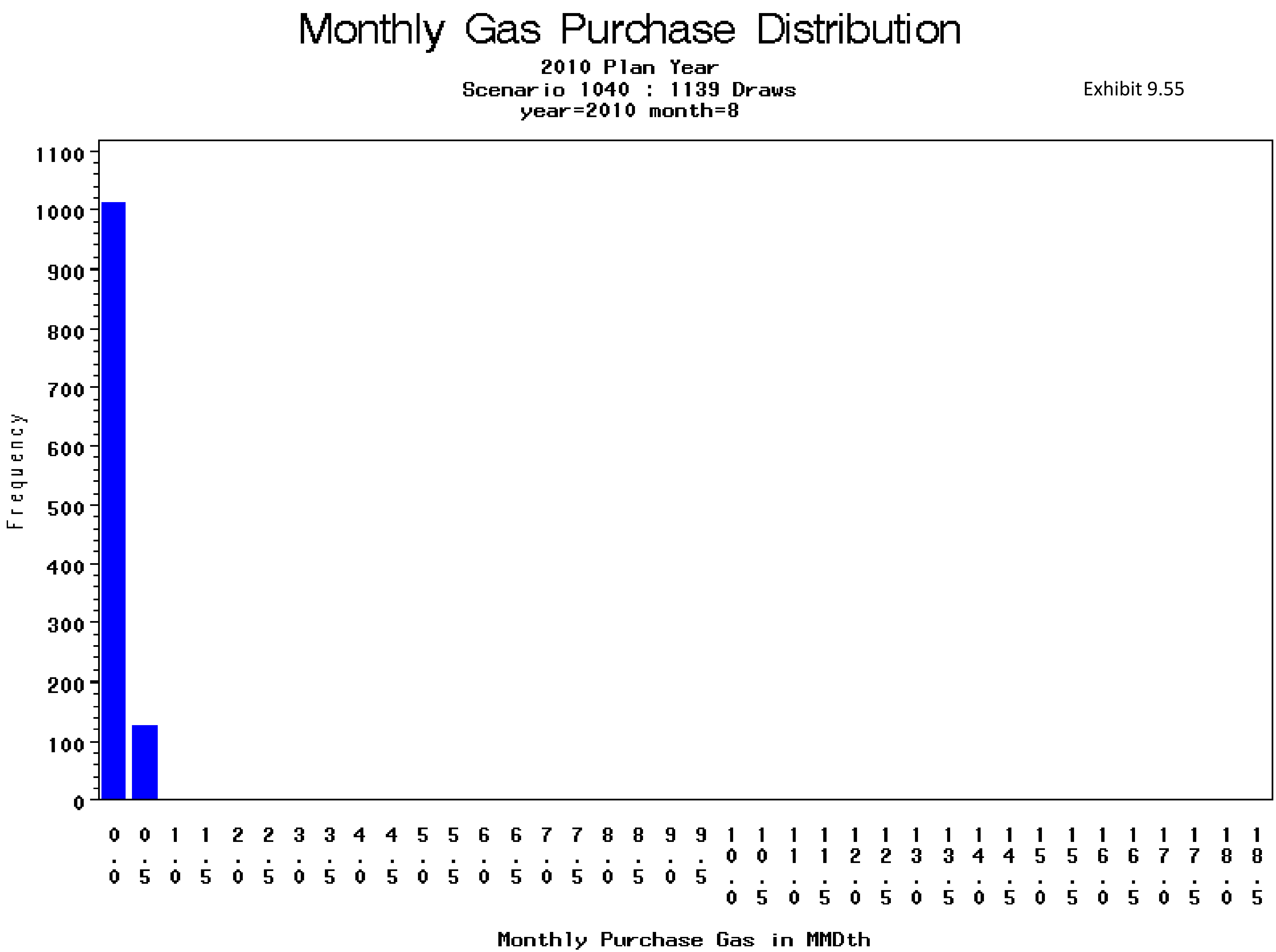

Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=6
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
200
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
6.5
7.0
7.5
8.0
8.5
9.0
9.5
10.0
10.5
11.0
11.5
12.0
12.5
13.0
13.5
14.0
14.5
15.0
15.5
16.0
16.5
17.0
17.5
18.0
18.5
Monthly Purchase Gas in MMDth

# Monthly Gas Purchase Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7

Exhibit 9.54




Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8
Exhibit 9.55
Frequency
Monthly Purchase Gas in MMDth
0
100
200
300
400
500
600
700
800
900
1000
1100
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

# Monthly Gas Purchase Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=9

Exhibit 9.56

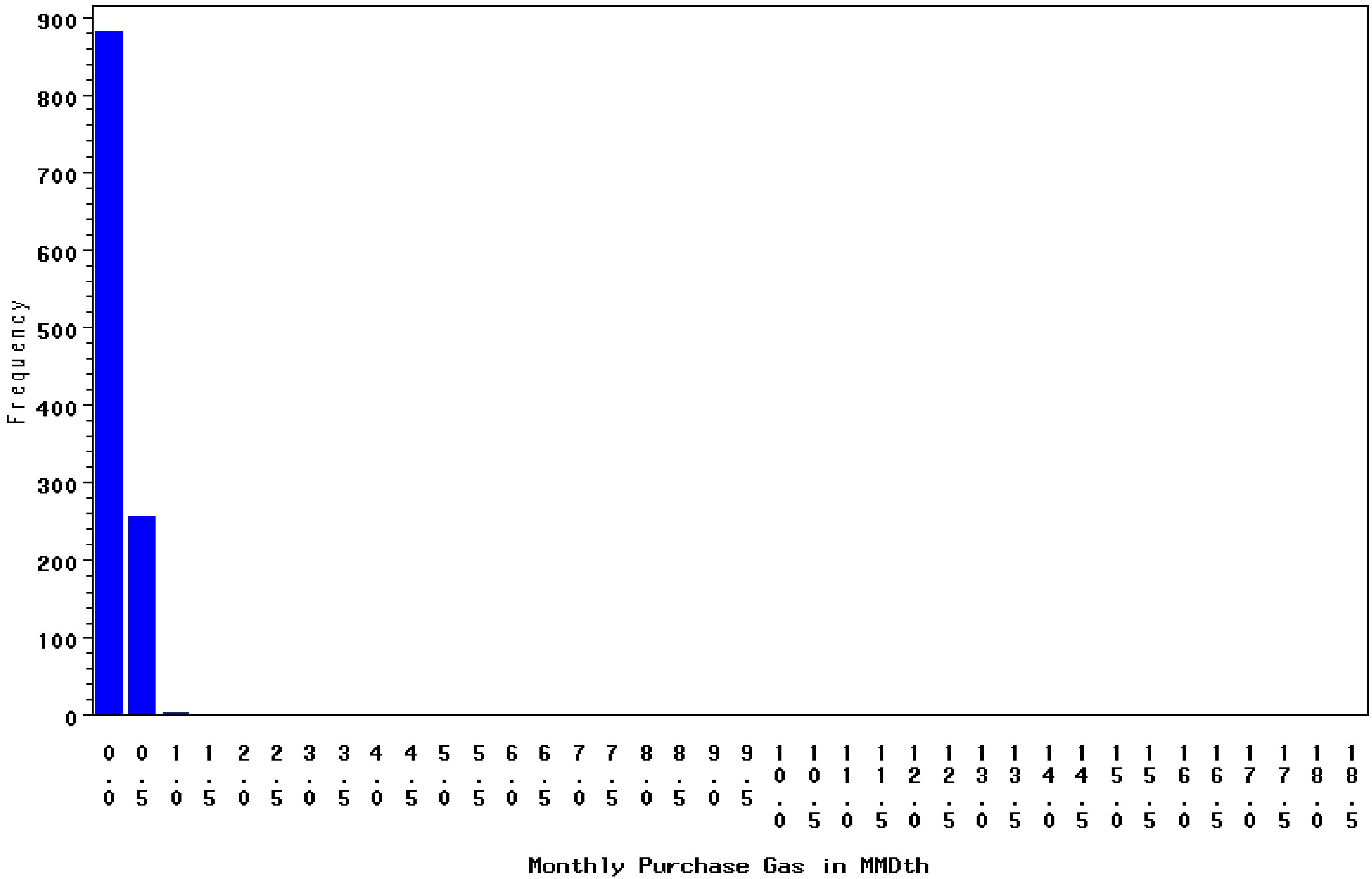
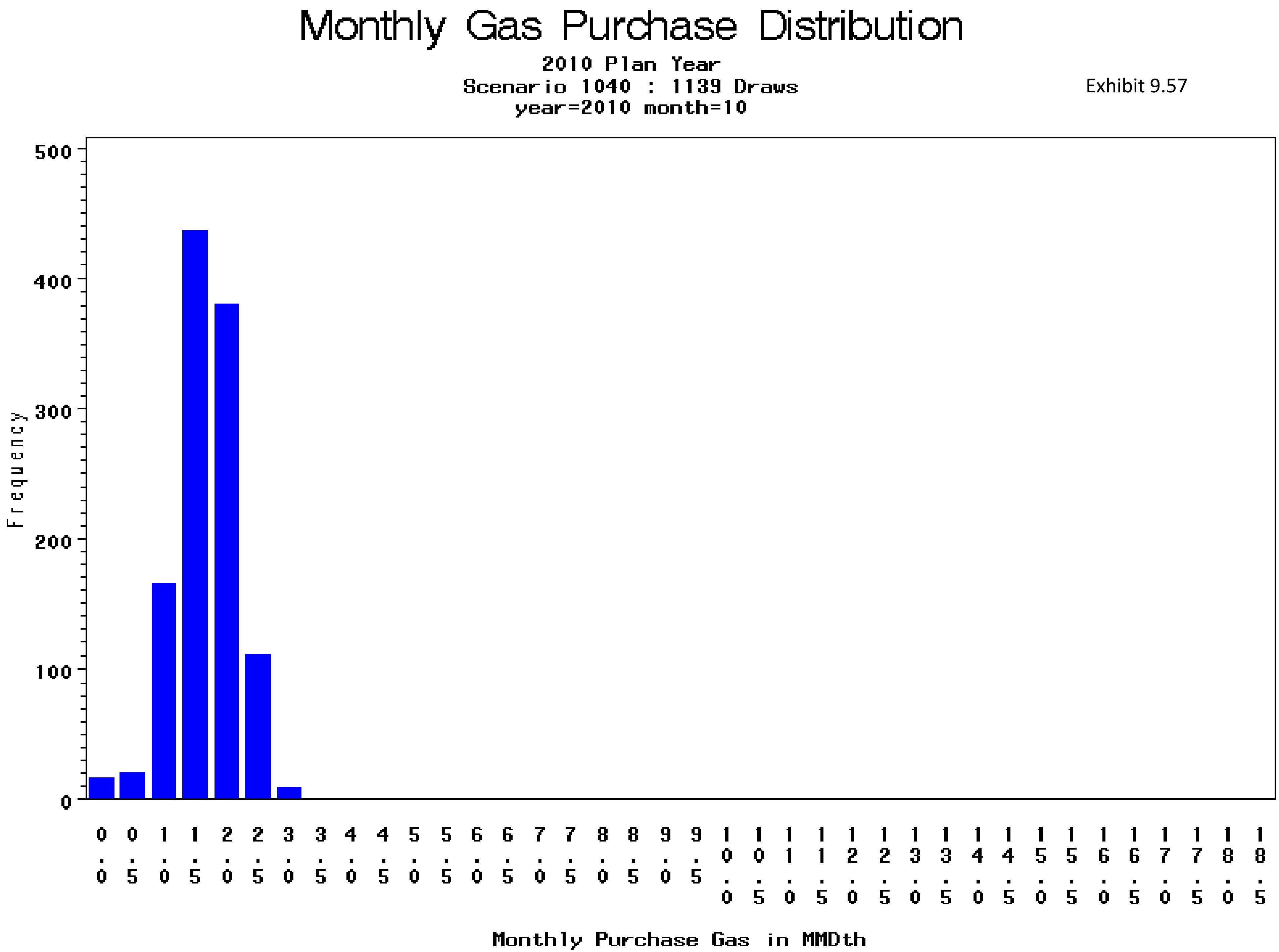


Exhibit 9.57

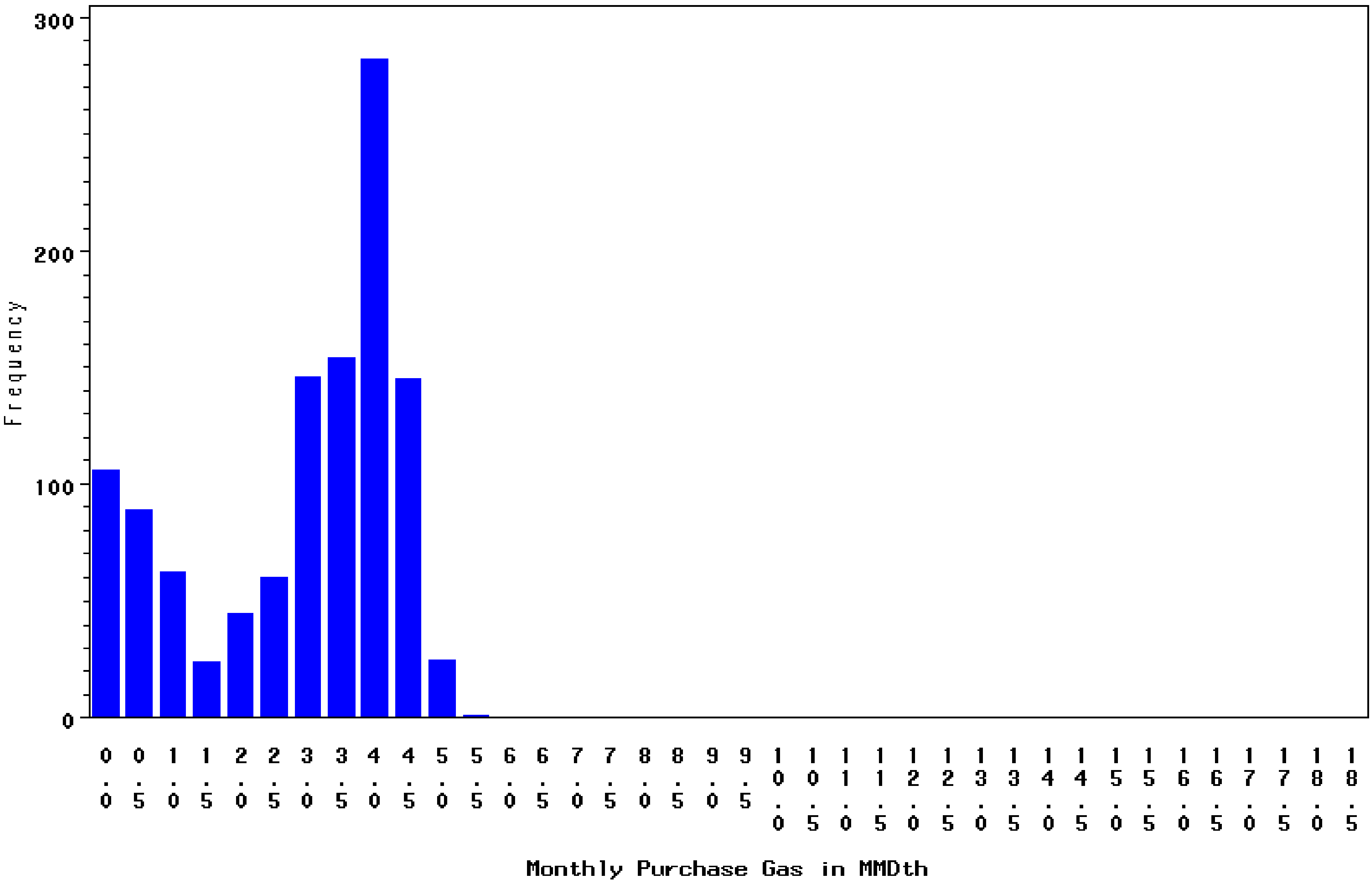


Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10
Frequency
500
400
300
200
100
0
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
6.5
7.0
7.5
8.0
8.5
9.0
9.5
10.0
10.5
11.0
11.5
12.0
12.5
13.0
13.5
14.0
14.5
15.0
15.5
16.0
16.5
17.0
17.5
18.0
18.5
Monthly Purchase Gas in MMDth

Exhibit 9.58

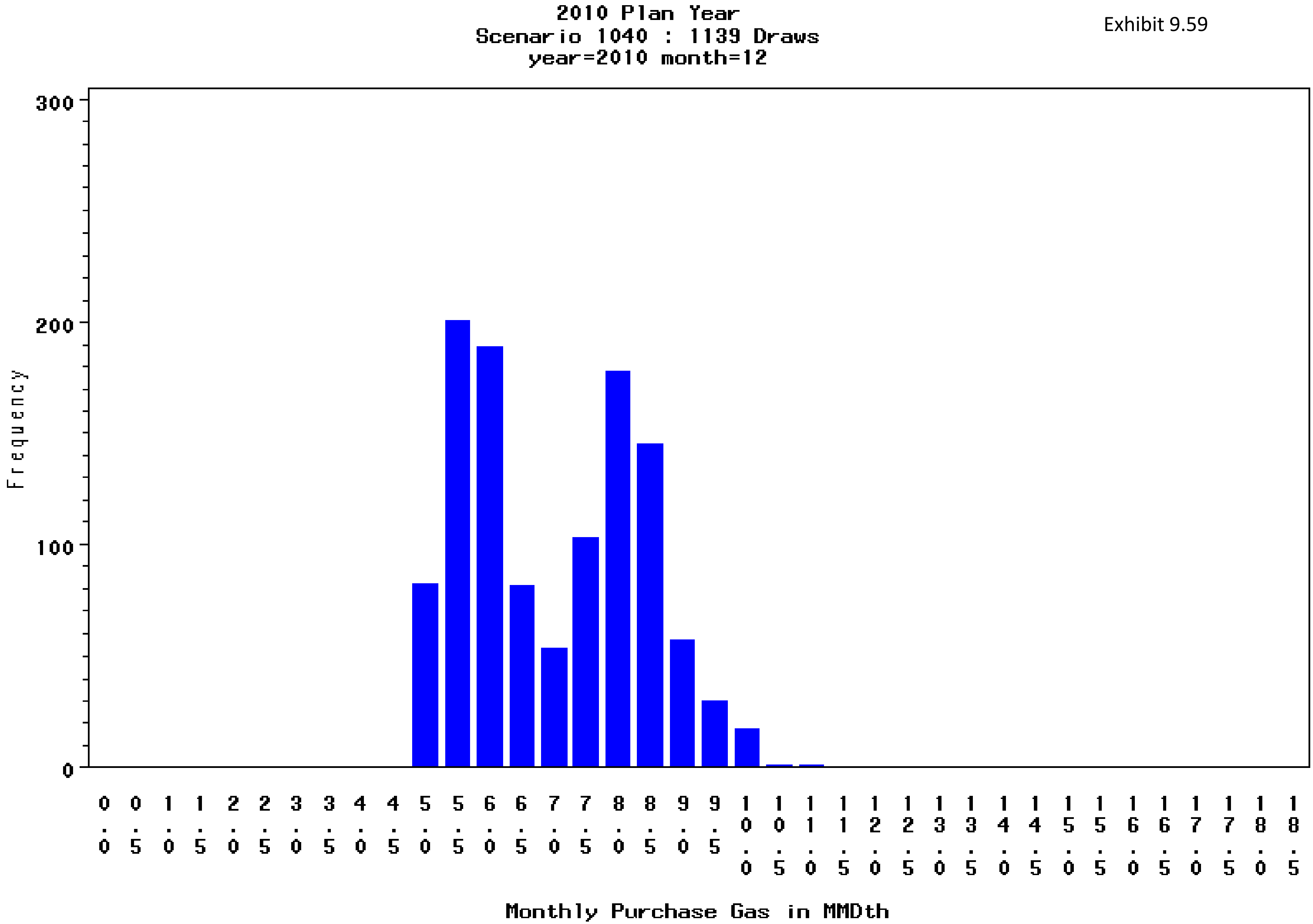
# Monthly Gas Purchase Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=11



# Monthly Gas Purchase Distribution

Exhibit 9.59



# Monthly Gas Purchase Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1

Exhibit 9.60

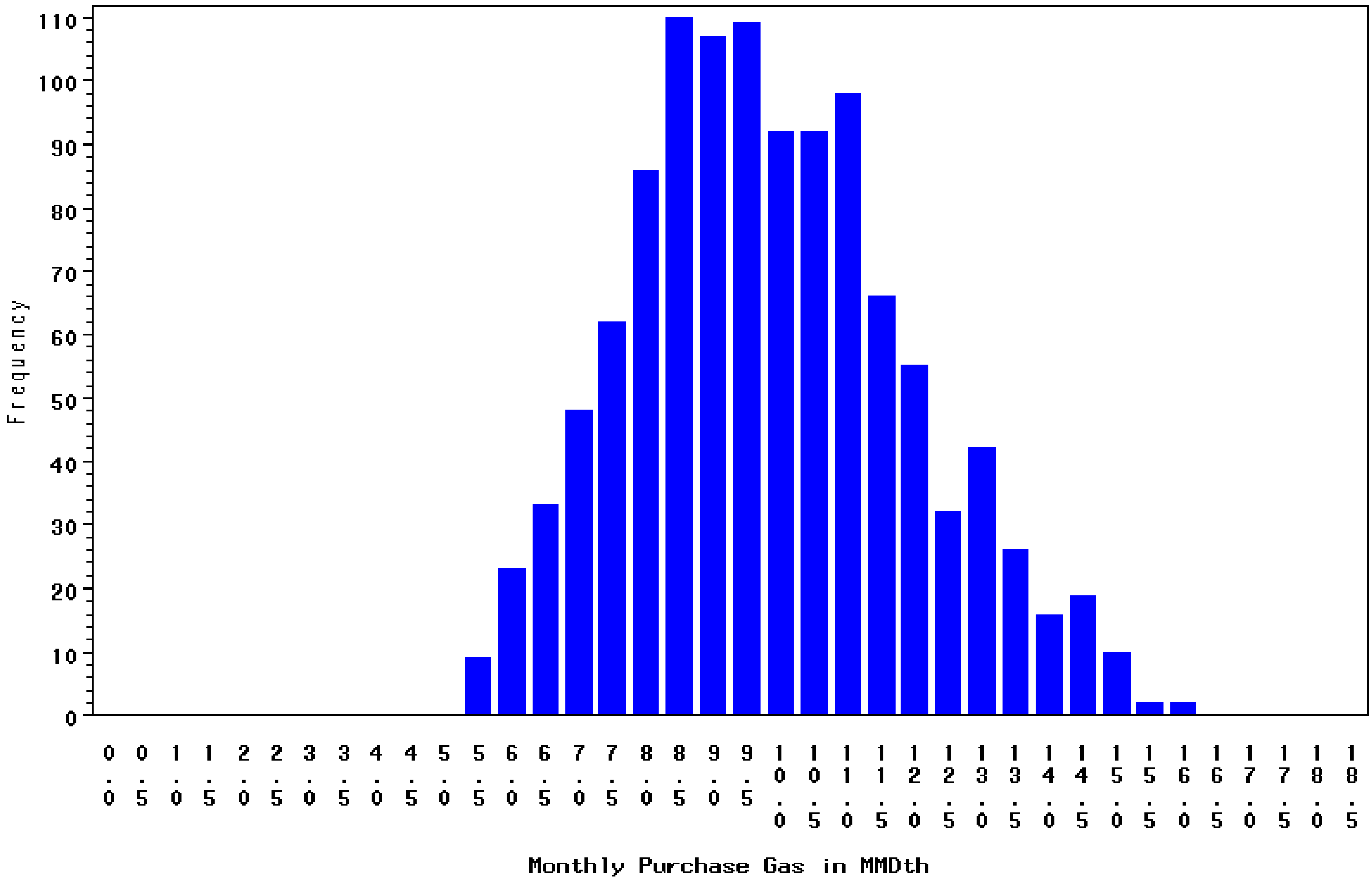
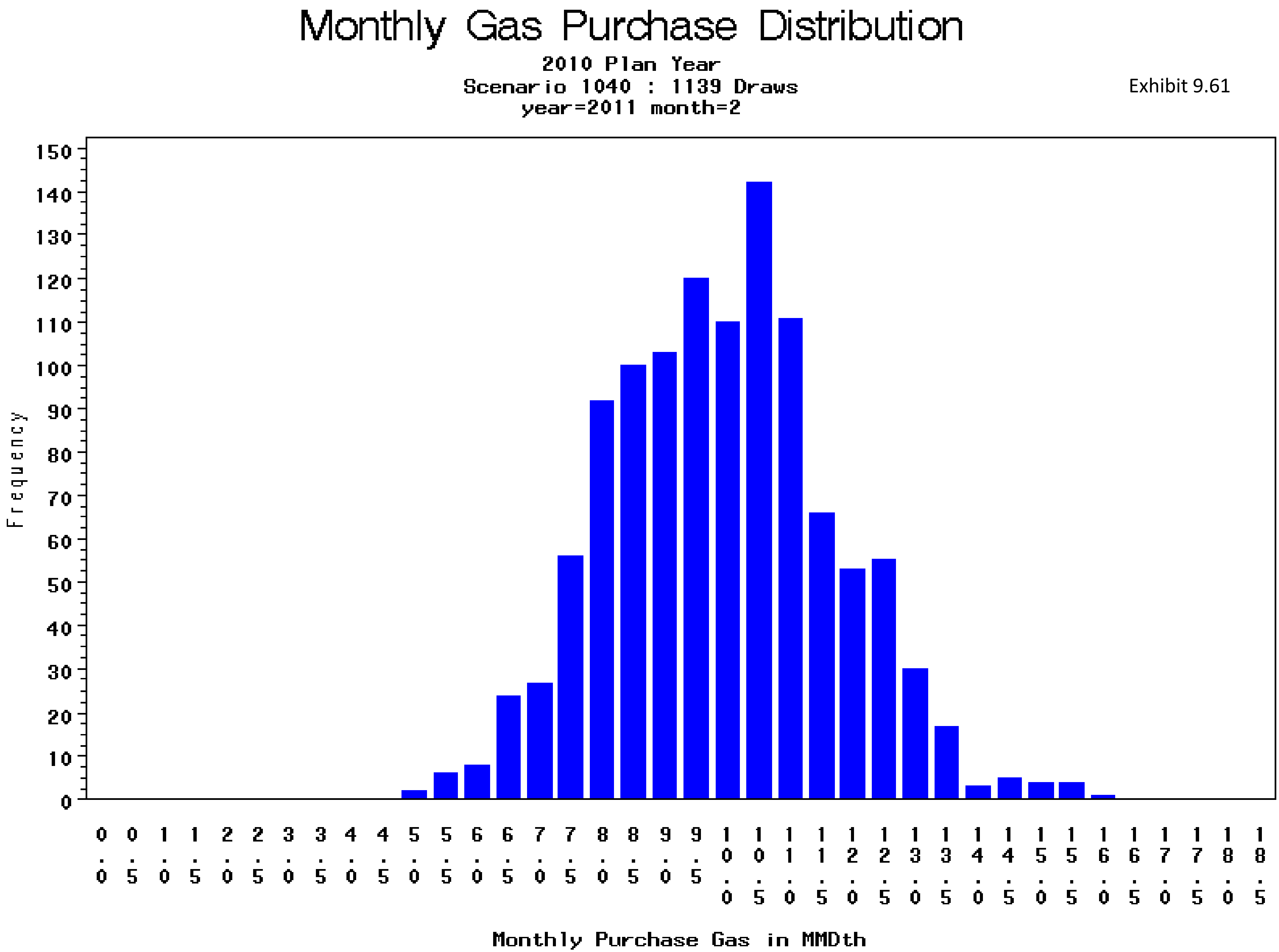
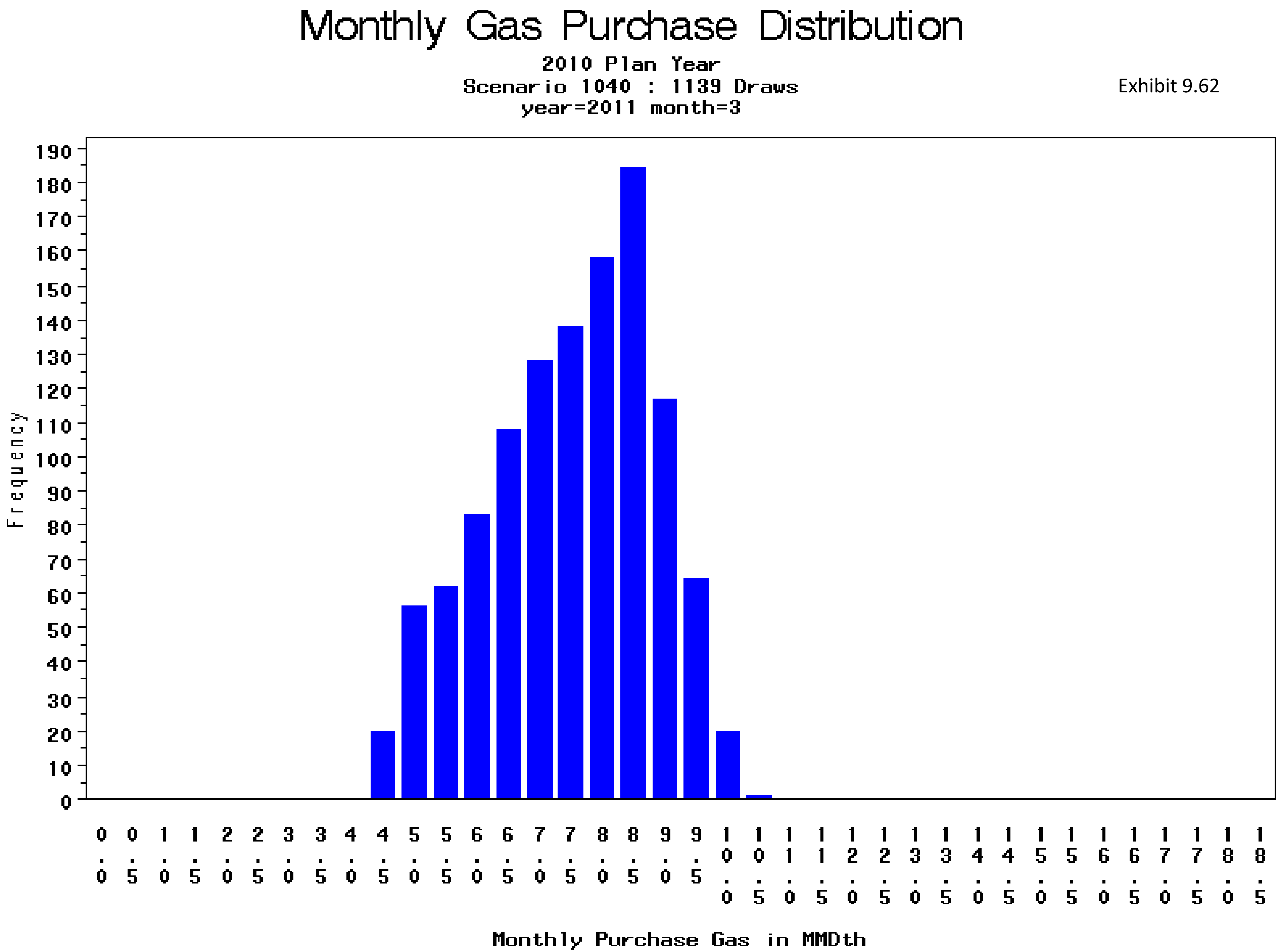
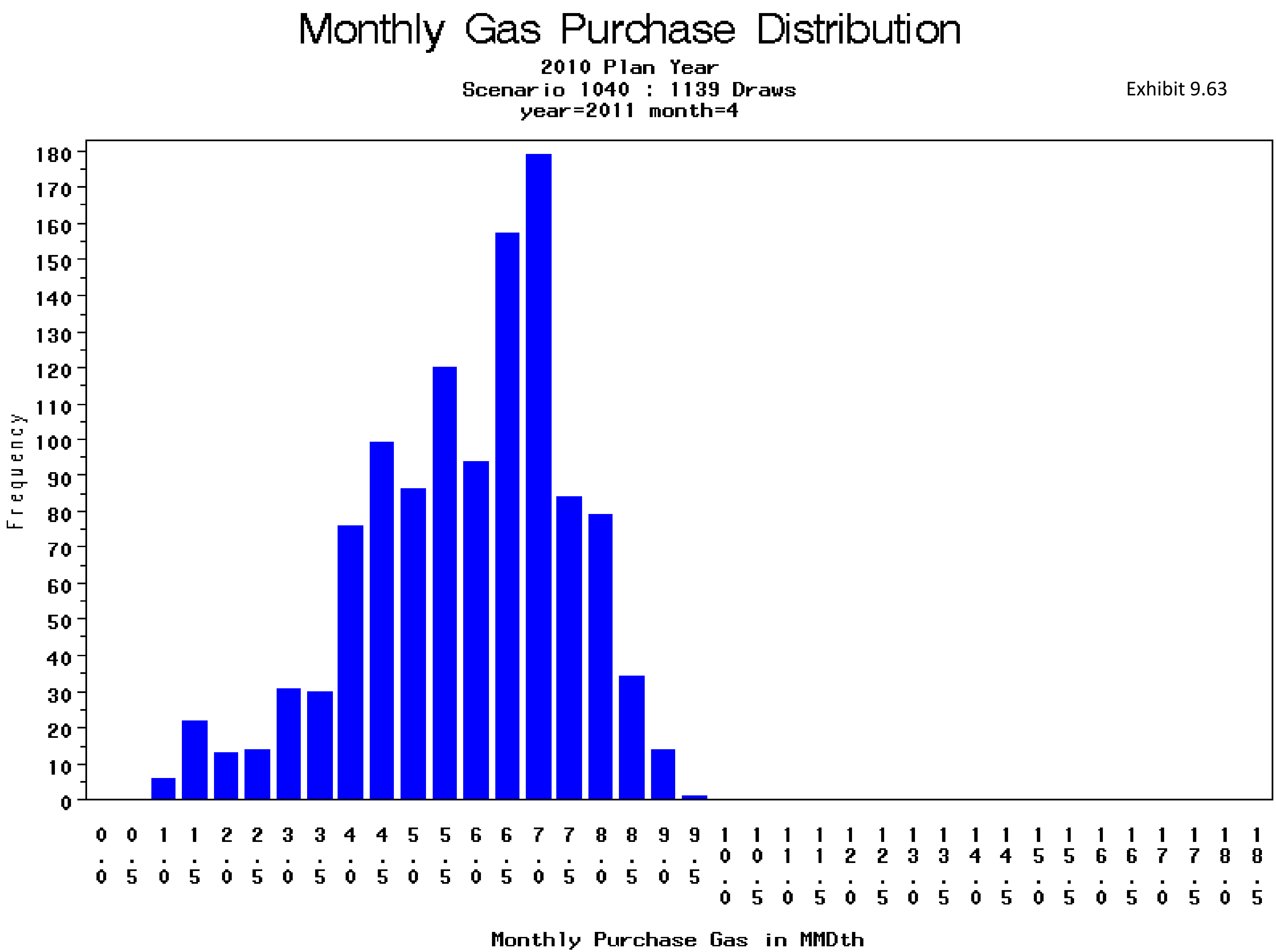


Exhibit 9.61

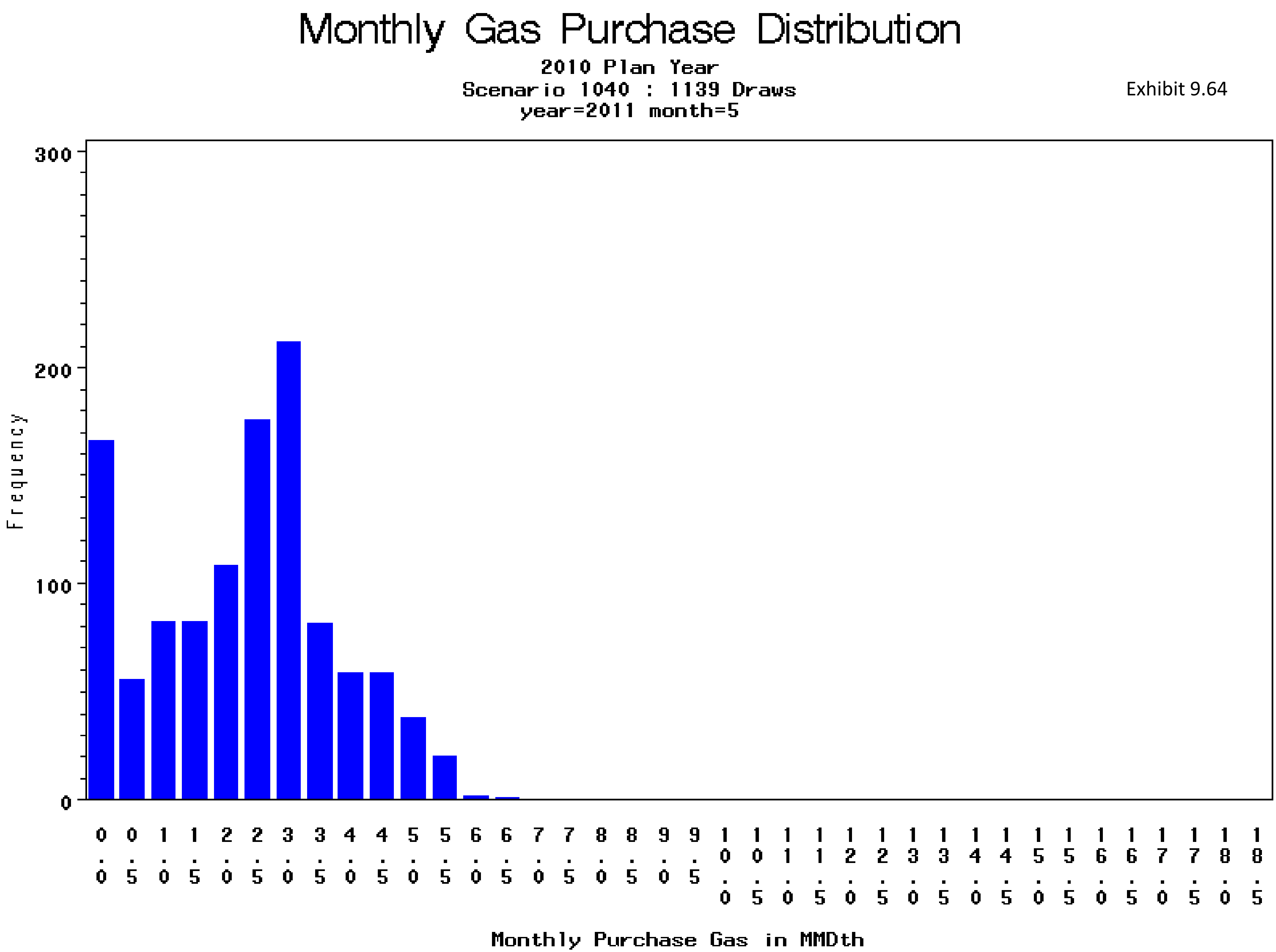

Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=2
Frequency
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0 7.5 8.0 8.5 9.0 9.5 10.0 10.5 11.0 11.5 12.0 12.5 13.0 13.5 14.0 14.5 15.0 15.5 16.0 16.5 17.0 17.5 18.0 18.5
Monthly Purchase Gas in MMDth



Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3
Exhibit 9.62
Frequency
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180 190
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
Monthly Purchase Gas in MMDth

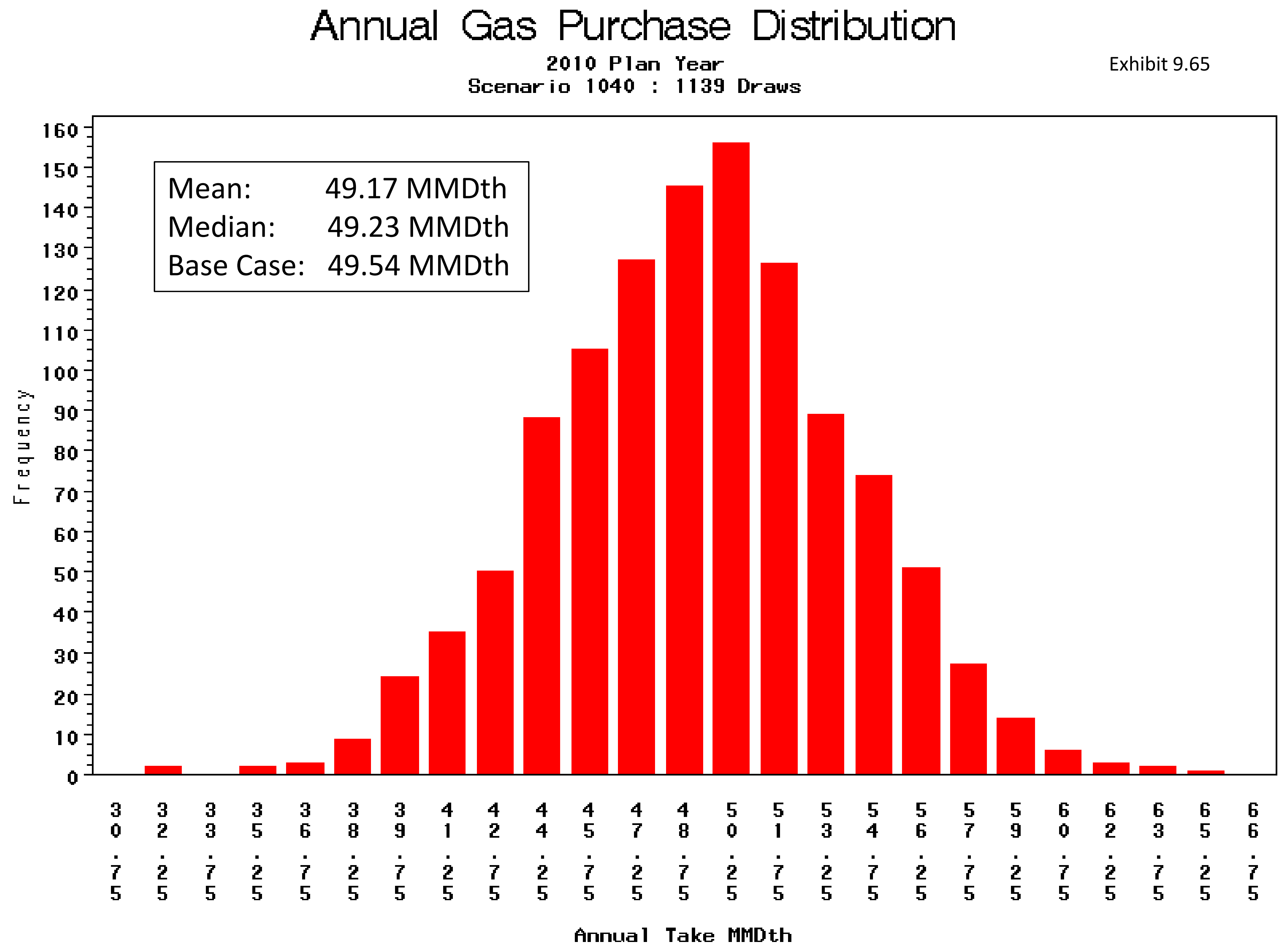


Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4
Exhibit 9.63
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
6.5
7.0
7.5
8.0
8.5
9.0
9.5
10.0
10.5
11.0
11.5
12.0
12.5
13.0
13.5
14.0
14.5
15.0
15.5
16.0
16.5
17.0
17.5
18.0
18.5
Monthly Purchase Gas in MMDth



Monthly Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5
Exhibit 9.64
Frequency
0
100
200
300
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
Monthly Purchase Gas in MMDth

Exhibit 9.65



Annual Gas Purchase Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
Mean: 49.17 MMDth
Median: 49.23 MMDth
Base Case: 49.54 MMDth
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
30.75
32.25
33.75
35.25
36.75
38.25
39.75
41.25
42.75
44.25
45.75
47.25
48.75
50.25
51.75
53.25
54.75
56.25
57.75
59.25
60.75
62.25
63.75
65.25
66.75
Annual Take MMDth

Exhibit 9.66

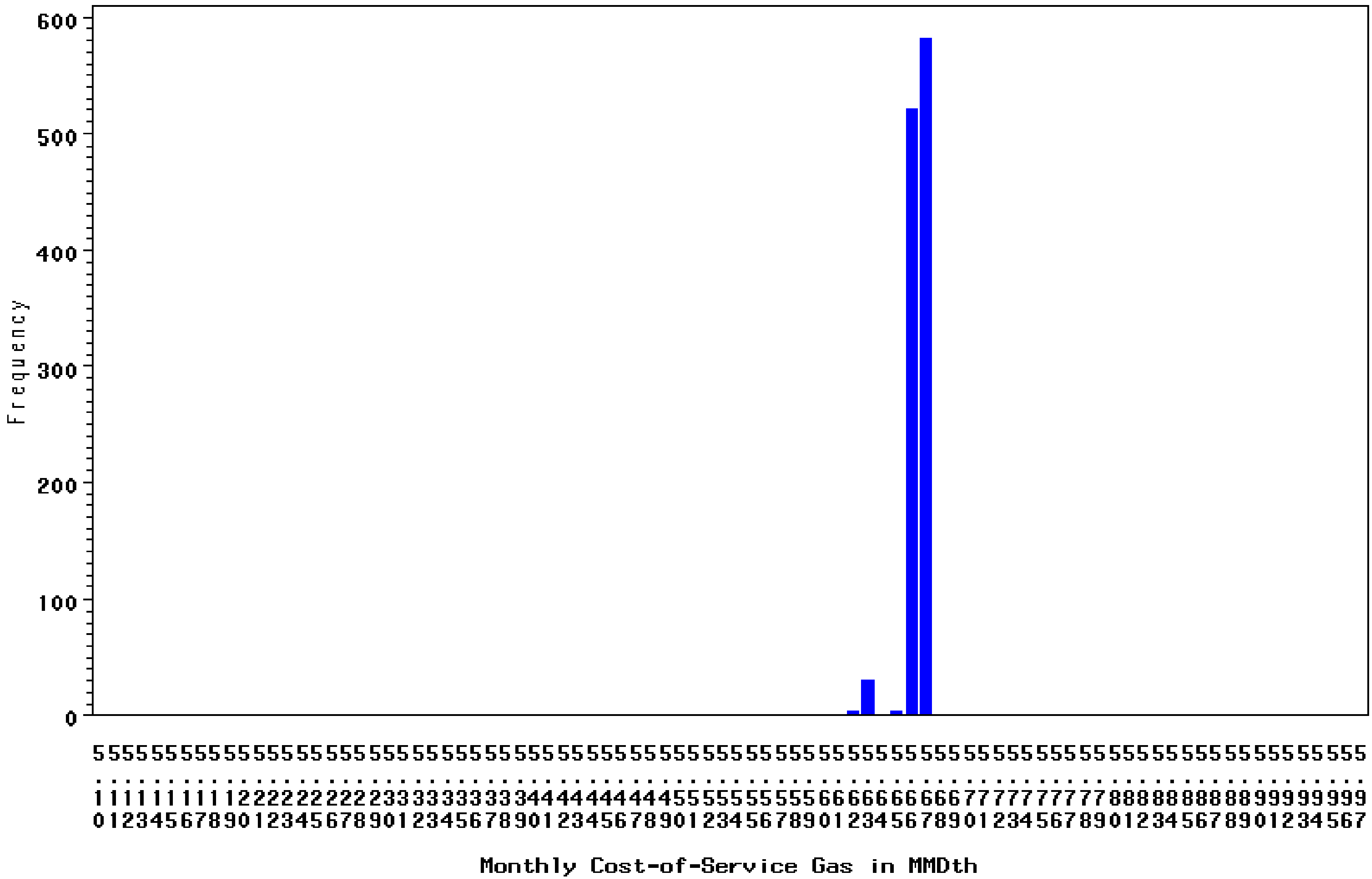
**Monthly Gas Purchase Distribution**
**2010 Plan Year**
**Scenario 1040 : 1139 Draws**

| Obs | year | month | mean | max | p95 | p90 | med | p10 | p5 | min |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2010 | 6 | 1.62 | 5.76 | 3.56 | 2.85 | 1.63 | 0.09 | 0.01 | 0.01 |
| 2 | 2010 | 7 | 0.34 | 1.90 | 1.17 | 1.00 | 0.15 | 0.00 | 0.00 | 0.00 |
| 3 | 2010 | 8 | 0.11 | 0.49 | 0.33 | 0.27 | 0.09 | 0.00 | 0.00 | 0.00 |
| 4 | 2010 | 9 | 0.15 | 0.78 | 0.52 | 0.40 | 0.09 | 0.01 | 0.00 | 0.00 |
| 5 | 2010 | 10 | 1.67 | 3.06 | 2.43 | 2.26 | 1.69 | 1.06 | 0.88 | 0.00 |
| 6 | 2010 | 11 | 2.87 | 5.48 | 4.64 | 4.40 | 3.42 | 0.29 | 0.07 | 0.00 |
| 7 | 2010 | 12 | 7.00 | 11.03 | 9.16 | 8.67 | 6.96 | 5.35 | 5.18 | 5.05 |
| 8 | 2011 | 1 | 9.85 | 15.78 | 13.53 | 12.80 | 9.65 | 7.25 | 6.56 | 5.43 |
| 9 | 2011 | 2 | 9.90 | 15.87 | 12.88 | 12.32 | 9.88 | 7.68 | 7.06 | 4.96 |
| 10 | 2011 | 3 | 7.49 | 10.40 | 9.38 | 9.11 | 7.64 | 5.61 | 5.03 | 4.49 |
| 11 | 2011 | 4 | 5.85 | 9.52 | 8.19 | 7.85 | 6.15 | 3.72 | 2.78 | 1.05 |
| 12 | 2011 | 5 | 2.31 | 6.42 | 4.77 | 4.28 | 2.48 | 0.14 | 0.07 | 0.00 |

# Monthly Cost-of-Service Gas Distribution

Exhibit 9.67

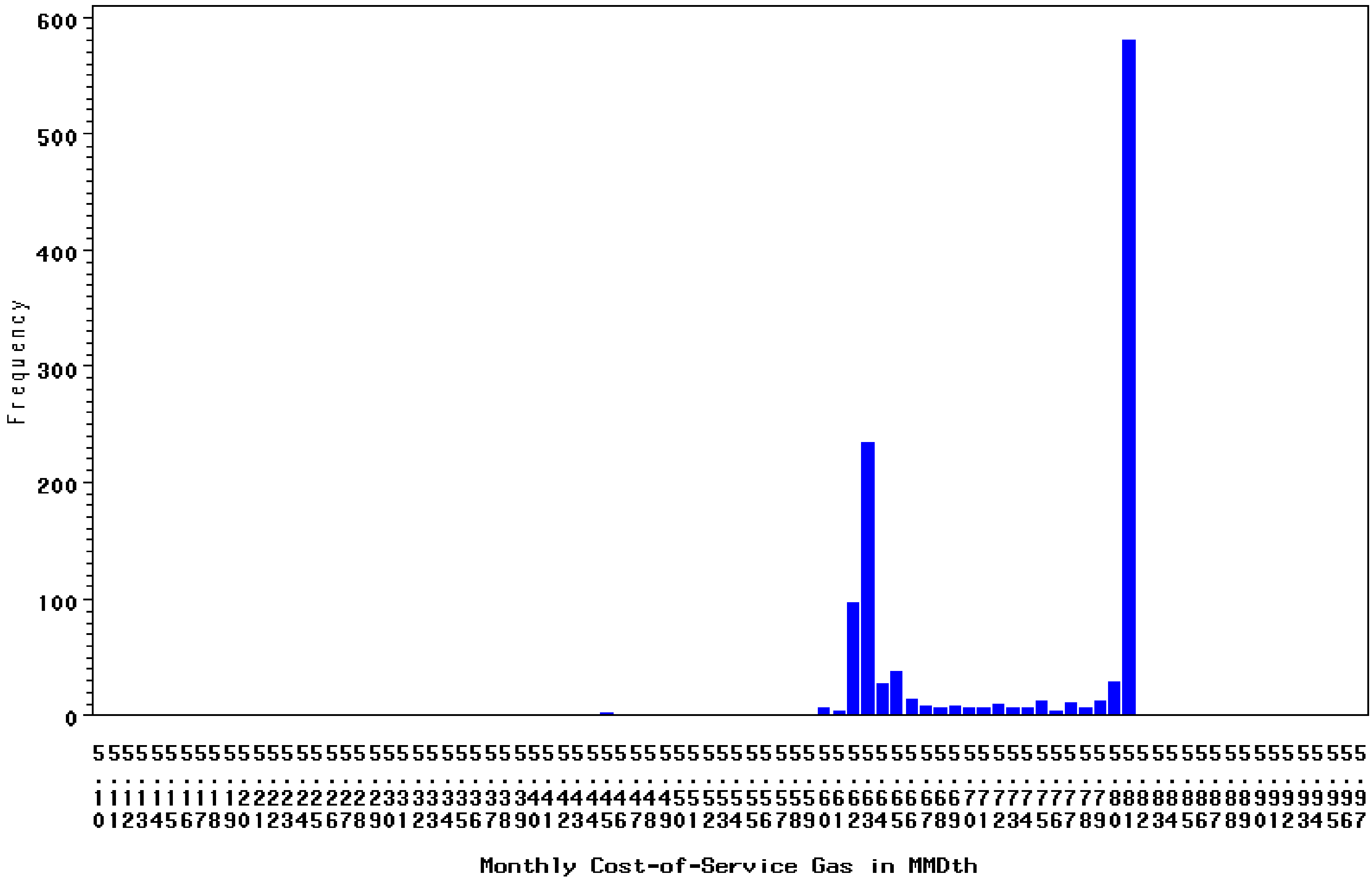
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=6



# Monthly Cost-of-Service Gas Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=7

Exhibit 9.68



# Monthly Cost-of-Service Gas Distribution

Exhibit 9.69

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=8

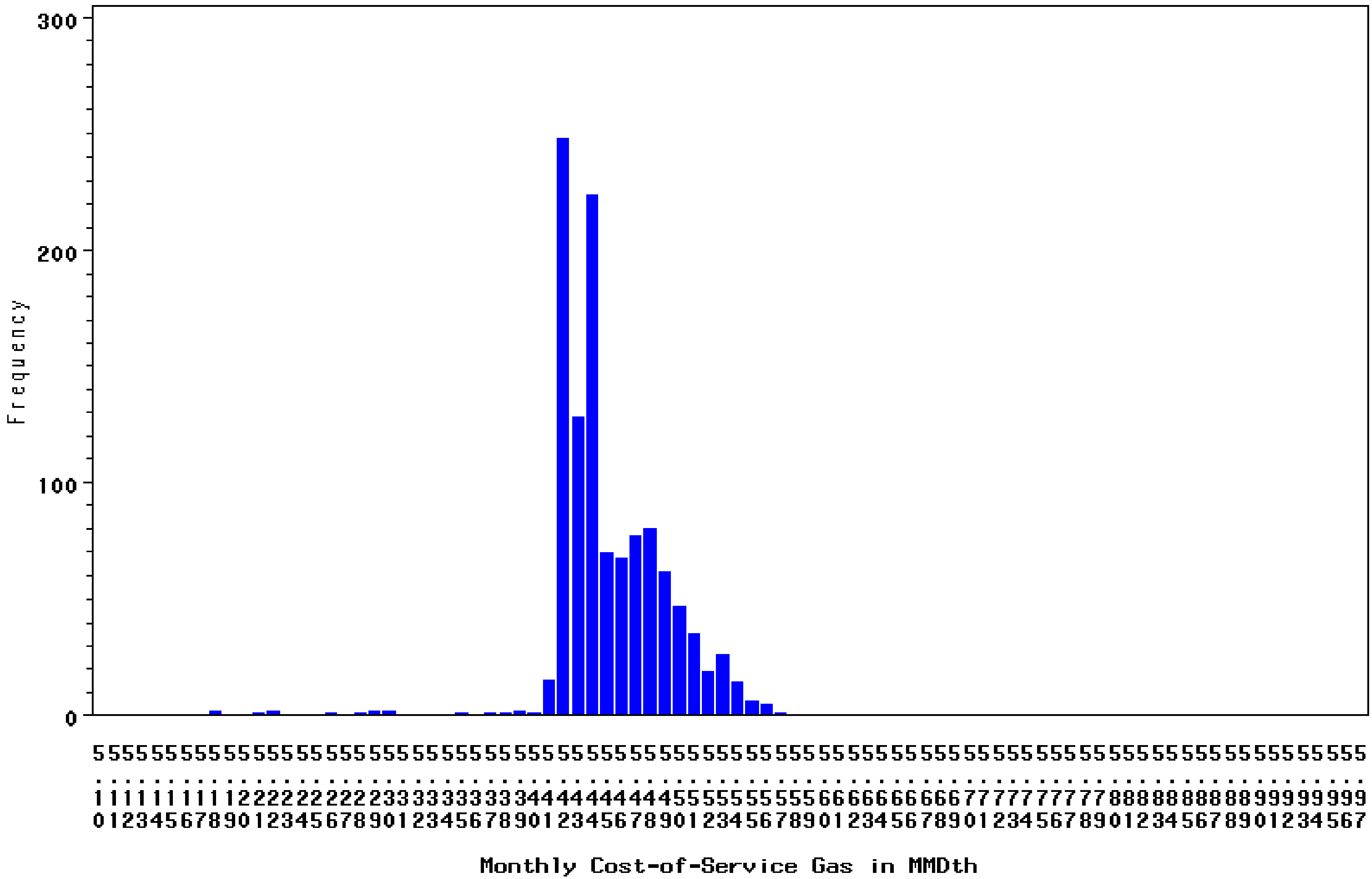
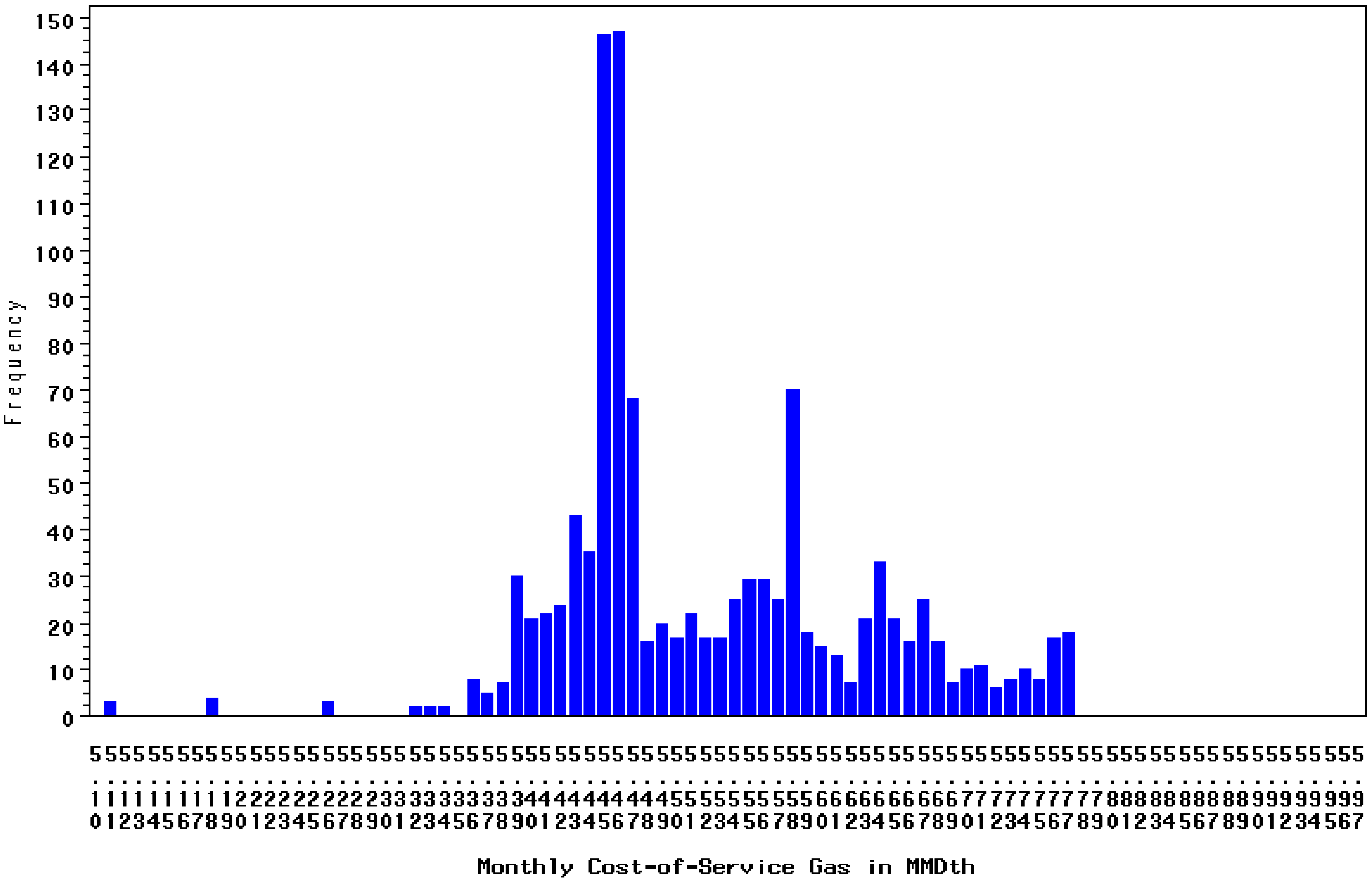


Exhibit 9.70

# Monthly Cost-of-Service Gas Distribution

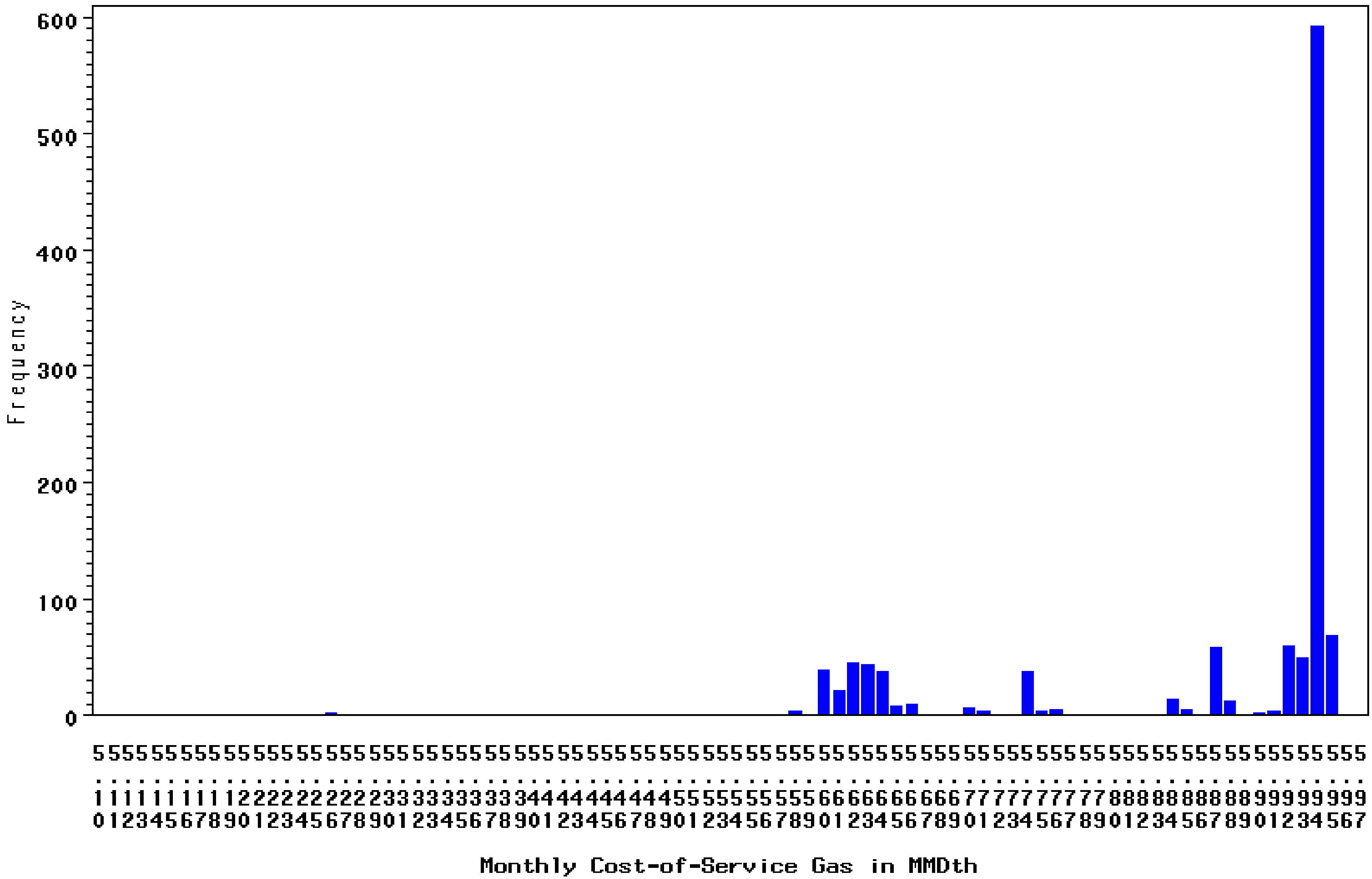
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=9



# Monthly Cost-of-Service Gas Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=10

Exhibit 9.71



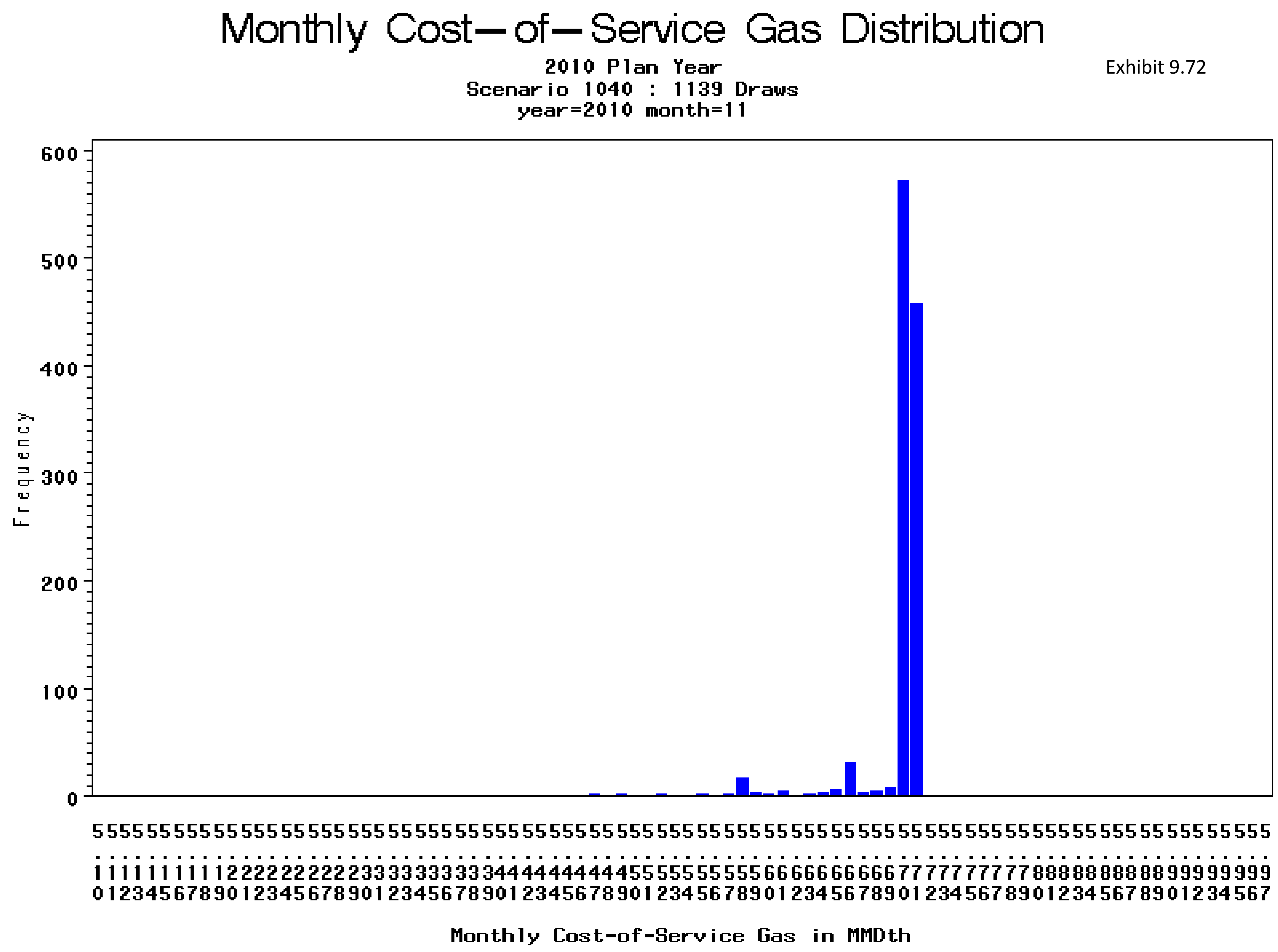
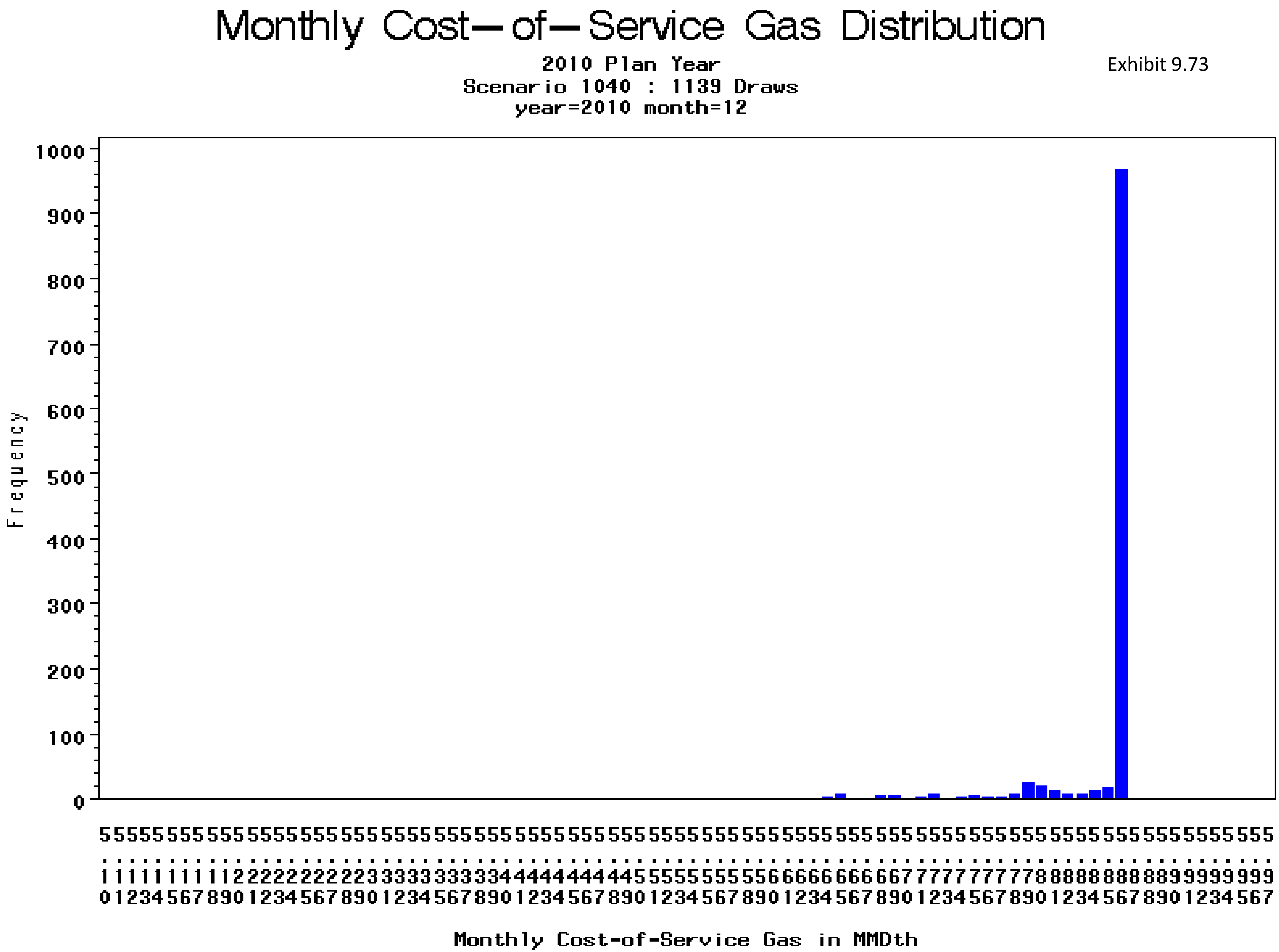

Monthly Cost-of-Service Gas Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=11
Exhibit 9.72
Frequency
Monthly Cost-of-Service Gas in MMDth

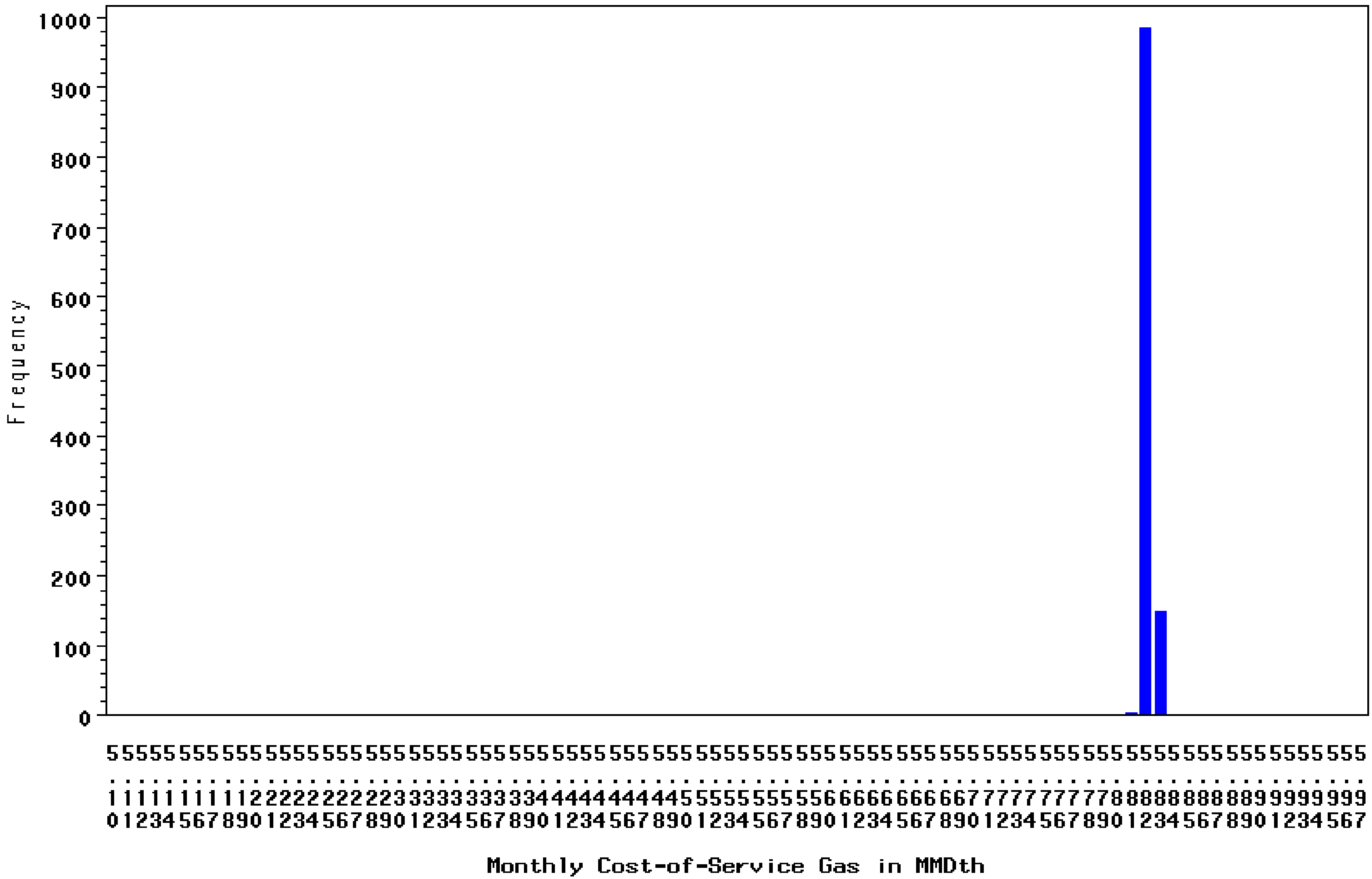
Exhibit 9.73


Monthly Cost-of-Service Gas Distribution
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2010 month=12
Frequency
Monthly Cost-of-Service Gas in MMDth

# Monthly Cost-of-Service Gas Distribution

Exhibit 9.74

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=1



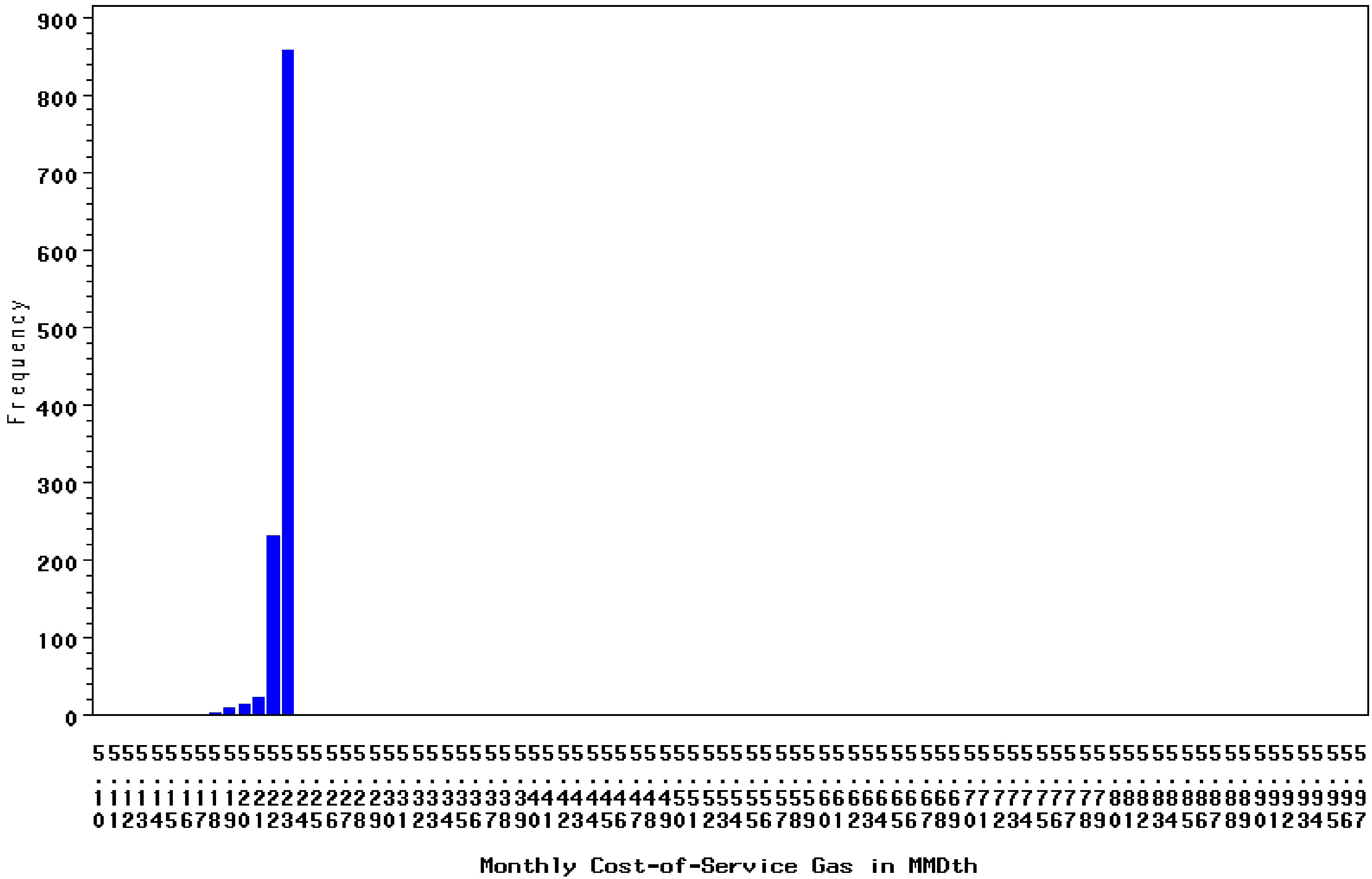
# Monthly Cost-of-Service Gas Distribution

2010 Plan Year

Exhibit 9.75

Scenario 1040 : 1139 Draws

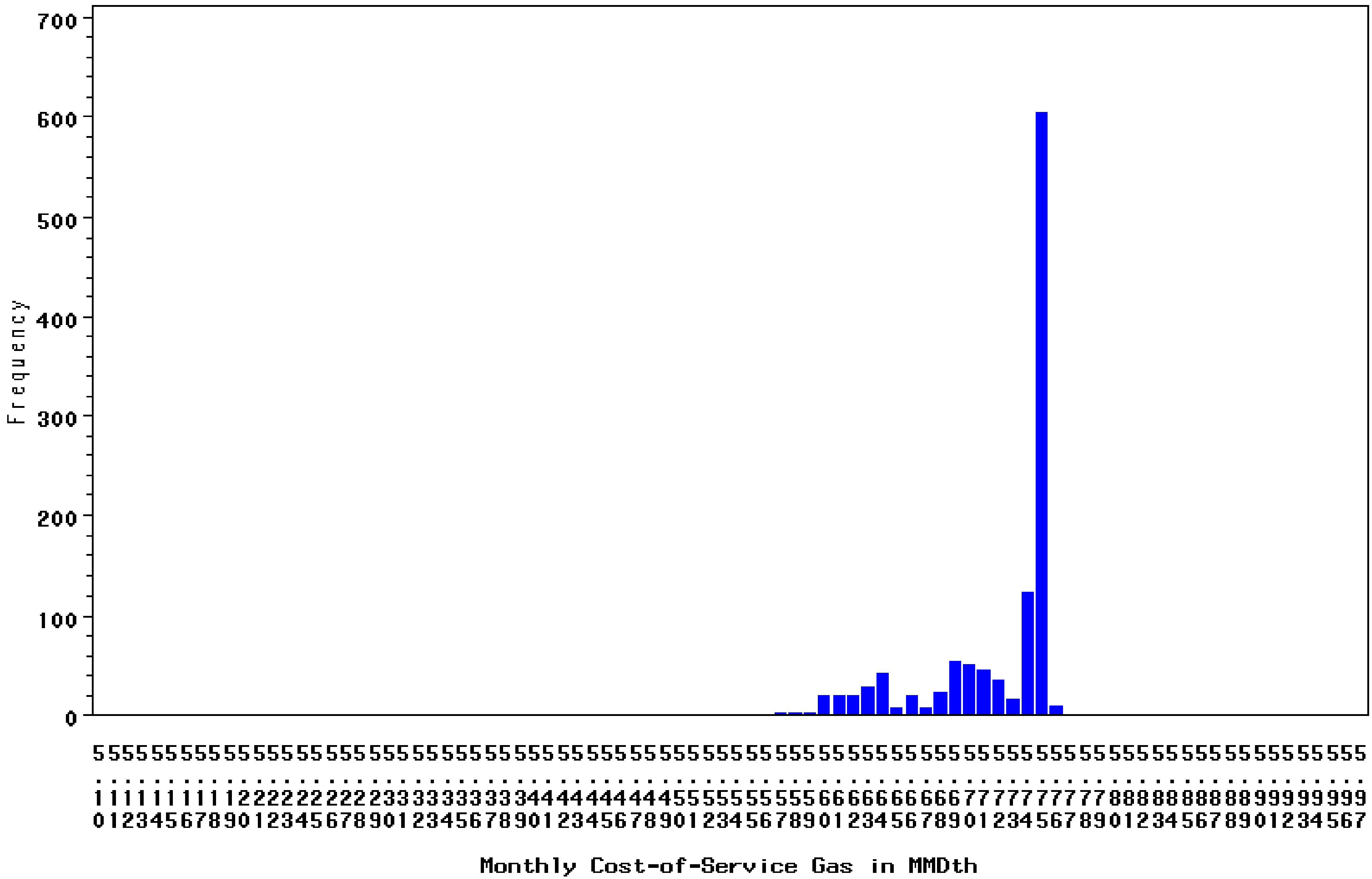
year=2011 month=2



# Monthly Cost-of-Service Gas Distribution

Exhibit 9.76

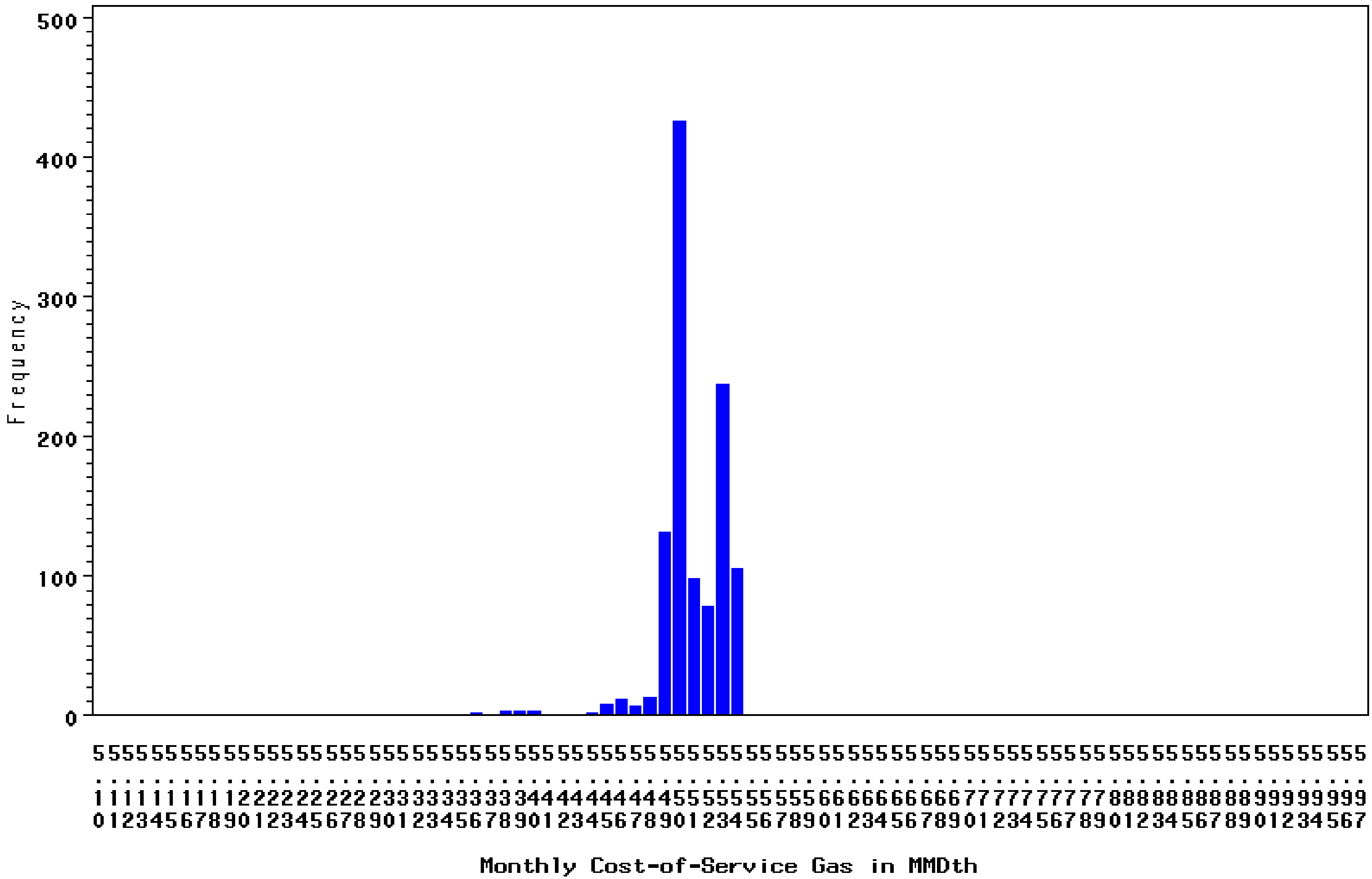
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=3



# Monthly Cost-of-Service Gas Distribution

Exhibit 9.77

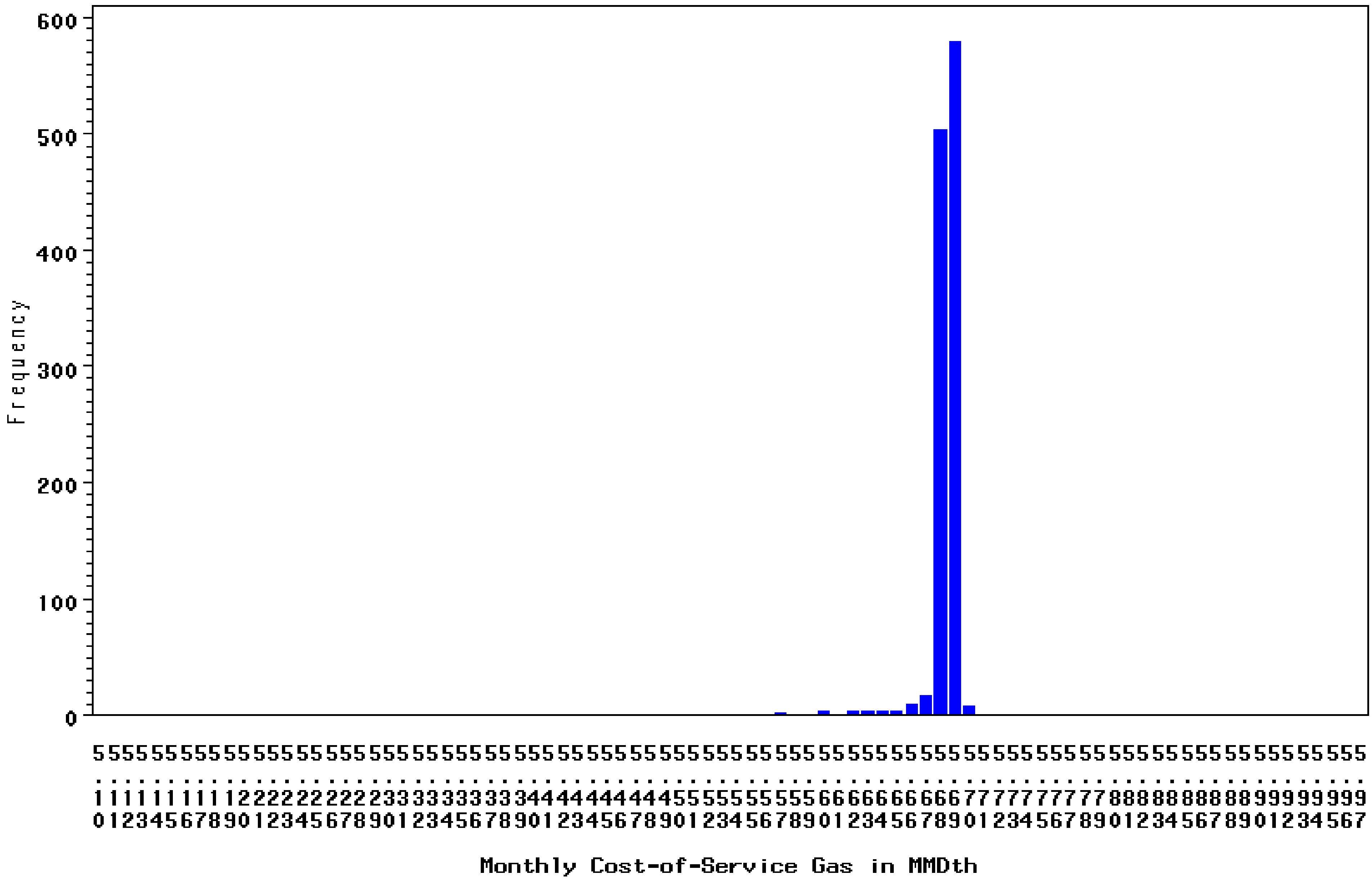
2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=4

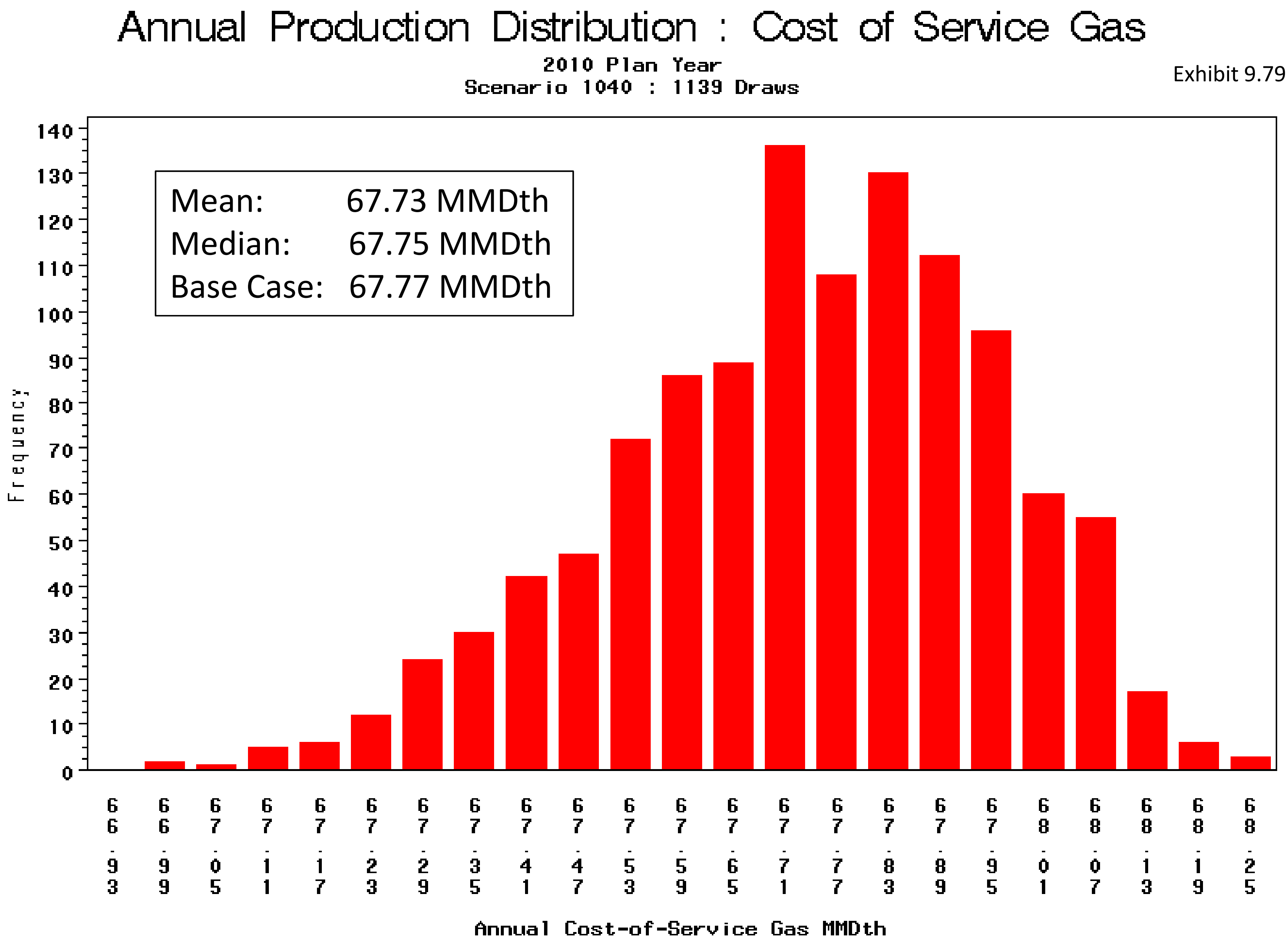


# Monthly Cost-of-Service Gas Distribution

2010 Plan Year
Scenario 1040 : 1139 Draws
year=2011 month=5

Exhibit 9.78





Annual Production Distribution : Cost of Service Gas
2010 Plan Year
Scenario 1040 : 1139 Draws
Mean: 67.73 MMDth
Median: 67.75 MMDth
Base Case: 67.77 MMDth
Frequency
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
66.93
66.99
67.05
67.11
67.17
67.23
67.29
67.35
67.41
67.47
67.53
67.59
67.65
67.71
67.77
67.83
67.89
67.95
68.01
68.07
68.13
68.19
68.25
Annual Cost-of-Service Gas MMDth

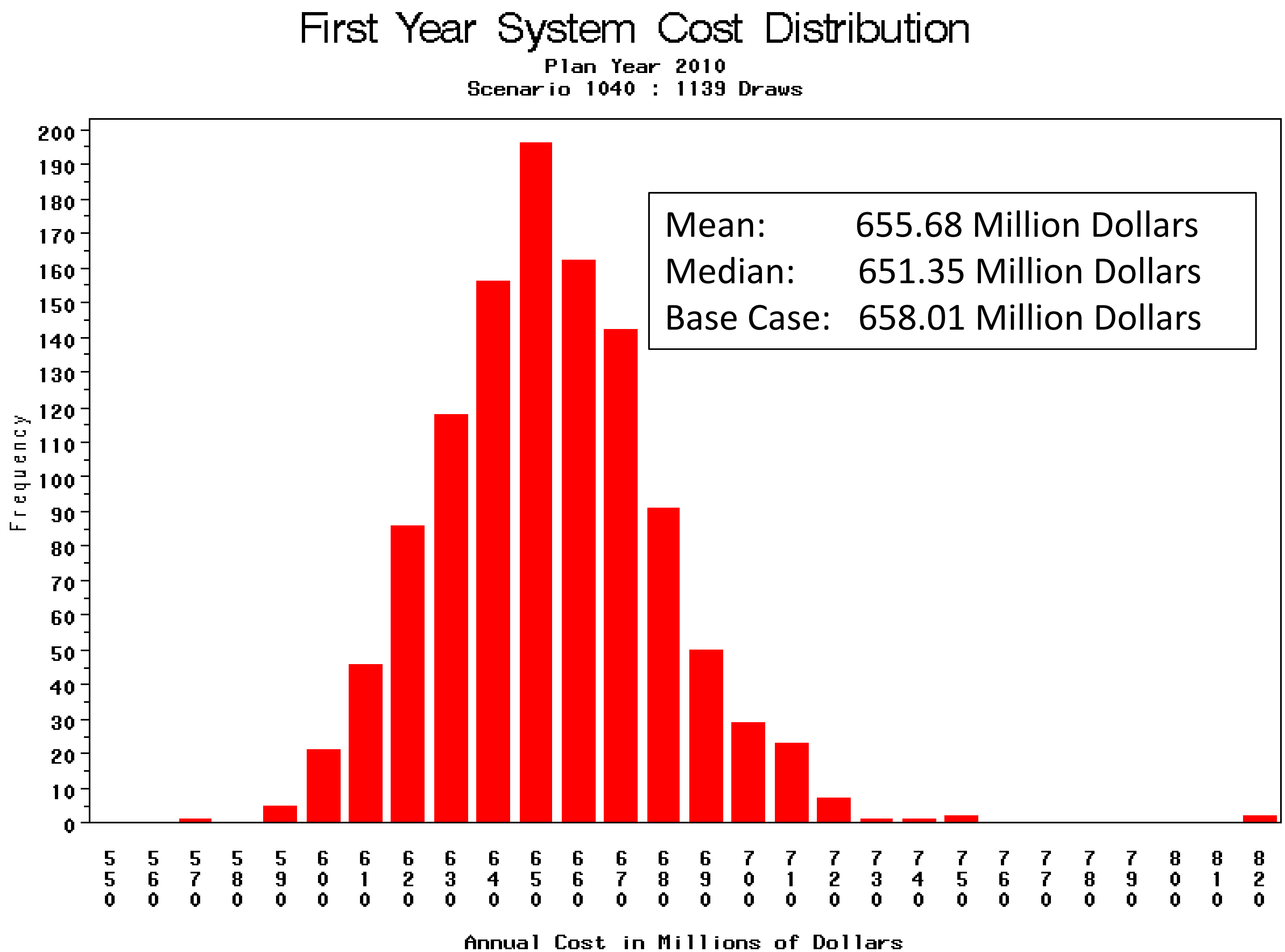

Exhibit 9.79

Exhibit 9.80

**Monthly Cost-of-Service Gas Distribution**
**2010 Plan Year**
**Scenario 1040 : 1139 Draws**

| Obs | year | month | mean | max | p95 | p90 | med | p10 | p5 | min |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2010 | 6 | 5.67 | 5.67 | 5.67 | 5.67 | 5.67 | 5.66 | 5.66 | 5.39 |
| 2 | 2010 | 7 | 5.73 | 5.81 | 5.81 | 5.81 | 5.81 | 5.62 | 5.62 | 5.45 |
| 3 | 2010 | 8 | 5.45 | 5.57 | 5.52 | 5.50 | 5.44 | 5.42 | 5.42 | 5.18 |
| 4 | 2010 | 9 | 5.52 | 5.77 | 5.73 | 5.67 | 5.47 | 5.42 | 5.39 | 5.11 |
| 5 | 2010 | 10 | 5.86 | 5.95 | 5.95 | 5.94 | 5.94 | 5.63 | 5.61 | 5.26 |
| 6 | 2010 | 11 | 5.70 | 5.71 | 5.71 | 5.71 | 5.70 | 5.70 | 5.65 | 5.38 |
| 7 | 2010 | 12 | 5.85 | 5.87 | 5.86 | 5.86 | 5.86 | 5.81 | 5.78 | 5.44 |
| 8 | 2011 | 1 | 5.82 | 5.83 | 5.83 | 5.83 | 5.82 | 5.82 | 5.82 | 5.67 |
| 9 | 2011 | 2 | 5.23 | 5.23 | 5.23 | 5.23 | 5.23 | 5.22 | 5.22 | 5.12 |
| 10 | 2011 | 3 | 5.72 | 5.76 | 5.75 | 5.75 | 5.75 | 5.64 | 5.62 | 5.21 |
| 11 | 2011 | 4 | 5.51 | 5.54 | 5.54 | 5.53 | 5.50 | 5.49 | 5.48 | 5.24 |
| 12 | 2011 | 5 | 5.68 | 5.70 | 5.69 | 5.69 | 5.69 | 5.68 | 5.68 | 5.45 |

Exhibit 9.81



First Year System Cost Distribution
Plan Year 2010
Scenario 1040 : 1139 Draws
Mean: 655.68 Million Dollars
Median: 651.35 Million Dollars
Base Case: 658.01 Million Dollars
Frequency
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
200
550
560
570
580
590
600
610
620
630
640
650
660
670
680
690
700
710
720
730
740
750
760
770
780
790
800
810
820
Annual Cost in Millions of Dollars

Exhibit 9.82

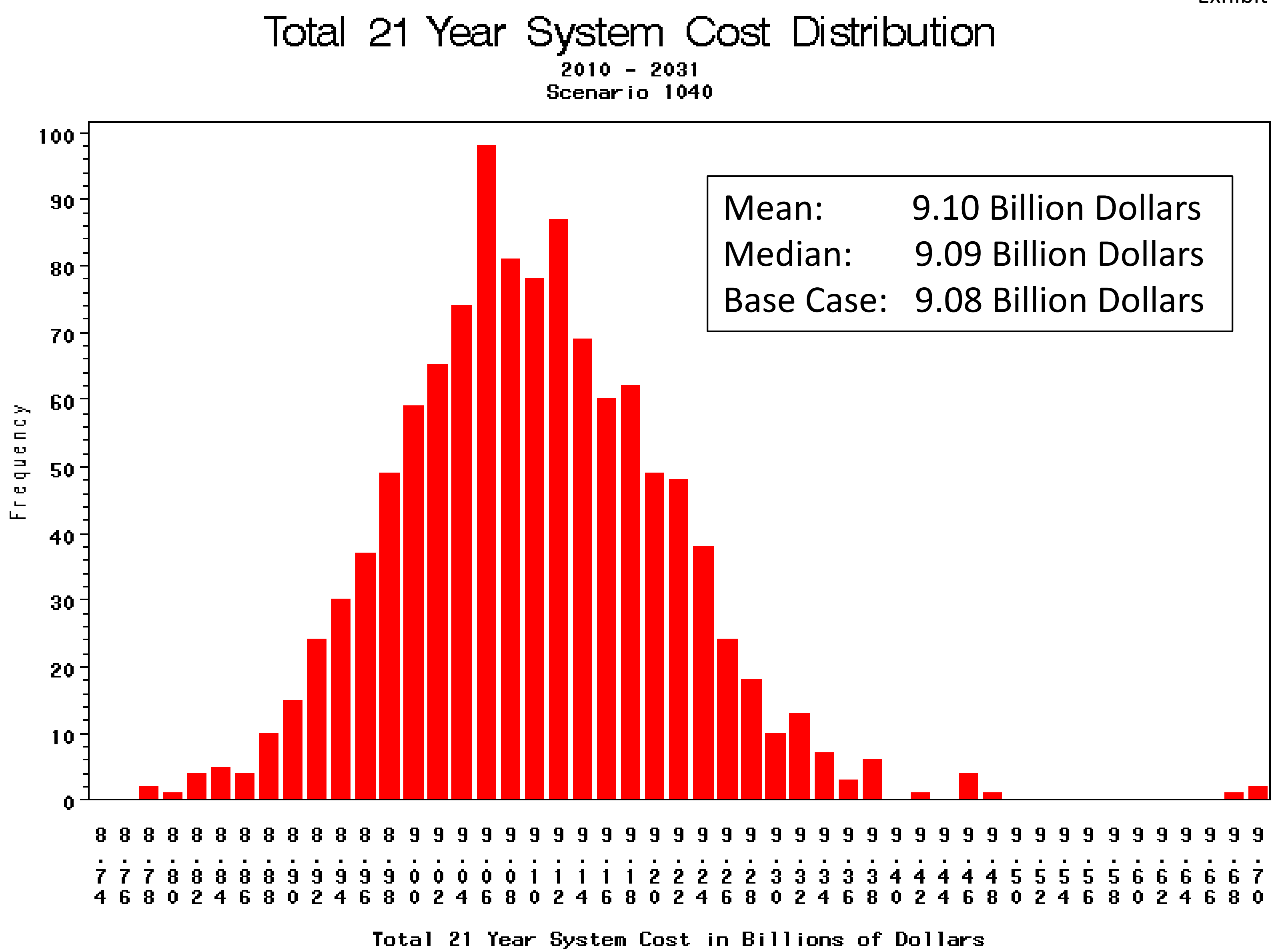

Total 21 Year System Cost Distribution
2010 - 2031
Scenario 1040
Mean: 9.10 Billion Dollars
Median: 9.09 Billion Dollars
Base Case: 9.08 Billion Dollars
Frequency
0 10 20 30 40 50 60 70 80 90 100
8.74 8.76 8.78 8.80 8.82 8.84 8.86 8.88 8.90 8.92 8.94 8.96 8.98 9.00 9.02 9.04 9.06 9.08 9.10 9.12 9.14 9.16 9.18 9.20 9.22 9.24 9.26 9.28 9.30 9.32 9.34 9.36 9.38 9.40 9.42 9.44 9.46 9.48 9.50 9.52 9.54 9.56 9.58 9.60 9.62 9.64 9.66 9.68 9.70
Total 21 Year System Cost in Billions of Dollars

Exhibit 9.87

Natural Gas Requirements v. Supply

Forecast Demand

Units: MDT

| Area | Class | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ut KRGT | GS_COM | 7.3 | 3.4 | 3.4 | 3.6 | 6.3 | 11.0 | 21.5 | 30.5 | 20.0 | 21.5 | 13.3 | 7.7 | 149.6 |
| Ut KRGT | GS_RES | 17.1 | 9.5 | 9.5 | 10.6 | 16.3 | 28.3 | 49.8 | 69.6 | 46.2 | 49.4 | 30.3 | 19.5 | 356.0 |
| Ut KRGT | L_and_U | 0.5 | 0.3 | 0.3 | 0.3 | 0.5 | 0.8 | 1.4 | 2.0 | 1.3 | 1.4 | 0.9 | 0.6 | 10.3 |
| UT NPC | GS_COM | 6.8 | 3.2 | 3.2 | 3.4 | 5.9 | 10.3 | 20.2 | 28.6 | 18.8 | 20.1 | 12.4 | 7.2 | 140.2 |
| UT NPC | GS_RES | 16.0 | 8.9 | 8.9 | 9.9 | 15.3 | 26.5 | 46.7 | 65.3 | 43.4 | 46.2 | 28.4 | 18.3 | 333.8 |
| UT NPC | L_and_U | 0.5 | 0.2 | 0.2 | 0.3 | 0.4 | 0.7 | 1.4 | 1.9 | 1.3 | 1.3 | 0.8 | 0.5 | 9.6 |
| Ut/Id | FS_COM | 347.7 | 281.2 | 292.1 | 322.1 | 379.2 | 385.6 | 507.9 | 547.2 | 411.1 | 435.3 | 366.9 | 322.8 | 4599.2 |
| Ut/Id | FS_IND | 224.7 | 182.8 | 182.7 | 204.0 | 204.2 | 231.0 | 268.0 | 328.8 | 254.2 | 256.1 | 232.0 | 203.8 | 2772.2 |
| Ut/Id | GS_COM | 1293.5 | 570.9 | 571.1 | 596.6 | 1097.2 | 2030.8 | 4087.9 | 5843.8 | 3820.4 | 4077.2 | 2471.4 | 1393.6 | 27854.4 |
| Ut/Id | GS_RES | 3030.3 | 1585.9 | 1586.4 | 1739.2 | 2839.0 | 5206.5 | 9436.7 | 13372.7 | 8812.9 | 9364.5 | 5637.8 | 3530.9 | 66142.8 |
| Ut/Id | IS_COM | 27.1 | 19.5 | 19.5 | 21.0 | 43.1 | 57.9 | 78.5 | 93.7 | 61.5 | 69.9 | 57.2 | 34.2 | 583.1 |
| Ut/Id | IS_ELC | 10.5 | 0.0 | 29.4 | 6.3 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.3 | 52.7 |
| Ut/Id | IS_IND | 94.0 | 82.8 | 269.2 | 153.6 | 140.4 | 121.5 | 83.2 | 87.1 | 84.8 | 84.0 | 83.9 | 95.9 | 1380.3 |
| Ut/Id | L_and_U | 102.1 | 55.3 | 59.9 | 61.8 | 95.5 | 163.1 | 293.6 | 411.5 | 272.9 | 290.0 | 179.6 | 113.4 | 2098.7 |
| Wy QGC | FS_COM | 16.1 | 10.2 | 10.2 | 11.7 | 15.9 | 18.2 | 26.4 | 33.6 | 23.4 | 28.2 | 20.3 | 15.5 | 229.7 |
| Wy QGC | FS_IND | 1.1 | 1.2 | 1.5 | 1.6 | 1.7 | 2.4 | 2.8 | 3.0 | 2.4 | 3.0 | 2.4 | 1.6 | 24.8 |
| Wy QGC | GS_COM | 40.1 | 9.9 | 9.8 | 19.1 | 53.5 | 90.2 | 155.2 | 215.2 | 137.4 | 179.3 | 104.0 | 57.2 | 1070.8 |
| Wy QGC | GS_RES | 93.6 | 34.1 | 34.1 | 45.6 | 92.2 | 165.0 | 260.2 | 339.9 | 236.1 | 294.8 | 171.8 | 112.3 | 1879.7 |
| Wy QGC | IS_COM | 7.0 | 2.8 | 2.8 | 2.8 | 5.6 | 7.9 | 10.0 | 15.3 | 9.8 | 12.6 | 9.7 | 7.5 | 93.7 |
| Wy QGC | IS_IND | 5.7 | 3.8 | 6.0 | 6.3 | 4.4 | 6.6 | 6.3 | 3.6 | 3.9 | 4.0 | 3.2 | 3.5 | 57.3 |
| Wy QGC | L_and_U | 3.3 | 1.3 | 1.3 | 1.8 | 3.5 | 5.9 | 9.4 | 12.4 | 8.4 | 10.6 | 6.3 | 4.0 | 68.1 |
| Wy Wam | GS_COM | 3.2 | 1.4 | 1.4 | 1.8 | 3.4 | 5.8 | 11.0 | 16.0 | 10.0 | 11.0 | 6.7 | 3.8 | 75.6 |
| Wy Wam | GS_RES | 6.5 | 3.7 | 3.7 | 3.8 | 5.5 | 9.8 | 17.3 | 23.7 | 16.2 | 17.0 | 10.5 | 7.0 | 124.6 |
| Wy Wam | L_and_U | 0.2 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 0.6 | 0.8 | 0.5 | 0.6 | 0.3 | 0.2 | 4.1 |
| Total Demand | | 5355.0 | 2872.4 | 3106.7 | 3227.1 | 5029.5 | 8586.1 | 15395.7 | 21546.1 | 14296.9 | 15278.0 | 9450.3 | 5967.5 | 110111.2 |

Fuel Consumed

| | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transport | 306.1 | 297.2 | 289.6 | 287.5 | 320.4 | 331.8 | 462.2 | 476.4 | 357.8 | 458.7 | 312.3 | 320.4 | 4220.4 |
| Injection | 48.5 | 48.3 | 44.1 | 45.0 | 46.7 | 17.2 | 1.4 | 0.2 | 22.2 | 0.0 | 45.5 | 29.7 | 348.8 |
| Withdrawal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.3 | 0.3 | 0.7 | 26.1 | 0.0 | 0.0 | 28.7 |
| Total Fuel | 354.6 | 345.5 | 333.7 | 332.5 | 367.2 | 349.3 | 464.8 | 476.9 | 380.6 | 484.8 | 357.8 | 350.1 | 4597.8 |

Exhibit 9.88

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Storage Injections** | | | | | | | | | | | | | |
| Aquifer | 0.0 | 0.0 | 0.0 | 313.7 | 583.8 | 74.7 | 86.1 | 19.7 | 49.7 | 0.0 | 0.0 | 0.0 | 1127.7 |
| Clay Basin | 2439.6 | 2427.3 | 2217.4 | 1957.8 | 1851.8 | 815.0 | 16.0 | 0.0 | 1086.6 | 0.0 | 2289.3 | 1493.9 | 16594.7 |
| NE Other | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Injection | 2439.6 | 2427.3 | 2217.4 | 2271.6 | 2435.6 | 889.6 | 102.1 | 19.7 | 1136.3 | 0.0 | 2289.3 | 1493.9 | 17722.4 |
| Total Required | 8149.2 | 5645.2 | 5657.7 | 5831.1 | 7832.3 | 9825.0 | 15962.6 | 22042.7 | 15813.9 | 15762.9 | 12097.4 | 7811.5 | 132431.4 |

Natural Gas Requirements v. Supply

Units: MDT

| Sources of Supply | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pot Base Con | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5053.0 | 5239.0 | 4732.0 | 4464.0 | 1050.0 | 0.0 | 20538.0 |
| Spot | 2336.5 | 0.0 | 172.5 | 366.7 | 1888.6 | 3078.0 | 925.5 | 4935.6 | 5306.3 | 671.9 | 5254.7 | 1978.7 | 26915.0 |
| Pot Peak Con | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 688.4 | 23.4 | 1012.2 | 361.6 | 0.0 | 0.0 | 0.0 | 2085.6 |
| Total Take | 2336.5 | 0.0 | 172.5 | 366.7 | 1888.6 | 3766.3 | 6001.9 | 11186.9 | 10399.9 | 5135.9 | 6304.7 | 1978.7 | 49538.6 |
| **Storage Withdrawals** | | | | | | | | | | | | | |
| Company | 5669.1 | 5643.7 | 5483.6 | 5462.2 | 5938.2 | 5705.4 | 5859.2 | 5822.2 | 5225.7 | 5751.7 | 5522.4 | 5693.6 | 67777.0 |
| Aquifer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 25.1 | 86.1 | 19.7 | 49.7 | 1124.7 | 0.0 | 0.0 | 1305.3 |
| Clay Basin | 137.4 | 0.0 | 0.0 | 0.0 | 0.0 | 315.8 | 3990.3 | 4977.0 | 115.0 | 3725.6 | 256.1 | 131.6 | 13648.9 |
| Total Withdrawals | 5806.5 | 5643.7 | 5483.6 | 5462.2 | 5938.2 | 6046.3 | 9935.5 | 10818.9 | 5390.5 | 10601.9 | 5778.5 | 5825.3 | 82731.1 |
| Total Supply | 8143.0 | 5643.7 | 5656.2 | 5828.9 | 7826.8 | 9812.6 | 15937.4 | 22005.8 | 15790.4 | 15737.8 | 12083.2 | 7803.9 | 132269.7 |
| Req. minus Supply | 6.2 | 1.5 | 1.5 | 2.2 | 5.5 | 12.4 | 25.2 | 36.9 | 23.5 | 25.1 | 14.2 | 7.6 | 161.7 |
| **Unsupplied Demand** | | | | | | | | | | | | | |
| FS_COM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| FS_IND | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GS_COM | 3.0 | 0.0 | 0.0 | 1.8 | 0.1 | 5.8 | 9.4 | 13.2 | 9.2 | 9.6 | 4.4 | 0.6 | 57.1 |
| GS_RES | 3.0 | 1.4 | 1.4 | 0.3 | 5.3 | 6.6 | 15.8 | 23.7 | 14.4 | 15.5 | 9.8 | 6.9 | 104.1 |
| IS_COM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IS_ELC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IS_IND | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| L_and_U | 0.2 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 |
| | 6.2 | 1.5 | 1.5 | 2.2 | 5.4 | 12.4 | 25.2 | 36.9 | 23.6 | 25.1 | 14.2 | 7.5 | 161.7 |

Exhibit 9.83

Base Case Gas Supply : IRP Year 1
Mdth : Wellhead

**Nomination Group**

| | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 100D24CBFR | 17.3 | 17.3 | 15.4 | 16.5 | 17.5 | 16.8 | 17.3 | 17.2 | 15.5 | 17.1 | 15.9 | 16.9 | 200.7 |
| 100MXHWAP1-3 | 101.8 | 27.2 | 3.4 | 0.0 | 105.3 | 100.9 | 103.4 | 102.5 | 91.8 | 100.8 | 93.7 | 99.5 | 930.3 |
| 100MXHWAP2 | 63.9 | 65.4 | 56.5 | 60.1 | 63.6 | 60.9 | 62.4 | 61.8 | 55.3 | 60.7 | 56.6 | 59.8 | 727.0 |
| 100MXMOSU | 7.6 | 7.9 | 7.9 | 7.6 | 7.8 | 7.5 | 7.7 | 7.7 | 6.9 | 7.7 | 7.4 | 7.6 | 91.3 |
| 100MXMUSCOMP | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.1 | 0.7 |
| 100MXPDW1A1B | 41.9 | 41.7 | 1.4 | 0.0 | 42.7 | 41.0 | 42.1 | 41.8 | 37.5 | 41.3 | 38.4 | 40.8 | 410.6 |
| 100MXPDWMT | 23.3 | 23.6 | 23.0 | 21.7 | 21.9 | 20.6 | 20.8 | 20.3 | 17.9 | 19.4 | 18.4 | 18.7 | 249.6 |
| 100MXPDWPLT2 | 260.0 | 266.5 | 254.7 | 249.6 | 258.8 | 248.0 | 254.0 | 251.8 | 225.4 | 247.5 | 237.6 | 243.9 | 2997.8 |
| 100MXPDWPLT3 | 105.7 | 108.4 | 107.5 | 103.2 | 105.7 | 101.5 | 104.1 | 103.3 | 92.6 | 101.8 | 97.8 | 100.5 | 1232.1 |
| 100PC SGRLF | 50.9 | 0.0 | 1.7 | 0.0 | 53.8 | 51.6 | 52.9 | 52.5 | 47.0 | 51.7 | 48.0 | 51.0 | 461.1 |
| 100PCCBFR | 65.6 | 65.3 | 10.7 | 0.0 | 66.8 | 64.2 | 66.0 | 65.6 | 58.9 | 64.8 | 60.3 | 64.2 | 652.4 |
| 100PCNBXCAMP | 6.8 | 6.7 | 6.0 | 0.0 | 6.9 | 6.6 | 6.8 | 6.8 | 6.1 | 6.7 | 6.2 | 6.6 | 72.2 |
| 100PCNOBXFLD | 3.8 | 0.0 | 0.1 | 0.0 | 4.0 | 3.9 | 4.0 | 3.9 | 3.5 | 3.9 | 3.6 | 3.7 | 34.4 |
| 100PCWHWA | 115.4 | 118.3 | 117.1 | 112.2 | 114.8 | 110.0 | 112.7 | 111.7 | 100.0 | 109.8 | 105.4 | 108.2 | 1335.6 |
| 100PCWWILSON | 27.0 | 0.0 | 0.9 | 0.0 | 28.6 | 27.4 | 28.1 | 28.0 | 25.1 | 27.6 | 25.6 | 27.3 | 245.6 |
| ACEJDPC | 39.8 | 40.9 | 40.6 | 39.0 | 40.0 | 38.4 | 39.4 | 39.1 | 35.1 | 38.6 | 37.2 | 38.2 | 466.3 |
| BIRCH CREEK | 237.4 | 244.1 | 242.6 | 233.3 | 239.6 | 230.4 | 236.8 | 235.5 | 211.5 | 232.9 | 224.3 | 230.9 | 2799.3 |
| BKSPR UNIT 6 | 3.6 | 3.6 | 3.6 | 3.4 | 3.5 | 3.4 | 3.4 | 3.4 | 3.0 | 3.3 | 3.2 | 3.3 | 40.7 |
| BRADYD24 | 53.0 | 54.1 | 53.2 | 50.7 | 51.5 | 49.0 | 50.0 | 49.2 | 43.8 | 47.9 | 45.8 | 46.8 | 595.0 |
| BRADYTAPJACK | 6.7 | 6.9 | 6.8 | 6.5 | 6.6 | 6.3 | 6.5 | 6.4 | 5.7 | 6.3 | 6.0 | 6.2 | 76.9 |
| BRFD24M | 1.8 | 1.9 | 1.9 | 1.8 | 1.8 | 1.7 | 1.8 | 1.8 | 1.6 | 1.7 | 1.7 | 1.7 | 21.2 |
| BRFD24Q | 305.9 | 313.2 | 309.8 | 296.5 | 303.1 | 290.0 | 296.8 | 293.9 | 262.8 | 288.3 | 276.6 | 283.8 | 3520.7 |
| BRFD24QMT | 36.4 | 37.4 | 37.1 | 35.7 | 36.6 | 35.1 | 36.1 | 35.8 | 32.1 | 35.3 | 34.0 | 35.0 | 426.6 |
| BRFD24W | 183.6 | 187.7 | 185.3 | 177.1 | 180.7 | 172.7 | 176.5 | 174.5 | 155.8 | 170.7 | 163.5 | 167.6 | 2095.7 |
| BRFPCQ | 47.0 | 48.2 | 47.8 | 45.9 | 47.1 | 45.2 | 46.3 | 46.0 | 41.2 | 45.3 | 43.6 | 44.8 | 548.4 |
| BRFPCW | 8.0 | 8.2 | 8.1 | 7.8 | 8.0 | 7.7 | 7.9 | 7.8 | 7.0 | 7.7 | 7.4 | 7.6 | 93.2 |
| CBU BUFFER | 5.0 | 5.1 | 5.1 | 4.9 | 5.0 | 4.8 | 4.9 | 4.9 | 4.4 | 4.8 | 4.6 | 4.8 | 58.3 |
| CBU CAT 1 | 63.0 | 64.7 | 64.2 | 61.7 | 63.2 | 60.7 | 62.4 | 62.0 | 55.6 | 61.2 | 58.9 | 60.5 | 738.1 |
| CBU CAT 2-3 | 536.4 | 549.9 | 544.6 | 522.0 | 534.3 | 512.0 | 524.7 | 520.1 | 465.8 | 511.5 | 491.3 | 504.4 | 6217.0 |
| CCRUNITSWEX | 308.7 | 317.1 | 314.9 | 302.5 | 310.4 | 298.2 | 306.3 | 304.3 | 273.1 | 300.6 | 289.3 | 297.5 | 3622.9 |
| DRYPINEY6 | 3.7 | 3.8 | 3.7 | 3.6 | 3.7 | 3.5 | 3.6 | 3.6 | 3.2 | 3.5 | 3.4 | 3.5 | 42.8 |
| DRYPINEYUNIT | 31.6 | 32.5 | 32.2 | 31.0 | 31.7 | 30.5 | 31.3 | 31.1 | 27.9 | 30.7 | 29.5 | 30.3 | 370.3 |
| FOGARTYPC | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.6 | 0.7 | 0.6 | 0.7 | 8.2 |
| HIAWATH DEEP | 43.6 | 44.7 | 44.3 | 42.5 | 43.6 | 41.8 | 42.9 | 42.6 | 38.2 | 41.9 | 40.3 | 41.4 | 507.8 |
| ISLAND129 | 141.3 | 145.3 | 144.5 | 139.0 | 142.8 | 137.4 | 141.2 | 140.5 | 126.3 | 139.1 | 134.0 | 138.0 | 1669.4 |
| JHNRDG46-17 | 3.4 | 3.5 | 3.5 | 3.4 | 3.4 | 3.3 | 3.4 | 3.4 | 3.0 | 3.4 | 3.2 | 3.3 | 40.2 |
| JOHNSONRIDGE | 7.0 | 7.2 | 7.2 | 6.9 | 7.1 | 6.8 | 6.9 | 6.9 | 6.2 | 6.8 | 6.5 | 6.7 | 82.2 |
| KINNEY FLD | 20.6 | 21.2 | 18.4 | 19.7 | 21.0 | 20.2 | 20.8 | 20.7 | 18.6 | 20.6 | 19.2 | 20.5 | 241.5 |
| LEUCITE PC | 2.9 | 3.0 | 3.0 | 2.9 | 2.9 | 2.8 | 2.9 | 2.9 | 2.6 | 2.9 | 2.8 | 2.9 | 34.5 |
| MESA | 1370.2 | 1403.8 | 1389.6 | 1331.0 | 1361.6 | 1304.0 | 1335.4 | 1323.2 | 1184.2 | 1299.9 | 1247.9 | 1280.7 | 15831.5 |
| MIDBAXCOMP | 4.4 | 4.4 | 3.9 | 0.0 | 4.5 | 4.3 | 4.4 | 4.4 | 4.0 | 4.4 | 4.1 | 4.3 | 47.1 |
| RABBITMTN | 12.4 | 0.0 | 0.4 | 0.0 | 13.1 | 12.6 | 12.9 | 12.7 | 11.4 | 12.5 | 11.6 | 12.3 | 111.9 |
| SBX SWEET | 5.3 | 5.4 | 5.4 | 5.2 | 5.3 | 5.1 | 5.2 | 5.2 | 4.6 | 5.1 | 4.9 | 5.1 | 61.8 |
| SBXSOUR | 7.1 | 7.3 | 6.4 | 6.8 | 7.2 | 7.0 | 7.2 | 7.2 | 6.5 | 7.1 | 6.7 | 7.1 | 83.6 |
| TRAIL | 121.2 | 124.6 | 123.7 | 118.9 | 122.1 | 117.3 | 120.5 | 119.8 | 107.5 | 118.4 | 114.0 | 117.2 | 1425.2 |
| WAMSUTTER | 3.6 | 3.7 | 3.7 | 3.6 | 3.6 | 3.5 | 3.6 | 3.6 | 3.2 | 3.5 | 3.4 | 3.5 | 42.5 |
| z ND 2010 | 1162.7 | 1201.4 | 1220.8 | 1387.8 | 1434.1 | 1387.8 | 1434.1 | 1434.1 | 1295.3 | 1434.1 | 1387.8 | 1434.1 | 16214.1 |
| | 5669.1 | 5643.8 | 5483.3 | 5462.7 | 5938.0 | 5705.2 | 5859.2 | 5822.3 | 5225.4 | 5751.6 | 5522.2 | 5693.5 | 67776.3 |

Mdth : CityGate

**Storage Withdrawals**

| | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chalk Creek | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 33.1 | 0.0 | 0.0 | 321.0 | 0.0 | 0.0 | 354.1 |
| Clay Basin | 137.4 | 0.0 | 0.0 | 0.0 | 0.0 | 315.8 | 3990.3 | 4977.0 | 115.0 | 3725.6 | 256.1 | 131.6 | 13648.8 |
| Coalville | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 25.1 | 53.0 | 19.7 | 49.7 | 360.2 | 0.0 | 0.0 | 507.7 |
| Leroy | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 443.5 | 0.0 | 0.0 | 443.5 |
| | 137.4 | 0.0 | 0.0 | 0.0 | 0.0 | 340.9 | 4076.4 | 4996.7 | 164.7 | 4850.3 | 256.1 | 131.6 | 14954.1 |

Exhibit 9.84

Base Case Gas Supply : IRP Year 1

Mdth : Wellhead

| Source | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| d - Spot | 100.0 | 0.0 | 72.5 | 366.7 | 0.0 | 2972.3 | 121.0 | 2015.6 | 2773.7 | 54.3 | 2900.0 | 1907.7 | 13283.8 |
| d - SpotKR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 105.6 | 0.0 | 0.0 | 0.0 | 0.0 | 100.6 | 4.9 | 211.1 |
| d - SpotKRCG | 20.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.2 |
| Spot | 2201.6 | 0.0 | 100.0 | 0.0 | 1877.1 | 0.0 | 764.5 | 2900.0 | 2532.6 | 617.6 | 2244.1 | 66.1 | 13303.6 |
| SpotKR | 14.7 | 0.0 | 0.0 | 0.0 | 11.6 | 0.0 | 40.0 | 20.0 | 0.0 | 0.0 | 10.0 | 0.0 | 96.3 |
| Existing 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 930.0 | 930.0 | 840.0 | 930.0 | 900.0 | 0.0 | 4530.0 |
| Existing 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 186.0 | 168.0 | 186.0 | 0.0 | 0.0 | 540.0 |
| Existing 3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 155.0 | 150.0 | 0.0 | 755.0 |
| RFP Contract 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 23.4 | 536.4 | 190.5 | 0.0 | 0.0 | 0.0 | 750.3 |
| RFP Contract 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 155.0 | 0.0 | 0.0 | 605.0 |
| RFP Contract 3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 248.0 | 248.0 | 224.0 | 248.0 | 0.0 | 0.0 | 968.0 |
| RFP Contract 4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 1.7 | 0.0 | 0.0 | 0.0 | 41.7 |
| RFP Contract 5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 465.0 | 465.0 | 420.0 | 465.0 | 0.0 | 0.0 | 1815.0 |
| RFP Contract 6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 165.0 | 43.2 | 0.0 | 0.0 | 0.0 | 208.2 |
| RFP Contract 7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 0.0 | 0.0 | 0.0 | 450.0 |
| RFP Contract 8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 20.0 | 0.0 | 0.0 | 0.0 | 40.0 |
| RFP Contract 9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| RFP Contract 10 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 109.5 | 0.0 | 11.2 | 0.0 | 0.0 | 0.0 | 0.0 | 120.7 |
| RFP Contract 11 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 155.0 | 0.0 | 0.0 | 605.0 |
| RFP Contract 12 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 0.0 | 0.0 | 0.0 | 450.0 |
| RFP Contract 13 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 578.9 | 0.0 | 70.2 | 66.1 | 0.0 | 0.0 | 0.0 | 715.2 |
| RFP Contract 14 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 40.0 | 0.0 | 0.0 | 0.0 | 80.0 |
| RFP Contract 15 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| RFP Contract 16 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 465.0 | 465.0 | 420.0 | 465.0 | 0.0 | 0.0 | 1815.0 |
| RFP Contract 17 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 140.0 | 155.0 | 0.0 | 0.0 | 605.0 |
| RFP Contract 18 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| RFP Contract 19 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 69.5 | 0.0 | 0.0 | 0.0 | 0.0 | 69.5 |
| RFP Contract 20 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 465.0 | 465.0 | 420.0 | 0.0 | 0.0 | 0.0 | 1350.0 |
| RFP Contract 21 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1550.0 | 1550.0 | 1400.0 | 1550.0 | 0.0 | 0.0 | 6050.0 |
| | 2336.5 | 0.0 | 172.5 | 366.7 | 1888.7 | 3766.3 | 6001.9 | 11186.9 | 10399.8 | 5135.9 | 6304.7 | 1978.7 | 49538.6 |

Mdth : CityGate

| Storage Injection | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chalk Creek | 0.0 | 0.0 | 0.0 | 0.0 | 271.4 | 49.6 | 33.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 354.1 |
| Clay Basin | 2439.6 | 2427.3 | 2217.4 | 1957.8 | 1851.8 | 815.0 | 16.0 | 0.0 | 1086.6 | 0.0 | 2289.3 | 1493.9 | 16594.7 |
| Coalville | 0.0 | 0.0 | 0.0 | 180.3 | 179.1 | 25.1 | 53.0 | 19.7 | 49.7 | 0.0 | 0.0 | 0.0 | 506.9 |
| Leroy | 0.0 | 0.0 | 0.0 | 133.4 | 133.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 266.8 |
| | 2439.6 | 2427.3 | 2217.4 | 2271.5 | 2435.7 | 889.7 | 102.1 | 19.7 | 1136.3 | 0.0 | 2289.3 | 1493.9 | 17722.5 |

Base Case Gas Supply : IRP Year 2
Mdth : Wellhead

Exhibit 9.85

**Nomination Group**

| | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 100D24CBFR | 16.3 | 16.2 | 0.5 | 0.0 | 16.7 | 16.1 | 16.5 | 16.4 | 15.3 | 15.8 | 15.7 | 15.6 | 161.2 |
| 100MXHWAP1-3 | 92.3 | 12.5 | 3.2 | 0.0 | 97.5 | 93.5 | 95.8 | 95.0 | 88.1 | 90.4 | 89.6 | 89.0 | 846.7 |
| 100MXHWAP2 | 57.4 | 56.8 | 28.1 | 55.9 | 57.3 | 55.0 | 56.2 | 55.7 | 51.6 | 53.0 | 52.5 | 52.1 | 631.6 |
| 100MXMOSU | 7.4 | 7.6 | 7.6 | 7.3 | 7.5 | 7.2 | 7.5 | 7.4 | 6.9 | 7.4 | 7.1 | 7.3 | 88.2 |
| 100MXMUSCOMP | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.6 |
| 100MXPDW1A1B | 37.9 | 29.9 | 1.3 | 0.0 | 40.0 | 38.5 | 39.5 | 39.2 | 36.4 | 37.4 | 37.2 | 37.0 | 374.3 |
| 100MXPDWMT | 17.7 | 17.8 | 17.4 | 16.4 | 16.6 | 15.7 | 15.8 | 15.4 | 14.1 | 14.7 | 13.9 | 14.1 | 189.8 |
| 100MXPDWPLT2 | 233.9 | 238.0 | 214.4 | 227.4 | 232.9 | 223.4 | 228.8 | 226.6 | 210.1 | 215.5 | 213.6 | 212.1 | 2676.8 |
| 100MXPDWPLT3 | 96.5 | 98.9 | 98.2 | 94.1 | 96.6 | 92.8 | 95.1 | 94.3 | 87.6 | 91.9 | 89.3 | 91.7 | 1126.9 |
| 100PC SGRLF | 47.3 | 1.6 | 1.6 | 0.0 | 50.1 | 46.5 | 49.3 | 48.9 | 45.3 | 46.5 | 46.2 | 45.9 | 429.2 |
| 100PCCBFR | 60.9 | 55.2 | 2.0 | 0.0 | 63.0 | 60.6 | 62.2 | 61.8 | 57.5 | 59.1 | 58.8 | 58.5 | 599.6 |
| 100PCNBXCAMP | 6.2 | 6.3 | 0.2 | 0.0 | 6.5 | 6.3 | 6.4 | 6.4 | 6.0 | 6.1 | 6.1 | 6.1 | 62.7 |
| 100PCNOBXFLD | 3.6 | 0.1 | 0.1 | 0.0 | 3.8 | 0.4 | 3.7 | 3.7 | 3.4 | 3.5 | 3.5 | 3.5 | 29.2 |
| 100PCWHWA | 103.8 | 106.2 | 105.3 | 100.8 | 103.3 | 99.1 | 101.4 | 100.5 | 93.2 | 98.7 | 94.7 | 97.1 | 1204.2 |
| 100PCWWILSON | 25.3 | 0.9 | 0.9 | 0.0 | 26.8 | 25.8 | 26.5 | 26.3 | 24.4 | 25.1 | 24.9 | 24.8 | 231.7 |
| ACEJDPC | 36.7 | 37.6 | 37.4 | 35.9 | 36.9 | 35.4 | 36.3 | 36.1 | 33.5 | 35.6 | 34.2 | 35.2 | 430.9 |
| BIRCH CREEK | 222.1 | 228.1 | 226.9 | 218.1 | 224.1 | 215.7 | 221.6 | 220.3 | 205.0 | 210.9 | 209.7 | 211.8 | 2614.4 |
| BKSPR UNIT 6 | 3.1 | 3.2 | 3.2 | 3.0 | 3.1 | 3.0 | 3.0 | 3.0 | 2.8 | 2.9 | 2.8 | 2.9 | 35.9 |
| BRADYD24 | 44.6 | 45.3 | 44.7 | 42.5 | 43.3 | 41.3 | 42.1 | 41.4 | 38.2 | 40.2 | 38.4 | 39.2 | 501.2 |
| BRADYTAPJACK | 5.9 | 6.0 | 6.0 | 5.7 | 5.8 | 5.6 | 5.7 | 5.7 | 5.2 | 5.5 | 5.3 | 5.4 | 68.0 |
| BRFD24M | 1.6 | 1.7 | 1.6 | 1.6 | 1.6 | 1.5 | 1.6 | 1.6 | 1.4 | 1.5 | 1.5 | 1.5 | 18.7 |
| BRFD24Q | 271.9 | 277.7 | 275.2 | 263.1 | 269.3 | 258.1 | 263.9 | 261.2 | 242.0 | 256.1 | 245.4 | 251.5 | 3135.5 |
| BRFD24QMT | 33.6 | 34.5 | 34.2 | 32.9 | 33.7 | 32.4 | 33.3 | 33.1 | 30.7 | 32.6 | 31.3 | 32.2 | 394.6 |
| BRFD24W | 160.3 | 163.5 | 161.8 | 154.4 | 157.8 | 151.0 | 154.2 | 152.4 | 140.9 | 149.0 | 142.5 | 145.9 | 1833.7 |
| BRFPCQ | 43.0 | 44.1 | 43.8 | 42.0 | 43.1 | 41.4 | 42.5 | 42.1 | 39.1 | 41.5 | 39.9 | 41.0 | 503.5 |
| BRFPCW | 7.3 | 7.5 | 7.4 | 7.1 | 7.3 | 7.0 | 7.2 | 7.2 | 6.6 | 7.0 | 6.8 | 7.0 | 85.5 |
| CBU BUFFER | 4.6 | 4.7 | 4.7 | 4.5 | 4.6 | 4.4 | 4.5 | 4.5 | 4.2 | 4.4 | 4.3 | 4.4 | 53.7 |
| CBU CAT 1 | 58.2 | 59.7 | 59.3 | 56.9 | 58.4 | 56.2 | 57.7 | 57.3 | 53.2 | 56.5 | 54.3 | 55.8 | 683.6 |
| CBU CAT 2-3 | 483.9 | 495.1 | 491.1 | 470.3 | 481.9 | 462.4 | 473.5 | 469.3 | 435.2 | 461.3 | 442.5 | 454.0 | 5620.5 |
| CCRUNITSWEX | 286.0 | 293.4 | 291.6 | 280.1 | 287.6 | 276.6 | 283.9 | 282.0 | 262.1 | 278.5 | 267.8 | 275.2 | 3364.8 |
| DRYPINEY6 | 3.3 | 3.4 | 3.4 | 3.3 | 3.4 | 3.2 | 3.3 | 3.3 | 3.0 | 3.2 | 3.1 | 3.2 | 39.2 |
| DRYPINEYUNIT | 29.2 | 29.9 | 29.7 | 28.5 | 29.3 | 28.1 | 28.9 | 28.7 | 26.6 | 28.3 | 27.2 | 27.9 | 342.1 |
| FOGARTYPC | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.5 | 0.6 | 0.6 | 0.6 | 7.2 |
| HIAWATH DEEP | 39.8 | 40.8 | 40.5 | 38.8 | 39.8 | 38.2 | 39.2 | 38.9 | 36.1 | 38.3 | 36.8 | 37.8 | 464.8 |
| ISLAND129 | 132.8 | 136.4 | 135.8 | 130.6 | 134.2 | 129.2 | 132.8 | 132.1 | 122.9 | 130.8 | 125.9 | 129.5 | 1573.0 |
| JHNRDG46-17 | 3.2 | 3.3 | 3.3 | 3.1 | 3.2 | 3.1 | 3.2 | 3.2 | 2.9 | 3.1 | 3.0 | 3.1 | 37.8 |
| JOHNSONRIDGE | 6.5 | 6.6 | 6.6 | 6.3 | 6.5 | 6.2 | 6.4 | 6.3 | 5.9 | 6.2 | 6.0 | 6.1 | 75.5 |
| KINNEY FLD | 19.7 | 19.7 | 0.7 | 19.6 | 20.2 | 19.4 | 20.0 | 19.9 | 18.6 | 19.2 | 19.1 | 19.0 | 215.0 |
| LEUCITE PC | 2.8 | 2.8 | 2.8 | 2.7 | 2.8 | 2.7 | 2.8 | 2.8 | 2.6 | 2.7 | 2.6 | 2.7 | 32.8 |
| MESA | 1227.8 | 1255.4 | 1244.6 | 1191.1 | 1220.0 | 1169.8 | 1197.4 | 1186.0 | 1099.3 | 1164.4 | 1116.5 | 1145.0 | 14217.3 |
| MIDBAXCOMP | 4.0 | 4.1 | 0.1 | 0.0 | 4.2 | 4.1 | 4.2 | 4.2 | 3.9 | 4.0 | 4.0 | 4.0 | 40.8 |
| RABBITMTN | 11.4 | 0.4 | 0.4 | 0.0 | 12.1 | 1.2 | 12.0 | 11.9 | 11.0 | 11.3 | 11.2 | 11.1 | 93.8 |
| SBX SWEET | 4.9 | 5.0 | 5.0 | 4.8 | 4.9 | 4.7 | 4.8 | 4.8 | 4.4 | 4.6 | 4.5 | 4.5 | 56.7 |
| SBXSOUR | 6.8 | 6.8 | 0.2 | 6.8 | 7.0 | 6.8 | 7.0 | 6.9 | 6.5 | 6.7 | 6.7 | 6.6 | 74.8 |
| TRAIL | 112.8 | 115.7 | 115.0 | 110.5 | 113.5 | 109.2 | 112.1 | 111.4 | 103.6 | 110.1 | 105.9 | 108.9 | 1328.9 |
| WAMSUTTER | 3.4 | 3.4 | 3.4 | 3.3 | 3.4 | 3.3 | 3.3 | 3.3 | 3.1 | 3.3 | 3.1 | 3.2 | 39.6 |
| z ND 2010 | 972.2 | 1004.6 | 1004.6 | 972.2 | 1004.6 | 972.2 | 1004.6 | 1004.6 | 939.8 | 1004.6 | 972.2 | 1004.6 | 11860.6 |
| z ND 2011 | 615.0 | 635.5 | 635.5 | 615.0 | 635.5 | 1286.9 | 1432.0 | 1432.0 | 1339.6 | 1432.0 | 1385.8 | 1432.0 | 12876.9 |
| | 5665.6 | 5624.5 | 5401.9 | 5257.2 | 5722.3 | 6161.8 | 6450.4 | 6415.8 | 5970.4 | 6322.1 | 6114.1 | 6267.7 | 71373.8 |

Mdth : CityGate

| Storage Withdrawal | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chalk Creek | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Clay Basin | 144.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2508.5 | 857.7 | 198.1 | 386.9 | 4888.8 | 1300.1 | 10284.4 |
| Coalville | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.5 | 0.0 | 360.2 | 0.0 | 367.7 |
| Leroy | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 12.8 | 130.8 | 0.0 | 143.6 |
| | 144.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2508.5 | 857.7 | 205.6 | 399.7 | 5379.8 | 1300.1 | 10795.8 |

Exhibit 9.86

Base Case Gs Supply : IRP Year 2

Mdth : Wellhead

| Source | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| a IT Supply | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 148.7 | 225.4 | 125.9 | 0.0 | 0.0 | 500.0 |
| d - Spot | 17.9 | 0.0 | 100.0 | 283.7 | 0.0 | 2929.5 | 76.6 | 2854.9 | 2800.0 | 591.7 | 76.1 | 100.0 | 9830.4 |
| d - SpotKR | 0.0 | 0.0 | 1.8 | 0.0 | 0.0 | 44.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 45.8 |
| Spot | 100.0 | 51.5 | 100.0 | 0.0 | 1699.9 | 237.1 | 2930.7 | 3065.9 | 2872.5 | 3000.0 | 704.9 | 70.8 | 14833.3 |
| SpotKR | 0.0 | 0.0 | 10.0 | 0.0 | 40.0 | 0.0 | 10.6 | 0.0 | 50.0 | 0.0 | 0.0 | 0.0 | 110.6 |
| Existing 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 145.0 | 155.0 | 150.0 | 0.0 | 760.0 |
| SXM090M100 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1910.3 | 1787.0 | 1910.3 | 0.0 | 0.0 | 5607.5 |
| SXM120M100 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2035.5 | 2035.5 | 1904.2 | 2035.5 | 0.0 | 0.0 | 8010.7 |
| RFP Contract 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 145.0 | 0.0 | 0.0 | 0.0 | 455.0 |
| RFP Contract 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 | 145.0 | 0.0 | 0.0 | 0.0 | 455.0 |
| RFP Contract 3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 250.0 | 0.0 | 0.0 | 0.0 | 250.0 |
| | 117.9 | 51.5 | 211.8 | 283.7 | 1739.9 | 3210.6 | 5518.4 | 10480.3 | 10324.1 | 7818.4 | 931.0 | 170.8 | 40858.4 |

Mdth : CityGate

**Storage Injection**

| | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chalk Creek | 0.0 | 0.0 | 0.0 | 0.0 | 134.9 | 186.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 321.0 |
| Clay Basin | 1081.4 | 2270.3 | 2103.6 | 1844.2 | 1726.8 | 1091.2 | 0.0 | 52.8 | 859.7 | 58.8 | 26.2 | 184.5 | 11299.5 |
| Coalville | 0.0 | 0.0 | 0.0 | 179.2 | 173.5 | 7.5 | 0.0 | 0.0 | 7.5 | 0.0 | 0.0 | 0.0 | 367.7 |
| Leroy | 0.0 | 0.0 | 0.0 | 137.5 | 288.9 | 17.1 | 0.0 | 0.0 | 0.0 | 12.8 | 0.0 | 0.0 | 456.3 |
| | 1081.4 | 2270.3 | 2103.6 | 2160.9 | 2324.1 | 1301.9 | 0.0 | 52.8 | 867.2 | 71.6 | 26.2 | 184.5 | 12444.5 |

# GENERAL IRP GUIDELINES/GOALS FOR GAS SUPPLY AND ENERGY EFFICIENCY RESOURCES

Questar Gas has compiled a list of general guidelines to help direct the day-to-day decision-making processes of the Company 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 SENDOUT model is used to help reassess the appropriate mix of market resources. The guidelines for this year are as follows:

- Generally produce approximately 67.7 million Dth of cost-of-service gas, recognizing the uncertainties associated with demand, operating conditions, and gas well productivity.
- Generally produce the categories of cost-of-service gas as determined this year in the modeling exercise as contained in Exhibit 9.3.
- Purchase a balanced portfolio of gas of approximately 49.5 million Dth.
- Accommodate deviations from normal weather with purchased gas and the use of existing storage to the extent possible.
- 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 normal conditions in the modeling simulation.
- Undertake price stabilization measures for purchased gas contracts to mitigate the risk of volatility in the marketplace.
- In Utah and Wyoming, continue to incorporate cost-effective energy-efficiency measures.

# APPENDIX A

**Questar Gas Company**
**Considerations Affecting Production Shut-Ins**

## Background

In early November, 2009, representatives of Questar Gas Company (Questar Gas or the Company) met with representatives of the Utah Division of Public Utilities (Division). Among the matters discussed were factors influencing the decision to shut-in cost-of-service production, particularly during periods of time when the prevailing market prices of natural gas are relatively low. Such shut-ins have occurred in the past and most recently, during the summer and fall of 2009. At the conclusion of the early November meeting, the Division requested a report outlining these factors and containing simplified illustrative analyses for several cost-of-service production sources (described in more detail later).

Also, during November and December of 2009, discussions took place between representatives of the Company and various Commissioners and/or Commission Staff serving with both the Utah Public Service Commission and the Public Service Commission of Wyoming where similar topics were discussed. This report is provided in direct response to the request of the Division and also to answer questions and clarify issues raised in recent regulatory discussions in Wyoming and Utah.

## Executive Summary

The analysis required to determine whether to shut-in cost-of-service production is relatively complex and sophisticated modeling tools should be used. Multiple factors must be considered in the decision-making process including: operational constraints, intergenerational equity considerations, producer imbalances, and the general well costs.

It is inappropriate, at any point in time, to compare the current cost of cost-of-service supplies with the price of market gas in making a decision to shut in production (metaphorically, a comparison of apples with oranges). In some years, cost-of-service production, on a per-unit basis, can be more expensive than the price of market-based purchased-gas, and still minimize overall gas costs over the long term. It also may be economically appropriate from time to time, depending on current market prices and expected future prices, to temporarily shut in certain sources of cost-of-service gas, when other factors do not govern, and save these supplies for later use.

## Introduction

Since 1981, the customers of Questar Gas have benefitted from cost-of-service natural gas production supplied pursuant to the Wexpro Agreement.[1] One of the major

[1] "The Wexpro Stipulation and Agreement," Executed October 14, 1981, Approved October 28, 1981, by Public Service Commission of Wyoming and December 31, 1981, by Public Service Commission of Utah; Parties:

contributing factors in keeping Questar Gas' rates among the lowest in the nation has been the availability of this low-cost resource. Natural gas, under the Wexpro Agreement, is provided according to a traditional cost-of-service methodology. Although some components of this cost-of-service methodology are subject to price volatility and inflation, the overall cost of this production over the long term has been more stable and lower priced than market gas.

As part of its integrated resource planning exercise engaged in each year, Questar Gas performs a modeling analysis to determine the appropriate utilization of this resource.[2] Because cost-of-service production is a long-term resource which can last for decades, it is important to engage in a relatively long-term analysis. Questar Gas utilizes a computer-based linear-programming modeling tool (SENDOUT) to evaluate both supply-side and demand-side resources over a 21-year modeling time horizon.

Several key decision-making factors are considered when determining whether to produce or shut-in cost-of-service supplies. Some of these factors can be quantitatively modeled in SENDOUT whereas others must be evaluated externally. In the remaining sections of this report, the following topics will be discussed; operational constraints, intergenerational equity considerations, producer imbalances, and the fundamental underlying cost-based economics. To facilitate discussion of concepts, a brief glossary of terms is included as Exhibit A.

**Operational Constraints**

Operational constraints must be considered in the production shut-in decision. When a new well is drilled, hydraulic fracturing techniques are often undertaken to enhance production. If new wells are not produced continuously at the outset, damage can occur to the reservoir which may be permanent, or at a minimum, very expensive to remedy. Older wells, if shut in for long periods of time, can also be damaged. In some fields, wells with differing working interest partners may be drawing from an interconnected reservoir. If one well is shut in, economic value may be permanently lost to the working interest owners in adjacent wells. This is referred to as "drainage," and wells subject to this phenomenon must be produced continuously. In these situations, production groups must be created for similar wells and modeled as "must take" categories.

Some gas wells have associated oil production and must be continuously produced. Other wells may have down-hole problems requiring continuous production, or are required to remain on to provide fuel for compressors or "camp gas." Some wells must be on due to casing problems, a tendency to load up with water or paraffin, or a tendency to freeze up.

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Mountain Fuel Supply Company, Wexpro Company, Utah Department of Business Regulations, Division of Public Utilities, Utah Committee of Consumer Services, and Staff of Wyoming Public Service Commission.
[2] Questar Gas Company Integrated Resource Plan (For Plan Year: May 1, 2009 to April 30, 2010), Submitted: May 4, 2009.

Wexpro reservoir and production engineers and operating personnel communicate regularly with Questar Gas personnel on all wells which must be continuously produced.

Situations also occur where wells must be shut-in due to operational reasons. For example, during the summer months, Questar Gas nominates substantial quantities of cost-of-service gas for injection into Questar Pipeline's Clay Basin storage facility. Some years ago, a lightning strike disabled equipment at Clay Basin necessitating the shut-in, for a number of days, of cost-of-service gas which had been flowing to Clay Basin, until parts could be acquired and installed. Likewise equipment failures in processing, gathering, and or interstate pipeline facilities can necessitate cost-of-service gas shut-ins.

## Intergenerational Equity Considerations

Extended shut-ins of cost-of-service production are potentially a concern from the standpoint of intergenerational equity considerations. Intergenerational equity considerations are not new to the Company, or to regulatory agencies, and can exist any time asset lives extend over multiple generations of customers. Some assets can have useful lives long after they are fully depreciated. Natural gas wells can last for many decades. For example, wells drilled in the Church Buttes Field in the late 1940's are still producing significant quantities today. When wells are drilled, those costs are capitalized and booked as a depreciable asset. Typically, wells are amortized using the units-of-production depreciation method. This method involves the calculation of a depreciation rate which is determined each year based on net book plant and the total recoverable reserves. Adjustments to both of these numbers can occur over time for any well or field. As the well or field is produced, net book plant is adjusted accordingly.[3] If the well or field is not produced, the pretax rate of return authorized by the Wexpro Agreement is earned on an asset account that is not diminishing. This pretax return is referred to in this document as the "carrying cost" of a well or group of wells.[4] Natural gas that would have been produced during a shut-in is recovered gradually over the remaining life of the well which now has a slightly longer life than it had before giving rise to additional carrying costs. In the ratemaking process, it is impossible to be perfectly equitable with any long-term asset. But, the issue arises when one customer generation pays the carrying costs associated with the capitalized costs of a well, and another customer generation receives the benefit of the gas. As will be illustrated in a subsequent section of this report discussing fundamental underlying costs, the least-cost solution for cost-of-service production can include the conserving of natural gas for later years. Long-term continuous shut-ins are not likely to occur, however, with cost-of-service gas since the operating constraints discussed previously are likely to govern long before intergenerational equity issues become too problematic.

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[3] When actual recoverable reserves greatly exceed estimated reserves over time, the depreciation rate can approach zero.

[4] See Exhibit E of the Wexpro Agreement for the methodology to be used in calculating the monthly Operator Service Fee.

**Producer Imbalances**

*Definition and cause.*

In most of the wells where Questar Gas receives cost-of-service gas, 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 doesn't exist. No individual working interest owner can control, in the short term, the level of producer imbalances associated with a well because they do not have control over the volumes that their partners 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.

Further complicating matters is 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. 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 partners, 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. Also complicating the process is the fact that advance notice of several weeks is typically required before imbalance recoupment can begin to be nominated.

*Inability to model.*

The SENDOUT model was not designed to model producer imbalances. The complexity of relationships, the breadth of data, and the uncertainty of information regarding the intended production policies of working interest partners make it impractical to model. The fact that Questar Gas does not model individual wells in SENDOUT but rather models nomination groups consisting, in some cases, of many dozens of wells also makes it impractical. In Questar Gas' most recent IRP, 52 nomination groups were modeled. Some of these groups may contain numerous wells each of which is subject to balancing. Never-the-less, the impracticalities of modeling producer imbalances does not lessen the need to consider this factor in the production decision.

*Importance of consideration.*

Results of the SENDOUT model may suggest that certain categories of cost-of-service production remain on most of the time. If one or more working interest partners decide to not take their entitlements for any reason, it could create a situation where an imbalance level could be exacerbated. A similar result can ensue in the opposite situation where the SENDOUT model results suggest that Questar Gas not produce its entitlements from a relatively low carrying cost source for a short period of time (to take advantage of low cost market prices) while other working interest partners continue taking production which could also potentially exacerbate an imbalance. In these situations, the results of the SENDOUT model must be overridden. The fundamental underlying economics of cost-of-service supply sources will be explained in more detail in the next section.

**General Well Costs**

The economic evaluation of whether to produce or shut-in a gas-supply source is not trivial. Questar Gas for years has relied on SENDOUT, a sophisticated linear programming model, to facilitate the decision-making processes associated with the production of the Company's cost-of-service gas.[5] Even with all the capabilities of the SENDOUT model, simplifying assumptions must be made for cost-of-service production. Among the more complex relationships modeled are the production profiles that are typically modeled as a function of remaining reserves.

To facilitate discussion of the key economic factors in the production versus shut-in decision, a simplified illustrative spreadsheet model has been created in Excel. Exhibit B lists the assumptions utilized in the spreadsheet.

- The spreadsheet has a demand profile which must be met with only two sources of natural gas, purchased gas and cost-of-service gas.
- All available cost-of-service gas is used to meet demand with the remaining demand met with purchased gas.
- Even though cost-of-service sources typically last for decades, a ten-year time frame has been assumed for simplicity.
- Also assumed for simplicity is a straight-line relationship between the production rate and beginning reserves.[6]
- To avoid "end effects," it is assumed that no new reserves are added to the model, and, all cost-of-service natural gas (when available to the model) is produced during the ten year period.
- A decline rate has been selected that will allow for first-year cost-of-service production to be shut-in at various rates (including a 100 percent shut-in) without extending this production beyond the ten year time horizon.

The discounted (NPV) results of 13 scenarios are contained in Exhibit C, and will be discussed shortly. Exhibit D contains the detailed output for the 13 scenarios, each of which has unique assumptions.

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[5] See the "Introduction and Background" and the "Cost-of-Service Gas" sections of Questar Gas's 2009 IRP.

[6] Production from new wells produced continuously typically declines in a hyperbolic fashion over time. In SENDOUT, production is modeled independently of time as a linear function of remaining reserves. (Multiple linear segments can be used for each production category.) Production from wells shut-in can result in "flush production" for a short period of time which cannot be effectively modeled in SENDOUT.

The first scenario in Exhibit D, page 1 of 13, assumes no cost-of-service production is available causing only purchased gas to be used in meeting demand. Line 4 shows the annual demand profile which must be met. Line 8 shows the market price for purchased natural gas over the assumed ten year horizon. Lines 13 through 24 are of no relevance in this scenario since it has been assumed that no cost-of-service gas is available to the model. (Note: These lines calculate costs associated with cost-of-service gas.) Line 35 shows the purchased gas costs which for this scenario are the same as the total gas supply costs shown on line 37. On line 39, yearly costs expended to meet the demand profile are calculated and discounted back to time zero, using the discount rate on line 25, to facilitate comparison of costs in different time periods. In this case, where no cost-of-service gas is available, the cumulative discounted cost for gas supplies is $44,962 (see line 40). It should be pointed out at the outset that all the other scenarios assume cost-of-service gas is available. No other scenario modeled for this exercise has a higher discounted cost than this scenario as can be seen from the summary results in Exhibit C.

The second scenario shown in Exhibit D, page 2 of 13, assumes that cost-of-service production is available. Line 13 shows the beginning book basis each year for a higher-carrying-cost source of gas. Line 14 shows the beginning reserves and the calculated depreciation rate is shown on line 15. Line 19 shows the assumed annual production. The diminishing reserves each year can be seen on line 20, and line 21 shows the net plant (adjusted book basis). The pretax carrying cost (line 23) is calculated by multiplying the pre-tax rate of return by the average of the beginning and ending book bases for cost-of-service gas for the year. Starting with line 26, the total gas supply costs are shown. Using the data from lines 9 through 12, production taxes, royalties and variable production costs are calculated. The total cumulative discounted cost for this scenario is $41,414 (line 40). The key distinguishing features of this scenario are the 1) a first year purchased gas price of $5.00 per decatherm, 2) a beginning book basis of $5,000, 3) a first year production load factor of 100 percent for cost-of-service gas, and 4) a pre-tax cost-of-service rate of return of 30 percent. This data is generally consistent with a higher carrying-cost source of natural gas. The four boxes outlined on each scenario of Exhibit D in the "Year 1" column contain the four inputs to be varied for the remaining 11 scenarios of this analysis (see lines 8, 13, 18, and 22).

In Exhibit C, the cumulative discounted costs for each scenario have been compiled. Lines 3 through 5 show the results for a higher carrying-cost source of cost-of-service gas. Similar sources under the Wexpro Agreement have come to be known as "D-24" sources which are from developmental wells drilled after 1981. The allowed after-tax rate of return varies from year to year as prescribed in the Wexpro Agreement. In 1982, the allowed after-tax rate of return was approximately 24 percent, hence the reference "D-24". It should be pointed out that D-24 sources do not always have the highest depreciation rates even though drilling costs are typically higher than pre-1981 wells ("prior company" or "PC" wells). Some D-24 wells have such vast reserves that the associated depreciation rates are lower than PC wells. Lines 7 through 9 show cumulative discounted cost results for a lower carrying-cost source of cost-of-service gas more typical of PC wells. These scenarios show the results for first-year cost-of-service production load factors varying from 100 percent to zero percent for two first-year purchased gas prices of $5.00/Dth and $2.50/Dth. The higher carrying-cost scenarios show the cumulative discounted cost increasing as cost of service gas is shut-in in the first year for both first year prices of purchased gas. The assumptions used in this analysis suggest that, barring producer imbalance and operating considerations, this source of natural gas should remain on to minimize costs. It should be pointed out that for the $5.00/Dth first-year purchased gas price and 100 percent load factor scenario (Scenario #2), the average first-year cost of cost-of-service production is $5.55/Dth which is higher than the first-year purchased gas price of $5.00/Dth. Never-the-less, having this source of cost-of-service production available minimizes overall gas costs when compared with the 100 percent purchased-gas scenario.

As can be seen in each of these 13 scenarios, it is inappropriate to compare the average annual cost of cost-of-service production at any point in time with the price of market gas in making a shut-in decision. Shutting in cost-of-service production always incurs additional carrying costs which, for the higher carrying cost scenarios, results in higher overall cumulative discounted costs.[7] Total carrying costs and cumulative carrying costs are broken out in the scenarios included in Exhibit D.

Lines 7 through 9 of Exhibit C show cumulative discounted costs for a lower carrying-cost source of cost-of-service gas (similar to what might occur for a PC gas source). At the $5.00/Dth first-year purchased-gas price, decreasing load factor results in higher cumulative discounted costs. This would suggest that absent other considerations, this cost-of-service gas source should not be shut in. At a $2.50/Dth first-year purchased-gas price, however, a decreasing first-year production load factor results in a lower cumulative discounted cost (see line 9 of Exhibit C). This would suggest that in the absence of other considerations, this cost-of-service gas source should be shut in. This is the phenomenon which over the years has come to be known as the "husbanding" of cost-of-service natural gas. It is better in this case to forgo the benefit of lower-carrying cost gas in year one and purchase low-priced market sources and save this production to offset the need to purchase much higher priced gas in year ten.

It should be pointed out that although carrying cost has the biggest impact in most cases, any other cost can affect the decision to shut-in to some degree, hence the need for more sophisticated modeling tools such as SENDOUT where all resources with all their attendant costs can be analyzed together. In all of the analyses performed for this report involving cost-of-service natural gas, no variables have been modified from scenario to scenario other than the four previously identified (see data in the "Year 1" column of rows 8, 13, 18 and 22 in Exhibit D).

## Conclusions

The decision to shut in cost-of-service production is not trivial. The use of sophisticated tools such as the SENDOUT linear-programming model, are appropriate. A

[7] Assuming that net book plant is not zero, which would almost always be the case.

number of factors should be considered before making a decision to shut in cost-of-service production. Those factors include: operational constraints, intergenerational equity considerations, producer imbalances, and the general well costs.

It is improper to compare the average annual cost of cost-of-service production at any point in time with the price of market gas in making a shut-in decision because such a comparison fails to account for future carrying costs and the price of future market gas. It is also possible in some years for the average cost of cost-of-service production on a per-unit basis to exceed the market-based purchased-gas price and still minimize overall gas costs over the long term. It also may be economically appropriate to temporarily shut in low-carrying-cost sources of cost-of-service gas, when other factors do not govern, and "husband" these supplies for later use to take advantage of unusually low current market prices and to offset the purchase of expected higher prices in the future.

**Brief, Non-Technical Glossary**

Carrying Cost: As used in this document, carrying cost refers to the pretax return earned on the un-depreciated plant investment authorized by the Wexpro Stipulation and Agreement either on a total dollar basis or on a per decatherm basis. References to high and low carrying costs only have relevance on a per decatherm basis.

Cost-of-service production: A general reference to certain natural gas supplies from certain properties produced for the Company at a prescribed cost pursuant to the Wexpro Agreement. In previous years, this production has also been referred to by some as "Wexpro Gas" or "Company-Owned Gas."

D-24 Well: An acronym generally referring to a development gas well completed after July 31, 1981, in a productive gas reservoir that meets the cost and production criteria as specified in the Wexpro Stipulation and Agreement such that it can be designated a commercial well. The "24" is a reference to the approximately 24 percent after-tax rate-of-return-on-equity these wells were allowed to earn at the time the Wexpro Stipulation and Agreement was executed. This rate varies from year to year as governed by provisions in the Wexpro Agreement.

Drainage: The permanent loss of natural gas supplies from a working interest partner in one well to a working interest partner in another well where both wells draw from an interconnected reservoir.

Hydraulic Fracturing: A method of stimulating production from a formation by creating fractures through the application of extremely high fluid pressures. Fractures in the formation are typically maintained by injecting proppant into the formation. The proppant (such as grains of sand or ceramic material) prevents the fissures in the formation from closing when the injection of high pressure fluids is terminated.

Net book plant: Gross plant minus accumulated depreciation.

Nomination: A request for a quantity of natural gas over a specified period of time.

Prior Company Well: A well completed on or before July 31, 1981, and capitalized in the utility accounts of Mountain Fuel Supply Company (the predecessor of Questar Gas Company) on that date. See Schedule 3(b) of the Wexpro Stipulation and Agreement for a list of prior Company wells.

**Brief, Non-Technical Glossary (continued)**

Producer Imbalance: Producer imbalances arise from working interest partners taking volumes over time that differ from their legal entitlements. A producer imbalance consists of a cumulative accounting balance for each working interest partner in a well formation, or group of wells, designating the volume of natural gas owed to, or from, other working interest partners in the same well formation.

SENDOUT: A computer-based linear-programming modeling tool used by the Company to evaluate both supply-side and demand-side resources in meeting the natural gas requirements of its customers. SENDOUT is owned and maintained by Ventyx, a business solutions provider to global energy, utility and communications organizations.

Well shut-in: The process of electronically or manually actuating mechanical valves resulting in the cessation of natural gas production from a well.

Working interest partner: A partner in a well having specific ownership rights to minerals produced from that well.

**Assumptions**

1. Round numbers are generally used for simplicity.
2. Modeling focus is on relationships between variables and not on absolute numbers.
3. No specific category of cost-of-service gas or purchased-gas is modeled.
4. Modeling time frame is 10 years for simplicity.
5. Year one demand is 1,000 decatherms.
6. Demand is grown at two percent per year.
7. Year one purchased gas price is $5.00/Dth.
8. The purchased gas price is grown at four percent per year.
9. The production tax rate is ten percent (net of 12.5 percent government royalty).
10. The royalty rate is 15 percent.
11. Variable production costs start at $0.50/Dth and grow at three percent per year.
12. Fixed costs (less credits) are $175/year and grow at three percent per year.
13. Fixed costs are set to zero for the no-cost-of-service-gas scenario.
14. For higher carrying cost gas, the beginning book basis is $5,000.
15. For lower carrying cost gas, the beginning book basis is $450.
16. Beginning reserves are 5,000 decatherms.
17. Production is modeled as 11.11 percent of starting reserves (1/9 years) before the year-one override.
18. The pre-tax cost-of-service rate of return on investment for the higher carrying-cost scenarios is 30 percent.
19. The pre-tax cost-of-service rate of return on investment for the lower carrying-cost scenarios is 11.5 percent.
20. Assume an annual carrying-cost and cost-of-service calculation rather than monthly as is the case under the Wexpro Agreement.
21. The discount rate is 7 percent.
22. COS = Cost of Service
23. LF = Load Factor
24. Only the year one price is overridden with, for this exercise, a $2.50/Dth price.

**Summary of Discounted Results**

| Line # | | First-Year COS Gas Load Factor | | |
|---|---|---|---|---|
| 1 | **No Cost-of-Service Production** (Scenario #1) | $44,962 | | |
| 2 | **Higher Carrying-Cost Production** | | | |
| 3 | | 100% | 50% | 0% |
| 4 | First-Year Purchased Gas Price ($5.00/Dth) (Scenarios #2, #3, #4) | $41,414 | $42,006 | $42,599 |
| 5 | First-Year Purchased Gas Price ($2.50/Dth) (Scenarios #5, #6, #7) | $40,067 | $40,165 | $40,263 |
| 6 | **Lower Carrying-Cost Production** | | | |
| 7 | | 100% | 50% | 0% |
| 8 | First-Year Purchased Gas Price ($5.00/Dth) (Scenarios #8, #9, #10) | $32,932 | $33,125 | $33,319 |
| 9 | First-Year Purchased Gas Price ($2.50/Dth) (Scenarios #11, #12, #13) | $31,585 | $31,284 | $30,982 |

Note: COS = Cost-of-Service

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #1: No Cost-of-Service Production**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Beginning Book Basis COS Gas | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 16 | Production % of Starting Reserves | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 17 | Production (Dth) (L14*L16) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | First Year Production Load Factor | | 100% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 24 | Cumulative Carrying Cost | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 28 | Variable Costs (L11*L19) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | Depreciation (L15*L19) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 30 | Royalties (L10*L19*L8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 32 | Pre-Tax Carrying Cost | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | Total COS Gas Costs | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $5,000 | $5,304 | $5,626 | $5,969 | $6,331 | $6,716 | $7,125 | $7,558 | $8,017 | $8,505 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $5,000 | $5,304 | $5,626 | $5,969 | $6,331 | $6,716 | $7,125 | $7,558 | $8,017 | $8,505 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 39 | Discounted Total Cost | | $4,673 | $4,633 | $4,593 | $4,553 | $4,514 | $4,475 | $4,437 | $4,399 | $4,361 | $4,323 |
| 40 | Cumulative Discounted Cost | $44,962 | | | | | | | | | | |

Illustrative Production Shut-In Analysis
(Simplified Relationships, Rough Assumptions)

Scenario #2: Higher Carrying Cost, $5.00 Yr 1 Purch, 100% LF Yr 1 COS Gas



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| | | | | | | | | | | | | |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| | | | | | | | | | | | | |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| | | | | | | | | | | | | |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 18 | First Year Production Load Factor | | 100% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,417 | $1,250 | $1,083 | $917 | $750 | $583 | $417 | $250 | $83 | $0 |
| 24 | Cumulative Carrying Cost | | $1,417 | $2,667 | $3,750 | $4,667 | $5,417 | $6,000 | $6,417 | $6,667 | $6,750 | $6,750 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| | | | | | | | | | | | | |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 278 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 0 |
| 29 | Depreciation (L15*L19) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 30 | Royalties (L10*L19*L8) | | 417 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 0 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 243 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 0 |
| 32 | Pre-Tax Carrying Cost | | 1,417 | 1,250 | 1,083 | 917 | 750 | 583 | 417 | 250 | 83 | 0 |
| 33 | Total COS Gas Costs | | $3,085 | $2,958 | $2,833 | $2,709 | $2,587 | $2,466 | $2,348 | $2,231 | $2,115 | $228 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $5.55 | $5.32 | $5.10 | $4.88 | $4.66 | $4.44 | $4.23 | $4.02 | $3.81 | n.a. |
| | | | | | | | | | | | | |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $2,222 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $8,505 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| | | | | | | | | | | | | |
| 37 | Total Costs (L33+L35) | | $5,307 | $5,373 | $5,455 | $5,553 | $5,669 | $5,803 | $5,958 | $6,133 | $6,331 | $8,733 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $5.31 | $5.27 | $5.24 | $5.23 | $5.24 | $5.26 | $5.29 | $5.34 | $5.40 | $7.31 |
| 39 | Discounted Total Cost | | $4,960 | $4,693 | $4,453 | $4,236 | $4,042 | $3,867 | $3,710 | $3,570 | $3,444 | $4,440 |
| 40 | Cumulative Discounted Cost | $41,414 | | | | | | | | | | |

| Line # | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $4,722 | $4,167 | $3,611 | $3,056 | $2,500 | $1,944 | $1,389 | $833 | $278 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 18 | First Year Production Load Factor | | 50% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $4,722 | $4,167 | $3,611 | $3,056 | $2,500 | $1,944 | $1,389 | $833 | $278 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,458 | $1,333 | $1,167 | $1,000 | $833 | $667 | $500 | $333 | $167 | $42 |
| 24 | Cumulative Carrying Cost | | $1,458 | $2,792 | $3,958 | $4,958 | $5,792 | $6,458 | $6,958 | $7,292 | $7,458 | $7,500 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 139 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 181 |
| 29 | Depreciation (L15*L19) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 30 | Royalties (L10*L19*L8) | | 208 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 297 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 122 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 173 |
| 32 | Pre-Tax Carrying Cost | | 1,458 | 1,333 | 1,167 | 1,000 | 833 | 667 | 500 | 333 | 167 | 42 |
| 33 | Total COS Gas Costs | | $2,380 | $3,041 | $2,916 | $2,792 | $2,670 | $2,550 | $2,431 | $2,314 | $2,199 | $1,199 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $8.57 | $5.47 | $5.25 | $5.03 | $4.81 | $4.59 | $4.38 | $4.17 | $3.96 | $4.31 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $3,611 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $6,528 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $5,991 | $5,456 | $5,538 | $5,636 | $5,752 | $5,887 | $6,041 | $6,216 | $6,415 | $7,727 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $5.99 | $5.35 | $5.32 | $5.31 | $5.31 | $5.33 | $5.36 | $5.41 | $5.47 | $6.47 |
| 39 | Discounted Total Cost | | $5,599 | $4,766 | $4,521 | $4,300 | $4,101 | $3,922 | $3,762 | $3,618 | $3,489 | $3,928 |
| 40 | Cumulative Discounted Cost | $42,006 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #4: Higher Carrying Cost, $5.00 Yr 1 Purch, 0% LF Yr 1 COS Gas**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 18 | First Year Production Load Factor | | 0% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,500 | $1,417 | $1,250 | $1,083 | $917 | $750 | $583 | $417 | $250 | $83 |
| 24 | Cumulative Carrying Cost | | $1,500 | $2,917 | $4,167 | $5,250 | $6,167 | $6,917 | $7,500 | $7,917 | $8,167 | $8,250 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 0 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 362 |
| 29 | Depreciation (L15*L19) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 30 | Royalties (L10*L19*L8) | | 0 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 593 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 0 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 346 |
| 32 | Pre-Tax Carrying Cost | | 1,500 | 1,417 | 1,250 | 1,083 | 917 | 750 | 583 | 417 | 250 | 83 |
| 33 | Total COS Gas Costs | | $1,675 | $3,125 | $2,999 | $2,876 | $2,754 | $2,633 | $2,514 | $2,397 | $2,282 | $2,169 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | n.a. | $5.62 | $5.40 | $5.18 | $4.96 | $4.74 | $4.53 | $4.32 | $4.11 | $3.90 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $5,000 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $4,551 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $6,675 | $5,540 | $5,622 | $5,720 | $5,835 | $5,970 | $6,124 | $6,300 | $6,498 | $6,720 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $6.68 | $5.43 | $5.40 | $5.39 | $5.39 | $5.41 | $5.44 | $5.48 | $5.55 | $5.62 |
| 39 | Discounted Total Cost | | $6,238 | $4,839 | $4,589 | $4,364 | $4,161 | $3,978 | $3,814 | $3,667 | $3,534 | $3,416 |
| 40 | Cumulative Discounted Cost | $42,599 | | | | | | | | | | |

Illustrative Production Shut-In Analysis
(Simplified Relationships, Rough Assumptions)

Scenario #5: Higher Carrying Cost, $2.50 Yr 1 Purch, 100% LF Yr 1 COS Gas

| Line # | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 18 | First Year Production Load Factor | | 100% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,417 | $1,250 | $1,083 | $917 | $750 | $583 | $417 | $250 | $83 | $0 |
| 24 | Cumulative Carrying Cost | | $1,417 | $2,667 | $3,750 | $4,667 | $5,417 | $6,000 | $6,417 | $6,667 | $6,750 | $6,750 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 278 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 0 |
| 29 | Depreciation (L15*L19) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 30 | Royalties (L10*L19*L8) | | 208 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 0 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 122 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 0 |
| 32 | Pre-Tax Carrying Cost | | 1,417 | 1,250 | 1,083 | 917 | 750 | 583 | 417 | 250 | 83 | 0 |
| 33 | Total COS Gas Costs | | $2,755 | $2,958 | $2,833 | $2,709 | $2,587 | $2,466 | $2,348 | $2,231 | $2,115 | $228 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $4.96 | $5.32 | $5.10 | $4.88 | $4.66 | $4.44 | $4.23 | $4.02 | $3.81 | n.a. |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $1,111 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $8,505 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $3,866 | $5,373 | $5,455 | $5,553 | $5,669 | $5,803 | $5,958 | $6,133 | $6,331 | $8,733 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $3.87 | $5.27 | $5.24 | $5.23 | $5.24 | $5.26 | $5.29 | $5.34 | $5.40 | $7.31 |
| 39 | Discounted Total Cost | | $3,613 | $4,693 | $4,453 | $4,236 | $4,042 | $3,867 | $3,710 | $3,570 | $3,444 | $4,440 |
| 40 | Cumulative Discounted Cost | $40,067 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #6: Higher Carrying Cost, $2.50 Yr 1 Purch, 50% LF Yr 1 COS Gas**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $4,722 | $4,167 | $3,611 | $3,056 | $2,500 | $1,944 | $1,389 | $833 | $278 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 18 | First Year Production Load Factor | | 50% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $4,722 | $4,167 | $3,611 | $3,056 | $2,500 | $1,944 | $1,389 | $833 | $278 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,458 | $1,333 | $1,167 | $1,000 | $833 | $667 | $500 | $333 | $167 | $42 |
| 24 | Cumulative Carrying Cost | | $1,458 | $2,792 | $3,958 | $4,958 | $5,792 | $6,458 | $6,958 | $7,292 | $7,458 | $7,500 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 139 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 181 |
| 29 | Depreciation (L15*L19) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 30 | Royalties (L10*L19*L8) | | 104 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 297 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 61 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 173 |
| 32 | Pre-Tax Carrying Cost | | 1,458 | 1,333 | 1,167 | 1,000 | 833 | 667 | 500 | 333 | 167 | 42 |
| 33 | Total COS Gas Costs | | $2,215 | $3,041 | $2,916 | $2,792 | $2,670 | $2,550 | $2,431 | $2,314 | $2,199 | $1,199 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $7.97 | $5.47 | $5.25 | $5.03 | $4.81 | $4.59 | $4.38 | $4.17 | $3.96 | $4.31 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $1,806 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $6,528 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $4,020 | $5,456 | $5,538 | $5,636 | $5,752 | $5,887 | $6,041 | $6,216 | $6,415 | $7,727 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $4.02 | $5.35 | $5.32 | $5.31 | $5.31 | $5.33 | $5.36 | $5.41 | $5.47 | $6.47 |
| 39 | Discounted Total Cost | | $3,757 | $4,766 | $4,521 | $4,300 | $4,101 | $3,922 | $3,762 | $3,618 | $3,489 | $3,928 |
| 40 | Cumulative Discounted Cost | $40,165 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #7: Higher Carrying Cost, $2.50 Yr 1 Purch, 0% LF Yr 1 COS Gas**

| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $5,000 | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 | $1.00 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 18 | First Year Production Load Factor | | 0% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $5,000 | $4,444 | $3,889 | $3,333 | $2,778 | $2,222 | $1,667 | $1,111 | $556 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% | 30.0% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $1,500 | $1,417 | $1,250 | $1,083 | $917 | $750 | $583 | $417 | $250 | $83 |
| 24 | Cumulative Carrying Cost | | $1,500 | $2,917 | $4,167 | $5,250 | $6,167 | $6,917 | $7,500 | $7,917 | $8,167 | $8,250 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 0 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 362 |
| 29 | Depreciation (L15*L19) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 30 | Royalties (L10*L19*L8) | | 0 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 593 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 0 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 346 |
| 32 | Pre-Tax Carrying Cost | | 1,500 | 1,417 | 1,250 | 1,083 | 917 | 750 | 583 | 417 | 250 | 83 |
| 33 | Total COS Gas Costs | | $1,675 | $3,125 | $2,999 | $2,876 | $2,754 | $2,633 | $2,514 | $2,397 | $2,282 | $2,169 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | n.a. | $5.62 | $5.40 | $5.18 | $4.96 | $4.74 | $4.53 | $4.32 | $4.11 | $3.90 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $2,500 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $4,551 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $4,175 | $5,540 | $5,622 | $5,720 | $5,835 | $5,970 | $6,124 | $6,300 | $6,498 | $6,720 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $4.18 | $5.43 | $5.40 | $5.39 | $5.39 | $5.41 | $5.44 | $5.48 | $5.55 | $5.62 |
| 39 | Discounted Total Cost | | $3,902 | $4,839 | $4,589 | $4,364 | $4,161 | $3,978 | $3,814 | $3,667 | $3,534 | $3,416 |
| 40 | Cumulative Discounted Cost | $40,263 | | | | | | | | | | |

Illustrative Production Shut-In Analysis
(Simplified Relationships, Rough Assumptions)

**Scenario #8: Lower Carrying Cost, $5.00 Yr 1 Purch, 100% LF Yr 1 COS Gas**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 18 | First Year Production Load Factor | | 100% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $49 | $43 | $37 | $32 | $26 | $20 | $14 | $9 | $3 | $0 |
| 24 | Cumulative Carrying Cost | | $49 | $92 | $129 | $161 | $187 | $207 | $221 | $230 | $233 | $233 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 278 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 0 |
| 29 | Depreciation (L15*L19) | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 0 |
| 30 | Royalties (L10*L19*L8) | | 417 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 0 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 243 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 0 |
| 32 | Pre-Tax Carrying Cost | | 49 | 43 | 37 | 32 | 26 | 20 | 14 | 9 | 3 | 0 |
| 33 | Total COS Gas Costs | | $1,211 | $1,246 | $1,281 | $1,318 | $1,357 | $1,398 | $1,440 | $1,484 | $1,529 | $228 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $2.18 | $2.24 | $2.31 | $2.37 | $2.44 | $2.52 | $2.59 | $2.67 | $2.75 | n.a. |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $2,222 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $8,505 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $3,434 | $3,661 | $3,903 | $4,162 | $4,439 | $4,734 | $5,050 | $5,386 | $5,745 | $8,733 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $3.43 | $3.59 | $3.75 | $3.92 | $4.10 | $4.29 | $4.48 | $4.69 | $4.90 | $7.31 |
| 39 | Discounted Total Cost | | $3,209 | $3,197 | $3,186 | $3,176 | $3,165 | $3,155 | $3,145 | $3,135 | $3,125 | $4,440 |
| 40 | Cumulative Discounted Cost | $32,932 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #9: Lower Carrying Cost, $5.00 Yr 1 Purch, 50% LF Yr 1 COS Gas**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $450 | $425 | $375 | $325 | $275 | $225 | $175 | $125 | $75 | $25 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 18 | First Year Production Load Factor | | 50% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $425 | $375 | $325 | $275 | $225 | $175 | $125 | $75 | $25 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $50 | $46 | $40 | $35 | $29 | $23 | $17 | $12 | $6 | $1 |
| 24 | Cumulative Carrying Cost | | $50 | $96 | $137 | $171 | $200 | $223 | $240 | $252 | $257 | $259 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 139 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 181 |
| 29 | Depreciation (L15*L19) | | 25 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 25 |
| 30 | Royalties (L10*L19*L8) | | 208 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 297 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 122 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 173 |
| 32 | Pre-Tax Carrying Cost | | 50 | 46 | 40 | 35 | 29 | 23 | 17 | 12 | 6 | 1 |
| 33 | Total COS Gas Costs | | $719 | $1,248 | $1,284 | $1,321 | $1,360 | $1,401 | $1,443 | $1,487 | $1,532 | $905 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $2.59 | $2.25 | $2.31 | $2.38 | $2.45 | $2.52 | $2.60 | $2.68 | $2.76 | $3.26 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $3,611 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $6,528 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $4,330 | $3,664 | $3,906 | $4,165 | $4,442 | $4,737 | $5,053 | $5,389 | $5,748 | $7,434 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $4.33 | $3.59 | $3.75 | $3.93 | $4.10 | $4.29 | $4.49 | $4.69 | $4.91 | $6.22 |
| 39 | Discounted Total Cost | | $4,047 | $3,200 | $3,189 | $3,178 | $3,167 | $3,157 | $3,147 | $3,137 | $3,127 | $3,779 |
| 40 | Cumulative Discounted Cost | $33,125 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #10: Lower Carrying Cost, $5.00 Yr 1 Purch, 0% LF Yr 1 COS Gas**



| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $450 | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 18 | First Year Production Load Factor | | 0% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $52 | $49 | $43 | $37 | $32 | $26 | $20 | $14 | $9 | $3 |
| 24 | Cumulative Carrying Cost | | $52 | $101 | $144 | $181 | $213 | $239 | $259 | $273 | $282 | $285 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 0 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 362 |
| 29 | Depreciation (L15*L19) | | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 30 | Royalties (L10*L19*L8) | | 0 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 593 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 0 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 346 |
| 32 | Pre-Tax Carrying Cost | | 52 | 49 | 43 | 37 | 32 | 26 | 20 | 14 | 9 | 3 |
| 33 | Total COS Gas Costs | | $227 | $1,251 | $1,287 | $1,324 | $1,363 | $1,403 | $1,446 | $1,489 | $1,535 | $1,583 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | n.a. | $2.25 | $2.32 | $2.38 | $2.45 | $2.53 | $2.60 | $2.68 | $2.76 | $2.85 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $5,000 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $4,551 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $5,227 | $3,666 | $3,909 | $4,168 | $4,445 | $4,740 | $5,056 | $5,392 | $5,751 | $6,134 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $5.23 | $3.59 | $3.76 | $3.93 | $4.11 | $4.29 | $4.49 | $4.69 | $4.91 | $5.13 |
| 39 | Discounted Total Cost | | $4,885 | $3,202 | $3,191 | $3,180 | $3,169 | $3,159 | $3,148 | $3,138 | $3,128 | $3,118 |
| 40 | Cumulative Discounted Cost | $33,319 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #11: Lower Carrying Cost, $2.50 Yr 1 Purch, 100% LF Yr 1 COS Gas**

| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| | | | | | | | | | | | | |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| | | | | | | | | | | | | |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| | | | | | | | | | | | | |
| 13 | Beginning Book Basis COS Gas | | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 18 | First Year Production Load Factor | | 100% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 0 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $49 | $43 | $37 | $32 | $26 | $20 | $14 | $9 | $3 | $0 |
| 24 | Cumulative Carrying Cost | | $49 | $92 | $129 | $161 | $187 | $207 | $221 | $230 | $233 | $233 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| | | | | | | | | | | | | |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 278 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 0 |
| 29 | Depreciation (L15*L19) | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 0 |
| 30 | Royalties (L10*L19*L8) | | 208 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 0 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 122 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 0 |
| 32 | Pre-Tax Carrying Cost | | 49 | 43 | 37 | 32 | 26 | 20 | 14 | 9 | 3 | 0 |
| 33 | Total COS Gas Costs | | $882 | $1,246 | $1,281 | $1,318 | $1,357 | $1,398 | $1,440 | $1,484 | $1,529 | $228 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $1.59 | $2.24 | $2.31 | $2.37 | $2.44 | $2.52 | $2.59 | $2.67 | $2.75 | n.a. |
| | | | | | | | | | | | | |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $1,111 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $8,505 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| | | | | | | | | | | | | |
| 37 | Total Costs (L33+L35) | | $1,993 | $3,661 | $3,903 | $4,162 | $4,439 | $4,734 | $5,050 | $5,386 | $5,745 | $8,733 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $1.99 | $3.59 | $3.75 | $3.92 | $4.10 | $4.29 | $4.48 | $4.69 | $4.90 | $7.31 |
| 39 | Discounted Total Cost | | $1,862 | $3,197 | $3,186 | $3,176 | $3,165 | $3,155 | $3,145 | $3,135 | $3,125 | $4,440 |
| 40 | Cumulative Discounted Cost | $31,585 | | | | | | | | | | |

Illustrative Production Shut-In Analysis
(Simplified Relationships, Rough Assumptions)

Scenario #12: Lower Carrying Cost, $2.50 Yr 1 Purch, 50% LF Yr 1 COS Gas



| Line # | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $450 | $425 | $375 | $325 | $275 | $225 | $175 | $125 | $75 | $25 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 18 | First Year Production Load Factor | | 50% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 278 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 278 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 4,722 | 4,167 | 3,611 | 3,056 | 2,500 | 1,944 | 1,389 | 833 | 278 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $425 | $375 | $325 | $275 | $225 | $175 | $125 | $75 | $25 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $50 | $46 | $40 | $35 | $29 | $23 | $17 | $12 | $6 | $1 |
| 24 | Cumulative Carrying Cost | | $50 | $96 | $137 | $171 | $200 | $223 | $240 | $252 | $257 | $259 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 139 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 181 |
| 29 | Depreciation (L15*L19) | | 25 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 25 |
| 30 | Royalties (L10*L19*L8) | | 104 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 297 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 61 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 173 |
| 32 | Pre-Tax Carrying Cost | | 50 | 46 | 40 | 35 | 29 | 23 | 17 | 12 | 6 | 1 |
| 33 | Total COS Gas Costs | | $554 | $1,248 | $1,284 | $1,321 | $1,360 | $1,401 | $1,443 | $1,487 | $1,532 | $905 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | $1.99 | $2.25 | $2.31 | $2.38 | $2.45 | $2.52 | $2.60 | $2.68 | $2.76 | $3.26 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $1,806 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $6,528 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $2,360 | $3,664 | $3,906 | $4,165 | $4,442 | $4,737 | $5,053 | $5,389 | $5,748 | $7,434 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $2.36 | $3.59 | $3.75 | $3.93 | $4.10 | $4.29 | $4.49 | $4.69 | $4.91 | $6.22 |
| 39 | Discounted Total Cost | | $2,205 | $3,200 | $3,189 | $3,178 | $3,167 | $3,157 | $3,147 | $3,137 | $3,127 | $3,779 |
| 40 | Cumulative Discounted Cost | $31,284 | | | | | | | | | | |

**Illustrative Production Shut-In Analysis**
(Simplified Relationships, Rough Assumptions)

**Scenario #13: Lower Carrying Cost, $2.50 Yr 1 Purch, 0% LF Yr 1 COS Gas**

| Line # | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2 | Starting Total Demand (Dth) | | 1,000 | | | | | | | | | |
| 3 | Demand Growth Rate | | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 4 | Total Demand (Dth) | | 1,000 | 1,020 | 1,040 | 1,061 | 1,082 | 1,104 | 1,126 | 1,149 | 1,172 | 1,195 |
| 5 | Starting Purchased Gas Price/Dth | | $5.00 | | | | | | | | | |
| 6 | Purchased Gas Price Escalation | | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 7 | Yearly Purchased Gas Price/Dth | | $5.00 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 8 | Year 1 Purch. Gas Price Override/Dth | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 9 | Production Tax Rate | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| 10 | Royalty Rate | | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| 11 | Variable Production Costs/Dth | | $0.50 | $0.52 | $0.53 | $0.55 | $0.56 | $0.58 | $0.60 | $0.61 | $0.63 | $0.65 |
| 12 | Fixed Costs Less Credits | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 13 | Beginning Book Basis COS Gas | | $450 | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 |
| 14 | Beginning Reserves (Dth) | | 5,000 | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 |
| 15 | Depreciation Rate/Dth (L13/L14) | | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| 16 | Production % of Starting Reserves | | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% | 11.11% |
| 17 | Production (Dth) (L14*L16) | | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 18 | First Year Production Load Factor | | 0% | | | | | | | | | |
| 19 | Year-1 Production Override (Dth) | | 0 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 | 556 |
| 20 | Ending Reserves (Dth) (L14-L19) | | 5,000 | 4,444 | 3,889 | 3,333 | 2,778 | 2,222 | 1,667 | 1,111 | 556 | 0 |
| 21 | Ending Book Basis COS Gas (L13-(L19*L15)) | | $450 | $400 | $350 | $300 | $250 | $200 | $150 | $100 | $50 | $0 |
| 22 | Pre-Tax COS Rate of Return | | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| 23 | Pre-Tax Carrying Cost (((L13+L21)/2)*L22) | | $52 | $49 | $43 | $37 | $32 | $26 | $20 | $14 | $9 | $3 |
| 24 | Cumulative Carrying Cost | | $52 | $101 | $144 | $181 | $213 | $239 | $259 | $273 | $282 | $285 |
| 25 | Discount Rate | | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| 26 | **Total Gas Supply Costs** | | | | | | | | | | | |
| 27 | Fixed Costs | | $175 | $180 | $186 | $191 | $197 | $203 | $209 | $215 | $222 | $228 |
| 28 | Variable Costs (L11*L19) | | 0 | 286 | 295 | 304 | 313 | 322 | 332 | 342 | 352 | 362 |
| 29 | Depreciation (L15*L19) | | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 30 | Royalties (L10*L19*L8) | | 0 | 433 | 451 | 469 | 487 | 507 | 527 | 548 | 570 | 593 |
| 31 | Production Taxes ((L9*L19*L8)*(0.875)) | | 0 | 253 | 263 | 273 | 284 | 296 | 308 | 320 | 333 | 346 |
| 32 | Pre-Tax Carrying Cost | | 52 | 49 | 43 | 37 | 32 | 26 | 20 | 14 | 9 | 3 |
| 33 | Total COS Gas Costs | | $227 | $1,251 | $1,287 | $1,324 | $1,363 | $1,403 | $1,446 | $1,489 | $1,535 | $1,583 |
| 34 | Total COS Gas Costs/Dth (L33/L19) | | n.a. | $2.25 | $2.32 | $2.38 | $2.45 | $2.53 | $2.60 | $2.68 | $2.76 | $2.85 |
| 35 | Purchased Gas Costs ((L4-L19)*L8) | | $2,500 | $2,415 | $2,622 | $2,844 | $3,082 | $3,337 | $3,610 | $3,903 | $4,216 | $4,551 |
| 36 | Purchased Gas Costs/Dth (L35/(L4-L19)) | | $2.50 | $5.20 | $5.41 | $5.62 | $5.85 | $6.08 | $6.33 | $6.58 | $6.84 | $7.12 |
| 37 | Total Costs (L33+L35) | | $2,727 | $3,666 | $3,909 | $4,168 | $4,445 | $4,740 | $5,056 | $5,392 | $5,751 | $6,134 |
| 38 | Total Costs/Dth of Demand (L37/L4) | | $2.73 | $3.59 | $3.76 | $3.93 | $4.11 | $4.29 | $4.49 | $4.69 | $4.91 | $5.13 |
| 39 | Discounted Total Cost | | $2,548 | $3,202 | $3,191 | $3,180 | $3,169 | $3,159 | $3,148 | $3,138 | $3,128 | $3,118 |
| 40 | Cumulative Discounted Cost | $30,982 | | | | | | | | | | |