SYSTEM CAPABILITIES AND CONSTRAINTS

Questar Gas System Overview

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. The operation of this integrated system remains intact as a result of Questar Gas' relationship with Questar Pipeline Company (Questar Pipeline). Questar Gas' ability to serve its customers is dependent primarily upon deliveries from Questar Pipeline and augmented by deliveries from Kern River Gas Transmission Company (KRGT). The Company also 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 La Barge and Big Piney in Wyoming; and Colorado Interstate Gas Company to serve the towns of Wamsutter and Rock Springs. These pipeline systems are part of the modeling process discussed in other IRP sections. This section will focus on Questar Gas' local distribution system.

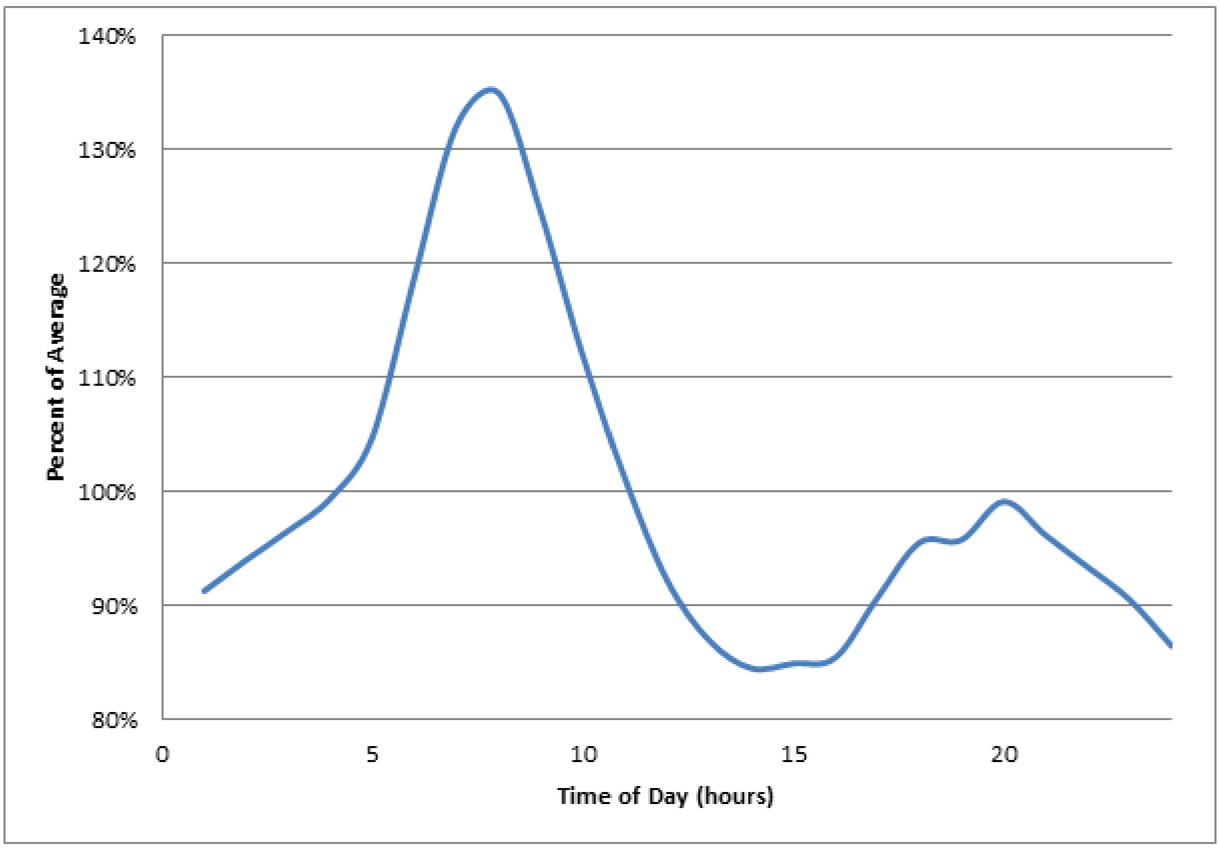

Figure 4.1: Daily Profile

Questar Gas builds steady-state and unsteady-state Gas Network Analysis (GNA) system models each year to account for changes in facilities and customer growth. The Company updates these models annually to include facilities and demands as of February of the current year. Questar Gas adjusts the models to match the predicted demand for the following year based on the growth projections. The modeling results provided in this report are based on the 2013-2014 models which were created in March 2013.

Questar Gas uses these GNA models to perform system analysis to meet future capacity requirements while maintaining system reliability. Each time Questar Gas builds the models, the engineering department verifies their accuracy and then reviews the results to determine any required system improvements, supply changes, or contract revisions. The models can then be expanded to meet system analysis needs including planning and operational analysis, creating models at different temperatures and creating different types of models from the standard system model.

System Operations

January 2013 was one of the coldest months experienced in Utah. For 14 of the 31 days in January, the Salt Lake International Airport observed-high temperature was at or below the normal-low temperature. Some interesting statistics from January 2013 are:

- 15 of Questar Gas' top 25 total daily system demand days occurred in January 2013.

- January 14, 2013 was the highest total daily system demand in the history of Questar Gas at 1,225,730 Dth.
    - This was 83% of the predicted peak day of 1,474,000 Dth.
    - The previous high was 1,194,133 Dth on February 1, 2011.

- Stretches of 6 and 13 consecutive days of total daily system demand of at least 1,000,000 Dth.
    - Previously there had never been more than four consecutive days of total daily system sales of at least 1,000,000 Dth.

This period of high sendout provided a good test of the adequacy of the distribution system and the upstream transportation and storage facilities contracted by Questar Gas. During this period, there were no major issues with upstream supplies and no pressure problems on the Questar Gas system.

Supply availability benefited from the improved access to Wexpro production and cost efficient supply points associated with the extension of Contract No. 2945 (discussed further in Section 7 – Gathering, Transportation and Storage). These amendments provided increased access to some of the best priced supplies in the area and also provided additional capacity using Overthrust Pipeline.

The gate stations served by Questar Pipeline are mostly pressure set stations. This allows them to be used to meet the hourly load swings of customers on the Questar Gas system. The use of the capacity on Overthrust Pipeline improved Questar Pipeline's ability to meet these large load swings. Figure 1 shows the impact of these load swings on sendout to the northern system.

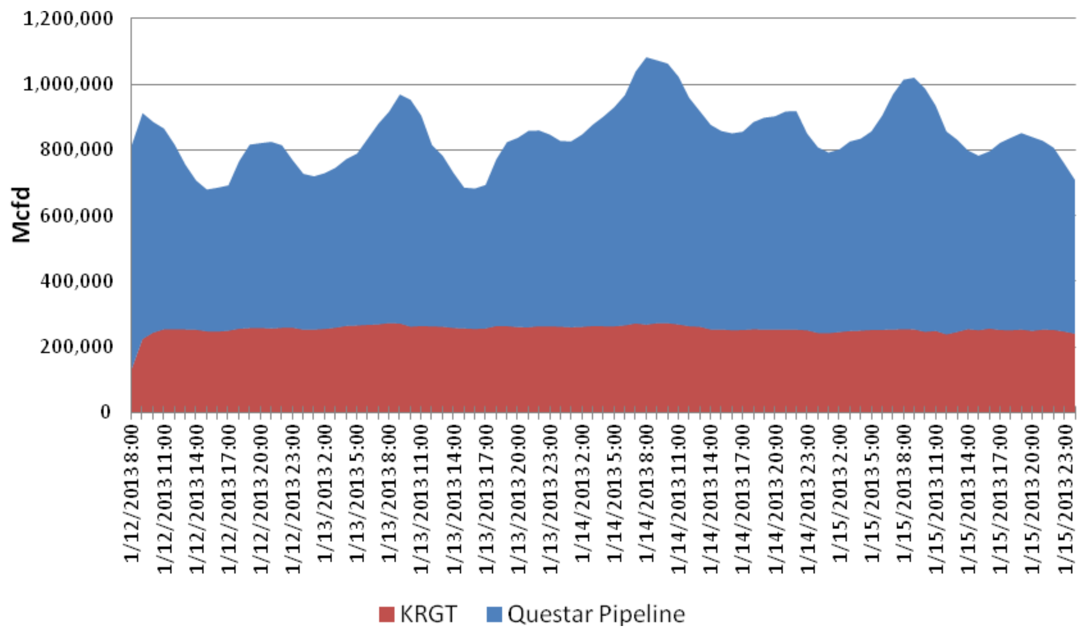

Figure 4.2: Northern System Sendout During High Demand Period

During the highest sendout day, January 14, the highest sendout hour was almost 20% greater than the daily average and over 35% greater than the minimum hour of the day. The total swing from minimum to maximum sendout was 280,941 mcfh on this day. Questar Pipeline stations provided 250,488 mcfh of that swing on this day, which made up 89% of the total daily swing on the Questar Gas system. The ability to meet the hourly load swings is critical to the operation of the Questar Gas System.

Ongoing and Future System Analysis Projects

Master Planning Models

Questar Gas has created master planning models and some potential methods to update them. These models have been created using expected growth projections provided by the Regulatory Affairs department, as well as with input from region engineers on planned developments in their systems. The Company anticipates that, by using these models, the resulting pressures of the peak day analysis will be impacted by the specific growth centers and provide more realistic projections than flat growth models. These models are used in future projected analyses to determine the probable conditions.

System Supply Analysis

The Questar Gas system supplies are analyzed each year to determine if the current contracts, at each Meter Allocation Point (MAP), and available capacity will meet the coming year's demands. This analysis carefully considers the upstream (transmission pipelines) constraints and capabilities as well as the ability to acquire gas to deliver to the Questar Gas system on a peak day. The purpose of this analysis is to determine the amount of gas required on a peak day and if the current contracts (sales and transportation) facilitate this required delivery.

Interruption Analysis

There are a number of non-GS customers on the Questar Gas system who have opted to purchase gas on an interruptible rate utilizing any available excess capacity. While the system is not designed for these customers, it is important to understand at which temperature(s) interruption is required. This analysis divides the system into interruption zones and determines the temperature at which interruption of a specific zone is necessary to maintain service to the surrounding firm customers.

Contingency Planning

Questar Gas uses the HP system models to develop contingency plans for potential emergency scenarios. Questar Gas' engineering and pipeline compliance groups coordinate to incorporate the various scenarios into its Emergency Plan. Questar Gas' engineering department develops studies using the unsteady-state model 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 is beneficial to prepare general plans that can be tailored to specific events.

Construction Timeline Analysis

During construction season, there are numerous projects that require feeder lines and high pressure facilities to either be limited (pressure or flow) or shut down completely. Each month a construction timeline analysis is performed to determine whether or not the planned construction can take place without adversely impacting customers. This analysis considers the gate station settings, gas supply contracts, construction on the transmission pipelines upstream of the High Pressure (HP) system, probable temperatures and other specific conditions. This allows construction to proceed with confidence that the work planned will not have negative impacts.

Operational Models

Another way Questar Gas prepares to respond to unforeseen scenarios is by developing and maintaining operational models of the system. Questar Gas maintains these models to represent current actual conditions that exist in the system at expected temperatures. Questar Gas' engineers review these models on an ongoing basis with Questar Gas' gas control, gas supply, marketing, operations, and measurement and control departments in order to inform them of expected system conditions.

System Modeling and Reinforcement

Questar Gas' engineering department utilizes steady-state IHP models to determine the required improvements in order to maintain operational pressures. Questar Gas uses these models to identify the required location(s) and sizing of new mains and/or regulator stations. Questar Gas also uses the models to compare the required flow from the regulator stations to the maximum capacity of the existing stations. This analysis provides Questar Gas with the information necessary to determine which reinforcements should be constructed each year. Based on the modeling results, Questar Gas constructs a number of mains and new stations, as well as upgrades to existing stations.

The HP system models have more variables than the IHP system models. Engineers consider gate stations, existing supply contracts, supply availability, line pack, and the piping system in conducting HP analysis. Because HP projects typically take longer to complete than similar IHP projects, Questar Gas must also identify the need for HP improvements earlier than would be required on IHP projects. Questar Gas and the interstate pipeline companies that supply its system collaborate to identify potential constraints to ensure that Questar Gas' supply needs are met.

Model Verification

Questar Gas verified the accuracy of the steady-state (24 hour period) GNA models using recorded pressure data and calculated demands. Questar Gas' engineers built steady-state models to represent the system conditions on Monday, January 14, 2013 using actual data from that day (verification day). Model settings were adjusted to match the actual temperatures and other conditions for this day. The model pressures were compared to actual pressures at verification points and were found to be within 7 percent of the actual pressures on that day. Based on this analysis, Questar Gas has deemed the loads and infrastructure utilized in the GNA models are accurate and the models can confidently be used for their intended purpose.

January 14, 2013 is the highest demand the Questar Gas HP system has ever endured. System operation would not have gone as smoothly as it did without properly verified models that are the basis for system design. Questar Gas performs model verification annually to ensure that existing facilities and customer demands are accurately represented in the system models. Verified models provide confidence in peak day projected models. Figure 2 shows the hourly volume difference from the Central and Northern Gate stations.

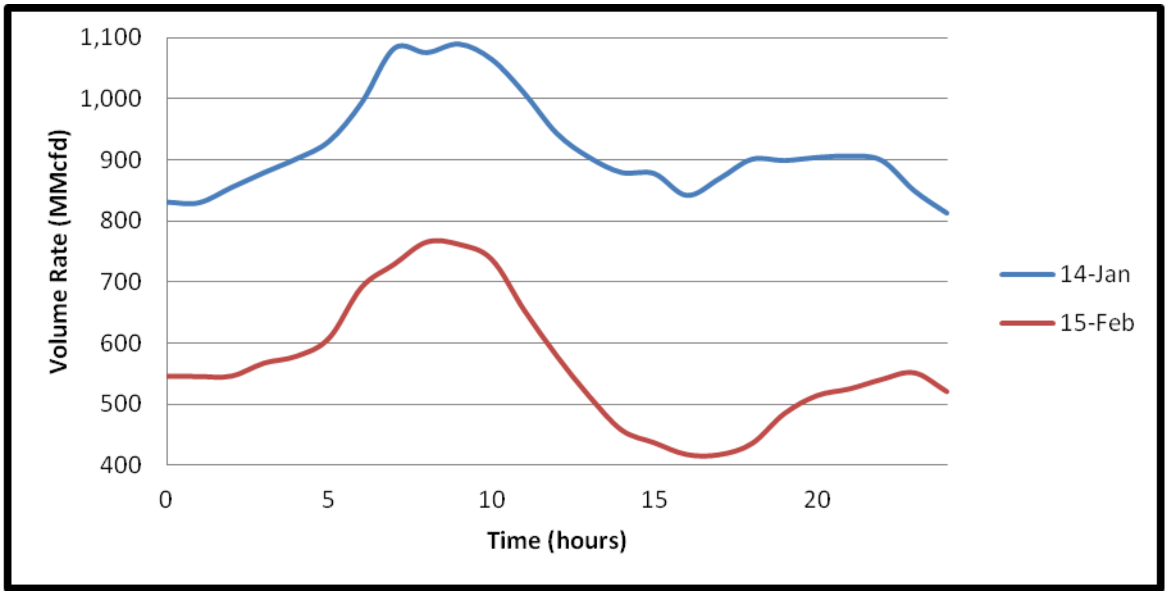

Figure 4.3: Central and Northern Gate Stations Jan 14 versus Feb 15, 2013

Questar Gas also compared the total modeled demand with the daily recorded deliveries (sendout) for the same verification day at the gate stations. The results of this analysis showed that the demand the model predicted was within approximately 10 percent of the actual deliveries for the verification day. This difference is likely due to the fact that the steady-state model does not account for system line pack or any lost and unaccounted for gas. Actual system flows would provide for some line pack in the system. The results of the comparisons confirm the accuracy of the calculated demand used in the steady-state models.

Questar Gas verified the unsteady-state (hourly results for a 24-hour period) models in the same manner as the steady-state models. Questar Gas matched the temperatures and the gate station flows and pressures as closely as possible. The Central and Northern Regions are the largest connected high pressure systems belonging to Questar Gas with 7 gate stations and 2 maximum allowable operating pressure (MAOP) zones. There are three smaller isolated systems which also require unsteady-state model analysis: Summit/Wasatch, Eastern, and Southern. This analysis has 47 pressure verification points as well as the known pressures and flows from the gate stations. None of the pressure differences at the verification points have error values higher than 7 percent, when compared to the actual minimum and average pressures. The results of these comparisons confirm the accuracy of the unsteady-state models.

The unsteady-state models provide the ability for engineers to design for the daily swings in flow and pressure. This is paramount to system design since gate stations like Little Mountain may swing 1.5 times the average or more depending on the settings of other gate stations. Without the ability to model this phenomenon, the value of peak day model results would be greatly diminished.

Gate Station Flows vs. Capacity

The gate stations, in the system models, must stay within the physical pressure and flow limits of each specific station. To ensure this, Questar Gas completed a capacity study for each of the gate stations. Questar Gas calculated the hourly and daily flow capacities for each station based on facility limitations, set pressures, and inlet pressures provided by Questar Pipeline and those identified in interconnect agreements with other suppliers. Gate station requirements are influenced by Questar Pipeline's ability to supply gas at varying volumes throughout the day as the customers' demands swings throughout the day.

Joint Operating Agreement

On January 26, 2012 Questar Gas and Questar Pipeline completed a joint operating agreement (JOA). The primary purpose of this agreement was to provide "a listing of the expected operating conditions projected for a peak day during the next winter heating season at each of the major Interconnect Facilities" (JOA Page 1). This agreement allowed the Questar Gas' system planning group to more accurately model the inlet pressures to gate stations from Questar Pipeline. These improvements led to higher modeled pressures throughout the Questar Gas system. This agreement will be updated on an annual basis.

System Pressures

Once Questar Gas verifies the system models and properly sets contractual obligations and station capacities, Questar Gas uses the models to analyze the system to verify that the system has adequate pressures in order to supply Questar Gas customers. Questar Gas uses peak model(s) for this analysis. Peak models include firm loads for sales and transport customers. Questar Gas uses the daily contract limits for applicable customers and assumes that interruptible demands are off system during the peak day.

Northern

The Northern Region includes the main system around Salt Lake City and northern Utah, including Salt Lake, Tooele, Summit, Utah, Wasatch, Davis, Morgan, Weber, Cache, and Box Elder counties. Questar Gas serves this region through interconnects with Questar Pipeline at MAP 164 through the Hyrum, Little Mountain, Payson, Porter's Lane, and Sunset stations. Questar Gas also serves the region through multiple smaller taps from Questar Pipeline (MAP 162) and KRGT at Hunter Park and Riverton stations.

Questar Gas meets the peak-day demands by serving customers in the Northern Region from both Questar Pipeline and KRGT. Questar Gas utilizes the KRGT gate stations to provide up to 450 MMcfd of fixed flow gas. Questar Gas utilizes its firm capacity along with its no notice capacity to reserve capacity on Questar Pipeline to manage peak hourly and daily deliveries.

In the steady-state model, the calculated low point in the main portion of the northern system is 267 psig at the endpoint of Feeder Line 36 (FL 36) in West Jordan. The next lowest pressure in the Northern Region is at Alta, with a steady-state pressure of 266 psig. These pressures remain higher than Questar Gas' minimum allowable pressure of 125 psig.

The steady-state pressures at some of the key locations in the Northern Region are shown in Table 1 and Figure 3. Questar Gas models these pressures on a peak day at system endpoints, low points in the area and important intersections. Questar Gas builds steady-state models using average daily flows that most closely represent average pressures for the peak day. The unsteady-state models profile the load throughout the day and represent the pressure fluctuations throughout the peak day.

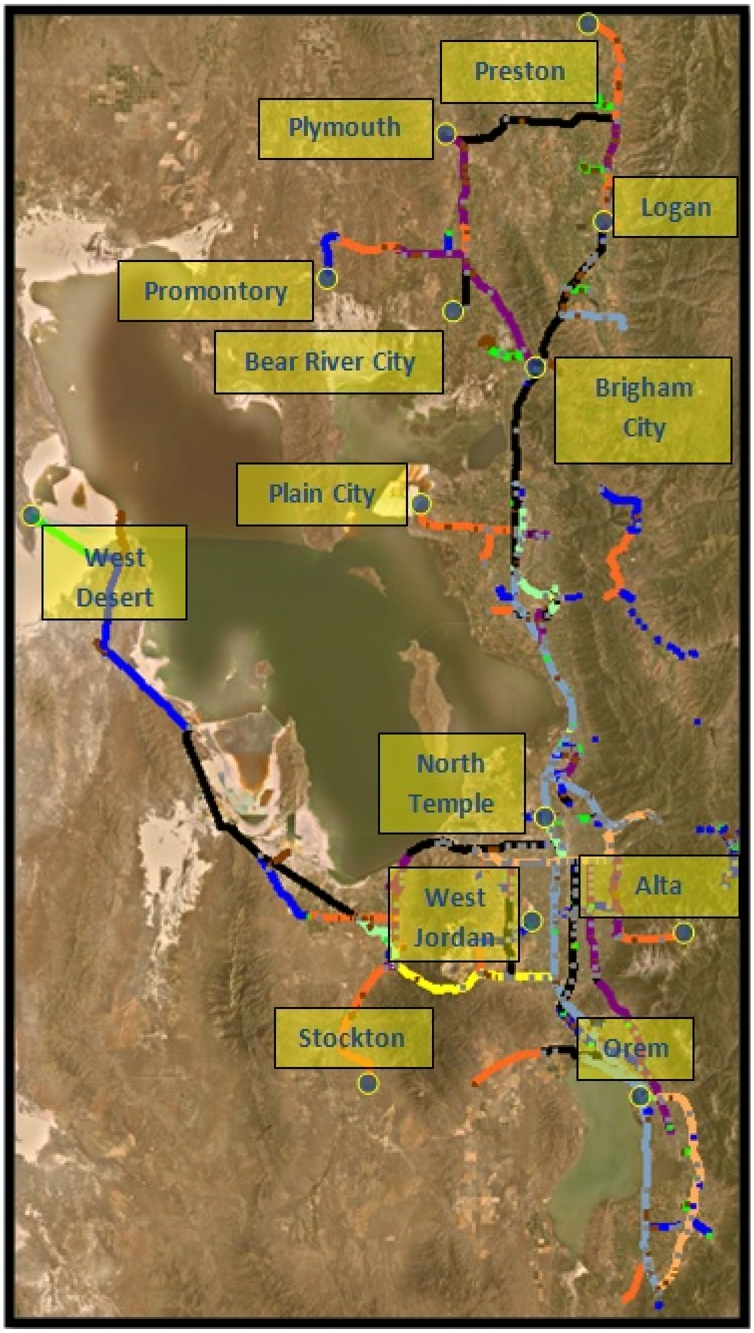

Figure 4.4: Northern Region Key Pressures

Table 1: Steady-State Peak Day Pressures

Location	Pressure (psig)
Endpoint of FL29 – Plymouth	308
Endpoint of FL36 – West Jordan	267
Endpoint of FL48 – Stockton	329
Endpoint of FL51 – Plain City	331
Endpoint of FL62 – Alta	266
Endpoint of FL63 – West Desert	324
Endpoint of FL70 – Promontory	323
Endpoint of FL74 – Preston	299
Endpoint of FL106 – Bear River City	330
Intersection of FL29 & FL23 – Brigham City	386

The curves shown in Figures 4, 5, and 6 are the expected peak-day pressures in the Northern Region. In the unsteady-state models, the low point in the Northern Region is Charleston, at 126 psig, in the Summit Wasatch system. Questar Gas is currently monitoring the Summit Wasatch HP system in order to determine when system improvements are required in the area.

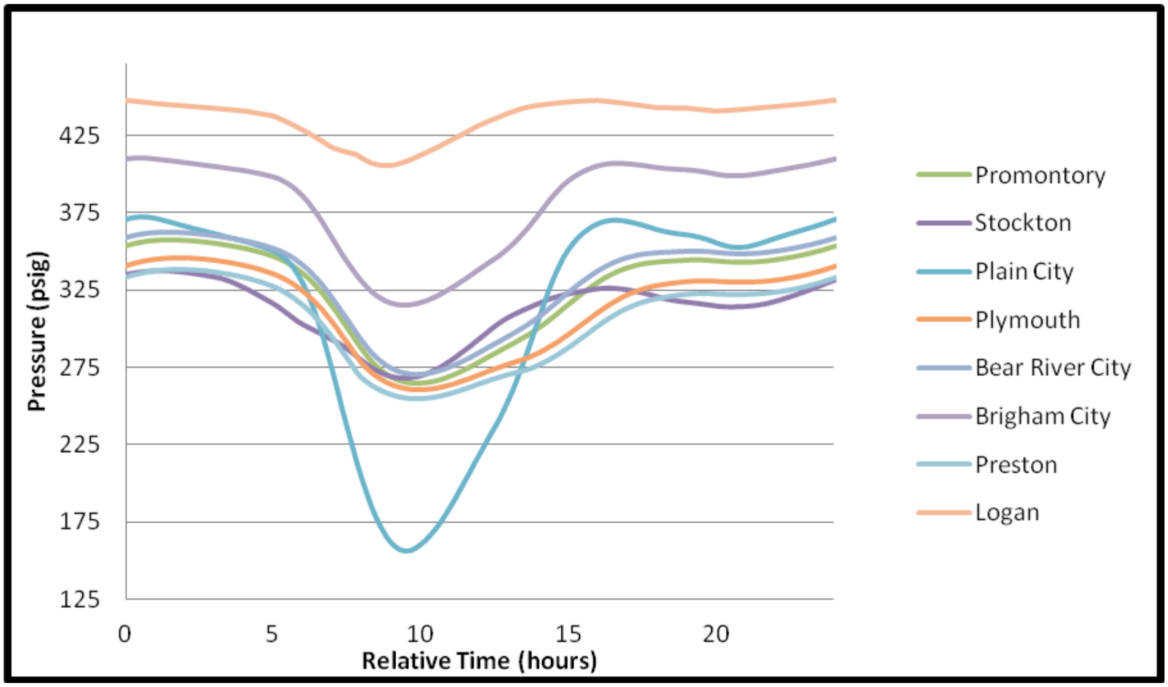

Figure 4.5: 2013 Northern Peak Day Pressures (North of North Temple)

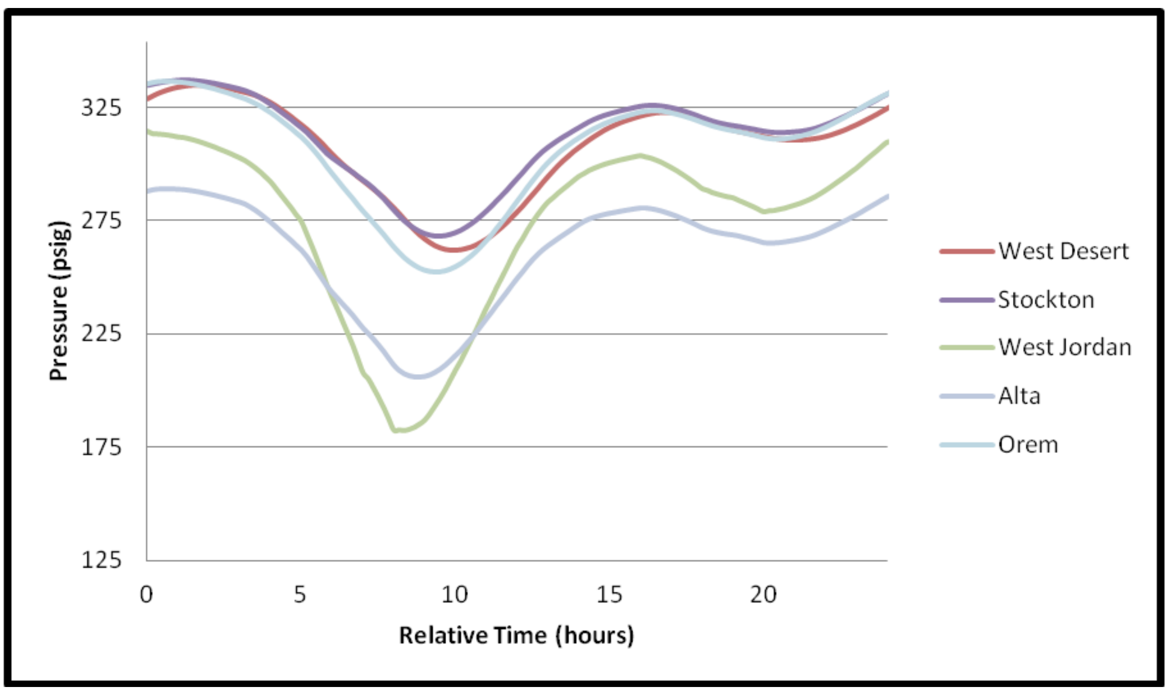

Figure 4.6: 2013 Northern Peak Day Pressures (South of North Temple)

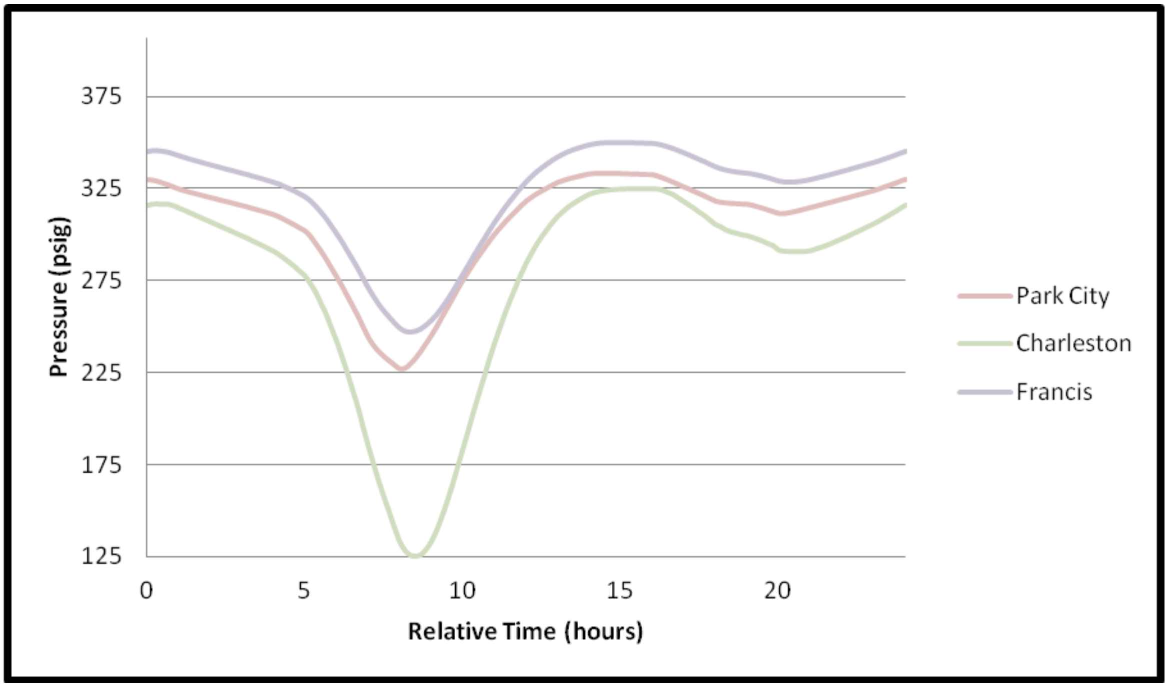

Figure 4.7: 2013 Northern Peak Day Pressures (Summit and Wasatch Counties)

The gate stations in the Northern system have varying flow throughout the day. Figure 7 shows the expected peak day flow rates for the large (average volumes greater than 40 MMcfd) gate stations in the Northern System. Little Mountain gate station is the key station in maintaining pressures in the entire Northern HP system. Without Little Mountain's constantly adjusting flow rates, the current system configuration would not function on a peak day.

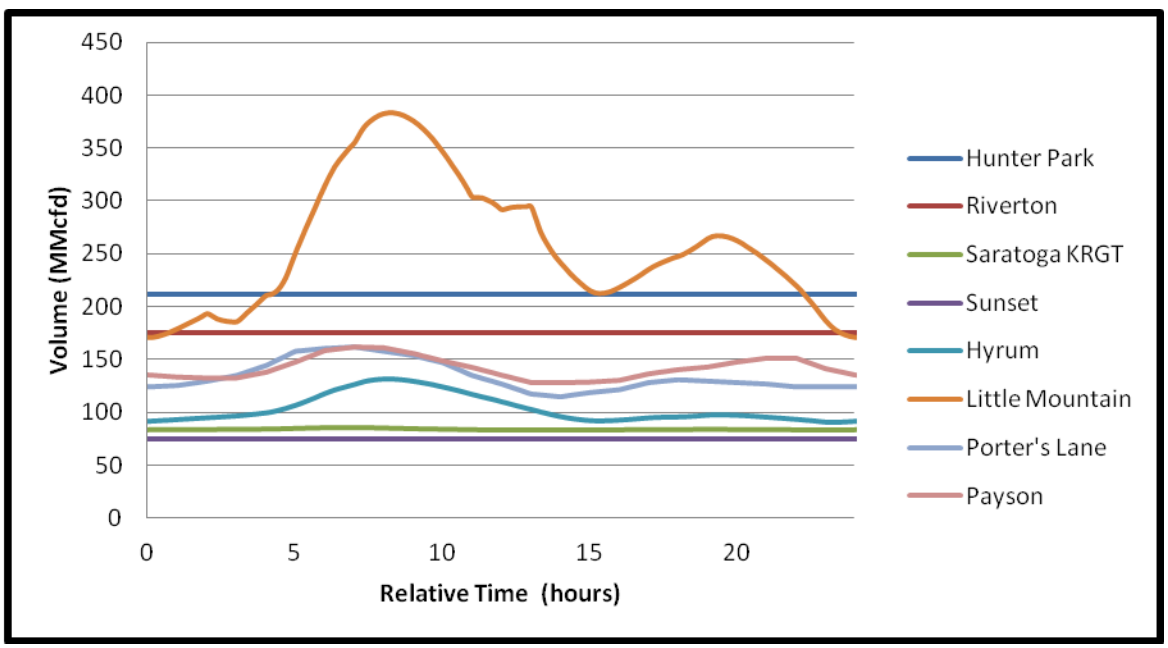

Figure 4.8: 2013 Peak Day Gate Station Flow

Eastern (North)

The Eastern (North) Region includes Duchesne, Uintah, Carbon, and Emery counties, including the cities of Price and Vernal. The Vernal system is a system that was previously owned by Utah Gas Company. This area is served from Questar Pipeline by multiple taps through MAP 163. The pressure at the end of Feeder Line 90 (FL 90), in west Vernal, is being monitored. The minimum pressure calculated by the model is 154 psig during a peak event.

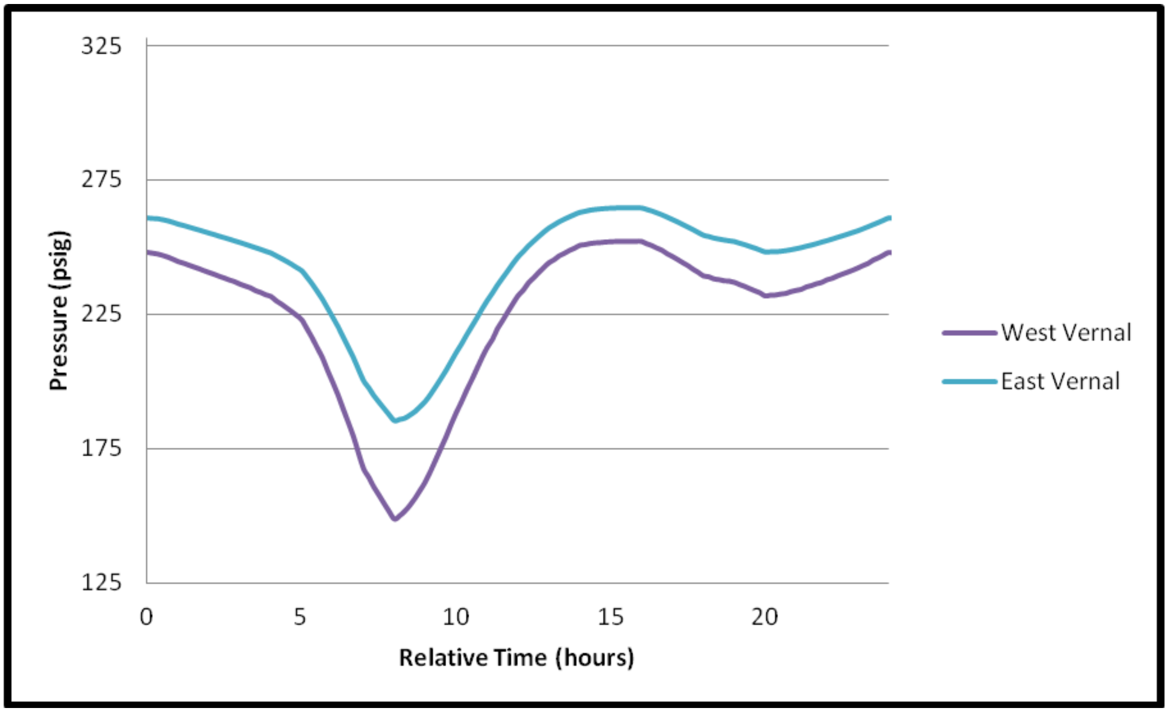

Figure 4.9: 2013 Eastern Peak Day Pressures

Eastern (Northwest Pipeline)

The Eastern (Northwest Pipeline) Region includes the cities of Moab, Monticello and Dutch John. Utah Gas Company previously owned the southeast systems. Questar Gas serves these areas from Northwest Pipeline with two stations in Moab, one station in Monticello, and one tap in Dutch John.

The system in this area is made up of separate subsystems with individual taps off Northwest Pipeline. All of the segments in this area have adequate pressures and do not require any improvement to meet the existing general service demand.

Southern (Main System)

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

Using the steady-state model, the lowest modeled pressure on a peak day is 506 psig at Brian Head. This is higher than the pressures in the northern system due to the higher operating pressures that range between 625-700 psig. Using the unsteady-state model, the lowest pressure in the southern area is 469 psig at Brian Head.

Questar Gas is designing a new pressure station in Santa Clara on the 8-inch feeder line from the KRGT interconnect at Central Station, a pressure increase for Feeder Line 81 (FL 81) and compression at Central Station, in order to meet the growing demand in this area. Questar Gas is currently installing the compressor station and uprating FL 81 so that the uprated facilities will be operational prior to the 2013 heating season. 2013 models assume these improvements have been installed and are functioning.

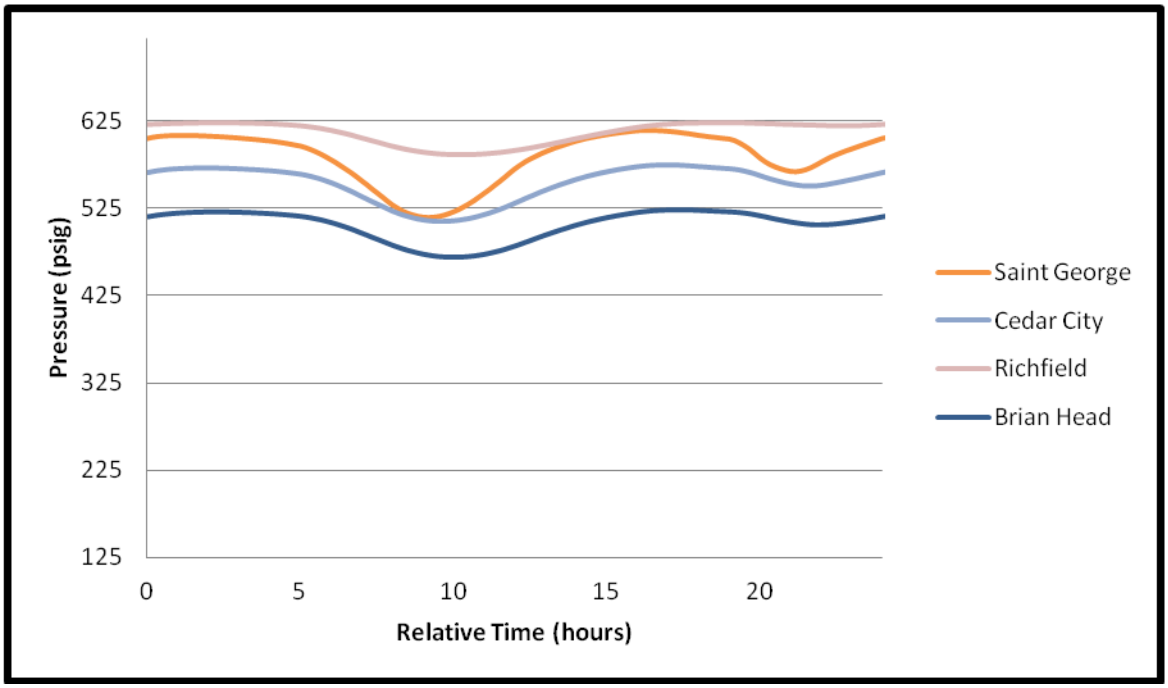

Figure 4.10: 2013 Southern Peak Day Pressures

Southern (KRGT Taps)

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

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

Wyoming

The Wyoming Region includes Rock Springs, Evanston, Lyman, Kemmerer, Baggs, and Granger. These areas are served from Questar Pipeline through MAP 168, MAP 169, and MAP 177; from Colorado Interstate Gas (CIG) at Wamsutter and Rock Springs; and from Williams Field Services (WFS) at La Barge and Big Piney.

The Big Piney high pressures system is being uprated this year. The minimum expected pressure for the 2013 heating season is 184 psig. The uprate will provide an additional pressure buffer and will support a limited amount of system growth in the area.

System Capacity Conclusions

Questar Gas' HP feeder line system is capable of meeting the current peak day demands with adequate supply and capacity in the system. This system assessment is based on the fact that the gate stations and feeder line system have adequate capacity to meet average daily and peak hourly demands, the supply contracts are adequate, and system models show that pressures do not drop below the design minimum of 125 psig. The system will continue to grow along with the demand and Questar Gas will conduct an analysis annually to ensure that the system continues to meet the peak day needs.

Questar Gas is conducting analysis relating to several system constraints including the following:

- *Increasing Demand in the Northern and Central Regions.* Questar Gas is evaluating installing new interconnects with Questar Pipeline, KRGT, and/or Ruby Pipeline in order to meet the supply needs associated with long term growth of the Northern and Central Regions. Questar Gas is also considering upgrading existing stations and procuring additional supply contracts for areas experiencing growth.

  Before April of 2014, the Payson Gate Station will be uprated along with a portion of Feeder Line 26 (FL 26) in order to facilitate delivery of higher pressures into FL 26. This improvement will allow this segment of FL 26 to operate near its expected MAOP of 720 psig and absorb a portion of the peak-day swing that Questar Pipeline allows Questar Gas. The expected peak day pressures in the Central system will increase as a result of this improvement. This project is discussed in more detail in the DNG Action Plan section of this IRP.

- *Growth in the Southern Region.* Questar Gas' Southern Region is reaching capacity. The first improvement to mitigate capacity issues is to install compression on FL 81 at the Central Tap and uprate portions of FL 81. This project is discussed in more detail in the DNG Action Plan section of this IRP.

- *Low Pressures in the Northern Region.* Questar Gas' modeling shows that pressures near the end of FL 51 (Plain City), in the Northern Region, are low and will likely require improvements in the foreseeable future. Questar Gas is considering a variety of options to increase the pressures in that area including a replacement or increased pressures at one of the gate stations in the area.

- *Low Pressures in West Jordan.* Questar Gas is currently installing a new regulator station extending from Feeder Line 34 (FL 34) that will displace a portion of the demand in West Jordan, relieving FL 36 of the full demand. This will increase pressures in the area. This project is discussed in more detail in the "DNG Action Plan" section of this IRP. HP systems' pressures in the West Jordan area will also be improved dramatically after completion of the FL 26 uprate project.

- *Low Pressures in Charleston.* Questar Gas is planning improvements in the Charleston area in Summit County. Current improvement plans upstream of Charleston will increase pressures. The main method being considered to increase pressures at the Charleston regulator station is to extend a high pressure line from Feeder Line 99, a 12-inch line. This improvement will increase pressures in Charleston and Park City. This project is discussed in more detail in the DNG Action Plan section of this IRP.

- *Growth in Vernal.* Additional growth in Vernal may result in the need to reinforce FL 90. Questar Gas will monitor growth in the area in order to determine when further reinforcement is appropriate. The Company is considering the potential of extending Feeder Line 89 (FL 89) across Vernal and tying to FL 90.

DNG Action Plan

Questar Gas is currently planning, designing and constructing several reinforcement and replacement projects on its system. The following is a brief description of the major projects anticipated by Questar Gas in 2013 and beyond.

Gate Station Projects

1. Hunter Park Gate Station Project: Questar Gas has been improving the capacity and functionality of the Hunter Park Gate Station since 2008. This project was discussed in detail in the 2012-2013 IRP. Questar Gas also provided an update to this project in the 2nd Quarter 2012 IRP Variance Report. As indicated in these documents, in 2013, Questar Gas is installing a new line heater, two ultrasonic meters, two control valves, a filter separator for liquids and solids removal, a new control system, upgrades to the security system and electrical system, and backup generation for the entire facility.

   This project was bid in April of 2013 and began construction May 2013. As mentioned in the variance report, Questar Gas estimates the 2013 costs to be approximately $8,164,000 with a revenue requirement of $1.4 million. This amount exceeds the costs detailed in the 2012-2013 IRP. This increase in cost can mainly be attributed to increased costs in right-of-way, material procurement, construction contractors and inspection costs.

2. Central Gate Station Project: This project was discussed in detail in the 2012-2013 IRP and updated in the 2nd Quarter 2012 IRP variance report. The costs for KRGT to complete the upgrade on its facilities was $4,497,000, with a revenue requirement of $747,000. KRGT will construct this project in 2013. This project will give Questar Gas immediate capacity of 47 MMcfd at the station, with potential for possible future expansion to approximately 100 MMcfd.

Feeder Line Projects

1. St. George Reinforcement: This project was discussed in detail in the 2012-2013 IRP. Questar Gas started construction of these improvements in March 2013. The anticipated service date for the project is November 1, 2013. Estimated 2013 expenditures are $20,500,000 with a revenue requirement of $3 million.

2. Feeder Line 26 Uprate Project: This project was briefly discussed in the 2012-2013 IRP, and in more detail in the 1st Quarter IRP variance report. In August of 2011 Questar Gas responded to an RFP from PacifiCorp to provide up to 90,000 Dth/day of high pressure gas service to serve the expansion of its Lake Side power plant. In June of 2012, the Commission issued a Report and Order in Docket No. 12-057-04 approving the agreement with PacifiCorp. Questar Gas is uprating its FL 26 to 720 psig in order the meet the requirements of the agreement with PacifiCorp. Questar Gas is currently on schedule to have the project completed in 2013. The estimated total cost for the project is $13,712,000 with a revenue requirement of $2 million. As part of this project Questar Gas will:

   - Install line heaters at nine district regulator stations.
   - Install regulation and heaters at the cross-over between FL 26 and FL 24.
   - Replace approximately two miles of FL 26.
   - Install 3,000 lf of 24” diameter tap line to Lake Side power plant.
   - Install receiver for in-line inspection tools at Lake Side power plant.
   - Install regulation and in-line heaters for the portion of FL 26 north of the new Lake Side tap.
   - Uprate the portion of FL 26 from Payson Gate to Vineyard.

3. Charleston Feeder Line (Feeder Line 99 Extension): Questar Gas has been analyzing this project since 2010. A detailed description of this project can be

seen in the 2011-12 IRP. Recent GNA modeling shows that growth in the area will require that this project be in service by fall of 2015.

For this project Questar Gas plans to install approximately 8.5 miles of 12” HP pipeline from the current termination of FL 99 near Francis, Utah along state road SR-32, and terminating with a tie-in to Questar Gas’ FL 16 on SR-40.

In 2014, Questar Gas will commence with right-of-way acquisition and preliminary engineering studies along the proposed route. Questar Gas estimates spending approximately $500,000 in 2014 with a revenue requirement of $99,000. Current plans are to construct the pipeline extension starting spring 2015. The estimated 2015 expenditure for this project is $11,040,000, with an estimated revenue requirement of $1.9 million.

4. Heber City Reinforcement: This project was discussed in detail in the 2011-2012 IRP. Questar Gas completed the preliminary design for this project in 2008. Since then Questar Gas has been monitoring the area for load growth to determine the appropriate time to construct the project. With current load growth projections, it does not appear this project will be required until 2016 or later. The Company will continue to monitor this area for growth and report any changes, if needed, as part of the IRP variance report process.

5. 90th South Feeder Line Extension (Feeder Line 34): The route alternatives for this project were discussed in detail in the 2011-12 IRP. Questar Gas finished the design phase and has started construction of certain sections of this project that required coordination with third-party entities. The majority of the project is currently scheduled to start construction in June 2013. The estimated cost for this project is $1,800,000 with a revenue requirement of $314,000. Any change in project scope or cost will be detailed, if needed, as part of the IRP variance report process.

6. Utah Feeder Line Reinforcement Projects: Questar Gas is currently starting planning for feeder line projects in Mapleton and North Ogden. These projects will likely take place in the 2015 or 2016 construction seasons. At this time, Questar Gas has not established route possibilities or developed options for constructing these projects. Questar Gas will provide updates, including a comparison of options, as part of the IRP Variance Report process.

7. Feeder Line Replacement Project: Questar Gas is continuing its Feeder Line Replacement program in 2013 with replacements planned on FL 8, FL 14, FL 20, FL 36, FL 41 and FL 50. Pursuant to the Utah Commission’s order approving the Settlement Stipulation, in Docket No. 09-057-16, the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs, and other relevant information.

Intermediate High-Pressure Projects

1. <u>Salt Lake City Belt Main Replacement</u>: The Salt Lake belt main replacement program was discussed in a technical conference with the Commission and Division on March 27 and in a follow-up meeting with the Division on April 29, 2013. The following is a summary.

   In 2011, Questar Gas began replacing large diameter IHP belt mains in Salt Lake City. Many of these mains are 1929 vintage and provide critical feed to the city. Questar Gas evaluated several replacement alternatives including bringing high-pressure into the downtown core to decrease IHP line sizes but this proved to be cost prohibitive. (The belt mains could only be downsized from 16 to 12-inch.) To date, approximately 5,500 linear feet or 3% of the total has been replaced.

   In 2013, Questar Gas will replace 2,300 linear feet of 16-inch IHP steel belt main on 1000 East from South Temple to 300 South. On south Temple, an additional 375 linear feet of 14-inch IHP steel main will also be replaced. Approximately 4,800 linear feet of 2-inch IHP plastic main will also be installed to remove services from the belt main. The total estimated project cost for 2013 is $1,500,000 with a revenue requirement of $249,000. There are no viable alternatives for replacement of vintage main.

   In 2014, Questar Gas plans to replace an additional 4,100 linear feet of 16-inch IHP steel belt main on 1000 East from 300 South to 800 South. A portion of this line will be relocated to 900 East (between 300 South to 500 South) to avoid crossing conflicts at 400 South. Approximately 3,000 linear feet of 2-inch IHP plastic main will also be installed to remove services from the belt main. The total estimated project cost for 2014 is $2,000,000 with a revenue requirement of $375,000. There are no viable alternatives for replacement of vintage main.

   In 2015, Questar Gas plans to replace 8,700 linear feet of 10-inch IHP steel belt main on 400 South from 1000 East to 200 West. The 10-inch steel main will be replaced with 8-inch plastic. Because the 8-inch plastic main can be shut down without valves, services will be tied to it. The total estimated project cost for 2015 is $2,500,000 with a revenue requirement of $469,000. There are no viable alternatives for replacement of vintage main.

2. <u>Utah County Belt Main Replacement:</u> The Utah County belt main replacement program was discussed in a technical conference with the Utah Commission, the Division and the Office on March 27 and in a follow-up meeting with the Division on April 29, 2013. The following is a summary.

   In 2011, Questar Gas began replacing large diameter IHP belt mains in Utah County. Many of these mains are 1931 vintage and provide critical feed to Provo City. To date, approximately 22,000 linear feet or 60% of total has been replaced.

In 2013, Questar Gas will install 2,500 linear feet of 10-inch IHP steel main from State Street to a new regulator station on 900 South. This new station allowed the downsizing of 1.9 miles of belt main (from 16-inch steel to 8-inch plastic) to the south. Questar Gas plans to replace approximately 2,000 linear feet of 12-inch IHP steel belt main with 10-inch steel on 400 South from 500 East to 100 East. Approximately 1,900 linear feet of 4-inch IHP plastic main will also be installed to remove services from the belt main. Questar Gas also plans to replace approximately 500 linear feet of 10-inch IHP steel belt main with 8-inch plastic near 900 North 800 West, a portion of which crosses the Provo River. The total estimated project cost for 2013 is $1,250,000 with a revenue requirement of $208,000. There are no viable alternatives for replacement of vintage main.

In 2014, Questar Gas plans to replace 5,100 linear feet of 10-inch and 12-inch IHP steel belt main on 400 South from 100 East to 800 West with 10-inch steel and 8-inch plastic. The total estimated project cost for 2014 is $700,000 with a revenue requirement of $131,000. There are no viable alternatives for replacement of vintage main.

In 2015, Questar Gas plans to replace approximately 6,300 linear feet of 10-inch IHP steel belt main on 800 West from 900 North to 400 South with 8-inch plastic. Questar Gas also plans to replace approximately 1,000 linear feet of 10-inch IHP steel main on 300 North from 800 West to 600 West with 6-inch plastic. The total estimated project cost for 2015 is $700,000 with a revenue requirement of $131,000. There are no viable alternatives for replacement of vintage main.

3. <u>Weber County Belt Main Replacement:</u> The Weber County belt main replacement program was discussed in a technical conference with the Utah Commission, the Division and the Office on March 27 and in a follow-up meeting with the Division on April 29, 2013. Questar Gas will continue to evaluate these lines for future replacement and will offer further updates on the Company's plans for replacement in future Variance Reports and/or Integrated Resource Plans.

4. <u>Eastern Utah System Replacements</u>: Questar Gas acquired the distribution systems in Moab, Vernal, and Monticello from Utah Gas Company in 2001. After several years of operation, it was determined that these systems were in need of replacement.

   In 2009, Questar Gas began a replacement program. Replacements in Monticello have been completed. Work in Moab and Vernal is underway. In 2013, Questar Gas will complete the work below.

   Moab Replacements: Approximately 70,000 lf of main and 500 services will be replaced. A majority of the main (53,000 lf) will be 2-inch plastic. The total estimated project cost for 2013 is $2,600,000 with a revenue requirement of $389,000. There are no viable alternatives for replacement.

Vernal Replacements: The scope of work for Vernal is still being determined and will be based on budget availability. It is likely to cost less than $1 million.

Project Summary

2013 Projects:

1. Hunter Tap Gate Station.
2. Central Gate Station.
3. St. George Reinforcement.
4. Feeder Line 26 Uprate Project.
5. 90^{th} South Extension (Feeder Line 34).
6. Continuation of the Feeder Line Replacement Project.
7. Continuation of the Belt Main Replacement Project.

2014 Projects:

1. Pre-engineering for Charleston Reinforcement Project (Feeder Line 99 Extension).
2. Continuation of the Feeder Line Replacement Project.
3. Continuation of the Belt Main Replacement Project.

2015 Projects:

1. Continuation of the Feeder Line Replacement Project.
2. Continuation of the Belt Main Replacement Project.
3. Charleston Reinforcement Project (Feeder Line 99 Extension).

Integrity Management Plan Activities and Associated Costs

Overview

Questar Gas Company continues to implement integrity 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 Part 192 Subpart O). 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[34]. Once these high consequence areas are defined, a risk score is then calculated for each segment located in the high consequence area. These risk scores are then summed up for each unique feeder line. These risk scores establish the baseline and sets the priority for when these segments are assessed for integrity. The verification of high consequence areas and calculating the risk score is completed

[34] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operating Pressure (MAOP) at or above a pressure that produces a hoop stress of 20% of specified Minimum Yield Strength (SMYS).

on an annual basis. Questar Gas Company had ten years[35] to complete the baseline assessment of all segments in high consequence areas. As explained in the technical conference on March 27, 2013, Questar Gas completed its baseline analysis, with the exception of 1,041 feet of non-contiguous pipe segments located in casing. Each segment must be reassessed at intervals not exceeding seven years or sooner depending on the results of the initial assessment.

Questar Gas Company is required by the transmission integrity rule to conduct additional preventive and mitigative measures on feeder lines in high consequence areas and class[36] 3 and 4 locations. These additional measures include monitoring excavations (excavation standby) near these feeder lines and performing semi-annual leak surveys. Other integrity activities include annual high consequence area validation 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 with the following elements:

> Knowledge; identify threats; evaluate and rank risks; identify and implement measures to address risks; measure performance, monitor results, and evaluate effectiveness; periodically evaluate and improve program; and report results.

Questar Gas Company continues to implement activities defined in its Distribution Integrity Management plan for the distribution system. The activities are implemented to mitigate the threats that are identified in the plan.

Transmission Integrity Management

Costs

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

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. The most common threats on the pipeline include the following: external corrosion, internal corrosion, and third party damage. The assessment methods utilized to address these threats are external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), direct visual examination, and inline inspection.

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[35] The baseline assessment must be completed by 12/17/2012 (49 CFR §192.921 (d)).
[36] Class location as defined by 49 CFR Part 192 (§192.5).

The Baseline Assessment Plan was completed in December of 2012, with the exception of 1,041 feet of non-contiguous pipe segments located in casings. There were a total of 10 segments located in casings that were not assessed prior to the December 17, 2012 deadline. These segments are scheduled for final assessment in May of 2013. Questar Gas filed for a special permit to extend the deadline for completing the baseline assessment for these 10 segments.

External Corrosion Direct Assessment

ECDA is an assessment method that evaluates the integrity of pipeline segments for the threat of external corrosion. This includes segments of cased gas transmission pipelines. Refer to Figure 1 for an overview of the ECDA process.

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

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

2. Indirect Inspection - The Indirect Inspection step utilizes above ground inspection methods (such as close interval survey, pipeline current mapper or direct current voltage gradient survey) to identify and quantify the severity of coating faults and areas of diminished cathodic protection. The analysis of this data can help identify areas along the pipeline segment where corrosion may have occurred or may be occurring. 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. Indications for indirect inspections are categorized according to severity. A third indirect inspection tool is required for initial assessments of the segment.

3. Direct Examination – This step includes excavations of the pipe for direct examination to determine if there is corrosion occurring on the pipeline. For initial assessments, a minimum of two excavations are required for each ECDA region and a minimum of four excavations in total for the ECDA project. The ECDA project may contain more than one pipeline and more than one ECDA region. Reassessments require a minimum of one excavation pre ECDA region and a minimum of two excavations in total for the ECDA project. The excavation sites are selected based on a review of the data collected during the pre-assessment and the indirect surveys. This information is used to identify the most likely areas on the pipeline within each region where external corrosion is most likely. The required excavations also include an excavation at a location where no indications are identified. This site is used to help validate the effectiveness of

the ECDA process. During the Direct Examination step, when corrosion or other pipeline damage or coating damage is found, the pipe or coating is repaired. Additional sites may be selected for examination based on the findings of the required direct examinations.

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 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.

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

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

ICDA was included in the initial baseline assessment plan but will not be required going forward. After completing the initial assessments for internal corrosion and based on the findings of no internal corrosion, the ICDA process will not be required. The threat of internal corrosion is being addressed through the implementation of Questar Gas' internal corrosion plan.

Visual Examination of Above-Ground Pipe and Pipe in Vaults

Above ground piping (i.e. spans) and piping in vaults that are located in high consequence areas that will not or cannot be assessed utilizing other methods are assessed by visual examination.

Inline Inspection

Pipelines that are constructed and configured or are retro-fitted in such a way as to allow for inline inspection are assessed by inline inspection tools also referred to in the industry as "smart pigs." These tools are equipped with sensors that collect data as the tool travels through the pipeline and can reveal areas of wall loss and dents that may require repair or cutout. Some of the pipelines in Questar Gas' system are currently capable of utilizing this method of assessment. As aging infrastructure is replaced, these new pipelines are being designed and built to accommodate inline inspection tools. There are also advancements being made in new technology that allow some limited application of inline inspection tools for non-piggable pipelines that Questar Gas has helped fund through their research and development program. These advanced tools have been used by Questar Gas to assess locations of their system that were not previously assessable without this new technology.

The inline inspection tools provide specific data on the condition of the pipeline segment being inspected. The data that is collected along the pipeline segment is analyzed for defects and areas of concerns (e.g. wall loss or dents) are excavated for further evaluation and repair or cut out if necessary.

High Consequence Area (HCA) Validation

Each year, Questar Gas conducts an on-the-ground survey of all transmission line segments to validate the current HCAs as well as any new potential sites that may trigger a new HCA. Sites that may trigger a new HCA include the following: office buildings, businesses, community centers, churches, day care centers, retirement centers, hospitals, and prisons.

This information is maintained in Questar Gas' mapping system and is used to calculate HCA areas along each transmission segment on an annual basis.

Distribution Integrity Management

Costs

See attached table (Table 3- Distribution Integrity Management Costs) for details on the anticipated costs associated with distribution integrity management.

Implementation

Questar Gas implemented their written distribution integrity management plan in August of 2011. Implementation included identifying the threats associated with the distribution system within each operating region as well as calculating a risk score for each identified threat. The risk scores are derived by utilizing known infrastructure data and leak history. The threats and the associated risk scores are validated by operating personnel within each operating region. Once the threats were identified and the risk scores calculated for each threat, each operating region identified possible measures that could be implemented or are currently being implemented that would help mitigate the risks on the distribution system. The process of identifying threats and calculating the risk for each threat is an ongoing process and will be done on an annual basis.

New Regulations That May Impact Future Costs Associated With Integrity

The Pipeline Safety Improvement Act of 2011 requires the Office of Pipeline Safety to study the following items:

1. Automatic and Remote-Controlled Shut-Off Valves for New Transmission Lines – The study will review the benefits of requiring operators to install either automatic or remote-controlled shut-off valves on transmission lines constructed or entirely replaced.

2. Integrity Management – The study will review if integrity management system requirements or elements of integrity management should be expanded beyond HCAs.

3. Excess Flow Valves – The study is looking at expanding the current requirement for installing excess flow valves on new or entirely replaced distribution branch services, multifamily facilities, and small commercial facilities.

Figure 10 – ECDA Process Overview

Table 2 – Transmission Integrity Management Costs

$ Thousands

Activity	2013	2014	2015
Transmission Integrity Management			
ECDA (Utah Only)			
Pre-Assessment			
2013 (FL18, 19, 21, 22, 47, 51, 53) (38 HCA miles @ 2K/mile)	76		
2014 (FL23, 28, 29, 71, 81) (23 HCA miles @ 2K/mile)		46	
2015 (FL64, 65, 66, 68, 69, 70, 72, 74, 83, 84, 99) (14 HCA miles @ 2K/mile)			28
Indirect Inspections			
2013 (FL18, 19, 21, 22, 47, 51, 53) (38 HCA miles @ 30K/mile)	1140		
2014 (FL23, 28, 29, 71, 81) (23 HCA miles @ 30K/mile)		690	
2015 (FL64, 65, 66, 68, 69, 70, 72, 74, 83, 84, 99) (14 HCA miles @ 30K/mile)			420
Direct Examinations			
2011 ECDA (casings – carried over) (FL11, 26, 34) (Pipetel[34] - 2 sites, 3 casings @ 125K/site)	250		
2012 (FL06, 12, 13, 24, 33, 46) (13 excavations @ 12 K ea.)	156		
2013 (FL18, 19, 21, 22, 47) (15 excavations @ 12 K ea.)	60	120	
[37]Pipetel is a self-propelled inline inspection tool equipped with wall loss sensors and cameras.			

Table 2 – Transmission Integrity Management Costs

$ Thousands

Activity	**2013**	**2014**	**2015**
2013 (FL18, 19, 21, 22, 47) (Pipetel – 5 sites, 5 casings @ 150K site)		750	
2014 (FL23, 28, 29, 71, 81) (20 excavations @ 12 K ea.)		120	120
2014 (FL23, 28, 29, 71, 81) (Pipetel - 4 sites, 4 casings @ 150 K ea.)			600
2015 (FL64, 65, 66, 68, 69, 70, 72, 74, 83, 84, 99) (24 excavations @ 12K/ea.)(12 in 2015, 12 in 2016)			144
2015 (FL64, 65, 66, 68, 69, 70, 72, 74, 83, 84, 99) (Pipetel – 3 sites, 3 casings @ 150K/site) complete in 2016			
Post Assessment			
2013 (FL18, 19, 21, 22, 47) (38 HCA miles @ 1.5 K/mile)	57		
2014 (FL23, 28, 29, 71, 81) (23 HCA miles @ 1.5 K/mile)		34.5	
2015 (FL64, 65, 66, 68, 69, 70, 72, 74, 83, 84, 99) (14 HCA miles @ 1.5 K/mile)			21
ICDA (Utah Only)			
ICDA Complete, no longer required			
Inline Inspection			
2011 ILI (FL 26) Excavations (2 @ 12K ea.)	24		
2013 (FL04)	300		

Table 2 – Transmission Integrity Management Costs

$ Thousands

Activity	**2013**	**2014**	**2015**
2013 Excavations/ Validation Digs/ Remediation (3 excavations @ 12 K ea)	36		
2013 Casings – Pipetel (6 sites, 6 casings @ 150 K/site)	900		
2014 (FL85)		350	
2014 (FL71)		350	
2014 Excavations/ Validations Digs/ Remediation (4 excavations @ 12 K ea)		180	
2014 Casings – Pipetel (3 sites, 3 casings @ 150K/site)		450	
2015 (FL26)			350
2015 (FL104)			350
2015 (FL71)			300
2015 Excavations/ Validations Digs/ Remediation (15 excavations @ 12 K ea)			180
2015 Casings – Pipetel (4 sites, 4 casings @ 150 K/site)			600
Direct Examination – Spans and Vaults			
2013 - Spans Reassessment (7 @ 10K/span)	70		
2013 - Vaults (8 @ 10K/vault)	80		
2014 – Spans Reassessment (7 @ 10 K/span)		70	

Table 2 – Transmission Integrity Management Costs

$ Thousands

Activity	**2013**	**2014**	**2015**
2014 – Vaults (8 @ 10K/span)		80	
2015 – Spans Reassessment (7 @ 10K/span)			70
2015 - Vaults (8 @ 10K/vault)			80
Pressure Test Assessment			
2013 Casings (4 casings @ 100K/casing)	400		
2014 Casings (4 casings @ 100K/casing)		400	
2015 Casings (4 casings @ 100K/casing)			400
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
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
Additional Cathodic Protection Survey			

Table 2 – Transmission Integrity Management Costs

$ Thousands

Activity	**2013**	**2014**	**2015**
System Integrity Support - Cathodic Protection (2080 hrs x $70.00/hr)	145.6	145.6	145.6
Administration			
Project Coordination (3 employees (2080 hrs x 3 x $70.00/hr))	436.8	436.8	436.8
Engineer - Operations Support (0.5 employee (2080 hrs x 0.5 x $70.00/hr))	72.8	72.8	72.8
Data Integration Specialists (1.5 employees (2080 hrs x 1.5 x $70/hr))	218.4	218.4	218.4
Technical Writer – Intern (1 employee (1040 hrs @ $30/hr))	31.2		
Consultant – 3rd Party Plan Review	25		25
Supervisor (2080 hrs x $70/hr)	145.6	145.6	145.6
Manager (1040 hrs x $70/hr) 50% TIMP/ 50% DIMP	72.8	72.8	72.8
Training (for IM and Engineering personnel)	22.45	22.45	22.45
Transmission Integrity Management Total ($ Thousands)	$ 5,351	$ 5,387	$ 5,134

Table 3 – Distribution Integrity Management Costs

Activity	2013	2014	2015
	$ Thousands		
Distribution Integrity Management			
NOTE: *The costs estimated here are based on additional and accelerated actions initiated based on the threats identified. The costs also reflect the administration costs associated with this new regulation.*			
Additional and Accelerated Actions			
Stray Current Surveys	350	350	350
Additional Leak Survey	300	300	300
Region Specific Accelerated Actions	150	150	150
Administration			
Engineer – Operations Support (0.5 employee (2080 hrs x 0.5 x $70.00/hr))	72.8	72.8	72.8
Data Integration Specialists (0.5 employees (2080 hrs x 0.5 x $70/hr))	72.8	72.8	72.8
Manager (1040 hrs x $70/hr) 50% TIMP/50% DIMP	72.8	72.8	72.8
Training (for IM and Engineering personnel)	12	12	12
Distribution Integrity Management Total ($ Thousands)	$ 1,030.40	$ 1,055.40	$ 1,030.40

Environmental Review

Questar Gas is committed to compliance with environmental laws and regulations. Some of the regulations with which Questar Gas must comply include the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, and the National Historic Preservation Act, as well as similar state and local laws.

Agencies permitting and enforcing these regulations frequently place restrictions on company activities. Requirements have become more stringent over time and can affect the location and construction of Questar Gas infrastructure. When projects may impact the environment, regulatory agencies require permit applications, agency review and public comment periods prior to permit approval. Permit conditions can be rigorous and costly, requiring compliance activities long after project completion, and sometimes for the life of the installation. For example, the U.S. Fish and Wildlife Service may designate critical habitat areas to protect certain listed threatened and endangered species. A critical habitat designation for a protected species, such as the sage grouse or desert tortoise, can result in restrictions to federal and state land use which can delay or prohibit access or use of that land. Because Questar Gas infrastructure crosses many miles of federal and state lands that include the critical habitat of listed plant and animal species, there can be a material impact on location of pipeline facilities and construction schedules. The Clean Water Act and similar state laws regulate discharges of storm water, hydrostatic test water, wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges or accidental releases could result in civil and criminal penalties, orders to cease such discharges, corrective actions, and other costs and damages.

Pre-existing conditions complicating project construction include situations where Questar Gas's pipelines, both new and existing, cross contaminated sites owned by third parties. These sites, usually regulated by the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or comparable state regulations, require corrective actions as construction activities proceed. Soils disposition must be determined prior to construction (when presence of the contamination is known), employees properly trained and equipped with protective equipment, and proper disposal and decontamination procedures invoked. Accidental spills and releases requiring cleanup may also occur in the ordinary course of business, requiring remediation; substantial costs may be incurred to take corrective actions in all of these cases. As standards change, the Company may incur significant costs in situations where past operations followed practices that were considered acceptable at the time but now require remedial actions to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, or injunctions.

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

The U.S. EPA adopted the Greenhouse Gas (GHG) Reporting Regulations for the measurement and reporting of carbon dioxide equivalent (CO_2e) emissions emitted from combustion at large facilities (emitting more than 25,000 metric tons/year of CO_2e) that began with 2010 emissions. That year Questar Gas reported 7.5 million metric tons of CO_2e emissions attributable to combustion emissions for all of its customers except those emissions of downstream natural gas local distribution company customers and industrial customers using more than 460 MMCF of natural gas annually for 2010. Reporting under this regulation was expanded to include measurement and reporting of GHG emissions attributed to fugitive methane emissions starting in 2011, incorporating measurement and monitoring of gate-station methane emissions for Questar Gas. Questar Gas reported 7.7 million metric tons of CO_2e emissions in Utah in 2011, with approximately 66,260 metric tons attributable to fugitive emissions. For 2012, Questar Gas' Utah emissions totaled approximately 6.35 million metric tons, with about 67,500 metric tons due to fugitive methane. The difference in quantity of GHG emissions from 2011 to 2012 may be related to the mild winter conditions in 2012, resulting in less natural gas flowing into the Questar Gas distribution system for use in residential appliances.

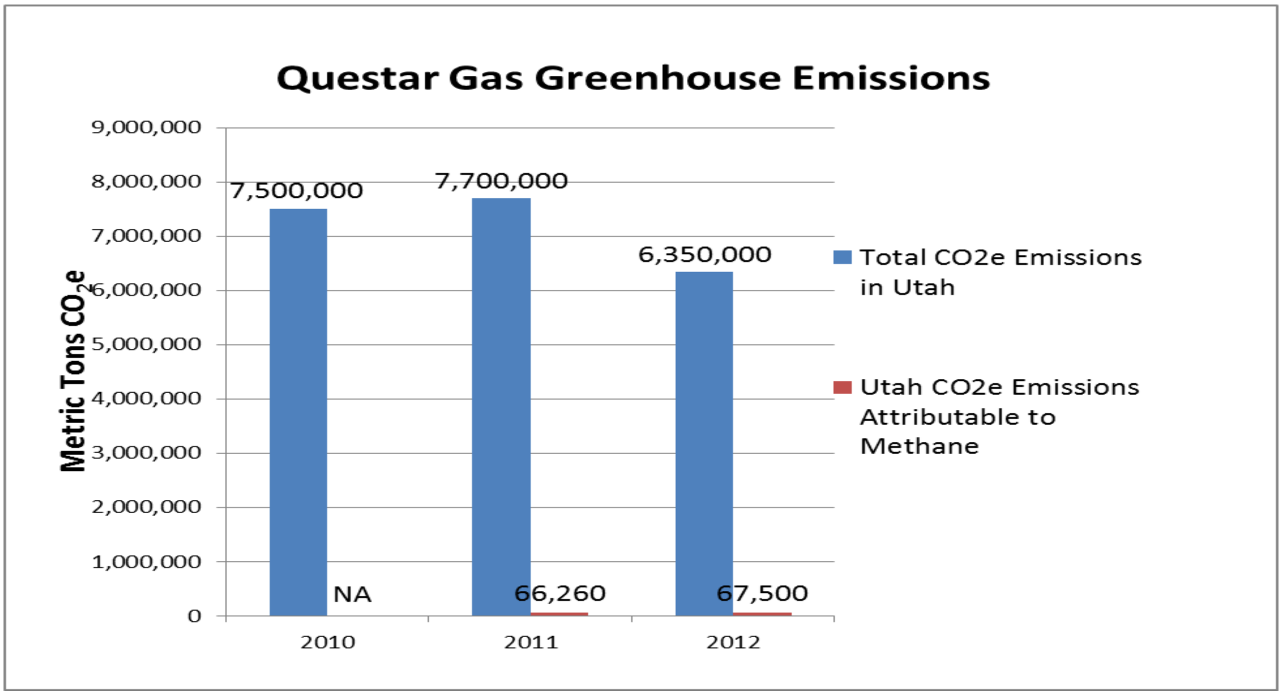

Figure 11

Questar Gas believes that it is important for the natural gas industry to be able to scientifically estimate methane emissions from fugitive emissions. In the past, Questar Gas has participated in industry studies to quantify these emissions. In 2013, Questar Gas will participate in the Environmental Defense Fund's (EDF) project to estimate leakage from the local distribution system, one module of a 5-part study to quantify methane emissions across the natural gas value chain. This study, conducted collaboratively with industry, academia, a consultant and the EDF, will identify realistic GHG emissions factors for the natural gas industry that could then be applied in EPA's GHG Reporting Rule.