First Quarter Variance Report

June 2022
Through
August 2022
Docket No. 22-057-02

Dominion Energy Utah
First Quarter Variance Report
June 2022 –August 2022

Questar Gas Company *dba* Dominion Energy Utah (Dominion Energy or Company) respectfully submits this First Quarter Variance Report for the period June 2022 – August 2022. This report identifies the variance between the actual results and the projections set forth in the 2022 - 2023 Integrated Resource Plan (IRP).

Weather — Exhibits 1.1 – 1.3

During the first quarter, June was warmer than normal and had fewer heating degrees days than expected. July and August had near-normal temperatures.

Gas Storage — Exhibits 2.1 – 2.4

In the first quarter, Clay Basin inventory started lower than the 2022 – 2023 IRP estimates. Cooler temperatures and higher prices resulted in a lower beginning inventory in May. The Company avoided higher purchase prices in July and August by not filling storage to forecasted levels in the first quarter. See Exhibit 2.1

Aquifer inventory was slightly higher than the 2022 – 2023 IRP estimates for the entire quarter due to a slightly higher-than-anticipated starting level. See Exhibit 2.2

Firm Sales — Exhibits 3.1 – 3.4

Actual sales through the first quarter of the 2022 – 2023 IRP year were 12% lower than projected normal-weather usage. Most of the variance occurred in the month of June when actual heating degree days were 41% below the normal. See Exhibit 3.1.

Gas Purchased from Third Parties Volume Variance — Exhibits 4.1 – 4.3

Gas purchases for June were below the forecasted purchase amounts. Purchases were limited through the first quarter due to much higher than forecasted pricing during the quarter. Gas being purchased during the first quarter is mostly used to fill storage inventories and supply La Barge and Big Piney. Updated model guidance, based on updated pricing forecasts, suggested waiting on purchases until later in the summer. See Exhibit 4.1.

Gas Purchased from Third Parties Cost Variance — Exhibits 5.1 – 5.3

Purchase gas costs were slightly lower in June of the first quarter due to the reduced purchased volumes. The purchased gas costs for July and August were higher than expected despite reduced volumes due to the high unit costs. Prices were extremely volatile during the entire quarter. See Exhibit 5.1.

Gas Purchased from Third Parties Unit Cost Variance — Exhibits 6.1, 6.2

In June, purchase gas unit costs increased and rose significantly toward the end of the quarter. High pricing continued to be driven by high global demand for LNG due to high pricing in Europe and Asia. Also, high pricing in offsetting fuels, such as coal, continued to prevent gas-to-coal switching in the power generating sector. See Exhibit 6.1.

Cost-of-Service Gas Exhibits 7.1 – 7.3

The cost-of-service gas production was slightly higher than expected for June and July and near projections for August. This variance was in part due to the inclusion of production of the newly acquired Alkali Gulch acquisition. However, in August the production increases were offset by compressor downtimes associated with maintenance of wells spread across multiple fields, along with delays in new drill in the Island Unit. See Exhibit 7.1.

Cost-of-Service Gas New Drill Component Exhibits 8.1 – 8.3

Expected new drill in was near projections for June and lower than expected in July and August. Delays in the new drill were caused by supply chain issues. See Exhibit 8.1.

Table 1 below summarizes purchase and cost-of-service volume variances using 2022 – 2023 IRP projections and actual results as a percent of total. The 2022 – 2023 IRP projected purchase gas is expected to be 9.33% for the quarter. The actual purchase gas percentage came in at 6.91%, lower than the forecast.

TABLE 1

	Actual Purchase as Percent of Total	Normal Purchase as Percent of Total	Actual Cost-of-Service as Percent of Total	Normal Cost-of-Service as Percent of Total
Jun-22	9.69%	13.94%	90.31%	86.06%
Jul-22	5.05%	5.95%	94.95%	94.05%
Aug-22	5.91%	7.71%	94.09%	92.29%
Q1	6.91%	9.33%	93.09%	90.67%

Table 2 below summarizes estimated average daily shut-in verses actual average daily shut-in during the first quarter. There were no shut ins during the quarter.

TABLE 2

	June	July	August	Total Dth for Quarter
Estimated Shut-in (dth/day)	159	158	157	14,505
Actual Shut-in (dth/day)	0	0	0	0

Supplemental Graphs Confidential Exhibits 9.1 – 9.3

These exhibits reflect source data for Cost-of-service, New Drill and Purchase Gas exhibits.

Average Market Price and Cost-of-Service Price Exhibit 10.1, 10.2

Exhibit 10.1 shows the price difference between cost-of-service gas and average market price. Exhibit 10.2 compares the actual market price with the trailing twelve months (TTM) price of cost-of-service gas on an into-pipe basis.

Modeling Adjustments

This summer, after filing the IRP, the Company discovered that the forecasted monthly production rates by nomination group for cost-of-service production were not correctly updated during the IRP modeling process. However, the total available cost-of-service production was correct in the IRP model. Before creating the variance file, the Company reran the model to get more accurate expectation of monthly production from each nomination group. These updated numbers are now being used in all IRP and operational models. As a whole the amount expected to be provided by cost-of-service production increased by a total of 1,200 MDTh for the entire IRP year which is a 2% increase.

Additionally, the Company did not initially include production from the Alkali Gulch acquisition in the IRP modeling because the acquisition had not yet been approved by the Commission. However, the production from these wells is now included in the actual production that the Company reports.

The Company also made adjustments to the model for injection-capacity limits for storage facilities in order to match actual current capacity amounts. MountainWest Pipeline adjusts injection and withdrawal capacities throughout the year. These capacity "ratchets" exceed the maximum guaranteed amount in the Company's contract with MountainWest Pipeline. The IRP model originally included the contractual amounts rather than the actual amounts. Now, the IRP model includes the ratcheted amounts.

Finally, the Company made adjustments in the model to prevent Clay Basin from being empty in March. The Company's Gas Control department has requested that the Company maintain a minimum of 1Mdth in Clay Basin inventory through March in order to be prepared for the colder weather that often occurs in March.

DNG Action Plan

The following projects were updated during the first quarter.

SY0002 Syracuse District Regulator Station and FL47 Extension for the SY0002 Station, Syracuse, Utah

The construction has commenced but will not be completed until the summer or fall of 2023 due to permitting issues.

WA1602 New FL13 East HP Regulator Station, District Regulator Station and ILI Facilities, Salt Lake City, Utah

The construction will commence this year but will not be complete until summer 2023 due to city permitting issues.

On-System LNG Facility, Magna, Utah

The liquified natural gas facility in Magna, Utah is on schedule to be in service in the 4th quarter of 2022 and will provide additional gas supply reliability in the 2022-2023 winter heating season. The liquefaction function is operational and the Company began filling the tank in November of 2022. The Company is filling the tank to a level where the vaporization can be tested. The Company anticipates testing the vaporization function in December. Per the discussion in the Company's pass-through filing in Docket 22-057-16, DEU and the DPU have agreed that DEU will only partially fill the LNG facility to allow three to four days of withdrawal capacity this winter heating season.

Rural Expansion Update

The Company completed construction on the majority of the Eureka system in mid-November 2021. It has commenced natural gas service to some customers, and more customers are in the process of converting their equipment to safely burn natural gas. The Company remains in contact with Eureka city officials and customers to ensure that homes are properly and safely converted.

The Company completed construction on the majority of the Goshen and Elberta systems on November 14, 2022. As of November 21, 2022, 256 customers had signed up for service in those communities. Service lines have been installed for 214 of those customers, and 26 meters have been installed. The Company remains in contact with Goshen and Elberta city officials and customers to ensure that homes are properly and safely converted.

The Company continues to make progress toward providing service to the community of Green River Construction of the Green River project will begin in early 2023. Engineering, design, and permit acquisition are all under way for the remaining work in that community

Heating Degree Day Graphs
Exhibit 1.1 – 1.3
Docket No. 22-057-02

Gas Storage Graphs
Exhibits 2.1 – 2.4
Docket No. 22-057-02

Firm Sales Graphs
Exhibits 3.1 – 3.4
Docket No. 22-057-02

Gas Purchased From Third Parties

Volume Variance Exhibits 4.1 – 4.3 Docket No. 22-057-02

Gas Purchased
From Third Parties

Cost Variance
Exhibits 5.1 – 5.3
Docket No. 22-057-02

Gas Purchased From Third Parties

Unit Cost Variance Exhibits 6.1 – 6.2 Docket No. 22-057-02

Cost-of-Service Gas
Exhibits 7.1 – 7.3
Docket No. 22-057-02

Cost-of-Service Gas
New Drill Component
Exhibits 8.1 – 8.3
Docket No. 22-057-02

Data
Confidential
Exhibits 9.1 – 9.3
Docket No. 22-057-02

Average Market Price and Cost-of-Service Price
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