Office of the Secretary
Service Date
February 23, 2018

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INTEGRATED RESOURCE PLAN FILING OF INTERMOUNTAIN GAS COMPANY	**CASE NO. INT-G-17-04** **ORDER NO. 33997**

On August 4, 2017, Intermountain Gas Company (Company) filed its Integrated Resource Plan (IRP) for the years 2017-2021. The Company files an IRP every two years to describe the Company's plans to meet its customers' future natural gas needs. The IRP must discuss the subjects required by Commission Order Nos. 25342, 27024 and 27098, and section 303(b)(3) of the Public Utility Regulatory Policies Act (PURPA), 15 U.S.C. § 3202. The Commission reviews the IRP to ensure that it discusses these subjects and represents a diligent effort by the Company to plan for the anticipated supply and demand for natural gas.

The Commission issued a Notice of Filing that provided notice of the IRP and set a deadline for submitting Petitions to Intervene. Order No. 33870. No Petitions to Intervene were received. The Commission then issued a Notice of Modified Procedure setting deadlines for comments and reply comments. Order No. 33922. Commission Staff timely submitted the only comments filed in the case. The Commission now issues this Order acknowledging the IRP.

BACKGROUND

A natural gas IRP describes a company's plans to meet its customers' future natural gas needs. In Order No. 25342, the Commission adopted IRP requirements for local gas distribution companies in response to amended Section 303 of the Public Utility Regulatory Policies Act of 1978 (PURPA). In Order No. 27024, the Commission shortened the required planning horizon from 20 years to at least 5 years. Order No. 27098 removed any requirement that IRPs formally evaluate potential demand-side management (DSM) programs, and instead directed the companies to explain whether cost-effective DSM opportunities exist. In summary, these three orders direct gas utilities to file an IRP every two years that includes:

1. A forecast of future gas demand for each customer class, which includes the number, type, and efficiency of gas end-users as well as effects from economic forces on gas consumption;

2. An analysis of gas supply options for each customer class, which includes a projection of spot market versus long-term purchases for both firm and interruptible markets, an evaluation of the opportunities for using company-owned or contracted storage or production, an analysis of prospects for company participation in a gas futures market, and an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers;

3. A comparative analysis of gas purchasing options, and an explanation of whether there are cost-effective DSM opportunities;

4. The integration of the demand forecast and resource evaluations into a long range (at least a five-year) plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers;

5. A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the IRP;

6. A progress report that relates the new plan to the previously filed plan; and

7. Public participation.

Additionally, in its order on the Company's 2013 IRP, the Commission allowed the Company to stop filing semi-annual lost and unaccounted for gas (LAUF Gas) reports.[1] Instead, the Company was to discuss LAUF Gas in the Company's future Purchased Gas Cost Adjustment (PGA) cases[2] and IRPs. The IRP's LAUF Gas section must explain the Company's (a) framework for how it has tested for, identified, and remediated equipment measurement errors or leaks, and (b) business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing. *See* Order No. 32855. Finally, in its order on the Company's 2015 IRP, the Commission directed the Company to include more detail in its future IRPs about how the Company calculates avoided costs and uses those calculations to determine whether natural gas DSM opportunities are or are not cost-effective. *See* Order No. 33314.

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[1] LAUF Gas is the difference between the amount of natural gas delivered to the Company's distribution system at the city gate and amount of natural gas ultimately recorded at the customers' meters.

[2] The Company files a PGA each year to adjust rates to reflect changes in the Company's costs to buy natural gas from suppliers—including transportation, storage, and other related costs.

INTERMOUNTAIN'S IRP FILING

The Company regularly forecasts the demand of its growing customer base and determines how to best meet that demand. The Company's IRP represents a snapshot in time of the Company's ongoing planning process; it describes the anticipated conditions over a five-year planning horizon, the anticipated resource selections, and the process for making resource decisions. *See* IRP at 2. The Company sells natural gas to two major markets: the residential/commercial market and the industrial market. In 2016, the Company served an average of 313,000 residential customers and 32,000 commercial customers, which is a 2.2% increase in average residential and commercial customers from 2011. Residential and commercial customers use natural gas primarily for space and water heating. Industrial customers use natural gas for boiler and manufacturing applications. The agricultural economy and the price of alternative fuels strongly influence industrial demand for natural gas. In 2016, industrial sales and transportation accounted for 52% of the throughput on Intermountain's system. *Id.* at 2-3.

In this IRP, the Company forecasted changes to its peak-day loads due to customer growth under base case, and high- and low-growth economic scenarios. The Company forecasted a base case growth scenario in which its total residential, commercial, and industrial peak-day loads increase each year for five years by an average of 2.68%. According to the Company, this increase in peak-day loads corresponds to expected growth in the Company's markets for residential and small commercial customers. The Company saw no peak-day delivery deficits over the next five years when it matches its forecasted peak-day delivery against its existing resources. *Id.* at 3- 4.

The Company also analyzed different geographic areas so it can plan to meet any projected deficits in those areas. In this IRP, the Company analyzed the Idaho Falls Lateral, the Sun Valley Lateral, the Canyon County Region, the State Street Lateral, and the Central Ada Area. *Id.* at 5-10.

The Idaho Falls Lateral is 104 miles long and serves cities between Pocatello and St. Anthony in eastern Idaho. It served about 15% of the Company's customers and 14% of the Company's projected peak-day delivery for January 2017. The Company stated that matching the Idaho Falls Lateral's forecasted peak-day delivery against its existing peak-day capacity showed that the Company can meet this area's peak-day demands for the five-year IRP period. The Company also noted that the Company can use its portable liquefied natural gas (LNG) facility in

Rexburg to reduce system peak loads and meet customer demand by supplementing firm capacity on the lateral during peak-day events. The Company planned to use the Rexburg LNG facility's additional capacity in 2021. *Id.* at 5-6.

The Sun Valley Lateral served about 3% of the Company's total customers and 3% of the Company's projected peak-day delivery for January 2017. The Company stated that matching the Sun Valley Lateral's forecasted peak-day delivery against its existing peak-day distribution capacity (199,500 therms) showed that the Company can meet this area's peak-day demands for the five-year IRP period. *Id.* at 6-7.

The Canyon County Lateral served about 14% of the Company's total customers and 19% of the Company's projected peak-day delivery for January 2017. The Company stated that matching the Canyon County Lateral's forecasted peak-day delivery against its existing peak-day distribution capacity (860,000 therms in 2019 and 930,000 therms in 2020) showed that the Company can meet this area's peak-day demands during the five-year IRP period. The IRP noted this region's diverse industrial customer base currently has limited ability to mitigate peak-day delivery by switching to alternative fuels. The Company is thus exploring other ways to enhance this area's distribution capability, mainly regarding potential biogas production. *Id.* at 7-8.

The State Street Lateral in northwest Boise is 16.2 miles long. It primarily serves residential and commercial customers that comprised about 14% of the Company's total customers and 15% of the Company's projected peak-day delivery for January 2017. The Company stated that matching the State Street Lateral's forecasted peak-day delivery against its existing peak-day distribution capacity (670,000 therms in 2019 and 765,000 therms in 2020) showed that the Company can meet this area's peak-day demands for the five-year IRP period. *Id.* at 9.

The Central Ada Area in the Boise area consists of multiple high-pressure pipeline systems. It serves a diverse base of residential and commercial customers that comprised about 15% of the Company's total customers and 12% of the Company's projected peak-day delivery for January 2017. The Company stated that matching the Central Ada Area's forecasted peak-day delivery against its existing peak-day distribution capacity (710,000 therms) showed that the Company can meet this area's peak-day demands during the five-year IRP period. *Id.* at 10.

In summary, the IRP analyzed residential, commercial, and industrial customer growth and its impact on the Company's distribution system using design weather conditions under various scenarios for Idaho's economy. The Company measured peak-day delivery under each customer growth scenario against the available natural gas delivery systems to project the magnitude and timing of delivery deficits on a total Company and regional perspective. The Company analyzed the resources needed to meet any projected deficits within a framework of options to help determine the most cost-effective means to manage the deficits. The Company explained that these options allow its core market and firm transportation customers to rely on uninterrupted service now and for years to come. *Id.* at 11.

STAFF COMMENTS

Commission Staff believed the Company's IRP is reasonable and should be acknowledged, but also identifies areas for improvement in future IRPs. Staff Comments at 3.

Staff believed the Company's demand forecast methodology is generally reasonable, and appreciated the Company's detailed explanation of its customer growth and peak weather forecasting methodologies. *Id.* at 3, 4. However, Staff recommended the Company further explain its models for estimating usage-per-customer and the time series models it applies, and how it uses its customer growth forecasts and weather models to determine a system growth rate. *Id.* at 4.

Staff identified two areas of the Company's system, the Canyon County Lateral and the State Street Lateral, where the Company indicated that no capacity deficit occurs during the IRP period (when forecasted demand is matched against existing peak-day distribution capacity), but where the Company also projected that an enhancement is needed within the IRP period. *Id.* at 5-7. In both cases, the Company's deficit analysis assumed distribution capacity increases in 2020, and Staff understood the increase is due to the enhancement project. *Id.* at 6, 7. Staff believed this practice—including future enhancements as existing delivery capability in the analysis of demand and resources—"obscures the magnitude and timing of potential capacity deficits and does not provide a transparent and robust method for comparing alternatives." *Id.* at 6 (*see also* 7). Staff recommended that in future IRPs, "the Company identify potential deficits by comparing expected demand to existing capability <u>without</u> planned enhancements." *Id.* (emphasis in original). Once deficits have been established, the Company should conduct a transparent and robust analysis of supply- and demand-side alternatives to resolve the deficits. *Id.* Staff also recommended the Company provide information regarding analysis of alternatives and an explanation of why a specific solution was selected. *Id.* at 7. Staff believed the Company's analysis of demand and available resources for the areas of its system was otherwise reasonable. *Id.* at 5.

Staff believed most of the Company's analysis of its supply options was reasonable, but identified concerns with its analysis of the Nampa LNG facility and DSM resources. *Id.* at 7. Specifically regarding the Nampa LNG facility, Staff asserted the Company did not provide sufficient information for Staff to assess the operation and cost-effectiveness of the facility, compared to other options. *Id.* at 8. Staff asserted such information is critical to developing a least-cost, least-risk plan, and recommended the next IRP include such operational and cost information. *Id.*

Regarding DSM resources, Staff acknowledged and supported many of the Company's efforts. *Id.* at 8-9. Staff also identified certain concerns and recommendations. First, Staff discussed a research and development project described in the 2017 IRP, and noted that it appears to be the same project discussed in the 2015 IRP. *Id.* at 9. Staff recommended the Company use the results of the research project to "develop or enhance programs in its service territory." *Id.*

Second, Staff had concerns with how the Company approaches DSM in its IRP. The IRP listed several DSM objectives, but omitted what Staff characterized as the "primary goal of DSM": to acquire cost-effective resources. *Id.* at 9. Staff also did not agree that the Company should focus solely on "the most" cost-effective DSM measures. *Id.* at 9-10. Rather, the Company should pursue <u>all</u> cost-effective DSM to ensure customers are provided all the available cost-effective resources. *Id.* at 10 (emphasis in original). Finally, Staff believed the IRP did not adequately model DSM as a resource. *Id.* Staff explained the Company selected certain DSM measures and included only the resulting therms savings. *Id.* Staff believed the Company should have modeled other DSM resources to determine which are cost-effective and therefore should be pursued. *Id.* Staff also indicated the IRP did not discuss how DSM could impact the Company's need for future and planned capacity upgrades or how DSM acquisition will impact its load forecast. *Id.* The Company also did not discuss how DSM avoided costs will be updated because of this IRP. *Id.*

Staff recognized that the Company's DSM program is new and that it will take time to implement and model a fully developed DSM portfolio. *Id.* Staff recommended the Company convene an energy efficiency advisory group to assist with the effort. *Id.* Staff believed the next IRP should include "a more robust analysis of DSM resources, including a modeling process by which DSM measures are selected based on cost-effectiveness, an explanation and update of avoided costs, and an explanation of the impact of DSM on supply and capacity needs." *Id.*

Finally, Staff discussed whether and how the Company had addressed certain items discussed by the Commission in its order on the Company's last IRP, Order No. 33314. *Id.* Staff believed that the Company had addressed some items but, as noted above, did not sufficiently explain enhancement projects, the calculation of DSM avoided costs, or how those costs are used to determine the cost-effectiveness of DSM resources. *Id.* at 10-11. Staff also indicated that public participation in the Company's development of its IRP remains a concern. *Id.* at 11. Staff acknowledged the Company increased the number of public IRP presentations (from three to four) and encouraged public feedback and input. *Id.* However, Staff emphasized "the Company should provide an opportunity for public involvement *as the IRP is being developed*—not simply after-the-fact." *Id.* (emphasis in original). Staff encouraged the Company to convene an IRP advisory group to improve public participation in developing future IRPs. *Id.* Finally, Staff acknowledged the Company's improvement in its LAUF Gas rate of 0.31%, which the Company reports as being one of the best in the industry. *Id.*

In sum, Staff's primary concern with the IRP was that it does not transparently or robustly analyze the supply and demand-side options for meeting capacity deficits. *Id.* Staff also believed the Company should provide more information about how it models its storage facilities and DSM resources, and that it should increase public involvement in developing the IRP. *Id.* Staff made the following recommendations for future IRPs:

1) Convene an IRP advisory group (made up of key stakeholders and open to the public).
2) Work with the IRP advisory group to develop an IRP that (a) identifies the magnitude and timing of potential deficits with existing resources, and (b) includes a transparent analysis of supply- and demand-side resource options to determine the most cost-effective solution to all identified deficits.
3) Include a more thorough explanation of per-customer consumption models and the time series models applied to them. Explain in more detail how the Company uses its customer growth forecasts and weather models to determine a system growth rate.
4) Describe how DSM avoided costs change because of the IRP.

In summary, Staff believed the IRP analyzed residential, commercial, and industrial customer growth and its impact on the Company's system under various scenarios. Peak-day demand under each scenario was measured against the Company's available natural gas delivery systems, including planned enhancements, to project deficits for each of several regions. The IRP determined there are no peak-day delivery deficits for the 2017-2021 IRP period. Staff believed the 2017 IRP is reasonable and recommended the Commission acknowledge it.

COMMISSION FINDINGS AND DECISION

Intermountain Gas Company is a natural gas corporation and public utility. *See Idaho Code* §§ 61-116, -117, and -129. The Commission has jurisdiction over the Company and the issues in this case under Title 61 of the Idaho Code, including *Idaho Code* § 61-501.

We have reviewed the record, including the Company's IRP and the Staff's comments. Based on our review, we find that the Company's IRP substantially complies with the Commission's prior orders. We thus acknowledge that the Company has filed its IRP. In doing so, we reiterate that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. It is a plan, not a blueprint, and by issuing this Order we merely acknowledge *the Company's ongoing planning process*, not the conclusions or results reached through that process. With this Order, we do not approve of the IRP or any resource acquisitions referenced in it, or endorse any particular element in it, and we offer no opinion on the prudency of the Company's election of its preferred resource portfolio. The appropriate place to determine the prudence of the IRP or the Company's decision to follow or not follow it, and the validation of predicted performance under the IRP, will be a general rate case or other proceeding in which the issue is noticed. *See* Order Nos. 24981 and 25342.

The Commission also acknowledges the Staff's comments. In particular, we find it reasonable that the Company should convene an IRP advisory group and work with the group to develop future IRPs that comprehensively and transparently consider demand, existing resources, and potential supply- and demand-side options for meeting any deficits. Such advisory groups have proven informative and helpful to other utilities in developing their IRPs. We strongly encourage the Company to also consider Staff's other comments and recommendations as it develops its future IRPs.

ORDER

IT IS HEREBY ORDERED that the filing of the Company's 2017-2021 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 23rd day of February 2018.

PAUL KJELLANDER, PRESIDENT

KRISTINE RAPER, COMMISSIONER

ERIC ANDERSON, COMMISSIONER

ATTEST:

Diane M. Hanian
Commission Secretary

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