UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

GAS TRANSMISSION NORTHWEST LLC	))))	**Docket No. CP22-2-000**

COMMENT BY WASHINGTON, OREGON AND CALIFORNIA REGARDING GAS TRANSMISSION NORTHWEST'S APRIL 18, 2023 DATA RESPONSE

While the Attorneys General for Washington, Oregon, and California (the "States") anticipate the Commission will identify the shortcomings of GTN's response, we file this comment to clarify the record. GTN does not respond meaningfully to the Commission's questions. At the outset, GTN's response confirms that it cannot show the GTN Xpress Project is unsubsidized. Because GTN cannot meet this threshold requirement, the Commission must deny GTN's Application and need not further analyze public need or conflict with State law.

Should the Commission choose to evaluate other factors, it must still deny the Application because GTN's precedent agreements fail to show public need, even without considering the impact of State laws. Relevant State laws do exist, however, and place mandatory restraints on future consumption of gas in the region. This further shows the Project is not required and is not in the public interest. Staff requested GTN to provide evidence that "gas consumption in the region is expected to increase, taking into account recent legislation." GTN Response to April 4, 2023 Data Request (April 18, 2023) ("GTN Response"), at 3. Despite this invitation from Staff, GTN provided no such evidence and asks the Commission to blind itself to these mandates in analyzing public need. The Commission should deny the Application.

I. GTN FAILS TO SHOW THE PROJECT LACKS FINANCIAL SUBSIDIES.

Although the Commission provided GTN an opportunity to do so, GTN failed to show the Project is unsubsidized. Instead, its response confirms that existing ratepayers will subsidize GTN's expansion because the Project does not include costs to replace compressor units at the Athol, Kent, and Starbuck Stations.

GTN's response shows that there was at least one smaller compressor that could have met the needs of existing shippers at Starbuck and Athol Stations, and possibly also at Kent Station. As staff will note, Table 8-1 states the smaller Solar Mars 100 would exceed the certificated output of 14,300 horsepower with the altitude and temperature conditions at each station except Kent. GTN Response 13. Thus, GTN's filing demonstrates that the larger compressor was *not* the "nearest reliable size available" for at least two of the three stations. GTN Response 12. Further, while the Solar Mars 100 could not reach 14,300 horsepower given the altitude and temperature conditions at Kent, neither could the prior unit, which GTN used without incident for roughly fifty years. *See id*. GTN has also not explained whether it looked for other smaller models, including electric models, before deciding on the larger option and imposing million-dollar costs on consumers. *See* States' Mot. Intervene and Protest (Aug. 22, 2022) ("States' Protest"), Ex. B, Lander Decl., 16-18; Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) ("1999 Policy Statement"), at 21 (noting a subsidy may exist where "new customers would not face the full cost of the construction that makes their new service possible" because existing customers bore those costs entirely).

GTN lacked incentive to look for smaller alternatives, since GTN always intended these replacements to increase capacity. Engineering Request Number Six notes that GTN sold precedent agreements to expand in 2019, but commenced the "2.55(b)(1) replacement activities" in 2020. GTN Response 11. When the Commission requested "a discussion of GTN's decision process and design requirements in sizing each compressor unit [in 2020]," GTN refused to admit the obvious – that it selected compressors intending to expand the system. GTN Response 11-12 (failing to explain how its 2019 precedent agreements for the expansion factored into its design process for the 2020 compressor replacements). GTN was much more candid about its decision process with investors, however. *See* States' Protest, Ex. E, TC Energy 2019 Earnings Call Transcript, at 86 ("[GTN Xpress] is an approximately $335 million project that cons[ists of] both reliability work on the GTN system together with additional firm transportation service up to 250[,]000 dekatherms per day").

Charging pre-expansion ratepayers with the costs to expand capacity is classic subsidization. The Commission should therefore deny the Application without further review. *See* 1999 Policy Statement 20; States' Protest 11-14.

II. GTN'S RESPONSE DOES NOT SHOW A PUBLIC NECESSITY.

GTN does not provide evidence "that natural gas consumption in the region is expected to increase, taking account of the recent state laws." GTN Response 3. Overall, GTN's response ignores the requirements of State laws limiting gas use and emissions – including specific requirements for Cascade Natural Gas, a Project shipper.[1] GTN apparently presumes these State laws will have no effect. Unfortunately for GTN, they will, and their impacts have

[1] *See* States' Comments on the Draft EIS (Aug. 22, 2022) at 7.

been predicted and quantified. *See* States' Protest, Exs. A-C (presenting evidence of mandatory state and local laws limiting gas use and emissions, evidence of thousands of megawatts of renewable energy projects in development, and expert testimony finding the Project is not needed and poses unacceptable risks to consumers). The Commission must engage with all the evidence before it, including the States' uncontroverted evidence about relevant legal mandates, market dynamics, and their effects on Project need.

Instead of considering State laws and other market dynamics, GTN argues the Commission should only look at precedent agreements. GTN Response 3-4. As the States previously argued, these particular precedent agreements are not convincing evidence of need. *See* States' Protest 19-23. Nothing in GTN's response changes this conclusion. To clarify the record, the States make three points about GTN's response.

First, GTN's letter from a Project shipper, Cascade Natural Gas, misreads the States' expert analysis. Cascade suggests the States incorrectly assumed Cascade's precedent agreement for the Project was not included in its Integrated Resource Plan. *See* GTN Response 15. The States did not err. Expert Gregory Lander's analysis of Cascade's existing capacity is based on the Index of Customers that GTN and Northwest Pipeline reported to the Commission, not Cascade's Resource Plan. *See* States' Protest, Ex. B, at 18-19. Cascade also does not refute the States' argument that their forecast methods are "overly simplistic and ignore evidence of market dynamics, customer choice, and state and local laws favoring electrification." *See* States' Protest 20 (citing Ex. C, Energy Futures Report, at 45-46); *see also* Comments of the Oregon Citizens' Utility Board (Jan. 27, 2023) (raising similar concerns).

Second, GTN's letter from Intermountain Gas Company, another Project shipper, does not support a finding of need and raises significant questions about its evidentiary value. Intermountain claims it contracted for pipeline capacity downstream of the pipeline's connection to its system because "as agreed to with GTN, [this] would still result in primary firm delivery of gas to the Stanfield interconnect with Northwest." GTN Response 18. The record does not show that this agreement conforms to GTN's tariff. By paying for service from Kingsgate to Malin, but only using service to Stanfield, will Intermountain be paying more than the maximum allowed rate for Kingsgate to Stanfield? Before making a decision, the Commission should ensure that the Project will conform to existing tariffs, if approved.

Intermountain's plan for "cost mitigation efforts through marketing of such unutilized capacity to secondary third-party markets" raises additional concerns. *Id*. In some instances, when a gas company has capacity that consumers paid for and did not need, it may sell the excess capacity to generate shareholder profit. *See* States' Answer and Mot. Leave to File Answer (Sept. 21, 2022) at 9.[2] Intermountain indicates it is signing up for excess capacity with plans to sell it, likely for shareholder gain. *See* GTN Response 18; *see also* Rogue Climate's Comments on the Draft EIS, 9–10 (Aug. 22, 2022) (noting Intermountain has frequently sold unutilized pipeline capacity for profit). Intermountain has an apparent profit incentive to select the Project over other alternatives. This should, at minimum, lead the Commission to question whether any need for additional capacity could be met through other means. *See, e.g.,*

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[2] The States' Reply cited an expert report by Gregory Lander filed in *Transcontinental*, describing this dynamic in general terms. The States now attach that report for the record. *See* Ex. A, Expert Report Regarding Capacity Sufficiency in Regional Access Energy Expansion, CP21-94-000 (Sept. 9, 2022), at 19-20.

Intermountain Gas Company, *Integrated Resource Plan 2021-2026*, 165-66 (Dec. 17, 2021) (noting that renewing existing contracts was a viable option to meet a capacity shortfall) (attached as Ex. B). For example, could Intermountain have obtained that capacity at the open season following expiry of the current third-party contracts it relied on? Could Intermountain request a permanent release of the capacity from the existing third-party shippers, thus vesting Intermountain with a right to renew the contracts? Without information on these alternatives, the Commission cannot determine whether Intermountain's customers require the Project or will be subsidizing it.

Third, GTN's excerpt from an "IHS Markit" report and letter from Tourmaline, a Project shipper, are not reliable[3] or persuasive evidence of need due to an allegedly declining supply in the Rocky Mountains. Neither document answers the Commission's question of whether GTN Xpress "would be needed despite the projected drop in demand in the region." GTN Response 8. Neither document projects future demand, taking into account State legislation. *See id*. Further, neither document discusses whether other available supply sources, such as the Permian Basin, could fill any anticipated gap from a reduced Rockies supply. Finally, even if there is a gap between all available supply sources and future demand, there is no evidence in the record that Western Canada production could or would ramp up to fill that gap.

[3] Both documents fail to meet basic evidentiary requirements for expert opinion. *See generally* Fed. R. Evid. 702. GTN's IHS Markit report excerpt is unauthenticated, not filed under oath, and does not include sufficient information to identify the author, much less the author's qualifications, methods, or sources of data. *See* GTN Response 25. Tourmaline's letter, signed by the Vice President of Marketing, has similar shortfalls. *See id*. at 20-22. Additionally, none of GTN's attachments comply with the Commission's request for responses to be filed under oath. *See* Data Request (April 4, 2023), at 2; 18 C.F.R. § 2005.

CONCLUSION

For these reasons, and the reasons stated in prior filings[4], the Commission should deny the Application.

Respectfully submitted this 5th day of May, 2023,

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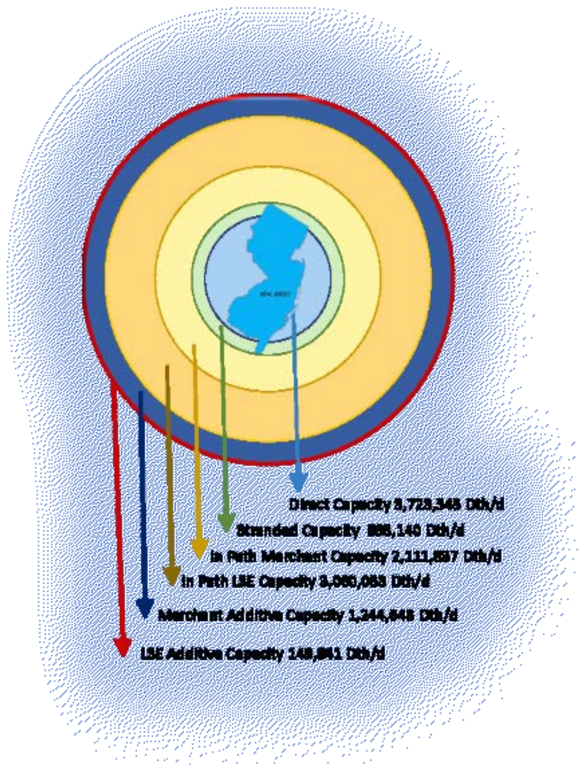
[4] *See* States' Mot. Intervene and Protest (Aug. 22, 2022); States' Comments on Draft EIS (Aug. 22, 2022); States' Answer and Request for Leave to Respond to GTN's Answer (Sept. 21, 2022); States' Comment on Final EIS (Dec. 20, 2022); Letter from the States' Regarding CEQ's Greenhouse Gas Guidance (Feb. 10, 2023).

EXHIBIT A

Expert Report Regarding Capacity Sufficiency in Regional Access Energy Expansion, CP21-94-000 (Sept. 9, 2022)

Capacity Sufficiency Study for Transco's Proposed Regional Energy Access Expansion Project



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for

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About Skipping Stone

Skipping Stone is a global energy markets consulting and technology services firm that helps clients navigate market changes, capitalize on opportunities and manage business risks. Our diverse services include market assessment, strategy development, strategy implementation, managed services, talent management and innovation collaboration. Market sector focus areas include natural gas and power markets, renewable energy, demand response, technology services and distributed energy resources. Skipping Stone's model of deploying only energy industry veterans has delivered measurable bottom-line results for over 260 clients globally. Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit www.SkippingStone.com

Skipping Stone operates Capacity Center which is a proprietary technology platform and data center that is the only all-in-one Capacity Release and Operational Notice information source synced with the Interstate pipeline system. Our database not only collects the data as it occurs, it is a storehouse of historical Capacity Release transactions since 1994. We also track shipper entity status and the pipeline receipt and/or delivery points, flows and capacity. Our analysts and consultants have years of experience working in natural gas markets. Capacity Center has worked with over a hundred clients on a wide variety of natural gas market and pipeline related reports and projects.

Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit www.SkippingStone.com.

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Executive Summary

In this report, Skipping Stone analyzes the need for Transco's Regional Energy Access Expansion Project (REAE), namely a need for additional gas capacity for New Jersey local distribution companies (LDCs) who hold 65% of subscribed capacity for Transco's proposed 829,400 Dth/day project. This is a foundational factual question that Skipping Stone answered during this analysis: additional capacity is unneeded and uneconomic. First, this study reviews the four types of firm delivery capacity available to New Jersey LDCs. Then, the study presents data for each category of firm delivery capacity, assessing actual and excess capacity available to all of NJ for each category, excluding any capacity that would require system alteration for LDCs to access it. Then, Skipping Stone presents actual delivered supply to LDCs, as well as projected demand, by charting load duration curves against gas capacity that is available to all of New Jersey, generally, and specifically to REAE's NJ LDC-shippers. This analysis is predicated on those LDC's own design day figures and actual deliveries. (Prior analysis by Skipping Stone addressed the tangential claims that potential single points of failure could serve as a predicate yielding any public benefit from a REAE-type supply offering.)

The documents in the Board of Public Utilities (BPU) proceeding on New Jersey's gas capacity provided robust analysis of these claims,[1] and Skipping Stone previously submitted data and analyses demonstrating why even the Board's London Economics International Study ("LEI Study") was an underestimate of available capacity, because in some analytical notes it conflated availability with price. With this study, Skipping Stone specifically examines the actual 2018-19 load duration curve, which was enabled by capacity existing at that time. It demonstrates that the then-existing capacity *far exceeded NJ LDCs' estimated design day requirements of 2032-33.* The 2032-33 peak demand, which represents less than 2% load factor, is almost 2,000,000 Dth/d less than currently existing firm delivery capacity for Direct Delivery, In Path Stranded, and In Path Merchant-Held. When In Path LSE is added in, currently existing capacity exceeds the 2032-33 estimated peak design day demand by almost 5,000,000 Dth/d.

Nor did the 2032-33 design day requirements used in this report reflect NJ BPU's Board Order[2] that mandates demand reductions, which, if modeled, would yield an even greater delta between available capacity and design day requirements. Cumulative capacity available to NJ from direct, stranded and in path merchant capacity totals more than 6.7 Bcf/d. Total capacity available to and through NJ totals almost 10 Bcf/d.

Our analysis shows that REAE is neither needed nor yields any public benefits, but rather that it is potentially motivated by a perversion of a rational economic system meant to incent LDCs to utilize or shed excess capacity. Skipping Stone concludes by presenting this possible rationale for NJ LDCs signing

1 *In the Matter of the Exploration of Gas Capacity and Related Issues*, NJBPU Docket No. GO1907084 (posted Dec. 16, 2021) (The LEI Study determining that New Jersey LDCs have sufficient gas supply out to 2030 to meet system demand, and do not need additional infrastructure) ("LEI Study").

2 *Implementation of P.L. 2018, c. 17, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs,* BPU Docket Nos. QO1901040, QO19060748 & QO17091004, (Order dated June 10, 2020).

precedent agreements for REAE in the absence of any demonstrable need or benefit, and presents how, if constructed, NJ ratepayers would bear the entire cost of infrastructure not designed to meet or serve their demand, while the LDCs-shippers' shareholders would reap the economic rewards of their secondary off-system sales of and/or release of excess capacity.

Analysis and Key Findings

A. Review and Explanation of the Four Kinds of Firm Direct Gas Delivery Capacity Available to New Jersey Homes and Businesses

In order to understand whether New Jersey LDCs need additional gas capacity, a preliminary discussion of the different types of firm delivery capacity is important to define the universe of available capacity. This review is limited to firm delivery capacity, because that is the type of capacity for which an LDC contracts on a proposed project, such as Transco's REAE. There are four kinds of Firm Delivery Capacity available to provide natural gas to New Jersey homes and businesses.[3] They are:

1. **Direct Delivery Capacity**: Direct Delivery Capacity is capacity for which the New Jersey gate station(s) from the pipeline are stated in a firm contract with associated Daily Firm Delivery Quantities. For this study, where the sum of delivery point Firm Maximum Daily Quantities (MDQ) exceed the contract's Maximum Daily Transportation Quantity (MDTQ), Skipping Stone limited the total of such point quantities to the contracts' MDTQs.[4]
2. **In Path Stranded Capacity**: In Path Stranded Capacity is capacity where the firm contracted capacity path: (a) traverses New Jersey; (b) there are New Jersey delivery points along the path; and (c) the downstream location (whether another pipeline or a distribution system) at the delivery point has more firm capacity delivering gas to the location than the location has either the firm capacity to take away the gas; or market demand to accept the gas. And, like the In Path Merchant and the In Path LSE Capacities, Skipping Stone totaled the MDTQs.
3. **In Path Merchant-held Capacity**: In Path Merchant-held capacity is capacity where the: (a) firm contracted capacity path traverses New Jersey; (b) there are New Jersey delivery points along the path; and (c) the entity holding the capacity does not have native load that the capacity has to be available to serve. For this category of capacity, Skipping Stone totaled the MDTQs.

[3] In both Levitan studies, the one LEI critiqued and the one done for Transco, Levitan focused on only contracted Direct Capacity held by shippers with primary delivery points and capacity in New Jersey.

[4] Skipping Stone has access to actual, historical MDTQs, and used these data sets to perform this analysis. They represent the most accurate metric available to understand pipeline capacity. This is because when there is demand for capacity, pipelines subscribe, on a firm basis, all the capacity that they have the facilities to enable firm service.

4. **In Path LSE Capacity**: In Path LSE capacity is capacity for which a load serving entity (LSE), like an LDC or vertically integrated electric utility, holds firm capacity and such firm contracted capacity path: (a) traverses New Jersey; and (b) there are New Jersey delivery points along the path. Here, as well, Skipping Stone totaled MDTQs.

B. Quantification of Direct Delivery Capacity serving New Jersey Residents and Businesses

There are five (5) existing pipelines with Direct Delivery Capacity currently serving New Jersey. This represents robust, significant supply available to meet NJ demand. These pipelines are, in descending order of Direct Delivery Capacity, set forth in Table 1 below:

Table 1. Firm Direct Delivery Capacity to New Jersey[5] [6]

Pipeline	Direct Capacity (Dth/d)
Transco	1,573,881
TETCO	1,510,820
TCO	421,250
TGP	184,592
AGT	33,000
Totals	3,723,543

Table 1.'s Direct Delivery Capacity Pipelines' figures *exclude* all contracted delivery capacity to other pipelines, even when those delivery points are in New Jersey.[7]

5 These figures are derived from each pipeline's Index of Customers (IOC) posting for January 2022. IOC postings are required to be posted and filed with the Federal Energy Regulatory Commission (FERC) quarterly. The above figures are taken from such postings. Note there are some pipelines that sell to certain customers, in total, more delivery point capacity than contracted mainline; meaning even though the delivery point total capacity exceeds mainline; their contracts and/or tariff limit deliveries to the mainline quantity. The above figures reflect these mainline capacity limits.

6 Transco is an abbreviation for Transcontinental Gas Pipe Line; TETCO is an abbreviation for Texas Eastern Transmission Company; TCO is an abbreviation for Columbia Gas Transmission; TGP is an abbreviation for Tennessee Gas Pipeline; and AGT is an abbreviation for Algonquin Gas Transmission.

7 In New Jersey, Transco, TCO, and AGT have firm contracted capacity to TETCO. In addition, in, or immediately adjacent to, New Jersey, TETCO, Transco, TGP, TCO and Millennium have firm contracted capacity to AGT. Likewise, in New Jersey, TETCO has firm contracted capacity to Transco. None of these contracted capacities are counted in the figures in Table 1.

C. Quantification of In Path Stranded Capacity available to New Jersey Residents and Businesses

Table 2 sets forth below the In Path Stranded Capacity that is available to New Jersey. Table 2 capacity is *additive* to Table 1 capacity.

Table 2. In Path Stranded Capacity Available to New Jersey

Pipeline	Stranded/ (Deficit) In Path Capacity (Dth/d)	Notes
Transco	2,549	Transco to AGT
TETCO	893,591	TETCO to AGT & ConEd
TCO	(3,000)	TCO to AGT
TGP		
AGT		
Total	893,140	**Net Stranded and Avail to NJ**

Table 2's In Path Stranded Capacity is comprised of capacity on the listed pipeline to the locations on those pipelines detailed in the Notes column. When contracted capacity *to* the pipeline/location exceeds contracted firm takeaway capacity, the number is positive. When the number is negative, the pipeline detailed in the Notes column has more contracted firm takeaway capacity *from* the listed delivering pipeline than contracted capacity *to* the Noted pipeline.

Table 2 shows that the *net* Stranded capacity available to NJ is composed of capacity on pipelines feeding Algonquin Gas Transmission (AGT) and Consolidated Edison ("ConEd"). In short, there is more firm, contracted capacity to AGT than AGT can takeaway to markets on AGT, as well as more firm contracted capacity to ConEd than ConEd has ever been able to takeaway. This results in 893,140 Dth/d of In Path Stranded Capacity that is available to New Jersey LDCs. As noted above, this capacity is additive to the 3,723,543 Dth/d of Direct Delivery capacity set out in Table 1.[8]

It is important to examine each component part of this 893,140 Dth/d of In Path Stranded Capacity to demonstrate precisely what it is, and why it is available throughout New Jersey. Below, Tables 3, 4, 5 and 6 identify what constitutes this In Path Stranded Capacity, showing why each part is available to New Jersey.

8 These available capacity values are summed in Table 11, below, together with the other existing types of available capacity, to yield an aggregate figure of 9,788,552 Dth/d of capacity that is currently available to NJ LDCs without any anticipated system modifications. REAE's proffered capacity would be additional capacity, *in excess of this figure*.

Table 3. Algonquin Firm Takeaway Capacity from New Jersey Receipt Locations

Firm AGT Receipt Capacity (Dth/d)	Away from Pipeline on AGT
1,018,391	From TETCO
807,160	From Millennium
181,129	From TGP
66,718	From Transco
65,545	From TCO
2,138,943	**Total Takeaway**

Table 3 above presents all the firm takeaway capacity Algonquin (AGT) has contracted to receive into its system in, or adjacent[9] to, New Jersey from each pipeline: a total of 2,138,943 Dth/d.

Table 4 presents all of the Firm delivery Capacity that has been sold to deliver to AGT in New Jersey from each of the five connecting pipelines. As can be readily seen, there is 3,745,582 Dth/d of capacity that has been sold to AGT. This is *far in excess* of the 2,138,943 of capacity that AGT can actually receive, which leaves gas capacity stranded on the delivering pipelines. Table 5 below further breaks this down, by depicting the winter capacity on each of the five pipelines that is contracted to AGT, but is greater than the capacity contracted on AGT to receive from each of those pipelines. This provides an important distinction, showing why some of this capacity is not currently available to New Jersey LDCs, or to serve only portions of New Jersey. Because of these current limitations on those portions of the stranded capacity, Skipping Stone has accordingly subtracted them from the total amount of In Path Stranded Capacity. The total In Path Stranded Capacity is thus 586,919 Dth/d, stemming from TETCO and Transco.

Table 4. Firm Delivery Capacity to Algonquin in or adjacent to New Jersey Locations

Firm Delivery Capacity to AGT (Dth/d)	To AGT From Pipeline
1,602,761	TETCO to AGT
1,021,875	Millennium to AGT
989,134	TGP to AGT
69,267	Transco to AGT
62,545	TCO to AGT
3,745,582	**Total at AGT Doorstep**

9 The delivery point to AGT from Millennium is in Ramapo, NY just over the New Jersey / New York border.

Table 5 below also notes which stranded capacity is available to New Jersey (and what parts of New Jersey) as well as that stranded capacity to AGT that is not available to New Jersey.

From a practical, existing capacity and existing New Jersey market point of view, the stranded capacity to AGT on TETCO and Transco is available to New Jersey with no facility enhancements of either TETCO or Transco. The * notes that the remaining stranded capacity, available at present to NW New Jersey (from TCO and/or TGP) is greater than market demands directly from those pipelines in NW New Jersey; but could be made available to the rest of New Jersey with facility enhancements to either or both of AGT to TETCO and/or AGT to Transco. The net stranded 214,715 Dth/d that is not currently available to New Jersey represents the excess delivery capacity on Millennium to AGT at Ramapo, New Jersey. This stranded Millennium capacity too could be made available to New Jersey with similar facility enhancements on AGT to bring the gas to either or both of TETCO and Transco for delivery to New Jersey locations served by those two pipelines.

Table 5. Stranded Capacity on Pipes with Firm Capacity to Algonquin

Net Capacity Left in Pipes to AGT (Dth/d)	By Pipe	Notes
584,370	TETCO	Available to All of NJ
214,715	Millennium	Not Avail to NJ
808,005	TGP	Avail to NW NJ
2,549	Transco	Available to All of NJ
(3,000)	TCO	Avail to NW NJ
1,606,639	**Net Stranded All Pipes**	
586,919	**Net Stranded TETCO & Transco Avail to All of NJ**	
805,005	**Net Stranded TGP & TCO Avail to NW NJ ***	
214,715	**Net Stranded *not* Avail to NJ**	

Below, Table 6 presents stranded capacity on TETCO that is available to NJ because contracted capacity to ConEd Manhattan exceeds the greatest ConEd Manhattan takeaway ever, going back to 2014, when the capacity was constructed and contracted. With respect to Table 6, although the January 2022 TETCO posting of its Index of Customers shows that 774,750 Dth/d is contracted to the ConEd Manhattan delivery point, the expansion that TETCO made, and the initial contracts were for 800,000 Dth/d; or 25,250 Dth/d more. Skipping Stone *conservatively used current contracted capacity for this quantity*. Likewise, while deliveries to ConEd

Manhattan in the last 5 years were never higher than 440,000 Dth/d, about 25,000 Dth/d less than the previous high when in 2014 deliveries previously topped out at 465,529 Dth/d. Again, to be conservative as to the quantity of stranded TETCO to ConEd (which could arguably be about 50,000 Dth/d higher), for the purposes of this study, Skipping Stone used the lower 309,221 Dth/d of stranded TETCO-ConEd capacity as being available to New Jersey.

Table 6. Stranded TETCO Capacity to ConEd Manhattan

Pipeline	**Winter 2022 Subscibed Capacity to ConEd (Dth/d)**	**Notes**
TETCO	774,750	ConEd-Manhattan Delivery 1/
	Maximum Flow to ConEd Manhattan (Dth/d)	
TETCO	465,529	Maximum Experienced Flow during 2014-'15 thru 2021-'22 Winters 2/
TETCO	309,221	**Stranded TETCO Capacity Avail to NJ**

Below, Table 7 shows the sum of Table 5's (Stranded capacity on TETCO and Transco to AGT Available to All of NJ) in the amount of 586,919 Dth/d; and Table 6's ConEd Manhattan (Stranded TETCO Capacity Avail to NJ) in the amount of 309,221 Dth/d. Table 7 provides additional detail demonstrating how Skipping Stone derived the figures in Table 2, which presents aggregated In Path Stranded Capacity available to NJ's LDCs.

Table 7. Sum of Stranded/Deficit In Path Capacity on Transco, TETCO and TCO Available to New Jersey

Pipeline	Stranded/ (Deficit) In Path Capacity (Dth/d)	Notes
Transco	2,549	Transco to AGT
TETCO	584,370	TETCO to AGT
TETCO	309,221	TETCO to ConEd
TCO	(3,000)	TCO to AGT
Total	893,140	Avail to All of NJ

As shown in above in Table 2 (with detailed figures broken out in Tables 3 – 7), the capacity readily available to New Jersey is the sum of the net stranded capacity to AGT from TETCO and Transco (Table 5) and stranded capacity on TETCO to ConEd Manhattan (Table 6) which together totals 893,140 Dth/d. *All 893,140 Dth/d is available "In Path" between the receipt points on those contracts to New Jersey points on the way to AGT or ConEd respectively*.

D. Quantification of In Path Merchant-held Capacity available to New Jersey Residents and Businesses

In addition to the Direct Delivery Capacity (Table 1) and the In Path Stranded Capacity (Table 2), there is capacity held by Merchants, that is available "In Path" to New Jersey markets. As described in Part A above, this category of capacity is In Path Merchant-Held Capacity, and it represents a third bucket of firm delivery capacity available to New Jersey homes and businesses.

Below, Table 8 sets forth the In Path Merchant-Held Capacity available to serve New Jersey locations. Table 8 capacity is additive to Table 1 and Table 2 capacities.

Table 8 capacity is comprised of both South to North capacity (i.e., originating at pipeline interconnects in Transco Zones 5, 4, and further southward as well as southwestern Zone M3 of TETCO) as well as Transco North to South capacity (i.e., originating at production and gathering interconnects in the Northeast Pennsylvania Marcellus gas supply region). Importantly, like the stranded TGP and Millennium capacity to AGT, described and delineated in Table 5 above, the existing, contracted capacity consisting of 983,088 Dth/d of Merchant-held capacity on TGP that is currently available only to N/NW New Jersey points also could be made available to the rest of

New Jersey with facility enhancements discussed with Skipping Stone's presentation of Table 5, above.

Table 8. In Path Merchant-Held Capacity Available to New Jersey

Pipeline	In Path Merchant Capacity (Dth/d)	Notes
Transco	1,042,876	All of NJ
TETCO	1,068,961	All of NJ
TCO	0	N/A
TGP	983,088	N/NW NJ Only
AGT	0	N/A
Totals	3,094,925	
	2,111,837	All of NJ

E. Quantification of In Path LSE Capacity available to New Jersey Residents and Businesses

Below, Table 9 presents capacity of Load Serving Entities (LSEs) other than New Jersey LSEs whose capacity is in path to New Jersey Markets. Skipping Stone *deducted* the Stranded AGT (represented in Table 5) and ConEd Manhattan capacity (represented in Table 6) from this calculation of In Path LSE Capacity, so that it did not double-count such capacity.

Table 9. "In Path" capacity through NJ of Load Serving Entities

Pipeline	Total Load Serving In Path Capacity (Excludes Stranded) Avail to All NJ (Dth/d)	Notes
Transco	1,965,895	Excludes Stranded
TETCO	1,094,138	Excludes Stranded
TCO	0	
TGP	0	
AGT	0	
Total	3,060,033	

F. Summation of the Total Dth/D Derived From the Four Kinds of Firm Delivery Capacity Available to New Jersey Markets

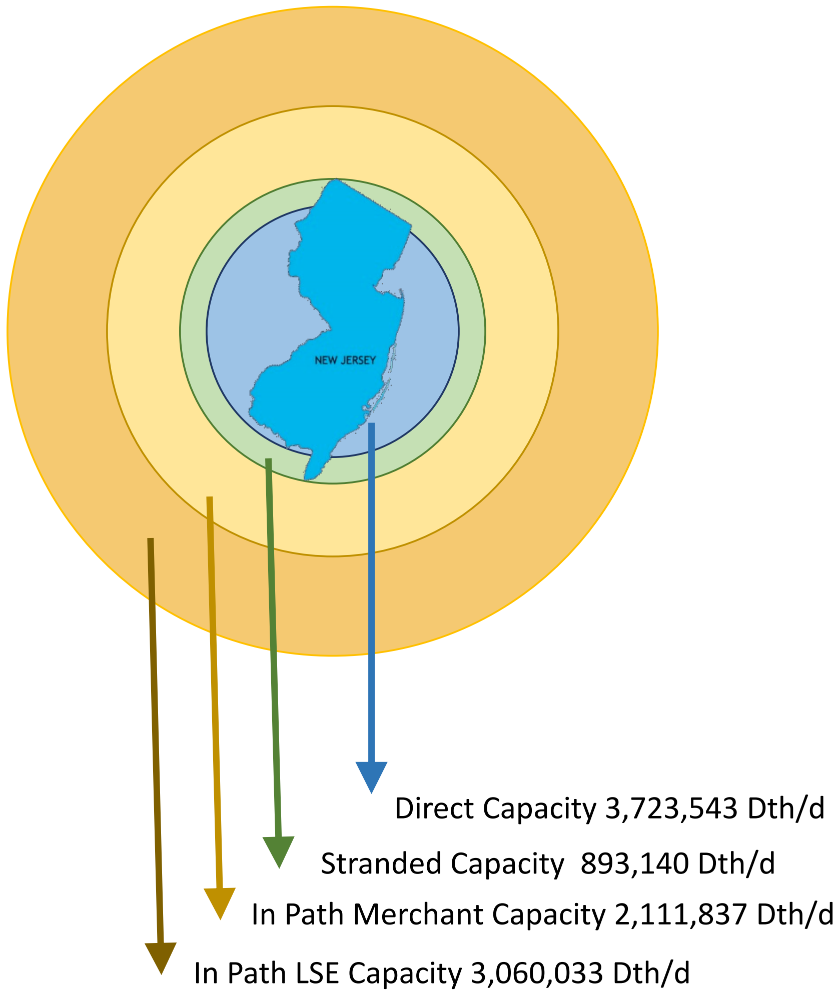
Below, Table 10 presents the cumulative firm delivery capacity available throughout New Jersey, which sums each of the four kinds of firm delivery capacity examined above: Table 1 (Firm Direct); Table 2 (In Path Stranded); Table 8 (In Path Merchant-Held); and Table 9 (In Path LSE) . Table 10 shows that the cumulative capacity available to New Jersey for the first three capacity types (i.e., Firm Direct, In Path Stranded and In Path Merchant-Held) totals more than 6.7 Bcf/d). It also shows that total Capacity to and through New Jersey totals nearly 10 Bcf/d, when In Path LSE Capacity is added into the pool.

Table 10. Capacity Available to New Jersey by Capacity Type

Capacity Type	Capacity (Dth/d)	Cumulative Capacity Available to NJ
Direct	3,723,543	3,723,543
Stranded	893,140	4,616,682
In Path Merchant	2,111,837	6,728,519
In Path LSE	3,060,033	9,788,552
Total	9,788,552	9,788,552

In the below graphic (indicatively scaled) presentation of the Table 10 data, one can see how this capacity stacks up with respect to New Jersey's demand.

Graphic 1: Indicative Representation of the Four Capacity Types Available to New Jersey



Below, Table 11 presents two types of "Additive" capacity to New Jersey. The first is "In Path" capacity of LSEs with capacity that is additive to NW New Jersey and with enhancements to AGT can be made available from AGT to one or both of TETCO and Transco to Serve markets in New Jersey. The other "Additive" capacity is capacity held by Producer-Marketers to AGT which exceeds current AGT takeaway and which with enhancements to AGT can be made available from AGT to one or both of TETCO and Transco to Serve markets in New Jersey.

This capacity is in addition to the total 9,788,552 Dth/d calculated in Table 10.

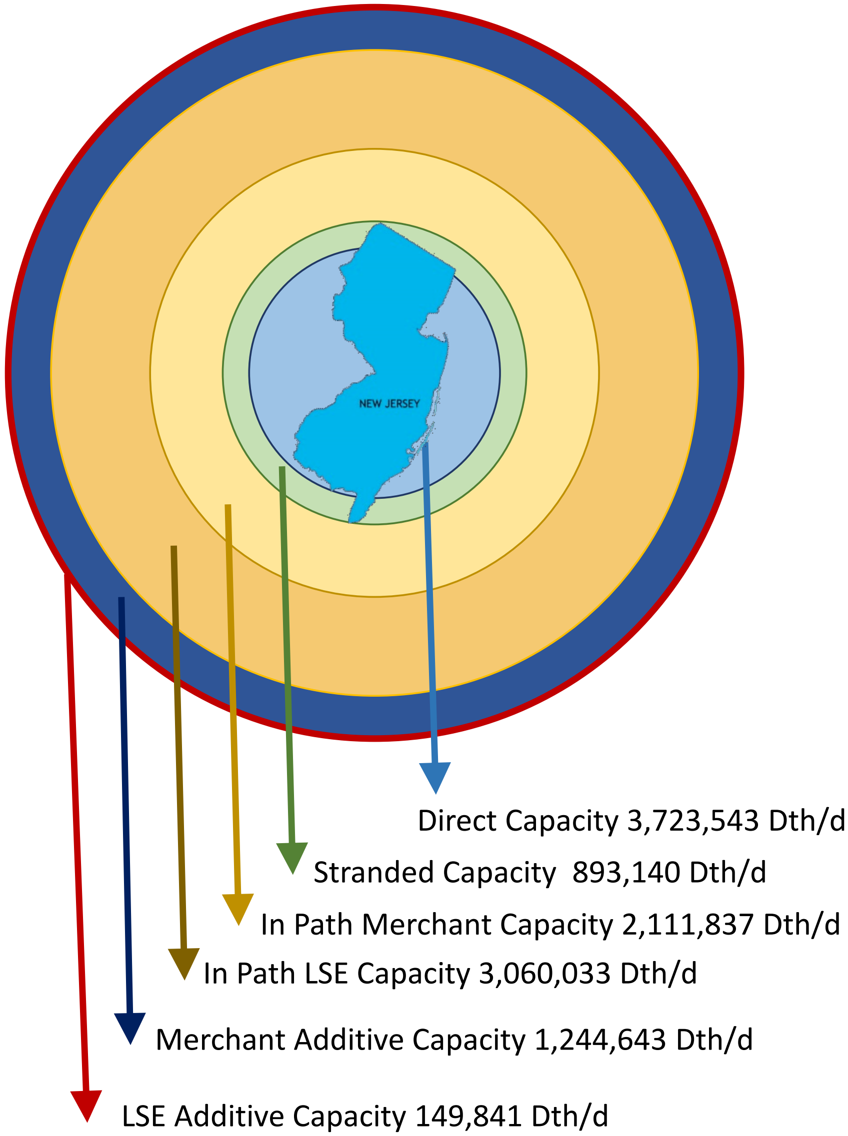
Table 11. In Path N/NW NJ LSE Capacity and Potentially Additive Capacity to New Jersey After System Modifications

Pipeline	Capacity Type	Capacity (Dth/d)	Notes
TCO	LSE Additive	43,795	Available to NW NJ & with Facility Enhancements to AGT, available to TETCO and/or Transco for NJ
TGP	LSE Additive	106,046	Available to NW NJ & with Facility Enhancements to AGT, available to TETCO and/or Transco for NJ
TGP	Prod- Mktr Additive	1,029,928	Available to NJ with Facility Enhancements to AGT, available to TETCO and/or Transco for NJ
Millennium	Prod- Mktr Additive	214,715	Available to NJ with Facility Enhancements to AGT, available to TETCO and/or Transco for NJ
Total		1,394,484	

Table 11 above depicts a total of nearly 1.4 Bcf/day of Potentially Additive Capacity to the New Jersey Market on existing pipelines and paths which, with enhancements to AGT to bring that capacity to either or both of TETCO or Transco would be available to meet additional demand (if any) in New Jersey. Of that nearly 1.4 Bcf/day, fully 1.2 Bcf/day is currently held by entities, (i.e., Merchants) that do not have native load to serve and whose capacity is currently stranded at the doorstep of AGT.

The below Graphic 2 indicatively depicts the sum of Tables 10 and 11.

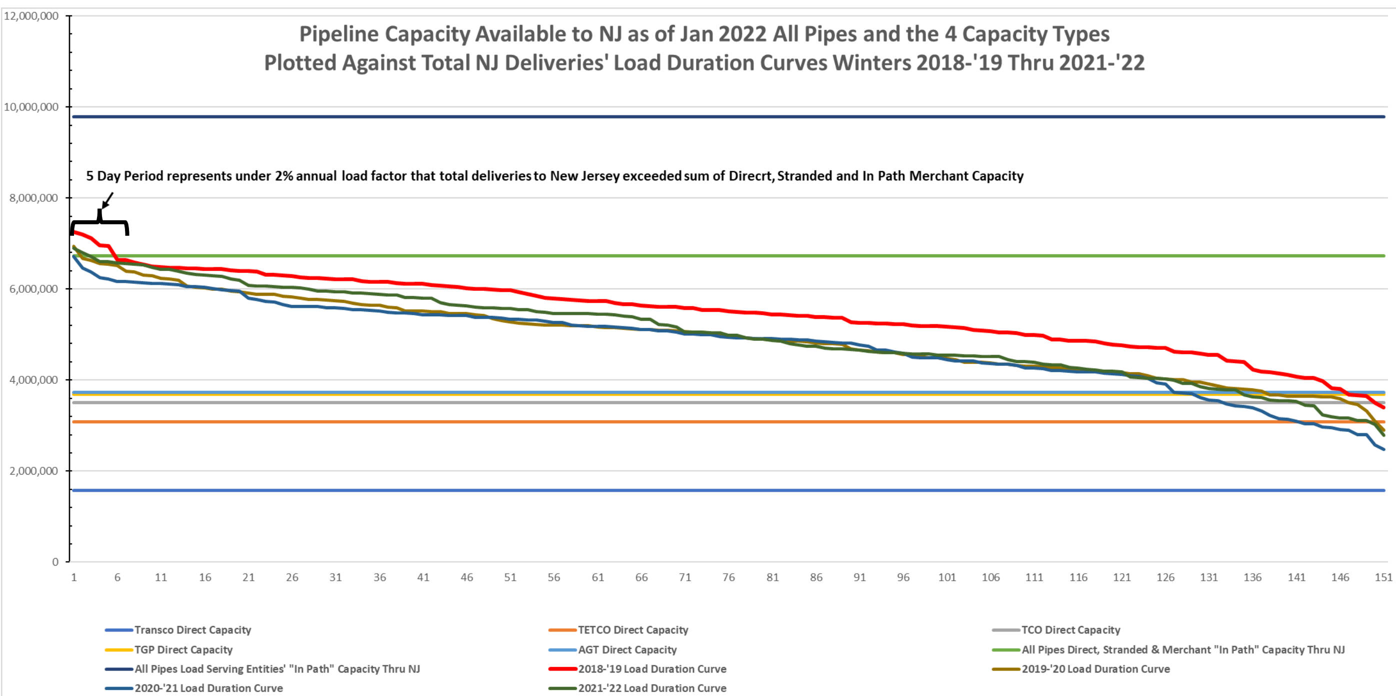
Graphic 2: Indicative Capacity Available when Potentially Additive Capacity is Included



G. Comparison of Available Capacity for New Jersey Markets with NJ Load Duration Curves for Deliveries to all Load Types

Below, Chart 1 presents the Load Duration Curves for New Jersey Deliveries to all load types (i.e., including Power generators and interruptible loads and excluding deliveries to other pipelines for the winters 2018-’19 through 2021-’22. The below Chart 1 plots load duration curves for winters 2018-’19 through 202-’22 against the four types of capacity outlined in Table 10. Chart 1 does not include the nearly 1.4 Bcf/day of Potentially Additive Capacity of Table 11.

Chart 1. Load Duration Curves for NJ Deliveries plotted Against Contracted Capacities Available to NJ Locations



Note that the above chart represents *all deliveries by pipelines* to NJ and does not include any on-system LNG or propane supplies, which would provide additional supply.

One of Skipping Stone’s significant observations with respect to the data presented by Chart 1 is that *actual deliveries to NJ Locations exceed the sum of contracted deliveries*, including Direct (i.e., primary) delivery NJ locations, secondary capacity comprised of stranded capacity, and capacity held by Merchants. This means that some portion of the 3 Bcf/d plus of capacity held by LSEs not in New Jersey ***is currently being utilized so as to enable existing capacity to meet all New Jersey demands.*** This is critically important to understand, because it means that the relevant total available capacity figure for New Jersey demands is the almost 10,000,000 Dth/d figure presented in Table 10. This is not a “hypothetically” available amount – some portion of the LSE In Path capacity is actually available and deployed capacity.

A second key observation is that the Chart 1 deliveries represent all load demands in New Jersey, not just Firm LDC demands, which demands are much less than the total of all loads served by pipelines in New Jersey. See Part I. below. The demands that are in addition to the firm demands of New Jersey LDCs are comprised of interruptible loads, such as those of most power generators. Thus, those loads are currently being met, with a large supply of available capacity ***without Transco's proposed REAE.***

A third key observation is that the *magnitude* of load that exceeds the capacity level comprised of the first three capacity types, (Firm Direct, In Path Stranded, In Path Merchant-held) discussed above, has a very low load factor. As can be interpolated from the data in Chart 1, in the winter of 2018-'19, demand exceeded the first three types of capacity *for just 5 days*. On an annual basis, 5 days are less than 2% of days in a year.

H. REAE's Proffered Capacity Would Have Been An Entirely Uneconomic Way to "Firm-Up" Pipeline Capacity For The Five Days in 2018-19 Where NJ Demand Was Served By The Fourth Category Of Firm Capacity, In Path LSE Capacity.

To put this observation into economic focus, imagine that a company with ratepayers wanted to "firm-up" their pipeline capacity to cover the approximately 530,000 Dth/d (0.533 Bcf/d) of peak exceedance of the first three capacity types (i.e., firm up the difference between 6.72 Bcf/d and 7.26 Bcf/d). Then imagine that the cost of year-round pipeline capacity was $0.60 per Dth per day for each of 365 days a year. Finally, imagine that over those 5 days, you used a total of 1.835 Bcf of gas through that capacity. The annual cost of that capacity would be $116,507,909. For the capacity used, not counting gas cost, the per Dth used cost of that capacity would be $63.49 per Dth!! (532,000 Dth per day times $0.60 times 365 = $116,507,909 then $116,508,000 divided by 1,835,000 Dth = $63.49 per Dth actually used). The below Table 12 presents these calculations.

Table 12. Calculations of Effective Indicative Cost per Dth

Reserved Capacity (Dth/d)	Reservation Cost per Dth/d	Days per Year	Annual Cost of Capacity
532,000	$0.60	365	$116,508,000
Capacity Cost ($)	**Days Capacity used**	**Gas used through the Capacity**	**Unit Cost of Capacity used**
$116,508,000	5	1,835,000	$63.49

This indicative analysis can and should be used to compare the per Dth cost of gas used when assessing alternatives to any particular expansion to meet peak-period demand.

Skipping Stone also analyzed the New Jersey LDCs' projections of Design Day demand and compared that to the same January 2022 stack of existing capacity available to New Jersey.

I. While REAE's Proffered Capacity Would Have Been An Exceedingly Expensive Choice to "Firm Up" Pipeline Capacity in 2018-19, NJ LDCs' Design Day Estimated Load Duration Curve for 2032-33 Makes Clear That The First Three Categories of Available Capacity More Than Meet Any Projected Peak Exceedances.

Below, Chart 2 takes New Jersey LDCs' currently projected 2024-'25 Design Day figures[10] and escalates such estimates by an annual 1.2% growth rate[11]; and, then plots those estimated Load Duration curves as well as the 2018-'19 Actual Load Duration curve against 2022 (i.e., existing) contracted capacity.

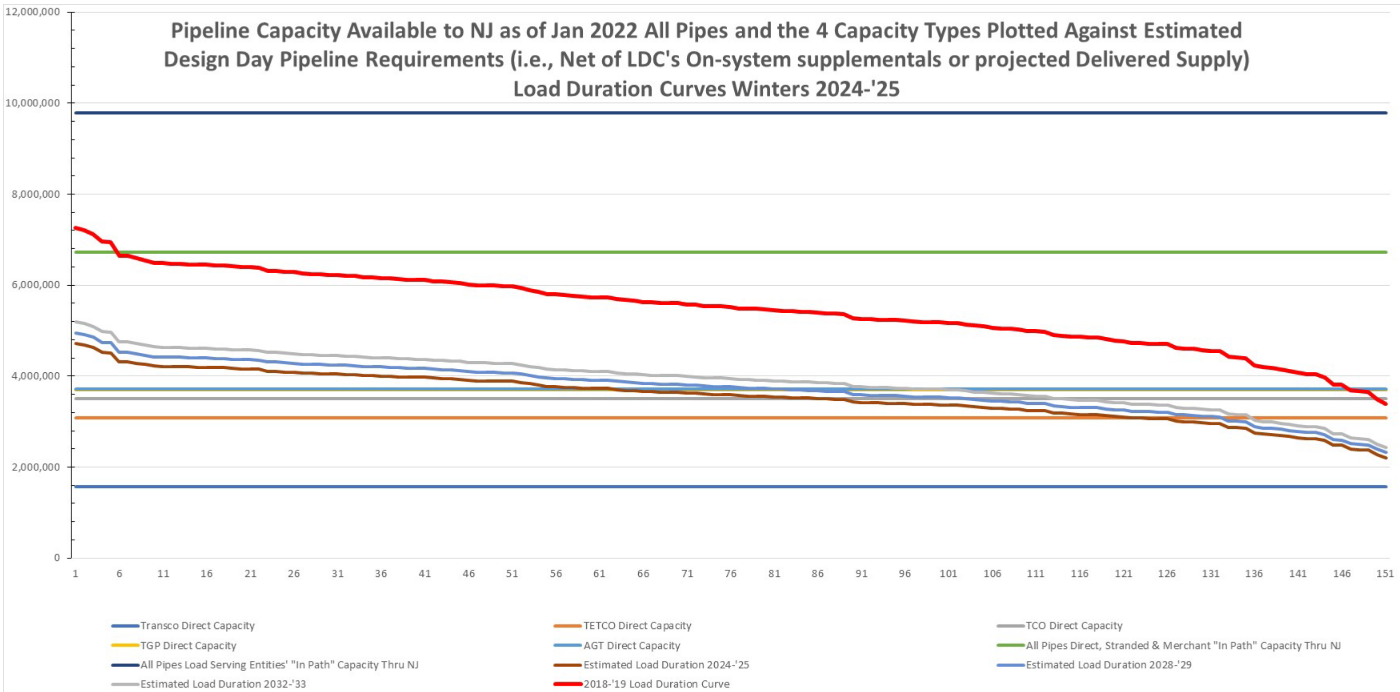
Chart 2 shows that the *actual* 2018-'19 Load duration curve, which was enabled by *existing* capacity in 2018-'19, far exceeds the New Jersey LDCs' estimated Design Day requirements of 2032-'33 *with existing 2022 regional capacity available to New Jersey*. Moreover, Chart 2's estimated Design Day Load Duration curves do not even take into account the New Jersey Board of Public Utilities' (BPU) order that mandates NJ LDCs to reduce demand by increased energy efficiency or other means by 1.10% by 2026.[12] Chart 2 estimates business as usual for the New Jersey LDCs (a conservative approach that ignores the existing Order), and takes projected 2024-'25 Load Duration of LDC Design Days and annually escalates the same by 1.2%. If the LDCs abide by the directly applicable BPU Order governing them, the increases shown above *will not materialize.* Yet even with those increases, Chart 2 reflects that the first three categories of firm delivered capacity greatly exceed even the less than 2% load duration factor of total deliveries to all loads.

10 Design Day figures are taken from BGSS filings for Elizabethtown, South Jersey and PSEG and from the Levitan Report done for Transco in the case of New Jersey Natural Gas. NJNG did not publicly file its Working Paper containing its design day figure in its most recent BGSS filing.

11 The modeled 1.2% annual growth rate was conservatively chosen as it exceeds the 1.02% annual growth rate used in the Levitan study performed for Transco by 15%.

12 LEI Study, P. 48.

Chart 2. Plot of Estimated LDC Design Day Load Duration Curves vs. Actual 2018-'19 New Jersey Load Duration Curve



J. Description of the Interaction between State-Level Incentives and Expansion Capacity

New Jersey Conservation Foundation ("NJCF") filed a motion for an evidentiary hearing that preceded the release of this Capacity Sufficiency Study,[13] NJCF identified significant questions with respect to the interaction between state-level LDC business operations and incentives that may accompany pipeline expansion proposals, which raise red flags undermining the probative value of the REAE precedent agreements.

In particular, it is Skipping Stone's understanding that current practices in New Jersey and other states encourage LDCs to utilize their idle capacity to make off-system sales as well as to monetize such idle capacity by making capacity release transactions. The main method of encouragement is "margin sharing"; where the LDC shareholders retain, outside of regulated return on equity, a portion of the revenues/profits realized from making off-system gas sales and/or from capacity release transactions. Depending on the market conditions, these shareholder dollars can be in the millions of dollars.

A simple description of how such margin sharing mechanisms work in principle follows.

13 *New Jersey Conservation Foundation et al., Motion for an Evidentiary Hearing,* FERC Docket No. CP21-94-000, Accession No. 20220906-5099 (Sep. 6, 2022).

An LDC can earn additional profits for its shareholders by monetizing the value of firm capacity during periods when the capacity is not needed to meet native load and the opportunity to utilize that capacity for profit presents itself. This can be during periods of high regional demand or when there are depressed prices in a supply area due to insufficient supply area takeaway capacity relative to supply deliverability. During these periods, an LDC can extract value from this capacity by delivering gas at margin-generating prices to buyers located along the capacity path, or it can simply sell the capacity itself.

An LDC can buy gas that it does not intend to bring to its system, transport that gas through its contracted firm capacity and sell it to a buyer at a location along its contracted capacity path. Then the LDC calculates the difference between the cost of the gas it bought for this purpose and the sales price (usually deducting from the sales price (or adding to the gas cost) the variable cost of transporting the gas and fuel retained by the pipeline). Then that difference, that margin on the transaction, is divided between ratepayers and the LDC's shareholders.

One way to look at this sort of arrangement is that the contracted capacity (paid for by ratepayers) is used to generate shareholder dollars (i.e., their share of the margin). In essence from a gas marketer's and shareholders' point of view, the margin is "free-money."

Likewise, it is also often the case that capacity release transactions also generate margin; usually 100% of the revenue from the party acquiring the LDC's released capacity[14]. Here too, this margin is split with ratepayers getting some and shareholders getting what doesn't go the ratepayers.

When the capacity being used for these margin generating activities is absolutely needed to meet LDC customers' demand, then it makes sense to encourage the LDC to generate revenues from idle capacity.

On the other hand, when the capacity was paid for by ratepayers, but unneeded by those ratepayers to meet realistic demand, yet was used to generate shareholder rewards, it would be a perversion of this otherwise sensible mechanism. In other words, it is conceivable that the desire to generate shareholder revenues from subscribed capacity that was not needed, but nevertheless paid for by ratepayers, could be a significant factor driving an LDC to add to its capacity holdings beyond realistic need to meet ratepayer demand. Here, the data show that there is no additional capacity needed to meet current or future NJ ratepayer demand.

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[14] Note in the case of capacity release margins, the "cost" is zero meaning that the margin is whatever revenue the capacity was sold for; **meaning the entire "cost" of the capacity is borne by ratepayers because there is no deduction of that capacity's "cost" from the revenues (i.e., margin) associated with capacity release transactions.**

Document Content(s)

EXHIBIT B

Intermountain Gas Company, Integrated Resource Plan 2021-2026
(Dec. 17, 2021)

Intermountain Gas Company

Integrated Resource Plan

2021 – 2026

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

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Overview

Executive Summary

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and electric power peaking plants, all rely on natural gas to provide an economic, efficient, environmentally friendly, comfortable form of heating energy. Intermountain Gas Company (Intermountain, IGC, or Company) encourages the wise and efficient use of energy in general and, in particular, natural gas for end uses across Intermountain's service area.

The Integrated Resource Plan (IRP) is a document that describes the currently anticipated customer demand conditions over a five-year planning horizon, the anticipated resource selections to meet that demand, and the process for making resource decisions. Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of the IRP planning process. The demand forecasting and resource decision making process is ongoing and accordingly the Company files with the Idaho Public Utilities Commission an update to the IRP every two years. This IRP represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions, as conditions will change over the planning horizon impacting areas covered by this plan. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

About the Company

Intermountain Gas, a subsidiary of MDU Resources Group, Inc., is a natural gas local distribution company that was founded in 1950. The Company served its first customer in 1956. Intermountain is the sole distributor of natural gas in southern Idaho. Its service area extends across the entire breadth of southern Idaho as illustrated in Figure 2 (see page 6), an area of 50,000 square miles, with a population of roughly 1,404,000. At the end of 2020, Intermountain served approximately 387,000 total customers in 76 communities through a system of over 13,300 miles of transmission, distribution and service lines. In 2020, approximately 755 million therms were delivered to customers and over 260 miles of transmission, distribution and service lines were added to accommodate new customer additions and maintain service for Intermountain’s growing customer base.

Customer Base

The economy of Intermountain's service area is based primarily on agriculture and related industries. Major crops are potatoes, milk and sugar beets. Major agricultural-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and service to two major markets: the residential/commercial market and the large volume market. The Company's residential and commercial customers use natural gas primarily for space and water heating. Intermountain's large volume customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications. Large volume demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. During 2020, nearly 50% of the throughput on Intermountain's system was attributable to large volume sales and transportation.

The IRP Process

Intermountain's Integrated Resource Plan is assembled by a talented cross-functional team from various departments within the Company. The IRP begins with a five-year forecast that considers customer demand and supply and delivery resources. The optimization model used in the development of the IRP identifies potential deficits and considers all available resources to meet the needs of Intermountain's customers on a consistent and comparable basis. A high-level overview of the process is described below. Each step in the process will be outlined in greater detail in later sections of this document.

Demand

As a starting point, Intermountain develops base case, high growth, and low growth scenarios to project the customer demand on its system for both core market and large volume customers. The core market includes residential and commercial customers. Large volume customers are high usage customers that are not eligible for residential or commercial service.

For the core market, the first step involves forecasting customer growth for both residential and commercial customers. Next, Intermountain develops design weather. Then the Company determines the core market usage per customer using historical usage, weather and geographic data. The usage per customer number is then applied to the customer forecast under design weather conditions to determine the core market demand.

To forecast both therm usage and contract demand for large volume customers, the Company analyzes historical usage, economic trends, and direct input from large volume customers. This approach is appropriate given the small population size of these customer classes. Because large volume customers typically use natural gas for industrial processes, weather data is not generally considered.

Both core market and large volume demand forecasts are developed by areas of interest (AOI) and then aggregated to provide a total company perspective. Analyzing demand by AOI allows the Company to consider factors specifically related to a geographic area when considering potential capacity enhancements.

Supply & Delivery Resources

After determining customer demand for the five-year period, the Company identifies and reviews currently available supply and delivery resources. Additionally, the Company includes in its resource portfolio analysis various non-traditional resources as well as potential therm savings resulting from its energy efficiency program.

Optimization

The final step in the development of the IRP is the optimization modeling process, which matches demand against supply and deliverability resources by AOI and for the entire Company to identify any potential deficits. Potential capacity enhancements are then analyzed to identify the most cost effective and operationally practical option to address potential deficits. The Planning Results section shows how all deficits will be met over the planning horizon of the study. Figure 1 provides a visual overview of the IRP process.

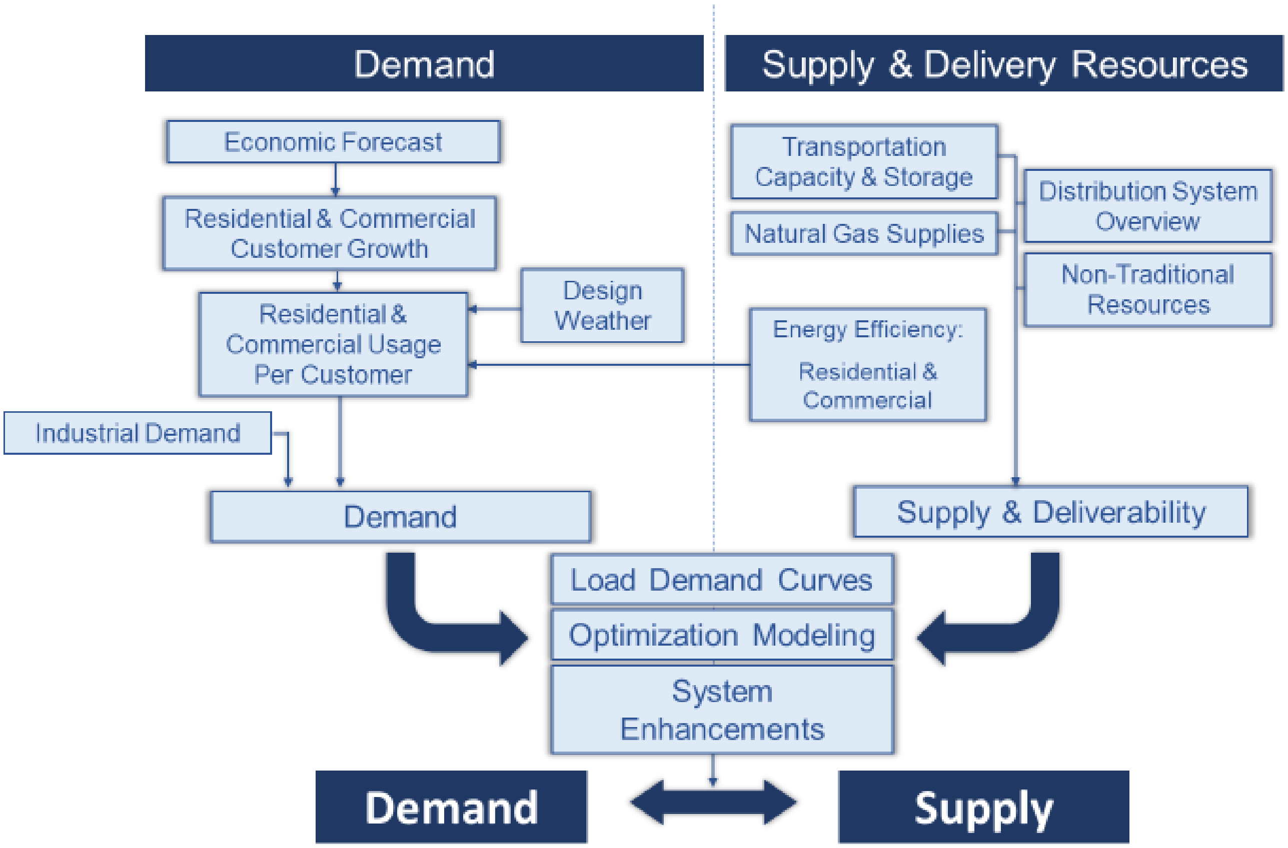

Figure 1: The IRP Process

Intermountain Gas Resource Advisory Committee

To enhance the Integrated Resource Plan development, the Company established the Intermountain Gas Resource Advisory Committee (IGRAC). The intent of the committee is to provide a forum through which public participation can occur as the IRP is developed.

Advisory committee members were solicited from across Intermountain's service territory as representatives of the communities served by Intermountain. Exhibit 1, Section A, is a sample of the invitation to join the committee. Committee members have varied backgrounds in regulation, economic development, and business. A full listing of IGRAC members is included in Exhibit 1, Section A.

For this IRP cycle, Intermountain held its IGRAC meetings on a virtual platform to ensure that committee members from across the state could safely and easily participate. A total of three virtual meetings were held in 2021 between the months of March and July. Included in Exhibit 1, Sections B, C, and D are sample invitations and copies of the presentations from the meetings.

After each meeting, for members who were unable to attend, an email containing the materials covered was sent out. The Company provided a comment period after each meeting to ensure feedback was timely and could be incorporated into the IRP. Intermountain also established an email account where feedback and information requests could be managed.

Summary

Through the process explained above, Intermountain analyzed residential, commercial and large volume demand growth and the consequent impact on Intermountain's distribution system using design weather conditions under various scenarios. Forecast demand under each of the customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of potential delivery deficits, both from a total company perspective as well as an AOI perspective. The resources needed to meet these projected deficits were analyzed within a framework of traditional, non-traditional and energy efficiency options to determine the most cost effective and operationally practical means available to manage the deficits. In utilizing these options, Intermountain's core market and firm transportation customers can continue to rely on safe, reliable, affordable firm service both now and in the future.

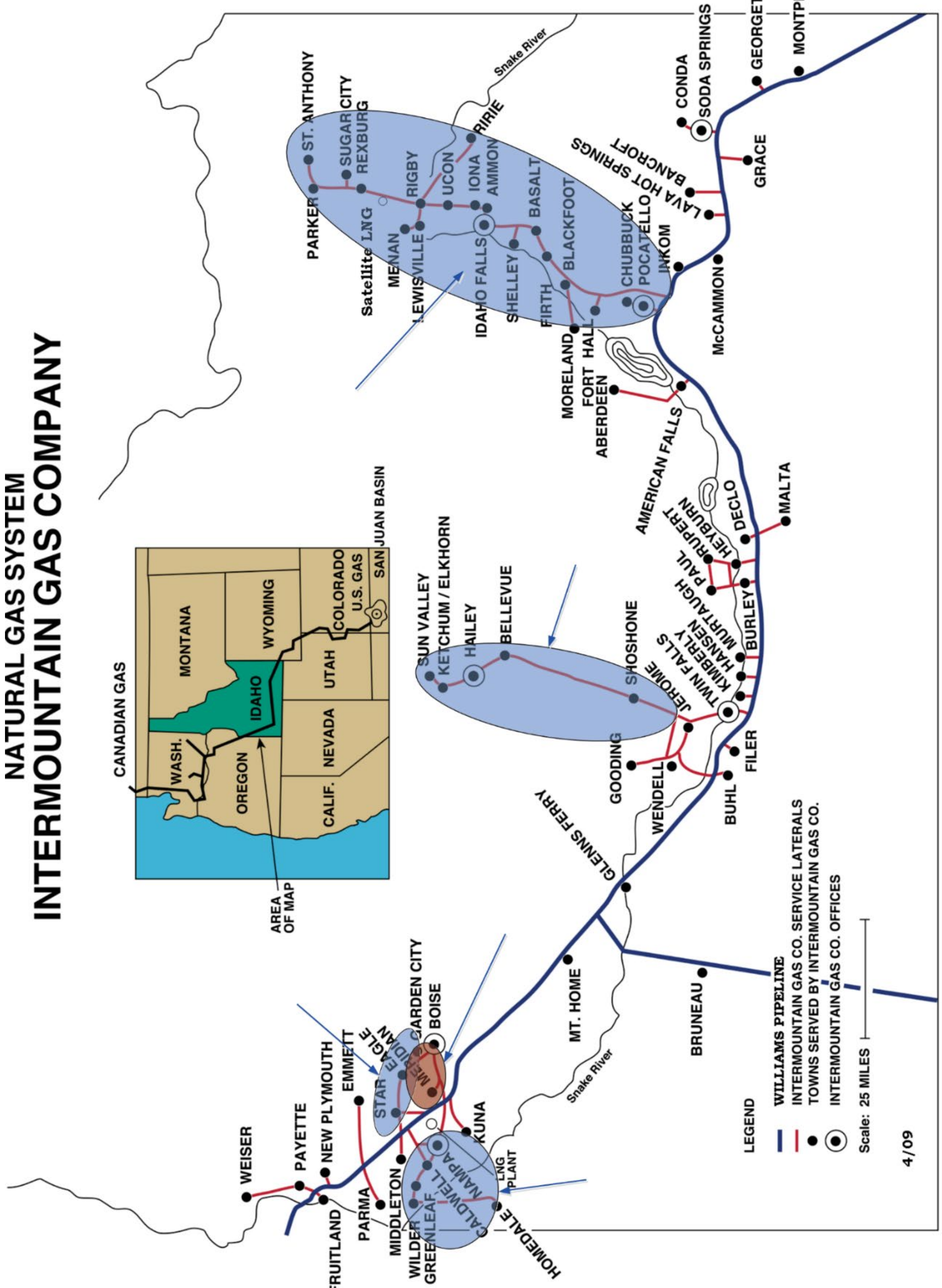

Figure 2: Intermountain Gas System Map

About the Natural Gas Industry

Natural Gas and the National Energy Picture

The blue flame. Curling up next to a natural gas fireplace, starting the morning with a hot shower, coming home to a warm house. The blue flame of natural gas represents warmth and comfort, and provides warmth and comfort in the cleanest, safest, most affordable way possible.

Natural gas is the cleanest fossil fuel. It burns efficiently, producing primarily heat and water vapor. Natural gas has also led U.S. carbon emission reductions to 27-year lows, and the U.S. Energy Information Administration projects that trend will continue. [1] The Environmental Protection Agency's (EPA) "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2019" reveals that once again natural gas distribution systems have a small emissions footprint shaped by a declining trend. Methane emissions from the natural gas industry account for only 2.7 percent of total greenhouse gas emissions. These annual emissions have declined from 69 percent of the total in 1990 even as natural gas distribution companies added more than 788,000 miles of pipeline nationally to serve 21 million more customers. [2] A Washington State University study found that as little as 0.1% of the natural gas delivered nationwide is emitted from local distribution systems. [3]

Natural gas pipelines are the safest and most efficient mode of transportation, surpassing rail and truck, according to the U.S. Department of Transportation. Pipeline incidents or disruptions to natural gas service are rare because of the industry's consistent focus on safety and reliability. [4] Intermountain considers safety and reliability at every stage, from pipeline design to construction to ongoing maintenance.

Natural gas is affordable. Since 2008, the price of natural gas has fallen by about 37% (adjusted for inflation). According to the Northwest Gas Association, households that use natural gas for heating, cooking and clothes drying spend an average of $874 less per year than homes using electricity for those same applications. [5] The American Gas Association also reported that for residential customers, the cost of natural gas has been lower than the cost of propane, fuel oil, or electricity since 2010, and is forecasted to stay low through 2040. [6]

According to the American Gas Association, in the United States natural gas currently meets more than 25% of the nation's energy needs, providing energy to almost 75 million residential,

[1] https://www.aga.org/contentassets/4c04bee66b4648f086bcde31e4815e4e/building-the-value-of-natural-gas---a-fact-base-may-2020.pdf
[2] https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/
[3] https://www.aga.org/policy/Environment/infographic-emissions-from-systems-operated-by-natural-gas-utilities-continue-to-decline/
[4] https://www.ingaa.org/File.aspx?id=28478
[5] https://www.nwga.org/wp-content/uploads/2021/03/NWGA_Facts_2021_Final.pdf
[6] https://www.aga.org/natural-gas/affordable/

commercial and industrial customers. [7] Natural gas is now even more plentiful than ever in North America, with an estimated 84 year supply at current consumption levels. [8] Even with this plentiful supply, however, it remains vital that all natural gas customers use the energy as wisely and as efficiently as possible.

The Direct Use of Natural Gas

The direct use of natural gas refers to employing natural gas at the end-use point for space heating, water heating, and other applications. This is opposed to the indirect use of natural gas to generate electricity which is then transported to the end-use point and employed for space or water heating. The direct use of natural gas is 91% efficient from production to the consumer end-use, compared to an efficiency of only 36% for the indirect use of natural gas.

As electric generating capacity becomes more constrained in the Pacific Northwest, additional peak generating capacity will primarily be natural gas fired. Direct use will mitigate the need for future generating capacity. If more homes and businesses use natural gas for heating and commercial applications, then the need for additional generating resources will be reduced.

From a resource and environmental perspective, the direct use of natural gas makes the most sense. More energy is delivered using the same amount of natural gas, resulting in lower cost and lower CO_2 emissions. This direct, and therefore, more efficient natural gas usage will serve to keep natural gas prices, as well as electricity prices, lower in the future.

Intermountain plays a critical role in providing energy throughout southern Idaho. The Company's residential customers use roughly 201.5 million therms a year for space heating applications. If this demand had to be served by electricity, it would mean that Intermountain's residential customers would require approximately 5,079,000 megawatt hours a year to replace the natural gas currently used to heat their homes. This would require nearly doubling the total residential electric load currently being supplied in the region, which according to Idaho Power's 2020 annual report is approximately 5,463,000 MWh. This scenario would prove a considerable burden for both electric generation and transmission.

Ultimately, using natural gas for direct use in heating applications is the best use of the resource, and mitigates the need for costly generation and infrastructure expansion across the U.S. electric grid.

[7] https://www.aga.org/globalassets/2019-natural-gas-factsts-updated.pdf
[8] https://www.eia.gov/tools/faqs/faq.php?id=58&t=8

Clean Energy Future

Natural gas is not only safe, reliable and affordable, but the natural gas distribution system will also be a critical component in delivering clean energy in the future. Intermountain is actively involved in the research and development of low- and zero-carbon energy technologies through its participation in Gas Technology Institute (GTI) and the Low-Carbon Resources Initiative (LCRI).

LCRI is a joint venture of GTI and the Electric Power Research Institute. Its mission is to accelerate the deployment of the low- and zero-carbon energy technologies that will be required for deep decarbonization. LCRI is specifically targeting advances in the production, distribution, and application of low-carbon, alternative energy carriers and the cross-cutting technologies that enable their integration at scale. These energy carriers - which include hydrogen, ammonia, synthetic fuels, and biofuels - are needed to enable affordable pathways to achieve deep carbon reductions across the energy economy. The LCRI is focused on technologies that can be developed and deployed beyond 2030 to support the achievement of a net zero emission economy by 2050.

Intermountain is also playing an important role in the growth and development of the emerging Renewable Natural Gas (RNG) industry. The Company's RNG Facilitation agreement allows Intermountain to provide access to its distribution system for RNG producers to transport RNG to their end use customers. RNG takes a waste stream that is currently emitting greenhouse gasses, captures it, and puts it to a beneficial end use. Although RNG is currently more expensive than traditional natural gas, as the technology matures the Company anticipates the costs will continue to decrease which will make it a viable supply option for customers in the future.

Demand

Demand Forecast Overview

The first step in resource planning is forecasting future load requirements. Three essential components of the load forecast include projecting the number of customers requiring service, forecasting the weather sensitive customers' response to temperatures and estimating the weather those customers may experience. To complete the demand forecast, contracted maximum deliveries to industrial customers are also included.

Intermountain's long range demand forecast incorporates various factors including divergent customer forecasts, statistically based gas usage per customer calculations, and varied weather profiles, all of which are discussed later in this document. Using various combinations of these factors results in six separate and diverse demand forecast scenarios for the weather sensitive core market customers.

Combining those projections with the large volume market forecast provides Intermountain with six total company demand scenarios that envelop a wide range of potential outcomes. These forecasts not only project monthly and annual loads but also predict daily usage including peak demand events. The inclusion of all this detail allows Intermountain to evaluate the adequacy of its supply arrangements and delivery under a wide range of demand scenarios.

Intermountain's resource planning looks at distinct segments (i.e. AOIs) within its current distribution system as depicted in Figure 2 on page 6. After analyzing resource requirements at the segment level, the data is aggregated to provide a total company perspective. The AOIs for planning purposes are as follows:

- The Canyon County Area (CCA), which serves core market customers in Canyon County.
- The Sun Valley Lateral (SVL), which serves core market customers in Blaine and Lincoln counties.
- The Idaho Falls Lateral (IFL), which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties.
- The Central Ada County (CAC), which serves core market customers in the area of Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west.
- The State Street Lateral (SSL), which serves core market customers in the area of Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21.
- The All Other segment, which serves core market customers in Ada County not included in the State Street Lateral and Central Ada Area, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties.

Residential & Commercial Customer Growth Forecast

This section of Intermountain's IRP describes and summarizes the residential and commercial customer growth forecast for the years 2021 through 2026. This forecast provides the anticipated magnitude and direction of Intermountain's residential and commercial customer growth by the identified Areas of Interest for Intermountain's service territory. Customer growth is the primary driving factor in Intermountain's five-year demand forecast contained within this IRP.

The Company's customer growth forecast includes three key components:

1. Residential new construction customers,
2. Residential customers who convert to natural gas from an alternative fuel, and
3. Commercial customers

To calculate the number of residential customers added each year, the annual change in households for each county in the Company's service territory is determined using the Idaho Economics Winter 2020 Economic Forecast for the State of Idaho by John S. Church ('20 Forecast), dated April 2021 (see Exhibit 2, Section A). Using the assumption that a new household means a new dwelling is needed, the annual change in households by county is multiplied by Intermountain's market penetration rate in that region to determine the additional residential new construction customers. Next, that number is multiplied by the Intermountain conversion rate, which is the anticipated percentage of conversion customers relative to new construction customers in those locales. This results in the number of expected residential conversion customers, which when added to the residential new construction numbers, equals the total expected additional residential customers by county.

To accurately estimate growth for the State Street AOI, which contains a small portion of Canyon County and a large portion of Ada County, an additional estimate is utilized. The Community Planning Association of Southwest Idaho (COMPASS) conducts annual forecasts based on defined 'Traffic Analysis Zones' (TAZ) within Ada County. According to COMPASS, the TAZ that coincides with the State Street AOI boundary is expected to grow 3.59% per year over the next 5 years. This annual growth rate is applied to the current customer count within that boundary to derive the estimated growth of the State Street AOI over the same time period.

The Central Ada AOI sits entirely in Ada County. Using the same methodology as described above, the Central Ada AOI growth was calculated to be 1.85% per year.

The commercial customers are forecasted in a different manner. Intermountain utilizes an ARIMA model which incorporates employment forecasts as an explanatory variable. An ARIMA model is an autoregressive integrated moving average model that is used on time series data to better predict future points. The employment data measures actual and forecasted full- and part-time jobs by place of work. Generally, when employment is increasing, commercial customer counts are also increasing, thus, the reason for including employment as an explanatory variable. The Company modeled households as an explanatory variable as well but found that employment provided better results. Each County in Intermountain's service territory is modeled separately. The commercial customer forecast model is as follows:

$$C_{County} = \alpha_0 + \alpha_1 Emp^{County} + ARIMA\epsilon(p,d,q)$$

Where:

- $C_{County} = Commercial\ Customers\ by\ County$
- $Emp^{County} = Employment\ by\ County$
- $ARIMA\epsilon(p,d,q) = Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms$

Exhibit 2 shows the Company's residential and commercial customer forecast.

Similar to the 2019 IRP, which demonstrated a continued resurgence in the housing market Intermountain's growth projections continue to stay strong. The '20 Forecast household numbers are employed to determine the relative overall number of customer additions, as well as the distribution of those customer additions across the Company's service territory.

The following graph (Figure 3) depicts the relationship, or shape, of customer additions by AOI:

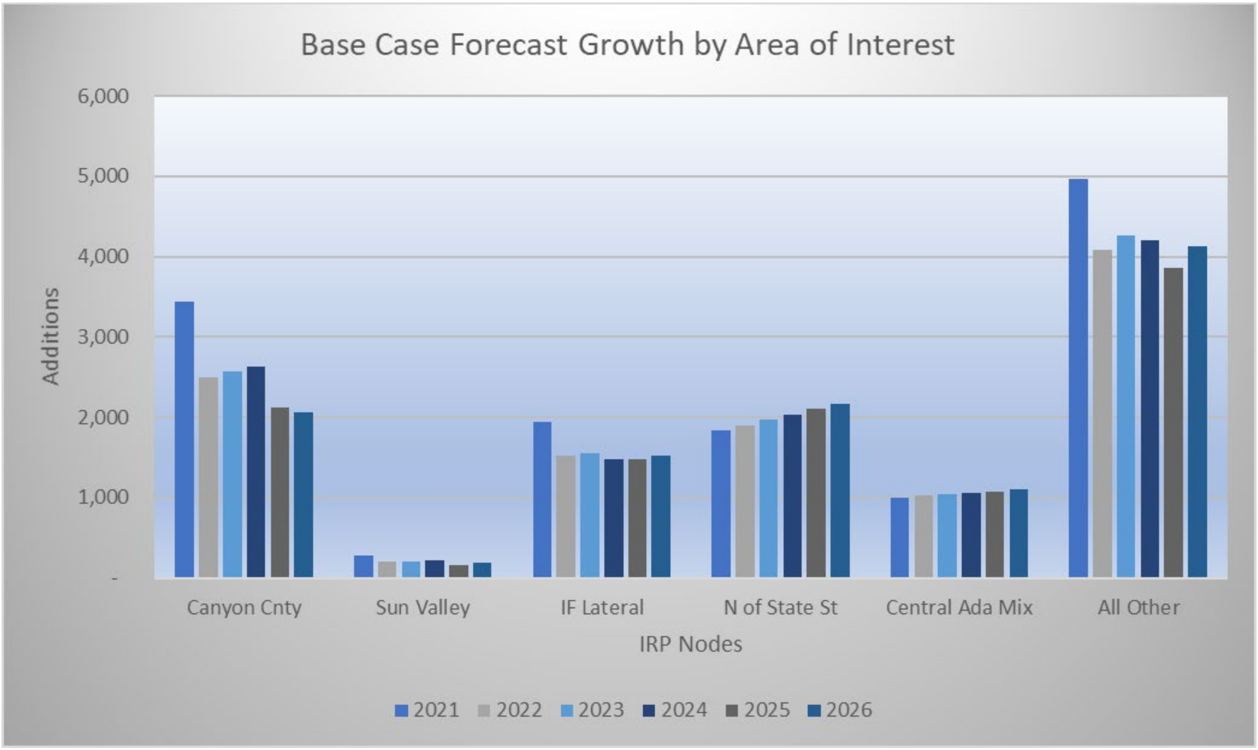

Figure 3: Base Case Forecast Growth by Area of Interest

The ’20 Forecast contains three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model and has developed three five-year core market customer growth forecasts. The following graph (Figure 4) shows the annual additional customer forecast for each of the three economic scenarios.

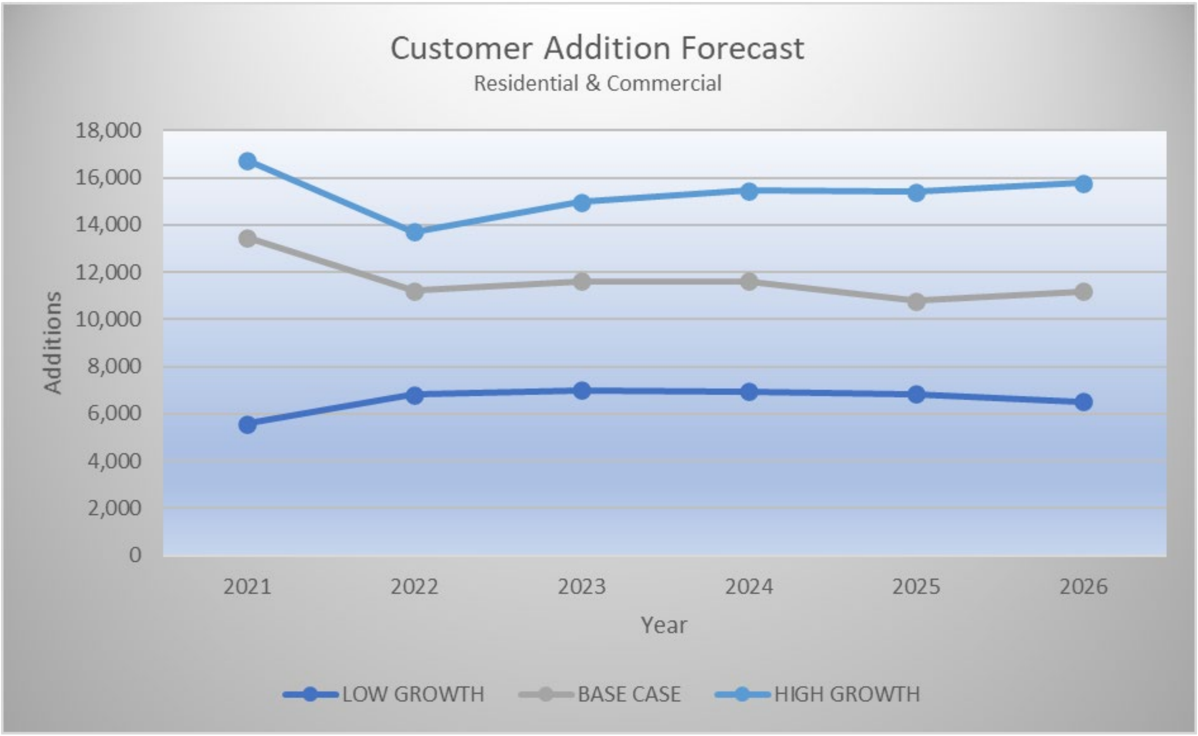

Figure 4: Customer Addition Forecast - Residential & Commercial

The following graph (Figure 5) shows the difference in base case annual additional customers between the 2019 and 2021 IRP forecast years common to both studies:

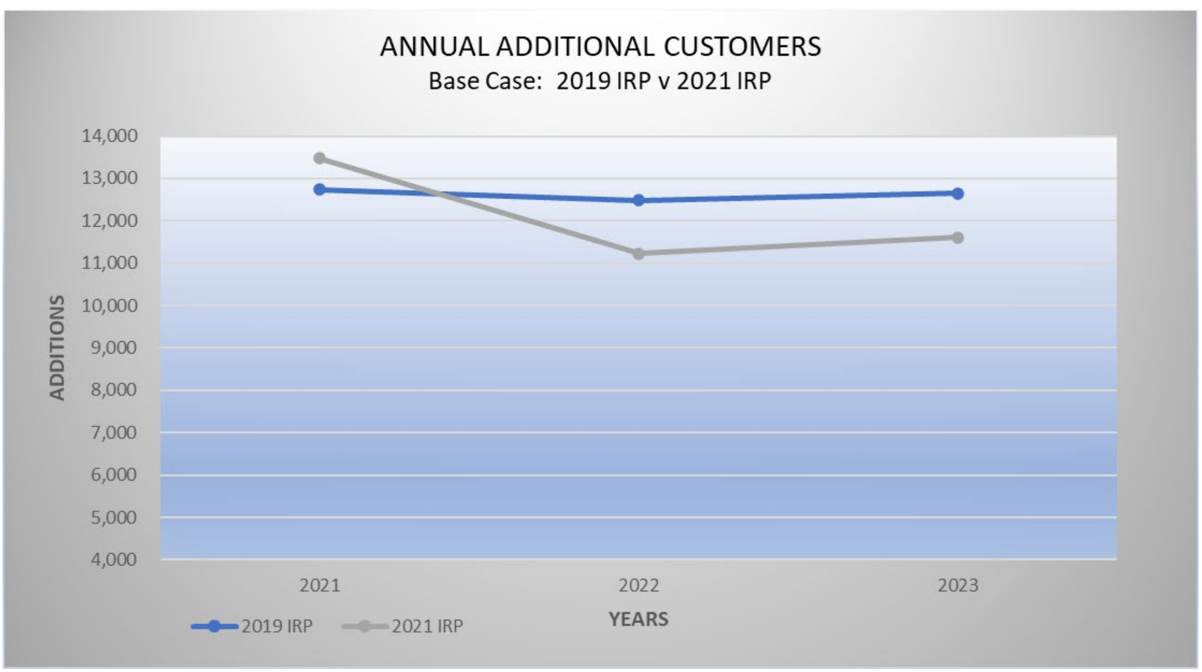

Figure 5: Annual Additional Customers - Base Case: 2019 IRP vs 2021 IRP

The following tables show the results from the five-year customer growth model for each scenario for the annual additional or incremental customers and total customers at each year-end.

Table 1: Forecast New Customers

Forecast New Customers						
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
LOW GROWTH	5,566	6,801	7,002	6,957	6,842	6,505
BASE CASE	13,472	11,221	11,608	11,617	10,796	11,180
HIGH GROWTH	16,733	13,704	14,978	15,442	15,399	15,768

Table 2: Forecast Total Customers

Forecast Total Customers						
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
LOW GROWTH	392,884	399,685	406,686	413,644	420,486	426,991
BASE CASE	400,790	412,012	423,620	435,236	446,032	457,212
HIGH GROWTH	404,051	417,756	432,734	448,176	463,575	479,342

The following sections explore more fully the different components of the customer forecast, including the '20 Forecast, market penetration and conversion rates, and commercial customer growth.

Household Projections

The '20 Forecast provides county by county projections of output, employment and wage data for 21 industry categories for the state of Idaho, as well as population and household forecasts. This simultaneous equation model uses personal income and employment by industry as the main economic drivers of the forecast. The model also utilizes forecasts of national inputs and demand for those sectors of the Idaho economy having a national or international exposure. Industries that do not have as large a national profile and are thus serving local communities and demand are considered secondary industries. Local economic factors, rather than the national economy, determine demand for these products.

The ’20 Forecast uses two methods for population projections: (1) a cohort-component population model in which annual births and deaths are forecast, the net of which is either added to or subtracted from the population; and (2) an econometric model which forecasts population as a function of economic activity. The two forecasts are then compared and reconciled for each quarter of the forecast. Migration into or out of the state is derived as a result of this reconciliation.

As previously mentioned, the ‘20 Forecast provides three scenarios: (1) base case, (2) high growth, and (3) low growth. The base case scenario assumes a normal amount of economic fluctuation and a normal business cycle. This becomes the standard against which changes in customer growth, as affected by the low and high growth scenarios can be measured.

The Base Case Economic Growth Scenario

In the Base Case Scenario of the Winter 2020 Idaho Economic Forecast it is projected that Idaho will continue to be an attractive environment for future economic, population and household growth. In the decade of the 1990s Idaho's population increased at a strong annual average rate of 2.5 percent per year. The Great Recession of 2008 caused a significant slowing in Idaho's economy. The 2008 recession caused Idaho’s nonagricultural employment to contract by nearly 51,000 jobs (7.8%) in the years 2008 through 2010.

As the recession took hold in Idaho the state did not immediately experience a slowdown in population growth which averaged 1.9% per year over the 2000 to 2010 period. Nevertheless, population growth slowed to a pace of less than 1.0% per year in 2011 and 2012.

Nonagricultural employment in Idaho regained its upward momentum in 2011 with an annual average increase of 1.2% - 7,200 jobs. In the years 2012 – 2019 Idaho’s nonagricultural employment gains were strong with an annual average increase of 2.9% per year, a gain of 137,500 jobs over the 7-year period.

In 2020 the COVID-19 pandemic brought Idaho’s economic growth to a halt. Nonagricultural employment in Idaho declined 74,300 jobs between February 2020 and April 2020. However, in the following months Idaho regained many of those jobs that were lost. So much so that the state’s November 2020 total employment numbers were down only 7,200 jobs from year earlier levels. While the November 2020 number of persons unemployed in Idaho was nearly 25,000 above year earlier levels the sum of the number of employed plus the unemployed is indicative of an economy that continues to exhibit an underlying upward momentum and future growth.

While Idaho’s economy may not post the gains seen in the 2015 to 2019 period in 2021 and 2022 it is forecasted to continue its economic gains over the longer term 2020 to 2045 forecast period.

Total non-agricultural employment in the State is projected to increase by 709,000 (an annual average increase of 2.5 percent per year) over the 2020 to 2045 period. Ada and Canyon counties are projected to capture the majority of the non-ag employment gains with a projected increase of 460,000 non-ag jobs in the two counties, an annual average increase of 3.4 percent per year over the 2020 to 2045 period. During those twenty-five years Ada and Canyon counties are projected to account for nearly 64.8 percent of the projected total non-ag employment gains statewide. Other areas of projected employment growth are in Bannock, Bonneville, Jefferson and Madison counties of Eastern Idaho. Over the 2020 to 2045 forecast period non-ag employment in these the Eastern Idaho counties is projected to increase by 86,400 jobs, a 2.2 percent annual average increase.

As has been the case over the last two decades, employment and population growth in the state is projected to be concentrated in the few, more urban, counties. Ada and Canyon counties will continue to capture over 60 percent of the state's projected future employment and population growth. In second place Kootenai and Bonner counties in North Idaho are projected to capture nearly 20% of the 2020 to 2045 employment and population growth. And the Eastern Idaho counties along Intermountain Gas Company's Idaho Falls Lateral (Bannock, Bingham, Bonneville, Butte, Fremont, Jefferson, Madison, and Power counties) are projected to account for nearly 12 percent of future employment and population gains in the state.

Idaho's manufacturing industries will not be the driver of future economic growth in the state. In the years 2000 to 2010 manufacturing employment in Idaho decreased by nearly 17,200 jobs. In what can only be considered as a somewhat remarkable turnaround in the years since 2010, and through mid-year 2020 Idaho regained nearly 14,000 manufacturing jobs.

In the last twenty years food processing employment in Ada, Canyon, Twin Falls, and Jerome counties had been increasing, largely on the strength of the expansion of the dairy industry in the state. Job gains in the dairy products manufacturing sector have been strong. In the forecast period it is expected that the dairy products manufacturing firms will continue to post job gains. At the same time, it is projected that the vegetable processing firms in Southern Idaho will, over the 2020 to 2045 forecast period, experience further job losses as processing plant consolidation, processing automation, and production efficiencies continue. The total effect of these trends in the food processing industry is that it is not projected that the food processing sector will be a significant contributor to future manufacturing employment gains in Idaho.

A new dynamic seen in the state over the last ten years is an increased number of small to medium size manufacturing firms relocating from other states to Idaho. Many of these firms are seeking lower costs of production, less regulation, and improved business climate; and many of those firms are from California.

Employment in Idaho's traditional Lumber and Wood Products manufacturing sector slipped in the 2008 Great Recession. It has not recovered and its unlikely that it will recover with the possible exception of the production of higher value-added processed wood products. Future job gains in the Lumber and Wood Products manufacturing sector is projected to be minimal over the 2020 to 2045 forecast period. Statewide employment in Stone, Clay, and Glass Products and Fabricated Metal Products manufacturing is expected to increase in proportion to population and household growth in the state. Idaho's Electronics and Machinery manufacturing sectors are not expected to regain the jobs lost during the last recession. No new large-scale machinery or electronics manufacturing facilities are assumed to be located in Idaho during the 2020 to 2045 forecast period.

In the 2020 to 2045 forecast period manufacturing employment in Idaho is projected to increase by nearly 23,400 jobs; an annual average gain of close to 2.0 percent per year. This represents a continuation of the pace of manufacturing employment gains that the state experienced from the low points of the 2008 Great Recession. Manufacturing employment in Ada and Canyon counties is projected to capture nearly 17,000 (about 75 percent) of the state's projected 2020 to 2045 growth in manufacturing employment.

Statewide employment in the Transportation, Trade, and Utilities industries is projected to increase by nearly 87,600 jobs over the 2020 to 2045 forecast period; an annual average increase of nearly 2.0 percent per year. In general, employment in Transportation, Trade, and Utilities is projected to increase at a pace that is slower than the forecasted rate of population and household growth statewide. In Ada and Canyon counties Transportation, Trade, and Utilities employment is projected to increase by 63,400 over the forecast period, representing 72.0 percent of the projected statewide employment gains in the sector. A new Amazon fulfillment facility in Canyon County and a second Amazon facility (different than the Canyon County fulfillment center) in Ada County are expected to increase employment dramatically in the near term.

The service industries in Idaho have been the fastest growing in terms of employment gains over the last twenty years. Idaho employment in the Professional and Business Services sector increased by nearly 32,000 jobs between 2000 and mid-year 2019; an annual average increase of 2.1 percent per year. Ada and Canyon counties captured nearly 61.0 percent of the State's Professional and Business Services employment growth between 2000 and mid-year 2019. In the 2020 to 2045 forecast period Professional and Business Services employment is projected to increase by 130,800; an annual average compound rate of 3.6 percent per year. Historically the Professional and Business Services sector in Idaho has posted employment gains and losses that could be considered volatile. This has been due to the business classification of subcontractors utilized by the US Department of Energy at the Idaho National Laboratory (INL). Changes in INL subcontractors have caused Professional and Business Services employment in the state to change rapidly in the past and they may change in the future.

Idaho employment in Educational and Health Services increased by nearly 57,400 jobs between 2000 and mid-year 2019; an annual average increase of 3.7 percent per year. Ada and Canyon counties captured 29,200, nearly 50.8 percent, of the state's Educational and Health Services employment growth between 2000 and mid-year 2019. In the 2020 to 2045 forecast period Educational and Health Services employment is projected to increase by 168,800; an annual average compound rate of 3.7 percent per year. Jobs in Idaho's Educational and Health Services sector are more spatially diverse that the Professional and Business Services sector. Almost every county in Idaho is projected to post an increase in employment over the 2020 to 2045 forecast period. In the counties along Intermountain Gas Company's Idaho Falls Lateral the Educational and Health Services sector is projected add 14,700 jobs over the 2020 to 2045 forecast period.

Idaho employment in Leisure and Hospitality Services increased by nearly 26,700 jobs between 2000 and mid-year 2019; an annual average increase of 2.1 percent per year. Ada and Canyon counties captured 13.200, nearly 49.3 percent, of the state's Leisure and Hospitality Services employment growth between 2000 and mid-year 2019. In the 2020 to 2045 forecast period Leisure and Hospitality Services employment is projected to increase by 64,900; an annual average compound rate of 2.4 percent per year. In the counties along Intermountain Gas Company's Idaho Falls Lateral the Leisure and Hospitality Services sector is projected to add nearly 6,700 jobs over the 2020 to 2045 forecast period.

Employment in the Government sector increased by 7,700 jobs between 2000 and mid-year 2019; an annual average increase of 0.3 percent per year. Government employment gained 10,200 jobs in Ada and Canyon counties between 2000 and mid-year 2019, a reflection of the faster than average population and household growth in the two counties which has caused significant increases in local government employment. In the 2020 to 2045 forecast period Government employment is projected to increase by 110,900; an annual average compound rate of 2.7 percent per year. No specific growth assumptions are made concerning government future employment at Idaho's two largest government facilities – Mountain Home Air Force Base and the INL.

Population and Household Growth

US Census Bureau population estimates indicate that Idaho has experienced a significant increase in population growth since the end of the 2008 Great Recession. Over the last 5 years, 2014 through 2019, population growth in Idaho was twice ranked as the fastest growing in the nation, and in every year of the last five years Idaho was always ranked one of the fastest growing states in the country.

While the COVID-19 pandemic has caused significant economic hardship in the country and the state it initially appears that Idaho has fared better than many other states. Unemployment in Idaho surged dramatically in March and April of 2020. But, in short order the state exhibited that the COVID-19 induced recession in Idaho was going to be a V-shaped recession with an initial sharp downturn in economic activity and thereafter a quick recovery in economic activity. And while there are many people in Idaho who are still under tremendous economic pressures because of the COVID-19 pandemic the state has nearly recovered to its pre-pandemic level of total employment.

The latest US Census Bureau's estimates of 2020 state populations (this is an estimate that is not based on the official 2020 US Census tabulation) has Idaho ranked as the fastest growing state in the nation with an annual average population increase of 2.12%. At this time the US Census Bureau's estimate of Idaho's 2020 population is 1,839,000.

In five years after the effects of the 2008 Great Recession (2014 – 2019), Idaho's population increased by 136,000, an overall increase of 8.2 percent. Ada and Canyon counties accounted for 53.6 percent of the state's population growth over those five years. Idaho's population growth over the 2014 through 2019 period was very concentrated. If population growth in the Eastern Idaho counties of Bannock, Bonneville, Jefferson, and Madison are included these six counties represent 66.4 percent of the state's population growth. Add in the population growth in Twin Falls county and that share increases to 70.2 percent. Lastly, adding in the population growth that occurred in Kootenai and Bonner counties in North Idaho and these nine counties accounted for 85.3 percent of the state's population growth over the 2014 to 2019 period. That concentration of the state's population growth is projected to continue in the forecast period.

It is projected that during the 2020 to 2045 forecast period Idaho's population will increase by 1,283,000 reaching a total population of 3,024,600 by the year 2045, an annual average pace of 2.2 percent per year. The number of households in the state is expected to increase by approximately 366,000 over the 2020 to 2045 forecast period.

Ada and Canyon counties are projected to capture the majority of Idaho's population growth over the forecast period. Population in Ada and Canyon counties are projected to reach 881,000 and 410,500, respectively, by the year 2045. This represents an increase of 433,400 in Ada County population and a 179,500 increase in Canyon County population over the 2020 to 2045 forecast period. In total, population growth in Ada and Canyon counties are projected to account for 47.9 percent of the 2020 to 2045 projected population growth in the state.

In Eastern Idaho, Bonneville, Madison, Bannock, and Jefferson counties are expected to see increases in population of 66,000, 49,100, 49,200 and 25,300, respectively, a total population increase for the four counties of 189,600 over the 2020 to 2045 forecast period. These four Eastern Idaho counties are projected to account for 14.8 percent of the state's population growth over the forecast period. A total growth in population and households of 140,400 persons and 61,630 households is projected in the eight counties along the Idaho Falls Lateral over the 2020 to 2045 forecast period.

The High and Low Economic Growth Scenarios

The high growth and low growth scenarios of the ‘20 Forecast present alternative views of the economic future of Idaho and its 44 counties. The high growth scenario of the ‘20 Forecast presents a vision of a more rapidly growing economy in Idaho. The high growth scenario average annual compound rate of population growth from 2020 to 2045 is 2.5% per year.

Alternatively, the low growth Scenario of the ‘20 Forecast presents a slower economic outlook for the Idaho economy. In the low growth scenario, Idaho’s population is exhibiting an annual average compound growth rate of 1.4% per year from 2020 to 2045.

An examination of the possible economic and demographic events that could produce the economic and population growth projected in the high and low growth scenarios are outlined below.

The High Growth Economic Scenario

The High Growth Scenario of the ‘20 Forecast assumes that Idaho will be a more attractive environment for the relocation of firms from other states. Many small to medium businesses currently operating in California, Oregon, and Washington are examining their options to relocate to other areas with lower taxes, operating costs, and regulation. This is not a new phenomenon. In the 1990’s many firms relocated some or all of their operations from California and spurred on economic growth in Nevada and Arizona. In the next decade (2000 to 2010) this trend continued with Nevada, Arizona, and Utah seeing an influx of firms and an increase in population in-migration. Idaho and Southwestern Oregon also captured a portion of economic and population growth caused by this dynamic. The High Growth Scenario assumes that this phenomenon will continue, and that Idaho will capture a larger share of that relocation and growth dynamic.

The High Growth Scenario projects an Idaho population of 3,368,200 in the year 2045. The High Scenario projected population at the end of the forecast period is 11.4 percent (343,500) higher than in the Base Scenario forecast. As is the case in the Base Scenario forecast Ada and Canyon Counties realize the lion’s share of Idaho’s population growth. The 2045 population in Ada County is forecasted to reach 1,011,200 and Canyon County population grows to 437,800. Ada and Canyon county High Scenario populations in the year 2045 are projected to be 157,800 (12.2 percent) higher than in the Base Scenario. The accelerated population growth in the High Scenario also increases the projected number of households in the state. In the High Scenario Forecast the counties along Intermountain Gas Company’s Idaho Falls Lateral are projected to attain a population of 628,400, and a total of 205,600 households. These projections represent an increase in the 2045 population of 99,000, and an increase of 26,300 households when compared to the Base Scenario Forecast. Bonneville County is forecasted to account for nearly 46.0 percent of the population gains along the Idaho Falls Lateral with Bannock, Madison, and Jefferson counties accounting for 21.0 percent, 20.0 percent, and 11.0 percent respectively of the area's population gains in the High Scenario. High Scenario population gains in Butte, Fremont, and Power counties are forecasted to account for only about 2.0 percent of the area's population gains.

In the High Growth Scenario of the '20 Forecast it is assumed that Idaho will be a modestly more attractive environment for manufacturing firms. Therefore, manufacturing employment in Idaho continues a recovery that started after the end of the 2008 Great Recession. It is forecasted in the High Scenario of the Winter 2020 Economic Forecast that manufacturing employment in Idaho will reach 97,600 in the year 2045. This is 5,500 jobs higher (5.9% higher) than projected employment in the Base Scenario forecast.

It is assumed in the High Scenario that Idaho's Food Processing industry will shed a lower number of jobs in its vegetable processing facilities across the state. Furthermore, it is assumed that Idaho will continue to attract new, higher value-added, food processing firms to the State. And as was the case in the Base Scenario Forecast there is no expectation for the location of a new electronics manufacturing plant in the State. It is expected that Idaho's manufacturing employment associated with the Lumber and Wood Products, Paper Products, and Chemical Products manufacturing will remain relatively constant and will not be a significant factor driving future manufacturing employment growth. Lastly, it is assumed that manufacturing employment in the State's Transportation Equipment industry will not directly benefit from the High Scenario forecast's stronger economic growth. Growth in Idaho's Transportation Equipment manufacturing may only occur without an in-migration of those firms, relatively small in scale, relocating to Idaho. However, it is assumed that the state will gain manufacturing employment due to an in-migration of smaller firms in the Machinery and Equipment and Fabricated Metals manufacturing industries.

The Service Industries are forecasted to provide most of the employment gains in the High Scenario Forecast. At the year 2045, it is forecasted in the High Scenario that employment in the Professional and Business Services industry will be nearly 32,000 (14.4 percent) higher than the Base Scenario Forecast. Likewise, the Education and Health Services and the Leisure and Hospitality Services industries which are forecasted to have their High Scenario employment in the State reach levels that are 39,300 (14.1 percent) and 21,200 (14.7 percent) higher than in the Base Scenario Forecast. Ada and Canyon counties are projected to account for nearly 60.0 percent of the additional service industry employment projected in the High Scenario Forecast. Kootenai and Bonner counties in Northern Idaho are projected to account for nearly 13,000 jobs (14.0 percent) of the additional service industry in the High Scenario Forecast.

The Low Growth Economic Scenario

By the year 2045 it is projected in the Low Scenario of the '20 Forecast that population in Idaho will be 2,558,500. The Low Scenario forecast of population in the year 2045 is 466,200 lower

(-15.4 percent) than the 2045 Base Scenario Forecast of population. The 2045 forecasted number of households in Idaho is 182,800 lower (-17.5 percent) in the Low Scenario Forecast.

In the Low Case Economic Forecast, it is assumed that the strong population in-migration to Idaho that has occurred over the last two decades will not accelerate in the future. A net migration of persons and business out of California to other states will be increasingly captured by other states in the West and Southwest. This represents a reversion to the pattern seen from 1990 through 2000 where Nevada, and then Arizona, and lastly Utah captured most of the economic growth attributable to migration out of California.

The capture of this migration by other states will cause Idaho to grow at a slower pace and will make the state less attractive to a job-seeking population that would otherwise migrate to Idaho. Adding to this phenomenon the loss of a major employer or a substantial downturn in a major industry in the state and a low economic growth could be a reality for Idaho. For example, a closure of Micron's operations in Idaho or a corporate takeover of an Idaho company could lead to the relocation of a corporate headquarters from Idaho. And lastly as an example, a substantial downturn in the dairy industry could lead to a reduction of dairy herds in Idaho, and thereafter a cutback or closure of dairy processing facilities in Idaho.

In the Low Scenario of the '20 Forecast total nonagricultural employment in Idaho is projected to reach 1,523,100 in the year 2045. This is 13.0 percent, or 198,800 jobs, lower than Idaho's forecasted 2045 nonagricultural employment projected in the Base Scenario Forecast.

Idaho's manufacturing employment in the Low Scenario Forecast is projected to reach a 92,200 in the year 2045 which is 8,800 jobs (9.6 percent less than the 2045 Base Scenario Forecast of Idaho's manufacturing employment). In the Low Scenario forecast the State's loss of jobs in the Food Processing industry accelerates and nearly 1,500 additional jobs are lost over the years of 2020 to 2045. The most likely scenario is that the potato processing plants in Southern Idaho would experience the bulk of these job losses. It is assumed in the Low Scenario that one or more potato processing plants would be substantially cut back or even closed. A further assumption in the Low Scenario Forecast is that the sugar processing plants in Southern Idaho would also feel increased pressure from competition and would find it necessary to close one of the sugar processing plants in either Nampa, Paul, or Twin Falls, Idaho. The dairy industry and its associated food processing plants would reach a point where no further capacity could be added due to increased population and environmental pressures.

Employment losses in Idaho's Lumber and Wood Products manufacturing industry are assumed to accelerate in the Low Scenario. In this scenario the brunt of these additional losses would be felt in those portions of the wood products industry that could be increasingly vulnerable to low cost foreign produced products - the Wood Grain Molding plants in Fruitland and Nampa, Idaho.

Idaho's Electronics and Machinery manufacturing industries would experience further job losses over the forecast period. Employment in Stone, Clay, and Glass Products and Fabricated Metal Products manufacturing are both projected to be at lower levels of total employment than in the Base Scenario of the economic forecast.

Transportation, Trade, and Utilities employment in the Low Scenario Forecast is projected to have nearly 9,600 fewer jobs (-4.4 percent) in the year 2045 than in the Base Scenario forecast. The impact of slower economic growth in the state inherent in the Low Scenario Forecast produces lower levels of demand for transportation services and for the buying opportunities of additional retail stores.

The Low Scenario forecast of statewide 2045 employment in the Finance, Insurance, and Real Estate and the Information sectors of the economy are projected to be nearly 15,900 (-14.5 percent) lower than expected in the Base Scenario Forecast by the year 2040. Again, the difference is largely due to the lower levels of population and household growth inherent in the Low Case Scenario.

The outlook for Service industry employment in the Low Scenario Forecast assumes that employment growth in the Service sector slows proportionate to the projected slower growth in population and households statewide. In total, employment in the Professional and Business Services, Educational and Health Services, and Leisure and Hospitality Services industries are projected in the Low Scenario Forecast to attain a 2045 level of employment of 525,700, which is 120,160 lower (- 18.6 percent) than in the Base Scenario Forecast.

Future Government employment in the Low Scenario is projected to be 11.7 percent (26,600 jobs) lower than the Base Scenario forecast by the year 2045. As previously mentioned for other industries the reason for projected lower levels of Government employment in the Low Scenario forecast are the slower rates of population and household growth in the Low Scenario Forecast. It is assumed in the Low Scenario Forecast that the number of assigned military personnel at Mountain Home Airforce Base will remain at levels that are similar to those at the present time.

Forecast Households

As previously stated, the basis for the customer growth forecast relies on the annual variance, or change, in households from year to year, within the counties in which Intermountain operates.

The graph below (Figure 6) provides a visual depiction of the variance in household growth for high growth, base case and low growth scenarios for the counties which Intermountain Gas Company serves.

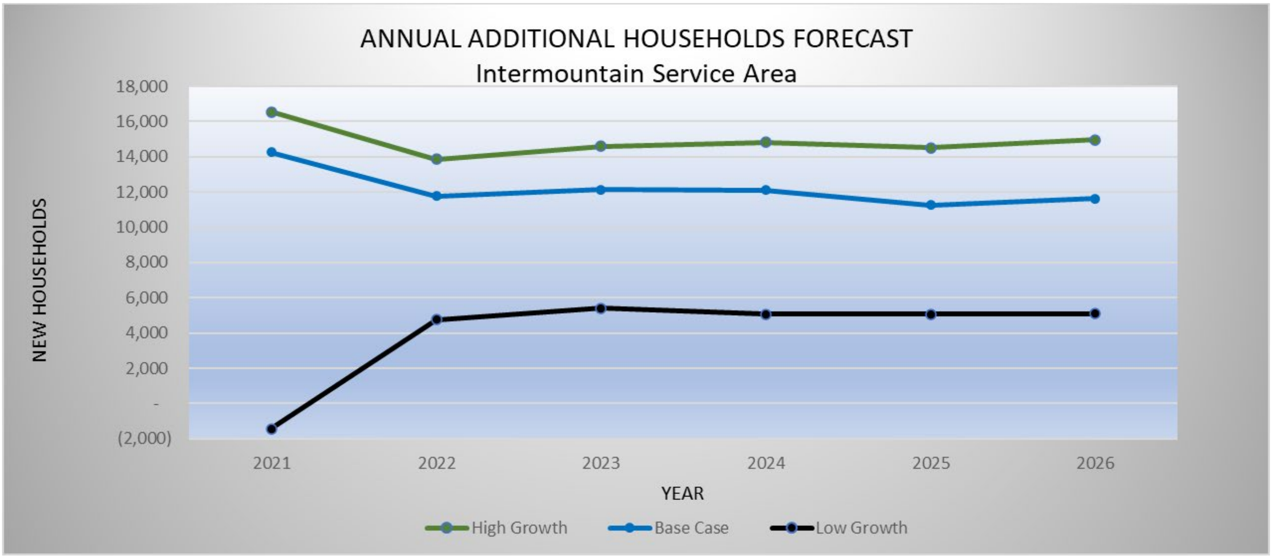

Figure 6: Annual Additional Households Forecast

A comparison of the base case household growth, between the common years in the 2019 and 2021 IRPs, is depicted below (Figure 7).

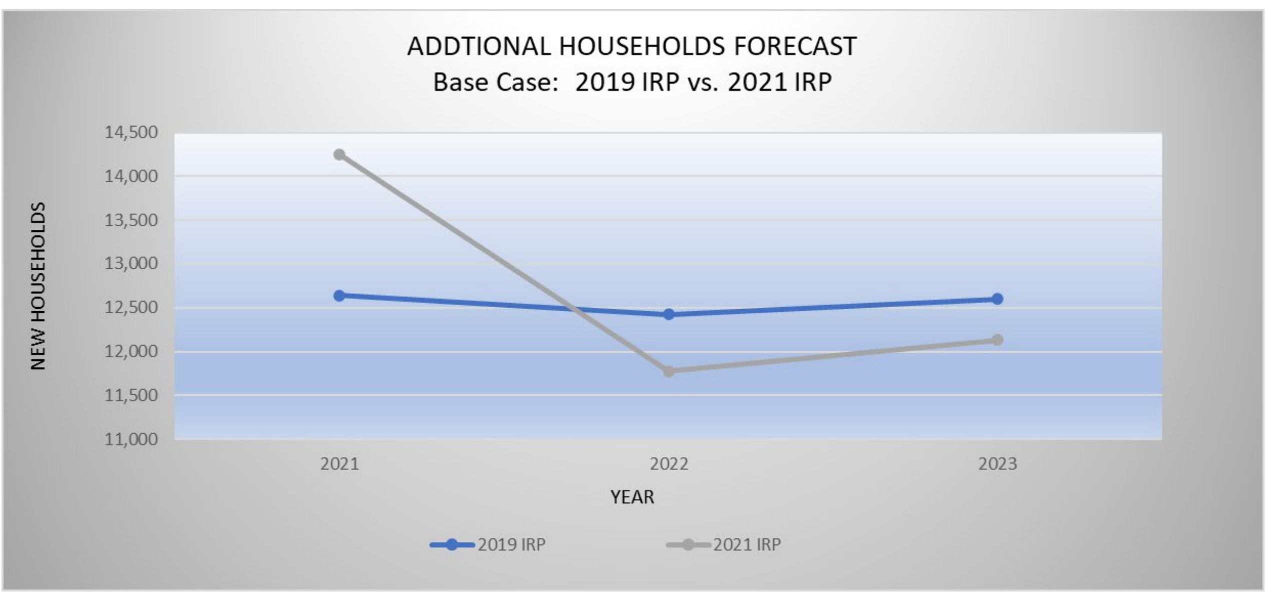

Figure 7: Additional Households Forecast - Base Case: 2019 IRP vs 2021 IRP

Market Share Rates

To determine the potential market share of new households, Intermountain takes a historical look at its past performance in regard to the ratio of customer acquisitions per building permit issued; then applies that factor to future estimates of household growth across its 5 Operations Districts.

Intermountain develops market penetration rates by way of county building permit reports which the Company's Energy Service personnel use in prospecting for new construction customers. These reports are made available through Construction Monitor, a nationwide building permit monitoring service to which Intermountain subscribes. To derive the penetration rate for this IRP, a query of street addresses of all residential permits issued from 2016- 2020 was compared to a query of all active residential service points addresses in Intermountain's customer billing system. The results were then scrubbed for false negatives due to addressing variations between the data sets. i.e.; Rd. vs Road, St. vs Street or compass designations N, S, E, W. Once this task was completed, the results were sorted by District. This methodology is congruent with the derivation of Household growth figures by county. It is assumed that some permits are issued outside of the Company's reachable service territory, but within the counties. This penetration rate is then applied, by District, to the Household growth figures to derive an estimate of future customer acquisition. See Figure 8 below for market penetration rates by district.

District	Permits	Installed	Rate
Boise	21,343	20,944	98%
Idaho Falls	5,315	3,511	66%
Nampa	9,617	8,571	89%
Pocatello	1,741	1,163	67%
Twin Falls	3,468	2,514	73%

Figure 8: Market Penetration Rate - By District

The following graph (Figure 9) illustrates the relationship between the three economic scenarios for the annual residential new construction growth forecast for 2021 – 2026:

Figure 9: Residential New Construction Growth

The following graph (Figure 10) shows the difference in base case residential new construction customer growth between the 2019 and 2021 IRP forecast years common to both studies:

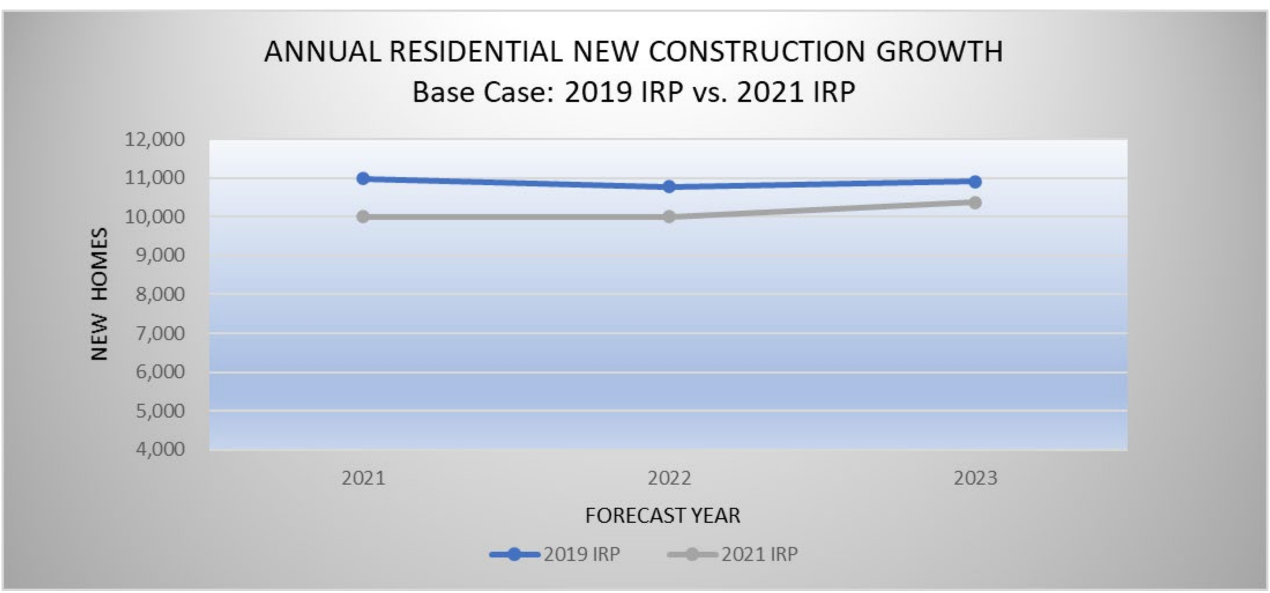

Figure 10: Annual Residential New Construction Growth - Base Case: 2019 IRP vs 2021 IRP

Conversion Rates

The conversion market represents another source of customer growth for the Company. Intermountain acquires these customers when homeowners replace an electric, oil, coal, wood, or other alternate fuel source furnace/water heater with a natural gas unit. Intermountain forecasts these customer additions by applying regional conversion rates based on historical data and future expectations. The following table shows, by region, the assumed conversion rates used in the IRP. These rates represent the percentage of new customer additions which will be conversions. The calculated conversion forecast is then added to the new construction forecast to derive the total residential growth forecast.

The table below illustrates the conversion rates used in the 2021 and 2019 IRPs.

Table 3: Regional Conversion Rate

Regional Conversion Rate		
	2021	**2019**
EASTERN REGION	5%	7%
CENTRAL DIVISION	12%	20%
WESTERN REGION	15%	19%

The following graph (Figure 11) illustrates the relationship between the three economic scenarios for the annual residential conversion growth forecast for 2021 – 2026:

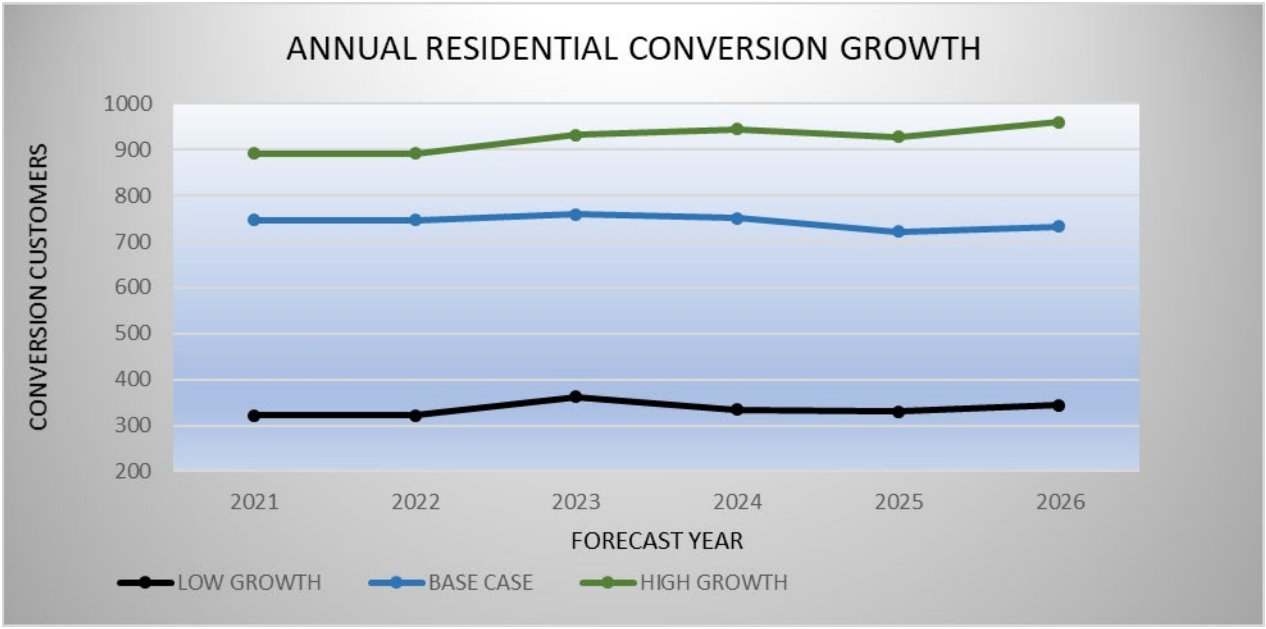

Figure 11: Annual Residential Conversion Growth

The following graph (Figure 12) shows the difference in the base case forecast of residential conversion customer growth between the 2019 and 2021 IRP forecast years common to both studies:

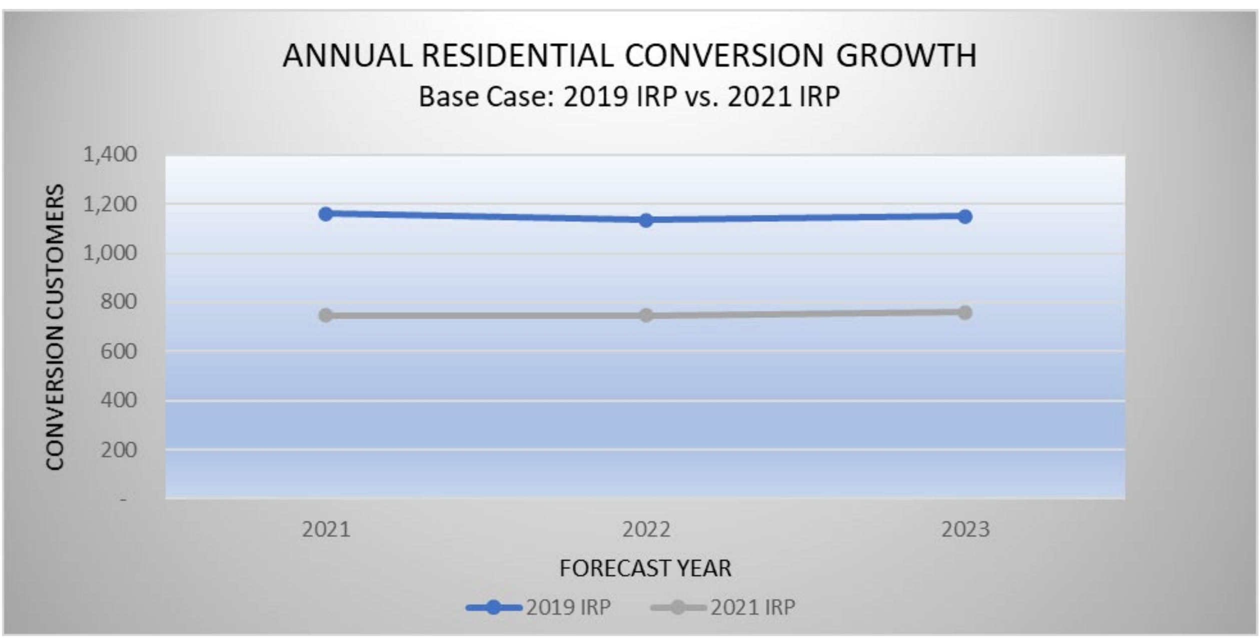

Figure 12: Annual Residential Conversion Growth – Base Case: 2019 IRP vs. 2021 IRP

Commercial Customer Forecast

The following graph (Figure 13) shows the forecast annual additional commercial customers based on the low growth, base case and high growth scenarios developed using the methodology explained previously.

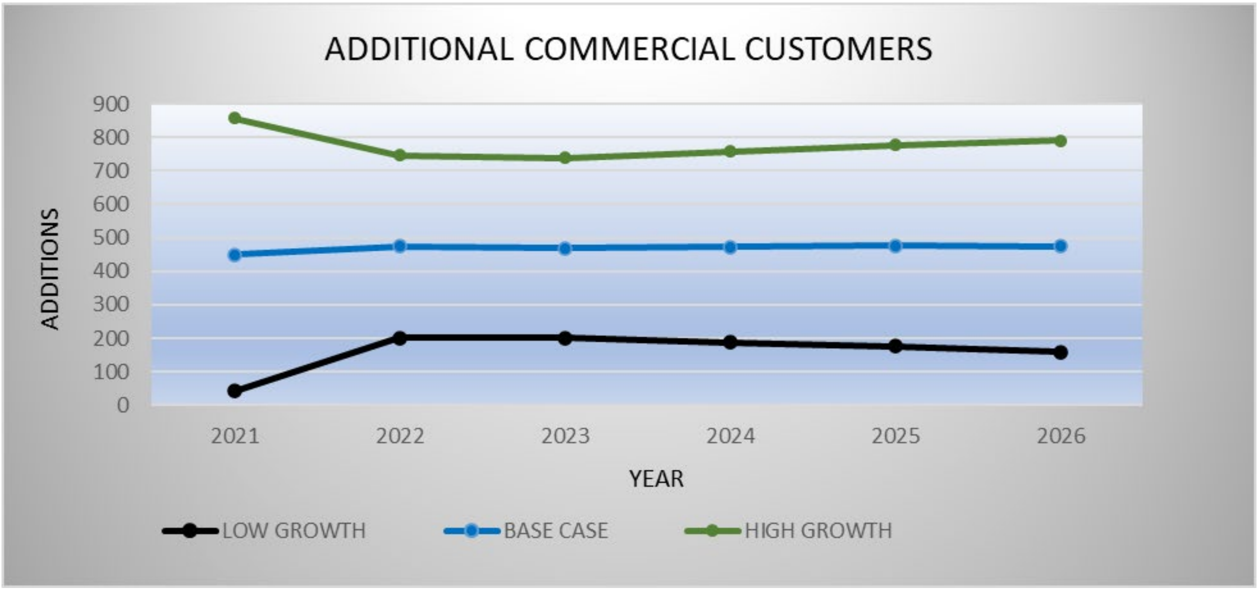

Figure 13: Additional Commercial Customers

The following graph (Figure 14) shows the difference in base case commercial customer growth between the 2019 and 2021 IRP forecast years common to both studies:

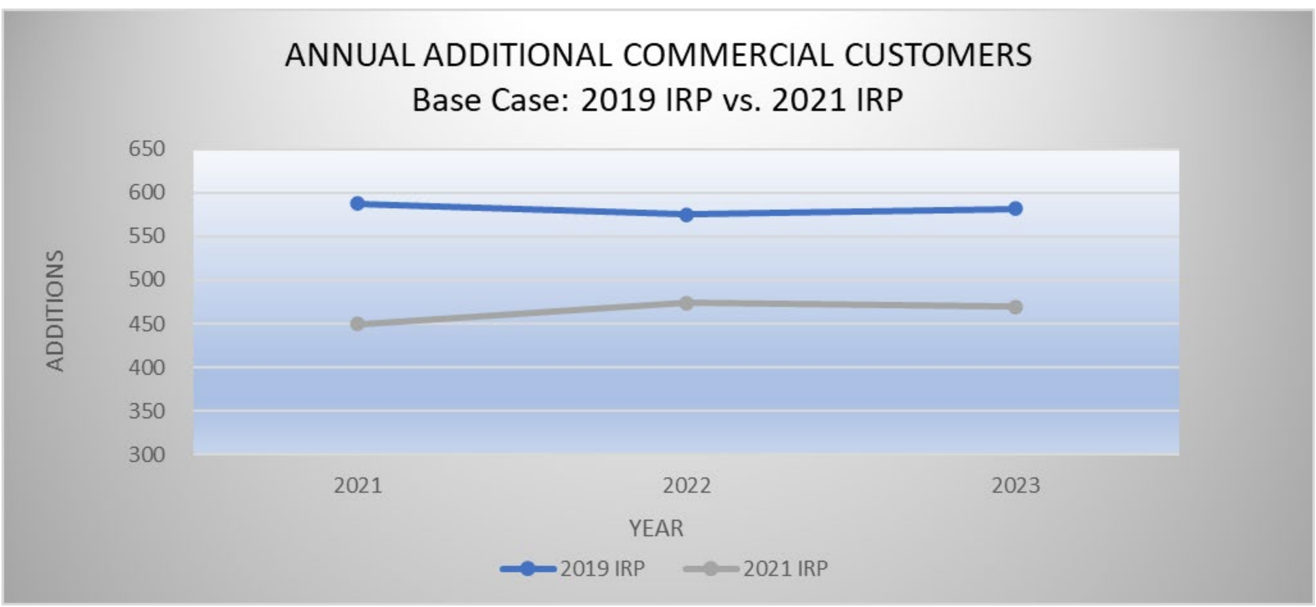

Figure 14: Annual Additional Commercial Customers – Base Case: 2019 IRP vs. 2021 IRP

Heating Degree Days & Design Weather

Intermountain's demand forecast captures the influence weather has on system loads by using Heating Degree Days (HDDs) as an input. HDDs are a measure of the coldness of the weather based on the extent to which the daily mean temperature falls below a reference temperature base. HDD values are inversely related to temperature, which means that as temperatures decline, HDDs increase. The standard HDD base, and the one Intermountain utilizes in its IRP, is 65°F (also called HDD65). As an example, if one assumes a day where the mean outdoor temperature is 30°F, the resulting HDD65 would be 35 (i.e. 65°F base minus the 30°F mean temperature = 35 Heating Degree Days). Two distinct groups of heating degree days are used in the development of the IRP: Normal Degree Days and Design Degree Days.

Since Intermountain's service territory is composed of a diverse geographic area with differing weather patterns and elevations, Intermountain uses weather data from seven National Oceanic and Atmospheric Administration (NOAA) weather stations located throughout the communities it serves. This weather data is weighted by the quantity of residential and commercial customers in each of the weather districts to best reflect the temperatures experienced across the service territory. Several AOIs are also addressed specifically by this IRP. Those segments are assigned unique degree days as discussed in further detail below.

Normal Degree Days

A Normal Degree Day is calculated based on historical data, and represents the weather that could reasonably be expected to occur on a given day. The Normal Degree Day that Intermountain utilizes in the IRP is computed based on weather data for the thirty years ended December 2020. The HDD65 for January 1st for each year of the thirty-year period is averaged to come up with the average HDD65 for the thirty-year period for January 1st. This method is used for each day of the year to arrive at a year's worth of Normal Degree Days.

Design Degree Days

Design Degree Days represent the coldest temperatures that can be expected to occur for a given day. Design Degree Days are a critical input for modelling the level of customer demand that may occur during extreme cold or "peak" weather events. For IRP load forecasting purposes, Intermountain makes use of design weather assumptions.

Intermountain's design year is based on the premise that the coldest weather experienced for any month, season, or year could occur again. The Company reviewed NOAA temperature data over the period of record and found the coldest twelve consecutive months in Intermountain's service territory to be the 1984/1985 heating season (October 1984 through September 1985).

That year, with certain modifications discussed below, represents the base year for design weather.

Peak Heating Degree Day Calculation

Intermountain engaged the services of Dr. Russell Qualls, Idaho State Climatologist, to perform a review of the methodology used to calculate design weather, and to provide suggestions to enhance the design weather planning. Dr. Qualls assisted Intermountain in developing a method to calculate probability-derived peak HDD values, as well as in designing the days surrounding the peak day.

To develop the peak heating degree day, or coldest day of the design year, Dr. Qualls fitted probability distributions to as much of the entire period of record from seven weather station locations (Caldwell, Boise, Hailey, Twin Falls, Pocatello, Idaho Falls, and Rexburg) as was deemed reliable. From these distributions he calculated monthly and annual minimum daily average temperatures for each weather location, corresponding to different values of exceedance probability. Two probability distributions were fitted, a Normal Distribution, and a Pearson Type III (P3) distribution. Dr. Qualls suggested it is more appropriate for Intermountain to use the P3 distribution as it is more conservative from a risk reduction standpoint. The final climatology report can be found attached as Exhibit 3.

According to Dr. Qualls, "selecting design temperatures from the values generated by these probability distributions is preferable over using the coldest observed daily average temperature, because exceedance probabilities corresponding to values obtained from the probability distributions are known. This enables IGC to choose a design temperature, from among a range of values, which corresponds to an exceedance probability that IGC considers appropriate for the intended use".

Intermountain used Dr. Qualls' exceedance probability results to review the data associated with both the 50 and 100 year probability events. After careful consideration of the data, Intermountain determined that the company-wide 50 year probability event, which was a 78 degree day, would be appropriate to use in the design weather model.

Base Year Design Weather

To create a design weather year from the base year, a few adjustments were made to the base design year. First, since the coldest month of the last thirty years was December 1985, the weather profile for December 1985 replaced the January 1985 data in the base design year. For planning purposes, the aforementioned peak day event was placed on January 15th.

To model the days surrounding the peak event, Dr. Qualls suggested calculating a 5-day moving average of the temperatures for the past thirty-year period to select the 5 coldest consecutive days from the period. December 1990 contained this cold data. The coldest day of the peak month (December 1985) was replaced with the 78 degree day peak day. Then, the day prior and three days following the peak day, were replaced with the 4 cold days surrounding the December 1990 peak day.

While taking a closer look at the heating degree days used for the Load Demand Curves (LDCs), the Company noticed that the design HDDs in some of the shoulder and summer months were lower than the normal weather HDDs for those months. This occurred because, while the 1985 heating year was overall the coldest on record, the shoulder months were in some cases warmer than normal. Manipulating the shoulder and summer month design weather to make it colder would add degree days to the already coldest year on record, creating an unnecessary layer of added degree days. Intermountain decided not to adjust the summer and shoulder months of the design year.

After design modifications were completed, the total design HDD curve assumed a bell-shaped curve with a peak at mid-January (see Figure 15 below). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.

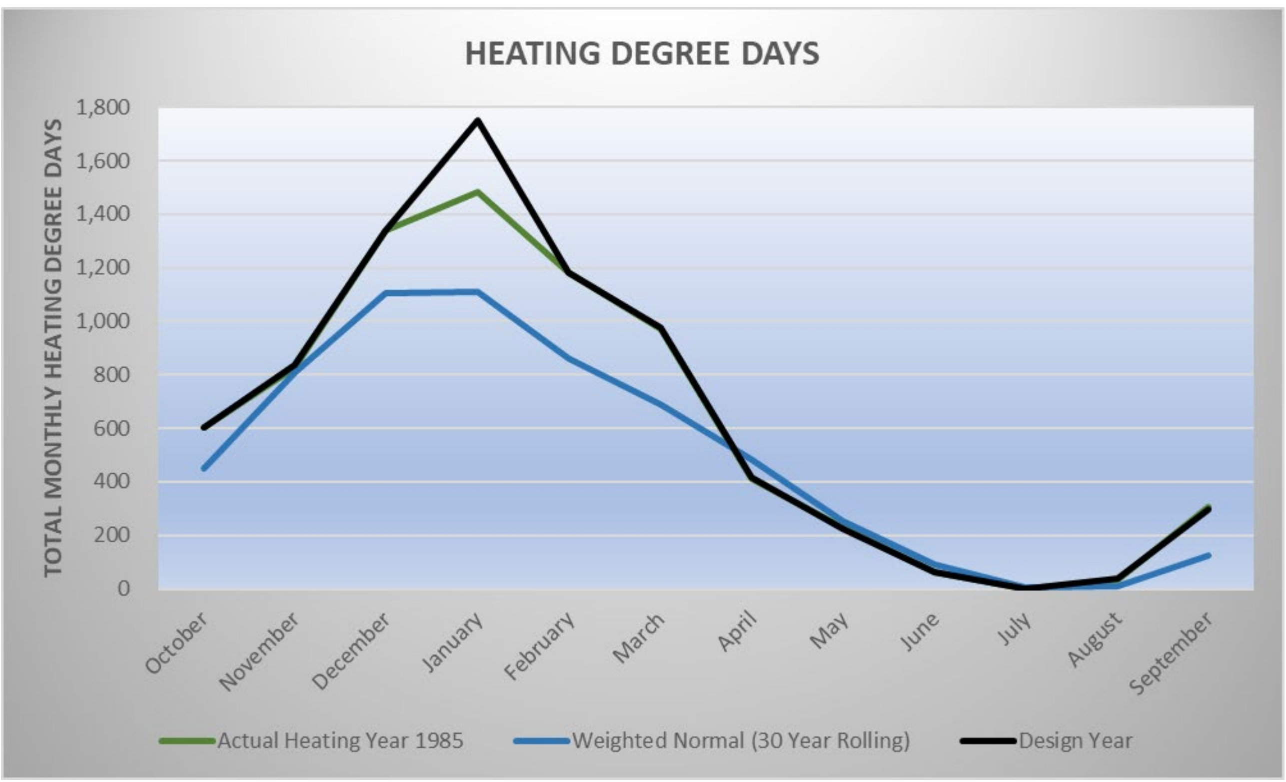

Figure 15: Design Heating Degree Days

The resulting Normal, Base Year (1985), and Design Year degree days by month are outlined in Table 4 below:

Table 4: Monthly Heating Degree Days

Monthly Heating Degree Days			
	Actual Heating Year 1985	Weighted Normal (30 Year Rolling)	Design Year
October	604	452	603
November	827	809	836
December	1,338	1,103	1,338
January	1,483	1,109	1,749
February	1,180	861	1,180
March	972	688	974
April	413	484	414
May	231	253	226
June	62	91	63
July	0	3	0
August	36	10	39
September	306	123	299
Total	7,452	5,986	7,721

Area Specific Degree Days

As noted earlier in this IRP, Intermountain has identified certain areas of interest. These are areas Intermountain carefully manages to ensure adequate delivery capabilities either due to a unique geographic location, customer growth, or both.

The temperatures in these areas can be quite different from each other and from the total company. For example, the temperatures experienced in Idaho Falls or Sun Valley can be significantly different from those experienced in Boise or Pocatello. Intermountain continues to work on improving its capability to uniquely forecast loads for these distinct areas. A key driver to these area specific load forecasts is area specific heating degree days.

Intermountain has developed Normal and Design Degree Days for each of the areas of interest. The methods employed to calculate the Normal and Design Degree Days for each AOI mirrors the methods used to calculate Total Company Normal and Design Degree Days.

Usage Per Customer

The IRP planning process utilizes customer usage as an essential calculation to translate current and future customer counts into estimated demands on the distribution system and total demand for gas supply and interstate transportation planning. The calculated usage per customer is dependent upon weather and geographic location.

Methodology

Intermountain Gas utilizes a Customer Management Module (CMM) software product, provided by DNV (formerly known as DNV GL) as part of their Synergi Gas product line, to analyze natural gas usage data and to predict usage patterns on the individual customer level. DNV operates in over 100 countries and specializes in the maritime, oil, gas and energy industries. Its array of pipeline software has been a powerful engineering tool within the United States for decades, used by natural gas companies such as Avista, Pacific Gas and Electric, Dominion, Northwest Natural and Williams. The CMM product branch is used in correlation with Synergi Gas, a hydraulic modeling software program discussed in the Distribution System Modeling section beginning on page 92 of this IRP.

The first step in operating CMM is extensive data gathering from the Company's Customer Information System (CIS). The CIS houses historical monthly meter read data for each of Intermountain's customers, along with daily historical weather and the physical location of each customer. The weather data is associated with each customer based on location, and then related to each customer's monthly meter read according to the date range of usage.

After the correct weather information has been correlated to each meter read, a base load and weather dependent load are calculated for each customer through regression analysis over the historical usage period. DNV states that it uses a "standard least-squares-fit on ordered pairs of usage and degree day" regression. The result is a customer specific base load that is weather independent, and a heat load that is multiplied by a weather variable, to create a custom regression equation.

The Company used approximately three years of data from its CIS. Should insufficient data exist to adequately predict a customer's usage factors, then CMM will perform factor substitution. Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute load factor data for a customer which lacks sufficient information for independent analysis.

Usage per Customer by Geographic Area

The Company recognizes that there could be significant differences in the way its customers use natural gas throughout its geographically and economically diverse service territory. Being sensitive to areas that may require capital improvements to keep pace with demand growth, Intermountain separated customers into distinct AOIs, and then determined specific usages per customer for each.

In order to refine usage per customer to an AOI, customer addresses were used to create groups by town, and towns were combined with their related AOI. Central Ada and State Street AOI's share towns in their respective territories, so a combined geographic area was created to calculate their shared usage per customer. Towns on the Sun Valley Lateral were combined to calculate a single usage per customer, but for flow analysis purposes it was found that more granular customer breakdowns are required, and the usage per customer was represented separately for each town due to the range of usages and geographic sensitivity along the lateral. The same Sun Valley Lateral methodology was applied to the Idaho Falls Lateral.

Model Validation

To check the usage per customer Intermountain validates the models for a specific temperature event. Following construction of the model, Intermountain worked with DNV to validate regulator pressures, source flows, and temperature information for verification points across the system. DNV made a peak hour factor and heating degree day adjustment to allow for accurate load comparison. This check verified that CMM-predicted loads align with actual supply system flow. Comparing the model results to actual pressures and flows allows the Company to validate the model and have confidence that the usage per customer from CMM is accurate to temperatures experienced in each geographic area.

In a separate validation check, Intermountain compared customer usage predicted in CMM to actual customer usage on its fixed network. Intermountain pulled available fixed network data for a temperature event and compared the customer usage for a small number of meters that have fixed network capability and found that the usage per customer was reasonable for the current quality of its fixed network data. Currently Intermountain only has a limited number of meters on fixed network and the fixed network system has limitations on gas correction factors. As discussed on page 79, the Company is in the process of implementing a fixed network metering system. As the fixed network system becomes fully deployed, the Company will be able to utilize the gathered data to further refine its usage per customer validation process.

Conclusion

The process described above is an effective methodology for calculating usage per customer. As discussed in the Load Demand Curves Section of this IRP, the usage per customer data produced from the process described above is a critical component in the development of the Company's load demand curves. The usage per customer data is applied to the customer forecast and design weather to create daily core market load projections for the IRP period.

Large Volume Customer Forecast

Introduction

The Large Volume (LV) customer group is comprised of approximately 140 of the largest customers on Intermountain's system from both an annual therm use and a peak day basis. Only customers that use at least 200,000 therms per year are eligible for Intermountain's LV tariffs. The LV tariffs provide two firm delivery services: a bundled sales tariff (LV-1) and a distribution system only transport tariff (T-4). The company also offers an interruptible distribution system only transportation tariff (T-3).

The LV customers are made up of a mix of industrial and commercial loads and, on average, they account for nearly 50% of Intermountain's annual throughput and 28% of the projected 2021 design Base Case peak day. Nearly 97% of 2020 LV throughput reflects distribution system-only transportation tariffs where customer-owned natural gas supplies are delivered to Intermountain's various Citygate stations for ultimate redelivery to the customers' facilities.

Because the LV customers' volumes account for such a large part of Intermountain's overall throughput, the method of forecasting these customers' overall usage is an important part of the IRP. These customers' growth and usage patterns differ significantly from the residential and commercial customer groups in two significant ways. First, the LV customers' gas usage pattern as a whole is not nearly as weather sensitive as the core market customers, meaning that forecasting their volumes using standard regression techniques based on projected weather does not provide statistically significant results. Secondly, the total LV customer count is so few that it falls below the number required to provide an adequate statistical population/sample size.

Therefore, Intermountain has developed and utilizes an alternate, but very accurate method of forecasting based on historical usage, economic trends, and direct input from these Large Volume customers. The chart below (Figure 16) shows a comparison of total actual LV therm use against forecast therm use from the 2019 IRP for the years 2019 – 2021.

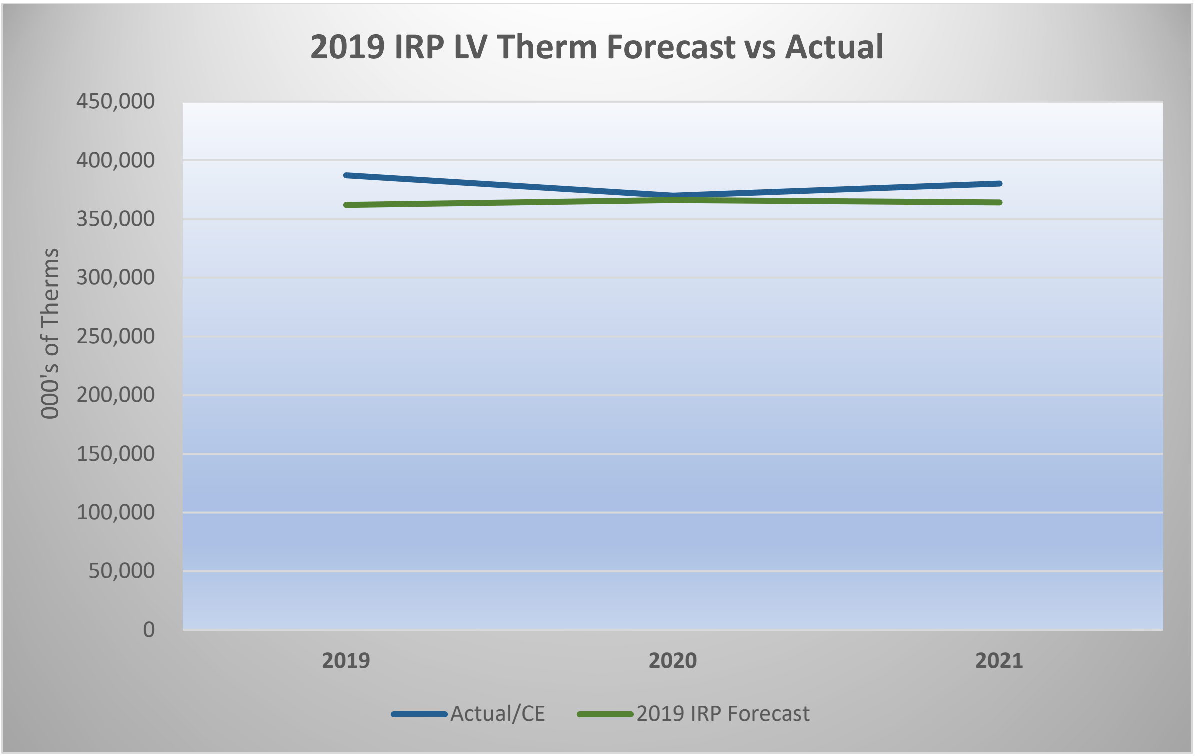

Figure 16: LV Therms - 2019 IRP Forecast vs Actuals

Method of Forecasting

Intermountain maintains a historical therm use database containing over thirty years of monthly therm use data. The LV forecasting methodology begins by assessing each LV customer's monthly usage for the most recent 3 years. Then a representative twelve-month period is selected as the "base" year. Typically, more weight is applied to the most recent twelve-month period available unless known material variations would suggest a different base year.

An important source of forecasting information comes from the customers themselves. Prior to each IRP cycle, Intermountain sends out a survey to each customer requesting information relating to changes in usage patterns. Such a survey was sent out in November 2020. As shown on page 46 (Figure 17), the survey form included a cover letter explaining the need for and the use of the requested information with the assurance that all responses would remain confidential. The surveys provided each customer's historical peak day and monthly usage for the two years ending September 2019 and 2020 . See Figure 18 on page 47 for a sample of the survey.

The historical information was provided to help LV customer's management, engineers, and/or operations personnel identify how much and when recent natural gas usage patterns were likely to change going forward. Specifically, the survey requested projections of changes in natural gas consumption related to plant expansion, equipment modification or replacement and anticipated changes in product demand and production cycles through 2026.

Additionally, each customer was provided an opportunity to give recommendations for additional service options or other feedback. About 35% of customers returned completed surveys and analysis of the returned surveys was completed by early March 2021. Where customers predicted material changes in future therm use, the Company adjusted the annual 2022-26 base year data.

Forecast Scenarios

For the IRP, Intermountain prepared three separate LV monthly gas consumption forecasts (Base Case, High Growth and Low Growth). The Base Case forecast started with the adjusted base year data as described above. That data was then combined with assumptions based on the most likely economic trend to develop during the five-year Base Case forecast. Other available data, including the economic forecast provided by John Church (see Exhibit 2, Section A), other economic development organizations and alternate economic forecasts/assumptions were utilized to develop the High Growth and Low Growth scenarios. For ease of analysis, the 140 existing and up to 14 projected new customers (per the High Growth scenario) were combined into six (6) homogeneous market segments:

2021 Customers by Market Segment:

- 18 potato processors
- 44 other food processors including sugar, milk, beef, and seed companies
- 3 chemical and fertilizer companies
- 31 light manufacturing companies including electronics, paper, and asphalt companies
- 32 schools, hospitals, and other weather sensitive customers
- 12 “other” companies including transportation-related businesses

Contract Demand

Every LV customer is required to sign a contract to receive service under any of the LV tariffs. An important element of the firm LV-1 sales and T-4 transportation contracts is the Maximum Daily Firm Quantity (“MDFQ”) which reflects the agreed upon maximum amount of daily gas and/or capacity the Company must be prepared to provide that firm LV customer on any given day including the projected system peak day that would occur during design weather.

T-3 interruptible customers’ contracts include a Maximum Daily Quantity or “MDQ” which only represents the maximum amount of gas the Company’s service line and meter can flow. Because T-3 service is interruptible, Intermountain makes no assurances of the amount of distribution capacity that will be available on any given day. For peak event modeling purposes, the IRP assumes T-3 customers are reduced to minimal emergency plant-heat only. The IRP will use the term contract demand (CD) when referencing both MDFQ and MDQ. For this IRP, Intermountain utilized LV customer CD's as they existed at January 1, 2021 for the beginning point for Base Case CD's.

While many of LV customers' surveys predict their annual usage requirements will likely grow through 2026, their peak day requirements are not projected to grow by a similar rate of increase. This is due in part to their increased use of extended work schedules, adding additional daily shifts or adding production in weeks or months not previously utilized at 100% load factor (i.e. seasonal increases) and to the fact that customers often take time to "grow" past an existing CD. Therefore, a certain pattern of therm use will not necessarily equate with a commensurate level of growth in CD.

"Load Profile" vs MDFQ

Even though a monthly therm usage projection (i.e. load profile) is available for each customer, the IRP optimization model does not use the load profile for modeling purposes. The model instead uses the LV CD's because, as explained above, the LV customer group is not significantly weather sensitive so attempting to estimate daily usage using degree days, as is done for the core market, does not provide acceptable results. And without weather as the driver, it is difficult to estimate daily usage patterns. For these reasons it makes sense to use the customer CD as the daily requirement, as it reflects the known peak day obligation for every customer and each AOI. Most importantly, since Intermountain does not provide gas supply or interstate pipeline capacity for any of the transportation customers, the model does not need to project gas supply requirements for these customers but only the maximum amount of distribution capacity they will need on any given day; customer CDs provide this data.

Once the CDs are final, they are loaded directly into the optimization model by AOI and period. The optimization model also assumes that transport customers deliver an amount of zero cost gas supply equal to their aggregated CD for each transport rate class by AOI and period. That assumption allows the model to recognize that gas supply and/or interstate capacity requirements for the transport customers need to be delivered each day but because it is not provided by Intermountain, there is no need to attempt to calculate an unknown cost that is meaningless to Intermountain.

System Reliability

It is important to note that before adding new firm load, engineers tests the system via its modeling system to determine whether or not the Company could serve that added load under design weather peak day loads before proceeding. That analysis is always completed prior to executing any firm contract for any new customer or an existing customer's expansion. Since the Company knows the various parts of the system that may be at or nearing constraints, those

AOI's are given particular attention under load growth scenarios. This procedure assures current firm customers that new customers are not negatively affecting peak day deliverability.

General Assumptions

All current customers were assumed to remain on their current tariff and all forecast scenarios used the 2020 operating budget as a starting point. The IRP also calculated LV therm use and MDFQ by AOI so that each geographic area of concern can be accurately modeled.

Base Case Scenario Summary

The Base Case was compiled using historical usage and surveys with adjustments made to reflect known or probable changes of existing customers. The projected annual usage in the Base Case forecast increased by 20 million therms (or an annualized rate of 1.0%) as seen in Table 5 below. The rate of projected annualized growth remains strong compared to the last IRP largely due to growth in Other Food, Manufacturing, and Institutional customers.

Table 5: Large Volume Therm Forecast - Base Case Scenario

Large Volume Therm Forecast - Base Case Scenario by Market Segment (Thousands of Therms)							
	2021	2022	2023	2024	2025	2026	Rate of Growth
Potato (A)	115,563	108,793	112,927	113,804	112,754	112,625	-0.5%
Other Food (B)	109,595	115,025	116,296	116,453	116,513	116,576	1.2%
Meat, Dairy and Ag (C)	50,409	55,208	55,558	59,213	59,718	59,728	3.5%
Chemical/Fertilizer (D)	33,272	31,150	32,150	32,572	32,572	32,572	-0.4%
Manufacturing (E)	23,428	26,033	26,634	27,498	27,513	27,529	3.3%
Institutional (F)	24,835	26,475	26,763	26,831	26,831	26,831	1.6%
Other (G)	17,708	10,464	15,444	19,262	19,298	19,029	1.4%
Total Base Case	374,810	373,148	385,772	395,633	395,199	394,890	1.0%

A. The Potato Processors group is forecast to slightly decline over the forecast period. Demand for potato products is projected to soften as consumer tastes change although inventory remains adequate. No new plants are assumed in the forecast while recent plant expansions have not increased gas usage as expected. Most of the plants in this group are looking for ways to lower the overall cost of production, conserve resources and maximize efficiencies leading to the projected decline in projected usage.

B. The Other Food Processing group is projected to see fairly strong growth over the forecast period. The growth is largely due to strong growth in sugar and frozen food production.

C. The Meat, Dairy and Ag segment is projected to see very strong growth which largely reflects several new meat plants and at least one new dairy processing plant to come online by 2024.

D. The Chemical/Fertilizer production companies' usage is expected to remain relatively flat over the forecast period.

E. The Manufacturing group is expected to see strong growth. Intermountain expects to see increases in electronics manufacturing and also expects to see growth in businesses engaged in new construction.

F. The Institutional group is projected to grow at 1.6% a year due to a return to normal weather, to existing hospitals expanding facilities, and to new hospitals that have recently been built or new facilities that will be built in the coming years.

G. The usage in the Other group is projected to see some reasonably strong growth largely due to customers using more natural gas as a transportation fuel. The Company assumes that renewable fuel production customers will not be slowed by the pandemic or due to increased calls for electrification.

High Growth Forecast Summary

The High Growth forecast incorporates usage data directly from the survey with adjustments for additional growth that would occur if the economy continues to recover and expand. The scenario assumes very competitive natural gas prices compared to other alternatives and that the economy fully recovers from the downswing due to COVID-19. Projected sales in year 2022 of the High Growth forecast of 378.7 million therms is approximately 1.5% above Base Case. By 2026 the High Growth scenario's annual sales grow to 428.4 million therms an increase of 33.5 million therms (8.5%) over 2026 Base Case. The following table summarizes the High Growth changes over the forecast period:

Table 6: Large Volume Therm Forecast - High Growth Scenario

Large Volume Therm Forecast - High Growth Scenario by Market Segment (Thousands of Therms)							
	2021	2022	2023	2024	2025	2026	Rate of Growth
Potato (A)	115,563	109,393	117,005	118,757	120,728	122,754	1.2%
Other Food (B)	109,595	115,125	122,085	123,142	123,902	124,216	2.5%
Meat, Dairy and Ag (C)	50,409	55,268	60,787	68,768	70,078	70,293	6.9%
Chemical/Fertilizer (D)	33,272	33,913	35,663	36,084	36,084	36,084	1.6%
Manufacturing (E)	23,428	26,033	26,769	28,013	28,093	28,124	3.7%
Institutional (F)	24,835	26,475	26,886	27,099	27,606	27,656	2.2%
Other (G)	17,708	12,538	16,518	19,527	19,564	19,295	1.7%
Total Base Case	374,810	378,745	405,713	421,390	426,055	428,422	2.7%

A. Potato production is up from the 2019 IRP projections and future growth is strong. This scenario shows the processors consistently growing and includes an assumption of at least one new customer. Natural gas prices are predicted to stay competitive and steady which would keep the plants using gas rather than other energy sources.

B. Other Food Processors growth is projected to be strong as demand for sugar, frozen foods and other vegetable continues to grow. This scenario assumes 2 new customers will come online during the forecast period.

C. The Meat, Dairy and Ag group is projected to show very strong growth as existing facilities expand and several new meat producers and at least two new dairy processors come online during the forecast period.

D. The Chemical/Fertilizer group's gas usage is anticipated to increase over the five-year period due to growth in phosphate production.

E. The Manufacturing group is projected to have a strong growth over the forecast period reflecting increases in electronics and building-related industries. This scenario assumes the addition of one large electronics/high tech related facility.

F. The institutional group is expected to grow 2.2% over the five-year period as some growth is projected in a few of the larger universities and several hospitals.

G. Growth is expected to be strong in the Other segment as the effects of the COVID-19 pandemic on renewable fuels and CNG customers should dissipate.

Low Growth Forecast Summary

The projected usage for this scenario is based upon the assumption that the economy enters a long-term stall due to the pandemic. It is also assumed that natural gas prices will be less competitive and other renewable sources begin to increase market share vis-à-vis natural gas. With those assumptions, the agricultural part of the economy will be flat with very little growth in sales and production. Declines are expected in Potato Processing and the Other segments is expected to fall as the renewable fuels market declines and CNG markets are replaced by EV's. Projected sales in year 2022 of the Low Growth Scenario are approximately 1% below the Base Case but by 2026 are projected sales are 24.3 million therms (6.2%) under Base Case. The following table summarizes the Low Growth changes over the forecast period:

Table 7: Large Volume Therm Forecast - Low Growth Scenario

Large Volume Therm Forecast - Low Growth Scenario by Market Segment (Thousands of Therms)							
	2021	2022	2023	2024	2025	2026	Rate of Growth
Potato (A)	115,563	108,793	110,429	110,858	109,708	109,678	-1.0%
Other Food (B)	109,595	114,743	114,814	114,871	114,931	114,995	1.0%
Meat, Dairy and Ag (C)	50,409	55,008	58,358	58,613	58,618	58,628	3.1%
Chemical/Fertilizer (D)	33,272	31,850	31,600	32,272	32,272	32,272	-0.6%
Manufacturing (E)	23,428	25,260	24,998	24,678	24,678	24,678	1.0%
Institutional (F)	24,835	24,704	24,682	24,562	24,247	24,112	-0.6%
Other (G)	17,708	9,961	7,014	6,775	6,617	6,196	-18.9%
Total Base Case	374,810	370,319	371,895	372,629	371,071	370,559	-0.2%

A. The price of natural gas is assumed to be less competitive against the delivered price of oil and other energy sources and overall market demand is expected to decline. This group, as a whole, looks at any way possible to conserve energy and make its plants more efficient.

B. The Other Food Processor group is expected to remain steady. Existing facilities will remain flat.

C. The Meat and Dairy group is projected to increase over the period as demand for meat and dairy is expected to grow.

D. The Chemical/Fertilizer segment is forecast with a small decline in gas usage as demand for chemicals decrease.

E. The Manufacturing group is also projected to increase over the period by 1.0% reflecting some strength in the high tech/electronics and building markets.

F. The institutional group is projected to also show slowing growth that would lead to a small decrease in annual gas use.

G. At least one very large renewable fuels facility in the Other group is projected to go out of business and other customers using natural gas to power fleets of vehicles are assumed to begin the move to electric fleets.

LARGE VOLUME CUSTOMER SURVEY – COVER LETTER

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

November 16, 2020

Dear Intermountain Gas Customer,

Intermountain Gas values you as a customer and we are committed to meeting your expectation of receiving reliable energy services to your facility. While the past year has been unusual due to the pandemic, we continue to see strong new customer growth and recovery of natural gas usage in most sectors of our business. That growth coupled with the potential for extremely frigid winter weather underscores the importance of our long-term planning efforts.

The Idaho Public Utilities Commission (IPUC) requires Intermountain to file a bi-annual, long-term Integrated Resource Plan (IRP) that gives both the IPUC and our customers a close-up view of our planning efforts. The IRP provides an opportunity for you to participate in the process in two way. First, we ask that you provide projected gas usage information for your facility. Once we input your data into our IRP then you will be able to assess and comment on our forecast including data inputs, our underlying methodologies and final conclusions. The IRP we file with the IPUC documents the entire process and it provides assurance to our customers that we utilize detailed, transparent and industry accepted practices as we plan to meet your energy needs in a prudent manner.

We are now beginning to prepare the demand data inputs for the 2021–2026 IRP. Our demand or usage forecast is the basis for the entire IRP and therefore it is critical that it be as accurate as possible. To this end, I am writing to request your assistance by providing projections of your facility's annualized natural gas requirements for through 2026.

I have attached a survey form that requests information relative to projected changes in your facility's annual and peak day natural gas requirements and alternate fuel plans. To provide context, I have included actual annual and peak day therm use (where available) for the two most recent 12-month periods ending September 2019 and September 2020. Where applicable, I have also attached a chart showing daily usage (in MMBtu which is equal to 10 therms). I recognize the time commitment required to complete this survey but including your projections in our IRP will improve its accuracy and I assure you that we will use the data you provide.

Please return your completed survey, including any comments or questions you may have, by December 18, 2020. To show my appreciation for your participating in our IRP process, if you return the completely filled-out survey by the December 11th deadline, I will enter your name in a raffle for a box of Titleist PRO V1 golf balls. Note only one entry per company will be entered into the raffle.

As always, any information you provide will be strictly confidential, will not be shared with any other entity and will be aggregated with data from other similarly situated customers in any public filing. Should you have any questions please call me at my office (208-377-6118), my cell phone (208-850-2139) or you can always email me at dave.swenson@intgas.com.

I thank you in advance for your willingness to help.

David Swenson
Manager, Industrial Services
Intermountain Gas Company

Attachments

Figure 17: Large Volume Customer Survey Cover Letter

Intermountain Gas Company – 2021-2026 IRP Large Volume Customer Survey

[redacted]
Account # [redacted]
[redacted]

Rate Class: T-4
Contract Expiration Date: [redacted]
Contract Demand (or MDFQ): [redacted]
Notes: [redacted]

HISTORICAL INFORMATION

	Annual Therms	Peak Therms	Peak Day Date
12 Months Ending September 2019	[redacted]	[redacted]	[redacted]
12 Months Ending September 2020	[redacted]	[redacted]	[redacted]

REQUESTED DATA – PROJECTED THERMS

Description	2021	2022	2023	2024	2025	2026
Annual Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Peak Day Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

What is the prime reason for the projected change in therm use? full production rate of new flake plant

Are the 2021-26 therm use projections above lower than they otherwise might have been due to the use of an alternative energy source? ☐ Yes ☑ No
If yes, how much of your 2020 natural gas usage did alternative energy offset? Annual Therms= ______ Peak Day Therms ______

Going forward what percent of your current peak day energy needs, served by natural gas, can be served by existing alternative fuel? 10%

What is your existing alternative source of energy? ☐ None ☐ Coal ☐ Oil ☑ Other (specify) Wood - for a small portion of plant needs - only used when absolutely necessary

If you are contemplating incorporating an alternative energy source, what is your preference? ☑ None ☐ Coal ☐ Oil ☐ Other (specify) ______

Do you plan to employ energy saving or other conservation measures that will reduce your use of natural gas? ☐ Yes ☑ No
If yes, please estimate the reduction natural gas therms (therms or percent): Annual Therms = ______ Peak Day Therms = ______

What is the combined total of the input ratings for all natural gas-fired equipment? (circle correct units) ______ [btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]

Do you plan to install additional natural gas fired equipment through 2021? ☐ Yes ☑ No Through 2026? ☐ Yes ☑ No.
If yes, what year do you expect to install ______ and what is the input rating? (circle correct units) ______ [btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]

Would you prefer the option to purchase Renewable Natural Gas thru Intermountain? ☐ Yes ☑ No.
If yes, how much of a per-therm cost increase would be acceptable? ______

Are there any additional service options would you like Intermountain to consider or do you have any suggestions for Intermountain that could help enhance its service?

ANY INFORMATION PROVIDED VIA THIS FORM WILL REMAIN CONFIDENTIAL WITH INTERMOUNTAIN GAS COMPANY
Please return via mail to 555 S Cole Road, Boise ID 83709 or email to dave.swenson@intgas.com by December 18, 2020

Figure 18: Large Volume Customer Survey Questions

Supply & Delivery Resources

Supply & Delivery Resources Overview

Once future load requirements have been forecasted, currently available supply and delivery resources are matched with demand to identify system deficits. Essential components considered when reviewing supply and delivery resources include identifying currently available supply resources, delivery capacity, and other resources that can offset demand such as energy efficiency programs or large volume customers with alternative fuel sources.

Supply and deliverability are considered by AOI to identify system constraints that result from forecasted demand. By comparing demand versus capacity for each AOI, the Company is better able to select capacity constraint solutions that consider cost effectiveness, operations and maintenance impacts, project viability, and future growth.

After analyzing resource requirements for each AOI, the data is aggregated to provide a total company perspective. Supply and delivery resources that are currently available are compared to the six total company demand scenarios that were established in the demand forecast. In the Load Demand Curves Section, beginning on page 118, demand and capacity are compared to clearly identify deficits. Alternative solutions for how the deliverability deficits will be resolved are considered in the Optimization and Planning Results sections of this Integrated Resource Plan.

Traditional Supply Resources

Overview

Natural gas is a fundamental fuel for Idaho’s economic and environmental future: heating our homes, powering businesses, moving vehicles, and serving as a key component in many of our most vital industrial processes. The natural gas marketplace continues to change but Intermountain's commitment to act with integrity to provide secure, reliable and price-competitive firm natural gas delivery to its customers has not. In today’s energy environment, Intermountain bears the responsibility to structure and manage a gas supply and delivery portfolio that will effectively, efficiently, reliably and with best value meet its customers’ year-round energy needs. Through its long-term planning, Intermountain continues to identify, evaluate and employ best-practice strategies as it builds a portfolio of resources that will provide the value of service that its customers expect.

The Traditional Supply Resources section outlines the energy molecule and related infrastructure resources upstream of Intermountain’s distribution system necessary to deliver natural gas to the Company’s distribution system. Specifically included in this discussion is the natural gas commodity (or the gas molecule), various types of storage facilities, and interstate gas transportation pipeline capacity. This section will identify and discuss the supply, storage, and transportation capacity resources available to Intermountain and how they may be employed in the Company’s portfolio approach to gas delivery management.

Background

The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Natural gas is a fossil fuel; a naturally occurring mixture of combustible gases, principally methane, found in porous geologic formations beneath the surface of the earth. It is produced or extracted by drilling into those underground formations or reservoirs and then moving the gas through gathering systems and pipelines to customers in often far away locations.

Intermountain is fortunate to be located between two prolific gas producing regions in North America. The first, the Western Canadian Sedimentary Basin (WCSB) in Alberta and British Columbia supplies approximately 79% of Intermountain’s natural gas portfolio. The other region, known as the Rockies, includes many different producing basins in the states of Wyoming, Colorado, and Utah where the remainder of the Company’s supplies are sourced. The Company also utilizes storage facilities to store natural gas supply during the summer when prices are traditionally lower and save it for use during the winter to offset higher seasonal pricing.

Intermountain's access to the gas produced in these basins is wholly dependent upon the availability of pipeline transportation capacity to move gas from those supply basins to Intermountain's distribution system. The Company is fortunate, in that the interstate pipeline that runs through Intermountain's service territory is a bi-directional pipeline. This means it can bring gas from the north or south. Having the bi-directional flow capability allows Intermountain's customers to benefit from the least cost gas pricing in most situations and ample capacity to transport natural gas to Intermountain's citygates.

Gas Supply Resource Options

Over the past decade, advances in technology have allowed for the discovery and development of abundant supplies of natural gas within shale plays across the United States and Canada. This shale gas revolution has changed the energy landscape in the United States. Natural gas production levels continue to surpass expectations despite low gas prices (see Figure 19 below).

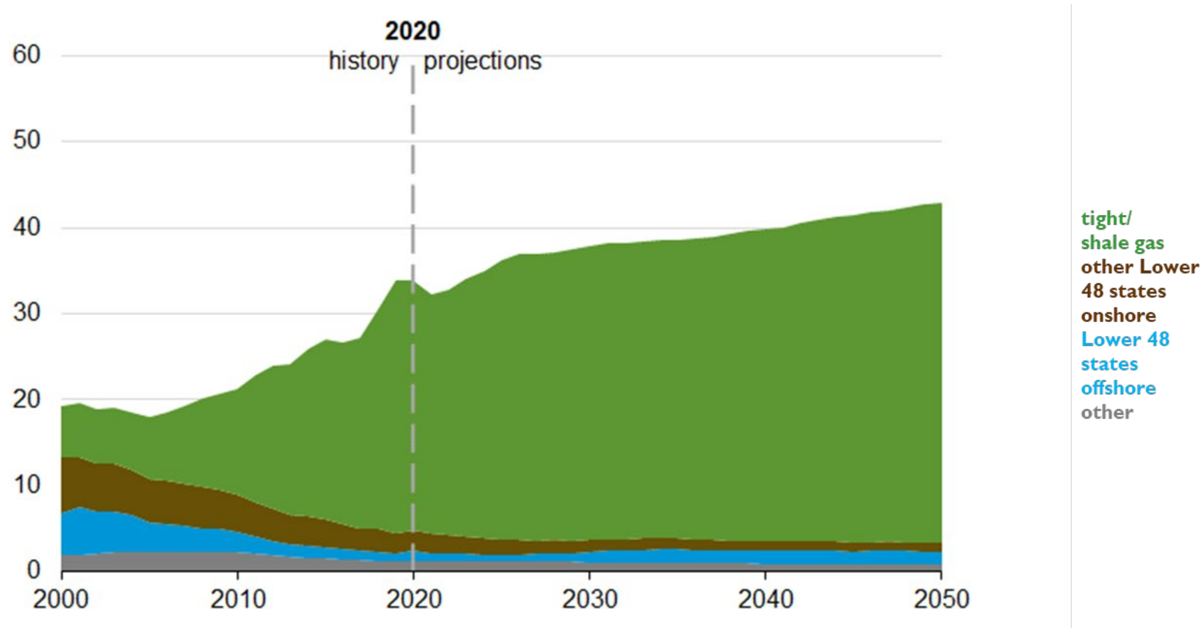

Figure 19: Natural Gas Sources

Source: EIA AEO2021

Projected low prices for natural gas have made it a very attractive fuel for natural gas fired electric generation as utilities are replacing coal-fired generation. Combine this with the industrial sector's recovery from the 2007-2009 recession as they take advantage of low natural gas prices, and the result is a significant change in demand loads. See Figure 20 below for consumption by sector, 2000-2050.

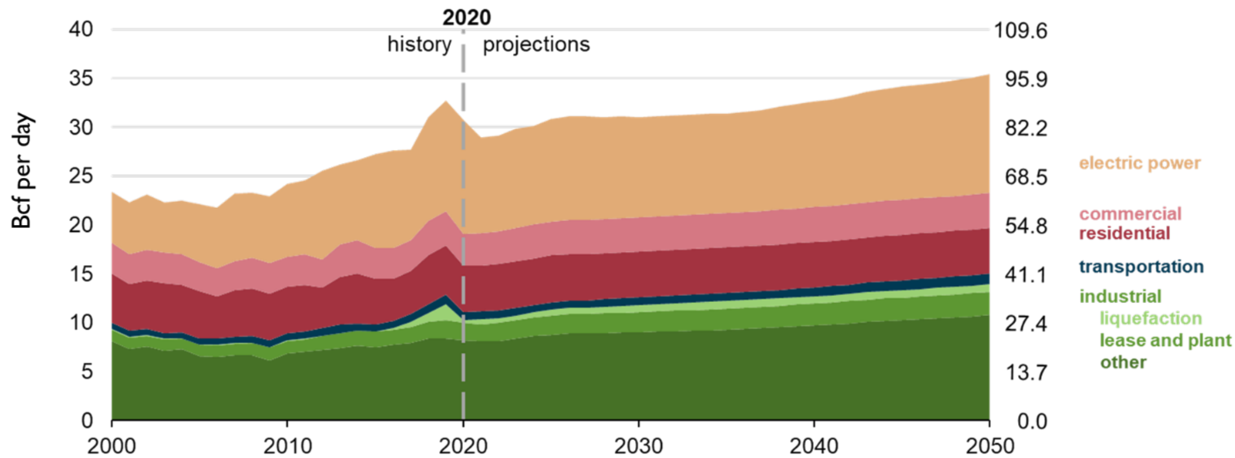

Figure 20: Natural Gas Consumption by Sector

Source: EIA AEO2021

Improved technologies for finding and producing nonconventional gas supplies have led to dramatic increases in gas supplies. Figure 21 below shows that shale gas production is not only replacing declines in other sources but is projected to increase total annual production levels through 2050.

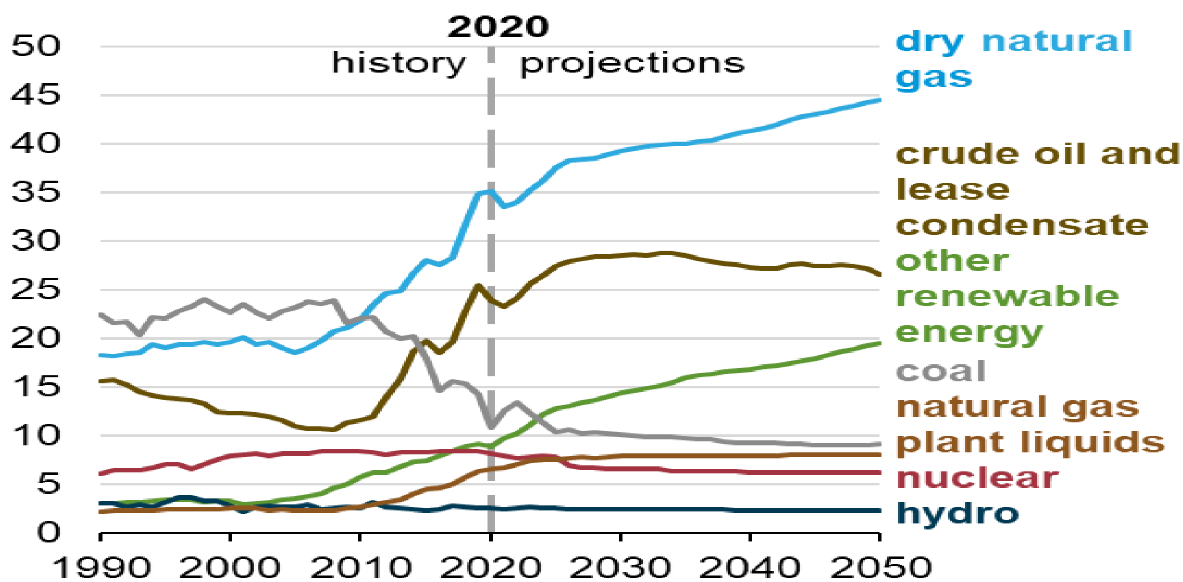

Figure 21: Shale Gas Production Trend

Source: EIA AEO2021

While natural gas prices continue to exhibit volatility from national, global, and regional perspectives, the laws of supply and demand clearly govern the availability and pricing of natural gas. Recent history shows that periods of growing demand tends to drive prices up which in turn generally results in consumers seeking to lower consumption. At the same time, producers typically increase investment in activities that will further enhance production. Thus, falling demand coupled with increasing supplies tends to swing prices lower. This in turn leads to falling supplies and increased demand which begins the cycle anew (see Figure 21 for shifting demand). Finding equilibrium in the market has been challenging for all market participants but at the end of the day, the competitive market clearly works; the challenge is avoiding huge swings that result in either demand destruction or financial distress in the exploration and production business.

Driven by technological breakthroughs in unconventional gas production, major increases in North American natural gas reserves and production have led to supply growth significantly outgaining forecasts in recent years. Thus, natural gas producers have sought new and additional sources of demand for the newfound volumes. The abundant supply of natural gas discussed above has resulted in the United States becoming a net exporter of liquefied natural gas (LNG) versus being a net importer several years ago. The currently operational LNG export facilities in the United States together with additional new facilities on the drawing board will result in a significant new market for the incremental gas supplies being developed and produced.

Shale Gas

Shale gas has changed the face of U.S. energy. Today, reserve and production forecasts predict ample and growing gas supplies through 2050 because of shale gas. The fact that shale gas is being produced in the mid-section of the U.S has displaced production from more traditional supply basins in Canada and the Gulf Coast. There have been some perceived environmental issues relating to shale production, but most studies indicate that if done properly, shale gas can be produced safely. Customers now enjoy the lowest natural gas prices in years due to the increased production of shale gas. Figure 22 below identifies the shale plays in the lower 48 states.

Per the EIA, the portion of U.S. energy consumption supplied by domestic production decreased in 2020[9], in large part due to responses to the COVID-19 pandemic. “Demand for energy delivered to the four U.S. end-use sectors (residential, commercial, transportation, and industrial) decreased to 90% of its 2019 level in 2020; a steeper decline than seen in real GDP. Compared with the financial crisis of 2008, the COVID-19-related decline in the total demand for delivered energy is about 70% larger. In the AEO2021 Reference case, EIA projects that U.S. energy demand takes until 2029 to return to 2019 levels.”

[9] https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

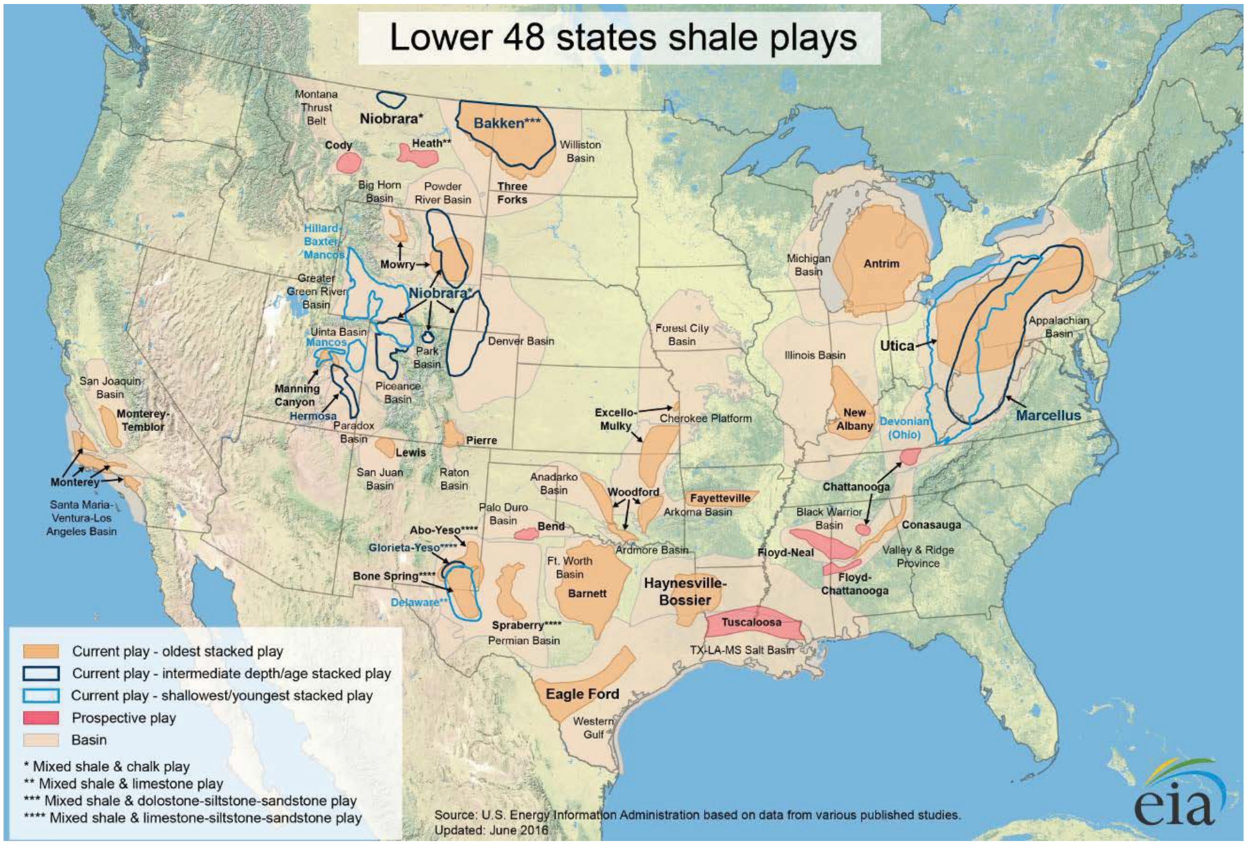

Figure 22: US Lower 48 States Shale Plays

Source: Energy Information Administration based on data from various published studies.

Supply Regions

As previously stated, Intermountain's natural gas supplies are obtained primarily from the WCSB and the Rockies. Access to those abundant supplies is completely dependent upon the amount of firm transportation capacity held on the applicable pipelines for delivering such gas to Intermountain's service territory. Transportation capacity is so important that a discussion of the Company's purchases of natural gas cannot be fully explored without also addressing pipeline capacity. On average, Intermountain currently purchases approximately 79% of its gas supplies from the WCSB and the remainder from the Rockies. However, due to certain flexibility in Intermountain's firm transportation portfolio, it is afforded the opportunity to procure some portion of its annual needs from supply basins which may offer lower cost gas supplies in the future.

Alberta

Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Energy via NOVA Gas Transmission Ltd. (NOVA) and Foothills Pipe Lines Ltd. (Foothills)) and two U.S. pipelines (Gas Transmission Northwest (GTN) and Williams Northwest Pipeline (NWP)) as seen below in Figure 23.

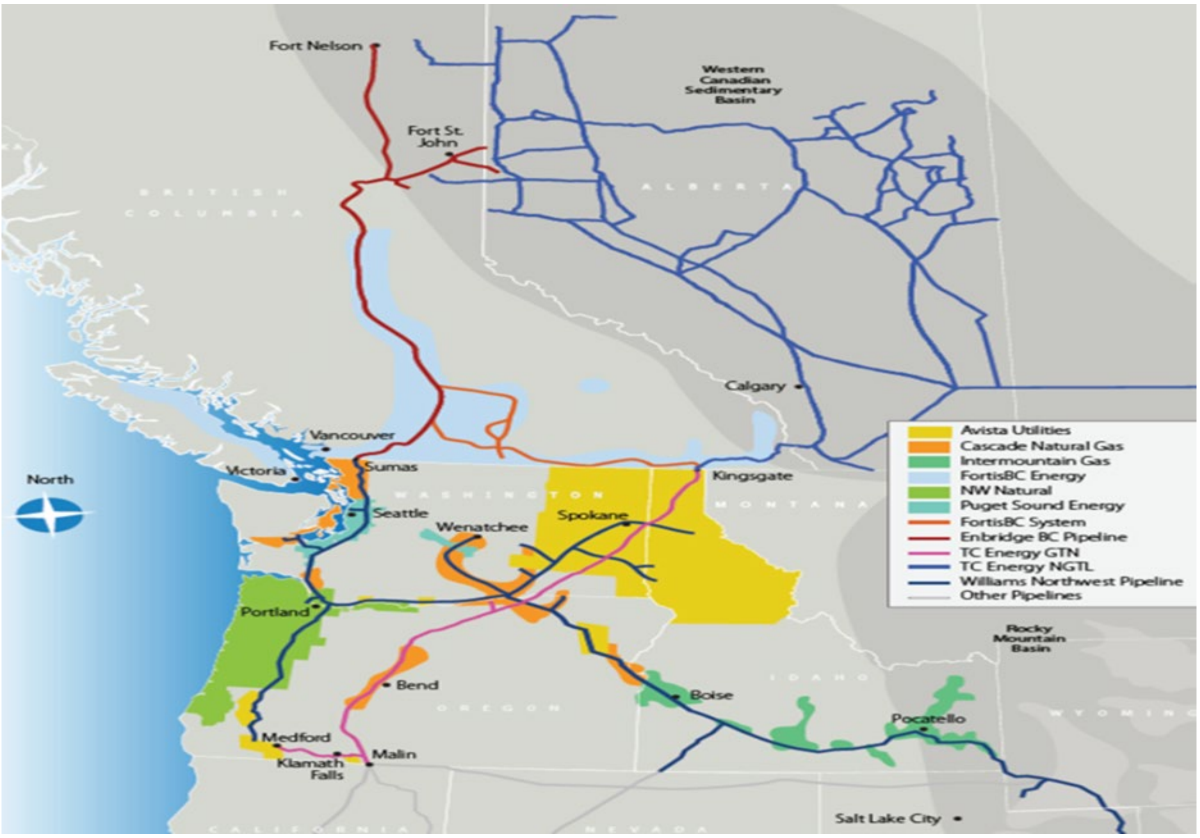

Figure 23: Supply Pipeline Map

Source: Northwest Gas Association 2020 Gas Market Outlook

Intermountain will continue to utilize a significant amount of Alberta supplies in its portfolio. The Stanfield interconnect between NWP and GTN offers operational reliability and flexibility over other receipts points both north and south. Where these supplies once amounted to a minor portion of the Company’s portfolio, today’s purchases amount to approximately 76% of the Company's annual purchases.

British Columbia

British Columbia has traditionally been a source of competitively priced and abundant gas supplies for the Pacific Northwest. Gas supplies produced in the province are transported by

Enbridge (Westcoast) to an interconnect with NWP near Sumas, WA. Historically, much of the provincial supply had been somewhat captive to the region due to the lack of alternative pipeline options into eastern Canada or the midwestern U.S. However, pipeline expansions into these regions have eliminated that bottleneck. Although these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to impede ultimate delivery to Intermountain's citygates. An exception to pipeline constraints occurred during the winter of 2018 when Enbridge had a major disruption from a pipeline rupture that occurred on October 9, 2018. The ensuing winter months saw a reduction in capacity in British Columbia gas supplies to be delivered at Sumas due to the incident and pipeline integrity testing required by the Canada Energy Regulator [10] in Canada to ensure safe and reliable pipeline conditions. Those interruptions along with a cold and long winter had a significant impact on pricing. However, due to the predominance of Intermountain's supplies coming from Alberta and being delivered via GTN at Stanfield, coupled with Intermountain's ability to utilize its liquefied natural gas storage contracts on NWP's system, it was able to mitigate the impact to its customers of the dramatic short-term price increases.

Rockies

Rockies supply has been the second largest source of supply for Intermountain because of the ever-growing reserves and production from the region coupled with firm pipeline capacity available to Intermountain. Additionally, Rockies supplies have been readily available and highly reliable. Historically, pipeline capacity to move Rockies supplies out of the region has been limited, which has forced producers to compete to sell their supplies to markets with firm pipeline takeaway capacity. Several pipeline expansions out of the Rockies have greatly minimized or eliminated most of the capacity bottlenecks, so these supplies can now more easily move to higher priced markets found in the Midwest, East or in California. Consequently, even though growth in Rockies reserves and production continues at a rapid pace reflecting increased success in finding tight sand, coal seam and shale gas, the more efficient pipeline system has largely eliminated the price advantage that Pacific Northwest markets had enjoyed.

While Intermountain's firm transportation portfolio does provide for accessing Rockies gas supplies, as discussed above, Intermountain has chosen today and for the foreseeable future to purchase the predominance of its annual supply needs out of Alberta due to the lower cost environment from that supply basin. However, due to its close proximity, Intermountain does purchase the lower cost Rockies gas supplies in the summer for injection into its Clay Basin storage accounts located in northeastern Utah.

[10] The Canada Energy Regulator (CER) is the agency of the Government of Canada under its Natural Resources Canada portfolio, which licenses, supervises, regulates, and enforces all applicable Canadian laws as regards to interprovincial and international oil, gas, and electric utilities. The agency came into being on August 28, 2019, under the provision of the Canada Energy Regulator Act of the Parliament of Canada superseding the National Energy Board from which it took over responsibilities.

Export LNG

Growth in North American natural gas supplies (see Shale Gas above) has eliminated discussion about LNG import facilities. Because LNG is traded on the global market, where prices are typically tied to oil, U.S. produced LNG is very competitive. LNG exports now play a role in the overall supply portfolio of U.S. supply, with several new LNG export facilities proposed or in production. As seen in Figure 24 below, the U.S. is now a net exporter of natural gas in large part due to LNG.

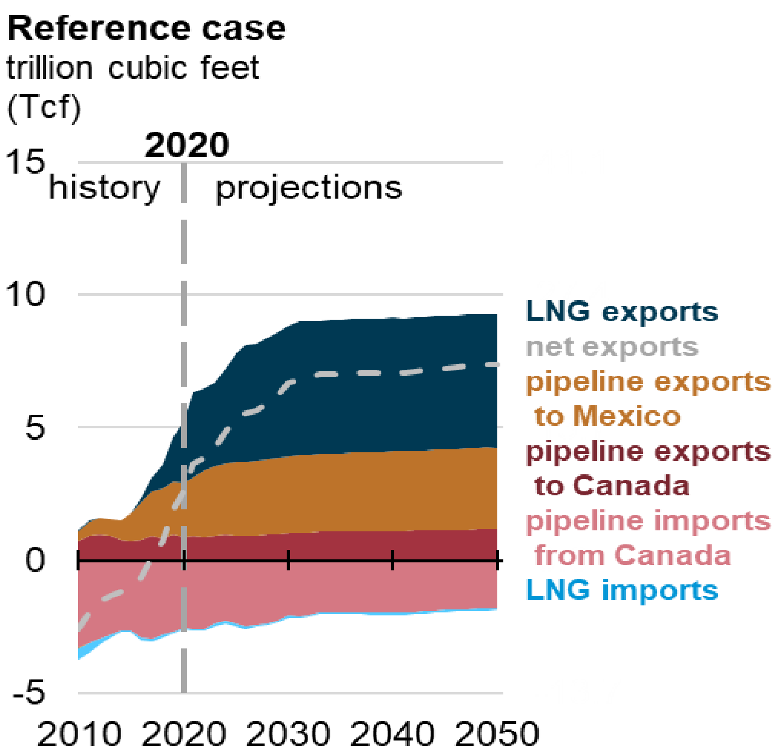

Figure 24: Natural Gas Trade

Source: EIA AEO2021

Types of Supply

There are essentially two main types of gas supply: firm and interruptible. Firm gas commits the seller to make the contracted amount of gas available each day during the term of the contract and commits the buyer to take that gas each day. The only exception would be force majeure events where one or both parties cannot control external events that make delivery or receipt impossible. Interruptible or best-efforts gas supply typically is bought and sold with the understanding that either party, for various reasons, does not have a firm or binding commitment to take or deliver the gas.

Intermountain builds its supply portfolio on a base of firm, long-term gas supply contracts but includes all the types of gas supplies as described below:

1. Long-term: gas that is contracted for a period of over one year.
2. Short-term: gas that is often contracted for one month at a time.
3. Spot: gas that is not under a long-term contract; it is generally purchased in the short-term on a day ahead basis for day gas and during bid week prior to the beginning of the month for monthly spot gas.
4. Winter Baseload: gas supply that is purchased for a multi-month period most often during winter or peak load months.
5. Citygate Delivery: natural gas supply that is bundled with interstate transportation capacity and delivered to the Intermountain citygate meaning that it does not use the Company's existing transportation capacity.

Pricing

The Company does not currently utilize NYMEX based products to hedge forward prices but buys a portion of its gas supply portfolio at fixed priced forward physicals. Purchasing fixed price physicals provides the same price protection without the credit issues that come with financial instruments. A certain level of fixed price contracts allows Intermountain to participate in the competitive market while avoiding upside pricing exposure. While the Company does not utilize a fully mechanistic approach, its Gas Supply Oversight Committee meets frequently to discuss all gas portfolio issues which helps to provide stable and competitive prices for its customers.

For IRP purposes, the Company develops a base, high, and low natural gas price forecast. Demand, oil price volatility, the global economy, electric generation, environmental policies, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. Intermountain considers price forecasts from several sources, such as Wood Mackenzie, EIA, S&P Global, NYMEX Henry Hub, and Northwest Power and Conservation Council, as well as Intermountain's own observations of the market to develop the low, base, and high price forecasts. For optimization purposes, Intermountain uses pricing forecasts from four sources for the AECO, Rockies and Sumas pricing points along with a proprietary model based upon those forecasts. The selected forecast includes a monthly base price projection for each of the three purchase points, as seen in Figure 25.

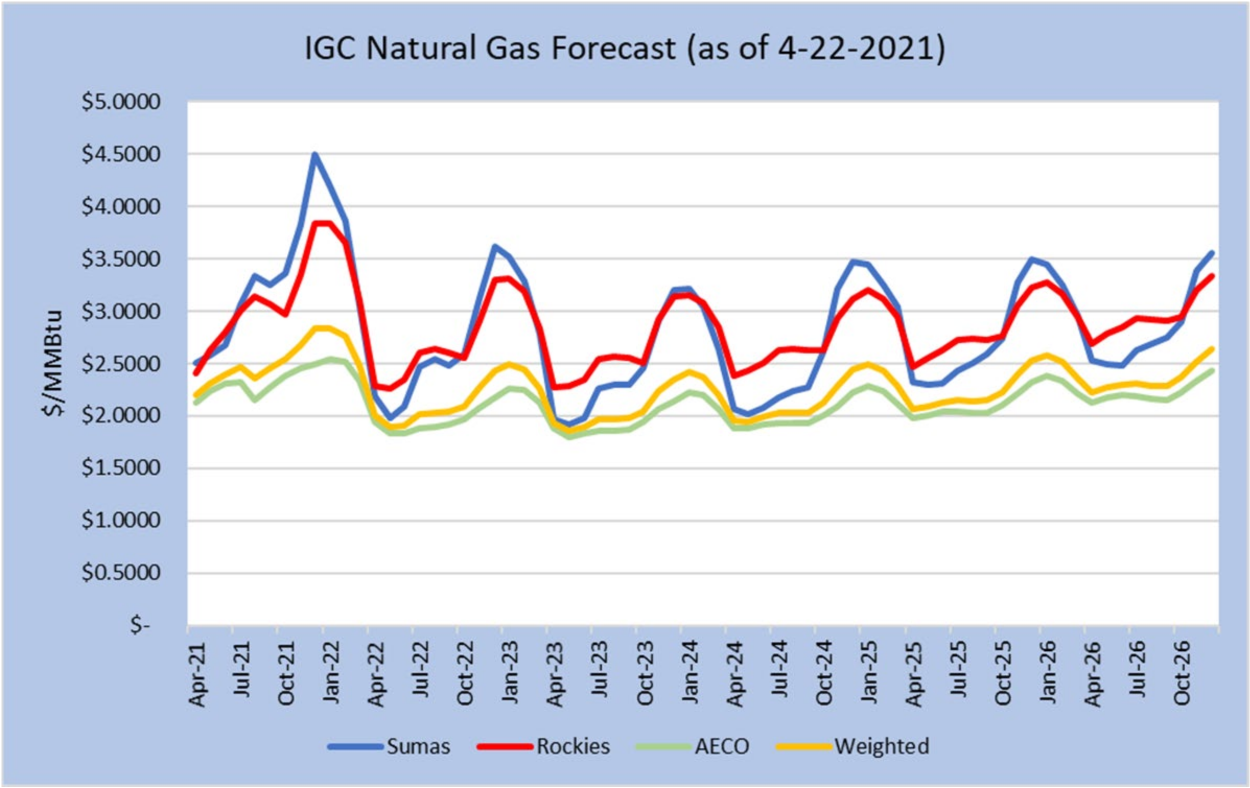

Figure 25: Intermountain Price Forecast as of 04/22/2021

Storage Resources

The production of natural gas and the amount of available pipeline capacity are very linear in nature; changes in temperatures or market demand does not materially affect how much of either is available daily. As the Resource Optimization Section discusses (see page 139), a peak day only occurs for, at most, a few days out of the year. The demand curve then drops rapidly back to more normal winter supply levels before dropping off drastically headed into the summer months. Attempting to serve the entire year at levels required to meet peak demand would be enormously expensive. So, the ability to store natural gas during periods of non-peak demand for use during peak periods is a cost-effective way to fill the gap between static levels of supply and capacity versus the non-linear demand curve.

Intermountain utilizes storage capacity in four different facilities from western Washington to northeastern Utah. Two are operated by NWP: one is an underground project located near Jackson Prairie, WA (JP) and the other is a liquefied gas (LS) facility located near Plymouth, WA (see Figure 26 below). Intermountain also leases capacity from Dominion Energy Pipeline's Clay Basin underground storage field in Wyoming, and operates its own LNG facility located in Nampa, ID. Additionally, Intermountain owns a satellite LNG facility in Rexburg, ID. The Rexburg facility is supplied with LNG from the Nampa LNG facility.

All storage resources allow Intermountain to inject gas into storage during off-peak periods and then hold it for withdrawal whenever the need arises. The advantage is three-fold: 1) the Company can serve the extreme winter peak while minimizing year-round firm gas supplies; 2) storage allows the Company to minimize the amount of the year-round interstate capacity resources required and helps it to use existing capacity more efficiently; and 3) storage provides a natural price hedge against the typically higher winter gas prices. Thus, storage allows the Company to meet its winter loads more efficiently and in a cost-effective manner.

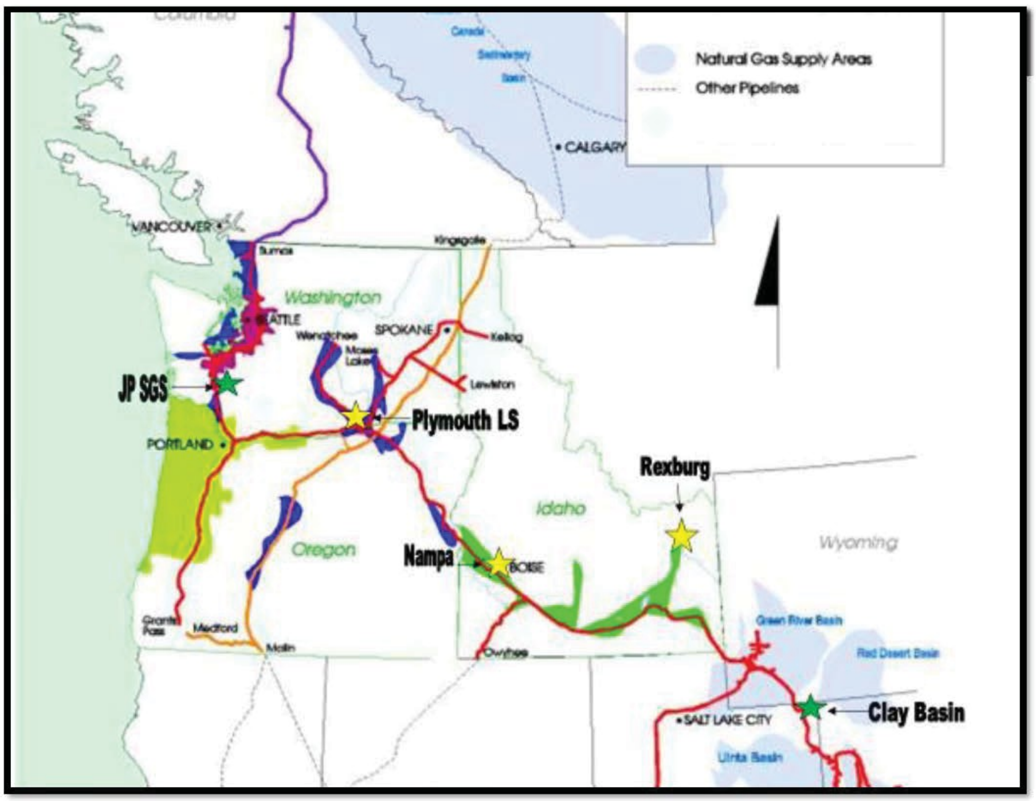

Figure 26: Intermountain Storage Facilities

Liquefied Storage

Liquefied storage facilities make use of a process that super cools and liquefies gaseous methane under pressure until it reaches approximately minus 260°F. LNG occupies only one-six-hundredth the volume compared to its gaseous state, so it is an efficient method for storing peak requirements. LNG is also non-toxic; it is non-corrosive and will only burn when vaporized to a 5-15% concentration with air. Because of the characteristics of liquid, its natural propensity to boil-off and the enormous amount of energy stored, LNG is normally stored in man-made steel tanks.

Liquefying natural gas is, relatively-speaking, a time-consuming process, the compression and storage equipment is costly, and liquefaction requires large amounts of added energy. It typically requires as much as one unit of natural gas burned as fuel for every three to four units liquefied. Also, a full liquefaction cycle may take five to six months to complete. Because of the high cost and length of time involved in filling a typical LNG facility, they are usually cycled only once per year and are reserved for peaking purposes. This makes the unit cost of the gas withdrawn somewhat expensive when compared to other options.

Vaporization, or the process of changing the liquid back into the gaseous state, on the other hand, is a very efficient process. Under typical atmospheric and temperature conditions, the natural state of methane is gaseous and lighter than air as opposed to the dense state in its liquid form. Consequently, vaporization requires little energy and can happen very quickly. Vaporization of LNG is usually accomplished by utilizing pressure differentials by opening and closing valves in concert with the use of some hot-water bath units. The high-pressure LNG is vaporized as it is warmed and is then allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and, as opposed to the long liquefaction cycle, a typical full withdrawal cycle may last 10 days or less at full rate. Because of the cost and cycle characteristics, LNG withdrawals are typically reserved for needle peaking during very cold weather events or for system integrity events.

Neither of the two LNG facilities utilized by Intermountain require the use of year-round transportation capacity for delivery of withdrawals to Intermountain's customers. The Plymouth facility is bundled with redelivery capacity for delivery to Intermountain and the Nampa and Rexburg LNG tank withdrawals go directly into the Company's distribution system. The IRP assumes liquid storage will serve as a needle peak supply.

Underground Storage

This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities typically require less hardware compared to LNG projects and are usually less expensive to build and operate than liquefaction storage facilities. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. The lower costs allow for the more frequent cycling of inventory and in fact, many such projects are utilized to arbitrage variations in market prices.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, maximum daily injection levels are much higher, so a typical underground injection season is much shorter, typically lasting only three to four months. But the lower pressures also mean that maximum withdrawals are typically much less than liquefied storage at maximum withdrawal. So, it could take 35 days or more to completely empty an underground facility. The longer withdrawal period and minimal commodity costs make underground storage an ideal tool for winter baseload or daily load balancing, and therefore, Intermountain normally uses underground storage before liquid storage is withdrawn. Underground storage is not ideal for delivering a large amount of gas quickly, however, so LNG is a better solution for satisfying a peak situation.

Intermountain contracts with two pipelines for underground storage: Dominion Energy for capacity at its Clay Basin facility in northeastern Utah and NWP for capacity at its Jackson Prairie facility in Washington. Clay Basin provides the Company with the largest amount of seasonal storage and daily withdrawal. However, since Clay Basin is not bundled with redelivery capacity, Intermountain must use its year-round capacity when these volumes are withdrawn. For this reason, the Company normally uses Clay Basin withdrawals during the November to March winter period to satisfy baseload needs.

Just like NWP's Plymouth LS facility, NWP's JP storage is bundled with redelivery capacity so Intermountain typically layers JP withdrawals between Clay Basin and its LNG withdrawals. The IRP uses Clay Basin as a winter baseload supply and JP is used as the first layer of peak supply. Table 8 below outlines the Company's storage resources for this IRP.

Table 8: Storage Resources

Facility	Seasonal Capacity	Daily Withdrawal (Dth) Max Vol	% of 2021 Peak	Daily Injection (Dth) Max Vol	# of Days	Redelivery Capacity
Nampa	600,000	60,000	13%	3,500	166	None
Plymouth	1,475,135	155,175	33%	12,500	213	TF-2
Subtotal Liquid	2,075,135	215,175	46%	16,000		
Jackson Prairie	1,092,099	30,337	7%	30,337	36	TF-2
Clay Basin	8,413,500	70,114	15%	70,114	120	TF-1
Subtotal Underground	9,505,599	100,451	22%	100,451		
Grand Total	11,580,734	315,626	68%	116,451		

All the storage facilities require the use of Intermountain's every-day, year-round capacity for injection or liquefaction. Because injections usually occur during the summer months, use of year-round capacity for injections helps the Company make more efficient use of its every-day transport capacity and term gas supplies during those off-peak months when the core market loads are lower.

Nampa LNG Plant

The primary purpose of the Nampa LNG plant is to supplement gas supply onto Intermountain Gas' distribution system. The Nampa LNG plant can store up to 600 million cubic feet of natural gas in liquid form and can re-gasify back into Intermountain's system at a rate of approximately 60 million cubic feet per day.

During a needle peak event the plant is able to supplement supply during gas storage shortages or transportation restrictions into Idaho, and the plant has the added benefit of supplying natural gas directly into the connected Canyon County and Ada County distribution systems without use of interstate pipeline transportation, which eliminates another risk variable typically associated with gas supply. The Nampa LNG plant typically performs liquefaction operations during non-peak weather times of the year, resulting in lower priced natural gas going into liquid storage, and providing potential cost savings when re-gasification occurs during peak cold weather events, gas supply shortages and interstate transportation restrictions.

Storage Summary

The Company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lesser extent, for system balancing. Intermountain believes that the geographic and operational diversity of the four facilities utilized offers the Company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the Company flexibility to determine its best use compared to other supply alternatives such as winter baseload or peak protection gas, price arbitrage or system balancing.

Interstate Pipeline Transportation Capacity

As discussed earlier, Intermountain is dependent upon firm pipeline transportation capacity to move natural gas from the areas where it is produced, to end-use customers who consume the gas. In general, firm transportation capacity provides a mechanism whereby a pipeline will reserve the right, on behalf of a designated and approved shipper, to receive a specified amount of natural gas supply delivered by that shipper, at designated receipt points on its pipeline system and subsequently redeliver that volume to delivery point(s) as designated by the shipper.

Intermountain holds firm capacity on four different pipeline systems including NWP. NWP is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system (other than Nampa LNG) via citygate taps with NWP. Table 9 below summarizes the Company's year- round capacity on NWP (TF-1) and its storage specific redelivery capacity (TF-2). Between the amount of capacity Intermountain holds on the GTN, Foothills, and NOVA pipelines and firm- purchase contracts at Stanfield, it controls enough capacity to deliver a volume of gas commensurate with the Company's Stanfield takeaway capacity on NWP. Upstream pipelines bring natural gas from the production fields in Canada to the interconnect with NWP.

Table 9: Northwest Pipeline Transport Capacity

City Gate Delivery Quantity (MMBtu per day)	2021	2022	2023	2024	2025	2026
TF-1 Capacity -						
Sumas Base Capacity	90,941	90,941	90,941	90,941	90,941	90,941
Sumas Segmentation and Release	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)
Sumas Winter Only Capacity	3,000	3,000	3,000	3,000	-	-
Stanfield Base Capacity	133,774	133,774	133,774	133,774	133,774	130,624
Stanfield Capacity Via Segmentation	90,941	90,941	90,941	90,941	90,941	90,941
Rockies	103,328	103,328	94,328	94,328	94,328	50,328
Total TF-1 Capacity	331,043	331,043	322,043	322,043	319,043	271,893
City Gate Supply	10,000	10,000	10,000	10,000	10,000	-
Total City Gate Delivery Before TF-2	341,043	341,043	332,043	332,043	329,043	271,893
TF-2 Capacity -						
Plymouth (LS)	155,175	155,175	155,175	155,175	155,175	155,175
Jackson Prairie (JP)	30,337	30,337	30,337	30,337	30,337	-
Total TF-2 Capacity	185,512	185,512	185,512	185,512	185,512	155,175
Nampa LNG (does not include Rexburg)	60,000	60,000	60,000	60,000	60,000	60,000
Total City Gate Delivery	586,555	586,555	577,555	577,555	574,555	487,068

Northwest Pipeline's facilities essentially run from the Four Corners area north to western Wyoming, across southern Idaho to western Washington. The pipeline then continues up the I-5 corridor where it interconnects with Spectra Energy, a Canadian pipeline in British Columbia, near Sumas, Washington. The Sumas interconnect receives natural gas produced in British Columbia. Gas supplies produced in the province of Alberta are delivered to NWP via NOVA, Foothills and then GTN near Stanfield, Oregon. NWP also connects with other U.S. pipelines and gathering systems in several western U.S. states (Rockies) where it receives gas produced in basins located in Wyoming, Utah, Colorado, and New Mexico. The major pipelines in the Pacific Northwest, several of which NWP interconnects with can be seen below (Figure 27).

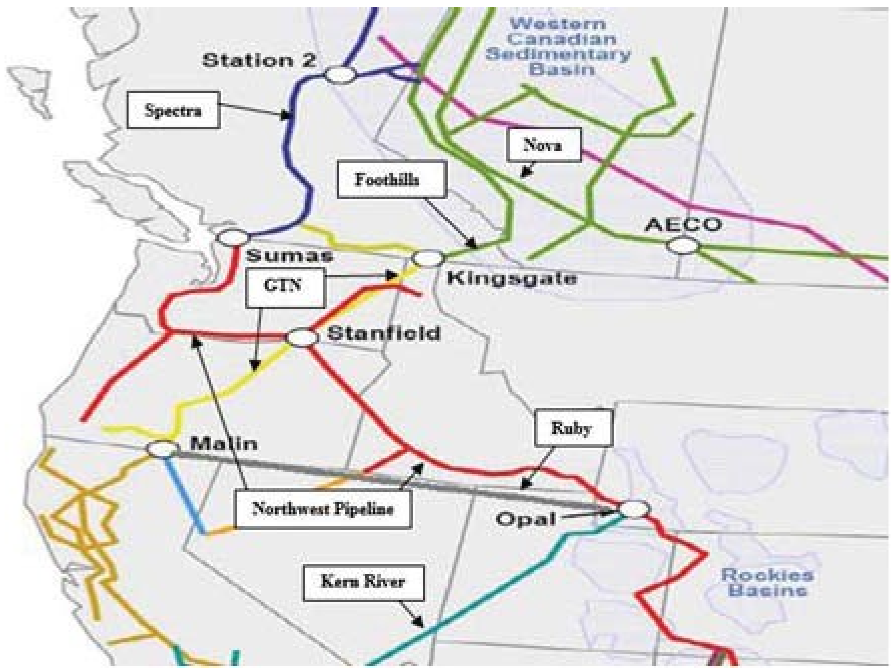

Figure 27: Pacific Northwest Pipelines Map

Because natural gas must flow along pipelines with finite flow capabilities, demand frequently cannot be met from a market's preferred basin. Competition among markets for these preferred gas supplies can cause capacity bottlenecks and these bottlenecks often result in pricing variations between basins supplying the same market area. In the short to medium term, producers in constrained basins invariably must either discount or in some fashion differentiate their product to compete with other also constrained supplies. In the longer run however, disproportionate regional pricing encourages capacity enhancements on the interstate pipeline grid, from producing areas with excess supply, to markets with constrained delivery capacity. Such added capacity nearly always results in a more integrated, efficient delivery system that tends to eliminate or at least minimize such price variances.

Consequently, new pipeline capacity - or expansion of existing infrastructure – in western North America has increased take-away capacity out of the WCSB and the Rockies, providing producers with access to higher priced markets in the East, Midwest and in California. Therefore, less-expensive gas supplies once captive to the northwest region of the continent, now have greater access to the national market resulting in less favorable price differentials for the Pacific Northwest market. Today, wholesale prices at the major trading points supplying the Pacific Northwest region (other than Alberta supplies) are trending towards equilibrium. At the same time, new shale gas production in the mid-continent is beginning to displace traditionally higher-priced supplies from the Gulf coast which, from a national perspective, has been causing an overall softening trend in natural gas prices with less regional differentials.

Today, Intermountain and the Pacific Northwest are in an increasingly mega-regional marketplace where market conditions across the continent - including pipeline capacities - can, and often do, affect regional supply availability and pricing dynamics. According to the EIA, "In October, the natural gas spot price at Henry Hub averaged $5.51 per million British thermal units (MMBtu), which was up from the September average of $5.16/MMBtu and up from an average of $3.25/MMBtu in the first half of 2021. The rising natural gas prices in recent months reflect U.S. natural gas inventory levels that are below the five-year (2016–20) average. Despite high prices demand for natural gas for electric power generation has remained relatively high, which along with strong global demand for U.S. liquefied natural gas (LNG) has limited downward natural gas price pressures." [11]

Supply Resources Summary

Because of the dynamic environment in which it operates, the Company will continue to evaluate customer demand to provide an efficient mix of supply resources to meet its goal of providing reliable, secure, and economic firm service to its customers. Intermountain actively manages its supply and delivery portfolio and consistently seeks additional resources where needed. The Company actively monitors natural gas pricing and production trends to maintain a secure, reliable and price competitive portfolio and seeks innovative techniques to manage its transportation and storage assets to provide both economic benefits to customers and operational efficiencies to its interstate and distribution assets. The IRP process culminates with the optimization model that helps to ensure that the Company's strategies meet its traditional gas supply goals and are based on sound, real-world, economic principles (see the Optimization Model Section beginning on page 139).

[11] https://www.eia.gov/outlooks/steo

Capacity Release & Mitigation Process

Overview

Capacity release was implemented by FERC to allow markets to more efficiently utilize pipeline transportation and storage capacity. This mechanism allows a shipper with any such unused capacity to auction the excess to another shipper that offers the highest bid. Thus, capacity that would otherwise sit idle can be used by a replacement shipper. The result is a more efficient use of capacity as replacement shippers maximize annualized use of existing capacity. One effect of maximizing the utilization of existing capacity is that pipelines are less inclined to build new capacity until the market recognizes that it is really needed and is willing to pay for new infrastructure. However, a more fully utilized pipeline can also mean existing shippers have less operational flexibility.

Intermountain has and continues to be active in the capacity release market. Intermountain obtains significant amounts of unutilized capacity mitigation on NWP and GTN via capacity releases. The Company frequently releases seasonal and/or daily capacity during periods of reduced demand. Intermountain also utilizes a specific type of capacity release called segmentation to convert capacity from Sumas to Idaho into two paths of Sumas to Stanfield and Stanfield to Idaho. Intermountain uses the Stanfield to Idaho component to take delivery of the lower cost AECO gas supplies that are delivered by GTN to the interconnect with NWP at Stanfield. IGI Resources, Inc. (IGI) is then able to market the upper segment of Sumas to Stanfield to other customers.

Capacity release has also resulted in a bundled service called citygate, in which gas marketers bundle gas supplies with available capacity to be delivered directly to a market's gate station. This grants additional flexibility to customers attempting to procure gas supplies for a specified period (i.e. during a peak or winter period) by allowing the customer to avoid contracting for year-round capacity which would not be used during off-peak periods.

Pursuant to the requirements under the Services Agreement between Intermountain and IGI, IGI is obligated to generate the maximum cost mitigation possible on any unutilized firm transportation capacity Intermountain has throughout the year. In performing this obligation, IGI must also ensure that: 1) in no way will there be any degradation of firm service to Intermountain's residential and commercial customers, and 2) that Intermountain always has first call rights on any of its firm transportation capacity throughout the year and if necessary Intermountain has the right to recall any previously released capacity if needed to meet core market demands.

With the introduction of natural gas deregulation under FERC Order 436 in 1985 and the subsequent FERC Orders 636, 712, 712A and 712B, the rules and regulations around capacity release transactions for interstate pipeline capacity were developed. These rules cover such activity as: 1) shipper must have title; 2) prohibition against tying arrangements and 3) illegal buy/sell transactions. These rules and regulations are very strict and must always be adhered to or the shipper is subject to significant fines (up to $1 million per day per violation) if ever violated. IGI is very aware of these regulations and at all times ensures adherence to such when looking for replacement shippers of Intermountain's unutilized pipeline capacity.

The FERC jurisdiction of interstate pipelines for which Intermountain holds capacity are NWP and GTN. To facilitate capacity release transactions, all pipelines have developed an Electronic Bulletin Board (EBB) for which such transactions are to be posted. All released transportation capacity must be posted to the applicable pipeline EBB and in a manner that allows a competing party to bid on it.

Capacity Release Process

Because of its significant market presence in the Pacific Northwest, IGI has been able to generate several millions of dollars per year in released capacity mitigation dollars on behalf of Intermountain for pass-back to its core market customers and to reduce the cost of unutilized firm transportation capacity rights. In this effort, IGI can determine what the appetite is in the competitive marketplace for firm transportation releases on NWP and GTN. It does this via direct communication with third parties or by market intelligence it receives from its marketing team as it deals with its customers and other markets throughout the region. However, the most effective way of determining interest in capacity releases is using the EBB. IGI performs its obligation to Intermountain in one of two ways. First, if IGI itself is interested in utilizing any of Intermountain's unutilized firm transportation capacity, it determines what it believes is a market competitive offer for such and that is then posted to the EBB as a pre-arranged deal. As a pre-arranged deal, the transaction remains on the EBB for the requisite time and any third party has the opportunity to offer a higher bid. If this is done, then IGI can chose to match the higher bid and retain the use of the capacity, or not to match and the capacity will be awarded to the higher third-party bidder.

Second, if IGI is not interested in securing any unutilized Intermountain capacity then it will post such capacity to the EBB as available and subject to open bidding by any third party. As such, the unutilized capacity will be awarded to the highest bidder. It should be noted that IGI posts to the EBB, as available capacity, certain volumes of capacity for certain periods every month during bid week. This affords the most exposure to parties that may be interested in securing certain capacity rights. However, to date, third parties have chosen to bid on such available capacity only a handful of times over all these years.

It should also be noted, that to protect the availability of firm transportation to Intermountain's residential and commercial customers during the year, all released capacity postings to the EBB, whether pre-arranged or not, are posted as recallable capacity. This means that Intermountain can recall the capacity at any time, if necessary, to cover its customer demand.

Mitigation Process

IGI is also obligated to use its best efforts to mitigate the cost of transportation on the pipeline facilities of Nova and Foothills when they are not being used by Intermountain for its own needs. These pipelines are located in Canada and as such are not subject to the rules and regulations of FERC Order 436, 636, 712(A) and 712(B). However, IGI uses much the same evaluation methods for these Canadian pipelines as it does for NWP and GTN. IGI periodically inquires with third parties as to any interest in potential unused capacity on Nova and Foothills for certain periods of time known to be available. IGI also determines if it has any interest in such available capacity for its use in serving other markets in the Pacific Northwest. There is no EBB process on these Canadian pipelines. However, IGI employs much the same process as on NWP and GTN to determine the best mitigation value for Intermountain. Also, similar to the process on NWP and GTN, any of the unused NOVA and Foothills capacity used by IGI or other third parties is always subject to recall should Intermountain have any need for that capacity to serve its customers.

Non-Traditional Supply Resources

Non-traditional supply resources help supplement the traditional supply-side resources during peak demand conditions. Non-traditional resources consist of energy supplies not received from an interstate pipeline supplier, producer or interstate storage operator. Seven non-traditional supply resources were considered in this IRP and are as follows:

Non-Traditional Supply Resources

1. Diesel/Fuel Oil
2. Coal
3. Wood Chips
4. Propane
5. Satellite/Portable LNG Facilities
6. Renewable Natural Gas (RNG)
7. Hydrogen

Non-Traditional Resources

While a large volume industrial customer's load profile is relatively flat compared to most residential and commercial customers, the Company's industrial customers are still a significant contributor to overall peak demand. However, some industrial customers have the ability to use alternate fuel sources to temporarily reduce their reliance on natural gas. By using alternative energy resources such as coal, propane, diesel and wood chips, an industrial customer can lower their natural gas requirement during peak load periods while continuing to receive the energy required for their specific process. Although these alternative resources and related equipment typically have the ability to operate any time during the year, most are ideally suited to run during peak demand from a supply resource perspective. However, only the industrial market has the ability to use any of the aforementioned alternate fuels in large enough volumes to make any material difference in system demand. In order to rely on these types of peak supplies Intermountain would need to engage in negotiations with specific customers to ensure availability. The overall expense of these kinds of arrangements, if any, is difficult to assess.

The non-traditional resources of satellite/portable liquid natural gas (LNG) facilities and RNG do not technically reduce system demand. However, LNG typically has the ability to provide additional natural gas supply at favorable locations within a potentially constrained distribution system. RNG and hydrogen production could potentially supply a distribution system in a similar fashion, however, the location of such facilities, which are determined by the producer, may not align with a constrained location of the distribution system, thus limiting their potential efficacy as a non-traditional supply resource.

Diesel/Fuel Oil

Intermountain is aware of two large volume customers along the IFL that currently have the potential to use diesel or fuel oil as a natural gas supplement. The facilities are able to switch their boilers over to burn oil and decrease a portion of their gas usage. Burning diesel or fuel oil in lieu of natural gas requires permitting from the local governing agencies, increases the level of emissions, and can have a lengthy approval process depending on the specific type of fuel oil used. The cost of diesel or fuel oil varies depending on fuel grade and classification, time of purchase and quantity of purchase.

Coal

Coal use is very limited as a non-traditional supply resource for firm industrial customers within Intermountain's service territory. A coal user must have a separate coal burning boiler installed along with their natural gas burning boilers and typically must have additional equipment installed to transport the large quantities of coal within their facility. Regulations and permitting requirements can also be a challenge. Intermountain is currently aware of only one industrial customer on its system that has a coal backup system.

The cost of coal varies depending on the quality of the coal. Lower BTU coal would range from 8,000 – 13,000 BTU per pound while higher quality coal would range from 12,000 - 15,000 BTU per pound.

Wood Chips

Historically Intermountain has had one large volume industrial customer on the IFL that had the ability to utilize wood chips as an alternative fuel. However, after a recent expansion it is unclear how much or often this customer utilizes this alternative fuel. In order to accommodate wood burning there must be additional equipment installed, such as wood fired boilers, wood chip transport and dry storage facilities. The wood is supplied from various tree clearing and wood mill operations that produce chips within regulatory specifications to be used as fuel. The chips are then transported by truck to the location where the customer could utilize them as a fuel source for a few months each year.

The cost of wood is continually changing based on transportation, availability, location and the type of wood processing plant that is providing the chips. Wood has a typical value of 5,000-6,000 BTU's per pound, which converts into 16-20 pounds of wood being burned to produce one therm of natural gas.

Propane

Since propane is similar to natural gas, the conversion to propane is much easier than a conversion to most other non-traditional supply resources. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce an industrial customer's natural gas needs by 100%. The use of propane requires onsite storage, additional piping and a reliable supply of propane to maintain adequate storage. Currently there are no industrial customers on Intermountain's system that have the ability to use propane as a feasible alternative to natural gas.

Capital costs for propane facilities can become relatively high due to storage requirements. As with oil, storage facilities should be designed to accommodate a peak day delivery load for approximately seven (7) days. One gallon of propane is approximately 91,600 BTU.

Satellite/Portable LNG Equipment

Satellite/Portable LNG equipment allows natural gas to be transported in tanker trucks in a cooled liquid form; meaning that larger BTU quantities can be delivered to key supply locations that can support LNG deliveries. Liquefied natural gas has tremendous withdrawal capability because the natural gas is in a denser state of matter. Portable equipment has the ability to boil LNG back to a gaseous form and deliver it into the distribution system by heating the liquid from -260 degree Fahrenheit to a typical temperature of 50 – 70 degree Fahrenheit. This portable equipment is available to lease or purchase from various companies and can be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG production plants and are dependent upon the specific location where the portable LNG equipment is placed. The available delivery pressure from LNG equipment ranges from 150 psig to 650 psig with a typical flow capability of approximately 2,000 - 8,000 therms per hour.

Intermountain Gas currently operates a portable LNG unit on the northern end of the Idaho Falls Lateral to assist in peak shaving the system. In addition to the portable equipment, Intermountain also has a permanent LNG facility on the IFL that is designed to accommodate the portable equipment, provide an onsite control building and allow onsite LNG storage capabilities. The ability to store LNG onsite allows Intermountain to partially mitigate the risk associated with relying on truck deliveries during critical flow periods. The LNG delivery risk is also reduced now that Intermountain has the ability to withdraw LNG from the Nampa LNG Storage Tank and can transport this LNG across the state in a timely manner. With Nampa LNG readily available the cost and dependence on third-party supply is removed.

Renewable Natural Gas

RNG can be defined as utilizing any biomass material to produce a renewable fuel gas. Biomass is any biodegradable organic material that can be derived from plants, animals, animal byproduct, wastewater, food/production byproduct and municipal solid waste. After processing of RNG to industry purity standards the gas can then be used within Company facilities.

Idaho is one of the nation's largest dairy producing states which make it a prime location for RNG production utilizing the abundant supply of animal and farm byproducts. Southern Idaho currently has three RNG producers on Intermountain's distribution system. All three producers supply RNG from dairy operations and are located in the Twin Falls area. In addition to these current producers, the Company is currently working with multiple prospective projects and expects additional RNG producers to come onto Intermountain's distribution systems in coming years.

Intermountain has included RNG as a potential resource to solve any supply shortfalls the Company may have. RNG that has been cleaned to the Company's specifications can be used interchangeably with traditional natural gas in Intermountain's pipelines and in the customers' end use equipment. The Company estimated the price of RNG at $15/MMBTu, which was based on an American Gas Foundation report that states "…many landfill gas projects are estimated to produce RNG at a cost of $10-20/MMBtu, and dairy manure projects may produce RNG at a cost of closer to $40/MMBtu." [12] However, the report goes on to discuss an ICF report that describes substantial RNG production volumes at prices lower than $20/MMBtu. Intermountain is assuming the price of this renewable resource will continue to fall as the technology becomes more mature, and thus settled on a price within the range of current landfill gas projects for all RNG. Results of the RNG analysis are discussed on in the Planning Results section.

Hydrogen

Hydrogen is a clean alternative to methane. "Hydrogen can be produced from various conventional and renewable energy sources including as a responsive load on the electric grid. Hydrogen has many current applications and many more potential applications, such as energy for transportation—used directly in fuel cell electric vehicles (FCEVs), as a feedstock for synthetic fuels, and to upgrade oil and biomass—feedstock for industry (e.g., for ammonia production, metals refining, and other end uses), heat for industry and buildings, and electricity storage. Owing to its flexibility and fungibility, a hydrogen intermediate could link energy sources that have surplus availability to markets that require energy or chemical feedstocks, benefiting both." [13] Hydrogen can be produced by a variety of sources that are delineated by colors:

[12] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
[13] https://www.nrel.gov/docs/fy21osti/77610.pdf

- Blue hydrogen: Hydrogen produced using natural gas to create steam while capturing CO2;
- Green hydrogen: Hydrogen produced through electricity from renewables;
- Brown hydrogen: Hydrogen produced by coal;
- Pink hydrogen: Hydrogen produced through electricity from nuclear reactors; and
- Gray hydrogen: Hydrogen produced using natural gas to create steam without capturing CO2;

"Green hydrogen, (which is considered one of the cleaner forms of hydrogen), produced with renewable resources costs between about $3/kg and $6.55/kg, according to the European Commission's July 2020 hydrogen strategy." [14] With a conversion rate for kg per MMBtu at 7.5, hydrogen prices range from about $22.5/dth to $49.12/dth. There is significant global interest in hydrogen. In June 2021, the U.S. Department of Energy launched its "Hydrogen Shot" which seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade ("1 1 1"). [15] With the current pricing of hydrogen, however, Intermountain is only monitoring hydrogen at this time and will continue to consider it as a potential resource in future IRPs.

[14] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/experts-explain-why-green-hydrogen-costs-have-fallen-and-will-keep-falling-63037203
[15] https://www.energy.gov/eere/fuelcells/hydrogen-shot

Lost and Unaccounted For Natural Gas Monitoring

Intermountain Gas Company is pro-active in finding and eliminating sources of Lost and Unaccounted For (LAUF) natural gas. LAUF is the difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers. Intermountain is consistently one of the best performing companies in the industry with a three-year average LAUF percentage of -0.1193% (see Figure 28 below).

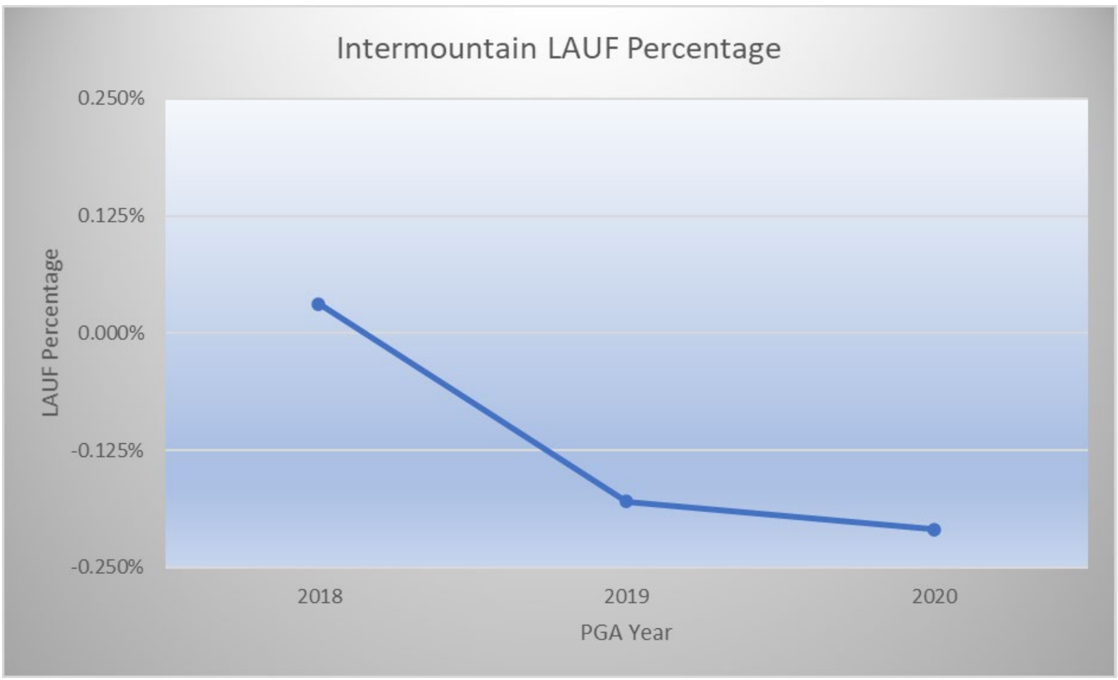

Figure 28: Intermountain LAUF Statistics

Intermountain utilizes a system to monitor and maintain a historically low amount of LAUF natural gas. This system is made up of the following combination of business practices:

- Perform ongoing billing and meter audits
- Routinely rotate and test meters for accuracy
- Conduct leak surveys on one-year and four-year cycles to find leaks on the system
- Natural gas line damage prevention and monitoring
- Implementing an advanced metering infrastructure system to improve the meter reading audit process
- Monitor ten weather location points to ensure the accuracy of temperature related billing factors
- Utilize hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors

Billing and Meter Audits

Intermountain conducts billing audits to identify irregular usage with each billing cycle. Intermountain also works to ensure billing accuracy of newly installed meters. These audits are performed to ensure that the meter and billing system are functioning correctly to avoid billing errors. If errors are identified, then corrective action is taken.

Intermountain also compares on a daily and monthly basis its telemetered usage versus the metered usage that Northwest Pipeline records. These frequent comparisons enable Intermountain to find any material measurement variances between Intermountain's distribution system meters and Northwest Pipeline's meters.

Table 10: 2018 - 2020 Billing and Meter Audit Results

Billing and Meter Audit Results			
	2018	2019	2020
Dead Meters	310	211	184
Drive Rate Errors	4	1	2
Pressure Errors	24	21	14
Totals	338	233	200

Meter Rotation and Testing

Meter rotations are also an important tool in keeping LAUF levels low. Intermountain regularly tests samples of its meters for accuracy. Sampled meters are pulled from the field and brought to the meter shop for testing. The results of tests are evaluated by meter family to determine the pass/fail of a family based on sampling procedure allowable defects. If the sample audit determines that the accuracy of certain batches of purchased meters are in question, additional targeted samples are pulled and any necessary follow up remedial measures are taken.

In addition to these regular meter audits, Intermountain also identifies the potential for incorrectly sized and/or type of meter in use by our larger industrial customers. Intermountain conducts a monthly comparison to the billed volumes as determined by the customer's meter. If a discrepancy exists between the two measured volumes, remedial action is taken.

Leak Survey

On a regular and programmed basis, Intermountain technicians check Intermountain's entire distribution system for natural gas leaks using sophisticated equipment that can detect even the smallest leak. The surveys are done on a one-year cycle in business districts and a four-year cycle in other areas. This is more frequent than the code requirement, which mandates leak surveys on one-year and five-year cycles. When such leaks are identified, which is very infrequent, they are graded and addressed according to grade. Grade 1 leaks are repaired immediately, Grade 2 leaks are addressed within six months, and Grade 3 leaks are addressed within 15 months. This approach is more aggressive than the industry standard, where lower grade leaks are often monitored for safety and not repaired immediately.

Damage Prevention and Monitoring

Unfortunately, human error leads to unintentional excavation damage to our distribution system. When such a gas loss situation occurs, an estimate is made of the escaped gas and that gas then becomes “found gas” and not “lost gas”.

A damage prevention department has been created for the utility group. The department focuses on education to both business and agencies that interact with Intermountain and the public. Industry education and awareness has centered around trainings with contractors, excavators and first responders.

To educate the general public on the importance of calling 811 prior to any type of digging, Intermountain has participated in a variety of informational activities. The Company sponsors many events and activities across the state of Idaho each year.

The additional focus on education and awareness is having an impact. Intermountain has seen a decrease in incidents that damage facilities, and especially a decrease in incidents that cause gas loss. There is still work to do, however. There continue to be instances where the contractor or individual either does not call 811 before digging or calls but does not pay attention to the marking of the utility facilities. Continued focus on damage prevention by Intermountain as well as the support of the Idaho Damage Prevention Board should help to further reduce the incidences of excavation damage and related gas loss in the future. Figure 29 shows the damage rate per 1,000 locates, and Figure 30 shows the total locates for 2018 through 2020.

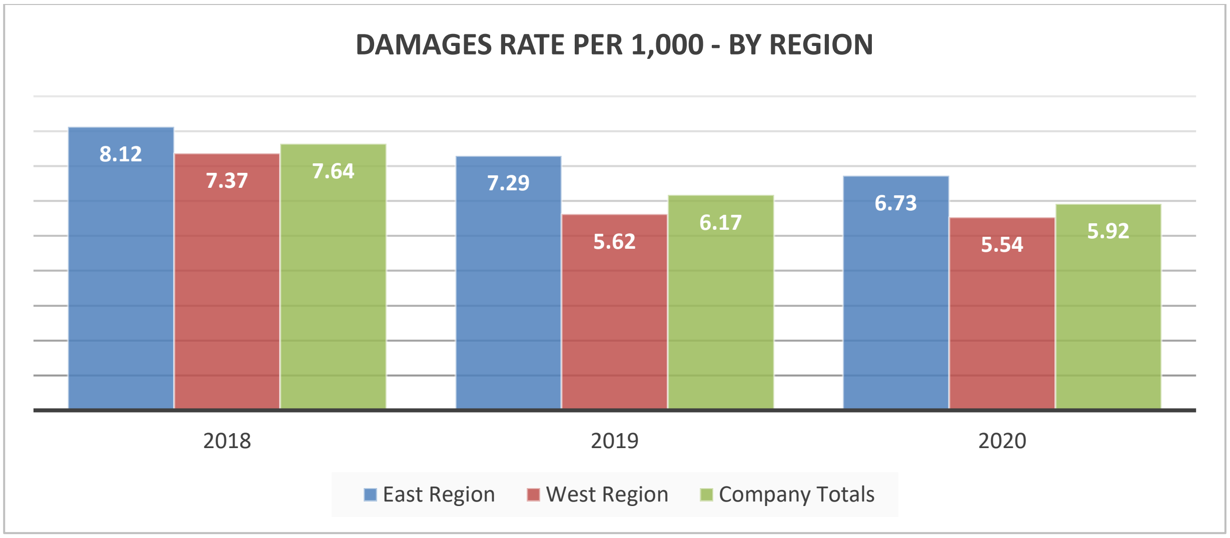

Figure 29: Damage Rates per 1,000 Locates by Region

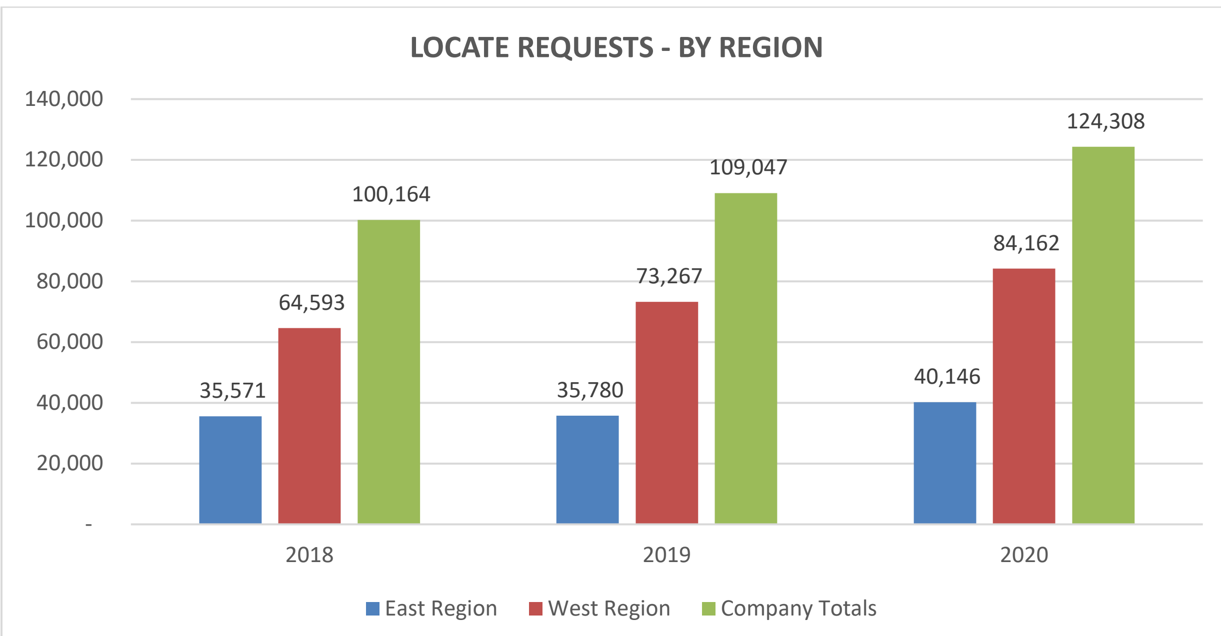

Figure 30: Intermountain Locate Requests by Region

Figure 31 below shows total damages by region and year for 2018 through 2020.

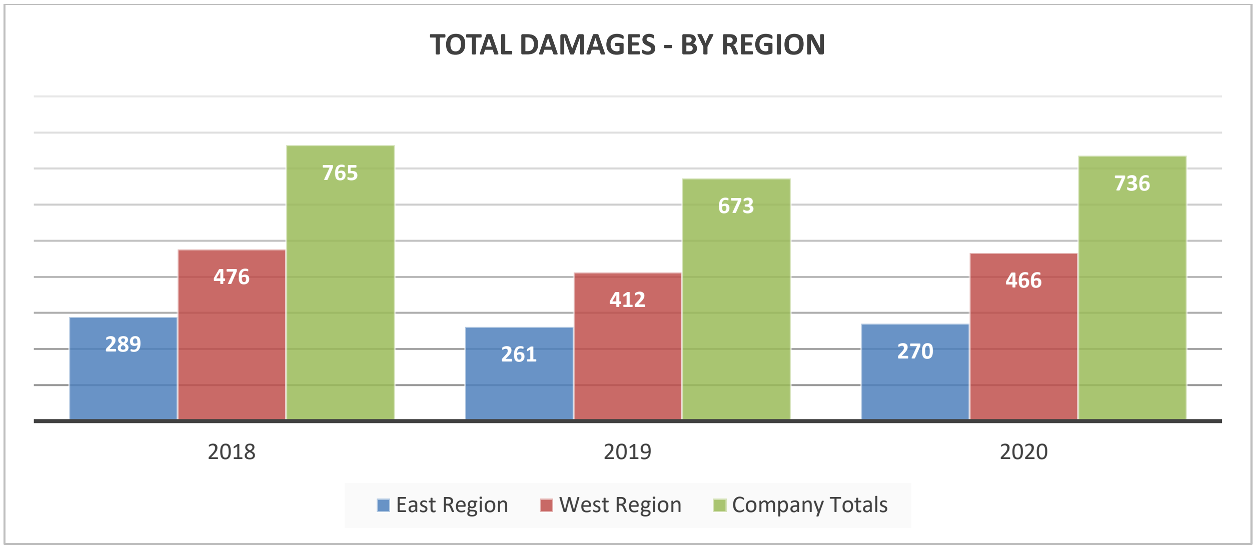

Figure 31: Intermountain Total Damages by Region

Advanced Metering Infrastructure

Intermountain is in the process of implementing Itron's fixed-network metering infrastructure. In the Company's previous IRP, it was anticipated that the system would be complete by the end of 2020. However, COVID-19 and the related labor and supply chain issues have hampered installation efforts. The system is currently 60% complete and is planned to reach 90% coverage by the end of 2022. This system utilizes a fixed mounted data collector using two-way communication to endpoints and to the repeater to collect on-demand reads and issue network commands. This system provides a robust collection of time-synchronized interval data, and when coupled with a meter data management system, it helps Intermountain:

- Improve customer service
- Refine forecasted consumption
- Manage and control tampering and theft
- Synchronize endpoint clocks to ensure data collected territory-wide is accurately time-stamped
- Retrieve missing interval data in the event of an outage
- Streamline the process of identifying billing errors

Weather and Temperature Monitoring

Intermountain increased the number of weather monitoring stations in the early 2000's, from five to ten weather location points, to ensure the accuracy of temperature related billing factors. Additionally, Intermountain utilizes hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors. The weather and temperature monitoring provide for a better temperature component of the billing factor used to calculate customer energy consumption.

Summary

Intermountain continues to monitor LAUF levels and continuously improves business processes to ensure the Company maintains a LAUF rate among the lowest in the natural gas distribution industry.

Core Market Energy Efficiency

The Company's residential and commercial energy efficiency programs promote the wise and efficient use of natural gas which helps the Company's customers save money and energy. Additionally, the Company's energy efficiency programs will, over time, help negate or delay the need for expensive system upgrades while still allowing Intermountain to provide safe, reliable, and affordable service to its customers.

Residential & Commercial Energy Efficiency Programs

The goal of Intermountain's Residential and Commercial Energy Efficiency Programs (EE Program) is to acquire cost-effective demand side resources. Unlike supply side resources, which are purchased directly from a supplier, demand side resources are acquired through the reduction of natural gas consumption due to increases in the efficiency of energy use. Demand side resources acquired through the Company's EE Program (also referred to as Demand Side Management or DSM) ultimately allow Intermountain to displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcement on the Company's distribution system. The Company strives to raise awareness about energy efficiency and inspire customers to reduce their individual demand for gas through outreach and education.

Collections for funding the Residential EE Program began on October 1, 2017. Active promotion and staffing of the Residential EE Program launched in January 2018. Since the launch, the Residential EE Program has continued to grow year over year in number of total rebates claimed by customers and energy savings. Intermountain launched its Commercial EE Program on April 1, 2021 and began collecting funds through an Energy Efficiency Charge.

Conservation Potential Assessment

In its 2019 IRP, the Company estimated DSM therm savings for the 2019-2023 planning period based on the Conservation Potential Assessment (CPA) commissioned by Intermountain. The CPA provides a robust analysis of all cost-effective DSM measures and is intended to support both short-term energy efficiency planning and long-term resource planning activities.

The CPA is intended to be used for the following:

- **Resource planning**: evaluate the impact of energy efficiency, fuel switching and codes and standards on long-term energy consumption and demand needs
- **Identify opportunities**: assess achievable DSM opportunities to improve DSM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential

- **Efficiency program planning**: inform portfolio and program design considering funding level, market readiness and other constraints.

Dunsky Energy Consulting (Dunsky) was retained to perform the assessment. Dunsky utilized the expertise of GTI, the leading natural gas energy and environmental research organization, as the primary research lead for the study. The scope of the study included conservation potential for both the residential and commercial sectors, over the 2020-2039 time period.

The purpose of the potential assessment was "to provide a realistic, high-level assessment of the long-term energy efficiency potential that is technically feasible, cost-effective, and achievable through efficiency programs." Three categories of potential savings, depicted in Figure 32, were examined by applying economic considerations such as market barriers and cost tests. The Utility Cost Test (UCT) was applied to the theoretical maximum savings opportunity, or the technical savings category, to screen for only the cost-effective measures, resulting in the economic savings potential. The economic savings potential of cost-effective measures was further screened by applying market barriers to establish the achievable energy efficiency potential. To study the impacts on achievable potential savings, three different scenarios were tested: the low case, the base case and the max case. A more detailed description of the methodology can be found in the final CPA report completed in 2019, and attached as Exhibit 4.

Technical: Theoretical maximum savings opportunity, ignoring constraints such as cost-effectiveness and market barriers.

Economic: Applies economic considerations to technical potential, leaving only measures that are cost-effective. Screened on the Utility Cost Test (UCT).

Achievable: Applies market barriers to economic potential, resulting in an estimate of savings that can be achieved through efficiency program. Different scenarios are tested to examine their impacts on savings.

Figure 32: Categories of Potential Savings

Details of the three scenarios and the key insights to be examined with each scenario were as follows:

- Low Case - low incentive levels, (35% of incremental measure costs), but with no budget constraints and over a broad set of cost-effective measures

  Key insight: *What level of saving can be achieved with a comprehensive offer, with incentives that are in the lower range?*

- Base Case – incentives increased to 50%, barrier reduction in Program Year 6, unconstrained budget – standard program approach

  Key insight: *How much more savings can be expected with increased incentive levels?*

- Maximum Case – incentive levels at 65%, barrier-reducing program delivery, unconstrained budget and measures

  Key Insight: *How would improved program delivery increase savings (e.g. consumer education, contractor training and support, etc.)*

In addition to the CPA report, Dunsky provided a savings modeling tool called the Dunsky Energy Efficiency Potential Model (DEEP Model), which employs a multi-step process to develop the Technical, Economic and Achievable potentials as shown in Figure 33. Since the 2019 IRP, Intermountain updated the DEEP model to align with the 2021-2026 planning window, utilize the latest avoided cost calculations and to reflect the introduction of the Commercial EE Program.

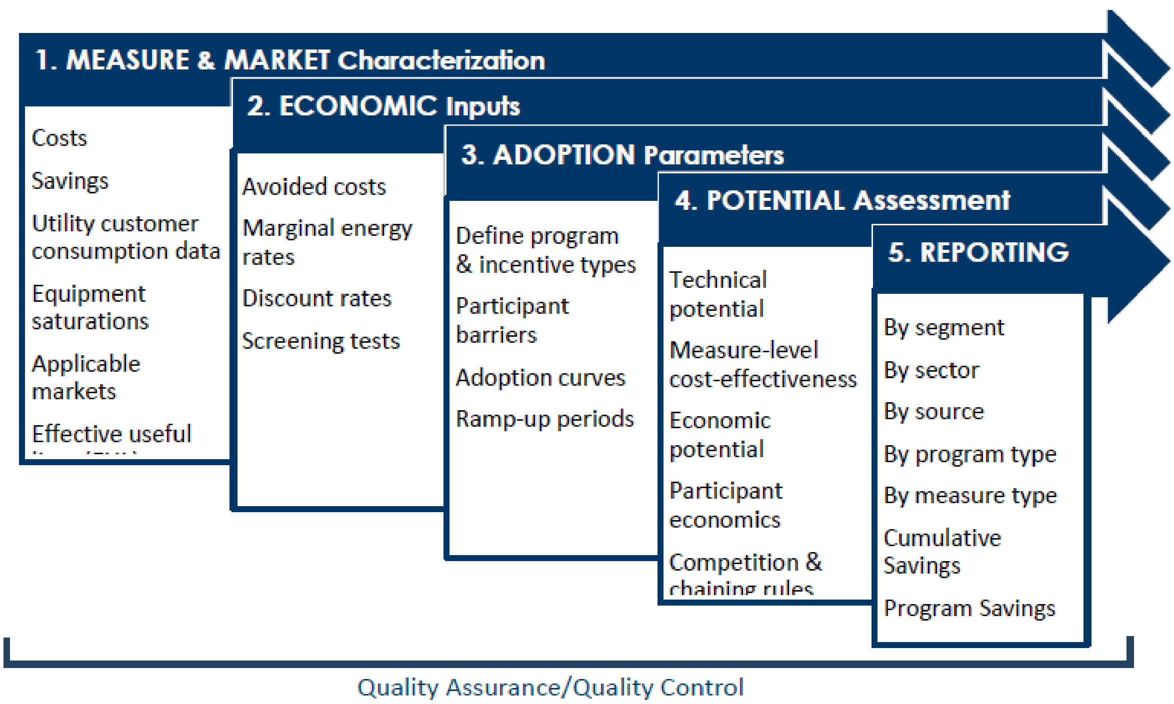

Figure 33: Key Steps and Inputs in Study Methodology

Therm Savings

As seen in Figure 34 below, cumulative therm savings for 2021-2026 from the DEEP Model are shown by category of potential savings and by the three scenarios of achievable potential (low, base and max).

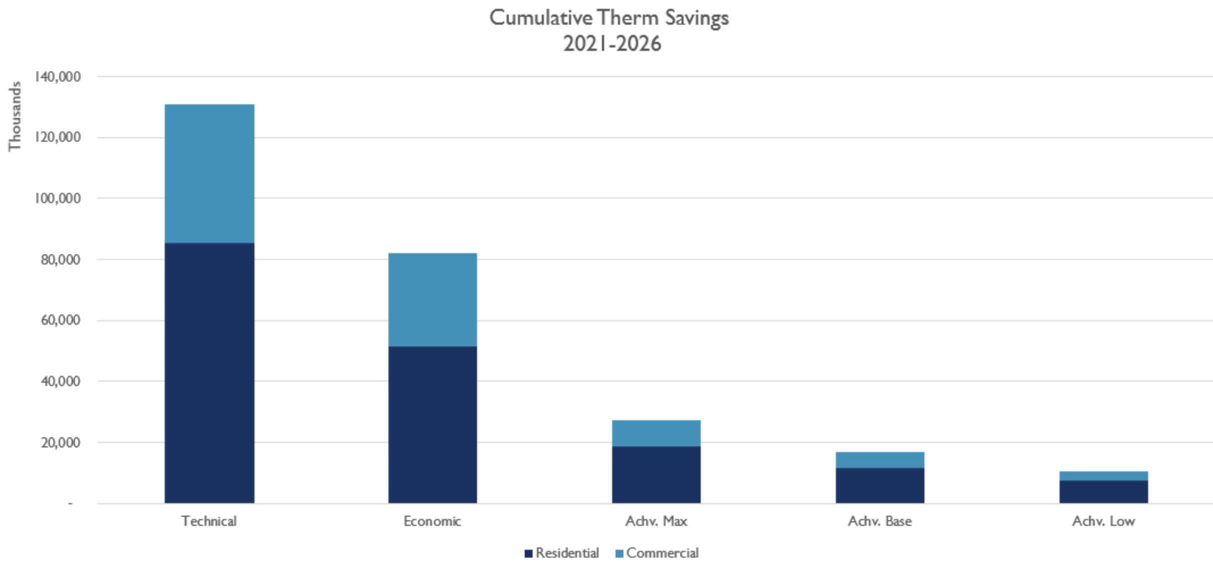

Figure 34: Cumulative Therm Savings

Focusing strictly on the Achievable Base scenario, Figure 35, shows the cumulative potential therm savings, by program, for the 2021-2026 time period.

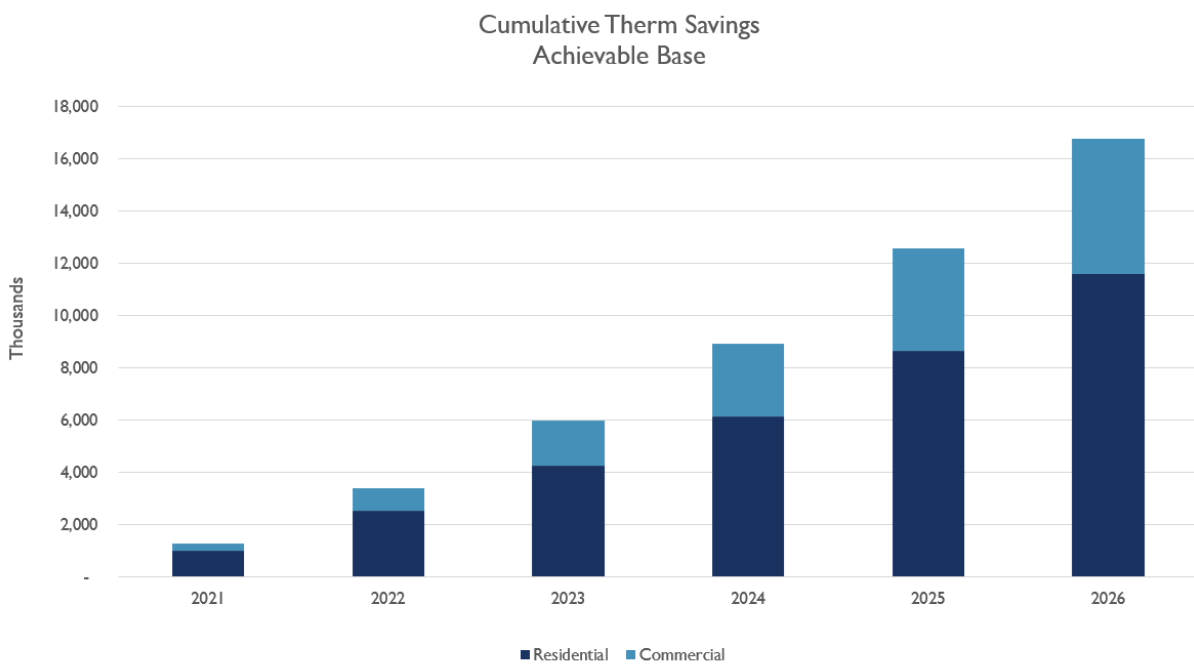

Figure 35: Cumulative Therm Savings, Base Achievable Scenario

As shown in Figure 36, 69% of achievable savings will come from the residential sector. The three next highest achievable savings all come from the commercial sector: education (12%), retail and food sales (5%), and office (5%).

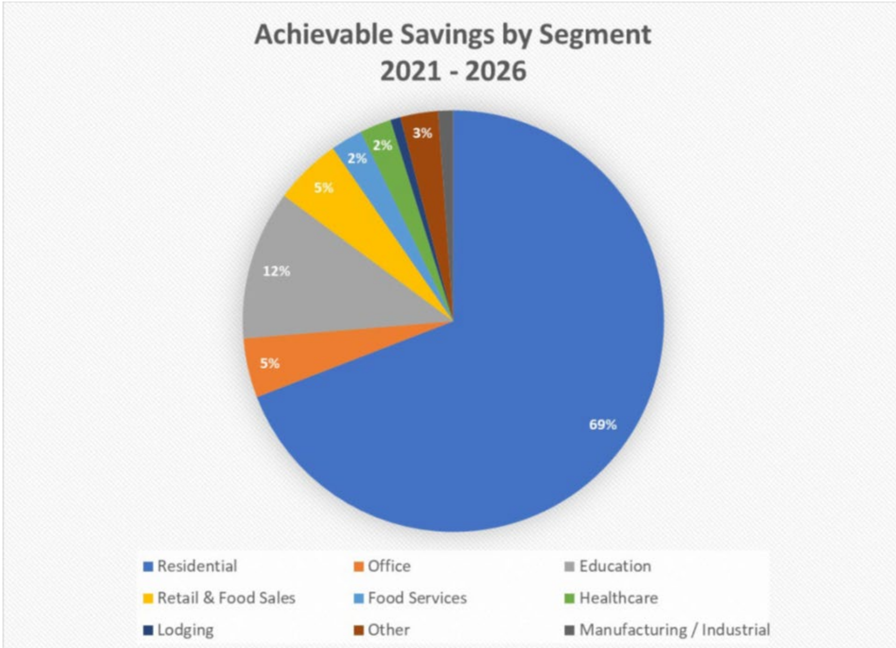

Figure 36: Achievable Savings by Segment 2021 - 2026

The achievable savings by application for the combined sectors, commercial and residential, is shown in Figure 37.

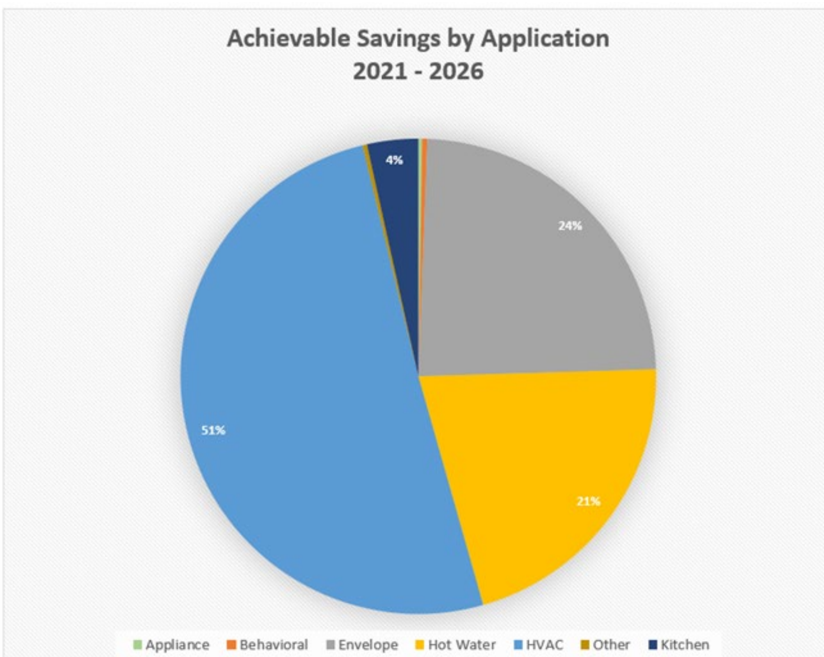

Figure 37: Achievable Savings by Application 2021 - 2026

In the residential sector, the CPA identified envelope and HVAC applications as the two largest categories of potential savings. The top HVAC measures identified included connected thermostats, duct insulation and efficient boilers. To capture these savings potentials, Intermountain revised its Residential EE Program to add smart thermostats and high-efficiency boilers. Furthermore, the Whole Home rebate for new construction was updated to include specific energy performance targets for maximum air change per hour limits achieved by improved air sealing and reducing duct leakage allowances through better duct insulation and above-code ceiling insulation requirements. These changes that are targeted to improve therm savings became effective April 1, 2021.

In the commercial sector, HVAC applications also provided the greatest savings potential. Equipment-based measures like condensing boilers and energy recovery ventilators represented a significant share of potential in the first five years of the program. Commercial kitchen appliances were also identified as an untapped savings opportunity. As mentioned above, Intermountain launched its Commercial EE Program on April 1, 2021 with a modest initial offering of rebates for condensing boilers, boiler reset controls, condensing unit heaters, and commercial kitchen equipment. A complete listing of Commercial Energy Efficiency Rebates is shown in Figure 38.

HEATING INCENTIVES

Eligible Appliance	Efficiency Rating	Rebate
Condensing Unit Heater	90% AFUE or Greater Efficiency	$1,500
Boiler Reset Control	N/A	$350
High-Efficiency Condensing Boiler	90% or Greater Thermal Efficiency and ≥300 kBTUh	$4.50/kBTUh

KITCHEN EQUIPMENT INCENTIVES

Eligible Appliance	Efficiency Rating	Rebate
Fryer	ENERGY STAR® Certified	$800
Steamer	ENERGY STAR® Certified (≥38% cooking eff/≤2,038 BTU/hr/pan Idle Rate)	$1,100
Griddle	ENERGY STAR® Certified (≥38% cooking eff/≤2,650 BTU/hr/pan Idle Rate)	$200

Figure 38: Commercial Energy Efficiency Rebates

Savings potential from the base scenario were incorporated as a DSM resource in the Optimization Model.

Ensuring an Energy Efficient Future

Intermountain Gas is committed to the efficient use of natural gas today, and also works to secure an energy efficient future. Intermountain has been a long-time member of the Gas Technology Institute (GTI). GTI is the leading research, development and training organization addressing energy and environmental challenges to enable a secure, abundant, and affordable energy future. As a GTI member, Intermountain is able to leverage research and development investments by collaborating with other interested members in funding and steering the direction of a project, while allowing GTI to manage the program and perform the research. Intermountain participates on the Operations Technology Development (OTD) and Utilization Technology Development (UTD) collaborative member groups which are focused on different aspects of the value chain. OTD is a member-controlled partnership to develop, test, and implement new technologies related to the safe and reliable operation of the natural gas infrastructure. UTD, also a member-controlled partnership, conducts near-term applied research to develop, test and deploy energy-efficient end-use technologies.

Intermountain's Energy Efficiency Program participates specifically in UTD's Emerging Technology Program (ETP), which is a member-driven collaborative to accelerate the introduction and acceptance of new emerging technologies for energy efficiency programs. ETP picks up at the final stages of UTD's research process and focuses on "identifying and addressing data or market barriers, including the development of new measures, impacts of disruptive technologies, awareness and education." Gas heat pumps are an emerging technology that has been a part of the ETP program and is well positioned to take the next step in becoming a commercially available product.

To build on GTI's work in gas heat pump technology, Intermountain joined the North American Gas Heat Pump Collaborative (Collaborative) as a charter member. The Collaborative is a coalition of 14 gas utilities and energy efficiency administrators representing 31% of gas-served households in North America. Its mission is to advance the successful commercialization of gas heat pump technology from pre-commercialization, to product rollouts, to realization of a mature commercial marketplace. This effort is part of a larger strategy to enable the gas industry to play a significant role in the decarbonization of energy and the development of a cleaner economy. Intermountain participates on the operations committee, the gas heat pump water heater working group and the residential combination working group. The Collaborative continues to make excellent progress as a newly formed North American effort advancing the adoption of gas heat pump technology.

To further the effort of securing a clean energy future, Intermountain also joined the newly formed Low-Carbon Resources Initiative (LCRI) which is a joint venture of GTI and the Electric Power Research Institute (EPRI). This is a unique, international collaboration spanning the natural gas and electric sectors that will help advance global, deep decarbonization of all segments of the economy. The goal of the five-year initiative is to accelerate the development and demonstration of low-carbon energy technologies, leading to affordable options to accelerate an intelligent transformation toward a cleaner, reliable, and affordable energy future by mid-century.

Large Volume Energy Efficiency

Through discussions with the customers and the information provided via the IRP surveys, it is apparent that maximizing plant efficiency by optimizing production volumes while using the least amount of energy is a very high priority for the owners, operators, and managers of Intermountain’s large volume facilities. Nearly 20 years ago Intermountain developed an informational tool using SCADA and remote radio telemetry technology to gather, transmit and record the customer’s hourly therm usage data. This data is saved in an internal database and made available to customers and their marketers/agents via an internal server on a password protected website.

Usage data is useful in tracking and evaluating energy saving measures, new production procedures and/or usage characteristics of new equipment. To deploy this tool, Intermountain installs SCADA units on customers’ meters to record the meter volume each hour. That data is then transmitted via radio/telemetry communication technology to Intermountain’s servers so it can be made available to customers.

Figure 39: Large Volume Website Login

In order to provide customers access to this data, Intermountain has designed and hosts a Large Volume website, which is pictured in Figure 39. The website is available on a 24/7 basis for Large Volume customers to log-in via the internet using a company specific username and customer managed passwords. After a successful log-in, the user immediately sees a chart showing the last 30 days of hourly usage for the applicable meter or meters. The customer also has the option to adjust the date range to see just a few hours or up to several years of usage data. An example of a month’s worth of data is provided in Figure 40. The user can also download the data in CSV format to review, evaluate, save and analyze natural gas consumption at their specific facility on an hourly, weekly, monthly, and annual basis as far back as 2017. Each customer may elect to have one or multiple employees access the site. Logins can also be created to make this same data available to a transport customer's natural gas marketer.

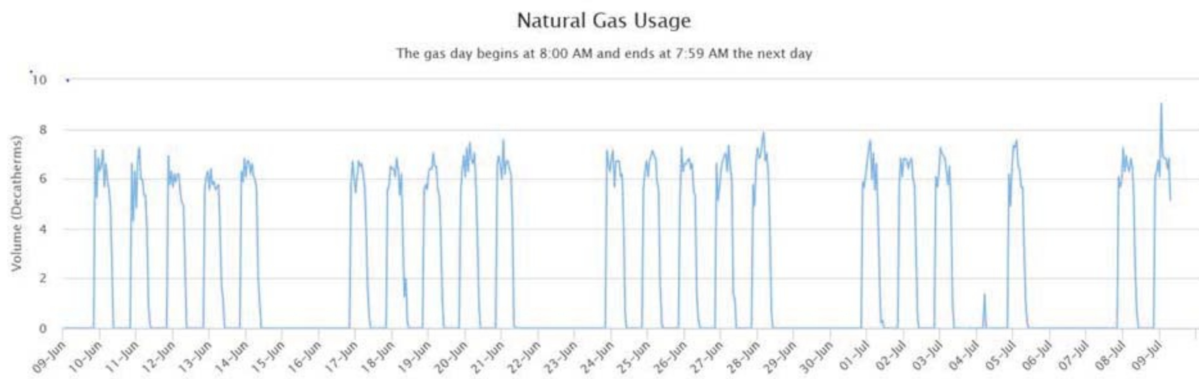

Figure 40: Natural Gas Usage History

The website also contains a great deal of additional information useful to the Large Volume customer. Customers can access information such as the different tariff services offered, answers to frequently asked questions and a potential marketer list for those interested in exploring transport service. The customer is also provided a "Contact Us" link and, in order to keep this site in the most usable format for the customer, a website feedback link is provided. The site allows the Company to post information regarding things such as system maintenance, price changes, rate case information and any other communication that might assist the customer or its marketer.

Avoided Costs

Overview

The avoided cost represents those costs that the Company does not incur as a result of energy savings generated by its Energy Efficiency Program. The calculation is used both to economically evaluate the present value of the therms saved over the life span of a measure and to track the performance of the program as a whole.

Avoided costs are forecasted out 30 years in order to properly assess Energy Efficiency measures with longer lifespans. This forecast is based on the performance of the Company's portfolio under expected market conditions. The Avoided Cost values can be found in Exhibit 5.

Costs Incorporated

Intermountain's avoided cost calculation contains the following components:

$$AC_{nominal} = CC + TC + VDC$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year.
- *CC* = Commodity Costs
- *TC* = Transportation Costs
- *VDC* = Variable Distribution Costs

The following parameters are also used in the calculation of the avoided cost:

- The assumed forward-looking annual inflation rate is 2.0%.
- The discount rate is derived using Intermountain's tax-effected cost of capital.
- Standard present value and levelized cost methodologies are utilized to develop a real and nominal levelized avoided cost by year.

Understanding Each Component

Commodity Costs

Commodity costs represent the purchase price of the natural gas molecules that the Company does not need to buy due to therm savings generated by its Energy Efficiency Program. To calculate the commodity costs, the Company first utilizes price forecasts included in its IRP for three primary basins (AECO, Sumas, and Rockies) then weights these forecasts based on Intermountain's historical day-gas purchase data. Day-gas purchases represent the first costs that could be avoided through Energy Efficiency Program savings. To account for the seasonal nature of energy savings, the weighted price is shaped by normal monthly weather, measured in heating degree days with a base of 65 degrees. The original basin price forecasts span through 2040 and then an escalator is applied through the remainder of the forecast period. The gas price forecasts will be updated in each IRP planning cycle.

Transportation Costs

Transportation costs are the costs the Company incurs to deliver gas to its distribution system. As the Company's Energy Efficiency Program generates therm savings, the Company can reduce pipeline capacity needs and monetize any excess capacity to reduce costs for all customers through credits in the Company's annual Purchased Gas Cost Adjustment (PGA) filing. The Company calculates the per therm transportation cost as the weighted average of the gas transportation costs listed on the Company's residential and commercial tariffs. The nominal value of the transportation cost is increased each year by the model inflation rate of 2.0%. The inflated nominal value is then discounted back to today's dollars as part of the final step in the avoided cost calculation. The Company will update the transportation cost each year to reflect the most current gas transportation cost as filed in its PGA.

Variable Distribution Costs

Variable distribution costs are the avoidable portion of costs incurred by Intermountain to deliver gas to customers via its distribution system. Lowering gas consumption through the Company's Energy Efficiency Program allows Intermountain to delay costly capacity expansion projects and utilize existing pipeline infrastructure more efficiently. While these cost benefits are intuitively apparent, the Company and its Stakeholder group are investigating methods to quantify these savings. The Company is currently using a placeholder value of zero for this component.

Optimization

Distribution System Modeling

Overview

A natural gas pipeline is constrained by the laws of fluid mechanics which dictate that a pressure differential must exist to move gas from a source to any other location on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a pipeline system, typically during the operation of natural gas equipment, then the pressure in the system at that point becomes lower than the supply pressure in the system. This pressure differential causes gas to flow from the supply pressure to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to Intermountain's distribution systems. It is important that engineers design a distribution system in which the beginning pressure sources, which could be from interstate pipelines, compressor stations or regulator stations, have adequately high pressure, and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity; which is constrained by minimum pressure allowances at a determined point or points along the distribution system, and maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain size and length within specified operating pressures; the laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and distribution system can be ascertained for any set of known gas demand data. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day.

In order to evaluate intricate pipeline structures a system model is created to assist Intermountain's engineering team in determining the flow capacity and dynamics of those pipeline structures. For example, before a large volume customer is incorporated into an existing distribution system the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipated future customer growth.

Modeling Methodology

Intermountain utilizes a hydraulic gas network modeling and analysis software program called Synergi Gas, distributed and supported by DNV, to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program individual models have been created for each of Intermountain's various distribution systems including high pressure laterals, intermediate pressure systems, distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Intermountain defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in the system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. The entire pipeline system is broken into three individual models for ease of use and to reduce the time requirements during a model run analysis. The largest model in use consists of approximately 71,500 active nodes, 580,000 graphic nodes and 76,400 facilities which are used along with additional model inputs to solve simultaneous equations through an iterative process, calculating pressures for over 70,500 unknown locations prior to analysis.

Synergi can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time; which more closely simulates real life operation utilizing gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this integrated resource plan Intermountain can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost-effective methods of enhancing the constrained location. The feasibility, timeline, cost and increased capacity for each theoretical system enhancement is determined and then placed into a comparison analysis and used within the IRP model.

Capacity Enhancements

Overview

Throughout previous sections of the IRP, it has been shown that projected growth throughout Intermountain' s distribution systems could possibly create capacity deficits in the future. Using a gas modeling system that incorporates total customer loads, existing pipe and system configurations along with current distribution system capacities, each potential deficit has been defined with respect to timing and magnitude. For each capacity deficit identified, the Company evaluates and compares potential system capacity enhancements in its optimization model and selects a final capacity enhancement based on cost, capacity increase and long-term planning. After the capacity enhancement has been selected it is included in Intermountain's 5-year budget based on when the capacity enhancement needs to occur to avoid capacity deficiencies.

The net present value (NPV) costs for each potential capacity enhancement are presented in the discussion below. To determine the NPV costs, the Company compared the initial project cost to the estimated annual costs of the project, inflated by 2% each year and discounted to current dollars using the nominal discount rate of 6.68% from the Company's avoided cost model presented in Exhibit 5. The final NPV calculations can be found attached in Exhibit 6.

The summary presented at the end of this section shows the timing for all capacity enhancements selected and the corresponding capacity increases for each AOI.

Capacity Enhancement Options

The capacity enhancements discussed in this section are as follows:

1. Pipeline Loop
2. Pipeline Uprate
3. Compressor Station
4. Pipeline Replacement

These capacity enhancements do not reduce demand nor do they create additional supply points, rather they increase the overall capacity of a pipeline system while utilizing the existing gate station supply points.

Pipeline Loop

Pipeline looping is a traditional method of increasing capacity within an existing distribution system. The loop refers to the construction of new pipe installed parallel to an existing pipeline that has, or may become, a constraint point. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, or steep and rocky terrain can greatly increase the cost to unjustifiable amounts when compared with alternative enhancement solutions.

Pipeline Uprate

A pipeline uprate is a method of increasing the capacity of an existing pipeline by increasing the maximum allowable operating pressure of the pipeline. Operating a pipeline at a higher pressure allows for greater throughput down the pipeline. Uprates allow a company to maximize the potential of their existing systems before constructing additional facilities and they are normally a lower-cost option compared to pipeline looping to increase capacity; however, leaks and damages are sometimes found or incurred during the uprate process creating costly repairs. There are also safety considerations and pipe regulations that restrict the feasibility of increasing the pressure in any pipeline, such as the material composition, pressure test, operations and maintenance history of the pipeline and location of the existing pipeline. Another consideration to an uprate is if the uprate could take the specific maximum yield stress (SMYS) of the pipeline into Transmission Classification. Increased regulatory requirements would incur increased operations and maintenance costs for Transmission class lines.

Compressor Station

Compressor stations are typically installed on large diameter pipelines or laterals that run several miles and have significant gas flow demands. Compressor stations boost pressures and flows down the lateral to meet delivery pressure needs on the system and can be a feasible solution to lateral point constraints. Regulatory and environmental approvals to install a compressor station can be a significant deterrent and not all site locations may be favorable. Operation and maintenance of the compressor should also be considered in the analysis since compressors require additional cost to run and maintain the compressor and without redundancy could require outage coordination if the compressor needs to be taken offline to make repairs.

Pipeline Replacement

A fourth option to gain capacity on a pipeline that cannot be uprated or does not have a feasible route to loop the line is to replace the pipeline with a new pipeline that meets design specifications for the demand. Pipeline replacements should be considered on older vintage pipe that does not have all of the pipeline records required to uprate the line. Pipeline replacement would also be considered if the line has an integrity concern or potential issue that would not be favorable to uprate the line.

Canyon County

AOI Summary/System Dynamics

The Canyon County AOI consists of an interconnected system of high-pressure (HP) pipelines that serve communities from Star Road west to Highway 95. The system originally serving Nampa and Caldwell was continually extended west to additional towns and industrial customers. In 2013 the Canyon County system was connected to, and back fed from, a new pipeline installed to the town of Parma. This Parma Lateral 6-inch HP pipeline project provided a secondary feed to the Canyon County area. The next large system enhancement occurred in 2018 with the 12-inch Ustick Phase I HP pipeline project installed on the east side of Caldwell.

Capacity Limiter

Due to significant growth in Nampa and surrounding communities this AOI requires a capacity enhancement by both 2021 and 2023 to meet IRP growth predictions. The Canyon County AOI's capacity is currently limited by high flow rates on the 6-inch, 8-inch and 10-inch HP pipeline on Ustick Rd which is causing high pressure to drop in this section, compromising pressures downstream, and impacting the line's capacity. This bottleneck is highlighted in yellow in Figure 41.

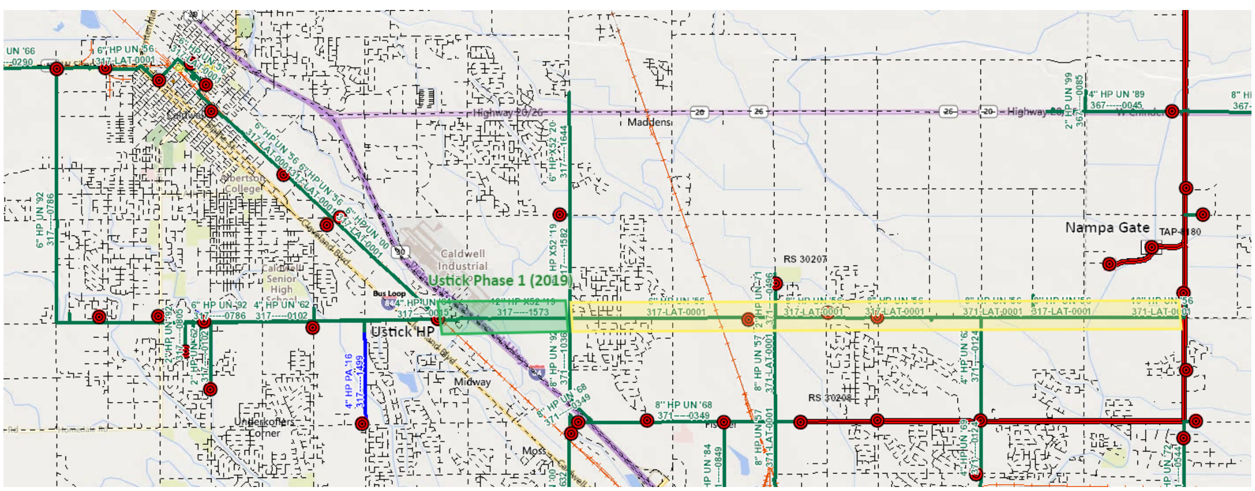

Figure 41: Canyon County Capacity Limiter

<u>Capacity Enhancement Alternatives Considered</u>

Alternative One: Ustick Phase II

The first capacity enhancement alternative is to install 2 miles of 12-inch steel HP pipe along Ustick Rd as shown in Figure 42.

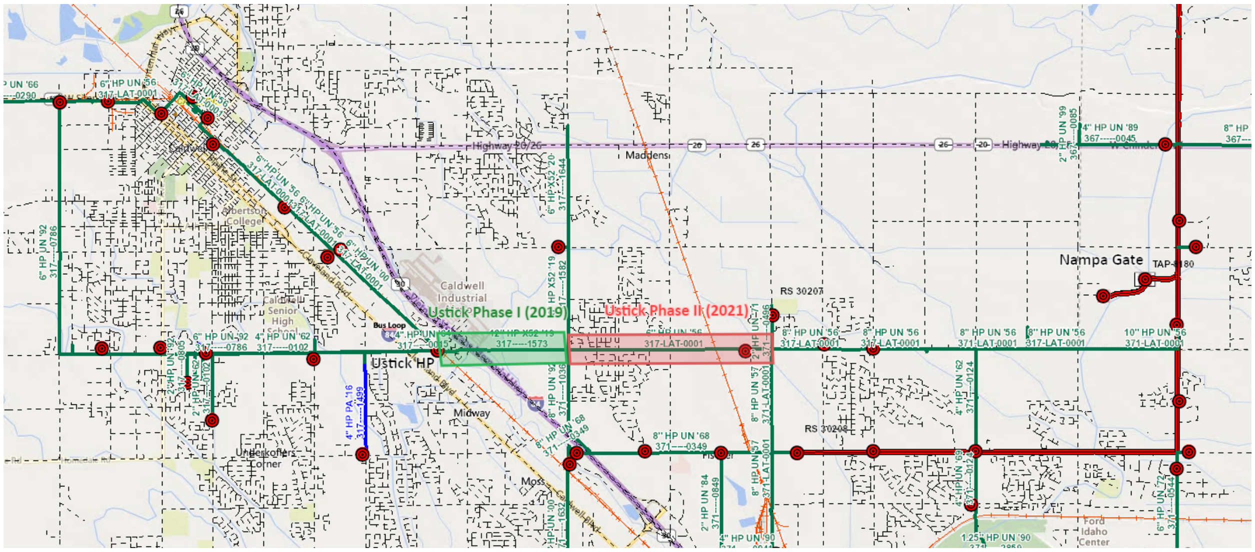

Figure 42: Canyon County Alternative One

This option will bring the capacity up to 1,032,000 therms per day which will meet predicted growth through 2022 and will allow IGC to downrate the existing 6-inch HP pipe to distribution pressure (DP), boost the distribution system capacity, and allow for the retirement of a DP regulator station and several high-pressure service sets (HPSS). This option was selected in the 2019 IRP. NPV cost for this option is estimated at $3,255,075

Alternative Two: Ustick Phase III

The second capacity enhancement alternative is to install 4.1 miles of 12-inch steel HP pipe along Ustick Rd and install 4 HP regulator stations as shown in Figure 43.

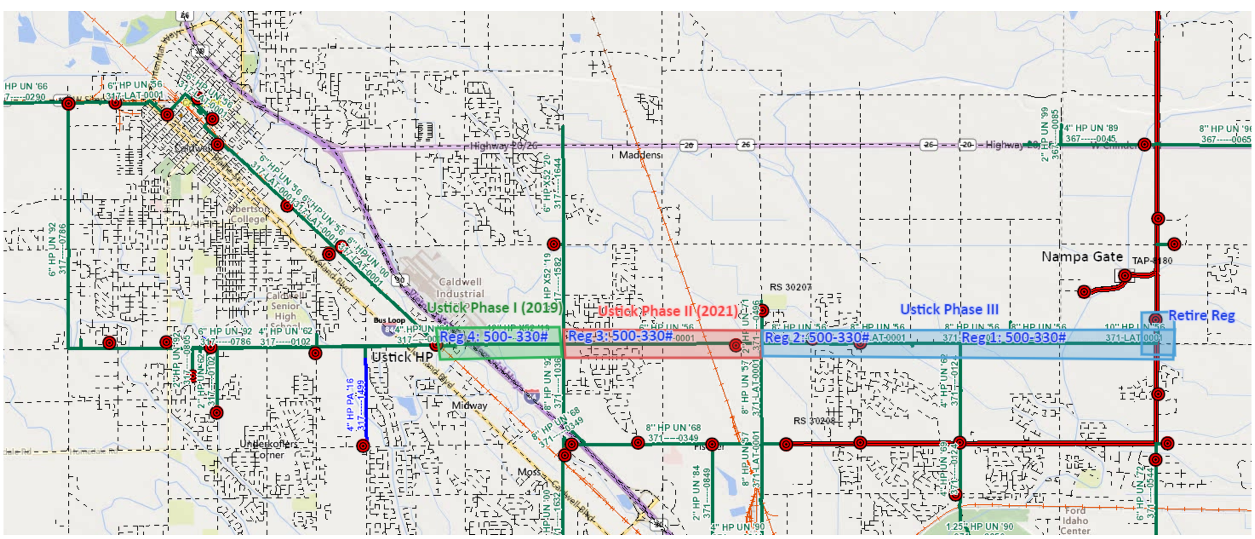

Figure 43: Canyon County Alternative Two

This project builds off the Phase I and Phase II enhancements and would increase capacity to 1,390,000 therms per day which would meet growth through 2026. Completing this project would allow IGC to downrate the existing 10-inch and 8-inch HP pipelines on Ustick Rd to DP and eliminate several regulator stations and HPSS's. Eliminating these stations would reduce operations and maintenance costs. NPV cost for this option is estimated at $8,613,403.

Alternative Three: Ustick Uprate

The third capacity enhancement alternative is to retest and then uprate the 4.1 miles of 10-inch HP steel pipe and 3.1 miles of 8-inch HP steel pipe on Ustick Rd and install 4 HP regulator stations as shown in Figure 44.

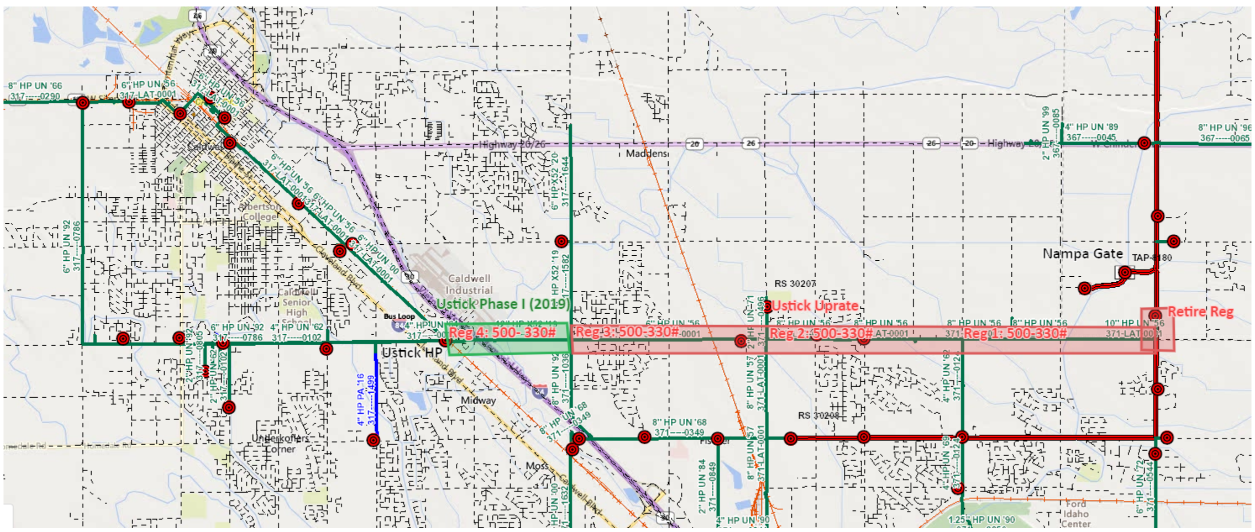

Figure 44: Canyon County Alternative Three

This option would bring the capacity up to 1,178,000 therms per day which would meet predicted growth through 2026 assuming Ustick Phase II has been completed. Other considerations associated with this uprate include unknowns with pressure testing 1956 vintage pipe and the potential that this pipe could not pass uprate requirements to operate at a higher pressure. NPV cost for this option is estimated at $1,300,000.

Alternative Four: 8-inch HP extension north of Ustick at 500 psig MAOP

The fourth capacity enhancement alternative is to install 6.5 miles of 8-inch HP steel pipe north of Ustick Rd on Linden Rd and a HP regulator station as shown in Figure 45.

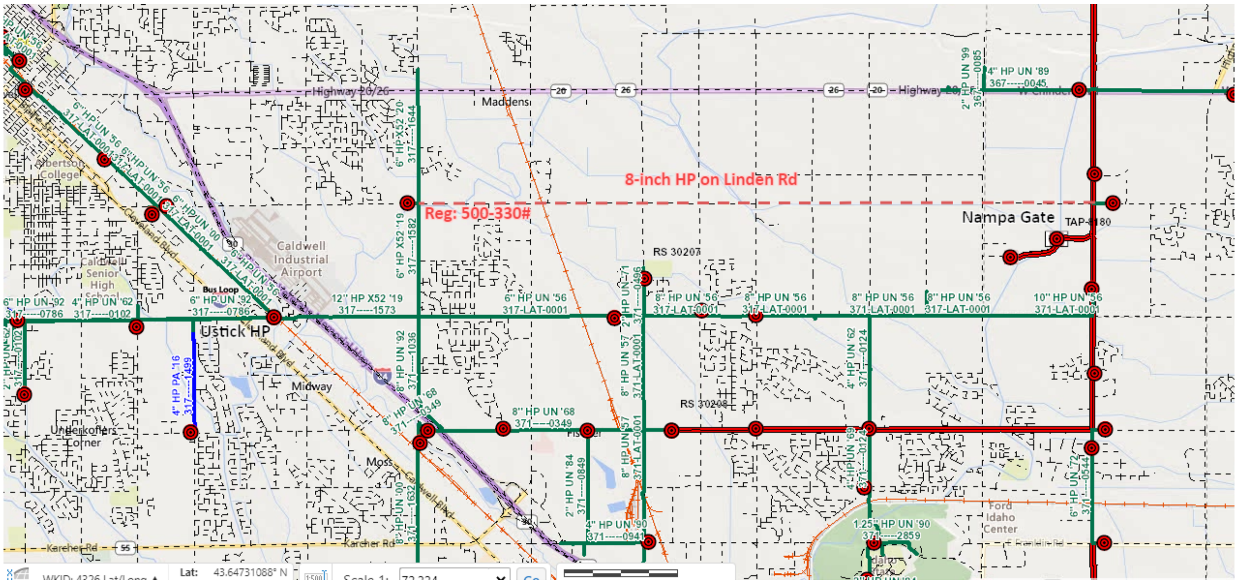

Figure 45: Canyon County Alternative Four

This option would bring the capacity up to 1,232,000 therms per day which would meet predicted growth through 2026 assuming Ustick Phase II has been completed. NPV cost for this option is estimated at $6,551,492.

Table 11: Canyon County Alternative Summary

Alternative #	Alternative Description	NPV Cost ($)	Alternative Capacity (th/day)	Alternative Capacity Gain (%)
1	Ustick Phase II	$3,255,074.59	1,032,000	0%
2	Ustick Phase III	$8,613,402.92	1,390,000	35%
3	Ustick Uprate	$1,300,000.00	1,178,000	14%
4	8-inch HP Extension north of Ustick	$6,551,492.43	1,232,000	19%

Capacity Enhancement Selected

Intermountain selected alternative one (Ustick Phase II) in the 2019 IRP. Alternative two (Ustick Phase III) has been selected to meet 2026 growth predictions. Alternatives one and two provide the highest capacity to the AOI and continues upon Intermountain's long term planning for the Ustick HP system to operate at 500 psig. Additionally, the Company determined that constructing a new line with defined costs is preferable to the uprate option which has unknown costs and could have significant cost creep due to the uncertainty of pressure testing the vintage pipe. Ustick Phase II is currently in construction and will be completed by the end of 2021 and Ustick Phase III will begin design in 2022 with construction planned to be completed in 2023.

State Street Lateral

AOI Summary/System Dynamics

The State Street Lateral is a 16-mile stretch of high pressure, large diameter main that begins in Middleton and runs east along State Street serving the towns of Star, north Meridian, Eagle and into northern Boise. The lateral is fed directly from a gate station along with a back feed from another high-pressure pipeline from the south. Much of the pipeline is closely surrounded by residential and commercial structures that create a difficult situation for construction and/or large land acquisition, thus making a compressor station or Liquified Natural Gas (LNG) equipment less favorable.

Capacity Limiter

Due to significant growth in Boise and north of Boise this AOI requires a capacity enhancement by 2023 to meet IRP growth predictions. The current capacity limiter to this AOI is a 12-inch HP bottleneck on State Street and a 4-inch HP bottleneck on Linder Rd as shown in yellow in Figure 46 below.

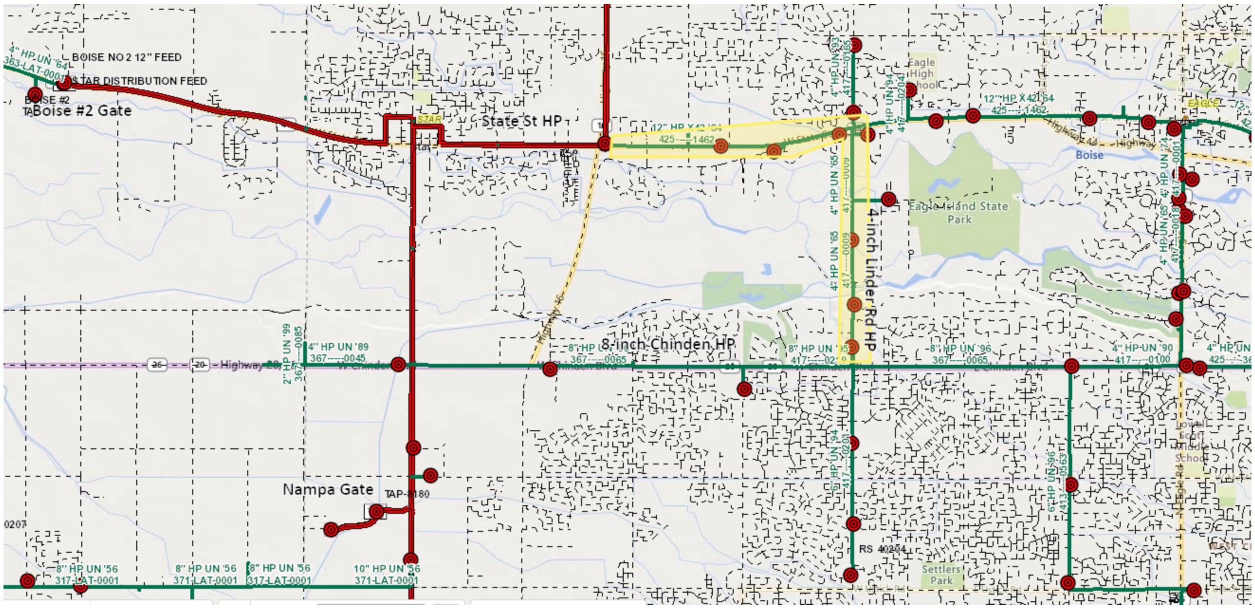

Figure 46: State Street Capacity Limiter

Capacity Enhancement Alternatives Considered

Alternative One: State Street Phase II Uprate

The first capacity enhancement alternative is to retest and then uprate the 2.3 miles of 12-inch HP steel pipe on State Street and 2 miles of 4-inch HP steel pipe on Linder Road and install a HP regulator station as shown in Figure 47. In addition, this project will require 2.3 miles of 6-inch plastic trunk line on State Street and a 2-mile 4-inch plastic trunk line on Linder Road paralleling the uprate to allow Intermountain to maintain service while the HP pipes are taken out of service for the retest and uprate.

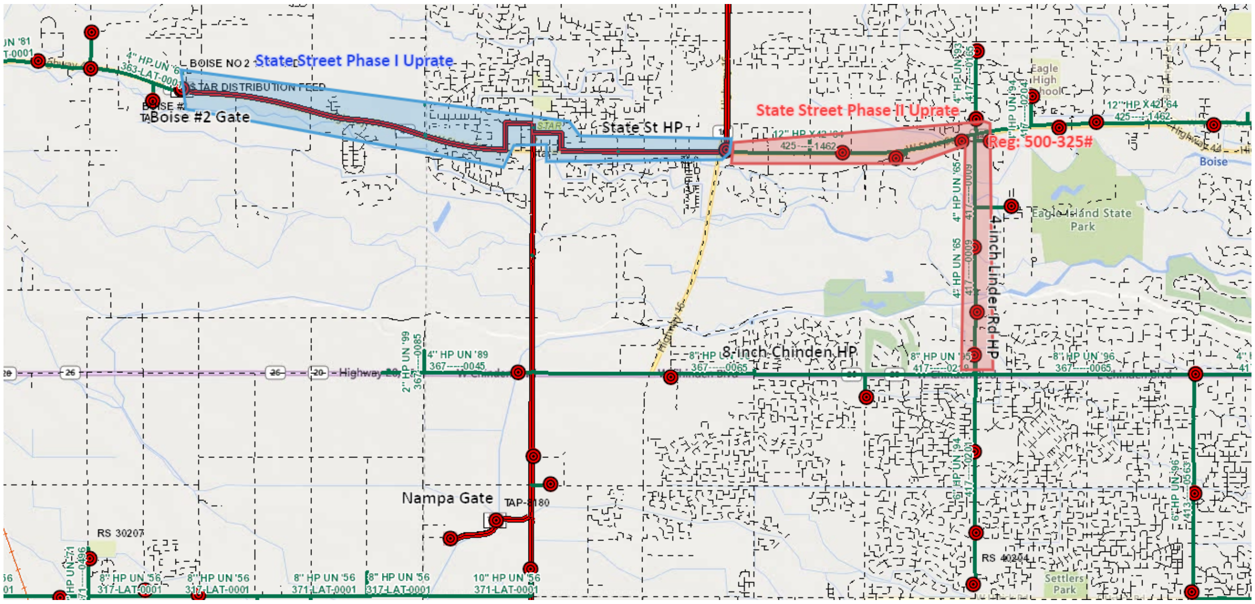

Figure 47: State Street Alternative One

This option would bring the capacity up to 950,000 therms per day which would meet predicted growth through 2026. Other considerations associated with this uprate include unknowns with pressure testing 1964 vintage pipe and the potential that this pipe could not pass uprate requirements to operate at a higher pressure. However, in 2019 the State Street Phase 1 uprate was successful without any major issues. Uprating this line would also bring the 12-inch HP on State Street to transmission classification which would increase future operations and maintenance costs. This project would allow Intermountain to retire several HP and DP regulator stations. NPV cost for this option is estimated at $2,030,592.

Alternative Two: Replace 12-inch HP pipe on State Street and Replace 4-inch HP pipe on Linder to operate at 500 psig MAOP

The second capacity enhancement alternative is to replace the 2.3 miles of 12-inch HP steel pipe on State Street and 2 miles of 4-inch HP steel pipe on Linder Road and install an HP regulator station as shown in Figure 48.

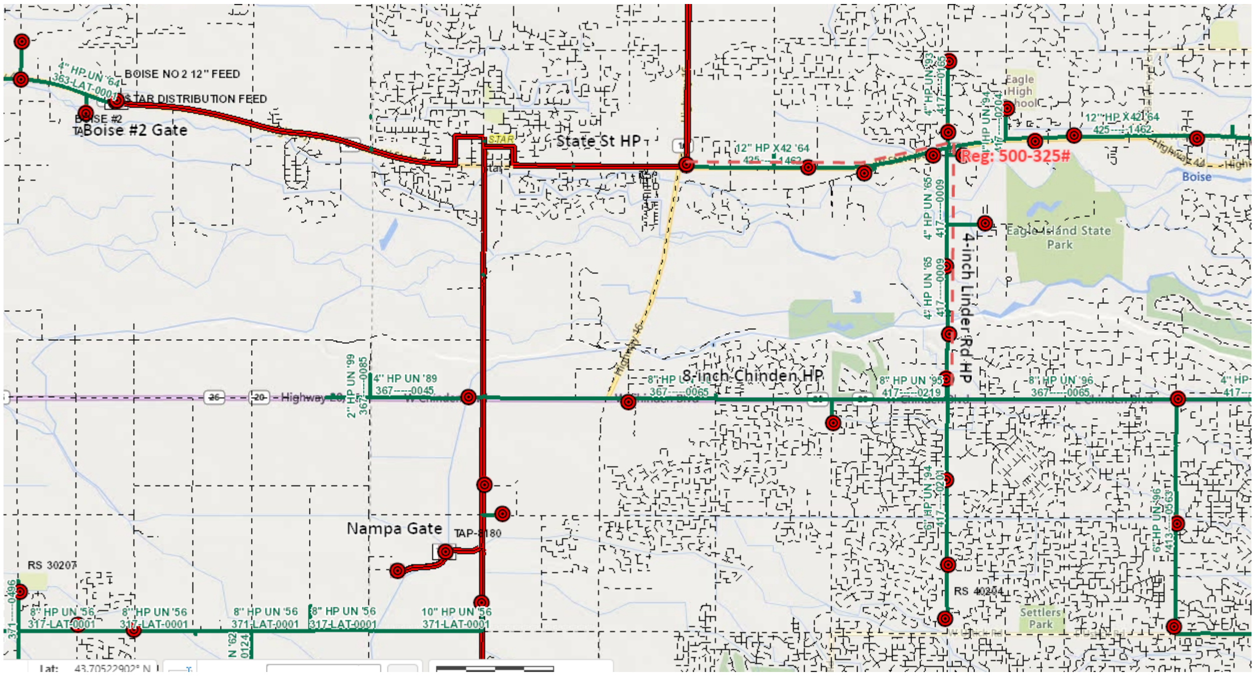

Figure 48: State Street Alternative Two

This option would bring the capacity up to 950,000 therms per day which would meet predicted growth through 2026. This project would allow IGC to retire a couple HP regulator stations and the new line would be designed to be an HP line. NPV cost for this option is estimated at $5,536,657.

Table 12: State Street Alternative Summary

Alternative #	Alternative Description	NPV Cost ($)	Alternative Capacity (th/day)	Alternative Capacity Gain (%)
1	State St. Phase II Uprate	$ 2,030,591.75	950,000	16%
2	Replace 12-inch HP on State St and Linder to operate at 500#	$ 5,536,656.65	950,000	16%

Capacity Enhancement Selected

Intermountain selected alternative one (State Street Phase II Uprate) to meet 2026 growth predictions. Alternative one is the lowest cost option, and because Intermountain recently pressure tested and uprated State Street Phase I (completed in 2019), the Company does not expect any issues associated with the pressure test or uprate. State Street Phase II Uprate is currently in design with construction planned to be completed in 2023.

Central Ada County

AOI Summary/System Dynamics

The Central Ada County AOI consists of high pressure and distribution pressure systems in an area of Ada County that has historically experienced high levels of growth and development. The system currently has high pressure supplied from Chinden Boulevard on the north side of the defined area and high pressure supplied from Victory Road on the south side of the defined area. Initially the continued growth demands between these two separate systems taxed the Chinden high pressure pipeline and the branch lines supplied from Chinden. In 2016 an 8-inch high pressure pipeline was installed on Cloverdale Road that connected the Victory system to a branch of the Chinden system, which alleviated the excess demand supplied from the Chinden pipeline. The connection between the two systems was an initial step in the long-term plan, and while the project successfully increased capacity in the area, the two systems are operating at different pressures and are currently disconnected through system valving.

Capacity Limiter

Due to significant growth in Boise and Meridian the Central Ada County AOI requires a capacity enhancement by 2022 to meet IRP growth predictions. The current capacity limiter for this AOI is a 10-inch and 8-inch HP bottleneck on Meridian Rd and Victory Rd directly downstream of the Meridian Gate as shown in yellow in Figure 49 below.

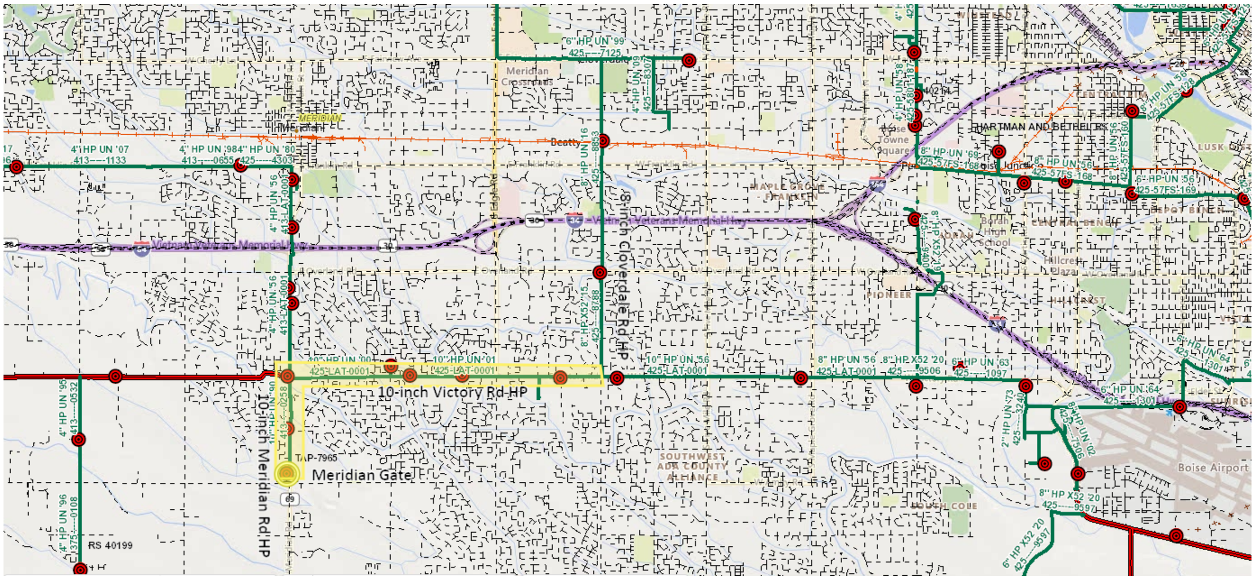

Figure 49: Central Ada County Capacity Limiter

Capacity Enhancement Alternatives Considered

Alternative One: 12-inch South Boise Loop

The first capacity enhancement alternative is to install 3.7 miles of 12-inch HP steel pipe on Cloverdale Road from the Kuna Gate north to Victory Road as shown in Figure 50. In addition, this project would require the Kuna gate station be upgraded and installation of a HP regulator station located at Victory Road and Cloverdale Road.

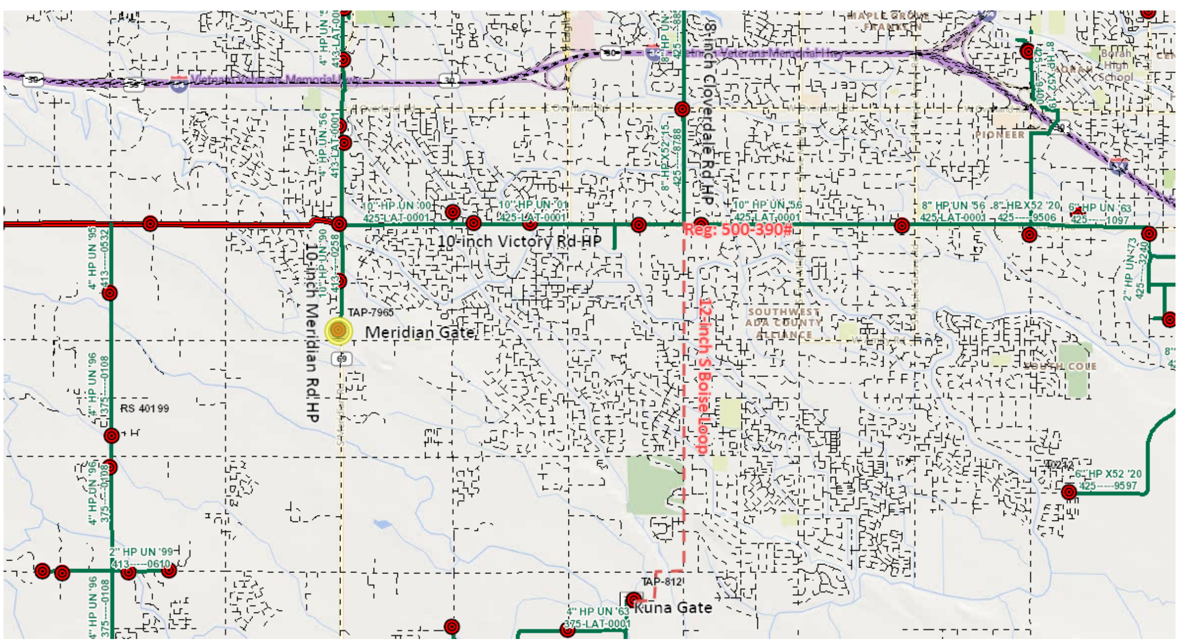

Figure 50: Central Ada County Alternative One

This option would bring the capacity up to 870,000 therms per day which would meet predicted growth through 2026. This project would provide a third feed into the Boise HP system and would loop the Nampa, Meridian and Kuna gates. NPV cost for this option is estimated at $10,321,364.

Alternative Two: Uprate 10-inch HP on Meridian and Victory Rd to operate at 500 psig

The second capacity enhancement alternative is to retest and then uprate 2.5 miles of 10-inch HP steel pipe on Meridian Road and Victory Road and install two new HP regulator stations as shown in Figure 51.

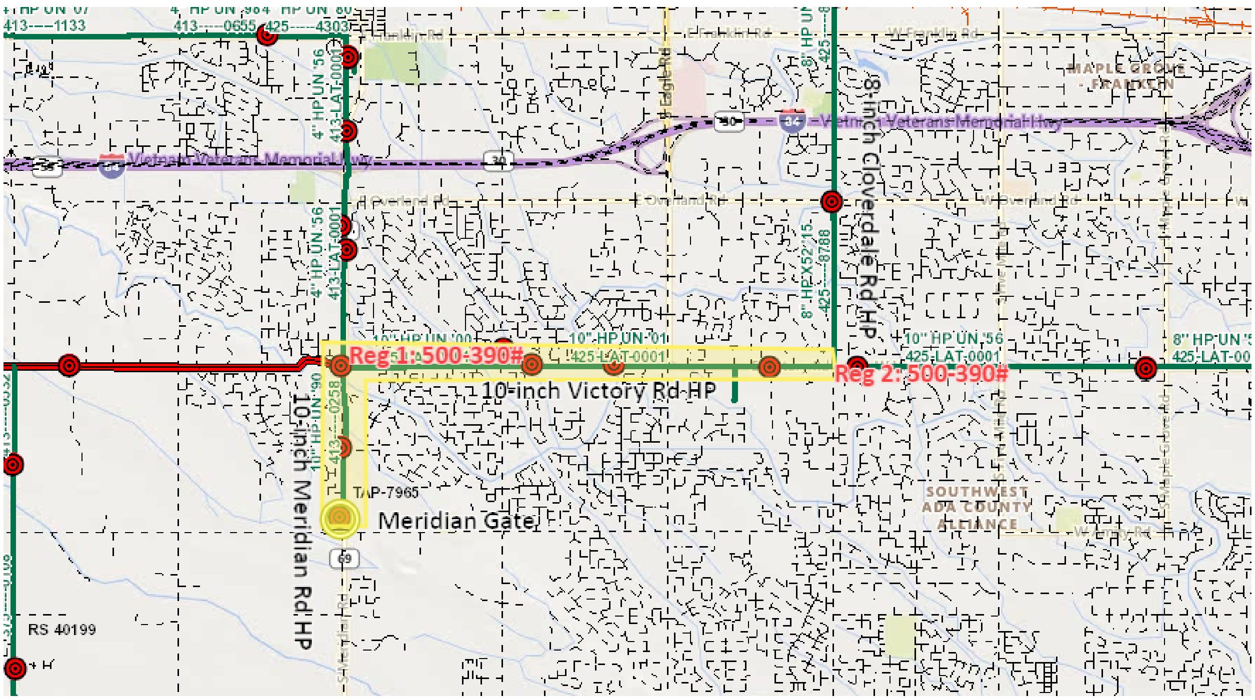

Figure 51: Central Ada County Alternative Two

This option would bring the capacity up to 817,000 therms per day which would meet predicted growth through 2026. Other considerations associated with this uprate include unknowns with pressure testing 1956 vintage pipe and the potential that this pipe could not pass uprate requirements to operate at a higher pressure. Uprating this line would also bring the 10-inch HP on Meridian Road and Victory Road to transmission classification which would increase future operations and maintenance costs. Another consideration to this uprate is both Meridian Road and Victory Road are high traffic areas and any work on this road would require extensive traffic control and detours which could impact city projects and would make this project very challenging to schedule and it would be expensive to restore excavations associated with the pressure test. NPV cost for this option is estimated at $2,034,763.

Alternative 3: Install compressor station on Victory Rd to boost pressure to 380 psig at Cloverdale

The third capacity enhancement alternative is to install a Compressor Station near Victory Road and Cloverdale Road as shown in Figure 52.

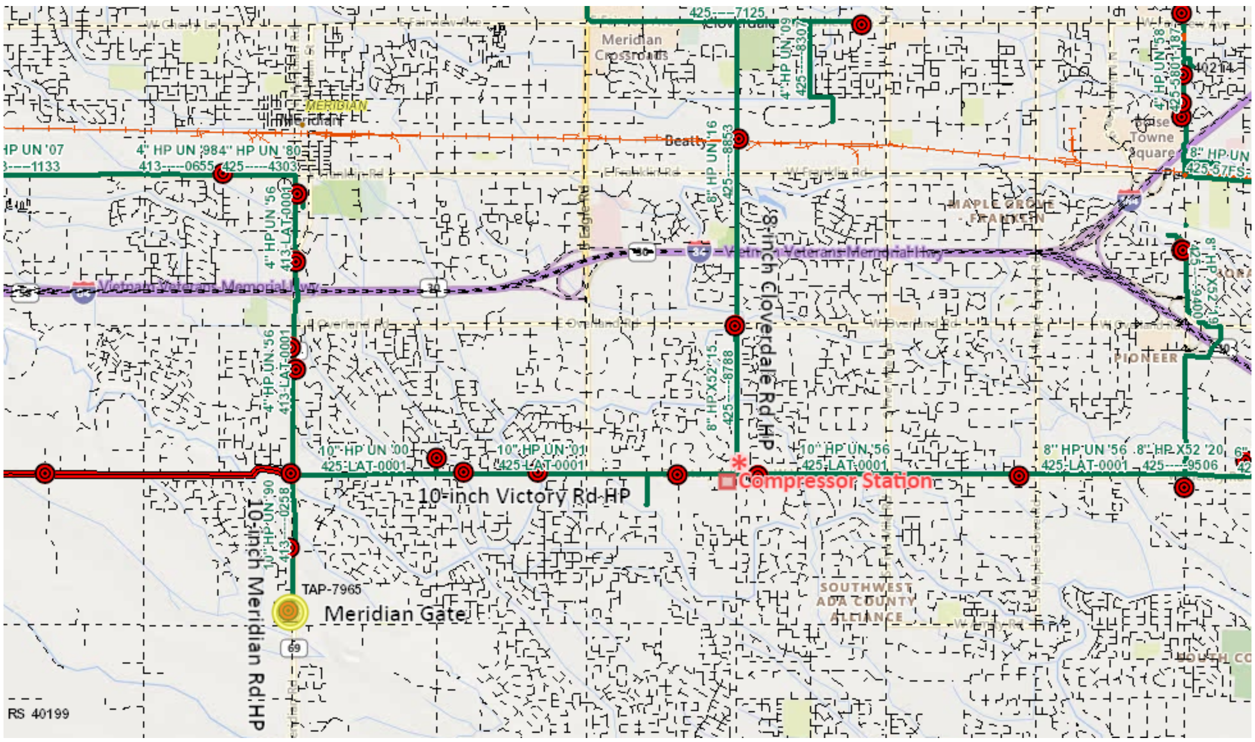

Figure 52: Central Ada County Alternative Three

This option would bring the capacity up to 817,000 therms per day which would meet predicted growth through 2026. Other considerations associated with installing a compressor station within city limits is it would be unlikely to find a two-acre site near the Company's existing 10-inch pipeline. To install a compressor, the Company would also need to obtain a compressor permit and it is uncertain if Intermountain could obtain a permit in this area. Intermountain would also have additional cost to run and maintain the compressor and a compressor provides no redundancy or system looping to Intermountain's system. NPV cost for this option is estimated at $12,807,602.

Table 13: Central Ada County Alternative Summary

Alternative #	Alternative Description	NPV Cost ($)	Alternative Capacity (th/day)	Alternative Capacity Gain (%)
1	12-inch South Boise Loop	$ 10,321,364.12	870,000	17%
2	Uprate 10-inch HP on Meridian and Victory Rd	$ 2,034,763.35	817,000	10%
3	Compressor Station at Victory and Cloverdale	$ 12,807,602.46	817,000	10%

Capacity Enhancement Selected

Intermountain selected alternative one (12-inch South Boise Loop) to meet 2026 growth predictions. When compared to alternative three, alternative one provides the highest capacity increase to the AOI, the lowest cost, and is the more feasible option. Additionally, the Company determined that constructing a new line with defined costs is preferable to the uprate option which has unknown costs and could have significant cost creep due to the uncertainty of pressure testing the vintage pipe. Furthermore, alternative one provides a significant benefit because upgrading the Kuna gate station will add a second feed to the Boise HP systems and provide looping to the HP system fed from the Nampa gate station. The 12-inch South Boise Loop is currently in design with construction planned to be completed in 2022.

Sun Valley Lateral

AOI Summary/System Dynamics

The Sun Valley Lateral is a 68-mile-long, 8-inch high pressure pipeline that has almost its entire demand at the far end of the lateral away from the source of gas. Obtaining land near this customer load center is either expensive or simply unobtainable. Throughout the years Intermountain has uprated and upgraded this existing lateral, and most recently installed the Jerome Compressor Station towards the south end of the lateral to maintain capacity and increase flow toward the north end of the system.

Capacity Limiter

Due to growth in Sun Valley this AOI requires a capacity enhancement to meet IRP growth predictions. The current capacity limiter for this AOI is the end of line pressure on the lateral to the Ketchum area as shown in yellow in Figure 53.

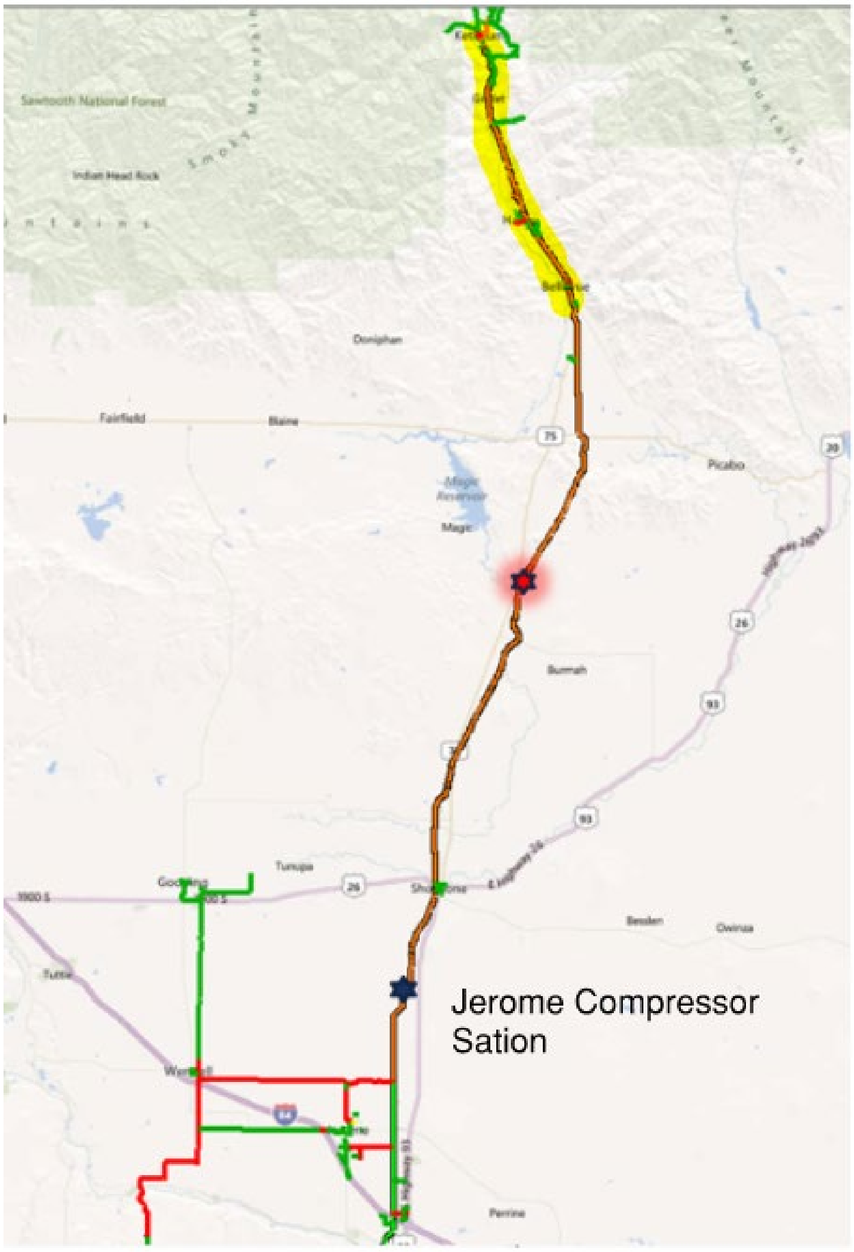

Figure 53: Sun Valley Capacity Limiter

Capacity Enhancement Alternatives Considered

Alternative One: Shoshone Compressor Station

The first and only capacity enhancement alternative considered is to install a second compressor station near Mile Post (MP) 32 near Shoshone on the Sun Valley Lateral as shown in Figure 54. This project was previously evaluated and selected in the Company's 2019 IRP filing.

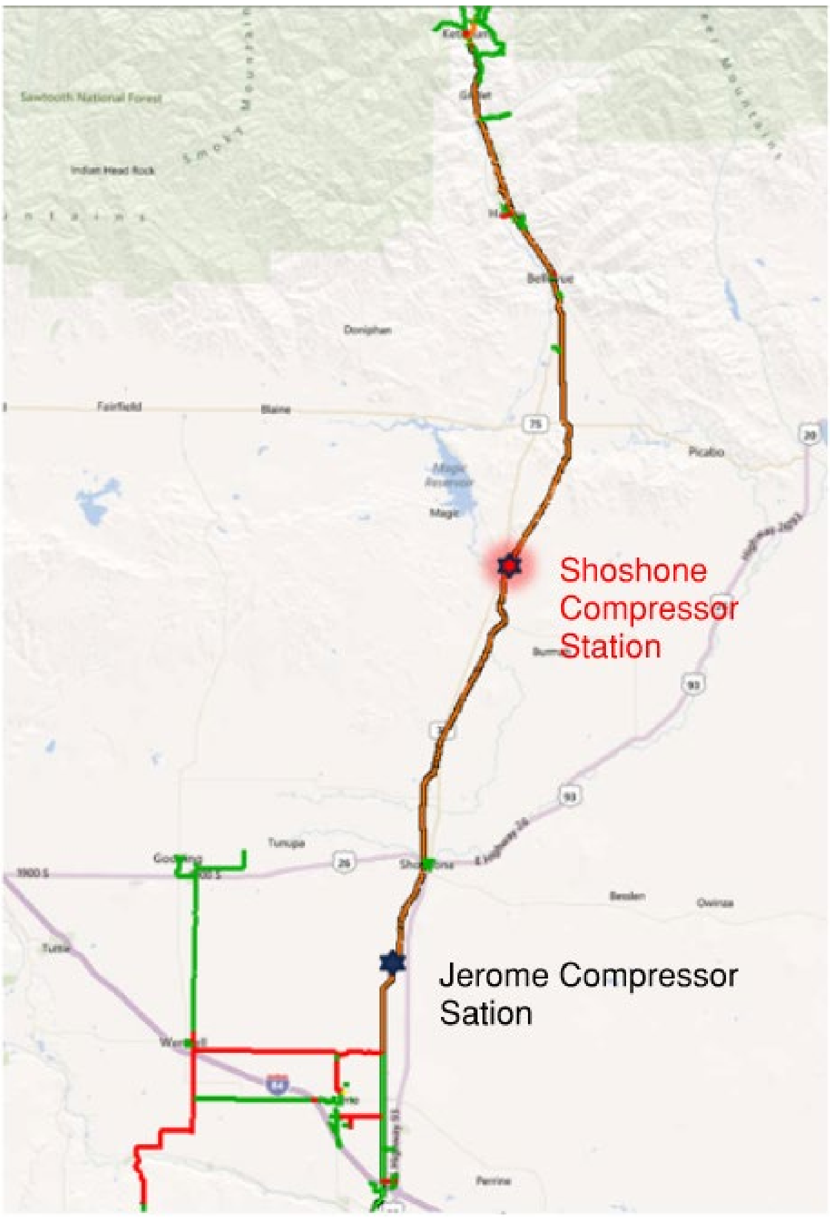

Figure 54: Sun Valley Lateral Alternative One

This option will bring the capacity up to 247,500 therms per day which will meet predicted growth through 2026. A compressor permit will be required for this project. IGC will have additional cost to run and maintain the compressor and a compressor provides no redundancy or system looping to Intermountain's system. NPV cost for this option is estimated at $5,807,602.

Table 14: Sun Valley Lateral Alternative Summary

Alternative #	Alternative Description	NPV Cost ($)	Alternative Capacity (th/day)	Alternative Capacity Gain (%)
1	Shoshone Compressor Station	$ 5,807,602.46	247,500	0%

Capacity Enhancement Selected

Intermountain selected alternative one (Shoshone Compressor Station) to meet 2026 growth predictions in the 2019 IRP. The Shoshone Compressor Station has been ordered and construction will be completed in the summer of 2022.

Idaho Falls Lateral

AOI Summary/System Dynamics

The Idaho Falls Lateral began as a 52-mile, 10-inch pipeline that originated just south of Pocatello and ended at the city of Idaho Falls. The IFL was later expanded farther to the north extending an additional 52 miles with 8-inch pipe to serve the growing towns of Rigby, Lewisville, Rexburg, Sugar City and Saint Anthony. As demand has continually increased along the IFL, Intermountain has been completing capacity enhancements for the past 25 years; including, compression (now retired), a satellite LNG facility, 40 miles of 12-inch pipeline loop, and 50.5 miles of 16-inch pipeline loop.

Capacity Limiter

Due to growth in Idaho Falls this AOI requires a capacity enhancement by 2023 to meet IRP growth predictions. The current capacity limiter for this AOI is the end of line pressure on the lateral to St. Anthony as shown in yellow in Figure 55.

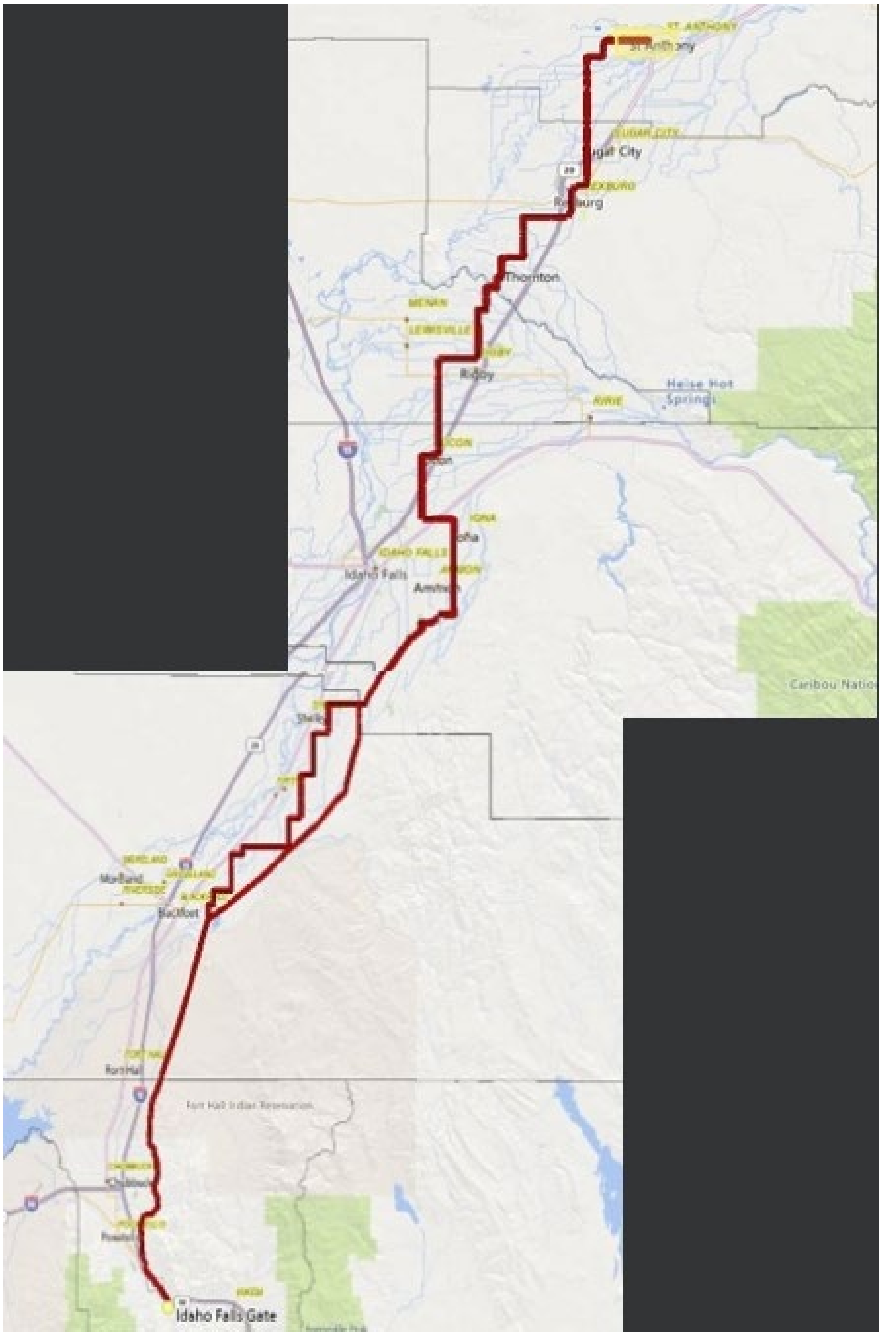

Figure 55: Idaho Falls Lateral Capacity Limiter

Capacity Enhancement Alternatives Considered

Alternative One: Blackfoot Compressor Station

The first enhancement alternative considered is to install a compressor station near Blackfoot, ID on the Idaho Falls lateral as shown in Figure 56.

3 Potential Compressor Locations:

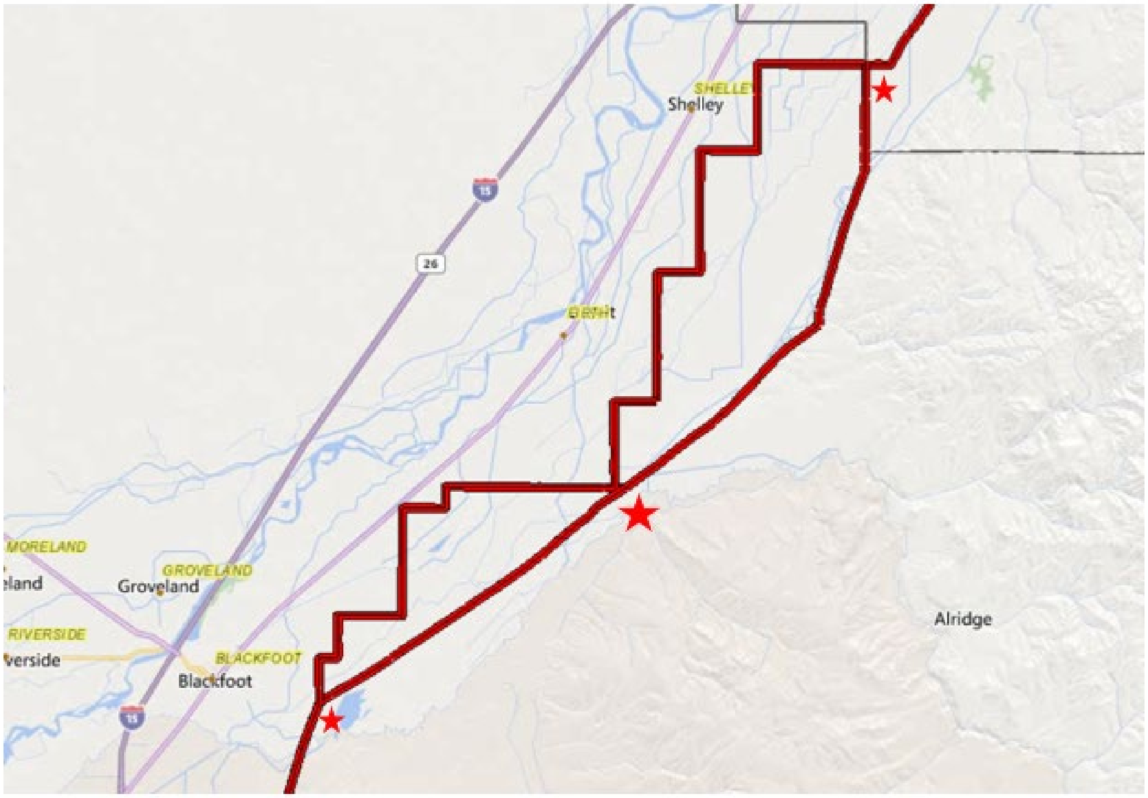

Figure 56: Idaho Falls Lateral Alternative One

This option would bring the capacity up to 1,093,000 therms per day (assumes Rexburg LNG is offline) which would meet predicted growth through 2026. A compressor permit would be required for this project. Intermountain will have additional cost to run and maintain the compressor and a compressor provides no redundancy or system looping to the Company's system. NPV cost for this option is estimated at $15,807,602.

Alternative Two: Phase VI with a second Satellite LNG tank at Rexburg

The second enhancement alternative considered is to install a second satellite LNG tank at Rexburg and install 10.5 miles of 16-inch pipe from Iona to Rigby as shown in Figure 57.

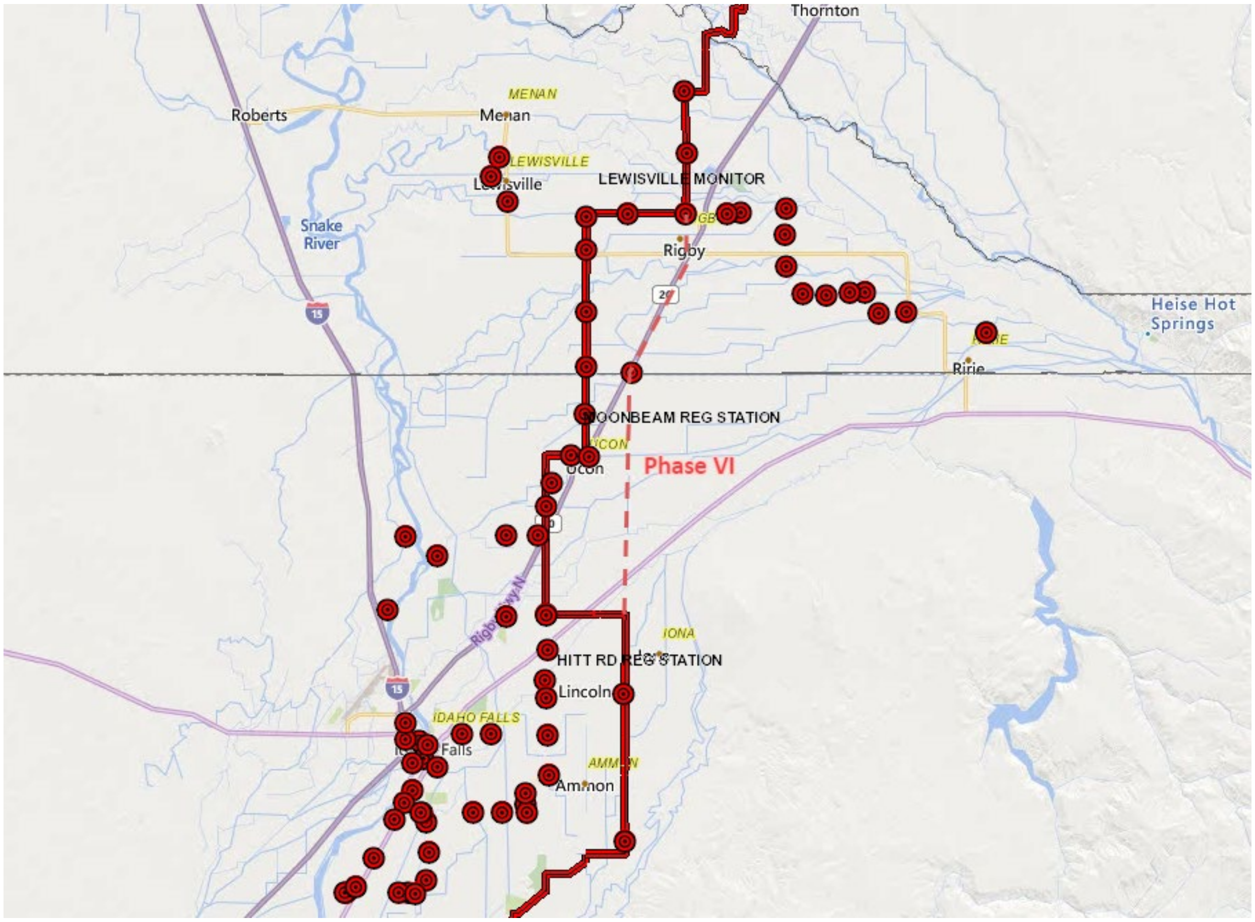

Figure 57: Idaho Falls Lateral Alternative Two

This option would bring the capacity up to 963,000 therms per day which would meet predicted growth through 2026. This option would provide looping and redundancy to the Company's system, but the Rexburg LNG site would still be required. NPV cost for this option is estimated at $23,246,006.

Table 15: Idaho Falls Lateral Alternative Summary

Alternative #	Alternative Description	NPV Cost ($)	Alternative Capacity (th/day)	Alternative Capacity Gain (%)
1	IFL Compressor Station	$ 15,807,602.46	1,093,000	21%
2	Phase VI with a second LNG tank at Rexburg	$ 23,246,006.08	963,000	7%

Capacity Enhancement Selected

Intermountain selected alternative one (Idaho Falls Lateral Compressor Station) to meet 2026 growth predictions. This is the lowest cost alternative and provides the largest capacity increase to the AOI. The Idaho Falls Compressor Station will be designed in 2022 and construction is planned for 2023.

With the decision to add the Blackfoot compressor station, Intermountain will need to keep the Rexburg satellite LNG facility as a peak shaving facility until 2023 when the Blackfoot compressor station comes online. After 2023, Intermountain plans to keep the Rexburg satellite LNG facility as an emergency backup to provide additional system reliability to the Idaho Falls lateral.

Summary

Table 16 provides a summary of the capacity enhancements selected by AOI based on the analysis above.

Table 16: AOI Capacity Summary and Timings

AOI →	Central Ada County		State Street Lateral		Canyon County		Sun Valley Lateral		Idaho Falls Lateral	
Year ↓	**Capacity (th/day)**	**Capacity Enhancement Selected**	**Capacity (th/day)**	**Capacity Enhancement Selected**	**Capacity (th/day)**	**Capacity Enhancement Selected**	**Capacity (th/day)**	**Capacity Enhancement Selected**	**Capacity (th/day)**	**Capacity Enhancement Selected**
2021	745,000	None	820,000	None	1,032,000	12-inch Ustick Phase II	200,000	None	904,000	None
2022	870,000	12-inch S Boise Loop	820,000	None	1,032,000	None	247,500	Shoshone Compressor Station	904,000	None
2023	870,000	None	950,000	State Street Phase II Uprate	1,390,000	12-inch Ustick Phase III	247,500	None	1,093,000	IFL Compressor Station
2024	870,000	None	950,000	None	1,390,000	None	247,500	None	1,093,000	None
2025	870,000	None	950,000	None	1,390,000	None	247,500	None	1,093,000	None
2026	870,000	None	950,000	None	1,390,000	None	247,500	None	1,093,000	None

Based on Table 16, the Company's planning horizon provides sufficient time to identify, budget, plan, design and construct projects to address capacity deficits. As part of the IRP process, Intermountain will revisit the identified capacity deficits and alternatives considered for capacity enhancement in its next IRP filling in 2023 and adjust its plan, as needed, to ensure reliable service to the Company's customers.

Load Demand Curves

The culmination of the demand forecasting process is aggregating the information discussed in the previous sections into a forecast of future load requirements. As the previous sections illustrate, the customer forecast, design weather, core market usage per customer data, large volume usage forecast, and demand side management are all key drivers in the development of the Load Demand Curves (LDC).

The IRP customer forecast provides a total Company daily projection through Planning Year (PY) 2026 and includes a forecast for each of the five AOIs of the distribution system. Each forecast was developed under each of three different customer growth scenarios: low growth, base case, and high growth.

The development of a design weather curve – which reflects the coldest anticipated weather patterns across the Company's service area – provides a means to distribute the core market's heat sensitive portion of Intermountain's load on a daily basis. Applying design weather to the residential and small commercial usage per customer forecast creates core market usage per customer under design weather conditions. That combined with the applicable customer forecast yields a daily core market load projection through PY26 for the entire company, as well as for each AOI. Similar to the above, normal weather scenario modeling was also completed.

As discussed in the Large Volume Customer Forecast Section, the forecast also incorporates the large volume Contract Demand from both a Company-wide perspective (interstate capacity) as well as from an AOI perspective (distribution capacity). When added to the core market figures, the result is a grand total daily forecast for both gas supply and capacity requirements including a break-out by AOI.

Peak day sendout under each of these customer growth scenarios was measured against the currently available capacity to project the magnitude, frequency and timing of potential delivery deficits, both from a Company perspective and an AOI perspective.

Once the demand forecasts were finished and the evaluation complete, the data was input into SENDOUT®, the Company's optimization model, for IRP modeling. The LDC incorporates all the factors that will impact Intermountain's future loads. The LDC is the basic tool used to reflect demand in the IRP Optimization Model.

It is important to note that the Load Demand Curves represent existing resources and are intended to identify potential capacity constraints and to assist in the long-term planning process. Plans to address any identified deficits will be discussed in the Planning Results Section of this report.

Customer Growth Summary Observations – Design Weather – All Scenarios

Idaho Falls Lateral

The Idaho Falls Lateral low growth scenario projects an increase in customers of 4,793 PY21 through PY26 (Jan 1, 2021 to Dec 31, 2026) which corresponds to an annualized growth rate of 1.32%. In the base case scenario customers are forecasted to increase by 9,493 (2.54% annualized growth rate), while the high growth scenario forecasts an increase of 12,330 customers (3.24% annualized growth rate).

Sun Valley Lateral

The Sun Valley Lateral low growth scenario (PY21 – PY26) projects an increase of 423 customers (0.55% annualized growth rate). In the base case scenario customers are projected to increase by 1,262 (1.61% annualized growth rate), while the high growth scenario shows an increase of 1,976 customers (2.46% annualized growth rate).

Canyon County Area

The low growth customer forecast (PY21 – PY26) for Canyon County Area reflects an increase of 11,536 customers (3.08% annualized growth rate). In the base case scenario customers are forecasted to increase by 15,324 (4.00% annualized growth rate), while the high growth scenario projects an increase of 21,038 customers (5.31% annualized growth rate).

State Street Lateral

The low growth customer forecast (PY21 – PY26) for the State Street Lateral reflects an increase of 6,039 customers (1.70% annualized growth rate). The base case scenario projects an increase of 12,008 customers (3.25% annualized growth rate), while the high growth scenario forecasts an increase of 17,977 customers (4.69% annualized growth rate).

Central Ada County

The low growth customer forecast (PY21 – PY26) for the Central Ada County reflects an increase of 6,026 customers (1.69% annualized growth rate). In the base case scenario customers are forecasted to increase by 6,300 (1.77% annualized growth rate), while the high growth scenario projects an increase of 6,574 customers (1.84% annualized growth rate).

Total Company

The Total Company (TC) low growth customer forecast (PY21 – PY26) projects an increase of 39,673 customers (1.64% annualized growth rate). The base case scenario forecasts an increase of 69,894 customers (2.80% annualized growth rate), while the high growth scenario projects an increase of 92,025 customers (3.62% annualized growth rate). Please note that the TC forecasts include the AOIs mentioned above as well as all other customers not located in a particular AOI.

Using the LDC analyses allows Intermountain to anticipate changes in future demand requirements and plan for the use of existing resources and the timely acquisition of additional resources.

Core Customer Distribution Sendout Summary – Design and Normal Weather – All Scenarios

Idaho Falls Lateral

Idaho Falls Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	7,313,723	7,393,050	7,467,578	7,538,923	7,591,011	7,603,492
Base	7,330,393	7,548,555	7,709,736	7,864,706	7,989,242	8,100,127
High	7,332,838	7,577,888	7,794,859	8,011,007	8,206,853	8,389,385

Idaho Falls Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	6,310,642	6,376,739	6,436,739	6,493,082	6,529,576	6,530,147
Base	6,325,284	6,510,959	6,645,887	6,774,348	6,873,508	6,958,959
High	6,327,432	6,536,445	6,719,460	6,900,777	7,061,442	7,208,740

Sun Valley Lateral

Sun Valley Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	2,317,982	2,325,822	2,334,490	2,341,042	2,341,667	2,338,517
Base	2,323,078	2,370,563	2,402,427	2,433,267	2,458,832	2,474,391
High	2,324,946	2,389,141	2,443,139	2,496,617	2,545,395	2,584,595

Sun Valley Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	1,949,889	1,956,046	1,962,477	1,966,853	1,965,431	1,960,246
Base	1,953,961	1,993,534	2,019,518	2,044,322	2,063,899	2,074,458
High	1,955,454	2,009,066	2,053,657	2,097,508	2,136,610	2,167,055

Canyon County Area

Canyon County Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	7,217,073	7,450,502	7,688,923	7,912,084	8,096,459	8,253,084
Base	7,234,310	7,627,230	7,911,261	8,198,271	8,468,104	8,678,267
High	7,240,200	7,696,801	8,070,845	8,499,019	8,897,187	9,255,869

Canyon County Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	5,570,583	5,746,227	5,922,908	6,087,259	6,218,398	6,326,719
Base	5,583,487	5,882,344	6,094,568	6,308,215	6,505,278	6,655,038
High	5,587,896	5,935,942	6,217,646	6,540,228	6,836,449	7,100,871

State Street Lateral

State Street Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	7,334,413	7,429,544	7,517,954	7,625,128	7,710,794	7,763,896
Base	7,345,613	7,557,350	7,763,234	7,976,172	8,184,892	8,398,836
High	7,356,812	7,685,157	8,008,514	8,327,217	8,658,989	9,033,776

State Street Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	5,656,133	5,723,436	5,782,335	5,855,320	5,908,973	5,936,781
Base	5,664,500	5,821,816	5,971,390	6,126,088	6,274,665	6,426,521
High	5,672,867	5,920,196	6,160,446	6,396,857	6,640,356	6,916,261

Central Ada County

Central Ada Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	7,341,834	7,420,571	7,526,646	7,620,523	7,696,622	7,792,613
Base	7,345,106	7,451,591	7,548,554	7,647,021	7,736,397	7,825,454
High	7,348,378	7,482,610	7,570,462	7,673,519	7,776,171	7,858,295

Central Ada Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	5,662,622	5,718,077	5,791,755	5,855,929	5,903,778	5,966,307
Base	5,665,067	5,741,949	5,808,695	5,876,377	5,934,445	5,991,679
High	5,667,511	5,765,820	5,825,636	5,896,825	5,965,113	6,017,051

Total Company

Total Company Design Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	50,028,542	50,613,073	51,242,752	51,880,441	52,413,238	52,886,679
Base	50,132,521	51,677,636	52,898,239	54,132,992	55,254,789	56,254,884
High	50,175,415	52,128,464	53,689,357	55,364,769	56,992,544	58,583,685

Total Company Normal Weather - Annual Core Market Distribution Sendout (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	40,246,788	40,686,882	41,145,192	41,606,486	41,964,189	42,266,236
Base	40,329,618	41,542,427	42,477,389	43,419,467	44,251,028	44,977,296
High	40,363,787	41,904,858	43,114,099	44,410,853	45,649,638	46,851,454

Projected Capacity Deficits – Design Weather – All Scenarios

Residential, commercial and industrial peak day load growth on Intermountain's system is forecast over the six-year period to grow at an average annual rate of 1.14% (low growth), 2.18% (base case) and 3.10% (high growth), highlighting the need for long-term planning. The next section illustrates the projected capacity deficits by AOI during the IRP planning horizon.

Idaho Falls Lateral LDC Study

When forecast peak day sendout on the Idaho Falls Lateral is matched against the existing peak day distribution capacity (90,400), peak day delivery deficit occurs under the base case scenario beginning in PY25.

Idaho Falls Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	0	0	0	0	0	0
Base	0	0	0	0	379	1,806
High	0	0	0	338	3,526	5,615

Sun Valley Lateral LDC Study

When forecasted peak day send out on the Sun Valley Lateral is matched against the existing peak day distribution capacity (20,000 Dth), peak day delivery deficits occur in PY21-PY26 under the base case scenario.

Sun Valley Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	327	397	344	430	118	171
Base	341	744	1,018	1,295	1,569	1,765
High	347	926	1,427	1,902	2,401	2,804

Canyon County Area LDC Study

When forecasted peak day send out for the Canyon County Area is matched against the existing peak day distribution capacity (103,200 Dth), peak day delivery deficits occur beginning in PY24 under the base case scenario.

Canyon County Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	0	0	0	0	0	1,435
Base	0	0	0	178	3,143	5,507
High	0	0	0	3,952	8,111	11,898

State Street Lateral LDC Study

When forecasted peak day send out for the State Street Lateral is matched against the existing peak day distribution capacity (82,000 Dth), a peak day delivery deficit occurs in PY26 under the base case scenario.

State Street Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	0	0	0	0	0	0
Base	0	0	0	0	0	604
High	0	0	0	0	2,592	6,586

Central Ada County LDC Study

When forecasted peak day send out for the Central Ada County is matched against the existing peak day distribution capacity (74,500 Dth), peak day delivery deficits occur in PY24-PY26 under the base case scenario.

Central Ada Design Weather - Peak Day Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	0	0	0	0	769	2,045
Base	0	0	0	84	1,262	2,452
High	0	0	0	373	1,706	2,809

Total Company LDC Study

The Total Company perspective differs from the laterals in that it reflects the amount of gas that can be delivered to Intermountain via the various resources on the interstate system. Hence, total system deliveries should provide at least the net sum demand – or the total available distribution capacity where applicable - of all the laterals/AOIs on the distribution system. The following table shows only peak day deficits based on existing resources in the year of 2026 due to the amount of transportation expiring. The solution for this shortfall is discussed further in the Upstream Modeling Results portion of the Planning Results section.

Total Company Design Weather - Peak Day SENDOUT (Core+LV-1) Deficit Under Existing Resources (Dth)						
Growth Scenario	2021	2022	2023	2024	2025	2026
Low	0	0	0	0	0	10,828
Base	0	0	0	0	0	42,147
High	0	0	0	0	0	63,449

2019 IRP vs. 2021 IRP Common Year Comparisons

This section compares the Total Company and each AOI during the three common years of the 2021 and 2019 IRP filings. In some cases, the distribution transportation capacity is forecast to be lower in the 2021 IRP than it was in the 2019 IRP. This is the result of differences in, or fine tuning of, planned capacity upgrades.

Total Company Design Weather/ Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2021	457,525	140,364	597,889
2022	472,744	140,779	613,523
2023	485,297	141,379	626,676

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2021	466,361	146,729	613,090
2022	481,569	147,522	629,091
2023	496,500	148,830	645,330

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE Over/(Under) 2019 IRP (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2021	(8,836)	(6,365)	(15,201)
2022	(8,825)	(6,743)	(15,568)
2023	(11,203)	(7,451)	(18,654)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Total Company Peak Day Deliverability Comparison

2021 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2021	2022	2023
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	341,043	341,043	332,043
Total Peak Day Deliverability	586,555	586,555	577,555

2019 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2021	2022	2023
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	297,043	297,043	297,043
Total Peak Day Deliverability	542,555	542,555	542,555

2021 IRP PEAK DAY FIRM DELIVERY CAPABILITY Over/(Under) 2019 (Dth)			
	2021	2022	2023
Maximum Daily Storage Withdrawals:			
Nampa LNG	0	0	0
Plymouth LS	0	0	0
Jackson Prairie SGS	0	0	0
Total Storage	0	0	0
Maximum Deliverability (NWP)	44,000	44,000	35,000
Total Peak Day Deliverability	44,000	44,000	35,000

Idaho Falls Lateral Design Weather/Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	90,400	62,926	21,281	84,207
2022	90,400	64,937	21,281	86,218
2023	109,300	66,479	21,331	87,810

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	88,400	63,154	21,469	84,623
2022	88,400	64,940	21,464	86,404
2023	94,000	66,728	21,681	88,409

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE

Over/(Under) 2019 IRP (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	2,000	(228)	(188)	(416)
2022	2,000	(3)	(183)	(186)
2023	15,300	(249)	(350)	(599)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Sun Valley Lateral Design Weather/ Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – SVL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	20,000	18,406	1,935	20,341
2022	24,750	18,809	1,935	20,744
2023	24,750	19,083	1,935	21,018

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	22,000	18,704	1,395	20,099
2022	22,000	19,114	1,395	20,509
2023	22,000	19,519	1,380	20,899

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE

Over/(Under) 2019 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	(2,000)	(298)	540	242
2022	2,750	(305)	540	235
2023	2,750	(436)	555	119

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Canyon County Area Design Weather/ Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	103,200	68,791	24,740	93,531
2022	103,200	72,756	24,790	97,546
2023	139,000	75,629	24,790	100,419

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	98,000	70,339	25,218	95,557
2022	106,000	74,041	25,245	99,286
2023	106,000	77,818	25,268	103,086

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE

Over/(Under) 2019 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	5,200	(1,548)	(478)	(2,026)
2022	(2,800)	(1,285)	(455)	(1,740)
2023	33,000	(2,189)	(478)	(2,667)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

State Street Lateral Design Weather/ Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout Core Market	Firm CD[1]	Total
2021	82,000	70,114	990	71,104
2022	82,000	72,284	990	73,274
2023	95,000	74,518	990	75,508

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout Core Market	Firm CD[1]	Total
2021	73,000	68,146	1,220	69,366
2022	73,000	69,973	1,220	71,193
2023	77,000	71,850	1,220	73,070

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE

Over/(Under) 2019 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	9,000	1,968	(230)	1,738
2022	9,000	2,311	(230)	2,081
2023	18,000	2,668	(230)	2,438

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Central Ada County Design Weather/ Base Case Growth Comparison

2021 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout Core Market	Firm CD[1]	Total
2021	74,500	70,145	850	70,995
2022	87,000	71,295	950	72,245
2023	87,000	72,457	950	73,407

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout Core Market	Firm CD[1]	Total
2021	70,000	67,932	1,448	69,380
2022	78,000	69,645	1,485	71,130
2023	78,000	71,401	1,530	72,931

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2021 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE

Over/(Under) 2019 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2021	4,500	2,213	(598)	1,615
2022	9,000	1,650	(535)	1,115
2023	9,000	1,056	(580)	476

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Resource Optimization

Introduction

Intermountain's IRP utilizes an optimization model that selects resource amounts over a pre-determined planning horizon to meet forecasted loads by minimizing the present value of resource costs. The model evaluates and selects the least cost mix of supply and transportation resources utilizing a standard mathematical technique called linear programming. Essentially, the model integrates/coordinates all the individual functional components of the IRP such as demand, supply, demand side management, transport and supply into a least cost mix of resources that meet demands over the IRP planning horizon, 2021 to 2026.

This section of the IRP will describe the functional components of the model, the model structure and its assumptions in general. At the end, model results will be discussed.

Functional Components of the Model

The optimization model has the following functional components:

- Demand Forecast by AOI
- Supply Resources, Storage and Supply, by Area
- Transportation Capacity Resources, Local Laterals and Major Pipelines, Between Areas
- Non-Traditional Resources such as Renewable Natural Gas
- Demand Side Management

Underlying these functional components is a model structure that has gas supply and demand by area of interest with gas transported by major pipelines and local distribution laterals between supply and demand. This model mirrors, in general, how Intermountain's delivery system contractually and operationally functions. In previous IRPs, Intermountain utilized Boris Metrics to perform the optimization modeling. Beginning with this IRP, the Company is utilizing its in-house expertise to perform the optimization modeling to streamline processes. The optimization modeling results have yielded comparable results.

Demand SENDOUT® Optimization Model

Resource integration is one of the final steps in Intermountain's IRP process. It involves finding the reasonable least cost and least risk mix of reliable demand and supply side resources to serve the forecasted load requirements of the core customers. The tool used to accomplish this task is a computer optimization model known as SENDOUT®.

SENDOUT® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources and optimizing their utilization at the lowest net present cost over the entire planning period for a given demand forecast. SENDOUT® permits the Company to develop and analyze a variety of resource portfolios quickly and to determine the type, size, and timing of resources best matched to forecast requirements.

Model Structure

To develop a basic understanding of how gas supply flows from the various receipt points to ultimate delivery to the Company's end-use customers, a graphical representation of Intermountain's system is helpful. Figure 2 (page 6) is a map of the Intermountain system. Generally, gas flows from supply areas such as Canada and the Rockies, and from storage in Washington state and Clay Basin in the Rockies region, across major pipelines to southern Idaho. In southern Idaho, the gas is transported to demand areas by local distribution laterals. The model utilizes a simplified structure of the Figure 2 map.

Figure 58 presents the model of system flows by major pipelines and supply areas. The Figure also shows four major supply receipt areas including Sumas, Stanfield, AECO and Rockies with ultimate delivery to Intermountain in southern Idaho.

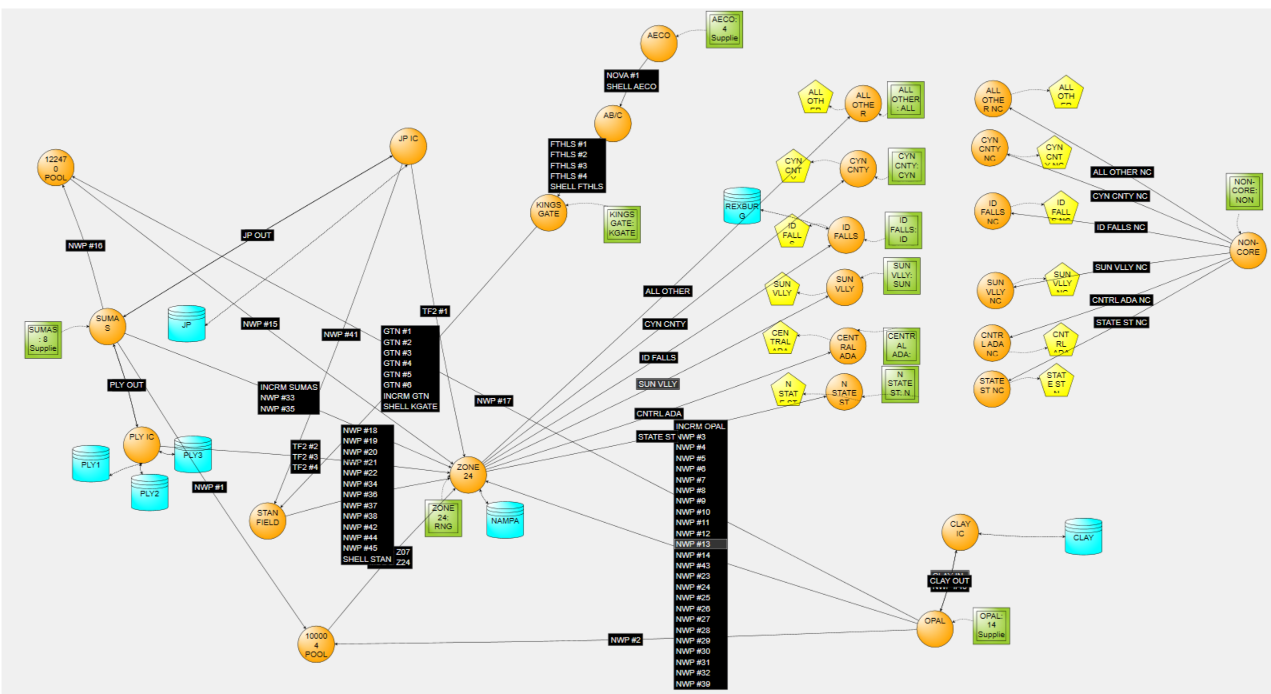

Figure 58: IGC Natural Gas Modeling System Map

Supplies from the supply receipt areas are then delivered and aggregated at the IGC pool (Zone 24) where they are allocated to be delivered to the appropriate demand areas, or AOIs, by local distribution laterals as depicted in Figure 58.

Demand Area Forecasts

As previously discussed in the Load Demand Curves Section beginning on page 118, demand is forecasted using a unique load demand curve for each AOI. The sum of all six areas is equal to system gas demand. A map of the AOIs is included at the end of the Executive Summary Section on page 6. Intermountain forecasts peak demand to be 457,525 dth for RS (Residential) and GS (commercial) customers and 140,364 dth for LV-1 and T-4 customers in 2021 and growing to 522,487 dth and 143,374 dth in 2026, respectively.

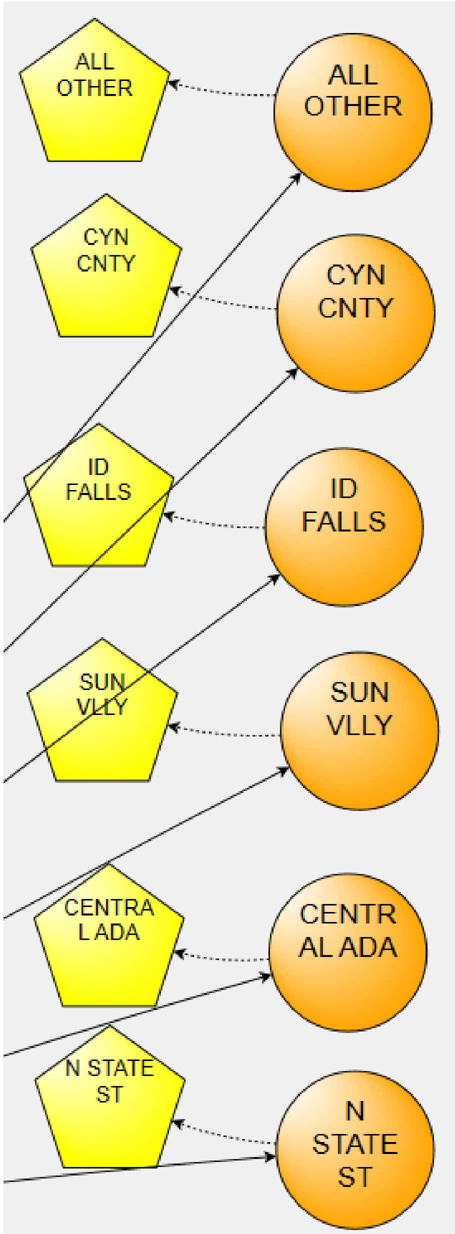

Figure 59: IGC Laterals from Zone 24

The demand areas listed in Figure 59 are:

- Central Ada Area
- State Street Lateral
- Canyon County Region
- Idaho Falls Lateral
- Sun Valley Lateral
- All Other

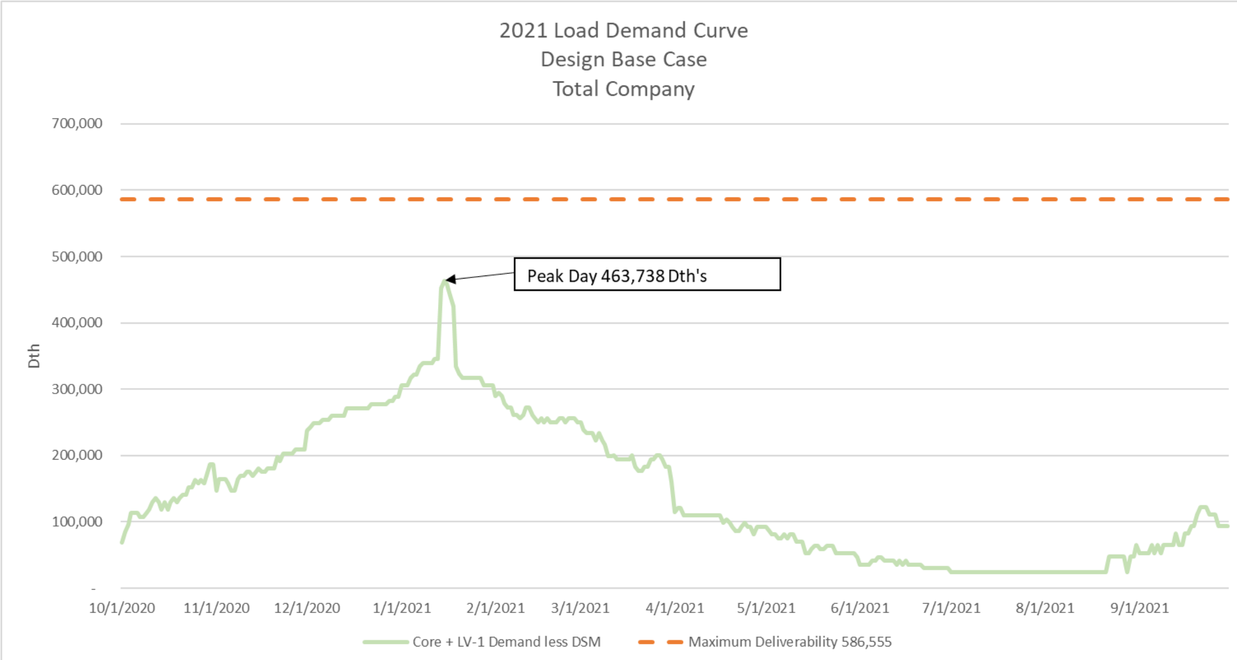

Figure 60: Total Company Design Base 2021

The model is also programmed to recognize that Intermountain must provide gas supply and both interstate and distribution transportation for its core market and LV-1 customers, but only firm distribution capacity for T-4 customers. Figure 60 shows the core market demand with LV-1 customers less DSM, compared to the maximum upstream distribution Intermountain has to serve the demand. T-3 customers are served on an interruptible basis and therefore are not included in the analysis. Because Intermountain is contractually obligated to provide a certain level of firm transport capacity for its firm transporters each day, the industrial demand forecast for these customers is not load-shaped but reflects the aggregate firm industrial CD for each class by specific AOI for each period in the demand curve.

Scenarios for the load demand curves include specific weather and customer growth assumptions which are described elsewhere in this IRP. The weather scenarios are normal weather and design weather. Customer growth is separated into low growth, base case and high growth scenarios. This results in a total of six scenarios. The combination of the design weather and base case scenarios (Design Base) form the critical planning scenario for the IRP and will be reported as the main optimization results. Other scenarios are also available, but all others, except for the combined scenarios of design weather and high growth, would have sufficient resources as long as the Design Base does.

Supply Resources

Resource options for the model are of two types: supply resources and storage contracts, which, from a modeling standpoint, are utilized in a similar manner. All resources have beginning and ending years of availability, periods of availability, must take usage, period and annual flow capability and a peak day capability. Supply resources have price/cost information entered in the model over all points on the load demand curve for the study period. Additionally, information relating to storage resources includes injection period, injection rate, fuel losses and other storage related parameters.

Each resource must be sourced from a specific receipt point or supply area. For example, Figure 61 shows the supply area (in green) providing gas at the Opal interconnect. One advantage of citygate supplies and certain storage withdrawals is that they do not utilize any of Intermountain's existing interstate capacity as the resource is either sited within a demand area or are bundled with their own specific redelivery capacity. Supply resources from British Columbia are delivered into the NWP system at Sumas while Rockies supplies are received from receipt pools known as North of Green River and South of Green River. Alberta supplies are delivered to Northwest's Stanfield interconnect utilizing available upstream capacity - the available quantity at Stanfield is the limiting factor regardless of capacity of any single upstream pipeline. Each supply resource utilizes transport that reaches Zone 24 from its supply receipt node.

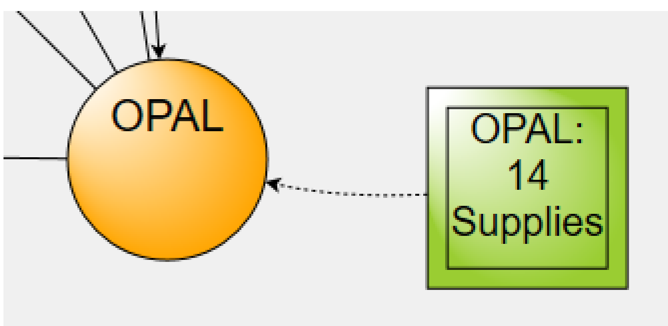

Figure 61: IGC Supply Model Example

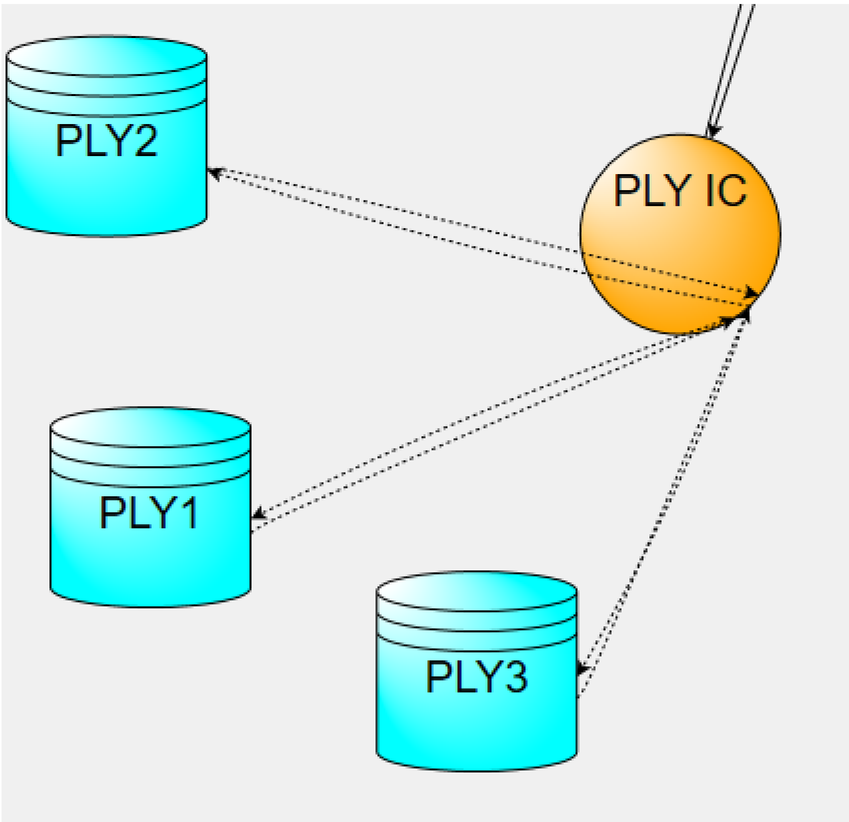

Figure 62: IGC Storage Model Example

Figure 62 shows an example of the SENDOUT modeling perspective of Storage contracts connected to the rest of the system. From a model perspective, the DSM resources are considered a subset of supply resources and fill demand needs on the applicable AOI by offsetting other supply resources when the cost of such is less than other available resources. Figure 63 shows the DSM applied directly to the AOI. These DSM resources have costs and resource capacity that were determined by a separate DSM analysis as detailed in the Core Market Energy Efficiency Section (starting on page 81).

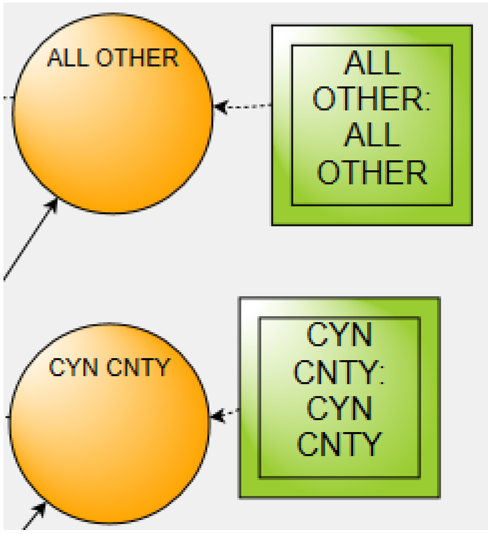

Figure 63: IGC DSM Model Example

Transport Resources

Transport resources represent the way supplies flow from specific receipt areas to Intermountain’s ultimate receipt pool at Zone 24, where all supplies are pooled for ultimate delivery into the Company’s various Areas of Interest. Transport resources reflect contracts for interstate capacity, primarily on Northwest Pipeline, but also for the three separate pipelines that deliver gas supplies to Northwest’s Stanfield interconnect from AECO. Certain supplies, such as Rexburg LNG, are already located on Intermountain’s distribution system on a specific demand lateral and therefore do not require interstate pipeline transportation. The system representation recognizes Northwest’s postage stamp pricing and capacity release as well as the per mile rates seen on the transportation contracts from AECO to Stanfield.

Transport resources have a peak day capability and are assumed to be available year-round unless otherwise noted. Transport resources can have different cost and capabilities assigned to them as well as different years of availability. An example of SENDOUT®’s transportation model is seen in Figure 64.

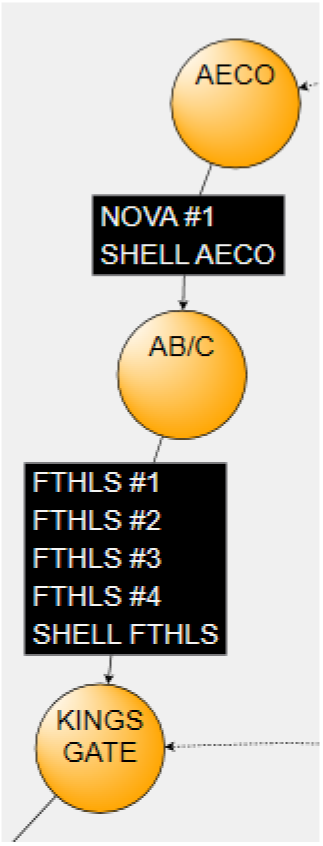

Figure 64: IGC Transport Model Example

Model Operation

The selection of a least cost mix of resources, or resource optimization, is based on the cost, availability and capability of the available resources as compared to the projected loads at each of the AOIs. The model chooses the mix of resources which meet the optimization goal of minimizing the present value cost of delivering gas supply to meet customer demand. The model recognizes contractual take commitments and all resources are evaluated for reasonableness prior to input. Both the fixed and variable costs of transport, storage and supply can be included. The model will exclude resources it deems too expensive compared to other available alternatives.

The model can treat fixed costs as sunk costs for certain resources already under contract. If a fixed cost or annual cost is entered for a resource, the model can include that cost for the resource in the selection process, if directed, which will influence its inclusion vis-à-vis other available resources. If certain resources are committed to and the associated fixed cost will be paid regardless of the level of usage, only the variable cost of that resource is considered during the selection process, but the fixed cost is included in the summary. However, any new resources, which would be additional to the resource mix, will be evaluated using both fixed and variable costs. For cost summary purposes, fixed costs were included, whether sunk or included in the least cost present value optimization, to approximate the expected total costs for transport and supply.

Special Constraints

As stated earlier, the model minimizes cost while satisfying demand and operational constraints. Several constraints specific to Intermountain's system were modeled.

- Nampa LNG storage does not require redelivery transport capacity. Both SGS and LS storage are bundled with firm redelivery capacity; transportation utilization of this capacity matches storage withdrawal from these facilities. SGS, LS and Clay Basin refills are typically injected in the summer.
- All core market and LV-1 sales loads are completely bundled.
- T-4 customer transportation requirements utilize only Intermountain's distribution capacity. The T-4 firm CD is input as a no-cost supply delivered at Zone 24. T-3 customers are served on an interruptible basis and therefore not included in the analysis.
- Traditional resources destined for a specific AOI must be first transported to Zone 24 and then to the AOI.
- Non-traditional resources such as mobile LNG that are designed to serve a specific lateral can only be employed when lateral capacity is otherwise fully utilized.

Model Inputs

The optimization model utilizes these three inputs which do not vary by scenario:

- Transport Resources
- Supply Resources by Year
- Supply Price Format for Supply Resources by Yearly Periods

The model selects the best cost portfolio based on least cost of present value resource costs over the planning horizon. However, the model also has been designed to comply with operational and contractual constraints that exist in the real world (i.e. if the most inexpensive supply is located at Sumas, the model can only take as much as can be transported from that point; additionally, it will not take inexpensive spot gas until all constraints related to term gas or storage are fulfilled). For the results to provide a reasonable representation of actual operations, all existing resources that have committed must-take contracts are assigned as "must run" resources. The Company's minimal commitment for summer must-take supplies means that those supplies do not exceed demand. In the real world, having excess summer supplies results in selling those volumes into the market at the then prevailing prices whereas the model only identifies those volumes and related cost. Please note that this level of sales is small relative to total supply.

Another important assumption relates to the supply fill or balancing options. Supply fill resources provide intelligence as to where and how much of any deficit in any existing resource exists. The model treats these resources as economic commodities (i.e. the availability is dynamic up to its maximum capability). The model can select available fill supply at any basin, for any period and in any volume that it needs to help fill capacity constraints. To ensure that the model provides results that mirror reality, these supplies have been aggregated into peak, winter (base and day), summer (base and day) and annual price periods. Base gas is typically a longer-term contract than day gas. Each aggregated group has a different relative price with the peak price being the highest, and the summer price being the lowest. Additionally, since term pricing is normally based on the monthly spot index price, no attempt has been made to develop fixed pricing for fill resources, but each such resource includes a reasonable market premium if applicable.

All transport resources are labeled to specify the pipeline as well as a contract number associated with the transport contract in the Transport table in Exhibit 8. Capability and pricing are included by resource. Figure 65 provides a sample of the input information provided in Exhibit 8. The main inputs for each transportation contract are provided. This includes the Monthly Daily Quantity (MDQ), D1 rate, Transportation Rate, and Fuel percentage. The MDQ is the contract's specific maximum allowable gas in dekatherms the Company can transport on a given day. The D1 rate is the reservation rate for the transport contract. The transportation rate is the rate charged to the volumes flowed if the pipeline was utilized for the day. The fuel loss percentage is the statutory percent of gas based on the tariff from the pipeline that is lost and unaccounted for from the point of where the gas was purchased to the delivery point.

Transport	Data Item	2020: Oct	2020: Nov	2020: Dec	2021: Jan	2021: Feb	2021: Mar
FTHLS Contract 1	First of Month MDQ by Transport (000s dths)	7.105	7.105	7.105	7.105	7.105	7.105
FTHLS Contract 1	Rate: D1 by Transport ($/Mmbtu)	$ 2.80	$ 2.71	$ 2.80	$ 2.80	$ 2.53	$ 2.80
FTHLS Contract 2	First of Month MDQ by Transport (000s dths)	87.639	87.639	87.639	87.639	87.639	87.639
FTHLS Contract 2	Rate: D1 by Transport ($/Mmbtu)	$ 2.80	$ 2.71	$ 2.80	$ 2.80	$ 2.53	$ 2.80
FTHLS Contract 3	First of Month MDQ by Transport (000s dths)	0.000	22.094	22.094	20.941	20.941	20.941
FTHLS Contract 3	Rate: D1 by Transport ($/Mmbtu)	$ 2.80	$ 2.71	$ 2.80	$ 2.80	$ 2.53	$ 2.80
FTHLS Contract 4	First of Month MDQ by Transport (000s dths)	7.387	7.387	7.387	7.387	7.387	7.387
FTHLS Contract 4	Rate: D1 by Transport ($/Mmbtu)	$ 2.80	$ 2.71	$ 2.80	$ 2.80	$ 2.53	$ 2.80
GTN Contract1	First of Month MDQ by Transport (000s dths)	7.158	7.158	7.158	7.158	7.158	7.158
GTN Contract1	Fuel by Transport (%)	0.005	0.005	0.005	0.005	0.005	0.005
GTN Contract1	Rate: D1 by Transport ($/Mmbtu)	$ 4.17	$ 4.04	$ 4.17	$ 4.17	$ 3.77	$ 4.17
GTN Contract1	Rate: Transportation by Transport ($/Mmbtu)	$ 0.14	$ 0.13	$ 0.14	$ 0.14	$ 0.12	$ 0.14

Figure 65: Transport Input Summary

The price forecast is provided in the Traditional Supply Resources section.

Model Results

The optimization model results for the design weather, base price and base case scenario for the years 2021 through 2026 are presented and discussed below. The results of the model are summarized, for each scenario using the tables described below:

- Upstream Transportation and Lateral Summary Tables (Exhibit 9)
- Annual Transportation Resources Results (Exhibit 8)
- Annual Supply Resources Results (Exhibit 8)

Model Output for Design Base Scenario

The following provides a description of the information presented by type of output tables in Exhibit 9 and the implication for the Design Base scenario.

Exhibit 9 provides a snapshot by year of whether a specific lateral to an AOI needs an expansion and whether that expansion is a preferred one as opposed to a fill or an alternative lateral resource. Figure 66 shows the first year of the Upstream Transportation and Lateral Summary, for the Design Base scenario.

The “Total Peak Day” is the peak day that includes RS, GS, LV-1, and T-4 customers, since the distribution system must maintain reliability for these customers. The “Existing Capacity” column is the amount of deliverability Intermountain has on the distribution system for each area of interest. The “% of Existing Capacity” is the percentage of total peak day compared to existing capacity. The “Existing + Upgrade Capacity” column is the amount of deliverability Intermountain has on the distribution system for each area of interest after the upgrades discussed in the Capacity Enhancements section take place. The “% of Existing + Upgrade Capacity” is the percentage of total peak day compared to the upgraded capacity. The table for the base year through the final year in the planning horizon displays these conditions for the Design Base scenario (Exhibit 9).

2021	Base Year (Dth)					
Area of Interest	Total Peak Day	Existing Capacity	% of Existing Capacity	Planned Capacity Upgrade	Existing + Upgrade Capacity	% of Existing + Upgrade Capacity
IDAHO FALLS	84,207	90,400	93%	-	90,400	93%
SUN VALLEY	20,341	20,000	102%	-	20,000	102%
CANYON COUNTY	93,531	103,200	91%	-	103,200	91%
STATE STREET	71,104	82,000	87%	-	82,000	87%
CENTRAL ADA	70,995	74,500	95%	-	74,500	95%
ALL OTHER	257,711					

Figure 66: Lateral Summary by Year

Figure 67 shows the Annual Traditional Supply Resources Results from Exhibit 8 for the Design Base scenario for the major supply areas. DSM is also provided in Exhibit 8 in a separate table.

Annual Traditional Supply Resources Results							
Supply Group	Data Item	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
AECO	Commodity Cost ($000)	$72,663.60	$65,579.13	$52,853.27	$47,800.77	$49,398.63	$58,827.48
AECO	Take: Monthly by Supply (MDT)	30,403	27,802	24,062	22,266	22,430	25,375
AECO	Unit Commodity Cost ($/dth)	$ 2.39	$ 2.36	$ 2.20	$ 2.15	$ 2.20	$ 2.32
OPAL	Commodity Cost ($000)	$33,115.46	$46,590.63	$36,740.13	$29,578.37	$39,326.21	$12,261.24
OPAL	Take: Monthly by Supply (MDT)	11,291	15,540	12,349	9,915	13,057	3,907
OPAL	Unit Commodity Cost ($/dth)	$ 2.93	$ 3.00	$ 2.98	$ 2.98	$ 3.01	$ 3.14
SUMAS	Commodity Cost ($000)	$30,513.92	$25,921.78	$42,425.67	$54,240.21	$54,313.33	$61,033.39
SUMAS	Take: Monthly by Supply (MDT)	10,833	11,118	19,318	24,674	22,303	23,049
SUMAS	Unit Commodity Cost ($/dth)	$ 2.82	$ 2.33	$ 2.20	$ 2.20	$ 2.44	$ 2.65

Figure 67: Annual Traditional Supply Resources Results

The supply resources in the detailed output tables have the following output parameters:

- Total Commodity Cost by year
- Monthly Supply by basin and type of Supply
- Unit Commodity Cost

The total commodity cost is the total dollar amount spent on gas purchased at the supply group location on an annual basis. The monthly supply is the amount of gas purchased at the supply group. The unit commodity cost is the dollar per dekatherm that was spent on purchasing the gas at each supply location. Exhibit 8 also includes the daily purchase amount by supply location for design day.

A sample of the Annual Transportation Resources Results from Exhibit 8 for the Design Base scenario is displayed Figure 68. Exhibit 8 also provides transportation results by month for the planning horizon.

Annual Transportation Resources Results							
Transport Group	Data Item	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
FOOTHILLS	D1 Cost by Transport ($000)	$ 3,654.02	$ 3,654.02	$ 3,654.02	$ 3,654.02	$ 3,654.02	$ 3,654.02
FOOTHILLS	Outflow (Net Flow) by Transport (MDT)	23,507	24,448	20,699	18,897	18,745	20,196
GTN	D1 Cost by Transport ($000)	$ 5,455.27	$ 5,455.27	$ 5,455.27	$ 5,455.27	$ 5,455.27	$ 5,455.27
GTN	Outflow (Net Flow) by Transport (MDT)	26,704	24,722	21,913	20,107	20,282	22,756
GTN	Transp Cost by Transport ($000)	$ 3,596.07	$ 3,323.51	$ 2,944.88	$ 2,696.35	$ 2,720.50	$ 3,055.36
NOVA	D1 Cost by Transport ($000)	$ 7,646.78	$ 7,646.78	$ 7,646.78	$ 7,646.78	$ 7,646.78	$ 7,646.78
NOVA	Outflow (Net Flow) by Transport (MDT)	23,891	24,203	20,756	18,957	18,807	20,378

Figure 68: Annual Transportation Resources Results

The transportation resources in the detailed output tables have the following output parameters:

- D1 Cost
- Outflow
- Transportation Cost

The D1 cost is the total dollars spent on the transportation contracts based on the pipelines. The outflow is the actual amount of gas that flowed on the associated transport group and the transportation costs are the total dollars spent on the transportation rate. Exhibit 8 also includes the outflow on design day.

Other Scenarios

Upstream Transportation and Lateral Summary tables for the high and low customer growth as well as normal weather are provided in Exhibit 10. One notable result from the other scenarios is that even under the most extreme scenario, design weather with high growth, there is still sufficient upstream transportation and distribution system capacity to serve customers through the planning horizon when including the planned solutions for shortfalls in the Planning Results chapter.

Summary

In summary, the optimization model employs utility standard practice method to optimize Intermountain's system via linear programming through SENDOUT®. The optimization includes DSM as a decrement to demand and also optimizes storage injections and withdrawals across seasons. An analysis on lateral expansion is performed as well as an analysis to check for any shortfalls in upstream transportation or supply capacity.

Planning Results

Overview

Throughout previous sections of the IRP, robust analysis has been performed to determine how the Company will provide safe, reliable, and least cost gas to customers. This section discusses the planning results from distribution system planning after capacity enhancements are applied. After discussing the enhancement solutions for the forecasted capacity deficits, this section will also compare the peak delivery deficits of the total company as well as each AOI during the three common years of the 2021 and 2019 IRP filings. Finally, the planning results for upstream transportation shortfalls are discussed.

Distribution System Planning

Canyon County

In the Capacity Enhancements section, four options are discussed to determine the best way to solve capacity shortfalls for the Canyon County AOI. The options chosen were the Ustick Phase II and Ustick Phase III enhancements.

The following graph (Figure 69) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrades.

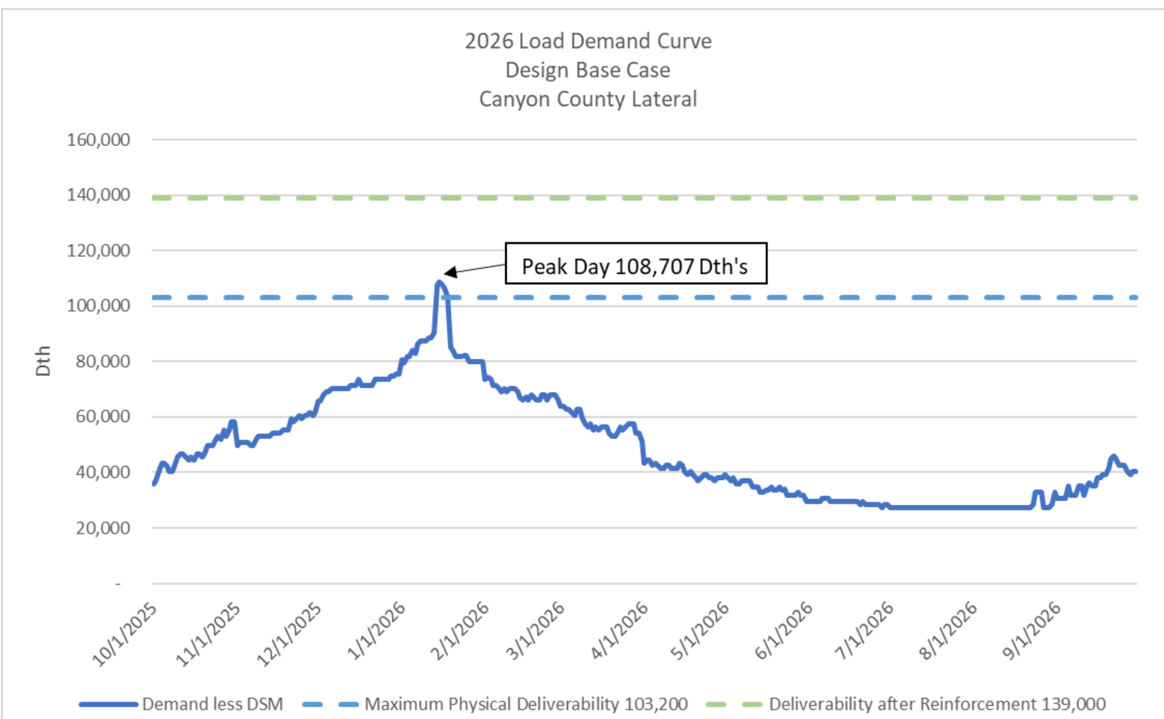

Figure 69: LDC Design Base Case – Canyon County Lateral

State Street Lateral

In the Capacity Enhancements section, two options are discussed to determine the best way to solve capacity shortfalls for the State Street Lateral. The option chosen was the State Street Phase II Uprate.

The following graph (Figure 70) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

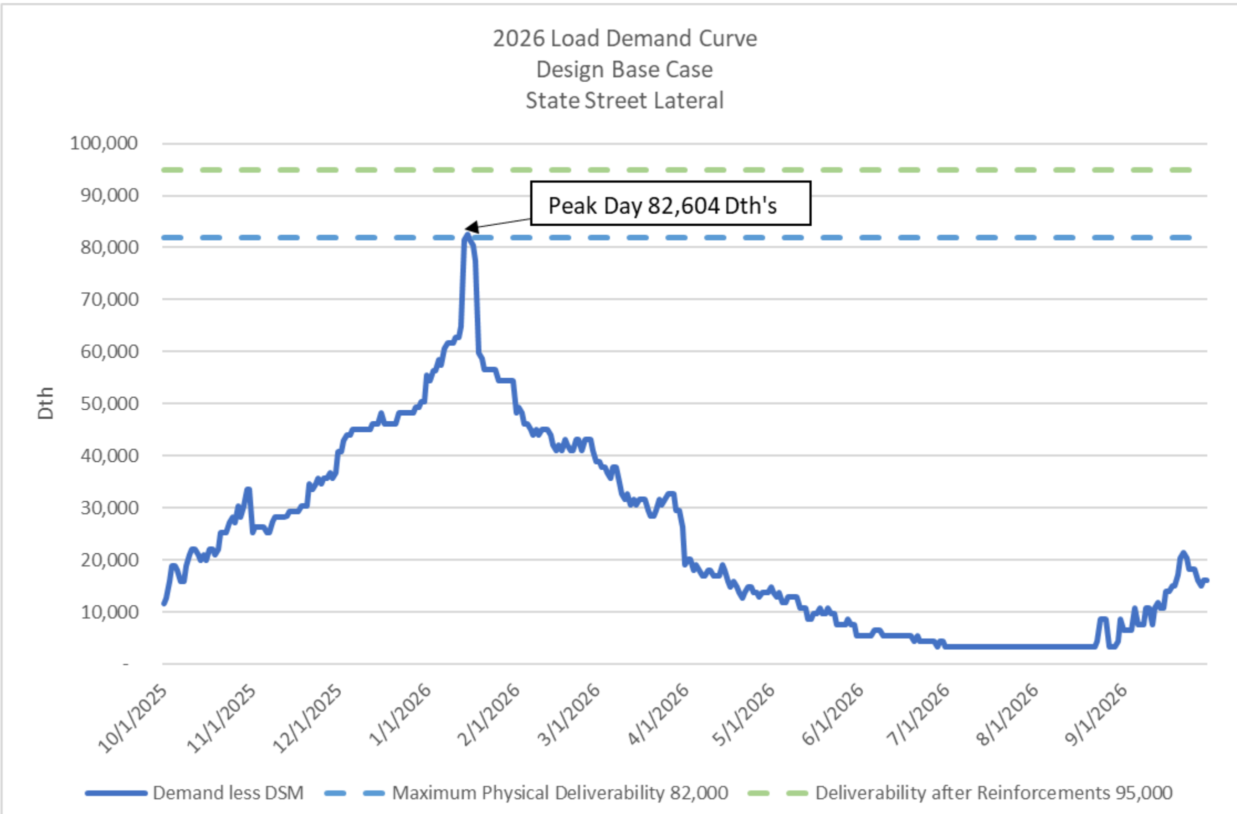

Figure 70: LDC Design Base Case – State Street Lateral

Central Ada County

In the Capacity Enhancements section, three options are discussed to determine the best way to solve capacity shortfalls for the Central Ada County AOI. The option chosen was the 12-inch South Boise Loop upgrade.

The following graph (Figure 71) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

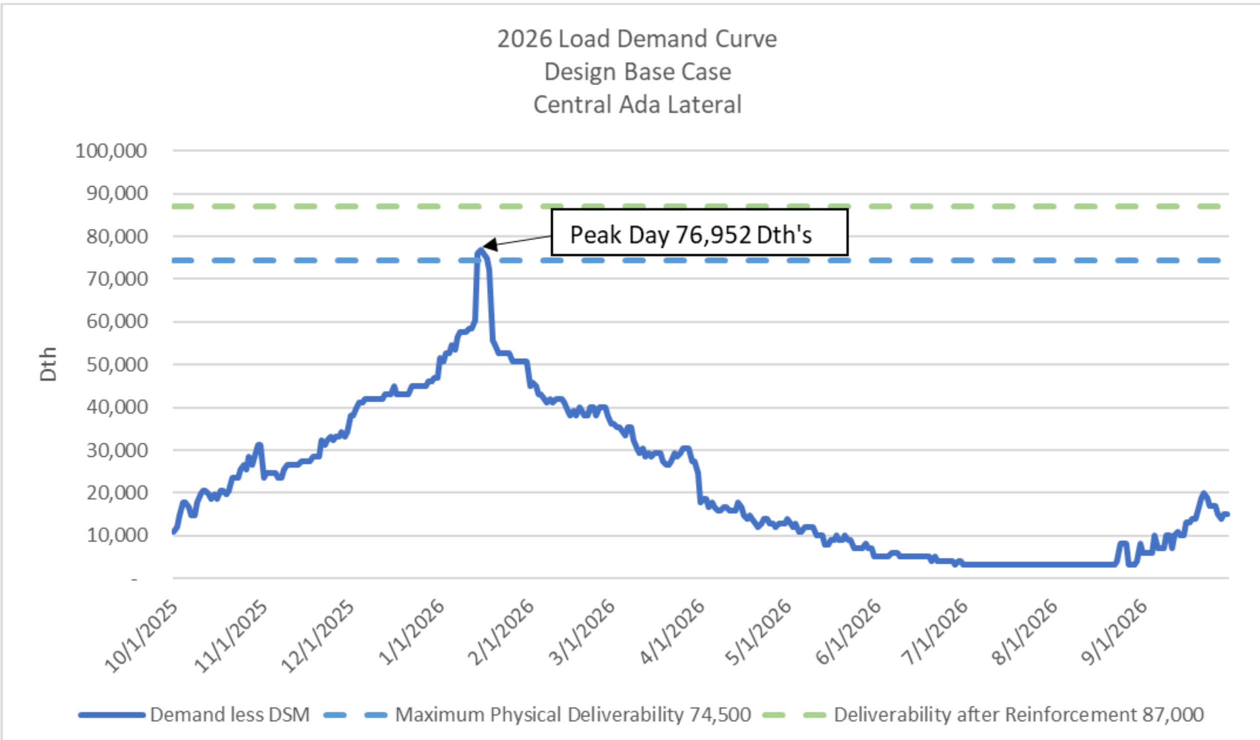

Figure 71: LDC Design Base Case – Central Ada Lateral

Sun Valley Lateral

In the Capacity Enhancements section, one option was identified in the 2019 IRP as the best way to solve capacity shortfalls for the Sun Valley Lateral: Shoshone Compressor Station. The Shoshone compressor station was planned to be installed by the end of 2021 but due to land acquisition delays will not be completed until summer of 2022. To address potential shortfalls during a cold weather event on the Sun Valley Lateral until the Shoshone compressor station comes online, Intermountain has developed a plan for the 2021-2022 winter. The plan for this lateral consists of communicating with downstream customers to turn off their snow melt equipment, running the Jerome compressor station ahead of a severe weather event to pack the lateral, bypassing critical regulator stations as needed to maintain service and to keep pressure on the lateral as high as possible and communicating with large volume customers to adhere to their contract demands during the cold weather event. Because the identified deficit is relatively small, Intermountain believes these measures will keep customers adequately supplied should a cold weather event occur.

The following graph (Figure 72) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

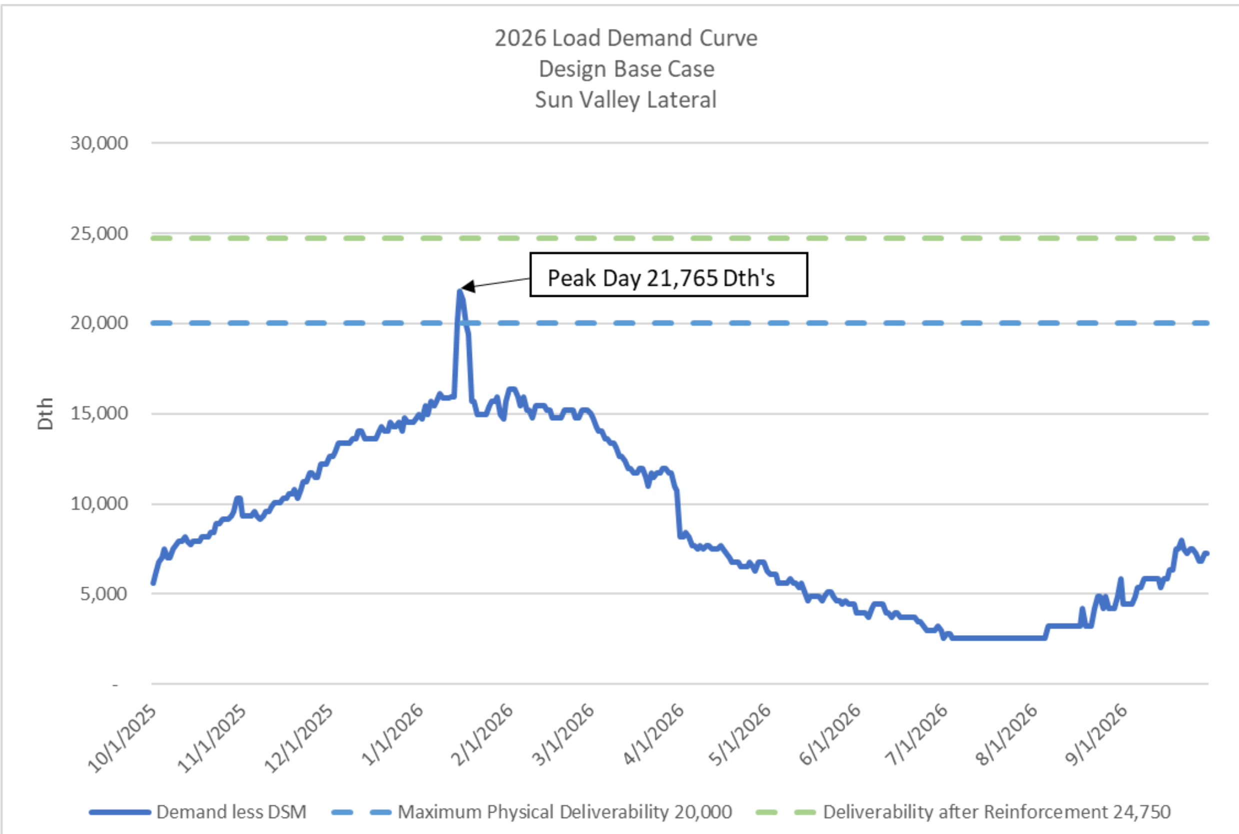

Figure 72: LDC Design Base Case – Sun Valley Lateral

Idaho Falls Lateral

In the Capacity Enhancements section, two options are discussed to determine the best way to solve capacity shortfalls for the Idaho Falls Lateral. The option chosen was the Idaho Falls Lateral Compressor Station.

The following graph (Figure 73) shows no deficit in the final year of the planning horizon under the base case scenario after completion of the proposed capacity upgrade.

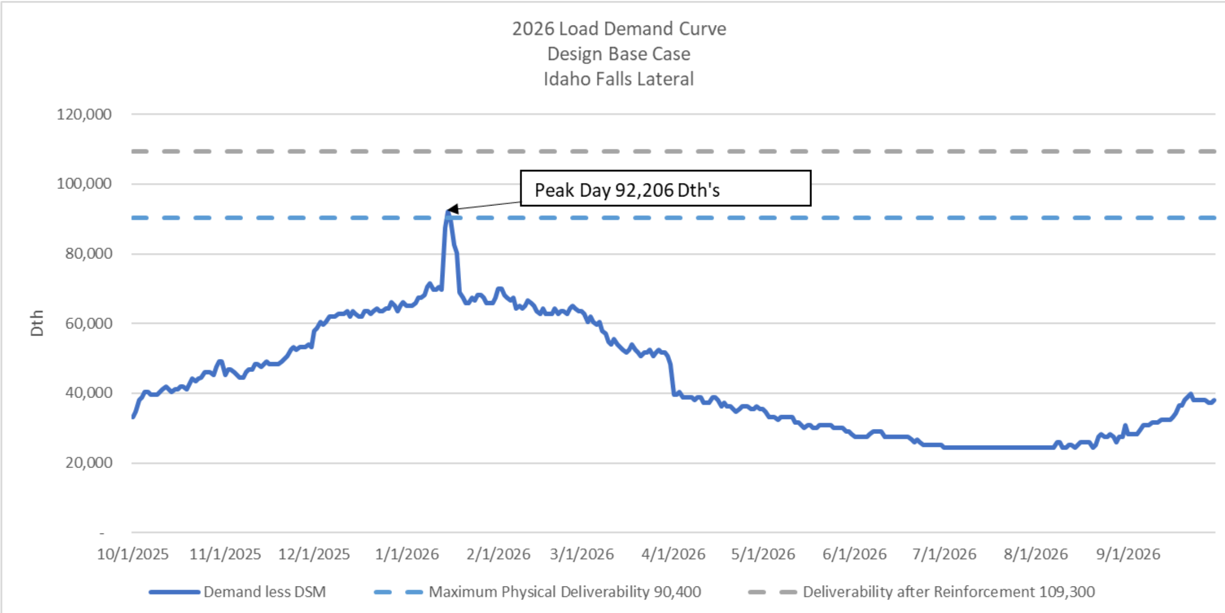

Figure 73: LDC Design Base Case – Idaho Falls Lateral

2019 IRP vs. 2021 IRP Common Year Comparisons

This section compares any firm delivery deficits for Total Company and each AOI during the three common years of the 2021 and 2019 IRP filings.

Total Company Peak Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2019 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2021 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE Over/(Under) 2019 (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Idaho Falls Lateral Peak Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2021 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE Over/(Under) 2019 (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Sun Valley Lateral Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	341	0	0
Total Winter Deficit[1]	341	0	0
Days Requiring Additional Resources	1	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2021 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE Over/(Under) 2019 (Dth)

	2021	2022	2023
Peak Day Deficit	341	0	0
Total Winter Deficit[1]	341	0	0
Days Requiring Additional Resources	1	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Canyon County Area Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2021 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE Over/(Under) 2019 (Dth)

	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

State Street Lateral Firm Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2021 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE Over/(Under) 2019 (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Central Ada County Firm Delivery Deficit Comparison

2021 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2021 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE Over/(Under) 2019 (Dth)			
	2021	2022	2023
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Upstream Modeling

Upstream Modeling Results

The upstream modeling results look at the upstream resources to ensure there is sufficient supply, storage, and transportation of gas to Intermountain's distribution system. As mentioned in the Traditional Supply Resources section, supply remains plentiful at the supply basins for the foreseeable future. As indicated in Table 9 on page 64, Total City Gate Delivery declines beginning in 2023 as upstream transportation contracts begin to expire. Due to expiring contracts, Intermountain does show a shortfall in the final year of the planning horizon. The following graph (Figure 74) shows the shortfall created by expiring contracts.

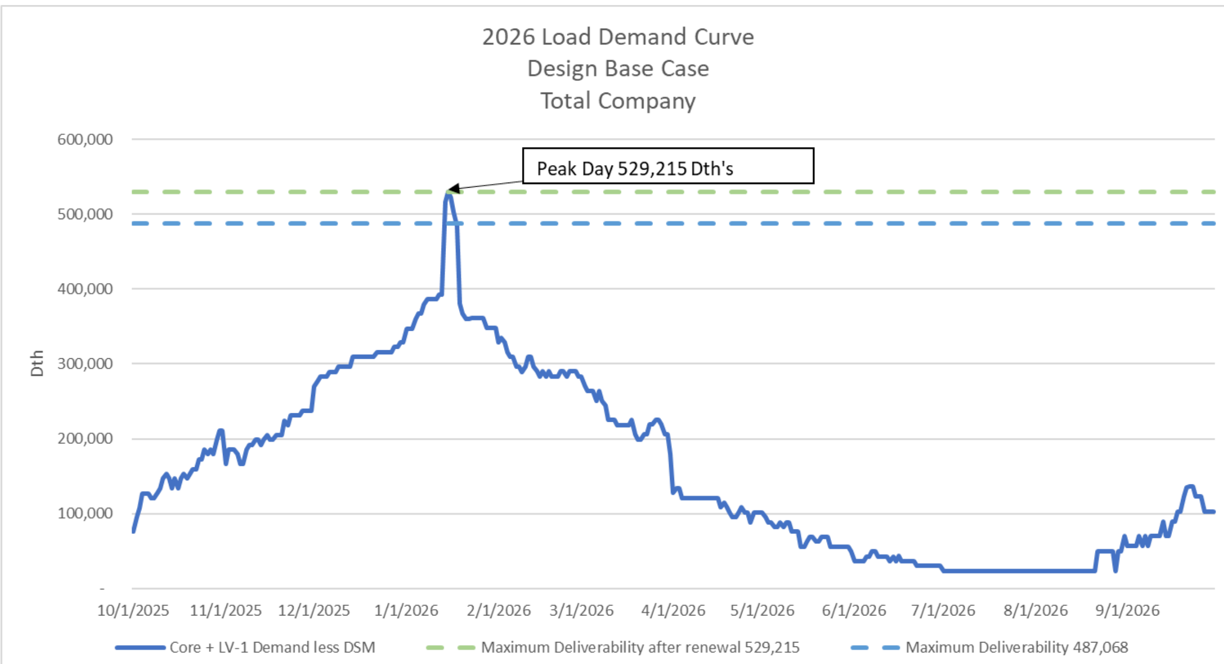

Figure 74: 2026 Design Base Case – Total Company

Solving Upstream Resources Shortfall

The options to solve the current transportation shortfall are contract renewal, alternative transportation uptake, and RNG. Under the contract renewal option, the contracts that will expire will be evergreened, or auto renewed, which provides Intermountain with sufficient transportation to meet load. Under the alternative transportation uptake, the model has the option to choose an alternative transportation rather than renewing. An example of this would be picking up more GTN rather than renewing a contract that moves gas from Sumas to Stanfield. In the RNG option, Intermountain models potentially decreasing the need of upstream transportation by giving the resource optimization model the option to take RNG.

The results in Exhibit 8 show that the options chosen to solve the shortfall are contract renewal and alternative transportation uptake. Currently, due to the high price of RNG, it was not selected to meet the shortfall solve as it would not have been the least-cost option. The resource optimization model has chosen to renew several of the expiring contracts while also choosing not to renew some contracts. With that said, the model also picked up about 6,000 dth a day of incremental GTN in the final year of the planning horizon.

It is important to remember that the resource optimization model provides information and does not decide the ultimate solution. The resource optimization model results will be provided to Intermountain's Gas Supply Oversight Committee (GSOC. GSOC will need to consider a longer time frame when looking at upstream transportation since those contracts typically are only available for purchase in long-term blocks. Therefore, it may make more sense to do a full renewal. Ultimately, GSOC will make a final decision on the solution to meet the forecasted transportation shortfall.

Conclusion

The distribution system planning results showed that the Company needs to address capacity shortfalls at each of the Area of Interests. The Capacity Enhancements section describes each solution and the updated capacity values are shown in this section to provide sufficient capacity over the planning horizon. The upstream modeling showed a shortfall due to expiring transportation contracts. That shortfall will be solved by taking either renewed or alternative transportation contracts, with the ultimate decision coming from Intermountain's GSOC.

Non-Utility LNG Forecast

Introduction

Since 1974, Intermountain has operated its Nampa Liquid Natural Gas (LNG) facility as a winter peaking supply source. The plant is designed to liquefy natural gas into LNG, store it in an onsite tank and vaporize it for injection into the Company's distribution system. The plant design includes a 50,000 gallon per day liquefaction train, a seven million-gallon storage tank and two water-bath vaporization units. The Nampa facility is utilized as the top of the Company's supply stack, or in other words, the last supply source that is used in the event of very cold weather or extraordinary system constraints.

In 2012 Intermountain began an efficiency review that focused on how it might better utilize its Nampa asset. Utilizing the then current IRP forecast, Intermountain determined how many gallons were projected to be withdrawn each winter season. That analysis showed that even under design weather assumptions, an excess of LNG supply would likely be available in each winter season.

Concurrent with the efficiency study, Intermountain began a study to determine the status of the regional LNG supply market relative to providing LNG to the Company's remote LNG facility near Rexburg, Idaho. Intermountain contacted several producing and marketing entities in the area who were then engaged in the non-utility LNG business to gauge future supply as well as the potential to enter the market as a supplier of LNG. It was discovered that due to already existing firm commitment during the heating season, it would be difficult to guarantee that an LNG supply would be available to Intermountain's Rexburg facility during the peak winter months.

History

LNG is a clean burning fuel that has the advantages of easy storage and transport under the right conditions. The two biggest markets for regional LNG are trucking fleets and remote-site heat and/or power applications. Though in relative infancy in the United States – particularly in the Pacific Northwest – LNG from a global perspective has a longer track record and continues to be in high demand in energy import areas like Asia.

As a direct result of the LNG supply study, Intermountain received an emergency supply request in late January 2013 to supply LNG to a small LNG-based distribution utility located in southwestern Wyoming that temporarily had lost its supply of LNG. The Idaho Public Utilities Commission (Commission) immediately granted emergency authority for Intermountain to supply the needed LNG pursuant to Case No. INT-G-13-01. Based on the efficiency review, the market study and the experience gained from supplying the emergency LNG, the Company filed Case No. INT-G-13-02 to request on-going authority from the Commission to sell "excess" LNG to non-utility customers.

Method of Forecasting

Intermountain utilized the results of the supply study (see Load Demand Curves starting on page 118) in this IRP to determine how much Nampa LNG would be needed for the core market during each year under the design weather/high growth scenario. To determine the annual amount of "excess" LNG, Intermountain begins with the annual core market withdrawal requirement and adds 1.2 million gallons of annual boiloff gas (boiloff naturally occurs with the warming of LNG), 300,000 gallons to maintain operational and training requirements at the Nampa and Rexburg LNG facilities, and 500,000 gallons of "permanent" inventory to ensure that all LNG does not boiloff. After summing those potential needs for each year in the forecast, the remaining capacity is assumed to be available for non-utility LNG sales customers. The table below shows the annual amount of Nampa LNG assumed to be available for non-utility sales over the IRP period. For planning purposes, Intermountain will not allow the tank inventory level to drop below the Net Utility Requirements shown below at any time during December – February of any year since this is the peak demand season for the Company's distribution system. Further, should the need arise, all volumes in the tank are always available to serve the core market. It should be noted that the amount shown as "Available for Non-utility Sales" is a point-in-time figure.

Table 17: Nampa LNG Inventory Available for Non-Utility Sales

Nampa LNG Inventory Available for Non-Utility Sales					
Gallons	2022	2023	2024	2025	2026
Projected Withdrawal (High Growth)	0	0	1,282,682	2,248,848	2,240,988
Annual Boil-off	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Permanent Inventory	500,000	500,000	500,000	500,000	500,000
Nampa & Rexburg Requirements	300,000	300,000	300,000	300,000	300,000
Net Utility Requirement	2,000,000	2,000,000	3,282,682	4,248,848	4,240,988
Available for Non-utility Sales	5,000,000	5,000,000	3,717,318	2,751,152	2,759,012

Benefits to Customers

Intermountain's customers benefit from Intermountain's LNG sales activities in several different ways. First, Intermountain continues to defer 2.5¢ per gallon sold into a capital account and utilizes that balance as it identifies capital costs that were accelerated due to increased use of the Nampa LNG facility. That procedure directly reduces both rate base and depreciation expense. Intermountain also continues to pass back to customers in its annual PGA filing a credit of 2.5¢ per gallon sold as an offset to increased operating and maintenance costs as a result of non-utility sales. Finally, Intermountain's customers also benefit from the current margin sharing mechanism which offsets gas purchase costs in the Company's annual PGA.

Since April 2013, Intermountain has sold approximately 35 million gallons of LNG to non-utility customers. These sales have provided nearly $880,000 to offset increased capital costs. Additionally, through its PGA the Company has credited to its utility customers approximately $880,000 to offset increased O&M costs and nearly $4.6 million from the margin sharing mechanism. Further, the PGA passback has reduced Intermountain's gas costs every year since the PGA filed in August 2013.

Another benefit comes from the fact that the Company has been selling much of its LNG to markets which utilize it in Idaho. The sales primarily provide fuel to trucks that formerly burned diesel as a fuel. LNG sales have increased economic growth in the state and have also provided cleaner air benefits. The markets Intermountain sells LNG to have expressed appreciation for a local, reliable, competitively priced fuel. Further, many of the truck drivers have expressed a preference to load at Nampa as the design and operations allow for more convenient and quicker trailer fills.

2021 Plant Downtime

During a maintenance review in early 2021, Intermountain discovered corrosion along a welded seam in the outer steel tank. Because repairs could not occur with methane in the tank, the facility was shut down in early May 2021 and the remaining LNG was vaporized or allowed to boiloff. When the tank was completely empty and purged or all remaining methane, the corrosion repairs were started. Repairs have been completed and liquefaction is scheduled to begin in early January 2022. The first 2 million gallons of liquefaction will be designated as utility LNG. Due to the limited liquefaction window, non-utility liquefaction may not begin until several months into 2022 meaning that non-utility sales may not begin again until the second quarter of 2022. The plant downtime greatly minimized 2021 non-utility sales and will have a similar effect on 2022 sales.

On-Going Challenges

Since one of the biggest potential target markets for Intermountain's non-utility sales is "big rig" diesel fuel replacement, the price differential between LNG and diesel is important. Low diesel prices tighten the cost differential between diesel and LNG and consequently the Company has had little ability to increase sales prices. In recent years a comparatively low price differential has slowed growth in the LNG-based trucking market.

A further challenge has been the lack of available large displacement LNG engines. Because of the frequency and magnitude of roadway inclines, the mountain west trucking industry prefers to rely on 15-liter engines. However, manufacturers do not produce a 15-liter LNG engine, resulting in a challenge to utilize natural gas-powered engines to haul the heaviest loads. Thus, lower diesel prices combined with the lack of a 15-liter, LNG-powered engine has hampered growth in LNG sales demand. These challenges have limited revenue growth in Intermountain's non-utility LNG sales. As the economy enters into a period of higher oil and gas prices, Intermountain will watch the market for opportunity to grow non-utility sales.

The good news is that continuing efforts to work with existing LNG markets while also marketing to new entities has resulted in Intermountain growing its sales every year since 2013 until the temporary plant shutdown in 2021. Further, Intermountain looks for opportunities to manage its inventory cost which has helped to support average sales margins.

Safeguards

As described above, Intermountain takes steps to ensure that it maintains enough LNG in the tank to provide for all projected customer withdrawal needs. This insulates the core market from the risk of having no LNG should the need for needle peak withdrawals arise. Intermountain has also committed to the Commission that all volumes in the tank, regardless of the intended market, would always be available to serve the core market should the need arise. Additionally, while the Company shares LNG margins with its customers through the PGA, it also insulates its end-use customers from any risk of loss due to non-utility sales.

Future

Intermountain continues to see growth in non-utility LNG sales and may even reach a point where annual liquefaction levels are maximized. As the market continues to look for ways to satisfy ever more stringent emissions standards, it is believed that LNG will generate more interest. Looking to the future, the energy market has seen extremes in supply and pricing. Current forecasts predict strong increases in oil and natural gas prices which could have a short-term affect on margins once the tank is back in service. Barring major variances in price differentials or LNG demand destruction, the Company expects that future sales volumes and margins will likely return to results seen in 2020.

One advantage the Company has is the ability to store large amounts of LNG which would last for an extended period of time for vaporization purposes. Because of its storage capability, some markets look to Nampa as a backstop supplier when other facilities might experience outages or planned downtime. Should the non-utility sales market continue to show strong growth, the Company would likely not need more storage capacity, but could address the need for more day-to-day sales volumes by adding to or upgrading its liquefaction train in order to increase the daily production of LNG.

The biggest disadvantage of the Nampa plant relates to the cost of liquefaction. Stand-alone commercial LNG production facilities do not need large storage tanks, vaporizers or other equipment designed to support peak shaving withdrawals and can therefore operate at a lower cost. In addition, newer facilities utilize more recent technology that can simply liquefy more efficiently than older facilities. A potential risk to Intermountain's LNG sales would be the construction of new commercial LNG facilities in the region that would have lower operating costs which could result in the loss of customers currently served by the Nampa facility or lower sales margins.

Recommendation

Notwithstanding the plant shutdown, challenges relating to growth in sales volumes and a market facing flat margin growth will remain. A longer-term increase in diesel prices vis-à-vis natural gas prices would provide more opportunity to grow both non-utility LNG sales and margins. Intermountain's Nampa LNG facility is located in an area without direct competitors and the Company continues to build brand loyalty. Based on the benefits to Intermountain and its utility customers, the lack of risk to its customers and the ability to make more efficient use of the Nampa LNG assets, Intermountain recommends that it continue to sell excess LNG to non-utility customers.

Infrastructure Replacement

Intermountain Gas Company is committed to providing safe and reliable natural gas service to its customers. As part of this commitment, Intermountain proactively monitors its pipeline system utilizing risk management tools and engineering analysis. Additionally, the Company adheres to federal, state and local requirements to replace or improve pipelines and infrastructure as required. Infrastructure that is identified as a potential risk is reviewed and prioritized for replacement or risk mitigation.

During the IRP planning period, Intermountain will address three significant infrastructure replacement projects. These replacement projects are not growth driven.

American Falls Neely Bridge Snake River Crossing

The Neely bridge crossing is a six-inch steel high pressure pipeline above ground crossing over the Snake River where the pipe is hanging on a bridge and is recommended for replacement in 2022. The pipe has been identified for replacement since it is a suspended crossing installed in 1961 which is difficult to inspect and maintain coating on and has had issues with expansion and contraction of the bridge which has resulted in damage to the facilities.

To address these issues Intermountain is recommending that this above ground crossing be replaced with a below ground crossing under the Snake River using horizontal directional drilling.

Rexburg Snake River Crossing

The Rexburg Snake River crossing is an eight-inch steel transmission pipeline installed under the Snake River southwest of Rexburg which has been identified as an infrastructure replacement project, tentatively scheduled for planning year 2024. The pipeline was identified for replacement due to risks related to the Snake River and surrounding flood plain. The location of the pipeline under the Snake River and perpendicular to the river along its east bank leave the pipeline susceptible to loss of adequate cover should the river’s rate of flow increase to the point of spilling over the existing bank and/or scouring the existing river bottom.

The Rexburg Snake River crossing has been monitored and has required occasional attention. The riverbank has been rebuilt and reinforced by Intermountain to prevent undermining of the bank and reduce the potential to flood, and the Company has installed engineered scour protection measures over the top of the pipeline to prevent cover loss within the river. These efforts have been successful to date. However, due to the ongoing monitoring and mitigation efforts, along with the ever-present risks associated with this scenario, the Company plans to replace the existing pipeline.

Intermountain's selected replacement method for this existing river crossing is to utilize horizontal directional drilling technology to install a new pipeline much further below the river bottom and surrounding flood area. Horizontal directional drilling will allow the pipeline to be installed much deeper in the ground than conventional installation practices and will avoid any disturbance to the Snake River and the sensitive land surrounding the river. The significant increase in pipeline depth will mitigate the existing risk.

System Safety and Integrity Program (SSIP)

Intermountain utilizes an Integrity Management Program to identify, analyze and monitor risks related to the distribution system, and to create programs that will reduce or remove risks. In order to identify risks on the system, Intermountain utilizes system knowledge based on known distribution systems characteristics, historical maintenance information, available outside source information, and the use of Subject Matter Experts (SME's) who are knowledgeable in operation, maintenance, design and construction. From this information a risk model is used to manage and assess the risk and to assign appropriate likelihood and consequence factors based on known system knowledge and threats to the Company's distribution system.

- Likelihood factors represent the possibility of a specific threat occurring on the distribution system.
- Consequence factors are numerical weighting factors to represent consequences that may be anticipated in case of an integrity issue.

Intermountain uses a GIS-based risk model to calculate relative risk scores for facilities. The risk model sums the assigned likelihood scores for each threat to calculate a total likelihood factor within a 50-foot grid (raster). The same summing calculation is also done for each of the assigned consequence factors within the same 50-foot grid. The total likelihood factor is then multiplied by the total consequence factor to establish a total relative risk score for the grid.

Risk Score* = *Likelihood Factor x Consequence Factor

Beginning in 2020, a System Safety and Integrity Program (SSIP) was implemented to rank each distribution system utilizing a weighted average of the risk score per foot of pipe. This weighted average is called the Risk Ratio and is used to prioritize high risk systems for replacement.

Risk Ratio = ∑ (Total Relative Risk Score x Pipe Length) / ∑ Pipe Length

Results of the replacement projects on system Risk Ratios are trended and reviewed as part of Intermountain's Distribution Integrity Management Program (DIMP) Performance Management program to ensure that integrity management activities are having the desired effect of mitigating risks.

High risk pipeline segments that are targeted for replacement include:

- Early Vintage Plastic Pipe (EVPP) – Plastic mains, service lines, and associated fittings installed earlier than 1/1/1995.
    - Pre-1983 (i.e. Adyl-A): These pipelines include pipe installed prior to 1/1/1983 that may be susceptible to possible Low Ductile Inner Wall (LDIW) characteristics that can result in slow crack growth and slit failures, as documented by PHMSA–2004–19856.
    - Post-1982: These pipelines were installed between 1/1/1983 and 12/31/1994 and are classified as EVPP to account for different inventory levels and rates of new material adoption.
- Early Vintage Steel Pipe (EVSP) – Steel mains, service lines, and associated fittings installed earlier than 1/1/1970. EVSP includes aging and/or obsolete pipeline segments, bare steel or poorly coated pipe, pipe with unknown attributes or missing data, gas meters located indoors, and/or pipeline segments with mechanical couplings and fittings.

Since 2013, Intermountain has been actively replacing segments of EVPP within the distribution system. In 2020 Intermountain started SSIP replacement in St. Anthony, ID which continued into 2021, and is anticipated to be completed in 2022. After St. Anthony, Intermountain will be moving to the next highest risk system based on the risk prioritization. Intermountain currently has approximately $3.6 (2021) – $4.4 (2025) million budgeted for SSIP replacement annually, which is used for replacing high risk distribution main and services. The SSIP replacement plan will continue through the duration of the IRP

Glossary

Agent (Marketer)

A legal representative of buyers, sellers or shippers of natural gas in negotiation or operations of contractual agreements.

All Other Customers Segment (All Other)

All other segments of the Company's distribution system serving core market customers in Ada County not included in the State Street Lateral or Central Ada County, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties; an Area of Interest for Intermountain.

Area of Interest (AOI)

Distinct segments within Intermountain's current distribution system.

British Thermal Unit (BTU)

The amount of heat that is necessary to raise the temperature of one pound of water by 1 degree Fahrenheit

Bundled Service

Gas sales service and transportation service packaged together in a single transaction in which the utility, on behalf of the customer, buys gas from producers and then transports and delivers it to the customer.

Canyon County Area (CCA)

A distinct segment of Intermountain's distribution system which serves core market customers in Canyon County; an Area of Interest for Intermountain.

Central Ada County (CAC)

Multiple high-pressure pipeline systems which serve core market customers in Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west; an Area of Interest for Intermountain.

Citygate

The points of delivery between the interstate pipelines providing service to the utility or the location(s) at which custody of gas passes from the pipeline to the utility.

Commercial

A customer that is neither a residential nor a contract/large volume customer whose requirements for natural gas service do not exceed 2,000 therms per day. These customers are typically commercial businesses or small manufacturing facilities.

Contract Demand (CD)
The maximum peak day amount of distribution capacity that Intermountain guarantees to reserve for a firm customer each day. The amount is specified in the customer contract. Also see MDFQ.

Core Market
All residential and commercial customers of Intermountain Gas Company. Includes all customers receiving service under the RS and GS tariffs.

Customer Management Module (CMM)
A software product, provided by DNV as part of their Synergi Gas product line, to analyze natural gas usage data and predict usage patterns on an individual customer level.

Delivery (Receipt Point)
Designated points where natural gas is transferred from one party to another. Receipt points are those locations where a local distribution company delivers, and an interstate pipeline receives, gas supplies for re-delivery to the local distribution company's city gates.

Design Year
An estimate of the highest level of annual customer demand that may occur, incorporating extreme cold or peak weather events; a measure used for planning capacity requirements.

Design Weather
Heating degree days that represent the coldest temperatures that may occur in the IGC service territory.

Direct Use
The use of natural gas at the point of final heating energy use, such as natural gas space heating, water heating, cooking, and other heating uses, as opposed to burning natural gas in a power plant to generate electricity to be used at the point(s) of use to for site space heat, water heat, cooking heat and other heat applications. Direct use is a much more efficient use of natural gas.

Demand Side Management (DSM)
Programs implemented by the Company and utilized by its customers to influence the amount and timing of natural gas consumption.

Electronic Bulletin Board (EBB)
A generic name for the system of electronic posting of pipeline transmission information as mandated by FERC.

FERC - Federal Energy Regulatory Commission

The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act. Successor to the Federal Power Commission, the FERC is considered an independent regulatory agency responsible primarily to Congress, but it is housed in the Department of Energy.

Firm Customer

A customer receiving service under rate schedules or contracts designed to provide the customer's gas supply and distribution needs on a continuous basis, even on a peak day.

Firm Service

A service offered to customers under schedules or contracts which anticipate no interruptions.

Fixed Physical

A fixed forward (also known as a fixed price physical contract) is an agreement between two parties to buy or sell a specified amount of natural gas at a certain future time, at a specific price, which is agreed upon at the time the deal is executed. It operates much like the price swap without the margin call risk.

Formation

A formation refers to either a certain layer of the earth's crust, or a certain area of a layer. It often refers to the area of rock where a petroleum or other hydrocarbon reservoir is located. Other related terms are basin or play.

Gas Transmission Northwest (GTN)

A U.S. pipeline which begins at the U.S.-Canadian border near Kingsgate, British Columbia and interconnects with Williams Northwest Pipeline at the Stanfield receipt point in Oregon.

Heating Degree Day (HDD)

An industry-wide standard, measuring how cold the weather is based on the extent to which the daily mean temperature falls below a reference temperature base, which for IGC, is 65 degrees Fahrenheit.

Idaho Falls Lateral (IFL)

A distinct segment of Intermountain’s distribution system which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties; an Area of Interest for Intermountain.

Industrial Customer

For purposes of categorizing large volume customers, any customer utilizing natural gas for vegetable, feedstock or chemical production, equipment fabrication and/or manufacturing or heating load for production purposes.

Institutional Customer
For purposes of categorizing large volume customers, this would include business such as hospitals, schools, and other weather sensitive customers.

Interruptible Customer
A customer receiving service under rate schedules or contracts which permit interruption of service on short notice due to insufficient gas supply or capacity.

Interruptible Service
Lower-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the higher priority claim of firm service customers and other higher priority users. Service is available at any time of the year if distribution capacity and/or pressure is sufficient.

Large Volume Customer
Any customer receiving service under one of the Company’s large volume tariffs including LV-1, T-3, and T-4. Such service requires the customer to sign a minimum one-year contract and use at least 200,000 therms per contract year.

Liquefied Natural Gas (LNG)
Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. In volume, it occupies one-six-hundredth of that of the vapor at standard conditions.

Load Demand Curve (LDC)
A forecast of daily gas demand using design or normal temperatures, and predetermined usage per customer.

Local Distribution Company
A retail gas distribution company, utility, that delivers retail natural gas to end users.

Lost and Unaccounted for Natural Gas (LAUF)
The difference between volumes of natural gas delivered to Intermountain’s distribution system and volumes of natural gas billed to Intermountain’s customers.

Maximum Daily Firm Quantity (MDFQ)
The contractual amount that Intermountain guarantees to deliver to the customer each day. Also see Contract Demand.

Methane

Methane is commonly known as natural gas (or CH_4) and is the most common of the hydrocarbon gases. It is colorless and naturally odorless and burns efficiently without many by products. Natural gas only has an odor when it enters a customer's home because the local distributor adds it as a safety measure.

Normal Weather

Normal weather is comprised of HDD's that represent the average mean temperature for each day of the year. Intermountain's Normal Weather is a 30-year rolling average of NOAA's daily mean temperature.

Northwest Pipeline (Williams Northwest Pipeline, Northwest, NWP)

A 3,900-mile, bi-directional transmission pipeline crossing the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado and the only interstate pipeline which interconnects to Intermountain's distribution system; all gas supply received by the Company is transported by this pipeline.

NYMEX Futures

New York Mercantile Exchange is the world's largest physical commodity futures exchange. Futures are financial contracts obligating the buyer to purchase an asset (or the seller to sell an asset), such as a physical commodity, at a predetermined future date and price. Futures contracts detail the quality and quantity of the underlying asset; they are standardized to facilitate trading on a futures exchange. Some futures contracts may call for physical delivery of the asset, while others are settled in cash.

Peak Shaving

Using sources of energy, such as natural gas from storage, to supplement the normal amounts delivered to customers during peak-use periods. Using these supplemental sources prevents pipelines from having to expand their delivery facilities just to accommodate short periods of extremely high demand.

Peak Day

The coldest day of the design year; a measure used for planning system capacity requirements. For Intermountain, that day is currently January 15 of the design year.

PSIG (Pounds per Square Inch Gauge)

Pressure measured with respect to that of the atmosphere. This is a pressure gauge reading in which the gauge is adjusted to read zero at the surrounding atmospheric pressure. It is commonly called gauge pressure.

Producer

A natural gas producer is generally involved in exploration, drilling, and refinement of natural gas. There are independent producers, as well as integrated producers, which are generally larger companies that produce, transport and distribute natural gas.

Purchased Gas Adjustment or PGA

Intermountain's annual price change to adjust the cost of gas service to its customers, based on deferrals from the prior year and forward-looking cost forecasts.

Residential Customer

Any customer receiving service under the Company's RS Rate Schedule.

SCADA (Supervisory Control and Data Acquisition)

Remote controlled equipment used by pipelines and utilities to operate their gas systems. These computerized networks can acquire immediate data concerning flow, pressure or volumes of gas, as well as control different aspects of gas transmission throughout a pipeline system.

State Street Lateral (SSL)

A distinct segment of Intermountain's distribution system which serves core market customers in Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21; an Area of Interest for Intermountain.

Sun Valley Lateral (SVL)

A distinct segment of Intermountain's distribution system that serves customers in Blaine and Lincoln counties; an Area of Interest for Intermountain.

Therm

A unit of heat energy equal to 100,000 British thermal units (BTU). It is approximately the energy equivalent of burning 100 cubic feet (1 CCF) of natural gas.

Traffic Analysis Zones (TAZ)

An analysis of traffic patterns in certain high traffic areas.

Transportation Tariff

Tariffs that provide for the redelivery of a shipper's natural gas received into an interstate pipeline or Intermountain's distribution system. A transportation customer is responsible for procuring its own supply of natural gas and transporting it on the interstate pipeline system for delivery to Intermountain at one of its citygate locations.

WCSB (Western Canadian Sedimentary Basin)

A vast natural gas producing region encompassing 1,400,000 square kilometers (540,000 sq mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic mail.

Dated this 5th day of May, 2023 in Seattle, Washington.

/s/ Megan Sallomi

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