BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 79

In the Matter of NW Natural, 2022 Integrated Resource Plan.	Staff Opening Comments

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Introduction

NW Natural's 2022 IRP: A Brief Background

Chapter 2 of NW Natural's (Company or NWN) Integrated Resource Plan (IRP) provides a thorough description of the Company's current policy and economic background.[1] Staff provides a brief summary of the IRP background here for reference.

Integrated Resource Plans of utilities regulated by the Oregon Public Utilities Commission (OPUC) are filed pursuant to the OPUC's IRP Guidelines in Order Nos. 07-047 and 08-339. These guidelines were written over ten years ago, and utility planning has increased in uncertainty, complexity, and sophistication in that time.

In 2019 the Oregon Legislature enacted Senate Bill 98 (SB 98), which allows natural gas utilities in Oregon to pursue voluntary Renewable Natural Gas (RNG) (including biomethane, hydrogen, and/or synthetic methane) targets. NW Natural may make qualified investments and/or procure these fuels to meet the following portfolio targets for the percentage of gas purchased for distribution to retail natural gas customers:

- Five percent from 2020 to 2024;
- Ten percent from 2025 to 2029;
- Fifteen percent from 2030 to 2034;
- Twenty percent from 2035 to 2039;
- Twenty-five percent from 2040 to 2044;
- And thirty percent beginning in 2045.

In December 2021, the Oregon Department of Environmental Quality's (DEQ) Climate Protection Program (CPP) went into effect. The CPP requires covered entities, including natural gas utilities, to reduce emissions 50 percent by 2035 and 90 percent by 2050.[2] This major policy development creates a new dynamic in gas resource planning. The CPP requires utilities, stakeholders, and Staff to incorporate new considerations for least-cost, least-risk investments. As such, NW Natural's IRP will be the first full Oregon gas IRP filed and commented upon since the adoption of the CPP. This document and future memos will reflect Staff's evolving thinking and approach to gas resource planning in an era of deep decarbonization in Oregon.

NW Natural held seven Technical Working Group workshops and one meeting for the public as part of its IRP process at which it discussed the analysis planned for the IRP and accepted feedback from participants.

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[1] NW Natural. 2022 Integrated Resource Plan. Chapter 2: Planning Environment.

[2] Oregon Exec. Order No. 20-04, *Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions* (March 10, 2020); Oregon Climate Protection Plan, Chapter 340, Division 271 (adopted December 15, 2021). Specifically, OAR 340-271-9000. Table 4.

In spring of 2021 the OPUC opened Docket No. 2178, the Natural Gas Fact Finding docket. This docket sought to investigate the regulatory tools the PUC could employ to mitigate the impact to customers from the costs and risks faced by the natural gas industry as it meets greenhouse gas (GHG) reduction requirements directed in the CPP. This work helped identify regulatory tools well suited to mitigate potential customer impacts, and it will help inform future policy decisions and make it clear what additional analysis is needed for least-cost least-risk decision making.

Staff's Review of NW Natural's 2022 IRP

Staff's IRP review focuses on assessing whether the IRP results in a near-term action plan and long-term portfolio that reliably meet load and policy requirements with the best balance of cost and risk for ratepayers. Staff made a best effort to perform all the usual requirements of an IRP review from the new perspective of CPP compliance.

Some of the concepts and recommendations from the Natural Gas Fact Finding were incorporated into this plan by NW Natural, including:

- Estimated bill impacts
- Transport energy efficiency programs
- Exploring IRP guidance from UM 2178 Draft Report Appendix B, such as expanding IRP communications, reflecting impacts of local policies to limit gas growth, and others.

Throughout the 2022 IRP review process, Staff will continue to consider ways to bring recommendations from the Natural Gas Fact Finding into consideration in this IRP.

Generally, when reading Staff's Opening Comments, there are a few items to note:

- Staff hired a consultant, Synapse Energy Economics Inc., to support Staff by performing a parallel review of NW Natural's IRP and helping identify and analyze issues related to IRP guidelines and CPP Compliance. Staff worked closely with Synapse and our opening comments benefitted greatly from their work and insights. Synapse will continue to work with Staff in reviewing and analyzing the IRP and help Staff consider stakeholder feedback. Finally, Synapse will also recommend best practices and next steps for review of all future gas company IRPs in an era of deep decarbonization.
- The Executive Summary of Staff's comments includes all of Staff's major arguments and requests/recommendations, referencing the more detailed analysis included in later sections.
- These comments contain recommendations to the Commission and requests for NW Natural. Requests for NW Natural are addressed to the Company and do not necessarily require Commissioner discussion or action at this time. Recommendations for the Commission ask Commissioners to consider or do something at a certain time.
- While SB 98 and some recent studies define the term RNG as being inclusive of several different low-carbon alternatives to natural gas, Staff's comments will refer to RNG,

hydrogen, and synthetic methane separately. Staff will use the term RNG only to refer to biomethane.

- All hydrogen resources considered by NW Natural in the 2022 IRP are green hydrogen from renewable energy.[3]
- Staff uses the terms 'scenario' and 'portfolio' interchangeably in comments.
- Page numbers referencing the 2022 IRP are referring to the updated IRP filing of October 21, 2022.

[3] NW Natural. 2022 Integrated Resource Plan. Page 190.

Section 1: Executive Summary

Rose Anderson, Senior Economist

Staff's review of the 2022 IRP focuses on whether the IRP follows the IRP Guidelines and reliably meets load and decarbonization requirements given the new and significant challenges and uncertainties facing the Company. NW Natural has done impressive work, in collaboration and consultation with participants in its Technical Working Groups, to study a wide range of potential futures for its system. Yet, Staff's opening comments question whether the IRP has been thorough enough to find answers that best balance cost and risk for customers. In summary:

- The Scenario and Monte Carlo analysis in the IRP appear to leave significant room for improvement. The Company's Monte Carlo methodology should be refined to better assess risk under a variety of circumstances. Additionally, efficiency, demand response, and electrification are not considered as selectable resource options in the scenario or Monte Carlo modeling, or in any sensitivity. This likely obscures some of the best pathways for customers as these resources are not compared on an even basis.
- Distribution system capital costs, as well as other capital investments that may differ between scenarios, are incorrectly represented as being the same in each scenario.
- The Company's IRP analysis assumes that SB 98 RNG targets will be met throughout the planning timeframe, even though CPP decarbonization requirements can be met more cost-effectively through Climate Community Investments (CCI) purchases.
- There may yet be an opportunity to explore non-pipe alternatives to the Forest Grove Feeder uprate and the Portland LNG Cold Box.
- Some IRP inputs, assumptions, and methodologies may be excessively biased toward high load and peak load forecasts.
- The Company's assumptions about availability and cost of biomethane RNG, green hydrogen, and synthetic methane seem optimistic compared to some other recent studies. Optimistic forecasts for emerging technologies may increase risk for customers.

Section 1.1 – IRP Analysis: Scenarios and Monte Carlo Simulation

Section 1.1.1 – Summary of IRP Scenario and Monte Carlo Analysis

NW Natural's 2022 IRP looks at ten different scenarios in total. First, a reference case scenario uses historical trends to forecast resource need, without taking into consideration recent regulatory and market changes/risks for natural gas companies. Nine other scenarios adjust the reference case assumptions to look at a variety of possible futures with varying levels of demand, technology costs, load, and other variables. NW Natural notes that the Company chose these nine scenarios with input from participants in the IRP development process.[4]

[4] NW Natural's response to Staff IR 69.

The statistical Monte Carlo analysis assesses 500 potential futures, using variable distributions based on values across the ten IRP scenarios. Monte Carlo variable values in these 500 futures generally range between the highest and lowest variable values from the ten scenarios. Monte Carlo variables are listed by the Company in Figure 7.4 of the IRP and include temperatures, RNG prices, natural gas prices, customer growth rates, and technology adoption rates.

Section 1.1.2 – Assessment of Scenario and Monte Carlo Analysis

Risk Assessment in Monte Carlo Analysis

Staff comments in Section 3 describe the Monte Carlo study in the IRP, noting that it assesses the future stochastically using variable inputs from across the scenarios. This process inherently assumes knowledge of the likelihood of the outcome for each variable, even when the likelihood is not in fact known.[5] For example, it is not known which load forecast is the most likely. NW Natural's Monte Carlo analysis assumes that all scenarios are equally likely, which is an assumption that lacks explanation and discussion in the IRP, and seems likely to bias the results of the Monte Carlo.[6] In Section 3, Staff recommends that performing Monte Carlo analysis *within each* scenario instead of *across all* scenarios would correct this issue.[7] There may also be other ways to address this issue, and Staff will collaborate with Synapse in reviewing the Monte Carlo methodology, how statistical distributions were created, and how samples were drawn.

Another significant issue with the Monte Carlo analysis is the upward bias resulting from using the reference case customer count forecast in six out of nine scenarios.[8] The reference case customer forecast does not consider the effects of recent policies like new customer moratoria at the city and state level, and NW Natural acknowledges that the likelihood of the reference case occurring is minimal.[9] The resulting upward bias in many of the individual scenarios is likely to cause upward bias in the Monte Carlo analysis because the Monte Carlo inputs are based on the scenarios.

Additionally, the unrealistic reference case scenario load forecast is included in the range of load forecasts used in Monte Carlo analysis. This is concerning because it again skews the results upward in an unrealistic manner. NW Natural views the Monte Carlo analysis as its risk analysis that defines a preferred portfolio. For this reason, a biased load forecast in the Monte Carlo analysis is concerning.

Furthermore, for unknown reasons, the statistical distribution in the Monte Carlo analysis does not appear to include the lowest load forecast from scenario analysis (Scenario 6 – Full Building

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[5] OPUC Staff Opening Comments. Section 3.
[6] NW Natural. TWG 2 Presentation. Page 122.
[7] OPUC Staff Opening Comments. Section 3.
[8] OPUC Staff Opening Comments. Section 14.
[9] NW Natural. 2022 Integrated Resource Plan. Page 59.

Electrification.) The distribution also does not appear to include any draws that adequately represent a dual fuel heat pump future. The lack of inclusion of these possibilities in the Monte Carlo analysis points to a lack of consideration in the risk assessment.

Staff's comments generally find the risk assessment to be lacking in support and justification and overly biased toward higher load forecasts. Additionally, the Company only vaguely describes its preferred portfolio in Chapter 7 of the IRP, and it is not clear from the IRP exactly which resources the Company plans to rely on after the action plan timeframe.

Requests for NW Natural:

- Request 4: Staff requests that the Company file an addendum to the IRP identifying a preferred portfolio that lists the relied-upon assets. The filing should more clearly identify the resource decisions by year in the preferred portfolio on which the action plan is based and discuss how the analysis done in Chapter 7 led to the portfolio selection.
- Request 6: In Reply Comments, Staff requests that NW Natural conduct a trigger point analysis described in Guideline 8 or further discuss which aspects of its current scenario and stochastic analysis drive changes in the optimal portfolio.
- Request 7: Staff requests that in future IRPs, NW Natural does not treat its scenario analyses as entirely deterministic. Instead, Staff requests that NW Natural conduct stochastic analysis within each scenario rather than across all scenarios. Additionally, sensitivities for some scenarios should be considered to help inform how the scenario would change under certain potential conditions such as different RNG costs or a different load forecast.
- Request 2: NW Natural should use the stochastic capabilities of PLEXOS to assess the variability and severity of risks in its preferred portfolio before the Commission's acknowledgement decision in this IRP.

Consideration of All Options in Scenario Analysis

Staff opening comments in Section 2 discuss NW Natural's IRP in the context of the IRP Guidelines, including guidelines around efficiency and demand side resources. Scenario analysis in PLEXOS does not consider efficiency, demand response, or electrification as investments that could help meet resource or decarbonization needs. For energy efficiency modeling, NW Natural received forecasts from the Energy Trust of Oregon (Energy Trust) and used them as hard-coded inputs to the PLEXOS model, also using outboard adjustments in some scenarios to represent futures with higher levels of conservation. However, the IRP guidelines say that an IRP should include a scenario to assess efficiency as a resource with the assumption there are no funding limits.[10] NW Natural should perform a study that allows PLEXOS to select efficiency beyond the amounts identified by Energy Trust.[11]

[10] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning*, Docket No. UM 1065, Order No. 07-074 ("OPUC IRP Guidelines"), Guideline 6(c) at 6.
[11] OPUC Staff Opening Comments. Section 2.

Increasing the amount of Demand Response (DR) is an important way to reduce peak load and potentially reduce or forestall the need for system capacity upgrades. NW Natural proposes a DR pilot by 2024. However, NW Natural's scenario analysis in PLEXOS did not consider DR as a selectable resource, which would have facilitated comparing it on an equal basis with other capacity resources, per IRP Guideline 1 and Guideline 7.[12] Given that the Company's peak planning standard is very stringent (about 100 percent higher than recent peak load events) it will be essential to consider all potential capacity resources, including DR, in IRP modeling to help manage capacity costs. [13,14]

Request for NW Natural:

- Request 5: In Reply Comments, Staff requests that NW Natural discuss its ability to complete a PLEXOS model run, before the acknowledgement decision in this IRP, for each scenario where demand-side resources can be optimally chosen by PLEXOS. The full electrification scenarios, i.e., Scenarios 5 and 6, can be excluded from this request.
- Request 3: NW Natural should do an additional model run to see what PLEXOS would select from the Energy Trust technical potential if given the option to compete all efficiency measures with supply-side resources, rather than hard-coding energy efficiency to the levels forecasted as cost-effective by Energy Trust. Demand response resources should also be included.

NPVRR Transparency and Comparability in Scenarios and Monte Carlo Analysis

Staff opening comments in Section 2.1 discuss that IRP guidelines require utilities to "use present value of revenue requirement (PVRR) as the key cost metric" and include "Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results." [15, 16] However, the IRP does not include transparent NPVRR metrics. NW Natural has been hesitant to provide NPVRR data upon request and has consistently discouraged the comparison of NPVRR between portfolios. NW Natural claims that they are not comparable to one another because they do not include the full costs of electrification. In response to Staff IR 1, NW Natural states that rate impacts, as assessed by NW Natural in the IRP, should instead be compared.[17, 18] However, given that certain significant capital investments and price elasticity of demand are not included in the rate impact analysis, Staff doubts the usefulness of comparing NW Natural's rate impact estimates for scenarios.

The IRP portfolios appear to not be comparable to one another in part because they exclude costs of electrification, and additionally because they exclude some capital costs that would

[12] OPUC IRP Guidelines at 1 and 6.
[13] NW Natural. TWG 2 Presentation. Slide 46.
[14] Attachment 1 to NW Natural's reply to Staff IR 77 shows actual peak day load for recent years.
[15] OPUC IRP Guidelines, Guideline 1 at 2; Guideline 4j at 5.
[16] OPUC Staff Opening Comments. Section 2.
[17] NW Natural. 2022 Integrated Resource Plan. Pages 262 - 344.
[18] NW Natural's response to OPUC DR 1.

differ between scenarios with different load forecasts. The exclusion of these capital costs is significant because they can be expected to vary between portfolios, and because the IRP Guidelines say the IRP should include, "analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases."[19] The analysis of long-lived capital expenditures and how they might differ between scenarios throughout the IRP timeframe is missing from this IRP.

Including capital expenditures that reflect the load level in each scenario would improve the ability to compare scenarios to each other, because scenarios would reflect an estimate of capital investment appropriate for the customer infrastructure needs and the load/peak load forecast in each individual scenario.

Additionally, including an estimate of electrification costs could help with the ability to compare the total cost to customers in the different scenarios. While the full cost of electrification is not known at this time, this should not deter Staff, stakeholders, or the utilities from directional analysis in this IRP that attempts to estimate the costs and benefits to customers and the electric system from different gas planning scenarios for informational purposes.

Staff proposes a study by Synapse, supported by OPUC Staff, that would add proxy electrification and capital investment costs to NW Natural's NPVRR in each scenario. The intent of the study would be to provide information for a conversation about the costs of electrification scenarios as compared to other decarbonization pathways. This could be a step toward the type of analysis considered in Docket No. UM 2178 that looks at coordinating assumptions between gas and electric IRPs. While such a study could potentially be made available before the acknowledgement decision in this IRP, it would likely be used as a starting point for a longer conversation about how to consider costs of electrification versus gas decarbonization, and not leaned upon heavily by Staff in acknowledgement discussions.

Request for NW Natural:

Request 1: NW Natural should respond in Reply Comments regarding its ability to consider capital expenses that vary between scenarios and price elasticity of demand in its rate impact analysis.

Section 1.2 – Policy and Risk

In Section 4, Staff discusses risk management in the new paradigm of CPP compliance and decarbonization. Focus is placed on full consideration of demand-side resources, costs of customer growth, and the use of conservative planning assumptions for new technologies such as low-carbon fuels. Staff describes expectations that the Company should address risk through:

[19] OPUC IRP Guidelines, Guideline 1(c) at 2.

- Heightened evaluation of the compliance cost impact of customer growth and long-term investments that reduce compliance flexibility, such as those in the distribution system;
- Flexible portfolios developed through evaluation of all resources - demand-side and supply-side - using consistent assumptions and on a comparable basis; and
- Application of reasonable, conservative, and supported assumptions.[20]

Section 4 looks at new perspectives regarding demand-side resources. The concept of what constitutes a demand-side resource in gas planning has been opened to debate since the adoption of the CPP. In an era of deep decarbonization, a question emerges as to whether or the extent to which electrification should be included as a potential resource in least-cost, least risk planning. As Staff discusses in Section 4, strategic consideration of electrification, efficiency, temporary moratoriums, and alternative fuels, potentially through RFPs for non-pipe alternatives (NPA), may be a tool to reduce risk to ratepayers from the many forms of uncertainty faced by the Company at present, including uncertain future costs and potentially stranded assets.

Section 5 discusses additional steps the Company should take to more fully consider and support all cost-effective efficiency resources.

Requests for NW Natural:

- Request 9: Future IRPs should strive for compliance path flexibility by considering proactive strategies to minimize growth related investments in the distribution system.
- Request 10: In Reply Comments, NW Natural should explain how it considered the potential for reduced compliance flexibility and stranded asset risks that come with long term investments associated with new customers.
- Request 11: In Reply Comments, NW Natural should respond to Staff's recommendation that the Company consider a non-pipe alternative RFP as a part of certain high-cost distribution system upgrade decisions.
- Request 12: In Reply Comments, NW Natural should provide more discussion around the costs/benefits of the dual fuel scenario, which appears to provide a well-balanced approach.
- Request 13: In Reply Comments, NW Natural should discuss how IRP analysis could more appropriately compare and select supply side and demand side resources.
- Request 14: In Reply Comments, NW Natural should discuss whether Scenario 8: Limited RNG assumptions are more reasonable and conservative than those used in the majority of the other scenarios.
- Request 15: In Reply Comments, Staff requests that the Company describe: 1) How the Company has been assisting Energy Trust in ramping up to meet the Company's energy efficiency acquisition needs, and 2) What alternative plans the Company has to address

[20] Staff opening comments. Section 4.

any gap between Energy Trust energy efficiency acquisitions and the amount of savings the Company needs to meet carbon compliance goals cost-effectively.

- Request 16: In Reply Comments, Staff requests that the Company describe what key activities will take place in 2023 to support the launch of an energy efficiency program for transport customers in 2024, including coordinating activities with Energy Trust. Further, Staff would like to know if there is any way to accelerate the launch of this program.
- Request 17: Staff requests that the Company provide Energy Trust with the list of transport customers so that Energy Trust can provide additional insight that the Company can use to inform and refine these estimates. In Reply Comments, Staff requests that the Company describe what activities the Company has undertaken between December 2019 and now to study and develop opportunities to use new demand response programs as demand-side resource options.
- Request 18: In Reply Comments, Staff requests that the Company describe what activities the Company has undertaken between December 2019 and now to study and develop opportunities to use new demand response programs as demand-side resource options.
- Request 19: In Reply Comments, Staff requests that the Company describe what key activities will take place in 2023 to support the launch of a demand response program in 2024, including coordinating activities with Energy Trust and selection of demand response measures. If the Company plans to have a pilot phase, please describe how that would fit into the timeline.
- Request 20: In Reply Comments, confirm that the Company will participate in discussion between Energy Trust and the utilities on how to fund a dual-fuel heat pump pilot.

Section 1.3 – SB 98 RNG

As discussed in Section 6 of Staff opening comments, the Company's IRP analysis assumes that SB 98 RNG targets will be met throughout the planning timeframe, even though some of the Company's CPP decarbonization requirements can be met more cost-effectively through CCI purchases.[21,22,23] While NW Natural is authorized to acquire RNG by SB 98, RNG acquisition is also subject to prudence review, and Staff's Opening Comments question the prudence of continuing to voluntarily meet SB 98 targets when less expensive alternatives are available for the Company's significant decarbonization needs. Staff recommends relaxing SB 98 targets and acquiring more CCIs.[24]

Requests for NW Natural:

- Request 21: NW Natural should revise its action plan to relax its approach to SB 98 targets and increase low-cost CCIs.

[21] NW Natural. 2022 Integrated Resource Plan. Figure 6.21.
[22] NW Natural. 2022 Integrated Resource Plan. Page 346.
[23] OPUC Staff Opening Comments. Section 6.
[24] OPUC Staff Opening Comments. Section 6.

- Request 22: NW Natural should run a model sensitivity to determine the PVRR improvement by acquiring CCIs up to DEQ limits, as needed, in each year that they are less expensive than other compliance options (by removing must-take assumptions for SB 98 resources.)
- Request 23: NW Natural should discuss in Reply Comments whether the Company would agree to update its avoided costs for efficiency and RNG to reflect a more relaxed approach to SB 98 targets, and the reasons why or why not.

Section 1.4 – RNG Procurement

In Section 7, Staff discusses NW Natural's current requirements and practices around procurement of low-carbon fuels and compares them to the RFP requirements for electric utilities. Staff makes several recommendations for increased process and oversight of the Company's procurement. These recommendations are designed to address potential utility ownership bias and provide additional oversight of the risks of different contract types.

Additionally, Staff has concerns and questions about the RNG workbook, its accuracy, updates, modeling of risk, and its modeling assumptions including discount rates.

Recommendations for the Commission:

- Recommendation 1: Require filing of updated evaluation models in the IRP. This model should update all variables with the IRP assumptions.
- Recommendation 2: Periodic auditing of NW Natural's approach to RNG acquisition.
- Recommendation 3: Consider requiring RFP scoring details to be included in IRP filings.
- Recommendation 4: Discuss ways to ensure ratepayers are not negatively impacted by NW Natural's choice of deal structure.

Requests for NW Natural:

- Request 25: Staff requests that NW Natural meet with Staff to discuss Staff's questions and concerns regarding the RNG workbook before February 7, 2023.
- Request 24: In Reply Comments, NW Natural should more clearly list and describe the changes made to the RNG Evaluation Methodology.

Section 1.5 – RNG, Green Hydrogen, and Synthetic Gas Quantity and Price Forecasts

In Sections 10 and 11, Staff investigates the Company's assumptions about cost and availability of RNG, green hydrogen, and synthetic methane. By considering a variety of studies, Staff's comments show that NW Natural's cost and availability assumptions are generally optimistic in comparison. However, NW Natural's IRP, as well as most studies of cost and availability, were performed before the passage of the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), which included significant incentives, funding, and programs to support these fuels. Staff asks for clarification on some modeling details regarding RNG costs and availability.

Requests for NW Natural:

- Request 28: In Reply Comments, the Company should provide further discussion supporting and providing justification for its RNG, hydrogen, and synthetic cost assumptions.
- Request 29: In the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity for future IRPs. The cost estimate should be on the higher end of recent, relevant publicly available forecasts.
- Request 30: For the next IRP, the Company should continue to evaluate future cost and availability projections for alternative fuels to natural gas.
- Request 31: For the next IRP, the Company should consider using RNG forecast studies where the underlying data can be examined.
- Request 26: Staff would like NW Natural to provide more information in its Reply Comments about its reasons for assuming that methanation will be inexpensive in comparison to the E3 conservative estimate.
- Request 27: NW Natural should explain in Reply Comments why the additional step of removing the cost of brown gas, transportation, and capacity is necessary or beneficial before modeling low-carbon fuels in PLEXOS. How does this step add value that is greater than the cost of the added complexity and lost transparency? How are the full costs of the fuels reflected in PLEXOS?

Section 1.6 – Load Forecast and Design Peak Planning Standard

Section 1.6.1 – Load Forecast

Section 14 of Staff's opening comments discuss the load forecast, noting that NW Natural's load forecast is likely biased upward because the reference case customer count forecast is used in six out of nine scenarios.[25] The reference case does not consider recent policy and market changes expected to reduce load growth.

Additionally, potential sampling issues with the Monte Carlo analysis where high load forecasts are over-represented may bias the load forecast upward. Staff and Synapse plan to further investigate this trend.

Requests for NW Natural:

- Request 40: Future IRPs must adequately consider the likelihood of declines in customer growth over the planning horizon.

[25] OPUC Staff Opening Comments. Section 14.

- Request 41: In Reply Comments, Staff request that NW Natural share the peak day system load model's regression summary statistics, restricting the use of interaction terms to only that of wind speed interacted with outside air temperature.
- Request 42: In Reply Comments, Staff requests that NW Natural address the causes of the increased usage forecast for new construction commercial customers in Reply Comments.

Section 1.6.2 – Peak Planning Standard

NW Natural's peak planning standard is approximately 100 percent higher than recent peak load events. [26,27] The standard uses 100 years of data to create a Monte Carlo analysis that NW Natural says is designed to meet peak demand with 99 percent certainty.[28] As Staff noted in its Opening Comments in the 2018 IRP, this standard may be too high because of climate trends that may have affected peak cold temperatures over the last 100 years.[29] Staff is also interested in looking further into the Monte Carlo analysis for the peak planning standard and whether it may have inherent bias.

Section 1.7 – Distribution System Planning and Investments

NW Natural describes a new forward-looking distribution system planning process that considers alternatives to pipeline upgrades, including efficiency and demand response. Staff is supportive of this approach. However, Staff questions why NW Natural did not include any forward-looking distribution system projects with timelines of greater than 5 years in this IRP, and how long it will be until NW Natural will begin to introduce forward looking projects in its IRPs and IRP Updates.

Section 1.7.1 – Forest Grove Feeder

NW Natural's investment to uprate the Forest Grove Feeder seems designed to prevent impacts to reliability that could be seen at cold temperatures. Staff comments in Section 12 describe the reasoning and evidence that NW Natural has provided in support of the need for this upgrade, finding that more clarification and data is needed before Staff can make a recommendation on acknowledgement. Pending further information, Staff is cautious regarding whether potential decreases in load could call into question the near-term need for this project. Staff notes that operational mitigation, including the possibility of mobile CNG injection, during a few cold hours of the year should be considered to buy time for considering a non-pipeline solution. Additionally, the cold event in the Pacific Northwest in December, 2022 will be a test of the Forest Grove feeder's performance. Staff requests a report from NW Natural on the effects of this recent cold event on pressures at the Forest Grove feeder.

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[26] NW Natural. TWG 2 Presentation. Slide 46.
[27] Attachment 1 to NW Natural's reply to Staff IR 77 shows actual peak day load for recent years.
[28] NW Natural. 2018 Integrated Resource Plan (Docket No. LC 71.) Page 1.8.
[29] OPUC Staff. Opening Comments in Docket No. LC 71. Page 10.

Requests for NW Natural:

- Request 32: By March 7, 2023, Staff requests that NW Natural provide further analysis of the events that might cause load levels to trigger a pressure drop of 40 percent or higher on the Forest Grove Feeder and the forecasted timing of that occurring. The proposed analysis should take account of uncertainties in customer growth, such as the decrease in customer numbers due to current trends of distributed energy resources, demand-side solutions or likely electrification rates.
- Request 33: By March 7, 2023, for any anticipated rare occasions of pressure drops, NW Natural quantify the impact of loss of pressure in the Forest Grove area in terms of the impacted number of nodes, affected number of customers, and the typical duration of outages for temperature-dependent customers.
- Request 34: By March 7, 2023 Staff would like NW Natural to re-study previously considered non-pipeline alternatives on the demand-side if the Forest Grove Uprate Project is proven to be not needed in the near term. The identification and cost-benefit analysis of non-pipeline alternatives should be as extensive as pipeline solutions, and may include testing: the extent of geographically targeted residential/commercial demand response; and the potential for peak-focused energy efficiency.
- Request 35: By March 7, 2023, for short term measures of predicted low pressure events for less than two days per season, consider the economics of new non-pipe solutions on the supply side, such as mobile CNG injection.
- Request 36: In Reply Comments, NW Natural should provide a detailed report on any pressure drop or other event at the Forest Grove feeder during the cold event of late December, 2022. The report should include the average daily temperature in Forest Grove during the event.

Section 1.7.2 – Portland LNG Cold Box

Staff also discusses the historical usage of the Portland LNG Cold Box in Section 13, noting that the full capacity of the Portland LNG facility has not generally been used in recent years, and stating that:

> Even on high draw down years (such as 2019 or 2022), there is still about a quarter of liquified capacity still available by the end of the year. […] Staff would like to explore the reasons NW Natural did not consider a smaller capacity storage when planning for the replacement of the cold box. Unless there are other reasons, a lower capacity cold box may be a more feasible option congruent with the valid assumption of lower reliance on natural gas in the long term in order to comply with lower CPP targets.[30]

[30] OPUC Staff Opening Comments. Section 13.

Staff requests more information on the potential alternatives considered for the Cold Box, including RNG, the installation of a smaller cold box, or retaining partial functionality at the LNG facility without a cold box.

Requests for NW Natural:

- Request 37: If the original design of the Cold Box has higher capacity than currently needed, NW Natural should investigate a lower capacity cold box replacement project as a lower-cost alternative and share the analysis with Staff before March 7, 2023.
- Request 38: Staff would like to see in the Reply Comments that NW Natural has exhausted all alternatives to pursuing the Cold Box replacement project and for NW Natural to consider supply-side non-pipe solutions.
- Request 39: NW Natural needs to consider the scenarios of falling demand due to decarbonization when calculating the costs and benefits of trucking LNG for the study years starting from 2026. What are the potential benefits of using mobile LNG for a few peak seasons, if load eventually declines making the Cold Box unnecessary?

Section 1.8 – Gas Price Forecast

Staff looks into the Company's forecast for natural gas prices in Section 15. These comments explain that the conventional gas price forecast is important because it affects IRP portfolio resource selection, as well as the avoided costs of efficiency investments and RNG investments.[31] NW Natural's forecast is shown to be similar to other utility gas price forecasts. Staff requests more information and transparency on the natural gas price forecast from the Company in its Reply Comments.

Staff opening comments also discuss the statistical approach to the natural gas price forecast, noting that the approach could be improved by implementing a Vector Autoregressive (VAR) model to allow price shocks to occur at any gas hub, not just the Sumas hub.[32]

Requests for NW Natural:

- Request 43: Staff requests the Company explain in its Reply Comments if and how demand and supply side factors such as conservation efforts, state and local climate policies, electrification, and the availability of conventional natural gas alternatives like RNG and others were considered in the gas price forecasts used in the IRP.
- Request 44: Staff requests NW Natural to include in its Reply Comments on whether it could work with IHS Markit to construct a metric(s) for a growing share of RNG in the system and/or aggressive electrification in the West and pick a representative gas price forecast for a future incorporating this metric(s).
- Request 45: Staff requests NW Natural explain in its Reply Comments how price events at Sumas or the price variations across hubs in general may affect avoided cost

[31] OPUC Staff Opening Comments. Section 15.

[32] OPUC Staff Opening Comments. Section 3.

calculations for energy efficiency, RNG resources, and distribution system investments. The explanation should provide additional information regarding why the Company views the inclusion of higher, more volatile prices at Sumas as an improvement to the accuracy of avoided costs.

- Request 8: Staff requests that NW Natural revisit the stochastic modelling used in its gas price forecast in a future IRP, particularly to evaluate whether a Vector Autoregressive or similar time-series cointegrated model should be implemented.

Section 2: IRP Guidelines

Rose Anderson, Senior Economist

Staff reviewed the OPUC's IRP Guidelines and found that NW Natural's IRP follows the guidelines with a few exceptions. This section discusses several ways that NW Natural's 2022 IRP methodology could be improved to better meet the OPUC's IRP Guidelines.

Section 2.1 – Cost

The OPUC IRP Guidelines state that the IRP should include the following:

i. *Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*[33]

ii. *Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*[34]

Additionally, OPUC IRP Guideline 5 states:

> *Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered* [35]

The NW Natural IRP does not rank order portfolios, but instead looks at a variety of potential futures and attempts to plan for an 'average' future based on the Monte Carlo analysis.[36,37]

NW Natural's portfolios do not consider the cost of distribution pipeline upgrades that will be required to accommodate load growth in portfolios. In the past, when each portfolio had a similar amount of load, exclusion of distribution system costs was acceptable since costs were likely to be the same in each portfolio. Now that different portfolios/scenarios can have very different load forecasts, NW Natural needs to move toward a portfolio analysis that considers the cost of capital investment, including distribution system upgrades in each portfolio.

NW Natural provides a 'rate impact' analysis that theoretically could be used to compare portfolios. However, this analysis has much room for improvement, as it does not consider differences in long term capital spending between scenarios with vastly different loads. It also does not appear to consider any elasticity of demand that could cause changes in demand resulting from changes in rates.

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[33] OPUC IRP Guideline 4j at 5.
[34] OPUC IRP Guideline 4l at 5.
[35] OPUC IRP Guideline 5 at 5.
[36] NW Natural. 2022 Integrated Resource Plan. Page 19.
[37] NW Natural's response to OPUC Staff DR 69. Page 3.

In order for a given portfolio to represent the best combination of cost and risk for the utility and its customers, NW Natural needs to consider the capital costs associated with varying levels of load in its scenarios. Consideration of elasticity of demand is also relevant, but Staff currently finds that changes in distribution system costs should be prioritized as a first step toward more accurate portfolio costs.

Request for NW Natural:

Request 1: NW Natural should respond in Reply Comments regarding its ability to consider capital expenses that vary between scenarios and price elasticity of demand in its rate impact analysis.

Section 2.2 – Risk

OPUC IRP Guideline 4i requires an IRP to include:

> *Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*[38]

The IRP looks at nine scenarios and attempts to find an average future through Monte Carlo analysis. This approach lacks an assessment of how certain scenarios would perform under different circumstances. For example, how does the portfolio from the balanced decarbonization scenario perform if RNG or H2 are less available? How does the 'average' portfolio described in Section 7.6 perform if natural gas prices turn out to be higher or lower than expected? This type of risk analysis is a fairly simple next step that should have been performed in this IRP.

OPUC IRP Guideline 1(c) provides:

> *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.*[39]

The IRP assesses risk but falls short in important ways. The Monte Carlo analysis used to assess risk includes questionable assumptions, such as the probability of each portfolio being equal.[40] This assumption is not discussed or supported in the IRP itself. This IRP also does not adequately assess long-term capital costs that may differ between scenarios. Additionally, NW Natural fails to consider the risk of unnecessary distribution system upgrades to customers (or equivalently, distribution system stranded cost risk for the Company). Distribution system upgrades are discussed further in Section 4 and in Section 12.

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[38] OPUC IRP Guidelines at 5.
[39] OPUC IRP Guidelines at 1-2.
[40] NW Natural. TWG 2 Presentation. Page 122.

OPUC IRP Guideline 1(c) states:

> *To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*[41]

Because the NW Natural IRP does not consider sensitivities to its scenarios to help assess their performance, it cannot compare the PVRR variability and severity risks of bad outcomes for its scenarios. While it may not be necessary to conduct this analysis for every scenario in the IRP, the IRP analysis cannot meet the requirements of the IRP guidelines without some assessment of variability and severity, especially for the preferred portfolio. Staff's comments further discuss the assessment of risk through Monte Carlo analysis in Section 3.

Request for NW Natural:

Request 2: NW Natural should use the stochastic capabilities of PLEXOS to assess the variability and severity of risks in its preferred portfolio before the Commission's acknowledgement decision in this IRP.

Section 2.3 – Conservation

OPUC IRP Guideline 6 provides that:

> *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*
>
> - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
>
> - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.* [42]

NW Natural's 2022 IRP does not meet the requirement to consider the acquisition of conservation resources "without regard to any limits on funding of conservation programs." There is no scenario in the IRP that allows the PLEXOS model to look at acquiring efficiency to meet compliance needs and reduce costs for customers above and beyond what Energy Trust of Oregon (Energy Trust) has predicted will be available and cost-effective.

[41] OPUC IRP Guidelines at 2.
[42] OPUC IRP Guidelines at 6.

Demand response is also not considered as a resource option in PLEXOS. Given that the Company's peak planning standard is about 100 percent higher than recent peak load events, inclusion of all potential capacity resources including demand response will result in more cost-effective portfolios.

Request for NW Natural:

Request 3: NW Natural should do an additional model run to see what PLEXOS would select from the Energy Trust technical potential if given the option to compete all efficiency measures with supply-side resources, rather than hard-coding energy efficiency to the levels forecasted as cost-effective by Energy Trust. Demand response resources should also be included.

Section 3: Portfolio Evaluation

Curtis Dlouhy, Economist/Senior Utility Analyst

Portfolio Evaluation Background

In its portfolio selection section of its 2022 IRP, Northwest Natural presents the results of analyzing nine individual scenarios in the PLEXOS model and a summary of a 500-draw Monte Carlo simulation. The inputs to the Monte Carlo simulation are based on the assumptions in the individual scenarios. For example, the range of different load forecasts considered in the Monte Carlo simulation are approximately bounded by the lowest and highest load forecasts from the individual scenarios. By Staff's understanding, the nine scenarios employ a deterministic lens of the future whose core assumptions come from a common base case and then are modified to meet the needs of a certain scenario. For example, the scenarios exploring aggressive electrification or no new customer growth would both modify the relevant assumptions around load or customer count to fit the scenario but would leave unrelated base case assumptions untouched, such as weather or the gas price forecast. The full list of scenarios with their assumptions is contained in Table 7.3 of NW Natural's 2022 IRP filing, reproduced below.

Table 1: Reproduction of Table 7.3 in NW Natural's 2022 IRP

	2022 IRP Scenarios- Summary Version	Reference (Trend Continuation) Case	1 Balanced Approach	2 Carbon Neutral by 2050	3 Dual-Fuel Heating Systems	4 New Direct Use Gas Customer Moratorium in 2025	5 Aggressive Building Electrification	6 Full Building Electrification	7 RNG and H2 Production Tax Credit	8 Limited RNG Availability	9 Supply-Focused Decarbonization
Demand-Side	Weather	Climate change adjusted expected ("normal") weather in each year									
Demand-Side	Customer Growth	Current expectations				No New Customers After 2025			Current expectations		
Demand-Side	Space and Water Heating Equipment	Current EE expectations	Moderate gas powered heat pump and hybrid heating adoption		All residential and commercial space heating becomes hybrid heating by 2050	Moderate gas heat pump and hybrid adoption for existing customers	High electrification of existing residential and commercial load by 2050	Full electrification of existing residential and commercial load by 2050	Moderate gas heat pump and hybrid heating adoption		No gas powered heat pumps and low levels of hybrid heating
Demand-Side	Industrial Use Efficiency		Consultant projection	High sensitivity	Consultant projection		60% Electrified by 2050	90% Electrified by 2050	Consultant projection		
Demand-Side	Building Shell Improvement		Energy Trust projection	Energy Trust high sensitivity projection	Ajusted Energy Trust projection				Energy Trust projection		
Supply-Side Assumptions	Conventional Gas	Expected pricing in each month									
Supply-Side Assumptions	Capacity Resources	All capacity resources available at expected cost									
Supply-Side Assumptions	Renewable Natural Gas	Expected availability and cost		Higher availability and expected cost	Expected availability and cost				High avail and low cost to customers	Low availability and high cost	Expected availability and cost
Supply-Side Assumptions	Hydrogen	20% Energy maximum (blended and dedicated) and expected cost		40% Energy maximum and expected cost	20% Energy maximum and expected cost				30% energy max and low cost to customers	12% energy max and high cost	35% max and expected cost
Supply-Side Assumptions	Synthetic Methane	No energy max and expected cost							No energy max and low cost to customers	No energy max and high cost	No energy max and expected cost
	OR- CCIs	Costs and limits defined in CPP rule									
	WA- Allowances & Offsets	Higher of social cost of carbon or California allowance projection in each year									

In addition to the scenario analyses discussed above, the Company presents a stochastic analysis that is based on the results of a 500-draw Monte Carlo simulation. NW Natural explains that when constructing each Monte Carlo draw in its stochastic analysis, it builds in correlations between related variables while assuming some stochastic processes are uncorrelated.[43] For example, the price of conventional natural gas at the four hubs NW Natural

[43] NW Natural. 2022 Integrated Resource Plan. Page 256

uses are likely correlated with each other, but there is no clear reason to expect a strong correlation between customer growth rate and a capacity resource's cost. In particular, it appears that the Company assumes that gas prices are correlated across hubs, climate and weather are correlated across loads, and fixed resource costs are partially correlated due to the cost of labor inputs.[44]

NW Natural finds that the Portland LNG Cold Box is the least cost solution in the reference case, all nine scenarios, and all Monte Carlo draws. It also finds that some level of Mist Recall will be used as a capacity resource in all scenarios and all but four of the 500 Monte Carlo draws.[45] When it comes to compliance resources, all scenarios rely on reducing demand and investing in some level of RNG in the timeline of the IRP action plan. In all but the full building electrification scenario, a non-trivial level of CCI purchases are used fill in any Oregon compliance gaps.[46] The Company notes that CCIs (and offsets and allowances in Washington) can be used to flexibly fill in the gaps on the front or back end of a compliance period, leading to spikes in their use that can be seen in the results of the Company's Monte Carlo draws.[47,48]

Staff is generally appreciative of the effort Northwest Natural has made to consider various future events in the 2022 IRP. However, Staff has some concerns about the way the Company has chosen to carry out certain parts of its risk analysis and the lack of a clearly identified preferred portfolio.

Staff Comments

Staff is supportive of some of the techniques used by the Company in its portfolio selection. In particular, the Company put a lot of thought in parsing out which stochastic inputs should be modelled as correlated or uncorrelated. However, Staff has concerns about the Company's Monte Carlo analysis and gas price forecasts that may impact the fairness and accuracy of some of NW Natural's analysis. Staff believes the Company can address these concerns with changes to the modelling choices of each process and how they are implemented.

Section 3.1 - Monte Carlo Analysis

In an ideal world, the Company could conduct stochastic analysis from more than the 500 Monte Carlo draws it used in its portfolio evaluation. However, the Company explained to Staff that its chosen method of IRP analysis required a separate PLEXOS run for each Monte Carlo draw, which cumulatively took upwards of a month to complete. With this in mind, Staff believes that 500 Monte Carlo draws used by the Company can be sufficient to learn how the optimal portfolio changes when faced with risk. However, these 500 Monte Carlo draws could be better matched to each scenario to illustrate stochastic risk and scenario uncertainty.

[44] NW Natural. 2022 Integrated Resource Plan. Appendix F
[45] NW Natural. 2022 Integrated Resource Plan. Page 347
[46] NW Natural. 2022 Integrated Resource Plan. Page 325
[47] NW Natural. 2022 Integrated Resource Plan. Page 350
[48] It should be noted that while Washington allows CCIs, offsets, and allowances for compliance purposes, Oregon only allows the use of CCIs. This is further discussed in Chapter 6.5.

To articulate Staff's concerns, it is worth introducing the economic definitions of "risk" versus "uncertainty." In his seminal book, Frank Knight draws a distinction between these two core ideas discussing the unknown.[49] As Knight defines it, something is "risky" if the outcome is unknown, but the probability distribution of the outcome is known. This framework works well for well-understood, longstanding processes backed with data such as weather, price fluctuations, or population modeling. Conversely, something is "uncertain" if neither the outcome nor the probability distribution is known. This is more appropriate for future events that do not have much precedent or data, such as the effects of novel policy changes or adoption of new, disruptive technologies. Fitting a probability distribution to uncertain outcomes treats uncertain events improperly as risky events, muddying this subtle but important distinction. Staff finds this to be a valuable distinction in the context of the IRP not only to best set up a fair comparison between portfolios, but also because the IRP guidelines contained in Order 07-002 separately discusses risk and uncertainty multiple times.

Section 3.2 - Distribution of Outcomes

Using this distinction between risk and uncertainty, Staff outlines its concerns about the structure of the Company's stochastic analysis and Monte Carlo simulations. As a reminder, the Company does one deterministic PLEXOS model run for the reference case and each of the nine scenarios previously identified. The Company creates a distribution of outcomes whose outer bounds are informed by the extreme values of the scenarios, essentially treating the characteristics associated with each scenario as risky outcomes. For example, the customer count and the resulting effects on load appear to be modeled as a random value between the reference case and the full building electrification case. By randomly assigning loads based on very different and uncertain scenarios, the Company is tacitly functionalizing the probability of reaching each of its scenarios.

Imposing a probability distribution *across* these uncertain futures is an improper use of stochastic analysis that biases analysis towards outcomes that the distribution – which is not well justified by data or precedent – deems more likely. Instead, Staff would like to see the results of a stochastic analysis *within* each of the scenarios identified. In this way, the Company could more clearly present where the risk within each scenario lies and which portfolio options are robust to both scenario uncertainty and the more well-understood stochastic risk as prescribed by guidelines 1(b), 4(i), and 4(k). By identifying and trying to hold constant the uncertain aspects that characterize certain scenarios, the Company would avoid the perils of defining a distribution across uncertain outcomes, while including valuable information about how risk functions within the scenario. For example, price fluctuations in a high-electrification scenario likely have a much different impact than they do in a supply-side decarbonization scenario that is useful to interpret, but trying to also define the probability of being in a world similar to one of these scenarios clouds the interpretability of the price fluctuations. This risk-within-scenario setup allows the evaluator of the portfolio to better understand the potential

[49] Knight, F. H. (1921). *Risk, uncertainty and profit* (Vol. 31). Houghton Mifflin.

cracks in the plan without being overly concerned with the modeling choices used to functionalize the uncertain aspects of each scenario. In this way, a smaller number of PLEXOS runs within each scenario would be more useful than the 500 PLEXOS runs across all scenarios. It could be more informative to produce 55 Monte Carlo draws and associated PLEXOS runs on each of the nine scenarios. Staff recommends that the Company structure their future stochastic analysis in this way. Additionally, sensitivities for some scenarios should be considered to help inform how the scenario would change under certain potential conditions, such as different RNG costs or a different load forecast.

Section 3.3 - Demand-Side Resource Selection in PLEXOS

The Company does not allow PLEXOS to select demand-side resources as part of an optimal portfolio even though PLEXOS has the ability to do so.[50] The Company claims that this is because Energy Trust and the Applied Energy Group (AEG) in Washington must assess the cost-effective available demand-side resources. Even if this were the case, it to be worthwhile to see how PLEXOS would choose to deploy demand-side resources given current expectations around cost effectiveness. In fact, the IRP guidelines require a study of how much conservation would be required in absence of any Energy Trust limits on funding.[51] Staff recommends that the Company include a PLEXOS model run where demand-side resources are an option for informational purposes under each scenario.

Section 3.4 - Lack of a Preferred Portfolio

The lack of a clearly identified preferred portfolio in NW Natural's IRP makes it difficult to say that the Company has followed the IRP guidelines. IRP guidelines 4i, 4j, and 4k require the Company to rank candidate portfolios based on various criteria, and guideline 4l requires the Company to select "a portfolio that represents the best combination of cost and risk for the utility and its customers."[52] The Company claims that these rankings and selections are done in Chapter 7 of its IRP filing, its chapter on portfolio selection.[53] Staff's review and analysis of the Chapter 7 found no such ranking of portfolios or anything identifying a particular candidate portfolio that minimizes cost and risk. The IRP action plan does identify near-term actions that align with the overall findings in Chapter 7, such as moving forward with the Portland LNG Cold Box, recalling Mist or pursuing a city gate deal, scoping demand response programs, acquiring RNG and acquiring energy savings.[54] However, the lack of a clearly identified, longer-term plan prevents Staff from effectively weighing in on the Company's overall resource direction. The Company has since clarified with Staff that the average of its Monte Carlo simulations is its preferred portfolio.[55] In order to meet the criteria of acceptance, Staff recommends that the Company file an addendum identifying a preferred portfolio that lists the relied-upon assets.

[50] Response to Staff DR 8 and 9.
[51] IRP Guideline 6(c). Order No. 07-047.
[52] Order No. 07-047, Page 6.
[53] Appendix A, Page 19.
[54] NW Natural. 2022 Integrated Resource Plan. Page 396
[55] NW Natural. Response to Staff DR 69(c)

Section 3.5 - Trigger Point Analysis

Staff also notes that the Company's method to address guideline 8 is to conduct scenario analysis and stochastic analysis in place of a trigger point analysis. While Staff has brought up criticisms of the interaction between the scenario and stochastic analysis, Staff finds that the scenario analysis conducted by the Company could be used to demonstrate the trigger points driving large changes in the optimal scenario. However, the structure and presentation of analysis conducted by NW Natural makes it difficult for a reader to determine which aspects or collection of aspects in each scenario lead to these changes. Staff requests that NW Natural provide a clear comparison between the optimal scenario portfolios that highlights the scenario aspects that "trigger" large changes in the optimal portfolio.

Staff's criticisms of NW Natural's approach aside, the Company's PLEXOS modeling indicates that, investing in the Portland LNG Cold Box and relying on some level of Mist Recall are least-cost and least-risk capacity investments. Although the Company's gas price forecast could be more nuanced and the Company's stochastic modelling should have been better targeted, Staff does not believe improvements to the portfolio analysis would have altered the action plan in this proceeding. NW Natural's sheer volume of analysis considered enough outcomes pointing to the same capacity resource conclusion and appears to meet the requirements set forth in guideline 4. Each of the nine scenarios and the reference case in PLEXOS recommended adopting these resources, and nearly all of the stochastic analyses point to the same outcome. Although Staff raises concerns about the details of the stochastic analysis and recommends that they be modified for future IRPs, the stochastic analysis in the IRP appears to be adequate to support the Cold Box and Mist Recall resource options as they are modeled in PLEXOS.

NW Natural conducted distribution system analysis of potential alternatives to the Portland LNG Cold Box outside of the PLEXOS model. This analysis is discussed in in Chapter 8 of the IRP on Distribution System Planning. The Staff comments in Section 13 discuss potential alternatives to the Portland LNG Cold Box, including some alternatives that were not considered in NW Natural's distribution system analysis or in PLEXOS, and could potentially be lower cost/risk. While the PLEXOS results indicate that the Portland LNG Cold Box is the least-cost least-risk capacity investment, Staff notes that the inclusion of these alternatives in PLEXOS could potentially change the results.

Section 3.6 – Gas Price Forecast

The gas price forecast is one area in particular where the Company can improve its stochastic analysis. As described in Appendix F, the Company assumes that the only source of stochastic shocks enter the model through an ARIMA process at the AECO hub, and any shocks propagate out from there to the other three hubs.[56] While this allows for correlation across hubs and for a shock at AECO to affect other hub prices, this means that the model cannot capture the effects of a random event that occurs at a non-AECO hub, such as a localized supply shock or pipeline

[56] NW Natural. 2022 Integrated Resource Plan. Appendix F, page 145.

disruption. Building in this nuance would allow the model to capture supply shocks that were otherwise ignored, such as a possible equipment failure at Sumas.

A computationally simple way to add in randomness at each hub while preserving the correlation is through respecifying Step 5 of the Company's gas price forecast methodology as a Vector Autoregressive (VAR) model. Put simply, VAR models can capture the correlation between time-series processes while maintaining that the correlations may not be symmetric and that each time series might have its own stochastic process. Staff implementing a VAR model with monthly dummy variables using monthly prices at NW Natural's four main hubs and found promising model fit, model behavior, and residual patterns. While Staff does not expect that the gas price stochastic modelling choice significantly altered the results of the portfolio selection in the IRP for reasons described above, Staff recommends NW Natural reassess its stochastic modelling of its gas price forecast for future IRPs as a matter of best practice.

Requests for NW Natural:

Request 4: Staff requests that the Company file an addendum to the IRP identifying a preferred portfolio that lists the relied-upon assets. The filing should more clearly identify the resource decisions by year in the preferred portfolio on which the action plan is based and discuss how the analysis done in Chapter 7 led to the portfolio selection.

Request 5: In Reply Comments, Staff requests that NW Natural discuss its ability to complete a PLEXOS model run, before the acknowledgement decision in this IRP, for each scenario where demand-side resources can be optimally chosen by PLEXOS. The full electrification scenarios, i.e., Scenarios 5 and 6, can be excluded from this request.

Request 6: In Reply Comments, Staff requests that NW Natural conduct a trigger point analysis described in Guideline 8 or further discuss which aspects of its current scenario and stochastic analysis drive changes in the optimal portfolio.

Request 7: Staff requests that in future IRPs, NW Natural does not treat its scenario analyses as entirely deterministic. Instead, Staff requests that NW Natural conduct stochastic analysis within each scenario rather than across all scenarios. Additionally, sensitivities for some scenarios should be considered to help inform how the scenario would change under certain potential conditions such as different RNG costs or a different load forecast.

Request 8: Staff requests that NW Natural revisit the stochastic modelling used in its gas price forecast in a future IRP, particularly to evaluate whether a Vector Autoregressive or similar time-series cointegrated model should be implemented.

Section 4: CPP Compliance & Risk Evaluation

Kim Herb, Utility Strategy & Planning Manager

Given great uncertainty regarding capacity need and lowest cost emission reduction resources, rather than a traditional 'preferred portfolio,' the Company presented an Action Plan that it describes as a "low-regret path forward."[57] The Action Plan ensures reliability and meets near-term emission compliance obligations, including CPP requirements.[58]

Staff appreciates the challenges of modeling uncertainty during the Company's transition to a decarbonized system. However, given these uncertainties, Staff has concerns with whether NW Natural's assumptions and modeling used to evaluate different paths for CPP compliance and the resulting Action Plan meet IRP Guideline 1 requirements.[59]

Guideline 1a requires that all resources be evaluated on a consistent and comparable basis. However, NW Natural's IRP struggles to evaluate and consider demand side options, such as energy efficiency and demand response, on a consistent and comparable basis to supply side options. Failure to consistently and comparably evaluate all resources subsequently affects its ability to meet Guideline 1b.

Guideline 1b requires that gas utilities consider the risk of commodity supply and price. NW Natural's IRP considers these costs and risks in its modeling but presents a supply-heavy approach that exposes its customers to increasing variable fuel costs with high levels of price uncertainty. Staff is concerned that all financial risks are not fully present in the Company's supply-heavy approach.

Guideline 1c states that gas utilities, in seeking the selection of a portfolio of resources with the best combination of expected costs, associated risks, and uncertainties for the utility and its customers, should include analysis of current and estimated future costs for all long-lived resources, such as power plants, gas storage facilities, and pipelines. NW Natural's IRP does not capture how existing customers are exposed to costs and risks of long-lived resources related to continued system growth from the acquisition of new customers, such as pipelines.

NW Natural has presented an approach that does not evaluate demand side options on a consistent and comparable basis with supply-side options, is optimistically supply-side oriented, and overlooks implicit costs of new customers. The resulting plan appears to present an unbalanced approach to managing the uncertainty associated with decarbonization that most likely results in increased risk exposure for customers.

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[57] NW Natural 2022 IRP at 25.
[58] LC 79 IRP page 28.
[59] Order No. 07-047

Given the level of uncertainty around capacity needs and least cost, least risk solutions, Staff would expect to see risk modeling that limits exposure by:

- Full consideration of all demand side options,
- Highly scrutinizing the implicit cost of expanded systems from continued customer acquisition trends, and
- Employing conservative price and availability assumptions that represent low risk-tolerance where there are high levels of uncertainty.

Unfortunately, the scenarios NW Natural analyzed fail to adequately consider these approaches. While the paths presented by the Company are all designed to meet the CPP emission reduction requirements, the Action Plan may not represent a least cost, least risk plan.

Section 4.1 – Uncertainty and Risk Mitigation Evaluation

In this section, Staff explores the various scenarios and assumptions in the context of risk to customers. Staff draws the distinction between "uncertainty" and "risk" as referenced in Section 3.[60] In the Natural Gas Fact Finding investigation (UM 2178) participants described ways to improve gas system planning and identified approaches that could help mitigate risk and manage uncertainty.[61] There are several potential approaches to reducing uncertainties and mitigating risks to consider in gas resource planning:

- Avoiding activities that increase future compliance obligations or affect the distribution of compliance costs to mitigate compliance-related risk;[62]
- Preserving compliance flexibility, which includes avoiding an over commitment to compliance strategies that may lead to greater levels of stranded assets;[63]
- Prioritizing investments in known and available solutions;[64] and
- Being conservative in projecting costs and availability (both volumes and timing) of emerging solutions/technologies to help manage uncertainty related to the relative unpredictability in nascent technologies.[65]

These approaches could be demonstrated in a gas utility Action Plan that includes the following characteristics:

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[60] Knight, F. H. (1921). *Risk, Uncertainty and Profit* (Vol. 31). Houghton Mifflin.

[61] While that process did not result in explicit recommendation, Staff intends to further explore and apply the learnings from that process in active dockets. See UM 2178 Draft Report, Comment Summary for October 26, 2021, December 3, 2021, and June 3, 2022, Comment Periods in docket UM 2178, and UM 2178 July 21, 2022 Special Public Meeting.

[62] UM 2178 Comment Summary for October 26, 2021, December 3, 2021, and June 3, 2022 Comment Periods, pages 7 and 12,

[63] UM 2178 Draft Report, page 7.

[64] UM 2178 Draft Report, page 21.

[65] UM 2178 Draft Report, page 26 and Appendix B, page xiv - xv.

- Heightened evaluation of the compliance cost impact of customer growth and long-term investments that reduce compliance flexibility, such as those in the distribution system;
- Flexible portfolios developed through evaluation of all resources - demand-side and supply-side - using consistent assumptions and on a comparable basis; and
- Application of reasonable, conservative, and supported assumptions.

NW Natural's Oregon Action Plan includes capacity resources through Mist Recall and investment in the Portland Cold Box. It includes compliance items of RNG and CCI credit purchases and ongoing energy efficiency savings through Energy Trust programs. It also includes development of transportation customer energy efficiency programs by 2024 and a demand response program for residential and commercial customers. Lastly, its Action Plan includes one distribution system component update, in service in 2025, to the Forest Grove (or McKay Creek) feeder.[66] This Action Plan includes both demand and supply side actions. Staff questions the scale at which these actions are considered or deployed, the unconsidered risks (e.g., expanding pipeline system to accommodate ongoing customer growth; elevated RNG prices; etc.), and the additional compliance obligations it may create.

NW Natural did not present a preferred portfolio. Instead, NW Natural shared ten scenarios with varying policy and market assumptions ranging from supply-side resource decarbonization measures, gas moratoriums, and full building electrification:[67]

- Scenario 0 – Reference Case
- Scenario 1 – Balanced Decarbonization
- Scenario 2 – Carbon Neutral
- Scenario 3 – Dual-Fuel Heating
- Scenario 4 – New Customer Moratorium
- Scenario 5 – Aggressive Building Electrification
- Scenario 6 – Full Building Electrification
- Scenario 7 – RNG & H_2 Federal Policy Support
- Scenario 8 – Limited RNG Availability
- Scenario 9 – Supply-Focused Decarbonization

These scenarios provide Staff some insight into what the Company would seek to procure under a variety of different regulatory, cost, and electrification futures. The range of assumptions and results between the scenarios also helps inform the risks faced by both the Company and customers, given the vastly different futures the Company may face and the divergence of the paths it would take to respond to each future. But as discussed in the sections that follow, Staff has questions about the assumptions used within these scenarios, comparability across these scenarios, and whether risk is adequately considered through the use of these scenarios.

[66] IRP, Section 9.

[67] See Table 7.3 in the IRP for a more detailed summary of each scenario.

Section 4.2 – Avoiding Increased Compliance Obligations and Long-term Costs

Each new customer on NW Natural's system brings additional compliance obligations and increased infrastructure costs, both of which are costs spread across existing customers. This becomes even more problematic with the risk of customers responding to price signals or emissions concerns by transitioning off the gas system, which could reduce the number of customers over which to spread the cost of new investments in long-lived infrastructure. Staff is concerned that the IRP modeling does not capture the distribution system expansion costs that would be associated with the addition of new customers.

In UG 435 the Oregon Citizens' Utility Board (CUB) raised CPP compliance obligation costs associated with line extension allowances for new customers and successfully argued for modifications to the PUC's line extension allowance (LEA) for NW Natural. In summarizing CUB's argument, the Commission noted that:

> CUB maintains that as the system grows, the costs to reduce emissions to comply with the CPP will also increase. […] CUB asserts that […] under a traditional paradigm adding new customers mitigates cost impacts, it is not true when new customers bring additional emission reduction costs to all customers.[68]…[U]nder the CPP, NW Natural must reduce its greenhouse gas emissions by 50 percent from a historic baseline, but that as the system grows, NW Natural will have to reduce baseline emissions by 69 percent to accommodate the load growth and still meet the emissions reduction requirements. CUB argues that this increases the costs to existing customers. […] CUB maintains that NW Natural is seeking to significantly increase its energy efficiency spending to reduce therms while also spending millions on capital investments through the LEA to increase therms. CUB asserts that therms from existing customers are different than those from new customers, because it takes decades to pay back LEA spending and it is more cost effective to not subsidize growth through the LEA than to pay incentives to customers to reduce usage.[69] CUB contends that NW Natural is asking customers both to pay to grow the system and pay for energy efficiency incentives.[70]

The Commission agreed with CUB on this issue and states:

> The primary reason that NW Natural's current LEA is problematic is that it fails to take into account any of the costs that are brought to

[68] UG 435 CUB Opening Brief at 12.
[69] UG 435 CUB Opening Brief at 13.
[70] Order No. 22-388 at 34.

> NW Natural's system from new customers associated with greenhouse gas emission abatement obligations placed on the company under the CPP. As shown in this case, those costs could be significant.[71] In fact, the record demonstrates that those costs, when accurately accounted for, could result in no or negligible economic benefit being brought to the existing system from the addition of new customers.[72]

This Commission Order, in recognizing that new customers bring new compliance obligations and related costs, raised the bar on the burden of proof regarding the value brought by the addition of new customers to the system. In doing so, it signals awareness of increased risks of new customers and that this is an area worthy of heightened scrutiny in both planning and cost recovery dockets.

There are several ways that NW Natural's IRP scenarios do not account for the full cost and risk associated with new customers. Except for scenarios 4, 5, and 6, every scenario assumes continued customer growth based on historic trends. Yet, NW Natural's optimization modeling excludes the NPVRR of projected future capital expenditures to support these customers. This results in an inadequate representation of system costs across these portfolios. Further, it does not appear that the company accounts for the potential for reduced compliance flexibility and stranded asset risks that come with long term investments associated with new customers.

Additionally, Staff notes that the Action Plan presented by the Company represents a notable and significant increase in the amount of energy efficiency in the early years, which helps it maintain an almost flat demand despite customer growth. Increased investment in efficiency could be one approach to reducing compliance costs associated with new customers. However, it is not clear to Staff whether the projected load reductions adequately reflect the additional spending required to mitigate emissions associated with new customers. Staff continues to review Energy Trust's EE modeling and budget and NW Natural's projected energy efficiency. At a minimum, energy efficiency investment should be sufficient to counter the emissions from new customers.

A more direct approach to reducing the costs and risks of customer growth would be to implement a fuel-neutral RFP for non-pipe alternatives. For example, if an especially expensive new distribution system investment is expected to be required in a residential area based on a customer growth forecast, then NW Natural could issue an RFP for peak load reduction alternatives to a distribution system upgrade. Alternatives could include electrification, efficiency, and alternative fuels blending approaches. RFPs for Non-Pipe Alternatives (NPAs)

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[71] From UG 435, Order No. 22-388 See, e.g. CUB/100, Jenks/12, 13 (identifying costs of compliance associated with new customers added to the system).

[72] UG 435 Order No. 22-388 at 48

have recently been used by ConEdison and NYSEG.[73,74] ConEdison implemented a temporary moratorium on new customers while it searched for NPA solutions for its constrained system. Staff invites further discussion of whether this approach could be appropriate for NW Natural to reduce cost and risk to existing customers.[75]

Given infrastructure and compliance cost and risk implications of continued increased customer counts, the action plan does little to address these specific uncertainties. Staff notes that the Commission provided guidance relevant to CPP compliance costs and customer growth in Order No. 22-388 regarding the nature of analysis the Company should be expected to conduct to support arguments for LEA. Similar guidance may be valuable insofar as it relates to analysis conducted in the planning process. This includes:

- Conducting analysis of how each new customer addition changes the costs of CPP compliance for other customers; and
- An analysis supporting the company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics are factored in.[76]

Requests for NW Natural:

Request 9: Future IRPs should strive for compliance path flexibility by considering proactive strategies to minimize growth related investments in the distribution system.

Request 10: In Reply Comments, NW Natural should explain how it considered the potential for reduced compliance flexibility and stranded asset risks that come with long term investments associated with new customers.

Request 11: In Reply Comments, NW Natural should respond to Staff's recommendation that the Company consider a non-pipe alternative RFP as a part of certain high-cost distribution system upgrade decisions.

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[73] NYSEG. RFP for Innovative Solutions. Accessed at: https://www.peakload.org/index.php?option=com_content&view=article&id=1314:nyseg-rfp-for-innovative-solutions&catid=29:latest-news&Itemid=334 on 12/20/2022.

[74] https://powersuite.aee.net/dockets/ny-17-02100-17-g-0606/ filings/9558574?version=beta&filing_search_id=1226436&document_id=163613018

[75] ConEdison. Notice of Temporary Moratorium. 01/17/2019. Accessed at: NYSDPS-DMM: Matter Master on 12/20/2022.

[76] See UG 435, Order No. 22-388 page 52.

Section 4.3 – Prioritize Investments in Known/Available Low-Cost Solutions – Consistent and Comparable Evaluation of Supply and Demand Side Investments

Given the uncertainty around the costs and availability of future supply-side decarbonization options, the PVRR analysis used for portfolios should place a greater premium on proactively reducing that risk with strategies that have higher levels of compliance certainty.

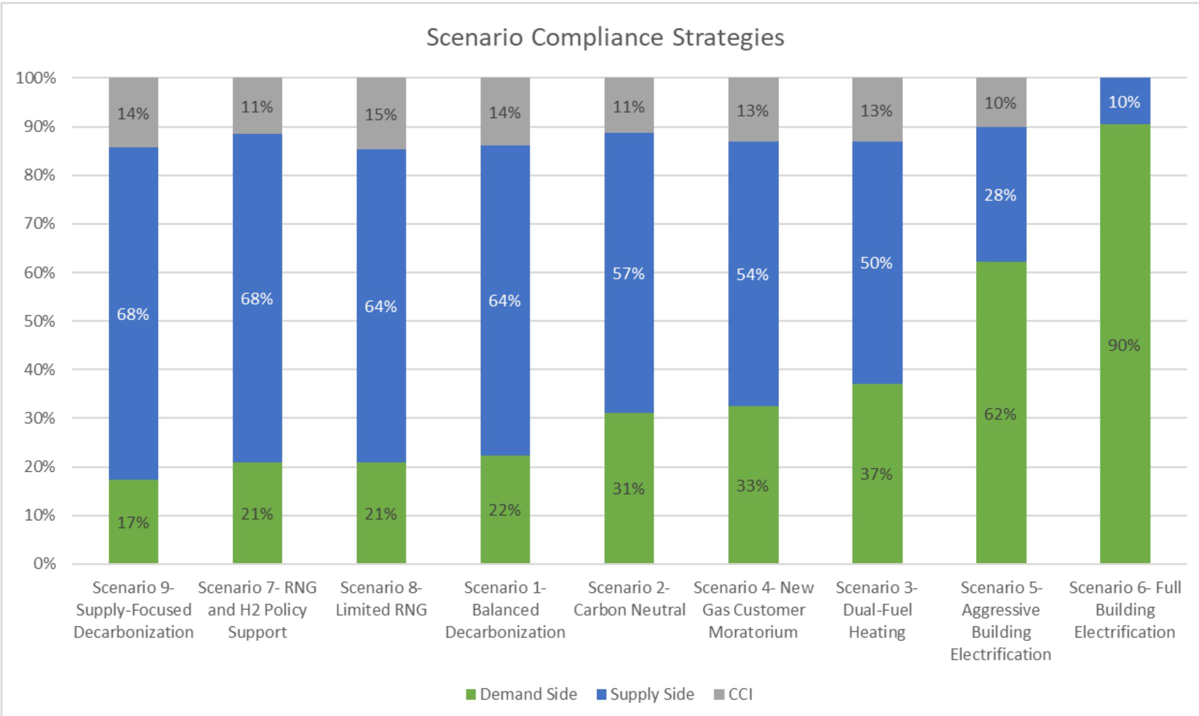
The state's CPP along with a myriad of other decarbonization policy efforts at the municipal and national level to reduce energy sector emissions have accelerated both the consideration of new technologies **and** demand reduction strategies. Staff feels this can be better reflected in the IRP modeling.

Regardless, new technologies and demand reduction strategies carry high levels of uncertainty associated with many variables, which is to say, many new options with variables for which "neither the outcome nor the probability distribution is known." Maintaining flexibility and the ability to "pivot" allows the Company and the Commission to react to new information as it arises. This could be facilitated by prioritizing balanced approaches that include a high level of near-term actions supporting deployment of higher certainty and lower risk demand side solutions while providing space for nascent supply side decarbonization actions without losing consideration of the risk of stranded assets.

Most of the scenarios presented, even Scenario 1"balanced decarbonization," rely heavily on supply decarbonization strategies. Given the high levels of uncertainty associated with future price and availability of decarbonized supply options, an appropriate way to manage this uncertainty is with the added flexibility of approaches that more fully account for demand and supply side emission reduction strategies. Staff is concerned that the resulting Action Plan reflects an approach to compliance that does not sufficiently accommodate flexibility in a time of high uncertainty and does not prioritize highly certain, low risk solutions.

Figure 1 shows the nine scenarios and the percent of emissions reduced using the various demand (green), supply (blue), and CCI (grey) strategies. Only three solutions include more than 35 percent emission reductions from demand side options. The rest rely heavily on solutions with high uncertainty for cost and availability. And of those, all but Scenario 4 may include long-term infrastructure investments that bring stranded cost risks, such as investments in expanded distribution systems related to customer growth.

Figure 1: Nine Scenarios' Compliance Strategies

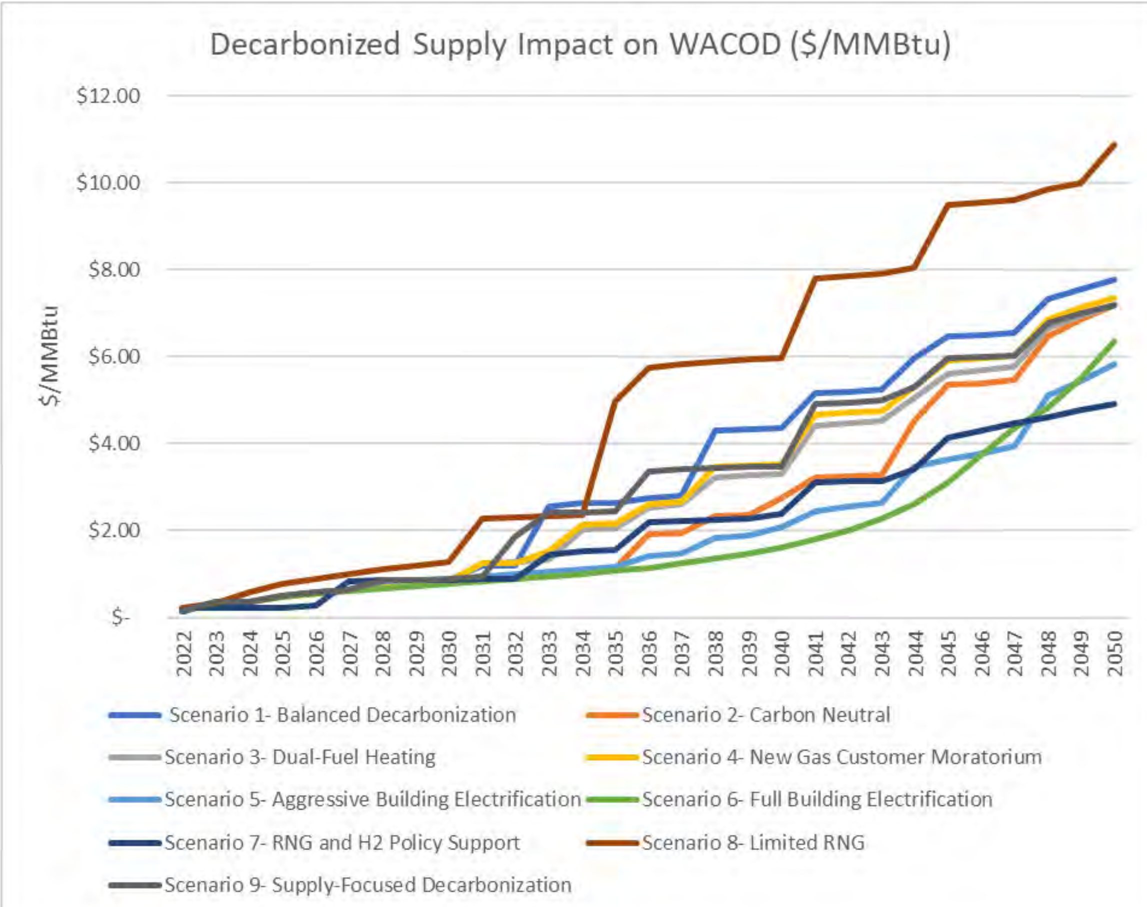


While NW Natural explains that its approach performs well under many different scenarios, its supply-heavy approach appears to expose customers to increasing variable (fuel) and fixed (infrastructure) costs while also increasing risk associated with its compliance obligation and associated costs.

Per Guideline 1c, the Company must explain how its resource choices appropriately balance cost and risk. Given the current levels of uncertainty, Staff would expect to see more activities in the Company's Action Plan that mitigate risk by prioritizing investments in demand reduction activities. In particular, Staff is interested in understanding more about the attributes of Scenario 3 – Dual-Fuel Heating, that could be advanced in the Company's Action Plan.

NW Natural calculated a weighted average cost of decarbonization (WACOD), which it broke out into RNG, CCI, and Demand side $/MMBtu. Staff looked at the "RNG" related WACOD (biofuel tranches 1 and 2, hydrogen, and synthetic methane) across the scenarios to understand how the cost of decarbonized fuel as a compliance element changed over time for the different scenarios.

Figure 2: Staff Chart Created from NWN Workpapers_2022 IRP Scenario Results – Compliance Data – Decarbonized Supply Impact on Weighted Average Cost of Decarbonization by Scenario



Compliance solutions that rely on decarbonized fuel run the risk of high gas costs being passed along to customers through purchased gas adjustments, especially if the Company's price trajectories turn out to be too optimistic, as demonstrated by Scenario 8.

There are a number of issues with NW Natural's modeling and assumptions that may have influenced what appears to be a trend of more supply-heavy compliance approaches in most scenarios. These are mostly addressed in other sections, but include:

- The must-take handling of SB 98 RNG as referenced in section 6
- Optimistically low forecasts for hydrogen and synthetic methane prices and optimistically high forecasts for biomethane RNG availability as referenced in section 10 and Section 11.
- Hard-coded modeling of EE as referenced in Section 2.3
- The omission of certain capital costs as reference above and in Section 2.1

Staff's requests and recommendations regarding SB 98 RNG, selection of efficiency resources, capital investment modeling, alternative fuels are covered in the above referenced sections. Additionally, Staff requests the Company address the following:

Requests for NW Natural:

Request 12: In Reply Comments, NW Natural should provide more discussion around the costs/benefits of the dual fuel scenario, which appears to provide a well-balanced approach.

Request 13: In Reply Comments, NW Natural should discuss how IRP analysis could more appropriately compare and select supply side and demand side resources.

Section 4.4 – Reasonable, Conservative, and Supported Assumptions

RNG, green hydrogen, and synthetic methane represent relatively new supply side additions to natural gas planning in Oregon. Being conservative in projecting costs and availability (both volumes and timing) of emerging solutions/technologies can help manage uncertainty related to the relative unpredictability of these variables, especially for nascent technologies like hydrogen and synthetic methane. Sections 9 and 10 provide details on Staff's review of green hydrogen and synthetic gas price trajectories, and Section 11 speaks to Staff's concerns about RNG availability. Staff raises both issues here to address them in the context of risk mitigation and managing uncertainty.

In multiple scenarios, NW Natural projects varying levels of supply-side decarbonization. These scenarios include assumptions about the price and availability forecasts for RNG, synthetic methane, and green hydrogen that do not appear to reflect conservative planning assumptions.

Staff opening comments in Section 10 discuss price forecasts for alternative fuels and find that NW Natural has utilized some cost assumptions aligned with the most optimistic estimates in other studies. For example, the Company's IRP references a figure from a report by McKinsey & Company as the basis for its green hydrogen cost trajectory.[77] The cost trajectory in NW Natural's IRP is consistent with the lowest value in the range of costs from the McKinsey report. This is not a conservative assumption, and it may increase risk to customers.

The McKinsey report also emphasizes the many applications for hydrogen, including long haul trucking, shipping, steel, refining, fertilizer production, heavy mining trucks, trains, shipping, and aviation. The report identifies "other end-applications such as buildings and power" as needing a higher carbon cost in order to become cost competitive.[78] While the CPP can be seen as making hydrogen more cost competitive for gas utilities, the competition from other sectors may make it more difficult to secure at the low costs forecast by the Company.

[77] NW Natural 2022 Integrated Resource Plan at 214.
[78] Hydrogen Insights Report 2021, https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf, at vii.

Concerns about competition increasing the cost of alternative fuels apply equally to RNG, hydrogen, and synthetic methane. Instead of using optimistic assumptions, NW Natural's long-term planning should use conservative assumptions that reflect this risk.

In response to stakeholder and Staff feedback, the Company includes Scenario 8, which represents a future in which there is limited RNG availability. In this scenario RNG and green hydrogen availability is limited, but similar limits do not apply to synthetic methane. The price of synthetic methane ranges from 22 to 32 percent higher than those in Scenario 1, and the price of hydrogen ranges from 23 to 63 percent higher. The Limited RNG Scenario has a continued high reliance on supply side resources of green hydrogen and synthetic methane at those higher costs. Hydrogen's percent of deliveries, by energy, goes from 20 percent to 12 percent, and this Scenario is the only one in which RNG Tranche 2 is included. This scenario applies the same customer growth and demand-side resources assumptions as Scenario 1. The strategy for compliance, in this case, is to increase the amount of synthetic methane. Because CPP compliance costs presented in the Company's workpapers do not capture costs associated with loads that shift to an electric utility, it is not appropriate to make cost comparisons across scenarios. However, Staff notes that Scenario 8 has the highest cost in $/MMBtu reduced ($10,845/MMBtu) and the highest total compliance cost ($16B).

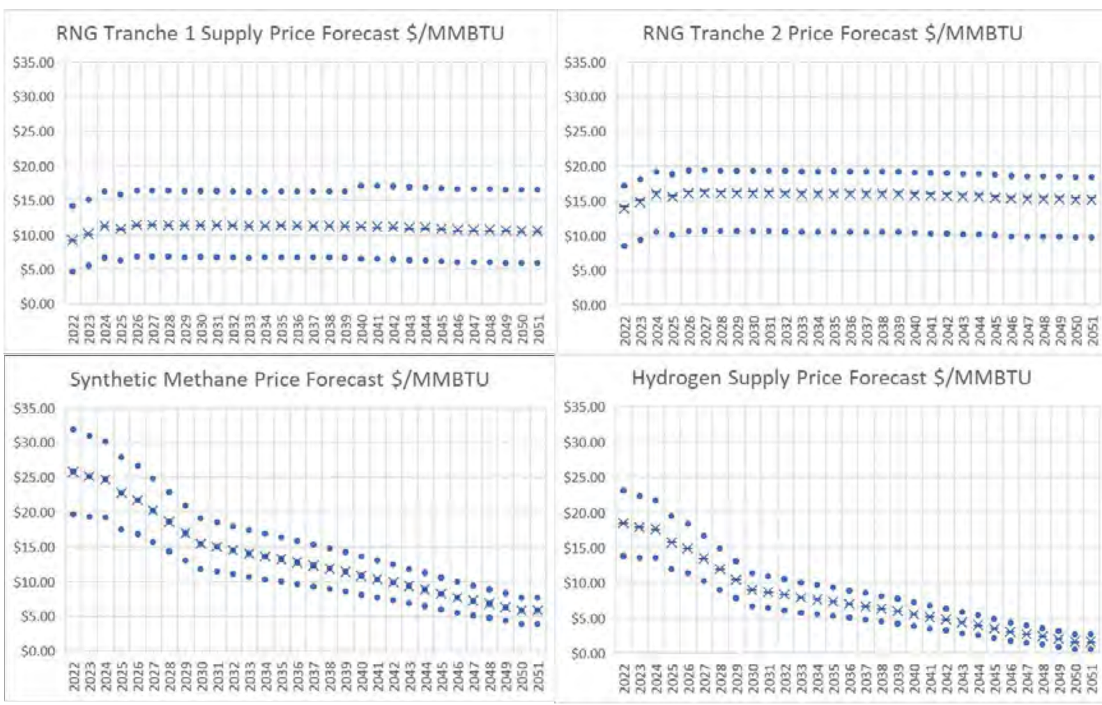
Table 2: Scenario Cost Comparisons

Scenario	**Renewable Supply**	**CCI**	**Incremental Load Reductions**	**Total Compliance Cost**	**$/MMBtu reduced**
Scenario 1- Balanced Decarbonization	$9.1B	$1.3B	$1.4B	$11.8B	$7,926
Scenario 2- Carbon Neutral	$6.3B	$1.0B	$2.8B	$10.1B	$7,220
Scenario 3- Dual-Fuel Heating	$6.9B	$1.3B	$0.8B	$8.9B	$6,002
Scenario 4- New Gas Customer Moratorium	$7.5B	$1.3B	$1.0B	$9.8B	$6,575
Scenario 5- Aggressive Building Electrification	$3.7B	$1.0B	$0.0B	$4.7B	$3,133
Scenario 6- Full Building Electrification	$1.7B	$0.0B	$0.0B	$1.7B	$959
Scenario 7- RNG and H2 Policy Support	$5.9B	$1.1B	$1.3B	$8.3B	$5,563
Scenario 8- Limited RNG	**$13.3B**	**$1.4B**	**$1.3B**	**$16.1B**	**$10,845**
Scenario 9- Supply-Focused Decarbonization	$8.9B	$1.4B	$0.3B	$10.6B	$7,096

Staff is exploring whether the higher costs and limited supply represented in the Limited RNG Scenario may better represent a conservative set of assumptions for nascent and highly sought after decarbonization resource options.

As part of Staff's concerns about optimistic price and availability assumptions for RNG, Staff would also like to understand more about the Company's approach for managing price uncertainty in future years for green hydrogen and synthetic methane. In Figure 3, Staff shows the average, high and low supply prices for Tranche 1 and 2 RNG, green hydrogen, and synthetic methane over the planning horizon, using data provided by the Company in its workbook Workpapers_2022 IRP Scenario Results. The Company appears to create a range of future prices for each year by applying a consistent percentage higher and lower than the forecasted price. But with this approach, as the forecasted price goes down, the range of uncertainty naturally narrows. This effect is more pronounced with hydrogen and synthetic methane where the price drops dramatically.

Figure 3: RNG, H2 and Synthetic Methane Supply Prices from NWN Workpapers_2022 IRP Scenario Results - MC_Supply Prices



This is counter intuitive. Given the uncertainty of new fuel decarbonization approaches, Staff would expect the Company to include wider margins for future prices as the years go out. Staff invites more conversation with the Company about how supply price ranges were considered.

Request for NW Natural:

Request 14: In Reply Comments, NW Natural should discuss whether Scenario 8: Limited RNG assumptions are more reasonable and conservative than those used in the majority of the other scenarios.

Section 4.5 – Conclusion

The Company presented an Action Plan that appears compliant with the CPP under a variety of scenarios. However, Staff has concerns about how well risk and uncertainty are addressed in the scenarios and resulting action plan. As such, Staff is still looking into whether the plan presented by the Company represents a least cost, least risk plan.

Section 5: Demand-Side Resources

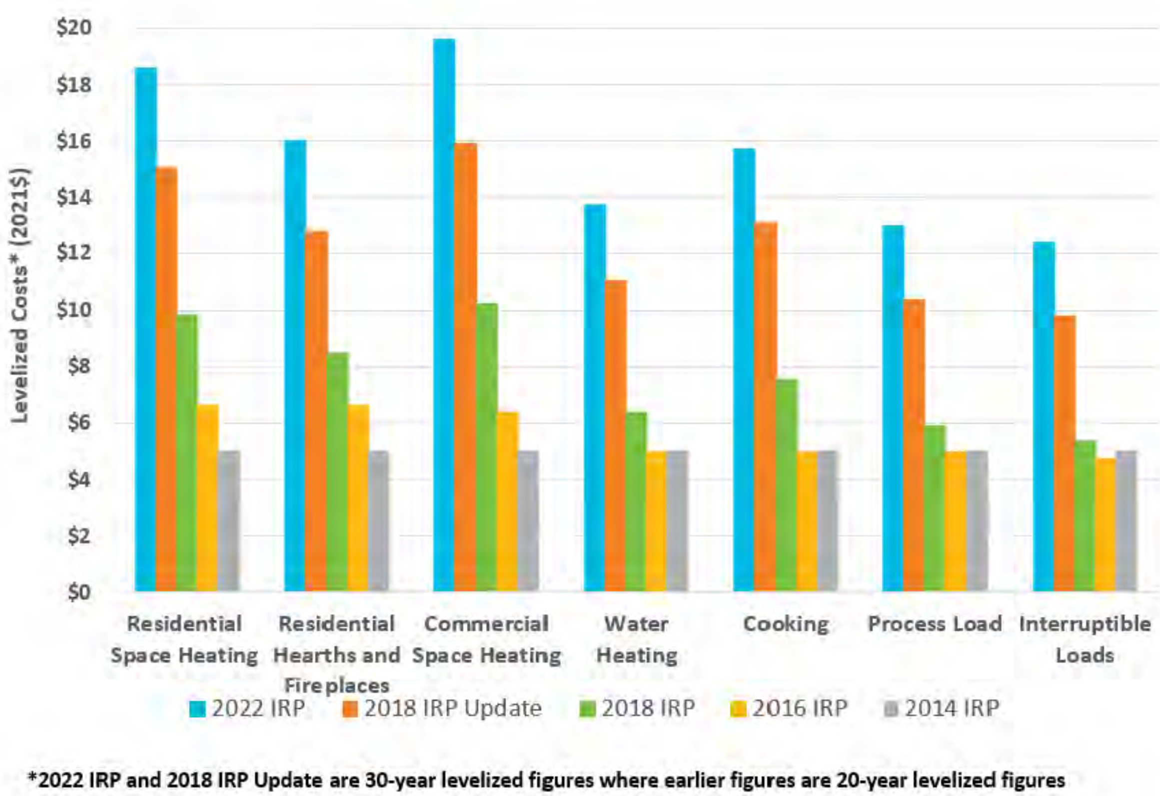
Anna Kim, Sr. Utility Analyst

In this section, Staff discusses demand-side resources and their use in the IRP. This includes energy efficiency and demand response.

Section 5.1 Avoided Costs

NW Natural implemented significant changes in its 2018 IRP Update, which resulted in major differences between the 2018 IRP and the 2022 IRP. One of these differences is that total avoided costs increased by nearly half between the 2018 IRP and 2022 IRP. This is mainly due to the Company incorporating GHG compliance costs into its 2018 IRP Update.

Figure 4: Oregon 30-Year Levelized Avoided Costs by End Use [79]



While the changes from the 2018 IRP Update to the 2022 IRP are smaller than the increase between the 2018 IRP and the 2018 IRP Update, Staff is still interested in understanding these changes in avoided costs. Staff observes that while the main sources of increased value between the 2018 IRP and the 2018 IRP update were avoided GHG compliance costs, the main

[79] 2022 IRP, Figure 4.6, p. 127.

sources of increased values between the 2018 IRP Update and the 2022 IRP were from supply capacity and risk reduction.

The Company states that the methodology for calculation of supply capacity costs has not changed since the last IRP.[80] However, the values have changed between the 2018 IRP, the 2018 IRP Update, and the 2022 IRP. Staff will continue to review this topic to understand the drivers of change.

In contrast, the Company adopted a new methodology for calculating risk reduction value. The Company previously used a hypothetical long-term contract to hedge against natural gas price volatility and compared energy efficiency to this contract. In this IRP, the Company instead applies a stochastic approach to modeling the value of risk reduction.[81] This methodology appears to be more similar to the methodology currently used by the electric utilities to model commodity price risk reduction value, and Staff is overall supportive of moving towards this type of approach.

The Company also changed the planning horizon from the typical 20 years to 30 years. This impacts energy efficiency in two ways. First, load reductions from energy efficiency measures with long measure lives impact load forecasts over a longer period of time. For example, a new building built in 2023 will still have a reduced load in 2050. Second, it will appear as if there is less energy efficiency available in later years. It is difficult to predict the full potential for energy efficiency far into the future where savings will be based off of new technologies that are not currently available, resulting in an underestimation of available energy savings.

In Section 6 on SB 98 Targets, Staff discusses concerns about the Company's assumptions for resource acquisitions through SB 98 and requests opening a discussion on how resources elected under SB 98 interact with resources selected to meet CPP targets, particularly to relax its approach to near-term SB 98 targets and increase low-cost CCIs. The Company's avoided costs should reflect the costs of this update. Staff wants to ensure that resource acquisitions represent the least-cost plan including all mandatory regulatory requirements, including fully maximizing the use of energy efficiency to avoid acquiring the most expensive of these resources.

Please see Section 6 SB 98 Targets to learn more about Staff's recommendation.

Section 5.2 Energy Efficiency Action Items

To address energy efficiency, the Company proposes the following action item:

> Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.

[80] 2022 IRP, p. 218.
[81] 2022 IRP, p. 217.

Staff appreciates the Company's support for Energy Trust's efforts to acquire all cost-effective energy efficiency but is also concerned about the gap between this action item and Energy Trust's current forecast for savings. Staff notes that Energy Trust's current forecast for 2023 savings is 5.0 million therms and 5.9 million therms for 2024. There is a twelve percent gap between this action item and Energy Trust's current forecast.

Staff understands that NW Natural is limited in its ability to control Energy Trust plans. However, Staff seeks to understand how the Company can assist Energy Trust in maximizing acquisitions and addressing the challenges that Energy Trust faces.

Request for NW Natural:

Request 15: In Reply Comments, Staff requests that the Company describe: 1) How the Company has been assisting Energy Trust in ramping up to meet the Company's energy efficiency acquisition needs, and 2) What alternative plans the Company has to address any gap between Energy Trust energy efficiency acquisitions and the amount of savings the Company needs to meet carbon compliance goals cost-effectively.

To address transport customers, the Company proposes the following action item:

> Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.

Staff is fully supportive of this action item. While many of these customers have access to energy efficiency services for electric uses, whether through Energy Trust or through a consumer-owned utility, they have not had similar access to energy efficiency services for gas. This suggests that 1) there are substantial savings opportunities and 2) it would be simple for Energy Trust to launch and run programs starting with customers who are familiar with their electric offerings.

Staff understands that the Company is not seeking Commission acknowledgement on this action item, but Staff would like more detail about it.

Staff understands that the Company hired AEG to conduct a study to estimate the potential for energy efficiency with transport customers. Staff would like to understand how the Company has worked with Energy Trust to use all available information about these customers. Staff requests that the Company provide Energy Trust with the list of transport customers so that Energy Trust can provide additional insight that the Company can use to inform and refine these estimates.

Requests for NW Natural:

Request 16: In Reply Comments, Staff requests that the Company describe what key activities will take place in 2023 to support the launch of an energy efficiency program for transport customers in 2024, including coordinating activities with Energy Trust. Further, Staff would like to know if there is any way to accelerate the launch of this program.

Request 17: Staff requests that the Company provide Energy Trust with the list of transport customers so that Energy Trust can provide additional insight that the Company can use to inform and refine these estimates.

Section 5.3 Modeling Energy Efficiency

In Section 2 IRP Guidelines, Staff discusses concerns about how the Company is meeting IRP Guideline 6. NW Natural's 2022 IRP does not meet the requirement to consider the acquisition of conservation resources "'without regard to any limits on funding of conservation programs."' and recommends that the Company create an additional model run that can select additional energy efficiency. Please see Section 2 IRP Guidelines.

Section 5.4 Demand Response Action Items

The Company hired a third-party consultant to estimate demand response potential as requested in Order No. 19-073, Staff Recommendation #9. The Company provided Staff a preliminary presentation on December 9, 2022 that included results that were available in 2019. Staff is disappointed that while preliminary results were available in late 2019, the requested report has not been made publicly available.[82]

To address demand response, the Company proposes the following action item:

> Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

Staff appreciates the Company's interest in further exploring demand response opportunities to manage peak loads. Demand response will also naturally align with the existing use of interruptible and transport sales for controlling peak demand. Staff would like more details about the Company's work with demand response and this action item in particular. Staff notes that the Company has been aware of the potential for demand response since late 2019 and is only planning to launch programs in 2024 and would like to understand why there is a multi-year delay between initial findings and a future program.

[82] The report was shared confidentially in response to Staff IR 108.

Request for NW Natural:

Request 18: In Reply Comments, Staff requests that the Company describe what activities the Company has undertaken between December 2019 and now to study and develop opportunities to use new demand response programs as demand-side resource options.

Request 19: In Reply Comments, Staff requests that the Company describe what key activities will take place in 2023 to support the launch of a demand response program in 2024, including coordinating activities with Energy Trust and selection of demand response measures. If the Company plans to have a pilot phase, please describe how that would fit into the timeline.

Section 5.5 Other Demand-Side Measures

Staff appreciates the Company's discussion of emerging demand-side technologies in Section 2.5, 5.6, and 5.7 of the 2022 IRP, including gas water heaters, rooftop units, high performance windows, and dual-fuel systems. Staff notes that Energy Trust has proposed a dual-fuel pilot to install ductless heat pumps and smart thermostats in homes with functioning furnaces to determine their costs and benefits. NW Natural has declined to fund the initially proposed pilot, citing concerns about how different ratepayers should fund this research. Staff notes that Avista Utilities and Cascade Natural Gas opted to keep this work in their respective utility-specific action plans with a minor amount of funding coming from Portland General Electric and Pacific Power.

Energy Trust is planning to convene all of its gas and electric utilities in Q1 2023 to discuss funding models for this pilot so that there is enough funding to support a minimum number of installations to conduct this research. Staff requests confirmation that NW Natural will attend this discussion and explore funding models with the other utilities.

Request for NW Natural:

Request 20: In Reply Comments, confirm that the Company will participate in discussion between Energy Trust and the utilities on how to fund a dual-fuel heat pump pilot.

Section 6: SB 98 Targets

Rose Anderson, Senior Economist

It appears that NW Natural has assumed it should meet its SB 98 targets before considering all other cost-effective resources to meet CPP requirements. Staff would like to open a discussion about this decision and whether it is still reasonable to focus on meeting SB 98 targets now that the CPP is effective.

In considering the prudence of meeting SB 98 targets, Staff reviewed the introductory language to SB 98, which states:

> The Legislative Assembly finds and declares that:
>
> (a) Renewable natural gas provides benefits to natural gas utility customers and to the public; and
>
> (b) The development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Oregon.
>
> The Legislative Assembly therefore declares that:
>
> (a) Natural gas utilities can reduce emissions from the direct use of natural gas by procuring renewable natural gas and investing in renewable natural gas infrastructure;
>
> (b) Regulatory guidelines for the procurement of renewable natural gas and investments in renewable natural gas infrastructure should enable the procurements and investments while also protecting Oregon consumers; and
>
> (c) Renewable natural gas should be included in the broader set of low carbon resources that may leverage the natural gas system to reduce greenhouse gas emissions.
>
> …
>
> The commission shall adopt ratemaking mechanisms that ensure the recovery of all prudently incurred costs that contribute to the large natural gas utility's meeting the targets set forth in subsection (1) of this section

SB 98 was enacted before the CPP was finalized. Given that the CPP now exists, and NW Natural has a challenging requirement to decarbonize by 90 percent by 2050, it may no longer be prudent for NW Natural to pursue the full targeted amounts of SB 98 RNG if that pursuit increases the cost of decarbonization to ratepayers. CCI instruments through CPP are forecast to be significantly less expensive than RNG through 2050. The aims of SB 98 to encourage the development of RNG, hydrogen, and other low-carbon resources may be achieved in a more cost-effective (if slightly delayed) way if NW Natural focuses on CPP requirements and lower-cost CCIs first, instead of on strictly meeting SB 98 targets. Staff would like to see less focus on meeting the full targets of SB 98 in long-term planning and more focus on cost effective decarbonization.

Requests for NW Natural

Request 21: NW Natural should revise its action plan to relax its approach to SB 98 targets and increase low-cost CCIs.

Request 22: NW Natural should run a model sensitivity to determine the PVRR improvement by acquiring CCIs up to DEQ limits, as needed, in each year that they are less expensive than other compliance options (by removing must-take assumptions for SB 98 resources.)

Request 23: NW Natural should discuss in Reply Comments whether the Company would agree to update its avoided costs for efficiency and RNG to reflect a more relaxed approach to SB 98 targets, and the reasons why or why not.

Section 7: Risks/benefits of RNG/H2 Ownership vs. Contractual purchases

Ted Drennan, Energy Policy Analyst

As part of the IRP review process Staff considered the potential benefits and risks of ownership of RNG/Hydrogen facilities versus purchasing arrangements. As for ownership structure, Staff is agnostic at this point regarding the best ownership structure, assuming there is appropriate selection process and adequate customer protections. Utility ownership of facilities can have potentially long-term benefits, such as cost-of-service rates for fully depreciated assets. The other side of the coin is a long-lived asset could become a sunk cost with limited benefits.

There are other risks and benefits for the structural arrangements. For example, ownership could offer tax benefits that affiliate-ownership or contractual purchases of RNG may not offer. However, there are likely contractual protections afforded by the latter that ownership may not include. Thus, it is important to consider all of the costs and benefits in modeling the resource options. NW Natural states its RNG Workbook is agnostic among resource types. Staff has requested the underlying Cost-of-Service models that feed into the workbook. Staff assumes these Cost-of-Service models appropriately capture the costs, including tax treatments, of the resources, but has not yet had the opportunity to verify.

The Commission could consider using procurement requirements along the lines of what is done on the electric side, where the discussion has been much more robust. Historically, the Commission has tried to guard against utility ownership bias in selecting resources for electric utilities. The Commission opened Docket UM 1276, "to address the bias inherent in the utility resource procurement process that favors utility ownership of generation assets over Power Purchase Agreements (PPAs) with third parties."[83] There is the potential for this same bias in RNG procurement.

The procurement process for major resource acquisition for electric utilities has been the subject of multiple investigations at the Commission. The rules are well-developed and allow for a robust process.[84] Highlights of the process include:

- Use of a Commission-approved independent evaluator to ensure fairness
- Commission approval of the RFP documents, and bid scoring criteria prior to RFP issuance
- Separation of utility (or affiliate) employees who work on scoring from those who prepared benchmark or affiliate bids

[83] *In the Matter of the Public Utility Commission of Oregon, An Investigation Regarding Performance-Based Ratemaking Mechanisms to Address Build vs. Buy Bias*, Docket No. UM 1276, Order No. 11-001 at 1.
[84] *See* Chapter 860, Division 89 Resources Procurement for Electric Companies.

- Scoring requirements – consistent with IRP assumptions
- Selection of short list

To guard against potential bias with RNG acquisition, the Commission should carefully review the Company's resource selection process and identify any potential issues. This could include review of RFPs for RNG and the associated RFP scoring. According to their IRP, NW Natural's selection of renewable resources is guided by the methodology described in Appendix K, (discussed in Section 9 of Staff's comments) which bases selection on the first-year risk-adjusted levelized incremental cost (FYRALIC). It is not clear if that modeling has been accurate to date in resource selection. The Commission should consider regular audits of the RNG Model to ensure the Company's models work accurately.

Appendix K also includes process requirements for updating variables for the analysis. OAR 860-150-0200 states:

> A large natural gas utility must apply a cost-effectiveness calculation to all RNG that the utility acquires for its retail natural gas customers. The cost-effectiveness calculation must be consistent with the methodology used to evaluate RNG resources in the utility's most recently acknowledged integrated resource plan, or integrated resource plan update, or as the utility may otherwise be directed by order of the Commission.

Given the requirement for consistency with an approved methodology, the Company should be required to notify the Commission if they intend to deviate from their approved methodology. Staff has additional information requests to the Company outstanding and will continue to review NW Natural's approach and modeling.

At this point, there are currently limited requirements for RFPs in the RNG sector covered in OAR 860-150-0500, which states:

> Pursuant to ORS 757.396, before making a qualified investment in biogas production that is upstream of conditioning equipment, pipeline interconnection or gas cleaning, a large natural gas utility must engage in a competitive bidding process as provided in this rule.

There are no requirements for RFPs for acquisition of RNG itself or renewable thermal certificates (RTCs). However, it is Staff understanding that the Company has made use of RFPs in securing RNG.[85] The Company should be encouraged to continue this approach.

As the RNG market develops, and NW Natural continues to accrue more RNG, there may be need for more guidance from the Commission on the acquisition process, similar to that on the electric side. The Commission should direct the utility to file their evaluation model (RNG Workpapers) with updated assumptions as part of the IRP process going forward. Similar to the guidance in the rules for resources procurement for electric utilities, the Commission should

[85] NW Natural. 2022 Integrated Resource Plan: Errata Filing. Page 49

encourage the Company to provide information related to RFP scoring (price and non-price) in future IRPs or IRP Updates. The Company should also consider including standard form contracts in the IRP.

Recommendations for the Commission:

Recommendation 1: Require filing of updated evaluation models in the IRP. This model should update all variables with the IRP assumptions.

Recommendation 2: Periodic auditing of NW Natural's approach to RNG acquisition.

Recommendation 3: Consider requiring RFP scoring details to be included in IRP filings.

Recommendation 4: Discuss ways to ensure ratepayers are not negatively impacted by NW Natural's choice of deal structure.

Section 8: RNG Evaluation Methodology

Rose Anderson, Senior Economist

There is room for improvement in the clarity and transparency of NW Natural's RNG Evaluation Methodology Appendix. NW Natural states that the appendix "updates the methodology approved in OPUC Order No. 20-043 to account for developments from SB 98 rulemaking in Oregon and the establishment of Oregon DEQ's Climate Protection Program." However, upon reading Appendix K, it is not clear which aspects of the methodology have changed and how. The appendix is brief and vague. In the next update of the RNG Methodology, NW Natural should provide a more methodical documentation of what has changed since the last acknowledged version of the Methodology.

Further evaluation of the methodologies in the Incremental Cost Workbook, which implements the RNG Evaluation Methodology, can be found in Staff's comments in Section 8.

Request for NW Natural:

Request 24: In Reply Comments, NW Natural should more clearly list and describe the changes made to the RNG Evaluation Methodology.

Section 9: RNG Modeling and Appendix K

Ted Drennan, Energy Policy Analyst

As part of the IRP review process, Staff examined the RNG Workbook provided by the Company in addition to Appendix K: Low Emissions Gas Resource Evaluation Methodology. The Company included their methodology for analyzing potential RNG projects, the Incremental Cost Workbook (ICW or RNG workbook).[86] The Company filed Appendix K on October 21, 2022 as part of NW Natural's 2022 Integrated Resource Plan: Errata Filing. The associated workbook was included with the workpapers filed October 24, 2022. A corrected version of the model was provided on October 31, after Staff notified the Company of several reference errors (#REF!) within the original model.

The workbook is an Excel-based model designed to calculate, "the incremental cost of RNG based upon "all-in costs," where the difference in the cost of service of an RNG resource and the costs avoided from not needing to procure an equivalent amount of conventional natural gas is the incremental cost."[87] The basic formula for calculating costs is:[88]

> Annual all-in cost of RNG (R) = Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

For each potential project, the model calculates a deterministic levelized incremental cost, as well as a first-year risk-adjusted levelized incremental cost (FYRALIC). The latter, the FYRALIC, is used in comparing the different RNG projects. It is calculated as follows:[89]

$$FYRALIC = 0.75 * \text{deterministic } LIC + \ 0.25 * \text{95th Percentile Stochastic } LIC$$

The methodology has been designed to accommodate multiple resource types. These include: On-System Bundled RNG Purchase, RNG with Delivery to NW Natural's System – Bundled, RNG with Sale of Brown Gas, and Unbundled Environmental Attributes (these are synonymous with renewable thermal certificates, aka RTCs).

In the process of reviewing the model, Staff discussed it directly with the Company and submitted several interrogatories. The discussion below is Staff's current thinking on the model. There are still outstanding interrogatories, and Staff may have additional questions for the Company, depending on additional analysis.

[86] Unless otherwise stated, discussion of the RNG Model relies on the Company's file titled "Workpapers_2022 IRP - RNG Incremental Cost Workbook_REFCORRECTED"
[87] Page 195 of Appendices
[88] Page 197 of Appendices
[89] Page 198 of Appendices

Modeling Issues
In examining the model, Staff found several potential issues that need to be addressed by the Company. The first is related to treatment of unbundled environmental attributes. According to NW Natural, the incremental cost metric is, "the expected incremental cost of an RNG resource to NW Natural customers and is not risk adjusted."[90] From a theoretical perspective, the cost of an unbundled environmental attribute or RTC should be the incremental compliance cost, similar to using the cost of a renewable energy certificate (REC) as the incremental cost of compliance on the electric side. However, when looking at attachments included with Highly Confidential LC 79 OPUC IR 13 this did not appear to be the case. From interrogatories sent to the Company the differential seen is driven entirely by the Environmental Compliance Costs included in the model.

Also related to the Base Case environmental costs is the lack of consistency in the assumptions in the IRP and RNG workbook. It appears there is a different set of Base Case Environmental Compliance cost assumptions for Oregon in the RNG workbook as compared to the Avoided Cost Workbook(s) submitted.[91] The following compares the costs in the RNG Workbook with the values contained in Table C.1 Avoided Cost Summary by State, Year, and Policy.[92] (These are the same as those in Workpapers_2022 IRP Avoided Costs - Final IRP.) Note the RNG Workbook is confidential – thus the graph is as well. Staff continues to look into this issue and potential ramifications.

[BEGIN CONFIDENTIAL]

[redacted]

[90] Page 195 of Appendices
[91] NW Natural submitted two workbooks for Avoided Costs Workpapers,_2022 IRP Avoided Costs - Final IRP" submitted on September 23, 2022, and an updated version of the file, "Workpapers_2022 IRP Avoided Costs - Final IRP_Updated", submitted on October 21, 2022
[92] The annual values in Table C.1 for Oregon match with those in the file Workpapers_2022 IRP Avoided Costs - Final IRP. The levelized values differ which could be due to a different discount rate. As an aside, the Washington values in the Workpapers_2022 IRP Avoided Costs - Final IRP do not match with those in table C.1, Staff has not examined any potential impact of this discrepancy.

[redacted]

[END CONFIDENTIAL]

Additionally, the Avoided Cost by End Uses[93] for Oregon and Washington differ between the RNG Workbook and the Avoided Cost workpapers. For Washington, the values in NW Natural's Table C.2: Avoided Cost by Year match with those in the RNG workbook. For Oregon, there are three different sets of values between the RNG Workbook, Avoided Cost workpapers, and Table C.2. It is unclear why there are these differences between assumptions. Staff continues to look into any potential impacts.

Likewise, there are potential discrepancies with discount rates. The discount rate included in NW Natural's file, Workpapers_2022 IRP Avoided Costs - Final IRP.xls, filed in September contained discount rates that were different from those in the RNG Workpapers. The Company supplied an update, Workpapers_2022 IRP Avoided Costs - Final IRP (updated).xls, that contained discount rates matching the RNG workpapers. It is unclear why this file was not included in September when it appears the update was complete in May of 2022.[94] In response to an interrogatory about what appeared to be different discount rates, the Company responded:

> Real-after tax discount rates are updated to reflect the most current allowed rate of return on capital from the Company's most recently finalized general rate case (UG 435) adjusted for the inflation expectations and tax rates of that time. As such, the discount rates adjust through time as rate cases are finalized, inflation expectations change, and tax obligations change.

In examining Highly Confidential LC 79 OPUC DR 13 Attachments 2 through 5, as submitted in UG 432, it appears the discount rates used there do not match with the ones from NW

[93] End uses include, Residential Space Heating, Residential Hearths and Fireplaces, Commercial Space Heating, Water Heating, Cooking, Process Load, and Interruptible Load.

[94] NW Natural. 2022 Integrated Resource Plan: Errata Filing Page 140, footnote 95. "NW Natural provided the 3.83 percent discount rate to ETO in 2021 and updated the discount rate to 3.4 percent in May 2022".

Natural's acknowledged 2018 IRP. As such, it is not clear if the methodology the Commission was asked to approve is being followed. From Table K.2: Project Evaluation Component Descriptions the discount rate used in project evaluation should be, "Discount Rate from most recently acknowledged IRP."[95] Staff continues to examine this issue.

The RNG model submitted contains a spot to select the project type on the RNG Dashboard tab. After reviewing discovery responses from the Company, it is not clear why this is included. Project types in the drop-down list include: Bundled Delivery to NWN, On-System Bundled Resource, RNG with Sale of Brown Gas - Choose Sales Hub, Unbundled Environmental Attribute Purchase. However, as discussed in NW Natural's response to Information Request 113, there is outboard analysis in the COS model that could lead to double counting if the accurate type of project was selected in the RNG model:

> Because the value of the brown gas resale was already embedded in the cost-of-service model, we did not select the "bundled" resource in the incremental cost model in Highly Confidential LC 79 OPUC DR 13 Attachment 5, as that would have double-counted the value of the brown gas sale.

Neither the Appendix, nor the "Notes and Directions" tab of the RNG model provide direction on selecting the appropriate project type. This approach to modeling seems rife for errors and misunderstanding, Staff suggests removing the "Project Type" or ensuring the model can actually accept the appropriate project type to avoid future confusion.

Staff also notes that the Company excludes RTC retirement costs from their model. While it is unlikely a five-cent charge per retired RTC would sway the analysis, it is a known cost and as such it should be included. There could be an impact at the margin, especially when comparing resources with different timing.

Finally, the revised RNG model presented has additional factors for assessing risk that are not well explained. In Cost-of-Service (COS) models, project components are broken up into buckets by FERC account number, and assumptions related to life-cycle and depreciation are determined. In the risk categories in the RNG Workpapers there is not such a structure. It appears the risks and assumptions are dependent on the modeler. It is not clear to Staff that the same expected costs, or FYRALIC, would be the same with two different modelers. It is also not clear that some of these risks are not already accounted for in the COS models. For instance, contingency values are often included in COS models to account for risks. Response to Staff's Information Request 112 pointed to UG 435, Exhibit 1314 COS model. There are contingencies included within that model. It is not clear to Staff whether some risks may be accounted for twice: in the COS model, and the RNG workbook.

Another potential issue is the assumptions around risk distribution. Here different risk distributions are assumed based on what a modeler inputs. If a modeler inputs symmetrical

[95] Appendices at page 199

uncertainty band, +/-20 percent for instance, risk distribution is assumed to be normal. If the modeler inputs asymmetrical uncertainty bands, -19 percent and +20 percent for instance, there will be a lognormal risk distribution. Staff is looking into whether this modeling of asymmetrical risks is appropriate.

In discussion with the Company, it was stated that downside risk is ignored in the RNG modeling – only risks that increase the cost to ratepayers is assessed on the assumption that ratepayers are risk adverse. Imagine two projects with identical output, cost and risk profiles, with one exception, Project A has the possibility of an additional 20 percent output compared to Project B. It is Staff's understanding that NW Natural's risk assessment in the RNG Workbook would calculate identical first-year risk-adjusted levelized incremental costs for the projects, with the Company indifferent between the two. In this case there should be a preference for the project with the potential for a larger output it would appear. Staff continues to examine this issue.

Staff's understanding is that the RNG Workbook is NW Natural's tool for assessing project value for customers in its RFPs. For comparison, on the electric side, for major resources, electric utilities have much more rigorous requirements around scoring bids on both price, and non-price scoring, as compared to the current RNG workbook. Given the limited guidance in Appendix K and the "Notes and Directions" tab, it appears different modelers could have different conclusions on the overall cost of the project. Staff suggests having more objective criteria for RNG RFPs.

While Staff has pointed out many issues with the RNG workbook, this is not an exhaustive review. Because of the timing of the filing of both Appendix K and associated workpapers and delays in receiving information responses from the Company, Staff has not delved into all model aspects. Review is ongoing and may be impacted by outstanding information requests.

Request for NW Natural:

Request 25: Staff requests that NW Natural meet with Staff to discuss Staff's questions and concerns regarding the RNG workbook before February 7, 2023.

Section 10: Cost Trajectories

Rose Anderson, Senior Economist

NW Natural's expected costs for green hydrogen and synthetic methane show significant decreases through 2050. Green hydrogen costs fall from $23/MMBtu in 2022 to $5/MMBtu in 2050, and synthetic methane costs fall from $30/MMBtu in 2022 to $9/MMBtu in 2050. [96]

Although there may not be a way to definitively state the likelihood of NW Natural's cost trajectories being accurate, recent studies and legislation can help provide some insight into the possible future cost trajectories of these technologies.

Importantly, just before the filing of the IRP, Congress enacted the Infrastructure Investment and Jobs Act (IIJA) (November 2021) and Inflation Reduction Act (IRA) (August 2022). These policies include a variety of measures that will likely reduce the cost of alternative fuels, and NW Natural's IRP did not include the effects of these policies in its analysis. These significant pieces of legislation are so recent that most studies of technology costs also do not take them into account.

Before discussing this recent legislation, a comparison of NW Natural's cost trajectories to other estimates may be informative.

Cost Trajectories for Clean Hydrogen

PwC/EPRI Study

A 2021 Price Waterhouse Cooper (PwC) analysis, in collaboration with the Electric Power Research Institute (EPRI), analyzed six different reports on expected green hydrogen cost trajectories. PwC/EPRI found that green hydrogen production costs may decrease by about 50 percent through 2030, and then continue to fall steadily at a slightly slower rate until 2050.[97] The PwC/EPRI analysis notes that for green hydrogen, decreasing costs of renewable energy are the main driver of decreasing operating (OPEX) costs, while economies of scale in production are expected to reduce capital costs (CAPEX.)[98]

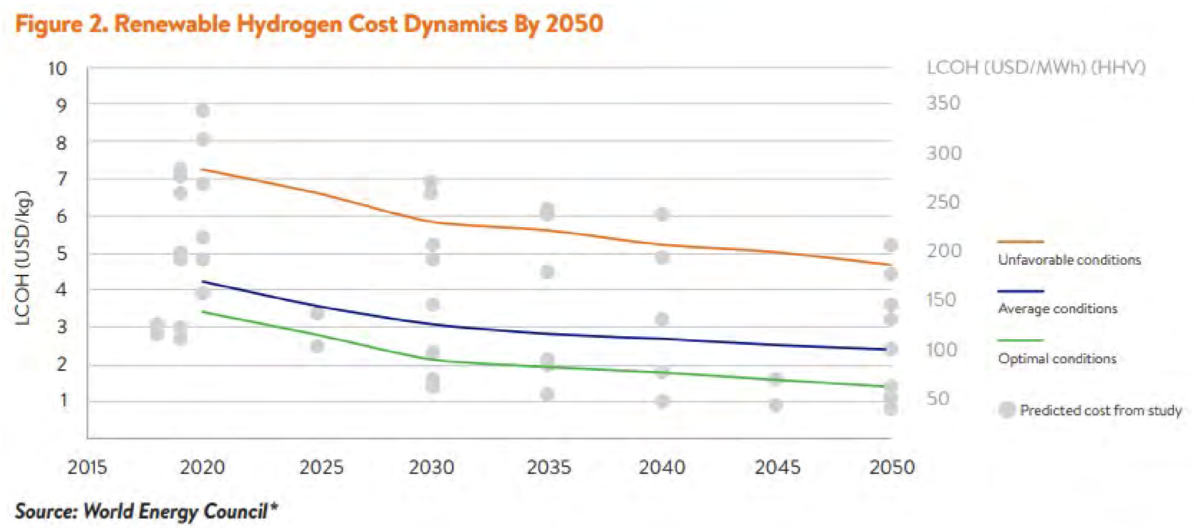
This downward trend is similar to the trend in NW Natural's cost trajectory, which also has a steep ~50 percent decline through 2030 followed by a slower fall through 2050.

NW Natural's forecast for hydrogen costs is generally lower than the 'optimal conditions' cost trajectory in the PwC/EPRI report, however. Using a conversion factor of 8.7 kg/MMBtu for hydrogen, Staff estimates that NW Natural's 2022 hydrogen cost estimate, at about $2.64/kg, is

[96] NW Natural. 2022 Integrated Resource Plan. Page 217.
[97] https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html
[98] Working_Paper_-_Hydrogen_Demand_And_Cost_Dynamics_-_September_2021.pdf (worldenergy.org). Page 7.

below the lowest cost trajectory modeled.[99] NW Natural's 2050 estimate is also below the PwC/EPRI optimal forecast.

Figure 6: PwC/EPRI Renewable Hydrogen Cost Dynamics by 2050



100

BNEF Study

Bloomberg NEF (BNEF) analysis from before the passage of the IRA and IIJA found that delivered costs for green hydrogen could be ~$2/kg by 2030 and ~$1/kg in 2050. The analysis noted that costs could be 25 percent lower in places with the best access to renewable energy, including the US.[101] NW Natural's cost trajectory is similar, falling to approximately $9/MMBtu ($1.03/kg) by 2050.

Goldman Sachs Study

A Goldman Sachs study from February 2022, after the passage of the IIJA but before the IRA, also seems to expect that electrolyzer costs could decline rapidly. This forecast also sees green hydrogen at ~$1/kg (~$8.7/MMBtu) by 2050.[102]

Lazard Levelized Cost of Hydrogen Analysis

A 2021 Lazard study of the levelized cost of green hydrogen resulted in then-current levelized cost estimates ranging from $12.30/MMBtu to $18.90/MMBtu for large green hydrogen

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[99] A conversion factor of 8.7 is consistent with the factor used in Lazard's levelized cost of hydrogen analysis, and with the value provided by NREL at https://www.nrel.gov/docs/gen/fy08/43061.pdf

[100] World Energy Council. Working Paper - Hydrogen Demand And Cost Dynamics - September 2021.pdf (worldenergy.org). Page 6. Accessed 12/29/2022.

[101] Henry Edwardes-Evans. Green hydrogen costs 'can hit $2/kg benchmark' by 2030: BNEF.. Accessed 12.29.2022.

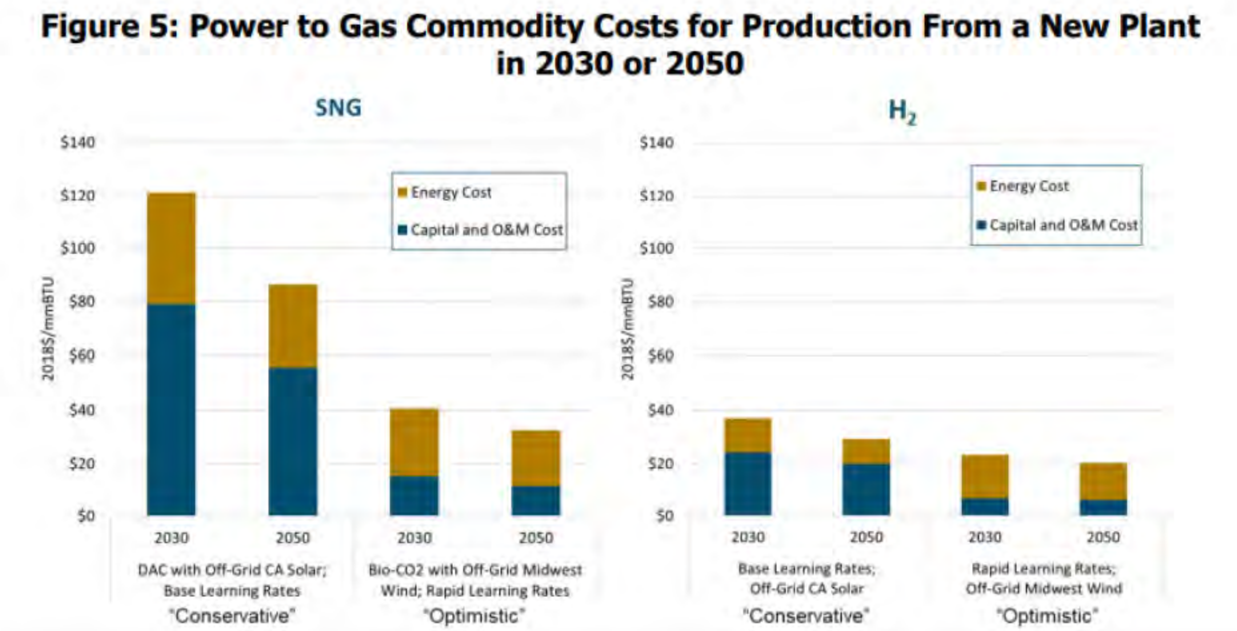
[102] Goldman Sachs. Carbonomics The Clean Hydrogen Revolution. Accessed 12/29/2022.

facilities.[103] For context, NW Natural's estimate for 2022 is approximately $23/MMBtu, putting it above the range of Lazard's cost estimates.

E3 Study

A 2020 study by E3 looked at the costs of decarbonizing California's pipeline gas system.[104] The E3 study showed cost estimates for green hydrogen that do not fall below $20/MMBtu ($2.30/kg) by 2050, even in the 'optimistic' scenario with a rapid learning rate:

Figure 7: Power to Gas Commodity Costs for Production From a New Plant in 2030 or 2050 (source E3)



The E3 values fall within the range of values studied in the PwC/EPRI review, although the 'optimistic' E3 values are considered approximately 'average' in the PwC/EPRI study.

Staff finds it notable that the difference between hydrogen and synthetic methane in NW Natural's cost trajectory is approximately $7/MMBtu, yet the cost difference in the 'conservative' E3 scenario is approximately $60/MMBtu. This substantial difference in the expected cost of methanation of green hydrogen deserves more discussion.

Request for NW Natural:

Request 26: Staff would like NW Natural to provide more information in its Reply Comments about its reasons for assuming that methanation will be inexpensive in comparison to the E3 conservative estimate.

[103] Lazard. Lazard's Levelized Cost of Hydrogen Analysis. Page 12. Accessed 12/29/2022.

[104] E3. The Challenge of Retail Gas in California's Low-Carbon Future. Page 24.

NW Natural in Context

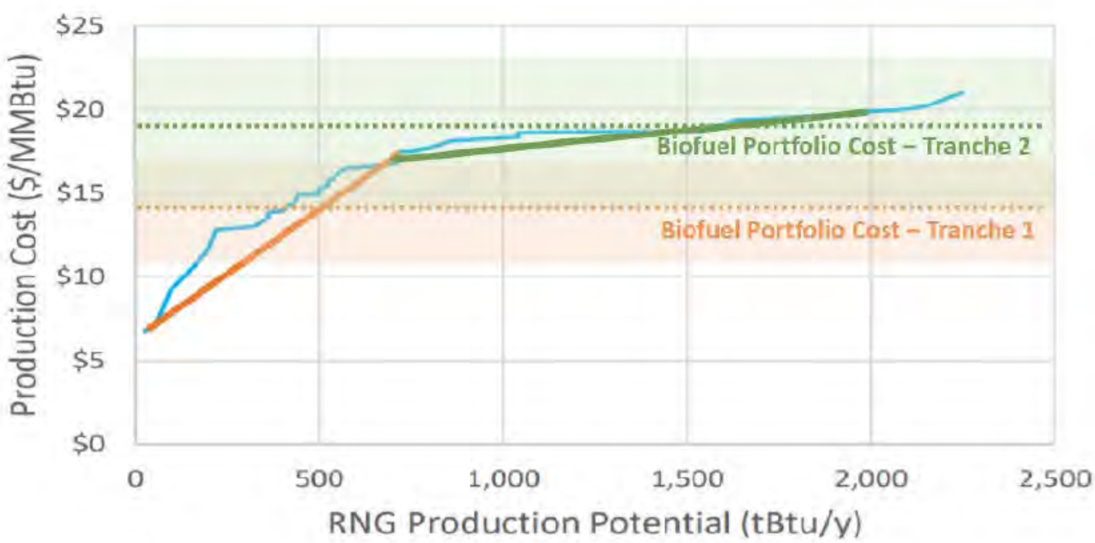
NW Natural's cost estimates for hydrogen appear to be on the low end of the range of most estimates from other reports on the topic (with Lazard's estimate being an exception among the reports reviewed by Staff.) Although NW Natural appears to utilize optimistic cost estimates, some optimism may be warranted given the abundance of low-cost renewable energy in the US and the recent legislation passed to help reduce the costs of this technology.

Modeling of Unbundled RTCs in PLEXOS

NW Natural forecasts costs of RNG, green hydrogen, and synthetic methane. However, before entering these costs into PLEXOS, the Company removes the 'avoided costs' of the underlying brown gas, any transportation cost, and any capacity cost.[105] This step seems potentially unnecessary and reduces transparency by adding an additional calculation before costs are entered as an input into PLEXOS.

For example, NW Natural's Figure 6.19 shows the RNG prices forecast by ICF and how NW Natural converted those prices into two tranches of available RNG. Tranche 1 is about $14/MMBtu and Tranche 2 is about $19/MMBtu:

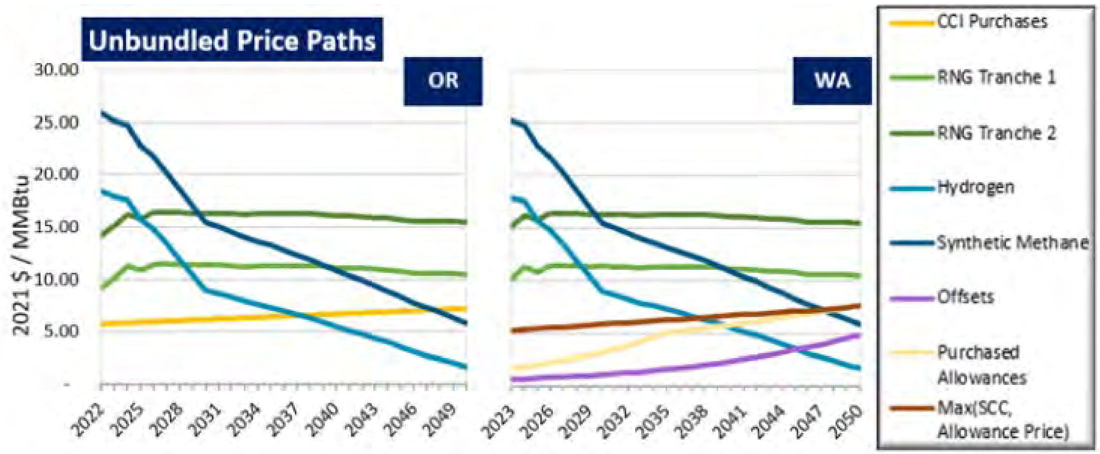
Figure 8: NWN's Figure 6.19 Biofuels Supply Curve and Tranche 1 & 2 Portfolio Cost



However, NW Natural's calculations of 'unbundled' RNG costs result in PLEXOS inputs that are about $5/MMBtu lower than those represented Chapter 6.

105 NW Natural's response to Staff DR 70.

Figure 9: NWN's Unbundled Price Paths from IRP Page 260[106,107]



Staff requests a detailed explanation of why low-carbon fuels have been modeled as 'unbundled' price paths, and how the full cost of the fuels is reflected in the PLEXOS modeling after certain elements are removed from PLEXOS inputs.

Request for NW Natural:

Request 27: NW Natural should explain in Reply Comments why the additional step of removing the cost of brown gas, transportation, and capacity is necessary or beneficial before modeling low-carbon fuels in PLEXOS. How does this step add value that is greater than the cost of the added complexity and lost transparency? How are the full costs of the fuels reflected in PLEXOS?

Summary of IRA and IJA

The sections of the IRA most relevant to price forecasts for RNG, hydrogen, and synthetic methane are:

- A tax credit of up to $3 per kg for qualified clean hydrogen beginning in 2023. The credit begins at $0.60/kg and increases depending on meeting certain goals for emissions, wages, and labor. Alternatively, an ITC of up to 30 percent of capital costs is available, also dependent on lifecycle emissions, wages, and labor.[108][109] This element is likely to place downward pressure on prices of green hydrogen and Synthetic Methane. Given that current estimates of green hydrogen costs range from about $2.20/kg (Lazard) to about $7/kg (PwC unfavorable conditions) the potential $3/kg incentive is substantial.

[106] NW Natural. 2022 Integrated Resource Plan. Page 260.
[107] Note that the graphs in Chapter 7 show unbundled costs, without the underlying gas or transportation costs.
[108] National Law Review. Clean Hydrogen Tax Credits Under the IRA (natlawreview.com) Accessed 12/29/2022.
[109] Green Hydrogen Organization. United States: Tax credits for green hydrogen under the US Inflation Reduction Act 2022 | Green Hydrogen Organisation (gh2.org). Accessed 12/29/2022.

- An increase in the 45Q tax credit for carbon sequestration associated with hydrogen production.
- A substantial credit for clean commercial vehicles, along with the expansion of the alternative fuel station credit.[110]

The IIJA appears likely to place downward pressure on hydrogen costs. The sections of the IIJA most relevant to price forecasts for RNG, hydrogen, and synthetic methane are:

- $9.5 billion in total for development of clean hydrogen:
    - Establishment of a clean hydrogen R&D program, national strategy to facilitate hydrogen, and grants for R&D.[111]
    - $8 billion for regional clean hydrogen hubs.[112]

[110] King & Spalding. Hydrogen-Related Provisions of the Inflation Reduction Act of 2022 - King & Spalding (kslaw.com). Accessed 12/29/2022.
[111] Orrick. Key Hydrogen Provisions of the Bi-Partisan Infrastructure Plan (orrick.com). Accessed 12/29/2022.
[112] US Department of Energy. DOE Establishes Bipartisan Infrastructure Law's $9.5 Billion Clean Hydrogen Initiatives. Accessed 12/29/2022.

Section 11: RNG and Hydrogen Markets

Ted Drennan, Energy Policy Analyst

Section 11.1 – RNG Availability and Cost

In order to decarbonize its system, NW Natural places a heavy reliance on non-emitting supply-side resources to meet customer needs. The forecast of available resources and associated costs play a large role in the NW Natural IRP. Staff continues to examine the assumptions related to RNG, hydrogen, and synthetic gas acquisition potential by NW Natural. At this point, it is difficult to determine if the Company's assumptions about availability of these fuels are appropriate. For RNG availability, the Company relies on a 2021 study from consulting firm ICF, supported by the American Gas Association (AGA), which is generally not considered an independent organization. The 2021 study was an update of a 2019 study and assumes a more aggressive net-zero carbon goal and more utility renewables development. The 2021 update found a much greater amount of RNG available, including a 78 percent increase in feedstock utilization. The 2021 ICF update is more of a pathways analysis than an actual forecast, and it includes a series of activities and assumptions required to get to economy-wide decarbonization by 2050. The 2021 study included the assumption of deep decarbonization, which "typically reflects emission reduction targets of between 80-100% by 2050 (e.g. Net-Zero)."[113] Staff has concerns about the levels of RNG availability projected in the ICF study and in NW Natural's IRP, especially when compared to other recent forecasts, as discussed below.

Given the design of the ICF 2021 update, it seems optimistic. The study has a zero carbon goal by 2050, which allowed for more aggressive RNG development assumptions as compared to the 2019 version. This represents an 'all-hands onboard' approach. One potentially optimistic assumption for instance, is the recovery of 95 percent of food waste for RNG production.[114] This seems optimistic given the goals the EPA put forth to limit food loss and waste in 2015.[115] EPA used 2010 as a baseline year, when food loss was approximately 31 percent of the food supply. Their 2030 goal is to reduce this by half. This would be a drop from 133 billion pounds of food waste available for potential RNG production to 66 billion pounds by 2030.

While food waste is a small part of the overall potential available feedstock for RNG, there is another component in the ICF study, "Energy Crops," that makes up a substantial proportion. The amount of energy crops projected in the updated ICF study for 2050 is roughly double what was projected in the high case of the 2019 ICF study.[116]

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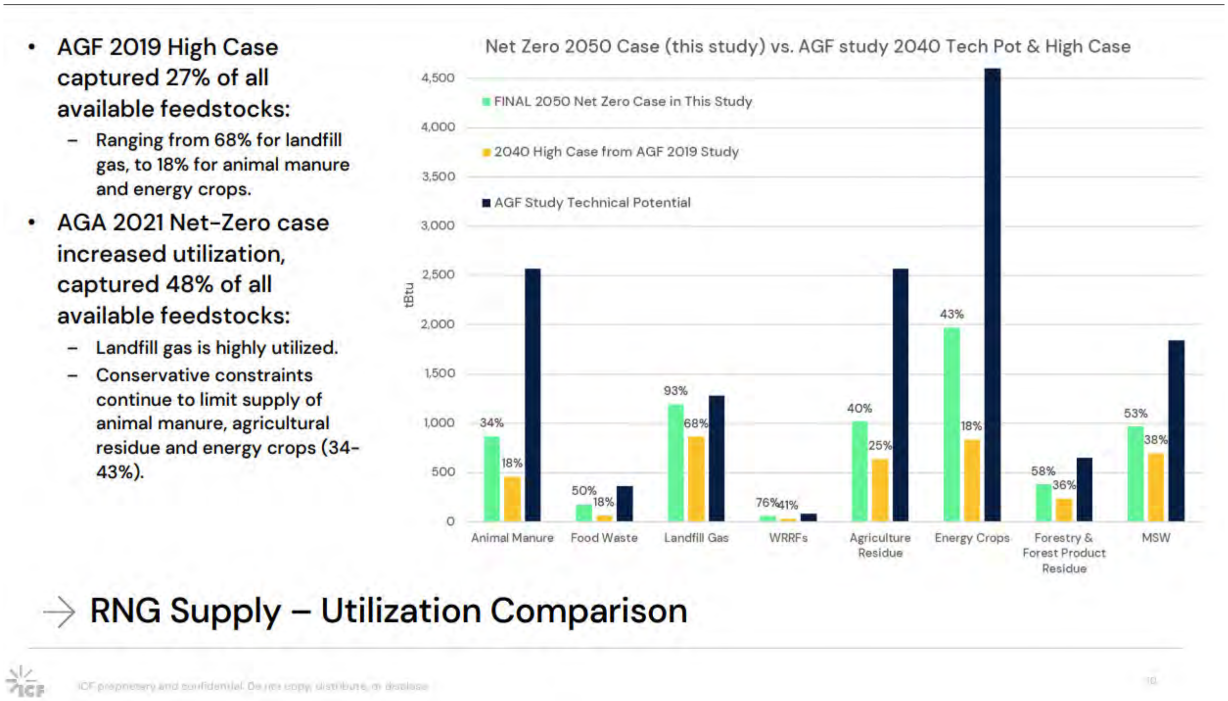
[113] NW Natural. 2022 Integrated Resource Plan: Errata Filing Page 186, Figure 6.4 ICF Net Zero Report Key Findings
[114] NW Natural. TWG #3 Presentation, slide 75 (available at https://www.youtube.com/watch?v=-A5KoGTtasg accessed 12/07/2022)
[115] United States 2030 Food Loss and Waste Reduction Goal (Available at https://www.epa.gov/sustainable-management-food/united-states-2030-food-loss-and-waste-reduction-goal accessed 12/07/2022)
[116] NW Natural. 2022 Integrated Resource Plan: Errata Filing Page 186, Figure 6.4 ICF Net Zero Report Key Findings

Figure 10 is a slide from NW Natural's third technical working group demonstrating the changes from the ICF 2019 Study to the 2021 update. Here they project 78 percent more total feedstock utilization, an increase from 27 percent of all available feedstocks by 2040 in the 2019 High Case to 48 percent by 2050 in the current, updated study. This is a compound annual growth rate (CAGR) of 6 percent, for the decade, which seems optimistic.[117] Precedence Research recently completed a study that estimated CAGR for the biogas market for the United States at 4.4 percent from 2022 to 2030.[118] Grand View Research has a report that suggests 4.3 percent CAGR for biogas worldwide from 2022-2030, with the United States CAGR at 2.7 percent over the same time frame.[119]

Figure 10: ICF Study Update Slide from NWN Third TWG



While much of the technology to produce RNG via anaerobic digestion has been around for years, the broader RNG market, as defined below, is nascent. Currently there are multiple studies with differing assumptions on RNG availability and cost. For instance, E3 prepared a report for the California Energy Commission (CEC) in 2020 titled, "The Challenge of Retail Gas in

[117] CAGR = $(V_{final}/V_{initial})$^(1/time)-1. In this case CAGR = (48/27)^(1/10)-1 = 5.92%

[118] Biogas Market Size to Worth Around US$ 78.8 Billion by 2030 https://www.globenewswire.com/en/news-release/2022/04/19/2425025/0/en/Biogas-Market-Size-to-Worth-Around-US-78-8-Billion-by-2030.html (accessed 12/12/2022

[119] Biogas Market Size, Share & Trends Analysis Report By Source (Municipal, Agricultural, Industrial), By Application (Vehicle Fuel, Electricity, Heat, Upgraded Biogas, Cooking Gas), By Region, And Segment Forecasts, 2022 – 2030 https://www.grandviewresearch.com/industry-analysis/biogas-market (accessed 12/12/2022)

California's Low-Carbon Future."[120] The study includes green hydrogen and synthetic gas in its definition of RNG, defining RNG as:

> (C)limate-neutral gaseous fuels and uses it as an umbrella term to encompass four fuels, including 1) biomethane produced from anaerobic digestion of biomass wastes, 2) biomethane produced from gasification of biomass wastes and residues, 3) climate-neutral sources of hydrogen gas, and 4) methane produced synthetically from a climate-neutral source of carbon and hydrogen.[121]

Figure 11 below is from the E3 study which shows the four natural gas alternatives that are considered in the study.[122] Constraints on the use of the resources are included with costs, availability, and competition being the main drivers.

Figure 11: E3 Four Categories of RNG (E3 Figure 2)

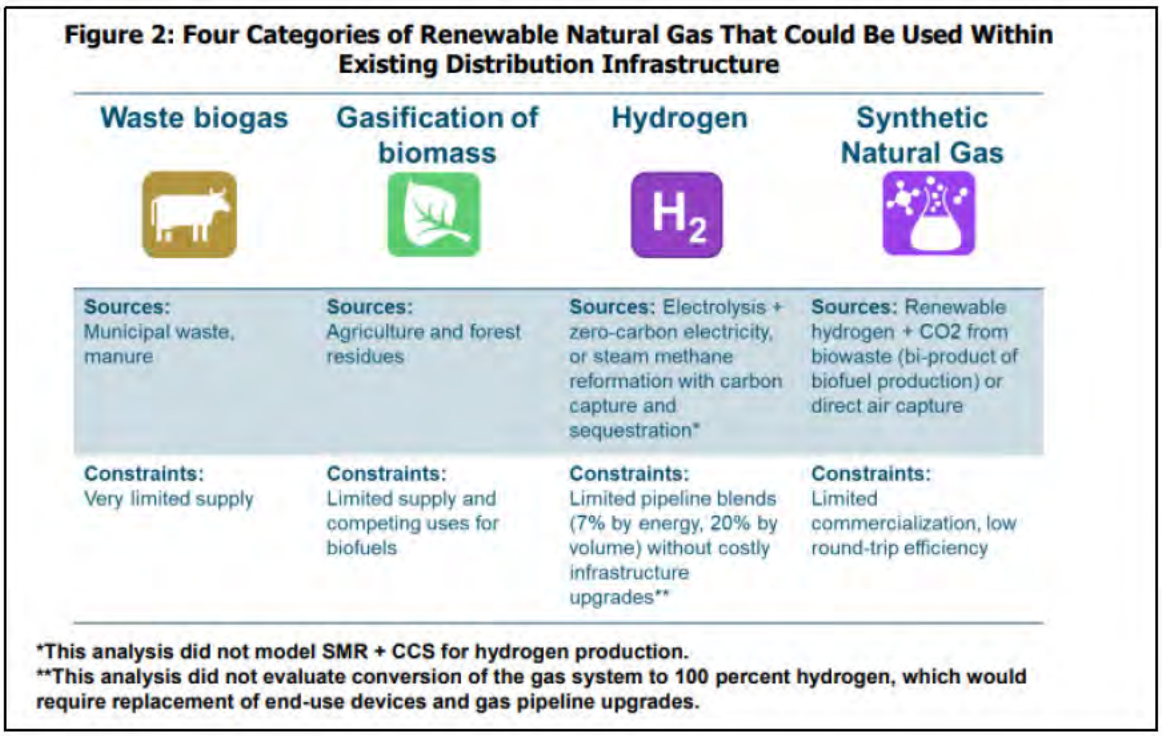


Figure 2: Four Categories of Renewable Natural Gas That Could Be Used Within Existing Distribution Infrastructure

Waste biogas	Gasification of biomass	Hydrogen	Synthetic Natural Gas
Sources: Municipal waste, manure	**Sources:** Agriculture and forest residues	**Sources:** Electrolysis + zero-carbon electricity, or steam methane reformation with carbon capture and sequestration*	**Sources:** Renewable hydrogen + CO2 from biowaste (bi-product of biofuel production) or direct air capture
Constraints: Very limited supply	**Constraints:** Limited supply and competing uses for biofuels	**Constraints:** Limited pipeline blends (7% by energy, 20% by volume) without costly infrastructure upgrades**	**Constraints:** Limited commercialization, low round-trip efficiency

***This analysis did not model SMR + CCS for hydrogen production.**
****This analysis did not evaluate conversion of the gas system to 100 percent hydrogen, which would require replacement of end-use devices and gas pipeline upgrades.**

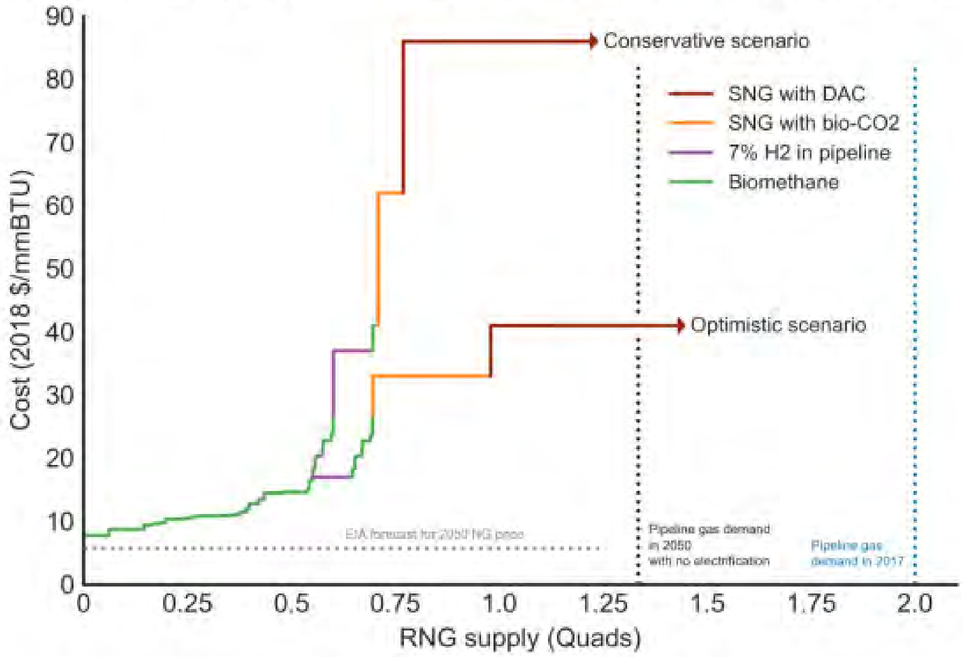
E3 developed a potential supply curve for these fuels in California in the year 2050. Figure 6 from the study is shown as Figure 12 below.[123] Similar to NW Natural's approach, the amount

[120] Aas, Dan, et al. "The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use." California Energy Commission https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf (accessed 12/09/2022)
[121] Ibid at page 1
[122] Ibid at page 17
[123] Ibid at page 25

of biomethane is based on California's population-weighted share of the United States supply.

Figure 12: E3 RNG Potential 2050 Supply Curve (E3 Figure 6)

Figure 6: California Renewable Natural Gas Technical Potential Supply Curve in 2050, Assuming All Biomass Is Directed to Renewable Natural Gas



The biomethane supply curve segments (green) are based on allocating California's population-weighted share of United States waste and residue biomass entirely to biomethane. In the PATHWAYS scenarios, much of the biomass is used for liquid fuels to displace petroleum consumption in transportation and industry.

Source: E3

The supply curve starts with the least expensive alternate fuel, biomethane, and then adds other types until it reaches the most expensive type, synthetic gas (SNG) with direct air capture (DAC) of CO2 used for the methanation process. This resource, SNG with DAC, would be the marginal resource used for decarbonization of the California gas system. The scale at the bottom is in quadrillions of Btus. For reference the pipeline gas demanded in 2017 in California was 2 quadrillion (1,000 tera = 1 quadrillion) Btus – shown as the blue dotted vertical line on the right of the chart. This value could drop to 1.3 quadrillion Btus with high energy efficiency and renewable generation by 2050. Staff is continuing to look into whether the RNG cost and availability assumptions in the E3 study are at odds with the ICF study update relied on by NW Natural.

The assumptions E3 has for biomethane use by retail pipeline gas customers may also be optimistic. According to the study:

> Much of the biomass may be used to displace relatively expensive and high-GHG-intensity petroleum fuels, such as diesel and jet fuel. Indeed, current [California] state policy directs nearly all biofuel production toward transportation, most of this as liquid biofuels.[124]

The Northwest Power and Conservation Council's (Council) 2021 Power Plan was the first Power Plan where they incorporated RNG into their planning process.[125] In developing the Power Plan, the Council examined studies from:

1. Oregon Department of Energy
2. ICF's 2019 Study, and
3. Washington State University Energy Program and the Washington Department of Commerce.

Relying on these studies, the Council examined the long-term supply potential for biogas RNG in Washington, Oregon, and the US as a whole. The Council study limited RNG here to anaerobic digestion and thermal gasification, assuming that hydrogen would be used for transportation. Table 3 shows the upper and lower bounds of RNG supply as a percentage of natural gas end use projected for the country as a whole and with state-specific values for Oregon and Washington.

Table 3: Comparison of RNG as a Percentage of Natural Gas End Use Consumption

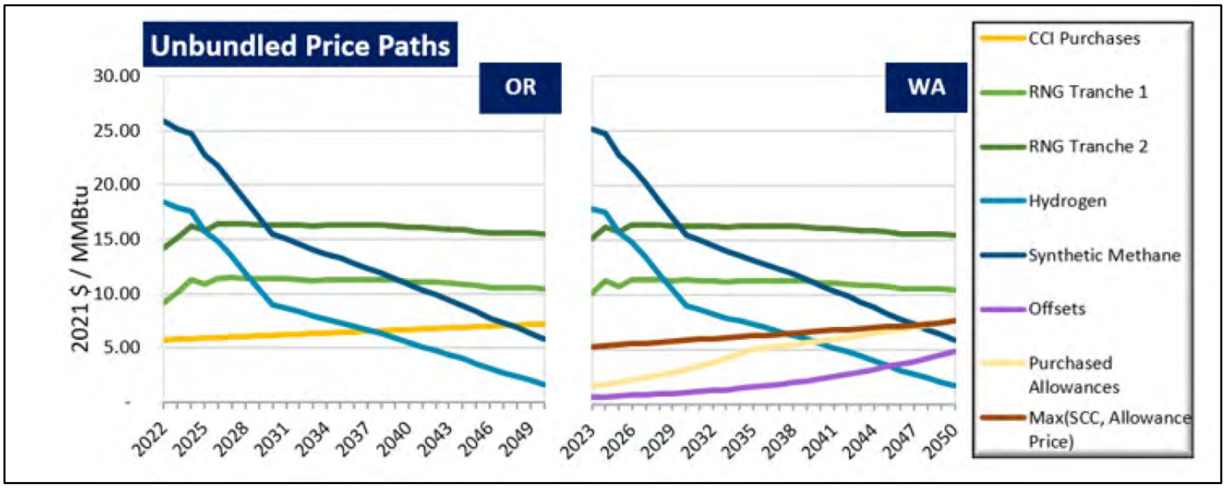
Comparison of RNG as a Percentage of Natural Gas End Use Consumption				
Region	Upper Bound	Study	Lower Bound	Study
US	18.1%	ICF High	7.5%	ICF Low
OR	37.6%	ODOE	8.5%	ICF Low
WA	15.7%	ICG High	6.3%	WADOC

If relying only on in-state resources, it is obvious that there is not enough regional RNG to meet NW Natural's demand level to replace convention gas with RNG. Staff understands that NW Natural does not need to rely solely on in-state resources. However, the ICF study also recognized that there is not enough potential biogas RNG to replace all currently consumed natural gas nationwide.

In comparing the expected costs in E3's study, shown in Figure 12 above, with the unbundled price paths included in NW Natural's IRP for the differing scenarios, there may be discrepancies. According to NW Natural, Scenario 8 helps to answer the question, "What are the implications if biofuel RNG is less plentiful and more expensive than expected?"[126] As Figure 13 below shows, even in Scenario 8, unbundled RNG costs never exceed $20.

[124] ibid
[125] Webpage: https://www.nwcouncil.org/2021powerplan_renewable-natural-gas/ (accessed 12/09/2022
[126] Ibid at page 334.

Figure 13: NWN's Decarbonized Fuel Unbundled Price Paths for Scenario 8



Looking at the Unbundled Price Paths for the differing scenarios, there did not appear to be much difference in costs associated with the supplies. Staff examined the workpapers provided by NW Natural to investigate this and found an apparent error in the graph from the IRP Errata filing. Figure 13 comes from Section 7 of the Company's Errata filing. The graphs from the same section in the *initial filing* appear to show higher price paths for Scenario 8 and is consistent with the Company's workpapers.

Regardless, assuming the workpaper values are the correct RNG values, Figure 14 below compares the workpaper values of the RNG Tranche 2 costs for Oregon between Scenario 1 – Balanced Decarbonization, and Scenario 8. As you can see, even for the expensive Tranche 2 RNG, the unbundled price never goes above $20/mmBtu. Staff notes that these unbundled costs exclude the cost of the underlying gas, generally resulting in about $5/MMBtu lower costs than the cost of the bundled product. NW Natural's decision to model unbundled price paths adds complexity and reduces transparency in IRP analysis, as discussed in Section 10 of Staff's comments.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

The E3 study has RNG from biofuels reaching $25/MMBtu and even has a small second tranche around $40/MMBtu. Staff is continuing to look into whether the IRP cost estimates are at odds with the E3 cost estimates.

One other point of interest deals with the RNG Tranche 2 costs assumed for NW Natural's Scenario 7 – RNG and H2 Policy Support. Here the costs are much lower than those in the other scenarios, with an approximate annual average drop in price of 36 percent. This is an unusual approach to modeling, since Scenario 7 reflects a much larger price drop than Scenario 8, which reflects a price increase. Prices can only fall to zero, while there is no upper limit on how high they can go, in theory. As such, modeling usually assumes price sensitivities that can go higher than they fall. NW Natural's approach is the opposite, with a bigger potential drop than increase as compared with the base assumptions, Scenario 1 used for this comparison. Staff also notes that the "Unbundled Price Paths" for Scenario 7 included in the NW Natural's 2022 IRP Errata Filing seem incorrect along with those for Scenario 8, although those in the initial filing may be accurate.

Also of note, NW Natural anticipates hydrogen and synthetic methane at much lower costs than those included with the E3 study. While E3 anticipates those will both be much more costly than RNG in 2050, NW Natural's graphs suggest the two fuels will be less than RNG, and perhaps less than conventional gas. NW Natural has hydrogen well under $5.00 and synthetic gas just above the $5.00 mark in 2050. Staff opening comments discuss price trajectories for these technologies further in Section 10.

One final note, the E3 study uses 2018 dollars for their base year compared to NW Natural with 2021$ dollars. Although Staff did not compare assumptions in the same year's dollars, it is obvious that the two studies differ in fundamental assumptions on the market going forward.

Other organizations have produced studies on RNG. See for instance the Rocky Mountain Institute (RMI) report on building decarbonization[127] or Sightline Institute's article titled "The Four Fatal Flaws of Renewable Natural Gas."[128] Staff did not complete an extensive literature review of potential levels of RNG available in the coming years, but the sources available varied widely in their projections of availability and costs. The Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity for future IRPs. Scenario 8 studies RNG costs that are slightly increased from the reference case (approximately 19 percent annually), but an additional scenario should look at a future with higher RNG, hydrogen, and synthetic gas costs, perhaps in line with the E3 study referenced above. Without examining the full range of potential costs, the Company is not sufficiently examining potential risks.

If the amounts of RNG available turn out to be much lower than those projected by the Company, the Company may still have some inherent advantages in procuring RNG. For instance, they have some first-mover advantages due to regional RNG and decarbonization policies. The emissions reduction goals of California, Oregon, and Washington make RNG attractive, and few other regions have similar policies. That should give NW Natural an initial advantage in procuring supplies.

NW Natural assumes it will have access to its customers' population weighted share of national RNG supply potential, which is similar to the assumption used for the E3 study for California. While this assumption may be reasonable, there may be competition from other low-carbon fuels uses. The dollar values associated with Renewable Identification Numbers (RINs) under the federal Renewable Fuels Standard Program for transportation fuels, for instance, have been higher than values associated with RNG compliance. That is, RNG developers can receive more money from selling their environmental attributes in the RIN market than they can get from a local distribution company (LDC) like NW Natural. Staff continues to examine this issue and its impact on future RNG supplies.

Requests for NW Natural:

Request 28: In Reply Comments, the Company should provide further discussion supporting and providing justification for its RNG, hydrogen, and synthetic cost assumptions.

[127] Sherri Billimoria, Mike Henchen, Regulatory Solutions for Building Decarbonization: Tools for Commissions and Other Government Agencies, Rocky Mountain Institute, 2020, page 22 (Available at https://rmi.org/wp-content/uploads/2020/07/Regulatory-Solutions-Framework-Report-070820.pdf accessed (12/07/2022)
[128] See https://www.sightline.org/2021/03/09/the-four-fatal-flaws-of-renewable-natural-gas/ (accessed 12/08/2022)

Request 29: In the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity for future IRPs. The cost estimate should be on the higher end of recent, relevant publicly available forecasts.

Request 30: For the next IRP, the Company should continue to evaluate future cost and availability projections for alternative fuels to natural gas.

Request 31: For the next IRP, the Company should consider using RNG forecast studies where the underlying data can be examined.

Section 12: Distribution System Planning

Abe Abdallah, Senior Utility Analyst

Section 12.1 – Acknowledgement of Distribution System Planning Projects

Staff welcomes the transitioning of NW Natural to a forward-looking distribution system planning process, which will anticipate growth-related reliability issues further into the future and plan for the most suitable solutions accordingly. As the Company stated in the IRP, this approach should allow more non-pipeline demand-side options to be considered, as the projects originating from such alternative solutions usually take longer to implement.[129] Introducing more non-pipeline investments is a positive step towards achieving the decarbonization goals of the State of Oregon.

Following the adoption of the CPP, which caps GHG emissions from local gas distribution companies (LDCs),[130] Staff will be using a high-level assessment framework for recommending whether to acknowledge newly proposed distribution system projects based on additional analysis. Assessing the least cost, least risk action plan in a gas company's IRP will require additional analysis of costs, risks, and benefits associated with a company's near- and long-term GHG emissions and compliance to CPP rules in general.

As such, Staff's new approach for making recommendations to acknowledge projects is based on two overarching principles of clear understanding of the absolute need for any proposed upgrade *and* of how that upgrade fits within the company's system-wide CPP compliance plan, both in the near- and long- term.

Staff's framework will classify distribution system upgrade projects according to the rationale behind the upgrade. Upgrades due to safety or general system reliability will continue to be analyzed on the basis of issue and need followed by a cost-benefit analysis. On the other hand, for upgrades arising from reliability related to customer growth, Staff will pay special attention to analysis in four main areas:

- Ground truthing of models used to assess distribution system upgrades
- Local load and forecast assessment to demonstrate breach of minimum standards
- Identification and costs and benefits of non-pipeline alternatives
- Alignment with company's CPP compliance strategy.

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[129] See Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 355.

[130] Oregon Secretary of State, Department of Environmental Quality, Chapter 340, Division 21, Oregon Climate Protection Program. (Available at https://secure.sos.state.or.us/oard/displayDivisionRules.action;JSESSIONID_OARD=PkrQuebCfNDGZeRb08MPY8tGXAdoX-69HgfRYRHEmJaOcXr3eCDd!-758782503?selectedDivision=6597. Accessed 12/02/2022.)

Staff's approach to distribution system project analysis post-CPP adoption is explained and put into practice for assessing the proposed upgrade projects put forth by Cascade Natural Gas in its 2020 Integrated Resource Plan Update filed in docket LC 76.[131] Attachment A of Staff's Report on the Cascade Natural Gas IRP Update includes specific information that Staff will be seeking when assessing growth-driven distribution system projects. [132]

Section 12.2 – Assessment of the Forest Grove Feeder Uprate Project

In its 2022 IRP, NW Natural seeks acknowledgement of action item 8 to uprate the Forest Grove Feeder to be in service for the 2025 gas year at an estimated cost in the range of \$3.0 million to \$7.0 million.[133]

Section 12.2.1 – Needs Assessment

The Company states that Synergi modelling of the Forest Grove Feeder indicates the feeder is operating beyond its design capacity during extreme conditions. The model demonstrates that extreme conditions start when the weather gets colder and the temperature goes as low as 25°F (equivalent to an HDD of 40)[134]. At this temperature, as demands are added due to cold weather or growth,[135] the modeled pressure drop between the Forest Grove district regulator inlet pressure and the end of the system exceeds 40 percent. This is a high pressure benchmark chosen by NW Natural to indicate a threshold not to be exceeded to avoid downstream pressure problems. A 40 percent pressure reduction equates to the pipeline operating at 80 percent capacity. As temperatures decrease further, pipeline pressure decreases rapidly, which increases the risk of outages. This reasoning explains why the Company considers any pressure drop above 40percent to be unacceptable.

In order to understand the risk of outages in the Forest Grove area, Staff's analysis addresses the potential impact of pressure drops on the affected section of the Forest Grove feeder and the duration and timing of such impact. In practical terms, the analysis seeks to quantify the likelihood of the average daily temperature reaching 25°F or lower and the duration of days of such low temperature. It also attempts to identify the level of demand which typically coincides with an HDD of 40, and whether it triggers or comes close to triggering a 40 percent drop in pressure.

Average Temperature

It is stated in the IRP that an average daily temperature of less than 25°F is experienced once every 3 years, and the last cold event at or below this level occurred in 2017.

[131] See Docket No. LC 76, Cascade's 2020 IRP Update, Staff Report, October 7, 2022, pages 1-23.
[132] See Docket No. LC 76, Cascade's 2020 IRP Update, Staff Report, October 7, 2022, pages 19-23.
[133] See Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 396.
[134] Heating Degree Day (HDD) = 65 – Temperature (F) assuming an HDD threshold of 65 °F
[135] See Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 386.

In Information Request (IR) 62, Staff requested historical data for average daily temperatures equivalent to 40 HDD or higher, pressure drops, and load levels for the Forest Grove District. The Company provided daily average temperature from January 1985 until April 2021. The pressure data was largely not available from measurements. NW Natural provided pressure data derived from the curve of the existing system representing the non-linear relationship between Forest Grove inlet pressure and HDD. According to the model, load data (in therms/hour) is assumed to have a linear relationship with HDD.

With respect to daily temperature data, there are 14 years when HDD was above 40 on at least one day. These 14 years represent 37 percent of the total number of years studied, which supports the statement in the IRP that the area experiences a cold event with an average daily temperature less than 25°F about once every 3 years.[136] However, when the data is observed on a daily basis, the occurrence rate drops to 1.3 percent for the season of colder months (November to February) when all the HDDs above 40 occur, which is equivalent to 1.55 days per season.

Inlet Pressure

According to the HDD-Load relationship provided in response to IR 62, a Load of 3,118 therms/hour will cause a pressure drop of 41.2 percent at HDD of 40. In response to IR 63, the company stated that it did not have a specific future date when the Forest Grove Feeder would experience a 40 percent pressure drop. In the response to IR 62, daily recordings of average temperatures and pressure drops supplied by the Company from November 11, 2020 to June 9, 2021 show three consecutive days of HDDs from 35.5 to 38.0 (equivalent to average temperatures of 29.5°F to 27°F) during mid-February, 2021. However, the minimum inlet pressure recorded for those days were still quite high resulting in acceptable pressure drops between 23.1 percent and 25.2 percent.

In response to IR 64, the Company provided more granular hourly pressure recordings measured by the Electronic Portable Pressure Recorder (EPPR) for the Forest Grove District Regulator from November 11, 2020 to April 8, 2022. This set of recent actual data shows nine individual hours (all between 6:00am and 9:00am), where the pressure drop is above 30 percent. The average case temperatures in those hours ranged from 24.2°F to 28.9°F.

Load

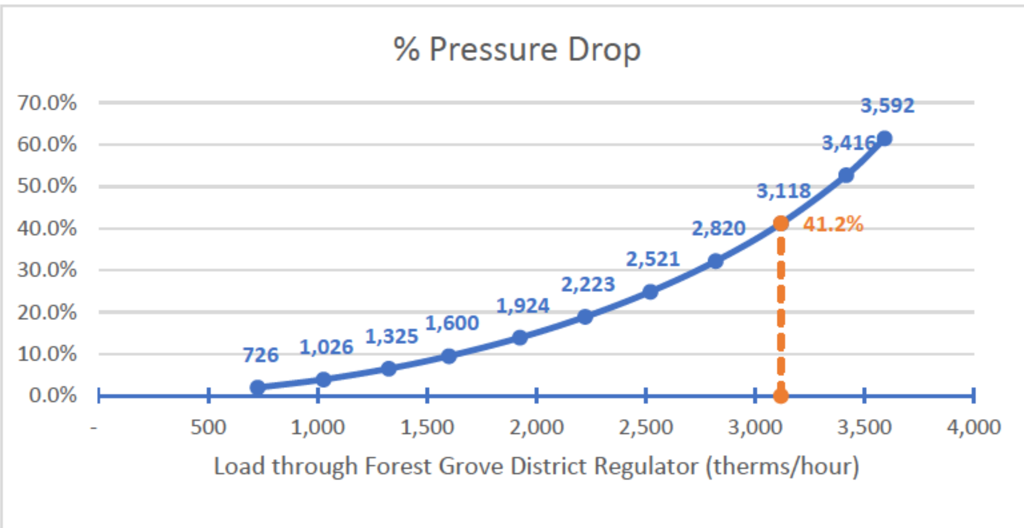
A day of particular interest is February 23, 2022, when the average case temperature was 32.3°F, which is equivalent to an HDD of 32.7. According to the HDD-pressure relationship provided by the Company in response to IR 62 and shown in Figure 15, the corresponding inlet pressure would have been about 113.2 psig, which is equivalent to 28.8 percent pressure drop. According to the HDD-Load linear relationship provided in IR 62, the corresponding load at this pressure is expected to be about 2,682 therms/hour.

[136] See Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 387.

During that day, the pressure drop went as high as 31.6 percent for a couple of hours in the morning. Also, the average temperature dropped as low as 21.8°F at 5:00am and averaged about 25°F in the first 11 hours of the day before it started rising from midday onwards.

Had the low temperatures averaged around 25°F throughout the whole day, which is equivalent to HDD of 40, it could be argued such persistent low temperature would have resulted in a pressure drop above 40 percent. As shown in Figure 15, the critical point on the modeled pressure-load curve at HDD of 40 shows a load of 3,118 therms/hour, which will cause a pressure drop of 41.2 percent, which is above the Company's standard of 40 percent. This load would represent a 16.2 percent increase from the estimated highest load reached on February 23, at 2,682 therms/hour, as derived from Figure 15.

Figure 15: Load vs Pressure Drop (reproduced from response to IR 62)



Conclusion and recommendations

Based on the analysis above, Staff understands that extreme drop in temperature could lead to an HDD of 40 or above and subsequent significant drop in pressure above 40 percent, or higher. However, it is not clear at what point in time the level of load (triggered by extreme low temperature or load growth) will cause such a pressure drop.

As such, Staff recommends that NW Natural provide more clarifications on the impact of the Forest Grove pressure drops and durations of such drops, including the intermediate and low pressure systems. In particular, the Company needs to quantify the estimated number of nodes and customers affected and the forecasted growth scenarios used to demonstrate that sufficient loads will cause unacceptable pressure drops by 2025. This level of detail in the data will help explore alternative options for mitigation.

Pending further data, Staff considers at this stage of the analysis that the Forest Grove Project may be growth-driven for the design day peak and, hence, needs to be analyzed under the new framework discussed in the previous section. With load growth being uncertain due to initiatives such as energy efficiency and heating electrification, the near-term need for the project does not seem strong. Furthermore, operational mitigation of a few hours in the year of high pressure drops should be considered within NW Natural's cold weather action plan. This workaround can buy enough time for developing an alternative non-pipeline solution.

Requests for NW Natural:

Request 32: By March 7, 2023, Staff requests that NW Natural provide further analysis of the events that might cause load levels to trigger a pressure drop of 40 percent or higher on the Forest Grove Feeder and the forecasted timing of that occurring. The proposed analysis should take account of uncertainties in customer growth, such as the decrease in customer numbers due to current trends of distributed energy resources, demand-side solutions or likely electrification rates.

Request 33: By March 7, 2023, for any anticipated rare occasions of pressure drops, NW Natural quantify the impact of loss of pressure in the Forest Grove area in terms of the impacted number of nodes, affected number of customers, and the typical duration of outages for temperature-dependent customers.

Section 12.2.2 – Support for CPP Compliance Strategy

Section 8.5.6 of the IRP briefly discusses the three alternative options to traditional pipeline solutions for the Forest Grove Feeder: interruptible industrial loads, a satellite LNG facility, and a geographically targeted RNG/Synthetic Methane supply. Inadequate resources or prohibitive costs were the main reasons for the Company not considering those options.

Given the needs analysis in the previous section, Staff considers that should the Forest Grove project prove to be needed in the long term only, this serves as a prompt to investigating non-pipeline solutions. A longer term lens may include relooking at options already studied, though rejected in the short term, such as extending the potential of targeted demand response during the cold days or peak-focused energy efficiency. In this regard, Staff considers that NW Natural's transition to the forward-looking distribution planning process will facilitate the active consideration of such longer term non-pipeline solutions, especially on the demand side.

On the other hand, if current load is predicted to cause unacceptable pressure drops at very low temperatures on rare occasions, NW Natural should explore other short-term options such as injecting gas using a mobile CNG facility during the very short periods of need.

Requests for NW Natural:

Request 34: By March 7, 2023 Staff would like NW Natural to re-study previously considered non-pipeline alternatives on the demand-side if the Forest Grove Uprate Project is proven to be not needed in the near term. The identification and cost-benefit analysis of non-pipeline alternatives should be as extensive as pipeline solutions, and may include testing: the extent of geographically targeted residential/commercial demand response; and the potential for peak-focused energy efficiency.

Request 35: By March 7, 2023, for short term measures of predicted low pressure events for less than two days per season, consider the economics of new non-pipe solutions on the supply side, such as mobile CNG injection.

Request 36: In Reply Comments, NW Natural should provide a detailed report on any pressure drop or other event at the Forest Grove feeder during the cold event of late December, 2022. The report should include the average daily temperature in Forest Grove during the event.

Section 13: Portland LNG

Abe Abdallah, Senior Utility Analyst

In its 2022 IRP, NW Natural seeks acknowledgement of action item 2 to replace the Cold Box at the Portland liquified natural gas (LNG) facility by 2027 at an estimated cost of $7.5 million to $15 million.[137]

Section 13.1 – Assessment of Portland LNG Project

Portland LNG facility is a natural gas storage facility and consists of LNG liquefaction, storage, and LNG vaporization. The facility is used as an 'on-system' peak shaving resource during the winter months. As the facility was commissioned in 1968, many components in the facility are old. In particular, the Cold Box used for liquifying gas, is past its design life and is prone to failure anytime from now. The Company stated in the IRP that failure of the Cold Box would result in unserved demand during peak times.

Section 13.1.1 – Resource Usage and Cold Box replacement

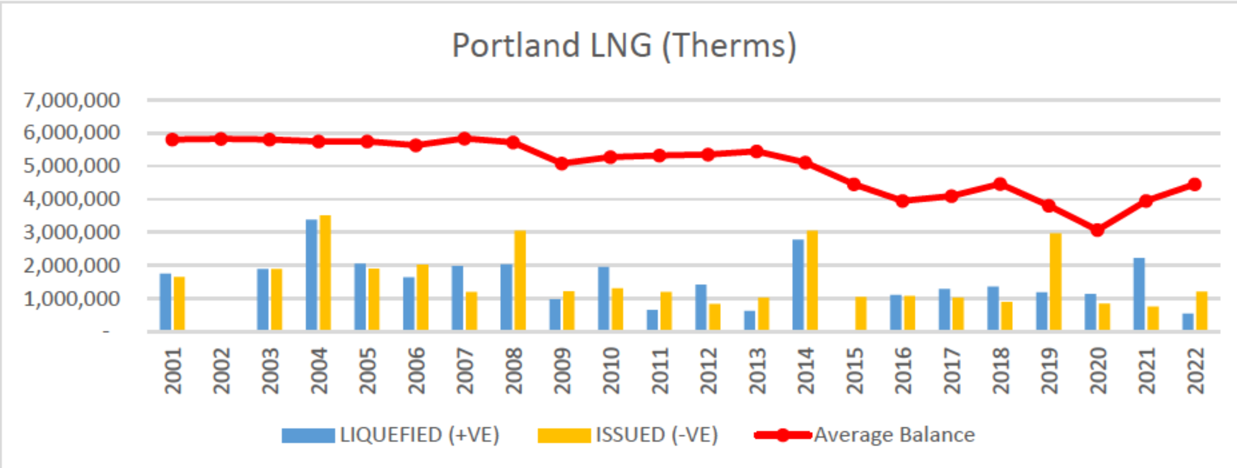
The Portland LNG Facility has a capacity to provide gas up to 130,800 Dth/day (or 1,308,000 therms/day). In IR 92, Staff requested from NW Natural the dates, duration, and quantities of gas drawn from the Portland LNG facility on a daily basis in the last 20 years. NW Natural is to be commended on their comprehensive response of the facility's daily gas quantities issued (withdrawn from the facility) and liquified (injected into the facility) and a monthly summary for each year showing the beginning and ending balance for the quantity and value of gas in storage.

Staff noticed the daily pattern of the facility providing around 5,000 therms, and up to 10,000 therms, per day during winter months, with the occasional high spike in gas injections during cold snaps, such as on February 23 and 24, 2022, when the facility provided more than 240,000 therms to the system.

Based on the monthly data supplied by NW Natural,[138] Staff assembled a summary of the data from 2001 to 2022 to identify any trends from gas issues (withdrawals) and liquefaction (injections) and average balance of storage for each year, as shown in Figure 16.

[137] See Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 396.
[138] See NW Natural's response to Staff's IR 92.

Figure 16: Portland LNG Yearly Gas Storage Movements (reproduced from response to IR 92)



It is evident from Figure 16 that storage level at Portland LNG has dropped in recent years to less than four million therms since 2015 from its earlier level closer to six million therms in the early 2000s. This observation may be attributed to the reasons mentioned in the 2022 IRP of plant age and change in gas composition.[139] Coinciding with this capacity drop, the average gas withdrawn from the plant dropped to a lower average level of roughly one million therms per year. This means that only a small portion of the current full capacity is usually needed. Even on high draw down years (such as 2019 or 2022), there is still about a quarter of liquified capacity still available by the end of the year.

Staff would like to explore the reasons NW Natural did not consider a smaller capacity storage when planning for the replacement of the cold box. Unless there are other reasons, a lower capacity cold box may be a more feasible option congruent with the valid assumption of lower reliance on natural gas in the long term in order to comply with lower CPP targets.

Request for NW Natural:

Request 37: If the original design of the Cold Box has higher capacity than currently needed, NW Natural should investigate a lower capacity cold box replacement project as a lower-cost alternative and share the analysis with Staff before March 7, 2023.

Section 13.1.2 – Non-pipeline Alternatives

With regards to alternative analysis, the 2022 IRP states that none of the additional demand response or energy efficiency beyond the current demand response and energy efficiency projects were deemed viable replacement of the Cold Box.[140] The brief reason given was that the daily deliverability of the Portland LNG Facility represented a capacity resource.

[139] See Docket No. LC 79 – NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 226.
[140] See Docket No. LC 79 – NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 225.

Staff acknowledges the important role that the Portland LNG Facility plays to meet peak needs but would like to see more elaboration on the feasibility of non-pipeline solutions, especially on the supply-side. For example, most scenarios in the system resource planning of the 2022 IRP includes Renewable Natural Gas (RNG) as a resource to meet the emissions compliance obligation of Oregon's CPP in the long term, but no project for RNG or synthetic methane was considered to replace the need for the Portland LNG Facility in the long term.

The delivery date of a Cold Box replacement was proposed to be in 2027 to coincide with the deliverability of other alternatives. Similarly, this could be an excellent opportunity to explore how this date could be changed to coincide with the deliverability of potential long-term non-pipe resources. If the Company already has a contingency plan of a short-term outage of the Cold Box, Staff is curious to know whether reliability would be compromised if the decommissioning date of the Cold Box in 2027 is pushed out by one or two more years. Depending on the scale of a suitable replacement, this option may allow for a potential non-pipe project or a group of projects to be built as a solution.

Request for NW Natural:

Request 38: Staff would like to see in the Reply Comments that NW Natural has exhausted all alternatives to pursuing the Cold Box replacement project and for NW Natural to consider supply-side non-pipe solutions.

Section 13.1.3 – Retaining partial functionality

Staff suggested in IR 93 that it would like NW Natural to evaluate the possibility of decommissioning the pretreatment and liquefaction processes at the Portland LNG facility and importing LNG instead. The Company responded with a detailed analysis, backed with actual quotes and estimates, of trucking in third-party LNG, conducting a present value revenue requirement (PVRR) in 2026 of this option and comparing the results with the Cold Box replacement project. Staff appreciates the time and effort NW Natural took to explore this option in detail.

The results of the studies show that the cost of trucking in LNG for boil off only is comparable to the cost of the Cold Box replacement project. Using 50 percent or 100 percent of the full storage tank capacity would triple or quintuple the cost of trucking LNG, respectively. The amount of gas for boil off used by the Company in response to IR 93 is 960,000 therms, which is roughly equivalent to the average offtake from the Portland LNG Facility per year over the last seven years (see Figure 16).

Staff is interested in pursuing more detail on the option of trucking LNG, and is keen on understanding two issues:

- The costs calculated for the PVRR of trucked LNG in response to IR 93 are constant throughout the 20 years of study. Should the demand for LNG be falling as RNG/synthetic methane or Hydrogen become more dominant resources in the future?

- There is a question on how often 50 percent or 100 percent cycling of the LNG in the storage tank will occur. What would be a realistic annual amount of gas to be cycled given that “Portland LNG is a peak shaving facility that is not expected to be needed to serve peak loads in every year”, as stated in the Company’s response to Staff’s IR 93?

Request for NW Natural:

Request 39: NW Natural needs to consider the scenarios of falling demand due to decarbonization when calculating the costs and benefits of trucking LNG for the study years starting from 2026. What are the potential benefits of using mobile LNG for a few peak seasons, if load eventually declines making the Cold Box unnecessary?

Section 14: Load Forecast

Ryan Bain, Senior Utility Analyst

In this section, Staff addresses the load forecast, associated capacity planning, and concerns with potential overstatement of both forecasts.

Section 14.1 – Customer Counts

In NW Natural's load forecasting, customer count forecasts are combined with use-per-customer forecasts to provide total load forecast. Staff appreciates NW Natural's efforts to project population growth down to population and load centers. However, Staff has concerns with the Company's use of reference case customer count assumptions in six of the nine scenarios.

Specifically, Staff is concerned that with the uncertainty and headwinds facing fossil fuel usage, the reference case customer count over the planning horizon is likely overstated. Reasonable people can disagree on how to attenuate the future customer count growth rate, but it is imperative that the impacts of greenhouse gas regulation and clean energy incentives are appropriately taken into account when forecasting load growth or decline. The reference case customer count uses historical trends to predict future customer growth without regard for new policies like the recent restrictions or moratoriums on gas for new construction in Washington state, Eugene, Oregon, and Milwaukie, Oregon. The use of the reference case customer count forecast in six of the nine scenarios is likely causing load forecasts in each of these scenarios to be overstated.

Request for NW Natural:

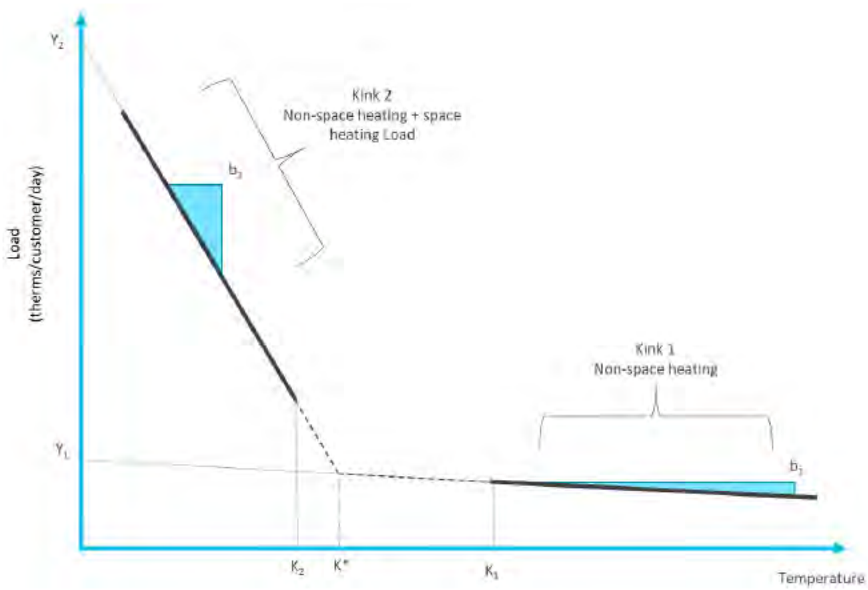
Request 40: Future IRPs must adequately consider the likelihood of declines in customer growth over the planning horizon.

Section 14.2 - Daily System Load Model

Staff has serious methodological concerns with NW Natural's liberal use of interaction terms in their daily system load modelling. In particular, the constant term fit to the model in Table "B.7: Model Coefficients – Daily System Load"[141] is not statistically significant. Staff is concerned that this could be due to the large number of coefficients fit to the model. It would be unusual to find that a constant term is not a significant predictor of daily usage, given that there is a baseline level of natural gas usage that does not tend to vary greatly with temperature. This is demonstrated in the Company's Figure 3.13: "UPC model."[142]

[141] *See* NW Natural 2022 IRP, Errata Filing, Appendix B at 58.
[142] *See* NW Natural 2022 IRP, Errata Filing at 83.

Figure 17: NWN 2022 IRP Figure 3.13 UPC Model



Additionally, many of the temperature interacted terms in the daily system load model lack a clear or intuitive interpretation, and none are offered. For example, it is unclear to Staff how the number of years since the 2008 recession multiplied by temperature realistically informs the daily usage model, other than that this term happens to be statistically significant. In this regard, it is not made clear why the 'holiday' dummy variable is not interacted with temperature when individual weekend days are interacted with this variable. It is stated in the IRP that the Bull Run water inlet temperature is the only term that is not interacted with outside temperature[143].

Ongoing Analysis – Staff would like to verify that the addition of temperature interaction terms in the daily system load model are increasing the model's predictive capacity in excess of the cost of their additions in terms of model complexity, as measured by either adjusted R^2 or AIC.

Section 14.3 – Peak Day Firm Sales Forecast

Staff notes that the Company's peak-day design forecast of approximately 1 million Dth is approximately twice as large as recent historical actual peak day sales.[144,145] Staff is continuing to consider whether the peak-day design forecast is ignoring climate trends by using 100 years of data on an equally weighted basis, when recent trends (over the last 30 years) indicate fewer cold days as shown in Figure 18, which shows Figure 3.36 from the Company's 2018 IRP[146]:

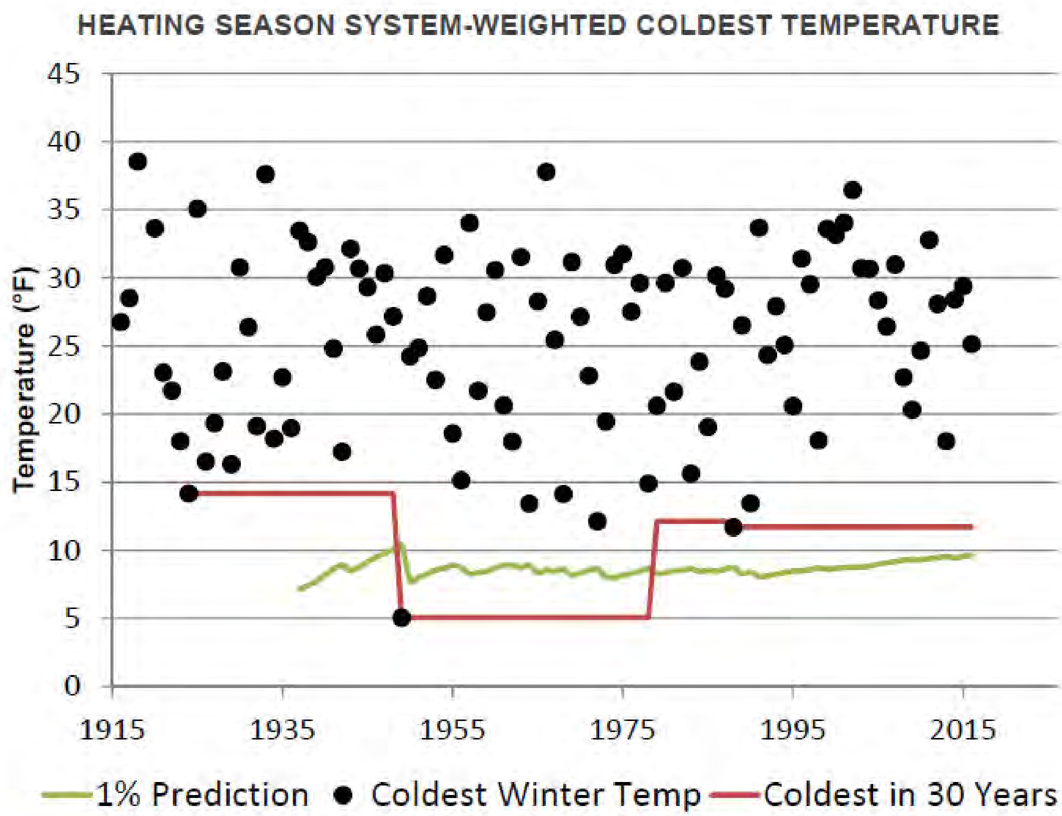
[143] *See* NW Natural 2022 IRP, Errata Filing, at 95.

[144] NW Natural. TWG 2 Presentation. Slide 46.

[145] Attachment 1 to NW Natural's reply to Staff IR 77 shows actual peak day load for recent years.

[146] NW Natural. 2018 Integrated Resource Plan. P 3.42.

Figure 18: Heating Season System-Weighted Coldest Temperature from NWN IRP Figure 3.36



Section 14.4 – First Year Commercial Annual UPC

The Company's 2022 IRP states that new construction commercial customers on average use more gas than existing customers.[147] In response to Staff information requests inquiring about this phenomenon, the Company states that this is driven primarily by changes in broader trends in new construction (building type, size, etc.).[148] The Company also offers that changes in building characteristics, such as building age, changes in commercial customer types, and changes to the mix of gas equipment utilized by new customers are contributing factors.[149]

While it is conceivable that the increased gas usage by new first year customers is due to changes in new building construction, NW Natural's reply that the issue is also possibly due to new customers coming online in older buildings than in the past does not seem to make sense for new construction commercial customers.

[147] *See* NW Natural 2022 IRP, Errata Filing, at 84.
[148] *See* NW Natural Response to OPUC Staff IR 30.
[149] *See* NW Natural Response to OPUC Staff IR 29.

As the company maintains a survey of customer equipment saturation, it would be useful to see analysis focused on identifying the direct or primary drivers of the higher first year commercial new construction customer usage, as opposed to identifying possible causes, as soon as possible. Staff requests that NW Natural address the causes of the increased usage forecast for new construction commercial customers in Reply Comments.

Request for NW Natural:

Request 41: In Reply Comments, Staff request that NW Natural share the peak day system load model's regression summary statistics, restricting the use of interaction terms to only that of wind speed interacted with outside air temperature.

Request 42: In Reply Comments, Staff requests that NW Natural address the causes of the increased usage forecast for new construction commercial customers in Reply Comments.

Section 15: Natural Gas Price Forecasting

Sudeshna Pal, Senior Energy Policy Analyst

Section 15.1 – Introduction

Long-term resource acquisition, emissions reduction and energy demand are impacted by macroeconomic and policy variables including the market price of natural gas. Since a gas utility is planning over a period of 20 or more years, future market prices for natural gas must be forecasted. Natural gas price forecasts generally impact a gas utility in the following ways:

a. Avoided costs of energy efficiency and renewable natural gas.
The cost effectiveness of these resources is directly impacted by forecasted gas prices. Higher forecasted prices of conventional natural gas can lead to higher avoided commodity cost of gas making alternatives such as energy efficiency and RNG more cost effective.

b. Reference Portfolio Costs and Performing Portfolio Risk analyses.
Resource portfolios, or 'scenarios' in this IRP, are generally evaluated using a reference price so that they are comparable with respect to cost effectiveness. The portfolios are also subject to a risk analysis to account for future uncertainties in the planning environment, which includes future natural gas prices. Generally, in gas IRPs, the cost effectiveness and risk analyses are used to select a least-cost least-risk portfolio.

   NW Natural's risk analysis uses a distribution of 500 price trajectories and calculates the average of these 500 simulated future gas prices to sync with the IHS Markit forecasted gas price.

It is therefore important that natural gas price forecasts accurately reflect the future planning environment. This section discusses Staff's observation, analysis, and recommendations regarding natural gas forecasts used in NW Natural's IRP.

Section 15.2 – Gas Price Forecasting Model and Visibility in the 2022 IRP

NW Natural uses natural gas forecasts from IHS Markit (now owned by S&P Global) for its reference case price. NW Natural uses IHS Markit price forecasts for four different gas hubs, namely, Sumas, West Coast Station 2, AECO and Opal. These are the hubs from which NW Natural purchases gas to meet its load needs. IHS Markit is a subscribed database. NW Natural only has access to the forecasts but not to IHS Markit's forecasting tools, including the forecasting model and the list of demand and supply side variables that are used as inputs in a price forecasting model. However, NW Natural shared that IHS Markit uses a long-term demand supply balancing Gas Price Competition Model based on their own long-term assumptions and updates the forecasts every six months.[150] NW Natural uses IHS Markit's August 2022 forecasts

[150] NW Natural's Response to OPUC DR 33.

as reference case prices for each scenario in the portfolio analysis[151] and calculation of avoided costs. In the absence of model visibility and access to proprietary demand supply data, Staff considered forecasts from NW Natural's peer utilities for a comparison of gas price forecasts across utilities. Staff also acknowledges that NW Natural provides a comprehensive overview of current conditions in natural gas prices that are driving current market prices and volatility.

Section 15.3 – Natural Gas Market Background

NW Natural explains in the IRP, Chapter 2, how changes in demand and supply conditions are expected to impact natural gas prices. Current market conditions are putting an upward pressure on natural gas prices, levels, and volatility. NW Natural explains that insufficient supply, low storage inventory, rising demand from electric utilities, increasing LNG exports, and the economic recovery after COVID impacts are the factors contributing to the observed high and volatile gas prices. However, supply is expected to catch up, which will eventually contain the current price hikes.

Staff appreciates the description of current market conditions and an account of NW Natural's expectation of future gas market conditions. Staff adds that future demand and supply will also be impacted by conservation efforts, state and local climate policies, and the availability of conventional natural gas alternatives like RNG. Accounting for these factors is important in natural gas price forecasting.

Requests for NW Natural:

Request 43: Staff requests the Company explain in its Reply Comments if and how demand and supply side factors such as conservation efforts, state and local climate policies, electrification, and the availability of conventional natural gas alternatives like RNG and others were considered in the gas price forecasts used in the IRP.[152]

Request 44: Staff requests NW Natural to include in its Reply Comments on whether it could work with IHS Markit to construct a metric(s) for a growing share of RNG in the system and/or aggressive electrification in the West and pick a representative gas price forecast for a future incorporating this metric(s).

Section 15.4 – 2022 IRP Gas Price Forecast – Staff's Observations

Figure 2.13 in NW Natural's 2022 IRP presents graphs of forecasted natural gas prices in real terms (2021 $/MMBtu) derived from IHS Markit's forecasts for the four hubs, namely, AECO, Sumas, West Coast Station 2, and Opal. All four hubs show a steep decline from 2022 levels

[151] NW Natural's response to OPUC DR 34. Also note here that August 2022 prices are used for the Reference Case. However, a combination of July 2022 short-term price forecasts and February 2022 long-term forecasts are used for gas price simulations. Staff's understanding is the mean or median of these price simulations reflect the third-party forecast used in the Reference Case.

[152] [Begin Confidential] [redacted] [End Confidential].

(~$6/MMBtu) over the next two years, possibly the waning effect of the current energy crisis triggered by Russia's invasion of Ukraine. The prices in all four hubs show an upward trend but remain below the $4/MMBtu (in real terms) mark for the rest of the planning period (2023-2050). Figure 2.13 also shows a subset of the 500 simulations of the gas price forecasts that show a range for the mean or median gas price. The maximum forecast values are in the $8 - $10/MMBtu range (in real terms).

Staff notes that Figure 2.10 shows higher and more volatile price forecasts for Sumas for the near to medium-term (2027-2037). NW Natural explained this to be triggered by the Woodfibre LNG facility, which is expected to be in operation around that time. This increase in demand would create interstate pipeline constraints that in turn would raise prices at the Sumas hub.[153]

As discussed above, cost-effectiveness calculations based on forecasted natural gas prices will have a direct impact on avoided cost estimates for energy efficiency measures and RNG. Since NW Natural purchases gas from four different hubs and uses the price forecasts from these hubs to estimate avoided costs for the system, the impact of an outlier, like Sumas could result in over or underestimation of these avoided cost estimates while adding uncertainty to these estimates.

Request for NW Natural:

Request 45: Staff requests NW Natural explain in its Reply Comments how price events at Sumas or the price variations across hubs in general may affect avoided cost calculations for energy efficiency, RNG resources, and distribution system investments. The explanation should provide additional information regarding why the Company views the inclusion of higher, more volatile prices at Sumas as an improvement to the accuracy of avoided costs.

15.5 – A Comparison of 2021 Gas NW Natural IRP Gas Price Forecast with other IRPs

To evaluate the reasonableness of the gas price forecasts used in the Reference Case, Staff compared the forecasts from the NW Natural 2022 IRP with those used by other electric and natural gas utilities in their IRP modeling analyses and NW Natural's own forecasts in its 2018 IRP. Table 4 below is a summary of those findings.

Table 4: Natural Gas Price Forecast Comparisons

Company	IRP	Gas Price Forecast Source	Forecast Period	Gas Price Forecasts
NW Natural	2018	IHS Markit (S&P Global)	2019 – 2038	A little over $4/MMBtu (real prices). All four hubs moving in

[153] LC 79 OPUC DR 37.

				tandem with no significant spread or spike.
Avista Gas Corporation	2023	North America Gas Service – Wood McKenzie	2020 - 2050	Consistent with forecast used in NW Natural's 2021 IRP.[154]
Idaho Power Company	2023	S&P Global Platts	2022 - 2040	Begins at a little higher than \$7/MMBtu (nominal) with a steep decline to \$4.50 in the near term. Rises back up close to \$5.50 in 2040.[155]
PacifiCorp	2023	Henry Hub	2022 - 2040	The forecast shows a decline in natural gas prices (nominal) to below \$4 in the near-term, then rises post 2028 and reaches approximately \$6/MMBtu in 2040.[156]

Based on these comparisons, Staff concludes that natural gas price forecast used in the Reference Case in NW Natural's 2021 IRP is reasonable. Staff looks forward to NW Natural's Reply Comments with responses to the recommendations that Staff has made with regards to natural gas price forecasting.

[154] https://www.myavista.com/about-us/integrated-resource-planning. See Avista TAC 4 Presentation Slides 48-63.
[155] Notes from Idaho Power 2023 IRPAC, October 13 Meeting.
[156] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_May_12_2022.pdf. See slide 41.

This concludes Staff's Opening Comments.

Dated at Salem, Oregon, this 30th day of December, 2022.

Rose ANDERSON

Rose Anderson
Senior Economist
Energy Resources and Planning Division

CERTIFICATE OF SERVICE

LC 79

I certify that I have this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 30th day of December, 2022 at Salem, Oregon.

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