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February 3, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: LC 79 – NW Natural's 2022 Integrated Resource Plan: Reply Comments

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company) files herewith its reply to the December 30, 2022 Stakeholder comments. The comments contain proprietary information and are considered confidential under General Protective Order No. 22-374.

Please address correspondence on this matter to me at rebecca.trujillo@nwnatural.com with copies to the following:

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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
Regulatory Consultant

Attachment

OPUC LC 79 NW Natural Reply Comments
February 3, 2023

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Introduction

Northwest Natural Gas Company (NW Natural or the Company) files these Reply Comments in response to the Opening Comments submitted in this docket by the Public Utility Commission of Oregon (OPUC) Staff, the Alliance of Western Energy Consumers (AWEC), the Oregon Citizens' Utility Board (CUB), Green Energy Institute at Lewis and Clark Law School, Climate Solutions, Community Energy Project, Columbia Riverkeeper, Electrify Now, Metro Climate Action Team, NRDC and Sierra Club (Advocates) and Small Business Utility Advocates (SBUA).

Prior to addressing Staff's, AWEC's, CUB's, and Advocates specific comments, NW Natural would like to thank all participants in its Integrated Resource Planning (IRP or Plan) process for their engagement, comments, and the time they have spent since our first technical working group in 2021.

PART 1: Key Issues

1.1 Action Plan is the Result of a Comprehensive Evaluation to Serve Existing Customer Load

NW Natural filed its 2022 IRP on September 23, 2022,[1] roughly nine months after the Oregon Department of Environmental Quality's (ODEQ) Climate Protection Program (CPP) rules were established. This is a compressed timeframe to complete an IRP analysis and to conduct a robust stakeholder process. Pursuant to Order No. 21-013 in Docket LC-71, the Company launched its 2022 Technical Working Groups upon ODEQ's release of draft CPP rules. The Company held two comprehensive stakeholder workshops[2] in 2021- Load Considerations and Emissions Considerations - to discuss key issues that would need to be analyzed in the 2022 IRP. Following these supplemental workshops, NW Natural held six full day and one-half day stakeholder workshops in the first half of 2022. Here, key assumptions, analytical methodologies and tools were presented in detail in a transparent manner as the analysis for the 2022 IRP was being conducted. Stakeholder feedback was sought during the workshops themselves, as well as in writing after the workshops during informal comment periods.

All Technical Working Groups were listed on NW Natural's website and were announced to the IRP distribution list.[3] As all stakeholder workshops were held virtually, the majority were recorded, and these, as well as all workshop presentations, can be viewed on the Company's website. Further, NW Natural held additional workshops and open office hours prior to, and after the draft IRP was distributed on July 29, 2022[4]. During these sessions, the Company was available to answer questions and receive feedback from stakeholders. We thank stakeholders for their thoughtful feedback that was provided during this time. NW Natural took into account this feedback, which led to many changes seen in the final IRP.[5] The Company believes the public process was robust and transparent.

While we expect to continually enhance future IRPs given the incredibly dynamic – and uncertain – policy environment, the Company has completed all the analysis and taken all the feedback that could reasonably be expected given the constraints of timing and uncertainty. The resulting IRP is arguably the most complex, thorough, and analytically advanced gas utility IRP ever filed in Oregon (and possibly in

[1] An errata filing was made on October 21, 2022.
[2] NW Natural names its public stakeholder workshops Technical Working Groups (TWGs).
[3] NW Natural's IRP Distribution List is a 'living document' and is updated regularly as stakeholders request to be added or removed or are otherwise identified.
[4] The Company additionally held a Meeting for the Public which was announced to all customers via a bill insert as well as a posting an announcement on the NW Natural website. The associated presentation for this meeting is also available on the Company website and is described within Chapter 10 of the 2022 IRP.
[5] Feedback received on the draft IRP is summarized in Appendix J of the 2022 IRP.

the United States). While we expect critical stakeholder feedback, we feel compelled to level set on the monumental undertaking achieved in this IRP.

The IRP comprehensively evaluates the resource options available to the Company to serve its customers' energy, capacity, and environmental compliance needs of the transformative CPP. The analysis includes many new components – such as customer bill impacts, detailed load analysis of dual-fuel heating systems, and stochastic simulation-based risk-adjusted preferred portfolio development – that go above and beyond what is required by the Commission's guidelines or even what was suggested in the UM 2178 Natural Gas Fact-Finding Draft Report, Appendix B IRP Guidance.[6] These components were included in an effort to provide the information sought by the Commission and stakeholders, and to shed light on key longer-term issues while developing an Action Plan that addresses urgent, shorter-term needs. The analysis was developed with the current uncertain policy environment in mind, and it evaluated incredibly wide ranges of possibilities for all key inputs and potential outcomes.

Some stakeholders have made the following arguments:

- long-term assumptions need to be adjudicated and settled by the Commission to evaluate the Action Plan,
- there is not enough information for the Commission to evaluate the Company's action items, and/or
- developments that have happened since the filing of the IRP mean more analysis is needed before moving forward.

If the IRP were lacking key analysis; or if any actions in the Action Plan were largely dependent upon long-term load projections; or if it were seeking acknowledgement of projects based upon new or unproven technologies; or if it were seeking acknowledgement of large investments that could substantially impact the cost of service to customers as stranded assets in the future, then stakeholder arguments would be pertinent to the approval of the Company's Action Plan. However, this is not the case for any action item in the 2022 IRP Action Plan. Rather, the Company has taken feedback from stakeholders and Commission Staff and developed an Action Plan which *only* includes investments that are needed to maintain reliable service for *current* customers; comply with SB 98; and comply with the first three-year compliance period of the CPP with proven technologies.

IRPs are a natural forum for discussion about the future of natural gas utilities as it pertains to system planning and the reasonableness of the Company's longer-term projections for CPP compliance. Indeed, a significant portion of NW Natural's reply comments focus on these policy issues and key longer-term assumptions. That being said, the total investment of the actions being sought for acknowledgement is quite modest relative to other IRPs evaluated by the Commission and no action item in the Action Plan is materially dependent upon medium-, or long-term customer growth or load projections. Likewise, no action item in the Action Plan is materially dependent upon the availability or cost assumptions of technologies like natural gas heat pumps, dual-fuel heating systems, or hydrogen-based gas products.

[6] Please see UM 2178 at https://edocs.puc.state.or.us/efdocs/HAH/um2178hah155046.pdf

It is important to reiterate that while the CPP program rules were established at the end of 2021, the first year of compliance started immediately afterward in 2022, and the three-year compliance period will be halfway complete when the Action Plan will be deliberated by the Commission in June 2023.[7] We recognize that it is challenging to make decisions in the face of uncertainty, and the current policy environment is relatively uncertain. However, stakeholders and the Commission have long been willing to recognize that uncertainty and a lack of perfect information, which is not possible to attain, should not stop deliberation of acknowledgement of investments that are needed to maintain safe and reliable service now and in the near-term. For example, while PacifiCorp's 2021 IRP did not include analysis of the company's recently established requirements under HB 2021 in Oregon and stakeholders and the Commission pointed out the issues regarding evaluating the action plan in the IRP without the analysis of that transformative policy, the Commission nevertheless thoughtfully deliberated acknowledgement of key investments given the risks of delaying decisions. This is not to criticize PacifiCorp's 2021 IRP, as IRPs are highly complex and substantial modeling changes require long lead times to be implemented and quality controlled, so the lack of inclusion is understandable. In fact, most IRP action items are deliberated in an uncertain environment that recognizes these are not "set it and forget it" long-term plans but rather IRP planning as an iterative process with regular updates that provides the utility and our stakeholders with the ability to be flexible as the future unfolds.

While it is a challenge for resource planning that the CPP went into effect directly after the program rules were established at the end of 2021 and NW Natural's compliance period began in 2022 (i.e., in the midst of the 2022 IRP process), the Action Plan proposes actions - on behalf of our customers - to respond to this challenge in time for the first compliance period. The Action Plan calls for needed action for CPP compliance, as well as investments to maintain safe and reliable service. To the extent stakeholders are requesting that needed near-term actions in the IRP Action Plan should not be acknowledged based upon longer-term uncertainties that could be evaluated in future analysis, doing so would present substantial risk to customers and undermine the strong tradition of IRPs that has been established over the last three decades in Oregon.

Furthermore, there are multiple requests from stakeholders for additional analysis utilizing new information and developments that have yet to be finalized or have happened since the IRP was filed, let alone before analytical assumptions needed to be locked down and the final analysis completed for inclusion in the IRP. Examples of these requests include the federal Inflation Reduction Act, developments in the Energy Trust of Oregon budget process, Staff reports on other IRPs, municipal gas moratorium activity, NW Natural's general rate case outcome, and the outcome of the UM 2178 process. NW Natural recognizes that, in certain other circumstances, new developments could be sufficiently substantive to render analysis and action items in an IRP obsolete, and could necessitate substantial changes to the analysis in an IRP and a refiling of the plan. For example, the issuance of EO 20-04 and the ensuing development of the CPP in the spring of 2020 rendered what would have been NW Natural's 2020 IRP incapable of developing an Action Plan robust to CPP compliance. NW Natural worked with parties to defer the filing of the IRP until we could incorporate the critical needs of CPP

[7] Following an extended 8-month process compared to the normal 6-month post-filing process leading to an acknowledgement decision on the IRP.

compliance. We are now at the time where the compliance needs from the establishment of the CPP are urgent.

The developments since the 2022 IRP was filed in late September do not reach such a threshold to necessitate major changes or refiling the plan. There is a real risk of further delaying the IRP, as compliance decisions need to be made and projects completed to maintain safe and reliable service. The Company anticipated changes to the policy and market environments and conducted analysis with ranges on key inputs that all post-filing developments fit squarely within. The post-filing developments would not lead to a tangible change in the Action Plan were these developments taken explicitly into account and analysis redone. Again, referencing PacifiCorp's 2021 IRP, the Action Plan in that docket was evaluated for acknowledgement even though it did not include analysis of laws passed months *before* filing of that IRP, let alone developments that occurred after that IRP filed. Given that the world is constantly changing, NW Natural urges stakeholders and the Commission to consider the implications of requiring/requesting updates to analysis for post-filing developments given the time and care it takes to complete IRP analysis.

In addition, much of the feedback provided by stakeholders in post-filing comments was not provided during the lead up to IRP filing when changes and additions to the analysis were possible. NW Natural made best efforts to solicit and incorporate stakeholder feedback and recommendations into the analysis in the 2022 IRP (see Section 1.2). IRPs are complex and voluminous and surely impose challenging time constraints on those who provide thoughtful reviews of them. NW Natural appreciates thoughtful engagement from all stakeholders and the IRP benefits from diverse perspectives, something NW Natural actively and consistently seeks out.[8] Furthermore, while the Company believes that customers and the IRP would have benefitted from the majority of feedback being provided in the pre-filing process so that it could have been incorporated into the analysis and IRP filing as appropriate, we recognize that some stakeholders can only meaningfully engage after the IRP is filed. With this context, many of the critiques of the analytical work and assumptions in the IRP could have been provided during IRP development but were first seen by NW Natural in post-filing comments. This, of course, does not render these comments unreasonable or incorrect, but the Company hopes that these critiques are not seen as assessments repeatedly expressed to NW Natural without effect.

Lastly, there are a high number of requests for additional analysis or work in these comments or this IRP process. While NW Natural will strive to prioritize and complete these requests, there is simply not enough time to complete all of them in detail and with the necessary quality control to be reasonably certain that it is appropriate to base decisions upon the work. Additionally, where we do not believe that these requests will result in additional information that will help stakeholders review the IRP and the Action Plan, we explain why that is the case. There are a number of requests that would, in NW Natural's view, require a change to current law or Commission policy or are premature until critical questions are first answered to be able to implement a change without unintended consequences, direct conflict with other policies, or potential misalignment with other policy aims.

[8] Engagement with the IRP process was one of the key reasons NW Natural established a compensated Community and Equity Advisory Group (CEAG). See Section 10.4 of the errata 2022 IRP.

With that background, to make sure NW Natural's position on the Action Plan is clear, below is a summary of the key action items in the 2022 IRP:

Portland LNG Cold Box – A cold box is a piece of equipment that allows natural gas to be converted to liquified natural gas (LNG) for more efficient storage. The Portland LNG facility is a critical peaking facility that is a large part of NW Natural's peak capacity portfolio, and in a region that is already capacity constrained, a key regional resource for maintaining regional energy service during cold weather events. The Portland LNG facility cannot be refilled without a functioning cold box, and the current cold box is at the end of its useful life and showing signs it could become inoperable in the near future. The Portland LNG facility is needed to serve current customers, and even if incredibly aggressive electrification of NW Natural load were to happen moving forward, the facility would be a needed part of the Company's resource portfolio. The need for the Portland LNG facility is not contingent upon any customer growth and is needed in futures with high levels of electrification among the Company's existing customer base. Replacing the cold box at a moderate investment of roughly $10 million would allow keeping a key part of the peak resource portfolio safe and reliable. The alternatives analysis conducted to arrive at this conclusion is the most robust alternatives analysis ever completed by NW Natural for an investment in an existing facility and replacing the cold box is less costly and less risky than other alternatives evaluated.

Forest Grove Feeder Uprate – The Forest Grove feeder is the primary feed into NW Natural's system in the Forest Grove area. Uprating means making an existing pipeline safe to deliver more gas by increasing the pressure it can be operated. Over the last two IRPs, NW Natural has worked with OPUC Staff and stakeholders to determine what evidence should be provided to support the need for distribution system upgrades. NW Natural provided that information – and more – to complete an alternatives analysis inclusive of non-pipeline solutions to demonstrate that the Forest Grove feeder uprate is needed to maintain service to *existing* customers without an assumption of *any* customer growth in Forest Grove were a planning peak day to be experienced. While the Company understands the conversation about avoiding or delaying "growth related" projects and is addressing that issue directly (see Section 1.4), this project is not based upon a projection of customer or peak growth. Even if a customer addition moratorium were put into place in Forest Grove today, something that would not be appropriate in NW Natural's view even if it could be effective in alleviating the need for the project, the project would still be necessary to maintain reliable service. It is NW Natural's position on the assertion that this project can be avoided or is unnecessary at the current time would put customers at risk of losing heating at dangerously low temperatures, which is the precise scenario a gas utility must plan to avoid. This reliability risk should be weighed against any potential "stranded asset" risk being cited as a rationale for not acknowledging the needed uprate at a moderate cost of approximately $5 million. Furthermore, classifying a supply-side tanker truck based peaking service in the Forest Grove area, which is a more complex, less reliable, and a more infrastructure-heavy investment than the pipeline uprate itself, as a preferred "non-pipeline solution" is misguided.

Environmental Compliance Actions –NW Natural believes that the analysis in the IRP is comprehensive and demonstrates that long-term CPP compliance under many different potential future outcomes can be achieved at a reasonable cost. The IRP analysis also shows that as more electrification occurs, there is a greater risk of stranded assets and spikes in customer bills for the customers that remain on the system. This assessment is disputed by some stakeholders. This is an important discussion, and one that makes sense to have in the evaluation of IRPs. Specifically, the discussion about what policy or market environment could prevail and how that relates to comparing the cost and feasibility of gas decarbonization focused alternatives against electrification focused ones moving forward is critical. NW Natural is not proposing any large hydrogen-based projects (or other large-scale compliance projects) or meaningful incentives for gas powered heat pumps. Resolving issues around dual-fuel heating systems or gas customer financed electrification cannot be done in NW Natural's IRP alone. Attempting to analyze these issues within NW Natural's IRP would in fact be rushing important discussions and lacking the necessary supporting Oregon specific multi-utility analysis.

Furthermore, resolving these important issues is not necessary for deliberation of this Action Plan as it is not dependent upon whether a gas decarbonization or electrification-based focused outcome unfolds. A wide range of outcomes on this spectrum were included in the risk analysis upon which the Action Plan is based. The actions in the Action Plan related to environmental compliance only cover the first compliance period of the CPP (2022-2024)[9] and the years 2024 and 2025 for SB 98. Given that NW Natural's emissions cap is reduced through 2050, even under aggressive electrification scenarios,[10] the amount of RNG and energy efficiency being sought for acknowledgement in the Action Plan period would not be greater than the amount that would likely be needed for compliance with the CPP and SB 98 in 2050. The concerns raised by stakeholders about availability and pricing of biofuels (RNG) and hydrogen derived products are only applicable to the immediate CPP compliance period if stakeholders believe the amount of biofuels proposed in the Action Plan cannot be acquired. NW Natural is confident these volumes can be acquired, and no stakeholders are making that claim.

NW Natural is in a compliance period and must comply with the CPP, and its compliance plan with the CPP and SB 98, as demonstrated by the Action Plan, is lower risk than other available alternatives. Lastly, as discussed in Section 1.3, the Commission's least cost/least-risk standard and the existence of the CPP does not minimize the provisions of SB 98 given that it is law and former Oregon Governor Brown's Executive Order 20-04 (EO 20-04) that led to the CPP rulemaking explicitly supports the use of renewable natural gas.

1.2 Key Assumptions are Reasonable and Wide Ranges Have Been Evaluated

Key planning assumptions and methodologies for developing them are understandably a focus of stakeholder comments. Most of the responses to comments, recommendations, and critiques of key assumptions are found in the direct responses to requests in Section 2 or the clarifications on statements made in Section 3. However, NW Natural would like to provide clarifications on issues that the Company views as most critical to reviewing the IRP. While there appears to be some confusion about what some assumptions in the IRP actually are and how they are deployed, there are, in some cases, disagreements about what assumptions are "reasonable." We have received contradicting feedback on different assumptions from different stakeholders. Given that we are discussing

[9] Noting that banking of compliance instruments means that NW Natural is not seeking acknowledgement of actions that have already been taken or on which a final investment decision has been made.
[10] And assuming long-term commitments for RNG and long-lived savings investments for energy efficiency.

assumptions about technological, market, and policy developments over multiple decades, this is unavoidable. With that, and per Section 1.1, it is important to point out that most of these assumptions impact long-term plans; their impact on the Action Plan is minimal. For example, while customer count forecasts are important, the Action Plan covers the years 2024 and 2025, and the current number of customers NW Natural could have next year or the year after cannot vary greatly from current levels- either up or down.

1. Customer Count Forecasting – There are numerous stakeholder comments that would assert that NW Natural's IRP is based upon a customer count forecast that is too high given environmental policy developments and changing customer preferences. For example, see the following included in stakeholder comments:

OPUC Staff:

> *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.*[11]
>
> *Request 40: Future IRPs must adequately consider the likelihood of declines in customer growth over the planning horizon.*[12]

CUB:

> *NWN's load forecast uses historic results to project future growth in customer counts. With the exceptions of the scenario that model electrification, all scenarios assume that there will 200,000 new customers added to the system. CUB believes that the historic data comes from a period before electrification, this is not a reasonable assumption.*[13]

Advocates:

> *The IRP reference case's load forecast is not realistic. NWN's customer count trends do not take into account 1) residential building cost updates in Washington, 2) line extension allowance updates in Oregon, and 3) Inflation Reduction Act incentives to accelerate building electrification. Climate Advocates are also concerned that NWN is not accounting for the possibility of reduced load associated with local policies supportive of beneficial electrification. Each of these policy changes, particularly Washington's building code updates and Oregon's line extension allowance reduction, will likely have near-term impacts as discussed below.*[14]
>
> *NWN uses the reference cast customer count in six out of the nine scenarios. The customer count forecast, based on historic trends, is an overestimation considering the factors that will significantly reduce demand in the short and long term.*[15]

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[11] Staff Comments at 7.
[12] Staff Comments at 83.
[13] CUB Comments at 21.
[14] Advocate Comments at 47-48.
[15] Advocate Comments at 48.

These comments do not recognize the changes NW Natural implemented to its customer count forecasting in this IRP, the purpose of the Scenarios in the IRP, the fact that the Company does not have a single load forecasting technique to supplement the statistical approach that generates the reference case, nor the fact that the average of the stochastic Monte Carlo simulations is being used to develop the preferred portfolio and the figures found in the Action Plan. Without reading the IRP or reviewing the work done in detail, one may conclude from reading these stakeholder comments that NW Natural's customer projections are based upon historical trends. This is simply untrue. NW Natural recognizes its role in the confusion, as the description of how the scenario analysis and the stochastic Monte Carlo analysis work together, and how the average of the 500 stochastic draws is the source of the preferred portfolio and the Action Plan that results in the IRP is not written in enough detail for reviewers to understand the approach taken. That said, the executive summary of the IRP lists the key changes in the 2022 IRP and includes the following statement that makes it clear that the reference case does not represent "the" customer count forecast of the IRP:

6. Using stochastic risk analysis as the primary tool for developing the Action Plan

- *While NW Natural has conducted robust risk analysis for numerous IRPs, in past IRPs a single base case was developed, and the Action Plan was constructed primarily using the results from this base case. Given the high degree of uncertainty and the transformative new policies which we are implementing the Action Plan and preferred portfolio in this IRP is based upon a risk-adjusted approach based upon the range of outcomes of our stochastic Monte Carlo simulations.*[16]

Furthermore, a special callout in Chapter 2 defines the reference case:

> ***Reference Case*** *– a projection of demand based on historical trends of customer additions and gas usage. The reference case shows what load would look like if all trends embedded in historical data continued over the remainder of the planning horizon to 2050. The reference case is not a base case or preferred portfolio, it is a tool to show how scenarios being modeled in the IRP differ from the prior "business-as-usual" state.*

This issue was asked and addressed directly in data requests, where NW Natural provided the following responses to Staff requests:[17]

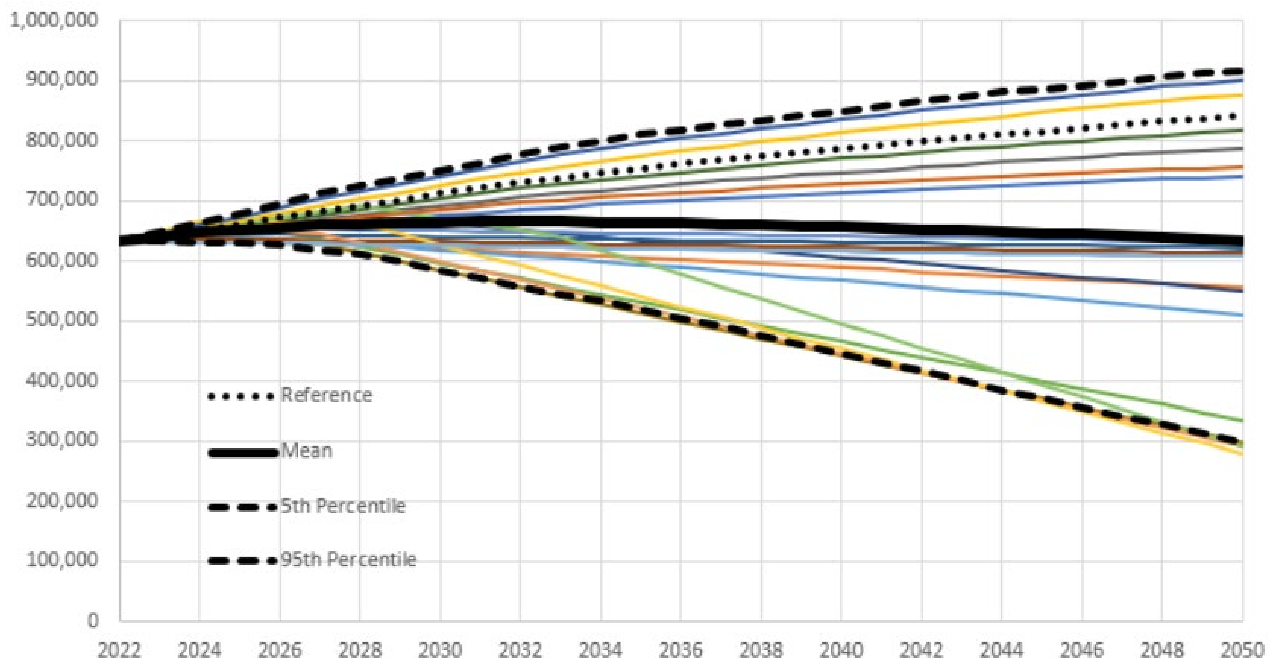
> <u>Staff Request:</u> *Does NWN's IRP have a NWN Preferred Resource Portfolio covering the period through 2050?*
>
> <u>NW Natural Response:</u> *Yes, the preferred portfolio is the average of the outcomes from the stochastic Monte Carlo risk analysis detailed throughout the IRP with the results being shown in Chapter 7, Section 6.*

Furthermore, the stochastic customer count forecasts are not a random draw of the customer count forecasts seen in the 9 scenarios, as the underlying code provided in the request to a Data Request, and

[16] See page 19 of the errata 2022 IRP.
[17] See the response to LC 79 OPUC DR 69, which is provided as Appendix A.

the cell formulae intact workpapers provided to stakeholders by NW Natural demonstrate. The 500 results from the stochastic Monte Carlo process were used to construct Figure 3.37 in the 2022 IRP which shows the Oregon Residential customer count forecasts across the Monte Carlo simulations in the IRP:

IRP Figure 3.37: Oregon Residential Customer Count Monte Carlo Results



As can be seen from this graph, the average of the Monte Carlo draws (the solid black line) shows far fewer customers than the reference case and shows a decline in customers starting in 2032. The average of the stochastic simulations is 25% lower in 2050 than the reference case and ~85% of the stochastic draws have a customer count that is lower in 2050 than the reference case.[18]

The following graph shows the same information but in terms of customers added or lost in a year[19] and shows a stark difference in the current customer count forecast on a historical and forecast basis, featuring a substantial decline relative to previous forecasts. The black line represents the total net additions historically and shows that the driver has been, and continues to be, activity in new construction (see the brown historical line). Forecasts from prior IRPs (the hashed colored lines) and the current reference case (blue hashed line), which were forecasted based upon state projections of new building activity, have performed reasonably well.

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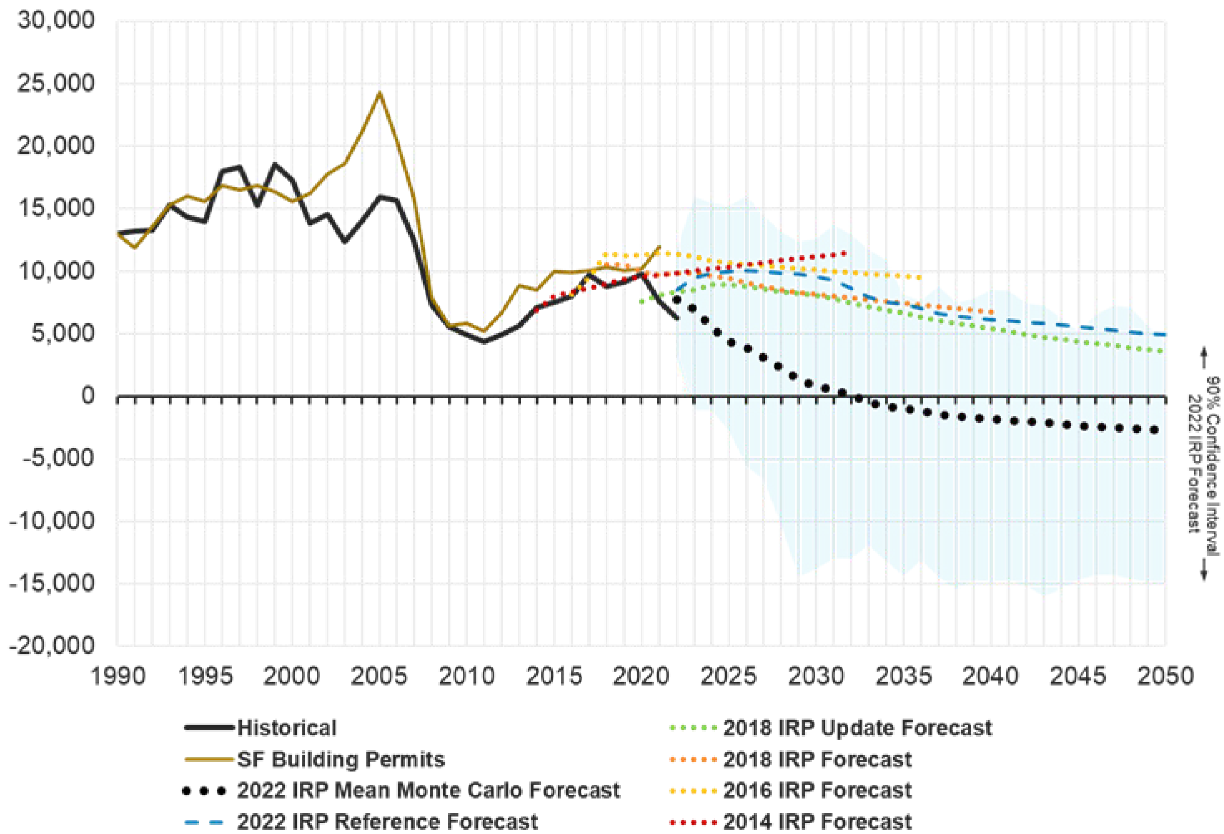
[18] Demonstrating that the claim about six of nine scenarios using the reference case forecast are biasing the stochastic Monte Carlo draws to be too high is incorrect.

[19] Customer net additions = new construction customers added + new conversion customers added – existing customers who leave NW Natural's system.

The dotted black line represents the current forecast upon which the preferred portfolio is based, and the blue area represents the 5th to the 95th percentile range of the stochastic simulations.

Figure 1: Oregon Residential Customer Net Additions



The forecast falls sharply from current levels until net customer declines are projected starting in 2032. This is not driven by a stark decline in expected new construction activity in the state, but a change in methodology that was implemented *in response to stakeholder feedback throughout the IRP process.* This is the primary mechanism through which electrification is modeled in the IRP, and wide ranges of electrification are modelled via these customer projections, including more aggressive electrification than any policy currently being discussed.

Throughout the past 30 years NW Natural's net customer additions have been consistent, tied to new construction activity in the Company's service territory and been net positive – including in the most recent years when some stakeholders have recommended lower customer projections citing environmental policy changes and customer preferences that have not materialized. NW Natural analysts do not believe that the customer count forecast in the 2022 IRP that drives the Action Plan is the most likely scenario and will likely understate customer growth going forward. Given this major compromise made by NW Natural in response to pre-filing stakeholder feedback the Company was surprised that Staff, CUB, and the Advocates all criticized the customer forecast in the 2022 IRP as *too* *high* and focused comments on “customer growth” and the reference case when electrification driven customer declines are actually being projected. This is especially surprising given that the IRP highlights that the reference case forecast is not the forecast used for decision making and data request responses clarified that the average of the stochastic simulations is the forecast that drives the preferred portfolio. It is unclear to NW Natural whether this is due to confusion or a view by stakeholders that the customer count forecast in the IRP based upon the average of the stochastic Monte Carlo simulations is still “too high,” “biased,” or “not reasonable.” NW Natural’s assessment is that the current customer forecast is already artificially low, so if the latter, the Company disagrees with this assessment. NW Natural requests that stakeholders provide a more detailed explanation as to why the customer forecast is too high, and Staff justify their position that *future IRPs must adequately consider the likelihood of declines in customer growth over the planning horizon,* as stated in Staff Request 40, if they believe this IRP does not adequately do so given the sharp decline shown in the figure above.

2. Renewable Supply Availability and Cost-

Understandably, stakeholder comments include lots of discussion about assumptions for renewable supply (biofuels, hydrogen for blending, hydrogen for dedicated delivery, and synthetic methane) cost and availability. NW Natural developed these assumptions directly from respected third-party sources, our own active market participation, and stakeholder feedback. The Company believes its assumptions relative to these resources are reasonable and the stochastic Monte Carlo simulation analysis used to develop the preferred portfolio analyzes wide ranges for these sources of low emitting gas. That said, differing views on what assumptions are appropriate is unavoidable and we look forward to further discussion with stakeholders on this topic in future IRPs and IRP Updates. NW Natural’s perspective is that the best estimate for each input should be used for optimization and uncertainty in those estimates accounted for in scenario and stochastic work to understand the implications things turn out to be higher or lower. If a conservative (i.e., relatively high) estimate is used in comparison to other resources it biases acquisition against the resource with a conservative assumption as well as biases overall cost estimates higher than actual expectations.

<u>Biofuels</u>

NW Natural defined its biofuel availability assumptions based upon the most comprehensive and up to date analysis on this issue, work completed by ICF and presented at a Technical Working Group. That being said, while the Company maintains that its availability assumptions are reasonable and this was not known prior to the analysis being completed, a relatively small portion of the biofuels assumed available are actually selected across scenarios (see Figure 2) and most of the stochastic Monte Carlo draws. Additionally, the company analyzed a wide range for availability in the Monte Carlo simulations. Figure 3 shows the amount of biofuels that showed as cost effective relative to the assumed availability for across Scenarios and the average of the Monte Carlo draws.

Figure 2: Biofuels Availability vs Selected Across Monte Carlo Draws (2050)

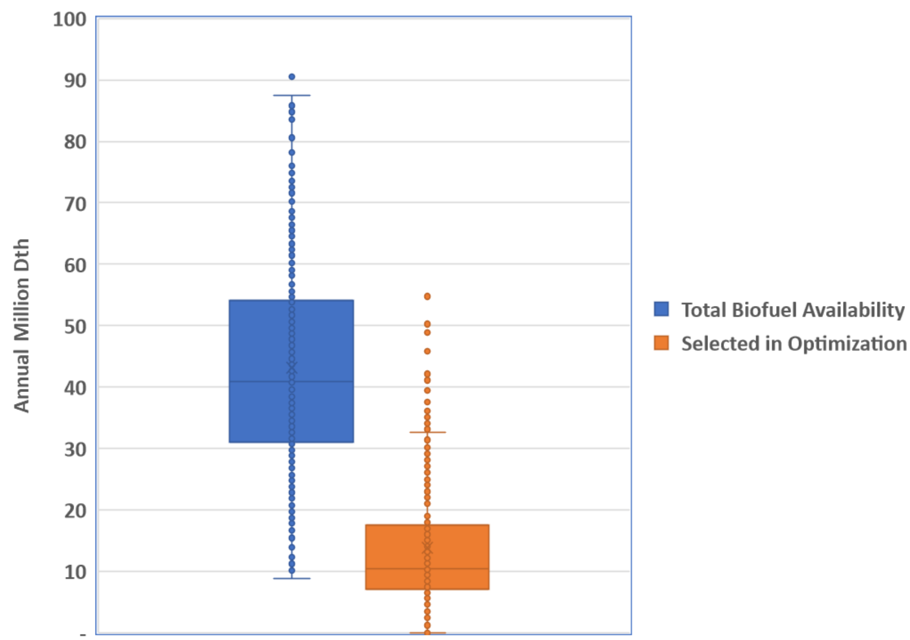
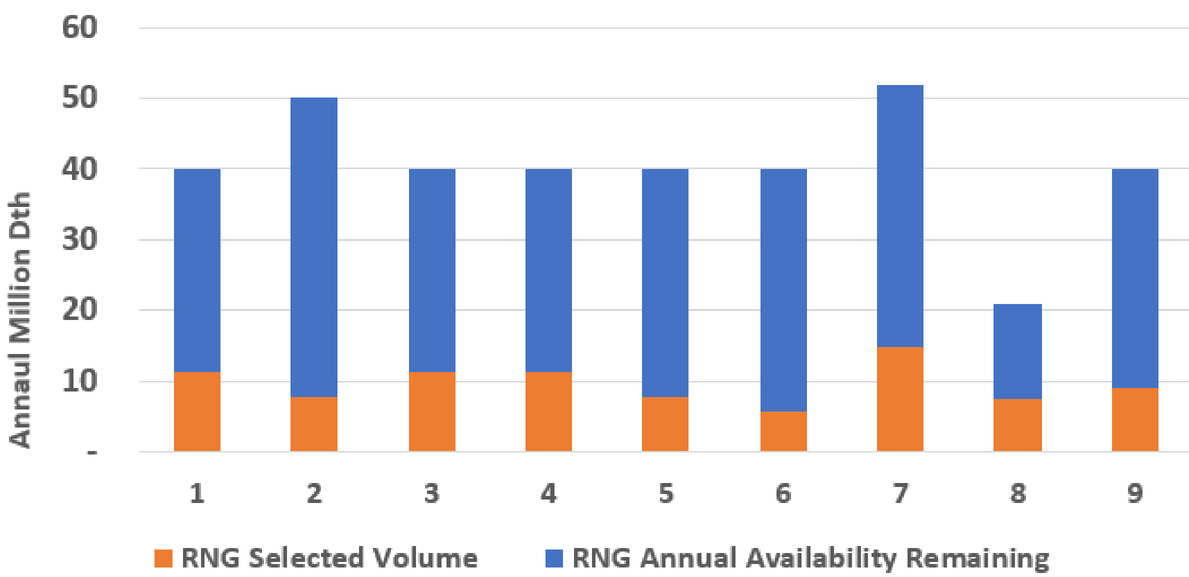


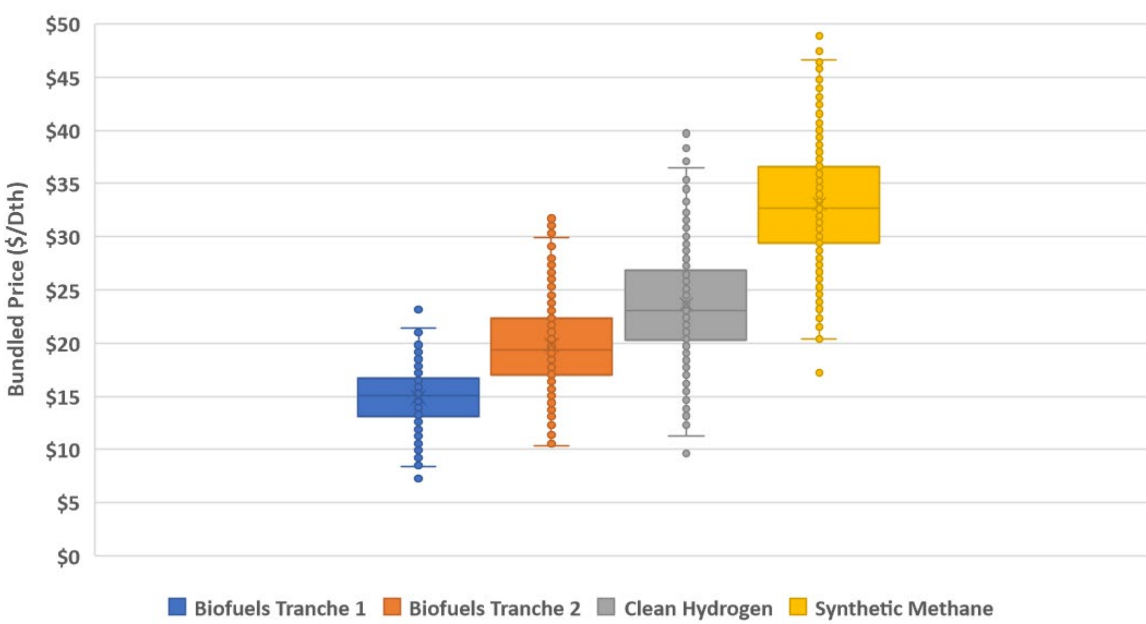
Figure 3: Biofuels Availability vs Selected by Scenario (2050)



Roughly one-third of the biofuels assessed to be available are selected as part of the optimized portfolio across the 500 stochastic draws, a result that is consistent with selection across the Scenarios modeled. As such, while discussions about availability of biofuels are important, the subsequent resource optimization process renders this discussion less relevant, especially as it pertains to the Action Plan.

In terms of the pricing of biofuels NW Natural believes its assumptions for the first tranche of the portfolio (which is the relevant price in the near- to medium-term) to be realistic based upon active market participation, RFP responses for actual resources, and existing biofuel projects delivering RNG to our customers today. "Tranche 1" biofuels are the only resources selected during the period covered by the Action Plan in all of the Scenarios evaluated and the vast majority of the stochastic draws, and therefore represents the most relevant assumption for evaluating the emissions compliance action plans Biofuel price assumptions are thoroughly described in the IRP. Figure 4 shows the price ranges for the renewable supply.

Figure 4: Monte Carlo Simulation 2022 Renewable Supply Price Variation

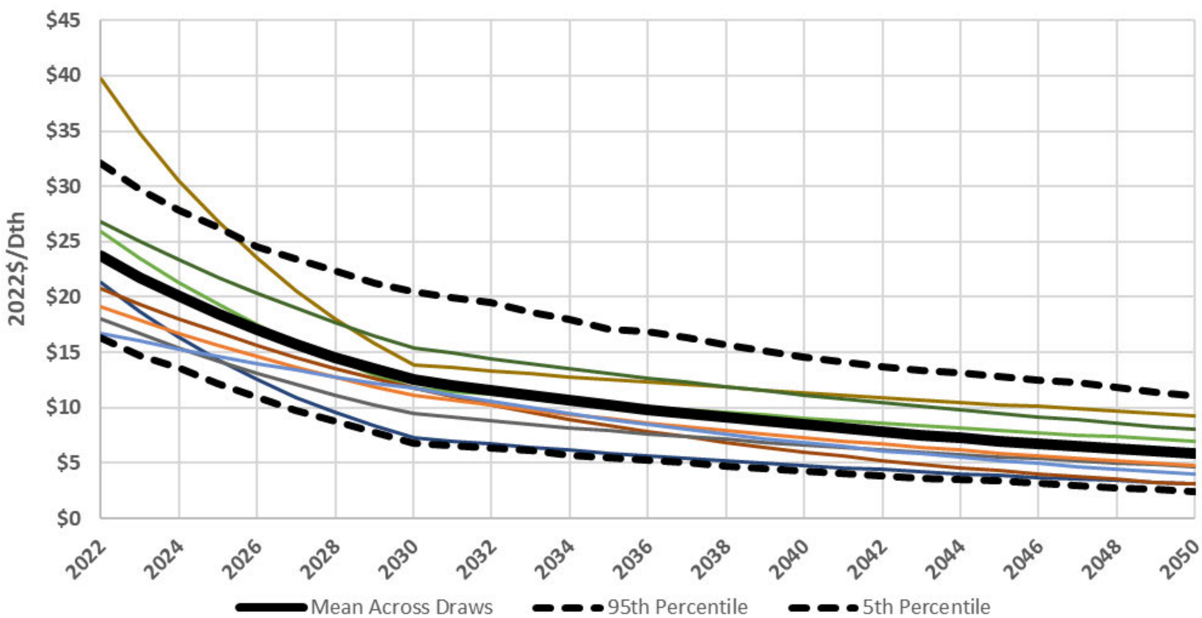


The biofuels currently being delivered to NW Natural customers are being delivered at an incremental (unbundled) portfolio price between $11 and $12/Dth, in line with the Biofuels Tranche 1 baseline estimate in the IRP. Furthermore, as demonstrated by Figure 4 above, a wide range of costs were evaluated.

<u>Hydrogen and Synthetic Methane</u>

It is important to note that the action items in the Action Plan that cover the period until 2025 do not rely upon any hydrogen or synthetic methane and that most scenarios and Monte Carlo draws start deploying hydrogen in the 2030s, with synthetic methane being selected a few years later. NW Natural will continue to monitor estimates of hydrogen and methanated hydrogen (synthetic gas) for future IRPs and IRP Updates as estimates for these resources are quite dynamic and estimates have been falling through time as more information is collected. NW Natural evaluated a fairly large range of costs for hydrogen derived products, something that seems to be a source of confusion for some stakeholders. Figure 5 shows the dispersion in the hydrogen prices forecasts used in the stochastic Monte Carlo analysis.

Figure 5: Hydrogen Price Monte Carlo Simulation Variation



NW Natural's assumptions, which were transparently provided throughout the IRP filing process, are based upon extensive research, including the studies cited by Staff in regard to hydrogen pricing, and active market participation to evaluate actual hydrogen opportunities and projects.

There also appears to be some confusion about the assumptions for the allowed levels of hydrogen gas deployment. The maximum amount of hydrogen gas allowed to serve load in a given scenario or stochastic simulation draw is given on a percentage basis – and it is *a combination* of hydrogen gas blended into the supply of natural gas (conventional or renewably sourced) and strategic deployment of pure hydrogen delivery to large usage industrial customers and/or "hydrogen hubs" in strategic locations. NW Natural is not evaluating options that assume hydrogen *blending* exceeds 20% by volume.

In regard to methanated hydrogen (synthetic methane) and its pricing and availability, NW Natural believes its assumptions to be supported by a plurality of third-party estimates. There are numerous potential sources for hydrogen production, and using dedicated renewable electricity costs for the source is not an aggressive assumption given many long-term estimates for other types of clean hydrogen are expected to be lower than for power-to-gas projects. Additionally, there is no practical limit to sources of carbon to be used for methanation. Therefore, while assessing cost uncertainty makes sense for synthetic gas, assuming a limit on the quantity that can acquired for NW Natural's customers because synthetic methane is a "new" technology is not appropriate in NW Natural's view.

3. Natural Gas-Powered Heat Pumps- NW Natural feels the focus on natural gas-powered heat pump deployment assumptions in stakeholder comments is misplaced. CUB and the Climate Advocates are presenting the results of an intermediate step as final results. Table 1 represents the average deployment of gas heat-pumps from in terms of the customers who use gas heating across the stochastic Monte Carlo. In other words, the figures in the Table 1 represent the breakdown of gas heating equipment that is in the preferred portfolio.

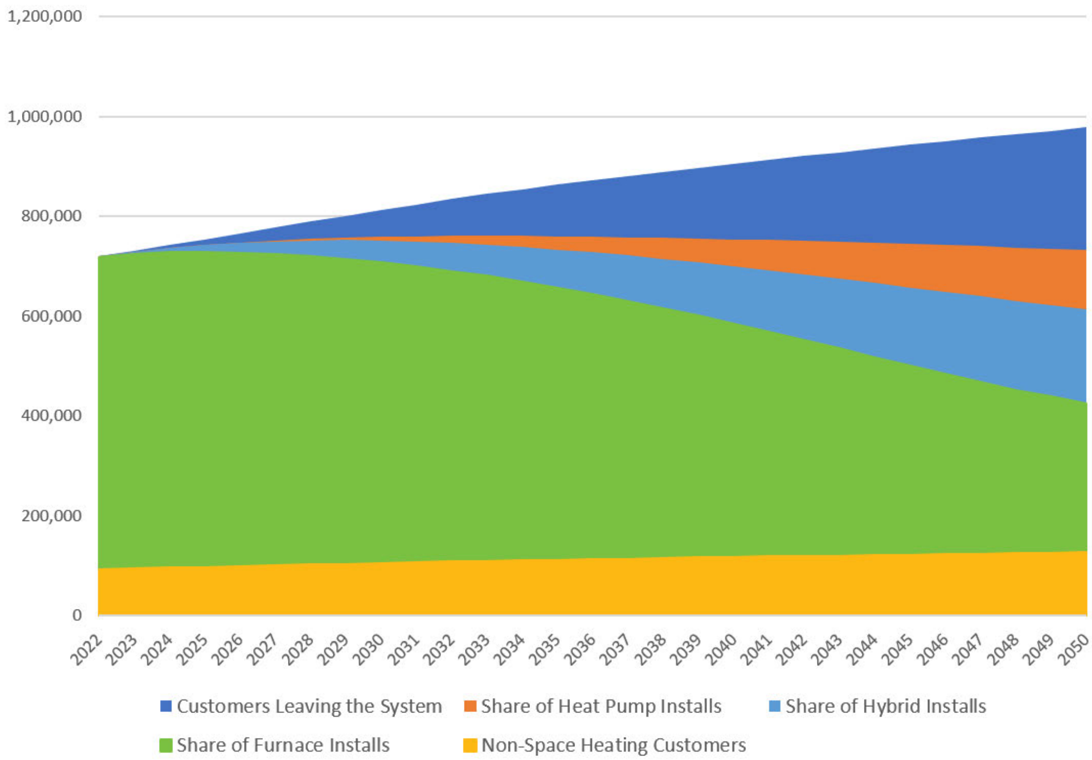
Table 1: Heating Equipment Penetration of Customers with Gas Heating Equipment (Average of Monte Carlo Simulations)

	Gas Heat Pump	Hybrid Heat Pump	Furnace
2022	0%	0%	100%
2030	1%	6%	93%
2040	7%	15%	78%
2050	16%	26%	58%

As this table demonstrates, gas heat pump penetration is assumed to be 1% in 2030 and 16% in 2050. This level of deployment is not a large contributor to overall emissions reduction activity in the preferred portfolio and has no impact on the Action Plan. Furthermore, a characterization of this level of deployment as contradicting Energy Trust projections is misplaced. This level of deployment represents a highly discounted deployment relative to estimates provided to NW Natural by the Northwest Energy Efficiency Alliance (NEEA). This discount was implemented by NW Natural in response to stakeholder feedback and is another example where NW Natural subject matter experts believe that it is more likely than not that the assumptions about gas heat pump deployment in the 2022 IRP will turn out to be understated.

Importantly, the intermediate analysis and workbooks cited incorrectly by CUB and the Climate Advocates does not include the next step: combining stochastic installation figures with electrification assumptions. When one combines these two pieces and recognizes the difference between the share of installations in a given year and penetration amongst the customer base it is hard to come to the conclusion that the gas heat pump assumptions are a key driver of the results in the IRP or that they are unreasonable. Figure 6 below shows the actual deployment in comparison to reference case:

Figure 6: Heating Equipment Penetration Average of Monte Carlo Simulations



In 2050 natural gas heat pumps make up a small portion of heating systems. It is also pertinent to point out that since the IRP was filed the Inflation Reduction Act passed and includes new incentives for natural gas-powered heat pumps.

1.3 The CPP Does Not Modify NW Natural's or the Commission's Rights and Responsibilities Under SB 98

In its comments, Staff states that "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."[20] AWEC also recommends that NW Natural purchase the maximum amount of CCIs available, even if it means not acquiring the amounts of RNG necessary to meet SB 98 targets.[21]

[20] Staff Comments at 47.

[21] AWEC Comments at 5-6. SB 98 targets are codified in ORS 757.396.

These issues raise legal questions, which must be contemplated before their recommendations can be evaluated. The issue with Staff's and AWEC's comments is that the CPP does not revise SB 98. An administrative rule is subordinate to statute and only the legislature can amend or modify a statute.[22]

Staff appears to believe that the Commission can determine that NW Natural should not meet SB 98 sales targets, but this is contrary to the statutory direction given in SB 98: "The Public Utility Commission shall adopt by rule a large renewable natural gas program for large natural gas utilities pursuant to the provisions of ORS 757.396." ORS 757.396 authorizes NW Natural to acquire RNG:

> *A large natural gas utility that participates in the large renewable natural gas program adopted by rule by the Public Utility Commission under ORS 757.394 (Renewable natural gas programs) (1) may make qualified investments and procure renewable natural gas from third parties to meet the . . . portfolio targets for the percentage of gas purchased by the large natural gas utility for distribution to retail natural gas customers in Oregon that is renewable natural gas.*

NW Natural is concerned with Staff's comments that continuing to give effect to SB 98, while complying with the CPP, "may no longer be prudent." By claiming that the CPP may no longer permit NW Natural to meet the SB 98 sales targets, Staff appears to be suggesting that the CPP somehow rescinded or modified these targets. That suggestion is entirely at odds with the principles of statutory construction, as explained above. Similarly, it would be improper to rely on the prudency standard in an effort to revise SB 98, which is a power reserved to the legislature. Under SB 98, the Commission is charged with "adopt[ing] 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 [ORS 757.396(1)]". In other words, the Commission evaluates the prudency of NW Natural's actions to meet the targets, not whether NW Natural should not have attempted to meet the SB 98 targets at all.

Even if the CPP were in statute, however, there would be no inherent conflict between it and SB 98. Both allow NW Natural to decarbonize using RNG, and there is nothing in the CPP that requires NW Natural to purchase CCIs prior to pursuing other alternatives, such as acquiring RNG. Since there is no "plain, unavoidable, and irreconcilable repugnancy" between SB 98 and the CPP, Oregon statute and case law require that "where there are several provisions relating to a subject, such construction is to be adopted as will give effect to all."[23]

As such, NW Natural intends to comply with both the CPP and meet SB 98 targets (i.e., "give effect" to them both). As Staff pointed out in the first page of its comments, SB 98 authorizes NW Natural to

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[22] State v. Newell, 242 P.3d 709, 712 (Or. App. 2010) ("It is elementary that, when an administrative rule cannot be reconciled with a statute, it is the statute that controls.").

[23] City of Lowell v. Wilson, 105 P.3d 856, 866 (Or. App. 2005) (quoting ORS 174.010: "In the construction of a statute, the office of the judge is simply to ascertain and declare what is, in terms or in substance, contained therein, not to insert what has been omitted, or to omit what has been inserted; and where there are several provisions or particulars such construction is, if possible, to be adopted as will give effect to all.")

acquire RNG. These acquisitions will assist in complying with the CPP. Aside from acquiring RNG, NW Natural will take any incremental actions necessary to comply with the CPP.

Finally, by suggesting that the Company acquire RNG only if it is the least-cost/least-risk resource way to comply with the CPP, Staff and AWEC run the risk of turning SB 98 into a nullity.[24] SB 98 would have no practical purpose if it only meant that NW Natural could only acquire RNG to meet its CPP compliance obligations, not SB 98 targets.

The Company is balancing its CPP obligations with state policy that favors the acquisition of RNG. RNG, after all, has its own specific statutory scheme (SB 98) that encourages its acquisition. Executive Order 20-04, which led to the establishment of the CPP, supports its acquisition as well, stating that "transitioning the traditional natural gas supply to renewable natural gas can significantly reduce GHG emissions." The Company's IRP, therefore, seeks to implement the policy of the state by acquiring RNG to meet SB 98 targets.

1.4 Gas Utility Customer Funded Electrification in System Planning

<u>Modeling Gas Customer Funded Electrification is Fundamental Shift in Resource Planning</u>

An IRP evaluates the resources available to a utility, both demand- and supply-side, to provide service to its customers. As CUB aptly noted,

> *Electrification is not a resource option that can be chosen or rejected by a gas utility as part of an IRP. It is a government policy, and a choice by builders and homeowners that impacts a gas utility.*[25]

While the Commission has certainly permitted electric utilities to offer incentives for efficient electric appliances where the Commission has determined that an *electric utility's* provision of such an incentive provides a cost-effective way for the electric utility to meet its customers' needs *for electric service,* electrification is not a resource available to a natural gas utility to meet the needs of its customers' natural gas use. Modeling gas customer funded electrification would be modeling a third-party's ability to provide would-be gas energy services without an assessment of the costs of those services from its provider.

While it makes sense for a gas utility to model voluntary or policy-directed customer defection to electric service as NW Natural has done extensively in our 2022 IRP, modeling of this nature keeps intact the fundamental nature of an IRP: an exercise to determine how a utility can best provide its customers with the product they have chosen to purchase from the utility.

An IRP is a tool used to evaluate the least-cost resources available to a utility to meet its own customers' demand. The demand at issue is the demand for the product being sold. Here, that is gas, not electric service. Staff's request to model electrification as an alternative to be paid for by gas customers is

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[24] Oregon courts "will not construe a statute in a way that renders its provisions superfluous." Keller v. SAIF, 27 P.3d 1064, 1066 (Or. App. 2001); *see also* ORS 174.010 ("[W]here there are several provisions or particulars such construction is, if possible, to be adopted as will give effect to all.").

[25] CUB Comments at 21.

effectively a request for the utility to provide information the Commission can use to determine whether the *utility's customers should remain its customers*. This is not a standard IRP modeling request; it is a radical transformation of integrated resource planning that requires consideration of its legality and the implications of the request before being adopted.

Gas Customer Funded Electrification Exacerbates Cost Risk to Gas Customers

The proposal to include electrification as a resource that can be selected as part of a natural gas utility's "portfolio" of resources is not only inconsistent with the goal of the utility's IRP, but the argument that electrification could lower the natural gas utility's system costs is misplaced.

To better understand this issue, it is important to recognize that electrification was modeled extensively in NW Natural's 2022 IRP. The electrification modeled in the IRP is assumed to be *zero cost to NW Natural's customers*,[26] in alignment with the idea that electrification is not an option for selection by a gas utility but something that can occur, and the impact planned for within the IRP. With that, when one compares the residential customer bill impacts provided with each scenario in the 2022 IRP, it is generally true that the scenarios with the highest amount of assumed *free* electrification have the largest customer bill increases for the customers that remain on the system in comparison to scenarios with relatively less electrification.[27] If some amount of cost was assumed to be collected from gas customers to make that same electrification occur, the customer bill impact results would only be exacerbated. Therefore, if one is concerned that gas customers need to be protected against the impacts of electrification, it would be counterproductive to ask those same gas customers to *pay for that electrification*.

Additionally, efforts to reduce the number of customers who help pay for the state's gas infrastructure could inadvertently impact the financial health of gas utilities—either by forcing a smaller base of customers to pay for the system, or by sending market signals that undermine utility's access to capital markets—thus irreversibly damaging the statewide benefits provided by Oregon's gas system.

Lastly, given that CPP compliance is being cited as the rationale for considering gas customer funded electrification in IRPs, it follows that there is an assumption that electrification of natural gas utility load reduces emissions – not just the emissions reported by the gas utility, but by society for the energy services being electrified (e.g., the emissions from heating a home). This presumption is problematic, as electrification does not necessarily mean decarbonization. The societal emissions impact from electrification first needs to be examined specific to Oregonians and their utilities. Replacing a natural gas furnace with an electric heat pump today would raise emissions for many Oregonians, and result in

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[26] NW Natural did model gas utility customer funded dual-fuel/hybrid heating systems, but restricted the gas utility funding to the incremental cost of keeping a gas furnace in a home as the supplemental heat source in comparison to cost of installing an electric air handler without a supplemental heat source. As such, NW Natural did not model a collection of electrification funds for its customers even though dual-fuel hybrid heating installation where there would be full gas heating is a form of electrification. See Section 1.6.

[27] Noting here that this is generally the result of the need to spread fixed costs over a smaller customer base and load, and further noting that Staff is incorrect in stating that there are not differences in these costs (distribution system costs, labor, IT, etc.) across scenarios as an estimate of how the costs could be reduced is included in the electrification heavy scenarios. See Section 1.2.

minimal emissions savings for many more. The emissions impact through time should be explicitly modeled in the context of the compliance obligations of both HB 2021 and the CPP.

Gas Funded Electrification and Ratemaking Authority

The Commission has interpreted ORS 757.020 to mean that a utility has the obligation to service the public in its service territory.[28] In exchange, the utility receives a monopoly franchise to serve customers with the utility product at issue and the right to rates for that service that balance the interests of shareholders and customers.[29] Utilities in Oregon have the right, by law, to offer their product to customers at fair and reasonable rates, taking into consideration the cost of compliance with new laws.

Requiring gas utilities to pay—through gas rates—for service and equipment needed for electric service, runs afoul of the Commission's basic ratemaking authority. The following statutes are worth noting:

> *757.020 Duty of utilities to furnish adequate and safe service at reasonable rates. Every public utility is required to furnish adequate and safe service, equipment and facilities, and the charges made by any public utility for any service rendered or to be rendered in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited.*

In this instance, the "service" for which gas customers may legally be required to pay "rates" is gas service.

> *757.355 Costs of property not presently providing utility service excluded from rate base; exception. (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.*

In this instance, the "service" that justifies inclusion of rate base in a gas utility's rates is gas service, not electric service. New regulatory requirements have arisen time and time again in the regulatory context but has never served as a catalyst for fundamentally transforming the IRP into a resource elimination exercise; the CPP is no different.

When Oregon passed Renewable Portfolio Standards, and electric utilities became obligated to comply with new regulations that necessitated the purchase of new, renewable energy resources (expensive at the time), the appropriate regulatory response was to determine the least-cost, least-risk resources available to serve electric customers *using electricity,* taking into account the new costs of compliance.

In the electric sector, that same paradigm now applies to HB 2021. HB 2021 will raise challenges and impose costs. It will drive the need for expensive transmission lines, significant investments in unproven technologies, new products, new efficiencies, and new ways of thinking. The Commission's job, in that

[28] See, *e.g., Re Oregon Electric Utility Company, LLC, et al*., PUC Docket No. UM 1121, Order No. 05-114 (Mar. 10, 2005) (noting Portland General Electric's obligation to serve).
[29]*See, e.g., In re Application of PGE for Investigation Into Least Cost Plan Plant Retirement*, Docket No. DR. 10, Order No. 08-487 at 4-5 (Sept. 30, 2008).

context, is to ensure the utilities' investments in the *electric system* are in alignment with applicable laws and regulations. The Commission's job, in that context, is to ensure the utilities' investments in the *electric system* comply with. The CPP is no different.

Under Oregon law, the appropriate regulatory response to HB 2021 is not to analyze whether electric customers should pay to disconnect a neighborhood from the electric grid using rooftop solar, Tesla Powerwalls, and back-up generators. Getting customers off the grid is not a least-cost option for an electric utility's provision of electric service in Oregon.

State policy requires emissions reductions from the direct use gas sector—not fuel switching—and explicitly recognizes the value of investment in products like renewable natural gas. Moreover, NW Natural has demonstrated through extensive modeling in this IRP the existence of viable and affordable pathways for complying with the CPP.

<u>Electrification as a Geographically-Targeted Distribution System Planning Alternative</u>

As noted previously, asking NW Natural to model "electrification" as a potential least-cost resource means that the resources *actually available to the gas utility for serving gas customers* would be measured in a decision-making document against a purported alternative that the gas utility cannot adequately control or model.

Actual non-pipe alternatives for natural gas customers, such as energy efficiency or demand response, can be modeled in a natural gas IRP by measuring the long-term costs and benefits of a supply side option against a demand-side alternative. This is an apples-to-apples comparison. By contrast, no single utility can model whether electrification would be more or less expensive to customers than decarbonized natural gas options, the legal issues with the concept aside.

1.5 Energy Efficiency and Demand Response as Selectable Resources in the Resource Optimization Model

A common thread in Staff's opening comments proposes having NW Natural's IRP analysis include statewide demand-side resources (energy efficiency and demand response) for the system within the resource optimization model (PLEXOS®). Per Staff's proposal, this approach could evaluate the demand-side and supply-side resources all within the same PLEXOS® run, and hence, the results from the PLEXOS® model would then provide a resource forecast for <u>both</u> demand-side and supply-side resources. It is understandable that this approach, on its surface, would better align with IRP Guideline 1(a); that all resources (demand-side and supply-side) must be evaluated on a consistent and comparable basis.

Staff comments:

> *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.[30]

Energy Efficiency

In this section, NW Natural will focus on the energy efficiency component of Staff's comment. This section provides some historical context for Energy Trust's role in the IRP process, a discussion about the capabilities/limitations of the PLEXOS® model, implications of overlapping work from Energy Trust, and a request for clear direction from OPUC Staff and the Commission for how utilities should be modeling energy efficiency in IRPs. In short, NW Natural is not opposed to modeling energy efficiency directly in the resource optimization software, however; compiling the inputs, coordinating with energy efficiency consultants (e.g., Energy Trust and AEG), and generating meaningful results is a major shift from the current process that will take a full IRP cycle to incorporate.

Historical Context

In 1999, SB 1149 passed into law requiring the two investor-owned electric utilities in Oregon to collect a public purpose charge from their customers to support conservation in K-12 school, low-income energy assistance, and renewable energy programs.[31] SB 1149 authorized the OPUC to direct how the funds would be spent, leading to the Energy Trust of Oregon entering into a grant agreement with the OPUC in 2001.[32] NW Natural has partnered with Energy Trust since 2003 to deliver cost-effective energy saving programs for our customers. Energy Trust plays a key role as a non-profit organization authorized by the OPUC for evaluating cost-effective conservation programs.

Through our partnership with Energy Trust, we have developed a process of providing a customer count forecast, a load forecast, and avoided costs to Energy Trust (i.e., the energy efficiency consultant) who then uses those inputs to develop a cost-effective energy efficiency deployment forecast (a.k.a. conservation potential assessment (CPA)). This CPA develops cost-effectiveness tests and deployment at a measure-level that then aggregates up to an overall savings deployment. The CPA feeds back into NW Natural's load forecast to account for future savings. By using avoided costs, which include the avoided CPP compliance costs, this approach has historically been considered acceptable and in alignment with IRP guideline 1(a).

Chapter 4 of the 2018 IRP as well as Chapter 4 of the 2022 IRP discusses the necessary iteration of forecasting when working across two separate organizations, Energy Trust and NW Natural, to complete the IRP. NW Natural reached out to Energy Trust and confirmed that four of the five investor-owned utilities operating in Oregon and working with Energy Trust apply a similar approach through their IRPs.[33] PacifiCorp, which operates in six separate states, is the only one of the five utilities that develops tranches or bundles of energy efficiency to be evaluated side-by-side in their optimization resource modelling:

[30] Staff Comments at 6.
[31]SB 1149, Codified as ORS 757.612: https://www.energytrust.org/wp-content/uploads/2016/10/sb1149.pdf.
[32] Grant Agreement: https://www.energytrust.org/wp-content/uploads/2016/10/grant_agreement.pdf.
[33] Idaho Power works with another energy efficiency consultant other than Energy Trust.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated almost 30,000 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number. [34]

During NW Natural's 2016 IRP, the Company contemplated moving to a similar approach as being used by PacifiCorp. In the 2016 IRP, we identified numerous reasons why this switch would be difficult, but still proposed an aspirational process that could deploy energy efficiency within the resource optimization model.[35] Stakeholder feedback from that IRP suggested that the current methodology was sufficient, and that Energy Trust should remain the primary source of the energy efficiency forecast. In response to this feedback, the proposal was not pursued for the 2018 IRP.

The demand-side bundling approach has the benefit for a direct supply-side competition within the same model (i.e., endogenous selections) across scenarios and Monte Carlo simulations. The downside is that it loses the measure level granularity that Energy Trust provides. Although NW Natural takes the baseline energy efficiency forecast as a given (i.e., exogenous selection), energy efficiency levels are adaptive to each scenario and stochastic Monte Carlo draw based on scenario work done by Energy Trust (and AEG for Washington customers) to reflect higher or lower levels of energy efficiency. Scenario assumptions are shown in Table 7.3 in the 2022 IRP and simulations for varying levels of energy efficiency are generated for Monte Carlo results.[36]

In theory, measures evaluated on avoided costs would result in the same deployment as if we could model every measure with the appropriate costs and deployment constraints within PLEXOS®. In practice, there are some major hurdles to overcome when developing this approach.

PLEXOS® Capabilities and Limitations

PLEXOS® does have the capability to incorporate demand-side resources as a selectable option to meet energy requirements. However, as noted above, there are significant challenges with attempting to model demand-side resources in this fashion. The hurdles for such modeling reside with determining the appropriate costs, quantity restrictions, and number of model objects and inputs that would need to be developed.

First, PLEXOS® inherently implements a utility cost test (UCT) for all resources being evaluated within the model as it selects resources that minimize costs while serving demand. The OPUC has determined that the total resource cost test (TRC) is appropriate for evaluating energy efficiency. The TRC includes *non-energy benefits* that Energy Trust has the expertise to include in their evaluation. In addition to the

[34] PacifiCorp – 2021 IRP, page 208

[35] OPUC LC 64 – NW Natural 2016 IRP, pages 5.1-5.3. The resources optimization software at that time was call SENDOUT.

[36] A more detailed summary table of scenario assumptions was provided in the technical working group.

non-energy benefits, there are three other components of avoided costs that would not be directly avoided within the PLEXOS® modeling:

1) the avoided distribution system costs – PLEXOS® is used for evaluating system resources and does not model a forecast of distribution system projects
2) the risk-reduction value (also known as the hedge value) – PLEXOS® has perfect foresight meaning that within a single run there is no risk[37]
3) the 10% conservation adder

We could deploy modeling techniques to incorporate the additional benefits that are not considered in the optimization by decrementing these benefits from the overall costs for each measure modeled, but it would take substantial time and collaboration with Energy Trust to implement this appropriately.

Second, Energy Trust's model accounts for realistic deployment of measures. For example, high-efficiency water heaters would only be deployed through replacement on burn out or in new construction. Ramp rates are applied to other measures, such as shell measures, that even with cost-effective incentives, will be achieved gradually over time. In other words, just because these measures offer cost-effective incentives, they are not achieved all in a single year.

Third, modeling energy efficiency in PLEXOS® would necessarily be utility specific, which conflicts with the approach filed annually through UM 1893 that blends avoided costs from the three gas utilities for implementation. Modeling energy efficiency within PLEXOS® would drive a wedge between what is modeled (utility specific avoided costs) and what is used for implementation (blended avoided costs). The current process mitigates this disconnect as the near-term forecast from Energy Trusts comes from near-term saving projections from Energy Trust's program subject matter experts, which are based on the blended avoided costs from UM 1893.

Lastly, as PacifiCorp points out, it would be impractical to model every measure Energy Trust offers into the PLEXOS® model. Appendix D in the 2022 IRP lists about 160 separate measures evaluated by Energy Trust. To incorporate these into PLEXOS®, NW Natural would need to work with Energy Trust and AEG to bundle measures to an appropriate level that balances model granularity with model complexity. For each bundle, Energy Trust and AEG would need to provide a cost and annual quantity limitation.

During Technical Working Groups the Company had stakeholders ask questions about how the current methodology aligns with Guideline 1. We presented the current process of using avoided costs and had Energy Trust and AEG both present their methodologies. Prior to Staff's initial comments, we did not receive any feedback that we should be taking a different approach for modeling energy efficiency within PLEXOS®. Given enough time and help from Energy Trust subject matter experts, NW Natural can feasibly address all the modeling concerns described in this section, though it is not possible to complete in the timeframe established for this IRP.

Overlapping work with Energy Trust

Staff's further comments on IRP Guideline 6(c):

[37] This perfect foresight quality of the algorithm is the reason why we run 500 Monte Carlo draws.

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.*[38]

Staff cites IRP Guideline 6(c) in Staff's comments footnote 51, which states:

> *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*

Energy Trust provides an estimate of technical potential, achievable potential, and cost-effective potential. These are three levels of the energy efficiency stock as an aggregate resource. Energy Trust explains this methodology in Chapter 5, Section 5.1.2, and it is well illustrated by Figure 5.3 in the IRP.

IRP Figure 5.3: Three categories of savings potential identified by RA Model

<table>
<tr><td>Not technically feasible</td><td colspan="3">Technical Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td colspan="2">Achievable Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td>Not cost effective</td><td>Cost-Effective Potential</td></tr>
</table>

Once the total cost-effective potential (i.e., last row in Figure 5.3) is calculated, Energy Trust uses near-term SME program estimates and long-term ramp rates to forecast the deployment of energy efficiency to NW Natural customers.

Limits on funding, as specified by Guideline 6(c), could be interpreted as disregarding deployment expectation (e.g., SME forecast and ramp rates) or providing incentive levels beyond any cost-effectiveness threshold that would achieve the full technical potential. These three levels of stock potential for energy efficiency give three different quantities of energy efficiency potential that would be obtained depending on how one may interpret Guideline 6(c).

From a PLEXOS® modeling perspective, if deployment constraints (e.g., ramp rates) are ignored the model will select all cost-effective energy efficiency measures in the first year. Having the model show a spike in energy efficiency in the first year that is infeasible for Energy Trust to deploy does not seem to

[38] Staff Comments at 51.

be helpful or informative, especially since Energy Trust already provides the cost-effective stock potential. The same logic can be applied to ignoring cost-effectiveness thresholds. In other words, if we model the technical potential as a free resource and ignore deployment constraints, the PLEXOS model will select all of it in the first year.[39] This would not tell us anything new or different from the technical potential provided by Energy Trust.

The output from Staff's recommended approach is an energy efficiency forecast produced from PLEXOS®. Historically, this forecasting has been seen as best served by Energy Trust. In theory, if measures were bundled appropriately, assigned the correct costs and quantity constraints, the energy efficiency forecast output from PLEXOS® would be close to the forecast developed by Energy Trust. In practice, this would take significant coordination between the two organizations to align all the inputs into the model. In the end, there are three potential outcomes that could be obtained:

1) Sufficiently calibrate or force the PLEXOS® model to produce the same energy efficiency forecast as the CPA consultants (i.e., Energy Trust and AEG)
2) Generate two different energy efficiency forecasts; one from the consultants and one from PLEXOS; this could result in different forecasts that would need to be reconciled with stakeholders for which forecast should inform the IRP action plan
3) Coordinate with Energy Trust to provide the measure level input cost and quantity constraints, but ultimately have the resource optimization tool produce the long-term energy efficiency forecast for the IRP and Energy Trust targets[40]

Request for OPUC Staff and the Commission

Given the historical context and the hurdles to incorporate energy efficiency into the optimization resource model, NW Natural is requesting clear direction from OPUC Staff and the Commission on Staff's recommendation to include energy efficiency as a selectable resource within PLEXOS®. NW Natural and the other utilities have developed a process with Energy Trust over a long history of using avoided costs to have energy efficiency comply with IRP Guideline 1.

We recognize that this process can evolve and change. Compliance with the CPP may justify a new approach. NW Natural is not opposed to this change, but if this pathway is recommended, subject matter experts will need to begin coordinating with Energy Trust now to be able to have the appropriate inputs and modeling completed for the next IRP. Only by doing the leg work on the right costs and constraints to input into PLEXOS® will we be able to produce meaningful and informative results.

For actionable outcomes from these comments, NW Natural respectfully requests Staff and the Commission provide clear direction for the following questions:

1. Does Staff recommend that NW Natural pursue incorporating energy-efficiency as a selectable resource in PLEXOS®? Should this be in place of the current process of having Energy Trust

[39] There would be some measures that trickle in overtime from savings associated with new construction or replacement on burnout.

[40] For Washington this option is not feasible as HB 1257 requires an independent third party to conduct a CPA.

provide a forecast based on avoided costs or in parallel with Energy Trust's forecast? If parallel, how should NW Natural consider discrepancies between forecasts to inform the action plan?

2. How does Staff recommend accounting for a disconnect between blended avoided costs filed in UM 1893 and a utility specific PLEXOS® model? Would Staff consider this disconnect an acceptable variance between modeling and implementation?
3. Other than PacifiCorp, do any of the other utilities in Oregon model energy efficiency as a selectable resource in their IRPs? If yes, can Staff highlight any best practices for modeling energy efficiency? If no, does Staff intend to recommend that the other four utilities that work with Energy Trust also include demand-side resources as selectable options in their resource optimization models?
4. Can Staff clarify if Energy Trust's stock estimates for technical, achievable, and cost-effective energy efficiency comply with Guideline 6(c)? If no, can Staff clarify how conservation in the absence of any Energy Trust limits on funding should be modeled in a scenario if energy-efficiency is incorporated as a selectable resource in PLEXOS®? Specifically, does this mean dis-regarding ramp rate constraints, allowing the model to exceed cost-effectiveness standards, or something else?

<u>Demand Response</u>

In this section, NW Natural will focus on the demand response component of Staff's comment as a selectable resource for PLEXOS®. For contextual grounding, we'll state here that the purpose for demand response is to shed or shift demand away from peak periods as a tool for meeting peak energy requirements. Some demand response programs that shift demands off peak or shift energy demand to less clean sources will reduce peak demand but increase overall societal emissions. With this framework, demand response is a tool for capacity planning (i.e., not a tool for emission compliance).[41] Staff understands this concept, but we spell it out here as it is a critical distinction for this discussion.

Section 3.2.10 of the IRP discusses our current demand response potential from our interruptible tariffs:

> *Figure 3.34- Existing Demand Response Impact shows what NW Natural's peak load would be by hour without its interruptible schedules. More than 2% of sales load on a peak day can be interrupted during peak periods, and roughly 9% of deliveries can be interrupted during a peak hour to maintain pressure on the distribution system.*

In previous versions of the optimization modeling (when we were still using the SENDOUT software), we did model demand response from interruptible customers as a selectable option. Since the model has perfect foresight, there is the opportunity that the model interrupts customers for reasons other than for capacity. For example, it could be lower cost to interrupt interruptible customers in November to preserve gas in storage to ensure the storage facility could serve a peak requirement in February. Another possibility could arise where the model is selecting interruptible customers as a method to reduce emissions to meet an emissions cap.[42] Operationally we do not have perfect foresight; nor would

[41] This can be either system capacity planning or distribution capacity planning.
[42] Note some interruptible customers switch to a more carbon intensive fuel, such as diesel fuel, when interruptions are called upon.

it be appropriate to interrupt customers for CPP compliance. While there could be several modelling techniques that could be employed to ensure interruptible loads are only selected for capacity purposes, the most simplistic approach is to not include interruptible loads in our peak requirement forecasts. In other words, we plan our system capacity resources to meet firm sales customer demand.

Another type of demand response that Staff may be referring to is demand response for residential and commercial sales customers. Action Item #3 of the IRP is:

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

NW Natural had a consultant conduct an initial demand response potential assessment for residential and small commercial programs. This assessment and appropriate evaluation of demand response is discussed in detail in OPUC LC 79 DR 108, Part C. We reference a portion of this response as it highlights the important concepts related to modeling residential and commercial demand response programs as selectable option within PLEXOS®:

> *The demand response potential study included in the attachment is based upon a load forecast that was being developed for what would have been the 2020 IRP that was delayed due to the issuance of Executive Order 20-04. This load forecast is similar to the reference case (or historical trend continuation) forecast in the 2022 IRP. As such, the forecast used for the demand response potential study attached includes a peak day firm sales forecast that increases over the IRP planning horizon. However, as seen in Figure 3.42, the majority of the long-term peak day firm sales forecasts in the Monte Carlo analysis upon which the Action Plan is developed (as well as the peak day forecasts across the Scenarios evaluated as shown in Figure 3.41) are not increasing long-term. This development, which is the result of numerous policies that have developed since this draft report [by The Brattle Group] was conducted, has the potential to drastically change the calculus of evaluating the cost-effectiveness of demand response programs.*
>
> *What avoided costs make sense to use in a declining peak load scenario is a question of key consideration that also depends upon whether the marginal gas supply capacity resource (Mist Recall) could be removed from the portfolio if not needed to serve peak load. Review of the load forecasts in this IRP are a key source of information about how to develop avoided costs for the application of demand response programs.*
>
> *Furthermore, the PLEXOS model evaluates peak firm sales on a gas day (whereas distribution system planning evaluated peak hour needs) given that in contrast to electric system contracts gas supply contracts cover an entire gas day and when the gas is consumed within that day does not matter. Given that the gas day covers a period from 7a.m. to 7a.m. Pacific Standard Time and NW Natural peak hour is generally the 7a.m. hour, a demand response program that could alter peak day needs would need to shift or shed load from after 7 am on a peak to earlier in the*

morning and/or move load from the next morning to the following gas day. This issue is discussed in the potential assessment report and drives the result that the majority of avoided costs assessed for gas demand response programs for NW Natural are related to savings on the distribution system, which is not applicable to the work completed for the planning for peak day in PLEXOS.

….

Given this highly dynamic policy environment, the potential for declining peak loads, the current metering technology (AMR), the relatively small potential peak savings shown in the assessment from residential and small commercial customers, and numerous policy questions about application of avoided costs and opt-out programs in the context of fuel-switching discussions and the aforementioned possibility of declining peak loads, NW Natural decided to wait for a review of its peak load forecasts in this IRP before refreshing the DR potential study and bringing these issues before the Commission in the context of a demand response program.

In summary, the magnitude of the maximum potential of commercial and residential demand response programs identified by the consultant is fairly limited as a peak day system capacity resource.[43] The maximum cost-effective potential is further reduced, roughly 5% of firm sales. This limited potential is based off a load forecast before any impacts from electrification. If NW Natural sees declining customers and a declining peak day load, the avoided costs used for cost-effectiveness would be less. In this scenario there is less maximum potential and a smaller portion of that maximum potential that would be cost-effective, further reducing the magnitude as a system capacity resource.

NW Natural is not opposed to modeling residential and commercial demand response programs as selectable options in PLEXOS®. To do this, we will need to develop demand response supply curves, which Action Item #3 will help inform. It is possible that once programs are scoped and deployed, we find these programs to be more effective than expected. However, given the results from the consultant, we want to manage expectations for the extent that residential and commercial programs can provide as a system capacity resource. Additionally, once deployed a residential and commercial demand response program will take time to ramp up. NW Natural does not believe the incremental impact from these programs would materially alleviate the near-term capacity resource need (i.e., from Mist Recall) or be able to completely displace the peaking services of the Portland LNG facility, roughly 13% of current system capacity resources.

1.6 NW Natural Supports Evaluation of Dual-Fuel (Hybrid) Heating Systems

Reading stakeholder comments might lead one to the conclusion that NW Natural is not interested in the potential of, or supportive of efforts to learn more about, efforts to scale deployment of dual-fuel (hybrid) heating systems. In their comments Staff requests that NW Natural comment on its willingness

[43] Note that "system capacity" and "gas supply capacity" are synonymous terms used to describe both demand-side and supply-side resources used to provide energy services to NW Natural's entire system.

to participate in a discussion of a dual-fuel heat pump pilot in these comments[44] and that “NW Natural declined to fund the initially proposed [ETO dual-fuel heat pump] pilot”[45] while CUB states that “there is little evidence that the utility is interested in pursuing [dual-fuel heating systems].”[46] No context or background is provided for these statements. NW Natural has put substantial resources into understanding dual-fuel heating over multiple years and is eager to engage with stakeholders on the key issues that need to be addressed if a dual-fuel heating pilot is to be effective in making progress on a path forward for these heating systems at a scalable level. This has always been the case and NW Natural has repeatably expressed to Staff our interest in these systems, as well as made it known in the Technical Working Group meetings for the 2022 IRP. Far from being resistant to dual-fuel heating, NW Natural has shown leadership on this issue by proactively modeling dual-fuel/hybrid heating systems in both UM 2178 and in greater detail in our 2022 IRP. We were the first utility in the region to complete this detailed work and believe there are many learnings that can be had from analyzing the work in this IRP to better understand the potential benefits and drawbacks of scalable hybrid heating. Additionally, the Company recently pursued a pilot with an electric utility partner. That pilot proposal, as well as analysis NW Natural has proposed completing with other utilities in the region using existing data, is included as Appendix D. The Company considered an action item in this IRP related to dual-fuel/hybrid heating systems, but ultimately decided stakeholders might view such an action as premature given the substantial engagement needed to develop a scalable dual-fuel heating program, while simultaneously evaluating the Action Items in the first IRP under SB 98 and CPP compliance.

CUB makes an initial assessment of the potential pros and cons of hybrid heating in their comments.[47] Staff’s comments make little mention of the possible benefits and drawbacks of dual-fuel heating systems, nor an evaluation of the work done in the IRP that would allow one to compare their deployment to other options from the perspective of gas utility customers (for example by comparing the results of Scenario 3 – “Dual-Fuel Heating” against the other Scenarios). NW Natural states the following in the IRP:

> *Hybrid heating systems consist of using an electric heat pump as the main source of space heating, but it is teamed with a natural gas furnace for back up heat. The benefit of using both energy systems is that it helps with energy system resource adequacy. With the natural gas energy system providing peak heat, these dual-fuel systems serve as demand response for the electric grid and allows the existing seasonal storage infrastructure to serve peak needs in a region that is capacity constrained. By displacing [electric] resistance back up heat and using natural gas only in times of cold temperatures not only does this help with resource adequacy*

[44] NW Natural notes that Staff Opening Comments in this IRP are an unusual forum to make such a request, particularly given that NW Natural has attempted to make clear to Staff its support and interest in dual-fuel heating systems being actively pursued so long as it makes sense for NW Natural’s customers.
[45] Staff Comments at 46.
[46] CUB Comments at 24.
[47] NW Natural does not agree with all of CUB’s interpretations or thoughts on what issues need to be addressed relative to dual-fuel heating, but greatly appreciates the discussion.

but it also supports energy efficiency and decarbonization efforts. Decarbonization efforts are further supported as both energy system use more renewable energy or low carbon energy.[48]

Furthermore, it is critical to understand what was modeled in the 2022 IRP relative to dual-fuel heating systems to understand how they can be beneficial to gas customers – or could drive the bad outcomes cited as risks to gas utility customers. Scenario 3 assumes that $400 is collected from NW Natural customers per residential dual-fuel heating installation[49] for incentivization including in new construction,[50] a figure that represents NW Natural's estimate of the incremental cost of installing a gas furnace relative to an electric furnace as a backup system to an electric heat pump in a home that would not face conversion costs to install an electric furnace.[51] Therefore, while the Company modeled in detail the impact of dual-fuel heating systems, *NW Natural did not model collecting money from natural gas utility customers to install electric equipment.*[52] This is a relatively small portion of the costs needed to install dual-fuel heating systems, as the installation of the electric heat pump alone is thousands of dollars. With these assumptions residential customer bills for gas service are comparable with gas decarbonization focused scenarios like Scenario 1 and cheaper than the electrification heavy scenarios (Scenarios 4, 5, and 6). These results suggest that under these assumptions further pursuing the potential of large-scale deployment of dual-fuel heating systems could make sense for NW Natural's customers and warrants further investigation.

While the analysis in the IRP demonstrates the potential benefit of dual-fuel heating for NW Natural's customers, the Company's extensive research on the issue has led us to the conclusion there are four primary components that all need deliberation and resolution for widespread deployment to be sustainable.[53] We think that to be successful a pilot should consider the following components in detail:

1. **Emissions Impact**– A detailed accounting of expected emissions savings that is both utility specific and from the societal perspective is imperative. While it is often assumed that electric heat pumps provide emissions benefits to society relative to direct use natural gas service, this is not always true in Oregon, and for those that an electric heat pump does reduce emissions, the reduction if often less than 20%. Given that emissions policies are cited as a reason for electrification – noting that dual-fuel heating of would-be natural gas utility load is a form of fuel-switching – it is important to understand the utility specific emissions impacts, both now

[48] See page 171 of the errata IRP filing.

[49] The stochastic Monte Carlo simulations have an average collection of $400 per installation with 5th and 95th percent confidence intervals of $200 to $600 per installation.

[50] This represents the net cost to customers, where there are many potential routes this net outcome could be achieved between the collection for inventive disbursement from gas customers and a capacity payment from an electric utility to the gas utility for demand response (i.e. capacity) services like the recently approved agreement between Hydro Quebec (and electric utility) and Énergir (a gas utility).

[51] In reality, these conversion costs are usually thousands of dollars if a gas heated home were to go to a 100% electric heating solution.

[52] This was elaborated on in the response to LC 79 OPUC Data Request 118. See Section 1.4 for more information on legal and policy questions about gas customer funded electrification.

[53] Whether the IRP is the best forum to have this discussion is a question NW Natural has for stakeholders, but provides this background, which seems it might be beyond the scope of IRP work, in order to respond to requests in Stakeholder comments.

and into the future, of full direct use natural gas heating, full electric heating, and dual-fuel heating systems.

2. **System Planning Implications**– A detailed analysis of the expected costs to both the natural gas and electric grids with a focus on real world peak usage at different levels of deployment are necessary to understand whether dual-fuel heating systems are a benefit to society, and whether this changes with the level of deployment. Importantly, dual-fuel heating systems act as demand response to the electric grid so are a more obvious benefit to electric utilities, but put cost pressures on natural gas utilities via sharply reduced loads on an annual basis but similar peak loads to an all-gas heating alternative. Also, there are enough hybrid heating systems currently installed that it is possible to know which residences and businesses already have them with combined electric and gas utility usage data. Using this set of real-world customers would allow good estimates of the peak and annual impacts of dual-fuel systems relative to all gas or all electric heating alternatives from an analysis of data that already exists rather than seeking to get this data from newly installed units with additional customer funds. Electric utility system cost estimates developed in IRPs with peak loads from different types of heating based upon this actual data are a crucial data point to understanding the potential benefit of dual-fuel systems to Oregonians.

3. **Cost Allocation and Rate Design** – Cost sharing between electric and gas utilities on customer incentives and valuation of the demand response to the electric utility are an important consideration. In order to consider the risk of dual-fuel heating systems to natural gas utility customers, discussions about compensation models like the recently approved partnership between the electric utility Hydro-Québec and the gas utility Énergir in Quebec, Canada[54] should be discussed.

4. **Programs and Customer Engagement** – An evaluation of the differences in costs paid for heating by utility customers (inclusive of both gas and electricity) is important to consider. Furthermore, determining which customers should be targeted/considered for incentives for dual-fuel systems are important and what is needed to drive customer and trade ally behavior and develop outreach programs is critical.

When NW Natural was first approached by the Energy Trust in September (notably after IRP analysis was locked down for drafting) about a potential dual-fuel heating pilot NW Natural engaged in discussion to gain more understanding of the goals of the pilot, its purpose, what research questions it was seeking to answer, and funding structure. At that time the pilot was at a concept level with no proposal document. The Energy Trust informed NW Natural that the pilot would look at hybrid systems as a gas conservation measure and would be collecting money from gas utility customers to install electric heat pumps.[55] Similarly to how stakeholders would not agree to move forward with a pilot

[54] Dossier R-4169-2021 found at http://publicsde.regieenergie.qc.ca/_layouts/publicsite/ProjectPhaseDetail.aspx?ProjectID=597&phase=1&Provenance=A&generate=true

[55] See Section 1.4

proposed by NW Natural without a clearly defined objective or even a high level pilot plan for review, NW Natural was uncomfortable agreeing to move forward with a pilot until the Company had more information and preferred the pilot be much broader in scope and include additional stakeholders. This in no way should be interpreted as NW Natural not being supportive of looking to find a sustainable way to understand more about hybrid heating systems. NW Natural supports thoughtful progress on this issue and has continued to help move this pilot forward.

Since Stakeholders' opening comments were filed NW Natural has received a broadened, high-level pilot proposal from Energy Trust that is reflective of the engagement between the Energy Trust and NW Natural. This pilot proposal includes funding from both electric and gas utilities to install electric heat pumps in existing low-income homes. It is important to note that the investment in the current proposal is significantly greater than the costs included in scenario 3. Due to the high per-home funding the current Energy Trust pilot design should not be considered as directly scalable. For context, this level of investment would result in collecting roughly $200 million annually from NW Natural customers for the installation of electric equipment. Energy Trust has communicated that this pilot is not intended to set precedent but rather to inform all parties about hybrid system impacts on household energy bills and energy system dynamics.

While the proposed pilot design is not inclusive of all issues NW Natural believes to be most pertinent to making a dual fuel heating future viable for natural gas utility customers the company looks forward to continued engagement on the pilot design. Thoughtful inclusion of aspects of system planning, carbon accounting and cost allocation could make a resultant program sustainable.

NW Natural hopes Staff can comment in their Staff Report in this proceeding what they believe (i) the potential benefits of dual-fuel heating system to be, (ii) what the detailed purpose of a hybrid pilot is, (iii) what detailed research questions the pilot is seeking to answer, and (iv) how the proposed pilot is the best approach to answering those questions.

PART 2: Specific Requests and Recommendations

2.1 Requests from Staff's Opening Comments

OPUC Staff 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.

The capital expenses that are included in the PLEXOS® modeling are directly considered and vary across Scenarios and Monte Carlo stochastic draws. Capital expenses not included in the PLEXOS® resource planning model – for example existing rate base and distribution system costs – are accounted for in the customer bill impact estimates along with other costs (like labor costs, O & M costs, IT costs, etc.). A high-level estimate of these costs, which are largely thought to be fixed in the short term, and how they could be reduced is developed using a proxy of peak load was deployed across Scenarios.[56] Issues of cost allocation and how such an estimate should made are valid questions, ones that NW Natural was transparent about in Technical Working Groups. This IRP appears to be the first attempt to forecast these costs and how they might vary with load. However, without making some type of projection here, it is not possible to estimate customer bills in a meaningful way.

The workpapers for how this was deployed were provided with the response to a Staff data request. Relative to price elasticity NW Natural has not been able to find a statistically significant price elasticity in the terms of customer rates.[57] The issue of long-term price elasticity, which is exhibited more through equipment choice decisions rather than day to day is most important for long-term projections. To some extent price elasticity is accounted for in the analysis in the Company's 2022 IRP. Scenarios and draws with more electrification

OPUC Staff 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.

Staff's Request 2 can be interpreted as potentially two separate concerns which Staff is trying to address. NW Natural discusses both parts separately here:

Stochastic Capabilities of PLEXOS®

The first potential concern is that NW Natural conducts all the stochastic simulations (e.g., gas prices, electrification rates, weather, etc.) on the front end.[58] In other words, these simulations are conducted outside of PLEXOS® and then are used as inputs for PLEXOS®. The PLEXOS® model then solves for the optimal resource portfolio for each simulated future. The PLEXOS® software does have the capability to generate stochastic simulations internal to the software, however, the methods within the software can be limiting. For example, a stochastic variable within PLEXOS® can be generated from either a normal or log-normal distribution. Stochastic variables such as gas prices follow neither of these distributions. Instead, NW Natural's simulation for gas prices uses historical data to generate the distribution for the simulation.

Generating the simulations outside of PLEXOS® allows for the flexibility to incorporate key correlations across correlated variables (e.g., the price at AECO and the price at Sumas). Developing these key correlations within the PLEXOS® software is possible but is a very complex modeling process and will have some limitations (e.g., limited distributions). The transparency for how stochastic variables are generated would also be limited to those who have the PLEXOS® software and have sufficient proficiency using the PLEXOS® software. NW Natural is not opposed to building the model to generate

[56] Refuting the statement in the Executive Summary of Staff' comments that says "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."
[57] The price customers pay for gas typically changes once per year on November 1st, even though gas prices might change daily.
[58] All stochastic variables are listed in Table 7.4: Stochastic Variables for Risk Analysis.

the stochastics within PLEXOS® for the next IRP, but the Company believes our approach better represents realistic correlations and is more transparent for Staff.

Variability and Severity of Risks in its Preferred Portfolio

NW Natural's IRP model solves for the optimal resource portfolio stochastically through 500 different potential futures with a very wide range of load forecasts and resource costs randomly paired together. This approach does assess the variability and severity of risks across 500 potential futures and is used to develop the Action Plan.

Staff's concern is regarding how the variability and severity of risks would impact our *preferred portfolio*.[59] NW Natural believes the question that needs to be considered [instead] is "what are the severity of risks associated with the decisions being made from this IRP (i.e., the decisions in the Action Plan)?"

The risk analysis should not lock in a set of future resource decisions and then evaluate those future decisions for different levels of load and resource prices. Future resource decisions will be dependent on how the future unfolds. For example, if electrification of existing gas customers occurs faster than expected (i.e., the average of the Monte Carlo) and therefore our emissions compliance with CPP would be far less, we would not need the same level of compliance resources as the preferred portfolio (e.g., the average RNG acquisition of the Monte Carlo). The same logic holds for varying resources costs. The acquisition of compliance resources will be dependent on the price ratio between the available options. If hydrogen and synthetic methane prices do not decrease as expected (i.e., average of the Monte Carlo simulation), then NW Natural would need to rely on RNG and CCIs further out into the future. Holding the preferred portfolio fixed over the planning horizon and varying costs would be inconsistent with least-cost planning for the resources acquisition decisions that can be changed as the future unfolds.

We continue to state that IRPs provide long term projections and plans, the projections beyond the current action plan are not set in stone. Forecasts, assumptions, and inputs will continue to evolve as we regularly file IRPs in the future. By looking at the alternative options and the range of costs for those alternatives, the Monte Carlo PLEXOS® results can help provide the insight and metrics needed to assess the severity of risks for each of the Action Items informed by PLEXOS®.[60]

OPUC Staff 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.

Please see response in Section 1.5 of Part 1 and response to Staff Request 5.

OPUC Staff 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

[59] In technical terms the average is defined as the expected outcome, which in response to Staff's request 4 is how NW Natural is defining the preferred portfolio.
[60] The Forest Grove Feeder Uprate is a distribution system project, where the severity of risks are informed through other process other than PLEXOS.

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.

NW Natural will file an addendum in February that includes more detail regarding the preferred portfolio that is based upon the average of the stochastic Monte Carlo draws, which is detailed in Figures 7.5, 7.6. 7.7, and 7.8 of the 2022 IRP. The addendum will include more detail on how the action items in the Action Plan represent the preferred portfolio.

OPUC Staff 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.

Staff's comments:

> *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.[61]*

Staff's comment, "*Even if this were the case, …*" mis-characterizes NW Natural's response to LC 79 OPUC DR 9 (referenced by Staff's footnote 50) as a questionable response to Staff data request.

To clarify, NW Natural's response to LC 79 OPUC DR 9 is not claiming that Energy Trust **must** conduct a CPA, but points to how the **current process** functions using avoided costs to test for cost-effectiveness. The response to LC 79 OPUC DR 9 states:

> *…the current IRP process (see Figure 4.2 from the 2022 IRP pasted below) requires that the cost-effective available demand-side resources be assessed and selected by Energy Trust of Oregon (ETO) for Oregon and Applied Energy Group (AEG) for Washington because the savings from the demand-side resources have to be projected before supply-side resource choice modeling and subtracted from load to start the supply-side resource optimization.*

We note that for our Washington customers, Washington HB 1257 does require an independent 3rd party to conduct a CPA based on avoided costs using the social cost of carbon. Please see Section 1.5 of Part 1: Key Issues for further discussion regarding Staff request #5 for incorporating energy efficiency and demand response into PLEXOS®.

[61] Staff Comments at 26

OPUC Staff 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.

IRP Guideline 8(c) states:

> *TRIGGER-POINT ANALYSIS AND ALTERNATIVE PORTFOLIOS: The utility should identify at least one set of CO2 compliance costs within the range of alternative regulatory scenarios considered that would lead to, or "trigger," a set of resources that is substantially different from the preferred portfolio. The utility should fully develop an alternative portfolio optimized for each of these "trigger-point scenarios" and compare the portfolio's expected cost and risk performance to that of the initially preferred portfolio under the base-case conditions and under each of the CO2 compliance scenarios. For each of the trigger points identified through the analyses, the utility should include an assessment that a CO2 regulatory future will be mandated that is equally or more stringent.*[62]

NW Natural analyzed nine different scenarios. Eight of the scenarios comply with regulations set forth from the CPP and one scenario (Scenario 2 – Carbon Neutral) goes above and beyond the targets set by the CPP. Complying with the CPP under various scenarios is NW Natural's best understanding of appropriately applying CO2 regulatory costs as stated in Guideline 8. Each of the 9 scenarios analyzed contemplate drastically different potential futures, and have very different implications for resource acquisitions, both for capacity and compliance resources. Staff requests:

> *NW Natural provide a* clear *comparison between the optimal scenario portfolios that highlights the scenario aspects that "trigger" large changes in the optimal portfolio.*[63]

This is the purpose of the summary results described for each scenario provided in Chapter 7 and provided by the workpapers. Each scenario has large changes in the optimal portfolio that would be the least-cost portfolio under those scenario assumptions. Differences across scenarios are summarized in Section 7.5 of the IRP.

Additionally, Staff's comments incorrectly state:

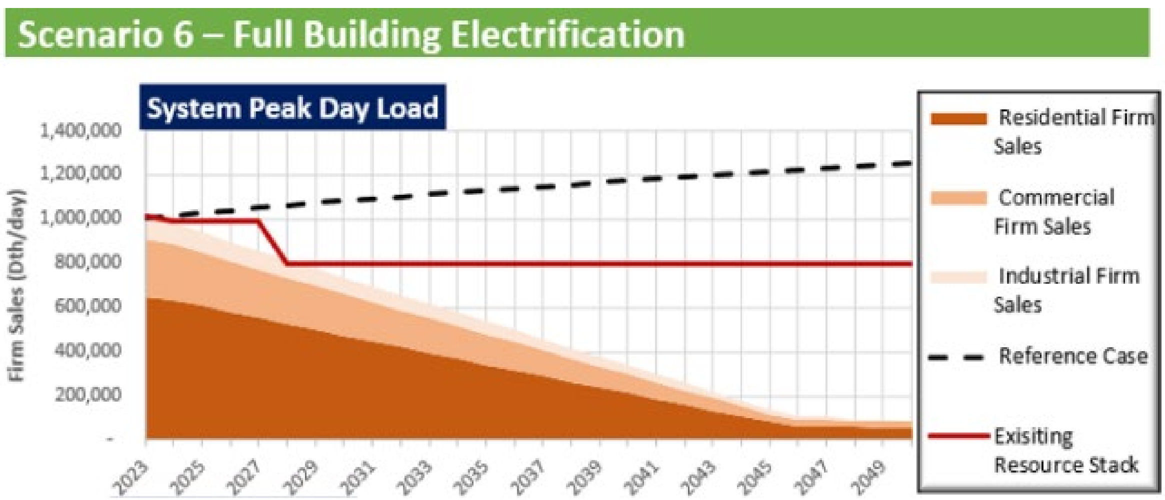
> *NW Natural finds that the Portland LNG Cold Box is the least cost solution in the reference case, all nine scenarios, and all Monte Carlo draws.*[64]

Some version of this statement was made in several sections of Staff's comments, however, the scenario results in Chapter 7 show that the Portland LNG Cold Box is selected in eight of the nine scenarios, not all nine as stated by Staff. This confusion is understandable as there was an error in compiling the 9 scenarios for the initial submission of the IRP for Scenario 6 with wording about capacity resources mimicking scenario 5. NW Natural corrected this wording in the LC 79 – NW Natural's 2022 IRP: Errata

[62] Modified Order 08-339 Appendix A at 2.
[63] Staff Comments at 56.
[64] Staff Comments at 24.

Filing filed in October for Scenario 6 to correctly reflect the results for capacity resources as provided in the workpapers.

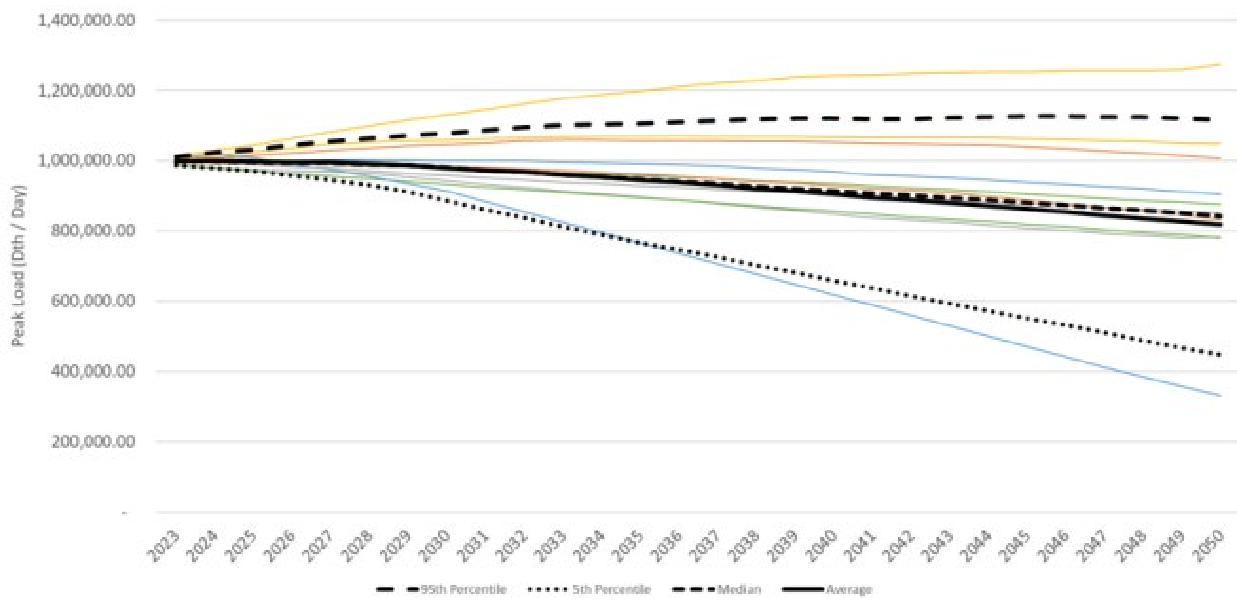
Scenario 6 – Full Building Electrification, asks what if, starting in 2022, every single residential and commercial customer in NW Natural's service territory who heats their homes and businesses with natural gas leaves the system when their gas furnace reaches its end-of-life. This includes replacing their cooking and water heating appliances, in addition to replacing their furnace. This scenario shows a sufficient decline in peak day capacity needs and that the system capacity of 130,000 Dth/day that the Portland LNG provides would not be needed, and therefore the model does not select a Cold Box investment. A figure from Scenario 6 in the IRP shows the peak day firm sales load relative to the system capacity resources that exist if the Portland LNG facility were to shut down (red line). The firm sales peak day load requirement forecasted for extreme electrification barely squeezes under the resource capacity line in 2027, which is the level of daily system resource capacity if Portland LNG were to shut down.



NW Natural does not see a future where all gas appliances are completely banned from being installed in existing houses throughout Oregon and Washington as realistic. NW Natural has been clear throughout the technical working groups that the Company understands Scenario 6 represents an unrealistic future, however, we provide this extreme case to be able to demonstrate the policy drivers that could produce a technically feasible lower bound.

As a lower bound, none of the Monte Carlo draws are as extreme as Scenario 6. Some draws do include extremely aggressive electrification of NW Natural's load and have a drastic decline in the Company's peak day capacity requirements as shown by Figure 3.42 in the IRP (the dotted black line representing the 5th percentile of the firm sales peak day in each year).

IRP Figure 3.42: System Firm Sales Peak Day Load Stochastic Simulation Results



Staff is correct that the Cold Box is selected for all 500 Monte Carlo draws. Only in the most extreme Scenario 6, where strict statewide policy would ban the installation of all gas appliances in existing homes starting one year ago, does peak day load fall fast enough to obviate the need for maintaining the peak day system capacity from a resource with the size of Portland LNG.

Staff also incorrectly states:

> *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.*[65]

Staff has appeared to conflate system capacity resources and distribution system planning. Keeping the Portland LNG facility via investment of the Cold Box and the many alternatives are discussed in Chapter 6 as a system capacity resource (i.e., not Chapter 8). Staff is correct that NW Natural conducted distribution system analysis of the Cold Box alternatives outside of PLEXOS®, however, this was done to evaluate the viability of the alternatives as discussed in Chapter 6. The Cold Box is not mentioned in Chapter 8, which does focus on distribution system planning (i.e., not system capacity resource planning). Of the many alternatives considered for the Cold Box and discussed in Chapter 6, three viable alternatives and the Cold Box itself were included as options available for selection within PLEXOS® and are identified in Chapter 6:

> Page 234 - *In collaboration with SHA, NW Natural examined several potential pathways for Alternative 1 – Keep Portland LNG Operational. Of these pathways, the option to replace the Cold Box and keep the existing pretreatment system, was the*

[65] Staff Comments at 27.

least-cost least-risk pathway in order keep Portland LNG operational and is one of the four high-level alternatives modeled in PLEXOS® as a capacity option for selection.

Page 239 - *For the reasons above, the Middle Corridor Route 4 was selected as the alternative to model in PLEXOS®.*

Page 242 - Portland LNG and segmented capacity are the two capacity resources, which fall off the capacity resource stack within the planning horizon. Without these resources, NW Natural has 800,000 Dth/day of capacity. 30,000 Dth/day of Mist Recall would still be required to fill the gap if peak demand were to decline to a point where Alternative 4 is a viable option. We impose a constraint into our resource planning optimization model (PLEXOS®), where Alternative 4 is not available if it selects more than 30,000 Dth/day of Mist Recall.

Page 243 - The model must select the Portland LNG Cold Box or one of the alternatives discussed Section 6.6.6 in the year 2027.[142] *While the Cold Box could fail between now and 2027, the year 2027 was selected as this was the earliest timeframe any of the other alternatives could feasibly be constructed.*

IRP Table 6.24: Capacity Resource Cost and Deliverability

Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	As needed Max : 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800†
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800‡

Notes: Pipeline options are available for selection November 1st of year; storage options are available for selection May 1st in each year. Newport Takeaway options must occur sequentially.

† Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 240,492 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

‡ Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 204,422 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

Regardless of the confusion, the Cold Box represents one of many changes that can vary across scenarios. Other examples include the acquisitions of different types, quantities, and timing of compliance resources for the CPP. Not only is it important to understand the major differences across scenarios, but also the similarities and trends that are common in the optimized resource portfolio across vastly different futures. If trigger point analysis is defined as analyzing *scenario aspects that "trigger" large changes in the optimal portfolio*, then the nine scenarios and 500 Monte Carlo simulations studied in the IRP represent a robust *trigger point* analysis. These results have been summarized through the IRP and provided in detail through workpapers, which can be seen and studied by stakeholders.

The results from the 500 Monte Carlo draws provide insight into an array of different possible futures. For example, there are draws with high electrification and limited RNG or there are draws with business-as-usual customer growth with high penetration of hybrid systems. If Staff is wishing to view a specific set of scenario aspects that they believe NW Natural did not analyze for a trigger point analysis, we would ask Staff to please clarify in detail the scenario metrics they would like to see, and we can identify a draw that represents that future and view the implications for resources planning.

OPUC Staff 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.

Per the discussion about customer count forecasting in Section 1.2 there appears that there is confusion about how the Scenario analysis informed the stochastic Monte Carlo process. NW Natural understands Staff's concern about defining distribution for stochastic analysis, though is not convinced that Staff's recommendations resolve the issue (the Company believes that because the actual underlying distributions for key assumptions is unknowable, Staff's approach could also lead to "bias" depending on one's views). This approach would also seem to *require* that all scenarios analyzed be developed so that they are equally likely to occur. With that said, if upon further discussion Staff would still prefer Monte Carlo draws within scenarios in the next IRP, NW Natural would not be opposed. NW Natural also appreciates Staff recognition of the time required to run a single draw and the benefits of keeping draws to a few hundred to maintain reasonable model run times.

OPUC Staff 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.

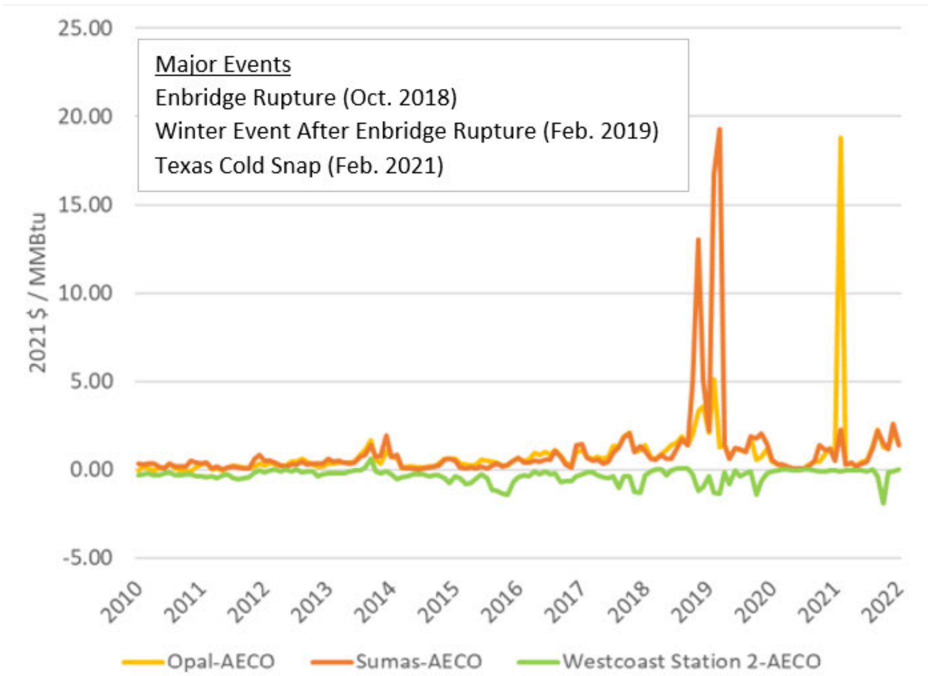
NW Natural is open to revisiting the gas price simulation methodology and looking at using a Vector Autoregressive (VAR) cointegration model that accounts for monthly variation in gas prices as proposed by Staff. However, the approach suggested by Staff is not materially different from NW Natural's current methodology, which is described in Appendix F and was fully provided to Staff in its entirety through LC 79 OPUC DR 2 and LC 79 OPUC DR 3. There appears to be confusion about how the simulation works as Staff comments incorrectly state:

> *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. 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 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.[66]

The stochastic simulation relies on historical data to randomly select a corresponding historical month to be applied to a forecast month. In other words, the difference between AECO and the other three hubs for any future year-month in the simulation is as random as the historical variation in gas prices across hubs, which we showed in Figure F.2: Historical Basis in the IRP.[67] In this figure, we specifically identify 2 supply shocks and 1 pipeline disruption leading to price spikes at Opal and Sumas.

IRP Figure F.2: Historical AECO Basis



Staff is correct that the Company uses an ARIMA process to apply stochastic shocks to gas prices at AECO at an annual average, but Staff is incorrect to say that this is the only stochastic process. There is a second stochastic process to apply monthly shocks at individual hubs that captures the random events at non-AECO hubs. This process is described in phase 2 of Appendix F.

***Phase 2**: Simulate monthly gas prices for each gas hub over the planning horizon*

Step 1: Calculate historical monthly shape by dividing the monthly prices by the annual price

Step 2: For each forecast year and draw, randomly select a historical year and apply that monthly shape to the stochastically forecasted annual price.

[66] Staff Comments at 27-28.

[67] There was typo in Figure F.2 with the spelling of Enbridge and was fixed for these comments.

The output for all 500 simulations, the input data, and code used to generate the simulation were provided to Staff in LC 79 OPUC DR 2. By graphing the AECO basis (i.e., the difference between AECO price and the price at the other hub) from any two draws from the 500 simulations, the stochastic process across hubs, and described by phase 2, is apparent. Draw 206 and draw 311 are shown here.

Figure 7: Simulated AECO Basis, Draw 206

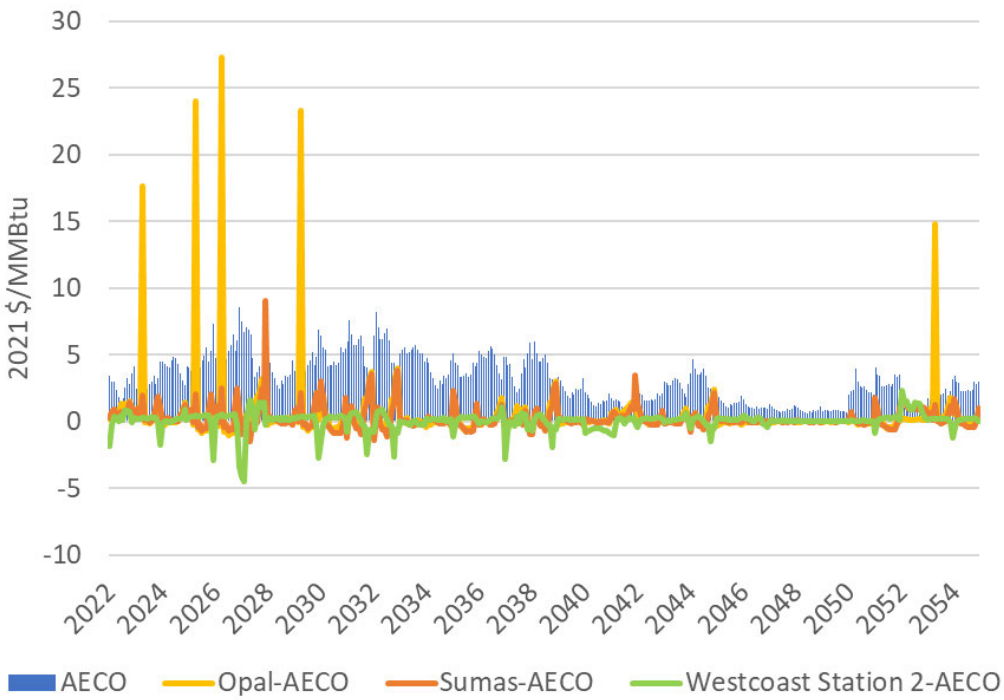
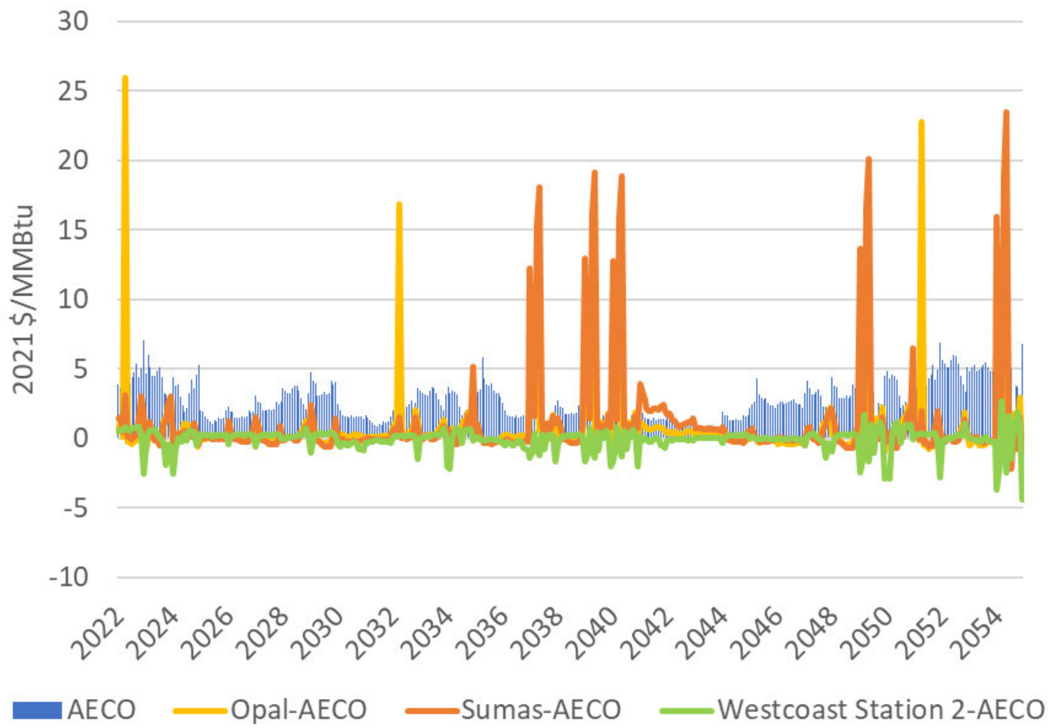


Figure 8: Simulated AECO Basis, Draw 311



Even though there would not be a material change in the gas price simulation results, Staff's proposed methodology is another good approach as it would also create a simulation using a model informed by historical data. NW Natural will explore using a VAR in the next IRP for gas price simulations, but the Company hopes this additional clarification addresses any concerns Staff has about the gas price simulation used in this IRP.

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

NW Natural will continue to develop its ability to deploy geographically targeted energy efficiency, demand response, and renewable supply if cost-effective as part of its move to a more forward-looking distribution system planning process that will be deployed in the next IRP.

OPUC Staff 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.

See Section 1.4. The 2022 IRP evaluates a wide range of Scenarios and stochastic simulation draws. When one compares the results across these outcomes it is apparent that the greater the electrification the higher the bills for the customers that remain on the system. In this sense, the more electrification that occurs the greater the risk for stranded assets. This result is due to the impact of needing to spread fixed costs over a smaller customer base and less usage has a bigger impact on customer bills than the additional costs needed *at the system level* to comply with the CPP and SB 98 that are spread over a larger customer base.[68] For example, when one compares the bill impacts of Scenario 4– "New Gas Customer Moratorium" with and Scenario 1- "Balanced Decarbonization" which uses the reference case customer count forecast it can be seen that customer bills are meaningfully higher in the customer moratorium scenario relative to the scenario where customer growth continues at historical levels. While the total amount of investment needed for emissions compliance is greater in Scenario 1 in comparison to Scenario 4, on a per customer basis this result does not hold. While some stakeholders have made the claim that customer growth is likely to result in bad outcomes for natural gas utility customers in terms of stranded assets this result is not supported by the analysis in the IRP.

OPUC Staff 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.

Please see the Company's responses to OPUC Staff Requests 34, 35, 38, and Sections 1.1 (Forest Grove Feeder Uprate) and 1.4 (under "Electrification as a Geographically-Targeted Distribution System Planning Alternative") of these Reply Comments.

OPUC Staff 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.

See Section 1.6 above.

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

See Section 1.5 above.

OPUC Staff 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.

Scenario 8: Limited RNG does restrict the availability of RNG compared to all other scenarios, so the scenario is indeed more conservative on RNG availability than in other scenarios. However, NW Natural does not believe this scenario is more reasonable, as the other scenarios that assume larger availability of RNG reflect current assessments of RNG availability. Scenario 8 sets 8 BCF as the maximum for Tranche 1 RNG, whereas the other scenarios set 13, 15, and 17 BCF as the maximums for Tranche 1 RNG. Most scenarios have little or no selection of the more expensive RNG in Tranche 2. For instance, the Oregon Department of Energy's 2018 inventory of potential RNG resources in the state alone found that about 50 billion cubic feet of potential existed in the material available at the time of the report.[69] In 2019 ICF International evaluated the nationwide potential for RNG and found a total technical

[68] Noting that Staff is incorrect that NW Natural did not model the potential for reduced costs (capital, employee compensation, IT, etc.) under scenarios with more electrification.
[69] https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf

potential for the US of 14,000,000 BCF by 2040.[70] While not all of that technical potential will be economic to pursue, it is instructive to understand the total amount of waste material that could generate RNG. Thus, NW Natural believes that all the RNG potential maximums in each scenario are quite reasonable and well within the constraints presented by the various evaluations of RNG potential at both the state and national level.

OPUC Staff 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.

1. The Company has been actively engaging and assisting Energy Trust to show the increased value to NW Natural's customers of energy efficiency in the context of compliance with the CPP, which resulted in a substantially higher near-term energy efficiency (EE) forecast in the 2022 IRP than the initial forecast provided by Energy Trust. NW Natural has a long-recorded history of collaboration with Energy Trust, and most pertinent to the IRP the planning team at Energy Trust. This collaboration includes providing data and information on customer segments (e.g., historical and forecasted customers counts and demand), discussions on aligning avoided costs to the appropriate end-use measures, and lining up the Company's cost-effectively affordable EE budgets needed for Energy Trust's EE planning and acquisition.

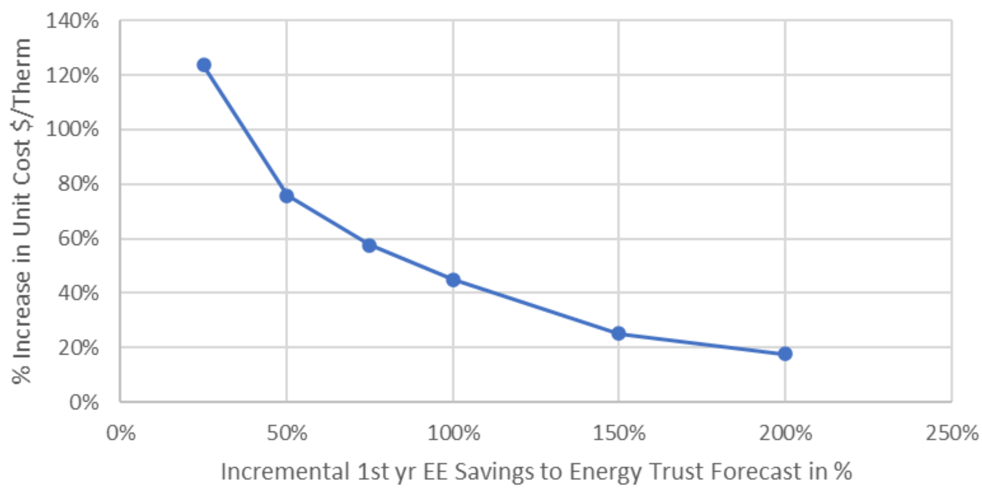
As evidenced in the most recent IRP, such close collaboration has resulted in a ramping up and successful completion of the 2022 IRP EE savings projections delivered by Energy Trust in August 2022. When Energy Trust provided its draft EE savings projections in February 2022, the gross savings over a 20-year planning period of 2022 to 2041 were projected to be 138 million therms with relatively more uniform annual savings throughout, which was a decline from the forecast in the 2018 IRP even though there had been a substantial increase in avoided costs provided to Energy Trust for this IRP relative to the 2018 IRP. Using an Excel-based CPP and CCA compliance resource assessment model developed by the NW Natural IRP team, the Company analyzed the relationship between the incremental EE savings to the Energy Trust forecast and the maximum increase in unit costs of the incremental EE savings at which the incremental EE savings are still more cost-effective than RNG as environmental compliance resources (see Figure 9).

As shown in the figure below, a maximum increase of 124 percent in historical per unit first year cost can be allowed for a first year EE savings increase of 25 percent to the Energy Trust forecast over the next 20-year planning horizon. That is, if the increase in unit costs for the incremental EE is 124 percent higher than the historical first year unit cost per therm saved, the incremental EE savings of 25 percent over the Energy Trust forecast will be displaced by RNG. When the incremental EE savings relative to the Energy Trust forecast approach 200 percent, the maximum allowable increase in first year unit cost of EE savings decreases to 18 percent. The Company presented these results to the Energy Trust planning team in April 2022. Upon the data and information support from and multiple meetings with the

[70] Please see the combined presentation from NW Natural and ICF for Technical Working Group 3- Supply Side Resources March 28, 2022. Presentations can be found at the following link: https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

Company, Energy Trust increased this savings projection over the same planning period to 147 million therms (see Table 5.5 in Chapter 5 of the 2022 IRP) and ramped up the annual savings projection for the first 10 years over the 2022 to 2031 period (see Figure 5.2 in Chapter 5 of the 2022 IRP) in July 2022 for the final 2022 IRP filing.

Figure 9: Maximum Increase in First Year Savings Cost Computed to Historical



2. Staff's premise that there exists a *"gap"* in compliance with the carbon compliance goals set by the CPP is mis-guided. To clarify, each scenario and Monte Carlo simulation uses a mix of demand-side and supply-side resources to comply with the CPP, which means there is no *"gap"* in meeting compliance goals.

As stated at the beginning of Chapter 5, Section 5.1, of the 2022 IRP, Energy Trust is the administrator for the Company's EE programs and completes the cost-effectiveness evaluation of the EE programs available to the Company's customers. Also, the cost-effective EE savings identified by Energy Trust are already compared with the supply-side resources through an Energy Trust Resource Assessment Economic Modeling Tool. In the tool, avoided costs, which include the cost of complying with the CPP, are derived from the incremental costs of the supply-side resources that the EE programs displace provided by the Company. As described in Chapter 1, Section 1.3 of the 2022 IRP, the expected cost-effective EE savings quantified by Energy Trust will be fully acquired and used to adjust the annual load to determine the resource needs for energy, capacity and compliance in the Company's IRP modeling system. Therefore, the Company does not identify itself the amount of EE savings that is needed to meet carbon compliance goals cost-effectively. Instead, carbon compliance goals are met through a combination of EE, CCIs, and renewable resources (such as RNG, hydrogen, and synthetic methane) deemed to be low-cost and low-risk by the IRP modeling system.

OPUC Staff 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.

NW Natural has several activities planned in both states in 2023 to support the launch of an energy efficiency program for transport customers. In Washington, NW Natural is offering high level site assessments to all industrial and transport customers to gauge customer interest and better understand the savings potential. NW Natural plans on using information gathered to determine what energy efficiency services would be the most beneficial.

Similarly, in Oregon, NW Natural is planning on conducting in-depth building analyses on some of the largest transport customers in 2023. The purpose is to focus on decarbonization beyond traditional energy efficiency to understand full reduction potential. In addition, NW Natural is partnering with Lawrence Berkley National Lab to offer a limited time Strategic Energy Management pilot in 2023. NW Natural is leveraging this federal program to directly benefit transport customers at no cost to them and better understand the savings potential of a behavioral energy efficiency program for transportation customers.

NW Natural also wants to partner with Energy Trust to deliver some programming to transportation customers. Key activities that must happen to establish an Energy Trust program include: engaging with stakeholders, revising Oregon Administrative Rules, outlining a program, and creating a rate recovery mechanism.

OPUC Staff 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.

Per Oregon Administrative Rules (OAR) Chapter 860, Division 86 - OAR 860-086-0040(2)(j), there are stated limits on the transfer of utility customer information and transfer of data specific to transport customer information. The company continues to engage with The Energy Trust and large customers to understand possible pathways forward.

> 860-086-0040
> Gas Utility Customer Information and Transfer of Data
> "(2) A gas utility may not transfer to the Administrator the following customer information:
> (a) Social security numbers;
> (b) Billing and payment history;
> (c) Credit information;
> (d) Tax identification numbers;
> (e) Driver license numbers;
> (f) Life support information;
> (g) Medical information;
> (h) Proprietary customer information protected by the password provision required per OAR 860-021-0009(6);
> (i) Proprietary customer information for customers who have requested that their information not be shared with third parties; or
> **(j) Proprietary customer information including usage data for the gas utility's transportation customers.**"

OPUC Staff 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.

When NW Natural was reviewing the demand response potential study with its consultant in early 2020 Executive Order 20-04 and other environmental policy discussions brought a paradigm shifting discussion point to the fore with regards to demand response (DR). Demand response is like energy efficiency in that a load forecast[71] is a critical input into a DR potential study and the load forecast drives both the cost-effectiveness and potential savings that can be achieved from demand response programs. Furthermore, like EE, new construction represents a unique opportunity for DR and a disproportionate share of potential DR savings. However, unlike energy efficiency, demand response does not necessarily result in costs avoided in an environment of declining peak loads. The draft DR potential study dated in December of 2019 is based upon what would have been the base case load forecast in the (never filed) 2020 IRP – in other words a forecast similar to the reference case forecast in the 2022 IRP. There are numerous requests where Staff questions if the potential for declining load is considered, and potential DR cost-effectiveness is something that is drastically different for a gas utility in a declining load Scenario. For example, given that distribution system capacity costs avoided are much greater than system supply capacity costs avoided a reduction, if distribution system capacity costs avoided fall to zero the cost-effectiveness of potential DR programs changes substantially and unless cost-effectiveness waivers are provided the incentive that could be supported would be far lower, or the program would be moved from the cost-effective to the non-cost-effective category. This potential for declining peak loads to change the cost-effectiveness paradigm was presented along with the draft DR study to Staff members during study development.

Given this, and after a meeting with Staff and the consultant to discuss this issue NW Natural decided it best to hold finalizing the DR potential study to until there was more certainty relative to what would become the CPP given the risks to establishing programs that could become non-cost-effective with a change in load forecast.

OPUC Staff 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.

Given the response to Staff Request 18, a key step in 2023 will be resolution of the 2022 IRP and understanding what load forecast should be used for developing demand response programs. If it is determined that declining peak load forecasts should be used for planning purposes the cost-effective potential of residential and small commercial demand response programs is likely to be quite small. This is because less DR is cost-effective for gas utilities relative to electric utilities in general due to the lower costs of serving peak loads (driven primarily by the low-cost seasonal storage widely deployed to serve gas utility customers). Furthermore, for NW Natural in particular, who has a low-cost gas supply storage resource in Mist Recall available to serve incremental peak needs distribution system costs avoided from

[71] For energy efficiency the key forecasts needs are customer counts and annual usage forecasts, where for demand response it is customer counts and peak forecasts.

DR make up the majority of the total avoided costs for DR. It would be difficult to argue that distribution system costs avoided should not be zero in a declining peak load environment.

Following resolution of the peak load forecast question an updated potential study can be completed (likely by year end 2023) and if cost-effective savings are found could support subsequent program development. NW Natural is of the opinion that there is enough information known about DR programs and enough evolution in “internet-of-things” devices that development of scalable residential and small commercial without a pilot would be possible in 2024.

Relative to geographically-targeted demand response NW Natural posed a number of policy related questions to be discussed as part of its ongoing geographically-targeted energy efficiency (GeoTEE) pilot that would need to have resolution before moving forward with geographically-targeted programs in general, whether they are EE, DR, or combo programs.

OPUC Staff 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.

See Section 1.6. NW Natural is supportive of advancing understanding of the potential for dual-fuel heating systems and will continue to participate in discussions with Energy Trust and other about a duel-fuel heating pilot.

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

Please see response in Section 1.3 in Part 1. By planning to acquire RNG up to the SB 98 targets, NW Natural seeks to comply with the CPP in a manner that is consistent with the policy and RNG targets set forth in ORS 757.390 through 757.396.

OPUC Staff 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.)

Please see response in Section 1.3 in Part 1 regarding SB 98 targets. See table below in response to Staff Request 22. Appendix C shows a side-by-side comparison for compliance resources acquisitions with and without SB 98 compliance.

Table 2: SB 98 Compliance PVRR Comparison

Scenario	Planning Horizon PVRR of Costs With SB 98 Compliance	Without SB 98 Compliance	Percentage Difference
Scenario 1- Balanced Decarbonization	$ 13,582,825,185	$13,436,453,499	1.1%
Scenario 2- Carbon Neutral	$ 12,549,347,025	$12,313,367,972	1.9%
Scenario 3- Dual-Fuel Heating	$ 11,472,450,454	$11,318,367,769	1.4%
Scenario 4- New Gas Customer Moratorium	$ 12,017,507,276	$11,863,631,225	1.3%
Scenario 5- Aggressive Building Electrification	$ 8,957,933,338	$ 8,727,174,357	2.6%
Scenario 6- Full Building Electrification	$ 6,097,075,111	$ 5,092,801,147	17.9%
Scenario 7- RNG and H2 Policy Support	$ 11,684,834,911	$11,662,526,414	0.2%
Scenario 8- Limited RNG	$ 15,988,731,247	$15,679,212,064	2.0%
Scenario 9- Supply-Focused Decarbonization	$ 12,949,488,808	$12,806,955,280	1.1%

Table note: These PVRR costs include all the costs modelled in PLEXOS, minus the difference in costs between the total WA allowance cost modelled with the SCC and the total WA allowance cost using what we expect customers to pay for, plus the incremental costs for demand-side reductions (modelled outside of PLEXOS). These costs do not include additional non-resource related utility costs that would not be impacted by compliance with SB 98 but do make up roughly half of the NW Natural's revenue requirement. These costs also do not include any costs to the electric grid that would result from aggressive electrification. If these costs were to be included the difference between the two scenarios would be a smaller percentage difference.

OPUC Staff 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 4.3.2 in the 2022 IRP states:

> *As shown in Figure 4.3, the sharp increase in avoided costs in Oregon this IRP comes from a significant increase in avoided GHG compliance costs. In Oregon, energy efficiency cannot avoid RNG acquisition to support SB 98, but it can be used for compliance under the Climate Protection Program (CPP), and as such the avoided GHG compliance costs are represented by the marginal emissions reduction activity expected to comply with the CPP in each year. Per Chapter 7 [footnote 84 states: Marginal resources from Scenario 1 are used to determine avoided costs.], the marginal CPP activity is expected to be Community Climate Investments (CCIs) until 2035. However, the limit on the number of CCIs used for compliance will be reached in 2036. At this point in time the marginal cost of emissions reduction from the incremental renewable supply resource in a given year becomes the cost that can be avoided with additional EE savings. It is noticeable in Figure 4.3 that the avoided GHG compliance costs are decreasing over time after 2036, in alignment with the trend in renewable resource costs as described in Chapter 6.*

Also as stated in the Company's response to LC 79 OPUC DR 109:

> *While the marginal resource avoided for compliance purposes in Oregon for energy efficiency is expected to shift from CCIs to RNG when the CCI limit is reached (shown in this IRP based upon*

> *Scenario 1) in 2036, RNG purchases cannot avoid RNG purchases in terms of emissions compliance. The marginal resource that would be avoided with RNG purchases is kept as CCIs for the entirety of the planning horizon, hence the difference between avoided emissions compliance costs for energy efficiency and RNG starting in 2036*.

In summary, the avoided costs for energy efficiency and RNG that have been obtained in the 2022 IRP are not influenced by the SB 98 targets. Instead, they are determined either by the costs of CCIs (for RNG throughout the planning horizon and for efficiency until 2035) or by the costs of avoided RNG resources needed for GHG compliance (for efficiency after 2035). Therefore, a more relaxed approach to SB 98 targets will not change the avoided cost values reported for efficiency and RNG in the current 2022 IRP. Furthermore, please see response in Section 1.3 in Part 1 for NW Natural's response about SB 98.

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

The key components of the evaluation methodology – how to calculate the all-in costs of conventional gas and the all-in cost of the RNG project has not changed. With that, there are three primary changes to the methodology in the 2022 IRP relative to the version found in OPUC Docket No. UM 2030:

Primary change 1: In UM 2030 the methodology was framed in terms of determining when the all-in cost of RNG was lower than the all-in cost of conventional gas. In Appendix K in the 2022 IRP the all-in cost of conventional gas and the all-in cost of RNG are calculated using the same formula, however it is to determine the incremental cost of RNG, which is defined as the all-in cost of RNG minus the all-in cost of conventional gas in bundled terms (per SB 98 rules).

Primary change 2: In UM 2030 the methodology contemplated running the resource planning optimization model (PLEXOS® in the 2022 IRP, it was SENDOUT when UM 2030 was filed) inclusive of a full stochastic process to evaluate each prospective RNG project. Upon evaluating actual RNG projects it became apparent it would not be possible to allow RNG projects to be compared against one another on an apples-to-apples basis given that it takes multiple days of model run time to complete a full risk analysis and NW Natural is continually monitoring numerous existing and prospective RNG projects. Allowing a true apples-to-apples comparison would require all prospective RNG projects in the portfolio to undergo this multi-day process any time there was a change in terms of one prospective RNG project. This would not allow timely negotiation of terms with counterparties and take copious amounts of bandwidth in terms of modeling. It was determined that it was most appropriate to develop a self-contained incremental cost workbook that can be used for each prospective RNG project that uses the same math (or nearly so) as would result from running the full Monte Carlo analysis in PLEXOS® for each project. As such, the implemented methodology has the same calculations as that in UM 2030 at a high level, but the outputs from PLEXOS® are used as inputs in the incremental cost workbook. In this way each prospective project can have its own incremental cost workbook to calculate incremental cost and these can be compared across prospective and existing RNG projects.

Primary change 3: The 2022 IRP implements the risk assessments for the cost the RNG projects themselves (not the avoided costs associated with the conventional gas alternative from the resource planning optimization) in the incremental cost workbook. This risk assessment was contemplated in UM 2030, though how this risk assessment would be implemented had not yet been determined.

In terms of the actual variables that constitute the components that make the calculations of the methodology, a side-by-side comparison of variable list in UM 2030 with the list in Appendix K of the 2022 IRP shows that changes to actual have been minimal.

Here are the detailed for the calculations in UM 2030:

Term	Units	Description	Source	Project Specific?	Input or Output of Optimization?	Treated as Uncertain?
R	$/Year	Annual all-in cost of prospective renewable natural gas (RNG) project	Output of RNG evaluation process	Yes	Output	Yes
C	$/Year	Annual all-in cost of conventional natural gas alternative	Output of RNG evaluation process	Yes	Output	Yes
M	$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of RNG evaluation process	Yes	Output	Yes
E	$/Year	Annual greenhouse gas emissions compliance costs	Output of RNG evaluation process	Yes	Output	Yes
I	$/Year	Annual infrastructure costs avoided with on-system supply	Output of RNG evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted daily quantity of RNG supplied by project	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
P	$/Dth	Contracted or expected volumetric price of RNG	Project evaluation or RNG supplier counterparty; Max cost-effective price determined by methodology if NWN initiating negotiations	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
k	Year	When the RNG purchase starts in # of years in the future; k = RNG start year - current year	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
z	Years	Duration of RNG purchase in years	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
t	Days	Day number in year ***T*** from 1 to 365	N/A	No	Input	No
V	$/Dth	Price of conventional gas that would be displaced by RNG project	Average price of last ***Q*** quantity of conventional gas dispatched without RNG project	Yes	Output	Yes
Y	$/Dth	Variable transport costs to deliver gas to NWN's system	*For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from the marginal unit of gas dispatched to meet demand	Yes	Output	No
X	$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e /Dth	Greenhouse gas intensity of natural gas being considered	Based on expected policy treatment of carbon intensity of for reported emissions from RNG resources	Yes	Input	No
G	$ /TonCO_2e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recent update	No	Input	Yes
S	$/Dth	System gas supply capacity cost to serve one Dth of peak DAY load	Based upon marginal supply capacity resource that is being deferred using Base Case resource availability from the most recent update	No	Output	Yes
A	Dth	Minimum natural gas injected on to NWN system during a peak DAY by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
D	$/Dth	Distribution system capacity cost to serve one DTH of peak HOUR load	Distribution system cost to serve peak hour load from avoided costs in most recent update	No	Input	No
H	Dth	Minimum natural gas injected on to NWN system during a peak HOUR by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount Rate	Discount rate from most recent update	No	Input	No

Here is the variable list from Appendix K in the 2022 IRP for comparison:

Term	Units	Description	Source	Project Specific?	Input or Output of IC Workbook?	Treated as Uncertain?
R	$/Year	Annual all-in cost of prospective renewable natural gas (RNG) project	Output of RNG evaluation process	Yes	Output	Yes
C	$/Year	Annual all-in cost of conventional natural gas alternative	Output of RNG evaluation process	Yes	Output	Yes
M	$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of RNG evaluation process	Yes	Output	Yes
E	$/Year	Annual greenhouse gas emissions compliance costs	Output of RNG evaluation process	Yes	Output	Yes
I	$/Year	Annual infrastructure costs avoided with on-system supply	Output of RNG evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted daily quantity of RNG supplied by project	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
P	$/Dth	Contracted or expected volumetric price of RNG	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
k	Year	When the RNG purhcase starts in # of years in the future; k = RNG start year - current year	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
z	Years	Duration of RNG purchase in years	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
t	Days	Day number in year ***T*** from 1 to 365	N/A	No	Input	No
V	$/Dth	Price of conventional gas that would be displaced by RNG project	Marginal price of conventional gas dispatched in PLEXOS in run without RNG project	Yes	Input	Yes
Y	$/Dth	Variable transport costs to deliver gas to NWN's system	*For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from marginal gas dispatched in PLEXOS	Yes	Input	No
X	$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e /Dth	Greenhouse gas intensity of natural gas being considered	From actual project certification if available, from California Air & Resources Board by biogas type if no certification has been completed	Yes	Input	No
G	$ /TonCO_2e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recently acknowledged IRP	No	Input	Yes
S	$/Dth	System supply capacity cost to serve one Dth of peak DAY load	Based upon marginal supply capacity resource cost by year as determined from PLEXOS modeling in most recent IRP	No	Input	Yes
A	Dth	Minimum natural gas supplied on a peak DAY by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
D	$/Dth	Distribution system capacity cost to serve one DTH of peak HOUR load	Distribution system cost to serve peak hour load from avoided costs in most recently acknowledged IRP	No	Input	No
H	Dth	Minimum natural gas supplied on a peak HOUR by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount Rate	Discount rate from most recently acknowledged IRP	No	Input	No

NW Natural will include an update with more description of these changes in the addendum it will file for the IRP (see OPUC Staff Request 4).

OPUC Staff 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.

NW Natural held a meeting with Staff to discuss Staff's questions on the low carbon gas incremental cost workbook in January 2023.

OPUC Staff 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.

The E3 estimate Staff is referencing is the outlier of the estimates considered by Staff. It is far higher than the other estimates mentioned by Staff in their comments. Evaluating multiple sources and choosing the highest cost estimate to be "conservative" does not align with how NW Natural believes estimates should be made. NW Natural's perspective is that the best estimate for each input should be used for optimization and uncertainty in those estimates accounted for in scenario and stochastic work to understand the implications if costs turn out to be higher or lower than expected. If a conservative (i.e., relatively high) estimate is used in comparison to other resources it biases acquisition against the resource with a conservative assumption as well as biases overall cost estimates higher than actual expectations. High-cost outcomes can be assessed via scenario and stochastic simulation work.

Relative to the E3 estimate, E3 modeled methanation costs using off-grid hydrogen production, which leads to much lower utilization factors for electrolyzers. The reasoning provided is that new transmission costs to connect these production facilities would be too high. This view essentially "islands" hydrogen production, and provides no access to other renewable or low-carbon generation sources thereby decreasing utilization factor, nor does it allow for any value add to the grid through demand response, voltage regulation, etc.

NW Natural's view is that hydrogen production will be connected to the grid wherever possible to maximize synthetic methane output and provide grid benefits, and thereby minimize costs. This logic is reasonable since all of the green hydrogen and methanated hydrogen production facilities NW Natural is currently in negotiations with for supply agreements are grid-connected and has yet to encounter a hydrogen or methanation proposal that is not grid connected. There may be "islanded" projects proposed in the future, or even today; however, they will need to compete with projects that will have much higher utilization factors.

The price quoted for the most mature methanation project with NW Natural is $16.75/MMBtu for RTCs today. Given a market price of $5/MMBtu for the brown gas, the bundled price would be approximately $22/MMBtu, which is already lower than the E3 2050 "Optimistic" price listed by E3 of $30/MMBtu. NW Natural expects these prices to fall over time given economies of scale in hydrogen and methanation equipment.

OPUC Staff 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?

Staff's premise for this request that NW Natural removed the "cost of brown gas, transportation, and capacity" from the modeled low-carbon fuels is incorrect and needs clarification prior to being able to answer Staff's request. Staff's comments state:

> *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.*[72]

For clarification, it is incorrect that transportation and capacity costs are subtracted from costs that are input to PLEXOS®. Only an average gas price is subtracted to represent the cost of the brown gas. Attached to Staff's comments about this is footnote 105 that references LC 79 OPUC DR 70. NW Natural's response to this DR discusses the incremental cost for all types of RNG:

> *The prices for these resources, as shown in the Scenario key assumptions and results workbook (see pages 258-345) are in incremental cost terms (i.e., the avoided costs gas commodity and transport costs and capacity costs if applicable have been subtracted out of) though are sourced from the costs depicted in Table 6.6.*[73]

When compliance resources are selected in the PLEXOS® model, only a carbon credit is provided to NW Natural's system and not the underlying gas commodity. Therefore, the transport costs and capacity costs are not applicable and are not subtracted. The response to LC 79 OPUC DR 70, "(i.e., *the avoided costs gas commodity and transport costs and capacity costs if applicable have been subtracted out of),* was stated in terms of describing incremental costs where the avoided costs for transportation and capacity costs would be subtracted in the evaluation for any on-system projects. The compliance resources modelled in PLEXOS are not on-system and only the commodity cost of gas is subtracted from the cost of a bundled compliance resource for RNG Tranche 1, RNG Tranche 2, hydrogen, and synthetic methane.

By subtracting out an average gas price, the compliance resources modeled in PLEXOS® are representative of an unbundled RTC. Section 6.1.1 of the IRP describes the distinction between bundled and unbundled RTCs. The full costs (i.e., prices) for the compliance resources are reflected by the PLEXOS® input data files provided to Staff for each compliance resource as an unbundled resource, for each scenario, and for each Monte Carlo draw.

NW Natural is the first IRP in the state across all utilities to model carbon compliance under the CPP. To do this the Company needed to develop a completely new optimization model in a new software (PLEXOS®) to have the ability to evaluate compliance resources under a carbon constraint. This PLEXOS® model has thousands of inputs and properties for hundreds of objects that all need to be created with appropriate memberships (i.e., relationship or connections to each other). Staff's request 27 is phrased

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[72] Staff Comments at 61.

as if there is a tradeoff of added value versus added complexity, but the true trade-off here is having complexity in a part of the model versus shifting that complexity to another part of the model. Appendix B-PLEXOS® Model Complexity for Unbundled Compliance Resources, dives into the reasons and technical details for why we modelled renewable resources as unbundled products.

Staff's request 27 also implies that the methodology selected is less transparent. There are benefits to this methodology that NW Natural would argue make this approach more transparent. By using the price of unbundled RTCs for RNG, hydrogen, and synthetic methane, we can make an apples-to-apples comparison to the costs of other compliance resources, such as CCIs for Oregon, and offsets and allowances for Washington, that are inherently unbundled. Each scenario in Chapter 7 contains graphs showing this comparison in costs over time across compliance resources as unbundled carbon credits. Without these graphs comparing costs of the different types of unbundled RTCs to the costs of CCIs, offsets or carbon allowances the analysis would be less transparent.

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

Larger and larger scale RNG projects are being developed, and NW Natural expects these projects to benefit from the economies of scale inherent in RNG project development. In particular, large-scale gasification projects, which are currently in early-stage development in several locations in the Pacific NW, expect to produce very large amounts of RNG (e.g., over 4-5 BCF/year) at prices at or below the lower-priced resources in our recent RFP. NW Natural stays in close contact with many project developers. While project developers may claim that they can produce a certain amount of volume at a certain price, NW Natural understands that these resources may not materialize as planned. However, the increased investment in project development tracked by the RNG Coalition[74] reflects the maturation of the industry and the comfort with which financing partners, especially, are getting with RNG equipment and processes. NW Natural expects continued technological advancement in the sector.

RNG production costs can range widely depending on the size and type of project. One analysis by the World Resources Institute found that production costs ranged from $3 to $30/MMBtu. At present the RNG available in the market typically fetches a price higher than production costs, due largely to the strong demand driven by the federal Renewable Fuel Standard and the California and Oregon Clean Fuel programs. These markets are impacting the RNG that is being offered to NW Natural under offtake contract structures. NW Natural expects that if the utility developed RNG projects become a larger percentage of the utility's RNG portfolio, then costs for NW Natural customers will trend toward production costs, rather than the costs paid by other market participants in other RNG markets. At present our estimates of different project costs support the two tranches of RNG costs reflected in the IRP.

NW Natural expects hydrogen to be available from numerous sources, including electrolytic supplies using low-carbon electricity and supplies produced from reformed natural gas combined with carbon

[74] See weblink https://images.squarespace-cdn.com/content/v1/53a09c47e4b050b5ad5bf4f5/bb654b2f-4fe0-46b6-9117-fe9e5fe73c1e/1292931_RNG+Facility+Map+NA_squarespace_1_112322.png?format=1000w

capture. These hydrogen resources will continue to be evaluated using a least-cost, least-risk framework. In addition, these supplies may be delivered via pipeline (purity or blended) and/or through local production and supply sources, or to other common carrier pipelines where book and claim accounting would be used.

Estimates from other entities such as Bloomberg, NW Natural modeled the cost of hydrogen starting at roughly $23/MMBtu with a higher rate of decline through 2030 where it pivots to a slower trajectory, but still decreases to roughly $5/MMBtu by 2050.[75] Synthetic methane was modeled through all scenarios and simulations as the price of hydrogen plus an additional adder. This adder starts at $7/MMBtu and decreases over the planning horizon, but the primary driver of the cost decline for synthetic methane is the decline in the cost of hydrogen. We note that this adder for synthetic methane above the price of hydrogen is uncertain and is analyzed in the risk analysis.[76]

The prices used in our models for hydrogen are reasonable given:

- Low-carbon hydrogen can be produced from natural gas using reforming and pyrolysis technologies at marginal incremental costs.[77] As described in Section 2.3.2 of the 2022 IRP, NW Natural estimates average natural gas prices being between $3 and $4/MMBtu for the next 20 years. Reforming natural gas with carbon capture uses mature technology and is well understood, while pyrolysis of natural gas is a developing field with fifteen (or more) companies and institutions working towards maturing it. That said, Monolith[78] has the first large-scale methane pyrolysis plant in operation (81MMBtu/hr reactor) with an expansion currently under development (972MMBtu/hr).
- Natural gas reforming with carbon capture and pyrolysis are expected to produce low enough emissions to produce production tax credits, now enabled by the Inflation Reduction Act (IRA), in the range of $1 to $3/kg ($7.40 - $22/MMBtu) given estimated emissions of 1.45kgH2/kgCO2 or less provided by technology providers.
- Hydrogen produced from electricity uses mature technology (electrolyzers) that will benefit from capital cost reductions as scale-up occurs. And while the majority of the cost of hydrogen is based on the cost of electricity, the renewable production tax credit stacked with the hydrogen tax credit makes the levelized cost of hydrogen negative in some estimates.[79]

Since developing the hydrogen costs for the IRP, federal policy now includes $8 billion for hydrogen hubs and the hydrogen production tax credit are paving the way for significant hydrogen infrastructure investments and make it competitive with traditional fuels. Both hydrogen suppliers and consumers are expected to increase over the next few decades and take advantage of these new incentives.

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[75] NW Natural's 2022 IRP pg. 214 (pdf pg. 231)

[76] NW Natural's 2022 IRP pg. 215 (pdf pg. 232)

[77] Al-Qahtani, A., Parkinson, B., Hellgardt, K., Shah, N., & Guillen-Gosalbez, G. (2021). Uncovering the true cost of hydrogen production routes using life cycle monetisation. *Applied Energy*, *281*. https://doi.org/https://www.sciencedirect.com/science/article/pii/S0306261920314136?via%3Dihub

[78] https://monolith-corp.com/

[79] https://www.credit-suisse.com/treeprintusinflationreductionact

In addition to the US, other regions and countries are developing hydrogen supplies and investing in new infrastructure. Canada, the source of the majority of natural gas for NW Natural, is no different and has developed a hydrogen strategy. If fully implemented, the strategy would "Position Canada to become a world-leading supplier of clean hydrogen."[80] Supplies of hydrogen available globally and closer to home are expected to become more and more abundant.

OPUC Staff 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.

While this is the intention of Scenario 8 ("Limited RNG") which was developed with stakeholder feedback, as well as the stochastic draws with high prices for renewable supply (which can be found using the draw finder provided in the workpapers), NW Natural will continue to engage stakeholders and develop a high-cost Scenario in the next IRP.

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

NW Natural will continue to evaluate future cost and availability projections for alternative fuels to natural gas in the next IRP.

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

NW Natural will take this into consideration for the next IRP.

OPUC Staff 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.

The presumption embedded in Staff's request is incorrect regarding how distributed energy resources (DER) work to supply energy to the system in a targeted manor or how demand-side solutions work to reduce peak energy requirements. Staff's comment on a "…decrease in customer numbers due to current trends of distributed energy resources, demand-side solutions..." also misses the point because new DER or demand-side solutions (e.g., installing high efficiency appliances or improved shell measures) do **not decrease** the number of customers the system is serving.

Furthermore, if NW Natural correctly understands that "electrification rates" means a decrease in customers in the Forest Grove area due to customers leaving the gas system, we would request Staff to explain why they see this as "likely" in the Forest Grove area in the immediate term. NW Natural has only ever seen an *increase* in the number of customers in the area through time, including since the analysis that was conducted for the IRP. The analysis conducted shows a violation of our planning criteria *for the existing customers* in the area now. Even if policies that would ban gas in new

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[80] https://www.nrcan.gc.ca/climate-change/what-success-looks-our-vision-for-2050/23108

construction passed in the Forest Grove area, we would still expect some level of growth for some time until the policy went into effect. Any electrification in the area from existing customers would then take additional time before it offset that growth. System monitoring and modeling shows customers in the area are at risk of losing reliable service today and that risk is growing through time due to ongoing customer growth in the area.

NW Natural considers several alternatives when evaluating distribution system projects as shown by Table 8.2 in the IRP that includes several DER and targeted DSM options that were evaluated for this area.

IRP Table 8.2: Distribution System Planning Alternatives

Distribution System Planning Alternatives (not all options are possible or applicable in all situations)				Option Currently Considered for Cost-Effectiveness Evaluation
Supply-Side Alternatives	Pipeline Related Capacity Options		Loop existing pipeline	✓
			Replace existing pipeline	✓
			Install pipeline from different source location into area	✓
			Uprate existing pipeline infrastructure	✓
			Add or upgrade regulator to serve area of weakness	✓
			Gate station upgrades	✓
			Add compression to increase capacity of existing pipelines	✓
	Non-Pipeline Solutions	Distributed Energy Resources (DER)	Mobile/fixed geographically targeted CNG storage	✓
			Mobile/fixed geographically targeted LNG storage	✓
			On-system gas supply (e.g. renewable natural gas, H2)	✓
			Geographically targeted underground storage	✓
Demand-Side Alternatives		Demand Response	Interruptible schedules (DR by rate design)	✓
			Geographically targeted interruptibility agreements	✓
			Geographically targeted Res & Com demand response (GeoDR)	
		Energy Efficiency	Peak hour savings from normal statewide EE programs	✓
			Geographically targeted peak-focused energy efficiency (GeoTEE)	

Options such as Geographically Targeted Energy Efficiency (GeoTEE) and Geographically Targeted Demand Response (GeoDR) still need additional information on costs and reliability being gather by through the GeoTEE pilot as well as direction from the Commission on the social desirability of such targeted programs before bringing a GeoTEE or GeoDR project through an IRP.

While there are a number of factors that impact load (e.g., school closures, wind speed, etc…), to better characterize what events would trigger a pressure drop of 40 percent or higher, we use the Synergi™ Gas modeling to measure the impact to pressure drop on the Forest Grove gas distribution system from three key aspects that can be incorporated into Synergi™ Gas:

- Temperature
- Btu Value
- Large Customer Load

Temperature

Temperature is a fundamental variable for forecasting gas consumption and therefore pressure on a gas distribution system. Gas consumption changes as temperature changes: gas consumption increases (i.e., pressure decreases) with lower temperatures. Synergi™ Modeling, which calculates pressure for different parts of the system, was conducted based on daily average temperatures for the Forest Grove Feeder.

Btu Value

The Btu Value, also known as the heat content, for the supply gas delivered from the Forest Grove Feeder can vary.[81] Supply gas Btu Value on NW Natural's distribution system can increase or decrease near instantaneously and without warning, making it near impossible to predict. The Btu Value of natural gas is an important attribute affecting gas hydraulics because it influences the pressure drop through a piping system. If the Btu Value drops unexpectedly, then the pressure drop across a pipeline will be immediately affected. Btu Values determine the volumes of gas required to serve energy needs. Consumption on a natural gas network is determined by the amount of energy consumed, typically expressed in Therms or Btu's. If the energy needs remain constant while the Btu Value of a cubic foot of gas decreases, then it requires a higher volume of gas to meet the same energy demand. Higher volumes of gas required, equates to additional pressure drop along a pipeline system because of frictional losses.

Large Customer Load

Waste Management is a firm customer on the Forest Grove Class B System (under 60 psig MAOP). Waste Management is the highest usage customer on the Forest Grove Distribution System. Waste Management operates Compressed Natural Gas (CNG) compressors to fuel their fleet of waste hauling trucks with natural gas. When the CNG compressors are fueling the trucks, there is a significant demand on the system, resulting in a reduction of pressure on the Forest Grove System. Although Waste Management typically maximizes usage during the off-peak hours, there are instances when Waste Management consumes large quantities of gas during the morning burn.

The chart below shows different scenarios of gas modeling with varying average daily temperatures, Btu content, and with Waste Management load toggled on or off. The model results are graphed against actual demands recorded by the Electronic Portable Pressure Recorder (EPPR) located at the Forest Grove Feeder District Regulator. The Synergi™ Gas predictions are based on perfect flows through a hypothetically perfect Forest Grove District Regulator, which implies that the regulator is not restricted by inlet pressure and flows until the inlet pressure drops below the regulator setpoint. The graph comprises the following data points:

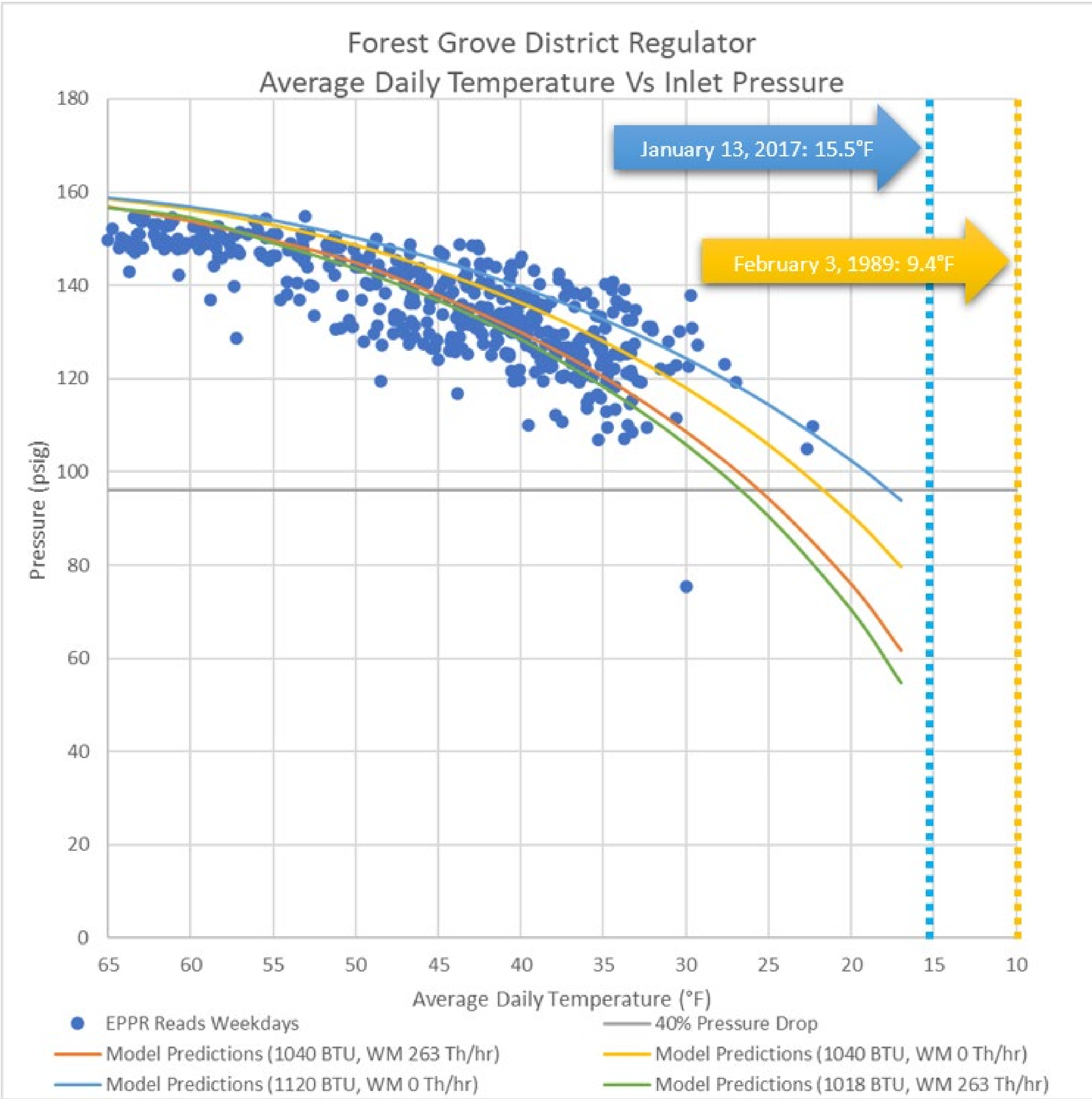
- Blue dots – Data reads from the (EPPR) sited on the Forest Grove District Regulator. The dots show recorded minimum pressure against average daily temperature for weekdays. Weekend

[81] Natural gas heat content can range from about 1,000 Btu/scf to 1,100 Btu/scf. This heat content is dependent on the gas mixture, which is often dependent on where the gas is sourced and/or how it is processed prior to entering NW Natural distribution system.

days were excluded from the data source because distribution system planning is conducted for weekdays when gas consumption is higher.

- Blue Line – Scenario providing the lowest pressure drop Forest Grove Feeder. Gas is modeled at 1120 Btu/scf (higher than usual, with Waste Management gas demand disabled in the model).
- Yellow Line – Natural Gas is modeled at 1040 Btu/scf with Waste Management gas demand disabled in the model.
- Orange Line – Modeling Provided in the 2022 IRP. Natural Gas is modeled at 1040 Btu/scf with Waste Management gas demand enabled in the model.
- Green Line – Scenario providing the highest pressure drop on the Forest Grove Feeder. Gas is modeled at 1018 Btu (lower than usual, but not lower than we have seen recently) with Waste Management gas demand disabled in the model.
- Gray Line – 40 Percent Pressure drop.
- Historical temperature data from the nearby Hillsboro Airport shown by the vertical dotted lines.

Figure 10: Forest Grove District Regulator Average Daily Temperature Vs Inlet



Depending on the unique conditions, the blue dots can vary even for a specific temperature. This shows that although temperature impacts usage, variation exists within a specific temperature because of other influencing factors.

Table 4 below shows when we can expect a 40 percent pressure drop based on the modeling results. Synergi^{TM} Gas modeling predictions show that a 40 percent pressure drop can occur between an average daily temperature of 17°F and 26°F.

Table 3: 40% Pressure Drop Model Predictions

Average Daily Temperature	Chart Line Color	Waste Management Demand	BTU Value
26°F	Green	263 Th/hr	1018
25°F	Orange	263 Th/hr	1040
21°F	Yellow	0 Th/hr	1040
17°F	Blue	0 Th/hr	1120

January 30, 2023 - 53 Percent Pressure Drop

As shown in Figure 10 above, the Forest Grove Feeder experienced a greater than 40 percent pressure drop event just a few days ago, which is represented by the blue dot below the 40 percent pressure drop line (96 psig). On January 30, 2023, the EPPR installed on the Forest Grove District Regulator measured an inlet pressure below 96 psig for 5 hours, getting as low as 75.32 psig for two hours. This low-pressure measurement corresponds to a 53 percent pressure drop, which exceeds NW Natural's high-pressure planning criteria of 40 precent pressure drop. The average daily EPPR case temperature on January 30, 2023, was 30°F, which is warmer than the temperature used for a peak planning day. Table 4 below provides the Forest Grove District Regulator EPPR inlet pressure, outlet pressure, and temperature for the January 30, 2023 low-pressure event.

Table 4: Forest Grove District Regulator EPPR inlet pressure, outlet pressure, and temperature for the January 30, 2023

Date/Time	Forest Grove Outlet Hourly Min Pressure (psig)	Forest Grove Inlet Hourly Min Pressure (psig)	Hourly Avg Case Temp
1/30/23 0:00	48.68	136.27	24.7
1/30/23 1:00	48.69	135.09	23.9
1/30/23 2:00	48.43	132.87	23.1
1/30/23 3:00	48.25	129.11	22.1
1/30/23 4:00	47.89	122.28	21.2
1/30/23 5:00	47.8	119.18	20.3
1/30/23 6:00	46.91	84.33	22.6
1/30/23 7:00	52.15	75.32	23.6
1/30/23 8:00	50.46	75.32	23.6
1/30/23 9:00	51.85	76.79	20.4
1/30/23 10:00	47.42	88.54	21.9
1/30/23 11:00	48.01	117.26	25.8
1/30/23 12:00	48.75	122.61	30.1
1/30/23 13:00	48.89	129.47	31.4
1/30/23 14:00	47.46	130.95	36.9
1/30/23 15:00	48.48	131.15	44.3
1/30/23 16:00	48.66	131.84	49.5
1/30/23 17:00	48.37	128.51	50.2
1/30/23 18:00	48.28	126.07	44.1
1/30/23 19:00	48.34	124.88	37.9
1/30/23 20:00	48.34	123.65	33.8
1/30/23 21:00	48.23	123.87	31.1
1/30/23 22:00	48.93	130.73	29.2
1/30/23 23:00	48.87	137.66	28.2

EPPR data collected during December 22, 2022, weather event revealed that the Forest Grove District Regulator outlet pressure drooped by approximately 20 percent, or 10 psig due to low inlet pressure. Droop occurs when the flow increases above what a regulator can output with that inlet pressure and desired output pressure, causing the outlet pressure to diverge from the regulator setpoint, or droop. Droop on the Forest Grove District Regulator reduces the outlet pressure of the Forest Grove District Regulator, which can compromise the reliability of the Class B distribution system because lower starting pressures equate to higher pressure drop across a pipeline network resulting in even lower pressures.

NW Natural bypassed the Forest Grove District Regulator on January 30, 2023, to mitigate pressure droop at the outlet of the District Regulator because of demand induced by cold weather. Bypassing the Forest Grove District Regulator required a team of Field Operations personnel to add gauges on the upstream and downstream sides of the District Regulator, manually throttle open a set of valves, while continuously monitoring the downstream pressure, so as not to exceed MAOP while maintaining adequate supply and pressure to the Class B distribution system.

As stated above, Waste Management is the highest usage customer in Forest Grove. During the January 30, 2023, event Waste Management used between 0 Th/hr and 13 Th/hr during the morning burn. Table 5 shows Waste Management's hourly usage during the morning burn

Table 5: Waste Management Morning Burn Consumption

Waste Management Consumption	
Time	Average Hourly Usage (Th/hr)
6:00 AM	13
7:00 AM	1
8:00 AM	0
9:00 AM	0
10:00 AM	0

NW Natural did not call a demand response event through interrupting interruptible customers on January 30, 2023. NW Natural has two interruptible customers that are fed from the Forest Grove Feeder. Table 6 below includes the hourly usage of the two customers during the morning burn. The interruptible customer usage was not excessive during the January 30 event, implementing a demand response event to reduce load on the system by the two interruptible customers usage would not have reduced the pressure drop to below the 40 percent threshold for January 30, 2023.

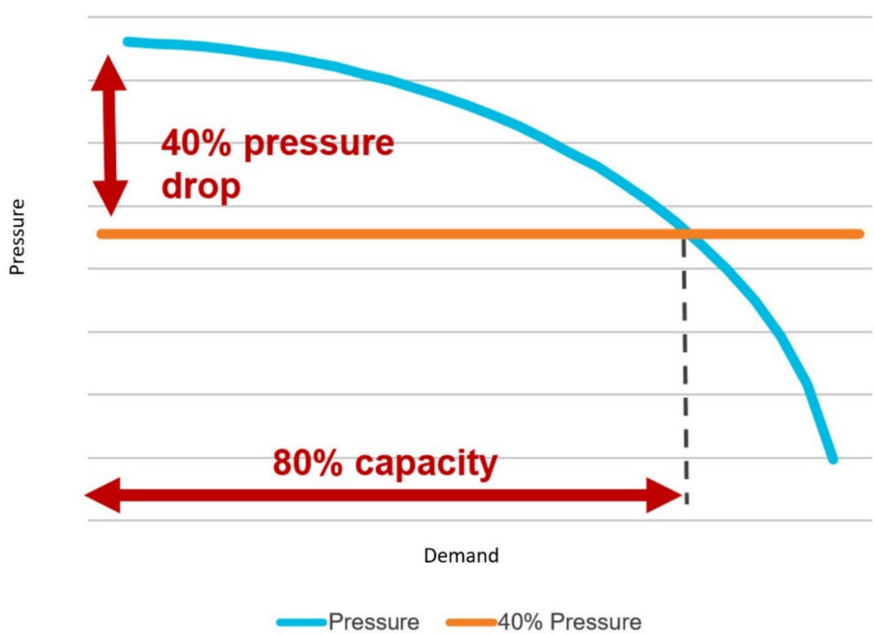
Table 6: Forest Grove Interruptible Customer Morning Burn Consumption

Interruptible Customers Consumption	
Time	Average Hourly Usage (Th/hr)
6:00 AM	61
7:00 AM	105
8:00 AM	101
9:00 AM	95
10:00 AM	107

OPUC Staff 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.**

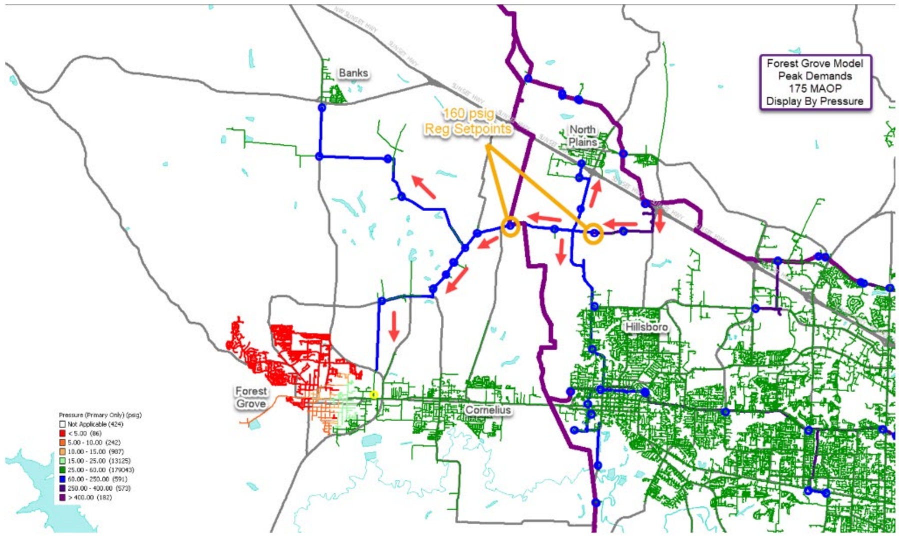
As noted in Figure 8.20 of the 2022 IRP Filing, a 40% pressure drop equates to a loss of 80% of the pipeline's capacity. The pressure vs capacity relationship is not linear, and the pipeline's remaining capacity continues to drop as pressures fall further beyond the 40% pressure drop. Figure 8.20 does not account for the diminished performance of pressure regulators when the inlet pressures droop and lead to a reduced amount of flow through the regulating equipment.

IRP Figure 8.20: Pressure Drop Vs Demand



Synergi™ Gas modeling identifies areas that may have potential low pressures during extreme weather conditions. Customers in the red region in Figure 8.18 in the 2022 IRP may be impacted by low pressures during a peak event and are susceptible to gas outages during cold weather events. The Synergi™ Gas heat map indicates an area of low pressure where customers can lose service because of insufficient delivery pressure during extreme weather. The low-pressure area consists of approximately 2,700 NW Natural customers at the time of the filing of the 2022 IRP. Synergi™ Gas is not a tool utilized to determine the number of customer outages. Customer outages in this area would be based on attributes such as delivery pressure and equipment type.

IRP Figure 8.18: Existing System Peak Model



<u>Outage Duration</u>

Unfortunately, there are no “typical” outages for temperature dependent customers. The duration of gas service outages can range from hours to days. Once a system loses pressure there is a concern that gas equipment pilot lights may go out. The process to relight customer equipment, after a loss of pressure, is lengthy as outlined below.

A loss of pressure to an area of our distribution system can affect many customers that depend on gas service for space heating needs, as well as customers who rely on gas for items such as water heating, cooking and industrial uses. If pressure is lost on a distribution system, then gas service may be interrupted for an extended period of time that can extend beyond several days. Unlike electric power distribution systems, service is not instantly restored once upstream pressure issues have been resolved. The process to restore gas service to the distribution system once pressure is lost is as follows:

1. Field crews close valves on pipelines supplying gas to the local system. This action prevents gas from returning to the customer’s equipment before we are ready to relight customers.
2. Field technicians install blind washers on the inlet side of every customer’s gas service riser which blocks gas from flowing on the inlet side of gas meter at customer’s address.
3. Field crews install purge fittings on gas mains (near end of main locations) throughout the distribution system, to prepare to purge the system to ensure that no air has entered the system, and only 100% natural gas is present.
4. Once pressure on the high-pressure feeder is high enough to ensure continuous adequate pressure in the Class B system to all the customers that lost service, field crews will re-open line

valves and purge Class B gas mains in the distribution system, to ensure only 100% natural gas is present in the gas mains.

5. Once gas mains have been purged, field technicians will begin the process to purge each gas service to confirm 100% gas, then remove the blind washer at the gas service riser.
6. Once the gas service is purged, field technicians will turn the meter back on then purge and relight the customer's equipment. This step is required to ensure customer equipment is operating correctly.

The outage duration is difficult to predict. Outage duration is dependent upon the number of customers, characteristics of the system affected, resources available to restore service, etc. During an extreme cold weather event if we were to experience loss of pressure in more than one distribution system within our service territory this could slow down our ability to restore gas service.

For a loss of service affecting only 100-200 customers, we would expect to be relighting customers equipment within 24 hours. Our ability to isolate the area of the system that lost pressure so that we can isolate the affected customers and purge the gas mains is dependent up on the location of our main line gas valves. If mainline gas valves are not conveniently located close to the actual outage, additional customers may lose service as we isolate the area of the system that has lost pressure.

For larger events, we would likely rely on Mutual Aid staff support from neighboring utilities or utilities beyond the Pacific Northwest that participate in the national Mutual Aid program. There is typically a 1-2 day lag between when Mutual Aid support is requested and when resources (external staff) begin to arrive in our service territory.

NW Natural has recent experience with a larger outage event. On Dec. 20, 2020, a vehicle crashed into Williams' Gate Station in White Salmon, Washington. This crash damaged the gate station equipment and supply to the high-pressure feeders and the Class B distribution systems were shut-off for two days while repairs were being made. The high-pressure and Class B distribution pressure systems in White Salmon, Hood River, and Odell all lost pressure and went flat (zero pressure) during the first hour of the morning burn, causing loss of service to approximately 5,500 customers. We began relighting customer equipment for the 1,400+ customers in White Salmon on December 22, 2020, and 90% of the relights for White Salmon were complete by December 25, 2020. We began relighting 400+ customers in Odell, Oregon on December 24, 2020, and the 3,600+ customers in Hood River, Oregon on December 25, 2020. 70% of the customer relights for Odell and Hood River were completed by the end of day on December 26, 2020. 93% of customer relights for White Salmon, Odell and Hood River were completed by the end of the day on December 27, 2020. Remaining customer relights continued for another 2-4 days as some customers had left the area to find shelter elsewhere.

In summary, the process to restore customer service after an outage is lengthy. Unlike the power distribution system there is no such thing as a rolling gas blackout to manage temporary outages, and we cannot flip a switch and restore gas service to a customer(s) once they have lost service.

OPUC Staff 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.

NW Natural believes it has demonstrated thoroughly, including via recent field readings in violation of system planning criteria, that the Forest Grove Uprate project is needed to serve existing customers and is not based upon any assumption of customer growth. The project is needed without delay to maintain safe and reliable service during cold weather. Additionally, NW Natural currently deploys large scale demand response programs via its interruptible service schedules that are avoiding or delaying would-be projects today and per Action Item 3 will develop residential and small commercial demand response programs and finish its geographically-targeted energy efficiency pilot before the next IRP for deployment.

OPUC Staff 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.

As stated in Section 8.4.1 of the 2022 IRP, NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, a liquefied natural gas (LNG) trailer rated at 900 Dth capacity, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of cold weather operations, or while conducting pipeline maintenance procedures.

NW Natural's current portfolio of CNG trailers does not have sufficient flow rates or inventory to address the throughput limitations on the Forest Grove Feeder.

Further, NW Natural cautions against thinking in binary terms between "pipeline" vs "non-pipeline" solutions and presuming the latter is always preferred. Mobile CNG deployment and injection presents far more operational risk, could require relying on large trucks to drive on icy roads during cold events, and is a far more infrastructure-heavy solution than a pipeline uprate, even if it can be classified as a "non-pipeline" solution.

OPUC Staff 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.

The table below summarizes the EPPR pressure recording and daily temperature for the Forest Grove Feeder during the late December 2022 cold event.

Table 7: EPPR Data

Date	Minimum Pressure (psig)	Average Daily Case Temp (°F)
12/22/2022	104.9	22.7
12/23/2023	109.7	22.3

During the December 2022 weather event, the lowest average daily temperature, as recorded by the EPPR, was 22.3 °F, which is warmer than the temperature used for a peak planning day. The lowest pressure recorded by the EPPR on the Forest Grove District Regulator was 104.91 psig. This pressure reading corresponds to a 34.4% pressure drop, which is below NW Natural's 40% pressure drop criteria. The EPPR data for the December 2022 weather event is provided below. Synergi™ Gas modeling in the IRP did not consider District Regulator Droop.

Table 8: EPPR Data 12/22/2022

Date/Time	Forest Grove Outlet Hourly Min Pressure (psig)	Forest Grove Inlet Hourly Min Pressure (psig)	Hourly Avg Case Temp
12/22/2022 0:00	48.39	133.33	24.1
12/22/2022 1:00	48.34	131.83	23.1
12/22/2022 2:00	48.05	129.54	22.2
12/22/2022 3:00	47.69	124.87	21.3
12/22/2022 4:00	47.48	119.7	20.9
12/22/2022 5:00	45.71	113.03	23.6
12/22/2022 6:00	43.87	108.53	24.7
12/22/2022 7:00	39.72	104.91	25.3
12/22/2022 8:00	38.49	104.91	25.3
12/22/2022 9:00	39.37	108.1	22.1
12/22/2022 10:00	38.59	108.2	20.9
12/22/2022 11:00	39.58	108.37	21.3
12/22/2022 12:00	41.27	108.74	22.4
12/22/2022 13:00	44.86	110.47	23.6
12/22/2022 14:00	41.27	106.45	27
12/22/2022 15:00	43.2	109.47	25.9
12/22/2022 16:00	43.61	109.68	24.7
12/22/2022 17:00	44.18	109.95	23.3
12/22/2022 18:00	44.14	109.76	22.1
12/22/2022 19:00	44.87	110.23	21.3
12/22/2022 20:00	46.18	111.31	20.9
12/22/2022 21:00	46.86	112.07	20
12/22/2022 22:00	48.74	120.52	19.7

Table 9: EPPR Data 12/23/2022

Date/Time	Forest Grove Outlet Hourly Min Pressure (psig)	Forest Grove Inlet Hourly Min Pressure (psig)	Hourly Avg Case Temp
12/23/2022 0:00	48.37	128.63	19.1
12/23/2022 1:00	48.44	128.71	18.4
12/23/2022 2:00	48.6	127.84	18.2
12/23/2022 3:00	48.2	125.22	18.2
12/23/2022 4:00	48.15	124.2	18.7
12/23/2022 5:00	46.01	116.62	21.9
12/23/2022 6:00	45.09	111.81	23.4
12/23/2022 7:00	45.09	109.7	23.8
12/23/2022 8:00	45.09	110.32	24.4
12/23/2022 9:00	46.68	113.12	21.6
12/23/2022 10:00	46.79	113.29	20.9
12/23/2022 11:00	47.48	115.1	21.8
12/23/2022 12:00	47.92	117.24	22.7
12/23/2022 13:00	48.42	118.86	23.1
12/23/2022 14:00	46.95	119.05	26
12/23/2022 15:00	48.63	124.51	24.6
12/23/2022 16:00	48.39	124.62	24
12/23/2022 17:00	48.72	126.04	23.6
12/23/2022 18:00	48.76	127.02	23.6
12/23/2022 19:00	48.82	128.72	23.6
12/23/2022 20:00	48.87	130.74	23.6
12/23/2022 21:00	48.91	133.02	23.6
12/23/2022 22:00	49.01	136.86	23.6
12/23/2022 23:00	49.16	138.78	23.6

District Regulators are designed to control pressure from a higher pressure (inlet) to a lower pressure (outlet). An appropriately sized regulator provides constant outlet pressure to feed a lower pressure system. As shown in the tables above, during the late December 2022, weather event, EPPR data revealed that the Forest Grove District Regulator outlet pressure varied from 49.16 psig to 38.49 psig. The lower outlet pressure indicates that the Forest Grove District Regulator outlet pressure drooped by 11 psig from the regulator setpoint of 50 psig. Droop occurs when the inlet pressure is too low for the regulator to maintain desired outlet pressure with the volumes flowing through it. It is important to note that the Forest Grove District Regulator droop, limits the flow rate through the Forest Grove Feeder. Lowering the flow rate decreases the pressure drop on a pipeline. For the Forest Grove Class B System, as the outlet pressure drops, more gas is being supplemented from the east, from the Hillsboro Class B System, there is a relatively small volume that the Hillsboro Class B system can supplement. Synergi™ Gas Modeling shows that the Class B connection to the Hillsboro system, along Tualatin Valley Highway, does not have enough capacity to serve Forest Grove peak demands. Rebuilding the Forest Grove District Regulator addresses outlet pressure droop issues but does not provide adequate capacity on the Forest Grove Feeder to support peak hourly demands. A system pressure uprate eliminates the need to rebuild the Forest Grove district regulator and also provided adequate capacity on the Forest Grove Feeder to support current peak hourly demands during a peak day event.

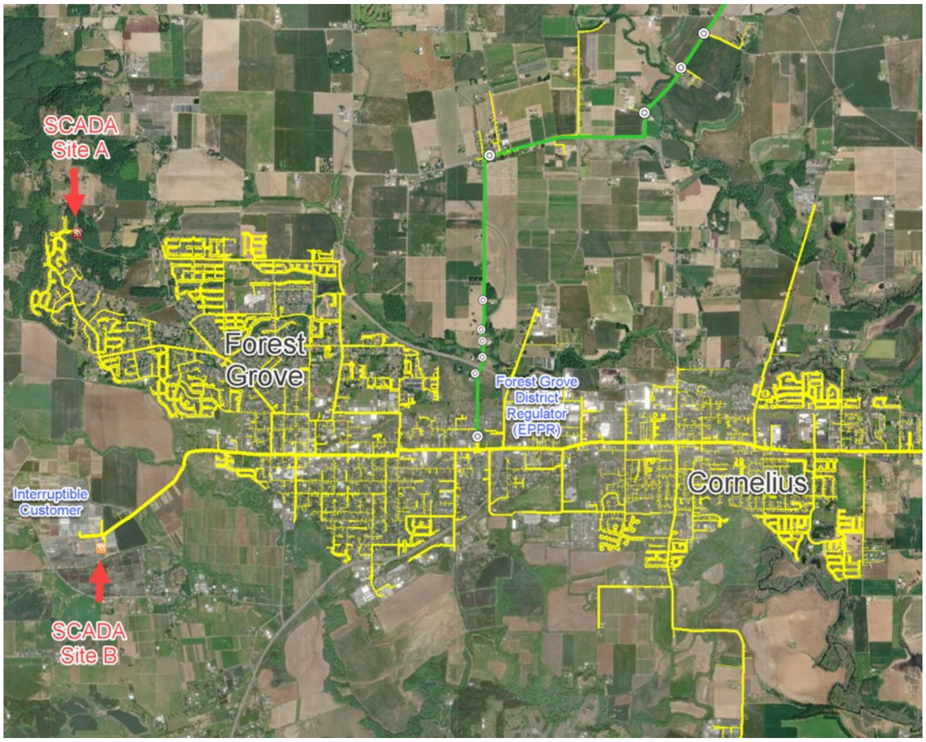
As mentioned in Request 31, large customer usage is a major contributor to the pressure drop on the Forest Grove Feeder. Over the last 3 years Waste Management had a maximum average hourly usage of 349 Th/hr. For the same three-year period, Waste Management had a morning burn (6 AM – 10 AM) maximum hourly usage of 286 Th/hr. Although Waste Management's peak load typically occurs before the morning burn, their CNG compressors do occasionally ramp up during the morning burn. NW Natural applied a demand of 263 Th/hr at Waste Management for Forest Grove modeling to cover potential usage. During the December event Waste Management used between 0 Th/hr and 36 Th/hr during the morning burn.

Table 10: Waste Management December Morning Burn Usage (Th/hr)

Date	6 AM	7 AM	8 AM	9 AM	10 AM
12/1/2022	20	0	0	0	0
12/2/2022	1	0	0	0	0
12/3/2022	0	0	0	109	0
12/4/2022	0	0	11	0	0
12/5/2022	6	0	0	0	4
12/6/2022	0	0	0	0	0
12/7/2022	3	2	0	0	0
12/8/2022	0	5	0	0	0
12/9/2022	30	0	0	0	0
12/10/2022	0	0	0	86	0
12/11/2022	0	0	0	0	0
12/12/2022	0	0	15	0	0
12/13/2022	6	0	8	8	0
12/14/2022	0	0	0	0	0
12/15/2022	40	0	0	0	0
12/16/2022	11	1	4	2	1
12/17/2022	47	31	24	25	0
12/18/2022	0	0	0	30	0
12/19/2022	0	0	0	0	15
12/20/2022	98	0	0	0	10
12/21/2022	0	0	1	0	0
12/22/2022	1	17	0	2	27
12/23/2022	36	2	4	6	9
12/24/2022	1	0	2	1	0
12/25/2022	0	0	0	0	4
12/26/2022	0	0	0	0	0
12/27/2022	0	0	0	0	22
12/28/2022	0	3	0	0	0
12/29/2022	66	0	0	0	0
12/30/2022	98	0	21	0	0
12/31/2022	157	157	156	156	7

As stated in LC 79 OPUC DR 134, NW Natural has two separate SCADA telemetry sites on the Forest Grove Class B system (60 MAOP). The two SCADA sites (identified as SCADA Site A and SCADA Site B in the image below) allow NW Natural to remotely monitor Forest Grove pressure data every two minutes. The image below provides the location for these two sites.

Figure 11: Forest Grove Class B system SCADA telemetry sites Pressure



The two charts below represent SCADA pressure data for December 22 and 23, 2022. Please note, SCADA Site A lost telemetry on December 22nd due to loss of cellular service. SCADA Site B remained online providing a connection to view pressures on the Forest Grove Class B system.[82]

[82] Temporary malfunctions in the SCADA telemetry occasionally causes spikes in the data. The spike shown in Figure 13 at 12:00 does not represent anything meaningful in the data.

Figure 12: SCADA Site A

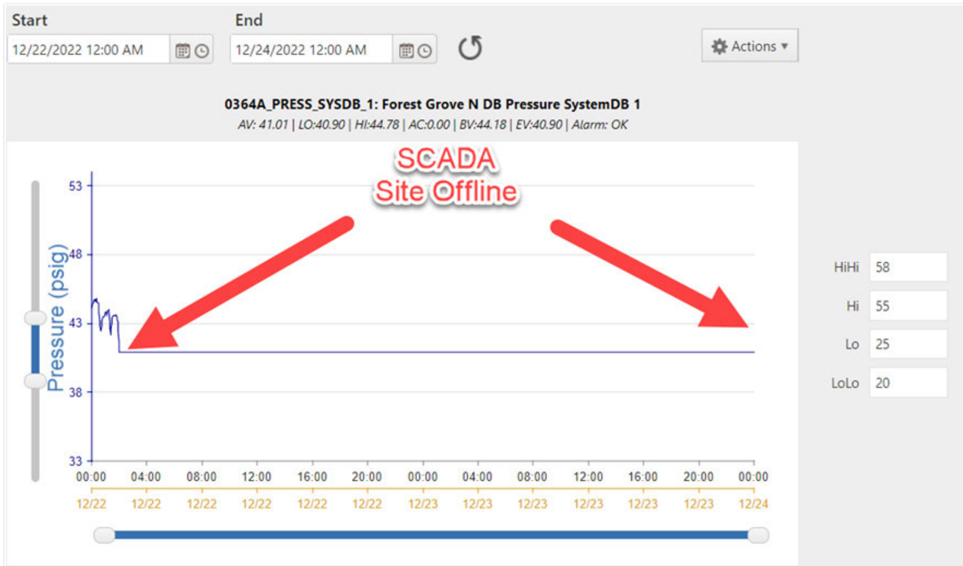
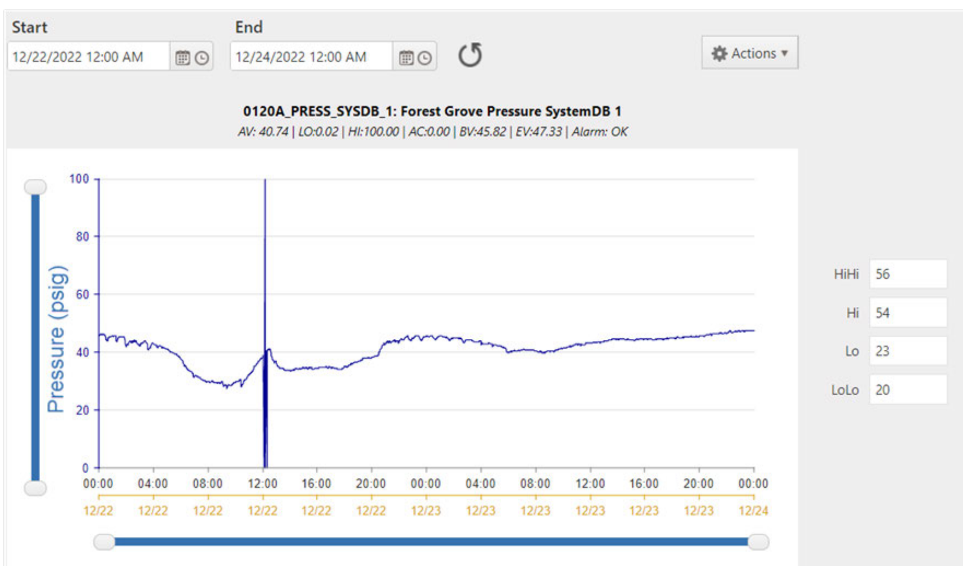


Figure 13: SCADA Site B



As stated in LC 79 OPUC DR 134, a Cold Weather Pressure Survey was conducted on the morning of December 22nd to record pressure measurements at select locations within our Class B distribution system. One of the sites on the Cold Weather Pressure survey is on the west side of the Forest Grove Class B distribution system. The pressure measurement was taken when consumption during the day was not at the highest point. EPPR data for December 22, shows that the Forest Grove District Regulator lowest outlet pressure occurred approximately two hours after the Cold Weather Pressure Survey measurement was taken. The results of the cold weather survey are provided below:

Address	City	Date	Time	Temp	PSIG
3004 NW Forest Gale Dr	Forest Grove	12/22/2022	6:00am	22	32

OPUC Staff 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.

To clarify, the original design of the Cold Box does not have a higher capacity than currently needed. The replacement Cold Box equipment is sized to match the size of the existing Cold Box.

The capacity of the Portland LNG tank and the rate at which our pretreatment equipment and Cold Box can make LNG are not related. The capacity of the current pre-treatment system and the existing Cold Box are such that it takes more than one season to fully refill the Portland LNG tank after the tank has been drained below about 40%.

Staff notes on Page 80 that the average storage level for the Portland LNG facility has dropped in recent years. The observation is correct, but the reasoning is different than Staff suggests. There are numerous contributing factors behind Staff's observation:

1. High CO2 levels in incoming feed gas regularly exceeded the capacity of the pre-treatment equipment and the pretreatment process had to be shut down more often during the liquefaction season to remove the CO2 build-up, leading to an increase in time required to fill the tank. Please refer to OPUC LC 79 DR 122 Attachment 1 for the Pretreatment System Evaluation report for a discussion about how the feed gas high CO2 levels slows the pretreatment process.
2. The slow refill rate for the Portland LNG tank leads us to prioritize its use as a peak shaving facility for our colder weather events.
3. In 2018 NW Natural lowered the storage level in the tank in response to recommendations from a seismic study prepared for NW Natural by an outside consultant. The LNG tank foundation is supported by piles that extend to the underlying bedrock, however during a seismic event the tank could move enough to cause the liquid to slosh inside the tank. NW Natural's consultant recommended reducing the storage level by 24% to reduce the sloshing of the liquid during the seismic event. Lowering the storage level was not in response to the age of the facility or the gas composition, as the storage level is independent of the liquefaction process (i.e., the capacity to make LNG). When delivering gas from the Portland LNG tank at maximum send out capacity, the Portland LNG tank has enough capacity for three to four days of natural gas supply. When fully empty the LNG tank requires more than one liquefaction season to refill. High CO2 levels can further slow the refill rate.
4. Breakage or maintenance of the pretreatment system equipment, turboexpander, or Cold Box equipment during the liquefaction season reduces the volume of liquid LNG produced. Between

2015 and 2020 numerous repairs and small construction projects during the liquefaction season limited or prevented production of LNG during the liquefaction season.

The size of the Cold Box is proportional to the volumetric flow rate of gas passing through the Cold Box. A smaller cold box would cool gas at a lesser flow rate, which would further increase the length of time to refill the LNG storage tank.

As noted in OPUC DR 126 the Cold Box equipment is estimated to cost 48% of the total project's cost. Any reduction in Cold Box sizing would only target cost savings for 48% of the project's total costs and would have little impact on the other 52% of the project estimate costs.

In summary, the reason that NW Natural did not pursue a Cold Box with a lower cooling capacity is three-fold:

1. Reducing the size of the Cold Box would slow the tank's refill rate and increase the time needed to refill the tank.
2. In the event of an equipment failure or third-party damage that limits the ability of Mist Gas to reach our distribution system, the Portland LNG facility offers backup supply when needed.
3. In the event of an Interstate pipeline disruption the Portland LNG facility serves as a potential emergency source of gas supply.

OPUC Staff 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.

NW Natural evaluated several alternatives of the Cold Box itself that would keep Portland LNG facility functioning and several alternatives that looked at decommissioning the entire Portland LNG facility. A high-level summary of the options evaluated in the IRP are presented in Table 6.8 in the IRP.

IRP Table 6.8: Portland LNG Alternatives

Alternative		Sub-Option	Feasible beyond 2027?	Cost of Service	Modeled Option in PLEXOS®
1	Keep Portland LNG Facility	A- Replace Cold Box and upgrade pre-treatment system	Yes		
		B- Replace Cold Box and keep existing pre-treatment system	Yes		✓
		C- Keep existing Cold Box and pre-treatment system	No	N/A	
2	Decommission Portland LNG and enhance Mist takeaway capabilities	A- North Pipeline	No	N/A	
		B- Middle Pipeline	Yes		✓
		C- South Pipeline	No		
3	Decommission Portland LNG and enhance Northwest Pipeline takeaway capabilities		Yes		✓
4	Decommission Portland LNG and complete no replacement alternative		Highly Unlikely		✓

Staff Request 38 is asking for supply-side non-pipeline solutions. Supply-side non-pipeline options are very limited for the gas system, particularly for system capacity resources. LC 79 OPUC DR 91 and LC 79 OPUC DR 93 inquire about trucking in LNG to the facility instead of on-site liquefaction through the Cold Box. Our response to these two data requests provides a thorough discussion of the costs and the risks of trucking in LNG to the facility and why it is not a reasonable solution to the Cold Box.

Staff comments point to RNG or synthetic methane to be considered as alternatives to the Cold Box:

> *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.*[83]

To contribute to capacity requirements any RNG or synthetic methane project must be on-system (i.e., injecting gas directly onto NW Natural's system). NW Natural currently has 3 on-system connections that provide brown gas to the system from a biofuel feedstock.[84] In total these three projects inject roughly 1,700 Dth/day. Portland LNG provides 130,000 Dth/day of capacity. While the size of a RNG project can vary, if we use the three current connections as a proxy, there would need to be about 230 on-system RNG projects. NW Natural wishes we had the opportunity to be currently evaluating 230 sources of direct-connect biofuel feedstock sources, but we are currently only evaluating or have evaluated a little over a dozen potential on-system projects.

NW Natural's incremental cost evaluation does attribute a capacity value for on-system RNG projects based on how much capacity they do provide, however; on-system RNG projects are likely to be more valuable as a compliance resource for customers as they are a low/zero emissions resources of gas year-round. These projects are limited in their ability to provide system capacity. In other words, these on-system RNG resources are likely not going to be a dispatchable resource to meet peak demand.[85]

Staff is correct in considering alternatives for the Cold Box based on their contribution to system capacity to meet *peak needs*, however; the ability for any alternatives to work within the current distribution system also needs to be considered. NW Natural's current resources have grown and evolved to serve design peak demand requirements with Portland LNG located in the NE Portland area. This consideration is exactly why we had to evaluate the distribution impacts of the alternatives discussed in Chapters 6 if Portland LNG was decommissioned. If we had enough on-system RNG to replace the capacity of the Portland LNG facility, it would be unlikely that it would be distributed

[83] Staff Comments at 81.
[84] These projects are selling the environmental attributes into separate markets, so NW Natural cannot claim this gas as renewable natural gas flowing on its system.
[85] We use the qualifier "likely" as there could be a potential for on-site storage co-located with RNG projects or other ways to increase flow from bio-digesters in anticipation of cold weather. If these techniques materialize as viable options, we can attribute the appropriate capacity value for evaluation.

throughout the system in a manner that would not require significant investments in the distribution system.

A synthetic methane facility built on the same site as the Portland LNG facility could potentially be technically feasible and work with the current distribution system, but costs to site and install an electrolyzer and methanation equipment are much greater than the investment in a single piece of equipment (i.e., the Cold Box). Additionally, the NW Natural would not characterize this solution as a non-pipeline solution as it would require more electricity infrastructure to run the electrolyzer and still have same pipelines to transport the synthetic methane.

The last supply-side non-pipeline solution that NW Natural could consider would be decommissioning the Portland LNG and replacing it with a fleet of LNG trucks. The number of trucks needed to provide the same services as the Portland LNG facility would necessarily take up more land than the current facility as these are simply smaller tanks on wheels. This option would necessarily be far more expensive than contracting LNG trucks to fill the tank as was discussed in LC 79 OPUC DR 91 and LC 79 OPUC DR 93. Other supply-side *non-pipeline* solutions, such as hooking up propane or oil tanks for furnaces and providing the corresponding fuel delivery service to residential homes seems out-of-scope of NW Natural's business model. NW Natural requests Staff to clarify what they would define as the options included in supply-side non-pipeline alternatives for system capacity resources.

OPUC Staff 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?

NW Natural's load forecast simulation encompasses a wide range of electrification and energy efficiency, both factors that reduce NW Natural's load. Even though 99% of the demand simulations have less load in 2050 than today, a few simulations show deliveries of gas (i.e., demand for both Sales and Transport customers) remaining relative flat over the planning horizon. For those simulations, NW Natural will still be able to comply with CPP emissions reduction requirements, albeit by relying on more expensive renewable fuels. While reducing demand through energy efficiency is one resource for emissions compliance, NW Natural disagrees with Staff's premise that *demand must fall due to decarbonization*.

Staff is correct to point out that one of the main drivers of cost difference between the cost for trucking LNG and the Cold Box is the amount LNG that is cycling through the facility. Our response to LC 79 OPUC DR 93 shows a cost comparison between the two options:

PVRR in 2026	Cold Box		Truck in LNG	
	Low	High	Low	High
Boil Off Only	$7,497,804	$16,038,233	$7,458,518	$14,393,526
Boil Off +50% Cycling	$7,544,546	$16,084,975	$21,443,238	$41,381,388
Boil Off +100% Cycling	$7,591,288	$16,131,717	$35,427,958	$68,369,249

While it appears that trucking in LNG could potentially be cost competitive with replacing the cold box if only replacing boil off, the more LNG needed in a year quickly makes trucking in LNG non-cost-competitive, even before factoring in the costs not considered or quantifying the risks detailed above.

The *risks* not quantified in the PVRR numbers above and mentioned in our response are:

- *Relying on a third-party supplier of LNG as well as a third-party trucking company to supply the tank.*

- *Higher risk of accident from trucking LNG via highway system given the expectation that more than 100 trucks would need to be used per year to replace boil off alone. While the liability of this concern to NW Natural and its customers could be mitigated contractually, this is a risk for society that should be considered.*

- *Reduced flexibility in terms of withdrawal needs, or leaves NW Natural without a long-term contract for all refilling needs it might have from year to year. For example, while it would be advisable to secure a long-term contract for at least the amount of boil off experienced in a year, securing more LNG contractually would require withdrawal from the facility regardless of need. Additionally, contractually securing long-term supplies for a full cycle of the facility in each year (even if a supplier could be found for this amount) would increase gas costs for customers given that costs to customers for trucking in LNG are far above costs from gas shipped via NW Natural's upstream pipeline contracts. Portland LNG is a peak shaving facility that is not expected to be needed to serve peak loads in every year. Withdrawals based upon needs to serve load are not consistent from year to year due to differences in weather.*

Additional costs not included in PVRR calculations above and mentioned in our response are:

- *the cost of decommissioning the liquefaction system at the plant,*
- *the cost of service of installing a truck receiving and loading bay,*
- *the cost of needing to increase staffing at the Portland LNG facility to handle scheduling and receipt of the LNG trucks.*

Although the PVRR calculation in our data response above did assume that trucking LNG to the facility would continue over the planning horizon, it does highlight the significant high-end risk in the cost from trucking LNG to refill the Portland LNG tank.

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

See Section 1.2. The 2022 IRP already considers the likelihood of declines in customer growth. Please reference Figures 3.4 and 3.5 in the 2022 IRP, which show the reference case customer forecasts for residential and commercial customers systemwide. Both forecasts include declines in customer growth over the planning horizon. The growth rate for residential customers in the reference case is 1.2 percent, a decline from the 1.5 percent rate forecasted in the 2018 IRP.

The nine additional scenarios analyzed and presented in Chapter 7 of the 2022 IRP and detailed in Table 7.3 include three scenarios with no new customers after 2025. The company was very responsive to stakeholder feedback throughout the IRP process to address the likelihood of declines in customer growth, which we did with lower growth in the reference case and additional scenarios showing no growth after 2025. In sum, every scenario analyzed for the 2022 IRP, including the reference case, includes forecasted declines in customer growth from previous IRPs and historical trends.

Figure 1 shows the company's Oregon residential customer net additions, or net customer count change, over the past three decades and the 2022 planning horizon. The forecasted decline in customer growth over the planning horizon is evident, whether it's the 2022 IRP reference forecast, or 2022 IRP mean Monte Carlo forecast, which shows no net customer additions after 2032.

OPUC Staff 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.

While NW Natural fully responds to Staff Request 41, the Company first needs to clarify several of Staff comments from Section 14 regarding the daily system load regression model specification and firm sales peak day forecast. Staff's comments incorrectly state:

> *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.*[86]

There are regression models used in other areas in the industry that model load as a function of HDDs. Those models are typically some variations of a simple function:

$$Load = \alpha + \beta * HDDs$$

As temperature increases, HDD values decrease and become zero above a threshold temperature where heating load stops. If HDD = 0 then load = α (the constant term), and for this specification α could be interpreted as a constant baseline level of usage independent of HDDs.

The daily system load regression model, however, estimates load as a function of temperature and several other variables *but not HDDs*. The constant term is not a measure for a baseline level of natural gas. The daily system load model specification is a multivariate equation. If we think about breaking it down to a simple univariate equation of load and temperature, the equation would look as follows:

$$Load = \alpha + \beta * Temperature$$

If temperature is equal to 0°F then load equals α (the constant term). Intuitively the forecasted load for natural gas would be extremely high for a zero-degree temperature as most of the gas flowing through the system on a cold day is used for space heating. Therefore α (the constant term) is not the baseline

[86] Staff Comments at 83.

level that does not vary with temperature as suggested by Staff.[87] The daily system load model is a much more complex equation and was provided in abbreviated form for the 2022 IRP:

$$System\ Firm\ Sales_t = \alpha + \sum_{i=1}^{23} \beta_i\ Drivers_{it} + \epsilon_t$$

When Staff comments about the statistical significance of the constant term, they are referring to the constant term being statistically different from zero. If we were running a univariate model using temperature only, as demonstrated above, it would be extremely unlikely that a temperature of 0°F would result in NW Natural's load being statistically different from zero. If the regression model were a univariate model with only temperature, then Staff's critique would be valid, and it would be very concerning that the constant term was not statistically significant. However, the model is multivariate with one of the drivers being customer counts. The constant term represents what load would equal if all driver variables had a value of zero.[88] It is not unexpected that the constant term is not statistically different from zero, as having zero customers would result in a load that necessarily would be equal to zero.

Having customer counts as a driver variable may be a theoretical justification for removing the constant term from the specification, but it is general practice for econometricians to leave in the constant term as to not overly constrain the model (i.e., forcing the constant term to equal 0 could introduce biases in β_i slope estimates) even if it is not statistically significant. For these reasons, NW Natural disagrees with Staff's above-quoted comment.

Additionally, Staff uses Figure 3.13 from our use-per-customer (UPC) model as justification for a constant baseline load above a specific temperature. NW Natural would like to clarify that this figure representing the UPC model does not represent the daily system load model used for firm sales peak day planning. The daily system load model uses daily system data less than 59°F and is described in Chapter 3, Section 3.2.6 of the IRP.

Staff further uses Figure 3.13 to justify a statistically significant constant term for a baseline load. NW Natural would like to clarify that we show Figure 3.13 with a line that contains a slope at these higher temperatures on purpose, as we see data driven evidence that this is true for some customer segments on our system. Staff is correct that load does not vary *greatly* with temperature; however, for some customer segments data driven analysis shows that non-heating load at higher temperatures is not a constant baseline. The customer segments where this slope at these higher temperatures is statistically significant is presented in the UPC model parameters in Appendix B, Table B.5: UPC Model Coefficients, which is not the same model used for firm sales peak day planning.

Staff comments also state:

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[87] Note that a system-wide temperature of 0°F is far more extreme than our design peak planning and is only used here to illustrate how constant terms in regression modeling should be interpreted.
[88] In an x y two-dimensional plot this is where the line crosses the y-axis.

> *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.*[89]

Staff's assertion that the reason why interaction terms are included in the model specification is none other than "that this term happens to be statistically significant", is concerning. Stakeholders could infer from that assertion that NW Natural is arbitrarily selecting the model specifications that help us estimate how to heat people's homes if we were to experience temperatures of a 1-in-100-year type of event (roughly 20°F below freezing). NW Natural, **realistically,** has a theoretical justification for the model specification selected and stands behind its peak planning standard and model specification used to inform that threshold. NW Natural takes its responsibility to serve customers and the supporting analysis seriously, as the consequences of not being able to serve energy needs for multiple hours or days that are far below freezing are severe.

Indeed, NW Natural's 2022 IRP explicitly has a section describing interaction effects:

> *Interaction Effects: Beginning with the 2018 IRP daily system load model, we have been incorporating interaction effects between variables, primarily temperature and other independent variables. The reason for including interaction effects starts with recognizing that a single driver alone fails to sufficiently explain changes in daily demand primarily used for space heating. For example, demand on a warm summer day with no wind will not be very different from demand on a windy summer day. However, the impact of wind greatly increases as temperatures decrease. In other words, demand on a cold windy day will be much greater than demand on a day with the same temperature and no wind. For more technical details on the daily system load model see Appendix B.*

Beyond this particular excerpt of the 2022 IRP, the model specification, driver variables, and the importance of the interaction terms are discussed in much further detail in the 2018 IRP, where there was a significant change from the 2016 IRP in estimating peak day load. The 2022 IRP did not go into much detail discussing the daily system load model as it is the same methodology as the 2018 IRP update #3, which only had minor changes from the 2018 IRP. These minor changes were discussed in the 2018 IRP update #3; however, due to Staff's concerns we will explain the importance of interaction terms with temperature here, for the benefit of new stakeholders.

What is written in the 2022 IRP, as stated in this response, describes the importance of interaction effects with temperature using the wind speed interaction effect as an example. Another clear example is the necessary interaction of customer counts and temperature. The impact of adding a customer to the system will vary with temperature. In other words, an additional customer with gas heating will use

[89] Staff Comments at 84 (emphasis added).

more gas at cold temperatures than that same customer would use at warmer temperatures. Interaction effects account for this concept.

Not including an interaction effect would pretend that the impact of an additional customer to the system would be the average impact over the range of temperatures seen in the historical data since 2009 (roughly 20°F-50°F). Since we are using this model to plan for system peak conditions (roughly 11°F), if we were to exclude the interaction effect it would grossly under-estimate the impact of adding a customer during peak conditions, which would result in under planning the system. We demonstrated this point in NW Natural's second Technical Working Group by using the model to estimate the impact of some of the driver variables at different temperatures (known as the marginal effect). The presentation of this Technical Working Group is available on NW Natural's website.

Table 11: Variable Marginal Effects (Presented in TWG 2)

Marginal Effect	Evaluated at 25°F	Evaluated at 45°F
Previous-Day Temperature	-5,262	-2,431
Wind Speed	4,300	3,341
Solar Radiation	-9.5	-6.36
Customer Count	1.446	0.360
Saturday Indicator	-27,138	-20,228

NW Natural will now specifically address Staff's comments regarding the interaction of "years since the 2008 recession" and using an interaction term with temperature. First, NW Natural is unclear why staff points out the 2008 recession in their comments. NW Natural has daily system level data available from 2009 to present. We use all the available data, which is why the time trend variable starts in 2009.

We include years since 2008 as time trend in our model to account for underlying macro trends that are occurring within the data and across our system. These trends account for underlying trends such as changes in building codes, accumulation of energy efficiency, and changes in consumer usage preferences. Including a time trend is a common practice for regression modeling when dealing with data over time. This has been discussed many times through previous IRPs and Technical Working Groups. We include a temperature interaction with time to capture the impact from these underlying trends, such as accumulation of peak day savings from energy efficiency. Similar to the example of wind speed or customer count, these underlying trends do impact the system differently at different temperatures. For one example, the impact of accumulating energy savings from shell measures, such as insulation, will save more gas at colder temperatures than at warmer temperatures. The model is showing both a level shift over time and a change over time in how our entire system is responding to temperature (i.e., the slope coefficient on temperature).

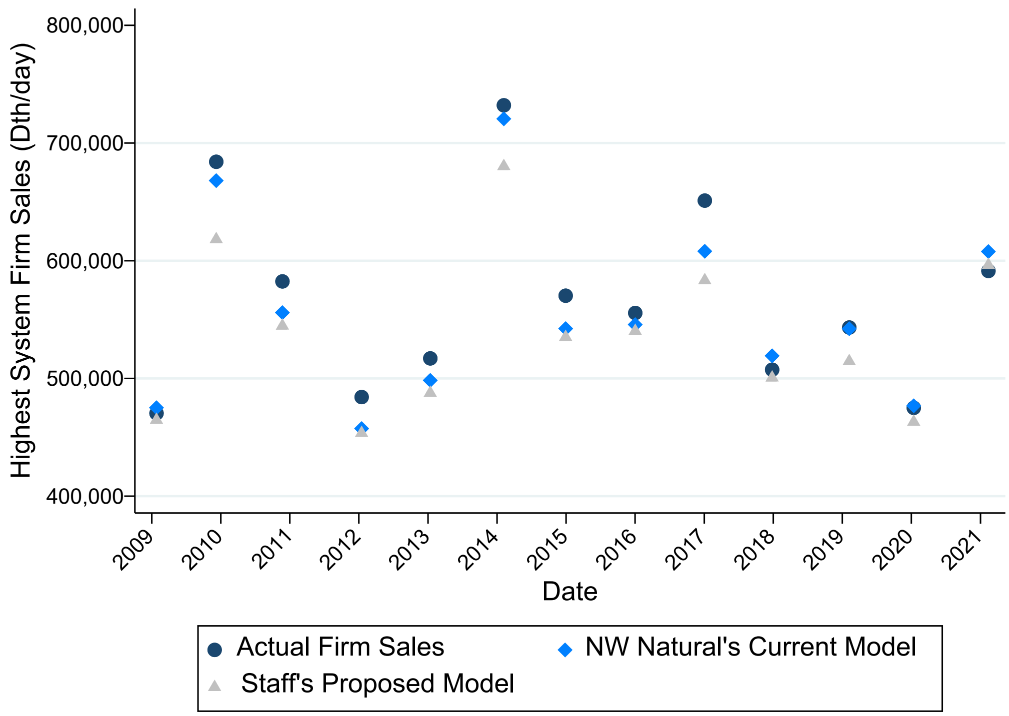
Staff comments:

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. [90]

It is reasonable for Staff to ask for the traditional metrics, such the adjusted R^2 and AIC, that are commonly used to measure a "goodness-of-fit" when comparing across different model specifications. However, these two metrics measure the in-sample fit of the model over the data that is being used. This model is being used to project peak day levels of firm sales demand for a 1-in-a-100-year event. Weather conditions for a 1-in-a-100-year event, understandably, have not occurred since 2009 (i.e., the time frame of our data).[91] Using our weather distribution metrics, the last time we saw an event on this scale for the whole service territory was in February of 1989, although localized extreme weather has occurred much more recently, for example, in Eugene, in December of 2013. The level of demand that the Company is trying to predict is out-of-sample. For this purpose, the Company uses a different metric for evaluating model specification that focuses on how well the model predicts the highest load actuals over time.[92] Figure 14, shows the high firm sales demand for each year in the data.

[90] Staff Comments at 84.
[91] 2009 is the earliest that our daily-system-level data is available, but we have detailed hourly weather data back to 1985, and daily temperature data back to the early 1900s.
[92] Note this metric was described in the 2018 IRP as looking at how well the model predicts the coldest days in the data set, but has been further refined to look at the highest loads over time.

Figure 14: Annual Firm Sales Demand



From this graph, NW Natural's model produces a better prediction for the highest firm sales load 11 of the 13 years in the data. For more robust metrics, the Company looks at the 3 highest firm sales load days for each of the years and focuses on the overall accuracy (mean absolute percentage error (MAPE)) and the overall bias (mean percentage error (MPE)) of the model on these days.

	MAPE	**MPE**
Natural's Current Model	2.75%	-0.83%
Staff's Proposed Model	4.70%	-3.81%

While both models are under-forecasting actual values (shown by negative MPE), NW Natural's current model has an average bias within 1% at the coldest temperatures. This is primarily attributed to the interaction terms contained within the model. We focus on this bias as under forecasting system requirements during peak conditions can have serious consequences.

For the reasons discussed in this response, the adjusted-R^2 and AIC metrics are not appropriate model testing metrics for a daily system load model that is used to estimate an out-of-sample peak day. However, to be responsive to Staff's request, NW Natural provides the adjusted-R^2 and AIC metrics for both models. For context, adjusted R^2 will usually range between 0 and 1, but a higher number usually indicates a better in-sample model fit. The AIC metric can be any value, but a lower number indicates a better in-sample model fit.

	Adjusted R^2	AIC
NW Natural's Current Model	.9766	41,431
Staff's Proposed Model	.9708	41,840

Staff also states:

> *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.*[93]

The characterization that peak is approximately twice as large as recent history is mostly incorrect. Staff comments reference the following data (Staff comments footnote 144) for justification of this claim.

Table 12: Historical Peak Day as Percentage of Current Peak Day

	Historical Peak Day (Dth/day)	Percentage of Current Peak Day
2009-10	692,640	69%
2010-11	586,421	58%
2011-12	490,402	49%
2012-13	527,980	53%
2013-14	741,816	74%
2014-15	576,846	57%
2015-16	569,155	57%
2016-17	661,712	66%
2017-18	515,795	51%
2018-19	557,265	55%
2019-20	483,442	48%

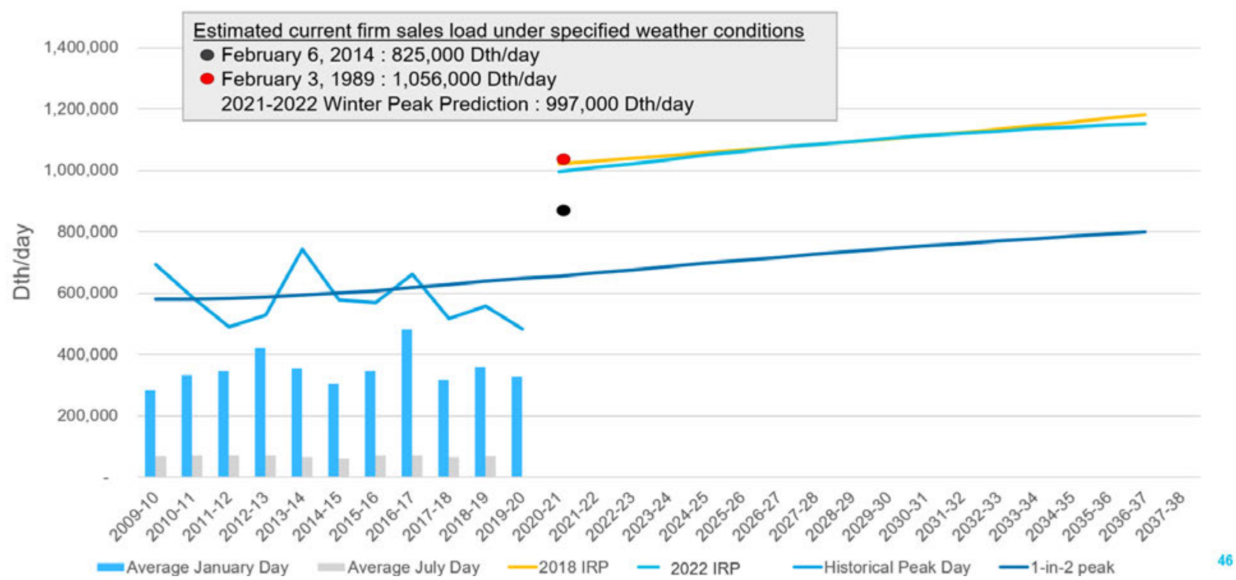
Staff is partially correct that in some years our service territory does not experience a very cold event and our peak firm sales for that gas-year does not reach 50% of our peak day requirements. This is not a surprising result as we are planning resources to meet a 1-in-100-year peak winter weather event. The

[93] Staff Comments at 84.

highest daily firm sales seen here occurred on February 6th, 2014 (see highlighted row). Since this date, NW Natural has added nearly 80,000 customers to the system through the year 2020.[94]

In the same comment, Staff also uses the following figure from NW Natural's second Technical Working Group for their justification (Staff comments footnote 145).

Figure 15: Peak Day Firm Sales Forecast (presented in TWG 2)



The black dot shows what our firm sales load would be with those additional 80,000 customers if we were to experience the same weather as we did on February 6th, 2014. For context, the temperature for that day was about 21°F, with 12 mph wind speeds. The red dot shows what our firm sales load would be if we experienced the weather from February 3rd, 1989 (roughly 11°F and 22 mph wind speed).[95] The red dot being a little above our peak day forecast suggests that the weather from 1989 was about representative of a 1-in-100-year event. As discussed in the 2018 IRP, a 1-in-100-year event has a probability of occurrence in each year, and hence, it is possible to experience more than one such event over the course of 100 years. Stated in another manner, experiencing a 1-in-100-year event 33 years ago does not exclude the possibility that this weather could occur in the next 67 years.

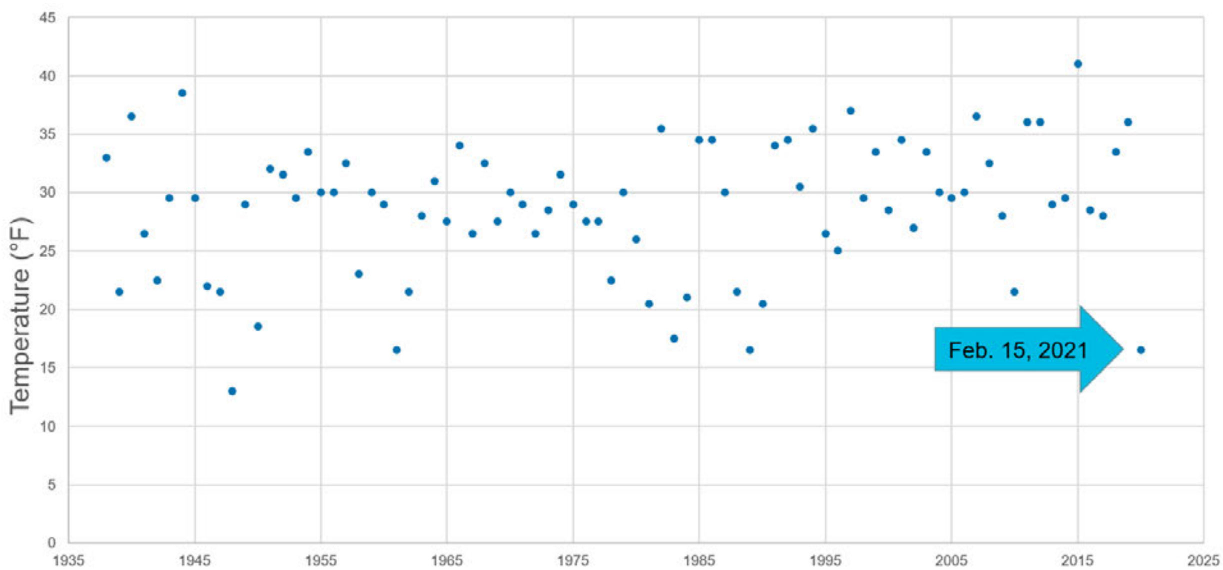
Staff's comments further may cause stakeholders to infer that NW Natural is not adequately incorporating climate change into its peak day forecast. NW Natural fully recognizes that climate change is occurring, it needs to be addressed through decarbonization of the economy, and NW Natural has a critical role to play in an equitable decarbonization path forward. As discussed in the 2018 IRP update #3 and the 2022 IRP, NW Natural uses climate models from the Intergovernmental Panel on Climate

[94] NW Natural has added roughly 100,000 customers through 2022, but the 2020 is referenced to align with the data that is presented, and the graph referenced by Staff.

[95] The daily system load model includes many more drivers, but temperature and windspeed are two of the primary drivers and are pointed out here.

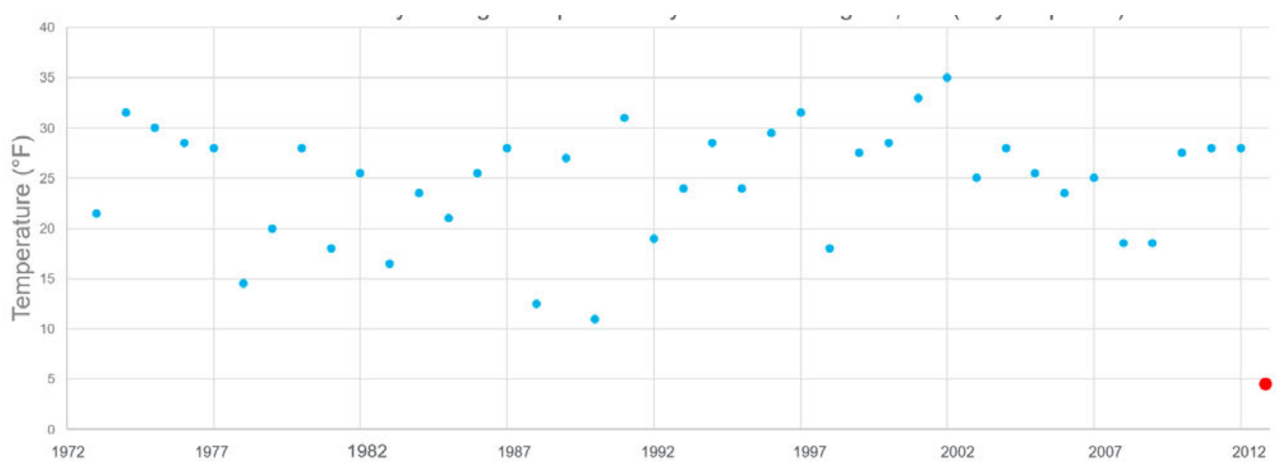
Change (IPCC) to adapt the weather forecast used for load forecasting. The overall HDDs are declining over time as average temperatures rise, which impacts NW Natural's overall heating load. While the IPCC models provide trends for rising annual average temperatures, the experts are unclear as to what climate change means for extreme weather, including very cold events, often referred to as polar vortexes. The slide right before the slide referenced by Staff's comments footnote 145, shows the coldest day in each gas year for Austin, TX to demonstrate how these polar vortexes could occur in the United States. Austin, TX had not seen a day as cold since 1989 (32 years prior). Prior to the day in 1989 temperatures had not been colder since 1949 (40 years prior). While the cold weather in 2021 in TX exposed numerous issues with resource planning in the area, the region had seen similar temperatures in its history.

Figure 16: Coldest Daily Temperature by Gas Year: Austin, TX (presented in TWG



In the same Technical Working Group, we examined a similar look for an area within our own service territory, the Eugene load center.

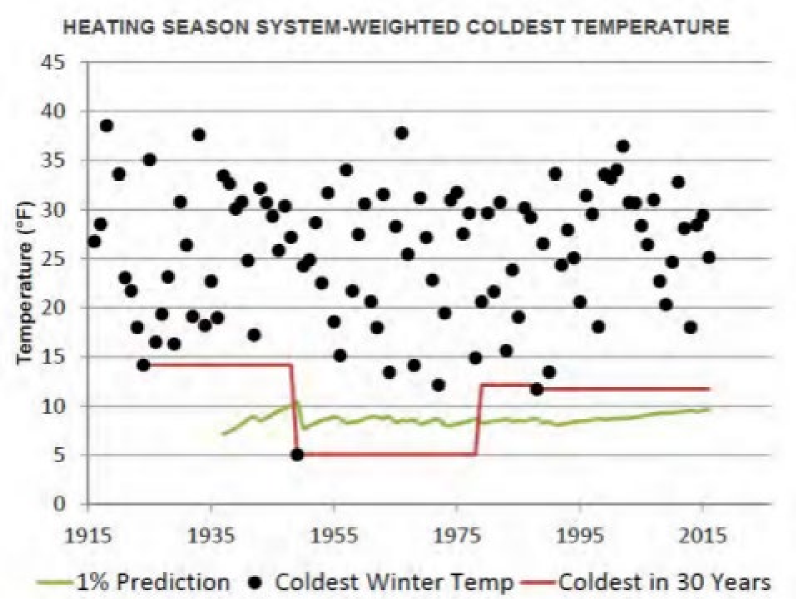
Figure 17: Coldest Daily Average Temperature by Gas Year: Eugene, OR (presented in TWG 2)



As recent as 2013, Eugene experienced a daily average temperature of roughly 5°F (shown by the red dot). Temperatures this low had not been seen since 1972 (41 years prior). Prior to 1972 temperatures that low had not been experienced since 1919 (53 years prior).[96]

Staff references and presents Figure 3.36 from the Company's 2018 IRP in their comments.

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



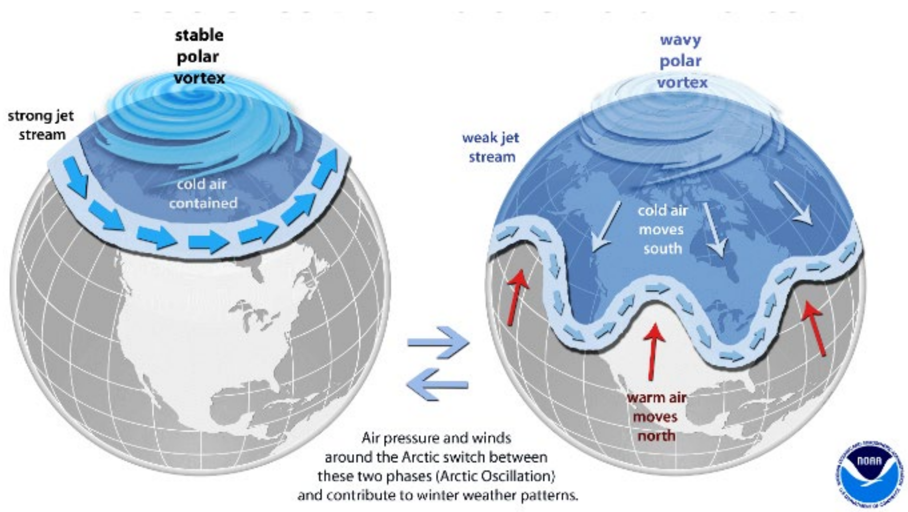
[96] The data presented is the average of the daily min and the daily max for each day in history and is sourced from the National Oceanic and Atmospheric Administration (NOAA).

This figure uses a NW Natural system weighted temperature for our service territory and displays the coldest day in each winter, same as the data shown for Austin, TX and Eugene, OR data in this response. Staff mis-interprets this graph and incorrectly states that this figure "indicates fewer cold days" over the last 30 years.[97] These graphs show data points for a single day in each year, which does not reflect the frequency of cold days within a year. It is more accurate to state that Figure 3.36 from the Company's 2018 IRP indicates that NW Natural's service territory, *as a whole*, has not experienced an extremely cold event (about 11°F) over the last 33 years, since February 3, 1989.

NW Natural stands by using all the historical data available on extreme temperatures when planning system resources. As shown by two examples from Eugene, OR and Austin, TX, limiting the scope to 30 years (i.e., 30 data points) does not provide sufficient data for understanding what weather conditions are possible, even if they are infrequent. These extremely cold events happen few and far between, but it would be inappropriate and imprudent to plan our resources as if they never occur.

Figure 18: The Science Behind the Polar Vortex

The Science Behind the Polar Vortex[98]



NW Natural is not claiming to be experts in climate change science, but the research and reports that we have examined from experts have not been definitive about how climate change is impacting the likelihood and severity of polar vortex events. Although the 2013 event in Eugene was highly localized to the Southern Willamette Valley, recent events such as Texas in 2021 and the cold snap that occurred early this winter across most of the U.S. (Figure 19), show that entire regions can be affected. If Staff is

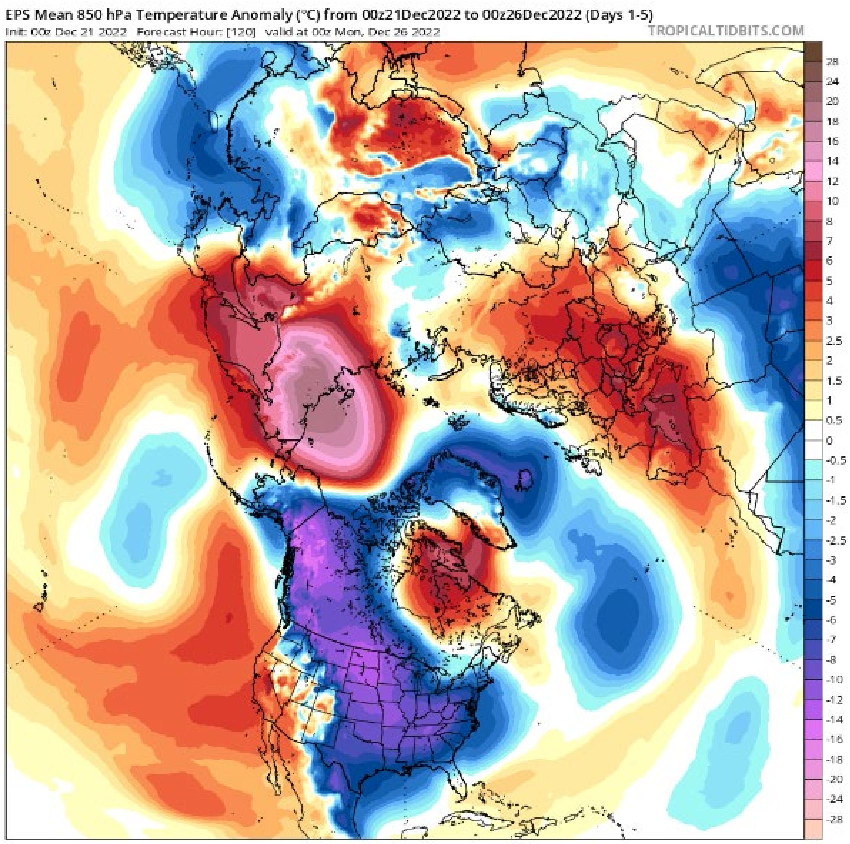
[97] NW Natural recognizes that climate is causing warmer average temperatures and is using the climate change modeling to factor in warming temperatures throughout the year.

[98] Environmental and Energy Study Institute https://www.eesi.org/briefings/view/041322climatechange#:~:text=Changes%20in%20temperature%20differences%20can,severity%20of%20polar%20vortex%20events.

aware of any reports or expertise that suggest that polar vortexes are becoming less severe or less frequent, NW Natural would appreciate knowing about that those studies to improve our forecasting methods.

Fiaure 19: The Science Behind the Polar Vortex

Regional Effect of Polar Vortex[99]



OPUC Staff 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.

As explained in the Company's response to LC 79 OPUC DR 30, a higher usage per customer (UPC) forecast for new construction commercial customers relative to existing commercial customers is due to the difference in actual usage per customer between these two customer segments:

> *Page 90 of the 2022 IRP (or page 84 of the errata filing of the 2022 IRP) states that "commercial average annual use per customer for the reference case increases over the planning horizon.*

[99] https://www.severe-weather.eu/global-weather/winter-season-2022-2023-polar-vortex-power-up-stratospheric-warming-wave-forecast-united-states-europe-fa/

This increase in the reference case commercial UPC is reflective of the new construction commercial customers on average using more gas than existing customers." The reason this is occurring is a mix of the factors described in the response to LC 79 OPUC DR 29, and is driven primarily by changes in broader trends in new construction (building type, size, etc.)

We see evidence of this trend in the regression modeling using billing data for existing commercial customers and new construction commercial customers, as seen in Appendix Table B.5 UPC coefficients. Portland commercial existing compared to Oregon commercial new construction is highlighted below as an example. Note that new construction is any new construction since 2018 as discussed in Table 3.6: UPC Regression Data Details.

To provide further evidence regarding the difference in actual usage per customer for the two customer groups, the Company has summarized the first full year usage of new construction commercial customers that are added to the system by year from 2010 to 2020 and the usage of existing commercial customers in the corresponding years below:

Table 13: Use Per Commercial Customer by Market Segment (therms)

New Customer in	Actual			Weather Normalized		HDDs (Base = 58 F Degrees)
	Year	New Construction	Existing	New Construction	Existing	
2010	2011	5,242	4,170	4,667	3,713	2,939
2011	2012	4,379	3,915	4,279	3,826	2,545
2012	2013	4,037	4,019	3,712	3,696	2,793
2013	2014	5,512	3,829	5,660	3,932	2,363
2014	2015	4,275	3,401	4,895	3,894	2,021
2015	2016	5,001	3,506	5,709	4,002	2,029
2016	2017	8,239	4,257	7,296	3,770	2,965
2017	2018	5,513	3,842	5,959	4,152	2,193
2018	2019	5,824	4,191	5,622	4,046	2,592
2019	2020	4,997	3,623	5,239	3,799	2,292
2020	2021	NA	NA	NA	NA	2,269

UPC data for new customers in 2020 are not included in the table because customer billing data used in the UPC model estimation for the 2022 IRP ends in April 2021, and therefore no complete following-year usage data are available for the new customers added in 2020. It can be seen in the table above that new construction commercial customers have a remarkably higher UPC than their existing counterparts consistently over the past 10 years without exception. The Company has also reviewed its responses to Staff's data requests and did not find the Company once stated that "the issue is also possibly due to new customers coming online in older buildings than in the past". The Company agrees with Staff that such attribution does not make sense for new construction commercial customers because, as suggested by the name, no new construction commercial customers would come online from old buildings.

While the reason why new construction commercial customers have a higher UPC than existing commercial customers is beyond the scope of the 2022 IRP, the causes of the increase in UPC that the Company mentioned in the prior responses to Staff's data requests are supported by various recent survey reports on commercial buildings. For example, the 2018 Commercial Buildings Energy Consumption Survey conducted by the U.S. Energy Information Agency (EIA), published in 2022, shows that at the national level, newer buildings have been consistently getting larger and larger, on average, than older commercial buildings over time, and the types of newer commercial buildings are more likely to be health care, lodging, and public order and safety buildings.[100] At the northwestern regional level, a similar increasing trend in building size for the new construction commercial buildings is reported in the Commercial Building Stock Assessment (CBSA) 4 (2019) Final Report prepared for NEEA by the Cadmus Group in 2020.[101] The 2019 CBSA report also finds a natural gas energy use intensity (EUI) of 0.36 therms per square foot for the Northwest commercial buildings, slightly higher than the 2014 study EUI of 0.35 therms per square foot (consumption histories for long-term (30-year) weather conditions were adjusted to calculate weather-normalized EUIs). The study attributes this overall average increase from 2014 largely to substantially higher natural gas EUIs for hospitals and restaurants. Therefore, a higher UPC for new construction commercial buildings as evidenced in the actual billing data and modeled in the 2022 IRP is well in alignment with the findings in the latest commercial building survey studies.

OPUC Staff 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. *footnote 152*

The IHS Markit that provides the gas price forecasts is now owned by S&P Global[102], who employs over 30,000 people and currently has a market capital over 120 billion dollars. The limited subscription for a North American Natural Gas Outlook that NW Natural receives through IHS Markit is coming from a large, industry-trusted, operation and organization. Gas price forecasting for various locations in North America is one small aspect amongst the variety of forecasting, reports, and services which S&P Global provides to varying levels of subscriptions to a broad customer base. The S&P Global business model depends on their reputation as credible source of information that is developed from analytics and

[100] See web link: https://www.eia.gov/consumption/commercial/data/2018/pdf/CBECS_2018_Building_Characteristics_Flipbook.pdf

[101] See web link: https://neea.org/resources/cbsa-4-2019-final-report.

[102] See merger announcement: https://www.spglobal.com/en/merger/?utm_campaign=e_All_Day1_CustomerAnnouncement&utm_medium=email&utm_source=Eloqua

expert insight across many dimensions of the economy, including state and local policies, electrification, and RNG production.

Gas prices are a critical piece needed for resource evaluation and NW Natural has relied on IHS forecasts for over a decade. NW Natural believes using IHS's robust modeling and independent expertise is in the best interests of customers. Here are some key insights from the August 2022 North American Natural Gas Long-Term Outlook. The full report is included as an attachment, Confidential Attachment 1.

Begin confidential:

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

End confidential

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).

NW Natural has recently requested quotes from S&P Global to conduct “what if” scenarios regarding potential upstream regional pipeline expansions in Canada to understand the price impacts to the Canadian hubs. While we ultimately determined it was premature to conduct this study, S&P Global gave us a high-level quote of **Begin confidential:** [redacted] **End confidential** to produce unique “what if” scenarios. Analyzing the impact from changes in several interconnected markets for RNG and the increased load on electric grid from electrification is more complex than analyzing a few pipeline expansions and would likely be higher in cost.

Working with S&P Global to construct a metric(s) for a growing share of RNG in the system and/or aggressive electrification is possible, but it would be incremental to what their current expectations are for those two impacts. In a vacuum[103], the combination of more gas supply from RNG and less demand from direct use natural gas would cause gas prices to fall. On the other hand, demand for RNG is also growing, putting upward pressure on gas prices. The combination of all of this is very complex and NW Natural, and Oregon as whole, is a small player in a continent-wide, and arguably global market, for natural gas. Where the incremental RNG in country is being produce will impact gas prices. It also matters where, when, and what type of aggressive electrification is occurring. Electrification could result in an increase in natural gas demand that is needed for incremental electricity generation. These assumptions beyond S&P Global current assumptions for the whole west would need to be considered and provided to S&P Global to conduct a “what if” scenario.

While it could be interesting and informative to understand how incremental RNG flow and incremental electrification beyond the S&P Global expectations could impact natural gas prices in the region, it would not provide any additional value for what it means for NW Natural’s resource planning. NW Natural’s IRP looked across a wide range of possible gas prices through our Monte Carlo simulation results. Using those results we already understand what it means for planning resources under an extremely high gas price future or an extremely low gas price future. Because it would not provide value for NW Natural’s IRP, we do not recommend NW Natural pursuing such a study by itself. If this is of continued interest by the commission, it could be appropriate to discuss such a study with all Oregon utilities who could provide insight to the study, be provided access to the results and benefit from the information.

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[103] Economists use a term as ceteris paribus, meaning “all else equal”.

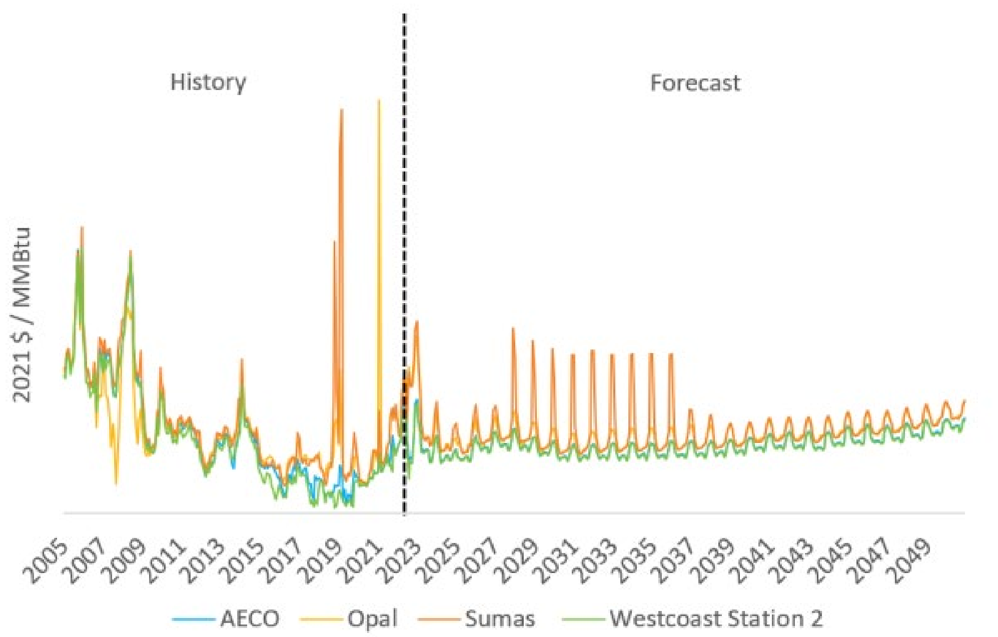
OPUC Staff Request 45: Staff requests NW Natural explain in its Reply Comments how price events at Sumas or the price variations across hubs in general may affect avoided cost calculations for energy efficiency, RNG resources, and distribution system investments. The explanation should provide additional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

NW Natural's avoided costs already account for volatile prices seen at Sumas and Opal through two components of avoided cost; 1) the natural gas purchase and shipping costs and 2) the commodity price risk reduction value (referred to as the hedge value in the past). The first component is based on the marginal price of gas as described in Chapter 4, Section 4.2.2:

> *On any given day in the forecast period the avoided gas and transport costs represent the cost of the last unit of gas sold during that particular day,[73] where that unit may be from an expected daily spot purchase or a storage withdrawal depending on the load that needs to be served and gas prices on that day. This daily figure comes from the resource planning optimization model and is aggregated to the monthly level.*

IRP Figure 2.10 shows how S&P Global forecasts higher prices at Sumas and Opal during winter months.

IRP Figure 2.10: Historical Natural Gas Prices and Forecasts by Trading Hub



This graph shows that the expected higher winter prices are nowhere near as big as the large price spikes seen in recent history. Even though we do not expect to see these extreme price spikes every winter, accounting for the volatility of gas prices is the purpose of the second component mentioned, the commodity price risk reduction value. This component of avoided costs relies on the marginal cost of gas from the stochastic simulations to measure price risk.[104]

Staff comments state:

> *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.*[105]

Staff's comments might be based on a misunderstanding of how the avoided costs are developed. Staff's concerns would be warranted if we were simply taking a weighted average across gas hubs, however; this is not our methodology. Both components of avoided costs, commodity prices and risk reduction value, presented in Appendix C of the IRP use post optimization marginal costs (i.e., output from PLEXOS®). The marginal cost is equal to the cost of the most expensive unit of gas purchased and delivered to NW Natural's system on any given day. In other words, the cost minimization algorithm, which has perfect foresight will avoid purchasing high Sumas prices, whenever it is cost minimizing while still serving demand. This modelling best reflects how NW Natural aims to conduct business when buying gas each day.

The next logical argument would be that avoided costs are under-valued as the computer model has perfect foresight and our gas purchasers do not. This could lead to a difference in what is modeled verse what is conducted operationally. However, this is another reason why we include the risk reduction value component for avoided costs, hence the reason why it has historically been referred to the hedge value. Essentially, we can address some uncertainty in gas prices through hedging practices.

2.2 AWEC Action Item Proposals

NW Natural appreciated AWEC's focus on the Action Plan in of its review. AWEC recommends a number of changes to the Action Plan that the Company will respond to here:

AWEC Request 1: Action Item 6 Modification: NW Natural will independently procure discrete transportation energy efficiency projects at a fixed rate equal to $14.00/dth, while continuing to develop a transportation energy efficiency program in collaboration with the ETO, AWEC, Staff and other interested parties.

NW Natural believes that transportation energy efficiency should follow the same cost-effectiveness calculations as other EE so as to maintain an applies-to-apples comparison. The same avoided costs should be used for transportation energy efficiency as other energy efficiency from a methodology perspective (noting that avoided costs differ by end use). While the 30-year levelized costs for process loads (presumed to be the majority of transport load) is close to $14 there (being around $13) avoided costs change through time and a year-by-year assessment like other EE programs is not, in NW Natural's mind, unduly burdensome. As such, while NW Natural will continue to work with stakeholders to

[104] The methodology is explained in Chapter 4, Section 4.2.4.
[105] Staff Comments at 87.

develop transportation EE programs it cannot support changing Action Item 6 based upon AWEC's recommended modification.

Additionally, AWEC's assertion in its comments that NW Natural's compliance plan in the 2022 IRP does not include assumed savings from transport customer energy efficiency is incorrect. It is also important to note the Action Item 6 is not proposing a CPA but program development, which seems to be a source of confusion based upon AWEC's comments.

AWEC Request 2: Action Item 7 Modification: NW Natural will procure the maximum amount of CCIs for CPP compliance in each compliance year and will include CCIs as a compliance alternative in PLEXOS in future IRPs.

NW Natural does not accept this modification. See Section 1.3.

AWEC Request 3: Proposed Action Item: NW Natural will develop a method to attribute carbon savings resulting from the CPP to transportation customers since the CPP compliance instruments are obtained on transportation customers' behalf.

NW Natural is willing to work with AWEC to better understand this request, though is not willing to add this proposed Action Item to Action Plan at this time given that it appears AWEC is asking NW Natural to take action that would actually need to be taken by the Oregon Department of Environmental Quality (ODEQ) based upon a reading of the ODEQ's Climate Protection Program rules.

AWEC Request 4: Proposed Action Item: NW Natural will study the impact of weather variable loads and load variability on CPP compliance for each rate class in the next IRP.

This work was done in detail in the 2022 IRP and is a lynchpin of the strategy for compliance with the CPP. NW Natural is willing to meet with AWEC and any other interested stakeholders to explain how this impact can be isolated from the Monte Carlo analysis. Given that this was done in the 2022 IRP and will be done on an ongoing basis going forward NW Natural does not see the need to add the proposed Action Item to the Action Plan.

AWEC Request 5: Proposed Action Item: NW Natural will study the value of interruptible throughput in the next IRP.

NW Natural studies the value of interruptible customers in each IRP. The discount interruptible customers receive for volunteering to be interruptible customers is based upon the value they provide to all customers. NW Natural's sizeable demand response programs via interruptible rate schedules is a benefit to all customers, and presumably to interruptible customers themselves, or they would not voluntarily select to be interruptible schedules.

Appendix A: OPUC LC 79 DR 69

Rates & Regulatory Affairs
LC 79
Integrated Resource Planning
Data Request Response

Request No.: LC 79 OPUC DR 69

69. Re: Appendix A, Guideline 8a, "NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis to inform its action plan until the next IRP. Within the scenarios analyzed, NW Natural believes Scenario 1- Balanced Decarbonization reflects the most likely near-term regulatory compliance future."

a. State succinctly the underlying rationale for NWN's belief that Scenario 1 represents the "most likely near-term regulatory compliance future."

b. Confirm or explain otherwise that "near-term regulatory compliance future" represents the Action Plan period, and extends no further than 2026 at this time.

c. Does NWN's IRP have a NWN Preferred Resource Portfolio covering the period through 2050?

d. If NWN's IRP does have a Preferred Resource Portfolio, confirm or explain otherwise that Scenario 1 is that Preferred Resource Portfolio.

e. Does Scenario 1 represent a least cost scenario across the 2022-2050 period when compared to the other possible scenarios? Provide the underlying quantitative evidence if this is the case, and any required explanation.

Response:

For context IRP Guideline 8(a) states that "the utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future…." In Appendix A, NW Natural is detailing how the IRP meets the IRP Guidelines. The IRP Guidelines were a key topic of discussion in Docket No. UM 2178, and from that process NW Natural anticipates it is possible or likely that the IRP Guidelines might be modified going forward. With that, the exact wording for Guideline 8, which appears to be contemplating potential future policy more than actual policy like the Climate Protection Program (CPP), seems somewhat inapt for the current environment.

We state in Chapter 1: “While NW Natural has conducted robust risk analysis for numerous IRPs, in past IRPs a single base case was developed, and the Action Plan was constructed primarily using the results from this base case. Given the high degree of uncertainty and the transformative new policies which we are implementing[,] the Action Plan and preferred portfolio in this IRP is based upon a risk-adjusted approach based upon the range of outcomes of our stochastic Monte Carlo simulations.”

We state in Chapter 2: “In addition to the Reference Case, the IRP conducts several ’what-if’ scenarios where a few key demand and supply inputs are explicitly modified in-contrast to the Reference Case. The results from these scenarios provide insights to the resource planning impacts, risks, and rate implications from changes specific input assumptions. [footnote omitted] Separate from the scenario work, the IRP process also employs stochastic simulations, which randomly varies numerous key inputs that have a high level of uncertainty over the planning horizon (such as gas prices). This stochastic process simulates 500 different potential futures for the resources optimization software to solve for the optimal resource portfolio for each of the 500 simulations. Unlike previous IRPs, this IRP does not define or select any single scenario or set of outcomes as a base case. Typically, a base case consists of a set of assumptions and outcomes, which given the knowledge at a moment in time, represent the Company’s best expectations of the future. With these transformative policies, the resources need, and the cost and availability of demand-side and supply-side resources required to meet those needs is very uncertain. Therefore, this IRP does not present a base case, but instead outlines a wide range of potential outcomes through scenario and simulation work. Using this work, we develop an action plan that is robust to the uncertain future. Per the above, with feedback from stakeholders NW Natural defined 9 scenarios to better understand the impact of changing key assumptions in the context of complying with transformation climate policies. The goal of scenario development is not to predict the future, and it is important not to vary too many variables when comparing one scenario to another, or the primary driver of differing results between scenarios may be hard to untangle. The specific assumptions of each of the scenarios is discussed in more detail throughout this IRP and the key inputs and results by scenario are detailed in Chapter 7.”

This process of developing a preferred portfolio and Action Plan from a robust risk analysis rather than selecting a single base case, which NW Natural maintains is most appropriate in the current environment, does not align perfectly with Guideline 8. For example, since the IRP analysis was completed the Inflation Reduction Act (IRA) was passed and NW Natural’s general rate case was finalized. Had NW Natural selected a base case in its 2022 IRP filing it would naturally lead to questions about whether the base case aligns with the IRA and the outcome of the rate case. However, given that NW Natural recognized the uncertainty in the current environment, both of these developments fit well within the analysis process that led to the Action Plan and do not require new analysis or a change to the Action Plan in the IRP.

a. Given the above discussion, NW Natural believes its Action Plan represents the best course of action in the current environment, though this approach does not fit nicely into wording about "most likely regulatory compliance future." We do not believe it makes sense to choose a Scenario to base the Action Plan upon, but if forced to choose one of the Scenarios analyzed, we believe Scenario 1 is the most appropriate Scenario to understand NW Natural's regulatory compliance obligations and path for regulatory compliance.
b. Yes, "near-term regulatory compliance future" represents the period covered by the Action Plan, or the 2023-2026 period.
c. Yes, the preferred portfolio is the average of the outcomes from the stochastic Monte Carlo risk analysis detailed throughout the IRP with the results being shown in Chapter 7, Section 6.
d. Scenario 1 is not the preferred portfolio, and neither is any of the other Scenarios analyzed, as described above.
e. See the context above for the reason NW Natural does not believe it makes sense to choose amongst Scenarios and this is not the purpose of Scenario analysis or development. This topic was a topic of discussion at numerous of the Company's Technical Working Group (TWG) stakeholder workshops held in advance of IRP filing, including the last TWG, where there was a robust discussion on this topic. The TWG was recorded and can be found on NW Natural's website, it is linked here, where the discussion starts at 13:30 of the video and goes to roughly the 1 hour mark of the presentation.
   Additionally, the response to LC 79 OPUC DR 1 discusses how it is not possible to determine the lowest cost path forward for Oregon utility customers from a single entity's IRP. With that context, the Action Plan, based upon the stochastic risk analysis represents the Company's preferred path forward in the current environment. Per Section 9.1 of the 2022 IRP: "The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment."

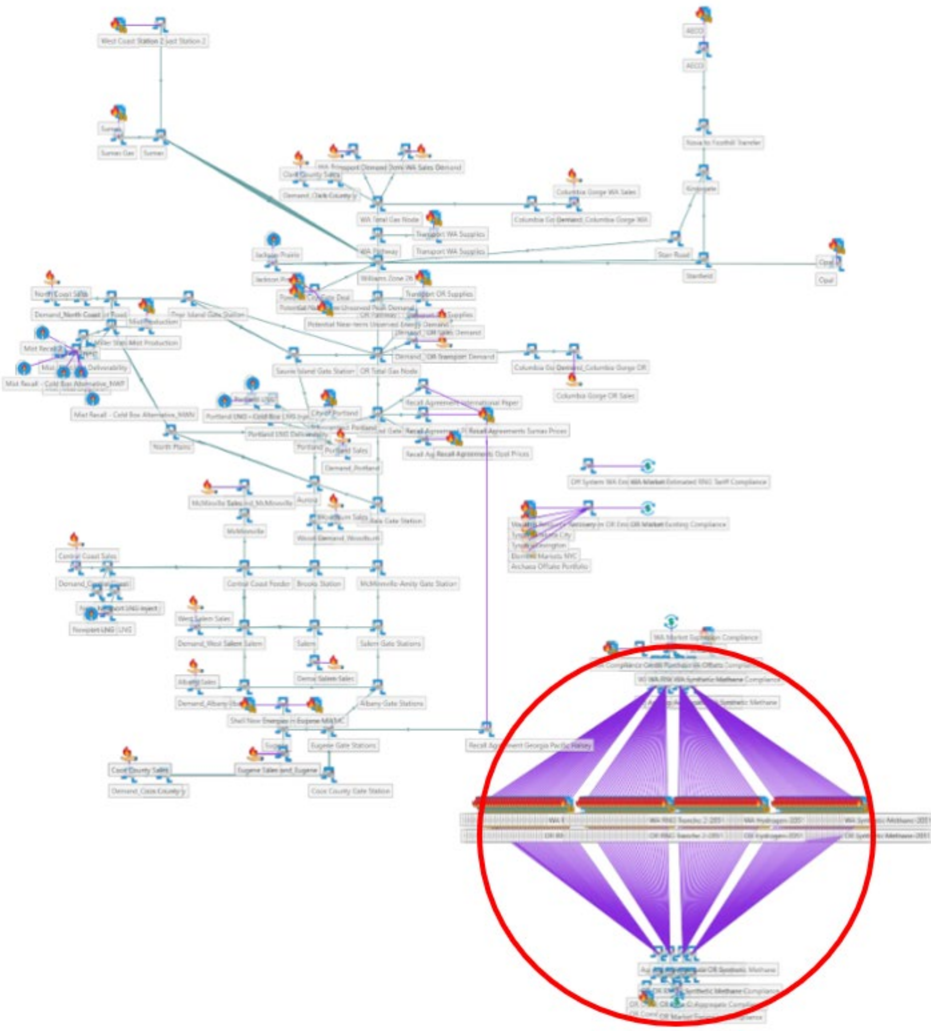
Appendix B: PLEXOS® Model Complexity for Unbundled Compliance Resources

Despite the major upgrade to PLEXOS® as NW Natural resource optimization software, we must be thoughtful about how we model complex realities within limitations of the software. The company knew that developing an optimization model to evaluate resources under a carbon constraint would be challenging. We held a pre-technical working group titled "Emissions Considerations for the 2022 IRP" to tee up some of the major hurdles we foresaw in developing the model. While no solutions were presented at this working group the Company teed up many of the challenges for implementing a new model that we knew we'd be facing. Among others, these issues include how to model bundled versus unbundled RTCs, the nature of modeling long-term contracts, and separation of compliance resources by state. These are the three elements that form the crux for modeling RNG Tranche 1, RNG Tranche 2, Hydrogen, and Synthetic methane as unbundled RTCs (i.e., the cost of a bundled RTC minus an average gas cost) as we have done.

As described in Chapter 6, Section 6.5.6 of the IRP, we model these resource options as long-term decisions that, once selected as a least-cost resource, remain throughout the rest of the planning horizon. Within the model, what this means is that any future decision is a function of any previous decisions, while all being optimized over the planning horizon. PLEXOS® has a property to model an annual baseload contract that selects the amount of gas to purchase each day for the whole year and we can restrict the model to when the model can make a new baseload decision. NW Natural had many discussions with Energy Exemplar (vendor of PLEXOS®) modeling experts who work with utilities across the country and this baseload object was discussed to be the best way to model long-term contract decisions for RNG Tranche 1, RNG Tranche 2, Hydrogen, and Synthetic methane made in each year and for each state.

This meant creating 224 baseload objects (4 resource types x 28 years x 2 states) plus additional other objects (e.g., nodes, connections, zero revenue off-take markets) each with their own set of properties (e.g., decision date). As a part of LC 79 OPUC DR 47, NW Natural provided a high resolution of the PLEXOS® topography shown in Figure 7.3 of the IRP. The purple diamond shaped figure (circled in red here), represents the structure for these 224 objects.

IRP Figure 7.3: 2022 IRP PLEXOS® Model Topography



This purple diamond structure is where the state specific compliance resources are purchased and applied to the carbon constraint. Aside from the carbon constraint, none of the purple diamond structure is connected to the rest of the model. Therefore, the gas does not flow to serve NW Natural demand (i.e., there are no blue lines connecting the purple diamond to demand nodes).[106]

NW Natural considered allowing RNG to flow gas to the demand node via a pipeline connection, but to do this appropriately for peak day capacity consideration, we would need to have it connect upstream of our pipeline capacity contracts. If connecting directly to the system, the model may select compliance resources for peak day capacity needs as if they were on-system resources (i.e., behind the gate

[106] The gas flows into a disconnected zero-revenue generating market. This is just as 'sink' for the gas to flow into.

station).[107] If the model took this approach, a location of injection would be needed, however; it would be flawed to select a single location (e.g., Opal) as then the gas flowing from the compliance resources would only avoid the price of the gas in that specific location. To model a bundled compliance resource appropriately, we would need to create four purple diamonds connected to each gas purchasing hub. This would increase the total number of base load objects created from 224 to 896. This quadrupling of objects goes beyond just the number of objects in the model diagram as data files and data inputs of various properties would need to be correspondingly quadrupled, connected appropriately, and tested for quality control. In this sense, the value of the current complexity here is the avoided cost of additional complexity and potential for human error in modeling.

Since filing the IRP, NW Natural attended a PLEXOS® user group conference in November 2022. Through discussion with some of the top expert modelers, we have identified functionality within PLEXOS® that builds a custom constraint across time periods that would allow for a single baseload object by type and state (i.e., no need by year as well). This will drastically reduce the number of objects in the topography; however, we would still not characterize including this functionality as less complexity. Despite this functionality, it still may be preferable to model compliance resources as unbundled products in future IRP models.

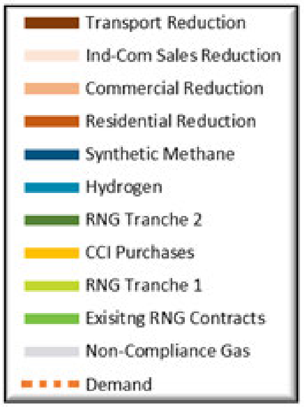
NW Natural strives to be as transparent as possible for stakeholders. Through this IRP we provided all the input data files to PLEXOS® and all the key outputs from the model to all stakeholders. Additionally, we have creating graphing tools and drop-down menus to summarize the data through workbooks provided to stakeholders and have held workshops and office hours to help support our stakeholders. While not an IRP requirement, these efforts underscore how NW Natural has tried to make this complex IRP as transparent as possible and is beyond anything done in previous IRPs. Energy system modeling is inherently complex, and we do our best to distill the key and important components into a manageable format for review.

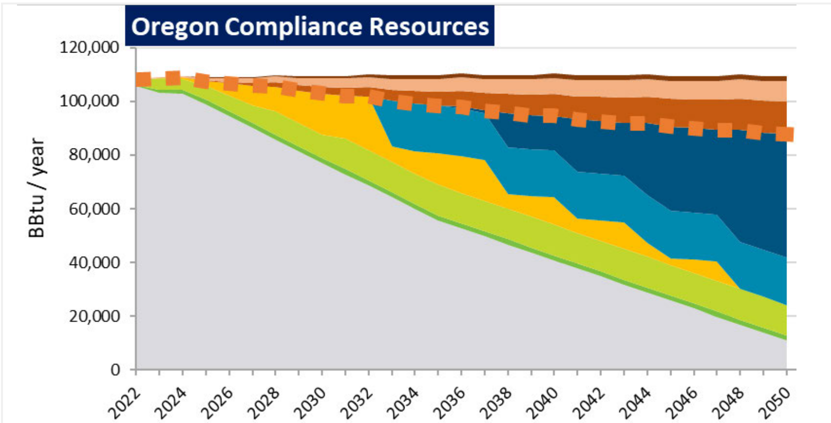
[107] NW Natural is interested in pursuing on on-system RNG opportunities if they are available and least-cost options. The incremental cost workbook applies the on-system benefits to this evaluation for specific projects. These on-system benefits are not applied to the purple diamond compliance resources in PLEXOS® as discussed in NW Natural's response to Staff Request 27 regarding transportation and capacity costs.

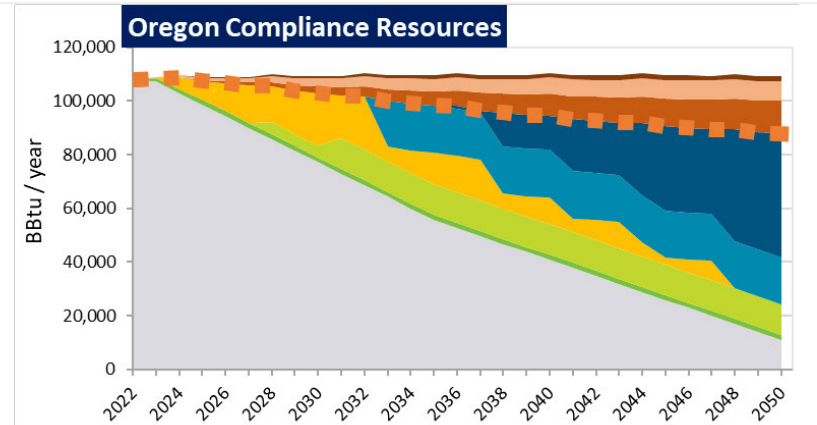
Appendix C: Scenario Comparisons With and Without SB 98 Compliance

Legend	With SB 98 Compliance	Without SB 98 Compliance

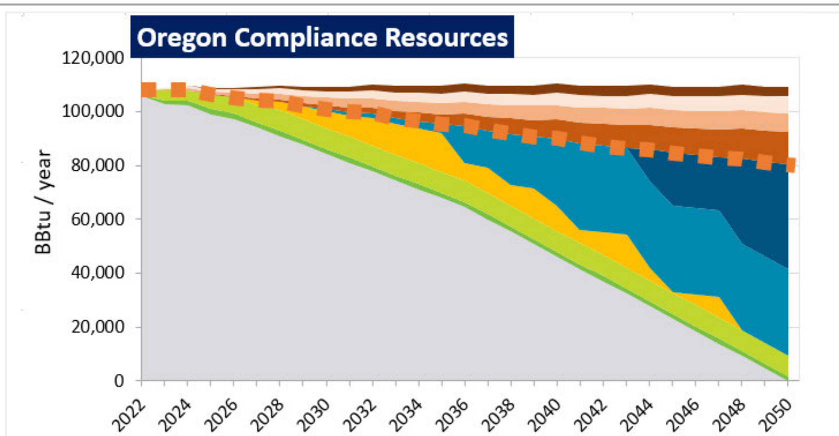
Scenario 1- Balanced Decarbonization

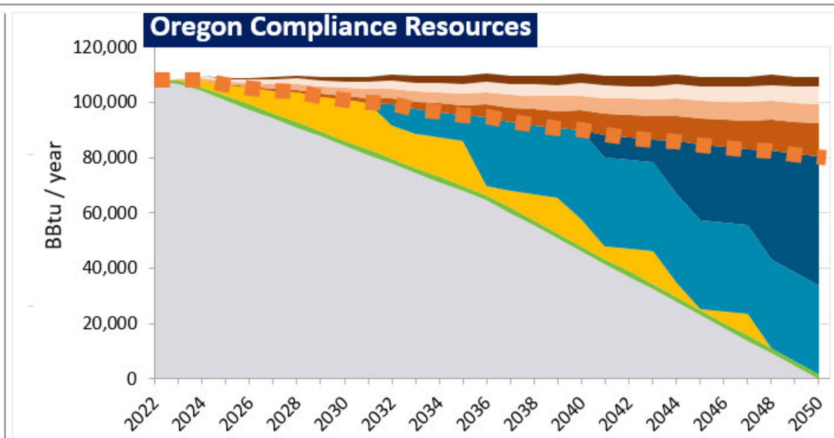






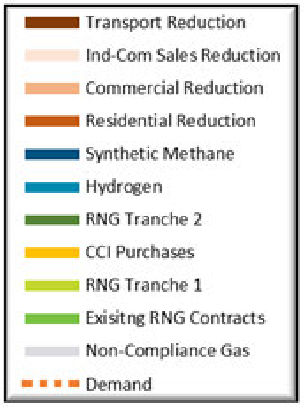
Scenario 2- Carbon Neutral

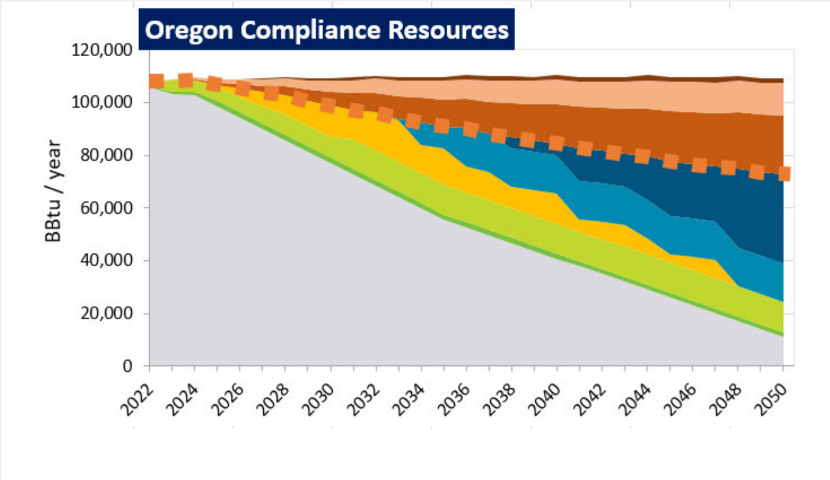


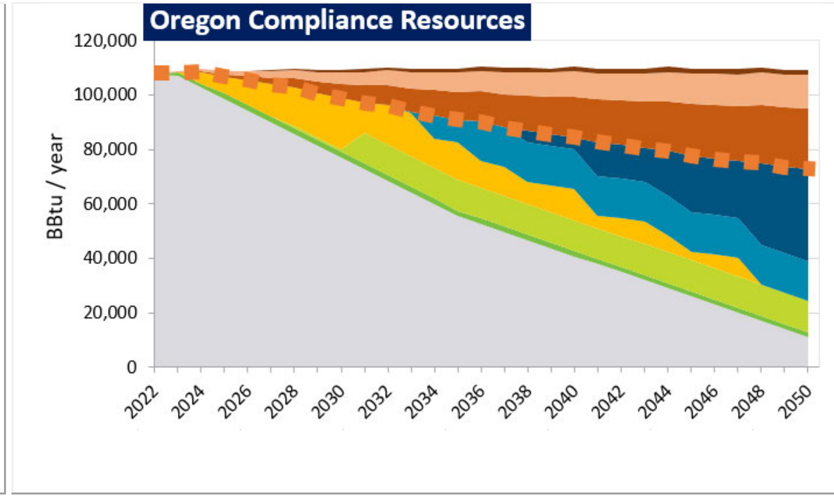


Legend	With SB 98 Compliance	Without SB 98 Compliance

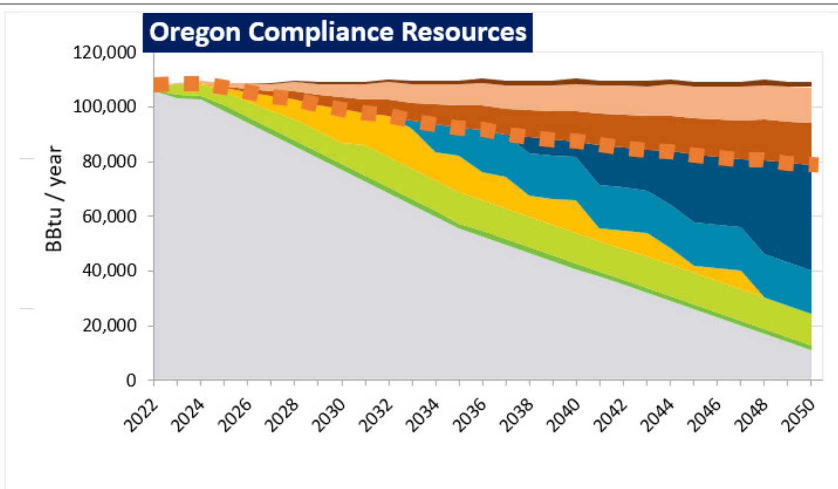
Scenario 3- Duel Fuel Heating

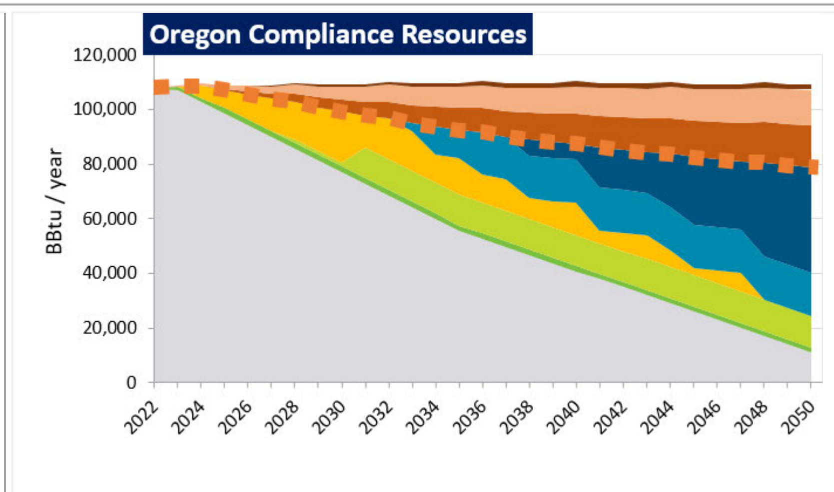






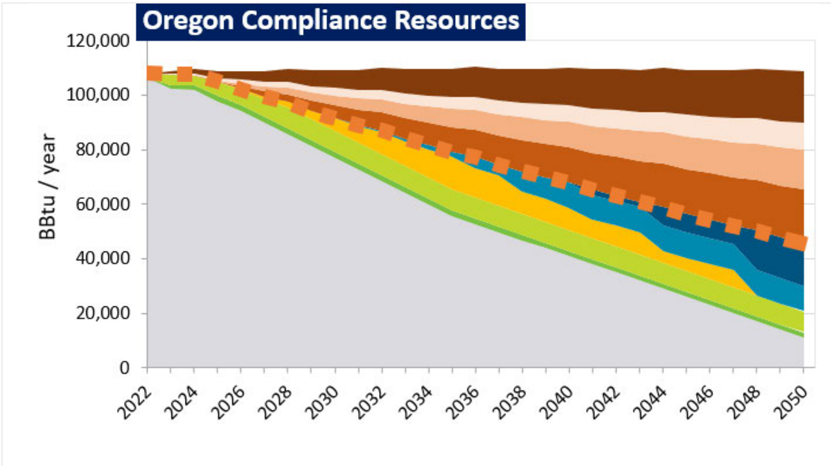
Scenario 4- New Gas Customer Moratorium

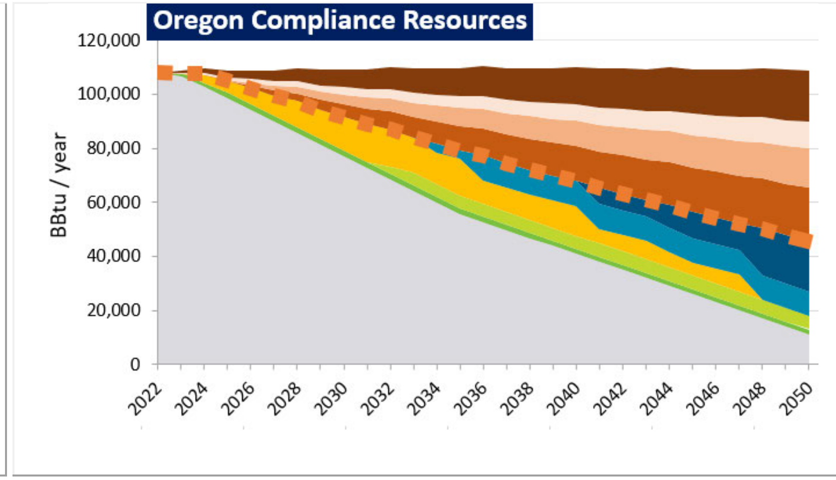




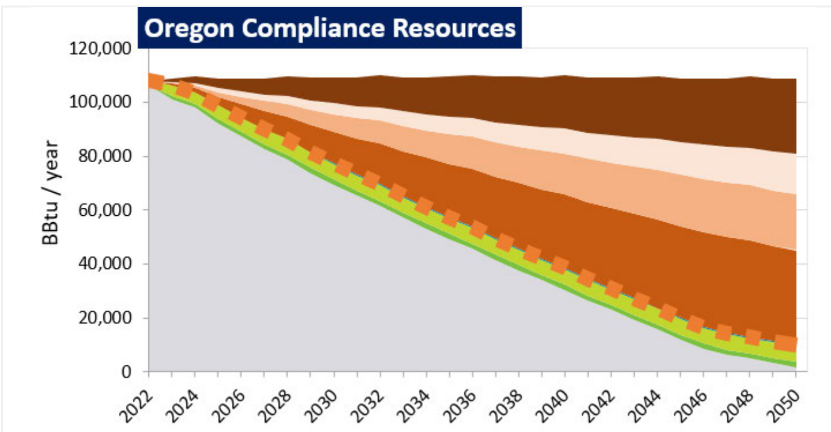
Legend	With SB 98 Compliance	Without SB 98 Compliance

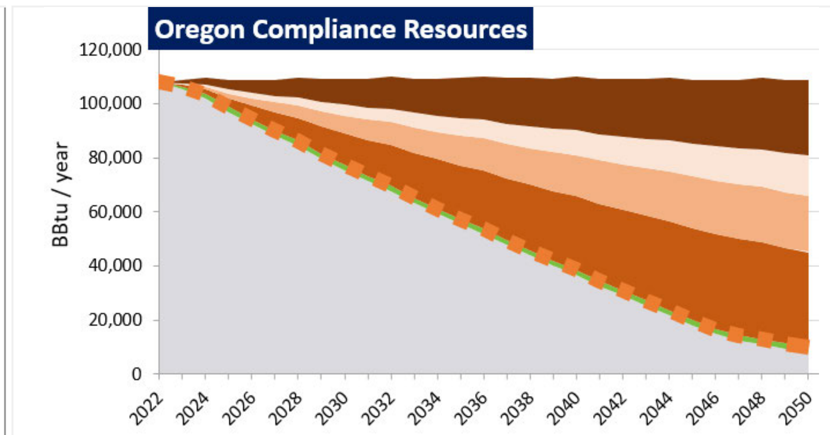
Scenario 5- Aggressive Building Electrification





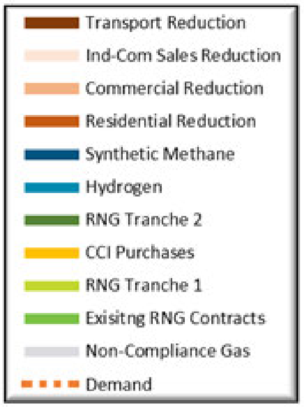
Scenario 6- Full Building Electrification

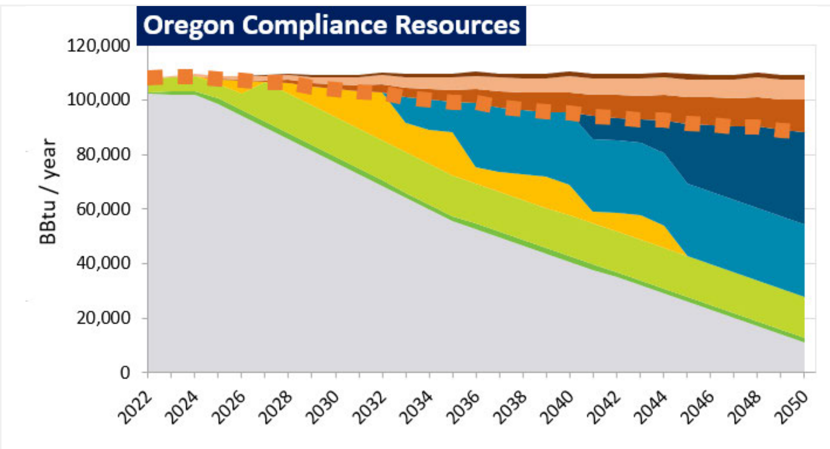


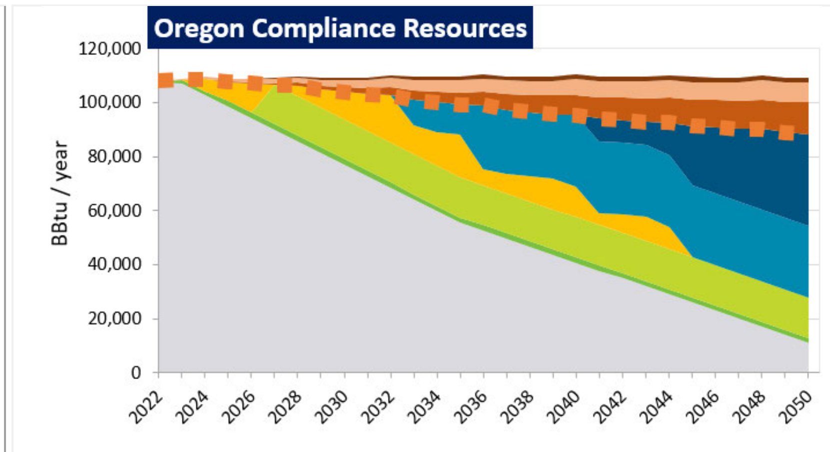


Legend	With SB 98 Compliance	Without SB 98 Compliance

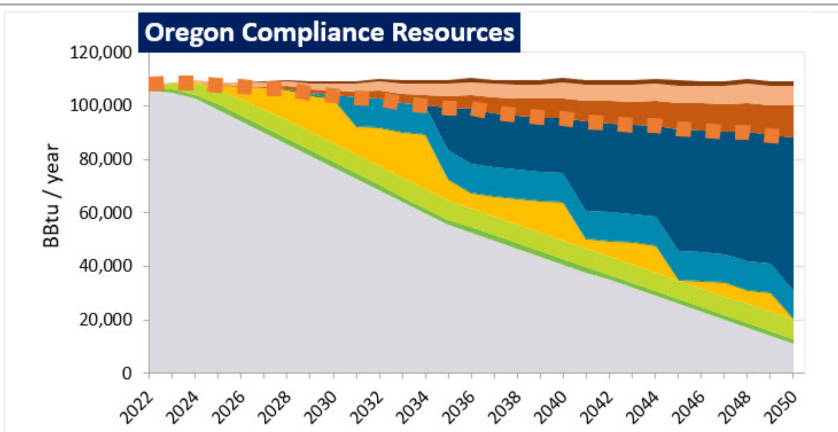
Scenario 7- RNG and H2 Policy Support

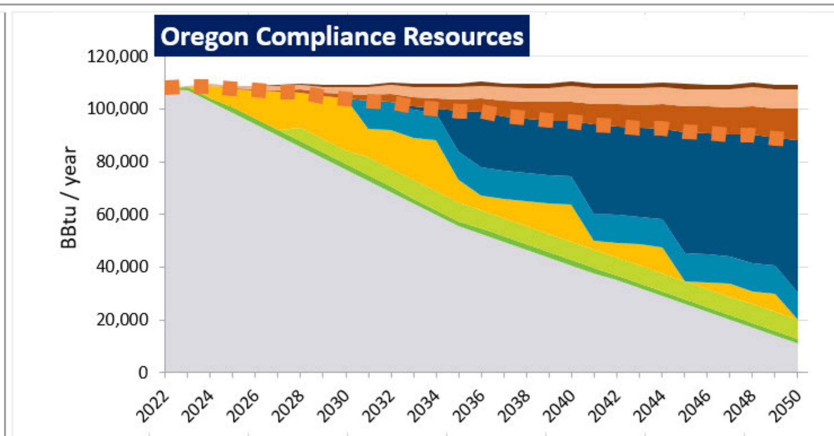






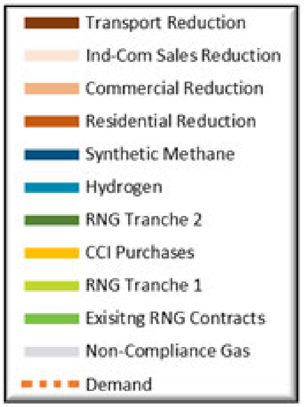
Scenario 8- Limited RNG

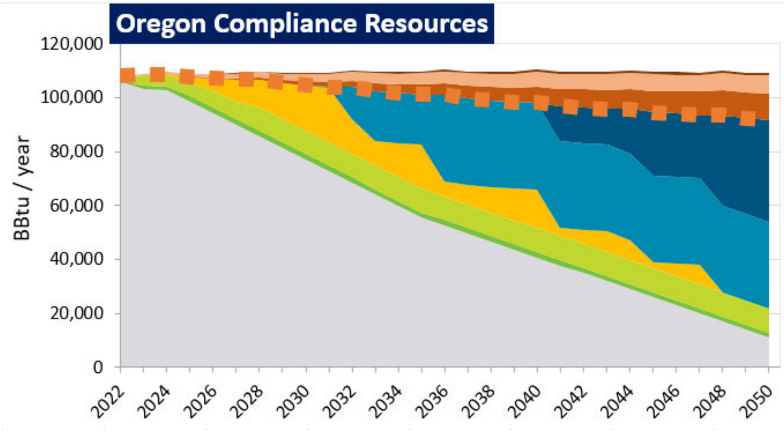


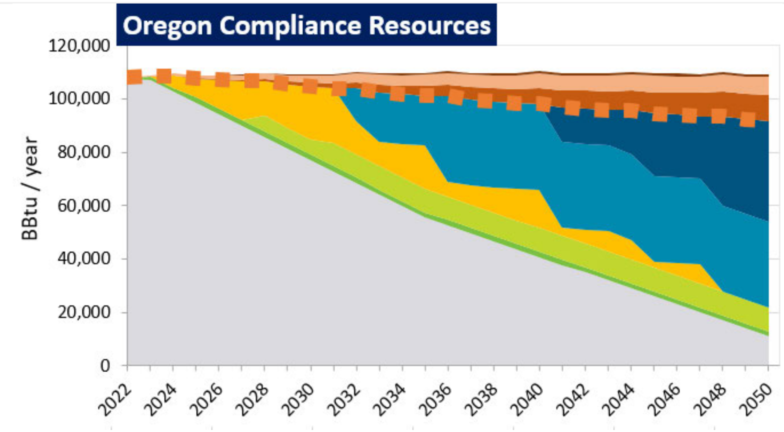


Legend	With SB 98 Compliance	Without SB 98 Compliance

Scenario 9- Supply Focused Decarbonization







Appendix D: Hybrid Heating Pilot

<u>Proposed Dual-Fuel Heating Emissions Reduction Electricity Demand Response Pilot</u>

Background:

Electricity and natural gas are both part of the total energy system. The electricity system is connected to – and dependent upon – natural gas infrastructure. Additionally, electricity and direct use natural gas serve the same buildings and energy needs. Maintaining a reliable and affordable electric system under increased renewable penetration, retirements of dispatchable fossil fuel and hydro generation, and growing loads under electrification is required. As we continue along the path to decarbonization in the Pacific Northwest it makes sense to explore ways to optimize the entire energy system, more broadly than individual sectors, to determine if it is possible to achieve both emissions and cost savings relative to planning the electricity and direct use natural gas systems separately.

Heating, ventilation, and air conditioning (HVAC) loads are the key driver of both seasonality in energy use and peak loads that drive infrastructure investment on both systems, making joint electricity-natural gas planning of HVAC loads an opportunity. Specifically, hybrid (or "dual-fuel") electric heat pumps with natural gas backup could provide demand response peaking services to an electric utility via the backup natural gas furnace carrying space heating loads during winter weather events. There is a strong potential for this setup to reduce emissions from the biggest energy need of most buildings – space heating – while also providing cost savings to Oregonians relative to full electrification or decarbonization of natural gas supply alone. This opportunity could prove even more beneficial as both the electricity and natural gas sectors de-carbonize or "de-fossilize".

Project Purpose:

Evaluate both the present day and future potential emissions and cost savings of hybrid- electric heat pump/natural gas backup HVAC systems relative to primary gas or all electric heating for Oregonians. If hybrid heating systems benefit Oregonians, develop a program that incents hybrid system installation and compensates the direct use natural gas system for the capacity services provided by the natural gas backup furnace that serves as demand response for the electric grid.

Proposal:

<u>Phase 1: Project Feasibility Scoping</u>

Phase 1 involves discussion amongst the electric utility and NW Natural teams to share the value we believe hybrid systems can provide to Oregonians and determine if our respective views on the the value of demand response and emissions savings to the electric utility are compatible. Phase 1 would also entail a discussion on the scope and timing of a potential hybrid system pilot project described in the subsequent phases.

<u>Phase 2: Metering/Billing analysis</u>

Phase 2 is dependent upon established compatibility in Phase 1 and involves completing a joint statistical analysis of metering/billing data to determine the annual and peak weather usage (both electric and gas) of buildings in Oregon with different HVAC systems. This work can be used to estimate the actual demand response potential from natural gas demand response in Oregon. While building science simulations are instructive, any eventual program will need to be based upon verifiable and measurable results. This work will be used to update and refine existing emissions and load estimates from buildings with different HVAC systems, and a key output of this work is a refined estimate of the expected demand response savings to the electric utility from a hybrid system during peak winter events. which can then be evaluated alongside the value of demand response determined in Phase 1. NW Natural is open to Phase 2 work being completed by a 3rd party consultant.

Primary Research Questions:

1. What is the average annual usage of (i) electric heat pumps, (ii) hybrid electric heat pumps with gas backup (electric and gas usage), and (iii) primary natural gas furnaces with air conditioning (gas and electric usage) in the field?
2. What is the expected revenue to the electric utility and NW Natural for these three types of systems?
3. What is the expected emissions of each of these setups using expected average Northwest Power Pool hourly emissions profiles based upon temperature?
4. What is the average usage of the three systems considered by temperature and hour of the day under cold weather conditions?
5. What is the expected usage of the three systems during peak planning conditions (both hourly and over a peak day and peak weather event)?
6. What is the average expected difference in electric usage during peak events for all-electric heat pumps vs hybrid electric heat pump-backup natural gas furnace?

Phase 3: Establish Field Pilot Partners and Install Hybrid Systems

If the results from Phase 2 show that there is meaningful demand response potential from hybrid systems and there is a shared understanding of how the electric utility will value demand response savings from Phase 1, the teams will work together to develop a new construction hybrid HVAC system demand response field pilot proposal for Oregon to bring to the appropriate bodies for review and approval. The program would require joint outreach to builders/developers and is likely to require incentives to motivate the installation of hybrid systems. The incentive required to motivate builders to install hybrid systems is a key consideration that the pilot would look to determine. This work would also require establishing control groups of similar new homes that are heated only by electric heat pumps or by natural gas furnaces or understanding the similarity to recently constructed homes to use the metered usage of those existing homes for comparison with the homes in the pilot. Likely pilot design would incorporate a diversity in system-sizing and the temperature that the system is set to switch from the primary electric heat pump to the backup natural gas furnace. Builder/developer incentive costs for the pilot would be shared between the electric utility and NW Natural.

Primary Research Questions:

1. What incentive is required to get builders to install a hybrid system in a home?
2. What are the costs to build a home with the three types of HVAC systems considered?

Phase 4: Field Pilot Evaluation

How customer behavior, HVAC system-size and setback temperatures, and the costs imposed on the electric utility and NW Natural to serve the load would be monitored as the systems are used by pilot participants and better assess the costs that can be avoided by hybrid systems. NW Natural is open to the field pilot and evaluation being completed by a 3rd party consultant.

Primary Research Questions:

1. How does switchover temperature to the gas backup system impact costs and emissions?
2. Is active utility engagement possible or advisable to be able to respond to weather and market conditions as part of a potential program (i.e. requiring smart thermostat control as part of the program vs. determining best switchover temperature in most conditions to establish a passive "setting and forget it" program)?
3. If a passive approach is used, what is the optimal temperature – on average – to set up systems to switch from electric to gas operation optimize the costs and emissions the electric utility and NW Natural incur to serve customers?
4. What is the optimal temperature to switch to gas operation to minimize total utility payments by the customers, and how different is this temperature than the one that optimizes system emissions and costs?
5. What marginal system variable costs (wholesale purchases, etc.) were incurred to serve the load of each of the three HVAC systems based upon daily trading prices?

Phase 5: Establishing Contract Terms for a Hybrid-HVAC System Demand Response Program

The learnings from the field pilot should provide the information to allow the electric utility and NW Natural to determine if it is in the interest of Oregonians for the two parties to enter negotiation on the terms for a demand response program that the electric utility and NW Natural could propose to their respective approval bodies and the Public Utility Commission of Oregon.

Proposed HVAC System Heating Peak Load Study

Most decarbonization studies either do a rudimentary job of accounting for heat pump efficiencies under extreme weather or assume very aggressive improvement in heat pump efficiency at cold temperatures (or don't recognize the importance of the assumption at all). This translates directly into the expected costs of electrification by being the primary driver in expected peak loads expectations on the electric system under electrification. For example, some decarbonization studies assume all heat pumps that would be installed under electrification in the Pacific Northwest are 470% efficient, and because this efficiency isn't dependent upon temperature (this makes modeling much simpler), they are also assumed to be 470% efficient during peak winter conditions and that no supplemental heat source is needed to serve peak heating needs. In combination with the assumption that all resistance heating is eliminated the studies estimate a relatively minor peak impact from electrifying space heating load.

Even in more recent decarbonization work meant to address this weakness assumes that “cold climate” heat pumps are the only type of heat pump installed and that these systems are roughly 300% efficient and don’t require supplemental heat under peak conditions.

A self-reported cold-climate heat pump (CCHP) classification from Northeast Energy Efficiency Partnerships (NEEP) uses a specification of *the heat pump unit itself not inclusive of backup heat* as being at least 175% efficient at 5°F. This specification applies only to the efficiency of the heat pump itself and not the combined efficiency of the entire HVAC system, which may also rely upon supplemental heating under peak conditions. This distinction between total space heating loads and loads from the heat pump itself is critical, and is where heat pump sizing must be taken into consideration. Heat pumps lose not only efficiency, but also lose heating capacity the colder it gets. This is why *it is standard* for ducted heat pump installations to include a supplemental heat source in the Pacific Northwest, with the most common option being an electric furnace that is 100% efficient on site. It is not efficient from a building science perspective to install a heat pump that is sufficiently large to serve all of the heating needs of a single-family home under peak conditions, and therefore a supplemental heat source is almost always installed to reduce wear on the heat pump system. With a typical installation the supplemental heat source becomes the only source used under peak conditions for comfort reasons and to minimize callbacks to the HVAC installation community. Installations without designed supplemental heat are possible, but their prevalence is unknown, and this doesn’t preclude home occupants from using non HVAC-system connected supplemental heat sources (e.g. space heaters or natural gas fireplaces) that increase comfort but make large contributions to energy use in the home during peak times.

With this, it is likely that homes with heat pumps that are more efficient than code are still using much more electricity during peak times than most decarbonization studies suggest they do. While there have been numerous studies in the energy efficiency world analyzing electric heat pump loads over an entire heating season, there has not been a detailed study in the region on how much electricity homes heated by heat pumps use during peak conditions in the Pacific Northwest. This study cannot be done properly using monthly billing data alone, but can be done in a fairly straightforward manner with data currently available to utilities with smart meters and other high frequency meters.

A great data set to study is the actual electric usage of homes that have received an incentive to install a high efficiency heat pump (more efficient than code) over the last few years during peak times.

Proposed analysis:

Together electric and natural gas utilities have the data that will allow such an analysis in a fairly straightforward manner. For each home the electric utility and the natural gas utility will populate the following:

- Premise/Customer Account #
- Square Footage
- Year Built
- Whether a heat pump incentive was received in 2013 or a more recent year
    - If a heat pump incentive was received, date of incentive
- Maximum hourly electric usage of the home for each year from 2013 through 2019

- Hour of max usage

- Electric usage for the 7am hour for December 7th 2013, January 5th 2017, and January 14th 2020
- Electric usage for the 7am hour for July 15th of 2013, 2016, and 2019
- Gas usage in December 2013, January 2017, and January 2020 (if possible daily usage for 12/7/2013, 1/5/2017, and 1/14/2020)
- Gas usage in July 2013, 2016, and 2019 (if possible daily usage for July 15th of each year)
- Annual electric usage for each year starting in 2013
- Natural gas usage for each year starting in 2013

Analysis of this data will provide an estimate of the impact on the electric grid of electrification of space heating with heat pumps and provide important evidence in the building electrification discussion in the Pacific Northwest.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL

LC 79

2022 INTEGRATED RESOURCE PLAN

NW Natural's Reply Comments

Attachment 1

The following attachment contains proprietary information considered confidential in its entirety under General Protective Order No. 22-374 and has been redacted

February 3, 2023

CERTIFICATE OF SERVICE
LC 79

I hereby certify that on February 3, 2023, I served by electronic mail the foregoing unredacted, confidential version of NW NATURAL'S REPLY COMMENTS upon all parties of record who have signed General Protective Order No. 22-374 in docket LC 79.

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