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May 5, 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: NW Natural Comments on Staff's Final Comments and Recommendations

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company") files herewith its NW Natural's Comments on Staff's Final Comments and Recommendation dated March 30, 2023 reply to the December 30, 2022 Stakeholder comments.

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Enclosure

OPUC LC 79 - NW NATURAL'S FINAL COMMENTS
MAY 5, 2023

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Introduction

Northwest Natural Gas Company (NW Natural or the Company) files these Final Comments in response to Oregon Public Utility Commission (OPUC) Staff's Final 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 dedicated to this process and our 2022 IRP since our first Technical Working Group (TWG) stakeholder workshop in 2021.

Part 1 of our Comments highlight the key issues the Company would like the Commission to consider - relative to Staff's Final Comments. Staff's Final Comments include 43 specific recommendations. Staff is asking the Commission direct NW Natural to follow, including recommendations on the items in the Company's Action Plan and requests for changes for future IRPs. Our brief response to each of Staff's recommendation is found in Part 2. For the Staff recommendations where we felt there is more information that can better help the Commission understand our summary response in Part 2, we have included that supplemental information in Part 3. Part 4 is a brief review of the Synapse Energy Economics report included as Appendix A to Staff's Final Comments.

PART 1: Key Issues

1.1. The Commission Should Acknowledge Action Item 5 Related to SB 98 RNG.

While NW Natural appreciates the time and effort that Staff have spent on this issue, the Company strongly disagrees with Staff's recommendation not to acknowledge Action Item 5: seeking to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load, respectively, in those years.

Action Item 5 is the result of analysis to support Senate Bill 98 (SB 98) and the Commission's rules to implement it. The 2022 IRP demonstrates least-cost/least-risk compliance with the Oregon Department of Environmental Quality's (ODEQ's) Climate Protection Plan (CPP) while recognizing that the CPP does not revise or supersede SB 98. Furthermore, the CPP does not and cannot change either the Company's or the Commission's rights and responsibilities under SB 98, which is a statutory path entirely separate from the CPP. [1] Additionally, Staff neither considers any risk associated with Community Climate Investments (CCIs) nor the unique benefits achieved with RNG, including direct – and faster - emissions reductions for NW Natural customers and the state of Oregon.

Our comments lay out this position in more detail by:

1) Summarizing Staff's comments and recommendations;
2) Demonstrating that SB 98, the CPP, and the Commission's frameworks and IRP Guidelines can be given appropriate meaning and interpreted consistently;
3) Revisiting what SB 98, the Commission's rules to implement it, and EO 20-04 says about RNG and what that means in the context of the CPP; and
4) Detailing why the analysis in the IRP is appropriate and supports Action Item 5

[1] ORS 757.390-398.

Before going on to discuss:

5) The benefits RNG provides to NW Natural's customers and Oregon;
AHow RNG is likely to provide more emissions reduction, and faster, for NW Natural customers and Oregon than CCIs; and
6) The risks of relying primarily on CCIs for compliance with the CPP.

1. Staff's Final Comments on Action Item 5

Staff appears to find that the subsequent issuance of Governor Brown's Executive Order 20-04 (EO 20-04) and the establishment of the CPP, in combination with the Commission's least cost/least risk standard and IRP Guidelines, removes NW Natural's option to move forward with acquiring RNG in support of SB 98. Staff supports its recommendation to not acknowledge Action Item 5 by first citating to a portion of a provision of the rules established by the Commission, at the direction of the Oregon legislature, to support SB 98 as required in the law. Staff states:

> *The OPUC administrative rules addressing RNG in resource planning expressly state that "all requirements concerning integrated resource plans contained in OAR 860-027-0400 and as specified by Commission Order Numbers 07-002 and 07-047" apply to RNG. Orders 07-002, 07-047, and 08-339 contain the OPUC IRP Guidelines and provide that the primary goal of an IRP, "must be the selection of a portfolio of resources with the best combination of expected costs and associated risk and uncertainties for the utility and its customers*." *To this end, Guideline 1(b)(2) requires utilities to consider risk and uncertainty, and for natural gas utilities, that includes "demand, commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions." In the IRP, the utility should explain "how its resource choices appropriately balance cost and risk." Significantly, an IRP "must be consistent with the long-run public interest as expressed in Oregon and federal energy policies."*

After noting the purported voluntary nature of SB 98, Staff goes on to state:

> *In its 2022 IRP, NW Natural prioritized achievement of voluntary targets under SB 98 over properly analyzing the least cost and least risk strategy to meet mandatory CPP requirements. The Company configured the PLEXOS model to include SB 98 RNG by default as a hard-coded input, which made it impossible to evaluate whether RNG acquisition is the least cost/least risk method of complying with the CPP.*

Staff then concludes that 1) because Community Climate Investments (CCIs) are a lower cost way to comply with the CPP in the near term, 2) are more likely to be local than RNG, and 3) because of the supposed beneficial attributes of CCIs from Staff's perspective, that the Commission should direct NW Natural to replace expected RNG acquisition to support SB 98 with purchases of CCIs so long as CCIs are cheaper,[2] and hence not acknowledge Action Item 5.

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[2] Staff Recommendation 8 recommends that RNG can be used to comply with the CPP if the amount of CCIs allowed in the program are not sufficient for compliance. However, for the period covered by the Action Plan in the 2022 IRP, the maximum amount of CCIs allowed for compliance with the CPP is more than would be needed

2. SB 98, the CPP, and the Commission's Frameworks and IRP Guidelines are not in Conflict

Contrary to Staff's recommendation and as NW Natural has shown in its previous reply comments, there is no inherent conflict between the CPP, SB 98, and the least cost/least risk standard. Rather it is possible, and in fact required by Oregon law, to give meaning to both if possible.[3]

Stated another way, no CPP regulation prevents NW Natural from acquiring RNG under SB 98 and, as Staff correctly points out, NW Natural can comply with the CPP by acquiring RNG. Similarly, the least cost/least risk standard must be interpreted in light of what NW Natural is statutorily authorized to do, which is acquire RNG up to the targets specified in ORS 757.396. As such, the Commission is given the responsibility to ensure that these acquisitions are prudent (i.e., least cost/least risk way of meeting ORS 757.396 targets).[4] But SB 98 does not give the Commission the authority to prevent NW Natural from meeting these targets at all. Instead, ORS 757.396 authorizes NW Natural to meet these targets:

> *"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 may make qualified investments and procure renewable natural gas from third parties to meet the . . . portfolio targets . . ."*

Staff's argument that the CPP, the Commission's least-cost/least-risk planning standard, and the IRP Guidelines are somehow in conflict with SB 98 and, to resolve that conflict, one must subordinate SB 98 to administrative rules and guidelines is misguided and ultimately unnecessary. Instead, the Commission should follow established Oregon law and seek to give effect to every provision, which NW Natural believes is entirely consistent with meeting the ORS 757.396 targets. If, however, the Commission believes there is an inconsistency between SB 98 and these other rules/guidelines, then these rules/guidelines must be subordinate to statute (SB 98). [5]

NW Natural urges the Commission to consider the reason SB 98 was enacted to begin with. Prior to enacting SB 98, the Commission's least-cost/least-risk standard and IRP Guidelines resulted in a situation where RNG was not being procured for gas utility customers. This is not to say that the Commission's least-cost/least-risk standard is inappropriate; rather it was not leading gas utilities to procure RNG as fast as Oregon lawmakers determined appropriate. As such, SB 98 was enacted primarily to direct the Commission to incorporate additional goals along with its existing standards to arrive at a different outcome: in this case the procurement of RNG along the trajectory deemed beneficial by Oregon lawmakers. This is supported by ORS 757.394, which directs the Commission to adopt rules to implement that law.

3. Revisiting the Provisions of SB 98, the OPUC's Rules to Implement it and RNG in EO 20-04

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for compliance in the first compliance period, meaning that no incremental RNG would be needed in the period covered by the Action Plan.

[3] 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.").

[4] ORS 757.396(2) ("The commission shall adopt ratemaking mechanisms that ensure the recovery of all prudently incurred costs *that contribute to the large natural gas utility's meeting the targets* . . .").

[5] 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.").

Given Staff's and NW Natural's conflicting interpretations of the interaction of SB 98, CPP, and the Commission's least-cost/least-risk standards it is relevant to review what SB 98 and the Commission's rules to implement it say, as well as the relevant direction provided in EO 20-04.

Prior to the provisions cited above relative to what SB 98 authorizes gas utilities to do, the law includes rationale for the RNG targets it is establishing and authority it is granting:

> *SECTION 2. (1) The Legislative Assembly finds and declares that:*
>
> *(a) Renewable natural gas provides benefits to natural gas utility customers and to the public; and*
>
> *(b) The development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Oregon.*
>
> *(2) The Legislative Assembly therefore declares that:*
>
> *(a) Natural gas utilities can reduce emissions from the direct use of natural gas by procuring renewable natural gas and investing in renewable natural gas infrastructure;*
>
> *(b) Regulatory guidelines for the procurement of renewable natural gas and investments in renewable natural gas infrastructure should enable the procurements and investments while also protecting Oregon consumers; and*
>
> *(c) Renewable natural gas should be included in the broader set of low carbon resources that may leverage the natural gas system to reduce greenhouse gas emissions.*

Furthermore, SB 98 has a customer protection provision that limits the incremental cost of qualified RNG investments to no more than 5 percent of the utility's revenue requirement.[6]

At the direction of SB 98, the Commission established OAR 860-150 provisions 0005-0600 in Order No. 20-227 in Docket No. AR 632. Order 20-227 states simply the purpose of the rules: "In this order, we adopt initial rules to implement 2019 Senate Bill 98, a new legislative policy to encourage Oregon's large and small natural gas utilities to supply natural gas from renewable sources." As such, OAR 860-150 provisions are meant to promote RNG acquisitions, not hinder them. Most pertinent to the discussion in this IRP are provisions pertaining to integrated resource planning, a portion of which is cited by Staff in its Final Comments:

> ***860-150-0100: Renewable Natural Gas Resource Planning***
>
> *(1) Each large natural gas utility and small natural gas utility must, as part of an integrated resource plan filed after August 1, 2020, include information relevant to the RNG market, prices, technology, and availability that would otherwise be required under the Commission's Integrated Resource Plan Guidelines, by order of the Commission, or by administrative rules.*

[6] NW Natural has demonstrated in its IRP analysis that this cost cap would not likely be triggered and, if it were triggered, the Company would stop making qualified investments as provided in law.

(2) In addition to the information required under section (1), a large natural gas utility must also include in each integrated resource plan:

*(a) Information about opportunities, challenges, and **the natural gas utility's strategy for meeting annual RNG targets in ORS 757.396** (Participating large natural gas utilities) during the period of the integrated resource plan's action plan; and*

(b) The cost effectiveness calculation that the utility will use to evaluate RNG resources, pursuant to OAR 860-150-0200 (Incremental Costs).

(3) In addition to the information required under section (1), each small natural gas utility must also include in its integrated resource plan:

(a) An indication whether and when the utility expects to make a filing with the Commission, pursuant to OAR 860-150-0400 (Mechanisms for Recovery of Prudently Incurred Costs by Small Natural Gas Utilities), of its intent to begin participating in the RNG program described in these rules, if the utility has not already started to participate in the RNG program;

(b) Information about opportunities, challenges, perceived barriers, and the natural gas utility's strategy for participation in the RNG program described in these rules; and

(c) The cost effectiveness calculation that the utility will use, pursuant to OAR 860-150-0200 (Incremental Costs), to evaluate RNG resources, if the utility has not already filed this with the Commission pursuant to OAR 860-150-0400 (Mechanisms for Recovery of Prudently Incurred Costs by Small Natural Gas Utilities).

*(4) The requirements of this rule are in addition to **all requirements concerning integrated resource plans contained in OAR 860-027-0400 (Integrated Resource Plan Filing, Review, and Update) and as specified by Commission Order Numbers 07-002 and 07-047**.*

Additionally, given Staff cites the CPP and the CCIs that are a component of the program and ODEQ cited EO 20-04 as authority to establish the CPP, along with its own least-cost/least-risk standards and IRP Guidelines, as rationale for recommending the Commission not acknowledge Action Item 5, it is relevant to consider the direction provided in EO 20-04. EO 20-04 reiterates state policy that RNG is beneficial to Oregonians and that existing laws – like SB 98 – should be utilized to assist implementation of EO 20-04, and includes the following:[7]

Whereas, transitioning the traditional natural gas supply to renewable natural gas can significantly reduce GHG emissions

Whereas, existing laws grant authority to state agencies to take actions to regulate and encourage a reduction of GHG emissions in a variety of circumstances

<u>4. The Analysis in the 2022 IRP is Appropriate and Supports Action Item 5</u>

[7] Also, while building electrification in comparison to decarbonization of the natural gas system is cited by some stakeholders in this proceeding as a rationale for not procuring RNG, EO 20-04 does not call out building electrification as a strategy that should be deployed to implement the Order; in contrast, EO 20-04 specifically calls out the benefits of transportation electrification and energy efficiency in addition to RNG.

Oregon law and the Commission's rules support the analytical approach taken in the 2022 IRP where the Company modeled acquiring the RNG to support SB 98 *along with* compliance with the CPP. NW Natural has complied with the OAR 860-150-0100 (quoted above), and per OAR 860-150-0100(2)(a), demonstrated its strategy for meeting the annual RNG targets in SB 98 with the analysis in the IRP, recognizing the cost cap provisions in the law. The result is Action Item 5. As such, the Company strongly disagrees with Staff's assertion that the analysis in the 2022 IRP is not "properly analyzing" CPP compliance, citing OAR 860-150-0100(4) as justification. OAR 860-150-0100(4) is to clarify that the Commission's requirements for IRPs and the IRP Guidelines still apply *as natural gas utilities comply with the other rules in OAR 860-150-1000,* not to imply that the Commission's least-cost/least-risk standard and the IRP Guidelines supersede and invalidate the other provisions in this section of rules as Staff's comments conclude. Developing this plan and Action Item 5 is the primary intent of the OAR 860-150-0100 provisions.

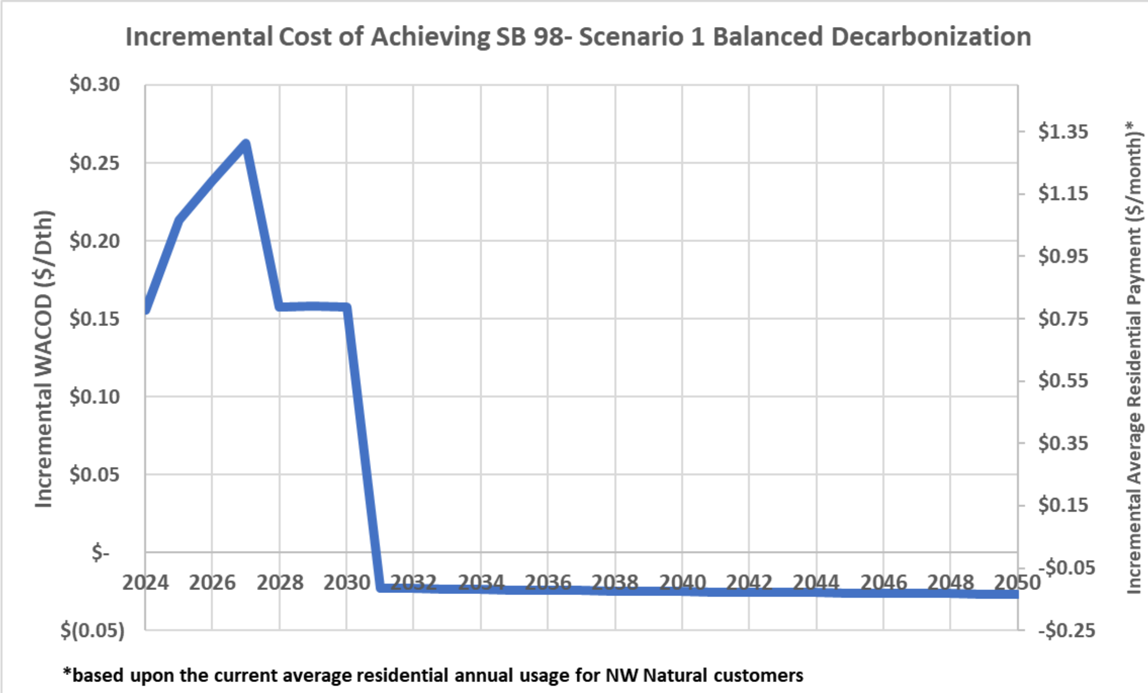
Nonetheless, NW Natural completed an analysis to understand the impact of ignoring SB 98 while complying with the CPP as requested by Staff in its Opening Comments and included these results in the Company's reply comments and made the associated workpapers available to stakeholders.

Also, Staff's Final Comments about the difference in costs between the RNG included in Action Item 5 to support SB 98, and what costs would exist if the Commission were not to acknowledge Action Item 5 and CCI purchases replace that RNG, might lead one to the belief that meeting SB 98 targets is substantially more expensive than using CCIs as the primary compliance strategy in the near-term. That belief is false. In Staff's Final Comments, they compare the differences in the present value of revenue requirement (PVRR) of Scenario 1 with and without SB 98 acquisition, which is the summation of the present value of costs over the entire planning period (29 years in this IRP) to one year of revenue requirement. As Staff points out, for Scenario 1 there is a ~$150 million difference in PVRR over this 29-year timespan. As noted in NW Natural's Reply Comments[8] for Scenario 1 this equates to an NPVRR that is 1.1% higher over the 29-year planning period if SB 98 targets are acquired relative to replacing those purchases with CCIs in the near term.

To put this cost difference in a context that is more aligned with how customers experience the cost of utility service from NW Natural, Figure 1 shows the difference in the weighted average cost of decarbonization that a NW Natural customer would be expected to pay for decarbonization action with and without SB 98 while also complying with the CPP:

[8]See Table 2 of NW Natural's Reply Comments at 52.

Figure 1: Weighted Average Cost of Decarbonization (WACOD) Comparison



As the graph shows, the difference in the weighted-average-cost-of-decarbonization (WACOD) to comply with the CPP while also acquiring SB 98 targets relative to compliance with the CPP with CCIs alone in the near-term, which is the incremental cost of all action to decarbonize that NW Natural customers would pay per unit of gas they use, is never expected to exceed $0.26/Dth ($0.026/therm). Gas costs often change far more than $0.26/Dth from year to year due to changes in the price of conventional gas.

The right-hand axis shows this same information in terms of the average amount an average NW Natural residential customer would be expected to pay more per month relative to the compliance strategy being recommended by Staff. The average residential customer would expect a monthly bill roughly $1 higher per month over the 2024-2030 period if Action Item 5 is acknowledged until the strategy would then be expected to save customers money for the remainder of the planning horizon.[9] This is a reasonable cost to pay for a resource portfolio that reduces actual NW Natural customer –as well as Oregon – emissions faster and with less risk than the strategy recommended by Staff (see below).

<u>5. RNG is Beneficial to NW Natural Customers and Oregonians</u>

Staff's comments include the purposes of CCIs and the supposed greater likelihood they are local projects in comparison to RNG projects as part of their conclusion that CCIs should be purchased rather than the RNG volumes authorized by SB 98. NW Natural questions the appropriateness to take on a policy making role in deciding the relative non-economic merits of RNG and CCIs that are not otherwise

[9] Saving money, the later years is a result of the model locking in RNG in the short-term at lower incremental costs due to relatively high gas prices in the short-term (see unbundled price path graphs for scenario 1).

required in statute or rule.[10] Staff's analysis is focused on the non-economic benefits of CCIs, so NW Natural is compelled to detail the non-economic benefits of RNG as well.

Many of NW Natural's customers have well-defined and significant goals related to long-term greenhouse gas emissions reductions. These types of emissions reduction claims are typically guided by national and international standards and protocols that very clearly delineate how companies' environmental, social, and corporate governance (ESG) goals should be tracked and how progress against those goals should be measured. RNG resources deliver actual emissions savings to customers under these standards and protocols. Therefore, NW Natural is concerned that a compliance portfolio built only of CCIs would fail to provide our customers with the emission reductions they need to comply with their established emission goals. Recent proposed rules from the U.S. Securities and Exchange Commission (SEC) further clarify the importance of using verifiable and measurable emission reduction tools.

Additionally, the presumption that CCIs provide more local benefit than RNG is unfounded. In addition to the immediate reduction in greenhouse gas emissions (which have a global impact), RNG projects are being developed throughout the Pacific NW that will offer additional benefits, such as reduction in particulate matter, improved groundwater quality, and local economic development. NW Natural is far along in the process of developing two RNG projects in Oregon and one in Washington and has many other Oregon- and Washington-based projects in earlier stages of development. SB 98 was broadly supported by a vast majority of the Oregon legislature following a robust assessment of the potential for RNG developing in Oregon conducted by the Oregon Department of Energy. During the process of that assessment, RNG developers recognized the critical importance of gas utilities to enter into long-term contracts to drive development of new RNG projects, which find productive uses for waste methane resources. Absent participation from gas utilities to be a long-term reliable buyer of RNG, many RNG projects will not be developed, leaving significant waste methane resources emitted to the atmosphere.

6. RNG vs CCI Emissions Reduction Timing and Implications for Oregon's Emissions

As described above, acquiring the RNG detailed in Action Item 5 results in direct and immediate emissions reductions for NW Natural's customers. This is unlike how purchasing CCIs works for NW Natural's customers, which are compliance units covered parties in the CPP can purchase but act like offsets to the covered parties that purchase them. A covered party can purchase a CCI at the cost prescribed in the CPP rules and receive a CCI credit that can be used to net against their compliance obligation.[11,12] This can be done even on a backward-looking basis.[13] For example, in 2024 a covered party could purchase CCIs that can be used for emissions that were emitted in 2022 and 2023 (for the 2022-2024 CPP compliance period) since a CCI is credited to the covered party and can be used for compliance when the covered party pays for it, not when those funds are disbursed for CCI projects or

[10] While it is not always possible to contain things within precise guardrails, NW Natural views the IRP process as a policy implementation process rather a policy making one.
[11] See OAR 340-271-0820
[12] So long as an approved CCI entity exists for covered parties to provide funds to make an application to ODEQ for the generation of CCIs based upon that payment. Currently there are no CCI entities approved for a covered party to provide funds to even though OAR 340-271-0810(1(b)) allows covered parties to begin making payments to CCI entities in order to receive CCIs from DEQ as of March 1, 2023.
[13] See OAR 340-271-0810(4(a)) and OAR 340-271-0450(2).

when that project ultimately begins generating emissions savings. Therefore, it is possible to purchase CCIs in 2024 for compliance in 2023 and those funds might not be utilized on emissions reduction projects until 2025 or even a date further in the future. While this makes CCIs a very flexible compliance mechanism for covered parties, it is likely to drive a wedge between when emissions reductions are claimed by covered parties and when the emissions reductions claimed from CCI projects actually occur. In other words, it is likely that the CCI program will allow covered parties to claim emissions savings with CCIs before those emissions reductions actually take place.

An example to demonstrate this mismatch in timing of when CCIs are used for compliance and when emissions reductions occur can be useful, and one of the expected CCI program activities most pertinent to deliberation of NW Natural's IRP, is probably most elucidating. ODEQ descriptions of the CCI program have used funding the installation of electric heat pumps by Oregonians who are not currently heating their homes and businesses with electricity – like NW Natural customers – with CCI funds as one the examples expected from the CCI program.

While covered parties in the CPP who purchase CCIs contribute to all CCI entities as opposed to specific projects,[14] for this example it will be easier to think about CCI funds from a covered party going directly to a specific CCI project – in this case a NW Natural customer installing an electric heat pump with incentive funds from a CCI project. In this example, NW Natural purchases 15 CCIs at the end of year 2024, as it is allowed to do, at the program prescribed price of $120/CCI[15] for demonstrating compliance with the first CPP compliance period (2022-2024). This $1,800 is provided to a NW Natural residential customer in 2025 to incentivize the installation of an electric heat pump.[16] In this example, we will assume that this results in emissions savings of 1 metric ton per year for the expected 15-year life of the heat pump (i.e. on ton of emissions reduction for each year from 2025 through 2039).[17,18] This means that while NW Natural would use the 15 CCIs it purchased in 2024 to reduce its compliance obligation in the CPP by 15 metric tons for the first CPP compliance period (2022-2024), the CCI program would achieve these savings slowly over the 2025-2039 period. Actual emissions saved by the CCIs in 2024

[14] See OAR 340-271-0810(1).

[15] This is an approximation that is in line with what the actual figure is likely to be depending on inflation and is a round number that makes the math in this example simpler.

[16] Heat pump installations are far more expensive than $1,800, and the installation cost for a home converting from natural gas heating to a heat pump are typically thousands of dollars on top of the cost of installing the unit itself, so this figure is for making the math work in this example and not based upon an estimate of the amount that would be required to drive customers to electrify their natural gas heating. Additionally, practically there would be overhead for the heat pump installation program administration so it would not be possible to provide the full $1,800 to the customer as an incentive. Roughly half of the cost of existing energy efficiency programs is for overhead with the other half going to customer incentives.

[17] It is important to point out this example is for demonstrative purposes only, for many NW Natural customers installing an electric heat pump would result in an increase in emissions in the near-term and on average for the state the emissions associated with electric heat pump heating and natural gas heating with a natural gas furnace are comparable. Some natural gas customers would achieve expected emissions savings of roughly 1 metric ton per year, so that figure is used for this example.

[18] It would be possible to have the program achieve 15 metric tons of *first year* savings for 2025 – a delay of only one year relative to when the CCIs were used for compliance by NW Natural – but this would require incentivizing the installation of 15 heat pumps in this example from the $1,800 (or $120 per installation), a figure unlikely to be sufficient to drive changes in customer behavior.

would be zero and per year savings starting in 2025 would be 1 metric ton per year, even though 15 metric tons would be netted against the NW Natural's compliance obligation in 2024. It is important to note this distinction between first year savings and cumulative savings of an incentive program like this anticipated CCI program for electric heat pumps, and that it is highly likely savings for the program would be based upon cumulative savings over many years.[19] Table 1 shows when CCIs are purchased and used to demonstrate compliance (2024), when emissions are actually saved, and how the heat pump installation ultimately achieves the 15 metric tons of emissions reduction claimed in 2024.

Table 1:Timing of CCIs used for Compliance vs Actual Emissions Savings

Compliance Period	Year	CCIs Purchased (MT CO2e Equivalent Offset)	Emissions Saved (MT CO2e/year)	Cumulative Emissions (Total MT CO2e)
1	2023	0	0	0
	2024	15	0	0
2	2025	0	1	1
	2026	0	1	2
	2027	0	1	3
3	2028	0	1	4
	2029	0	1	5
	2030	0	1	6
4	2031	0	1	7
	2032	0	1	8
	2033	0	1	9
5	2034	0	1	10
	2035	0	1	11
	2036	0	1	12
6	2037	0	1	13
	2038	0	1	14
	2039	0	1	15

This situation where emissions are claimed as reduced with CCIs by the covered party in the CPP program far in advance of when those emissions reductions actually occur, is far different than if RNG is used for compliance (as SB 98 RNG can be). Renewable Thermal Certificates (RTCs) are only generated *after* RNG is injected into a common carrier pipeline for delivery to an end user (i.e., RNG can only be used for compliance after that RNG has been physically injected into the natural gas system). RNG being used for compliance in 2024 would require an RTC with a vintage of 2024 or before, meaning that the emissions reductions from RNG would be required to already have occurred for them to be used for compliance. In this way RNG provides an immediate emissions reduction for Oregonians compared to CCIs.

An additional emissions reduction timing consideration is that the CCI program could also suffer from a near-term "double-counting" issue that would result in an additional overstatement of the emissions reduced by the CPP program compared to Oregon's actual level of emissions above and beyond what is detailed in Table 1 above. Continuing with the above example, when a CCI is provided to NW Natural

[19] A synonymous example with timing could be made for incentives for any piece of equipment that would be expected to have a stream of savings through time (e.g. an electric vehicle).

upon its purchase the program is treating CCIs as an offset to NW Natural from a carbon accounting perspective.[20]

This would not present a potential near-term double-counting issue if CCIs *were actually offsets* to the parties covered in the program. However, as the electric heat pump electrification example illustrates, projects in the CCI program are expected to also reduce emissions directly from covered parties in the CPP, meaning they would not actually be offsets to covered parties. When the electric heat pump is installed NW Natural would not only receive the CCIs it purchased, but also experience a reduction in its load (and the resulting emissions reduction for NW Natural as a covered entity along with it). For simplicity, assume in this example that NW Natural experiences a reduction in load in 2025 that generates emissions savings of 15 metric tons in terms of NW Natural's compliance obligation when the heat pump is installed.[21] This means that when NW Natural purchases the CCIs it gets 15 CCIs it can use to net against its compliance obligation *and* experiences a reduction in its emissions of an additional 15 metric tons for a total impact on compliance of 30 metric tons between 2024 and 2025. This means that, although from a societal perspective only 1 metric ton of emissions is saved in 2024, from a compliance perspective NW Natural received 30 metric tons of emissions reduction.

Avoiding double-counting and timing mismatches is a major component of the offset provisions in other jurisdictions that allow entities to comply with mechanisms (like CCIs) that are explicitly meant to come from emissions reductions outside the covered party. It remains to be seen whether the CCI program will develop strict standards to ensure that Oregon's emissions are actually reduced by the amount the CPP program claims it is reducing and along a timeline that would maintain the integrity of the overall CPP cap if ODEQ maintains the current policy that (1) a covered party receives a full CCI when it pays for one[22] rather than when emissions are saved, and (2) that the CCI program intends to target emissions reduction activity from the emissions of the parties covered in the CPP buying the CCIs.

In summary, CCIs are a flexible compliance mechanism for covered parties in the CPP. However, because the program distributes a CCI to covered parties *when they pay for it* and CCIs funds are expected to target emissions reductions from parties covered under the CPP with equipment replacement incentive programs that would save emissions over multiple years, there is real risk the CPP will result in slower and less emissions reduction for Oregon than the caps for the CPP program suggest. RNG carries neither of these risks.

[20] Using the following definition of offsets: a reduction of greenhouse gas (GHG) emissions to make up for emissions that occur elsewhere.

[21] It is important to note that NW Natural's emissions in this example are not a full emissions accounting in this scenario as the emissions associated with the usage of the electric heat pump would also need to be considered to understand the impact on emissions from a societal perspective (i.e., to understand the full impact to Oregon's emissions from that installation). It is possible that NW Natural's emissions are reduced by 15 metric tons from the reduction in load and that the incremental load generates 14 incremental metric tons of emissions on the electric system.

[22] Noting that this certainty of getting a CCI whenever one wants to pay for one (up to the limits in the program of course) is what provides covered parties assurance of using CCIs as compliance strategy.

7. Other Long-Term Risks of CCIs not Considered by Staff

In its recommendations, Staff also does not address the long-term risks of pursuing CCIs as the primary way of complying with the CPP, especially in the first compliance period (2022-2024) that is most pertinent for the period covered by the Action Plan in this IRP. Specifically, Staff fails to mention that NW Natural, now well into the second year of a three-year CPP compliance period, 1) cannot currently purchase CCIs because there are no CCI entities approved by ODEQ to accept funds from NW Natural so that ODEQ can distribute CCIs to covered parties; and 2) cannot control what projects it funds through CCI purchases.

At the earliest, CCIs will be available for purchase later this year. ODEQ is accepting applications from non-profits seeking CCI funds through May 10, and it is currently unclear what entities will apply, how many applications ODEQ will accept, whether ODEQ will approve of at least one CCI entity for covered parties to provide funds so they can receive CCIs from ODEQ, the demand for CCIs in comparison to potential CCI projects, or whether the projects will in fact reduce greenhouse gas emissions by an average of at least one MT CO2e per CCI credit.

At the current time, where no actual CCI projects exist, it is difficult to define what CCIs are in any detail, let alone precisely quantify their risk and uncertainties. This lack of definition is apparent in Staff's comments. Staff states that CCIs are "designated *only* for projects in Oregon that reduce greenhouse gas emissions by an average of at least one MT CO2e per CCI credit." This is incorrect. Rather the purpose of the program is for the *portfolio* of CCI projects to provide an overall emissions savings of at least one metric ton per CCI credit, but it is not a program requirement (i.e., there is no guarantee that such emissions savings will be achieved and there are no consequences if they are not). Staff also erroneously suggests that NW Natural can pick and choose CCI projects, stating that "NW Natural can offer CCI funds to the CCI entity of its choice," which would, in theory, allow it to direct funds towards certain projects with the greatest amount of savings. This is simply not the case. Instead, the rules state that NW Natural must provide equal amounts of funding to all CCI entities:

> "*If more than one CCI entity is approved to accept funds according to subsection (a) the covered fuel supplier must contribute an equal amount of CCI funds to each CCI entity that may receive funds consistent with its agreement with DEQ according to OAR 340-271-0920(2)*."[23]

This creates a long-term risk. If the CCI project fails to meet projected GHG reductions, then incremental action must be taken at some point in the future to meet Oregon's GHG reduction goals, potentially resulting in additional costs to reduce emissions associated with natural gas use.

NW Natural recognizes that CCIs will likely be an important feature of CPP compliance going forward. However, in addition to NW Natural's view that Staff's recommendation is inconsistent with law as detailed above, the Company believes it is inappropriate to rely on CCIs almost exclusively for compliance, especially given the uncertainty of the CCI program for the first compliance period of the CPP.

The Commission should Acknowledge Action Item 5

[23] OAR 340-271-0810(1).

Action Item 5 is the result of analysis to support SB 98 and the Commission's rules to implement it. The 2022 IRP demonstrates least-cost/least-risk compliance with the CPP while recognizing that the CPP and SB 98 can be implemented consistently. Furthermore, the CPP does not and cannot change either the Company's or the Commission's rights and responsibilities under SB 98. It was never the intent of EO 20-04 for the programs it set in motion to nullify or dilute SB 98 as Staff Recommendation 7 implies. EO 20-04 supports SB 98 and reiterates that RNG can significantly reduce emissions. The Commission should continue to both implement that law and support EO 20-04 by acknowledging Action Item 5.

1.2. The PLNG Cold Box and Forest Grove Feeder Uprate Should be Acknowledged

NW Natural appreciates Staff's thoughtful engagement and review of the Portland LNG Cold Box and the Forest Grove Feeder Uprate and recommendation that the Action Items associated with these projects be acknowledged by the Commission in their Final Report.[24] As we detailed in the IRP and in our reply comments, these projects are needed to serve current customer needs, do not depend on customer growth, and would still be the least cost way to serve customer needs even under high levels of building electrification. If other stakeholders recommend not acknowledging either or both projects, we urge the Commission to consider the evidence presented throughout this docket and to acknowledge these Action Items. NW Natural's analysis provided to support these projects surpassed any project presented in our prior IRPs, and even met the expectations Staff detailed in Staff's Final Report in UM 2178 and Cascade Natural Gas's most recent IRP Update, both of which were put forth after NW Natural filed its 2022 IRP. These projects are necessary and establish the least-cost/least-risk alternative for NW Natural to continue to provide safe and reliable service to all its customers.

Additionally, we understand the thoughtful discussion and focus on making improvements to analysis of "non-pipeline" solutions in IRP updates and future IRPs. We appreciate Staff and stakeholder support of Action Item 3 to establish before the next IRP residential and small commercial demand response (DR) programs to supplement the large commercial and industrial programs benefitting NW Natural customers today. As we detailed in the IRP, our reply comments, and in the discovery process, this Action Item was always intended to include the development of the ability to consider geographically-targeted DR (GeoDR) as an option for distribution system planning along with other non-pipeline solutions like geographically-targeted energy efficiency (GeoTEE).

1.3. NW Natural's 2022 IRP is Consistent with the IRP Guidelines

While not one of Staff's specific recommendations, Staff states it "can not recommend acknowledgment of the long-term plan at this time because the long-term plan does not adequately assess or mitigate risk, and does not include reasonably accurate estimates of all relevant inputs."[25]

NW Natural is not clear what Staff is recommending to the Commission on this point. If Staff is recommending that the Commission, a) not acknowledge the specific resources detailed in the long-term preferred portfolio due to uncertainty about what resources will ultimately be the best combination of cost and risk for NW Natural's customers over the three-decade planning horizon, and b) reminding stakeholders that IRPs are not set-it-and forget it plans but an iterative check-in that will be updated going forward, NW Natural disagrees with framing this concept in terms of "acknowledgement/non-acknowledgement," but conceptually understands Staff's approach. However,

[24] Action Item 2 for the Portland LNG Cold Box and Action Item 8 for the Forest Grove Feeder uprate.

[25] Staff Final Comments at 38.

if Staff is asking that the Commission determine that the Company's 2022 IRP is not consistent with the Commission's IRP Guidelines, NW Natural adamantly disagrees. The Company takes compliance with the IRP Guidelines seriously and has made best efforts to do so.

NW Natural disagrees with Staff's assertion that the Company's 2022 IRP does not adequately assess or mitigate risk, and cites that Staff is recommending acknowledgement of the majority of the Company's Action Items as evidence. As the Company detailed in the Plan, analysis in the IRP was used to support the low regret Action Plan that represents the Company's best effort at developing the least-cost/least-risk way to comply with laws and rules while accounting for uncertainty in the current environment. If NW Natural were including Action Items that were "doubling down" on large projects for resources that are quite uncertain, the conclusion that the Company is not adequately mitigating risk could have merit. However, the Company recognized that the biggest risk in this IRP is the current uncertain situation. To this end, the low regret Action Plan and the individual actions that are a part of it are a primary way of mitigating this risk.

Staff makes recommendations for *how* it would like NW Natural to conduct risk analysis in future IRPs, and while NW Natural disagrees with some of Staff's recommendations, the Company understands Staff's position and will conduct the analysis requested if directed by the Commission. NW Natural recognizes that IRP analysis needs to evolve and improvements made from IRP to IRP and can accept this type of feedback. However, a lesser version of the risk analysis completed in the 2022 IRP was completed by NW Natural in prior IRPs, and upon acknowledgement of NW Natural's most recent IRP there was not direction from Staff or the Commission relative to the Company's risk analysis.[26] Furthermore, Staff's recommendations for the Company's risk analysis in this IRP were not provided as part of feedback received from Staff by NW Natural throughout the pre-filing stakeholder workshops where the analysis was presented in detail or in comments of the Draft IRP.

Relative to Staff's comment that the 2022 IRP "does not include reasonably accurate estimates of all relevant inputs," NW Natural first points out that it does not agree with Staff's implication that "accurate" estimates of all relevant inputs over the 29-year planning horizon are knowable. Two examples from NW Natural's 2018 IRP support the Company's belief that what is an accurate forecast is unknowable, and what is reasonable is a matter of interpretation. The Company's analysis in the 2018 IRP evaluated RNG using different emissions intensities associated with different RNG feedstocks. This assumption, though reasonable in 2018, has turned out to not have been "accurate," as RNG resources are all treated as zero emissions resources in the key policies that have been enacted in Oregon since the 2018 IRP was filed. Likewise, in the 2018 IRP Staff Final Comments included a recommendation that NW Natural include a carbon price path of zero for the entire planning horizon as one of the options in its stochastic Monte Carlo simulations.[27] NW Natural argued this might not be appropriate given the state of policy in Oregon at the time. While Staff's opinion was reasonable, this assessment did not turn out to be "accurate." In our Reply Comments in this IRP, we stated the following in relation to thinking about what is reasonable relative to renewable supply assumptions:

> *Understandably, stakeholder comments include lots of discussion about assumptions for renewable supply (biofuels, hydrogen for blending, hydrogen for dedicated delivery, and*

[26] OPUC Order No. 19-073 in LC 71.
[27] See Staff Recommendation No. 11 from the Staff Report in LC 71.

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.

Staff has not elaborated on how the analysis in prior NW Natural IRPs was consistent with the IRP Guidelines, but the superior work done in the 2022 IRP is not. NW Natural recognizes Staff and the Commission need to be responsive to stakeholder feedback, but it is hard to square that, because some stakeholders recommend the Commission not acknowledge NW Natural's IRP, this IRP somehow is not consistent with the Commission's Guidelines. See Section 1.4 for more information about why the Company believes consistently applied and sufficiently detailed IRP Guidelines are necessary for setting expectations of both stakeholders and utilities filing IRPs and why the Company is currently unclear of Staff's and the Commission's expectations.

The Commission's IRP Guidelines have not been altered in 15 years and the Commission has acknowledged each of NW Natural's IRPs since the IRP Guidelines were last updated. The Company's risk analysis and research and information to support input assumptions in prior IRPs were deemed to be consistent with the IRP Guidelines by the Commission. The Company's 2022 IRP includes the most comprehensive and sophisticated risk analysis and the most detailed and researched estimates of relevant inputs ever filed by the Company, enhancing the analysis that was deemed to be consistent with the same guidelines in prior IRPs. Furthermore, Staff does not include in their final comments any declaration that NW Natural has not complied with any of the IRP Guidelines to support any of their recommendations related to risk analysis or input assumptions. There are different ways to interpret each Guideline, and NW Natural believes Staff and stakeholders would agree that in certain instances exceptions are made to specific guidelines (e.g., how energy efficiency projections for most utilities in the State are conducted by the Energy Trust of Oregon rather than included in the optimization models run by the utilities). NW Natural agrees with Staff's Final Report in UM 2178 as well as discussion in this IRP that the IRP Guidelines may need to be revisited in the current environment, but believes it would be a mistake for the Commission to inconsistently apply its IRP Guidelines across utilities and time by not acknowledging NW Natural's 2022 IRP is consistent with the existing Guidelines.

NW Natural recommends that the Commission acknowledge the 2022 IRP is consistent with the IRP Guidelines. However, NW Natural does not see why the Commission would not be able to both acknowledge that the IRP is consistent with its Guidelines but also state that the risk analysis in the 2022 IRP should be improved in the next IRP per Staff's recommendations if the Commission finds that recommendation appropriate.

1.4. The Commission Should Revisit the IRP Guidelines

NW Natural recommends the Commission open a docket to engage all utilities in a meaningful review and update of the IRP Guidelines and apply them consistently across utilities. It has been 16 years since the Commission made substantial changes to the IRP Guidelines. IRP analysis, documentation, and process have evolved significantly over this time. Additionally, the current Guidelines are compiled through three separate orders, which can lead to confusion if stakeholders are unaware of subsequent orders. Given the landscape changes and the length of time since the Guidelines were reviewed and assessed, NW Natural believes it is an appropriate time to review the Guidelines in a separate proceeding with all utilities and stakeholders.

NW Natural also finds that it is increasingly challenging to chart a course for adherence to the Guidelines while there is significant differences in stakeholders' interpretations of the Guidelines. We also perceive developments in this and other recent utilities' IRPs where more waivers, clarifications, and exceptions to the Guidelines are being requested or approved in a single utility's IRP. This is not to say that these actions are not warranted on case-by-case basis, but these iterative developments create a planning framework marked by increasing ambiguity. As we have commented in this proceeding and others, we agree with the findings from Staff's Final Report in UM 2178 that was issued after NW Natural filed its 2022 IRP:

> *Stakeholders called out that there may be a need to revisit the IRP guidelines and providing input on how such a process could take place. They highlighted an interest in further discussion about the IRP elements proposed in Appendix B and where methodologies should be clarified and how assumptions should be supported.*

While UM 2178 was solely focused on natural gas utilities, a new docket to review the IRP Guidelines should bring both gas and electric utilities to the table to develop guidelines that can be consistently applied across service territories and resources.

With that background, Staff has several recommendations that are being asked for in NW Natural's next IRP, which seem to modify, clarify, or be inconsistent with the IRP Guidelines. For example, Staff recommends:

> *Recommendation 10: Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.*[28]

Staff is recommending that one set of GHG compliance avoided costs be applied specifically for distribution system planning and another set of GHG compliance avoided costs be applied to other resources in the IRP such as statewide energy efficiency programs or RNG. Staff's justification for this recommendation is to be "supportive of doing everything possible to eliminate unnecessary investments in the gas distribution system…"[29] NW Natural has two primary concerns with Staff making this type of recommendation.

First, as resource planners we should aim to eliminate all unnecessary investments to provide reliable energy services. Second, NW Natural does not believe this should only apply in the context of natural gas distribution system planning, or it would represent a clear example of putting the proverbial "thumb on the scale." NW Natural does not understand how applying a different set of GHG compliance costs specifically to non-pipeline solutions is not in direct conflict with IRP Guideline 1a:

All resources must be evaluated on a consistent and comparable basis.

[28] Staff's Final Comments at 15.
[29] Staff's Final Comments at 14.

Furthermore, the Company does not see it as appropriate that this would be a criterion that applies only to NW Natural's distribution system planning and not the other utilities in Oregon, both gas and electric. If Staff does intend for this recommendation to apply to all utilities, NW Natural does not believe it is appropriate to adjudicate this issue in our IRP as the other utilities may not be aware of this conversation and could provide useful input on this issue for Commission deliberation.

Another example where NW Natural is concerned about consistency across IRPs is the following Staff recommendation:

> *Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.*[30]

It is unclear to NW Natural the characteristics of different resources that require different standards of support or evaluation than others. For example, in the context of Recommendation 41, NW Natural's synthetic methane estimates were developed by third-party sources. Absent further clarification from Staff, it is unclear what factor is driving the recommendation for a third-party engagement for this resource. Factors could include a cost threshold for resources in the preferred portfolio, the current state of the technology, stakeholder requests, or some combination of these factors. There are a host of other resources that may be applicable to any such criterion, including utility scale electricity batteries, offshore wind, or "generic emerging resources"[31] If there is something unique about specific resources that requires additional scrutiny, then the Guidelines should provide the criteria for identifying these resources.

Along with Staff recommendation 10 and 41, Staff recommendations 15, 22, 27, and 39 also present possible inconsistencies with the Guidelines, inconsistent treatment of a single type of resource, or a significant divergence from the Guidelines that may/should be applied to other utilities. Please see PART 2: Summary Responses to Staff Recommendations for a summary of our direct responses to these individual recommendations and PART 3: for any in-depth detail to each recommendation.

The IRP Guidelines are important as they establish the "rules of the road." If Staff or the Commission have expectations for IRPs that go beyond the current Guidelines, the Commission should update the Guidelines. It is not reasonable to change the rules of the road at every pit stop.

1.5. Electrification in Gas Utility IRPs and Joint System Planning

NW Natural agrees with Staff that "one of the elements which should be considered in gas and electric utility planning moving forward is the variety of costs and risks associated with electrification" and that "the Commission will be better able to ensure just and reasonable rates if it can look holistically at the effects of various decarbonization pathways on households as gas and electric customers, rather than just their gas bills." [32] NW Natural is also supportive of Staff's recommendation that "it may be better to wait" to decide next steps on issues of modeling electrification in both electric and gas IRPs until the Cadmus study is complete this summer and the recognition that understanding issues of joint system

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[30] Staff's Final Comments at 62.

[31] See page 295 of PGE's recently filed 2023 IRP for their definition and cost assumptions for generic emerging resources.

[32] Staff Final Comments at 39-40.

planning are critical to better understanding the implications of different decarbonization pathways. NW Natural supports a holistic view of system planning and looks forward to engaging on this issue moving forward.

NW Natural also agrees with Staff that it would be advisable to “request feedback from stakeholders on the questions of how to proceed and what the scope of work and qualifications for any third-party should be.” NW Natural also believes that a transparent stakeholder engagement process should be used for similar engagements in NW Natural’s IRP going forward. We appreciate Staff’s openness to this feedback as they scope these important projects.

PART 2: Summary Responses to Staff Recommendations

OPUC Staff Recommendation 1: The Commission should direct the Company to include four years of planning detail in its next Action Plan.

NW Natural does not support recommendation 1. NW Natural is unclear which four years Staff is requesting be included with this recommendation. For example, the 2022 IRP was filed in 2022, an acknowledgement decision from the Commission is expected in 2023, and the Action Plan is centered primarily on the years 2024 and 2025 as a result, though the Portland LNG Cold Box in-service date is 2026. NW Natural is not supportive of this recommendation if it is meant that four years *post-expected acknowledgment decision* be included in the action plan and apply to resources that are expected to be re-evaluated in the next IRP and included in the following IRP's Action Plan (e.g., specific volumes of RNG for SB 98 or Energy Trust of Oregon energy efficiency targets). Please see Part 3 for more details for this response. Further, NW Natural believes action plan timeframe expectations should be consistent across all utilities in the state and be included clearly in the IRP Guidelines.

OPUC Staff Recommendation 2: Staff recommends acknowledgement of Action Item 1 to acquire deliverability from Mist Recall and citygate deals.

NW Natural supports Staff's recommendation 2. NW Natural plans our system capacity resources to be able to serve customers in the event of uncommon and extreme winter weather. Acquiring Mist Recall or citygate deals ensures that we have the necessary supplies to reliably serve our customers during weather events when it would be the most dangerous for customers to lose service.

OPUC Staff Recommendation 3: Staff recommends the Commission acknowledge the Portland Cold Box replacement.

NW Natural supports Staff's recommendation 3. In our stochastic risk analysis, the Portland LNG Cold Box was selected in all 500 draws, many of which have drastic declines in NW Natural's customer base. The Portland LNG Cold Box is needed to support reliable service for a wide range of potential levels of electrification going into the future. Our Reply Comments include more detail about why this Action Item should be acknowledged.

OPUC Staff Recommendation 4: For future IRPs, the Company's portfolio modeling must consider non-renewal of unneeded firm delivery capacity contracts upon expiration and the retirement of other capacity resources as appropriate.

NW Natural is receptive to Staff's recommendation and NW Natural will explore retirement, transfer and/or other potential alternatives for reducing capacity resources for utility customers as appropriate. The Portland LNG Cold Box is a key example of how non-renewal for a firm delivery resource is entered into the model as an option for the model to decommission if not needed, as seen in Scenario #6. Apart from this example, this recommendation has implications for other resources such as Mist Recall, where historically Mist assets have been transferred from Interstate Storage to the utility at depreciated costs. Staff's recommendation suggests analyzing the reverse circumstances, where if NW Natural experiences a decline in peak day requirements, Mist assets could be transferred away from the utility at depreciated costs.

OPUC Staff Recommendation 5: Staff recommends the Commission acknowledge Action Item 3 for residential and commercial demand response subject to the condition that the Company includes in its demand response filing a discussion of how the Company's residential and commercial demand response program will interact with and support any future locational demand response program.
NW Natural supports recommendation 5. Per the 2022 IRP, NW Natural intends to include assessing geographical-targeted demand response (GeoDR) as part of its upcoming residential and small commercial demand response program and will include information on GeoDR as part of its program filing.

OPUC Staff Recommendation 6: Staff recommends acknowledgement of Action Item 4 to work with Energy Trust to acquire efficiency in 2023 and 2024.
NW Natural supports recommendation 6. NW Natural appreciates Staff's thoughtful engagement on the issue and recognition of the collaboration between Energy Trust and the Company that made the higher amount of efficiency in the near term, as specified in Action Item 4, possible.

OPUC Staff Recommendation 7: Staff recommends non-acknowledgment of the SB 98 RNG acquisition under Action Item 5 because acquisition of CCIs is a significantly less costly and risky method of complying with the CPP.
NW Natural appreciates the time and effort that Staff has spent on this issue. However, as detailed in Section 1.1, NW Natural strongly disagrees with Staff and recommends the Commission acknowledge Action Item 5. Action Item 5 is the result of analysis to support Senate Bill 98 (SB 98) and the Commission's rules to implement it. The 2022 IRP demonstrates least-cost/least-risk compliance with the Climate Protection Plan (CPP) while recognizing that the CPP does not revise or supersede SB 98.. Please see Part 3 for additional clarifications on modeling SB 98 in the IRP.

OPUC Staff Recommendation 8: Staff recommends acknowledgement of Action Item 7 to purchase CCIs, conditional on the Company using CCIs and RTCs in combination in the most economical way possible to meet compliance flexibility needs, as informed by the decision on Action Item 5 and near-term SB 98 procurement.
NW Natural recommends that Action Item 5 and Action Item 7 be acknowledged as included in NW Natural's IRP. See the response to Staff Recommendation 7 above. For clarification, NW Natural interprets holding RTCs as delivering RNG to customers. Additionally, NW Natural has clarified with Staff that this Staff recommendation means that if CCI purchases alone can be used for the Company's incremental compliance needs without exceeding the CCI limits of the program, then only CCIs should be purchased so long as they are cheaper than RNG. In the near-term, it is highly likely that CCIs alone could be used for compliance in the near-term if the Commission decides not to acknowledge Action Item 5. NW Natural's position on this issue is elaborated upon in Section 1.1.

OPUC Staff Recommendation 9: Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen-blend readiness.
NW Natural supports Staff's recommendation for acknowledgment of the Forest Grove Feeder. NW Natural disagrees with Staff's condition for an expert third party evaluator to validate NW Natural's uprate plans for pressure control equipment for a hydrogen blend compatibility. Pressure modeling is fundamental to the utility's core business model, expertise, and what the Company does day in and day

out. Chapter 8, Section 8.5.5 of the IRP specifically addresses the proposed uprate's compatibility for a hydrogen blend. NW Natural maintains that the Company's engineers are experts in pressure modeling, inclusive of analyzing hydrogen blending, and a third-party validation of our uprate plans is unnecessary and will only add costs to our customers. See Part 3 for additional information.

OPUC Staff Recommendation 10: Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.

NW Natural does not support recommendation 10. This recommendation conflicts with IRP Guideline 1: resources be evaluated on a fair and consistent basis. The Company believes that if this recommendation were to be adopted for NW Natural alone it would lead to inconsistent application of the IRP Guidelines across utilities. If the Commission accepts this recommendation it should apply to all distribution system planning in the state for all utilities, electric and gas. NW Natural recommends that exceptions or alterations to the Guidelines, like this recommendation, be applied consistently to all utilities and be addressed in a docket to review the IRP Guidelines that includes all stakeholders and energy utilities regulated by the Commission. More detail on this is provided in Section 1.4.

OPUC Staff Recommendation 11: In future IRPs, NWN should include a system map with an associated database containing information about feeders, in-service dates of pipes, and lowest recent observed pressures.

NW Natural does not support this Recommendation. The Transportation Security Administration of the US Department of Homeland Security has advised against providing these types of maps at a certain level of detail due to the fact they could be misused by terrorists and providing this information could be deemed a national security threat. Furthermore, setting aside the security risk, having in-service dates and pressure readings of pipes would not help stakeholders achieve their stated aim to assist in "system pruning," even if one were to agree that "system pruning" is appropriate (NW Natural does not). Pipelines require testing for safety along timeline intervals determined by regulators and are not replaced once they reach a certain age. Finally, the data being requested does not exist in the form that Staff recommends. Utilities utilize group method accounting and depreciation. Utilities do not track every asset or the specific depreciable life of each asset.

OPUC Staff Recommendation 12: Staff requests that the Company, before the next IRP, provide statistical evidence of the significance of the variables that influence demand, and hence pressure, at a specific temperature.

NW Natural does not object to this recommendation. However, NW Natural has already provided statistical evidence that, beyond temperature, wind speeds, solar radiation, day of the week, holidays, inclement weather, and school or business closures also impact demand, and therefore, impact expected pressures during extreme cold events.

OPUC Staff Recommendation 13: Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, including information requested by Staff in Final Comments.

NW Natural is not opposed to providing information about the potential risks and benefits of deploying CNG or LNG trailers as a system planning tool for distribution system constraints. However, the Company has already provided the reasons why it is does not view these trailers as a sustainable or reliable system planning solution. NW Natural provided rationale for the determination that using CNG or LNG trailers as a systematic tool to alleviate distribution system constraints during cold weather events in its response to OPUC DR 162, which states:

> *While mobile CNG/LNG storage can be used to alleviate smaller scale issues on the distribution system, NW Natural does not view mobile CNG/LNG as a viable medium- or long-term solution to alleviate sizeable distribution system weaknesses like currently exists in Forest Grove. Permanently citing a delivery point for CNG or LNG trucks to deliver gas to inject into the system during cold events and buying and maintaining the trucks to deliver the gas to the area, while also likely being more expensive than the uprate project, is considered by NW Natural operations experts as rather risky given that it would likely require relying on the ability of trucks to safely navigate to the area during extreme cold events that often correspond with dangerous road conditions. Furthermore, seeking to deploy mobile CNG/LNG to different locations on the distribution system as weaknesses arise would lead to an unsustainable situation through time where mobile CNG/LNG would be relied upon to be injected into numerous locations on the distribution system during peak events. Also, while it might be technically correct to deem mobile CNG/LNG as a "non-pipeline" alternative it would be, in NW Natural's view, incorrect to deem mobile CNG/LNG as more forward-thinking or avoiding the need for infrastructure in comparison to a pipeline uprate project. For these reasons, NW Natural did not develop a detailed cost estimate for mobile CNG/LNG as an alternative for the Forest Grove area.*

OPUC Staff Recommendation 14: Staff requests that the Company explore with stakeholders prior to its IRP Update the Company's Contingency Plan in preparation for cold days with a potential for detrimental events occurring, including information requested by Staff in Final Comments.

The Company does not object to this recommendation. The Company will share its high demand contingency plan guidelines for upcoming cold weather days with stakeholders prior to the next IRP Update.

OPUC Staff Recommendation 15: In the forward-looking distribution system planning included in future IRPs, NW Natural should consider in its study of non-pipe alternatives whether it could develop an operational flow tariff for reductions of peak usage on the constrained portion of the distribution system with different price and load reduction requirements than the current interruptible tariff.

NW Natural already deploys the type of interruptible option described by Staff in this section of their comments and has for many years. Large commercial and industrial customers can choose firm service for some portion of their load and interruptible service for the rest. NW Natural refers to this type of customer as a "base block" customer and currently has 37 base block customers. GeoDR via incremental interruptibility from customers in a constrained area on the distribution system would require special contracts for these customers based upon location specific avoided costs and could provide certain customers a windfall due to geographic happenstance, something NW Natural believes warrants further discussion around equity.

OPUC Staff Recommendation 16: Toward the goal of facilitating forward-looking distribution planning, NW Natural should provide a 10-year distribution system plan in its next IRP Update, as the Company indicated it plans to do.

The Company will provide a copy of our most recent 10-year distribution system plan in the next IRP Update, as detailed in the IRP.

OPUC Staff Recommendation 17: In future IRPs, Staff recommends that when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time should be allowed for evaluation and analysis of GeoTEE and Geographically Targeted Demand Response (GeoDR), among other alternative solutions.

NW Natural supports Staff's recommendation and this is the primary driver why the Company has been transitioning to a forward-looking distribution system planning process. NW Natural discusses this concept in the 2016 IRP, 2018 IRP, and in the GeoTEE pilot filing. This transition has been a major change from just-in-time planning and will allow more lead time for targeted efforts such as GeoTEE if found to be a cost-effective option. Please see Part 3for supplemental information supporting NW Natural's position on this recommendation.

OPUC Staff Recommendation 18: In the near-term, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third-parties.

As described in the IRP, NW Natural anticipates GeoTEE and GeoDR load reduction programs to be available for consideration by the next IRP. However, if these programs are not available, NW Natural will issue an RFP for geographically targeted demand response to third parties for consideration in alternatives analyses.

OPUC Staff Recommendation 19: In future IRPs, for multimillion dollar upgrade projects presented, NW Natural needs to demonstrate that its system reinforcement guidelines and customer delivery requirements represent a realistic risk of loss of load. For example, given that the Company's system reinforcement guidelines are based on a 40 percent pressure drop equivalent to a pipeline at 80 percent of its capacity, under what circumstances would an unexpected weather or load event result in use of the additional 20 percent of peak capacity that could lead to a loss of load event?

NW Natural has already provided substantial detail to support its System Reinforcement Standards. The support for these criteria was provided in the 2018 IRP and reviewed by Staff and stakeholders in detail. In the Staff Report in the 2018 IRP Staff noted that it requested – and received – "an in-depth explanation of the engineering basis for NW Natural's high-pressure distribution system reinforcement standards."[33]. The response to OPUC DR 95 and OPUC DR 52 in NW Natural's 2018 IRP (LC 71), where this information was provided, is included as Appendix A. As such, NW Natural is not opposed to providing this information in future IRPs.

[33] See the February 26, 2019 Staff Final Report in LC 71 at 13.

OPUC Staff Recommendation 20: In future IRPs, NWN should provide an RNG procurement scoring methodology and associated modeling details, including up to date and accurate table(s) that list all sources of data inputs to the RNG acquisition model, as well as a narrative description of all updates and changes.

NW Natural agrees to continue to better articulate its approach to evaluating and securing RNG resources both within the RFP process and outside of it, and to fully share that approach in future IRPs. The RNG market is not a liquid market, and so while NW Natural endeavors to use the best available information and recent RFP responses to forecast RNG prices for purposes of the IRP, the actual resources available for the Company to execute at any given time may look different from what national analyses of the RNG market suggest. While the current RNG portfolio being considered by the Company can and does inform IRPs, the Company will continue to leverage analysis from third party resources to ensure we are reflecting the best available information about the market.

Additionally, NW Natural will complete its internal policy related to RNG resource acquisitions in 2023 and can share it with stakeholders once complete and provide it as part of its Renewable Gas Evaluation Methodology in each IRP, in both cases with appropriate confidentiality protection.

OPUC Staff Recommendation 21: If the Company updates its RNG procurement approach from what was included in its most recent acknowledged IRP, the Company should notify the Commission of the changes in its IRP Update. The update should include, at a minimum, where inputs and assumptions differ from those in its most recently acknowledged IRP and provide rationale for all changes.

The Company does not object to this recommendation. If NW Natural updates its RNG procurement approach the Company will include these changes in its IRP Update and include the information requested by Staff.

OPUC Staff Recommendation 22: In the next IRP, NWN should discuss whether and how the RNG projects secured since the last IRP are in the best interest of ratepayers, including a discussion on how the various project types and associated deal structures (buy vs build) share costs, benefits, and risk across ratepayers and shareholders.

NW Natural does not support this recommendation. The Company is willing to provide detail of all existing projects delivering – or contracted to deliver in the future – RNG to NW Natural customers in the next IRP as it has done in the 2022 IRP. Furthermore, the Company will continue to include *how* it evaluates whether RNG resources are in the best interests of customers via updates to its Renewable Gas Evaluation Methodology (Appendix K in the 2022 IRP) in each IRP, including information requested in Staff Recommendation 20. However, NW Natural does not believe IRPs are the appropriate venue to demonstrate how projects that are already delivering RNG or are contractually obligated to deliver RNG are in the best interest of ratepayers. NW Natural believes that prudency evaluations in annual purchased gas adjustment (in the case of “offtake” agreement RNG) and the RNG automatic adjustment clause (in the case of development RNG) are the appropriate dockets to demonstrate why these projects are in the best interest of ratepayers.

OPUC Staff Recommendation 23: NW Natural should convene a stakeholder group immediately following the conclusion of the IRP to establish a transport customer efficiency program in time to be able to report on its status in the 2024 IRP update.

NW Natural supports this recommendation. Staff and NW Natural are on the same page regarding the importance of energy efficiency (EE) to NW Natural’s CPP compliance strategy and the immediate need for stakeholder engagement on the progress of the energy efficiency program for transportation customers. NW Natural proactively moved the ball forward on transport EE programs by including the first conservation potential assessment (CPA) for Oregon customers on transportation schedules in the 2022 IRP. NW Natural will schedule a stakeholder workshop in the summer to discuss next steps to establishing transport customer EE programs.

OPUC Staff Recommendation 24: NW Natural, in the development of a transport customer efficiency program for 2024, should explore and share findings regarding an incentive that would adequately incentivize efficiency, but would not be applied as a flat, per therm rate to usage reductions for operational, economic, or other reasons.

NW Natural supports this recommendation. To this end, avoided cost values and their derived cost-effectiveness assessment metrics appropriate for transportation EE programs have been listed among the core agenda for the above-mentioned upcoming stakeholder workshop to be held this summer. At this workshop, NW Natural is open to insights and feedback from all stakeholders and in addition, NW Natural is seeking further direction from the Commission on how a fair and adequate incentive should be designed to incentivize transportation customers to achieve EE savings without causing potential equity issues to other customer groups. It is also NW Natural's intention to include a proposed incentive design in the development of the transportation customer EE program for 2024. This is in alignment with NW Natural's response to AWEC Request 1 "that transportation energy efficiency should follow the same cost-effectiveness calculations as other EE so as to maintain an apples-to-apples comparison."[34]

OPUC Staff Recommendation 25: Staff recommends the Company reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and make any appropriate updates in the 2022 IRP Update.

NW Natural will reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and discuss potential updates for the next IRP Update.

OPUC Staff Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.

Staff is mistaken that this information is not included in the 2022 IRP. This IRP is the first IRP to include this information as part of the rate impact analysis in any IRP filed with the OPUC. That this first attempt, while somewhat rudimentary, was made in the IRP and detailed in the IRP discovery process and the Company's Reply Comments. Part 3 provides more information on the work that was done and how the costs were varied across scenarios by variation in load. The Company is committed to improving upon this analysis in the next IRP. NW Natural believes that having these costs included and vary with load should be a consistent expectation across all utilities filing IRPs in the state and is best addressed through a review of the IRP Guidelines.

OPUC Staff Recommendation 27: The Company should provide NPVRR for each portfolio in the next IRP and a breakdown of portfolio NPVRR into cost categories in workpapers filed with the IRP.

Staff's Final Comments requests in its support for this recommendation:

[34] See Section 2.2 in NW Natural's Reply Comments at 102.

> *the Company provide a clear breakout of costs by type and by year in the next IRP. For example, categories could include distribution LEA, distribution system upgrade, supply side resources, capacity resources, and demand response.*

NW Natural did provide Staff and Stakeholders with the relevant costs by year that need to be considered for system resource planning, including total gas costs, investment costs in capacity resources, investments costs in incremental demand-side actions, and total compliance costs. This was done for every scenario and every Monte Carlo draw. Additionally, estimates for the remaining annual revenue requirement, which would include costs associated with distribution LEA and distribution system upgrades, were also in the work papers provided, and factored into the bill impact analysis for each scenario. NW Natural will work with Staff to better clarify the cost categories that they are interested in seeing more clearly presented in the next IRP.

OPUC Staff Recommendation 28: In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.

NW Natural does not support this recommendation. We see its recommended approach as more limiting in information and value. Staff states that the:

> *current approach makes it difficult to analyze how the NPVRR of a portfolio resulting from a low RNG price scenario would respond to an unexpected change in load or the adoption of gas heat pumps*

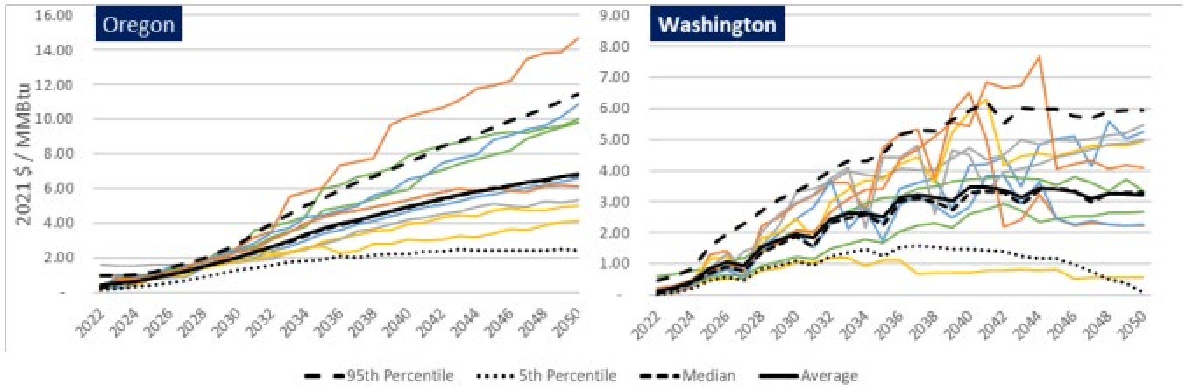
As shown in detail in Part 3 for this recommendation, we can use the outputs from the IRP to assess this very question and show the implications of high and low heat pump adoption in a low RNG price environment. Because of the approach we took, we can put this analysis together from the outputs of the Monte Carlo analysis despite it not being requested early in the IRP process. Therefore, the outputs from the IRP can be beneficial beyond the IRP process, with less regret of not having conducted specific sensitivities within a single scenario. NW Natural recommends continuing to implement its current approach in the next IRP of treating all key variables as uncertain in our Monte Carlo analysis. See Part 3 for supplemental information to support the Company's position on this recommendation.

OPUC Staff Recommendation 29: NW Natural's next IRP should provide metrics comparing the severity and variability of risk in key portfolios.

Staff references risk metrics and methods deployed by PacifiCorp and PGE for evaluating investment decisions. Please see Part 3 for further discussion about the fundamental differences and similarities between the investment decisions being considered by NW Natural and the investment decisions electric utilities are facing.

In general, NW Natural is receptive to Staff's asking for risk metrics in the next IRP but points out that the dispersion graphs that are provided in the 2022 IRP are the risk metrics comparing the severity and variability of costs for compliance with the CPP. Figure 7.13 specifically shows the severity and variability of the weighted cost of decarbonization for complying with the CPP.

Figure 7.13: Monte Carlo Total WACOD



NW Natural believes the 2022 IRP has sufficiently analyzed the risks and severity of bad outcomes for meeting SB 98 targets and complying with the CPP. This risk analysis has informed the decisions that we are asking to be deliberated in our Action Plan.

OPUC Staff Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential and the effects of dual fuel technology on peak and average load on the gas system.

Staff is mistaken that the 2022 IRP does not provide an in-depth study of the potential for dual-fuel heat pumps. NW Natural's IRP is the first IRP in the region to evaluate this resource in detail. Each scenario and Monte Carlo Simulation has a different penetration of dual-fuel heat pumps, and the impact of the heat pumps is analyzed at the daily level depending on temperature – including the peak forecast driving capacity needs in that scenario or stochastic draw, as NW Natural detailed in discovery. NW Natural has packaged this information to specifically highlight key results relative to dual-fuel heat pumps in the 2022 IRP in Part 3. NW Natural is supportive of efforts to assess the potential for dual-fuel heat pumps and is committed to advancing this issue further in processes that are expected to take place before the next IRP.

OPUC Staff Recommendation 31: In the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies.

NW Natural disagrees with Staff's assertion that that the reference case should "better" reflect current local, state, and federal policies in its reference case. NW Natural stands by how we defined the reference case in the 2022 IRP to reflect historical trends, such that the impact from transformative policies can be measured against a "business-as-usual" future. NW Natural is receptive to recommendations that our reference case should reflect existing policies, including any resolutions or legislation that is enacted, but does not take immediate effect. However, at time of filing the 2022 IRP, no cities in our Oregon service territory had passed resolutions restricting natural gas. We re-iterate that the reference case is not a base case or NW Natural's expectation of the future. The Company maintains that it would be improper to bake in assumptions about future political outcomes into the reference case, which is used to be able to show how action (like complying with the CPP) compares to the historical trend continuation reference case. We also maintain that the reference case is appropriate for scenario analysis that is used to compare differences in key inputs across scenarios and to set a baseline to evaluate the impact of future policies. Please see Part 3 for further discussion.

OPUC Staff Recommendation 32: In the next IRP, NW Natural should clearly show which load reductions are because of efficiency and which are because of electrification.

Staff is mistaken that a breakdown of load reductions was not included in the 2022 IRP. A detailed breakdown was included in the workpapers provided to stakeholders in this process, as the Company detailed through discovery. For the next IRP NW Natural will include more breakdowns of the sources of load reductions for the graphs included in the IRP document itself relative to efficiency vs electrification.

OPUC Staff Recommendation 33: The Company should update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency.

NW Natural can update the avoided costs to reflect the Commission's decision on Action Item 5 after that decision is made. NW Natural disagrees with Staff's view that RNG for SB 98 can be avoided with energy efficiency given that SB 98 is a target based upon gas deliveries. NW Natural uses the marginal resource needed for CPP compliance as the avoided compliance cost and maintains this is appropriate. In the near-term, this is the cost of CCIs (regardless of modeling SB 98 or not) and is what is reflected in the near-term avoided compliance costs filed in the IRP. There is a slight change in timing of when the marginal CPP compliance resource changes from CCI's to RNG if SB 98 is modelled. For more details about the avoided cost calculation and reasons why SB 98 RNG cannot be avoided with efficiency, see the Company's response to this recommendation in Part 3.

OPUC Staff Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.

NW Natural provided an updated Appendix K with the IRP Addendum filed on March 27th, 2023.

OPUC Staff Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.

NW Natural will discuss this topic in a Technical Working Group stakeholder workshop for the next IRP and provide support for the approach in the next IRP.

OPUC Staff Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.

NW Natural supports this recommendation and has also been integrating approaches to selecting risk values into the aforementioned (Recommendation 20) internal RNG acquisition policy. Each deal or project opportunity will have different structural or contractual elements that may not lend itself to a prescriptive approach to risk values, but the Company will endeavor to develop "buckets" for different elements of risk that most projects' risk values will fall into. NW Natural also agrees to further discuss this topic in future Technical Working Groups.

OPUC Staff Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.

After a discussion with stakeholders about customer risk-aversion as it relates to utility bills in detail at a Technical Working Group stakeholder workshop for the 2018 IRP, the risk-adjusted approach applied in Appendix K was detailed in the 2018 IRP. Including the risk that resources may turn out to be cheaper than expected (noted by Staff here as "downside risks") would move the calculation away from a risk-averse perspective on customer preferences to more risk-neutral or risk-loving perspective. Noting that assessing customer risk preferences is needed to develop a risk-adjusted approach highlights that what is “least-risk” is unavoidably a matter of perspective. That said, NW Natural will discuss this issue in its next IRP Update and is open to including “downside risks” in its risk-adjusted calculations if stakeholders agree it is a better representation of customer preferences.

OPUC Staff Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.

NW Natural has included reasonable estimates based upon estimates from third party forecasts on the higher end of costs for RNG, hydrogen, and synthetic gas in its stochastic Monte Carlo draws, all 500 of which could be viewed as a “sensitivity.” The higher end of these estimates in the near-term included in the Monte Carlo analysis are not only higher than most third-party estimates, but higher than actual resources NW Natural could contract today. The estimates used for these resources were the result of a comprehensive literature review, engagement in numerous organizations specializing in RNG and hydrogen-based fuels, and actual resources being considered for acquisition for NW Natural customers, all of which were provided in detail through discovery. NW Natural will continue to include ranges for all relevant cost inputs in the next IRP, including estimates on the higher end of available forecasts. NW Natural’s Reply Comments detailed the ranges for these resources included in stochastic Monte Carlo draws in the IRP to show that estimates considered high priced by Staff are included in these ranges.

OPUC Staff Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.

NW Natural conducted a comprehensive literature review and has been actively engaged in the RNG market for a few years. This is the basis for the estimate of price and availability in the IRP, as was detailed in the discovery process in this IRP. NW Natural is open to working with Staff to understand the type of literature review it would like to see in the next IRP, but it would be incorrect to say that a literature review was not conducted for the input assumptions in the IRP related to RNG prices and availability.

OPUC Staff Recommendation 40: In the next IRP, the Company should refine its cost estimate for green hydrogen by modeling a resource with a precise capacity, utilization rate, and a precise quantity of renewable energy available to it at a given price. These assumptions should be shared in the Technical Working Group process and in the IRP itself.

NW Natural agrees that modeling green hydrogen with a precise capacity and utilization rate is very important. NW Natural included this in the 2022 IRP and will include it in the next IRP. Because all the hydrogen costs are modeled from dedicated resources, the capacity factor and utilization rate are built into the cost estimate. Costs are developed based on the levelized cost of energy (LCOE), which includes an assumed capacity factor in the calculation. Additionally, NW Natural determined there is no practical limit of hydrogen supply to NW Natural customers. This conclusion is based on the relatively small amount of hydrogen that NW Natural would need relative to the entire potential hydrogen market in the country. Green hydrogen cost assumptions were shared as part of the IRP process, but more information on calculations and electricity sources could be shared in Technical Working Groups for the next IRP.

OPUC Staff Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.

The Company disagrees with Staff's recommendation that a third-party needs to be engaged to assist in estimating the cost of synthetic methane. The Company has utilized an abundance of quality, objective, third-party resources to formulate cost estimates for synthetic methane. NW Natural has transparently provided the sources it found most compelling in its literature review of hydrogen and methanation estimates through the discovery process. NW Natural acknowledges it may make sense to engage a third-party for some analyses, which in fact, the Company has done in this case, including accessing information through subscription services. The Company is concerned, however, that there are not clear guidelines regarding when a third-party should be engaged directly rather than third-party sources used (as is typical of most key input assumptions in an IRP), and that the layering on of additional consultants may only add unnecessary costs to customers.

OPUC Staff Recommendation 42: In the next IRP Technical Working Group process, NW Natural should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year for several key portfolios. The Company should also provide the cost and quantity of CO2 needed in each year in key portfolios to support syngas production. The Company should request feedback from participants regarding the likelihood of these resources being readily available and consider applying any emerging technology availability discount at that time.

NW Natural agrees that estimates of the capacity in MW of electrolyzers, renewable generation, and methanation equipment are important and that is why they are included in the hydrogen cost assumptions, which feed into the synthetic methane assumptions, and in the synthetic methane cost assumptions. NW Natural provided this information through the DR process, but it could be included earlier in the Technical Working Group process for the next IRP. Page 215 of the IRP discusses synthetic methane assumptions in depth. In summary, the IRP only models synthetic methane that comes from renewable hydrogen. Hydrogen is the primary cost component for creating synthetic methane, however, the cost of methanation is also required to get a synthetic gas estimate. The response to OPUC DR 137 includes several of the studies that were part of the literature review conducted on methanation and used to develop the methanation costs in the IRP, which recognize the state of the technology in developing the cost esimates. As described in the discovery process, the estimate used for the cost of methanation in the 2022 IRP is from a technology called direct air capture, which means capturing carbon from the atmosphere directly. Given that air is available anywhere on earth, there is no practical limitation to the CO_2 feedstock used for direct air capture technologies.

OPUC Staff Recommendation 43: The Commission should indicate whether risk sharing will be considered at cost recovery for any future SB 98 RNG projects.

NW Natural does not support this recommendation. The Commission has already addressed this issue in NW Natural's recent general rate case order, which was issued last October. In that order, the Commission approved an RNG automatic adjustment clause (Schedule 198). Under Schedule 198, the Company and its customers share the risk of any difference between the annual forecasted cost of its RNG investments and its actual costs. Specifically, any difference is subject to an earnings test deadband that is set at 50 basis points below and 50 basis points above authorized ROE. Given that the Commission has already addressed RNG risk sharing by approving an automatic adjustment clause with "modifications offered by Staff and CUB [that] are necessary to achieve a reasonable risk balance [e.g., the earnings test above]", Staff's recommendation is unnecessary.

NW Natural also believes it is inappropriate to consider any changes to Schedule 198 or any other rate recovery mechanism in an IRP docket. Rather any changes to these rate mechanisms should be done in proceedings specific to the existing RNG rate mechanisms involved and not through a generic IRP docket. NW Natural strongly believes that ratemaking should not occur in an IRP, especially when the Commission already addressed the issue that concerns Staff, and was previously raised by Staff in a rate case, less than a year ago.

PART 3: Supplemental Information to Support NW Natural's Response to Staff's Recommendations

OPUC Staff Recommendation 1: The Commission should direct the Company to include four years of planning detail in its next Action Plan.

NW Natural is not supportive of this recommendation as stated as it would likely lead to asking the Commission to deliberate on Action Items that were deliberated on in the previous IRPs. For example, if we had brought the Forest Grove project through the 2018 IRP as an Action Item with the current timeline for the project, it is unlikely that the Commission would have made a definitive acknowledgment or non-acknowledgement of the project knowing that we would need to re-evaluate it in the 2022 IRP. The Company views the Action Plan as specific items that the Company has not yet materially invested in and is asking the Commission to acknowledge.

The Company recognizes that acknowledgment is not pre-approval, however, acknowledgment from the Commission is meaningful for the investments we make on behalf of customers. We aim to bring projects through the Action Plan with consideration of the IRP cadence (every two years), the IRP discovery process timeline and lead times needed for those projects. While we appreciate why Staff may want to extend the Action Plan window, we recommend that the onus remain on the Company to decide what we should bring through the Action Plan for acknowledgment decisions.

Additionally, NW Natural is also unclear about what content Staff is requesting to be included in the planning detail in its next Action Plan. As stated in this IRP process numerous times, the Company will continue to improve and update various assumptions by performing future studies, continuing to review literature, subscribing to third-party data sources, and obtaining information from subject matter experts. These are activities that the Company will do in the normal course of business in preparation for future IRPs. Additionally, in a previous Cascade Natural Gas IRP[35], Staff stated:

> *The action items should not include actions that are business-as-usual utility activities.*

Given that several of Staff's recommendations refer to items that NW Natural perceives as business-as-usual activities, it would be helpful for the Commission to clarify how it defines business-as-usual utility activities.

[35] Docket LC 59, See Order 16-054 dated 2/9/2016, Appendix A, at 4.

OPUC Staff Recommendation 7: Staff recommends non-acknowledgment of the SB 98 RNG acquisition under Action Item 5 because acquisition of CCIs is a significantly less costly and risky method of complying with the CPP.

Throughout the IRP, NW Natural was transparent about its interpretation of SB 98 legislation and how the Company intends to meet SB 98 targets. Developing a PLEXOS© model that does not reflect these intentions would be misleading to stakeholders and the Commission. The modeling of SB 98 on NW Natural's Oregon emissions compliance was presented in TWGs and was described in the draft 2022 IRP for comment.

Staff's Final Comments state:

> *The Company configured the PLEXOS model to include SB 98 RNG by default as a hard-coded input, which made it impossible to evaluate whether RNG acquisition is the least cost/least risk method of complying with the CPP.*[36]

To clarify Staff's phrasing of a "hard-coded input", the PLEXOS® model is constructed with an SB 98 constraint that allows it to select the least-cost resources that qualify for SB 98. This was discussed this in Chapter 7, Section 7.2 Resource Planning Optimization Model (PLEXOS®):

> *In addition to the required properties for each object in the model (example shown in Table 7.2), user defined constraints are developed to ensure that: ….*
>
> > • *least cost qualifying resources are acquired to meet SB 98 targets ….*

As such, the cost minimizing optimization model is still making an economic decision for the resources that qualify for SB 98 (i.e., RNG tranche 1, RNG tranche 2, hydrogen, and synthetic methane) depending on relative costs of these resources and taking other constraints into consideration (e.g., blending limitations of hydrogen). The phrase "hard-coded input" should not be interpreted as NW Natural pre-determining the amount and what types of resources are selected to meet SB 98 targets. Having this design allows the model to adjust the mix or quantity of qualifying resources for each scenario or Monte Carlo draw.

NW Natural disagrees with Staff's assessment that having this constraint in the model made it impossible to evaluate the cost and risk impact of meeting SB 98 target along with complying with the CPP. Staff requested that NW Natural conduct an analysis that "relaxes" the SB 98 constraint in their opening comments. Through additional questioning, the Company understood this to mean that the Company should run a sensitivity that "disregards" the SB 98 policy for each scenario. While Staff did make some inquiries about how SB 98 would interact with the CPP in response comments to the draft IRP, Staff's opening comments were the first time the Company was asked for this analysis. NW Natural promptly conducted this analysis and provided a summary of the results our reply comments and the full dataset of results through LC 79 OPUC DR 157.

Prior to providing the full analysis without the SB 98 constraint, NW Natural's work papers provided to stakeholders contained the costs, quantities, and resource type (i.e., RNG 1, RNG 2, Hydrogen, or Synthetic Methane) by year that were selected to meet SB 98 targets for each scenario. This is illustrated by the graph below for Scenario 1 (underlying data for this graph is a part of the workpapers

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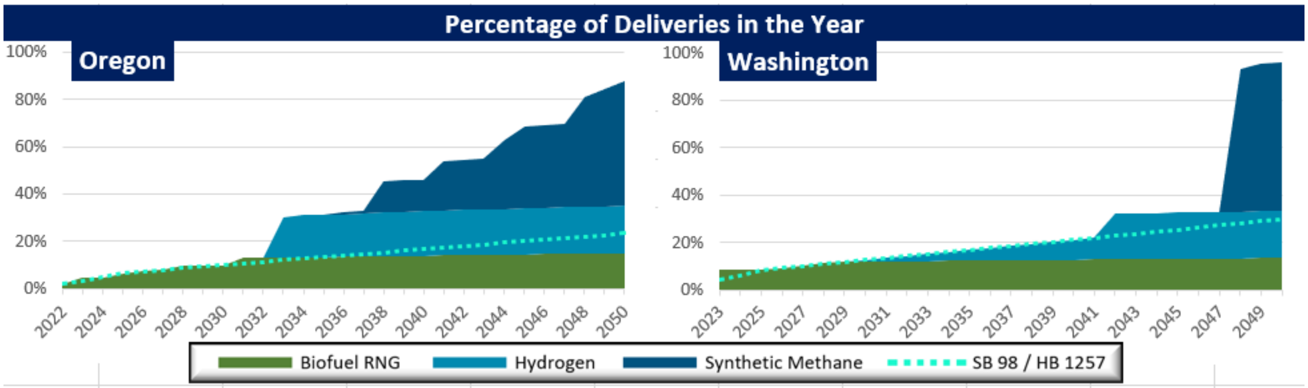
[36] Staff Final Comments at 8.

provided). A relative comparison to the cost of an equivalent amount of CCIs in each year is a reasonable starting point to evaluate the cost impact of SB 98 relative to purchasing CCIs.



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Staff's Comments also states:

> *The Company provides no explanation of how or why a choice that leads to a potential cost differential of $150,000,000 or more results in "a portfolio of resources with the best combination of expected costs and associated risk and uncertainties for the utility and its customers."*[38]

As discussed in Section 1.1, the Company has explained its view that SB 98 is not invalidated by the CPP. The Company believes we have been transparent about this position and our intentions to meet SB 98 targets; therefore we disagree with Staff's characterization that "no explanation" was provided. Additionally, Staff points out "a potential cost differential of $150,000,000 or <u>more</u>" with the *more* referring to scenarios 2, 6, or 8, yet Staff does not recognize that it could be significantly <u>less</u> if there is significant federal support for hydrogen and renewable natural gas, which was analyzed in Scenario 7. Since filing the IRP, the IRA is offering significant federal funding for renewable fuels. It is premature to disregard a possible future where it could be cheaper for NW Natural customers to meet SB 98 targets.

OPUC Staff Recommendation 9: Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen-blend readiness.

Uprating pipelines to increase the capacity of the existing pipeline is common practice throughout the regulated and unregulated natural gas industry and is regulated by the US Department of Transportation as per the criteria outlined in 49 CFR 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS. NW Natural's engineering staff has successfully guided previous Company efforts to uprate other pipelines in our gas distribution system in compliance with 49 CFR 192.557. The formal procedure to uprate the Forest Grove Feeder will be shared with OPUC Safety Staff in advance of the field procedure to inform staff of the upcoming procedure. For uprate projects like this, if NW Natural finds that its own engineers are not available to design the improvements for this

[37] NW Natural's 2022 Integrated Resource Plan: Errata Filing at 262.
[38] Staff Final Comments at 9. Quoted statement is not cited, however, NW Natural has identified it as the beginning of IRP Guideline 1c.

project, then it is common practice for NW Natural to hire an outside engineering consultant to assist with the design of the improvements associated with the pipeline uprate, but doing so does not need to be prerequisite to move forward with the Forest Grove uprate.

NW Natural is continuously increasing its expertise on gaseous energy delivery systems, including hydrogen blending into the Class B distribution system. At this time, the common understanding within the industry is that regulator maintenance and pressure setting adjustment won't change for natural gas blended with hydrogen. NW Natural tracks research being performed to assess the impacts of hydrogen blending on natural gas equipment. Additionally, we are currently blending hydrogen at our Operations training town facility in Sherwood, which tests real applications of hydrogen blending on appliances in a controlled and safe environment on isolated systems. A second study is in the final design phase and is anticipated to commence later this year. The company participates in regular knowledge transfer sessions with staff from 19 other gas utilities throughout North America to share learnings on their past, present, and future hydrogen blending projects.

In addition to its blending work at our Sherwood facility, which includes office and warehouse space, as well as an Operations training town facility, NW Natural participates in forums, such as the Low-carbon Resources Initiative (LCRI), which is performing in-depth research into different levels of hydrogen blending on transmission and distribution gas pipes. NW Natural is also a member of the Center for Hydrogen Safety which advises and influences standard practices, GTI Energy, which performs gas distribution system and downstream appliance hydrogen blend research, and HyReady, which is focused on developing guidelines for hydrogen blending by gas distribution and transmission companies.

The heart of NW Natural's utility business is to provide reliable service to our customers. This starts with our Engineering and Operations staff. The engineers that we hire are the experts in this field and without their expertise reliable gas service would be at risk. Our field employees are qualified to maintain pressure regulation equipment. We re-iterate that NW Natural is at the forefront of understanding the impacts of blending hydrogen into our system and our engineers are experts in pressure modeling, inclusive of blending hydrogen onto our system.

OPUC Staff Recommendation 13: Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, including information requested by Staff in Final Comments.

Staff's Final Comments at 22 states,

> *For example, given that the Company currently maintains enough infrastructure to provide 1,000 Therms for 9 hours in one location…*

Staff references NW Natural's reply comments for this statement and there is some confusion between capacity (size of the tank) and deliverability (flow capability) for our CNG and LNG trailers. To clarify, the Company owns two CNG trailers with a total of 1,000 therms gross capacity per trailer, and about 800 therms net usable capacity per trailer. The deliverability capability of these CNG trailers is a function of the delivery pressure needed to inject. This will be dependent where the CNG is injecting onto the system, but the 1,000 therm (800 net usable capacity) CNG trailer can deliver 300 therms per hour at approximately 400 psig delivery pressure. This is 300 therms per hour for a maximum of about 2.5 hours from each trailer.

The Company has one LNG trailer, which has a capacity of 8,500 therms but the vaporizer can only produce (i.e., deliver) 300-400 therms per hour of natural gas.

OPUC Staff Recommendation 17: In future IRPs, Staff recommends that when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time should be allowed for evaluation and analysis of GeoTEE and Geographically Targeted Demand Response (GeoDR), among other alternative solutions.

In the 2016 IRP, NW Natural developed a new approach to distribution system planning and "created a ten-year-forward system planning document" (2016 IPR section 7.2). NW Natural first began to look at "transition[ing] to a fully forward looking distribution system planning process" in the 2018 IRP (2018 IRP section 8.4). In the 2018 IRP Update Attachment 1, Geographically-Targeted Energy Efficiency Pilot Program, NW Natural states, "given that some options to address distribution system weaknesses, including GeoTEE, likely have longer lead times to have the desired impact, the Company is transitioning to a more forward-looking distribution system planning process" (2018 IRP Update Attachment 1, Geographically-Targeted Energy Efficiency Pilot Program, pg. 14).

Staff Final Comments state:

> *Staff stresses that two crucial factors in determining distribution system investments need to be explored more fully by the next IRP. The first factor is the timing of when evaluations and analysis need to be conducted for areas of the distribution system under observation for expected future issues….*
>
> *…Regarding the first factor, in the case of Forest Grove Feeder uprate project, if there had been more time available for planning to prevent low pressure events, then other alternative solutions may have been achieved. Unfortunately, neither the 2018 IRP filed in August 2018 or the IRP 2018 Update filed in March 2021 mentioned Forest Grove as an area that had been monitored and might require a system upgrade.*[39]

NW Natural agrees with Staff's that *when* an evaluation occurs is a crucial factor for evaluating GeoTEE or GeoDR as these have additional lead times required to implement and ramp up to the required level. However, we disagree with Staff's assessment that additional time for the Forest Grove area could have resulted in an alternative solution to maintain reliable service in the area. Contrary to Staff's statement, the Forest Grove area has been an area NW Natural has been monitoring for several years and has been included in the Company's 10-year distribution system as indicated by our 2018 IRP filings. Staff is incorrect here, as the 10-year plan was filed with the 2018 IRP as a part of the discovery process in LC 71 OPUC DR 123. Staff is correct that the Forest Grove area was not mentioned in the 2018 IRP update #3 or any of subsequent filings associated with the update, but the Forest Grove area has been in the Company's 10-year plan and has been monitored several years now.

NW Natural conducted a thorough alternatives analysis, looking at targeted interruptibility agreements with large firm customers and satellite LNG. Costs, technical feasibility, and social desirability of implementing Geographically Targeted Energy Efficiency (GeoTEE) or Geographically Targeted Demand (GeoDR) as real options are still in development and were not considered for the Forest Grove area as action is currently needed to maintain reliable service in the area.

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[39] Staff's Final Comments at 25.

OPUC Staff Recommendation 23: NW Natural should convene a stakeholder group immediately following the conclusion of the IRP to establish a transport customer efficiency program in time to be able to report on its status in the 2024 IRP update.

NW Natural agrees with Staff on this recommendation and is encouraged to note that Staff and NW Natural are on the same page regarding the importance of energy efficiency (EE) to NW Natural's CPP compliance strategy and the immediate need for stakeholder engagement to update stakeholders on the progress of the energy efficiency program for transportation customers. Indeed, NW Natural has been proactively pursuing a transportation EE program and intends to hold a stakeholder workshop on the transportation EE program in July 2023. Specifically, anticipating the establishment of the CPP directed by Executive Order 2020-04 by Governor Brown in March 2020, NW Natural engaged AEG to conduct a transportation conservation potential study for Oregon, which was completed in 2022 and provided annual EE savings forecasts for the transportation customers in Oregon from 2022 to 2050 (see Chapter 5 Section 5.3 in the 2022 IRP for more details). In addition to the transportation potential study, NW Natural has included transportation schedule loads in the 2022 IRP optimization modeling (see Executive Summary Section 1.3 in the 2022 IRP for a high-level description and Section 3.2.4 for more details) and conducted some field audits at transportation customer sites wherever accessible to better our understanding of what typical site projects and energy reductions look like. As detailed in NW Natural's reply to LC 79 OPUC DR 16 (Page 49 of 119) on Feb 3, 2023:

> *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.*

The scheduled stakeholder workshop is intended to update stakeholders on the status of the transportation EE program activities NW Natural has accomplished so far and collect feedback on program design, implementation, oversight, and evaluation from all stakeholders including AWEC, Commission Staff, and potentially ETO. Furthermore, NW Natural is also appreciative of Staff's support for "immediately waiving the rules prohibiting the sharing of transport customer information with Energy Trust" in their Final Comments. As stated in the Executive Summary, Oregon Emissions Compliance Action Items #6, in the 2022 IRP, NW Natural has planned to "Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024. While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action."

OPUC Staff Recommendation 24: NW Natural, in the development of a transport customer efficiency program for 2024, should explore and share findings regarding an incentive that would adequately incentivize efficiency, but would not be applied as a flat, per therm rate to usage reductions for operational, economic, or other reasons.

As explained in Chapter 4, Section 4.3.2 in the 2022 IRP as well as in NW Natural's response to Staff LC 79 OPUC DR 109, energy efficiency will displace differing marginal resources with time-varying costs for CPP compliance over the planning horizon:

> *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.*

Offering EE programs to transportation customers whom NW Natural does not sell gas to is new and full of challenges not only to NW Natural but also to ETO as well as other relevant stakeholders. Avoided cost values and their derived cost-effectiveness assessment metrics appropriate for transportation EE programs have been listed among the core agenda for the upcoming stakeholder workshop to be held in the summer.

Staff's Final Comments state "a value for one customer type in avoiding these costs, should be extended to all customer types" so as to avoid potential equity issues to other customer types. It is also the Company's intention to include the findings and proposed incentive design in the development of the transportation customer EE program for 2024. This is in alignment with NW Natural's response to LC 79 AWEC DR 1:

> *Transportation energy efficiency should follow the same cost-effectiveness calculations as other EE so as to maintain an apples-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 develop transportation EE programs it cannot support changing Action Item 6 based upon AWEC's recommended modification.*[40]

[40] NW Natural Reply Comments at 102.

OPUC Staff Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.

Staff's Final Comments incorrectly assert:[41]

> *Line extension costs have been on the order of $30 million per year, or about $2.5 million per year in revenue requirement. This is a substantial amount, and it should be reflected in IRP modeling as a cost that varies between portfolios with different amounts of new customers.*
>
> *In a scenario with load decreasing, the number of new distribution system upgrades needed would also decrease as compared to a scenario with load growth. This difference is not reflected in current IRP scenarios.*

NW Natural agrees that costs that have not historically been included within resource planning models like PLEXOS are important to understanding the total impact to customers. This is why NW Natural is the first – and still the only – utility that has taken the step of attempting to include these costs and combine them with the outputs of the resource planning model to project the total bills customers would be expected to pay inclusive of all costs. This led to NW Natural estimating how these costs, including distribution line extension costs, but also including IT costs, O&M costs, and existing rate base vary across the IRP Scenarios as load (both annual and on peak) vary with load.[42] That NW Natural has done this work was mentioned in the IRP, presented and discussed at Technical Working Group #7 and detailed in the Company's Reply Comments that stated:[43]

> *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. 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.*

For example, the revenue requirement of costs not included in the PLEXOS model by Scenario was assumed to be 40% lower in 2050 in the Full Building Electrification Scenario (Scenario 6) relative to a Scenarios that include a continuation of historical trend load forecast (i.e., reference case forecast, like in Scenario 1) that was used for Scenarios that use a reference case load forecast. It is important to note that much of what makes up these costs are generally considered "fixed" costs, like payments to existing rate base and IT costs.

While NW Natural has not conducted a detailed study to support this 40% reduction figure, we recognize that if load were to fall and fewer customers were added that these costs could decline

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[41] Staff Final Comments at 39.

[42] Noting that synonymous costs are not included in the resource planning optimization models that are used to estimate PVRR in *any* of the utility's IRPs that are filed with the OPUC.

[43] See NW Natural's Reply Comments, at 34-35.

through time. We commit to improving on the groundbreaking work included in the Company's 2022 IRP that allowed the Company to be the first utility in the state to include total customer bill impact projections with the results of each Scenario. Furthermore, the Company commits to providing bill impacts for all Monte Carlo stochastic draws in the next IRP, something that was not done in the 2022 IRP.

In summary, while Staff's comments about the deficiency of not estimating these costs and how they vary across Scenarios would be true for every other utility that files IRPs with the OPUC, its comments are incorrect relative to NW Natural's IRP. Completing this work allowed NW Natural to be the first utility in Oregon to include customer bill impacts in its IRP. NW Natural hopes Staff is consistent in asking for this information for all IRPs filed in Oregon, as understanding customer bill impacts across utilities is important to understanding the relative costs of different types of decarbonization.

It is perhaps noteworthy that the IRPs filed with the OPUC since NW Natural filed its IRP in September, 2022, do not include customer bill projections and do not include an estimate of distribution system costs in the PVRR's for each scenario at all, let alone how they vary with different loads.

OPUC Staff Recommendation 28: In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.

Table 7.4 in the IRP shows all the variables that were treated as uncertain in the Stochastic Monte Carlo Risk analysis.

Table 7.4: Stochastic Variables for Risk Analysis

Stochastic Variables		
Demand Drivers	**Supply Costs and Prices**	**Capacity Resource Costs**
- Weather Daily Temperatures	- Price of Conventional Natural Gas	- Mist Recall
By Load Center: *Albany,*	By hub: *AECO, Opal, Sumas*	- Newport Takeaway 1
Astoria, Coos Bay, The Dalles,	*West Coast Station 2*	- Newport Takeaway 2
Eugene, Lincoln City, Portland,	- Price of RNG Tranche 1	- Newport Takeaway 3
Salem, Vancouver	- Price of RNG Tranche 2	- Upstream Pipeline Expansion
- Customer Growth Rates	- Price Path of Hydrogen	- Mist Expansion
- Growth Moratorium Start Dates	- Cost Adder and Path for Methanation	- Portland LNG Alternative
- Customer Losses	- Allowance Prices	Portland LNG - Cold Box
- Gas Heat Pump Penetration	- Offset Prices	Middle Corridor Mist Takeaway
- Hybrid Heating Penetration	**Supply Availability**	Williams NWP Enhancement
- Building Shell Improvements	- Max Allowable Hydrogen Blend	
- Industrial Energy Efficiency	- Max Annual Quantity of RNG Tranche 1	
	- Max Annual Quantity of RNG Tranche 2	

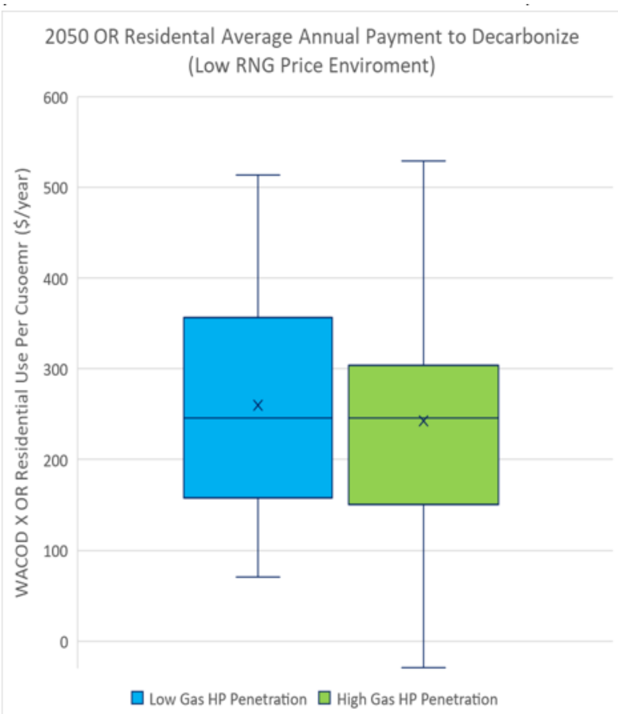
Whereas the stochastic risk analysis treats each variable as uncertain, Scenario analysis does the opposite and pre-determines values for these variables for each scenario. Staff's recommendation is arguing that some of these variables be selected as pre-determined variables, while others are treated as stochastic. If we kept an analysis very high-level to look at varying combinations for pre-determined variables and stochastic variables among the four primary categories, the result is nine sets of analysis that could potentially be included an IRP and 18 sets if stakeholders wished to see counter-factual results for the pre-determined values.

	Demand Drivers	Supply Costs and Prices	Supply Availability	Capacity Resource Costs
Combination 1	Pre-determined	Stochastic	Stochastic	Stochastic
Combination 2	Pre-determined	Pre-determined	Stochastic	Stochastic
Combination 3	Pre-determined	Pre-determined	Pre-determined	Stochastic
Combination 4	Stochastic	Pre-determined	Stochastic	Stochastic
Combination 5	Stochastic	Pre-determined	Pre-determined	Stochastic
Combination 6	Stochastic	Pre-determined	Pre-determined	Pre-determined
Combination 7	Stochastic	Stochastic	Pre-determined	Stochastic
Combination 8	Stochastic	Stochastic	Pre-determined	Pre-determined
Combination 9	Stochastic	Stochastic	Stochastic	Pre-determined

Staff, however, uses an example asking for analysis of combination of pre-determined values and stochastic values of specific variables within these broad categories. Staff's Final Comments state,

> *For example, the Company's current approach makes it difficult to analyze how the NPVRR of a portfolio resulting from a low RNG price scenario would respond to an unexpected change in load or the adoption of gas heat pumps.*

Given the list of stochastic variables in Table 7.4, this type of recommendation could lead to 325 sets of pre-determined vs stochastic combinations (and 650 sets if counter-factual are requested).



Low RNG Price/Low Gas HP Penetration (52 Draws)

- Average of RNG Tranche 1 and RNG Tranche 2 bundled price is less than $17.35 / MMBtu (mean)

- Gas Heat Pump Penetration in 2050 is less than 15% (20th percentile)

Low RNG Price/High Gas HP Penetration (50 Draws)

- Average of RNG Tranche 1 and RNG Tranche 2 bundled price is less than $17.35 / MMBtu (mean)

- Gas Heat Pump Penetration in 2050 is greater than 30% (80th percentile)

NW Natural's approach allows the outputs from the Monte Carlo process to provide the information needed to assess any potential combination of uncertain variables that stakeholders may wish to examine. As an example, we can use the results from Monte Carlo analysis provided in the work papers to understand the implications on residential payments to decarbonize for high/low gas heat pump adoption rates in a low RNG price environment as pointed out in Staff's example.

This example illustrates of how our approach allows the outputs from the IRP to be beneficial beyond writing the IRP, with less regret of not having conducted specific sensitivities within a single scenario. Running Monte Carlo sensitives (i.e., selecting some variables as stochastic while pre-determining others) for specific variables through PLEXOS is a significant amount of work and it is not possible to conduct for all 650 combinations pre-determined and stochastics variables. Nor can we predict the specific combinations that stakeholders would want to see.

NW Natural is not opposed to running specific sensitives requested by Staff, but we request that these asks have a clear justification how a Monte Carlo sensitivity for a subset for specific variables would help evaluate the Action Plan beyond the information already provided by our Monte Carlo approach. For this example, it is unclear how a sensitivity on pre-determined low RNG prices combined with stochastic heat pump adoption rates would benefit an evaluation of any of our Action Plan items. NW Natural believes the best approach is treating the key uncertain variables as uncertain across all variables using the best knowledge that we to inform the range, average, and underlying distribution of those stochastic variables. With a reasonable sample size, we can use the outputs to examine numerous sensitivities.

OPUC Staff Recommendation 29: NW Natural's next IRP should provide metrics comparing the severity and variability of risk in key portfolios.

Staff's report references metrics and methods used by electric utilities to evaluate major investments in different types of resources (e.g., wind plus batteries, pumped hydro, or combined cycle). Staff references Appendix H of PGE's 2019 IRP, which shows risk metrics for 46 separate combinations of near-term resources investments that were considered in their IRP as potential candidates for acknowledgement in their Action Plan. These separate combinations of electric resources are first selected to maintain a level of reliable service.[44] However, beyond meeting the reliability requirement, these resources all provide different levels and different types of secondary services all at different costs. For example, both batteries and a combustion turbine can provide capacity during peak times, but only the combustion turbine generates electricity. Additionally, these different electric resources also have significant differences in their impact on emissions. Beyond the near-term (i.e., potential decisions for the Action Plan) PGE's modelling is unrestricted to select resources as appropriate in the long-term. Given this diverse set of resources that could appear in PGE's Action Plan, it is appropriate for the electric utilities to analyze the different risk metrics they have presented before asking for acknowledgment of a large investment.

NW Natural does calculate risk metrics for investment decisions. For example, risk metrics are a critical component to the RNG incremental cost workbook used for evaluating and justifying prospective RNG projects. For capacity resources, Mist Recall is shown to be the least-cost resource in all 500 draws to meet incremental peak day requirements. The Portland Cold Box was also selected in all 500 Monte Carlo draws. A counter factual, where replacing the Cold Box was not an option made available for selection requiring the next best alternative is selected, would only skew the NPVRR towards higher costs in every draw. If the Cold Box was selected in half of the Monte Carlo draws and not selected in

[44] PGE's Appendix H specifies that each portfolio must meet a loss of load expectation (LOLE) requirement of 2.4 hours per year.

the other half of the draws, risk metrics, such as a risk adjusted PVRR, could be used to be used to determine the appropriate course of action.

NW Natural uses the risk adjusted PVRR (rPVRR) as a risk metric to compare investment options. As an example this risk metric is deployed in the incremental cost workbook for RNG and is defined as (75%)*deterministic PVRR + (25%)*95th Percentile PVRR. As the Cold Box was selected in all 500 draws it was not necessary to calculate this rPVRR relative to the other options. Staff Recommendation 37 is requesting that NW Natural consider downside risk (i.e., the potential of good outcomes) to be factored into the equation. The current calculation is constructed to be risk adverse and only consider risk of bad outcomes but may change in the next IRP. Please see NW Natural's response to recommendation 37.

For compliance resources, Staff's recommendation would be valid if NW Natural was attempting to evaluate a large investment in an on-system hydrogen project in lieu of RNG resources. If this were the case, then it would make sense for analysis to examine the range of outcomes for making the investment against an alternative portfolio.

OPUC Staff Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential and the effects of dual fuel technology on peak and average load on the gas system.

Staff Final Comments state[45,46]:

> *(I)n the next IRP, NW Natural should study the effect of dual fuel systems on gas system peak load, storage needs during cold weather periods, and gas system daily average load. It will be important to gain insight into what types of resource decisions today have the lowest regrets in a dual fuel heat pump future. Staff recommends the next IRP more fully explore the potential of dual fuel heat pumps an ensure that some dual-fuel futures are represented in any Monte Carlo risk analysis. These types of low load, high peak load scenarios do not appear to be represented in the present IRP's Monte Carlo.*

The 2022 IRP includes incredibly in-depth information that can be used for understanding the potential impact to peak and average load on the gas system of dual-fuel heating systems. One of the most challenging analytical and computational issues NW Natural faced in completing the analysis for the 2022 IRP was deploying its dual-fuel heat pump penetration assumptions into the daily load forecasts of each Scenario and Monte Carlo stochastic draw, inclusive of under peak conditions. This required estimating the change in the temperature dependent usage coefficients of the average residential and small commercial customer for temperatures above and below the assumed temperature when supplemental heat is needed and the customer begins using gas for heating rather than the electric heat pump (assumed to be 40 degrees in the 2022 IRP). Combining these average customer usage coefficients as a function of temperature and with the daily stochastic results from the weather simulations and customer count simulations allowed daily load to be calculated for day for each Monte Carlo draw while incorporating the expected impact of hybrid heating systems (as well as gas heat pumps and other energy efficiency). Peak weather conditions were imposed upon a single day in each year of each draw to ensure that capacity needs were met in each year of each Monte Carlo draw.

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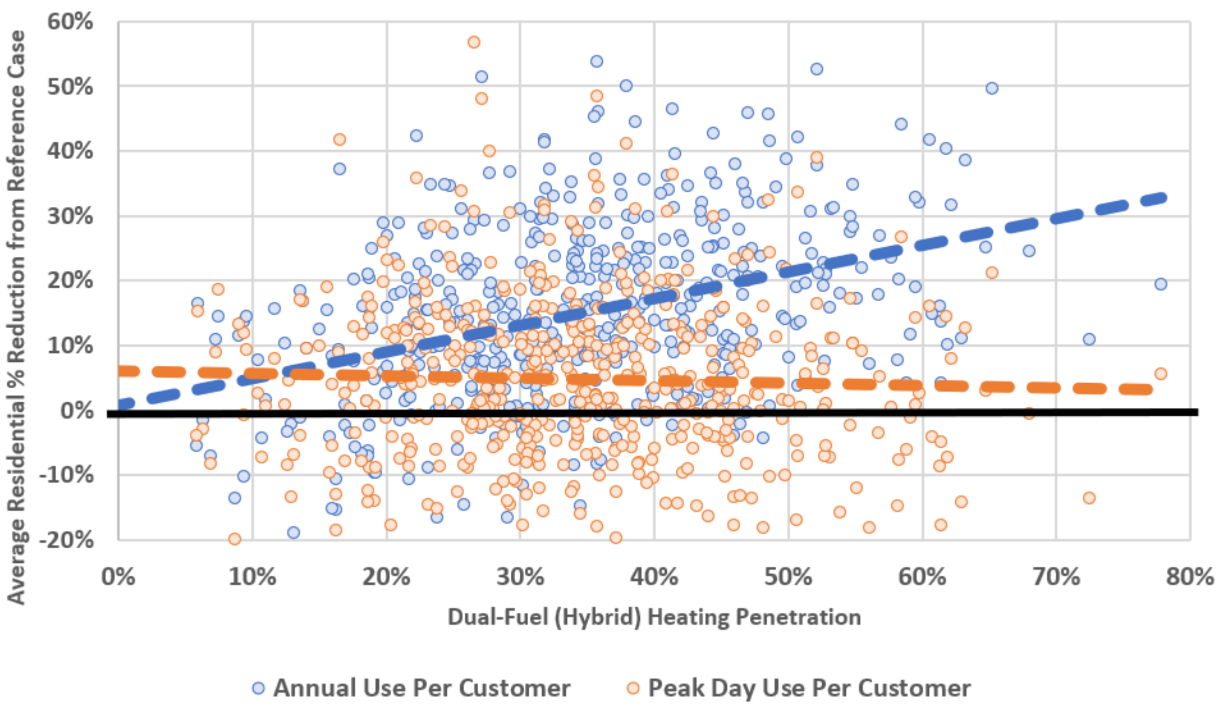
[45] Staff Final Comments, at 47-48.

[46] While Staff's statement about what is included in the IRP is incorrect, NW Natural appreciates the non-declarative nature of the comment.

Figure 2 shows the impact on load in 2050 – both on an annual basis and on the peak day – for the average residential customer across the 500 Monte Carlo stochastic simulation draws as a function of the penetration of dual-fuel heating as a share of customers. It is important to note that variation is expected given that there are many other factors that vary across the stochastic draws (e.g., natural gas heat pump penetration, shell measure energy efficiency, existing vs. new customer breakdowns, and most importantly given that we are looking only at one year is weather):

Figure 2: Monte Carlo Draw Results in 2050: Impact of Dual-Fuel Heating on Residential Load



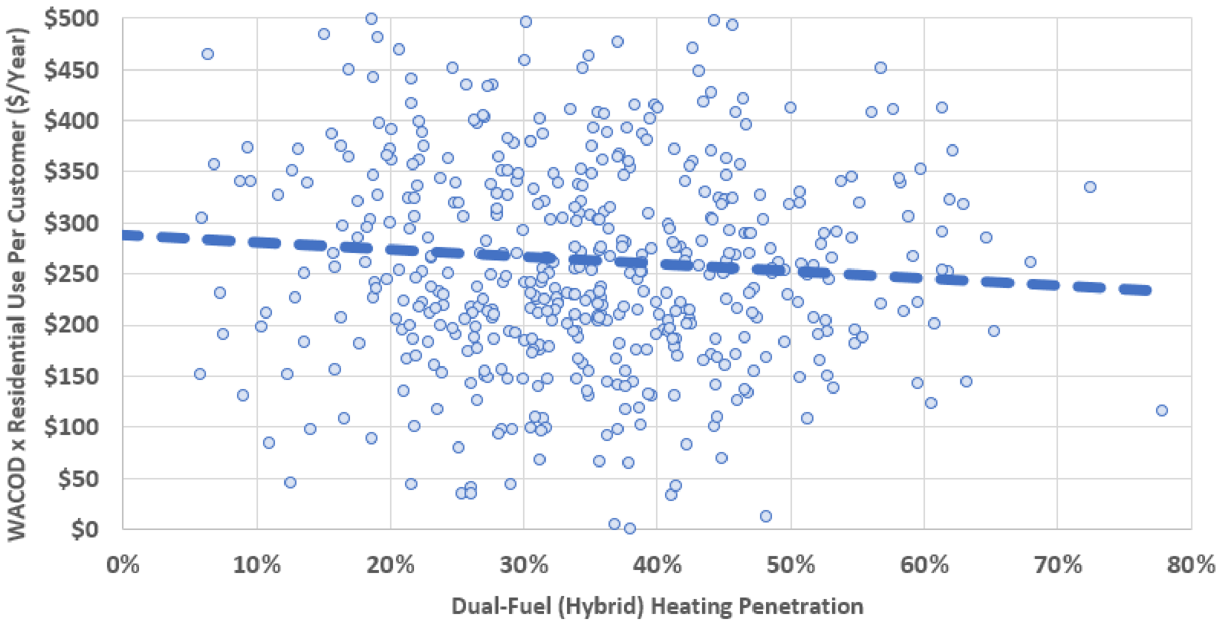
The results are as expected: on average across draws, dual-fuel heating penetration does not have much of an impact on average residential *peak day* usage, but the greater the dual-fuel heating penetration, the greater the reduction in average annual residential usage, and the reduction in annual load is substantial at high penetrations of dual-fuel heating.[47] For example, a 70% penetration of dual-fuel heating would be expected to reduce total annual residential usage by 30%.[48]

Figure 3 shows much the average residential customer would be paying for decarbonization (including supply-side measures like RNG and hydrogen, CCIs, and demand-side measures like dual-fuel heating incentives and other energy efficiency work) across stochastic draws:

[47] Noting that the average is includes customers with a hybrid system and other heating system types, and that usage is far lower for the customers with hybrid heating systems on an annual basis.

[48] This figure is not surprising when one considers that not all gas heating load is eliminated when a dual-fuel system is deployed and that residential customers also use gas for other end uses like water heating and cooking.

Figure 3: Monte Carlo Draw Results in 2050: Impact of Dual-Fuel Heating on Annual Average Payment to Decarbonization



This graph shows that on average the greater the heat pump penetration that there is a moderate reduction in the expected amount the average residential customer would pay for decarbonization on an annual basis (i.e., compliance with climate policy) at the end of the planning horizon. If dual-fuel heating penetration is about 75% in 2050 it is expected that a residential customer would pay $50 less per year for decarbonization than if there is no dual-fuel heating penetration. This suggests that dual-fuel heating system deployment, at the assumed incentives levels in the 2022 IRP ($400 collected from NW Natural customers to incent each installation on average[49]),[50] would likely be beneficial to NW Natural customers in terms of complying with the CPP. It is important to note both Figure 2 and 3 (above), while newly generated figures not included in the IRP, are not the result of new analysis. Rather they are constructed with figures included in the workpapers associated with the 2022 IRP provided to stakeholders.

There are many other questions that can be answered relative to what dual-fuel system penetration could mean for NW Natural customers with the results from the analysis in the 2022 IRP that can be helpful now. The Company agrees with Staff that:

> *Given the uncertainty around alternative fuels, electrification, and the interaction of decarbonization policies on the state's energy system broadly, a closer look at dual fuel heating may be a valuable way to understand how this innovative approach to heating may be operated to maximize the benefit to the gas system, the electric system, ratepayers, and the state. The Commission should encourage collaboration between gas and electric utilities in understanding*

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[49] +/- 50% at the 5th and 95th percentile across the stochastic simulations.

[50] See the Company's Reply Comments for a detailed explanation of how this figure is not using gas utility customer funds for electric equipment incentives.

the costs and benefits of dual fuel heat pump scenarios, as compared to electrification scenarios, under decarbonization requirements

And:

dual fuel potential should be among the topics in any discussion of coordination between gas and electric utilities long-term planning that may take place in another venue as directed by the Commission

NW Natural has provided rich information to help understand the impact of dual-fuel systems to gas utility customers that can be useful in the coordination and collaboration with electric utilities as Staff recommends.

OPUC Staff Recommendation 31: In the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies.

The reference case is not a base case and does not represent NW Natural's expected future. This IRP explicitly defined the reference case as:

> *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 used to show how the scenarios being modeled in the IRP differ from the prior "business-as-usual" state.*

Definitionally the load forecast in the Company's preferred portfolio does reflect local, state and federal policies that were enacted since the "business-as-usual" state was altered (in this case with SB 98 and the CPP). As such, unless there is a definitional change, the reference case should not attempt to guess what future local, state, or federal legislation and resolutions may occur, but rather reflect the current laws that were established and included in the historical data that is being used to develop the historical trend projection reference case.

The load forecast in the Company's preferred portfolio, which is the average of the stochastic Monte Carlo draws *does* reflect current and potential future local, state and federal policies as a wide range of possibilities are included in the 500 draws that make up the average.

Additionally, Staff's points out that:

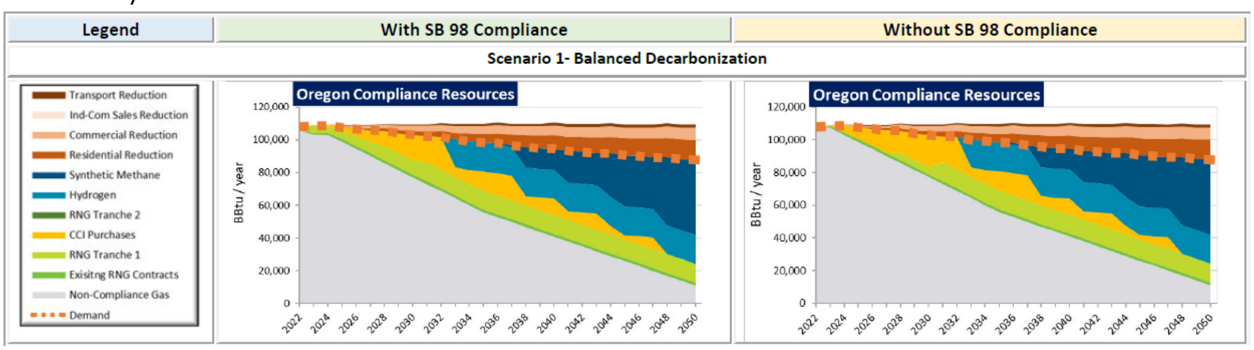
> *Much of the scenario analysis in this IRP is based on an unrealistic customer count forecast and is therefore less useful than it could be.*

NW Natural disagrees with this point. The reference case customer count forecast is used as a baseline for scenario comparison to highlight differences across scenarios for specific changes in underlying scenario inputs. NW Natural believes that is more useful to be able to compare scenarios such as a Customer Moratorium (Scenario 4) or Aggressive Building Electrification (Scenario 5) to a reference case that does not already bake in an assumption about Moratoriums or Electrification. Scenario 3 uses the reference case customer count forecast, but is able to show the impact of dual-fuel heating systems. The results from this scenario would less clear if there was also an arbitrary decrement to the customer count forecast (i.e., how much of the load decline is attributed to the decline in customers versus dual-fuel systems).

OPUC Staff Recommendation 33: The Company should update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency.

NW Natural disagrees with Staff's view that RNG for SB 98 can be avoided with energy efficiency. NW Natural uses the marginal resource needed for CPP compliance as the avoided compliance cost in Oregon. In the near-term, this is the cost of CCIs (regardless of modeling SB 98 or not) and is what is reflected in the near-term avoided compliance costs filed in the IRP. There is a slight change in timing of when the marginal CPP compliance resource changes from CCI's to RNG if SB 98 is modelled, as is discussed here.

In an effort to respond to the December 30, 2022 Stakeholder comments, NW Natural reran the IRP resource optimization model for all nine scenarios without SB 98 compliance and summarized the results in its Reply Comments filed on Feb 3, 2023. As illustrated in Appendix C Scenario Comparisons With and Without SB 98 Compliance for Scenario 1 (per Chapter 4 footnote 84: Marginal resources from Scenario 1 are used to determine avoided costs) (see Pages 110 in OPUC LC NW Natural Reply comments):



When SB 98 is disregarded (see graph on the right), CCIs are the only resource needed for the CPP compliance until 2027. Starting from 2028 to 2032, the marginal resource identified for the CPP compliance is RNG Tranche 1 since the CCI limit has been reached in 2027. In 2033 hydrogen is acquired for CPP compliance as the marginal resources and remains so till 2035 because of its price advantage compared to RNG Tranche 1. Beginning in 2036 synthetic methane is identified to be the additional compliance resource needed for the CPP till the end of the planning horizon of 2050. Because RNG resources rather than CCIs become the marginal compliance resources for the CPP earlier in the planning horizon when SB 98 is modeled as voluntary, the overall avoided costs when SB 98 is voluntary turn out to be 4.1 to 6.5 percent higher than with SB 98 compliance (see their corresponding avoided cost values reported in Tables 2 and 3 shown below).[51]

[51] Table 2 is excerpted from Table 4.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2021$/Dth) in the 2022 IRP: Errata Filing.

Table 2: Avoided Costs with SB 98 Compliance

30 Year Levelized Avoided Costs									
		Natural Gas and Transport Costs	Greenhouse Gas Compliance Costs	Risk Reduction (Hedge) Value	Supply System Costs	Distribution System Costs	10% Conservation Credit	**Total Avoided Costs**
Oregon	Residential Space Heating	$3.83	$7.61	$0.86	$0.64	$4.72	$0.92	**$18.58**
	Residential Hearths and Fireplaces	$3.83	$7.61	$0.86	$0.64	$2.37	$0.68	**$16.00**
	Commercial Space Heating	$3.83	$7.61	$0.86	$0.57	$5.69	$1.01	**$19.57**
	Water Heating	$3.58	$7.61	$0.86	$0.11	$1.07	$0.48	**$13.70**
	Cooking	$3.55	$7.61	$0.86	$0.12	$2.92	$0.66	**$15.72**
	Process Load	$3.55	$7.61	$0.86	$0.09	$0.47	$0.41	**$12.99**
	Interruptible Loads	$3.55	$7.61	$0.86	$0.00	$0.00	$0.36	**$12.38**

Table 3: Avoided Costs without SB 98 Compliance

30 Year Levelized Avoided Costs									
		Natural Gas and Transport Costs	Greenhouse Gas Compliance Costs	Risk Reduction (Hedge) Value	Supply System Costs	Distribution System Costs	10% Conservation Credit	**Total Avoided Costs**	% Change Relative with SB 98
Oregon	Residential Space Heating	$3.83	$8.42	$0.86	$0.64	$4.72	$0.92	**$19.39**	4.4%
	Residential Hearths and Fireplaces	$3.83	$8.42	$0.86	$0.64	$2.37	$0.68	**$16.81**	5.1%
	Commercial Space Heating	$3.83	$8.42	$0.86	$0.57	$5.69	$1.01	**$20.38**	4.1%
	Water Heating	$3.58	$8.42	$0.86	$0.11	$1.07	$0.48	**$14.51**	5.9%
	Cooking	$3.55	$8.42	$0.86	$0.12	$2.92	$0.66	**$16.53**	5.2%
	Process Load	$3.55	$8.42	$0.86	$0.09	$0.47	$0.41	**$13.80**	6.2%
	Interruptible Loads	$3.55	$8.42	$0.86	$0.00	$0.00	$0.36	**$13.19**	6.5%

While NW Natural's analysis indicates avoided costs without SB 98 compliance can be derived and that avoided costs without SB 98 compliance seem to be only slightly higher than those with SB 98 compliance, NW Natural does not support such an update because it is not in alignment with NW Natural's position to comply with both the CPP and meet SB 98 targets because there is no plain, unavoidable, and irreconcilable conflict between SB 98 and the CPP as explained in Section 1.3 of the NW Natural Reply Comments. Moreover, complying with SB 98 RNG acquisition is in effect a useful instrument for the CPP compliance widely accepted by natural gas utilities in Oregon. It is worth noting that as discussed in Chapter 4 Section 4.3.2 in the 2022 IRP, energy efficiency can be used for the CPP compliance, 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. However, energy efficiency cannot avoid RNG acquisition to support SB 98 since no matter how much load is reduced by efficiency, the remaining load served by NW Natural is still subject to the annual RNG percent targets set by SB 98. Therefore, energy efficiency along with early and adequate RNG acquisition is highly desirable for both the CPP and SB 98 compliance given NW Natural's intention to comply with CPP and meet SB 98 targets.

OPUC Staff Recommendations 38-42: NW Natural's General Comments Regarding Cost and Quantity Estimates for Renewable Fuels

Staff's recommendations 38-42 all revolve around concerns about estimating the costs and availability of renewable fuels or have concerns about appropriately analyzing the risks of relying on renewable fuels for CPP compliance. All five recommendations characterize work that needs to be done for the next IRP, but NW Natural would like to make clear to Stakeholders that the requests in these recommendations, to a large extent, were conducted for this IRP and provided through workpapers and data requests. NW Natural uses third party sources for all our cost estimates and provided these sources to Staff. We also use, if available, pricing information for actual projects to justify our cost predictions and Monte Carlo sampling ranges.

Stakeholders may disagree with the sources that NW Natural used to inform our estimates or there may be confusion on how those estimates are translated to the actual inputs into the PLEXOS model. However, both Scenario 8 and the Monte Carlo analysis examined high RNG price/low availability sensitivities. If Stakeholders believe there to be a more realistic representation of the future of RNG (which NW Natural's does not) then we still have and presented the analysis to understand the implication for customers.

NW Natural believes our assessment of the total amount of RNG (roughly 50 million MMBtu/year) available for NW Natural is a conservative estimate. Additionally, only about half the Monte Carlo draws select RNG levels above 11 million MMBtu/year due to cheaper compliance options for the CPP (e.g., CCI in the near-term, and then hydrogen and subsequently synthetic methane later in the planning horizon). NW Natural disagrees with Stakeholders characterizations that hydrogen and synthetic methane are un-proven technologies. Both electrolysis and methanation have been developed and scientifically tested, however; neither are widely deployed due to their higher costs. With policies like the CPP that require decarbonization of the gas system these renewable fuels will become quickly sought after.

OPUC Staff Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.

Staff's final report states,

> Setting aside for a moment the impressive price quote NW Natural has received, it is important to discuss the rigor and transparency of the syngas price forecast in the IRP.[52]

NW Natural see prices of actual actionable resources as stronger evidence to support assumptions than any projection, which is meant to provide an estimate of the prices one would see for actual resources. We do not believe it is appropriate to set this evidence aside.

Part 4: Synapse Energy Economics Report

Synapse's report can be separated into components, 1) a review of NW Natural's IRP and 2) an endeavor to quantify the costs of electrifying NW Natural customers. As a critique of the IRP, there are numerous mischaracterizations about our IRP analysis throughout their report. For example, the report states:

> NWN does not describe how its key Action Plan items, or even the longer-term implication of its preferred portfolio, would be affected by such bad outcomes.

[52] Staff Final Comments, pg. 61.

> Further, NWN does not test important combinations such as lower load and higher RNG prices to determine how robust its preferred portfolio may be.

The Company disagrees with this statement as our Monte Carlo analysis has sufficiently examined a range of futures, including combinations of lower load and higher RNG prices. For other mischaracterization that have filtered through to Staff's comments the Company believes we have addressed these in the Sections 2 and Section 3 and for go addressing further misstatements in Synapses report. Instead, we focus on the second aspect of Synapse's report that looks at the cost of electrification.

To this end, NW Natural appreciates that Staff is actively engaging in studying the consequences to the electric grid, the emissions impact, and the total costs of electrifying NW Natural's customers. Attempting to understand the incremental costs to both the individual customer for electrifying their home and the rate impacts to all electric customers for incremental generation, transmission and distribution system upgrades is a step towards this goal. However, NW Natural sees 4 major shortcomings that the Company believes makes the electrification cost estimates in the report dangerous to use and biased towards electrification. We note that these are not the only issues NW Natural sees as problematic with this report and has additional concerns about the lack of transparency and engagement of utilities for producing this report.

Reason 1: Costs Estimates for electrification uses current electric rates

> *Operational costs of electrified load, using $/MWh average retail costs across the three major sectors. We use current electric rates in the Pacific Northwest (PGE as a proxy) and we assume constant real costs in electricity rates for electrified load.*

Current electrification rates, specifically PGE's rates, do not reflect the rate impacts from the investments that must occur for PGE to meet HB 2021 targets. The generation and transmission resources needed to meeting HB 2021 targets will necessarily increase electricity rates. This even prior to needing additional generation and transmission investments if the grid must meet NW Natural's space heating and water heating requirements.

NW Natural is not surprised that Synapse did not attempt to forecast the impacts of HB 2021 or electrification of space heating into electric rates. This is a task that only the electric utilities can realistically do using their own resource planning tools that acquires the least cost resources to both reliably serve customers and reduce emissions and taking those investments through a customer rate impact analysis. NW Natural has pointed this out in several forums and is the reason why the Company does not attempt to develop our own estimates of electric rate impacts in our IRP scenarios. NW Natural does not believe that it is feasible for electric utilities in Oregon to comply with HB 2021 and absorb electrifying customers without a significant impact to electricity rates.

Reason 2: Electrification of space heating will have a major impact to electric system peak load.

> *This assumption may hold true if heating electrification does not dramatically increase the overall electric system peak load. Given the high prevalence of resistive heating technologies in the Pacific region—26 percent of households (EIA. 2020. Residential Energy Consumption Survey)—converting resistive heating equipment to*

heat pumps could substantially lower winter peak loads relative to a scenario that does not.

Synapse justifies using current rates as a proxy if space heating electrification does not increase the electric system peak load. This is not a realistic claim, especially for a region whose electricity grid is already winter peaking. Every customer that electrifies from natural gas space heating contributes incremental load to the electric grid, regardless of the efficiency of the heat pumps that is being installed. Synapse points to being able to target the replacement of resistive heating with heat pumps to mitigate the peak requirement. NW Natural does not dispute that this could be an effective peak savings EE program, but then the costs of replacing a quarter of the regions heating systems would need to be included into the electrification cost estimate appropriately evaluated for it over all peak impact relative to adding NW Natural's customer base to the electric grid.

Reason 3: Synapse assumes that all electrification has zero carbon emissions

For the purposes of this proxy analysis, we assumed newly electrifying heating and hot water load to be zero carbon emissions. We note that RNG resources as used in the IRP context are also considered to be zero-carbon resources. While both these assumptions are likely inaccurate—RNG will have carbon emissions, and electricity will still carry an emission component in the early period of the transformation of the Pacific Northwest system to fully decarbonized sources—for the purpose of this report it is a reasonable assumption to make.

Synapse analysis is assuming the electrifying space and water heating load will have zero carbon emissions. Both PGE and Pacific Corp will be reporting positive emissions to ODEQ through 2040 per HB 2021. Synapse's assumption is deeply flawed and their justification for this assumption is that the life-cycle carbon intensity of RNG is not actually zero as treated by the CPP. Despite that some RNG projects from agricultural waste have a negative carbon intensity, NW Natural does not see how RNG's emissions intensity is relevant for estimating the cost or emission impact for electrification. For further questions on the carbon intensity of RNG and compliance with the CPP, please refer to Chapter 6 of the IRP.

Reason 4: Unreasonably low household and business conversion costs

Synapse suggests that the average incremental cost of converting a residential natural gas customer to electricity would be about $2,068 per household, including $995 per household ($398 per ton with an average of 2.5 tons per household) for space heating and $1,073 per household for water heating. These cost estimates are based on comparative technology cost estimates from California. The costs estimated by Synergy include only the new equipment costs and the costs of installing new equipment but do not accurately reflect the full costs of converting existing residential buildings from gas to electricity.

a. Synergy uses California equipment cost estimates to calculate an incremental conversion cost at the time of equipment replacement. However, assessments of conversion costs should be based on actual data where available, and we are now starting to see actual conversion cost data from other states.

b. A recent California pilot program converted more than 10,000 residential customers to electricity at an average cost of $18,876 per household for space heating and $7,245 per household for water heating.[53]
c. Using the actual conversion costs per household from the California pilot program would increase the electrification costs for the residential sector estimated by Synergy for Scenario 6 by more than $18 billion, making the electrification scenario much more expensive than any of the other scenarios evaluated.
d.

Respectfully Submitted,

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[53] https://techcleanca.com/

Appendix A

NW Natural Reponses to
LC 71 OPUC DR 52, 71 OPUC DR 95,
and LC 71 OPUC DR 137 Supplemental

Request No.: LC 71 OPUC DR 52
52. Please provide further explanation of the January 2017 outages and/or pressure drops experienced in each of the locations for which NW Natural is seeking acknowledgement in the Action Plan for reinforcement projects. In your response, please include the following information:

a. Was this an isolated incident that occurred on one day or was this a prolonged event? Please provide dates and times for all related projects.

b. At what time and on which days in January 2017 were there observed pressure drops during non-peak conditions at the affected locations?

c. What percentage share of customers served in each of these locations separately was impacted by outage event(s)? How many customers were impacted by the January 2017 event?

d. Please provide all outage reports associated with the January 2017 event, with a narrative and references to the outage reports, illustrating why current operating conditions no longer meet demand or safety standards.

Request No.: LC 71 OPUC DR 52 – **Supplement Request**
52. Please provide at 10 different data points each for both the Happy Valley and North Eugene distribution system projects and using these additional data points, demonstrate how the modeling is accurate.

1. For the localized model verification, we request all SCADA data, field pressure readings, and charts from the relevant local area during the recent cold weather event. These should be displayed side-by-side with the Synergi modeling output for the same location under the same conditions.
2. We also request all nearby field pressure reading data for the relevant local area surrounding each project. The data should include the precise location of the pressure reading. Please include all data fields documented about these field readings, including any remedial action taken.

Response:

DR's 52, 55, 56, 57, and 58 are requests to gather information about the six 2018 IRP action item projects in an attempt to clarify why these projects need to be completed. NW Natural met with OPUC staff on Wednesday, October 10, 2018 to relay information about many of our processes and to clarify data requests. OPUC staff requested that NW Natural present the results for these data requests in project specific narrative format to ease individual project interpretation and evaluation.

LC 71 OPUC DR 52 Attachment A and Attachments 1-2 provide narratives and supporting data for each individual action item project that are presented in lieu of direct responses to DR's 52, 55, 56, 57, and 58.

LC 71 OPUC DR 52 Attachment A contains project narratives for each of the six action item projects.

LC 71 OPUC DR Attachment 1 contains a list of customer outages that occurred during the January 5-6, 2017 cold weather event from the Hood River and Oregon City project areas.

LC 71 OPUC DR Attachment 2 contains historical weather data (1985-Present) for each of the project areas. This data ranks cold weather events by severity and is presented to support that January 2017 weather was not anomalous, nor a peak weather event.

<u>February 8, 2019 Supplemental Response:</u>

As a supplement to DR 52, Staff is requesting additional information that validates the accuracy of the Synergi modeling process for each low pressure distribution system project during a cold weather event. The projects in Happy Valley and North Eugene were initiated by modeled results that show substandard pressures which will impact customers under peak demand conditions. Models cannot be validated at peak because peak pressure data is not available. Pressure data from January 2017 must be used to validate models. Data tables and maps are presented for the two low pressure distribution system projects below.

Happy Valley Reinforcement Project

The Happy Valley Project area is surrounded by SCADA sites but there is no SCADA data directly in the weakest zone. There are Cold Weather Pressure Survey sites within the weakest zone and a cold weather survey was performed in the Portland area on Jan 4, 2017. Note that the data from map locations #1 through #4 have not been provided to date. In revisiting pressure read records, we were able to locate actual pressure data from within the project area confirming that system standards were violated. The field pressure reading of 9 psig at location #2 indicates a violation of distribution system reinforcement standards. Colder weather actually occurred on Jan 5 & 6, 2017 but no cold weather pressure survey was performed. A model date of Jan 4, 2017 at 7am was selected to provide the greatest number of points for comparison.

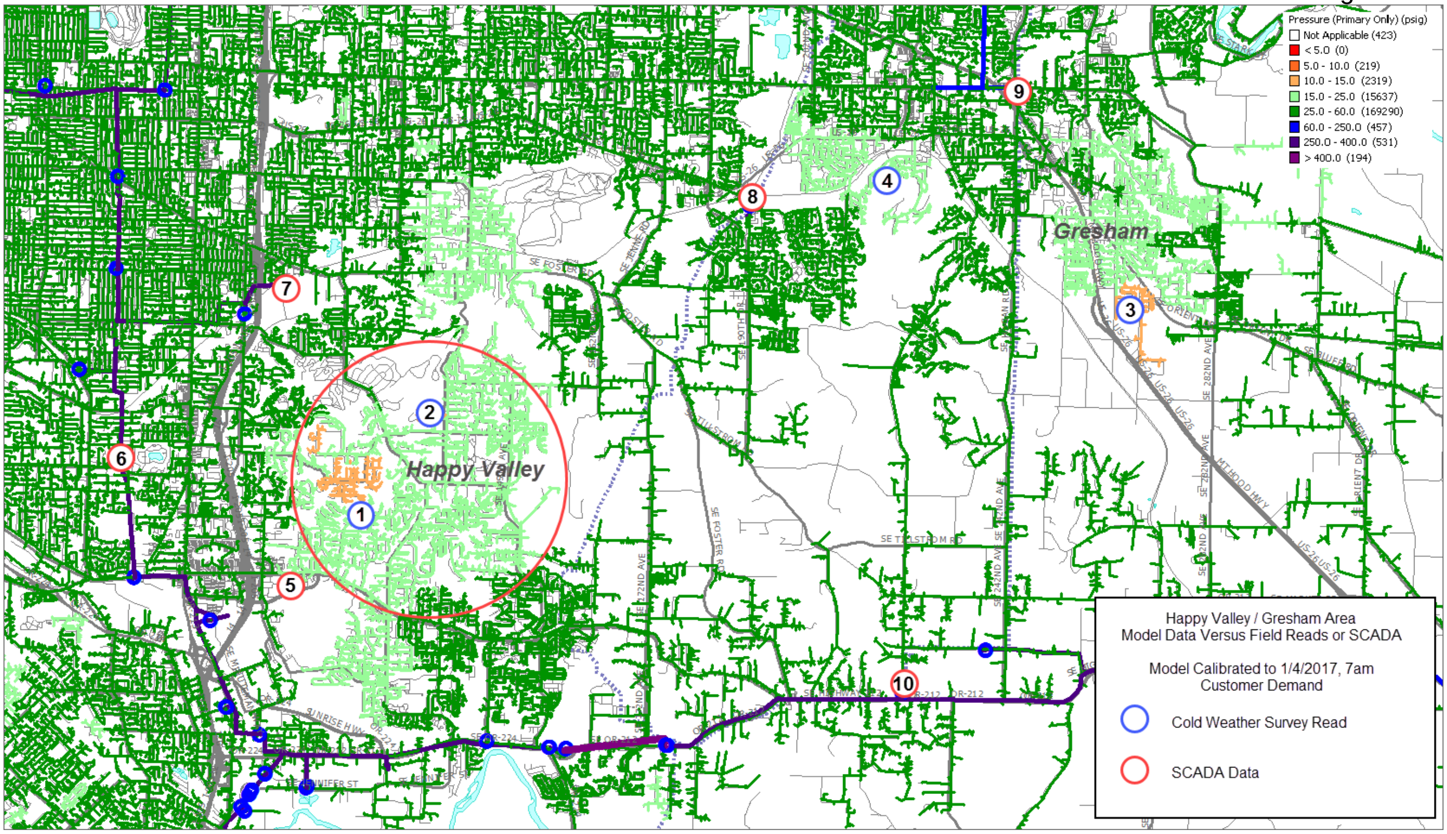
Happy Valley Area Modeling Data versus Field Collected Data or SCADA Data

Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	1-041-042	11150 SE Valley View Terrace	Happy Valley	01/04/17	7:15 AM	22	18.7
2	1-039-043	12601 SE Callahan Rd	Happy Valley	01/04/17	7:00 AM	9	11
3	1-036-056	2927 SE Kane Ave	Gresham	01/04/17	6:57 AM	17	14.5
4	1-034-052	830 SW Florence Place	Gresham	01/04/17	6:45 AM	18	18.3

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/04/17	7:00 AM	23.5	24.1
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/04/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/04/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/04/17	7:00 AM	42	48.3
9	1-032-054	Gresham Gate Station	Gresham	01/04/17	7:00 AM	45	48.6
10	1-044-054	Sandy Gate Station	Boring	01/04/17	7:00 AM	47.8	50

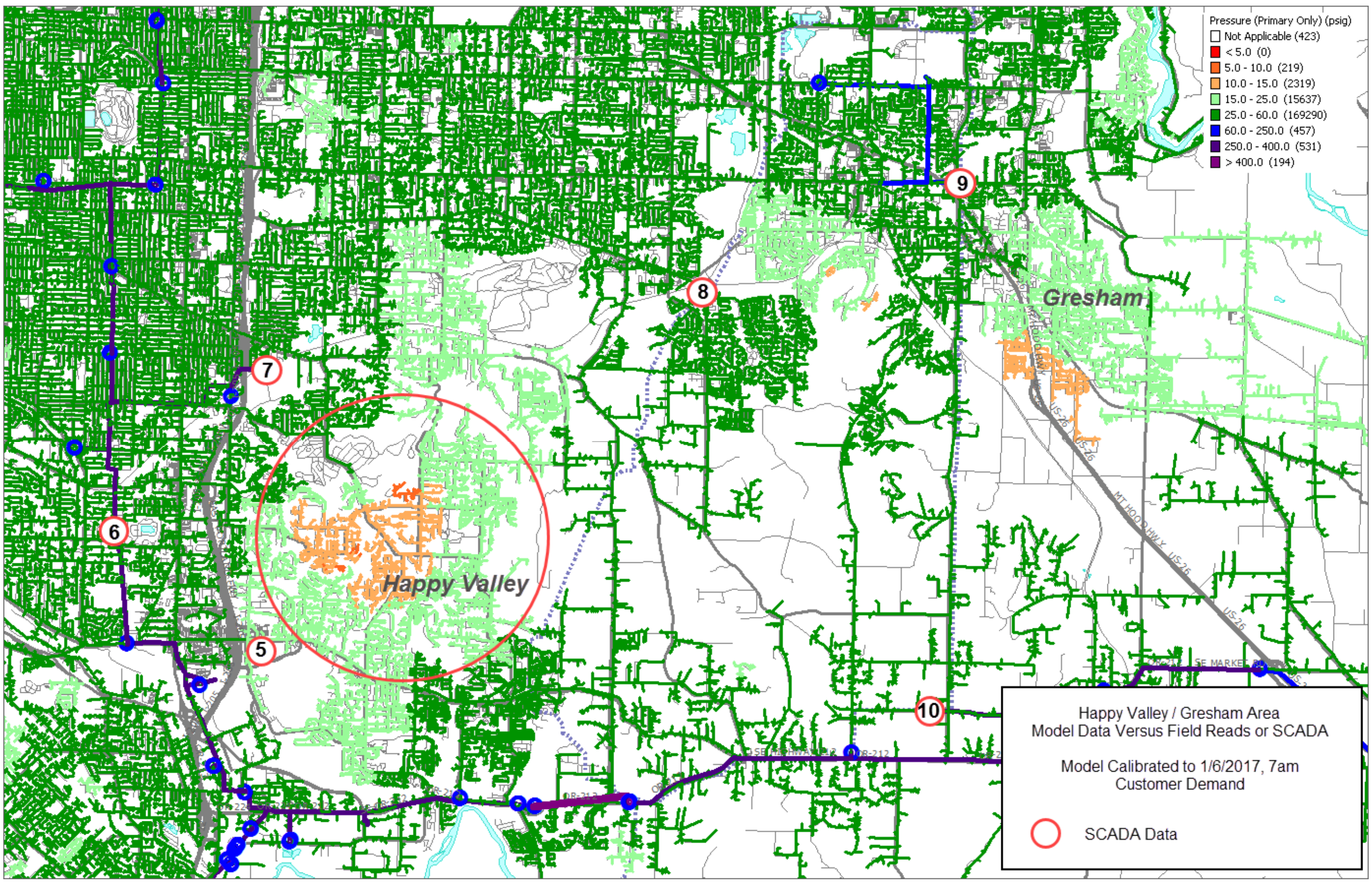
The model used for this analysis was tuned for Jan 4, 2017, 7am, the time of the highest instantaneous demand for the day. This day was chosen because it corresponds with pressure data collected from a Cold Weather Pressure Survey.

The following map shows the location of the pressure comparison data points and the general project area for Happy Valley. Note that the figure below shows system conditions based on January 4th, 2017 at 7am.

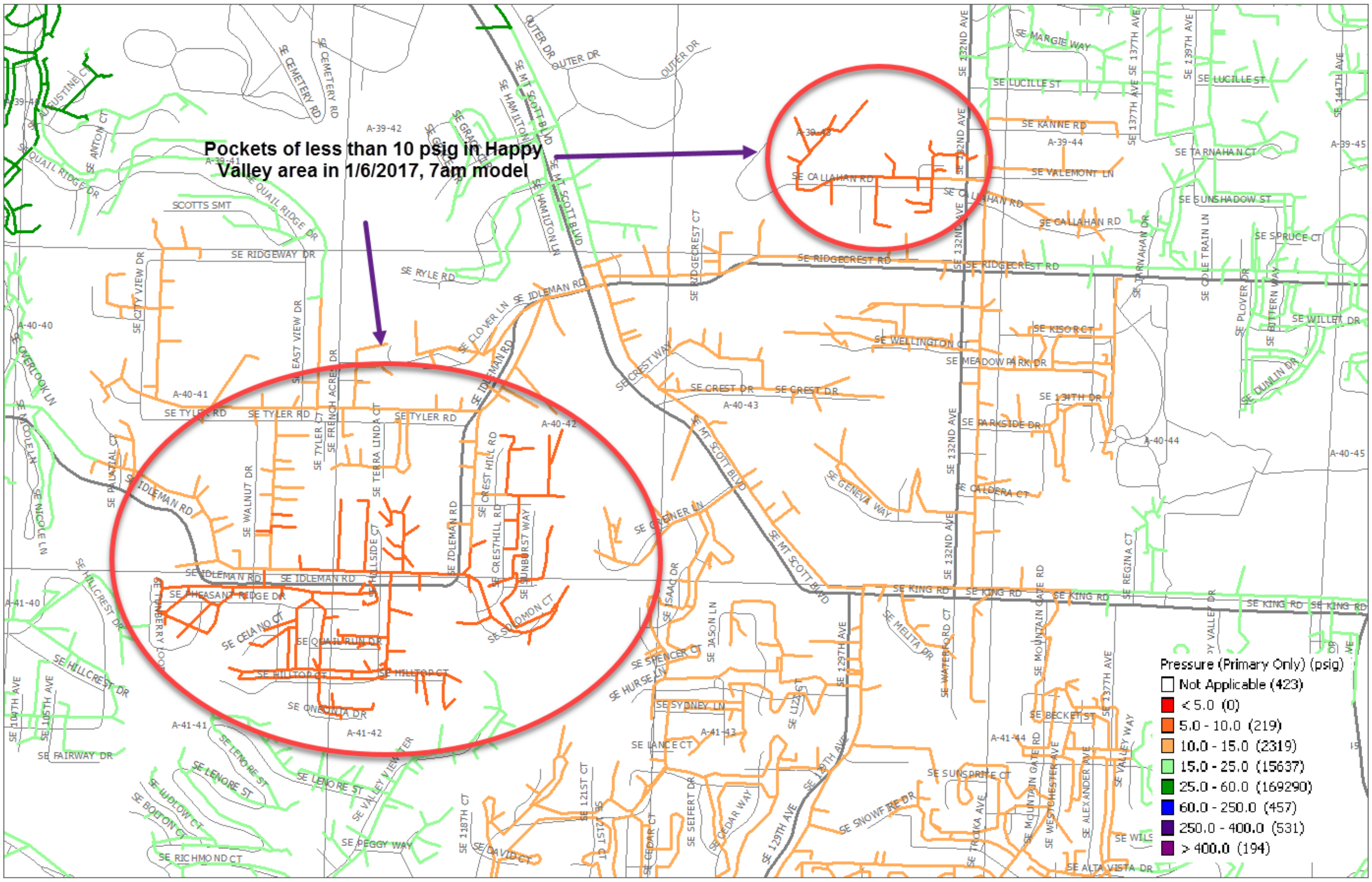

Pressure (Primary Only) (psig)
Not Applicable (423)
< 5.0 (0)
5.0 - 10.0 (219)
10.0 - 15.0 (2319)
15.0 - 25.0 (15637)
25.0 - 60.0 (169290)
60.0 - 250.0 (457)
250.0 - 400.0 (531)
> 400.0 (194)
Happy Valley
Gresham
Happy Valley / Gresham Area
Model Data Versus Field Reads or SCADA
Model Calibrated to 1/4/2017, 7am
Customer Demand
Cold Weather Survey Read
SCADA Data

The table and map below show modeled system conditions based on January 6th, 2017, 7am customer demand when temperatures were on average, four degrees colder. Note the significant change in pressures within the Happy Valley area between the two cold mornings.

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/06/17	7:00 AM	19.6	21.4
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/06/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/06/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/06/17	7:00 AM	39.6	47.3
9	1-032-054	Gresham Gate Station	Gresham	01/06/17	7:00 AM	43.9	48
10	1-044-054	Sandy Gate Station	Boring	01/06/17	7:00 AM	47.5	50



The following map shows the areas of Happy Valley that the Jan 6, 2017 7am model calculates pressures to be less than 10 psig, violating our distribution system standards.



North Eugene Reinforcement Project

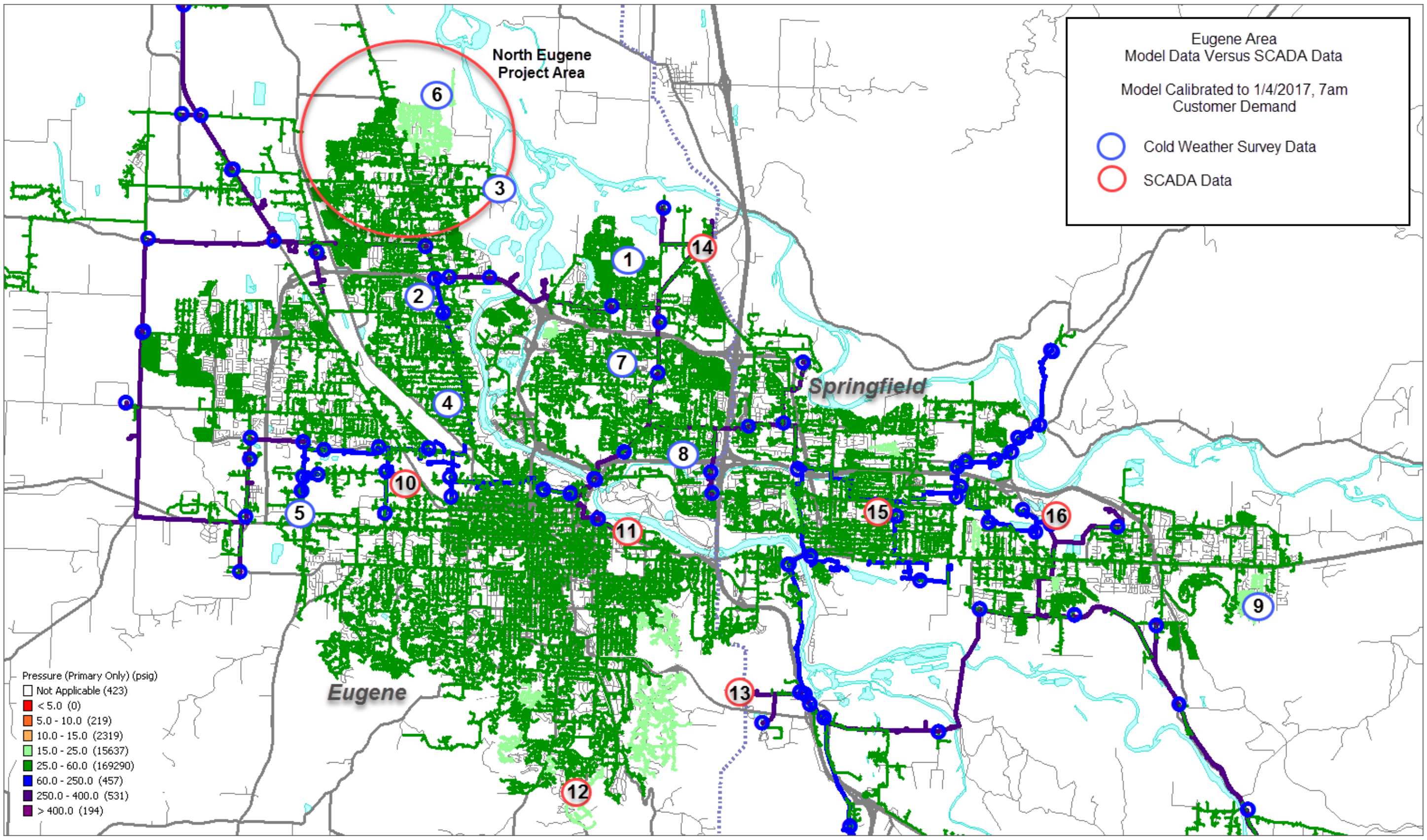
The North Eugene Project area has no SCADA sites within the project area or nearby. There are Cold Weather Pressure Survey sites within the weakest zone and a cold weather survey was performed in the Eugene area on Jan 4, 2017. Note that the data from map locations #1 through #9 have not been provided to date. Similar to Happy Valley, in revisiting pressure read records, we were able to locate actual pressure data from within the project area. A model date of Jan 4, 2017 was selected because it was the highest demand day in this area.

Eugene Area Modeling Data versus Field Collected or SCADA Data

Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	2-226-010	3402 Honeywood St	Eugene	01/04/17	8:24 AM	35	38.1
2	2-227-016	200 Silver Ln	Eugene	01/04/17	7:30 AM	34	35.3
3	2-224-014	205 Chapman Rd	Eugene	01/04/17	7:45 AM	30	27.8
4	2-229-016	1224 Elkay Rd	Eugene	01/04/17	7:18 AM	33	33.3
5	2-233-019	4201 Commerce St	Eugene	01/04/17	7:00 AM	31	34.7
6	2-222-016	909 Beacon (Nursery)	Eugene	01/04/17	7:54 AM	26.5	22.0
7	2-229-010	2225 Jeppesen Acres Rd	Eugene	01/04/17	7:30 AM	34	34.5
8	2-231-009	3395 Oxbow Way	Eugene	01/04/17	7:15 AM	28	28.5
9	1-235-007	1220 S 69th Pl	Springfield	01/04/17	7:15 AM	22	24.2

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
10	2-232-016	Emerald Forest Products	Eugene	01/04/17	7:00 AM	121.2	125.9
11	2-233-010	University of Oregon	Eugene	01/04/17	7:00 AM	352.9	352.6
12	2-240-011	Eugene City Pressure	Eugene	01/04/17	7:00 AM	25.5	25.0
13	2-238-007	South Eugene Gate	Eugene	01/04/17	7:00 AM	379.7	383.7
14	2-226-008	North Eugene Gate	Eugene	01/04/17	7:00 AM	369.9	367.9
15	2-233-003	Springfield City Pressure	Springfield	01/04/17	7:00 AM	26.3	27.9
16	1-232-001	International Paper Reg	Springfield	01/04/17	7:00 AM	135.29	135.0

The following map shows the location of the pressure comparison data points and the general project area for North Eugene. Note that the figure below shows system conditions based on January 4, 2017 at 7:00 am.



Rates & Regulatory Affairs
LC 71
Integrated Resource Planning
Data Request Response

Request No.: LC 71 OPUC DR 95
95. See page 8.5-8.6 of the IRP. The Company describes a series of system reinforcement standards it uses for distribution system planning. Are these Company standards or federal and state safety standards? If these are Company standards, please provide a copy of Company codes that illustrate the standard. If these are federal or state standards, please provide a copy of the code or links to the section that illustrate the standard. If they are both, please provide copies of both standards and provide a description of the differences.

Request No.: LC 71 OPUC DR 95 – **Supplemental Request**
Please provide the citation and quote from the Gas Engineering and Operating Practices (GEOP),that specifically supports NW Natural's parameter (shown below) for high pressure distribution systems and specifically makes reference to the 40% pressure drop.

- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization.

For clarification per Staff: The engineering language supporting the 40% distribution reinforcement standard, and an explanation of why the language supports a 40% reinforcement standard.

Response:

NW Natural has provided the same series of system reinforcement standards it has used for distribution system planning in the 2016, and 2018 IRP's and has been using for many years. Per 8.5-8.6 of the 2018 IRP:

> Transmission and high pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:
>
> - Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated

- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization

This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems

This standard is based on pressure regulator manufacturer requirements. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. Typical manufacturer and models of pressure regulators NW Natural uses are the Mooney Flowgrid, the Honeywell American Axial Flow, and the Fisher 627.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- The ability to meet firm service customer delivery requirements (flow or pressure)

- Identified in the IRP associated with supply requirements or needs

The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated

- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical

This standard is based on the minimum inlet pressure required for an Excess Flow Valve (EFV) to properly function, per 49 CFR §192.381 Service lines: Excess flow valve performance standards:

> (a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- Firm service customer delivery requirements (flow or pressure)

<u>February 8, 2019 Supplemental Response:</u>

NW Natural bases its high pressure pipeline design on the industry design standard documented in Gas Engineering and Operations Practice (GEOP) System Design book. The GEOP design book was created by the American Gas Association and industry members to provide an overview of design practices for gas distribution systems as noted in the Preface of the book (Figure 2 below). Part 1, Capacity Design, of the GEOP book introduces pipeline sizing and pressure drops stating “a properly sized pipe system will have the capacity to deliver gas a sufficient pressure to all customers at all times” (Figure 3 and 4 below). Chapter 2, Gas Flow Calculations, provides an overview of the background of compressed natural gas flow calculations (Figure 5 below).

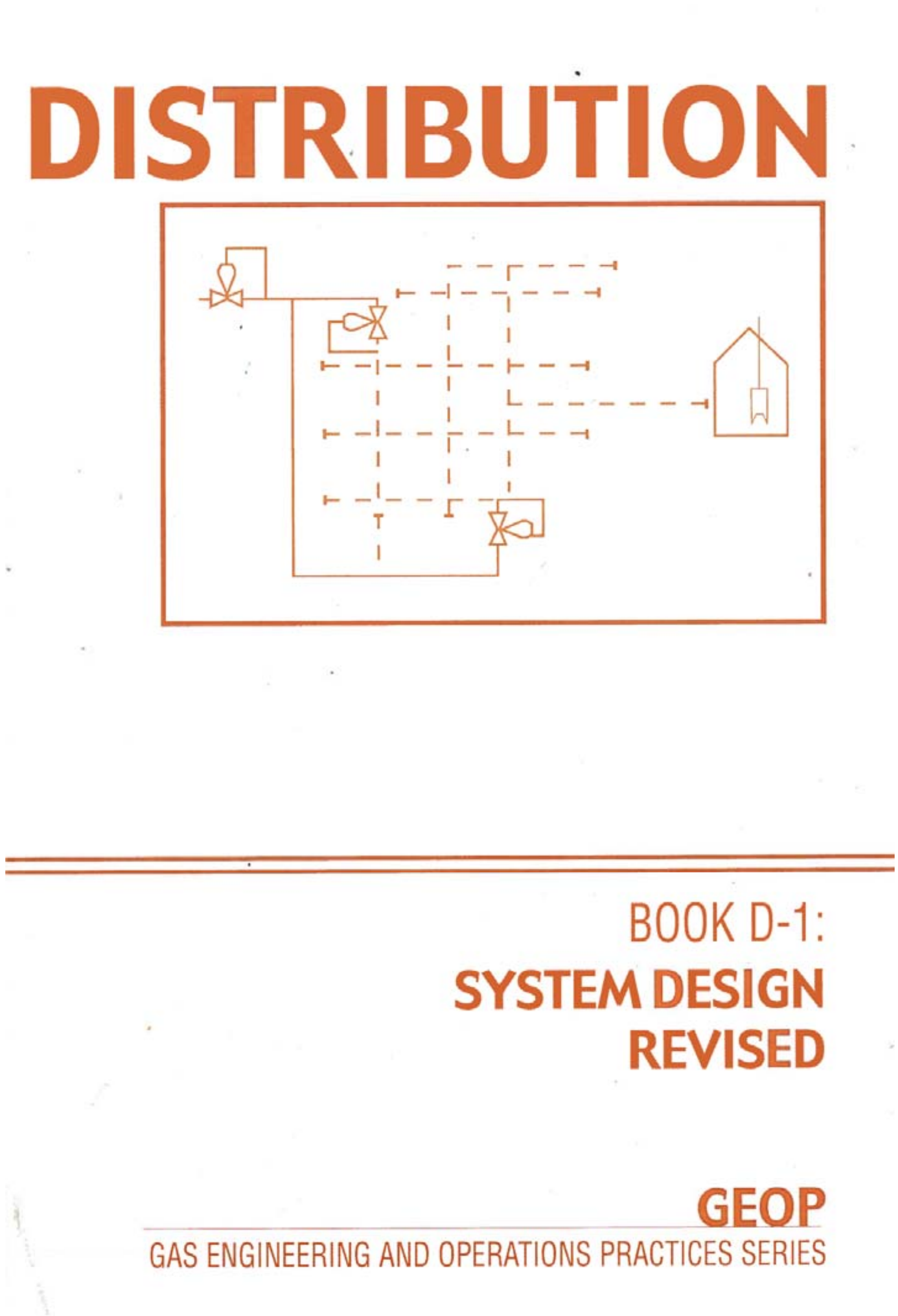


Figure 1 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Cover

PREFACE

Washington, DC
September, 2004

System Design was the sixth book published in 1990 as part of the original Gas Engineering and Operating Practices (GEOP) series. The series comprises six volumes, each consisting of from one to three books in the operational areas of Supply, Transmission, Distribution, Measurement, Utilization, and Technical Services.

System Design, along with *Mains and Services - Operating Considerations,* make up the GEOP Distribution volume. Its purpose is to provide a current, concise-but complete-overview of the materials, equipment, and design practices for gas distribution systems. Whether a new hire or a CEO, you will be pleased with the way that GEOP authors and editors have simplified complicated subjects and gratified to find so much experience and knowledge at your fingertips.

As comprehensive as it is, *System Design* does not pretend to offer specific answers to every question that might arise in practice. The references it provides to other gas technology literature expands its usefulness beyond its contents. Readers owe a special debt of gratitude to Manuela Erickson of Safety and Compliance Evaluation, Inc. who indexed the book.

The contributions of the late Samuel I. Hyman touch many areas in the book. Not only did Sam, a prolific communicator with exceptional knowledge of a broad range of gas industry technology, write extensively for *System Design*, he was also reviewing manuscripts of other writers up to the very end of his life. The result owes much to his contributions, both direct and through his input to and stimulation of others.

Gerald G. Wilson
Chairman, GEOP Task Group, 1990

Robert L. Parker
Editor, 1990

Manuela Erickson, PE
Editor, 2004

Figure 2 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Preface

PART I
CAPACITY DESIGN

SCOPE

When gas is compressed, energy is stored in it; the pressure of the compressed gas is a measure of the amount of energy stored. As compressed natural gas flows through the distribution system's pipe from the source to the customer, its pressure gradually decreases because some of its stored energy is converted by friction to heat, which is lost to the earth in the vicinity of the pipe.

If the mains in a distribution system are too small, the pressure decrease (drop) will be excessive during periods of peak gas demand, resulting in pressures at remote locations in the system that are too low for proper operation of appliances. A properly sized pipe system will have the capacity to deliver gas at sufficient pressure to all customers at all times.

The optimum system will provide the proper capacity with the lowest possible investment. It will have been built with the pipe material most suited to the local circumstances and with proper regard for safety during construction and subsequent operations.

The technology and procedures for handling all of the common types of pipe sizing problems are covered in this Part of the book. The same kinds of information are required to define all pipe-sizing problems:

- Nature of the gas distributed
- Location of gas sources
- Operating restrictions, such as delivery pressures required by commercial or industrial customers
- Amount and distribution of the design load

After this information has been collected, the solution of a service or stub-main problem is straightforward. The smallest size pipe that will do the job should be used. The data used and the calculation procedures are presented in Chapter 2, and examples of their application are presented in Chapter 3.

The first step in the solution of a network problem is to assume a configuration of the pipe sections connecting the gas sources to all the customers. Guidelines for developing good layout patterns for new systems and alternatives for existing systems are presented in Chapter 4. The adequacy of the assumed configuration is checked by a calculation procedure called network analysis, which is described in Chapter 5. Usually, it is necessary to try several pipe configurations and compare their costs before the most economical layout is discerned. System cost comparisons should include the *timing* of the various investments as well as their amounts, because the interest on borrowed capital has a significant influence on the cost outcome, as discussed in

Figure 3 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Part 1, Capacity Design, page 5

Chapter 6.

Computer programs have been developed that use optimization logic to arrive at near-optimum reinforcements for existing systems or pipe layouts for new systems. These also are discussed in Chapter 6.

In summary, the material in Part I provides guidelines and describes many of the tools for capacity planning.

Gerald G. Wilson

Figure 4 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Part 1, Capacity Design, page 6

Chapter 2

GAS FLOW CALCULATIONS

Gerald G. Wilson

The pressure of the gas flowing through a pipe of uniform internal diameter gradually decreases in the direction of flow. The magnitude of the pressure decrease or drop depends on (1) the flow rate, (2) the dimensions and wall roughness of the pipe, and (3) the temperature, average pressure, and physical properties of the flowing gas. Calculations of the pressure drop are often used to determine whether a pipe configuration can deliver gas to the customers it serves at adequate pressure during design conditions.

Usually, the first step in the design of a gas piping system is to use one of the methods described in Chapter 1 to estimate the magnitude and distribution of the design loads that the system will be called upon to carry. Then, flow calculations are used to establish either the pipe sizes required to maintain adequate pressures throughout a new system under design conditions or the ability of an existing system to maintain adequate pressures. The specific procedures used for the common types of design situations are covered in later chapters; this chapter is concerned with the basic flow calculation procedures.

Flow calculations are based on the use of a flow equation, an algebraic relationship that relates the pressure drop to the other flow variables. Since the beginning of commercial transportation and distribution of gas, many different flow equations have been developed and used by the gas industry. The general form of most of them is derived from the Bernoulli energy balance. It includes a frictional energy loss term that must be evaluated empirically from the results of gas flow experiments. Since the experiments on which the various practical flow equations are based were conducted over different ranges of flow conditions, on pipes of different internal surface roughness, and to varying degrees of accuracy, these equations do not give the same results. Most are applicable over only a limited range of flow and pipe surface conditions.

Following a brief review of essential flow fundamentals, this chapter presents a general flow calculation procedure and outlines the ranges of applicability for the various practical flow equations. Examples of common types of flow calculations are given. Finally, some procedures that often can be used to simplify flow calculations are described.

FUNDAMENTALS OF FLUID FLOW

Any basic textbook on fluid mechanics published in the last three decades provides thorough coverage of gas flow behavior. Therefore, this section will be confined to a brief review of essential fundamentals.

Figure 5 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Chapter 2: Gas Flow Calculations, page 63

Figure 6 below is a copy of page 111 of the GEOP book. On that page is a graph (GEOP Figure 38) showing the relation between flow rate and pressure loss in a high pressure pipeline. The curve is non-linear and a 40% pressure drop represents 80% of the maximum possible flow through the pipeline segment (Figures 7 and 8 show the mathematical basis for pressure curve). GEOP states that “measures should be taken to increase capacity…” when a pipeline pressure drops “below 60% of the initial absolute pressure” (i.e. exceeds a 40% pressure drop). GEOP presents the 40% pressure drop as a rule of thumb and NW Natural considers the following additional factors when reviewing new high pressure system reinforcement projects:

- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- The ability to meet firm service customer delivery requirements (flow or pressure)
- Identified in the IRP associated with supply requirements or needs

NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. These pressure regulators are mechanically driven and use the pressure in the pipeline to properly function. In Staff’s final comments, Staff mentions that regulator inlet pressures must be at least 20 psi above the outlet pressure. To clarify, this 20 psi should not be used as a design standard. It was referenced by NW Natural in DR 52 as the typical pressure restriction that a district regulator has on gas flows. As inlet pressure decreases, the capacity, or amount of gas that can be served by the regulator, drops dramatically. The inlet pressure of a district regulator must be high enough to serve the load downstream, hence the use of the 40% pressure drop as a design standard.

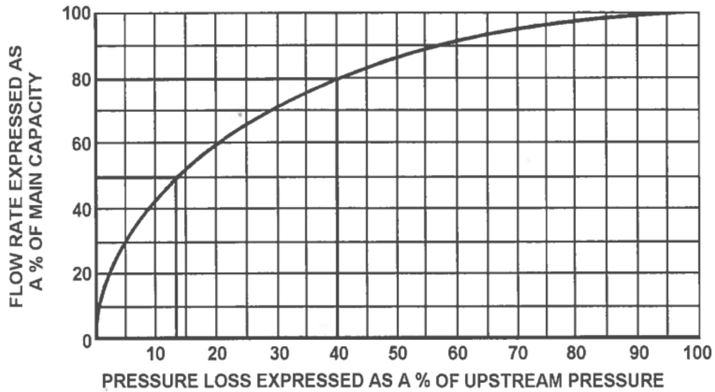


Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

RULE-OF-THUMB TEST OF ADEQUACY

A high degree of accuracy often is not required to obtain workable answers to pipe sizing and capacity problems. Some gas engineers have developed simple rule-of-thumb methods to solve many of the common problems that they encounter on a day-to-day basis.

For example, it has been found that a graph similar in form to the one shown in Figure 38 and derived in Appendix H is obtained for any pipe sections in a high pressure distribution system if percent main capacity is plotted against percent loss of upstream pressure.[19]

These plots are based on the use of a flow formula of the form:

$$\Delta P^2 = KQ_b^2$$

Examination of this curve shows that the gas flow rate is approximately 80% of the maximum possible flow rate when the absolute downstream pressure is dropped to 60% of the initial absolute upstream pressure. This observation has resulted in the rule-of-thumb that measures should be taken to increase the capacity or reduce the gas flow on a pipe section in a high pressure distribution system when its measured absolute downstream pressure approaches or begins to drop below 60% of the absolute upstream pressure.

Rule-of-thumb methods are not sufficiently accurate or general to serve as the basis for the overall design of a distribution system. Instead, they are best regarded as guides that can be used to obtain rapid, order-of-magnitude answers to some system capacity and pipe sizing questions.

Figure 6 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Chapter 2: Gas Flow Calculations, page 111

Appendix H

BASIS OF THE RULE-OF-THUMB TEST OF ADEQUACY

Gerald G. Wilson

If a square-law flow equation describes the flow behaviour of a section of pipe, then for any flow rate:

$$P_1^2 - P_2^2 = KQ^2 \qquad \text{(Eq. H-1)}$$

When the pipe operates at capacity:

$$P_1^2 - P_c^2 = KQ_c^2 \qquad \text{(Eq. H-2)}$$

where: P_c = pressure at downstream end of line when it is operating at capacity [psia]

Q_c = capacity of the section of pipe for an inlet pressure of P_1 [Mft^3/h]

Division of Equation H-1 by Equation H-2 yields:

$$\frac{P_1^2 - P_2^2}{P_1^2 - P_c^2} = \frac{KQ^2}{KQ_c^2} = \frac{Q^2}{Q_c^2}$$

When the numerator and denominator of the left member of this equation are divided by P_1^2, the equation becomes:

$$\frac{\dfrac{P_1^2}{P_1^2} - \dfrac{P_2^2}{P_1^2}}{\dfrac{P_1^2}{P_1^2} - \dfrac{P_c^2}{P_1^2}} = \frac{\left[1 - \left(\dfrac{P_2}{P_1}\right)^2\right]}{\left[1 - \left(\dfrac{P_c}{P_1}\right)^2\right]} = \frac{Q^2}{Q_c^2}$$

Taking the square-root of both sides of this equation:

$$\frac{Q}{Q_c} = \sqrt{\frac{1 - (P_2 / P_1)^2}{1 - (P_c / P_1)^2}} \qquad \text{(Eq. H-3)}$$

To arrive at the equation plotted in Figure 14 in Chapter 2, it is necessary to assume that $(P_c/P_1)^2 \cong 0$. This assumption simplifies Equation H-3 to:

$$\frac{Q}{Q_c} = \sqrt{1 - (P_2 / P_1)^2} \qquad \text{(Eq. H-4)}$$

It can be shown easily that Equation H-4 yields the rule-of-thumb given in Chapter 2. When the downstream pressure is 60% of the upstream pressure:

Figure 7 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Appendix H, Basis of the Rule of Thumb Adequacy, page 517

$P_2 = 0.6P_1$

$P_2/P_1 = 0.6P_1/P_1 = 0.6$

Substitution of 0.6 for P_2/P_1 in Equation H-4 gives:

$$Q/Qc = \sqrt{1-(0.6)^2} = 0.8$$

$Q = 0.8Q_c$

The last equation shows that the flow rate is 80% of capacity when the downstream pressure is 60% of the upstream pressure.

This rule-of-thumb is a rough approximation because the assumption that $(P_c/P_1)^2 \cong 0$ is only roughly true. Table H-1 presents values of $(P_c/P_1)^2$ over the range of pressures encountered in high-pressure distribution systems. The value of 2 psig (14 kPa) used as the downstream pressure at capacity is a representative value of the minimum main pressure needed to assure proper operation of all appliances connected to a high-pressure distribution system. This rule is not applicable at inlet pressures below 13 psig (90 kPa) since the downstream pressure corresponding to 60% of the inlet pressure would be less than the 2 psig (14 kPa) pressure at capacity. The values of $(P_c/P_1)^2$ in Table H-1 show that it approximates zero at inlet pressures of 30 psig (207 kPa) and above but deviates quite significantly from zero at lower inlet pressures. Thus, the rule-of-thumb is most nearly correct at high inlet pressures; it tends to become increasingly conservative as the inlet pressure decreases.

That is, at moderate inlet pressures, the flow rate through a pipe section is greater than 80% of capacity when the downstream pressure has dropped to 60% of the inlet pressure. This can be deduced from Equation H-3 by use of the values in Table H-1.

TABLE H-1
Selected Values of $(P_c/P_1)^2$

P_1			
Gage [psig (kPa)]	**Absolute* [psia (kPa)]**	**(P_c/P_1)****	**$(P_c/P_1)^2$**
15 (103)	29.4 (203)	0.558	0.311
30 (207)	44.4 (306)	0.370	0.136
45 (310)	59.4 (410)	0.276	0.076
60 (414)	74.4 (513)	0.220	0.048

* For atmospheric pressure of 14.4 psia (99.3 kPa)
** For P_c= 16.4 psia (113 kPa)

Because of its conservative tendency, the rule-of-thumb is a useful test of adequacy throughout the range of pressures normally experienced in high-pressure systems.

Figure 8 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Appendix H, Basis of the Rule of Thumb Adequacy, page 518

Sandy Feeder Project

The measured pressure drop on the Sandy Feeder on January 6. 2017 was 318 psig (390 - 72) or 81.5%, which results in approximately 96% of the maximum flow rate capacity for the pipeline. This greatly exceeds the 40% pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Sandy Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
390	72	318 psi (81.5%)

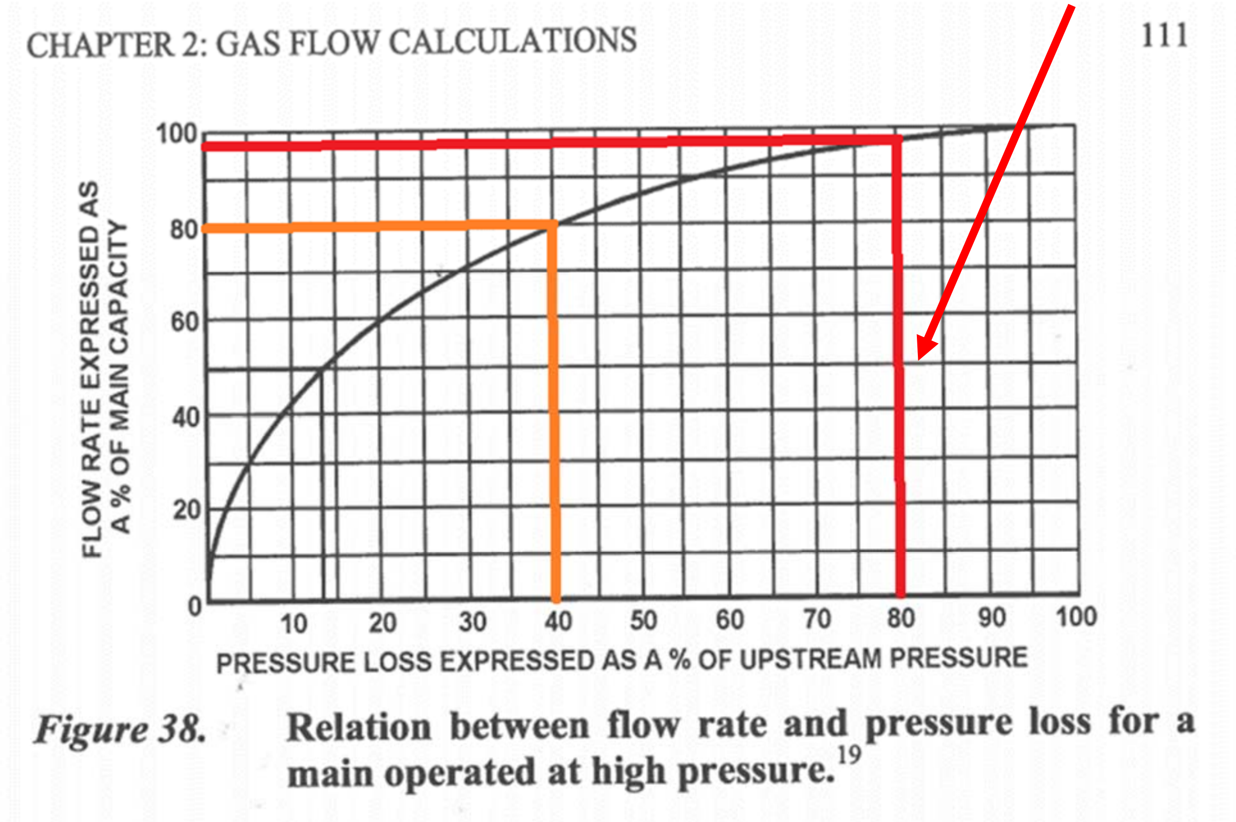


Figure 9 – Measured pressure drop from Sandy Feeder from January 2017 showing 81.5% pressure drop representing 96% capacity in red. NW Natural design standard of 40% pressure drop shown in orange.

Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the end of the Sandy Feeder was bypassed during morning hours to maximize pressures. There are no interruptible customers in the Sandy system which could have been curtailed to remove demand from the feeder.

The performance of the lower pressure distribution system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlet. The following district regulator is installed at the end of the Sandy Feeder:

District Regulator 1-047-068-R-01: US Hwy 26 W. of Reuben Rd.

2" Mooney Flowgrid Regulator, 400 MAOP inlet, 57 MAOP outlet (outlet set-point 50 psig).

The Maximum Design Capacity is 604.5 MSCFH[1] at 400 psig inlet, 57 psig outlet, and the actual Capacity is 96.3 MSCFH[1] at 72 psig inlet, 50 psig outlet with the conditions experienced in January 2017. This corresponds to a regulator capacity reduction of 84.1%. As the downstream distribution system being fed by this district regulator continues the draw more flow, the pressure will be further reduced and at an increased rate. This would cause widespread customer outages in the Sandy distribution system.

To prevent outages, the regulator was bypassed, and manually operated by NW Natural crews to ensure adequate gas pressured during this cold weather event. This is an additional indication that the high pressure pipeline feeding Sandy is inadequate to serve existing customers further supporting the proposed pipeline reinforcement project.

Kuebler Road Project

The measured pressure drop on the South Salem system from Turner gate to the Kuebler Regulator on January 6. 2017 was 140 psig (220 - 80) or 63.8%, which results in approximately 93% of the maximum flow rate capacity for the pipeline. This exceeds our 40% system reinforcement pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Turner Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
220	80	140 psi (63.6%)

[1] MSCFH means Thousands of Standard Cubic Feet per Hour

CHAPTER 2: GAS FLOW CALCULATIONS 111

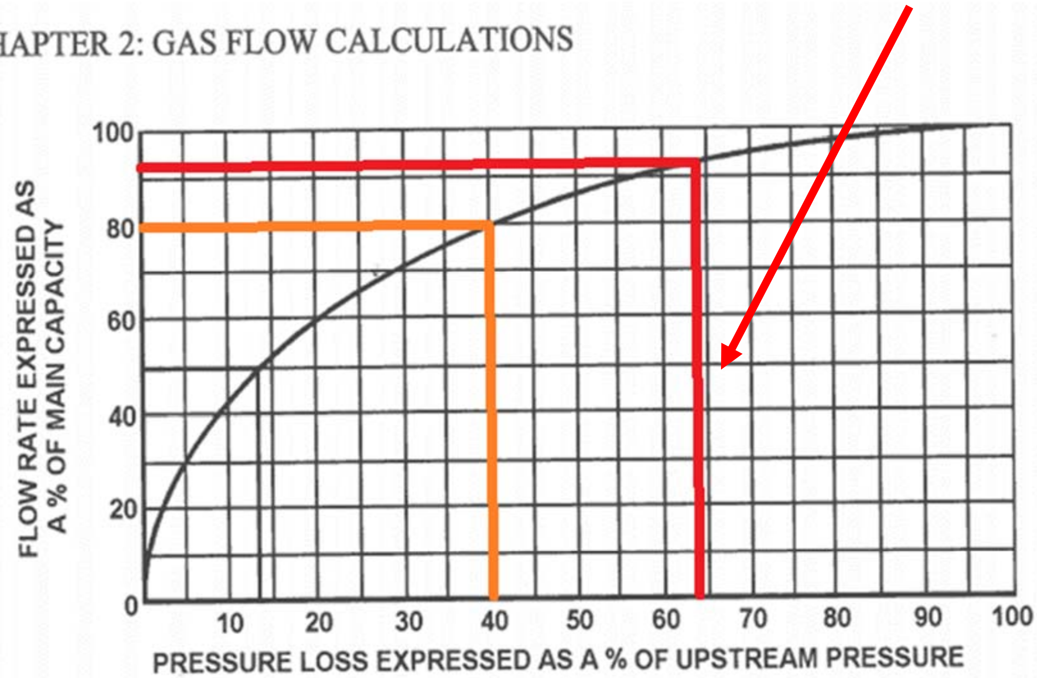


Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

Figure 10 – Measured pressure drop from Turner gate to Kuebler Rd from January 2017 showing 63.6% pressure drop representing 93% capacity in red. NW Natural design standard of 40% pressure drop shown in orange.

Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the southwest end of the Salem high pressure system (Kuebler Blvd. & Skyline Rd.) was bypassed during morning hours to maximize pressures. The regulator inlet pressure at this location reached a low pressure of 80 psig on the morning of January 6, 2017. There are no interruptible customers downstream of this regulator which could have removed demand from this regulator and its upstream system.

The performance of the lower pressure distribution system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlet. The following district regulator is installed at Keubler Blvd and Skyline Rd

District Regulator 2-118-009-R01: Kuebler Blvd. & Skyline Rd.

2" American Axial Flow Regulator, 225 MAOP inlet, 45 MAOP outlet (outlet set-point 40 psig).

The Maximum Design Capacity is 606.1 MSCFH at 225 psig inlet, 45 psig outlet, and the actual Capacity is 234.2 MSCFH[1] at 80 psig inlet, 40 psig outlet with the conditions experienced in January 2017. This corresponds to a regulator capacity reduction of 61.4%. As the downstream distribution system being fed by this district regulator continues the draw more flow, the pressure will be further reduced and at an increased rate. This would cause widespread customer outages in the Salem distribution system.

To prevent outages, the regulator was bypassed, and manually operated by NW Natural crews to ensure adequate gas pressured during this cold weather event. This is an additional indication that the high pressure pipeline feeding Salem is inadequate to serve existing customers further supporting the proposed pipeline reinforcement project.

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

Request No.: LC 79 OPUC DR 137

137. Does the IRP assume a cost for CO_2 feedstock to the methanation process? If so, please state the cost and the source or justification for NW Natural's CO_2 cost data.

Response:

There are lots of potential sources of carbon dioxide that could be used for methanation of hydrogen, including direct air capture (i.e., capturing CO_2 directly from the atmosphere). For direct air capture, there would be no need to pay for the CO_2 feedstock. However, there are options that would require finding a source of CO_2 for methanation that would likely require compensation. Which method is likely to be the cheapest is the primary question. Which method is cheapest might also change through time.

Methanation cost averages for the Monte Carlo analysis start at roughly $180/metric ton of CO_2 savings for the methanation portion of synthetic methane with a range from $100-$320/MT for 2022, falling to an average of $60/MT in 2050 with a range from $11-$220/MT. These costs are added on to the cost estimates for hydrogen production/acquisition to determine the cost of synthetic methane (see the "Workpapers_2022 IRP Monte Carlo Supply Inputs Final.xlsx" available on the FTP site set up to provide stakeholders access to key workpapers).

NW Natural developed its methanation costs from numerous third-party sources and evaluation of actual projects. The cost estimates are in the form of cost estimates of direct air capture, where a sample of the consequential studies reviewed include the following sources:

https://www.sciencedirect.com/science/article/pii/S1875510021002845

https://www.sciencedirect.com/science/article/pii/S0306261919312681

https://www.sciencedirect.com/science/article/pii/S030626191931654X