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Chair Decker and Commissioners Tawney and Thompson

Enclosed is Staff's Final Report to conclude the agency's Natural Gas Fact Finding investigation. The Final Report is the summation of a two-year assessment that the Public Utility Commission (PUC) held with regulated gas utilities and stakeholders. Staff explored the potential ratepayer and system impacts of limiting gas utility greenhouse gas (GHG) emissions and the regulatory tools needed achieve compliance with state GHG policies.

As you are aware, this report is just one element of an extensive and ongoing conversation on utilities' role in decarbonizing the Oregon economy. This conversation was well underway before the PUC undertook this investigation and it has shaped PUC decision-making and activities over the last two years. Through our work across various dockets, Staff envisions this conversation will continue to proceed, evolve, and grow in importance as utilities work towards compliance with state decarbonization goals. The Fact Finding process has been integral to surfacing key issues for consideration and debate and will inform the PUC's approach to utility regulation, as it already has in 2022.

In this Final Report, Staff sought to address and incorporate the valuable feedback provided by numerous parties to the Draft Report. Staff also sought to reflect the PUC's decarbonization planning work and activities that continued throughout 2022, including Northwest Natural's 2022 General Rate Case and Cascade Natural Gas' Update to its 2020 Integrated Resource Plan.

Decarbonization of the natural gas sector is still in its earliest stages. There is much to be learned from the initial steps taken by Oregon utilities and stakeholders as well as the actions being taken regionally, nationally, and globally. As recognized in the Final Report, an effective and successful decarbonization of Oregon's natural gas sector will require continued and thoughtful analysis, communication, and review by all parties so that lessons can be learned and plans can be adapted as quickly and efficiently as possible to reach decarbonization goals. To aid in this work, Staff is seeking to bolster its own knowledge development by bringing in outside expertise to address targeted questions raised by the Fact Finding process—including studying how the PUC can begin taking steps towards a holistic, system-wide approach to decarbonization planning and evaluating the accuracy, appropriateness, and adequacy of existing utility integrated resource planning.

Staff thanks all the participants to the Fact Finding process and hopes that readers find the Final Report as useful as Staff found the entire development process.

Sincerely,

JP Batmale
Energy Resources and Planning Division Administrator, Public Utility Commission

Natural Gas Fact Finding

Final Report

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Oregon Public Utility Commission

Natural Gas Fact Finding Final Report

Contents

Table 1: List of Acronyms and Abbreviations

AC	Avoided Cost
AQCC	Colorado Air Quality Control Commission
AVA/Avista	Avista Corporation
AWEC	Alliance of Western Energy Consumers
BE	Better Energy LLC
BIPOC	Black Indigenous and People of Color
BUILD	California Energy Commission Building Initiative for Low-Emission Development Program
CAA	Community Action Agencies
CCI	Community Climate Investment
CCSU	Carbon Capture Sequestration and Utilization
CEC	California Energy Commission
CECP	Massachusetts Clean Energy and Climate Plan
CEE	Minnesota Center for Energy and Environment
Climate Reality	Climate Reality Project, Portland Chapter
CNG	Cascade Natural Gas Company
CO2e	Carbon Dioxide Equivalent
CPP	Climate Protection Program
CPUC	California Public Utility Commission
CS	Climate Solutions
CUB	Oregon Citizens' Utility Board
DEI	Diversity, Equity, and Inclusion
DEQ	Oregon Department of Environmental Quality
DPU	Massachusetts Department of Public Utilities
DSP	Distribution System Planning
EC	Electrify Coalition
EDF	Environmental Defense Fund
EE	Energy Efficiency
EITE	Emission Intensive Trade Exposed
EJ	Environmental Justice
EO	Executive Order
ETO	Energy Trust of Oregon
GHG	Greenhouse Gas
HB	House Bill
IEPR	California Integrated Energy Policy Report
IRP	Integrated Resource Plan
JC - CS et al.	Joint Comments - Climate Solutions et al. (29 Organizations)
JC - EC et al.	Joint Comments - Electrify Coalition et al. (41 Organizations)
JC - Mayoral	Joint Mayor City Official Letter
JC - MCAT	Joint Comments - Metro Climate Action Team et al. (3 Organizations)
JC - NWGA et al.	Joint Comments - NWGA et al. (17 Organizations)

LDC	Local Distribution Company
LEA	Line Extension Allowance
LI	Low Income
LMI	Low - Medium Income
LWVO	League of Women Voters of Oregon
MCAT	Metro Climate Action Team
MMBtu	1 Million British Thermal Units
MT	Metric Tons
Multnomah County	Multnomah County Office of Sustainability
NEEA	Northwest Energy Efficiency Alliance
NG	Natural Gas
NGFF	Natural Gas Fact Finding
NOPR	Notice of Proposed Rulemaking
NRDC	Natural Resources Defense Council
NWEC	Northwest Energy Coalition
NWGA	Northwest Gas Association
NWN	Northwest Natural
OAR	Oregon Administrative Rules
ODOE	Oregon Department of Energy
OPSR	Oregon Physicians for Social Responsibility
ORS	Oregon Revised Statutes
PBR	Performance Based Ratemaking/Regulation
PM	Public Meeting
PUC	Oregon Public Utility Commission
RAP	Regulatory Assistance Project
RFA	Rates, Finance, and Audit Division
RHN	Renewable Heat Now
RMI	Rocky Mountain Institute
RNG	Renewable Natural Gas
RNW	Renewable Northwest
SC	Sierra Club
SCC	Social Cost of Carbon
SPM	Special Public Meeting
TNC	The Nature Conservancy
UG	Oregon Utility Gas Proceeding
UM	Oregon Utility Miscellaneous Proceeding

1 NATURAL GAS FACT FINDING EXECUTIVE SUMMARY

Oregon has taken explicit steps to reshape the state's energy market by introducing Greenhouse Gas (GHG) emission reduction targets reflecting national trends to actively address climate change through state policy. Policies like the Oregon Department of Environmental Quality's (DEQ) Climate Protection Program (CPP) and House Bill (HB) 2021 set ambitious GHG emission reduction targets that will have a permanent impact on regulated utility investments and operations. In addition, trends related to climate change and climate adaptation are driving consideration of deep decarbonization pathways. These trends include the evolution of regional and national policies that cap or price GHG emissions and the rapid development and deployment of solutions designed to reduce energy related GHG emissions.

For the natural gas utilities overseen by the Oregon Public Utility Commission (PUC), the Environmental Quality Commission's 2021 adoption of CPP rules for DEQ represented a significant step in reorienting these utilities' near-term planning and future operations. By complying with the CPP, Oregon's fossil fuel suppliers – including the regulated gas utilities – must collectively achieve emission reductions of 50 percent by 2035 and 90 percent by 2050.

To assess the impact of the CPP on gas utilities, their customers, and other potential decarbonization activities, PUC Staff engaged in a dynamic, six-month public process of fact finding (UM 2178). The purpose of this Natural Gas Fact Finding (Fact Finding or NGFF) was twofold. The first was to conduct an initial analysis of the potential ratepayer bill impacts from the limiting of natural gas utilities' GHG emissions under the DEQ's CPP. The second was to identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action.

To achieve these purposes, Staff collaborated with stakeholders, utilities, and expert consultants to identify CPP compliance pathways in a Draft Report, posted April 2022. The PUC then collected extensive public comment over the summer of 2022 on this draft. Concurrently with these efforts, the PUC conducted various public proceedings affecting natural gas utilities, including the completion of a major gas rate case, launched and/or completed two gas Integrated Resource Plan (IRP) dockets, and finalized the 2023 budget and action plan for Energy Trust.

Staff submits this Final Report to conclude this investigation. Our experiences and interactions with the Commissioners, utilities, and broad collection of stakeholders of these experiences and interactions have shaped this Final Report on the docket findings and suggested next steps for the PUC.

Broadly, our findings are that:

- Stakeholders bring **increasingly divergent approaches** to emission reductions, namely either limiting gas expansion <u>or</u> developing gas supply decarbonization innovations.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** – identified and organized below under the categories of Planning, Programs, and Rate Making – are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization.

- A number of potential regulatory tools identified require an optimization across the energy system, rather than a focus on a single fuel (i.e., natural gas or electricity). Implementing such tools requires work across a variety of dockets and utilities and an unprecedented degree of **coordination and additional resources**.

Accordingly, Staff developed a set of regulatory tool recommendations that begin to address the identified issues given various constraints. The table below functions as a high-level summary of the near-term regulatory tools Staff recommends.

Table 2: Roadmap of Staff Regulatory Tools for Oregon (See Section 5.7 for more details)

Section 5 Analysis	**Recommendation**	**Regulatory Tool**		
		Planning	Programs	Ratemaking
Protecting Customers	Estimated Ratepayer Bill impact	X		
	Direct ETO to target programs to LI and EJ		X	
	Target IRA Incentives		X	
	EE programs to include transport		X	
	Assess CPP compliance risk in distribution system investments	X		X
	Explore rate impacts of accelerated depreciation in rate cases			X
	Transport customer cost of compliance in rate cases			X
Access and Info	Quarterly stakeholder Communications in UM 2178	X		
	RFA docket engagement through PUC AHD			X
Full Cost	Compliance costs into EE AC			X
	Develop marginal abatement cost curve	X		
	Utilities articulate electrification assumption in IRPs	X		
	Electrification info and data from DSP	X		
Decarbonization Planning & Cost-Recovery	Gas system maps with infrastructure age and depreciation information	X		
	IRPs include growth-related DSP investment details from Appendix F and provide analysis of demand-side options and non-pipe alternatives	X		
	Independent 3rd party analysis of key tech and market assumptions used by utilities	X		
	CPP as an acknowledgeable item in IRPs	X		
	Exploring IRP guidance from UM 2178	X		
	Follow Order No. 22-388 guidance regarding customer growth and compliance costs	X		X
Monitoring, Tracking, and Reporting	Utilities host annual presentation to PUC on CPP compliance filings	X		
	Purchased Gas Adjustment includes full CPP compliance costs			X
	Explore linking CPP amortization to CPP performance			X
Incentivize GHG Reductions	Explore use of SB 844 for emerging technologies	X		
	Pilot or Joint pilots with electric utilities proposals by 2025			X

The Final Report attempts to reflect participants' feedback and positions. Where applicable, Staff uses footnotes to indicate changes to actions or regulatory tools based on feedback or new learnings. The Final Report also includes a summary of Stakeholder Comments as Appendix E and has "Stakeholder

Insights" subsections and sidebars throughout the report to call attention to the perspectives of stakeholders on specific topics.

PUC Next Steps
This investigation and subsequent report created a foundation to shape the PUC's role relative to GHG emission reduction needs and policies in Oregon. The purpose was to better prepare Commissioners, stakeholders, and Staff for issues and positions that will arise across multiple dockets. Over the last six months of 2022, the PUC has already begun actively weaving early learnings from this Fact Finding and natural gas utility compliance with the CPP into existing dockets and activities.

The continued incorporation of the Fact Finding's regulatory tools serves as enhancements to the PUC's pursuit of the same goals that it has always had namely, to:

1. Determine whether the utilities have a least-cost, least-risk strategy, including for CPP compliance;
2. Ensure utilities are passing on to ratepayers only prudent and reasonable costs;
3. Set rates that represent reasonable balance of future risks and incentives between the company and ratepayers; and
4. Ensure that different customer classes are each allocated a reasonable proportion of the costs and benefits of utility service.

Going forward, as Staff learns more by incorporating NGFF recommendations and associated experiences into familiar regulatory proceedings, Staff may eventually recommend proactive new rulemakings or proceedings.

2 Background

2.1 PUC's Natural Gas Fact Finding

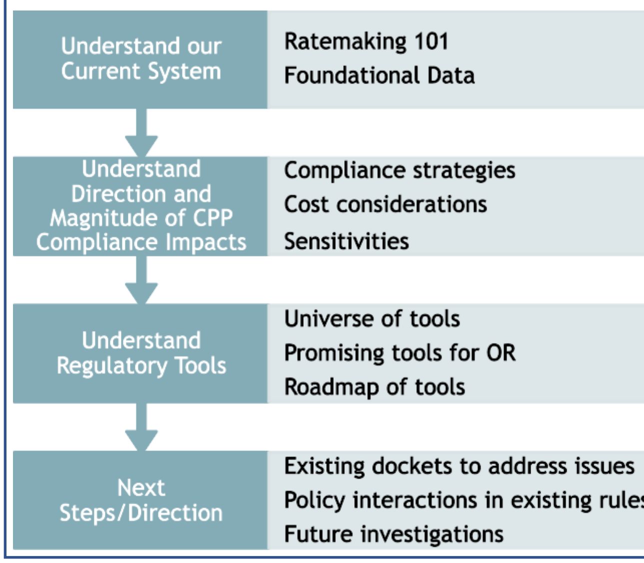
The Oregon PUC requires utilities to plan and prepare for all risks, including new regulatory requirements, and to take action to mitigate customer risks in advance. In the natural gas sector, utility IRP planning has been considering for several years various decarbonization policy futures and how to develop a least-cost, least-risk strategy to comply with future policies. But, as state and national pressure for the gas sector to address climate began to build, the PUC took additional action and, in 2021, directed its Staff to conduct a "fact-finding" to lay a foundation for understanding the customer implications of decarbonization policy in the natural gas sector. Specifically for gas customers, the work plan proposed a study of the impact of the proposed DEQ CPP rulemaking to "understand the customer dimensions and impacts of different decarbonization scenarios and thus help inform future decision making."[1]

In June 2021, Staff officially opened this Fact Finding under Docket No. UM 2178. The purpose of this Fact Finding was to analyze the potential natural gas utility ratepayer bill impacts that may result from

[1] To some extent Natural Gas Fact Finding work built on Staff's existing work plan to implement Governor Brown's Executive Order 20-04. See Oregon Public Utility Commission EO 20-04 Work Plans. Page 10. https://www.oregon.gov/puc/utilities/Documents/EO-20-04-Work_plans-Final.pdf.

limiting GHG emissions of regulated natural gas utilities under the CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. It was crafted to produce two primary outcomes: 1) An understanding of potential natural gas ratepayer bill impacts associated with the CPP GHG emission target compliance; and 2) the identification of strategies and regulatory tools that equitably mitigate potential harm to natural gas customers while accommodating action that supports compliance.[2] The ultimate goal of the Fact Finding was to inform future policy decisions and other key analyses to be considered in 2022, once the CPP is in place.

Figure 1: Natural Gas Fact Finding Process



The work plan (as outlined in Figure 1) was designed to:

- Help Staff and stakeholders understand current natural gas and cost recovery systems;
- Understand the potential impacts of CPP compliance;
- Explore applicable regulatory tools; and
- Identify actions the Commission could take to protect customers.

Staff utilized a process that mixed facilitated workshops, public comments, and external analysis to develop an extensive set of documents.

Staff held six workshops, each of which was generally attended by over 90 people. In addition, the PUC offered multiple opportunities for public comment and access to utility compliance modeling workbooks. Staff also engaged the Regulatory Assistance Project (RAP) to assist staff and explore regulatory tools.

Staff's Draft Report was filed on April 15, 2022. By June 3, 22 groups provided feedback on the Draft Report and Staff received an additional 290 public comment emails outside of the UM 2178 docket. On July 12, the PUC hosted a Commissioner workshop and a subsequent Public Hearing to hear from stakeholders and to discuss issued raised in the fact finding and the Draft Report.

2.2 Natural Gas Use in Oregon

Oregon is served by three natural gas Investor-Owned Utilities. All operate as standalone gas companies in Oregon, with no retail electricity sales in the state. Annual sales revenues for Oregon's three natural gas utilities were over $810 million in 2019.[3] In 2019, Oregon's natural gas customers consumed about 1.6 billion therms, or about 4.4 million therms per day.[4] NW Natural is the largest of Oregon's three gas

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[2] *See* UM 2178, Staff's Initial Application, June 8, 2021. Page 16 of pdf. https://edocs.puc.state.or.us/efdocs/HAA/um2178haa11959.pdf.

[3] 2019 Oregon PUC Statistics Book. Page 42. https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2019-Oregon-Utility-Statistics-Book.pdf.

[4] Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

utilities, providing about 80 percent of total natural gas retail sales, with Avista Corporation (Avista) representing 12 percent of retail sales and Cascade Natural Gas (CNG) representing 8 percent.

Oregon's customers are divided into four categories: Residential, Firm Commercial & Industrial (Firm C&I), Interruptible C&I, and Transport. Firm C&I customers are generally small businesses, while Interruptible C&I customers are generally larger businesses. Transport customers are large, non-residential utility customers that have purchased their gas from another natural gas supplier (e.g., gas marketer) but who continue to use the regulated utility's distribution system to deliver their gas.

As can be seen in Figures 2 and 3,[5] while most natural gas utilities' revenues come from residential customers, much of gas delivered annually by these utilities is for transport customers. The revenues from transport customers to the regulated utilities is relatively small because these customers purchase their gas from gas marketers, not the utilities, and only use the utility's distribution system to deliver the gas to their location.

Figure 2: OR Natural Gas Utilities' 2019 Sales Revenue

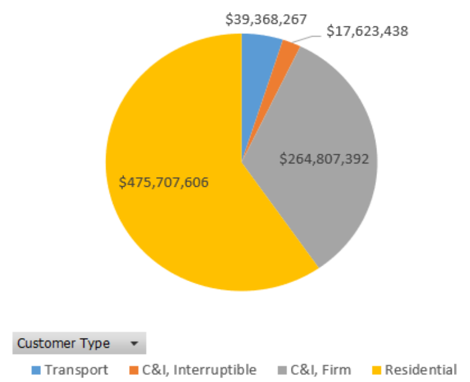
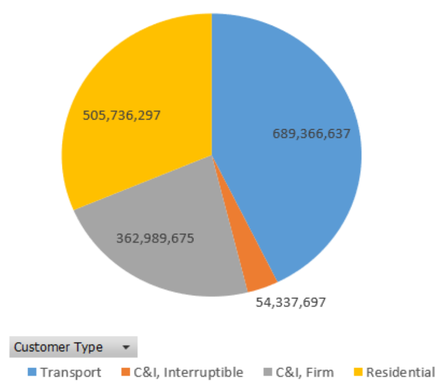


Figure 2: OR Natural Gas 2019 Delivery (Therms)



2.3 The Climate Protection Program

The CPP, effective in January 2022 (OAR Chapter 340 Division 271), is designed to substantially reduce GHG emissions in Oregon over the next thirty years. The CPP establishes a declining limit, or cap, on GHG emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas, and propane. This includes emissions from fossil fuels used in transportation, residential, commercial, and industrial settings. It also uses a best available emissions reductions approach for other site-specific emissions at facilities, such as emissions from industrial processes.

Companies regulated under the declining cap, known as covered fuel suppliers, include the three natural gas utilities and other suppliers of liquid and gaseous fossil fuels. The aggregate emissions covered under the CPP represent about half of the state's GHG emissions, with natural gas utilities making up 26 percent of total CPP covered emissions (NW Natural with 21 percent, and Avista and Cascade with

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[5] *See* Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

3 percent each).[6] The 2022 cap is based on average emissions from 2017 to 2019 for the covered fuel suppliers. The CPP requires GHG reductions of 50 percent by 2035 and 90 percent by 2050.[7]

Covered fuel suppliers must demonstrate compliance every three years along a steady trajectory towards those two milestones in 2035 and 2050. The first compliance period is 2022-2024, with covered fuel suppliers first demonstrating compliance in November 2025. Companies demonstrate compliance by submitting one compliance instrument or community climate investment (CCI) credit (discussed in more detail below) for each ton of covered emissions reported in their annual GHG emissions reports to DEQ during the compliance period. Under the CPP, each natural gas utility receives a free annual distribution of compliance instruments based on their share of the overall declining emissions cap.

While DEQ prescribes exactly the number of compliance instruments that will be supplied to each natural gas utility in years 2022-2050, there are additional flexibility mechanisms. Covered fossil fuel suppliers can trade unused compliance instruments or bank them for future use. These companies can also optionally contribute funds to DEQ-approved third parties in order to receive CCIs that work similarly to the compliance instruments DEQ distributes (e.g., each CCI credit allowing supply of fossil fuels that when combusted emit 1 metric ton CO2 equivalent).

Covered fuel suppliers can earn CCI credits by contributing funds to third-party entities to implement projects that reduce GHG emissions in Oregon. The contribution amount for a CCI credit is established by DEQ. The contribution amount starts at $107 ($2021) per CCI credit and increases over time.[8] CCIs are designed to reduce emissions by at least one MT CO2e on average, prioritize benefits in or near environmental justice communities and reduce co-pollutants. CCI credits can be banked for two compliance periods and cannot be traded. Covered fuel suppliers can only use a limited number of CCIs to meet compliance obligations. The limit begins at 10 percent of total compliance obligations for the first compliance period and eventually grows to 20 percent by the third compliance period.[9]

In short, DEQ's CPP lays out a regulatory framework that reduces GHG emissions associated with natural gas by the three utilities. These amounts decline by 50 percent from the outset in 2022 by 2035, and by 90 percent by 2050. While there are some flexibilities such as trading and CCIs, these requirements represent a significant, rapid, and mandatory requirement in the reduction of the utilities' natural gas related emissions.

2.4 STAKEHOLDER FEEDBACK

Staff received feedback on its Draft Report in June 2022. Much of it indicated that stakeholders did not adequately see their positions and feedback represented. The Final Report attempts to better reflect participants' feedback and positions, and where applicable, language has been changed in response to this feedback. The Final Report also includes a summary of Stakeholder Comments as Appendix E and has "Stakeholder Insights" subsections and sidebars throughout the report to call attention to the perspectives of stakeholders on specific topics.

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[6] *See* Supplemental Cap Information Excel Workbook. Available on Oregon DEQ's Climate Protection Program website = [https://www.oregon.gov/deq/ghgp/pages/climate-protection.aspx.](https://www.oregon.gov/deq/ghgp/pages/climate-protection.aspx)
[7] *See* OAR 340-271-9000, Table 4.
[8] *See* OAR 340-271-9000, Table 7.
[9] *See* OAR 340-271-9000, Table 6.

Additional feedback on the Draft Report generally addressed the scope of the fact finding, utility modeling, the regulatory tools presented, action and regulatory tool prioritization, next steps, and the role of the PUC.

Staff attempted to strike a balance in scope that permitted for discrete analysis without omitting critical information. This was especially challenging in the case of how to consider electrification as an emission reduction strategy for gas utilities. Staff appreciates both the direction from stakeholders on this analysis, as well as the gas utilities' efforts to model electrification scenarios and impacts. That said, all parties appear to agree that the outcomes were inadequate. Staff has included more detail about the importance and challenges of modeling electrification with Oregon utilities.

Staff notes where it modified recommendations about regulatory tools based on stakeholder feedback. The Final Report also includes a new section on Stakeholder Insights on Prioritization and Next Steps. Staff appreciates stakeholder perspectives on the role of the PUC and captures this feedback in Appendix E but has not made further modifications to the Final Report based on this feedback. The most voluminous feedback came from environmental, climate, and environmental justice advocacy groups and associated grassroots organizations.

Table 3: Environmental, Climate, & Environmental Justice Advocacy Groups Feedback

Feedback	Staff Response
More direct action by the PUC to phase out gas and use electricity for space and water heating	As was clear throughout this proceeding, determining the role of electrification of space and water heating is paramount. Staff believes that its analysis, and utility planning, must expand to be able to provide guidance about when electrification is determined to be a least-cost, least-risk solution. Staff agrees that rigorous scrutiny and analysis of utility modeling and fuel decarbonization are critical elements of utility regulation. Staff recommends deploying an increased analytical focus on these topics, accompanied by expanded analytical capabilities to better evaluate and provide guidance on this topic in IRPs, procurement activities, and ultimately general rate cases.
Rigorous scrutiny and analysis of utility modeling and fuel decarbonization efforts	
Regulatory tools that focus on protecting customers, not gas companies	Staff included stakeholder guidance on prioritization to better reflect a focus on protecting customers. Staff also updated several near-term actions to reflect this prioritization.

We also heard from consumer groups such as the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board (CUB).

Table 4: Consumer Groups Feedback

Feedback	Staff Response/modification
Offered modifications and additions to the list of regulatory tools to be considered	Staff has attempted to capture this feedback in the applicable Staff Analysis sections, and notes where suggestions resulted in modifications.

Offered approaches for considering cost and risk allocation	
Presented different perspectives on the value or liability of existing and potential future infrastructure	Staff expands and updates section 5.4.3 on CPP Investments where there is further discussion of Line Extension Allowances and infrastructure investments to reflect both stakeholder feedback and recent PUC activities in rate cases and IRPs.
Presented perspectives on the role of renewable natural gas and hydrogen.	Staff incorporated additional stakeholder feedback on fuel decarbonization in Section 5.4.3 on CPP Investments where there is further discussion on decarbonizing supply. As noted above, Staff recommends heightened scrutiny and analysis of the role of decarbonized fuels in least-cost, least-risk planning, and expect that analysis will be informed by the best available science and information.

Last, we received feedback from Oregon's gas utilities and the gas industry.

Table 5: Gas Utility and Industry Feedback

Feedback	Staff Response
Reliability and cost concerns associated with electrification of heating loads	Staff has incorporated this feedback in the applicable sections of this report
The value of leveraging existing infrastructure in decarbonization efforts through decarbonizing fuels	
The near-term need to provide guidance on CPP cost recovery and develop EE programs for transport customers.	

Additionally, Staff found the guidance regarding prioritization of actions and next steps a valuable addition to this effort and include these insights below.

<u>Prioritization</u>

Stakeholders offered direction regarding how the Final Report and the PUC should prioritize its efforts. Staff notes that all commenters who spoke to this issue noted the need to prioritize near term GHG emission reductions and the need to provide clear direction on ways to protect customers. In addition, stakeholder providing the following feedback on prioritization:

Environmental, Climate, & Environmental Justice Advocacy Groups Feedback

- *Prioritization 1: Prioritize low-risk solutions that result in near term emission reductions via regulatory tools that support the deployment of existing, proven, established, and cost-effective tools, citing energy efficiency, weatherization, and electric heat pumps targeted to LMI customers. - TNC, NRDC, Multnomah County, JC - CS et al., and BE*

- *Prioritization 2: Prioritize Staff time by not developing pilots that focus on hydrogen or other nascent technologies. - JC - CS et al.*

- *Prioritization 3: Energy Efficiency and non-pipe alternative programs should prioritize GHG emission reductions by being fuel neutral and accommodating consideration of beneficial electrification. - TNC*

- *Prioritization 4: Solutions should be realistically available to achieve GHG reductions in the short term, and geared toward their best use. - JC - CS et al.*

- *Prioritization 5: Prioritize tools that can be implemented in the near term to protect customers. – NWEC*

- *Prioritization 6: Focus on protecting customers rather than preserving utility gas customers and allowing for system growth. - NWEC, TNC, and JC - EC et al.*

- *Prioritization 7: LMI-targeted electric heat pump deployment programs that bring resiliency co-benefit of cooling. - Multnomah County and JC - Mayoral*

Utility, Gas Industry, and Large Energy Customers

- *Prioritization 8: Regulatory tools should prioritize near term natural gas decarbonization efforts to meet CPP targets. - NWN*

- *Prioritization 9: Exercise caution and avoid hurried decisions in this time of heightened uncertainty and transition - JC - NWGA et al.*

- *Prioritization 10: Programs to help customers should be flexible, be allocated funds, and focus on low income and energy burdened customers. - CNG*

- *Prioritization 11: Protect customers, in part by protecting the viability of gas utilities to accomplish other GHG emission reduction goals. - NWN*

Stakeholder Recommended Next Steps

Staff heard stakeholders express a desire to see some explicit next steps and provided input about what those next steps could be.

NWN recommends and CNG stresses the PUC open a docket to address CPP compliance and cost allocation. CNG states the investigation should carefully consider the role of sending appropriate price signals. AWEC adds that the principles of cost causation should be maintained in rate spread approaches.

Avista, AWEC, NWN and JC - CS et al. describe the need to conduct an Oregon specific electrification study and provided details about what the study should include. This has also been referenced by other commenters as a beneficial electrification study.

CUB identified topics it had expected this investigation to investigate, which Staff believes can inform next steps. These include "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."

Staff is not opining on Stakeholder Recommended Next Steps but includes them here as part of the feedback received from Stakeholders and sees this as valuable information for the PUC to consider.

3 KEY FINDINGS, ISSUES, AND STAFF ANALYSIS

The compliance modeling, stakeholder dialogue, and discussion around regulatory tools in the Fact Finding led to several findings:

- Stakeholders bring **increasingly divergent approaches** to emission reductions, namely either limiting gas expansion or developing gas supply decarbonization innovations.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029, depending on the customer and their existing level of energy burden.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization and the PUC most likely has sufficient authority to implement them.
- A number of potential regulatory tools identified in this Fact Finding would require an optimization across the energy system, rather than a focus on a single fuel (i.e. natural gas or electricity). Implementing such tools would require work across a variety of dockets and utilities over the next decade. For these reasons, these tools would require an unprecedented degree of internal and external **coordination and additional resources**.

3.1 DIVERGENT APPROACHES

Broadly speaking, two camps have emerged regarding the preferred approach to gas utility decarbonization. One group generally highlights the risks of gas system expansion and advocates to reduce or switch energy use away from the Oregon gas system. An opposing view generally proposes solutions that leverage the existing gas system through the accelerated deployment of gas decarbonization innovations such as methanated hydrogen and gas-powered heat pumps. This Fact Finding directly experienced this tension across the analysis and comments.

These divergent pathways for the gas industry are often described as being in opposition to each other. Although the Fact Finding confirmed this to largely be true, Staff finds that some combination of choices – between encouraging low-to-zero carbon gas technologic advances *in conjunction* with regulatory actions that moderate future gas customer and infrastructure growth – may best balance among the various technology, cost, and regulatory risks associated with meeting the state's near-term GHG emission targets.

3.2 MODELING COSTS & RISK

The structure of the NGFF allowed utilities and stakeholders to explore a wide range of possible compliance scenarios. As a result, participants were able to glean an initial understanding of the possible impact of various pathways, explore sensitivities, and begin the process of stress testing the reasonableness of underlying assumptions put forth by both utilities and various stakeholders.

As a foundation for all other analytic inquiries, Staff asked the gas utilities to model how they would comply with DEQ's CPP. Each utility modeled three overall CPP compliance scenarios (base case, high innovation, and accelerated electrification) with multiple sensitivities. The purpose of the modeling was to understand more about the cost and timing of the strategies the companies were contemplating to meet CPP GHG emission targets. By broadly understanding how utilities might comply and the associated costs and timelines for different strategies, the PUC, Staff and stakeholders might better understand where, when, and which regulatory tools might be used to mitigate costs and risks.

There were two general points of agreement:

1. Gas utilities will need to take significant near-term action to decarbonize: "Business As Usual" growth and operations of the system result in emissions exceeding the 2035 compliance targets.
2. Any compliance pathway will very likely increase the costs of energy service for all categories of customers over the next decade.[10]

3.2.1 Scenarios as Compliance Pathways

The gas companies were asked first to model how they might envision complying with the CPP, and then to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. These sensitivities tested decarbonized gas availability, decreases in the number of customers, a more aggressive policy environment, and a reduction in availability of alternative compliance mechanisms. The gas companies were further asked to model scenarios with high electrification and high levels of support for innovation as different scenarios. A summary of the sensitivities and scenarios are in Table 6. Full descriptions can be found in Appendix A.

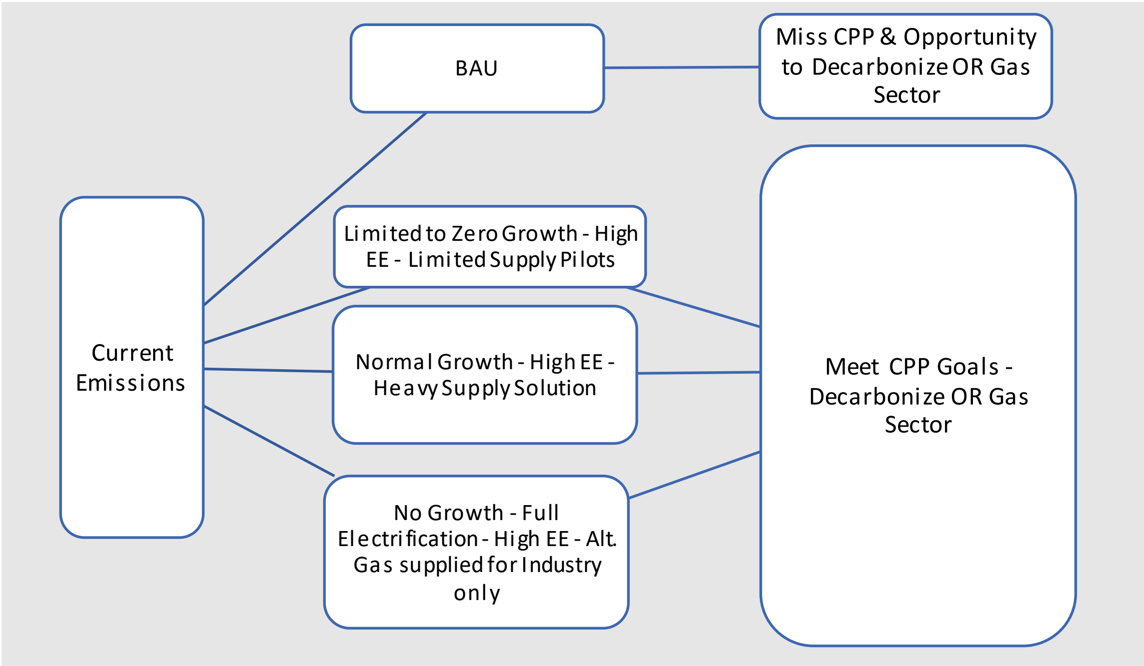
[10] As the only outlier, NW Natural's base case modeling actually projected slightly lower residential customer bills in 2050.

Table 6: Scenarios and Sensitivities

Scenarios	Base Case Scenario	Utilities model what they see as most optimal compliance pathways
	Alt. Scenario 1 – Innovation / Electrification / SCC	Modeled a Production Tax Credit for green hydrogen and syngas before 2026, use of higher Social Cost of Carbon, and high electrification of buildings
	Alt. Scenario 2 – Delayed innovation / Accelerated Electrification	Lower energy efficiency (EE) technology adoption curves, limited availability of RNG, and very rapid electrification of existing customers
Sensitivities	Declining Customer Counts	Modeled sensitivities that consider zero and negative customer growth
	Aggressive Timeline	CPP targets are advanced to align more closely with HB 2021: CPP targets 45% below baseline by 2030, 80% below baseline by 2040
	No CCIs	Modeled impacts of removing CCI compliance options
	Restricted RNG	Applied constraints on assumptions about the availability of RNG to meet emission reduction goals

The scenarios represent factors that are outside utility control, such as market and policy assumption variations. Scenarios combined with sensitivities test how well compliance pathways respond when market and policy factors differ from what was thought to be most likely as represented in the base case. The various scenarios modeled produced different compliance pathways. The uncertainty in costs, performance risks, and availability of resource options for each pathway to decarbonize has raised many more questions to be addressed to ensure the planning and decision-making process supports the identification of the least-cost and least-risk approaches to future GHG emission compliance. While the gas companies, stakeholders, policy makers, and regulators must chart a pathway to meet the CPP requirements, technology costs and performance remain highly speculative. The analysis from the NGFF, while informative, made it clear that more robust modeling and rigorous vetting of resource assumptions within IRPs would be required to make informed assessments about least-cost, least-risk paths for compliance.

Figure 3: Compliance Pathways



3.2.2 Lessons on Costs and Risks from Scenarios

While the modeling showed a general trend of increased ratepayer bills attributable to CPP compliance, it also often provided a wide range of results from which trends were difficult to detect. All parties agreed that the rigor and analysis that comes with a full IRP would be needed for more definitive modeling conclusions.[11] However, there were still many important learnings gleaned from the Fact Finding that we continue to find playing out in various dockets.

Perhaps more than anything, this exercise afforded stakeholders an opportunity to highlight concerns and challenge assumptions that will inform future IRPs.[12] Most notably, future IRPs must include rigorously vetted assumptions, and alignment with Staff and Stakeholders on the following topics to help assess least-cost/least-risk compliance strategies.

- Cost, feasibility, and ratepayer impacts of CPP specific compliance strategies;
- A need to understand the interdependency of the gas and electric systems in terms of costs and emissions that result from policies that shift load away from gas;
- The necessity to include transport customers in CPP compliance activities;.
- Costs of non-compliance, while not modeled, drives understanding of risk in future planning;
- Assumptions about the availability and cost of RNG;
- Cost, availability, timeline, and highest value use of hydrogen;
- Consistent modeling approaches for energy efficiency and associated avoided costs;

[11] The IRP presents a utility's current plan to meet the future energy and capacity needs of its customers through a "least-cost, least-risk" combination of energy generation and demand reduction. The plan includes estimates of those future energy needs, analysis of the resources available to meet those needs, and the activities required to secure those resources. *See* https://www.oregon.gov/puc/utilities/Pages/Energy-Planning.aspx.

[12] *See* Appendix B on Suggested changes to IRPs.

- Commercial readiness of proposed approaches (e.g. gas heat pumps);
- Data informing cost, benefits, and modeling guidance for beneficial electrification; and
- Load forecasts

Base Case

The Fact Finding's base case scenario was presented by each utility in September 2021 and represented a starting point for analysis.[13] Each base case reflected the gas utilities' preferred compliance strategies for residential, commercial, and industrial customers, given their most recent planning and what was understood about the CPP rules prior to adoption.

In the base case scenarios, annual ratepayer bills increased in the near term and showed a range of outcomes.[14] The estimated ratepayer bill increases varied across companies, customer types, and the assumptions made about future technology advances. Additionally, the rate and direction of ratepayer bill increase changed in later years of the model. CPP compliance costs to gas customers range from single digit percentages to rather substantial by 2025, depending on the customer and choices in the utility modeling. Figure 5 and Table 7 illustrate the estimated ratepayer bill impacts over time.[15]

Figure 4: Annual Ratepayer Bill Impacts in Base Case

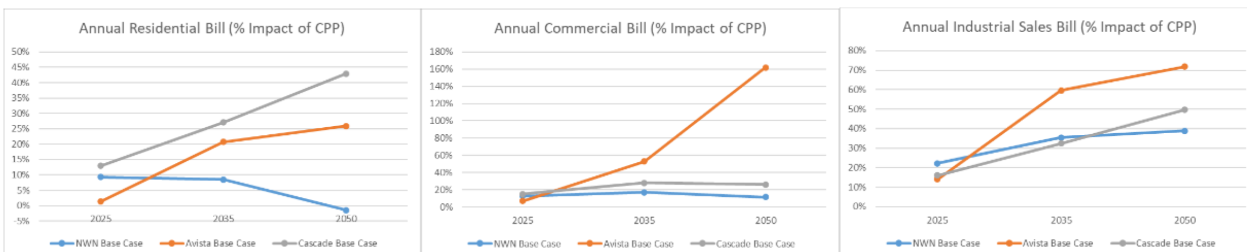


Table 7: Trends in Estimated Ratepayer Bill Impacts over Time

	2025			**2035**			**2050***		
Util.	Res.	Com.	Ind.	Res.	Com.	Ind.	Res.	Com.	Ind.
AVA	1%	7%	14%	21%	53%	60%	26%	162%	72%
CNG	13%	15%	16%	27%	28%	32%	43%	26%	50%
NWN	9%	17%	22%	9%	17%	35%	-2%	12%	39%

*AVA and CNG only go to 2040 so those values were used in place of 2050

Transport Customers

Transport customers are customers that pay Oregon's gas utilities to transport gas to their location, but that pay a gas marketer, not the gas utility, for the actual gas commodity. However, it is the gas utility that is a regulated entity under CPP and is the entity through which transport gas emissions are regulated.

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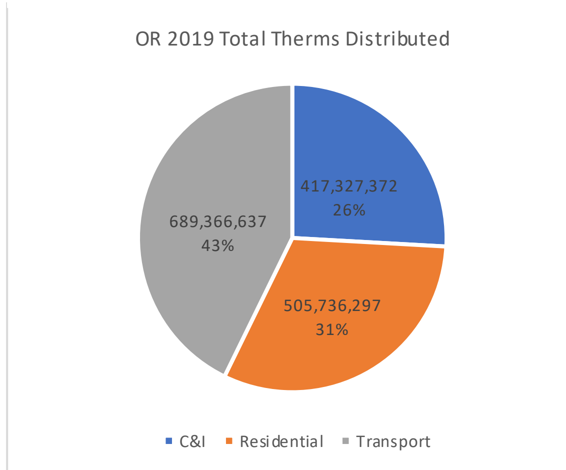
[13] *See* NGFF Workshop 3 presentations and link to modeling materials available on Oregon PUC's Natural Gas Fact Finding website – https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.
[14] Avista notes that its compliance cost had been added to the price per dekatherm of natural gas available as supply into the Company's system and may not be indicative of actual rate spread.
[15] *Ibid.*

As can be seen in Figure 6, which simplifies customers into three categories, Transport customers accounted for over 40 percent of total therms distributed in 2019. With the adoption of CPP rules, the gas utility is now accountable for this large portion of emissions. This creates a situation in which the regulated gas utilities will need to consider developing more programs and activities aimed directly at reducing transport customers' GHG emissions and ways for those customers to pay for those programs.

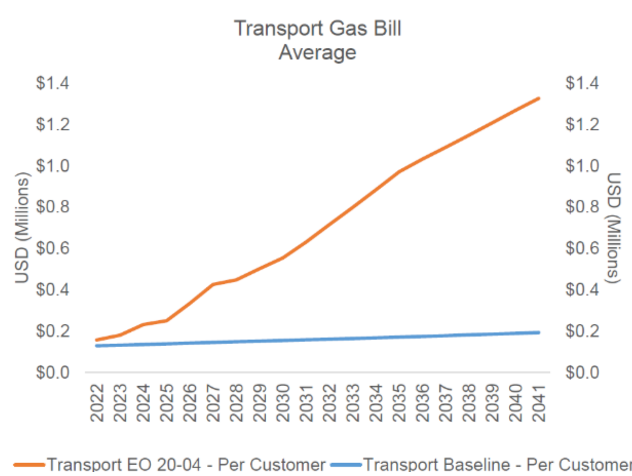
Figure 6: 2019 Total Therms Distributed



The regulated charges that transport customers pay to a gas utility represent a small portion of their total gas costs.[16] The additional cost to transport customers from their regulated utility for CPP compliance, on a $/therm basis, appears large on a relative basis as it is only compared to what transport customers pay now to the regulated gas utilities, which is the cost of moving their gas. It is important to note that rate spread determinations have not yet been established and how compliance costs would be spread across all customers has not been determined.

However, as an imperfect way to try to understand CPP compliance for transport customers, Staff pulled from the utility modeling how an evenly spread $/therm could manifest. As an example, Avista modeled price impacts to transport customers in its base case as seen in Figure 7. Transport customers see an increase in the average ratepayer bills they receive from the gas company, which reflects the increased cost of compliance per therm over the time horizon. Understanding how compliance costs could be spread is an open and unresolved issue that will need to be further explored in future cost recovery dockets. Additionally, transport load, as well as associated emissions and compliance costs,

Figure 7: Avista Base Case Transport Ratepayer Bill Increases due to CPP



[16] When representing the CPP compliance ratepayer bill impacts to these customers as a percent of the ratepayer bill impact, one only captures the increase to what transport customers pay to regulated gas utilities. It would not accurately represent the percent increase because it would not include the cost of the gas itself and the percent increase would appear very high, as compared to the total ratepayer bill paid to the regulated gas utilities.

have not previously been addressed in IRPs and will need to be captured in future gas IRPs.

Renewable Natural Gas

Assumptions about RNG (biogenic, hydrogen, and synthetic methane) costs and availability was also a topic of interest. Utilities modeled RNG use for compliance in all scenarios. Given the nascent market for RNG of various types, the use of RNG as a compliance strategy creates uncertainty and will require additional analysis of RNG costs and availability in future IRPs.[17] By 2025, the utility models projected RNG costs ranging from about $6/dekatherm to $12/dekatherm and these costs are assumed to decrease at different rates after 2025. For comparison purposes, natural gas is currently trading in a range of $3 to $5 per dekatherm.

Each of the three utilities came up with different assumptions about how much RNG they would be able to secure over time. These varying assumptions made it difficult to generalize about the costs and availability of RNG, as well as the impacts on future ratepayer bills. However, the use of neutral third-party market information about the RNG market and other nascent compliance solutions and technologies should provide a way to reduce uncertainty around compliance costs and risks in future IRP analyses.

Declining Customer Counts

Finally, modeling scenarios with declining customer counts provided limited insights. This may be due to inconsistencies in how each company modeled assumptions about how to handle the relatively fixed costs of existing infrastructure given a shrinking customer base. For example, Cascade's modeling showed the ratepayer bill impact from declining customer counts to be virtually unchanged when compared with its base case. Avista's model showed customer costs decreasing significantly in its declining customer count scenario when compared with its base case. Meanwhile, NWN's model showed a substantial increase in customer costs under its declining customer scenario. This reinforces the need to refine and standardize how such scenarios of declining customer counts should be modeled in future IRPs. The Table 8, summarizes the modeling results by scenario and sensitivity. More information on modeling results can be found in Appendix A.

Modeling Electrification

There was substantial disagreement about the consideration of electrification in the modeling. Staff provided initial electrification modeling direction in the Alternative Scenarios, and utilities followed with feedback on the challenges of this modeling. At stake were issues regarding what costs to include, how to assess ratepayer bill impacts, and concerns about reliability. Staff notes there is significant room for improvement

STAKEHOLDER INSIGHTS

MODELING ELECTRIFICATION

The costs of electrifications were not included in utility modeling, are unknown, and need further study - NWN *and JC – NWGA et al.*

Utilities modeled their ability to comply with CPP without relying on electrification - *NWN*

Load shifts from gas to electric could bring reliability risks in peak times - *Avista*

Reliability concerns are not supported and switching resistance heating to electric heat pumps would largely address load concerns – *JC – CS et al. and JC - MCAT*

Electrification might take longer than stakeholders who support it realize – *Avista*

Even swift moves toward electrification [of the gas system] take time to implement and [electricity] reliability concerns can be addressed in long-term planning – *JC – CS et al. and JC – MCAT*

[17] *See* RNG modeling recommendations for IRP in Appendix B.

in electrification modeling and that the electrification modeling for this fact finding is missing important cost and reliability elements.

Table 8: Scenario Modeling Summary

Scenario	Results – high level summary
Base Case	Generally, compliance with GHG emission regulations resulted in a range of both increased and decreased ratepayer bill impacts. The source of those ratepayer bill changes varied by company and compliance strategy. There is a lot of variation in the models, which reinforces the need to look at these issues more closely in the context of a planning document such as an IRP.
Restricted RNG	Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher compliance costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced their overall cost of compliance compared to their base case scenarios.
Declining Customer Counts	NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.[18]
Aggressive Timeline	NWN costs increased in the middle years of the model run but the difference between this scenario and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.
No CCIs	All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years. But by 2050 the three utilities' modeling runs arrived at different conclusions with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking, and Cascade's annual compliance costs were the same as in its base case.
Alt. Scenario 1 - Innovation	Cascade's model resulted in ratepayer bill impacts that were lower than in their base case. Avista's modeling summary showed zero change in ratepayer bill impacts, but the workbooks showed negative ratepayer bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's ratepayer bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318% increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.

[18] Avista noted in their Comments to the Draft Report that their costs in scenarios with declining customer counts erroneously omitted ratepayer bill increase customers would face as fixed costs are distributed over fewer customers. This omission affected all high electrification and customer decrease scenarios. *See* Avista June 3, 2022, Comments in UM 2178.

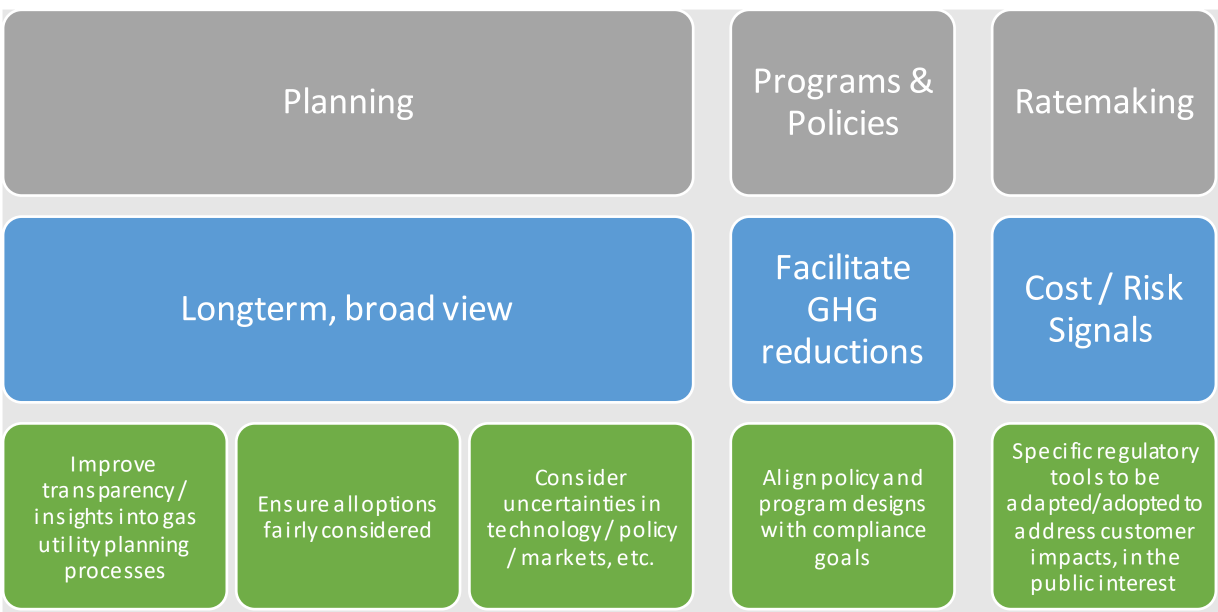
Alt. Scenario 2 – Accelerated Electrification	Like Scenario 1, Cascade modeled ratepayer bill impacts that were lower than their base case. Avista's summary showed zero ratepayer bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405% increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

3.3 REGULATORY TOOLS

In this proceeding, Staff, stakeholders, and utilities, led by the Regulatory Assistance Project (RAP), explored regulatory tools that could be used to address the customer impacts while meeting CPP targets.

Staff relied on a framework provided by RAP (summarized in Figure 8) to organize categories of tools and explore the benefits and tradeoffs associated with the different tools. These categories include three types of tools: planning, programs, and ratemaking. Additional information about these tools can be found in workshop 4a materials.[19]

Figure 8: Categories and Goals of Regulatory Tools



Staff believes current PUC authority is sufficient to apply all of the regulatory tools discussed in this report in the categories of planning, programs, and ratemaking as they are already being or have been implemented in some shape or form. These tools can support any number of CPP compliance pathways. However, some of the tools require new resources (e.g., reports, staffing, etc.), enhanced understanding

[19] See Docket No. UM 2178 September 24, 2021 Workshop 4a at:https://edocs.puc.state.or.us/efdocs/HAH/um2178hah101818.pdf

of costs and risks, and a coordinated, strategic focus to optimize decisions across Oregon's entire energy system, not just a single fuel type.

4 STAFF ANALYSIS AND RECOMMENDATIONS

The compliance modeling, workshops, and stakeholder input gave Staff an excellent set of raw materials from which to analyze costs, risks, and implementation options. The analysis and considerations below are meant to serve as an initial guide into the application of the identified regulatory tools.

Staff believes compliance with the CPP will very likely increase costs to all customers in the near-term and the modeling suggests it may have differing impacts. The extent of rate impacts depends upon the type of customer, compliance strategies deployed, and gas company characteristics.

While utility modeling showed a range of customer impacts from CPP compliance, in the absence of some form of intervention, the greatest burden from any increased ratepayer bills will likely fall to those already experiencing high energy burdens. All stakeholders involved in the workshops expressed concern about the potential impacts that will result from further burdening low-income and other at-risk customers. Further, the risk is not limited to gas customers. Initial analysis and research point to electrification costs, for either new or existing gas customers, spilling over into ratepayer impacts on electricity customers as well.[20]

The rate pressure risk grows beyond just the increasing cost of compliance for the existing system. Customer migration to the electric system, due to any number factors, spreads the cost of gas infrastructure over a smaller customer base. The potential for a feedback loop emerges, where a shrinking customer count potentially accelerates cost pressures, which further motivates those customers that can leave to do so. This problem also calls into question annual expansion of the gas system, as each new customer not only brings increased CPP compliance obligations, but also more gas infrastructure for future ratepayers to cover.

To understand this possible feedback loop better, Staff conducted its own investigation of residential customers' propensity to connect or disconnect from the natural gas grid.[21] Our research into the elasticity of residential demand confirmed two things: 1) Decisions to depart the system happen only after sustained price increases and generally lag those increases by two to three years, and 2) Cost increases will be felt more acutely by energy burdened customers because their options to respond to price signals are limited. Communications about the permanency of CPP compliance costs and Oregon's commitment to decarbonization may have an impact on the lag in gas consumer decisions.

Utility modeling confirmed that there could be significant cost impacts to commercial, industrial, and transport customers, not just residential customers. In short, CPP compliance has the potential to create rate pressure risks that could exacerbate energy burden issues for many types of customers. In light of this, Staff recommends regulatory tools that mitigate near-term price increases, limit long-term risks, and fairly manage any transition to new technologies. Potential solutions are discussed below, organized around various themes.

[20] Gridworks Central California Pilot of CPUC. https://gridworks.org/2021/09/lessons-learned-so-far-in-targeted-building-electrification/.

[21] See Appendix D – Elasticity.

4.1 PROTECTING CUSTOMERS WITH LIMITED OPTIONS

Stakeholders identified two types of customers especially at risk from higher costs because they lacked the ability to easily substitute away from the natural gas system. Those two groups were low-income residential customers and businesses reliant upon gas for specific end-use processes. For low-income customers, higher costs create and increase an unavoidable energy burden. Some Oregon businesses have limited-to-no-economic substitutes to gas use for processes like emissions control technologies, outdoor heating for nurseries, and process heat to meet food safety standards. Tools that provide targeted mitigation of certain ratepayer bill increases, without hindering progress toward compliance, would be of high value to the process of gas system decarbonization. One such tool that has emerged since the Draft Report was published in April 2022, is the U.S. Inflation Reduction Act (IRA). Most notably for this section, the IRA has a generous set of rebates, via the High-Efficiency Electric Home (HEEH) Program, for low- to moderate-income households (i.e., ≤150 percent of Area Median Income), including up to $8,000 for electric heat pumps. Working with the administrator of these funds in Oregon to prioritize the use of IRA rebates for the gas companies' most vulnerable residential customers would go a long way toward protecting customers with limited options as the gas system seeks to decarbonize.

> STAKEHOLDER INSIGHTS
>
> PROTECTING CUSTOMERS
>
> LMI-targeted deployment of electric heat pump deployment brings resiliency co-benefits of cooling - *Multnomah County and JC - Mayoral*
>
> Focus on customer protections, not utility incentives - *NWEC, TNC, and JC - EC et al.*
>
> Exercise caution and avoid hurried decisions in this time of heighten uncertainty and transition - *JC - NWGA et al.*
>
> Protect customers, in part by protecting the viability of gas utilities to accomplish other GHG emission reduction goals. – *NWN*
>
> Prioritize near term implementation of tools that protect customers – *NWEC*
>
> Identify options for accelerating amortization schedules - *JC - EC et al.*
>
> Deny rate recovery for investments in unproven technologies - *JC - EC et al.*
>
> Implement rate class policies (e.g. HB 2475) - *JC - EC et al.*
>
> HB 2475 is good, but insufficient protection - *Multnomah County*

4.1.1 Actions

To address a primary goal of this Fact Finding, Staff identified the following near-term actions that could help protect ratepayers from bill increases. Many of the comments from Stakeholders regarding protecting customers are also reflected in the priorities identified in Section 2.4, as well as throughout the NGFF report.

Planning

- Include estimated ratepayer bill impact analysis in IRPs to ensure transparency of trends and implications of compliance pathways as represented in portfolios.

Programs[22]

[22] The Draft Report previously included the recommendation: "Prioritization of incremental energy efficiency for CPP compliance that lowers natural gas usage but allows for customer count growth to continue at some level so as to avoid near-term outcomes that place upward rate pressures on those customers unable to exit the gas system and would therefore be forced to cover an increasing proportion of fixed costs." Staff decided to remove this action. The analysis in Cascade Natural Gas' IRP Update and the Commission decision on Line Extension

- Direct Energy Trust of Oregon (ETO or Energy Trust) and Community Action agencies to work with utilities to expand and target energy efficiency programs to low income and environmental justice communities to reduce energy burden and minimize anticipated ratepayer bill impacts.
- Assist in targeting IRA incentives and rebates, including but not limited to the installation of heat pumps as either a replacement for inefficient furnaces or in dual fuel configuration, for qualified low- to moderate- income households. Targeting includes securely providing data on customers to Oregon's IRA administrator(s) so they can prioritize rebates and incentives to these gas customers at risk from potentially elevated costs from ongoing CPP compliance activities and decarbonization investments.
- Ensure the gas utilities enroll transport gas customer into efficiency programs and that these customers pay their fair share relative to what other ratepayers pay for energy efficiency programs.

Rates[23]

- Include assessments of CPP compliance risks, like load growth from new customers, in prudency review of investments in the distribution system, in order to limit uncertainty around accumulation of long-term capital assets.
- Explore accelerated depreciation of unamortized investments in the gas utilities' next depreciation studies and provide a sensitivity analysis to better to understand rate impacts.
- Explore transport customer rate spread and rate design issues related CPP Compliance in general rate cases.[24]

4.2 Accessing Information and Proceedings

Stakeholders continually raised concerns about the complexity and resource commitment necessary to acquire key regulatory information and meaningfully engage in planning processes and other gas dockets. Much like the outcome of the PUC's 2018 Senate Bill 978 report,[25] community-based and business organizations interested in impacting PUC and utility CPP decisions noted the difficulty in achieving procedural inclusion across the spectrum of gas dockets.

Allowances in UG 435 underscored the several risks associated with continued system growth due to increased customer counts and that any associated benefits were more indeterminate and uncertain than previously thought in April of 2022.

[23] The Draft Report included the recommendation regarding the implementation of HB 2475 bill discount regime that will mitigate rate increases for energy burdened customers, in conjunction with aggressive energy efficiency." Staff removed this recommendation because it is currently being implemented.

[24] AWEC notes in its June 3 Comments that the principles of cost causation should be maintained in rate spread approaches.

[25] Oregon PUC. SB 978 – Actively Adapting to the Changing Electricity Sector. September 2018.

4.2.1 Actions

The following activities would improve stakeholder's access and awareness of gas utility's information and proceedings.

Planning[26]

- Facilitate stakeholder awareness of gas planning and CPP compliance related dockets through outreach coordinated by Energy Resources and Planning Division Staff, including, to the extent possible, how and when stakeholders could get involved.

STAKEHOLDER INSIGHTS

COMMUNICATIONS & ACCESS

Apply communication strategies to both gas and electric IRPs – *NWN*

Staff should produce manuals on effective participation – *JC – CS et al.*

Ratemaking

- Encourage parties interested engaging in rate cases to work with PUC's Administrative Hearings Division's efforts to expand eligibility for intervenor funding to fund participation in PUC proceedings.

4.3 FULL COST OF AGGRESSIVE DEMAND REDUCTION – LOAD SHIFT IMPACTS OF ELECTRIFICATION

Many stakeholders put forth ideas to rapidly reduce customer demand to meet CPP targets. These range from energy efficiency to Beneficial Electrification (BE).

STAKEHOLDER INSIGHTS

EE AVOIDED COSTS (AC)

CPP compliance costs should be reflected in EE AC – *CNG and NWN*

AC in NWN's current IRP and AC filings will reflect CPP costs – *NWN*

EE AC should reflect avoided gas infrastructure costs – *TNC*

Include AC of climate impacts and non-energy benefits – *Multnomah County*

Energy Efficiency Avoided Costs

The calculation and application of energy efficiency avoided costs is a key input in planning as it dictates what energy efficiency measures are deemed cost effective. Many stakeholders pointed to the important role of Energy Efficiency Avoided Costs (EE AC) in facilitating cost-effective GHG emission reductions. This included comments on the inclusion of CPP compliance costs, consideration of avoided gas infrastructure, consideration of climate impacts, and capturing non-energy benefits.

Beneficial Electrification

BE emerged as a key concept in UM 2178. The Regulatory Assistance Project (RAP) offers this description of beneficial electrification:

> For electrification to be considered beneficial, it must meet one or more of the following conditions without adversely affecting the other two: 1) Saves consumers money over the long run; 2) Enables better grid management; or 3) Reduces negative environmental impacts.[27]

[27] Farnsworth, D., Shipley, J., Lazar, J., and Seidman, N. (2018, June). Beneficial electrification: Ensuring electrification in the public interest. Montpelier, VT: Regulatory Assistance Project.

Multiple stakeholders pointed to the role electrification can play in near term emission reductions, the need to consider the likelihood of future electrification policies and actions, as well as equitable transitions via building electrification and associated co-benefits in the planning process. However, there was substantial stakeholder conversation about whether and how electrification should be considered as a strategy for reducing emission or a regulatory tool. For residential customers, this may include replacing gas fired furnaces, stoves, and water-heaters with those powered by electric heat pump and induction technology. For commercial customers, this may include swapping an existing gas-fired boiler for an electric boiler. Much is unknown about how to deploy BE in Oregon and what the resulting emissions and cost impacts might be to the electric system. Without careful analysis, planning, and execution, electrification has the potential to shift greater energy demand, peak risk, distribution costs, and reliability concerns to electric ratepayers. Most stakeholders acknowledged that more must be learned to understand the costs and risks from electrification so that with good planning, electrification could create system benefits.

To this end, Staff has engaged two consultants to begin exploring some of these topics. First, in LC 79, Synapse will be exploring ways to add electrification costs to gas IRP. The intent of the study will be to provide information for a conversation about the costs of electrification scenarios as compared to other decarbonization pathways. Second, through a generous grant from the US Climate Alliance, the Cadmus Group and Moment Energy Insights will conduct a technical study to inform **future** gas and electric IRPs with guidance on information requirements to facilitate joint utility decision making for least-cost, least-risk GHG emission reduction strategies.

4.3.1 Actions

Staff believes the following tools could be used to facilitate coordination between gas and electric utilities to enable analysis of customer costs, grid management, and emission impacts of load reduction associated with aggressive gas demand reduction.

STAKEHOLDER INSIGHTS

BENEFICIAL ELECTRIFICATION

Electrification policies as a compliance pathway eliminate customer choice - *JC - NWGA et al. and NWN*

Electrification can play a role in near term emission reductions, there is a high likelihood of future electrification policies and actions, and building electrification can be part of an equitable transitions due to associated indoor air quality co-benefits with direct impacts to Black, Indigenous, and other Environmental Justice communities - *SC, NWEC, Multnomah County, JC - CS et al., and CUB*

The biggest risk of potential customer decreases and associated rate pressure increase are not from gas company compliance costs, but rather from policies that would drive customer defection - *NWN*

While electrification is a preferred strategy for building decarbonization, the Commission should be prepared to protect LMI gas customers from anticipated negative cost impacts - *SC, NWEC, Multnomah County, JC - CS et al., and CUB.*

Conduct electrification study - *Avista, AWEC, NWN, and JC - CS et al.*

Create a timeline for building electrification, ensure targeting incentives for phased electrification and decommissioning of gas - *JC – MCAT*

The Commission should develop and provide direction about how gas companies should consider electrification in IRPs and analysis of stranded asset risk - *JC - CS et al.*

Electrification should not be considered as a 'regulatory tool' - *AWEC, NWN, Avista*

Sources cited to support electrification were too generalized or based on states with very different attributes and should not be relied upon for assessing electrification impacts and costs and, that because the case for electrification is unsupported, that inclusion as an option sends 'calamitous' market signals – *NWN*

Planning

- Develop marginal abatement cost curves for IRPs that identify all resources potentially used by utilities in CPP compliance, including currently non-cost effective energy efficiency.
- Request gas and electric utilities to develop and articulate individual electrification assumptions in future gas and electric IRPs that others can reference, based on feedback from Staff's two sets of consultants exploring different aspects of this issue.
- Work with electric utilities in future DSP filings to identify the cost elements, costing methodology, and estimated average distribution cost to electrify existing gas customers.

Programs

- Adopt a compliance cost of carbon and an enhanced risk reduction value into gas energy efficiency avoided costs that reflects CPP-related risks in order to accurately value and support energy efficiency opportunities and investments so as to encourage more aggressive demand reduction.

4.4 Decarbonization Policies as Key Determinants to Planning and Cost-Recovery

The GHG emission reduction targets with the passage of HB 2021 and the adoption of the CPP rules reshaped Oregon's energy policy landscape. Resource planning will increasingly require systems thinking across all utility types.[28] Utilities, stakeholders, and the PUC will need to consider the energy system on a whole and ratepayers as households. Key policy decisions can easily have consequential, systemwide feedback loops that span beyond an individual gas or electric utility's IRP or operations. Yet, understanding impacts across utilities proves challenging in Oregon's resource planning environment as interplaying impacts are not readily apparent or captured by the current planning processes.

Energy System Planning

Attempts to model interactions between gas and electric utilities as part of this investigation proved to be beyond the limitations of the NGFF modeling. It also showed how difficult it would be to analyze the costs and benefits of strategies that contemplate shifting heating loads from gas to electric in Oregon as part of a single fuel utility's IRP. To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the planning of both gas and electric utilities will require the sharing of key data in the near-term and the explicit recognition of planning interdependencies. Conducting least-cost, least-risk analysis to determine the best solutions to reduce GHG emissions requires the ability to

STAKEHOLDER INSIGHTS

ENERGY SYSTEM ANALYSIS

Energy system analysis should be a formal coordination planning process, beyond just shared assumptions and data - *TNC*

Develop combined IRP to identify how loads can be met most cost effectively, rather than how companies can best meet loads for their customers - *NRDC*

Gas utilities should collaborate with electric Distribution System Planning on joint planning efforts - *NWN and CNG*

Commission should task a third party to oversee a new joint planning process - *JC – CS et al.*

Joint utility planning scope should closely engage with electric utility to understand cost and reliability information to holistically understand costs of gas decarbonization - *NWN*

[28] Systems thinking is defined as a way of making sense of the complexity of a situation by looking at it in terms of wholes and relationships rather than by splitting it down into its parts.

understand trade-offs across different types of energy utilities (gas or electric) that share the same customer.

Stakeholders provided guidance about what energy system planning ought to include, some of which is referenced in the section on Full Cost of Aggressive Demand Reduction. However, there was general agreement that there is a need for a more holistic understanding of the interactions between gas and electric utility planning.

4.4.1 IRPs - Guidelines & Improvements, Assumptions, and Acknowledgement

Oversight of Oregon's gas utilities meeting DEQ's CPP requirements in a least-cost, least-risk manner is part of the PUC's broad mandate. Much of this oversight begins with the IRP development and review. The PUC IRP process requires utilities to produce plans that adhere to the PUC's IRP Guidelines, which were established in 2007.[29]

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. The issue of assumption validation and support was raised as part of the conversation around IRPs generally, as well as specifically with regard to decarbonizing supply. Comments regarding decarbonized supply are addressed in the following section regarding CPP investments and section 5.5 regarding Risk and Uncertainty.

STAKEHOLDER INSIGHTS

IRP GUIDANCE AND GUIDELINES

Update Guidelines to better capture emerging risk and uncertainty and require analysis of fuel switching – *Joint Climate Solutions Pre-June 3 Comments*

Open a separate proceeding to address changes proposed in Appendix B regarding IRPs, consideration of marginal abatement cost curves, and modeling assumptions - *NWN, CNG and AWEC*

Commission should work with Companies and stakeholders to develop a uniform methodology for converting IRP investments into estimated ratepayer bill impacts - *CNG*

CPP compliance should be acknowledgeable in IRPs. *CNG and NWN.*

CPP compliance should be mandatory, not just acknowledgeable. *JC - CS et al.*

Group method accounting means utilities do not track all assets or depreciable life and is not consistent with publicly available data from depreciation studies – *Avista*

Mapping may be a security issue – *NWN and Avista*

4.4.2 CPP Investments

Infrastructure and Line Extension Allowances

Infrastructure investments may be related to "safety or generally system reliability" or "customer growth or reliability related to growth." As noted above, system growth brings both additional GHG compliance obligation and infrastructure costs with long depreciation timeframes at risk from uncertainty around the number of customers. Many stakeholders commented on the need for heightened scrutiny of investments in gas infrastructure. Comments ranged from the value of using existing infrastructure for innovative fuel decarbonization options, to concerns about the risk of stranded costs associated with long term investments, as well as an interest in strategic system contractions with electrification.

[29] See Order Nos. 07-002 and 07-047.

During the course of this investigation, the topic of how to consider infrastructure investments was raised in Cascade Natural Cas's IRP Update, LC 76. In that docket, Staff noted that:

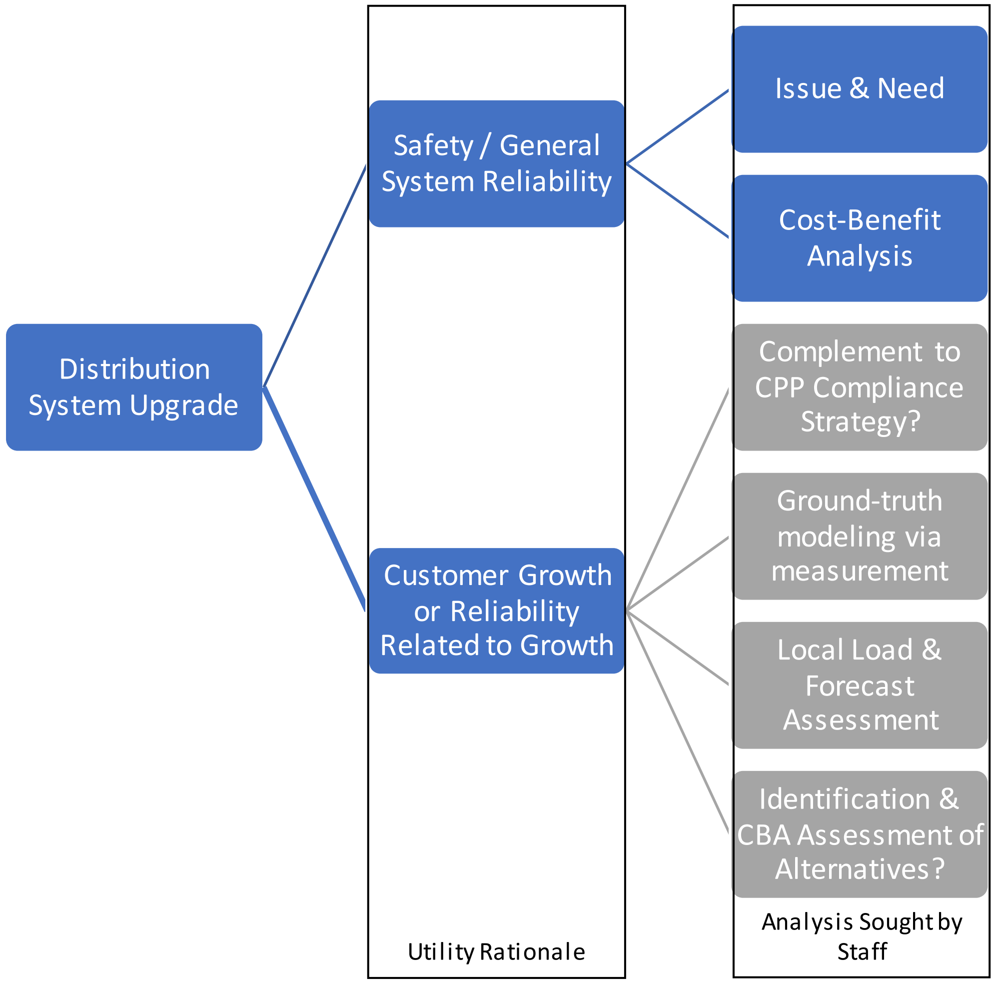
> [g]rowth in natural gas demand requires compensatory investments or actions to stay in line with the CPP's steadily declining trajectory of annual emissions. Determining the acknowledgability – and potentially even the prudency – of distribution upgrades now requires an understanding of the absolute need for any proposed upgrade *and* of how that upgrade fits within the company's system-wide CPP compliance plan, both in the near- and long- term.[30]

In that proceeding, CUB also called for CNG to begin piloting "alternative approaches to distribution system upgrades, like targeted energy efficiency and demand response, to more fully consider non-pipe alternatives in future resource planning."[31]

Staff's comments above presented a high-level framework for how Staff plans to assess gas LDC's proposed distribution system upgrades going forward with new criteria found in grey in **Error! Reference source not found.**9.[32]

[30] See LC 76 Cascade IRP Update, Staff Final Report, October 7, 2022, page 5.
[31] See LC 76 Cascade IRP Update, CUB Comments, July 22, 2022, page 4.
[32] See LC 76, Staff Comments, July 22, 2022, page 11.

Figure 9: *Staff's Proposed Approach in Cascade's IRP Update (LC 76) to Distribution System Project Analysis Post-CPP Adoption*



The grey boxes represent new criteria Staff proposed to use when assessing distribution system projects driven by future customer growth. Appendix F details specific information Staff would request on any growth-driven distribution system project in the future. As Staff learns more and engages with IRPs and stakeholders, we envision this framework evolving.

In addition to the infrastructure issues raised in LC 76, the issue of line extension allowances (LEA) was raised in NW Natural's rate case, docket UG 435. In UG 435, CUB raised CPP compliance obligation costs associated with LEAs for new customers and successfully argued for modifications to the PUC's LEA for NW Natural. In summarizing CUB's argument, the PUC noted that:

> CUB maintains that as the system grows, the costs to reduce emissions to comply with the CPP will also increase. * * * CUB asserts that * * * under a traditional paradigm adding new customers mitigates cost impacts, it is not true when new customers bring additional emission reduction costs to all customers. * * * [U]nder the CPP, NW Natural must reduce its greenhouse gas emissions by 50 percent from a historic baseline, but that as the system grows, NW Natural will have to reduce baseline emissions by 69 percent to accommodate the load growth and still meet the emissions reduction requirements. CUB argues that this increases the costs to existing customers. * * * CUB maintains that NW Natural is seeking to significantly increase its energy efficiency spending to reduce therms while also spending millions on capital investments through the LEA to increase therms. CUB asserts that therms from existing customers are different than those from new customers, because it takes decades to pay back LEA spending and it is more cost effective to not subsidize growth through the LEA than to pay incentives to customers to reduce usage. CUB contends that NW Natural is asking customers both to pay to grow the system and pay for energy efficiency incentives.[33]

The PUC agreed with CUB on this issue and stated:

> The primary reason that NW Natural's current LEA is problematic is that it fails to take into account any of the costs that are brought to NW Natural's system from new customers associated with greenhouse gas emission abatement obligations placed on the company under the CPP. As shown in this case, those costs could be significant. In fact, the record demonstrates that those costs, when accurately accounted for, could result in no or negligible economic benefit being brought to the existing system from the addition of new customers.[34]

STAKEHOLDER INSIGHTS

INFRASTRUCTURE

Immediately halt gas system expansion – *CUB, JC-EC et al., MCAT Joint, and OSPR*

Addition of new gas customers creates a stranded cost risk – *CUB*

NWN Disputes the claim that investments in gas infrastructure will lead to stranded assets - *NWN*

Support decarbonization polices that embrace innovation and make use of existing energy delivery infrastructure - *JC - NWGA et al.*

Investigate opportunities to "branch pruning" sections and replace with electrification - *JC-EC et al.*

LINE EXTENSION ALLOWANCES

Eliminate or phase out Line Extension Allowances for gas and revisit those that consider behind the meter upgrades supporting electrification- *JC-EC et al. JC-CS et al., TNC*

Growth of gas customers is unsustainable and incentives should align to protect customers associated with gas customer declines - *TNC*

LEAs should be based in sound economic and rate making principles (equity among rate

[33] *In the Matter of NW Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Order No. 22-388 at 34 (October 24, 2022)(fo*otnotes omitted*).
[34] *Id*., at 48 (footnotes omitted).

This PUC's decision signals awareness of increased risks of new customers and that this is an area worthy of heightened scrutiny in both planning and cost recovery dockets.

The PUC also provided guidance relevant to CPP compliance costs and customer growth in its decision Order No. 22-388. Guidance from this rate case will be valuable to analysis in the integrated planning process. Specifically:

- Conducting analysis of how each new customer addition changes the costs of CPP compliance for other customers; and
- Reviewing analysis supporting the company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics are factored in.[35]

Decarbonizing Supply

RNG, green hydrogen, and synthetic methane represent relatively new supply side additions to natural gas planning in Oregon. Being conservative in projecting costs and availability (both volumes and timing) of emerging solutions/technologies can help manage uncertainty related to the relative unpredictability of these variables, especially for nascent technologies like hydrogen and synthetic methane.

Stakeholders expressed concern about the assumptions of availability and cost of RNG as modeled by the gas utilities. Stakeholders noted discrepancies between the availability cited by the gas companies and that provided in a recent ODOE report, and further questioned the availability assumptions used by the gas companies. They indicate that biomass sources will be difficult to access and costly. These stakeholders urged Staff to provide heightened scrutiny to utility RNG modeling and assumptions.

If RNG and H2 are to be used, stakeholders suggested additional backstops and guardrails to help protect customers, including information about current and future development sites, confirmation that Renewable Thermal Credits can be used for CPP compliance, and close tracking of RNG market potential. It was also suggested that the PUC should not allow expansion of the gas system unless utilities can demonstrate their ability to acquire RNG and Green H2 in a cost competitive manner, and that they can demonstrate the safe use of H2 before approval of any rate-based incentives.

Alternatively, NWN argued that utility activity is a driver of markets, so we should be careful in assuming that general market reports reflect what is possible in the region. Further, both NWN and CNG support use of SB 844 to incentivize H2 deployment.

STAKEHOLDER INSIGHTS

DECARBONIZING SUPPLY

Only Green H2 should be modeled, conservative assumptions should be used regarding availability and cost, and RNG and H2 should be reserved for hard to electrify end uses. - *JC-MCAT et al., JC-CS et al.*

RNG commits customers to gas home heating equipment and eliminates opportunity to electrify - *NRDC*

Market adoption of RNG may be different across locations and demographics - *CNG*

RNG development activity and markets should be tracked closely, and all RNG must be CPP compliant - *JC - CS et al.*

Do not expand the gas system until utilities can demonstrate that RNG can be acquired in a way that is cost competitive and safe – *Multnomah County*

National or general assumptions about RNG do not reflect large utility influence on the market – *NWN*

SB 844 could be a tool for developing H2 – *NWN and CNG*

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

Cost Recovery

The issue of cost recovery associated with CPP compliance was raised by several stakeholders.

NWN, CNG and AWEC expressed concern about limiting cost recovery options for CPP compliance and stated that ensuring adequate cost recovery was critical to maintain safety and reliability, and the ability to bring lower carbon fuels on to the system, like H2. They also expressed concern about connecting cost recovery with CPP compliance.

JC – MCAT *et al.* recommended the PUC deny cost recovery for high-cost and high-risk investments in unproven technologies.

STAKEHOLDER INSIGHTS

COST RECOVERY

Ensuring adequate cost recovery is critical for maintaining safety and reliability and cost recovery should not be limited to CPP compliance – *NWN, CNG, and AWEC*

Deny cost recovery for high cost, high risk investments in unproven technologies – *JC-MCAT et al.*

4.4.3 Actions

To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the IRP for both gas and electric utilities will require the sharing of key data and the explicit recognition of planning interdependencies, the inclusion and review of new information reflecting various supply and demand side compliance approaches, an expansion of data regarding distribution system investments associated with growth, and compliance costs and risks. To address these issues Staff identified the following applicable near-term actions:

<u>Planning</u>

- Make publicly available maps of the gas system overlaying depreciation and age data and include lists of infrastructure and associated depreciation schedules.
- In IRPs, gas utilities should support proposed growth-related distribution system planning investments with analysis and details proposed in Appendix F and ensure that modeling said investments allows them to compete comparably with other demand-side options and non-pipe alternatives.
- To inform utility planning, the PUC should contract with an independent third party (*e.g.*, consulting firm or regional non-profit like NEEA) on a regular basis to evaluate market trends around alternative fuel and low-carbon technology cost and availability and to analyze Pacific Northwest market adoption of decarbonization technologies that are central to any utilities' CPP compliance pathway.
- Staff to treat CPP compliance as an acknowledgeable element of any future gas IRP or IRP update.
- Staff recommends exploring in the future the use of the IRP guidance found in Appendix B. Staff will seek a waiver to adopt this new guidance where it conflicts with existing IRP guidance in Order Nos. 07-002 and 07-047 or existing GHG planning guidance in Order No. 08-339.
- In IRPs gas utilities should include or conduct similar analysis to that directed in Order No. 22-388 regarding two items. First, new customer addition costs and risks to existing customers for CPP compliance. Second, supply analysis regarding new and existing customer retention and how changing policy dynamics are factored in.

4.5 Robust Compliance Monitoring, Tracking, and Reporting

Each utilities' base case CPP compliance modeling relied on decarbonizing the fuel they provide through large amounts of RNG, green hydrogen, and/or synthetic gas. These supply-side alternatives to natural gas currently represent a significant part of each companies' compliance strategy. Notably, large-scale hydrogen availability at a reasonable price is necessary in less than 15 years.

Table 9: Alternative Supply Projections

Utility	RNG Supply Penetration by 2025[36]		RNG Supply Penetration by 2035	
	Volume (Dth/year)	% Of Deliveries	Volume (Dth/year)	% Of Deliveries
Avista	317,875	2%	2,932,134	40%[37]
Cascade Natural Gas	1,544,229	10%	6,673,003	26%
NW Natural	4,842,842	4%	8,399,503 (bio) 13,551,224 (H2)	23%

Many stakeholders believed the quantities and the timeline of availability put forth by the companies were not realistic. Further, they made the case that relying on these natural gas alternatives placed a tremendous amount of compliance and financial risk on the companies, and thus ratepayers. It allows for the continued expansion of the gas system with the promise of future low-to-zero GHG fuel supplies. To inform risk assessments robust monitoring, tracking, and reporting of trends from Oregon activities and the broader market will be necessary to inform compliance risk in planning dockets and rate cases.

Strategies reliant on solutions with high levels of uncertainty (*i.e.*, abundant, carbon-neutral, and low-cost synthetic methane) function amidst a backdrop of uncertainty: the risk of non-compliance with the CPP. The compliance regime for the CPP has already begun. In just over three years, the DEQ will close the first compliance demonstration window and assess fuel supplier performance, including the gas utilities.

CPP rules grant the DEQ broad discretion to impose penalties for enforcement.[38] While the DEQ has not yet announced how it will apply penalties, Staff's operating assumption is that the floor of any non-compliance penalty should be at least the cost of a CCI on a per metric ton basis. For the current three-year compliance period, the average cost of a CCI as an alternative compliance mechanism will be approximately $108/metric ton, unadjusted for inflation. However, stakeholders argued the cost of non-compliance should be double or triple the price of a CCI.

Regardless, imposing a penalty at the CCI price on a per metric ton basis poses a potentially sizeable, near-term, financial risk to the gas utilities. The table below attempts to characterize this financial impact should the utilities exceed their three-year emissions allowance by just 1.5 percent.

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[36] RNG Supply Penetration refers to all renewable supply options, including biofuel, hydrogen, and synthetic gas.
[37] Avista noted in comments that it believes this value should 19.5 percent of deliveries. However, Staff notes that the value provided by Avista appears to be its 2030 value, not 2035, which is what the above table is intended to capture.
[38] OAR 340-271-0010.

Table 10: Potential Impact of Missed Compliance

Utility	3-Year, CPP Emissions Allowance[39] (Metric Tons)	1.5% CPP Exceedance (Metric Tons)	1.5% Exceedance in Gas Sales (Therms)	Potential 2025 Fine @ Avg. CCI $/Metric Ton	Comparator: *2020 Operating Expenses*
AVA	2,028,960	30,434	5,636,000	$3,286,915	$96,658,000
CNG	2,145,309	32,180	5,959,192	$3,475,401	$48,930,000
NWN	16,615,303	249,230	46,153,619	$26,916,791	$402,484,000

With this in mind it is worth noting that persuasive arguments could be made that avoidable fines should not be paid by ratepayers.

The resulting uncertainty and possible financial risk highlight the need for robust monitoring, tracking, and reporting of both the efficacy of compliance strategies and market developments informing the selected compliance strategy. For reference purposes, each gas utility put forth their preferred strategy to achieve compliance by 2025 in this docket. The table below summarizes each utility's preferred 2022 through 2024 compliance strategy by element.

Table 11: Total Aggregate Reduction for 2022 through 2024 Period by Strategy

Utility	Aggregate 3-Year, CPP Emissions Reduction Goal *(Tons Reduced From Baseline)*	Additional EE/DR			RNG			CCI		Other			Total
		%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons*1
AVA	188,282	7%	251,710	13,985	12%	-	23,095	81%	153,521	2%	75,148	3,973	190,601
CNG	249,567	14%	164,500	34,801	9%	403,350	21,402	77%	193,364				249,567
NWN	759,354	14%	2,007,951	106,542	51%	3,657,331	386,279	35%	264,718				757,539
	Totals		2,424,160			4,060,681			611,603		75,148		

** - ton equivalent for CCIs*

**1 - Modeled totals may not equal the Aggregate 3-Year CPP Emission Reduction Goal.*

The emissions levels set for the first compliance window (2022 through 2024) require that the gas utilities accomplish what appear to be achievable emission reductions with all three companies making use of allowed CCIs to aid overall company compliance. Perhaps the two biggest near-term challenges will be their reliance on RNG and building the compliance-related infrastructure for the 2025-2027 time period. To this end, NWN is actively pursuing RNG projects, and both Cascade and Avista have indicated in their most recent IRPs that RNG is a resource they have begun pursuing and that the PUC should expect to see it in their forthcoming IRPs.

By comparison, the GHG emission reducing resources required by the end of the second compliance window (2025 through 2027) are substantially larger than the first compliance window.

As shown in Table 12, collectively Oregon's gas utilities will need by 2027:

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[39] Calculated using the numbers in OAR 340-271-9000. Table 4.

- 61.6 million Dekatherms of additional avoided demand with energy efficiency and demand reduction,
- 30 million Dekatherms of biogenic RNG,
- 1.7 million CCI credits,
- 920,000 Dekatherms of hydrogen, and
- 300,000 Dekatherms of avoided demand with other programs.

Table 12: Total Aggregate Reduction for 2022 through 2027 by Strategy

Utility	Aggregate 6-Year, CPP Emissions Reduction Goal	Additional EE/DR			RNG			Hydrogen			CCI		Other			Total
	(Tons Reduced From Baseline)	%	Dth	Tons	%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons
AVA	630,153	7%	835,252	44,156	19%	2,780,979	119,785	8%	919,771	48,624	64%	410,229	3%	377,496	19,956	642,751
CNG	812,939	12%	1,816,124	96,364	43%	6,600,449	350,220	0%	-	-	45%	366,356	0%			812,939
NWN	3,537,123	20%	79,987,893	701,017	38%	25,264,527	1,340,536	0%	-	-	42%	1,483,624	0%			3,525,177
	Totals		82,639,268			34,645,955			919,771			2,260,210		302,348		
	Additional from first compliance window		61,639,346			30,148,407			919,771			1,648,606				

With less than six years before the first GHG reduction requirements in the CPP must be met, the gas utilities and markets will need to move at an unprecedented scale and speed. To manage and mitigate ratepayer risk, the PUC will need to regularly assess and validate performance of the utilities' preferred compliance strategies so course corrections can be made quickly, if necessary.

While each utility is unique and must be afforded the space to choose how they meet CPP compliance, they all function within the same set of market and regulatory constraints. Staff found the divergent forecasts of technology progress and the market availability of alternatives in the utilities' compliance strategies somewhat perplexing and unhelpful overall given the market they share. This highlights the uncertainty that remains around utility compliance across three different companies with a rapidly evolving set of markets and technology. Given the time constraints of the CPP goals, Staff believes the IRP process of each utility individually assessing technology progress and forecasting alternative fuel availability may be inefficient and lead to counterproductive outcomes in planning to meet compliance needs.

4.5.1 Actions

To inform risk assessments, Staff believes the following tools would help the PUC and stakeholders monitor, track, and incorporate market trends and forecasts for alternative gas availability and costs.

<u>Planning</u>

- Host an annual presentation to Commissioners on CPP compliance, comparing forecasted versus actual emission reductions and CPP costs.

<u>Rates</u>

- Submit through the Purchased Gas Adjustment process, or other annual docket, an annual report on full CPP compliance costs.
- Explore linking the amortization of CPP compliance costs from deferrals to actual CPP performance. Should gas companies selected CPP compliance activities fall short of meeting a DEQ, 3-year CPP compliance demonstration window, PUC Staff should investigate the extent to which deferred CPP costs should be amortized in subsequent years.

4.6 ACTIVELY INCENTIVIZE OR FACILITATE GHG EMISSION REDUCTION PATHWAYS

Gas utilities need to develop and deploy strategies to meet CPP compliance obligations. During the Fact Finding, stakeholders explored how the PUC processes could facilitate the deployment of nascent technologies to decarbonize fuels and improve energy efficiency, as well as exercising new policy direction to promote fuel switching to reduce natural gas use.

The PUC has existing tools at its disposal, like SB 844, which allows gas companies to receive financial incentives for GHG emission reductions activity costs that are outside their normal course of business. Other tools may need to be revisited to explore the boundaries of what is possible within them (*e.g.*, ETO energy efficiency programs).

Incentives and Pilots

The base case long-term compliance strategies of the utilities all rely on growing amounts of RNG, green hydrogen, synthetic biofuels, and new energy efficient gas equipment technologies. By doing so, these strategies mitigate the need for electrification and placing any limits on new customer hook-ups. However, the potential variance around the future cost, availability, and market adoption of new technology makes the efficacy of these compliance strategies uncertain.

Further, while every pathway – from renewable hydrogen to aggressive electrification – most likely requires piloting to achieve broad implementation, Staff cautions that any gas companies' pilots should avoid excessive financial risks to customers. Pilot projects – like Energy Trust's proposed Dual Fuel[40] pilot – require significant coordination across organizations but stand to benefit ratepayers from understanding the extent to which this strategy achieves cost-effective emission reductions.

[40] *See* Energy Trust 2023 Budget and 2023-2024 Action Plan, Dec. 16, 2022, mentioned in each utility action plan.

STAKEHOLDER INSIGHTS

PILOTS

H2 / CCSU pilots may be beneficial, but program costs should be fairly allocated between shareholders and rate payers – traditional ratemaking might not work – *AWEC*

Ratepayers should not pay for alternative gas pilots at the expense of leveraging proven technologies and innovation should be funded by investors, not ratepayers – *JC-CS et al.*

Pilots should not be used for gas heat pumps as doing so interferes with Energy Trust's analysis on potential, and NEEA is already doing work in this space – *CUB*

Gas utilities should fund ETO to conduct conservation potential study on how CPP emission reductions and costs of RNG affect cost effectiveness of energy efficiency; this would help inform whether NG heat pump pilots are appropriate at this time – *CUB*

Supports ETO training on gas and electric heat pumps – *NWN and CNG*

Public funds should not be used to promote gas heat pumps because of their relatively low commercial and technology readiness as compared to electric heat pumps - *CUB, JC - EC et al., JC - CS et al., JC - MCAT, NRDC, TNC*

STAKEHOLDER INSIGHTS

ROLE OF INCENTIVES

Eliminate subsidies or incentives that promote or support gas system expansion, gas heat pumps, or RNG - *JC - EC et al., JC - CS et al., Multnomah County, Zero Coalition and JC – Mayoral*

The role of PUC is to ensure compliance and protect customers, not provide incentives for utilities to comply with the law – *NWEC*

PUC should encourage gas companies to innovate to reduce emissions - *NWN, CNG, AWEC, and JC - NWGA et al.*

Support for innovation should only be for hard to decarbonize end uses *JC - CS et al.*

PUC has long history of not supporting customer-funded R&D, there is sufficient federal and private support for Green H2, and PUC should focus on directing utilities to do things they would not otherwise do, like electrification and limiting new hook ups – *NWEC*

Utilities drive market trends and the Commission should strongly encourage near-term investments in promising new decarbonization strategies - NWN

4.6.1 Actions

Staff finds the PUC's existing tools provide the flexibility to explore a range of CPP compliance strategies. Feedback from these projects – and from DEQ annual compliance reporting – will help inform planning and prudency determinations in the future.

The PUC remains open to new investments and pilots under SB 98 and SB 844. They provide space for experimentation and evaluation and, when paired with market research and regular evaluation, support the PUC's heighten awareness of and responsiveness to CPP compliance investments.

Planning

- Continue the use of SB 844 to as a tool for exploring emerging technologies that could be important to reaching 2050 targets, but that currently do not demonstrate cost-effectiveness because of their early-stage commercial or technological readiness.

Programs[41]

- Request the gas and electric utilities explore studying – between themselves and with organizations such as Energy Trust – the development of joint pilots where the coordination between the two utilities might result in better outcomes for customers (*e.g.*, for such things as Green Hydrogen production and Demand Side Management options such as dual-fuel heat pump deployment) and present their findings to the PUC before January 2025.

[41] The Draft Report previously included the following recommendation, "Direct Energy Trust to expand training vendors on heat pump technology through education and pilots and increase the marketing of heat pump technology on its website." Based on stakeholder comments and further research, this recommendation was deemed unnecessary.

4.7 Roadmap Summarizing Staff's Near-Term Recommendations

The regulatory actions identified through our Fact Finding effort may not reflect all the potential actions raised by stakeholders and available to the PUC. Stakeholders responded to Staff's list of near-term actions in the Draft Report and provided guidance about additional tools that are available to the PUC and regulatory tools they had hoped to have discussed as part of this docket.[42]

These included: a more explicit conversation about phasing out gas LEAs; more attention to Energy Trust policies to identify and remove barriers to gas and bulk fuel customers choosing to transition to more-efficient electric options; expanding low-income weatherization programs to allow for funds to be used for low-income electrification options and/or create a pilot program to encourage equitable electrification for LMI households; continuing and expanding current efforts to ensure robust low-income ratepayer protections; and exploring the value of pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades.

CUB, in particular stated the docket should have included investigation of: "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."

These additional regulatory tools and issues are reflected above to help inform future investigations and to inform the PUC's work in relevant dockets. In particular, in

- IRPs, where Staff asks whether the company's resource strategy least-cost, least-risk in light of the obligations of the CPP;
- General Rate Cases, where Staff asks whether rates reflect prudent and reasonable costs, balance of risks and incentives, proportional allocation of costs and benefits of CPP compliance; and
- PUC oversight of Energy Trust of Oregon to ensure energy efficiency is fully leveraged as a significant part of every utility's emission reduction pathway.

STAKEHOLDER INSIGHTS

NEAR TERM ACTIONS

Phase out gas Line Extension Allowances - *JC - CS et al.*

Update Energy Trust policies to facilitate access to electric options – *JC-CS et al.*

Expand low-income weatherization programs to include electrification options - *JC - CS et al.*

Explore gas system pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades - *JC - CS et al.*

Differentiate ratepayer bill impacts by LMI – *JC – CS et al.*

[42] Please see Section 2.4 and Appendix E for more details

Given this and the PUC's decisions and activities undertaken during the last half of 2022 (*e.g.,* UG 435 Order No. 22-388, LC 76 acknowledgement, and the Energy Trust 2023 budget) Staff's list of NGFF recommendations has evolved since the Draft Report was published in April 2022. The revised list is as follows.

Table 13: Roadmap of Near-Term Actions

Section 5 Analysis	**Recommendation**	**Regulatory Tool**		
		Planning	Programs	Ratemaking
Protecting Customers	Estimated Ratepayer Bill impact	X		
	Direct ETO to target programs to LI and EJ		X	
	Target IRA Incentives		X	
	EE programs to include transport		X	
	Assess CPP compliance risk in distribution system investments	X		X
	Explore rate impacts of accelerated depreciation in rate cases			X
	Transport customer cost of compliance in rate cases			X
Access and Info	Quarterly stakeholder Communications in UM 2178	X		
	RFA docket engagement through PUC AHD			X
Full Cost	Compliance costs into EE AC			X
	Develop marginal abatement cost curve	X		
	Utilities articulate electrification assumption in IRPs	X		
	Electrification info and data from DSP	X		
Decarbonization Planning & Cost-Recovery	Gas system maps with infrastructure age and depreciation information	X		
	IRPs include growth-related DSP investments details from Appendix F and provide analysis of demand-side options and non-pipe alternatives	X		
	Independent 3rd party analysis of key tech and market assumptions used utilities	X		
	CPP as an acknowledgeable item in IRPs	X		
	Exploring IRP guidance from UM 2178	X		
	Follow Order No. 22-388 guidance regarding customer growth and compliance costs	X		X
Monitoring, Tracking, and Reporting	Utilities host annual presentation to PUC on CPP compliance filings	X		
	Purchased Gas Adjustment includes full CPP compliance costs			X
	Explore linking CPP amortization to CPP performance			X
Incentivize GHG Reductions	Explore use of SB 844 for emerging technologies	X		
	Pilot or Joint pilots with electric utilities proposals by 2025			X

5 CONCLUSION

This investigation sought to establish an initial understanding of the impact of the CPP on the gas utilities and their customers and explore the regulatory tools available to achieve compliance while mitigating certain cost impacts. The timely modeling completed by each gas utility and the constructive engagement by dozens of stakeholders resulted in an initial analytic foundation from which to guide PUC activities, analysis, and decision making in both the near- and long- term.

Meeting the emissions targets in the CPP is the energy policy of the state. Collectively, Oregon's three gas utilities must find and secure approximately 1.2 million metric tons of GHG emission reductions by 2025. Further, the pressure for near-term emissions reductions increases greatly after 2025. By 2028, in less than six years, an additional 3.8 million metric tons of new GHG emission reductions must be secured. Solutions – be they supply oriented or demand reducing – must scale quickly in the near-term.

Modeling done by the gas utilities in this docket provided our first insights into the nature of the impacts of compliance with the CPP and existing barriers to assessing and mitigating energy decarbonization risk in planning more broadly. It is highly likely that most if not all CPP compliance strategies will come with increased costs and risks that must be monitored and tracked, and when appropriate, mitigated. If thoughtfully done, the transition to a decarbonized gas sector can create benefits and long-term cost savings for customers and the Oregon economy.

The issues identified by stakeholders and Staff and the suggested next steps are driven by the urgent need for action. Despite uncertainty around the efficacy and long-term cost trends of compliance tools, the pace of necessary emission reductions will likely require utilities and customers to assume increased levels of risk over the next ten years.

Feedback from both the utilities and other stakeholders throughout the process made it clear that this urgency is understood. Stakeholders agreed that regulatory tools should facilitate strategies that result in real reductions in GHG emissions and that they should do so in ways that seek to minimize costs and risks to protect customers. All stakeholders supported compliance strategies and associated regulatory tools that reduced gas use per customer. Staff believes that customers, especially low-income customers, are best protected with compliance strategies and regulatory tools that reduce compliance uncertainty at relatively low-cost in the near-term and maintain compliance flexibility.

Further strategy-specific regulatory tools that attempt to address uncertainty, costs, and risks associated with compliance also bring their own risks. As the utilities, stakeholders, and the PUC gain experience from implementation of tools and strategies for compliance in individual utility dockets over the next few years, it will also be important for Staff and/or the PUC to identify a future docket where a comprehensive dialogue can occur among all stakeholders around the collective efficacy of CPP compliance. A notable juncture to bring all stakeholders and utilities together for a group conversation on joint planning would be after 2023, when the first round of IRPs since the CPP adoption and HB 2021's passage are complete.

This report captures some of the regulatory tools that hold gas utilities accountable as they plan and pursue least-cost, least-risk options to reduce their GHG emissions by: increasing transparency, maintaining optionality, and enhancing engagement. Staff intends to apply these principles as it considers which tools to bring forward as it develops recommendations in IRPs and rate cases.

Appendices

6 APPENDIX A: SCENARIO DESCRIPTIONS

6.1 MODELING DIRECTION: DELIVERABLES, SENSITIVITIES, AND ALTERNATIVE SCENARIOS

A key component of the PUC's Natural Gas Fact Finding (NGFF, Fact Finding, or UM 2178) was the development of Compliance Models to establish a range of potential costs associated with achieving the goals of DEQ's Climate Protection Program (CPP). The development of this data served as the foundation for identifying and assessing which regulatory tools may be needed in the future by the utilities and the PUC to support the CPP and natural gas utility decarbonization.

The launch and completion of the utility Fact Finding modeling occurred before two key events: each utility's Integrated Resource Plan (IRP) and the finalization of DEQ's CPP in rules. Because of this, the utilities lacked the latest IRP information, the time and resources to run full IRP models, and complete certainty of important operational details. Thus, Staff informed all Fact Finding participants that while the accuracy of any modeling cost estimates would be limited, the information would be valuable going into 2022. In that year, CPP compliance would begin, and each utility would begin development – and for NW Natural, completion – of their next IRPs. The information from the Fact Finding would serve to foreshadow utility compliance strategy and the direction and magnitude of compliance potential costs, in addition to starting an important dialogue among all stakeholders about the application and efficacy of regulatory tools needed to achieve the state's GHG reduction goals.

Prior to any utility modeling, Staff created a summary of key utility data that could help stakeholders with their analysis of utility compliance modeling. Titled "Foundational Data," these documents comprise two Excel workbooks using data from multiple public sources and can be found online at this link.

The utilities were asked to deliver two large sets of deliverables in a very short time. The first was a presentation and underlying data to their initial NGFF model runs with selected sensitivities. The second was a presentation using alternative scenarios, which were shaped by participant input in the form of written and verbal comments. The table below captures the major milestones in the NGFF compliance modeling activities, with links to key documents.

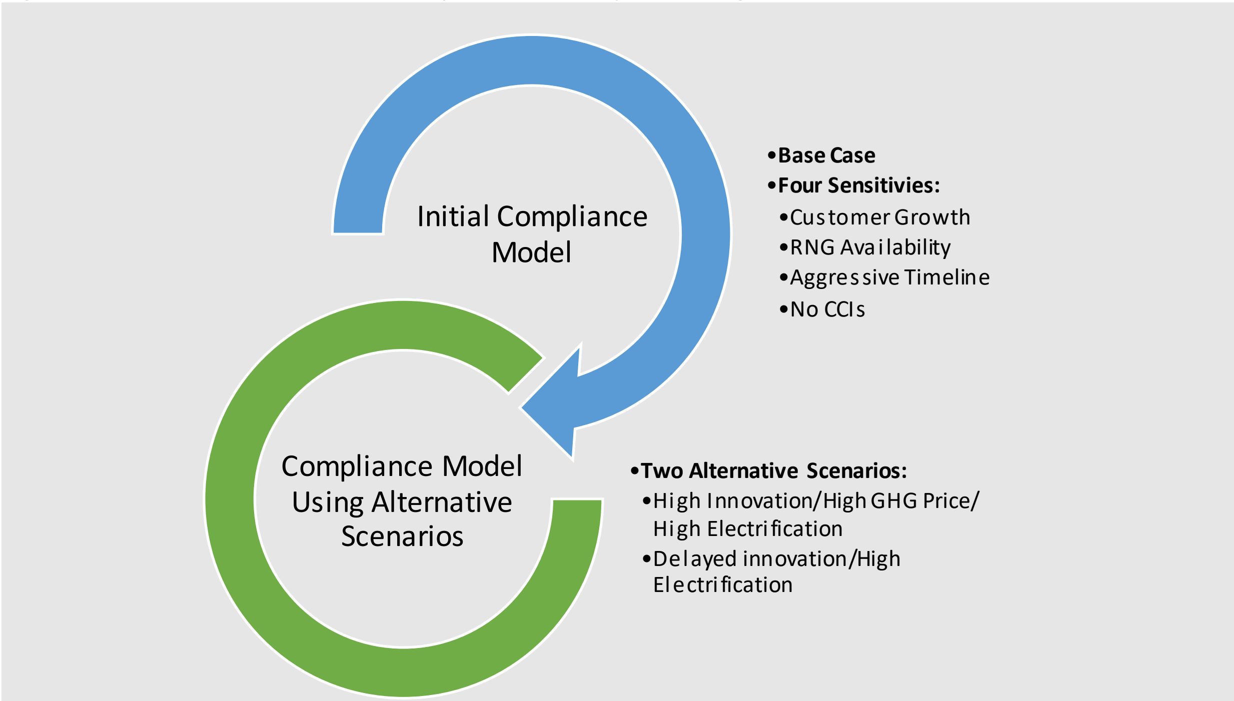
Table A1: Major Milestones in NGFF Modeling Activities

Date	Deliverable/Item	Additional information
July 8, 2021	Staff's initial compliance modeling proposal	Initial expectations for data to be used (inputs) by utilities in their analysis, the key deliverables to be shared (outputs). Modeling sensitivity selection occurs after input from stakeholders.
July 26 -30, 2021	Stakeholder comments on modeling proposal and suggestions for potential sensitivities	*See docket for more information.*
Aug. 4, 2021	Modeling sensitivities to inform initial model	Four sensitives selected by Staff after stakeholder input.

Date	Deliverable/Item	Additional information
Sept. 7-24, 2021	Utilities' initial modeling results	Initial modeling results provided on Sept. 7 with some supplemental and revised filings through Sept. 24. *See docket for more information.*
Sept. 24-27, 2021	Stakeholder comments on utility modeling results	Alliance of Western Energy Consumers Sierra Club Joint Parties, including Climate Solutions Citizens' Utility Board NW Natural Wendy Woods RNG Coalition Metro Climate Action #1 & #2
Oct. 1, 2021	Staff's alternative modeling scenarios	Alternative scenarios differ from sensitivities in that the scenarios alter the underlying assumptions, and in some cases, the data used by the initial model. Two alternate scenarios were selected based on participant feedback in NGFF workshops and from comments.
Nov. 17, 2021	Utilities' alternative modeling scenario runs	Avista's presentation of results CNG's presentation of results NW Natural's presentation of results

Given the timing and short turnaround time for the initial model runs, the natural gas companies were asked to use past IRP data, the most current version of CPP rules, and to model a base case of CPP compliance strategies they envisioned worked best for their company. They were also asked to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. The selected alternative modeling scenarios attempted to show the impact of CPP compliance in two possible futures, combining multiple sensitivities within the initial model: one in which there was aggressive electrification of gas loads, and one in which efforts were directed to accelerate innovation in decarbonizing gas. Figure A1 provides a graphic representation of the scenarios and sensitivities the utilities modeled.

Figure A1: Scenarios and Sensitivities for NGFF Utility Modeling



6.1.1 Key Deliverables from initial modeling

Each utility delivered a presentation and underlying data as part of the model runs. Specified outputs to be shared included the following:

1. Forecast of emissions (weather adjusted):
    a. Graphic of million metric tons CO2e per year
        i. Stacked Area chart
        ii. Estimates of avoided emissions by compliance strategy and technology
    b. Supporting table capturing underlying data used in graphic by year
    c. Annual emissions reduction by compliance strategy, technology, and portfolio of technologies
    d. Annual emissions reduction in metric tons by technology by year
    e. Annual emissions above or below annual DEQ CPP threshold

2. Data supporting the development of emissions forecasts, including but not limited to:
    a. Load forecast and growth assumptions
    b. Use per customer estimates
    c. Compliance strategy assumptions
        i. Demand, supply, and capture assumptions
        ii. Sector/customer class reduction assumptions
        iii. Technology assumptions
            1. Cost trajectory curves over time for each technology
            2. Tons of emissions avoided per therm for each technology
            3. Variable costs per therm for each technology
    d. Any major distribution or transmission system upgrades or changes

e. In addition to the above data, all model inputs, outputs, and workpapers provided in electronic format with all references and formulae intact.

3. Description of approach and/or assumptions, including but not limited to:
    a. Values and terms selected for DEQ key assumptions
    b. Model methodology
    c. Description of weather pattern forecasts impacting load forecast
    d. Avoided costs assumptions, such as peak day usage and savings ratios

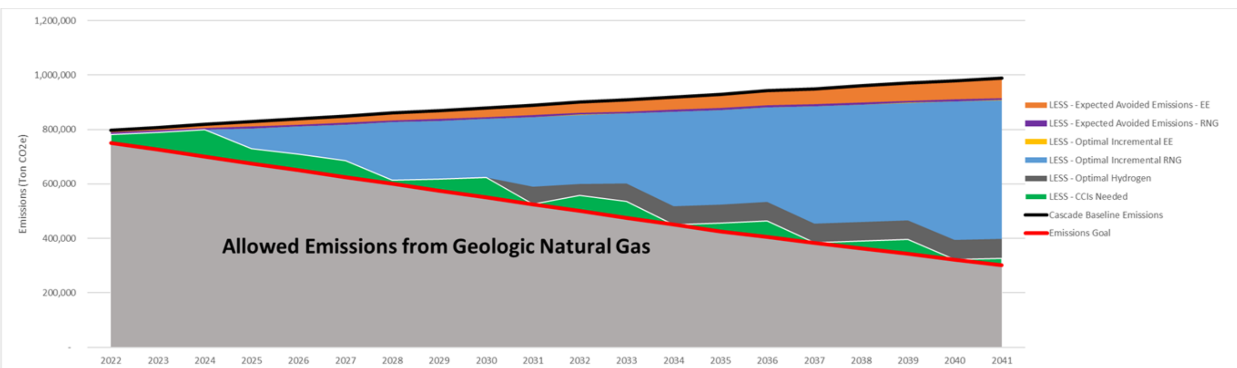
4. Estimated Net Present Revenue Requirement of Compliance Model and Comparison Across Selected Sensitivities:
    a. Twenty year time horizon minimum
    b. Annual and total Revenue Requirement difference between Compliance Model and most recent IRP's preferred portfolio
    c. Annual and total Revenue Requirement difference between Compliance Model and selected sensitivities.

6.1.2 Results of Base Case Compliance Strategies

The base case strategies for CPP compliance varied across utilities. Figures A2-A4 below summarize the compliance strategies each utility presented in UM 2178 workshops.

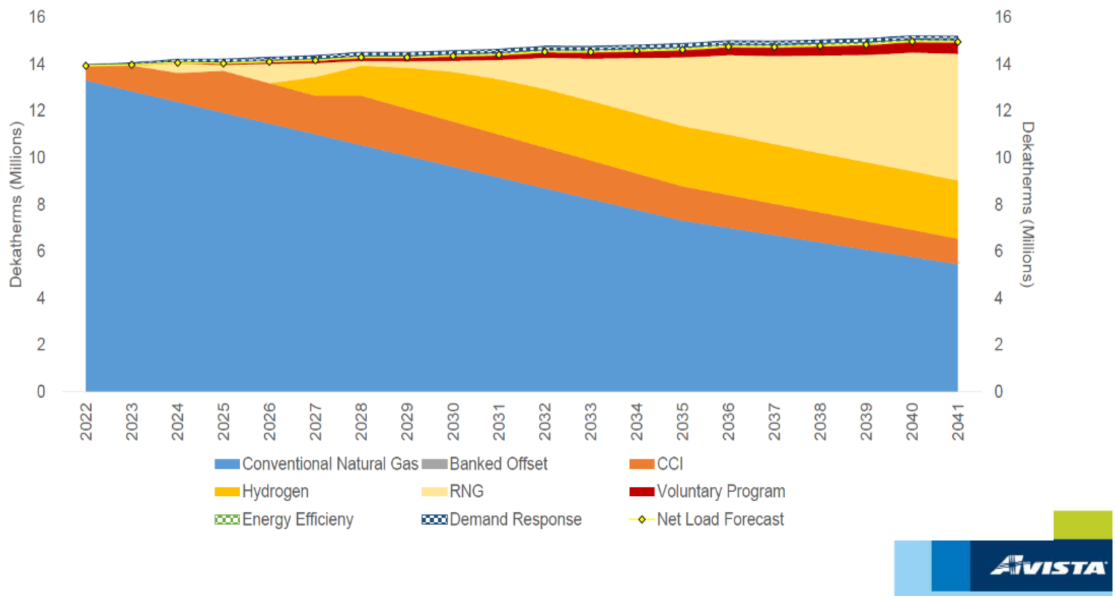
Cascade relied on CCIs in the near term and then heavily on incremental RNG (blue sliver in Figure A2) beyond what it planned for with SB 98 RNG (purple sliver in Figure A2).

Figure A2: Cascade CPP Base Case Compliance Strategies



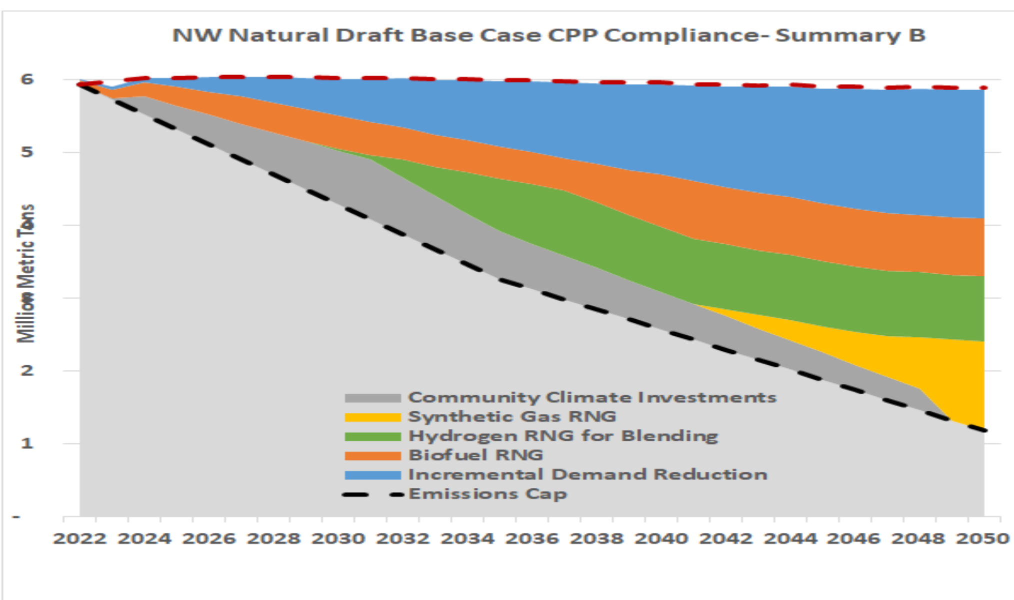
Avista also relied on CCIs in the near term and biofuel RNG throughout, but brings in hydrogen in 2026.

Figure A3: Avista Base Case CPP Compliance Strategies



NW Natural increasingly relies on demand reduction/EE over the course of the compliance timeframe. Its use of biofuel RNG and CCIs start in the near term and play a moderate role throughout, with CCI's decreasing and RNG increasing. By 2031 it introduces hydrogen and by about 2040, begins to envision the inclusion of synthetic gas RNG.

Figure A4: NW Natural Base Case CPP Compliance Strategies



6.1.3 Sensitivities

Below is a description of each of the four sensitivities to accompany the initial model run's base case. Each sensitivity was run in isolation from the other. A comparison of the results for each sensitivity are included in Figures A5-A8.

6.1.3.1 Customer Decline

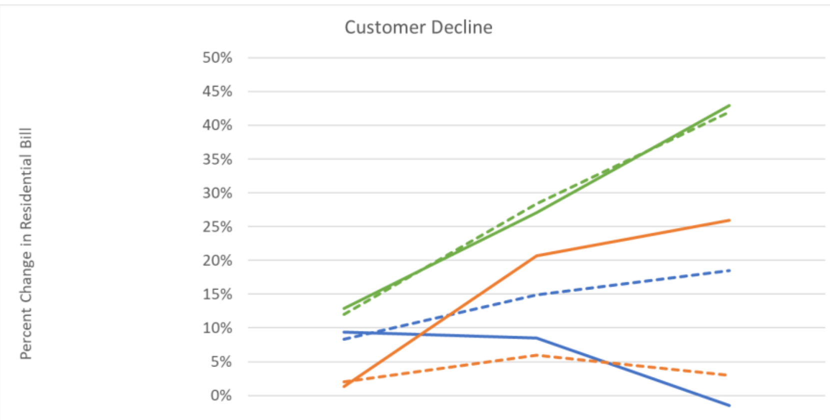
Issue: How might policies limiting customer growth and associated GHG emissions inform regulatory tools to consider?

Approach: Model sensitivities that consider zero and negative customer growth.

Sensitivity: Current IRP forecasted load growth through 2025; no new customers beginning from 2025 through 2030; -0.75 percent customer growth beginning in 2031 through the end of model's time horizon.

Results: NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.[43]

Figure A5: Customer Decline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Customer Decline	8%	15%	18%
Avista Base Case	1%	21%	26%
Avista Customer Decline	2%	6%	3%
Cascade Base Case	13%	27%	43%
Cascade Customer Decline	12%	28%	42%

6.1.3.2 RNG Availability

Issue: Uncertainty about availability of RNG.

[43] Avista noted that its modeling did not accurately reflect the increase in cost per customer that would result from customer declines because of the need to spread fixed costs over fewer customers. This omission, it says, makes all its electrification and ratepayer decline scenario bill impacts lower than they should be.

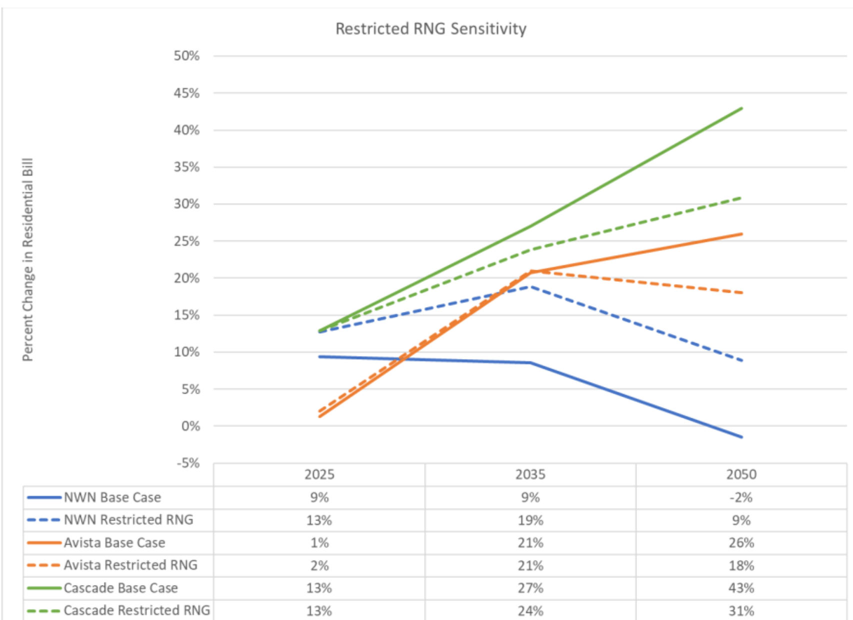
Approach: Apply constraints on assumptions about the availability of RNG to meet emission reduction goals.

Sensitivity: Limit RNG availability to the annual percentages set by SB 98 and found in ORS 757.396(1).

(a) In each of the calendar years 2020 through 2024, five percent may be renewable natural gas;
(b) In each of the calendar years 2025 through 2029, 10 percent may be renewable natural gas;
(c) In each of the calendar years 2030 through 2034, 15 percent may be renewable natural gas;
(d) In each of the calendar years 2035 through 2039, 20 percent may be renewable natural gas;
(e) In each of the calendar years 2040 through 2044, 25 percent may be renewable natural gas; and
(f) In each of the calendar years 2045 through 2050, 30 percent may be renewable natural gas.

Results: Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced the overall cost of compliance compared to their base case scenarios. This generally increased cost of compliance for NWN, but Cascade and Avista saw decreased compliance costs in the later years of the model run when compared to their base cases.

Figure A6: Restricted RNG Sensitivity Comparison



6.1.3.3 More Aggressive Timeline on Climate Policy

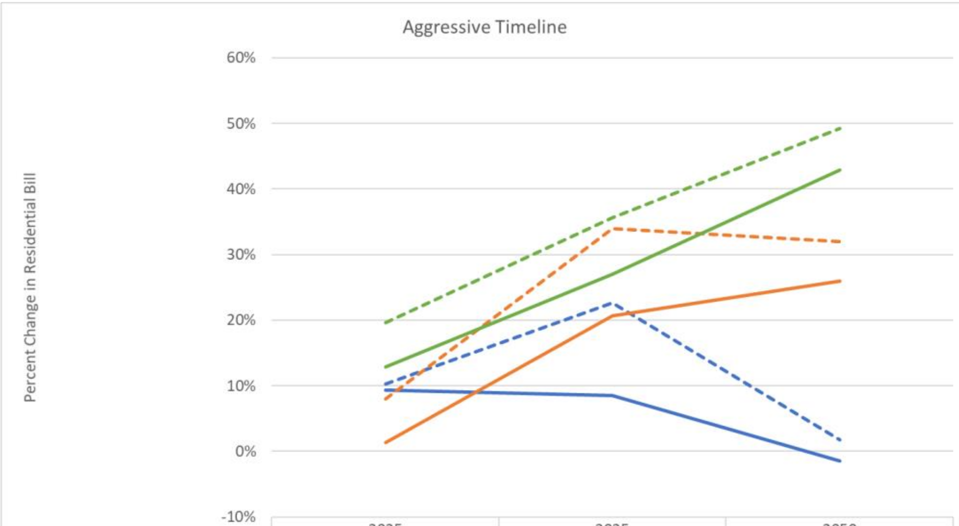
Issue: The Governor's Executive Order set state emission reduction targets of at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050. The DEQ Climate Protection Program is poised to make progress towards these state emission reduction targets. However, there is the potential for future policy to have more aggressive targets.

Approach: Using the same target reduction emissions currently contemplated by DEQ for 2035 and 2050, advance the dates to align with the date bookends (2030 and 2040) of the recently passed Oregon legislation for electric utilities (HB 2021).

Sensitivity: CPP targets of 45 percent below baseline by 2030, 80 percent below baseline by 2040.

Results: NWN costs increased in the middle years of the model run but the difference between this sensitivity and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.

Figure A7: Aggressive Timeline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Aggressive Timeline	10%	23%	2%
Avista Base Case	1%	21%	26%
Avista Aggressive Timeline	8%	34%	32%
Cascade Base Case	13%	27%	43%
Cascade Aggressive Timeline	20%	36%	49%

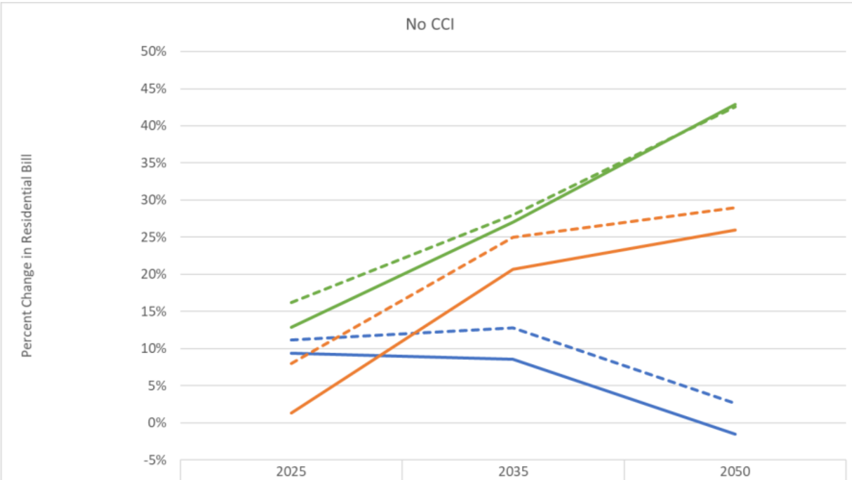
6.1.3.4 No CCI

Issue: Community Climate Investments (CCI) are a CPP compliance instrument. However, it is not currently clear to the PUC how the emissions associated with these projects will be quantified and verified. PUC Staff would like to understand the role CCIs play in accomplishing compliance with emission reductions and what emission reduction options become more viable if they are not part of a solution set.

Approach: Remove the availability of CCIs.

Results: All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years. But by 2050 the three utilities' modeling runs arrived at different conclusions with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking and Cascade's annual compliance costs were the same as in its base case.

Figure A8: No CCI Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN No CCIs	11%	13%	3%
Avista Base Case	1%	21%	26%
Avista No CCIs	8%	25%	29%
Cascade Base Case	13%	27%	43%
Cascade No CCIs	16%	28%	43%

6.1.4 Alternative Scenarios

The alternative scenarios were run after the initial compliance models were completed and shared. They were greatly shaped by participant feedback. They combined multiple sensitivities from the previous model run, in some cases with new data. These two scenarios were designed to characterize possible futures that explored potential impacts, suggesting different policy and planning approaches.

6.1.4.1 Alt. Scenario 1: Accelerated Innovation / Electrification / High Social Cost of Greenhouse Gas

Approach:

- **Accelerated Innovation:** Assume a 30 percent six-year production tax credit for the production of green hydrogen and syngas for which construction begins before 2026.[44] It is anticipated that projects may be outside the ordinary course of business and would result in near-term and aggressive emission reductions.
- **Higher Cost of GHG**: Assume updates to the social cost of carbon. Beginning in 2026, adjust the CCI price to align with the Social Cost of Carbon's 95th percentile with a three percent discount.[45] For example, starting in 2026 use the starting value of $173.

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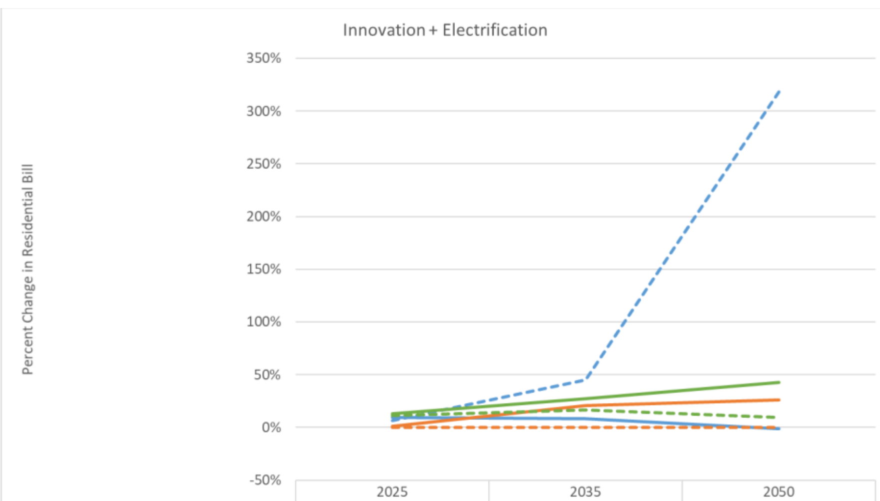
[44] *See* page 49 of the Department of the Treasury, General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf.
[45] *See* Social Cost of Carbon table A-1 in Appendix – Annual SC-CO2, SC-CH4, and SC-N2O Values, in 2020-2050. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

- **<u>Electrification:</u>**
    - Fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2030 and stays zero thereafter.
    - Existing buildings converting to electricity goes from its present share to 90 percent in 2050.
    - Light industry converts to 90 percent electricity by 2050.

Results: Cascade's model resulted in ratepayer bill impacts that were lower than in their base case.[46] Avista's modeling summary showed zero change in ratepayer bill impacts, but the workbooks showed negative ratepayer bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's ratepayer bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318 percent increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.

Figure A9: High Innovation + Electrification + High SCC Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 1 - Innovation	6%	45%	318%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 1 - Innovation	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 1 - Innovation	11%	17%	9%

[46] CNG noted that differences in electrification modeling may have been due to differing interpretations of the guidance from Staff.

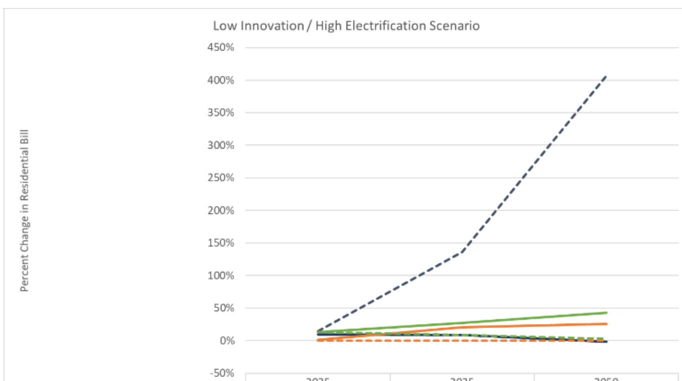
6.1.4.2 Alt. Scenario 2: Delayed Innovation / Accelerated Electrification

Approach:

- **<u>Delayed Innovation:</u>** Use a slower energy efficiency technology adoption curve. Gas heat pump water heaters come to market, but there are no gas heat pumps until after 2030 and they assume a traditional s-curve adoption pattern.[47]
- **<u>Supply Competition:</u>** RNG availability is limited to the percentage of the national RNG resource equal to the company's throughput share of total gas use in the U.S., including power sector use. National RNG resource is ICF's Low Resource Potential for RNG in 2040, namely 1,660 trillion Btu (tBtu) of RNG produced annually for pipeline injection by 2040.[48]
- **<u>Very Rapid Electrification:</u>**
  - The fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2025 and stays zero thereafter.
  - Fraction of existing buildings converting to electricity goes from its present share to 90 percent by 2040.

Results: Like the Accelerated Innovation and Electrification w/High SCC Scenario, Cascade modeled ratepayer bill impacts that were lower than their base case. Avista's summary showed zero ratepayer bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405% increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

Figure A10: Delayed Innovation/High Electrification Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 2 - Electrification	15%	136%	407%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 2 - Electrification	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 2 - Electrification	13%	8%	3%

[47] *See* Comments of the Oregon Citizens' Utility Board on Modeling and Alternative Scenarios. Filed September 24, 2021. https://edocs.puc.state.or.us/efdocs/HAH/um2178hah163235.pdf.

[48] *See* American Gas Foundation Study Prepared by ICF. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. December 2019. https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

6.1.4.3 Modeling Parameters for Alternative Scenarios

Companies were instructed to use existing models and data to create the alterative scenarios with the following deliverables:

- Updated graphics and tables comparable in format to those submitted for the base case and associated sensitivities.
- To the extent possible and applicable, Staff asked that Avista and Cascade replicate the Scenario Comparison table created and shared by NW Natural, and that all companies use this format to include the alternative scenarios described above.
- **Data for Electrification:**
    - Where a load currently served by gas is not eliminated, but rather served by another resource, total annual MMBtu transferred to the alternative source must be identified for each year.
    - Staff will calculate estimated costs of the transferred load and associated emissions, taking into consideration the electrification cost elements proposed by stakeholders in comments.
- **Low and Moderate Income Customers**: Indicate the assumed or known percentage of low and moderate income residential customers.
- **Ratepayer Bill Impacts**: Report ratepayer bill impacts in terms of $/therm.

Table A2. Summary of Compliance Base Case, Sensitivities, and Scenarios Impacts

	Sensitivities/ Scenarios	Renewable Supply Penetration (% of Deliveries)			Biofuel RNG Penetration (% of Current Deliveries)			Renewable Supply Portfolio Cost (2020$/Dth)			Total Incremental Cost of CPP Program (Million 2020$/Year)[49]			Community Climate Investments (% of Emissions)			Annual Residential Bill Impact (% Impact of CPP)			Annual Industrial Sales Bill Impact (% Impact of CPP)		
		2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050
Northwest Natural	Base Case	*4%*	*23%*	*72%*	*4%*	*8%*	*14%*	*$12.25*	*$11.85*	*$11.77*	*$142*	*$256*	*$242*	*6%*	*20%*	*0%*	*9%*	*9%*	*-2%*	*22%*	*35%*	*39%*
	Restricted RNG	4%	23%	72%	4%	9%	11%	$18.75	$18.26	$16.90	$142	$317	$324	6%	20%	0%	13%	19%	9%	30%	59%	68%
	Customer Decline	4%	17%	65%	4%	9%	15%	$12.25	$11.93	$11.59	$118	$181	$186	6%	20%	0%	8%	15%	18%	18%	27%	37%
	Aggressive Timeline	4%	47%	65%	4%	16%	20%	$12.25	$13.15	$11.74	$168	$493	$360	13%	20%	20%	10%	23%	2%	27%	73%	58%
	No CCIs	10%	36%	72%	10%	15%	18%	$12.25	$12.64	$12.89	$167	$313	$296	0%	0%	0%	11%	13%	3%	26%	45%	51%
	Fed RNG Support	4%	23%	72%	4%	8%	14%	$8.58	$8.76	$8.80	$142	$239	$160	6%	20%	0%	7%	4%	-9%	18%	26%	17%
	Vol Comm Support	4%	16%	48%	4%	8%	9%	$12.25	$11.85	$11.25	$124	$214	$160	2%	20%	20%	8%	6%	-6%	19%	30%	25%
	Alt. Scn. #1	4%	12%	23%	4%	6%	6%	$12.25	$12.13	$12.13	$0	$0	$0	0%	0%	0%	6%	45%	318%	Unknown		
	Alt. Scn. #2	4%	9%	14%	4%	5%	5%	$12.25	$12.25	$12.25	$0	$6	$13	0%	0%	0%	15%	136%	407%			
Avista	*Base Case*	*2%*	*40%*	*54%*	*2%*	*20%*	*34%*	*$12.23*	*$9.71*	*$8.95*	*$2*	*$19*	*$26*	*13%*	*17%*	*17%*	*1%*	*21%*	*26%*	*14%*	*60%*	*72%*
	Restricted RNG	2%	40%	49%	2%	20%	27%	$12.23	$9.69	$8.54	$2	$19	$24	13%	17%	17%	2%	21%	18%	16%	62%	54%
	Customer Decline	2%	35%	47%	2%	15%	27%	$12.23	$9.31	$8.64	$2	$13	$15	13%	17%	17%	2%	6%	3%	16%	52%	59%
	Aggressive Timeline	9%	59%	76%	9%	39%	54%	$12.23	$10.55	$9.40	$6	$38	$46	13%	17%	17%	8%	34%	32%	33%	99%	93%
	No CCIs	15%	50%	61%	15%	30%	41%	$12.23	$10.23	$9.22	$7	$28	$35	0%	0%	0%	8%	25%	29%	34%	72%	80%
	Alt. Scn. #1	0%	26%	32%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	7%	0%	0%	0%	0%	0%	0%	0%	0%
	Alt. Scn. #2	0%	28%	49%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	5%	0%	0%	0%	0%	0%	0%	0%	0%
Cascade	*Base Case*	*10%*	*26%*	*65%*	*10%*	*26%*	*57%*	*$5.86*	*$4.94*	*$3.01*	*$12*	*$25*	*$33*	*6%*	*8%*	*0%*	*13%*	*27%*	*43%*	*16%*	*32%*	*50%*
	Restricted RNG	10%	25%	54%	10%	25%	46%	$5.86	$4.91	$2.75	$12	$21	$20	6%	6%	0%	13%	24%	31%	16%	29%	37%
	Customer Decline	6%	17%	28%	6%	15%	27%	$5.86	$4.91	$3.05	$11	$27	$32	10%	9%	10%	12%	28%	42%	15%	34%	49%
	Aggressive Timeline	17%	43%	83%	17%	37%	75%	$5.86	$4.78	$2.97	$20	$37	$43	6%	6%	0%	20%	36%	49%	24%	42%	56%
	No CCIs	16%	35%	65%	16%	27%	57%	$5.86	$4.59	$2.91	$16	$26	$33	0%	0%	0%	16%	28%	43%	20%	33%	49%
	Alt. Scn. #1	11%	33%	45%	11%	33%	44%	$5.86	$4.81	$2.39	$13	$24	$12	6%	0%	0%	11%	17%	9%	14%	21%	12%
	Alt. Scn. #2	6%	8%	13%	2%	3%	5%	$11.76	$4.66	$1.70	$16	$9	$2	9%	9%	3%	13%	8%	3%	16%	11%	4%

[49] Red figures indicate that the cost of compliance to NW Natural is offset by assumed electrification, where the cost of this electrification needs to be assessed on the electric rather than gas grid

7 Appendix B: IRP Guidance

Throughout the Fact Finding workshops and comments, Staff heard feedback from stakeholders about ways to leverage and improve upon the existing gas utility integrated resource planning process. Staff, with support from the Regulatory Assistance Project, attempted to capture and categorize this feedback in Table B1 to help inform future IRPs. This table serves as a reference and compendium for ideas received as part of UM 2178 and to be considered potentially in the future when the Commission embarks on revising IRP guidance.

Table B1: IRP-related Feedback

Category	Addition to IRP
Expand Public Access & Equity	Expand communications about IRP - basics, process and outcomes/implications, start to expand customer understanding of impacts of new policies (CPP)
	Utilities should record and post workshops on website
	Capture additional customer information, create a baseline of customer statistics (energy burden, participation in programs - e.g. EE and LI) by location (e.g. zip code)
Load Forecast – Improvements	Consider and reflect potential impacts of local policies to limit gas in new construction.
	Provide data on customer trend gas and electric usage assumed for space and water heating, (gas furnaces/electric heat pumps/gas domestic hot water heaters/heat pump water heaters) across service territory population, by county or zip code, # of customers and share of electric utility overlap (*recent history and current state*)
	Provide transparent assumptions and data about customer technology adoption and behavior, including end use fuel splits between electric and gas over time and justification for technology adoption assumptions (e.g. relying on technology adoption modeling? Does modeling approach assess/compare all customer options?) (*forward looking*)
	Identify transportation load - industry types/end uses and explore H2 potential for these customers. Characterize how this load is currently served to understand new liability for compliance – include seasonality and daily nature of emissions
	Conduct sensitivities to load forecast around customer adoption of emerging EE technologies
RNG	Quantify the near- and long-term geographic availability of RNG potential, updated regularly. Provide detailed discussion/description with supporting workpapers for assumptions used to model RNG resources and market. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base/low/high volumes. Essentially creating a resource potential assessment for RNG. Be explicit about total RNG resource potential and justify assumptions about what will be available to Oregon gas utilities.
	Provide Bundled vs unbundled RNG assumptions
	Discussion of RNG affiliate plans

H2	Provide detailed discussion/description with supporting workpapers for assumptions used to model H2 resources. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base /low/high volumes. Essentially creating a resource potential assessment for H2 designed around end uses that can feasibly use H2. Be explicit about total H2 resource potential and justify assumptions about what will be available to Oregon gas utilities. Assumptions should include whether sited with energy user or if transport from production to end user required and costs/risks of new pipeline delivery infrastructure or storage needed.
EE and Beneficial Electrification	Review cost effective EE potential
	Develop Beneficial Electrification assumptions in coordination with electric utility
System Mapping / Infrastructure	Include planned infrastructure costs identified as new customer vs. maintenance of existing system. Identify high priority projects and 5 year planned investments with non-pipeline alternatives considered.
	Identify areas of new development / system expansion- with as much granularity as possible
	Scenarios of load decline should include assessment of stranded asset risk
	Include current rate base depreciation assumptions, list of assets and amortization schedules
Scenarios	H2 and RNG delayed growth vs. base case assumptions
	CPP compliance requirements more stringent than current (as modeled in UM 2178 scenario)
	Decline in load starting in 2030, after 2025-2030 no growth (as modeled in UM 2178)
Transparency and Clarity	Provide input data and results in a clear and transparent manner. Including such things as units, methodologies, assumptions, sources, and application.
Emissions	All portfolios should be designed to meet CPP, include discussion around risk of noncompliance costs
Cost and Risks	Account for biogenic CO_2 from RNG

8 APPENDIX C: RMI BUILDING ELECTRIFICATION POLICY PRESSURES

This table is an excerpt from materials provided by the Rocky Mountain Institute to PUC Staff via email on November 2, 2022.

- It is an informal landscape scan of the future of gas proceedings across the country.
- - While RMI intends to keep it updated, it is a work in progress and not intended to be comprehensive or up-to-the-minute. Some states may have more details than others.
- - For the most accurate information, refer to the state PUC dockets, many of which are linked in the "proceedings" tab
- - If you have questions, corrections, or additions, please contact Sherri Billimoria (sbillimoria@rmi.org) or Abby Alter (aalter@rmi.org)

State	Docket #	Title/link	Key filings to date	State-wide energy strategies, plans, or studies	Any state commitments / indications around electrification?
California	R1807006	Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service	Fourth Amended Scoping Memo and Ruling from 9.15.21		SB 1477 (2018) funded and required CPUC to develop BUILD and TECH programs to reduce GHG from buildings AB 3232 (2018) required CEC to release an assessment of "the feasibility of reducing [GHG] emissions of California's buildings 40 percent below 1990 levels by 2030" link
	R1901011	Order Instituting Rulemaking Regarding Building Decarbonization			
	R2001007	Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning	10/14/21 Amended scoping memo outlines tracks 2a, 2b, and 2c scope and timeline. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF		
	R1202008	Order Instituting Rulemaking To Adopt Biomethane Standards And Requirements, Pipeline Open Access Rules, And Related Enforcement Provisions.	Staff published proposal.		
	CEC 21-IEPR-05	Natural Gas Outlook and Assessments -- IEPR (Integrated Energy Policy Report)			

Colorado	21M-0395G	Commission Review of the Regulation of Gas Utilities	Opening order C21-0516 (lists of questions for comment periods, plus procedural/leg background)	Colorado Greenhouse Gas Pollution Reduction Roadmap (Jan. 2021)	Roadmap shows significant electrification is needed AQCC says building reductions will be 100%
	21R-0449G	Proposed Amendments to the Commission's Rules Regulating Gas Utilities, 4 Code of Colorado Regulations 723-4, Relating to Gas Utility Planning and Implementing SB 21-264 Regarding Clean Heat Plans and HB 21-1238 Regarding Demand Side Management	NOPR filed 10/1/2021		
	20M-0439G	Investigation Into Retail Natural Gas for GHG Emissions			
Massachusetts	20-80	Investigation by the DPU on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals		Massachusetts 2050 Decarbonization Roadmap (Dec 2020) 2030 Clean Energy and Climate Plan (Dec 2020)	2050 Roadmap ID's high-electrification as the least-cost pathway 2030 CECP states that Mass Save will work to phase out incentives for fossil fuel appliances by 2025

Minnesota	21-566	In the Matter of Establishing Frameworks to Compare Lifecycle Greenhouse Gas Emissions Intensities of Various Resources, and to Measure Cost-Effectiveness of Individual Resources and of Overall Innovative Plans	Notice of comment issued 9/3/21	Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations (July 2021)	
	21-565	In The Matter Of A Commission Evaluation Of Changes To Natural Gas Utility Regulatory And Policy Structures To Meet State Greenhouse Gas Reduction Goals	7/28: Centerpoint, CEE, Fresh Energy made a procedural proposal (which was filed in both 566 and 565) suggesting to suspend the 21-324 (where Centerpoint was applying for approval of RNG tariffs) proceeding in order to address the carbon accounting (for NGIA technologies) through public process		
Nevada	21-05002	Investigation Regarding Long-Term Planning For Natural Gas Utility Service In Nevada.	Procedural order filed 9/24/21	Pathways and Policies to Achieve Nevada's Climate Goals: An Emissions, Equity, and Economic Analysis (Oct 2020)	

New Jersey	GO20010033	In the Matter of New Jersey Natural Gas Commodity and Delivery Capacities in the State of New Jersey - Investigation of the Current and Mid-Term Future Supply and Demand	Opening order/notice of hearing filed April 20, 2021		
New York	20-G-0131	Proceeding on Motion of the Commission in Regard to Gas Planning Procedures	3.19.20 Opening order 8.10.20 Preliminary comments of Renewable Heat Now 2.12.21 Staff proposals on gas system planning and moratorium management 5.4.21 RHN Gas Planning Comments		No sector-specific ghg target; significant heat pump targets within efficiency programs
Philadelphia		PGW Diversification Study			
Washington	UG-210729	Consideration of whether to continue to use the Perpetual Net Present Value Methodology to calculate natural gas line extension allowances	Notice of item to be considered... filed 9/21/21	2021 State Energy Strategy	

Washington, D.C.	U-210553	Examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets		2021 State Energy Strategy	
	FC1167	In the Matter of the Implementation of the Climate Business Plan	WGL's compliance filing 9.1.21 (comments due within 60 days) Pepco's electrification study 8.27.21 (comments due within 60 days) Commission order No. 20754 lays out next steps		Carbon Free DC has identified the need to eliminate fossil fuel use in buildings, primarily via electrification (link)
Wisconsin	5-FE-104	Focus on Energy Quadrennial Planning Process IV	EE Potential Study filed 9.10.21		

9 APPENDIX D: ELASTICITY

The Fact Finding modeling suggests that under most scenarios all customers (residential, commercial, and industrial) will see cost increases in the near term. NWN modeling suggests that by 2040, under some scenarios, some customers would see a cost *decline*. However, given how far out in the future those cost declines are projected and the disagreement between NWN and the other gas utilities' models, Staff believes it is appropriate to plan for cost increases to customers under all scenarios proposed by utilities.

Part of what initiated the Fact Finding was the concern that as the energy system decarbonizes, low income customers would not only experience increases in fuel costs, but also be saddled with increasing costs associated infrastructure costs being spread over a smaller customer base. This, it was assumed, could be the result of decarbonization efforts that motivated more affluent customers to leave the gas system entirely and to switch to all electric homes. Staff conducted its own analysis of ratepayer bill impacts of natural gas decarbonization to better understand the extent to which this might warrant the use of policy intervention. That analysis follows.

10.1 STAFF's ELASTICITY ANALYSIS

Staff notes that if a natural gas utility raises its rates, natural gas customers are likely to change their behavior accordingly. These behavior changes can come in two possible forms:

- Changes in natural gas consumption
- Deciding whether to remain on the natural gas grid or seek alternative energy sources

The elasticity of natural gas consumption has been well studied in academic literature, particularly in the last few years. Using data from over 300 million household natural gas ratepayer bills in California and rigorous econometrics, Auffhammer and Rubin 2018 estimate that the residential natural gas consumption elasticity is between -0.17 and -0.23. Staff created its own econometric model using data aggregated to the state-year level and found an elasticity that is also near this range.

Aufhammer and Rubin break down the elasticity by season and by income and notes that low income households exhibit higher elasticity than high income households, and households in the winter exhibit higher elasticity than in the summer. These elasticity estimates vary from -.05 for high-income households in summer to -.52 for low-income households in the winter. This implies that should natural gas prices rise in response to decarbonization, low-income households in the winter are most likely to change their consumption patterns.

Staff conducted preliminary empirical modeling to investigate residential customers' propensity to connect or disconnect from the natural gas grid. Staff created an econometric model using annual data on state-level natural gas connections, residential natural prices, population and economic activity and various sets of controls. The econometric model assumes that residential consumers would not immediately change their equipment in response to a change in natural gas price, but instead do so after observing sustained price changes for multiple years. While Staff's results are preliminary and not corroborated by any known literature, they are suggestive of the following things:

- At an aggregate level, residential customers' natural gas connection decisions only react to a price change after at least 2-3 years. Absent outside pressures to connect or disconnect, it is unclear whether this reaction comes through existing customers switching natural gas connections to electric connections or new residential structures selecting non-gas heat sources.

- Regardless of the time lag, residential natural gas connection or disconnection appears to be highly price inelastic. Staff's preliminary model suggests that the price elasticity is approximately -.10. However, Staff reiterates that this value is preliminary and does not account for endogeneity of variables that likely biases the estimate in an indeterminant manner.

Due to data limitations, Staff's estimates do not account for any changes in technology or financial incentives that may reduce the costs to switch from natural gas to electricity. However, Staff's estimated negative elasticity implies that there will be some, albeit small, natural attrition from the natural gas system or slowdown in new connections if the push to decarbonize results in higher prices even without added incentives.

There is unfortunately also a gap in the academic literature regarding the elasticity of natural gas connections and disconnections, which makes it difficult to precisely determine the rate at which customers defect from the natural gas system. However, there has been recent research investigating the effects of the switch away from natural gas. Lucas and Hausman 2021 investigates who bears the cost of a declining utility and notes that a ten percent decrease in residential utility customers leads to only a five percent decrease in revenues, implying that the remaining utility residential customers bear a higher burden in costs. This is to say that should there be a large defection from natural gas utilities due to decarbonization, the remaining infrastructure costs will not scale down and will be paid by those remaining on the system.

What this suggests is that any cost increase is felt more acutely by customers that are already facing energy burden. Energy burdened customers' ability to respond to price signals appears to be limited to reduction in use, which in the case of gas used for heating, may result in a decrease in home comfort felt more by these customers than those who can maintain home heating expectations by either absorbing the cost increase, or ultimately changing heating sources.

10 APPENDIX E: SUMMARY OF STAKEHOLDER COMMENTS

UM 2178 Comment Summary for October 26, 2021, December 3, 2021, and June 3, 2022, Comment Periods

The following material attempts to summarize comments received in UM 2178 regarding the Report Draft, docket scope, and general policy positions. It generally does not capture the feedback received regarding the modeling and associated scenarios.

Table 14: Abbreviations – Organizations that submitted comments and that were referenced in the Comment Summary

Abbreviation	Organization
A Sherrett	Arlene Sherrett, Oregon Native and Climate Advocate
Avista	Avista Corporation
AWEC	Alliance of Western Energy Consumers
BE	Better Energy LLC
C Reed	Carly Reed
Climate Reality	Climate Reality Project, Portland Chapter
CNG	Cascade Natural Gas Company
CUB	Oregon Citizens' Utility Board
EDF	Environmental Defense Fund
JC - Mayoral	Joint Mayor City Official Letter
JC - CS et al.	Joint Comments - Climate Solutions et al. (29 Organizations)
JC - EC et al.	Joint Comments - Electrify Coalition et al. (41 Organizations)
JC - NWGA et al.	Joint Comments - NWGA et al. (17 Organizations)
LWVO	League of Women Voters of Oregon
JC - MCAT	Joint Comments - Metro Climate Action Team et al. (3 Organizations)
Multnomah County	Multnomah County Office of Sustainability
NRDC	Natural Resources Defense Council
NWEC	NW Energy Coalition
NWN	Northwest Natural
OPSR	Oregon Physicians for Social Responsibility
RNW	Renewable Northwest

SC	Sierra Club
TNC	The Nature Conservancy
Zero Coalition	Zero Coalition

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
1	Decarbonization	Decarbonize Planning	Study	NWN, RNW, and EDF discuss the importance of relying on economy wide decarbonization studies. RNW and EDF cite that an existing decarbonization study conducted by Evolved Energy support the role electrification plays in decarbonization in the Northwest. NWN states that such a study is still needed, and should be sponsored by the Commission, because the existing studies reference to date are not specific to the Northwest or are lacking in sufficient detail to fully understand the impacts of load shifting from electrification and goes on to describe what the study should include.
2	Decarbonization	EITE - Leakage		AWEC and JC - NWGA et al. expressed concerns about Emission Intensive Trade Exposed (EITE) leakage and impacts to the economy.
3	Decarbonization	Fuel-Neutrality	No fuel switch	NWN, JC - NWGA et al., and CNG all indicate that the PUC should remain fuel neutral. AWEC says decarbonization should be fuel neutral, based on facts and studies and consistent with state law; and NWN further states that the Executive Order (EO) 20-04 further establishes fuel neutral GHG reduction goals and calls out Renewable Natural Gas (RNG) as beneficial for Oregonians.
4	Decarbonization	Fugitive Emissions		BE and Climate Reality PDX state that the PUC should include life cycle emissions and capture fugitive emissions in its decision making. NWN states that is has one of the most modern pipeline systems in the US, that leaks are not an issue, and that its system is well prepared for hydrogen (H_2).
5	Decarbonization	Reliability		AWEC, NWN, and JC - NWGA et al. state that natural gas provides reliable, affordable, safe energy services for customers, including during peak loads and extreme weather. NWN cites the E3 decarbonization report stating that it concludes that natural gas companies serving existing and new customers while decarbonizing "is a cost-effective strategy to meet the region's climate goals while also reliably serving winter peak demands."

Ln	Feedback Issue	Topic	Subtopic	Summary
6	Direction/PUC Role	Commission Authorities / Responsibilities	Broader decarb authority	Environmental and climate advocates also assert that it is the responsibility of the PUC to protect customers, but that doing so necessarily means protecting customers from expensive or high-risk strategies taken by gas companies to meet climate policy obligations. They state that it is the responsibility of the PUC to ensure gas companies consider and deploy existing, proven technologies and strategies for reducing emissions, including supporting strategies such as fuel switching from gas to electric and ceasing socialization of gas line extension costs. They further state that the PUC has an obligation to protect customers, not maintain particular utility business models or protect gas company market share. (TNC, NWEC, CUB, JC - MCAT)
7	Direction/PUC Role	Commission Authorities / Responsibilities	Decision making/direction	Stakeholders opined on both the topics on which the commission should provide direction and the issues that should be considered in decision-making. Commenters generally agree that decisions should be based on the best available science, should be fact based, lawful, and within existing authority, although as mentioned above, there were differing opinions about how broad that authority is. Some stakeholders indicated that it was important that the PUC include public health and climate impacts in decision making. (See Comment Regulatory Tools – Beneficial Electrification 4). Commenters expressed frustration that the report did not provide more explicit direction to influence current IRPs and other PUC proceedings or future investigations. They argued that the PUC should be "decisive and proactive in implementing decarbonization policy and provide unambiguous direction based in climate science, available technology, and economic data (TNC). JC - CS et al. expressed concern that by allowing gas companies to continue to expand and allowing for consideration of alternative fuels to be used where electrification alternatives exist, the report puts a premium on flexibility that "abdicates the commission's responsibility to regulate." (See Direction/PUC Role Optionality 339).

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
8	Direction/PUC Role	Commission Authorities / Responsibilities	Limited decarb authority	Many commenters opined on the authority and responsibilities of the PUC, including regarding its general statutory obligations, its role with regard to policy implementation and leadership, its obligations to customers and utilities and associated least-cost, least-risk planning, PUC actions in relation to state climate policies, fuel neutrality, and obligations to public processes. NWN and Avista state that the PUC's authority is to ensure safe, reliable and affordable natural gas service and to remain fuel neutral. They explain that attempts to establish decarbonization mandates in the form of either reducing access to natural gas or effectuating declines in gas customers via electrification as means to achieving climate action goals is an overreach. They indicate that this falls into policy direction and that that is the purview of the legislature, not the PUC. Similarly, the JC - NWGA et al. further state that forced electrification and policies that phase out natural gas violate the regulatory compact and increase costs of energy for individuals and businesses.
9	Direction/PUC Role	CPP		LWVO suggests the PUC request that DEQ modify CPP for transport gas so that regulation lives with the party that can control the emissions
10	Direction/PUC Role	Customer count	Do not prohibit growth	NWN states that proposals that seek to reduce emissions by decreasing customers counts by prohibiting new hook ups go against the commission mandate to ensure safe, reliable utility services and that the Commission should focus on emission reductions specifically rather than on customer count limitations. It further states that the modeling demonstrated that there are cost effective compliance strategies that do not rely on prohibiting new customer hook ups.
11	Direction/PUC Role	Customer count	No growth	Multiple commenters expressed concerns about Staff seeking regulatory tools that allow for continued customer growth. They indicate that it was reasonable to assume that customer counts would decrease because the "market response to economic, climate and associated policy pressures" make for reasonable assumptions about consumer decisions to move away from gas" (CUB), that studies show electrification of space and water heating is a cost-effective emission reduction solution that is available today, that allowing for growth

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				increases risk to gas customers both because it makes it more difficult and expensive to meet emission reduction targets, and increases infrastructure costs that they argue will inevitably be borne by fewer customers, who also will likely be Low-Moderate Income (LMI) customers less able to transition to electric options (JC - CS et al., CUB, NWEC, JC - EC et al., TNC,). Rather, they argue that at a minimum the Commission should not get in the way of customers that may want to fuel switch by limiting incentives to that could allow a switch, and that regulatory tools should be focused on how to manage declining customer counts.
12	Direction/PUC Role	Decarbonize Supply - general		NWN suggests that EO 20-04, 2019's Senate Bill (SB) 98 and 2013's SB 844 all demonstrate support for efforts to decarbonize supply.
13	Direction/PUC Role	Joint Planning		Many stakeholders commented on the need to perform some kind of joint utility planning or system-wide analysis and evaluation of GHG emission reduction approaches and the collaborative assessment of the impacts of electrification (Multnomah County, NWN, Avista, CNG, TNC, NWEC, NRDC, LWVO, JC - MCAT, Climate Solutions Joint Commenters pre-June 6, and BE).
14	Direction/PUC Role	Joint Planning		Some stakeholders provided additional guidance about what joint planning ought to include. JC - MCAT state it should include a timeline for building electrification, targeting of incentives for phased electrification, and phase decommissioning of gas. TNC notes that there should be a more formal coordinated planning process, beyond just shared assumptions and data. NRDC notes the process should develop "a combined "IRP" that begins with how loads can be met most effectively and cost-efficiently rather than how existing companies can best meet them for their customers." NWN and CNG both note support for collaborating with current electric Distribution System Planning filings on joint planning efforts. JC - CS et al. notes the Commission should task a third party to oversee a new joint planning process. NWN further notes that the scope of joint utility planning should closely engage with electric utilities to understand cost and reliability information to holistically understand costs of gas decarbonization efforts.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
15	Direction/PUC Role	Optionality		NWN stresses the importance of optionality and not taking "premature" actions that could limit the development of nascent technologies, especially with regard to building electrification, noting that the E3 study demonstrates that "any rush to judgement on the future of gas is misguided and that rapid, wholesale electrification of building load is neither economical nor necessary for meeting Oregon's decarbonization targets." JC - CS et al. express concern that the Report's "premium on flexibility" abdicates the Commission's responsibility to regulate.
16	Direction/PUC Role	Prioritization	Focus on EE and Electrification	Stakeholders offered direction regarding how the Final Report and the Commission should prioritize its efforts. All commenters who spoke to this issue note the need to prioritize near term GHG emission reductions and the need to provide clear direction on ways to protect customers. TNC, NRDC, Multnomah County, JC - CS et al., and BE say the Final Report should focus on supporting low-risk solutions that result in near term emission reductions via regulatory tools that support the deployment of existing, proven, established, and cost-effective tools, citing energy efficiency, weatherization, and electric heat pumps targeted to LMI customers. JC - CS et al. additionally note that given limited Staff resources that the Commission should not use Staff time developing pilots that focus on hydrogen or other nascent technologies. TNC notes that EE and non-pipe alternative programs should prioritize GHG emission reductions by being fuel neutral and accommodating consideration of beneficial electrification. NWN states that regulatory tools should prioritize near term natural gas decarbonization efforts to meet CPP targets.
17	Direction/PUC Role	Prioritization		JC - CS et al. notes that all solutions should be CPP compliant, realistically available to achieve GHG reductions in the short term, and geared toward their best use
18	Direction/PUC Role	Protecting Customers	Flexibility & $	JC - NWGA et al. note heighten uncertainty during this time of transition and that this is "not the time for hurried decisions that could cost Oregonians for decades." CNG notes that programs to help customers should be flexible, be allocated funds, and focus on low income and energy burdened customers. And while NWN

Ln	Feedback Issue	Topic	Subtopic	Summary
				supports programs to protect customers, including implementation of HB 2475, it notes that its modeling showed it could comply with CPP without significant cost impacts to customers.
19	Direction/PUC Role	Protecting Customers	Implement tools to help customers	NWEC notes that UM 2178 should continue with an updated purpose on how to use tools identified to manage customer risk.
20	Direction/PUC Role	Protecting Customers	Protect customers, not gas utilities	NWEC, TNC, and JC - EC et al. state that the regulatory tools that the Commission considers should focus on protecting customers rather than what they perceive as protecting utilities by preserving gas customers and allowing for system growth. JC - EC et al. express concern that the report closely aligns with gas industry positions, and in doing so fails to protect customer interests. NWEC notes that the report devoted too much time to how to help gas companies reduce GHG emissions and not enough time considering the interests of customers. TNC notes that all commenters need to acknowledge that continued growth of gas customers is unsustainable and align incentives accordingly to protect customers associated with a gas customer declines. Further, Multnomah County and JC - Mayoral comments recommends considering the targeted resiliency co-benefit of cooling associated with programs that support the deployment of electric heat pump technologies to LMI customers. NWN's comments do not counter the need to protect customers, but they do point to the importance of protecting the viability of gas utilities to accomplish other GHG emission reduction goals. They state, "HB 2021 relies on the financial health of gas companies: Commission action that minimizes the number of customers who help pay for the state's gas infrastructure could inadvertently impact the financial health of gas utilities, irreversibly damaging the statewide benefits provide by OR gas system."
21	Direction/PUC Role	Regulatory tools		NWEC supports tools that can be implemented in the near term to protect customers.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
22	Direction/PUC Role	Report Changes - Direction		Some stakeholders said that the Final Report needs to result in tangible direction from the Commission to the utilities, in many instances citing specific regulatory tools. NWEC notes that a key path to avoid customer risk is by providing guidance as soon as possible and note that the lack of guidance leaves customers at risk to either gas companies' failure to meet CPP targets or paying much more than necessary for energy services. JC - CS et al. note that where possible the Commission should not delay providing direction in the name of planning, but in doing so should be careful of stranded assets. NWN states that the modeling results were limited, which reinforces the need to stay with the existing regulatory process of "modeling, reporting, and follow-through."
23	Direction/PUC Role	Scope	Too broad	Throughout the docket, stakeholder discussed and challenged the proposed scope of the NGFF. Stakeholders continued to comment on the scope in response to the Draft Report. JC - NWGA et al., AWEC, and Avista state that electrification was beyond the scope of this docket and should not have been considered. Avista states the report takes an "anti-natural gas perspective" by including tools geared toward winding down natural gas business on the path to electrification. CUB, notes that the original objective as stated in the PUC's EO 20-04 workplan was not accomplished. They state the "EO 20-04 workplan includes ..."determine whether utility portfolios and customer programs reduce risks and costs by making rapid progress toward reducing GHG emissions" and prioritized proceedings and activities that advance decarbonization in utility sector to reduce GHG emissions." They further note the initial request from CUB for the NGFF was that it "provide guidance to IRPs about how to consider options for emissions reductions and the need to investigate how to minimize customer risk, including with stranded costs associated with impacts of policies that require GHG emissions reductions and further state the NGFF has not accomplished this. Rather, they state the NGFF has focused on gas company's ability to comply with CPP, where it should have included "...analysis of the future of natural gas within the PUC's proposed pathways to compliance with the EO directives, including

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				utility planning framework (IRPs)." NWEC comments that it believed the Draft Report generally meets the state outcomes of the NGFF, but that exploring the optimal pathway for natural gas decarbonization is important, but secondary to protecting customers as we decrease GHG emissions.
24	Direction/PUC Role	UM 2178 Process	Next Step	TNC recommends opening an investigation for additional revenue decoupling and Performance Based Regulation (PBR) options to "reduce tension between policy goals and growth-oriented utility business models."
25	Direction/PUC Role	UM 2178 Process		CUB and NWN suggest the UM 2178 process needed additional opportunities for stakeholder engagement. CUB wants Staff to host the final workshop before the July 12 SPM so Staff can consider feedback from that workshop in the Final Report. NWN suggested that Staff add another comment period after the July 12 SPM.
26	Direction/PUC Role	UM 2178 Process		CUB comments that the final workshop, as noted in previous docket schedules, should be expedited and be held prior to the July 12, 2022, SPM.
27	Direction/PUC Role	UM 2178 Process		NWEC states that the next phase of UM 2178 should include "more robust independent analysis, active effort to overcome business as usual, and be laser focused on protecting customers in GHG constrained world."
28	Modeling	CCI Penalty		JC - CS et al. state that Staff's assumptions about cost of non-compliance should be increased. The CPP provides limited access to the use of CCI for compliance, so if the cost of non-compliance was just the cost of the CCI, that effectively permits unlimited purchases of CCIs. They argue the cost of non-compliance should be doubled or tripled.
29	Modeling	Decarbonize Supply - general		AWEC, NWN, and JC - NWGA et al. state that the modeling shows that gas companies can meet CPP targets by decarbonizing their fuel supply without electrification and that they should be given an opportunity to demonstrate compliance with this strategy. However, many stakeholders expressed concern that the utility assumptions were not adequately scrutinized by Staff and that analysis on RNG, and gas heat pump should come from a party other than the utilities. (See Regulatory Tools: Decarbonize Supply – RNG line #40)

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
30	Modeling	Electrification - Costs		Avista and CNG note that they did not report electrification bill impacts associated with reduced numbers of customers. Avista replied in comments that it should have included these impacts.
31	Modeling	Modeling	Unsupported claims / assumptions	Stakeholders identified issues regarding the modeling used for the Draft Report, including concerns about utility assumptions, concerns about inconsistencies in modeling and application of direction provided by Staff, and various weaknesses of the modeling itself. Many commenters stated that Staff did an inadequate job challenging the claims and assumptions associated with utility modeling and indicated that utilities played an outsized role in the process, and the utilities need to better support their claims (JC - CS et al., SC, CUB). Gas utilities noted that the process was rushed and that results should not be relied upon for decision-making, but NWN noted that of the modeling, the base case scenarios were most heavily scrutinized and should be relied upon over the alternatives. In particular, the electrification modeling was considered to be missing important information about load shift impacts, costs, and resulting impacts on the number of customers. Avista and NWN provide additional information about how to model electrification in future IRPs and stressed the importance of using more sophisticated modeling techniques (Plexos), and the need for data and information consistency. CNG notes that differences in electrification modeling may have been due to differing interpretations of the guidance from Staff and recommends Staff capture more detail about how electrification was modeled by the utilities. JC - CS et al. recommends moving more of the modeling findings from the Appendix to the body of the text.
32	Next Steps	CPP Compliance & Cost Allocation	Next Steps	NWN recommends and CNG stress the Commission open a docket to address CPP compliance and cost allocation. CNG states the investigation should carefully consider the role of sending appropriate price signals. AWEC adds that the principles of cost causation should be maintained in rate spread approaches.

Ln	**Feedback Issue**	*Topic*	*Subtopic*	**Summary**
33	Next Steps	Electrification Study		Avista, AWEC, NWN and JC - CS et al. describe the need to conduct an Oregon specific electrification study and provided details about what the study should include. This has also been referenced by other commenters as a beneficial electrification study.
34	Other	Business model		JC - CS et al. suggest that the regulatory tools presented in the report protected the gas utility business model and stated that the PUC should prioritize the public over protecting the existing, "unsustainable" gas utility business model. Others suggested the gas utilities should pursue other business models (e.g., carbon-free energy for industrial customers or green hydrogen for seasonal storage), but did not provide additional feedback on the role of the PUC in consideration or development of alternative business models (JC - MCAT, and A. Sherret).
35	Regulatory Tools	Beneficial Electrification		Many stakeholders stated that beneficial electrification was inadequately addressed in the report. Supporters of beneficial electrification would like the Final Report to address this topic in more detail and earlier in the document, and state that it should include a discussion about the direct and co-benefits of electrification as a decarbonization pathway, including public health benefits (JC - CS et al.). Whereas NWN indicates that beneficial electrification was presented as a viable solution without the inclusion of the full cost and implications to customers and stated that the report should "unambiguously" indicate that the full cost burden borne by energy customers was not considered.
36	Regulatory Tools	Decarb Planning & Cost Recovery		JC – MCAT et al. recommend the commission deny cost recovery for high-cost and high-risk investments in unproven technologies.
37	Regulatory Tools	Decarb Planning & Cost Recovery		The issue of cost recovery associated with CPP compliance was raised by a number of stakeholders. NWN, CNG and AWEC expressed concern about limiting cost recovery options for CPP compliance and stated that ensuring adequate cost recovery was critical to maintain safety and reliability, and the ability to bring lower carbon fuels on to the system, like H_2. They also expressed concern about connecting cost recovery with CPP compliance.
38	Regulatory Tools	Decarb Planning & Cost Recovery - Accelerated Depreciation		AWEC states that depreciation of assets should reflect the useful life of the asset and that inappropriately increasing or decreasing the time period over which costs are recovered is not in the best interest of customers. It says this assumes electrification as a future path without studying whether this is an appropriate

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				assumption. CNG raise additional concerns, citing that changing asset depreciation timelines with anticipated use over a decarbonization timeline may be problematic for accounting purposes and may violate the matching principle. But it alternatively indicated support for "regulatory approval to accelerate depreciation expense since the assumption implies these assets will face obsolesce in the near future and the company would be faced with recovering fixed costs with smaller customer base."
39	Regulatory Tools	Decarbonize Supply - H_2		JC – MCAT et al., JC - CS et al., Multnomah County, NRDC, and NWEC expressed concerns about the role of H_2 in meeting CPP targets. They note that only Green H_2 should be modeled as a resource option, that the report erroneously assumes cost-effective availability of this resources for use in building heating applications, and does not adequately take into consideration a variety of risks, such as competition, redesign and replacement of pipelines and appliances, and stranded asset risks. Further, many stakeholders indicate that RNG and H_2 should be reserved for hard-to-electrify end uses. NRDC further notes that leveraging RNG and H_2 for home heating brings opportunity costs, because in an emergency, if a system fails, it is most likely replaced with the same, thus eliminating an opportunity to switch to electrification.
40	Regulatory Tools	Decarbonize Supply - RNG		There were disagreements about the assumptions of availability and cost of RNG as modeled by the gas utilities. CNG states the underlying market assumptions were consistent across all gas utilities, but that Staff should seek to understand differences in market adoption across different locations and demographics. However, other Stakeholders note discrepancies between the availability cited by the gas companies and that provided in a recent ODOE report, and further question the availability assumptions used by the gas companies. They indicate that biomass sources will be difficult to access and costly. Many of these stakeholders indicate that Staff needs to provide more scrutiny to the modeling done by utilities.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
41	Regulatory Tools	Decarbonize Supply - RNG		If RNG and H_2 are to be used, stakeholders provided additional backstops and guardrails to help protect customers, including information about current and future development sites, confirmation that Renewable Thermal Credits can be used for CPP compliance, and close tracking of RNG market potential. Further Multnomah County states that the PUC should not allow expansion of the gas system unless utilities can demonstrate their ability to acquire RNG and Green H_2 in a cost competitive manner, and that they can demonstrate the safe use of H_2 before approval of any rate-based incentives. Additionally, in an effort to value RNG produced in OR, assessments should capture local benefits in Cost-Effectiveness calculations.
42	Regulatory Tools	Decarbonize Supply - RNG		NWN argues that utility activity is a driver of markets, so we should be careful to assume that general market reports reflect what is possible in the region. Further, both NWN and CNG support use of SB 844 to incentivize H_2 deployment. Avista notes that if SB 844 is to be used that the requirements need to be reevaluated to make it easier for gas companies to leverage.
43	Regulatory Tools	Decoupling / PBR		AWEC does not support PBR if what Staff means is crafting revenue stability for NG utilities that increases cost to ratepayers to encourage electrification.
44	Regulatory Tools	EE Avoided Cost (AC)		CNG and NWN support that CPP compliance costs should be reflected in energy efficiency avoided cost and align with CPP cost alternatives. NWN further states that the AC it will use in the current IRP and AC filings will be based upon CPP GHG costs. TNC adds that avoided gas infrastructure renewal costs should also be captured in EE AC. Multnomah County indicates that cost effectiveness "calculations should include AC of climate impacts and reducing emissions, and EE and non-energy benefits."
45	Regulatory Tools	Electrification - Choice		JC - NWGA et al. and NWN state that electrification policies eliminate customer choice and do not agree with Staff that electrification should be considered a compliance pathway.
46	Regulatory Tools	Electrification - Costs		There was substantial disagreement about the consideration of electrification costs in the modeling. NWN, JC - NWGA et al. state the high cost of electrification was not included and is currently unknown. NWN further indicates the need for further study and provides examples of what assumptions need to be considered, and states that its modeling shows compliance without electrification.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
47	Regulatory Tools	Electrification - Costs		JC - EC et al. cites a Rocky Mountain Institute (RMI) report that studied electrification in Seattle that shows lower upfront costs for all electric homes but slightly higher annual utility ratepayer bills.
48	Regulatory Tools	Electrification - Fuel Switching		JC - CS et al., Multnomah County, and SC state the Commission needs to revisit fuel switching policies to allow Energy Trust and Community Action Agencies (CAAs) to engage in fuel switching, especially for Low Income (LI) and rural communities, and that fuel switching needs to be revisited in IRP Guideline Order (07-002).
49	Regulatory Tools	Electrification - General	Against	AWEC, NWN, and Avista were generally unsupportive of including electrification as a regulatory tool to be considered in the Final Report. NWN argues that the sources cited to support electrification were too generalized or based on states with very different attributes and should not be relied upon for assessing electrification impacts and costs. NWN further argues that because the case for electrification is unsupported, that inclusion as an option sends 'calamitous' market signals. They argue that the biggest risk of potential customer decreases and associated rate pressure increase are not from gas company compliance costs, but rather from policies that would drive customer defection.
50	Regulatory Tools	Electrification - General	For	Multiple stakeholders stated that the Draft Report does not adequately capture the role electrification can play in near term emission reductions, the likelihood of future electrification policies and actions, or the stakeholder comments addressing equitable transitions via building electrification and associated indoor air quality co-benefits with direct impacts to Black, Indigenous, and other Environmental Justice (EJ) communities. Further, some argue that while electrification is a preferred strategy for building decarbonization, the Commission should be prepared to protect LMI gas customers from anticipated negative cost impacts. (SC, NWEC, Multnomah County, JC - CS et al., and CUB).
51	Regulatory Tools	Electrification - Reliability		Avista is concerned about risks associated with load shifts from gas to electric but said both that electrification might take longer than stakeholders who support it realize, and that load shifts could make the electric system unreliable in peak times. Alternatively, JC - CS et al. and JC - MCAT believe arguments against electrification

Ln	Feedback Issue	Topic	Subtopic	Summary
				based on "reliability" are unsupported. They argue that switching resistance heating to electric heat pumps will largely address load concerns, and that even swift moves toward electrification will take time to implement, and reliability concerns can be addressed in long-term planning.
52	Regulatory Tools	Energy Trust Heat Pump		CUB states that funds coming from gas companies to Energy Trust should be used to conduct a conservation potential study focusing on how CPP emission requirements and costs of RNG affect cost effectiveness of energy efficiency. They indicate that it would include potential of NG heat pumps and would inform whether NG heat pump pilots are appropriate at this time.
53	Regulatory Tools	Energy Trust Heat Pump		NWN states the Commission will need to do more than direct Energy Trust. "The Commission and utilities will first need to address ETO budget development, as well as funding and delivery mechanisms for program expansion" e.g., expanded expertise may be needed.
54	Regulatory Tools	Energy Trust Heat Pump		NWN and CNG support Energy Trust training for both gas and electric heat pump technology. Joint commenters oppose the use of public funds for gas heat pump technologies, and many other commenters objected to public funds for gas heat pump technology promotion because of its relatively low commercial and technology readiness as compared to electric heat pumps. (See Regulatory Tools Technology Readiness line #83).
55	Regulatory Tools	Gas Infrastructure	Against	CUB, JC - EC et al., MCAT joint, and OPSR recommend an immediate halt of gas system expansion. Some specify that this just be the case for residential and commercial buildings. JC - EC et al. add that gas Line Extension Allowances (LEAs) should be eliminated immediately, and that the PUC should investigate the opportunity to "branch prune" sections of the existing gas system and replace those portions with electric heating. CUB states that the Report's suggestions that gas system expansion is necessary to protect customers should not be treated as fact. CUB further provides a cost comparison showing that reducing customer count reduces utility revenue by about $70-100/year, but that it is offset by reducing capital investment of about $2500. It would take more than 20 years for the additional customer charge to pay for the cost of the capital investment, creating a stranded cost risk if that customer later converts to an electric heat pump.

Ln	**Feedback Issue**	*Topic*	*Subtopic*	**Summary**
56	Regulatory Tools	Gas Infrastructure	For	NWN disputes the claim that investments in gas infrastructure will lead to stranded assets, and JC - NWGA et al. support decarbonization polices that embrace innovation and make use of existing energy delivery infrastructure.
57	Regulatory Tools	GHG Emission Reductions		NWN argues that a rush to electrification could increase emissions in the short run because of the current mix of electric generation and inhibit large-scale emission reductions in the long run. They cite an E3 Study - Pacific Northwest Pathways to 2050 the company commissioned in 2018. The company also notes that electrifying all natural gas high efficiency heat pumps would reduce OR emissions by less than 1 percent while increasing customer heating bills.
58	Regulatory Tools	Incentives - eliminate gas incentives		JC - EC et al., JC - CS et al., Multnomah County, Zero Coalition and JC - Mayoral comments indicate that the report should include the elimination of subsidies or incentives associated with the development or promotion of gas system expansion, gas heat pumps, or renewable natural gas. NWEC further states that the PUC does not need to incentivize anything because CPP is law and that the role of the PUC is to ensure compliance and make sure customers pay fair, just, and reasonable rates.
59	Regulatory Tools	Increase access to information		Comments regarding increased access to information were all generally supportive, the primary exception was with regard to mapping (see Regulatory Tools – Mapping lines #66 and #70). NWN notes that notices and quarterly update requirements should apply equally to gas and electric companies. JC - CS et al. notes that the Commission should direct utilities to host public workshops for lay audiences including explanations of the planning process, how the models work, and how to understand utility investments. They further note that staff should produce manuals on how to effectively participate in various proceedings, particularly IRPs.
60	Regulatory Tools	Innovation	For	NWN, CNG, AWEC, and JC - NWGA et al. believe the PUC should encourage gas companies to innovate to reduce emissions. AWEC notes pilot programs could be beneficial for hydrogen and CCSU but cautions that pilot programs costs should be fairly allocated between shareholders and rate payers, noting that traditional ratemaking paradigms might not work. JC - CS et al. indicate support for innovation only for hard to decarbonize end uses, not on residential or commercial heat. NWN notes that the Commission would need to provide

Ln	Feedback Issue	Topic	Subtopic	Summary
				additional clarity on goals of the pilot to ensure benefits to both gas and electric are explored.
61	Regulatory Tools	Innovation - Green H_2	Against	CUB, JC - CS et al., and NWEC were generally not supportive of incentivizing Green H_2 pilots and cautions against other pilots. JC - CS et al. indicate that ratepayers should not pay for alternative gas pilots at the expense of leveraging proven technologies, that new technologies take time to commercialize and scale to be effective, and that innovation should be funded by investors, not ratepayers. CUB argues that pilots should not be used for gas heat pumps and that doing so interferes with Energy Trust's analysis on potential, that NEEA is already conducting analysis in this space, but has not yet run a pilot, and that because there are no commercially available natural gas heat pumps for the residential market, that it does not make sense to run pilots with them. NWEC notes that the Commission has a long history of not supporting customer funded R&D, and this should continue as there is sufficient federal and private support for Green H_2 research. Further, the Commission should focus on directing the utilities to do things they would not otherwise do, such as implementing electrification and placing limits on new customer hook ups.
62	Regulatory Tools	IRP	Appendix B	NWN and Avista recommend against implementing IRP recommendations included in Appendix B in current IRPs via a waiver. NWN states that the IRP process has been vetted and that adding elements via a waiver risks adding unclear and unvetted requirements into an established process, which may produce flawed results. Additionally, NWN notes that allowing waivers might undermine the validity of the IRP guidelines and circumvent the public process. JC - CS et al. suggests that Appendix B should feature more prominently in the report, highlighting the need for tangible near term direction from the Commission regarding IRP analysis.

Ln	Feedback Issue	Topic	Subtopic	Summary
63	Regulatory Tools	IRP	Appendix B	Some commenters note concerns about the fact that all three gas utilities are in the process of developing their IRPs and recommend elements of Appendix B and any other applicable IRP related recommendation be implemented in the current IRPs (NWEC, LWVO, SC, CUB). NWN and Avista note that some of the changes proposed for IRPs in Appendix B are likely non-controversial, but they should not be applied to the current IRPs because there has not been a public process to discuss these changes and, in NWN's case, the IRP is too far along to make some of the changes requested. NWN also states that it is premature to take any action from UM 2178 that might undermine NWN's IRP action plan.
64	Regulatory Tools	IRP	CPP Acknowledgement	Regarding CPP compliance being acknowledgeable in IRPs, CNG and NWN agree that it should be acknowledgeable. JC - CS et al. however say CPP compliance should be mandatory, not just acknowledgeable.
65	Regulatory Tools	IRP	Elements	Many stakeholders convey differing positions regarding particular elements being included in the next round of IRPs. CNG notes that CPP compliance bill impacts should be included but should include uncertainly levels and a focus on near term action items and to the extent possible, CPP compliance costs should carry over into electric IRPs. Avista notes that demographic information should not be part of the IRP but should be with EE and energy assistance discussions and reporting. Avista also notes that gas companies would not know information about space and water heating across its territory, but that a consultant could be hired to find this information. It also notes that it would not know new technology adoption rates. NWN states that Marginal Abatement Cost curves should not be required in IRPs because they are not "sufficiently detailed to make accurate determinations about relative cost effectiveness of specific investments or actions."
66	Regulatory Tools	IRP	Proceeding	NWN, CNG and AWEC state that to consider changes proposed in Appendix B regarding IRPs that the Commission should open a proceeding on IRP guideline changes, pertaining to both gas and electrics. NWN notes that companies need to work with the Commission and stakeholders to develop a uniform methodology for converting IRP investments into ratepayer bill estimated impacts. NWN notes that the consideration of marginal abatement cost curves should be discussed in

Ln	Feedback Issue	Topic	Subtopic	Summary
				this broader IRP proceeding. CNG notes that modeling assumptions should be a topic when considering modifications to the current IRP process. Joint Climate Solutions comments prior to June 3 note that the IRP guidelines need to be updated to better capture emerging risk and uncertainty and that IRPs should require an analysis of fuel switching.
67	Regulatory Tools	IRP - Electrification	Electrification	JC - CS et al. state that that the Commission should develop and provide more direction about how gas companies should consider electrification in IRPs, including requiring that IRPs have realistic electrification scenarios and the ability to analyze stranded asset risk. They state the Commission should at least direct gas companies to conduct low, medium, and high electrification scenarios and identify cost impacts.
68	Regulatory Tools	Line extension allowances	Change/Eliminate	JC - CS et al. and NWN note that the Line Extension Allowance recommendation provided in the Draft Report needs clarification. JC - CS et al., TNC, and JC - EC et al. state that LEAs for gas companies need to be phased out immediately and that those for electric utilities should be revisited to consider behind the meter upgrades that support electrification. CNG and AWEC note that LEAs should be based in sound economic, and rate making principles (equity among rate payers and cost causation) and not be used to effectuate electrification without further conversation about decarbonization strategies. Regarding the process proposed by Staff in the recommendation, NWN says the Commission should refrain from making 'interim' changes, and TNC notes that discussions about LEA changes should allow stakeholder input.
69	Regulatory Tools	Mapping		NWN and Avista do not support providing infrastructure maps, stating that it is a security issue, the information Staff is seeking is not available, and that utilities use “group method” accounting and depreciation, so they do not track every asset or depreciable life. Avista also notes that the mapping information about depreciation would not be consistent with publicly available data from the Company's depreciation studies, which are provided every 5 years. NWN further notes that if maps are required that Staff should explain the goals of the mapping

Ln	Feedback Issue	Topic	Subtopic	Summary
				to enable constructive discussion and that requirements should apply equally to gas and electric utilities. CNG states that it does not believe additional mapping proposed by Staff provides value, given the effort required and notes that Staff should clarify the value of the mapping proposed.
70	Regulatory Tools	Mapping		JC - CS et al. states that maps of the gas system should help inform opportunities to prune the system with electrification.
71	Regulatory Tools	Monitoring, Tracking and Reporting	CPP Reports	Regarding monitoring, tracking and reporting, stakeholders commented on the urgent need for rulemaking to determine the cadence, form, and data required for CPP reporting and alternative fuel related reporting (RNG/ H_2). CNG indicates a preference for leveraging existing platforms such as IRPs and Purchased Gas Adjustments. NWN further comments on the need for "well-designed measures to monitor utility compliance" that should be accompanied by cost recovery that enables compliance. It states that lacking clear standards for cost recovery for investments makes compliance more challenging because it sends negative signals to "much-needed investors in Oregon's energy future...". NWN also stresses the urgency of initiating CPP reporting rulemaking. JC - CS et al. supports monitoring, tracking, and reporting, but cautions against prioritizing this such that it delays action.
72	Regulatory Tools	Programs		Climate Solutions Joint comments submitted prior to the Draft Report recommend a series of program related tools. They include: promote shell and weatherization improvements; eliminate incentives for methane gas measures; prioritize LMI, EJ - rural opportunities, rental units; heat pumps for LMI; include public health and climate impacts program/measure design; align funding for EE with least-cost decarb pathways; and remove barriers to Energy Trust conducting beneficial electrification.
73	Regulatory Tools	Programs		NWN, Avista, and CNG support the expansion of EE programs to assist in least-cost, least-risk CPP compliance. Avista notes that this will require a review of EE cost effectiveness assumptions for avoided cost calculations.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
74	Regulatory Tools	Programs		JC - CS et al. comment that 2/3 of the program recommendations encourage gas system growth, namely EE measures that allow for customer hook-ups and EE programs for transport customers.
75	Regulatory Tools	Protecting Customers	Recommended tools	JC - EC et al. suggest specific actions and tools to be considered to protect customers, including accelerating amortization schedules, denying rate recovery for investments in unproven technologies, and implementing rate class policies (HB 2475). However, Multnomah County notes that HB 2475 has limitations and is not sufficient protection for vulnerable customers from upward rate pressure.
76	Regulatory Tools	Protecting Customers - participation	Outreach	Zero Coalition recommends expanded outreach and reduced administrative burden for BIPOC, tenants, and LMI populations to facilitate participation in incentive programs.
77	Regulatory Tools	Rate Spread/design		CNG and NWN note the need to consider rate design and rate spread in a near term proceeding on CPP compliance and that it should include consideration of how to handle transport customers. CNG notes it is supportive of alternative rate design mechanisms if they promote positive outcomes and maintain safe and reliable service while protecting customers. CNG notes it prefers voluntary conservation based on price signals and enrollment in conservation programs provided by the company.
78	Regulatory Tools	Rates		NWEC and JC - CS et al. indicate support for the rate tools being considered. Climate Solutions joint comments prior to the Draft Report suggest the Commission should consider Multi-year Rate Plans, Performance Incentive Mechanisms, securitization, as well as heightened scrutiny of the impact of new infrastructure investments. However, JC - CS et al. note that the Commission should not let ratepayer risk "slow energy transition progress."
79	Regulatory Tools	Reduce Demand - EE	Expand EE Offerings	Expanded EE offerings was consistently supported by stakeholders who commented on the topic and expanded support for Energy Trust was regularly cited as a path by which this should be accomplished. Avista notes that Energy Trust does not provide LI weatherization, that CAAs do, but that they have been limited in their ability to meet demand for weatherization. They note that expanded outreach will not address this, rather that new solutions are needed to serve LI customers with weatherization. JC - CS et al. note that EE program spending should only be for insulation, shell improvements, and electrification.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
80	Regulatory Tools	Reduce Demand - Electrification	More focus on electrification	Multiple stakeholders note that the Final Report should more thoughtfully address electrification as a core decarbonization strategy (Zero Coalition, TNC, JC - NWGA et al., Multnomah County, MCAT Joint, and BE). However, JC - NWGA et al. state that electrification does not equate to decarbonization. Several stakeholders cited multiple sources and studies that show that electrification of water and space heating is the most cost-effective way to decarbonize buildings (MCAT joint, Zero Coalition, and BE). SC notes that utility planning related to electrification is within the sphere of influence of the PUC, whereas guaranteeing an affordable and available supply of RNG is not.
81	Regulatory Tools	Regulatory tools		JC - CS et al. provide a list of tools that should be captured in the Final Report, including: phase out gas LEAs; update Energy Trust policy to remove artificial barriers so gas and bulk fuel customers can choose to transition to more-efficient electric options; Expand low-income weatherization programs to allow for funds to be used for low-income electrification options and/or create a pilot program to encourage equitable electrification for LMI households; Continue and expand current efforts to ensure robust low-income ratepayer protections; and explore the value of pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades. They further note that ratepayer bill impacts should be differentiated by LMI.
82	Regulatory Tools	Report Changes - Direction		CUB states the docket should have included investigation of: "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."
83	Regulatory Tools	Technology Readiness		Many stakeholders commented that the Final Report recommendations should rely on proven technologies that exist in the market today, which are more readily available to reduce GHG emissions, are less costly, and less risky. Staff should also consider ways to further incentivize use of existing GHG emission reduction technologies, namely energy efficiency, weatherization, electrification. (CUB, JC - EC et al., JC - CS et al., JC - MCAT, NRDC, TNC). Alternatively, NWN notes that

Ln	Feedback Issue	Topic	Subtopic	Summary
				utilities like NWN drive market trends and that the Commission should strongly encourage near-term investments in promising new decarbonization strategies.
84	Regulatory Tools	Third Party Support		AWEC, CNG, and NWN provided comments regarding the use of third-party consultants to inform technical and market assumptions. AWEC notes that said party should be unbiased and fuel neutral. CNG notes said party should be selected via a transparent process with stakeholder participation, and that results should be informational, not prescriptive. NWN seeks clarification from Staff on how the findings would be used and expressed concerns about generic reports not being representative of what is possible via utility driven investments and that such an analysis could hinder encouragement of reasonable investments in nascent technologies.
85	Regulatory Tools	Transport - EE		AWEC, Avista, CNG, and NWN commented on the need for EE programs for transport customers and highlighted some of the challenges that will need to be considered. NWN notes that the challenges and regulatory considerations warrant opening an "industry-wide" proceeding on EE programs for transport customers and the PUC's regulatory authority over this customer class. The issues include how to fund, implement, and administer such a program and how to address associated compliance costs and rate spread. AWEC further provides suggestions for a "Large Customer Carbon Reduction" program (AWEC pg. 3-5)
86	Report	Analysis and Conclusion		CUB states the report lacked analysis and scrutiny of utility modeling or assumptions; it did not include any findings on the modeling or provide ratepayer bill impacts; it did not include consideration of feedback and data from stakeholders; nor did it provide conclusions regarding appropriate tools to mitigate potential customer impacts.
87	Report	Climate and health risks	Public health	JC - CS et al., OPSR, and TNC want the Final Report to include more information about the public health harms of methane gas use.
88	Report	Climate and health risks	Urgency	JC - CS et al. and JC - Mayoral comments indicated that the Final Report should better reflect climate urgency and the science supporting the need to rapidly, substantially, and continually reduce methane emissions. They indicate that the Final Report should better reflect climate urgency in its justification and prioritization of regulatory tools.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
89	Report	Costs		Regarding CPP costs, AWEC indicates that decarbonization goals should consider the cost of compliance for consumers in Oregon. However, NWEC and JC - CS et al. express concern that this investigation's focus on compliance costs, and less on the benefits of CPP compliance, might be used as an attempt to challenge the CPP rules. They caution the PUC about making statements about cost without knowing overall energy costs, energy burden, and tradeoffs. Additionally, many commenters indicate that it was important that the Final Report couch CPP compliance cost in the context of the benefits provided by the CPP.
90	Report	Elasticity		CNG and JC – CS et al. wants Staff to share its econometric model on elasticity or move the elasticity report to the body of the text.
91	Report	GHG Emission Reductions		BE, Climate Reality PDX, and Multnomah County state that the climate crisis requires that the Commission focus decision making on emission reductions. CUB states that gas companies have yet to demonstrate their ability to reduce emissions with existing customers "let alone accommodate growth and increase load." And JC - MCAT state that the Draft Report's "all of the above" approach is contrary to OR statewide energy policy, citing CPP rules and further notes that Staff's recommendations fail to facilitate GHG emission reductions. JC - EC et al. note that actions proven to reduce emission from gas utilities and protect ratepayers are: 1. Eliminate further expansion of the gas system; 2. Reduce the quantities of gas that are consumed by existing gas customers; and 3. Replace methane combustion with less polluting, high efficiency electric heating wherever possible.
92	Report	Reduce Demand - Electrification: Trends		Multnomah County and JC - EC et al. note that policy and customer choice will increasing lead to electrification of end uses. JC - EC et al. cites cities, counties, and states enacting building codes supporting a move to electrification.
93	Report	Report Changes	Clarify	NWN, Avista, and CNG request clarification on select recommendations and other aspects of the report and indicate that Staff should allow commenters to respond to clarifications before any PM addressing the Draft Report. Recommendations that need clarification include: - Rates 5.1.1(6): Align near-term investment levels with annual progress in CPP compliance in order to limit uncertainty around accumulation of long-term capital assets.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				- Rates 5.4(3): Explore linking the amortization of CPP compliance costs from deferrals to actual CPP performance. TNC indicates that Staff's recommendation regarding cost recovery associated with CPP compliance and CPP amortization links to CPP performance was unclear.
94	Report	Report Changes	Clarify	CNG notes section 3.2.2 regarding transport customers should explicitly exclude electric generation customers and be indicated as such.
95	Report	Report Changes	Clarify	CNG notes the Final Report should clarify whether the elasticity relationship is evaluated relative to gas prices, ratepayer bills or utility rates.
96	Report	Report Changes	Clarify	For section 4.3, fifth bullet – Avista notes it is unclear what is meant by "business model motivation" and aligning utility behavior with transition targets. Additional detail should be provided to articulate what this bullet is attempting to portray.
97	Report	Report Changes	Correction	Avista notes that in Table 5 - alternative Supply Projections the RNG Supply Penetration by 2035 - the Avista column incorrectly states 40 percent of overall deliveries – it should state 19.5 percent.
98	Report	Report Changes	Correction	Avista notes that Avista's general rate revision proposal does not include a differential rate proposal. Avista is proposing to implement a ratepayer bill discount program pursuant to HB 2475, but it is outside of its general rate case.
99	Report	Report Changes	Correction	Avista notes that it is not necessarily true that compliance with the CPP will likely increase costs to all customers in the near-term.
100	Report	Report Changes	Correction	Avista notes that its compliance cost had been added to the price per dekatherm of natural gas available as supply into the Company's system and may not be indicative of actual rate spread.
101	Report	Report Changes	Fact Check	Avista notes that the Draft Report incorrectly states the CPP lays out framework that "prohibits supply of natural gas."
102	Report	Report Changes		JC - CS et al. state that the background section should include how other states (MA and CA) are addressing future of gas.
103	Report	Report changes - momentum		Avista and JC - CS et al. noted they both disagreed with the language characterizing natural gas 'momentum'.

Ln	**Feedback Issue**	*Topic*	*Subtopic*	**Summary**
104	Report	Report Changes - Stakeholder Feedback		Many stakeholders commented that the Draft Report disregards stakeholder feedback and data and does not provide justification for Staff positions with regard to stakeholder feedback and data. This includes, but it not limited to modeling, electrification, RNG/ H_2 assumptions, and natural gas heat pumps. (CUB, JC – EC et al., JC – CS et al., TNC, Avista)
105	Report	Report Changes - Unsupported claims		Multiple stakeholders note that the Draft Report contained unsupported or unsubstantiated claims and challenged whether the report accomplished its goal of fact finding. JC - CS et al. notes that the Report fails to "meaningfully parse through the discord between gas utilities' analysis and recommendations, and those of third-party experts and community stakeholder to come up with actual facts." NWN comments that its decarbonization pathways are credible and supported by facts. CUB notes that the Final Report should detail and weigh in on compliance scenarios informed by utilities, but also market and industry data, science-based information, stakeholder input, and PUC experience. CUB further notes that the Final Report should clearly indicate where issues were in dispute and/or explain the basis for Staff conclusions where issues were in dispute.
106	Report	Risk		Multnomah County, JC - CS et al., JC - EC et al., and Avista commented that the Report inadequately addressed various risks. JC - CS et al. notes the report should better capture uncertainty regarding various CPP compliance strategies and that the Report inaccurately reflects the risks of electrification as being on par with the risks of decarbonizing gas; Multnomah County says the Report should better reflect environmental and financial risk of failing to decarbonize the gas sector; and JC - EC et al. state the PUC should address emerging risks of CPP non-compliance by adopting least-cost, least-risk strategies proposed by stakeholders and RAP. Avista notes that the risks associated with electrification as a CPP compliance strategy has not be adequately addressed in the Report.

11 APPENDIX F: DISTRIBUTION SYSTEM PROJECT INFORMATION IN FUTURE GAS IRPS

Staff seeks the analysis and information on proposed distribution system upgrades to determine rationale and thus inform acknowledgability under the CPP. Specifically, Staff seeks:

- An understanding of the model parameters used to identify and justify an upgrade.
- Information to assess model performance against observed conditions at the proposed upgrade location, including scenarios and probability of those scenarios, e.g., Number of Heating Degree Day in targeted years at the investment location
- Minimum standards for operation around the proposed upgrades
- Alternative activities or investments analyzed or already enacted, particularly focused on minimizing growth of overall throughput of the network
- If a distribution system project was selected over an alternative investment, the rationale supporting the selection

Staff has developed a set of questions, akin to standard data requests, divided into four categories, with the goal of helping to guide the information submitted about distribution system projects and clarify expectations. To the extent that any gas company's IRP omits this analysis and information, Staff may ask for it in Information Requests.

Distribution System Upgrade, Model Basics

Goal: To help Staff and stakeholders understand fundamental modeling assumptions used by the Company to assess distribution system upgrades and the logic used to model a system, identify upgrades, and assess alternatives to upgrades.

1. For any proposed distribution system project provide the following in Excel format with formulas intact:
    a. Model parameters,
    b. Customer-temperature correlation and confidence, particularly focusing on those customers for whom correlation is not high (e.g., non-temperature dependent use types),
    c. HDD scenarios considered and the influence of more extreme use cases,
    d. Minimum delivery pressures, and
    e. Correlation and confidence of location-specific temperature cases.

Distribution System Upgrade, Ground Truthing

Goal: To help Staff and stakeholders understand how well a model reflects actual conditions observed at the location of a proposed distribution upgrade. This helps to establish confidence in the need for a project.

2. Describe **how** the Company assessed model accuracy for pressure recordings and weather data against actual observations.

3. Provide data demonstrating how modeled conditions appeared in observations. This should include:
    a. A description of when they happened;
    b. Locally measured temperatures and other relevant weather parameters;
    c. How often they happened;
    d. How long they were observed for; and
    e. Clarification about whether during the observations any contingency actions were deployed, including but not limited to curtailing interruptible customers, effecting cold weather actions (i.e. bypassing regulator stations), local injection of gas, or the use of any energy efficiency or demand side management approaches.

4. Provide data supporting where in the system the largest line losses occurred to determine the best mitigation for the reduced delivery pressure cases.

Distribution System Upgrade, Minimum Standards

Goal: To help Staff and stakeholders gain insights into the engineering and operational standards under which a utility seeks to operate its distribution system. These standards provide a better understanding of the extent to which the current system falls outside of those standards and how the proposed upgrades address those issues.

5. Provide the following information for each category of a utility's system
    a. High pressure distribution system:
        i. Maximum allowable operating pressure (MAOP)
            1. Limiting component(s)
        ii. Specified minimum yield strength (SMYS)
        iii. Normal operating pressure
        iv. Minimum operating pressure
        v. Standard pipe sizes, materials, and grades
        vi. Minimum cover depth
        vii. Main pipeline leaks by grade
        viii. How many leaks are carried over from prior calendar year by grade
    b. Intermediate pressure distribution system:
        i. Maximum allowable operating pressure
            1. Limiting components
        ii. Normal operating pressure
        iii. Minimum operating pressure
        iv. Standard pipe sizes, materials, and grades
        v. Minimum cover depth

vi. Main pipeline leaks by grade
vii. How many leaks are carried over from prior calendar year by grade

c. Industrial services:
    i. Maximum allowable operating pressure
    ii. Normal operating pressure
    iii. Minimum operating pressure
    iv. Standard pipe sizes, materials, and grades
    v. Minimum cover by grade
    vi. Service line leaks by grade
    vii. How many leaks are carried over from prior calendar year by grade
d. Residential and commercial services:
    i. Maximum allowable operating pressure
    ii. Normal operating pressure
    iii. Minimum operating pressure
    iv. Standard pipe sizes, materials, and grades
    v. Minimum cover depth by grade
    vi. Service line leaks by grade
    vii. How many leaks are carried over from prior calendar year by grade

6. For each project identified outline:
    a. Existing maximum allowable operating pressure.
    b. Proposed maximum allowable operating pressure.
    c. Normal operating pressure.
    d. Design day (hour) minimum pressure and related HDD.
    e. All data supporting the validation of the local network model, including pressure recording charts.
    f. The model under the variety of cases with various thematics, including delivery pressures and line losses.
    g. Cathodic protection records demonstrating the effectiveness of the program for this corridor.
    h. Leak history for transmission, distribution mains and service lines by grade.
    i. If cover or other safety or reliability concern is relevant to the project's completion, please identify the data supporting that concern. For instance, in the case of insufficient cover, provide evidence of how pervasive the cover limitations are, e.g., pothole history or other supporting material. If any metal coupons of the pipeline have been tested, please provide such information.

Distribution System Upgrade, Cost Effective Alternatives

Distribution system upgrades that can increase emissions put financial pressure on ratepayers and the Company to reduce emissions elsewhere on the system. Thus, resource planning in Oregon must now explore the extent to which upgrade alternatives that fore stall or even avoid expanding distribution system capacity were explored. The questions below seek to establish the alternatives explored, how they were identified, and, if applicable, why distribution system upgrades were selected over the explored alternatives.

1. Describe the alternatives to distribution system investments that were explored as part of the Company's research.

2. Identify the frequency with which the Company has performed contingency actions to ensure proper system delivery, such as bypassing regulator stations, injecting CNG or other measures. For each time such actions were taken, provide all supporting records about the actions taken.

3. List the number of interruptible customers and their hourly maximum demand, as well as any curtailments conducted during peak events. Additionally, describe how much each interruptible customer is estimated to use at peak and how the model used for distribution system upgrades incorporates the interaction with interruptible customers when assessing the size and timing of a distribution system upgrade, especially a gate upgrade.

4. Identify the extent to which the Company analyzed the potential for large loads in the area of the upgrades to either shift or be shed during peak events to avoid upgrades.

5. Identify the extent to which the Company analyzed the use of energy efficiency and/or demand response (e.g., thermostat pre-heating or reducing peak demand) programs to forestall or avoid the proposed upgrades. If such analysis was conducted, please summarize the impact on the size and timing of any of the proposed upgrades and why such energy efficiency and/or demand response was not pursued.