NW Natural®

2025 NW Natural Integrated Resource Plan

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A Message from NW Natural President

NW Natural provides an essential service to our customers and the communities that depend on us. In light of this responsibility, the company's IRP is guided by three objectives: (1) reliability and safety, (2) affordability, and (3) achieving Pacific Northwest carbon emission reduction goals. NW Natural believes we must succeed at all three objectives simultaneously because failure on any single objective will jeopardize the ability to accomplish the others.

To do so in an increasingly challenging and complex energy landscape requires comprehensive, evidence-based energy system planning. This 2025 IRP contains a significant amount of analysis based on input from a wide variety of voices. While a multitude of scenarios and sensitivities were assessed in this Plan, a key element is the evaluation of building electrification as a carbon compliance tool.

NW Natural commissioned the firm ICF to conduct an assessment of various electrification scenarios and their cost impacts. In addition to a reference case that utilizes a mix of gas system technologies and low carbon gas resources, two electrification scenarios were analyzed: 1) an aggressive deployment of hybrid systems to reduce electric system peak challenges, and 2) a strategy that relies solely on adoption of electrification of gas use in homes and commercial buildings.

The results are illuminating. While all three scenarios necessitate a marked increase in consumer energy costs to achieve Oregon and Washington's carbon emission reduction program requirements, there were substantial differences in costs, risks, and levels of uncertainty.

The Reference Case reduces emissions at the lowest cost but is still projected to increase energy costs by $6.7 billion on a net present value basis from 2025 to 2050. In comparison to the Reference Case, the Hybrid Electrification scenario would increase consumer costs by an additional $7.7 billion (net present value), while the All-Electric scenario would increase consumer costs by an additional $12 billion (net present value). These total costs are ultimately borne by natural gas and electric utility customers, either directly in the form of equipment conversion costs or in the form of increased utility rates.

An independent Advisory Group of electric industry leaders reviewed the ICF analysis and found the electrification scenarios depend too heavily on optimistic assumptions. They believe the electric system will struggle to meet current policy goals and load growth even before the electrification of natural gas end-uses is considered. These challenges to meet state climate targets have only been compounded since the Advisory Group's review due to recent policy changes removing clean energy funding and tax credits at the federal level. If the Advisory Group's perspective proves accurate, affordability and reliability—particularly during extreme cold when public health is at stake—would be at greater risk.

The choices before us to achieve all our collective goals are difficult and NW Natural has made considerable effort to better understand and respond to public input. As a result, we firmly believe a fundamental aspect to addressing social equity is a thoughtful consideration of energy security and costs—for low-income customers, but also moderate income and middle-class customers, and the businesses our communities rely on for economic viability.

A successful energy transition involves a balanced, integrated approach which informs our Action Plan summarized in Section 1.10. Our Action Plan provides flexibility and optionality, while exploring and investing in a variety of solutions, and encouraging stakeholder collaboration and joint electric and gas system planning. Through this approach, the Pacific Northwest and NW Natural can achieve decarbonization goals while maintaining safe, reliable, and affordable energy for our communities.

Thank you for your participation in this process. We look forward to a productive discussion.

Kim Rush
President

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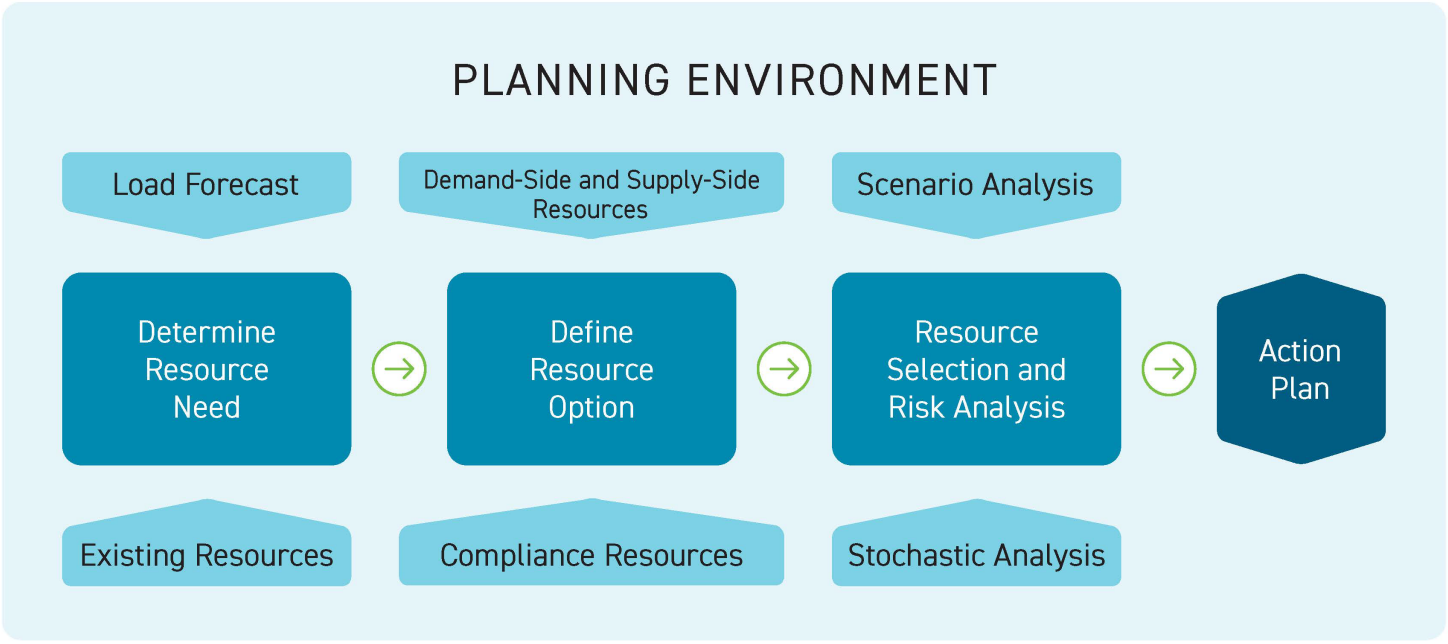
1 Executive Summary



NW Natural®

This Chapter provides an executive summary for NW Natural's 2025 IRP and Action Plan. Abbreviations and Glossary is provided following Chapter 13 on pages a-k.

1.1 Company Overview

NW Natural is a local natural gas distribution and storage utility headquartered in Portland, Oregon with a 166-year history. NW Natural serves approximately two million people in Oregon and Washington through over 800,000 customer accounts. The Company's service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, much of the Oregon Coast, and a portion of the Columbia River Gorge (see Figure 1.1). Approximately 88 percent of NW Natural's customers reside in Oregon, with the other 12 percent in the state of Washington. Residential customers account for roughly 91 percent of the Company's customer accounts.

Figure 1.1: NW Natural Service Territory

1.2 Integrated Resource Plan Planning Process

Guided by the economic, political, and technological landscape in which NW Natural operates, and consistent with the requirements for Integrated Resource Planning set forth in Oregon Administrative Rule (OAR) 860-027-400[1] and Washington Administrative Code (WAC) 480-90-238, NW Natural develops a resource acquisition plan (an Integrated Resource Plan, or IRP) on approximately two-year cycles, with this plan looking out to 2050.

The IRP is the result of a rigorous analytical process that follows three broad steps:

1. forecasting NW Natural customers' current and future energy, capacity, and environmental compliance needs;
2. determining the resource options available to meet those needs, inclusive of both resource options that help reduce the amount of gas customers use (demand-side resources), resource options that help NW Natural deliver energy (supply-side resources), and resource options that help meet emissions compliance obligations (compliance resources); and finally
3. identifying the portfolio of resources with the best combination of cost and risk for customers.

NW Natural conducts this involved analytical IRP process to ensure that the Company has adequate resources to meet customer energy needs throughout the year (energy planning) and the energy needs during the coldest days the region might experience (capacity planning). Additionally, NW Natural acquires compliance resources in accordance with environmental compliance laws and rules focused on green-house-gas (GHG) reductions (compliance planning).

The IRP includes two levels of planning that are separate types of planning but are not fully independent.

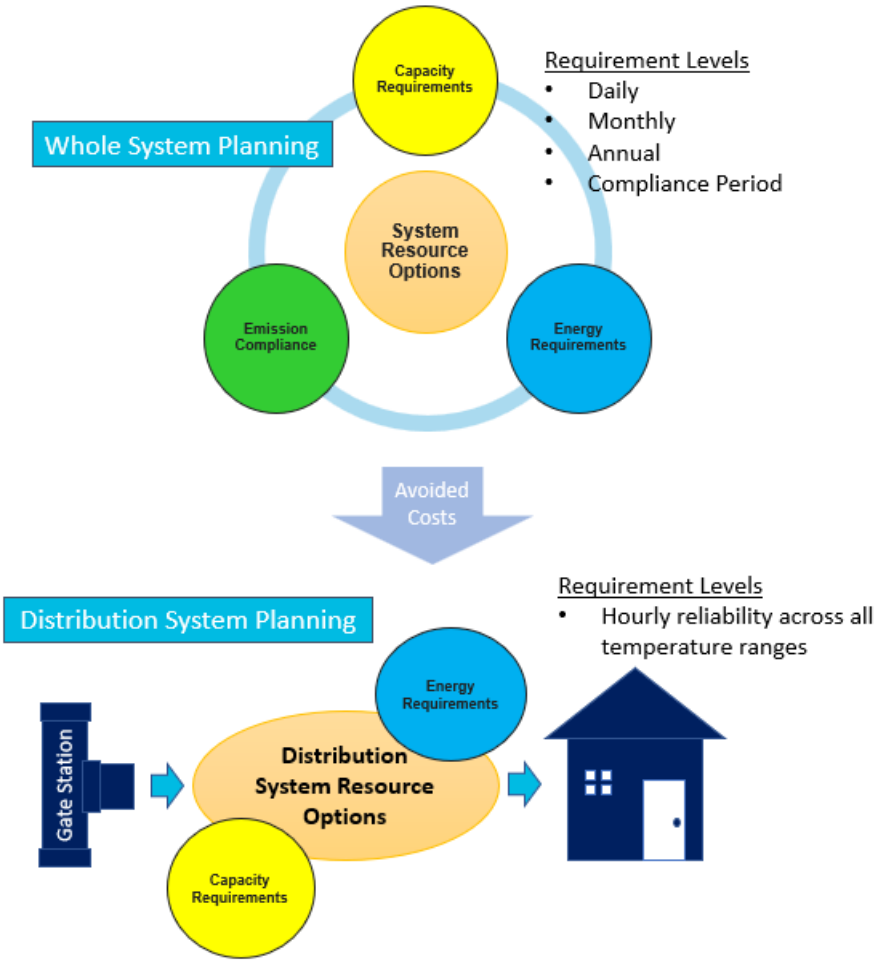
1. Whole system planning (focus of Chapters 4-9)
2. Distribution system planning (focus of Chapter 12)

These two levels of planning utilize separate tools, rely on separate types of analysis, and have separate requirement objectives, however; results from whole system planning do impact distribution system planning through avoided costs (discussed in Chapter 5). Avoided costs, which are a result of the whole system planning and used in a variety of applications, are

[1] Currently Docket AR 669 is ongoing and in the process of repealing OAR 860-027-0400 and replacing it with a new OAR Chapter 860, Division 90, System Planning.

incorporated into the cost-benefit analysis for evaluating non-pipeline alternatives (NPAs) for distribution system planning. Figure 1.2 summarizes the two separate planning processes.

Figure 1.2: Analytical Process for Both System and Distribution Planning



The primary output of each IRP is the Action Plan (see Chapter 13), which details the Company's long-term resource strategies and proposed near-term actions. Given that IRPs are completed roughly every two years and are updated annually, this IRP should not be viewed as a "set it and forget it" plan, but rather a snapshot of potential least-cost resource portfolios that meet customer energy needs under varying assumptions. The 2025 IRP uses information currently available and future IRPs will use updated information to adapt and modify NW Natural's Action Plan accordingly. Additionally, Chapter 9 defines the Company's preferred resource portfolio as the set of the least-cost resources acquired through assumptions derived from the Company's preferred resource strategy (PRS).[2] This preferred resource portfolio does not

[2] See Section 9.4.2.

dictate the items outlined in the Action Plan but is merely one outcome that informs the Action Plan. In other words, the Action Plan is developed by the entirety of the analysis conducted in this IRP to advance low-risk near-term actions and long-term strategies to provide customers with reliable and affordable energy services across both natural gas and electric services.

1.3 Updates to the 2025 Integrated Resource Plan

Taking feedback from the Commissions, Staffs, and other stakeholders from the 2022 IRP, NW Natural has made significant updates to this IRP. These efforts will be discussed below.

1.3.1 Electrification

Building electrification refers to shifting energy services currently being met by natural gas to electricity providers through the replacement of natural gas appliances with electric appliances. Conditional on the electric grid fully transitioning away from fossil fuels, many policymakers view building electrification as the vehicle to decarbonize the small amount of emissions associated with direct use natural gas in homes and businesses (see Section 1.5.3 for state specific GHG reporting percentages). As space heating is the main end-use of natural gas, building electrification has primarily focused on converting natural gas furnaces to electric heat pumps. Consumers and home builders ultimately choose the types of appliances they want to install, but policies to modify building codes, provide electric equipment incentives, or banning the installation of natural gas appliances have been raised in policy settings by those advocating for building electrification.

For this IRP, the Company engaged ICF to perform an electrification study to help identify the full costs of building electrification and understand the implications for Oregon and Washington consumers. Quantifying and identifying the full implications of shifting energy services from the natural gas system to the electric system is critical to inform least-cost, least risk climate policies.

To further this discussion and better understand the comprehensive impacts of building electrification as a potential decarbonization mechanism, NW Natural also engaged with several electric utility counterparts to seek relevant information and, importantly, sought guidance from recognized experts in the field for key assumption validation. As part of this study, the Company included a detailed look at an all-electric approach as well as using hybrid heating (i.e., dual fuel heat pumps). This study demonstrates that NW Natural's non-electrification compliance pathways for the CPP in Oregon and CCA in Washington are lower cost than either two of the electrification scenarios. However, NW Natural recognizes the potential emissions and reliability benefits of hybrid systems to both the gas and electric systems, and NW Natural is seeking to continue to explore programs and pilots that can leverage both energy systems,

even though such actions could potentially lead to higher consumer costs. As such, NW Natural is seeking to advance joint system planning to best effectuate these benefits while minimizing costs.

Chapter 10 and Chapter 11 discuss the study in more detail.

1.3.2 Renewable Natural Gas Acquisitions (SB 98 and HB 1257)

In Oregon Public Utility Commission (OPUC) docket LC 79 and in Washington Utilities and Transportation Commission (WUTC) docket UG-210094, as part of the action plan, NW Natural prioritized purchases of renewable natural gas (RNG) under Senate Bill 98 (SB 98) and House Bill 1257 (HB 1257) to meet specific renewable natural gas targets. This procured more expensive RNG over the purchase of various lower cost compliance resources such as Community Climate Investments (CCIs) or Climate Commitment Allowances (CCAs). The Oregon Public Utility Commission disagreed with this approach and emphasized that if RNG was not a least-cost resource, the Company should make the case for RNG as a way to mitigate risk to customers[3].

The 2025 IRP, and the resulting preferred portfolio, incorporates this feedback. Specifically, to comply with the Oregon Climate Protection Program (CPP), NW Natural will first purchase CCIs while incorporating limited amounts of near-term RNG purchases that will not exceed the cost-cap provisions specified in SB 98. Similarly, NW Natural purchases a limited amount of RNG in the near term under HB 1257.

Chapter 9 discusses this strategy in more detail.

1.3.3 Material Increase in Number of Alternative Fuels Evaluated

In this IRP, the number of alternative fuels evaluated has increased from four categories (i.e., low cost RNG, high cost RNG, hydrogen, and synthetic menthane) to 22 alternative fuel categories. This expansion of fuels captures the resources evaluated in the previous IRP and allows for a more detailed analysis of specific types of resources (e.g., feedstock, facility size, etc.). Additionally, the Company has evaluated two categories of Carbon Capture Utilization and Storage/Sequestration (CCUS) in this IRP. To help better inform cost and volumes for these resources, the Company joined both Avista Utilities and Cascade Natural Gas to fund an Alternative Fuels Study, which can be found in Appendix E. By incorporating these additional fuels, the Company can provide enhanced granularity into the types of alternatives that may be attractive to pursue in the future and gain additional insights into future costs. While this

[3] The WUTC's letter (dated August 24, 2023) acknowledging UG-210094's compliance with WAC 480-90-238, did not specifically address the Company's Washington Emissions Compliance Action Item 10 regarding RNG under HB 1257.

expansion adds material complexity to the analysis, it provides useful additional insights as well.

Chapter 7 and Chapter 9 discuss these resources in more detail.

1.3.4 Use of Non-Pipeline Alternatives

Using a new Customer Management Module (CMM) system and Forward-Looking Distribution System Planning Process for every distribution project discussed, non-pipeline alternatives (NPAs) are being proposed as actions to either defer, or avoid, the infrastructure project. While the Company is continuing to scope distribution system infrastructure projects, this is done as a risk mitigation measure due to the uncertainty related to NPAs.

Of note, since the 2022 IRP, the Company has launched a system-wide residential and small commercial customer demand response program (see Chapter 6), and that program is being leveraged to create additional NPAs for distribution system pipeline infrastructure projects.

Chapter 12 discusses this in more detail.

1.3.5 Recognition of Equity Considerations

Energy equity and affordability are foundational to how NW Natural serves its communities. New to the Company's overall IRP process is the recognition of equity in the planning process. There have been a number of new regulatory developments in this area, and indeed several dockets providing guidance on how to consider equity are currently underway. In Washington, the Equity Docket A-230217 is one such example. For the 2025 IRP, the Company includes a chapter dedicated to equity considerations, focusing on improving procedural justice in an effort to be more intentional in this important area.

The Company is dedicating the Equity Considerations and Public Participation Chapter to procedural equity and the public engagement enhancements conducted in the development of the IRP to champion a more accessible energy planning process. This IRP builds on NW Natural's tradition of public engagement by expanding opportunities for inclusive participation and integrating diverse perspectives into the planning process. Diversifying the voices, lived experiences, and perspectives that inform NW Natural's practices is a critical step to serving all customers better. The chapter highlights the concrete actions NW Natural took to strengthen inclusive, informed, and meaningful public engagement specific to this IRP.

An overview of the Company's energy equity and energy affordability portfolio is provided within the chapter to offer a broader picture of the work NW Natural is implementing in the communities it serves.

Chapter 3 provides additional context.

1.4 Updates to the Action Plan and Addition of Long-Term Resource Strategy

While the IRP Modernization rulemaking in Oregon[4] is ongoing and not yet final, this 2025 IRP includes an extended near-term Action Plan that looks out five years, recognizing that IRP updates and a full IRP will be filed within this near-term timeframe and that action items may be updated or changed in those filings. Additionally, the Company is including a Long-term Resource Strategy consistent with the IRP Modernization rulemaking. This Long-Term Resource Strategy sets forth approaches that NW Natural is evaluating to meet customer needs and comply with all federal and state energy policies over the planning horizon, while taking into consideration technological developments, policy changes, and other major uncertainties.

Chapter 13 is dedicated to outlining items for both long-term strategies and near-term actions.

1.5 Planning Environment

Broad policy conditions and developments influence the resource options that are suitable for NW Natural to serve customer gas needs. While the planning environment presents analytical challenges and uncertainty in every IRP, the recent combination of dynamic environmental policy associated with the energy evolution in the Pacific Northwest, and shifting Federal energy market policies, make the current planning environment particularly challenging.

Chapter 2 discusses the Planning Environment.

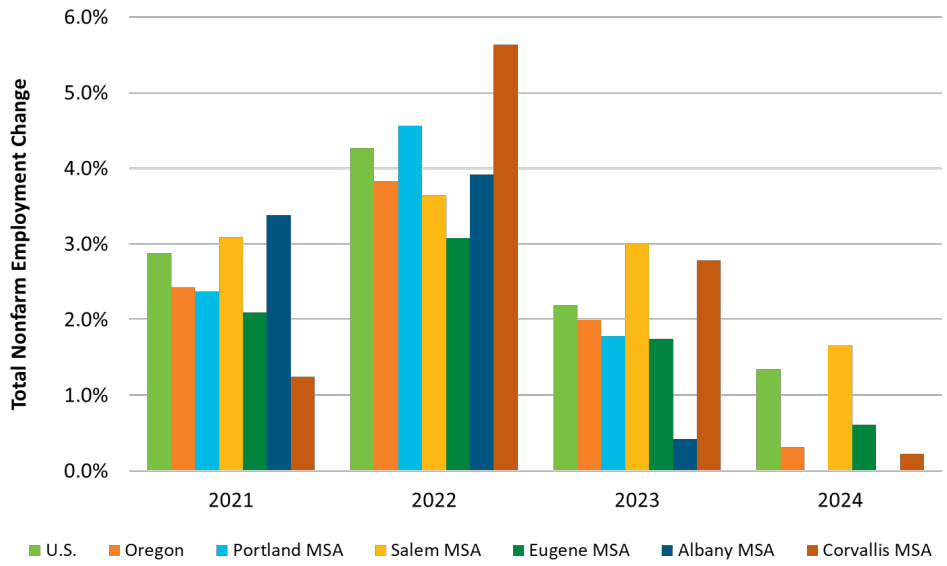
1.5.1 Economic Outlook

Macroeconomic trends are important drivers of customer growth and gas use of NW Natural customers. Inflation, policy uncertainty, and slower growth are key challenges facing the economy in 2025. Employment in NW Natural's service territory has eclipsed pre-pandemic levels and unemployment rates remain low, but growth is slowing, and unemployment is rising. Inflation remains elevated and there is growing concern stagflation, or a recession, could occur in the short-run. Policy uncertainty around tariffs and resulting impacts to the Company and customers present another potential headwind in 2025 and beyond. Changes in economic and demographic trends in the service territory since the COVID-19 pandemic have come into clearer focus with expectations for lower population, employment, and residential building growth over the long-run in Oregon, and to a lesser degree, in Southwest Washington. Oregon population is forecasted to grow 0.6 percent annually over the next ten years compared to 1

[4] OPUC docket AR 669 Updates to IRP Requirements and Competitive Bidding Rules

percent over the last decade. Population growth in Clark County is projected to modestly slow from 1.7 percent annual growth over the previous decade to 1.3 percent over the next ten years. Employment in Oregon is also forecasted to be lower at 0.6 percent annually—one-third of last decade's growth rate. Oregon's cost of living has increased more than any other state since 2008, driven in large part by higher housing costs.[5] Slower residential building growth has contributed to less affordable housing, with supply lagging demand. Oregon building permits in 2024 were down to their lowest level since 2013, when Oregon had 350,000 less people than it does now, and the forecast is for housing starts to grow slowly over the next ten years. Clark County, which saw much stronger building permit growth than Oregon over the last decade, has also seen permits slow dramatically over the past three years. Overall, the economic outlook is for less growth in the short- and long-run, which will impact NW Natural customer growth and residential, commercial, and industrial gas usage moving forward.

Figure 1.3: Employment Slowing Across System Area



Source: U.S. Bureau of Labor Statistics.

Chapter 2 discusses the economic outlook in more detail.

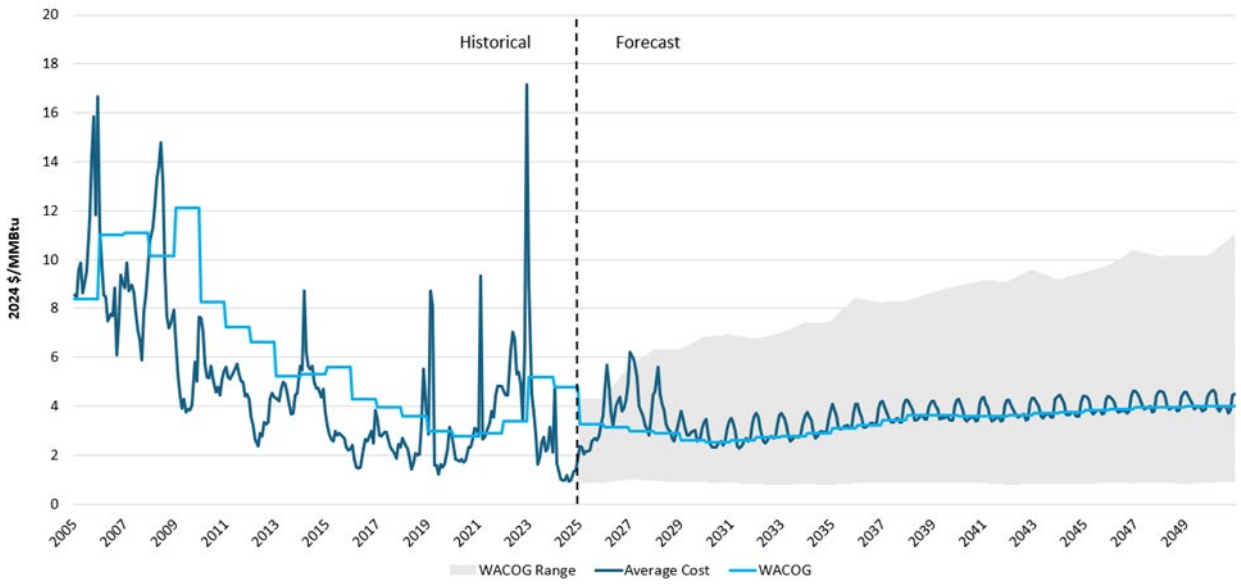
1.5.2 Energy Markets

There are several factors that are important in conventional natural gas markets, where NW Natural purchases gas on behalf of customers. On the supply side, U.S. natural gas production remains strong, with dry gas output projected to average around 106 Bcf/d in both 2025 and 2026, up from roughly 103 Bcf/d in 2024, or a 3 Bcf/d year-over-year increase. Primary demand

[5] U.S. Bureau of Economic Analysis, Regional Price Parities by State, 2008-2023.

drivers include sustained LNG export growth along with increased domestic consumption, which combine to average a 4 Bcf/d increase year-over-year. This strong demand growth, relative to supply, has slowed the national storage refill this summer and put upward pressure on futures prices. More regionally, weather and infrastructure constraints have the largest impact on natural gas pricing for customers. NW Natural is also monitoring the potential impact of tariffs on gas costs, but NW Natural is currently exempt from Canadian tariffs under the United States-Mexico-Canada Agreement (USMCA).

Figure 1.4: Average Natural Gas Spot Price Cost vs. WACOG



1.5.3 Environmental Policy

NW Natural is subject to environmental policy regulations at the federal and state levels.

1.5.3.1 Climate Policy Updates Since the 2022 IRP – Federal

With the change in leadership in the executive branch and within the Environmental Protection Agency (EPA) there is uncertainty in the policy landscape. While there have already been many policy changes in 2025 at the federal level, NW Natural remains subject to the greenhouse gas (GHG) reporting program.

1.5.3.2 Climate Policy Updates Since the 2022 IRP – State

At the state levels, NW Natural is subject to GHG reporting and carbon compliance programs through the Oregon Department of Environmental Quality (DEQ) and the Washington Department of Ecology (Ecology). Figure 1.5 shows NW Natural customer emissions relative to the Oregon state GHG inventory.

Figure 1.5: Oregon Greenhouse Gas Emissions

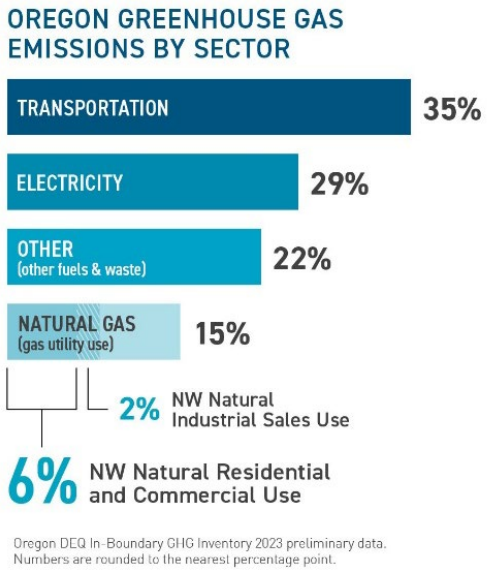
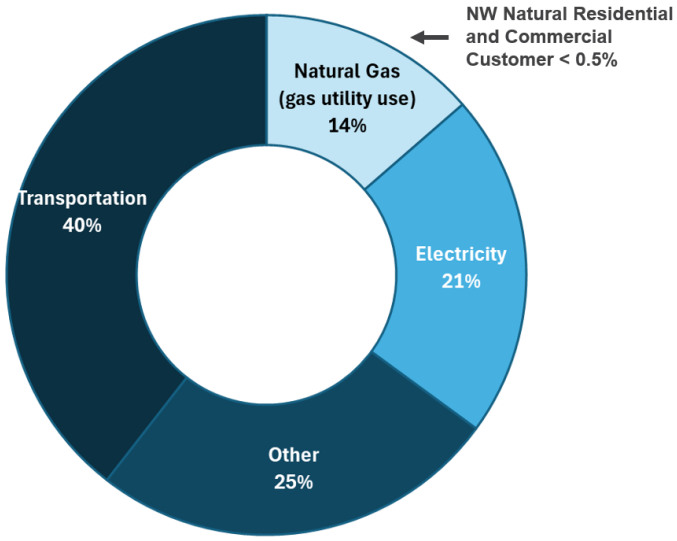


Figure 1.6 shows NW Natural customer emissions relative to the Washington State GHG emissions inventory.

Figure 1.6: Washington Greenhouse Gas Emissions

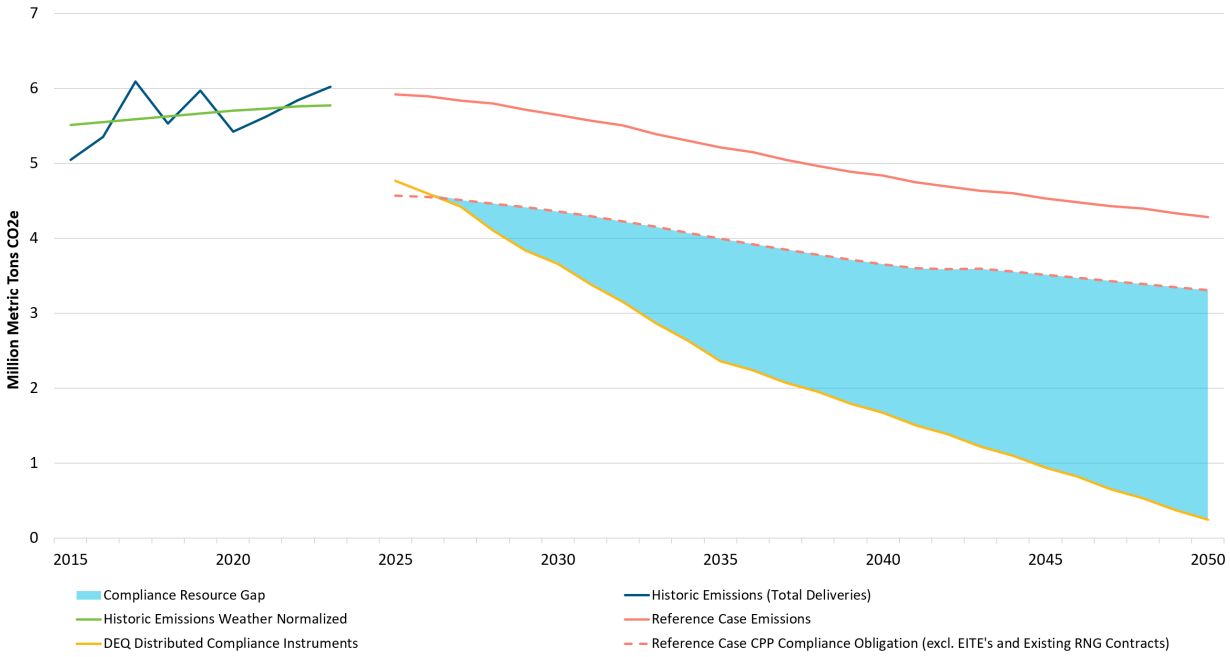


Source: Washington State Greenhouse Gas Emissions Inventory 2019 data

Since January 1, 2025, NW Natural's Oregon operations have been subject to the new Climate Protection Program (CPP). Under this cap and reduce carbon program, NW Natural carries the

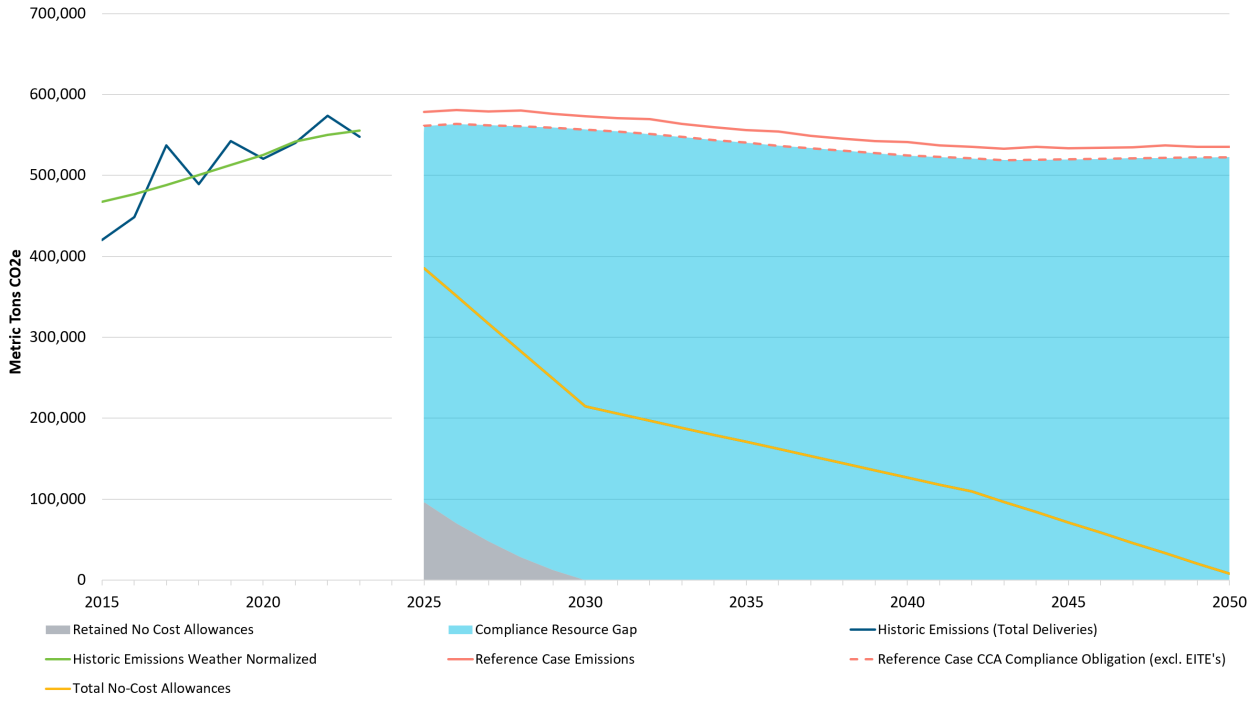
compliance obligation for most its customers' emissions. Figure 1.7 shows the modeled compliance obligation for NW Natural under the CPP.

Figure 1.7: CPP Compliance Obligation



In Washington, NW Natural is subject to the state's cap and trade program, the Climate Commitment Act (CCA). Like Oregon's CPP, NW Natural carries the compliance obligation for most its customers' carbon emissions. Figure 1.8 shows NW Natural's modeled compliance obligation under CCA.

Figure 1.8: CCA Compliance Obligation



Chapter 4 discusses compliance emissions reductions in more detail.

1.5.3.3 Renewable Natural Gas Enabling Policy – State

In addition to carbon policy, both Oregon and Washington have an enabling policy to spur the development and deployment of RNG to utility customers. In Oregon, SB 98 sets targets and price caps for RNG distribution to local distribution company retail customers. In Washington, HB 1257 also allows local distribution companies to procure RNG for utility customers.

1.5.4 Building Codes

While updates to building codes are traditionally focused on improvements in safety and energy efficiency, codes in recent history have attempted to include emissions accounting to reduce GHG emissions. Building codes that utilize emissions accounting or site-based energy use metrics tend to ignore the emissions associated with electricity generation and ignore any benefits from the utilization of low carbon fuels on the gas grid. As a result, these codes can drive builders' choices for end-use equipment in new construction and renovations away from natural gas fuel in favor of electric appliances, causing additional uncertainty for planning purposes. This is particularly true in Washington, where state building codes required new residential homes and commercial buildings to meet carbon emission standards (WSEC-2018) and now require site-based energy use metrics (WSEC-2021). Most recently, Washington Ballot

Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court).

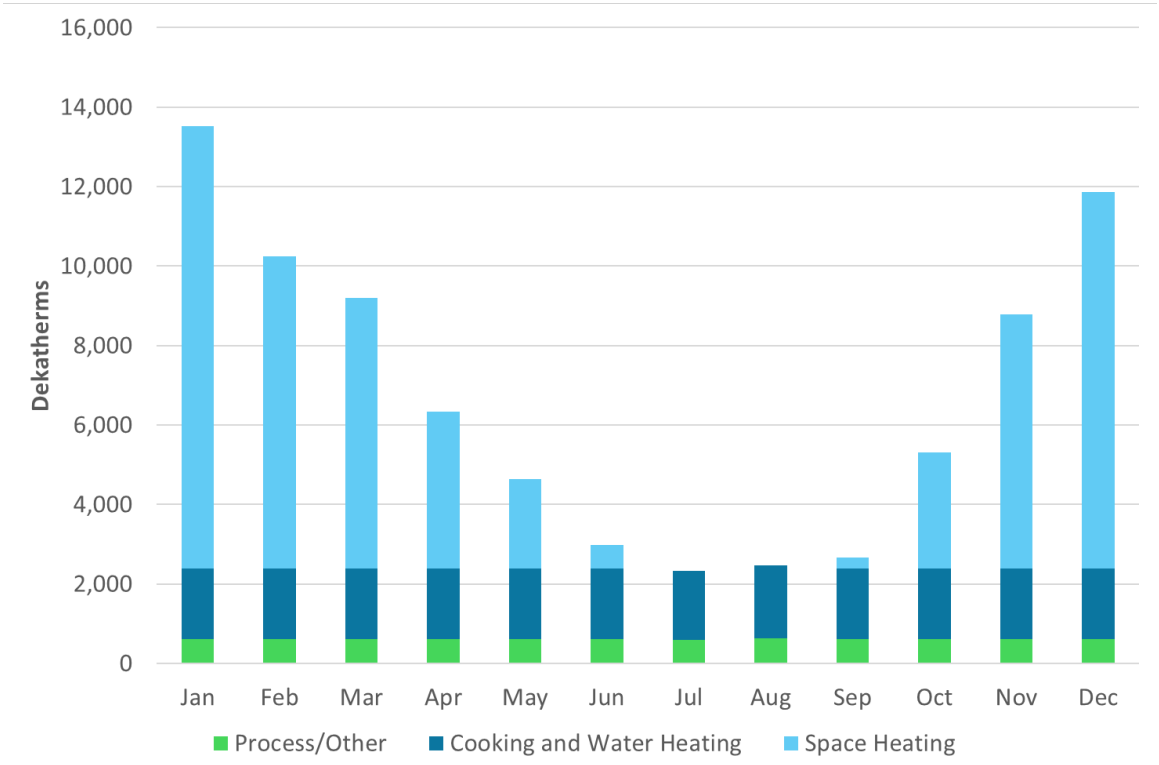
1.6 Determining Resource Requirements – Capacity, Energy, and Emissions Compliance

The resource requirements that NW Natural plans for in order to reliably serve customers and comply with state emissions policies are ultimately dependent on the annual energy demands in the Company's service territory.

1.6.1 Annual Demand

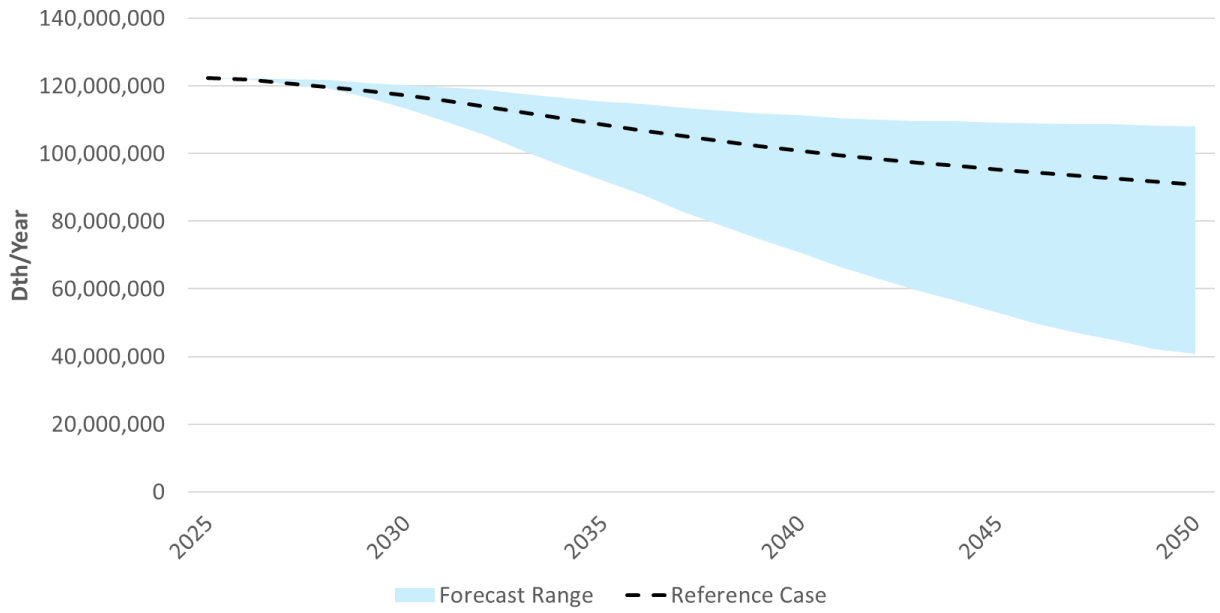
As shown in Figure 1.9, customer demand (also referred to as load) spikes during cold winter months due to space heating requirements. In particular, NW Natural's residential and commercial customer demand is very seasonal with "needle" peaks occurring during extreme cold weather events, where space heating demand is significantly higher than average daily winter requirements. The Company plans its capacity resources to meet firm demand requirements under peak weather conditions (also referred to as design peak).

Figure 1.9: 2024 Actual Monthly Sales Load by End Use



On an annual basis, after adjusting for energy efficiency savings and climate projections over the planning horizon, annual load is expected to decline over time (see Figure 1.10). Annual load forecasts are meaningful for both energy and compliance resource planning.[6] The Company's resources to bring natural gas onto NW Natural's system are primarily a mixture of storage facilities and interstate pipeline capacity, and since NW Naturals's service territory in Oregon and Washington is contiguous, the same capacity and energy resources serve customers in both states. Therefore, the Company plans these resources to meet the total system requirements rather than planning for each state individually.

Figure 1.10: Forecast Range of Total System Deliveries



There is substantial uncertainty in forecasting customer demand. In the near-term, variation in weather (particularly winter temperatures) is the primary driver of demand uncertainty, whereas in the later years of the planning horizon demand uncertainty will be driven by longer-term trends around state and federal policy, technological innovation, customer preferences, and end-use appliance adoption rates. Figure 1.10 shows the range of total annual deliveries (i.e., total demand) evaluated for resource planning in this IRP.

Chapter 4 details the forecasting methodology for the various customer types.

[6] Planning resources to meet energy requirements refers to having the right mix of resource types to ensure reliability throughout the year.

1.6.2 Demand Segments

There are four high-level types of service that NW Natural provides to customers that ultimately drive the three types of resource requirements discussed above. These four types of service are a combination of the following:

1. Sales vs. Transportation Service

   Sales: Service provided whereby NW Natural acquires gas supply and delivers it to customers. NW Natural purchases gas and holds all the upstream capacity requirements to meet demand from these customers. Note that all residential rate schedules are categorized as sales service.

   Transportation: Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility (i.e., NW Natural) only for transportation of the gas over its distribution system to the customer's facility. These customers, which are often large industrial customers, are responsible for all upstream capacity requirements to ensure delivery to NW Natural's system.

2. Firm vs. Interruptible Service

   Firm: Service offered to customers under schedules or contracts, which anticipate no interruptions.[7]

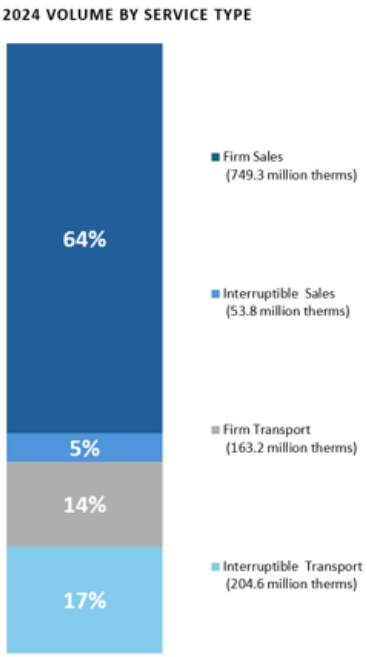
   Interruptible: Service offered to customers like firm service in operation, but a low priority for scheduling, subject to interruption if capacity is required for firm service. Interruptible customers trade the risk of occasional and temporary interruptions in return for a lower service rate.

Figure 1.11 summarizes these types of services and the planning requirements that are required for customers for each type of service.

[7] The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

Figure 1.11: Customer Category and Resource Requirements[8]

Customer Category	System Capacity Resource Planning: Design Winter Weather Energy Requirements	System Capacity Resource Planning: Peak Day Capacity Requirements	System Capacity Resource Planning: Compliance Requirements	Distribution System Planning: Peak Hour Capacity Requirements
Firm Sales	✓	✓	✓	✓
Interruptible Sales	✓		✓	
Firm Transport			✓	✓
Interruptible Transport			✓	



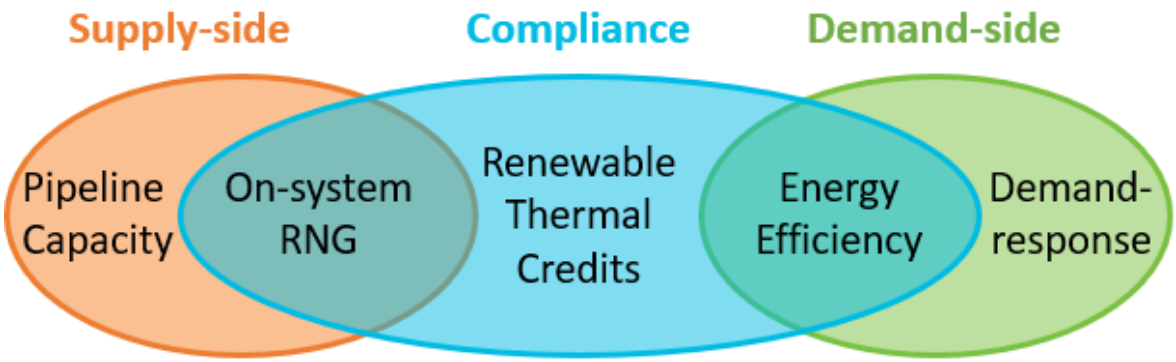
As discussed above, NW Natural must adhere to GHG emissions compliance laws in both Oregon and Washington. Annual demand forecasts are directly tied to NW Natural's emissions forecast and therefore will drive compliance resources planning. However, unlike capacity and energy resources, both states currently have different GHG compliance laws. Thus, NW Natural plans compliance resources separately for Oregon and Washington (see Section 1.5.3).

1.7 Resource Options to Meet Requirements

After identifying the Company's resource requirements, the IRP process considers the resource options available to meet capacity, energy, and compliance requirements. For options to be considered, NW Natural must have reasonable cost and availability estimates. Resource options are categorized as follows: demand-side, supply-side, or compliance. Compliance resources can be classified as a demand-side, supply-side, or neither; however, a resource option cannot be both a demand-side and supply-side option. Figure 1.12 illustrates a Venn diagram of these categories and an example of a resource that falls into each potential classification.

[8] Both CCA and CPP carve out EITE customers from NW Natural's compliance obligation. These EITE customers manage their own emissions and compliance under both programs.

Figure 1.12: Resource Option Categories



1.7.1 Least-Cost Resource Selection

Within the three resource categorizations there are diverse types of resources with varying costs and benefits. Furthermore, each resource option has differing operational, implementation, or timing constraints. The IRP process must consider these various types of risks—some which are quantifiable and some which are qualitative–when selecting resources. Although the term "least-cost, least-risk planning" is often used to describe the IRP, this language can be misleading, as costs and risks are often direct tradeoffs with each other.[9] In other words, risks can be mitigated by increasing costs. The IRP seeks a balance between risks and costs to develop the near-term action items and long-term resource strategies found in the Action Plan.

To achieve this goal, the IRP utilizes a software program, PLEXOS®, to select, operate, and dispatch resources in a manner that minimizes costs over the planning horizon, while still meeting all three resource requirements (capacity, energy, and compliance). Although PLEXOS® is a powerful resource, the software is used in combination with other tools (e.g., avoided cost analysis) and methodologies (e.g., scenario analysis and Monte Carlo simulations) for resource selection.

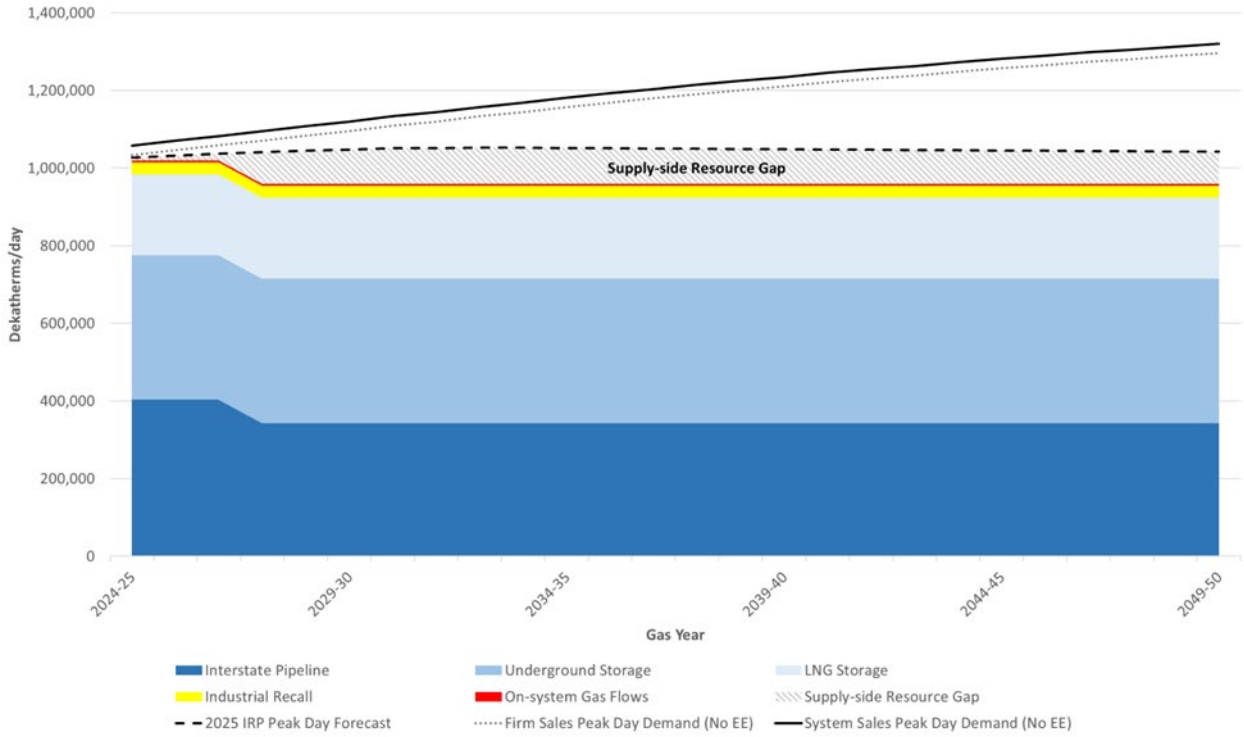
1.7.2 Energy and Capacity Options

After accounting for peak energy efficiency savings and demand response (which includes interrupting service to interruptible customers), the firm sales design peak day forecast determines the capacity requirements for the system. The capacity requirement and current

[9] 480-90-238 (2) uses a "Lowest Reasonable Cost" standard and defines this to include taking various risks into consideration.

resource capacity is shown in Figure 1.13. In the short- to medium-term, peak load is expected to grow modestly but flattens over the full planning horizon.

Figure 1.13: Resource Stack vs. Firm Sales Peak Day Forecast



Mist Recall is the least-cost supply-side resource to meet the capacity requirement shown in Figure 1.13. Additionally, it also provides customers with more underground storage capacity, providing additional energy benefits for customers.

The long-term firm sales peak-day forecast has decreased relative to previous IRPs. Even in the high-customer growth scenario evaluated in this IRP, there is enough Mist Recall avaliable to meet design day capacity requirements. Therefore, more expensive alternatives that were evaluated in previous IRPs, such as Mist expansion(s) or additional NW Pipeline capacity, are not evaluted in the 2025 IRP.[10]

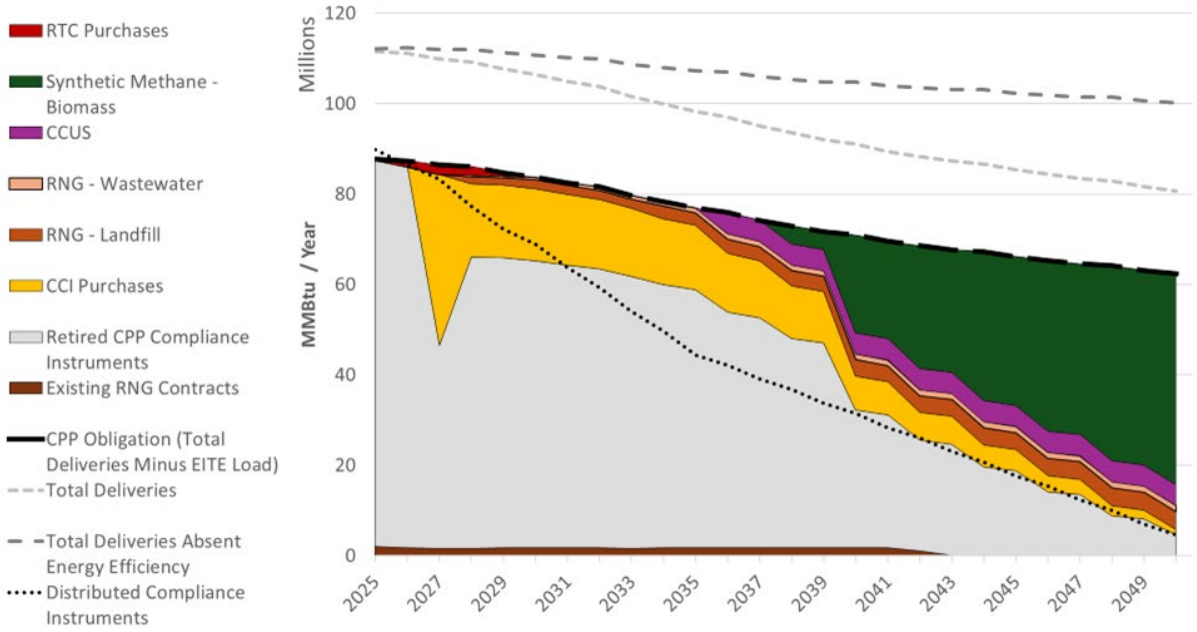
1.7.3 Emissions Policy Compliance Options

Cost-effective energy efficiency remains a least-cost emissions compliance resource in both Oregon and Washington. In addition to energy efficiency, Figure 1.14 illustrates the preferred

[10] Increasing Newport takeaway capacity is selected in some scenarios as the resource optimization model releases small pieces of upstream pipeline capacity in favor of the Newport Takeaway 1 project. If selected, the timing of this project, in all scenarios, is beyond the 5-years of the near-term action plan window.

resource portfolio for Oregon that complies with the CPP and acquires a limited amount of RNG under SB 98.

Figure 1.14: Preferred Resource Strategy – Oregon Compliance Resource Portfolio[11]

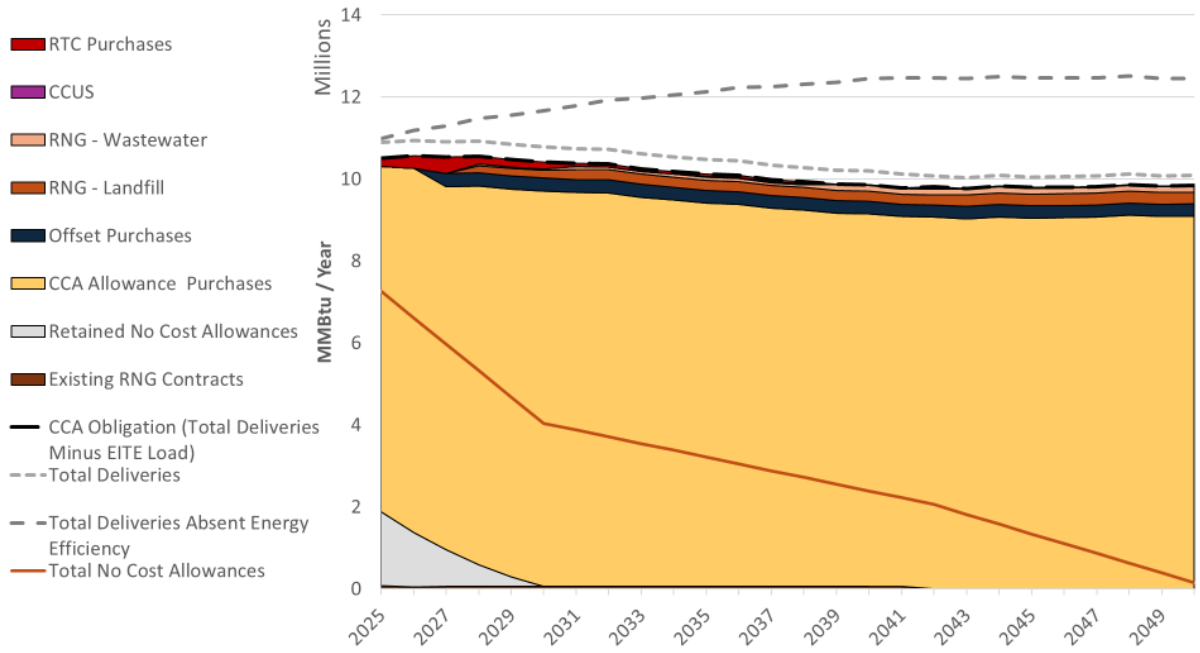


NW Natural will primarily use CCI purchases and DEQ compliance instruments for near-term CPP compliance. NW Natural will also purchase small amounts of voluntary RNG, from various sources, to continue to pursue decarbonizing the energy delivered to Oregon customers. Pursuing voluntary RNG helps mitigate risks from the dynamic environmental policy, at the federal, state, and local levels. In the longer-term, the Company will need to rely on additional RNG, CCUS, and synthetic methane from biomass for CPP compliance.

Figure 1.15 illustrates the preferred resource portfolio for Washington that complies with the CCA and acquires a limited amount of RNG under HB 1257.

[11] Results are from scenario PRS.a.

Figure 1.15: Preferred Resource Strategy – Washington Compliance Resource Portfolio[12]



NW Natural will primarily rely on CCA allowance purchases for compliance in the near- and long-term, with restricted reliance on offsets due to regulatory limits and limited availability. Like Oregon's results, NW Natural will also rely on small amounts of voluntary RNG purchases from various sources to continue to pursue decarbonizing the energy delivered to Washington customers.

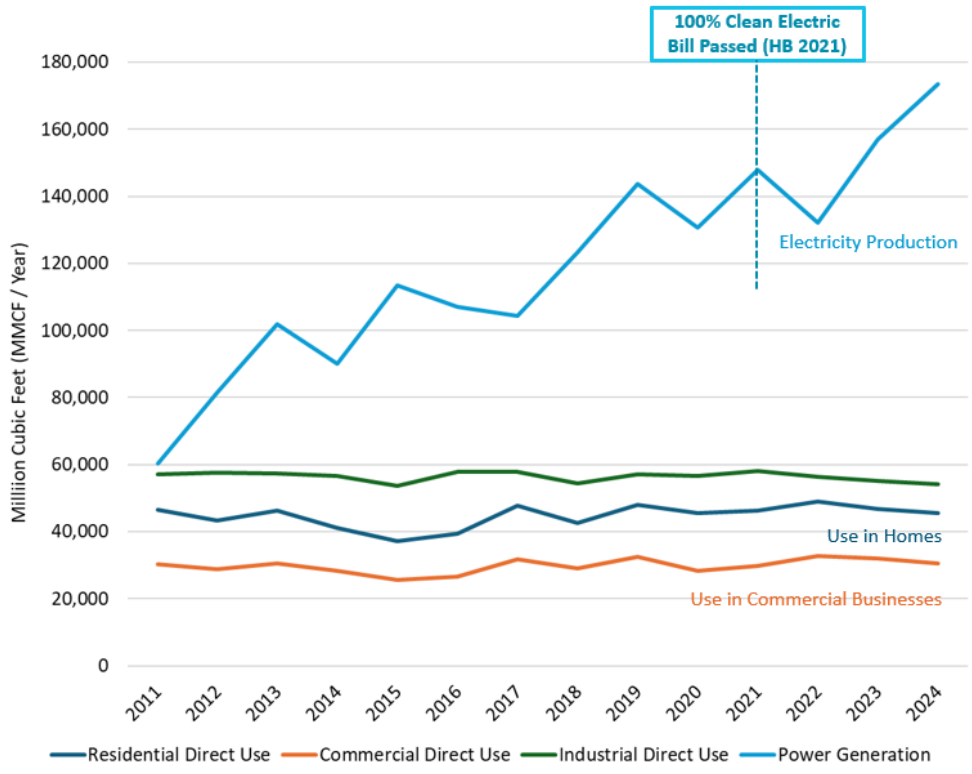
1.8 Electrification Study

In the previous 2022 IRP, NW Natural evaluated four separate electrification scenarios and implications for NW Natural's resource planning. As NW Natural is a standalone LDC (i.e., not a combination gas and electric utility), the 2022 IRP assessed the costs and risks only from NW Natural's perspective and did not attempt to quantify the impacts and cost of electrification for electric utilities. As a result, OPUC expressed "concern[s] that a categorical refusal to look at electrification as a resource for CPP compliance may fail to protect and potentially harm customers, given that it appears to be a valid method for achieving CPP compliance. We expect the next cycle of IRPs to advance significantly in this area…".[13]

[12] Results are from scenario PRS.a
[13] In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan, Docket No. LC 79, Order No. 23-281, at 11 (Aug. 2, 2023).

Electrification of NW Natural's customers creates a burden on electric utilities to meet additional capacity, energy, and compliance requirements. Unlike energy efficiency and conservation, replacing natural gas with electricity (known as fuel switching), does not guarantee a reduction in GHG emissions and has the potential to increase state emissions if electric utilities are unable to meet clean electricity targets. In this circumstance, building electrification would decrease NW Natural's CPP and CCA obligation; however, it would increase state emissions, which is counter to the goals of the CPP and CCA. Some electric utilities have made progress towards reducing carbon emissions by shifting away from more carbon intensive sources, such as coal generation; however, electric generation from natural gas in both Oregon and Washington has steadily been increasing over the last 14 years (see Figure 1.16).[14]

Figure 1.16: Oregon Natural Gas Consumption, 2011 - 2024



Source: U.S. Energy Information Administration, May 2025

[14] Data for Oregon (Natural Gas Consumption by End Use) can be found at EIA.gov: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SOR_a.htm.
Data for Washington (Natural Gas Consumption by End Use) can be found for at EIA.gov: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SWA_a.htm.

While the impact of building electrification on future in-state GHG emissions is uncertain, what is certain is that fuel switching energy service from the gas system to the electric system will increase costs for electric utilities. In addition to the incremental in- home equipment costs and other home system improvements, full building electrification of NW Natural customers will increase generation, transmission, and distribution costs for electric utilities. To consider electrification as a potential mechanism for decreasing NW Natural's compliance obligation, there should be credible evidence that electric utilities could cost-effectively serve this increase in electric demand compared to the natural gas system, in particular winter peak demand for space heating, without increasing overall emissions. In the near term, this is unlikely given the current trajectories of power generation from natural gas. In the longer term, the significant increases in peak winter electricity would have to be met with commercially available, cost-effective, carbon-free dispatchable generation technology, which would need to evolve significantly from its current state.

NW Natural has not seen building electrification being evaluated in electric IRPs at the significant levels that are being discussed by policy makers. Therefore, the implications for electric costs, reliability and emissions reductions are not fully understood. OPUC contracted with Synapse to develop high-level estimated costs of electrification as a part of the 2022 IRP process.[15] NW Natural did not have a chance to review this study prior to its filing and as such filed comments with the Company's concerns; primarily Synapse's finding that electrifying NW Natural load would have no impact to winter peak electric demand and the assumption that all incremental electrified load would be emissions free.[16] Given these concerns, and to advance the conversation on electrification, NW Natural contracted with ICF to conduct a robust electrification study.[17]

NW Natural's resource optimization software (PLEXOS®) does have the capability to incorporate demand-side options as selectable decisions; however, there are still many hurdles that NW Natural is grappling with before this can be done for electrification, which includes developing a reasonable cost and technical potential to incorporate into the model. The electrification study is an attempt to develop these estimates and integration into our modeling tool (PLEXOS®) can be considered for a future IRP.

An alternative approach might utilize an avoided cost framework, like cost-effectiveness evaluations for energy efficiency, to evaluate electrification based on the all-in cost. Unlike energy efficiency, which has detailed cost information from the Energy Trust of Oregon (ETO),

[15] Synapse Energy Economics, Inc. is a consulting firm headquartered in Cambridge, Massachusetts.
[16] See NW Natural's Reply Comments, filed on February 3, 2023, in OPUC docket LC 79.
[17] ICF International, Inc. is consulting firm headquartered in Reston, Virginia.

electrification of NW Natural customers as a compliance option—absent this electrification study—does not have reliable cost estimates, which are needed for either a PLEXOS® or avoided cost approach. The ICF electrification study is an attempt to measure and understand such costs.

The study is indicative of the costs of electrifying customers; however, it should be recognized that electrifying the first 10,000 customers will be a much different cost than electrifying the last 10,000 customers. With unlimited time and budget, ICF could model multiple future electrification scenarios to better analyze the non-linear cost impacts. Modeling all potential levels of electrification was not possible for this IRP; however, the four demand variation scenarios do provide insights into varying levels and types of electrification.

Correspondingly, quantifying certain gas system savings, should electrification occur, was analyzed. The Company identified the cost savings from gas commodity, pipeline capacity, and compliance costs associated with alternative fuels. However, more analysis needs to be done to understand what additional savings may accrue relative to NW Natural specific gas infrastructure for varying levels of natural gas customers. In a scenario where 90 percent of the residential customer base is electrified, further investigation is necessary to identify what infrastructure and company operations would still be required to serve the remaining ten percent of customers.

To this point, when starting to consider utility cost savings from having less customers, there are important considerations that cannot be ignored:

- NW Natural has an obligation to safely and reliably serve all customers who remain on the system.
- Other types of expenses would be highly dependent on *how* building electrification happens across the system (e.g., electrifying whole communities or a diverse random spread). Even if a small number of customers remain on the system in an area, system integrity projects would be the same as if no customers left the system, as these projects ensure safety and reliability.
- How labor expenses would be impacted by a smaller customers base is highly uncertain. NW Natural currently employs over 1,200 employees and works with even more contractors. Jobs in some operations of the company may decrease, whereas, other operations would be independent of the number of customers. Without an in-depth analysis, an assumption about the cost savings from reducing NW Natural labor force would be highly speculative.
- Cost increases will occur in some operations for the company (e.g., pipeline retirement costs) that would offset some of cost savings being discussed.

Costs associated with distribution system investments and maintenance are often referenced by stakeholders as potential cost savings that should be considered if customers are no longer being added to the gas system and the customer base began to decline. To provide some context, costs associated with adding new customers accounts for 7 percent of the current revenue requirement. Distribution system O&M costs (6 percent in Oregon and 7 percent in Washington of current revenue requirement) may vary with customer counts, but as discussed above the extent that these costs may fluctuate with a decrease in customer base is highly uncertain and requires additional analysis. These relatively small percentages are consistent with a recently updated decarbonization study completed by Puget Sound Energy.[18]

Furthermore, if there were significant building electrification, the utility may request an accelerated depreciation of assets to minimize the inequitable impacts of the Company's rate base being recovered over a smaller number of customers who remain on the system. This accelerated depreciation increases the cost to customers over the planning horizon, which also could offset some, or all, of the cost savings from forgone distribution reinforcement investments.

Absent a robust study to specifically answer these questions, the Company does not forecast the cost savings from reduced distribution system expenditures due to electrification in this IRP. While there is more work to do, the Company believes this electrification study has been a good faith effort to advance the electrification discussion, especially as it relates to the benefits from hybrid heating systems.

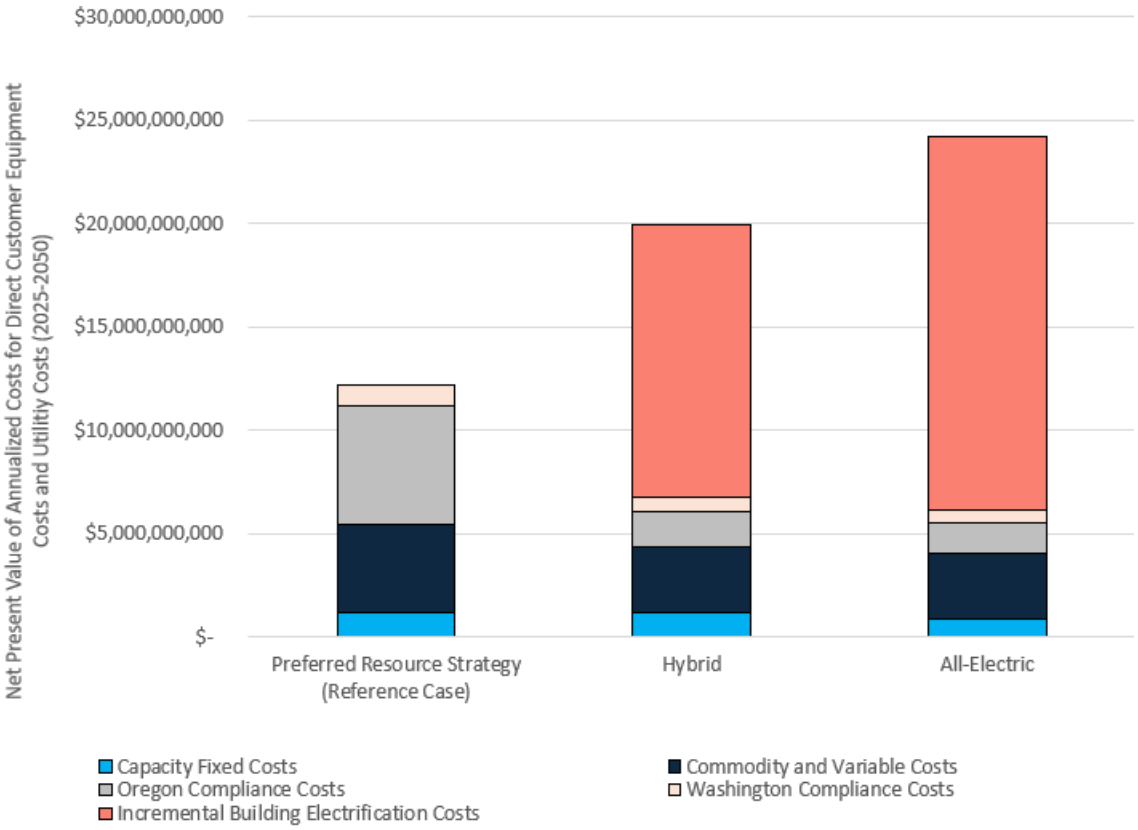
Figure 1.17 shows the net present value cost comparison for NW Natural Preferred Resource Strategy (PRS), also referred to as the Reference Case, the Hybrid scenario, and the All-Electric scenario.

When considering capacity fixed costs, commodity and variable costs, NW Natural compliance resource costs, and incremental building electrification costs, the PRS is about $12.2 billion dollars; the Hybrid scenario is about $19.9 billion, and the All-Electric scenario is about $24.2 billion in net present value of all annualized costs which includes NW Natural system cost and compliance costs, incremental electrification costs for electric utilities and direct customer costs for equipment conversion and other household improvements to support the conversion. While this graph does not include all potential costs (e.g., incremental wildfire mitigation costs) or all potential cost savings (e.g., reduced gas system distribution system costs), it does highlight the significant electrification costs that are considered through the electrification

[18] Puget Sound Energy. "Updated 2023 Decarbonization Study Summary Report," January 2025. https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0131_UpdatedDecarbStudyReport.pdf. Please see Figure 1, page 3.

study, even in the Hybrid scenario. It is important to remember that the Hybrid scenario is intentionally designed as a counter-factual to the All-Electric scenario to highlight the benefits of hybrid HVAC systems.[19] That said though, the figure shows that even in the Reference Case compliance cost will account for about 50 percent of overall revenue requirement modeled in the IRP, that costs is modest relative to the incremental costs of the other two electrification scenarios. In all three scenarios the ***same*** level of GHG compliance (i.e., compliance with CETA, CCA, HB 2021, and CPP) is achieved. NW Natural's PRS (Reference Case) does this at the lowest total cost.

Figure 1.17: Net Present Value of Annualized Costs for Direct Customer Equipment Costs and Utility Costs by Scenario[20]



[19] The Hybrid scenario has the same adoption level of Hybrid HVAC systems as the adoption level of all electric heat pump in the All-Electric scenario.

[20] Figure 1.17 shows the costs by scenario, including NW Natural compliance, fixed capacity, commodity and variable costs. In addition to these gas utility costs, Figure 1.17 also includes incremental costs for the electrification scenarios, which account for customer equipment conversions costs, as well as projected incremental electric system costs for generation, transmission and distribution. The costs shown are the Net Present Value of annualized system costs over the period from 2025 - 2050.

1.9 Principal Conclusions from this IRP

The scope of NW Natural's 2025 IRP has surpassed any previous IRP. NW Natural has significantly expanded the number of compliance resources being explored, conducted an electrification study to highlight the full costs of building electrification, taken steps to incorporate equity consideration into the IRP process, and expanded its public outreach. From this robust analysis, NW Natural provides ten principal conclusions for policy considerations.

1. Cost-effective energy efficiency remains a low-regret resource option for NW Natural to meet capacity, energy, and compliance requirements.
2. Growth for NW Natural's system capacity requirements continues to increase in the near-term but has slowed compared to previous IRPs. However, the capacity requirements of the full natural gas system in the region remains highly constrained during peak demand periods as electric generation from natural gas in both Oregon and Washington continues to increase.
3. Decarbonization of energy services in Oregon and Washington is a priority for the region; however, achieving these decarbonization goals will come at a high cost to both natural gas and electric customers.
4. Beyond cost-effective energy efficiency, NW Natural can reduce GHG emissions of the energy services provided to customers through alternative fuels and carbon capture and sequestration. Since both gas and electric systems benefit from alternative fuels, research/pilots which promote their development should be pursued.
5. While the Reference Case appears to be the lowest cost scenario, hybrid heating is a promising approach to reducing emissions while retaining optionality and flexibility of two major energy systems. As such, pilots and programs that further the understanding of how this can scale to be a cost-effective solution for both energy systems should be pursued.
6. Joint system planning will continue to increase in importance as constraints and interdependencies on both the gas and electric systems grow.
7. Policies that encourage optionality, flexibility, and joint system planning should be encouraged. Additionally, supportive policies that recognize the need to balance affordability, reliability, and emissions reductions should be pursued.
8. Cost-effective NPA programs should continue to be pursued and used to delay or avoid distribution system infrastructure.
9. The integration of equity considerations should continue to evolve in gas system resource planning.

10. NW Natural's central recommendation and strategy is to maintain maximum optionality and flexibility, as well as for its near-term Action Plan to improve certainty and validate (or invalidate) key assumptions and to then adjust accordingly.

Summary

Given the significant uncertainties surrounding future costs, timing, technologies, and policies, NW Natural is committed to pursuing a low- or no-regrets strategy centered on optionality and future flexibility. This approach aligns with NW Natural's goals of maintaining reliable, safe, affordable energy while advancing state carbon goals.

Key considerations include:

Cost Implications: All electrification scenarios, as well as the PRS developed from the Reference Case, are projected to result in **substantial customer rate increases**. The electrification scenarios (All-Electric and Hybrid) have much higher cost to customers than the PRS.

Comparative Risk: While Hybrid and **All-Electric** electrification pathways may meet carbon and reliability goals, they come at a **significantly higher cost** and **greater risk** to affordability and reliability—especially during extreme weather events without material emissions reductions over the Reference Case.

Industry Insight: Electric industry experts have cautioned that electrification assumptions may be **overly optimistic**, potentially underestimating risks and cost.[21]

Collaborative Planning: NW Natural supports **joint system planning with electric utilities** to explore **least-cost, carbon-free integrated strategies**.

Pilot Programs: The company is pursuing **hybrid heat pump pilot programs** in addition to other technology pilots to diversify carbon reduction strategies and assess costs against benefits.

1.10 - IRP Action Plan Summary

New to this IRP is an extended two-part action plan that provides both a long-term resource strategy along with a near-term Action Plan. Both long-term strategies and near-term actions contain specific items that take into account the quantitative results and qualitative considerations of the whole 2025 IRP. Chapter 13 fully outlines each of these items for OPUC and WUTC consideration to pursue safe, reliable, and affordable energy services for NW Natural customers, while meeting compliance obligations. This executive summary concludes with a bullet point summary of the full Chapter 13 Action Plan.

[21] Please refer to Appendix L for a statement from the Independent Advisory Group.

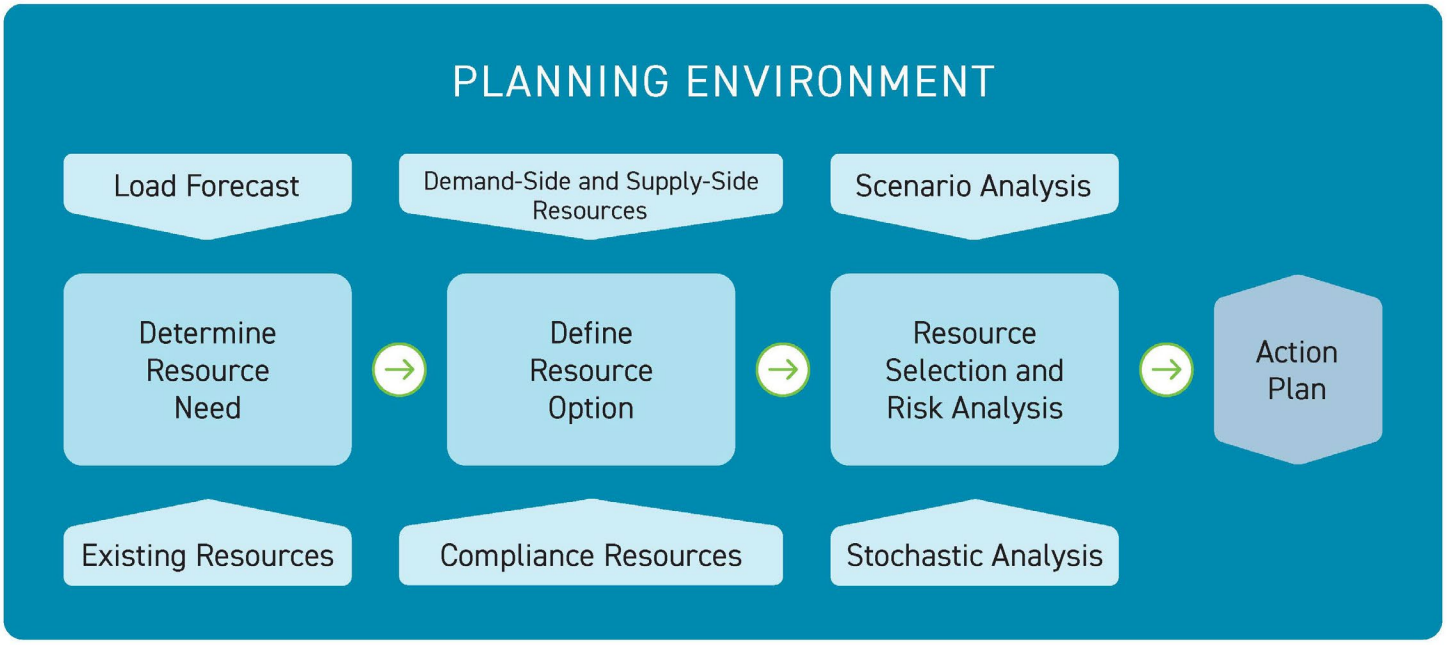
Long-term Resource Strategy Summary:

- **Energy Efficiency**: Leverage cost-effective energy efficiency to reduce peak, energy, and compliance resource requirements.
- **Demand Response and Resource Utilization**: Expand and explore cost-effective demand response programs to meet peak demand. Rely on Mist Recall as the incremental capacity resource, while evaluating other potential opportunities to meet peak day system requirements.
- **Emissions Planning and Compliance**: Continue to use IRP modeling to evaluate compliance resources to meet emissions obligations and voluntary RNG goals.
- **Hybrid Heating Systems**: Develop programs exploring hybrid heating systems to reduce natural gas emissions while maintaining reliability and affordability.
- **Joint System Planning**: Support gas and electric joint system planning to achieve decarbonization goals affordably and reliably.
- **Energy Burden Assessment**: Perform regular assessments to inform programs aimed at reducing energy burden for low-income customers.

Near-term Action Items Summary:

- **Capacity Resources**: Mist Recall, energy efficiency, and demand response.
- **Oregon Compliance Resources:** Energy efficiency, CCI purchase, voluntary RNG to meet goal of five percent of sales volumes, acquire RNG from a local on-system water resource recovery facility and retire associated RTCs.
- **Washington Compliance Resources**: Energy efficiency, allowance purchases, voluntary RNG to meet goal of five percent of sales volumes, offsets if available and cost-effective.
- **Enabling Pilots and Studies:** Commercial gas-fired heat pump, CCUS pilot, Hybrid-HVAC pilot, CCUS geological screening study, synthetic methane from biomass study.
- **Distribution System Planning:** Pursing non-pipeline solutions in all three areas identified in the forward-looking plan (Creswell, Dallas, and McMinnville) to delay pipeline reinforcement investments.
- **Equity:** Increase community awareness in energy planning and utility programs by working with community partners.

2 Planning Environment



NW Natural®

Environmental policy, economic conditions, and market forces are the backdrop that helps define key assumptions and objectives in an IRP. This chapter lays out this planning environment.

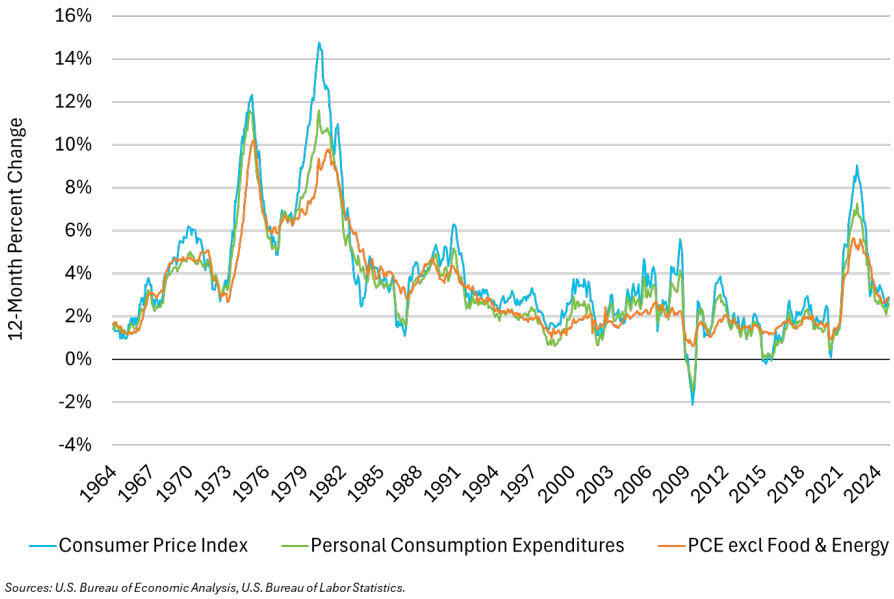
2.1 Economic and Demographic Trends

Economic and demographic trends heavily influence changes in demand within the service territory. Population, housing, and employment data and forecasts are key inputs into the 2025 IRP load forecast. Some of these trends and forecasts have changed significantly since the 2022 IRP, especially in Oregon.

2.1.1 U.S. Macroeconomic Outlook

Inflation, uncertainty, and slower growth pose challenges for the U.S. economy in 2025. After the highest inflation seen in the U.S. since 1981, inflation moderated considerably in 2023 and 2024 and was down to about 3 percent by the end of 2024 (see Figure 2.1). The Federal Reserve (the Fed) increased interest rates significantly over the past two years to reduce inflation, which was largely successful, and proceeded to cut rates in the fourth quarter of 2024 to add a little bit of fuel to a slowing economy as inflation continued to cool. But inflation has been sticky around 3 percent and remains above the Fed's target rate of 2 percent. U.S. real GDP growth was 2.8 percent in 2024, down from 2.9 percent in 2023. Growth slowed at the end of 2024 (2.4 percent in the fourth quarter) and the Fed is forecasting lower growth in 2025 (1.7 percent). With expectations that the U.S. economy further slows in 2025, the Fed finds itself in a difficult position where rate cuts could help the economy, but accelerate inflation, while rate increases could lower inflation but further slow the economy.

Figure 2.1: Inflation Down from 40-Year High



Sources: U.S. Bureau of Economic Analysis, U.S. Bureau of Labor Statistics.

The labor market remains strong with unemployment hovering around 4 percent at the end of 2024 and employment continues to grow, but unemployment is higher than it was a year ago, and employment growth has slowed as well. Consumer spending remains strong and, together with government spending, fueled GDP growth in 2024, but that is expected to change in 2025 as the boost to the economy provided by massive deficit spending in the wake of COVID-19 and expansionary monetary policy (which helped fuel high inflation), is coming to an end.[22,23,24,25] State and local governments will also be impacted by reduced federal spending as they received the bulk of pandemic related federal dollars and will need to pull back spending as well.[26] Private sector investment and employment slowed in 2024, with employment growth down to

[22] Satyam Panday et al., "Economic Outlook U.S. Q2 2025: Losing Steam Amid Shifting Policies," S&P Global, March 25, 2025, https://www.spglobal.com/ratings/en/regulatory/article/250325-economic-outlook-u-s-q2-2025-losing-steam-amid-shifting-policies-s13450076.

[23] U.S. Department of the Treasury. Fiscal Service, "Federal Surplus or Deficit", Federal Reserve Economic Data (FRED), Federal Reserve Bank of St. Louis, accessed July 15, 2025, https://fred.stlouisfed.org/series/MTSDS133FMS.

[24] Board of Governors of the Federal Reserve System, "M2", Federal Reserve Economic Data (FRED), Federal Reserve Bank of St. Louis, accessed July 15, 2025, https://fred.stlouisfed.org/series/WM2NS.

[25] "This analysis suggests a potentially sizable role that fiscal policy may have played in contributing to upward price pressures." Francois de Soyres, Ana Maria Santacreu, and Henry Young, "Demand-Supply Imbalance during the COVID-19 Pandemic: The Role of Fiscal Policy," Federal Reserve Bank of St. Louis *Review*, First Quarter 2023, *105*(1), pp. 21-50, ttps://doi.org/10.20955/r.105.21-50.

[26] Panday et al.

1.1 percent in 2024 from 2.1 percent in 2023. Manufacturing lost jobs in 2024 for the first time since 2020, dropping 0.4 percent.

As challenging as inflation and slower growth are to the U.S. economy, policy uncertainty at the federal level, including numerous policy changes, uncertain federal spending, and the imposition of higher tariffs on our trade partners, may bring new challenges to the national economy. Fears of a recession are present and rising in the first half of 2025, but most baseline forecasts call for continued growth, albeit at lower levels than the last two years.[27]

2.1.2 Regional Macroeconomic Outlook

Economic and demographic trends since the COVID-19 pandemic have changed in the region, especially in Oregon, which makes up nearly 90 percent of NW Natural's service territory. Oregon, pre-pandemic, was an above average state in terms of population and employment growth. Driven by in-migration of young, educated workers into the region and a diverse group of competitive and emerging industries, Oregon's economy flourished in the previous decade. After the pandemic, trends began to emerge that revealed Oregon had lost some of its competitive edge. Population declined as out-migration outpaced in-migration. Some of the reasons for this change include decreased affordability (higher house prices and taxes), higher remote work, and decreased livability related to increased crime, homelessness, drug use, and mental health and public safety issues.[28,29,30,31] These issues are pronounced in the Portland metro area, but not exclusive to it. Oregon population is forecasted to grow more slowly over the next ten years at 0.6 percent annually[32] compared to 1.0 percent over the last decade (see Figure 2.2).

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[27] Panday et al.

[28] "Despite the region's stunning natural amenities, people have been "voting with their feet" against the Portland area in the post-pandemic era. High housing costs are a primary factor, but the contrasting growth patterns between the Oregon and Washington sides of the border strongly suggest that taxes and public services are also playing an outsized role as well." *2025 State of the Economy*, ECONorthwest, https://portlandmetrochamber.com/resources/2025-state-of-the-economy/.

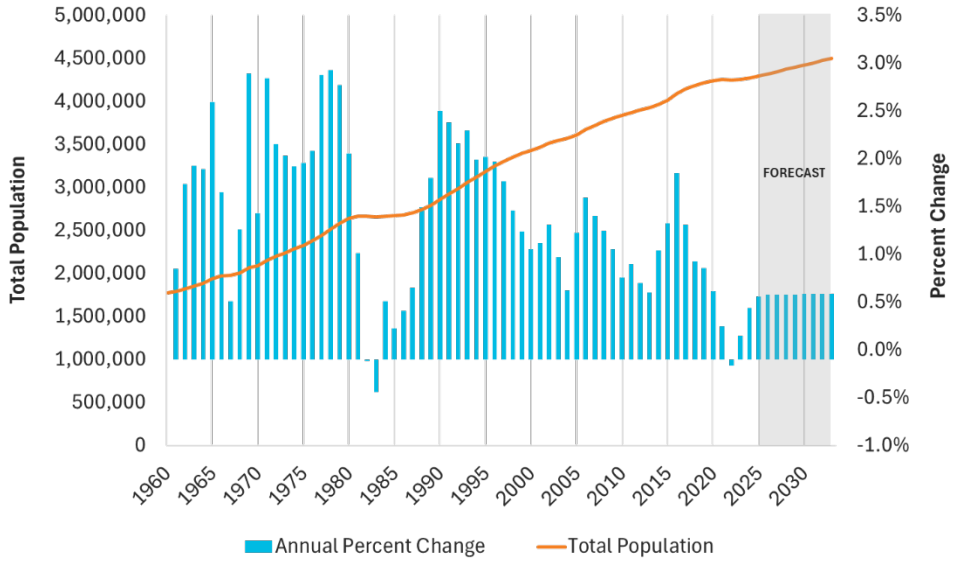
[29] "Homelessness and the affordability of housing are the top issues in the region." *Portland Metro Chamber Economy Survey*, DHM Research, https://portlandmetrochamber.com/resources/2025-voter-poll/.

[30] "While some view the state as a good place to do business, others cite high taxes, regulatory challenges, and social issues like homelessness and crime as significant drawbacks." *External Business Recruitment: Are businesses leaving Oregon, and if so, why?*, University of Oregon Institute for Policy Research & Engagement, iv (2025).

[31] "To summarize, high taxes, lots of overdoses, and crime, especially in downtown, mean lots of people who can leave, do leave." *The Story*, "Portland population and income loss, housing and crime woes centered in task force briefing," Pat Dorris, aired August 24, 2023, KGW-TV, https://www.youtube.com/watch?v=lHffWBkUF6k&t=4s.

[32] Oregon Office of Economic Analysis, "Oregon's Annual Population Forecast," March 2025 vintage, https://www.oregon.gov/das/oea/Pages/forecastdemographic.aspx.

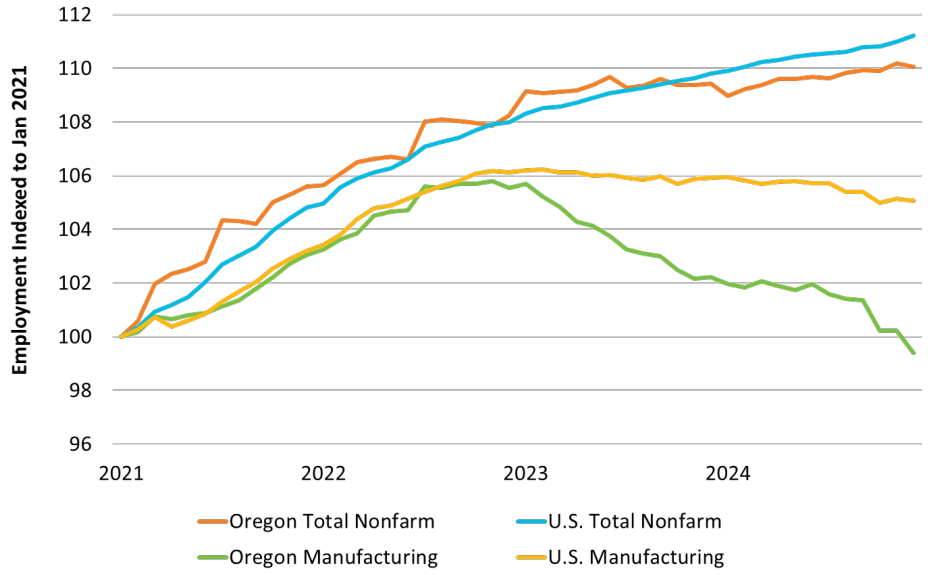
Figure 2.2: Oregon Population Growth Much Lower



Sources: U.S. Census Bureau, Oregon Office of Economic Analysis, Oregon Economic and Revenue Forecast December 2024.

Oregon employment annual growth between 2020 and 2024 was 2.1 percent, which was slower than the U.S. (2.7 percent), and ranked 35th amongst states. Historically, Oregon adds jobs faster than the U.S. coming out of recessions since the state has a higher percentage of manufacturing jobs than average, especially in durable goods. For example, between 2010 and 2014, Oregon added jobs at 1.8 percent annually, ranking 14th amongst states and faster than the U.S. (1.6 percent). Early in the post-pandemic recovery, Oregon employment again grew faster than the U.S., but things changed at the end of 2022, as manufacturing employment began to decline. Manufacturing, a stalwart of Oregon's economy and its competitive industries, is in a recession that has lasted over two years (Figure 2.3). Job losses have been concentrated in computers and electronics, fabricated metals, machinery, wood products, and food processing. Like population, employment growth is forecasted to be slower over the next ten years, growing at 0.6 percent annually compared to 1.9 percent over the last decade.

Figure 2.3: Oregon Manufacturing in Recession



Source: U.S. Bureau of Labor Statistics.

Affordability, particularly housing affordability, continues to be an issue in the region. While home prices remain high, home sales have slowed dramatically due to higher mortgage rates and homeowners that locked in historically low rates between 2020 and 2022. Residential construction appears to not be keeping up with demand either, as housing starts in Oregon have steadily dropped and were down to about 14,000 in 2024 – the lowest they've been since 2013 when Oregon had 350,000 less people than it does now. Barring a slowdown in demand, pressure on home prices will likely persist as the OEA forecasts Oregon housing starts to grow slowly over the next ten years, not reaching 20,000 again until 2031.

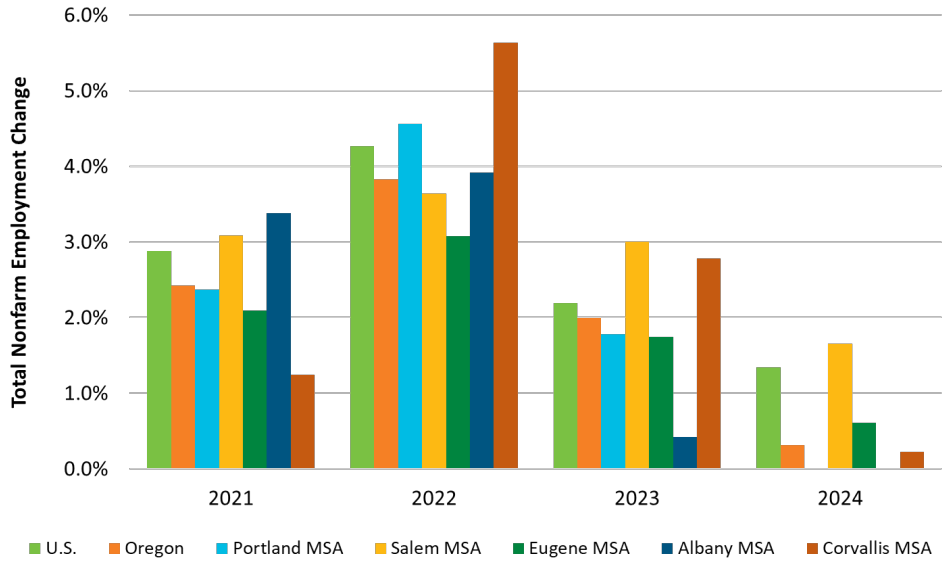
2.1.3 NW Natural System Area Macroeconomic Outlook

The macroeconomic outlook in NW Natural's system area varies, but overall, trends are lower than they were pre-pandemic. Multnomah County, the most populous county in the service territory saw population decline by an annual rate of -0.6 percent between 2020 and 2024 – a loss of over 20,000 residents. Elsewhere in the Portland metro area, Washington and Clackamas counties saw annual growth of 0.4 and 0.2 percent. In stark contrast to slow or declining population in the Oregon portion of the Portland metro area, Clark County in Washington had annual growth of 1.1 percent. While Clark County has historically enjoyed a growth advantage over the Portland metro counties in Oregon, the difference has widened post-pandemic due in part to better affordability, no state income taxes for remote workers, and the aforementioned

issues around homelessness, drug use, and mental health and public safety concerns in Portland. In other parts of the system area, population growth ranged from 1.4 percent in Benton County, 0.5 percent in Marion County, and -0.1 percent in Lane County. Slower population growth throughout the system area will, all things equal, lead to lower growth for utilities as well.

Employment trends in the system area have also slowed (see Figure 2.4). The Portland metro area added no jobs in 2024, compared to the U.S. rate of 1.3 percent, ranking 24th out of the top 25 metro areas. The Eugene, Albany, and Corvallis metro areas also lagged in growth. The Salem metro area has enjoyed above average growth throughout the post-pandemic recovery due in part to federal deficit spending that flowed through state governments. Federal spending is expected to decrease dramatically now that COVID-19 related funding is expiring and the new administration in Washington, D.C. looks to downsize government.[33] Like Oregon, employment growth throughout the system area is projected to be lower than pre-pandemic levels.

Figure 2.4: Employment Slowing Across System Area



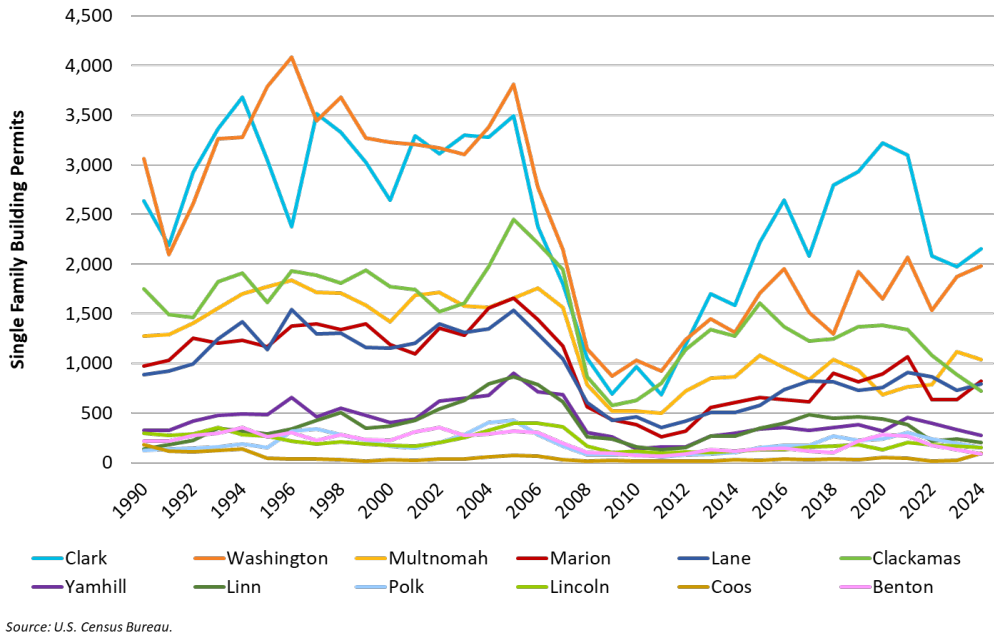
Source: U.S. Bureau of Labor Statistics.

Building permit data across the system area looks similar to statewide trends in Oregon, with fewer homes being built. The top counties for single-family building permits in the system area (Figure 2.5) continue to experience much lower growth than they did in the two decades preceding the Great Recession, and lower growth than the decade preceding the pandemic.

[33] Panday et al.

Clark and Washington counties continue to be the top producing areas for single-family permits. Clark County experienced a large increase in permits between 2011 and 2021, eclipsing 3,200 in 2020 for the first time since 2005, but has since cooled. Clackamas, the third highest producing county until 2022, saw permits decline precipitously over the past two years and produced less single-family permits in 2024 than Marion and Lane counties for the first time since the time series began (1990).

Figure 2.5: Building Permits Trending Lower in System Area



Source: U.S. Census Bureau.

2.2 Natural Gas Markets

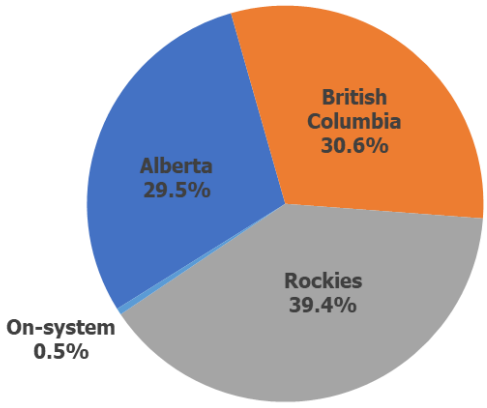
This section provides a high-level summary of where NW Natural purchases natural gas, the expectations of natural gas prices in the future.

2.2.1 Natural Gas Supply Sources

NW Natural purchases natural gas on behalf of all sales customers. Purchasing natural gas from producers located in Canada or the Western U.S. requires the corresponding interstate/interprovincial pipeline capacity rights to ship the gas from the location of production to our service territory. NW Natural, as customer of the interstate/interprovincial pipeline companies, holds capacity contracts that allow us to ship natural gas that is purchased from out-of-state production basins and deliver it to NW Natural's service territory. NW

Natural's current upstream pipeline capacity contracts allow us to access and buy Canadian natural gas, which is shipped south from British Columbia and Alberta, and natural gas coming out of the Rockies, primarily in Wyoming and Colorado. In 2024, these contracts enabled us to purchase roughly 39 percent of our supplies from Rockies, 30 percent from Alberta and 31 percent from British Columbia (see Figure 2.6).

Figure 2.6: Supply Diversity by Location January 2024-December 2024



While NW Natural's contracts allow the Company to access various points along the interstate/interprovincial pipelines, the gas prices paid for gas produced in these basins are closely correlated with three major natural gas trading hubs in the corresponding production areas: AECO (Alberta), Opal (Rockies), and Westcoast Station 2 (British Columbia). Additionally, NW Natural purchases gas at a fourth trading hub at Sumas, which is on the Washington (U.S.)/British Columbia (Canada) border, however, there are no major production operations associated with Sumas.

2.2.2 Natural Gas Price Forecast

NW Natural subscribes to a gas market fundamentals forecasting service through a third-party, S&P Global.[34] S&P Global implements a nation-wide supply and demand fundamentals model for the natural gas sector. Using this model, S&P Global publishes monthly long-term gas price forecasts for numerous natural gas hubs throughout the U.S. and Canada. NW Natural focuses on the four natural gas hubs where the Company purchases gas: AECO, Opal (i.e., Rockies), Sumas and West Coast Station 2. NW Natural uses the S&P Global long-term forecast and market forward prices to develop a monthly forecast to be used in the IRP. Forward prices are

[34] Previously IHS Markit.

blended into the S&P Global forecast for the first six years at a decreasing rate. This blending allows for even more accurate forecasting, as NW Natural's Gas Supply team uses forward prices to develop their hedging strategy and represent prices that are currently available in the market. The IRP uses this blended gas price forecast, as seen in Figure 2.7, as the expected gas price for the four natural gas price hubs.

Figure 2.7: Historical and Forecasted Natural Gas Prices by Trading Hub

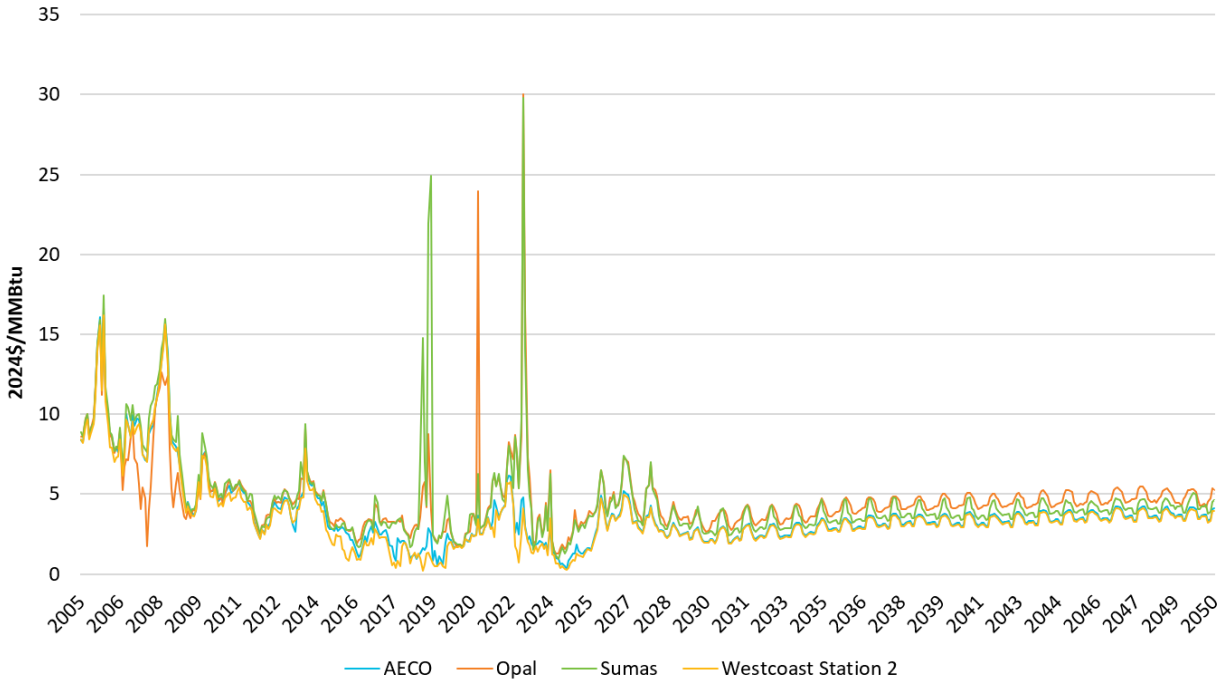
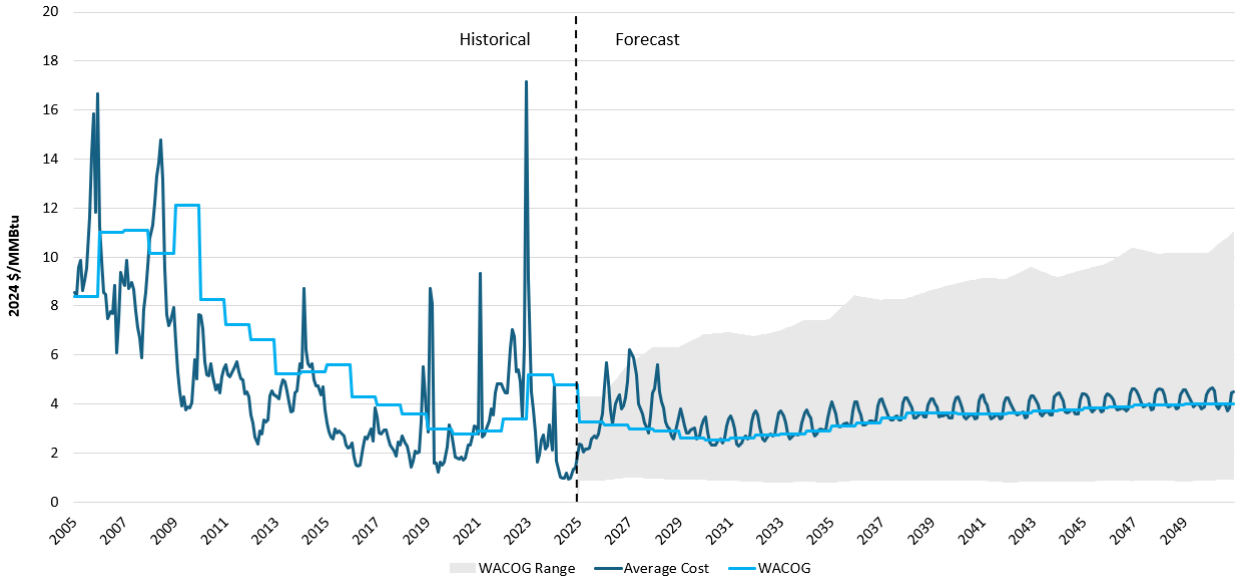


Figure 2.8 shows the historical average gas price, the historical weighted average cost of gas (WACOG), and the forecasted WACOG over the planning horizon. The range of the forecasted WACOG[35] is determined through the monte Carlo analysis discussed in the next section. The WACOG includes fuel and variable charges that are incurred to ship the gas to NW Natural's system. The WACOG is forecasted in advance for the upcoming gas year (November 1 – October 31) and filed each fall through the purchased gas adjustment (PGA) filing. Any over or under collection of revenues from the WACOG is largely trued up in rates in the following year's PGA.

[35] The range of the WACOG is represented using the 5th and 95th percentile from the Monte Carlo simulation.

Figure 2.8: Average Natural Gas Spot Price Cost vs. WACOG



2.2.3 Current Conditions

Record U.S. Lower 48 production levels occasionally reaching nearly 107 Bcf/d during April 2025 combined with lackluster late-season heating demand, helped to eliminate the national storage deficit. April 2025 also marked the earliest 100+ Bcf injection week since summer 2019. These trends have continued in recent weeks as a reemerged inventory surplus could balloon to 100 Bcf by the end of May. S&P Global now expects summer 2025 Henry Hub prices to average $3.63/MMBtu, as storage inventories built up to 2.26 Tcf, 57 Bcf above the five-year average, as of May 9, 2025 and are projected to fall to deficit only toward the end of summer. The injection season would still finish barely above 3.7 Tcf, extending a tight market into winter 2025–26. Key factors affecting the pricing trajectory this year are the strength of associated gas, Haynesville and Northeast production, the commissioning pace of new LNG export facilities, and the level of gas-to-coal switching in the summer months.

U.S. Lower 48 production averaged 105.3 Bcf/d through May 15, 2025, down 0.2 Bcf/d from the previous month. This decline is driven by a 0.2 Bcf/d drop in the Marcellus, as total Northeast demand has fallen over 4.0 Bcf/d from April levels and 0.5 Bcf/d below year-earlier levels. Marcellus production is beginning to show signs of a seasonal slowdown after exhibiting steady growth from the peak winter months through March and April.

U.S. LNG feedgas averaged 16.4 Bcf/d in April 2025, a record. May volumes are unlikely to continue the recent trend, however, as maintenance at Cameron LNG and fluctuations at

Corpus Christi LNG have led to a 0.9 Bcf/d month-over-month decline in feedgas through May 15. Further impacting summer 2025 LNG feedgas volumes, Cheniere Energy Inc. announced major maintenance at Sabine Pass LNG Trains 3-4 to commence later this quarter. In June 2023, a similar takedown of Sabine Pass LNG Trains 1-2 resulted in a 1.5-Bcf/d decline in U.S. Lower 48 feedgas month over month.

AECO-Nova Inventory Transfer (NIT) prices through early May have trended lower than last month, reflecting maintenance that restricted export capacity to the U.S. West, as well as weak seasonal demand both domestically and in the U.S. Lower 48. S&P Global anticipates that monthly prices will average US$1.42/MMBtu.

2.3 Renewable Natural Gas Markets

Policies that promote Renewable Natural Gas (RNG) adoption in the U.S. have traditionally prioritized its use in the transportation sector by offering financial incentives for RNG (and other biofuels blended with gasoline or diesel) for conventional road use. Examples include the United States Environmental Protection Agency's Renewable Fuel Standard, the California Low Carbon Fuel Standard, and the Oregon Clean Fuels Program. Such financial incentives have allowed RNG to capture a substantial 79 percent market share in the natural gas vehicle transportation sector as of 2023[36]. However, state policies are increasingly supporting the use of RNG for heat and power generation.

The U.S. RNG market is experiencing rapid expansion, fueled by rising renewable energy targets and environmental regulations. Since the first RNG facility was established in 1982, the industry in North America has grown swiftly, reaching a milestone of over 500 operating facilities in June 2025. As illustrated in Figure 2.9, by June 2025, there were 505 operational facilities, 153 under construction, and 293 planned.

[36] https://transportproject.org/2024/04/24/renewable-natural-gas-breaking-motor-fuel-usage-records-2/

Figure 2.9: RNG Facilities in the United States

Source: https://www.rngcoalition.com/infographic

To stay informed about current market dynamics and identify new resource opportunities, NW Natural issues an annual RFP for RNG resources. The 2024 RFP saw a particularly strong response, with 53 proposals submitted compared to 30 in 2023. This robust response highlights a clear interest in selling RNG to markets such as gas utilities, which can offer revenue opportunities distinct from the transportation fuel credit markets. While those credit markets are lucrative, they are also highly volatile and difficult to predict or hedge against. Utilities, therefore, provide a steady and reliable source of revenue for RNG projects, helping project developers secure project-level financing.

2.4 Environmental Policy

NW Natural believes it has a pivotal role to play in helping our region move to a lower-carbon, renewable energy future in a more resilient, efficient, and affordable way. Through voluntary and compliance actions, NW Natural demonstrates its core value of Environmental Stewardship. The Company stays current on environmental policy changes at the federal, state, and local levels.

2.4.1 Environmental Policy – Federal

Under 40 CFR Part 98, the Greenhouse Gas Reporting Rule, NW Natural reports to EPA the emissions from the use of our product by our customers and the fugitive emissions from our system. Emissions are reported separately for operations in Oregon and Washington.

At this time, there is not a federal carbon market. In 2024, a Waste Emissions Charge (WEC) was established for segments of the natural gas supply chain. The WEC created a charge for companies with fugitive emissions above defined thresholds. The gas distribution segment and local distribution companies were excluded from the WEC. In March 2025, a joint Congressional resolution disapproved the 2024 Final Waste Emissions Charge Rule and EPA is evaluating next steps.

With the federal administration changes, some of the previously proposed tax incentives for renewable energy are in jeopardy based on the funding pauses stemming from Presidential Executive Order, Unleashing American Energy.[37]

2.4.2 Environmental Policy – State

2.4.2.1 Oregon

Oregon Greenhouse Gas Reporting Program (OAR 340-215)

The Oregon Department of Environmental Quality (DEQ) requires all stationary sources emitting more than 2,500 metric tons of CO2e per year, electricity utilities, local distribution companies, and fuel suppliers to report annual greenhouse gas emissions. Similar to the federal reporting under 40 CFR Part 98, NW Natural submits emissions from the use of its product, as a supplier and the emissions from their actual system operations. Additionally, the Company reports emissions from any of its facilities that exceed 2,500 metric tons of emissions.

The emissions reported in the supplier reports serve as the basis for compliance under the state's carbon program, described below. Historical emissions from 2017-2019 define the Company's baseline and current reporting years define the compliance obligation for the Company. These emissions include the combustion emissions from the fuel delivered to customers including natural gas and renewable natural gas. In the future, NW Natural anticipates reporting hydrogen and carbon capture emissions in this report.

Oregon Climate Protection Program (OAR 340-273)

In November 2024, the Oregon Environmental Quality Commission adopted a new iteration of the Climate Protection Program (CPP). This is a cap and reduce carbon policy that covers a portion of the state's economy including fuel suppliers, local distribution companies, emissions intensive trade exposed (EITE) manufacturing, and direct natural gas users. The program establishes a declining carbon emissions cap for covered entities to target a 50 percent reduction in emissions by 2035 and 90 percent reduction by 2050 from a 2017-2019 baseline.

[37] https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy/

Under the program, NW Natural holds the compliance obligation for all of its Oregon customers' natural gas emissions, except for EITE customers. Under the CPP, EITE customers hold their own obligation and receive their own allocation of compliance instruments from the Oregon DEQ. The customers that NW Natural holds the obligation for include sales and transportation customers. The CPP also includes a category of covered entities called "Direct Natural Gas Users", but NW Natural does not have any customers in that category.

CPP compliance tools available to NW Natural include compliance instruments, community climate investments, energy efficiency, alternative fuels, and carbon capture. Compliance instruments are described below and details about additional compliance tools are provided in Emissions Compliance Resources section (Chapter 7) of this IRP.

Compliance instruments are CO2e emissions allocations from the program cap. A compliance instrument is defined in OAR 340-273-0020 as an instrument issued by DEQ that authorized the emission of one MT CO2e of greenhouse gases. Annually, NW Natural is allocated a portion of the declining program cap using the procedure outlined in OAR 340-273-0420. DEQ will take the program cap, distribute compliance instruments to EITEs according to the percentages outlined in OAR 340-273-9000 Table 8, and then will apply the percentage for NW Natural listed in OAR 340-273-9000 Table 4.

*(Annual Cap-Allocation to EITE) *NW Natural Allocation Percentage= Annual Allocation to NW Natural*

In the first compliance period (2025-2027), EITEs are exempt from the program, so NW Natural's allocation of compliance instruments is a direct percentage of the program cap. In the CPP rule language, DEQ is proposing to undertake additional rule making regarding EITE's which could impact the allocation of compliance instruments to local distribution companies. Since that rule making is not anticipated to begin until 2026, NW Natural is using the procedure currently outlined in the rules.

Under the program, Oregon compliance instruments are bankable and tradable with other covered entities in the program. The modeling included in this IRP allows for banking of compliance instruments but does not attempt to model the purchase or sale of compliance instruments with counter parties. Since the OR CPP is not a market-based program and there is no reliable pricing structure for purchasing instruments from counter parties and NW Natural has no incentive to sell allocated instruments with such a steep program trajectory, it would be premature to make assumptions about how a secondary market for these instruments that NW Natural could participate in would develop.

2.4.2.2 Washington

Greenhouse Gas Reporting Program (WAC 173-441)

The Washington Department of Ecology (Ecology) requires greenhouse gas emissions reporting from fuel suppliers, local distribution companies, electricity suppliers/generators, and facilities that emit more than 10,000 metric tons of CO2e emissions per year. Historically, there was a higher reporting threshold for local distribution companies and NW Natural was below the threshold and not required to report. In 2022 the rules were updated to accommodate the state's cap and invest program described below. At that time NW Natural began reporting emissions to Ecology and also submitted historical emissions back to 2015. The emissions that NW Natural reports to Ecology include our customers use of gas (supplier report) and our system fugitive emissions.

The emissions reported in the supplier reports serve as the basis for compliance under the Climate Commitment Act. Historical emissions from 2015-2019 define the Company's baseline for the program and current reporting years define the compliance obligation for the Company. These emissions include the combustion emissions from the fuel delivered to customers including natural gas and renewable natural gas. In the future, NW Natural anticipates reporting hydrogen and carbon capture emissions in this report.

Climate Commitment Act (WAC 173-446)

Authorized by the Legislature in 2021 under Chapter 70A.65 RCW and administered by the Washington Department of Ecology, the Climate Commitment Act (CCA) is a cap-and-invest program, which is a market-based approach to reducing greenhouse gas emissions. It sets a declining cap on greenhouse gas for the state. The goal of the program is to reduce state-wide greenhouse gas emissions by 95 percent by 2050. The CCA is an economy-wide carbon program that includes fuel suppliers, local distribution companies, electricity suppliers, electricity producers, and emissions intensive trade exposed manufacturing operations.

Under the program, NW Natural holds the compliance obligation for all its Washington customers' emissions from the use of natural gas, except for EITE customers. Customers usage covered by NW Natural's compliance obligation includes usage for both sales and transportation schedule customers. Under the CCA, EITE customers hold their own obligation and receive their own allocation of no cost allowances from the Department of Ecology.

Regulated entities must acquire and then retire allowances and offsets equal to their emissions for each compliance period of the program. Other compliance tools for lowering emissions include energy efficiency, alternative fuels such as RNG and Hydrogen, and carbon capture. CCA

allowances are described below and details on additional compliance tools will be provided in Emissions Compliance Resources section (Chapter 7) of this IRP.

Under the CCA, Ecology issues allowances that represent the amount of emissions allowed under the program's cap. Each allowance authorizes the release of one metric tons of CO2e. These allowances are acquired through a variety of pathways under the CCA. Certain categories of covered entities, like local distribution companies, are allocated a limited number of no cost allowances annually from the Department of Ecology. Additional allowances can be purchased at auction or in a secondary market from other program participants.

NW Natural receives no cost allowances from Ecology based on its customers' baseline covered emissions from 2015-2019. Covered emissions do not include EITE customers' emission. The allocation calculation takes the average of these annual emissions and then applies the program cap reduction percentage to the baseline to calculate the annual reduction of allowances granted to NW Natural each year. NW Natural's baseline average annual covered emissions are 487,445 metric tons CO2e. From 2023-2030, there is a decrease of seven percent of the non-cost allowances provided to NW Natural, or a reduction of 34,121 allowances each year. From 2031 to 2042 this percentage changes to 1.8 percent of baseline reduction or 8,774 allowances each year. Finally, from 2043 to 2050, NW Natural's allocation of no cost allowances is reduced by 2.6 percent of baseline each year, or 12,674 allowances a year.

Under the CCA program, local distribution companies are required to consign a specific percentage of their no cost allowances to auction each year. Table 2.1 outlines the percentage of allowances that NW Natural must consign to auction and the remaining may be retained and used for compliance.

Table 2.1: Percentage of Allowances to Consign at Auction

Year	Percentage Consigned to Auction
2023	65%
2024	70%
2025	75%
2026	80%
2027	85%
2028	90%
2029	95%
2030 and beyond	100%

NW Natural can purchase additional allowances at auction or on the secondary market. Additional details on CCA auctions can be found on Ecology's CCA website.[38] Additionally, if covered entities are not able to secure enough compliance tools to cover their emissions by a compliance deadline, Ecology can issue additional allowances to that entity at the annual allowance ceiling price.

2.5 Building Codes

While building codes are typically centered energy efficiency, some recent codes have tried to include an emissions reductions element; this is particularly true in Washington. The following sections discuss building codes to add planning context.

2.5.1 Oregon

By executive order, Oregon's energy codes must increasingly reduce energy use every code cycle. The 2023 Oregon Residential Specialty Code (ORSC) became mandatory in April 2024 and is based on the 2021 International Residential Code. The current ORSC is fuel neutral. The next residential code cycle process is expected to begin late in 2025 and will be effective in the Fall of 2026.

Oregon's commercial energy code – mandatory as of January 1, 2025 – is based on the national standard ASHRAE 90.1 – 2022. This standard became effective in 2022 and is based on energy cost. The Oregon Building Codes Division has expressed the intent to use the ASHRAE standard for all upcoming commercial energy code cycles.

2.5.2 Washington

Since February 2021, Washington state building codes (WSEC-2018) have required new residential homes to meet energy efficiency standards based on carbon emissions assumptions. These assumptions treat electric appliances as having lower on-site greenhouse gas emissions than similar gas appliances. As a result, building new homes with natural gas can be more expensive, depending on factors like home size, equipment choices, and building insulation.

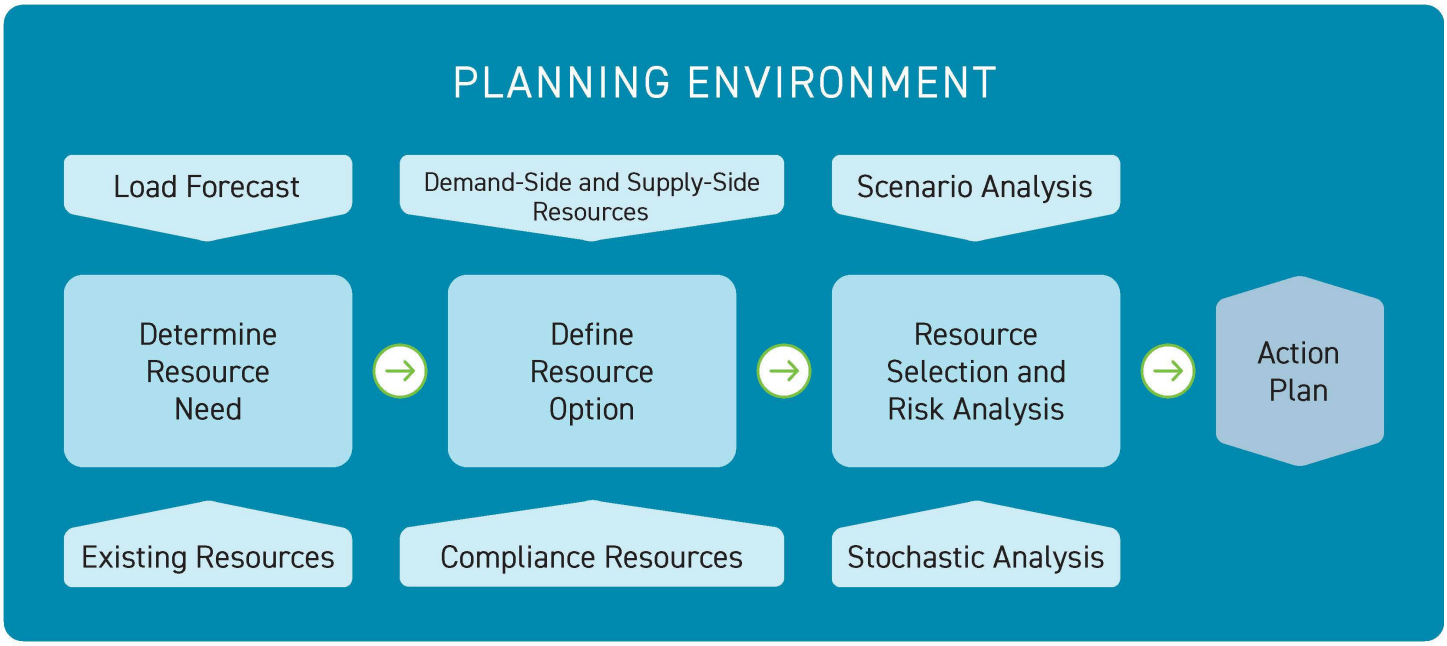
In March 2024, new rules issued by the Washington State Building Code Council (SBCC) under WSEC-2021 went into effect. These changes updated the 2021 codes and, overall, tend to limit or effectively ban the use of gas space and water heating in new residential and commercial buildings. Currently, these codes are being challenged as preempted by the Energy Policy Conservation Act (EPCA).

[38] Auctions & market - Washington State Department of Ecology

Then, in November 2024, Washington voters passed Ballot Initiative I-2066. The measure was described as blocking state and local governments from limiting access to natural gas, barring the SBCC from discouraging or penalizing natural gas use in buildings, requiring natural gas utilities to provide service regardless of other energy options, and preventing the Washington Utilities and Transportation Commission (WUTC) from approving multi-year rate plans that would push gas companies to end service or make it prohibitively expensive.

The Ballot Initiative is being challenged and a King County Superior Court judge recently ruled that I-2066 is unconstitutional under Washington state law. That decision is now being appealed to the Washington Supreme Court. While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.

3 Equity Considerations and Public Participation



NW Natural®

This chapter signals NW Natural's efforts to integrate equity considerations into its utility planning approach. It introduces foundational equity concepts, outlines the relevant regulatory context, and acknowledges the Company's early efforts to reflect these principles in stakeholder engagement and resource planning.

3.1 Introduction

As energy planning becomes increasingly intertwined with equity, climate policy, and public trust, NW Natural is rethinking its approach to meaningful public engagement. The 2025 Integrated Resource Plan reflects this shift by broadening participation pathways and embedding community-informed perspectives into the Company's resource planning framework. These efforts are not only central to NW Natural's equity commitments, they also directly respond to evolving regulatory expectations in Oregon and Washington that call for greater transparency, procedural fairness, and inclusive decision-making.

This IRP represents a move beyond traditional stakeholder engagement and toward a more participatory approach that recognizes the value of lived experience alongside technical expertise. This chapter introduces key equity concepts, summarizes the regulatory landscape that governs utility planning, and demonstrates NW Natural's commitment to advancing energy equity and energy affordability for its customers and the communities it serves.

3.2 Working Equity Language: Concepts, Context, and Considerations

In recognition of the Public Utility Commission of Oregon's (OPUC) and Washington Utilities and Transportation Commission's (WUTC) ongoing work to advance equity in utility regulation, this IRP references definitions and concepts that have been articulated by the Commissions to inform their regulatory approaches. These include the tenets of energy justice: procedural, distributional, recognition, and restorative; and key concepts including energy burden, environmental equity and justice, and energy equity and energy justice.

These references are not intended to formalize specific definitions or frameworks; rather, they are included to acknowledge the Commissions' stated priorities—as well as to support shared language and understanding of concepts and definitions that are still emerging. This helps to position the Company's stakeholders to engage more meaningfully in the IRP process, while being mindful that language should remain flexible and contextual and that multiple definitions can exist without invalidating each other. NW Natural also recognizes the ongoing, iterative process this important work entails.

3.3 Equity in the Utility Regulatory Landscape

NW Natural's 2025 IRP navigates a complex and broad landscape of regulatory dockets that emphasize equity and public participation in energy planning and utility operations. Appendix A specifically addresses how the Company complies with IRP Guidelines and Commission Orders specific to NW Natural's IRP.

Oregon House Bill 2475, which became law on January 1, 2022, allowed for the consideration of "…differential energy burdens[39] on low-income customers and other economic, social equity, or environmental justice[40] factors that affect affordability for certain classes of utility customers, and any other reasonable consideration".[41] The bill also introduced intervenor funding[42] for organizations representing environmental justice communities. OPUC docket UM 2211 was opened in late 2021 for the Commission's implementation of HB 2475. Docket UM 2211 has completed phases one and two and is in its third phase, which focuses on data collection and analysis to support equitable energy systems and rate design.

Similarly, in Washington, legislative actions and dockets have focused on climate action and advancing energy equity.[43] Key initiatives include the Climate Commitment Act (CCA) and the Multiyear Rate Plan (MYRP) statute. Executive Order 22-04 required state agencies to implement plans designed to address equity – although the WUTC was not obligated to follow the order, it voluntarily aligned its practices with its goals. In response to these actions, the WUTC began issuing guidance to utilities through various dockets based on its understanding of these broad mandates. WUTC Staff has further indicated that the principle of equity is a

[39] The OPUC defines "energy burden" as the percentage of household income that goes toward energy costs (gas and electricity). If a household spends more than six percent of their income on energy-related costs, they are considered energy-burdened (https://energyinfo.oregon.gov/blog/2019/1/7/new-state-plan-outlines-steps-for-reducing-energy-burden-improving-energy-efficiency#:~:text=Energy%20burden%20is%20defined%20as,they%20are%20considered%20energy%2Dburdened).
[40] The OPUC defines "Environmental Justice" and "Environmental Justice communities" in ORS 756.010; which was amended through the enactment of Oregon HB 2475. "Environmental justice" means equal protection from environmental and health hazards and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality, and play. "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure, and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth, and persons with disabilities.
[41] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2475/Enrolled
[42] "Intervenor funding is available to ensure that those qualified organizations who represent distinct classes of utility customers have the financial resources to participate in the PUC's proceedings. The PUC must approve any agreement before financial assistance can be provided." (https://www.oregon.gov/puc/filing-center/Pages/Intervenor-Funding.aspx).
[43] WUTC provided definitions related to energy equity and the four tenets of equity are included for reference in Appendix I.

concern in all public interest considerations.[44] With the intent to better coordinate its work related to equity across the agency and amongst its regulated entities, the WUTC opened docket A-230217.[45] The docket is structured into four phases to explore equity, each focused on a different aspect (tenet) of equity; distributional, procedural, recognition, and restorative justice.[46] The first phase of this docket has been completed and the WUTC has issued an interim policy statement and guidance specific to procedural justice.

3.4 Equity Considerations at NW Natural

Energy equity and energy affordability for all customers guide NW Natural's work. The Company recognizes the pressing issue of energy burden and energy justice and remains steadfast in its commitment to ensuring that low-income customers, who often face the greatest challenges in affording their energy bills, receive the resources and attention they need. The following priorities shape NW Natural's approach to advancing energy equity and energy affordability:

- Prioritizing measures for vulnerable customers and focusing on interventions that target our lowest-income, highest-burdened customers.
- Developing and implementing measures informed by robust data analysis.
- Pursuing, vetting, and prioritizing cost-effective solutions.
- Balancing immediate support with longer-term strategies.
- Regularly evaluating efforts and adjusting strategies as needed to maintain and enhance their effectiveness.

As guidelines for integrating equity considerations into natural gas IRPs are still evolving, the Company recognizes that equity in the utility sector should ensure that all stakeholders—whether they are customers, shareholders, or communities—have equitable access to the advantages provided by natural gas infrastructure.

The Company recognizes that certain factors lie beyond its direct influence. Broader economic policies, regulatory frameworks, and societal structures, while impactful, are beyond the Company's immediate reach and influence. The Company's IRP focuses on what it can directly impact, including enhancing public participation, integrating diverse perspectives into our

[44] Notice of Opportunity to File Written Comments, serviced on September 29, 2023; in WUTC docket A-230217 states that a "notable" development by the Commission to implement recent statutes and requirements is "Evaluating…and gas and electric integrated resource plans with an equity lens" and further adds the statement "…the Commission is seeking to incorporate an equity lens in all of its work and is requiring regulated companies do the same."
[45] WUTC docket A-230217. Interim Policy Statement Regarding Procedural Justice serviced on May 12, 2025.
[46] WUTC provided definitions related to equity and the four tenets are included for reference in Appendix I.

planning processes, and a vehicle for raising awareness of the Company's energy assistance programs. By doing so, NW Natural can advance equity within its operations as it delivers on its mandate to safely and reliably provide affordable natural gas service to all its customers.

The 2025 IRP is NW Natural's first to include a chapter dedicated to equity considerations. While IRPs have always been open to the public, the 2025 IRP builds on the historical practice of public engagement to bring in more voices and diverse perspectives in energy planning. The Company works collaboratively with stakeholders to continually assess and refine strategies. This journey involves taking thoughtful actions, making necessary adjustments, and listening to the voices of those the Company serves. Plans and decision-making are more informed if they are based on the input of all of those they intend to impact, not just a subset. Diversifying the voices, lived experiences, and perspectives that inform NW Natural's practices is an important step to better serving all customers.

Enhancements to public participation in the IRP process play an important role in advancing equity principles. This chapter focuses on the actions NW Natural took to strengthen inclusive, informed, and meaningful public engagement specific to the 2025 IRP. NW Natural emphasizes that the Equity Considerations and Public Participation Chapter in the IRP should not be considered the Company's primary effort to further its energy equity work, rather the chapter is part of a much larger constellation[47] of resources NW Natural has to address energy burden. Table 3.1 includes a snapshot of the Company's equity and affordability-focused portfolio. A more detailed review of income-based energy efficiency programs can be found in Chapter 6.

[47] Stakeholders can refer to NW Natural's website and 2023 Community and Sustainability Report: https://s23.q4cdn.com/611156738/files/doc_downloads/2024/12/20/ESG_2023_Report_Combined_fnl_b.pdf for a broader look at its energy equity efforts.

Table 3.1: Energy Equity and Affordability Portfolio

Offering	Description
Community Equity Advisory Group (CEAG)	Strengthen Procedural Equity practices; broaden engagement and participation in energy planning
Community Grants and Funds	Support over 250 nonprofit organizations through NW Natural territory
Conservation Programs	Improve energy efficiency through conservation efforts
Energy Education	Tools, programs, and resources available to help customers lower bills; improve engagement, and understanding of role of utilities and programs, customer bills and charges, and safety
Gas Assistance Program* (GAP)	Company and employee funded energy assistance for customers in Oregon and Washington
Gas Residential Energy Assistance Tariff* (GREAT)	Washington bill assistance
Oregon Bill Discount Program*	Four-tiered program with highest discounts reserved for lowest income households to address energy burden and improve affordability
Oregon Low-Income Gas Assistance* (OLGA)	Oregon bill assistance
Oregon Low-Income Energy Efficiency* (OLIEE)	OLIEE finances whole home retrofits, weatherization projects, high-efficiency gas equipment, and energy literacy service for income eligible customers
Residential Weatherization Kits	Improve energy efficiency and reduce energy bills through efficiency gains
Washington Arrearage Management Program 2024*	Supplemental grant program to cover past-due bills for lowest income customers
Washington Bill Discount Program*	Four-tiered program with highest discounts reserved for lowest income households to address energy burden and improve affordability
Washington Low-Income Energy Efficiency program* (WALIEE)	WALIEE finances whole-home retrofits, weatherization projects, high-efficient gas equipment, and energy literacy services for income-eligible customers
Notes: 1. Items marked with an asterisk indicate an income qualified program. 2. List is non-exhaustive.	

3.4.1 Evidence and Engagement that Shape NW Natural's Energy Equity and Affordability Portfolio

NW Natural relies on a variety of resources to design, evaluate, and refine its programs. A snapshot of these is detailed below.

Energy Burden Metrics Reporting: NW Natural provides required periodic reporting to both the OPUC and WUTC on various metrics related to energy burden issues, such as participation levels in the Company's bill assistance, bill discount, and arrearage management programs, costs associated with such programs, customer arrearage data, disconnection for non-payment data, customer notices, and service reconnections. The analysis and evaluation of this data, including identifying any trends, are valuable tools to assess effectiveness of programs and program outreach.

Energy Burden Assessment: In alignment with directives in OPUC docket UM 2211, NW Natural completed its second Energy Burden Assessment (EBA) in 2024 with support from Empower Dataworks, a regional consulting firm that specializes in energy equity analytics and has performed similar assessments for numerous utilities throughout the Pacific Northwest.[48] The EBA calculated three types of metrics: (1) those related to energy burden based on demographic and geographic characteristics, (2) participation in and funding levels for Energy Assistance Programs, and (3) customer energy use characteristics.

NW Natural provided several customer-level datasets to Empower Dataworks (governed by a confidentiality agreement) to enable this analysis. Customer Information System (CIS) data included monthly gas bills; on-time payment, late payment and disconnection notices; and customer accounts participating in the Company's bill discount program, other income-eligible energy assistance programs (OLGA, GREAT, GAP, OLIEE) and LIHEAP, along with discount levels and participation timeframes. This data covered a 27-month period from January 2022 through March 2024 and reflected the most up to date and reliable data on customer billing, payment behavior, and participation in assistance programs available at that time. As time passes, the risk of data obsolescence increases; therefore, the Company is proposing to update the underlying datasets every four years to maintain the integrity of the analysis and ensure that programs align with customer needs.

[48] Chapter 2, Section 2.6.6 of the 2022 IRP describes the Company's first efforts to conduct a Low Income Need Assessment (LINA). The LINA consisted of a compilation and analysis of relevant data to inform NW Natural's low-income programs in both Oregon and Washington. The Company revised and replaced its LINA with an updated assessment that aligned with workstreams outlined in OPUC docket UM 2211 which focused on the implementation of Oregon HB 2475. A complete EBA report and findings were filed in OPUC docket UM 2211 on September 16, 2024.

The Company provided the completed EBA to stakeholders in an OPUC docket UM 2211 filing on September 16, 2024. The report findings and recommendations, as prepared by Empower Dataworks, were presented to Commission Staff, UM 2211 stakeholders, and other stakeholders, including members of the Company's Washington GREAT Advisory Group, at a workshop the Company hosted on September 11, 2024.

Gas energy burden for a household is calculated by dividing annual gas expenses by gross household income:

$$Gas\ Burden\ [\%] = \frac{Annual\ Gas\ Expenses\ [\$]}{Annual\ Household\ Income\ [\$]}$$

Key findings from the Company's 2024 EBA[49] include the following:

Table 3.2: 2024 Energy Burden Assessment Key Findings

Metric	Oregon	Washington
Total customers	567,000	78,000
Percent eligible for bill discount program	12.5%	23%[50]
Average gas burden (all customers)	1.4%	1.5%
Median gas burden[51] (low-income customers)	0.9%	1%
Customers with energy burden greater than 3%	75,000 (estimate)	13,000 (estimate)
Low-income customers with energy burden greater than 3%	50,000	10,000
Average annual natural gas consumption	720 therms	740 therms
Home vintage[52]	1980-Present: 48% 1940-1979: 36% Pre-1939: 16%	1980-Present: 85% 1940-1979: 11% Pre 1939: 4%

[49] NW Natural's 2024 EBA can be found in OPUC docket UM 2211 at the following link: https://edocs.puc.state.or.us/efdocs/HAH/um2211hah331407120.pdf

[50] 23 percent of Washington's 78,000 customers (18,000) meet income guidelines; a rate nearly double that of Oregon's NW Natural customer base and attributed to the higher income threshold in Washington's program. In Washington, it is the greater of 80 percent the area median income or 200 percent of the federal poverty line; in Oregon, it is 60 percent of state median income. In dollars alone, this translates to a $25,000 higher income threshold in Washington. Specifically, for a family of four, households that earn up to $94,400 are eligible for some level of discount; it's just under $71,000 in Oregon.

[51] NW Natural's median total energy burden, including an estimate of electricity burden, is between other rural and metropolitan regions in the Pacific Northwest.

[52] Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

In both states, average household natural gas energy burden rates fell below the threshold for high energy burden (three percent).

In the first two years of Oregon's program (November 1, 2022 – October 31, 2024), 55,272 customers enrolled, representing 78 percent of NW Natural customers likely eligible for the program. In the first 12 months of the Washington program, 7,847 customers enrolled, representing 44 percent of the Company's estimated income-eligible population in the state.

The EBA revealed early and healthy participation in the bill discount program driven by strong partnerships, robust outreach and a streamlined enrollment design. The EBA also uncovered pockets of need and opportunities to strengthen engagement and participation including coastal and non-urban areas, households with high energy burdens and high use patterns, geographically and/or linguistically isolated customers, mobile home park residents, and households that have demonstrated difficulty paying their bills in the past (as evidenced by a past due notice and/or risk of disconnection). The Company has begun a direct mail campaign to over 15,000 customers identified through the EBA as likely eligible but not participating in the bill discount program. A copy of the postcard is available in Appendix I.

Community and Equity Advisory Group: The Community and Equity Advisory Group (CEAG) is an extension of existing community engagement priorities at NW Natural and a natural outgrowth of NW Natural's commitment to improving energy equity and easing energy burden for our most vulnerable customers. From a place of listening and learning, the CEAG seeks out and elevates historically underrepresented voices, perspectives, and lived experiences to advance inclusive practices and institutional actions and bring a racial equity and environmental justice lens to NW Natural's energy and operational planning.

The purpose of the CEAG is to provide NW Natural direct feedback, recommendations, advice, and review on areas related to Company operations and programs.[53] NW Natural is committed to an authentic and effective process: a core tenet of the group is to solicit ideas and encourage engagement from new perspectives, voices, and lived experiences in a genuine, non-extractive way, avoiding the pitfalls of diversity, equity, and inclusion work that can be transactional and performative. The CEAG convenes quarterly; member organizations are compensated for their time and expertise and meetings are facilitated by a third-party consultant. A notable highlight of the year was CEAG engagement in the development of the Company's 2025 IRP, the details of which are found later in this chapter.

[53] CEAG members have requested and reiterated a preference for distinct topics where a correlation can be made to the impact on and/or relation to communities served.

Oregon Low Income Energy Efficiency Advisory Committee: Oregon Low Income Energy Efficiency (OLIEE) Advisory Committee (OAC) meets biannually to share updates, raise issues, troubleshoot challenges, and report on project completions. NW Natural worked with the OAC to develop changes to Schedule 320—which defines the Company's low-income energy efficiency program—to reach more income eligible customers, accelerate project completions, expand support, and ease the administrative burden on the agencies responsible for implementing OLIEE projects. The Company releases an annual report at the close of each program year to summarize progress and outcomes.

Gas Residential Energy Assistance Tariff Advisory Group: The Gas Residential Energy Assistance Tariff (GREAT) Advisory Group was established in August 2019 as part of a WUTC-adopted joint settlement agreement in NW Natural's general rate case, with goals to keep customers connected to natural gas service, provide energy assistance to more customers, lower the energy burden of participants, collect data to assess program effectiveness, and inform ongoing policy discussions. NW Natural has been meeting with the GREAT Advisory Group at least monthly.

Oregon Low Income Gas Assistance Advisory Group: NW Natural's Oregon Low-Income Gas Assistance (OLGA) Program provides natural gas bill payment assistance to income-eligible households. The OLGA program is designed to supplement federal Low-Income Home Energy Assistance Program (LIHEAP) funding. Since OLGA's inception in 2003, the Company has worked closely with staff members from the OPUC, Oregon Housing and Community Services (OHCS), Community Action Partnership of Oregon (CAPO), and the Community Action Partnership Agencies ("the Agencies") who deliver the OLGA program to customers. Representatives from each of the Agencies have jointly formed the OLGA Advisory Council ("the Council"). The Council meets quarterly to ensure that application and program administration processes are streamlined and managed effectively, and all concerns are addressed so that the shared goal of serving as many qualifying customers as possible is attained.

Energy Efficiency Advisory Group: NW Natural's Energy Efficiency Advisory Group (EEAG) was established in 2009 to provide guidance and oversight of the Company's energy efficiency programs and pilot offerings in Washington. The EEAG is comprised of representatives from the WUTC, Washington Public Counsel, Northwest Energy Coalition (NWEC), Alliance of Western Energy Consumers (AWEC), Energy Project, and program staff. Quarterly calls are held to review current program activity and seek guidance on proposed program changes or strategies.

Oregon Low Income Energy Efficiency Program Surveys: NW Natural conducts satisfaction surveys of its Oregon Low Income Energy Efficiency (OLIEE) program to assess experience, including:

- Annual customer service survey to gather feedback from Community Action Agencies to assess satisfaction with NW Natural in implementing the OLIEE program
- Post-weatherization engagement survey to solicit feedback from customers who received no-cost upgrades through the OLIEE program, as well as provide important reminders and education on household energy efficiency

3.4.2 Equity Considerations in NW Natural's Integrated Resource Plan

In developing the IRP, the Company is committed to focusing on areas where it can make a direct and meaningful impact. This IRP is designed to address specific equity considerations where NW Natural can drive tangible improvements. This includes enhancing public participation, integrating diverse perspectives into planning processes, and increasing awareness of energy assistance programs[54]. By concentrating on these areas, the Company can ensure that its actions are impactful and achievable, *and* that the IRP remains a practical and effective tool for resource planning, rather than an aspirational document with unattainable goals. Equity considerations in the 2025 IRP focus on procedural equity, and NW Natural remains committed to strengthening equity considerations in future resource planning processes. The Company reiterates that work must continue to be iterative and adaptable.

The following sections, in addition to further detail in Appendix I, provide NW Natural's efforts to enhance awareness of and participation in resource planning.

3.5 Stakeholder Engagement and Public Participation

Stakeholder[55] engagement and public participation are essential to the development of an IRP. In accordance with guidelines[56] from Oregon and Washington, and to encourage an open and transparent process, NW Natural encourages customers and community members to attend IRP workshops and other engagements, and to submit comments during public comment periods. While the guidelines highlight both the need for and importance of engaging with the public, specific guidance on how to implement this is open to interpretation.

NW Natural has been and continues to be invested in increasing effective and informed participation in the development of its IRP. Between each IRP cycle, NW Natural reviews its IRP engagement and participation processes, sourcing feedback from Commission Staff and other

[54] NW Natural provides a suite of energy assistance programs to its customers – please refer to Table 3.1 for a snapshot of these. Income qualified energy efficiency programs are described in Chapter 6.
[55] When speaking about engagement in the IRP, the following terms are often used interchangeably: 'stakeholder'; 'public'; 'interested parties'.
[56] See Appendix A for IRP Guidelines.

stakeholders as well as reviewing peer utility processes. In some instances, the Company may adjust mid-cycle as new information becomes known.

Improving public participation in the IRP process is crucial for advancing equity principles. The Company defined the following goals with regard to enhancements in the 2025 IRP:

- Increasing awareness of energy planning processes
- Aligning participation objectives and techniques
- Clearly communicating when and how members of the public could provide input and feedback on IRP topics, assumptions, and inputs
- Offering straightforward and diverse methods for engagement
- Indicating how feedback is incorporated into process enhancements and/or analysis

3.5.1 Integrated Resource Plan Development | Challenges and Realities

The Company believes that it is important to speak to some of the challenges that exist for engaging stakeholders and the public at large, particularly in today's climate of transition and uncertainty at the federal and state levels. The following is a non-exhaustive snapshot of the challenges and obstacles the Company encountered with regard to participation in the IRP development process. Efforts to address these challenges and more are detailed later in this chapter.

- **Limited Public Understanding of Energy Planning**: The IRP process is governed by various guidelines, orders, and laws that are unfamiliar to most audiences. There is also general lack of awareness or knowledge about how utilities are operated and regulated. These realities can lead to misconceptions and hinder meaningful and informed engagement.
- **Utilities and Government**: The Company has observed a misconception that investor-owned utilities are part of the government. This challenge has been particularly pronounced in the current political environment, where significant policy changes at the federal level have heightened public apprehension.
- **Inaccessible and Technical Terminology**: The term 'Integrated Resource Plan' is technical and non-intuitive and may not have translation equivalents for non-English speakers. The Company made significant efforts to make information more accessible, such as offering translation and interpretation services, incorporating plain language reviews, and ensuring virtual platforms and in-person meeting spaces support accessibility features, but information barriers persist.
- **Capacity Constraints**: Individuals and organizations face bandwidth and capacity constraints that hinder participation in utility processes. Without a clear connection to

their most urgent priorities, participation in utility processes like Integrated Resource Planning may be overlooked or deprioritized.

As previously stated, incorporating equity is an iterative process. Given these compounded challenges and recent changes in the federal political landscape, NW Natural adjusted its approach to certain aspects of the IRP engagement strategy mid-development.

3.5.2 Continuous Enhancements: Insights from the 2022 IRP and the Community and Equity Advisory Group

As discussed in Chapter 2 and Chapter 10 of the 2022 IRP, the creation of NW Natural's Community and Equity Advisory Group (CEAG) came out of the Company's recognition for the need to hear voices from communities historically underrepresented in public processes.[57] NW Natural holds quarterly CEAG discussions with its members on specific topics related to equity, energy justice, or other topics of interest related to NW Natural's operations and energy services. More information about the CEAG can be found on the Company website.[58] The 2025 IRP is the first of NW Natural's IRPs to incorporate CEAG feedback into its processes.

In August 2023, CEAG member organizations were introduced to Integrated Resource Planning through short presentations about NW Natural operations. The intended type of engagement during this session was informational and served as a foundation for future meetings.[59] This introduction to resource planning built upon prior CEAG meeting topics in which the Company's presentations covered its regulatory requirements, stakeholders traditionally involved in its public proceedings, and the meaning and implications of energy planning, affordability and equity.

The second meeting of the CEAG Year 2 took place on February 22, 2024.[60] The aim of that meeting was to discuss procedural justice in relation to NW Natural's Integrated Resource Plan process and to review and receive feedback on proposed engagement activities for the 2025 IRP public process.

CEAG members were provided with an IRP public engagement proposal document one week in advance of the meeting for review. This document provided an overview of the IRP purpose and content, historical practices for public engagement opportunities during the IRP process, a proposal for changes in the process, and a request that members come prepared to discuss and

[57] See NW Natural's 2022 IRP, Chapter 2, Section 2.6.5 and Chapter 10, Section 10.4.
[58] https://www.nwnatural.com/about-us/community/caring
[59] While NW Natural does not officially utilize the IAP2 Spectrum of Public Participation, the Company does indicate the type of participation it is intending for its IRP and CEAG engagements.
[60] See Attachment A of NW Natural's 2025 IRP Workplan, filed on May 1, 2024 in WUTC docket UG-240312.

provide feedback. As has become standard practice for CEAG materials, this document was written in plain language and translated into Spanish.[61]

In addition to foundational information provided before and during the meeting, a mix of polls, break-out rooms, and large group discussions were utilized to facilitate the conversation. Subsequently, an online survey with poll questions was provided to CEAG members to share with their communities to collect more feedback after the meeting was held. A total of 31 individual responses were collected from the survey between the CEAG member answers at the February 22nd CEAG meeting and additional survey respondents.

CEAG Procedural Equity & Justice Discussion Summary

CEAG members discussed procedural equity and procedural justice. Using word-cloud and breakout room sessions, discussions centered on the meanings of various words, phrases, and concepts as understood by members, and shared examples of successful and missed opportunities for practicing procedural equity. The CEAG highlighted several recommendations to advance procedural equity in resource planning:

- **Providing a clear closed circle on how feedback is being utilized when it is collected from communities**: This involves ensuring that community feedback is not only collected but also transparently integrated into decision-making processes, creating a loop where community members can see the impact of their input.
- **Acknowledging multiple ways of learning and grasping information:** This includes recognizing and accommodating different learning styles and ensuring both information and physical accessibility. It emphasizes the importance of making information accessible to everyone, regardless of their preferred learning method or physical abilities.
- **Making sure those who are going to be impacted are really part of those earlier planning decisions and conversations:** This practice ensures that the voices of those affected by decisions are included from the outset, fostering inclusive and participatory planning processes.
- **Creating a safe and welcoming space for those who may not be as familiar with a process or jargon**: This involves supporting learning without shaming, making sure that everyone feels comfortable and included, regardless of their familiarity with specific processes or terminology.

[61] The Company offers translation into any language by request and has received consistent requests for Spanish language materials.

CEAG Integrated Resource Plan Public Participation Discussion Summary

During the February 2024 CEAG session, the IRP team reviewed the current IRP process (including both the utility-led and Commission-led portions) and past stakeholder engagement. The IRP team guided CEAG members through proposed adjustments to the IRP public engagement process to enhance procedural equity considerations, with each proposal discussed in detail. Finally, the group discussed if and how the new proposal moved the Company in the direction of improving procedural equity and justice.

The discussion on the IRP engagement strategy emphasized the importance of utilizing community feedback, simplifying language when appropriate, and prioritizing information related to direct customer impacts, such as bill impacts. Leveraging existing relationships with community organizations and implementing targeted strategies were also highlighted as crucial elements.

The meeting concluded with the question, "Do changes in the proposed public engagement strategy document move the IRP toward procedural equity and justice?" Participants agreed that the proposal moves the Company in the right direction but cautioned that it will naturally be an iterative process that will continue to evolve.

A summary of the 2025 IRP participation enhancements is provided in Section 3.5.3.

Further discussions with the CEAG

The August 2024 CEAG meeting focused on several key aspects of energy planning and the importance of the IRP in ensuring NW Natural's capacity to meet energy demands during extreme weather events. The Company emphasized that while the IRP is a dense and technical document, its influence shows up in our daily lives—pointing to uninterrupted gas service during the January 2024 cold snap to illustrate the everyday relevance of the IRP. When temperatures dropped significantly and demands on both the electric system and gas infrastructure were pushed to their limits, NW Natural was still able to deliver gas to its customers without interruption. This event underscored the IRP's role as a strategic roadmap that guides NW Natural in planning for and managing such extreme weather events, ensuring that NW Natural can maintain service reliability and safety even during periods of high demand.

The Company provided a progress report on its public participation enhancements, highlighting progress made on the IRP Fair[62] concept that stemmed from the CEAG meeting earlier that

[62] During its development the Winter Preparedness and Energy Planning Fair was dubbed the 'IRP Fair'. A second event in which resource planning information was shared with the public took place on June 7th, 2025, in Clark County, Washington.

year. The planning team requested feedback on red/green flags for the concept at this early planning stage. Here, members helped to inform the date/time of event, location, partnerships, and high-level tabling details.

The meeting also covered webpage functionality enhancements to boost accessibility and usability of IRP-related information. Following this early planning check in, the discussion moved to goals and examples of a refreshed IRP webpage – an area of opportunity for improvement to procedural equity called out by stakeholders. The Company outlined its goals for the refresh to include:

- Increasing accessibility of information for a diverse audience
- Expanding awareness of resource planning and associated regulatory processes
- Improving and generating effective participation
- Providing a formal pathway to submit direct feedback to the Company
- Improving transparency within the resource planning process
- Bridging utility-led and Commission-led processes

The CEAG illuminated the significant challenges to public participation in the IRP: 1) IRP language itself is challenging and inaccessible; even the term "Integrated Resource Plan" is a barrier and 2) no matter how accessible information is presented or how meetings are structured, utility resource planning will always fall below other priorities. This feedback was echoed by other stakeholders and detailed previously (Section 3.5.1 of this chapter).

The Company was able to incorporate feedback from the CEAG on enhancements to the IRP webpage, details of which are covered in the next section.

3.5.3 2025 Integrated Resource Plan Public Participation Enhancements

NW Natural took several steps to redesign its 2025 IRP public engagement strategy—enhancements were heavily informed by direct feedback from the CEAG, as well as guidance received during the 2022 IRP process. Updates included adding and diversifying opportunities to engage and adding or modifying tools to streamline engagement.

Historically, participation in IRP development primarily involved technical experts from organizations such as utility commissions, consumer advocates (i.e. Citizens Utility Board, Alliance of Western Energy Consumers, and Public Counsel), and more recently, environmental advocates. For the 2025 IRP, NW Natural focused on broadening the range of voices heard during the development process. While the aim has been to increase awareness of and

participation in resource planning, the Company reiterates that this continues to be a challenge[63] and echoes similar reports from peer utilities.

A summary of the 2025 IRP engagement tools and enhancements are below. Report-outs and metrics can be found in Appendix I.

General Accessibility Tools and Features

The Company is committed to integrating accessibility features and offerings across its programming, customer communications, and public outreach. Whenever a new tool becomes known or available in one area, efforts are made to implement it throughout the Company as appropriate. For example, when Plain Language accessibility was recommended for bill discount program information materials, the Company's Communications team began incorporating these language screens across its material development process, in addition to bill discount material. This is in addition to NW Natural's practice of providing program information in the top five most used languages in the Company's territory (Chinese, Vietnamese, Russian, Spanish, and English).

During the 2025 IRP development and its public engagements, the Company introduced new accessibility features and resources, including translation services upon request. Other new and notable enhancements include plain language reviews of presented materials, visual accessibility reviews and adjustments to content, and the use of facilitators who specialize in communications and engagement.

Moreover, virtual spaces have enhanced the availability and functionality of accessibility features. These features were highlighted at the beginning of each virtual and hybrid IRP engagement event and included in presentation materials. To date, no requests have been made for translation or additional accessibility resources for IRP related activities.

Dedicated Integrated Resource Planning Webpage and Contact Information

For many years, NW Natural has maintained a resource planning webpage[64] that provides information on past and present IRPs, upcoming meetings and workshops, related materials, recordings of meetings, and contact details for the IRP team. In preparation for the 2025 IRP development, this webpage was updated to offer more comprehensive information on the IRP development process, ways to get involved, and a section for Frequently Asked Questions (FAQs). Additional improvements included a plain language review, broader search term

[63] Although NW Natural saw about 40-50 attendees in each of its Technical Working Groups, participation primarily came from a small subset of attendees during and after each TWG.
[64] https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan

coverage, and renaming the webpage from "Integrated Resource Plan" to "Energy Planning" to enhance clarity and accessibility for the general public.

Within the website sections related to involvement in the IRP, NW Natural has included links to both the OPUC and WUTC websites. The Company has additionally included links to the associated dockets on its site. . While this was a planned action based upon stakeholder feedback in the 2022 IRP, it aligns with the guidance provided by the WUTC to utilities in its Interim Policy Statement Regarding Procedural Justice to "include a link to the appropriate Commission docket associated with the most recently completed GRC, IRP, CEIP...."[65]

NW Natural's dedicated email address for IRP-related communications (IRP@nwnatural.com) remains unchanged. This email address is featured prominently on the resource planning webpage and shared multiple times during each IRP engagement.

Feedback Form

The IRP team regularly requests and responds to feedback. For the 2025 IRP, the team developed an IRP Feedback Form to establish a more standardized approach to its feedback process. The form is publicly accessible on the Company's Energy/Resource Planning webpage and highlighted during each IRP workshop, TWG, and other public engagement events. Feedback form details can be found in Appendix I.

Third-Party Facilitation

The Company engaged a professional Public Engagement Facilitator to help guide and improve its public and technical working group process. NW Natural sought external counsel to provide impartial facilitation and expertise in managing technically complex public processes and fostering meaningful dialogue and collaboration among technical experts, the general public, and the Company. This idea was further endorsed by peer-utilities and CEAG members.

For the 2025 IRP, NW Natural issued a Request for Proposal (RFP) and engaged Maul Foster and Alongi (MFA) to assist in creating, improving, and implementing engagement strategies, provide guidance on public engagement and engagement tools, and incorporate stakeholder feedback regarding IRP public engagement. NW Natural engaged MFA to support its Technical Working Groups, Webinars, and Office Hours.

Open House Workshop

Similar to past IRP cycles, the Company's Open House Workshop kicked off IRP engagement. For the 2025 IRP, the Company offered the workshop as a hybrid event to introduce the IRP

[65] Serviced on May 12, 2025 WUTC docket A-230217, at page 18.

team to stakeholders and foster relationships for the work ahead. Workshop information was presented following accessibility best practices, ensuring it catered to both technically and non-technically inclined attendees. Details can be found in Appendix I.

Two-Track Approach Trial

Mindful that certain aspects of IRP development require technical discussions, the Company sought to establish a dual-track approach to stakeholder engagement, consisting of a technical track and a non-technical track.[66]

In the summer of 2024, NW Natural in consultation with MFA, its third-party facilitation consultant, created an application process for its technical track, referred to as Technical Working Groups (TWGs). The goals of this process were to: 1) broaden the range of voices heard during development, 2) ensure participants possessed the technical knowledge necessary for constructive engagement, and 3) maintain continuity from meeting to meeting.

During development, MFA interviewed past NW Natural IRP stakeholders to gather feedback on the proposed two-track approach. Through these conversations, the Company learned that stakeholders preferred the original TWG process. Consequently, NW Natural discontinued the application process and opened the technical track to all interested parties. Simultaneously, the non-technical track was adjusted to reflect the openness of the TWGs.

Technical Working Groups

In the past, Technical Working Groups (TWGs) were day-long workshops designed to present crucial technical information to stakeholders, covering topics such as risk analysis, scenario development, and modeling methods. However, for the 2025 IRP, NW Natural modified these workshops based on stakeholder input to feature more frequent, but shorter meetings. Specifically, TWGs were shortened to three-hour sessions (down from six to seven hours per session in past IRP cycles), while maintaining their role as a technical forum for consultation and IRP development.

Efforts were made to provide materials in plain language and to adapt visual accessibility best practices where feasible. As has become standard in NW Natural's IRP process, TWGs were recorded and posted to the Company's publicly available webpage. In response to feedback during the 2022 IRP, the Company also made best efforts to provide TWG materials at least two days in advance of each meeting.

[66] This process was described in detail in the Washington IRP Workplan initially filed on May 1, 2024 in docket UG-230801.

Individual TWG meeting summaries are provided in Appendix I. TWG presentations and recordings are additionally available on the Company's website.

In-person Tabling Engagements & Partner Workshops

In-person tabling engagements were utilized to improve awareness and engagement among non-technical audiences. As detailed in Section 3.5.2, the "IRP Fair" was borne out of conversations with the CEAG on ways to improve procedural equity practices and public engagement opportunities in the development of the IRP. CEAG members highlighted the need for a community-based, family-friendly event that provided tangible, meaningful resources and emphasized partnering with trusted organizations, expanding the event's focus beyond energy planning, and scheduling it to accommodate working families and public transportation users.

From these conversations, the Company partnered with a trusted organization to create a comprehensive, resource-rich event that offered free winter coats for kids, weatherization kits, a vaccine clinic, food boxes, and a bill discount sign-up station covering several utilities and services for income-eligible households, which also served to improve awareness of energy planning and ultimately increase informed participation in the future. Importantly, the fair was designed for community benefit and not for the advocacy of any energy policy position.

Initially, fair events were planned to occur twice during the IRP cycle: once at the beginning and once as the plan's development neared a draft release, the goal being to provide an informal pathway to resource planning education and engagement.

As the IRP cycle progressed, the Company had to reassess and adjust the scope of the second fair due to significant changes and impacts in the broader community. Conversations with community partners and direct service providers revealed that many planned events for early 2025 were cancelled, postponed, or anticipated significantly reduced attendance compared to previous years. Loss of funding or uncertain funding, and fear of immigration-related enforcement in public spaces were cited as the primary causes of this shift. Beyond IRP development, the Company actively engages in in-person community events and tabling opportunities across its territory to deliver information on topics such as gas safety, energy efficiency and weatherization, bill discount programs, and emergency preparedness. When the need for a strategic pivot became clear, the Company examined these existing engagement events in which to incorporate resource planning information. For this integration, the Company created an IRP informational toolkit to utilize at community events.

A summary of in-person tabling engagements can be found in Appendix I.

Although adjustments to how the Company engaged with communities were necessary during this IRP cycle, NW Natural recognizes these types of engagements are valuable to customers

and the broader community. Informed by feedback from community members and event organizers, the Company is proposing to build upon these community engagement efforts by bringing forward an annual resource fair focused on energy planning and energy services rather than holding engagements on IRP cycles only.

Partner Workshops

In addition to in-person engagements, the Company participates in virtual workshops and webinars organized by community organizations for direct service providers. During the 2025 IRP development, the Company trialed integrating awareness of energy resource planning into such presentations.

IRP Toolkit

The IRP Toolkit is a foundational set of materials on the IRP for use at in-person events and includes:

- One-pager describing IRPs (available in the top five languages spoken in NW Natural's territory)
- Spec sheets for types of participation with associated QR codes (available in the top five languages spoken in NW Natural's territory)
- IRP business card with QR code

Public Engagement Webinars

Public Engagement Webinars (PEWs) were intended to be part of the non-technical track covered in the Two-Track Trial section previously discussed. With the decision to open the TWGs to the public, the Company modified the non-technical track to include additional engagement opportunities outside of the TWGs, one of which was in the form of a Public Engagement Webinar.

These webinars aimed to introduce the topic of energy planning to individuals who had not previously been involved in such planning efforts. To ensure the webinars were accessible, safe, and open to all stakeholders to learn and participate, the Company engaged MFA, its third-party facilitator. The webinars provided information in a non-technical manner and were designed to encourage engagement through Q&A[67] functions, as well as in-meeting polls and surveys.

[67] Q&A, referring to the abbreviation of Questions and Answers, is a standard webinar feature.

Draft Release Notice

Pursuant to the IRP Guidelines and expectations around equity, NW Natural explored alternative methods to announce its IRP draft release and gather stakeholder feedback. The Company recently updated customer bill formatting and printing, enabling broader outreach to customers. With this update, NW Natural transitioned from using bill inserts to on-bill announcements for the IRP draft release. The public was also informed of the IRP draft release through presentations, e-newsletters, and direct partner outreach.

Outreach for Commission-led Process

NW Natural has committed to improving how it communicates how and/or when to get involved with its stakeholders and customers. The Company has included more information on the processes on its website including links to both the OPUC and WUTC resource planning sections of the agency websites. Similar to IRP meetings and workshops, notice will be posted on the Company's IRP webpage regarding Commission proceedings for NW Natural's 2025 IRP.

3.5.4 Public Engagement Summary

Table 3.3 provides the schedule of public engagement opportunities hosted by the Company during development of the 2025 IRP, while Figure 3.1 provides a summary of participation. Presentation materials, recordings, and other resources related to IRP engagement activities are housed on the Company's website[68] and can be accessed by any member of the public. Detailed summaries of engagement activities and attendee lists are included in Appendix I.

[68] https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan

Table 3.3: Schedule of 2025 IRP Public Engagement

Public Engagement Opportunity & Topic	Date/ Time/ Location	Type & Purpose of Engagement
IRP Open House About NW Natural & Intro to IRPs	Oct 10, 2024; 9-11:30a.m.; Hybrid	Kickoff for the IRP. Meet and greet with opportunity to learn and connect with IRP team.
TWG#1 (TWG 1-1): Planning Environment, Environmental Policy, & Equity Considerations	Oct. 22, 2024; 1-4p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
TWG#2 (TWG 1-2): Planning Envt. follow-up; Scenarios	Nov 1, 2024; 9a.m. – 12p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
Energy Fair: Winter Preparedness & Energy Planning	Nov. 16, 2024; 11a.m. - 2p.m. Portland, OR	Informational and resource forum. Opportunity to learn and engage on Energy Planning and utility programs. Event held in collaboration with community partners.
TWG#3: Scenarios and Climate	Nov. 21, 2024; 9a.m. – 12p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
TWG#4: Load Forecast	December 17, 2024; 1-4p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
TWG#5: Avoided Costs & Demand Side Resources	Jan. 21, 2025; 1-4p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
TWG#6: Supply-Side & Compliance Resources	Jan. 28, 2025; 1-5p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
Public Engagement Webinar #1: Intro to Energy Planning	March 5; 6-7p.m.; Virtual	Webinar format. Opportunity to learn and engage energy planning and utility energy services.
TWG#7	Repurposed	Repurposed to Office Hours
Office Hours: ICF study follow-up	April 1, 2025; 1-4p.m.; Virtual	Technical Forum. Opportunity for TWG participants to ask questions of the Company and third-party consultant regarding a specific study.

TWG#8: Distribution System Planning	April 8, 2025; 1-4p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
Community Partner Workshop: Utility Affordability Programs	April 15, 2025; Virtual	Educational Forum. Convened by and for community partners servicing low-income customers. Content focused on utility energy equity programs and activities.
TWG#9: Resource Optimization Planning Model	May 29, 2025; 9a.m. - 12p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution.
Tabling Event: Energy Planning and Safety	June 7, 2025; 12-3p.m.; Vancouver, WA	Informational and resource forum. Opportunity to learn and engage on safety, energy planning, weatherization, and bill discounts. Event held in collaboration with community partners.
Draft IRP Announcement / Comment Period	June 13, 2025-July 11, 2025; Virtual	Opportunity to be informed and provide feedback.
TWG#10: ICF Study Results and Action Plan	June 26, 2025; 9a.m. - 12p.m.; Virtual	Technical forum. Opportunity for participants to become informed, ask questions, consult on topic, and have opportunity to be involved in and/or collaborate on a solution. Action plan presented and information on how to comment on the draft 2025 IRP provided.
File 2025 IRP	August 1, 2025; Virtual	Opportunity to be informed and provide feedback.

Figure 3.1: 2025 Public Engagement Summary

4 Resource Requirements

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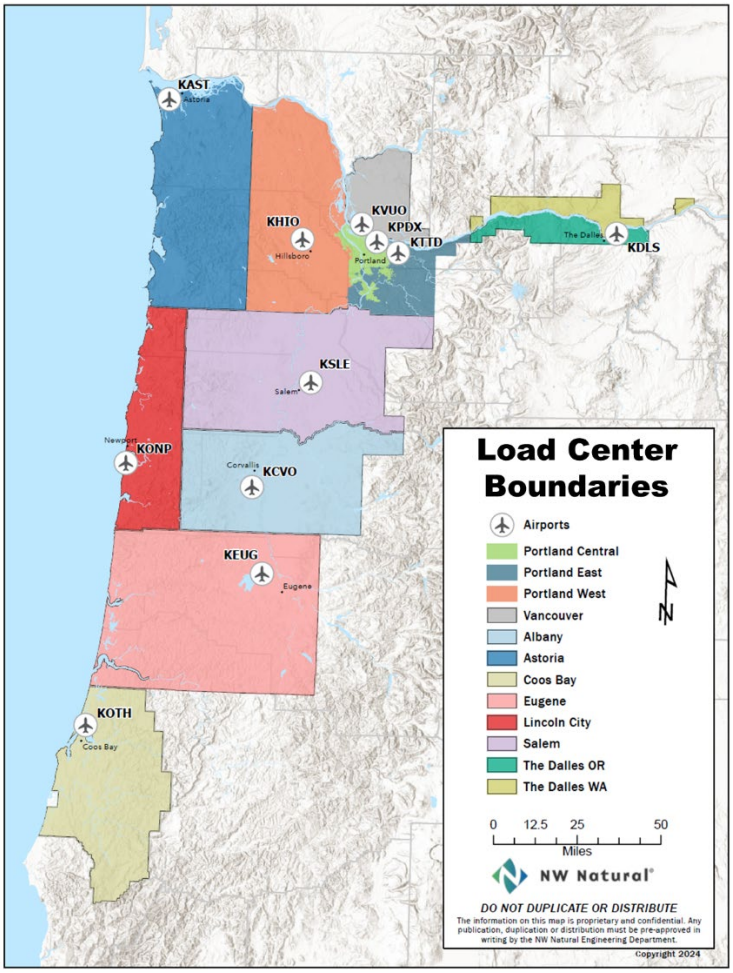
The resource requirements that NW Natural plans for to reliably serve customers and comply with state emissions are ultimately dependent on the energy demanded in the Company's service territory. This chapter breaks down how NW Natural forecasts demand that is primarily driven by the number of customers on the system, weather, and industrial usage.

4.1 Customer Forecast – Reference Case

Forecasting demand for gas begins with an analysis of current residential, commercial, and industrial customers. The IRP defines a single customer as a natural gas meter in service. Once current customer counts are determined, forecasts of these customer groups over the planning horizon are required to forecast load demand. The customer count forecast is an integral part of the load forecast since resource requirements are ultimately determined by the aggregate demand across all customer types.

Customer count forecasts for residential and commercial customers are forecasted by state, including components of new construction, conversions, and existing customers. Forecasts by state are distributed across 12 load centers spanning the service territory. Customer count forecasts by load center allow for different usage profiles across the territory, where some areas may have more or less growth, and across geographies, where certain climates result in more or less gas usage per customer. Figure 4.1 shows the load centers with airports indicated where weather conditions are recorded and used for load forecasting.

Figure 4.1: Load Centers Used for Load Forecasting



4.1.1 Methodology

The customer count forecast relies on historical data, input from internal subject matter experts (SMEs), and econometric models to project residential and commercial customer counts over the planning horizon. The process can be divided into two parts: the near-term customer count forecast and the long-term customer count forecast. This process does not include a forecast of industrial and large commercial customers due to large differences in usage profiles amongst these customers. The process for forecasting industrial customers is described later in the chapter.

4.1.2 Near-term Customer Count Forecast

Also known as NW Natural's SME meter set forecast, the near-term customer count forecast relies on a combination of historical data, forecasts from the Oregon Office of Economic Analysis (OEA) and others, regression analyses, and knowledge from SMEs within the company. SMEs include representatives from Business Planning, Business Analytics, Customer Lifecycle Management, Marketing, and Account Services who have detailed knowledge of customer trends informed by data, analytics, market research, and discussions with customers across the service territory. The SME meter set forecast extends three years and includes annual counts for existing and new residential and commercial customers by state. It is conducted three times a year.

4.1.3 Long-term Customer Count Forecast

The long-term customer count forecast is based on econometric models for four major customer series: Oregon residential, Oregon commercial, Washington residential, and Washington commercial. NW Natural uses Autoregressive Integrated Moving Average (ARIMA) models to forecast all four series. ARIMA models are used for time series forecasting and predict future values based on a combination of past values and/or error terms. Models are selected based on the best combination of Akaike information criterion (AIC) and mean absolute percentage error (MAPE). NW Natural also uses independent variables in each ARIMA model to improve accuracy. Independent variables selected are shown to have a correlation to and effect on the time series being modeled. Independent variables used in the four ARIMA models are shown in Table 4.1.

Table 4.1: Independent Variables Used in Customer Count Forecast ARIMA Models

Model	Oregon	Washington
Residential	Oregon Housing Starts	Oregon Housing Starts
Commercial	Oregon Population	Oregon Total Nonfarm Employment

Source: Oregon Office of Economic Analysis, Oregon Economic and Revenue Forecast September 2024.

4.1.4 Near-term and Long-term Blending

The near-term customer count forecast is blended with the long-term customer count forecast at the beginning of the forecast period after which change rates from the four ARIMA models forecast customer counts out to the end of the forecast period. Once annual forecasts of total customer counts for the four series are complete, allocations of customer change are distributed to sub-segments of the forecasts, including new customers, conversions, and existing customers. Generally, these allocations are based on historical growth patterns. Finally,

these forecasts are allocated to 12 load centers in the Company's service territory, again, relying on historical growth patterns. Annual load center forecasts are then converted to monthly and daily customer counts for use in load forecasting.

4.1.5 Customer Count Forecast Methodology Changes in 2025 IRP

For every IRP, NW Natural explores changes to forecast methodologies that may be required or preferred, and to reflect input from stakeholders and OPUC and WUTC staff. For the 2025 IRP, a few changes were made to the customer count forecast methodology that are described below. Outside of these changes, the methodology is substantively unchanged from the 2022 IRP.

4.1.5.1 Near-term Customer Count Forecast as Forward-looking Time Series

The near-term customer count forecast was used as a forward-looking time series in the Oregon commercial and Washington residential models to provide more flexibility and policy responsiveness. This means the near-term forecast was added to historical data and ARIMA models were estimated on the combined time series. The near-term forecasts are far more sensitive to recent changes in growth and policy since they are conducted three times a year and include input from SMEs who do not rely exclusively on historical data for their forecasts. Without the forward-looking time series, historical data for the Oregon commercial and Washington residential models led to long-term forecasts that were out of line with near-term forecasts. Because the near-term forecast data is included in these ARIMA models it is not blended with the long-term forecast in the final forecast.

4.1.5.2 Shorter Time Series for Modeling

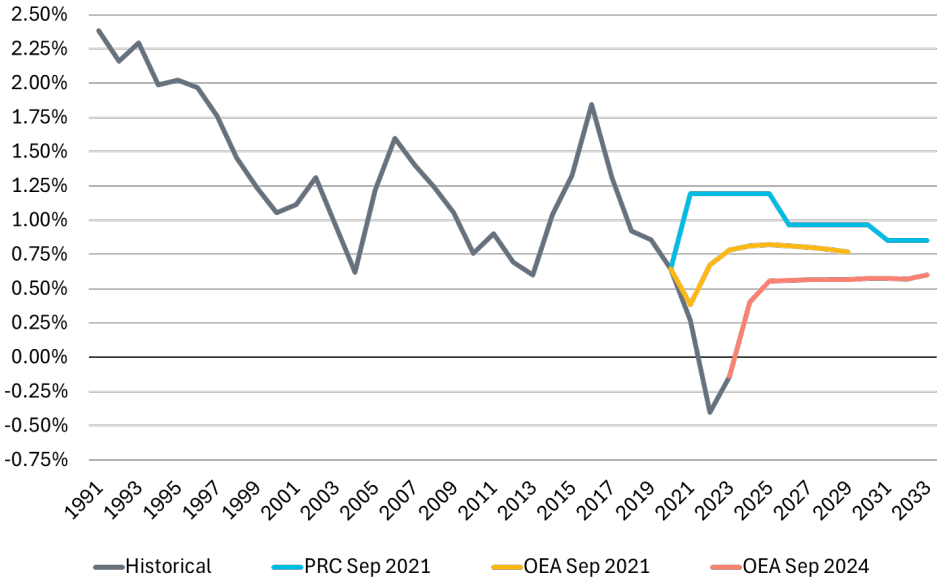
For Washington, shorter time series were included in the residential and commercial models to adapt to changes in growth patterns. Like the use of near-term customer count forecasts in modeling, shorter time series are another tool to provide more flexibility and policy responsiveness in the customer count forecast.

4.1.6 *Macroeconomic Drivers of Change in the Customer Count Forecast*

The macroeconomic environment in the Company's service territory has changed significantly since analysis was done for the 2022 IRP. All the independent variables used in the ARIMA models for the customer count forecast utilize data and forecasts from the OEA, which produces economic forecasts on a quarterly basis. The 2025 IRP customer count forecast uses forecasts of housing starts, employment, and population from OEA's September 2024 economic and revenue forecast (Table 4.1). Across the board, forecasts for these variables are lower than they were two years ago. As a result, customer count growth across the service territory is lower than was forecasted in the 2022 IRP, especially for Oregon, which has seen its population decline since 2021. Figures 4.2 and 4.3 show these forecast differences for Oregon population

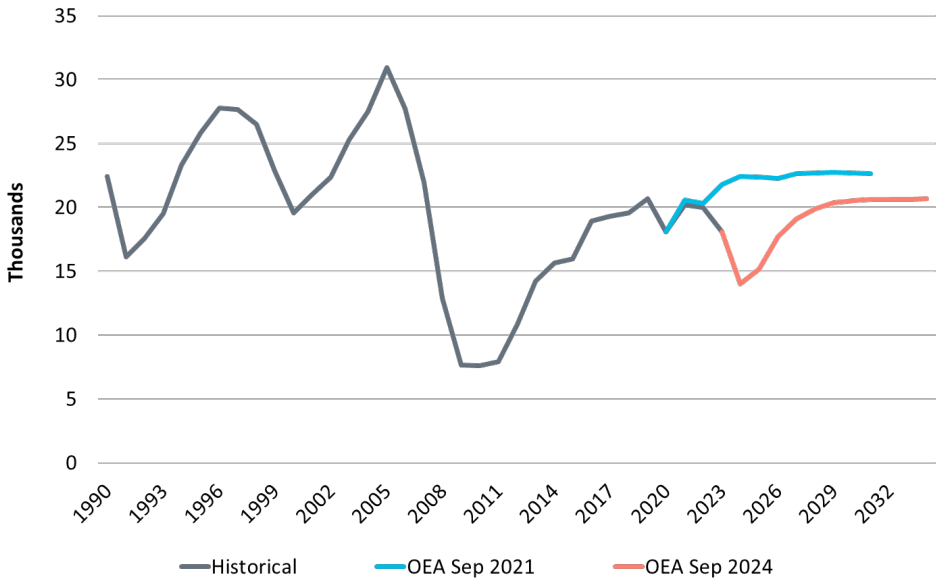
and housing starts. Within the population figure, the September 2021 population forecast from the Portland State University Population Research Center (PRC) was the population forecast used in the 2022 IRP. For the 2025 IRP, the Company has chosen to use the OEA population forecast since the PRC forecast has proven to be less reliable since 2021.

Figure 4.2: Oregon Population Change



Source: Oregon Office of Economic Analysis and Portland State University, Population Research Center.

Figure 4.3: Oregon Housing Starts



Source: Oregon Office of Economic Analysis.

4.1.7 Residential and Commercial Customer Count Forecast

The Reference Case customer count forecast represents a current business and policy perspective, which is to say it is the future the Company most likely expects to occur over the planning horizon under existing, current policies. Given the rapidly evolving policy environment and recent macroeconomic changes, this presents challenges creating a forecast that reflects past trends while capturing emerging trends. The methodological changes described above provide a way for the customer count forecast to deal with these challenges and produce a reference case that can continue to adapt to changes in near-term and long-term trends.

Figures 4.4 and 4.5 show the Reference Case residential and commercial customer count forecasts for the 2025 IRP. Further breakouts by state are included in Appendix B.

Figure 4.4: System Residential Customers – Reference Case

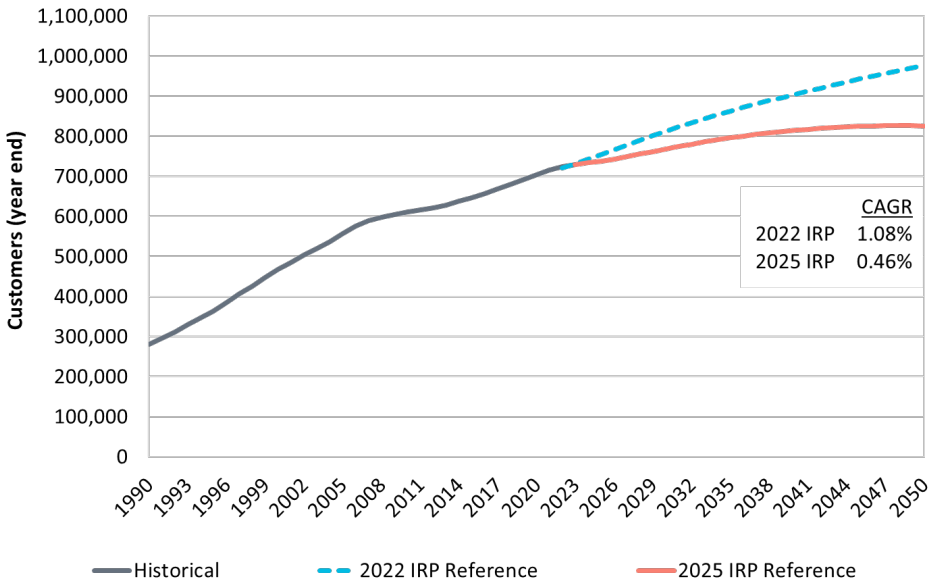
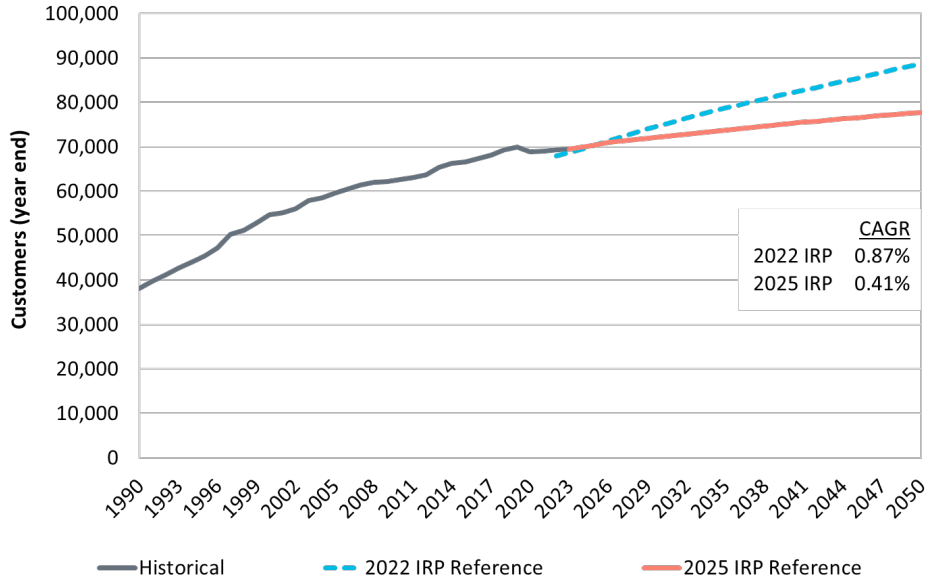


Figure 4.5: System Commercial Customers – Reference Case



4.2 Weather

This section discusses the development of the expected weather forecast, which is an input into NW Natural's Reference Case load modeling, over the planning horizon. This section also discusses how the Company models weather volatility, which is pivotal for both resource planning adequacy and complying with emissions obligations.

4.2.1 Climate Adjusted Weather Forecast

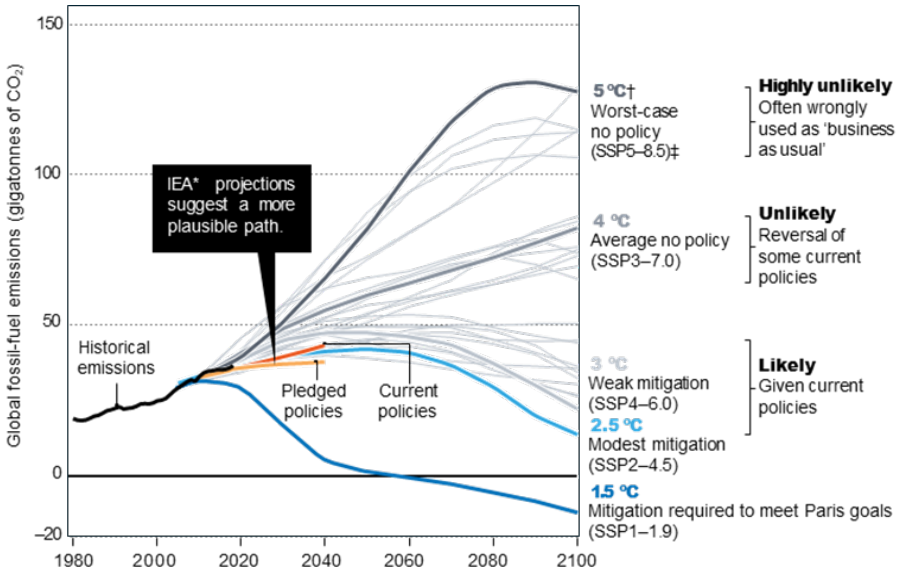
Climate change refers to long-term shifts in global temperatures and weather patterns. While the impact of climate change across the World is disparate, no region, including the Pacific Northwest, is completely insulated from its effects. Given that weather is a primary driver of natural gas demand, and hence a critical input to load forecasting, the trends in regional temperature shifts are important to consider for NW Natural's long-term resource planning. This section explains how climate change trends are incorporated into load forecast modeling.[69]

For the 2025 IRP, NW Natural contracted with ICF, a global advisory and technology services consultant, to integrate climate modeling into its weather forecasts and inform the long-term

[69] NW Natural has included climate change modeling into long-term load forecasting since the 2018 IRP Update #3.

trends in annual heating degree days (HDDs) over the forecast horizon.[70] The foundation of this process is Global Climate Model (GCM) projections, which simulate the Earth's climate and physical processes. A 22-member ensemble of GCMs is used by the Intergovernmental Panel on Climate Change (IPCC) to determine a range of potential future climate conditions amidst uncertainty. The most recent climate futures developed by the IPCC employ five distinct Shared Socioeconomic Pathways (SSPs) emission scenarios. Figure 4.6 shows the range of climate change scenarios, which represent emissions pathways under varying levels of greenhouse gas emissions reduction.[71]

Figure 4.6: Emissions Pathways

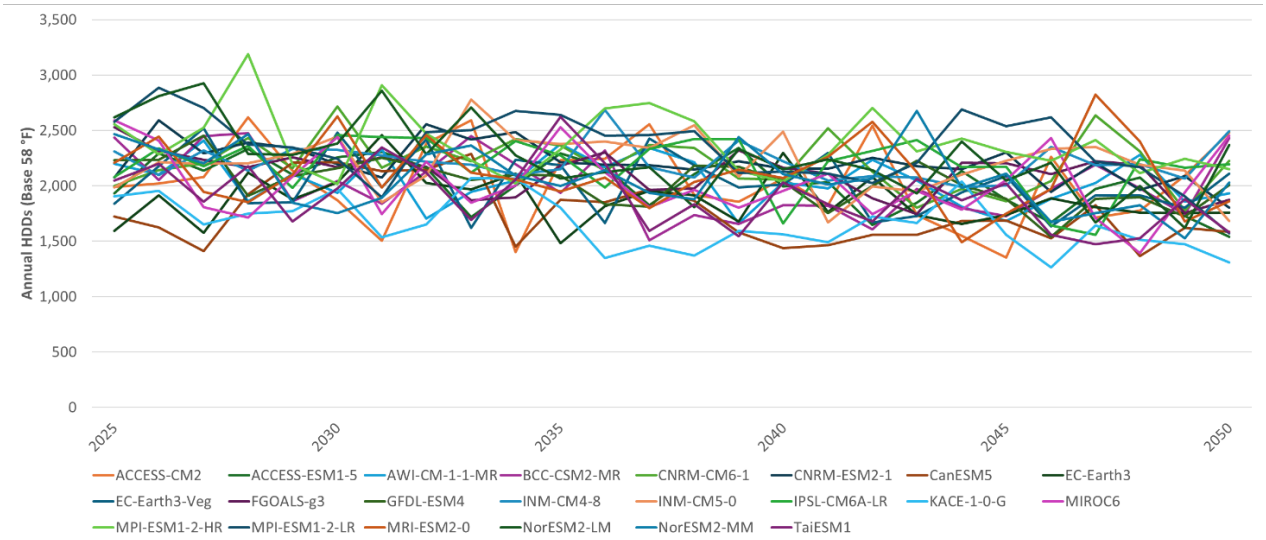


NW Natural developed climate projections specific to the Pacific Northwest under both SSP2-4.5 and SSP3-7.0 to account for uncertainty in future emissions and climate sensitivity. While SSP3-7.0 assumes greenhouse gas emissions increase throughout the century, SSP2-4.5, which is deemed as a relatively more likely path, assumes a meaningful reduction in greenhouse gas emissions by mid-century. The HDDs from SSP2-4.5 versus SSP3-7.0 for the Pacific Northwest are not materially different until after the planning horizon.[72] Therefore, for the 2025 IRP, the Company has selected SSP2-4.5 to incorporate into its load forecasting.

[70] For IRP load forecasting, heating degree day (HDD) calculations assume an average outside temperature of 58 °F. This temperature aligns with NW Natural's historical system usage for space heating.
[71] Hausfather, Z. and Peters, G.P., Emissions—the 'business as usual' story is misleading, 2020. *Nature*, 577 (7792), 618-620.
[72] For example, in the Reference Case, the Portland Central load center has only 19 (or 0.97%) more HDDs under SSP2-4.5 than SSPS3-7.0 in the year 2050.

Under SSP2-4.5, GCM projections are downscaled to a higher spatial resolution that better captures regional and local climate characteristics. Specifically, NW Natural used Localized Constructed Analogs Version 2 (LOCA2) downscaled climate projections to develop custom HDD projections for each of the load center weather stations in NW Natural's service territory.[73] To produce a robust outlook of protracted climate trends, the whole 22-member ensemble of downscaled GCMs were used. To illustrate, Figure 4.7 shows the HDD projections of the 22 GCMs for one of NW Natural's load centers—Portland Central. Projections show, on average, a declining trend in HDDs with significant interannual variability.

Figure 4.7: SSP2-4.5 Annual HDD GCM Projections for Portland Central



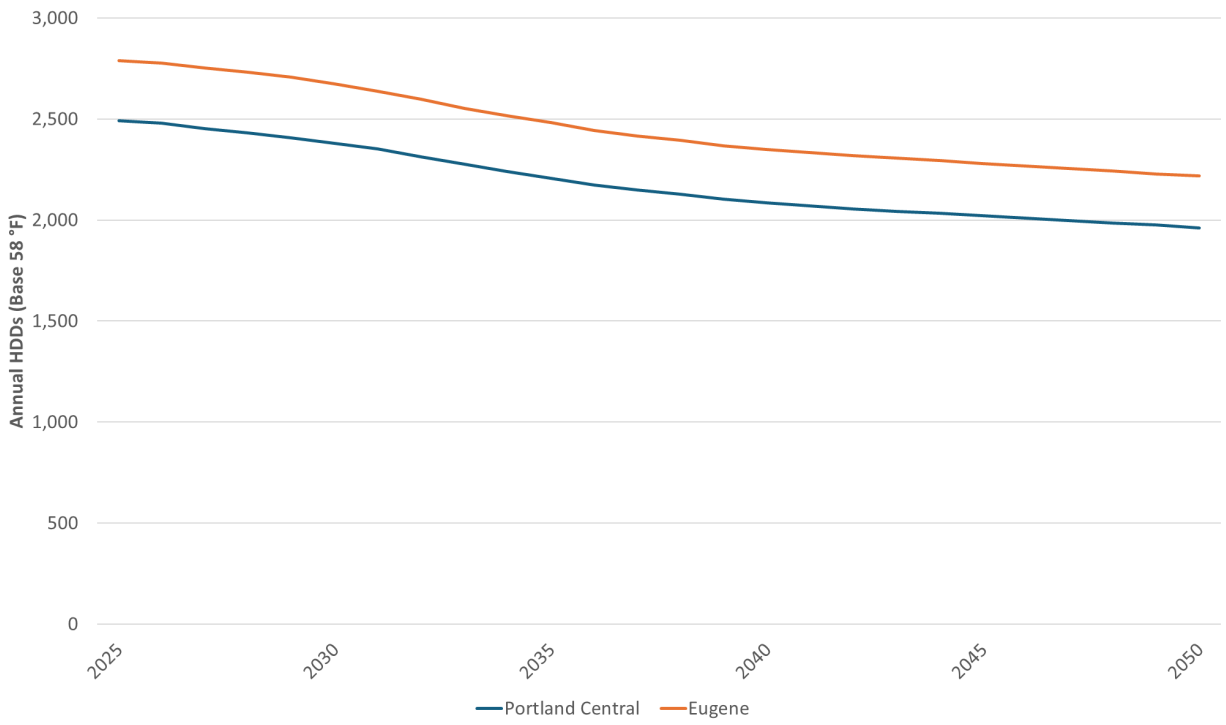
4.2.2 Expected Weather

Given that NW Natural's load is primarily driven by heating requirements, the expected weather forecast focuses on annual HDDs through the forecast horizon. Due to the stochastic nature of individual GCM projections, a disconnect exists between recently observed HDDs and near-term (i.e., less than 10 years) projections of climate models. To resolve this local climatology inconsistency, ICF developed a 30-year moving average of HDDs for the forecast period, 2025-2050. This approach blends projections of future HDDs with recent HDD observations, a more reliable predictor of near-term weather conditions, by applying

[73] Downscaling of the IPCC data to NW Natural's service territory is made available by Archive Collaborators (i.e., Bureau of Reclamation, California-Nevada Climate Applications Program, Climate Analytics Group, Cooperative Institute for Research in Environmental Sciences, Lawrence Livermore National Laboratory, National Center for Atmospheric Research, Santa Clara University, Scripps Institution of Oceanography, Southwest Climate Adaptation Science Center, U.S. Army Corps of Engineers, and U.S. Geological Survey). The downscaling tool is free to use and is hosted on a website maintained by Lawrence Livermore National Laboratory (LLNL): https://gdo-dcp.ucllnl.org/downscaled_cmip_projections.

progressively more weight to the GCMs for more distant time periods in the forecast. This methodology not only incorporates climate model uncertainties into the estimates but also minimizes interannual variability in the final time series.[74] As an example, Figure 4.8 shows the expected annual HDDs for two of NW Natural load centers—Portland Central and Eugene. While both load centers have distinct weather patterns, as indicated by the differing magnitude of HDDs, the trend of declining HDDs is similar.

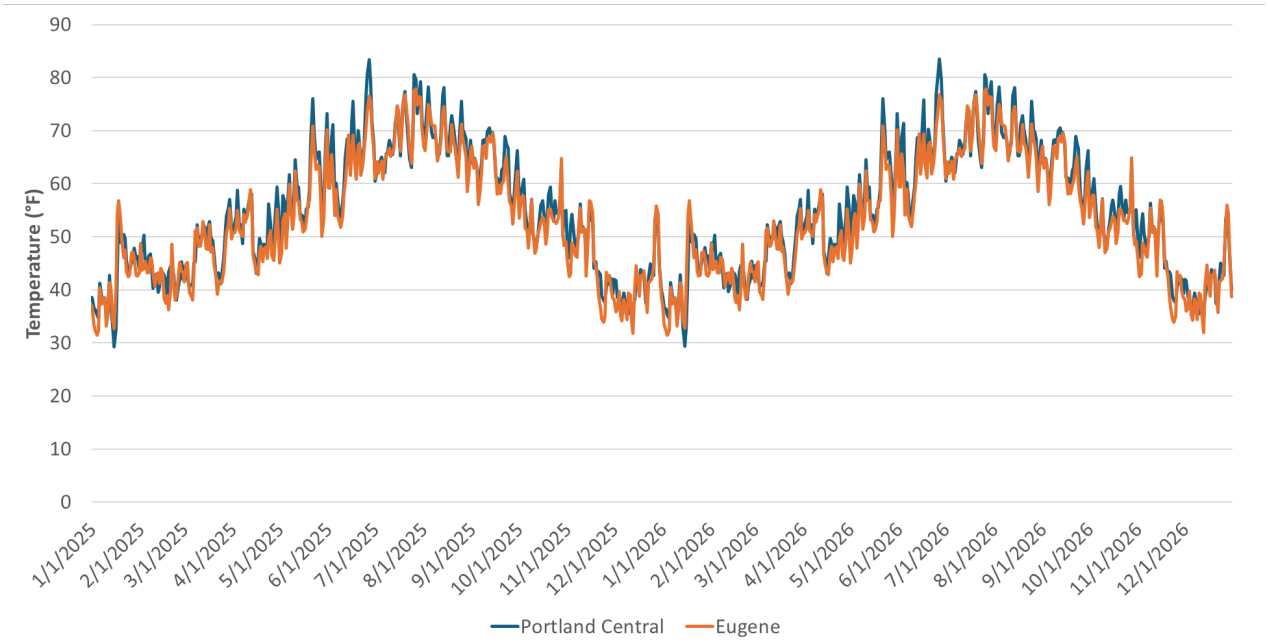
Figure 4.8: Expected Weather Annual HDDs by Load Center



The HDD moving average is the basis of NW Natural's expected weather forecast. Intra-year shaping is then applied to each forecast month, followed by intra-month shaping to each day, in order to translate the HDDs into a daily forecast of temperatures. This shaping process is developed using a representative temperature pattern that is applied to each year in the forecast.[75] In other words, each year in the forecast will have the same shape, but overall temperatures are increasing (i.e., HDDs are decreasing) through the planning horizon. Figure 4.9 displays the intra-year shaping for the first two years of the forecast horizon for both the Portland Central and Eugene load centers.

[74] For a detailed discussion of this methodology see Appendix B.
[75] Using a representative weather pattern creates realistic volatility in daily temperatures, which is important for modeling resource dispatching.

Figure 4.9: Expected Weather Intra-year Shaping by Load Center



4.2.3 Weather Uncertainty

While expected weather provides a reference which NW Natural can use for emissions compliance planning and resource portfolio evaluation, the reality is that weather is random, both at a daily level and at an annual level. Some years will be colder (warmer) than anticipated and have higher (lower) cumulative HDDs than expected. Moreover, it is also possible that the Pacific Northwest experiences consecutive colder (warmer) years relative to expected weather due to natural climate variability and longer-term trends (e.g., El Niño and La Niña phases of the climate cycle).

For NW Natural's system resource planning, it is important to understand the bounds of weather outcomes, especially with emissions compliance obligations under the CPP and CCA. Colder (warmer) years will generally result in higher (lower) emissions, but NW Natural's compliance obligation(s) under the CPP and CCA are a straight-line trajectory reduction from the baseline. Thus, consecutive cold years may have meaningful consequences for acquiring qualified compliance resources within a given compliance period.

This IRP implements a Monte Carlo weather simulation to understand the potential range of daily, monthly, and annual HDDs/temperatures.[76] Relying on both historical data and climate change modeling forecasts, weather is simulated for each load center over the planning horizon. The simulations provide variation in annual HDDs from one year to the next as well as intra-year weather patterns which correlate across the Company's load centers.[77] Figure 4.10 highlights such random variation with five randomly selected Monte Carlo draws for the Portland Central load center. Note that the term "*draw*" refers to a single randomized forecast generated from any of the simulation types discussed throughout this IRP.

Figure 4.10: Weather Simulation – Annual HDDs for Portland Central

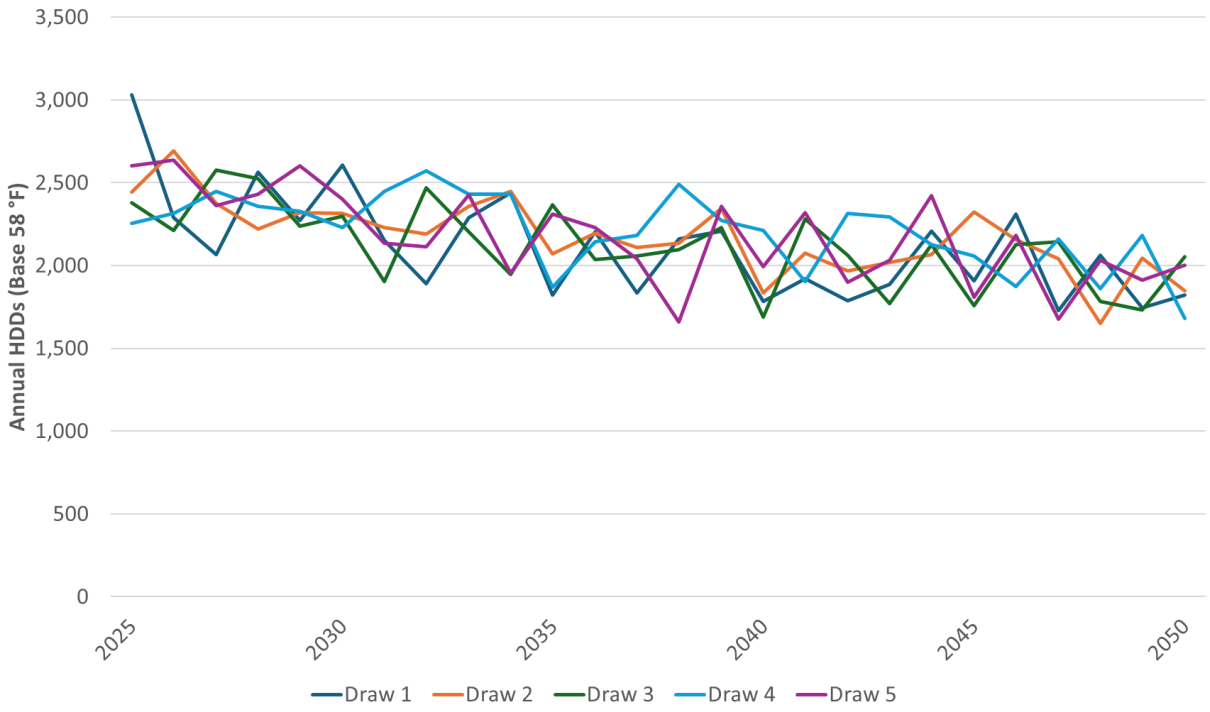
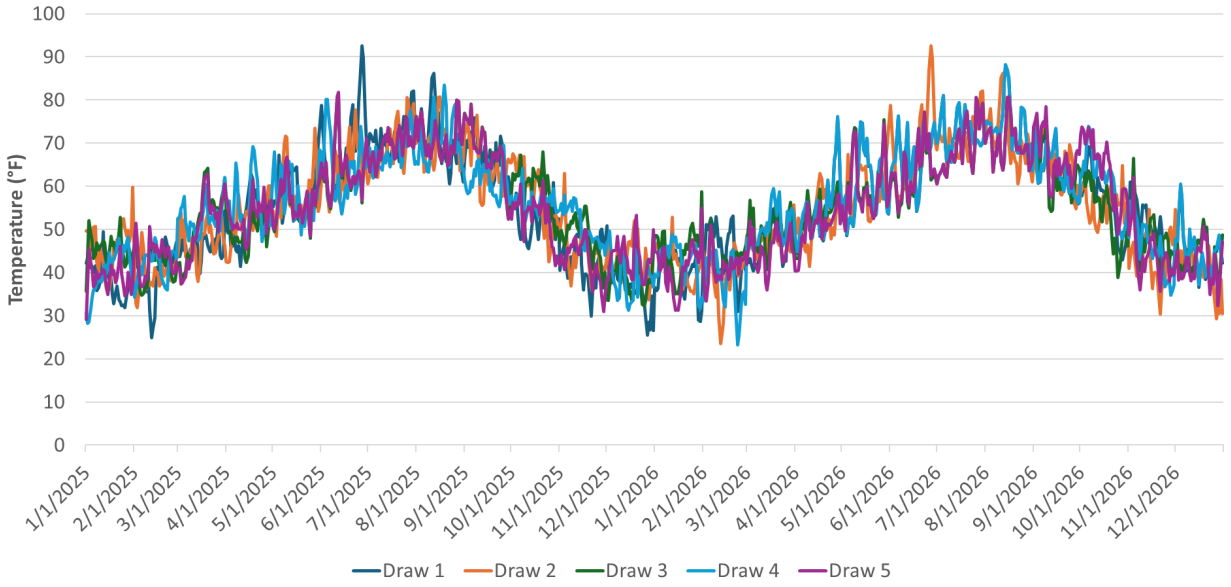


Figure 4.11 shows the translation of the annual HDDs in Figure 4.10 into daily temperatures for the first two years of the forecast horizon, illustrating the variability of intra-year weather shaping.

[76] The Monte Carlo simulation discussed in this section is distinct from the Monte Carlo methodology used to develop the design firm sales peak day forecast.
[77] In total, there are 500 weather simulations across each load center. Appendix B. provides additional details on the simulation process.

Figure 4.11: Weather Simulation – Daily Temperatures for Portland Central



4.3 Annual Load

This section discusses the development of the use-per-customer (UPC) model for residential and small commercial market segments to derive annual load estimates. Further, the incorporation of energy efficiency into these load estimates and the resulting impact is examined. Finally, the load modeling process for industrial and large commercial customers is also reviewed.

4.3.1 Residential and Small Commercial Use Per Customer

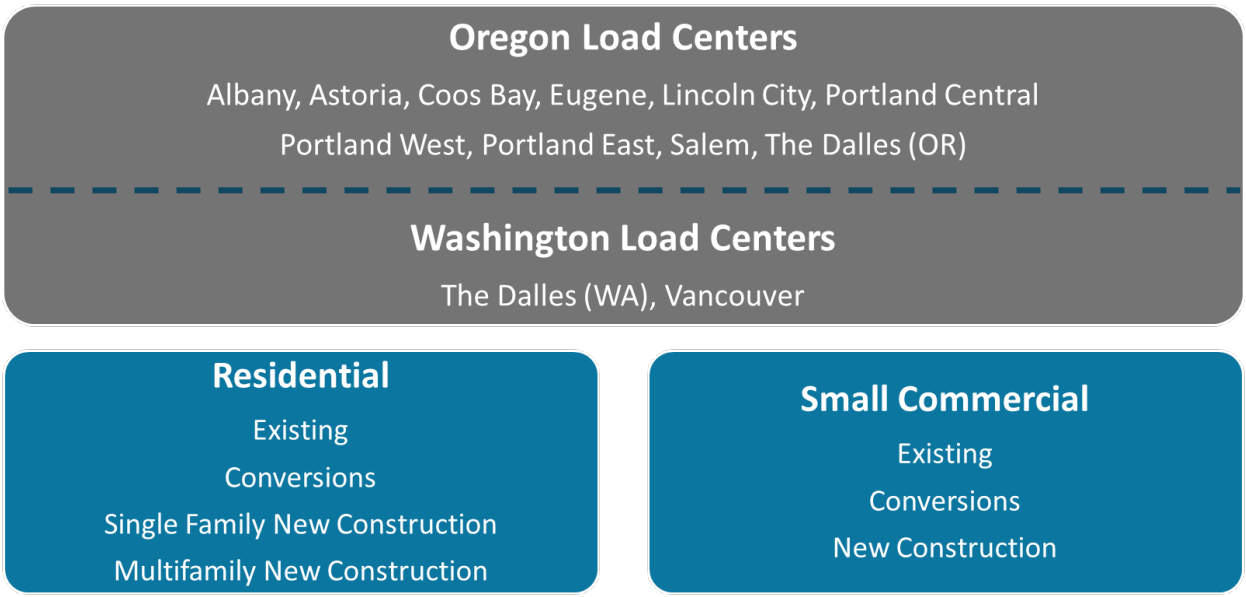
The Reference Case demand for residential and small commercial customers is developed via a bottom-up approach which combines the weather forecasts and customer count forecasts, as described in the previous sections, with historical billing and weather data.[78] In essence, by matching historical monthly customer billing data with corresponding weather data, NW Natural is able to model average daily use-per-customer demand as a function of daily temperatures. The average UPC can then be paired with weather and customer forecasts to estimate future demand.

To add specificity to the modeling process it is ideal to start with a visualization of the Company's load centers. Figure 4.12 displays a hierarchy of the Company's service territories.

[78] Small commercial load excludes rate schedules 31CSF/32CSF and C41SF/C42SF—these rate schedules are estimated separately as "Large Commercial."

At the top of this figure are the Company's 12 load centers, grouped by state. Each load center models two rate classes—residential and small commercial—and within each rate class are its respective market segments. For the existing residential and small commercial market segments, the UPC modeling process occurs at the load center level. That is, each load center will have its own UPC estimates (i.e., average therms per customer per day as a function of temperature) for these two market segments, for a total of 24 UPC estimates. Next, the existing UPC estimates are paired with their load centers' respective daily expected weather forecasts to determine appropriate future demand. Demand is then multiplied by the load center's customer count forecast to determine the expected daily load.

Figure 4.12: UPC Model Hierarchy

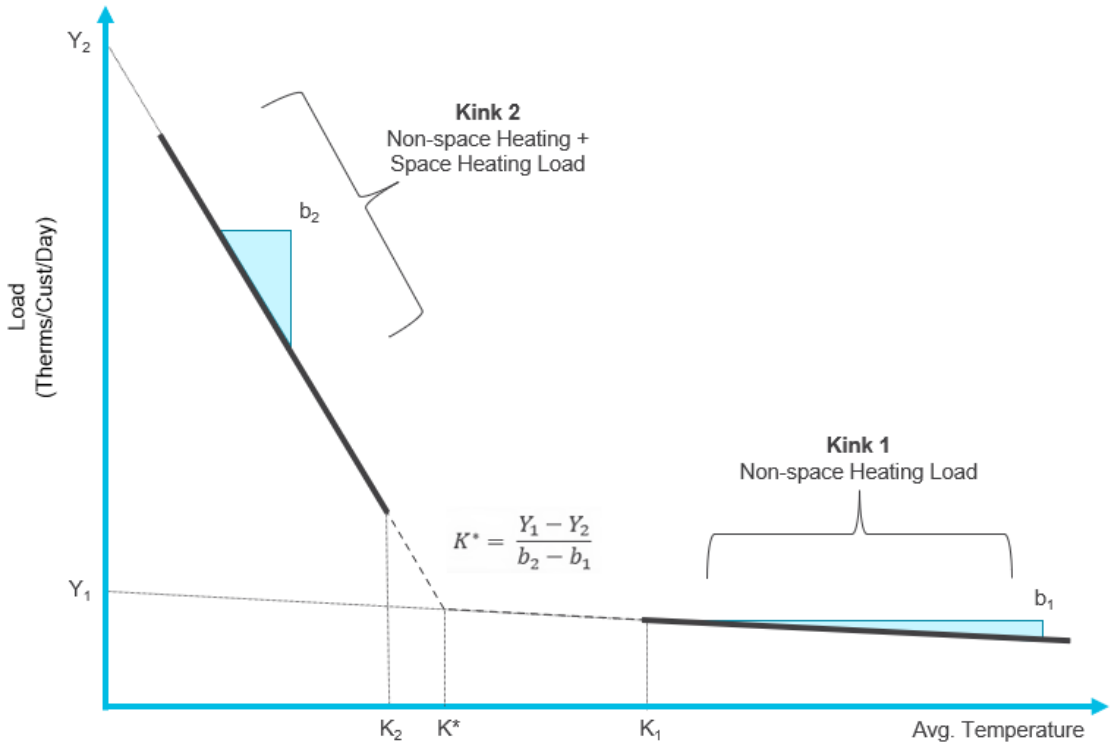


Given the ample supply of monthly billing data for existing customers, UPC estimates can be derived at the load center level.[79] However, due to data constraints the UPC estimates for the conversions and new construction market segments must be derived slightly differently.[80] In the latter case, UPC is estimated at the state level and subsequently applied across corresponding load centers within the state.[81] Still, load center specific weather and customer count forecasts are applied to each market segment to determine forecasted demand.

[79] All billing data used in this IRP spans the time frame January 1, 2021 – March 31, 2004, in order to best capture how customers are using gas currently. This contrasts with the 2022 IRP which used billing data going back to January 1, 2009.
[80] New construction is defined as customers who have come onto the NW Natural system since January 1, 2021.
[81] While the UPC estimates for the market segments are homogenous across a particular state, the weather data that is paired with those estimates is specific to the load center.

The UPC model employs a piece-wise demand function, where demand is solely a function of temperature. Each UPC estimate will have two demand curves. The flat demand curve represents customer usage over warmer temperatures (i.e., non-space heating load). The steep demand curve represents customer usage over colder temperatures (i.e., non-space heating plus space heating load). Figure 4.13 displays the theoretical model of a customer demand profile.

Figure 4.13: Theoretical UPC Model



Kink 1 is the demand profile for non-space heating load and is represented by the slope b_1. This slope is estimated using monthly data where the average temperature is greater than or equal to K_1. This cut-off point (i.e., K_1) reduces the impact of weather volatility on the demand profile during shoulder months, where monthly average temperatures may include a high mix of space-heating and non-space heating days. Kink 2 is the demand profile for non-space heating plus space heating load and is represented by the slope b_2. In contrast to kink 1, this slope is estimated with data where the average temperature is less than or equal to K_2.[82] This restriction is similarly performed to reduce the impact of weather volatility on the demand profile from shoulder months. Moving from right to left, along the x-axis, the average

[82] The values for K_1 and K_2 are optimized by selecting regression coefficients which yield the smallest in-sample mean absolute percentage error (MAPE), subject to minimum sample size constraints.

temperature inflection point (K*) represents where space heating load accelerates. It is evaluated as the point where the two demand curves intersect and, for the average customer, will vary by load center, rate class, and market segment. Equation (1) generalizes the piecewise linear model:

$$D_{j,l,r,m}(t) = \begin{cases} Y_{1_{l,r,m}} + b_{1_{l,r,m}} t_{j,l} + \epsilon_{1_{j,l,r,m}}, & t \geq K_1 \\ Y_{2_{l,r,m}} + b_{2_{l,r,m}} t_{j,l} + \epsilon_{2_{j,l,r,m}}, & t \leq K_2 \end{cases} \quad (1)$$

where, $D_j(t)$ is historical monthly demand (in therms), t_j is the historical average monthly temperature, Y_i is the intercept parameter, b_i is the slope parameter, ϵ_j is the residuals of the *j*th month, and subscripts *l, r, and m* represent the load center, rate class, and market segment, respectively.[83] The Ordinary Least Squares (OLS) estimator is used to estimate the equation parameters.[84]

Given the optimized regression parameters, the forecasted average daily UPC (UPC_i) can be calculated conditional on the forecasted average daily temperature (T_i) following equation (2):

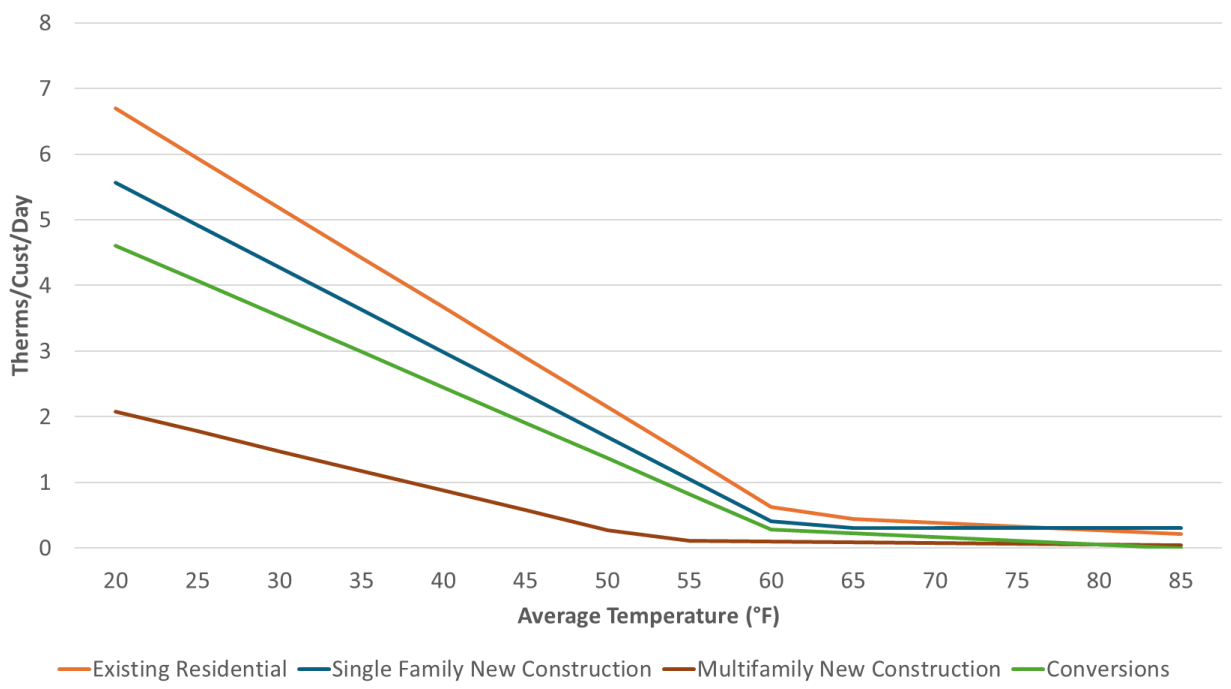
$$UPC_{i,l,r,m}|T_{i,l} = \begin{cases} Y_{1_{l,r,m}} + b_{1_{l,r,m}} T_{i,l}, & T_{i,l} \geq K^* \\ Y_{2_{l,r,m}} + b_{2_{l,r,m}} T_{i,l}, & T_{i,l} < K^* \end{cases} \quad (2)$$

where, subscript *i* represents the day in the forecast horizon.

Figure 4.14 illustrates the predicted UPC values for the Portland Central residential rate class. For each market segment it is clear that, for a given temperature, the steepness of the slope(s) varies, along with the inflection points between kink 1 and kink 2. For this load center, existing customers have a much higher UPC relative to new construction (single family and multifamily). The UPC for conversions sits between existing (the upper UPC bound) and multifamily new construction (the lower UPC bound).

[83] When estimating the UPC coefficients for both the conversions and new construction market segments, respectively, the load center subscript (*l*) reduces to the state-level and the regression effectively becomes a state panel.
[84] The table of parameter values for each load center, rate class, and market segment can be found in Appendix B.

Figure 4.14: Predicted UPC Values for Portland Central Residential



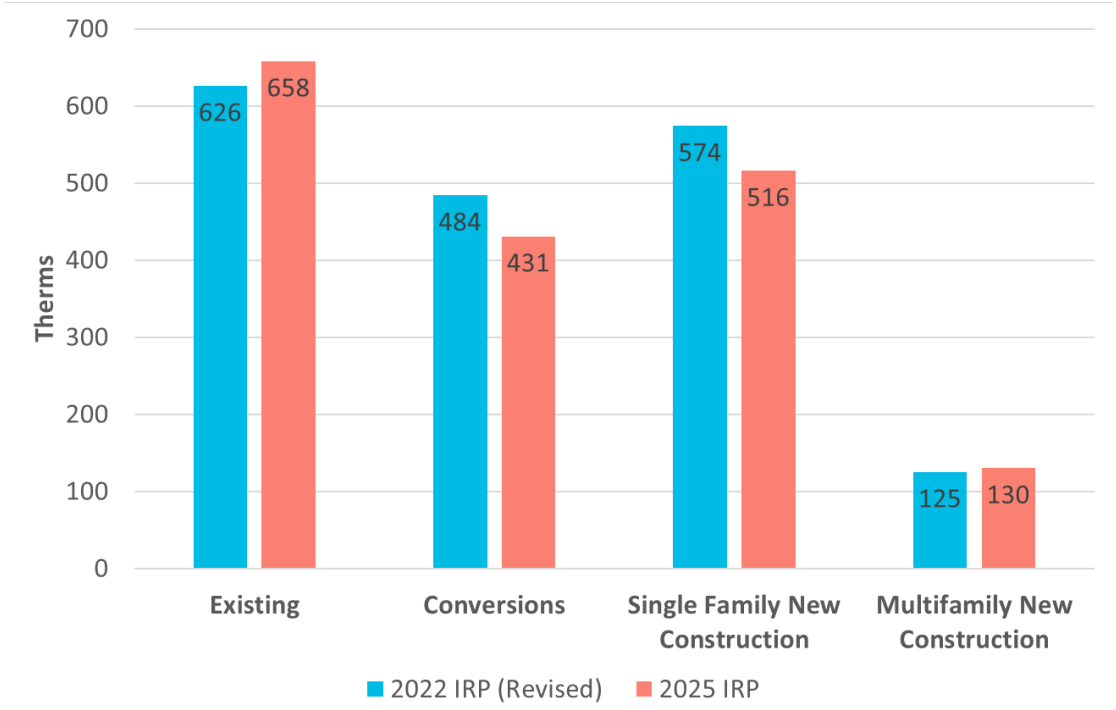
Following Figure 4.15, by incorporating the 2025 expected weather forecasts into the appropriate UPC estimates, grouped by rate class and market segment, and then multiplying the subsequent demand estimates by their respective customer count forecasts, the result is the average first-year UPC estimates for the Reference Case load forecast.

Figure 4.15: Flow Diagram of UPC First-year Estimates

Figures 4.16 and 4.17 compare these estimates to their respective 2022 IRP counterparts. Average residential existing usage has increased since the 2022 IRP. The higher first-year

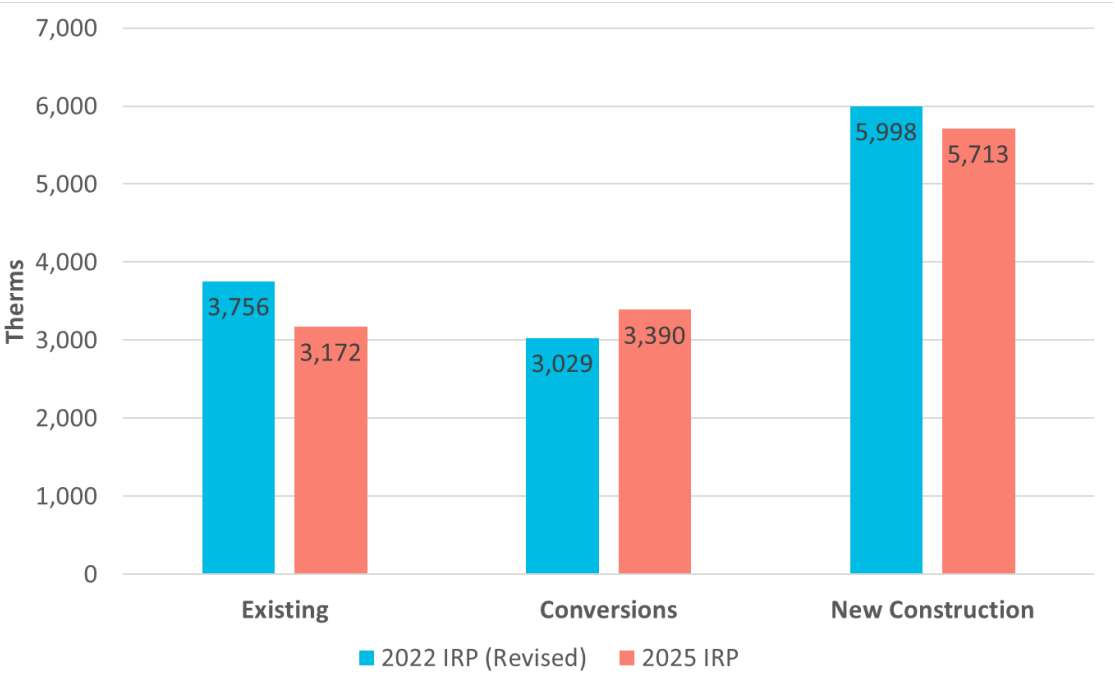
estimates for existing customers are consistent with the theme of more hybrid and remote work post-2020—a pattern we see bear out for many of NW Natural's load centers. Residential conversions and single family new construction have moderately lower estimates compared to the 2022 IRP, while multifamily new construction has remained relatively flat. In contrast to the residential rate class, average small commercial existing usage has declined since the 2022 IRP. These lower demand estimates similarly align with the hybrid/remote work theme. Small commercial conversions exhibit moderately higher average first-year estimates compared to the 2022 IRP, while the new construction market segment shows a decline in first-years estimates.[85]

Figure 4.16: Average First-year Residential Demand



[85] The first-year demand estimates do not incorporate any exogenous energy efficiency assumptions for comparison purposes across IRPs.

Figure 4.17: Average First-year Small Commercial Demand



4.3.1.1 Forecasted Energy Efficiency

NW Natural's load forecasting models incorporate energy efficiency savings estimates throughout the forecast horizon. The Energy Trust of Oregon (ETO) currently administers energy efficiency programs for residential, commercial, and industrial sales customers in Oregon and residential and commercial sales customers in Washington. NW Natural has recently established energy efficiency programs for industrial transportation customers across both states to further increase efficiency savings. The expectation is that NW Natural will see reasonable amounts of these savings materialize in Oregon in 2025 and in Washington in 2026.[86] Further, NW Natural is working to establish a cost-effective energy efficiency savings program for Washington industrial sales customers.

As shown in Table 4.2, ETO provides NW Natural with a therm savings forecast across multiple rate classes for sales customers, known as a conservation potential assessment (CPA), for the incentive programs currently being offered in Oregon. In Washington, NW Natural retained a third-party consultant, Applied Energy Group (AEG), to conduct a CPA for Washington sales

[86] The forecasted therm savings for Oregon transportation customers is approximately 550,000 therms. In Washington the forecasted savings is approximately 72,000 therms.

customers and provide two high-level CPAs for transportation customers in NW Natural's system.[87]

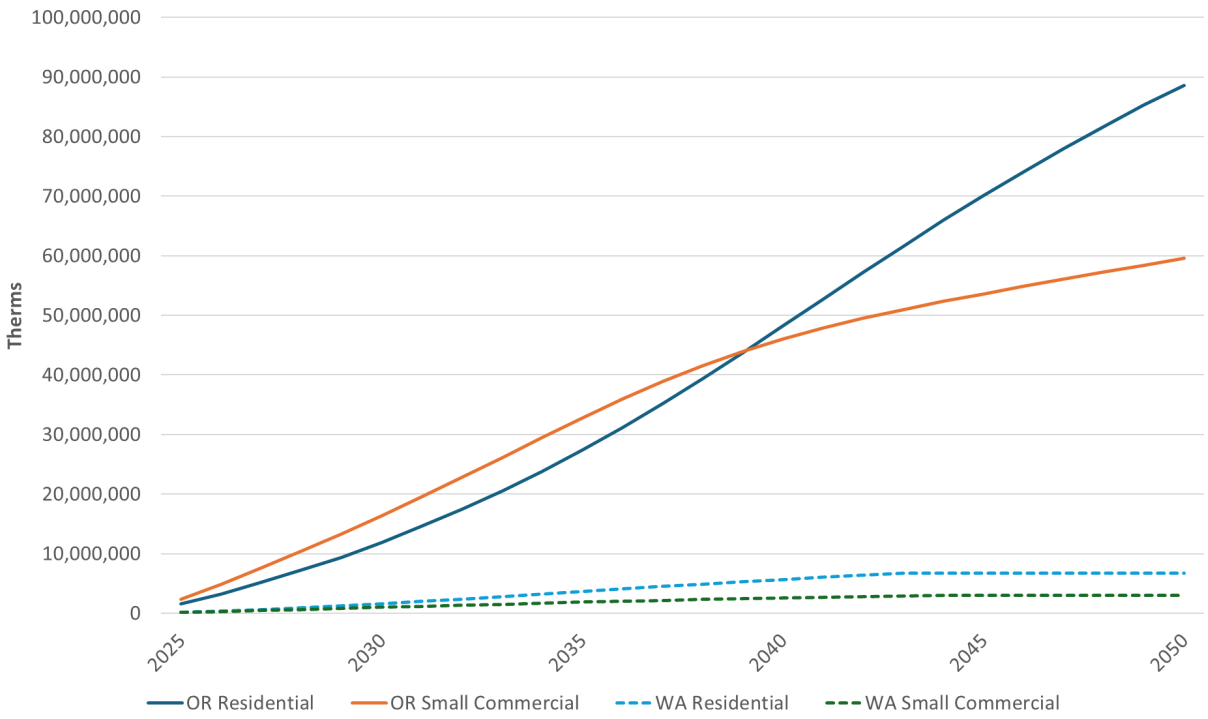
Table 4.2: CPA Organization

State	Customer Type	Rate Class	CPA Developer
Oregon	Sales	Residential Small Commercial Industrial	ETO
	Transportation	Industrial	AEG
Washington	Sales	Residential Small Commercial Industrial	AEG
	Transportation	Industrial	

Figure 4.18 shows the cumulative energy efficiency savings estimates, in therms, provided by both CPA developers for the residential and small commercial rate classes.[88] Oregon savings estimates are much larger than those of Washington largely due to Oregon being a much larger percentage of the Company's overall load.[89] These accumulated savings estimates are applied to their respective rate classes and market segments and allocated down to the daily forecast level based on annual load share percentages.

[87] See Chapter 6for additional details on the various CPAs.
[88] While AEG is the CPA developer for Washington, ETO administers the incentives program.
[89] It is worth noting that there is no longer an energy efficiency incentive program under the 2021 Washington State Energy Code that went into effect March 15, 2024.

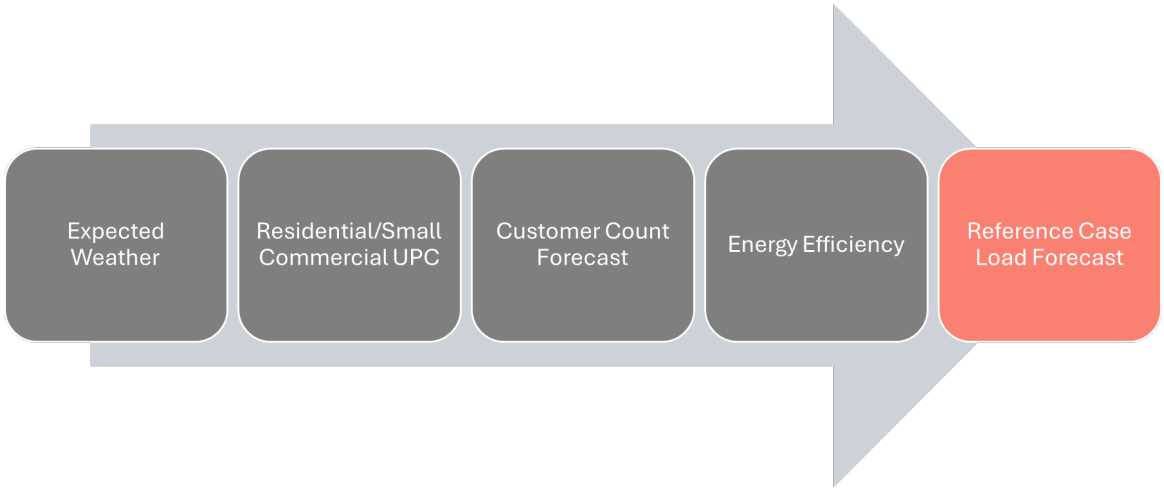
Figure 4.18: Residential and Small Commercial Cumulative Energy Savings



4.3.2 Residential and Commercial Annual Forecast

Following Figure 4.19, by incorporating the daily expected weather forecasts into the appropriate UPC estimates, multiplying those demand estimates by their respective customer count forecasts, and then decrementing the demand forecasts by the corresponding daily energy efficiency load share forecasts, the result is the daily Reference Case load forecast.

Figure 4.19: Flow Diagram of Residential and Small Commercial Reference Case Load Forecast



Aggregating the daily demand estimates for each year in the forecast horizon results in the top line annual load forecast. Specifically, for each year in the forecast horizon, the total residential load can be found using equation (3) and the total small commercial load using equation (4):

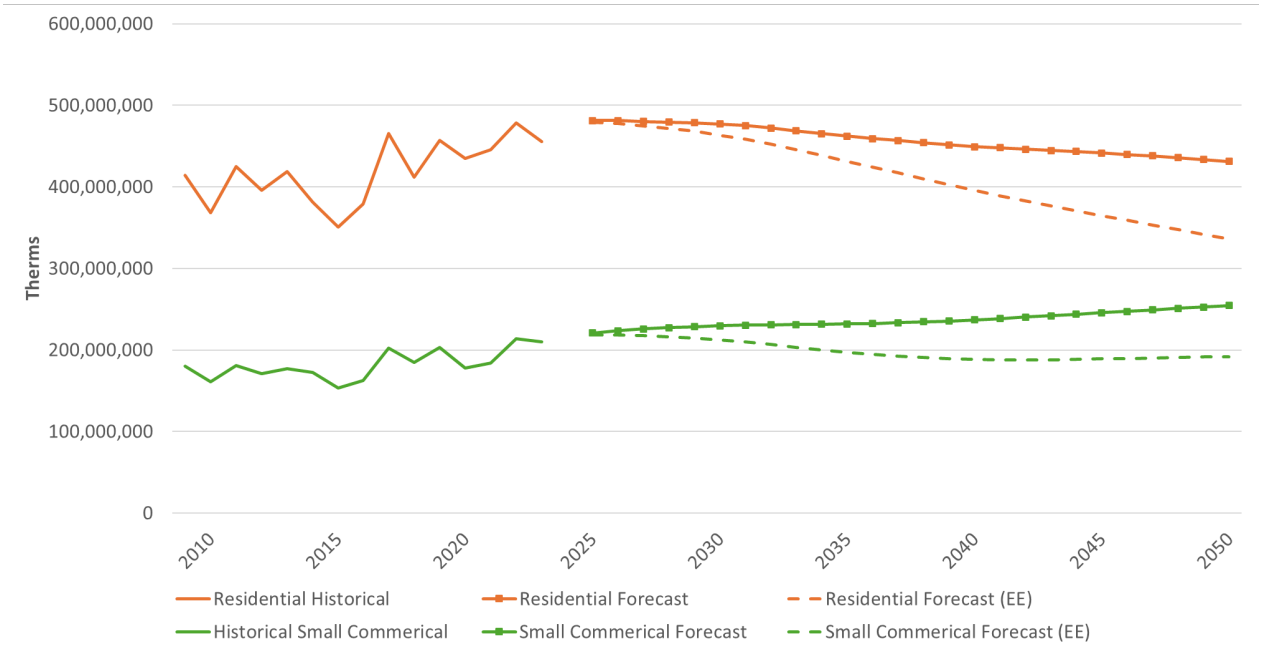
$$Annual\ Residential\ Load = \sum_{i,l,h} f\left(UPC_{i,l,h} \middle| T_{i,l}\right) * CC_{i,l,h} - EE_{i,h} \quad (3)$$

$$Annual\ Small\ Commercial\ Load = \sum_{i,l,k} f\left(UPC_{i,l,k} \middle| T_{i,l}\right) * CC_{i,l,k} - EE_{i,k} \quad (4)$$

where, UPC_i is the average daily use-per-customer, T_i is the forecasted average daily temperature, CC_i is the forecasted daily customer count, EE_i is the forecasted daily energy efficiency savings, and subscripts *i*, *l, h,* and *k* represent the day in the forecast year, load center, residential market segment, and small commercial market segment, respectively. Figure 4.20 presents the system-wide annual forecast for both residential and small commercial rate classes. Relative to the 2022 IRP, the trajectory of the annual load estimates for both rate classes have declined. While a downward revision in customer growth relative to the 2022 IRP certainly plays a part in these lower demand estimates, other drivers, discussed below, also play a pivotal role.

The solid orange line represents historical residential rate class usage. The orange line with square markers represents the load forecast with no energy efficiency estimates incorporated. The dashed orange line represents the load forecast with energy efficiency estimates incorporated. Over the planning horizon, NW Natural forecasts a declining residential load largely due to long-term energy efficiency gains, a declining trend in HDDs, and conversions and new construction market segments using less gas, on average, relative to the existing customer base. The solid green line represents historical small commercial rate class usage. The green line with the square markers represents the load forecast with no energy efficiency estimates incorporated. The dashed green line represents the load forecast with energy efficiency estimates incorporated. Over the planning horizon, NW Natural forecasts a relatively flat small commercial load. Like the residential load forecast, long-term energy efficiency estimates and declining HDDs drive the load lower over time. However, in contrast to residential, conversions and new construction gas usage, on average, is much higher than that of existing stock.

Figure 4.20: Reference Case – Residential and Small Commercial Demand Forecast



Figures 4.21 and 4.22 compare the average energy efficient UPC for the residential and small commercial rate classes, respectively, for the first (2025) and last (2050) year of the forecast horizon. Due to accumulating energy efficiency and declining HDDs the UPC for both rate classes is forecast to fall. Specifically, by the end of the forecast horizon residential UPC is reduced by approximately 38 percent and small commercial by 21 percent.[90]

[90] Note that if comparing the 2025 UPC estimates from Figures 4.16 and 4.17 to the 2025 UPC estimates from Figures 4.21 and 4.22, the former do not incorporate any exogenous energy efficiency assumptions for comparison purposes across IRPs.

Figure 4.21: System-wide Residential Average UPC

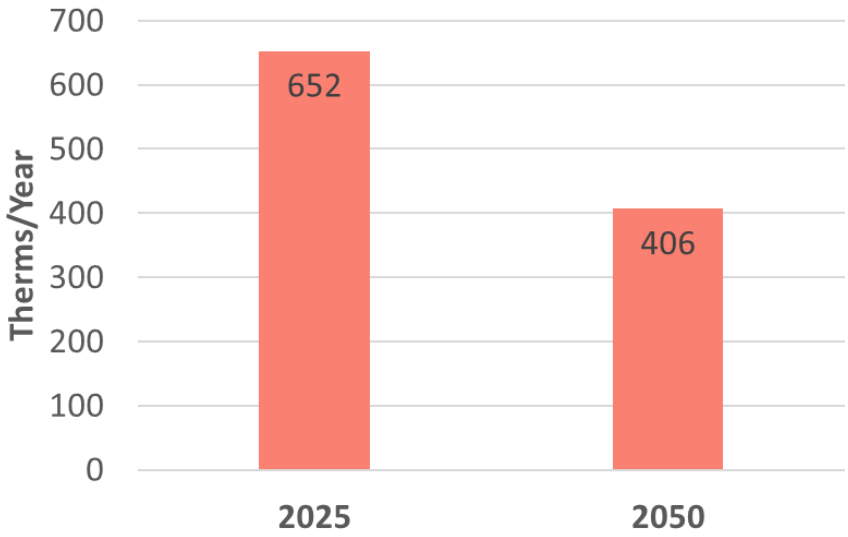
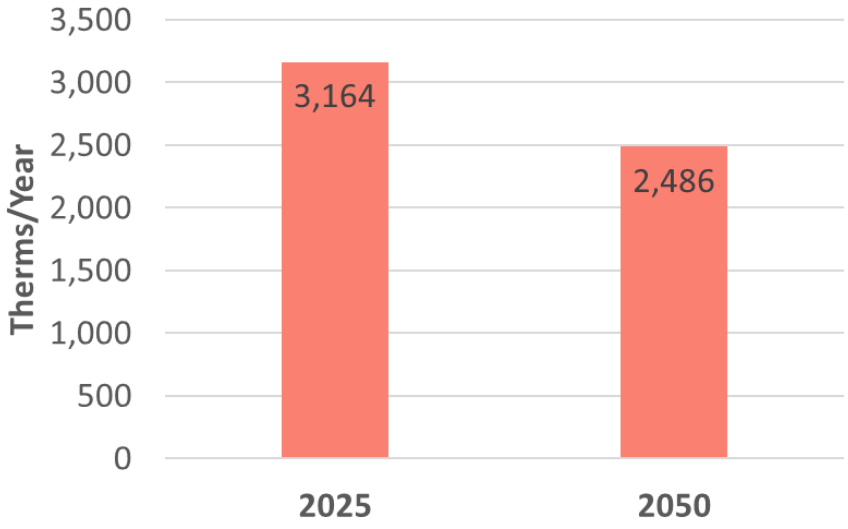


Figure 4.22: System-wide Small Commercial Average UPC



4.3.3 Industrial and Large Commercial

In contrast to residential and small commercial UPC load forecasting, industrial and large commercial load is forecasted at an aggregate level. The industrial forecast relies on NW Natural's Subject Matter Experts (SMEs) for a short-term forecast (i.e., the first two years of the horizon—2025 and 2026), and for a longer-term forecast (i.e., the remainder of the forecast horizon—2027 to 2050) the load is modeled as a function of macroeconomic data from the Oregon Office of Economic Analysis (OEA). NW Natural's industrial load can then be allocated

into four categories of service: firm sales, firm transportation, interruptible sales, and interruptible transportation.[91]

Large commercial (firm sales) load, composed of rate schedules 31CSF/32CSF and C41SF/C42SF, is forecasted separately from industrial customers. In terms of usage, these customers act more like industrial than small commercial customers, but they are not quite the size and scale of the industrial users. The large commercial forecast methodology is very similar to the longer-term portion of the industrial forecast, except that the load is modeled as a function of different macroeconomic data.

4.3.3.1 Subject Matter Expert Short-term Forecast

NW Natural's industrial subject matter experts (SMEs) are a group of high touch point individuals for the Company's industrial customers. The SMEs work to better understand the needs, concerns, and short-term outlook of the large industrial users and that work gets translated into the short-term load forecast. The SME group produces a two-year monthly forecast of the four industrial service categories, across all load centers. This short-term forecast is the origin of the total industrial forecast. The longer-term econometric forecast is appended to this outlook.

4.3.3.2 Econometric Forecasts

NW Natural forecasts annual aggregate (i.e., for all categories of service) industrial load growth based on a single-factor linear regression model that utilizes U.S. industrial output data from OEA. Industrial load growth sensitivity to changes in U.S. industrial output is then extrapolated forward through 2050 based on OEA forecasts of the loading factor. Forecasted load growth rates are subsequently allocated on a year-over-year basis to each load center and individual service category to produce a monthly forecast.

Large commercial load is forecasted separately but uses a similar methodology. However, in this forecast the loading factor is regional rather than national—Oregon information sector output—but similarly comes from OEA data. The state level data adequately captures changes in the Company's large commercial load growth. Like the industrial forecast, large commercial load growth sensitivity to changes in its loading factor are similarly extrapolated through 2050 based on OEA forecasts. The forecasted load growth rates are subsequently allocated on a year-

[91] There are a few large commercial customers on transportation rate schedules. Load from these customers is included in the industrial load forecast (i.e., not the large commercial sales forecast) and is not separated out from the overall transportation load forecast.

over-year basis to produce a monthly forecast.[92] Equation (5) generalizes the linear regression model for industrial and large commercial:

$$Y_t^n = \alpha^n + \beta^n K_t^n + \epsilon_t^n \quad (5)$$

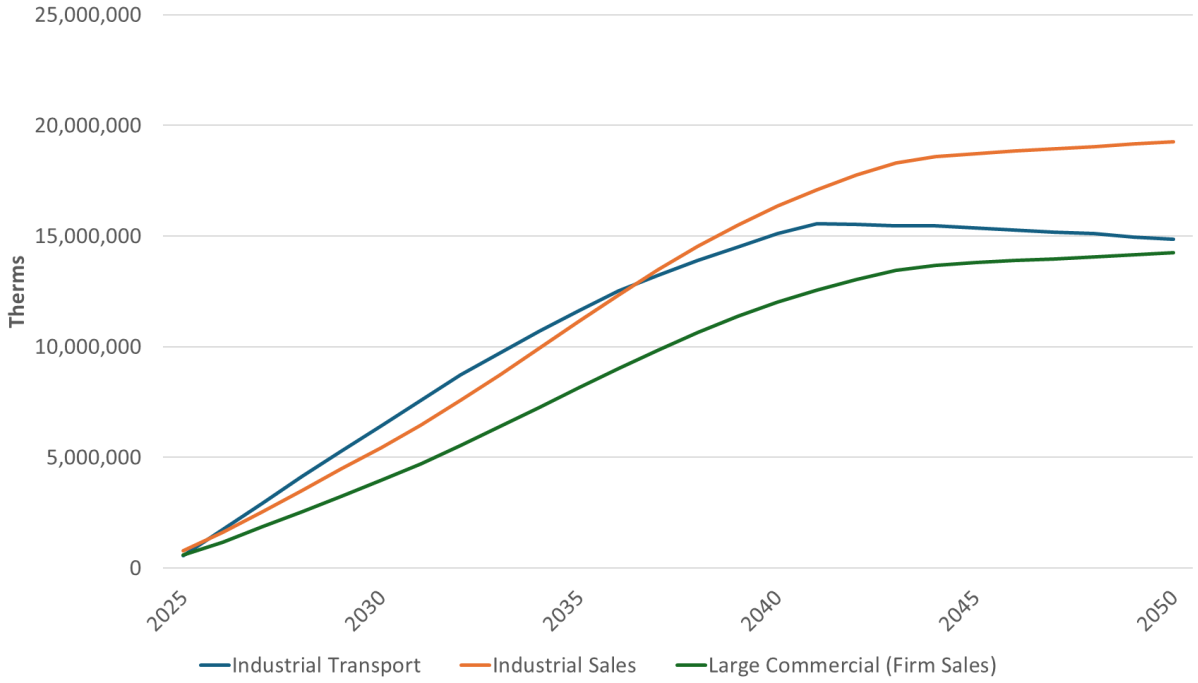
where, Y_t is historical annual load (in therms), K_t is the relevant macroeconomic variable, α is the intercept parameter, β is the slope parameter, ϵ_t is the residuals of the t^{th} year, and the superscript *n* represents the customer class (i.e., industrial vs. large commercial) being estimated.

4.3.3.3 Forecasted Energy Efficiency

As discussed earlier, forecasted energy efficiency is a key input into load modeling. ETO and AEG provide efficiency savings forecasts for both industrial and large customers. Specifically, an annual forecast is provided for: industrial transport, industrial sales, and large commercial.[93] Figure 4.23 shows the cumulative forecasted energy efficiency savings estimates, in therms, provided by the CPA developers for the three categories.[94] These accumulated savings estimates are subsequently allocated down to the monthly level based on annual load share percentages and applied as a load decrement to their respective customer class and service category.

[92] See Appendix B for technical details related to the econometric models used for industrial and large commercial load forecasting.
[93] AEG provides a forecast of industrial sales energy efficiency savings for Washington that they believe is cost-effective and achievable. NW Natural is currently working to establish a program to obtain those savings.
[94] There is an immaterial decline in cumulative energy efficiency savings for industrial transportation post-2040 as an outcome of the CPA modeling; the Company does not expect to see this decline in future CPAs.

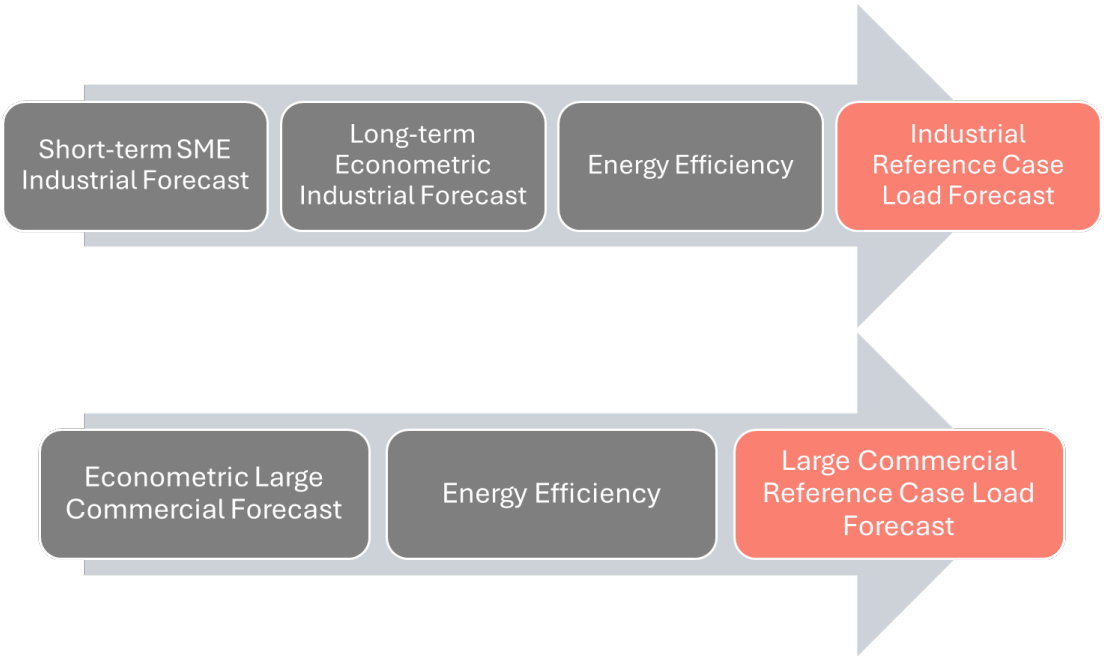
Figure 4.23: Industrial and Large Commercial Cumulative Energy Savings



4.3.4 Industrial and Large Commercial Annual Forecast

Following the upper half of Figure 4.24, the short-term monthly forecast is appended to the long-term monthly forecast. The demand profile is then decremented by the corresponding energy efficiency forecast to provide the monthly Reference Case load forecast. Ultimately, this industrial forecast is converted from a monthly to a daily frequency for long-term resource planning and emissions modeling. A similar process is outlined in the lower half of the figure for large commercial load. The key difference is that only one forecast is produced for this customer class.

Figure 4.24: Flow Diagram of Industrial and Large Commercial Reference Case Load Forecast



Aggregating the daily demand estimates for each year in the forecast horizon provides a top line annual load forecast. Specifically, for each year in the forecast horizon, the total industrial load can be found using equation (6) and the total large commercial load using equation (7):

$$Annual\ Industrial\ Load = \sum_{i,m} L_{i,m} - EE_{i,m} \quad (6)$$

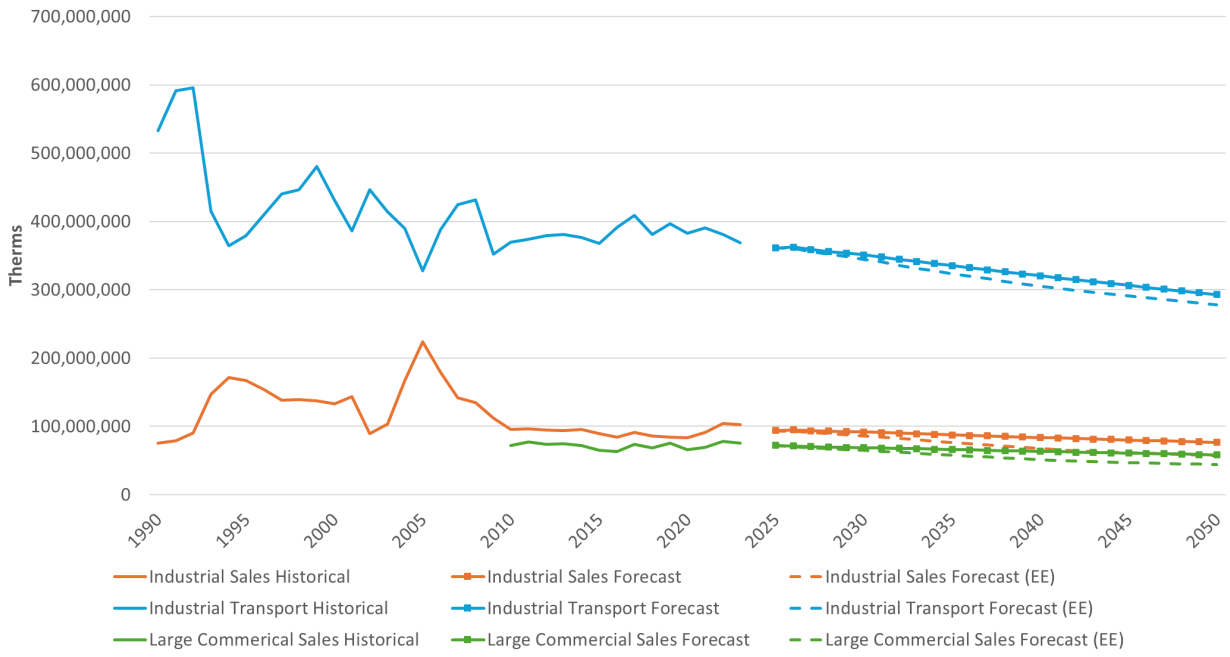
$$Annual\ Large\ Commercial\ Load = \sum_{i} L_i - EE_i \quad (7)$$

where, L_i is the daily load forecast, EE_i is the forecasted daily energy efficiency savings, and *i* and *m* represent the day in the forecast year and industrial category (i.e., sales vs. transport), respectively.

Figure 4.25 presents the system-wide annual forecast for industrial sales, industrial transport, and large commercial sales. Like the residential and small commercial forecast, the solid lines represent historical data, the lines with the square markers represent the load forecast with no energy efficiency decrements, and the dashed lines represent the load forecast with energy efficiency estimates incorporated. Over the forecast horizon there is a modest declining trend across the board. This updated trajectory is largely in line with the 2022 IRP forecast. For the industrial categories, the load decline after the first two years is principally a function of the

load sensitivity to a modest growth forecast in U.S. industrial production through 2050. Likewise, large commercial load is a function of the slight growth forecast in the Oregon information sector over the horizon.

Figure 4.25: Reference Case – Industrial and Large Commercial Demand Forecast

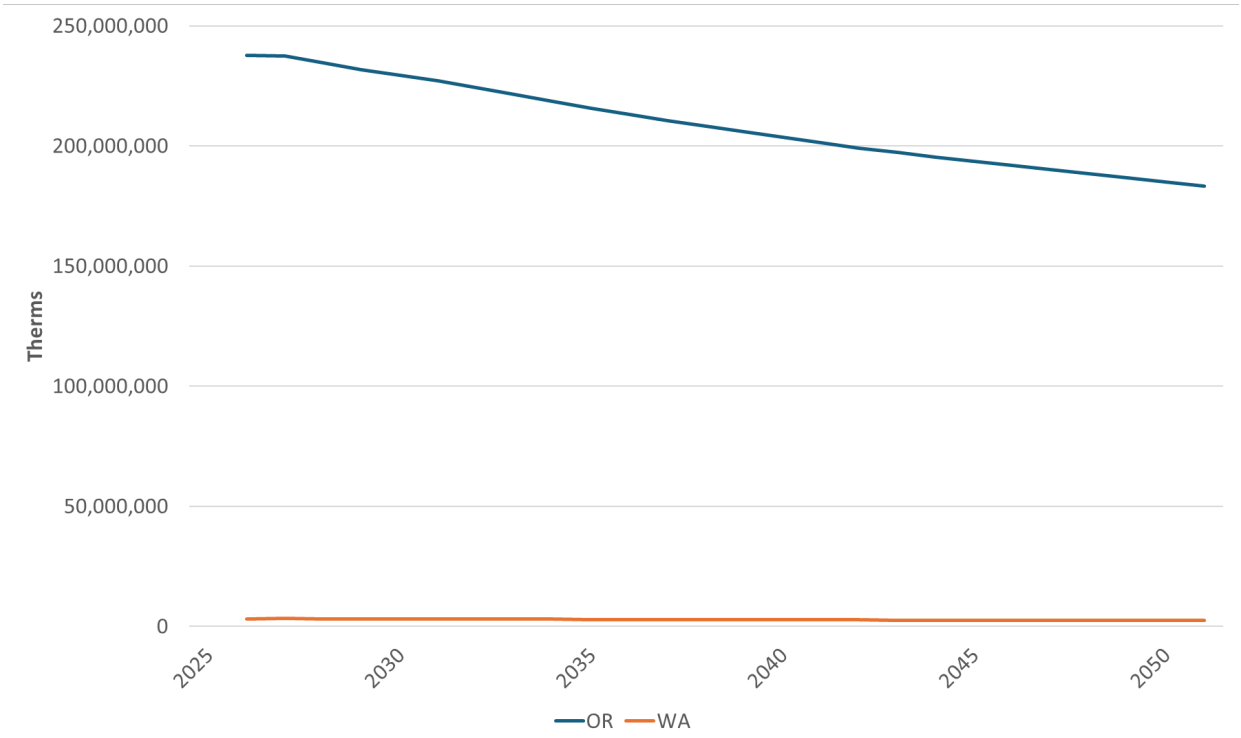


4.3.4.1 Forecast for Emissions- Intensive, Trade-Exposed Customers

NW Natural's Emissions-Intensive, Trade-Exposed (EITE) customers are industrial users in manufacturing sectors that produce large amounts of greenhouse gas (GHG) while facing significant competition for their products. This makes these entities particularly vulnerable to carbon compliance policies relative to competitors who face no restrictions at all.[95] Virtually all of NW Natural's EITE customers are transport customers.[96] For NW Natural's emissions reporting, for both CPP and CCA, the usage of these entities is removed, and the Company's compliance obligation is based on the total remaining throughput. Figure 4.26 shows the forecast for EITE load by state. For simplicity, following the short-term forecast by the SME, the EITE load is forecast to decline at the same rate as industrial transportation load in the Reference Case forecast.

[95] Examples of EITE industries include steel, aluminum, cement, and paper production.
[96] In Oregon (Washington) approximately 96% (87%) of EITE load is classified as transport over the period 2022-23.

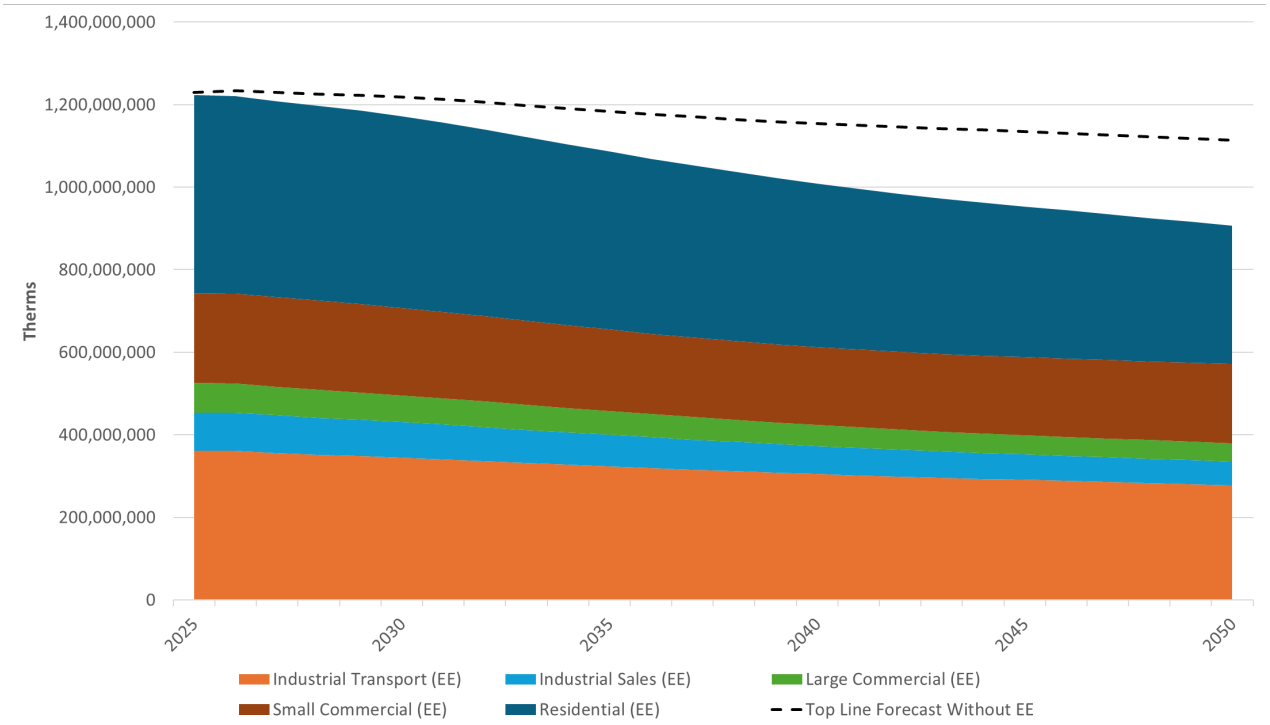
Figure 4.26: EITE Load Forecast



4.3.5 Annual Load – Annual Throughput Forecast

Aggregating the residential, small commercial, large commercial, and industrial Reference Case load forecasts yields the total system demand forecast, as shown in Figure 4.27. Each color bar represents the individual contribution of the customer group to the total system load. The top edge of the residential color bar illustrates the energy efficient system load forecast over the forecast horizon. The dotted line represents the total load forecast absent any forecasted energy efficiency savings.

Figure 4.27: Reference Case – Total System Natural Gas Usage Forecast



4.3.5.1 State Throughput Forecasts

Annual throughput forecasts for the Reference Case are provided at the state level for Oregon and Washington in Figure 4.28 and Figure 4.29, respectively. Note that the scale of demand in Oregon is roughly ten times the demand in the Company's Washington service territory.

Figure 4.28: Reference Case – State of Oregon Natural Gas Usage Forecast

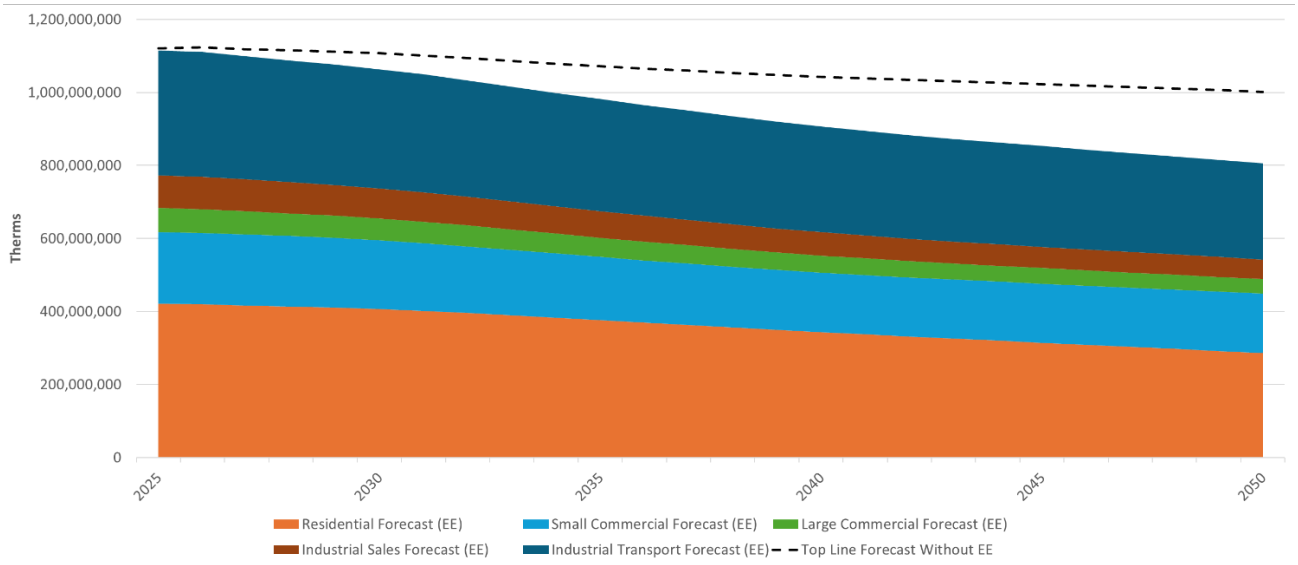
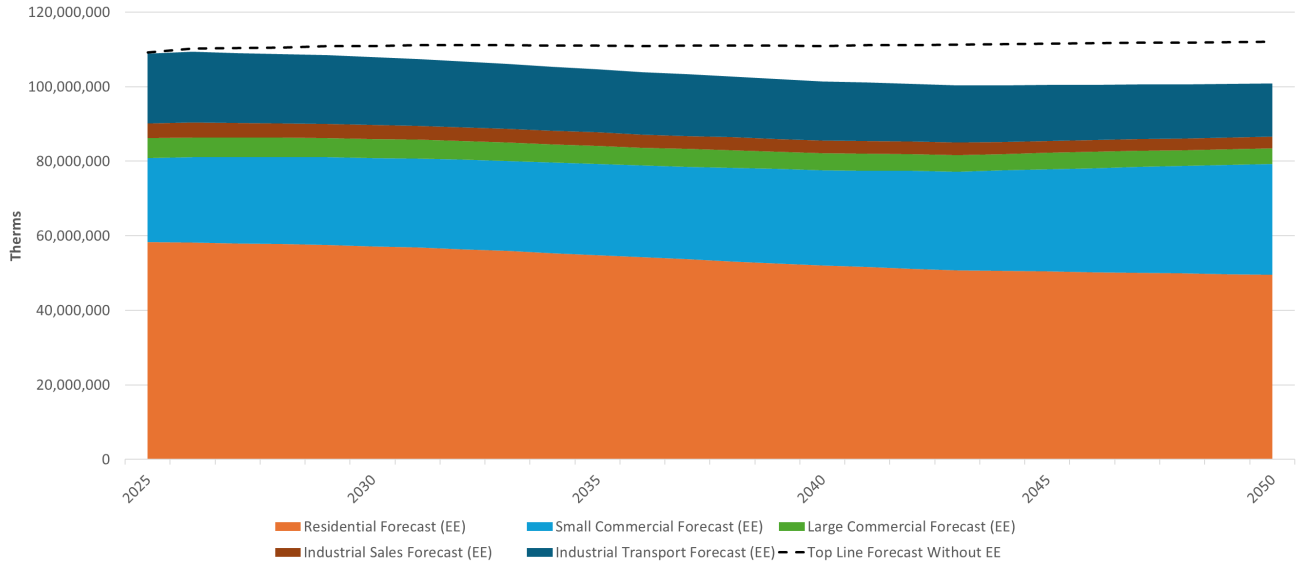


Figure 4.29: Reference Case – State of Washington Natural Gas Usage Forecast



4.4 Peak Day Load Forecast

This section discusses the NW Natural's peak day planning standard methodology, the incorporation of energy efficiency into the peak day load forecast, and the Company's resource stack and capacity needs.

4.4.1 Capacity Planning Standard

Developing a capacity planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure the reliability of service under design peak weather conditions.[97] NW Natural utilizes Monte Carlo simulations of demand predictors to establish a planning standard where the Company's resources can consistently serve the highest firm sales load going into each winter with 99 percent certainty, assuming all resources are available.[98] This standard is equivalent to planning for a 1-in-100-year weather event.[99]

4.4.2 Daily System Load Model

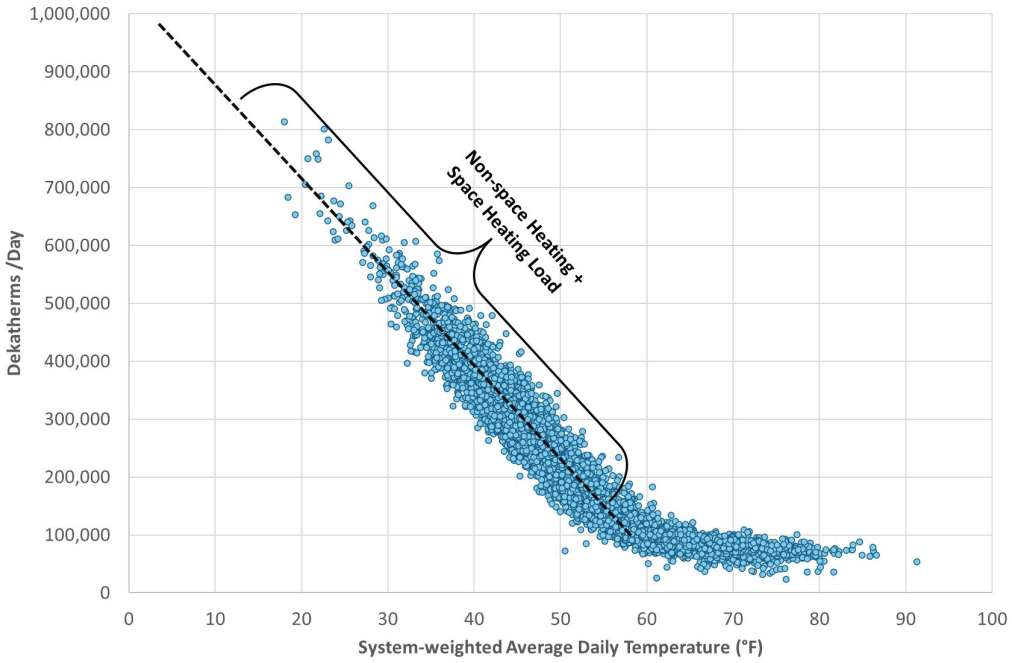
Like the UPC model, NW Natural uses an ordinary least squares (OLS) estimator to estimate the impact of an explanatory variable(s) on demand using historical data. Unlike the UPC model, the peak day model is a multifactor regression model, as opposed to a single-factor regression of temperature only. The daily system load is estimated using a collection of exogenous explanatory variables (e.g., temperature, wind speed, snow depth, etc.) and are discussed in detail in the sections immediately below. Equation (8) generalizes the linear model, in matrix notation:

$$Y = X\beta + \epsilon \quad (8)$$

where, Y is a $n \times 1$ vector of daily system firm sales, X is a $n \times 21$ matrix of explanatory variables and a constant term, β is a 21×1 vector of estimated coefficients, ϵ is $n \times 1$ vector of residuals, and n represents the number of daily observations. Specifically, the estimation of equation (8) only includes daily firm sales data for average temperatures less than, or equal to, 59°F.[100] Figure 4.30 shows a scatter plot of the average system-weighted temperature against the daily system firm sales load. Below 59°F a very clear negative linear relationship emerges between daily load and average temperature. The structural break in the relationship between average temperature and load at this 59°F inflection point is where space heating requirements ramp up.[101] This is analogous to the inflection point (K*) from the UPC modeling.

[97] Gas supply capacity requirements refer to the maximum daily volume of gas that the system can deliver to customers.
[98] This planning standard was first implemented in the 2018 IRP.
[99] A 1-in-100 winter is a measure of statistical likelihood. It does not mean that every 100 years a design winter occurs. It may be that two rare and cold winters occur within a 100-year time frame, or conversely, a design winter may not occur within a 100-year time frame.
[100] Since this analysis focuses on modeling a design peak day, load data and respective explanatory variables where the daily average temperature is greater than 59°F is excluded when estimating the model coefficients.
[101] During a design Winter peak event, it is predicted that more than 80 percent of NW Natural's firm sales would be used for space heating needs.

Figure 4.30: Daily System Firm Sales Load by Average Temperature (Jan. 2009 – Mar. 2024)



Ultimately, the estimated model coefficients are used in combination with Monte Carlo simulations of the explanatory variables to establish the peak day planning standard, discussed above, for resource capacity requirements.[102]

4.4.2.1 Explanatory Variables – Main Effects

Temperature is the predominant driver of load, but there are a variety of factors that can affect demand, particularly on a peak day. The daily system load model includes 12 explanatory variables—daily average temperature, previous day average temperature, customer count, wind speed, solar radiation, snow depth, a day-of-the-week indicator variable, a holiday indicator variable, a proxy for water heater inlet temperature, and an indicator variable for the COVID-19 pandemic shutdown beginning in March 2020.[103]

The remainder of this section discusses the rationale for the inclusion of these explanatory variables, referred to as the models "main effects," as well as their economic influence on daily load. Table 4.3 summarizes the directional impacts of these variables on daily load. A negative sign indicates that the values of the explanatory variable and load move in opposite directions

[102] NW Natural must purchase gas and have enough capacity resources to bring that gas onto system during a peak day for firm sales customers. Daily load for a gas day (7AM-7AM) is typically scheduled for an entire day in a day-ahead market.
[103] The day-of-the-week indicator variable is really three distinct daily indicator variables—Friday, Saturday, and Sunday.

(e.g., as temperature decreases, peak load increases). In contrast, a positive sign indicates that the values of the explanatory variable and load move in the same direction (e.g., as customer count increases, peak load increases).

Table 4.3: Main Effects on Daily Load

Variable	Load Impact
Temperature	-
Previous Day Temperature	-
Customer Count	+
Wind Speed	+
Solar Radiation	-
Snow Depth	-
Friday	-
Saturday	-
Sunday	-
Holiday	-
COVID-19 Closure	-
Bull Run River Temperature	-

The necessity of including a lag of the daily average temperature is due to the physical location of where data is collected and the speed at which gas flows through pipelines. Daily flow data is collected at NW Natural's gate stations and at on-system storage locations.[104] Since gas does not flow instantaneously, there is a delay between when customers use gas and when it flows and is measured through the gate stations.[105] Including the previous day's average temperature in the model helps capture this lagged response to changes in demand driven by temperature. Much like contemporaneous average temperature, a decline in the lagged average daily temperature will increase the estimated peak daily load.

Over time, NW Natural's customer count has increased, and this growth has resulted in an increase in the Company's peak daily load. The customer count variable captures the average effect of new (firm sales) customers joining the system. Relative to most of the weather and

[104] Any usage by non-firm sales customers is coincidently subtracted from flow data coming from the gate stations and on-system storage, but these customers may be located far from a gate station.
[105] The duration of the delay is dependent on several factors including the pipeline distance from the gate station and the speed of gas flow (which is dependent on the overall demand and pipeline pressure). This delayed response is applicable to all customers.

day-of-the-week variables, discussed below, the average impact of a single customer addition to daily load is economically, very small.[106]

Naturally, weather conditions beyond temperature alone will alter demand for natural gas. High wind speeds have the effect of cooling building shell structures, which in turn requires additional gas to maintain a constant interior temperature. In contrast, solar radiation heats building shells, thus reducing the need for additional gas to maintain a constant interior temperature. Both conditions have a statistically significant impact on daily load, but the economic impact of increasing wind speeds on daily demand dwarfs that of decreasing solar radiation.

Snow depth serves as a proxy for business and school closures. Accordingly, an increase in snow depth generally results in more closures, which at the system level results in a reduced estimated daily load since space heating needs are diminished.[107]

The day-of-the-week also impacts natural gas load. There is a statistically significant increase in average daily load during a weekday—defined as Monday through Thursday—relative to the weekend—defined as Saturday through Sunday. This weekend load reduction is mainly driven by business and school closures for the weekend; its effect is akin to that of increased snow depth, though the magnitude of the weekend impact on average demand is much larger. Friday similarly shows a statistically and economically significant average daily load decline relative to other weekdays.[108] Similar effects are also observed on U.S. holidays.[109]

The COVID-19 economic shutdown reduced average daily load, as virtually all schools and most businesses were forced to close for social distancing protocols. While residential usage increased over this time frame, the aggregate effect on the system demand was negative.[110] While the world has long moved past this point in time, it is important to control for its historical effects on load, when modeling peak day conditions.

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[106] The economic magnitude of a change in the explanatory variable on the (demand) response variable is determined by the coefficient estimates of the "main effects" and are reported in Appendix B. They can be interpreted as a one-unit change in the explanatory variable results in a x-unit change in the response variable, holding all else equal. For example, on average, a 1°F decrease in contemporaneous temperature results in an estimated increase of 11,464 dth/day, holding all else equal.

[107] Specific areas on NW Natural's system, particularly those with a high ratio of residential customers, may have a positive correlation with snow depth as residential customers are inclined to use more gas because of staying home, even after controlling for temperature.

[108] For a gas day, Friday includes seven hours of Saturday. The inclusion of these hours into a Friday is a large driver as to why this weekday differs.

[109] U.S. holidays are defined as all U.S. Federal holidays.

[110] The COVID-19 pandemic indicator variable takes the value of one over the time span March 12, 2020, to December 31, 2021, and is zero otherwise.

NW Natural uses the Bull Run River temperature as a proxy for water heater inlet temperature.[111] All else equal, colder inlet water temperatures require additional gas to heat the water to desired (warmer) temperatures and thus increases estimated peak day load.

4.4.2.2 Explanatory Variables – Interaction Effects

The peak day "main effects" explanatory variables recognize the importance of exogenous factors beyond the average temperature in estimating demand. The inclusion of "interaction effects" into the modeling fold acknowledges the importance of capturing the interplay between contemporaneous average temperature and other exogenous factors. In other words, the "main effects" are not the only thing that matter when modeling peak day load, and their individual impact on demand can be conditional on the average temperature. To illustrate, as discussed above, higher wind speeds have the effect of increasing demand—all else equal. However, the impact of wind speed on demand is not constant across the entire spectrum of cold temperatures. Intuitively, the impact of a one mile-per-hour increase in wind speed when the average temperature is 41 degrees will not have the same outsize impact on load as a one mile-per-hour increase when the average temperature is 15 degrees.

In total, there are eight "interaction effects" included in the model.[112] Table 4.4 summarizes the directional impacts of the interaction terms on daily load. The sign of the interaction term will typically take the opposite sign of the "main effects" variable. Hence, a negative interaction sign indicates that the effect of the directly related main variable on demand is dampened at higher average temperatures (i.e., the wind speed example). A positive interaction sign indicates that the effect of the inversely related main variable on demand is dampened at higher average temperatures.

[111] Portland is NW Natural's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).
[112] Not all "main effects" variables have a corresponding interaction term—this is due to either a reduction in model predictability or statistical insignificance.

Table 4.4: Interaction Effects on Daily Load

Variable	Load Impact
Temperature x Previous Day Temperature	+
Temperature x Customer Count	-
Temperature x Wind Speed	-
Temperature x Snow Depth	+
Temperature x Friday	+
Temperature x Saturday	+
Temperature x Sunday	+
Temperature x Holiday	+

The interactions of contemporaneous average temperature with the one-day temperature lag, snow depth, the day-of-the-week indicator variable, and holiday indicator variable all take a positive sign. Thus, at higher average temperatures, the inversely related "main effects" of these variables on load are reduced. The interactions of contemporaneous average temperature with customer count and wind speed both take a negative sign. Accordingly, at higher average temperatures, the directly related "main effects" of these variables on load are diminished.

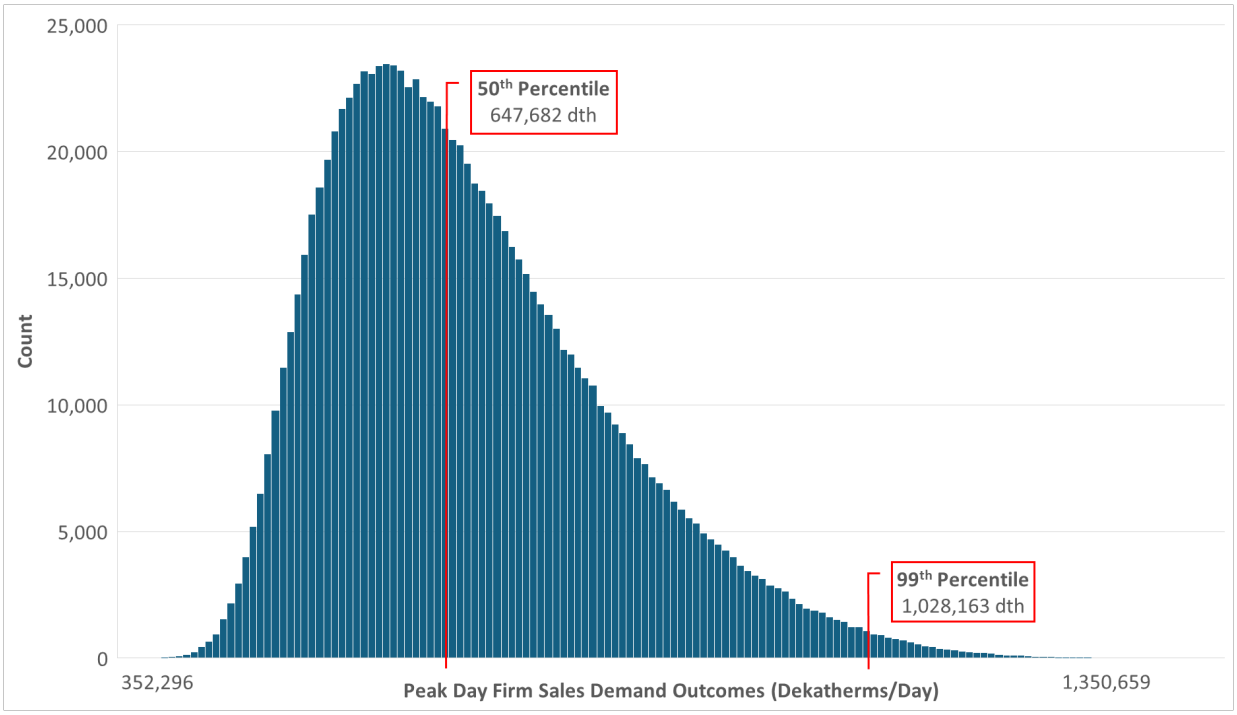
4.4.2.3 Design Peak Weather

The regression coefficients from the firm sales daily system load model require input data to estimate a design peak day load. As discussed at the outset of this section, NW Natural implements Monte Carlo simulations of the explanatory variables of demand to establish the 99th percentile planning standard. A Monte Carlo simulation is simply a method used to understand the behavior of system demand. It involves using random values for inputs to simulate many possible demand outcomes and then analyzing those outcomes to establish the capacity planning standard. In essence, Monte Carlo simulations are a way to model uncertainty

and variability in NW Natural's complex system by repeatedly sampling random values and observing the impact on demand.[113]

Ultimately, the Monte Carlo simulations of the explanatory variables create a distribution of peak day demand. From this distribution the 99th percentile is calculated to establish the firm sales peak load that has a one percent chance of occurring (i.e., akin to a 1-in-100-year weather event). To illustrate the standard which NW Natural plans its system resources for peak day, Figure 4.31 shows the difference between a 1-in-2-year (50th percentile) and a 1-in-100-year (99th percentile) firm sales peak load from one million Monte Carlo simulations.[114] Note that the 1-in-2-year threshold indicates the level of peak demand that NW Natural would expect to exceed about 50 percent of the time.

Figure 4.31: Peak Day Firm Sales Monte Carlo Distribution (2024-25 Gas Year)

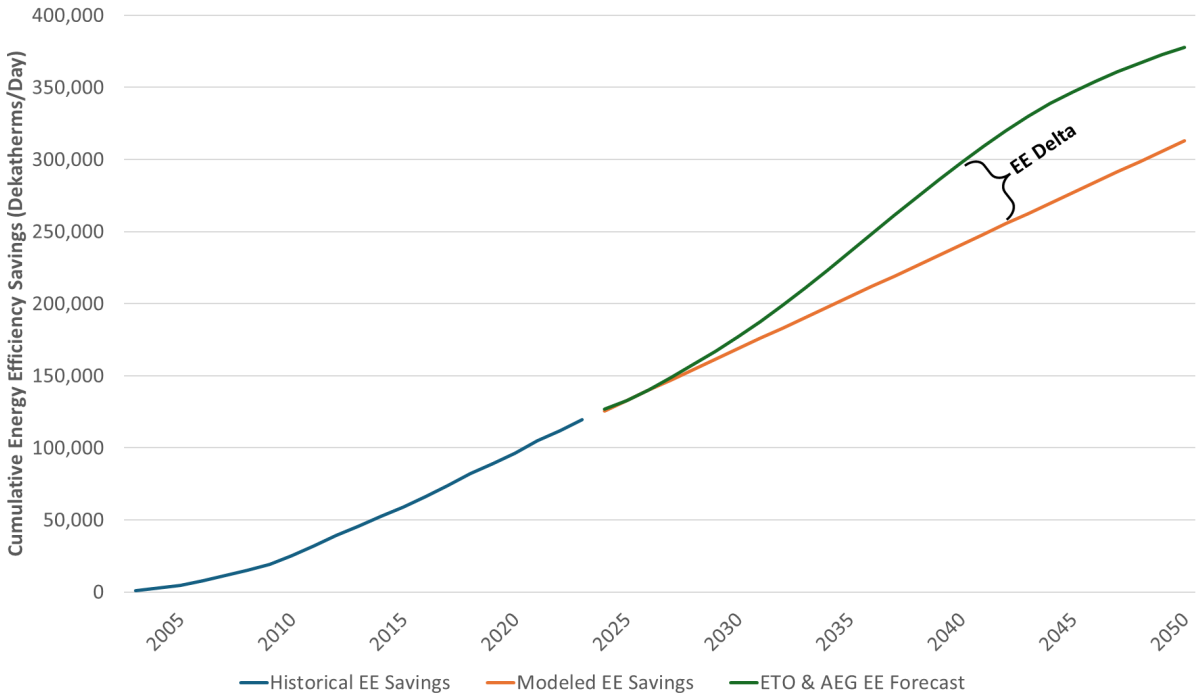


[113] Details of the Monte Carlo simulation are provided in Appendix B.
[114] Since customer count is a model input, the percentiles are dynamic and change in the future as a function of changes in the customer count forecast.

4.4.3 Design Peak Day Energy Efficiency

The 99th percentile demand for a peak day requires an adjustment based on the peak energy efficiency savings forecast. The peak day model utilizes SCADA data starting in 2009 to capture underlying trends in gas usage.[115] A cumulative increase in peak day savings from energy efficiency is one of these underlying trends. To account for this trend, NW Natural estimates a time trend regression of historical cumulative system peak day energy efficiency savings, driven by energy efficiency programs. The delta between the forecasted time trend energy efficiency savings and the peak day efficiency savings forecasted in the CPAs is subtracted from the 99th percentile load. Figure 4.32 shows the plot of these values over the forecast horizon.

Figure 4.32: Peak Day Savings Estimates



The design peak day therm savings are calculated using peak factors estimated by NW Natural for each end-use and are further discussed in detail in Chapter 6. These same factors are applied to the annual firm sales savings forecasted in the CPAs.

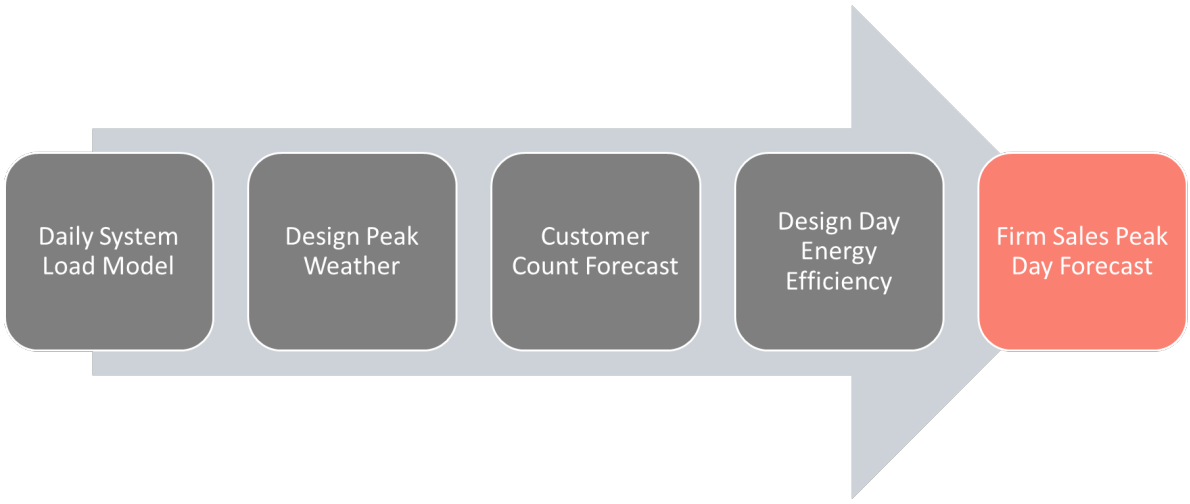
4.4.4 Peak Day Forecast

Following Figure 4.33, the daily system load model is estimated using historical cold weather data (i.e., less than 59°F). Next, Monte Carlo simulations are run for the explanatory variable

[115] Data for peak day modeling spans 15 years (2009 – 2023).

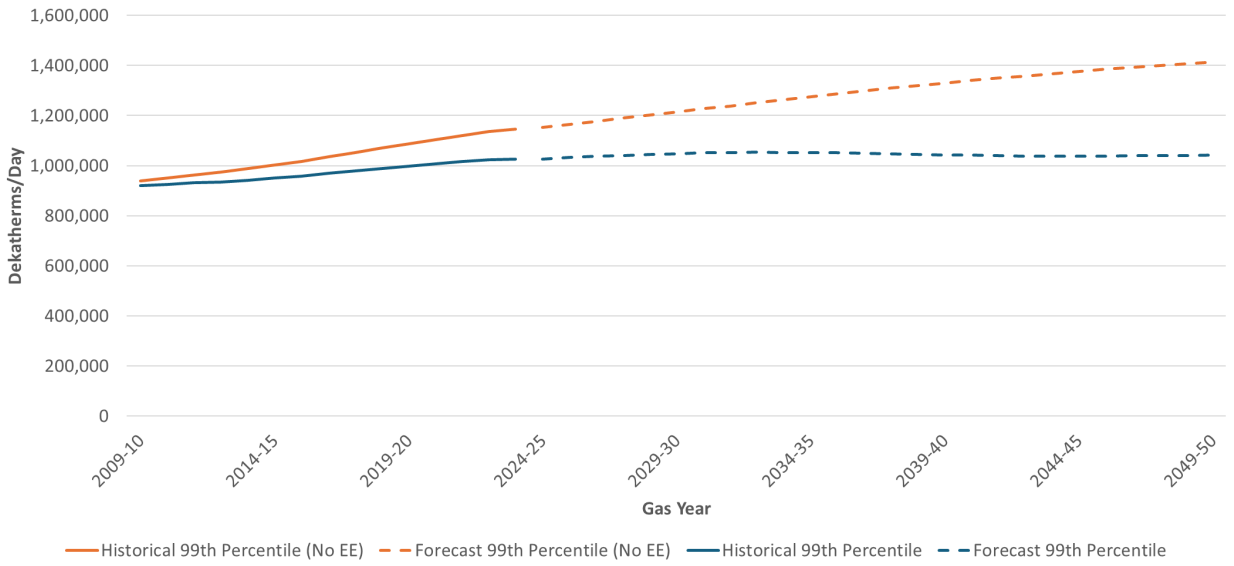
inputs. Next, the randomly simulated model inputs and the customer count forecast are passed through the daily system load model to generate peak day firm sales demand outcomes, from which the 99th percentile is extracted as NW Natural's planning standard. Finally, the 99th percentile load is decremented by the estimated energy efficiency savings delta to arrive at the design peak day load forecast (see Figure 4.35).

Figure 4.33: Flow Diagram of Peak Day Load Forecast



The impact of energy efficiency programs has been, and will continue to be, a noteworthy way to reduce load at both the annual level and for peak day. This is especially true of measures related to space heating. Figure 4.34 displays the peak day forecast over the planning horizon, both with and without cost-effective energy efficiency measures.

Figure 4.34: Firm Sales Peak Day Load Forecast with and without Energy Efficiency



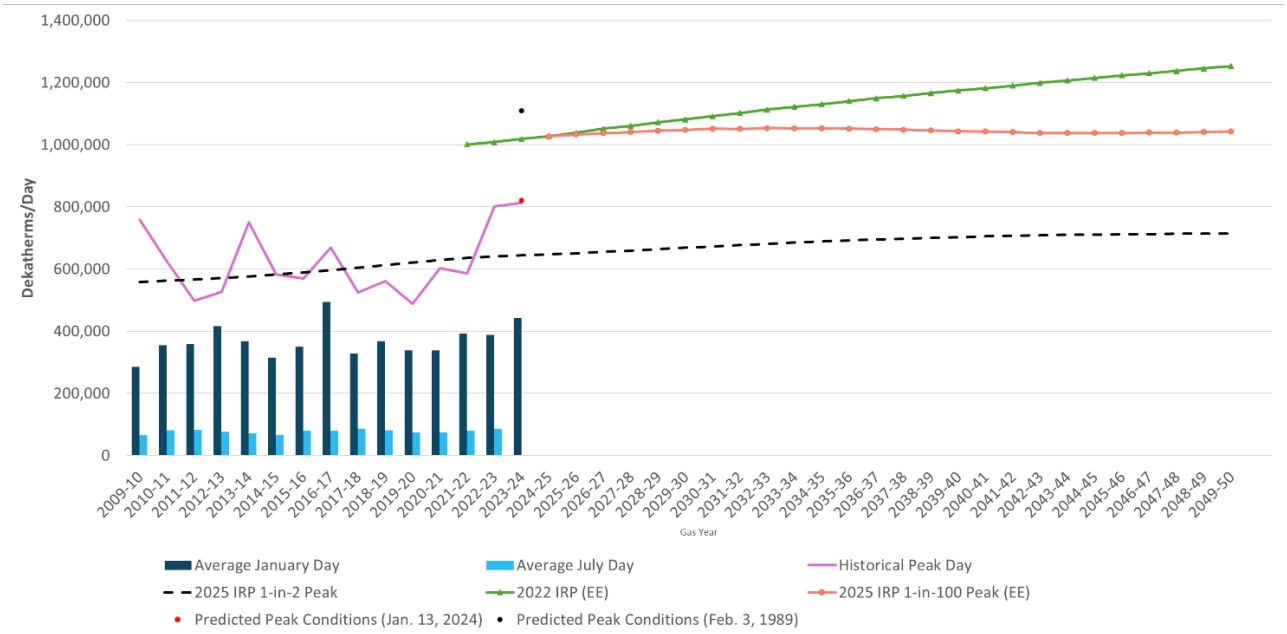
By 2050, energy efficiency programs will reduce peak day load by approximately 373,000 dekatherms, or 26 percent of peak load.

Figure 4.35 captures a tremendous amount of useful information around historical and forecasted design peak days. To contextualize the seasonal demand change for natural gas, the vertical bars highlight the larger average daily load and volatility in a winter month (January) vs. a summer month (July). Further, the magenta line charts NW Natural's firm sales peak day demand, by gas year, relative to the 50th percentile winter estimate (black dashed line) from the model. The red dot marks the daily system load model peak day prediction for the prior winter (gas year 2023-24).[116] In contrast, the black dot represents the weather conditions of February 3, 1989, applied to our current customer base.[117] Its value corresponds to 1,108,331 dth/day and highlights the importance of having a high planning standard for peak day as the conditions which drive such a high peak load have occurred within the last 40 years.[118] Finally, the salmon line with circle markers is the 2025 IRP peak day planning standard (i.e., the 99th percentile planning standard inclusive of estimated peak day energy efficiency savings).[119] The green line with triangle markers is the analogous peak day forecast from the 2022 IRP. In the near-term, the 2025 IRP peak day planning standard is indistinguishable from the 2022 IRP planning standard. However, further out in time the two forecasts begin to diverge due to a few

[116] The actual demand on January 13, 2024, was 813,860 dth/day vs. the model forecast of 818,948 dth/day.
[117] This is the coldest date on record for the state of Oregon.
[118] This estimated peak value is between the 99.7th and 99.8th percentile for the most recent gas year.
[119] The peak day forecast for the current (2024-25) gas year (i.e., the first salmon circle) is 1,026,865 dth/day.

methodological changes in the peak day weather design simulation, in addition to downward customer count forecast revisions relative to the 2022 IRP.

Figure 4.35: Historical and Forecast of Annual Peak Load

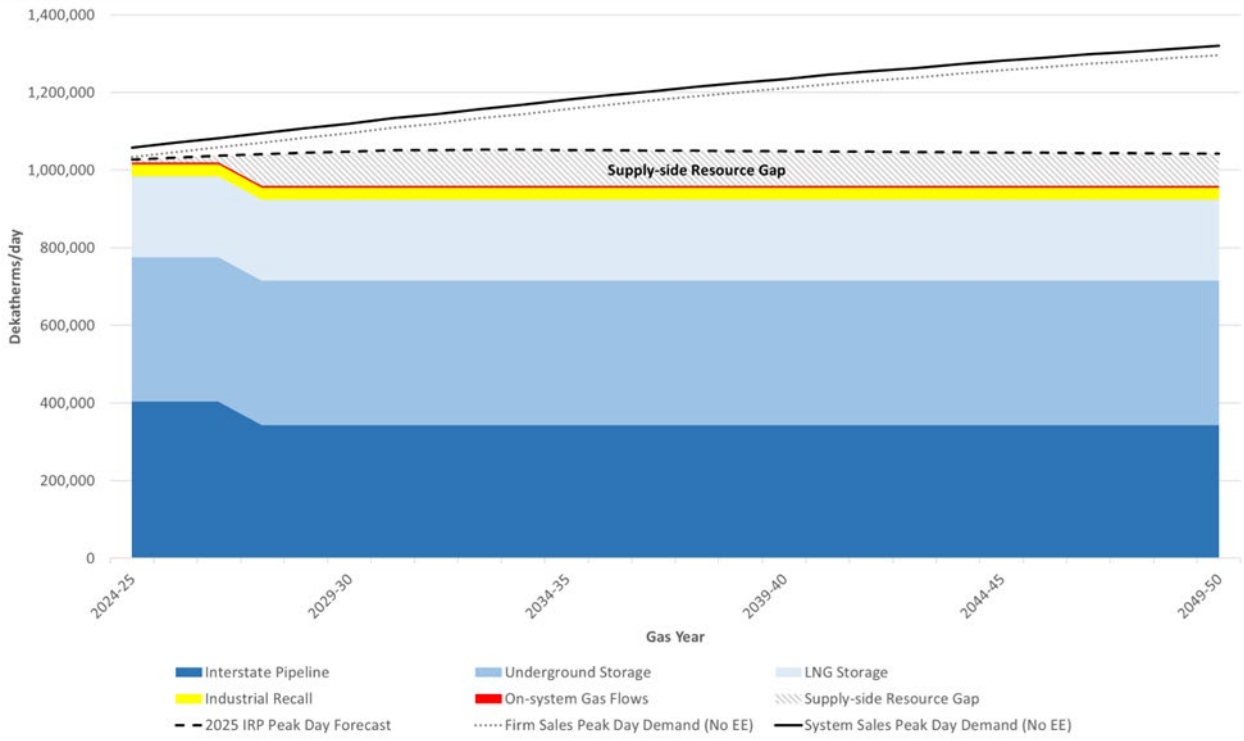


4.4.4.1 Resource Stack/Capacity Needs

Figure 4.36 illustrates NW Natural's resource stack to meet peak day needs. The gap between the design peak load net of energy efficiency and the expected resources represents the capacity needs for the Company to address.[120] The options to fill this gap are discussed in Chapter 8, and the least cost results for filling the gap for each scenario and across simulation draws are shown in Chapter 9.

[120] The decline in resources in the 2027-28 gas year is the projected date when Woodfibre LNG is projected to come online, and it is not fully understood how this will change the dynamics of flowing gas on segmented capacity. Therefore, this resource is removed.

Figure 4.36: Resource Stack vs. Firm Sales Peak Day Forecast



4.5 Load Uncertainty and Scenario Development

This section discusses system demand under stochastic weather conditions, as well as outlining the various demand scenarios where customer count is variable.

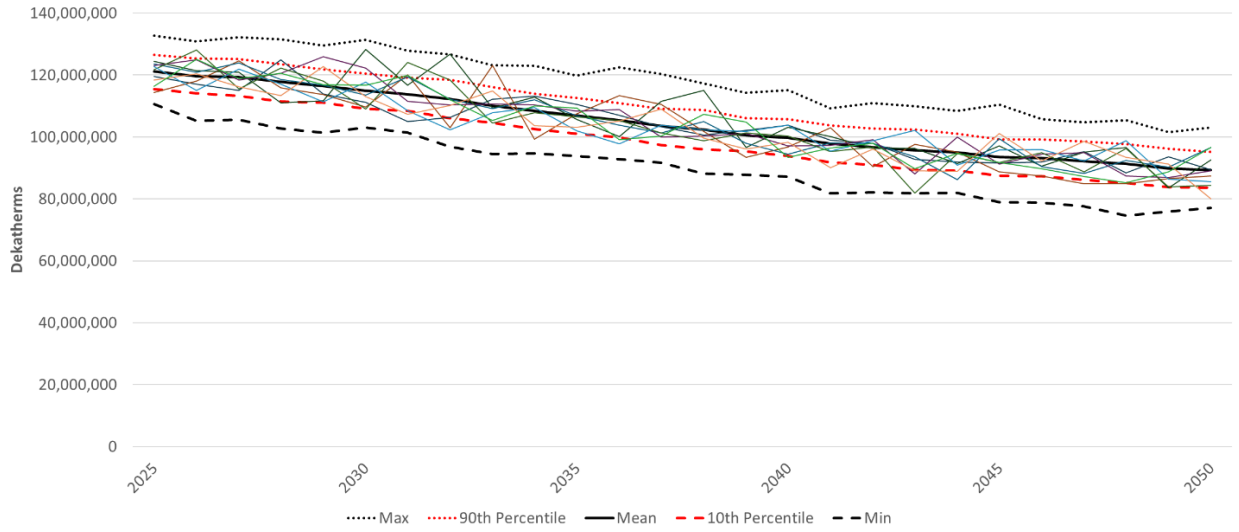
4.5.1 Reference Case Demand Stochastics

As discussed in prior sections, weather is a predominant driver of load. Given this, 500 stochastic weather simulations are run, and the resulting temperatures are input into the UPC model to estimate residential and small commercial load under those draws. Further, the industrial and large commercial econometric models are augmented with an HDD factor, so that these loads also exhibit some level of temperature sensitivity.[121] Aggregating these loads across the 500 draws, by year, produces Figure 4.37. The average load profile, across the planning horizon, exhibits the same downward trend as seen in the Reference Case. However,

[121] Both macroeconomic models yield significant betas when augmenting with annual log changes in HDDs. What is more, the sensitivity of these augmented factors to changes in HDDs is, economically, much smaller than the sensitivity to the models respective macroeconomic loading factor.

the stochastic analysis reveals much higher (lower) demand under colder (warmer) weather conditions, while still maintaining the downward trend.[122]

Figure 4.37: Total System Stochastic Weather Demand



4.5.2 Demand Scenarios

Scenario analysis is used to evaluate resource planning under several different futures. There are five demand scenarios in this IRP which are used to establish upper and lower bound load profiles. Table 4.5 provides a brief description of each of these scenarios. The assumptions and results of the Reference Case demand are discussed in the preceding sections, while the remaining demand scenario details are summarized in Appendix B.

[122] The solid colored lines represent ten randomly selected stochastic draws.

Table 4.5: Demand Scenarios

Demand Forecast	Description
Reference Case	Baseline load forecast.
Growth Recovery	Population, employment, and housing trends experience higher growth patterns than the Reference Case.[123]
Modest Customer Electrification	Aligns with trends from NEEA-RBSA, projections from electric utilities of existing buildings electrifying, and places limitations on natural gas in new construction buildings.
Hybrid System Electrification	Hybrid systems electric heat pump with gas furnace as back up are installed in existing buildings and new construction based on stock turn-over.
All-Electric Buildings	Significant levels of building electrification of existing buildings and new construction based on stock turn-over.

4.6 Emissions Requirements

As discussed in Chapter 2, NW Natural is subject to state-level emissions policy requirements in Oregon and Washington. This section compares state policy emissions requirements with NW Natural's forecasted emissions from the annual load projections described in Section 4.3. Section 4.6.1 compares emissions requirements under the Climate Protection Program (CPP) with NW Natural's load in Oregon, while Section 4.6.2 make a similar comparison based on emissions requirements under the Climate Commitment Act (CCA). Section 4.6.3 presents NW Natural's forecasted emissions based on annual load projects for other scenarios—specifically, the growth recovery scenario and three electrification scenarios: modest electrification, hybrid electrification, and full electrification.

4.6.1 Oregon Emissions Requirements

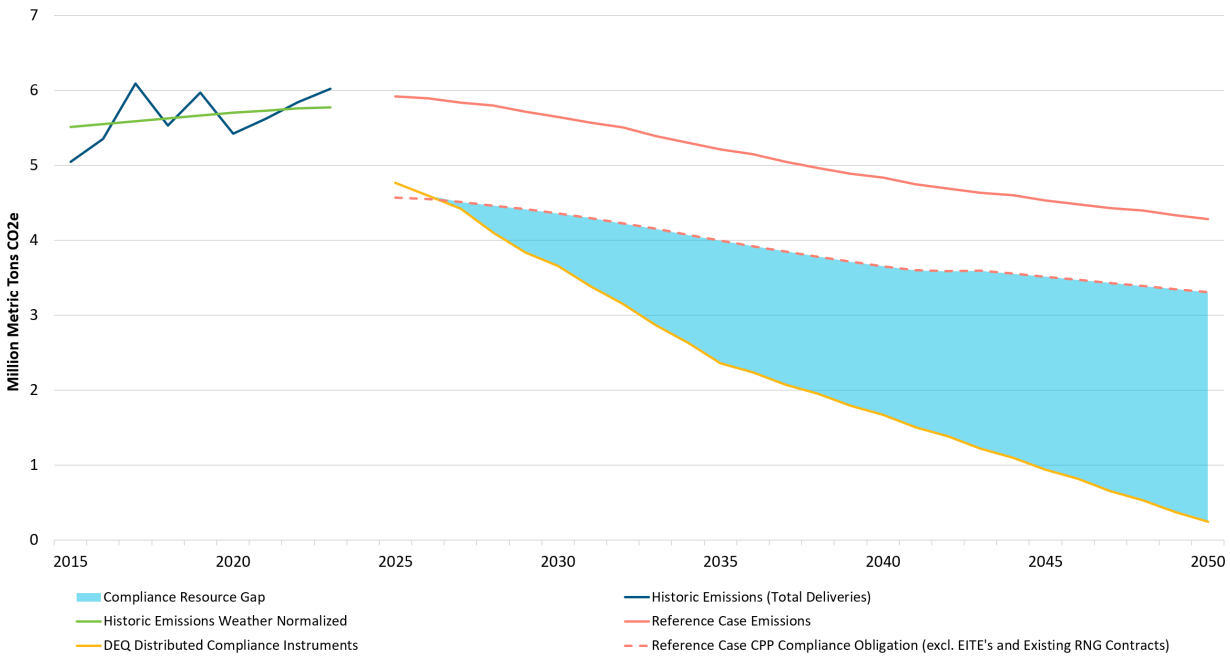
Figure 4.38 shows Oregon's emissions requirements under the Climate Protection Program (CPP) with NW Natural's forecasted emissions from the annual load projection.

[123] See Appendix B for details.

In the years before 2025, this figure contains two series. First, historical emissions from total deliveries between 2015 and 2023.[124] Historical emissions fluctuate due to variance in weather. Therefore, a second series that normalizes NW Natural's historical emissions is also shown.[125]

After 2025, the figure contains three series. The first series presents emissions associated with the Reference Case, while the second series removes both emissions from EITE (Emissions Intensive, Trade Exposed) customers and emissions from NW Natural's existing RNGs to capture NW Natural's compliance obligation under the CPP. The third series indicates emissions associated with the compliance instruments distributed to NW Natural under the CPP. The area shaded in blue represents the gap that NW Natural must meet to comply with the CPP.

Figure 4.38: Oregon Emissions Compliance Resource Requirements



Between 2015 and 2023, NW Natural's emissions ranged from 5.05 million (2015) and 6.09 million (2017) MTCO2e, with an average of 5.66 million and standard deviation of 0.33 million. In 2023, emissions were 6.02M MTCO2e. NW Natural projects that from 2025 to 2050, Oregon

[124] Oregon DEQ Historic Emissions (https://www.oregon.gov/deq/ghgp/Documents/ghgNatGasEms.xlsx). Accessed on 12/12/24.

[125] Oregon Historic Emissions were regressed on Oregon Customer Count and Heating Degree Days. The weather normalized emissions for each year reflect the fitted value of emissions when that year's customer count and the average HDD from 2015 – 2024 are plugged into the regression.

emissions in the Reference Case will fall from 5.93 to 4.28 million MTCO2e. Over the same period, compliance emissions (which excludes EITE's and existing RNG) is forecasted to fall from 4.57 to 3.31 million MTCO2e. On average, Oregon compliance emissions are 30 percent less than the total Reference Case forecasted emissions.

Starting in 2027, NW Natural does not expect to receive sufficient compliance instruments to cover compliance emissions. Between 2027 and 2050, the Company forecasts this gap will expand from 0.09 million (two percent) to 3.06 million MTCO2e (93 percent)[126]. This gap is based on energy use projections from expected weather. Due to variance in winter weather, the size of the realized compliance gap will vary much more from year to year.

In Chapter 7 (Emissions Compliance Resources), NW Natural describes options to cover this gap. In Chapter 9 (System Resource Planning and Portfolio Results), NW Natural reviews the output of the Company's resource planning model and discusses resource selection under the different scenarios examined in this IRP.

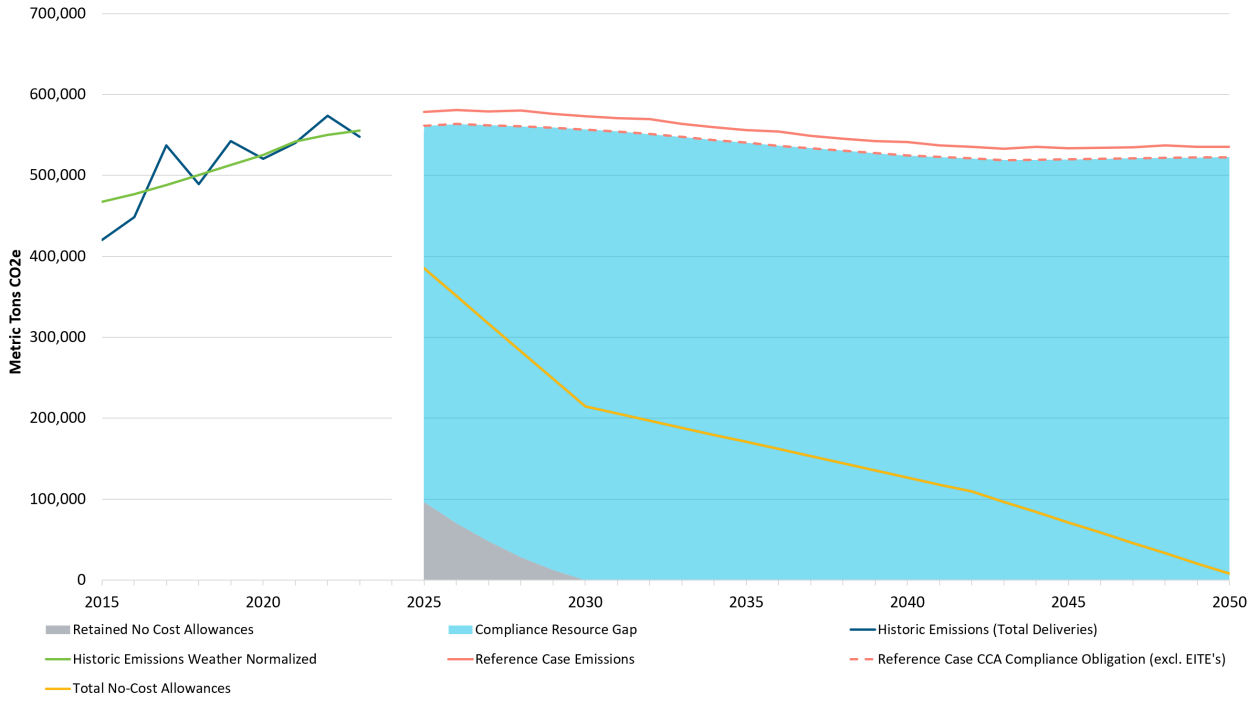
4.6.2 Washington Emissions Requirements

In similar fashion as Figure 4.38, Figure 4.39 contrasts Washington's emissions requirements under the Climate Commitment Act (CCA) with the NW Natural's forecasted emissions from the annual load projection described in Section 4.3. It shows historic emissions and weather-normalized historic emissions from 2015 – 2023, as well as Reference Case emissions and Reference Case emissions without emissions from EITEs.

Figure 4.39 also presents a series showing retained no-cost allowances granted to NW Natural between 2025 – 2029. The area shaded in red represents emissions covered by retained allowances. The area shaded in blue represents NW Natural's compliance gap under the CCA. Similar to Oregon, the compliance gap is based on energy use projections from the Reference Case. Due to variance in winter weather, the size of the realized compliance gap will vary much more from year to year. The final series shows the total number of no-cost allowances DEQ allots NW Natural, most of which must be consigned at auction.

[126] Percentages represent the compliance gap as a share of total compliance emissions for a given year.

Figure 4.39: Washington Emissions Compliance Resource Requirements



Between 2015 and 2023, NW Natural's emissions ranged from 419,862 (2015) and 573,619 (2022) MTCO2e, with an average of 513,223 and standard deviation of 47,725. In 2023, emissions were 547,472 MTCO2e. NW Natural projects that from 2025 to 2050, Washington emissions in the Reference Case will fall from 578,247 to 535,536 MTCO2e. Over the same period, compliance emissions (which excludes EITE's) is forecasted to fall from 561,236 to 522,544 MTCO2e. On average, Washington compliance emissions are three percent less than the total Reference Case forecasted emissions.

The gap in compliance emissions ranges from 464,965 in 2025 to 522,544 in 2050. Though NW Natural will have to consign most of them at auction, NW Natural anticipates receiving 385,081 allowances in 2025.[127] That figure falls to 7,799 by 2050. During this period, the Company forecasts total allowances as a share of compliance emissions will decline from 69 percent (2025) to 1.5 percent (2050).

In Chapter 7 (Emissions Compliance Resources), NW Natural describes options to cover this gap. In Chapter 9 (System Resource Planning and Portfolio Results), Natural reviews the output of

[127] Each allowance covers 1 MTCO2e.

the Company's resource planning model and discusses resource selection under the different scenarios examined in this IRP.

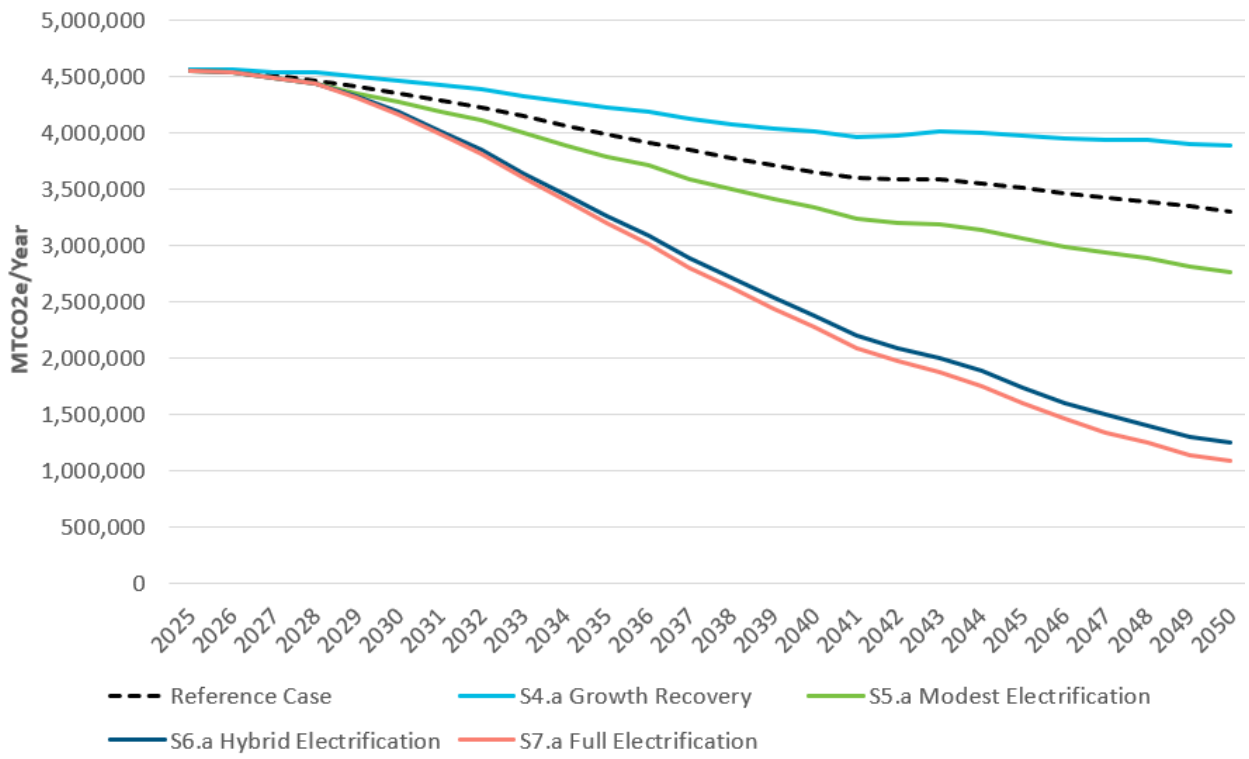
4.6.3 Emissions Under Various Load Scenarios

Figures 4.40 and Figure 4.41 compare the compliance obligations of five of the scenarios examined in this IRP for Oregon and Washington, respectively. They present emissions for the Reference Case, the growth recovery scenario, and three electrification scenarios: modest electrification, hybrid electrification, and full electrification.

The emissions projections in Figure 4.40 and Figure 4.41 represent CO2e that would be emitted if NW Natural's entire forecasted compliance load under a given scenario were to be served with conventional natural gas. To capture emissions from the compliance load, each series subtracts emissions from EITEs and, in Oregon, from NW Natural's existing RNGs. Therefore, the Reference Case series compliance in Figure 4.40 is identical to the Reference Case emissions series at the top of the shaded area in Figure 4.38.

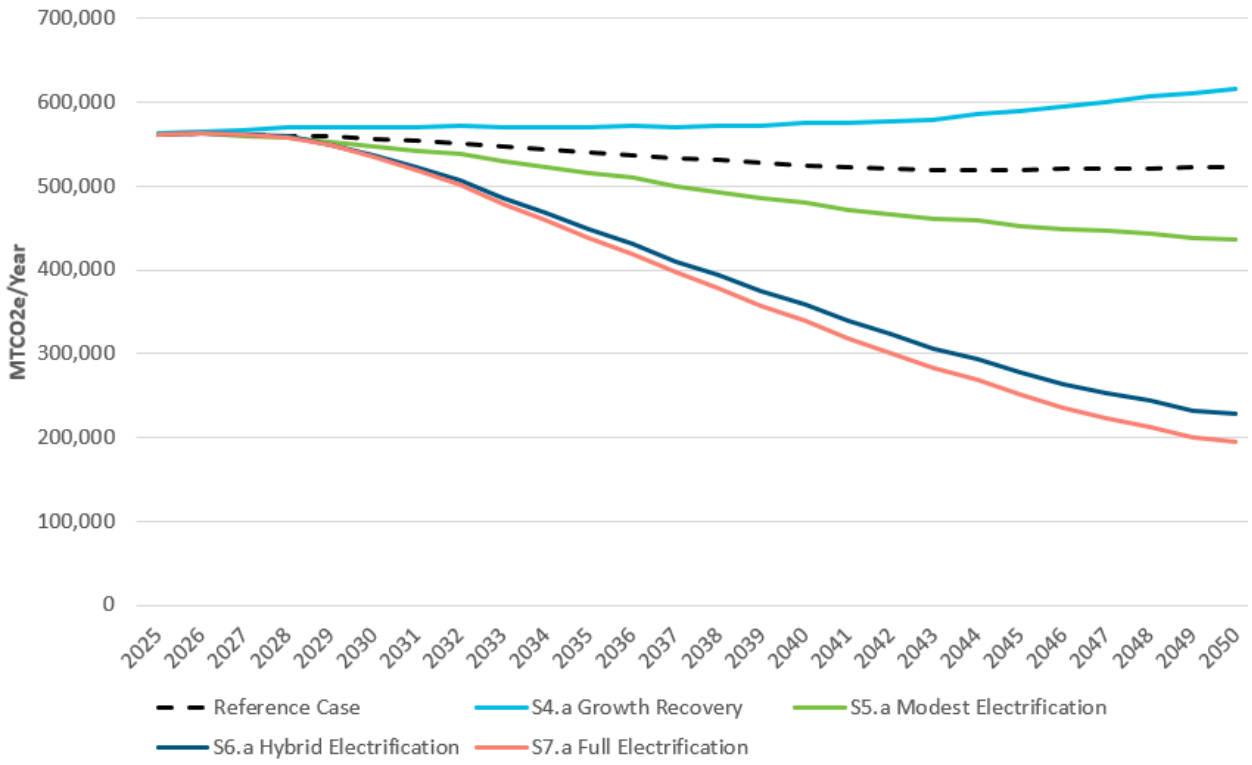
Since the two Figures compare compliance obligations, the emissions forecasts do not consider emissions reductions from the optimized deployment of compliance resources given by the PLEXOS® model under each scenario. The three electrification scenarios solely represent NW Natural's emissions. They do not include incremental emissions from the power served to customers who have electrified under these scenarios.

Figure 4.40: Oregon Compliance Load Under Various Scenarios



NW Natural's CPP compliance obligation emissions in the Reference Case projects to fall from 4.57 to 3.31 million MTCO2e between 2025 and 2050. While the compliance obligations under the other scenarios start in a similar place, they diverge significantly during the time period of the analysis. By 2050, compliance obligation emissions in the growth recovery scenario only fall to 3.89 million MTCO2e, 17.6 percent higher than Reference Case emissions in 2050. In the modest, hybrid, and full electrification scenarios, emissions fall to 2.76, 1.25, and 1.09 million MTCO2e, respectively by 2050. These represent decreases of 16.5 percent, 62.2 percent, and 67.1 percent from Reference Case emissions. See Chapter 9 for discussion of NW Natural's compliance resource strategy to meet its policy obligations under these scenarios and see Chapter 10 for discussion of the electrification scenarios.

Figure 4.41: Washington Compliance Load Under Various Scenarios



In Washington, NW Natural's CCA compliance obligation emissions in the Reference Case projects to fall from 561,236 to 522,544 MTCO2e between 2025 and 2050. By 2050, emissions in the growth recovery scenario rise to 615,667 MTCO2e, 17.8 percent higher than Reference Case emissions in 2050. In the modest, hybrid, and full electrification scenarios, emissions fall to 435,686 MTCO2e, 228,128 MTCO2e, and 195,587 MTCO2e, respectively by 2050. These represent decreases of 16.6 percent, 56.3 percent, and 62.6 percent from Reference Case emissions. See Chapter 9 for discussion of NW Natural's compliance resource strategy to meet its policy obligations under these scenarios and see Chapter 10 for discussion of the electrification scenarios.

5 Avoided Costs

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Choosing amongst resource options requires understanding the cost tradeoffs amongst resource options. This chapter describes the methodologies used to determine the costs that are avoided when one resource is chosen over the other available options.

5.1 Overview

As part of the IRP process, NW Natural forecasts avoided costs over the planning horizon. Total avoided cost is an estimate of the cost to serve the marginal unit of demand with conventional supply-side resources. This incremental cost represents the cost that could be avoided if that unit of gas were not demanded, due to efforts such as demand-side management (DSM), or through on-system supply side resources such as locally sourced renewable natural gas.

Therefore, the avoided cost forecast can be used as a guideline for comparing the cost of acquiring gas and supply-side resources to meet demand with other options so that the most cost-effective solutions are identified to meet customer needs. Practically, the avoided cost forecast is a key component of the cost-effectiveness test that is conducted by Energy Trust of Oregon (ETO) and other conservation potential assessment (CPA) contractors to determine the DSM savings projections for Oregon and Washington detailed in Chapter 6.

This chapter details the methodology used to calculate each component of NW Natural's avoided costs. The methodology used to calculate the avoided cost forecast has seen continued improvement since the 2014 IRP. For the 2025 IRP, NW Natural's avoided cost forecast features the following key methodological improvements:

- The reinstated Climate Protection Program (CPP) and Community Climate Investments (CCI) for Oregon and Climate Commitment Act (CCA) for Washington have been included in the 2025 IRP modeling assumptions. Instead of the use of incremental compliance resource costs alone as in the 2022 IRP, the avoided greenhouse gas (GHG) costs for environmental compliance in this IRP are determined by the higher of the social cost of carbon and the cost of incremental compliance resources to generate state-specific avoided costs in NW Natural's territory.
- The Company has, for the first time, estimated the risk reduction value of DSM for GHG compliance costs by applying the same method for commodity price risk reduction value calculation, since GHG compliance costs are also volatile, and DSM programs can not only avoid GHG compliance costs but also help mitigate the potential losses caused by fluctuations in GHG compliance costs.

This chapter also presents the avoided costs results for both the demand-side and the supply-side resources to which the concept is applied. NW Natural continues to work on improving its methodologies and internal processes relative to avoided costs in a continuing effort to ensure

that all resources, be they demand- or supply-side, are evaluated on a fair and consistent basis in a fully integrated process.

5.2 Avoided Cost Components

Table 5.1 summarizes each of the components of avoided costs and shows which components are included in the evaluation of the different resource options NW Natural considers in its resource planning. Additionally, Table 5.1 shows which values of the avoided cost components vary by end use or supply resource.

Table 5.1: Avoided Costs Components and Application Summary

Costs Avoided		Resource Options		
		Demand-Side Resources		
		Energy Efficiency	Demand Response	
			Interruptible Schedules	Other DR
Energy Related Avoided Costs	Natural Gas Purchase and Delivery Costs	✓	Depends	Depends
	Greenhouse Gas Costs	✓	Depends	Depends
	Risk Reduction Values	✓	Depends	Depends
Infrastructure Related Avoided Costs	Supply Capacity Costs	✓	✓	✓
	Distribution Capacity Costs	✓	✓	✓
Unquantified Conservation Costs	10% Northwest Power & Conservation Council Credit	✓	✓	✓

5.2.1 Energy Related Avoided Costs

These avoided costs apply on a per unit of natural gas saved basis. Gas prices are typically higher during winter months, therefore, gas savings achieved during winter provide a higher avoided gas purchase and delivery cost value. For avoided GHG compliance costs and risk reduction values, since it is either irrelevant or somewhat unimportant when the energy is saved, per unit savings are assumed to have the same values regardless of when the savings are achieved during the year.

5.2.1.1 Gas Purchase and Delivery Costs

This component represents the cost of the natural gas commodity itself. The main driver of this cost is the base case natural gas price forecast detailed in Chapter 2 (Section 2.2), though it also includes the following minor costs: 1) "line losses," or the amount of gas that is used to deliver gas from where it is purchased to where it is consumed; 2) applicable variable transmissions costs; and 3) storage inventory carrying costs. On any given day in the forecast period, the avoided gas purchase and delivery costs represent the cost of the last unit of gas sold during that particular day[128], where that unit may be from an expected daily spot purchase or a storage withdrawal depending on the load that needs to be served and gas prices on that day. This daily figure comes from the resource planning optimization PLEXOS® model and is aggregated to the monthly level. Note that avoided commodity and delivery costs varied not only through time but also across end uses. Therefore, each end use has its own gas purchase and delivery estimate based on the seasonal usage or supply portfolio of that resource and the seasonality of natural gas prices exhibited in the price forecast. The details of this calculation can be found in Appendix C.

5.2.1.2 Greenhouse Gas Emissions Compliance Costs

In the 2022 IRP, NW Natural explicitly included incremental environmental policy compliance resource costs for the former CPP in Oregon and the CCA in Washington in its portfolio modeling assumptions. Greenhouse Gas (GHG) compliance costs were separately determined based on the incremental policy compliance resource costs by state to meet environmental policy requirements specific to each state in NW Natural's territory. In this IRP, while NW Natural employs the same approach to model the reinstated CPP in Oregon and the CCA in Washington, the GHG emissions compliance costs are not simply determined as the incremental environmental compliance resource costs alone. Instead, to fully capture the life cycle GHG emissions costs caused by natural gas that would be avoided if NW Natural could purchase one less unit of energy for any given day, the GHG compliance costs are calculated by two sources of emissions as described at Technical Working Group 5:

[128] Which by cost minimization protocols is the most expensive unit of gas purchased that day.

Source 1. Combustion emissions costs by end use customers (Direct Use), calculated as the maximum of a or b:

$$MAX\begin{cases} a.\,Social\ Cost\ of\ Carbon\left(\frac{\$}{MT}\right) * Emissions\ Intensity\ of\ Combustion\left(\frac{MT}{Dth}\right) \\ b.\,GHG\ Policy\ Compliance\ Cost\ \left(\frac{\$}{Dth}\right) \end{cases}$$

Source 2. Gas supply chain emissions costs, calculated as:

$$Social\ Cost\ of\ Carbon\left(\frac{\$}{MT}\right) * Emissions\ Intensity\ of\ Gas\ Supply\ Chain\ \left(\frac{MT}{Dth}\right)$$

The total avoided GHG compliance costs are the sum of the combustion emissions costs and the supply chain emissions costs. Note both emissions intensity of gas combustion and the emissions intensity of gas supply chain are estimated based on data sources including EPA Subpart W, GREET Model, and GHGenius. The emissions intensity of gas supply chain also includes lifecycle system leakage in the form of CH4. Social cost of carbon is based on Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, August 2016, as approved by WA HB 1257 and published on WUTC website.[129] Also, social cost of carbon per Dth in the calculation of avoided combustion emissions costs (Source 1) represents the lower bound of the GHG avoided costs of natural gas for this emissions source.

5.2.1.3 Commodity Price Risk Reduction Value of DSM

Natural gas prices are volatile and uncertain, particularly when analyzing long-term price forecasts as is necessary to: 1) forecast costs in IRPs; and 2) evaluate the cost-effectiveness of resource options that provide energy savings or gas supply for multiple years (and in the case of DSM, sometimes indefinitely). If price hedging is not used to remove or mitigate this price volatility and uncertainty, customers are exposed to changes in the trend of prices in the long-term, and price fluctuations around this long-term trend in the short-term. DSM savings are a type of long-term hedge: if the actual energy savings that are going to be acquired and the costs to obtain those savings are known with certainty, acquiring demand-side savings removes the price risk associated with unhedged supply resources that would be necessary if energy savings were not acquired. [130]

The hedge value of DSM represents the risk premium gas purchasers need to pay (i.e., the cost to fix the price) to obtain a long-term fixed price financial hedge at the time of the IRP

[129] WUTC website https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

[130] This component is thus also referred to as the "hedge value of DSM".

analysis.[131] This IRP applies the same methodology as filed in the 2022 IRP to measure the commodity price risk reduction value as the portfolio risk-adjusted present value revenue requirement (rPVRR) calculated based on data from Monte Carlo gas price simulations equation:

Risk Adjusted Cost of Gas = 75% × Mean Stochastic Price + 25% × 95th Percentile Stochastic Price

The second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the associated price risk. This is the risk that a hedge protects against, and hence the risk reduction value is calculated in the equation below:

Risk Reduction Value = Risk Adjusted Cost of Gas – Mean Stochastic Price of Gas

When the price risk reduction value of DSM is added to the gas and transport costs described above, it represents the fixed price of gas that could be obtained through financial hedging instruments. The same risk reduction value is applied in both states and to all end uses.

5.2.1.4 Greenhouse Gas Compliance Cost Risk Reduction Value of DSM

In the 2025 IRP, NW Natural proposes the use of the approach to calculating the price risk reduction value described above to estimate risk reduction values for compliance costs given the uncertainty in environmental compliance costs. Environmental compliance costs are uncertain and even volatile for a couple of reasons. First, the social cost of carbon can be much higher than what is currently published on the WUTC website mentioned earlier per a recent report by U.S. Environmental Protection Agency (EPA).[132] Second, the costs of some environmental compliance resources such as renewable or low carbon natural gas are forecasts with uncertainty. PLEXOS® based Monte Carlo compliance cost simulations are used to generate data for this risk reduction value calculation:

Risk adjusted cost of compliance = 75% × Mean Stochastic Compliance Cost + 25% × 95th Percentile Compliance Cost

Again, the second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the cost risk associated with compliance resources. This risk reduction value is calculated in the equation below:

Compliance Risk Reduction Value = Risk adjusted cost of compliance – Mean Stochastic Compliance Cost

[131] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.
[132] https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

Similarly, the compliance cost risk reduction value of DSM is added to the compliance costs described above and represents the fixed cost of compliance that could be obtained from DSM. However, this risk reduction value varies across states since environmental policies and compliance resources could differ and so are the compliance costs. Within a state, this risk reduction value is the same for all end uses.

Note that when the methods for commodity prices and compliance costs described above lead to a calculated risk reduction value that is negative, a value of zero is assigned.

5.2.2 Infrastructure Related Avoided Costs

Infrastructure needs are driven by peak loads. Consequently, the extent to which energy is saved or supplied on peak determines the infrastructure costs resources avoid. To estimate infrastructure costs avoided by a resource, two calculations need to be conducted:

1. The incremental cost of serving additional peak load
2. The amount of energy that would be saved or supplied during a peak

Note that the incremental cost of serving additional peak load is the same for all resources but the energy supplied or saved on peak is resource specific. Take energy efficiency as an example. A significant share of the energy savings achieved through DSM programs comes from large industrial customers, though many of these customers elect to be on interruptible schedules. These customers are interrupted during peak events, so they do not contribute to peak load or the infrastructure designed to serve it. Therefore, savings acquired for interruptible customers avoid commodity related costs, but do not avoid infrastructure related costs related to peak planning as such infrastructure costs have already been avoided by the interruptible schedules as a DR program itself (see Table 5.1). On the other hand, DSM measures that target space heating, by contrast, result in relatively pronounced peak day load reductions (recall that space heating represents majority of the peak load) in addition to the energy savings they provide on an annual basis.

There are two infrastructure-related avoided costs components — supply capacity avoided costs and distribution system avoided costs. Supply capacity resources are the resources we use to get gas onto NW Natural's system of pipelines and are primarily interstate pipeline capacity and storage resources. Distribution system resources are the assets, primarily smaller pipelines, on NW Natural's system that distribute the gas that arrives at NW Natural's system via its supply resources to customers as it is demanded. Note that supply resources are held on a service territory-wide portfolio basis and serve both states, so supply capacity costs avoided per unit of gas are the same in both states. However, distribution assets are separate in Oregon and Washington, so distribution capacity costs avoided differ by state based upon the expected

costs of the distribution system in that state. Per Commission guidance and industry best practices, infrastructure resource costs are based upon the costs of the incremental capacity resource (i.e., cost of the marginal resource) needed to meet customer needs.

5.2.2.1 Supply Capacity Costs

NW Natural's methodology for estimating supply capacity costs has remained the same as in the prior two IRPs and has been applied to the end uses considered for DSM and the on-system supply resources discussed in Chapter 8.

1. Estimating the incremental infrastructure costs of serving peak day load:

Given the longstanding process of coordination between NW Natural and ETO/AEG (see Figure 5.1 for a visual depiction of this coordination) the DSM savings projections provided by ETO and AEG are completed before the supply resource optimization. Therefore, the incremental supply resources that would be saved for each year in the planning horizon with DSM need to be assumed before the supply resource optimization to assign a cost for the supply capacity costs being avoided based on prior IRP modeling output. The assumptions made about what supply portfolio resources would be acquired in each year can be different from the actual supply resource choices detailed in Chapter 12 (Distribution System).[133] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization. Different from prior IRPs, this IRP's modeling results show that avoided supply capacity costs exist from 2026 to 2033 and no avoided supply capacity costs at all from 2034 and onwards because there are no supply capacity expansion needs after 2033 as system peak day loads start to decline in 2034 till the end of the planning horizon (see Chapter 4).

2. Estimating the energy savings or supply on a peak day for each resource option:

To quantify the avoided supply capacity costs as benefits for DSM measures or supply resources, energy savings or supply on a peak day as well as the ratio of peak day savings or supply to normal weather annual energy savings or supply need to be estimated for each resource option. DSM measures or resources targeting at different end uses such as space heating, water heating or cooking have different peak day savings to annual savings or supply ratios that are defined in annual energy savings or supply shapes specific to each end use. Assuming the savings shape and the load shape are the same, these peak day to annual savings or supply can be obtained by estimating the peak day energy usage and annual usage of the end use to which a DSM measure or resource belongs with equation below:

[133] Note that the avoided cost figures have been updated and will be used by Energy Trust of Oregon for budgeting if the avoided costs in the 2025 IRP are acknowledged.

$$Peak\ Day\ to\ Annual\ Usage\ Ratio = \frac{Peak\ Day\ Energy\ Usage}{Normal\ Weather\ Annual\ Energy\ Usage}$$

These peak day to annual load ratios can then be used to calculate the supply infrastructure avoided costs on an energy basis by multiplying these ratios and the annual savings of their corresponding measures estimated by ETO and other CPA contractors.

As shown in Table 5.2, various approaches and sources of information were used to estimate the peak day to annual usage ratios for the end uses considered. The peak day to annual usage ratios for the largest contributor to peak day load, space heating, are estimated by the Company using a regression model based approach. More specifically, NW Natural collected the energy usage billing data and natural gas appliance and premise attribute data for the residential and commercial conversion customers who started their natural gas services with the Company in 2021 or after. Data collected from the new conversion customers is used for this analysis because information on gas appliances (i.e., furnace, fireplace, water heater, and stove) and premise attributes (i.e., square footage, building age and number of bathrooms) for the new conversion customers recorded in the Company's Customer Information System (CIS) is more likely to be valid and the billing usage data collected from these premises are more accurately reflective of the energy usage by these gas appliances for the given premise attributes. The Company regressed the energy usage on a set of appliance indicator variables, premise attribute variables, heating degree days (HDD) corresponding the usage, and interaction terms among the appliance indicators, premise attributes and HDD and used the estimated regression model and the normal weather HDD to calculate the annual normal weather energy usage for space heating as well as the peak day usage under the design peak day weather for space heating.

Table 5.2: End Use Specific Peak Day Usage/Savings Ratios

Peak DAY Usage to Normal Weather Annual Usage Factors for SUPPLY Costs		Source of Information
Residential Space Heating (Including Hearths and Fireplaces)	0.01767	NW Natural Regressions
Commercial Space Heating	0.01767	NW Natural Regressions
Water Heating	0.00330	NW Natural Regressions and NEEA Water Heater Study
Cooking	0.00356	Analysis of ODOE RECS Data
Process Load	0.00274	Annual/365

5.2.2.2 Distribution Capacity Costs

The same general process undertaken for supply resource capacity costs avoided is also completed for avoided distribution capacity costs, with the key metric being the incremental costs associated with enhancing or reinforcing the distribution system to serve peak hour demand, rather than peak day demand.

1. Estimating the incremental infrastructure costs of serving growing peak hour load:

In alignment with the guidance on the calculation of infrastructure avoided costs provided in OPUC Order No. 25-017,[134] this state-specific calculation relies on historical data of the costs to reinforce NW Natural's distribution system and is based on an average of the revenue requirement of reinforcement projects that were completed over the previous 10 years from 2014 to 2023. Note that these costs do not include the costs associated with installing new services or meters, operation and maintenance costs, or with commodity purchases or our supply capacity resources. They represent only the cost of service revenue requirement of capital expenditures to reinforce the distribution system so that it is sufficient to reliably serve all our customers. The primary driver of these costs is growing peak hour load. Therefore, to estimate the cost of reinforcing NW Natural's distribution system as peak hour load grows, the growth in peak hour load for each of Oregon and Washington over the same 10 years was estimated using the peak hour load forecasting technique described in Chapter 12. Dividing the revenue requirement from the sum of the reinforcement projects over the past 10 years by the growth in peak hour load over the same period, gives an estimate of the cost of incremental peak hour load on a per unit of peak hour load for the two states in our service territory. This is the estimate of the costs that would be avoided by serving or saving a unit of gas on a peak hour.

2. Estimating the energy savings or supply on a peak day for each resource option

For each resource considered, the amount of natural gas it will supply or save on a peak hour is what is determined for each resource evaluated. Given that the peak hour is typically the hour starting at 8 a.m. on the peak day, this is done by estimating the share of peak day savings/supply that will occur during that hour and multiplying this factor by the peak day factors in Table 5.3. Take the largest contributor to peak hour load, space heating, as an example: dividing the peak hour space heating load (8 a.m.) by the total space heating load for the peak day, provides an estimate of the share of peak day load served during the peak hour that distribution system infrastructure is designed to serve. This estimate was made using two sources, NW Natural system hourly flow regressions and the Electric Power Research Institute

[134] https://apps.puc.state.or.us/orders/2025ords/25-017.pdf

(EPRI) residential peak space heating load shape. These sources were averaged to calculate the hourly to daily peak hour factor for residential space heating. Using NW Natural's hourly load forecasting methodology described in Chapter 4, subtracting summer loads from peak day loads for each hour of the day provides an estimate of space heating load on a peak day, which can then be turned into the peak hour factor described above. For space heating, this factor is 5.21 percent for residential and 6.02 percent for commercial.[135] Multiplying this factor times the peak day factor in Table 5.3 gives an estimate that the average residential NW Natural customer would use the equivalent of 0.092 percent of their normal weather *annual* residential space heating load on a peak hour. This figure, along with the peak hour to annual usage ratios for the other end uses considered in this IRP, is shown in Table 5.3.

Table 5.3: End Use Specific Peak Hour Usage/Savings Ratios

Peak HOUR Usage to Normal Weather Annual Usage Factors for DISTRIBUTION System Costs		Source of Information
Residential Space Heating (Including Hearths and Fireplaces)	0.00092	NWN System Hourly Flows & EPRI Load Shape
Commercial Space Heating	0.00106	NWN System Hourly Flows & EPRI Load Shape
Water Heating	0.00018	NWN System Hourly Flows & EPRI Load Shape
Cooking	0.00027	National Renewable Energy Lab (NREL) Load Shape
Process Load	0.00011	Daily/24

Multiplying the factor shown in Table 5.3 by the annual normal weather usage for each end use measure or on-system supply resource gives an estimate of the energy saved or supplied on a peak hour, which can be multiplied by the estimate of the cost of serving an additional unit of peak hour load to estimate the costs avoided by that measure or supply resource.

5.2.2.3 Unquantified Conservation Avoided Costs

Ten Percent Northwest Power and Conservation Council Conservation Credit

In prior IRPs, this credit was applied for DSM and calculated from a summation of all the components of avoided costs except the risk reduction value of DSM and the GHG compliance

[135] Note that a flat load has a factor of 1/24, or 4.17 percent.

cost components. Per Staff recommendations adopted in OPUC Order No. 24-119,[136] this IRP applies this 10 percent conservation credit to all avoided cost value streams including the risk reduction value and avoided GHG compliance costs. Note that even though the ten percent conservation credit is applied consistently across all DSM resources, the actual credit included in avoided costs varies since some of the avoided costs components vary by state, end use, and/or time. While the credit was originally designed to apply to DSM, it is unclear whether it should also be applied to supply-side resources that also conserve the use of conventional natural gas (most notably renewable natural gas) so that demand- and supply-side resources are treated on a fair and consistent basis per Oregon PUC's IRP guidelines. NW Natural has not included the Conservation Credit in the avoided costs of any resources except DSM in this IRP, but it warrants consideration in future IRPs.

5.3 Demand Side Applications

This section discusses how avoided costs are used to evaluate the demand side resources such as energy efficiency and demand response in the IRP process and how their cost components are changing through time as well as across IRP filings. The section also provides details on how the avoided costs for carbon emissions compliance are determined by specific marginal compliance resources identified in the IRP modeling over the 2026 to 2050 planning horizon.

5.3.1 Avoided Costs and Demand-side Management in the Overall Integrated Resource Plan Process

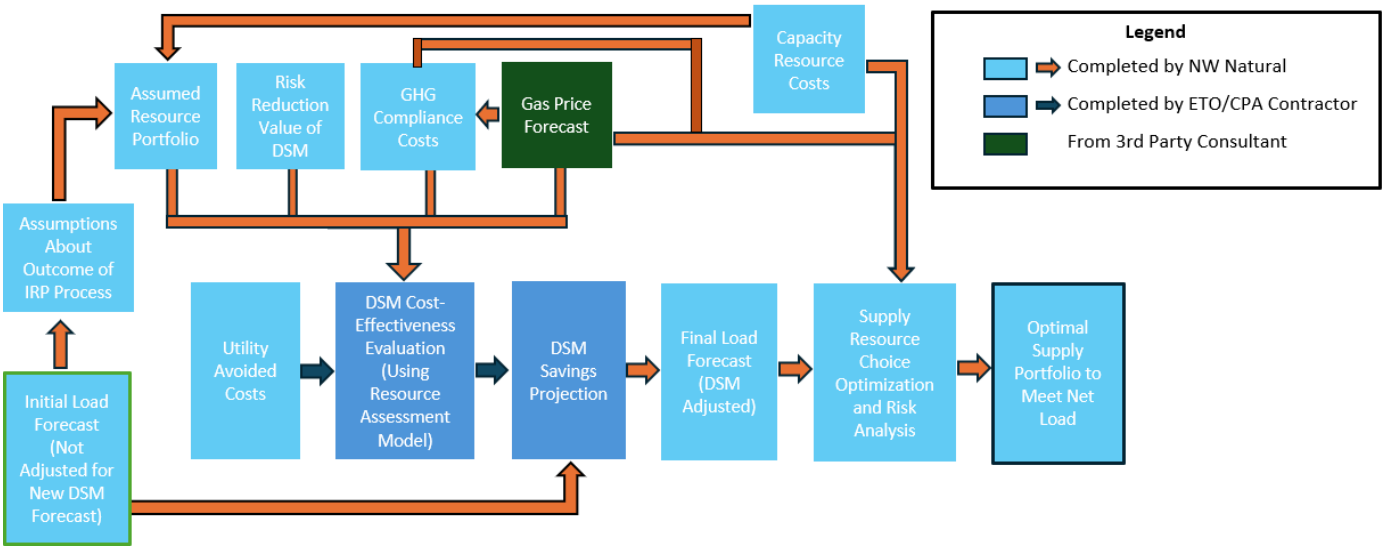
Figure 5.1 details how avoided costs and demand-side management (DSM) energy savings forecasts, also referred as conservation potential assessments (CPAs), are integrated into the broader IRP process and what work is completed by NW Natural and what work is completed by ETO or other CPA contractors. Note that NW Natural has been using an avoided cost approach to compare demand-side and supply-side resources and this approach is necessarily an iterative process between IRPs or IRP updates and CPAs.[137] This iterative process is used because the CPA is conducted first based on the most up-to-date avoided costs and load forecasts (absent DSM energy savings). Ultimately, the savings forecasted in the CPA are netted

[136] For more details about the OPUC Order No. 24-119, see https://apps.puc.state.or.us/orders/2024ords/24-119.pdf

[137] The work done by ETO and AEG to complete their DSM savings projections, and the projections for this IRP cycle, are the topic of Chapter 6.

out of the load forecast, an input to the Resource Planning Optimization Model (see Section 9.2 for further details) that results in a new set of avoided costs.[138]

Figure 5.1: NW Natural IRP Process



An alternative and separate approach would be to compile bundles of DSM savings as selectable options within the Resource Planning Optimization Model. There are pros and cons to either approach. NW Natural raised key questions and discussion points about pursuing this alternative approach in the first round of reply comments in OPUC docket LC 79.[139] These reply comments discuss the pros, cons, and level of coordination with the DSM implementors needed to employ this alternative approach. The discussion around moving to an alternative approach has yet to be concluded. For this IRP, NW Natural continues to rely on the avoided cost framework that has been in place for the last several IRPs for evaluating demand-side resources.

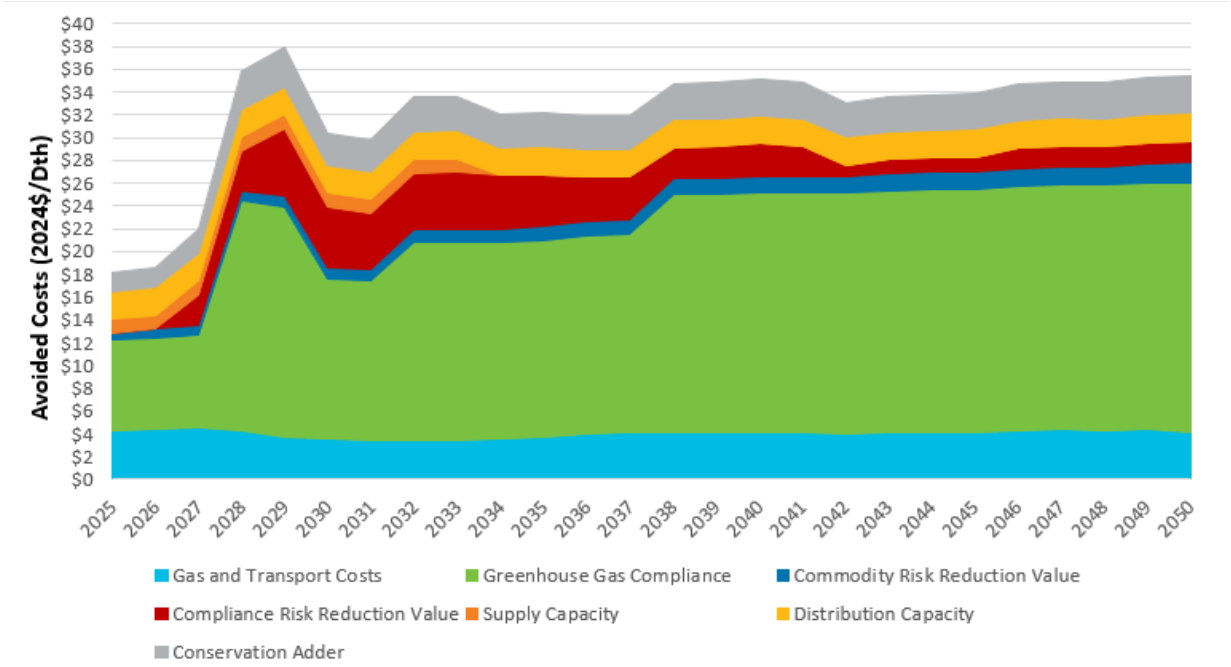
5.3.2 Avoided Costs Component Breakdown Through Time

For each end use, avoided costs vary through time (and by state). Figures 5.2 and 5.3 use residential space heating as an example to show the component breakdown of avoided costs through time for this end use in Oregon and Washington, respectively. Again, like the shapes presented in prior IRPs, avoided costs are not smooth and fluctuate remarkably. This is more

[138] The CPA work takes six to 12 months to complete and therefore the initial load forecast may not be the exact same as the final load forecast that the savings are netted from as the Company regularly updates components of the load forecast.
[139] See Section 1.5 Energy Efficiency and Demand Response as Selectable Resources in the Resource Optimization Model in NW Natural's reply comments filed February 3, 2023 in OPUC docket LC 79.

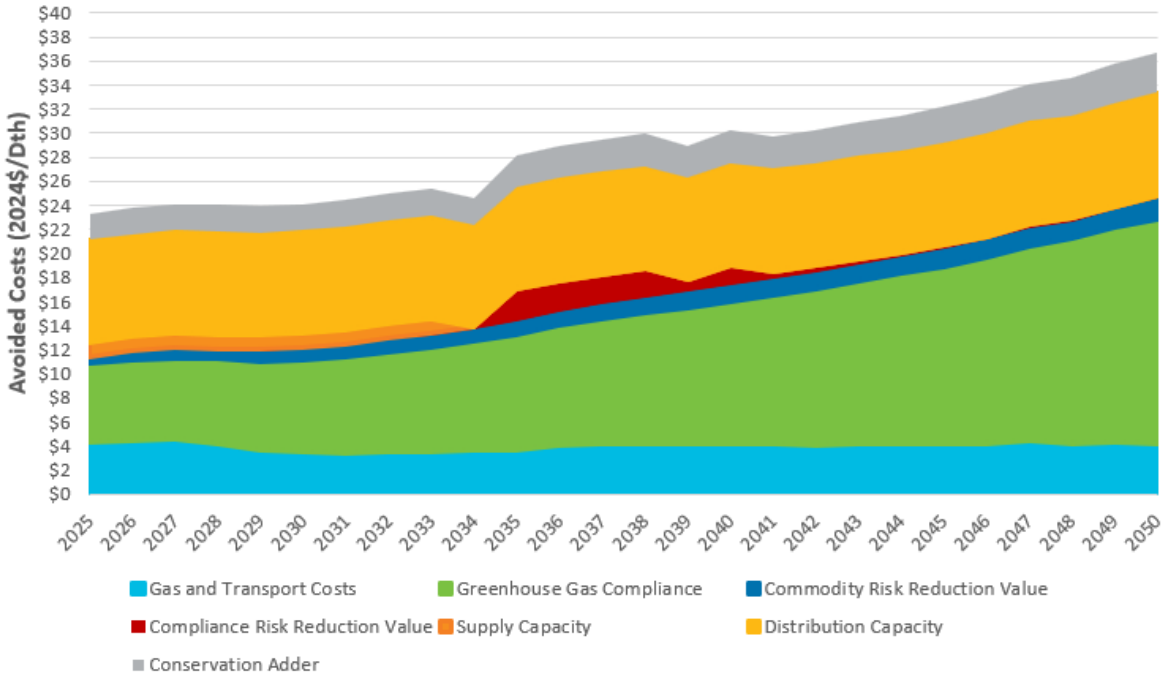
evident in the Oregon case due to the changes in compliance resource costs (see details in Section 5.3.4) as well as the consequent remarkable changes in compliance risk reduction values (see Table C.1 in Appendix C for annual compliance risk reduction values by state in detail). Also, it is worth noting that there are no avoided supply capacity costs to be claimed after 2033 as explained earlier in Section 5.2.2.1, and this creates the first visible dent in year 2034 in Figure 5.3 depicting the changes in avoided costs over time. With all the above-mentioned changes, in this IRP the levelized total avoided costs over the planning horizon for residential space heating have increased from $22.01 per Dth in the 2022 IRP to $31.26 per Dth in Oregon and from $23.43 per Dth to $27.65 per Dth in Washington, or by 42 percent and 18 percent, respectively.[140] As shown in Figures 5.2 and 5.3, the increase in avoided costs in this IRP comes mainly from a significant increase in avoided GHG compliance costs and the related risk reduction values for Oregon, avoided distribution capacity costs for Washington, and partially from the application of the ten percent conservation credits to all avoided cost components. Note that space heating has the largest impact on peak loads, so the distribution infrastructure costs avoided are largest for space heating relative to the other end uses.

Figure 5.2: Example Avoided Cost Breakdown Through Time – Oregon Residential Space Heating



[140] The avoided cost values are converted in 2024$.

Figure 5.3: Example Avoided Cost Breakdown Through Time – Washington Residential Space Heating



Figures 5.4 (Oregon), 5.5 (Washington) and Table 5.4 summarize the component breakdown of avoided costs by end use and by state. The values are presented in levelized terms to provide a more succinct summary of the results. Note that the first bar (far left) in Figures 5.4 and 5.5 is a levelized representation of the time path shown in Figures 5.2 and 5.3.

Figure 5.4: Oregon 26-year Levelized Avoided Costs by End Use

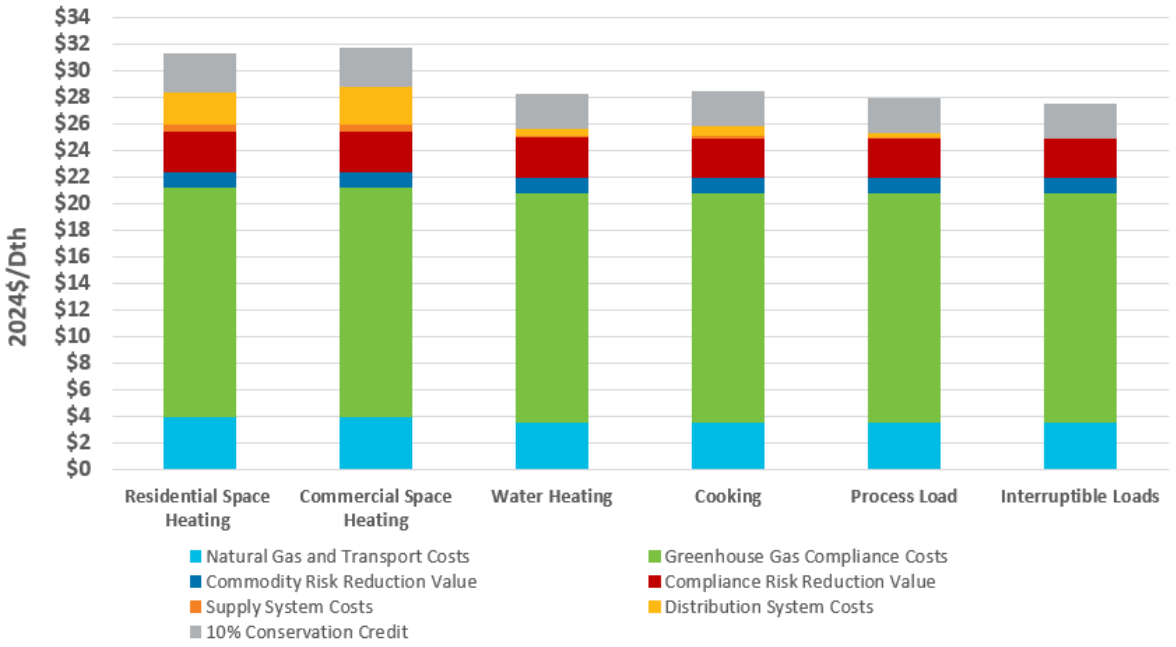


Figure 5.5: Washington 26-year Levelized Avoided Costs by End Use

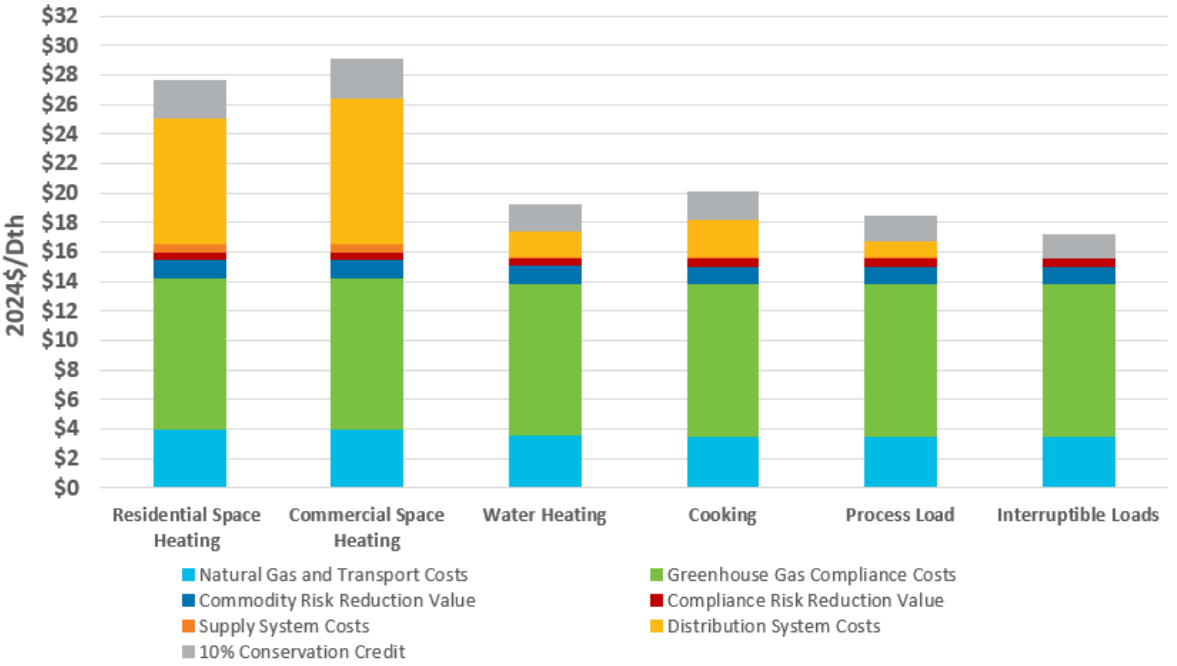


Table 5.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2024$/Dth)

26 Year Levelized Avoided Costs

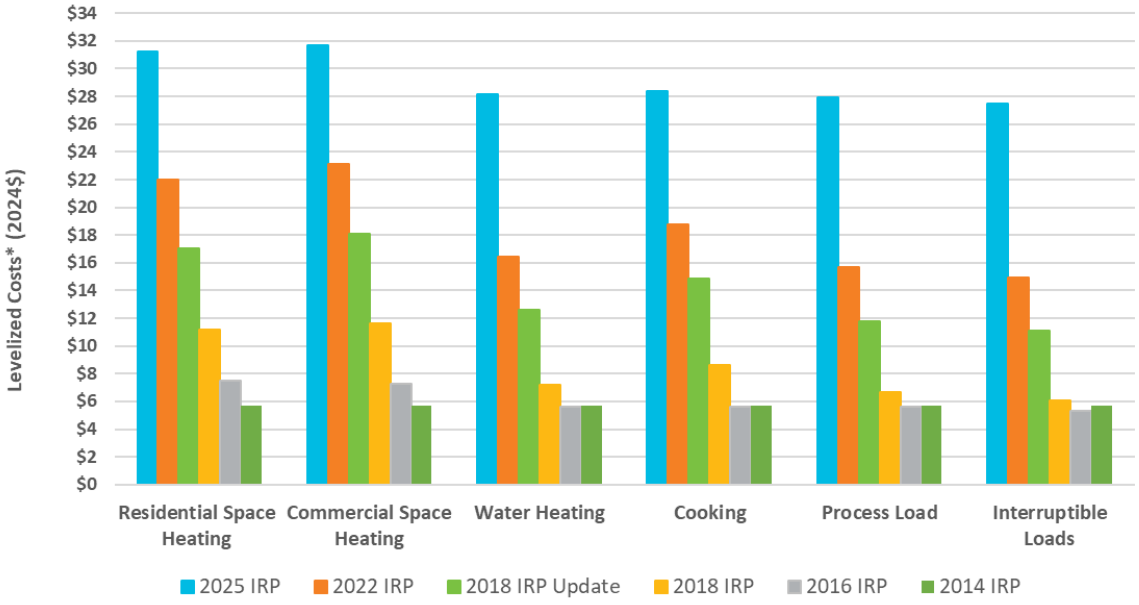
		Commodity Costs				Capacity Costs		10% Conservation Credit	Total Avoided Costs
		Natural Gas Commodity and Transport Costs	Greenhouse Gas Compliance Costs	Commodity Risk Reduction Value	Compliance Risk Reduction Value	Supply Capacity Costs Avoided	Distribution System Resources		
Oregon	Residential Space Heating	$4.00	$17.22	$1.18	$3.00	$0.54	$2.47	$2.84	**$31.26**
	Commercial Space Heating	$4.00				$0.54	$2.85	$2.88	**$31.68**
	Water Heating	$3.62				$0.10	$0.49	$2.56	**$28.18**
	Cooking	$3.57				$0.11	$0.74	$2.58	**$28.40**
	Process Load	$3.57				$0.08	$0.31	$2.54	**$27.90**
	Interruptible Loads	$3.57				X	X	$2.50	**$27.47**
Washington	Residential Space Heating	$4.00	$10.30	$1.18	$0.56	$0.54	$8.55	$2.51	**$27.65**
	Commercial Space Heating	$4.00				$0.54	$9.88	$2.65	**$29.11**
	Water Heating	$3.62				$0.10	$1.71	$1.75	**$19.22**
	Cooking	$3.57				$0.11	$2.55	$1.83	**$20.10**
	Process Load	$3.57				$0.08	$1.06	$1.67	**$18.43**
	Interruptible Loads	$3.57				X	X	$1.56	**$17.17**

Table 5.4. shows that Oregon avoided costs are consistently higher than Washington avoided costs for all end uses, due to the differences in avoided emissions compliance costs and their related compliance risk reduction values across the states. For space heating, the avoided costs in Oregon are not much higher than in Washington (about 12 percent higher for residential space heating and eight percent higher for commercial space heating), because Washington has a much higher avoided distribution capacity cost than Oregon, which compensates for the relatively lower emissions compliance costs in Washington.

5.3.3 Avoided Costs Across Integrated Resource Plans

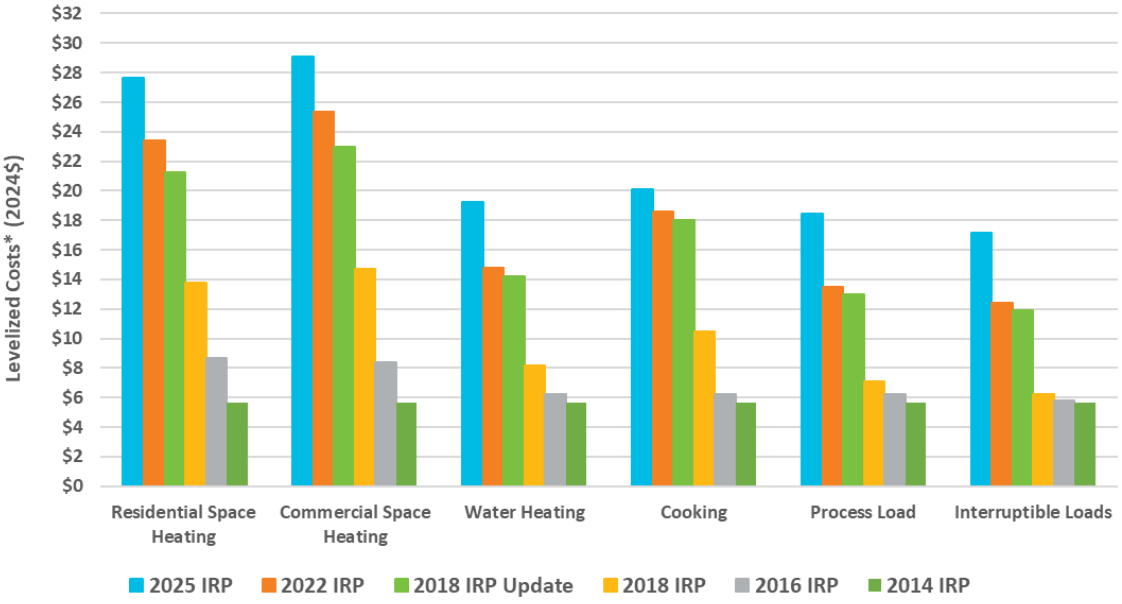
Figures 5.6 and 5.7 show avoided costs by end use evaluated in the IRPs filed from 2014 to 2025 for Oregon and Washington, respectively. Note that avoided costs filed in the 2014 IRP were the same across end uses. Since then, continuous and remarkable improvements to NW Natural's methodology for calculating avoided costs have been made throughout, with estimated avoided cost values being noticeably increasing across IRPs for all end uses in both Oregen and Washington.

Figure 5.6: Levelized Avoided Costs: 2025, 2022, 2018, 2016, and 2014 IRPs – Oregon



***2025 IRP is 26-year leverlized figures, 2022 IRP and 2018 IRP Update are 30-year, where earlier figures are 20-year levelized**

Figure 5.7: Levelized Avoided Costs: 2025, 2022, 2018, 2016, and 2014 IRPs – Washington



***2025 IRP is 26-year leverlized figures, 2022 IRP and 2018 IRP Update are 30-year, where earlier figures are 20-year levelized**

5.3.4 Avoided Costs for Carbon Emissions Compliance

As discussed in prior chapters, full compliance with the federal and state climate and environmental policies and regulations is a key requirement for this IRP. Potential GHG emissions compliance costs are consequently an important component of avoided costs. Following the method described in Section 5.2.1.2, the avoided costs for carbon compliance are calculated as a sum of two cost components: combustion emissions costs (i.e., the maximum of social cost of carbon from the direct end use and the GHG policy compliance cost), and the social cost of carbon from supply chain emissions (i.e., production/extraction, processing, transportation and storage, and on NW Natural system). The first cost component is state-specific, depending on how the costs of state-specific marginal compliance resources to be acquired per the IRP modeling outputs of the preferred resource portfolio selected under specific assumptions and constraints for the Reference Case are compared to the social cost of carbon from direct end use.[141] The second cost component is the same for both Oregon and Washington, assuming the supply chained emissions being the same for the Company's adjacent service territories across the two states. Figures 5.7 and 5.8 show how the avoided costs for carbon emissions compliance change over the planning horizon 2025-2050, and Table 5.5 details the specific compliance resources that are used and cost by state overtime. Table 5.5 indicates that the costs of CPP compliance resources in Oregon are higher than the social cost of carbon throughout the entire planning horizon, while in Washington the social cost of carbon is higher than the projected prices of emissions allowance from 2025 to 2027 but lower than the allowance prices from 2028 to 2050. Note that the avoided costs for carbon emissions compliance come primarily from CPP compliance in Oregon and CCA compliance in Washington, accounting for 92 percent of the total compliance cost on average in Oregon and 87 percent in Washington, respectively. The GHG costs avoided from the supply chain emissions are only eight percent in the total compliance cost for Oregon and 13 percent for Washington, respectively.

[141] For a summary of compliance resources by state, see Section 7.1 in Chapter 7. For more details about the preferred portfolio and the Reference Case, see Section 9.3.1 in Chapter 9.

Figure 5.8: Carbon Emissions Compliance Costs - Oregon

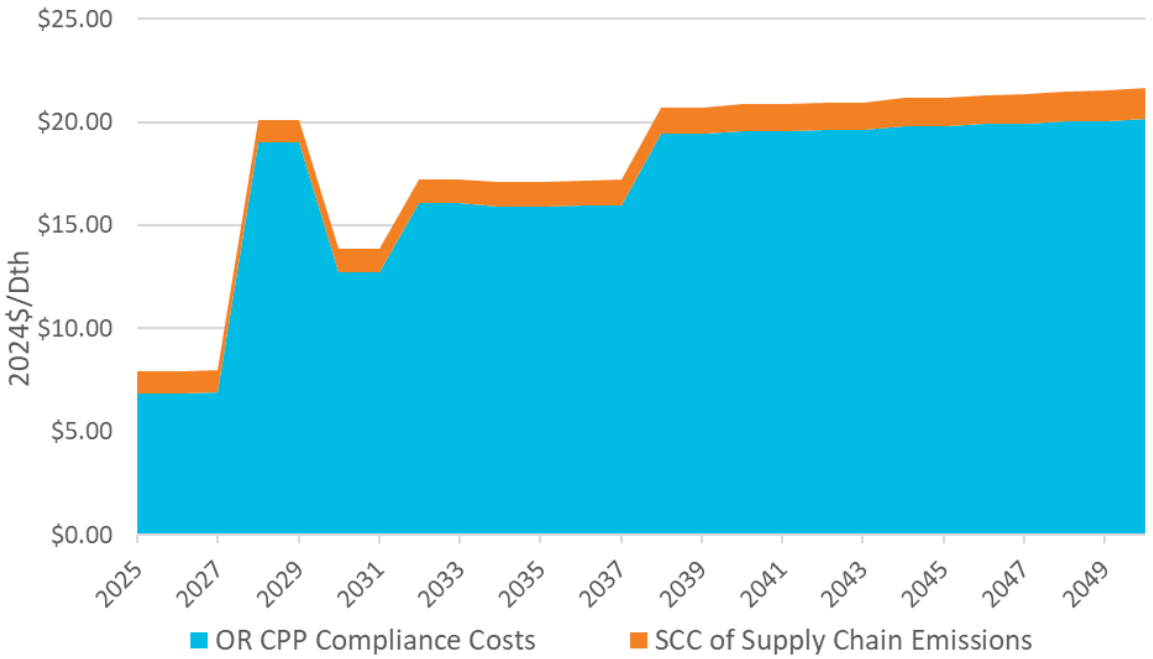


Figure 5.9: Carbon Emissions Compliance Costs – Washington

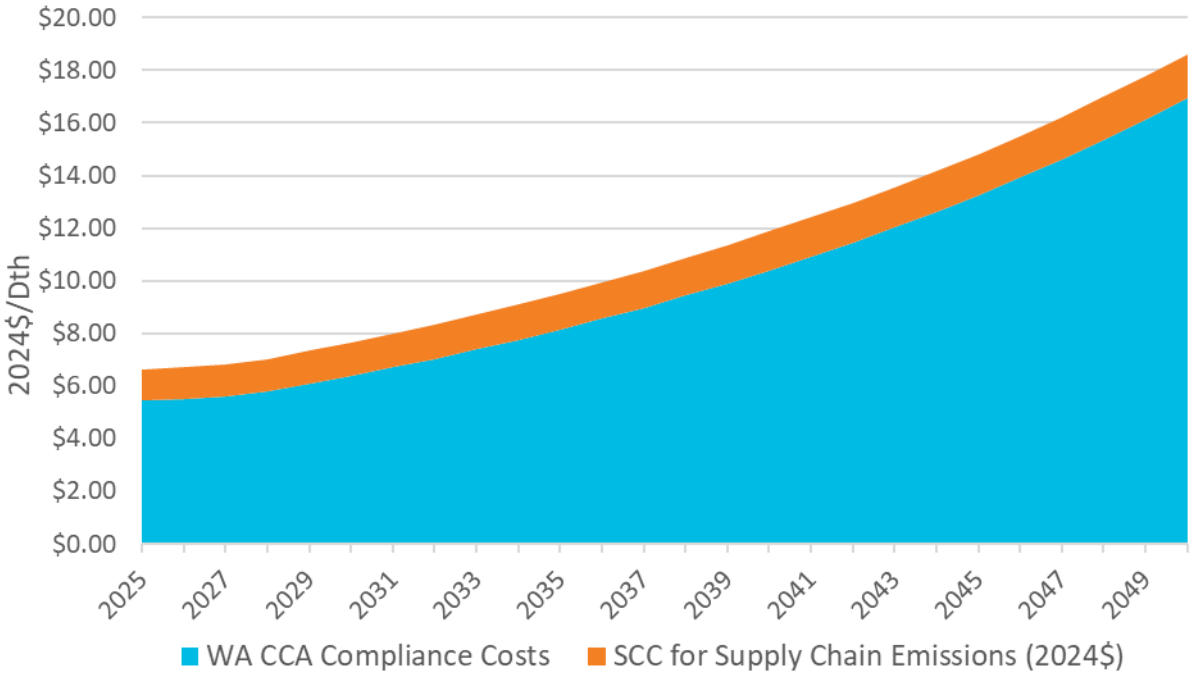


Table 5.5: Carbon Emissions Compliance Resources and Costs by State and Year

Year	OR CPP Compliance Costs (2024$/Dth)	OR CPP Compliance Resource	WA CCA Compliance Costs (2024$/Dth)	WA CPP Compliance Resource[142]	OR and WA Social Cost of Supply Chain Emissions (2024$/Dth)
2025	$6.85	CCI	$5.44	Social Cost of Carbon	$1.19
2026	$6.85	CCI	$5.51	Social Cost of Carbon	$1.20
2027	$6.90	CCI	$5.59	Social Cost of Carbon	$1.22
2028	$19.00	Near-term RTC Purchase	$5.79	Allowance Purchase	$1.24
2029	$19.00	Near-term RTC Purchase	$6.08	Allowance Purchase	$1.26
2030	$12.74	LFG-Mid	$6.38	Allowance Purchase	$1.27
2031	$12.74	LFG-Mid	$6.70	Allowance Purchase	$1.29
2032	$16.05	LFG-Mid	$7.03	Allowance Purchase	$1.31
2033	$16.05	LFG-Mid	$7.39	Allowance Purchase	$1.33
2034	$15.91	LFG-Mid	$7.76	Allowance Purchase	$1.34
2035	$15.91	LFG-Mid	$8.14	Allowance Purchase	$1.36
2036	$15.95	LFG-Mid	$8.55	Allowance Purchase	$1.38
2037	$15.95	LFG-Mid	$8.98	Allowance Purchase	$1.41
2038	$19.44	SM-Biomass	$9.43	Allowance Purchase	$1.43
2039	$19.44	SM-Biomass	$9.90	Allowance Purchase	$1.45
2040	$19.55	SM-Biomass	$10.39	Allowance Purchase	$1.47

[142] Social cost of carbon is shown as a CCA compliance resource from 2025 to 2027 because the social cost of direct end emissions is higher than the cost of allowance purchase, which is the marginal compliance resource identified by the 2025 IRP modeling system during this time periods.

2041	$19.55	SM-Biomass	$10.91	Allowance Purchase	$1.49
2042	$19.61	SM-Biomass	$11.46	Allowance Purchase	$1.51
2043	$19.61	SM-Biomass	$12.03	Allowance Purchase	$1.52
2044	$19.80	SM-Biomass	$12.63	Allowance Purchase	$1.54
2045	$19.80	SM-Biomass	$13.26	Allowance Purchase	$1.56
2046	$19.91	SM-Biomass	$13.93	Allowance Purchase	$1.58
2047	$19.91	SM-Biomass	$14.62	Allowance Purchase	$1.60
2048	$20.05	SM-Biomass	$15.36	Allowance Purchase	$1.63
2049	$20.05	SM-Biomass	$16.12	Allowance Purchase	$1.65
2050	$20.18	SM-Biomass	$16.93	Allowance Purchase	$1.67

5.4 Supply Side Applications

Non-conventional supply-side resources can also avoid costs associated with conventional resources. There are two primary examples where this can occur: 1) natural gas supply resources with lower carbon intensities, and 2) natural gas supply resources that are injected directly onto NW Natural's pipeline network ("on-system gas supply"). It is important to note that lower carbon on-system supply resources avoid both GHG compliance costs and the infrastructure costs associated with off-system gas supply.

5.4.1 Avoided Costs of Low Carbon Gas Supply

Natural gas supply alternatives that have a carbon intensity lower than conventional natural gas avoid expected GHG compliance costs, and under some regulatory frameworks the costs avoided depend upon the carbon intensity of the resource. For example, if a source of renewable natural gas has a carbon intensity of zero, it would avoid all of the expected GHG compliance costs associated with conventional natural gas. Chapter 7 details the average carbon intensities of different types of renewable natural gas. The specific avoided cost items applied to these lower carbon gas supply resources are shown in Table 5.6, which shows that GHG compliance costs avoided are applied to all low carbon gas resources.

Table 5.6: Costs Avoided by Low Carbon Resource Type

Costs Avoided by Resource Type	Conventional Gas Purchase and Transport Costs	Greenhouse Gas Compliance Costs	Gas Supply Capacity Costs- On-System Dispatch	Distribution Capacity Costs
On-System Bundled RNG Purchase	✓	✓	✓	✓
RNG with Delivery to NW Natural- Bundled	✓	✓	✓	
RNG with Sale of Brown Gas- Bundled - Choose Sales Hub	✓	✓		
Unbundled Environmental Attribute Purchase		✓		

5.4.2 Avoided Costs of On-System Gas Supply

As described above, on-system natural gas supply avoids the incremental costs associated with serving peak load based upon how much gas is supplied directly onto NW Natural's system during a peak hour and day. The amount of gas supplied during peak times is resource-specific and the more on-system resources can supply gas directly onto NW Natural's system during peak times, the more value the resource provides to NW Natural's system and customers via delayed or avoided infrastructure investments. Like with demand-side resources, avoided supply capacity infrastructure costs from on-system gas supply are determined by multiplying the cost to bring an additional unit of peak day load onto NW Natural's system by the amount of gas the resource is expected to supply on a peak day. Similarly, avoided distribution system enhancement costs are calculated by multiplying the costs to serve an additional unit of peak hour load on NW Natural's distribution system by the amount of gas the resource is expected to supply on a peak hour.

6 Demand-Side Resources

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Once customer needs are established, it is important to take a wide scope and assess what options are available to meet those needs. This chapter evaluates and forecasts resources that can be deployed to reduce customer energy use throughout the year (energy efficiency) and during the coldest days we experience (demand response).

6.1 Energy Efficiency

Since 2003, NW Natural has worked with implementers to provide energy efficiency incentives to customers. By pursuing energy efficiency, the Company reduces peak demand and overall throughput that would otherwise need to be delivered.

NW Natural has energy-efficiency programs for residential, commercial, and industrial customers. Program overviews and achievements are published in public reports filed with the OPUC and WUTC for programs in the respective states. Oregon results are included in Energy Trust's 2024 Annual Report[143] and all Washington reports are posted on the Company's regulatory activity page.[144]

Energy efficiency forecasts used in this IRP are developed by Energy Trust for Oregon, and by AEG, an independent third party, for Washington, using NW Natural's customer count and load forecasts, historical energy efficiency activity, and regional data sources. To ensure energy efficiency is a sound investment, both measures and programs are evaluated for cost-effectiveness using NW Natural's avoided costs. It is worth noting that cost-effective energy efficiency has been and will continue to be the most desirable decarbonization tool compared to all other decarbonization mechanisms.

Further details on the energy efficiency forecasts are included within the Oregon Energy Efficiency and Conservation Programs and Washington Conservation Potential Assessment sections below.

[143] Energy Trust 2024 Annual Report: https://www.energytrust.org/2024-annual-report/
[144] NW Natural Regulatory Activity Page: https://www.nwnatural.com/about-us/rates-and-regulations/regulatory-activity

6.2 Oregon Energy Efficiency and Conservation Programs

As the administrator for NW Natural energy efficiency programs, the Energy Trust provides the following information specific to NW Natural territory in Oregon[145] (shown in maroon text).

6.2.1 Energy Trust Background

In 2002, as part of an agreement that allowed NW Natural to implement a decoupling mechanism, the Public Utility Commission of Oregon directed the Company to collect a public purpose charge for the funding of its residential and commercial energy efficiency programs and low-income programs, and to transfer the responsibility of energy efficiency programs to a third party.[146]

NW Natural chose Energy Trust as its program administrator. Energy Trust is a non-profit organization that was established as a result of electric direct access legislation adopted in 2002 to administer the Oregon-based, investor-owned electric utilities' energy efficiency programs. Energy Trust began managing NW Natural's residential and commercial program in 2003. The programs are outlined in the Company's Tariff Schedule 350 and funded through the public purpose charge, Schedule 301.

After NW Natural's 2008 IRP[147] identified that cost-effective industrial savings were available, the Company worked with Energy Trust to launch an Industrial demand-side management (DSM) program in Oregon. This program is available to large Firm and Interruptible Sales customers. Costs for the program, described in Schedule 360 of the Company's tariff, are deferred for recovery a year later through the charge published annually in Schedule 188. NW Natural worked with Energy Trust to launch a DSM program for Transportation customers beginning in 2024.

With the exception of the first few years of the residential and commercial programs in Oregon, when gas customers were just learning about the availability of incentives for energy efficient equipment, Energy Trust has been meeting and even exceeding the annual savings goals.

Since October 1, 2009, NW Natural has provided energy efficiency programs to its Washington Residential and Commercial customers in compliance with the direction provided by the WUTC

[145] Energy Trust administers NW Natural's energy efficiency programs in both Oregon and Washington. The methodology and results in this chapter are provided by Energy Trust and are Oregon specific. NW Natural's Washington energy efficiency forecast was performed by a different entity and the results of which are described in a separate section.
[146] See Order No. 02-634 in Docket No. UG 143.
[147] See Docket No. LC 45.

in the Company's 2008 rate case.[148] The programs were developed and continue to evolve under the oversight of the Energy Efficiency Advisory Group (EEAG), which is comprised of interested parties to the Company's 2008 rate case. Energy Trust administers the programs, leveraging the offerings available in Oregon to customers located in Washington.[149]

6.2.2 Energy Trust Forecast Overview and High-Level Results

Energy Trust developed a 20-year DSM resource forecast for NW Natural territory in Oregon using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost-effective modeled savings potential. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to NW Natural for inclusion in the Company's forecasts. The 2025 IRP results show that NW Natural can save over 30 million therms[150] in Oregon in the next five years from 2025 to 2029 and over 149 million therms by 2044. These results represent an 8 percent decline and a 5 percent increase respectively in cost-effective DSM potential over the prior IRP in 2022. The main drivers of these changes in deployed potential are:

1) *Short term decrease:* In the 2022 IRP, NW Natural and Energy Trust coordinated on assumptions associated with accelerating the energy efficiency forecast to reflect increased annual program budgets in the first five years. While both parties are still committed to accelerating savings, the initial estimates from 2022 proved difficult to attain due to market barriers, primarily resulting from supply chain issues and labor shortages that are outcomes of the COVID pandemic on the Oregon economy.
2) *Long term increase:* There are multiple factors contributing to the slight increase in 20-year savings projection, including increased avoided costs, updated measure assumptions, growth in the industrial load forecast, new measures, measures under OPUC exception, and program expectations.

[148] See Order No. 4 in Docket UG-080546.
[149] The program's parameters are provided in the Company's Schedule G and its Energy Efficiency Plan, which by reference is part of the Tariff. The program is funded through a charge collected in accordance with Schedule 215.
[150] The savings discussed in this chapter and appendices, depicted in all tables and the following figures showing savings projections are in gross savings for Oregon unless otherwise explicitly noted. Energy Trust publicly reports its Oregon savings and goals in gross savings as determined in consultation with OPUC and stakeholders in 2019. Energy Trust public reports prior to 2020 included net savings which are adjusted for market effects including free ridership and spillover. Prior Energy Trust DSM chapters for NW Natural IRP were in gross savings. Gross savings are not adjusted for market effects and most accurately reflect the reductions NW Natural will see on their system.

Figure 6.1 depicts the full suite of savings potential identified both in the model (Technical, Achievable, Cost-effective achievable) as well as the amount included in the final savings projection, by Sector.

Figure 6.1: 20-year Savings Potential by Sector and Potential Type

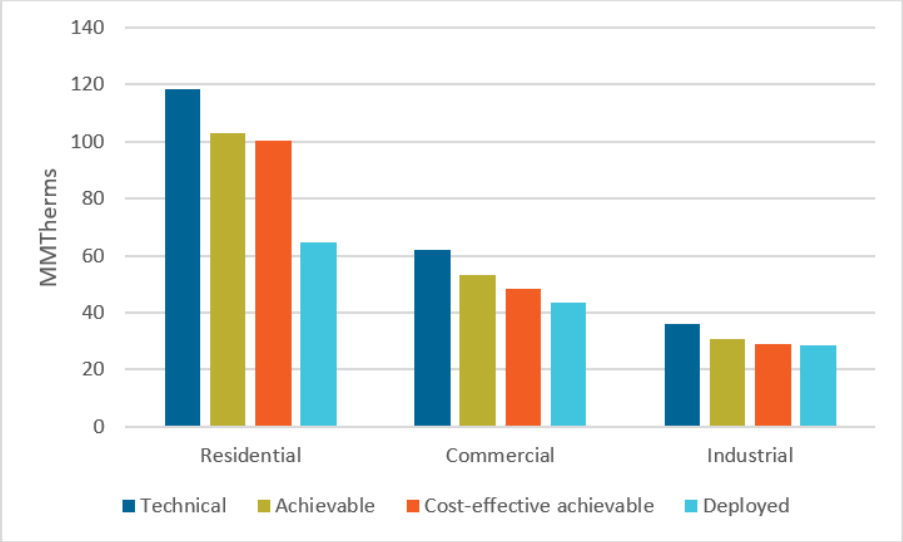
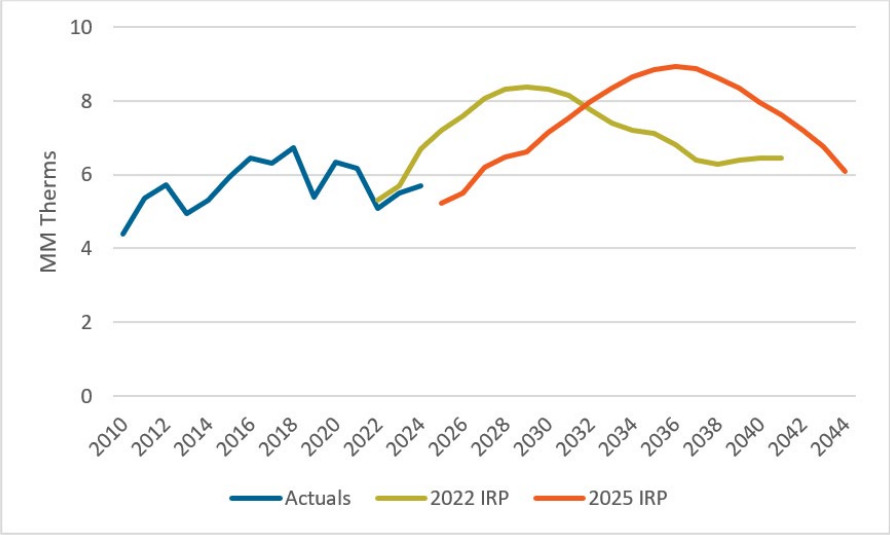


Figure 6.2 links actual historical savings going back to 2010 to the new deployed savings projection for the 2025 IRP. It also compares the current 2025 IRP deployed savings forecast to the 2022 IRP deployed savings forecast.

Figure 6.2: Annual Deployed Savings Projection Comparison for 2022 and 2025 IRPs, with Actual savings since 2010



6.2.3 Energy Trust Resource Assessment Economic Modeling Tool

Energy Trust owns, operates, and maintains an RA Model to perform the complex calculation process to create DSM forecasts for each of the utilities it serves, including NW Natural. The tool estimates the total technical, achievable, and cost-effective achievable potential for acquiring DSM resources in NW Natural's service territory across residential, commercial, and industrial sectors. The model primarily takes a bottom-up approach that begins with estimating available measure level savings and related cost and market penetration assumptions. These measure level savings are scaled up to NW Natural's service territory based on a set of applicability assumptions for each measure adjusted based on NW Natural inputs, such as customer and load forecasts, among others. The product of all these factors results in the total 20-year DSM savings potential available that can be acquired by providing energy efficiency services to NW Natural's customers.

In the intervening years since NW Natural's 2022 IRP, Energy Trust has made several updates and improvements to the RA model. These enhancements contributed to the increase in energy efficiency potential identified in this DSM forecast:

- *Refreshed measure level assumptions* – Measure inputs for measures spanning residential, commercial, and industrial program sectors were reviewed and updated using a combination of Energy Trust primary data review and analysis, regional secondary sources, and engineering analysis. The refreshed assumptions include baseline adjustments, savings and costs updates, as well as density assumptions pertaining to where measures can be installed and existing measure saturation rates.
    a. Residential space and water heating fuel splits as well as density, saturation and applicability assumptions were all updated with the most recent 2022 Residential Building Stock Assessment data published by the Northwest Energy Efficiency Alliance.

Table 6.1 shows a graphical representation of the three categories of savings potential identified by Energy Trust's RA Model. The following methodology section describes the inputs and methods to calculate each of these potential types in detail.

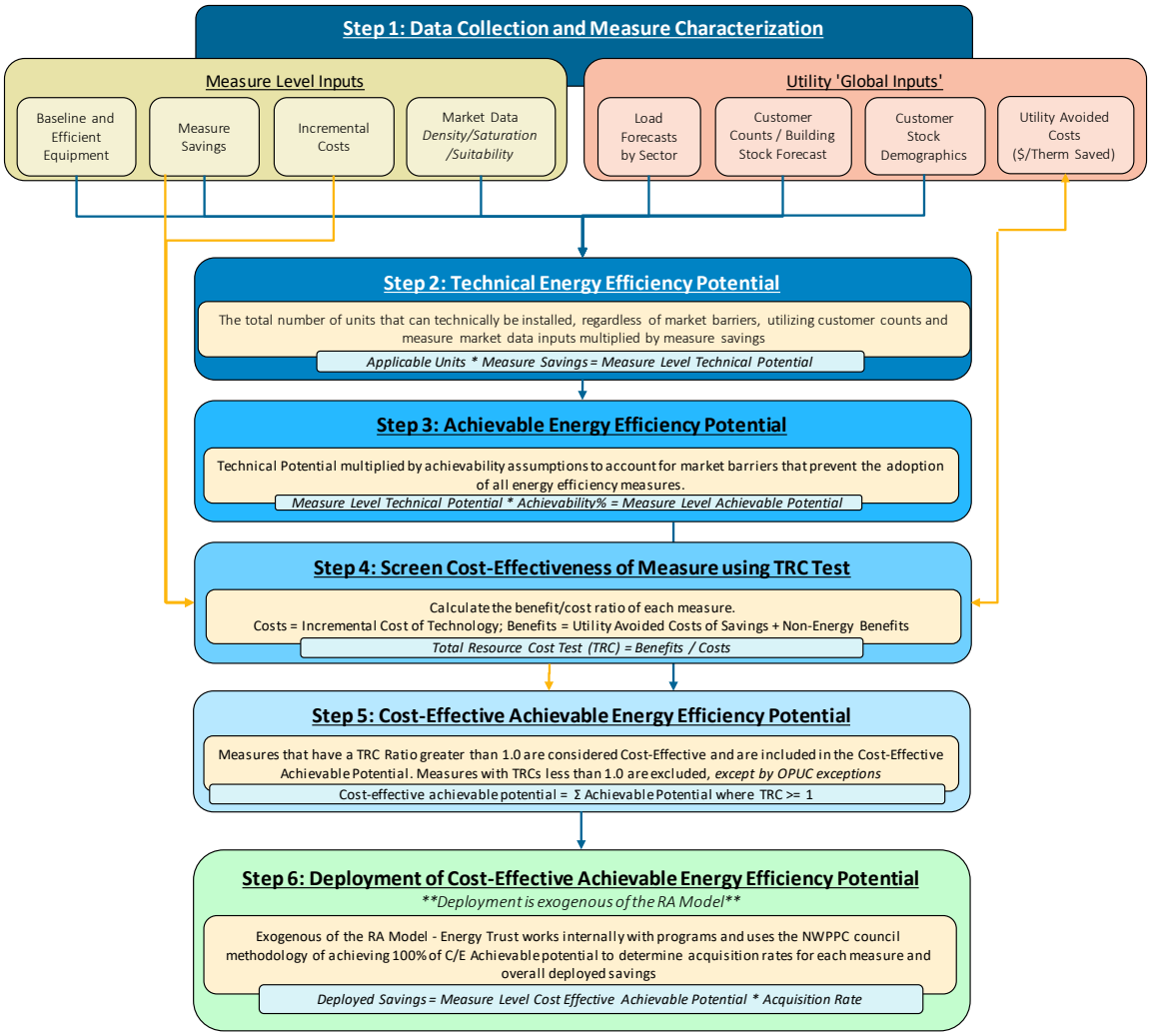
Table 6.1: Three categories of savings potential identified by RA Model

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

6.2.4 Methodology for Determining the Cost-Effective Demand-side Management Potential

Energy Trust's demand-side management (DSM) resource assessment follows six overarching steps from initial calculations to deployed savings, as shown in Figure 6.3. Steps 1 through 5 (Measure Identification/Input Development to Cost Effective Achievable Output) are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the forecast horizon. The actual deployment of these savings (the acquisition percentage of the total potential each year – Step 6 of Figure 6.3) is done exogenously of the RA model and is explained in further detail in the next section. The remainder of this section provides further detail on steps 1 – 5 of the overall methodology shown in Figure 6.3

Figure 6.3: Energy Trust's 20-Year DSM Forecast Determination Methodology



Step 1: Model and Measure Input Identification/Calculations

The first step of the modeling process is to identify and characterize the list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of all commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full

suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[151] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[152], and engineering analysis. There are over 30 measure level inputs that feed into the model, but at a high level, the inputs are put into the following categories:
  1. *Measure Definition and Equipment Identification*: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a 70+% EF gas storage water heater replacing an 60% EF baseline gas water heater).
  2. *Measure Savings:* The therm savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. *Incremental Costs:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a Retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a Replace on Burnout or New Construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. *Market Data:* Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs

[151] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

[152] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA)

are all generally derived from regional market data sources such as RBSA and CBSA.

- ***Utility Global Inputs:***
  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:
  1. *Customer and Load Forecasts:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that NW Natural serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.
  2. *Customer Stock Demographics:* These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).
  3. *Utility Avoided Costs:* Avoided costs are the net present value of avoided commodity and commodity-related costs as well as avoided supply-side and demand-side resource costs associated with energy efficiency savings represented as $s per therm saved. Avoided costs are the primary 'benefit' of energy efficiency in the cost effectiveness screen.

Step 2: Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g. # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does not take into account the various market barriers that will limit a 100 percent adoption rate.

Step 3: Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate, to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85 percent of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan, and Energy Trust has aligned the RA model with these assumptions. Many measures still have 85 percent achievability while market transformation and codes and standards are assumed to be 95 percent achievable.

Achievable Potential =	*Technical Potential * Achievability %*

Step 4: Determine Cost Effectiveness of Measure using TRC Test

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost effectiveness of the investment being made in a DSM measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where the Present Value of Benefits includes the sum of the following two components:

a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by NW Natural's avoided cost per therm.[153] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[154]

[153] See Chapter 5 for a discussion of NW Natural's avoided costs.
[154] NW Natural's real after-tax annual discount rates used by Energy Trust in the 2025 IRP is 3.39 percent.

b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. Operations and Maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

a) Incentives paid to the participant; and
b) The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, minus state and federal tax credits.

The cost effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures, unless an exception has been granted by the OPUC.

Step 5: Quantify the Output of Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then *achievable savings* from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions: 1) the OPUC has granted an exception to offer non-cost-effective measures under strict conditions or 2) the measure is cost-effective when using blended gas avoided costs[155] and is therefore offered by Energy Trust programs.

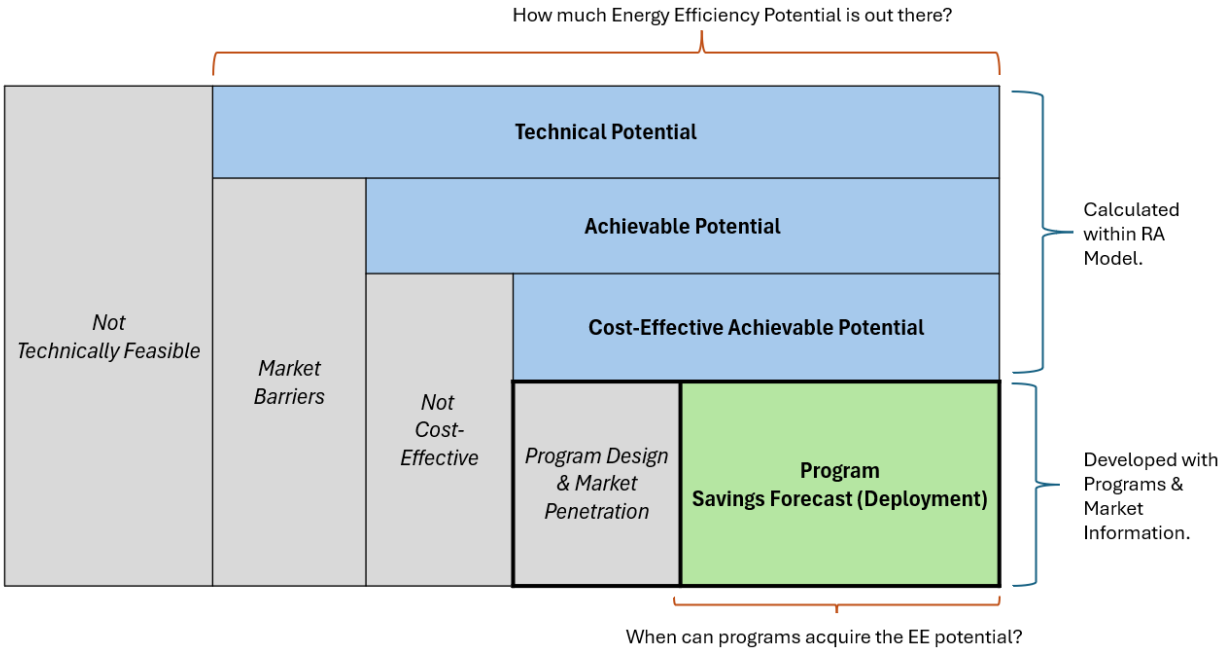
Step 6: Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the cumulative 20-year[156] cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on NW Natural's system. Energy Trust ramp rates are based on Northwest Power and Conservation Council methodology but are calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%. This savings forecast includes savings from

[155] Energy Trust uses blended avoided costs for measure development and cost-effectiveness screening to provide uniform gas offerings throughout Oregon. Utility specific avoided costs are used in RA modeling to align inputs with utility IRPs.
[156] Energy Trust provided NW Natural with a final savings projection extended to 2050. These results are discussed in Section 6.2.10.

program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy Trust is describing as a 'large project adder', savings that account for large unidentified projects that consistently appear in Energy Trust's historical savings record and have been a source of overachievement against IRP targets in prior years. The evolution from modeled technical potential to savings projections is depicted in Table 6.2

Table 6.2: The Progression to Program Savings Projections



6.2.5 RA Model Results and Outputs

The RA Model generates results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

6.2.6 Forecasted Savings Potential by Type

Table 6.3 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Table 6.1. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource

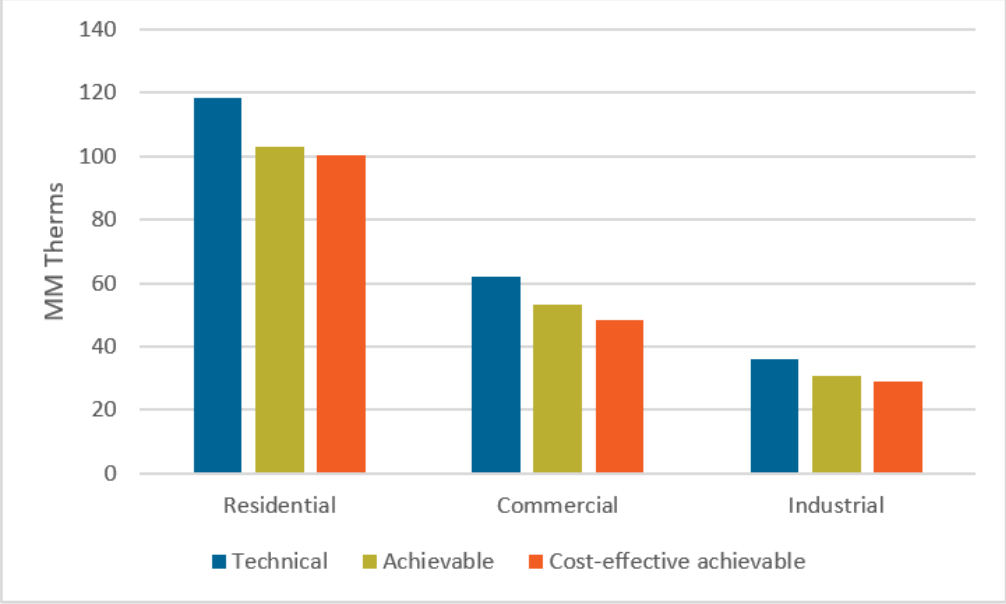
assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 6.3: Summary of Cumulative Modeled Savings Potential - 2025–2044

Sector	Technical Potential (MMTherms)	Achievable Potential (MMTherms)	Cost-Effective Achievable Potential (MMTherms)
Residential	118.29	103.11	100.30
Commercial	62.03	53.17	48.41
Industrial	36.03	30.62	29.10
Total	**216.35**	**186.90**	**177.81**

Figure 6.4 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in NW Natural's service territory.

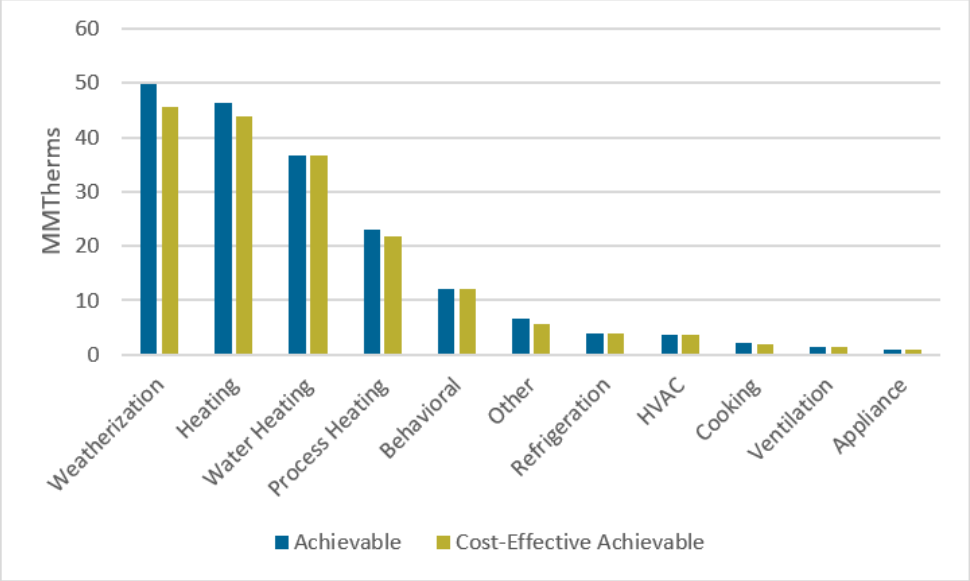
Figure 6.4: Summary of Cumulative Modeled Savings Potential - 2025–2044 - by Sector and type of Potential



These results show that for the Residential and Commercial Sectors, approximately 97 and 91 percent of the achievable potential identified in the model is found to be cost-effective, with the majority of the DSM potential coming from the residential sector. For the Industrial Sector, 95 percent of the achievable potential identified is found to be cost-effective.

Figure 6.5 provides a breakdown of NW Natural's 20-year DSM savings potential by end use and compares achievable to cost-effective achievable potential.

Figure 6.5: 20-year Cumulative Potential by End Use and Cost-Effectiveness



The weatherization, heating and water heating end uses top the list. Behavioral consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to develop the skills to identify operations and maintenance changes that make a difference in a building's energy use. The other category consists primarily of a commercial new construction design measure that is 10 percent better than code.

Figure 6.6 shows the amount of emerging technology savings within each category of DSM potential, highlighting the contributions of commercially available and emerging technology DSM. This graph shows that while roughly 35 million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, about 26 million, or 76 percent of that potential remains. For commercially available conventional measures, 83 percent of the technical potential is cost-effective. 15 percent of the total cost-effective achievable potential identified in the model is from emerging technology measures including gas heat pump water heaters for both residential and commercial.

Figure 6.6: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology

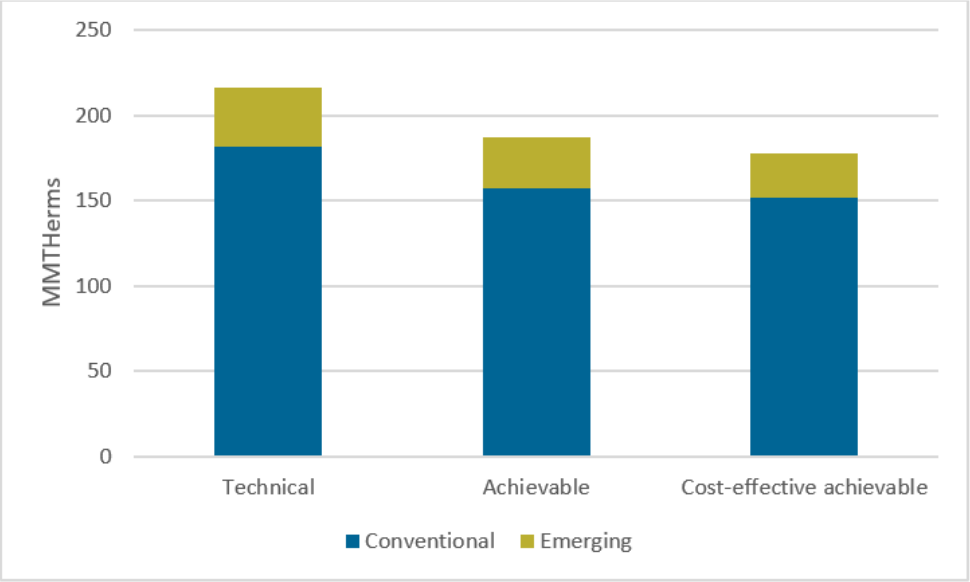


Table 6.4 shows the savings potential in the resource assessment model that was added by employing the cost-effectiveness override. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria.

1. The measure is not cost-effective but is offered through Energy Trust programs under an OPUC exception and is expected to be brought into cost-effective compliance in the near future.

2. The measure is cost-effective using Energy Trust's blended gas avoided costs and is currently offered through Energy Trust programs but is not cost-effective when modeled with NW Natural-specific avoided costs.

Table 6.4: Cumulative Cost-Effective Potential (2025-2044) due to use of Cost-effectiveness override (Millions of Therms)

Sector	Yes CE Override	No CE Override	Difference
Residential	100.30	63.42	36.89
Commercial	48.41	48.41	-
Industrial	29.10	29.10	-
Total	**177.81**	**140.92**	**36.89**

In this IRP, 21 percent of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures with exceptions. The measures that had this option applied to them for measures under OPUC exception included manufactured home replacement, clothes washers, and attic, floor, and wall insulation. Measures overridden due to ETO's use of blended avoided costs are residential whole home new construction measures. While non-cost-effective measures are included in both resource modeling and Energy Trust program offerings, they are not exempt from Energy Trust annual portfolio level cost-effective requirements. Furthermore, most of the non-cost-effective potential identified here is made up of measures with increased market barriers and the 21 percent is not reflective of the composition of achieved or forecasted savings.

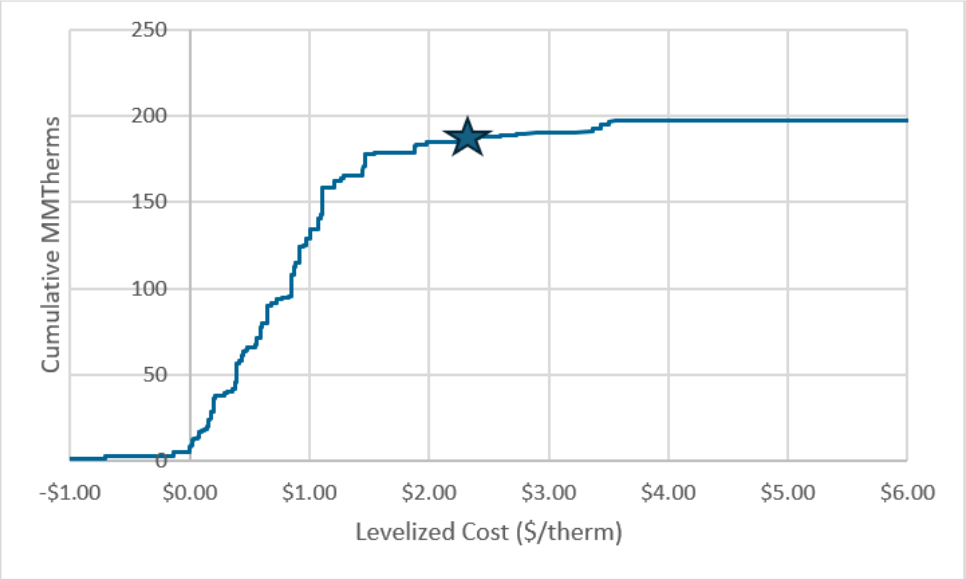
6.2.7 Supply Curve and Levelized Costs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure that graphically depicts the total potential therms that could be saved at various costs for all measures.

The levelized cost for each measure is determined by calculating the present value of the total cost of the measure over its economic life, converted to equal annual payments, per therm of energy savings. The levelized cost calculation starts with the customer's incremental total resource cost (TRC) of a given measure. The total cost is amortized over an estimated measure lifetime using the NW Natural's Oregon discount rate of 3.39 percent. The annualized measure cost is then divided by the annual energy savings.

Figure 6.7 shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources, where the star shows the approximate cost-effectiveness cutoff.

Figure 6.7: 20-year Gas Supply Curve[157]



6.2.8 2025 Model Results Compared to 2022

Table 6.5 shows the total modeled potential for DSM in this IRP compared to the prior IRP in 2022. Overall, the potential is relatively similar to what was estimated in 2022.

Table 6.5: Total 2025 IRP Cost-Effective Modeled Potential compared to 2022, by Sector

Sector	Total Cost-Effective Potential 2022 OR IRP (Millions of therms) 2022-2041	Total Cost-Effective Potential 2025 IRP (Millions of therms) 2025-2044
Residential	113.7	100.3
Commercial	49.7	48.4
Industrial	17.0	29.1
All DSM	180.4	177.8

[157] Measures with negative levelized costs have a high proportion of non-energy benefits, which outweigh the incremental total resource cost of the measures.

Table 6.6 builds off Table 6.5 and details the key factors that drove the change in cost-effective potential for DSM compared to the prior IRP. Change components of opposite directionalities net out to create a modest decrease in cost-effective achievable potential driven by model updates and increased avoided costs which partially offset the impacts of the lower load and building stock forecast seen in the 2025 IRP.

Table 6.6: Key Changes in Model that Increased Potential from 2022 IRP to 2025 IRP

Change Component	Change in DSM Savings (Millions of Therms) from 2022 to 2025 IRP
Load and Building Stock Forecast	-33.7
New Measures; Measure and Demographic Updates	26.6
Avoided Costs	4.5
Total Change from 2022 to 2025 IRP	-2.6

6.2.9 Final Savings Projection

The results of the final savings projection show that Energy Trust can acquire 30.1 million therms across NW Natural's system in Oregon in the next five years from 2025 to 2029 and 149.1 million therms through 2044.

The final savings projection of 149.1 million therms by 2044 in NW Natural's service territory in Oregon contains a reduction to the full cost-effective potential shown in Table 6.7. This is due to additional market-related constraints on the ability to capture all market activity in a given year for measures meant to replace equipment that fails and measures associated with the construction of new homes and buildings, otherwise known as 'lost opportunity' measures. These are measure opportunities that appear in a given year, but if lost, do not reappear again as savings potential until their useful life has passed. These savings are depicted in the savings deployment scenarios beginning on the next page.

Table 6.7 depicts savings projections for NW Natural's Oregon system. The 'Other' sector referenced in the savings projections is calculated outside of the RA model and includes the large project adder and Commercial New Buildings market transformation savings.

Table 6.7: 20-Year Cumulative Savings Potential by type, including final savings projection (Millions of Therms)

Sector	Technical	Achievable	Cost-effective	Energy Trust Savings Projection [158]
Residential	118.29	103.11	100.30	64.67
Commercial	62.03	53.17	48.41	43.34
Industrial	36.03	30.62	29.10	28.74
Other	-	-	-	12.31
All DSM	216.35	186.90	177.81	149.07

Figure 6.8 shows 20-year Energy Trust Savings Projection over time and by sector. The savings growth over the time period is driven by the Residential sector, while both Commercial and Industrial see annual savings declines in the later part of the forecast horizon as retrofit potential becomes exhausted. The net effect of these opposing trends peaks in 2036. It is worth noting that, by load and resource potential, Residential is the largest sector in NW Natural's Oregon territory. However, Residential is also the sector with the highest share of measures having market barriers and is the most expensive sector to achieve savings in terms of $/therm. It is here that increases in avoided costs do more than simply increase the amount of cost-effective achievable potential under the TRC; higher avoided costs raise incentive caps and support investment in program and delivery infrastructure that reduces market barriers.

[158] The savings deployment process applies ramp rates to shape forecasted annual cost-effective savings acquisition over the 20-year forecast horizon. The deployment accounts for near term program savings targets and past program activity. In general, deployments follow Power Council principles such that retrofit measures acquire all available cost-effective achievable savings in the 20-year period following a bell-shaped acquisition curve while lost opportunity measures ramp up throughout the modeling period to achieve 100% market annual penetration by the end of the forecast. Some measures assume a lower acquisition rate to reflect market characteristics, such as hard to reach measures including insulation and windows, and emerging technology. Emerging technology measures begin with low rates of forecasted market uptake and often do not ramp to full market penetration by the end of the forecast period. Hard to reach measures are the reason that the Residential savings deployment is proportionally less than the cost-effective achievable savings potential when compared to the projections for commercial and industrial as emerging technologies (primarily gas fired heat pump water heaters), multifamily, and shell make up a higher share of cost-effective achievable savings potential for this sector. Additionally, residential measures under OPUC cost-effective exception are prone to market barriers due to both cost and type (insulation and windows, manufactured home replacement) and make up 12 percent of the deployed savings projection.

Figure 6.8: 20-Year Annual Savings Projection by Sector

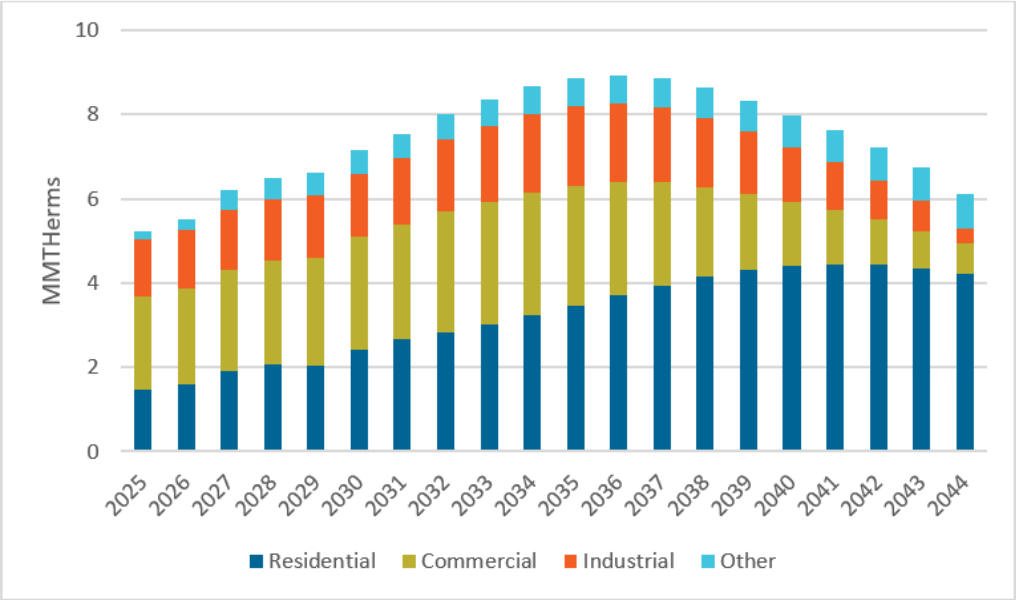
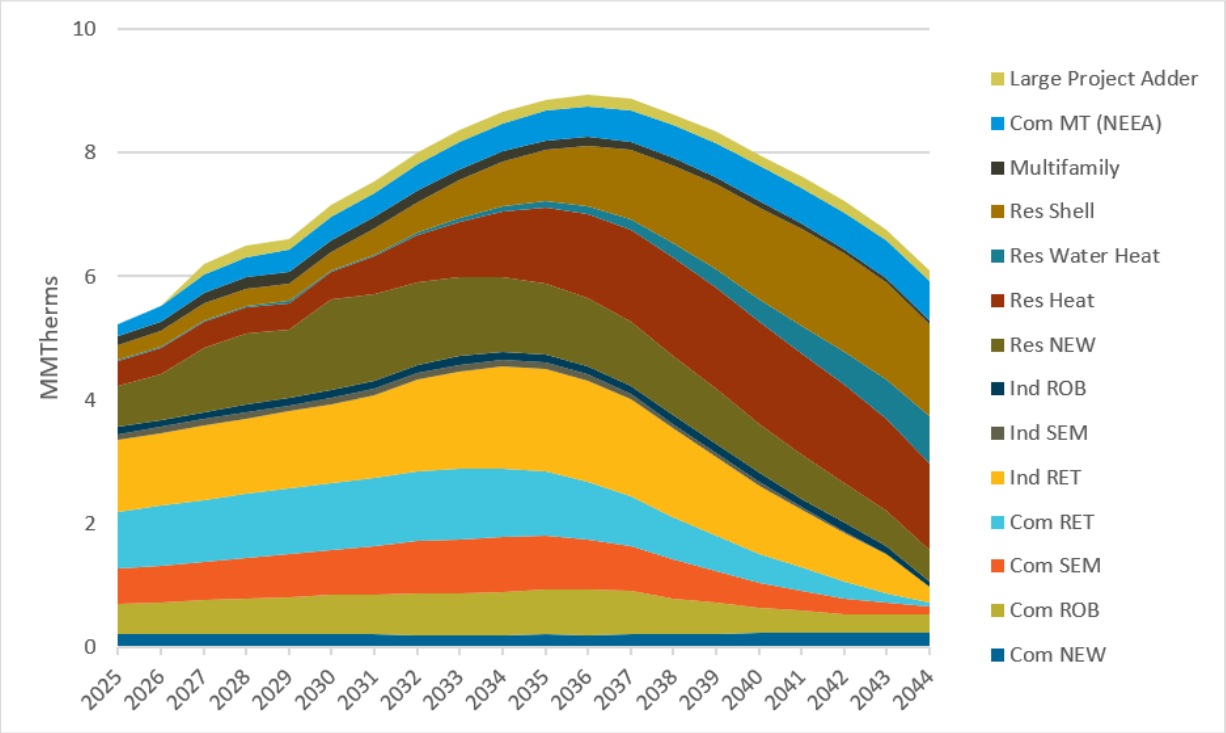


Figure 6.9 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

Figure 6.9: Annual Savings Projection by Sector-Measure Type



6.2.10 Final Savings Projection Extended to 2050

The Energy Trust RA model is configured to calculate savings potential results over a 20-year forecast horizon. Energy Trust then deploys the cost-effective achievable potential exogenously to the RA model as described in the section above. This deployment methodology has been modified to extend the final savings projection through 2050 to align with NW Natural's IRP horizon by continuing the energy efficiency acquisition curves for the additional six years. This projection is different depending on the curve that was applied. As stated previously, Energy Trust ramp rates are based on Northwest Power and Conservation Council method and ramp rates but are calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%.

Table 6.8: 20-year and 26-year Final Savings Projection (Millions of Therms)

Sector	20-Year Savings Projection	6-Year Savings Extension	Total Final Savings through 2050
Residential	64.67	22.32	86.99
Commercial	43.34	3.50	46.84
Industrial	28.74	0.14	28.88
Other	12.31	4.84	17.16
All DSM	149.07	30.80	179.86

Figure 6.10: Annual Savings Projection by Sector through 2050

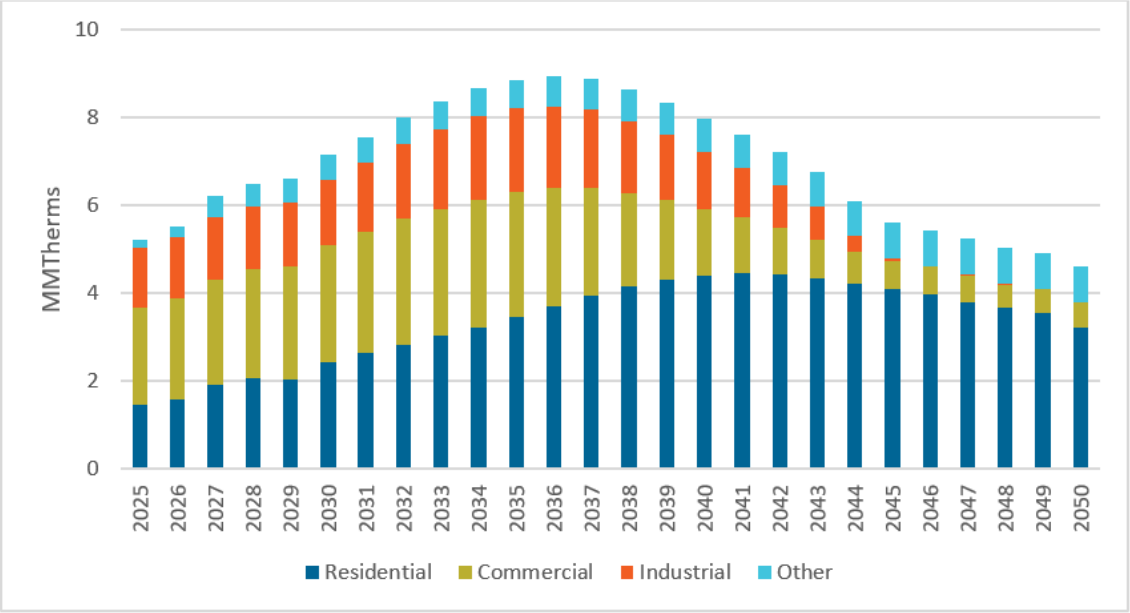
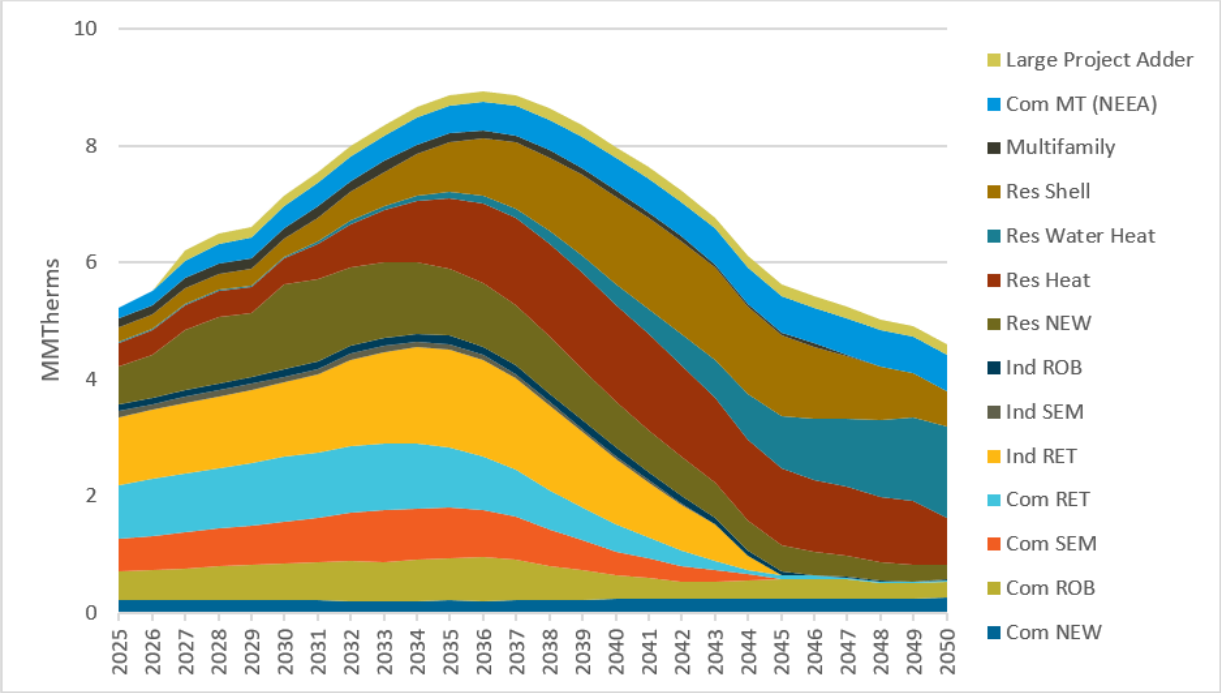


Figure 6.11: Annual Savings Projection by Sector through 2050



6.2.11 Peak Savings Deployment

Figure 6.12 and Figure 6.13 detail the amount of peak-day and peak-hour savings that Energy Trust forecasts to acquire as calculated from the annual savings projection using peak-day/annual use and peak-hour/annual use coincident load factors developed by NW Natural.

Figure 6.12: NW Natural's Annual Peak-Day Savings Projection by Sector

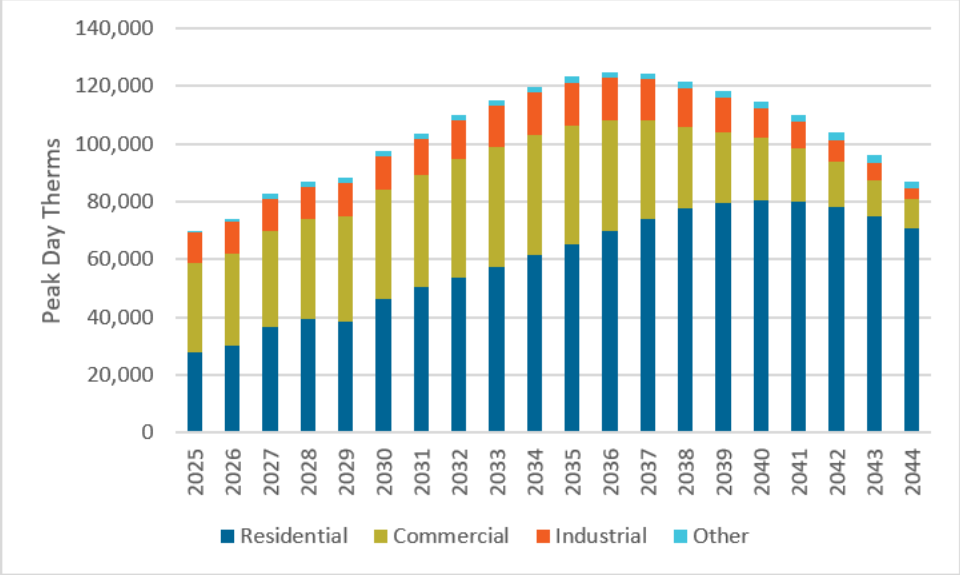
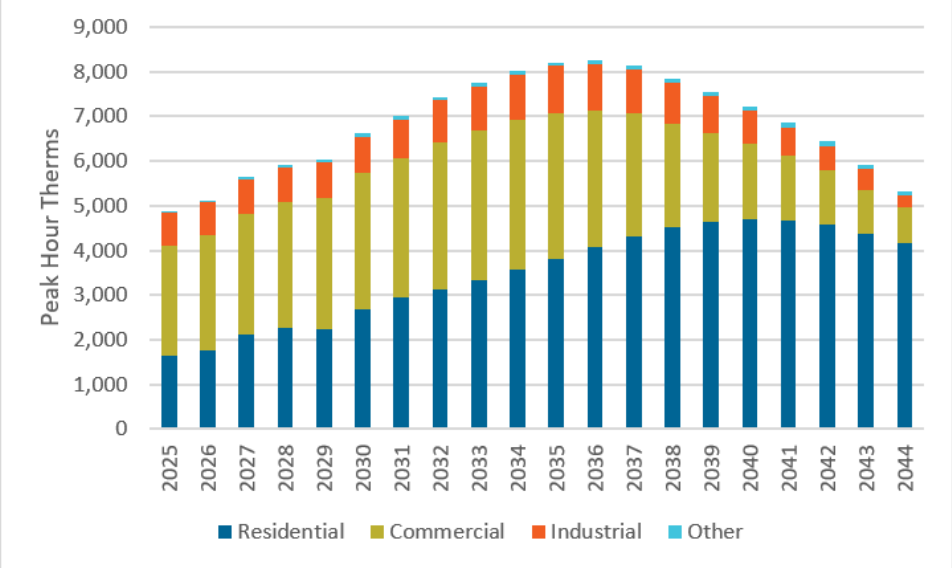


Figure 6.13: NW Natural's Annual Peak-Hour Savings Projection by Sector



Residential and Commercial heating measures have the greatest savings coincident with peak, and in this forecast contribute the most peak savings potential. The total peak-day savings over the 20-year savings projection is 2,070,691 peak-day therms or 1.4% of the 149.1 million therm

savings projection. The total peak-hour savings over the 20-year savings projection is 136,191 peak-hour therms or 0.09% of the 149.1 million therm savings projection.

6.2.12 Avoided Costs Scenario Runs

At the request of NW Natural, Energy Trust calculated two alternate avoided costs scenarios to test the sensitivity of cost-effective achievable potential. These scenarios represent:

1. *High Social Cost of Carbon*: The base case avoided costs use the Oregon DEQ social cost of carbon value of $128.98/MTCO2e. The EPA's 2023 Report on the Social Cost of Greenhouse Gas emissions value of $180.80/MTCO2e was used as a high avoided cost sensitivity test.
2. *Energy Trust Blended Avoided Costs*: As described above in Section 6.2.4, Energy Trust uses blended avoided costs by fuel to approve measures, set incentive caps and evaluate the cost-effectiveness of programs. This blending is performed as a weighted average by utility and fuel, where the weighting factor is a utility's share Energy Trust funding. Utility specific avoided costs are used in the RA model for IRPs to maintain consistency with other supply side costs in the utility models. This creates some discrepancy between the avoided costs used by Energy Trust and what is used in the TRC screen in the RA model.

Table 6.9 compares each avoided costs scenario to the reference avoided costs used in all results referenced previously in this report. The high social cost of carbon scenario generates roughly 29% higher avoided costs. Energy Trust blended avoided costs are about 2% lower than NW Natural specific avoided costs; this small difference is expected as NW Natural is the largest gas funder of Energy Trust and therefore has the greatest weighting in the avoided costs blending calculations.

Table 6.9: Avoided Costs Scenario Comparison ($/therm)

Load Profile	Reference ACs	High SCC ACs / % difference	ETO Blended ACs / % difference
Domestic Hot Water	$1.53	$2.02 / 33%	$1.53 / 0%
Flat	$1.45	$1.95 / 34%	$1.44 / -1%
Res Heating	$2.10	$2.60 / 24%	$2.16 / 3%
Com Heating	$2.22	$2.72 / 22%	$2.13 / -4%
Clothes washer	$1.50	$2.00 / 33%	$1.49 / -1%

Table 6.10 below shows how the different avoided costs scenarios impact the total amount of cost-effective achievable potential. The greatest impact is the high social cost of carbon scenario where a 29% increase in avoided costs generates 0.8% more cost-effective achievable potential. This highlights the supply curve and how incrementally more expensive additional energy efficiency costs. Using reference avoided costs, 95% of achievable potential is cost-effective under the TRC test and substantial increases in avoided costs would be necessary for the remaining 5% to become cost-effective. However, this is not to imply that increases in avoided costs are not meaningful, as Energy Trust measures and programs are evaluated using both the TRC and UCT tests. While increases in avoided costs do not meaningfully increase the amount of cost-effective achievable potential, they do impact incentive caps and investment in program and delivery infrastructure by increasing the net-present value of benefits for the measures that are already cost-effective. All things being equal this allows for greater $/therm investment for the same portfolio of cost-effective achievable potential.

Table 6.10: Avoided Costs Scenarios, 20-year Cost-Effective Achievable Potential (MMTherms)

Sector	Reference ACs	High SCC ACs / % difference	ETO Blended ACs / % difference
Residential	100.30	101.18 / 0.9%	100.31 / 0.0%
Commercial	48.41	49.00 / 1.2%	48.35 / -0.1%
Industrial	29.10	29.10 / 0.0%	29.10 / 0.0%
Total	177.81	179.27 / 0.8%	177.76 / 0.0%

6.3 Washington Conservation Potential Assessment / Sales

This section is extracted and summarized from the final report of the 2023 NW Natural Washington Conservation Potential Assessment (CPA) submitted by Applied Energy Group (AEG) to NW Natural. In 2024, NW Natural contracted with Lighthouse Consulting to complete the Company's 2025 CPA. The final report and supporting documents were filed with the WUTC on June 2, 2025.

6.3.1 Background

In early 2023, NW Natural contracted with Applied Energy Group (AEG), a consulting firm known for its services to the energy industry including gas utilities, to conduct an assessment of available conservation potential in its Washington service territory. This new iteration of the CPA refreshes key aspects of the 2021 CPA to assist NW Natural in developing the next iteration of the integrated resource plan (IRP).[159] Throughout this study, AEG worked with NW Natural to understand the baseline characteristics of their Washington service territory, including a detailed understanding of energy consumption in the territory, the assumptions and methodologies used in NW Natural's official load forecast, and recent programmatic accomplishments.

6.3.2 Analysis Approach

To perform the potential analysis, AEG used a bottom-up approach following the major steps listed below. These analysis steps are described in more detail throughout the remainder of this chapter.

1. Retained the robust market characterization developed for the 2021 CPA with an anchor year of 2019.
2. Calibrated the baseline projection of energy consumption by sector, segment, end use, and technology to 2022 actual customers and consumption, then continued the projection through 2050.
3. Reviewed high priority residential and commercial measures from 2021 CPA characterization, updating to the best available information.
4. Estimated technical, achievable technical, and achievable economic energy savings at the measure level for 2024-2050. Achievable economic potential was assessed using both the Total Resource Cost (TRC) and Utility Cost Test (UCT) screens.

[159] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

For this analysis, AEG used its Load Management Analysis and Planning tool (LoadMAP™) to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and potential studies since. Built in Excel, the LoadMAP framework is both accessible and transparent and possesses the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's Residential End-Use Energy Planning System (REEPS) and Commercial End-Use Planning System (COMMEND)) but in a simplified, more accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately. This is especially relevant in the state of Washington, where the 2021 Washington State Energy Code (WSEC) substantially impacts efficiency in the new construction market.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex customer choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach will enable users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for water heating is distinct from furnaces and fireplaces.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, climate zone, or income level).
- Exports model results in a detailed line-by-line summary file, allowing for review of input assumptions, cost-effectiveness results, and potential estimates at a granular level. It

also allows for the development of IRP supply curves, both at the achievable technical and achievable economic potential levels.

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.[160]

Three types of potential were analyzed in this AEG study: technical, achievable technical, and achievable economic. Table 6.11 provides detailed definitions on each type of potential.

Table 6.11: Levels of Potential

Potential Type	Definition
Technical	Everyone chooses the most efficient option regardless of cost at time of equipment replacement or measure adoption.
Achievable Technical	A modified technical potential that accounts for likely measure adoption within the market.
Achievable Economic	A subset of achievable technical potential that includes only cost-effective measures.

To estimate the savings potential from energy-efficiency measures, it is necessary to understand how much energy is used today and what equipment is currently in service. This market characterization begins with a segmentation of NW Natural's natural gas footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies in use. For this, AEG relies primarily on information from NW Natural, augmenting with secondary sources as necessary.

6.3.3 Baseline Load Projection

The baseline projection is the foundation for the analysis of savings in future conservation cases and scenarios as well as the metric against which potential savings are measured. AEG developed the reference baseline in alignment with NW Natural's long-term demand forecast, but some modifications to account for known future conditions were also made, including impacts from WSEC 2021 on residential and commercial new construction.

[160] The model computes energy forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy savings are calculated as the difference between the value in the baseline projection and the value in the potential forecast (e.g., the technical potential forecast).

AEG refined the baseline projection of annual natural gas use for 2024-2050 from the prior CPA to align with NW Natural's 2022 actual totals. The 2021 CPA Reference Case forecast was updated with the latest iteration of NW Natural's IRP customer growth projections and weather data, and market based (naturally occurring) efficient purchase shares were reviewed considering changes to the efficiency options provided for equipment replacement.

Inputs to the baseline projection include:

- Current economic and load growth forecasts (i.e., customer growth, climate change assumptions)
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- AEG presents the baseline projection results for the system as a whole and for each sector

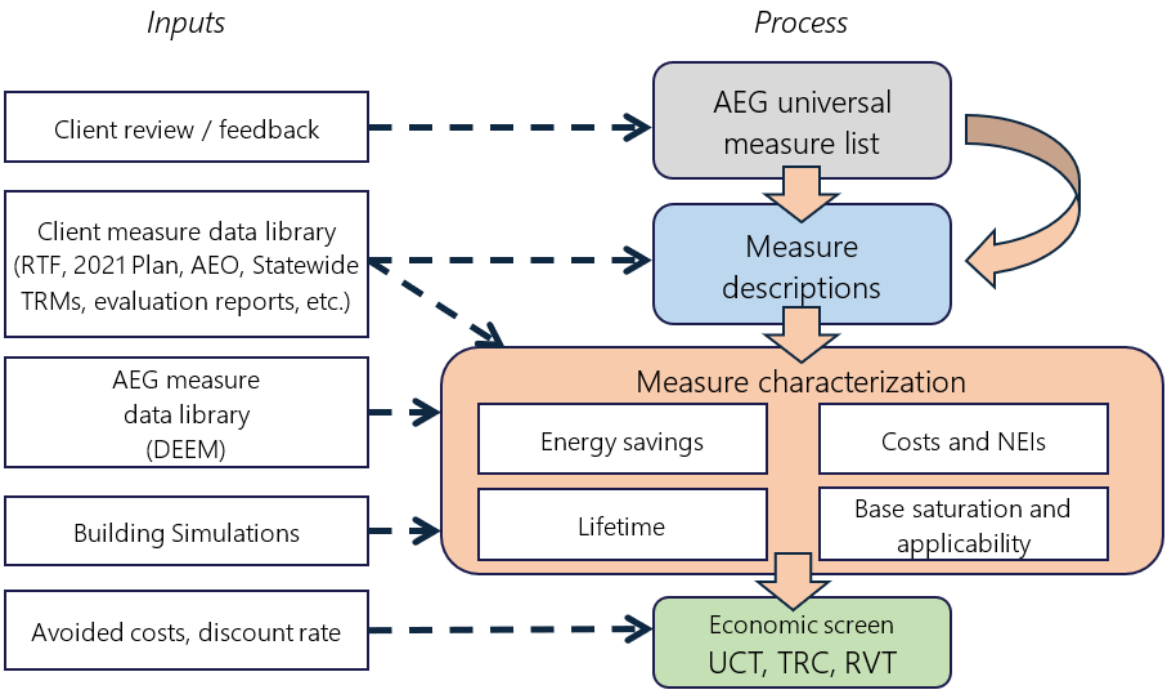
6.3.4 Energy Efficiency Measure Development

This section describes the framework used to assess the savings, costs, and other attributes of energy efficiency measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. To develop NW Natural's measure list, AEG used datasets provided by NW Natural and the Energy Trust of Oregon.

Figure 6.14 outlines the framework for measure characterization analysis. First, the list of measures is identified; each measure is then assigned an applicability for each market sector and segment and is characterized with appropriate savings, costs, and other attributes; then cost-effectiveness screening is performed. NW Natural provided feedback during each step of the process to ensure measure assumptions and results lined up with real-world programmatic experience.

We compiled a robust list of conservation measures for each customer sector, drawing upon NW Natural and the Energy Trust of Oregon's program experience, AEG's own measure databases and building simulation models, and secondary sources, primarily the Regional Technical Forum's (RTF) UES measure workbooks and the 2021 Power Plan's electric power conservation supply curves. This universal list of measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption.

Figure 6.14: Approach for Energy Efficiency Measure Characterization and Assessment



The selected measures are categorized into two types according to the LoadMAP modeling taxonomy: equipment measures and non-equipment measures.

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is a tankless residential water heater (UEF 0.95) that replaces a standard efficiency storage water heater (UEF 0.58). For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by a code or standard) up to the most efficient product commercially available. These measures are applied on a stock-turnover basis, and in general, are referred to as lost opportunity (LO) measures by the Northwest Power and Conservation Council because once a purchase decision is made, there will not be another opportunity to improve the efficiency of that equipment item until its end of useful life (EUL) is reached once again.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a furnace or water heater). Measure installation is not tied to a piece of equipment reaching the end of useful life, so these are generally categorized as “retrofit” measures. An example

would be insulation that modifies a household's space heating consumption but does not change the efficiency of the furnace. The existing insulation can be upgraded without waiting for any existing equipment to malfunction and saves energy used by the furnace. Non-equipment measures typically fall into one of the following categories:

- Building shell (windows, insulation, roofing material)
- Equipment controls (smart thermostats, water heater setback)
- Whole-building design (Built Green homes)
- Retro-commissioning
- Behavioral

AEG developed a preliminary list of efficiency measures, which was reviewed with NW Natural's project team and with the Energy Trust of Oregon to ensure a robust field of options and consistency with program activity where applicable. Once we assembled the list of measures, the AEG team assessed their energy-saving characteristics as well as incremental cost, service life, non-energy impacts, and other performance factors.

For this study, work from the 2021 CPA measure development was retained except for measures identified by AEG and NW Natural requiring an update based on updated technology and non-equipment assumptions made available since the completion of the 2021 CPA.

6.3.5 Energy Efficiency Potential

Table 6.12 and Figure 6.15 summarize the energy conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Savings are represented in cumulative terms, reflecting the effects of persistent savings in prior years in addition to new savings. This allows for the reporting of annual savings impacts as they actually impact each year of the forecast.

- **Technical Potential** reflects the adoption of all conservation measures regardless of cost-effectiveness. Technical potential is useful as a theoretical construct, applying an upper bound to the potential that may be realized in any one year. Other levels of potential are based off this level which makes it an important component in the estimation of potential. In this potential case, efficient equipment makes up all lost opportunity installations and all retrofit measures are installed, regardless of achievability.
- **Achievable Technical Potential** refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation

measures. For the 2024-2050 CPA, ramp rates from the 2021 Power Plan were customized for use in natural gas programs.

- **TRC Achievable Economic Potential** further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, the cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy benefits to the total customer and utility costs of delivering the measure through a utility program, including monetized non-energy impacts. AEG also applied benefits for non-gas energy savings, such as electric HVAC savings for weatherization and lighting savings for retro-commissioning. Specifically, AEG estimated TRC non-energy impacts in the following ways:
    - Include quantified and monetized non-energy impacts present in Council and Regional Technical Forum (RTF) workbooks;
    - Incorporate NEIs directly into the avoided cost (e.g., 10% conservation credit, carbon adders, and natural gas risk adders);
    - Account for the presence of secondary heating when calibrating energy models (e.g., apply a calibration credit to many space heating savings); and
    - Account for non-gas impacts, such as cooling savings within a weatherization program or lighting savings from a retro commissioning program.

  Moreover, AEG applied the Council's calibration credit to space heating savings to reflect the fact that additional fuels may be used as a supplemental heat source within an average home and may be accounted for within the TRC. Avoided costs of energy were provided by NW Natural, including ten percent conservation credit per the Council's methodology.

Potential under the TRC test is lower than UCT due to the inclusion of full measure costs rather than solely the utility portion.

- **UCT Achievable Economic Potential** further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, the cost-effectiveness is measured by the utility cost test (UCT), which compares lifetime energy benefits to the total utility costs of delivering the measure through a utility program, excluding monetized non-energy impacts. Avoided costs were provided by NW Natural with a ten percent conservation credit embedded per Council methodologies.

Table 6.12: Summary of Energy Efficiency Potential (mTherms)[161]

Summary of Energy Savings (TRC), Selected Years	2024	2025	2026	2030	2040	2050
Reference Baseline	86,056	85,329	84,624	82,162	76,123	70,733
Cumulative Savings (mTherms)						
Achievable Economic TRC Potential	355	720	1,115	3,099	9,223	11,129
Achievable Economic UCT Potential	518	1,043	1,597	4,137	10,736	12,658
Achievable Technical Potential	585	1,180	1,807	4,686	11,940	13,950
Technical Potential	1,168	2,335	3,532	8,442	17,305	18,809
Energy Savings (% of Baseline)						
Achievable Economic TRC Potential	0.4%	0.8%	1.3%	3.8%	12.1%	15.7%
Achievable Economic UCT Potential	0.6%	1.2%	1.9%	5.0%	14.1%	17.9%
Achievable Technical Potential	0.7%	1.4%	2.1%	5.7%	15.7%	19.7%
Technical Potential	1.4%	2.7%	4.2%	10.3%	22.7%	26.6%

Figure 6.15: Summary of Annual Cumulative Energy Efficiency Potential (mTherms)

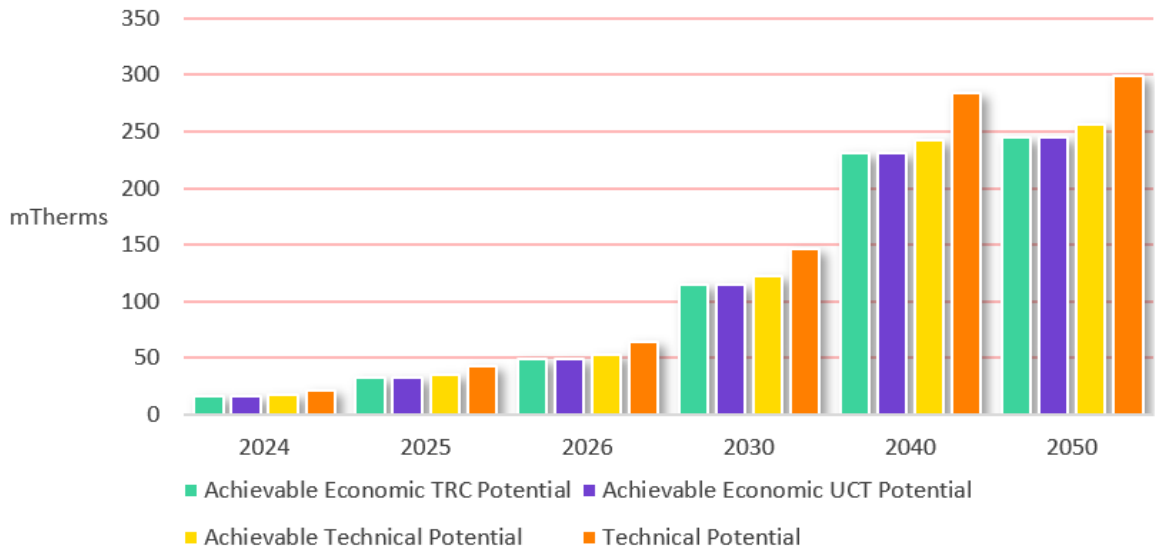


Table 6.13 summarizes TRC achievable potential by sector for selected years. While the precise distribution of savings among sectors shifts slightly over the course of the study, in general residential and commercial potential are well balanced. Since industrial sales customer

[161] Note that the potential EE savings reported in the tables and figures of this section include savings from both existing and new customers projected by AEG in the 2023 Washington CPA. The 2025 IRP uses the potential EE savings projected for the existing customers only to take account of the impact of the new building code in Washington on potential EE savings from the new customers.

consumption represents a small percentage of the baseline, potential for this sector makes up a lower percentage of the total. While residential and commercial potential ramps up, industrial potential is mainly retrofit in nature and is much flatter. This is because process equipment is highly custom and most potential comes from controls modifications or process adjustments rather than high-efficiency equipment upgrades. Additionally, AEG models retro-commissioning to phase in evenly over the next twenty years. This measure has a maintenance component, and not all existing facilities may be old enough to require the tune-up immediately but will be eligible at some point over the course of the study.

Table 6.13: Cumulative TRC Achievable Economic Potential by Sector, Selected Years (mTherms)

Sector	2024	2025	2026	2030	2040	2050
Residential	191	387	607	1,824	6,179	7,500
Commercial	147	300	459	1,160	2,814	3,384
Industrial	16	33	49	114	231	245
Total	355	720	1,115	3,099	9,223	11,129

Table 6.14 and Table 6.15 present the total reference baseline and potential savings for the peak day and peak hour, respectively. Peak day and hour impacts are estimated using the annual energy savings and conversion factors that relate peak day or hour consumption to annual consumption by end use, which were provided by NW Natural.

Table 6.14: Peak Day Potential Summary (mTherms)

Scenario	2024	2025	2026	2030	2040	2050
Baseline Forecast	1,115	1,106	1,096	1,061	959	862
Cumulative Savings						
TRC Achievable Economic Potential	5	11	16	41	115	137
UCT Achievable Economic Potential	8	16	24	59	141	163
Achievable Technical Potential	9	19	28	67	159	182
Technical Potential	14	28	42	99	212	236
Energy Savings (% of Baseline)						
TRC Achievable Economic Potential	0.5%	1.0%	1.5%	3.8%	12.0%	15.9%
UCT Achievable Economic Potential	0.7%	1.5%	2.2%	5.5%	14.7%	18.9%
Achievable Technical Potential	0.8%	1.7%	2.5%	6.3%	16.6%	21.2%
Technical Potential	1.3%	2.6%	3.9%	9.3%	22.1%	27.4%

Table 6.15: Peak Hour Potential Summary (mTherms)

Scenario	2024	2025	2026	2030	2040	2050
Baseline Forecast	85	84	83	80	74	67
Cumulative Savings						
TRC Achievable Economic Potential	0	1	1	3	10	11
UCT Achievable Economic Potential	1	1	2	4	11	13
Achievable Technical Potential	1	1	2	5	12	14
Technical Potential	1	2	4	9	18	20
Energy Savings (% of Baseline)						
TRC Achievable Economic Potential	0.4%	0.9%	1.4%	4.0%	13.1%	17.1%
UCT Achievable Economic Potential	0.6%	1.3%	2.0%	5.3%	15.2%	19.4%
Achievable Technical Potential	0.7%	1.4%	2.2%	6.0%	16.9%	21.4%
Technical Potential	1.4%	2.9%	4.5%	11.1%	24.8%	29.3%

Key opportunities for savings include residential connected thermostat, furnace and water heating equipment upgrades and weatherization, as well as behavioral programs and kitchen equipment. For detailed top DSM measures contributing to the potential savings reported above, refer to the 2023 Washington Conservation Potential Study.

6.4 Transportation Customers

Transportation customers are natural gas customers that procure their own gas and utilize NW Natural's distribution system for the delivery of the commodity to their site. Many transportation customers tend to be large industrial customers that require natural gas for process heat, but there is also a smaller subsect of commercial customers that are on transportation rate schedules.

When evaluating avoided costs, the commodity component is not included in the transportation customers' avoided costs. Due to the low avoided costs, NW Natural has not historically offered energy efficiency programs for transportation customers. However, this has begun to change with the introduction of carbon regulation in both Washington and Oregon.

In the 2022 IRP, NW Natural included transportation customer energy efficiency forecasts but did not have a program established to achieve natural gas savings. Since the filing of the 2022 IRP, NW Natural has engaged with stakeholders to develop offerings for this customer class.

6.4.1 Transportation – Oregon

NW Natural launched its initial Transportation EE program in partnership with the Energy Trust of Oregon (ETO) during the summer of 2024. At the time, Oregon's Climate Protection Program

(CPP) had been invalidated and further rulemaking was undergoing. The 2024 program was intended to enable NW Natural and ETO to lay the groundwork for future program years.

In 2025, NW Natural continues to partner with ETO to deliver their standard incentives to customers on transportation schedules. Standard incentives are for projects that have deemed savings and do not require a site-specific assessment.

NW Natural anticipates that the program will continue to grow and expand to include more offerings in future years. Stakeholder engagement will be a critical part of program offering and delivery development.

6.4.2 Transportation – Washington

In Washington, NW Natural contracted directly with an engineering consulting firm to offer high-level energy audits to both industrial sales and transportation customers. The offering was available through 2024 and helped identify several large projects. Information from the audits is currently being used to inform the development of an incentive program for Washington customers.

6.5 Income-based Energy Efficiency and Conservation Programs

NW Natural's Low Income Energy Efficiency programs in Oregon and Washington are designed to improve energy affordability, comfort, and housing stability for income-qualified customers. These programs provide no-cost energy upgrades, with eligibility and services tailored to meet the needs of vulnerable households across the utility's service areas.

6.5.1 Oregon Low Income Energy Efficiency

Since 2002, the Oregon Low Income Energy Efficiency (OLIEE) program, funded through a public purpose charge on Oregon residential and commercial customers energy bills, provides access to demand-side management (DSM) by funding free energy efficiency equipment and weatherization services to income qualified households. The program aims to deliver energy efficient retrofits, install high-efficiency gas equipment, and offer energy education to income eligible customers. The goals of the program include improving household health and comfort, reducing utility shutoffs, preserving the durability of low-income housing stock, and maximizing savings.

Funding is available for residential projects located within NW Natural's Oregon service territory. To qualify:

- The residence must have a gas line installed

- The dwelling or occupant must have an active NW Natural account or plan to open one by project completion
- The primary heating system must be fueled by natural gas
- Occupant must meet the income eligibility guidelines

OLIEE funding is delivered through two primary channels:

- Community Action Program (CAP)
- Open Solicitation (OSP)

6.5.1.1 Community Action Program

In collaboration with local community action agencies and community-based organizations, NW Natural administers OLIEE across the service territory. These agencies leverage OLIEE funds along with state, federal, and local funds to implement energy efficiency improvements. Community Action Program (CAP) primarily focuses on single-family homes projects and energy education.

In Spring 2024, following engagement with stakeholders, the OLIEE advisory committee, and Oregon Public Utility Commission (PUC) staff, the following updates to Schedule 320 were approved:

- Increased income eligibility threshold from 60 percent state median income (SMI) to 80 percent Area Median Income (AMI)
- Full funding of energy efficiency measures, along with necessary health, safety, and structural repairs
- Increased administrative support for program delivery agencies
- Enhanced funding for program and impact evaluation

Table 6.16: Homes served through OLIEE program

Program Year	Homes	Therms Saved
2022-2021	341	60,394
2021-2022	165	58,037
2022-2023	175	56,179
2023-2024	223	59,175

6.5.1.2 Open Solicitation Program

The primary goal of the Open Solicitation Program (OSP) is to provide cost-effective, energy efficiency assistance to a greater number of low-income households in NW Natural's Oregon

service territory. OSP is funded through the OLIEE program and enhances opportunities for dwellings that fall outside of the traditional single-family home program. This is achieved through a broad and diverse network of utility channels. To date, OSP has seven established partnerships across the service territory that work on a diverse type of dwelling like multifamily building, new development, and shelters. Examples of projects conducted since 2022 are summarized in Table 6.17.

Over the next two years, as a pilot initiative in collaboration with NW Natural, Latino Network[162] will expand its energy literacy and home weatherization outreach by coordinating 24 culturally specific community events, reaching approximately 1,000 individuals across Multnomah, Clackamas, and Washington Counties. This effort includes hiring dedicated staff to support utility assistance and outreach, while also building strategic partnerships with utilities and partner organizations to improve service delivery and address the energy needs of underserved communities.

Table 6.17: Examples of Projects Completed Since 2022

Organization	Project	Description	Heating Year
Oregon Energy Fund	**Albertina Kerr**	Full energy retrofits for five buildings in Kerr's real estate portfolio that house, support and care for 320 low-income youth and adults with intellectual and developmental disabilities each year; partnership model OEF, NAMCO and Albertina Kerr.	2022
	Agape Community	Full-building energy retrofits for 14 owner-occupied, Habitat for Humanity condominium units in the Agape Square community in Cully; pilot demonstration to assess the cost effectiveness of roof repair and/or upgrades (stipulation in Schedule 320 plus implications for future OSP investments).	2023

[162] Latino Network is an Oregon 501(c)(3) that was founded in 1996 to advocate for the needs of Oregon's growing, yet underinvested Latine community.

	Lindsey Lane	Full-building energy efficiency retrofits 14, owner occupied, Habitat for Humanity condominiums in the Lindsey Lane community in Hillsboro, OR. The units will need roof repair in order to add attic insulation, extensive mold mitigation, high efficiency windows, high efficiency doors, and A/C.	2025
Homes for Good	**Mission**	Energy efficiency upgrades and structural repairs to Eugene Mission shelter that serves 250 people a year.	2023
	Ground Source Heat Pump	Pilot. Proof of concept pilot installed 12 ground source heat pumps in homes of customers that participated in the weatherization program in the past. Dual-fuel pilot with furnace as a backup.	2024
	Heeran	Replacement of boiler system connected to a condenser water loop in 16-unit building for seniors with persisting mental health issues	2025
Latino Built	**OSP/CAP Pilot**	Energy efficiency for 20-25 single family homes in Salem and Beaverton; new approach to using OLIEE--OSP covers planning, outreach and community engagement costs; Energy efficiency through reimbursement-based single family.	2024
African American Alliance for Homeownership	**OSP/CAP Pilot**	Whole home energy efficiency upgrades and structural repairs to 40 single family homes in Portland; new approach to using OLIEE--OSP covers planning, outreach and community engagement costs; Energy efficiency through reimbursement-based single family.	2024
The Next Door	**Convening**	Convening for landlords and building managers of affordable, multiunit housing on benefits of energy efficiency and resources available through OSP funding.	2022

Rohingya Youth Association of Portland	**OSP/CAP Pilot**	Whole home energy efficiency upgrades and structural repairs to 20-25 single family homes in Portland; new approach to using OLIEE--OSP covers planning, outreach and community engagement costs; energy efficiency through reimbursement-based single family.	2025
Community Partners for Affordable Housing	**Multifamily EE Retrofits**	New housing development in Tigard with 63 affordable apartment homes. Serving homes 30% and 60% of AMI with 24 dedicated to extremely low income household's below 30% AMI. 22 units are permanent supportive housing with wraparound services. Retrofits include HVAC system for community room, insulation, water heating, and high efficiency windows.	2025
Housing Development Center	**Multifamily EE retrofits**	In collaboration with Linn Benton Housing Authority. This is the construction of 30 units for Veterans and people with mental disabilities. Pilot for resiliency and hooking up gas water heater to solar battery storage system.	2025

OLIEE experienced reduced participation due to COVID-19 and has undergone significant changes since 2022. NW Natural continues to monitor the impact of these changes and remains committed to increasing program accessibility and effectiveness.

6.5.1.3 Oregon Low Income Energy Efficiency Advisory Committee

Per Schedule 320, the Oregon Low Income Energy Efficiency (OLIEE) Advisory Committee (OAC) provides guidance to NW Natural on the implementation and evaluation of the OLIEE program. The committee includes representatives from NW Natural, Oregon Public Utility Commission staff, the Community Action Partnerships of Oregon (CAPO), and at least two members from community action agencies. Additional members include representatives from the Citizens' Utility Board (CUB) and the NW Energy Coalition (NWEC).

While the OAC does not hold decision making authority, it plays a critical role in shaping the delivery of the OLIEE programs. The committee meets a minimum of twice per program year to review progress and provide recommendations.

6.5.2 Washington Low Income Energy Efficiency

Launched in 2009, the Washington Low Income Energy Efficiency (WALIEE) program is modeled after Oregon's CAP programs and reimburses partner agencies for the installation of cost-effective weatherization measures. Currently, one agency administers the program in Washington, informed by the guidance of NW Natural's Energy Efficiency Advisory Group (EEAG).

Given that many homes in SW Washington are newer and have limited need for retrofits, program volume is low. Historically, WALIEE capped health and safety spending, but in 2024, NW Natural requested a tariff change that allows for greater project flexibility. Increased outreach efforts are also underway to enhance program visibility.

Table 6.18 shows the historical number of homes treated through the WALIEE program.

Table 6.18: Historical WALIEE Homes

Program Year	Homes	Therms Saved
2021	11	3,568
2022	11	2,581
2023	12	3,815
2024	9	666

6.5.2.1 Outreach and Energy Education

Outreach and Energy education are essential components of both the OLIEE and WALIEE programs, helping to connect eligible customers with available services and resources. These efforts take place through a variety of channels, including community events, partnerships with local organizations, and direct customer communication. NW Natural and its partner agencies have resumed in-person engagement activities that were paused during COVID-19, reflecting a renewed commitment to building trust and increasing awareness within underserved communities. Outreach strategies include participation in local events, the distribution of do-it-yourself (DIY) weatherization kits, and the use of customized bill inserts tailored to support partner organizations with program promotion and enrollment. The steady increase in outreach events in recent years highlights the growing emphasis on direct, community-based engagement. A communications plan outlining strategies for increasing program visibility across multiple platforms is provided in Appendix D.

Table 6.19 shows the number of outreach events attended by NW Natural.

Table 6.19: Outreach events attended by NW Natural by year

Program Year	Number of Events
2022-2023	8
2023-2024	12
2024-2025	15

6.5.2.2 Impact and Programs Evaluation

In late 2024, NW Natural conducted a third-party impact and programs evaluation of its low-income energy efficiency programs, OLIEE and WALIEE. The evaluation identified a number of strengths and opportunities to improve program delivery and long-term impact.

Both programs were found to be accessible and responsive to community needs. In Oregon, OLIEE's decision to shift in eligibility from 200 percent Federal Poverty Level (FPL) to 80 percent Area Median Income (AMI) broadened eligibility to the program. Additionally, NW Natural expanded the scope of allowable health and safety measures, enabling more holistic home upgrades. These changes were driven by requests from community-based organizations (CBOs) that confirmed that the program offers a wide and effective range of services.

In both Oregon and Washington, most participants and non-participants were already engaged with local community action agencies or community-based organizations for energy bill assistance, highlighting the importance of leveraging existing service networks. However, program awareness remains a challenge. Non-participating households frequently cited costs as a barrier, despite upgrades being provided at no cost. This suggests that many income eligible non-participants are unaware of the program or unsure of the eligibility.

Another shared finding across both programs is the impact of workforce shortages. Agencies expressed concerns that while funding is available and demand is strong, they are limited by the ability of qualified contractors and auditors. This challenge is particularly acute in rural areas and threatens the long-term sustainability of program delivery. In Oregon, collaboration with Oregon Training Institute was recommended as support is needed to grow a diverse and skilled workforce.

Based on a billing analysis, both programs demonstrated clear and statistically significant energy savings. OLIEE participants saved on average 93 to 119 therms per year, a reduction of 16 percent to 19 percent of energy savings compared to non-participants. These savings are in

line with or exceed typical benchmarks for weatherization and energy efficiency programs targeting low-income households.

The evaluation also revealed a reduction in arrearages among OLIEE participants, with an average annual decrease of $213 per household.

6.6 Energy Efficiency New Technologies

In any scenario, energy efficiency is a critical strategy and offers both cost savings and emissions reductions for our customers. The following sections discuss some energy efficient end use equipment developments.

6.7 Natural Gas Heat Pumps

Energy efficiency is an important part of managing both emissions reductions and affordability. One key strategy in accomplishing emissions reductions is to improve efficiency utilizing emerging high-efficiency technologies. One such technology is natural gas heat pumps (GHPs), also known as gas-fired heat pumps. Natural gas heat pumps, like electric heat pumps share a commonality for achieving high efficiency through extracting heat from outside air to achieve efficiencies greater than 100 percent. A key advantage is that they have the potential to operate at sustained efficiency in lower ambient temperatures without the need for electric resistance backup.

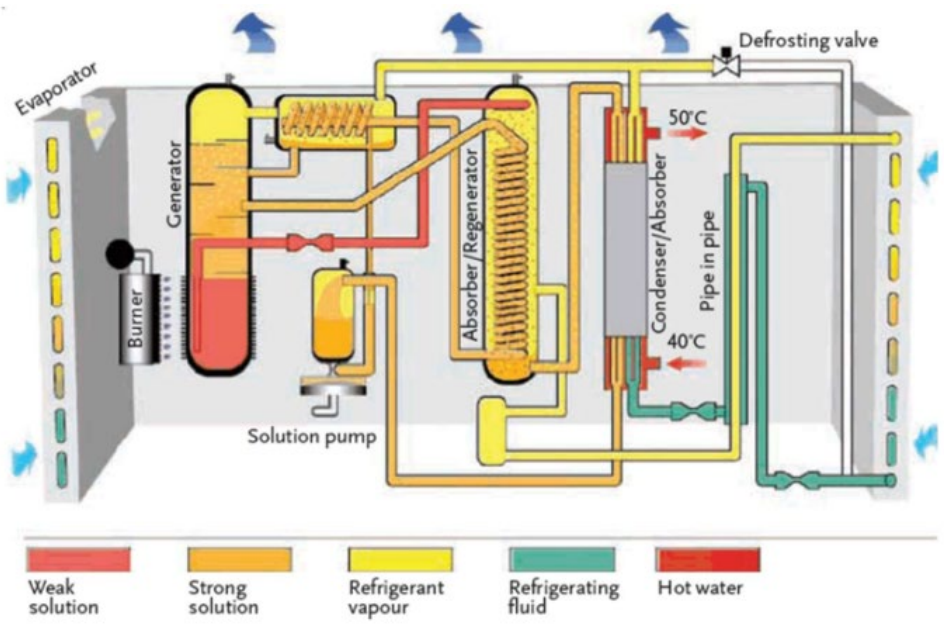
Similar to an electric heat pump, a gas-fired heat pump extracts heat from the outdoor ambient air and transfers it indoors for space and water heating. In the process, the gas heat pump creates more than one unit of heat for every unit of energy used, giving it more than 100 percent efficiency. The gas heat pump utilizes combustion at the site to drive the mechanical compression and expansion loop process in the heat pump. Because it utilizes some of the combustion heat, a GHP can operate with high efficiency at lower ambient temperatures.

A key benefit is the versatile use with traditional commercial HVAC applications:

> "GHPs can be utilized in a variety of applications. They can be combined with boilers, variable refrigerant flow (VRF) and domestic hot water (DHW) heaters for improved efficiency of existing systems and redundancy. In addition, GHPs can provide domestic hot water heating up to 140°F."[163]

[163] North American Gas Heat Pump Collaborative, Commercial HVAC Gas Heat Pump, Considerations for Installation, page 3. www.gasheatpumpcollab.org.

Figure 6.16: Gas Heat Pump Technology



Source: Robur; roburcorp.com/technical_dossiers/heat_pumps_absorption_technology

6.7.1.1 Commercial Natural Gas Heat Pumps

For several years, commercial gas heat pumps have been commercially available from various manufacturers, most widely in North America from Robur Corporation.[164]

In 2020, Northwest Energy Efficiency Alliance (NEEA) performed a commercial GHP Pilot in Salem, OR installing a Robur commercial gas heat pump and achieving approximately a 50 percent improvement in efficiency compared to their existing gas space and water heating systems.[165]

The summary report indicated that the unit provided[166]:

- Efficiency improvement with "a significant improvement in performance above conventional gas-fired technologies"
- System reliability with minimal maintenance
- Excellent technical support

[164] For more information on commercial gas heat pumps, please see the following manufacturer websites:
www.robur.com/en-us/company/research-and-development/heat-pumps
www.vicot.com.cn/english/a/PRODUCT/Gas_system/2021/0312/GAP-V65.html
www.lsmenergysolutions.com/yanmar-gas-heat-pumps.html
www.yanmar.com/global/energy/ghp/vrf/merits.html
[165] Tierney, Jennifer, P.E., et al, Robur Heat Pump Field Trial, NEEA report #E20-309, March 11, 2020. Page 24.
[166] Tierney, Jennifer, P.E., et al, Robur Heat Pump Field Trial, NEEA report #E20-309, March 11, 2020. Page 19.

Pilot study recommendations for future pilots included applications for commercial pools, laundry facilities, multifamily buildings, and food processing as well as other sites with large year-round hot water loads.

6.7.1.2 Residential Gas Heat Pumps

Residential GHPs are newcomers to the HVAC market and are being supported and promoted by the North American Gas Heat Pump Collaborative – an international collaborative of utilities in the USA and Canada representing 37 percent of households using gas in those nations. The Northwest Energy Efficiency Alliance (NEEA) is also driving market transformation efforts around GHPs.

Currently there is one commercially available GHP product designed for residential single-family/single-dwelling unit applications. It is from Stone Mountain Technologies Inc. (SMTI)[167] and it is a combination "combi" space and water heating solution – meaning a single outdoor heat pump unit provides hot water to both a hot water tank and furnace style air-handler to heat the home.

Like Commercial Gas Heat Pump pilots, more residential pilots are needed in the Pacific Northwest region to gather data of seasonal performance in associated climate zones to help inform incentive development of this technology in our service area.

6.8 Demand Response

This section provides a high-level update on the system wide residential and small commercial demand response program as proposed by the Company and acknowledged by the OPUC in the 2022 IRP. The performance of the program over the past winter season is summarized based on the program implementer and an independent third-party evaluator's preliminary evaluation reporting along with lessons learned and next steps for the program.

6.8.1 Residential and Small Commercial Bring Your Own Thermostat Demand Response Program

In NW Natural's 2022 IRP, docketed as LC 79 in Oregon and UG-210094 in Washington, the Company included an action item that focused on reducing load during peak demand period through a demand response program for residential and small commercial customers. Action Item 3 stated:

[167] https://stonemountaintechnologies.com/wp-content/uploads/2024/01/Anesi_ResidentialForcedAirSpaceHeating_AppNote_24-01_RFA.pdf

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

In Order No. 23-281, the OPUC agreed with Staff's recommendation and acknowledged this action item to scope a residential and small commercial demand response (DR) program with the condition that NW Natural provides a discussion of how its general (system-wide) demand response will interact with and support future locational (geographically targeted) DR programs.[168]

Upon receiving the Commission's acknowledgement on Action Item 3, the Company began scoping and developing a program plan. By the end of October 2023, the Company completed a DR program plan in which the scope, objectives, DR offerings, deliverables and timing for system-wide programs were developed. While several DR pathways were explored, a Bring Your Own Thermostat ("BYOT", or "Thermostat Rewards" as branded) Program was identified as the best opportunity to create a demand response program that targets residential and small commercial customers and the platform created for the system-wide program can be leveraged to support future locational DR programs and hence to comply with the condition for action item acknowledgement as recommended by OPUC Staff.

Smart thermostats are required for a BYOT program. Energy Trust of Oregon (ETO) data showed that over 61,000 smart thermostats have already been installed across NW Natural's service territory via Energy Trust's various energy efficiency programs. A separate survey by Northwest Energy Efficiency Alliance (NEEA) found that approximately 14 percent of single-family homes in the northwest region have installed certain types of smart thermostats.[169] The Company estimates that there are as many as 84,000 smart thermostats for single-family homes among the Company's residential customers. Given so many smart thermostats being already installed in NW Natural's service territory, the enrollment goal of the Thermostat Rewards Program is set to be 30,000 customers by the end of the three-year program period.

In February 2024 NW Natural issued a request for proposal (RFP) for the BYOT program. The Company hosted multiple rounds of interview sessions for each of the implementation vendors (RFP responders) during the RFP selection process from late March to May 2024 and eventually identified Resideo Grid Works ("Resideo") as the implementor. NW Natural negotiated a scope of work and contract in July 2024. Resideo began to set up the BYOT program in their

[168] The Company received a letter from the WUTC on August 24, 2023 acknowledging compliance with WAC 480-90-238 along with Commission Staff comments. There was no discussion about this action item.

[169] See 2022 Residential Building Stock Assessment – Findings Report, published by NEEA in April 2024.

distributed energy resource management system (DERMS) in August 2024 and the program began enrolling eligible customers on December 9, 2024.

In addition, the Company issued an Evaluation, Measurement and Verification (EM&V) RFP for the DR program in March 2024, seeking a qualified third-party EM&V service vendor to conduct an independent EM&V analysis of the BYOT program. Five EM&V service vendors submitted their proposals. The Company selected ADM Associates for the EM&V vendor and negotiated a statement of work in August 2024.

NW Natural's demand response program season is November 1 through March 31. The program DR event window will be from 7:00 AM through 11:00 AM. The maximum event duration is four hours and the number of events to be called is no more than ten in a season. Customers may opt in or out of an event anytime.

Each customer who enrolls in the Thermostat Rewards Program will receive an Enrollment Incentive in the form of a $25 Virtual Prepaid Mastercard®. In addition, customers enrolled may receive a $25 gift card as participation incentive after each season if they participate in 50 percent or more of the event hours during the DR season.

From the inception of the program to June 2, 2025, there are 11,065 customers/devices enrolled in the program. Over the past DR season, five DR events were dispatched between January 15 and February 12, 2025. Table 6.20 lists the different DR event parameters used during the season. With the first DR season, testing was used on a few parameters to get a better understanding of the impacts on event performance. For example, preheating was used in two of the five events. The results of the DR season are taken from ADM Associate's EM&V report. Table 6.21 is the overall DR season performance broken down by state. Table 6.22 showcases the participation by event with the opt-out and override rates, along with the number of devices enrolled for each event. Table 6.23 results show the total savings in therms for preheating, event hours, and snapback.

Table 6.20: DR Event Parameters

Event Date	1/15/25	1/21/25	1/27/25	2/5/25	2/12/25
Daily Temperature Range (F)	35-47	28-47	26-50	35-45	24-36
Event Start Time	7am	7am	7am	7am	7:30am
Event End Time	11am	11am	11am	11am	10:30am
Event Duration (Hours)	4	4	4	4	3
Setback Degrees (F)	3	4	4	4	4
Preheating Degrees (F)	0	2	0	1	0
Preheating Duration (Minutes)	0	45	0	90	0

Table 6.21: DR Season Performance Summary[170]

State	Number of Devices	Verified Demand Reduction per Device (therms/hr/device)	Verified Demand Reduction per Device, Maximum Hour (therms/hr/device)	Verified Peak Demand Savings (therms/hr)	Verified Savings [171] (therms)
WA	2,794	0.116	0.190	531	1,567
OR	6,640	0.116	0.190	1,262	3,724
Total	9,434[172]	0.116	0.190	1,792	5,291

Table 6.22: DR Season Participation Performance Summary[173]

Event Date	1/15	1/21	1/27	2/5	2/12
Total Number of Devices	3,694	4,953	4,928	6,361	6,337
Offline Rate (%)	0%	0%	1%	1%	1%
Opt-Out Rate (%)	2%	3%	3%	3%	2%
Override Rate (%)	19%	24%	24%	23%	19%

Table 6.23: DR Season Results by Event Period

Event Period	Total Verified Savings (therms)
Preheating	-1,859
Event Period	11,392
Snapback	-4,243
Entire Event	5,291

For each event, the average therms per hour per device are displayed in Figures 6.17-6.21. Each figure is for a full event day, which includes preheating, event hours, and snapback. The blue line is the actual load, while the orange line is the modeled baseline load from ADM's analysis. It is important to note that Ecobee devices will preheat regardless of the parameters that are selected for an event. Due to this, events without preheating will still have the preheating spike present. Event 4 has two preheating spikes because Google Nest, Honeywell, and Emerson

[170] Therms savings reported in the table are from the 2025 EM&V Report from ADM Associates.
[171] Verified Savings are defined as savings estimates after the impact analysis and energy impact evaluation has been completed.
[172] The total number of devices is based on data from March 31st, 2025.
[173] The figures reported in the table are from the 2025 EM&V report from ADM Associates. Opt-out is when customers choose to skip an event before the event starts. Overrides are when customers skip an event after the event curtailment period begins.

devices started preheating 90 minutes before the event started, followed by the preheating of Ecobee devices 60 minutes before the start time.

Figure 6.17: Actual versus Baseline Load per Device for Event 1 on January 15, 2025

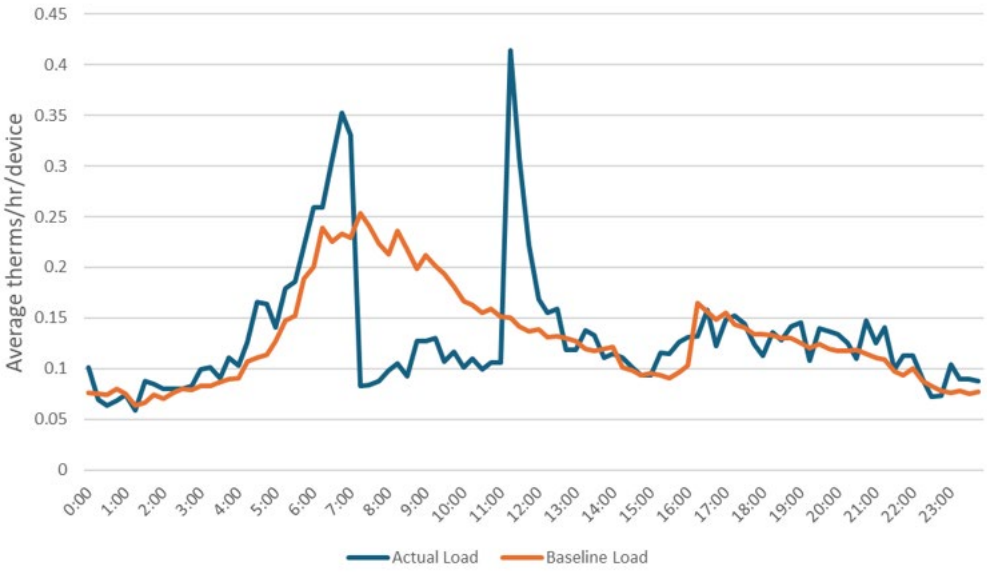


Figure 6.18: Actual versus Baseline Load per Device for Event 2 on January 21, 2025

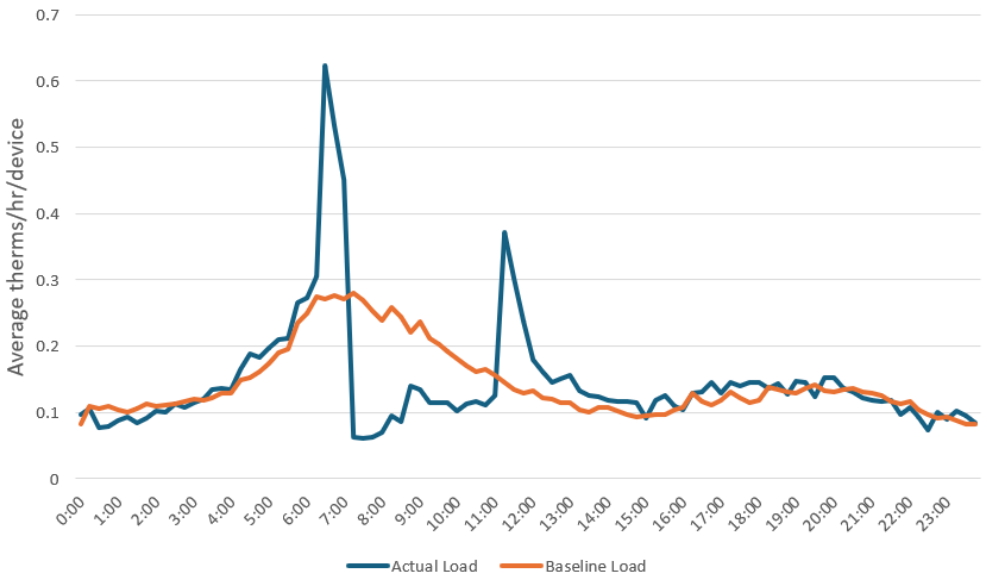


Figure 6.19: Actual versus Baseline Load per Device for Event 3 on January 27, 2025

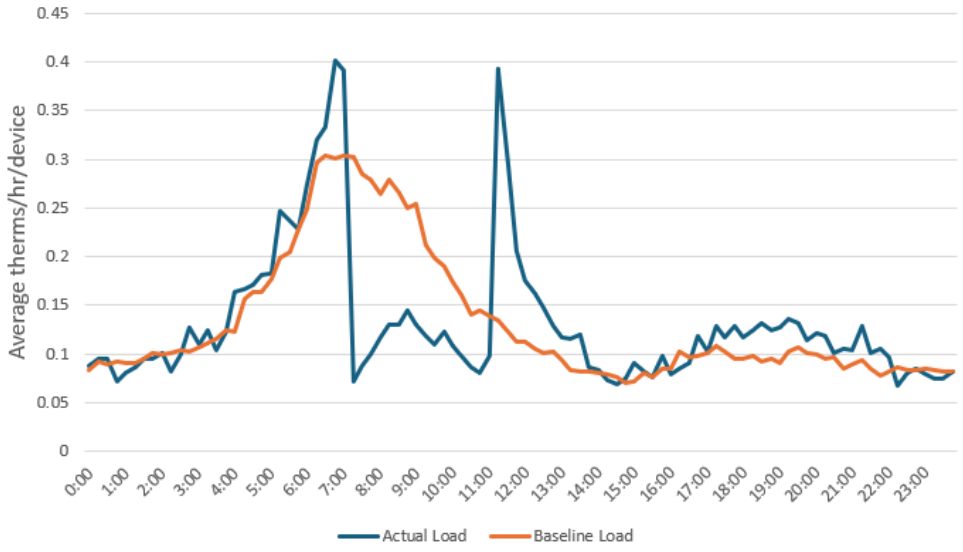


Figure 6.20: Actual versus Baseline Load per Device for Event 4 on February 5, 2025

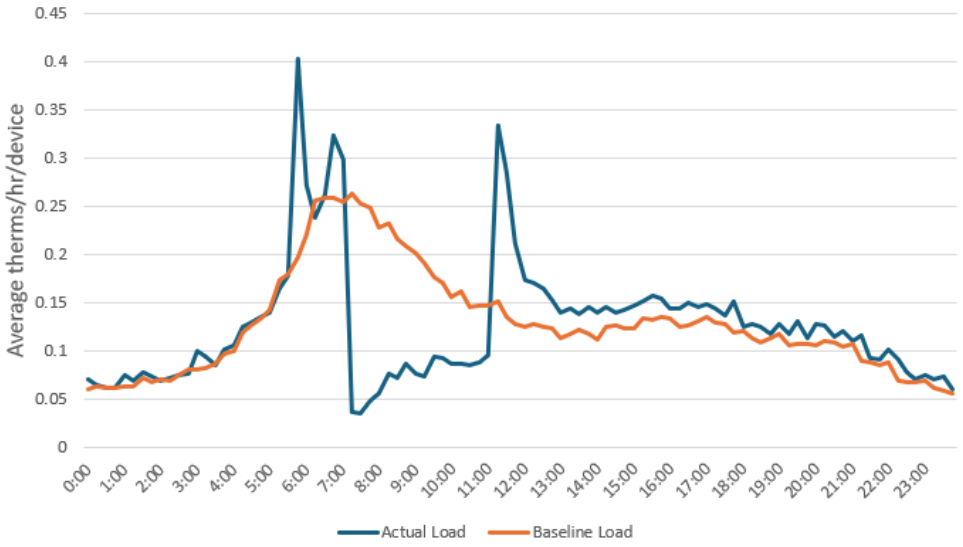
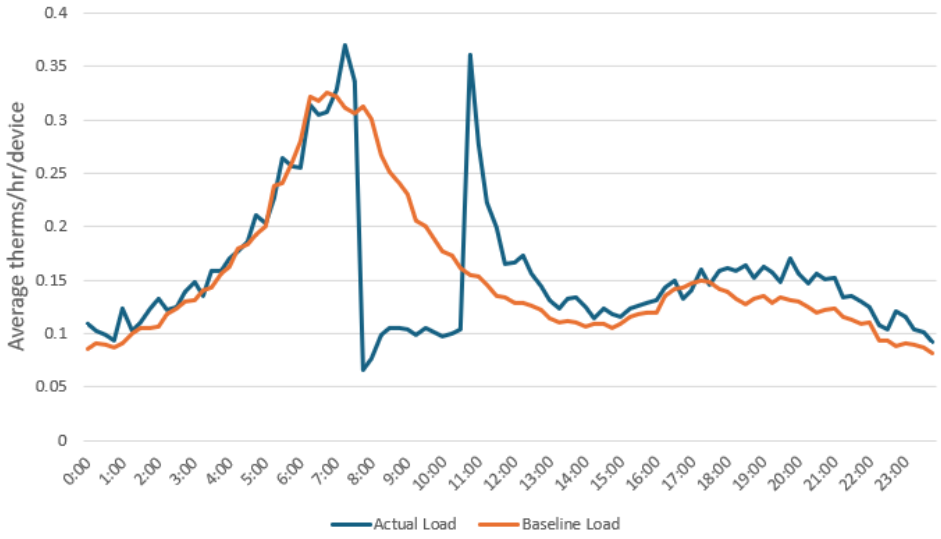


Figure 6.21: Actual versus Baseline Load per Device for Event 5 on February 12, 2025



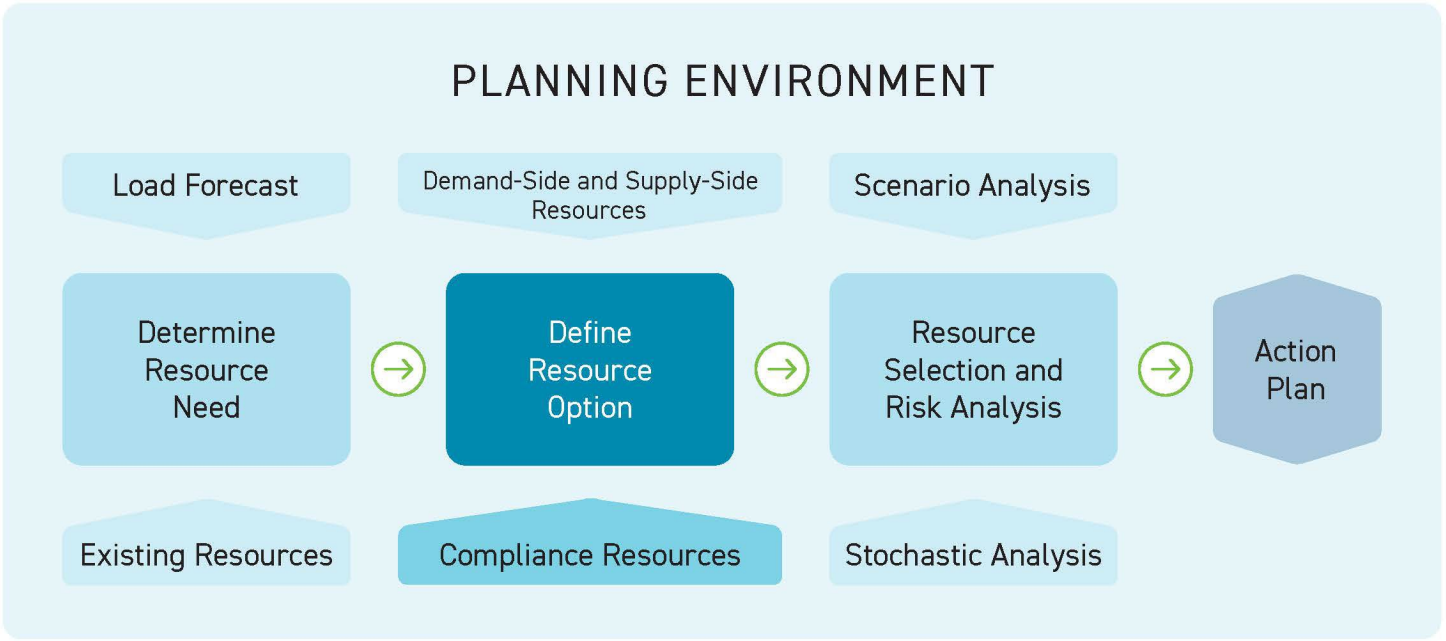
NW Natural recognizes that the Thermostat Rewards Program is new and fast growing and that it is premature to assess the cost-effectiveness of the program at such an early stage, yet its overall performance in the initial events aligns with industry expectations. The results indicate that the program has achieved comparable load reductions and participation rates to other gas BYOT programs. In terms of peak hour load reduction, per the DR potential study for NW Natural by Brattle, a BYOT program is expected to achieve an average reduction in peak hour demand by 0.09 therms/device/hour given the weather and load conditions in the Company's service territory.[174] The measurement and verification analysis by ADM Associates shows that over 0.116 therms/device/hour load savings may have been achieved in the program's first season with only five events. Participation rates for similar programs generally range between 51-74 percent across gas BYOT DR programs in the industry,[175] whereas Thermostat Rewards is averaging a 74 percent full participation rate. Additionally, the program has already reached its 2025 enrollment goal of 10,000 devices as of April 28, 2025, and is on track to achieving its three-year target of 30,000 devices.

As the Thermostat Rewards Program continues to develop, further testing will be conducted to optimize key DR event parameters such as setback degrees during events and preheating, preheating and event start times and durations. While initial testing was conducted during the

[174] The Potential for Gas Demand Response in the NW Natural Service Territory, the Brattle Group, December 2019.
[175] Overview of Gas Demand Response Programs, Memorandum by the Brattle Group, October 2022.

first season, additional assessments will be necessary to identify the best strategies to further improve the performance of the program.

7 Compliance Resources



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Once customer needs and compliance obligations are established, it is important to take a wide scope and assess what options are available to meet those needs. This chapter discusses resources that can be utilized to meet emissions compliance requirements.

7.1 Compliance Resources

The Oregon CPP and the Washington CCA each allow for a variety of resources to be utilized as compliance tools. While some of the compliance resources are accepted by both the CPP and CCA regulations, other resources are specific to either Oregon or Washington.

Table 7.1: Allowed Compliance Resources by State

Compliance Resource	Oregon CPP	Washington CCA
Reduced usage through conservation/energy efficiency	✓	✓
Compliance Instruments issued from state or acquired from other covered entity	✓	
Allowances issued from state, acquired at auctions, or on the secondary market		✓
Community Climate Investments (CCI) credits	✓	
Compliance Offsets		✓
Compliance Offsets on tribal lands		✓
Biomass derived fuels- renewable natural gas, synthetic methane	✓	✓
Hydrogen	✓	✓
Carbon Capture	✓	✓

NW Natural's conservation and energy efficiency efforts are detailed in Chapter 6. The remaining compliance resources listed in Table 7.1 are detailed in this chapter.

7.2 Compliance Instruments and Allowances

As described in the Environmental Policy section each program has their own compliance tools that represent allocation of emissions from the program cap. The Compliance instruments under the Oregon CPP and the Allowances under the Washington CCA can be used as compliance resources. See the environmental policy section in Chapter 2 for additional details on these resources.

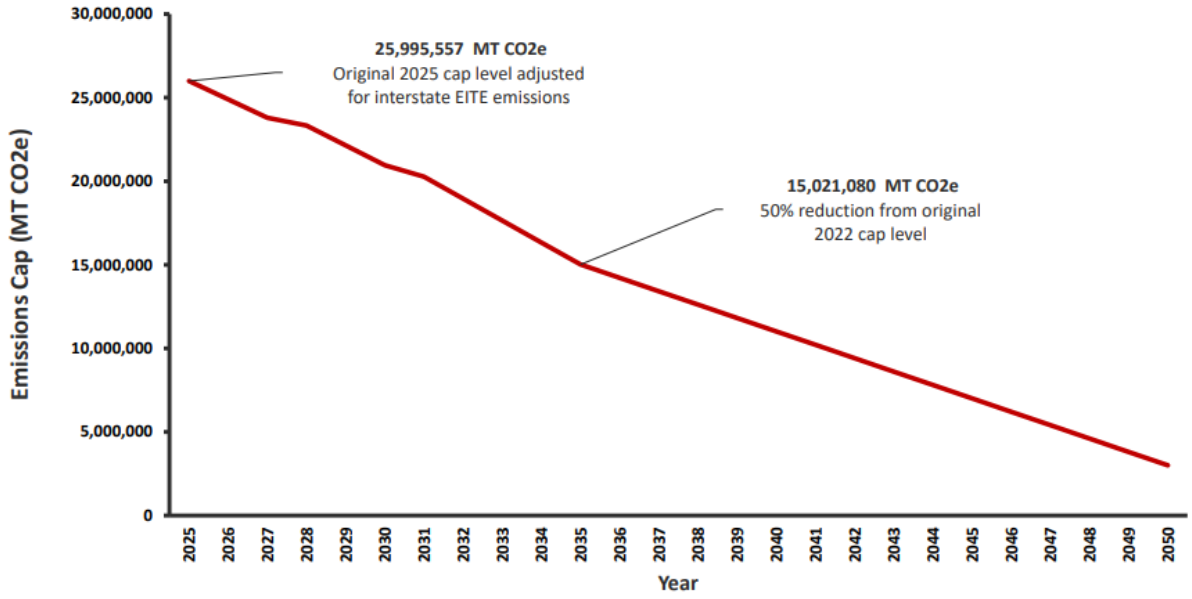
7.2.1 Oregon Compliance Instruments

In Oregon, allocations from the program cap are called compliance instruments. A compliance instrument is defined in OAR 340-273-0020 as an instrument issued by DEQ that authorized the emission of one MT CO_2e of greenhouse gases. Annually, NW Natural is allocated a portion of the declining portion of the program cap using the procedure outlined in OAR 340-273-0420. DEQ will take the program cap, distribute compliance instruments to EITEs according to the percentages outlined in OAR 340-273-9000 Table 8, and then will apply the percentage for NW Natural listed in OAR 340-273-9000 Table 4. Figure 7.1 outlines the Oregon CPP Cap Trajectory.

*(Annual Cap-Allocation to EITE) *NW Natural Allocation Percentage= Annual Allocation to NW Natural*

In the first compliance period (2025-2027), EITEs are exempt from the program, so NW Natural's allocation of compliance instruments is a direct percentage of the program cap. In the CPP rule language, DEQ is proposing to undertake additional rule making regarding EITEs which could impact the allocation of compliance instruments to local distribution companies. Since that rule making is not anticipated to begin until 2026, NW Natural is using the procedure set forth in the rules.

Figure 7.1: Oregon CPP Cap Trajectory



Source: https://ormswd2.synergydcs.com/HPRMWebDrawer/Record/6768300/File/document

Oregon compliance instruments are bankable and tradable with other covered entities in the program. The modeling included in this IRP allows for banking of compliance instruments but

does not include trading instruments with other parties. Since the CPP is not a market-based program and there is no pricing structure for these instruments or incentive to trade with such a steep program trajectory, it would be premature to assume a secondary market would develop that NW Natural would be able to participate in.

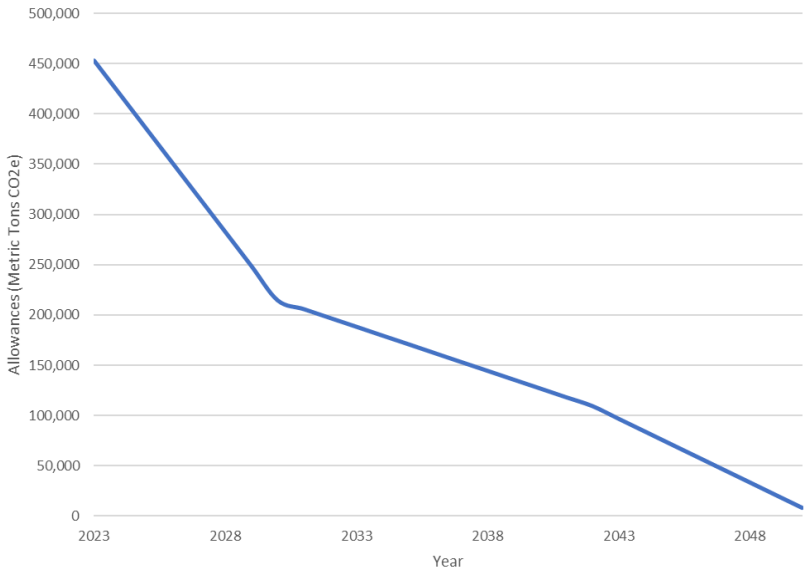
7.2.2 Washington Allowances

Like in Oregon, the Washington Climate Commitment Act (CCA) issues compliance tools that represent the amount of emissions allowed under the program's cap. These tools are called allowances in Washington. Each allowance authorizes the release of one metric ton (MT) of CO2e.

These allowances are acquired through a variety of pathways under the CCA. Certain categories of covered entities, like local distribution companies, are allocated "no cost" allowances annually from the Department of Ecology. Additional allowances can be purchased at auction or in a secondary market from other program participants.

NW Natural receives "no cost" allowances, as depicted in Figure 7.2, from Ecology based on its customers' baseline covered emissions from 2015-2019. Covered emissions do not include EITE customers' emission. The allocation calculation takes the average of these annual emissions and then applies the program cap reduction percentage to the baseline to calculate the annual reduction of allowances granted to NW Natural each year. NW Natural's baseline average annual covered emissions are 487,445 MT CO2e. From 2023-2030, there is a 7 percent baseline of reduction in the non-cost allowances provide to NW Natural, or a reduction of 34,121 allowances each year. From 2031 to 2042 this percentage changes to 1.8 percent of baseline reduction or 8,774 allowances each year. Finally, from 2043 to 2050, NW Natural's allocation of no cost allowances is reduced by 2.6 percent of baseline each year, or 12,674 allowances a year.

Figure 7.2: NW Natural Distribution of No Cost Allowances



While these allowances are provided to the Company at no cost, they have some additional requirements on them compared to allowances purchased at auction or on the secondary market. These allowances are not allowed to be traded and are deposited in either the Company's compliance account or limited use account. Under the CCA program, local distribution companies are required to consign a specific percentage of their no cost allowances to auction each year. Table 7.2 outlines the percentage of allowances that NW Natural must consign to auction and the remaining may be retained and used for compliance.

Table 7.2: Percentage Consigned to Auction

Year	Percentage Consigned to Auction
2023	65%
2024	70%
2025	75%
2026	80%
2027	85%
2028	90%
2029	95%
2030 and beyond	100%

NW Natural can purchase additional allowances at auction or on the secondary market. By rule, Ecology must hold four quarterly allowance auctions and one Allowance Price Containment Reserve (APCR) auction per year. Up to three additional APCR auctions can be held each year if the settlement price for the previous quarterly auction is about the APCR Tier 1 price. General market participants may purchase allowances in the quarterly auctions and sell them on the secondary market but are not allowed to participate in APCR auctions. Additionally, if covered entities are not able to secure enough compliance tools to cover their emissions by a compliance deadline, Ecology may issue additional allowances to that entity at the annual allowance ceiling price.

7.3 Offsets and Community Climate Investments

In addition to compliance tools that represent the emissions allowed under each state's program emission caps, the CPP and CCA allow for the use of an alternative compliance tool. In Oregon these tools are called Community Climate Investments and in Washington compliance offsets are allowed.

7.3.1 Oregon Community Climate Investments

The Oregon CPP does not allow for the use of traditional carbon offsets like other carbon compliance programs. Instead, Oregon DEQ created a tool unique to Oregon called a Community Climate Investment Credit (CCI). Under OAR 340-273-0020(5), Oregon DEQ defines a CCI Credit as "an instrument issued by DEQ to track a covered entity's payment of community climate investment funds, and which may be used in lieu of a compliance instrument." DEQ, with the assistance of an Equity Advisory Committee, will select at least one non-profit to be the CCI Entity and collect the CCI funds from covered parties. OAR 340-273-0020 defines a CCI Entity as a nonprofit organization that has been approved by DEQ and that has entered into a written agreement with DEQ consistent with OAR 340-273-0920 to implement projects supported by community climate investment funds. The CCI price is established by DEQ annually based on an initial value outlined in OAR 340-273-9000 Table 6 and adjusted by inflation.

CCI Credit Contribution Amount = CCI Credit Contribution Amount in Table 6 in OAR 340-273-9000 * (CPI-U West for January of the calendar year for the price in Table 6 in OAR 340-273-9000 that is currently in effect / CPI-U West for January 2024).

According to OAR 340-273-0900, the CCI funds are then to be invested in projects that:

- Reduce anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT CO2e per CCI credit distributed by DEQ;

- Reduce emissions of other air contaminants that are not greenhouse gases, particularly in or near environmental justice communities in Oregon;
- Promote public health, environmental, and economic benefits for environmental justice communities throughout Oregon to mitigate impacts from climate change, air contamination, energy costs, or any combination of these; and
- Accelerate the transition of residential, commercial, industrial and transportation-related uses of fossil fuels in or near environmental justice communities in Oregon to zero or to other lower greenhouse gas emissions sources of energy in order to protect people, communities and businesses from increases in the prices of fossil fuels.

CCI credits can be issued by DEQ upon receipt that the funds were paid to the CCI Entity and can be used for compliance any time after their date of issue, regardless of whether the funds have been spent or accomplished the purposed outlined above.

Covered entities, like NW Natural, are limited in the amount of CCIs that may be used for compliance in each period. In compliance period one (2025-2027) CCI use is limited to 15 percent of NW Natural's compliance obligation. In compliance period two (2028-2029) and beyond, CCI use is limited to 20 percent of NW Natural's compliance obligation.

Despite the CPP taking effect on January 1, 2025, CCI credits are not available for purchase and no CCI Entities have been named. Therefore, it is currently unknown which entity (or entities) will receive CCI credit dollars, what projects those entities would pursue, the emissions reductions associated with those projects, or what happens if the cost of emissions reductions is greater or lower than the price of CCI credits—which have already been set by rule.

7.3.2 Washington Compliance Offsets

Under the Washington CCA, the Legislature authorized the use of compliance offsets as an alternative compliance tool. Compliance offsets must meet specific guidelines outlined in WAC 173-446-500. Until the CCA links with another cap and trade program, all compliance offsets must provide a direct environmental benefit to the state. After linkage, 50 percent of the compliance offsets may be located in a linked jurisdiction. All compliance offsets must adhere to approved offset protocol, as outlines in WAC 173-446-505, and be issued by an approved offset program registry.

Covered entities are limited in their ability to use offsets to cover their compliance obligation. In compliance period one (2023-2026) covered entities, such as NW Natural may only satisfy up to five percent of their compliance obligation. An additional three percent of its compliance obligation can be met by offset projects located on federally recognized tribal land. In compliance period two (2027-2030) and beyond, the amount of offsets allowed for compliance

decreases to four percent with an additional two percent allowed from projects located on federally recognized tribal land.

7.4 Low to Zero Carbon Fuels

In recent years, there has been significant progress in the technologies and markets for various types of decarbonized gases. Biofuel-based resources, commonly known as Renewable Natural Gas (RNG), are one well-known type of low- or zero-carbon gas, as biogas has been utilized for decades for direct heating or power generation. However, new technologies have created new opportunities for decarbonized gases. Hydrogen generation from various sources has advanced significantly; projects are currently being developed to inject both pure hydrogen into gas lines and produce synthetic methane by combining clean hydrogen with waste CO2. Below is a discussion of the main types of low-carbon gases that NW Natural is currently considering as compliance resources.

7.4.1 Biofuels

Biofuel gas or RNG is pipeline-quality gas derived by cleaning up the raw biogas emitted as organic material chemically breaks down. RNG entering NW Natural's system must adhere to specified quality standards, containing at least 97.3 percent methane and an energy content of at least 985 Btu/SCF. Once integrated into NW Natural's or any gas utility's system, RNG is interchangeable with conventional natural gas.

Figure 7.3: Raw Biogas Sources Example

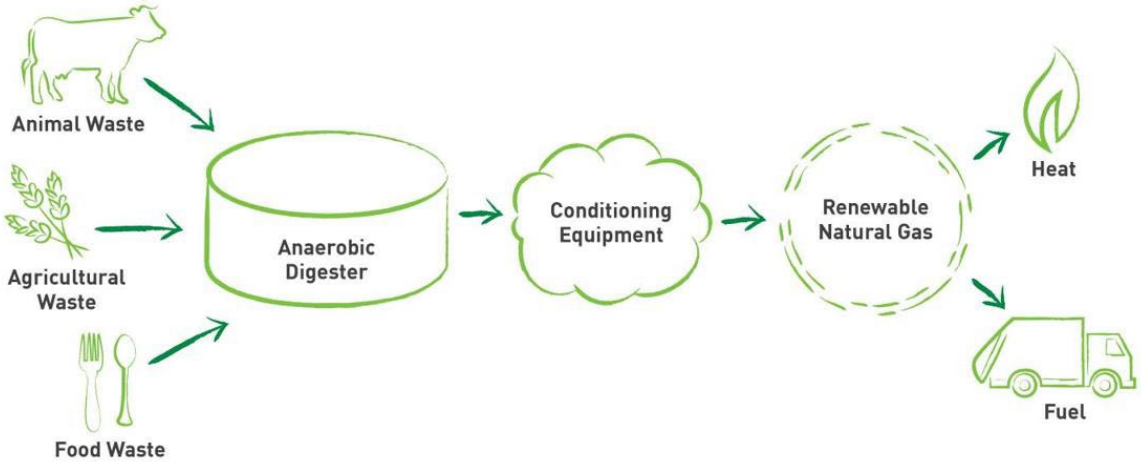
Oregon RNG was defined in 2019's Senate Bill 98 (SB 98) as:

> [A]ny of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; Hydrogen gas derived from renewable energy sources; or Methane gas derived from any combination of: Biogas; Hydrogen gas or carbon oxides derived from renewable energy sources; or waste carbon dioxide[176].

In Washington, per 2019's House Bill 1257, RNG "means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters." The bill further notes that "the [WUTC] may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels[177]."

[176] Oregon Senate Bill 98: https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled
[177] Washington House Bill 1257: https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20220917151937

Figure 7.4: RNG Illustration



There are many policies that drive NW Natural to procure RNG for its customers. Table 7.3 identifies the key driving policies that establish RNG goals, define RNG, and define its role in NW Natural's emissions compliance activities to secure least-cost RNG resources on behalf of its customers.

Table 7.3: Policies Driving RNG Acquisitions

Policy	Relevance for RNG
Oregon Senate Bill 98	Volumetric targets for RNG procurement for Oregon sales customers
Oregon Climate Protection Program (CPP)	Compliance will include RNG and hydrogen (above and beyond Senate Bill 98 volumes) when cost-effective to procure
Washington House Bill 1257	Established both an option for delivery for RNG to all gas customers as well as a requirement to offer customers a voluntary RNG tariff
Washington Climate Commitment Act (CCA)	Sets emissions cap that applies to gas utilities, which can use RNG and hydrogen as a compliance tool
Voluntary offerings to customers	Building options in Oregon and Washington to procure greater amounts of RNG and hydrogen

The policy that has had the largest impact to date on NW Natural's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG. The law allows gas utilities to procure RNG and invest in RNG projects, provided that the *incremental* cost of such

procurement does not exceed five percent of the company's annual revenue requirement. The calculation for what costs are incremental is discussed later in this chapter.

Under Senate Bill 98 gas utilities can purchase RNG (including hydrogen) for all customers as part of the utility's resource mix. It also allows gas utilities to invest in and own the equipment necessary to bring raw biogas and landfill gas up to pipeline quality, as well as the facilities to connect to the local gas distribution system. Senate Bill 98 describes the voluntary volumetric targets for both large and small gas utilities (NW Natural is classified as a large gas utility). It is worth noting that although the volumetric targets increase by five percent every five years, there is no corresponding increase in the percentage of the revenue requirement for RNG spends in SB 98, thereby limiting the amount of RNG procured by spend vs. volume given today's RNG prices.

Senate Bill 98 has been instrumental in the Company being a leader in the procurement of RNG among gas utilities and to develop programs and build a team around the development and procurement of RNG. This technical and market knowledge can now be applied to NW Natural's compliance and planning under programs such as the Climate Protection Program, Washington House Bill 1257, and the Washington Climate Commitment Act.

7.4.1.1 Emissions Benefits of Renewable Natural Gas

There are several ways to evaluate the emissions of RNG. Both Oregon and Washington's laws relating specifically to procurement of RNG by gas utilities do not set parameters around prescribed carbon intensity of RNG because the carbon dioxide that is emitted when RNG is combusted is biogenic—derived from and stored by organic matter—meaning that the combustion of it does not add any additional carbon into the carbon cycle. Therefore, under these legal frameworks, NW Natural treats RNG to be carbon neutral. NW Natural reports its emissions in both states on a "combustion basis," which reflects the view that the carbon in RNG is biogenic, and thus the carbon emitted when combusted is not reported. This same approach is used by the U.S. Environmental Protection Agency, the International Energy Agency, and the Intergovernmental Panel on Climate Change, which all recognize that because the CO2 in biogas is biogenic, it is appropriate to not report that carbon in RNG when reporting emissions.

There are other programs in the United States that use a different approach to measuring the emissions reduction benefits of RNG. These programs use lifecycle-based methodologies, which look at the total emissions embedded in the entire lifecycle of fuel's production and utilization. These programs are mostly found in transportation fuels, which have several different types of fuels and use the lifecycle-based approach to evaluate these fuels on an apples-to-apples basis. This approach derives a carbon intensity (CI) of a fuel and includes considerations of the

methane emissions that would have occurred had the RNG project not been constructed, how efficient the use of the fuel is in the end use (e.g., how efficient is a certain motor?) and other aspects. Each fuel is given a carbon intensity score, which can vary from month to month or year to year, depending on local policies that address methane emissions, project performance, etc. NW Natural does not use carbon intensity scores to evaluate RNG resources because the utility's compliance environment uses combustion-based emissions treatment. However, NW Natural does record the carbon intensity score of its resources and reports it in its annual Senate Bill 98 reports. Oregon's rules for Senate Bill 98 require annual reporting of the carbon intensity of RNG and reporting for Washington for RNG delivered as part of a House Bill 1257 program requires similar data.

The carbon intensity of a resource using the lifecycle-based approach will vary depending on the raw feedstock, the process used, the efficiency of the equipment, etc. State-level clean fuels programs are the most advanced programs in evaluating and tracking the carbon intensity of RNG using this approach.

In Oregon, NW Natural's compliance under the Climate Protection Program will be measured in part via the data reported in the Oregon Greenhouse Gas Reporting Program, which may include book and claim accounting in addition to RNG directly injected into NW Natural's system. Oregon DEQ notes that "…accounting for biomethane and hydrogen is done using "book and claim" accounting. Under the book and claim accounting model, the environmental attributes (either accounting for lifecycle or combustion basis) of the gas are detached from the physical molecules…"[178]. This approach—separating the environmental attributes of the RNG from the physical delivered gas—is the standard used throughout the RNG industry, including in the U.S. Environmental Protection Agency's Renewable Fuel Standard, the Oregon Clean Fuels Program, Oregon Senate Bill 98, and the California Low Carbon Fuel Standard. As noted earlier, under SB 98 and the OR GHG Reporting Program NW Natural is required to report the carbon intensity of all RNG resources utilizing the lifecycle approach, but carbon intensity is not used for compliance under the Climate Protection Program. Instead, the Climate Protection Program exempts the combustion emissions from biomass-derived fuels, including RNG.

7.4.1.2 Other Benefits of Renewable Natural Gas

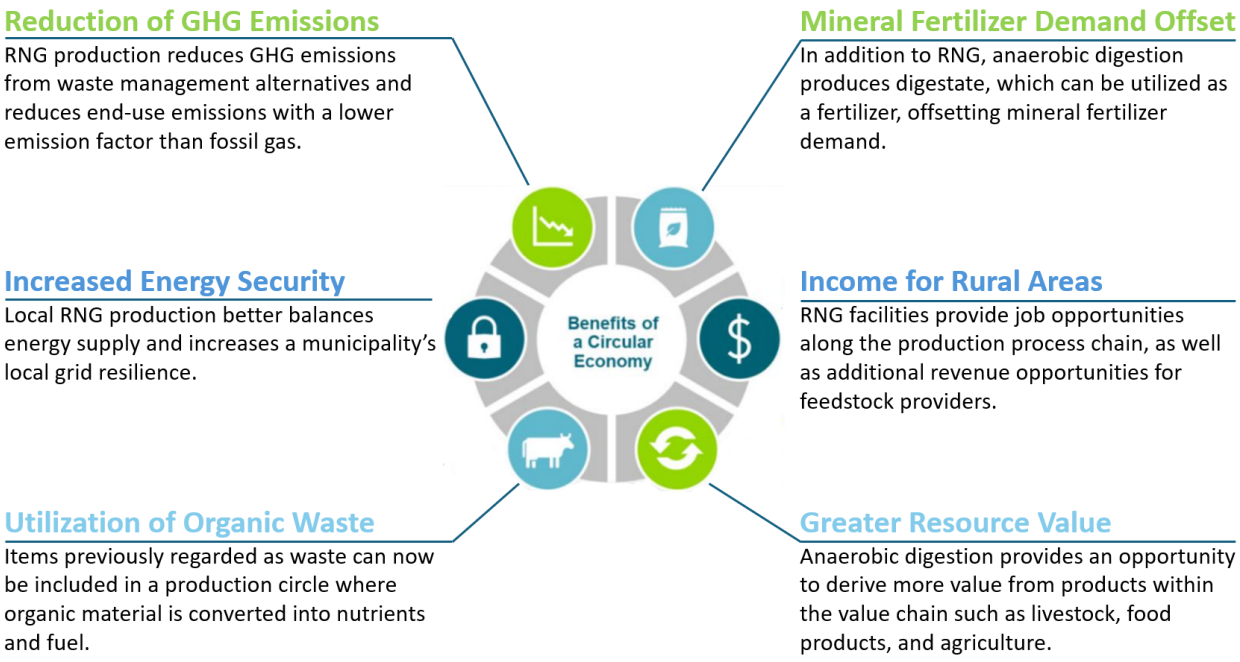
As shown in Figure 7.5, integrating renewable gases into a gas system offers numerous compound benefits beyond emissions reductions, such as:

- Displacing anthropogenic carbon dioxide emissions from fossil fuel combustion
- Enhancing energy security

[178] https://www.oregon.gov/deq/ghgp/Documents/BiomethaneProtocol.pdf

- Providing additional environmental benefits through improved organic waste management
- Increasing resource value and income for rural areas
- Reducing the demand for conventional fertilizers

Figure 7.5: RNG's Role in the Circular Economy



Source:
https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/6759c68149f2b8344218466e/1733936777572/RNG+Market+Today-+A+Primer.pdf

7.4.1.3 Renewable Thermal Certificates

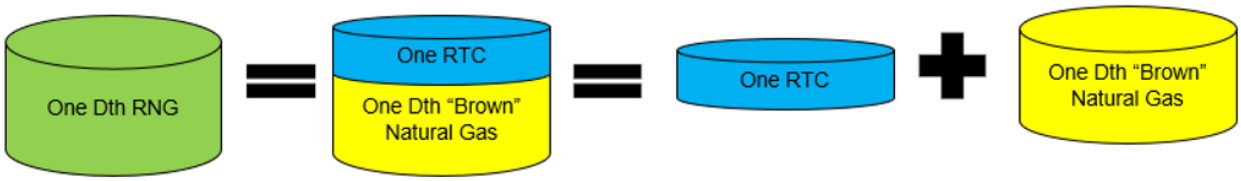
To track the environmental attributes of RNG and ensure that the benefits are not being claimed by multiple parties, the RNG industry uses the generation of "renewable thermal certificates" (RTCs) to track and record RNG transactions. Regardless of whether RNG is purchased bundled with or without the underlying physical gas, RTCs are recorded to ensure the environmental attributes of the gas are appropriately tracked.

An RTC is a sole claim to the environmental benefits of a dekatherm (Dth) of thermal energy from sources such as RNG, hydrogen or synthetic methane, and is separate from the physical gas (i.e., unbundled RNG or hydrogen). Renewable Thermal Certificates are procured to meet compliance needs and to provide an auditable pathway of how NW Natural is procuring renewable resources on behalf of its customers. The Midwest Renewable Energy Tracking

System (M-RETS), which has historically tracked the sale of electricity-based renewable energy credits (RECs) has emerged as the leading platform on which RTCs are tracked and recorded.

One RTC is created for every Dth of RNG produced and injected into the "common carrier" natural gas network or an LDC's distribution system. See Figure 7.6 for an illustration of how this separation occurs.

Figure 7.6: Tracking RTCs



NW Natural purchases both bundled and unbundled RNG resources. Bundled resources means that NW Natural is purchasing the physical molecules and the RTC together; unbundled means that NW Natural is purchasing the RTC only. Both are recognized as compliant resources under Senate Bill 98 and the Oregon Climate Protection Program. Contracts for RNG are either contracts for physical gas with special transaction confirmations and other elements that delineate what a producer will deliver, including RTCs entered into M-RETS as part of their contractual obligations, the RTCs only, or environmental attributes of RNG only.

7.4.1.4 Renewable Natural Gas Supply

The supply of renewable natural gas (RNG) has recently become, and remains, a significant topic of research and evaluation as the industry matures. More potential buyers are seeking to understand the types, quantities, and economics of available RNG supplies.

The Coalition for Renewable Natural Gas announced in June 2025 a major milestone in the growth of the renewable natural gas industry, with over 500 facilities now operational across North America. This achievement represents a significant leap from September 2024, when the North American RNG industry celebrated the establishment of 433 facilities[179]. While there has been healthy growth in the RNG market in recent years, there is still much more RNG that can be developed than what is already developed. Organizations such as the Oregon Department of Energy[180] and the American Gas Foundation[181] have published information regarding the

[179] https://www.rngcoalition.com/news/2024/9/12/north-american-rng-surpasses-400-operational-facilities
[180] https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf
[181] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

potential for RNG development. In addition to these sources, a literature review on forecasts of RNG availability and price is available in Appendix E.

There are numerous opportunities for RNG development in the Pacific Northwest. Volume, feedstock type and supplies, and proximity to natural gas infrastructure influence the viability of constructing these projects. NW Natural, like many other stakeholders, would prefer to source RNG from local supplies and would welcome development of projects such as the Wenatchee, WA landfill or the Clatsop County, OR biodigester.

NW Natural is a leader in RNG procurement and project development among gas utilities in the United States and Canada. In previous years, NW Natural considered the transportation fuel sector to be its primary competitor for low-cost RNG, due to the highly lucrative credit markets available to those sectors. However, in recent years other gas utilities and large commercial and industrial gas users have identified RNG as a critical resource for their decarbonization goals and targets and have begun to enter the market and buy RNG under both medium term (five years) and long-term (ten years+) contracts. NW Natural has internal RNG origination resources and have maintained active project origination and development efforts for several years. These activities and the company's annual RFP process for RNG will continue to help the Company identify cost-effective RNG resources in the future. NW Natural is able to offer longer-term contracts than most other market participants, and its credit rating allows it to be viewed as an extremely low-risk offtaker or purchaser of RNG by project developers and owners.

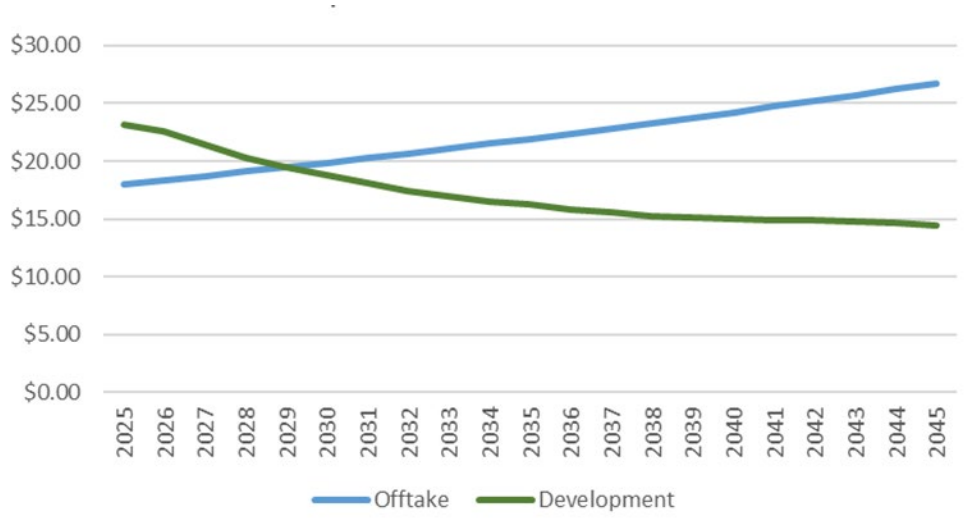
The cost of RNG on a dollar per MMBtu basis varies significantly depending on whether the project is a development by a utility itself or is an offtake-only opportunity. For utility development projects, the costs reflect the full scope of production, including financing, capital expenditures for equipment, ongoing operating expenses, and development costs such as legal and permitting fees. These projects benefit from economies of scale and avoid developer markups. Capital costs do increase with production volume; however, they do so at a slower pace, meaning the per-unit cost of RNG decreases as production capacity expands.

In contrast for offtake-only opportunities, the pricing is largely market-based. NW Natural typically purchases RNG from the non-vehicle fueling sector. However, the market lacks price transparency, making it difficult to assess costs directly. To mitigate this uncertainty, NW Natural relies on an annual RFP process to gather and analyze market data, allowing the company to make more informed decisions on the offtake opportunities it pursues. This approach helps ensure that NW Natural secures competitive pricing while maintaining flexibility in sourcing.

Figure 7.7 conveys the average cost of RNG, differentiating between development and offtake opportunities. Development opportunities are generally more cost effective than offtake opportunities as:

- Average RTC cost goes down over life with asset being depreciated
- Long term supply is enabled with development projects at low escalating price
- Revenue requirement to customers over life is substantially less
- Average RTC price goes up with offtake price increasing over life of contract

Figure 7.7: Development versus Offtake RTC Cost



7.4.1.5 Renewable Natural Gas Procurement

Oregon Senate Bill 98, Washington HB 1257, the Oregon Climate Protection Program, and the Washington Climate Commitment Act all underscore the need for NW Natural to secure low carbon gases, including biofuel-based RNG and hydrogen resources. While each program takes a slightly different view of RNG definitions, cost caps, etc., NW Natural endeavors to secure resources that it believes will work within a variety of policies, regulations, and other programs. For instance, all the RNG procured to date under Senate Bill 98 will also offer compliance benefits under Oregon CPP. As noted earlier, the Oregon DEQ has stated that off-system RNG, which is typically tracked via RTCs, will qualify as a resource under the Oregon CPP.

Renewable natural gas projects take several years to develop. NW Natural keeps track of projects at a variety of times in their lifespans. For instance, projects are sometimes in very early stages of development, with no definitive agreements or interconnection agreements signed, when they come to the company's attention. A developer may contact NW Natural

about buying the RNG, and NW Natural will express interest but convey that NW Natural cannot enter true negotiations until the project has a clear pathway toward full development. NW Natural may enter non-binding letters of intent (LOIs) and non-binding term sheets with developers and project owners. Only a small number of these resources become actual contracted resources but entering into these non-binding agreements allows the Company to learn more about the resource, exercise its due diligence, and assess the costs and benefits of a project. This is similar to how other utility projects are assessed, where there is initial investigation/origination, targeted due diligence, and then recommendations for an investment or resource selection.

Projects must be continually evaluated, which makes it difficult to put specific resources into an IRP. Typically, NW Natural must decide to enter into definitive agreements within a set timeline (e.g., within 90-day exclusivity period, or in response to a formal bid process with a hard deadline). Additionally, all projects, regardless of timing or whether they are identified through the RFP process are evaluated on the same metrics, which include incremental cost to customers, project risks, volume availability, etc.

NW Natural utilizes in-house origination resources as well as its external relationships in the industry to identify new potential RNG resources. An annual request for proposal process is also used to evaluate offtake opportunities in the market and understand the breadth of renewable resources that might be available. Figure 7.8 and Table 7.4 summarize the 2024 RFP responses.

Figure 7.8: 2024 RFP by Feedstock

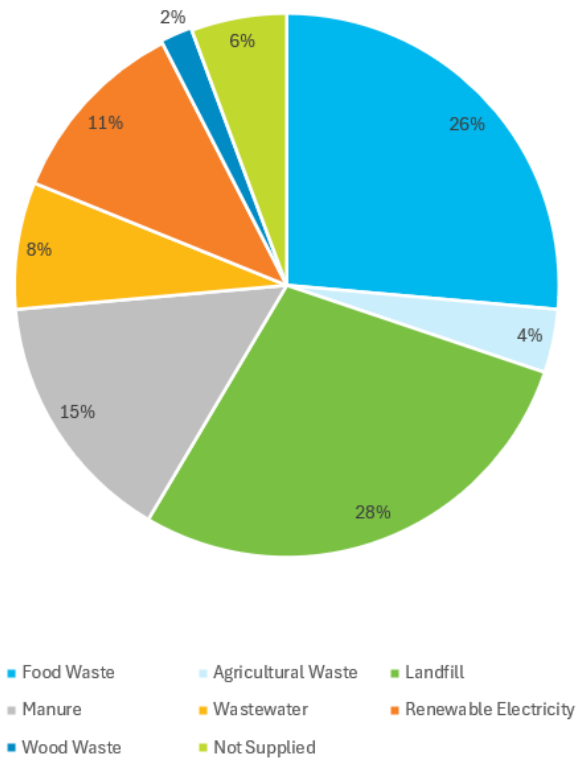


Table 7.4: 2024 RFP Responses- Summary

2024 RFP Response Summary	
Total Responses	53
Average Contract Term	15
Average Annual Volume of Resource	716,363 MMBtu
Bundled vs. Unbundled	38% / 62%

The 2025 RFP, issued on May 15, 2025, marks NW Natural's sixth annual call for RNG resources. Shortlisted respondents were notified in late July 2025 and further due diligence on these proposals began in July and will continue through August 2025. Final agreement negotiations will begin in the summer.

Between rounds of RFPs, NW Natural additionally evaluates resources on a rolling basis. This includes a rolling evaluation of other offtake resources as well as a rolling evaluation of RNG development opportunities. For development opportunities, the following agreements and activities are common during NW Natural's rolling evaluation process:

- Non-disclosure agreements signed to collect initial data
- Non-binding term sheets agreed to explore economic agreements with feedstock owners, developers, project owners, etc.
- Extensive diligence processes undertaken to assess project economics and risks, including technical, legal, regulatory, financial, environmental, etc.

Current RNG contracts will be discussed later in this chapter.

7.4.2 Hydrogen

Hydrogen is evaluated as a compliance resource option as it provides the needed emissions reductions for NW Natural customers similarly to RNG. The use of hydrogen has many benefits including: its compatibility with current gas system operations, increasing the diversity of supply sources, the ability to deliver high temperature energy (critical for industrial process loads), the potential to support new vehicle fuel demand (trucking, aviation, marine), and the ability to store energy long term at a low cost.

7.4.2.1 The Hydrogen Rainbow

Hydrogen can be sourced from many feedstocks and processes, including electrolysis of water, gasification or pyrolysis of woody biomass, reforming or pyrolysis of methane, and cracking of imported ammonia. There are many types of hydrogen, and the colors (see Table 7.5) represent the base source, production method, and products.

NW Natural is open to exploring all low-carbon sources of hydrogen inside and outside the region.[182]

[182] Gray hydrogen is presented for informational purposes only. As it is not a low-carbon source, NW Natural is not exploring this as an option.

Table 7.5: Hydrogen Sources[183]

	Gray Hydrogen	Blue Hydrogen	Turquoise Hydrogen	Green Hydrogen	Pink Hydrogen
Process	Steam methane reforming	Steam methane reforming with carbon capture sequestration	Reforming methane into hydrogen gas and elemental (solid) carbon	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen
Source	Methane	Methane	Methane	Renewably-generated electricity	Nuclear electricity generation

Regardless of the type of hydrogen that is produced or purchased, hydrogen molecules can be blended into existing pipelines and used by buildings, and commercial appliances. Studies and testing of hydrogen blends show a 20 percent by volume blend of hydrogen into natural gas distribution systems results in no significant safety, appliance compatibility, or leakage

[183] Each source of hydrogen carries a carbon footprint from a lifecycle perspective. Green hydrogen carries the carbon intensity of the energy used to create the electricity and build and maintain the associated generation infrastructure, blue and turquoise sources have up- and mid-stream methane emissions or CO2 sequestration efficiencies, etc. These carbon intensities depend on a number of design and production factors and can range from near-zero to the hundreds of grams of CO2 per MJ of energy. The Inflation Reduction Act provides hydrogen production tax credits (PTCs) based on the carbon intensity of the gas, as measure on a lifecycle basis using the GREET software created by Argonne National Laboratory. The PTCs are highly skewed towards the lowest carbon intensities possible:
Based on carbon intensity ($0.60/kg base credit, **5x** if prevailing wages & apprenticeship requirements met):
•0.45kgCO2/kgH2: 100% ($3.00/kg or $22/MMBtu)
•0.45-1.5kgCO2/kgH2: 33.4% ($1.00/kg or $7.43/MMBtu)
•1.5-2.5kgCO2/kgH2: 25% ($0.75/kg or $5.57/MMBtu)
•2.5-4.0kgCO2/kgH2: 20% ($0.60/kg or $4.46/MMBtu)

Any given hydrogen production pathway could be anywhere in this range of carbon intensities depending on the capital costs of the project. For example, electrolytic hydrogen using electricity from a coal generation plant could be on the lower end of carbon intensities using significant carbon capture infrastructure. The incentives to minimize the carbon intensity to obtain the maximize PTC are very high, and at a minimum, all hydrogen projects are expected to meet the definition of Clean Hydrogen as outlined in the Inflation Reduction Act, with the highest level being produced with emissions of 4kgCO2e/kgH_2 or less.

issues.[184,185] In addition to the distribution systems servicing homes and business, there is potential for hydrogen to have dedicated systems for large industrial processes currently relying on natural gas. These dedicated systems would flow 100 percent hydrogen that is completely separated from existing distribution systems delivering hydrogen/natural gas blends and would continue to provide the required energy for a large industrial customer.

Several natural gas distribution companies are exploring 100 percent hydrogen distribution systems as a natural evolution of the gas system:

- Northern Gas Networks (UK)[186]
- ATCO (Alberta, Canada)[187]
- Alliander (The Netherlands)[188]
- Clean Energy, part of the Holthausen Group (The Netherlands)[189]

One-hundred percent hydrogen distribution systems generally require new appliances and equipment for customers; however, the low distribution system pressures and material may well be compatible with 100 percent hydrogen, and the systems themselves create interesting opportunities for large amounts of decarbonization, distributed hydrogen generation not reliant on natural gas flows (blending), and customer net metering for production of hydrogen and storage in the gas system for later use when needed.

7.4.2.2 Power-to-gas

Power-to-gas (P2G), also referred to as green hydrogen or electrolytic hydrogen, describes a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen. Power-to-gas produces useful hydrogen that can be used as an energy source onsite (as in a fuel cell) or as mentioned above, blended into a gas grid to produce energy that is very similar to typical natural gas.

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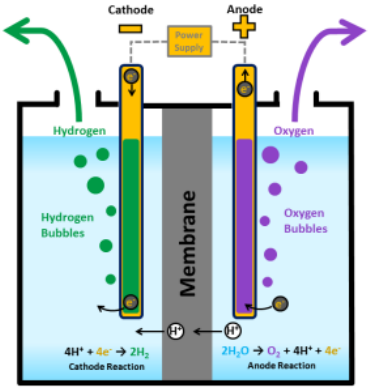
[184] Oxford Institute for Energy Studies, *Oxford Energy Forum: The Role of Hydrogen in the Energy Transition, Issue 127*, May 2021. Available at: https://www.oxfordenergy.org/publications/oxford-energy-forum-the-role-of-hydrogen-in-the-energy-transition-issue-127/ [Accessed 13 Feb. 2025].
[185] MacKinnon, M., et al., *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure*, 2020. Available at: https://www.researchgate.net/publication/339420288_Hydrogen_leaks_at_the_same_rate_as_natural_gas_in_typical_low-pressure_gas_infrastructure [Accessed 13 Feb. 2025].
[186] https://www.northerngasnetworks.co.uk/about-us/current-business-plan/our-hydrogen-home-welcome-to-green-gas/
[187] https://gas.atco.com/en-ca/community/projects/albertas-first-hydrogen-home.html
[188] https://www.bdrthermeagroup.com/stories/bdr-thermea-hydrogen-pilot-lochem
[189] https://northerntimes.nl/pilot-programme-to-heat-homes-with-hydrogen-to-begin-in-wagenborgen-in-groningen/

Figure 7.9 shows the basic reaction that occurs within an electrolyzer during electrolysis. An electrolyzer uses electricity to conduct this process, and if the electricity is sourced from zero-carbon resources, the entire production of hydrogen and oxygen is virtually zero-emissions.

Figure 7.9: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis



Source: U.S Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

7.4.2.3 Power-to-gas Existing Technologies and Trends

There are three primary electrolyzer technologies that are available today for power-to-gas applications. These are:

- Alkaline
- Proton exchange membrane (PEM)
- Solid oxide (SOE)

Of these technologies, alkaline electrolyzers have been in operation much longer than the other two. They are also less expensive than the other technologies, and more efficient in their production of hydrogen. However, PEM technologies have advantages over alkaline electrolyzers such as faster ramp-up times and a smaller footprint. SOE technology is less developed but offers the distinct advantage of using heat as one of the inputs to generate hydrogen, so it could potentially offer a productive use for existing waste heat resources. The choice of electrolyzer depends on the situation and the way it will be operated.

Europe and Asia have been leading the way with power to gas installations; some notable electrolyzer installations recently include:

- 24MW PEM electrolyzer installed at Herøya, Norway for decarbonization of ammonia in 2024
- 10MW PEM electrolyzer installed near Wesseling, Germany for decarbonization of chemicals

- 2MW PEM electrolyzer installed in Yokohama, Japan for e-methane production
- Five 5MW alkaline and one 2MW PEM electrolyzers (total of 27MW) installed in Daye, China for industrial decarbonization

7.4.2.4 The Economics of Power-to-gas for the Direct-use Natural Gas System

When P2G is utilized as a supply-side resource for the direct-use natural gas system, its economics are driven primarily by technology costs (i.e., electrolyzer and methanation facility costs), the price of electricity used as a feedstock, and how often the built facility is used to produce deliverable gas. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

The previously mentioned ICF Low Carbon Fuel Alternative Resources and Offsets report goes into great detail around the various inputs that influence hydrogen production from Power-to-gas. The report outlines the various technologies, electricity sources, and applicable tax credits and ultimately provides cost estimates for green hydrogen. These estimates were refined and simplified for use in the PLEXOS® modeling presented later in this IRP.

7.4.2.5 Methane Pyrolysis

Methane pyrolysis (also referred to as turquoise hydrogen), is a method of producing hydrogen from natural gas. In traditional steam methane reforming (SMR), natural gas is combined with high-temperature steam to produce hydrogen, but this process also generates carbon dioxide as a byproduct, contributing to greenhouse gas emissions. Methane pyrolysis, on the other hand, involves breaking down methane into its constituent elements in the absence of oxygen typically at temperatures above 700°C to produce hydrogen and solid carbon, without the production of carbon dioxide.

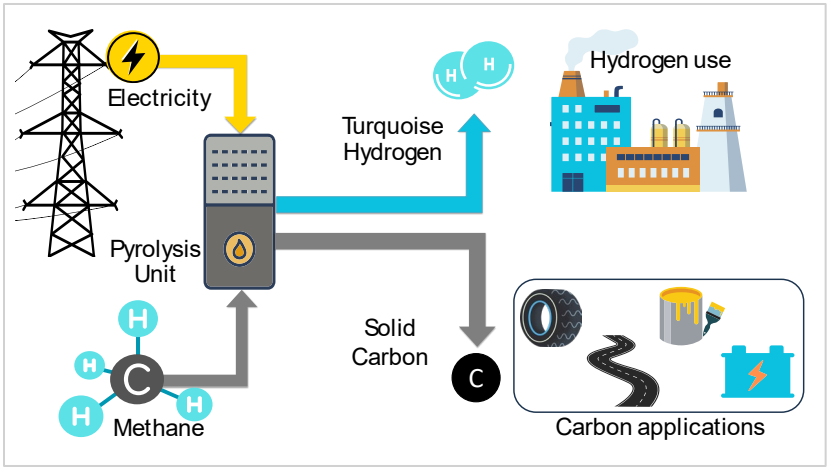
The high temperatures needed to pyrolyze the natural gas can be achieved through different processes, including thermal, microwaves, and plasma torches, further adding catalysts to decrease the amount of energy needed and to increase efficiency.

- Thermal processes use heat from the combustion of natural gas, hydrogen, or other fuels, and can use electricity as well.
- Microwaves and plasma torches use electricity to heat natural gas and typically have the advantage of ramping up and down quickly, which is advantageous for changing customer demands.

Hydrogen produced from fossil natural gas using methane pyrolysis is therefore a low-emission resource, since no/minimal amounts of CO2 are emitted. The hydrogen can even have negative emissions when paired with RNG as the source of energy. The solid carbon produced as a byproduct can potentially be used in various applications and products, including asphalt and

roofing materials, concrete, batteries, tires, aerospace materials, and more. This usefulness can create additional revenue to reduce the overall cost of the hydrogen; however, the value is directly tied to the type of carbon produced. This is shown in the illustration in Figure 7.10.

Figure 7.10: Hydrogen Schematic



The methods of methane pyrolysis and associated reaction conditions (e.g., pressure, temperature, on a surface or in the gas flow, etc.) dictate the molecular structure and consistency, which leads to the carbon classification. Graphene, Nanotubes, Carbon Black, and other types of carbon can be produced. There are a wide range of values; graphene can sell for $2,000/kg or more, while Carbon Black sees prices at around $2/kg.

There are significant advantages to turquoise hydrogen compared to other clean hydrogen production methods.

The existing gas system can be used to deliver energy to customers as it does today with hydrogen being produced on-site just before or behind the meter. Hydrogen blending or 100 percent dedicated hydrogen pipelines can deliver energy to customer equipment depending on their process needs and available equipment directly by the gas utility. This can lead to much more efficient decarbonization and decreased technology risk for NW Natural and its customers. It enables quicker scale up of hydrogen usage and can enable waste heat recovery for various processes on-site as well. Turquoise hydrogen requires no sequestration geology and is therefore not limited by geography. It also does not require any water usage, it is flexible in its input energy supplies, and initial modeling suggests it could be a very cost effective decarbonization resource compared to other options available to NW Natural.

There are considerations to turquoise hydrogen that NW Natural is analyzing, including increased system capacity demands, carbon management and markets, and technology

maturity. The solid carbon that is removed from the natural gas stream has potential chemical energy; the carbon could be burned, thereby releasing its potential chemical energy as heat. This stored chemical energy that is locked into the solid carbon is energy that would have been delivered to customers in the form of natural gas. Therefore, more natural gas is required to deliver the same amount of energy to any given customer as the energy from combusted natural gas. The total amount of energy needed on the input side is approximately double the original amount due to this removal of energy. This increases the required natural gas delivered to the methane pyrolysis site, which increases demands on distribution infrastructure, pipeline capacity, and purchased molecules. If these resources are not available all the time, in lieu of modifying them it is conceivable that designs and customer equipment would need to be able to accommodate switching back and forth from using hydrogen back to natural gas.

Efficient and safe carbon management is critical to the success of turquoise hydrogen projects. The carbon often exists as a fine powder and significant on-site storage, or frequent removal needs to be available. For every kg of hydrogen produced, three kg of carbon is produced, and at utility scales significant amounts of carbon are produced, which can have downward pricing effects on existing carbon commodities. However, these large amounts of various types of carbon create opportunities for new carbon markets that can take advantage of low-cost carbon and favorable physical and chemical characteristics.

There are approximately 30 turquoise hydrogen technology companies and entities in the world today, with more coming online every month. These start-up companies are in various stages of product development, funding, and commercialization. Some of these companies will succeed whereas some will fail due to market forces and their abilities to access funding, technical resources, and being at the right place at the right time. This nascent market structure presents risk when gas utilities are considering deployment of turquoise hydrogen and benefiting from its low cost of decarbonization. Technology and commercial risk can be mitigated by using third parties to test the equipment before it is delivered to customer sites and have payments based on meeting performance goals. In addition, minimal capital deployments are being planned for the concrete pads, utility connections, etc. to accommodate the turquoise hydrogen units. Carbon removal service agreements will be put in place to create pay-for-performance transactions and ownership of the units will remain with the technology providers. Coupling this with having multiple technology providers at the ready decreases commercial and technology risk even further.

7.4.2.6 Modern Hydrogen Pilot

In 2022, NW Natural entered into an agreement with Modern Hydrogen (then Modern Electron) to host one of its pilot units for evaluation. This will help the company evaluate

additional methane pyrolysis technologies and help mature and grow the technology to enable wide-spread usage to decarbonize its largest customers as efficiently as possible. The equipment was designed to produce five kg of hydrogen per day and the total term of the lease agreement is three years. During this time, NW Natural is evaluating the following:

- Availability and reliability of the technology
- Capabilities of Modern Hydrogen as a company to produce and support methane pyrolysis technology
- Efficiency of the natural gas to hydrogen conversion process
- Carbon storge and handling
- Safety of the technology
- Hydrogen metering and greenhouse gas reporting

The project has been well-supported by Modern Hydrogen to date and has been presented to numerous groups, including labor, elected officials, visiting utilities, etc. to educate them on the technology and decarbonization benefits for gas utilities.

The pilot project is expected to wrap up in 2026 and depending on what is learned and future developments in the methane pyrolysis space, NW Natural may pursue additional pilots.

Figure 7.11: Modern Hydrogen Pilot

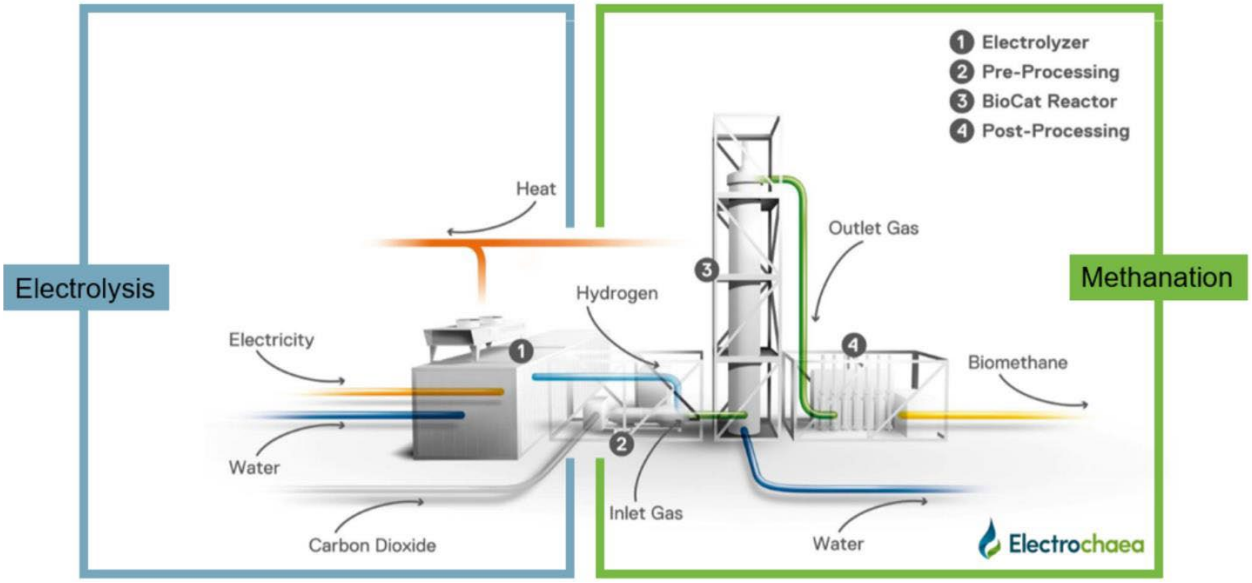
7.4.3 Synthetic Methane

Synthetic methane is a manufactured fuel that is designed to be a substitute for natural gas. It can be produced from biomass and hydrogen through different processes, each with unique advantages for sustainability and carbon neutrality.

7.4.3.1 Synthetic Methane - Hydrogen

Green hydrogen can be combined with waste CO2 to produce synthetic methane (also referred to as synthetic natural gas, methanated hydrogen, power-to-X, or e-methane) using chemical or biological processes, as depicted in Figure 7.12. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15 percent of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

Figure 7.12: Synthetic Methane Production Process Using Biogenic Methanation



Synthetic methane does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection into transmission lines have; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found.

In addition, RNG projects which have low-cost electricity nearby are also being explored for synthetic methane "bolt-on" projects, as RNG has the requisite low-cost and steady waste CO2 supply. By adding synthetic methane to RNG projects, almost twice the amount of gas can be produced at the site while leveraging the existing gas interconnect and compression infrastructure, thereby significantly decreasing the cost of low-carbon energy at the site.

Green hydrogen can be combined with waste CO2 to produce synthetic methane (also referred to as synthetic natural gas, methanated hydrogen, power-to-X, or e-methane) using chemical or biological processes, as depicted in Figure 7.12. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15 percent of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

7.4.3.2 Synthetic Methane - Woody Biomass

Synthetic Methane can be produced from woody biomass through thermochemical or biochemical processes that break down lignocellulosic materials into hydrogen-rich gases. The primary methods include:

- **Gasification:** Biomass is heated in a controlled oxygen environment to produce syngas (a mix of hydrogen, carbon monoxide, and methane). The hydrogen is then separated and purified.
- **Pyrolysis with Reforming**: Biomass is heated in the absence of oxygen to produce bio-oil, which is then reformed into hydrogen.
- **Biological Processes**: Certain microorganisms produce hydrogen through fermentation, though this method is less commercially viable.

Woody biomass, including forest residues, logging slash, and mill waste, is an abundant and renewable feedstock, making it a promising resource for hydrogen production. Oregon is well-positioned for hydrogen production from woody biomass due to several key factors, including abundant biomass supply, need and willingness to address wildfire risks, and aggressive natural gas system decarbonization goals.

Woody biomass plants could be positioned to take full advantage of the 45V tax credit, as the biogenic feedstock should elicit the full $3/kg$H_2$ amount (approximately $22/MMBtu). This tax credit would likely be needed to make this pathway viable due to the high capital costs of the

production plants and the relatively high feedstock costs. Gathering and transporting forest floor detritus and slash to a central location would be required.

To further decrease the cost of hydrogen or RNG sourced from woody biomass, the CO_2 that is produced from the process can be sequestered in subsurface storage reservoirs. This process decreases the carbon intensity of the energy and either allows for the sale of these green attributes in other markets to offset costs or it can be used to increase the amount of decarbonization coming from the plant.

Woody biomass projects could provide multiple wins for the state and NW Natural is monitoring pilots throughout the country to understand the costs and opportunities for this resource in the future. See Appendix M for NW Natural's proposed feasibility study for synthetic methane from woody biomass.

7.4.4 Renewable Natural Gas and Hydrogen Evaluation Methodology

The 2018 IRP included the nation's first comprehensive methodology to evaluate the cost-effectiveness of low-carbon gas supply resources and sought acknowledgement of this methodology in Oregon. This request resulted in the OPUC opening a docket (OPUC Docket No. UM 2030) for review of the proposed methodology. This process resulted in a modified methodology that was approved by the OPUC to evaluate low carbon gas supply resources. Also, as was previously mentioned a voluntary renewable gas portfolio standard (SB 98) passed in Oregon, and the resulting rules to implement the program included a placeholder for the evaluation methodology based upon the methodology acknowledged in the most recent IRP. NW Natural has been using this methodology to evaluate the incremental cost of potential resources to comply with climate policy in both Oregon and Washington.

As NW Natural has gained experience in the RNG market, NW Natural has made improvements to the methodology and modeling tools, resulting in a process that aligns with the realities of the RNG market. The following improvements have been made to the Incremental Cost Workbook: Avoided costs are updated annually, a new scenario tab was created where critical variables can be adjusted outside of the fifth and 95th percentile (capital expenditures, operations and maintenance costs, production), an investment tax credit scenario was created, and an on-system bundled model was created to simplify inputs and outputs which reduces the amount of formulas to track. The methodology is included in detail in Appendix K.

In addition, NW Natural added a risk scoring matrix to the offtake evaluation process which is designed to not only assess the risk of an opportunity but also help determine if contractual remedies might be warranted if the opportunity progressed to contract execution. Each opportunity is evaluated and assigned a score for seven risk categories as outlined in Figure

7.13. Those scores are then combined for a total risk score and risk categorization as outlined in Figure 7.14.

Figure 7.13: RNG & Hydrogen Opportunity Risk Matrix

	1	2	3	4	5
Finance risk	Fully financed	Funding has been secured and project is currently under development	Project can be internally financed by developer. Alternatively, project has financing agreement (e.g., primary lender, and tax equity as appropriate) with credible funding source with joint commitment to proceed	Negotiations underway for financing	Not financed
Constructability risk	In operation	COD within 12 months	In construction and/or major equipment is ordered	Design complete	Design not complete
Counterparty risk	Counterparty has bond rating in good standing, no legal issues	Counterparty does not have bond rating but can supply positive financial records	minimal data available, but no negative reports	Legal issues have been identified or poor bond rating	Unknown entity or bankrupt
Marketability	D3 RINs eligible and negative CI score	D3 RINs eligible	D5 eligible and negative CI score	D5 RIN eligible	No other market eligibility
Commercial Terms/ Legal risk	Fixed volumes that can be supplied by seller's portfolio at same price	Minimum volumes that can be supplied by seller's portfolio at same price	remedies included	Ability to exit contract if minimum quantities are not met for an extended period of time	No contract minimums, no remedies
Bidder Experience	Multiple successful projects and experienced staff	Minimum of on operating project and experienced staff	Minimum of one operating project	Similar projects in construction	No successful projects
Gas/Interconnect/Feedstock rights	All rights obtained	2/3 rights obtained, third in progress	2/3 rights obtained	1/3 rights obtained	No rights obtained

Figure 7.14: RNG & Hydrogen Opportunity Risk Score

Total	Color	Result
23 to 30	Red	Not moving forward
13 to 22	Yellow	Must have minimums or contract remedies
<12	Green	Would sign without contractual remedies

7.5 Current Renewable Natural Gas Projects

NW Natural has six current renewable natural gas RTC offtake agreements and two development projects (see Table 7.6 for details). In 2024 NW Natural retired 739,487 RTCs from RNG project(s) on behalf of customers.

Table 7.6: Current RNG Contracts

Projects [190]	Feedstock	Type	Start Date	Term (yr.)	CI Score (gCO2e/ MJ)	Projected Volumes (MMBtu/year)		
						2025	2026	2027
Offtake #1 (Western US)	Food Waste	Offtake	2022	5	27	73,000	66,800	
Offtake #2	Wastewater	Offtake	2022	4	45	264,780	66,195	
Offtake #3	Landfill	Offtake	2022	21	Various	1,000,000	1,000,000	1,000,000
Offtake #4	Landfill	Offtake	2025	1	TBD	660,000		
Offtake #5	Landfill	Offtake	2025	15	TBD	208,404	441,550	489,262
Offtake #6	Synthetic Methane & Dairy Manure	Offtake	2025	2	TBD	3,650	7,300	3,650
Tyson-Dakota City	Food & Brewery	Development	2023	20	21.99	98,994	116,464	116,464
Tyson-Lexington	Food & Brewery	Development	2022	20	32.57	79,112	83,067	87,221

For more information on current RNG offtakes, see Appendix E.

7.6 Carbon Capture Utilization and Storage/Sequestration

Carbon Capture, Utilization, and Storage (CCUS) encompasses a suite of technologies aimed at capturing CO2 emissions from sources such as industrial processes, power generation, renewable fuels production, direct air capture (DAC), etc., transporting the captured CO2 and either using it directly in products or as an industrial gas or storing it underground to prevent its release into the atmosphere. CCUS is emerging as a key decarbonization pathway in the portfolio of solutions to reduce greenhouse gas emissions, particularly from hard-to-abate sectors.

[190] At the request of the vendor, the Project Name has been redacted.

The process of capturing CO2 typically involves separating it from other gases produced during industrial activities. The primary methods include:

- **Post-Combustion Capture**: This technique captures CO2 from the flue gases emitted after fossil fuels are burned. It is commonly applied in power plants and involves the use of chemical solvents, such as amines, to absorb CO2 from the exhaust stream.
- **Pre-Combustion Capture**: In this method, fossil fuels are partially oxidized to produce a synthesis gas (syngas), consisting mainly of hydrogen and carbon monoxide. The carbon monoxide is then converted to CO2, which is separated, leaving hydrogen that can be used as a clean fuel. This process is used in producing blue hydrogen. Turquoise hydrogen can also be considered pre-combustion carbon capture, however, it is in a solid form and is sequestered in products or other permanent disposal methods other than injection underground as is being discussed here.
- **Direct Air Capture (DAC)**: DAC technologies extract CO2 directly from ambient air using chemical processes. Although currently more energy-intensive and costly, DAC offers the potential for negative emissions by removing existing CO2 from the atmosphere.

The chemicals (usually amine solvents) used in carbon capture systems absorb CO2 from flue gases. This reaction occurs in an absorber column where CO2-rich gas contacts the amine. The CO2-loaded solvent is then heated in a separate unit, releasing pure CO2 for storage and regenerates the amine for reuse.

The cost of capturing CO2 is significantly influenced by its concentration in the emission stream. High-purity CO2 streams, such as those from ethanol production or natural gas processing are less expensive to capture. In contrast, dilute CO2 streams from power plants or cement production are more challenging and costly to process. The energy required for capture contributes to higher operational costs, as additional fuel may be needed to power the capture systems.

Gaseous CO2 is typically converted to a liquid or a supercritical fluid for more efficient handling, storage, and transport. This step is done by compressing the gas and changing its temperature as needed. Supercritical CO2 behaves similarly to CO2 gas but has a higher density and lower viscosity than liquid CO2, which is beneficial for pipeline use and geological storage.

7.6.1 Utilization

Once captured, the CO2 is typically transported to another location where it can be used or permanently sequestered. The primary modes of transportation include:

- **Pipelines**: The most cost-effective and widely used method for transporting large volumes of CO2 over long distances. The United States has over 5,000 miles of CO2 pipelines, transporting approximately 80 million metric tons annually. Pipelines are regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to ensure safety and environmental protection.
- **Trucks and Rail**: Suitable for smaller quantities or regions lacking pipeline infrastructure. While offering flexibility, these methods are more expensive and less efficient for large-scale transport. Innovations like mobile carbon capture systems are being explored to capture and transport CO2 directly from vehicles.

Safety in CO2 transportation is paramount. Regulations exist for transport of supercritical CO2 through the Department of Transportation (DOT), Federal Railroad Administration (FRA), the American Petroleum Institute (API), and Pipeline and Hazardous Materials Safety Administration (PHMSA).

7.6.2 Sequestration

Effective and permanent storage of CO2 necessitates suitable geological formations that can securely contain the gas over extended periods. The primary types of geological formations used for CO2 sequestration include:

- **Deep Saline Aquifers**: These are porous rock formations saturated with brine, offering vast storage potential. They are widely distributed and can accommodate significant volumes of CO2.
- **Depleted Oil and Gas Reservoirs**: These formations have proven their ability to trap hydrocarbons for millions of years and can similarly store injected CO2. Utilizing these reservoirs can also leverage existing infrastructure.
- **Basalt Formations**: Rich in reactive minerals, basalts can facilitate the mineralization of CO2, converting it into stable carbonate minerals. This method is still in the early stages of development but offers promising long-term storage solutions.

The selection of a suitable storage site involves assessing factors such as depth (typically greater than 2,600 feet to maintain CO2 in a supercritical state), porosity, permeability, and the integrity of cap rocks to prevent leakage.

The concept of CO2 sequestration has evolved over several decades. One of the earliest applications was in Enhanced Oil Recovery (EOR) during the 1970s, where CO2 was injected into oil fields to increase oil production. Dedicated CO2 storage projects began to emerge in the

1990s. Various pilot and commercial-scale projects have been implemented worldwide, contributing to the maturation of CCUS technologies.

The Environmental Protection Agency (EPA) regulates the underground injection of CO2 through the Underground Injection Control (UIC) program. Class VI wells are specifically designated for the geologic sequestration of CO2 and must meet stringent criteria to ensure the protection of underground sources of drinking water, including:

- **Site Characterization**: Comprehensive analysis of the geology, hydrology, and potential pathways for CO2 migration.
- **Well Construction Standards**: Requirements for materials and construction techniques to prevent leaks.
- **Monitoring and Reporting**: Continuous monitoring of CO2 movement and pressure, with regular reporting to the EPA.
- **Post-Injection Site Care**: Ongoing surveillance after injection ceases to ensure long-term containment.
- There are currently four Class VI wells permitted by the EPA and four additional draft permits are pending. As of March 2024, there are now 130 individual well permit applications for a total of 44 projects that are currently pending at EPA[191].

While CO2 sequestration is generally considered safe, potential risks include leakage through faults, fractures, or improperly sealed wells. To mitigate these risks, several strategies are employed:

- **Site Selection**: Choosing locations with favorable geology and minimal seismic activity.
- **Well Integrity**: Ensuring robust construction and maintenance of injection wells.
- **Monitoring Systems**: Deploying technologies to detect CO2 movement and pressure changes.
- **Regulatory Oversight**: Adhering to EPA guidelines and obtaining necessary permits.

CCUS offers a pathway to decarbonize sectors where emissions are challenging to eliminate, such as cement, steel, and chemical manufacturing. While the initial costs of implementing CCUS can be high, economies of scale, technological advancements, and supportive policies can enhance its economic viability. Government incentives, such as tax credits and funding for demonstration projects, play a crucial role in promoting CCUS deployment. The United States has announced significant investments in CCUS, including $1.7 billion for carbon capture

[191] https://carboncapturecoalition.org/wp-content/uploads/2024/05/Class-VI-Fact-sheet-5.pdf

demonstration projects and $1.2 billion for direct air capture hubs under the Infrastructure Investment and Jobs Act. The 45Q tax credit currently incentivizes CCUS at the following rates:

- $85 per metric ton of CO2 permanently sequestered in:
  - Geologic storage (e.g., Class VI wells)
  - Enhanced oil recovery (EOR) (with some restrictions)
  - Utilization in certain qualified products (e.g., concrete, chemicals)
- $60 per metric ton of CO2 captured and utilized in:
  - Enhanced oil recovery (EOR) operations
  - Certain beneficial uses of CO2 (such as in algae production or chemical manufacturing)

Identifying and evaluating suitable sites for CO2 storage is essential for planning and implementing CCUS projects. The U.S. Geological Survey (USGS) and the National Energy Technology Laboratory (NETL) have developed comprehensive maps and atlases detailing potential storage formations across the country.[192] These resources provide insights into the capacity, geology, and feasibility of various regions for CO2 sequestration.

Interactive tools and databases allow stakeholders to assess storage options, plan infrastructure, and make informed decisions regarding CCUS investments. Continuous research and data collection are vital to refine these assessments and ensure the safe and effective deployment of CCUS technologies.

Carbon Capture, Utilization, and Storage represents a multifaceted approach to reducing CO2 emissions and mitigating climate change. While challenges remain in terms of cost, infrastructure, and public perception, advancements in technology, supportive policies, and increased awareness of climate imperatives are driving the growth and maturation of CCUS. As part of a comprehensive strategy, CCUS holds the potential to play a significant role in achieving global emissions reduction targets.

Oregon and Washington have favorable geology for CO2 sequestration; however, the level of exploration risk requires third party or state participation to make this happen. In addition, state decarbonization programs, such as the Climate Protection Program, would need to allow for applying these additional decarbonization activities directly to the hydrogen or RNG produced.

[192] https://www.usgs.gov/tools/geologic-carbon-dioxide-sequestration-interactive-map

7.7 Compliance Resource Study and Integrated Resource Plan Modeling

Alongside Cascade Natural Gas and Avista Natural Gas, NW Natural worked with ICF to develop the *Low Carbon Fuel Alternative Resources and Offsets for IRP Evaluation* study (see Appendix E for full report). This study (Alternative Fuels Study) developed forecasts for levelized cost, technical potential, resource life, and carbon intensity for various energy resources, including renewable natural gas, hydrogen, synthetic methane, carbon capture utilization and sequestration (CCUS), and renewable thermal credits (RTC) for Oregon and Washington. This collaboration aimed to provide a comprehensive analysis of these resources to support future energy planning and policy decisions. Understanding these factors is crucial for making informed decisions about the viability and sustainability of available decarbonization resources.

The Alternative Fuels Study covered five categories of alternatives:

- RTC Purchase
- Renewable Natural Gas
- Hydrogen
- Synthetic Methane
- Carbon Capture, Utilization, and Sequestration

Within each of these five categories the Alternative Fuels Study further examined different types of feedstocks, technologies, facility sizes, and production pathways. Table 7.7 provides a more detailed breakout of the types of alternatives examined within each of these categories.

The Alternative Fuels Study embedded 45V and 45Q tax credit[193] values into the costs of hydrogen and CCUS respectively, including the Department of the Treasury 45V final rules from January of 2025. It is assumed that these credits will be available to taxpayers in the foreseeable future. These tax credits are important for leveraging federal support to enhance the economic feasibility of clean hydrogen and carbon capture projects.

From the Alternative Fuels Study, the IRP model uses both expected results as well as stochastic results for both prices and available quantities. NW Natural will use these outcomes to model potential resource integration futures for planning consideration, ensuring that their energy strategies are robust and adaptable to various scenarios. Considering both expected and stochastic results helps NW Natural to prepare for a range of possible futures, enhancing the resilience and flexibility of their energy planning.

[193] For more information on 45V and 45Q tax credits, see https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

7.7.1 Alternative Fuels Study Price Projections Background

The cost of Renewable Natural Gas (RNG) spans a wide range due to differences in production methods, feedstock types, and regional policy treatment. RNG production costs are primarily driven by the type of feedstock used, facility design, and the technology required for upgrading and injecting gas into pipelines. However, RNG Renewable Thermal Certificate (RTC) offtake prices- the prices buyers pay- are largely determined by market dynamics, including supply and demand, regulatory policy, and the value of associated environmental credits.

Programs like California's Low Carbon Fuel Standard (LCFS), Oregon's Clean Fuels Program, and Washington's new Clean Fuel Standard assign value to RNG based on its lifecycle carbon intensity. These policy-driven markets create strong competition for environmental attributes, such as RTCs, which can be traded through book-and-claim systems. As a result, the price of RNG in the market can be significantly higher—or lower—than the cost to produce it, depending on the market value of these attributes. This divergence highlights the importance of distinguishing between RNG's production cost and its market price.

The ICF study focused on production cost modeling for each of the alternative fuel options to develop levelized costs that incorporates a utility weighted average cost of capital. These costs reflect the production costs of direct utility investment in a project, which eliminates the additional margin layer developers would require in their prices, and allow utilities to leverage lower costs of capital. These production costs models provide a bottom-up calculation of levelized costs of energy measured as $2024/MMBTU.

The levelized cost of energy (LCOE) is a measure of the average net present cost of production for a facility over its anticipated lifetime and enables the ability to compare costs across RNG feedstocks and other energy types on a consistent per unit energy basis. The LCOE can also be considered the average revenue per MMBtu produced that would be required to recover the costs of constructing and operating the facility during an assumed lifetime. The LCOE calculated as the discounted costs over the lifetime of an energy producing facility divided by a discounted sum of the actual energy amounts produced. The LCOE is calculated using the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where I_t is the capital cost expenditures (or investment expenditures) in year t, M_t represents the operations and maintenance expenses in year t, F_t represents the feedstock costs in year t (where appropriate), E_t represents the energy (i.e., MMBtu) produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

The ICF study also examined RTC offtake pricing which can deviate from production costs. To supplement the RTC offtake analysis, NW Natural also used information from the Company's 2024 RFP which solicits bids for RTC offtake agreements for near-term RTC purchase opportunities. This IRP uses these production costs and a forecast for D3 RIN prices as the basis for pricing used in the resource optimization model, however; this is a simplistic modeling approach, and the Company recognizes real world opportunities will range in cost, scale, and contract structure.

7.7.2 Aggregating Resource Options for Integrated Resource Plan Modeling

The Alternative Fuels Study provided 73 separate low carbon alternative options (see Appendix E) for full list). This includes both downscaled national and regional quantities that could be available to the Pacific NW and their corresponding prices (i.e., levelized costs), which are described in Appendix E.[194] Using the downscaled national and regional quantities, NW Natural further reduced those values as the Company applied a customer weighted value between Avista, Northwest Natural, Puget Sound Energy, and Cascade. This value is calculated to be approximately 33 percent.

In order to model these resources, NW Natural grouped resources provided by the Alternative Fuels Study into 20 proxy resources for evaluation in PLEXOS®. Table 7.7 lists all the resources that are modeled in PLEXOS® and their respective price in 2040. The resource groupings that were created from the Alt Fuel Study are indicated by the left-side column.

[194] Footnote 12 in the Alternative Fuels Study, discusses how domestic RNG production is downscale to what would be available to Pacific NW utilities.

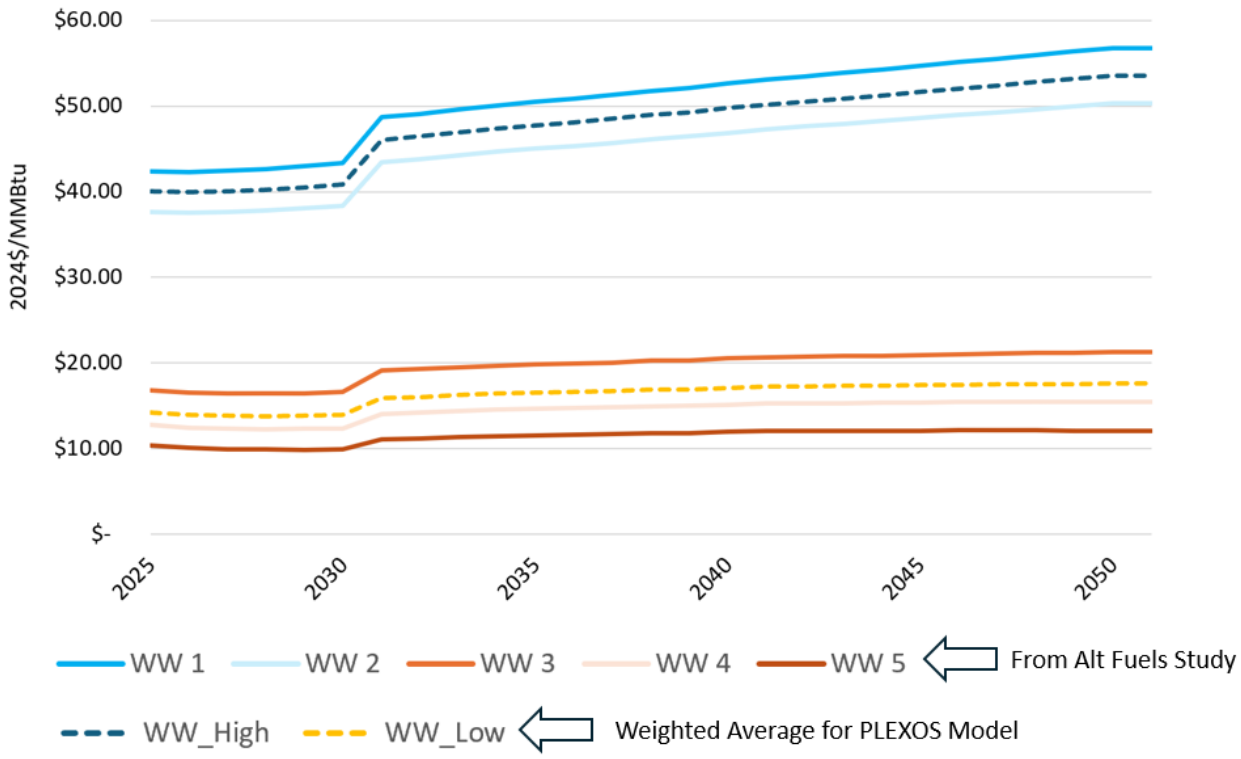
Table 7.7: Resources Modeled in PLEXOS®

	Category	Type	Costs Differentiation	2040 Costs ($2024 / Unbundled MMBtu)
	Compliance Instruments	Offsets	Base Cost	$5.32
		CCA Allowance Purchases	Base Cost	$10.40
		Community Climate Investments	Base Cost	$7.60
	Near Term RTC Opportunities	Local Water Resource Recovery Facility	Specific Cost	Not Available
		Short Term Contracts	Low Cost	Not Available
			High Cost	Not Available
		Long Term Contracts	Low Cost	Not Available
			High Cost	Not Available
Informed by Alternative Fuels Study	Long Term RTC Opportunities	RTC Purchases	Base Cost	$27.32
	Renewable Natural Gas	Land Fill Gas	Low Cost	$8.46
			Mid Cost	$16.14
			High Cost	$35.85
		Animal Manure	Low Cost	$48.88
			High Cost	$120.23
		Wastewater	Low Cost	$13.97
			High Cost	$48.62
		Food Waste	Low Cost	$56.05
			High Cost	$90.40
	Hydrogen	Green from Solar	Base Cost	$23.72
		Green from Wind	Base Cost	$36.05
		Blue Hydrogen	Base Cost	$22.57
		Turquoise Hydrogen	Base Cost	$44.10
	Synthetic Methane	Biomass	Low Cost	$19.55
			High Cost	$36.83
		Green from Solar	Base Cost	$43.15
		Green from Wind	Base Cost	$61.65
	Carbon Capture Utilization and Storage	Industrial Customers	Base Cost	$8.21
		Direct Air Capture	Base Cost	$30.79

Notes: Not Available indicates that the resource is not available for resource selection in 2040

As an example, the Alternative Fuels Study provided five resources for Wastewater (WW) that represent various facility sizes. Rather than modeling five WW resources, NW Natural summed the quantities for WW 1-2 and WW 3-5 to create WW High and WW Low, respectively. The granular resource quantities and prices were used to create weighted prices for WW High and WW Low. Figure 7.15 illustrates how the granular resources are grouped to inputs that are used in the PLEXOS® modeling.

Figure 7.15: WW RNG Gas Groups for PLEXOS® Model

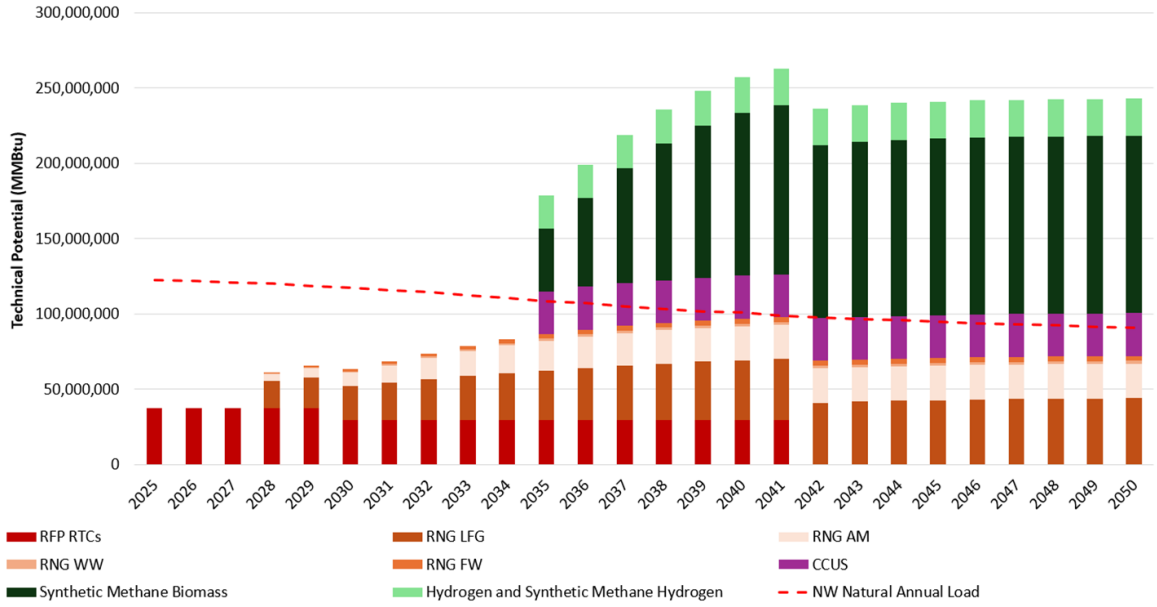


After the resources are grouped and the weighted average price is calculated, the commodity price of methane is subtracted out.[195] This yields an unbundled price, that represents the cost of the environmental attribute, which can be compared to other compliance resources such as offsets or RTC offtake purchases.

Figure 7.16 illustrates the total resources that are available for selection in the PLEXOS® model. These represent the downscaled quantities that could be available to NW Natural. In these quantities, hydrogen is capped of 20% of load by energy which accounts for both blending hydrogen into the system and industrial customers using 100 percent hydrogen. Synthetic Methane from Green Hydrogen is capped at the volumes available from green hydrogen (wind and solar respectively). PLEXOS® further constrains the models that the sum of Synthetic Methane and Hydrogen is also capped at the volumes available from Green Hydrogen. These constraints ensure that the availability of hydrogen is not double counted in the model.

[195] The Company notes that RNG projects may receive varying commodity prices depending on where in the country a project is located, however; this IRP does not speculate on project locations and uses the forecasted annual average Henry Hub gas price, a nation price benchmark for natural gas pricing, for this step.

Figure 7.16: Resource Quantities Available for Selection in PLEXOS® Model

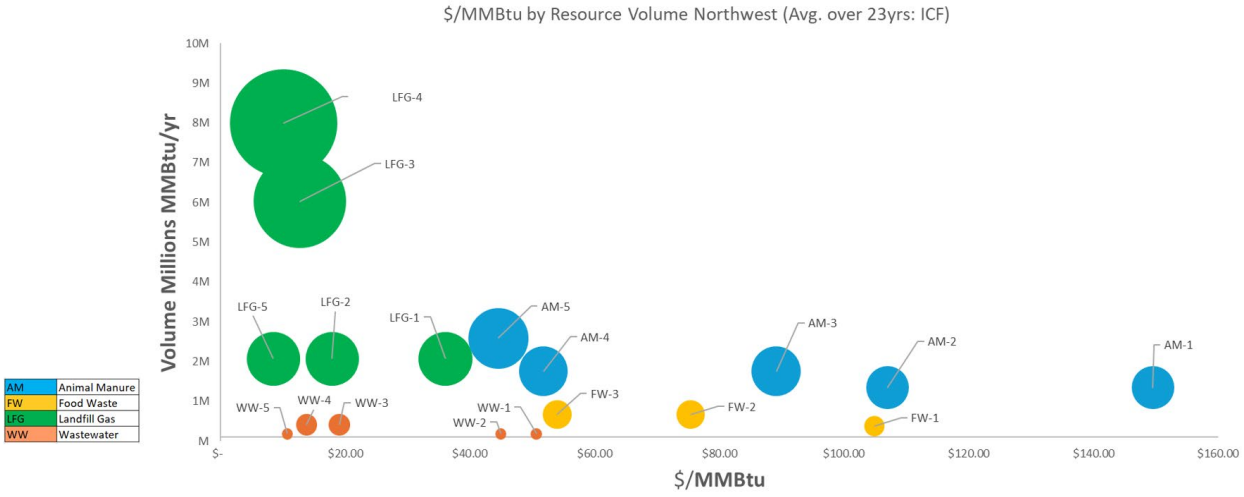


7.7.3 Renewable Natural Gas

Renewable natural gas (RNG) presents significant potential due to its interchangeability with conventional natural gas. RNG can be produced from a variety of feedstocks including animal manure (AM), food waste (FW), landfill gas (LFG), and water resource recovery facilities (WRRF; also abbreviate as wastewater (WW)). The successful implementation of RNG is largely contingent on the accessibility of biomass feedstocks as well as advancements in production technologies.

Figure 7.17 summarizes the granular results from the Alternative Fuels Study where the size of each circle helps convey the total volumes associate with each type.

Figure 7.17: ICF RNG Potential

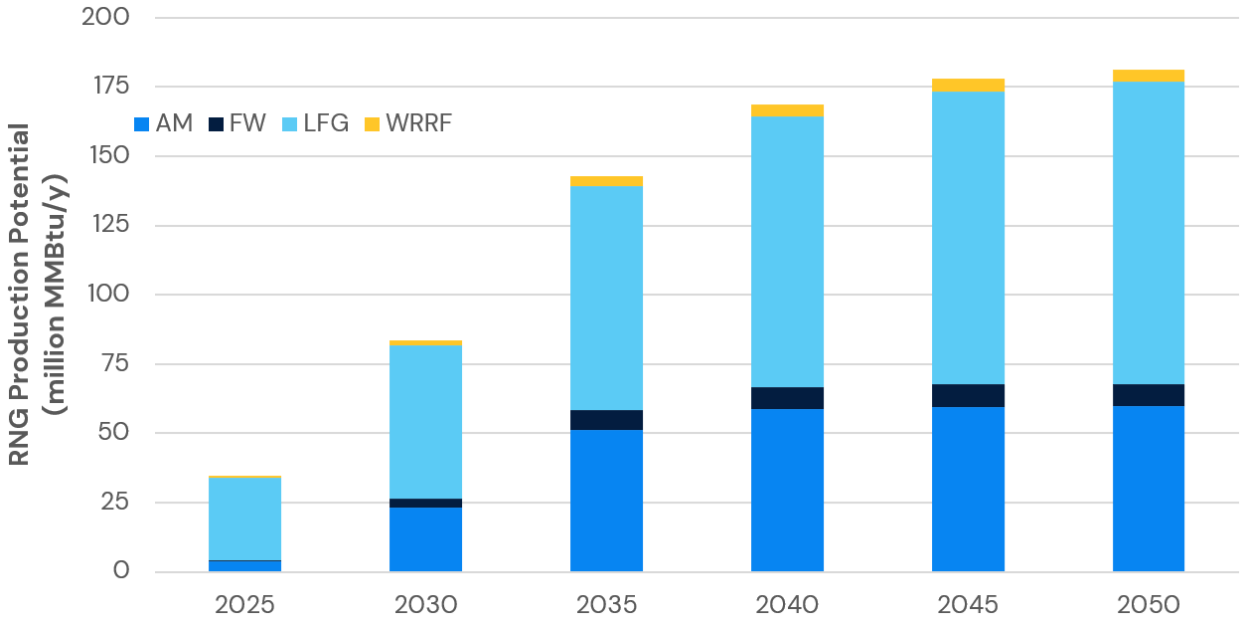


Different sized RNG facilities were modeled and are indicated by the numbers besides each resource with one (e.g., *LFG-1*) representing smaller facilities and higher numbers (e.g., *LFG-5*) representing larger facilities. This graph helps illustrate the economies of scale from larger scale RNG production sites.

7.7.3.1 Renewable Natural Gas Potential

The Alternative Fuels Study assumed that the Utilities would have substantial access to the resources designated for RNG development in Oregon and Washington. Additionally, ICF assumed that the Utilities would have a population-weighted share of first-mover access to national resources. Note that British Columbia and Québec were included as first movers as well due to their strong RNG policies and significant procurement of US-based RNG. Based on these assumptions, it is concluded that the Utilities are likely able to access roughly 13 percent of the total domestic RNG production. Figures 7.18 summarizes the maximum RNG potential for each feedstock (Animal Manure, Food Waste, Landfill Gas, and Water Resource Recovery Facilities) and production technology in Oregon and Washington.

Figure 7.18: RNG Resource Potential Projection Base Case Results (OR & WA)[196]



7.7.3.2 Renewable Natural Gas Levelized Cost

Tables 7.8 and 7.9 summarize the maximum RNG LCOE for each feedstock and production technology in Oregon and Washington and at the national level. These tables reflect how the range of facility sizes that can drive a wide range of per unit prices. The Alt Fuel Study assumed the investment tax credit (ITC) for RNG production is available and extended through 2030.

Table 7.8: RNG Levelized Cost Projection Base Case Results (Oregon and Washington, $/MMBtu)[197]

RNG Feedstock	2025	2050
Animal Manure	$35-$119	$50-$172
Food Waste	$42-$81	$61-$119
Landfill Gas	$7-$30	$10-$42
Water Resource Recovery Facilities	$10-$44	$12-$59

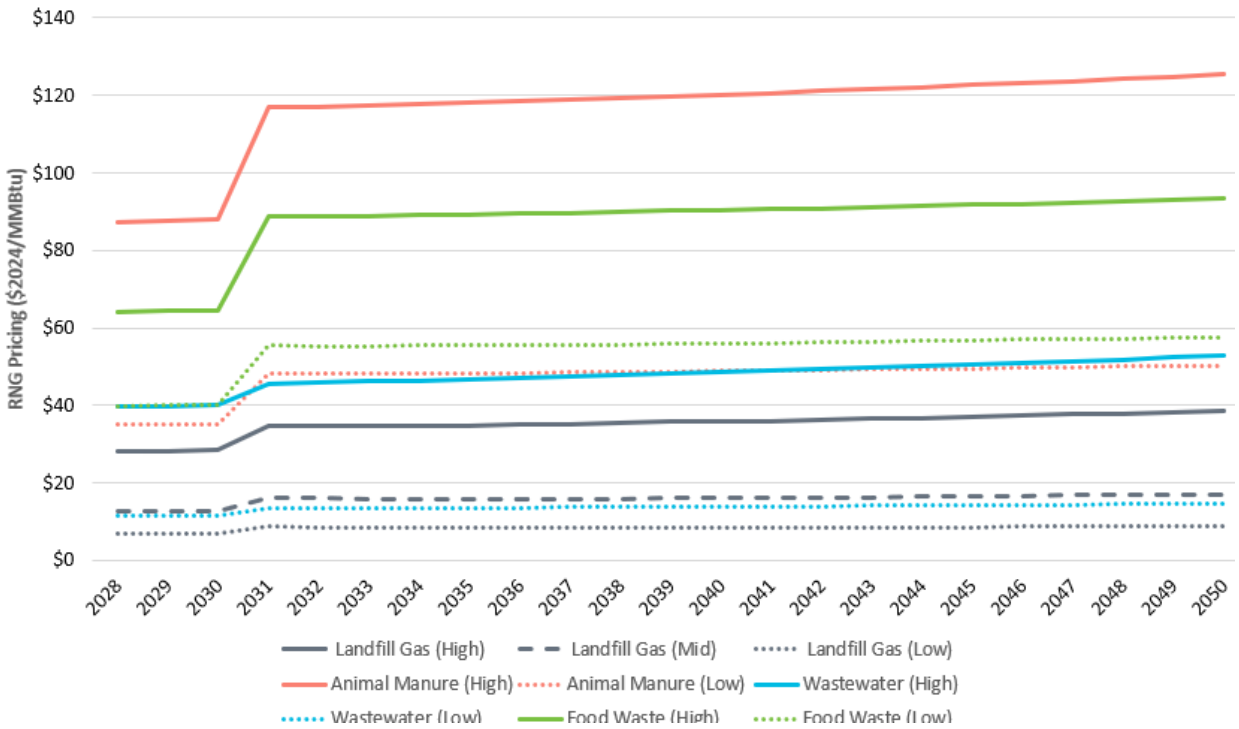
[196] See Alternative Fuels Study in Appendix E
[197] See Alternative Fuels Study in Appendix E

Table 7.9: RNG Levelized Cost Projection Base Case Results (National, $/MMBtu)[198]

RNG Feedstock	2025	2050
Animal Manure	$36-$120	$51-$172
Food Waste	$43-$83	$62-$120
Landfill Gas	$8-$31	$10-$43
Water Resource Recovery Facilities	$11-$45	$13-$60

While Tables 7.8 and 7.9 show the full costs for a bundled product, Figure 7.19 shows the unbundled prices paths for the aggregated categories for RNG being used in the Company's resource optimization model.

Figure 7.19: ICF Estimated Pricing for RNG ($2024/Unbundled MMBtu)[199]



This IRP also analyzed a specific local water resource recovery facility and is modeled to be available for resource selection in 2027. The unique timing of contract negotiations with this

[198] See Alternative Fuels Study in Appendix E
[199] See Alternative Fuels Study in Appendix E

local water resource recovery facility has allowed NW Natural to be able to incorporate this specific project into the full IRP analysis.[200] This project would be connected directly to NW Natural's system and provide approximately 0.05 percent of Oregon's sales load to NW Natural. Levelized costs for project are estimated to be similar the Wastewater (Low) category as shown in Figure 7.19. Relative to other RNG opportunities, via NW Natural's RFP process and current RNG portfolio, this project provides the lowest-cost RNG, while delivering local economic investment (see Appendix M for more details).

7.7.4 Hydrogen

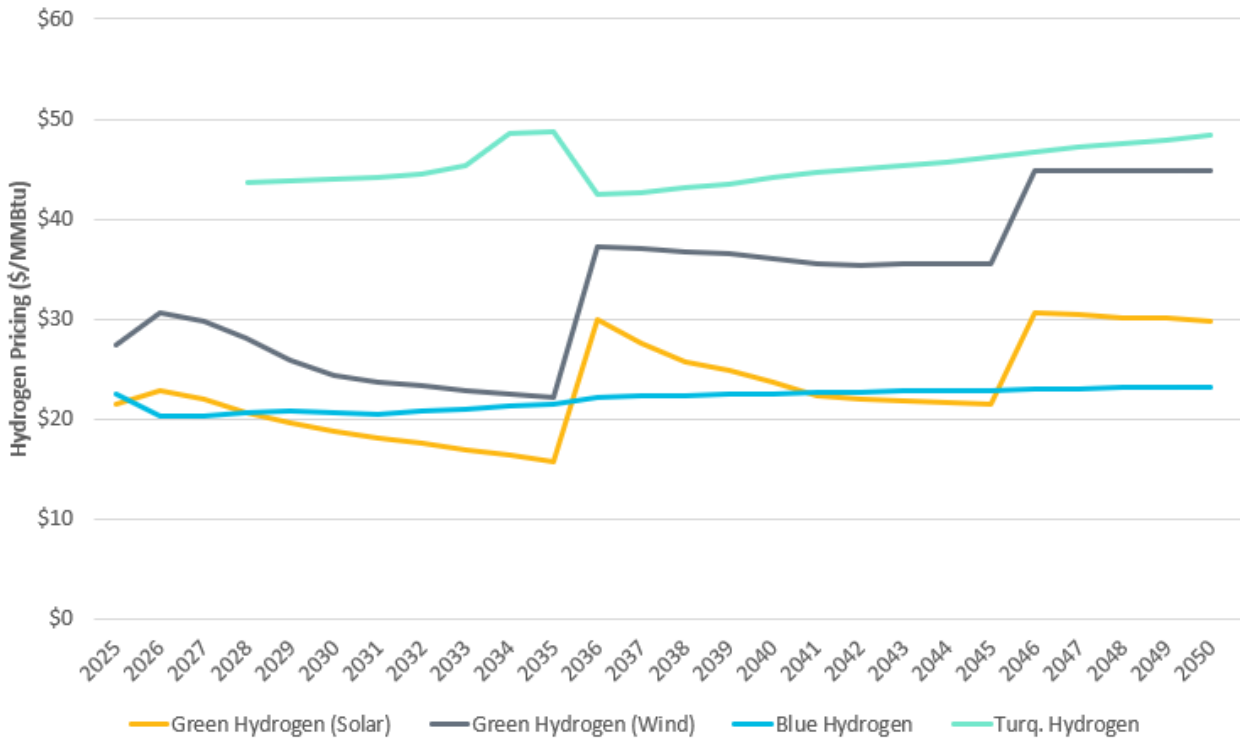
Hydrogen projections examined various feedstocks and carbon intensity ranges, denoted by different coloring scales; Green being from electrolysis using electricity from either solar or wind, Blue being natural gas or RNG from steam methane or autothermal reforming with 97 percent carbon capture and storage, Turquoise being natural gas and RNG from methane pyrolysis, and Pink being nuclear energy. Although Pink hydrogen was examined in the Alternative Fuels Study, it was not considered as a compliance resource for this IRP.[201]

This detailed modeling helps to understand the potential environmental and economic impacts of different hydrogen production methods, which assists in the evaluation of hydrogen as a viable low-carbon energy source. Evaluating different hydrogen types allows for a more nuanced approach to integrating hydrogen into the energy mix as different sources may become available sooner than others with varying costs and supply locations.

Given the most recent Treasury guidance on 45V not allowing blends of decarbonized gas to qualify a hydrogen production facility for the 45V tax credit, Blue Hydrogen and Turquoise Hydrogen resources were reduced to the last tier of credits ($0.60 for CI scores between 2.5 and four kgCO2e/kg H2) in NW Natural's modeling. The Alternative Fuels Study was complete prior to this ruling, however; NW Natural has updated the costs to Blue Hydrogen and Turquoise Hydrogen as depicted in Figure 7.20. Note the sudden price increases due to tax credits ending at times prescribed in statute.

[200] Contract negotiations are still on-going, and some contract specifics may still change.
[201] NW Natural will continue to monitor the development of pink hydrogen, but notes that the costs for pink hydrogen relative other alternatives are sufficiently high that it would not be selected as compliance resource even if it was included for any scenario or sensitivity.

Figure 7.20: ICF Estimated Pricing for Hydrogen ($2024/ Unbundled MMBtu)[202]

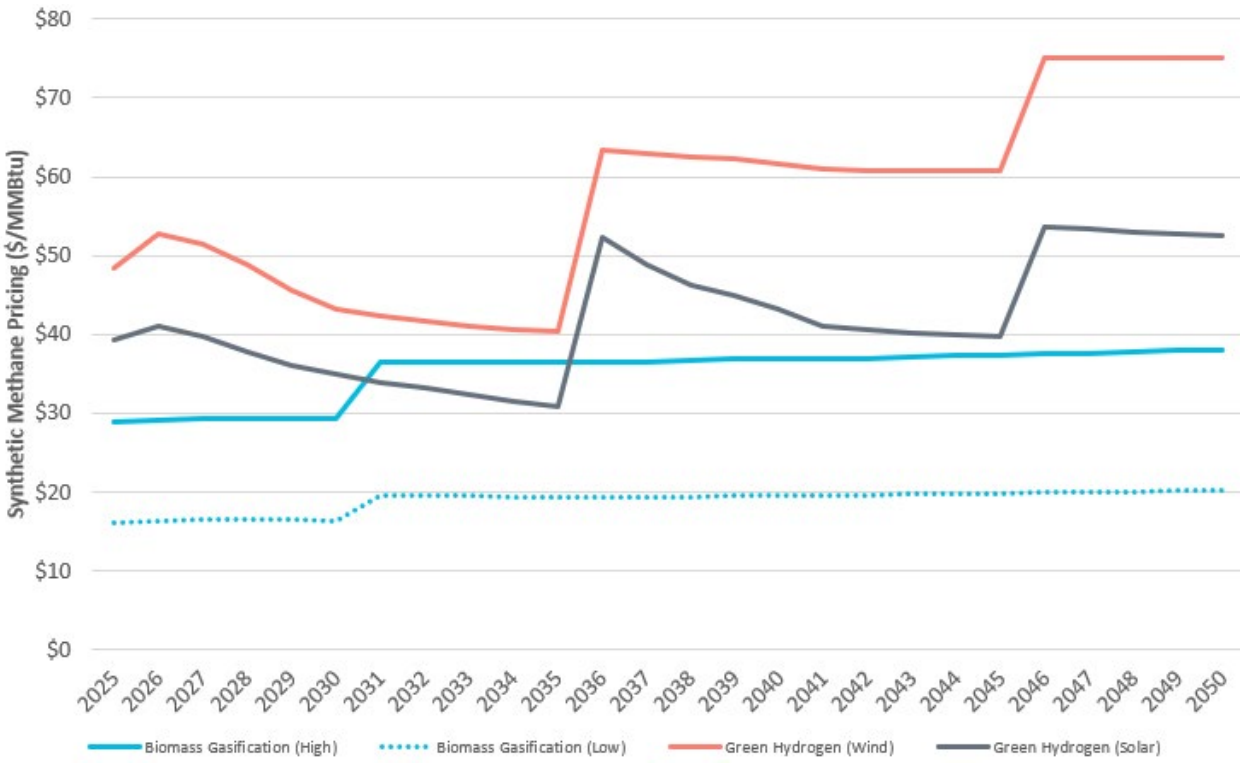


7.7.5 Synthetic Methane

Synthetic methane includes two different subcategories: methanation of syngas (CO and H_2) produced from gasification or pyrolysis of biomass, and catalytic methanation of green electrolytic hydrogen with biogenic CO2. Limits were placed on the amounts of synthetic methane volumes based on biogenic feedstocks and renewable electricity availabilities. Similar to varying hydrogen sources, looking at different synthetic methane pathways provides a richer analysis of this resource given differing availabilities and volumes over time. Figure 7.21 shows the unbundled price paths for each type of synthetic methane being used in in the resource optimization model.

[202] See Alternative Fuels Study in Appendix E. Graph uses base case prices.

Figure 7.21: ICF Estimated Pricing for Synthetic Methane ($2024/Unbundled MMBtu)[203]



7.7.6 Renewable Thermal Certificate

In renewable energy markets, a Renewable Thermal Certificate (RTC) verifies the environmental attributes of generating and using renewable thermal energy. M-RETS[204] issues one RTC for every Dth of verified renewable energy recorded on the platform. These certificates can be bought, sold, or retired by different organizations. NW Natural purchases RTCs to match the gas it supplies to customers, even though the actual renewable gas is used elsewhere. This is called a "book-and-claim" system -where the environmental benefit (or "green attribute") is separated from the physical gas and assigned to NW Natural through a contractual claim. The renewable gas is used locally near the production site, but the green attribute is applied to the traditional gas NW Natural delivers. The RTC projects are not developed by the utility and therefore include additional margins from other entities which increase costs.

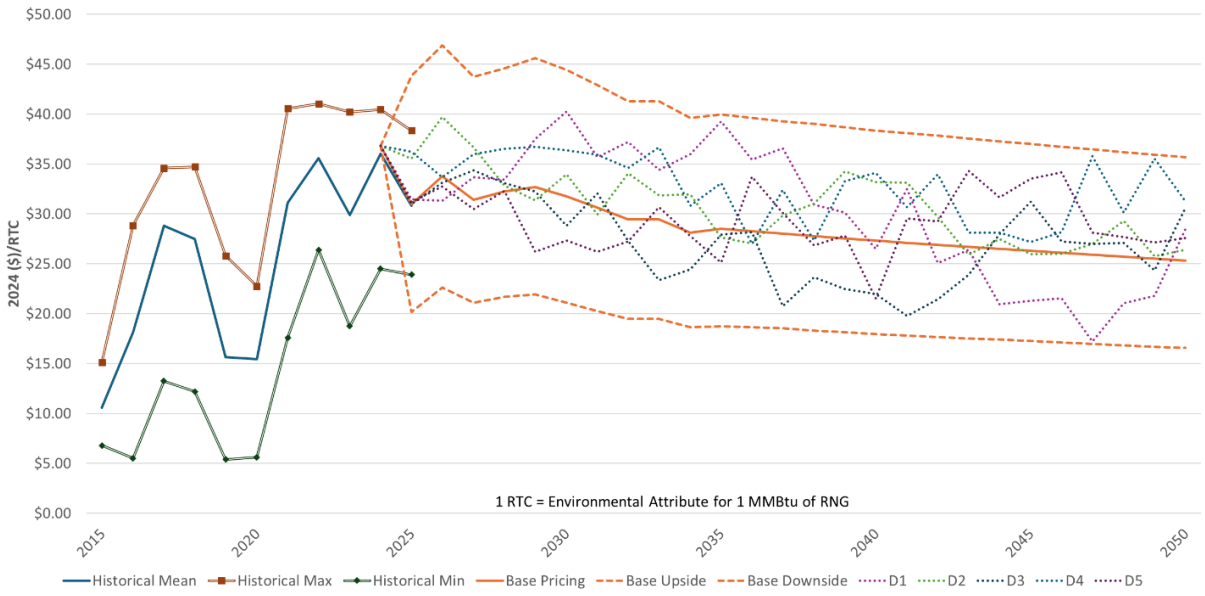
It is challenging to readily identify pricing and volumes within the RTC market. To address this issue, ICF opted to use environmental commodity pricing from the Renewable Fuel Standard

[203] See Alternative Fuels Study in Appendix E
[204] M-RETs is a nonprofit organization governed by an independent and multi-jurisdictional board of directors.

(RFS) as a benchmark. Under the RFS framework, RNG derived from most feedstocks qualifies as a cellulosic biofuel and is categorized as a D3 RIN. According to multiple data sources, RTC prices have historically traded at a discount relative to D3 RIN values.

ICF leveraged the forecasted D3 RIN pricing to develop a range of pricing that may be used for RTC benchmarking for the foreseeable future. As RNG demand in the non-transportation sector (e.g., for Utilities) increases significantly above RNG demand for on-road transportation, the D3 RIN will no longer serve as predictive benchmark. However, the D3 RIN pricing shown is consistent with moderate pricing observed in the RNG supply curves and may be reflective of where pricing will fall in the mid- to long-term future. Based on this analysis, ICF's projected RTC pricing assumptions for this IRP are outlined in Figure 7.22 along with the bounds used to capture uncertainty in RTC pricing and simulated prices, discussed further in Section 7.7.9.

Figure 7.22: ICF Estimated Pricing for RTCs ($/MMBtu)[205]



RTC can be sourced from qualifying RNG, hydrogen, and synthetic methane projects that are injected into common carrier pipelines. While generally more expensive, NW Natural does not foresee any technical limitations to procuring enough RTCs to meet compliance obligations, only cost limitations.

In addition to RTC purchase opportunities that are based on ICF's estimated pricing, NW Natural also includes in its resource optimization model options for near-term RTC contract opportunities with quantities, costs, and term lengths based on RTC offtake bids from the

[205] See Alternative Fuels Study in Appendix E

Company's 2024 RFP for RNG. Bids were aggregated into four categories. Table 7.10 outlines the specifics for these resource options.

Table 7.10: Near-term RTC Contract Opportunities

Contract Type	Unbundled RTC Cost ($2024/MMBtu)	Max Quantity (MMBtu/year)	Term Length (years)
Low-cost short term	19.00	3,800,000	3
Low-cost long term	19.00	17,400,000	15
High-cost short term	24.00	3,800,000	3
High-cost long term	32.00	12,400,000	15

7.7.7 Carbon Capture Utilization and Storage/Sequestration

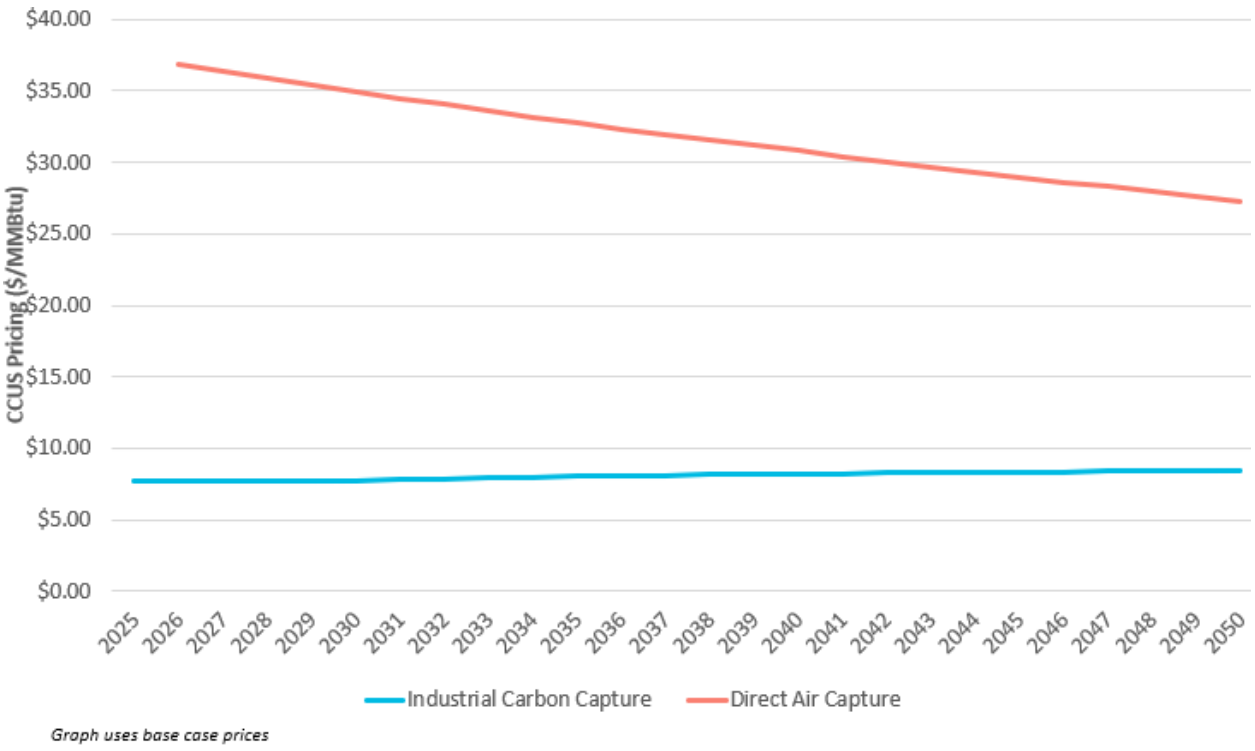
Carbon capture utilization and storage/sequestration (CCUS) prices are generally the lowest for all of the low-carbon resources analyzed by the Alternative Fuels Study. NW Natural assumed CCUS resources could be available in significant amounts as soon as by 2035 if not earlier. The Company includes the following types of CCUS into the resource optimization model; post-combustion capture and direct air capture.[206]

Post-combustion CCUS resources were modeled as being available to the load associated with NW Natural's largest 50 customers. As the study was being conducted in at the same time CPP rules were being finalized, this estimate ultimately included both EITE and non-EITE customers. Subsequent to completing the Alternative Fuels Study, NW Natural excluded loads from EITE customers in all but one sensitivity explored in Chapter 9, as only non-EITE customers would be available for applying CCUS technology and reduce NW Natural's emissions liability. Distributed carbon capture may be viable from cost and technology perspectives for smaller customers as well (i.e., not limited to the top 50 customers), which could justify another case where CCUS can be applied to a wider portion of NW Natural customers. The CCUS pilot project being proposed in the Action Plan is specifically designed to answer this question.

[206] Note that pre-combustion CCUS, as discussed in a previous section, is used in the production of blue and turquoise hydrogen and is therefore not modeled separately in the resource optimization model.

The Alternative Fuels Study also examined CCUS using direct air capture. Relative to post-combustion CCUS, CCUS from direct air capture is more expensive based on levelized costs as reflected in Figure 7.23.

Figure 7.23: ICF Estimated Pricing for CCUS ($/MMBtu of Methane Equivalent)[207]



The CCUS resource assumes geologic sequestration reservoirs and CO2 pipelines are available for distributed carbon capture or direct customer connection. Oregon has favorable geology for CO2 sequestration in the northwest corner of the state, which could be accessed relatively quickly should support for reservoir development arrive from public or private initiatives. Sequestration in basalt formations near the Gorge and across into Washington are also being explored by public and private entities alike that may be available for large-scale use in the near future.

7.7.8 Climate Commitment Act Allowances and Offsets

NW Natural relies on a third party (cCarbon) to conduct analysis and provide a forecast of CCA allowance prices and qualified CCA offset prices. The Reference Case allowance price forecast reaches the price ceiling starting in 2027 and remains at the price ceiling over the planning

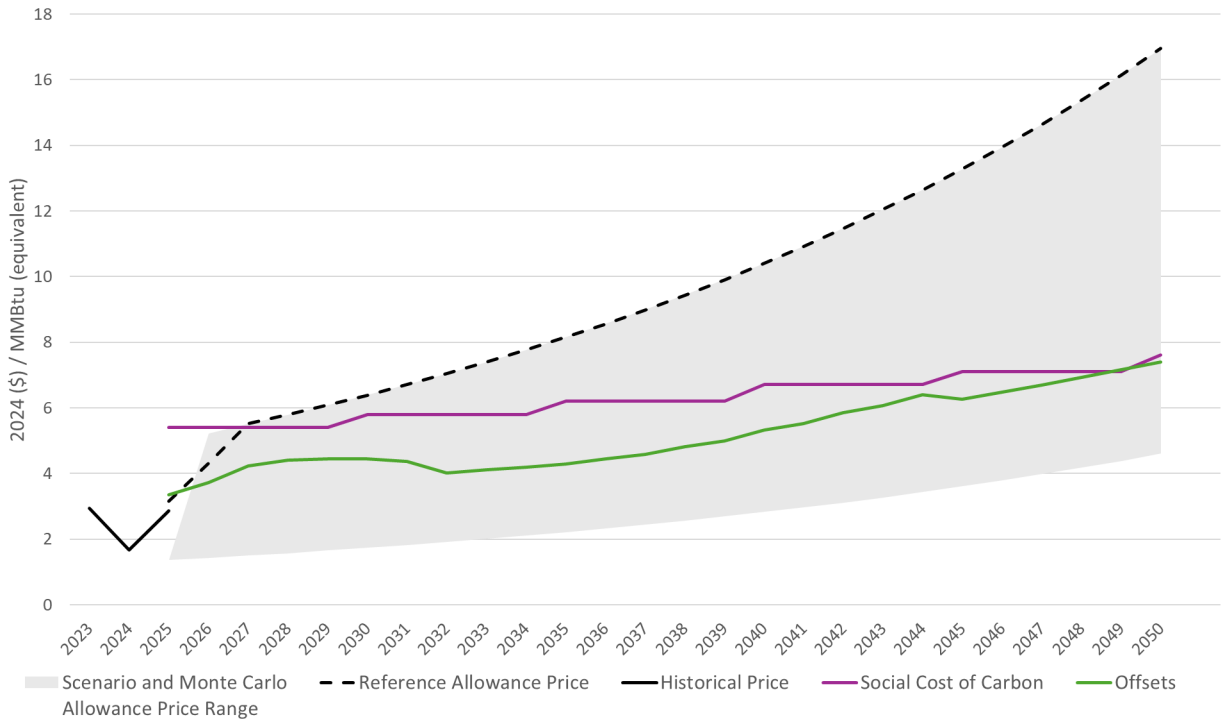
[207] See Alternative Fuels Study in Appendix E

horizon. This reflects an expectation of an increasingly tight allowance market as the cap on emissions across all CCA covered entities decreases and demand for these allowances outpaces the availability. Even though the Reference Case showcases this expectation, auction clearing prices to date have been significantly lower and there exists a potential for these lower prices to continue. The Company's CCA compliance costs are capped by the allowance price ceiling; however, there is potential for costs to be lower than expected (see Section 9.6.1 for further analysis).

For scenario analysis, NW Natural used a similar approach for allowance pricing that is used for avoided costs (i.e., the maximum of the Social Cost of Carbon (SCC) or the allowance price) to provide consistent treatment across demand-side, supply-side, and compliance resources. For example, if the price for RNG were greater than the allowance price, but less than the SCC, the resource optimization would favor the RNG resource over the allowance purchase.[208] As a practical matter, the reference allowance prices is only lower than the SCC for the first two years of the planning horizon, when all other compliance instruments (except for offsets) are not cost competitive for CCA compliance. If available, offsets are generally expected to be lower cost than allowance purchases. Figure 7.24 illustrates the reference allowance price forecast, the offset price forecast, the SCC, and the range of allowance prices evaluated through scenarios and Monte Carlo analysis.[209]

[208] Despite developing the model this way, this circumstance only applies to offsets in Scenario S1.a where offset prices are between the allowance price and SCC.
[209] Note that all the CCA cost results shown in Chapter 9 reflect the allowance price forecast (not the SCC). Due to the limitation on offset purchases, variations in offset prices were not explored.

Figure 7.24: CCA Allowance and Offset Price Forecast

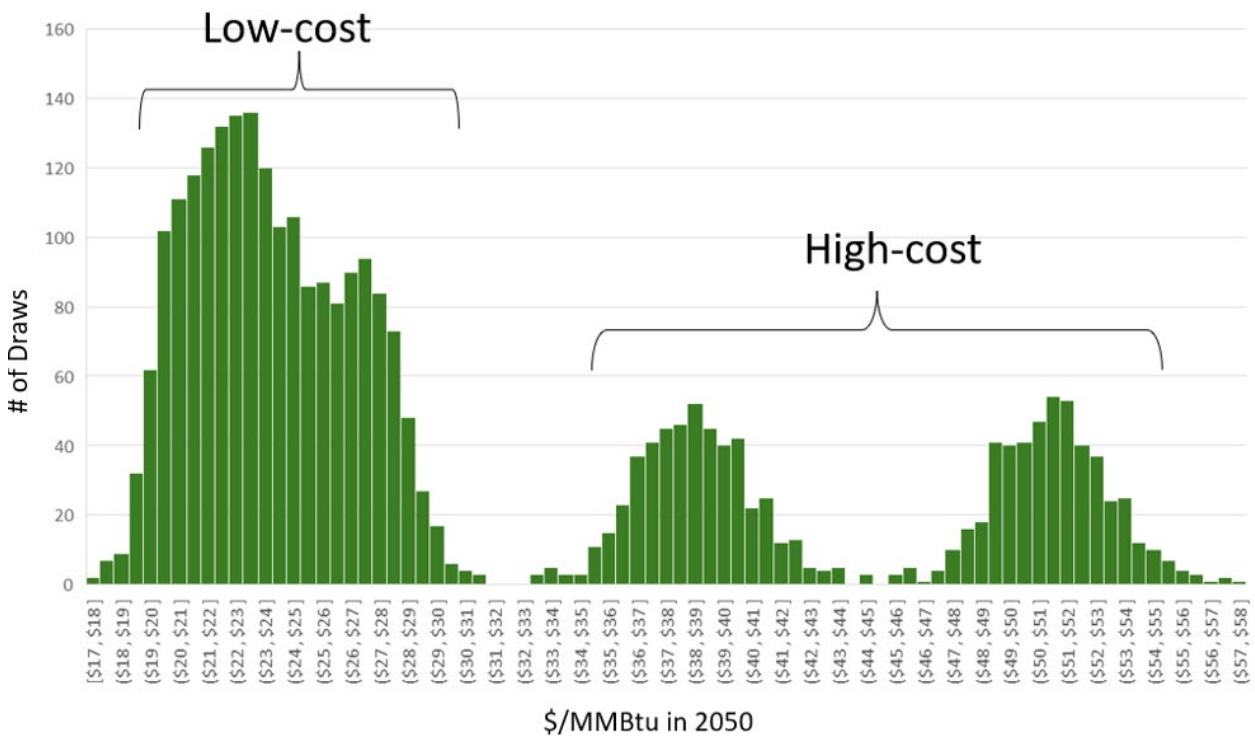


7.7.9 Compliance Resource Uncertainty

Unlike natural gas prices and weather, the Company does not have access to a history of price data for many of these alternative fuels as these markets are in their infancy and do not have liquid trading platforms to provide robust price discovery. In lieu of having historical data, the Alternative Fuels Study developed Monte Carlo simulations on the primary cost drivers and carried those simulations through the production cost models to generate stochastic draws on price. Figure 7.25 shows the histogram of costs in 2050 using simulations for the six separate categories for synthetic methane from biomass (see Appendix E). For each individual simulation, these six categories for synthetic methane from biomass are aggregated into two resource types consistent with the same methodology as describe in Section 7.7.2. These simulations and subsequent aggregation to type (see Table 7.7) were conducted each of the 74 separate low carbon alternative options in the Alternative Fuels Study.[210]

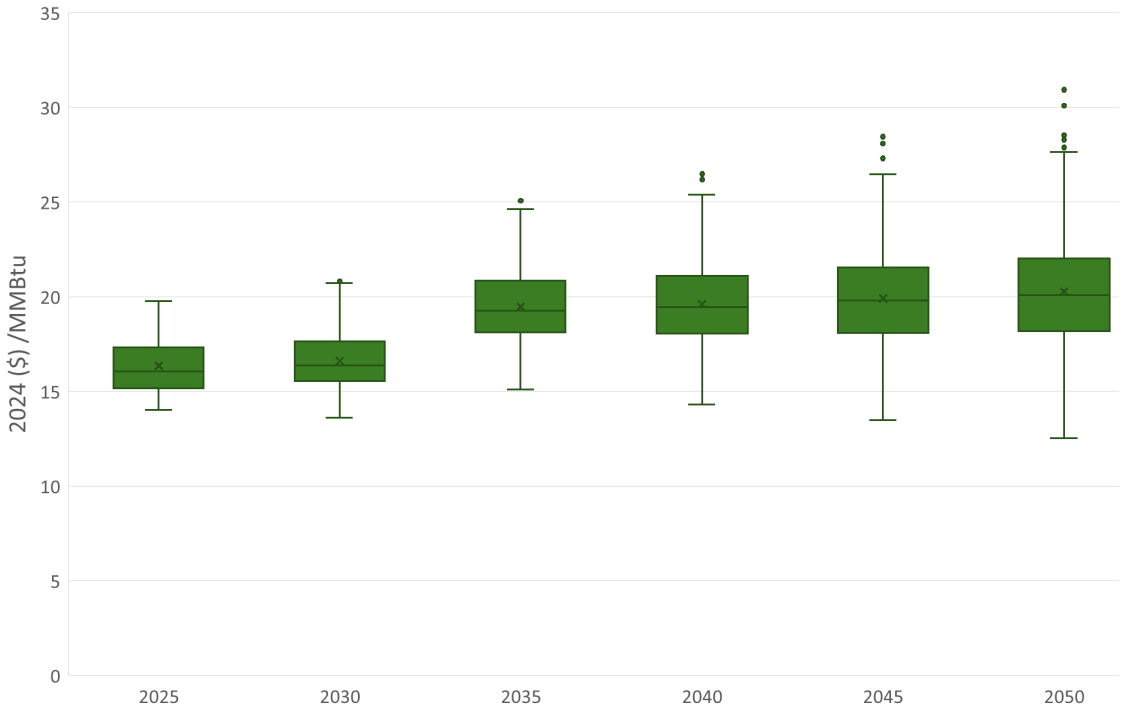
[210] The Alternative Fuels Study conducted 1,000 draws for each resource; however, due to limit computing power for PLEXOS modeling only a subset of those draws was used in the resource optimization model.

Figure 7.25: Synthetic Methane from Biomass 2050 Price Simulation Distribution from Alternative Fuels Study



Price uncertainty, for any resource, increases further into the future (i.e., variation in the price forecast of a specific resource should increase over time). This concept of variation as a function of time was not captured by the underlying production cost simulations in the Al Fuels Study. Therefore, NW Natural incorporated a simplistic method to increase variation in price overtime, while still utilizing the underlying simulations from the Alternative Fuels Study (see Appendix G for technical details). Figure 7.26 illustrates this concept for the low-cost synthetic methane proxy resource type using box and whisker plots over time.

Figure 7.26: Low-cost Synthetic Methane from Biomass with Increasing Price Variation



In addition to a price simulation, the Alternative Fuels Study also provided a simulation of the available quantities for each of the 74 compliance resources in the study. To explore potential futures where compliance resources are more limited, NW Natural imposes a 33 percent probability that any of the 74 compliance resources are simply not available at any point in the planning horizon. In other words, for any given draw, on average, one-third of the 74 resources are not accessible. Aggregation to the proxy resource types used in PLEXOS® was conducted after imposing this availability probabilities consistent with the methodology described in Section 7.7.2.

Not included in the Alternative Fuels Study were simulations for RTC prices and CCA allowance prices. A third-party consultant provided NW Natural with a reference case, up-side, and down-side price forecast for D3 RIN prices, which are used as a proxy for possible RTC purchases. Another third-party consultant provided a similar reference case, up-side, and down-side allowance price forecast for the CCA. Note that the only difference between the upside and reference case forecasts are in the first two years of the forecast, where starting in 2027 both are equal to the allowance ceiling price. Using the up-side and down-side of these third-party forecasts and in combination with historical data for CCA allowance and D3 RIN prices, NW Natural developed simulations for RTC prices and CCA allowance prices (See Appendix G for technical details).

8 Supply-Side Resources

NW Natural®

This chapter of the IRP discusses both current and potential supply-side resources that NW Natural uses to deliver natural gas to customers. Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options.

8.1 Traditional Natural Gas Supply Options

This suite of supply-side resources focused on in this chapter are associated with serving customers at the system level in both Oregon and Washington. Supply-side resource options associated with alleviating constraints in specific areas of the distribution system are discussed in Chapter 12.

From a Gas Supply perspective, all resources vary across two dynamics as to the value for what each resource provides to NW Natural's system: 1) the daily deliverability or capacity value, and 2) the overall energy a resource can provide throughout the year. For example, a year-round pipeline capacity contract provides capacity every day of the year but needs to be paired with gas purchases to provide energy. Storage LNG facilities are limited on the amount of energy they can provide but can provide deliverability for serving peak demand. Different resources also vary in costs, availability, and risks.

The rest of this chapter discusses general types of supply-side resources, NW Natural's current resource portfolio, and future capacity resources options available for NW Natural to address resource need. These current and future options are inputs to the resource planning optimization model discussed in Chapter 9. The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a diversity of resources available. The portfolio of supply-side resources available to NW Natural can be categorized under various primary resource types:

Natural gas supply contracts: These are contract agreements for natural gas purchased from a producer or gas marketer for a specified volume for a given period and at a specific location known as a receipt point. Natural gas supply contracts are purchased on a term basis, for example baseload contracts- or purchased on the spot (daily) market and must be used in conjunction with other supply-side resources, such as interstate pipeline contracts, to ship the gas from the receipt point to a delivery point connected to NW Natural's system, known as a citygate. See Appendix F for further details about gas purchasing practices.

Interstate/interprovincial pipeline capacity: NW Natural contracts with pipeline companies in the US and Canada to ship natural gas from receipt points, where gas flows onto the interstate/interprovincial pipeline, to delivery points where NW Natural physically takes

custody of the gas. These capacity rights are used to ship gas supplies purchased for NW Natural sales customers to NW Natural's system.

On-system production resources: On-system production resources are non-storage resources that produce gas and inject directly onto NW Natural's system. This primarily consists of injections from renewable methane sources, but also includes a minimal amount of Mist production gas still being collected from producing wells next to the underground Mist storage facility (a.k.a. Miller Station). The current on-system resources from renewable methane sources do not have environmental attributes, or RTCs, associated with the injected gas; however; future on-system renewable methane source could be bundled with the RTCs and used for emissions compliance for NW Natural customers.

Underground storage: There are 387 active underground natural gas storage fields in the Lower 48 states. These facilities utilize depleted oil or gas production wells, natural aquifers, or salt caverns to store gas supplies. The geological properties of each of these underground facilities offers an effective means of storing large amounts of natural gas which can be accessed relatively quickly to meet seasonal demand shifts throughout the year. Utilities, gas marketers, and other shippers of natural gas contract with the storage facility owners for both storage capacity (the total amount of gas stored underground) and storage deliverability (the amount of gas that can be withdrawn from storage in a day). While the storage capacity is a function of the geological properties of each facility, the storage deliverability is a function of the wells drilled into the formation and the piping and compression infrastructure used to withdraw stored gas. Note that storage capacity helps meet annual energy requirements, whereas storage deliverability helps meet daily system requirements as discussed at the start of this chapter.

In addition, deliverability from underground storage can be a function of the storage inventory level (i.e., how full the storage facility is at any given time). When the facility is full, the pressure of the gas underground is high and therefore will flow freely out of the ground. As the facility empties, pressure declines and deliverability will also decline. Due to the physics of these facilities, storage contracts often include clauses known as "ratchets", which specify the deliverability as a function of a customer's capacity inventory level.

Above-ground LNG storage: Above-ground LNG tanks and facilities super-cool natural gas into a liquid, known as liquefaction, and are an effective way to store more energy per volumetric unit (e.g., cubic foot) compared to its gaseous form. LNG storage facilities reverse the process, known as vaporization, to quickly inject gas back into the system to meet spikes in demand. Compared to underground storage, these facilities have a higher ratio of storage deliverability

to their overall storage capacity and are well-suited as “peaker” units to help meet demand spikes when temperatures plumet.

Industrial recall options: NW Natural contracts with two industrial counterparties for recall options wherein we would pay an industrial company to switch to an alternative fuel source and provide us with the natural gas supplies that they would have otherwise consumed. Note that these contracts are not with sales customers; therefore they would not be considered demand response. These contracts are agreements that provide additional interstate pipeline capacity and natural gas supplies if called upon. These contracts are limited to the number of days we can call on them in a winter season.

Citygate deliveries: The "citygate" is the point of delivery at which gas is transferred from an interstate or intrastate pipeline to a local distribution company’s custody. Citygate contracts are for gas supplies delivered directly to NW Natural’s service territory by the counterparty utilizing their own NW Pipeline capacity. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of NW Natural.

NW Natural has utilized citygate delivery agreements, on occasion, when cost effective. Such agreements usually take the form of swing arrangements that allow up to five days’ usage during the period of December through February. As a near-term capacity resource, city gate deliveries are relatively inexpensive, but if the option for deliveries is utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high. The long-term reliability of citygate deliveries is too uncertain to be evaluated as a long-term option for IRP analysis, but these options are evaluated as an alternative for meeting design peak demand going into each winter.

8.2 Current Resources

NW Natural’s current portfolio of resources sufficiently meets energy and capacity requirements for customers. This section discusses NW Natural’s current resource portfolio.

8.2.1 Gas Supply Contracts

NW Natural has a portfolio of term supply contracts for each year, which are presented and reviewed in the annual purchased gas adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contracts — for the 2024-25 PGA period — is included in Appendix F. Contracts volumes are designated using the term “Baseload Quantity,” which refers to a contractual obligation for daily delivery and payment.

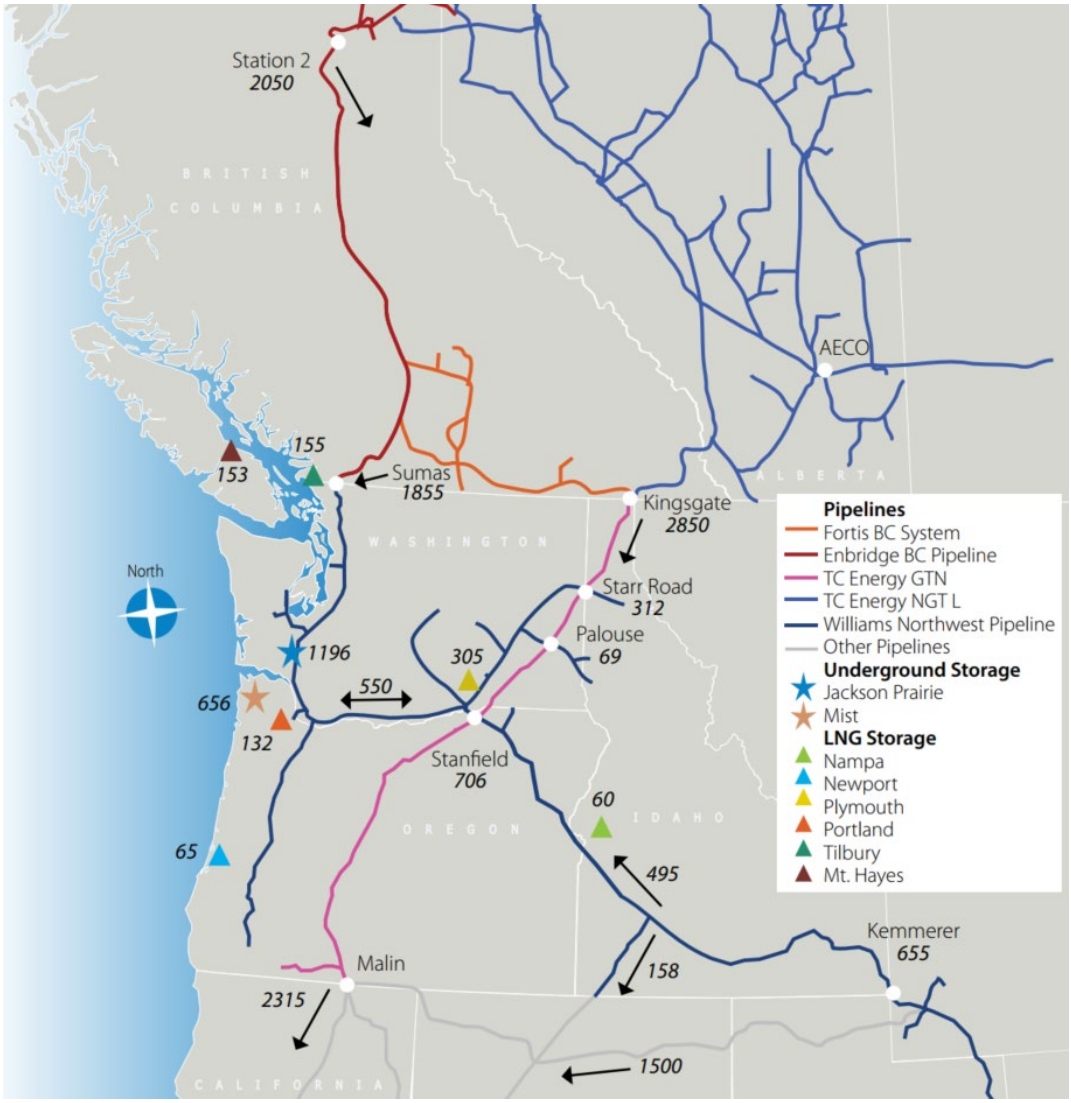
In addition to term contracts, NW Natural buys certain gas volumes on the “spot” market, meaning the volumes, pricing and delivery points are negotiated on a real-time basis for

delivery the following day or other near-term period, but no more than a month in advance. NW Natural maintains a diversified array of suppliers from whom gas can be bought on a spot or term basis.

8.2.2 Pipeline Capacity

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 8.1. Total pipeline capacities in the map are shown in thousands of Dths per day (MDth/day).

Figure 8.1: Pacific Northwest Infrastructure and Capacities (MDth/day)



Source: Northwest Gas Association, 2024 Gas Outlook

8.2.3 Firm Pipeline Transport Contracts

NW Natural holds firm transportation contracts for capacity on Williams Northwest Pipeline (NWP), over which all of NW Natural's supplies must flow except for the small amount of natural gas that comes from on-system resources, which are less than one percent of annual purchases.

For gas sourced in the U.S. Rockies, transportation over NWP is all that is needed to bring the supplies to NW Natural's territory.

For gas sourced in British Columbia, purchases are either made directly into the NWP system at the international border (called Sumas on the U.S. side and Huntingdon on the Canadian side) or purchased in Northern British Columbia at a trading hub called Station 2. Extending northward from the international border is the T-South pipeline system (owned by and referred to as Enbridge BC Pipeline in Figure 8.1), which creates a connection between Station 2 and Sumas/Huntington. Purchases made at Station 2 first require transportation by Enbridge before reaching the Sumas/Huntington interconnection point and movement onward by NWP to NW Natural.

For gas sourced in Alberta, purchases are made at the trading hub known as AECO. Gas sourced at the AECO hub reaches the NW Natural system via four pipeline systems, three owned by TC Energy, and the fourth being NWP. Starting in Alberta with NOVA Gas Transmission Limited (NGTL or NOVA), the molecules, then travel along the Foothills pipeline in southeastern British Columbia. The molecules continue south on this pipeline to the international border, at the Kingsgate point in northern Idaho, into Gas Transmission Northwest (GTN) pipeline, which extends southward and connects to NWP at Starr Road, in eastern Washington (near Spokane) and at Stanfield, in northeastern Oregon.

NW Natural has released a small portion of our NWP capacity to one customer but has retained certain heating season recall rights, discussed above as an Industrial recall option. Details of the current portfolio of pipeline transportation contracts are provided in Appendix F.

Since the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized, i.e., capacity can be bought and sold like other commodities. These acquisitions and releases occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have standardized many definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades can

also occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

Except for a small percentage of on-system supply, all the gas supplied to NW Natural customers must be transported over the NWP system, which is fully subscribed in the areas served by NW Natural. Usage among NWP capacity holders tends to peak in a nearly coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, NWP capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions.

Given the dynamics of market growth and pipeline expansion, NW Natural will continue to monitor and leverage the capacity release mechanism whenever appropriate, but this will primarily mean continuing to use our asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

8.2.4 Exposure to Sumas

About 30 percent of our contracts on the NWP system are sourced through Sumas. We can fill these contracts either with purchases directly at Sumas or with purchases further upstream at West Coast Station 2 (Station 2), which is a supply point where the commodity is being produced. Sumas on the other hand is a trading point where natural gas trading occurs but supplies at Sumas first must be transported there from a production source, such as Station 2. We have long-term Enbridge BC Pipeline (T-South) contracts that allow us to procure about half of the gas we need to ship from Sumas at Station 2. The other half of the supplies we ship from Sumas must be purchased directly at Sumas.

Historically, Sumas has been a high-priced, volatile trading point when compared to other trading points throughout North America. We are expecting this to be further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online. Woodfibre LNG, which is being constructed in Squamish, B.C. will convert about 300,000 Dth/day of natural gas per day to LNG which will then be shipped overseas. Woodfibre LNG already holds the T-South pipeline capacity they need for their operations and this capacity is currently used to ship Station 2 gas down to Sumas where these supplies are sold.

When the LNG facility is operational, currently forecasted to be in 2027, these supplies will be pulled from the Sumas market and used in the liquefaction process. This loss of gas supply equates to approximately 15 percent of the total available winter capacity to Sumas on the T-South system and will represent a fundamental shift in the region's gas supply availability to

serve existing demand. It will have significant adverse implications for customers relying on purchasing gas supply at Sumas unless there is an upstream pipeline expansion or another solution that would benefit the market at Sumas. In fact, if a regional peak cold weather event were to occur after Woodfibre is in service and before a solution could be found, we could possibly see supply shortages in the Pacific Northwest.

There are several pipeline solutions that are being marketed as a solution for this supply leaving the market at Sumas. One project is moving through the Canadian regulatory process but would not be in service until at least one year after Woodfibre starts liquefying. NW Natural did not participate in this first project, but we will evaluate participation in future projects as the opportunities present themselves. We will also evaluate longer-term physical purchases at Sumas or Mist Recall as solutions for the market disruption at Sumas.

Due to the expectation that Woodfibre LNG will begin operations in late 2027, thus tightening the Sumas market, we do not expect that we will be able to procure large volumes of Sumas spot gas during a cold weather event. While we are confident that gas supplies shipped on segmented capacity would flow, our ability to find these supplies will be restricted and that is why we are no longer relying on segmented capacity for a peak day starting in the 2027-28 winter, as is discussed in the segmented capacity section.

8.2.5 Segmented Capacity

Segmented capacity is secondary firm capacity on NWP that is deemed reliable due to the high probability that it will be available during times of peak usage. This reliability assumption is validated through an analysis of NWP flow data through the Chehalis Compressor Station along the I-5 corridor. The analysis uses flow data to validate that there is sufficient North to South capacity available as the weather gets colder.[211] These assumptions are based on current market dynamics as the ability to schedule segmented capacity is more reliable as weather becomes colder.[212]

For many years now, NW Natural has relied on segmented capacity and flexed the receipt and delivery points to create useful, albeit secondary, firm transportation on the NWP system. This segmented capacity flows from the north (Sumas) in a path that has not experienced constraints, during the coldest weather events in recent years. Utilizing segmented capacity does not incur an additional demand charge and only incurs NWP's variable and fuel charges in addition to the Sumas commodity costs. Because of this low opportunity cost, segmented capacity can be a very valuable resource for customers.

[211] For more detail on the Chehalis flow analysis please see Appendix E, Section E.4 of the 2022 IRP.
[212] For more details on the process of segmentation see Chapter 6, Section 3.3 in the 2018 IRP.

Modeling of segmented capacity began in 2014 with 43,800 Dth/day included in the analysis. Another 16,900 Dth/day of segmented capacity was subsequently created in 2016. This combined amount of 60,700 Dth/day was included in the 2016 and subsequent IRPs. This amount remains in the current IRP planning until 2027 when certain constraints in the Sumas market are expected to increase the risk of being able to procure spot gas on a peak day. This IRP does not rely on segmented capacity to meet peak demand starting in the 2027-28 gas year but does allow it to be used on colder non-peak days at 30,000 Dth/day the rest of the year.

8.2.6 Storage Assets

NW Natural relies on four existing storage facilities in and around our market area to augment the supplies shipped from British Columbia, Alberta and the U.S. Rockies. These consist of underground storage at Mist and Jackson Prairie, and LNG plants located in Portland and Newport, Oregon.

NW Natural owns and operates Mist, Portland LNG, and Newport LNG, all of which reside within NW Natural's service territory. Hence, gas typically is injected into storage at these facilities during warm periods and withdrawn when needed during cold periods directly onto NW Natural's system.

In contrast, Jackson Prairie underground storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside NW Natural's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. NW Natural contracts for Jackson Prairie storage service from NWP. Several separate contracts with NWP provide for the pipeline transportation service from Jackson Prairie to the NW Natural citygate.

Table 8.1 shows the maximum storage capacity and deliverability of these four firm storage resources.

Table 8.1: Firm Storage Resources

Facility	Maximum Daily Deliverability (Dth/day)*	Maximum Seasonal Storage Working Capacity (Dth)*
Mist	325,000	13,322,920
Newport LNG	78,000	866,014
Portland LNG	132,840	405,959
Jackson Prairie	46,030	1,082,517
Notes: *Volumes adjust each year based on heat content. These volumes are derived from 2024-25 PGA filing. Newport LNG available capacity takes into account a minimum 20% tank level needed for normal operations. Portland LNG maximum capacity currently de-rated due to seismic analysis, and the available capacity also considers a minimum 20% tank level needed for normal operations.		

The Mist storage deliverability and seasonal capacity shown in Table 8.1 represents the portion of the facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum daily deliverability of 501.47 million cubic feet per day (MMcf/day) with peak hourly deliverability at a rate of 515 MMcf/day, and a total working gas capacity of 17.5 billion cubic feet (Bcf). These volumetric figures are converted to energy values (Dth) using the heat content of the injected gas. That heat content conversion factor had been relatively constant at 1,010 Btu/cf in prior years but has increased to around 1,060 Btu/cf to 1,080 Btu/cf over the past several years.

Storage capacity and deliverability in excess of core needs are made available for the non-utility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist recall discussed later in this chapter.

8.2.7 On-system Production Resources

On-system production resources produce methane and do not require upstream capacity resources. In other words, these resources produce and inject gas directly onto NW Natural's system.

8.2.8 Mist Production

Natural gas wells owned by a third-party in the Mist area continue to produce small quantities of low Btu gas which NW Natural purchases and blends into larger volumes of gas supplies at Miller Station. Over time these wells continue to deplete, and new wells have not been drilled for several years. Unless there is a renewed interest in exploration and production of natural gas in the Mist area, it is expected that these volumes will continue to decline over time.

8.2.9 On-system Production

RNG projects owned by third parties are interconnected to the NW Natural distribution system. Currently, NW Natural only purchases the underlying commodity from these projects and does not have rights to the environmental attributes associated with this RNG. Expected volumes from these projects are included as gas supplies in the IRP as they do provide a capacity benefit, but not a compliance benefit.

8.2.10 Industrial Recall Options

NW Natural has contracts with two industrial companies located on or near our distribution system wherein we can call on natural gas supplies if needed in the winter. The price of these contracts is either fixed or tied to an alternate fuel source that the industrial company could use if we were to call on their flowing natural gas supplies. If called upon, these supplies would be delivered to NW Natural at our citygate on the industrial customers' capacity with NWP. Each contract has specific terms outlining when we can call on the capacity and at what volume. Contract volumes range from 1,000 Dth/day to 30,000 Dth/day.

8.3 Future Supply-side Capacity and Energy Resource Options

NW Natural considers additional gas supply resource options including Mist recall and increases to Newport take-away. Additionally, if less resources are needed in the future, we evaluate non-renewal of our existing pipeline capacity. These alternatives are described in more detail below.

8.3.1 Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core utility sales customers (see Table 8.1), NW Natural has developed additional capacity in advance of core customer needs. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire.

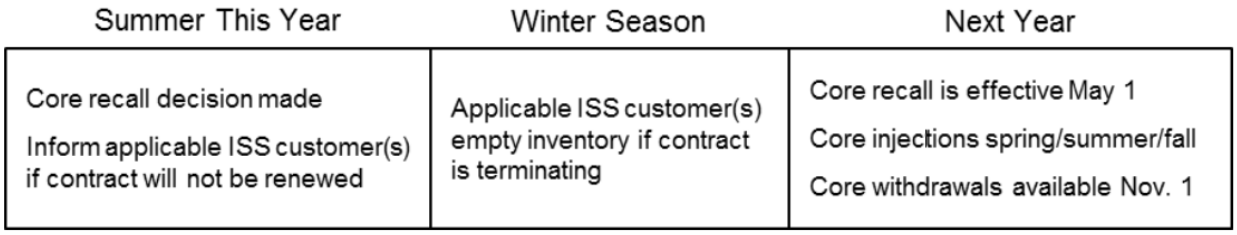
Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet load requirements in the Portland area, which can then free up other capacity resources to meet incremental system requirements.

There are three practical considerations that apply to Mist recall:

1. Recall decisions to transition capacity to the utility portfolio are made roughly a year prior to the core utility's forecasted capacity need. On or about May 1, NW Natural

wants to start filling any recalled storage capacity over the summer months to have the maximum inventory in place by the start of the following heating season. Working backwards from May 1, ISS customers need advance notice to empty their gas inventory accounts if their capacity is going to be recalled by NW Natural. NW Natural informs the ISS customer of a recall before the heating season if their contract will not be renewed. Accordingly, we have established the prior summer as the time at which operationally we must make our recall decisions. This timeline is depicted in Figure 8.2.

Figure 8.2: Mist Recall Decision Timeline



2. Mist ISS contracts are of various durations. While limiting Mist ISS contracts to 1-year terms would maximize the capacity available for recall each year, it also would limit ISS revenues, which utility customers share in a portion of those revenues. Accordingly, ISS contracts have staggered start dates and durations that create a profile of capacity available for recall that increases over time, in effect mirroring expectations of rising resource requirements.
3. Recalls are rounded (up or down) to the closest 5,000 Dth/day of deliverability. This is done to simplify the administration of recalls and the marketing of ISS service but are modeled as a completely divisible product in the resource planning optimization model discussed in Chapter 9. For scale, 5,000 Dth/day is roughly 0.5 percent of the current resource stack daily deliverability. The ability to recall Mist in such small increments is a very valuable option that allows customers to pay for a capacity resource only as needed.

8.3.2 Newport Takeaway

8.3.2.1 Newport Takeaway Options

As previously mentioned, the daily deliverability of the Newport LNG facility provides 73 MMscfd (78,000 Dth/day when adjusted for heat content) of system capacity under design peak conditions. This is due to pipeline infrastructure limitations flowing gas out from Newport back through the Central Coast feeder back towards Salem. However, the Newport LNG facility has the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To match the pipeline takeaway capability to Newport's vaporization capacity of 100 MMcf/day,

infrastructure additions would be needed on the Newport to Salem pipeline, known as the Central Coast feeder and other related pipelines. This would provide an incremental 27 MMcf/day (29,025 Dth/day). The 2018 IRP identified a three phased approach that could be done separately and sequentially at various costs to achieve the full incremental takeaway capability. Since then, we've improved our modeling capabilities and determined that the 100 MMscfd could be achieved differently, with less expense, and in a single phase or we could increase the take-away capability, without achieving the full 100 MMscfd for a lower cost. For the two options below, it is not necessary to do the first before the second, they are standalone, independent options.

1. Newport Take-away 1 – would increase the maximum pressure rating of 15 miles of the Central Coast Feeder, adding 11.12 MMscfd (11,954 Dth/day) at an estimated cost range of $6.5-12.9 million.
2. Newport Take-away 2 –would add a new compressor station near and west of Grand Ronde, Oregon, adding 27.4 MMscfd (29,455 Dth/day) at an estimated cost of roughly $55-75 million.

As the increased throughput created by the addition of a compressor (2.), would cause the pressure to be less than 600 psig where the Central Coast feeder currently transitions to 600 psig, option 1 above does not need to be done prior to option 2. They are two independent options, with independent and different take-away increases.

8.3.3 Pipeline Capacity Non-Renewal

8.3.3.1 Pipeline Capacity Non-Renewal

NW Natural holds contract and gate station capacity on: 1) NWP's mainline serving our service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington; and 2) NWP's Grant's Pass Lateral serving our loads in the Willamette Valley region of Oregon from Portland south to the Eugene area, as well as the central coast (e.g., Lincoln City, Newport) and south coast (e.g., Coos Bay) areas. We also hold contractual capacity on various upstream pipelines including GTN, Foothills, NGTL and T-South. The Company analyzes the future utilization, need, and value to customers of these contracts in our portfolio optimization modeling (i.e., PLEXOS®), which selects whether to continue these capacity contracts beyond their current expiration date.[213]

[213] This is an improvement in the resource optimization modeling from previous IRP modeling in response to OPUC Staff recommendation #4 from Staff's final report in OPUC docket LC 79.

8.3.3.2 Capacity Resources Comparison

NW Natural uses cost-of-service modeling, which captures the capital costs, operation and maintenance costs, taxes, construction and overhead, and all other estimated costs associated with an option over the planning horizon. Using the cost-of-service modeling, each option has a present value revenue requirement. These costs become an input into the resource planning optimization model, and they are incurred when a capacity option is selected.

Table 8.2 lists the capacity options, costs in terms of dollars per Dth per day, the daily deliverability, and the years each option is available for selection. These are fixed costs that are incurred everyday throughout the planning horizon if a capacity resource is selected. Note that only Mist Recall is a non-binary option, and the model can select as much Mist Recall as needed in each year. All other options must be selected at the full amount. Once an option is selected it remains in the resource stack and incurs the cost for the rest of the planning horizon.

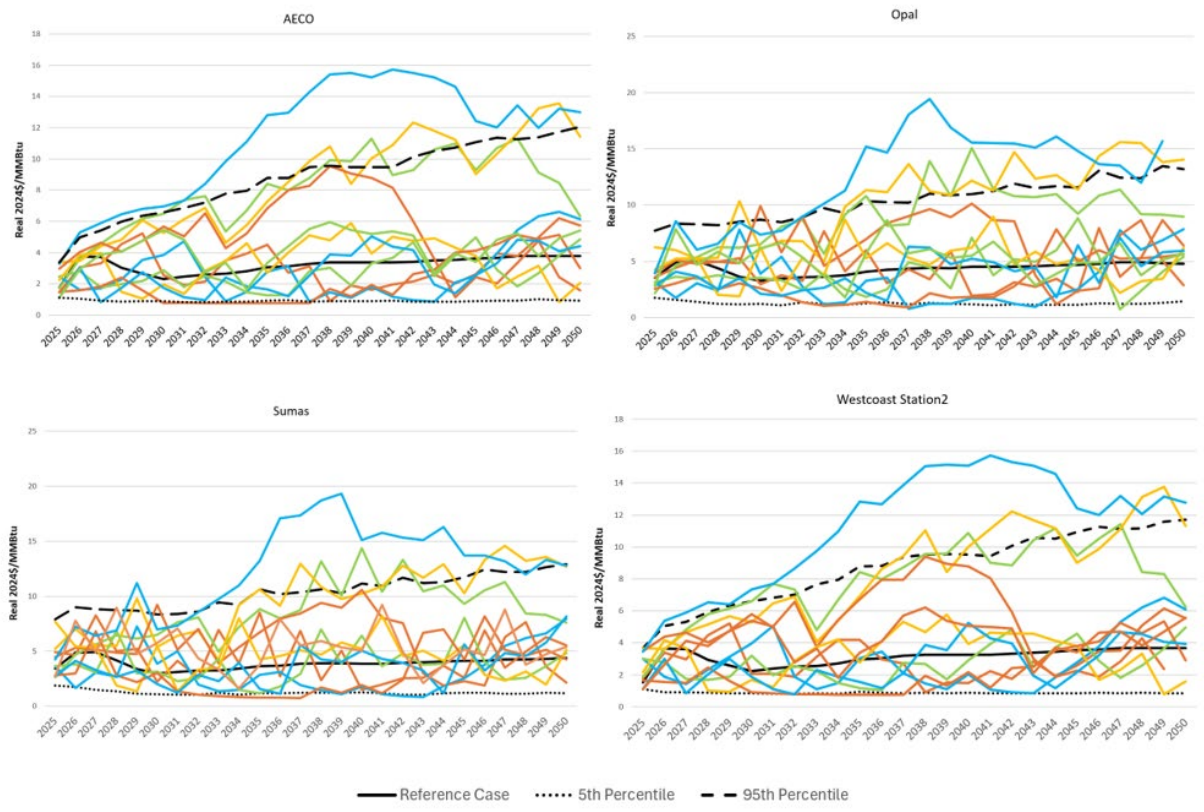
Table 8.2: Capacity Resource Cost and Deliverability

Capacity Resource	Deliverability (Dth/day)	Levelized Cost ($/Dth/Day)
Mist Recall	Up to 185,000	$0.177
Newport Take-away 1	12,000	$0.181
Newport Take-away 2	17,500	$1.587

8.4 Gas Price Uncertainty

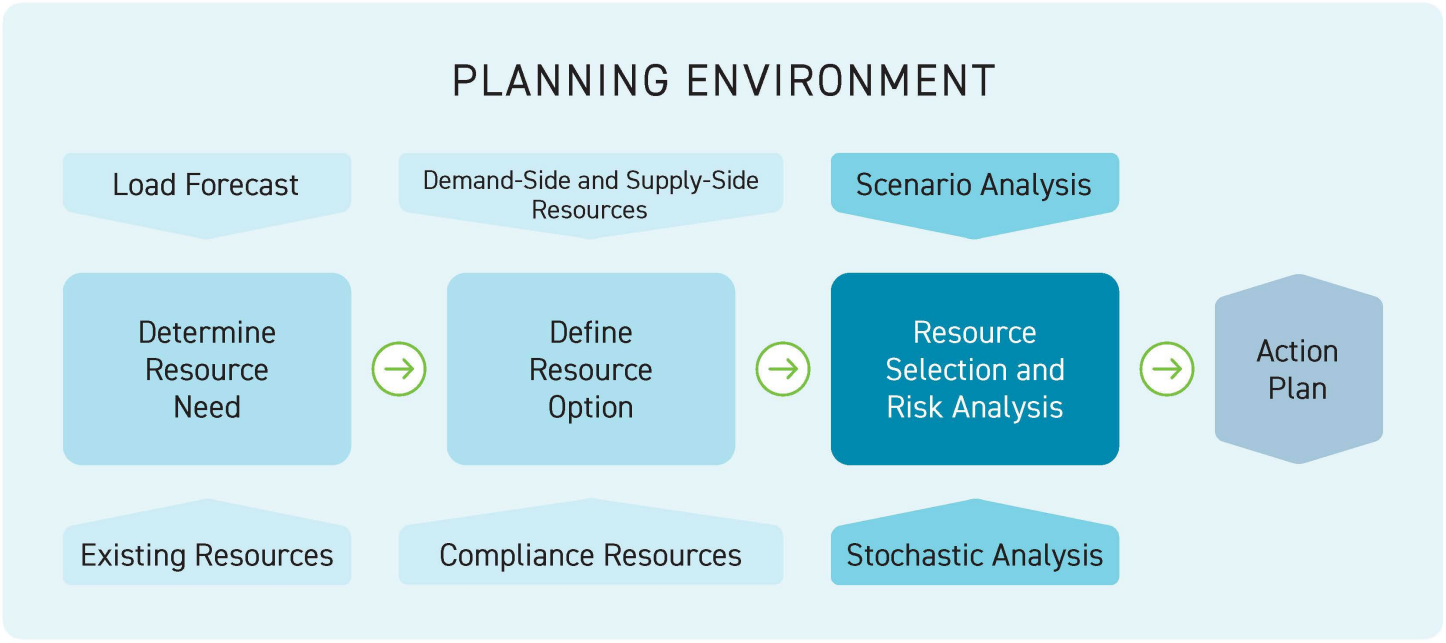
NW Natural uses a Monte Carlo simulation to address gas price uncertainty. NW Natural conducts a Monte Carlo simulation of natural gas prices using historical data in combination with the long-term natural gas prices forecast outlined above to simulate daily natural gas prices. This simulation provides insight into the range of potential short-term and long-term gas prices. Each simulation uses historical prices at each hub (AECO, Opal, Sumas, and Westcoast Station 2) from 2010 through 2024 to capture cross hub correlation, and incorporates potential price spikes. The simulation yields annual average prices at each of the four basins.

Figure 8.3: Monte Carlo Annual Average Prices



Further details regarding the gas price forecast and Monte Carlo can be found in Appendix G.

9 System Resource Planning and Portfolio Results



NW Natural®

Chapters 2 through 8 provide the key assumptions required to define the suite of system resource options that are available to serve NW Natural customers' energy and emissions needs. This chapter describes the modeling employed to determine the resources that represent the best combination of least cost and least risk to maintain safe and reliable service while meeting environmental policy obligations.

9.1 Portfolio Analysis

Chapters 4 through 8 outline NW Natural's resource requirements, NW Natural's existing resources, and the options available to meet three primary requirements:

- Emissions compliance – acquiring compliance resources as needed to meet emissions obligations for a given scenario,
- Capacity – the ability to reliably serve customers during a design peak cold event, and
- Annual energy – the ability to reliably serve customers throughout the year.

Different resources offer very different emissions, capacity, and energy contributions. Additionally, resource options vary in costs, availability, and timing. For example, NW Natural's Newport LNG facility provides a significant amount of capacity, but for a limited amount of total energy before being completely depleted. Off-system purchases of RNG help meet emissions compliance requirements, whereas on-system RNG can help meet all three requirements.

Due to the complexity of varying resources and resource requirements, NW Natural implements an optimization software called PLEXOS® to solve for the least cost mix of resources that complies with emission obligations, while reliably serving customers' daily demand over the planning horizon (2025-2050).[214] The PLEXOS® software is the tool that NW Natural uses for the IRP's Resource Planning Optimization Model. Scenarios and Monte Carlo simulations are also used in risk analysis to examine a wide range of potential futures and the portfolio resources acquired in those potential futures. Ultimately, this risk analysis helps inform the long-term strategy and the near-term action items for system resources in the IRP Action Plan. Note that distribution system action items are analyzed in Chapter 12 for distribution system planning.

9.2 Resource Planning Optimization Model

PLEXOS® implements a mixed integer program (MIP) algorithm. The algorithm selects resource acquisitions and dispatches—subject to a set of constraints—that minimize the net present value (NPV) of total system costs over a specified planning horizon. The cost minimization function is often called the objective function and is represented mathematically as:

[214] PLEXOS® is owned and licensed by Energy Exemplar.

$$Minimize \sum NPV(Cost_t) \; \forall \; daily \; costs$$

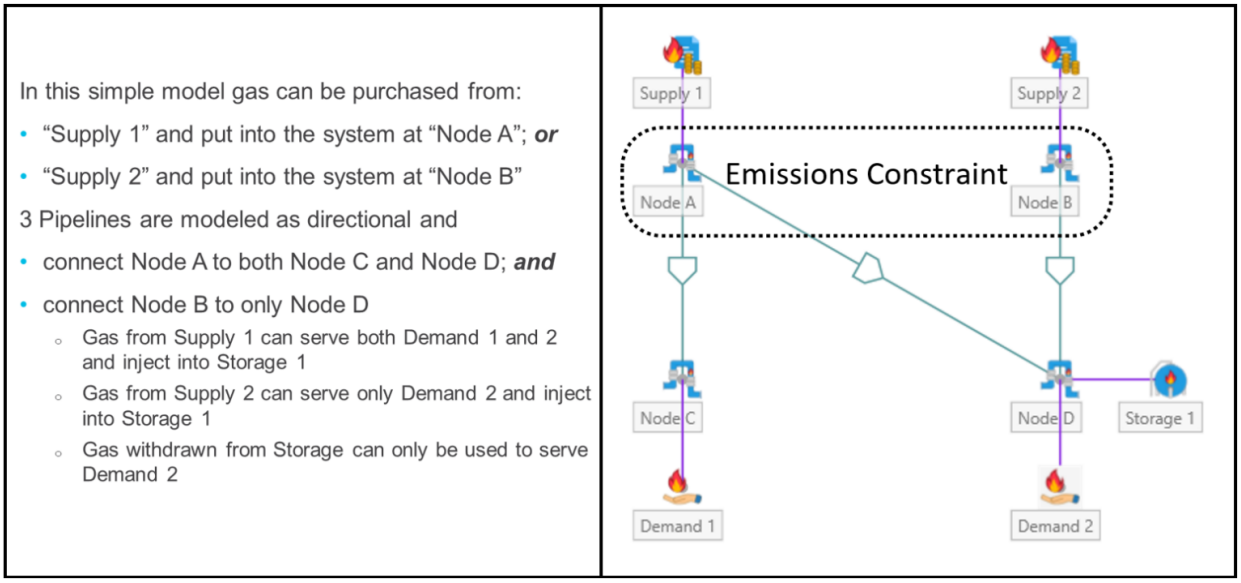
NW Natural's Resource Planning Optimization Model solves for each day in the planning horizon by adjusting choice variables, also known as decision variables, at the daily level to minimize the objective function (i.e., total system NPV costs). The model constraints are based on user-defined inputs and model parameters. These constraints mimic real world limitations, such as the maximum daily withdrawal capability from Mist storage. Table 9.1 provides a high-level list of the decision variables and constraints in NW Natural's IRP PLEXOS® model.

Table 9.1: High-level PLEXOS® Decision Variables and Constraints

Decision Variable	Constraints
• **Daily purchase of compliance resources (e.g., RNG, hydrogen, synthetic methane) and compliance instruments (e.g., CCI, allowances, offsets)** • **Daily selection of quantity and location to purchase and ship conventional gas** • **Daily storage operations (i.e., injections and withdrawals)** • **Annual acquisition of system capacity resources required to serve demand every day of the year** • **Annual renewal decision of pipeline contracts after current pipeline contracts expire**	• All demand served in both Oregon and Washington • Emissions compliance obligations in both Oregon and Washington • Pipeline constraints and costs • Storage constraints and costs • Supply purchasing constraints and costs • Compliance and capacity resource acquisition constraints and costs • Costs discounted at a rate equal to the Company's real after-tax weighted cost of capital

The PLEXOS® software creates a nodal model that links objects together. Objects can represent—but are not limited to—gas supply contracts, gas pipelines, gas storage, and gas demands. Figure 9.1 shows a simple PLEXOS® model with two supply contracts, three pipelines, one storage facility, and two demand areas. All objects can only be connected to other objects through "node" objects. Emissions constraints can be placed on any single node or group of nodes for the gas that is flowing through that node. In this simple example, there is a constraint placed on all gas flowing from Supply 1 and Supply 2 gas contracts.

Figure 9.1: PLEXOS® Simple Model Example



For each object numerous properties can be assigned. Objects in the model include, but are not limited to:

- existing upstream pipeline capacity,
- existing storage facilities,
- existing conventional gas purchasing hubs,
- existing RNG offtake agreement and developments,
- existing on-system production resources,
- future potential capacity resources options,
- future potential compliance resources options, and
- state-specific daily demand by service type (i.e., firm vs. interruptible), aggregated from the load forecast.

In addition to the required properties for each object in the model, the Company developed custom constraints to ensure that:

- compliance requirements, which vary by scenario, are met across both states by year,[215]
- qualifying resources are acquired to meet SB 98 and HB 1257,
- quantities from development projects for alternative fuels are limited by state,
- total hydrogen is constrained to 20 percent limit by volume for each state,
- CCI acquisitions are quantity constrained by year,

[215] See beginning of Section 9.4.1 for reasoning behind requiring compliance by year and not compliance period.

- offsets are quantity constrained by year,
- Newport Takeaway projects must be completed in order,
- potential pipeline resources are selected in November,
- potential storage resources are selected in May,
- Mist Recall amounts are constrained based on peak day requirements,
- pipeline segments that are a part of the same contract must expire at the same time, and
- additional operational constraints are satisfied.

The PLEXOS® model uses the information discussed in Chapters 4 through 8 as inputs. This includes demand forecasts, resource options, price forecasts, compliance obligations, etc. Given these inputs, the cost minimization algorithm of the model assumes perfect foresight of the future and optimizes the resource selection and dispatch across time accordingly. For instance, it can choose to inject into storage in one period to avoid paying high costs in the future. Unlike the PLEXOS® model, resource planners do not have perfect foresight and face significant uncertainty and risk across several factors. NW Natural's IRP risk analysis (both scenario and stochastic) varies key input components in the model to better understand these risks. An overview of the risk analysis is discussed in the following section.

9.3 Risk Analysis

Generally, an IRP risk analysis aims to understand the risks involved in pursuing irreversible near-term actions or a long-term strategy that relies on a specific assumption about the future. Scenario analysis and stochastic variable analysis are the two primary methodologies used to assess risk for system resources in this IRP. Table 9.2 outlines the primary scenarios considered in this IRP. Scenario numbers S1-S3 (policy variations), S4-S7 (demand variations), and the acronym "PRS" (preferred resource strategy) are used to distinguish the major differences between primary scenarios. Lettering (a through e) is used to distinguish sensitivities analyzed within a primary scenario (e.g., S1.a, S1.b, etc.). The intent of the sensitivity analysis is to gain further insight into the model outputs of a primary scenario by altering or constraining key inputs. The sensitivities are outlined in separate tables in their corresponding sections.

Table 9.2: Primary Scenarios

Policy Variations	S1	CPP/CCA Compliance	Eligible resources are acquired to meet CPP and CCA compliance. No SB 98 or HB 1257 targets are considered.
	S2	Voluntary RNG Targets	SB 98 eligible resources are acquired to meet voluntary SB 98 targets. Required by Oregon Administrative Rule 860-150-0100 to be studied in an IRP; Applies to WA for voluntary RNG under HB 1257. This scenario examines meeting SB 98 targets absent CPP or CCA policy.
	S3	No GHG Compliance Policies	Considers current building codes but not CPP/CCA or RNG procurement policies; customers are served with the lowest cost resources.
Demand Variations	PRS	Reference Case	Baseline of Reference Case load forecast and preferred resource strategy constraints.
	S4	Growth Recovery	Population and housing trends experience higher growth patterns than the Reference Case.
	S5	Modest Customer Electrification	Aims to align with trends from NEEA-RBSA, projections from electric utilities of existing buildings electrifying, and limitations on natural gas in new construction buildings.
	S6	Hybrid System Electrification	Hybrid systems (i.e., electric heat pump with gas furnace as back up) are installed in existing buildings and new construction based on stock turnover.
	S7	All-Electric Buildings	Significant levels of building electrification of existing buildings and new construction based on stock turnover.

9.3.1 Preferred Resource Strategy Development and Preferred Portfolio

Oregon IRP Guideline 4[216] outlines the fundamental plan components for the IRP. One of those components is the: "[s]*election of a portfolio that represents the best combination of cost and risk for the utility and its customers."* This selected portfolio is often referred to as the preferred portfolio. To develop a preferred portfolio, this IRP first develops a **preferred resource strategy** (PRS) that sets assumptions and constraints based on subject matter expertise to reflect NW Natural's expectations around resource lead times and availability. These assumptions and constraints for the PRS are defined in Section 9.4.2 of this chapter. The preferred portfolio is

[216] See Order No.07-047. Additionally, WAC 480-90-238(2) (a) & (b) indicates that the IRP should use the lowest reasonable cost for resource selection.

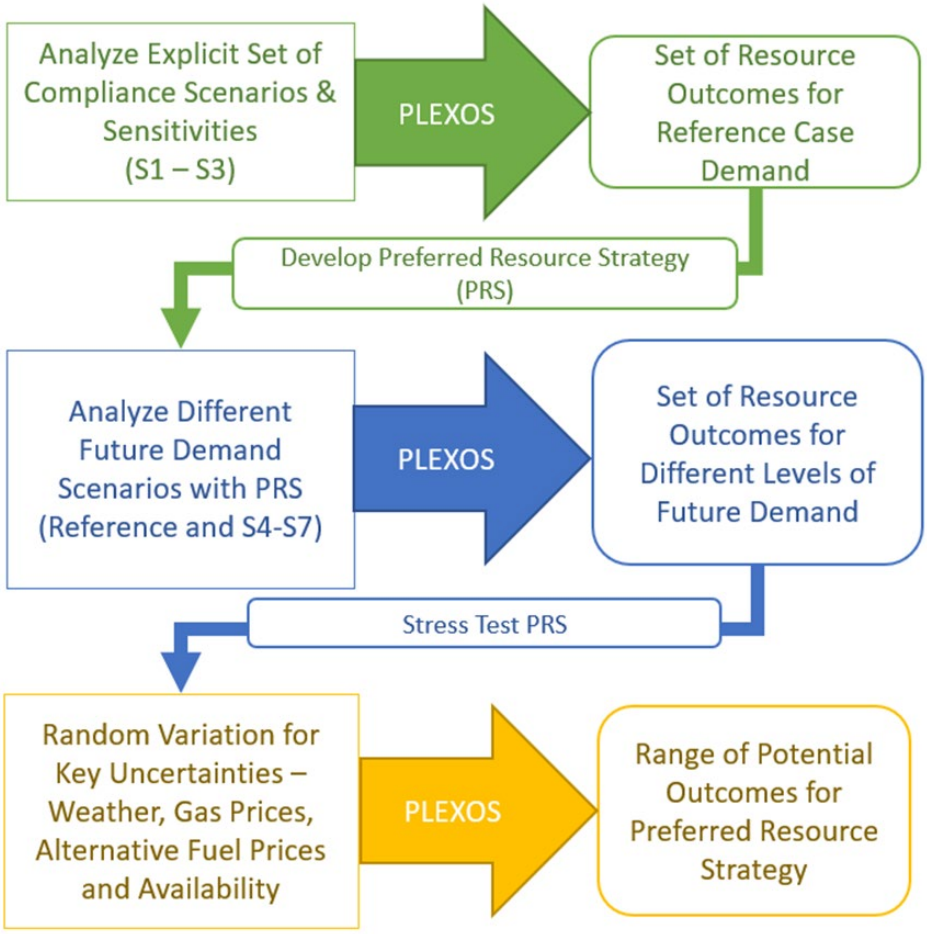
the portfolio of resources selected under these specific PRS assumptions and constraints. In other words, the preferred portfolio is an output of the PRS scenario—*PRS.a.* The results from *PRS.a* are used to calculate the avoided commodity, system capacity, and compliance costs of the avoided costs (see Appendix C).

The PRS scenario helps determine the preferred portfolio, which encompasses near-term resource acquisitions and leads to the items in the action plan associated with capacity and compliance resources. While the preferred portfolio results reflect expectations from PRS.a throughout the planning horizon, NW Natural's preferred resource path beyond the near-term action plan is to be **adaptable** to changes in resource costs, demand expectations, and levels of resource requirements over the planning horizon.

NW Natural does not find significant value in an analysis that locks in a set of preferred resources beyond the action plan and changes the relative prices of those resources, or levels of demand, but does not allow the model to dynamically adapt its resource selection. For example, if a high amount of electrification were to occur and natural gas demand were to decline, it would not be rational to force the model to purchase compliance resources in excess of what is required for compliance obligations, simply because the results from the PRS.a scenario dictate how much it should purchase. Operationally, the Company will be conducting IRPs every couple of years and will update the PRS and preferred portfolio to reflect changes in prices and demand as new information becomes available. Therefore, NW Natural prefers the use of scenarios and sensitivities to stress test how the preferred portfolio may adapt across varying demand levels, resource costs, and/or policy changes, by allowing the model to select the least cost, least risk resources to reliably serve customers and comply with emissions regulations.

Figure 9.2 diagrams the Company's process to combine scenario and stochastic analysis to develop and stress test a PRS, as well as examine sensitivities to gain deeper insight into differing resource portfolios.

Figure 9.2: Scenario and Stochastic Analysis Overview



9.4 Scenario Analysis – Compliance Resources

As mentioned above, the Company uses scenario analysis to understand the implications of various resources to inform the planning process. The section below analyzes various compliance resources and policy variations.

9.4.1 Policy Variations Analysis

This section focuses on the compliance resources required through various sensitivities around the three policy scenarios.

9.4.1.1 S1: Climate Protection Program/Climate Commitment Act Compliance – Description

Purpose: Understand the timing and cost ranges for compliance resource acquisitions to comply with the Climate Protection Program (CPP) in Oregon and the Climate Commitment Act (CCA) in Washington.

The results for all sensitivities under Scenario 1 (S1) acquire compliance resources to meet compliance obligations for the CCA and CPP obligations through the planning horizon.

The rules for the CPP and CCA require emissions obligations to be met by compliance period, and purchases of CCIs, CCA allowances, and/or offsets can be purchased within a compliance period. The initial versions of the optimization model reflected meeting obligations by compliance period, but since the model minimizes the NPV of future costs, compliance resources were being purchased on the last possible day of the compliance period for each compliance period. Operationally, intra-compliance period compliance resource procurement will be driven by many factors, such as weather, changes in customer growth, or the availability of compliance resource opportunities. IRP modeling provides guidance to achieving CPP and CCA compliance, not necessarily specifics on what compliance resources are acquired on any specific day in the forecast. Therefore, to create a smoother compliance pathway, emissions compliance, CCI limits, and offset limits are constrained by year in the model instead of compliance period. The Company notes that this approach can be overly rigid given the limited CCI allocation and severity of the compliance curve for the CPP. The exception to this constraint is the CCI purchase limit in the first CPP compliance period, as CCIs likely will not be available to purchase until late 2026, or 2027.

To understand the key resources and costs necessary to achieve compliance, the Company analyzes several sensitivities under this scenario. The notable modeling assumptions that hold across sensitivities for S1 include:

<u>CCA Compliance</u>

- The model can select as many CCA allowances quantities as needed at the auction price ceiling.
- Emissions obligations and offset limits are constrained in each year, rather than compliance period.

<u>CPP Compliance</u>

- CCIs are available starting in 2026, or later.
- CCI limits are constrained by 15 percent of compliance obligation of the first compliance period.

- After the first compliance period, CCIs are constrained to 20 percent for each year's emissions obligation.
- Emissions obligations are constrained to be in each year rather than compliance period.

Alt Fuels/RTCs/CCUS

- Development projects for RNG are not available until 2028, or later.
- Development projects for Hydrogen, Synthetic Methane, and CCUS are not available until 2035, if the resource is available.
- RTC contracts are available for the first three years based on NW Natural 2024 RFP cost and quantity results.
- RTC purchases are available as needed starting in 2028 at a cost based on ICFs D3 RIN market price forecast.

Table 9.3 lists five different sensitivities under S1, a description of each sensitivity, and the key changes between sensitivities.

Table 9.3: Sensitivity Descriptions

#	Sensitivity Parameters
S1.a	Name: **Low-cost compliance** Description: This is the least constrained model and sets the lower bound of CPP/CCA compliance costs. CCA Compliance • Low CCA Allowance Price forecast from cCarbon • Offsets available at full quantity; 8% of the obligation in each year for the first compliance period, and 6% starting in 2027 for the rest of the planning horizon CPP Compliance • CCI purchases are available starting in 2026 Alt Fuels/RTCs/CCUS • Access to all alternative fuels as specified in the alternative fuel study conducted by ICF and aggregated to buckets for PLEXOS® modeling; this includes low-cost LFG RNG projects and the full amount of CCUS • RNG is available in 2028 • Hydrogen, Synthetic Methane, and CCUS are not available until 2035
S1.b	Name: **Mid-cost compliance** Description: This sensitivity sets constraints on key resources that can drive higher compliance costs.

#	Sensitivity Parameters
	CCA Compliance • cCarbon Allowance price forecast for the linked scenario • Offsets are not available until 2027 • Offsets are limited to 3% of obligation per year CPP Compliance • CCI purchases are available starting in 2026 Alt Fuels/RTCs/CCUS • There is no access to low-cost LFG RNG projects • CCUS from EITE customers is not available for NW Natural's emission obligation • RNG is available in 2028 • Hydrogen, Synthetic Methane, and CCUS are not available until 2035
S1.c	Name: **High-cost compliance** Description: This sensitivity sets further constraints on key resources that can drive compliance costs higher and sets an upper bound of CPP/CCA compliance costs. CCA Compliance • Allowance prices are at the price ceiling for the entire planning horizon • Offsets are not available at any point in the planning horizon CPP Compliance • CCI purchases are not available until the second compliance period starting in 2028 Alt Fuels/RTCs/CCUS • There is no access to low-cost LFG RNG projects • NW Natural's share of RNG is reduced from 33% to 20% • Prices are 20% higher for all alternative fuel resources • ICFs D3 RIN high price forecast is used • CCUS is not available • Blue hydrogen is not available • RNG is available in 2028 • Hydrogen and Synthetic Methane are not available until 2035
S1.d	Name: **RTC dependence** Description: This sensitivity sets constraints on development projects not to be available until 2035. Synthetic Methane from Biomass is not available. Additional constraints mirror S1.b for comparison. CCA Compliance • cCarbon Allowance prices are forecasted for the linked scenario • Offsets are not available until 2027

#	Sensitivity Parameters
	• Offsets are limited to 3% of obligation per year CPP Compliance • CCI purchases are available starting in 2026 Alt Fuels/RTCs/CCUS • There is no access to low-cost LFG RNG projects • CCUS from EITE customers is not available for NW Natural's emission obligation • RNG is not available until 2035 • Hydrogen, Synthetic Methane, and CCUS are not available until 2035 • Synthetic Methane from Biomass is not available
S1.e	Name: **No CPP Instrument Banking** Description: This sensitivity does not allow for banking of DEQ Distributed Allowances across compliance periods. This restricts purchasing CCIs to meet the CPP compliance within a compliance period and does not allow for purchasing CCIs in advance to bank DEQ instruments for later use. Additional constraints mirror S1.b for comparison. CCA Compliance • Carbon Allowance price forecast for the linked scenario • Offsets are not available until 2027 • Offsets are limited to 3% of obligation in each year CPP Compliance • CCI purchases are available starting in 2026 • Banking DEQ Distributed Allowances across compliance periods is not allowed Alt Fuels/RTCs/CCUS • There is no access to low-cost LFG RNG projects • CCUS from EITE customers is not available for NW Natural's emission obligation • RNG is available in 2028 • Hydrogen, Synthetic Methane, and CCUS are not available until 2035

9.4.1.2 S1: Climate Protection Program/Climate Commitment Act Compliance – Results

Figure 9.3 shows the year-by-year CPP compliance resources acquired, and Figure 9.4 shows the year-by-year CCA resources acquired for the mid-cost compliance sensitivity (S1.b). For this sensitivity, CPP compliance shows a high reliance on CCI purchases, and RNG from landfills and waste-water treatment plants in the near-term. In the long-term, compliance will rely on CCUS and Synthetic Methane from Biomass once the model is allowed to select them starting in 2035, with a small amount of RTC purchases at the very end of the planning horizon. For CCA compliance, the results show a primary reliance on CCA allowances and offsets with a small

amount of RNG from wastewater at the end of the planning horizon. Results for each sensitivity are included in Appendix H.

Figure 9.3: S1.b CPP Compliance Resources

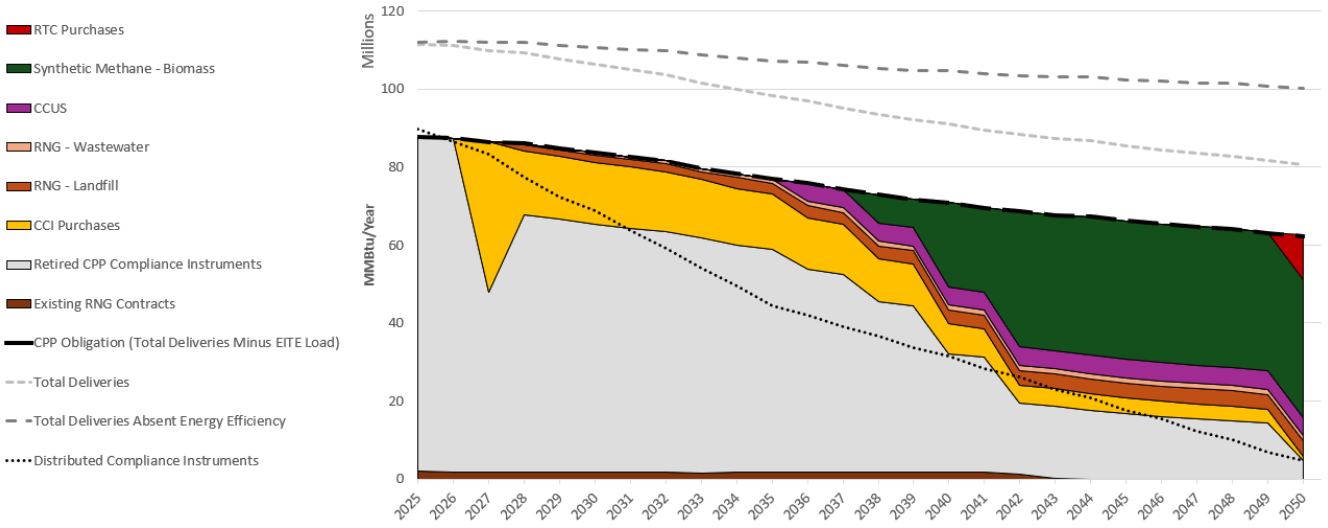
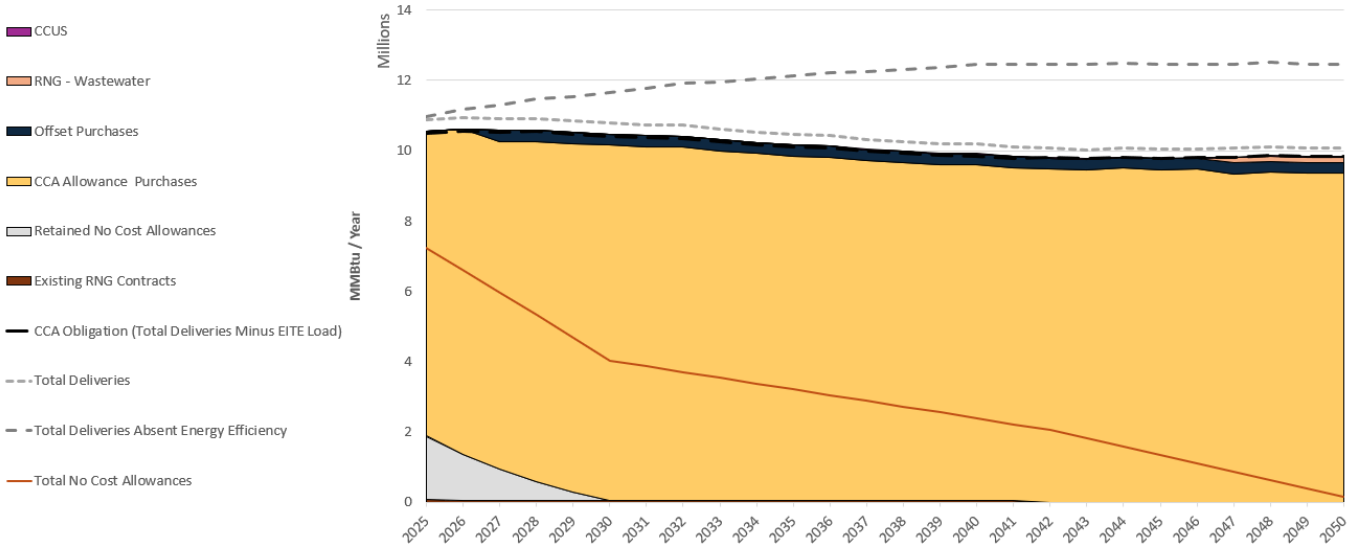


Figure 9.4: S1.b CCA Compliance Resources



Figures 9.5 and 9.6 further break down the costs of S1.b by year. Annual results for each sensitivity are included in Appendix H.

Figure 9.5: S1.b Annual Compliance Cost by CPP Compliance Period

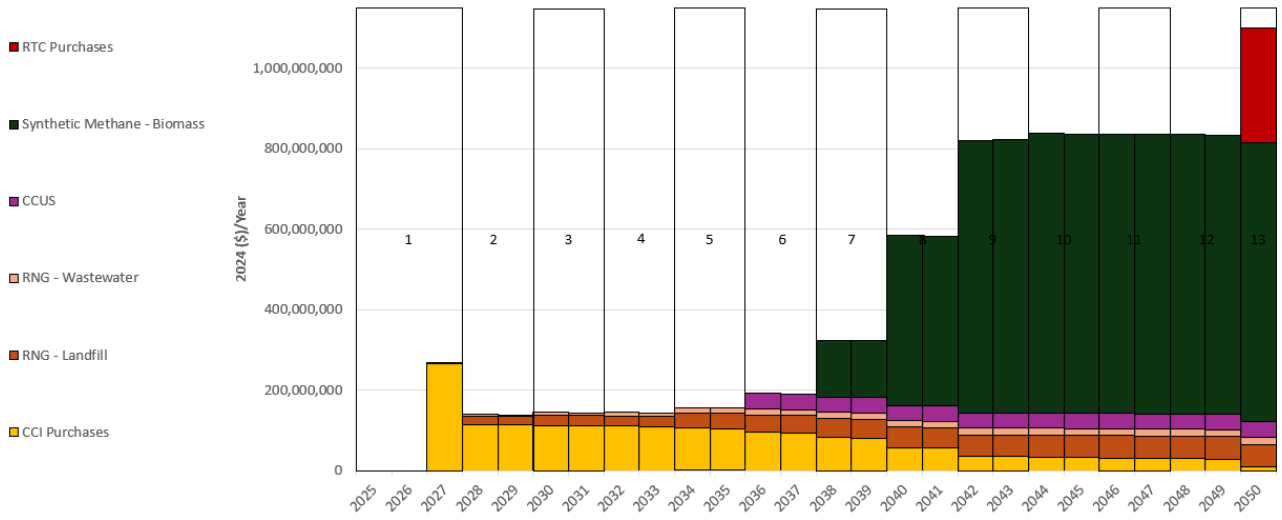
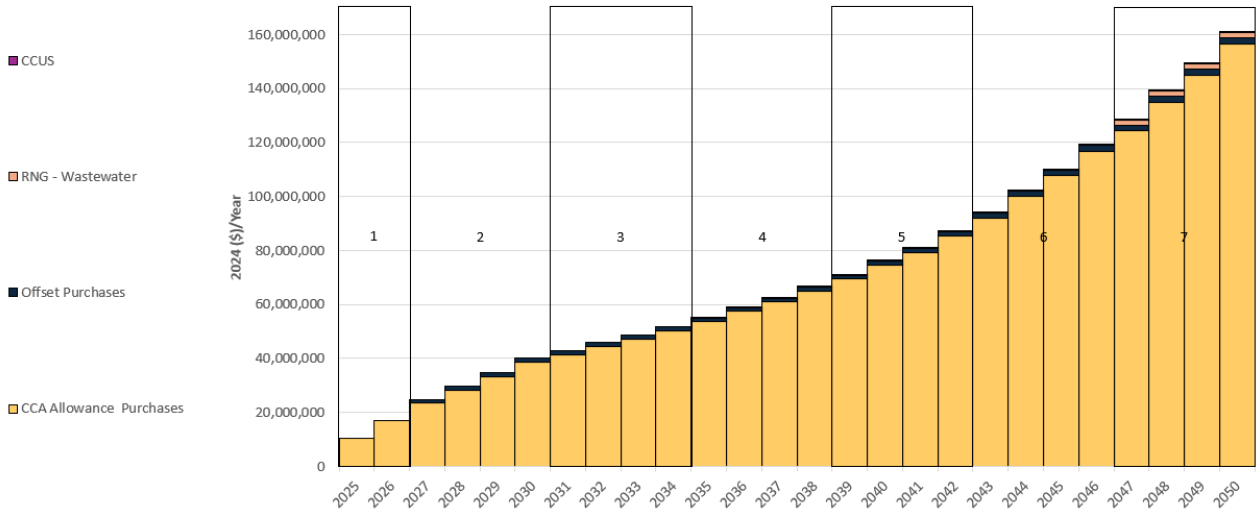


Figure 9.6: S1.b Annual Compliance Cost by CCA Compliance Period



To consolidate the results across sensitivities, Figures 9.7 and 9.8 show the NPV of the cumulative compliance resource expenditures for each sensitivity under S1 for CPP and CCA compliance, respectively.

Figure 9.7: S1 Net Present Value of CPP Compliance Costs

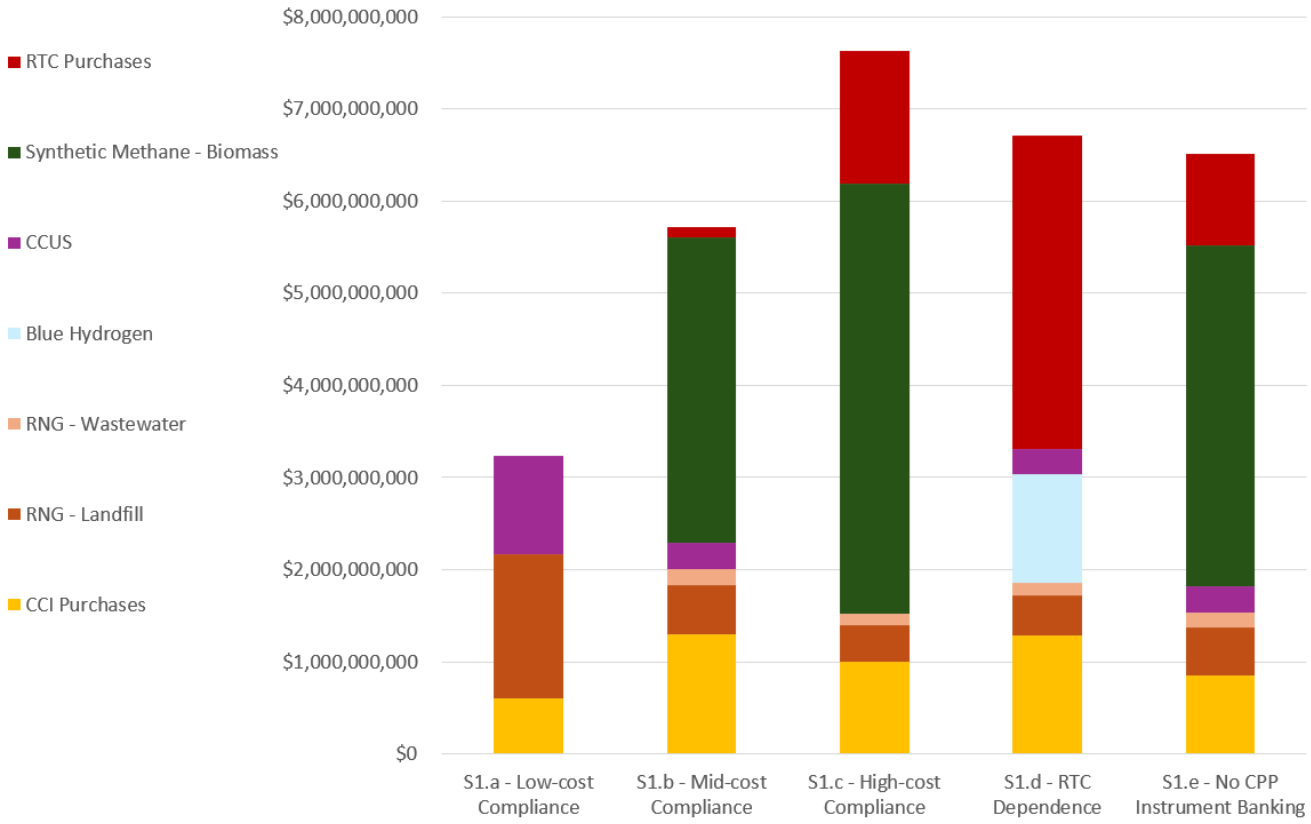


Figure 9.8: S1 Net Present Value of CCA Compliance Costs

9.4.1.3 S1: Climate Protection Program/Climate Commitment Act Compliance – Implications

The resource acquisition graphs and annual cost graphs for each sensitivity can be found in Appendix H. By comparing the results between sensitivities, and through various iterations of this analysis, the Company identified key resources and cost dependencies. In cases where NW Natural identified such dependencies, scenario and sensitivity analysis was utilized to explore further.

Climate Protection Program Summary

- **Comparing S1.a, S1.b and S1.e:** The Company should maximize CCI purchases in each compliance period unless low-cost RNG resources (e.g., low-cost LFG RNG) are available throughout the planning horizon. By maximizing CCI purchases, the Company can bank any excess DEQ compliance instruments to avoid higher cost alternative fuels needed for future compliance periods. Not pursuing this strategy and not banking DEQ compliance instruments would result in higher costs for customers in future years.

- **Comparing S1.b to S1.e:** The CCI cap (i.e., 20% in later compliance periods) is a percentage of the remaining obligation after subtracting out all other compliance resources. This creates a tradeoff the model must consider when solving—for every unit of alternative fuels required to meet CPP compliance, the CCI limit decreases by 1/20th. The CCIs limit as an absolute number is ultimately squeezed out over the planning horizon.
- **Model iteration**: The initial iterations of modeling CPP compliance demonstrated that the model could minimize NPV costs by purchasing CCIs at the end of each compliance period for the entire compliance period obligation. This effect is still observed in the first compliance period, as CCIs are purchased in 2027 for the full three-year compliance period 1 obligation (see Figure 9.3). Buying compliance resources in a single year to meet full compliance period obligations would also occur throughout the planning horizon with other compliance resources if the PLEXOS® model was constrained by compliance period instead of year.
- **Comparing S1.c to all other S1 and Model iteration:** CCUS is a critical resource for CPP compliance. The amount of CCUS available to NW Natural is very dependent on how many large industrial customers NW Natural can collaborate with and how CCUS from EITE customers are treated under CPP rules. The initial iterations of modeling CCUS were not constrained to a 10-year lead time and thus was selected prior to 2035. A 10-year lead time is a conservative modeling assumption for CCUS, and the Company does expect that some projects may be completed faster (e.g., CCUS Pilot mentioned below).
- **Comparing S1.b to S1.d:** Although RTC purchases are flexible, development projects from Landfill RNG, Wastewater RNG, and Synthetic Methane from Biomass are expected to be lower cost than an RTC dependent strategy; however, if Synthetic Methane from biomass is not available, NW Natural can comply with CPP through hydrogen development and RTC purchases.
- **Comparing all sensitivities:** The specific local water resource recovery facility RNG project that is being evaluated is selected for CPP compliance in all sensitivities except S1.a, where low cost RNG from landfill gas is available throughout the planning horizon. This project is a near-term opportunity and can only be selected in 2027. Analogous to the reasoning for maxing out the purchase of CCIs, the model selects this opportunity to displace some purchases of the more expensive Synthetic Methane from biomass in in the future.
- **Comparing S1.b to S1.c:** The results from S1.a demonstrate a future where compliance is achieved through development of low-cost RNG from landfill gas and CCUS. NW Natural views S1.b as a reasonable lower bound for CPP compliance costs and S1.c as a sensible upper bound under Reference Case expected weather demand levels. Monte

Carlo analysis, presented in Section 9.6, provides a range and distribution of NPV CPP compliances costs based on variation in weather and compliance resource costs. Scenarios with high levels of electrification will have significantly lower compliance costs. These costs are discussed in tandem with electrification costs in Chapter 11.

Climate Commitment Act Summary

- **Comparing S1.a, S1.b, and S1.c:** Compliance with the CCA in Washington will rely primarily on allowance purchases and any available offsets until the allowance prices exceed the costs of alternative compliance resources.
- **Comparing S1.a, S1.b, and S1.c:** Compliance costs for the CCA are highly dependent on how the allowance market prices evolve over time but are capped at the price ceiling.
- **Comparing S1.a, S1.b, and S1.c:** Allowance prices are expected to increase over time as the state-wide cap on allowances decreases. This will gradually increase CCA compliance costs over time.
- **Results from S1.b:** Small amounts of CCUS and RNG are expected to be cost competitive with allowance prices as allowance prices increase towards the end of the planning horizon, but the opportunities from these cost-competitive resources will be very limited.
- **Comparing S1.a to S1.c:** Unlike CPP compliance, S1.a does not rely on low-cost landfill RNG and significant amounts of CCUS for CCA compliance; thus, it represents a reasonable lower bound for CCA compliance costs and S1.c represents a reasonable upper bound under Reference Case expected weather demand. Monte Carlo analysis presented in Section 9.6 provides a range and distribution of NPV CCA compliances costs based on variation in weather and compliance resource costs. Scenarios with high levels of electrification will have significantly lower compliance costs. These costs are discussed in tandem with electrification costs in Chapter 11.

9.4.1.4 S2: SB 98 Renewable Natural Gas Targets – Description

Purpose: Understand the timing and range of costs for compliance resource acquisition to meet voluntary Renewable Natural Gas (RNG) targets in Oregon and Washington.

- The results for all sensitivities under S2 acquire compliance resources to meet voluntary RNG targets. This scenario complies with the Oregon Administrative Rule 860-150-0100 requirement that these targets and costs be studied in an IRP as well as understanding what decarbonization actions might look like in the absence of mandatory emissions reductions policies.
- Both SB 98 for Oregon and HB 1257 for Washington have cost containment conditions that limit the amount of voluntary RNG purchases.

> *SB 98: If the large natural gas utility's total incremental annual cost to meet the targets of the large renewable natural gas program exceeds five percent of the large natural gas utility's total revenue requirement for an individual year, the large natural gas utility may no longer be authorized to make additional qualified investments under the large renewable natural gas program for that year without approval from the commission.*
>
> *HB 1257: The customer charge for a renewable natural gas program may not exceed five percent of the amount charged to retail customers for natural gas*

There is no direct way to model cost containment constraints within NW Natural's current resource planning optimization model. Instead, NW Natural constrains the model to meet specified volumetric targets and then examines the cost of achieving those targets relative to five percent of the Company's current revenue requirement. Table 9.4 outlines two sensitivities that are examined in achieving these targets.

Table 9.4: S2 SB 98 / HB 1257 Sensitivities

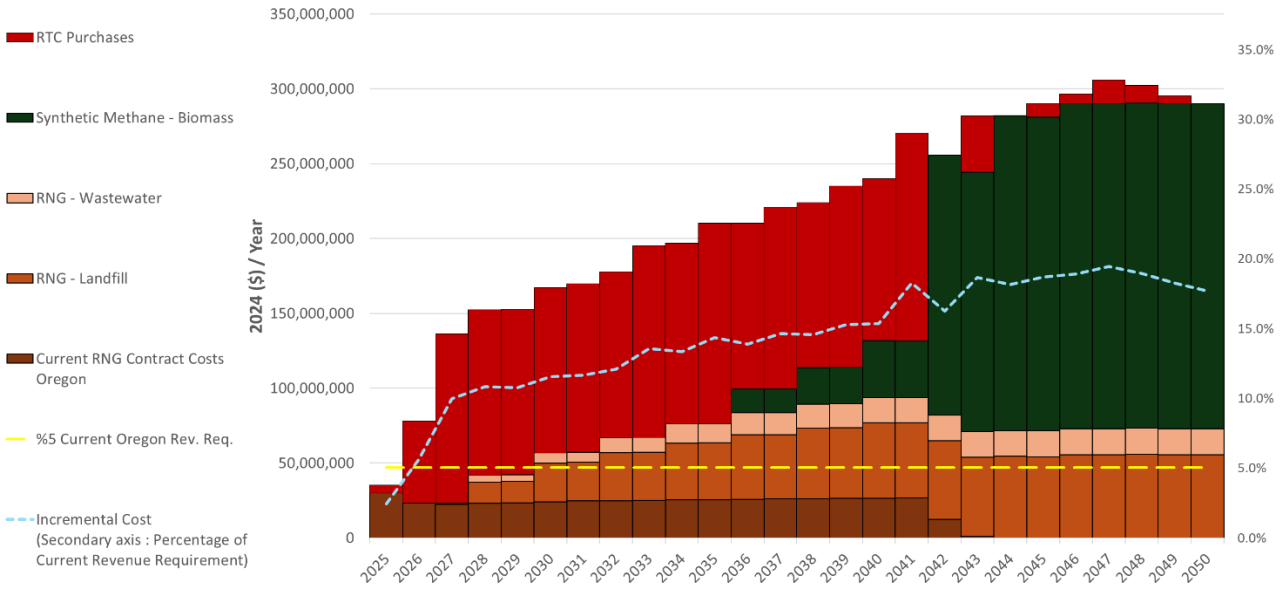
#	Sensitivity Parameters
S2.a	Name: **Voluntary RNG Low-cost** Description: This is the least constrained model and sets the lower bound of compliance costs for achieving voluntary targets. Alt Fuels/CCUS • Access to all alternative fuels as specified in the Alternative Fuels Study and aggregated into buckets for PLEXOS® modeling; this includes low-cost LFG RNG projects and the full amount of CCUS.
S2.b	Name: **Voluntary RNG Mid-cost** Description: This sensitivity sets constraints on key resources that can drive higher compliance costs for achieving voluntary targets. Alt Fuels/CCUS • There is no access to low-cost LFG RNG projects.

9.4.1.5 S2: SB 98 Renewable Natural Gas Targets – Results

Figures 9.9 and 9.10 show the incremental cost, by year, for Oregon and Washington, respectively, for sensitivity S2.b. Equivalent results for S2.a can be found in Appendix H. These cost graphs show the total cost for each individual resource and the full incremental cost. In

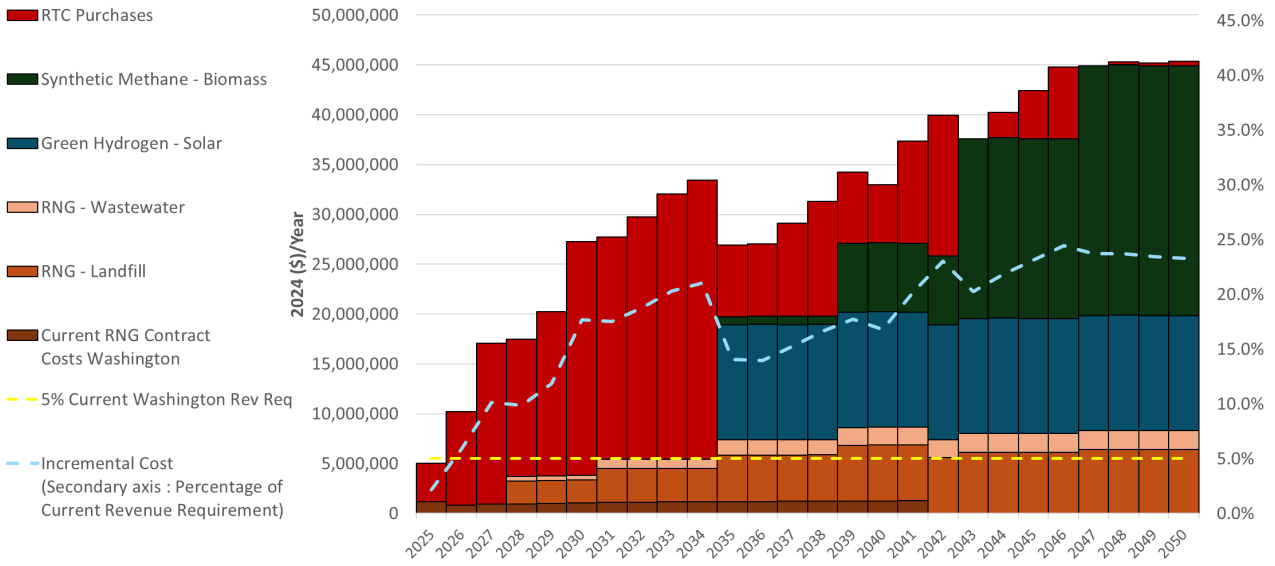
this scenario, without CPP or CCA compliance, avoided GHG combustions costs would equal the social cost of carbon, which is used to calculate incremental costs.[217] A scenario, such as the PRS discussed later in this chapter, with overlapping policies (e.g., SB 98+CPP or HB 1257+CCA) would have higher avoided GHG compliance costs.

Figure 9.9: S2.b Annual Compliance Costs for SB 98 Targets



[217] Avoided costs use the maximum of the social cost of carbon or GHG compliance costs for combustion.

Figure 9.10: S2.b Annual Compliance Costs for HB 1257 Targets

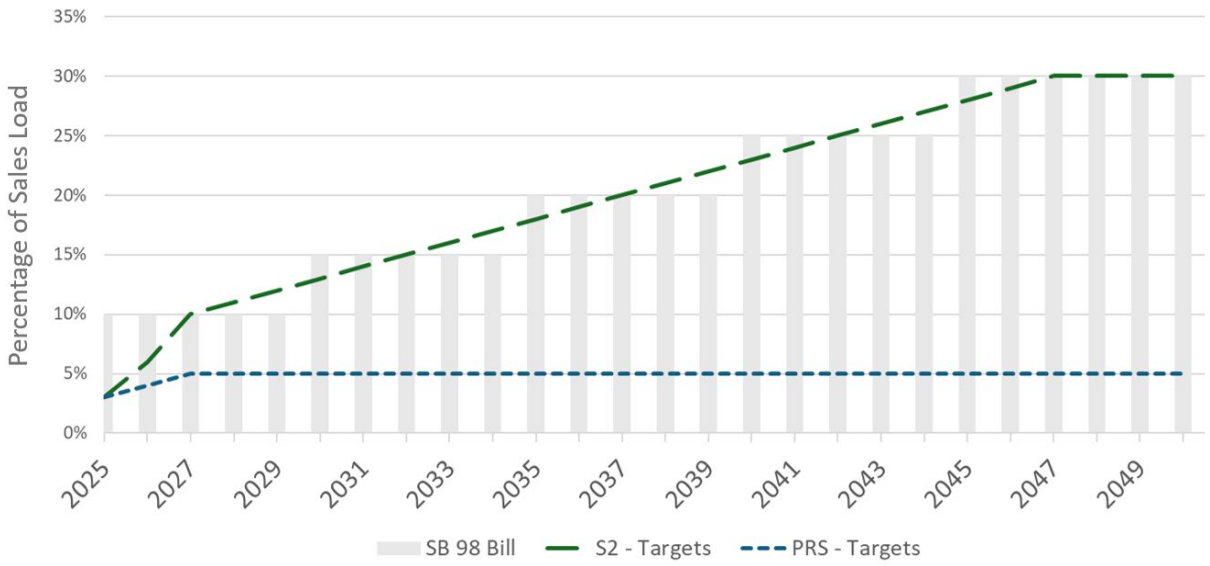


9.4.1.6 S2: SB 98 Renewable Natural Gas Targets – Implications

Many factors impact the revenue requirement, which will change throughout the planning horizon. Additionally, RNG opportunities can significantly vary in costs; however, the results of this scenario suggest that absent CPP and CCA policies, voluntary RNG procurements will be constrained by the cost containment provisions in SB 98 and HB 1257 in both the near- and long-term. Figures 9.9 and 9.10 show that roughly, a one percent increase in RNG volume translates to roughly incremental costs equaling one percent of the revenue requirement. Since both SB 98 and HB 1257 set a five percent cost threshold--albeit slightly different definitions in Oregon and Washington--NW Natural constrains the SB 98 and HB 1257 in the PRS to only five percent of sales demand.

Figure 9.11 shows the target levels as defined in the SB 98 bill, the targets modeled in S2, and ultimately what is used in the PRS.

Figure 9.11: Voluntary RNG Targets



Summary of Implications:

- At RTC prices observed from NW Natural's RFP process, a 1 percent acquisition of RNG corresponds to incremental costs equaling about 1 percent of the revenue requirement.
- Voluntary RNG will be limited by cost containment conditions specified in both Oregon and Washington statutes.
- The specific local water resource recovery facility RNG project that is being evaluated is a qualifying resource for SB 98 and is also selected as a least cost resource in S2.b, but is not selected in S2.a where lower cost RNG from landfill gas is available throughout the planning horizon.
- Estimated levelized RNG production costs can range from $7-$160 / MMBtu depending on the feedstock and scale of a project. Actual projects costs will depend on several factors and will vary widely from project to project; however, low-cost development projects will be key to containing costs as RTC purchases are likely to be higher cost options and subject to market volatility.

9.4.1.7 S3: No Greenhouse Gas Compliance Policies

Purpose: Establish a baseline to compare costs and resource acquisitions that are policy driven.

There are no incremental compliance resources or costs under this scenario. This section is intentionally included, and very brief, to reiterate that previous sections for S1 and S2 only focus on incremental compliance costs. Capacity and energy resource selections for varying levels of demand are discussed in Section 9.5.

9.4.2 Preferred Resource Strategy – Description

Purpose: Using insight from the sensitivity analysis for S1-S3, develop pragmatic assumptions and constraints for costs, availability, and lead time for compliance resources. The Preferred Resource Strategy (PRS) assumptions and constraints are used to stress test how the preferred portfolio would change under varying levels of demand.

After exploring several sensitivities around compliance resource selection, NW Natural developed a set of constraints to reflect the Company's expectations regarding the timing and availability of compliance resource options. Establishing the constraints for the PRS requires both quantitative and qualitative analysis but reflects what NW Natural views as a pragmatic outlook.

The following bullets outline the compliance resource constraints of NW Natural's PRS.

- *Compliance with CPP and CCA with limited amounts of voluntary RNG*

CPP: The PRS is rooted in OPUC and OPUC Staff guidance to pursue a least-cost, least-risk strategy to comply with the CPP. Unlike NW Natural's 2022 IRP, the Company is not proposing to meet SB 98 RNG targets first and then take incremental actions to comply with the CPP.[218] The OPUC disagreed with that strategy in the 2022 IRP, but neither OPUC nor OPUC Staff dismissed RNG acquisitions in order to comply with the CPP. The OPUC explained that it "expect[s] the Company to pursue RNG and CCIs in the most economical way possible to minimize compliance costs and risks," but "do[es] not direct NW Natural to pursue a CCI-only strategy."[219]

During commissioner deliberations on the 2022 IRP, former Chair Decker stated that she wanted NW Natural to "demonstrate[e] that RNG or a particular type of RNG is a way of

[218] Under SB 98 (ORS 757.396(1)), NW Natural "may make qualified investments and procure renewable natural gas from third parties to meet the . . . portfolio targets" listed in that law. NW Natural continues to maintain that the CPP does not alter or revise SB 98 in any way. However, NW Natural does not address this legal issue due to its CPP compliance strategy as explained above.

[219] In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan, Docket No. LC 79, Order No. 23-281, at 11 (Aug. 2, 2023).

mitigating risk across all the ways that the policy landscape of decarbonization can change going forward."[220] Similarly, OPUC Staff stated "[f]urther evaluation may show that slightly over-procuring RTCs for compliance flexibility could be a better value for customers than setting aside a portion of lower-cost CCIs to use just in case."[221]

The PRS incorporates OPUC and OPUC Staff's feedback on the 2022 IRP. Specifically, to comply with the CPP, NW Natural will first purchase CCIs while incorporating limited amounts of near-term RNG purchases. This strategy is a major change from the 2022 IRP where, as explained above, NW Natural had proposed first meeting SB 98 RNG targets and then purchasing CCIs as necessary to comply with the CPP.

However, NW Natural can only purchase a limited amount of CCIs and the Company's resource optimization model indicates that it should take additional compliance actions no later than 2028. Rather than waiting until the last possible moment to take these additional compliance actions, NW Natural proposes to acquire a limited amount of RNG. As a percentage of sales demand, these voluntary RNG targets are set to 3 percent for 2025; 4 percent for 2026; and 5 percent for 2027-2050. In comparison, the SB 98 targets are much higher—10 percent in 2025, growing to 30 percent by 2045.

NW Natural is setting modest RNG targets slightly ahead of mandatory CPP compliance needs for several reasons. First, RNG is not a liquid market. By participating in relatively frequent and relatively small RNG acquisitions, NW Natural can more easily obtain price discovery, helping mitigate cost risk over the longer term.

Second, securing relatively small amounts of RNG helps mitigate the risk that the CPP, including CCIs specifically, is not durable. For example, in the most recent Oregon legislative session there were discussions about replacing the CPP with a cap-and-trade system that is similar to Washington's and California's cap-and-trade systems. Similarly, a prior version of the CPP was invalidated by the Oregon Court of Appeals, and the long-term legal durability of the current CPP remains an open question that could be decided by the court system in the future. Further, the risks of CCIs must be better understood because even the basics about CCIs remain unknown, including the entity that will receive CCI dollars, what that entity will do with the dollars, when CCI credits will be available, whether and when emissions reductions will actually be attained, etc. All of this creates a risk around the CPP and, specifically, CCIs. Again, although NW Natural proposes to first purchase CCIs, the Company believes it is a sensible strategy to

[220] Special Public Meeting LC 79 NWN IRP Commissioner Work Session Video 1, Chair Decker, 1:12:47, (June 6, 2023) (available at: https://www.oregon.gov/puc/news-events/Pages/default.aspx).
[221] In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan, Docket No. LC 79, Order No. 23-281, at Appendix A 11-12 (Aug. 2, 2023).

take modest steps to mitigate the risks of a changing policy landscape while still taking actions to reduce emissions. Such RNG acquisitions are in-line with guidance from the last IRP cited above that encouraged NW Natural to demonstrate how RNG can mitigate risks of such changes.[222]

Third, the limited amounts of voluntary RNG being modeled never exceed five percent of sales load. Although many factors impact revenue requirement, this RNG volumetric cap limits costs to remain within the range specified by the cost containment conditions for SB 98 in Oregon and HB 1257 in Washington. In contrast, the 2022 IRP gradually increased RNG acquisitions to meet SB 98 targets, equaling 30 percent by 2050.

Fourth, to Staff's point in the prior IRP, there is value in "slightly over-procuring RTCs [environmental attributes associated with RNG] for compliance flexibility." Since CPP compliance obligations are not weather normalized and are set in specific volumetric terms, there is a risk that NW Natural may need to take additional compliance steps earlier than expected for various reasons that include colder than expected weather, higher customers growth, or less than expected realized energy efficiency savings. NW Natural can mitigate most of this risk in the first and second compliance period by maximizing CCI purchases and relying on banked DEQ instruments to meet the Company's obligation. By having a modest amount of RNG as a form of insurance, NW Natural can further increase the Company's bank of DEQ instruments, helping to mitigate this uncertainty risk further out in the future. NW Natural does not view penalty payments associated with non-compliance as viable options for customers in this IRP modeling.

Finally, the insurance that RNG provides is affordable. In the last IRP, NW Natural projected that its RNG acquisitions that corresponded to the targets outlined in SB 98 would increase costs by approximately $150 million net present value over the course of the 20-year plan. However, in this IRP, by taking a limited approach to acquiring voluntary RNG the cost impact to customers is immaterial, while mitigating a number of risks associated with CPP compliance.

CCA: As explained below, NW Natural's preferred portfolio will primarily rely on CCA allowance purchases. However, NW Natural will pursue CCA-qualified opportunities, if available, as well as relying on small amounts of RNG.

- *No available low-cost landfill RNG*

NW Natural will continue to pursue opportunities at landfills as they become available, but the costs associated with the low-cost landfill gas RNG are developed from very large landfills that

[222] Special Public Meeting LC 79 NWN IRP Commissioner Work Session Video 1, Chair Decker, 1:12:47, (June 6, 2023) (available at: https://www.oregon.gov/puc/news-events/Pages/default.aspx).

achieve their low cost through economies of scale. There is low likelihood that NW Natural would be able to develop a RNG project from these larger landfills because they are likely already developed by other owners/developers and producing RNG.

- *No CCUS from EITE customers*

CCUS from the Company's largest customers appears to be a promising CPP and CCA compliance pathway. The Alternative Fuels Study included all of our large customers, including EITE customers, in the analysis of CCUS because at the time the analysis was in development, the CPP rules for EITE were not final. Further, the CPP rules around acquiring the environmental benefits of NW Natural investments in CCUS at EITE locations are unclear, and therefore, NW Natural made the conservative assumption not to include any CCUS from EITE customers.

- *CCIs are available starting in late 2026*

DEQ's current timeline projects that CCIs will be available for purchase in Q4 of 2026, although the amount that NW Natural can purchase is limited by rule. The model allows for CCI purchases in 2026, but the model does not select them until 2027 for the first compliance demonstration.

- *General development projects for RNG will not be available until 2028 and RTCs are available in the near-term*

General development projects that are being evaluated today will likely take at least three years to complete. A specific development project that NW Natural is currently evaluating is included in the portfolio modeling. This project, briefly described in Section in 7.7.3 (more details are provided in Appendix M), and could begin production as early as 2027. In the near term (through 2027) RTCs are available. Costs, quantities, and contract lengths for RTCs are based on offtake projects that bid into NW Natural's 2024 RFP.

- *Development projects for Hydrogen, Synthetic Methane, and CCUS are not available until 2035*

While these compliance resources do come from proven technologies, developing these resources will require sufficient lead time to scope and develop. NW Natural expects that ten years is sufficient lead time if these projects are required for compliance.

- *Qualified CCA offset availability is limited to three percent of CCA obligation*

To date there has been a minimal number of offset projects that have qualified for CCA compliance. CCA rules allow for six percent of a covered entity's obligation to be met by offsets starting in the second compliance period, however; available qualified opportunities for the Company to pursue have yet to materialize. At this point, the Company anticipates that the lack of qualified offsets will likely be more constraining than the six percent limit outlined in CCA

rules, therefore; the PRS limits offsets purchases in the model to a maximum of three percent of the Company's CCA obligation.

9.4.2.1 PRS.a – Preferred Portfolio Results

Figures 9.12 and 9.13 show the compliance resources acquired under the PRS assumptions for Oregon and Washington, respectively. These results represent NW Natural's preferred portfolio for the 2025 IRP. The avoided GHG compliance costs (see Appendix C) are based on the marginal resources needed to comply with the CPP and CCA from this *PRS.a* scenario. Annual compliance costs graphs can be found in Appendix H.

Figure 9.12: PRS.a – Annual Oregon Compliance Resource Selection

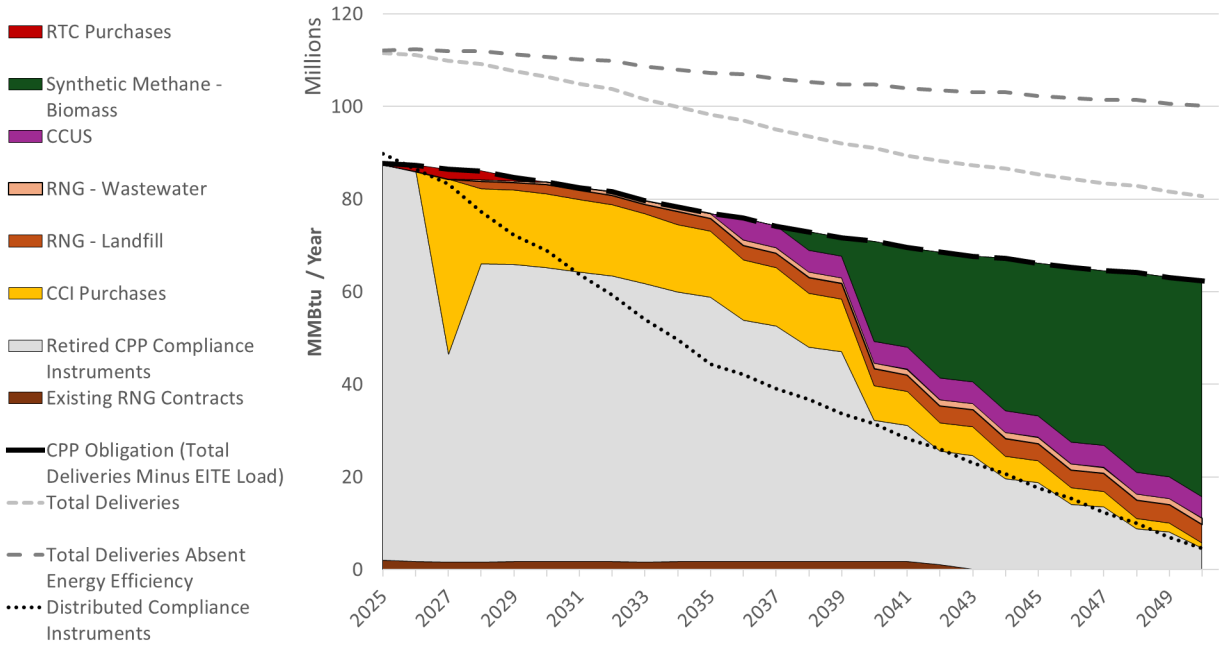
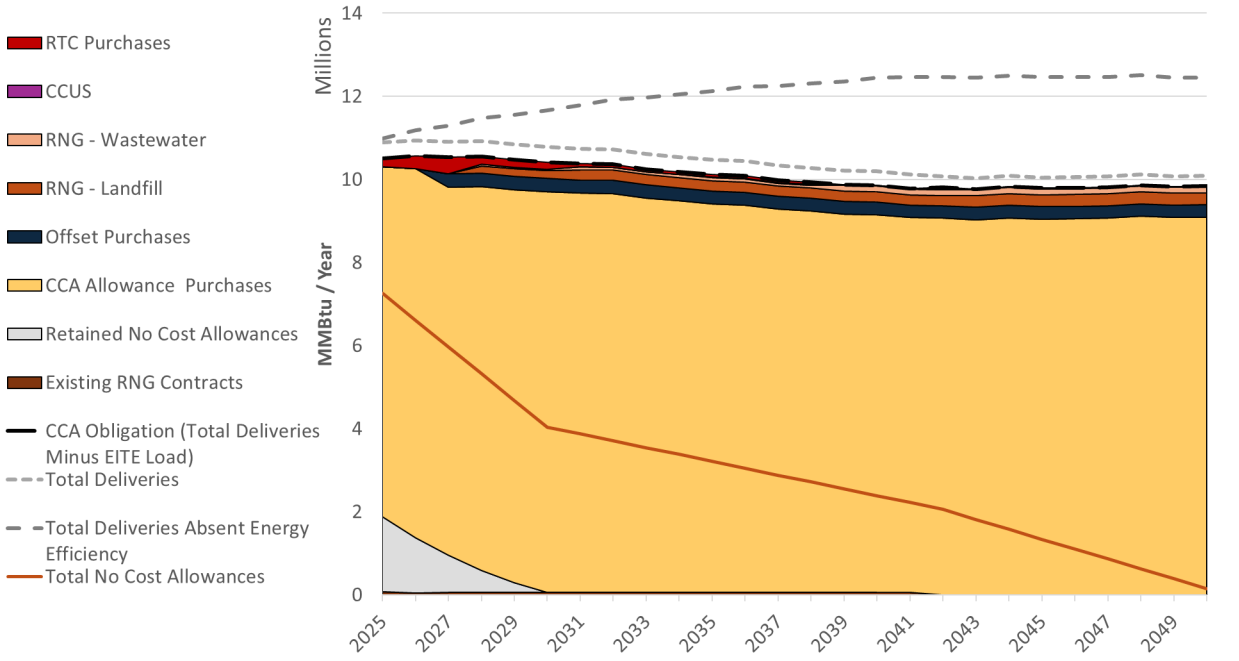


Figure 9.13: PRS.a – Annual Washington Compliance Resource Selection



9.4.2.2 *Oregon Compliance Resource Pathway*

The preferred portfolio will rely heavily on CCI purchases for CPP compliance in the near-term and bank DEQ compliance instruments. NW Natural will rely on small amounts of RNG from off-take agreements, landfills, wastewater treatment plants, or other low-cost RNG opportunities to meet its five percent of sales demand voluntary RNG target to mitigate risk from changing environmental policies and guidelines. Later in the planning horizon, the Company will need to rely on CCUS and synthetic methane from biomass to meet CPP compliance requirements.

9.4.2.3 *Washington Compliance Resource Pathway*

The preferred portfolio will primarily rely on CCA allowance purchases for CCA compliance. NW Natural will pursue any CCA qualified offset opportunities that become available if they are expected to be lower cost than allowance purchases; however, given the minimal number of projects that have qualified to date and that the amount of offsets that NW Natural can purchase for compliance are limited by rule, the Company does not expect offsets to be a major part of the CCA compliance portfolio. Like Oregon, NW Natural will rely on small amounts of RNG from off-take agreements, landfills, wastewater treatment plants, or other low-cost RNG opportunities to meet its five percent of sales demand voluntary RNG target ad mitigate risk from changing environmental policies.

9.4.3 Demand Variation Analysis

Purpose: The PRS constraints are modeled for the Reference Case demand forecast and four other demand variation scenarios. Under these conditions, the resources selected in *PRS.a* represent NW Natural's preferred portfolio. Variations shown in scenarios S4-S7 demonstrate how NW Natural's preferred portfolio would adapt to changes in the level of demand.

Changes in demand are driven by variations in both customer counts and usage profiles across each of the four scenarios. NW Natural develop a growth recovery scenario that shows a potential higher than expected customer growth. To align demand variation scenarios with the electrification scenarios, NW Natural provided the Reference Case daily demand and design peak day demand over the planning horizon for both Washington and Oregon to ICF. Using the NREL Res and Com Stock dataset ICF calculated the decrements to the Reference Case demand for each day and design peak day to provide an apples-to-apples comparison decreased natural gas demand due to electrification. See Chapter 10 and Chapter 11 for more detail and implications on the electrification modeling.

Figures 9.14 through Figure 9.15 show the impacts to annual demand and therefore annual emissions across the different demand variation scenarios. Note that the corresponding system emissions obligation are shown after subtracting out emissions from EITE customers and existing RNG contracts. Differences in design day peak demand for each scenario are shown in Section 9.5, which have implications for system capacity resources. Similar graphs are presented in Chapter 10, which focus on residential and commercial sectors.

Figure 9.14: Demand Variation Scenarios - Annual Demand

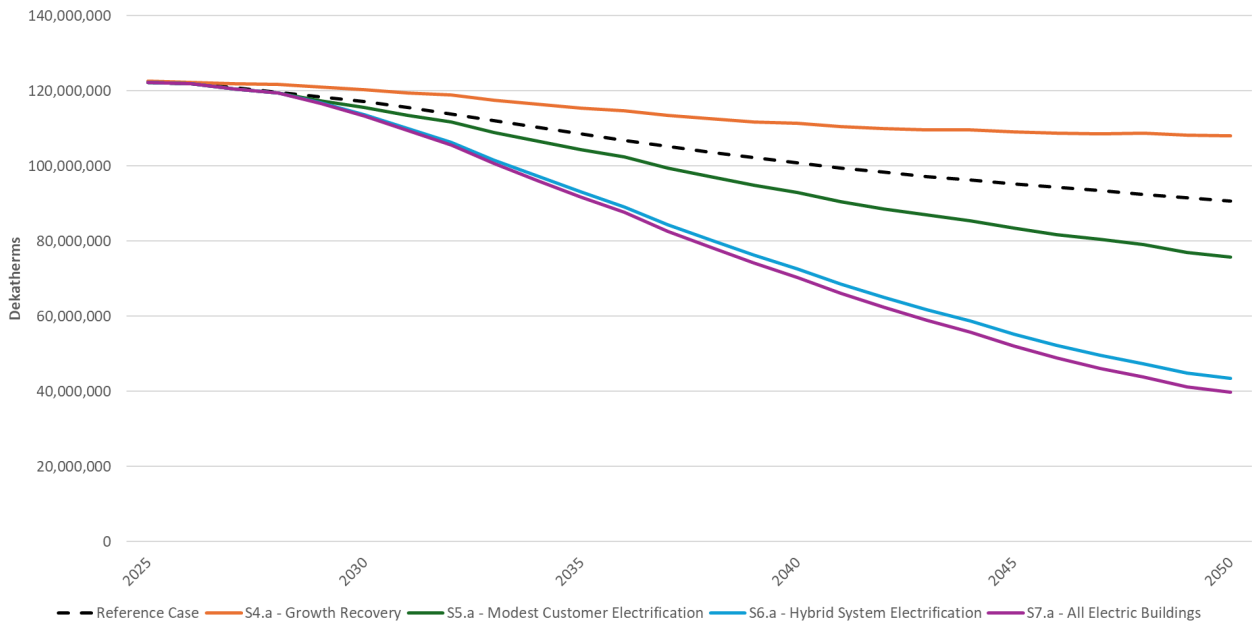
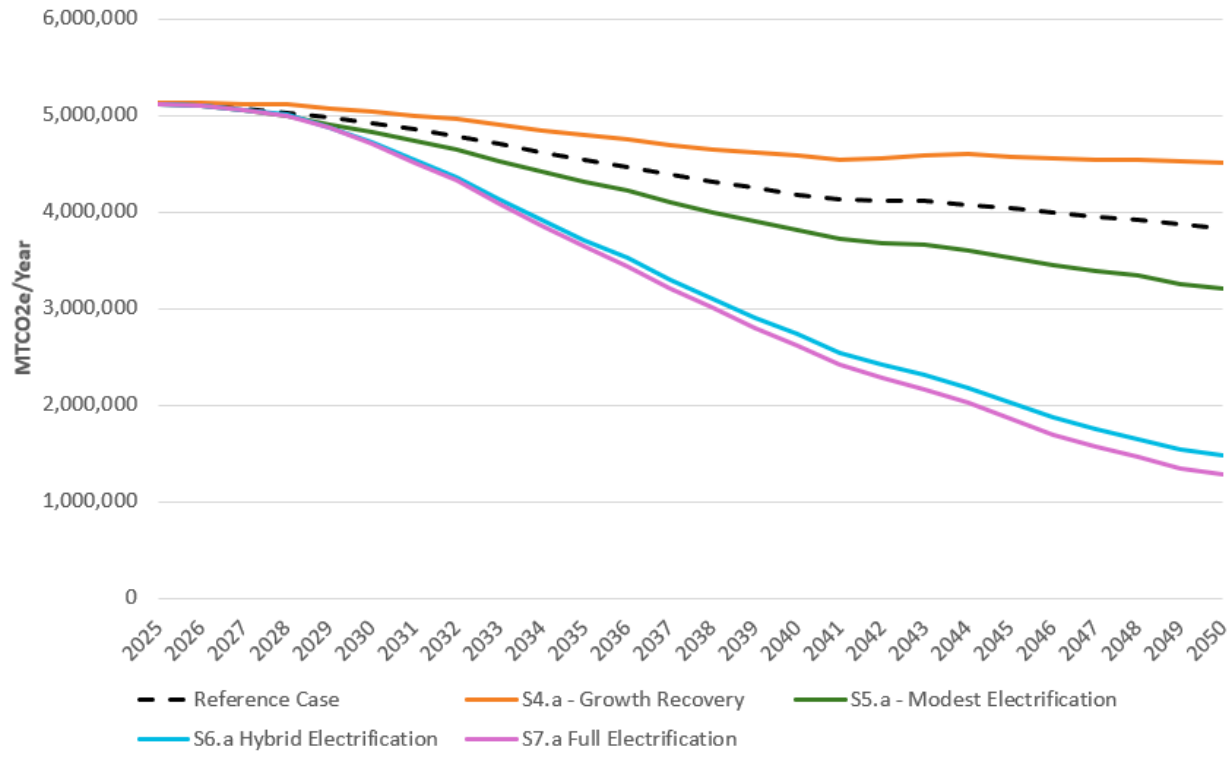


Figure 9.15: System Emissions – Combined CPP and CCA Compliance Obligation



Compliance resource pathways S4 and S5 are not materially different than the resource path for the PRS.a. Similarly, compliance resources pathways between S6 and S7 are not materially different from each other. Results for all demand variation scenarios can be found in Appendix H. Figure 9.16 and Figure 9.17 shows the resource compliance resource acquisition for S7.a - Full electrification scenario for both CPP and CCA Compliance. Costs for these different scenarios are discussed in tandem with the results for the electrification results in Chapter 10 and the implications are discussed in Chapter 11.

Figure 9.16: S7.a - All Electric Buildings CPP Compliance Resources

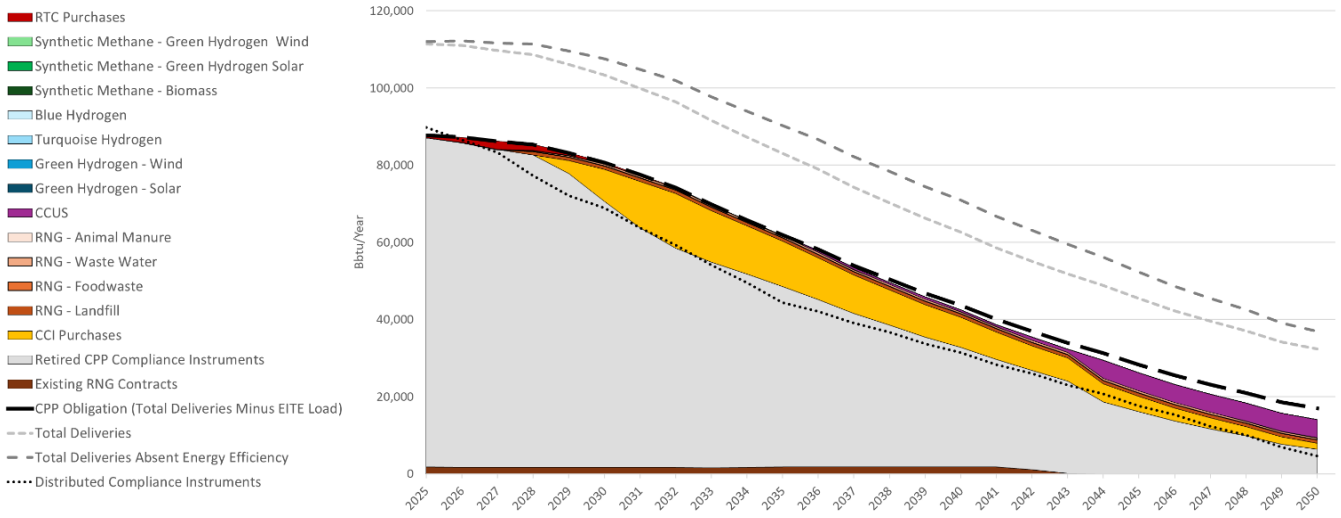
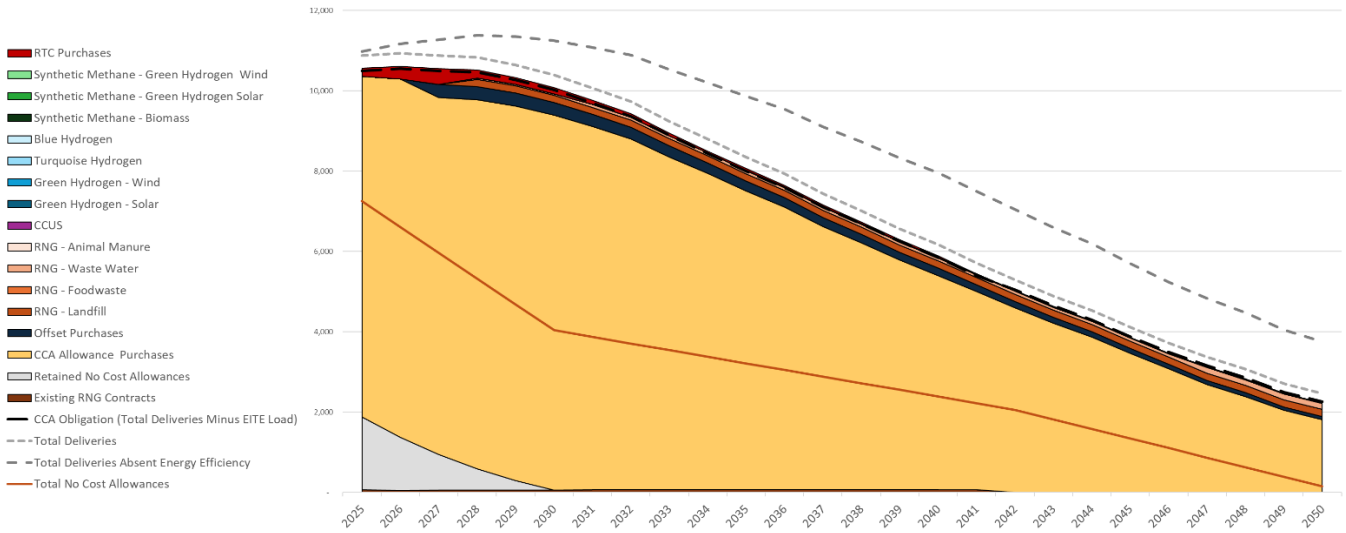


Figure 9.17: S7.a - All Electric Buildings CCA Compliance Resources



9.4.3.1 *Demand Variation Compliance Implications*

Growth Recovery Summary

- Despite adding customers, total demand decreases over time due to energy efficiency and less heating degree days.

- The preferred portfolio of compliance resources in this growth recovery scenario does not significantly change from the PRS.a in either Washington or Oregon.
- Total compliance costs will increase relative to the PRS.a portfolio as new customers to the system will add to compliance requirements for both states.

Modest Electrification

- Under modest building electrification NW Natural will still rely primarily on CCIs to meet CPP compliance requirement and will need to purchase up to the cap to avoid costly resources in the future.
- Synthetic methane from biogas is still a significant part of CPP compliance under modest rates of electrifications.

Hybrid System Electrification

- A full deployment of hybrid-HAVC systems has significant benefits from reduced CPP and CCA costs while still utilizing the existing gas system to help serve winter peak energy requirements.
- CCIs are selected as the primary CPP compliance resource and allowance purchases are the primary CCA compliance resource, but both are drastically reduced relative to the PRS.a results.
- Although limited in quantity, CCUS is still a least-cost compliance resource in both Washington and Oregon.
- Despite lower compliance costs for NW Natural customers, shifting this load from the gas system to the electric system has major cost implications for being able to decarbonize the electric and reliably serve customers throughout the year. These results are discussed further in Chapter 10.

All-Electric Buildings

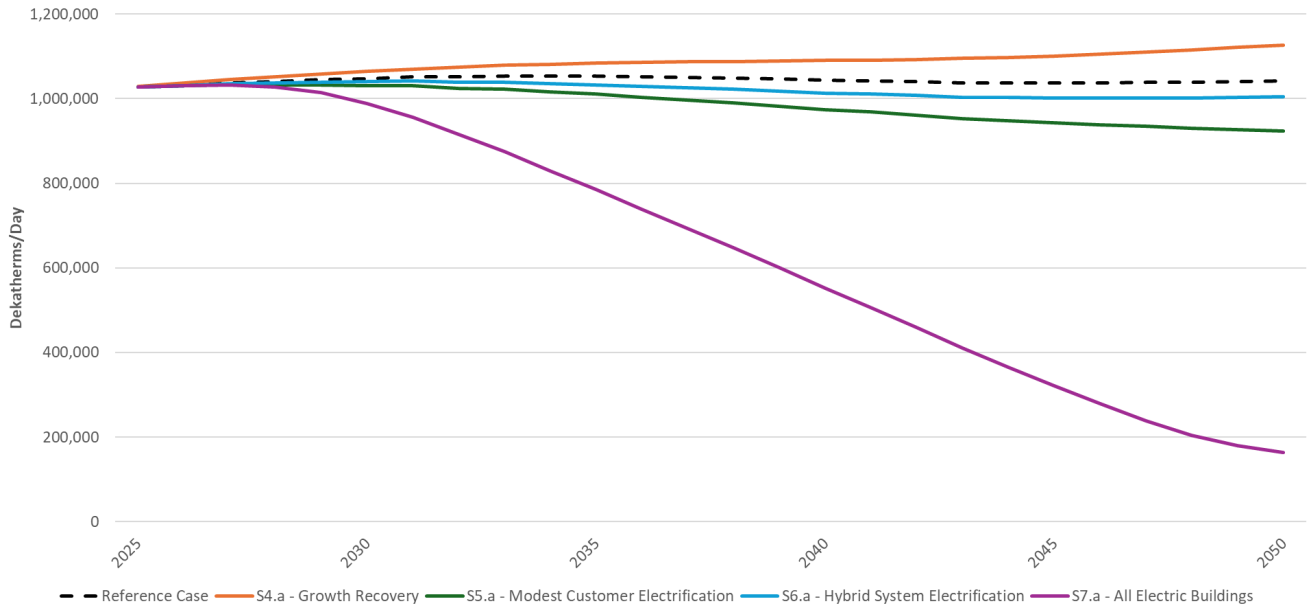
- Even in the most extreme electrification scenario, NW Natural will still rely on purchasing CCIs, however; purchase of CCIs can be delayed until 2029 (i.e., the second compliance period).
- Like S6, CCIs and allowance purchases are the primary CPP and CCA compliance resources respectively.
- Although limited in quantity, CCUS is still a least cost compliance resource in both Washington and Oregon.
- Lower compliance costs for NW Natural customers are more than offset by the increase in costs from the electric sector from shifting both energy and winter peak capacity requirements from the gas system to the electric system. These results are discussed further in Chapter 10.

9.5 Scenario Analysis – System Capacity and Energy Resources

In addition to compliance resource requirements, the resource planning optimization model also uses capacity expansion modeling to acquire system resources to meet winter design peak day capacity and expected annual load requirements. The model both acquires incremental capacity resources and discontinues upstream pipeline contracts if contracts are no longer needed and not economical to serve customers. Both peak requirements and annual requirements drive these resource decisions as the model balances pipeline capacity and storage resources.

S1-S3 and PRS.a all have the same demand requirements and therefore, have the same system capacity and energy resource selections. S4 through S7 all vary in their design peak demand and annual energy requirements and therefore have varying resource results. Annual demand requirements, which also drive compliance obligations were shown in Figures 9.14 and 9.15. Figure 9.18 shows the peak day demand requirements for firm sales customers from the gas system under each scenario.

Figure 9.18: Firm Sales Peak Day Demand by Scenario

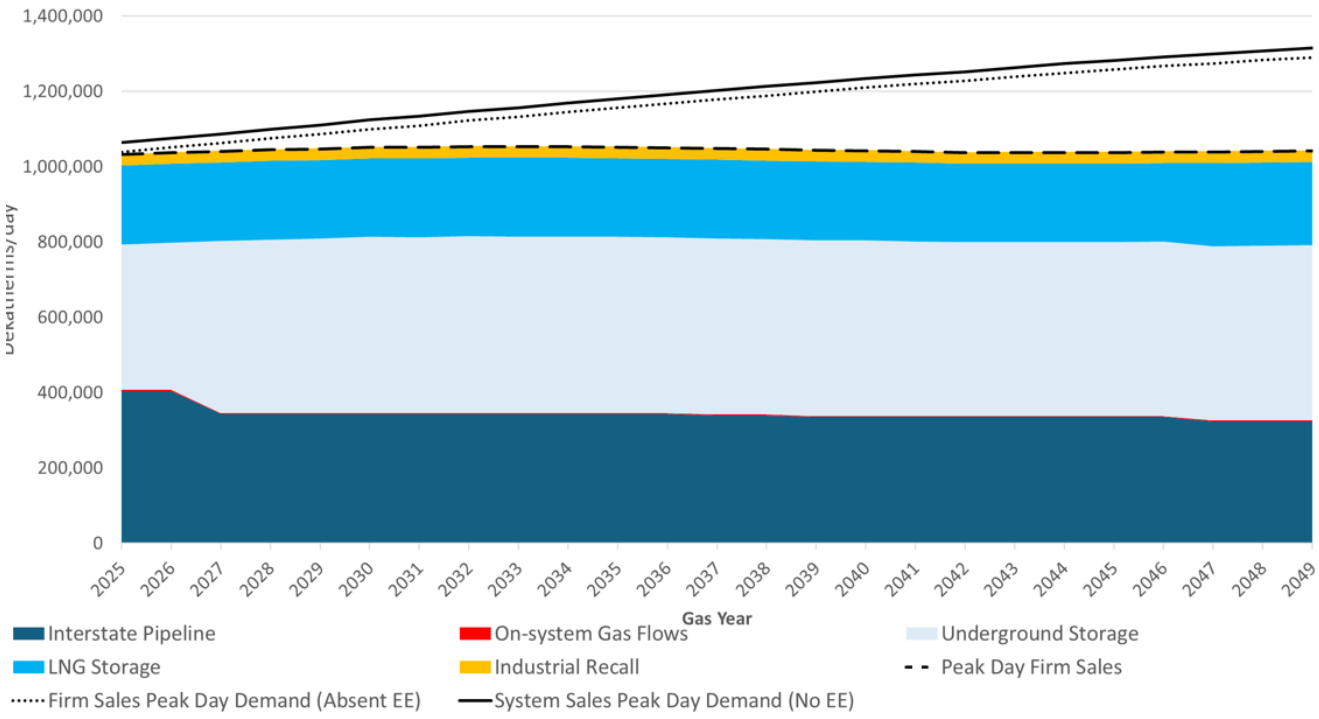


9.5.1 S1-S3, PRS.a – Reference Case Demand

The Reference Case firm sales peak day demand forecast increases through 2033 before slowly declining for the remainder of the planning horizon. Mist Recall is the least cost resource available to meet peak day requirements with additional benefits of underground storage

capacity. The amount of available deliverability (i.e., Dth/day) from Mist Recall is sufficient to meet peak day requirement growth through 2033. Figure 9.19 shows the change in the firm resource stack over the planning horizon. Capacity resources graphs for S4, S5, and S6 are not materially different and can be found in Appendix H.

Figure 9.19: S1-S3 and PRS.a Peak Day Capacity Resource Use



PRS.a Summary

- Peak energy efficiency grows over time and is a critical resource to meet peak day requirements in the future, comprising of 20 percent of the overall peak day energy requirements in 2050.
- Demand response from interruptible sales customers will continue to be relied upon as a firm resource, but only accounts for 2.3 percent of current peak day requirements. Other cost-effective demand response programs, such as the company's thermostat rewards program, is anticipated to grow over time.
- Segmented capacity will not be reliable on a firm basis during a design peak day starting in 2027, when Woodfibre LNG is expected to come on-line.

- Deliverability from Mist Recall is sufficient and the least cost resource to meet peak day capacity requirements after segmented capacity drops from the resource stack and any incremental peak day growth throughout the planning horizon.
- NW Natural will continue to rely on demand response from our interruptible sales customers to provide peak day savings.
- Continued growth in peak day savings from cost-effective energy efficiency is a significant resource by 2050 in mitigating growth in peak day requirements.
- The model selects Newport Takeaway 1 as least cost resources as in 2047, as a decline in peak day requirements in combination with a decline in annual demand allows the Newport Takeaway 1 to replace a small amount of more expensive upstream pipeline capacity.
- On-system RNG from the local water resource recovery facility is selected for compliance purposes but does provide trivial capacity.

9.5.2 S4: Growth Recovery S4: Growth Recovery

The growth recovery shows a future where customer counts are higher than expected in the Reference Case and peak day requirements (net of energy efficiency) continue to growth through 2050. Mist Recall is the least cost resource available to meet these peak day requirements. Despite higher customer growth, the amount of available deliverability from Mist Recall is still sufficient to meet peak day requirements over the planning horizon. The model does select Newport Takeaway 1, earlier in the planning horizon (2033) to replace a small amount of upstream pipeline capacity. Further analysis will be required to determine if replacing a small amount of upstream pipeline capacity with Newport Takeaway 1 would be an appropriate solution for customers to be able to serve not only design peak day capacity but also design winter requirements. Future IRPs will continue to examine these tradeoffs, as any action for Newport Takeaway is outside an actionable window for this IRP.

9.5.3 S5: Modest Customer Electrification

The modest electrification scenario sees a decline in design peak day requirements much sooner in the planning horizon starting in 2028. Newport Takeaway 1 is no longer selected at any point in the planning horizon and an additional 36,000 Dth/day of upstream pipeline capacity is released relative to the references case demand.

9.5.4 S6: Hybrid System Electrification

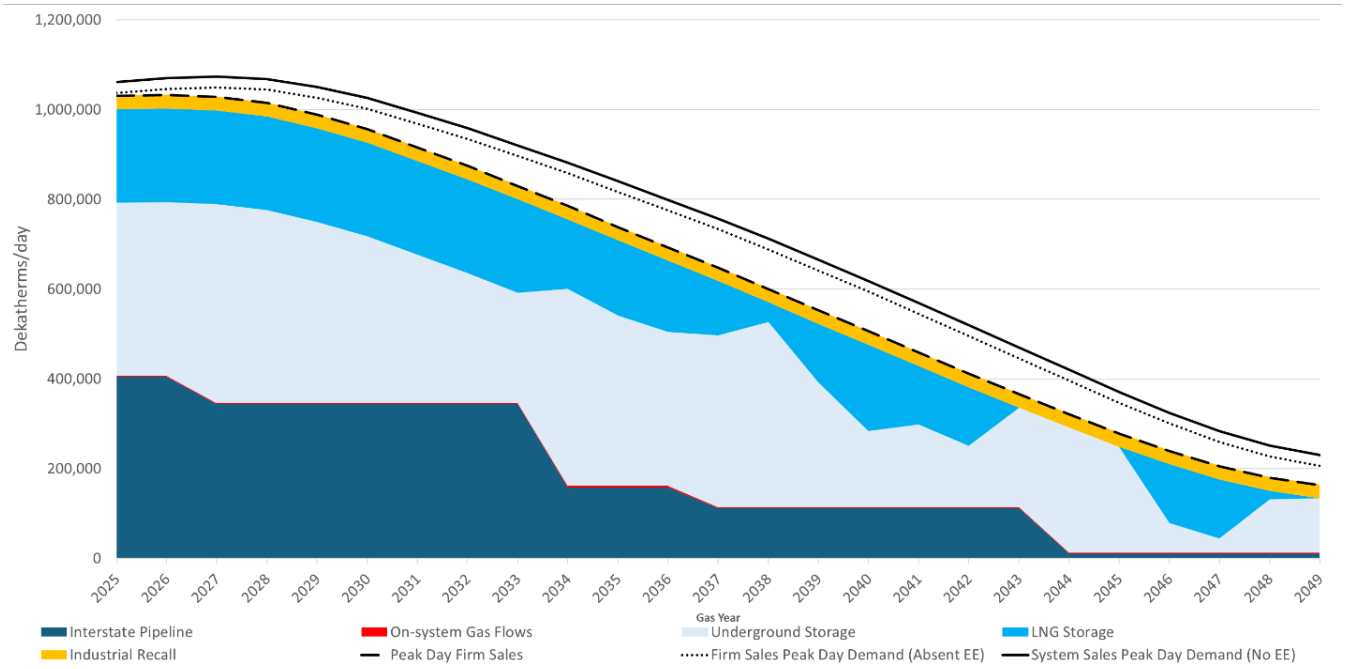
In the Hybrid System Electrification scenario, overall commodity costs drastically decline, but the system fixed cost associated with upstream capacity charges remain roughly at the same level as the Reference Case. Maintaining gas furnaces as backups to electric heat pumps

requires still requires significant levels of natural gas to be delivered during the coldest days of the year. This commodity and fixed costs are further discussed in tandem with the electrification results in Chapter 10.

9.5.5 S7: All-Electric Buildings

The all-electric buildings scenario creates a much different picture of peak day capacity resources used to meet peak day demand. Figure 9.20 shows a dramatic reduction in interstate pipeline capacity, relying primarily on storage facilities to provide nearly 75 percent of natural gas delivered on a peak day. This creates a new dynamic where interstate pipeline capacity is not fully utilized for peak day requirements, but capacity is still being retained above what is required on a peak day to be able to serve annual energy requirements.

Figure 9.20: S7 Peak Day Capacity Resource Use



9.6 Preferred Resource Strategy 300 Draws Monte Carlo Results

NW Natural developed Monte Carlo simulations on weather, gas prices, compliance resource prices, and compliance resource availability. This section describes how these simulations were conducted, how they were used as inputs to the resource optimization model, the results from the resource optimization model, and the implications and insights that a Monte Carlo simulation can provide.

Weather

Weather (mainly temperature) is a primary driver of demand uncertainty. The weather simulation is discussed in more detail in Section 4.2.3. Particularly in the near-term, weather is the dominant source of demand uncertainty and therefore the dominant source of compliance obligation uncertainty for near-term compliance periods for CPP and CCA.

Gas Prices

As described in Section 8.4, NW Natural procures natural gas from four different gas trading regions (AECO, Opal/Rockies, Sumas, and Westcoast Station 2). NW Natural develops gas price simulations that incorporate correlations across regions, correlation over time, and a correlation of daily gas price volatility to the daily weather from the weather simulation.

Compliance Resources

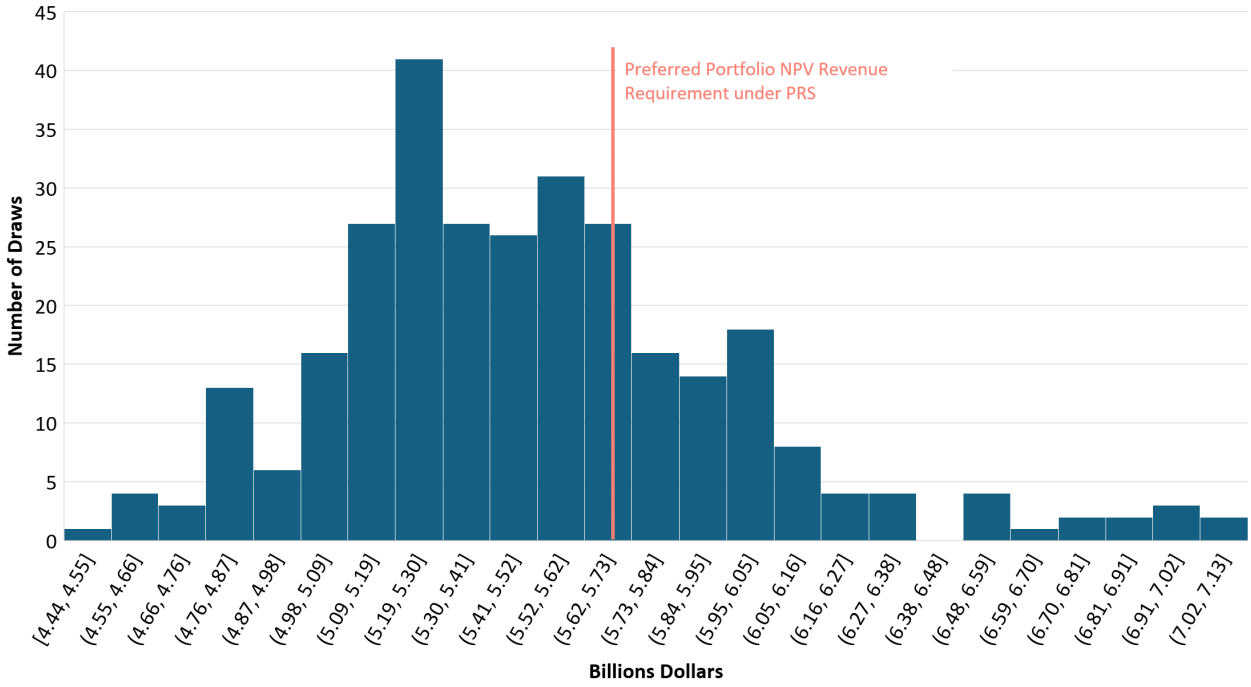
Simulations for compliance resource for both price and availability were developed primarily through the alternative fuels study. Additional modifications by NW Natural to this simulation are to account for increased uncertainty in price over time and availability discussed in Section 7.7.9.

All three simulation types (weather, gas prices, and alternative fuels) are used as inputs to the resource optimization model using the PRS constraints as defined in Section 9.4.2. The results of this analysis are used to calculate the commodity and compliance risk-reduction values of avoided costs as discussed in Chapter 5.

9.6.1 Oregon Compliance Resource Costs

Figure 9.21, illustrates the estimated distribution of net present value total Oregon compliance costs after running the resource optimization model.

Figure 9.21: Distribution of Monte Carlo Draws, NPV (2025-2050) Oregon Compliance Costs



The Company's NPV revenue requirement for CPP Compliance costs is expected to range from about $4.5 billion to $7 billion over the planning horizon. This is full compliance with the CPP, in that, there are zero Monte Carlo draws (by model design) where NW Natural fails to comply with CPP requirements.

As prices and availability vary across resources and draws, the resource optimization model selects different compliance resources to minimize costs. Figure 9.22 provides a heat map of the Oregon compliance resource volumes across all 300 draws for each year in the planning horizon.

Figure 9.22: Incremental Oregon Compliance Resource Acquisition Percentage Across all Draws by Year

	CCIs	RNG - Landfill Gas	RNG - Food Waste	RNG - Waste Water	RNG - Animal Manure	Green Hydrogen Solar	Green Hydrogen Wind	Turquoise Hydrogen	Blue Hydrogen	Carbon Capture Utilization and Storage	Synthetic Methane - Biomass	Synthetic Methane - Green Hydrogen Solar	Synthetic Methane Green Hydrogen Wind	Renewable Thermal Credits
2025	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2026	2.96%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	97.04%
2027	93.16%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.74%
2028	81.82%	5.21%	0.00%	0.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.06%
2029	85.23%	5.44%	0.00%	0.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	8.38%
2030	81.02%	11.44%	0.00%	3.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.31%
2031	80.82%	11.57%	0.00%	3.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.34%
2032	80.48%	11.77%	0.00%	3.33%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.41%
2033	80.28%	11.91%	0.00%	3.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.44%
2034	79.76%	12.25%	0.00%	3.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.51%
2035	79.52%	12.40%	0.00%	3.52%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.56%
2036	68.79%	14.30%	0.00%	5.92%	0.00%	0.00%	0.00%	0.00%	0.00%	5.38%	0.76%	0.70%	0.00%	4.15%
2037	68.44%	14.47%	0.00%	5.98%	0.00%	0.00%	0.00%	0.00%	0.00%	5.44%	0.77%	0.71%	0.00%	4.19%
2038	36.28%	11.22%	0.00%	4.15%	0.00%	16.37%	0.68%	0.00%	1.92%	3.63%	22.00%	0.48%	0.00%	3.27%
2039	35.70%	11.32%	0.00%	4.19%	0.00%	16.53%	0.69%	0.00%	1.94%	3.66%	22.21%	0.48%	0.00%	3.28%
2040	30.18%	12.56%	0.00%	4.55%	0.00%	15.26%	0.63%	0.00%	1.79%	3.38%	28.23%	0.44%	0.00%	2.98%
2041	29.48%	12.61%	0.00%	4.57%	0.00%	15.33%	0.64%	0.00%	1.80%	3.40%	28.35%	0.45%	0.00%	3.40%
2042	15.76%	9.48%	0.00%	3.43%	0.00%	11.51%	0.48%	0.00%	1.35%	2.55%	53.51%	0.33%	0.00%	1.60%
2043	15.69%	9.42%	0.00%	3.41%	0.00%	11.44%	0.47%	0.00%	1.35%	2.54%	53.20%	0.33%	0.00%	2.15%
2044	10.74%	8.39%	0.00%	3.03%	0.00%	10.18%	0.42%	0.00%	1.20%	2.26%	60.94%	0.30%	0.00%	2.54%
2045	10.24%	8.39%	0.00%	3.03%	0.00%	10.18%	0.42%	0.00%	1.20%	2.26%	60.93%	0.30%	0.00%	3.05%
2046	8.17%	8.56%	0.00%	2.95%	0.00%	10.33%	0.40%	0.00%	1.13%	2.43%	61.15%	1.08%	0.00%	3.80%
2047	7.76%	8.57%	0.00%	2.96%	0.00%	10.35%	0.40%	0.00%	1.13%	2.44%	61.25%	1.08%	0.00%	4.07%
2048	5.27%	8.07%	0.00%	2.77%	0.00%	10.15%	0.39%	0.00%	1.06%	2.28%	64.01%	1.01%	0.00%	5.00%
2049	4.71%	8.08%	0.00%	2.77%	0.00%	10.17%	0.39%	0.00%	1.06%	2.28%	64.15%	1.01%	0.00%	5.36%
2050	3.50%	8.12%	0.00%	2.70%	0.00%	9.80%	0.38%	0.00%	1.02%	2.58%	65.70%	0.98%	0.00%	5.21%

Low High

Figure 9.23: Preferred Portfolio Incremental Oregon Compliance Resource Acquisition Percentage

	CCIs	RNG - Landfill Gas	RNG - Food Waste	RNG - Waste Water	RNG - Animal Manure	Green Hydrogen Solar	Green Hydrogen Wind	Turquoise Hydrogen	Blue Hydrogen	Carbon Capture Utilization and Storage	Synthetic Methane - Biomass	Synthetic Methane - Green Hydrogen Solar	Synthetic Methane Green Hydrogen Wind	Renewable Thermal Credits
2025	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2026	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2027	94.59%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.31%
2028	80.73%	8.12%	0.00%	1.86%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.29%
2029	85.28%	8.58%	0.00%	1.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.16%
2030	85.94%	10.93%	0.00%	3.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2031	85.76%	11.07%	0.00%	3.17%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2032	84.45%	11.10%	0.00%	4.45%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2033	84.17%	11.30%	0.00%	4.53%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2034	79.28%	15.18%	0.00%	5.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2035	78.95%	15.42%	0.00%	5.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2036	59.28%	14.11%	0.00%	5.29%	0.00%	0.00%	0.00%	0.00%	0.00%	21.32%	0.00%	0.00%	0.00%	0.00%
2037	58.71%	14.30%	0.00%	5.37%	0.00%	0.00%	0.00%	0.00%	0.00%	21.62%	0.00%	0.00%	0.00%	0.00%
2038	46.64%	13.53%	0.00%	5.04%	0.00%	0.00%	0.00%	0.00%	0.00%	18.83%	15.95%	0.00%	0.00%	0.00%
2039	46.10%	13.67%	0.00%	5.09%	0.00%	0.00%	0.00%	0.00%	0.00%	19.02%	16.12%	0.00%	0.00%	0.00%
2040	19.60%	9.17%	0.00%	3.36%	0.00%	0.00%	0.00%	0.00%	0.00%	12.10%	55.77%	0.00%	0.00%	0.00%
2041	19.11%	9.23%	0.00%	3.38%	0.00%	0.00%	0.00%	0.00%	0.00%	12.17%	56.11%	0.00%	0.00%	0.00%
2042	14.22%	8.61%	0.00%	3.08%	0.00%	0.00%	0.00%	0.00%	0.00%	10.88%	63.21%	0.00%	0.00%	0.00%
2043	14.28%	8.60%	0.00%	3.08%	0.00%	0.00%	0.00%	0.00%	0.00%	10.87%	63.17%	0.00%	0.00%	0.00%
2044	10.26%	7.98%	0.00%	2.81%	0.00%	0.00%	0.00%	0.00%	0.00%	9.83%	69.12%	0.00%	0.00%	0.00%
2045	9.90%	8.01%	0.00%	2.82%	0.00%	0.00%	0.00%	0.00%	0.00%	9.87%	69.40%	0.00%	0.00%	0.00%
2046	6.89%	7.57%	0.00%	2.62%	0.00%	0.00%	0.00%	0.00%	0.00%	9.13%	73.79%	0.00%	0.00%	0.00%
2047	6.61%	7.60%	0.00%	2.63%	0.00%	0.00%	0.00%	0.00%	0.00%	9.16%	74.00%	0.00%	0.00%	0.00%
2048	3.99%	7.10%	0.00%	2.43%	0.00%	0.00%	0.00%	0.00%	0.00%	8.48%	77.99%	0.00%	0.00%	0.00%
2049	3.67%	7.13%	0.00%	2.44%	0.00%	0.00%	0.00%	0.00%	0.00%	8.50%	78.25%	0.00%	0.00%	0.00%
2050	2.01%	6.87%	0.00%	2.34%	0.00%	0.00%	0.00%	0.00%	0.00%	8.13%	80.65%	0.00%	0.00%	0.00%

Low High

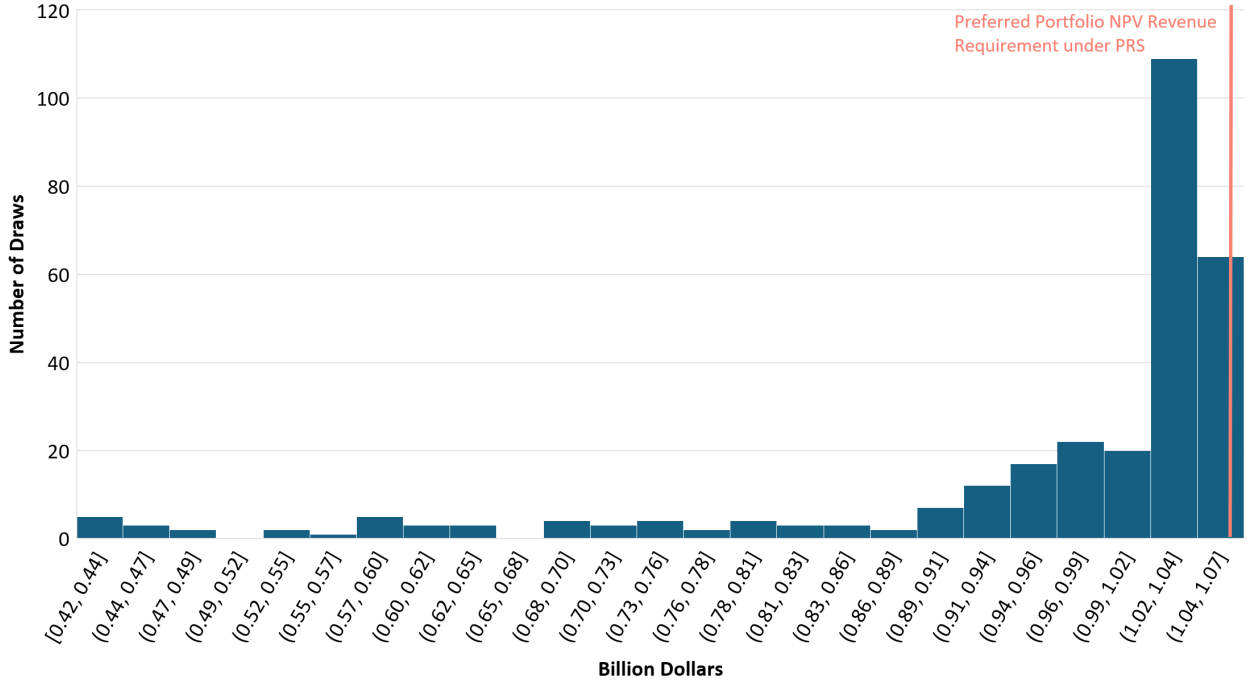
Figure 9.22 helps illustrate the potential need for other alternative fuels, such as green hydrogen from solar, which is within a similar price range as synthetic methane from biomass. Given the stochastic inputs of the compliance resources, there are futures where green hydrogen from solar is being selected as a least cost compliance resource, which is divergent from the PRS.a deterministic results, which primarily relied on synthetic methane from biomass as shown in Figure 9.23.

Figure 9.22 also highlights the resources that are simply not selected for CPP compliance in any of the draws, such as RNG from animal manure, however; Figure 9.22 should be considered as a general characterization of the relative cost-competitiveness and availability of compliance resources. Changes in federal funding, technological developments, or unique individual project characteristics could make some compliance resource more attractive and the Company will ultimately evaluate compliance resources based on project specific costs.

9.6.2 Washington Compliance Resource Costs

Stochastic analysis reveals a different narrative for compliance resource costs in Washington. Due to the price ceiling of allowances, the distribution of compliance costs is heavily skewed left as indicated by Figure 9.23. Aside from the cost variation for the small amounts of voluntary RNG procured under HB 1257 and potential cost variation and availability of offsets, compliance resource costs are capped by the price ceiling of allowances. While many draws reflect that most futures are expected to be at or near the price ceiling, there is a potential for compliance resource costs to be significantly less than the results under PRS.a if allowance auctions prices continue to clear at lower prices.

Figure 9.24: Distribution of Monte Carlo Draws, NPV (2025-2050) CCA Compliance Costs



The Company's NPV revenue requirement for CCA Compliance costs is expected to range from about $420 million to just over $1 billion over the planning horizon. This is full compliance with the CCA, in that, there are zero Monte Carlo draws (by model design) where NW Natural fails to comply with CCA requirements. The Preferred Portfolio costs fall at the high end of the range, because Washington CCA compliance relies heavily on allowance purchases. In the Preferred Portfolio, the allowance prices hit the auction ceiling price early in the planning horizon, which leads to a higher cost outcome. Figure 9.24 indicates that CCA compliance costs are highly dependent on allowance prices.

As prices and availability vary across resources and draws, the resource optimization model selects different compliance resources to minimize costs. Figure 9.25 provides a heat map of the compliance resource volumes across all 300 draws for each year in the planning horizon.

Figure 9.25: Incremental Washington Compliance Resource Acquisition Percentage Across all Draws by Year

	Purchased Allowances	Offsets	RNG - Landfill Gas	RNG - Food Waste	RNG - Waste Water	RNG - Animal Manure	Green Hydrogen Solar	Green Hydrogen Wind	Blue Hydrogen	Turquoise Hydrogen	Carbon Capture Utilization and Storage	Synthetic Methane - Biomass	Synthetic Methane - Green Hydrogen Solar	Synthetic Methane Green Hydrogen Wind	Renewable Thermal Credits
2025	98.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.93%
2026	97.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.99%
2027	93.83%	2.31%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.86%
2028	93.71%	2.38%	1.25%	0.00%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.50%
2029	93.75%	2.46%	1.25%	0.00%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.38%
2030	93.63%	2.60%	1.26%	0.00%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.36%
2031	93.57%	2.64%	2.12%	0.00%	0.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.05%
2032	93.41%	2.77%	2.14%	0.00%	0.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.06%
2033	93.37%	2.81%	2.14%	0.00%	0.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.06%
2034	93.31%	2.84%	2.17%	0.00%	0.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.05%
2035	92.39%	2.88%	2.18%	0.00%	0.72%	0.00%	0.02%	0.03%	0.77%	0.00%	0.07%	0.00%	0.00%	0.00%	0.95%
2036	92.34%	2.89%	2.20%	0.00%	0.73%	0.00%	0.02%	0.03%	0.78%	0.00%	0.07%	0.00%	0.00%	0.00%	0.96%
2037	92.32%	2.90%	2.20%	0.00%	0.73%	0.00%	0.02%	0.03%	0.78%	0.00%	0.07%	0.00%	0.00%	0.00%	0.96%
2038	92.29%	2.91%	2.21%	0.00%	0.73%	0.00%	0.02%	0.03%	0.78%	0.00%	0.07%	0.00%	0.00%	0.00%	0.96%
2039	91.17%	2.92%	2.36%	0.00%	1.02%	0.00%	0.57%	0.13%	0.79%	0.00%	0.09%	0.03%	0.00%	0.00%	0.92%
2040	91.70%	2.92%	2.37%	0.00%	1.02%	0.00%	0.58%	0.13%	0.80%	0.00%	0.09%	0.03%	0.00%	0.00%	0.37%
2041	91.95%	2.95%	2.38%	0.00%	1.03%	0.00%	0.58%	0.13%	0.80%	0.00%	0.09%	0.03%	0.00%	0.00%	0.06%
2042	91.79%	2.92%	2.37%	0.00%	1.02%	0.00%	0.58%	0.13%	0.80%	0.00%	0.09%	0.03%	0.00%	0.00%	0.27%
2043	91.55%	2.94%	2.50%	0.00%	1.28%	0.00%	0.58%	0.14%	0.80%	0.00%	0.10%	0.09%	0.00%	0.00%	0.02%
2044	91.55%	2.94%	2.49%	0.00%	1.28%	0.00%	0.58%	0.14%	0.80%	0.00%	0.10%	0.09%	0.00%	0.00%	0.03%
2045	91.52%	2.97%	2.50%	0.00%	1.28%	0.00%	0.58%	0.14%	0.80%	0.00%	0.10%	0.09%	0.00%	0.00%	0.02%
2046	91.55%	2.97%	2.48%	0.00%	1.27%	0.00%	0.57%	0.14%	0.80%	0.00%	0.10%	0.09%	0.00%	0.00%	0.04%
2047	88.28%	2.98%	3.04%	0.00%	1.51%	0.00%	1.82%	0.14%	0.80%	0.00%	0.10%	1.32%	0.00%	0.00%	0.01%
2048	88.28%	2.98%	3.04%	0.00%	1.51%	0.00%	1.82%	0.14%	0.80%	0.00%	0.10%	1.32%	0.00%	0.00%	0.01%
2049	88.20%	3.00%	3.06%	0.00%	1.52%	0.00%	1.83%	0.14%	0.81%	0.00%	0.10%	1.33%	0.00%	0.00%	0.01%
2050	88.18%	3.02%	3.04%	0.00%	1.51%	0.00%	1.82%	0.14%	0.80%	0.00%	0.10%	1.32%	0.00%	0.00%	0.06%

Low High

Figure 9.26: Preferred Portfolio Incremental Washington Compliance Resource Acquisition Percentage

	Purchased Allowances	Offsets	RNG - Landfill Gas	RNG - Food Waste	RNG - Waste Water	RNG - Animal Manure	Green Hydrogen Solar	Green Hydrogen Wind	Blue Hydrogen	Turquoise Hydrogen	Carbon Capture Utilization and Storage	Synthetic Methane - Biomass	Synthetic Methane - Green Hydrogen Solar	Synthetic Methane Green Hydrogen Wind	Renewable Thermal Credits
2025	93.77%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.23%
2026	92.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.93%
2027	84.10%	7.17%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	8.73%
2028	86.11%	6.27%	3.45%	0.00%	0.71%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.47%
2029	87.59%	5.62%	3.10%	0.00%	0.64%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.05%
2030	88.83%	5.07%	2.81%	0.00%	0.58%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.71%
2031	89.10%	4.96%	3.79%	0.00%	1.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.03%
2032	89.36%	4.84%	3.72%	0.00%	1.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.99%
2033	89.56%	4.75%	3.68%	0.00%	1.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.94%
2034	89.77%	4.65%	3.63%	0.00%	1.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.89%
2035	89.71%	4.55%	3.57%	0.00%	1.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.00%	0.00%	0.00%	0.87%
2036	89.91%	4.45%	3.51%	0.00%	1.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.00%	0.00%	0.00%	0.86%
2037	90.06%	4.36%	3.47%	0.00%	1.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.00%	0.00%	0.00%	0.85%
2038	90.36%	4.27%	3.42%	0.00%	1.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.23%	0.00%	0.00%	0.00%	0.71%
2039	90.28%	4.18%	3.37%	0.00%	1.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.23%	0.00%	0.00%	0.00%	0.06%
2040	90.46%	4.09%	3.31%	0.00%	1.85%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%	0.00%	0.00%	0.00%	0.06%
2041	90.68%	4.01%	3.26%	0.00%	1.82%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%	0.00%	0.00%	0.00%	0.00%
2042	90.39%	3.90%	3.18%	0.00%	1.78%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%	0.00%	0.00%	0.00%	0.54%
2043	90.63%	3.78%	3.57%	0.00%	1.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.21%	0.00%	0.00%	0.00%	0.00%
2044	90.93%	3.67%	3.45%	0.00%	1.75%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.00%	0.00%	0.00%	0.00%
2045	91.18%	3.57%	3.36%	0.00%	1.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.00%	0.00%	0.00%	0.00%
2046	91.41%	3.47%	3.26%	0.00%	1.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.01%
2047	91.60%	3.37%	3.22%	0.00%	1.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.00%
2048	91.84%	3.28%	3.13%	0.00%	1.57%	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.00%	0.00%	0.00%	0.00%
2049	92.04%	3.20%	3.05%	0.00%	1.53%	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.00%	0.00%	0.00%	0.00%
2050	92.24%	3.12%	2.97%	0.00%	1.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	0.00%	0.00%	0.00%	0.00%

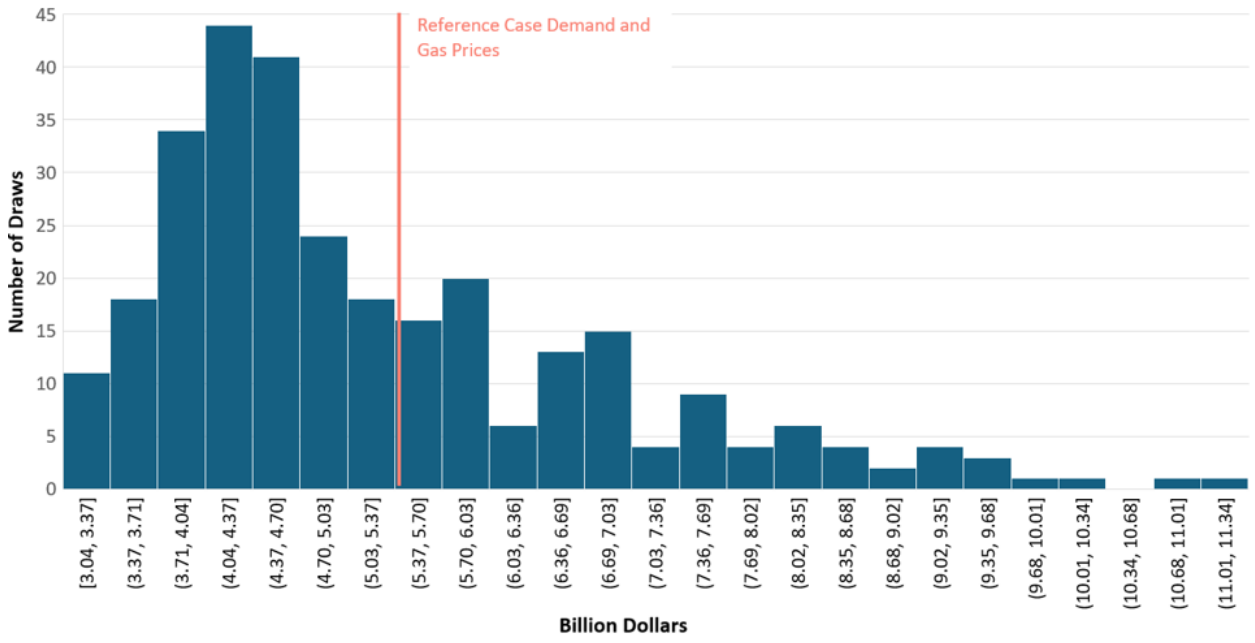
Low High

Figure 9.25 helps illustrate the potential need for other alternative fuels, such as green hydrogen from solar, blue hydrogen and synthetic methane from biomass, when these resources become less expensive than allowances. Given the stochastic inputs of the compliance resources, there are futures where other resources are being selected in small quantities, however, allowances remain the primary compliance resource in the preferred portfolio and across stochastic draws.

9.6.3 System Costs

NW Natural's resource optimization model optimizes gas purchases, resource expansions, or resource reductions. Figure 9.27 shows the distribution of costs associated with capacity and energy resources. This includes gas commodity purchases, reservation charges (also known as demand charges) for upstream pipeline capacity, variable charges for shipping gas on upstream pipelines, off-system storage contracts (i.e., Jackson Prairie), incremental on-system expansions (i.e., costs associated with Mist Recall or Newport Takeaway projects), and other system variables charges (e.g., fuels charges associated with liquefaction or vaporization of LNG at Newport LNG or Portland LNG facilities). Not included in the resource optimization model is costs associated with current assets as these are treated as sunk costs.

Figure 9.27: System Capacity and Energy Resource Costs, NPV (2025-2050)



The 300 draw Monte Carlo analysis utilized the capacity expansion and reduction results from the PRS.a, which is primarily driven by design peak day capacity requirements. The design firm sales peak day forecast is dynamic over the planning horizon as it is a function of the customer count forecast, however; NW Natural did not conduct a Monte Carlo simulation for customer counts; therefore, the firm sales peak day forecast is not stochastic.[223] As a result the fixed costs across draws remains the same, but variable costs are stochastic and driven by changes in demand due to stochastic weather and stochastic natural gas prices. The distribution of Figure 9.27 contains both fixed and variable costs and represents the net present value of revenue requirement associated with non-sunk energy and capacity resource costs.[224]

NPV revenue requirement for system capacity and energy costs model in the Monte Carlo analysis ranges from 3.0 to 11.3 billion dollars. For comparison, the NPV revenue requirement from the PRS (shown as the vertical line in Figure 9.27) is about five billion dollars, which is slightly lower than the mean, $5.27 billion, but slightly higher than the median, $4.72 billion. The results Figure 9.27 shows that a right skewed distribution of system capacity and energy costs. This is primarily driven by the fact natural gas commodity costs are currently relatively low and are forecasted to modestly increase overtime but also face a right skewed distribution. There is a low probability, but a high impact on costs if natural gas prices drastically increase. Conversely, there is a higher probability, but lower impact on costs from natural gas prices being lower than the Reference Case.

[223] Stochastic weather modeling is used to create a 99th percentile weather condition planning standard, however; the final peak day forecast itself is not stochastic. This modeling is separate from the stochastic weather modeling developed and create for the use-per-customer model which is a function of temperature and is used to create non-peak daily demands that aggregate to monthly and annual load to determine energy requirements.
[224] Reservation charges associated with pipeline capacity prior to a contract's expiration date could be considered sunk costs, however; these are still included in the model and included in Figure 9.27.

NW Natural IRP
Chapter 10 Electrification

Submitted to:
NW Natural

Submitted by:
ICF Resources, L.L.C.

07/25/2025

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10.1 Introduction to Electrification Analysis

This chapter of the IRP summarizes an analysis of the impacts of hypothetical building electrification scenarios on NW Natural customers. NW Natural engaged consulting firm ICF to conduct this analysis and outside experts with electric planning and operations background. This chapter includes an overview of the assumptions, approach, and draft results from this analysis. ICF's final report on the analysis is included as Appendix L.

During the last IRP process, questions were raised about the use of electrification of gas loads as a compliance resource as well as the need for future gas infrastructure, given the expectations some stakeholders have for building electrification. At this point in time, regional electric utility IRPs only consider minimal amounts of building electrification, leaving an information void on how significant levels of building electrification might impact costs, emissions and/or reliability concerns in the power sector. This analysis provides a more comprehensive look at the potential impacts of electrification than the scenarios included in the last NW Natural IRP, which only quantified the electrification impacts to NW Natural's system.

The purpose of this study is to start to fill that information void and provide analysis that informs the need for integrated joint system planning of the gas and electric energy systems to ensure affordable, reliable, and a low-emission energy supply for both gas and electric customers in Oregon and Washington.

More specific key objectives of this study include:

- Provide input on gas demand impacts to NW Natural's IRP on potential electrification scenarios
- Consider the electric supply requirements for these electrification scenarios – to give context and characterize costs
- Assess the overall impacts and costs associated with electrifying NW Natural customers
- Assess how hybrid heating (ASHP with gas back-up) would change the impacts and costs of electrification
- Consider load growth in other sectors, with focus on building electrification

Figure 10.1 provides an overview of the steps in the study process.

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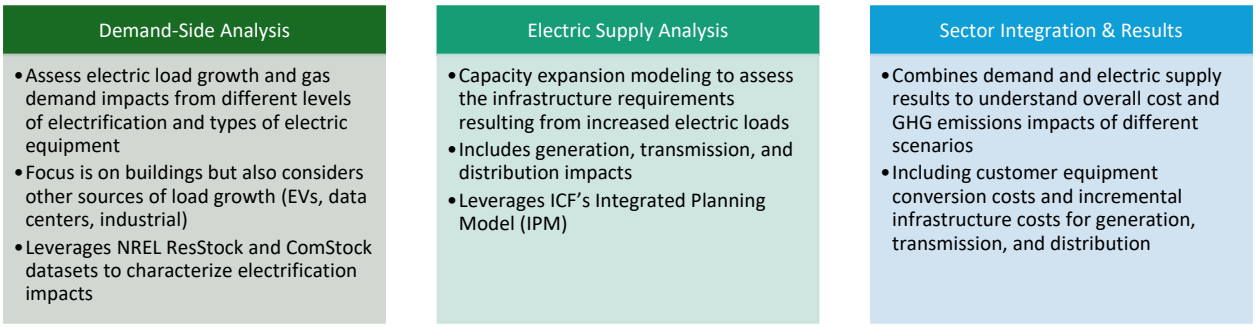
Figure 10.1: Overview of Study Phases



10.2 Electric Planning Environment

Understanding the current electric planning environment is critical to assessing the results of this electrification analysis in the proper context. The electric grid in Oregon and Washington is currently facing cost pressure and reliability challenges and is expecting several major changes, which will need to be planned for in ways to avoid further reliability challenges and energy affordability issues.

Many have noted the "close call" events such as in January 2024 in the Pacific Northwest (PNW). Electric rates across the state have increased over 25% in the last four years, and at even higher rates for residential customers at PGE and PacifiCorp, where rates between 2020 and 2024 have increased 40% and more. In several years, annual rate increases have exceeded 10% several times, with 12% and 21% in 2023 and 2024 for PGE and 15% for PacifiCorp customers in 2023. The electric systems of the region are also relying more heavily on the gas systems for electric generation, particularly for peak load service. For example, the PNW electric system was in severe emergency conditions last January 2024. Without record electric imports from the Southwest and Rocky Mountain states, the PNW could have experienced rolling blackouts of a magnitude that would be unprecedented in our region.

Some of the major changes and challenges that the electric system will need to prepare for in the coming decades include, but are not limited to, the following considerations:

- **Load Growth**: The level of electric demand growth anticipated by electric utility IRPs and regional authorities has increased significantly over the last few years. Expectations for load growth driven by data centers and AI are significant short-term drivers, while vehicle electrification load is a significant long-term driver given state policies requiring vehicle sales to shift to EVs. Electric utility IRPs in the region are not currently planning for significant levels of building electrification. The electric system will face a significant

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challenge in meeting the data center and EV loads, a challenge that would be made more difficult if electric utilities also need to start planning for significant electrification of natural gas space heating and other gas loads.

- **Changing Generation Options**: Legislation in Oregon and Washington that aims to reduce GHG emissions from the power sector will change the types of generation resources utilities are allowed to use. Oregon House Bill 2021 (HB 2021) mandates a transition to 100% clean electricity by 2040 for large investor-owned utilities (with interim targets of an 80% reduction from baseline levels by 2030 and a 90% reduction by 2035). Washington's Clean Energy Transformation Act (CETA) mandates that all electricity sold to Washington customers must be carbon-neutral by 2030 and 100% renewable or non-emitting by 2045. These regulations are expected to drive a large buildout of intermittent (e.g., non-dispatchable and non-firm) generation resources such as solar and wind. These regulations also limit or eliminate the use of some of the main firm and dispatchable resources currently relied upon in the PNW, including natural gas-fired generation. There is significant uncertainty as to what firm and/or dispatchable non-emitting resources might become available over the coming decades, and at what costs. For example, electric utilities are including in their IRPs unspecified "non-emitting firm capacity" resources as a placeholder for a recognized need, to maintain compliance, that they do not yet know how to fill.
- **Transmission Availability and Timelines:** New electricity transmission projects have often taken 20 to 30 years to develop in the PNW. It has been a policy objective to reduce these timelines for a long time. A significant uncertainty for electric planning is how much additional transmission capacity can be expected at materially quicker development timelines going forward. Electric system planning will ideally maintain some optionality/flexibility in case new transmission is limited and/or delayed (or fails to be accelerated). Utilities across the state have recognized the need for incremental transmission as a critical mechanism to achieve the resource mix transition required by HB 2021 and have assumed transmission improvements as a way to connect renewable resources in sufficient quantities to ensure compliance by 2030 and 2040. Actual transmission development timeframes have often exceeded those timeframe assumptions.
- **Planning for System Resiliency:** At the same time electric utilities are looking to reduce GHG emissions from their power generation mix, they also need to plan for growing concerns and risks from extreme demand conditions with an increasingly variable supply mix. This includes wildfire risk mitigation investments and preparing for more extreme hot and cold weather conditions which increase peak summer and winter demand. Without two of the major energy infrastructures, gas and petroleum (for

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transportation), potential resiliency and reliability impacts could also be amplified if there was a shift to a single fuel (electricity) system. For example, the natural gas system is already built to handle the extreme spikes in space heating loads during extremely cold temperatures. Most vehicles currently rely on petroleum-based fuel delivery systems. In electrification scenarios that shift natural gas and petroleum loads to the electricity system, planning for that electric system would not only need to account for meeting larger (and in the case of space heating, highly temperature dependent loads) but also for the more concentrated consequences of potential electric system failures during extreme weather conditions.

- **Changes to Electric System Planning Standards:** Given the reliability challenges already being faced by the electric systems in the PNW and across the nation, and the elements of change noted above (significant load growth, shift towards intermittent/non-dispatchable resources, extreme weather conditions, etc.), there may be a need for electric planning practices to shift away from the current approaches such as loss of load expectation metrics and the resulting Planning Reserve Margins (PRM) to planning for more comprehensive resource adequacy. This could mean significantly higher PRM values being used to ensure adequate capacity is built, changes to the capacity contributions attributable to batteries or different non-dispatchable resources for the purposes of meeting the resource adequacy requirements and PRM, or further evolution of the resource adequacy planning approaches to ensure higher and acceptable reliability of an evolving electricity system where more critical services (e.g. heat, transportation, refrigeration, etc.) depend more on a single electricity infrastructure.
- **Affordability Concerns:** Utilities in the PNW, and around the country, are seeing pushback from customers and regulators on rate increases. The electric rate increases that are currently being proposed, and often reduced or rejected, are based on planning before most of the factors above are considered. The compounding changes and challenges discussed in the previous bullets will make it difficult for electric utilities to plan for and meet growing demands and clean energy requirements without significant rate increases to fund the required infrastructure spending and energy transition.

The individual changes above each create uncertainty, but part of the planning challenge for the electric system is that all of these changes and requirements need to be considered simultaneously. This compounds the potential magnitude of change, the range of uncertainty, and the amount of risk associated with planning for a reliable electricity system going forward. Electrification of natural gas end uses and the associated load and peak demand growth, shifts in seasonal and daily load patterns and concentration of energy delivery into a single system

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would further add to these challenges. Utilities in Oregon already face many of these challenges today. In its 2023 CEP, PGE identified the need for infrastructure developments to connect the resources required to achieve HB 2021 compliance, as load growth necessitates more supply while simultaneously decarbonizing existing supply with non-emitting sources to achieve emission reduction limits. In its latest IRP filings in the Spring of 2025, PGE indicated that incremental transmission would be available in 2032 at the earliest, placing compliance requirements on the shoulder of near-term contracts to meet supply needs in absence of near-term transmission solutions.[225] Even with this delayed transmission assumption, PGE's preferred portfolio would necessitate the development of close to 7 GW of resources – more than PGE's current system today – that all require incremental transmission projects to be completed within a 6-year timeframe from 2032 to 2038.

The scope of the electrification analysis for NW Natural's IRP did not include all of the considerations above and is not able to model all of the potential impacts. This analysis focuses on addressing the potential challenge of currently anticipated load growth for utilities, and more specifically how most current electric utility IRPs are not including the potential impacts of significant levels of building electrification.

This analysis is grounded on capacity expansion and optimization modeling and is not expressly a specific reliability analysis and does not capture all of the potential reliability challenges that an evolving electricity system may need to anticipate in its planning. This issue has been identified by NW Natural's outside electric expert as a specific concern and point of caution. For example, the analysis continues to use the current Planning Reserve Margin (PRM) approach without extensive associated reliability modeling of the selected resources mixes. The analysis considers the colder temperatures experienced in January 2024 and quantifies certain aspects of meeting extended peaks under varying levels of electrification, such as fuel and potential fuel storage costs, but does not conduct detailed reliability analysis of multi-day peak events. These extreme hot or cold multi-day events have shown to be difficult situations for electric systems beyond just the Pacific Northwest (e.g. Texas and California).

This analysis also cannot replace or perfectly replicate electric utility data and modeling from their own IRPs or regional Resource Adequacy (RA) programs and reliability assessments performed by entities responsible for RA. This analysis, however, does inform and identify the need for future integrated joint system gas and electric planning to find better combined

[225] Campbell, Rob. "Integrated Resource Planning Roundtable Presentation." April 25, 2025. https://assets.ctfassets.net/416ywc1laqmd/23rNye7U9w5Fv7hlNB7A4y/72b3d002bccbcc1fa89c0af6e4fe0e40/CEP_IRP_Roundtable_April_25-3.pdf

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solutions for these challenges. Along with the results, we raise additional considerations that were not studied here but are expected to further support some of the findings here.

More details on the scenarios, analytical approach, assumptions, and results are provided in the sections that follow.

10.3 Demand Forecast Variations

This section provides an overview of the different demand-side scenarios that were included in the electrification analysis completed by ICF for the NW Natural IRP. The section is split into the following sub-sections:

- Scenario Overview
- Building Electrification Approach and Assumptions
- Building Electrification Results
- Overall Electric Load Impacts from Demand Scenarios

10.4 Scenario Overview

NW Natural's IRP includes a number of different policy and demand variation scenarios, as outlined in Figure 10.2. NW Natural developed the Reference Case and scenarios 1 through 4 in the table below, which have already been discussed in earlier chapters of this IRP. The focus of this chapter is the Modest Customer Electrification, Hybrid System Electrification, and All-Electric Buildings scenarios that were analyzed by ICF (numbered as S5, S6, and S7 in the table below). These are collectively referred to as the "electrification scenarios."

Figure 10.2: Electrification Scenarios in NW Natural IRP

Electrification Scenarios			
Demand Variations	Reference Case		Includes all known codes, policies and energy efficiency expectations and aligns with NW Natural's Reference Case expectations of building electrification.
	S5	Modest Customer Electrification	Aims to align with trends from NEEA-RBSA, projections from electric utilities of existing buildings electrifying, and limitations on natural gas in new construction buildings.
	S6	Hybrid System Electrification	Hybrid systems [electric heat pump with gas furnace as back up] are installed in existing buildings and new construction based on stock turn-over.
	S7	All-Electric Buildings	Significant levels of building electrification of existing buildings and new construction based on stock turn-over.

The electrification scenarios were all built based on specific changes to the types of equipment used by NW Natural customers and installed in new construction buildings in the Reference Case:

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- **Modest Customer Electrification:** Aimed to align with PGE and Pacific Corp IRP assumptions about moderate customer adoption levels for building electrification (a modest level of building electrification), but with limited level of detail into specific assumptions made by those utilities.

- **Hybrid System Electrification:** High levels of building electrification for NW Natural customers but using 'hybrid heating' approach that sees the installation of electric air-source heat pumps (ASHPs) but gas heating equipment maintained for supplemental peak and backup heating needs, especially during winter peaks.

- **All-Electric Buildings:** The same 'high levels' of building electrification for NW Natural customers but using an 'all-electric' approach that sees the installation of a mix of standard electric ASHPs and cold-climate ASHPs, with electric resistance used for any supplemental peak and backup heating needs, especially during winter peaks.

The focus in the electrification scenarios is to compare and contrast the impacts of different approaches to building electrification for the residential and commercial sectors. The analysis also considers electrification in other sectors, such as vehicle electrification and industrial electrification, but the changes in those non-building sectors were held constant across all three electrification scenarios to facilitate or highlight the comparison of the impacts of changes specifically in the buildings sector. Similarly, the Hybrid System Electrification and All-Electric Buildings scenarios were intentionally designed to use the same assumptions in almost all areas (e.g., the same level electrification of water heating and cooking electrification) so that the differences in results for these two scenarios would be driven by whether the customer was assumed to electrify with gas or electric backup heating.

A more specific comparison of the differences between each scenario is provided in Figure 10.3 which showcases the level of electrification assumed for residential and commercial customers, for existing buildings and new construction, and is differentiated by end-use. The electrification measures are all assumed to be implemented at end-of-life of the existing gas equipment for NW Natural customers. The percentages in the table below represent the portion of NW Natural customers in the Reference Case that are assumed to install electric equipment instead of gas equipment when their gas equipment needs replacing. In addition to the milestone values shown here, typical adoption S-curves were used to establish adoption rates in years building up to these milestones.

Figure 10.3 indicates that the level of electric equipment adoption used for existing NW Natural customers in both the Hybrid System Electrification and the All-Electric Buildings scenarios was chosen to align with some of the high-level assumptions available in the fall of 2024 from the Oregon Department of Energy's (ODOE) Oregon Energy Strategy Reference Case

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assumptions.[226] For example, the assumption that, by 2030, 65% of existing NW Natural residential space heating customers who need to replace their furnace that year would opt to install a heat pump (and 90% by 2040) were selected to align with the ODOE Oregon Energy Strategy. Similarly, assumptions for the timeline for water heating and cooking electrification in existing buildings were assumed to align with the ODOE study. While the overall adoption levels were chosen to align with the ODOE study, the decision for one scenario to focus exclusively on electric space heating technology with gas backup, and another scenario to focus exclusively on all-electric technology adoption, was not part of the ODOE study. This approach helps the analysis showcase how hybrid heating (ASHP with gas backup) would change the impacts and costs of electrification. As noted earlier, the Hybrid System Electrification scenario only changed the space heating technology approach from All-Electric Buildings scenario, while water heating and cooking equipment changes to fully electric equipment in both of these scenarios.

The inclusion of these benchmark electrification scenarios does not suggest that NW Natural or ICF endorses any of these demand-side scenarios as realistic or feasible. It should also be noted that neither the ODOE nor ICF models are analyzing what policy approaches or incentive levels would be required to drive these levels of adoption. Instead, the modeling represents a 'what if analysis', where the adoption levels are input assumptions and the analysis focuses on quantifying the resulting impacts of different potential scenarios.

[226] Oregon Department of Energy. "OREGON ENERGY STRATEGY MODELING ASSUMPTIONS AND SOURCES," March 14, 2025. https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy-Modeling-Assumptions-Sources.pdf

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Figure 10.3: Overview of Electrification Scenario Stock Turnover Assumptions

Customer Type	End Use	Modest Customer Electrification	Hybrid System Electrification	All-Electric Buildings
Residential Sector **Existing Gas Customers**	**Space Heating**	•15% heat pump sales by 2030 •Evenly split between heat pumps with electric backup and with gas backup	•Align with ODOE 65% heat pump sales by 2030 & 90% by 2040 •Energy Star AHSP with existing gas furnace system as backup	•65% heat pump sales by 2030 & 90% by 2040 •Mix of Energy Star and cold-climate heat pumps, with electric backup
	Water Heating	15% heat pump sales by 2030	50% heat pump sales by 2030 & 95% by 2045	50% heat pump sales by 2030 & 95% by 2045
	Cooking	15% sales of new appliances are electric by 2030	95% sales of new appliances are electric by 2035	95% sales of new appliances are electric by 2035
Residential Sector **New Construction**	**Space Heating**	50% heat pumps by 2035 (half are hybrids)	100% Hybrid Heating as of 2035	100% ASHP as of 2035
	Water Heating	50% Electric HPWH as of 2035	100% Electric HPWH as of 2035	100% Electric HPWH as of 2035
	Cooking	50% All-electric as of 2035	100% All-electric as of 2035	100% All-electric as of 2035
Commercial Sector **Existing Gas Customers**	**Space Heating**	•5% heat pump sales by 2030 •Evenly split between heat pumps with electric backup and with gas backup	•Small commercial: follows residential •Large commercial: 25% of all new sales are electric with gas backup by 2035 and 90% by 2045	•Small commercial: follows residential •Large commercial: 25% of all new sales are all-electric (ASHP or boiler) by 2035 and 90% by 2045
	Water Heating	5% incremental electric sales by 2030	•Small commercial: follows residential •Large commercial: 25% of all new sales are electric (HPWH or resistance) by 2035 and 90% by 2045	•Small commercial: follows residential •Large commercial: 25% of all new sales are electric (HPWH or resistance) by 2035 and 90% by 2045
	Cooking	5% sales of new appliances are electric by 2035	95% sales of new appliances are electric by 2035	95% sales of new appliances are electric by 2035
Commercial Sector **New Construction**	**Space Heating**	25% heat pumps by 2035 (half are hybrids)	100% Hybrid Heating as of 2035	100% electric as of 2035
	Water Heating	25% electric as of 2035	100% electric as of 2035	100% electric as of 2035
	Cooking	25% electric as of 2035	100% electric as of 2035	100% electric as of 2035

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10.5 Building Electrification Approach and Assumptions

This section provides an overview of the approach used in the building electrification analysis and key assumptions used in the analysis.

Overview of the Building Electrification Analytical Approach

The scenario definitions outlined the differences in adoption levels for different electric technologies in each electrification scenario. Most of the electric technologies used in the building analysis were selected from measures that had already been modelled by the National Renewable Energy Laboratory (NREL) as part of their ResStock and ComStock datasets. The NREL data defined the energy impacts (gas savings, annual electricity increase, peak electricity increase) specific to NW Natural customers for the electrification of different types of gas equipment. These 'per unit' impacts (e.g., the electric load increase from installing a single heat pump in a given building type) were calibrated to include energy efficiency improvements in line with the NW Natural Reference Case. Per unit cost assumptions were also developed. ICF's DER Planner model was used to model the stock turnover of equipment over time for the different scenarios, translating the 'per unit' energy and cost impacts into overall customer electrification conversions, gas savings, electric load increases, and customer equipment costs for the different electrification scenarios.

NREL ResStock and ComStock Data for Electrification Measures

ResStock[227] and ComStock[228] provide highly granular modeling of the U.S. housing and commercial building stock which uses a combination of sampling techniques from diverse public and private data sources, OpenStudio® building simulations, and advanced supercomputing capabilities. They have granular building equipment saturation data by states and climate zones which helps determine baseline usage and impacts of energy efficiency and electrification measures to a low level of granularity. NREL also periodically models the impacts of a variety of energy efficiency and electrification measures through ResStock and ComStock, and releases these datasets. This highly granular modeling provides results for different building types in each county of the country.

The ResStock and ComStock datasets used in this analysis are specifically modeled by NREL to represent the states/counties, and buildings, that make up NW Natural's service area. For the electrification measures included in these NREL datasets, details such as natural gas savings,

[227] National Renewable Energy Laboratory. "ResStock Dataset," 2024. https://resstock.nrel.gov/.
[228] National Renewable Energy Laboratory. "ComStock Dataset," 2024. https://comstock.nrel.gov/.

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increased electricity consumption, and 8760 load shapes for the newly electrified load were extracted from the datasets.

The residential electrification measures included in this analysis were chosen to align with ResStock measures, and are as follows:

- ENERGY STAR air-to-air heat pump with electric backup
- ENERGY STAR air-to-air heat pump with existing system as backup
- High efficiency cold-climate air-to-air heat pump with electric backup
- Heat Pump Water Heater (HPWH)
- Induction Cooking
- Electric Resistance Cooking

The commercial electrification measures included in this analysis were chosen to align with ComStock measures, and are as follows:

- Heat Pump Rooftop Unit (RTU)
- Heat Pump RTU with Original Fuel Backup
- Air-Source Heat Pump Boiler
- Air-Source Heat Pump Boiler and Natural Gas Boiler Backup
- VRF Heat Recovery with DOAS
- Heat Pump Water Heater (HPWH)
- Electric Boiler
- Electric Kitchen Equipment

In addition to the pre-run NREL data sets defining the energy impacts for the above measures, the ResStock building models were also used to analyze custom weather files including equivalent to a January 13, 2024 (low temperature of 15F in Portland) to estimate how much higher peak electric impacts were expected to be for the ASHP and cold-climate ASHP measures noted above.

Calibration to Align with NW Natural Data and Reference Case Forecast

While the NREL data discussed above provides details on the impact of converting natural gas equipment to electric equipment, for a wide range of building types in NW Natural's service area, it was important to ensure the building types assumed to generate these impacts were calibrated and aligned with NW Natural data and NW Natural's IRP Reference Case.

ResStock was used to define the gas consumption for each type of end-use (space heating, water heating, cooking) equipment of NW Natural customers (and the impacts to electrify those end-uses). A number of different sources, as shown in Figure 10.4, were used to establish how commonly the different types of gas equipment were found in the homes of NW Natural

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customers. For example, 85% of existing single family home NW Natural customers in Oregon use natural gas for space heating, but only 70% of that customer segment uses natural gas for water heating.

Figure 10.4: Portion of NW Natural Customers Using Natural Gas Equipment for Specific End Uses

State	Building Type		Space Heating	Water Heating	Cooking	Data Source
Oregon	Existing Buildings	Single Family	85%	70%	48%	NEEA - Regional Data
		Multi-Family	21%	44%	20%	NEEA - Regional Data
		Mobile Home	85%	18%	79%	NREL ResStock
	New Construction	Single Family	95%	73%	95%	NWN Data
		Multi Family	43%	41%	94%	NWN Data
Washington	Existing Buildings	Single Family	85%	70%	48%	NEEA - Regional Data
		Multi Family	21%	44%	20%	NEEA - Regional Data
		Mobile Home	0%	0%	83%	NREL ResStock
	New Construction	Single Family	51%	39%	94%	NWN Data
		Multi Family	20%	37%	80%	NWN Data

The NREL defined gas use per end-use for different building types was multiplied by the portion of customers where each end-use is present (from Figure 10.4) to establish the average (across all customers) consumption per end use showcased in Figure 10.5.[229] Combining the average consumption for each end-use results in the average 'Total Use per Dwelling' values shown below. A 'Total Use per Meter' value is also included below, as NREL models multi-family

[229] For example, ResStock indicated average annual space heating gas consumption of 565.4 therms across the single family buildings that use gas for space heating. Multiplied by 85% of NW Natural existing single family homes that use gas for space heating, this results in an average of 481 therms/year across all NW Natural existing single family home customers.

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buildings on a per unit basis, while NW Natural's customer for existing buildings will often have a single gas meter serving multiple different units with the building. The average number of units per multi-family building meter is not something NW Natural has data on, and so this ratio was adjusted to calibrate the average Total Use Per Meter values across the different types of existing buildings with the Use Per Customer data from NW Natural's IRP Reference Case, shown in the green columns in Figure 10.5.

NW Natural's IRP Reference Case includes forecasts of gas consumption and customer meter numbers, separate from existing customers and new construction. The Reference Case forecast did not include forecasts split between building types like single family homes vs. multi-family buildings, or forecasts split by end-uses like space heating and water heating.

Figure 10.5 also shows in the green columns how the average gas use per customer is forecast to reduce between 2025 and 2050 in the Reference Case. This reduction is driven by assumptions including significant energy efficiency improvements (provided to NW Natural by the Energy Trust of Oregon), demolition of a portion of older buildings (replaced with more efficient new construction), and warming average temperatures over the study horizon. In addition to calibrating the 2025 base year data to match the Reference Case, the annual reduction in use per customer is applied to the measure-level energy impacts from NREL, to ensure that the numbers continue to align with the Reference Case in all years (e.g., not showing more gas savings than actually exists in the Reference Case). Importantly, the annual use per customer reduction is applied not only to gas savings, but also to electric load increases from the NREL electrification measures. While this is not a purely apples to apples comparison (e.g., not all the use per customer savings is from building shell improvements that would apply equally to electric heating needs), this was treated as a general representation of the potential efficiency improvements for heat pump technology out to 2050.

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Figure 10.5: Average Natural Gas Use Per Customer by End Use and IRP Use Per Customer Forecast

State	Building Type		2025					2025	2050
			Space Heating	Water Heating	Cooking	Total Use per Dwelling	Total Use per Meter	IRP Use per Customer	IRP Use per Customer
Oregon	Existing Buildings	Single Family	481	121	14	**616**	**616**	658	449
		Multi-Family	39	56	5	**100**	**1,176**		
		Mobile Home	295	28	23	**346**	**346**		
	New Construction	Single Family	339	85	10	**434**	**434**	434	218
		Multi Family	52	75	6	**133**	**133**	134	105
Washington	Existing Buildings	Single Family	538	126	14	**678**	**678**	647	483
		Multi Family	31	59	5	**96**	**627**		
		Mobile Home	-	-	24	**24**	**24**		
	New Construction	Single Family	279	65	7	**352**	**352**	352	311
		Multi Family	33	62	6	**100**	**100**	100	91

For the commercial sector, the analysis also leveraged NW Natural data and ComStock data, while calibrating to the Reference Case forecast for how commercial gas consumption and customer counts would change by 2050. As with the residential sector, the commercial sector energy impacts from ComStock (both gas savings and electric load increases) were scaled down over the study period to match the same changes in the gas use per customer in the NW Natural Reference Case. This assumption for gas use per customer reductions (and corresponding reductions in electrification load increases) was applied evenly across all commercial sub-sectors and end-uses.

ComStock includes different types of space heating equipment for different commercial sub-sectors and this analysis focused on two of the main baseline types. Figure 10.6 shows the assumed split of baseline heating equipment types assumed for each commercial sub-sector,

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based on the ComStock data. At the bottom of the table, the relevant space heating electrification measures for each type of baseline heating equipment are shown. For example, for the Large Office sub-sector, where 100% of the baseline equipment is assumed to be gas boilers, the space heating electrification measures used will be the heat pump boilers with either gas or electric backup, none of the ASHP rooftop unit measures will be applied for this sub-sector. The righthand column of the table also shows which commercial sub-sectors were assumed to be small or large for the purposes of which adoption curves would be applied.

Figure 10.6: Breakdown Between Commercial Sector Baseline Space Heating Technologies and which Sub-sectors Assumed to Follow Small or Large Commercial Adoption Curves

Sub-Sectors	Gas Boilers	Gas RTU	Small or Large Adoption Curves
Full-Service Restaurant	0%	100%	Small
Hospital	75%	25%	Large
Large Hotel	100%	0%	Large
Large Office	100%	0%	Large
Medium Office	63%	38%	Small
Outpatient	55%	45%	Small
Primary School	39%	61%	Large
Quick Service Restaurant	13%	87%	Small
Retail Stand alone	60%	40%	Small
Retail Strip mall	0%	100%	Small
Secondary School	80%	20%	Large
Small Hotel	100%	0%	Small
Small Office	13%	87%	Small
Warehouse	20%	80%	Large

Applicable Space Heating Upgrades	HP Boiler, electric backup	ASHP RTU, electric backup
	HP Boiler, gas backup	ASHP RTU, gas backup
		VRF

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Electrification Technology Assumptions

This section provides an overview of the key assumptions of 'per unit' impacts for gas savings, electricity load increases, and equipment costs. Many of these impacts vary across building types and/or by specific county, but the values shown here are intended to give a sense of the key assumptions used, without listing values for every permutation.

In Figure 10.7 (Oregon) and Figure 10.7 (Washington), the gas savings and electric load increase per unit are based on NREL's ResStock data. The gas savings represent the full electrification of the relevant end-use for all measures except the ASHP with gas back-up (also referred to as 'existing system' backup by NREL), where some back-up gas space heating consumption remains after the conversion. The values shown here are for 2025, and as noted below would be reduced over time to align with use per customer reductions in NW Natural's IRP Reference Case.

This analysis relies on the NREL ResStock building modeling of heat pump impacts, however using building modeling results can have limitations in representing real world performance. For example, NREL's ResStock documentation230 notes that "because the heat pumps in this dataset's measure packages represent retrofits to existing dwelling units, there is a limitation in our modeling methodology surrounding duct size." NREL's model assumes that ducts will be re-sized as needed, allowing for an optimal configuration for the heat pump retrofits, while in reality homeowners will not always replace their ducts when installing heat pumps. Such assumptions can lead to an under-representation of annual and peak building electrification impacts. Uncertainty in this area is also captured by analysis completed by the ETO looking into how the actual electric savings achieved were significantly lower than expected for heat pump installations replacing electric furnaces. The 2020 ETO supported analysis for ducted heat pump conversions, found overall realization rates of 48% for site-built homes (e.g., just less than half of the expected electricity savings were actually achieved) and 73% for manufactured homes. A 2024 ETO analysis of residential ductless heat pump installations found a 45% realization rate. The issue of heat pump underperformance and the number of variables driving it has also been captured by the NWPPC's Regional Technical Forum. These items highlight how important it will be to monitor the performance of early heat pump installations and find ways to avoid the performance and/or installation issues driving the above issues, in order to avoid the electric grid facing even more challenging impacts from building electrification.

[230] Present, Elaina, Philip White, Chioke Harris, Rajendra Adhikari, Yingli Lou, Lixi Liu, Anthony Fontanini, Christopher Moreno, Joseph Robertson, and Jeff Maguire. "ResStock Dataset 2024.1 Documentation." Golden, Colorado: National Renewable Energy Laboratory (NREL), 2024. https://doi.org/10.2172/2319195.

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The incremental measure costs per unit included in Figure 10.7 represent the total incremental equipment conversion costs for the different electrification upgrades. The analysis assumed that electrification upgrades occur at the end of life of the existing gas equipment, and so the costs shown here are the incremental costs (the full costs less the baseline equipment upgrades the customer would otherwise have needed to make to put in new gas equipment). The analysis also assumes incremental re-participation costs after the end of life for the electric technologies that are installed in this analysis (so if an ASHP installed at a NW Natural customer in 2030 needs replacing in 2045, a new ASHP would again be installed but at a lower incremental cost than the original conversion). The costs for single family homes shown here are largely based on assumptions from the January 2025 update[231] to Puget Sound Energy's 2023 Decarbonization Study, which include costs for regular air source heat pumps, cold climate heat pumps, and hybrid heat pumps.[232] Costs for multi-family units and mobile homes were based on data available from the Regional Technical Forum.[233] In general, sources acknowledge that heat pump installations with gas-back up can have lower upfront costs.

[231] Puget Sound Energy. "Updated 2023 Decarbonization Study Summary Report," January 2025. https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0131_UpdatedDecarbStudyReport.pdf.
[232] Puget Sound Energy. "GRC Stipulation O: Updated Decarbonization Study," *p. 90*. December 22, 2023. https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3617&year=2022&docketNumber=220066.
[233] Northwest Power & Conservation Council. "UES Measures." Regional Technical Forum, 2025. https://rtf.nwcouncil.org/measures/.

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Figure 10.7: Key Assumptions for Residential Electrification Technologies in Oregon (Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-172	1,193	1,710 [234]
Electric Conventional Range/Oven	-30	706	130
Electric Induction Range/Oven	-30	758	470
Energy Star air-to-air heat pump, Electric Backup	-565	5,442	10,623 [235]
Energy Star air-to-air heat pump with existing gas system as backup	-504	4,121	10,825 [236]
High efficiency cold-climate air-to-air heat pump, Electric Backup	-565	3,809	15,822 [237]

[234] Based on a Full Cost of $68/gallon, or $3,400 for a 50 gallon tank HPWH. Incremental Cost of $1,710 subtracts an assumed cost of $1,690 for a typical gas water heater form the Full Cost.
[235] Estimated from the PSE Decarbonization Study costs in report referenced above. The Full Cost for an ASHP installation was found to be $20,093. To calculate the $10,623 Incremental Cost used here, first $6,555 is subtracted from the Full Cost to account for the customer otherwise needing to replace their furnace. Then an additional $2,915 is subtracted from the Full Cost to account for some customers (69% of Oregon single family homes) also having an air-conditioning unit that would be replaced by the ASHP and accounting for the fact that those air-conditioning units will not necessarily be at the end of their life when the customer's furnace needs replacing (so the incremental cost is reduced by 50% of the AC unit cost). The $8,450 Central AC replace on failure cost from PSE study * 50% * 69% = $2,915 in average AC savings for incremental costs.
[236] Estimated from the PSE Decarbonization Study costs in report referenced above, where the Full Cost of a Hybrid Heat Pump installation was found to be $13,740. This approach assumes the conversion happens at the gas furnaces end of life (hybrid systems can also go in at the AC unit end of life, paired with the existing furnace) so the customer would still need to purchase a new furnace. The Incremental Cost of $10,825 used here is based on the Full Cost minus $2,915 in savings from some customers replacing an AC unit before end of life, as described in the previous footnote.
[237] Estimated from the PSE Decarbonization Study costs in report referenced above, where the Full Cost of a Cold Climate Air Source Heat Pump installation was found to be $25,292. To calculate the $15,822 Incremental Cost used here, $6,555 is subtracted from the Full Cost to account for the customer otherwise needing to replace their furnace and $2,915 is subtracted for some customers replacing an AC unit before end of life, as described in the previous footnote.

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Figure 10.8: Key Assumptions for Residential Electrification Technologies in Washington (Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-180	1,352	1,710
Electric Conventional Range/Oven	-30	733	130
Electric Induction Range/Oven	-30	760	470
ENERGY STAR air-to-air heat pump, Electric Backup	-632	7,008	10,623
ENERGY STAR air-to-air heat pump with existing system as backup	-524	5,230	10,825
High efficiency cold-climate air-to-air heat pump, Electric Backup	-632	5,040	15,822

In the commercial sector, the gas savings and electric load increase per unit are based on NREL's ComStock data. The gas savings represent the full electrification of the relevant end-use for all measures except the heat pump with gas back-up options, where an average of 10% of gas consumption remains for back up heat. The values shown here are for 2025, and as noted below would be reduced over time to align with commercial sector use per customer reductions in NW Natural's IRP Reference Case. The baseline equipment size and energy impacts from equipment electrification in different commercial sub-sectors and building configurations can vary significantly. Figure 10.9 does not capture all different commercial sub-sectors, but for each measure provides impacts and costs for a different commercial sub-sector as an example. For the costs, there is also a column showing the range across all different commercial sub-sectors for that measure. The approach for the incremental measures costs included in Figure 10.8 aligns with residential sector equivalent discussed above. Costs per ton of equipment capacity were developed for the electrification upgrades and the baseline gas equipment options (in order to calculate an incremental cost) from a variety of sources like the

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EIA Updated Buildings Sector Appliance and Equipment Costs and Efficiencies,[238] an ACEEE report,[239] and utility Technical Resource Manuals (TRMs).

Figure 10.9: Key Assumptions for Commercial Electrification Technologies in Oregon

Measure Name	Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)	Incremental Cost Range across Building Types per Unit ($)
ASHP RTU with Electric Backup	Medium Office	4,455	3,117	$218,352	Incremental costs vary widely across building types, ranging from approximately $27,000 to nearly $3 million per building
ASHP RTU with Gas Backup	Medium Office	4,010	293	$244,204	$32,000 - $3.3 million
VRF	Medium Office	4,455	(149,396)	$939,882	$125,000 - $3.2 million
HP Boiler, Electric Backup	Large Office	20,215	165,983	$340,919	$80,000 - $1.9 million
HP Boiler, Gas Backup	Large Office	18,193	149,429	$327,605	$77,000 - $1.8 million
Electric Kitchen Equipment	Full Service Restaurant	5,023	75,701	$214,295	$54,000 - $390,000
Heat Pump Water Heater	Hospital	14,359	170,524	$1,411,806	$13,000 - $1.4 million
Electric resistance boiler	Hospital	14,359	397,566	$885,839	$9,000 - $880,000

[238] U.S. Energy Information Administration. "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies," March 2023.
[239] Nadel, Steven, and Chris Perry. "ELECTRIFYING SPACE HEATING IN EXISTING COMMERCIAL BUILDINGS: OPPORTUNITIES AND CHALLENGES." American Council for an Energy-Efficient Economy, October 2020. https://www.aceee.org/sites/default/files/pdfs/b2004.pdf
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Figure 10.10: Key Assumptions for Commercial Electrification Technologies in Washington

Measure Name	Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)	Incremental Cost Range per Unit ($)
ASHP RTU with Electric Backup	Medium Office	964	-16,408	218,352	Incremental costs vary widely across building types, ranging from approximately $27,000 to nearly $3 million per building
ASHP RTU with Gas Backup	Medium Office	835	-19,431	244,204	$29,000-$3.4 million
VRF	Medium Office	964	-108,583	939,882	$125,000-$3.2 million
HP Boiler, Electric Backup	Large Office	10,446	78,316	340,919	$80,000-$1.9 million
HP Boiler, Gas Backup	Large Office	9,402	68,537	327,605	$77,000-$1.8 million
Electric Kitchen Equipment	Full Service Restaurant	3,053	46,309	214,295	$54,000-$390,000
Heat Pump Water Heater	Hospital	3,285	39,012	1,411,806	$13,000-$1.4 million
Electric resistance boiler	Hospital	3,285	90,954	885,839	$9,000-$880,000

DER Planner Stock Turnover Modeling

ICF's DER Planner model was used to model the stock turnover of equipment over time for the different scenarios, based on the respective scenario assumptions for uptake of electric technologies. The 'per unit' assumptions developed for the gas savings, electric load increases, and equipment conversion costs, specific to different residential and commercial electrification technologies, regions, and sub-sectors were entered into DER Planner. DER Planner was then used to model the overall levels of electric equipment adoption and the resulting impacts. In addition to the annual gas, electric, and cost impacts, 8760 load shapes from NREL for each of the electrification measures were used to provide the resulting incremental loads for the power

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sector modeling. The savings applied to annual impacts to align with the use per customer reductions in the Reference Case are also applied to the 8760 load shapes (e.g., the gas use per customer assumptions for the Reference Case are also assumed to reduce peak electric impacts from building electrification).

This detailed analysis was conducted for NW Natural customers, not for the entire state of Oregon or Washington. The implications of customer electrification outside of NW Natural's service area are important, in particular for the power sector modeling. As such, estimates for similar electrification load growth in the rest of Oregon were made to feed the power sector modeling. The rest of state estimates scale the impacts found in this detailed analysis for NW Natural's customers, based on the number of other gas utility customers in each state. To the extent that other gas utilities in Oregon have colder service areas, this simplified approach may underestimate the state-wide increases in annual and peak electric load from building electrification.

The same scenario electrification adoption assumptions were applied to both Oregon and Washington, but as described above, the characterization of both Washington NW Natural customers and the impacts of electrification technologies on those Washington customers, used Washington-specific inputs.

10.6 Building Electrification Results

This section provides an overview of the residential and commercial building electrification impacts that were modelled based on the scenarios, assumptions, and approaches discussed above. Taken together, Figure 10.11, which shows how NW Natural's gas volumes change, and Figure 10.12, which shows how the utility's customer numbers change, provide an overview of the electrification scenario impacts on NW Natural's customers. Both charts show the combined impact for the Company's residential and commercial customers in Oregon and Washington. In general, the reductions in the residential sector are larger than those in the commercial sector.

First, it is important to note how gas consumption for residential and commercial customers in the **IRP Reference Case (black dotted lines)** declines 26% from 2025 to 2050, while the number of NW Natural customers grows 12% over that same period. This represents an average reduction in gas use per customer of 34% across these customer segments and is driven by assumptions for energy efficiency improvements (provided to NW Natural by the Energy Trust of Oregon), demolition of a portion of older buildings (replaced with more efficient new construction), and warming average temperatures over the study horizon. All three electrification scenarios are built upon this Reference Case, and the use per customer

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improvements were conservatively assumed to reduce both gas use and electricity impacts for converted customers.

The **Modest Customer Electrification scenario (yellow lines)** sees customer gas consumption in 2050 drop 38% relative to 2025, and 2050 customers decline 4% relative to 2025. The **All-Electric Buildings scenario (blue lines)** sees a larger 85% drop in customer gas consumption by 2050 relative to 2025, and 2050 customers decline 90% relative to 2025. It should be noted that even in this most aggressive All Electric scenario contemplated here, roughly 10% of NW Natural's 2025 residential and commercial customer base continues to rely on gas in 2050 (a larger portion on the commercial side than residential).

Then, the **Hybrid System Electrification (purple lines)** sees a significant divergence between the trends in the charts below. This scenario sees an 80% drop in customer gas consumption by 2050 relative to 2025, which is very similar to the All-Electric Buildings scenario. This is a result of the NREL ResStock and ComStock modeling of the electric heat pump measures with gas back-up heat for NW Natural counties, indicating that the electric heat pumps are able to provide the majority of the annual heating needs and rely on gas back-up primarily in a selection of colder hours.[240] While gas consumption in this scenario drops significantly, the Hybrid System Electrification scenario only sees customers decline -13% from 2025 levels, resulting in a decoupling of gas utility customer numbers and total customer gas consumption. In fact, in this scenario, gas space heating (back-up) customers continue to grow out to 2050 (in line with the reference case), but it is the electrification of the small portion of NW Natural customers that only use natural gas for water heating and/or cooking that drives the overall decline in customers in this scenario. The implications of the Hybrid System Electrification scenario are important and profound because it allows the electric systems to serve ASHPs much of the time, but does not require an electric system that would have to serve ASHPs all of the time, which the All-Electric scenario would require. The Hybrid scenario means the gas system serves the most extreme winter peaks and it does not require the electric system to build out expensive zero emissions peaking capacity to serve this need like the All-Electric scenario would.

[240] The All-Electric and Hybrid scenarios also use the same assumptions for full electrification of water heating and cooking end-uses, further bringing these lines together.

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Figure 10.11: Change in NW Natural Customer Gas Consumption (Res & Com) by Scenario – Oregon & Washington

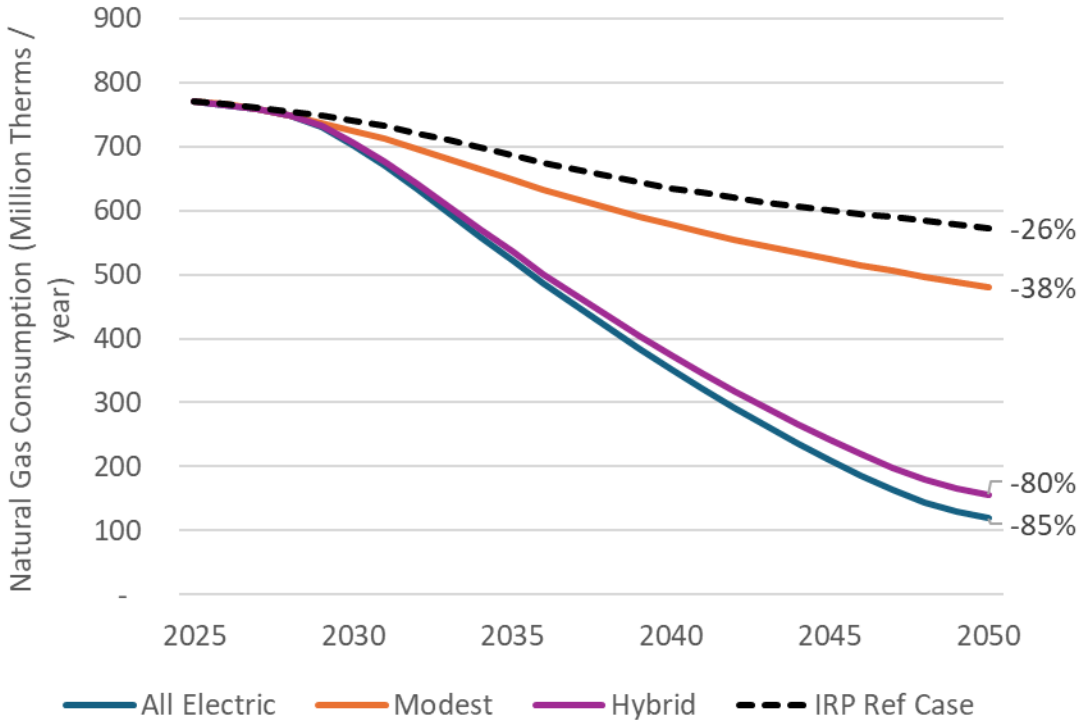

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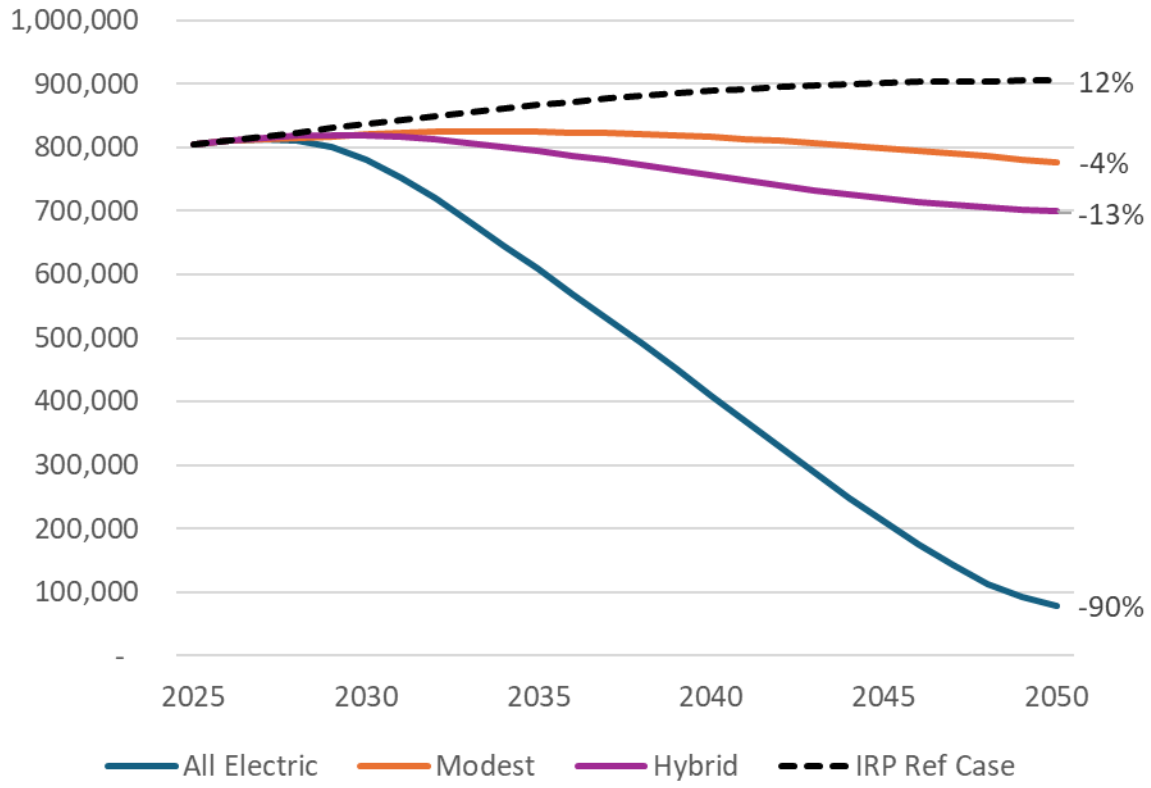
Figure 10.12: Change in NW Natural Customers (Res & Com) by Scenario – Oregon & Washington



The results from the previous figures are driven by the adoption levels for different electrification technologies. Given that the majority of NW Natural customer gas consumption is used for space heating, the largest impacts are driven by the uptake in heat pumps in each scenario. Figure 10.13 shows the cumulative total of NW Natural customers (from Reference Case) that are assumed to adopt heat pumps in each scenario, covering both Oregon and Washington. This includes both heat pumps with electric backup and gas backup, so the lines for the Hybrid and All-Electric scenarios overlap. Both of these scenarios assume roughly 712,000 heat pumps are installed by 2050. This study did not evaluate the feasibility of requiring a complete transformation of the HVAC contractor industry or supply chain implications to support this level of heat pump installations. The figure shows overall adoption rates slowing after 2045. Given how early and aggressive the adoption assumptions are in these two scenarios, all the stock has turned over and most customers have gone electric by 2045, so there is less turnover in gas customers remaining each year post-2045 that go electric.

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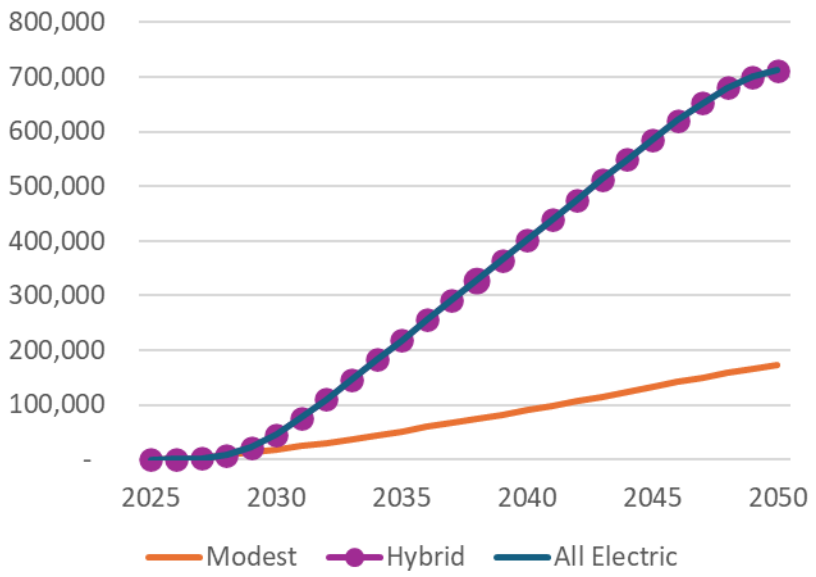
Figure 10.13: Cumulative Number of Air Source Heat Pumps Deployed by Scenario



The All-Electric and Hybrid scenarios incorporate bookend rates of heating equipment being replaced by a single type of technology based on assumed equipment stock turnover. To reiterate the objective of this analysis is to be able to compare and contrast different "what if" scenarios and it does not mean that NW Natural or ICF endorses any of these scenarios as realistic or feasible, as there will be a mix of technologies being deployed to meet space heating requirements.

The annual equipment cost impacts are lower in the Modest scenario, where adoption levels are also lower. Incremental customer equipment costs in the Hybrid Scenario and All-Electric scenarios are relatively similar. The equipment conversion costs in the Hybrid Scenario are a bit higher than the All-Electric scenario for the residential sector but are expected to be lower for the Commercial Sector. Both scenarios assume the same equipment adoption (and hence costs) for water heating and cooking equipment. Most of the costs are driven by heat pumps for space heating, but heat pump water heater costs also make up a significant portion of the total.

Space heating gas use is highly concentrated in colder winter days, meaning that space heating loads include significant spikes in 'peak demand.' Additionally, while electric heat pumps operate at high efficiencies on an annual average basis, both the heat output and the efficiency of heat pumps are reduced at lower temperatures, creating even larger spikes in peak demand relative to annual averages.

Figure 10.14 provides an overview of the peak demand impacts specific to building electrification in each of the study scenarios. These are peak hour loads in the winter from just

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the incremental electrification, not coincident peaks considering other loads on the electric system (e.g., building electrification peak hour does not necessarily drive overall electric system peak demand). The peak demand impacts are calculated to represent a winter day matching January 13, 2024, which got down to 15°F in parts of Portland. This analysis based on 15 degrees on January 13, 2024 is warmer than the NW Natural's current Design Day used for natural gas infrastructure planning, but colder than a 'weather normal' assumption typically used in electric planning. This chart represents peak demand just from electrification of NW Natural customers in Oregon, not the electrification of all gas customers in the state. Another implication NW Natural and ICF have identified is this difference between electric and gas system planning standards. While the implications of different standards maybe be less of an issue in a diverse "two fuel" heating system (gas and electricity), NW Natural's outside electric experts have raised this issue as a significant concern in a non-diverse "single fuel" heating system.

The All-Electric Buildings scenario in Figure 10.14 reaches a peak winter hour load impact in Oregon of 4.5 GW by 2050 (from just building electrification of NW Natural customers). The Hybrid scenario shows minimal winter peak demand impacts from water heating and cooking, at 0.25 GW by 2050, under the assumption that all heating needs would be provided by gas back-up systems on this cold temperature day.

The ability of the gas system to back up the electric system to meet the winter peak demands in this arrangement, leveraging existing gas infrastructure that has been built to store energy, deliver capacity, and serve large spikes from space heating, instead of building out significant additional new electric infrastructure to meet the extremely high cold weather spikes in heating loads, is a key benefit of the hybrid heating arrangements assumed in the Hybrid Scenario.

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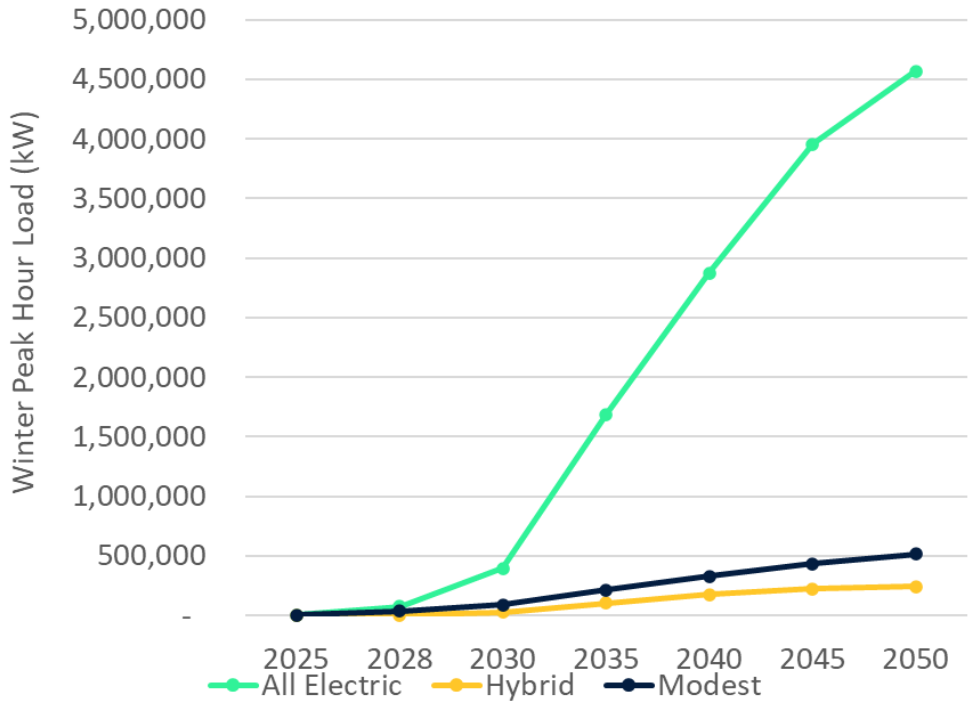
Figure 10.14: Incremental Peak Electricity Load from Building Electrification of NW Natural Customers (Res & Com) in Oregon



10.7 Overall Electric Load Impacts from Demand Scenarios

Energy and peak demand projections for the electrification analysis incorporate electric load projections from utilities in Oregon to the extent available, as well as projections for residential, commercial and industrial electrification from the building electrification scenarios described above.

For each year and scenario, hourly 8760 load shapes inform the overall annual load requirements as well as the seasonal peak demand requirements. The 8760 hourly load shapes for each year and scenario incorporate distinct hourly impacts from baseline load and electric load growth for residential, commercial and industrial customers, as well as vehicle electrification, data center loads, and building electrification. Section 10.7 of this report describes the electrification load impacts on the respective utility areas as well as Oregon and Washington State.

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Oregon Baseline Load

Baseline electric load growth informed by electric utility IRPs incorporates the impacts of energy efficiency, demand response, and underlying load growth expected for residential, commercial, and industrial customers in the utility service territories.

Annual load projections were sourced from electric utility data such as IRP publications and IRP stakeholder discussions, supplemented with load growth projections from NERC ES&D 2024 for the PNW for areas where utility data was not available. 8760 load shapes for the baseline load apply the 2018 hourly shape from FERC form 714[241] data to the projections of annual baseline load through 2050 to project hourly baseline load through 2050.

Data Center Loads

Utility projections on data center loads are incorporated into the forecasted annual electric load and peak demand projections based on data provided by utilities and modeled consistent with the approach of the individual utilities. While some utilities, such as PGE[242], incorporate data center growth in the load forecast referenced for this analysis, other utilities do not directly incorporate these loads into the forecast for their service territories and resource plans. Projections for data center loads and the treatment of data center loads as part of utility or broader regional energy load growth remains a significant area of uncertainty. For the purposes of this analysis, treatment of data center loads is consistent with the respective utility approaches and a flat 24h shape across the year is applied for all data center load to create an hourly 8760 shape for every year. All electrification scenarios feature the same levels of data center loads.

Electric Vehicle Loads

Oregon load projections incorporate EV loads based on data from utility projections on EV loads.[243] Hourly profiles for EV loads are based on electric vehicle modeling conducted by ICF in

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[241] Federal Energy Regulatory Commission. "Form 714," June 2021. https://www.ferc.gov/sites/default/files/2021-06/Form-714-csv-files-June-2021.zip

[242]https://assets.ctfassets.net/416ywc1laqmd/UCFpfZzIgecl6VQGosytA/350f50c7f9f8d8c4ff8552f9c235ca01/IRP_Roundtable_July_24-3presentation.pdf#page=13

[243] For PGE, EV assumptions are aligned with Reference Transportation Electrification forecast in the September 2024 CEP IRP stakeholder materials: Portland General Electric. "PGE CEP & IRP Roundtable 24-6." October 2, 2024. https://assets.ctfassets.net/416ywc1laqmd/6Gv0U2lLocu2YCSnHv4JRP/43c13f8b70898a4476a4655f5f783fd4/IRP_Roundtable_October_24-6.pdf.

For PacifiCorp, EV assumptions are assumed to be the growth driver of the "Misc" category referenced in September 2024 Stakeholder documents: Applied Energy Group. "2025 Integrated Resource Plan Public Input Meeting Supplemental Material," October 11, 2024. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_September_25_2024_Supplemental.pdf.

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EVI Pro[244] that include measures to mitigate peak demand impacts in the evening hours. Peak demand impacts of EV electrification vary by scenario, depending on the hourly load profile of all the combined electricity end-uses. All electrification scenarios feature the same levels of electric vehicle loads.

Washington Demand Baseline

Washington's electric load projections incorporate IRP projections for Clark PUD and PacifiCorp. The rest of the state is captured in aggregate, with 2023 electric sales grown with the growth rate of load in NERC's 2024 Electricity Supply & Demand forecast. For years outside of the NERC forecast range, the 3-year compound average growth rate (CAGR) of the last 3 years of available data is used to extrapolate load beyond the NERC timeframe.

End-Use Electrification

Impacts of end-use electrification in the residential, commercial, and industrial sectors were developed as part of the demand forecast projection outlined in section 10.3. End-use equipment changes and their resulting shift in natural gas loads to the electric sector resulted in 8760 load shapes for electric demand impacts for each scenario, year, electric utility region and customer segment. Hourly load impacts were stacked with other load components to create hourly load shapes for all electric demand sectors.

Demand Results

Oregon Annual Energy Demand Results

Without electrification of the end-use sectors, Oregon's load is projected to increase by 53% in 2050 compared to 2025 across all three scenarios. Data Center and EV growth are the primary drivers of increased electric demand growth over the next 25 years. EV demand is projected to contribute 16,000 GWh demand by 2050, whereas data center growth is projected to add up to 21,000 GWh to Oregon's electric demand by 2050. Building electrification loads are projected to add an additional 4,800 GWh – 5,200 GWh in the Hybrid and All Electric Scenarios. In the modest scenario, annual load increases by 1,875 GWh by 2050. While annual load increases impact the required energy that needs to be procured over the course of the year often through non-emitting generation – the primary impact of the building electrification is on peak demand projections, especially in the winter months, as discussed further below.

[244] National Renewable Energy Laboratory. "EVI-Pro: Electric Vehicle Infrastructure – Projection Tool." Transportation & Mobility Research, March 5, 2025. https://www.nrel.gov/transportation/evi-pro.

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Washington Annual Demand Results

Washington electric load in the Reference Case increases by 43,203 GWh between 2025 and 2050. Electrification of end uses in Washington further increases electric loads by 200 GWh in the Modest scenario, and between 617 and 707 GWh in the Hybrid and All-Electric Scenarios. Consistent with Oregon results, annual energy impacts of Hybrid and Al-Electric scenarios are consistent, as the primary impact of the electrification scenarios is on winter peak rather than annual energy demand.

Most of the energy demand increase in Washington occurs in Clark PUD, where the largest portion of NW Natural customers are located.

Oregon Seasonal Peak Demand Results

Annual impacts of electrification increase the required load to serve over the course of the year. Building space heating electrification peak impacts on load are concentrated in winter hours where heat pump performance drops as temperatures fall, increasing electricity energy and peak capacity requirements as more of the states' energy needs are delivered through electric energy with growing electrification. While annual energy load impacts between the Hybrid and the All-Electric Scenario are within 10%, peak demand impacts in the winter can be mitigated through the deployment of hybrid technology, shifting the fuel supply to natural gas as temperatures drop and reduce efficiency of the heat pumps.

As an example, the estimated seasonal peak demand projections for one of the main electric utilities with a service territory that partially overlaps Northwest Natural Gas customers is shown below.[245]

[245] While utility-level projections are informed by utility data to the extent possible, the process to develop annual and peak demand projections not intended to exactly replicate utility-level demand forecasting processes.

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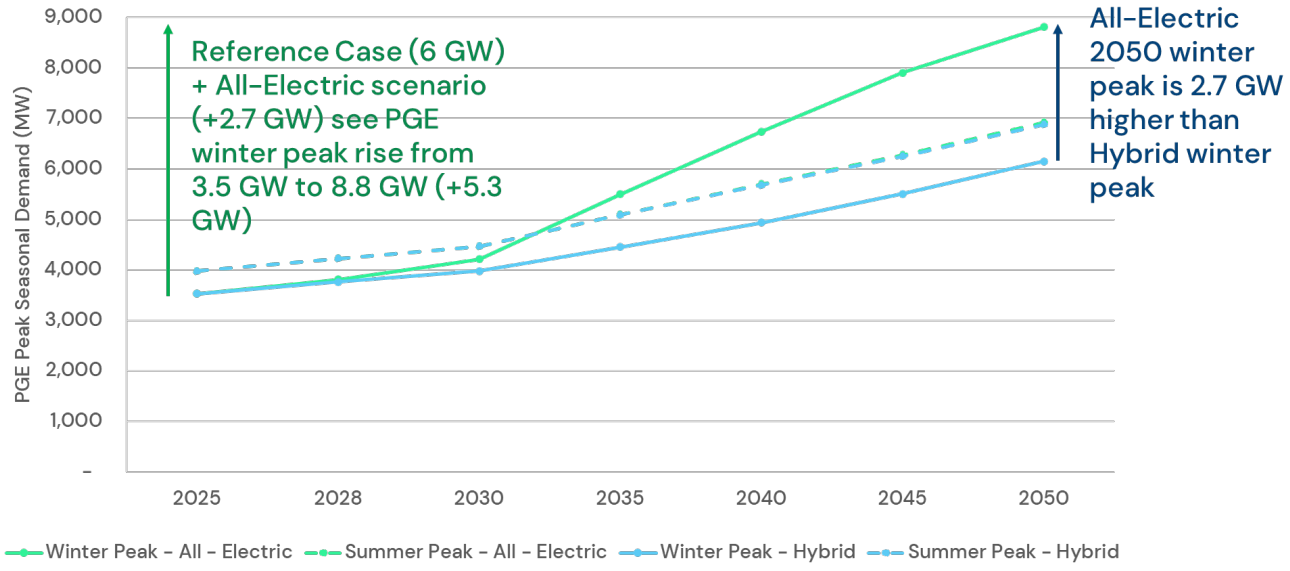
Figure 10.15: PGE Seasonal Peak Demand Projections – Hybrid and All-Electric Scenarios (MW)



With the gap between winter and summer peak demand only around 10%, electrification of natural gas end uses is projected to shift the annual peak to winter peaks in the All – Electric Scenario by 2035. While summer peaks also increase significantly over the forecast period to reach close to 7 GW by 2050, winter peaks in the All – Electric Scenario grow more rapidly to reach close to 9 GW by 2050. Winter peaks occur when solar and wind energy resources contribute little capacity to the electric system. These peaks would have to be met with expensive clean fuel firm and dispatchable resources in the All-Electric Scenario.

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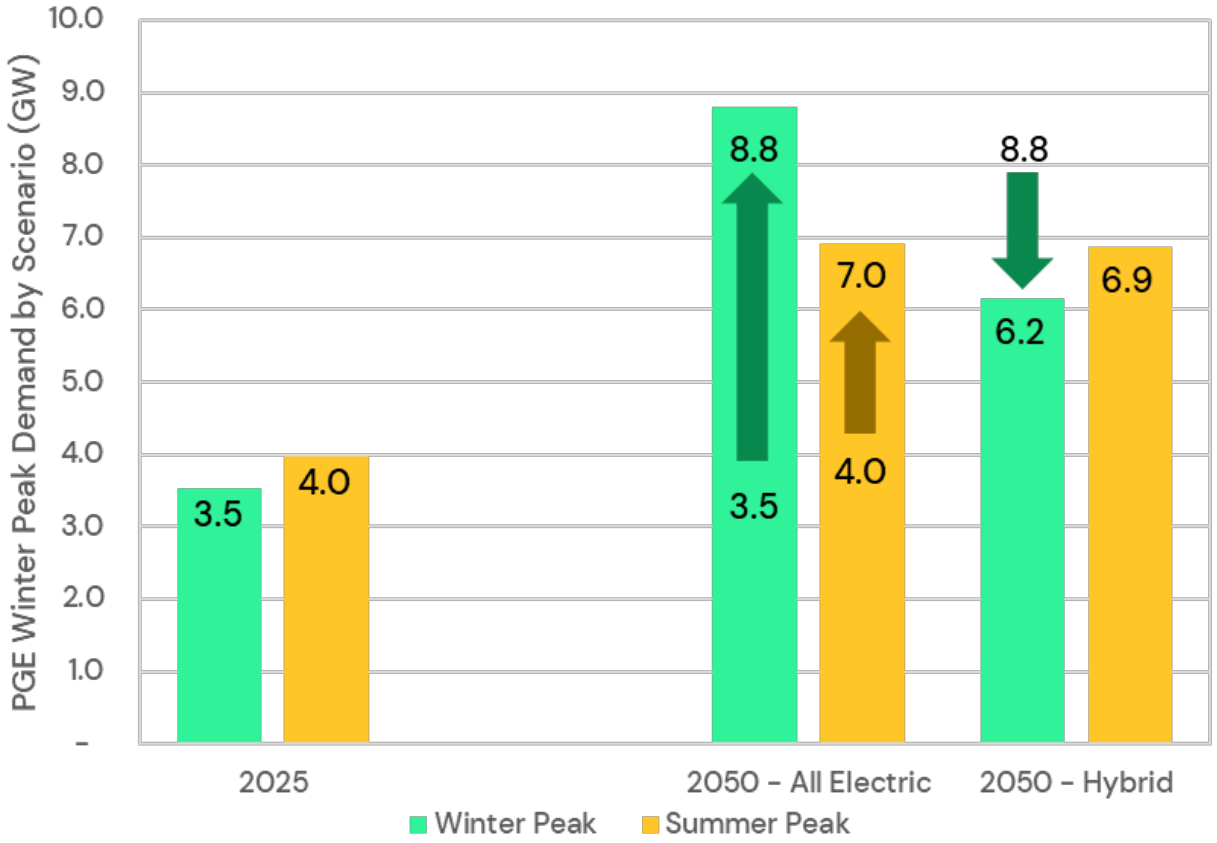
Figure 10.16: PGE Seasonal Peak Demand Growth by Scenario (MW)



As shown in Figure 10.16 above, the Hybrid Scenario mitigates winter peak demand impacts and reduces winter peaks by 2.7 GW, shifting the energy supplied during peak hours in the winter to the natural gas system already in place. In the Hybrid Scenario, the PGE peak remains in the summer, at close to 7 GW.

Washington Peak Demand Results

End-use electrification load growth in Washington contributes to rising peak demand. Annual peak increases by 17 - 18 GW, depending on the scenario, between 2025 and 2050. Compared to the Reference, the Moderate case peak does not change. 2050 peak demand in the Hybrid and All Electric cases increases by 487 MW and 749 MW respectively relative to the Reference Case. While increases on the state level are moderate given the small share of NW Natural customers of all Washington customers, individual utilities with larger shares of NW Natural customers see a larger peak demand increase. The All-Electric Scenario winter peak demand for Clark PUD increases to 1,801 MW in 2050 – an increase of 442 MW compared to the Reference

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Case. In the Hybrid scenario, the 2050 winter peak increases more modestly to 1,553 MW, representing a 194 MW increase compared to the Reference Case.

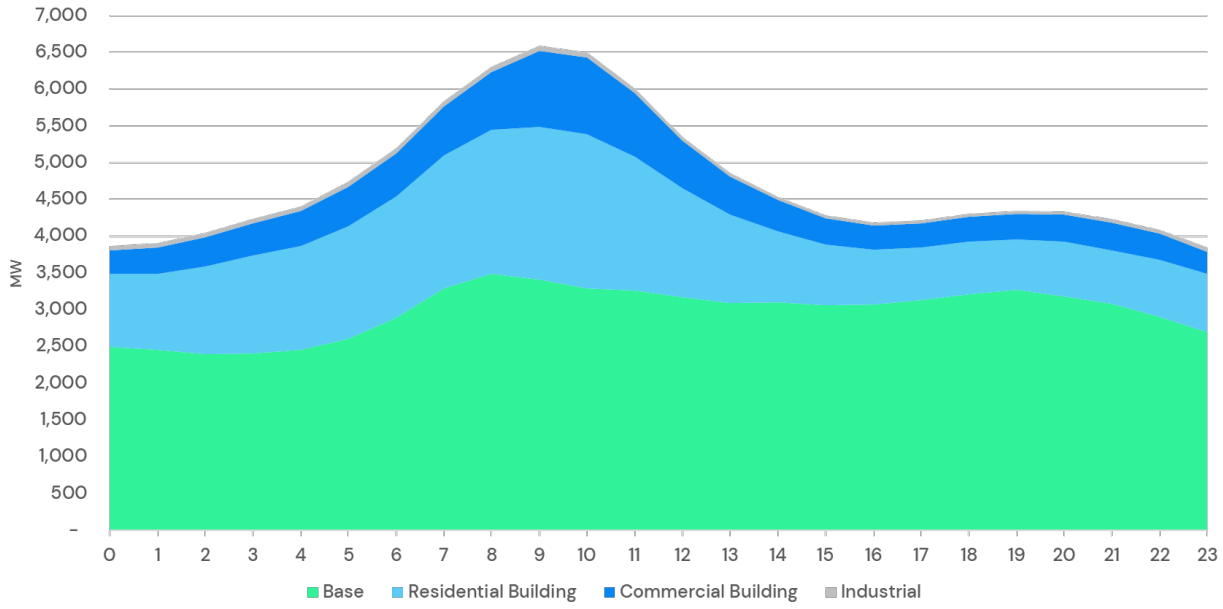
Given that Clark PUD is already winter peaking, any increase in loads due to electrification, such as hot water heating, directly increase peak demand for the scenario, whereas peak demand impacts in the summer peaking utilities in Oregon first caught the summer peak up with winter peak before impacting resulting in annual peak impacts.

While increases on the state level are moderate given the small share of NW Natural customers of all Washington customers, individual utilities with larger shares of NW Natural customers see a larger peak demand increase.

Peak Day Results

All Electric building electrification through deployment of air source heat pumps shifts the annual peak to the winter, specifically the morning hours during the coldest days, when low temperatures reduce heat pump performance, driving electric demand. Figure 10.17 shows that in PGE's service territory, the All-Electric building electrification loads add 3,200 MW to a base of 3,500 MW in 2050, absent EV and data center loads.

Figure 10.17: PGE 2050 Winter Peak (MW) - All Electric Base + Building Electrification



EVs and data centers are drivers of additional load growth in PGE's service territory. EV charging behavior—particularly when vehicles are plugged in during evening hours after commuters return home—creates a secondary peak in electricity demand between 6pm and 9pm. In

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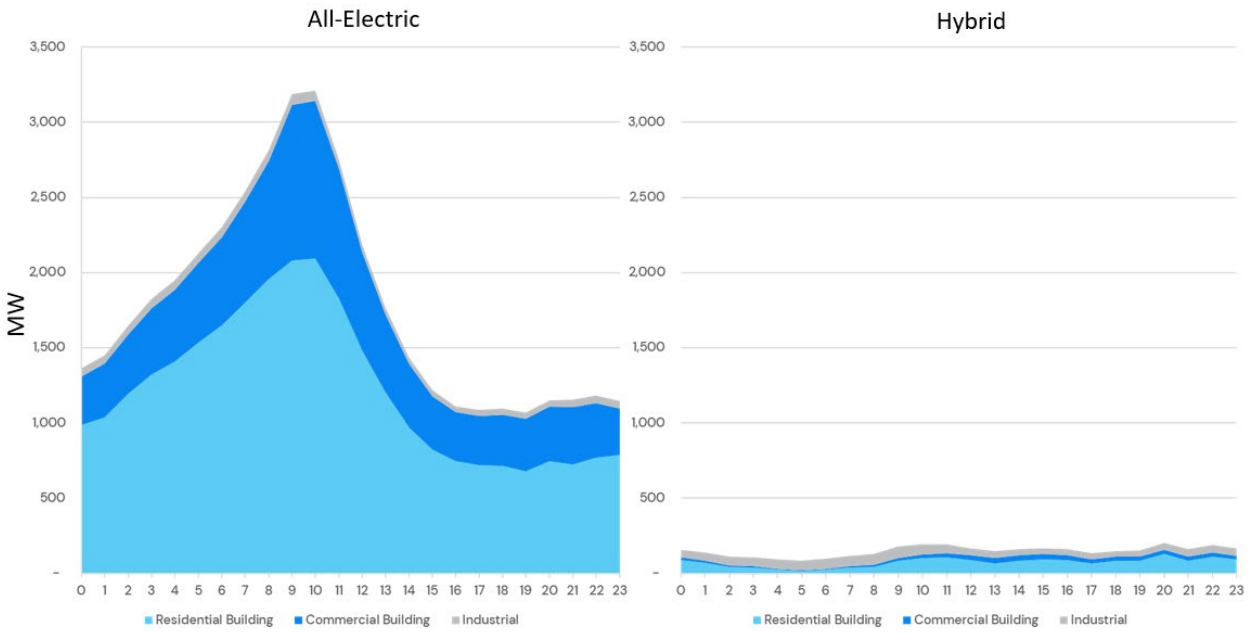
contrast, data center loads are assumed to be flat throughout the day, contributing to a steady baseline demand. As a result, the primary daily peak remains in the morning hours, while the evening peak becomes more pronounced due to transportation electrification.

The impact of building electrification is further shown in Figure 10.18 below. For the same day in Winter in 2050 during which the electric peak occurs in the All-Electric Scenario, the Hybrid Scenario mitigates peak loads by over 3,000 MW.

Figure 10.18: PGE Building Electrification Peak Day Impact – All-Electric and Hybrid Scenario (MW)



The Hybrid Scenario mitigates the winter peak impacts by leveraging gas heating in place of electric heating during the winter peak day. As shown in Figure 10.17 the winter peak in the Hybrid Scenario shifts back to the evening, as EV loads drive the peak hour in absence of significant heating load requirements. In addition to a significantly lower overall winter peak at 6,100 MW relative to 8,800 MW, the winter peak day exhibits a much flatter, consistent load shapes, and avoids large temperature-driven spikes in electric loads. In the All-Electric Scenario, peak demand ramps up by close to 1,500 MW in a matter of 3 hours in just PGE's system alone, a pattern observed in the rest of the system as well, given that most of the heating energy is delivered through the electric grid and as external factors like temperature driven demand growth. Load remains above 8,000 MW for at least 5 hours during the morning.

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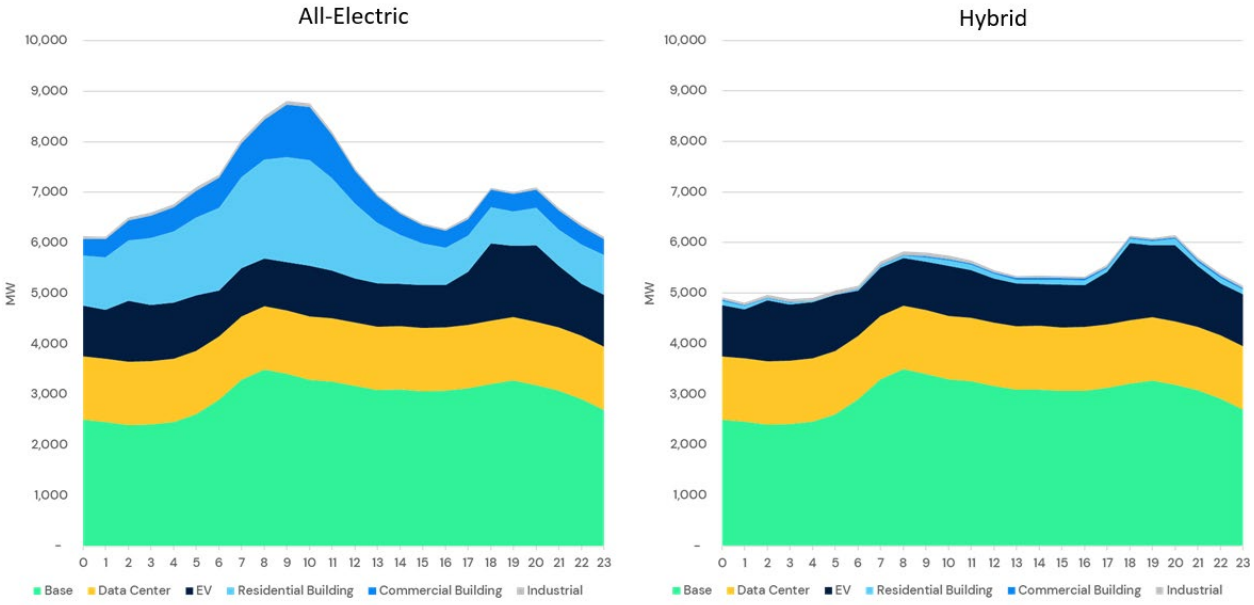
Figure 10.19: PGE All-Electric Winter Peak Demand (MW) vs. PGE Hybrid Winter Peak Demand (MW) in 2050



10.8 Power Sector Modeling

The electrification analysis presented in this IRP quantifies the impacts of building electrification on both the demand side of the natural gas sector, as well as the electric sector in Oregon and Washington.[246] As the building sector electrifies and load shifts from natural gas to electricity, annual load requirements will need to be met from an increasingly non-emitting resource base, while peak demand increases will require firm dispatchable resources to ensure grid reliability during cold winter days as heating loads electrify. Resource plans from electric utilities focus in detail on the potential future resource mix under a range of scenarios, assessing changes to electric demand and supply changes, availability of supply resources and the ability to connect resources in their service territories through transmission investments, but have yet to specifically analyze the potential impact of a range of building electrification scenarios. This is in part driven by the requirements for electric planning, the timeframe for planning, and the range of uncertainty across all of the assumptions incorporated into electric IRP proceedings.

[246] Modeling of electrification impacts on the load and supply side included modeling of Washington as well as Oregon. Load impacts of building electrification and associated supply-side changes in Washington are not included in this Draft IRP and will be discussed in a separate portion within the Final IRP.

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Including building electrification into electric planning proceedings would add additional complexity and uncertainty. To understand the full implications of building electrification on Oregon's energy system, the impacts on electric demand for both annual load and seasonal peak demands, and associated requirements to expand the electric systems beyond scenarios without electrification need to be assessed. This is especially important considering Oregon's climate policy objectives that aim to decarbonize a large share of electric supply, limited ability to interconnect new resources in the short and medium term and consistently increasing load growth projections of other sectors of demand, such as data centers and electric vehicles.

With Oregon's disaggregated electric and natural gas industry and absent joint electric and gas planning approaches, this analysis intends to capture the impact of building electrification on both the natural gas and electric sectors.

10.8.1 Overview of Power Sector Modeling Approach

This section outlines at a high level the current state of the electric sector in Oregon today, the policy changes that will re-shape the current mix of resources potentially supplying electricity to Northwest Natural customers in the state, and the potential changes and associated challenges with shifting natural gas loads onto the electric sector. The following section outlines in more detail the modeling approach to quantify these impacts.

Policy Compliance

Climate policy requires Oregon's electricity sector to shift towards a predominantly non-emitting resource base. House Bill 2021 (HB 2021) directs the Investor-Owned Utilities in the state and electricity service suppliers to decarbonize their retail sales by 2040, with 80% emission reductions by 2030 and 90% reductions by 2035, while also requiring compliance with Renewable Portfolio Standards across IOUs and consumer-owned utilities. In 2023, close to 50% of Oregon's retail supply was associated with emissions[247], including natural gas, coal, and unspecified market purchases that are assessed an emission factor specified by the ODEQ.[248]

HB 2021 emission requirements are enforced on PGE's and PacifiCorp's supply in 2030, 2035, and 2040 in the form of limits on total emissions to serve load, with the 2040 emission limit dropping to 0 and therefore requiring non-emitting generation to serve load in 2040 onwards. Market purchases from non-utility service territories are covered under the emission limits. While this modeling approximation captures the emission reduction targets and ensures

[247] Oregon Department of Environmental Quality. "Greenhouse Gas Emissions from Electricity Use 2010-2023," December 10, 2024. https://www.oregon.gov/deq/ghgp/Documents/ghgElectricityEms.xlsx
[248] Oregon Department of Environmental Quality. "Non-Multijurisdictional Investor-Owned Utilities and Electricity Service Suppliers: Instructions for Reporting Greenhouse Gas Emissions," December 4, 2023. https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocolN.pdf.

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sufficient non-emitting generation is procured within the respective utility territories, detailed compliance accounting mechanisms and modeling approaches are evolving as utilities refine compliance modeling in their respective Clean Energy Plans.

Alignment with Available Utility Information

This electrification analysis incorporates, to the extent possible and feasible, data from utility planning proceedings, such as Clean Energy Plans, Integrated Resource Plans and materials presented in associated stakeholder engagement proceedings. While electric utility IRP and utility data are incorporated, the electrification analysis and methods deployed for it are not intended to fully replicate the approaches deployed by utilities. Instead, the focus of the analysis is the quantification of electrifying natural gas end-use loads on the electric sector, associated costs and resource requirements, while adhering to general utility resource planning concepts, complying with Oregon state policy and incorporating the impacts of alternative fuels.

State and Utility Focus

Oregon's electricity sector is disaggregated into Consumer-Owned utilities, Electric Service Suppliers and Investor-Owned Utilities, some of which supply Oregon as part of a multi-state service territory, including PacifiCorp and Idaho Power Company. Not only are policy requirements for RPS and HB 2021 different between IOUs, Electricity Service Suppliers and Consumer-Owned Utilities, but so are methods of procuring electricity supply. In addition to market purchases on the wholesale electricity market, Consumer-Owned Utilities receive their power primarily through the Bonneville Power Administration supply, whereas IOUs either directly own their supply or contract for resources outside their service territory for delivery of energy and/or capacity into their service territory. NW Natural customers are spread across IOUs (approximately 88% of NW Natural Oregon customers overlap with PGE, PacifiCorp) as well as numerous Consumer-Owned Utilities such as the Eugene Water and Electric Board (EWEB) and Clark Public Utilities.

With a diverse set of policies and requirements, customers across IOU's and Consumer-Owned Utilities and various procurement mechanisms, the analysis of NW Natural gas customers distinguishes between the main utilities in Oregon, in addition to showcasing state-level results.

Transmission & Distribution

Transmission and distribution investments required to meet growing loads are captured through distinct assessments of the required costs to expand the transmission system to connect resources for supply, as well as distribution system investments required to meet growing peak demand requirements. Transmission costs are incorporated into capital cost

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assumptions for resources that are available to Oregon utilities for expanded supply and distribution costs are peak demand driven based on assumed $/MW distribution costs, developed from utility filings.

10.8.2 Power Supply-Side Assumptions

Assumptions that characterize the policy environment in the Pacific Northwest, the cost and performance of resources and the availability and costs of alternative fuels and transmission shape how the electric sector responds to demand increases from electrified building and industrial end uses. This section summarizes the key assumptions that characterize the cost and performance of resources, cost and availability of transmission and alternative fuels. This analysis focused on the electric supply scenario previously described as the "Current Trends" Scenario.

Resource Adequacy

Reserve Margin

This analysis incorporates a planning reserve margin aligned with utility assumptions. For PacifiCorp's West territory, seasonal reserve margins of 14.4% in the summer and 16.8% in the winter are assumed.[249] PGE does not specify an assumed reserve margin and instead carries out a reliability analysis to meet defined reliability criteria, and therefore PNUCC's planning reserve margin assumed in the 2025 Northwest Regional Forecast[250] was used. The same PNUCC assumption is implemented for the remainder of the regions in Oregon and Washington.

Resource Contributions

Resource contributions to peak demand requirement can vary regionally, seasonally, based on installed capacity and by technology type. In this analysis, reserve contributions for solar, wind, battery storage, hydro, and thermal resources are informed by the Western Resource Adequacy Program (WRAP) data provided for upcoming summer and winter seasons. WRAP data distinguishes by resource zone, season, and the penetration of resources in those regions.[251] Figure 10.20 below summarizes the seasonal Effective Load Carrying Capabilities (ELCCs) by

[249] PacifiCorp. "2025 Integrated Resource Plan: Volume 1," March 31, 2025. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_IRP_Vol_1.pdf.
[250] Pacific Northwest Utilities Conference Committee. "Northwest Regional Forecast of Power Loads and Resources: August 2025 through July 2035," April 2025. https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf.
[251] Western Power Pool. "Western Resource Adequacy Program: Review of Preliminary, Non-Binding WRAP Regional Data for the Current Participating Footprint for the Winter 2025-2026 Season." June 13, 2024. https://www.westernpowerpool.org/private-media/documents/2024-06-13_Webinar_Winter_2025-2026_and_2028-2029_Data.pdf.

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region and capacity type. Regional descriptions of the VER zones are available in the WRAP studies cited above.

Figure 10.20: ELCC By Seasons and Region Group

ELCC Assumptions		Summer ELCC				Winter ELCC			
Resource	**Zone**	**0-3 GW**	**3-6 GW**	**6-9 GW**	**9+ GW**	**0-3 GW**	**3-6 GW**	**6-9 GW**	**9+ GW**
Wind	VER1	11%	11%	11%	11%	11%	11%	11%	11%
	VER2	26%	24%	22%	22%	34%	28%	24%	24%
	VER3	19%	19%	19%	19%	18%	18%	18%	18%
	VER4	19%	18%	16%	16%	49%	40%	34%	34%
	VER5	17%	17%	17%	17%	17%	17%	17%	17%
Solar	VER1	57%	46%	34%	27%	15%	10%	7%	6%
	VER2	18%	18%	14%	14%	9%	9%	6%	6%
	VER3	25%	25%	19%	19%	5%	5%	3%	3%
Storage	MidC	99%	99%	80%	67%	98%	98%	80%	65%
	SWEDE	100%	89%	76%	65%	67%	67%	40%	33%

Reserve contributions of resources, especially battery storage, are evolving as more empirical data becomes available and as resource portfolios are evaluated against a range of load and weather conditions. While this analysis relies on available data from WRAP, resource contributions of battery storage may be significantly below the values assumed in this analysis. Recent assessments by PGE indicate that contribution of battery storage to winter peak demand could drop below 10% in the analyzed portfolio as early as 2030, and that other emerging and more expensive technologies such as long-duration storage resources may prove to be more cost-effective as marginal capacity resources.

Detailed reliability modeling to determine portfolio compliance with reliability metrics such as loss of load hours (LOLH) with was not conducted on the portfolios shown in this study.

Alternative Fuels

Alternative Fuel assumptions in the Electrification Analysis are aligned with the Alternative Fuels analysis conducted by ICF on behalf of Avista, Cascade Natural Gas and NW Natural. Hydrogen cost assumptions assumed green hydrogen production from solar electricity in the Northwest region, the most cost-effective green hydrogen fuel source from the Northwest.

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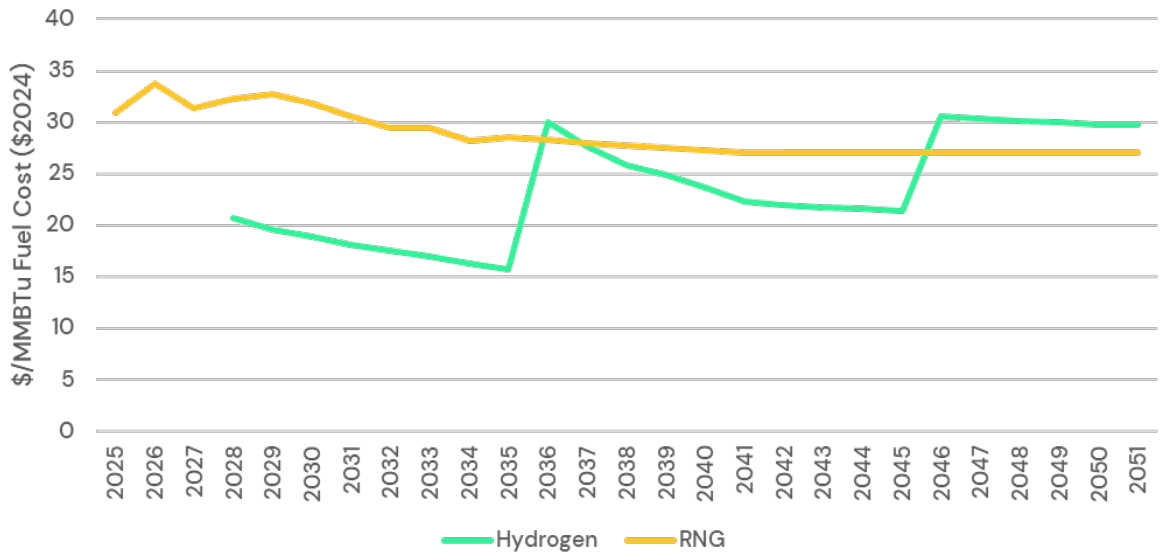
Hydrogen costs shown in Figure 10.21 below account only for the production cost of hydrogen, and do not incorporate other costs that may be associated with combustion of hydrogen in power plants, such as upgrades to pipeline infrastructure, hydrogen storage and other hydrogen transportation costs.

RNG costs are consistent with the potential cost of RNG procurement for NW Natural, reflected through the RIN credit cost. Opportunities for RNG procurement at lower costs may exist for NW Natural, RNG costs for consumption at power plants may not be within NW Natural's control. Therefore, RNG costs assumed are reflective of RNG market prices as reflected by the RIN credit price.

Figure 10.21: Non-Emitting Fuel Prices ($/MMBtu)



Renewable Cost and Performance

Renewable Cost and Performance assumptions for the supply-side analysis are informed by the latest Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL), as well as historical cost information presented in previous versions of the ATB (such as the 2021 costs presented in the 2022 ATB). The projected cost trends for wind, solar, and 4h battery storage apply the historical cost trajectory of renewable cost development between 2020 and 2023 to extrapolate the first year of reported costs in 2024 through to 2030. From 2036 to 2050, the capital costs feature the decline trajectory from NREL's assumed technology cost improvements.

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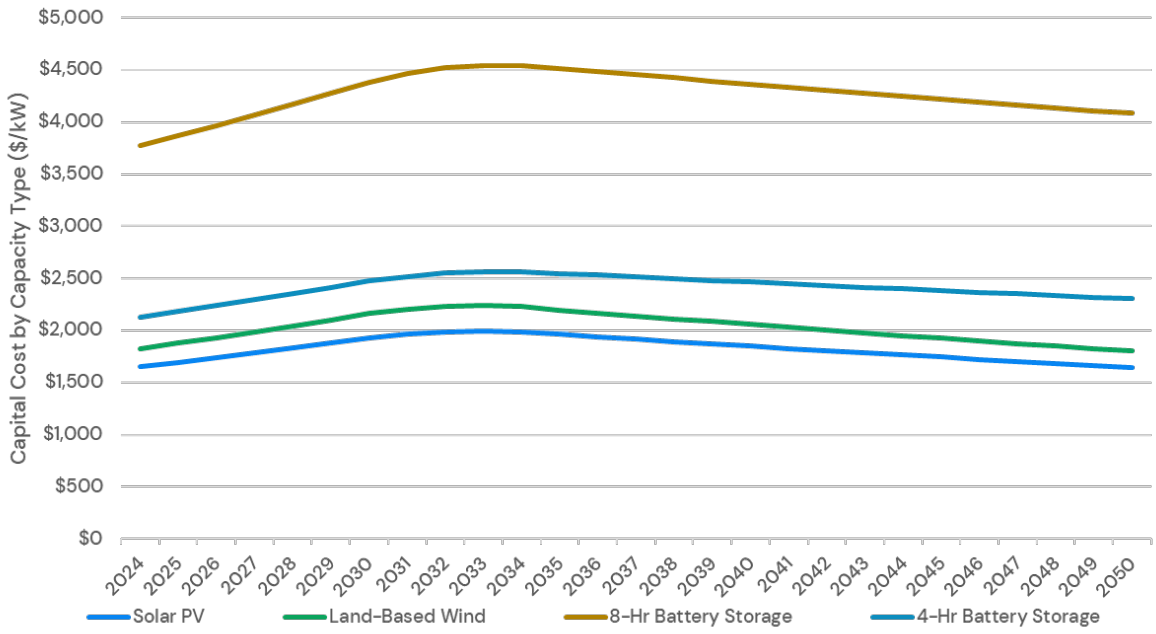
Since floating offshore wind and 8h battery storage costs lack cost data, capital cost trends are applied directly from NREL's Conservative Scenario.

In addition to national level capital costs, the analysis incorporates regionalization of capital costs and renewable supply curves consistent with EPA's most recent Reference Case relying on IPM[252]. In addition to capital costs, tax credits are applied to non-emitting technologies in the form of the production tax credit (PTC) for wind and solar facilities, and the investment tax credit (ITC) for offshore wind and battery storage resources. Potential impacts of tariff-related technology cost increases or the repeal of tax credits have not been incorporated for this analysis. Higher tariffs on imported materials and products and potential tax credit repeal would increase the cost of capacity additions, in particular renewable additions. As PGE determined in its recent CEP IRP roundtable, the repeal of the IRA could have a significant impact on the cost to serve load, as the mix of resources would not change the resource buildout but increase its costs.[253]

Figure 10.22: Renewable Capital Cost by Capacity Type ($/kW)



[252] U.S. Environmental Protection Agency. "Documentation for 2023 Reference Case." Power Sector Modeling, March 3, 2025. https://www.epa.gov/power-sector-modeling/documentation-2023-reference-case.
[253] Portland General Electric. "PGE CEP & IRP Roundtable 25-4." June 4, 2025. https://assets.ctfassets.net/416ywc1laqmd/2R28hOAx44R4HJJQbtdlVi/e645439527a2ba02d1743716ab21a502/CEP_IRP_Roundtable_June_25-4.pdf
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Transmission Interconnection

Background on Transmission Interconnection Relevance and Role in Electric Planning

The ability to expand the resource base in Oregon or Washington to meet growing load needs, maintain system reliability and achieve HB 2021 or CETA compliance requires interconnection of resources. In addition to utility-owned transmission resources, the Bonneville Power Administration (BPA) owns and operates the majority of the high voltage transmission network in Oregon and the PNW. BPA directly supplies long-term firm power through its transmission network to Consumer Owned Utilities through its primarily hydroelectric power plants and its marketing of the power from the PNW's only nuclear plant. BPA also provides access to its transmission network to utilities across the region to connect resources from outside the utilities' own service territory and transmission network footprint. Considering demand growth to accommodate data center, semiconductor industry and electric vehicle growth, emission reductions requirements for IOUs and Electricity Service Suppliers, and renewable resources located outside of the service territory of electric utilities, the ability to interconnect resources and deliver their electricity production to load centers is an important consideration for planning Oregon and Washington's electric grid. Utilities rely on their own transmission systems and hold transmission service rights on the BPA system to ensure delivery of power across the BPA system and additionally transact for power in the short term to balance their systems. To deliver power from additional generators, transmission service requests are submitted to BPA, which then conducts analysis to study the required system upgrades to interconnect these resources through its Transmission Service Request (TSR) Study & Expansion Process (TSEP). Identified projects are then proposed for development and further scoping. In recent years, BPA's available transmission capacity has decreased with the development of new resources. In its latest 2023 TSEP Study of projects, BPA assessed over 200 service requests totaling 16,000 MW of capacity, and awarded 88 MW of TSRs without required upgrades, identifying 14 transmission projects at an estimated cost of over $3.9 billion to connect additional resources. Interconnection requests considered in the 2023 study close to tripled in capacity compared to the previous 2021 study, where only ~6,000 MW of transmission demand was identified, and 305 MW of TSR were awarded without upgrade.

Figure 10.23: TSRs and Awarded Capacity in Recent BPA TSEP Studies

BPA TSEP Study Results	TSR Requests (MW)	Awarded without Upgrades (MW)
2021 TSEP Cluster Study	6,000	305
2023 TSEP Cluster Study	16,000	88

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Driven by these customer-needed projects identified through the TSEP process and regionally needed projects to reinforce the grid, maintain load service and support regional planning independent of specific generator requests, BPA has identified 23 priority transmission projects through its Evolving Grid Initiative, grouped into two stages of development and totaling over $5 billion in estimated costs.

The assumptions around available transmission capacity and future transmission development are of critical importance to the assessment of the projected resource mix in Oregon, given long lead times for transmission development, uncertainty around costs and feasibility of transmission projects and the role of transmission in connecting required resources with load centers. In its 2023 Clean Energy Plan and Integrated Resource Plan 2023 Preferred Portfolio analysis PGE concluded that, "*It is infeasible for PGE to meet the 2030 HB 2021 targets without any transmission upgrades and the magnitude of transmission needed increases throughout the planning horizon*"[254]

Transmission Assumptions

The modeling framework in this analysis does not carry out transmission assessments at the level of utility IRP planning, relying on zonal modeling approach without detailed power flow assessments or nodal transmission modeling. Transmission assumptions are informed by public documentation from IRP proceedings, as well as project information from BPA and other regional entities and transmission project developers. Three tiers of transmission assumptions inform the characterization of transmission in the electrification analysis:

1. Existing Transmission Interconnection Capacity
2. Planned Transmission Interconnection Capacity
3. Unplanned/Economic Transmission Capacity Expansion

Existing transmission interconnection capacity is limited, as indicated by BPA's limited award of TSRs without required transmission upgrades in its latest TSEP Study. PGE's discussions as part of its 2025 IRP estimate the available long-term firm transmission capacity for PGE's system at 753 MW, which includes resources in Montana and Washington as well as Oregon solar, wind, and offshore wind resources. An additional 1,753 MW of interconnection capacity

[254] Portland General Electric. "Clean Energy Plan and Integrated Resource Plan 2023," June 30, 2023. https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf

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is assumed available through conditional firm capacity, for a total available interconnection capacity of 2,506 MW.

Planned transmission interconnection capacity accounts for a range of projects that are assumed to reach commercial operation over the next decade. This includes the following projects and associated increases in transmission capacity:

1. **BPA Evolving Grid 1.0 Projects** – BPA currently estimates completion of the Evolving Grid 1.0 projects by 2032, including the Big Eddy to Chemawa upgrades, the last of the Evolving Grid 1.0 projects to be completed in 2032. BPA estimates that this portfolio of projects will make available an incremental 4,260 MW of interconnection capacity, of which 42% or 1,779 MW would support PGE's service territory, primarily through the conversion of conditional firm to long-term firm service. It is assumed that the remaining 58% or 2,481 MW increase transmission interconnection capacity throughout the rest of the Pacific Northwest
2. **Round Butte to Bethel Project –** The Round Butte to Bethel project is assumed to increase available transmission capacity between 2,385 MW and 4,770 MW, depending on the routing other project details to be finalized. Given the project's early-stage development process, the Current Trends Scenario assumes that the upgrade would not be in service until after the Zero emission targets for Oregon's IOU have gone into effect – after 2040. The assumed available transmission expansion through the project is assumed to be the lower end of the development range at 2,385 MW. This upgrade has been identified as a no-regrets upgrade in several of PGE's planning proceedings.
3. **Trojan to Harborton –** The Trojan to Harborton upgrade is anticipated to expand the capacity of the South of Allston constraint, which has been identified as one of the key constraints for delivery of additional resources into the PGE system. The incremental 800 MWs are assumed to be added as transmission capacity after the net zero emission requirements in 2040 take effect. This would realize improvements previously targeted by PGE at the South of Allston constraint.
4. **Boardman to Hemingway –** The B2H project – Segment H of PacifiCorp's Gateway Transmission Expansion Plan, is a 290-mile 500 kV high voltage transmission line capable of coming online as soon as 2027, with an anticipated incremental renewable interconnection capacity of 1,000 MW. While PacifiCorp's latest IRP is indicating that the project is still under evaluation, it is assumed to come online by 2030.

Economic/Unplanned transmission interconnection capacity enables incremental renewable capacity to interconnect beyond the assumed additional capacity facilitated by the planned transmission projects. The available resources to supply Oregon load are distinguished into capacity additions within Oregon – facilitated through further expansion of BPA's transmission system – as well as interconnection of resources beyond Oregon. Resources considered from out-of-state are aligned with resource options modeled in utility IRPs for PGE and PacifiCorp.

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PGE resources include solar resources in Arizona, Nevada and Idaho as well as wind resources in Montana, North Dakota, Wyoming and Idaho. Interconnection of these resources is assumed in 2050, except for the interconnection of Montana wind resources after the exit of PGE from the Colstrip coal facility, relying on its existing transmission rights to bring in incremental resources. Developing additional resources through local (BPA) or inter-state transmission resources is assumed to carry incremental capital costs aligned with assumed project costs. For BPA expansion, estimated project expenditure of Evolving Grid 1.0 projects and assumed increased renewable capacity enabled by said projects. For projects connecting resources beyond Oregon, estimated project costs increased based on the facilitated renewable expansion and project cost, ranging from $700 - $1,000/kW depending on the location of the project and the estimated costs of the transmission projects.

Required Transmission to Achieve HB 2021 Compliance

The assumptions outlined above specify the modeling approach for renewable interconnection and transmission development, based on review of existing IRP documentation, transmission planning processes and planning timelines, and feedback from utility planning experts in the Pacific Northwest. However, considering the emission reduction requirements in 2030, the assumptions laid out above were found to be insufficient to facilitate the achievement of these targets. By 2030, the reductions in natural gas generation and unspecified imports required to meet IOU emission targets will need to be replaced with more non-emitting capacity than is assumed is available. Thus, the assumptions outlined above had to be modified and relaxed to allow for interconnection of resources sooner than originally anticipated. This includes the Trojan to Harborton project and interconnection of Nevada solar resources and Wyoming or Idaho wind resources. Over 4 GW of capacity additions are anticipated to be required between 2025 and 2030 for PGE alone, outpacing the assumed available transmission availability by 2030. Transmission constraints were relaxed in this analysis to ensure that HB 2021 compliance is achieved.

Offshore Wind

Offshore Wind resources off Oregon's coast are a potential resource to supply non-emitting electricity to Oregon customers. Oregon's coastal characteristics restrict offshore wind potential to floating offshore wind facilities, which have not been commercially deployed in the US at scale and feature higher costs compared to fixed-bottom technology more commonly deployed in the industry currently. Cost and performance assumptions for floating offshore wind are based on NREL's Conservative cost scenario. Offshore wind availability is assumed to start in 2035, based on current estimates for commercial technology readiness, project lead-times and recent postponement of lease auctions due to a lack of developer interest.

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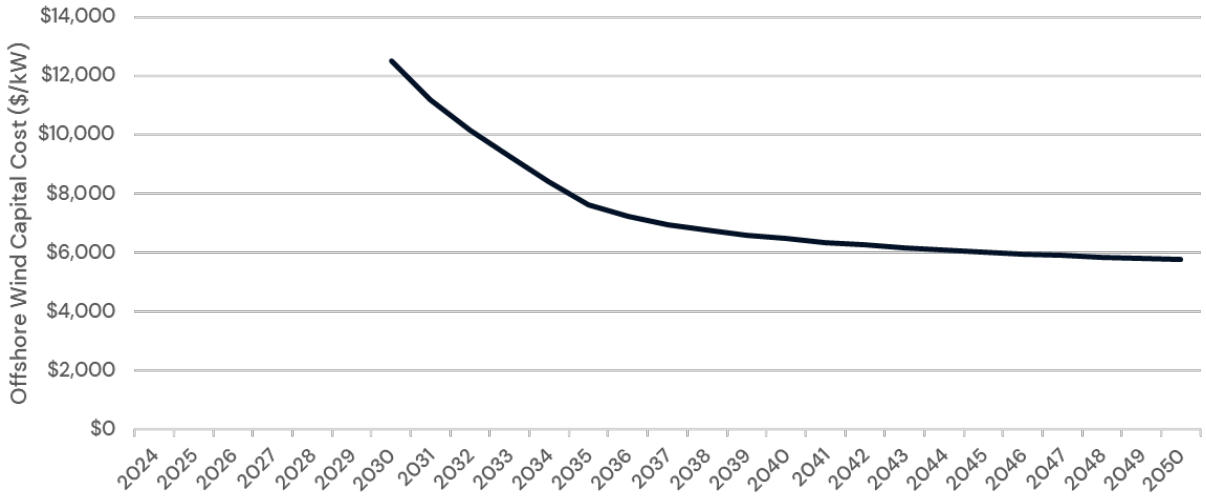
Figure 10.24: Offshore Wind Capital Costs ($/kW)



Distribution Cost

The assessment of system costs in the electric sector includes a quantification of estimated distribution cost for PGE, PacifiCorp, as well as EWEB. Distribution cost estimates are based on a review of up to 30 comparative utilities, focusing on the relationship between net distribution plant values and peak demand growth projections, including Oregon's utilities.[255] Trends between distribution net plant expenditure and historical peak demand growth over the same period were used to estimate $/MW distribution cost values. Utility-specific assumptions on discount rate translate the $/MW assumptions into $/kW-yr distribution cost estimates. While the $/kW-yr distribution cost estimates are kept constant over the course of the study, the significant levels of load growth projected in this analysis, the potential shift of peak demand to the winter in the All-Electric Scenario and the shifting demand patterns towards temperature-driven space heating loads may require distribution system changes that put further cost strain onto the system not quantified in this analysis.

10.8.3 Power Supply-Side Results

Capacity expansion rapidly accelerates to meet HB 2021 compliance requirements and reliability needs.

Incremental capacity needs emerge rapidly to facilitate HB 2021 compliance and meeting load growth. Emission limits for PGE and PacifiCorp limit the ability of the utilities to dispatch a large

[255] Given limited data availability for Clark PUD in Washington, distribution cost increases for Washington were estimated based on the peak demand increase in Washington and the average of utility distribution cost assumptions ($/kW-yr) for Oregon utilities examined for this study.

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part of the resources they currently rely on for dispatch. In 2023, PGE reported emissions of 5 MMT $CO2_e$ from specified coal and natural gas resources, associated with over 8,000 GWh of generation, enough to meet close to 50% of its load. 1.4 MMT $CO2_e$ of emissions are associated with an addition 4,000 GWh of unspecified generation. [256] Between 2023 and 2030, emissions are required to drop by over 5 MMT $CO2_e$ to 1.6 MMT $CO2_e$, and to 0.8 MMT $CO2_e$ in 2035. With the required coal phase-out and planned exit from Colstrip, this will require over 11,000 GWh of generation from natural gas and unspecified sources to drop to just over 4,000 GWh in 2030, while load is anticipated to grow by ~4,000 GWh.

In the 5 years between 2025 and 2030, the requirement to offset emitting generation in the face of load growth drives close to 3,500 MW of primarily onshore wind additions, as well as 1,000 MW of resources delivering energy to PGE from outside of the state, split between solar and wind power. About 4,500 MW of interconnection in the space of 5 years would require tripling the rate of renewable installations over the past 5 years. By 2030, PGE's capacity would need to almost double. These findings are consistent with PGE's latest assessments that have also identified a need for over 4,500 MW of resource additions by 2030 in its latest CEP/IRP modeling updates.[257]

[256] Oregon Department of Environmental Quality. "Greenhouse Gas Emissions from Electricity Use 2010-2023," December 10, 2024. https://www.oregon.gov/deq/ghgp/Documents/ghgElectricityEms.xlsx.
[257] Portland General Electric. "PGE CEP & IRP Roundtable 25-4." June 4, 2025. https://assets.ctfassets.net/416ywc1laqmd/2R28hOAx44R4HJJQbtdlVi/e645439527a2ba02d1743716ab21a502/CEP_IRP_Roundtable_June_25-4.pdf.

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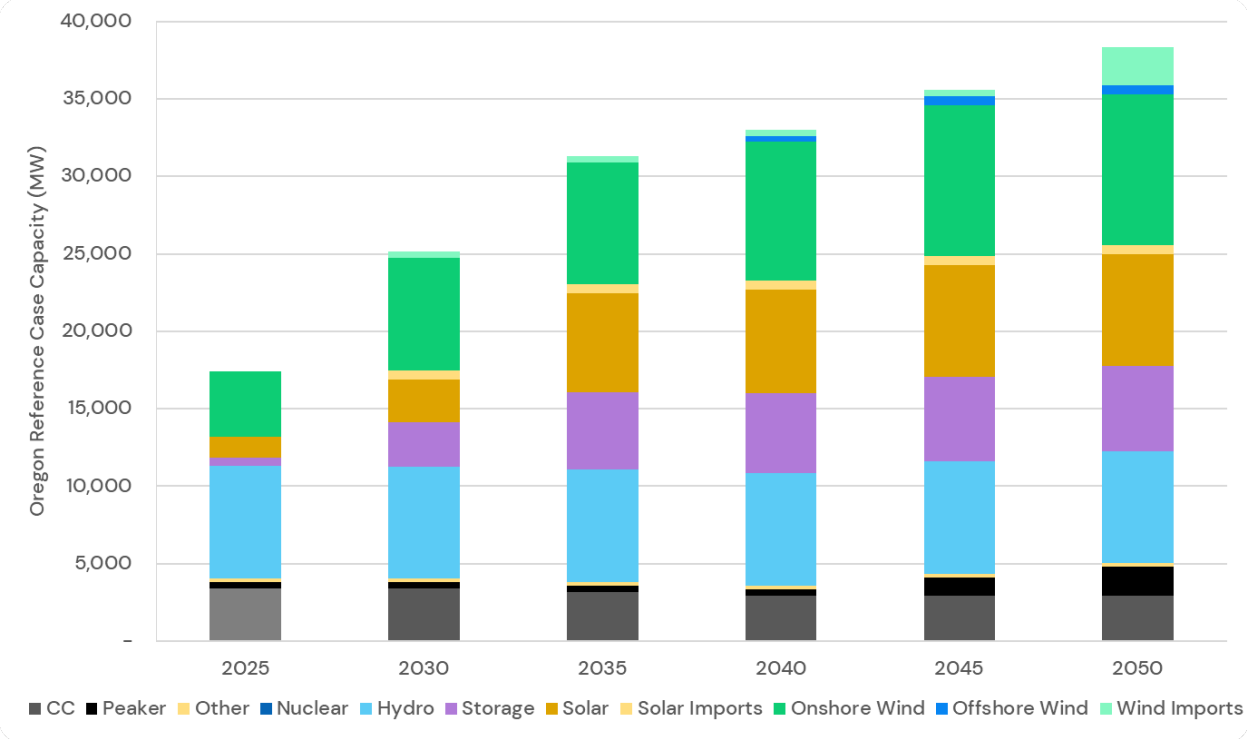
Figure 10.25: Oregon Reference Case Capacity (MW) from 2025 to 2050



Absent building electrification, renewable additions dominate in the Reference Case, with wind additions of 5,500 MW, solar additions of 5,800 MW, and additional storage capacity of over 5,000 MW. In addition to 600 MW offshore wind in 2040, additional renewable capacity of over 3,000 MW from out of state supplies utilities in Oregon to ensure compliance with clean energy mandates. In the winter periods with limited peak contributions from solar, onshore wind and battery storage, peaking capacity also increases by 1.5 GW.

Figure 10.25 highlights that while the Modest and Hybrid Scenario result in 1,200 MW of incremental capacity, the All-Electric Scenario features an additional 5,700 MW of capacity to meet increased electric peaks across Oregon, with capacity totals exceeding 44,000 MW. The shift to the winter peak in the All-Electric Scenario increases builds across all capacity types except solar, which contributes little to no reliable capacity to meet winter peak loads. As additional wind capacity is also de-rated in terms of its peak contribution, combustion capacity capable of consuming non-emitting clean fuel backs up renewables in combination with battery storage. Thermal peaking capacity and battery storage capacity increase by close to 5,000 MW. Recent analysis by PGE indicates that winter contribution from battery storage may be even lower than assumed in the WRAP data relied upon for this analysis, which could further increase the amount of firm and dispatchable capacity required to meet winter peak demand

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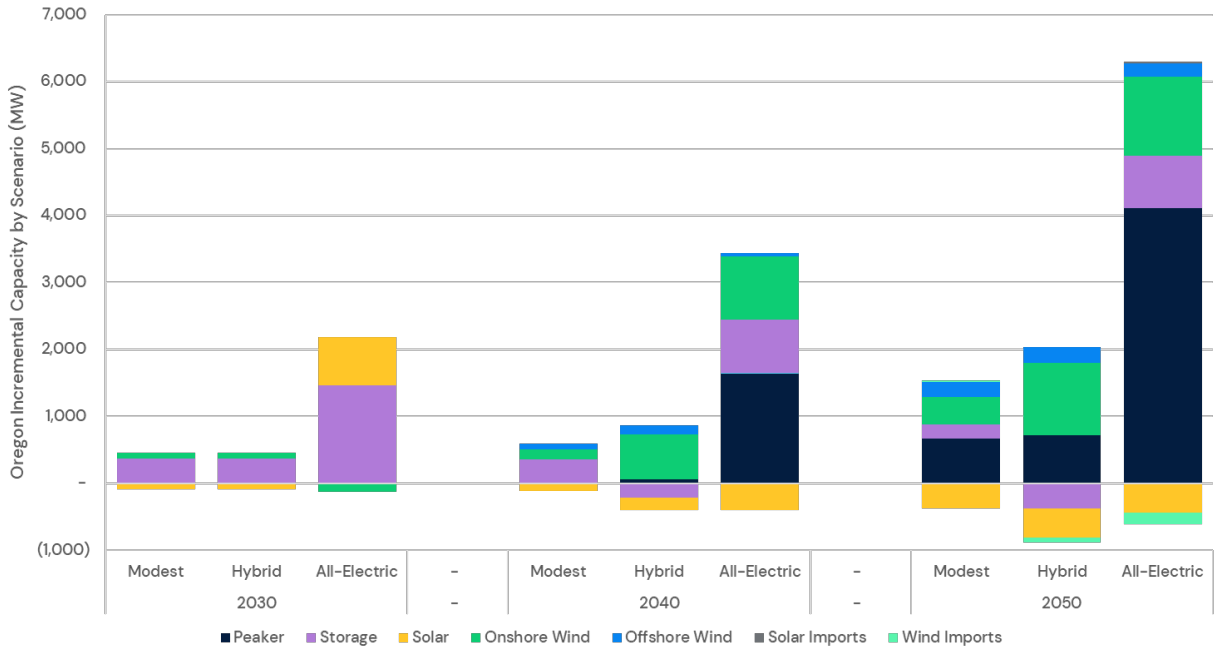
requirements.[258] Wind capacity increases to provide sufficient generation for HB 2021 compliance, as neither battery storage nor non-emitting peaking generation are capable or cost-effective to provide generation at scale.

Figure 10.26: Electrification Scenario Oregon Incremental Installed Capacity relative to Reference Case (MW)



To meet energy and peak demand requirements in 2050, PGE's capacity would need to grow to more than 4x the currently installed capacity in 2025, and more than 5x in the All-Electric Scenario, highlighting the growth in capacity needed when combining load growth from electric vehicles, industrial and data center loads and building electrification paired with compliance requirements under HB 2021.

Figures 10.26 and 10.27 show the expansion of the capacity mix in PGE's territory for the Reference Case (Figure 10.26) as well as the incremental capacity by scenario (Figure 10.27). State-wide trends are driven in many categories by PGE trends, with wind, solar, storage and non-emitting clean fuel peaking capacity additions in the Reference Case, and a shift towards more non-emitting clean fuel peaking capacity and wind capacity and less storage and solar capacity in the scenarios with higher peak demands in the winter in the All-Electric Scenario.

[258] Portland General Electric. "PGE CEP & IRP Roundtable 25-4." June 4, 2025. https://assets.ctfassets.net/416ywc1laqmd/2R28hOAx44R4HJJQbtdlVi/e645439527a2ba02d1743716ab21a502/CEP_IRP_Roundtable_June_25-4.pdf.

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While additions by capacity type vary to an extent due to modeling approaches and assumptions, PGE is currently projecting that their total capacity needs to expand to approximately 13,000 MW, consistent with the 13,000 MW Reference Case capacity projected in this analysis.[259]

Figure 10.27: PGE Reference Capacity (MW) from 2025 to 2050

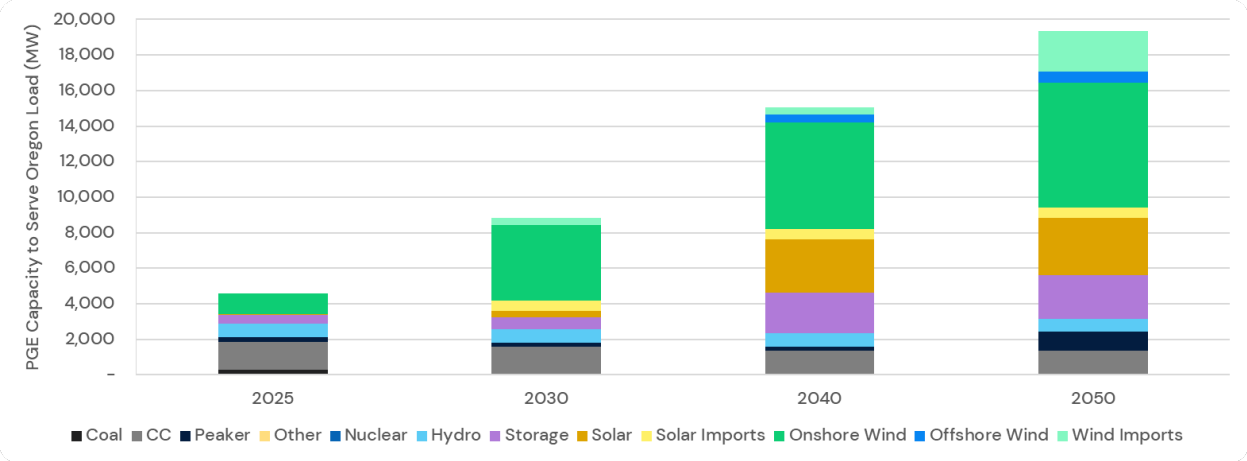
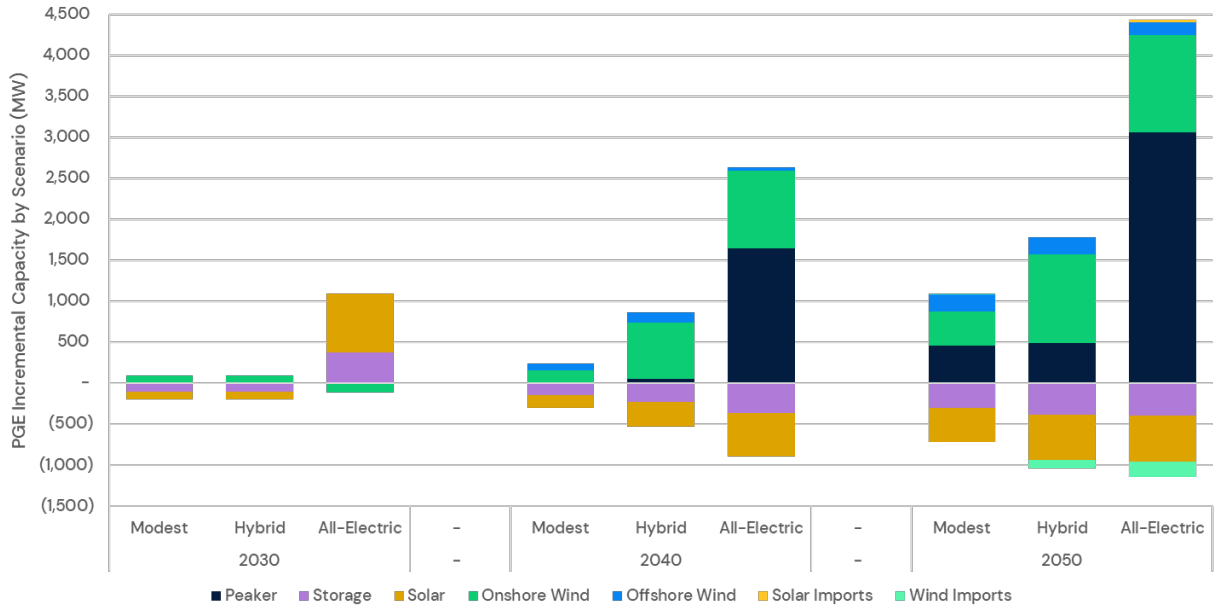


Figure 10.28: Incremental PGE Capacity (MW) by Scenario Relative to Reference Case



[259] Portland General Electric. "PGE CEP & IRP Roundtable 25-4." June 4, 2025. https://assets.ctfassets.net/416ywc1laqmd/2R28hOAx44R4HJJQbtdlVi/e645439527a2ba02d1743716ab21a502/CEP_IRP_Roundtable_June_25-4.pdf.

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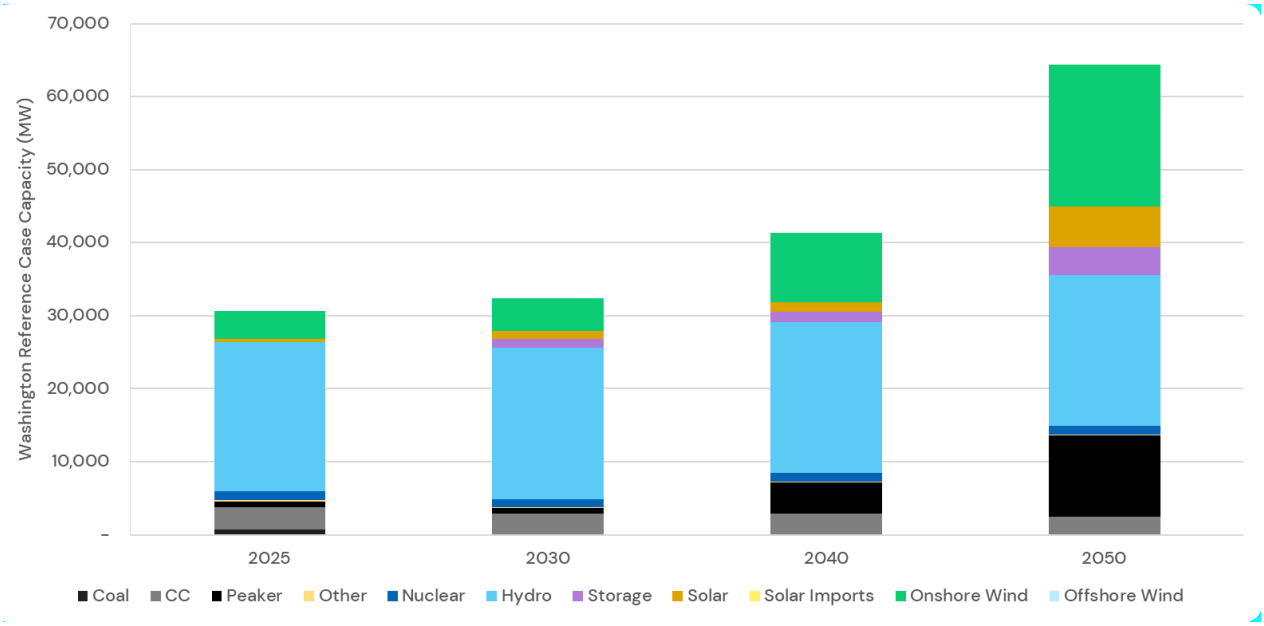
Renewable and Firm, Non-Emitting Thermal Capacity Dominate Washington Capacity Additions

Washington's installed capacity mix consists primarily of hydroelectric plants, in addition to wind combined cycle capacity. As shown in Figure 10.29, the installed capacity in the state is projected to double between 2025 and 2050, primarily through growth in onshore wind and solar, as well as close to 4,000 MW of battery storage. Onshore wind capacity grows to close to 20,000 MW to ensure sufficient generation to comply with CETA requirements in 2045 onwards. With lower winter reserve contributions for wind, solar and battery storage, peaking needs are also met by additions of natural gas peaking capacity capable of running on non-emitting fuels.

Figure 10.29: Washington State Reference Case Capacity Mix (MW)



As Washington energy and peak demand requirements increase due to electrification, onshore wind capacity increases to meet higher energy needs, and thermal peaking capacity increases to meet higher peak demand requirements. Figure 10.30 showcases the need for additional peaking capacity in particular in the All-Electric Scenario, where increasing winter peaks in 2035 and beyond drive more thermal and wind capacity into the system for peak and energy compliance, while relying less on battery storage, with its lower contribution to peak during winter peak demand periods. Washington's increase in capacity is reflective of not only the needs in the state, but also the higher winter peaks and energy demands across the Pacific Northwest. Given the close ties between Oregon and Washington systems through the BPA

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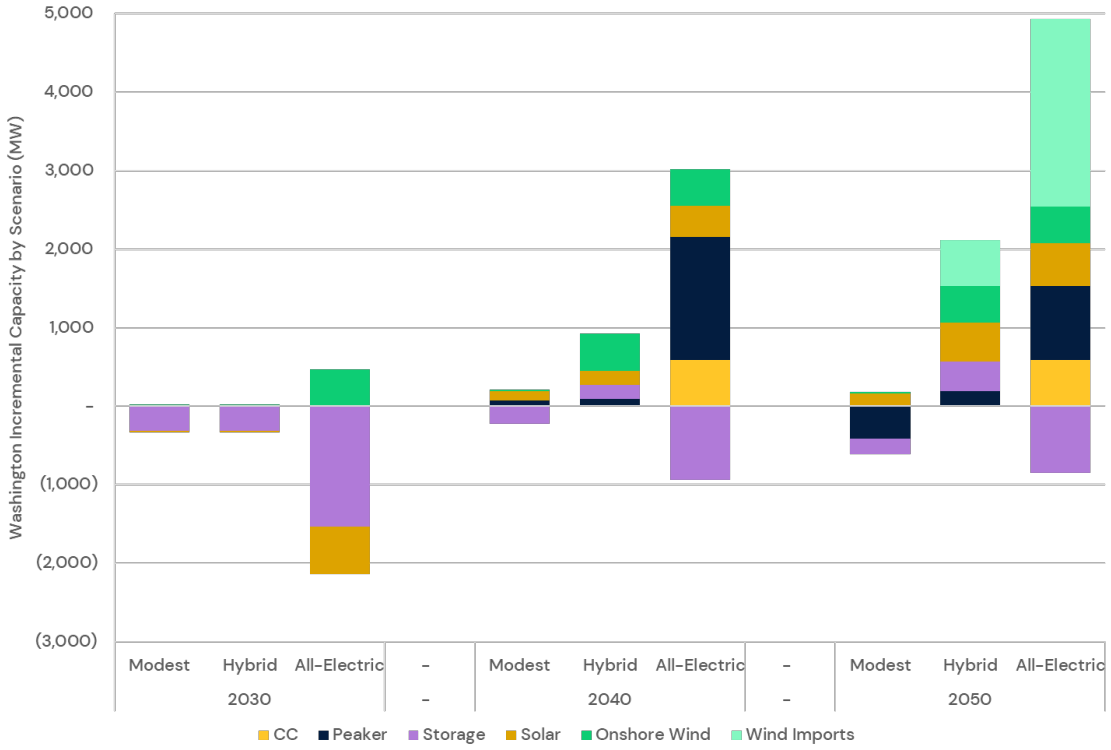
system and some electric utilities serving customers in both states while planning for their western systems in aggregate, the All-Electric scenario across Oregon and Washington increases both thermal peaking capacity and imports of wind from areas outside of the states. Access to resources within Oregon and Washington is limited, requiring supply from external regions as load increases due to building electrification.

Figure 10.30: Washington Incremental Capacity by Scenario



While both regions rely on incremental thermal peaking capacity as well as battery storage, the exact nature of firm, non-emitting dispatchable capacity that will back up the additional gigawatts of renewable capacity required for compliance with CETA and HB 2021 will ultimately depend on a variety of assumptions, technology developments over the coming decades and costs presented in this study may underestimate the cost to procure such resources in large quantities. The cost, availability, and characteristics of such resources was also subject to extensive discussions between NW Natural, ICF, as well as the Advisory Group, including concerns around the scale of the reliance on these resources for future peaking requirements even absent extensive reliability analysis.

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Transmission bottlenecks challenge HB 2021 compliance.

As mentioned above, the rapid expansion of the renewable capacity to meet HB 2021 requirements will necessitate transmission infrastructure development to either expand access to renewables within the utility service territories or connect resources from outside of utility territories. While all scenarios take into account PGE's projected ability to interconnect resources over the next few years, incremental resources beyond those assumed MW will be required. Given the short timeframe until HB 2021 compliance requirements, all scenarios resulted in a fundamental incompatibility of the assumed achievable pace and scale of the expansion of transmission and interconnection capabilities and the required resource additions. Too many resources are required beyond the currently apparent interconnection capacities, and several large-scale transmission projects, such as the completion of BPA's Evolving Grid 1.0 projects, required accelerated completion assumptions that far outpace the expected timelines. This finding aligns with PGE's assessment that HB 2021 will not be achievable without incremental transmission capacity. PGE's CEP update in 2023 relied on rapid resource interconnections and transmission expansion, whereas more recent analysis as part its 2025 IRP indicates compliance with HB 2021 through resource contracting approaches given anticipated transmission development timelines.

Reference Case costs increase as supply increases to meet growing loads and policy objectives

Oregon's electric system costs are projected to increase as generation capacity expands to meet load growth and HB 2021 compliance requirements even without building electrification. Building electrification adds substantially to winter peaking needs and costs, especially in the All-Electric Scenario. Costs presented in this section focus on the Reference Case costs and their evolution from 2025 to 2050 and include variable costs such as power plant variable operating and maintenance (O&M) costs and fuel costs, as well as fixed system cost such as fixed O&M costs, capital expenditures required to expand Oregon's generating capacity.[260] Capital costs for existing and planned and committed generation additions between 2025 and 2028 are not included as those costs are assumed to already have been incurred. The electrification scenarios then build incremental costs to the Reference Case isolate electrification costs from costs already expected to occur without electrification.

Included in the incremental cost estimates are projected distribution costs required to meet load growth across the electrification scenarios. Negative VOM costs shown reflect the

[260] Distribution costs assumptions for this analysis are based on the reported relationship between distribution investment and peak demand, and assumptions are kept consistent throughout the forecast period. Evolution of distribution cost assumptions due to the changes to the electric demand growth and daily/seasonal load changes due to electrification are not captured. Distribution costs shown here may therefore not fully capture future distribution costs required for electrifying loads.

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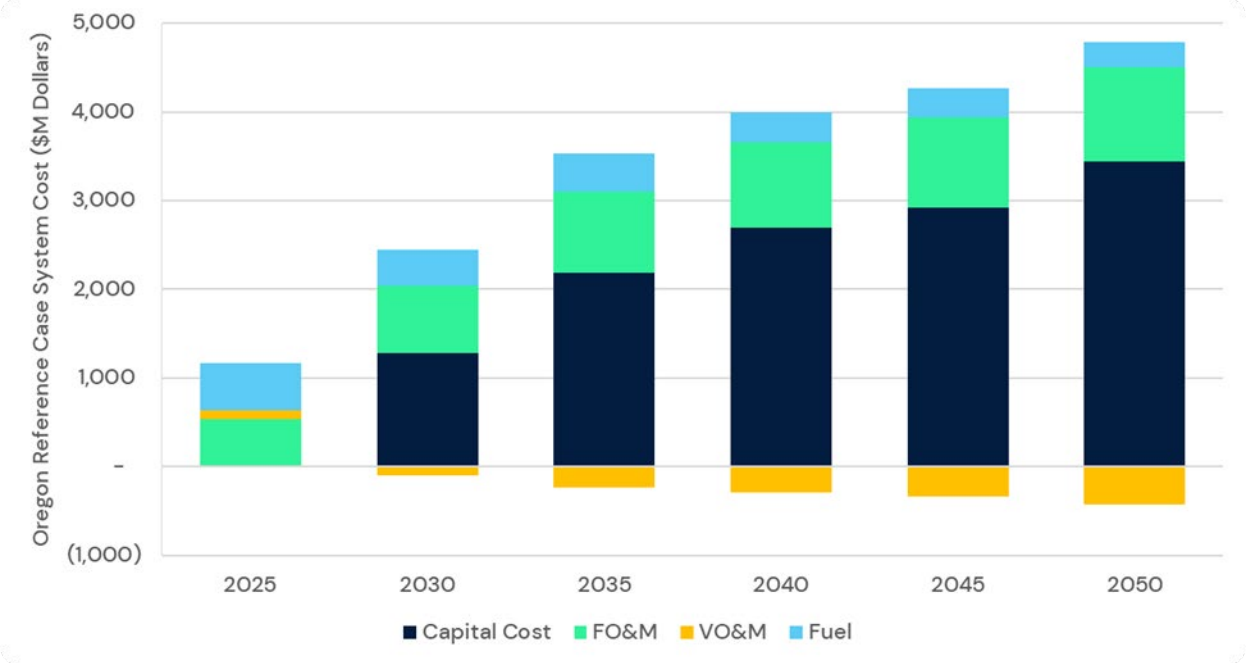
production tax credits (PTC) assumed through the Inflation Reduction Act (IRA), as analysis was completed prior to the passage of the more stringent qualification criteria as part of the Trump Administration's legislative package. Investment Tax Credits (ITC) are reflected in the capital cost component for battery storage and offshore wind. Also included in the capital costs shown are transmission costs that are required to interconnect renewable resources in Oregon beyond the available interconnection capacity assumed, as well as costs to expand inter-state transmission system to deliver wind and solar imports from outside of Oregon and Washington into the utility service territories.

As shown in Figure 10.31, the primary cost driver of system costs in Oregon are capital expenditures required to procure capacity to meet load growth and achieve compliance with HB 2021. Fuel costs decrease over time as natural gas generation decreases, and the system costs shift to a predominantly fixed cost driven cost structure.

Figure 10.31: Oregon Reference Case Annualized System Costs ($ Million)



System cost increases are particularly evident in the All-Electric Scenario when compared to the Hybrid Scenario. With peak increases of over 2 GW above the Reference Case, and a shift to winter peak demand with lower resource contributions to peak demand, the incremental capacity required to meet peak demand increases the system costs in the All-Electric Scenario. Incremental distribution costs also contribute by far the most to cost increases in the All-Electric Scenario.

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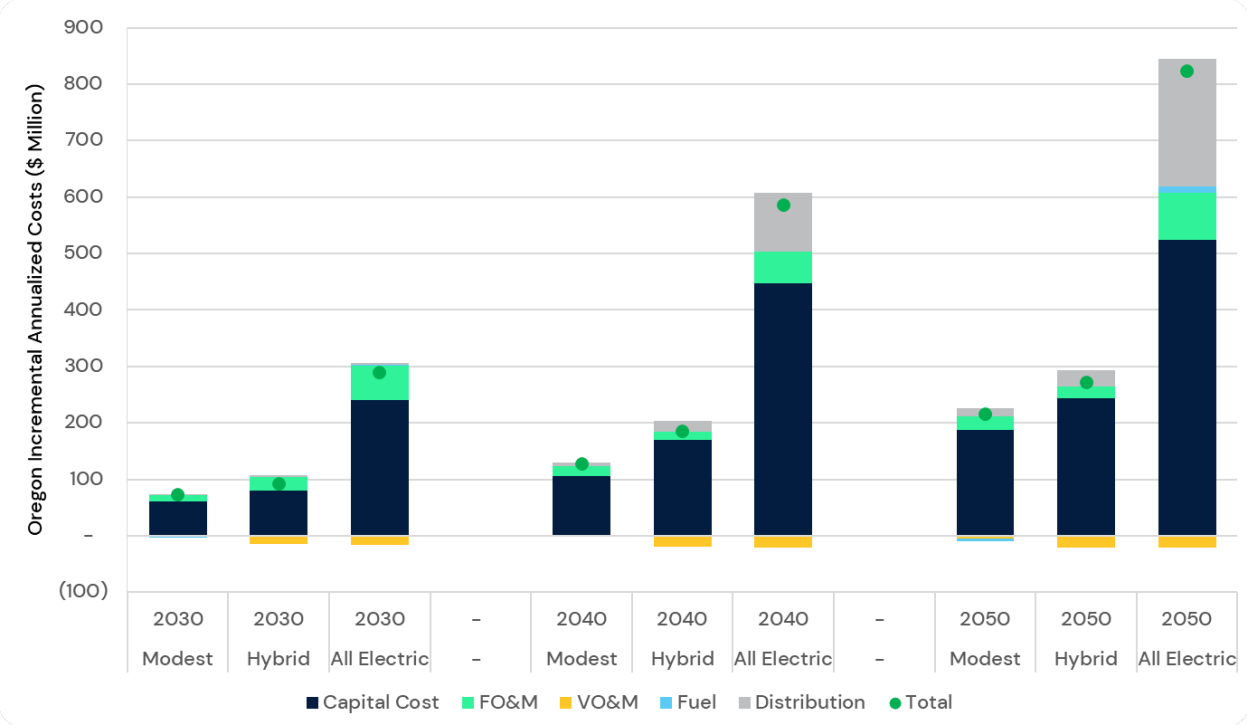
With its winter peak demand mitigation, the Hybrid Scenario avoids some of the cost increases for capital and distribution costs. Incremental capacity and associated costs are still required to meet the generation requirements of annual load increase, but peak demand-driven capacity increases being avoided reduces both capital, distribution and fixed operation costs.

Figure 10.32: Incremental Oregon Annualized Expenditure by Scenario ($ Million) Relative to Reference Case



As shown in Figure 10.32, over the course of the 25-year forecast period, electrification scenarios add between close to $4 billion in the Modest Scenario and over $13 billion in the All-Electric Scenario, with the Hybrid Scenario mitigating costs of close to $9 billion over the modeling horizon relative to the All-Electric scenario. In addition, the Hybrid Scenario and its peak load mitigation potential insulates the scenario from additional cost increases and risks not fully quantified in this analysis, as discussed in further detail in the section below. Not captured in this projection of cost increases are capital costs that would continue to be accrued in years beyond 2050, as 2050 investments will need to be recovered over 20+ years. By 2050, annual costs above the Reference Case exceed $800 million in the All-Electric Scenario.

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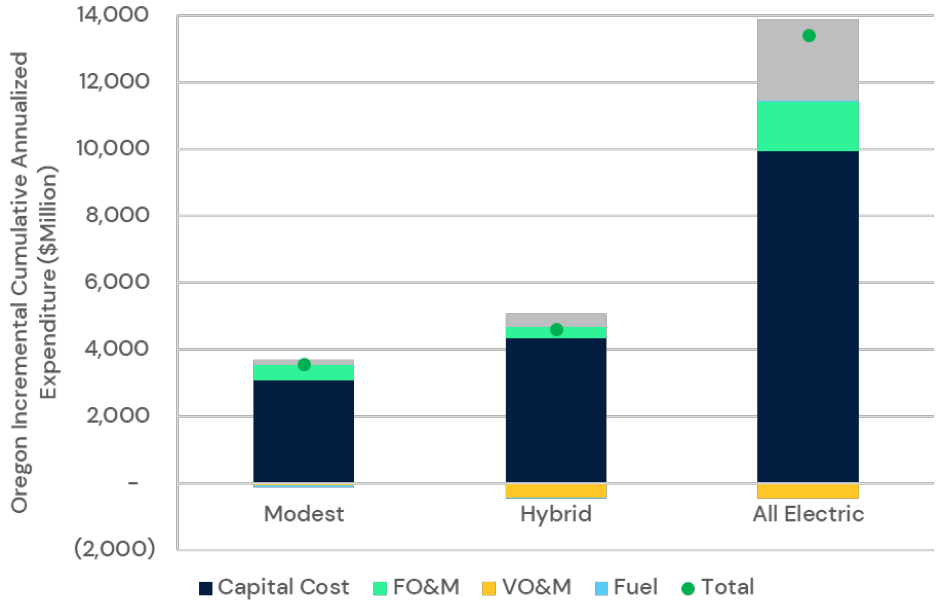
Figure 10.33: Oregon Incremental Cumulative Annualized Expenditure over Reference ($ Million)



Washington's system cost results tell a similar story of increasing fixed costs, primarily capital expenses for the expansion of onshore wind supply. While early additions are limited due to the CETA requirements still allowing for unbundled RECs to supply up to 20% of the CETA requirements, capacity additions and associated capital costs ramp up as load growth accelerates in the 2030s and CETA requirements require non-emitting supply without unbundled RECs starting in 2045. Figure 10.34 shows the increase in system costs in Washington.

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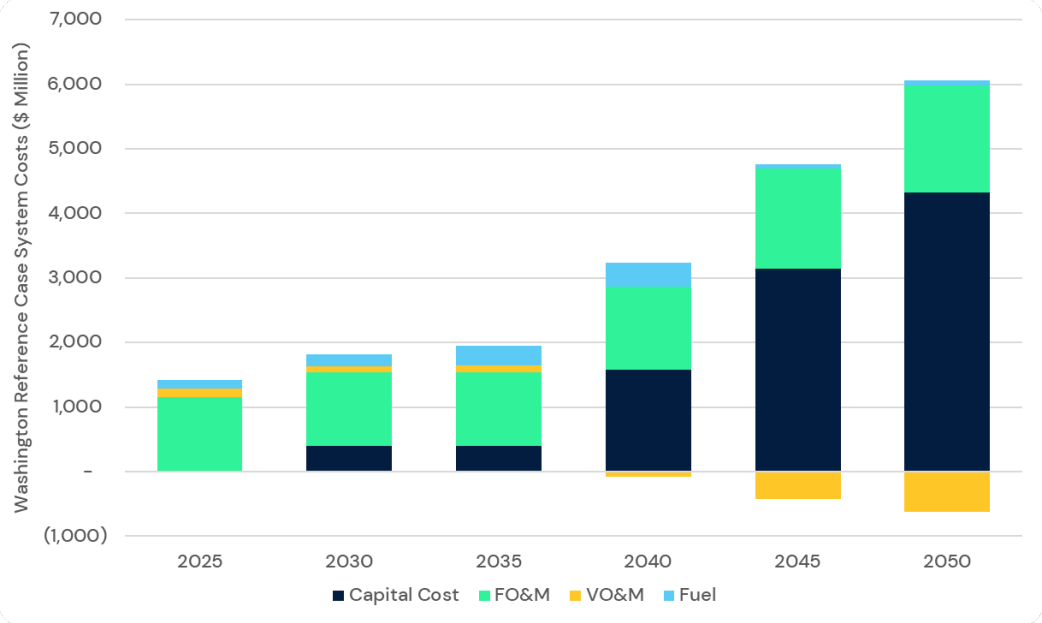
Figure 10.34: Washington Reference Case System Cost ($ Million)



Washington's system costs increase as load grows in electrification scenarios. The moderate scenario shows minimal cost impacts in Washington alone, given the small share of NW Natural customers relative to the state-wide customer count. Costs in the Hybrid scenario are driven by higher annual load requirements and the subsequent procurement of non-emitting generation to serve this load. The significant increase in 2050 system costs result from a demand for resources in Oregon and Washington and is primarily driven by increase in wind imports into the state, as well as higher annual peak demand requirements met with incremental clean firm peaking capacity.

Cost Impacts not quantified

The electrification analysis across all scenarios projects an Oregon electricity system that evolves towards non-emitting, variable supply, supported by hydroelectric generation, battery storage, and firm and dispatchable combustion capacity that relies on non-emitting clean fuels for peaking needs. On the demand side, the All-Electric scenario also shifts energy delivery in the state to the electricity system, resulting in peak demand spikes particularly during cold winter morning hours.

Both the supply and demand-side scenarios outlined and performed in this analysis result in uncertainties and compounding challenges that have not been comprehensively quantified in

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the costs presented in this section. This next section discusses how the results observed across scenarios may impact costs beyond the quantified aspects shown above.

Costs associated with reliance on non-emitting fuel supply to meet peak demands during prolonged periods of cold weather.

Across all scenarios, combustion-based peaking facilities supply firm and dispatchable capacity to the grid during peak hours – both in summer and in winter. In the All-Electric scenario, with reduced contribution of battery storage, wind, and solar capacity, several GW of such additional combustion capacity is projected to supply firm and dispatchable peaking capacity at peak hours. While the analysis ensured that sufficient capacity was available to meet the highest hour of demand, paired with a PRM of around 16%, not all costs of meeting extended peak demand periods driven by cold temperatures are fully incorporated into the results presented above.

Fuel Costs:

While fuel costs associated with hydrogen combustion would likely be concentrated on few winter hours/days and would not be expected to materially contribute to total system costs, fuel costs would be concentrated in a short period of time. To meet the difference in demand between the All-Electric and the Hybrid Scenario over a 3-day window would require fuel expenses of $30 - $35 million over the 3-day period. Hydrogen commodity costs do not include any potentially required fuel delivery system upgrades such as pipeline retrofits, adjustments to turbine configurations, and more importantly, on-site hydrogen storage to ensure a multi-day fuel supply during peak hours. While cost estimates for hydrogen storage at combustion facilities are highly speculative, capital costs for peaking turbines could increase materially to account for hydrogen storage needs that would allow facilities to guarantee deliverability of power during high load scenarios while also complying with HB 2021 emission requirements post 2040, when emissions from power generation to serve load would not be permitted for PGE and PacifiCorp.

Based on a hydrogen storage cost estimate of $30/kg of hydrogen for 8h of on-site storage[261], costs of hydrogen storage could exceed over $500 million for the All-Electric Scenario incremental to Reference Case costs, compared to $80 million in the Hybrid Scenario.[262] These estimates assume that combustion facilities meeting peak demand in the winter are required to

[261] ICF. "Examining the Current and Future Economics of Hydrogen Energy." Insights/Energy, August 13, 2021. https://www.icf.com/insights/energy/economics-hydrogen-energy.

[262] Storage costs were calculated for an 8h period and scaled up for required storage needs and scaled up for extended storage periods of up to 72h.

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store sufficient fuel to run at capacity for a 72h period (e.g., scale up the costs from 8 hour of storage to 72 hours).

The shift to winter peaks that feature limited contribution from renewable and battery storage will require additional investments in infrastructure beyond just the fuel and capital expense for the power plants themselves. While commodity and storage costs are quantified to provide an estimate of potential incremental costs, not all potential investments are captured in this analysis

Costs related to evolving reliability planning criteria

The electrification analysis presented in this chapter relies on a planning reserve margin (PRM) as the primary metric to incorporate system reliability into the projections for capacity on the utility-level. In addition to the demand-side planning reserve margin, resource contributions on the supply-side are based on summer and winter assessments from the Western Resource Adequacy Program (WRAP), a framework increasingly relied upon by electric utilities in the PNW to account for resource specific contributions to peak demand in the summer and the winter. PRM requirements are aligned with utility-specific planning requirements, such as PacifiCorp's seasonal summer and winter PRMs published in their 2025 Draft IRP, as well as the PRM relied upon for the region in the 2025 Northwest Regional Forecast published by the Pacific Northwest Utilities Conference Commission (PNUCC).[263]

While the PRM is an input into the electricity modeling conducted for this analysis, it is in many reliability assessments an outcome of more in-depth assessments of reliability. These assessments review the forecasted available supply against demand projections, incorporate stochastic analysis to examine variability of supply (wind and solar availability for example) and determine how much supply is required beyond peak demand to meet reliability metrics such as the Loss of Load Expectation (LOLE). A commonly used planning metric is 0.1 LOLE, equivalent to 0.1 loss of load expected days in one year. Over 10 years, this equates to a 1 day in 10 years standard. The supply that is determined to achieve this planning standard relative to peak demand informs the planning reserve margins.

This current approach to reliability planning may not be sufficient in an electric supply system that relies primarily on variable generation, with the majority of the energy delivery shifting to the electric sector. This section discusses three factors that may lead to an evolution of the planning environment, which would directly impact the required capacity for any given MW of

[263] Pacific Northwest Utilities Conference Committee. "Northwest Regional Forecast of Power Loads and Resources: August 2025 through July 2035," April 2025. https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf.

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load. Some of the factors listed below would impact the PRM resulting from current planning approaches, whereas others would result in different planning mechanisms altogether.

Scenarios that increase peak demand, such as the All-Electric Scenario, are much more sensitive to potential changes in electric planning standards and methodologies.

1. **Shifting hourly and seasonal load and supply patterns**
   Electrification of natural gas end-uses will shift the load profiles over the course of days, months, and seasons. Temperature driven heating load spikes are projected to drive demand towards winter mornings, whereas EV loads are expected to increase evening loads. Electricity systems with significant electric peak demand growth due to heating electrification are usually peakier with lower load factors, leading to higher resource build-outs specifically for hourly load spikes. A system where the peak demand is driven even more by temperature than today's summer peak is also more sensitive to extreme weather and extended cold temperatures or heat waves. At the same time, variability in supply increases as the share of non-emitting resources such as solar, wind, and offshore wind increases. Even under current planning standards, these factors may shift the required resource mix further above any given peak demand projections to ensure current reliability metrics. Notably, in the Carolinas, Duke Energy recently received approval to increase their winter reserve margin target from 17% to 22%, following service disruptions to over 1 Million customers during Winter Storm Elliot in 2022. In the Midwest, the Midcontinent Independent System Operator (MISO) has adopted a seasonal reserve margin construct and under this approach has increased winter PRMs for the 2024 -2025 planning year from 25.5% to over 33%.

2. **Shift in underlying reliability metrics**
   The current planning environment in the electric industry often relies upon the above-mentioned as the basis for reliability planning that focuses mainly on the probability of outages rather than total magnitude or duration of expected outages. In recent years, other metrics such as Expected Unserved Energy (EUE) have emerged that not only focus on the frequency of outages, but also the magnitude of unserved energy and therefore the severity of loss of load events. The added dimension of the magnitude of unserved energy in MWh allows for the quantification of unserved load and planning that balances the magnitude and frequency of outages against the cost of mitigating these events.

   Potential shifts in reliability planning metrics will impact and likely increase the required PRMs to achieve the varying standards. More detailed analysis will be required to assess

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the implications of alternative electric reliability planning metrics, and scenarios with greater peak demand variations will be most impacted by any changes to these planning metrics.

3. **Load criticality and fuel diversity**
   A shift to a largely electrified energy system in the All-Electric Scenario concentrates energy delivery into one primary form of energy – the electric system. Oregon's energy system today delivers energy through a diverse set of resources, including natural gas, hydroelectric power, an increasing supply of wind and solar resources, as well as imports from neighboring regions through contracted supply as well as market-driven imports. In the All-Electric scenario, fuel diversity shifts towards a supply from primarily non-emitting and variable wind and solar resources, backed up with battery storage and peaking capacity. With energy delivery concentrated into the electric sector, reliability metrics and planning standards may need to evolve to ensure reliable supply to critical loads previously served by the natural gas system with its own reliability standards and metrics.

Costs related to distribution system upgrades beyond currently observed utility expenditure

Distribution cost estimates included in the cost results presented in this analysis are based on current utility distribution capital expenditure and historical relationships between annual peak demand growth and system investment. After years of limited load growth, demand growth projections have been on the rise for the past 2-3 years, driven by electric vehicle growth, data center and other industrial load growth. The impact of these new load patterns extends not only to the anticipated annual load increases but also shift seasonal and hourly load patterns. Annual peaks in the All-Electric scenario are dominated by winter days with a lower load factor due to load spikes as temperatures drive electric heating loads. Overall peak demand growth and shifting hourly and seasonal patterns towards higher peaks without corresponding significant annual load increases in the All-Electric Scenario have the potential to shift distribution costs beyond the load and investment relationships relied upon for this analysis. With a reliance on existing cost and peak demand growth relationships, changes to utility distribution cost structures to meet growing peak demand growth and shifts in daily and seasonal load patterns are not captured in this analysis and current cost projections may therefore be understated.

In addition to the costs outlined above and associated with electrification loads identified in this analysis, other costs may shape the future of electric utility costs in Oregon over the coming decades. Another component that is driving utility costs are costs associated with mitigating

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wildfire risks and costs associated with the impact of wildfires. Utilities are required to file wildfire mitigation plans with the Oregon Public Utility Commission and conduct analysis to determine the most effective strategies to mitigate wildfire risks. Wildfire mitigation requirements in the future could also make the construction of incremental electric distribution and transmission infrastructure more expensive.

GHG emissions by Scenario and year

CO_2 emissions from resources in Oregon and resources directly contracted for by utilities to supply Oregon load are shown in Figure 10.35 below. Not included in this emissions total are emissions associated with serving load from unspecified sources that are assigned an emission intensity as per the Department of Environmental Quality's (DEQ) emission factor defined for unspecified imports – 0.428 MT $CO2_e$/MWh. Utilities with multi-state service territories may furthermore specify generation and associated emissions as supply to meet load in Oregon – resulting in accounting of emissions from units outside of Oregon but within the utility's broader service territory. Reporting of those utility emissions is dependent on the utility's approach to supplying Oregon load from their resource portfolios through specified resources with distinct emission rates, and the allocation of resource to Oregon's load requirements once coal-fired generation can no longer supply generation to Oregon customers starting in 2030. While the modeling approach for this analysis ensures that the combination of in-state emissions and unspecified market purchases cannot exceed the emissions target, and that sufficient non-emitting generation is available in the utility service territory to supply Oregon load, emissions from facilities that the utility allocates to meet Oregon demand from outside the state is not shown in the emissions accounting below.

As shown in Figure 10.35 below, electricity emissions from Oregon in-state generation and contracted generation sources fall by over 50% between 2025 and 2040 as compliance with HB-2021 for IOUs is required.

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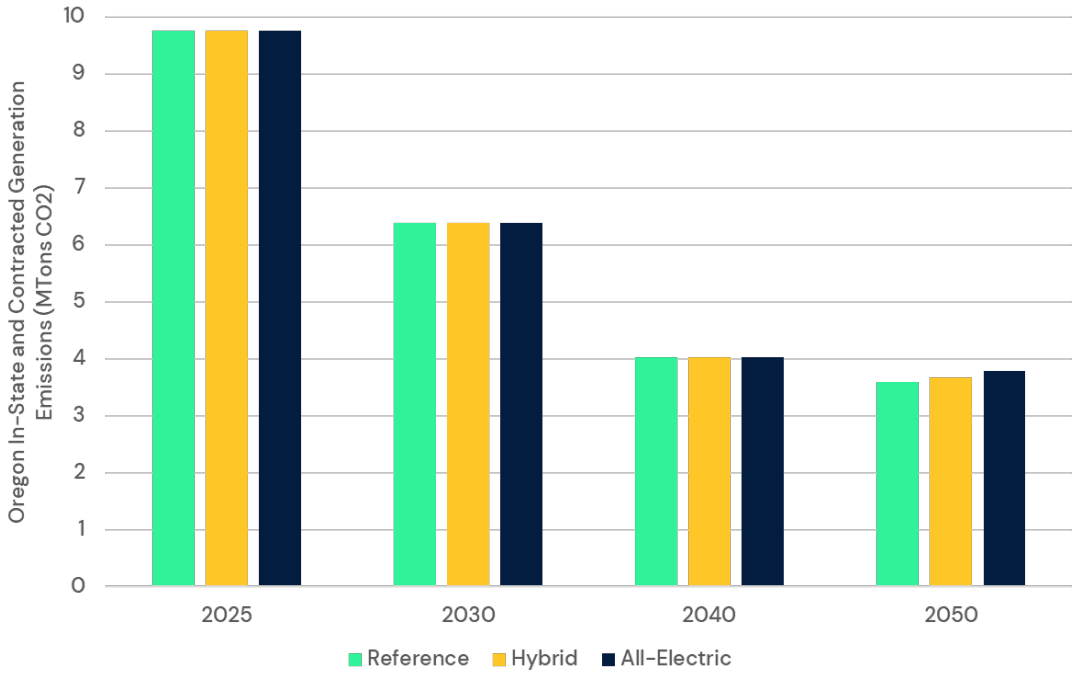
Figure 10.35: Oregon In-State and Contracted Generation Emissions (MTons CO2)



Even as HB 2021 compliance drives emission reductions in utility territories, not all emitting supply in the state is subject to emission reduction requirements. Merchant generators that supply wholesale power markets and retail electricity providers in Oregon and/or other utilities outside of the state are not covered directly under HB 2021 and are therefore not restricted in their dispatch. While no new facilities combusting natural gas can be permitted in the state, continued operation of existing facilities not covered by HB 2021 retains a baseline of emissions to meet load. Emissions do not vary significantly across electrification scenarios. In 2050, electricity sector emissions increase by less than 0.2 MMTons CO2, as the majority of load increases are in regions that require non-emitting supply. The Hybrid scenario increases emissions by less than 0.1 MMTons CO2, as load in areas not covered by HB 2021 also increases slightly in the electrification scenarios.

10.9 Summary of Electrification Analysis and Study

Even before analyzing potential electrification of gas loads in Oregon, the state's electricity sector will need to undergo a rapid and massive transformation of its supply sources away from contracted and utility-owned coal resources outside of the state, in-state natural gas generators, and unspecified market purchases that today combine for close to half of Oregon's electric supply. Within the next 5 years, utilities covered under HB 2021 will need to see an expansion of their non-emitting electric supply either through incremental transmission

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development or short-term contracting at rates that exceed development activity and resource interconnection of the past several years and decades. This clean energy transformation has only just begun and challenges with the lack of transmission and inability to interconnect new generation resources are already shaping and constraining how electric utilities plan for additions in their resources plans today. As mentioned above, electric rates for residential customers at PGE and PacifiCorp have increased 40% and more between 2020 and 2024.

Challenges with resource interconnection are exacerbated by long lead-times for transmission development necessary to connect new resources, as the existing transmission system reaches capacity, and load growth driven from industrial and electric vehicle loads will add to the load needed to be served by new resources and introduce further challenges of shifting loads to winter peaks, limiting the contribution of resources like solar and battery storage to peak demands.

Electrification of NW Natural's current gas end-uses, will add to the electric load growth anticipated by the electric utilities from electric vehicles and data centers and will substantially increase peak demands in utility service territories by several GW, reducing the fuel diversity of the energy delivery and increasing resource requirements in an already strained system. Costs and logistics of supplying the incremental loads, while quantified in this analysis, are highly uncertain and cannot be fully quantified at this point in time. The electric grid in 2050 may require new approaches to planning and permitting resource additions and consider more stringent planning reserve requirements to ensure resource adequacy. Electric reliability challenges have already appeared and were most evident in January 2024, and while large-scale customer outages due to supply shortages were avoided, the region relied heavily on neighboring western regions to prevent supply shortfalls in Oregon even without end-use electrification of current gas heating loads. By 2040, HB 2021 emission limits and the current emission factors associated with unspecified market purchases may limit the ability of the market to serve load in Oregon with imports, requiring more firmly contracted and owned generation from Oregon utilities to meet load as is. Planning challenges in this analysis emerged as early as 2030, where non-emitting additions are required at a scale that requires transmission investments at a much faster pace than recently observed or have been built in several decades.

Many of the same challenges impacting electric sector evolution over the coming 25 years are also present in Washington – rising electric loads even absent electrification of natural gas end uses, clean energy targets that require the expansion of generating resources to achieve a 100% non-emitting supply by 2045, and limited capacity to interconnect additional resources at scale to facilitate policy achievement without significant new investment into transmission capacity. While electrification impacts in Washington don't reach the scale of Oregon given the

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smaller number of NW Natural customers in the state, the relative impact of building electrification on peak demand is even larger, as Washington's utilities are primarily peaking in winter to begin with. As such, and with colder temperatures, any electrification of natural gas end-uses will directly increase peak demand, rather than winter peak demand catching up with higher summer peaks before having an impact on annual peak demand.

Outside experts helped NW Natural and ICF form several assumptions and cautioned against assumptions that were inconsistent with current realities like lead times and costs. In some cases, the analysis required "relaxing" assumptions to make the modeling achieve HB 2021 compliance while also meeting load growth and adhering to anticipated transmission development timelines. This "relaxing" is akin to PGE's assumption of transmission availability by 2030 in the 2023 CEP Update, or more recently the assumption of focusing near-term additions on contracting for supply given the anticipated transmission availability no earlier than 2032.

As stated earlier, neither ICF nor NW Natural endorse any decision or policy direction associated with the scenarios contained in this analysis. Rather the scenarios were studied to better understand and inform the public policy decision making. NW Natural included the Hybrid scenario to contrast the impacts on cost, emissions, and risks to the All-Electric scenario. The All-Electric scenario is a 'big bet' that puts all the eggs in the basket of future electric infrastructure. This analysis has shown the Hybrid scenario achieves nearly all the potential emissions reductions of the All-Electric Scenario, and mitigates potential risks associated with the All-Electric Scenario, such as significant winter peak demand growth and the uncertainty around the costs and ability of resources provide non-emitting, firm, clean power to meet winter peak loads.

The costs and associated risks to pursue the All-Electric scenario were found to be higher than the Hybrid scenario. The underlying legislation such as HB 2021 contains safeguards to protect affordability and reliability. The costs portrayed in this analysis need to be converted to a rate and affordability analysis to assess whether the legislative safeguards are pierced. Additionally, more detailed reliability analysis should be performed to ensure that reliability is not degraded for customers.

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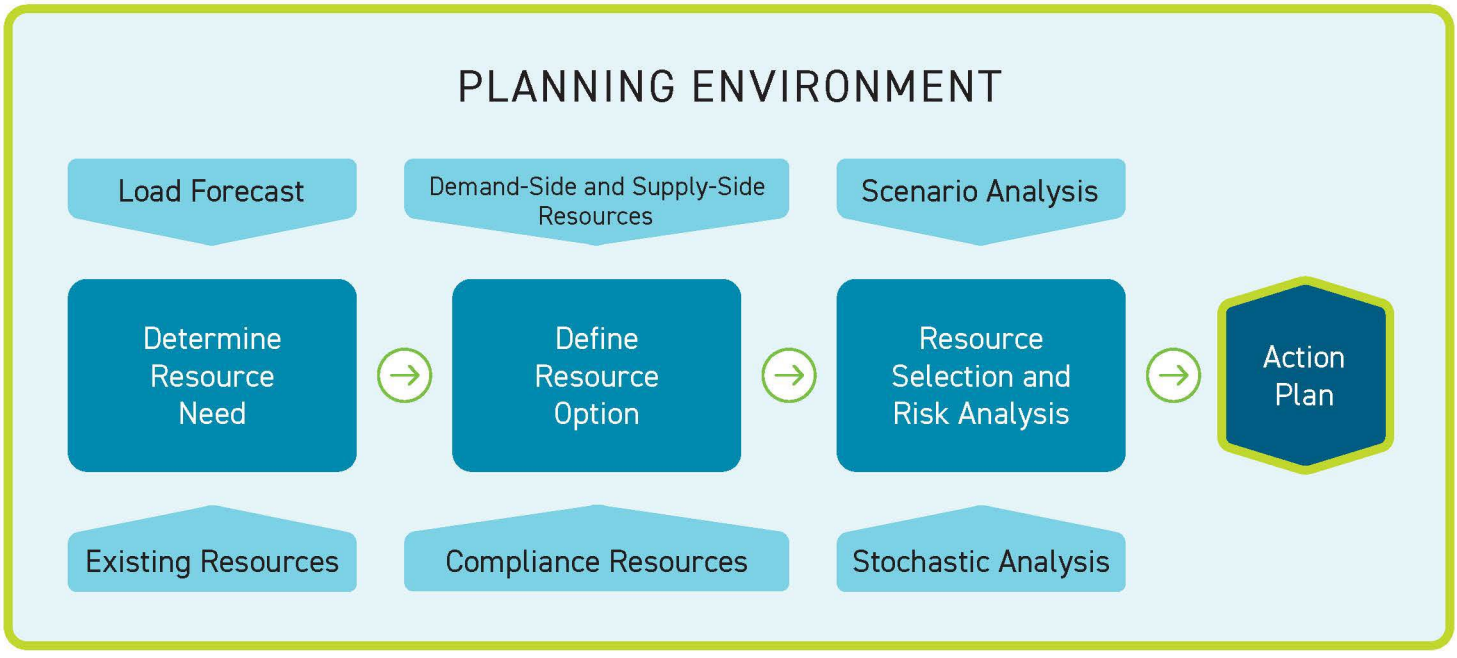
11 | Energy System Implications and Enabling Strategies



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The previous chapters identified the potential need, resources, costs, and risks. This section takes all that data and analysis and synthesizes it into the implications for planning purposes. It answers the question of: what are the key learnings that NW Natural should use to inform its Long-Term Resource Strategy and Near-Term Action Plan?

11.1 Energy System Implications

The following sections discuss both the Gas and Electric System Costs and the associated GHG emissions.

11.1.1 Electric and Gas Total System Costs and Greenhouse Gas Emissions

This section provides an overview of the key overall costs and GHG emissions results combining the demand-side and electric power sector results from the electrification study along with results from NW Natural's IRP PLEXOS® modeling.

11.1.1.1 Total System Costs

To provide an indication of the overall cost impacts, the combined *incremental* annual net costs (relative to the Reference Case) were compared over the study period and across the differing levels of building electrification examined in each scenario.[264] These total incremental net costs include equipment conversions and electric infrastructure required for building electrification along with natural gas utility cost savings. Since these costs compare incremental net costs relative to the Reference Case, these incremental electric infrastructure costs do not include the impacts from meeting EV loads, data center growth, or complying with emission reduction regulations, such as HB 2021, since all of those costs are captured within the study's Reference Case. The Reference Case also includes significant emissions compliance costs for NW Natural out to 2050, as the Company acquires compliance resources to meet its own CPP and CCA requirements. It should also be noted that these total system incremental net costs were developed to present the impacts for NW Natural customers in the Reference Case (i.e., this is not a total cost impact from electrifying all natural gas consumers in Oregon or Washington).

Figure 11.1 shows the comparison of cumulative incremental costs from both the building electrification scenarios (annual costs are not discounted in the cumulative totals), covering NW Natural customers in both Oregon and Washington. This overall data show that all of the electrification scenarios considered here are more expensive than the Reference Case. The

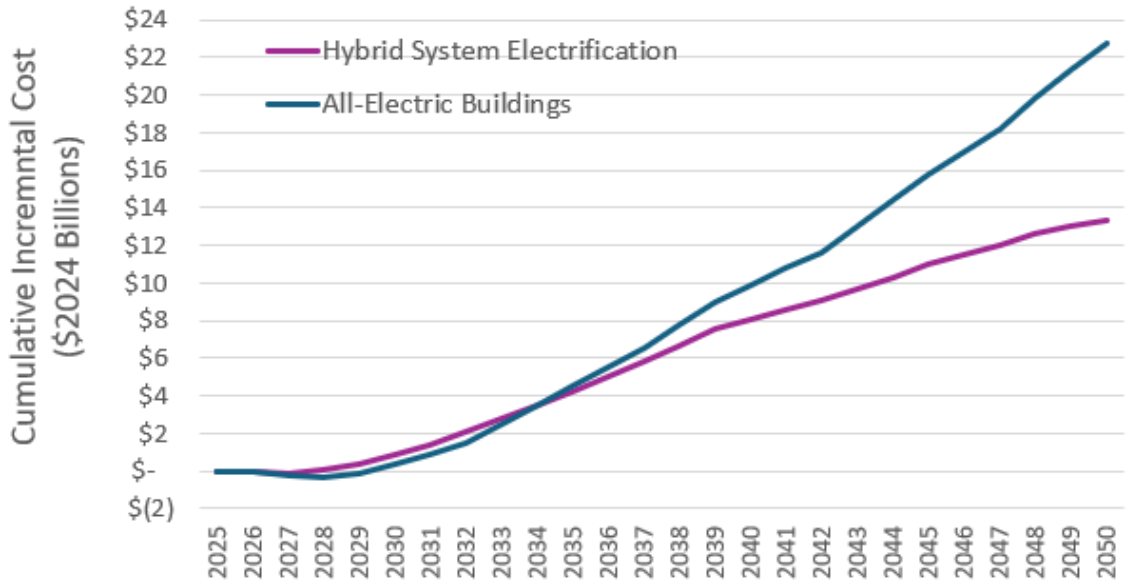
[264] The electrification analysis focused on the quantification of incremental costs of a range of electrification scenarios. Reference Case costs, while covered partially under the Electric Sector analysis and as mentioned previously are not fully quantified.

Reference Case also reduces GHG emissions significantly, by using an approach focused on energy efficiency, low-carbon gases, and other compliance resources.

The All-Electric Buildings scenario in Figure 11.1 has the largest increase in costs for NW Natural's customers over the planning horizon, with the cumulative cost increase reaching $22.7 billion more than the Reference Case by 2050. While in the Hybrid System Electrification scenario, maintaining gas back-up for aggressive ASHP adoption results in cumulative incremental costs of $13.3 billion by 2050, approximately $9.4 billion less than the approach with all-electric equipment provided in the All-Electric Buildings scenario. Between these two electrification scenarios, customer equipment conversion costs and gas utility savings are relatively similar, with the electrification-driven peak capacity infrastructure costs being the primary driver of the cost difference. This peak capacity requirement is driven by the All-Electric Buildings scenario that relies solely on the electric system whereas the Hybrid scenario relies on both the electric system and the gas system with the gas system serving as the peaking capacity.

It is also important to keep in mind that these incremental cost impacts are in addition to the cost impacts for GHG emission reduction policy captured in the Reference Case (e.g. costs for decarbonizing power supply for EVs and existing electricity uses, as well as emissions compliance costs for NW Natural).

Figure 11.1: Cumulative Total System Net Incremental Costs for NW Natural Oregon & Washington Customers Relative to Reference Case[265]



To put these cost differences in context, by 2050 the All-Electric Buildings scenario would have approximately 800,000 less NW Natural customers than in the Reference Case. The 2050 annual incremental cost in the All-Electric Buildings scenario is equivalent to around $1700/converted customer/year *more* than the Reference Case.

The incremental cumulative costs presented above are made up of the following components of annual costs or savings out to 2050 (all based on the difference vs. Reference Case). It should be noted that because of the complexity of this analysis, there was no time to remove IRA funding and re-run the modeling. Therefore, **the costs noted for the electric system, heat pumps, and for hydrogen (for both the electric and gas analysis) would be much higher**.

Customer equipment conversion costs to electrify (less IRA incentives): Customer equipment conversion costs capture the incremental costs (assuming customers otherwise would have

[265] This figure shows the cumulation of non-discounted values relative to the Reference Case (PRS.a). Therefore, the costs of the PRS.a are represented by "zero" on the y-axis. These cumulative costs include all the incremental in-home electrification measure costs (also referred as incremental in-home equipment costs), and the incremental electric generation, electric transmission, and electric distribution costs. This graph also includes the gas costs savings from reduced capacity costs, commodity and variable costs, and compliance costs relative to the preferred resource strategy (PRS.a or Reference Case) scenario. These savings are subtracted from these cost totals previously mentioned. Figure 1.15 demonstrates the same information, but discounts future costs to a present value.

needed to replace their furnaces and air-conditioning units) in the year conversions occur, including for residential, commercial, and industrial equipment electrification. Additionally, a high-level assumption is made that roughly 60 percent of the $113.76 million of IRA incentive funding available for Oregon might be leveraged for these customer conversions (IRA incentive funding, at the electrification adoption rates assumed here, would be exhausted by 2028). For Washington, 5 percent of the state's $166 million IRA incentive funding is assumed to be channeled to NW Natural customers, reflective of the Company's smaller share of total gas customers in Washington.

- **Increased electric costs from generation, transmission, and distribution investments and operations:** The power sector costs, outlined in Chapter 10, are annualized costs. This means that capital investments in generation, transmission, and distribution are being amortized over the lifetime of those electric utility investments (not showing the full CAPEX investments made by utilities each year). Hence, the annual electric infrastructure costs would need to remain at these elevated levels for many years after 2050 in order for the utility to recover its infrastructure investments (i.e., impacts not fully captured within the 2025-2050 cumulative costs).
- **NW Natural commodity & capacity cost savings:** In the electrification scenarios, where natural gas demand is reduced relative to the Reference Case, less gas commodity purchases are required and upstream pipeline capacity is released, resulting in cost savings relative to the Reference Case.
- **NW Natural compliance resource costs savings:** In the Reference Case, NW Natural is required to comply with emissions regulations that become increasingly stringent out to 2050, ramping up the Company's purchases of low-carbon fuels such as RNG and hydrogen. In the electrification scenarios, where natural gas demand is reduced relative to the Reference Case, less gas needs to be decarbonized, resulting in compliance cost savings relative to the Reference Case.

To give a better understanding of the cumulative costs, Figure 11.2 and Figure 11.3 show the relative contributions of the different cost and savings components discussed above to the net costs (relative to the Reference Case) for each scenario. These graphs blend positive and negative cost impacts, and the cumulative net cost impact is shown in the dotted line. The net cost from the dotted line for each scenario was compared earlier in this section.

Figure 11.2: Component-Level Cumulative Total System Net Incremental Costs for NW Natural Oregon & Washington Customers Relative to Reference Case – All-Electric Scenario

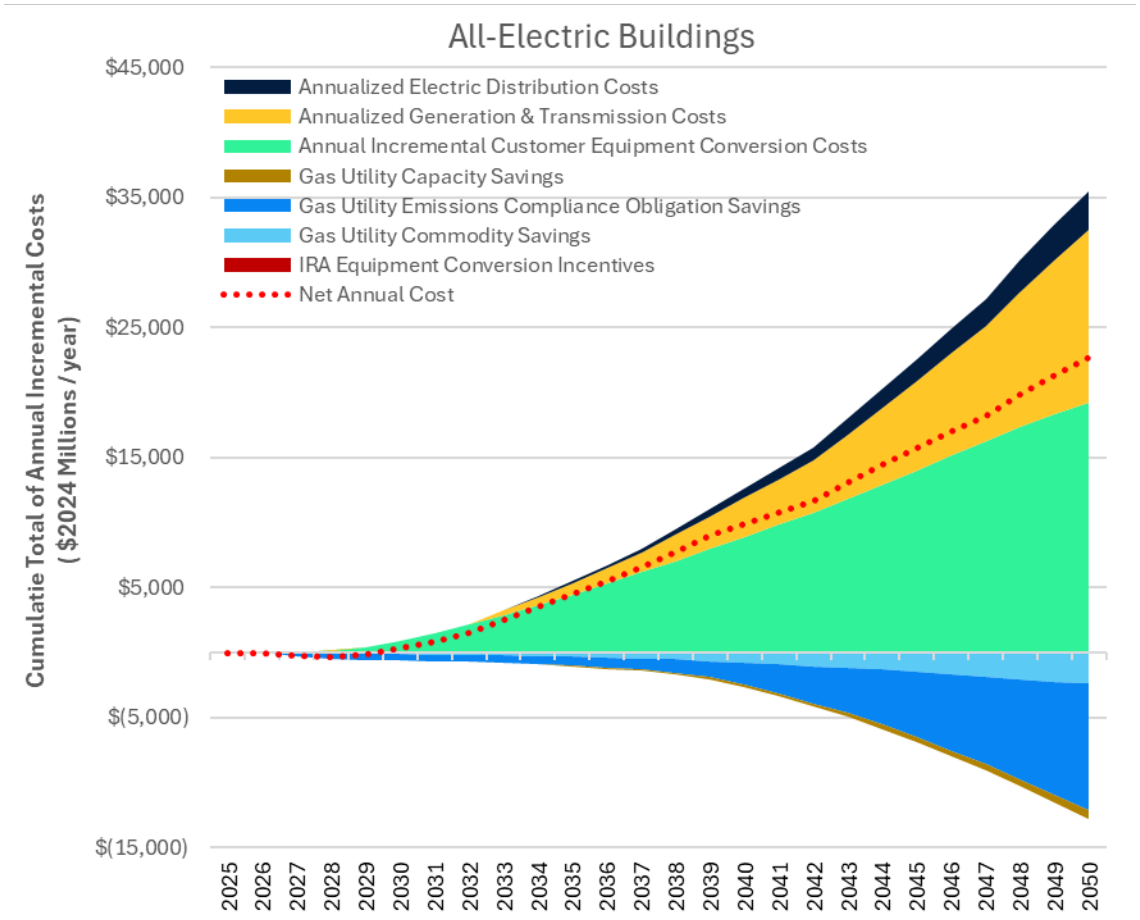
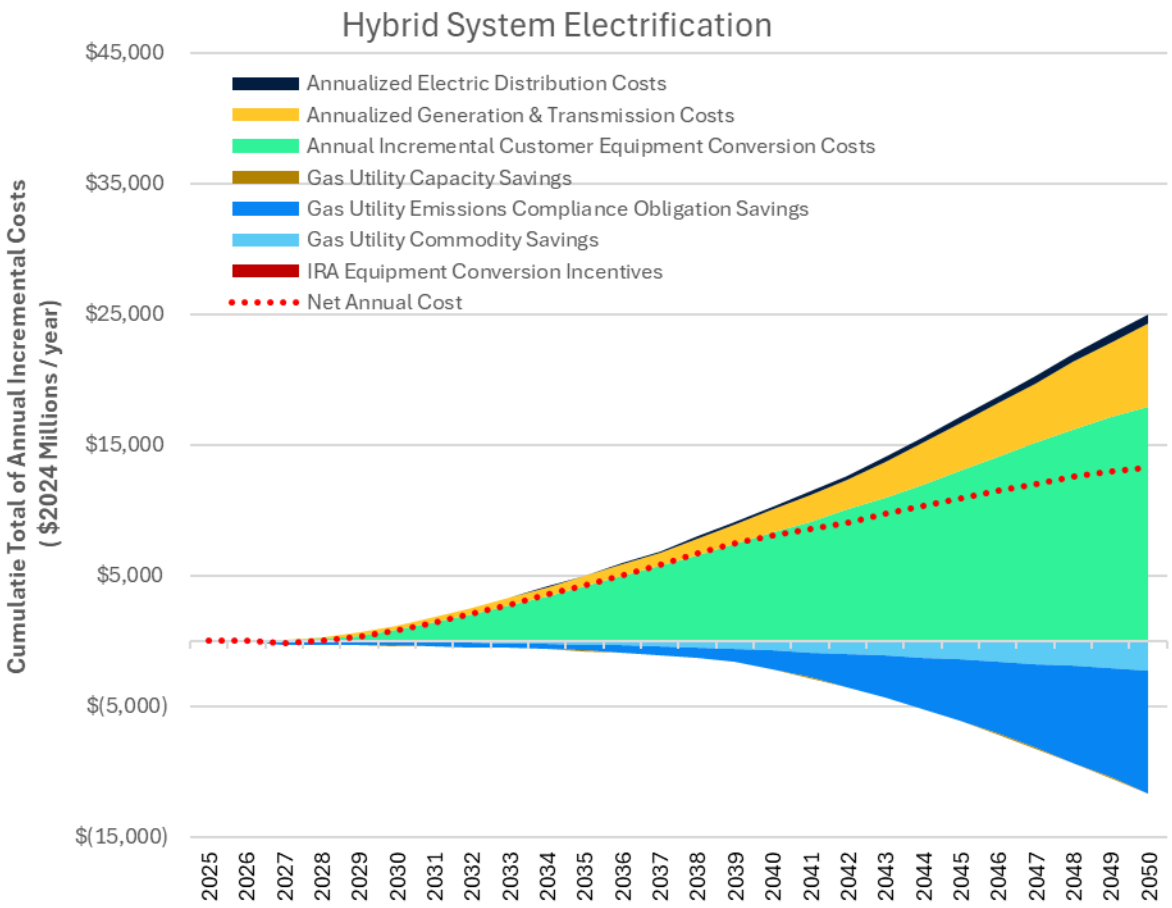


Figure 11.3: Component-Level Cumulative Total System Net Incremental Costs for NW Natural Oregon & Washington Customers Relative to Reference Case – Hybrid Scenario



There are also potentially additional 'unquantified costs' identified in Section 10.8.3, that are not captured in the total costs presented above. For example, this analysis does not include the potential need for additional hydrogen storage costs if clean peaking resources are required to have 72 hours of hydrogen fuel on site. Based on the high-level estimate from ICF for Oregon, having three days of clean fuel stored could add $500M to costs in the All-Electric scenario and $80M to costs in the Hybrid scenario.

11.1.1.2 Combined Greenhouse Gas Emissions Impacts

Another important impact to consider for the different IRP scenarios is the impact on GHG emissions for NW Natural customers. By 2050, there is *little difference* between net GHG emissions from NW Natural customers in the Reference Case and the Electrification Scenarios, because both gas and electricity supplies are assumed to decarbonize in line with state laws for both scenarios.

In the **Reference Case**, most NW Natural customer GHG emissions from the combustion of natural gas are expected to be reduced through required compliance tools and obligations (e.g., purchases of RNG, hydrogen, credits, etc.). [266]

In the **Electrification scenarios**, gas demand is reduced from the Reference Case and new electric loads are added to the grid. However, these scenarios provide minimal additional GHG savings compared to the Reference Case, because all scenarios are designed to reach the ultimate compliance goals. The modeling also assumes that Oregon's requirement for 100 percent clean electricity means new electric loads will add little to no additional greenhouse gas emissions, even from peaking and incremental resources used by major utilities.

To assess the combined GHG emissions impacts from the electrification scenarios the following components were calculated:

- **Baseline gas combustion GHG emissions** were calculated based on the annual gas consumption from non-EITE customers in each scenario and year, as well as a combustion emissions factor for geologic natural gas (0.0531 metric tons of CO2 per MMBtu). [267]
- **Compliance GHG emissions reductions** were calculated based on the amount of gas NW Natural purchased GHG compliance options for in each scenario and year, as part of the PLEXOS modeling. The compliance options are converted to GHG savings based on the same natural gas combustions emission factor mentioned above (0.0531 metric tons of CO2 per MMBtu).
- **Electric GHG emissions (HB 2021 or CETA)** were calculated based on the electric load added for building electrification in each scenario and year, multiplied by average annual GHG emissions factors from the electricity supply for NW Natural customers in each scenario. As with the costs discussed in the last section, this is a weighted combination of the electricity emissions from the different electric utilities that serve NW Natural customers (since different utilities in Oregon and Washington have different levels of compliance obligations in HB 2021 and CETA regulations). For example, the average annual electric sector emissions factor goes from 0.2 metric tons of CO2 per MWh in 2025 to 0.001 metric tons of CO2 per MWh in 2050 for the All-Electric Buildings scenario for Oregon.

[266] Some compliance options, like CCIs and allowance purchases, may not be directly tied to GHG emissions reductions on NW Naturals system but are mechanisms used by the state to claim GHG emission reductions.
[267] Emissions-Intensive Trade-Exposed (EITE) industrial customers are excluded from the Company's emissions reduction compliance requirements.

- **Incremental electric GHG emissions with NEEA GHG factor** is a sensitivity that shows additional emissions if power generation is not able to decarbonize as quickly, or deeply as assumed in the core scenarios based on HB 2021 compliance and instead remains fixed through the study at 0.421 metric tons of CO2e/MWh, in line with current NEEA assumed values.[268]
- **Net remaining GHG emissions** are calculated from the components above: Baseline Gas Consumption Emissions + Electric GHG Emissions - Compliance GHG Emission Reductions

Figure 11.2 shows the combined Oregon building electrification GHG impacts in terms of savings from reduced combustion of natural gas (declining green bands), compliance GHG emissions reduction purchases to decarbonize remaining gas consumption (yellow bands), increases from higher usage of electricity (narrow maroon band shows increase with HB 2021, blue band gives context on increased emissions assuming continued emissions in line with current NEEA assumptions), and the resulting net GHG impacts (dotted lines). The results in Figure 11.2 for Oregon show very similar levels of net GHG reductions for the Reference Case, Hybrid System Electrification, and All-Electric Buildings scenarios.[269] Figure 11.4 shows the equivalent information for Washington, where all scenarios are required to reach the same gas GHG emissions level by 2050. Since the power supply is assumed to deeply and rapidly decarbonize in order to comply with state level climate policy, the increases in GHG emissions from added electric load in red are not significant in either state.

[268] NEEA uses 0.93 lbs/kWh (equivalent to 0.421 metric tons of CO_2e/MWh) as the GHG intensity of electricity for the purposes of estimating energy conservation impacts. This estimate may understate the carbon intensity of such generation. The EPA recommends using eGrid data at the subregion level. For the Pacific Northwest, the applicable subregion is the Northwest Power Pool, which has an emissions rate of 1.745 lbs/kWh. See U.S. Environmental Protection Agency, Frequent Questions About eGRID (available at: https://www.epa.gov/egrid/frequent-questions-about-egrid#egrid1).

[269] Before accounting for increases in GHG emissions from electricity consumption, the 2025-2050 cumulative GHG savings from gas emissions and compliance options would be the same in the Reference Case and both electrification scenarios. But the 2050 net GHG emissions are slightly lower in the Reference Case because the PLEXOS model for these electrification scenarios was able to bank some additional GHG emission reductions earlier in the forecast period and use those for compliance purposes closer to 2050.

Figure 11.4: Changes in GHG Emissions by Scenario for NW Natural Oregon Customers

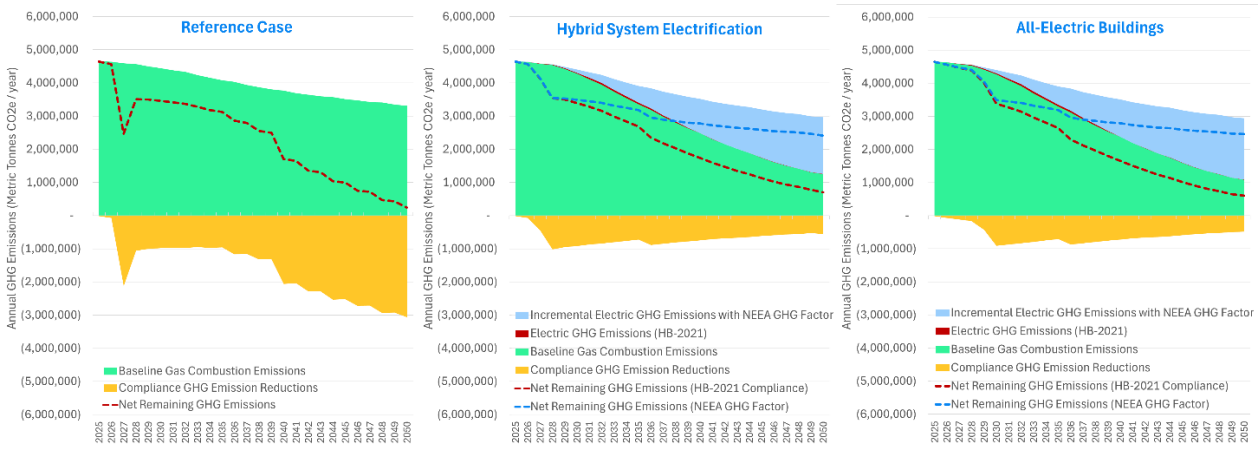
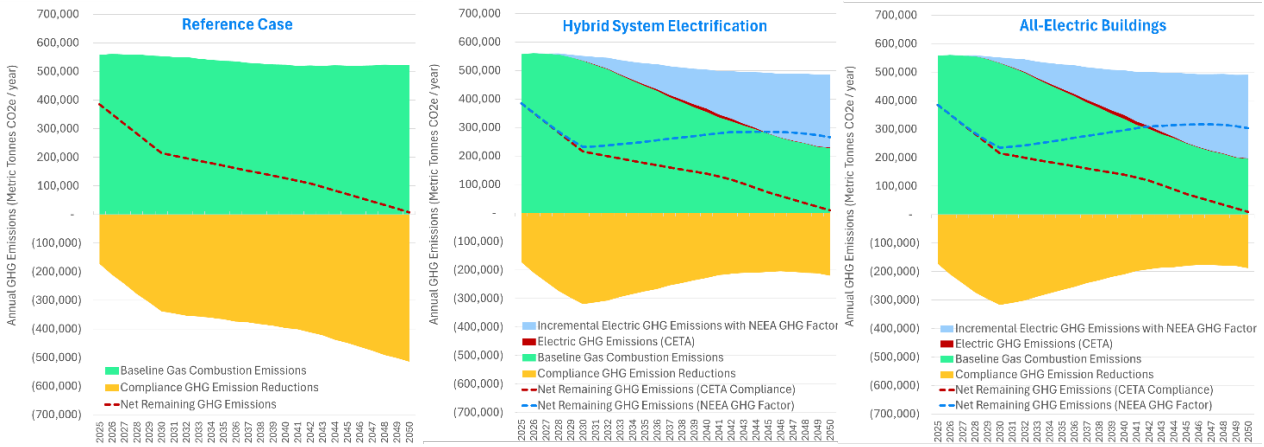


Figure 11.5: Changes in GHG Emissions by Scenario for NW Natural Washington Customers



It is important to keep in mind that these net GHG emission reductions are calculated based on average annual GHG emission factors modelled for the power sector.[270] In Oregon and Washington currently, natural gas generation (imported and in-state) is relied upon more heavily during the peak demand periods, such as summer AC-driven peaks and cold winter months such as December – February, driven by heating loads. During these colder periods, building electrification would add load served by natural gas generation. For this reason, marginal GHG emissions factors can be more indicative of the GHG impacts of building electrification. For example, the NEEA emissions factor noted above is closer to an emissions

[270] In the core analysis of power sector, following HB 2021, GHG emissions reductions targets for the electric sector require non-emitting marginal generation resources as well – so this distinction is less impactful.

factor for natural gas generation. Hence the NEEA GHG factor sensitivity on the charts, showing that if a similar marginal resource was needed for 100 percent of the building electrification needs in this study, then net GHG emissions for the All-Electric Buildings scenario would be substantially higher than in the Reference Case. In other words, if an electrification scenario is taken instead of decarbonizing the gas supply, but the electricity supply is not fully decarbonized, GHG emissions would increase. This could represent a lose-lose-lose scenario, where costs have increased over the Reference Case, GHG emissions are also higher than the Reference Case, and the energy system is less diverse, reliable, and resilient than in the Reference Case.

Figure 11.3 and Figure 11.4 present similar results as above but compare only the resulting net GHG emissions impacts for the different scenarios and sensitivities. Additionally, instead of the annual GHG emissions levels, this chart shows the cumulative reduction in annual GHGs, relative to 2025 GHG emissions from the Reference Case. Before accounting for increases in GHG emissions from electricity consumption, the 2025-2050 cumulative GHG savings from gas emissions and compliance options would be the same in the Reference Case and both electrification scenarios. There are some year-to-year variations in net gas GHG emissions between scenarios because the PLEXOS model for these electrification scenarios in Oregon was able to bank some additional GHG emission reductions earlier in the forecast period and use those for compliance purposes closer to 2050. Those annual differences even out by 2050, where cumulative net GHG emission reductions in each scenario are very similar. The remaining cumulative emissions differences in 2050 between scenarios are driven by the differences in the electric GHG emissions for different scenarios, which were shown earlier in Figure 11.2.

The bars with hash marks in Figure 11.3 and Figure 11.4 show the potential for a lose-lose-lose situation if the GHG-intensity of added electric load does not approach zero as assumed in the analysis for policy compliance purposes – this would result in lower cumulative GHG emission reductions from the electrification scenarios by 2050 than in the Reference Case.

Figure 11.6: Changes in Cumulative Net GHG Emissions by Scenario for Oregon NW Natural Customers

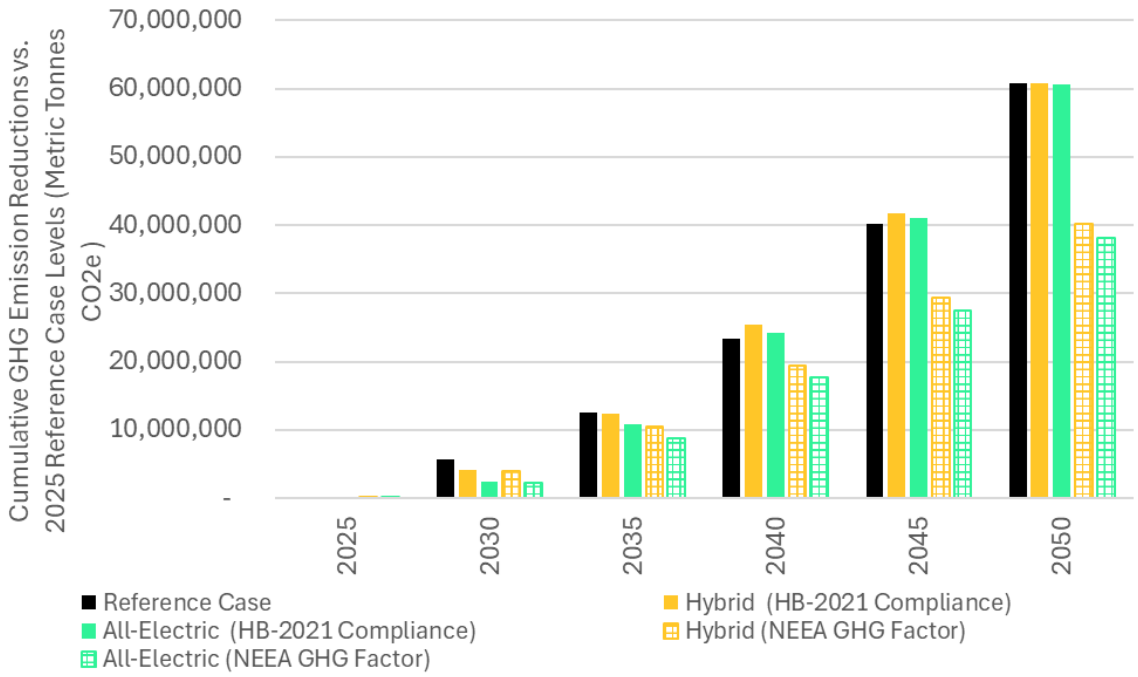
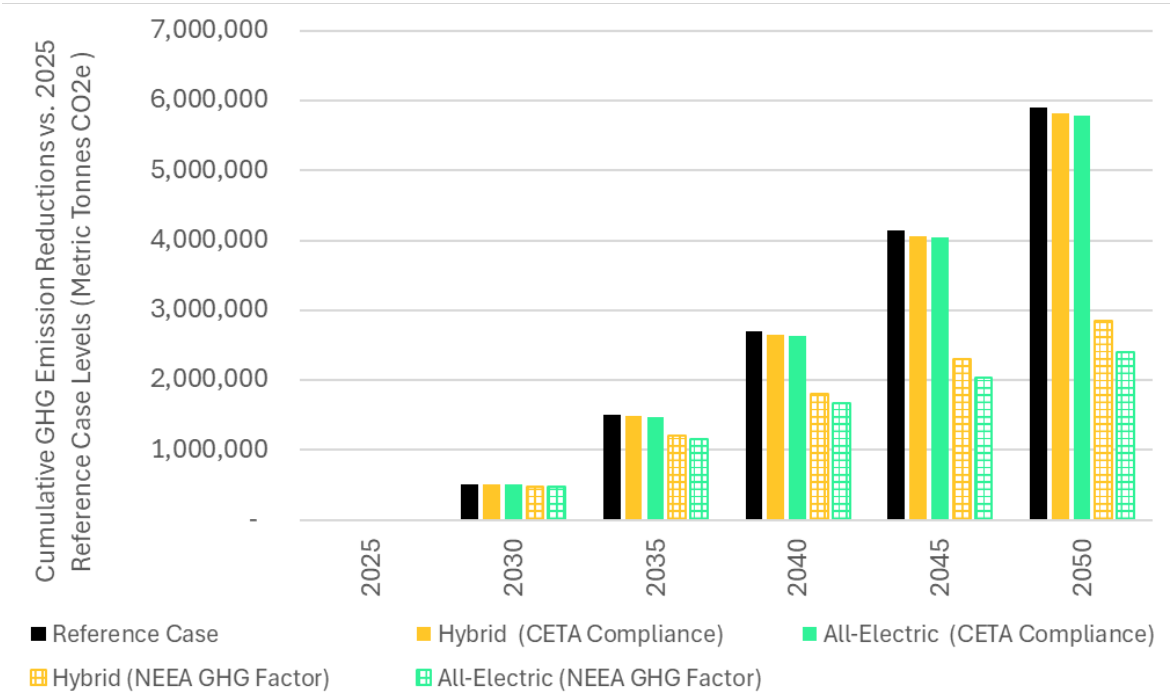


Figure 11.7: Changes in Cumulative Net GHG Emissions by Scenario for Washington NW Natural Customers



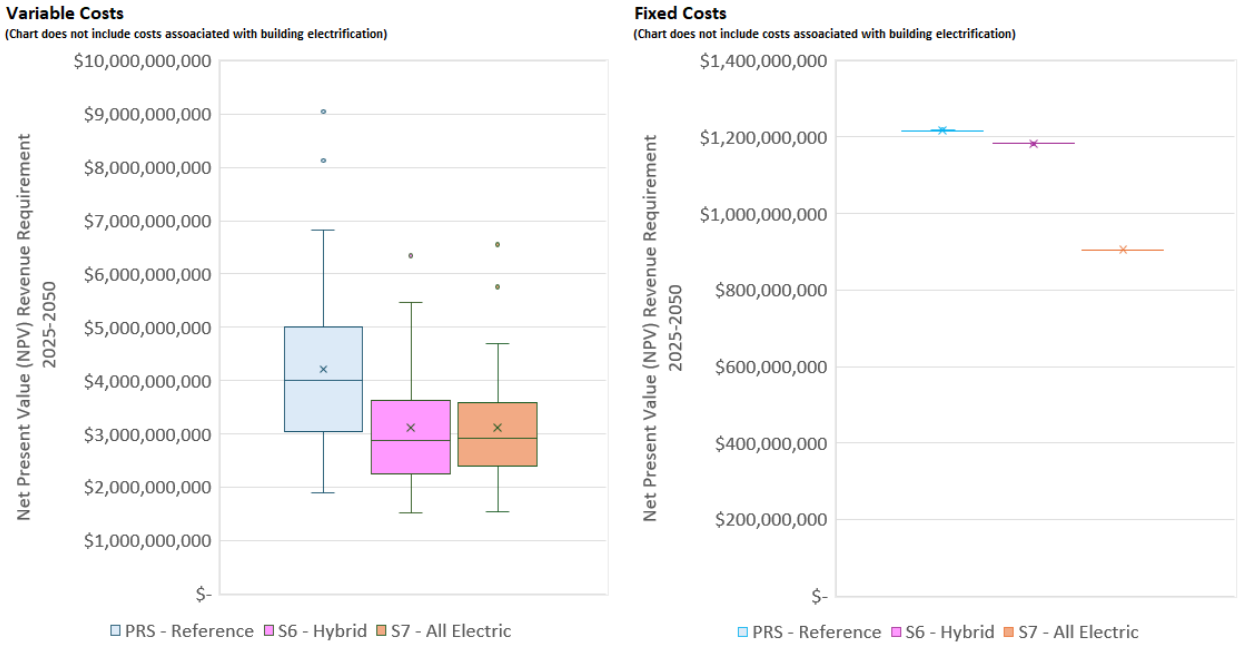
11.1.1.3 Monte Carlo Analysis 50 Draws within Preferred Resource Strategy, S6 – Hybrid, and S7-All Electric

One outcome of the 2022 IRP was a recommendation by OPUC staff to conduct Monte Carlo simulation within scenarios to help highlight the range of costs within those specific scenarios. NW Natural utilized 50 of the Monte Carlo simulations of gas prices, compliance resources costs, and compliance resource availability as inputs into the resource optimization model for the PRS, S6 – Hybrid, and S7 – All Electric scenarios.

The Company notes that the weather simulation was not included in this analysis. This exclusion was due to limited time and resources from both ICF and NW Natural that would have been required to develop variation in demand impacts from weather in the Hybrid and All-Electric scenarios. However, the Company compared the 50 draw results of the PRS in this section to the 300 draw PRS results (shown in Section 9.6), which included variation from weather, and the results did not significantly differ in the range or variance.

Figures 11.8 through 11.11 show box-and-whisker plots of NPV Cost for varying components across the 50 draws for the PRS, S6 – Hybrid, and S7 – All Electric scenarios. Note that the scale of the y-axis differs across each graph to highlight the differences across scenarios for each component. Figure 11.8 shows the variable and fixed costs across 50 simulations.

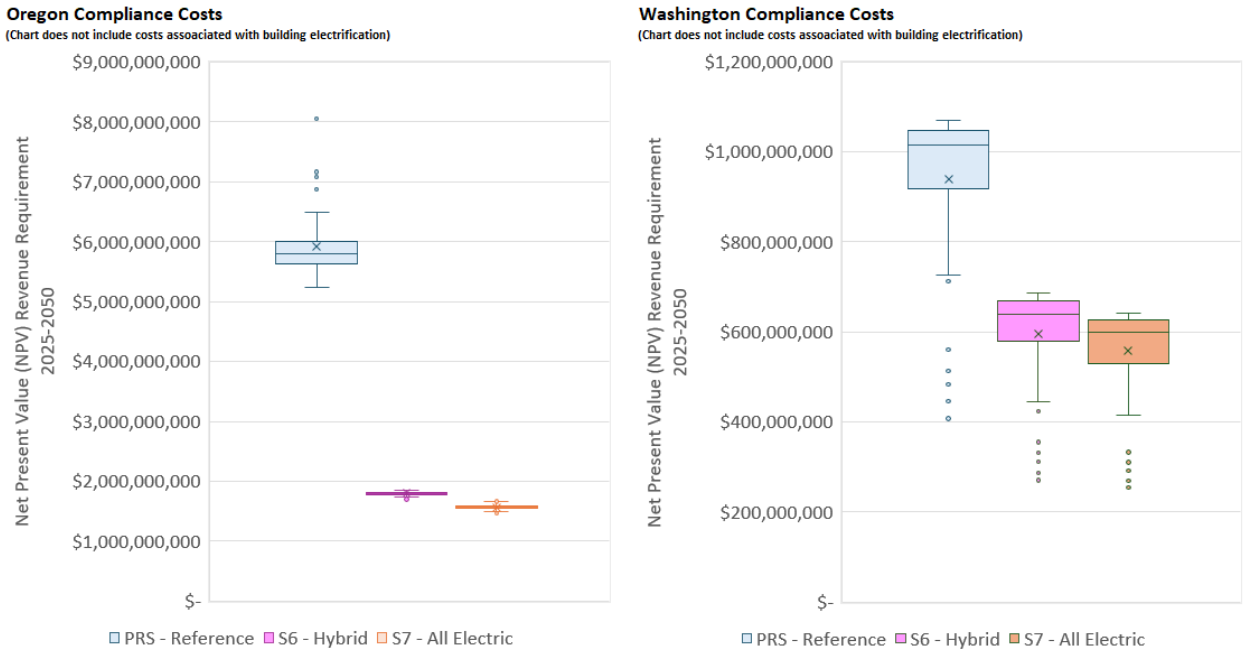
Figure 11.8: Monte Carlo Variable and Fixed Cost for PRS, S6, and S7 Scenarios



Gas commodity costs and variable shipping costs account for nearly all the modeled variable costs.[271] NW Natural did not run any simulations on upstream pipeline costs or Mist Recall costs; therefore, within a scenario the fixed costs for NW Natural have little to no variance.[272] Figure 11.8 does show how fixed costs vary across scenarios. In the S7-All Electric scenario, there is less Mist Recall and more release of upstream pipeline capacity, reducing the NPV of fixed costs paid by customers in this scenario.

Figure 11.9 shows the Monte Carlo results for the NPV of NW Natural's compliance resource costs in both Oregon and Washington by scenario.

Figure 11.9: Monte Carlo Compliance Resource Costs for PRS, S6, and S7 Scenarios by State



In both the S6 – Hybrid and S7 - All Electric scenarios, compliance resource requirements drop significantly in both Oregon and Washington. Due to this, the range of costs also decreases relative to the PRS scenario. This is especially true for Oregon, where both demand scenarios primarily rely on CCI purchases, which have a fixed purchase price. The little variation left in Oregon compliance costs is primarily driven by variation in costs of resources acquired to meet

[271] In the PRS commodity costs and variable costs associated with shipping the gas account for 99 percent of the variable cost. The other one percent is associated with variable cost to withdraw and inject gas into on-system storage facilities.

[272] Pipeline capacity costs and Mist Recall costs fluctuate and are subject to inflation, but do not face the same magnitude of uncertainty as other components, therefore, this IRP did not prioritize developing Monte Carlo simulations for these fixed resource costs.

limited voluntary RNG goals. Washington results also show a decrease in range due to lower compliance costs for the two demand scenarios but still maintain some uncertainty as the CCA allowance price can fluctuate based on market forces. All three scenarios for Washington exhibit a skewed left distribution that aligns with the findings discussed in Section 9.6.2 from the 300 draws.

NW Natural and ICF did not conduct any Monte Carlo simulations for the electrification study. The Company recognizes the future of electric transmission, generation, and distribution costs along with in-house equipment costs are highly uncertain and a Monte Carlo analysis could help quantify the range of uncertainty. Therefore, the omission of a Monte Carlo simulation, is not an oversight by NW Natural, but simply a limitation of time, resources, and scope of the electrification study. NW Natural would encourage further engagement through joint system planning on the cost ranges electric utilities may expect with significant level of building electrification. Despite not having any variation, Figure 11.10 shows the incremental electrification costs for each of the three scenarios. Note that the electrification costs for the PRS is zero, as this scenario does not include any incremental electrification beyond what is already being captured by the Reference Case demand.

Figure 11.10: Building Electrification Cost for PRS, S6, and S7 Scenarios

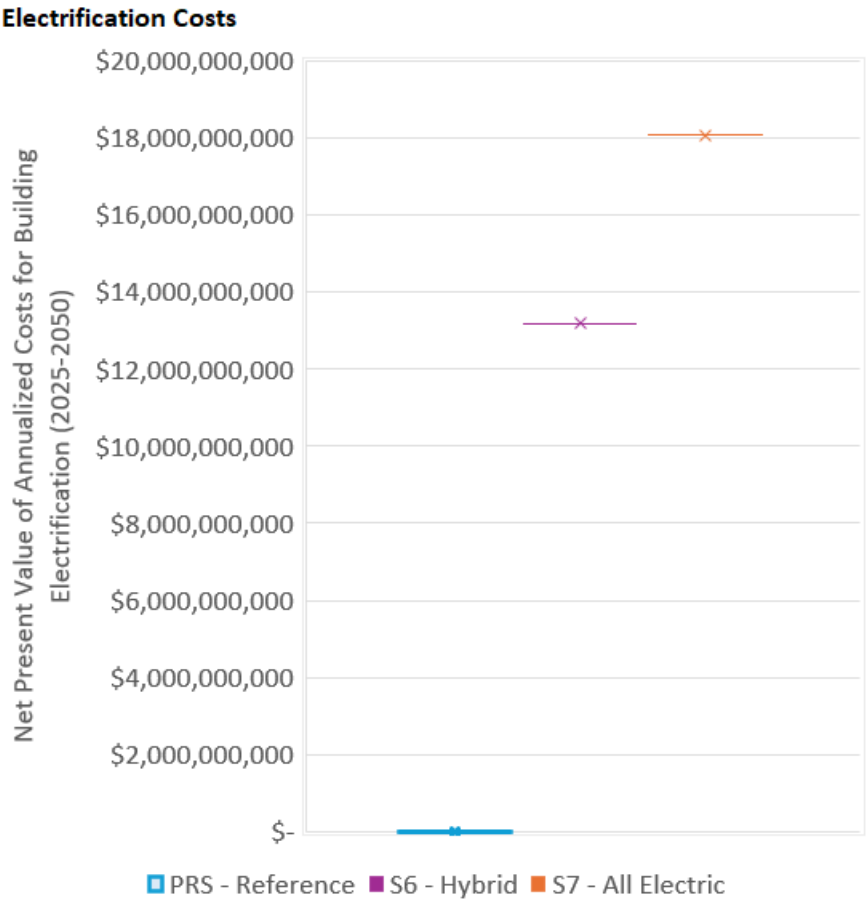
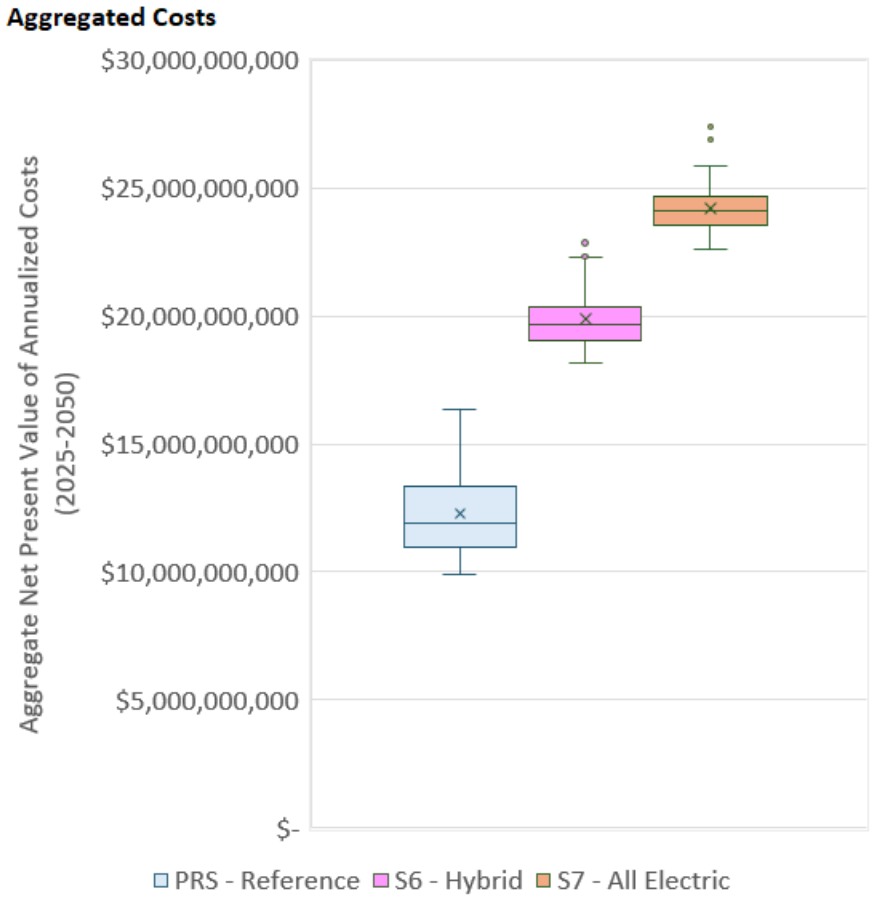


Figure 11.11 aggregates Figures 11.8 through Figures 11.10. where aggregated costs under the PRS is less total cost but has a larger range of $10-16 million, the S6-Hybrid scenario has a net present value range of $18-22 million, and the S7-All Electric scenario has a net present value range of $23-26 million.

Figure 11.11: Monte Carlo Aggregated Costs for PRS, S6, and S7 Scenarios



As noted above, a Monte Carlo analysis on the electric side of the analysis was not completed and therefore, the full range of electrification costs is not fully understood from this study. If a Monte Carlo analysis is completed to analyze the uncertainty of electricity costs (i.e., generation, transmission, and distribution costs) and end-use equipment costs (e.g., relative gas furnace and electric heat pump costs), the range of costs show in Figure 11.11 for the S6-Hybrid and S7-All Electric scenarios would be undoubtably greater. The variation in costs shown in Figure 11.11 are driven by 1) uncertainty of gas commodity prices, 2) uncertainty of costs for alternative fuels and CCUS, 3) and uncertainty of the availability of alternative fuels and CCUS.

While the box and whisker plots are helpful for illustrating the range of data, these charts fail to illustrate the correlation of costs across scenarios. For example, a future with high fuel costs in the PRS will also have high fuel costs in the S7-All electric scenario. Therefore, the maximum cost in the PRS is not comparable to the minimum cost in the S7-All electric scenario. However, when looking at the aggregated costs, there is no overlap in the distribution of net present

value costs between NW Natural's preferred resources strategy and the S6-Hybrid and S7-All Electric scenarios.

While this analysis is by no means a complete picture, Figure 11.11 helps demonstrate that uncertainty from these three cost drivers by themselves does not close the gap in total expected expenses from building electrification when comparing aggregated costs in the PRS and the S7-All Electric scenario.

11.1.2 Bill Impacts

This section provides a high-level indication of potential impacts to gas and electric bills from the electrification scenarios considered in this IRP. Both the electric and gas bills and rates warrant further investigation as it is recognized that not all costs have been included. By means of example, potential future accelerated depreciation and decommissioning costs on the gas side have not been included and similarly, incremental wildfire costs on the electric side have also not been included. It is hard for ICF and NW Natural to capture all cost expectations without more utility data, as well as assumptions on expected cost drivers such as wildfire and resiliency spending into the future. For both gas and electric bills, the impacts shown below are driven by the changes and results shown previously in this IRP.

The costs shown below highlight how both the gas and electric rate impacts are expected to be lowest in the Reference Case. The costs also show how among the electrification scenarios, the Hybrid approach has considerably lower bill impacts for both gas and electric customers than the All-Electric approach.

11.1.2.1 Gas Bill Impacts

As mentioned above, this is a simplified 'indicative' look at potential bill impacts for NW Natural. Despite the need for further analysis in these complicated areas, there was also a desire to explore the potential gas rate impacts based only on changes that were quantified by NW Natural and ICF in the IRP process.

What is included in the indicative rate/bill impacts:

- Changes to customer numbers and customer gas consumption levels from electrification scenarios.
- Changes to gas commodity and capacity costs from IRP PLEXOS modeling.
- Emissions compliance costs from PLEXOS modeling.
- Utility operating expenditures (OPEX) and capital expenditure (CAPEX) levels were assumed to grow with inflation, remaining flat at current levels out to 2050 in $Real terms. There are a lot of factors that play into these spending levels. For example,

the utility has PHMSA requirements and needs to maintain customer safety and provide reliable gas service to remaining customers even under an All-Electric scenario. All electrification scenarios in this study have some customers continuing to rely on the gas system in 2050, and if these customers are distributed throughout the Company's service area, it is a challenge to estimate how much of the pipeline network would no longer be needed (and what the cost to remove, or the avoided cost of not replacing at end of life, that infrastructure would be). The customer cost assumptions in the electrification scenarios also assumed all equipment could be replaced at its end-of-life, when the incremental cost would be lowest. So, any scenario that looked at trying to electrify segments of gas infrastructure would likely need to consider higher per customer equipment conversion costs for such an early replacement approach.

Examples of what is not included at this time:

- Changes to OPEX or CAPEX based on changes within the scenarios (e.g., lower customer growth), as discussed above.
- Additional costs to disconnect customers or potential costs to retire parts of the gas system, including higher electrification costs if customers need to be electrified before the end-of-life of their equipment (e.g., higher incremental cost).
- Regulatory changes to reduce and/or shift bill impacts, such as accelerated depreciation.
- Customer equipment conversion costs or an increase in utility spending to fund significant levels of customer incentives.

Figure 11.1 provides an overview of key impacts for residential NW Natural customers in Oregon and Washington from the changes discussed above. The top chart shows the estimated impacts in each scenario on residential gas rates for NW Natural customers. The Reference Case scenario has the lowest increase in natural gas rates. The bottom charts show the estimated annual gas bill impacts for average residential NW Natural customers, accounting for both the change in gas rates and the change in average per customer consumption levels. It should be noted that for the Hybrid scenario while average rates climb (given that utility costs are being spread over significantly smaller volumes of gas sales), average customer gas consumption also drops significantly, resulting in a decreasing average annual gas bill.[273]

[273] It should be noted here that these customers adopting hybrid systems would also have incremental electric costs, for the operation of their ASHP, which are not captured here. It should also be noted that this represents average customers in the Hybrid Scenario, but the majority of customers in this scenario adopt a hybrid heat pump

Figure 11.12: Indicative Impacts to NW Natural Gas Average Residential Gas Rates & Bills in Oregon and Washington (Real $2024)

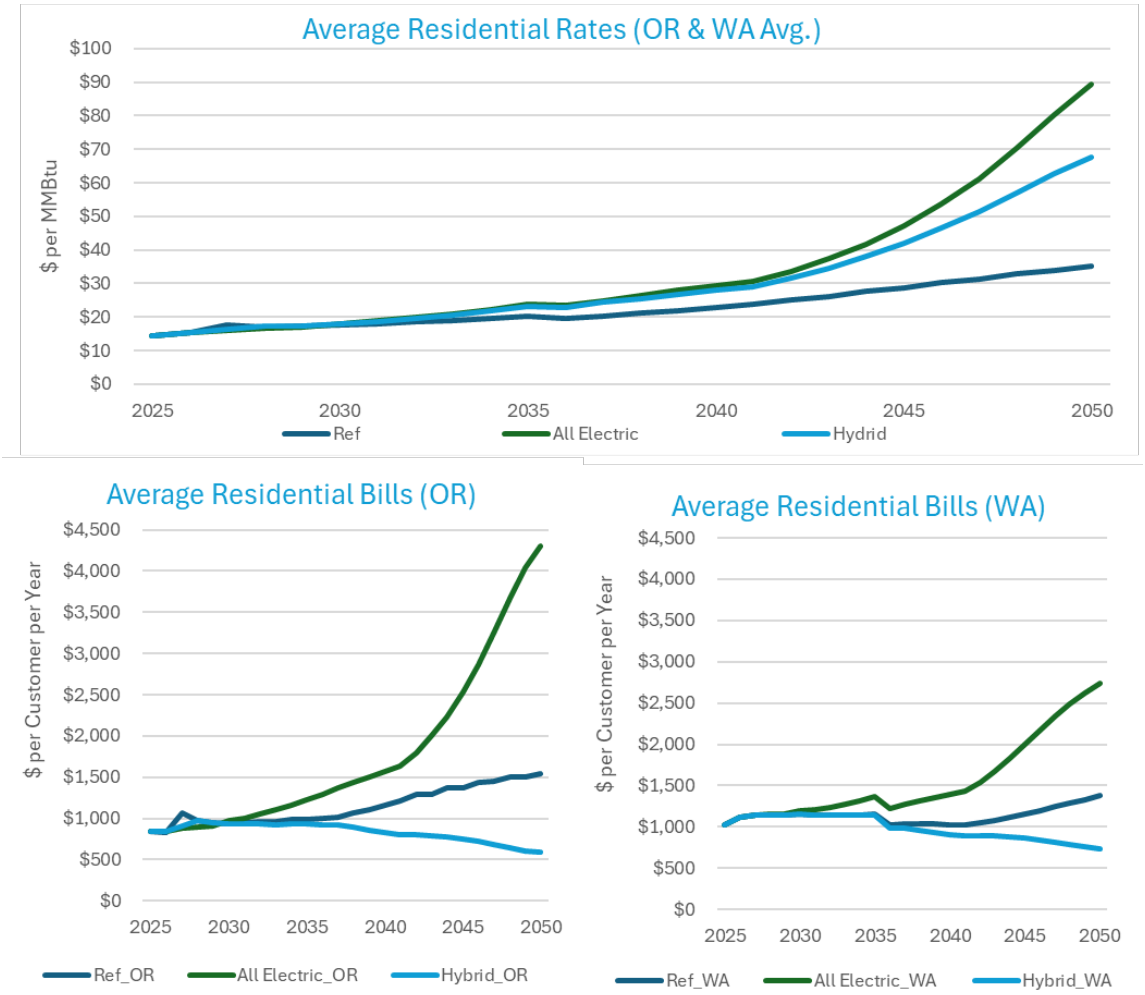
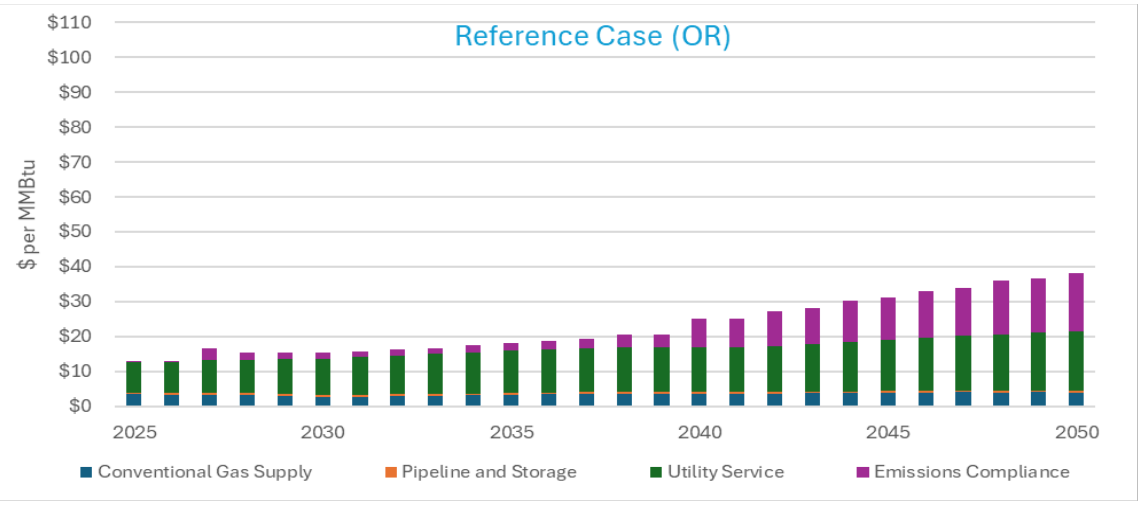


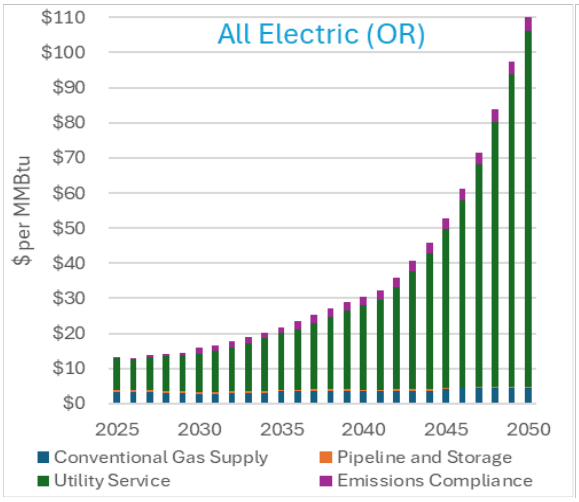
Figure 11.12 (Oregon) and Figure 11.13 (Washington) provide additional insight into what is driving the changes in the indicative gas rates compared to the previous charts. The 'total' line for each scenario in the figures below are what was compared in the previous figure. For the Reference Case, rate increases are primarily driven by emissions compliance costs. For the Hybrid and All-Electric scenarios, gas rates are driven up by utility service costs being spread over much smaller gas volumes. For these two electrification scenarios in Oregon, the reductions in NW Natural customer gas consumption significantly reduce the emissions compliance costs. However, in Washington, how the compliance requirements are structured

system and would have slightly lower than average annual gas costs, while absent regulatory or rate design changes, the smaller portion of customers that do not adopt a hybrid setup would have significantly higher annual gas bills than this average cost.

means that all of the scenarios see an increase in gas customers rates from emissions compliance costs.

Figure 11.13: Breakdown of Cost Drivers in NW Natural Gas Average Residential Gas Rates in Oregon





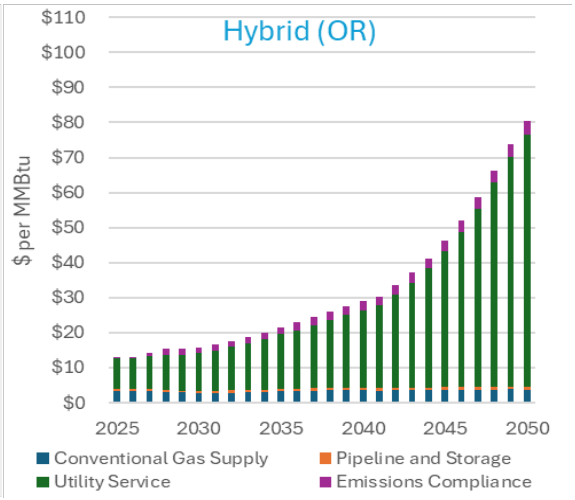
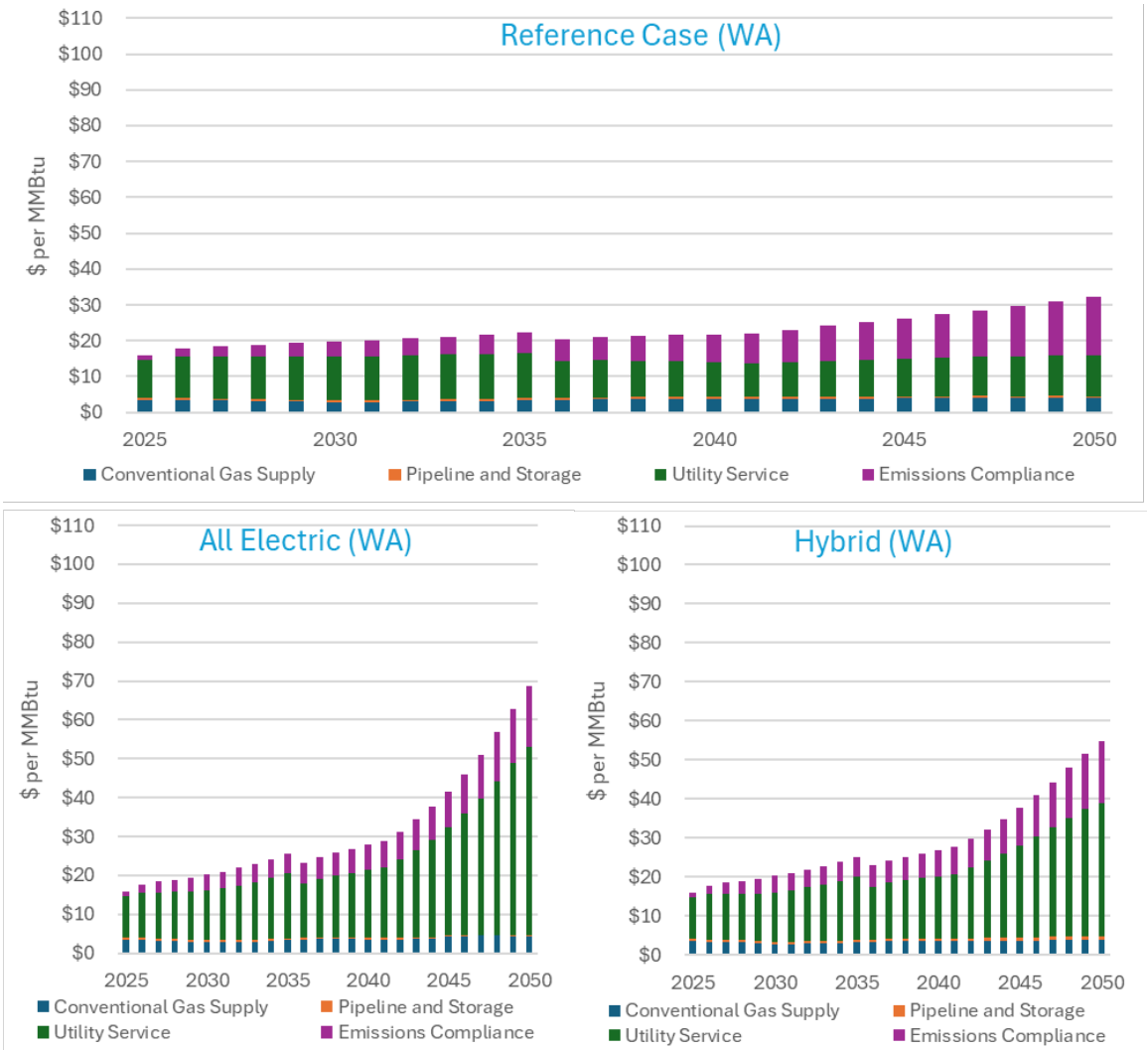


Figure 11.14: Breakdown of Cost Drivers in NW Natural Gas Average Residential Gas Rates in Washington



11.1.2.2 Electric Bill Impacts

In this section, an electric bill impact analysis was performed primarily based on PGE information.[274] This is not a PGE specific revenue requirements model and should not be viewed as such. PGE's publicly available filings provided the best available information to build a baseline for modeling representative of an electric utility in our shared service territory. These results are meant to be indicative rate and bill impacts, but any long range rate and bill impact analysis is going to be imprecise by its very nature. This exercise highlights the importance of

[274] Note that the assumptions behind the electric bill impact analysis were not reviewed by the AG.

joint system planning as future analysis would be best performed in collaboration with over-lapping electric utilities.

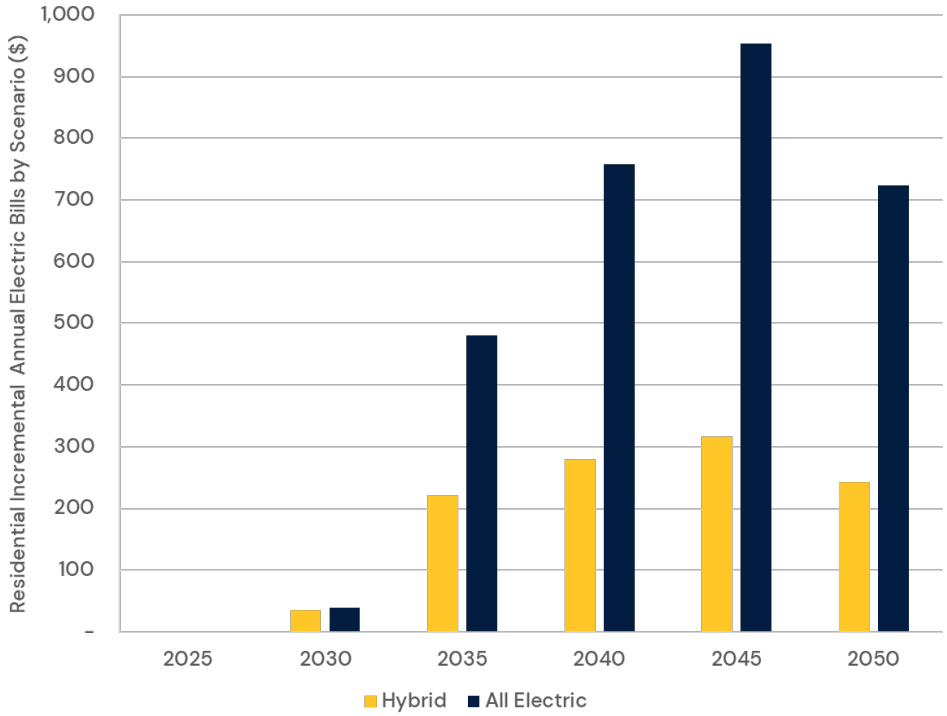
Electric bill impacts presented in this section are indicative of the bill impact for a PGE customer in Oregon. These are calculated based on the assumed average consumption per residential customer and the residential customer rates using the Reference Case, full electrification and hybrid electrification scenarios. Retail rate projections were developed at the utility level based on the projected revenue requirement and the load being served in each scenario.

These bill impacts serve as an example to estimate potential electric customer bill impacts for an electric utility where gas customers served by NW Natural convert from natural gas to electric heating, as modeled in the electrification scenarios. Many of the drivers impacting rates in PGE's service territory are similar for other utilities that serve NW Natural customers in Oregon and Washington, such as rising electric demand even absent load growth electrification, service of transmission and resource interconnection through BPA or neighboring regions, as well as clean energy requirements either through HB 2021 in Oregon or CETA in Washington. Utility-specific bill impacts will vary from utility to utility based on their specific set of supply options to meet their respective load growth and comply with policy requirement.

Electric bills relative to the Reference Case increase in both the Hybrid and the All-Electric electrification scenarios, with the greatest impacts at $317/year increase in 2045 for the Hybrid Scenario and over $950/year in the All-Electric Scenario.

As shown in Figure 11.15, bill impacts above the Reference Case are limited through 2030, as winter peak demand growth first catches up with summer peaks before increasing overall peak loads by 2035. After 2030, All-Electric scenario bill impacts increase rapidly as both the underlying electric rates increase due to the higher system costs and as customers have higher electric consumption due to the electrification of natural gas end uses. Hybrid Scenario bill impacts still increase even as peak investments are mitigated and rates increase much more moderately, due to higher sales on the annual level.

Figure 11.15: Residential Incremental Annual Electric Bill Impacts by Scenario



Bill impacts shown in Figure 11.15 represented average residential customer bill impacts, based on the projected annual use per customer that incorporates a static customer and baseline consumption estimate based 2023 residential customer data, with load added for electric vehicles[275] and the residential electrification impact of end use electrification. With this approach, the electrification driven load is spread across all residential customers. Among those customers, bill impacts will vary among customers that do and do not electrify. Customers that adopt electric space heating equipment will increase their annual consumption well beyond the average use per customer assumed for the bill impacts shown above. More specifically, this shows the residential bill impact for all residential customers regardless of whether they are or were gas customers and these costs would be in addition to any price increases from the Reference Case.

11.1.3 Price Elasticity of Demand and Consumer Response

There has been a broad range of stakeholder feedback and criticism for not incorporating price elasticity of demand—or more colloquially, price elasticity—into the resource planning models.

[275] Projected EV loads for all scenarios was broken out to residential and commercial sectors with a 70/30 split informed by PGE's transportation electrification plans.

This section aims to address these concerns, discuss the challenges of modeling price elasticity, and correct the misconception that price elasticity must be considered for adequate resource planning.

11.1.3.1 Short-run, Medium-run, and Long-run Price Elasticity

Price elasticity measures the responsiveness of demand for a given change in price. Specifically, in this IRP, price elasticity refers to a change in customer demand after a change in gas and electric utility rates, respectively. Utility rates are an important driver of three types of consumer choice, as illustrated in Table 11.1 below, which will ultimately impact resource planning. A NW Natural customer's demand profile is impacted by their decisions across three consumer choices.

Table 11.1: Customer Price Response Types

	Consumer Choice	Example	Time Scale
1	How much energy should I consume?	I will set my thermostat to keep my house at 68°F.	Short-run choice
2	What type of energy should I consume?	I will replace my oil furnace with a gas furnace.	Medium-run choice
3	Should I re-locate or shut/cease operations?	I will move to a location with lower energy costs.	Long-run choice

A customer's response to price signals, as it relates to natural gas utility rates, is defined as follows:

$$Price\ Elasiticy = \frac{Percentage\ change\ in\ Quantity\ Demanded}{Percentage\ change\ in\ Natural\ Gas\ Rates}$$

As indicated by Table 11.1, there is a customer demand response/choice associated with a given change in rates, and those choices occur on various time scales (indicated in the rightmost column). In the short-run, customers can quickly adjust how much natural gas they are using in response to price signals. In the medium-run customers can adjust their end-use equipment decisions in response to their expectations about future fuel costs across all fuel types. In the long-run, energy price signals can influence customer decisions to relocate or, in the case of commercial or industrial customers, cease operations. The exact timeframe of when individual customers face these decisions will vary, but the ordinal description of short-run, medium-run, and long-run time scales for these choices is consistent for all customers. Therefore, price elasticity metrics should be considered as three discrete types of elasticity: short-run price elasticity, medium-run price elasticity, and long-run price elasticity.

11.1.3.2 Measuring Price Elasticity

In aggregate, price elasticity for natural gas will be negative. This is known as the *law of demand*, which states that holding all else constant, as price increases, quantity demanded decreases.[276] Therefore, measuring price elasticity using data is only meaningful if you can control for other relevant factors driving customer choice. For instance, NW Natural rates typically change in November each year, which occurs precisely when temperatures get colder and customers start using more natural gas. Without controlling for temperature, an increase in rates in November will mechanically result in a positive short-term price elasticity metric and violate the law of demand. Table 11.2 further discusses the three types of price elasticities, the set of factors that would need to be controlled for, and NW Natural's ability to estimate these elasticities with available data.

Table 11.2: Possibility of Estimating Price Elasticity

	Type	Relevant Historical Data Required	Possibility to Estimate
1	Short-run	• Customer specific natural gas bills • Natural gas rates • Heating degree days • Customer Incomes	High
2	Medium-run	• All data used to estimate short-run • Customer specific electricity bills (i.e., data for individual customers) • Electric rates • Equipment cost (i.e., furnace costs, electric heat pump costs) net of incentives • Confirmation of existing customer specific equipment replacement and fuel type • Cooling degree days	Low
3	Long-run	• All data used to estimate short- and medium-run • All relevant cost data and benefits of living in, or operating a business in, other states/countries.	Very Low

NW Natural does not dispute that customers will respond to price signals; however, NW Natural serves a diverse set of over 800,000 customers that are all facing their own unique

[276] There are rare exceptions, known as the Giffen goods or Veblen goods, where price elasticities can be positive (i.e., violating the law of demand). These types of goods are not uncommon and occur under a specific set of conditions, which are not applicable to natural gas demand.

circumstances and constraints when making these three decisions. Their natural gas rate is merely one of many factors impacting individual customer choice. The notion that there is a specific tipping point of relative natural gas rates to electric rates that would cause all customers to immediately switch fuels is flawed given NW Natural's diverse customer base.

The Company does have the information needed to estimate short-run price elasticity; however, as Table 11.2 outlines, estimating medium- and long-run price elasticities become increasingly complex and unreasonable for NW Natural to conduct with any precision.

11.1.3.3 Incompatible to Incorporate into Existing IRP Models

If medium- and long-run price elasticities could indeed be estimated, which is currently beyond NW Natural's ability, incorporating price elasticity impacts into demand forecasting is not feasible. This is because existing IRP tools cannot endogenously solve for price and demand while minimizing the objective function (i.e. net present value costs). As the modeling is currently being conducted, cost impacts are a result of the least-cost IRP modeling, and the IRP load forecast is an input into the resource optimization models. Using the Company's existing tools, an iterative process would need to occur where incorporating price elasticity into the demand forecast that then feeds into the resource planning optimization model (which produces a new set of costs as an output), which then would re-inform the demand forecast. This process is untenable to conduct across all the various analyses required to ultimately produce the IRP results, with no guarantee that results would ever converge (i.e., how many iterations would be sufficient?).

Computable General Equilibrium (CGE) models, often used to model economy wide impacts, are better suited to handle these types of feedback loops as they incorporate the reaction from other sectors of the economy to balance any prices shocks. NW Natural is not aware of any utility that utilize CGE models for IRPs, which is most likely due to their complexity and reliance on generalized assumptions that are often hard for a single company to estimate. For example, NW Natural would not be able to estimate how the price of natural gas impacts LNG exports from Washington. These assumptions are beyond the scope of NW Natural's IRP.

11.1.3.4 Unnecessary to Incorporate into IRP Models

Given that medium-run and long-run price elasticities are unknowable and incorporating them into an iterative loop of demand and resource planning is infeasible, NW Natural uses scenario analysis to better understand the implications of reduced demand for resource planning. For instance, Scenario S7 – All-Electric Buildings is an extreme electrification scenario, where NW Natural's sales demand decreases by 85 percent by 2050 relative to 2025 and only 10 percent of customers remain on the system, which is remote given that NW Natural is still adding customers in both Oregon and Washington. This scenario is agnostic to why demand is

decreasing but plans resources accordingly. The Company views this scenario as a bookend that encapsulates any price driven impacts related to equipment choice, relocation, or ceasing business, where demand would drift down in the long-run. Moreover, given the results of the electrification study, customers may see electric utility rates increase relative to natural gas rates; thus, driving customers to retain their gas equipment. Even in municipalities that are limiting the installation of new gas equipment, this price elasticity effect would drive customers to spend more money to maintain existing gas systems. The Company believes the current scenarios are sufficient to cover the broad range of possible demand outcomes.

NW Natural reiterates that price signals do drive varying levels of customer behavior. The Company's IRP modeling and Action Plan do not discount this fact, but rather plans to adapt to it. Price signals and their impact on consumer preferences have existed throughout the Company's 166-year history and NW Natural has adjusted, and will continue to adjust, accordingly.

11.1.4 Combined Gas and Electric Results – Key Takeaways

1. **The energy transition already underway based on current policy requirements will be expensive and challenging for both the gas and electric systems. A successful energy transition for both gas and electric systems must consider and balance three fundamental needs and objectives: (1) risk reliability, and public health/safety, (2) cost and affordability, and (3) GHG emissions reduction.**

   All scenarios in this analysis, including NW Natural's IRP Reference Case, require major changes to meet GHG emissions reduction policies. The Reference Case accounts for electric utility impacts as it adapts to regulations like HB 2021, shifting to clean energy sources while addressing reliability concerns, EV demand, and data center expansion. The Reference Case also includes significant emissions compliance costs out to 2050 as NW Natural is required to bring increasing volumes of low-carbon gases, such as RNG and hydrogen, into the gas mix. So, for both the gas and electric systems, the Reference Case includes significant costs to comply with GHG emissions reduction policies.

   The Hybrid, and All-Electric scenarios —would raise costs above the Reference Case, have minimal impact on GHG emissions, and would create additional reliability risks by increasing capacity challenges for the electric system during critical winter periods.

   Given these challenges, policymakers must balance public health/safety risk and reliability, cost and affordability, and GHG emissions reduction. Ignoring any of these can lead to customer resistance and hinder acceptance. Pursuing energy infrastructure changes without ensuring reliability or affordability risks losing public support for emissions reduction efforts.

2. **Energy efficiency is a key pillar and essential for both the gas and electric systems and thus all cost-effective measures should be pursued.**

All of the scenarios in this analysis include assumptions for significant energy efficiency improvements. Average gas use per customer is assumed to drop more than 30 percent from 2025 to 2050, primarily driven by forecasted energy efficiency as discussed in Chapter 6. In the electrification scenarios, without these assumed energy efficiency improvements (which were applied equally to reduce building electrification load impacts), the annual and peak electric load and impacts from building electrification would be significantly higher. Measurement and verification of energy savings achieved by energy efficiency measures will be crucial to ensuring that compliance obligations are met and energy system planners have reliable load forecasts.

3. **The All-Electric Buildings scenario is the most expensive and likely the highest risk to ensuring reliability and public health/safety due to power outages. The Reference Case is the least expensive scenario and likely the lowest risk to maintaining reliability and public health/safety due to outages. The Hybrid scenario falls in between the Reference Case and the All-Electric Buildings scenario.**

As shown in Figure 11.11: Monte Carlo Aggregated Costs for PRS, S6, and S7 Scenarios above, the All-Electric scenario is the most expensive followed by the Hybrid scenario, with the PRS-Reference scenario, which focuses on decarbonizing the gas system, being the least cost scenario. As shown in Figure 11.1 Cumulative Total System Net Incremental Costs, the All-Electric Buildings scenario would increase costs for NW Natural's customers by a cumulative total of over $22 billion more than the Reference Case by 2050. The Hybrid scenario would increase costs for NW Natural's customers by a cumulative total of over $12 billion more than the Reference Case by 2050. While the cost increase is reduced with the Hybrid approach, both electrification scenarios increase costs more than the gas decarbonization approach to achieving similar emissions reductions taken in the Reference Case.

In addition to costs that were quantified in this analysis, there are additional reliability concerns and challenges for the electric system that could not be fully modelled in this study.[277] Electric systems in the region are already facing reliability challenges. There are anticipated effects due to multiple challenges, such as the transition to more intermittent

[277] The AG addressed the evolution of electric reliability in their comments. In particular, the movement towards improved analysis that addresses the magnitude and duration of outage probability in addition to frequency of events. Please see Appendix L for the AG letter.

non-dispatchable generation sources, managing substantial ongoing load growth even without building electrification, and the possible introduction of significant weather-dependent peak space heating electric loads that are considered essential. These transitions are expected to bring significant risks, and electric planning practices will likely need to evolve to maintain system reliability under these new conditions. Switching from dual gas-electric infrastructure to an all-electric system introduces added challenges and increases the impact of potential failures. These reliability concerns are especially significant for All-Electric Buildings, which create vastly higher peak winter demand dependent solely on the electric system.

4. **The Hybrid space heating scenario provides almost all the emissions reductions of All-Electric heating with significantly lower infrastructure costs and risks to reliability and public health/safety due to outages.**

The results of the analysis show very similar levels of net GHG reductions for the Hybrid and All-Electric Buildings scenarios. This reflects how the Hybrid scenario, where electric heat pumps are widely adopted but continue to benefit from gas back-up on coldest days, starts to decouple the number of gas utility customers from their GHG emissions. The combustion GHG emissions are based on how much gas those customers use, not how many customers there are, so customers adopting hybrid systems can still achieve significant reductions in gas consumption and the associated GHG emissions, even if they maintain gas back-up. Additionally, the minor differences that exist between gas consumption in these two electrification scenarios do not impact GHG emissions materially because NW Natural is also decarbonizing the gas supply over the planning period.

The Hybrid scenario has cumulative costs that are $9.4 billion less than the All-Electric Buildings scenario over the 2025 to 2050 period. Between these two scenarios, customer equipment conversion costs and gas utility savings are relatively similar. The primary driver of the cost difference between these two scenarios is the significantly higher electric peak demand that electric infrastructure needs to support in the All-Electric scenario.

5. **The Reference Case and Hybrid heating scenario retain future diversity and optionality of both the gas and electric systems. The Hybrid scenario requires a much smaller amount of gas to be decarbonized.**

A hybrid heating system uses gas and electric sources for optimal efficiency. Customers can benefit from both the high efficiencies of heat pumps (when it is not too cold) and the gas system's ability to heat, store and distribute large amounts of energy during cold periods. This combined approach can avoid significant electric infrastructure upgrade costs that would be necessary for the All-Electric Building scenario to meet peak winter demand loads.

The Hybrid scenario can still achieve significant reductions in natural gas demand, which in turn reduces the amount of low-carbon gases that NW Natural would require for its customers. The Hybrid scenario, where the gas system continues to be leveraged going forward, also eases transition challenges for industrial customers and other buildings customers who have not electrified, as they are not abruptly forced off a shrinking system.

6. **The Hybrid scenario, in addition to being a lower cost electrification approach, with lower risk to reliability, also provides the greatest flexibility to adjust to new future circumstances. As such regulatory model reforms should be explored under the Hybrid scenario to enable the gas system to be used as demand response or peaking capacity (in-home back-up capacity) for the electric system**

A hybrid heating approach also offers more optionality and flexibility than an All-Electric approach to adapting to changing circumstances. Forecasting for the year 2050 involves a considerable degree of uncertainty. Assumptions for savings, costs, technology availability, customer preferences, and more will change over time. The flexibility to adapt to changing circumstances and not to be locked into a single energy system can facilitate the reduction of GHG emissions.

This was illustrated by the GHG sensitivities in this analysis. The core scenarios are based on the assumption that HB 2021 will enable electricity emissions to reach near zero; however, this outcome may be difficult for electric utilities to attain. If electrification is pursued instead of decarbonizing the gas supply, but electricity is not fully decarbonized, greenhouse gas emissions could increase. This scenario could result in(i) reduced reliability of the energy system relative to the Reference Case, (ii) higher costs compared to the Reference Case that uses decarbonized gases and compliance instruments, (iii) greater greenhouse gas emissions than the Reference Case.

Furthermore, technologies such as hybrid heating can offer enhanced value when implemented through coordinated efforts between gas and electric utilities, necessitating some degree of joint planning. For instance, hybrid heating provides flexibility for electric utilities by enabling reliance on the system's gas backup not only during periods of extreme cold but also in response to other challenges, such as extended low wind generation or transmission outages. Within residences, the use of smart thermostats integrated with hybrid systems could optimize both cost effectiveness and emissions reductions across energy sources, while supporting the reliability of gas and electric networks. To maximize the benefits of hybrid heating systems, effective coordination between gas and electric utilities is essential.

In the Hybrid scenario, the number of gas residential and commercial customers only drops 13 percent by 2050 (in fact the number of space heating customers grows), but annual throughput in those customer segments decreases 80 percent over the same period. This would represent a dramatic shift for NW Natural, with the Company's energy infrastructure being leveraged to continue meeting the extreme peaks of winter space heating demand in order to avoid the need to build out new electric infrastructure to handle these spikes in heating demand. While this 'back-up' role for gas infrastructure may have lower overall costs and improved reliability and redundancy versus an All-Electric Buildings approach, a new regulatory model should be explored to ensure all parties, including gas customers, are compensated properly for their contributions to peak winter electric demand .

7. **Joint system planning of the gas and electric systems should be pursued with the purpose of identifying least cost options to meet consumer's energy needs, while retaining safety and reliability, maintaining affordability, and reducing emissions.**

Currently, regional electric utility IRPs include little building electrification, creating a lack of information about its potential effects on costs or power sector reliability. The electrification analysis was completed as part of this IRP. However, the results of this analysis do not substitute for electric utility data and modeling from individual IRPs. This analysis does provide information to support future integrated joint system gas and electric planning aimed at developing coordinated solutions to shared challenges.

Gas and electric infrastructure systems have different but complementary strengths and weaknesses when coordinated. Their growing interdependence can create challenges if not planned together. For instance, limited gas pipeline capacity into Oregon restricts how much in-state gas-fired generation can support electrification without expanding capacity.

There are also potential synergistic opportunities that both sectors could collaboratively pursue. For instance, the electric and gas utilities are each evaluating hydrogen as a compliance solution to address emissions reduction regulations. Jointly developing the necessary projects or infrastructure may result in more cost-effective outcomes.

11.1.5 Critical Assumptions

The scenarios in NW Natural's IRP have relied upon extensive studies and information from other parties (e.g. NREL, electric utility IRPs, etc.). As described earlier, the electric utility IRPs have not yet tackled the question of the extensive building electrification contemplated in the electrification scenarios studied here. ICF and NW Natural addressed this information gap using assumptions and various data sources from regional and national third parties.

As part of it process, NW Natural engaged with recognized experts in the electric utility industry with background and understanding of electric utility planning, operations, regulation and economics. This was the independent Advisory Group (AG) that focused particularly on the electric supply assumptions and analysis. The AG reviewed an early set of assumptions and generally concluded that many assumptions, including the least optimistic "current trends" assumptions, were too optimistic and inconsistent with their own personal experiences. The AG stated that the energy transition will be difficult, costly, and slow. They also raised concerns about shifting to a single energy system given current challenges in meeting carbon reduction targets and rising electricity demand. The AG's summary and recommendations are included in Appendix L.

To address the AG's concerns and outline key differences in future perspectives, NW Natural lists and explains all scenarios below, highlighting critical assumptions and their potential implications if inaccurate. This list is not exhaustive, and the All-Electric or other electrification scenarios are not contingent on all assumptions failing for a scenario to be considered unsuccessful. For instance, in the All-Electric scenario, incorrect assumptions could lead to higher customer costs, reduced reliability and energy security, and either insufficient or even increased GHG emissions if the electric sector cannot achieve planned reductions when additional load is shifted to it.

The AG did not examine the Reference Case for alternative gas decarbonization strategies beyond electrification. However, this section also discusses key assumptions underlying the Reference Case.

11.1.5.1 Things you Need to Believe or Accept – All-Electric Scenario

1. New electric generation resources will be developed at an unprecedented pace and scale. For example, in addition to significant load growth already expected in the electric sector, electrification of gas loads would require thousands and thousands of new MWs of wind, solar and firm dispatchable peaking plants and storage resources. The Northwest region has not increased its resources on this scale for several decades, and most existing resources were accumulated over more than fifty years. Utilities are already working to replace thousands of megawatts of coal plants as part of the clean energy transition. This would condense 50 years of post-WWII electric generation advances into just 10 years, with stricter environmental standards. Although wind and solar are now established commercially, they lack sufficient dispatchability to assure reliability. The necessary dispatchable peaking plants and clean fuels are not yet commercially viable, and current battery technology remains limited.

2. New electric transmission lines will be developed at an unprecedented pace and the additional barrier of complex, multi-state cost allocation issues will also be resolved quickly. Despite decades of public policy attempts to reduce permitting timelines, particularly at the federal level through transmission siting reforms, the buildout of transmission lines has shown to be extremely challenging. The primary transmission lines considered in this analysis, which are intended to deliver solar and wind energy to major load centers, currently require more than 20 years from inception to completion, if they are completed at all (e.g., Boardman to Hemingway). The IRP analysis assumes hundreds or thousands of miles of new transmission lines will be built in the next decade, even though BPA—the region's largest provider—has completed only a few dozen miles of 500 kV lines over recent decades and almost none lately. [278]
3. Resource development costs will continue to decrease, changes in tariffs will not increase costs, and current federal subsidies (e.g. IRA incentives) will be restored. Otherwise, costs will rise significantly over those calculated in this analysis.
4. Electric reliability and planning standards will remain unchanged, even though current data indicates updates are needed.
5. Commercial development of firm and dispatchable new resources will emerge such as hydrogen-fuel peakers with adequate pace, cost, scale, and storage capability.
6. Energy efficiency and new building stock turnover with associated energy savings will take place at a large scale.
7. Energy efficiency and electrification realization rates will be achieved despite evidence to the contrary, with heat pump efficiency gains in real-world conditions showing substantially lower savings than theoretical modeling suggests.[279]
8. Large land areas for renewable generation will be available and sited. The wind, solar, battery, and clean fuel plants considered here would require land several times larger than the City of Portland. One has to believe that this can be built over the next 10-20 years without running into community opposition.
9. Electric heat pumps will be available at a much greater scale and at a reasonable cost, and there will be a properly trained HVAC-contractor workforce available to implement a mass-scale conversion.

[278] See BPA presentation, "The Evolving Grid: Update on the State of Transmission," April 27, 2023, slide 18, https://www.bpa.gov/-/media/Aep/transmission/evolving-grid/042723-evolving-grid-bpat-final.pdf
[279] Energy Trust of Oregon, Summary of Recurve Analysis of Ducted Heat Pump Conversion Impacts, March 2020, available at: https://www.energytrust.org/wp-content/uploads/2021/04/Summary-Memo-of-Recurve-Ducted-Heat-Pump-Conversion-Impacts-Final.pdf; Energy Trust of Oregon, Billing Analysis of Residential Ductless Heat Pump Installations, August 2024, available at: https://www.energytrust.org/wp-content/uploads/2024/08/FINAL-REBA-DHP-Report-Memo-with-Output-Summaries.pdf; Regional Technical Forum, Air Source Heat Pump Measures, March 2025, available at: https://rtf.nwcouncil.org/calendar/rtf-meeting-2025-03-18/

10. Customers will accept mass-scale conversion of the HVAC infrastructure in their homes and businesses and they will agree to bear the substantial equipment and installation costs.
11. Rate increases caused by electrification, in addition to other existing cost increases for achieving carbon reduction goals and general system safety investments, would be politically palatable to policymakers and their constituents. In particular, low-income customers or renters who are unable to afford the direct costs of new equipment and higher rates will be fully subsided by other customers leading to higher costs for all other groups, including moderate-income and middle-class customers.

Both electrification scenarios rely on the stated assumptions, with the All-Electric scenario being especially dependent given its scale and the Hybrid scenario to a much lesser degree in especially related to electric winter peaking resources. By means of example, large land areas for renewable generation will still need to be available and sited, although not to the degree as full electrification. The Hybrid scenario also requires strong coordination between gas and electric sectors.

11.1.5.2 Things you Need to Believe or Accept – Reference Case Scenario or Gas Decarbonization

As explained in the introduction to this section, all the scenarios depend on assumptions including the Reference Case which is the gas decarbonization scenario.

1. CCIs will be available at the pace needed for compliance.
2. Clean fuels will be available at the pace and magnitude needed for compliance.
3. Changes in tariffs and current federal subsidies (e.g. IRA incentives) will not take place. If tariffs or current federal subsidies are eliminated or materially changed, it would substantially increase costs for hydrogen.
4. Energy efficiency and new building stock turnover with associated energy saving will take place at a large scale as assumed in this analysis.
5. Energy efficiency realization rates will be achieved as forecasted in this analysis.

Policymakers and customers will accept rate increases when alternative fuels are required for compliance.

Neither NW Natural nor the AG, which continued to express concern about electric transmission and supply assumptions, endorses the assumptions largely drawn from public sources and used in the analysis. Despite optimistic inputs, both electrification scenarios are found to be costlier and likely riskier than the Reference Case. The Hybrid scenario is lower cost than the All-Electric scenario and partially addresses the AG's concerns about meeting increased winter heating demand and reducing emissions. The Reference Case is the least cost

and likely lowest risk approach to meeting the carbon reduction targets while maintaining energy reliability.

11.1.6 Action Plan Themes and Recommended Direction

Bringing together all the analysis, takeaways, critical assumptions, and risks informs NW Natural's Long Term Resource Strategy and near-term action plan. More specifically, and as will be seen, it suggests the following themes:

- Knowing there are critical assumptions associated not only with an All-Electric scenario but also with a Hybrid scenario as well as a gas decarbonization or Reference Case scenario, it underscores the importance of optionality and flexibility. Optionality and flexibility are needed until costs, reliability, and system needs become clearer.
- Hybrid heating presents a promising approach to reducing emissions.
- Both gas and electric systems benefit from alternative fuels and thus, research and pilots to promote their development should be pursued.
- Joint system planning will continue to increase in importance as constraints and interdependencies on both the gas and electric systems grow.
- Without policies that recognize and address the need to balance affordability, reliability, and emissions reductions, there is potential for unfavorable outcomes—namely, increased carbon emissions, higher costs, and reduced reliability.

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11.2 Enabling Strategies

Given all the above, the Company has identified some enabling strategies to potentially mitigate risk. The sections below explore these strategies.

11.2.1 Geothermal Energy and Natural Gas Utilities

Geothermal energy represents a promising decarbonization option for NW Natural's gas customers, both at the single home/building level, as well as at a neighborhood scale utilizing thermal energy networks (TENs).

Eight states have passed legislation enabling natural gas utilities to explore diversifying into geothermal energy via thermal energy networks. On March 5, 2024, the Washington legislature unanimously passed HB 2131, which expanded utilities obligation to serve to include thermal energy networks. It also encouraged, via grant funding, utilities to apply for pilot sites by June 5, 2025.

NW Natural is evaluating the economics and logistics of deploying these systems to deliver low-carbon energy, how these technologies would align within the regulatory compact, and the Company's ability to leverage current LDC practices—for example, TEN installation requires similar drilling methods, and materials (e.g., poly pipe) as those used in natural gas delivery. However, deployment of geothermal technologies within the current regulatory compact of a natural gas utility is novel and payment by customers for these systems requires further consideration. NW Natural is investigating the cost-effectiveness of these systems to meet GHG compliance obligations in both Oregon and Washington.

11.2.1.1 Single Building Geothermal Systems[280]

Geothermal or ground-source heat pumps (GSHPs) circulate water through a closed loop of plastic pipe (or refrigerant through copper tubing) that is inserted into vertical boreholes or laid out horizontally in relatively shallow trenches. The fluid discharges heat from a building into the ground during summer and taps the ground's warmth during winter. This process, compared to conventional systems, reduces the amount of energy used by homes and commercial buildings by 40 to 70 percent (including fossil fuel use in the gas and electric grids) and can also heat water for domestic use. GSHPs use a small measure of electricity to move much greater volumes of renewable energy from the Earth to and from buildings. As a result, GSHPs deliver four to five times more energy to a home or commercial structure than the unit itself consumes from the power grid.

[280] This section is pulled from: https://geoexchange.org/geothermal-ecosystem/

Despite these benefits, these systems have higher upfront costs due to drilling and piping and are therefore not widely deployed. NW Natural is continuing to explore GSHPs as a potential cost-effective decarbonization option.

11.2.1.2 Networked Geothermal Systems (Thermal Energy Networks)

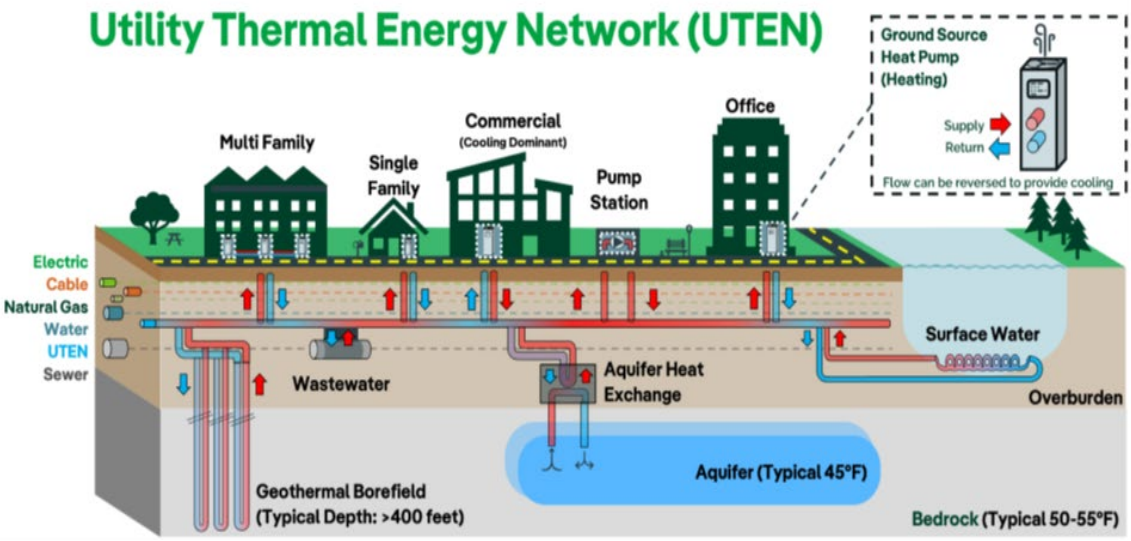
A Thermal Energy Network (TEN) is a utility-scale system that distributes heating and cooling through a shared underground piping infrastructure. Instead of relying on single building-based heating systems, TENs connect multiple buildings to a shared loop that uses pumps to circulate a heat-transfer fluid—typically water or a water-glycol mixture—through an ambient temperature loop connected to building heat exchangers. These systems leverage renewable and ambient sources of heat, such as underground water aquifers, wastewater energy recovery, or process waste heat recovery, to deliver simultaneous heating and cooling services.

TENs are anchored by thermal sources like geothermal boreholes, which serve as a long-term thermal battery, exchanging heat with the earth. A closed-loop system circulates fluid between buildings, each equipped with heat exchangers that extract or reject heat based on a building's current needs. This enables thermal load balancing—simultaneous cooling of one building while heating another—maximizing energy efficiency and reducing peak energy demand. Additionally, by leveraging low or ambient temperature fluid distribution, these networks facilitate decentralized energy sourcing, making them highly adaptable to available waste heat and renewable thermal resources.[281]

Figure 11.16 provides an illustration of a typical networked geothermal system.

[281] Transformative Strategies Consulting/Common Spark Consulting (May 2025), Thermal Energy Networks in the United States – Emerging Opportunities, Challenges, and Needs

Figure 11.16: Typical Thermal Energy Network



Source: NYSEG Utility Thermal Energy Network (UTEN) Fact Sheet

TENs offer potential benefits over fuel-based heating and cooling systems, including energy efficiency, cost savings, carbon reduction, and grid optimization. These systems are emerging as an alternative to traditional fuel-based heating and cooling, especially in urban and campus-style developments.

Ground-source heat pumps typically achieve upwards of 300–500 percent efficiency (Coefficient of Performance of 3-5+)[282], exceeding efficiencies for air sourced heat pumps. The networks themselves yield additional efficiencies by utilizing ambient temperature loops, which enable thermal exchange between buildings with diverse energy patterns or heating and cooling needs, thereby reducing the energy demands of the entire system. Because they harness ambient and renewable sources of heat, TENs are expected to have low and consistent operating costs throughout the year. TENs rely on renewable energy sources in the ground for heating and cooling. In this way, they align directly with climate goals and state-level decarbonization mandates.

Similar to single building Geothermal systems, a natural gas LDC is well positioned to help deploy TENs due to the similarities of laying pipeline for natural gas in the ground, however, like GSHPs, investments in TENs are novel to the regulatory compact. Regulatory support and new ratemaking will need to be explored.

[282] https://fresh-energy.org/whats-up-with-networked-geothermal

11.2.1 Hybrid Systems On-Going Pilots

Hybrid Systems (also referred to as "dual fuel systems") are HVAC systems that utilize electric air-source heat pump (ASHP) or ground-source heat pump (GSHP) equipment for heating and cooling while also maintaining gas equipment for supplemental or backup heat. Chapter 9 and Chapter 10 indicated hybrid systems can reduce GHG compliance cost on the gas system, while mitigating generation, transmission, distribution, and in-home equipment costs. Regional interest in hybrid systems continues to grow as they have the potential to reduce emissions and provide resiliency to customers.[283]

NW Natural is participating in several pilots to better understand how different hybrid systems perform and to quantify benefits associated with them.

11.2.2.1 Energy Trust Dual Fuel Air-Source Heat Pump Pilot

In 2023, Energy Trust of Oregon and all the funding utilities began working together on a dual fuel pilot. The original pilot scope was developed to target low-income homes without existing air-conditioning. Recruitment over 2024 was limited, which has led to an expansion of the income eligibility criteria. The goal is to install 50 single-speed air source heat pumps in homes of NW Natural customers that have existing high-efficiency gas furnaces. The primary research questions for this effort are to determine both the utility and customer costs and benefits. The final installations for this pilot will happen in 2025, enabling a savings evaluation to be performed over the next heating season.

11.2.2.2 Clark County Dual Fuel Air-Source Heat Pump Pilot

The Clark County Dual Fuel Pilot is being managed and delivered in partnership with the Northwest Energy Efficiency Alliance and Clark Public Utilities. This pilot is examining a hybrid application where an air-source heat pump is combined with an air handling unit and tankless gas water heater. The system is controlled with an iFlow Smart Controller that allows the heat pump and gas water heater to operate in parallel. Fifteen homes have been selected for this pilot.

The research objectives for this pilot are to evaluate the overall heating and water heating efficiency of this specific system along with the functionality of the iFlow Smart Controller. In addition to the efficiency research, demand response scenarios will also be performed on the systems. Final installations are currently underway.

[283] Northwest Energy Efficiency Alliance Dual-Fuel HVAC White Paper: https://neea.org/resource/dual-fuel-hvace-white-paper/; Energir Dual Fuel Grants: https://energir.com/en/residential/dual-energy Energir Dual Fuel Grants: https://energir.com/en/residential/dual-energy; Cascade Natural Gas Hybrid Pilot, see OPUC Docket ADV 1710: https://edocs.puc.state.or.us/efdocs/UAA/uaa335085026.pdf

11.2.2 Potential Pilot Programs and Studies

The sensitivity, scenario, and Monte Carlo analyses conducted in this IRP have provided numerous insights into the capacity, energy, and compliance resources required in the near-term (i.e., next five years). However, the resource requirements further out in the future remain uncertain. Despite this uncertainty, the analysis shows some common elements:

- Hybrid HVAC systems can help mitigate and lower costly investments for electric utilities to meet increasing winter peak demand, lower in-home customer equipment costs, and help NW Natural reduce its carbon compliance obligations, by utilizing the existing gas infrastructure to deliver energy during peak demand periods.
- Energy efficiency is a key resource to meet capacity, energy, and compliance requirements.
- Carbon Capture Utilization and Storage from the Company's larger customers is likely a least-cost solution to meeting GHG compliance requirements.
- The Company will need to rely on the development of alternative fuels to decarbonize the energy flowing to customers.

The levels of hybrid deployment, energy efficiency, CCUS, and alternative fuels needed over the planning horizon are not trivial. Work to develop programs and projects needs to start today to enable and support a resilient and decarbonized energy economy. To maximize progress towards these aims, as shown in Table 11.3, this section discusses three pilot projects, and two in-depth studies NW Natural recommends pursuing in the interests of customers.

Table 11.3: Potential Pilots and Studies Proposed in the 2025 IRP

Potential Pilot / Study	Status
Deployment of Hybrid Systems	Yet to be Scoped
Commercial Heat Pump Pilot	Scoped and Ready
Carbon Capture Utilization and Storage/Sequestration Building Heating Systems Pilot for Large Commercial Customers	Scoped and Ready
CCUS Geological Study	Scoped and Ready
Synthetic Methane from Biomass in Depth Study	Scoped and Ready

11.2.2.1 *Deployment of Hybrid Systems*

Investing in hybrid HVAC systems in either new construction or existing buildings can offer a capacity resource or an avoided peak load for electric utilities facing winter peak capacity

constraints. This requires joint system planning and deployment by NW Natural and any overlapping electric utility. An example of this type of coordination is the Clark County pilot described in the previous section. NW Natural would like to explore deployment of a hybrid incentive program, where—with an additional electric utility partner—either cost-effective incentive payments could be offered and/or demand response/capacity payments could be provided by electric utility partner to fund hybrid system installations. Purpose, objectives, overall scope, and costs for this pilot would be developed and included in a subsequent filing at the OPUC or WUTC.

11.2.2.2 *Commercial Heat Pump Pilot*

Energy efficiency is one of the pillars of decarbonization. Initiating pilot projects for gas heat pumps in commercial installations can capture therms savings from energy efficiency. More gas heat pumps (GHP) pilot installations are needed to influence market transformation toward this high-efficiency technology. The impact of widespread adoption of this technology will reduce demand on the gas and electric grids, reduce greenhouse gas emissions, and maintain the performance and reliability expectations our customers demand from fuel-fired equipment. Additionally, the validation of gas heat pumps in the market will lead the way toward consideration of commercial hybrid (electric plus gas) solutions.

Leveraging a NEEA sponsored Commercial Gas Heat Pump Pilot, NW Natural proposes a pilot that would install up to six commercial gas fired heat pumps in the NW Natural service territory. These pilot projects would be leveraged to gather data that would inform a commercial heat pump strategy.

This proposal aims to justify the initiation of pilot projects for GHPs in various commercial installations. The primary objectives are to evaluate the performance of GHPs under different scenarios, inform a broader strategy to reduce gas use and greenhouse gas (GHG) emissions, and demonstrate cost-effectiveness and proof of concept to the commercial market.

For more detailed information about the Commercial Heat Pump Pilot, please see Appendix M.

11.2.2.3 Carbon Capture Utilization and Storage/Sequestration Building Heating Systems Pilot for Large Commercial Customers

NW Natural aims to develop a carbon capture pilot to evaluate the feasibility of post-combustion carbon capture as a scalable and cost-effective decarbonization strategy for commercial and industrial customers.

This pilot aligns with results from our portfolio analysis and with the findings of the ICF Alternative Fuel Study which points to carbon capture, utilization, and storage (CCUS) as a likely least-cost pathway for NW Natural to decarbonize. It further supports the Company's

compliance to meet emissions targets under the CPP and it could add to local and state efforts to achieve climate goals.

Buildings are a major source of greenhouse gas (GHG) emissions. As they often rely on centralized systems like steam boilers, carbon capture could provide a viable option by reducing emissions from existing systems without major retrofits.

The potential scale is significant: if the pilot demonstrates effective CO2 removal with reasonable cost and operational reliability, the technology could be deployed across a broad range of large energy users: hospitals, universities, manufacturing facilities, and more, which are key to NW Natural decarbonization efforts, as commercial and industrial customers represent 38 percent of NW Natural's gas sales.

For more detailed information about this CCUS Pilot, please see Appendix M.

11.2.2.4 Initiate Geological Screening Study for CO2 Sequestration in Northwest Oregon

As seen in many of the scenarios and sensitivities, including the preferred portfolio (i.e., resources selected in PRS.a), carbon capture, utilization, and storage (CCUS) has been identified as a likely least-cost pathway for achieving deep emissions reductions for the utility. In alignment with this finding, the Company seeks to evaluate in-state geologic formations for their potential to serve as long-term CO2 storage reservoirs.

According to the Oregon Department of Geology and Mineral Industries (DOGAMI), two areas show significant potential for future Geologic Carbon Sequestration in the Pacific Northwest:

1. Western Oregon and Washington Basins
2. Columbia Basin of Eastern Oregon and Washington.

The geological screening study would leverage the existing geologic and geophysical data compiled in the 2022 consultant report to evaluate different CO2 sequestration methods. The study aims to:

- Validate the suitability of the Sunset Highway Sandstone for CO2 storage
- Evaluate the geological suitability and technical feasibility of Mist for CO2 storage via mineralization
- Identify data gaps and prioritize areas for further site characterization
- Estimate potential storage capacity and containment risks
- Recommend next steps, including seismic survey design and permitting needs.

The proposed study includes activities such as data retrieval, sampling, rock dissolution tests, reservoir modeling, legislation, licenses and permits assessment, techno-economic assessment, among others.

Additional details on the scope of the study can be found in Appendix M.

11.2.3.5 Woody Biomass-Derived Synthetic Methane Feasibility Study

Given the significant portion of synthetic methane from biomass in the preferred portfolio identified in the PRS.a, the Company recommends conducting a detailed 12-month study assessing woody biomass feedstocks in Oregon for synthetic methane production via gasification + syngas methanation and CO2 + green hydrogen methanation to support the near-term, least-cost decarbonization of the state's gas system. The action follows the finding of woody biomass derived synthetic gas as a potential least cost compliance resource in the PRS.

The Oregon Department of Energy's (ODOE) 2018 *Biogas and Renewable Natural Gas Inventory* identified over 40 billion cubic feet (BCF) of theoretical renewable gas potential statewide, with more than 75 percent attributable to woody biomass and other thermochemical feedstocks. The report noted the critical importance of coupling these resources with appropriate conversion technologies such as gasification and methanation. Since that time, forest health, wildfire severity, and decarbonization urgency have all intensified.

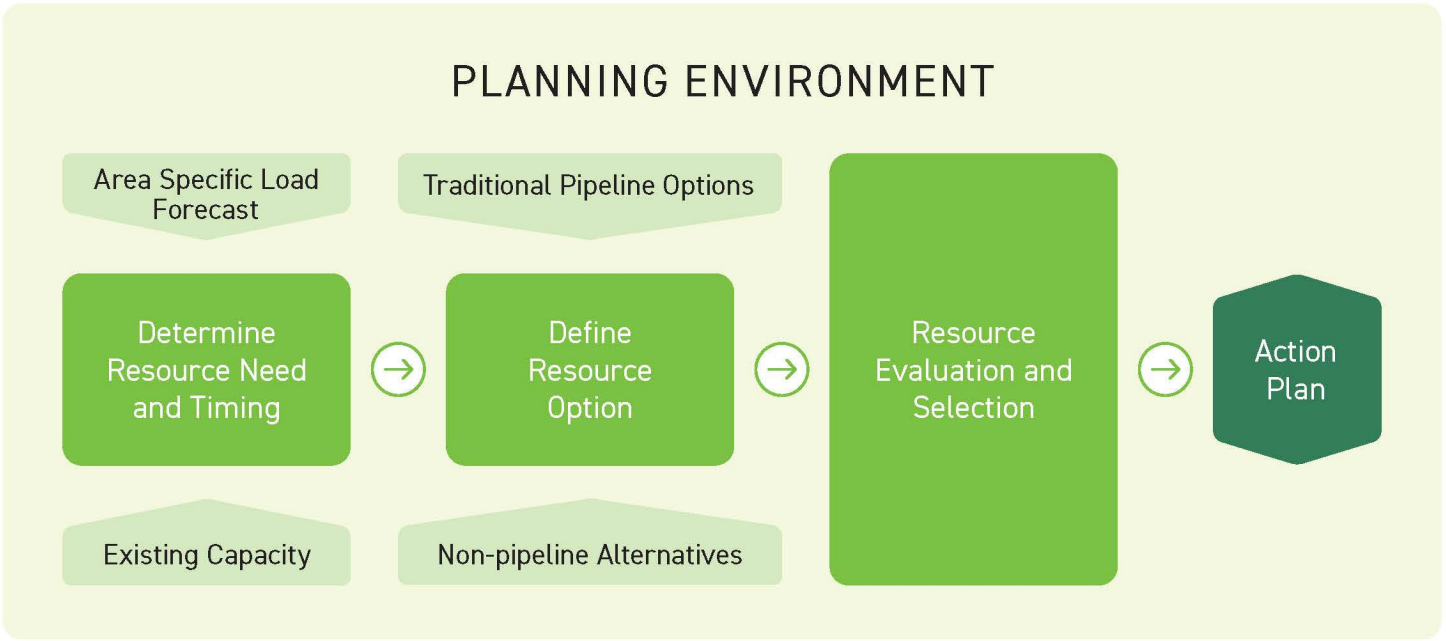
Oregon's forests, particularly in fire-prone regions of the Cascade Foothills and Klamath Basin, have accumulated hazardous fuels due to decades of fire suppression and disease. The strategic removal of low-value forest biomass not only reduces wildfire intensity and frequency but also generates a valuable renewable energy feedstock.

Synthetic methane (also called synthetic natural gas or SNG), created through biomass gasification or CO2 methanation with electrolytic hydrogen, enables a drop-in substitute for fossil natural gas. Synthetic methane is fully compatible with existing pipelines, appliances, and end-use infrastructure. This reduces transition friction while leveraging the state's existing energy delivery system.

This type of study is a critical next step in exploring the value, scale, and readiness of woody biomass-based synthetic methane as a foundational decarbonization resource in Oregon's integrated energy system.

For more details on the scope of this study please see Appendix M.

12 | Distribution System



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Chapters 4 through 11 focus on ensuring enough resources are available and secured to get enough energy on NW Natural's gas grid every day of the year to meet customer needs. This chapter discusses how needs and options are assessed to distribute gas on the grid so that each customer can be served reliably during any weather that could be reasonably expected.

12.1 Distribution System Planning

Distribution System Planning in this IRP is separate (but not fully independent) from the system-wide planning and PLEXOS® modeling discussed throughout the rest of the IRP. It involves identifying system needs at the distribution system level, assessing both demand-side and supply-side solutions, and making risk-adjusted resource selections. Some of the unique aspects of distribution system planning include:

- **Location Dependent Demand Forecasting:** Predicts peak hour usage for an area, net of demand side actions
- **Supply Modeling:** Simulates flows and pressures from gas sources on the gas network based on actual pipeline alignments and attributes
- **System Modeling:** Use of different software/modeling tools to simulate system under peak conditions and/or use field measurements during cold periods
- **Planning Criterial Application:** Applies a consistent approach to identify areas of concern on the distribution network

NW Natural historically used a "just-in-time" distribution system planning approach, responding to low pressure system issues as they occurred. The "just-in-time" reactive approach introduces risks to customers because customers being served in these areas may experience service interruptions before mitigation measures are in place. NW Natural has shifted from a "just-in-time" to a forward-looking distribution system planning process that looks at least five years ahead, allowing NW Natural to anticipate future needs. The forward-looking planning approach allows for improved integration of non-pipeline demand-side solutions as these projects take longer to implement and produce reliable peak load reductions. The transition began with NW Natural's Geographically Targeted Energy Efficiency (GeoTEE) pilot and has been a lengthy transition over several years. Although the forward looking planning process has been implemented, the system will continuously improve as more data is collected, and customer usage patterns are characterized.

NW Natural has improved its system modeling capabilities. A major improvement involves completing the implementation of Customer Management Module (CMM) into the Company's pressure system modeling software, Synergi™ Gas. CMM acts as a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ Gas,

enabling more efficient planning and system analysis. This improvement was successfully implemented across NW Natural's entire service territory in the third quarter of 2023. Details on the integration of CMM are provided in Section 12.4.2.

NW Natural conducts an annual review and updates the Forward Looking Distribution System Plan, which focuses on larger projects that may exceed design capacity in the future due to growth. This plan provides budgetary forecasts and establishes a Company-wide vision for prioritizing the distribution system planning process. The Forward Looking Distribution System Plan plays a key role in selecting projects for inclusion in the Integrated Resource Plan (IRP). Project selection is based on factors such as estimated cost, prioritization needs, supply implications, and timing considerations. NW Natural's Forward Looking Distribution System Plan is included in Appendix J of this document. Further details on this process will be discussed later in the document.

This chapter provides an overview of NW Natural's distribution system planning process, including the needs assessment process and tools used. It highlights improvements in engineering and computer modeling methods that support distribution system planning. Additionally, the chapter discusses existing and future distribution system resources, including both pipeline and non-pipeline solutions. The chapter concludes with an analysis of both pipeline and non-pipeline alternatives for areas identified in the Forward Looking Distribution System Plan.

12.2 Distribution System Planning Process

NW Natural's distribution system planning process is designed to provide reliable service by:

- Operating a distribution system capable of safely meeting firm service customers' peak hour demands
- Minimizing system reinforcement costs by selecting the most cost-effective alternative
- Proactively planning for future needs in a timely fashion
- Addressing distribution system needs related to localized customer demand

The goal of the distribution system planning is to ensure that the system can reliably meet peak hour gas demands for firm sales and firm transportation service customers, and to identify capacity constraints before service to customers is impacted. The planning process evaluates deficiencies during peak winter hour conditions, providing solutions, either demand-side or supply-side, to serve current localized forecasted firm energy requirements. Distribution system planning plays a critical role in identifying capacity constraints within the Company's gas network and develops solutions to address those weaknesses on the system. By knowing where and under what conditions pressure problems may occur, NW Natural can incorporate

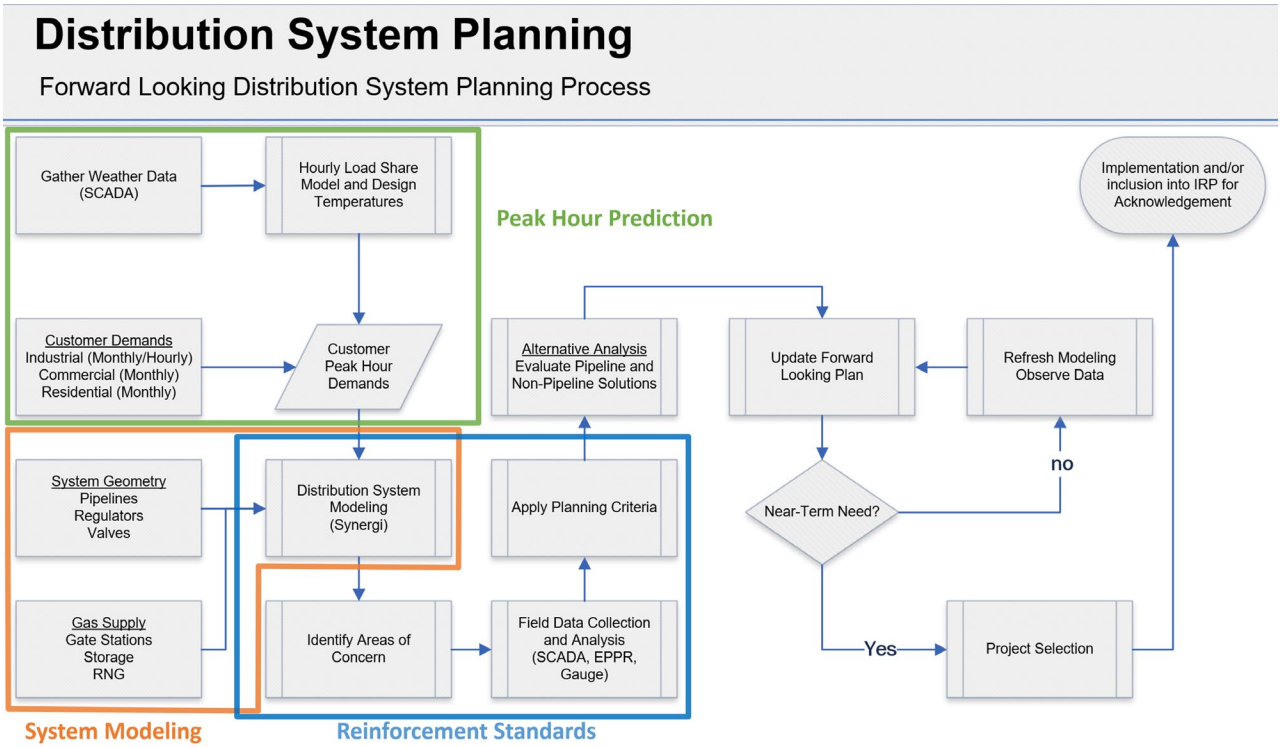
necessary projects into annual budgets and project planning. These planned solutions avoid costly reactive and disruptive emergency solutions.

NW Natural works closely with a variety of internal and external stakeholders including marketing departments, large customer account representatives, construction crews, external economic development and planning agencies, energy efficiency program administrators, and engineering design and construction firms, to develop feasible and reliable solutions for distribution system reliability concerns. These solutions can be either *non-pipeline* or *pipeline* solutions. Typical pipeline solutions include various forms of reinforcements, replacements, or expansions of NW Natural's distribution system. Non-pipeline solutions can be either supply-side solutions, for example deployment of a mobile CNG supply vehicle, or demand-side solutions, for example geographically targeted interpretability agreements. The costs, timing, and reliability varies across each of these options for distribution system planning and the suite of these options is discussed later in this chapter.

Distribution system planning follows the same overall process as system resource planning. The first step is identifying the need for additional resources. This step involves predicting peak hour customer demand and identifying potential constraints on the existing distribution system. After a need is identified, potential solutions are proposed that are capable of addressing the distribution system deficiency. A cost benefit analysis is conducted assessing the costs, risks, and benefits of the viable alternatives. The planning process is continuous and incorporates known public works projects, anticipated customer growth, and other relevant factors into NW Natural's construction forecasts.

Distribution system planning uses a pressure modeling software, Synergi™ Gas, to model pressure dynamics of actual pipe placement, specifications, and geographic location, along with peak hour usage estimates for the area in question (net of expected energy efficiency savings and demand response resources). Essentially this simulates the system under peak conditions, calibrates this simulation with actual field measurements during cold weather events, and is evaluated using a system planning criteria to identify areas of concern. This process helps identify areas at risk before those criteria are exceeded under actual peak conditions. Figure 12.1 presents a flow diagram for the distribution system planning process.

Figure 12.1: Distribution System Planning Process



As discussed in the introduction section of the chapter, NW Natural develops the Forward Looking Distribution System Plan that outlines areas of the distribution system under investigation. Areas for investigation do not currently violate system reinforcement criteria but are areas where the gas distribution system is approaching these thresholds and/or is showing evidence of growth in demand that could reach system monitoring thresholds within the next five years or beyond as will be discussed below. These areas are being monitored based on distribution system modeling under peak conditions, where growth may lead to safety or reliability concerns if system reinforcement standards are exceeded. In addition to identifying areas for cold weather observation, the Forward Looking Distribution Plan outlines the best (i.e., least-cost least-risk) solution for each geographic area being monitored.

Areas can be categorized as a near term or long-term potential need. Areas identified as long-term needs are projected to exceed design capacity of the distribution system within a four to ten year timeframe. For long-term need areas, NW Natural prepares preliminary modeling documentation and high-level cost estimates for potential non-pipeline and pipeline solutions. At the long-term stage project planning remains conceptual. Areas facing a near-term need are projected to have capacity constraints within a one to three year timeframe. For areas with near-term needs, NW Natural conducts a detailed planning process that includes system

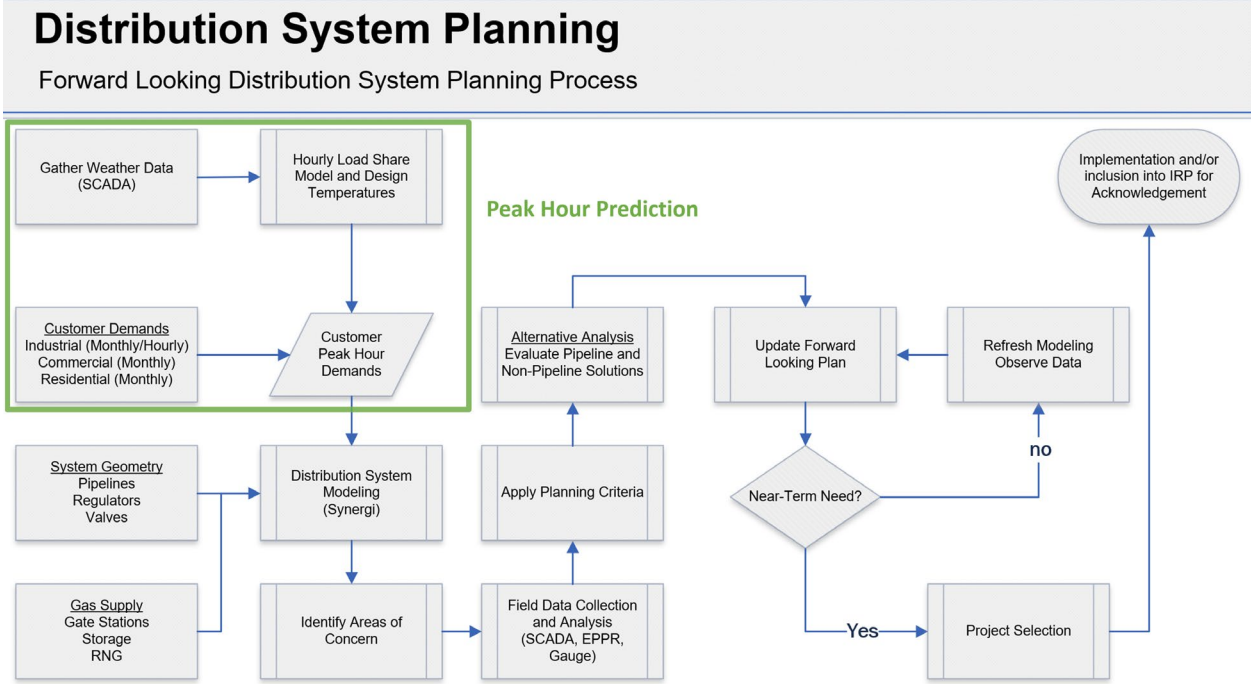
modeling, pressure read documentation, the most feasible pipeline solution with more precise cost estimates and an evaluation of more non-pipeline alternatives, which are discussed later in this chapter.

Depending on the scope, magnitude of the investment, or the lead time needed to implement a pipeline solution; any project on the Forward Looking Distribution Plan may be included for a full IRP evaluation. Generally, this happens to be the higher priority near-term violation areas being monitored. However, regardless of the lead times needed to implement a distribution system solution (either demand-side or supply-side), detailed cost and risk assessments, along with a robust alternatives analysis are conducted for any solutions that would be included in an IRP Action Plan.

12.3 Peak Hour Prediction and Forecasting

As shown in Figure 12.2, peak hour modeling methodology generally follows that of the peak day forecasts while incorporating more granular geographic and time dimensions. NW Natural designs its gas distribution system to meet predicted peak hourly demands, ensuring reliable supply for firm customers during the highest usage periods. Designing for peak hourly usage is essential because natural gas consumption varies throughout the day, with demand typically peaking during the morning burn period between 6:00 AM and 10:00 AM, when firm customers have the highest energy needs. During the morning burn, increased flow rates lead to higher gas velocities, which in turn produces greater pressure drops across gas facilities. If the pressure on the distribution system falls below the minimum pressures required for customer equipment, outages can occur. By designing the system to handle peak hourly demand, NW Natural can maintain adequate pressure levels, minimizing the risk of service disruptions due to insufficient system capacity.

Figure 12.2: Forward Looking Plan Peak Hour Prediction



Synergi™ Gas demand forecasting incorporates distinct load centers, each defined by a unique weather zone. Each weather zone represents a specific geographical area where customers experience similar weather patterns, allowing for more precise demand forecasting for peak hour system planning. These weather zones account for variations in peak design temperatures across NW Natural's service territory, ensuring that the distribution system is designed to the specific demand characteristics of each weather zone.

Table 12.1 illustrates the peak HDDs for each weather zone, which demonstrates how peak design temperatures differ across NW Natural's service territory.[284] Each weather zone has a unique non-coincidental design peak HDD, reflecting localized climate conditions. Typically, individual customers within weather zones with higher HDDs experience greater peak gas demand, as colder temperatures lead to increased heating needs. Conversely, areas with lower HDDs generally exhibit lower peak demand. NW Natural can optimize system reliability by forecasting customer demands based on specific HDD. The benefit of analyzing the distribution system for unique weather zones is that it allows NW natural to propose solutions to meet the specific needs of each region based on a unique peak HDD.

[284] The NW Natural engineering team assumes an average outside temperature of 65°F when calculating HDDs for distribution system planning.

Table 12.1: Peak HDDs by Weather Zone

Weather Zone	HDD
Clark County	57.4
Columbia River Gorge	66.8
Portland	57.0
Astoria	49.4
Salem	54.8
Lincoln City	45.7
Albany	54.5
Eugene	56.2
Coos County	41.9

The table of region-specific HDDs are derived from historical localized coldest average daily temperatures each year. Specifically, a normal distribution is developed around the mean and standard deviation, of the coldest average daily temperatures in each historical winter for each location (i.e., non-coincident). The first percentile temperature is then used as the distribution planning standard for calculating HDDs for each location.

NW Natural relies on two data sources for forecasting individual customer demands for Distribution System Modeling. These two data sources are the Industrial Billing Reports and the Customer Management Module (CMM).

Industrial Billing Reports contain hourly consumption for approximately 450 industrial and commercial customers. The customers included in the industrial billing reports are typically large consumers of gas, whose firm demands have the greatest impact on distribution system pressures. An analysis is conducted for each one of these customers to determine consumption during the morning burn when gas demands are at the highest levels.

NW Natural does not collect hourly usage for all customers on the distribution system. Therefore, other tools have to be incorporated to forecast individual firm customer demands. The Customer Management Module (CMM) is used to forecast peak hour gas demands on the distribution system for firm customers without hourly consumption data. CMM plays a key role in demand forecasting by estimating daily individual customer usage based on their unique historical consumption patterns and weather data. CMM calculates daily demand estimates for customers by using historical monthly usage and daily weather data sourced from NW Natural's Customer Information System (CIS). CMM is discussed more in depth later in this chapter.

A peak hourly factor is calculated to convert CMM daily Demands into hourly data. The peak hour factor is a function of the systemwide peak hour demand (see Appendix J), Industrial

Billing Reports, and CMM daily forecasted demands. The equation below provides how the peaking factor is used to convert CMM daily demands to peak hourly demands.

$$Peak\ Hour\ Factor\ = \frac{Systemwide\ Peak\ Hour\ Demand - \sum(\text{Industrial Billing Hourly Demands})}{\sum(\text{CMM Forecasted Peak Daily Demand})}$$

Modeling results, based on the calculated peak factor, are compared with data from cold weather events to validate the peak hour factor used in the demand predictions. This involves adjusting the Heating Degree Days (HDD) to align with actual weather conditions and comparing the modeled pressures to actual pressure readings during the morning burn, when gas consumption is at its highest. For a given HDD, actual pressures may be higher or lower than the modeled values. The peak hour modeling results for a specific area are considered valid if the majority of recorded pressures are reasonably close to the modeled results.

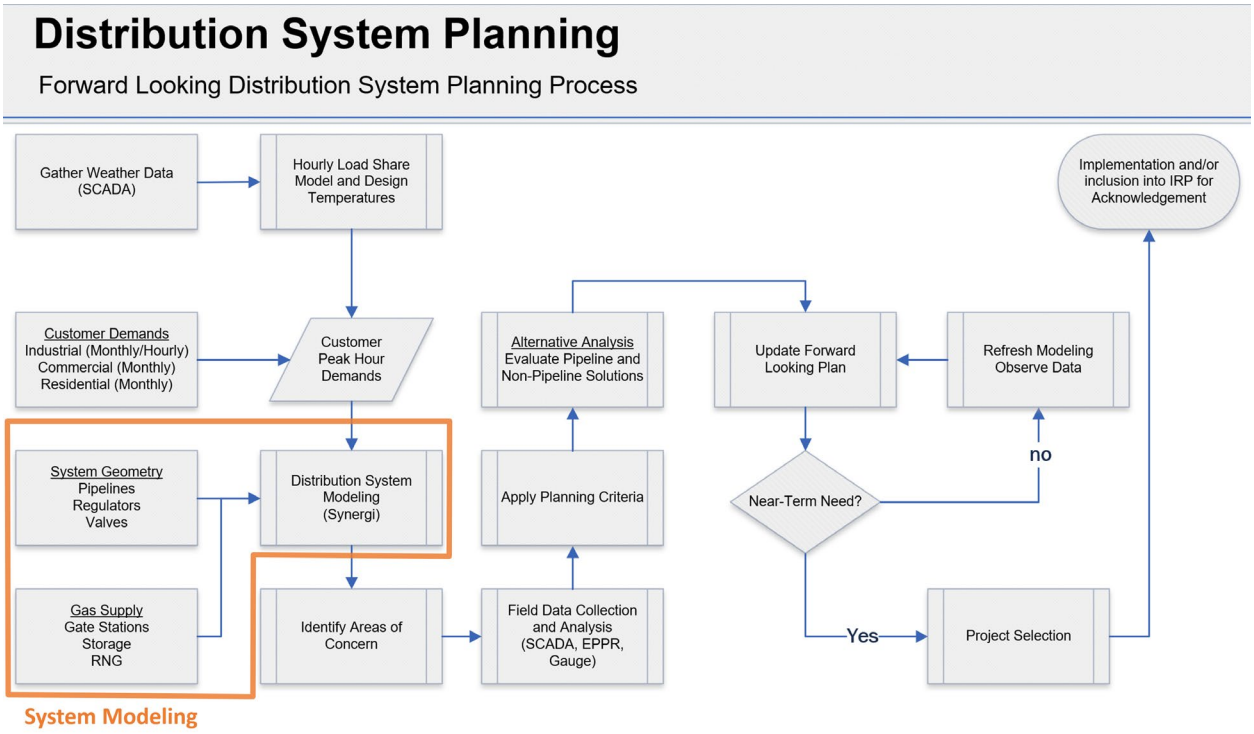
12.4 Distribution System Planning Tools and Standards

The following sections describe the planning tools and standards utilized for Distribution System Planning on NW Natural's system.

12.4.1 System Modeling

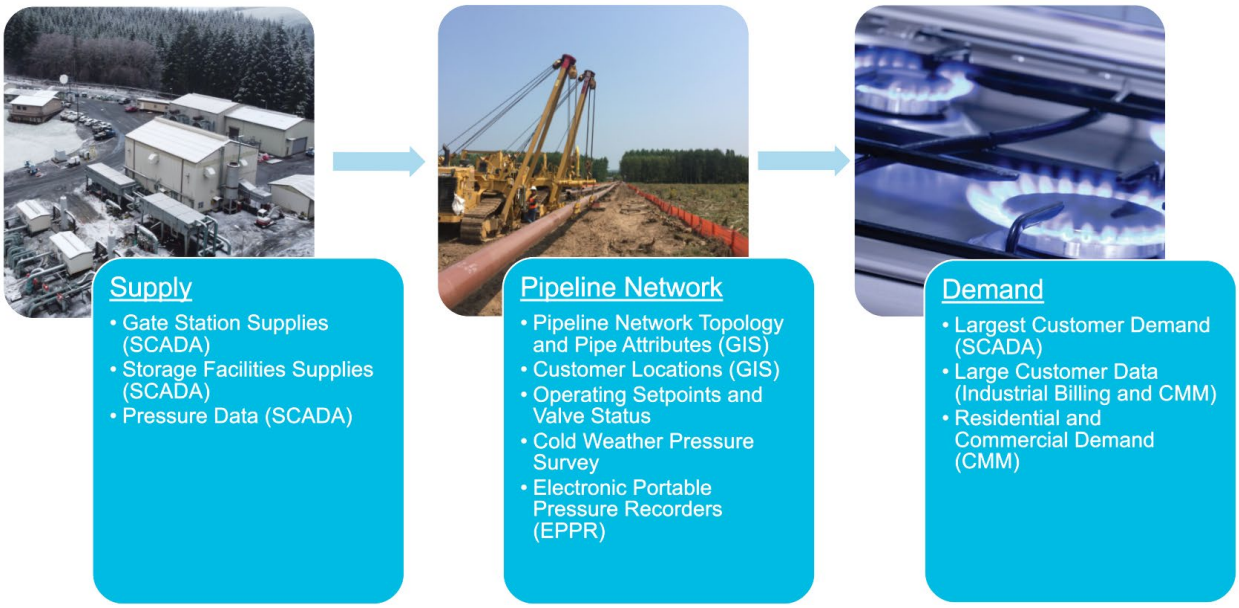
Figure 12.3 provides the components involved in System Modeling. System modeling is an important part of the distribution system planning process. Modeling allows accurate simulation of different aspects of NW Natural's system, from the receipt of natural gas from supplies, through NW Natural's pipeline networks, ending at customer locations. The purpose of System Modeling is to ensure adequate supply and pressure to customers, identify potential capacity constraints, and evaluate system performance under peak hourly conditions.

Figure 12.3: Forward Looking Plan System Modeling



Building the gas distribution network model is the first step in the System Modeling process. NW Natural develops Synergi™ Gas models in-house which represent the infrastructure found on the distribution system. Models are typically updated quarterly and completely rebuilt every two to four years. As shown in Figure 12.4, each model contains detailed information such as gas supply sources, pipe attributes (diameter, length, material, and roughness), regulator settings and characteristics, valve positions, customer demands, and other supporting information. These models are constructed using data from NW Natural's Geographic Information System (GIS) for pipe configuration and characteristics, the Customer Information System (CIS) for customer load sizing, and the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, and supply flow data. By integrating these data sources, the SynergiTM Gas model provides a comprehensive and accurate representation of the network, supporting the goals of providing reliable service to end-use customers.

Figure 12.4: SynergiTM Gas Modeling Needs



Synergi™ Gas applies user identified network data to construct a set of mathematical equations that form the model of the piping system. The solution of these equations provides predictions of pressures, flows, and other unknown values in models. A model is considered *balanced* when the relationship between flows and pressures at all points in the modeled system are within tolerance. A properly designed Synergi™ Gas model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi™ Gas models rely on assumptions about the actual system, and therefore modeling results may vary from actual results. Synergi™ Gas models are a representation of the actual system, and the outputs of these steady-state models are a static snapshot of expected system conditions.

A validation process is conducted for the Synergi™ Gas models to ensure that the predicted pressures fall within acceptable tolerance levels of actual pressures recorded during winter events. Synergi™ Gas may either underpredict or overpredict system pressures for a given HDD. CMM Demands loaded into Synergi™ Gas only applies a single independent variable (temperature) to predict customer demands. The variability between modeling pressures and actual pressures exists because other factors including wind speed, solar radiation, snow depth, day of the week, and water temperature are not included in CMM demand forecasting. A model is assumed to have accurate results if recorded pressures are within ±20 percent of actual pressures.

NW Natural uses three distinct data collection tools to validate the resulting pressures of its Synergi™ Gas models:

1. **Supervisory Control and Data Acquisition (SCADA) Flow/Pressure Data**: SCADA sites are located throughout the gas distribution system. These locations include Williams gate stations, regulator stations, regional stations, and various customer locations. These sites provide two-minute monitoring and control capabilities. Flow and/or pressure data can be viewed or exported in two-minute intervals, providing high granularity data related to system performance.
2. **Electronic Portable Pressure Recorders (EPPRs):** Battery operated temporary deployable devices placed in areas where low pressures are suspected. EPPRs collect pressure and temperature readings in hourly intervals, transmitting the recorded data using cellular technology. Their portable design allows them to be relocated as needed to satisfy data collection requirements.
3. **Cold Weather Survey Pressure Data:** Surveys may be conducted during cold weather events. This type of survey involves deploying NW Natural field personnel to specific sites to manually record pressures. These readings are then submitted to the Engineering team for analysis. Survey locations are selected to track system performance trends, identify potential low pressure areas, and assess the effectiveness of system reinforcements.

Synergi™ Gas software simulates gas pipeline operations and does not have the ability to perform automated pipeline route selection. Automated route selection for pipeline construction would require data with quality and coverage that are not available at this time. Instead, system planners perform an iterative process incorporating multiple economic, geologic, and infrastructure factors to draft the least cost, feasible route option. An identified route is further refined through field validation and right-of-way acquisition considerations.

Synergi™ Gas simulation capability allows NW Natural to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak hour delivery requirements to both planned and unplanned temporary service interruptions. Synergi™ Gas modeling allows NW Natural to evaluate various scenarios designed to stress test the system's response to alternative demand forecasts, future demand forecasts, emergency situations, new customer demands, customer growth, non-pipeline alternatives, and much more.

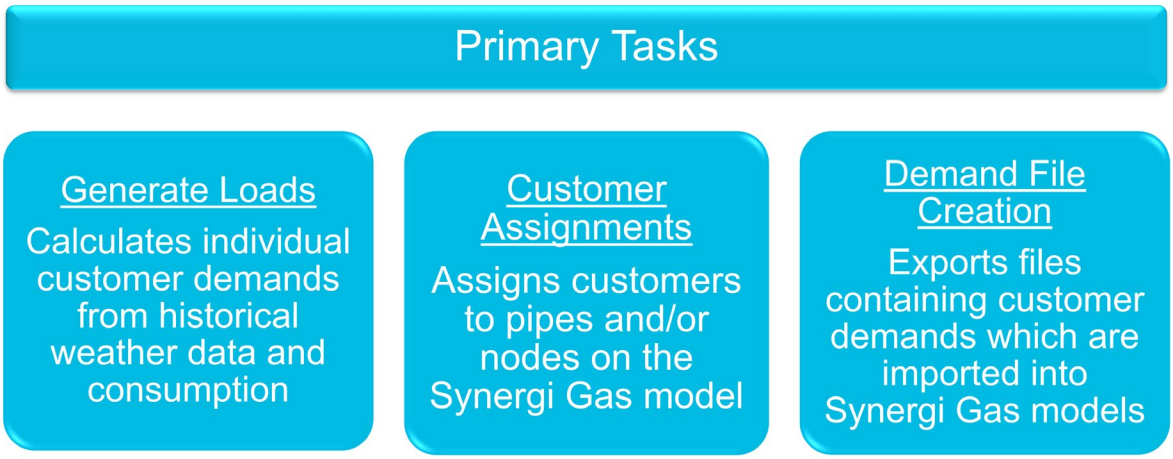
12.4.2 Customer Management Module

In 2021, NW Natural implemented the Customer Management Module (CMM) to predict demand for each individual customer on the system. Previous modeling methods utilized area-specific averages for residential and small commercial customers. For example, all residential customers in the Portland metropolitan area were previously assigned the same demand in the Synergi™ Gas models, whereas CMM allows customer-specific usages for each customer in the model based on historical consumption.

Part of integrating CMM into Synergi™ Gas modeling required all NW Natural models to be recreated. CMM based models are required to have the same coordinate system as the Geographical Information System (GIS) system. CMM models rely on NW Natural's current GIS coordinate standard, which was not utilized in previous models. Creating new models ensured alignment of spatial data between CMM demand locations and Synergi™ Gas. As of the third quarter of 2023, NW Natural has recreated all models to take advantage of CMM demand forecasting.

CMM is a forecasting software tool that works with Synergi™ Gas. CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ Gas. CMM is developed by DNV, which is the same developer who produces the Synergi™ Gas software. In summary, CMM provides three primary tasks as shown in Figure 12.5.

Figure 12.5: CMM Primary Tasks



Generate Loads: CMM uses a combination of historical monthly billing and temperature data to calculate a base load factor and a heat temperature-dependent load factor for each customer. The heating usage factors are determined through regression analyses that use monthly consumption data and the average daily temperature experienced.

Customer Assignments: Synergi™ Gas models consist of pipes and nodes representing the distribution system network. Synergi™ Gas models require that customer demands be assigned to a nearby pipe or node within the gas distribution system. When demands are correctly assigned to the correct position in Synergi™ Gas, it allows modelers to accurately evaluate localized system pressure conditions. CMM's customer assignment functionality matches each customer's load to the nearest node or pipe using geographic coordinates sourced from NW Natural's GIS system.

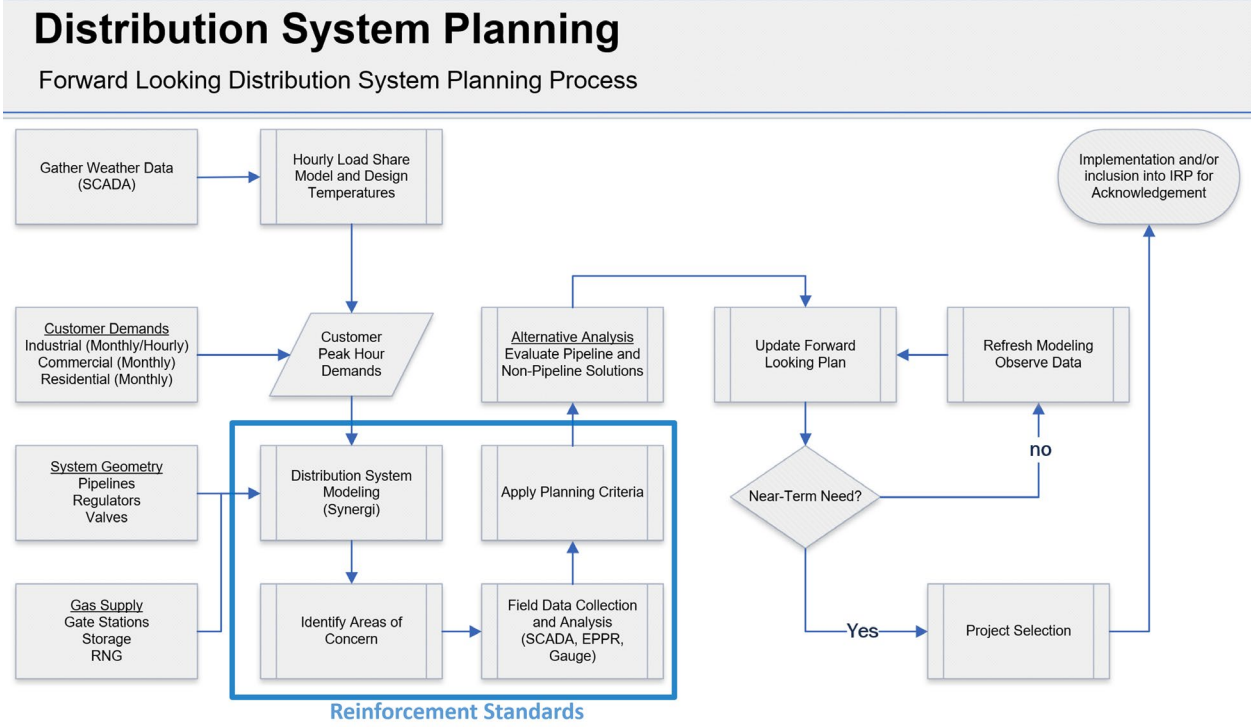
Demand File Creation: The purpose of the demand file is to import CMM calculated loads into the Synergi™ Gas model for accurate system simulation. Demand files generated from CMM include the relationship between customer location (pipe or node) in Synergi™ Gas models with corresponding calculated demands. These demand files contain pipe or node assignments as well as the base and heat load components for each customer, as well as whether the load is for residential, commercial, industrial, or interruptible use.

In addition to the primary tasks provided in Figure 12.5, CMM allows NW Natural to update modeling demands if a customer changes their status or service type, including whether customers are identified as active or inactive and if they are on a firm or interruptible rate schedule. Identifying customer status and rate schedule allows NW Natural to model active customers on the system. Firm customers are included in peak models, whereas interruptible customers are assumed to be curtailed during extreme cold weather. These qualities are important because having incorrect customer rate schedules and statuses would affect Synergi™ Gas pressures.

12.4.3 Distribution System Planning Criteria

As shown in Figure 12.6, system reinforcement standards are a required component of the distribution system planning process. These standards are developed based on suboptimal conditions such as a pipeline nearing peak capacity, a regulator near failure, or customers not being served with adequate pressure or volume. The system reinforcement standards represent trigger points indicating systems under stress and in need of imminent attention to reliably serve customers.

Figure 12.6: Forward Looking Plan Reinforcement Standards



12.4.3.1 System Reinforcement Standards

Transmission and high-pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well.

System reinforcement parameters for these systems include:

- For systems with nominal diameters less than six inches, or have a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less:
    - Experiencing or modeling a greater than 30 percent pressure drop from a source to the lowest pressure indicates an **investigation** will be initiated.
    - Experiencing or modeling a greater than 40 percent pressure drop from a source to the lowest pressure indicates reinforcing the facility is **critical**, as a 40 percent pressure drop equates to an 80 percent level of capacity utilization[285]
- For systems with nominal diameters of six inches or greater or have a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig:

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

    - Experiencing or modeling a pressure below 210 psig on the system indicates an **investigation** will be initiated
    - Experiencing or modeling a pressure below 180 psig on the system indicates reinforcing the facility is **critical**
- Consider the minimum inlet pressure requirements for proper regulator function, in addition to total pressure drop for pipelines that feed other high-pressure systems
- The ability to meet firm-service customer delivery requirements (flow or pressure)
- Identified in the IRP associated with supply requirements or needs

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

- Experiencing a minimum distribution pressure of 15 psig or less that indicates an **investigation** will be initiated
- Experiencing or modeling minimum distribution pressure of 10 psig or less that indicates reinforcement is **critical**
- Firm service customer delivery requirements (flow or pressure)

12.4.3.2 System Reinforcement Standard Updates

Since the last IRP, the Company has modified the 40 percent pressure drop system reinforcement criteria to apply to pipelines less than six-inches in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less. NW Natural adopted a new standard for pipelines six-inches and larger or systems with an MAOP of greater than 300 psig allowing flexibility to exceed the 40 percent pressure drop.

Under the revised standard, for pipelines six-inches or larger in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig, a system reinforcement is considered critical when the lowest pressure on the system drops below 180 psig. This change ensures that district regulators feeding Class B systems continue to operate at adequate inlet pressures while lowering the necessary system reinforcement projects to comply with the previous standard. At 180 psig, Class B District Regulators can reliably serve downstream demand. However, if inlet pressure falls below 180 psig, Class B district regulators may experience pressure droop, also known as starving a district regulator. A starved district regulator leads to reduced regulator and B-system capacity, which can result in lower downstream pressures and potential system reliability concerns because the district regulator cannot provide enough gas to meet the downstream demand.

Despite the increased flexibility in pressure drop for high-pressure mains, the updated System Reinforcement standards preserves system reliability by maintaining the performance threshold needed to support Class B district regulator operations.

The original 40 percent pressure drop criteria continues to apply to transmission and high pressure systems operating at or below an MAOP of 300 psig or with a nominal diameter less than six-inches. These systems remain at greater risk of not providing sufficient inlet pressure for Class B district regulators to operate. Smaller diameter and lower MAOP system pressures are more sensitive to changes in demand because increases in demand causes a much higher pressure drop on the system. These greater fluctuations increase the likelihood of system reliability issues. The more volatile swings in system pressures for lower MAOP and smaller diameter pipelines make it important to preserve the 40 percent pressure drop criteria for these systems.

The reinforcement criteria for Class B systems, or systems operating at or below 60 psig, remain unchanged.

12.4.3.3 Distribution System Planning Criteria – 40 percent Pressure Drop / 80 percent Capacity Utilization

The Company established a system reinforcement criteria action threshold for systems where the pressure drop exceeds 40 percent from the source to the end of the system for pipelines less than six-inches in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) less than 300 psig. This is because a system with a pressure reduction of 40 percent equates to an 80 percent level of capacity utilization (100 percent utilization means 0 psig at the end of the pipe). The Company needs to ensure that its gas distribution system will meet the demands of the firm load customers during peak cold weather events.

Although the models provide a good representation of system pressures, like any model they are not perfect at predicting real-world conditions. However, the Company endeavors to make the models as accurate as possible. Multiple uncertainties that pose risks are not accounted for in the system modeling. These are risks that could cause unplanned use of the usable portion of the remaining 20 percent capacity. Should one or more of these modeling uncertainties be realized, it can result in equipment issues or even customer outages. These limitations highlight the need to maintain a buffer to ensure system reliability. Below are some of the factors that the Company cannot account for in its peak demand system modeling:

- **Variability in gas energy content**: If the actual energy content of gas during a peak weather event falls below the assumed average (1040 Btu/scf), the system will

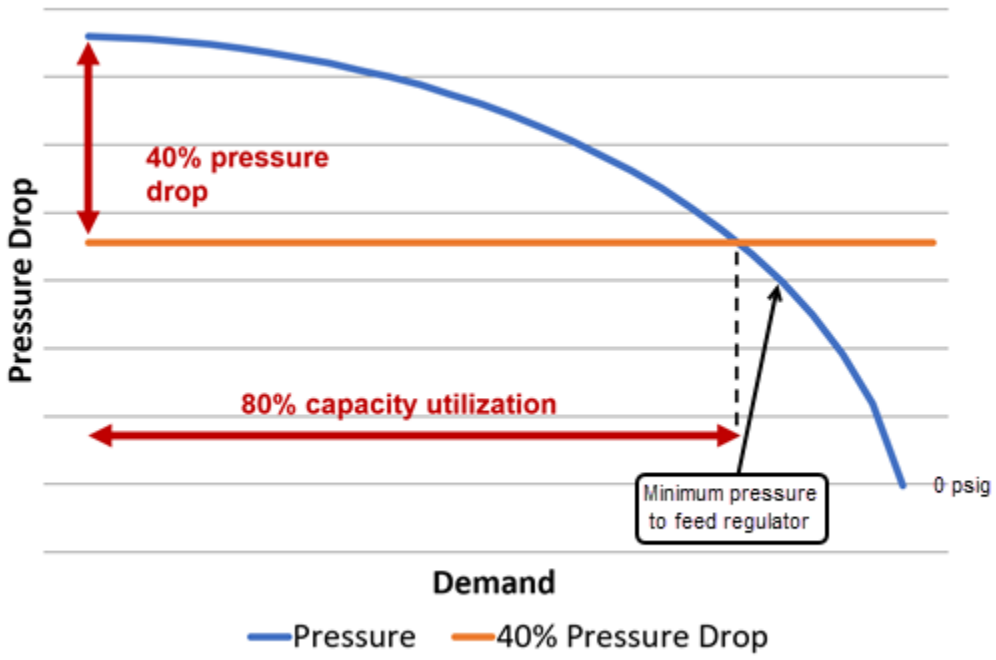
experience greater pressure drop, because it would require greater volumes of gas to deliver the same amount of energy.

- **Deviations in customer usage:** Customer usage behavior may differ from CMM calculated demands sourced from recent historical usage patterns (CMM calculated demands are based on the prior two years of customer usage).
- **Sudden spikes in demand:** Spikes in gas demand caused by restoration of electrical power to a large area of affected gas and electric customers.
- **Customer equipment changes:** Added customer equipment may not be accounted for in our system modeling as the Company may not have been notified about changes in customer equipment, and the install may have been recent enough to not properly register with CMM calculated demands.
- **Equipment malfunctions:** On-system equipment issues may occur during a peak weather event.
- **Interruptible customer usage:** Interruptible customers may continue to consume gas during a peak day (for which they will pay a penalty), which is not considered in peak day modeling.
- **Other independent variables:** CMM only considers temperature as an independent variable but other factors such as wind speed, solar radiation, snow depth, day of the week, holidays, water temperature, electrical outages, and differences in human behavior can cause variances in demand.
- **Modeling may predict lower pressures:** A model is considered validated when predicted pressures are within ±20 percent of field recorded pressures. If the model overestimates pressures (underestimates load), then actual pressures may be lower than peak modeling results.

Figure 12.7 below illustrates the nonlinear relationship between system demand and pressure drop. The image shows that pressure drop across a pipeline is not linear with respect to increasing demand. At lower levels of capacity utilization, pressure decreases gradually with increased demand. As the system approaches higher capacity utilization levels, it experiences larger pressure drops for the same demand increase. When a system is operating at or above 40 percent, small demand increases may cause pressures to fall below the minimum required pressures for district regulators to properly operate. If the pressure drops below the required minimum pressure for the regulator to flow the amount of gas the system needs, then the outlet pressure from the regulator drops below setpoint, resulting in a lower capacity of the system the regulator is feeding. The decreased district regulator capacity can lead to system reliability issues, especially during extreme cold weather events. Therefore, maintaining a

sufficient pressure buffer is essential for maintaining gas service to customers during cold weather events.

Figure 12.7: Pressure Loss Illustration



As can be seen in Figure 12.7, all of the remaining 20 percent of pipeline capacity is not available for utilization, as there needs to be sufficient remaining pressure to flow through the pressure regulating equipment then into the downstream system and ultimately to the customer. One hundred percent utilization of the pipes capacity would result in 0 psig at the end of the pipe. Utilization of 100 percent of the pipes capacity would lead to a loss of service to all customers affected.

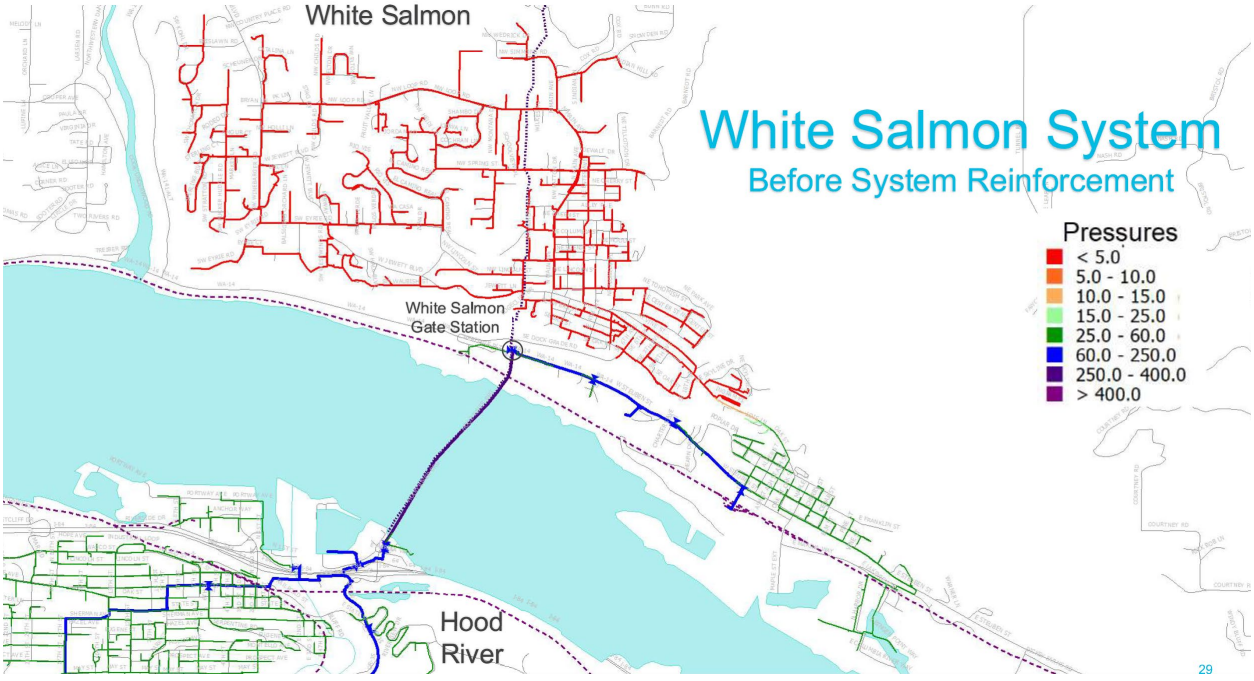
Loss of service requires a lengthy 3-step process to restore service to customers, and service cannot be restored until the gas distribution system pressures stabilize above five psig for residential customers. The Company must dispatch field service technicians to shut in the customer's service, purge any air that may have entered the gas lines and then reintroduce gas to the customer's gas service and appliances and relight the equipment. Air purging, and customer equipment relights, cannot begin until the pressures in the gas distribution pipelines permanently stabilize above five psig and relighting could take several days to weeks depending on the size of the affected area. If this loss of service were to happen in the midst of a multi-day cold weather event, the system would continue to lose pressure each day of the multi-day

event and customer service could not be restored until distribution pipeline pressures permanently stabilize above five psig.

12.4.4 Identification of System Distribution Needs

Accurate modeling and forecasted level of peak hour demand combine to indicate how the distribution system would operate during a predicted peak hour. The system reinforcement standards are then applied to the model results to identify specific areas of NW Natural's system that need reinforcement. Such areas are typically much smaller than the load center in which they are located. In the following Synergi™ Gas example, as shown in Figure 12.8, an area of the Class B distribution system in White Salmon, WA is forecasted, by modeling, to experience low system pressures or outages on a peak hour. Areas with pressure below ten psig are indicated in orange and red colors, while areas with more satisfactory pressure are indicated with shades of green. This modeling was validated in January of 2018 when SCADA revealed that the White Salmon distribution system experienced a pressure of 6.8 psig under non-peak conditions.

Figure 12.8: Synergi™ Gas example

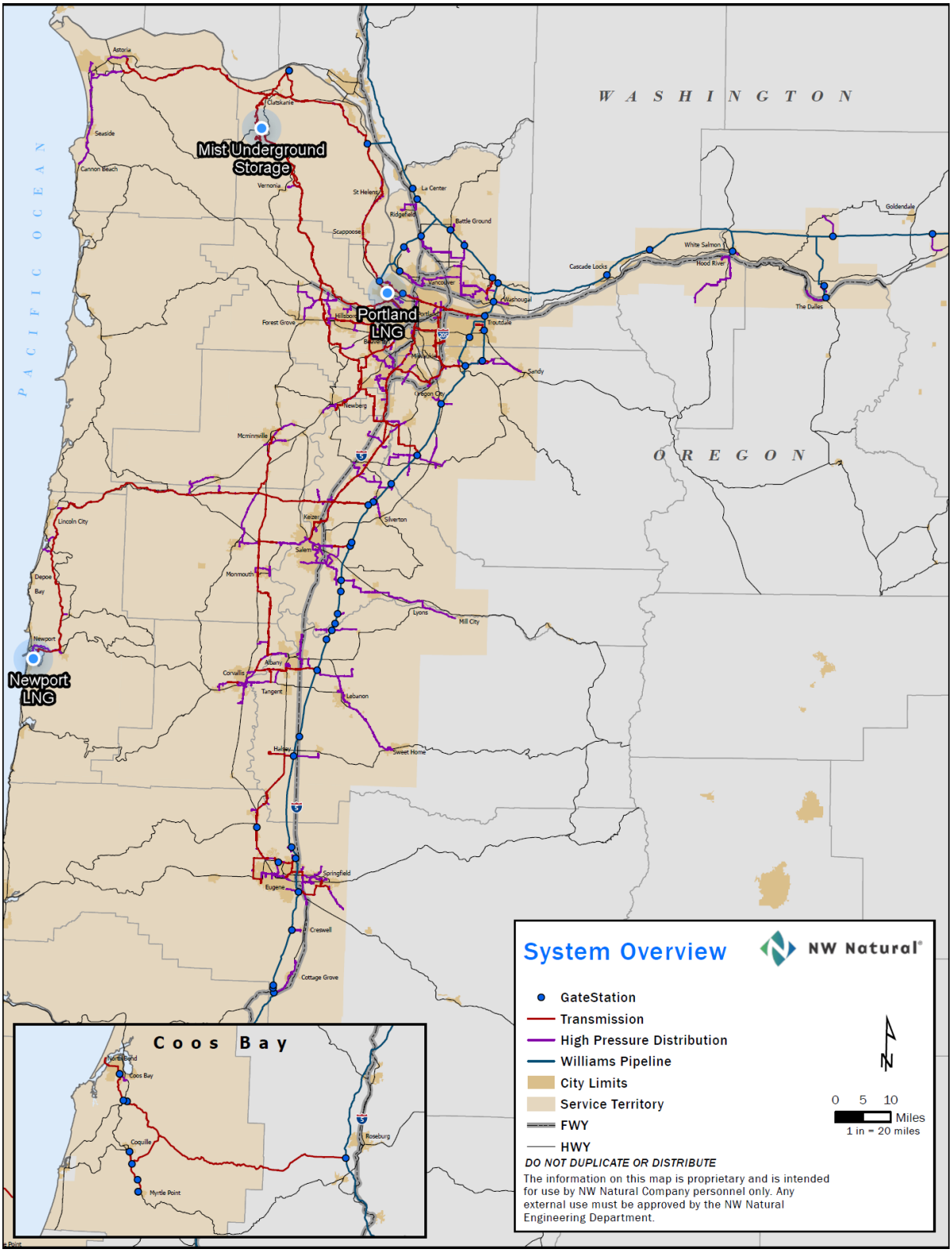


12.5 Distribution System Resources

NW Natural's gas distribution system consists of approximately 14.4 thousand miles of transmission and distribution mains, of which approximately 86 percent are in Oregon with the remaining 14 percent in Washington. NW Natural has replaced all identified Aldyl-A, cast iron, and bare steel mains with modern polyethylene and coated steel.

NW Natural's Oregon service area includes 39 gate stations and approximately 954 district regulator stations. NW Natural owns and operates two liquefied natural gas (LNG) storage plants and the Mist underground storage facility in Oregon, which are discussed in Chapter 8. NW Natural's Washington service area includes 15 gate stations and approximately 78 district regulator stations. Figure 12.9 provides a high-level system overview of the Company's natural gas network.

Figure 12.9: NW Natural Gas Network



NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of individual customers, or small localized systems during cold weather operations, or while conducting pipeline maintenance procedures.

12.6 Alternative Analysis/Solutions

As shown in Table 12.2, NW Natural evaluates various alternatives when faced with a potential system reinforcement. A discussion of pipeline alternatives will be presented below followed by non-pipeline alternatives.

Table 12.2: Distribution System Planning Alternatives

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

12.6.1 Pipeline Solutions (Supply-Side Resources)

Once NW Natural identifies a distribution system issue, in addition to demand-side alternatives, the Company evaluates multiple traditional pipeline solutions for addressing low pressures. NW Natural considers a variety of traditional pipeline solutions including:

- Constructing new pipelines

  - Distribution Pipeline Extensions
  - Distribution Pipeline Replacements
  - Distribution Pipeline Looping
- System pressure uprates
- New or improvements to regulator stations
- New or improvements to gate stations
- Constructing a new compressor station

The objective is to determine the most efficient, least cost, highly reliable, and low risk solution for the identified issue. Potential pipeline solutions are validated with hydraulic modeling and field testing to verify effectiveness.

Maintaining adequate pressure throughout the distribution system is essential for reliably serving customers on the distribution system. If pressures on the system are too low, it can lead to customer outages. Pipeline solutions are an important step in the alternative analysis to find feasible solutions to address areas experiencing low pressures.

12.6.1.1 Constructing New Pipelines

A common industry approach to resolve low pressure areas is to construct new distribution pipelines to reduce pressures losses through the existing gas network. The proposed distribution pipeline would allow more gas to flow to areas with weak pressures, thereby improving their pressures. Newly constructed pipelines can raise pressures in weak areas, reducing the likelihood of customer outages.

The Company conducts pipeline feasibility studies to evaluate potential pipeline projects. These pipeline feasibility studies assess various selection criteria including pipeline distance, ease of construction, operating pressure, material, pipeline diameter, load type, and existing network connectivity. The three primary types of new pipeline reinforcements include:

1. **Distribution Pipeline Extensions**: Installation of a gas distribution pipeline using a new alignment. A new distribution pipeline delivers higher pressure gas to an area of need, increasing the pressure and reliability of a distribution system. Depending on the relative operating pressures this could also include pressure regulation and overpressure protection equipment.
2. **Distribution Pipeline Replacements**: Replacing an existing pipeline with a new pipeline. Typically, the replacement distribution pipeline is larger in diameter than the original distribution pipeline, which reduces the pressure drop across the alignment.
3. **Distribution Pipeline Looping**: A new distribution pipeline is constructed parallel to an existing distribution pipeline. The looped mains are tied-in and work together to carry

the gas, reducing pressure drop along the original pipeline alignment because of load sharing.

NW Natural considers alternative characteristics for a pipeline solution to the identified issue as a first step in developing supply-side solutions. These alternative characteristics include proposed pipeline alignments, the size of the pipe, the material used in the pipe, and the probable methods – or combination of methods – of pipeline construction. The feasibility study incorporates all three scenarios as well as these alternative characteristics. The least cost option is provided as an input in the alternatives analysis to address an area in need.

Table 12.3 provides the design capacity for a 5-mile pipeline for various pipe sizes. The table shows that a 12-inch, 300 psig pipeline has approximately six times more carrying capacity than a 6-inch 300 psig pipeline. Increasing pipe diameter does not increase capacity linearly, doubling pipeline diameter of gas main equates to increasing the flow capacity by approximately six times.

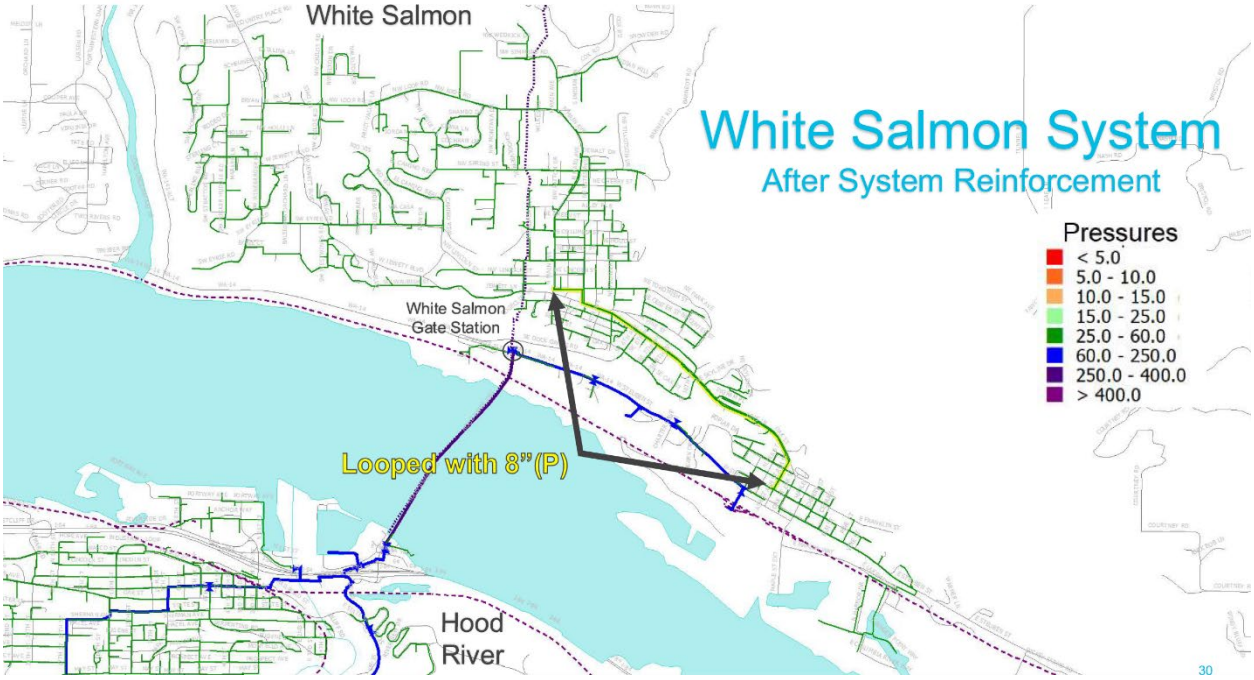
Table 12.3: Comparative Pipeline Capacity Based on Diameter

Nominal Diameter	Beginning Pressure	Ending Pressure	Pipeline Capacity[1,2]
2"	300 psig	180 psig	340 Th/hr
4"	300 psig	180 psig	1,956 Th/hr
6"	300 psig	180 psig	5,713 Th/hr
8"	300 psig	180 psig	12,257 Th/hr
12"	300 psig	180 psig	34,797 Th/hr

[1]40% Pressure Drop Pipeline Capacity
[2]Calculated using a Heating Value of 1040 Btu/scf

In the White Salmon example discussed earlier in Section 12.4.4, the primary weakness in the existing gas system was due to a single one-way feed serving the area to the north. This created a bottleneck, as nearly all gas supplied to customers had to pass through a small 3-inch diameter pipe, which had inadequate capacity to meet the demand in the northern part of the system. To address this issue, the implemented solution involved looping the existing 3-inch pipe with a new 8-inch pipeline. This significantly increased the system's capacity and provided adequate pressures to customers in the north. The majority of the gas is now delivered through the new 8-inch pipeline, which loops the existing 3-inch pipe, providing greater capacity than the 8-inch by itself, and reduces construction costs since the previously existing services and pipe laterals did not have to be tied over to the new 8-inch pipe. As a result, overall system pressures improved significantly. Areas that previously showed low pressure (indicated in red) are now operating at sufficient pressures (indicated in green).

Figure 12.10: White Salmon Example After Reinforcement



12.6.1.2 System Pressure Uprates

In many, but not all cases, the cost of uprating a portion of a distribution system is generally less than installing a new pipeline. Uprating pipelines is another form of increasing the capacity of a distribution system, by increasing the pipeline's Maximum Allowable Operating Pressure (MAOP). Before an uprate can be executed, a pipeline system must comply with Local and Federal Regulations. The uprating effort may include, but is not limited to, key activities such as reviewing records, pressure testing, replacements, field verification, inspections for all pipes and components on the portion of the distribution system being uprated, multiple leakage surveys before, during and after the pressure uprate process. Not all pipelines are eligible to be uprated, a system may have design or material limitations that prevent a distribution system pipeline from operating at a higher MAOP.

Table 12.4 shows the capacity for a five-mile, four-inch steel pipeline for varying operating pressures. The table shows that a pipeline operating at 600 psig with a 40 percent pressure drop along its length has approximately six times more capacity than a pipeline operating at 100 psig, also with a 40 percent pressure drop. A major benefit of uprating is that incremental capacity can be provided through existing distribution pipelines by safely operating them at higher pressures.

Table 12.4: Comparative Pipeline Capacity Based on Operating Pressure

Beginning Pressure	Ending Pressure	Pipeline Capacity[1,2]
100 psig	60 psig	662 Th/hr
200 psig	120 psig	1,304 Th/hr
300 psig	180 psig	1,956 Th/hr
400 psig	240 psig	2,617 Th/hr
500 psig	300 psig	3,289 Th/hr
600 psig	360 psig	3,971 Th/hr

[1]40% Pressure Drop Pipeline Capacity
[2]Calculated using a Heating Value of 1040 Btu/scf

12.6.1.3 District Regulator Stations

If an area is experiencing low pressures and is located near a higher-pressure distribution or transmission system, then installing a new district regulator may be a viable solution. District regulators reduce higher-pressure gas to a lower pressure, suitable for the lower operating pressure system. By strategically placing a district regulator, the higher-pressure system can feed gas into the lower-pressure system, providing an additional source of gas and reducing pressure drop on the existing gas network. In some cases, a high-pressure main extension may be required to site the district regulator at an optimal location.

District regulator stations may also need to be rebuilt if the existing equipment or piping is undersized. Regulators are designed to maintain consistent outlet pressure within a specific flow range. However, if the station is undersized, it can experience pressure droop. Pressure droop occurs when the outlet pressure drops below the regulator set point, due to insufficient inlet pressure or equipment capacity. There are two primary ways to address pressure droop. One method is to increase the inlet pressure, which may involve system reinforcements such as a pipeline uprate or new pipeline construction. Another option is to rebuild the regulator station with appropriately sized equipment. However, all district regulators introduce some level of impedance (pressure loss), and rebuilding the regulator station may not be a viable option if the upstream system lacks the capacity to support the needed flow through the station.

12.6.1.4 Compressor Stations

Although NW Natural does not currently have inline compressor stations, construction of a new inline compressor station can be an option to ensure reliable pressures or increase gas sendout out of NW Natural's existing storage assets. By boosting pressures along the pipeline, compressor stations increase the capacity of the system to help meet energy needs. The

optimal location and operating pressure of a compressor station are dependent on several factors including system MAOP, required horsepower, pipeline length, load placement along the system, potential need for additional compression in the future, availability of electrical power and communication capabilities, and surrounding site conditions. Balancing these factors are essential when designing a greenfield compressor station that meets performance, cost consideration goals, environmental and other regulatory requirements.

12.6.2 Non-pipeline Alternatives

The following sections provide a summary of the various non-pipeline alternatives (NPAs) NW Natural considers.

12.6.2.1 Trucking and Satellite Liquid Natural Gas and Compressed Natural Gas

Targeted Liquid Natural Gas (LNG) and Compressed Natural Gas (CNG) trailers can be deployed to support areas of the natural gas distribution system experiencing low pressures. These trailers are mobile supply sources, delivering gas directly into the system at an injection location where the CNG and LNG can be used to avoid distribution system outages. LNG and CNG trailers are required to be staged and connected to the NW Natural System before cold weather events begin. Natural gas used from these LNG and CNG trailers must be sourced from external facilities and transported to the site. This requires advanced coordination and financial commitment with external suppliers for the trailers to be full of fuel and available during the winter months.

Appendix J provides an overview of the risks and benefits as presented in TWG 8, as well as a discussion about a recently completed CNG and LNG trucking study.

12.6.2.2 Geographically Targeted Renewable Natural Gas

Geographically Targeted Renewable Natural Gas (GeoRNG) is another potential non-pipeline solution. As previously mentioned, RNG can be produced from a variety of feedstocks including animal manure, food waste, landfill gas, and water resource recovery facilities. If any of these feedstocks are available within the constrained areas, the Company could pursue GeoRNG. A strategically located RNG interconnection on NW Natural's system could have a similar impact in a constrained area of the distribution system as any targeted demand-side option. The additional RNG supply would be injected directly into a weak area of the system which could help avoid or delay a pipeline reinforcement project. The likelihood of an RNG facility providing the biogas needed in the perfect location as a specific alternative to a specific pipeline reinforcement project is small, but possible. After evaluation, the current constrained areas do not present any feasible GeoRNG project opportunities. The Company will continue to look at GeoRNG for NPA efforts within constrained areas.

12.6.2.3 Geographically Targeted Underground Storage

Similar to Satellite Liquid Natural Gas (LNG) and Compressed Natural Gas (CNG), Geographically Targeted Underground Storage (GeoUnderground) storage would be an alternative if there was local underground storage strategically located near enough to the NW Natural system so that an interconnection could be constructed and add supplies in a constrained area. The likelihood of this being a realistic option for the capacity constrained areas is quite small after evaluation.

12.6.2.4 Geographically Targeted Demand-Side Management Programs

Geographically targeted demand-side management (GeoDSM) is a general term for geographically targeted energy efficiency (GeoTEE) and geographically targeted demand response (GeoDR), both of which can be specifically designed to achieve incremental peak hour savings from distinctive energy efficiency and demand response offerings to customers in a targeted area where the distribution system is expected to be constrained in the near future. The Company started the investigation of GeoTEE as a potential non-pipeline alternative (NPA) in the 2016 IRP, partnered with Energy Trust to implement a GeoTEE pilot from 2019 to 2022, and concluded the pilot with a detailed summary report in the 2022 IRP Update filed in 2024.[286] For GeoDR, the Company filed an action item in the 2022 IRP to scope a residential and small demand response program to supplement its large commercial and industrial interruptible rate schedule program, and OPUC acknowledged this action item with the condition that NW Natural provides a discussion of how its general demand response will interact with and support future GeoDR programs. In compliance with OPUC's guidance, the Company has evaluated several demand response offerings as potential NPAs in the targeted areas. Each GeoDSM NPA is discussed separately and their impacts on peak load and cost effectiveness as well as the time delay for engineering investments that can be achieved from the combination of the GeoDSM efforts are summarized below.

Geographically Targeted Energy Efficiency Program

Leveraging the data and experience gained from the 2019-2022 Geographically Targeted Energy Efficiency (GeoTEE) pilot[287], Energy Trust of Oregon (ETO) assessed the potential peak load and annual energy savings and costs based on historical trends and generalized assumptions for each of the three targeted areas. ETO's GeoTEE savings and costs estimates feature the historical trend in energy efficiency program implementation by customer segment in these areas since 2017 while increasing marketing/outreach as well as incentive levels to increase energy efficiency uptake. The Company has used the highly likely achievable potential annual

[286] For more details about the GeoTEE pilot, see NW Natural's 2022 IRP Update in OPUC docket LC 79: https://edocs.puc.state.or.us/efdocs/HAH/lc79hah330506025.pdf
[287] GeoTEE is often referred to as TLM or Targeted Load Management by Energy Trust of Oregon.

and peak-hour therm savings and the corresponding costs to achieve these savings through a targeted approach.[288]

Interruptible Rate Schedule Program

NW Natural already relies upon substantial demand response resources in the form of interpretability to manage peak loads and save capacity resource costs on its distribution system, where about ten percent would-be peak load can be interrupted at the system level during peak events. This existing DR resource comes from 174 large industrial and transportation customers, having saved substantial infrastructure investments needed to serve the would-be peak load. In the GeoDSM targeted areas, two industrial and transportation customers are already enrolled in this rate schedule program and NW Natural is working with AWEC to explore opportunities to expand the program for other large commercial and industrial customers in these areas with area-specific rate schedules that provide higher incentives than the existing rate.

Behavioral Demand Response Program

As reported in the 2022 IRP Update filed in 2024, NW Natural ran a proof-of-concept effort from 2023 into 2024 that focused on a localized geographical demand response engagement in the Eugene area with a small subsection of NW Natural's customer base. The Company partnered with a third-party vendor, Copper Labs, to enable customers to see their current energy usage and receive notifications encouraging conservation during peak load times. Customers' usage data was available on both a customer app and a utility portal. Copper Lab's app allowed customers and NW Natural to see, in detail, their energy consumption patterns, peaks and valleys. The utility portal allowed NW Natural to send out notifications through the app during peak load times to customers encouraging them to reduce their usage.

Relying on similar technologies of the kind tested in the pilot mentioned above, NW Natural is working with AWEC to explore opportunities to enroll other large commercial and industrial customers in these areas in a behavioral demand response program. Unlike the interruptible rate schedule under which customers are required to completely shut down their natural gas usage for a whole day, customers enrolled in this behavioral demand response just need to reduce their usage by an agreed upon percentage or quantity during a DR event period of no more than four hours. The Company will work with individual prospective customers to identify measures to reduce peak hour load, set reasonable load reduction goals, and determine the size of incentives for the load reductions achieved. An independent third-party EM&V vendor,

[288] For more details about ETO's GeoTEE peak load saving and cost estimates, see NW Natural's TWG #8 available at the following site: https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan.

ADM Associates, has been contracted to verify the load reduction for each of participating customers using the time-interval usage data collected from metering devices developed by technology vendors like Copper Labs.

Bring Your Own Thermostat Demand Response Program

The Company will leverage the distributed energy resource management system (DERMS) established for the system-wide Bring Your Own Thermostat (BYOT) Demand Response Program ("Thermostat Rewards", as branded) and work with ETO to promote the program with area-specific increased enrollment and participation incentives along with ETO's smart thermostat energy efficiency program in the targeted areas. Since its rollout in December 2024, the numbers of smart thermostats that have been enrolled to date in the system-wide BYOT Demand Response Program in Creswell, Dallas, and McMinnville are 14, 43, and 68, respectively. Depending on the contribution of this geographically targeted demand response offering to the benefits obtained from delaying the corresponding pipeline solutions, the enrollment and participation incentives to be offered in these areas will be higher than those offered by the system-wide BYOT program while still ensuring the cost effectiveness of the offering in each of the targeted areas. Increased enrollment and participation incentives combined with ETO's intensified co-marketing and outreach for the smart thermostat energy efficiency and demand response programs are expected to significantly increase the uptake of both ETO's smart thermostat energy efficiency and NW Natural's BYOT demand response programs in the targeted areas.

Geographically Targeted Electrification

Geographically targeted electrification is a demand side approach where the Company would incent customers to electrify end-use equipment to achieve peak hour savings. Setting aside that the electrification analysis demonstrates that at a system level electrification is the most expensive compliance approach, the Company does not consider paying customers to remove gas equipment an appropriate approach.

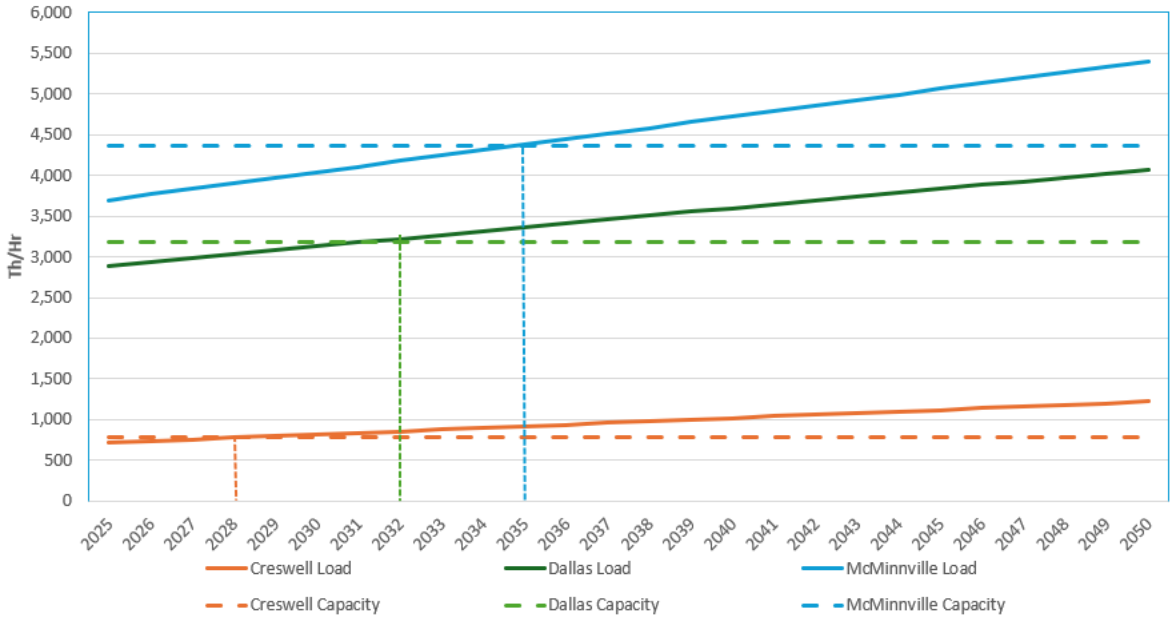
12.7 Forward Looking Plan

NW Natural's Forward Looking Distribution System Plan is intended to proactively identify areas on the distribution network that may require a solution five years or more into the future, either through traditional pipeline solutions or non-pipeline alternatives (NPAs) to continue to provide reliable service to firm customers.

The 2025 Forward Looking Distribution System Plan focuses on three areas in Oregon, which are Creswell, McMinnville, and Dallas. These areas were selected because forecasted demand growth could cause the distribution system to operate above design capacity at some time in

the future between 2028 and 2050. The 2024 Forward Looking Distribution System Plan included Lebanon, Oregon. After further review, it was determined that Lebanon no longer needs to be included in the plan, as current projections do not indicate that demand growth will result in capacity constraints within the current planning horizon. There are no areas in Washington identified in the Forward Looking Distribution Plan at this time, though the system is continuously being monitored.

Figure 12.11: Peak Hour Load Forecast for Distribution Capacity Constrained Areas (No GeoDSM)



The pipeline solutions outlined in the plan are conceptual and may never be constructed. Construction of a pipeline solution is dependent on localized growth and the effectiveness of non-pipeline alternatives. These solutions will be reassessed annually, and their scope may be adjusted based on changes in demand and system performance. Available capacities provided in the Forward Looking Distribution Plan are an approximation. The values could differ depending on where the location of the demand growth occurs. A pipeline can serve higher demand growth closer to sources (Gate Station, Pressure Reducing Equipment), than demand further downstream.

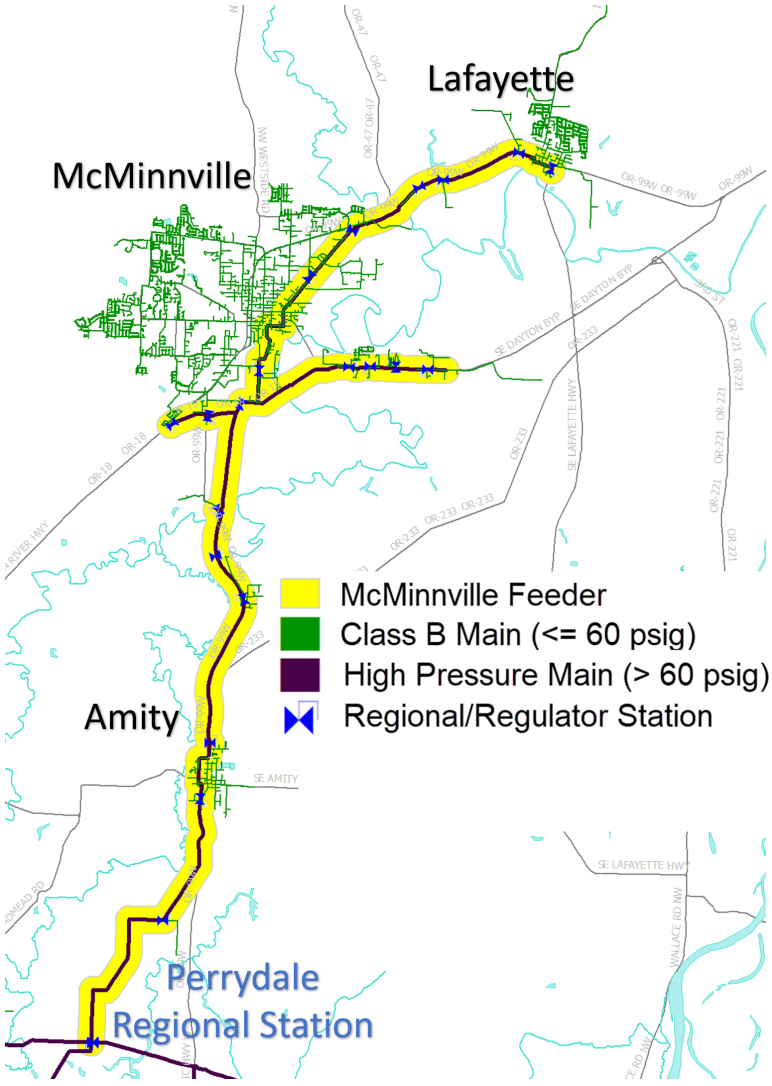
NW Natural will continue to monitor system pressures in all areas of concern and determine the appropriate level of response. Should a large project be selected as the preferred solution,

it will be included in the action plan of NW Natural's Integrated Resource Plan (IRP) for acknowledgement.

12.7.1 McMinnville

The McMinnville Feeder is a 17.2-mile, 6-inch high-pressure pipeline operating at 400 psig MAOP. The system is fed from the south from the Perrydale Regional Station. It includes two 4-inch laterals with a combined length of approximately 3.9 miles. The McMinnville Feeder provides service to Amity, McMinnville, and Lafayette. Synergi™ Gas modeling shows that the pipeline can support up to an additional 650 Th/hr of firm load. An image of the McMinnville Feeder is shown in Figure 12.12.

Figure 12.12: McMinnville Feeder



12.7.1.1 Supply Side Option

The McMinnville Feeder has two pipeline solutions to increase distribution system capacity. Both options would increase the available capacity on the system from approximately 650 Th/hr to approximately 1740 Th/hr.

- **Option A**: Adding approximately 500 horsepower of compression along the existing pipeline between Perrydale Regional Station and Amity.
- **Option B**: Looping the existing 6-inch High Pressure Main from Perrydale Regional Station to Amity.

12.7.1.2 Demand Side Option – GeoDSM Non-Pipe Alternatives

As mentioned above, NW Natural will continue to work with AWEC on recruiting large commercial and industrial customers in the interruptible rate schedule in the targeted areas. Due to the huge uncertainties in the number of customers that might be enrolled and the peak load impact that might be resulting from the program, the focus of the non-pipe alternative (NPA) analysis of the demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

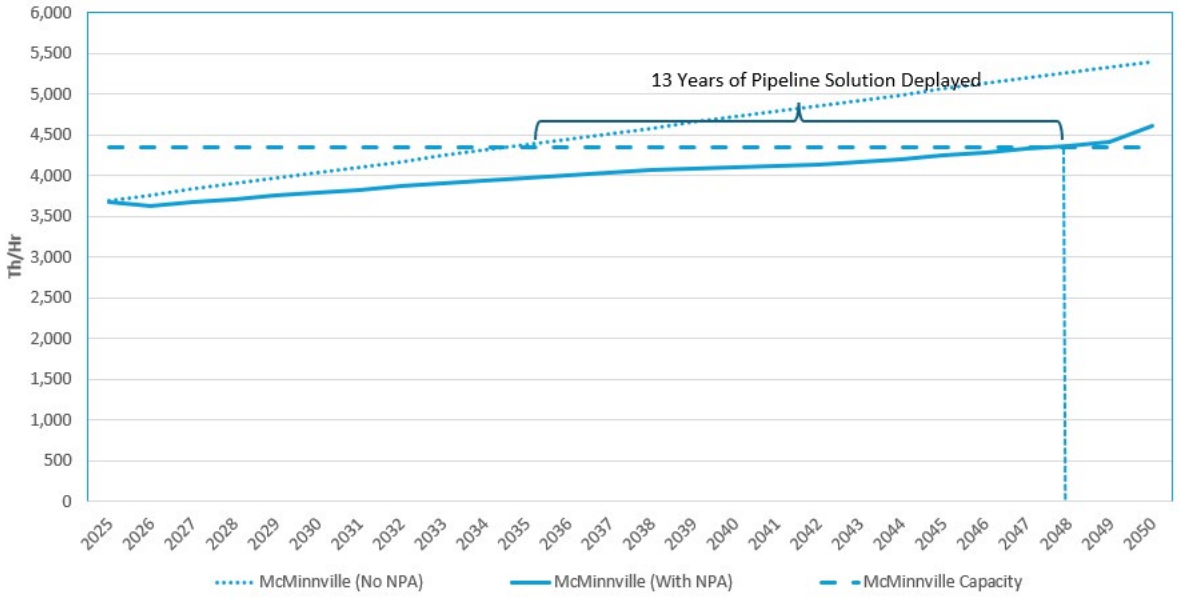
- **GeoTEE**: Pursuing the highly likely level of GeoTEE effort along with the corresponding implementation costs as identified in ETO's analysis.
- **BYOT DR**: Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.
- **Behavior DR:** Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

Table 12.5 summarizes the GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the McMinnville area, and Figure 12.13 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDSM NPA efforts in McMinnville from 2026 to 2048 together can cost-effectively delay the pipeline solution by 13 years. Note that the benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delayed pipeline investments in McMinnville.

Table 12.5: GeoDSM Summary for McMinnville

GeoDSM	Peak Hour Load Savings, Therms/Hour		Annual Energy Savings, Therms/Year		Benefit/Cost Ratio
	Start Year - 2026	End Year - 2048	Start Year - 2026	End Year - 2048	
GeoTEE[289]	23	540	25,944	596,712	4.08
BYOT DR	11	230	389	8,265	2.36
Behavioral DR	102	137	1,017	1,373	1.08

Figure 12.13: McMinnville Peak Hour Load Forecast With and Without GeoDSM NPAs



12.7.1.3 Preferred Option

The distribution capacity in McMinnville is projected to be exceeded in 2035. To defer or avoid the supply side pipeline solution, the Company's preferred option is to deploy the GeoDSM NPAs as described above starting from 2026 while keeping monitoring load and system pressures and updating the GeoDSM NPA analysis annually. The GeoDSM NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure

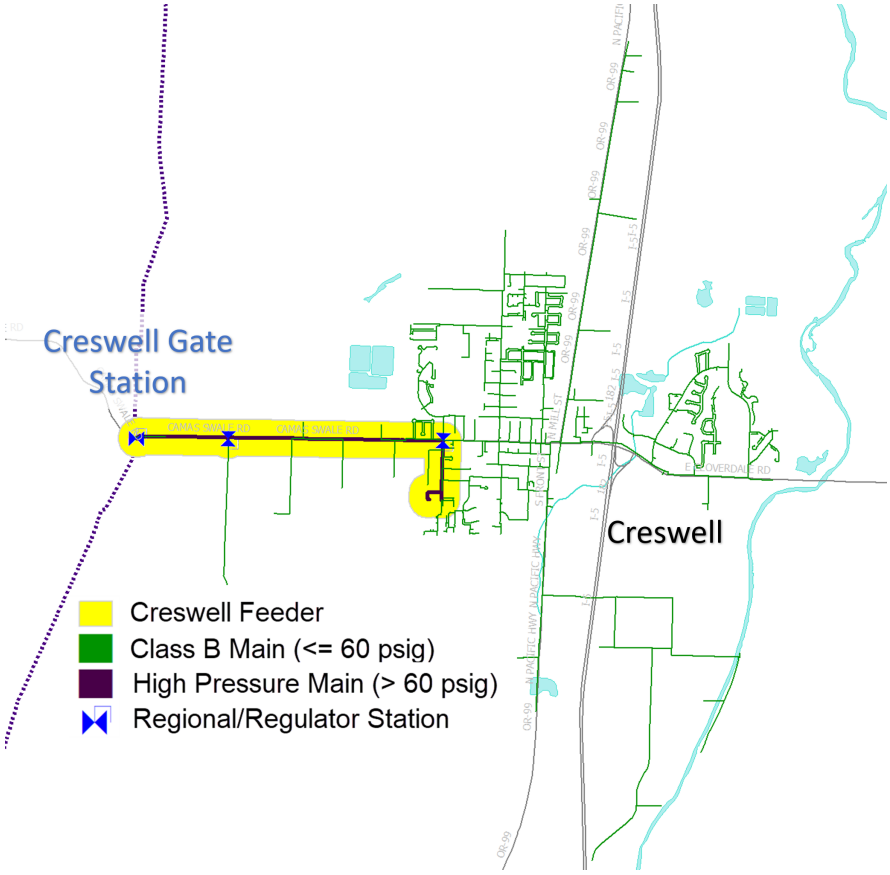
[289] ETO's GeoTEE efforts will start in 2027 and the peak hour load and annual energy savings in 2026 in the table represent the savings that can be achieved at the historical level of EE efforts in this area.

monitoring and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.

12.7.2 Creswell

The Creswell Feeder is a 1.9-mile-long, 3.5-inch high-pressure steel pipeline with a Maximum Allowable Operating Pressure (MAOP) of 150 psig. The system has a single source of gas, Creswell Gate Station, and supplies gas to the city of Creswell. Synergi™ Gas modeling shows that the pipeline can support up to an additional 80 Th/hr load. An image of the Creswell Feeder is shown in Figure 12.14.

Figure 12.14: Creswell Feeder



12.7.2.1 Supply Side Option

The proposed pipeline solution for Creswell involves uprating the 1.9 miles of 3.5-ich wrapped steel from Creswell Gate Station to the end of the high pressure main. This uprate includes increasing the MAOP from 150 psig to 300 psig. The project would increase available capacity from 80 Th/hr to approximately 900 Th/hr.

12.7.2.2 Demand Side Option – GeoDSM Non-Pipe Alternatives

For the same reason mentioned in the McMinnville section, the focus of the non-pipe alternative (NPA) analysis of the demand side options demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

- **Historical EE**: No GeoTEE effort is recommended by ETO given the time and resource constraints in this area; but the historical level of EE effort will be pursued along with the corresponding implementation costs as identified in ETO's analysis.[290]
- **BYOT DR**: Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.
- **Behavior DR:** Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

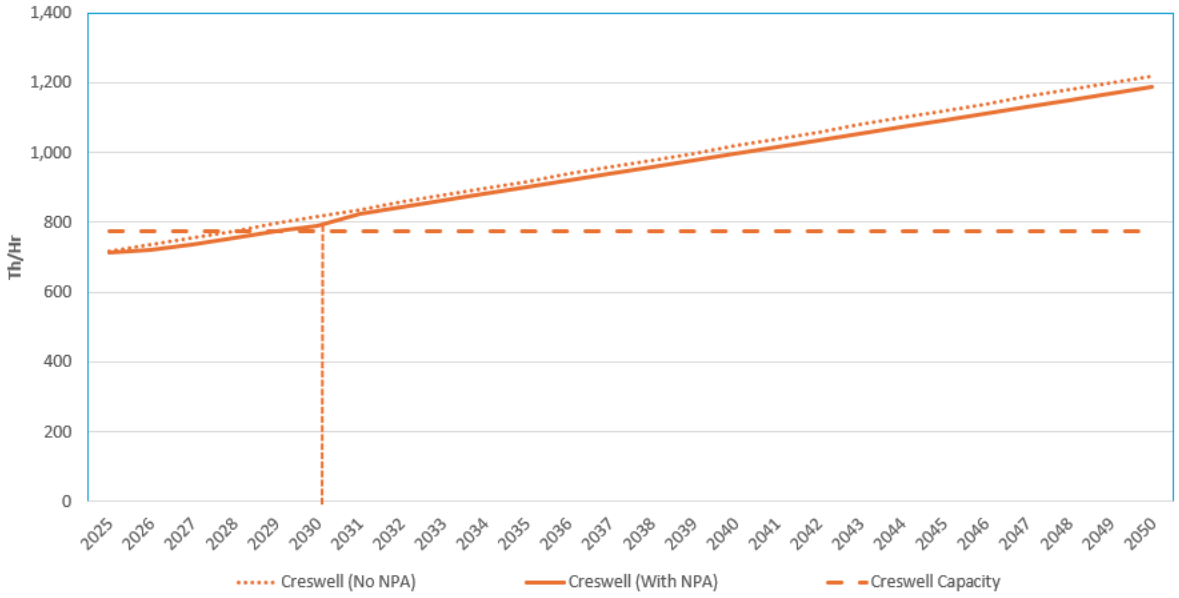
Table 12.6 summarizes the GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the Creswell area, and Figure 12.15 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDR efforts in Creswell from 2026 to 2030 together with a historical level of EE can cost-effectively delay the pipeline solution by two years. Again, the benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delaying pipeline investments in Creswell.

Table 12.6: GeoDSM Summary for Creswell

GeoDSM	Peak Hour Load Savings, Therms/Hour		Annual Energy Savings, Therms/Year		Benefit/Cost Ratio
	Start Year - 2026	End Year - 2030	Start Year - 2026	End Year - 2030	
Historical EE	2	6	1,726	5,178	1.54
BYOT DR	3	5	91	188	2.19
Behavioral DR	12	15	119	148	6.43

[290] Please see Appendix J for ETO's Memorandum on GeoTEE for more information.

Figure 12.15: Creswell Peak Hour Load Forecast With and Without GeoDSM NPAs



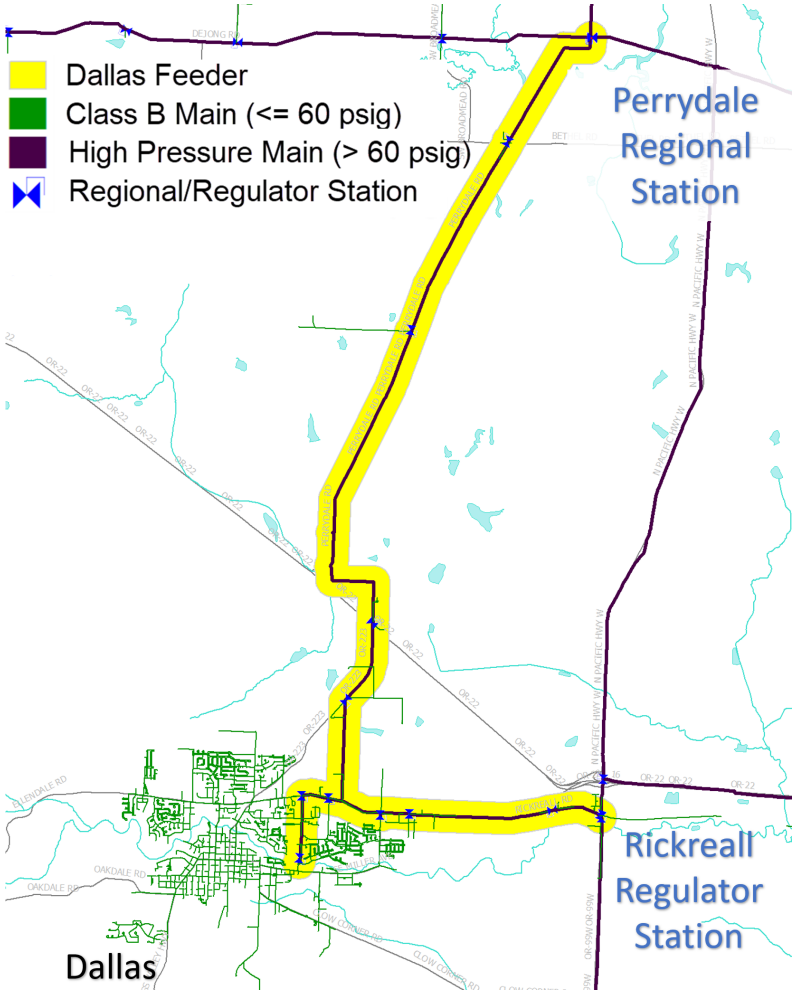
12.7.2.3 Preferred Option

The distribution capacity in Creswell is projected to be exceeded in 2028 and the GeoDSM efforts can delay the pipeline solution by only two years to 2030. The Company's preferred option in this area is to deploy the GeoDSM NPAs and make all necessary preparations for the pipeline solution as described above starting from 2026 since both the GeoDSM NPAs and the pipeline solution take time to implement. In the meantime, the Company will keep monitoring the load and system pressure and update the pipeline and GeoDSM NPA analysis annually. Both the pipeline and the NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure monitoring and pipeline and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.

12.7.3 Dallas

The Dallas Feeder is a 6-inch high-pressure pipeline rated at 175 psig MAOP, serving the community of Dallas, Oregon. It is a bi-directional pipeline, receiving gas from both Perrydale (via the Central Coast Feeder) and Rickreall (via the Mid-Willamette Valley Feeder). System modeling indicates that, under peak-day conditions the lowest pressure on the Dallas Feeder would be approximately 115.6 psig, which is 32 pressure drop. An image of the Dallas Feeder is shown in Figure 12.16.

Figure 12.16: Dallas Feeder



12.7.3.1 Supply Side Option

The Dallas Feeder pipeline solution includes two upgrades aimed to increase capacity to address potential growth. The first project includes replacing approximately 1100 ft of high pressure 4-inch wrapped steel with 6-inch wrapped steel. The second project is to uprate 15 miles of 6-inch wrapped steel from an MAOP of 175 psig to 300 psig. The two projects would increase the available capacity from 80 Th/hr to approximately 900 Th/hr.

12.7.3.2 Demand Side Option – GeoDSM Non-Pipe Alternatives

For the same reason mentioned in the McMinnville section, the focus of the non-pipe alternative (NPA) analysis of the demand side options demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

- **GeoTEE**: Pursuing the highly likely level of GeoTEE effort along with the corresponding implementation costs as identified in ETO's analysis.
- **BYOT DR**: Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.
- **Behavioral DR:** Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

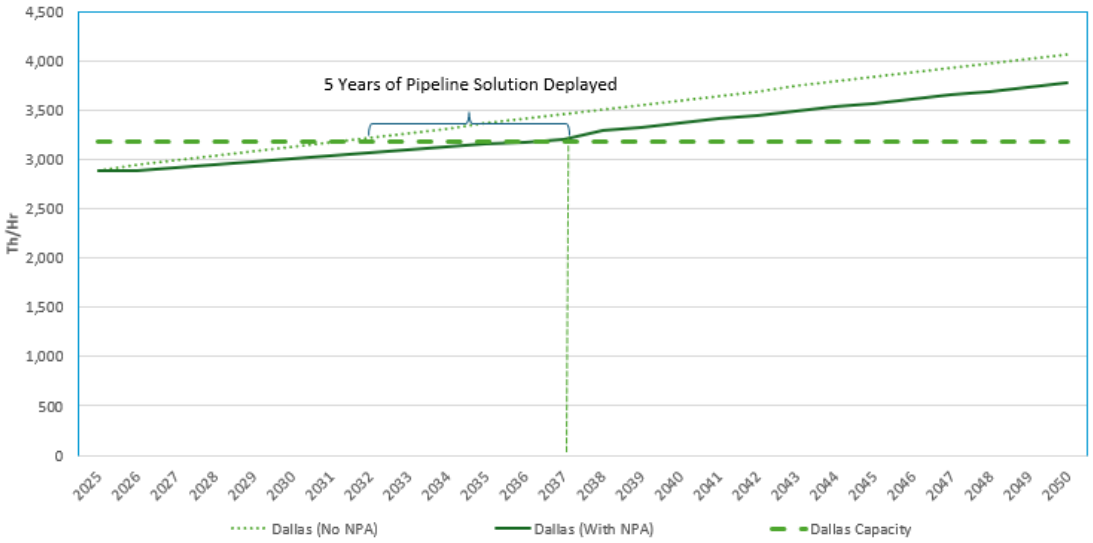
Table 12.7 summarizes GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the Dallas area, and Figure 12.17 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDSM NPA efforts in Dallas from 2026 to 2037 together can cost-effectively delay the pipeline solution by five years. The benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delayed pipeline investments in Dallas.

Table 12.7: GeoDSM Summary for Dallas

GeoDSM	Peak Hour Load Savings, Therms/Hour		Annual Energy Savings, Therms/Year		Benefit/Cost Ratio
	Start Year - 2026	End Year - 2037	Start Year - 2026	End Year - 2037	
GeoTEE[291]	13	159	13,619	163,430	4.13
BYOT DR	7	51	246	1,830	2.67
Behavioral DR	38	43	380	432	2.57

[291] ETO's GeoTEE efforts will start in 2027 and the peak hour load and annual energy savings in 2026 in the table represent the savings that can be achieved at the historical level of EE efforts in this area.

Figure 12.17: Peak Hour Load Forecast With and Without GeoDSM NPAs



12.7.3.3 Preferred Option

The distribution capacity in Dallas is projected to be exceeded in 2032 and the GeoDSM efforts can delay the pipeline solution by five years to 2037. The Company's preferred option in this area is to deploy the GeoDSM NPAs as described above starting from 2026 since the GeoDSM NPAs take time to implement. In the meantime, the Company will keep monitoring the load and system pressures and update the pipeline and GeoDSM NPA analysis annually. Both the pipeline and the NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure monitoring and pipeline and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.

13 | Action Plan

NW Natural®

Based upon the analysis in previous chapters, this chapter details the activities the Company intends to take to maintain safe, reliable, and affordable energy service for customers at the lowest reasonable cost while accounting for risks and meeting compliance obligations.

In Oregon, a proceeding to update IRP guidelines is underway and whilst a similar docket has not been initiated in Washington, the Company is trying to implement some of the changes that might be of benefit to both states and readers of this report. There are two updates in particular that are presented in the 2025 IRP.

Firstly, the 2025 IRP includes a Long-Term Resource Strategy. The Long-Term Resource Strategy reflects what the Company plans to do to meet customer needs and comply with all federal and state energy policies over the next 20 years while balancing these plans with the high degree of uncertainty that the Company is facing. To this end, the Company sets forth enabling strategies that it believes are worthy of exploration as well as enabling strategies to help enhance optionality that promote a low-risk strategy for the action plan.

Secondly, the Company has extended its Near-Term Action Plan from two to four years to now include two to five years. While the Company expects to file another IRP within five years, including the additional year in the Near-Term Action Plan provides readers with additional insight into the near-term actions of the Company.

Both the Long-Term Resource Strategy and the Near-Term Action Plan are informed by the analyses discussed throughout the IRP.

Specific items in the Long-Term Resource Strategy are presented first and labeled with the prefix A. Items for the Near-Term Action Plan are presented second and labeled with the prefix B.

13.1 Long-Term Resource Strategy

The following sections present the Company's long-term resource strategy. Given the high degree of uncertainty, the Long-Term Resource Strategy is centered around optionality. You will see low regret strategies that take into consideration future needs, risks, and technologies whilst recognizing that we will learn more with the next IRP cycle.

13.1.1 System Capacity and Energy Long-Term Resource Strategies

To meet both current and future customer capacity and resource needs, the Company intends to use the following strategies and approaches.

A-1. Continue to leverage cost-effective energy efficiency to reduce energy and peak demand requirements.

A-2. Continue to expand existing cost-effective demand response programs and explore the cost effectiveness of demand response offerings to meet peak demand requirements.

A-3. Continue to rely on existing resources and incremental amounts of Mist Recall to be able to meet peak demand requirements while evaluating other potential incremental options, such as city gate deals or increasing Newport Takeaway, to reliably serve design peak day demand.

A-4. Regularly update peak day forecasts and design winter load forecasts to ensure an appropriate mix of pipeline and storage resources required to reliably serve customers throughout the winter.

A-5. Use NW Natural resource optimization tool to evaluate pipeline contract extensions or capacity release deals under all demand- scenarios conducted in this IRP and maintain interstate pipeline options for customers whenever possible.

13.1.2 Oregon Compliance Long-Term Resource Strategies

In order to meet both current and future customer compliance resource needs in Oregon, the Company intends to use the following strategies and approaches. In addition to these approaches, additional compliance strategies are discussed below in the enabling strategies section.

A-6. Continue to leverage cost-effective energy efficiency to reduce compliance resources requirements.

A-7. Plan and purchase compliance resources as needed to meet a 95th percentile emissions obligation profile for the upcoming CPP compliance period.

A-8. Bank any DEQ distributed allowances that result from this planning and apply them to a future compliance period.

A-9. Rely on incremental CCI purchases, RTCs, and RNG as other alternatives develop for CPP compliance.

A-10. Monitor and evaluate any opportunities for purchasing compliance instruments from other covered entities.

13.1.3 Washington Compliance Long-Term Resource Strategies

To meet both current and future customer compliance resource needs in Washington, the Company intends to use the following strategies and approaches. In addition to these approaches, additional compliance strategies are discussed below in the enabling strategies section.

A-11. Continue to leverage cost-effective energy efficiency to reduce compliance resources requirements.

A-12. Plan and purchase compliance resources as needed to meet a 95th percentile emissions obligation profile for the upcoming CCA compliance period.

A-13. Engage in quarterly and Allowance Price Containment Reserve (APCR) allowance auctions to acquire CCA allowances, as needed.

A-14. Monitor the availability of qualified offsets and purchase any offsets that are cost-competitive with allowance prices.

A-15. Bank any unused allowances that results from this planning and apply those to the next compliance period to decrease our emissions obligation for the next compliance period.

A-16. Monitor the secondary allowance market and evaluate opportunities for participation.

A-17. Rely on the availability of ceiling price allowances up to the point where the allowance ceiling price exceeds the cost of other alternatives for CCA compliance.

13.1.4 System Enabling Long-term Compliance Strategies

A-18. Hybrid heating (dual-fuel space heating systems) presents a promising approach to reducing emissions on the gas system, while still maintaining reliability, affordability, and optionality for both energy systems. Accordingly, NW Natural will develop programs that promote the use of hybrid space heating systems and joint system planning.

A-19. Continue to evaluate and pursue RNG development projects and RTC purchases that qualify for voluntary SB 98 in Oregon and HB 1257 in Washington to continue to take steps forward with reducing the emissions associated with customers' use of the gas system.

A-20. Given the forecasted future reliance on alternative fuels and CCUS in all scenarios, continue to monitor market dynamics and update information as these resources develop.

A-21. Continue to find opportunities for gas and electric joint system planning to achieve emission reduction goals as affordably and reliably as possible.

13.1.5 Long-term Equity Enabling Strategy

A-22. Perform an Energy Burden Assessment at least every four years (pending current events at the time) to build upon our knowledge and analysis of low-income customers to inform energy affordability focused programs with the intent to continue to reduce energy burden for the most burdened customers.

13.2 Near-term Action Plan (5 years)

To meet both current and future customer capacity and resource needs, the company intends to pursue the following near-term actions.

13.2.1 System Capacity Resource Action Items

B-1. Meet customer peak day deliverability requirements by acquiring peak day energy efficiency and recalling Mist over the next 5-years, subject to updated load forecasts, information about Woodfibre LNG, other updates to our existing resources, or updated information on alternative options as follows:

Gas Year	Peak Day Energy Efficiency	Mist Recall
2026-2027	7,500 Dth/day	5,000 Dth/day
2027-2028	8,500 Dth/day	65,000 Dth/day
2028-2029	9,000 Dth/day	5,000 Dth/day
2029-2030	9,000 Dth/day	-
2030-2031	10,000 Dth/day	5,000 Dth/day

13.2.2 Oregon Compliance Resource Action Items

B-2. Working with Energy Trust of Oregon, acquire cost-effective first year energy efficiency therm savings IRP targets outlined below, or the revised amounts identified by the Energy Trust Board over the next 5 years through existing programs for residential, commercial and industrial sales customers.

Calendar Year	Oregon Sales First Year Therm Savings Targets
2026	5.518 - 6.56 million
2027	6.209 - 7.17 million
2028	6.494 - 7.90 million
2029	6.609 - 8.00 million
2030	7.147 - 8.68 million

B-3. Continue to expand the energy efficiency programs for Oregon transportation customers.

B-4. Maximize CCI purchases of 15 percent of NW Natural's emissions obligation in the first CPP compliance period, 2025-2027 calendar years, and 20 percent of NW Natural's emissions obligation in the second and third compliance periods, 2028-2029 and 2030-2031 calendar years as shown below:

Calendar Year	Expected # CCI Purchases*
Compliance Period 1: 2025-2027	2,014,000
Compliance Period 2: 2028-2029	1,712,000
Compliance Period 3: 2030-2031	1,677,000
Notes: *Actual CCI amounts will be weather dependent.	

B-5. Bank any DEQ distributed instruments from the first CPP compliance period that are in excess of NW Natural's emissions obligation.

B-6. As identified in the Preferred Resource Portfolio (PRS.a results) and in all sensitivities in scenario 1 except for S1.a, acquire RNG from a local on-system water resource recovery

facility as set forth in the table below and retire the RTCs on behalf of customers consistent with CPP compliance.

Calendar Year	Expected RNG Volumes from Project (Dth/year)
2027	5,000
2028	35,000
2029	35,000
2030	35,000

See Appendix M for additional information.

B-7. As identified in the Preferred Resource Portfolio (PRS.a results), synthetic gas is a potential cost-effective emission reduction pathway. Developing synthetic methane derived from woody biomass could have significant additional benefits such as a wildfire mitigation program. Accordingly, NW Natural will develop a Biomass Derived Synthetic Methane Feasibility Study. Conduct a detailed 12-month study assessing woody biomass feedstocks in Oregon for synthetic methane production via gasification + syngas methanation and CO2 + green hydrogen methanation. See Appendix M for more details about the study.

13.2.3 Washington Compliance Resource Strategies

B-8. Acquire cost-effective first year energy efficiency therm savings as outlined for residential and commercial sales customers below.

Calendar Year	Washington Sales First Year Therm Savings Targets
2026	225,000 - 383,000
2027	267,000 - 405,000
2028	337,000 - 457,000
2029	427,000 - 502,000
2030	533,000 - 543,000

B-9. Continue to develop energy efficiency programs for Washington transportation and industrial sales customers.

B-10. Purchase compliance offsets as they become available and are forecasted to be lower cost than auction allowances.

B-11. Rely on auction allowance purchases to meet remaining CCA compliance after accounting for offset purchases and any RNG procurement for the next 5-years.

13.2.4 Multi-state Compliance Resource Action Items

B-12. Continue to acquire RNG to achieve goals as set forth below to enable NW Natural to continue to reduce emissions associated with customers' use of the gas system, achieve compliance under CPP {while maximizing CCI purchases (see B-4 above)} and compliance under the CCA, while remaining in cost containment parameters established in SB 98 and HB 1257.

Calendar Year	Expected RNG Purchases as Percentage of Total Sales Load
2026	4%
2027	5%
2028	5%
2029	5%
2030	5%

B-13. Energy Efficiency remains a key demand side resource and compliance resource for the Company. Accordingly, NW Natural will develop a Commercial Gas Heat Pump pilot beginning in 2026. See Appendix M for more information.

B-14. As identified in the Preferred Resource Portfolio (PRS.a results), Carbon Capture and Sequestration is a near-term compliance resource for the CPP. Accordingly, NW Natural will develop a Geological Screening Study for CO2 Sequestration in Northwest Oregon. See Appendix M for additional information.

B-15. As identified in the Preferred Resource Portfolio (PRS.a results), Carbon Capture and Sequestration is a compliance resource for the CPP and CCA. Accordingly, NW Natural will develop a commercial CCUS pilot beginning in 2026. See Appendix M for more information.

B-16. Develop a hybrid heating pilot that explores joint system planning with an electric utility partner, including demand response/capacity payments. File this pilot (or provide status update) on or before the first IRP Update.

B-17. Develop a hybrid heating program providing cost effective emissions reduction incentives.

13.2.5 Oregon Distribution System Action Items

13.2.5.1 Creswell Area

B-18. Raise incentives for customers in the Creswell area for the BYOT program for the next 3-years (2026-2028) aimed at achieving 3.6 peak therm hour savings at a cost not to exceed an incremental $2,000 to baseline.

B-19. Pursue a 3-year Geo Behavioral DR program with large commercial customers and industrial customers in the Creswell area to achieve 13.4 peak hour therms at a cost not to exceed $24,400.

B-20. Continue scoping the Creswell Uprate of approximately 1.9 miles of 3" and 2" wrapped steel main from an MAOP of 150 psig to 300 psig, between Creswell Gate Station to the end of High Pressure main, with an anticipated in-service date of 2030.

B-21. Update analysis for Creswell area on an annual basis and report updated analysis through IRP Updates or subsequent IRPs until the Uprate is put into service or the analysis shows the Uprate is no longer needed. The Company anticipates continuing action items B-18 – B-20 beyond the 3-year action plan window and updating this analysis will inform the decision to continue or discontinue these NPA projects.

13.2.5.2 Dallas Area

B-22. In partnership with Energy Trust of Oregon, plan and develop a 3-year GeoTEE project starting in 2027 in the Dallas area with the goal of achieving 20 peak hour localized therm savings incremental to baseline energy efficiency efforts.

B-23. Raise incentives for customers in the Dallas area for the BYOT program for the next three years (2026-2028) aimed at achieving 9.8 peak therm hour savings at a cost not to exceed an incremental $8,800 to baseline.

B-24. Pursue a 3-year Geo Behavioral DR program with large commercial customers and industrial customers in the Dallas area to achieve 39.0 peak hour therms at a cost not to exceed $98,900.

B-25. Continue scoping the Dallas System Reinforcement, which includes: a) replacing approximately 1,100 ft of 4" wrapped steel main with 6" wrapped steel main and b) uprating the Dallas Feeder from an MAOP of 175 psig to 300 psig, with an anticipated in-service date of 2036.

B-26. Update analysis for Dallas area on an annual basis and report updated analysis through IRP Updates or subsequent IRPs until the system reinforcement is put into service or the analysis shows the system reinforcement is no longer needed. The Company anticipates continuing action items B-22 – B-25 beyond the 3-year action plan window and updating this analysis will inform the decision to continue or discontinue these NPA project.

13.2.5.3 McMinnville

B-27. In partnership with Energy Trust of Oregon, plan and develop a 3-year GeoTEE project starting in 2027 in the McMinnville area with the goal of achieving 35 peak hour localized therm savings incremental to baseline energy efficiency efforts.

B-28. Raise incentives for customer in the McMinnville area for the BYOT program for the next three years (2026-2028) aimed at achieving 15.6 peak therm hour savings at a cost not to exceed an incremental $18,800 to the baseline.

B-29. Pursue a 3-year Geo Behavioral DR programs with large commercial customers and industrial customers in the McMinnville area to achieve 104.8 peak hour therms at a cost not to exceed $331,500.

B-30. Continue scoping the two options for the McMinnville Feeder System Reinforcement which includes: a) installing compression between the Christensen Regional Station and Amity to raise the line pressure along the McMinnville feeder, increasing pipeline capacity to the McMinnville load center; or b) loop the existing 6-inch McMinnville Feeder with 5.2 miles of 400 MAOP 8" wrapped steel main to increase pipeline capacity to the McMinnville load center, with an anticipated in-service date of 2049. The costs of the two options will be examined annually and the lower cost option will be eventually selected when the pipeline solution is needed to implement.

B-31. Update analysis for McMinnville area on an annual basis and report updated analysis through IRP Updates or subsequent IRPs until the system reinforcement is put into service or the analysis shows the system reinforcement is no longer needed. The Company anticipates continuing action items B-27 – B-30 beyond the 3-year action plan window and updating this analysis will inform the decision to continue or discontinue these NPA projects.

13.2.6 System-wide Near Term Equity Action Item

B-32. Increase community awareness of/involvement in energy planning and utility programs by partnering with community partners and service providers (including peer/local utilities) to bring forward an annual resource fair centered on energy planning topics and resources.

Abbreviations and Glossary

This section is provided to ensure clarity and accessibility of the document for the reader. Industry and technical specific terms used throughout the document are defined. Abbreviations and acronyms used throughout the document are additionally provided to ensure readers have a consistent reference point.

Abbreviation/Term	Meaning
AECO	Alberta Energy Company
AEG	Applied Energy Group
AGA	American Gas Association
AIC	Akaike information criterion
AMA	Asset Management Agreement
AMI	Area median income
ARIMA	Autoregressive integrated moving average
AWEC	Alliance of Western Energy Consumers
Baseload demand	Refers to utility customer demand that is constant over the year
Bcf	A billion cubic feet
BIAW	Building Industry Association of Washington
Biogas	Gaseous fuel, especially methane, produced by fermentation of organic matter
Biomethane	A naturally occurring gas which is produced by anaerobic digestion of organic matter such as dead animal or plant material, manure, sewage, organic waste, etc.
Boiler	A large furnace in which water-filled tubes are heated to produce steam.
Book and Claim Accounting	A chain of custody model which recognizes that environmental attributes (e.g., RTCs) can be separated from physical product and possession of environmental attribute can be used to deliver sustainable product.
Brown Gas	The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included.
Btu	British thermal unit, a unit of measurement for heat or energy equivalent to the amount of heat required to raise

	the temperature of one pound of water by one degree Fahrenheit.
Bundled RNG	RNG including the physical gas molecules and renewable thermal certificate (RTC).
CAGR	Compound Annual Growth Rate
Capacity	The maximum load that a gas pipeline or gas storage facility can carry under existing service conditions.
Cap-and-Invest Program	Section of Washington's CCA, regulated by the Department of Ecology, which sets emissions caps, allowances, and trading mechanisms.
Carbon cap	A limit on the amount of allowable carbon produced in a given region for a defined time period.
Carbon Cap and Trade	A market mechanism to limit carbon emissions. Carbon emissions are capped at a certain level. Allowances are provided to companies and these allowances can be traded. The market sets the price of the allowances, creating a market incentive to reduce carbon emissions.
Carbon credits or allowances	A fixed amount of carbon emissions to be produced is set for a period of time, and allowances or credits are allocated to carbon generators. The idea is that entities producing less carbon than their allowed amount can sell their allowances to other parties who are producing more than their allowed credit allowance. Often these can be traded or re-sold.
CCA	Washington Climate Commitment Act
CCA allowances	A Cap-and-Invest Program mechanism for covered entities to obtain such allowances to cover emissions not reduced within a particular compliance period.
CCI	Community Climate Investment
CCI credit	"an instrument issued by DEQ to track a covered fuel supplier's payment of community climate investment funds, and which may be used in lieu of a compliance instrument, as further provided and limited in this division." OAR 340-271-0020
CD	Contract Demand
CEAG	Community and Equity Advisory Group
CELS	Community Engagement Liaison Services
CHP	Combined Heat and Power
CIS	Customer Information System

Citygate	The point of delivery at which a local gas distribution company takes custody of gas from an interstate pipeline; Meter stations which serve as designated point(s) on a distribution system where the distributor takes delivery of its gas supply from a pipeline source.
Class B (pipeline system)	A pipeline system operating at 60 psig or less
CMM	Customer Management Module
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Cogeneration	The use of a single prime fuel source to generate both electrical and thermal energy in order to optimize the efficiency of the fuel used. Usually, the dominant demand is for thermal energy, with any excess electrical energy being transmitted into the lines of local power supply company.
Common Carrier Pipeline	A pipeline that is connected to the continent-wide natural gas pipeline grid.
Compliance obligation	"Total quantity of covered emissions from a covered fuel supplier rounded to the nearest metric ton of CO2e." OAR 340-271-0020
Compliance resource	A tool used to comply with carbon regulations. These can include program specific credits/instruments, offsets, renewable fuels, energy efficiency, and carbon capture depending on the specific requirements of each regulatory program.
Conservation Potential Assessment (CPA)	Analysis preformed to provide an outlook on the potential amount of energy efficiency or energy conservation that is available within a given area or territory over a defined period of time.
Conversion	An existing residential or commercial building which adds natural gas service to the building and becomes a new NW Natural customer.
CPI	Consumer Price Index
CPP	Oregon Climate Protection Program
CSN	Community Services Network
CUB	Oregon Citizens' Utility Board
Curtailment	A method to balance natural gas requirements with available supply. Usually there is a hierarchy of customers for the curtailment plan. A customer may be required to

	partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and a customer's position in the hierarchy.
Degree day	The number of degrees that the average outdoor temperature falls below or exceeds a base value in a given period of time.
Demand-side resource	An energy resource such as conservation that is based on how energy is used, not produced.
DEQ	Department of Environmental Quality
DERMS	Distributed energy resource management system
Deterministic	A defined set of properties, constraints, or equations that explicitly defines the relationship between variables; deterministic solutions provide a single outcome; contrast with stochastic.
DR	Demand response; reducing peak demand by either shifting or interrupting load.
Draw	The term "*draw*" refers to a single randomized forecast generated from any of the simulation types discussed throughout this IRP.
DSM	Demand-side management
Dth	Dekatherm (or dekatherm), equal to ten therms or one MMBtu
Discount rate	An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value.
Distribution/Distribution System	The pipeline system that transports gas from interstate pipelines to customers.
EBA	Energy Burden Assessment
Ecology	Shorten form of Washington Department of Ecology. Ecology is the agency that administers Washington's Climate Commitment Act (CCA).
EE	Energy Efficiency; EE is a reduction in energy use, production, or distribution as a result of greater efficiency.
EIA	U.S. Energy Information Administration
EITE	Emissions intensive trade exposed
EM&V	Evaluation, Measurement, and Verification
Energy savings	A term used to define the reduced energy usage as a result of energy efficiency initiatives.

End-use consumer	Someone who uses energy to run equipment or appliances, such as for space heating and cooling, ventilation, refrigeration, and lighting.
Entitlement	An event during which gas shippers must not take delivery of more than a specified volume of gas in a day.
EPA	Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
EPPR	Electronic Portable Pressure Recorder
EPRI	Electric Power Research Institute
ERU	Emission Reduction Unit
ETO	Energy Trust of Oregon
Exogenous (variable)	A variable that is independent or determined outside of the model.
FERC	Federal Energy Regulatory Commission
Firm (Sales, Service, Customers)	Service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency.
GAP; GASP	Gas Acquisition Plan; Gas Acquisition Strategy and Policies
Gasco	NW Natural's Portland LNG plant
Gas Day	A period of twenty-four consecutive hours, coextensive with a "gas day" as defined in the tariff of the Transporter delivering Gas to the Delivery Point in a particular transaction.
GCM	Global Climate Model
GDP	Gross Domestic Product
GeoDR	Geographically Targeted Demand Response
GeoDSM	Geographically Targeted Demand Side Management
GeoRNG	Geographically Targeted Renewable Natural Gas
GeoTEE	Geographically Targeted Energy Efficiency
GIS	Geographical information system
GHG	Greenhouse gas
GHP	Gas heat pump or Gas-fired heat pump

GSHP	Ground source heat pump
GTI	Gas Technology Institute or GTI Energy
HDD	Heating degree day
Hedging	Any method of minimizing the risk of price change.
Henry Hub	A natural gas national trading hub typically used for referencing national natural gas prices.
HVAC	Heating, Ventilation, and Air Conditioning
ICF	A global advisory and technology services consultant
Incremental costs	Additional costs that a utility would incur by operating a power plant, the cost of the next MMBtu generated or purchased, or the cost of producing and/or transporting the next available unit of energy above the current base cost previously determined.
Interstate pipeline	Pipelines owned and operated by pipeline companies, where third-party shippers contract for firm and interruptible capacity.
Interruptible service (i.e., Sales or Transportation and also customers(s) of such service)	A service similar to firm service in operation, but a lower priority for scheduling, subject to interruption if capacity is required for firm service. Interruptible customers trade the risk of occasional and temporary supply interruptions in return for a lower service rate.
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
Jackson Prairie	A gas storage facility near Centralia, Washington, contracted by NW Natural.
LDC	Local Distribution Company
Least-cost planning	Method of meeting future energy needs by acquiring the lowest cost resources first, considering all possible means of meeting energy needs and all resource costs including construction, operation, transmission, distribution, fuel, waste disposal, end-of-cycle, consumer, and environmental costs.
Levelized (cost)	Equal periodic cost where the present value is equivalent to that of an unequal stream of periodic costs (typically expressed as a periodic rate; e.g., levelized cost per year).
LFG	Landfill Gas
LINA	Low Income Needs Assessment
LNG	Liquefied Natural Gas

Load	The demand for energy/power averaged over a specific time period.
Load center	Geographical service area or collection of areas defined by NW Natural.
Load factor	Ratio of total energy (example: therms) used in a period divided by the possible total energy used within the period, if used at the peak demand during the entire period.
MAOP	Maximum allowable operating pressure
MAPE	Mean absolute percentage error
Marginal cost	The cost of producing the marginal, or next, unit.
MBtu	Thousand British thermal units
MBtu/day	Thousand British thermal units per day
Mcf	Thousand cubic feet
MDDO	Maximum daily delivery obligation
MDT	Thousand dekatherms
MFA	Maul, Foster, and Alongi
MMBtu	Million British thermal units
MMBtu/day	Million British thermal units per day
MMcf	Million cubic feet
MMDT	Million dekatherms
MPH (or mph)	Velocity in miles per hour
MSA	Metropolitan Statistical Area: a geographical area as defined by the U.S. Office of Management and Budget (OMB).
M-RETS	Midwest Renewable Energy Tracking System, an environmental attribute tracking platform.
MTCO2e (or MT)	A metric ton (tonne) of carbon dioxide equivalent
Monte Carlo (simulation, analysis)	Statistical methods based on repeated sampling to simulate probability-based outcomes.
Moving average	A statistical average calculated over a rolling period in time series data.
NEEA	Northwest Energy Efficiency Alliance
New Construction	Newly constructed residential or commercial building with natural gas service which become a new NW Natural customer.

Nominations	The process of scheduling gas on the interstate pipeline. The shipper notifies the pipeline the volume and receipt point and the delivering receipt point in accordance with the transportation contract.
Normal distribution	Commonly used probability distribution in statistical analysis.
Normal weather	Expected weather conditions based on observed historical data.
NPVRR (also PVRR)	Net present value revenue requirement
NREL	National Renewable Energy Lab
NWEC	NW Energy Coalition
NWGA	Northwest Gas Association
NWPCC	Northwest Power and Conservation Council
NWPL	Northwest Pipeline
ODOE	Oregon Department of Energy
OEA	State of Oregon's Office of Economic Analysis
Off-peak	Refers to a period of relatively low demand on a natural gas system. This can also refer to low demand months.
OLIEE	Oregon Low Income Energy Efficiency
OPUC	Public Utility Commission of Oregon
ORSC	Oregon Residential Specialty Code
OSP	Open Solicitation Program
Outage	A period, scheduled or unexpected, during which the transmission of power stops or a particular power-producing facility ceases to provide generation.
Peak (day, hour)	A period in which a maximum value of a process (e.g., gas demand) occurs or is expected to occur.
Peak day shaving	A peak day is the one day (24 hours) of maximum system deliveries of gas during a year. Peak shaving is a load management technique where supplemental supplies, such as LNG or storage gas, are used to accommodate seasonal periods of peak customer demand.
PEW	Public Engagement Webinar
PGA	Purchased Gas Adjustment
Planning Horizon	The timeframe which the IRP evaluates the net present value costs and outcomes for resource decisions. For this IRP the planning horizon is 2025-2050.

PLEXOS®	Optimization modeling software used by NW Natural
Power-to-Gas (P2G)	A power-to-gas system uses electricity to split water into hydrogen and oxygen through electrolysis.
PNW	Pacific Northwest
PSIG	Pounds per square inch gauge, unit of pressure measurement
PST	Pacific Standard Time
Public Counsel	The Public Counsel Unit of the Washington State Attorney General's Office represents residential and small business interests in utility proceedings before the Washington Utilities and Transportation Commission (WUTC).
PVRR (also NPVRR)	Present value of revenue requirement
REC	Renewable energy certificate
Reference Case	An analytical scenario (e.g., forecast scenario) to which other scenarios are compared.
RFP	Request for proposal
RIN	Renewable identification number
RNG	Renewable natural gas. “RNG” is gas that satisfies the definition of “renewable natural gas” or “renewable hydrogen” in either Oregon or Washington. **Oregon definition per ORS 757.392(7)**: “Renewable natural gas” means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or c. Waste carbon dioxide. **Washington definitions per RCW 54.04.190(6):** "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.
RPS	Renewable Portfolio Standards

RTC	Renewable thermal certificate An RTC is a *sole* claim to the environmental benefits of a dekatherm of RNG, separate from the physical gas of RNG (i.e., unbundled RNG).
RTF	Regional Technical Forums
Sales (service, customers)	Service provided whereby NW Natural acquires gas supply and delivers it to customers.
SBCC	State Building Code Council (Washington)
SCADA (system)	Supervisory Control and Data Acquisition
SME	Subject Matter Expert
SMI	State Median Income
SOW	Scope of Work
Stochastic	The property of being randomly distributed or including a random component; a stochastic variable often feeds into a forecast, property or constraint providing a range of outcomes; contrasts with deterministic.
Supply-side resource	Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options.
Synergi™ Gas	A computer-based model used to simulate the physical natural gas system.
Synthetic Methane	A renewable gas produced by capturing carbon dioxide (CO2) and combining it with green hydrogen.
T-DSM	Targeted demand-side management
TF-1	Northwest Pipeline's rate schedule designation for firm, year-round transportation service on its system.
TF-2	Northwest Pipeline's rate schedule designation for firm transportation service on its system from certain storage facilities (e.g., Jackson Prairie). TF-2 service may have the same scheduling priority as, or may be subordinate/secondary in priority to, TF-1 service.
Therm	Unit of heat or energy measurement: 1 Therm = 29.3 KWh = 100,000Btu
Transportation (service, customers)	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility.
TRC	Total Resource Cost
TWG	Technical Working Group

UCT	Utility Cost Test
UES	Unit Energy Savings
UPC	Use per customer
WACOG	Weighted average cost of gas
WALIEE	Washington Low Income Energy Efficiency
Weatherization	The use of structural changes, such as storm windows and insulation, in order to decrease use of heating fuel.
Weather normalization	A method of averaging energy use under normal conditions. Also known as weather corrected, normalization enables comparison of energy use across periods of time or geography.
WEC	Waste emissions charge
WSEC	Washington State Energy Code
WUTC	Washington Utilities and Transportation Commission