NW Natural IRP Electrification Analysis

Final Report

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Table of Contents

Disclaimer:

Executive Summary

Introduction

Electric utility IRPs in the Pacific Northwest (PNW) have only recently started considering building electrification. The limited details available in this area left an information void on how different levels of building electrification might impact costs, emissions, and reliability concerns in the energy sector. Absent joint system planning gas utilities have been asking in their planning processes to evaluate the potential impact of building electrification on their systems and customers. In response, NW Natural engaged ICF to analyze the cost of large-scale electrification on customers in NW Natural's service area. Additional outside experts with electric planning and operations backgrounds (the "Advisory Group") were also hired to guide, critique, and pressure-test the assumptions and analysis. The purpose of this study is to evaluate costs and impacts from a variety of different building electrification scenarios on gas customers and on electric generation, transmission, and distribution infrastructure. This analysis compares and contrasts different "what if" scenarios and it does not mean that NW Natural or ICF endorses any of these illustrative scenarios as realistic or feasible.

Electric Planning Environment

The electric grid in Oregon and Washington is under pressure. Costs are rising, reliability is becoming a concern, and big changes are coming. These changes will need careful planning to avoid making reliability and affordability problems worse and to avoid "close call" events like one that occurred in January 2024. During that period in January, cold weather put serious strain on the electric grid in the region, leading to the reliability coordinator for the Western Interconnect calling the highest level of Energy Emergency Alert. Some of the major changes and challenges that the electric system will need to prepare for in the coming decades include:

- **Load Growth**: The level of electric demand growth anticipated by electric utility IRPs and regional authorities has been revised upwards in recent years.
- **Changing Generation Options**: Legislation in Oregon and Washington requires expansion of non-emitting supply and removes the ability of some utilities to utilize firm, fossil-fuel based generation.[1]
- **Transmission Availability and Timelines:** New electricity transmission projects in the PNW have often taken 20 to 30 years to develop, despite long-standing efforts to reduce development timelines.
- **Planning for Energy Resiliency:** A shift to a single energy system (electricity), without natural gas infrastructure, could amplify potential resiliency/reliability impacts. For example, during the January 2024 storm, NW Natural indicated that their customers who lost power were still able to use hot water, cooking, fireplaces, and back-up generators.
- **Changes to Electric System Planning Standards:** As electric demand rises and is supplied by more intermittent, weather dependent resources, the industry is evolving its approach to reliability planning.

[1] In Oregon, the state's investor-owned electric utilities (IOU), are subject to these requirements under HB2021, however, these requirements do not apply to the remaining electricity suppliers in the state including public utility districts (PUDs) or consumer-owned utilities (COUs). In Washington, all electricity suppliers in the state are subject to the Clean Energy Transformation Act (CETA).

- **Affordability Concerns:** Residential rates for Oregon's electric IOUs have recently seen some of their highest rate increases in the last 20 years.

These individual changes each create uncertainty, and part of the planning challenge for the electric system is that all these issues need to be considered simultaneously and holistically. This compounds the potential magnitude of change, the range of uncertainty, and the amount of risk and cost associated with planning for a reliable electricity system going forward. Peak demand increases resulting from gas end use electrification would shift seasonal and daily load patterns, and further add to these challenges.. This is particularly true since the Pacific Northwest has increased its share of natural gas-fired generation in the past 10 years to meet loads, a trend that will need to be reversed to comply with the clean electricity mandates described above

The analysis set out in this report focuses on addressing the challenge of currently anticipated load growth for utilities (current electricity utility IRP's) and additional scenarios with different levels of building electrification. This analysis does not capture all the challenges noted above, such as construction timelines and system reliability, which would be expected to make the infrastructure needs and costs in electrification scenarios even higher. More discussion of these challenges can be found in Section 2 of the report.

Overview of the Scenarios Used in the Analysis

NW Natural developed an IRP Reference Case and ICF and NW Natural worked together to define three additional electrification scenarios for simulation. These illustrative 'what if' scenarios, as well as various supporting assumptions, were selected for modeling purposes and are not forecasts based on any specific policies. The electrification scenarios consider specific changes to types of equipment used by existing NW Natural customers and installed in new construction buildings in the Reference Case:

- **Reference Case:** Includes all known codes, policies and energy efficiency expectations and aligns with NW Natural's reference case expectations of building electrification.
- **Modest Customer Electrification:** Aimed to align with utility IRP assumptions about moderate customer adoption levels for building electrification, but with limited level of detail into specific assumptions made by those utilities.[2]
- **All-Electric Buildings:** High levels of building electrification for NW Natural customers, chosen to align with the Oregon Department of Energy's (ODOE) Oregon Energy Strategy Reference Case assumptions. [3] This scenario includes the installation of a mix of standard electric air-source heat pumps (ASHPs) and cold-climate ASHPs, with electric resistance used for any supplemental peak and backup heating needs.
- **Hybrid System Electrification:** The same 'high levels' of building electrification for NW Natural customers as used in the All-Electric Buildings Scenario, but using a 'hybrid heating' approach that

[2] Utilities here refer to electric utilities that supply customers in NW Natural service territories.
[3] 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. 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.

involves the installation of electric ASHPs with gas heating equipment remaining for supplemental peak and backup heating needs, especially during winter peaks. [4] [5]

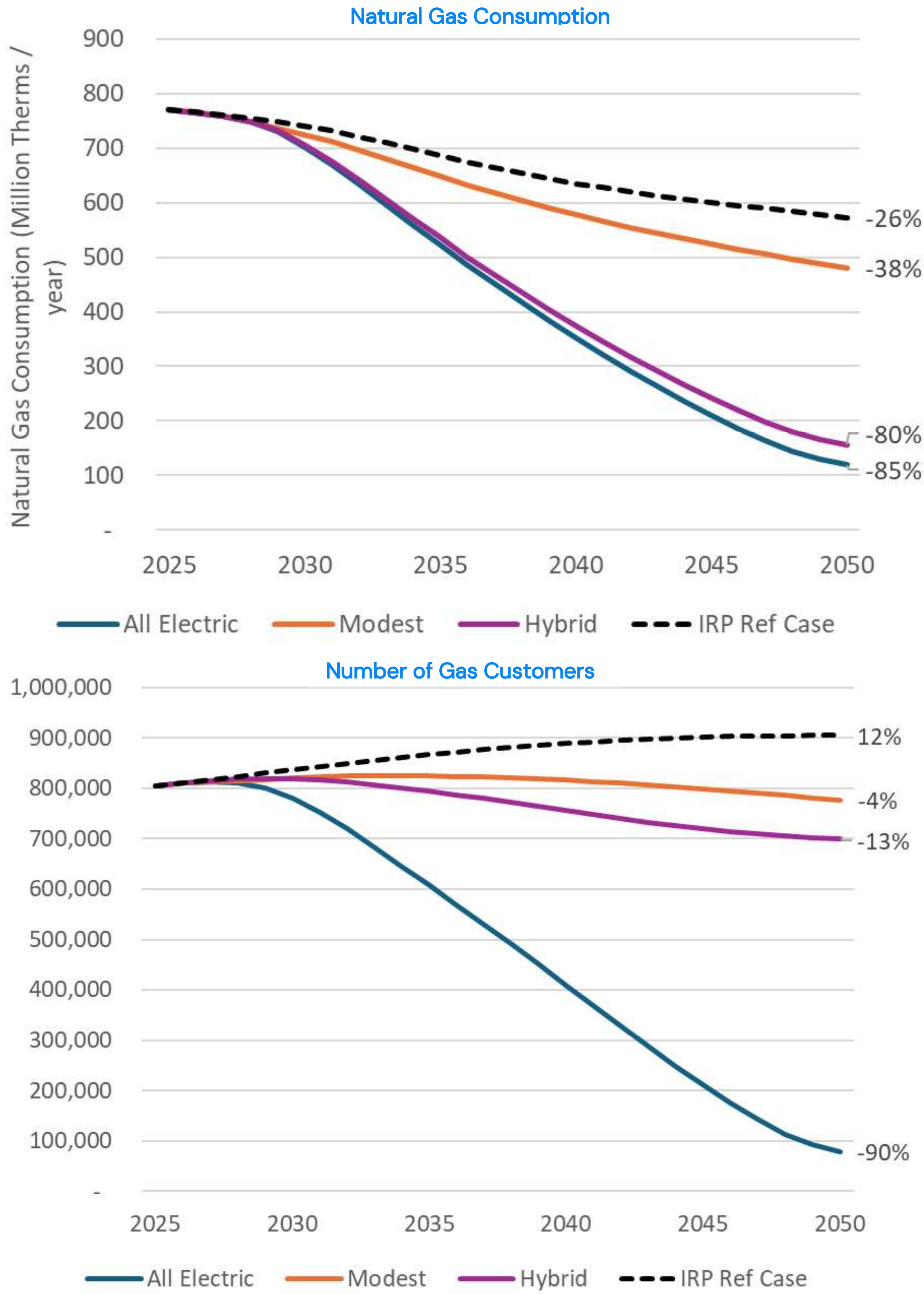
Overview of Study Results: Demand-Side Impacts

The impacts of these four scenarios on NW Natural load and customer count are summarized in Figure ES 1. In the **IRP Reference Case (black dotted lines)** gas consumption declines 26% from 2025 to 2050, while the number of NW Natural customers grows 12% over that same period. This is driven by assumptions for energy efficiency improvements provided to NW Natural by the Energy Trust of Oregon, which are also assumed for the three electrification scenarios. The **All-Electric Buildings scenario (blue lines)** forecasts an 85% drop in customer gas consumption by 2050 relative to 2025, and a 90% decrease of 2050 customers relative to 2025. The **Hybrid System Electrification scenario (purple lines)** shows an 80% drop in customer gas consumption by 2050 relative to 2025, which is similar to the All-Electric Buildings scenario. While gas consumption in this scenario drops significantly, the Hybrid System Electrification scenario only sees customer count decline by 13% from 2025 levels. The Hybrid System Electrification scenario allows the electric system to serve ASHPs most of the time but leverages the gas system to serve the most extreme winter peaks. It does not require the electric system to build out expensive zero emissions peaking capacity to serve this need, like the All-Electric Buildings scenario would.

[4] Hybrid heating combines an air-source heat pump (ASHP) with a natural gas furnace for backup. ASHPs extract heat from outdoor air and are more efficient than conventional electric resistance heating. However, as temperatures drop, their efficiency and capacity decline because it becomes harder to draw heat from colder air. For this reason, ASHPs are typically installed with a backup heat source. While backup can be electric resistance, hybrid heating uses the existing gas furnace, allowing the system to take advantage of the ASHP's high efficiency during milder temperatures while relying on gas equipment to meet peak heating needs during extreme cold.

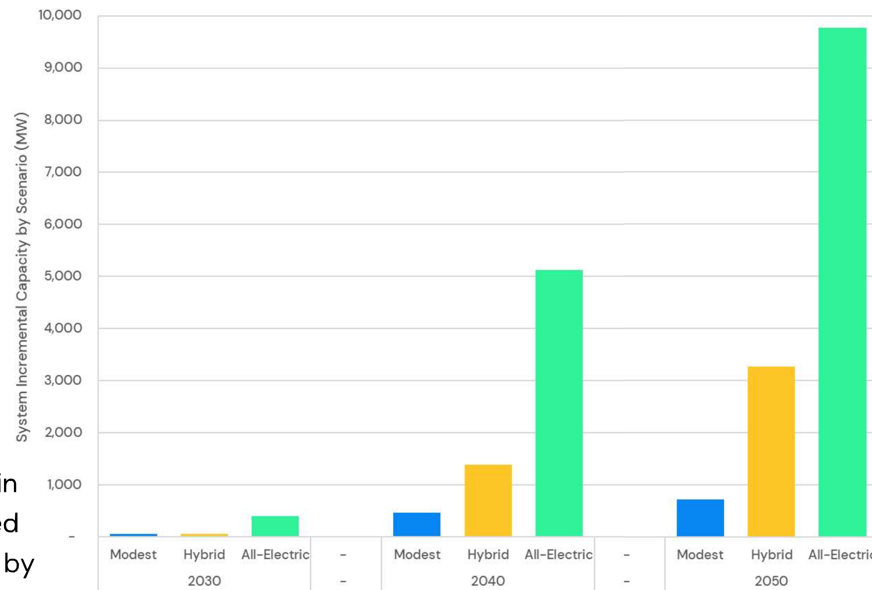
[5] The Hybrid System Electrification and All-Electric Buildings scenarios were intentionally designed to use the same assumptions in almost all areas (e.g., the same level electrification of water heating and cooking electrification) so that the differences in results clearly showcase how hybrid heating (ASHP with gas backup) would change the impacts and costs of electrification.

Figure ES 1: Change in NW Natural Customer Gas Consumption and Customer Count (Residential & Commercial) in Oregon & Washington



Overview of Study Results: Power Sector Impacts

Figure ES 2: System Capacity by Electrification Scenario Incremental to Reference (MW)



ICF modeled the resulting annual and peak electric load impacts from these electrification scenarios and conducted capacity expansion modeling to estimate the mix of electric generation and transmission resource builds that would be required to meet the growing load, while also complying with Oregon and Washington requirements for greenhouse gas (GHG) emission reductions from the power sector. Figure ES 2 shows the incremental capacity, above and beyond the Reference Case, that would be needed to meet growing energy and peak demand needs under the electrification scenarios. By 2050, in the All-Electric Buildings scenario, the installed capacity in Oregon and Washington expands by close to 10,000 MW, as peak demand increases require firm, non-emitting resources. Increased energy needs are met with non-emitting renewable resources, but these resources provide little capacity to reliably meet peak demand. For example, wind generation in Oregon might supply a significant portion of annual energy needs (MWh) but because of the intermittent nature of wind generation (e.g., the wind is not always blowing) only a small portion of wind generation capacity can be relied upon by electric system planners to meet the system's peak electric demand levels in their planning processes. The Hybrid System Electrification scenario mitigates peak demand increases and with that, avoids the need for approximately 6,500 MW of incremental capacity.

Overview of Study Results: Overall Cost Impacts

To provide an indication of the overall impacts from the electrification scenarios, Figure ES 3 shows the following combined incremental annual net costs (relative to the Reference Case)[6]:

- Increased electric costs from generation, transmission, and distribution investments [7]

[6] Since these values 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 to meet its 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).

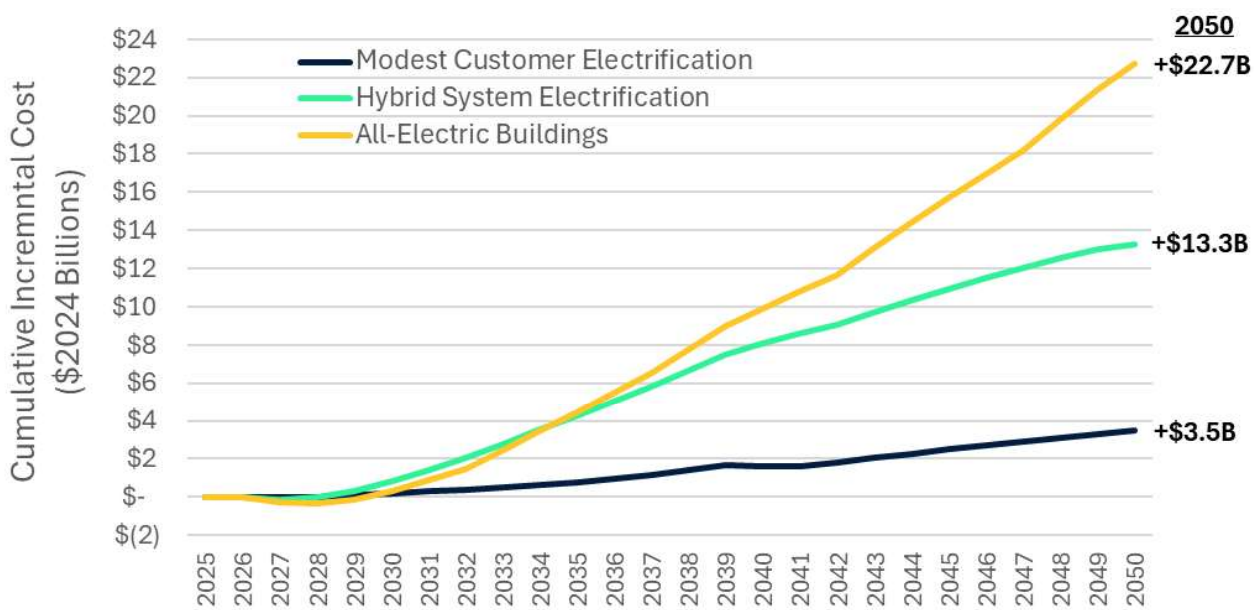
[7] This analysis does not reflect utility-specific assessments that may reduce reserve contributions from resources like battery storage. It also excludes potential changes to planning reserve margins driven by stricter resource adequacy criteria and reliability needs for electrified sectors. Additionally, it lacks detailed reliability evaluations of modeled portfolios under extreme multi-day weather events, which have challenged systems beyond the Pacific Northwest. Finally, this analysis cannot substitute for utilities' own IRPs or regional Resource Adequacy programs and their reliability assessments. These factors would be expected to further increase the costs of electrification scenarios.

- Customer equipment conversions costs to electrify (less Inflation Reduction Act incentives)
- NW Natural commodity & capacity cost savings [8]
- NW Natural reduced emissions compliance costs [4]

Note, this analysis was performed prior to the current Federal Administration's changes to the Inflation Reduction Act incentives. As such, the projected costs for renewable generation investments will be higher than the values shown in this analysis. This study also did not consider other reliability impacts such as wildfire risk, cyber security, or supply chain issues, that in the future could also make the investment into incremental electric generation, transmission, and distribution infrastructure more expensive. Finally, it should also be noted that there are differences between the gas and electric systems in terms of current planning practices related to system reliability, which makes it hard to provide an 'apples to apples' comparison between the two systems. There are additional costs not captured in this analysis that would be required for the electric system to match the more conservative reliability planning criteria used by the gas system.

This analysis finds that all the electrification scenarios are more expensive than the Reference Case (which focuses on energy efficiency and decarbonized gases), but that the Hybrid Electrification approach (maintaining gas backup) is significantly lower cost than the All-Electric approach.

Figure ES 3: Cumulative Total System Net Incremental Costs for Electrification of NW Natural Oregon & Washington Customers Relative to Reference Case



[8] NW Natural costs modeled by NW Natural in their IRP process and provided the results to ICF.

Overview of Study Results: Overall GHG Impacts

There is little difference between net GHG emissions from NW Natural customers in the Reference Case and the electrification scenarios by 2050. Figure ES 4 shows the results for each of the scenarios in Oregon. In all scenarios both gas and electricity supplies are assumed to decarbonize in line with state laws. This chart shows GHG from combustion of natural gas (declining green bands), reductions from the purchase of GHG compliance resources to decarbonize remaining gas consumption (yellow bands), GHG emissions from higher usage of electricity (maroon band), and the resulting net GHG impacts (dotted lines). The results for Washington, shown in Figure ES 5, show a similar trend.

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 renewable natural gas, hydrogen, credits, etc.). Some compliance options, like Community Climate Investments (CCIs) and allowance purchases, may not be directly tied to GHG emissions reductions on NW Natural's system but are mechanisms used by the state to claim GHG emission reductions, and for the purposes of these GHG estimates all such compliance mechanisms are assumed here to offset the corresponding customer GHG emissions from their combustion of natural gas.

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 for IOUs will add little to no additional greenhouse gas emissions, even from peaking and incremental resources.

Figure ES 4: Net Changes in GHG Emissions by Electrification Scenario for NW Natural Oregon Customers

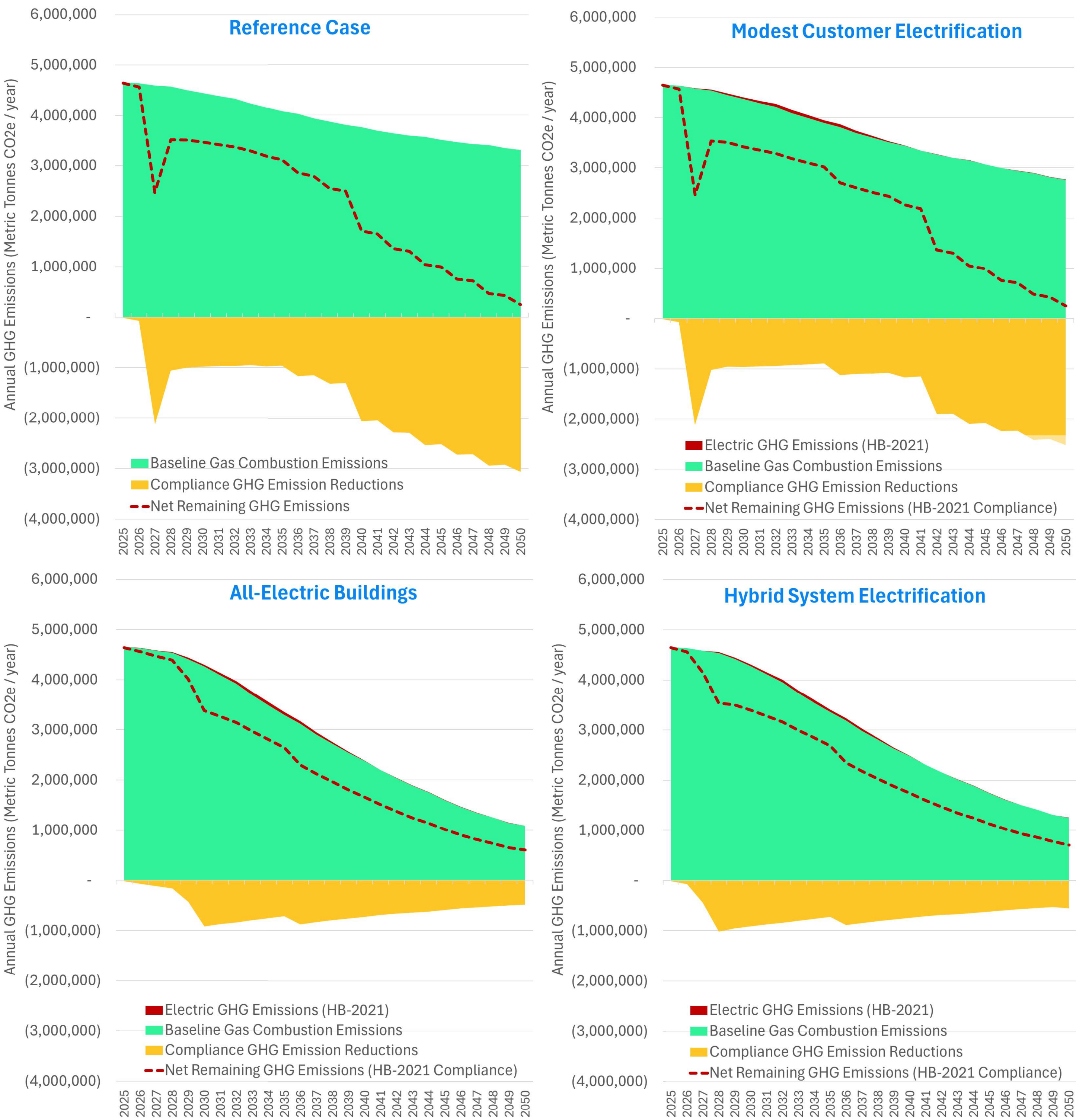
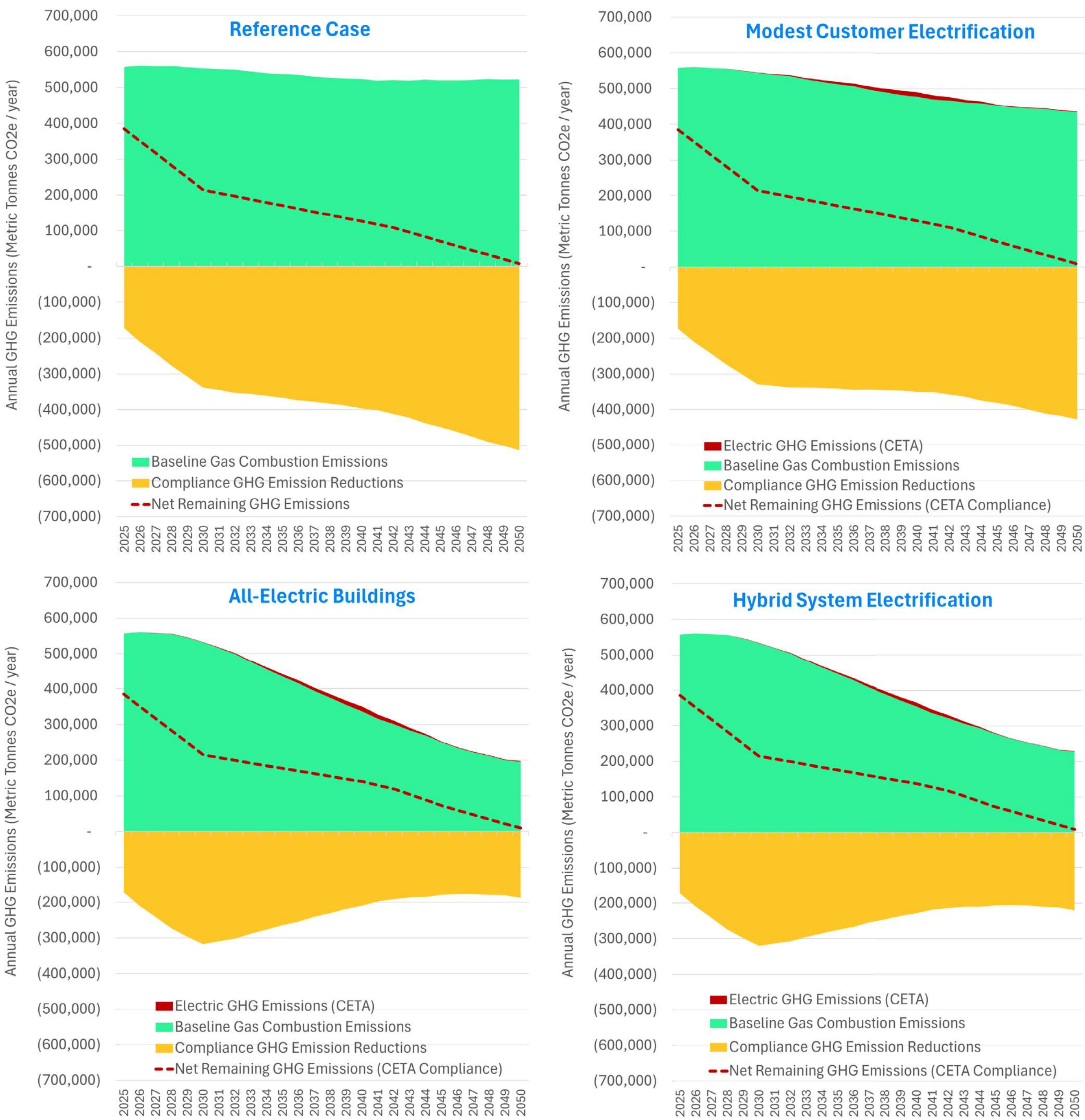


Figure ES 5: Net Changes in GHG Emissions by Electrification Scenario for NW Natural Washington Customers



Summary of Electrification Analysis

Even before analyzing potential electrification of gas loads in Oregon and Washington, the states' electricity sectors will need to undergo a rapid and massive transformation of its supply sources away from emitting resources. Within the next 5 years, utilities covered under HB-2021 and Clean Energy Transformation Act (CETA) will need to see an expansion of their non-emitting electric supply at rates that exceed development activity and resource interconnection of the past several years and decades. Challenges with electric resource interconnection are exacerbated by long lead-times for transmission development necessary to connect new generation resources, expand existing transmission system capacity, and load growth will add to the load needed to be served by new resources and introduce further challenges of shifting electric 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 would add to the electric load growth already anticipated by the electric utilities from electric vehicles and growth of data centers. These additional electric loads would substantially increase peak demands in utility service territories, reduce the fuel diversity of the energy delivery system, and increase resource requirements in an already strained system. This analysis quantifies many of the costs to supply incremental electrification loads, including equipment conversion costs, fuel costs, as well as electric generation, transmission and distribution costs resulting from higher electric loads driven by gas end-user electrification. The full nature of costs driven by electrification loads is, however, uncertain at this time, and this analysis does not fully capture all potential costs that may arise from building electrification, such as potential changes to electric reliability criteria that may be required under a single-fuel energy delivery system.

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. 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 have been built in several decades. Outside experts from the Advisory Group and the IRP technical working group helped NW Natural and ICF evaluate several assumptions and data sources for this analysis. The Advisory Group cautioned against assumptions that were inconsistent with current realities, like lead times and costs. However, in some cases the analysis still required "relaxing" assumptions to allow the modeling to achieve HB-2021 compliance while also meeting load growth.

Figure ES 6 provides a summary of key metrics from the electrification analysis. The analysis found all the illustrative electrification scenarios studied here to have higher overall costs than the Reference Case approach. The GHG emissions reductions achieved through all the scenarios were very similar, with the Reference Case resulting in the most reductions. Of the two main electrification scenarios, the costs and associated risks to pursue the All-Electric scenario were found to be higher than the Hybrid scenario. The All-Electric scenario would cost more than $22 Billion more while losing resiliency and reliability benefits from gas infrastructure. This analysis has shown that the Hybrid scenario has the potential to achieve similar GHG emissions reductions at a lower cost than 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 and achieve clean grid policy requirements. A more detailed reliability analysis should be performed to ensure that reliability is not degraded for customers in these scenarios. Scenarios with higher winter peak loads, such as the All-Electric scenario, are more likely to lead to additional investments required to ensure reliable supply, all else equal.

Figure ES 6: Summary of Electrification Analysis

Summary Metric	Reference Case	Modest Customer Electrification	Hybrid System Electrification	All-Electric Buildings
GHG Emission Reductions - Cumulative Total from 2025 to 2050 (Million Metric Tons CO_2e) [9]	66.7	66.5	66.5	66.4
Incremental Costs vs. Reference Case - Cumulative Total from 2025 to 2050 ($2024 Billions)	+$0 Billion [10]	+$3.5 Billion	+$13.3 Billion	+$22.7 Billion
Change in Number of NW Natural Residential & Commercial Gas Customers from 2025 to 2050 (%)	+12%	-4%	-13%	-90%
Change in Gas Consumption by NW Natural Residential & Commercial Gas Customers from 2025 to 2050 (%)	-26%	-38%	-80%	-85%

[9] The GHG emission reductions show the 2025 to 2050 cumulative total of annual GHG emissions savings in each scenario versus annual GHG emissions in 2025. Some compliance options used by NW Natural in the Reference Case and electrification scenarios, like allowance purchases, may not be directly tied to GHG emissions reductions on NW Natural's system but are mechanisms used by the state to claim GHG emission reductions, and for the purposes of these GHG estimates all such compliance mechanisms are assumed to offset the corresponding customer GHG emissions from their combustion of natural gas.

[10] There will be costs associated with the Reference Case, including compliance with CPP and HB-2021, but the costs shown for electrification scenarios are the costs in excess of the cost of the Reference Case. The costs of the Reference Case are not fully quantified in this analysis.

1 Introduction to Electrification Analysis

NW Natural engaged ICF to conduct this analysis, and also engaged outside experts with electric planning and operations backgrounds (the "Advisory Group" or "AG") to provide review and guidance. This report discusses the assumptions, approach, and results from the ICF analysis.

At this point in time, electric utility IRPs in the Pacific Northwest (PNW) region have only recently started considering building electrification with limited detail, 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 assesses the impacts of building electrification on electric generation, transmission, and distribution infrastructure to provide a broader view of the potential impacts of electrification than the scenarios included in the 2022 NW Natural IRP, which only quantified the electrification impacts to NW Natural's system.

More specifically, the study:

- Provides input on gas demand impacts to NW Natural's IRP on potential electrification scenarios
- Considers the electric supply requirements for these electrification scenarios – to give context and characterize costs
- Assesses the overall impacts and costs associated with electrifying NW Natural customers
- Assesses how (ASHP with gas back-up) would change the impacts and costs of electrification
- Considers electric load growth in other sectors, with focus on building electrification

Figure 1 provides an overview of the steps in the study process.

Figure 1: Overview of Study Phases

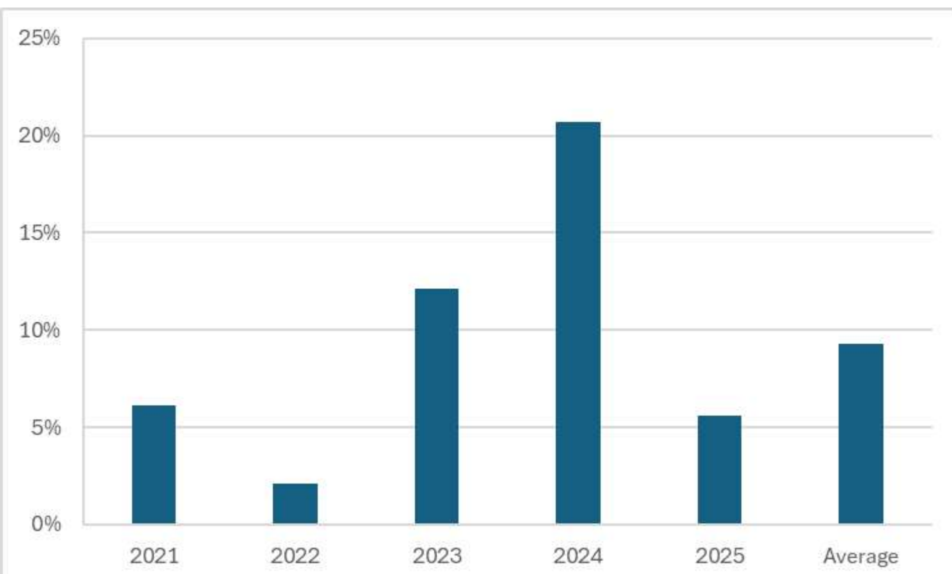
Demand-Side Analysis	Electric Supply Analysis	Sector Integration & Results
• Assess electric load growth and gas demand impacts from different levels of electrification and types of electric equipment • Focus on buildings but also consider other sources of load growth (EVs, data centers, industrial) • Utilize NREL ResStock and ComStock datasets to characterize electrification impacts	• Evaluate the infrastructure requirements resulting from increased electric loads through capacity expansion modeling, including generation, transmission, and distribution impacts • Simulate planning outcomes using ICF's Integrated Planning Model (IPM)	• Combine demand and electric supply results to understand overall cost and GHG emissions impacts of different scenarios • Consider and evaluate customer equipment conversion costs and incremental infrastructure costs for generation, transmission, and distribution

2 Electric Planning Environment

Understanding the current electric planning environment is critical to assessing the results of this electrification analysis. The electric grid in Oregon and Washington is currently facing cost pressure and reliability challenges and is expecting several major changes, which the sector will need to consider for future planning.

Oregon and Washington have experienced "close call" events such as in January 2024 in the PNW, where cold temperatures contributed to a strained electric grid that caused the issuance of the highest level of Energy Emergency Alert.[11] While supply-driven outages were avoided in part due to almost 5 GW of imports into the Northwest, incidents such as the events during winter storms Gerri and Heather highlighted the volume of energy delivery facilitated by the natural gas system and the potential implications of demand spikes and supply-side outages during weather-driven electric demand peaks – even absent building electrification. In addition to the reliability challenges brought on by cold weather events, on average, electric rates across the state have increased over 25% in the last four years. Between 2020 and 2024, rates for Oregon residential customers have increased by 40% or more depending on the utility serving them. Annual rate increases have exceeded 10% in multiple years, with 12% and 21% in 2023 and 2024 for PGE and 15% for PacifiCorp customers in 2023. Figure 2 shows the annual year-over-year and average residential rate increase over the last five years.

Figure 2: PGE Residential Rate Increases year-over-year between 2021 and 2025 (%)



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

[11] A Level 3 Energy Emergency Alert indicates that the grid is at risk of not meeting firm load and maintaining contingency reserves and is preparing for potential rotating power outages.

last January 2024. Without significant 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 been revised upwards in recent years, as shown in PGE's latest IRP filings from August 2025, where 20-year annual average energy growth rates increased from 1.2% in 2022 to 1.9% in 2024,[12] even without considering electrification. With electrification assumptions, annual average growth rates over 20 years increase even further, more than doubling relative to the 2022 forecast to 2.8% annually. Expectations for load growth driven by data centers and AI that utilities rely on for planning include customer requests and industry reports, and present short-term load drivers, while vehicle electrification load is a significant long-term driver given state policies requiring vehicle sales to shift to EVs. PGE's latest IRP update attributes 2.6% of the 2.9% average growth over the 2025 – 2030 period to large customer projects, and more than 50% of the load growth from 2030 – 2040 to electrification. Even with added electrification details in the most recent releases[13], electric utility IRPs in the region are not currently elaborating on the inputs that drive projections for building electrification, if included at all. The electric system will face a significant challenge in meeting the data center and EV loads, one 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 requirements 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 exactly how to fill.
- **Transmission Availability and Timelines:** New electricity transmission projects in the PNW have often taken 20 to 30 years to develop, despite long-standing efforts and the stated policy objective to reduce development timelines. Without changes to development times, it remains uncertain as to how much transmission capacity can reasonably be added and when that capacity could be energized. Electric system planning will ideally maintain some optionality/flexibility in case new transmission is

[12] Portland General Electric. "2023 Clean Energy Plan and Integrated Resource Plan Update. 2024. https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf

[13] Portland General Electric. "2023 Clean Energy Plan and Integrated Resource Plan Update. 2024. https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf

limited and/or delayed (or fails to be accelerated). Utilities across Oregon 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. In its IRP filings in the Spring of 2025, PGE indicated that large-scale new transmission would be available in 2032 at the earliest.[14] Without new transmission infrastructure, compliance with HB-2021 will require reliance on near-term contracts to meet supply needs in absence of near-term transmission solutions. Even with this delayed transmission assumption, PGE's preferred portfolio would require 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.

- **Planning for System Resiliency:** At the same time as 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. Both electric and gas systems feature physical infrastructure designed to meet the unique challenges of the respective sectors – including varying stringencies of reliability criteria (design day planning vs. PRM/loss-of-load planning) and resilience considerations. Shifting loads from the gas systems onto the electric systems will require significant expansion of the electric system to meet new growing loads (explored quantitatively in this report), as well as changes and potential expansion to incorporate the reliability and resilience approaches of the other energy delivery sectors (explored qualitatively in this report). Consolidating energy delivery into one system may require redundancy and planning approaches beyond current and even beyond currently envisioned electric planning processes, as potential service disruptions would impact the majority of energy delivery across Oregon and Washington.
- **Changes to Electric System Planning Standards:** As electric demand across the country rises due to data center, EV, and electrification loads, the industry is evolving its approach to reliability planning. With an increasing share of intermittent, weather dependent resources, and growing weather-dependent loads, both supply and demand are becoming more variable and driven by weather that itself is becoming more extreme. Traditional reliability metrics such as loss-of-load expectation, which underpins the commonly relied upon 1-day-in-10 years electric reliability standard for planning, do not account for the duration and magnitude nor the type of shortfall event. Industry groups such as the Energy Systems Integration Group (ESIG) have noted the "need to move beyond a single, one-size-fits-all resource adequacy criterion and augment it with multi-metric criteria." [15]

  Given the reliability challenges already being faced by the electric systems in the PNW under current planning approaches and the changing market conditions noted above, there may be a need for electric planning practices to evolve from the current approaches such as loss of load expectation metrics and the resulting PRM to planning for more comprehensive resource adequacy. Ensuring a reliable electric grid with the evolving factors listed above could result in adjustments 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

[14] Portland General Electric. "2023 Clean Energy Plan and Integrated Resource Plan Update. 2024. https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf

[15] Energy Systems Integration Group. 2024. New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements. Reston, VA. https://www.esig.energy/ new-resource-adequacy-criteria. https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf

electricity infrastructure. Relative to what is currently assumed by utilities for planning and in this study, the level of excess capacity beyond peak demand (the planning reserve margin, or PRM) would increase to ensure electric system reliability. Evidence of this can already be observed by utility requests for higher planning reserve margins in the Carolinas and markets such as the PJM Interconnection (PJM) and Southwest Power Pool (SPP).

All these factors would aim to shore up the electric system to a level of reliability that it would be trusted and relied upon to facilitate the energy delivery of not only the current and expected end-users but also those electrifying their natural gas loads. The higher electric loads, the more impactful required capacity changes in planning standards would be. PJM's recent increase of the PRM to over 19% results in a planning need of more than 6.75 GW, and even with Oregon's lower demand totals, the combination of declining resource contributions and higher PRM's, applied to higher load growth could increase the capacity needs by hundreds of MW or even GWs.

- **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 increase the resource requirements that utilities will need to plan for above and beyond the investments already required to meet clean energy targets alone. This additional infrastructure requirement beyond electric clean energy policy compliance – and the cost and rate recovery associated with these infrastructure needs – are not fully understood today.

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. The analytical approach for this study captured several, but not all of the considerations listed above. The following approaches are incorporated into the analysis:

- Capacity expansion modeling approach that incorporates planning reserve margins consistent with utility IRPs and PNUCC assumptions for areas in the PNW without utility PRM assumptions.
- Contributions of resources to reserve margins based on Western Resource Adequacy Program (WRAP) data.
- End-use electrification peak demand growth estimates consistent with temperatures experienced during January 14th, 2024.

The analysis does not capture the following:

- Utility-specific assessments of resource contributions are evolving rapidly and indicate potentially lower reserve contributions for resources such as battery storage.
- Changes to planning reserve margins to capture increased reliability and resiliency needs based on:
    - Application of alternative approaches to resource adequacy criteria, such as EUE or LOLH
    - Application of more stringent resource adequacy criteria to match reliability criteria for sectors that electrification load would delivery for instead
- Detailed reliability assessments of modeled portfolios to quantify reliability metrics – currently assumed LOLE or more modern approaches such as EUE or LOLH – under a range of extreme weather scenarios. 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.

3 Demand Side Analysis

This section provides an overview of the different demand-side scenarios that were included in the electrification analysis. The section is split into the following sub-sections:

- Scenario Overview
- Building Electrification Approach and Assumptions
- Building Electrification Results

3.1 Scenario Overview

The focus of the analysis set out in this section is to compare the impacts of different approaches to building electrification for the residential and commercial sectors on NW Natural customer energy demand and costs. This section explores the differences between three electrification scenarios from the perspective of natural gas and electricity consumption and customer equipment conversion costs. The analysis also considers electrification in the transportation and industrial sectors by recognizing changes in the sectors and holding them constant across all three electrification scenarios to highlight the impacts from the buildings sector. Later sections will quantify broader impacts from these demand changes on electric infrastructure. Figure 3 shows and describes these scenarios and the naming conventions used to identify them in NW Natural's IRP. Collectively, these are referred to as "electrification scenarios." It also describes NW Natural's Reference Case.

Figure 3: 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:

- **Modest Customer Electrification:** Aimed to align with PGE and PacifiCorp 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 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 4, which shows 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 the end-of-life of the existing gas equipment for NW Natural customers. The percentages in the Figure 4 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.

In Figure 4, bold values shows the levels of electric equipment adoption used for existing NW Natural customers in both the Hybrid System Electrification and the All-Electric Buildings scenarios that were chosen to align with the Oregon Department of Energy's (ODOE) Oregon Energy Strategy Reference Case assumptions.[16] 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 in bold 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 was taken to help the analysis show how hybrid heating (ASHP with gas backup) would change the impacts and costs of electrification.

[16] Only the information available at the time of preparation of different stages of this study was considered. The cutoff date for data collection for this model was fall 2024. 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.

Figure 4: 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

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.

In addition to the residential and commercial sector electrification levels described above, an illustrative level of industrial electrification was included in this study. The high-level industrial analysis assumed, in all of the electrification scenarios, that roughly 17% of industrial natural gas demand from NW Natural's IRP Reference Case is electrified by 2050.[17] The same level of industrial electrification was used in all three electrification scenarios, as the focus of this study was comparing different approaches in the residential and commercial sectors, and we wanted to make sure that diverging industrial sector assumptions were not driving the differences in results between each of the electrification scenarios.

While the industrial sector was not the focus of this analysis, the illustrative level of industrial electrification was included because leaving this load out altogether could underrepresent potential impacts and challenges on the electric system. However, decision making priorities and equipment turnover timelines make the industrial sector quite different than residential and commercial sectors. The industrial sector is also challenging to forecast, with the potential for big swings as large industrial sites open, close, or change their process equipment. The high-level and illustrative assumptions included here represent a general expectation for slower uptake of electric technologies in this sector, and the general expectation that industrial process equipment will be converted more slowly than space heating equipment. More aggressive assumptions for industrial electrification would result in even higher impacts on the electric grid.

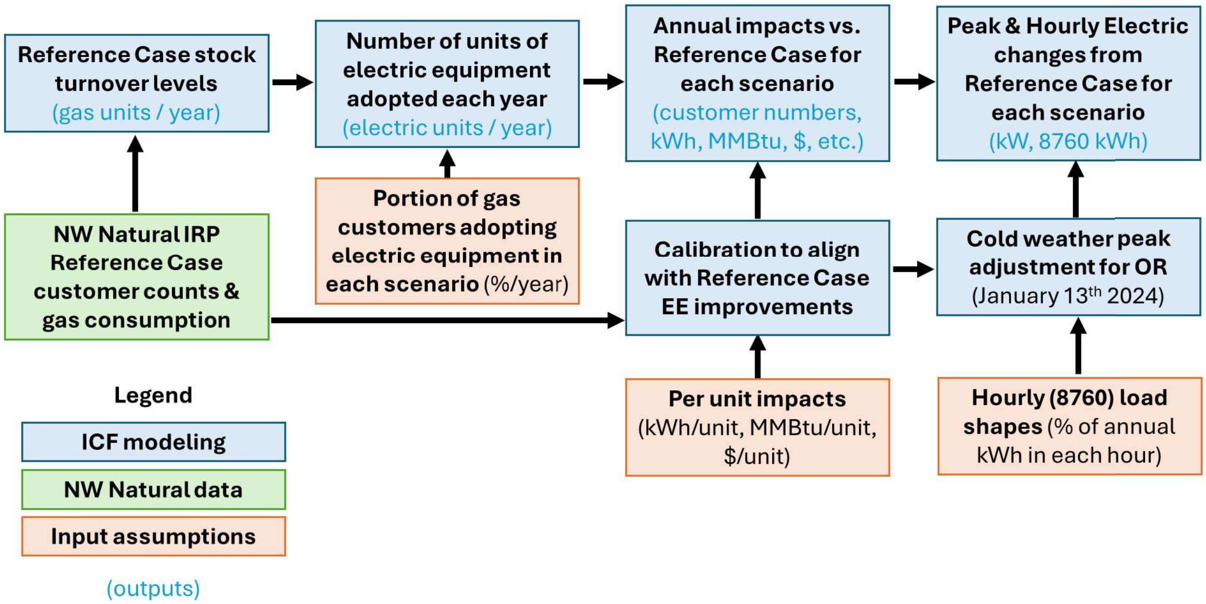
The inclusion of these benchmark electrification scenarios does not suggest that NW Natural or ICF endorses any of these demand-side scenarios as realistic or feasible. It should also be noted that neither the ODOE nor ICF models are analyzing what policy approaches or incentive levels would be required 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.

3.2 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. For each electrification scenario the analytical approach considered how many NW Natural customers from the Reference Case would shift from gas to electric equipment, as well as the impacts (energy use and costs) from those customer equipment changes. The steps in the building analysis process described are illustrated in Figure 5.

[17] NW Natural's industrial IRP Reference Case gas demand for small industrial customers ('sales' customers that buy their gas from NW Natural) and large industrial customers ('transport' customers that NW Natural delivers gas to, but who purchase their gas from 3rd parties) was split into seasonal heating gas demand (based on gas consumption that is higher during winter months) and other gas demand (based on baseload gas consumption across the year). For seasonal industrial heating demand from NW Natural's IRP Reference Case, the electrification scenarios assume that from 2031 to 2050 2% per year is electrified for small industrial facilities and 1% per year is electrified for large industrial facilities. For other uses of natural gas, the electrification scenarios assume that, starting in 2036, each year 1% of the IRP Reference Case gas demand is electrified, for both large and small industrial customers. This means that by 2050 all the electrification scenarios in this study assume industrial electrification of 40% of seasonal heating for small industry, 20% of seasonal heating for large industry, and 15% of all other industrial gas loads are electrified for both small and large industrial facilities. Industrial consumption in NW Natural's IRP Reference Case is heavily weighted towards the non-seasonal 'other' loads, resulting in the overall weighted average of 17%.

Figure 5: Overview of Building Electrification Analytical Approach



The scenario definitions outline the differences in adoption levels for different electric technologies. 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. ICF also developed per unit cost assumptions. ICF's Distributed Energy Resources Planner (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[18] and ComStock[19] provide county-level modeling of the U.S. housing and commercial building stock which uses a combination of sampling techniques from public and private data sources, OpenStudio® building simulations, and advanced supercomputing capabilities. They have building equipment saturation data by county, state, and climate zone which helps determine baseline usage and impacts of energy efficiency and electrification measures for different building types. 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.

[18] National Renewable Energy Laboratory. "ResStock Dataset," 2024. https://resstock.nrel.gov/.

[19] National Renewable Energy Laboratory. "ComStock Dataset," 2024. https://comstock.nrel.gov/.

The ResStock and ComStock datasets used in this analysis are specifically modeled by NREL to represent the buildings in counties that make up NW Natural's service area. For the electrification measures included in these NREL datasets, details such as natural gas savings, increased electricity consumption, and 8760 load shapes for the newly electrified load were extracted from the NREL datasets.

The residential electrification equipment included in this analysis were chosen to align with ResStock measures are:

- 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 equipment included in this analysis were chosen to align with ComStock measures are:

- 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 day (low temperature of 15F in Portland), in order to estimate how much higher peak electric load (kW) impacts were expected to be for the ASHP and cold-climate ASHP measures noted above on such a day.

Calibration to Align with NW Natural Data and Reference Case Forecast

The NREL data above shows how switching from natural gas to electric equipment affects different types of buildings in NW Natural's service territory. To make sure the results were accurate, we compared how the building types and gas consumption from NREL matched NW Natural's own data and the energy efficiency assumptions used in its IRP Reference Case, and calibrated (scaled up or down) some of the NREL data to ensure this analysis aligned with the 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). Figure 6 shows different sources that were used to establish how commonly the different types of gas equipment were found in the homes of NW Natural customers.

Figure 6: 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 6 to establish the average (across all customers) consumption per end use showcased in Figure 7. 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 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 7.

NW Natural's IRP Reference case, which was developed by NW Natural through a separate process, forecasts gas consumption and customer meter numbers, separate from existing customers and new construction. The Reference Case forecast did not include separate forecasts for different building types (e.g., single family homes vs. multi-family buildings), or separate forecasts split by end-uses (e.g., space heating vs. water heating). ICF worked to ensure that the assumptions included for measures within our electrification scenarios were consistent the IRP Reference Case developed by NW Natural (e.g., that both the electrification scenarios and the IRP Reference Case assume the same starting point for how much natural gas is consumed by average residential single family home customers in Oregon).

Figure 7 shows in the green columns the average gas use per customer forecast for 2025 and 2050 in the Reference Case. This reduction is driven by assumed energy efficiency improvements,[20] demolition and replacement of older buildings 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 align with the Reference Case in all years (e.g., not showing more gas savings than the Reference Case predicts). 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.[21] While this is not a purely one for one mapping (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.

Figure 7: 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

[20] Provided to NW Natural by the Energy Trust of Oregon.

[21] The electric load (annual kWh and peak kW) added when a NW Natural space heating customer in 2025 converts to an air-source heat pump was defined by NREL's ResStock model, but that base-year NREL-defined electric load impact from the heat pump is reduced for heat pumps adopted in later years of the study period, based on the same rate of improvement from gas energy efficiency in the Reference Case. For example, the electric load impacts (annual kwh and peak kW) from heat pumps adopted in 2045 were assumed to be lower than the load added by a heat pump adopted in 2025.

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.

Figure 8 shows the different commercial sub-sectors included in ComStock as well as ComStock data on the proportion of gas customers in NW Natural's service territory with each type of gas end-use. The two columns on the right of the figure below took NW Natural's 2025 IRP Reference Case totals for the Commercial sector and divided it amongst the different ComStock commercial sub-sector options based on an estimated split developed from the NAICS codes in NW Natural 2024 customer data. ComStock assumptions for baseline equipment energy consumption, as well as the energy impacts (gas and electric) from the electrification measures, were scaled for each commercial sub-sector so that the totals aligned with the IRP Reference Case.

Figure 8: Breakdown of Commercial End-Uses Present based on ComStock Data and NW Natural Customers Mapped to Each ComStock Sub-Sector

State	Building Type	ComStock			IRP Reference Case 2025 (Breakdown from NWN 2024 Customer Data)	
		Space Heating	Water Heating	Interior Equipment	Gas Consumption (therms)	Customer Count
Oregon	Full Service Restaurant	40%	48%	99%	2,499,967	315
	Hospital & Outpatient	56%	46%	43%	18,485,787	2,887
	Large Hotel	50%	75%	100%	10,380,159	219
	Large Office	71%	86%	0%	11,615,732	783
	Medium Office	95%	55%	0%	59,772,610	9,971
	Primary School	80%	63%	31%	15,507,204	1,081
	Quick Service Restaurant	32%	65%	31%	32,102,460	8,939
	Retail Standalone	100%	0%	0%	49,656,230	7,696
	Retail Strip mall	86%	62%	66%	3,892,832	431
	Secondary School	51%	57%	53%	17,943,027	915
	Small Hotel	9%	22%	0%	12,163,543	1,653
	Warehouse	100%	0%	0%	26,214,902	5,407
Washington	Full Service Restaurant	40%	60%	33%	4,468,712	536
	Hospital & Outpatient	49%	53%	20%	1,904,623	358
	Large Hotel	100%	100%	100%	2,607,828	244
	Large Office	67%	67%	0%	709,132	100
	Medium Office	80%	60%	0%	5,886,746	1,058
	Primary School	43%	71%	43%	2,307,538	198
	Retail Standalone	100%	0%	0%	5,871,275	856

	Retail Strip mall	76%	63%	0%	513,767	57
	Secondary School	67%	83%	51%	1,595,509	67
	Warehouse	100%	0%	0%	2,000,314	417

As with the residential sector, gas savings and electric load increases expectations for the commercial sector from ComStock were scaled down over the study period to match the equivalent changes in the use per customer gas used in the NW Natural IRP Reference Case. This assumption for efficiency improvements was applied evenly across all 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 9 shows the assumed split of baseline heating equipment types assumed for each commercial sub-sector, 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 9: Breakdown Between Commercial Sector Baseline Space Heating Technologies in Oregon 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
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

Figure 10: Breakdown Between Commercial Sector Baseline Space Heating Technologies in Washington 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	100%	0%	Large
Large Hotel	100%	0%	Large
Large Office	100%	0%	Large
Medium Office	83%	17%	Small
Outpatient	25%	75%	Small
Primary School	67%	33%	Large
Retail Stand alone	67%	33%	Small
Retail Strip mall	0%	100%	Small
Secondary School	67%	33%	Large
Warehouse	33%	67%	Large

Applicable Space Heating Upgrades	HP Boiler, electric backup	ASHP RTU, electric backup
	HP Boiler, gas backup	ASHP RTU, gas backup
		VRF

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. Additional details on assumptions for other building types and regions are provided in Appendix A.

In Figure 11 and Figure 12 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 documentation[22] notes that "because the heat pumps in this dataset's measure packages represent retrofits

[22] 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.

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 Energy Trust of Oregon (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 that found these replacements achieved less than half of the expected electricity savings for site-built homes (48%) while replacements for manufactured homes realized 73% of anticipated electricity savings. 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, to avoid the electric grid facing even more challenging impacts from building electrification.

The incremental measure costs per unit included in Figure 11 and Figure 12 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 put in new gas equipment).[23] 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).[24] The costs for single family homes shown here are largely based on assumptions from the January 2025 update[25] 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.[26] Costs for multi-family units and mobile homes were based on data available from the Regional Technical Forum.[27] In general, sources acknowledge that heat pump installations with gas-back up can have lower upfront costs.

[23] For calculating the rate of stock turnover for NW Natural residential customer gas equipment, ICF assumed a 20 year average useful life for gas space and water heating equipment and a 16 year life for gas cooking equipment. For the commercial sector stock turnover rates ICF assumed a 16 year life for gas space heating equipment, a 15 year life for gas water heating equipment, and a 12 year life for gas cooking equipment.

[24] For calculating when re-participation is required with the converted equipment, this analysis assumes a 13-year measure life for heat pump water heaters, a 17-year life for electric ranges/ovens, and a 15-year life for heat pumps.

[25] Puget Sound Energy. "Updated 2023 Decarbonization Study Summary Report," January 2025. https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0131_UpdatedDecarbStudyReport.pdf.

[26] 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.

[27] Northwest Power & Conservation Council. "UES Measures." Regional Technical Forum, 2025. https://rtf.nwcouncil.org/measures/.

Figure 11: 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 ($) [28]
Heat Pump Water Heater	-172	1,193	1,710 [29]
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 [30]
ENERGY STAR air-to-air heat pump with existing gas system as backup	-504	4,121	10,825 [31]
High efficiency cold-climate air-to-air heat pump, Electric Backup	-565	3,809	15,822 [32]

[28] An example of the incremental cost calculation is shown in Figure 67 in Appendix A.

[29] 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 from the Full Cost.

[30] 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.

[31] 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.

[32] 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.

Figure 12: 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 13 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 13 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 EIA Updated Buildings Sector Appliance and Equipment Costs and Efficiencies,[33] an ACEEE report,[34] and utility Technical Resource Manuals (TRMs). Additional details on assumptions for other building types are provided in Appendix A.

[33] U.S. Energy Information Administration. "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies," March 2023.

[34] 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.

Figure 13: 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) [35]	$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

DER Planner Stock Turnover Modeling

ICF's DER Planner model was used to forecast 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 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, 8,760 load shapes from NREL for

[35] The electric load added for the VRF is negative in this table, as NREL's ComStock modeling of this technology shows that on an annual basis the kWh savings in terms of reduced ventilation/fan usage over course of year is larger than the added kWh for space heating. It should be noted that the hourly 8,760 load shapes from NREL for this measure still result in the addition of peak winter space heating demand (kW) from this measure, given how the addition of space heating kWh is highly concentrated during those peak cold periods (while ventilation savings are spread throughout year).

each of the electrification measures were used to provide the resulting incremental loads for the power 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 8,760 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 territory 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 estimates for the portion of the natural gas customers in Oregon not served by NW Natural 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 territories, this simplified approach may underestimate the state-wide increases in annual and peak electric load from building electrification. The analysis did not estimate changes to non-NW Natural gas customers in Washington, as the NW Natural customers in Washington that were analyzed in this study represent a small portion of total gas customers in that state.

3.3 Building Electrification Results

This section presents the modeling results of the demand side analysis. Figure 14 and Figure 15, show the impacts of the electrification scenarios 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 customers and volumes in the residential sector are larger than those in the commercial sector.

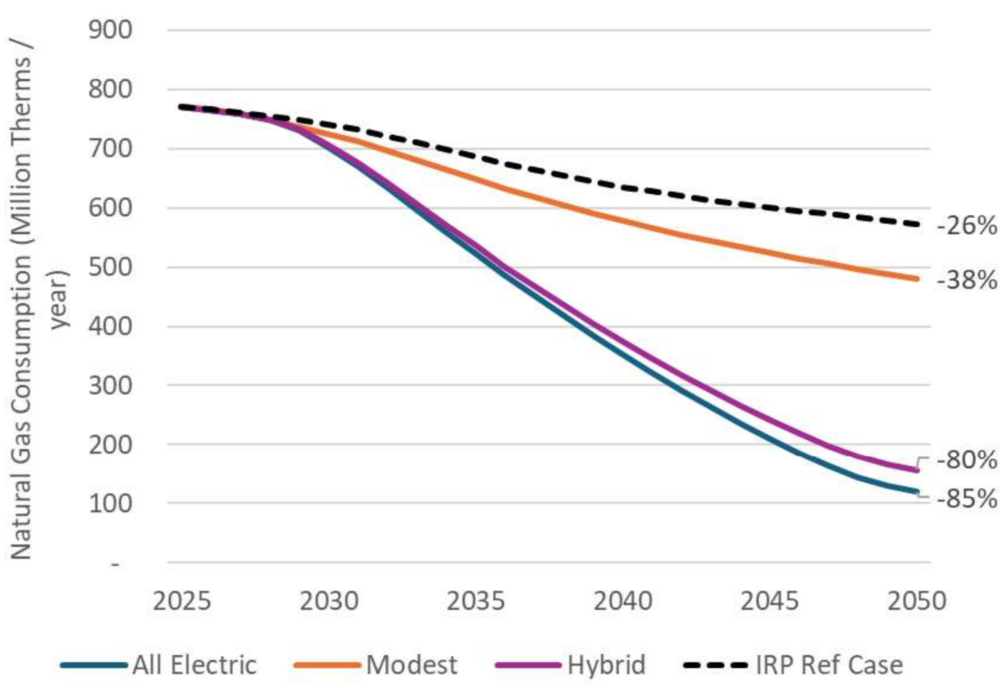
First, it is important to note how gas consumption for residential and commercial customers in the **IRP Reference Case (black dotted lines)** declines 26% from 2025 to 2050, while the number of NW Natural customers grows 12% over that same period. This represents an average reduction in gas use per 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 build off the Reference Case by making modifications to the Reference Case. With this approach the use per customer improvements discussed above for the Reference Case were assumed to reduce both gas use and electricity impacts for converted customers in all scenarios.

The Modest Customer Electrification scenario (orange lines) predicts customer gas consumption in 2050 will drop 38% relative to 2025, and 2050 customers will decline 4% relative to 2025. The All-Electric Buildings scenario (blue lines) forecasts an 85% drop in customer gas consumption by 2050 relative to 2025, and a 90% decrease of 2050 customers 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).

Lastly, the Hybrid System Electrification scenario (purple lines) shows a significant divergence between the trends in each of the charts below. This scenario forecasts an 80% drop in customer gas consumption by

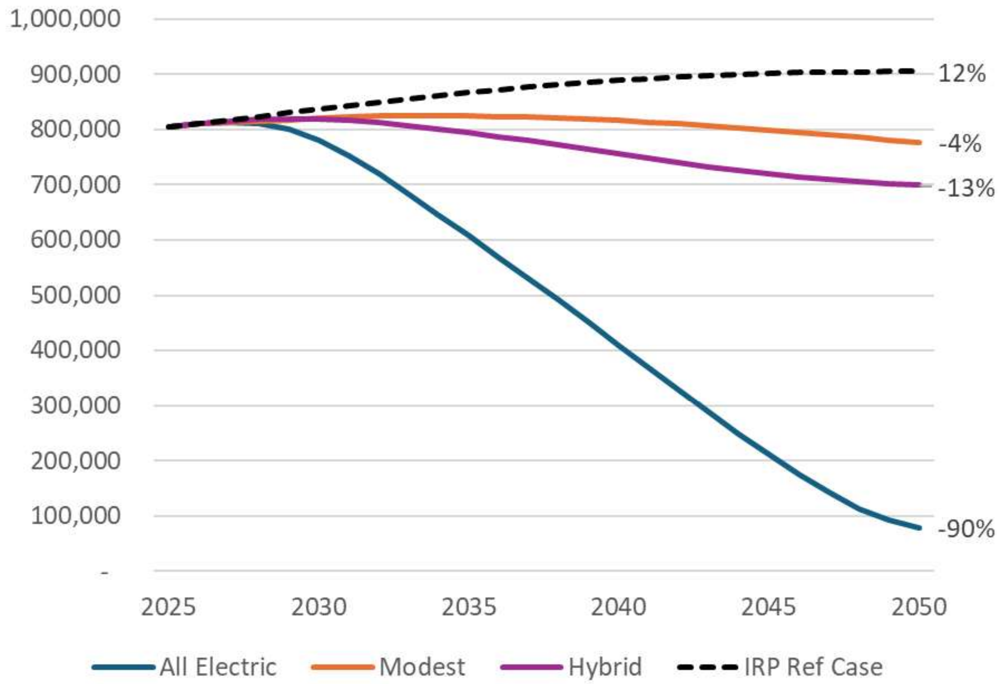
2050 relative to 2025, which is similar to the All-Electric Buildings scenario. This is a result of the NREL ResStock and ComStock modeling of the electric heat pump measures with gas back-up heat for NW Natural counties, indicating that the electric heat pumps are able to provide the majority of the annual heating needs and rely on gas back-up primarily in a selection of colder hours.[36] While gas consumption in this scenario drops significantly, the Hybrid System Electrification scenario only sees customers decline by 13% from 2025 levels, resulting in a decoupling of gas utility customer numbers and total customer gas consumption. 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 system 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.

Figure 14: Change in NW Natural Customer Gas Consumption (Res & Com) by Scenario – Oregon & Washington



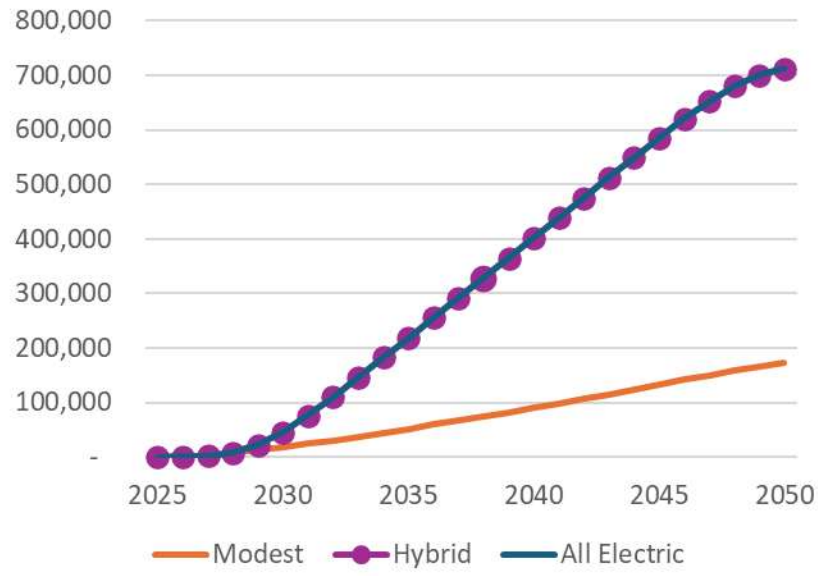
[36] The All-Electric and Hybrid scenarios also use the same assumptions for full electrification of water heating and cooking end-uses, further bringing these lines together.

Figure 15: Change in NW Natural Customers (Res & Com) by Scenario – Oregon & Washington



The results are driven by the adoption levels of different electrification technologies and based on the assumptions discussed in Figure 4 of the Scenario Overview section. 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 16 shows the cumulative total of NW Natural customers (from Reference Case) that are assumed to adopt heat pumps in each scenario. This includes both heat pumps with electric backup and gas backup, so the lines for the Hybrid and All-Electric scenarios overlap. Both 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.

Figure 16: Cumulative Number of Air Source Heat Pumps Deployed by Scenario in Oregon

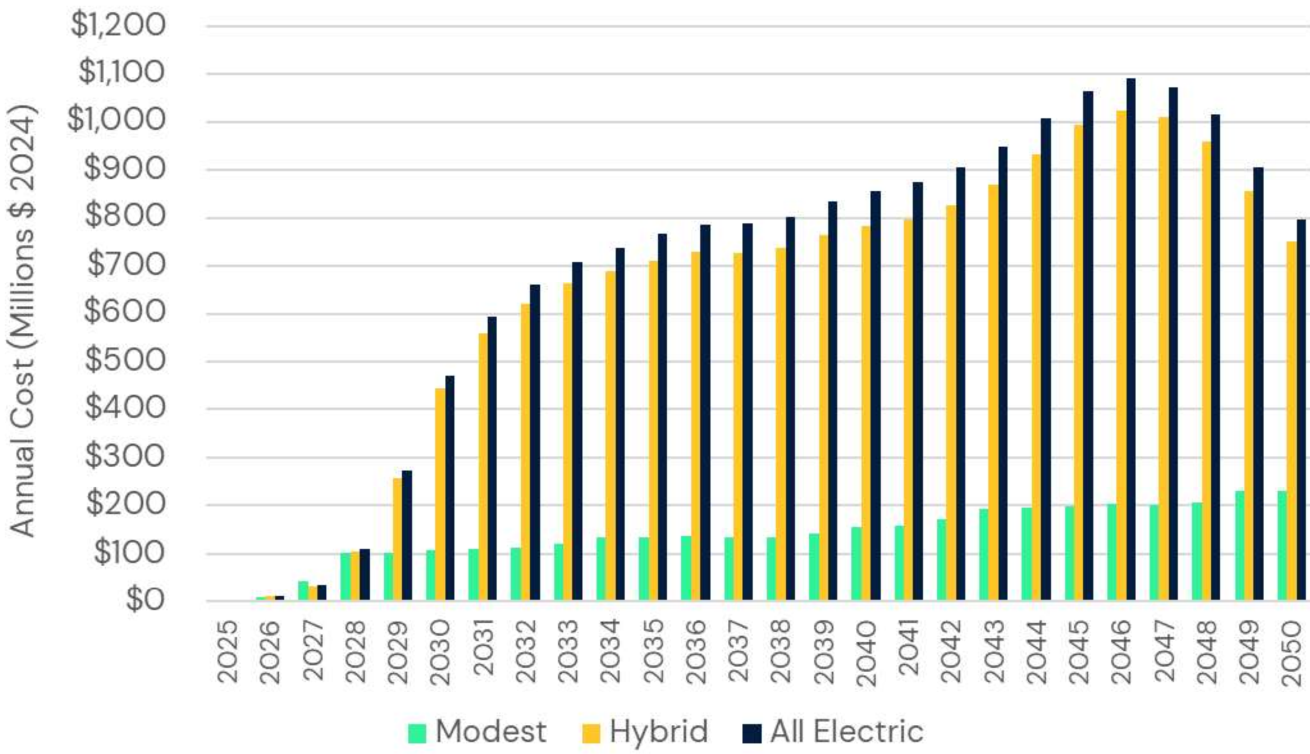


The All-Electric and Hybrid scenarios represent 'bookend' or 'benchmark' scenarios, incorporating high rates of heating equipment being replaced by a single type of technology based on assumed equipment stock turnover. To reiterate, the objective of this analysis is to be able to compare and contrast 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 comparison of incremental customer equipment conversion costs between scenarios in Figure 17 shows annual impacts rather than cumulative. These electrification equipment costs are 'incremental' to the Reference Case, representing the electrification costs above assumed equipment costs for gas equipment (and electric air conditioning) that customers would have otherwise installed in the Reference Case. In the All-Electric and Hybrid scenarios, annual incremental equipment costs rise quickly because many gas customers are expected to switch to electric systems. After 2045, these annual costs drop slightly. By then, most customers will have already switched to heat pumps. During the forecast period some customers are expected to replace their electric equipment more than once as equipment installed at the beginning for the forecast reaches the end of its useful life within that timeframe. In these instances, the 're-participation' cost is expected to be lower. For example, someone who installs an electric air-source heat pump (ASHP) in 2030 would replace it around 2045. That replacement is assumed to cost less because some expenses only apply to the first equipment conversion. The analysis assumes that equipment is replaced at end of life, so the customer equipment conversion costs are incremental costs (e.g., assuming customers otherwise would have needed to replace their furnaces and air-conditioning units).

The incremental annual equipment cost impacts in Figure 17 are lower in the Modest scenario, where adoption levels for electrification are lowest among these three scenarios. Incremental customer equipment costs in the Hybrid Scenario and All-Electric scenarios are relatively similar to one another. 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 rate (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.

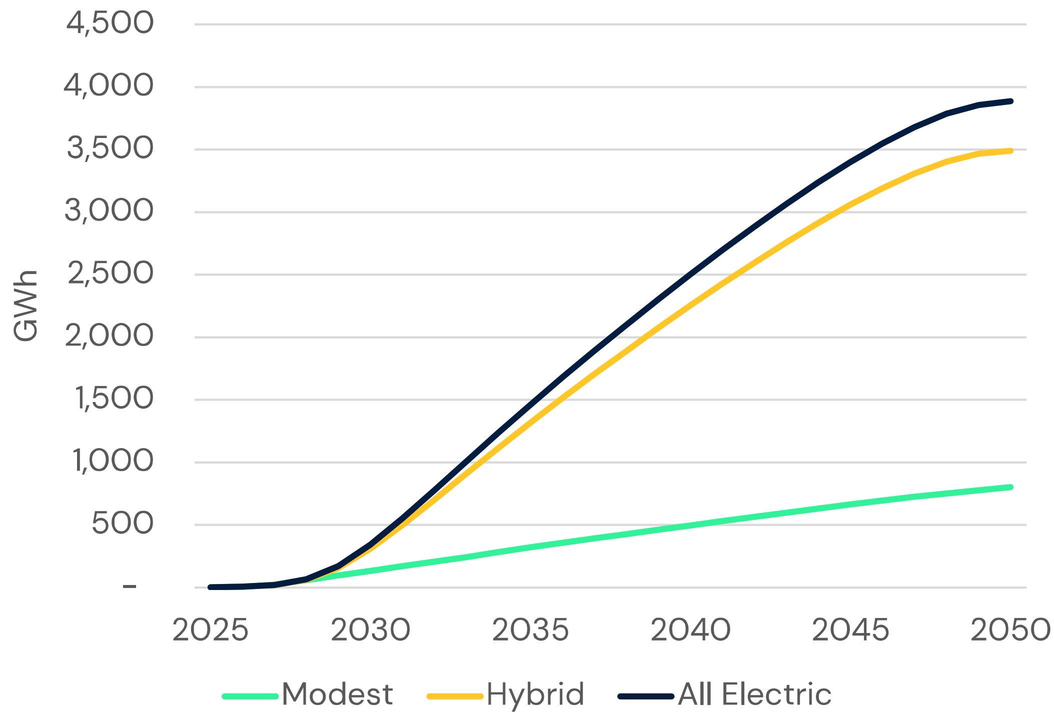
Figure 17: Incremental Customer Equipment Conversion Costs by Scenario (Res & Com)



Considering the total of the annual incremental costs shown above over the full study period (2025-2050), the cumulative incremental customer equipment conversion costs in Oregon total approximately $4.2 billion in the Modest scenario, $15.6 billion in the Hybrid scenario, and $16.9 billion in the All-Electric scenario (not discounted). In Washington, cumulative incremental customer equipment conversion costs over the same period total approximately $0.5 billion in the Modest scenario, $2.3 billion in the Hybrid scenario, and $2.2 billion in the All-Electric scenario.

The annual electric load increases from residential and commercial building electrification are shown in Figure 18. The trends here align with the previous charts on changes in natural gas consumption (e.g., there is a relationship between the amount of reduced gas load reduced in each electrification scenario and the amount of electric load added). The heat pumps with gas back-up installed as part of the Hybrid Electrification scenario operate in electric heating mode for most of the year, and so the annual load growth from these two scenarios is also similar.

Figure 18: Incremental Annual Electricity Consumption from Building Electrification of NW Natural Customers (Res & Com) by Scenario for Oregon



For building electrification, the annual electric load impacts do not tell the full story. 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 19 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 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.[37] This analysis

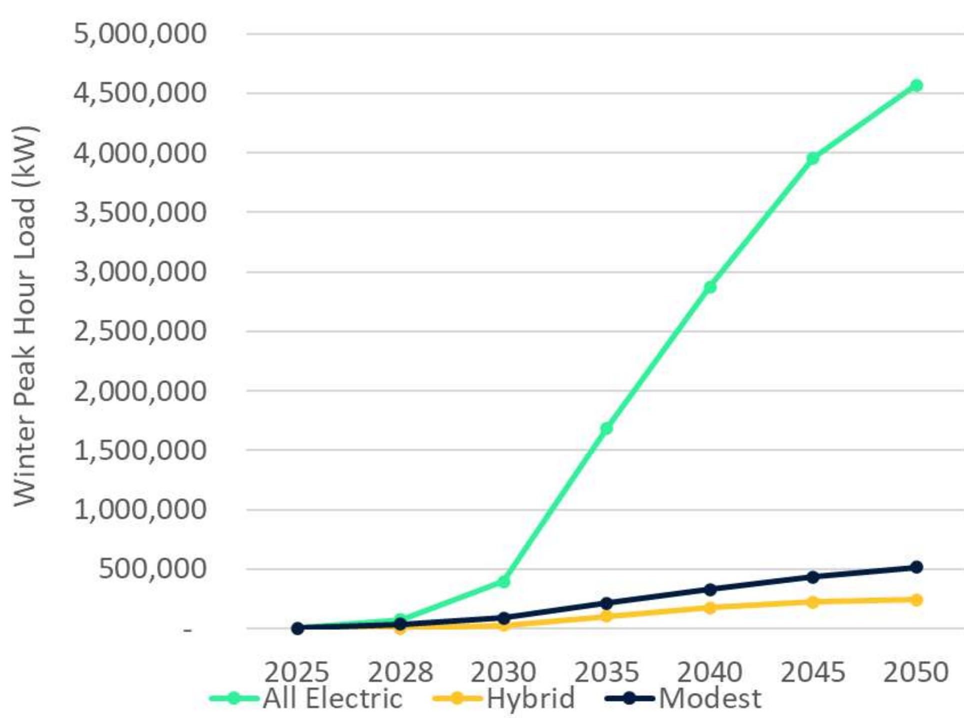
[37] Based on discussions with NW Natural it was felt that the electrification impacts being modelled by NREL with weather normal temperatures in their ResStock and ComStock datasets would significantly underrepresent the challenges that a future electric system would face in providing reliable electric service that could cover the spikes in peak winter demand from the All-Electric Scenario. To address this concern, ICF used the NREL ResStock building models for Oregon to run custom weather scenarios for a representative group of residential buildings. ICF did not perform this custom weather modeling for all building types. The peak electric impacts from the heat pump measures being used in this analysis from the custom weather modeling for a colder day going down to 15F were compared against the weather normal peak electric impacts for the same heat pump measures. On average for the group of building models that were analyzed in the customer weather modeling, we found a 43% increase in peak hour electric load for the residential ENERGY STAR ASHP measure, when considering the colder Jan 13th 2024 weather versus the peak hour from the NREL dataset version of this ASHP measure. The equivalent cold weather increase to peak electric demand for the cold climate ASHP measure was 25%. The 43% increase was also assumed to apply for commercial peak loads. These factors were used to scale up the winter peak electric demand impacts in Oregon for the power sector modeling, but the annual electric and gas demand impacts were not changed from the weather normal data

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 the difference between electric and gas system planning standards. While the implications of different standards may be less of an issue in a diverse "two fuel" heating system (gas and electricity), NW Natural's outside Advisory Group 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 19 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.

A key benefit of the hybrid heating arrangements assumed in the Hybrid scenario is the gas system's ability to backstop the electric system during winter peak demand. Using existing gas infrastructure, which already stores energy, delivers capacity, and absorbs spikes from space heating, reduces the need to build new electric infrastructure to manage loads during extreme winter weather events.

Figure 19: Incremental Peak Electricity Load from Building Electrification of NW Natural Customers (Res & Com) in Oregon



from the NREL datasets. This cold-day winter peak adjustment was not made for Washington in this analysis, meaning the impacts to peak demand in Washington are expected to be higher during extreme cold events.

Figure 20 provides an overview of the peak demand impacts per ASHP installed. The load per heat pump varies quite significantly across different customer segments and based on whether it is an existing building or new construction. The assumed IRP Reference Case efficiency improvement is seen in these results as well, with this customer segment seeing a 31% reduction in peak impacts from 2025 to 2050. These peak demand impacts are labeled as 'non-coincident' as they show the absolute highest peak demand hour for the heat pumps across the 8,760 hour load profile. In the electric load modeling for power sector analysis the different incremental loads are combined to find the overall peak demand hours (e.g., the heat pump's peak hour is not necessarily the exact hour of the combined overall system peak).

Figure 20: Non-Coincident Peak Hour Electric Impact (kW/unit) Per Heat pump installed in existing Single-Family Homes

Electrification Measure	2025	2030	2035	2040	2045	2050
R4 - Energy Star air-to-air heat pump, Electric Backup	9.5	9.1	8.4	7.7	7.1	6.6
R8 - High efficiency cold-climate air-to-air heat pump, Electric Backup	3.9	3.8	3.5	3.2	3.0	2.7

4 Overall Electric Load Impacts from Demand Scenarios

Energy and peak demand scenarios 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 8,760 load shapes inform the overall annual load requirements as well as the seasonal peak demand requirements. The 8,760 hourly load shapes capture 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 4 of this report describes the impact of electrification load on the respective utility service territories as well as Oregon and Washington States. Results shown at the state-level for Oregon extrapolate the electrification impact for NWN natural customers to the rest of the state. Given NW Natural's small share of customers in Washington, load results shown for Washington reflect only the electrification impact of NW Natural customers.[38]

4.1 Oregon Baseline Load

The baseline electric load growth reflected in electric utilities' IRPs shows the impacts of energy efficiency, demand response, and underlying load growth expected for residential, commercial, and industrial customers in each utility's service territory.

Annual load projections were sourced from electric utility IRP publications and IRP stakeholder discussions and supplemented with load growth projections from NERC ES&D 2024 for PNW service territories beyond PGE's, PacifiCorp's, Clark PUD's, and the Eugene Water & Electric Board (EWEB). 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 10-year NERC forecast timeframe. 8,760 load shapes for the baseline load apply the 2018 hourly shape from FERC form 714[39]. Specifically, the 2018 load shape is applied to projected annual baseline loads through 2050. This approach produces hourly baseline load estimates for each year through 2050.

Energy Efficiency, Demand Response and Distributed Energy Resources

Baseline load projections shown in this section incorporate energy efficiency, demand response and distributed energy resource projections for PGE and PacifiCorp as available from IRP filings and stakeholder discussions as of January 2025, as shown in Figure 21.

[38] While load impacts and state-wide power sector outcomes reflect state-wide electrification, cost impacts for NW Natural customers in subsequent sections only incorporate the costs associated with the electrification of NW Natural customers.

[39] Federal Energy Regulatory Commission. "Form 714," June 2021. https://www.ferc.gov/sites/default/files/2021-06/Form-714-csv-files-June-2021.zip.

Figure 21: Energy Efficiency and Demand Response Energy Impact Scenario Assumptions

EE/DER Energy Impact	PGE		PacifiCorp	
	Approach	Source	Approach	Source
Energy Efficiency	Estimated Economic Potential	September 2024 IRP Stakeholder Session	2025 Draft IRP Deployment Levels	2025 IRP Draft, Table D.4
Distributed Energy Resources (Rooftop Solar)	Low Case	October 2024 IRP Stakeholder Session	2025 Draft IRP Deployment Levels	2025 IRP Draft, Appendix L, Table 4-21

Figure 22: Energy Efficiency and Demand Response Peak Impact Scenario Assumptions

EE/DER/DR Peak Impact	PGE		PacifiCorp	
	Approach	Sources	Approach	Sources
Energy Efficiency	Estimated based on seasonal load factors and energy impact	September 2024 IRP Stakeholder Session	2025 Draft IRP Deployment Levels	2025 IRP Draft, Table D.4
Distributed Energy Resources (Rooftop Solar)	Estimated Low Case based on DER peak impact of comparable utilities	October 2024 IRP Stakeholder Session	2025 Draft IRP Deployment Levels	2025 IRP Draft, Appendix L, Table 4-21
Demand Response	Low Case	2024 Distribution System Plan	2025 Draft IRP Seasonal Deployment Levels	2025 IRP Draft, Table D.3

All electrification scenarios feature the same levels of energy efficiency, demand response and distributed energy resources.

Data Center Loads

Utility projections on data center loads are incorporated into the annual electric load and peak demand projections based on data provided by utilities and modeled consistent to the approach of the individual utilities. While some utilities, such as PGE[40], incorporate data center growth in load forecasts referenced for this analysis, other utilities do not directly incorporate these loads into forecasts for their service territory 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 this analysis, data center loads follow each utility's approach. A flat 24-hour profile is applied year-round, creating an hourly 8,760-hour

[40] Riter, Amber, and Shannon Greene. "Load Forecast." Presented at the Integrated Resource Planning Roundtable, July 11, 2024. https://assets.ctfassets.net/416ywc1laqmd/UCFpfZzIgecl6VQGosytA/350f50c7f9f8d8c4ff8552f9c235ca01/IRP_Roundtable_July_24-3presentation.pdf#page=13.

load shape for each year. All electrification scenarios feature the same levels of data center loads. Figure 23 shows the data center load projections.[41]

Figure 23: Oregon Data Center Load Projections (GWh)

Oregon Data Center Load Projections (MWh)	2025	2028	2030	2035	2040	2045	2050
	540,516	5,314,592	8,613,288	14,161,061	16,470,302	18,769,655	20,767,464

Electric Vehicle Loads

Oregon load projections incorporate EV loads based on data from utility projections on EV loads and are shown in Figure 24.[42]

Figure 24: Oregon EV Load Projections (GWh)

Oregon EV Load Projections (MWh)	2025	2030	2035	2040	2045	2050
	1,698,920	3,226,000	6,134,200	9,442,800	12,877,719	16,095,420

For PGE, EV assumptions are aligned with Reference Transportation Electrification forecast in the September 2024 CEP IRP stakeholder materials. For PacifiCorp, EV assumptions are assumed to be the growth driver of the "Misc" category referenced in September 2024 Stakeholder documents. Hourly profiles for EV loads are based on electric vehicle modeling conducted by ICF in EVI Pro[43] 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.

4.2 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.

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[41] Treatment of data center forecasts in utility planning proceedings varies from utility to utility given uncertainty around interconnection processes, the responsibility to provide supply for the associated demand and impacts on ratepayers. Load impacts of data centers in the analysis is treated consistent with individual utility approaches and shown here at the aggregate state level.

[42] The EV load forecast is driven by the EV load projections for PGE and PacifiCorp.
Portland General Electric. "PGE CEP & IRP Roundtable 24-6." October 2, 2024.
https://assets.ctfassets.net/416ywc1laqmd/6GvOU2ILocu2YCSnHv4JRP/43c13f8b70898a4476a4655f5f783fd4/IRP_Roundtable_October_24-6.pdf.
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.

[43] National Renewable Energy Laboratory. "EVI-Pro: Electric Vehicle Infrastructure – Projection Tool." Transportation & Mobility Research, March 5, 2025. https://www.nrel.gov/transportation/evi-pro.

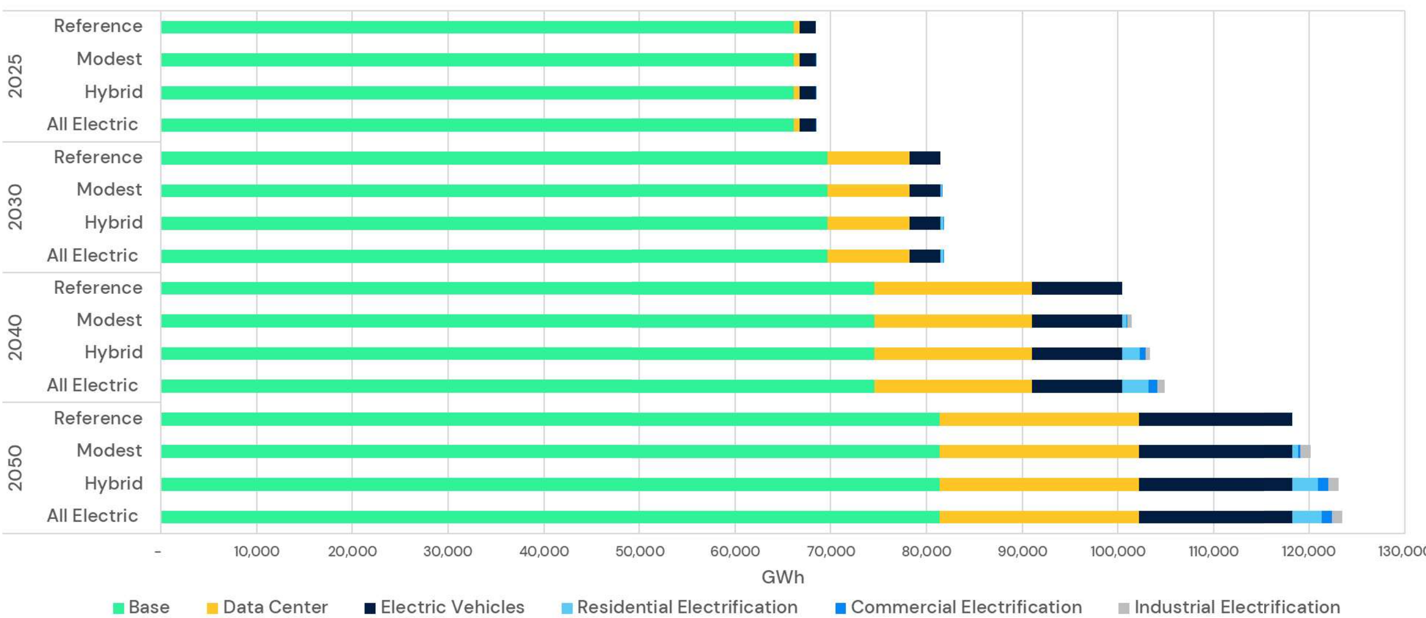
End-Use Electrification

Impacts of end-use electrification in the residential, commercial, and industrial sectors were developed as part of the demand forecast projection outlined in section 3. End-use equipment changes and their resulting shift in natural gas loads to the electric sector resulted in 8,760 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.

4.3 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. 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.

Figure 25: Oregon Annual Load by Category, Scenarios, and Year - Current Trends (GWh)



PGE/PacifiCorp Oregon Annual Energy Demand Results

PGE's annual load is projected to grow to over 40,000 GWh by 2050, doubling from current load levels. Load growth is driven by electric vehicle, data center, and industrial load growth. Impacts from building electrification add between 813 and 2,805 GWh in the Modest and All-Electric scenarios. Building electrification increases PacifiCorp load between 564 GWh in the Modest scenario and 1,435 GWh in the All-Electric scenario.

Figure 26: PGE Incremental Building Electrification Demand by Scenario (GWh)

PGE Load and Electrification Impact	2030	2040	2050
Modest Incremental	89	457	813
Hybrid Incremental	207	1,623	2,571
All-Electric Incremental	226	1,772	2,805

Figure 27: PacifiCorp Oregon Annual Energy Demand (GWh) and Incremental Building Electrification Demand by Scenario (GWh)

PacifiCorp Oregon Load and Electrification Impact	2030	2040	2050
Modest Incremental	38	271	564
Hybrid Incremental	88	776	1,336
All-Electric Incremental	96	839	1,435

Washington Annual Demand Results

Washington electric load in the Reference Case increases by 30,844 GWh between 2030 and 2050, even absent building electrification. Electrification of building 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 all-electric scenarios are consistent, as the primary impact of the electrification scenarios is on winter peak rather than annual energy demand.

Figure 28: Washington Total Annual Energy (GWh) by Scenario

Washington Annual Energy (GWh)	2030	2040	2050
Reference	115,805	130,008	146,449
Modest	115,823	130,110	146,648
Hybrid	115,846	130,362	147,066
All-Electric	115,852	130,413	147,156

The majority of the energy demand increases due to building electrification in Washington occurs in Clark PUD, where the largest portion of NW Natural customers are located and as Washington demand increases capture only the impact of electrification of NW Natural customers. Figure 29 summarizes the annual electrification impacts for Clark PUD.

Figure 29: Clark Electrification Impact (GWh) by Scenario

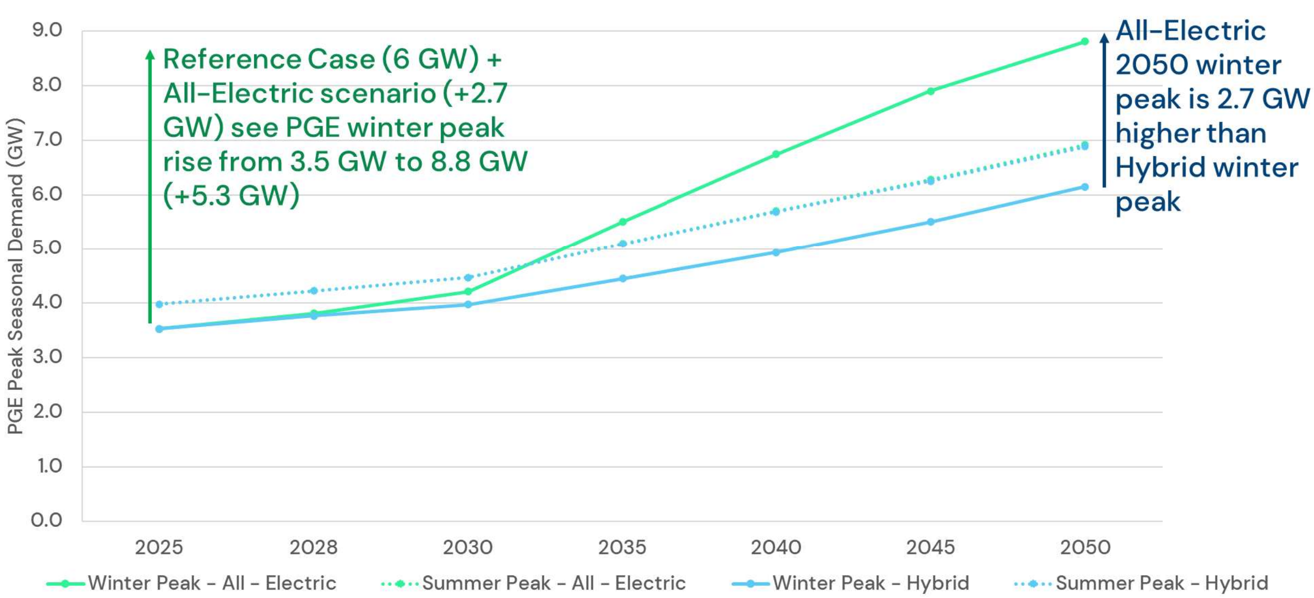
Clark Electrification Impact (GWh)	2030	2040	2050
Modest	17	97	191
Hybrid	39	338	590
All-Electric	45	387	676

Oregon Seasonal Peak Demand Results

Electrification increases the total energy load that must be served each year. These impacts require the procurement of additional capacity, which must come from non-emitting sources under current policy. The most significant effect of building space heating electrification is on peak demand, particularly during winter hours. As outdoor temperatures drop, heat pump performance declines, leading to higher electricity use and increased peak capacity needs. As Oregon shifts more of its energy demand to electricity, these effects become more pronounced. The difference in annual energy load between the Hybrid scenario and the All-Electric scenario is less than 10 percent. However, hybrid systems can reduce winter peak demand by switching to natural gas when heat pump efficiency falls.

As an example, the estimated seasonal peak demand projections for PGE, one of the main electric utilities with a service territory that partially overlaps NW Natural Gas customers, is shown in Figure 30 below.[44]

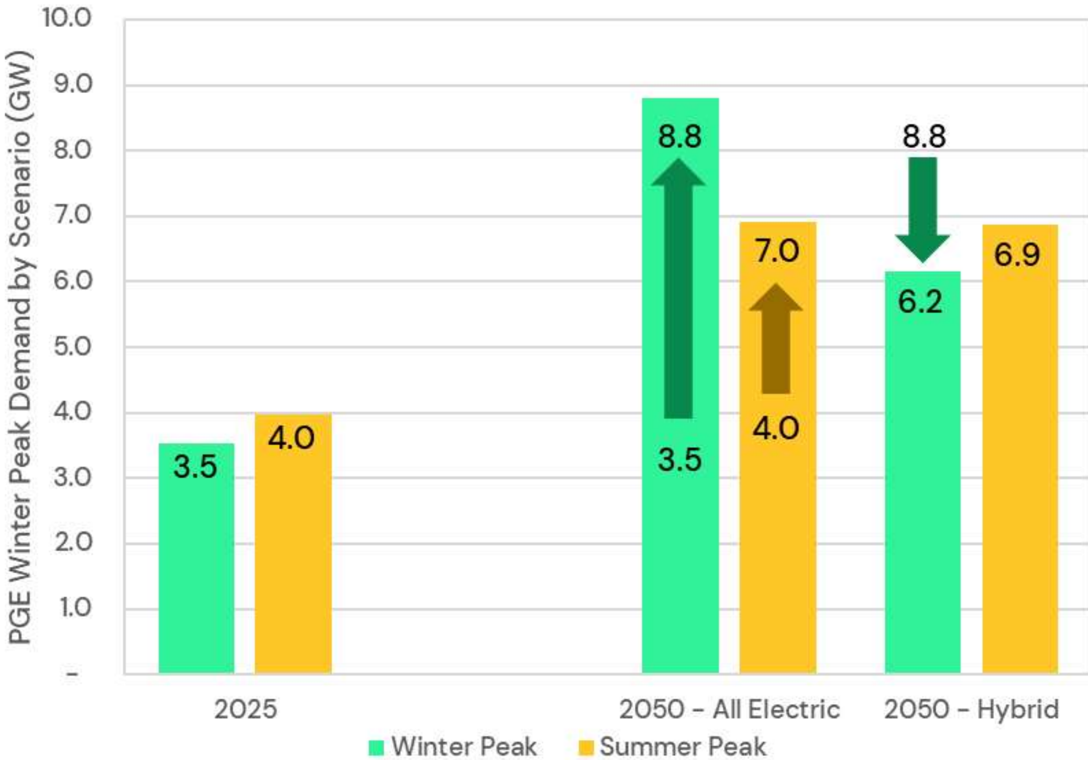
Figure 30: PGE Seasonal Peak Demand Projections – Hybrid and All-Electric Scenarios (GW)



[44] While utility-level projections are informed by utility data to the extent possible, the process to develop annual and peak demand projections are not intended to exactly replicate utility-level demand forecasting processes.

Winter and summer peak electricity demand are currently about 10 percent apart. Electrifying natural gas end uses is projected to shift the annual peak to winter by 2035 in the All-Electric scenario. Summer peak demand is expected to grow steadily, reaching nearly 7 gigawatts by 2050. However, winter peak demand grows faster, reaching nearly 9 gigawatts by 2050. In the All-Electric scenario, these peaks would need to be met with clean, firm, and dispatchable resources, which are expensive.

Figure 31: PGE Seasonal Peak Demand Growth by Scenario (GW)



As shown in Figure 31 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.
In the Modest scenario, the limited electrification does not shift the PGE peak to the winter, and the PGE summer peak increases by 74 MW, reaching 6.8 GW by 2050.

Washington Peak Demand Results

In Washington, statewide peak demand increases from building electrification are limited due to NW Natural's relatively small share of Washington's natural gas customers. Over 90% of the building electrification impacts from the electrification of NW Natural's customers fall into Clark PUD's electric service territory, where most NW Natural's natural gas customers are located.

In the All-Electric scenario, Clark PUD's 2050 winter peak demand increases from 951 MW in 2025 to over 1,800 MW, with an increase of 442 MW over the Reference Case, whereas Hybrid scenario peak demand increases by 194 MW. Peak demand increases in the Modest scenario amount to 11 MW by 2050. 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. Figure 32 summarizes Clark PUD's increase in peak demand from building electrification.

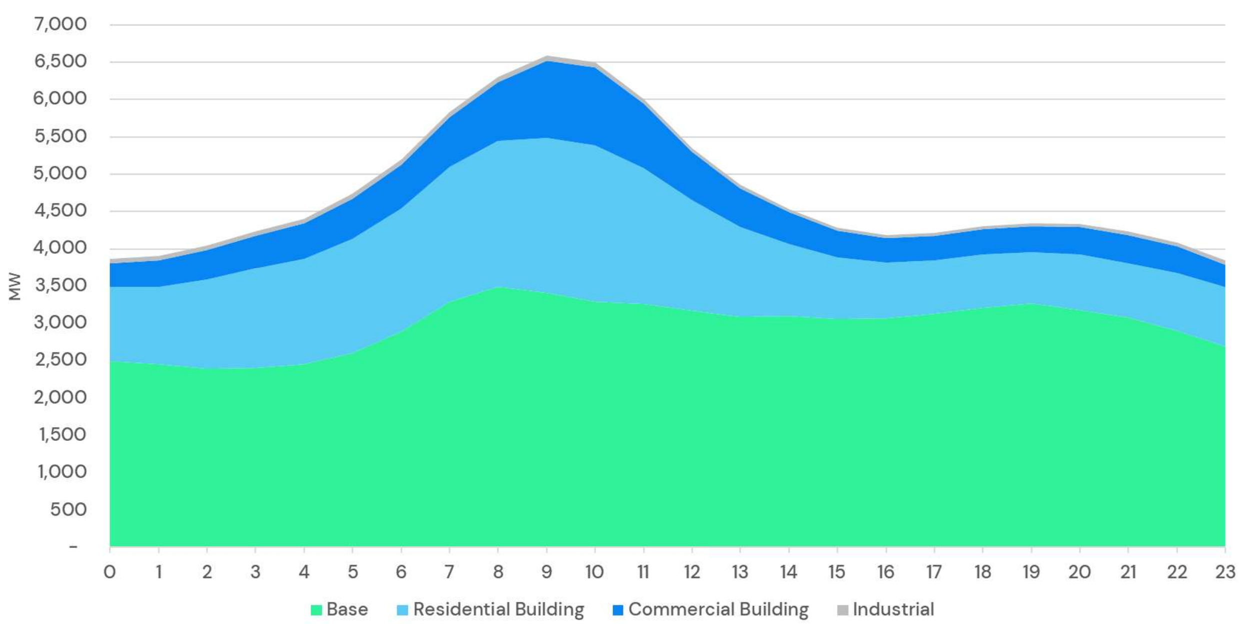
Figure 32: Clark PUD Incremental Peak Demand by Electrification Scenario (MW)

Clark Incremental Peak Demand (MW)	2030	2040	2050
Modest	0	5	11
Hybrid	10	92	194
All-Electric	27	231	442

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 upward. Figure 33 shows that in PGE's service territory, the All-Electric building electrification loads add 3,200 MW to a base load of 3,500 MW in 2050. While trends here are shown for PGE, utilities with a large share of NW Natural customers such as PacifiCorp Oregon show similar trends of peak hours shifts from summer evening peaks to morning winter peaks.

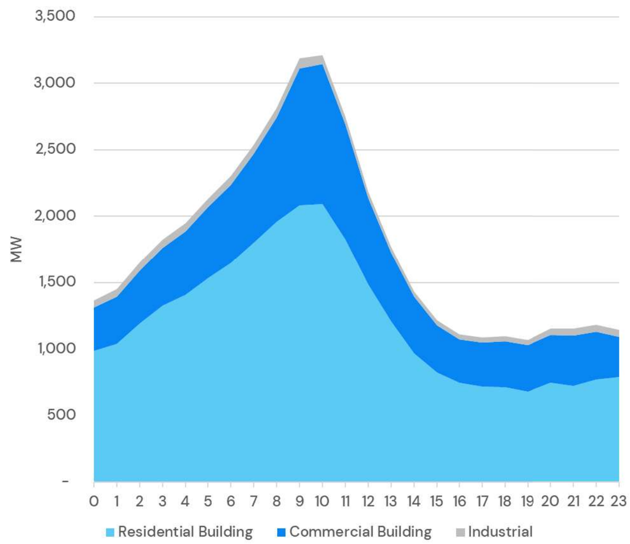
Figure 33: PGE 2050 Winter Peak (MW) - All-Electric Base + Building Electrification

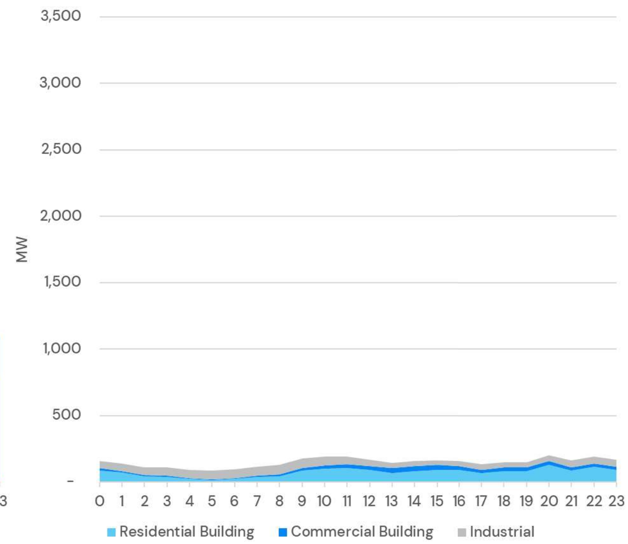


EVs and data centers are drivers of additional load growth in PGE's service territory. EV charging behavior, particularly when vehicles are plugged in during evening hours after commuters return home—creates a second peak between 6pm and 9pm. In contrast, data center loads are assumed to be flat throughout the day.

Figure 34 illustrates the impact of building electrification on winter peak demand. In the All-Electric scenario, peak load on a representative winter day in 2050 reaches its highest level. On that same calendar day, the Hybrid scenario shows a reduction in peak load of more than 3,000 megawatts relative to the All-Electric scenario, a reduction of incremental peak demand driven by electrification of over 90%. Although the shape and magnitude of the peak vary by utility, hybrid systems consistently prevent a shift to a winter peak and help limit peak demand growth across electric utilities.

Figure 34: PGE Building Electrification Peak Day Impact – All-Electric and Hybrid Scenario (MW)

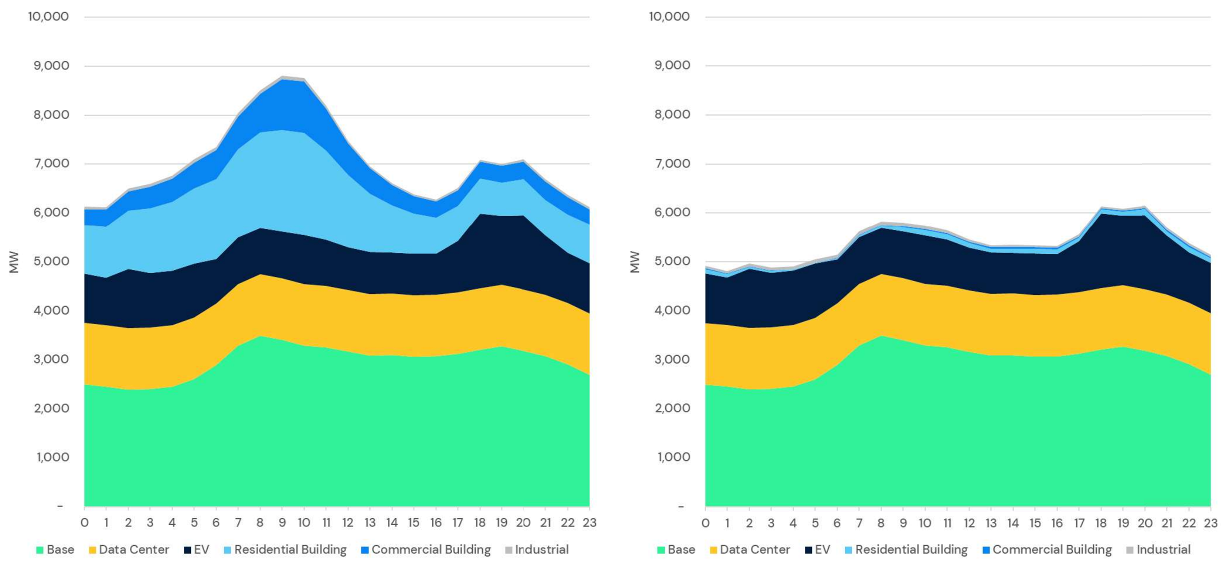




The Hybrid scenario reduces winter peak demand by using gas heating instead of electric heating on peak days. Figure 35 shows that, in this scenario, the winter peak shifts back to the evening. This shift occurs because electric vehicle charging drives the peak hour, while heating loads remain low. The overall winter peak is also lower—6,100 megawatts compared to 8,800 megawatts in the All-Electric scenario. The Hybrid scenario produces a flatter and more consistent load shape, avoiding large spikes caused by cold temperatures.

In contrast, the All-Electric scenario shows a sharp increase in demand. On PGE's system alone, peak demand rises by nearly 1,500 megawatts in just three hours. Similar patterns appear across other utilities, as most heating energy is delivered through the electric grid and responds directly to temperature changes. Load remains above 8,000 megawatts for at least five hours during the morning. The All-Electric scenario is also a peakier scenario compared to the Hybrid scenario – the All-Electric scenario peak hour is 25% higher than the average hourly peak day load, whereas the Hybrid scenario peak hour is only 5% higher than the average hourly peak day load.

Figure 35: PGE All-Electric Winter Peak Demand (MW) vs. PGE Hybrid Winter Peak Demand (MW) in 2050



In Washington, winter peak day impacts show a similar trend. Electrification loads increase demand in morning peak hours between 7am and 9am, with less impact during evening peak hours, with the resulting peak hour firmly into the morning hours. The main difference between Oregon and Washington is the fact that all winter peak demand increases from electrification directly increase annual peak demand for Clark PUD, as the region is winter peaking to begin with, while in Oregon the annual peak is currently in summer (meaning that in Oregon some of the increase in winter peak demand is 'catching up' to the annual summer peak, before the increase in winter peak demand starts driving an increase in overall annual peak demand).

5 Power Sector Modeling

The electrification analysis presented in this report 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. 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. Resource plans from electric utilities focus 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 and timelines for electric planning and the range of uncertainty across all of the assumptions incorporated into electric IRPs.

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.

5.1 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 describes the modeling approach to quantify these impacts.

Policy Compliance

Oregon's climate policy requires the electricity sector to transition to a fully non-emitting resource base by 2040. House Bill 2021 (HB-2021) mandates that investor-owned utilities (IOUs) and electricity service suppliers (ESSs) reduce greenhouse gas emissions from retail electricity sales by 80% by 2030, 90% by 2035, and 100% by 2040. These targets are measured against a baseline of average emissions from 2010 to 2012.

HB-2021 also requires utilities to submit Clean Energy Plans that demonstrate progress toward these goals. In addition, Oregon's Renewable Portfolio Standard (RPS) sets minimum renewable energy requirements for both IOUs and consumer-owned utilities. Large IOUs must meet a 50% renewable target by 2040; consumer-owned utilities face lower thresholds based on size and service territory.

As of 2023, about half of Oregon's retail electricity supply was linked to emissions. This includes electricity generated from natural gas and coal, as well as unspecified market purchases. These purchases are assigned an emissions factor by the Oregon Department of Environmental Quality (ODEQ).[45]

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, together with in-state emissions from natural gas facilities. For PGE, HB-2021 compliance requires the sum of allowances between unspecified imports and in-state thermal generation to remain within the emission limits. For PacifiCorp, compliance required in-state thermal generation and unspecified imports from non-PacifiCorp territories to comply with emission limits and for enough non-emitting generation to be available in PacifiCorp's territories to supply PacifiCorp's clean energy requirements as per HB-2021. Not all PacifiCorp clean generation has to be located within its Oregon service territory.

While this modeling approximation captures the emission reduction targets and ensures 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 and Washington 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, HB-2021 and CETA 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

[45] 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

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 in Washington.

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 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.

Available resources to utilities are informed by utility studies on available transmissions options to connect resource, such as the study conducted by PGE to inform its own IRP modeling. Transmission costs added to the capital cost of renewable development differentiate between upgrades to connect additional resources within the BPA footprint and resources brought in from states identified in PGE's transmission options study. Cost estimates for transmission interconnection within the BPA system are based on cost projection for BPA's Evolving Grid projects, whereas costs for transmission interconnection from neighboring regions is based on estimates of connected capacity and costs of transmission projects such as Western Bounty, NVE Greenlink, North Plains Connector and TransWest. Detailed transmission and distribution assumptions are presented in section 5.2 below.

5.2 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.

Resource Adequacy

This analysis relies on peak demand projections and planning reserve margins from electric utility planning processes and PNUCC to determine the capacity required to meet peak demand needs. On the supply side, resource contributions by season, capacity type, and resource penetration form the assumptions to determine capacity contributions to peak demand needs. The capacity mix presented for each of the scenarios presented complies with system reliability criteria based on the demand and supply side specifications listed above and have not been tested further through additional and more granular reliability modeling to determine metrics such as Loss of Load Hours (LOLH), Expected Unserved Energy (EUE) or Loss of Load Events (LOLE). More extensive analysis will be required to study the modeled supply portfolios to determine compliance with reliability standards. As mentioned throughout this report, this additional reliability assessment is further complicated by the potential evolution of reliability metrics to cover weather extremes, increased penetration of non-emitting resources and the impact of shifting energy delivery from the natural gas to the electric system, as envisioned in the All-Electric scenario.

Detailed reliability modeling to determine portfolio compliance with reliability metrics such as LOLH was not conducted on the portfolios shown in this study.

Reserve Margins

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.[46] 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[47] 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.[48] Figure 36 below summarizes the seasonal Effective Load Carrying Capabilities (ELCCs) by region and capacity type. Regional descriptions of the VER zones are available in the WRAP studies referenced above.

[46] 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.

[47] 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.

[48] 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.

Figure 36: 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%

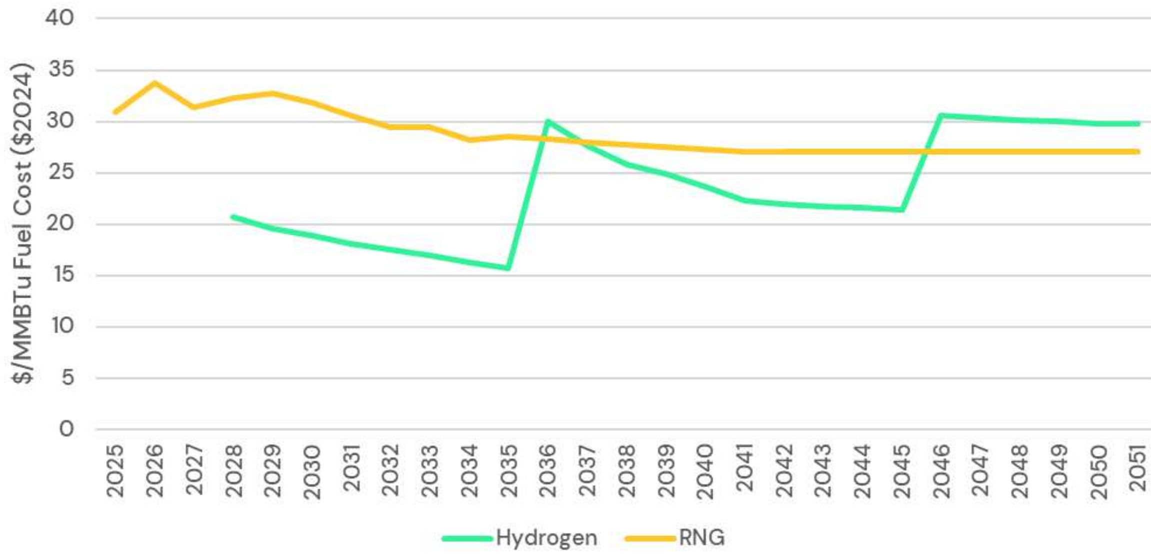
Reserve contributions of resources, especially battery storage, are evolving as more empirical data becomes available and as resource portfolios are evaluated against a range of load and weather conditions. While this analysis relies on available data from WRAP, resource contributions of battery storage 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 PGE's 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 compared to 4hr storage currently being deployed given the reduced winter peak demand contributions as early as 2030.

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. Hydrogen costs shown in Figure 37 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 37: Non-Emitting Fuel Prices ($/MMBtu)



Renewable Cost and Performance

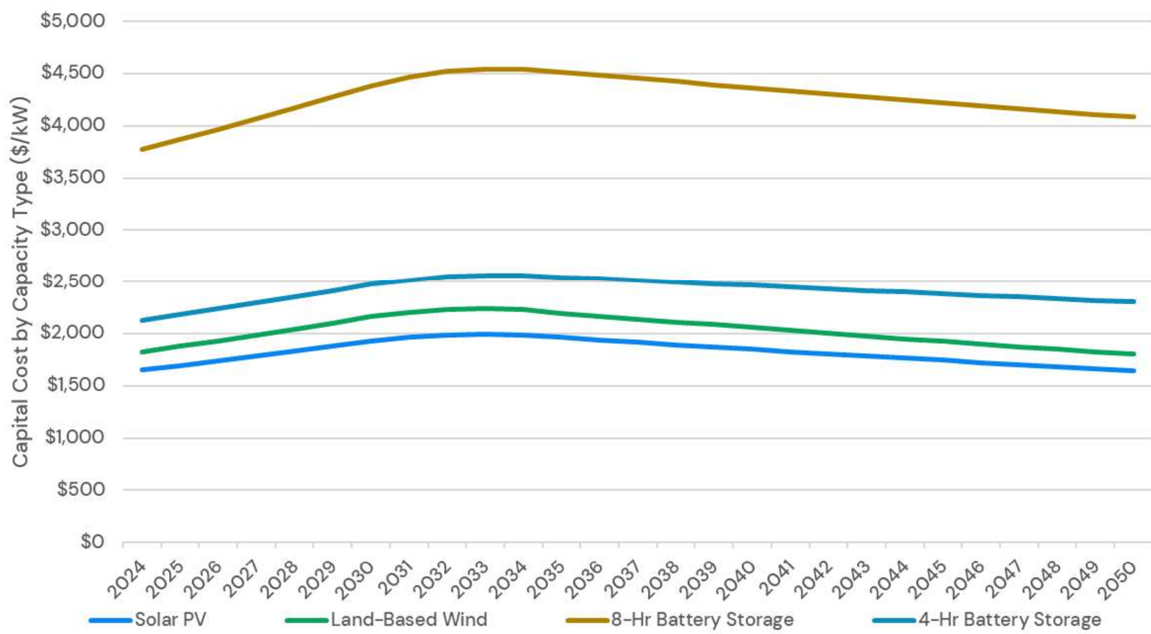
Renewable Cost and Performance assumptions for the supply-side analysis are informed by the latest Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL), as well as historical cost information presented in previous versions of the ATB (such as the 2021 costs presented 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. 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[49]. 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.[50]

[49] 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.

[50] 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.

Figure 38: Renewable Capital Cost by Capacity Type ($/kW)



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, the Bonneville Power Administration (BPA) owns and operates the majority of the high voltage transmission network in Oregon and Washington. 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 39: 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

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 HB2021 targets without any transmission upgrades and the magnitude of transmission needed increases throughout the planning horizon.*"[51]

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

[51] 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.

of interconnection capacity is assumed to be 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:

- **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 increases transmission interconnection capacity throughout the rest of the Pacific Northwest
- **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 it is assumed 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.
- **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.
- **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. 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.

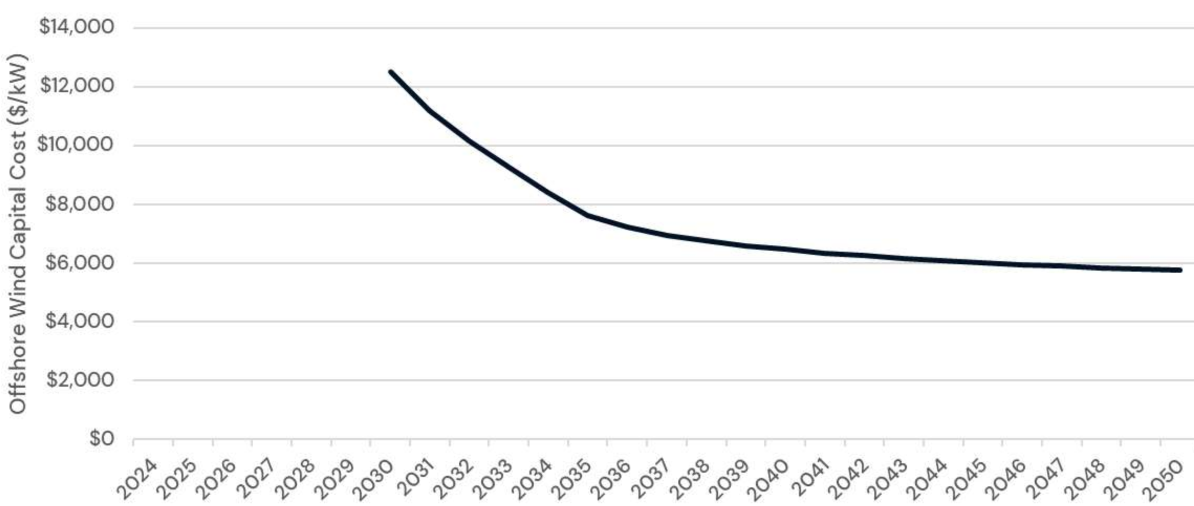
Required Transmission to Achieve HB-2021 Compliance

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 HB2021 compliance is achieved.

Offshore Wind

Offshore Wind resources are a potential resource to supply non-emitting electricity to Oregon customers. Oregon's coastal conditions limit offshore wind development to floating platforms, which are more expensive than fixed-bottom systems and have not yet been deployed at commercial scale in the U.S... 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.

Figure 40: 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. To estimate the cost per kilowatt ($/kW) needed to meet future demand growth, ICF built a linear regression model that linked net utility distribution plant value to peak demand, based on a sample of utilities similar to those in Oregon. This model allowed ICF to estimate the additional capital investment required to support specific future demand levels.

Once the cost per kilowatt of demand growth for each of the target utilities was developed from the regression, ICF developed a simple model to convert $/kW values to $/kW-yr. values, using a set of basic assumptions.

Data sources for the cost per kilowatt analysis included the Hitachi Energy Velocity Suite[52] which aggregates data from various sources, including Form EIA- 861[53], Annual Electric Power Industry Report and FERC Form 1[54] filings. The Hitachi Energy Velocity Suite dataset used in the analysis contains 210 utilities. A regression analysis that compared net distribution plant to peak demand was performed for a set of comparative utilities with similar characteristics (ownership of generation, transmission, distribution and other utility metrics such as the ratio of generation plan to total electric plant, the percentage of transmission and distribution plant that is underground, the underground to overhead ratio and distribution to transmission net plant ratio etc.). From the regression analyses, ICF derived the corresponding slopes of the regression lines. These slopes represent a relationship between net distribution plant and peak demand (in $/kW) for the set of peer utilities with similar values of derived metrics.

Once the $/kW values were obtained for each of the target utilities, ICF built a simple cost model to convert the values from $/kW to $/kW-yr. The input parameters to cost model and their sources included:

Figure 41: Distribution Cost Input Parameters

<table>
<tr><th>Input Parameters</th><th>Source</th></tr>
<tr><td>Discount Rate (as decimal)</td><td rowspan="2">Research on utility rate cases</td></tr>
<tr><td>O&M Cost (% of Capital, as decimal)</td></tr>
<tr><td>Capital Cost ($/kW)</td><td>Average of regression analyses</td></tr>
<tr><td>Discount Rate (as decimal)</td><td rowspan="3">Research on utility rate cases</td></tr>
<tr><td>Economic Life (years)</td></tr>
<tr><td>O&M Cost (% of Capital, as decimal)</td></tr>
</table>

[52] https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/market-intelligence-services/velocity-suite
[53] https://www.eia.gov/electricity/data/eia861/
[54] https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report

The cost model then computed the following values:

Figure 42: Computed Distribution Cost Values

Computed Values
Capital Recovery Factor (CRF)
Annualized Capital Cost ($/kW-yr)
Annual O&M Cost ($/kW-yr)
Total Annualized Cost ($/kW-yr)

The cost model computes a Capital Recovery Factor (CRF). The CRF is used to annualize capital costs and uses discount rate and economic life as inputs. For example, using an 8% discount rate, the CRF for a 30-year life comes out to be around 0.09. The model then uses the capital cost, capital recovery factor and O&M cost (as % of capital) to compute a total annualized cost in $/kW-yr. Figure 43 summarized the cost model factors and resultant $/kW-yr. costs for the three target utilities.

Figure 43: Summary of estimated utility distribution cost factors

Factor	PGE	PacifiCorp	EWEB
Capital cost, $/kw	638	847	549
Discount rate, %	7.5	8.5	6.5
Economic Life, yrs.	30	30	30
O&M cost % of capex	3.0	3.0	3.0
Cost ($/kW-yr.)	73	104	59

While the $/kW-yr distribution cost estimates are kept constant over the course of the study, the significant levels of load growth projected in this analysis, the potential shift of peak demand to the winter in the All-Electric scenario and the shifting demand patterns towards temperature-driven space heating loads may require distribution system changes that put further cost strain onto the system not quantified in this analysis. Given limited data availability for Clark PUD in Washington, distribution cost increases for Washington were estimated based on the peak demand increase in Washington and the average of utility distribution cost assumptions ($/kW-yr) for Oregon utilities examined for this study.

5.3 Power Sector Supply Side Results

This section shows the results of the power sector analysis of the electrification study, including capacity, generation, costs, and emissions. Results for the Reference Case are shown by region, and capacity, generation and costs are shown at the aggregate system level for Oregon and Washington, which aligns more closely with the interconnected nature of the electric grid in the Pacific Northwest and the way the model solves for demand across the region. More detailed, regional results for incremental capacity, generation, and costs are included in Appendix B for reference.

Capacity expansion rapidly accelerates to meet HB-2021 compliance requirements and reliability needs.

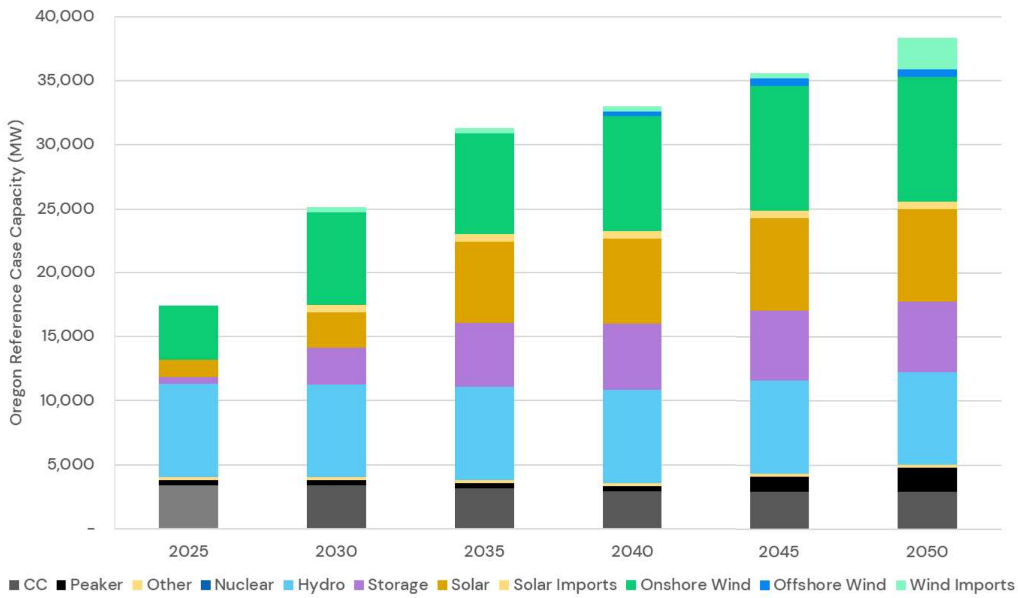
Incremental capacity needs emerge rapidly to facilitate HB-2021 compliance and meeting load growth. Emission limits for PGE and PacifiCorp limit the ability of the utilities to rely on thermal resources that they currently rely on to meet demand. In 2023, PGE reported emissions of 5 MMT CO_2e from specified 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 CO_2e of emissions are associated with an addition 4,000 GWh of unspecified generation. [55] Between 2023 and 2030, emissions are required to drop by over 5 MMT CO_2e to 1.6 MMT CO_2e, and to 0.8 MMT CO_2e 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.

Figure 44 shows the evolution of the installed capacity in Oregon between 2025 and 2050 under Reference Case conditions. 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.[56]

[55] 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.

[56] Portland General Electric. "PGE CEP & IRP Roundtable 25-3." April 25, 2025. https://assets.ctfassets.net/416ywc1laqmd/23rNye7U9w5Fv7hlNB7A4y/72b3d002bccbcc1fa89c0af6e4fe0e40/CEP_IRP_Roundtable_April_25-3.pdf.

Figure 44: Oregon Reference Case Capacity (MW) from 2025 to 2050

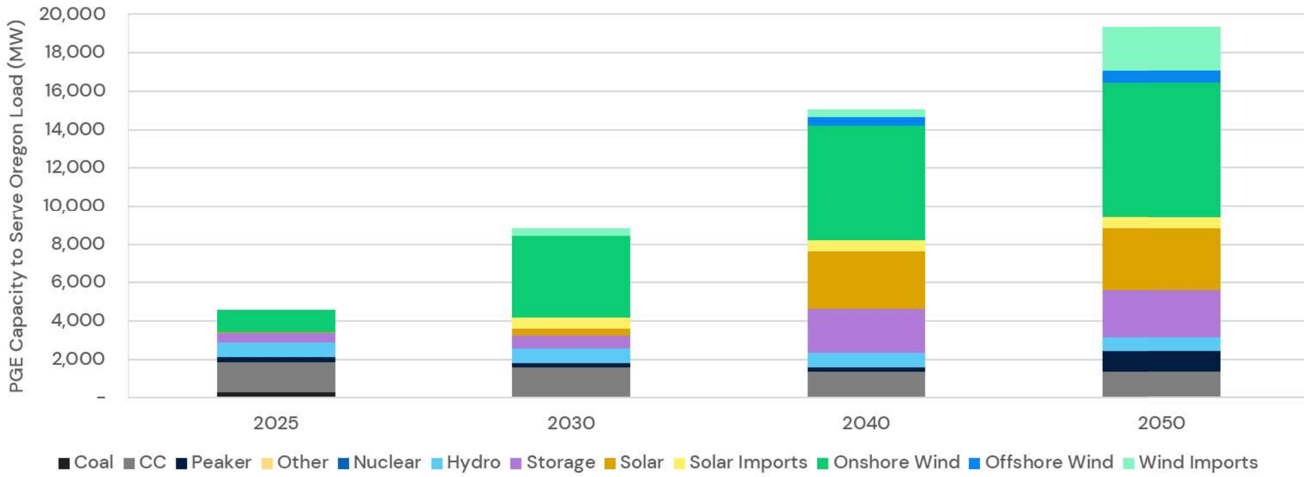


Absent building electrification, renewable additions dominate in the Reference Case, with wind additions of 5,500 MW, solar additions of 5,800 MW, and additional storage capacity of over 5,000 MW. In addition to 600 MW offshore wind in 2040, additional renewable capacity of over 3,000 MW from out of state supplies utilities in Oregon to ensure compliance with clean energy mandates by 2050. In the winter periods when contributions from solar, onshore wind and battery storage are limited, peaking capacity also increases by 1.5 GW.

Figure 45 shows the expansion of the capacity mix in PGE's territory for the Reference case. State-wide trends are driven in many categories by PGE trends. In the Reference Case, capacity additions occur in all capacity types, including wind and solar capacity to meet growing energy needs, as well as battery storage and non-emitting peaking units meeting peak demand increases. 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, 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. 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.[57]

[57] 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.

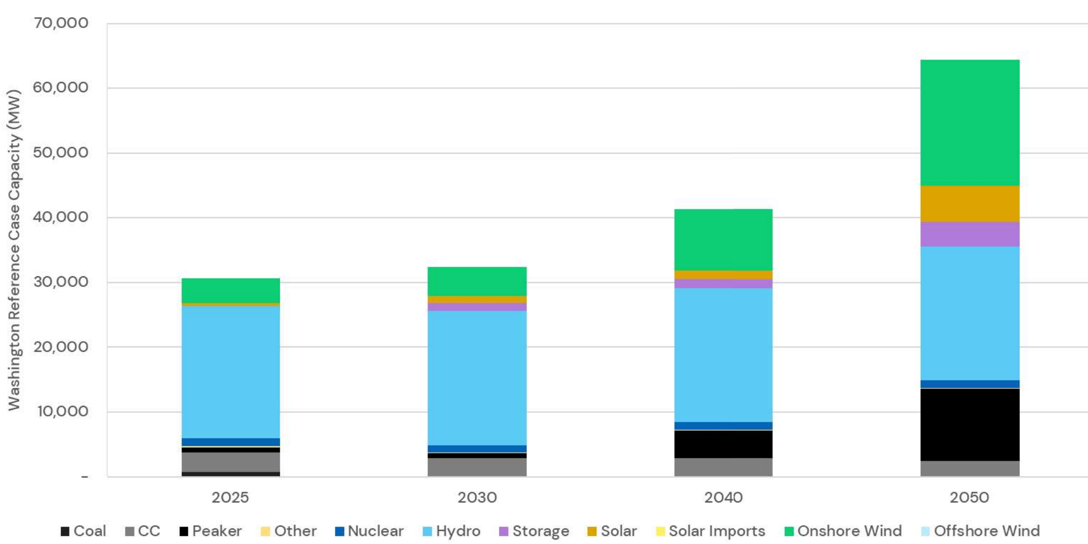
Figure 45: PGE Reference Case Capacity (MW) from 2025 to 2050



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 and combined cycle capacity. As shown in Figure 46, 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 46: Washington State Reference Capacity Mix (MW)

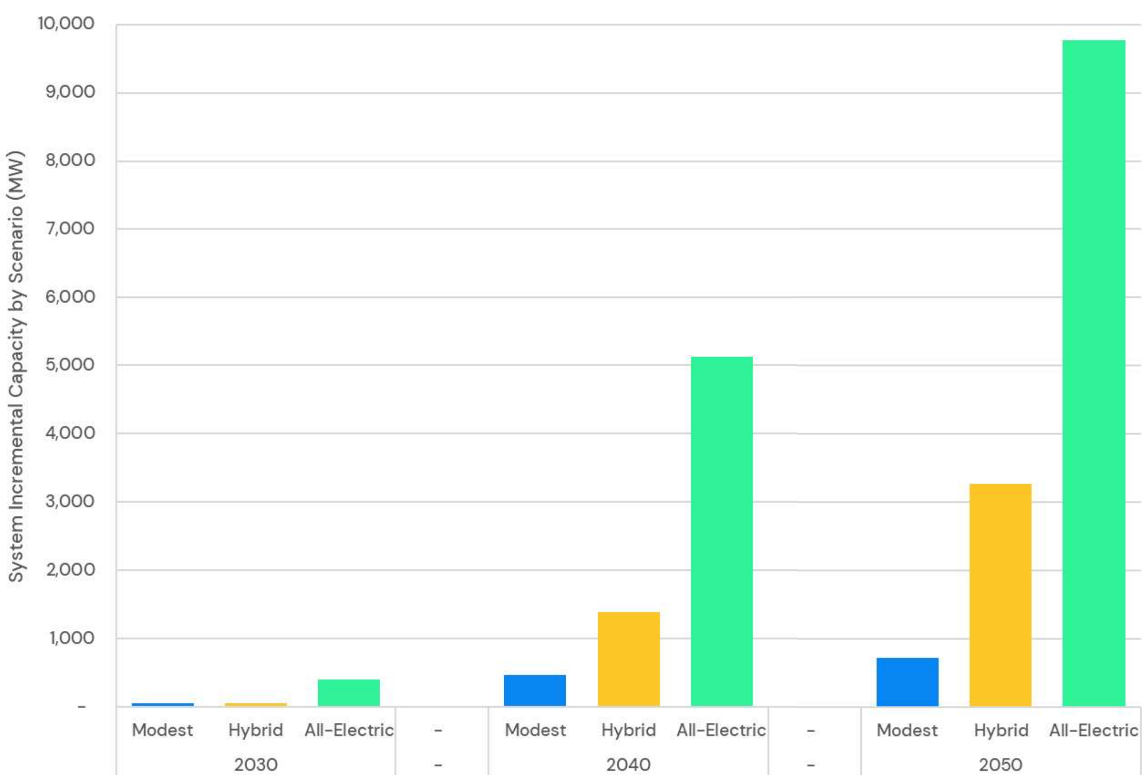


While both states rely on incremental thermal peaking capacity as well as battery storage, the exact nature of firm, non-emitting dispatchable capacity that will back up the additional gigawatts of renewable capacity required for compliance with CETA and HB-2021 will ultimately depend on a variety of assumptions, technology developments over the coming decades, and results 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.

The All-Electric Scenario requires over 6,500 MW more capacity across the Pacific Northwest than the Hybrid Scenario

Figure 47 shows the incremental capacity to meet growing energy and peak demand needs under the electrification scenarios. By 2050, the installed capacity in Oregon and Washington expands by close to 10,000 MW, as peak demand increases requires firm, non-emitting resources and increased energy needs are met from non-emitting renewable resources that provide little capacity to peak demand. The Hybrid scenario mitigates peak demand increases and with that approximately 6,500 MW of incremental capacity. As shown in more detail in Appendix B, the incremental capacity is comprised primarily of non-emitting peaking plants as well as wind within the region and imported into the region from neighboring states.

Figure 47: System Capacity by Electrification Scenario Incremental to Reference (MW)

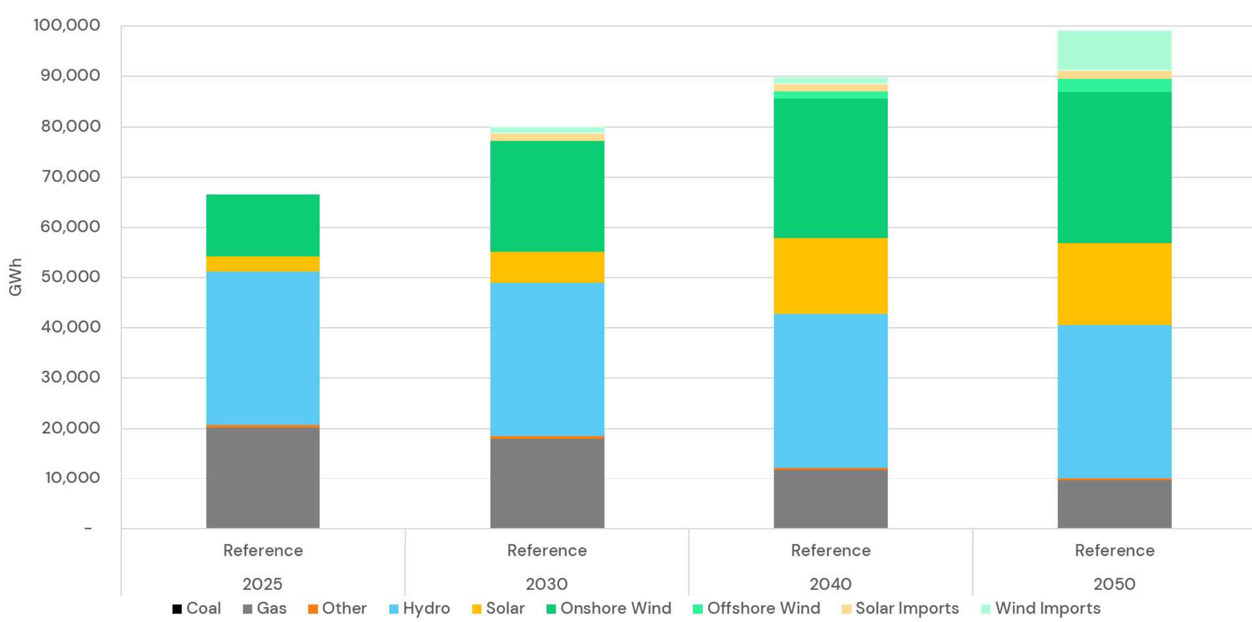


Transmission bottlenecks challenge HB-2021 compliance

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 account for 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.

Figure 48 showcases this rapid expansion of generation in Oregon, with net supply growth of over 10,000 GWh in the next 5 years, even as gas generation declines. By 2050, electricity generation in Oregon is projected to increase by 50%, with the share of wind and solar growing from 23% of Oregon's total generation to close to 60%. While thermal generation declines, hydropower continues to contribute to non-emitting in-state generation. Total gas-fired generation declines over time, reflecting compliance with HB-2021 by covered utilities such as PGE and PacifiCorp. Remaining gas generation dispatches into wholesale markets and are not subject to HB-2021 requirement.

Figure 48: Oregon In-State Reference Case Generation Mix (GWh)



Washington Expands Wind Generation as Primary CETA Compliance Strategy

As shown in Figure 49, Washington's generation mix in the Reference Case sees predominantly an expansion of renewable energy resources to meet load growth as well as more stringent clean energy requirements. By 2045, the state's energy mix requires 100% clean energy without the use of unbundled Renewable Energy Credits (RECs). Prior to 2045, natural gas generation still plays a role even with requirements from the Clean Energy Transformation Act (CETA) and the carbon pricing implemented through The Climate Commitment Act (CCA).

Figure 49: Washington Reference Case Generation Mix (GWh)

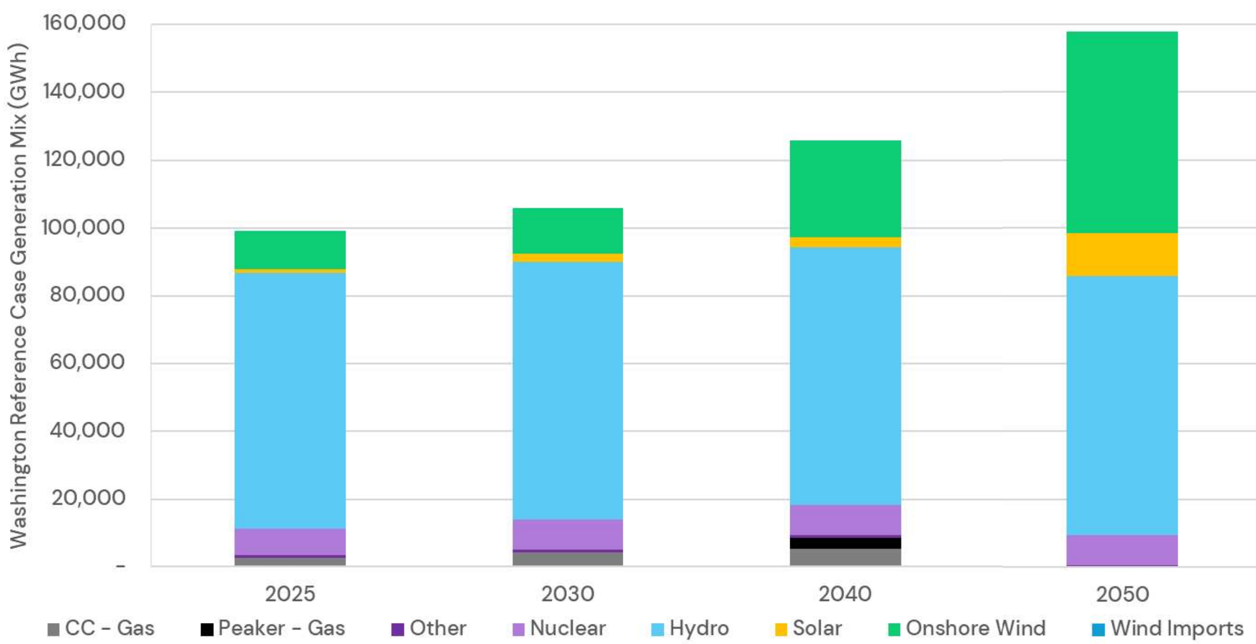
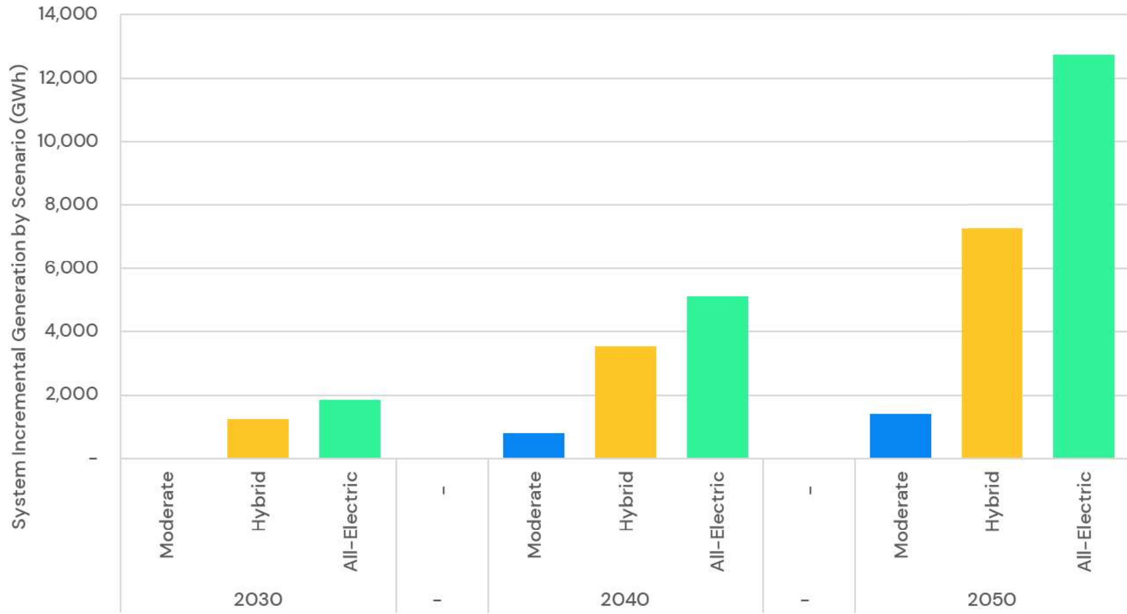


Figure 50 shows the incremental generation for the three electrification scenarios. Prior to 2045, incremental load from building electrification is met with a mix of renewable and thermal generation. Gas generation increases as the 100% clean energy requirements are not yet in effect and utilization of existing gas resources provides supply without requiring incremental capital investment into new resources. Starting in 2045, all incremental supply is non-emitting, as all thermal generation is phased out in compliance with CETA.

Figure 50: System Generation by Electrification Scenario Incremental to Reference (MW)



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[58]. Building electrification adds substantially to winter peaking needs and costs, especially 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.[59] 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. Incremental capacity additions meet the increased demand, resulting in costs incremental to the Reference Case that are directly attributable to the electrification load increases. 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 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 One Big Beautiful Bill Act. Investment Tax Credits (ITC) are reflected in the capital cost component for battery storage and offshore wind. Also included in the capital costs shown in the cost data are costs assumed to interconnect renewable resources in Oregon beyond the available interconnection

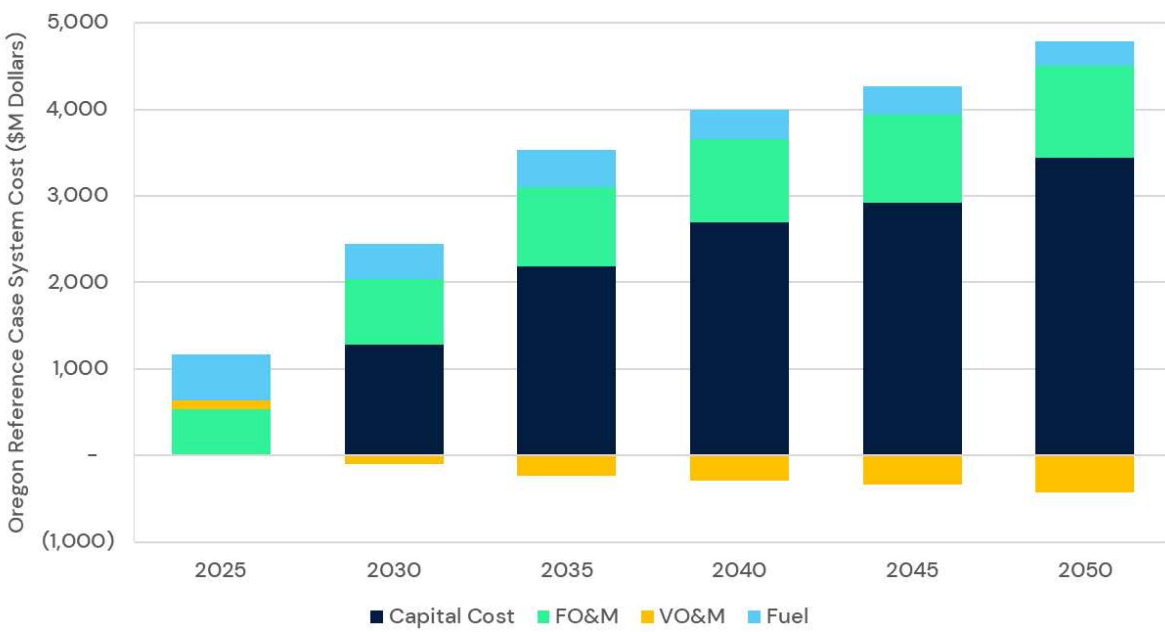
[58] Oregon and system-wide costs presented in section 5.2 reflect costs associated with the electrification of Oregon end-use demand across the entire state, extrapolated from trends modeled for NW Natural customers.

[59] 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.

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.

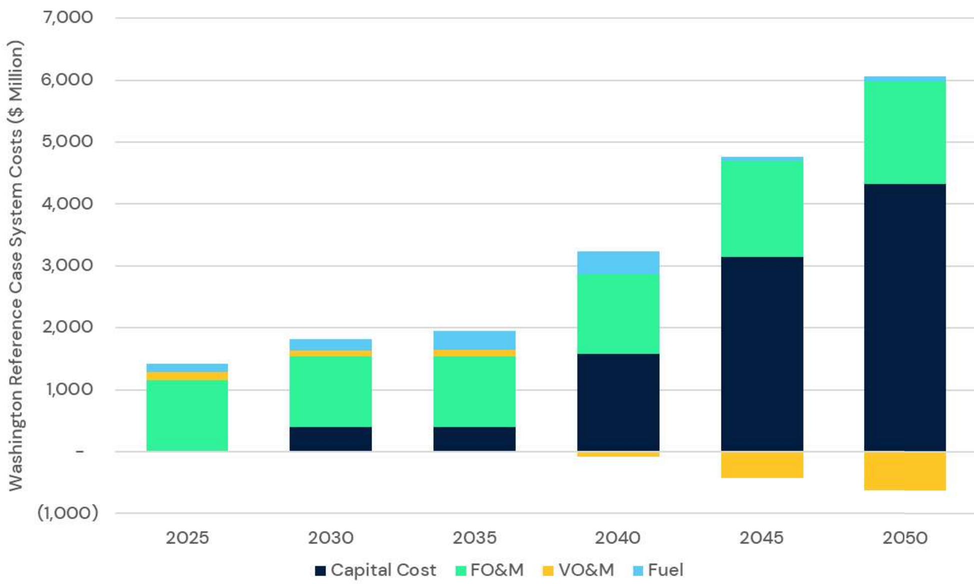
As shown in Figure 51, the primary cost driver of system costs in Oregon are capital expenditures required to procure capacity to meet load growth and achieve compliance with HB-2021. Fuel costs decrease over time as natural gas generation decreases, and the system costs shift to a predominantly fixed cost driven cost structure.

Figure 51: Oregon Reference Case Annualized System Costs ($ Million)



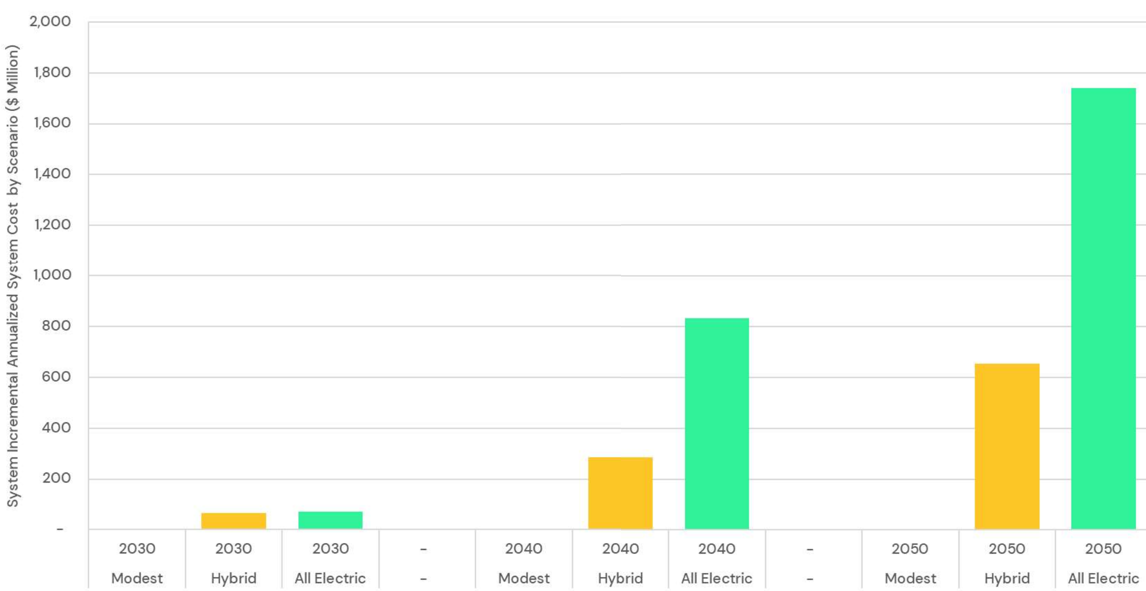
Washington's system cost results tell a similar story of increasing fixed costs, primarily capital expenses for the expansion of onshore wind supply. While early additions are limited due to the CETA requirements still allowing for unbundled RECs to supply up to 20% of the CETA requirements, capacity 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 52 shows the increase in system costs in Washington.

Figure 52: Washington Reference Case System Cost ($ Million)



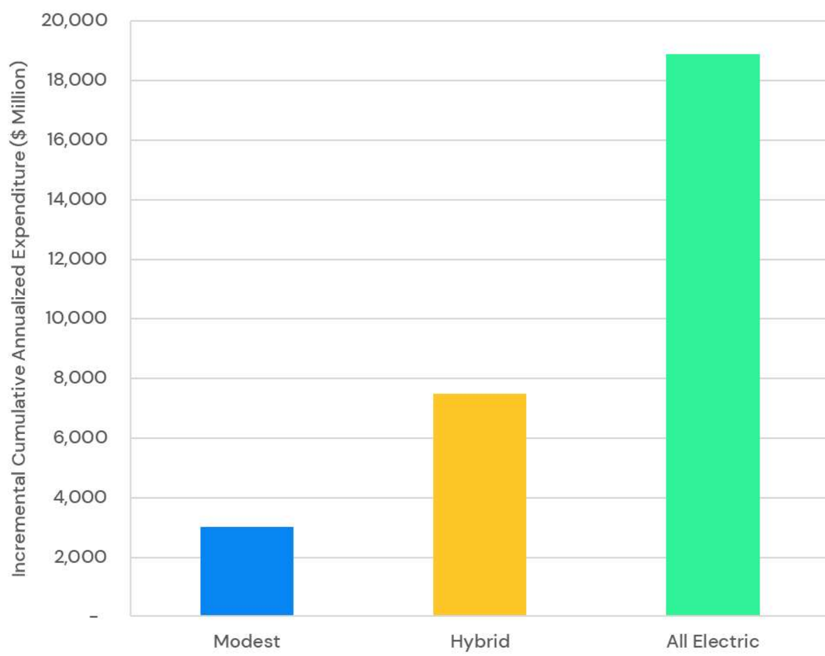
Across Oregon and Washinton, the annualized system costs in the All-Electric scenario increases by over $1.7 billion in 2050, primarily to the expansion on capital investment required to bring online new generating capacity to meet peak demand growth driven by end-use electrification, as well as distribution costs due to higher peak demand levels. With its winter peak demand mitigation, the Hybrid scenario avoids some of the cost increases for capital and distribution costs. System cost increases in the Hybrid scenario increase by more than $600 million, $1 billion less than the All-Electric scenario.

Figure 53: System-wide Annualized System Cost Incremental to Reference ($ Million – Yearly)



As shown in Figure 54, over the course of the 25-year forecast period, electrification scenarios add between roughly $3 billion in the Modest scenario and close to $19 billion in the All-Electric scenario, with the Hybrid scenario mitigating costs of over $11 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.

Figure 54: Incremental Cumulative Annualized Expenditure over Reference – Oregon and Washington Combined ($ Million)



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 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.

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[60], 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.[61] These estimates assume that combustion facilities meeting peak demand in the winter are required to 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 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, a framework increasingly relied upon by

[60] ICF. "Examining the Current and Future Economics of Hydrogen Energy." Insights/Energy, August 13, 2021. https://www.icf.com/insights/energy/economics-hydrogen-energy.

[61] 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.

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).[62]

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. 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 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 buildouts 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%.

[62] 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.

2. **Shift in underlying reliability metrics**

   The current planning environment in the electric industry often relies upon the above-mentioned 1-in-10-year standard 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 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. The one event in 10-year standard often relied upon for electric planning compares to planning standards for natural gas that are equivalent to a 1-in-100-year weather event. As the standards refer to different metrics, 1-in-100-year weather event on the natural gas system compared to a 1 outage event in 10 years, the systems currently plan for different reliability metrics and a reliance on an all-electric energy delivery system may require adjustments to the reliability metrics that have not been accounted for in this analysis.

   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 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 drives 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.

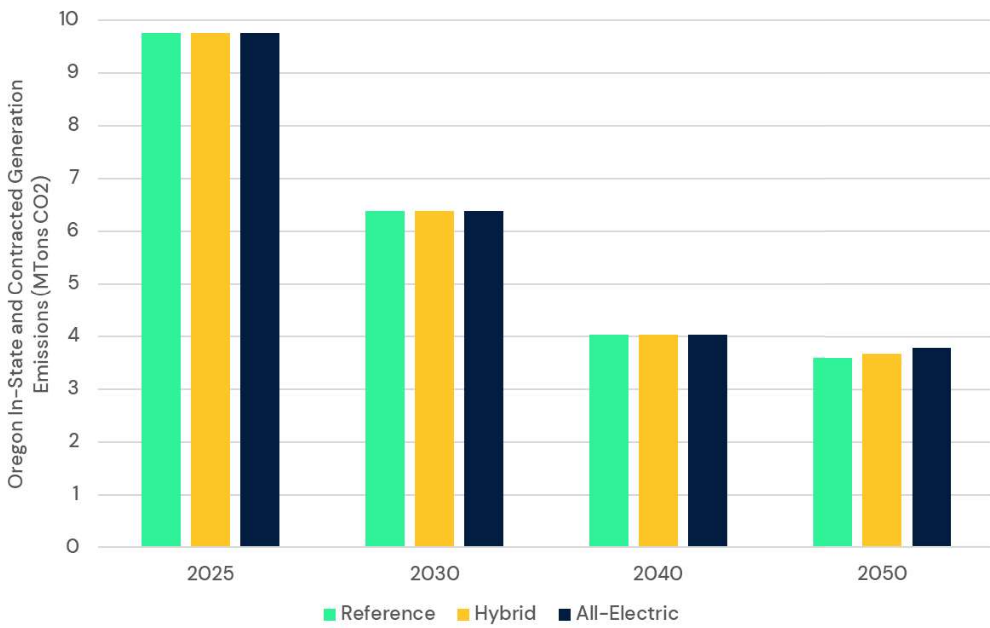
In addition to the costs outlined above and associated with electrification loads identified in this analysis, other costs may shape the future of electric utility costs in Oregon over the coming decades. Another component that is driving utility costs are costs associated with mitigating wildfire risks 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 55 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 CO_2e /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 resources 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. Emissions increase by less than 0.2 million tons in the All-Electric scenario as some of the load increase driven by building electrification occurs in regions that are not covered under the HB-2021 zero emission requirements, such as load increases in the EWEB territory.

As shown in Figure 55 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.

Figure 55: Oregon In-State and Contracted Generation Emissions (MTons CO_2)



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 emission in the same way that IOUs are. 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. The portion of load increase not covered by HB-2021 leads to emission increases in the All-Electric scenario, with an increase in emissions by less than 0.2 MMTons CO_2 over the Reference Case in 2050. The Hybrid scenario is projected to increase emissions by less than 0.1 MMTons CO_2. Emission increases from building electrification are limited to at most 0.2 MMTons CO_2 as most load increases occur in territories covered under HB-2021.

6 Overall Energy System Results

This section provides an overview of key overall cost and GHG emissions results, combining the demand-side and electric power sector results from the electrification analysis conducted by ICF with results from NW Natural's IRP PLEXOS modeling.

6.1 Costs

Cost Components

The categories of costs that are considered in the comparison of 'Electric and Gas Total System Costs' in NW Natural's IRP are described below. These are annual incremental costs relative to the Reference Case (e.g., all cost components are established based on the difference vs. Reference Case costs). The following cost components align with the categories used to show the results later in this section:

1. **Annual Incremental Customer Equipment Conversion Costs:** Customer equipment conversion costs, outlined in Section 3.3, capture the incremental costs for customers to install electric equipment instead of gas equipment (assuming customers otherwise would have needed to replace their furnaces and air-conditioning units) in the year conversions occur, including for residential, commercial, and industrial equipment electrification.
2. **IRA Equipment Conversion Incentives:** A high-level assumption is made that roughly 60% of the $113.76 million of IRA incentive funding planned to be 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, assumed 5% of the state's planned $166 million IRA incentive funding might be channeled to NW Natural customers, reflective of the Company's smaller share of total gas customers in Washington. Note that incentives from in-state energy efficiency and/or electrification programs (e.g., Energy Trust of Oregon) were not included as cost savings, since the funding for these incentives will be collected from the residents of Oregon and/or Washington.
3. **Annualized Generation & Transmission Costs:** Increased electric costs from generation and transmission investments and operations. These power sector costs, outlined in Section 5.2, are annualized costs. This means that capital investments in generation and transmission 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 for the utility to recover its infrastructure investments (i.e., impacts not fully captured within the 2025-2050 cumulative costs). [63] [64]
4. **Annualized Electric Distribution Costs:** Increased electric costs from distribution system investments and operations. These power sector costs, outlined in Section 5.3, are annualized costs that amortize the capital investments over the lifetime of the investment.
5. **NW Natural Commodity Savings:** In the electrification scenarios, where natural gas demand is reduced relative to the Reference Case, less gas commodity purchases are required, resulting in cost savings relative to the Reference Case.

[63] 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 and for hydrogen (for both ICF's power modeling and the NW Natural PLEXOS modeling) would be higher.

[64] Annualized Generation, Transmission and Distribution Costs taken from Section 5.3 are adjusted for Section 6.1 to only reflect costs associated with the load increases from electrification of NW Natural customers.

6. **NW Natural Capacity Savings:** In the electrification scenarios, where natural gas demand is reduced relative to the Reference Case, upstream pipeline capacity can sometimes be released, resulting in cost savings relative to the Reference Case.
7. **NW Natural Emissions Compliance Obligation 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, as well as other compliance options. In the electrification scenarios, where natural gas demand is reduced relative to the Reference Case, less gas needs to be decarbonized, resulting in compliance resource cost savings relative to the Reference Case.

Reference Case & Incremental vs. Full Costs

ICF's analysis as part of this IRP focused on the quantification of incremental costs (relative to the Reference Case) of a range of electrification scenarios. Reference Case costs, while partially covered under the Power Sector analysis, are not fully quantified. The focus on incremental costs was an intentional decision in ICF's proposed approach. There are a very large number of cost components or variables impacting costs that could theoretically be considered as part of looking at 'total costs', and focusing on incremental costs simplifies the analysis by avoiding the quantification of cost components that will be the same in the Reference Case and the electrification scenarios under consideration. Additionally, focusing on the incremental costs can also help isolate the impact of building electrification impacts, and emphasizes the marginal cost of achieving emissions reductions.

Additional context on why Reference Case costs are not calculated for some of the cost components discussed in this section are provided below.

Customer Equipment Conversion Costs (cost category 1 in previous section)

For the demand side analysis part of this study, the modeling was setup to calculate incremental customer equipment conversion costs, for example based on the per unit incremental cost to install a heat pump instead of a furnace and air-conditioning unit. While ICF did develop per unit costs for baseline equipment (e.g., furnace and air-conditioner costs), in order to establish the incremental costs used in the analysis, this study does not attempt to model all the baseline equipment costs for NW Natural customers. Since the analysis focused on modeling turnover in existing gas equipment, and not the turnover in all electric equipment, calculating a total Reference Case for customer equipment costs was not possible. For example, while most (but not all) NW Natural customers use gas for space heating, many NW Natural customers have electric water heating or cooking. For example, capturing the full Reference Case for NW Natural customer equipment conversion costs would require analysis of the costs when a NW Natural customer that currently uses an electric water heater needs to replace that unit with a new electric water heater. To consider 'total costs' it could then be similarly argued that you might need to account for customer costs to replace their microwave or other household appliances. That level of detail was out of scope of this study, with the approach being to assume that the customer purchases/costs for equipment not being analyzed would be the same in the Reference Case and the electrification scenarios (while still allowing the scenarios to show an incremental cost vs. the Reference Case).

Another example from the demand-side would be the significant energy efficiency savings that are built into NW Natural's IRP Reference Case, based on analysis provided by the ETO. To our knowledge, NW Natural did not receive details from the ETO on how much all the achievable energy efficiency potential would cost. Given that all the scenarios build off the Reference Case and assume the same efficiency improvements, the incremental costs for the electrification scenarios could be established without the costs for these energy efficiency savings. But trying to develop a comprehensive total Reference Case cost would also require such costs.

Power Sector (cost categories 3 and 4 in previous section)

While Section 5 above does present Reference Case costs for the power sector, these cost estimates are not fully comprehensive of all expected electric utility expenditures. This again suggests a focus on the incremental cost vs. reference case offers a better sense of the impact of building electrification on the power sector. The power sector Reference Case includes cost impacts from meeting load growth from EV loads and data centers, and complying with emission reduction regulations, such as HB-2021.

Power sector costs reported for the Reference Case include annualized operating expenses for power plants, including fixed and variable O&M expenses, as well as fuel costs. Capital expenditure reported includes the annualized capital costs expended to develop resources selected to meet demand growth, based on assumed capital expenditure (CAPEX) for resources, inclusive of assumed costs required to develop transmission to interconnect selected resources.

Not included in Reference Case is the CAPEX still being incurred for units already in the system. Annualized capex for existing units depends on the capex incurred at the time, specific financing assumptions and other factors not accounted for in forward-looking analysis. System costs therefore do not include existing unit capex. Estimates of existing unit capex were included in the electric rate analysis to develop the utility-specific revenue requirement estimates.

Also not included in the Reference Case costs are estimates for distribution costs. Distribution costs for the scenarios shown in this analysis are built up from the $/kW relationship between net distribution plant and load, and therefore, $/kW distribution cost estimates are a suitable proxy to project the expenditure required to meet the next MW of load (such as incremental load due to electrification), but is likely not fully reflective of all costs utilities incur to run operations and meet existing loads. Investments into electric distribution have increased more rapidly than other categories, increasing 160% in the 20 years between 2003 and 2023, and with capital additions for distribution accounting for close to 50% of capital additions in 2023.

Another example of potential electric utility cost increases that have not been factored into ICF's Reference Case estimates would be costs from wildfires or preventative resilience measures. Impacts of wildfire-related damages will in part depend on the outcome of several legislative and regulatory proceedings currently ongoing that aim to clarify which wildfire-related costs can be passed on to ratepayers, and which conditions need to be met to do so.

Gas Utility Savings (cost categories 5, 6, and 7 in previous section)
The results from NW Natural's IRP PLEXOS modeling that were provided to ICF include both total costs for the Reference Case and total costs for each of the electrification scenarios. The incremental costs for these categories included in this report were calculated by subtracting the Refence Case costs from the Electrification Scenario costs. Incremental costs were calculated for these categories to align with the other cost components that were assessed by ICF, but NW Natural's IRP also presents the total cost values.

Overall Cost Results

To provide an indication of the overall cost impacts, the combined incremental annual net costs (relative to the Reference Case) of all the cost categories outlined earlier in Section 6.1 were calculated for each of the electrification scenarios. 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 to meet its Oregon Climate Protection Program (CPP) and Washington Climate Commitment Act (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 56 shows the comparison of cumulative incremental costs from 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 shows that all of the electrification scenarios considered here are more expensive than the Reference Case.

Figure 56: Cumulative Total System Net Incremental Costs for Electrification of NW Natural Oregon & Washington Customers Relative to Reference Case

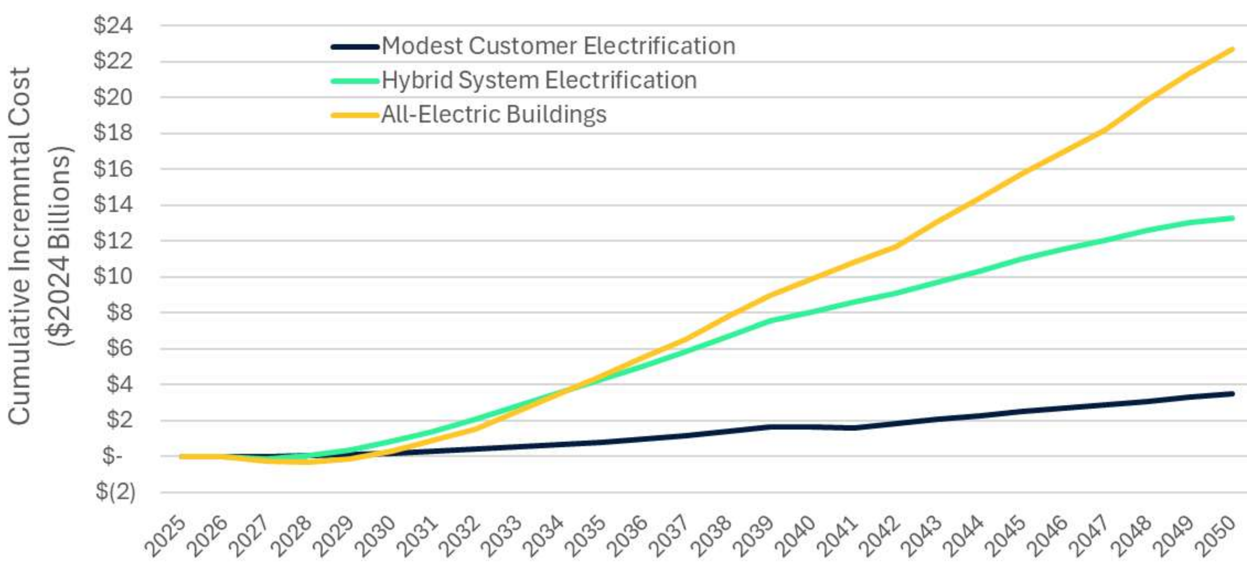
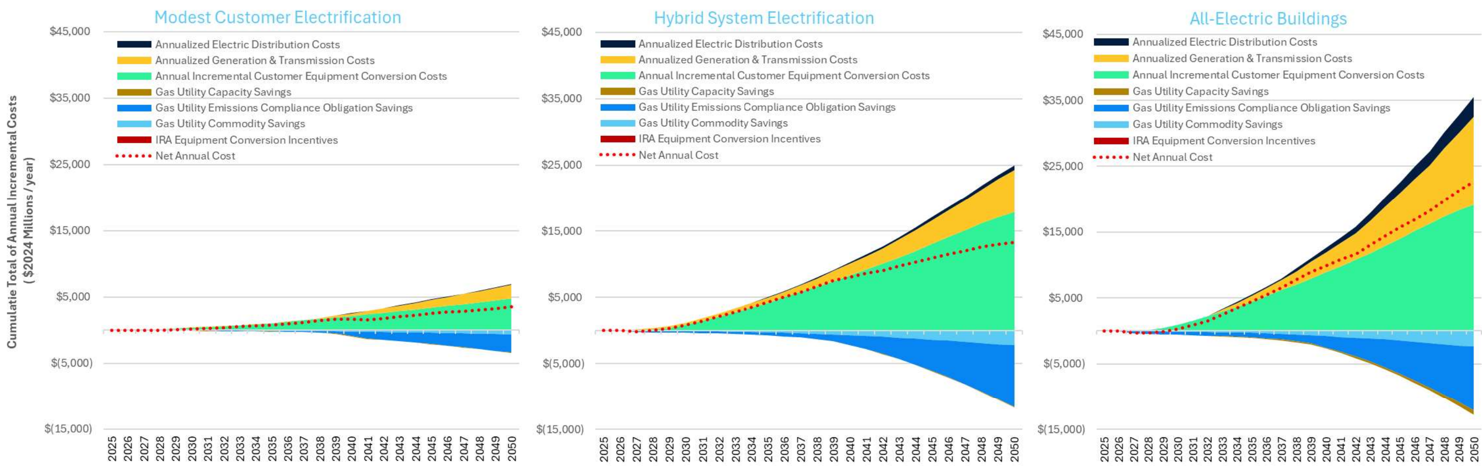


Figure 57 shows the relative contributions of the different cost and savings components discussed earlier in Section 6.1 (relative to the Reference Case) for each scenario. These graphs blend positive and negative cost impacts, and the cumulative net cost impact is shown in the dotted line. The net cost from the dotted line for each scenario is included in Figure 56.

Figure 57: Component-Level Cumulative Total System Net Incremental Costs for NW Natural Oregon & Washington Customers Relative to Reference Case



6.2 Summary of Combined GHG Impacts

Another important impact to consider for the electrification scenarios was the net impact on GHG emissions for NW Natural customers. A holistic view of net GHG emissions impacts required both the results of NW Natural's IRP PLEXOS modeling (which defines GHG emissions for remaining customer gas supply) as well as ICF's modeling in the electrification analysis (which defines the amount of electric load that is added and the GHG intensity of the electricity supply). 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 all 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.). Some compliance options, like CCIs and allowance purchases, may not be directly tied to GHG emissions reductions on NW Natural's system but are mechanisms used by the state to claim GHG emission reductions, and for the purposes of these GHG estimates all such compliance mechanisms are assumed to offset the corresponding customer GHG emissions from their combustion of natural gas.

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 for major utilities will add little to no additional greenhouse gas emissions, even from peaking and incremental resources.[65]

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 CO_2 per MMBtu). [66]
- **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 combustion emission factor mentioned above (0.0531 metric tons of CO_2 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 CO_2 per MWh in 2025 to 0.001 metric tons of CO_2 per MWh in 2050 for the All-Electric Buildings scenario for Oregon.
- **Net remaining GHG emissions** were calculated from the components above: Baseline Gas Consumption Emissions + Electric GHG Emissions - Compliance GHG Emission Reductions

Figure 58 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), and the resulting net GHG impacts (dotted lines). The results in Figure 58 for Oregon show very similar levels of net GHG reductions for the Reference Case, Modest Customer Electrification, Hybrid System Electrification, and All-Electric Buildings scenarios.[67]

Figure 59 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. [68]

[65] 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.

[66] Emissions-Intensive Trade-Exposed (EITE) industrial customers are excluded from the Company's emissions reduction compliance requirements.

[67] 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.

[68] Note that the versions of these two figures included in NW Natural's 2025 IRP (Figure 11.4 and Figure 11.5) also included a blue band estimating the potential incremental GHG emissions from power generation using a higher GHG emissions factor (instead of complying with HB-2021). Those additional estimates are not included in the versions of the figures shown here.

Figure 58: Net Changes in GHG Emissions by Electrification Scenario for NW Natural Oregon Customers

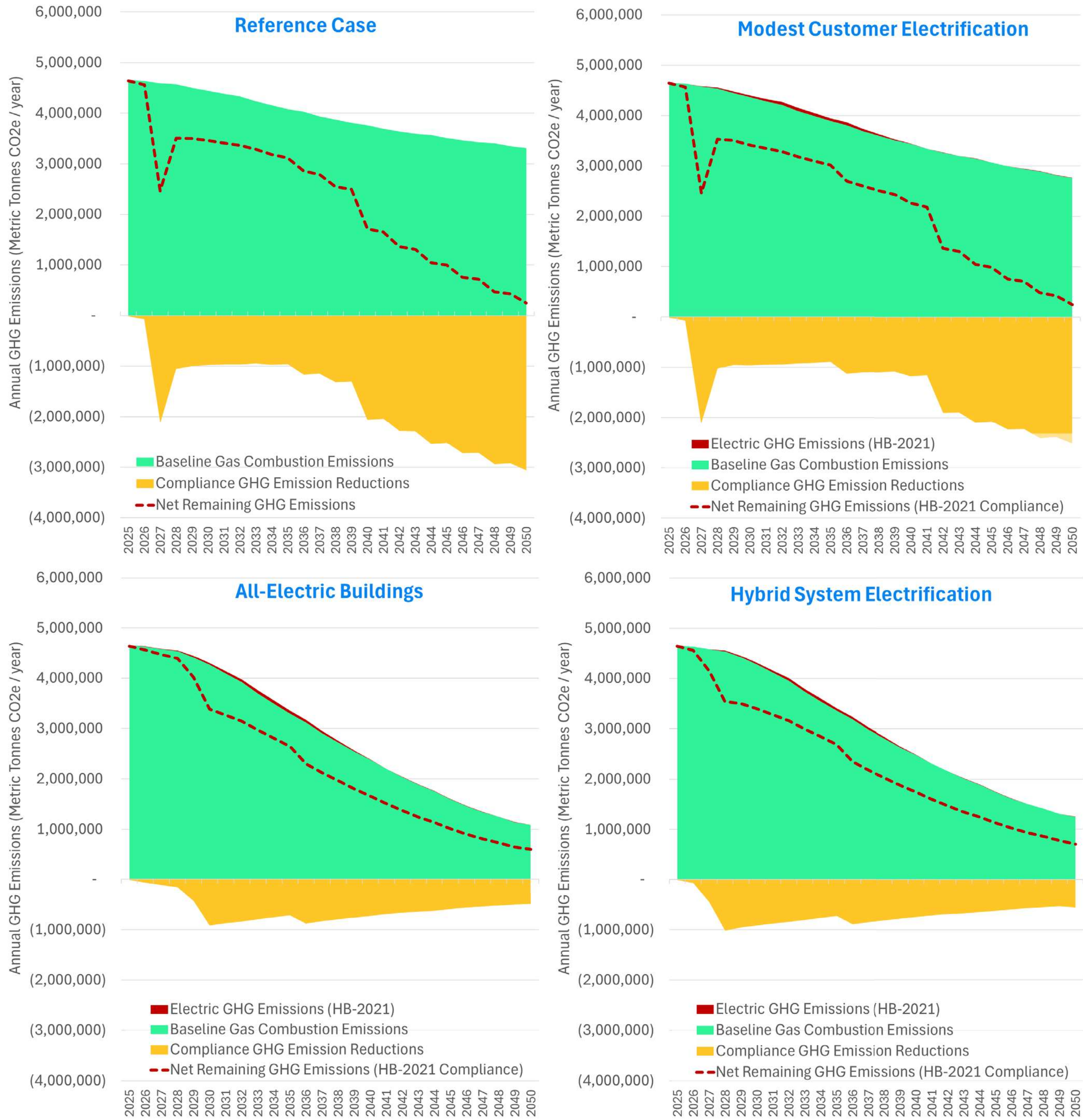
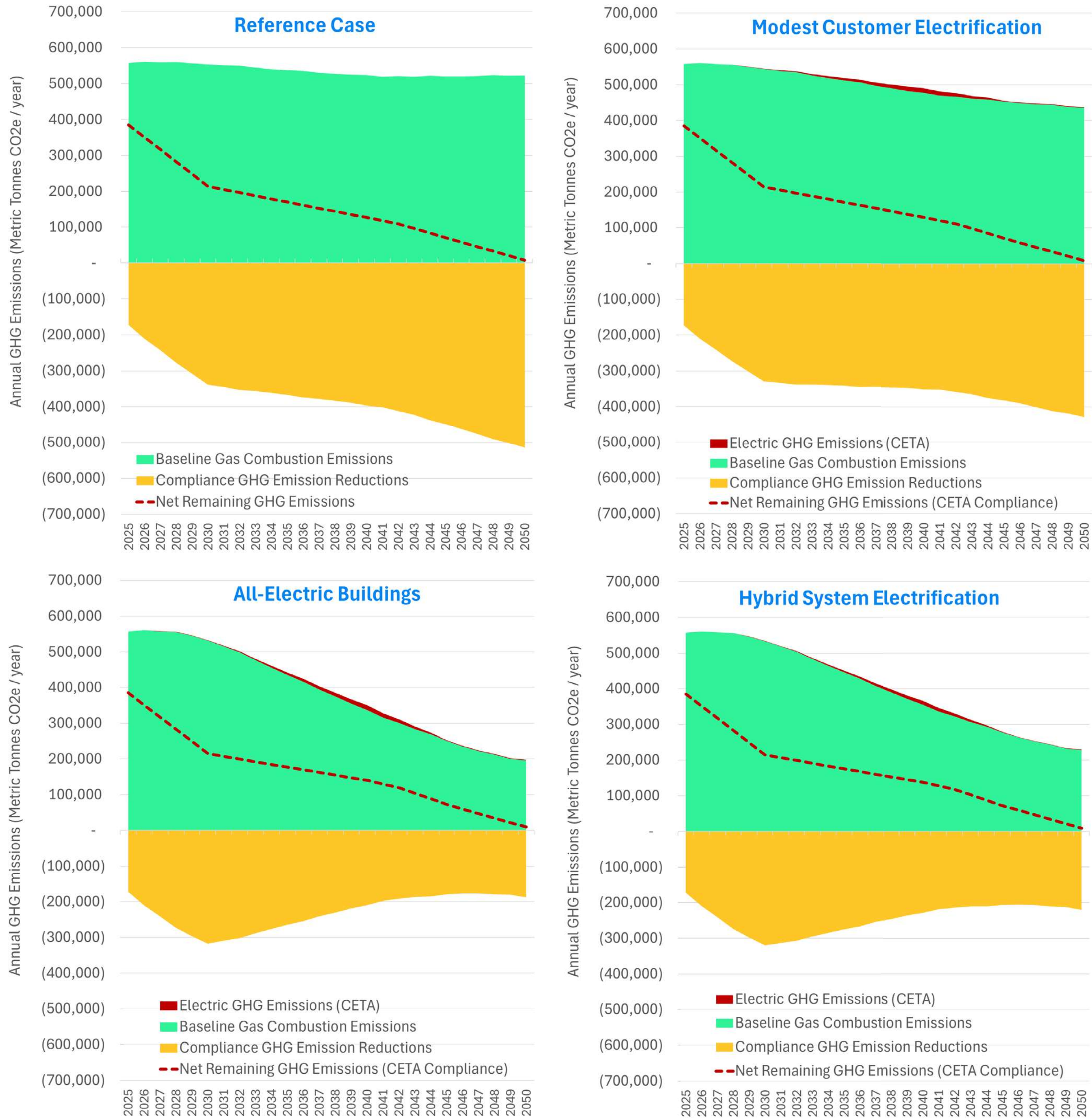


Figure 59: Net Changes in GHG Emissions by Electrification Scenario for NW Natural Washington Customers



7 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 cost impacts 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 in other parts of the IRP (based on results calculated by ICF and by NW Natural).

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.

7.1 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 territory, 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 equipment conversion 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 60 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.[69]

[69] 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 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.

Figure 60: Indicative Impacts to NW Natural Gas Average Residential Gas Rates & Bills in Oregon and Washington (Real $2024)

Figure 61 (Oregon) and Figure 62 (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 volumes. For these two electrification scenarios in Oregon, the reductions in NW Natural customer gas consumption significantly reduce the emissions compliance costs.

Figure 61: Breakdown of Cost Drivers in NW Natural Gas Average Residential Gas Rates in Oregon

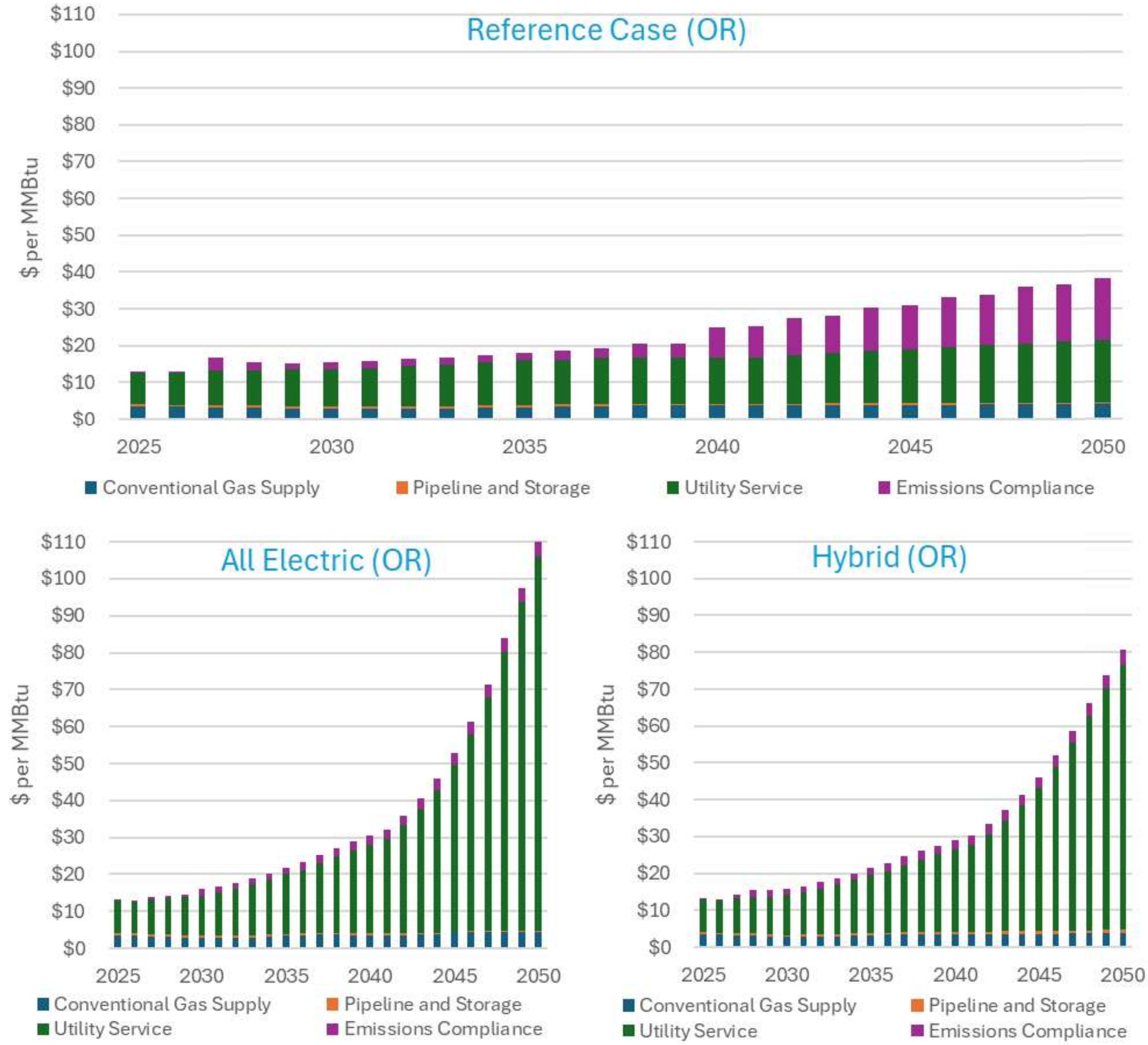
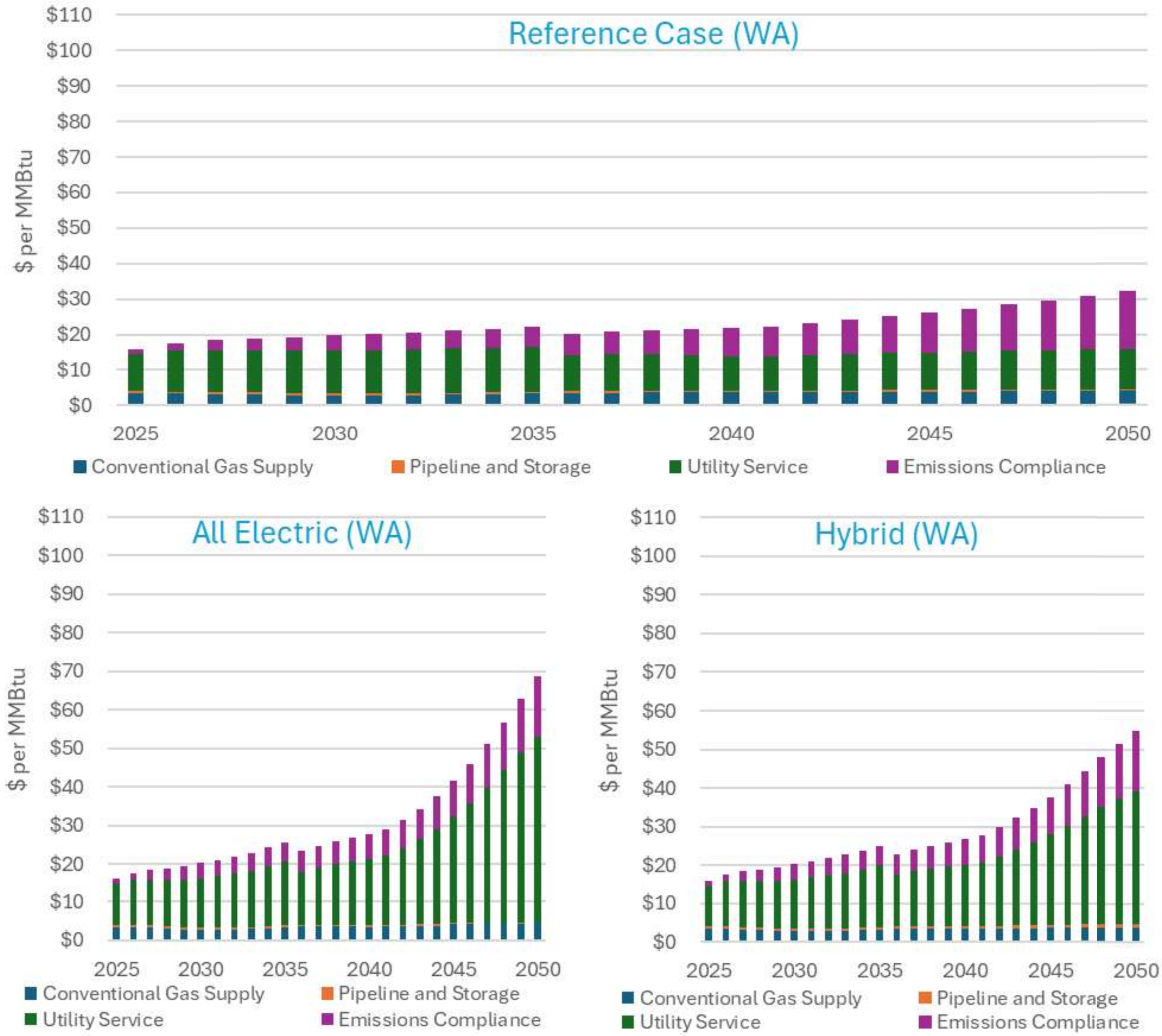


Figure 62: Breakdown of Cost Drivers in NW Natural Gas Average Residential Gas Rates in Washington



7.2 Electric Bill Impacts

In this section, an electric bill impact analysis was performed primarily based on PGE information.[70] 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 NW Natural's 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 joint system planning as future analysis would be best performed in collaboration with over-lapping electric utilities.

[70] Note that the assumptions behind the electric bill impact analysis were not reviewed by the AG.

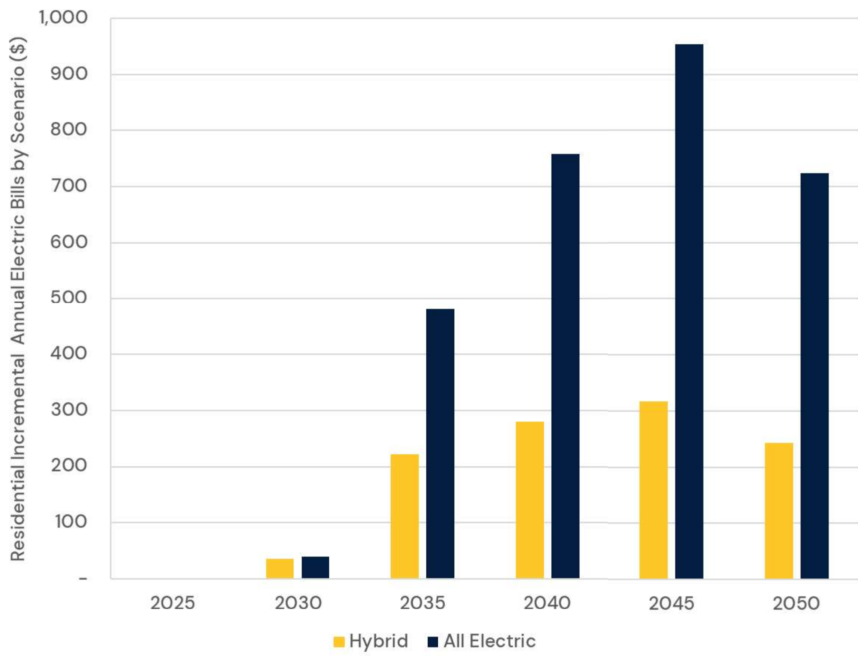
Electric bill impacts presented in this section are indicative of the bill impact for a PGE customer in Oregon. These are calculated based on the assumed average consumption per residential customer and the residential customer rates using the Reference Case, All-Electric and Hybrid electrification scenarios. 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.

Figure 63 shows the electric bill impacts above the Reference Case in each of the years shown. Values shown for each year reflect the incremental bill impact above the Reference Case in that particular year, and impacts shown are not additive over time. Bill impacts 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 63: Residential Electric Bill Impacts incremental to Reference Case by Scenario



Bill impacts shown in Figure 63 represented average residential customer bill impacts, based on the projected annual use per customer that incorporates a static customer and baseline consumption estimate based on 2023 residential customer data, with load added for electric vehicles[71] 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, Figure 63 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.

In terms of electric rates, the All-Electric scenario features the highest increase in electric rates relative to the Reference Case, with up to 3.5 cents/kWh higher rates in the 2045 period, driven by the generation resources required to meet load growth from electrification. The Hybrid scenario on the other hand limits increases in residential electric rates to just above 0.5 cents/kWh in 2035, and trends towards rates that are close to or within 0.5 cents/kWh compared to the Reference Case in other years. Importantly, the higher electric rates are not just paid by those customers that do electrify, and not just on the incremental electric load, but by all customers on the entirety of the electric consumption, including the load growth from EVs and data centers.[72]

[71] Projected EV loads for all scenarios were broken out to residential and commercial sectors with a 70/30 split informed by PGE's transportation electrification plans.

[72] This analysis assumes that the current relationship between residential, commercial, and industrial rate categories is maintained throughout the study period. Changes in ratemaking and rate-allocation across classes, such as the breakout of data centers into their own rate category, or specific EV-charging rates, are not assumed in this analysis.

8 Summary of Electrification Analysis and Study

Even before analyzing potential electrification of gas loads in Oregon and Washington, the states' electricity sectors will need to undergo a rapid and massive transformation of its supply sources away from emitting resources. Within the next 5 years, utilities covered under HB-2021 and Clean Energy Transformation Act (CETA) will need to see an expansion of their non-emitting electric supply at rates that exceed development activity and resource interconnection of the past several years and decades. Challenges with electric resource interconnection are exacerbated by long lead-times for transmission development necessary to connect new generation resources, expand existing transmission system capacity, and load growth will add to the load needed to be served by new resources and introduce further challenges of shifting electric 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 would add to the electric load growth already anticipated by the electric utilities from electric vehicles and growth of data centers. These additional electric loads would substantially increase peak demands in utility service territories, reduce the fuel diversity of the energy delivery system, and increase resource requirements in an already strained system. This analysis quantifies many of the costs to supply incremental electrification loads, including equipment conversion costs, fuel costs, as well as electric generation, transmission and distribution costs resulting from higher electric loads driven by gas end-user electrification. The full nature of costs driven by electrification loads is, however, uncertain at this time, and this analysis does not fully capture all potential costs that may arise from building electrification, such as potential changes to electric reliability criteria that may be required under a single-fuel energy delivery system.

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. 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 have been built in several decades. Outside experts from the Advisory Group and the IRP technical working group helped NW Natural and ICF evaluate several assumptions and data sources for this analysis. The Advisory Group cautioned against assumptions that were inconsistent with current realities, like lead times and costs. However, in some cases the analysis still required "relaxing" assumptions to allow the modeling to achieve HB-2021 compliance while also meeting load growth.

Figure 64 provides a summary of key metrics from the electrification analysis. The analysis found all the illustrative electrification scenarios studied here to have higher overall costs than the Reference Case approach. The GHG emissions reductions achieved through all the scenarios were very similar, with the Reference Case resulting in the most reductions. Of the two main electrification scenarios, the costs and associated risks to pursue the All-Electric scenario were found to be higher than the Hybrid scenario. The All-Electric scenario would cost more than $22 Billion more while losing resiliency and reliability benefits from gas infrastructure. This analysis has shown that the Hybrid scenario has the potential to achieve similar GHG emissions reductions at a lower cost than 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 and achieve clean grid policy requirements. A more detailed reliability analysis should be performed to ensure that reliability is not degraded for customers in these scenarios. Scenarios with higher winter peak loads, such as the All-Electric scenario, are more likely to lead to additional investments required to ensure reliable supply, all else equal.

Figure 64: Summary of Electrification Analysis

Summary Metric	Reference Case	Modest Customer Electrification	Hybrid System Electrification	All-Electric Buildings
GHG Emission Reductions - Cumulative Total from 2025 to 2050 (Million Metric Tons CO_2e) [73]	66.7	66.5	66.5	66.4
Incremental Costs vs. Reference Case - Cumulative Total from 2025 to 2050 ($2024 Billions)	+$0 Billion [74]	+$3.5 Billion	+$13.3 Billion	+$22.7 Billion
Change in Number of NW Natural Residential & Commercial Gas Customers from 2025 to 2050 (%)	+12%	-4%	-13%	-90%
Change in Gas Consumption by NW Natural Residential & Commercial Gas Customers from 2025 to 2050 (%)	-26%	-38%	-80%	-85%

[73] The GHG emission reductions show the 2025 to 2050 cumulative total of annual GHG emissions savings in each scenario versus annual GHG emissions in 2025. Some compliance options used by NW Natural in the Reference Case and electrification scenarios, like allowance purchases, may not be directly tied to GHG emissions reductions on NW Natural's system but are mechanisms used by the state to claim GHG emission reductions, and for the purposes of these GHG estimates all such compliance mechanisms are assumed to offset the corresponding customer GHG emissions from their combustion of natural gas.
[74] There will be costs associated with the Reference Case, including compliance with CPP and HB-2021, but the costs shown for electrification scenarios are the costs in excess of the cost of the Reference Case. The costs of the Reference Case are not fully quantified in this analysis.

Appendix A – Additional Measure Details

The figures in this appendix provide additional details on the assumptions used in this analysis for electrification measure costs and energy impacts.

Figure 65: Residential Sector Equipment Efficiency [75]

Category	Measure Package: ENERGY STAR ASHP + Electric Backup	Measure Package: High-Efficiency Cold-Climate ASHP + Electric Backup	Measure Package: ENERGY STAR ASHP + Existing System Backup
Applicable Dwelling Types	All dwellings with/without ducts	All dwellings with/without ducts	All dwellings with/without ducts
Backup Heat Type	Electric resistance	Electric resistance	Existing fossil fuel system
Ducted System Type	Centrally ducted ASHP	Centrally ducted ASHP	Centrally ducted ASHP
Non-Ducted System Type	Mini-Split Heat Pump (MSHP)	Mini-Split Heat Pump (MSHP)	Mini-Split Heat Pump (MSHP)
Ducted and Non-Ducted System SEER1 / HSPF1	16 / 9.2	20 / 11	16 / 9.2
Backup Details (for Ducted systems)	Electric resistance heat when needed. No lockouts.	Electric resistance heat when needed. No lockouts.	Existing fossil fuel furnace; compressor lockout @ 5°F, backup lockout @ 40°F
Compressor type	Single-Stage	Variable Speed	Single-Stage

Figure 66: Commercial Sector Equipment Efficiency

Measure	Efficiency	Backup Details
Heat Pump Rooftop Unit (RTU)	Varies with indoor/outdoor temperature and part load ratio; modeled using performance curves (includes cycling losses)	Electric resistance when needed
Heat Pump RTU with Original Fuel Backup	Varies with conditions; modeled using performance curves	Existing fuel system
Air-Source Heat Pump Boiler	COP = 2.85 at design outdoor air temperature	Electric resistance when needed
Air-Source Heat Pump Boiler and Natural Gas Boiler Backup	COP = 2.85 at design outdoor air temperature	Existing fuel system
VRF Heat Recovery with DOAS	COP approximately 3.0 to 4.0	Not specified

[75] White, Philip R., Elaina Present, Rajendra Adhikari, et al. "ResStock 2024.2 Release: Technical Documentation." January 2025. https://oedi-data-lake.s3.amazonaws.com/nrel-pds-building-stock/end-use-load-profiles-for-us-building-stock/2024/resstock_tmy3_release_2/resstock_documentation_2024_release_2.pdf.

Electric Kitchen Equipment	Fryers 86%, ovens 78%, steamers 68%, others (broilers, griddles, ranges).	Not applicable

Figure 67: Illustration of Incremental Space Heating Equipment Costs Assumptions for Existing Single-Family Homes

		Air Source Heat Pump	Cold Climate Air Source Heat Pump	Hybrid Heat Pump	Gas Furnace	Central AC	Notes / sources
Full Cost		$20,093	$25,292	$13,740	$6,555	$8,450	Costs taken from PSE 'Updated Decarb Study' content.[76]
Cost Savings	Furnace	-$6,555	-$6,555	NA	NA	NA	Hybrid system still requires a furnace to be installed.
	AC	-$2,915	-$2,915	-$2,915	NA	NA	NEEA data for Oregon says 69% of SFHs have an AC. Here they are credited with 50% of cost because AC's are not at end of life when replaced.
Incremental Cost		**$10,623**	**$15,822**	**$10,825**	**NA**	**NA**	This incremental cost is what is used in the modeling for existing single family homes.

Figure 68: Illustration of Incremental Space Heating Equipment Costs Assumptions for New Construction Single-Family Homes and Re-participation

		Air Source Heat Pump	Cold Climate Air Source Heat Pump	Hybrid Heat Pump	Gas Furnace	Central AC	Notes / sources

[76] 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.

Full Cost		$17,800	$19,425	$11,277	$6,555	$8,450	Costs taken from PSE 'Updated Decarb Study' content.[77]
Cost Savings	**Furnace**	-$6,555	-$6,555	NA	NA	NA	Hybrid system still requires a furnace to be installed.
	AC	-$5,831	-$5,831	-$5,831	NA	NA	NEEA data for Oregon says 69% of SFHs have an AC. $8,450 * 69%
Incremental Cost		**$5,415**	**$7,040**	**$5,447**	**NA**	**NA**	This incremental cost is what is used in the modeling for new construction and re-participation in single family homes.

Figure 69: Key Assumptions for Residential Electrification Technologies in Oregon (Existing Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-172	1,193	1,710 [78]	1,710
Electric Conventional Range/Oven	-30	706	130 [79]	-150 [80]
Electric Induction Range/Oven	-30	758	470 [81]	190
ENERGY STAR air-to-air heat pump, Electric Backup	-565	5,442	10,623 [82]	5,415

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[77] Puget Sound Energy. "GRC Stipulation O: Updated Decarbonization Study," p. 31. December 22, 2023. https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3617&year=2022&docketNumber=220066.

[78] 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 from the Full Cost.

[79] Estimated based on the U.S. Energy Information Administration's (EIA) 2023 Updated Buildings Sector Appliance and Equipment Costs and Efficiencies (https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/full.pdf). This incremental cost estimate for replacing existing gas equipment is based on a total installed cost for an electric range of $1,050 minus the total installed cost of a gas range of $920.

[80] Estimated based on the same EIA data source as the previous measure, but uses the lower cost assumption for the electric range to reflect a less complicated installation process when a pre-existing gas range does not need to be removed. This incremental cost estimate for replacing existing gas equipment is based on a total installed cost for an electric range of $770 minus the total installed cost of a gas range of $920.

[81] Estimated based on the same EIA data source as the previous measure, but adds an additional assumed incremental cost of $340 for the cooktops to use induction technology, based on the difference between High and Typical Residential Electric Cooktop equipment prices ($810 vs $470).

[82] 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.

ENERGY STAR air-to-air heat pump with existing gas system as backup	-504	4,121	10,825 [83]	5,447
High efficiency cold-climate air-to-air heat pump, Electric Backup	-565	3,809	15,822 [84]	7,040

Figure 70: Key Assumptions for Residential Electrification Technologies in Oregon (New Construction Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-117	810	1,710	1,710
Electric Conventional Range/Oven	-11	706	-150	-150
Electric Induction Range/Oven	-9	758	190	190
Energy Star air-to-air heat pump, Electric Backup	-356	3,431	5,415 [85]	5,415
Energy Star air-to-air heat pump with existing gas system as backup	-318	2,598	5,447 [86]	5,447
High efficiency cold-climate air-to-air heat pump, Electric Backup	-356	2,401	7,040 [87]	7,040

Figure 71: Key Assumptions for Residential Electrification Technologies in Oregon (Existing Multifamily Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-127	988	1,710	1,710
Electric Conventional Range/Oven	-24	704	130	-150

[83] 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.

[84] 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.

[85] Figure 68 presented earlier in this Appendix outlines the calculation of this incremental cost.

[86] Figure 68 presented earlier in this Appendix outlines the calculation of this incremental cost.

[87] Figure 68 presented earlier in this Appendix outlines the calculation of this incremental cost.

Electric Induction Range/Oven	-24	780	470	190
ENERGY STAR air-to-air heat pump, Electric Backup	-186	1,648	3,861 [88]	3,861
ENERGY STAR air-to-air heat pump with existing system as backup	-179	1,562	6,465 [89]	6,465
High efficiency cold-climate air-to-air heat pump, Electric Backup	-186	1,345	5,761 [90]	5,761

Figure 72: Key Assumptions for Residential Electrification Technologies in Oregon (New Construction Multifamily Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-184	1,426	1,710	1,710
Electric Conventional Range/Oven	-7	704	-150	-150
Electric Induction Range/Oven	-6	780	190	190
ENERGY STAR air-to-air heat pump, Electric Backup	-123	1,087	3,861	3,861
ENERGY STAR air-to-air heat pump with existing system as backup	-118	1,031	6,465	6,465

[88] This incremental cost was estimated based on cost data taken from worksheets (https://rtf.nwcouncil.org/measures) published by the Regional Technical Forum (RTF). The incremental cost estimate was calculated from a ductless heat pump cost of $6,052 ($4,620 in $2016 from RTF measure file ResDHPonFAF_v5._2 escalated by inflation to $6,052 in $2024) minus the $2,604 cost otherwise needed for a furnace replacement ($2,152 in $2020 from RTF measure file ResESGasFurnaces_v3_1 escalated by inflation to $2,604 in $2024) minus the $413 cost otherwise needed for an AC replacement ($315 in $2016 from RTF measure file ResDHPonFAF_v5._2 escalated by inflation to $413 in $2024).

[89] This incremental cost was estimated based on the same RTF cost data as the previous measure, but does not include the $2,604 cost savings from avoiding a furnace replacement (since a new furnace would still be required for hybrid heating system).

[90] This incremental cost was estimated based on the same RTF cost data as the ENERGY STAR ASHP with electric back-up measure, but includes an additional assumed incremental cost of $1,900 for the ASHP to be a cold-climate heat pump.

High efficiency cold-climate air-to-air heat pump, Electric Backup	-123	888	5,761	5,761

Figure 73: Key Assumptions for Residential Electrification Technologies in Oregon (Existing Mobile Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-157	1,269	1,710	1,710
Electric Conventional Range/Oven	-29	637	130	-150
Electric Induction Range/Oven	-25	199	470	190
ENERGY STAR air-to-air heat pump, Electric Backup	-348	3,401	6,631 [91]	6,631
ENERGY STAR air-to-air heat pump with existing system as backup	-333	3,038	9,315 [92]	9,315
High efficiency cold-climate air-to-air heat pump, Electric Backup	-348	2,712	6,984 [93]	6,984

Figure 74: Key Assumptions for Residential Electrification Technologies in Washington (Existing Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)

[91] This incremental cost was estimated based on cost data taken from worksheets (https://rtf.nwcouncil.org/measures) published by the Regional Technical Forum (RTF). The incremental cost estimate was calculated from a ductless heat pump cost of $9,760 ($7,450 in $2016 from RTF measure file ResDHPonFAF_v5._2 escalated by inflation to $9,760 in $2024) minus the $2,684 cost otherwise needed for a furnace replacement ($2,218 in $2020 from RTF measure file ResESGasFurnaces_v3_1 escalated by inflation to $2,684 in $2024) minus the $444 cost otherwise needed for an AC replacement ($339 in $2016 from RTF measure file ResDHPonFAF_v5._2 escalated by inflation to $444 in $2024).

[92] This incremental cost was estimated based on the same RTF cost data as the previous measure, but does not include the $2,684 cost savings from avoiding a furnace replacement (since a new furnace would still be required for hybrid heating system).

[93] This incremental cost was estimated based on the same RTF cost data as the ENERGY STAR ASHP with electric back-up measure, but includes an additional assumed incremental cost of $353 for the ASHP to be a cold-climate heat pump.

Heat Pump Water Heater	-180	1,352	1,710	1,710
Electric Conventional Range/Oven	-30	733	130	-150
Electric Induction Range/Oven	-30	760	470	190
ENERGY STAR air-to-air heat pump, Electric Backup	-632	7,008	10,623	5,415
ENERGY STAR air-to-air heat pump with existing system as backup	-524	5,230	10,825	5,447
High efficiency cold-climate air-to-air heat pump, Electric Backup	-632	5,040	15,822	7,040

Figure 75: Key Assumptions for Residential Electrification Technologies in Washington (New Construction Single-Family Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-166	1,248	1,710	1,710
Electric Conventional Range/Oven	-8	733	-150	-150
Electric Induction Range/Oven	-7	760	190	190
ENERGY STAR air-to-air heat pump, Electric Backup	-543	6,021	5,415	5,415
ENERGY STAR air-to-air heat pump with existing system as backup	-450	4,494	5,447	5,447
High efficiency cold-climate air-to-air heat pump, Electric Backup	-543	4,330	7,040	7,040

Figure 76: Key Assumptions for Residential Electrification Technologies in Washington (Existing Multifamily Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-134	933	1,710	1,710
Electric Conventional Range/Oven	-26	651	130	-150
Electric Induction Range/Oven	-26	766	470	190
ENERGY STAR air-to-air heat pump, Electric Backup	-150	1,630	3,861	3,861
ENERGY STAR air-to-air heat pump with existing system as backup	-121	1,010	6,465	6,465
High efficiency cold-climate air-to-air heat pump, Electric Backup	-150	846	5,761	5,761

Figure 77: Key Assumptions for Residential Electrification Technologies in Washington (New Construction Multifamily Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-167	1,163	1,710	1,710
Electric Conventional Range/Oven	-7	651	-150	-150
Electric Induction Range/Oven	-6	766	190	190
ENERGY STAR air-to-air heat pump, Electric Backup	-168	1,827	3,861	3,861
ENERGY STAR air-to-air heat pump with existing system as backup	-135	1,131	6,465	6,465
High efficiency cold-climate air-to-air heat pump, Electric Backup	-168	948	5,761	5,761

Figure 78: Key Assumptions for Residential Electrification Technologies in Washington (Existing Mobile Homes) for 2025

Measure Name	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Initial Incremental Measure Cost per Unit ($)	Re-participation Incremental Measure Cost per Unit ($)
Heat Pump Water Heater	-150	1,494	1,710	1,710
Electric Conventional Range/Oven	-29	727	130	-150
Electric Induction Range/Oven	-25	549	470	190
ENERGY STAR air-to-air heat pump, Electric Backup	-466	5,118	6,631	6,631
ENERGY STAR air-to-air heat pump with existing system as backup	-424	3,984	9,315	9,315
High efficiency cold-climate air-to-air heat pump, Electric Backup	-466	3,813	6,984	6,984

The cost figures below are used for existing buildings, new construction, and re-participation in the commercial sector modeling. The gas and electric impacts are presented for 2025, and decrease over time based on the energy efficiency included in the Reference Case.

Figure 79: Key Assumptions for Commercial Buildings in Oregon (ASHP RTU with Electric Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,026	4,327	28,393
Medium Office	-4,455	3,117	218,352
Large Office	-	-	-
Retail Standalone	-4,578	19,397	102,925
Retail Strip Mall	-4,973	18,167	223,262
Full Service Restaurant	-3,335	24,014	44,388
Quick Service Restaurant	-2,466	14,794	27,231
Primary School	-14,065	67,248	290,062
Secondary School	-31,241	216,005	475,176

Small Hotel	–	–	–
Large Hotel	–	–	–
Outpatient	-3,079	3,109	105,613
Hospital	-44,656	-841,776	2,974,432
Warehouse	-4,668	12,021	29,224

Figure 80: Key Assumptions for Commercial Buildings in Oregon (ASHP RTU with Gas Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-924	3,570	31,980
Medium Office	-4,010	293	244,204
Large Office	–	–	–
Retail Standalone	-4,120	11,798	118,115
Retail Strip Mall	-4,476	10,972	247,912
Full Service Restaurant	-3,002	18,562	52,525
Quick Service Restaurant	-2,219	10,055	31,999
Primary School	-12,658	44,518	330,538
Secondary School	-28,117	156,551	544,284
Small Hotel	–	–	–
Large Hotel	–	–	–
Outpatient	-2,771	-1,212	119,444
Hospital	-39,519	-935,859	3,387,620
Warehouse	-4,201	9,873	35,815

Figure 81: Key Assumptions for Commercial Buildings in Oregon (VRF) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,026	-7,108	125,436
Medium Office	-4,455	-149,396	939,882
Large Office	–	–	–
Retail Standalone	-4,578	-28,492	446,458
Retail Strip Mall	-4,973	-95,410	689,579
Full Service Restaurant	–	–	–
Quick Service Restaurant	–	–	–
Primary School	-14,065	24,089	1,390,083
Secondary School	-31,241	238,053	3,164,404
Small Hotel	–	–	–
Large Hotel	–	–	–

Outpatient	-3,079	18,449	591,510
Hospital	-	-	-
Warehouse	-4,668	12,937	709,108

Figure 82: Key Assumptions for Commercial Buildings in Oregon (HP Boiler with Electric Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,382	11,448	80,736
Medium Office	-7,036	57,395	133,894
Large Office	-20,215	165,983	340,919
Retail Standalone	-7,727	62,200	84,799
Retail Strip Mall	-	-	-
Full Service Restaurant	-	-	-
Quick Service Restaurant	-2,024	16,919	90,506
Primary School	-19,994	162,333	282,384
Secondary School	-38,524	353,805	859,058
Small Hotel	-2,718	28,439	481,828
Large Hotel	-22,378	245,289	1,536,137
Outpatient	-6,185	50,464	117,886
Hospital	-200,868	1,645,945	1,916,794
Warehouse	-5,585	45,737	106,639

Figure 83: Key Assumptions for Commercial Buildings in Oregon (HP Boiler with Gas Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,243	10,310	77,583
Medium Office	-6,333	51,697	128,665
Large Office	-18,193	149,429	327,605
Retail Standalone	-6,954	56,004	81,488
Retail Strip Mall	-	-	-
Full Service Restaurant	-	-	-
Quick Service Restaurant	-1,821	15,228	86,972
Primary School	-17,994	146,186	271,356
Secondary School	-34,672	312,613	825,509
Small Hotel	-2,446	25,596	463,011
Large Hotel	-20,141	220,768	1,476,146
Outpatient	-5,567	45,456	113,282

Hospital	-180,781	1,481,424	1,841,937
Warehouse	-5,026	41,212	102,475

Figure 84: Key Assumptions for Commercial Buildings in Oregon (Electric Kitchen Equipment) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	–	–	–
Medium Office	–	–	–
Large Office	–	–	–
Retail Standalone	–	–	–
Retail Strip Mall	-2,832	51,571	158,421
Full Service Restaurant	-5,023	75,701	214,295
Quick Service Restaurant	-1,483	26,326	159,796
Primary School	-607	10,358	53,917
Secondary School	-622	10,472	107,970
Small Hotel	–	–	–
Large Hotel	-11,196	154,114	229,010
Outpatient	–	–	–
Hospital	-10,177	213,627	392,790
Warehouse	–	–	–

Figure 85: Key Assumptions for Commercial Buildings in Oregon (Heat Pump Water Heater) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-42	361	13,875
Medium Office	-259	2,840	78,591
Large Office	-404	4,624	77,868
Retail Standalone	–	–	–
Retail Strip Mall	-2,629	26,732	142,611
Full Service Restaurant	-1,568	18,066	37,574
Quick Service Restaurant	-540	6,079	12,733
Primary School	-955	11,159	141,432
Secondary School	-450	5,299	144,116
Small Hotel	-2,157	25,421	58,989
Large Hotel	-11,299	133,852	137,954
Outpatient	-145	1,694	49,377
Hospital	-14,359	170,524	1,411,806

Warehouse	–	–	–

Figure 86: Key Assumptions for Commercial Buildings in Oregon (Electric Resistance Boiler) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-42	1,162	8,706
Medium Office	-259	7,171	49,312
Large Office	-404	11,172	48,858
Retail Standalone	–	–	–
Retail Strip Mall	-2,629	72,786	89,482
Full Service Restaurant	-1,568	43,407	23,576
Quick Service Restaurant	-540	14,948	7,989
Primary School	-955	26,439	88,742
Secondary School	-450	12,463	90,426
Small Hotel	-2,157	59,726	37,012
Large Hotel	-11,299	312,830	86,560
Outpatient	-145	4,008	30,982
Hospital	-14,359	397,566	885,839
Warehouse	–	–	–

Figure 87: Key Assumptions for Commercial Buildings in Washington (ASHP RTU with Electric Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,600	3,725	28,393
Medium Office	-964	-16,408	218,352
Large Office	–	–	–
Retail Standalone	-4,662	10,566	102,925
Retail Strip Mall	-5,563	-3,377	223,262
Full Service Restaurant	-4,684	20,467	44,388
Primary School	-29,424	158,385	290,062
Secondary School	-43,904	253,155	475,176
Large Hotel	–	–	–
Outpatient	-4,030	11,343	105,613
Hospital	–	–	–
Warehouse	-2,597	4,277	29,224

Figure 88: Key Assumptions for Commercial Buildings in Washington (ASHP RTU with Gas Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,440	3,151	31,980
Medium Office	-835	-19,431	244,204
Large Office	-	-	-
Retail Standalone	-4,196	5,176	118,115
Retail Strip Mall	-5,007	-8,089	247,912
Full Service Restaurant	-4,216	16,464	52,525
Primary School	-26,482	120,256	330,538
Secondary School	-39,513	196,755	544,284
Large Hotel	-	-	-
Outpatient	-3,627	5,665	119,444
Hospital	-	-	-
Warehouse	-2,337	3,503	35,815

Figure 89: Key Assumptions for Commercial Buildings in Washington (VRF) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-1,600	-19,077	125,436
Medium Office	-964	-108,583	939,882
Large Office	-	-	-
Retail Standalone	-4,662	-55,050	446,458
Retail Strip Mall	-5,563	-99,886	689,579
Full Service Restaurant	-4,684	5,733	226,831
Primary School	-29,424	46,924	1,390,083
Secondary School	-43,904	52,735	3,164,404
Large Hotel	-	-	-
Outpatient	-4,030	-22,952	591,510
Hospital	-	-	-
Warehouse	-2,597	-19,184	709,108

Figure 90: Key Assumptions for Commercial Buildings in Washington (HP Boiler with Electric Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)

Small Office	-868	418	80,736
Medium Office	-7,755	58,141	133,894
Large Office	-10,446	78,316	340,919
Retail Standalone	-7,963	45,915	84,799
Retail Strip Mall	-	-	-
Full Service Restaurant	-	-	-
Primary School	-16,148	133,826	282,384
Secondary School	-27,593	905,390	859,058
Large Hotel	-3,960	45,748	1,536,137
Outpatient	-15,354	276,495	117,886
Hospital	-32,995	285,406	1,916,794
Warehouse	-9,183	939,382	106,639

Figure 91: Key Assumptions for Commercial Buildings in Washington (HP Boiler with Gas Backup) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-781	378	77,583
Medium Office	-6,980	50,881	128,665
Large Office	-9,402	68,537	327,605
Retail Standalone	-7,032	40,173	81,488
Retail Strip Mall	-	-	-
Full Service Restaurant	-	-	-
Primary School	-14,533	120,197	271,356
Secondary School	-24,834	807,844	825,509
Large Hotel	-3,564	41,135	1,476,146
Outpatient	-13,818	246,294	113,282
Hospital	-29,695	256,413	1,841,937
Warehouse	-8,264	788,156	102,475

Figure 92: Key Assumptions for Commercial Buildings in Washington (Electric Kitchen Equipment) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-	-	-
Medium Office	-	-	-
Large Office	-	-	-
Retail Standalone	-	-	-
Retail Strip Mall	-2,571	45,335	158,421

Full Service Restaurant	-3,053	46,309	214,295
Primary School	-1,138	18,391	53,917
Secondary School	-2,282	37,838	107,970
Large Hotel	-1,429	23,144	229,010
Outpatient	-	-	-
Hospital	-11,640	185,564	392,790
Warehouse	-	-	-

Figure 93: Key Assumptions for Commercial Buildings in Washington (Heat Pump Water Heater) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-61	521	13,875
Medium Office	-268	2,937	78,591
Large Office	-153	1,755	77,868
Retail Standalone	-	-	-
Retail Strip Mall	-2,934	29,832	142,611
Full Service Restaurant	-3,318	38,240	37,574
Primary School	-2,295	26,812	141,432
Secondary School	-689	8,115	144,116
Large Hotel	-	-	-
Outpatient	-326	3,816	49,377
Hospital	-3,285	39,012	1,411,806
Warehouse	-	-	-

Figure 94: Key Assumptions for Commercial Buildings in Washington (Electric Resistance Boiler) by Building Type for 2025

Building Type	Gas Impacts per Unit (Therms)	Electric Impacts per Unit (kWh)	Incremental Measure Cost per Unit ($)
Small Office	-61	1,676	8,706
Medium Office	-268	7,416	49,312
Large Office	-153	4,241	48,858
Retail Standalone	-	-	-
Retail Strip Mall	-2,934	81,229	89,482
Full Service Restaurant	-3,318	91,878	23,576
Primary School	-2,295	63,528	88,742
Secondary School	-689	19,086	90,426
Large Hotel	-	-	-
Outpatient	-326	9,030	30,982

Hospital	-3,285	90,954	885,839
Warehouse	-	-	-

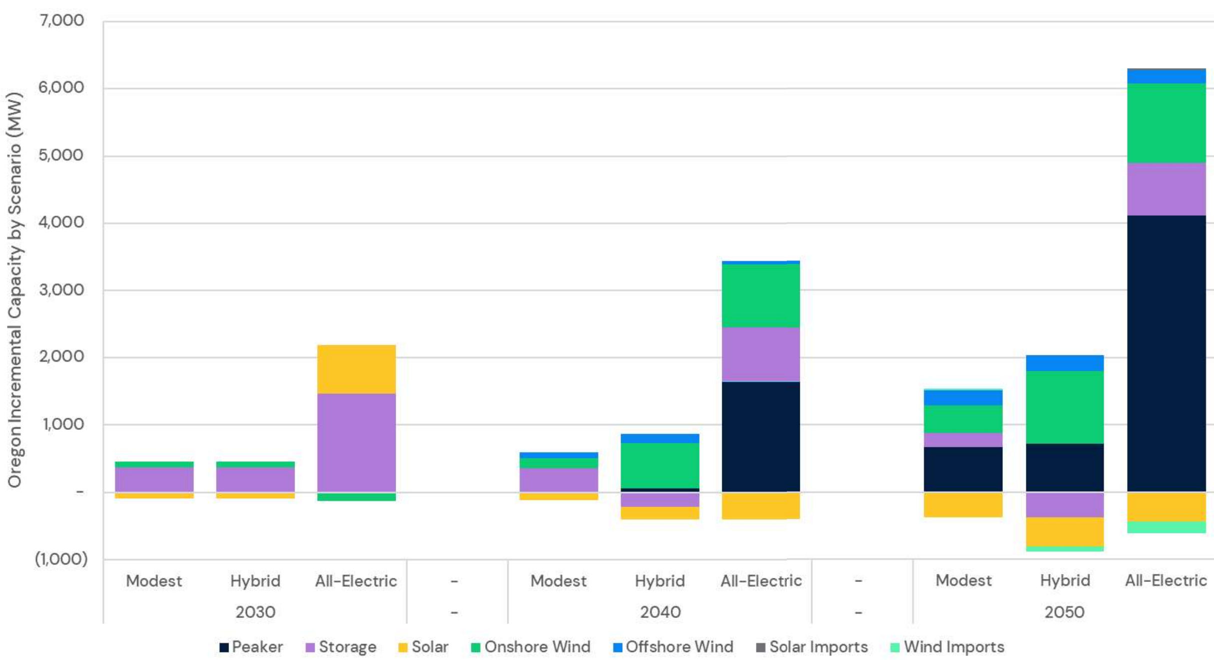
Appendix B – Additional Regional Power Sector Results

Appendix B includes additional regional power sector results that show incremental generation, capacity, and system costs relative to the Reference Case. Results included in Appendix B are broken out by region (PGE, Oregon, Washington).

Oregon Incremental Capacity

Figure 95 highlights that while the Modest and Hybrid scenario results in 1,200 MW of incremental capacity, the All-Electric scenario results in an additional 5,700 MW of capacity to meet increased electric peaks across the state, 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 requirements.[94] Wind capacity increases to provide sufficient generation for HB-2021 compliance, as neither battery storage nor non-emitting peaking generation are capable and cost-effective to provide generation at scale.

Figure 95: Electrification Scenario Oregon Incremental Installed Capacity relative to Reference Case (MW)

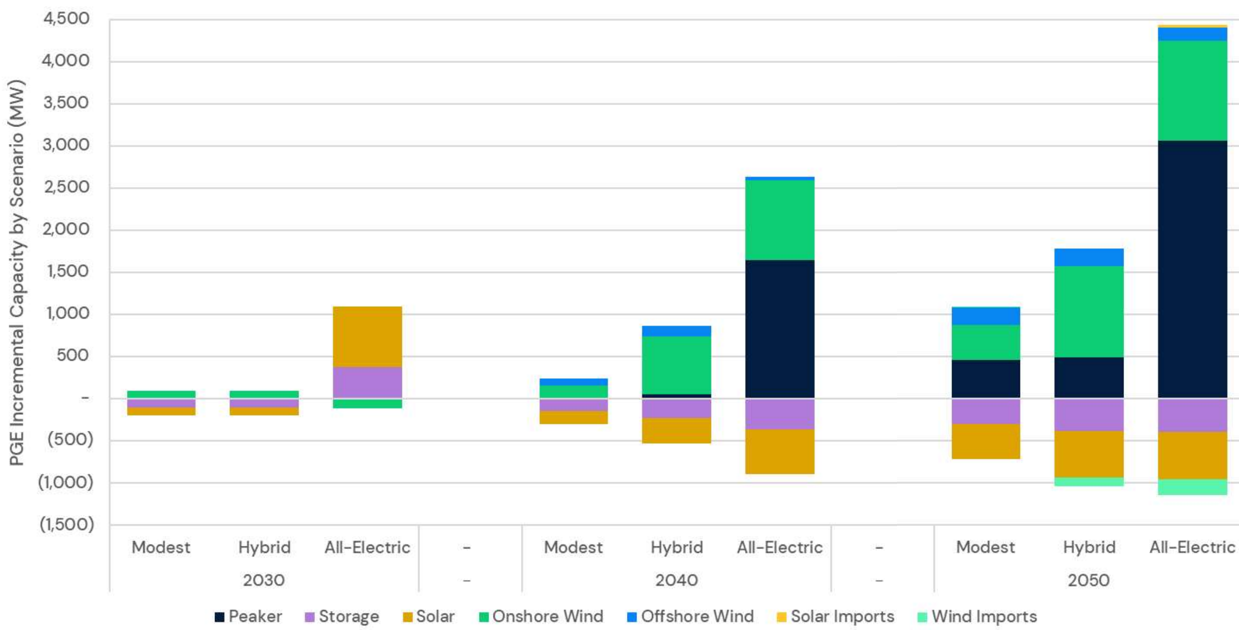


[94] Portland General Electric. "PGE CEP & IRP Roundtable 25-4." June 4, 2025. https://assets.ctfassets.net/416ywc1laqmd/2R28hOAx44R4HJJQbtdlVi/e645439527a2ba02d1743716ab21a502/CEP_IRP_Roundtable_June_25-4.pdf.

PGE Incremental Capacity

In the Modest and Hybrid scenarios, PGE capacity additions are limited to under 1,000 MW, including higher build-outs for wind and clean peaking resources. In the All-Electric scenario, an additional 3,500 MW over the Reference Case capacity is built, primarily in the form of clean peaking capacity to meet winter peak demand growth.

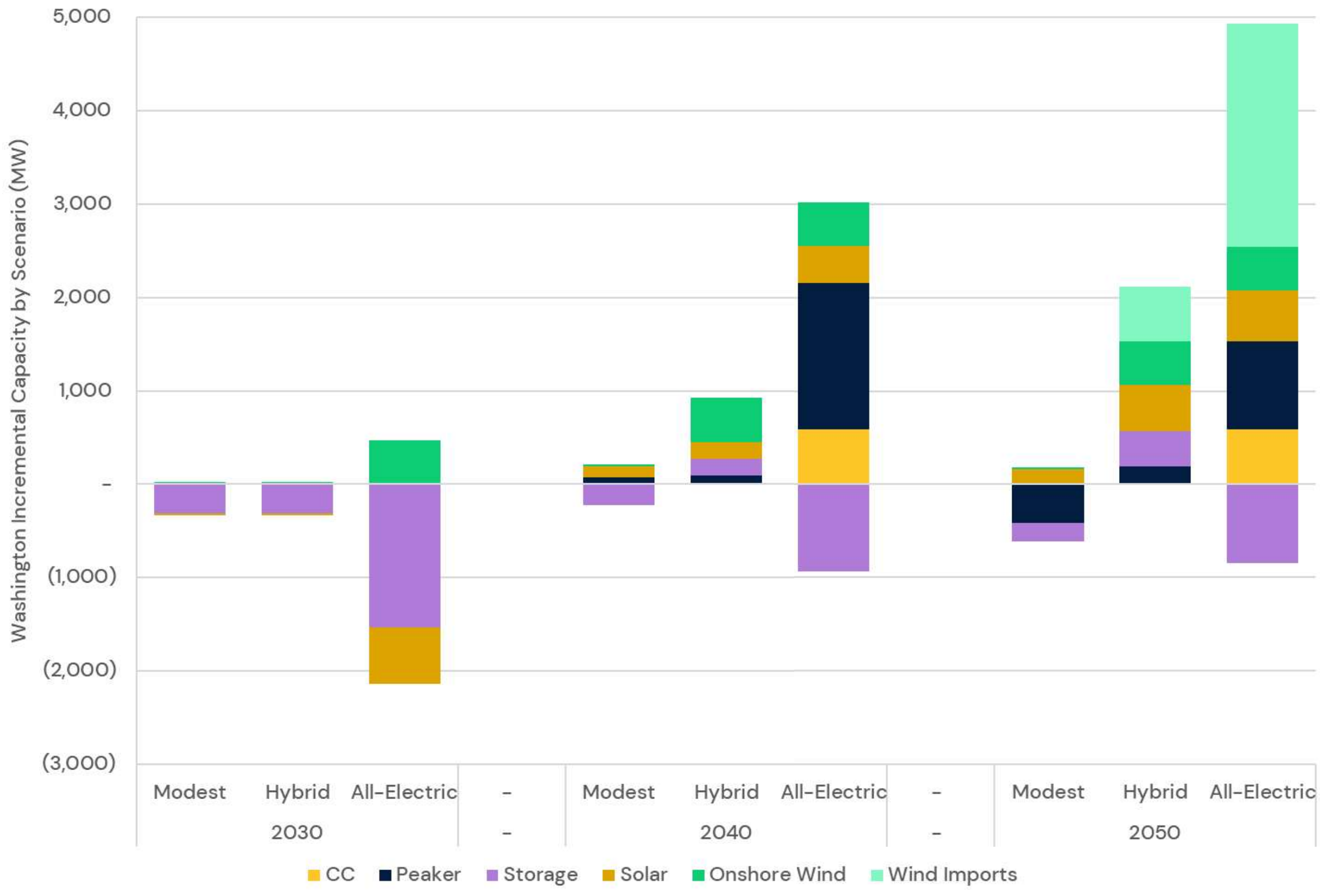
Figure 96: Incremental PGE Capacity (MW) by Scenario Relative to Reference Case



Washington Incremental Capacity

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 97 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 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.

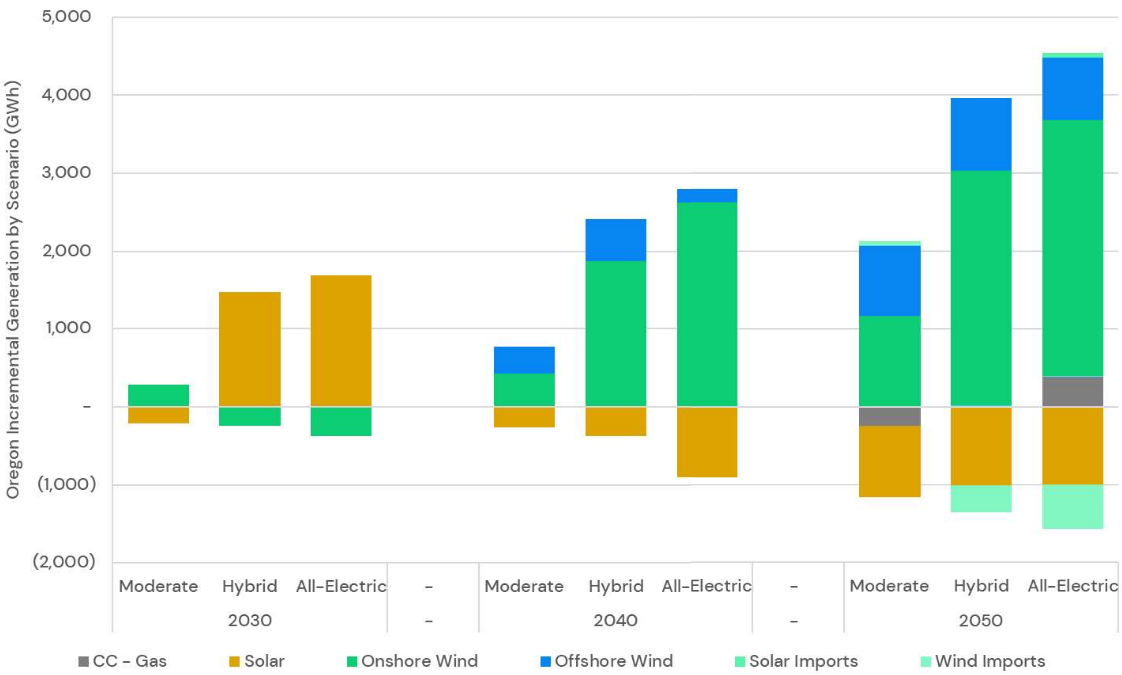
Figure 97: Washington Incremental Capacity by Scenario (MW)



Oregon Incremental Generation over Reference Case

As shown in Figure 98, due to the electrification of additional end-use sectors in the Hybrid and All-Electric scenarios, total generation increases by 2050 — between 2,000 and 4,000 GWh respectively - compared to the Reference Case. Since load increases primarily in regions subject to emission reduction targets, resulting generation must be non-emitting generation, specifically onshore wind and imports of firm wind capacity and generation into the state. Negative values shown for solar reflect that solar generates less energy compared to the Reference Case. As the majority of load increases occur in winter hours, incremental wind generation is preferred over solar generation, with a less favorable generation profile given the timing of the load additions.

Figure 98: Oregon Incremental Generation relative to Reference by Scenario 2030, 2040, & 2050 (GWh)

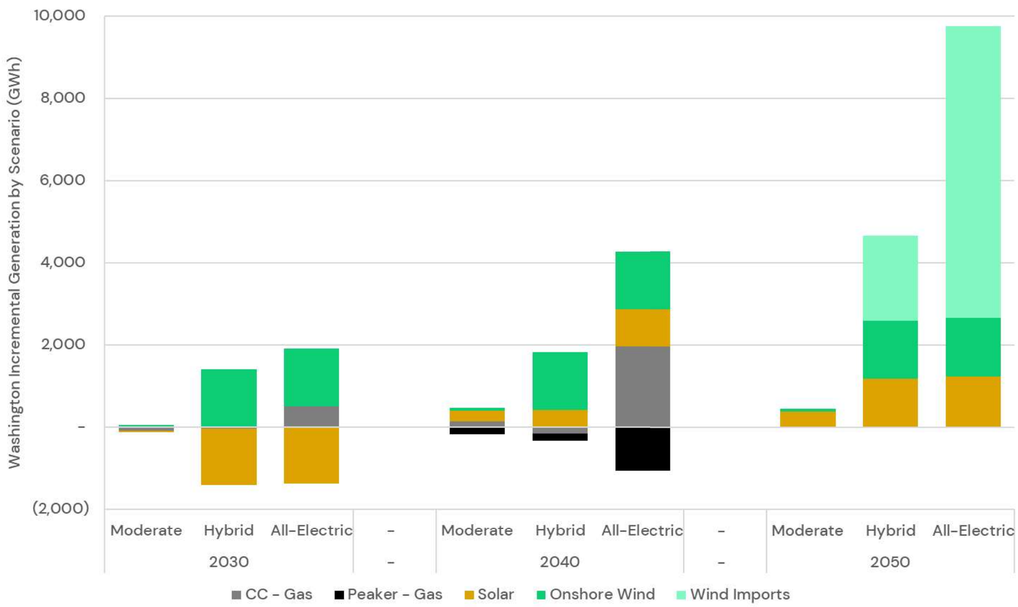


Generation increases primarily in regions where load increases, specifically PGE and PacifiCorp territories. The evolution of the generation mix will ultimately vary based on the compliance requirement and utilities with more stringent compliance requirements will have less flexibility in how to meet the increased load growth.

Washington Incremental Generation over Reference

Figure 99 shows the incremental generation relative to the Reference Case for each of the three electrification scenarios. Generation in the All-Electric scenario increases by close to 10,000 GWh in 2050, primarily from additions of wind built outside of Washington and Oregon to serve the increasing load requirements of the region. Prior to the CETA requirement of a 100% zero carbon electricity supply becoming effective in 2045, load increases from electrification result in higher generation from thermal combined cycle facilities, as well as more wind and solar to meet the carbon neutral supply targets are met. The Hybrid scenario limits generation increases in 2050 to just over 4,000 GWh, 5,000 GWh less generation compared to the All-Electric scenario.

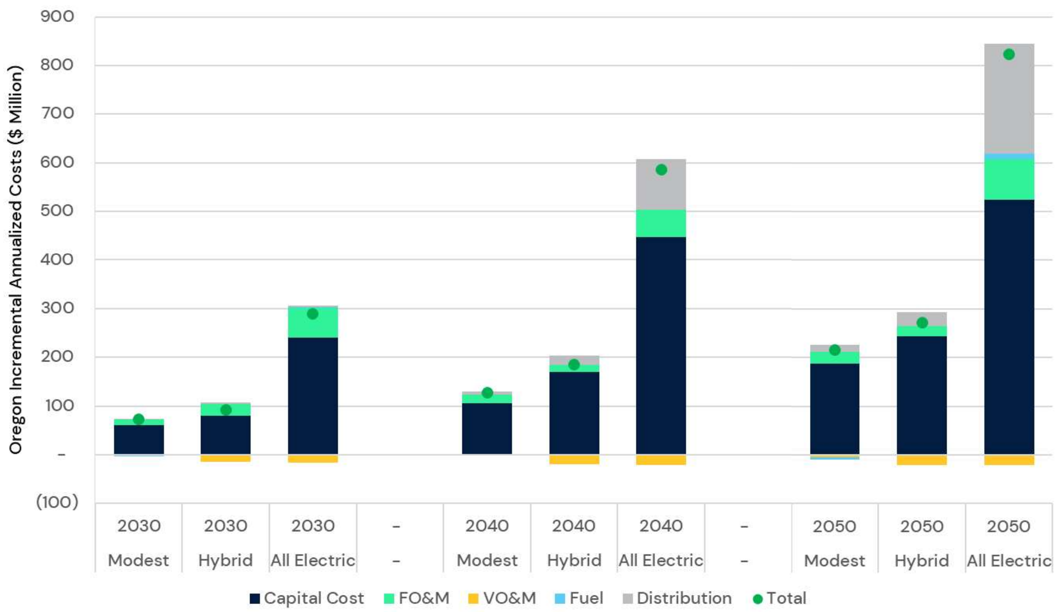
Figure 99: Washington Incremental Generation by Scenario (GWh)



Oregon Incremental Expenditure Relative to Reference Case

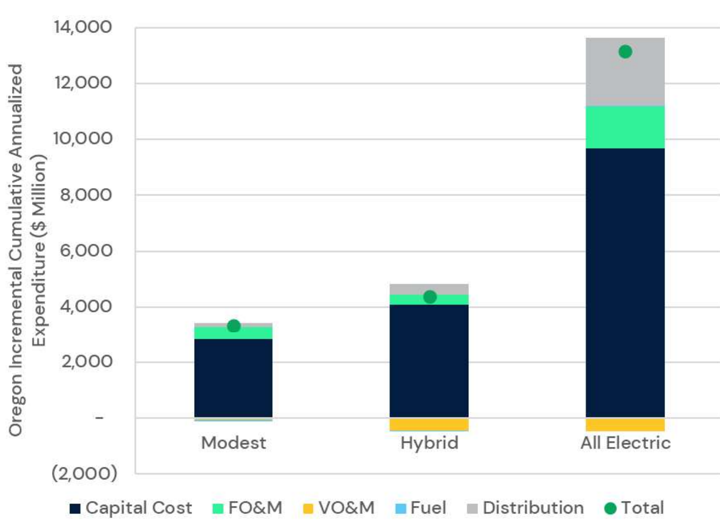
System cost increases are particularly evident in the All-Electric scenario when compared to the Hybrid scenario. With peak increases of over 2 GW above the Reference Case, and a shift to winter peak demand with lower resource contributions to peak demand, the incremental capacity required to meet peak 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. 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 100: Incremental Oregon Annualized Expenditure by Scenario ($ Million)



As shown in Figure 101, 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.

Figure 101: Oregon Incremental Cumulative Annualized Expenditure over Reference ($ Million)



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