
Managing the Gas Transition Saves Oregonians Billions

**Prepared for Climate Solutions and Oregon Citizens' Utility
Board**

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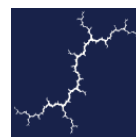
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EXECUTIVE SUMMARY

Oregon has adopted climate targets aiming to reduce greenhouse gas (GHG) emissions by 80 percent below 1990 levels by 2050. Decarbonizing Oregon's building sector is a key tactic to meet the state's goal. In 2023, emissions from the residential and commercial sectors represented 33 percent of the state's GHG emissions; 10 percent of statewide emissions are from fossil fuel combustion in buildings. Natural gas is the primary source of fossil fuel combustion emissions in homes: currently 37 percent of Oregon households heat with utility natural gas.

Oregon's Climate Protection Program (CPP) requires local gas distribution companies to achieve a 50 percent reduction in GHG emissions by 2035 and 90 percent reduction by 2050, relative to 2017–2019 levels, and **fundamentally changes the nature of gas utility planning and business models**. While achieving CPP compliance, gas utilities must consider lower-carbon supply resources, the impacts of declining customer counts and sales, and the potential for and impacts of increased electrification of consumer end uses. Oregon's energy transition will dramatically reduce gas consumption in the state—the Oregon Energy Strategy (OES) Reference scenario envisions that pipeline gas consumption would decline by more than 80 percent by 2050—raising questions about the future of the current gas utility business model.

An approach that doubles down on capital investment as sales decline risks creating unsustainably high gas rates. At high gas rates, customers will either face severe energy burdens or choose to electrify to reduce their costs. As customers with the means and opportunity to switch to electricity leave the gas system, the remaining system costs will be spread across fewer customers, causing rates to rise even faster and driving even more customers away from gas. Over time, this creates a self-reinforcing cycle in which gas system costs fall on a shrinking portion of the population—a portion that is more likely to be low income, disadvantaged, and renters.

The question, and how we approached it

Climate Solutions and Oregon Citizens' Utility Board hired Synapse Energy Economics, Inc. to model the benefits of a managed transition for the gas system in Oregon. This analysis focused on Northwest Natural (NWN) and Portland General Electric (PGE), which were chosen because they have closely corresponding service territories and are respectively the largest gas and electric utilities in the state. Synapse used its in-house Gas Rate Model (GRM) to analyze the impact on customers and utility finances from changes to gas customers and sales along different pathways to comply with the state's GHG targets. Synapse modeled four scenarios:

Business-As-Usual (BAU): Building equipment largely reflects today's system, with a continued shift from electric resistance to heat pumps, while gas combustion largely retains today's share of building heating; the gas system grows to reflect population growth. NWN achieves emission reductions primarily through use of community climate investment credits (CCIs) and renewable natural gas (RNG).



Managed OES: Building equipment transitions toward full electrification with heat pump adoption trajectories aligned with the OES Reference Case. Regulators and NWN manage electrification to allow geographically-targeted retirement of gas mains while NWN simultaneously adapts its finances to align with a shrinking system.

Unmanaged OES: The same full electrification as the Managed OES case, but occurring in a scattered manner so that retirement of gas mains is not possible until a large fraction of buildings have disconnected from the gas system (circa 2045, lagging the Managed OES case by a decade); NWN continues to invest in a BAU manner until then.

Hybrid: Building equipment transitions toward hybrid heat pump systems that retain gas furnace backup, instead of full electrification. The gas system must continue to serve every hybrid-heating building and grows in alignment with population growth, even as total sales fall.

We note that these scenarios do not account for the potential for NWN to engage in new business models or new lines of business (such as heating equipment provision or networked geothermal systems); we evaluate only the traditional gas-delivery portion of its business.

In all but the BAU case, equipment incentives are required to achieve desired adoption levels, the costs of which are securitized and shared between gas and electric ratepayers. In all cases, electric sales increase rapidly, driven by electric vehicles (EVs) and data centers. However, the Managed and Unmanaged OES scenarios show a notable increase in peak loads compared to the BAU and Hybrid cases as a result of building electrification.

What the scenarios show

Managing the transition is the lowest-cost path for the energy system as a whole. Across the combined gas and electric systems, the Managed OES combined net present value of revenue requirements (NPVRR) is \$117.7 billion (in 2024 dollars), \$6.8 billion less than the BAU case, which has a combined NPVRR of \$124.5 billion. NWN’s revenue requirement under the Managed OES case is nearly half of the BAU by 2050 and a third as large as the BAU in 2075 as gas customers depart and NWN retires portions of its system.

Table ES-1: Net present value of gas and electric revenue requirement by scenario (\$ billions, 2024 dollars).

Scenario	Electric	Gas	Total	Delta from BAU
BAU	\$83.0	\$41.5	\$124.5	n/a
Managed OES	\$92.9	\$24.8	\$117.7	–\$6.8
Hybrid	\$85.1	\$35.0	\$120.1	–\$4.4
Unmanaged OES	\$92.9	\$26.6	\$119.5	–\$5.0

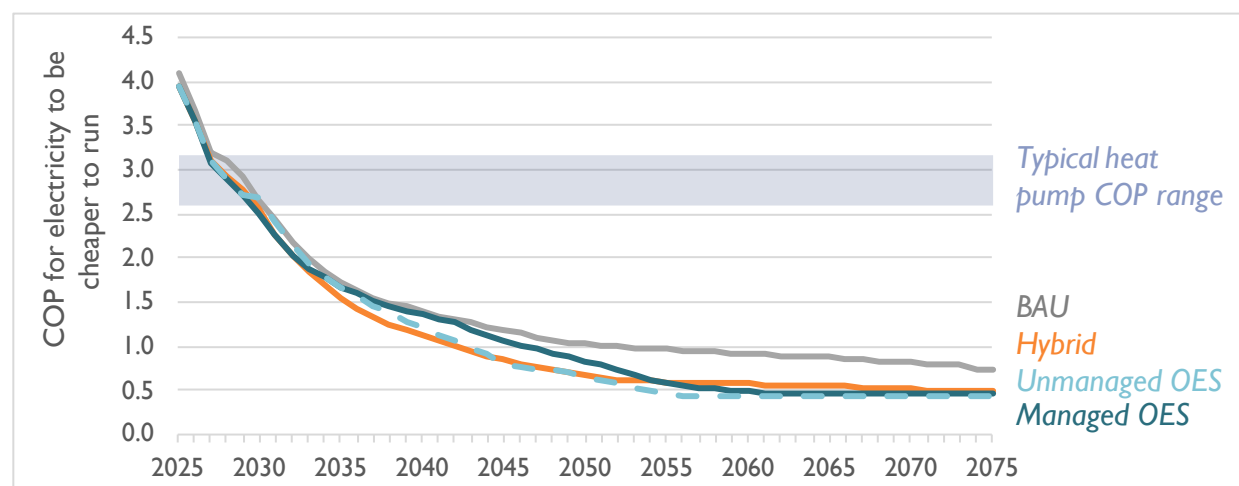


A managed transition also limits exposure to high-cost RNG. To comply with the CPP in the Hybrid case, by 2050 NWN would require 52 TBtu of RNG per year, accounting for 74 percent of NWN’s fuel supply—while a recent gas-industry study indicates that Oregon’s production potential for RNG is only 34.8 TBtu per year in 2050, even under an optimistic “high” scenario.¹ Relying on out-of-state resources doesn’t solve the RNG supply problem: the same study’s national “high” potential for 2050 is just 22 percent of current natural gas use in buildings and industry.² The Managed OES case achieves compliance primarily through deeper demand reductions, leaving a residual RNG need within Oregon’s estimated in-state production potential.

Customers who remain on the gas system face higher rates in every scenario. In the BAU scenario, gas rates double by 2035 and more than triple by 2050. Gas rates under the Unmanaged OES case are the highest, increasing by a factor of six by 2050, as customers defect from the gas system without corresponding adjustments to gas system investments. The financial and investment changes under the Managed OES case mitigate some of those impacts.

At the same time, electrification is becoming the cheaper way to heat. Because heat pumps are nearly three times more efficient than standard gas furnaces, we find that under all scenarios, by 2030 it will be cheaper for households to heat with a heat pump rather than a gas furnace ([Figure ES-1](#)), and the operating economics improve rapidly over time.

Figure ES-1: Residential spark gap by scenario— the heat pump coefficient of performance (COP) at which electricity becomes cheaper than gas for heating. The shaded band shows the typical heat pump COP range; once the lines fall below it, heat pumps are cheaper to run.



¹ American Gas Foundation and ICF. 2025. *Renewable Natural Gas Supply Assessment*. https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf

² U.S. EIA reports in the 2025 *Natural Gas Annual* (https://www.eia.gov/naturalgas/annual/pdf/table_015.pdf) that 2024 consumption in buildings and industry was 16,889 TBtu, while the ICF study finds 2050 “high” potential of 3,728 TBtu.

The choice ahead

Failing to plan is expensive. The contrast between the Managed and Unmanaged OES scenarios shows the cost of failing to plan. Both assume the same level of customer electrification and achieve the same emissions outcomes; the difference is whether NWN and Oregon regulators act early to align gas system investment, depreciation, and retirement planning with customer departures. In the Managed case, NWN’s revenue requirement is roughly half of the Unmanaged case by 2050, and residential gas rates are substantially lower throughout. Customers who remain on the gas system the longest—likely to be disproportionately lower income, renters, and those without the means to electrify—bear the cost of failing to manage the transition.

Avoiding gas system rebuild makes electrification more cost-effective. A central driver of the cost savings in the Managed OES case is the avoidance of capital expenditure on assets that would otherwise be replaced over the coming decades. These avoided costs in turn create room within the combined energy system to fund the incentives that drive customer electrification as well as the resulting electric system upgrades. The combined NPVRR results indicate that ratepayers as a whole are better off when ratepayer-funded programs accelerate the transition, even after accounting for incentive program and electric system upgrade costs.

Full electrification is lower cost and carries less risk. The combined NPVRR of the Hybrid scenario is within a few percent of the Managed OES scenario, but the two are not interchangeable. The Hybrid approach commits to reinvesting in the gas system, amplifying stranded cost risk. The Hybrid case, like the BAU case, also depends on very large quantities of RNG—far more than Oregon’s production potential—requiring substantial imports at uncertain cost and availability.

Cost allocation matters. The choice of cost recovery mechanism is fundamentally a policy question, not a modeling question, and policymakers should engage with it explicitly rather than defaulting to existing recovery mechanisms. The Hybrid case is not stable without dramatic changes in cost allocation, because using standard approaches leaves full electrification as the lower cost option and customers will fully electrify rather than stick with hybrid equipment. Different splits between gas and electric ratepayers, the use of state appropriations, or non-ratepayer funding sources would produce different distributional outcomes and warrant additional analysis before implementation.

Open questions for implementation

This analysis focuses on system-level costs and revenue requirements under stylized scenarios. Several questions would benefit from additional research, led by the Public Utility Commission with participation from gas and electric utilities, as Oregon moves toward implementation: rate design and customer-level impacts (including distributional analysis across income groups and housing types); gas system retirement logistics (which mains and services to retire first, and how to sequence retirements with customer conversions); more detailed power sector modeling; and electric transmission and distribution upgrade needs at the neighborhood level, coordinated with the gas system retirement plan.

1. INTRODUCTION AND BACKGROUND

Oregon has adopted climate targets aiming to reduce greenhouse gas (GHG) emissions by 80 percent below 1990 levels by 2050. Decarbonizing Oregon’s building sector is a key tactic to meet the state’s goal. In 2023, emissions from the residential and commercial sectors represented 33 percent of the state’s GHG emissions; 10 percent of statewide emissions are from fossil fuel combustion in buildings.³ Natural gas is the primary source of fossil fuel combustion emissions in homes: currently 37 percent of Oregon households heat with utility natural gas.⁴ Oregon’s energy transition will dramatically reduce gas consumption in the state, raising questions about the future of the current gas utility business model.

Climate Solutions and Oregon Citizens’ Utility Board hired Synapse to model the benefits of a managed transition for the gas system in Oregon. This analysis focused on Northwest Natural (NWN) and Portland General Electric (PGE). These utilities were chosen because they have closely corresponding service territories and are respectively the largest gas and electric utilities in the state. In this report, we compare the costs and benefits of different approaches to building sector decarbonization under Oregon’s climate policies.

The remainder of this introduction provides background on Oregon’s climate and energy policies and the utilities analyzed in this study. Section 2 details the methodology and assumptions for the modeled scenarios. Section 3 presents overall results of the scenario modeling and details on gas and electric system costs and customer impacts. Section 4 discusses the implications of these results and provides suggestions for further research.

1.1. Oregon and Utility Context

Policy context

Oregon has set strong climate targets. In 2007, the legislature established a statutory target of reducing GHG emissions by 75 percent relative to 1990 levels by 2050.⁵ In 2020, Governor Brown’s Executive Order 20-04 updated this target to set a goal of at least a 45 percent reduction below 1990 GHG levels

³ Oregon Department of Environmental Quality. Oregon Greenhouse Gas Sector–Based Inventory. <https://www.oregon.gov/deq/ghgp/Pages/GHG-Inventory.aspx>

⁴ U.S. Census Bureau. Table B25040 House Heating Fuel. 2024 ACS 1-Year Estimates. <https://data.census.gov/table/ACSDT1Y2024.B25040?g=040XX00US41>

⁵ Oregon Laws 2007, Chapter 907 (House Bill 3543), available at: https://www.oregonlegislature.gov/bills_laws/lawsstatutes/2007orLaw0907.html



by 2035, and 80 percent by 2050.⁶ Through the Climate Action Roadmap to 2030, the Oregon Climate Action Commission recommended updating the goals to a 70 percent reduction below 1990 levels by 2035 and a 95 percent reduction by 2050, with net-zero emissions by 2050 or as soon as practicable thereafter.⁷

Oregon's Climate Protection Program (CPP), recently finalized in November 2024,⁸ has substantial implications for the consumption and sale of natural gas in Oregon. The CPP consists in part of a binding carbon dioxide emission constraint and an associated compliance obligation for covered entities. The CPP sets a declining emissions cap for local distribution companies, fuel suppliers, large industrial facilities, and a few other entities. The CPP requires a 50 percent reduction in emissions by 2035 and 90 percent reduction by 2050, relative to 2017–2019 levels.⁹ Gas distribution companies hold the compliance obligation for all their customers' natural gas emissions, except for emissions-intensive, trade-exposed (EITE) manufacturing customers, who have their own obligation and compliance instruments under the CPP. Natural gas distribution companies can comply with the emissions cap set by the CPP through allocated "compliance instruments" (bankable, tradeable emissions allowances issued at zero cost by the state), by reducing emissions through measures such as electrification, energy efficiency, alternative low-carbon fuels, or other strategies, and by using Community Climate Investments to achieve a limited portion of their compliance obligation. Community Climate Investment (CCI) credits are a compliance mechanism allowing covered entities to fund external actions that contribute to meeting the GHG reduction requirement.

The CPP fundamentally changes the nature of gas utility planning and business models. To achieve CPP compliance, gas utilities must consider lower-carbon supply resources, the impacts of declining customer counts and sales, and the potential for and impacts of increased electrification of consumer end uses.

Oregon law will result in cleaner electricity over time, so electrification is a key pathway to reduce emissions. In 2016, SB 1547 established a renewable portfolio standard requiring 35 percent renewable energy by 2030, 45 percent by 2035, and 50 percent by 2040, in addition to phasing out coal-fired electricity generation by 2030.¹⁰ In 2021, HB 2021 required retail electricity providers to reduce

⁶ Office of the Governor. Executive Order No. 20-04, "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions." March 10, 2020. https://www.oregon.gov/gov/eo/eo_20-04.pdf

⁷ Oregon Climate Action Commission. "Meeting Our Goals." Available at: <https://climate.oregon.gov/meeting-our-goals>

⁸ Oregon Department of Environmental Quality. 2024. "Climate Protection Program 2024 – Adopted Rule". Available at: <https://www.oregon.gov/deq/rulemaking/pages/cpp2024.aspx>.

⁹ Oregon Department of Environmental Quality. 2024. "Fact Sheet: Climate Protection Program Overview." Available at: <https://www.oregon.gov/deq/ghgp/Documents/cppOverviewFS.pdf>.

¹⁰ Oregon Legislative Assembly. 2016 Regular Session. Senate Bill 1547 (Enrolled; 2016 Oregon Laws Chapter 28). Available at: <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/MeasureDocument/SB1547>.



emissions associated with retail electricity sales in Oregon by 80 percent by 2030, 90 percent by 2035, and 100 percent by 2040, relative to annual average emissions from 2010–2012.¹¹

Oregon has multiple policies promoting building electrification. Executive Order 20-04 set a goal that annual new residential and commercial building site consumption of energy (excluding electricity used for transportation or appliances) must be 60 percent more energy efficient than the 2006 codes require.¹² The state’s current energy efficiency building code requires high levels of efficiency, with the option for municipalities to adopt a voluntary reach code¹³ that requires increased levels of energy efficiency.

Another policy helping Oregon reach its emissions goals is the state’s Building Performance Standard (BPS). HB 3409 of 2023 directed the Oregon Department of Energy (ODOE) to create a BPS which sets energy use intensity targets for certain types of large commercial buildings.¹⁴ The first compliance period begins in 2028 for a subset of covered commercial buildings, and ODOE must update the standard every five years thereafter.

HB 3409 also establishes a goal of installing 500,000 new heat pumps in residential and commercial buildings by 2030.¹⁵ The state has several heat pump incentive programs aimed at increasing adoption of heat pump technologies.¹⁶

In 2023, the legislature passed HB 3630, directing the ODOE to develop a state energy strategy that identifies pathways for achieving Oregon’s energy policy objectives, in consultation with stakeholders and other state agencies.¹⁷ After a two-year data- and input-gathering process, ODOE published the Oregon Energy Strategy (OES).¹⁸ To inform the strategy, ODOE led a modeling exercise that modeled scenarios for meeting the state’s energy policy goals through 2050. This includes the OES Reference Scenario, designed to illustrate a least-cost pathway to achieving Oregon’s goals, as well as alternative scenarios and sensitivities. The OES Reference Scenario includes demand-side energy efficiency

¹¹ Oregon Legislative Assembly. 2021 Regular Session. House Bill 2021 (Enrolled; 2021 Oregon Laws Chapter 508). Available at: <https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled>

¹² Office of the Governor. Executive Order No. 20-04, “Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions.” March 10, 2020. https://www.oregon.gov/gov/eo/eo_20-04.pdf

¹³ Oregon Building Codes Division. “Reach Code.” <https://www.oregon.gov/bcd/codes-stand/Pages/reach.aspx>

¹⁴ Oregon Legislative Assembly. 2023 Regular Session. House Bill 3409 (Enrolled; 2023 Oregon Laws Chapter 442). Available at: <https://olis.oregonlegislature.gov/liz/2023R1/Downloads/MeasureDocument/HB3409/Enrolled>

¹⁵ Oregon Legislative Assembly. 2023 Regular Session. House Bill 3409 (Enrolled; 2023 Oregon Laws Chapter 442). Available at: <https://olis.oregonlegislature.gov/liz/2023R1/Downloads/MeasureDocument/HB3409/Enrolled>

¹⁶ Oregon Department of Energy. “Heat Pump Incentive Programs.” Available at: <https://www.oregon.gov/energy/incentives/pages/heat-pumps.aspx>

¹⁷ Oregon Legislative Assembly. 2023 Regular Session. House Bill 3630 (Enrolled; 2023 Oregon Laws Chapter 562). Available at: <https://olis.oregonlegislature.gov/liz/2023R1/Downloads/MeasureDocument/HB3630/Enrolled>

¹⁸ Oregon Department of Energy. 2025. *Oregon Energy Strategy*. Available at: <https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf>

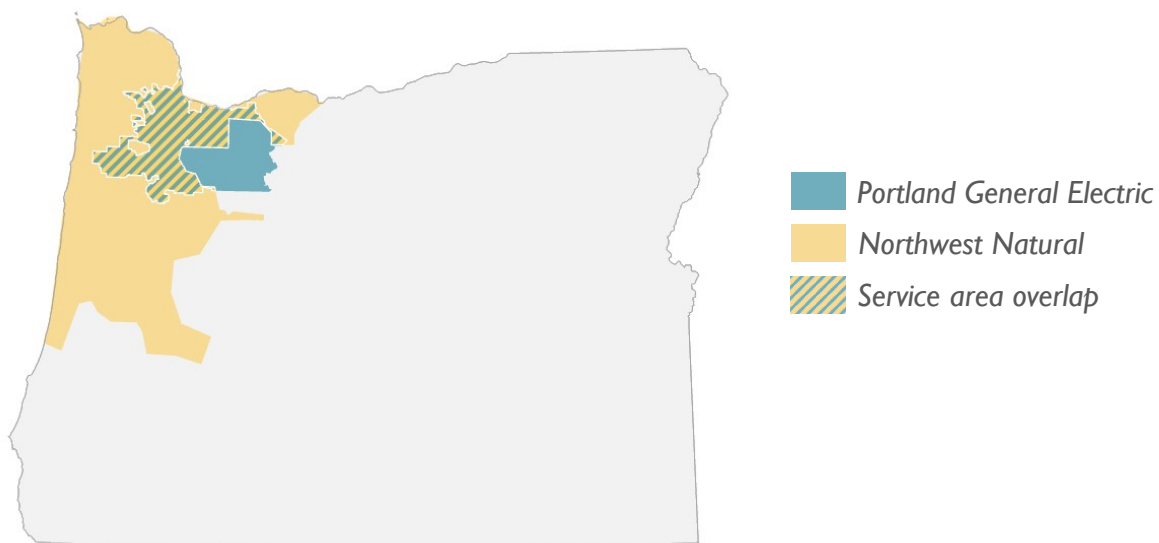


measures and electrification of end uses. The OES recommends pursuing energy efficiency and load flexibility and promoting strategic electrification across the residential, commercial, and industrial sectors, with support for low-carbon fuels to serve the hardest-to-electrify sectors. Governor Kotek’s Executive Order 25-29 directs state agencies to prioritize implementation of the OES, including taking “appropriate actions necessary... to advance the state’s interest in increasing cost-effective, strategic electrification of vehicles, buildings, and water heating systems.”¹⁹

Utility context

This analysis focused on two of the largest gas and electric utilities in Oregon: Northwest Natural (NWN) and Portland General Electric (PGE). These two utilities serve a partially overlapping area in northwestern Oregon, including Portland, as shown in [Figure 1](#).

Figure 1. PGE and NWN service territory in Oregon



Currently, 37 percent of Oregon households heat with utility natural gas.²⁰ NWN is Oregon’s largest natural gas utility. NWN serves over 700,000²¹ residential, commercial, and industrial customers across much of western Oregon, approximately 91 percent of which are residential customers. NWN’s

¹⁹ Office of the Governor, State of Oregon. *Executive Order 25-29*. <https://www.oregon.gov/gov/eo/eo-25-29.pdf>.

²⁰ U.S. Census Bureau. Table B25040 House Heating Fuel. 2024 ACS 1-Year Estimates. <https://data.census.gov/table/ACSDT1Y2024.B25040?g=040XX00US41>

²¹ U.S. Energy Information Administration. Natural Gas Annual Respondent Query System (NGQS), Form EIA-176 (annual company-level data). Available at: <https://www.eia.gov/naturalgas/ngqs/#?report=RPC&year1=2021&year2=2024&company=Name&items=1010CT,1020CT,1030CT>

distribution system consists of 12,388 miles of transmission and distribution mains in Oregon, primarily consisting of modern polyethylene and coated steel pipes.²²

NWN filed an integrated resource plan (IRP) in 2022, the first IRP after the adoption of the original CPP rules.²³ While the Oregon Public Utility Commission (OPUC) accepted most of NWN’s near-term action items, the OPUC did not acknowledge NWN’s long-term plan, citing concerns with its assumptions around the cost and availability of low-carbon fuels, the degree to which NWN assessed costs and risks for utility customers, and the evaluation of electrification as a compliance resource.²⁴ NWN filed its second IRP in August 2025.²⁵ As part of its second IRP, NWN conducted an electrification analysis. The electrification analysis evaluated three demand scenarios incorporating varying levels of electrification: a “modest customer electrification” scenario, which assumes modest levels of electrification in line with historical trends; an “All-Electric Buildings” scenario based on the OES, which assumes full building electrification; and a “hybrid system electrification” scenario, which assumes widespread adoption of hybrid heat pumps retaining gas furnace backup systems.²⁶ The OPUC acknowledged the 2025 IRP with conditions, including requiring NWN to work with Energy Trust of Oregon to develop a work plan for a hybrid heating pilot and monitor fuel-switching trends, and improve stakeholder engagement and transparency around electrification and demand forecasts in its next IRP.²⁷

Portland General Electric (PGE) is the state’s largest electric utility, serving parts of Portland and surrounding areas in Western Oregon. PGE serves over 940,000 customers in Oregon, 87 percent of which are residential.²⁸

PGE’s most recent IRP update highlights the key factors influencing the future of the electric system in Oregon. PGE forecasts total energy deliveries to grow at a rate of 3.8 percent per year over the next

²² U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration. “Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data.” Available at: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids>

²³ In the Matter of Northwest Natural Gas Company d/b/a NW Natural 2022 Integrated Resource Plan, LC 79, September 23, 2022, available at: <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23476>.

²⁴ Oregon Public Utility Commission. Order No. 23-281. Filed August 2, 2023, Docket LC 79. Pages 8-10. <https://apps.puc.state.or.us/orders/2023ords/23-281.pdf>

²⁵ See Docket No. LC 86. NW Natural 2025 Integrated Resource Plan (IRP). <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=24590>

²⁶ NW Natural. *2025 NW Natural Integrated Resource Plan*. Docket No. LC 86. Filed August 1, 2025. <https://edocs.puc.state.or.us/efdocs/HAA/lc86haa338770056.pdf>

²⁷ Oregon Public Utility Commission. Order No. 26-150. Filed April 30, 2026, Docket LC 86. <https://apps.puc.state.or.us/orders/2026ords/26-150.pdf>

²⁸ U.S. Energy Information Administration. Form EIA-861, Sales to Ultimate Customers. Available at: <https://www.eia.gov/electricity/data/eia861/>



20 years, including the impact of transportation and building electrification.²⁹ While building electrification is expected to increase building-sector loads, the increase in PGE's forecast is primarily driven by rapid growth in the industrial sector, specifically new data center load which PGE projects to more than double by 2030.³⁰ As PGE faces this rapid demand growth, it must also comply with increasingly stringent HB 2021 emissions reduction targets in 2030, 2035, and 2040.³¹ While expanded adoption of energy efficiency and distributed energy resources will offset some of this growth, PGE emphasizes that will require greater clean energy resource procurement and infrastructure development to support this demand.³²

Gas system transition

Market forces and state policies promoting efficiency and electrification threaten the current gas utility status quo. There is increased competition from electric technologies, in part due to advancements in cold-climate heat pump systems. Recent studies estimate that heat pumps account for approximately 25 percent of the heating and cooling market in Oregon in 2025 and expect the market share to grow by about 3 percent each year.³³ Furthermore, policies such as the state's Building Energy Performance Standard require efficiency improvements that will result in falling gas sales.

These forces will have a major impact. The OES Reference scenario envisions that pipeline gas consumption would decline by more than 80 percent by 2050.³⁴ The OES finds that electrification and energy efficiency can reduce Oregon's overall energy demand. And as the OES notes, there is also "a risk of stranded assets, and a need to manage retirement of parts of natural gas distribution systems that otherwise may require costly upgrades,"³⁵ with disproportionate burden falling on lower-income households unable to afford the switch to electric equipment. The OES notes that households, especially

²⁹ PGE CEP & IRP Roundtable presentation. October 22, 2025. Pages 19-20.
https://assets.ctfassets.net/416ywc1laqmd/5htkxP4gUoP87kOxDAGk8k/8dee7d830b3d4cf665bcaa081fda4d8d/CEP_IRP_Roundtable_Oct_25-7.pdf

³⁰ PGE CEP & IRP Roundtable presentation. October 22, 2025. Pages 19-20.
https://assets.ctfassets.net/416ywc1laqmd/5htkxP4gUoP87kOxDAGk8k/8dee7d830b3d4cf665bcaa081fda4d8d/CEP_IRP_Roundtable_Oct_25-7.pdf

³¹ Oregon Legislative Assembly. 2021 Regular Session. House Bill 2021 (Enrolled; 2021 Oregon Laws Chapter 508). Available at: <https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled>

³² PGE. 2023 *Clean Energy Plan and Integrated Resource Plan Update*. Updated August 15, 2025.
https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf

³³ Oregon Department of Energy. 2025. *Biennial Oregon Heat Pump Report*. Submitted to the Oregon Legislature.
<https://www.oregon.gov/energy/Data-and-Reports/Documents/2025-Biennial-Oregon-Heat-Pump-Report.pdf>

³⁴ Oregon Energy Strategy Data Library. Prepared for the Oregon Department of Energy by Evolved Energy Research. Updated November 19, 2025. <https://www.oregon.gov/energy/Data-and-Reports/Documents/2025-OES-Energy-Pathways-Modeling-Data-Library.xlsx>

³⁵ Oregon Department of Energy. *Oregon Energy Strategy*. <https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf> p. 70



those facing high energy burdens, may need support to transition from gas systems to electric.³⁶ The OES calls for proactive state policy to manage this decline by prioritizing efficiency and electrification over new fossil infrastructure investment, coordinating planning between electric and gas utilities, and repurposing existing gas infrastructure and supplier expertise toward low-carbon alternatives, such as thermal energy networks.

Falling sales combined with increased capital investment risk creating unsustainably high gas rates. At high gas rates, customers will either face severe energy burdens or choose to electrify in order to cut costs. As rates rise, and customers with the means and opportunity choose electricity, rates will rise even faster and drive even more customers away from gas. Gas system costs will fall on a smaller and smaller portion of the population—a portion that is more likely to be low income, disadvantaged, and renters. Such a future poses risks to Oregon ratepayers as well as to gas utility investors. Financial outcomes can also create safety risks: a financially unhealthy utility may not be able to take actions necessary to maintain safety.

This transition must include consideration of the interactive effects between the gas and electric utility systems. The OES recommends increased coordination between electric and gas system planning.

2. SCENARIOS FOR OREGON'S GAS SYSTEM

Synapse modeled different pathways for Oregon residential and commercial buildings based on existing and future conditions, reflecting the pace at which customers reduce gas use and adopt other heating technologies.

For this analysis, Synapse used its in-house Gas Rate Model (GRM) to analyze the impact on customers and utility finances from changes to gas customers and sales along different pathways to comply with the state's GHG targets. The GRM allows Synapse to project gas utility rates based on different scenarios for utility investment, sales, and financial models.³⁷ We use input data from annual utility financial reports. Additionally, the GRM uses data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to determine the scale of each utility's pipe system, as well as the age and material of pipes.³⁸ The model tracks utility plant in service, depreciation, capital additions and retirements, operations and maintenance, and income taxes. It also accounts for capital structure and

³⁶ Oregon Department of Energy. *Oregon Energy Strategy*. <https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf> p. 70

³⁷ The GRM does not dynamically account for the impact of gas or electric rates on sales or fuel choices.

³⁸ U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration. "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data." Available at: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids>.



changes in tax rates. Looking to the future, the model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement, early retirements, stranded costs, and changes in depreciation rates.

As described in further detail below, Synapse ran four scenarios modeling different pathways:

- **Business-As-Usual (BAU) Case:** Building equipment largely reflects today's system, with a continued shift from electric resistance to heat pumps for heating, while gas combustion largely retains today's share of building heating. CCI's drive some electrification, while the remaining emission reductions come from use of zero-carbon gases. The gas system grows to reflect population growth.
- **Managed OES Case:** Building equipment transitions toward full electrification with heat pump adoption trajectories in line with the OES Reference Case. Regulators and NWN manage electrification to allow geographically-targeted retirement of gas mains while NWN simultaneously adapts its finances to align with a shrinking system.
- **Unmanaged OES Case:** Building equipment transitions toward full electrification with heat pumps in line with the OES Reference Case. Electrification occurs in a scattered manner across the system, so mains retirements are not possible until a large fraction of buildings have disconnected from the gas system (circa 2045). NWN continues to invest in its system in a BAU manner until 2045, at which point it adapts its business model to a rapidly shrinking system.
- **Hybrid Case:** Modeled on the hybrid case in NWN's recent IRP, building equipment transitions toward hybrid heat pump systems that retain gas furnace backup, at the same rate as the OES Reference case fully electrifies. The gas system must serve every hybrid building and grow in alignment with population growth, even as total sales fall.

We note that these scenarios do not account for the potential for NWN to engage in new business models or new lines of business (such as heating equipment provision or networked geothermal systems); we evaluate only the traditional gas-delivery portion of its business.

2.1. Shared Assumptions

There are a few important shared assumptions to note before proceeding with the detailed descriptions and preliminary results for each financial approach.

Table 1. Shared scenario assumptions

Input	Assumption
Cost of debt, debt fraction of capital, after-tax return on equity (ROE)	Held constant at recently approved values.
Inflation	2% per year (based on the long-term Federal Reserve target)
Capital additions and retirements	Distribution plant mains and services and associated asset types are calculated separately and are based on customer additions and departures, electrification assumptions, and PHMSA data. Constant 2%



	growth rate for other capital (reflecting higher inflation in utility industry).
Operations and maintenance expenses	Constant underlying 2% growth rate (grows with inflation). Needed operations and maintenance (O&M) varies by scenario with the number of customers and size of the gas system.
Gas fuel price	Henry Hub Natural Gas Spot Price projections from Energy Information Administration's (EIA) Annual Energy Outlook, ³⁹ adjusted for the 10-year average incremental cost over this benchmark to account for transportation costs. ⁴⁰ Renewable natural gas (RNG) assumed to be available at needed quantities at average cost of \$30 per MMBtu (in 2024 dollars). ⁴¹
Depreciation rates	Start with depreciation rates equal to the values used in recent rate cases, with scenario-specific acceleration as detailed below.
Energy efficiency assumptions	0.5 percent annual gas use efficiency improvements reflecting combination of efficiency programs, appliance standards, warming winters, and building codes. 0.25 percent annual electric use efficiency improvements, in addition to those captured separately through resistance to heat pump switching.
Building sector equipment stock	Building equipment stock breakdown from National Laboratory of the Rockies' (NLR) ResStock ⁴² and ComStock ⁴³ datasets, calibrated to EIA data.
Electric assumptions	Building electric load shapes from NLR End Use Load Profiles datasets. Incremental transmission and distribution capital and O&M costs based on embedded average costs scaled to reflect marginal costs.

³⁹ U.S. EIA. *Annual Energy Outlook 2026*. Table 13: Natural Gas Supply, Disposition and Prices. Henry Hub Spot Price. High Electricity Demand Case. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2026®ion=0-0&cases=higheledmd&start=2025&end=2050&f=A&linechart=higheledmd-d021526a.31-13-AEO2026&ctype=linechart&sourcekey=0>

⁴⁰ U.S. EIA. Natural Gas Citygate Price in Oregon. <https://www.eia.gov/dnav/ng/hist/n3050or3m.htm>

⁴¹ Energy and Environmental Economics (E3). October 2021. *Maryland Building Decarbonization Study: Final Report*. Page 13. E3's models have an Optimistic marginal cost in a high-demand case of \$30/MMBTU and a Conservative case of \$70/MMBTU, in \$2021. \$30/MMBTU in \$2024 is \$26 in \$2021, so we are assuming lower RNG costs than the Optimistic scenario.

⁴² NLR. ResStock Dataset 2024.2 Release. End Use Load Profiles for the U.S. Building Stock. Available at: <https://resstock.nlr.gov/datasets>.

⁴³ NLR. ComStock Dataset 2025.2 Release. End Use Load Profiles for the U.S. Building Stock. Available at: <https://comstock.nlr.gov/page/datasets>.



	Electric supply costs from the northwestern region of EIA's Annual Energy Outlook. ⁴⁴ Incremental capacity costs for higher-peak scenarios based on levelized cost of new entry for capacity resources. ⁴⁵ Data center loads aligned with PGE IRP forecasts, ⁴⁶ extended at a slower rate of growth after the end of PGE's study period.
Electric vehicles (EVs)	Light-, medium- and heavy-duty EV adoption, loads, and efficiency improvements in line with OES Reference scenario. ⁴⁷ Charging load shapes from NLR and Lawrence Berkeley National Laboratory (LBNL) models. ⁴⁸

Building sector stock and energy consumption: We used NLR's ResStock and ComStock datasets to estimate the starting end-use equipment breakdown in residential and commercial buildings. We developed gas and electric building load shapes for different equipment types from NLR's EULP datasets to calculate energy consumption and electric peak impacts.^{49,50} We calibrated building equipment stocks to total gas customers and sales using EIA data.⁵¹ We calibrated electric sales and customers

⁴⁴ U.S. EIA. *Annual Energy Outlook 2026*. Table 54: Electric Power Projections by Electricity Market Module Region. High Electricity Demand Case. Region: Western Electricity Coordinating Council / Northwest Power Pool Area. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2026®ion=5-23&cases=higheledmd&start=2025&end=2050&f=A&linechart=higheledmd-d021526a.127-62-AEO2026.5-23~higheledmd-d021526a.128-62-AEO2026.5-23&ctype=linechart&sourcekey=0>

⁴⁵ The Brattle Group. "Sixth Review of PJM's Variable Resource Requirement Curve" available at <https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf>. The Brattle analysis estimates a dual-fuel combustion turbine (CT) reference resource Net CONE of \$528/MW-day or \$193/kw-year; we used a \$200/kw-year value to avoid the risk of understating the cost of capacity.

⁴⁶ PGE CEP & IRP Roundtable presentation. October 22, 2025. https://assets.ctfassets.net/416ywc1lagmd/5htkxP4gUoP87kOxDAGk8k/8dee7d830b3d4cf665bcaa081fda4d8d/CEP_IRP_Roundtable_Oct_25-7.pdf

⁴⁷ Oregon Energy Strategy Data Library. Prepared for the Oregon Department of Energy by Evolved Energy Research. Updated November 19, 2025. <https://www.oregon.gov/energy/Data-and-Reports/Documents/2025-OES-Energy-Pathways-Modeling-Data-Library.xlsx>

⁴⁸ Light duty EV load shapes from Speake, Andrew, Anthony Fontanini, Rajendra Adhikari, Philip White, Prateek Munankarmi, and Arthur Yip. 2025. Integration of Electric Vehicle Charging Loads in Residential Building Stock Energy Modeling. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-93766. <https://docs.nrel.gov/docs/fy25osti/93766.pdf>, adjusted to split charging between residential and commercial chargers by the split in EVI Pro Lite. Medium and heavy duty EV load shapes are smoothed data extracted from Black & Veatch, Proactive Grid Investment Assessment: Medium- and Heavy-Duty Vehicle Transportation Electrification, prepared for Environmental Defense Fund, and available at <https://library.edf.org/AssetLink/atal4338qv8ucl8226gok35dmm170r4e.pdf>, which cites to LBNL.

⁴⁹ NLR. ResStock Dataset 2024.2 Release. End Use Load Profiles for the U.S. Building Stock. Available at: <https://resstock.nlr.gov/datasets>.

⁵⁰ NLR. ComStock Dataset 2025.2 Release. End Use Load Profiles for the U.S. Building Stock. Available at: <https://comstock.nlr.gov/page/datasets>.

⁵¹ U.S. EIA. Annual company level data, Form EIA-176. <https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name>



using PGE’s Federal Energy Regulation Commission (FERC) Form 1 data.⁵² We did not model demand response or demand flexibility from buildings, EVs, industry, or data centers; addition of this resource could reduce electric system costs for all scenarios.

Industrial gas customers: We present results for residential, commercial, and industrial customers. Our analysis did not address pathways for emission reduction and CPP compliance in the industrial sector. On all scenarios, we assumed that industrial gas use stays constant at today’s level. For EITE industrial gas users, emissions reductions are not part of NWN’s responsibility, and we have not assumed any costs or emissions reductions in this sector. For non-EITE industry, we have assumed that NWN procures sufficient compliance instruments or zero-carbon fuels to meet its CPP obligations. These assumptions are not meant as a projection, but instead a recognition of our project’s focus on the building sector. By treating the industrial sector identically in all scenarios, we focus the results and analysis on the impact of policy and regulatory choices regarding buildings.

CPP compliance: For each year of the study period, we calculate NWN’s compliance obligation (i.e., the amount of covered emissions subject to compliance under the CPP) under each scenario.⁵³ For any emissions exceeding NWN’s share of the statutory emissions cap, we assume NWN first purchases CCI credits up to the allowed percentage.⁵⁴ We calculate the costs associated with CCI credit purchases based on the contribution amounts listed in statute,⁵⁵ and include them in the gas revenue requirement.

Where necessary to meet the emissions requirements of the CPP, we assume that NWN uses renewable natural gas for the remainder of its obligations (after demand reductions and CCI credit purchases). The potential for RNG use in the building sector is limited by both the availability and cost of RNG supply and competing demand from other sectors, such as transportation, electric generation, and industry. In its 2025 IRP, NWN includes other, higher-cost resources such as green hydrogen, synthetic methane (methane made from green hydrogen), and carbon capture and sequestration to bridge the supply gap.⁵⁶ For simplicity we have assumed that RNG is carbon neutral and available in the required quantities to meet CPP obligations. If these assumptions do not hold, cases which rely on more RNG will require more extensive action in other sectors to meet required economy-wide emissions reductions.

Equipment incentive program costs: We assumed that ambitious ratepayer-funded programs would be required to encourage customers to electrify and switch to heat pumps at the pace set by the OES Reference Case. We estimated current per-household incentives based on existing incentives provided

⁵² As filed in Docket No. RE 54, *PGE/Annual Report FERC Form 1*.

<https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=17519>

⁵³ Consistent with the requirements of the CPP, we exclude emissions from EITE industrial gas customers from the calculation of covered emissions.

⁵⁴ OAR 340-273-9000, Table 2, Table 4, and Table 5.

⁵⁵ OAR 340-273-9000, Table 6.

⁵⁶ Northwest Natural. *Final 2025 IRP Appendices, Appendix H*. https://www.nwnatural.com/-/media/nwnatural/pdfs/nwn2025integratedresourceplan_appendices_redacted.pdf.

through the state's Heat Pump Purchase Program, Community Heat Pump Deployment Program, Rental Home Heat Pump Program, and Energy Trust of Oregon incentives.^{57,58,59}

To estimate future incentive levels necessary to achieve the desired equipment adoption, we compared existing Oregon incentives to those offered in leading programs (including Massachusetts' MassSave, California's TECH program, and Energy Trust of Oregon's heat pump pilot program). We developed projected incentives for each scenario by scaling the base incentive level in reference to the expected level of policy support required to achieve certain emissions savings, while also accounting for existing or future building-sector policies in Oregon that encourage electrification. We assumed that no incentives are provided after 2045, assuming that (a) heat pumps will be substantially economically viable relative to gas heating after 2045 due to various factors such as cost reductions, performance improvements, and increased gas prices relative to electricity prices, and (b) future decarbonization policies (e.g., zero-emission heating equipment standards and building performance standards) will require the installation of heat pumps to meet future emissions targets rather than relying on incentives.

For each scenario, we count the annual number of customer conversions, i.e., where a customer changes space or water heating equipment to a more efficient electric unit. We multiply the forecasted per-unit incentive costs by scenario by the annual counts of equipment conversions in each scenario to estimate the total incentives required under each scenario. Finally, from the estimated per-customer incentive costs, we estimated expected total program costs, including administrative expenses, by applying an adder of 6.5 percent, based on the Energy Trust of Oregon's performance target.⁶⁰

We assumed that the costs of these incentive programs would be recovered in a few ways, depending on the equipment type and scenario. In all scenarios, we assume that the electric utility, PGE, continues to pay for electric energy efficiency measures, in particular electric resistance customers converting to electric heat pumps. Second, NWN's CCI credit purchases form a part of its expected program funding contribution. We assume that CCI credit payments result in fuel switching. CCI credit purchases are treated as a pass-through cost, recovered by the gas utility ratepayers.

For scenarios that require major shifts in customer uptake of electrification fuel switching beyond what would materialize as a result of CCI programs funded by NWN CCI credit purchases, we assume that these program costs would be securitized. Securitization refers to financing method where a utility's

⁵⁷ Oregon Department of Energy. 2025. *Biennial Oregon Heat Pump Report*. Submitted to the Oregon Legislature. <https://www.oregon.gov/energy/Data-and-Reports/Documents/2025-Biennial-Oregon-Heat-Pump-Report.pdf>

⁵⁸ Energy Trust of Oregon. 2026. *Dual Fuel Heat Pump Pilot Phase 1 Evaluation Report*. Submitted by Apex Analytics LLC and Ideal Community Strategies. <https://www.energytrust.org/wp-content/uploads/2026/03/Dual-Fuel-Heat-Pump-Pilot-Phase-1-Evaluation-Final-Report-w-SR.pdf>

⁵⁹ Energy Trust of Oregon. "Residential Water Heater Incentives." <https://www.energytrust.org/residential/incentives/water-heater/all>

⁶⁰ Energy Trust of Oregon. *2025 Annual Report to the Oregon Public Utility Commission*. April 15, 2026. <https://www.energytrust.org/wp-content/uploads/2026/04/Energy-Trust-2025-Annual-Report.pdf>

large upfront costs are repaid over time through a dedicated charge on customer bills, to mitigate the immediate rate shock to customers. We assume the program costs are securitized over a period of 30 years, at a rate equivalent to a 10-year municipal bond yield (3.37 percent),⁶¹ increased by 0.5 percent to reflect the longer 30-year period. We assume that in the first 15 years, the annual repayments of the securitized electrification program costs are primarily shouldered by gas customers. By 2035, securitized incentive program costs begin to be shared by electric and gas customers, and the remaining costs are eventually paid entirely by electric customers in 2060.

To the extent that regulatory approaches, such as business codes, air quality requirements, or other standards, require building owners to move away from combustion appliances, programmatic incentive costs could be lower.

Data center and EV electricity load: Based on PGE’s recent IRP stakeholder engagement materials, we assume large load customer demand corresponding to the reference case forecasts, reaching 2 GW by 2040.⁶² Industrial data center sales and peak increase five-fold by 2050 and eight-fold by 2075.

For electric vehicles, we utilized OES Reference scenario forecasts for light-, medium- and heavy-duty EV adoption, loads, and efficiency improvements.⁶³ Using charging load shapes from NLR and LBNL models as noted in [Table 1](#), we calculated projected EV loads by vehicle class. We allocated EV loads to customer classes, divided by residential (home charging) and commercial (public light-duty vehicle charging, plus commercial fleets) sectors.

2.2. Business As Usual Scenario

In the business-as-usual (BAU) scenario, building equipment largely reflects today’s system. The scenario captures two slow transformations. First, it includes a continued shift from electric resistance to heat pumps for space and water heating. Second, it directs the funding from NWN’s purchase of CCI credits into funding for incentives for full electrification. This results in some transition from gas to electric heat pumps in all-electric buildings.

This scenario assumes only two ratepayer-funded end-use programs that affect heating system choices: an electric efficiency program (paid by electric ratepayers) similar to that currently offered by Energy Trust of Oregon that encourages adoption of heat pumps in buildings currently heated with electric resistance heat, and an electrification program funded by NWN’s CCI purchases. The net effects of these

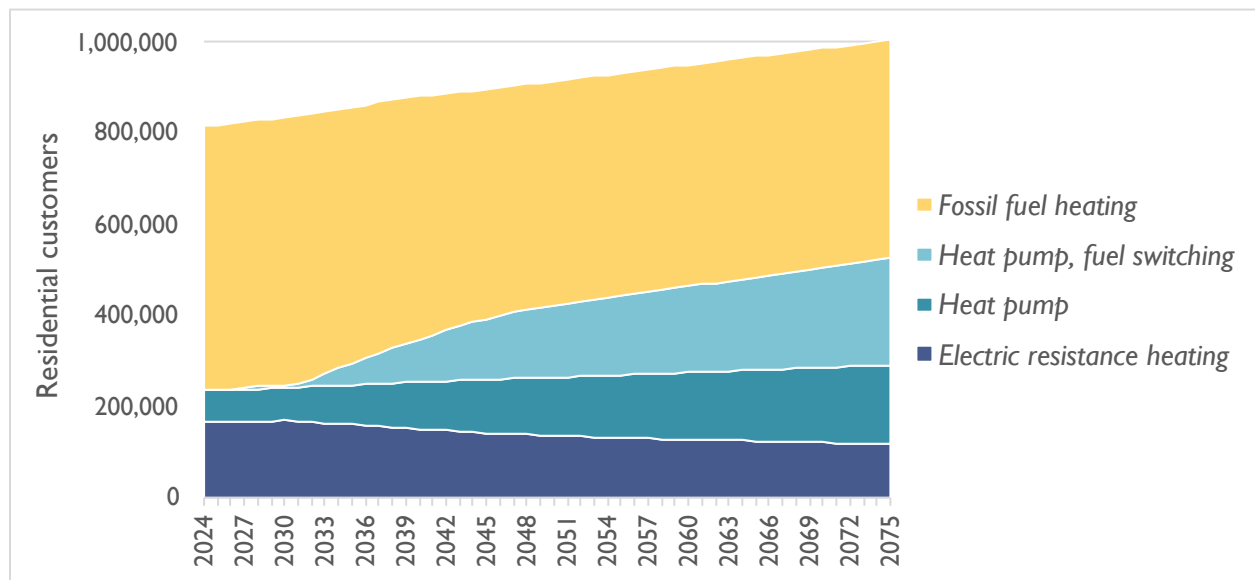
⁶¹ Fidelity Investments. “Western Asset Oregon Municipals Fund Class 1.” Accessed April 28, 2026. Available at: <https://fundresearch.fidelity.com/mutual-funds/summary/52469N401>

⁶² PGE CEP & IRP Roundtable presentation. October 22, 2025. https://assets.ctfassets.net/416ywc1laqmd/5htkxP4gUoP87kOxDAGk8k/8dee7d830b3d4cf665bcaa081fda4d8d/CEP_IRP_Roundtable_Oct_25-7.pdf

⁶³ Oregon Energy Strategy Data Library. Prepared for the Oregon Department of Energy by Evolved Energy Research. Updated November 19, 2025. <https://www.oregon.gov/energy/Data-and-Reports/Documents/2025-OES-Energy-Pathways-Modeling-Data-Library.xlsx>

two programs can be seen in [Figure 2](#), which shows the growth in the residential building stock (as represented by PGE’s electric customer count) and the shift from resistance and gas toward heat pumps and full electrification.

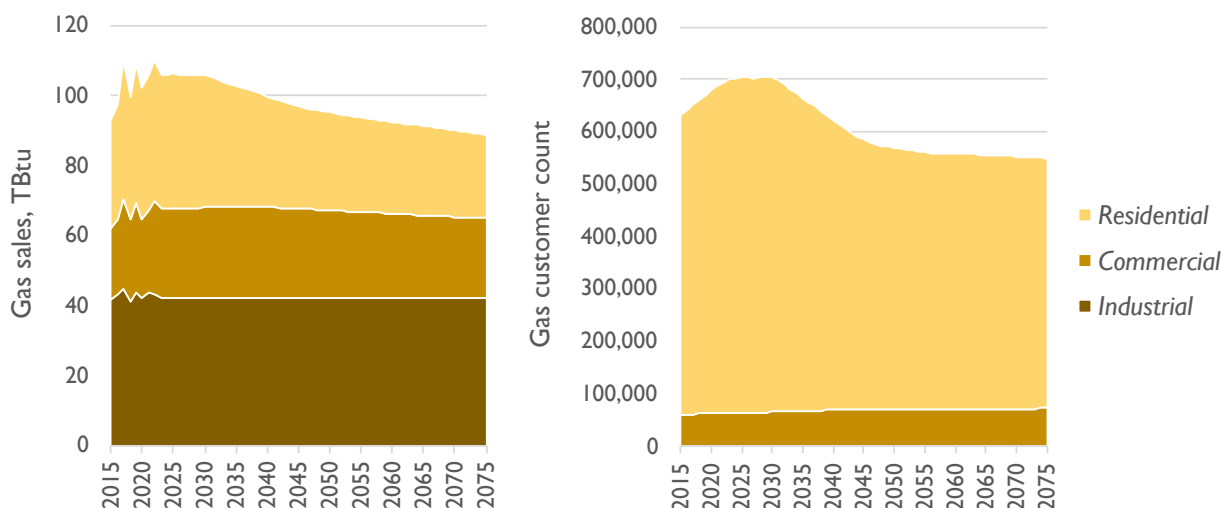
Figure 2. Residential electric customers by primary heating



Note: This figure shows customer counts, calibrated to PGE customers.

In the BAU case, total NWN customers decrease by 19 percent by 2050 due to modest levels of CCI-funded electrification for residential customers. Electrification and efficiency increases cause sales to gently decline over time, decreasing by 10 percent by 2050. While population increases drives sales and customers up, the effects are counteracted by CCI-funded electrification in the residential sector, which reduces overall sales and customers. Commercial and industrial sales remain relatively flat over the study period, and commercial and industrial customers increase slightly over time, reflecting population growth.

Figure 3. Gas sales (left) and customers (right) by sector, BAU scenario

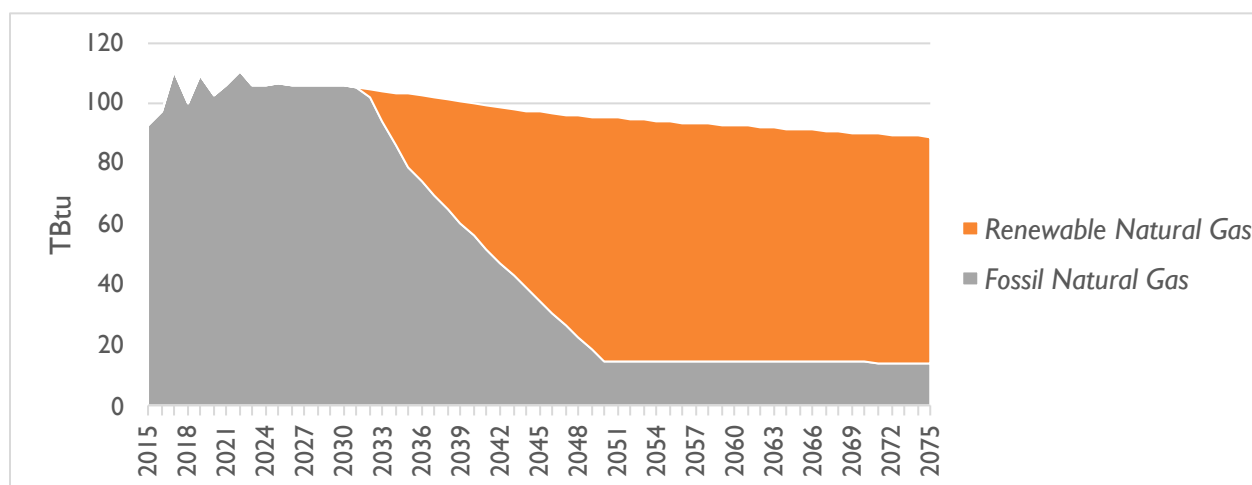


To comply with the CPP in the BAU case, the supply assumption would require the import of a substantial portion of the RNG that NWN delivers. By 2050, NWN would require more than 80 trillion British thermal units (TBtu) of RNG per year, accounting for 84 percent of NWN’s fuel supply (Figure 4). In contrast, a recent study by the American Gas Foundation and ICF indicates that Oregon’s production potential for RNG is only 34.8 TBtu per year in 2050, even under an optimistic “high” scenario.⁶⁴ Relying on out-of-state resources doesn’t solve the RNG supply problem: the same study’s national “high” potential for 2050 is just 22 percent of current natural gas use in buildings and industry.⁶⁵

⁶⁴ American Gas Foundation and ICF. 2025. *Renewable Natural Gas Supply Assessment*. https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf

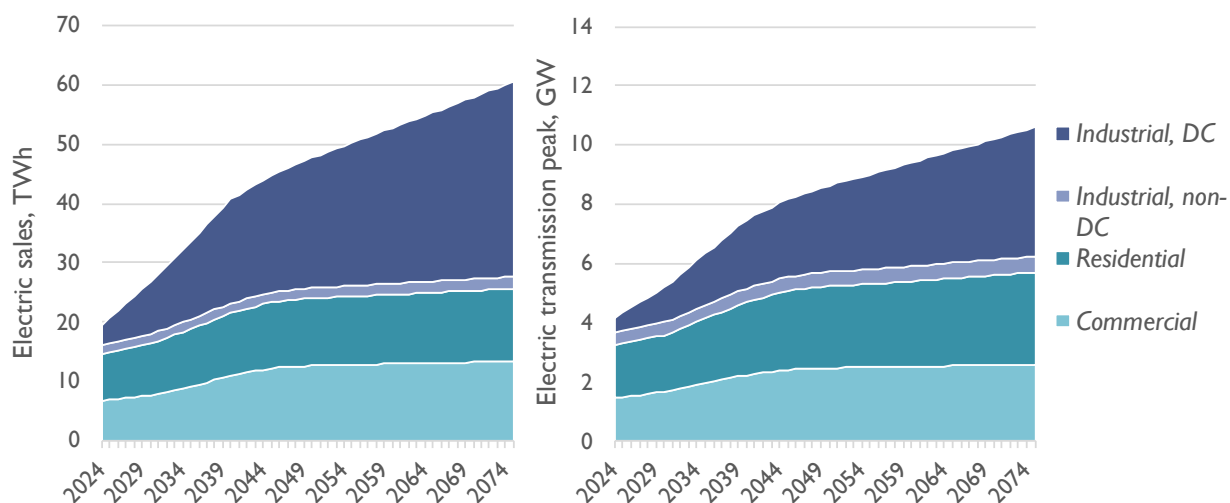
⁶⁵ U.S. EIA reports in the 2025 *Natural Gas Annual* (https://www.eia.gov/naturalgas/annual/pdf/table_015.pdf) that 2024 consumption in buildings and industry was 16,889 TBtu, while the ICF study finds 2050 “high” potential of 3,728 TBtu.

Figure 4. RNG share of fuel supply, BAU scenario



Electric sales increase rapidly in the BAU case, driven by EVs and data centers. Industrial data center sales and peak increase five-fold by 2050 and eight-fold by 2075. Non-EV building loads do not increase substantially due to the counterbalancing effects of resistance heating switching to heat pumps. Total residential and commercial sector sales increase by 65 percent by 2050 and 76 percent by 2075. Electric peak loads also rise, passing 8 GW in 2044 and rising to more than 10 GW by 2075, as shown in [Figure 5](#).

Figure 5. Electric sales (left) and transmission peak (right) by sector

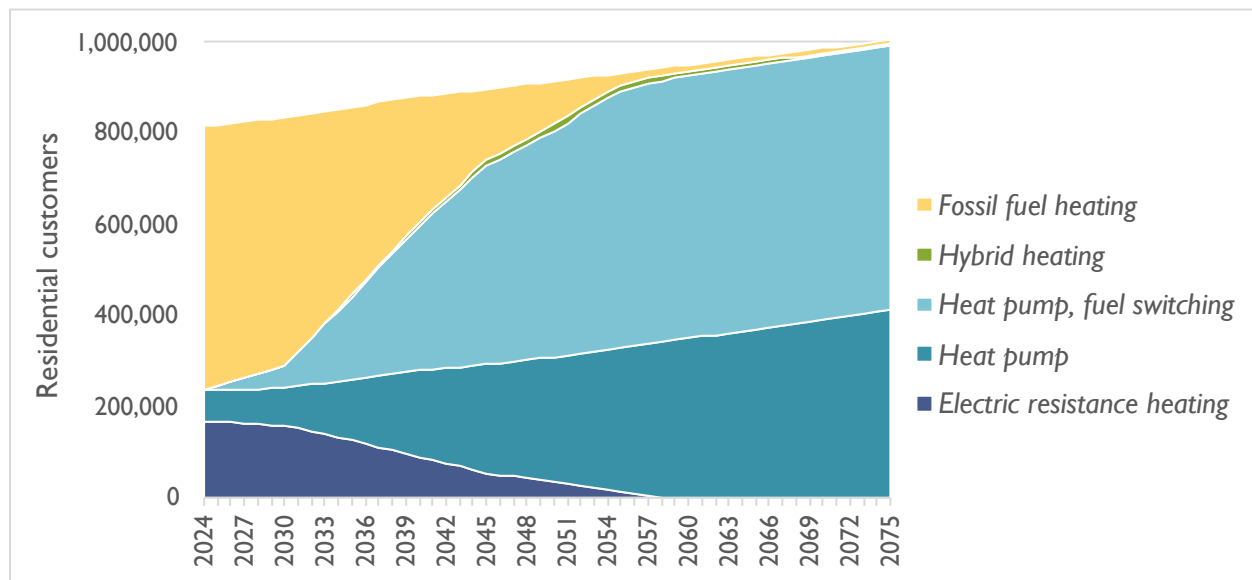


2.3. Managed Oregon Energy Strategy Scenario

The Managed Oregon Energy Strategy (OES) scenario assumes that most residential and commercial customers will fully electrify and depart the gas system by 2050, in alignment with the OES modeling by ODOE. We extended the trajectories past 2050 to 2075.

[Figure 6](#) shows the transition of the residential building stock from gas, electric resistance, and heat pumps toward near-universal use of heat pumps over the study period; the commercial sector transition is comparable.

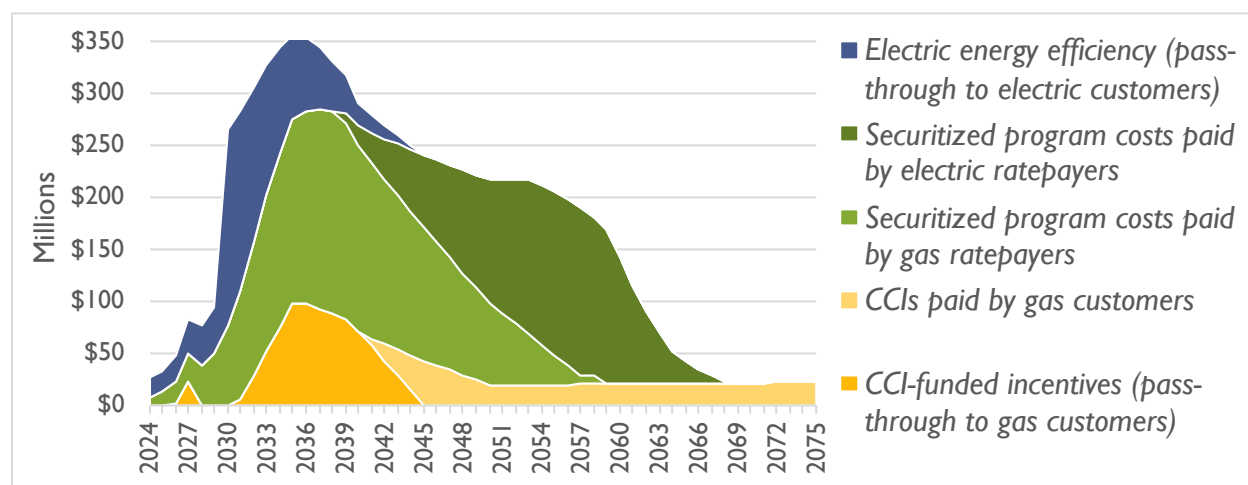
Figure 6. Residential electric customers by primary heating



Note: This figure shows customer counts, calibrated to PGE customers.

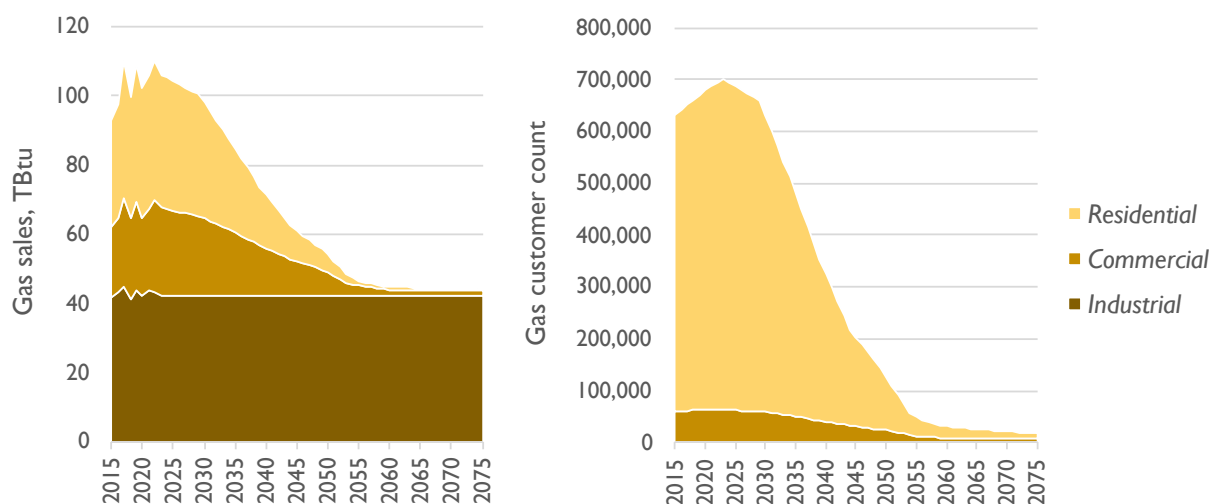
We assumed that ambitious ratepayer-funded programs would be required to encourage customers to electrify and switch to heat pumps at the pace set by the OES Reference Case. These incentives are higher than in the other cases because they reflect a need to encourage some customers to replace heating system equipment and other gas equipment outside their normally expected equipment replacement cycle. We assumed that some of this would be achieved through programs funded by NWN CCI credit purchases (in yellow). Other electrification incentives beyond that (in green) would be securitized and recovered over time, first from gas ratepayers, then transitioning to be paid by electric ratepayers, as shown in [Figure 7](#).

Figure 7. Annual incentive program costs by type and cost recovery method



NWN’s customer count and sales fall rapidly in this case, as shown in [Figure 8](#). By 2050, 82 percent of customers have left the gas system, and sales have fallen by nearly half. The remaining sales are almost entirely for industrial gas use, as residential and commercial sales fall by 81 percent by 2050, corresponding with customer declines. In the Managed OES scenario, we simplified the treatment of industrial gas use relative to ODOE’s OES and used the same assumption of flat gas demand in this sector (with emissions reduced using renewable natural gas) as in each of the other cases.

Figure 8. Gas sales (left) and customers (right) by sector, Managed OES scenario



As in all cases, we assumed that NWN meets its CPP obligations, after accounting for the decline in sales, first through CCIs, and then the remainder through RNG. NWN’s RNG need peaks in 2050 at about

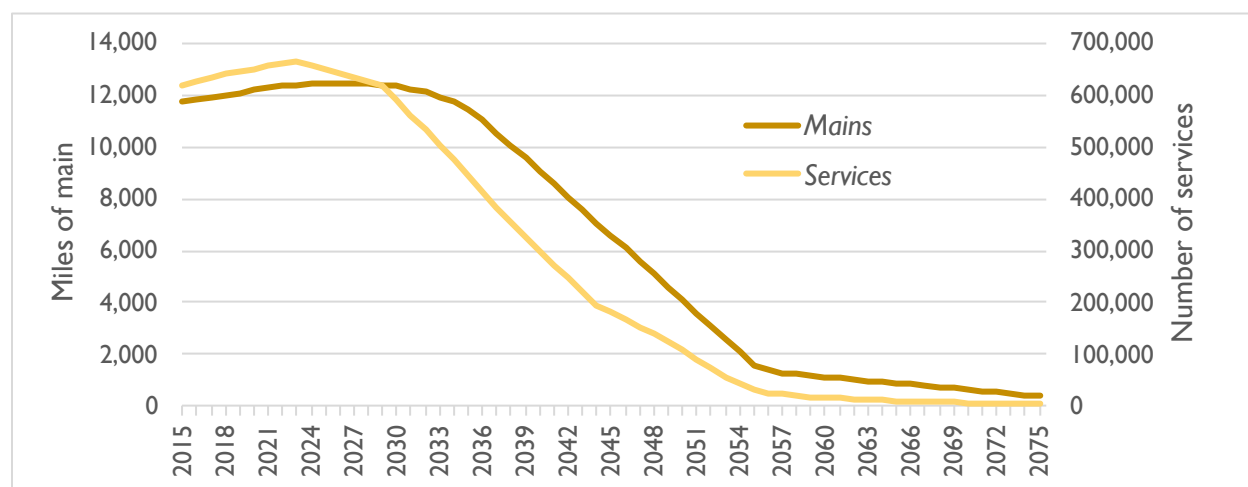
34 Tbtu, or about 43 percent of the need in the BAU case. According to the high scenario in the American Gas Foundation’s RNG study, Oregon could produce this much RNG.⁶⁶

This case is “managed” in two ways: physically and financially. Managing the physical transition means that electrification occurs in a planned and clustered fashion. Clustered electrification that is mindful of the topology of the gas system would allow NWN to retire mains and abandon portions of the gas system as customers electrify. This would reduce O&M costs as well as the need for any capital expenditure on those pipes. This case reduces capital expenditure relative to the BAU case primarily by avoiding the replacement of assets that are replaced in the BAU case over the next 50 years.

Managing the financial transition means adjusting depreciation rates to account for the changes in expected asset utilization. We modeled this by assuming that NWN moves to a utilization-based depreciation approach beginning in 2030, with depreciation rates calculated in reference to the expected future throughput of gas through each asset or type of asset. Utilization-based depreciation addresses intergenerational equity concerns by assigning depreciation expenses on a per-therm rather than per-year basis—more costs are recovered in the near term while there is still higher utilization of the system, which reduces future costs when there is less utilization and eliminates the risk of stranded costs.

NWN’s service line count falls in parallel with its falling customer count, while its mains also fall but with a roughly five-year delay to account for the need for all homes in a given area to stop using gas before the main can be retired. [Figure 9](#) shows these two transitions. By 2035, a third of services are retired, while miles of main have only decreased by 8 percent. By 2050, total miles of main have fallen by roughly two-thirds.

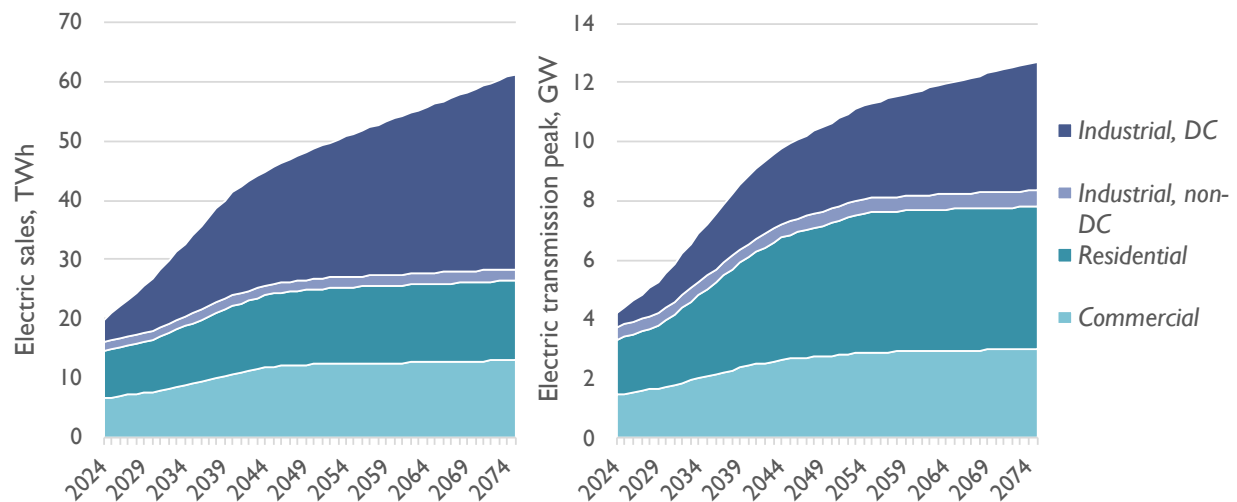
Figure 9. Miles of main and number of services on NWN system, Managed OES scenario



⁶⁶ American Gas Foundation and ICF. 2025. *Renewable Natural Gas Supply Assessment*. https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf

On the electric system, this case shows a minor increase in electric sales but a notable increase in peak loads compared with the BAU case ([Figure 10](#)). The Managed OES scenario assumes the same future data center sales and peak impacts as the BAU; building electrification drives the difference. Electric sales in 2050 are 1 TWh (2 percent) higher than the BAU case, whereas electric peak is 2 GW (23 percent) higher. Electric peak rises because of electrification, while also being moderated by the shift from resistance heating to heat pumps.

Figure 10. Electric sales (left) and transmission peak (right) by sector, Managed OES scenario



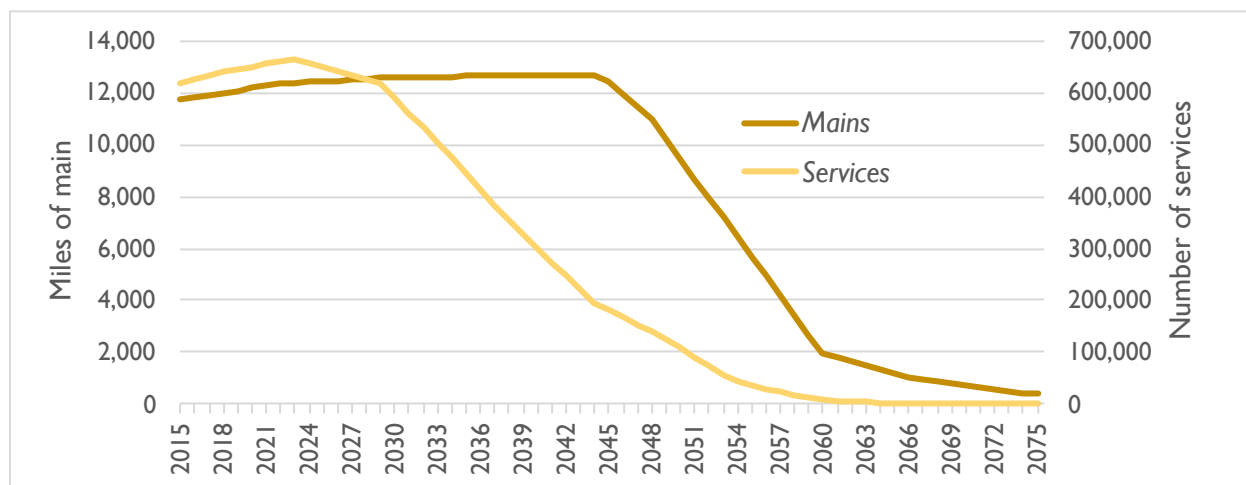
2.4. Unmanaged OES Scenario

The Unmanaged OES scenario assumes the same customer and sales trajectories as the Managed OES scenario, but without the physical or financial utility actions to manage the transition. Specifically, in this case NWN pursues the same approach to capital investment as in the BAU or hybrid cases until 2045, at which point it switches to a retirement mode and rapidly retires large portions of its mains. Similarly, in this case NWN switches to a utilization-based depreciation approach in 2045.

Customer incentive costs in this case are lower than in the Managed OES case because, while they achieve the same level of electrification, there is no need for extra incentives to cover the cost of out-of-cycle replacements required to retire neighborhood mains.

This case has the same overall building equipment stock turnover, number of gas customers and sales, and electric loads as the Managed OES case. [Figure 11](#) shows the primary physical difference: the delayed retirement of mains. By 2035, the number of services declines by a third, but the miles of main remain relatively flat. By 2050, when the number of services declines by 83 percent, only a quarter of the miles of main retire. By 2060, nearly 85 percent of main miles retire.

Figure 11. Miles of main and number of services on NWN system, Unmanaged OES scenario



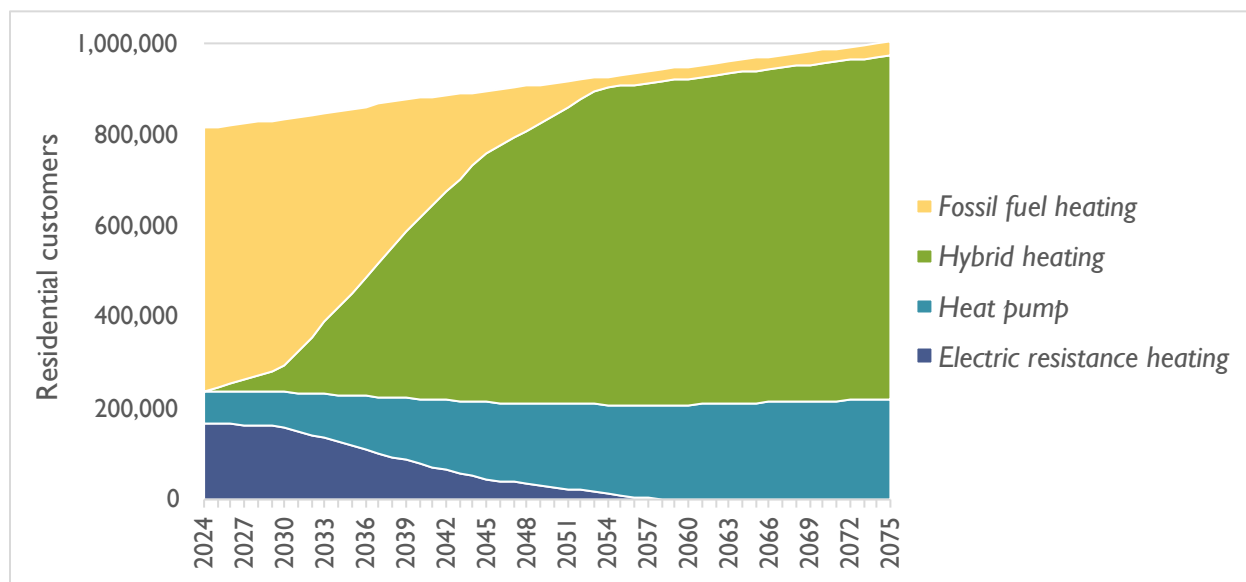
2.5. Hybrid Scenario

The Hybrid scenario is based on the Hybrid System Electrification demand variation scenario examined in NWN's most recent IRP. NWN defines this scenario as having the same conversions of gas customers to heat pump equipment as the OES Reference case, but those heat pumps are instead used in a hybrid configuration in which each building gets most of its heat from electric heat pumps, except on very cold days when the heat pump shuts off and heat comes from the pre-existing or jointly installed gas heating system.⁶⁷

We created this scenario for our modeling by shifting all gas-to-heat pump conversions to become gas-to-hybrid configurations. [Figure 12](#) shows the resulting distribution of heating systems.

⁶⁷ NW Natural. 2025 Integrated Resource Plan. <https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan>. See Figure 10.3 on page 10-11 and Figure 10.13 on page 10-28.

Figure 12. Residential electric customers by primary heating

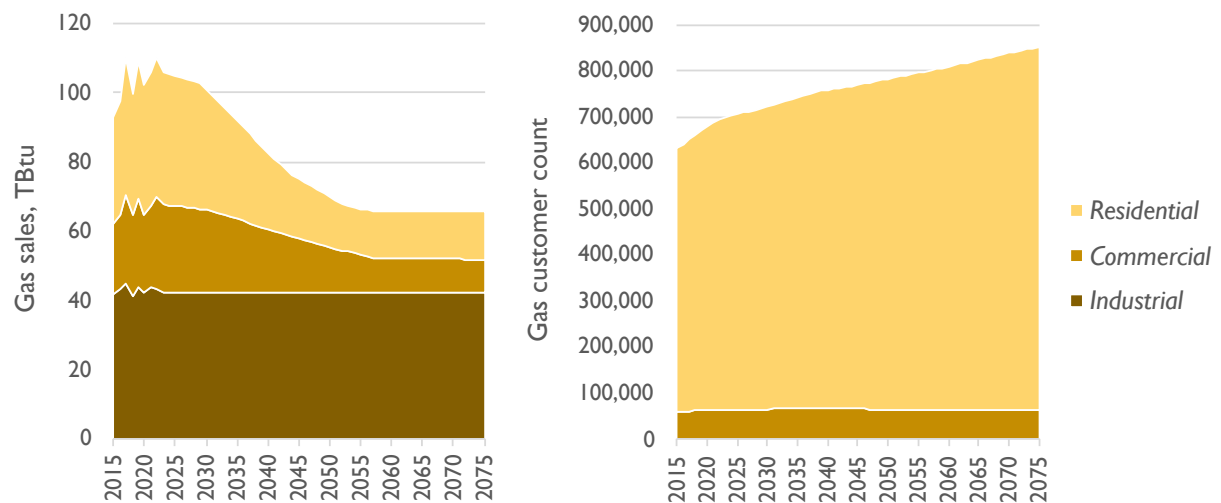


Note: This figure shows customer counts, calibrated to PGE customers.

We assumed that achieving this outcome would require ratepayer-funded incentives. The incentives are required to encourage hybrid electrification; these incentives can be smaller than in the OES cases because the heat pumps can have smaller capacity (and therefore slightly lower cost). NWN's CCI purchases fund some of these incentives. In contrast to the BAU case, where we assume CCIs would support full electrification and thus disconnection from the gas system, in this case they support hybrid configurations and continued use of the gas system.

NWN has more customers in this case than in any of the other cases, although its sales decrease and are closer to the OES cases than to the BAU case (Figure 13). Total customers increase by 11 percent by 2050, while sales decrease by 34 percent due to reductions in gas demand in the residential and commercial sectors. Required RNG peaks at 52 TBtu per year in 2050, serving 74 percent of NWN's fuel supply. While this case requires roughly two-thirds as much RNG as in the BAU case, substantial imports would still be required to support this level of RNG use.

Figure 13. Gas sales (left) and customers (right) by sector, Hybrid scenario

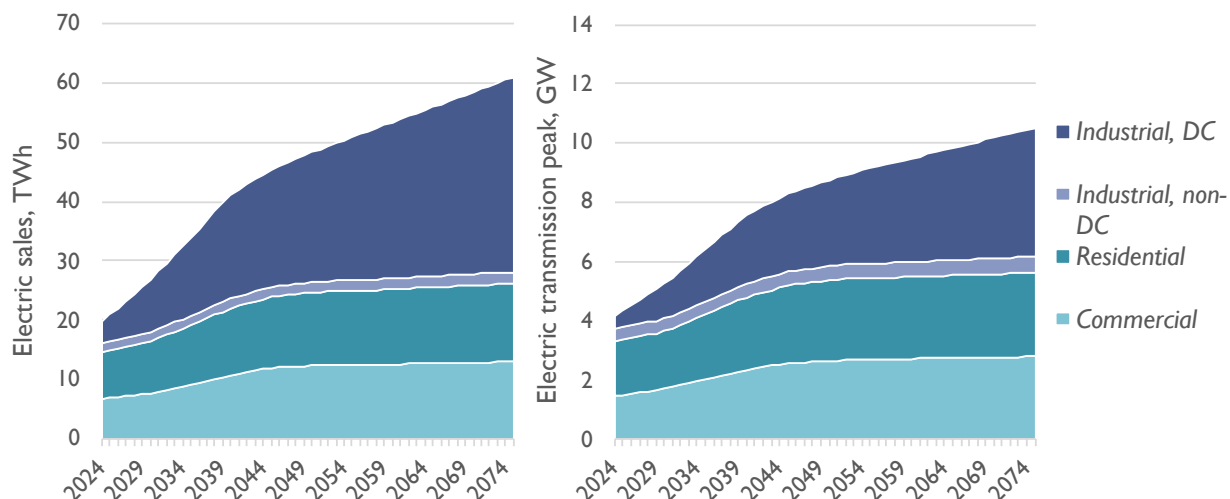


As hybrid heating customers do not completely electrify and remain on the gas system, total mains and services do not decline under the Hybrid scenario. In this case, NWN would invest in replacing assets and maintaining its full system, as in the BAU case.

The pursuit of a hybrid approach would require coordination between NWN, electric utilities, and regulators. There is no need for a distinction between a managed or unmanaged transition in this scenario, because gas customers remain on the system and no changes in distribution infrastructure investment or retirement are needed. However, we did adjust the depreciation schedules. We assumed that NWN would shift to a utilization-based depreciation approach in 2030 in this case. While existing customers would remain connected to the gas system indefinitely, a utilization-based approach allows more affordable rates in the hybrid steady state because the assets are more fully depreciated.

One of the major arguments that NWN makes in favor of the hybrid approach is the potential for lower electric system costs from a lower winter peak. [Figure 14](#) shows the electric sales and peak loads in this case. The transmission system peak in 2050 in this case is about 8.8 GW while it is 10.6 GW in the OES cases—a reduction of about 1.8 GW, roughly the same as in the BAU case.

Figure 14. Electric sales (left) and transmission peak (right) by sector, Hybrid scenario

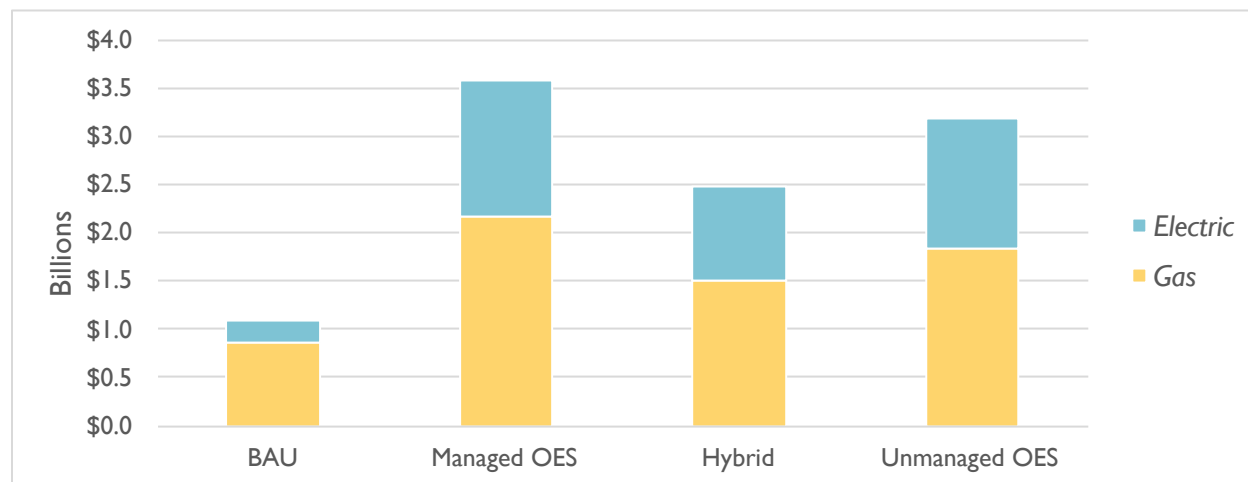


3. MODEL RESULTS

3.1. Incentive Program Costs

Figure 15 shows the net present value of gas and electric incentive program costs by scenario. This includes costs for all equipment incentive program types modeled (including electric energy efficiency programs, electrification programs funded by gas CCI credit purchases, and fuel-switching programs securitized and recovered from gas and electric ratepayers). All scenarios include programs that incentivize customer equipment conversions. The BAU scenario has the lowest total program cost, at \$1.1 billion. The Managed OES scenario requires the most program costs over the study period, as it requires the greatest level of customer fuel-switching equipment conversions at an accelerated pace.

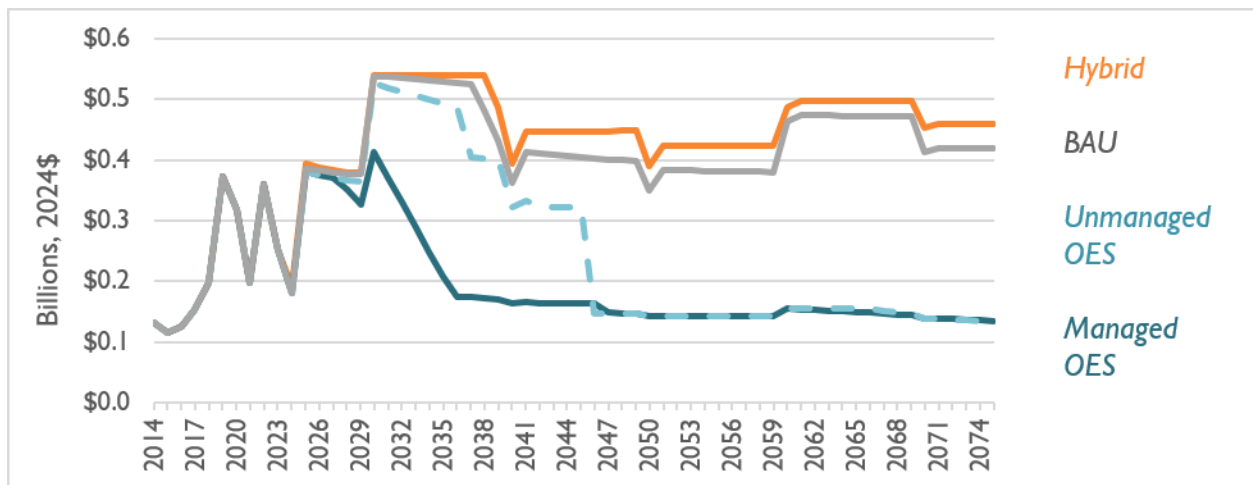
Figure 15. NPV of incentive program costs, by scenario



3.2. Gas Capital Expenditures

[Figure 16](#) shows historical and projected annual capital additions for NWN under each scenario, in real 2024 dollars.⁶⁸ Under the Hybrid and BAU cases, which maintain use of the gas system, there are continued capital investments, primarily associated with maintenance and replacement with distribution mains and services as the gas system ages and requires continued investment. In contrast, the Managed OES case rapidly decreases the level of annual capital expenditures by 2035, reflecting intentional system downsizing. The decline in the Unmanaged OES case lags the Managed OES case by a decade, as NWN continues to invest in its system.

Figure 16. Annual gas capital additions by scenario, 2024 dollars



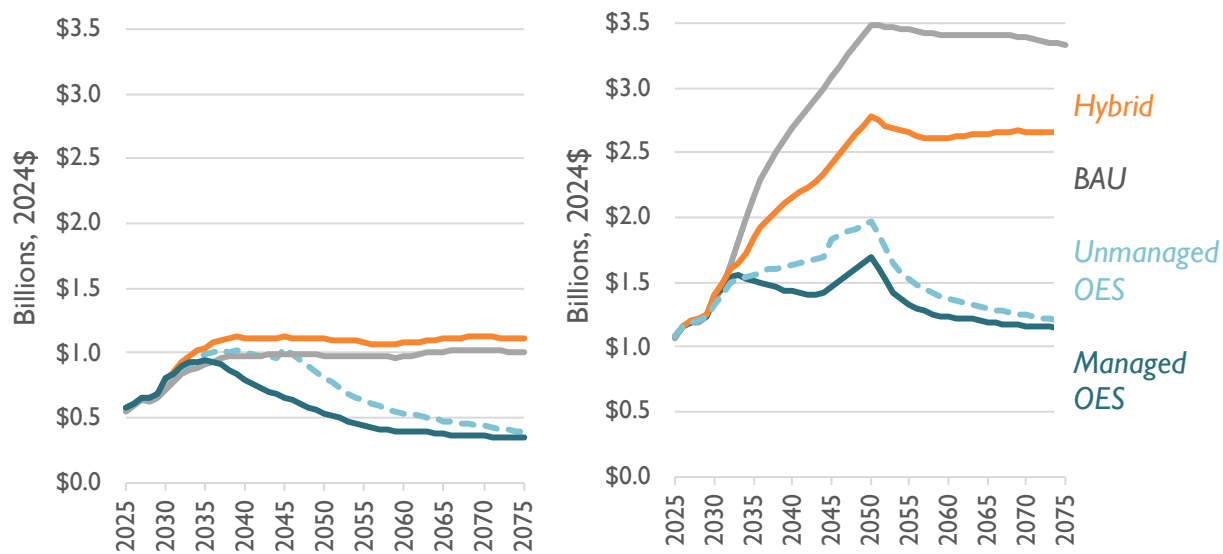
3.3. Total Utility System Costs

[Figure 17](#) shows the trajectories of revenue requirement with and without fuel costs for NWN under the four scenarios. The gas revenue requirement presented in this chart includes the recovery of incentive program costs from gas ratepayers, described further above. We find that NWN’s revenue requirement increases for all scenarios through 2035. However, the revenue requirement under the Managed OES case is nearly half of the BAU by 2050 and a third as large as the BAU in 2075 as gas customers depart and NWN retires portions of its system. The Unmanaged OES scenario lags the Managed case, staying on par with the BAU through 2045 before the impacts of rapid retirements kick in. The Hybrid case, which does not retire any mains or services and retains the most customers of any scenario, has the highest revenue requirement from 2030 through the end of the study period, remaining over 10 percent higher than the BAU case.

⁶⁸ The lumpiness of this projection is driven by the aggregation of available pipe asset data from PHMSA into decade-long age bins (e.g., pipe assets installed from 1990-1999 are aggregated into a single group).

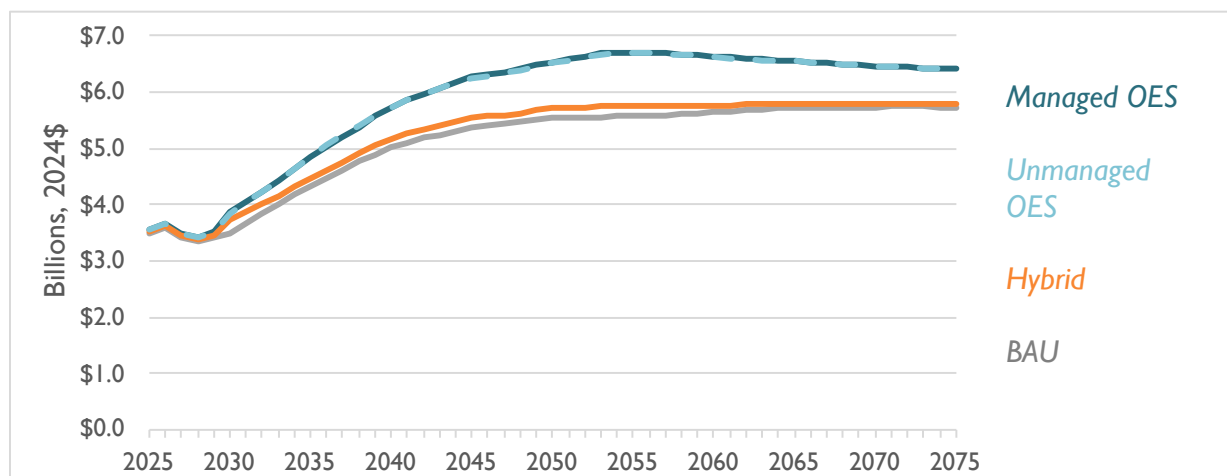
Accounting for the cost of fuels ([Figure 17](#), right), the BAU is by far the highest. NWN begins blending RNG into its supply in 2032 in the BAU case, 2034 in the Hybrid case, and 2037 in the OES cases. The BAU case, which requires the largest volumes of RNG to comply with the CPP, peaks at \$3.5 billion in 2024 dollars in 2050, nearly triple current levels. The Hybrid case, which has fewer sales and thus lower RNG supply costs, peaks at \$2.8 billion in 2024 dollars in 2050, 20 percent lower than the BAU. Finally, the Managed and Unmanaged OES scenarios require fewer volumes of high-cost RNG to comply with the CPP, as electrification reduces gas sales and thus emissions. By 2075, the Managed OES combined revenue requirement and fuel costs are 66 percent lower than the BAU.

Figure 17. Gas utility revenue requirement without fuel costs (left) and with fuel costs (right) by scenario



[Figure 18](#) presents the PGE’s electric revenue requirement, including electric supply costs, under each scenario. Electric revenue requirement rises in all scenarios as sales increase.

Figure 18. Electric utility revenue requirement (including supply costs) by scenario

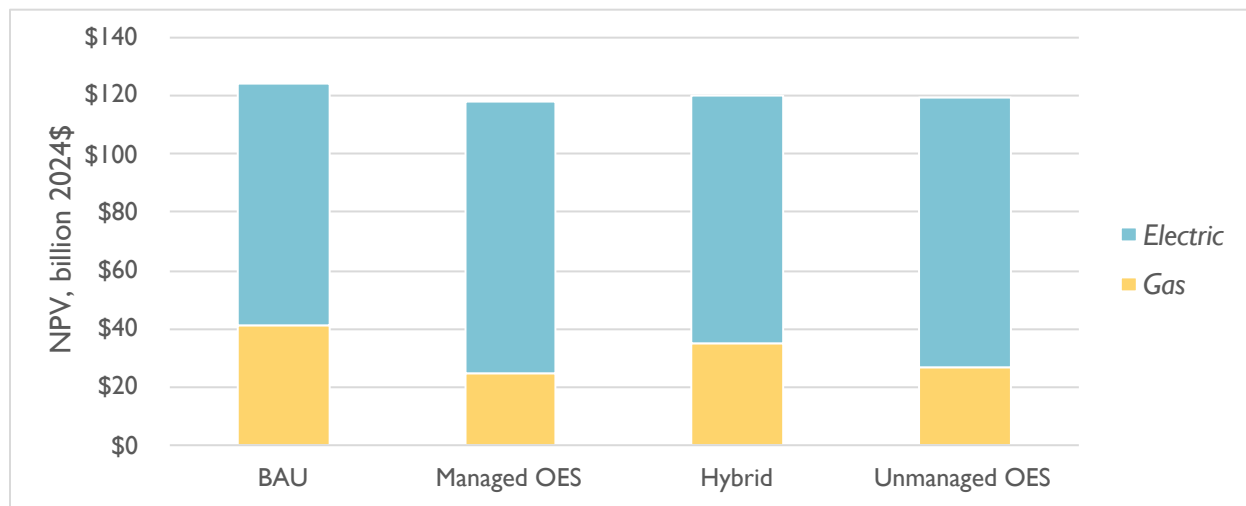


[Table 2](#) and [Figure 19](#) present the net present value of the revenue requirements (NPVRR), including fuel and supply costs, across the gas and electric systems combined. The electric NPVRR is highest in the Managed OES case, and lowest in the BAU case. However, these differences are offset by the gas side, where the total NPVRR is the highest under the BAU scenario and lowest under the Managed OES case. In total, the Managed OES combined NPVRR is \$117.7 billion (in 2024 dollars), \$6.8 billion less than the BAU case which has a combined NPVRR of \$124.5 billion.

Table 2. NPV of gas and electric revenue requirement by scenario

Scenario	Electric	Gas	Total	Delta from BAU
BAU	\$83.0	\$41.5	\$124.5	n/a
Managed OES	\$92.9	\$24.8	\$117.7	-\$6.8
Hybrid	\$85.1	\$35.0	\$120.1	-\$4.4
Unmanaged OES	\$92.9	\$26.6	\$119.5	-\$5.0

Figure 19. NPV of gas and electric revenue requirement

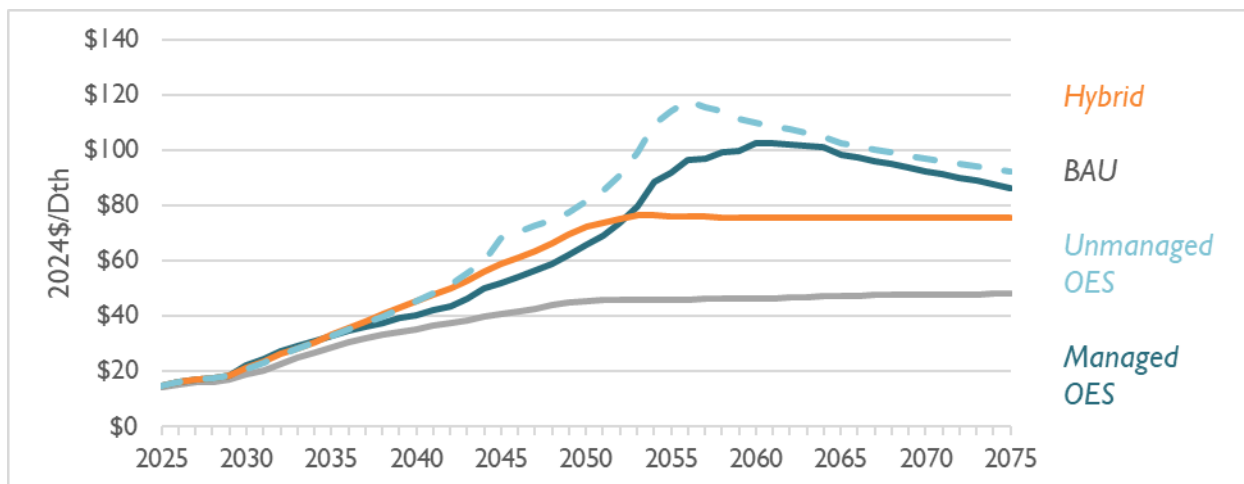


3.4. Bills and Rates

[Figure 20](#) shows average residential gas rates under each scenario. In all scenarios, customers who remain on the gas system are expected to face higher rates and pay higher annual gas bills. To estimate rate impacts, we divided the residential portion of NWN's revenue requirement and associated fuel costs by the volume of residential sales per year. In the BAU scenario, gas rates double by 2035 and more than triple by 2050, driven by modest customer declines and higher fuel supply costs due to RNG. Gas rates under the hybrid scenario increase five-fold by 2050 but remain relatively flat thereafter, as increased revenues are spread over a larger customer base. Gas rates under the Unmanaged OES case are the highest, increasing by a factor of six by 2050, as customers defect from the gas system without

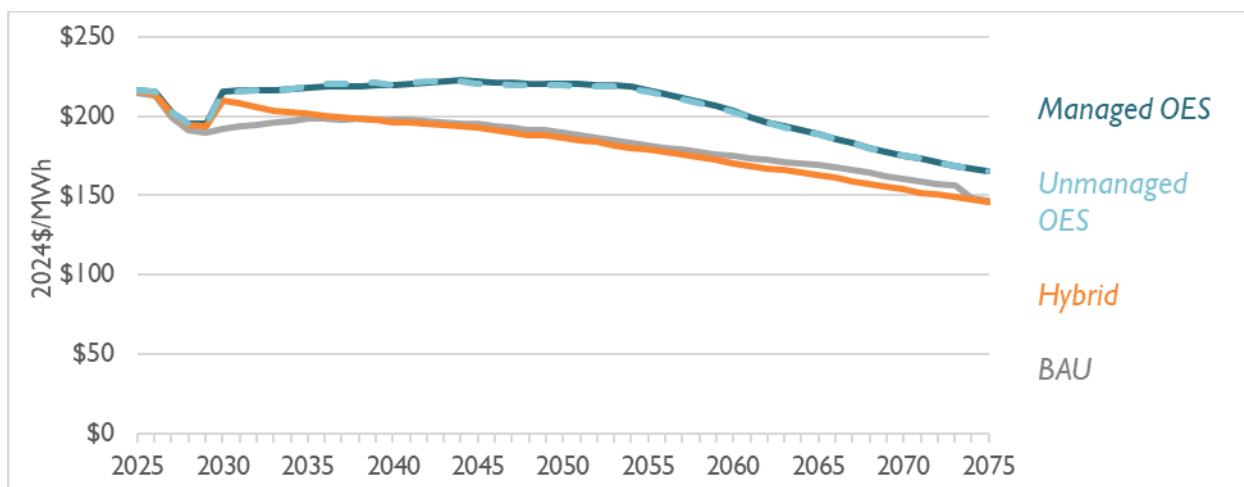
corresponding adjustments to gas system investments. The Managed OES case on the other hand mitigates some of those impacts.

Figure 20. Average residential gas rates, by scenario



[Figure 21](#) shows average electric rates across each scenario. In all scenarios, electric rates decrease by 2075, as more customers switch to using electricity to heat their homes.

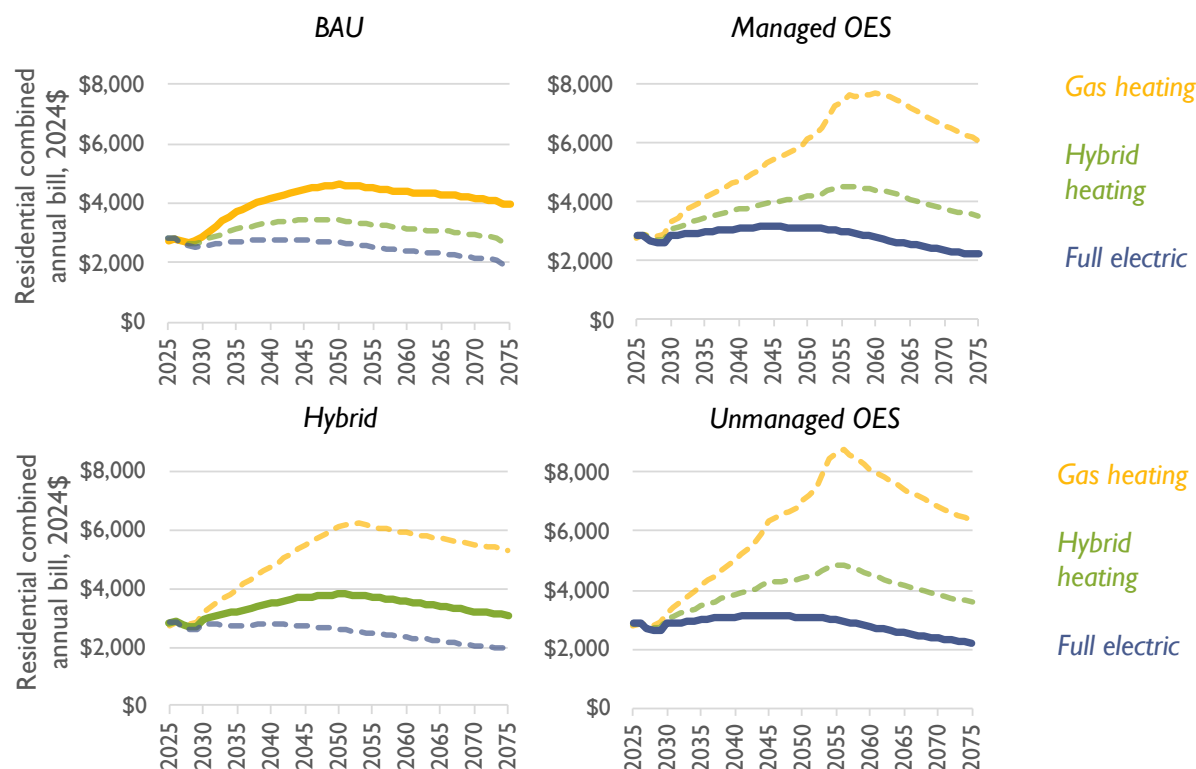
Figure 21. Average residential electric rates by scenario



[Figure 22](#) shows the combined residential energy wallet, i.e., total gas and electric bills across each scenario, for different customer types. Customers who continue to use gas for space and water heating consistently pay the highest bills across all scenarios. We find that all-electric households have the lowest total energy costs in all cases. [Figure 22](#) also identifies which household type is “supported” by the scenario, in bold, with the other household types in dotted lines. This highlights the internal inconsistency of a BAU or Hybrid future: customers who continue to use gas or hybrid heating systems

will pay more than households that switch to electricity, calling into question the validity of assuming customers will remain on the gas system.

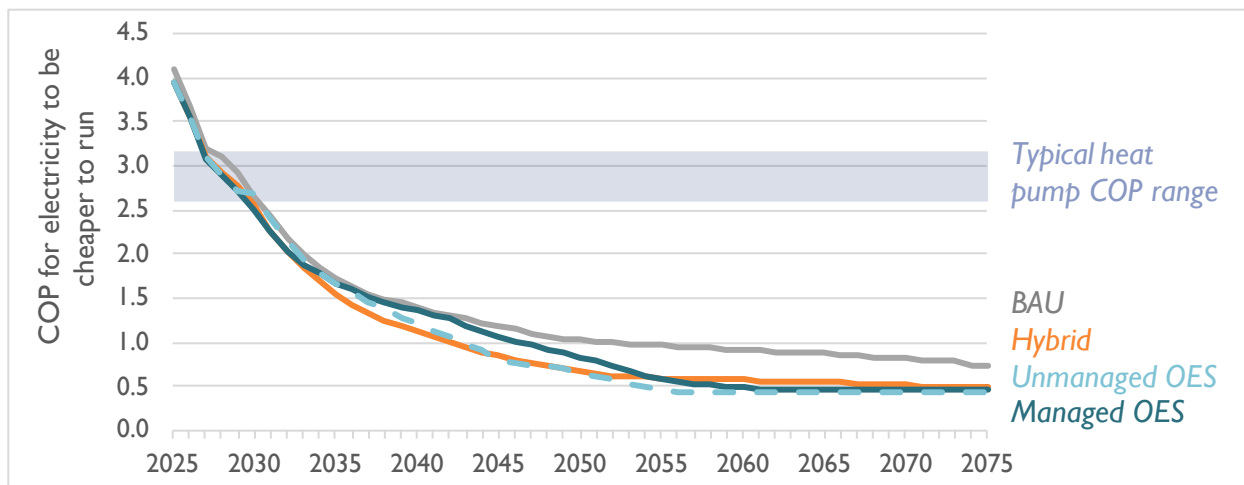
Figure 22. Combined residential annual energy bill for different household types, by scenario



The “spark gap” refers to the ratio between prices for electricity and for gas. [Figure 23](#) shows the residential spark gap by scenario. Accounting for the differences in efficiency between gas equipment⁶⁹ and heat pumps, we can see the coefficient of performance (COP) needed for a heat pump to be cheaper to heat a home than a gas furnace. Because heat pumps are nearly three times more efficient than standard gas furnaces, we find that under all scenarios, by 2030 it will be cheaper for households to heat with a heat pump rather than a gas furnace, and the operating cost advantage of efficient electric technologies grows rapidly in all cases.

⁶⁹ Assuming an average gas equipment efficiency, or AFUE, of 86 percent, which is the average single-family AFUE from NEEA’s 2022 Residential Building Stock Assessment. <https://neea.org/wp-content/uploads/2025/03/2022-Residential-Building-Stock-Assessment.pdf>

Figure 23. Residential spark gap by scenario



Notes: (1) Spark gap represents the ratio in average variable rates, excluding any fixed customer charges. (2) Average heat pump COP range based on average single-family efficiency for central and ductless mini-split heat pumps from NEEA's 2022 Residential Building Stock Assessment. <https://neea.org/wp-content/uploads/2025/03/2022-Residential-Building-Stock-Assessment.pdf>.

4. IMPLICATIONS & SUGGESTIONS FOR FURTHER RESEARCH

The scenarios analyzed in this report point to several implications for Oregon policymakers, regulators, utilities, and ratepayers as the state moves to meet its climate targets. Four themes emerge consistently from the results:

Failing to plan is expensive. The contrast between the Managed and Unmanaged OES scenarios is the clearest illustration of this point. Both scenarios assume the same level of customer electrification consistent with the OES Reference Case, and both achieve the same emissions outcomes. The difference is whether NWN and Oregon regulators act early to align gas system investment, depreciation, and retirement planning with the trajectory of customer departures. In the Managed case, NWN's revenue requirement is roughly half of the Unmanaged case by 2050, and residential gas rates are substantially lower throughout the study period. Customers who remain on the gas system the longest—disproportionately likely to be lower income, renters, and those without the means to electrify—bear the cost of failing to manage the transition.

This finding has implications for both gas and electric system planning. On the gas side, it suggests that regulators, utilities, and stakeholders should treat alignment with the OES pathway as the planning baseline rather than as an alternative scenario. They should evaluate proposed capital investments against the question of whether those assets will be needed and used through their full depreciable lives. Coordinated planning by electric and gas utilities is needed to ensure that the electric distribution system can accommodate the load growth associated with building electrification on a neighborhood-

by-neighborhood basis. Energy Trust of Oregon’s (or other implementers’) program portfolio and funding levels should likewise be calibrated to the level of electrification needed to follow the OES pathway.

Avoiding gas system rebuild makes electrification more cost-effective. A central driver of the cost savings in the Managed OES case is the avoidance of capital expenditure on assets that would otherwise be replaced over the coming decades. As customers electrify and clusters of mains can be retired rather than replaced, the gas utility’s forward capital plan shrinks substantially. These avoided costs in turn create room within the combined energy system to fund the incentives that drive customer electrification as well as the resulting electric system upgrades. If Energy Trust of Oregon (or other program) were authorized to explicitly fund customer electrification, the gas-side savings in the Managed case would more than justify deploying both gas and electric ratepayer funds toward this purpose. The combined NPVRR results indicate that ratepayers as a whole are better off when ratepayer-funded programs accelerate the transition, even after accounting for incentive program and grid upgrade costs.

Full electrification is lower cost and carries less risk. The combined NPVRR of the Hybrid scenario is within a few percent of the Managed OES scenario, and a casual reading of those numbers might suggest the two approaches are roughly interchangeable. They are not. The Hybrid approach commits to reinvesting in the gas system, amplifying stranded cost risk. The Hybrid case, like the BAU case, also depends on very large quantities of RNG—far more than Oregon’s RNG production potential under an optimistic scenario developed by a gas industry study. Meeting the CPP through RNG at the volumes assumed in the Hybrid and BAU cases would therefore require substantial imports of RNG from outside Oregon, at costs that may exceed the \$30 per MMBtu assumed here or would require finding additional emission reductions in other sectors of the economy. The Managed OES case, by contrast, achieves CPP compliance primarily through demand reductions, leaving a residual RNG need that is within Oregon’s estimated in-state production potential. Electrification on the OES trajectory is therefore not just comparable in cost to a hybrid approach—it is materially less exposed to RNG supply and price risk, and to the risk that emission reductions in other sectors prove harder than assumed.

Cost allocation matters. The scenarios in this report assume that incentive program costs are recovered through a combination of CCI pass-through and securitization, with securitized costs initially borne by gas ratepayers and gradually shifted to electric ratepayers as the customer base transitions. Securitization meaningfully reduces the near-term rate impact of program costs and is a useful tool for managing the transition, but it does so by extending the recovery period over 30 years and shifting some costs onto future ratepayers who may not have directly benefited from the original investment. Different cost allocation approaches—including alternative splits between gas and electric ratepayers for both programmatic and core utility system costs, the use of state appropriations, or the inclusion of non-ratepayer funding sources—would produce different distributional outcomes and would warrant additional analysis before implementation. The choice of cost recovery mechanism is fundamentally a policy question, not a modeling question, and policymakers should engage with it explicitly rather than defaulting to existing recovery mechanisms.

4.1. Suggestions for Further Research

This analysis focuses on system-level costs and revenue requirements under stylized scenarios. Several questions remain that would benefit from additional research, particularly as Oregon moves from scenario analysis toward implementation. The Public Utility Commission should lead this research, with the active participation of the gas and electric utilities which have the necessary system-level information, as well as stakeholder groups which bring customer-level perspectives. These areas require joint and coordinated action by electric and gas utilities; the Commission can provide the centralizing force that make this possible.

Rate design and customer-level impacts. This report presents average residential gas and electric rates and combined energy bills for stylized household types, but actual customer impacts depend heavily on rate design, including the balance between volumetric and fixed charges, the structure of time-varying rates, and the treatment of low-income customers. Rate design for both gas and electric service should be aligned with the state’s preferred transition pathway: gas rate design should not inadvertently make it harder for low-income customers to depart a shrinking system, and electric rate design should reflect the load shapes and volumes associated with high heat pump penetration. Detailed rate design and customer impact analysis, including distributional analysis across income groups and housing types, would be a valuable next step.

Gas system retirement logistics. A managed transition requires gas utilities to develop concrete operational plans for retiring portions of their distribution systems: which mains and services to retire first, how to sequence retirements with customer conversions, how to coordinate with municipal street and utility work, and how to manage the safety and reliability of the remaining system as it shrinks. These are detailed planning questions that the GRM does not address. Development of these detailed plans can start with learning from non-pipeline alternatives, such as the Targeted Voluntary Electrification pilot that Avista is implementing as a product of its most recent rate case.⁷⁰

Power sector modeling. The electric supply costs in this analysis are drawn from the EIA AEO and from PGE’s planning materials, with adjustments for incremental capacity needs in higher-peak scenarios. A more detailed power sector model—coordinated with the Northwest Power and Conservation Council’s planning process and utility IRPs—would allow for more precise estimates of generation, transmission, and capacity investment needs under different building electrification trajectories, and would help identify the resource mix and timing best suited to a transitioning gas system.

Electric T&D upgrade needs at the neighborhood level. This analysis treats incremental transmission and distribution costs as a scaled average. In practice, the localized impacts of electrification on distribution feeders, substations, and service drops will vary considerably across the state. Neighborhood-level analysis, coordinated with the gas system retirement plan, would help identify

⁷⁰ Public Utility Commission of Oregon. May 23, 2025. *Order No. 25-198. Disposition: Stipulation Adopted.* <https://apps.puc.state.or.us/orders/2025ords/25-198.pdf>.

locations where targeted electric system upgrades are needed and locations where coordinated gas retirement and electric upgrade timing could reduce total costs.

