# NW Natural's 2025 Draft Integrated Resource Plan

# Flight 1: Chapters 2, 4-8, 12

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# Abbreviations and Glossary

This section is provided to ensure clarity and accessibility of the document for the reader. Industry and technical specific terms used throughout the document are defined. Abbreviations and acronyms used throughout the document are additionally provided to ensure readers have a consistent reference point.

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| AECO | Alberta Energy Company |
| AEG | Applied Energy Group |
| AGA | American Gas Association |
| AIC | Akaike information criterion |
| AMA | Asset Management Agreement |
| AMI | Area median income |
| ARIMA | Autoregressive integrated moving average |
| AWEC | Alliance of Western Energy Consumers |
| Baseload demand | Refers to utility customer demand that is constant over the year |
| Bcf | A billion cubic feet |
| BIAW | Building Industry Association of Washington |
| Biogas | Gaseous fuel, especially methane, produced by fermentation of organic matter |
| Biomethane | A naturally occurring gas which is produced by anaerobic digestion of organic matter such as dead animal or plant material, manure, sewage, organic waste, etc. |
| Boiler | A large furnace in which water-filled tubes are heated to produce steam |
| Book and Claim Accounting | A chain of custody model which recognizes that environmental attributes (e.g., RTCs) can be separated from physical product and |

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| | possession of environmental attribute can be used to deliver sustainable product |
| Brown Gas | The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included |
| Btu | British thermal unit, a unit of measurement for heat or energy equivalent to the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit |
| Bundled RNG | RNG including the physical gas molecules and renewable thermal certificate (RTC) |
| CAGR | Compound Annual Growth Rate |
| Capacity | The maximum load that a gas pipeline or gas storage facility can carry under existing service conditions |
| Cap-and-Invest Program | Section of Washington's CCA, regulated by the Department of Ecology, which sets emissions caps, allowances, and trading mechanisms |
| Carbon cap | A limit on the amount of allowable carbon produced in a given region for a defined time period |
| Carbon Cap and Trade | A market mechanism to limit carbon emissions. Carbon emissions are capped at a certain level. Allowances are provided to companies and these allowances can be traded. The market sets the price of the allowances, creating a market incentive to reduce carbon emissions |
| Carbon credits or allowances | A fixed amount of carbon emissions to be produced is set for a period of time, and allowances or credits are allocated to carbon generators. The idea is that entities producing less carbon than their allowed amount can sell their allowances to other parties who are |

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| | producing more than their allowed credit allowance. Often these can be traded or re-sold |
| CCA | Washington Climate Commitment Act |
| CCA allowances | A Cap-and-Invest Program mechanism for covered entities to obtain such allowances to cover emissions not reduced within a particular compliance period |
| CCI | Community Climate Investment |
| CCI credit | "an instrument issued by DEQ to track a covered fuel supplier's payment of community climate investment funds, and which may be used in lieu of a compliance instrument, as further provided and limited in this division." OAR 340-271-0020 |
| CD | Contract Demand |
| CEAG | Community and Equity Advisory Group |
| CELS | Community Engagement Liaison Services |
| CHP | Combined Heat and Power |
| CIS | Customer Information System |
| Citygate | The point of delivery at which a local gas distribution company takes custody of gas from an interstate pipeline; Meter stations which serve as designated point(s) on a distribution system where the distributor takes delivery of its gas supply from a pipeline source |
| Class B (pipeline system) | A pipeline system operating at 60 psig or less |
| CMM | Customer Management Module |
| CNG | Compressed natural gas |
| $CO_2$ | Carbon dioxide |
| $CO_2e$ | Carbon dioxide equivalent |

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| Cogeneration | The use of a single prime fuel source to generate both electrical and thermal energy in order to optimize the efficiency of the fuel used. Usually, the dominant demand is for thermal energy, with any excess electrical energy being transmitted into the lines of local power supply company |
| Common Carrier Pipeline | A pipeline that is connected to the continent-wide natural gas pipeline grid |
| Compliance obligation | "Total quantity of covered emissions from a covered fuel supplier rounded to the nearest metric ton of $CO_2e$." OAR 340-271-0020 |
| Compliance resource | A tool used to comply with carbon regulations. These can include program specific credits/instruments, offsets, renewable fuels, energy efficiency, and carbon capture depending on the specific requirements of each regulatory program. |
| Conservation Potential Assessment (CPA) | Analysis preformed to provide an outlook on the potential amount of energy efficiency or energy conservation that is available within a given area or territory over a defined period of time. |
| Conversion | An existing residential or commercial building which adds natural gas service to the building and becomes a new NW Natural customer |
| CPI | Consumer Price Index |
| CPP | Oregon Climate Protection Program |
| CSN | Community Services Network |
| CUB | Oregon Citizens' Utility Board |

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| Curtailment | A method to balance natural gas requirements with available supply. Usually there is a hierarchy of customers for the curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and a customer's position in the hierarchy |
| Degree day | The number of degrees that the average outdoor temperature falls below or exceeds a base value in a given period of time |
| Demand-side resource | An energy resource such as conservation that is based on how energy is used, not produced |
| DEQ | Department of Environmental Quality |
| DERMS | Distributed energy resource management system |
| Deterministic | A defined set of properties, constraints, or equations that explicitly defines the relationship between variables; deterministic solutions provide a single outcome; contrast with stochastic |
| DR | Demand response; reducing peak demand by either shifting or interrupting load |
| DSM | Demand-side management |
| Dth | Dekatherm (or dekatherm), equal to ten therms or one MMBtu |
| Discount rate | An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value |
| Distribution/Distribution System | The pipeline system that transports gas from interstate pipelines to customers. |

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| EBA | Energy Burden Assessment |
| Ecology | Shorten form of Washington Department of Ecology. Ecology is the agency that administers Washington’s Climate Commitment Act (CCA). |
| EE | Energy Efficiency; EE is a reduction in energy use, production, or distribution as a result of greater efficiency |
| EIA | U.S. Energy Information Administration |
| EITE | Emissions intensive trade exposed |
| EM&V | Evaluation, Measurement, and Verification |
| Energy savings | A term used to define the reduced energy usage as a result of energy efficiency initiatives |
| End-use consumer | Someone who uses energy to run equipment or appliances, such as for space heating and cooling, ventilation, refrigeration, and lighting |
| Entitlement | An event during which gas shippers must not take delivery of more than a specified volume of gas in a day |
| EPA | Environmental Protection Agency |
| EPCA | Energy Policy and Conservation Act |
| EPPR | Electronic Portable Pressure Recorder |
| EPRI | Electric Power Research Institute |
| ERU | Emission Reduction Unit |
| ETO | Energy Trust of Oregon |
| Exogenous (variable) | A variable that is independent or determined outside of the model |
| FERC | Federal Energy Regulatory Commission |

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| Firm (Sales, Service, Customers) | Service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. |
| GAP; GASP | Gas Acquisition Plan; Gas Acquisition Strategy and Policies |
| Gasco | NW Natural's Portland LNG plant |
| Gas Day | A period of twenty-four consecutive hours, coextensive with a "gas day" as defined in the tariff of the Transporter delivering Gas to the Delivery Point in a particular transaction |
| GCM | Global Climate Model |
| GDP | Gross Domestic Product |
| GeoDR | Geographically Targeted Demand Response |
| GeoDSM | Geographically Targeted Demand Side Management |
| GeoRNG | Geographically Targeted Renewable Natural Gas |
| GeoTEE | Geographically Targeted Energy Efficiency |
| GIS | Geographical information system |
| GHG | Greenhouse gas |
| GHP | Gas heat pump or Gas-fired heat pump |
| GSHP | Ground source heat pump |
| GTI | Gas Technology Institute or GTI Energy |
| HDD | Heating degree day |
| Hedging | Any method of minimizing the risk of price change |

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| Henry Hub | A natural gas national trading hub typically used for referencing national natural gas prices |
| HVAC | Heating, Ventilation, and Air Conditioning |
| ICF | A global advisory and technology services consultant |
| Incremental costs | Additional costs that a utility would incur by operating a power plant, the cost of the next MMBtu generated or purchased, or the cost of producing and/or transporting the next available unit of energy above the current base cost previously determined |
| Interstate pipeline | Pipelines owned and operated by pipeline companies, where third-party shippers contract for firm and interruptible capacity |
| Interruptible (service, i.e., Sales or Transportation and also customers(s) of such service) | A transportation service similar to firm service in operation, but a lower priority for scheduling, subject to interruption if capacity is required for firm service. Interruptible customers trade the risk of occasional and temporary supply interruptions in return for a lower service rate. |
| IPCC | Intergovernmental Panel on Climate Change |
| IRP | Integrated Resource Plan |
| Jackson Prairie | A gas storage facility near Centralia, Washington, contracted by NW Natural |
| LDC | Local Distribution Company |
| Least-cost planning | Method of meeting future energy needs by acquiring the lowest cost resources first, considering all possible means of meeting energy needs and all resource costs including construction, operation, transmission, distribution, fuel, waste disposal, end-of-cycle, consumer, and environmental costs |

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| Levelized (cost) | Equal periodic cost where the present value is equivalent to that of an unequal stream of periodic costs (typically expressed as a periodic rate; e.g., levelized cost per year) |
| LINA | Low Income Needs Assessment |
| LNG | Liquefied Natural Gas |
| Load | The demand for energy/power averaged over a specific time period |
| Load center | Geographical service area or collection of areas defined by NW Natural |
| Load factor | Ratio of total energy (example: therms) used in a period divided by the possible total energy used within the period, if used at the peak demand during the entire period |
| MAOP | Maximum allowable operating pressure |
| MAPE | Mean absolute percentage error |
| Marginal cost | The cost of producing the marginal, or next, unit |
| MBtu | Thousand British thermal units |
| MBtu/day | Thousand British thermal units per day |
| Mcf | Thousand cubic feet |
| MDDO | Maximum daily delivery obligation |
| MDT | Thousand dekatherms |
| MFA | Maul, Foster, and Alongi |
| MMBtu | Million British thermal units |
| MMBtu/day | Million British thermal units per day |
| MMcf | Million cubic feet |
| MMDT | Million dekatherms |

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| MPH (or mph) | Velocity in miles per hour |
| MSA | Metropolitan Statistical Area: a geographical area as defined by the U.S. Office of Management and Budget (OMB) |
| M-RETS | Midwest Renewable Energy Tracking System, an environmental attribute tracking platform |
| $MTCO_2e$ (or MT) | A metric ton (tonne) of carbon dioxide equivalent |
| Monte Carlo (simulation, analysis) | Statistical methods based on repeated sampling to simulate probability-based outcomes |
| Moving average | A statistical average calculated over a rolling period in time series data |
| NEEA | Northwest Energy Efficiency Alliance |
| New Construction | Newly constructed residential or commercial building with natural gas service which become a new NW Natural customer |
| NGL | Natural gas liquids |
| Nominations | The process of scheduling gas on the interstate pipeline. The shipper notifies the pipeline the volume and receipt point and the delivering receipt point in accordance with the transportation contract |
| Normal distribution | Commonly used probability distribution in statistical analysis |
| Normal weather | Expected weather conditions based on observed historical data |
| NPVRR (also PVRR) | Net present value revenue requirement |
| NREL | National Renewable Energy Lab |
| NWEC | NW Energy Coalition |

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| NWGA | Northwest Gas Association |
| NWPCC | Northwest Power and Conservation Council |
| NWPL | Northwest Pipeline |
| ODOE | Oregon Department of Energy |
| OEA | State of Oregon’s Office of Economic Analysis |
| Off-peak | Refers to a period of relatively low demand on a natural gas system. This can also refer to low demand months. |
| OFO | Operational flow orders |
| OLIEE | Oregon Low Income Energy Efficiency |
| OPUC | Public Utility Commission of Oregon |
| ORSC | Oregon Residential Specialty Code |
| OSP | Open Solicitation Program |
| Outage | A period, scheduled or unexpected, during which the transmission of power stops or a particular power-producing facility ceases to provide generation |
| Peak (day, hour) | A period in which a maximum value of a process (e.g., gas demand) occurs or is expected to occur |
| Peak day shaving | A peak day is the one day (24 hours) of maximum system deliveries of gas during a year. Peak shaving is a load management technique where supplemental supplies, such as LNG or storage gas, are used to accommodate seasonal periods of peak customer demand. |
| PEW | Public Engagement Webinar |
| PGA | Purchased Gas Adjustment |
| Planning Horizon | The timeframe which the IRP evaluates the net present value costs and outcomes for resource |

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| | decisions. For this IRP the planning horizon is 2025-2050. |
| PLEXOS® | Optimization modeling software used by NW Natural |
| Power-to-Gas (P2G) | A power-to-gas system uses electricity to split water into hydrogen and oxygen through electrolysis |
| PSIG | Pounds per square inch gauge, unit of pressure measurement |
| PST | Pacific Standard Time |
| Public Counsel | The Public Counsel Unit of the Washington State Attorney General's Office represents residential and small business interests in utility proceedings before the Washington Utilities and Transportation Commission (UTC). |
| PVRR (also NPVRR) | Present value of revenue requirement |
| REC | Renewable energy certificate |
| Reference Case | An analytical scenario (e.g., forecast scenario) to which other scenarios are compared |
| RFP | Request for proposal |
| RIN | Renewable identification number |
| RNG | Renewable natural gas. “RNG” is gas that satisfies the definition of “renewable natural gas” or “renewable hydrogen” in either Oregon or Washington.<br><br>**Oregon definition per ORS 757.392(7)**: “Renewable natural gas” means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived |

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| | from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or c. Waste carbon dioxide.<br><br>**Washington definitions per RCW 54.04.190(6):**<br><br>"Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters.<br><br>"Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process. |
| ROW | Right of way |
| RPS | Renewable Portfolio Standards |
| RTC | Renewable thermal certificate<br><br>An RTC is a *sole* claim to the environmental benefits of a dekatherm of RNG, separate from the physical gas of RNG (i.e., unbundled RNG) |
| RTF | Regional Technical Forums |
| Sales (service, customers) | Service provided whereby NW Natural acquires gas supply and delivers it to customers |
| SBCC | The State Building Code Council (in Washington) |
| SCADA (system) | Supervisory Control and Data Acquisition |
| SME | Subject Matter Expert |
| SMI | State Median Income |
| SOW | Scope of Work |
| Stochastic | The property of being randomly distributed or including a random component; a stochastic |

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| | variable often feeds into a forecast, property or constraint providing a range of outcomes; contrasts with deterministic |
| Supply-side resource | Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options. |
| Synergi™ Gas | A computer-based model used to simulate the physical natural gas system |
| Synthetic Methane | A renewable gas produced by capturing carbon dioxide (CO2) and combining it with green hydrogen |
| T-DSM | Targeted demand-side management |
| TF-1 | Northwest Pipeline's rate schedule designation for firm, year-round transportation service on its system |
| TF-2 | Northwest Pipeline's rate schedule designation for firm transportation service on its system from certain storage facilities (e.g., Jackson Prairie). TF-2 service may have the same scheduling priority as, or may be subordinate/secondary in priority to, TF-1 service. |
| Therm | Unit of heat or energy measurement: 1 Therm = 29.3 KWh = 100,000Btu |
| Transportation (service, customers) | Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility |
| TRC | Total Resource Cost |
| TWG | Technical Working Group |
| UCT | Utility Cost Test |
| UES | Unit Energy Savings |

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| UPC | Use per customer |
| WACOG | Weighted average cost of gas |
| WALIEE | Washington Low Income Energy Efficiency |
| Weatherization | The use of structural changes, such as storm windows and insulation, in order to decrease use of heating fuel |
| Weather normalization | A method of averaging energy use under normal conditions. Also known as weather corrected, normalization enables comparison of energy use across periods of time or geography |
| WEC | Waste emissions charge |
| WSEC | Washington State Energy Code |
| WUTC | Washington Utilities & Transportation Commission |

# Chapter 2 - Planning Environment

Environmental policy, economic conditions, and market forces are the backdrop that helps define key assumptions and objectives in an IRP. Chapter 2 lays out this planning environment.

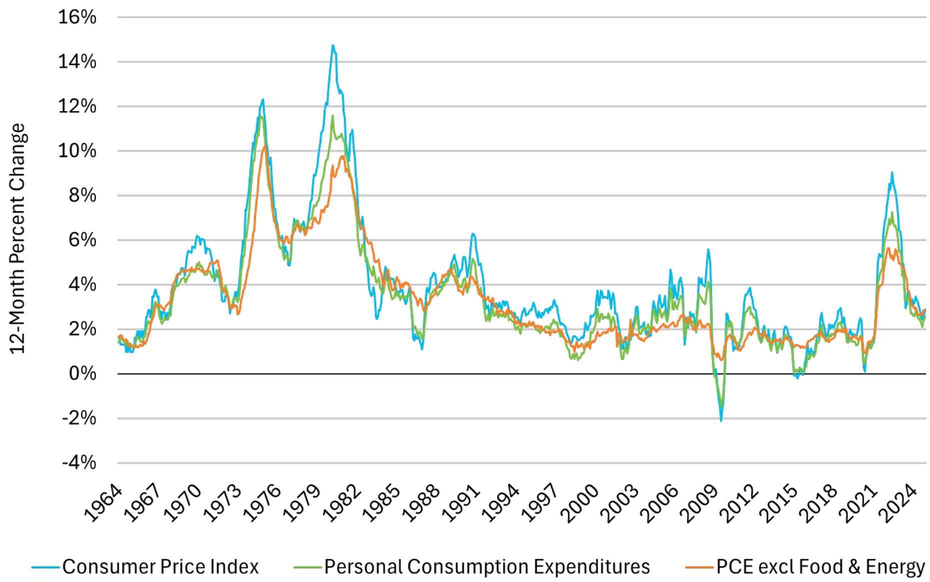
## 2.1 Economic and Demographic Trends

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

### 2.1.1 U.S. Macroeconomic Outlook

Inflation, uncertainty, and slower growth pose challenges for the U.S. economy in 2025. After the highest inflation seen in the U.S. since 1981, inflation moderated considerably in 2023 and 2024 and was down to about 3 percent by the end of 2024. The Federal Reserve (the Fed) increased interest rates significantly over the past two years to reduce inflation, which was largely successful, and proceeded to cut rates in the fourth quarter of 2024 to add a little bit of fuel to a slowing economy as inflation continued to cool. But inflation has been sticky around 3 percent and remains above the Fed's target rate of 2 percent. U.S. real GDP growth was 2.8 percent in 2024, down from 2.9 percent in 2023. Growth slowed at the end of 2024 (2.4 percent Q4) and the Fed is forecasting lower growth in 2025 (1.7 percent). With expectations that the U.S. economy further slows in 2025, the Fed finds itself in a difficult position where rate cuts could help the economy, but accelerate inflation, while rate increases could lower inflation but further slow the economy.

*Figure 2.1: Inflation Down from 40-Year High*




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

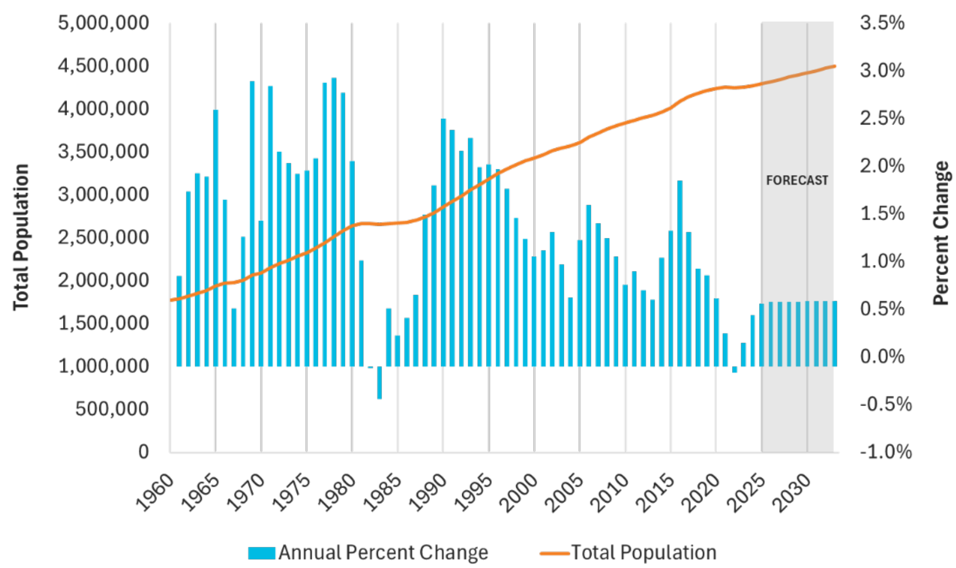
The labor market remains strong with unemployment hovering around 4 percent at the end of 2024 and employment continues to grow, but unemployment is higher than it was a year ago, and employment growth has slowed as well. Consumer spending remains strong and, together with government spending, fueled GDP growth in 2024, but that is expected to change in 2025 as the boost to the economy provided by massive deficit spending in the wake of COVID-19 and expansionary monetary policy (which helped fuel high inflation), is coming to an end. State and local governments will also be impacted by reduced federal spending as they received the bulk of pandemic related federal dollars and will need to pull back spending as well. Private sector investment and employment slowed in 2024, with employment growth down to 1.1 percent in 2024 from 2.1 percent in 2023. Manufacturing lost jobs in 2024 for the first time since 2020, dropping 0.4 percent.

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

### 2.1.2 Regional Macroeconomic Outlook

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

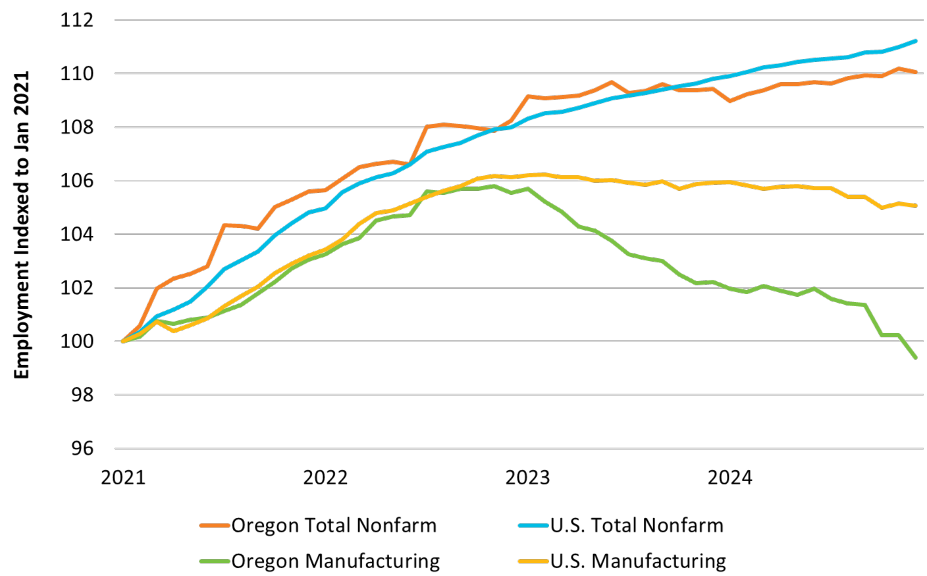
*Figure 2.2: Oregon Population Growth Much Lower*




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

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

*Figure 2.3: Oregon Manufacturing in Recession*




*Source: U.S. Bureau of Labor Statistics.*

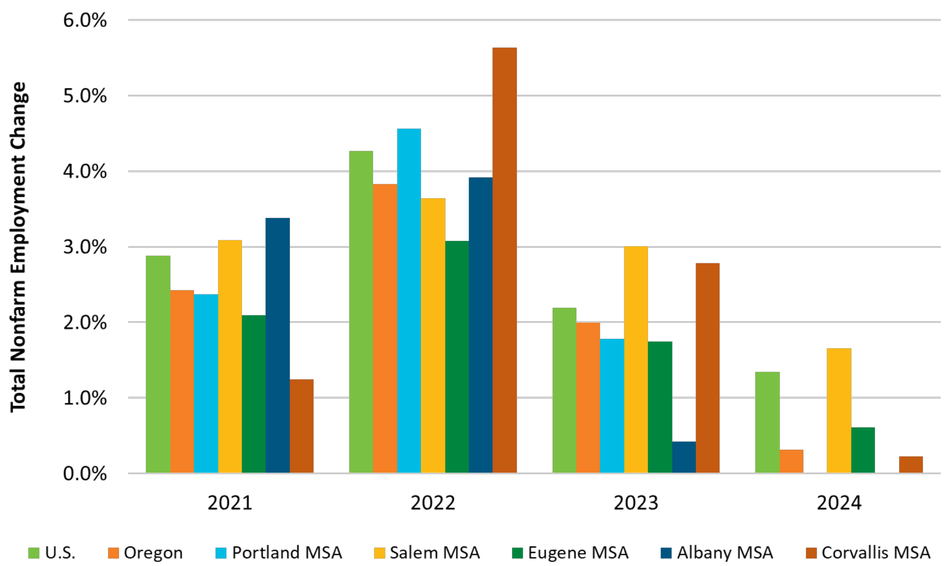
Affordability, particularly housing affordability, continues to be an issue in the region. While home prices remain high, home sales have slowed dramatically due to higher mortgage rates and homeowners that locked-in historically low rates between 2020 and 2022. Residential construction appears to not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

### 2.1.3 NW Natural System Area Macroeconomic Outlook

The macroeconomic outlook in NW Natural's system area varies, but overall, trends are lower than they were pre-pandemic. Multnomah County, the most populous county in the service territory saw population decline by an annual rate of -0.6 percent between 2020 and 2024 – a loss of over 20,000 residents. Elsewhere in the Portland metro area, Washington and Clackamas counties saw annual growth of 0.4 and 0.2 percent. In stark contrast to slow or declining population in the Oregon portion of the Portland metro area, Clark County in Washington had annual growth of 1.1 percent. While Clark County has historically enjoyed a growth advantage over the Portland metro counties in Oregon, the difference has widened post-pandemic due in part to better affordability, no state income taxes for remote workers, and the aforementioned issues around homelessness, drug use, and mental health and public safety concerns in Portland. In other parts of the system area, population growth ranged from 1.4 percent in Benton County, 0.5 percent in Marion County, and -0.1 percent in Lane County. Slower population growth throughout the system area will, all things equal, lead to lower growth for utilities as well.

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

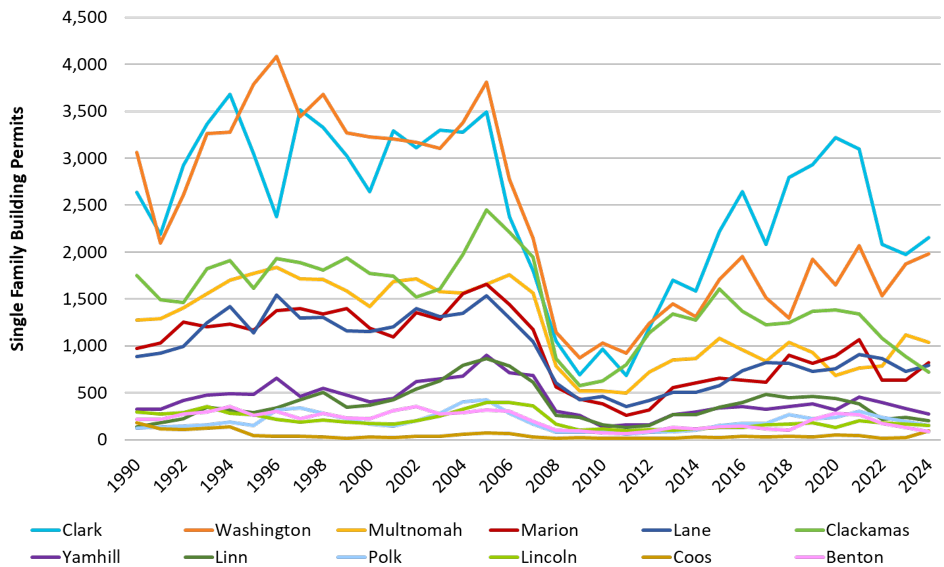
*Figure 2.4: Employment Slowing Across System Area*




*Source: U.S. Bureau of Labor Statistics.*

Building permit data across the system area looks similar to statewide trends in Oregon, with fewer homes being built. The top counties for single-family building permits in the system area (Figure 2.5) continue to experience much lower growth than they did in the two decades preceding the Great Recession, and lower growth than the decade preceding the pandemic. Clark and Washington counties continue to be the top producing areas for single-family permits. Clark County experienced a large increase in permits between 2011 and 2021, eclipsing 3,200 in 2020 for the first time since 2005, but has since cooled. Clackamas, the third highest producing county until 2022, saw permits decline precipitously over the past two years and produced less single-family permits in 2024 than Marion and Lane counties for first time since the time series began (1990).

*Figure 2.5: Building Permits Trending Lower in System Area*



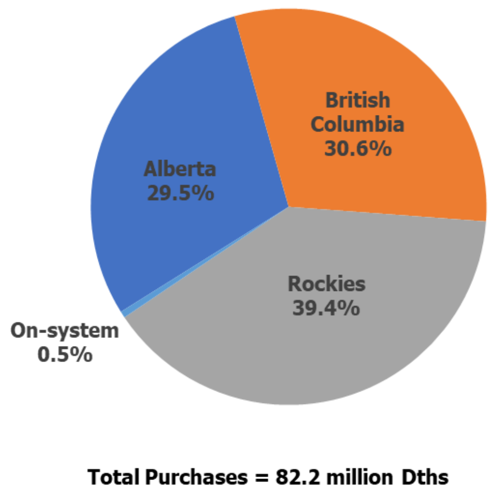

*Source: U.S. Census Bureau.*

## 2.2 Gas Price Forecast

### 2.2.1 Natural Gas Supply Sources

NW Natural purchases natural gas on behalf of all sales customers. Purchasing natural gas from producers located in Canada or the Western U.S. requires the corresponding interstate/interprovincial pipeline capacity rights to ship the gas from the location of production to our service territory. NW Natural, as customer of the interstate/interprovincial pipeline companies, holds capacity contracts that allow us to ship natural gas that is purchased from out-of-state production basins and deliver it to NW Natural's service territory. NW Natural's current upstream pipeline capacity contracts allow us to access and buy Canadian natural gas, which is shipped south from British Columbia and Alberta, and natural gas coming out of the Rockies, primarily in Wyoming and Colorado. In 2024, these contracts enabled us to purchase roughly 39 percent of our supplies from Rockies, 30 percent from Alberta and 31 percent from British Columbia (See Figure 2.6). Looking forward, gas from RNG sources, either with or without environmental attributes, will become a larger share of the Company's supply purchases.

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




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

## 2.2.2 Natural Gas Price Forecast

NW Natural subscribes to a gas market fundamentals forecasting service through a third-party, S&P Global[1]. S&P Global implements a nation-wide supply and demand fundamentals model for the natural gas sector. Using this model, S&P Global publishes monthly long-term gas price forecasts for numerous natural gas hubs throughout the U.S. and Canada. NW Natural focuses on the four natural gas hubs where the Company purchases gas: AECO, Opal (i.e., Rockies), Sumas and West Coast Station 2. NW Natural uses the S&P Global long-term forecast and market forward prices to develop a monthly forecast to be used in the IRP. Forward prices are blended into the S&P Global forecast for the first 6 years at a decreasing rate. This blending allows for even more accurate forecasting, as NW Natural's Gas Supply team uses forward prices to develop their hedging strategy and represent prices that are currently available in the market. The IRP uses this blended gas price forecast, as seen in Figure 2.7, as the expected gas price for the four natural gas price hubs.

[1] Previously IHS Markit.

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

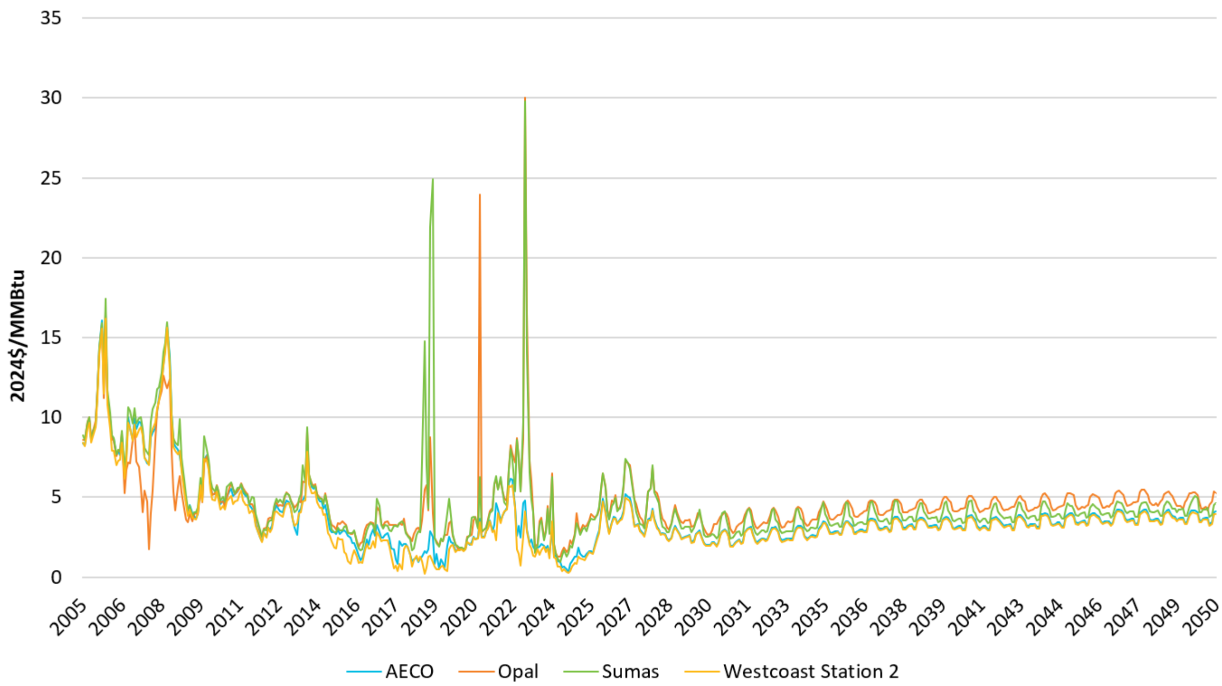
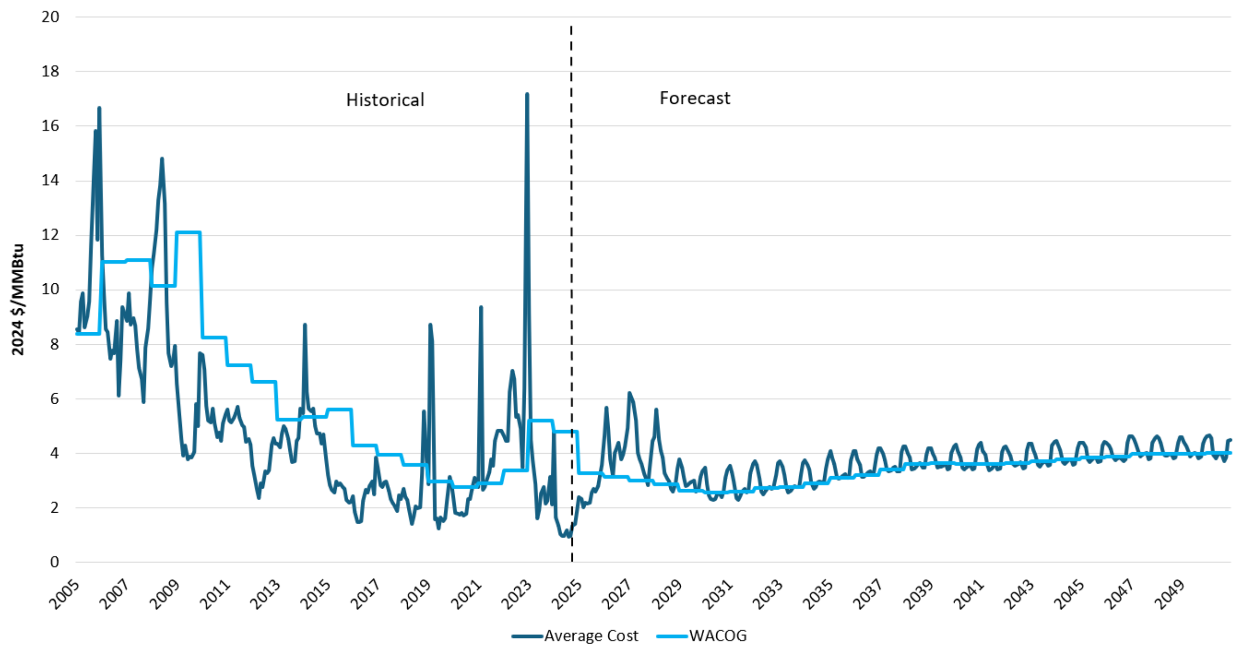



Figure 2.8 shows the historical average gas price, the historical weighted average cost of gas (WACOG), and the forecasted WACOG over the planning horizon. The range of the forecasted WACOG is determined through the monte carlo analysis discussed in the next section. The WACOG includes fuel and variable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

*Figure 2.8: Average Natural Gas Cost vs. WACOG*




## 2.2.3 Current Conditions

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

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

U.S. LNG feedgas averaged 16.4 Bcf/d in April 2025, a record. May volumes are unlikely to continue the recent trend, however, as maintenance at Cameron LNG and fluctuations at Corpus Christi LNG have led to a 0.9 Bcf/d month-over-month decline in feedgas through May

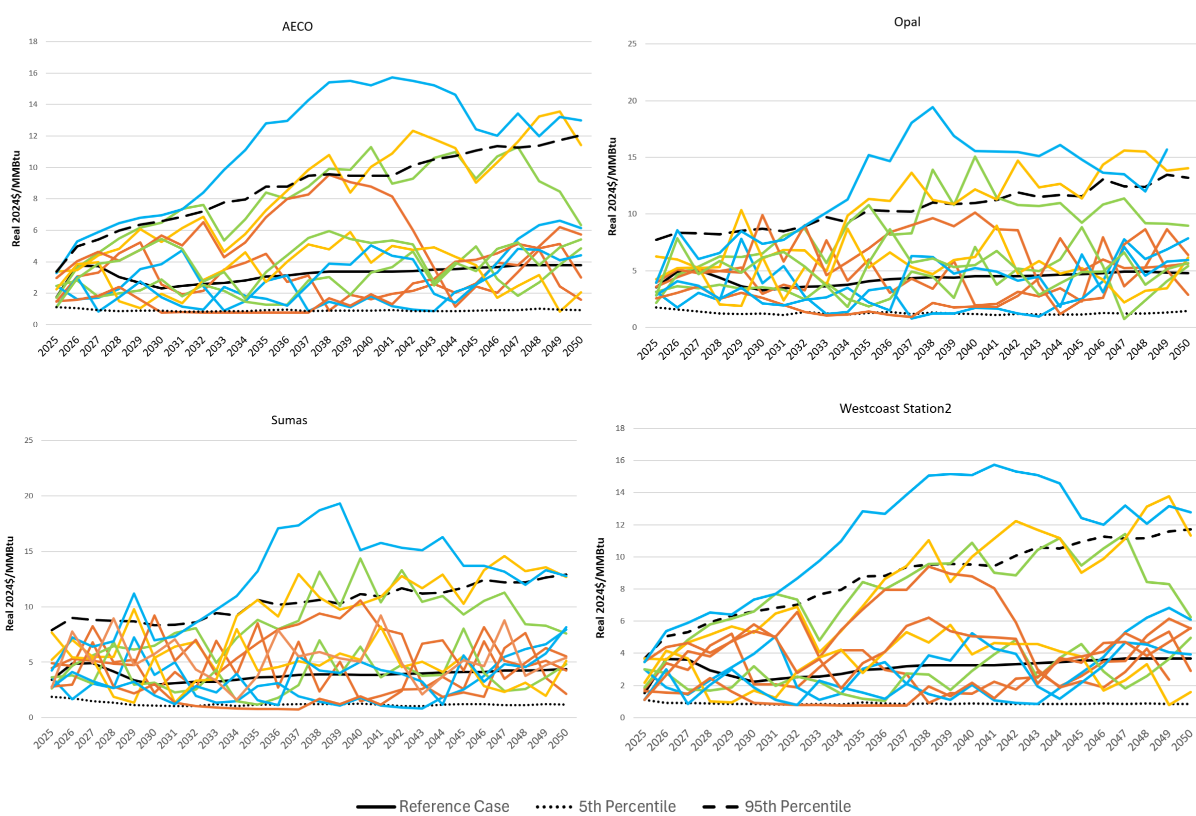
15. Further impacting summer 2025 LNG feedgas volumes, Cheniere Energy Inc. announced major maintenance at Sabine Pass LNG Trains 3-4 to commence later this quarter. In June 2023, a similar takedown of Sabine Pass LNG Trains 1-2 resulted in a 1.5-Bcf/d decline in U.S. Lower 48 feedgas month over month.

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

## 2.2.4 Gas Price Uncertainty

NW Natural uses a Monte Carlo simulation to address gas price uncertainty. NW Natural conducts a Monte Carlo simulation of natural gas prices using historical data in combination with the long-term natural gas prices forecast outlined above to simulate daily natural gas prices. This simulation provides insight into the range of potential short-term and long-term gas prices. Each simulation uses historical prices at each hub (AECO, Opal, Sumas, and Westcoast Station 2) from 2010 through 2024 to capture cross hub correlation, and incorporates potential price spikes. The simulation yields annual average prices at each of the four basins.

*Figure 2.9: Monte Carlo Annual Average Prices*



Further details regarding the gas price forecast and Monte Carlo can be found in Appendix G.1.

## 2.3 Renewable Natural Gas Markets

Policies that promote Renewable Natural Gas (RNG) adoption in the U.S. have traditionally prioritized its use in the transportation sector by offering financial incentives for RNG (and other biofuels blended with gasoline or diesel) for conventional road use. Examples include the United States Environmental Protection Agency's Renewable Fuel Standard, the California Low Carbon Fuel Standard, and the Oregon Clean Fuels Program. Such financial incentives have allowed RNG to capture a substantial 79 percent market share in the natural gas vehicle transportation sector as of 2023[2]. However, state policies are increasingly supporting the use of RNG for heat and power generation.

The U.S. RNG market is experiencing rapid expansion, fueled by rising renewable energy targets and environmental regulations. Since the first RNG facility was established in 1982, the industry in North America has grown swiftly, averaging about 50 new projects per year from 2019 to 2023. As illustrated in Figure 2.10, by December 2024, there were 474 operational facilities, 155 under construction, and 285 planned.

*Figure 2.10: RNG Facilities in the United States*[3]


To stay informed about current market dynamics and identify new resource opportunities, NW Natural issues an annual RFP for RNG resources. The 2024 RFP saw a particularly strong response, with 53 proposals submitted compared to 30 in 2023. This robust response highlights

[2] https://transportproject.org/2024/04/24/renewable-natural-gas-breaking-motor-fuel-usage-records-2/
[3] https://www.rngcoalition.com/infographic

a clear interest in selling RNG to markets such as gas utilities, which can offer revenue opportunities distinct from the transportation fuel credit markets. While those credit markets are lucrative, they are also highly volatile and difficult to predict or hedge against. Utilities, therefore, provide a steady and reliable source of revenue for RNG projects, helping project developers secure project-level financing.

## 2.4 Environmental Policy

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

### 2.4.1 Environmental Policy – Federal

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

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

With the federal administration changes, some of the previously proposed tax incentives for renewable energy are in jeopardy based on the funding pauses stemming from Presidential Executive Order, Unleashing American Energy.[4]

### 2.4.2 Environmental Policy – State

#### *2.4.2.1 Oregon*

**Oregon Greenhouse Gas Reporting Program (OAR 340-215)**

The Oregon Department of Environmental Quality (DEQ) requires all stationary sources emitting more than 2,500 metric tons of $CO_2e$ per year, electricity utilities, local distribution companies, and fuel suppliers to report annual greenhouse gas emissions. Similar to the federal reporting under 40 CFR Part 98, NW Natural submits emissions from the use of its product, as a

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

supplier and the emissions from their actual system operations. Additionally, the Company reports emissions from any of its facilities that exceed 2,500 metric tons of emissions.

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

**Oregon Climate Protection Program (OAR 340-273)**

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

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

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

Compliance instruments are $CO_2e$ emissions allocations from the program cap. A compliance instrument is defined in OAR 340-273-0020 as an instrument issued by DEQ that authorized the emission of one MT $CO_2e$ of greenhouse gases. Annually, NW Natural is allocated a portion of the declining program cap using the procedure outlined in OAR 340-273-0420. DEQ will take the program cap, distribute compliance instruments to EITEs according to the percentages outlined in OAR 340-273-9000 Table 8, and then will apply the percentage for NW Natural listed in OAR 340-273-9000 Table 4.

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

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

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

#### *2.4.2.2 Washington*

**Greenhouse Gas Reporting Program (WAC 173-441)**

The Washington Department of Ecology (Ecology) requires greenhouse gas emissions reporting from fuel suppliers, local distribution companies, electricity suppliers/generators, and facilities that emit more than 10,000 metric tons of $CO_2e$ emissions per year. Historically, there was a higher reporting threshold for local distribution companies and NW Natural was below the threshold and not required to report. In 2022 the rules were updated to accommodate the state's cap and invest program described below. At that time NW Natural began reporting emissions to Ecology and also submitted historical emissions back to 2015. The emissions that NW Natural reports to Ecology include our customers use of gas (supplier report) and our system fugitive emissions.

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

**Climate Commitment Act (WAC 173-446)**

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

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

Regulated entities must acquire and then retire allowances and offsets equal to their emissions for each compliance period of the program. Other compliance tools for lowering emissions include energy efficiency, alternative fuels such as RNG and Hydrogen, and carbon capture. CCA allowances are described below and details on additional compliance tools will be provided in Emissions Compliance Resources section of this IRP.

Under the CCA, Ecology issues allowances that represent the amount of emissions allowed under the program's cap. Each allowance authorizes the release of one metric tons of $CO_2e$. These allowances are acquired through a variety of pathways under the CCA. Certain categories of covered entities, like local distribution companies, are allocated a limited number of no cost allowances annually from the Department of Ecology. Additional allowances can be purchased at auction or in a secondary market from other program participants.

NW Natural receives no cost allowances from Ecology based on its customers' baseline covered emissions from 2015-2019. Covered emissions do not include EITE customers' emission. The allocation calculation takes the average of these annual emissions and then applies the program cap reduction percentage to the baseline to calculate the annual reduction of allowances granted to NW Natural each year. NW Natural's baseline average annual covered emissions are 487,445 metric tons $CO_2e$. From 2023-2030, there is a decrease of seven percent of the non-cost allowances provided to NW Natural, or a reduction of 34,121 allowances each year. From 2031 to 2042 this percentage changes to 1.8 percent of baseline reduction or 8,774 allowances each year. Finally, from 2043 to 2050, NW Natural's allocation of no cost allowances is reduced by 2.6 percent of baseline each year, or 12,674 allowances a year.

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

*Table 2.1: Percentage of Allowances to Consign at Auction*

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

NW Natural can purchase additional allowances at auction or on the secondary market. Additional details on CCA auctions can be found on Ecology's CCA website.[5] Additionally, if covered entities are not able to secure enough compliance tools to cover their emissions by a compliance deadline, Ecology can issue additional allowances to that entity at the annual allowance ceiling price.

## 2.5 Building Codes

### 2.5.1 Oregon

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

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

### 2.5.2 Washington

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

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

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

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

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

# Chapter 4 - Resource Requirements

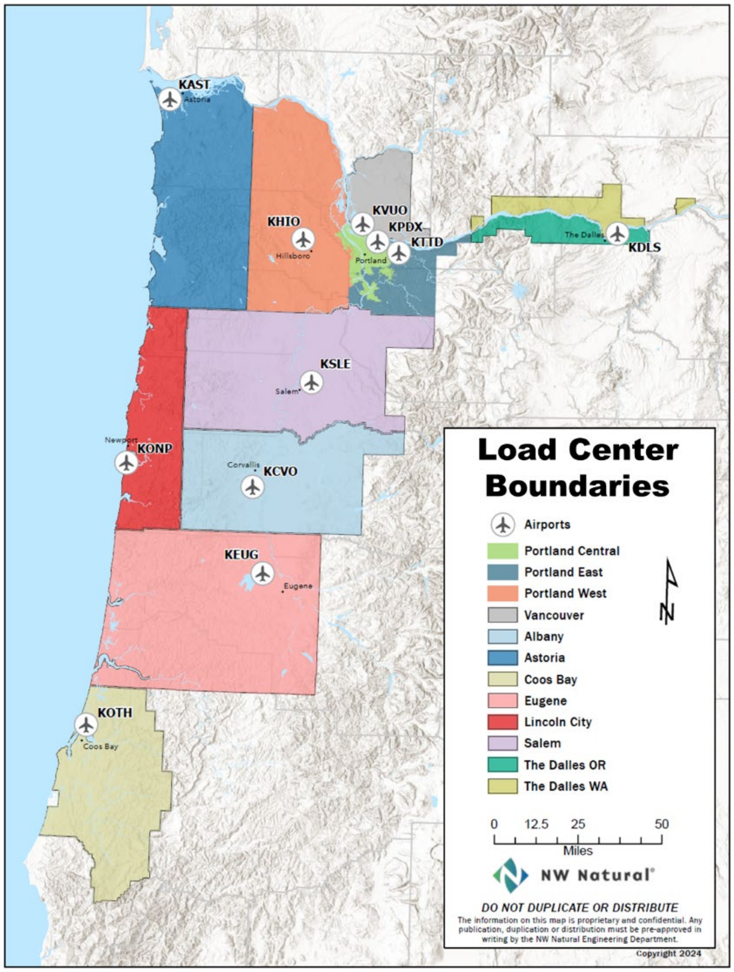
The resource requirements that NW Natural plans for to reliably serve customers and comply with state emissions are ultimately dependent on the energy demanded in the Company's service territory. This chapter breaks down how NW Natural forecasts demand that is primarily driven by the number of customers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

## 4.1.1 Customer Forecast – Reference Case

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

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

*Figure 4.1: Load Centers used for Load Forecasting*




## 4.1.2 Methodology

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

## 4.1.3 Near-term Customer Count Forecast

Also known as NW Natural's SME meter set forecast, the near-term customer count forecast relies on a combination of historical data, forecasts from the Oregon Office of Economic Analysis (OEA) and others, regression analyses, and knowledge from SMEs within the company.

SMEs include representatives from Business Planning, Business Analytics, Customer Lifecycle Management, Marketing, and Account Services who have detailed knowledge of customer trends informed by data, analytics, market research, and discussions with customers across the service territory. The SME meter set forecast extends three years and includes annual counts for existing and new residential and commercial customers by state. It is conducted three times a year.

### 4.1.4 Long-term Customer Count Forecast

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

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

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

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

### 4.1.5 Near-term and Long-term Blending

The near-term customer count forecast is blended with the long-term customer count forecast at the beginning of the forecast period after which change rates from the four ARIMA models forecast customer counts out to the end of the forecast period. Once annual forecasts of total customer counts for the four series are complete, allocations of customer change are distributed to sub-segments of the forecasts including new customers, conversions, and existing customers. Generally, these allocations are based on historical growth patterns. Finally, these forecasts are allocated to 12 load centers in the Company's service territory, again, relying on historical growth patterns. Annual load center forecasts are then converted to monthly and daily customer counts for use in load forecasting.

### 4.1.6 Customer count forecast methodology changes in 2025 IRP

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

#### *4.1.6.1 Near-term Customer Count Forecast as Forward-looking Time Series*

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

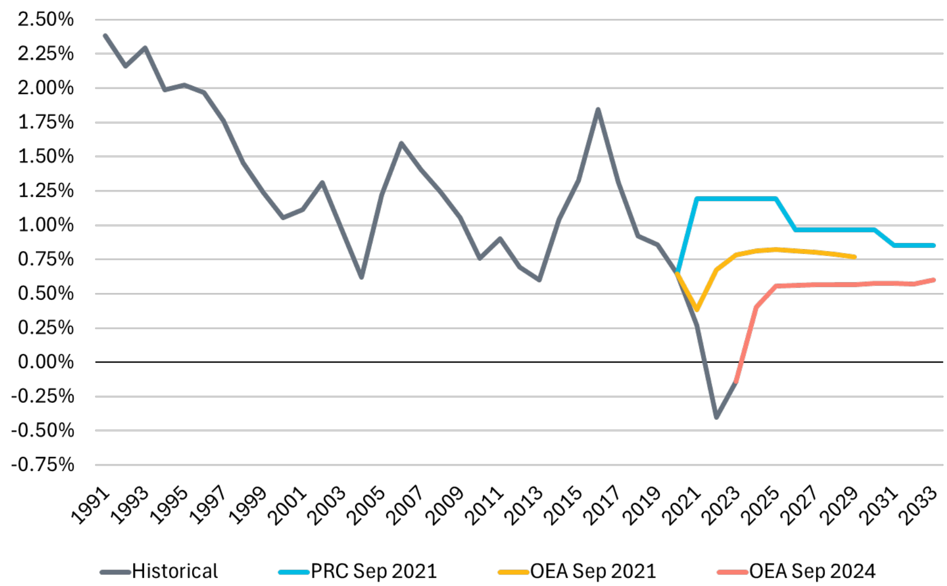
#### *4.1.6.2 Shorter time series for modeling*

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

### 4.1.7 Macroeconomic Drivers of Change in the Customer Count Forecast

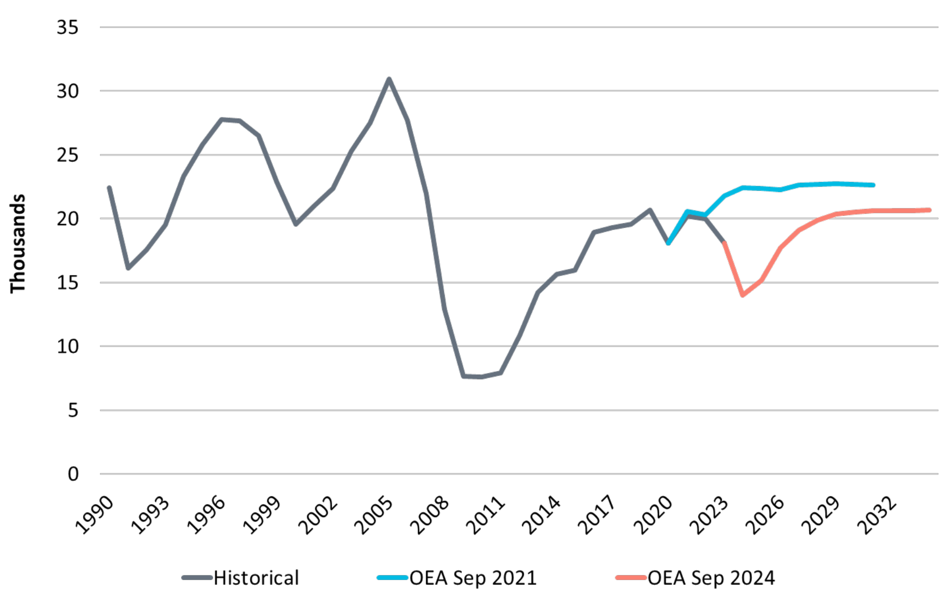
The macroeconomic environment in the Company's service territory has changed significantly since analysis was done for the 2022 IRP. All the independent variables used in the ARIMA models for the customer count forecast utilize data and forecasts from the OEA, which produces economic forecasts on a quarterly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

*Figure 4.2: Oregon Population Change*




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

*Figure 4.3: Oregon Housing Starts*




*Source: Oregon Office of Economic Analysis.*

## 4.1.8 Residential and Commercial Customer Count Forecast

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

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

*Figure 4.4: System Residential Customers – Reference Case*

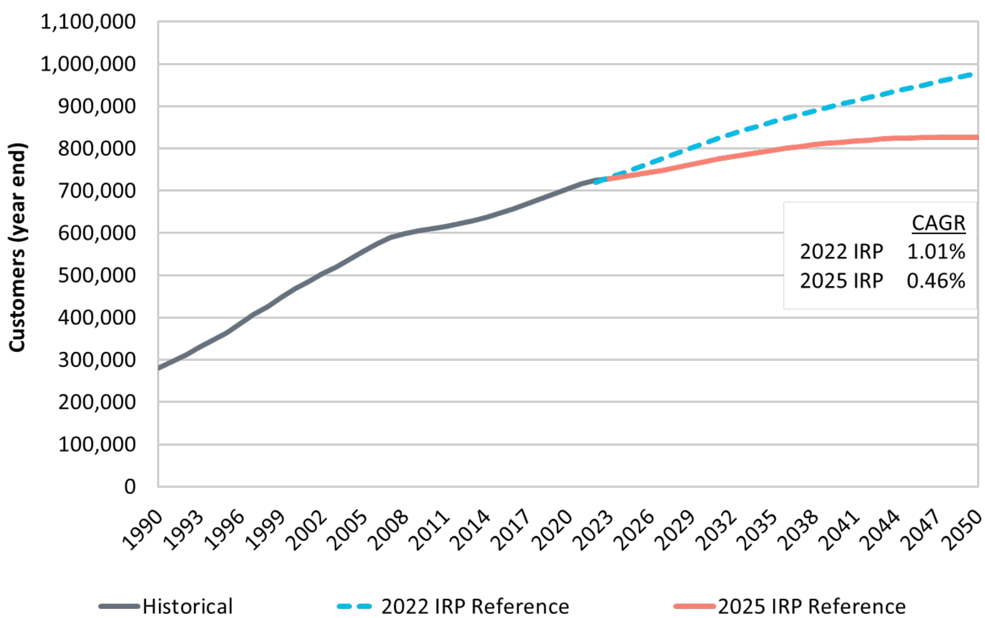
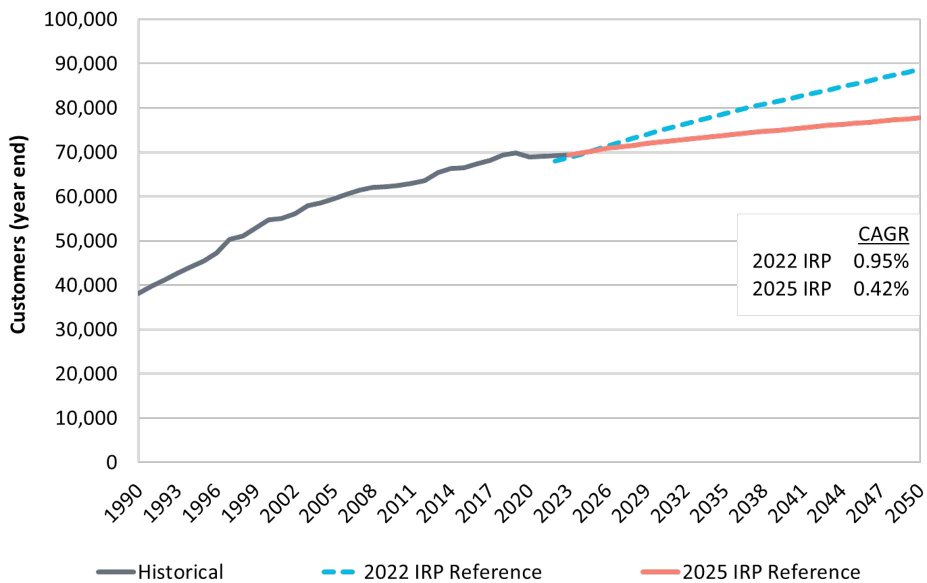


*Figure 4.5: System Commercial Customers – Reference Case*




## 4.2 Weather

### 4.2.1 Climate Adjusted Weather Forecast

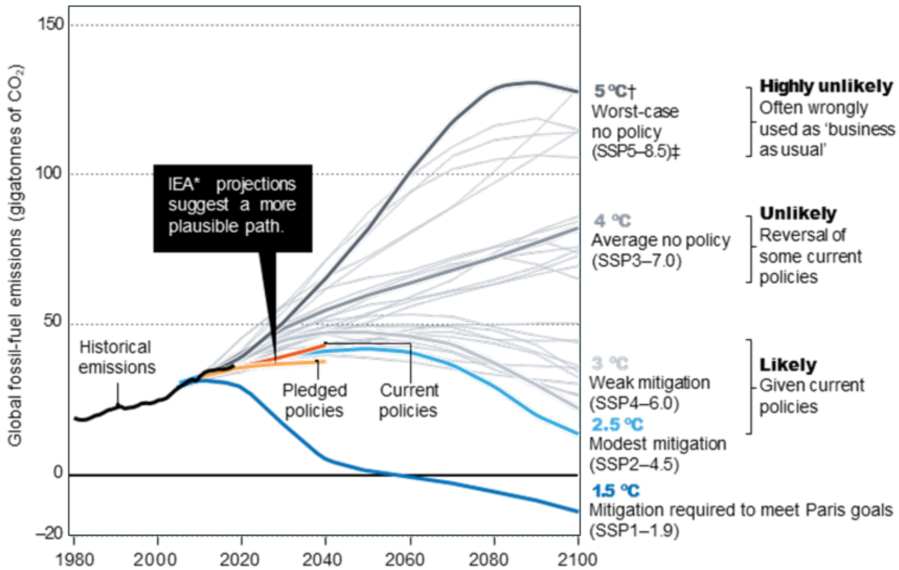
Climate change refers to long-term shifts in global temperatures and weather patterns. While the impact of climate change across the World is disparate, no region, including the Pacific Northwest, is completely insulated from its effects. Given that weather is a primary driver of natural gas demand, and hence a critical input to load forecasting, the trends in regional temperature shifts are important to consider for NW Natural's long-term resource planning. This section explains how climate change trends are incorporated into load forecast modeling.[6]

For the 2025 IRP, NW Natural contracted with ICF, a global advisory and technology services consultant, to integrate climate modeling into its weather forecasts and inform the long-term trends in annual heating degree days (HDDs) over the forecast horizon.[7] The foundation of this process is Global Climate Model (GCM) projections, which simulate the Earth's climate and physical processes. A 22-member ensemble of GCMs is used by the Intergovernmental Panel on Climate Change (IPCC) to determine a range of potential future climate conditions amidst uncertainty. The most recent climate futures developed by the IPCC employ five distinct Shared Socioeconomic Pathways (SSPs) emission scenarios. Figure 4.6 shows the range of climate

[6] NW Natural has included climate change modeling into long-term load forecasting since the 2018 IRP Update #3.
[7] For IRP load forecasting, heating degree day (HDD) calculations assume an average outside temperature of 58°F. This temperature aligns with NW Natural's historical system usage for space heating.

change scenarios, which represent emissions pathways under varying levels of greenhouse gas emissions reduction.[8]

*Figure 4.6: Emissions Pathways*




NW Natural developed climate projections specific to the Pacific Northwest under both SSP2-4.5 and SSP3-7.0 to account for uncertainty in future emissions and climate sensitivity. While SSP3-7.0 assumes greenhouse gas emissions increase throughout the century, SSP2-4.5, which is deemed as a relatively more likely path, assumes a meaningful reduction in greenhouse gas emissions by mid-century. The HDDs from SSP2-4.5 versus SSP3-7.0 for the Pacific Northwest are not materially different until after the planning horizon.[9] Therefore, for the 2025 IRP, the Company has selected SSP2-4.5 to incorporate into its load forecasting.

Under SSP2-4.5, GCM projections are downscaled to a higher spatial resolution that better captures regional and local climate characteristics. Specifically, NW Natural used Localized Constructed Analogs Version 2 (LOCA2) downscaled climate projections to develop custom HDD projections for each of the load center weather stations in NW Natural's service territory.[10] To

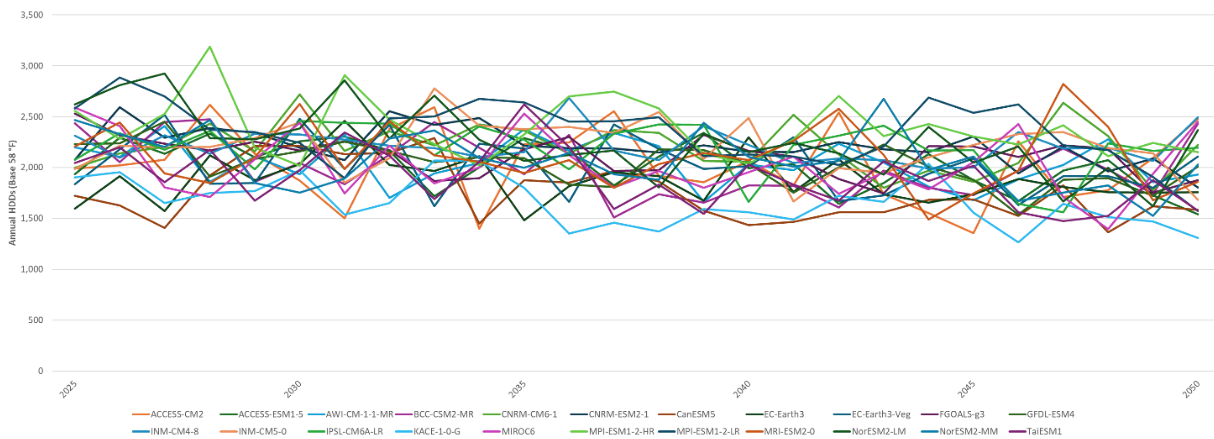
[8] Hausfather, Z. and Peters, G.P., Emissions—the 'business as usual' story is misleading, 2020. *Nature*, 577 (7792), 618-620.

[9] For example, in the reference case, the Portland Central load center has only 19 (or 0.97%) more HDDs under SSP2-4.5 than SSPS3-7.0 in the year 2050.

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

produce a robust outlook of protracted climate trends, the whole 22-member ensemble of downscaled GCMs were used. To illustrate, Figure 4.7 shows the HDD projections of the 22 GCMs for one of NW Natural's load centers—Portland Central. Projections show, on average, a declining trend in HDDs with significant interannual variability.

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

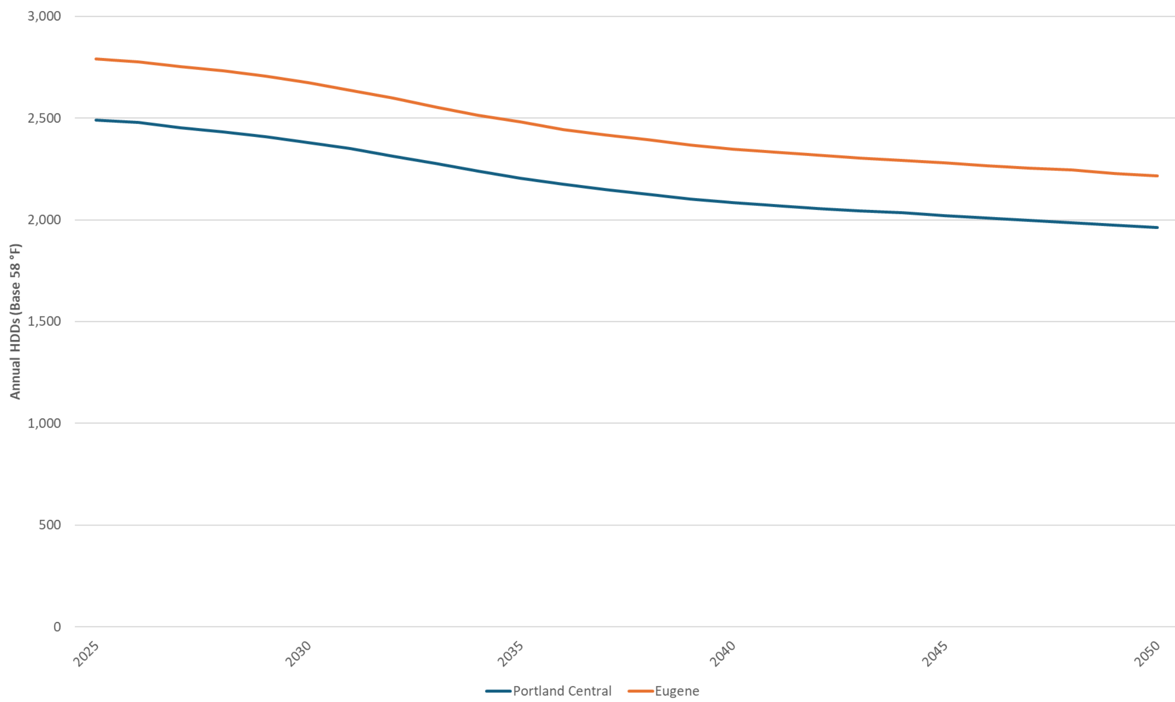



## 4.2.2 Expected Weather

Given that NW Natural's load is primarily driven by heating requirements, the expected weather forecast focuses on annual HDDs through the forecast horizon. Due to the stochastic nature of individual GCM projections, a disconnect exists between recently observed HDDs and near-term (i.e., less than 10 years) projections of climate models. To resolve this local climatology inconsistency, ICF developed a 30-year moving average of HDDs for the forecast period, 2025-2050. This approach blends projections of future HDDs with recent HDD observations, a more reliable predictor of near-term weather conditions, by applying progressively more weight to the GCMs for more distant time periods in the forecast. This methodology not only incorporates climate model uncertainties into the estimates, but also minimizes interannual variability in the final time series.[11] As an example, Figure 4.8 shows the expected annual HDDs for two of NW Natural load centers—Portland Central and Eugene. While both load centers have distinct weather patterns, as indicated by the differing magnitude of HDDs, the trend of declining HDDs is similar.

[11] For a detailed discussion of this methodology see Appendix B.2.

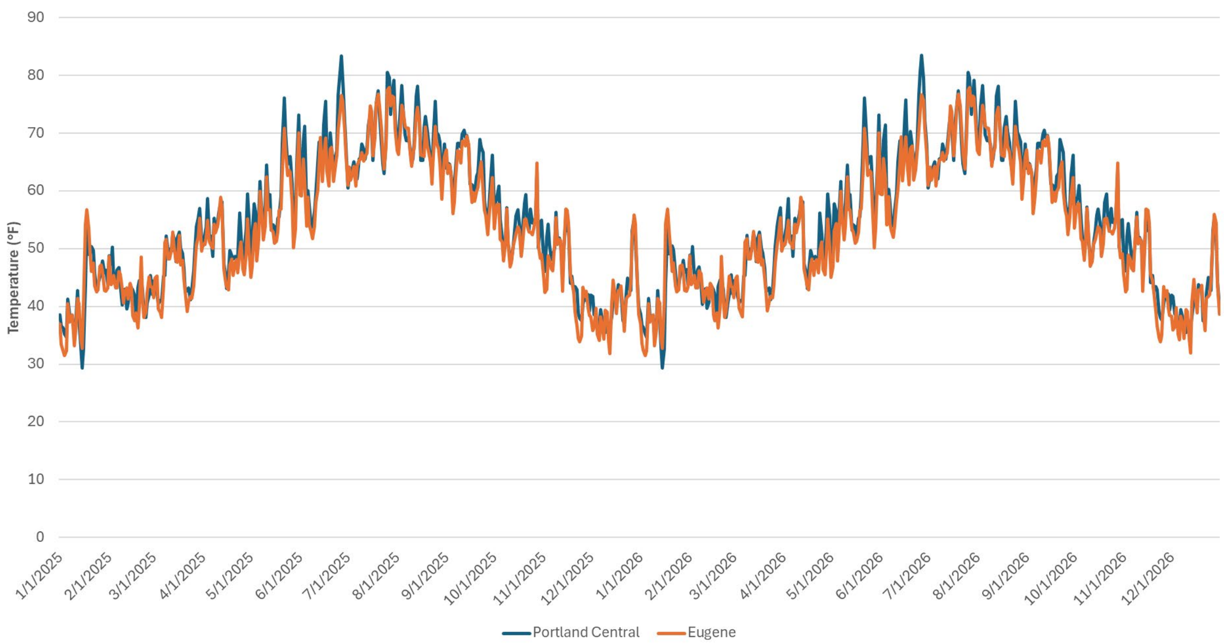
*Figure 4.8: Expected Weather Annual HDDs by Load Center*




The HDD moving average is the basis of NW Natural's expected weather forecast. Intra-year shaping is then applied to each forecast month, followed by intra-month shaping to each day, in order to translate the HDDs into a daily forecast of temperatures. This shaping process is developed using a representative temperature pattern that is applied to each year in the forecast.[12] In other words, each year in the forecast will have the same shape, but overall temperatures are increasing (i.e., HDDs are decreasing) through the planning horizon. Figure 4.9 displays the intra-year shaping for the first two years of the forecast horizon for both the Portland Central and Eugene load centers.

[12] Using a representative weather pattern creates realistic volatility in daily temperatures, which is important for modeling resource dispatching.

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




## 4.2.3 Weather Uncertainty

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

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

This IRP implements a Monte Carlo weather simulation to understand the potential range of daily, monthly, and annual HDDs/temperatures.[13] Relying on both historical data and climate change modeling forecasts, weather is simulated for each load center over the planning horizon. The simulations provide variation in annual HDDs from one year to the next as well as

[13] The Monte Carlo simulation discussed in this section is distinct from the Monte Carlo methodology used to develop the design firm sales peak day forecast.

intra-year weather patterns which correlate across the Company's load centers.[14] Figure 4.10 highlights such random variation with five randomly selected Monte Carlo draws for the Portland Central load center.

*Figure 4.10: Weather Simulation – Annual HDDs for Portland Central*

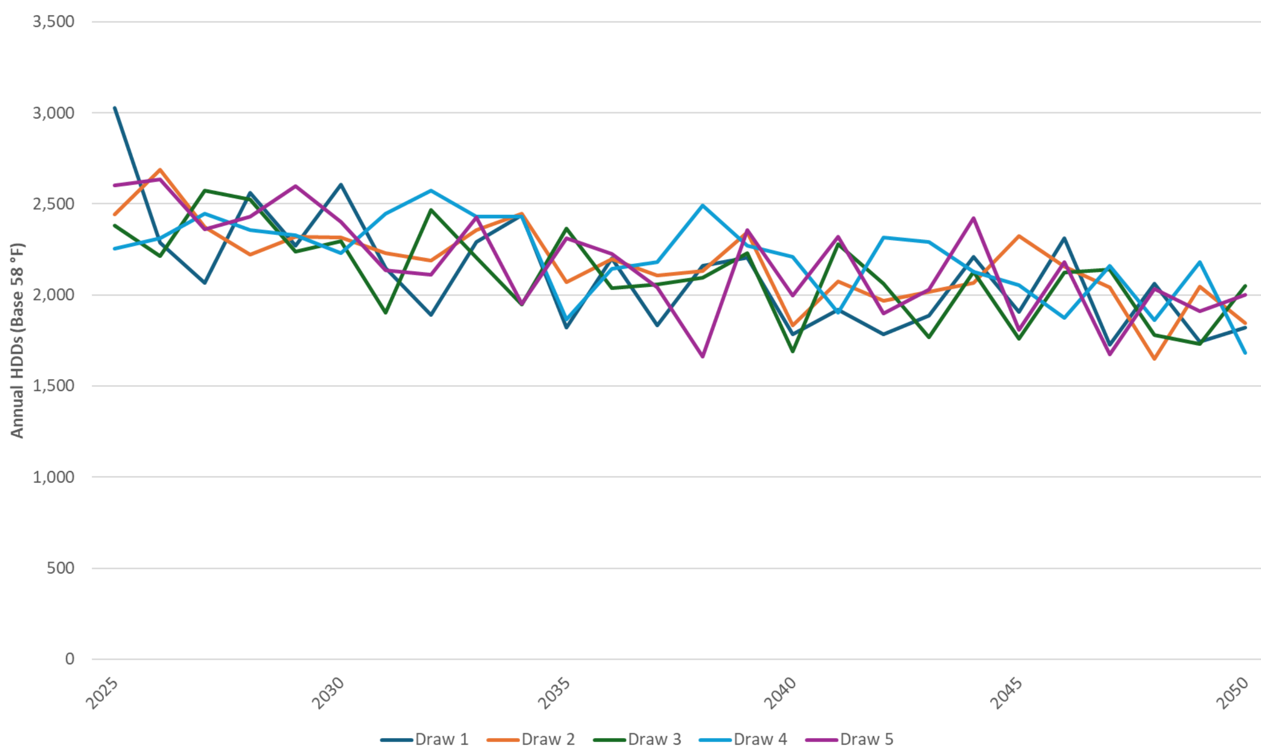
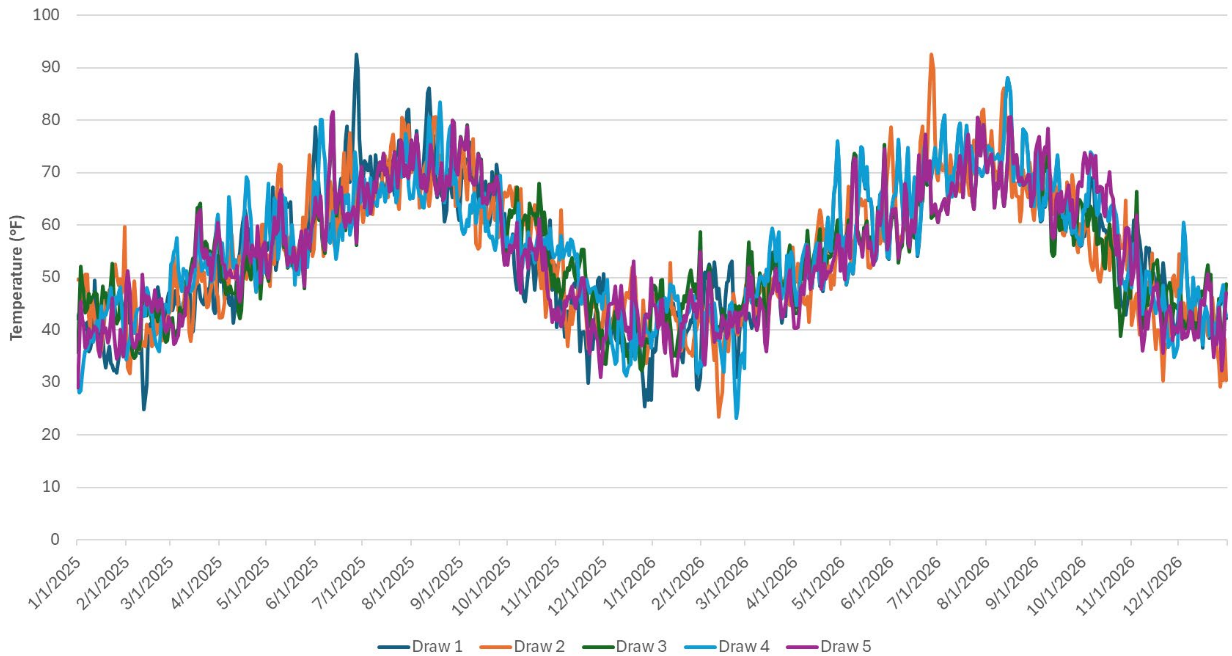



Figure 4.11 shows the translation of the annual HDDs in Figure 4.10 into daily temperatures for the first two years of the forecast horizon, illustrating the variability of intra-year weather shaping.

[14] In total, there are 500 weather simulations across each load center. Appendix B.3 provides additional details on the simulation process.

*Figure 4.11: Weather Simulation – Daily Temperatures for Portland Central*




# 4.3 Annual Load

## 4.3.1 Residential and Small Commercial Use Per Customer

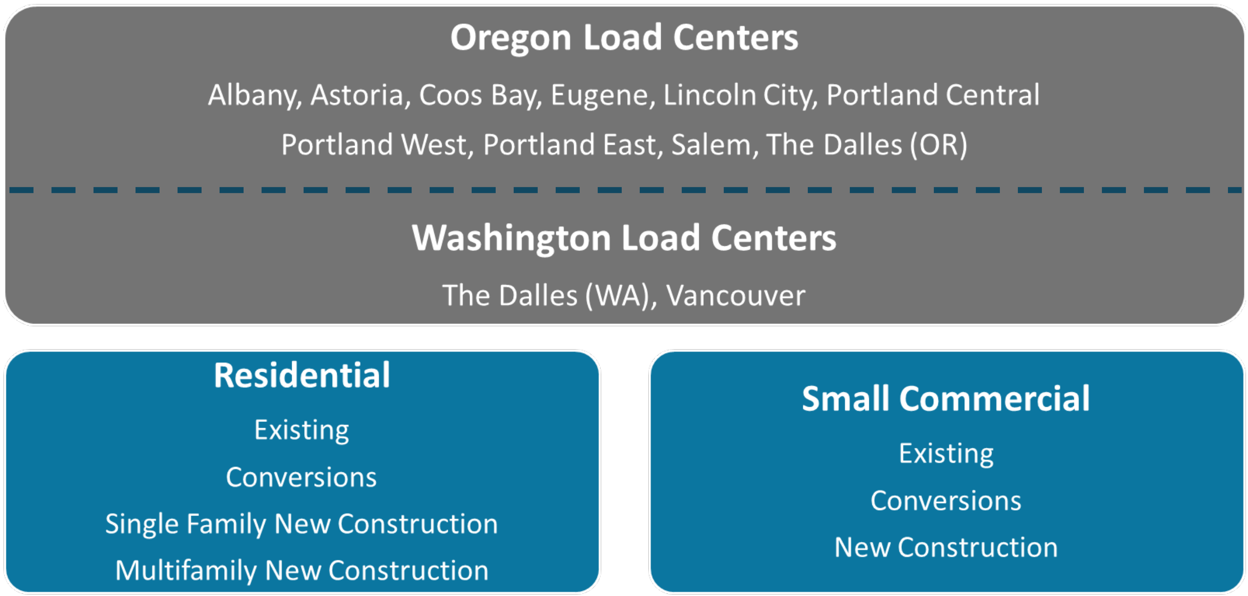
The reference case demand for residential and small commercial customers is developed via a bottom-up approach which combines the weather forecasts and customer count forecasts, as described in the previous sections, with historical billing and weather data.[15] In essence, by matching historical monthly customer billing data with corresponding weather data, NW Natural is able to model average daily use-per-customer (UPC) demand as a function of daily temperatures. The average UPC can then be paired with weather and customer forecasts to estimate future demand.

To add specificity to the modeling process it is ideal to start with a visualization of the Company's load centers. Figure 4.12 displays a hierarchy of the Company's service territories. At the top of this figure are the Company's 12 load centers, grouped by state. Each load center models two rate classes—residential and small commercial—and within each rate class are its respective market segments. For the existing residential and small commercial market segments, the UPC modeling process occurs at the load center level. That is, each load center will have its own UPC estimates (i.e., average therms per customer per day as a function of

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

temperature) for these two market segments, for a total of 24 UPC estimates. Next, the existing UPC estimates are paired with their load centers' respective daily expected weather forecasts to determine appropriate future demand. Demand is then multiplied by the load center's customer count forecast to determine the expected daily load.

*Figure* 4.12: UPC Model Hierarchy




Given the ample supply of monthly billing data for existing customers, UPC estimates can be derived at the load center level.[16] However, due to data constraints the UPC estimates for the conversions and new construction market segments must be derived slightly differently.[17] In the latter case, UPC is estimated at the state level and subsequently applied across corresponding load centers within the state.[18] Still, load center specific weather and customer count forecasts are applied to each market segment to determine forecasted demand.

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

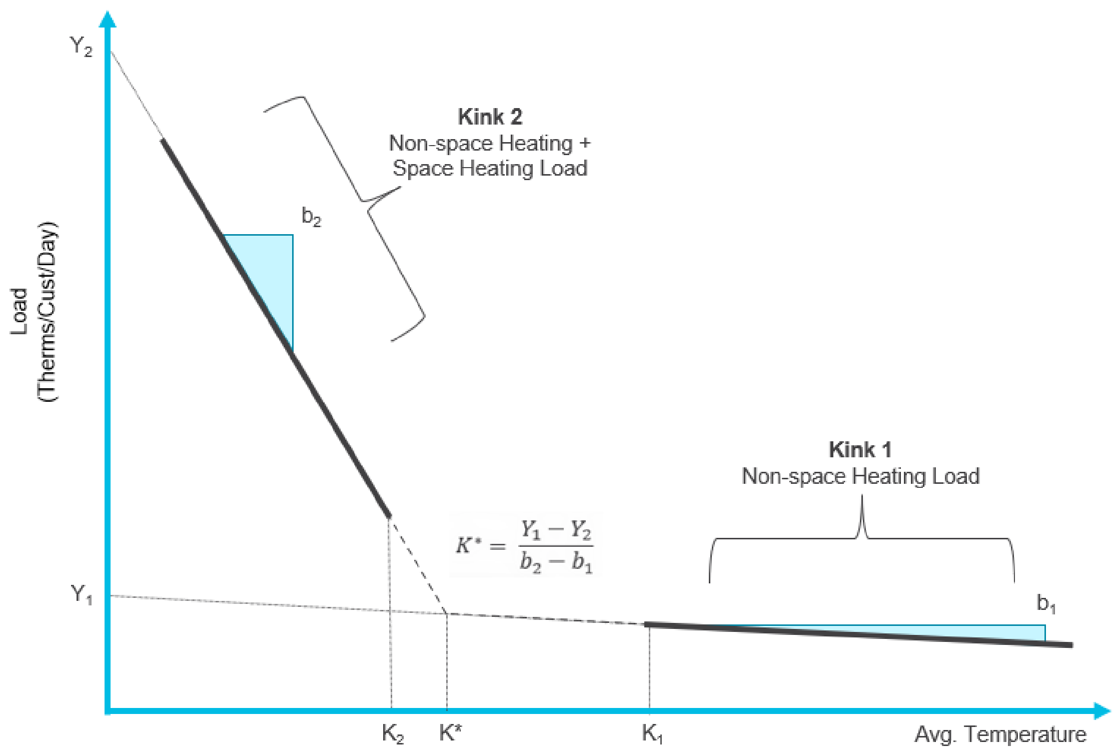
[16] All billing data used in this IRP spans the time frame January 1, 2021 – March 31, 2004, in order to best capture how customers are using gas currently. This contrasts with the 2022 IRP which used billing data going back to January 1, 2009.

[17] New construction is defined as customers who have come onto the NW Natural system since January 1, 2021.

[18] While the UPC estimates for the market segments are homogenous across a particular state, the weather data that is paired with those estimates is specific to the load center.

plus space heating load). Figure 4.13 displays the theoretical model of a customer demand profile.

*Figure 4.13: Theoretical UPC Model*




Kink 1 is the demand profile for non-space heating load and is represented by the slope $b_1$. This slope is estimated using monthly data where the average temperature is greater than or equal to $K_1$. This cut-off point (i.e., $K_1$) reduces the impact of weather volatility on the demand profile during shoulder months, where monthly average temperatures may include a high mix of space-heating and non-space heating days. Kink 2 is the demand profile for non-space heating plus space heating load and is represented by the slope $b_2$. In contrast to kink 1, this slope is estimated with data where the average temperature is less than or equal to $K_2$.[19] This restriction is similarly performed to reduce the impact of weather volatility on the demand profile from shoulder months. Moving from right to left, along the x-axis, the average temperature inflection point (K*) represents where space heating load accelerates. It is evaluated as the point where the two demand curves intersect and, for the average customer, will vary by load center, rate class, and market segment. Equation (1) generalizes the piecewise linear model:

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

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

where, $D_j(t)$ is historical monthly demand (in therms), $t_j$ is the historical average monthly temperature, $Y_i$ is the intercept parameter, $b_i$ is the slope parameter, $\epsilon_j$ is the residuals of the $j^{th}$ month, and subscripts *l, r, and m* represent the load center, rate class, and market segment, respectively.[20] The Ordinary Least Squares (OLS) estimator is used to estimate the equation parameters.[21]

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

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

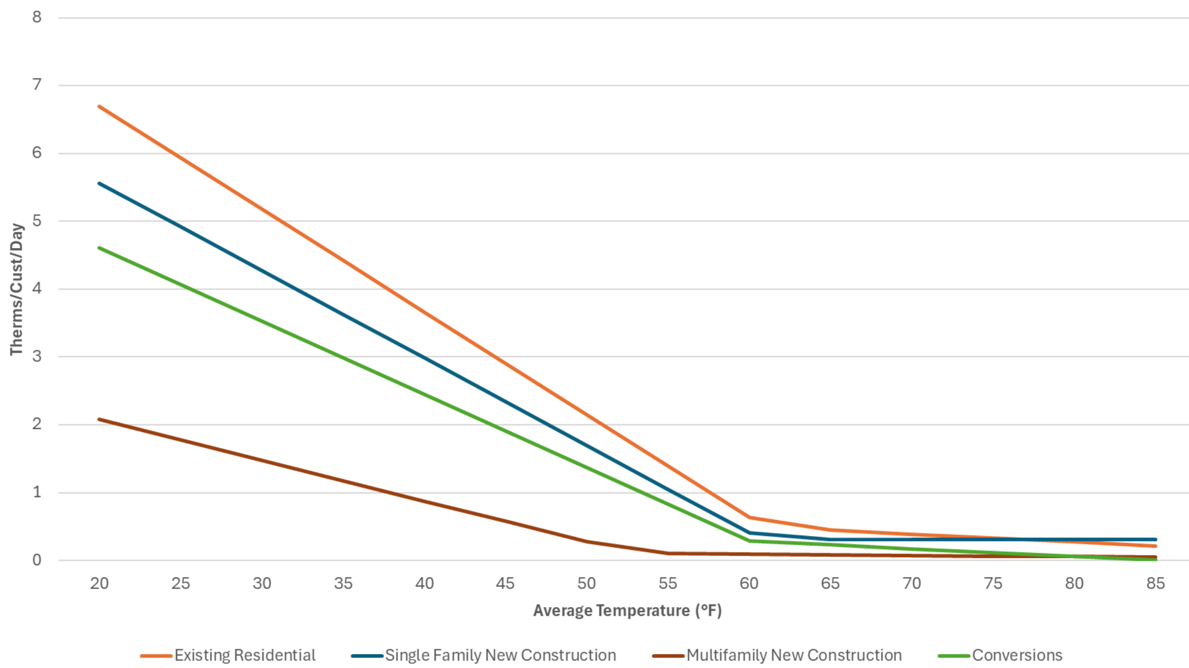
where, subscript *i* represents the day in the forecast horizon.

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

[20] When estimating the UPC coefficients for both the conversions and new construction market segments, respectively, the load center subscript (*l*) reduces to the state-level and the regression effectively becomes a state panel.

[21] The table of parameter values for each load center, rate class, and market segment can be found in Appendix B.4.

*Figure 4.14: Predicted UPC Values for Portland Central Residential*



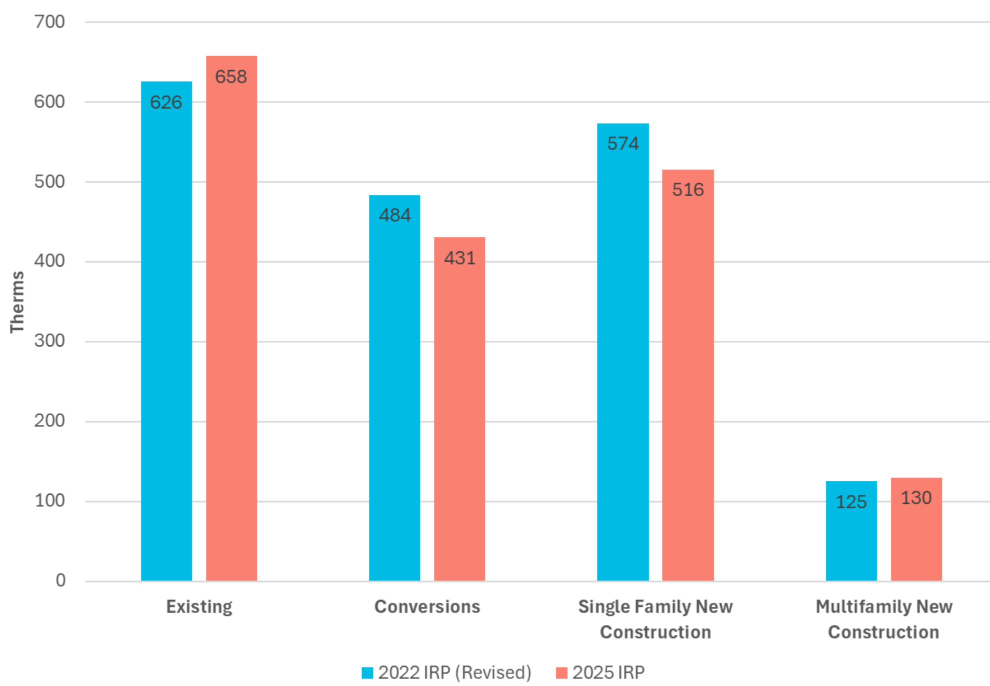

Following Figure 4.15, by incorporating the 2025 expected weather forecasts into the appropriate UPC estimates, grouped by rate class and market segment, and then multiplying the subsequent demand estimates by their respective customer count forecasts, the result is the average first-year UPC estimates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

*Figure 4.15: Flow Diagram of UPC First-year Estimates*


Figures 4.16 and 4.17 compare these estimates to their respective 2022 IRP counterparts. Average residential existing usage has increased since the 2022 IRP. The higher first-year estimates for existing customers are consistent with the theme of more hybrid and remote work post-2020—a pattern we see bear out for many of NW Natural's load centers. Residential

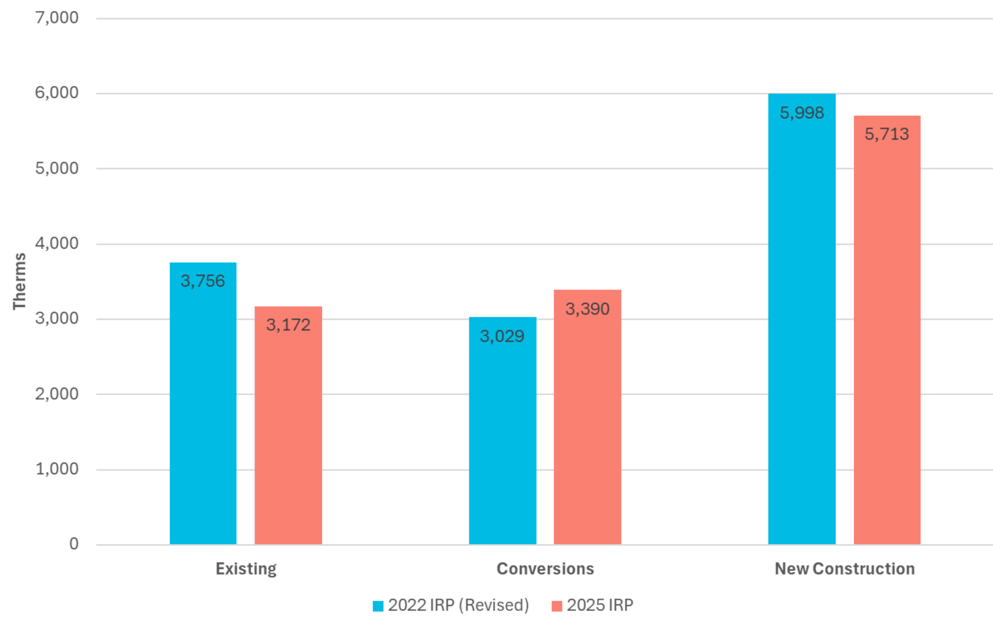
conversions and single family new construction have moderately lower estimates compared to the 2022 IRP, while multifamily new construction has remained relatively flat. In contrast to the residential rate class, average small commercial existing usage has declined since the 2022 IRP. These lower demand estimates similarly align with the hybrid/remote work theme. Small commercial conversions exhibit moderately higher average first-year estimates compared to the 2022 IRP, while the new construction market segment shows a decline in first-years estimates.[22]

*Figure 4.16: Average First-year Residential Demand*




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

*Figure 4.17: Average First-year Small Commercial Demand*




### *4.3.1.1 Forecasted Energy Efficiency*

NW Natural's load forecasting models incorporate energy efficiency savings estimates throughout the forecast horizon. The Energy Trust of Oregon (ETO) currently administers energy efficiency programs for residential, commercial, and industrial sales customers in Oregon and residential and commercial sales customers in Washington. NW Natural has recently established energy efficiency programs for industrial transportation customers across both states to further increase efficiency savings. The expectation is that NW Natural will see reasonable amounts of these savings materialize in Oregon in 2025 and in Washington in 2026.[23] Further, NW Natural is working to establish a cost-effective energy efficiency savings program for Washington industrial sales customers.

As shown in Table 4.2, ETO provides NW Natural with a therm savings forecast across multiple rate classes for sales customers, known as a conservation potential assessment (CPA), for the incentive programs currently being offered in Oregon. In Washington, NW Natural retained a third-party consultant, Applied Energy Group (AEG), to conduct a CPA for Washington sales customers and provide two high-level CPAs for transportation customers in NW Natural's system.[24]

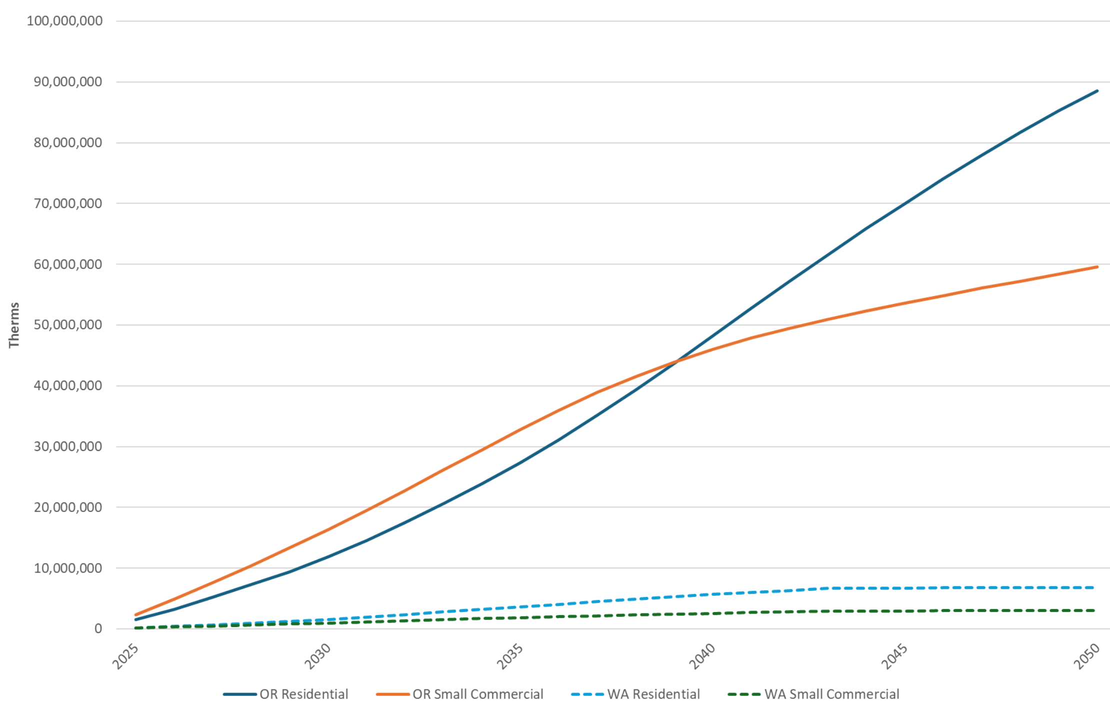
[23] The forecasted therm savings for Oregon transportation customers is approximately 550,000 therms. In Washington the forecasted savings is approximately 72,000 therms.
[24] See Chapter 6 for additional details on the various CPAs.

*Table 4.2: CPA Organization*

| State | Customer Type | Rate Class | CPA Developer |
|---|---|---|---|
| Oregon | Sales | Residential<br>Small Commercial<br>Industrial | ETO |
| | Transportation | Industrial | AEG |
| Washington | Sales | Residential<br>Small Commercial<br>Industrial | AEG |
| | Transportation | Industrial | |

Figure 4.18 shows the cumulative energy efficiency savings estimates, in therms, provided by both CPA developers for the residential and small commercial rate classes.[25] Oregon savings estimates are much larger than those of Washington largely due to Oregon being a much larger percentage of the Company's overall load.[26] These accumulated savings estimates are applied to their respective rate classes and market segments and allocated down to the daily forecast level based on annual load share percentages.

*Figure 4.18: Residential and Small Commercial Cumulative Energy Savings*



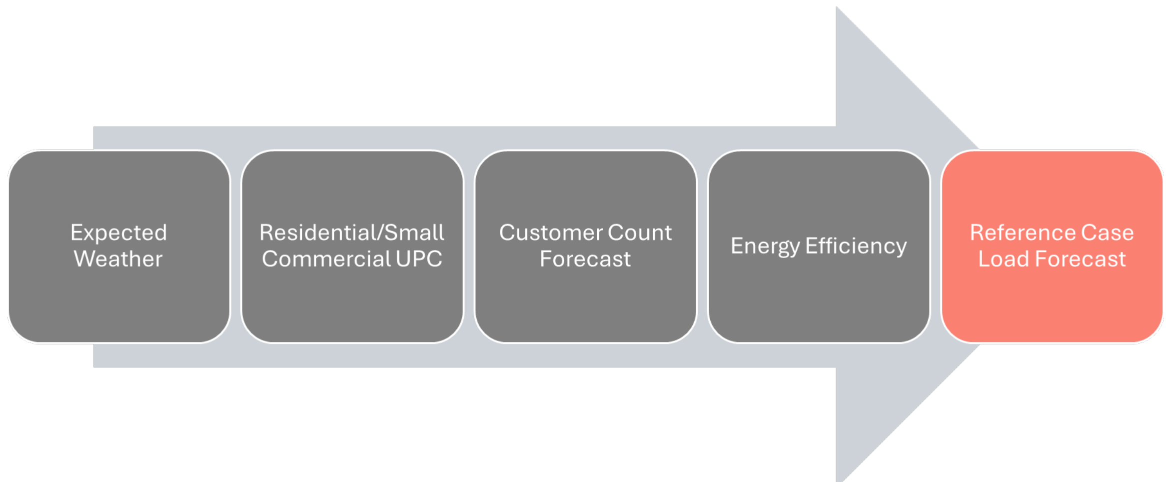

[25] While AEG is the CPA developer for Washington, ETO administers the incentives program.

[26] It is worth noting that there is no longer an energy efficiency incentive program under the 2021 Washington State Energy Code that went into effect March 15, 2024.

### 4.3.2 Residential and Commercial Annual Forecast

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

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




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

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

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

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

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

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


Figures 4.21 and 4.22 compare the average energy efficient UPC for the residential and small commercial rate classes, respectively, for the first (2025) and last (2050) year of the forecast horizon. Due to accumulating energy efficiency and declining HDDs the UPC for both rate

classes is forecast to fall. Specifically, by the end of the forecast horizon residential UPC is reduced by approximately 38 percent and small commercial by 21 percent.[27]

*Figure 4.21: System-wide Residential Average UPC*

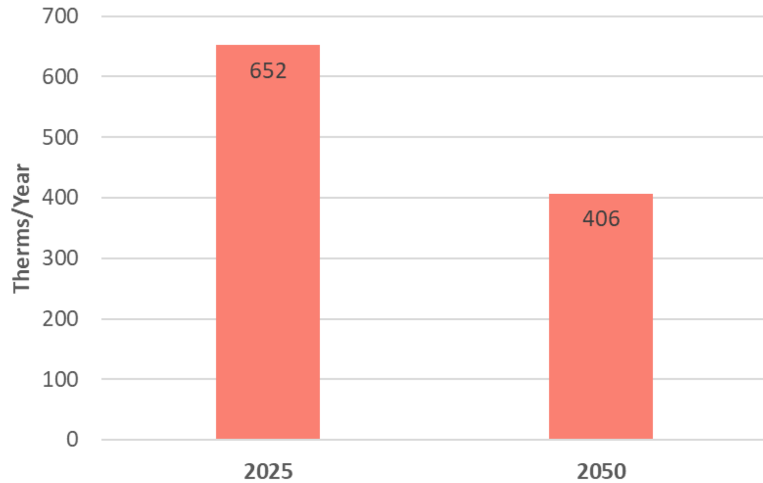
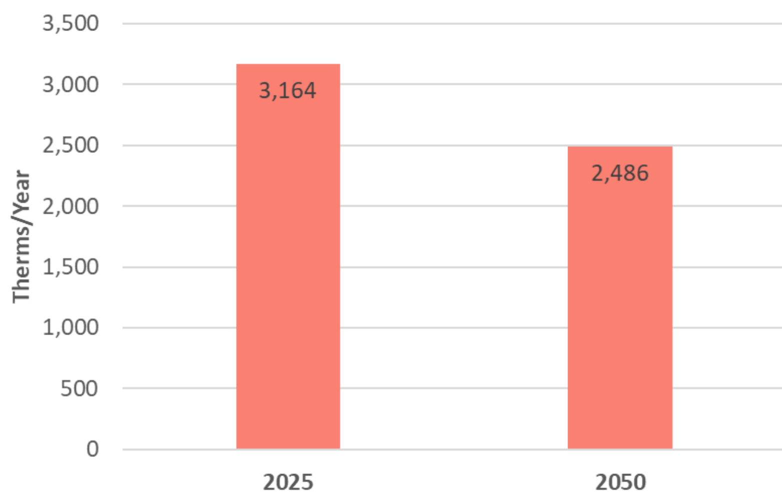



*Figure 4.22: System-wide Small Commercial Average UPC*




## 4.3.3 Industrial and Large Commercial

In contrast to residential and small commercial UPC load forecasting, industrial and large commercial load is forecasted at an aggregate level. The industrial forecast relies on NW Natural's Subject Matter Experts (SMEs) for a short-term forecast (i.e., the first two years of the horizon—2025 and 2026), and for a longer-term forecast (i.e., the remainder of the forecast

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

horizon—2027 to 2050) the load is modeled as a function of macroeconomic data from the Oregon Office of Economic Analysis (OEA). NW Natural's industrial load can then be allocated into four categories of service: firm sales, firm transportation, interruptible sales, and interruptible transportation.[28]

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

#### *4.3.3.1 Subject Matter Expert (SME) Short-term Forecast*

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

#### *4.3.3.2 Econometric Forecasts*

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

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

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

over-year basis to produce a monthly forecast.[29] Equation (5) generalizes the linear regression model for industrial and large commercial:

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

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

#### *4.3.3.3 Forecasted Energy Efficiency*

As discussed earlier, forecasted energy efficiency is a key input into load modeling. ETO and AEG provide efficiency savings forecasts for both industrial and large customers. Specifically, an annual forecast is provided for: industrial transport, industrial sales, and large commercial.[30] Figure 4.23 shows the cumulative forecasted energy efficiency savings estimates, in therms, provided by the CPA developers for the three categories.[31] These accumulated savings estimates are subsequently allocated down to the monthly level based on annual load share percentages and applied as a load decrement to their respective customer class and service category.

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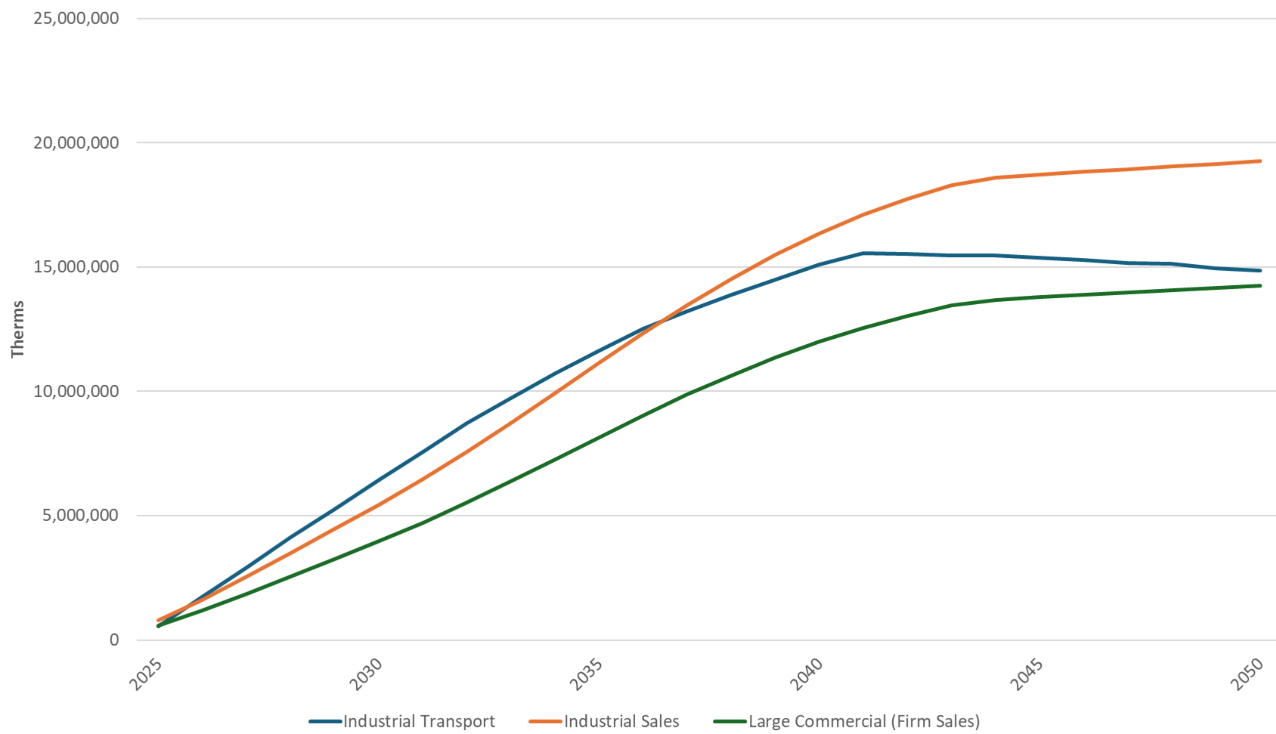
[29] See Appendix B.5 for technical details related to the econometric models used for industrial and large commercial load forecasting.

[30] AEG provides a forecast of industrial sales energy efficiency savings for Washington that they believe is cost-effective and achievable. NW Natural is currently working to establish a program to obtain those savings.

[31] There is an immaterial decline in cumulative energy efficiency savings for industrial transportation post-2040 as an outcome of the CPA modeling; the Company does not expect to see this decline in future CPAs.

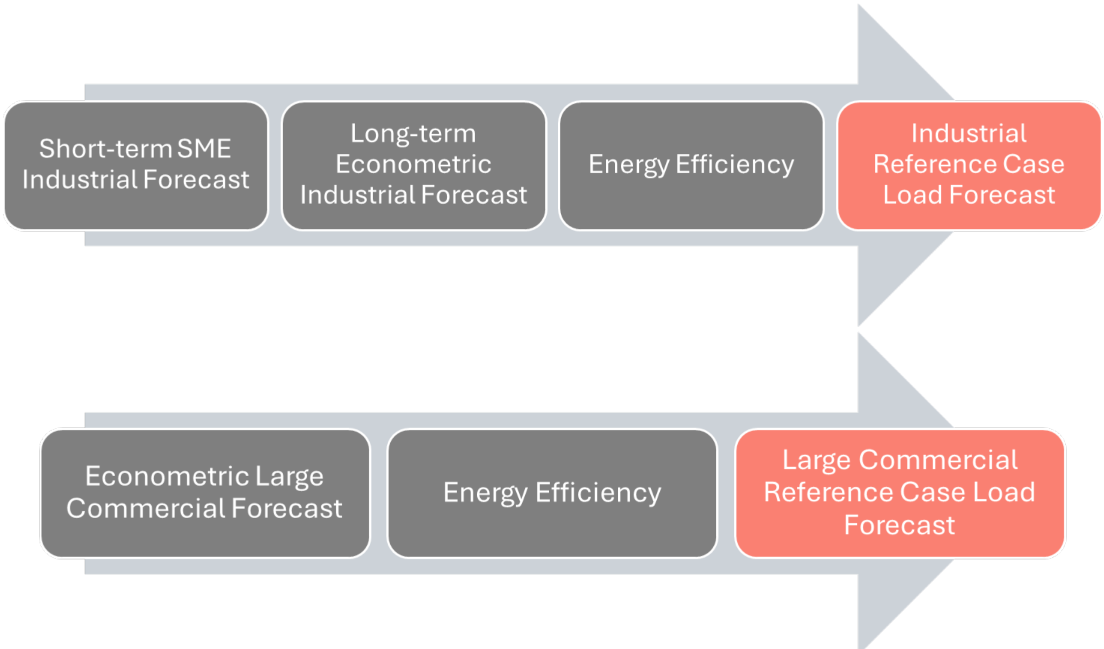
*Figure 4.23: Industrial and Large Commercial Cumulative Energy Savings*




## 4.3.4 Industrial and Large Commercial Annual Forecast

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

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




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

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

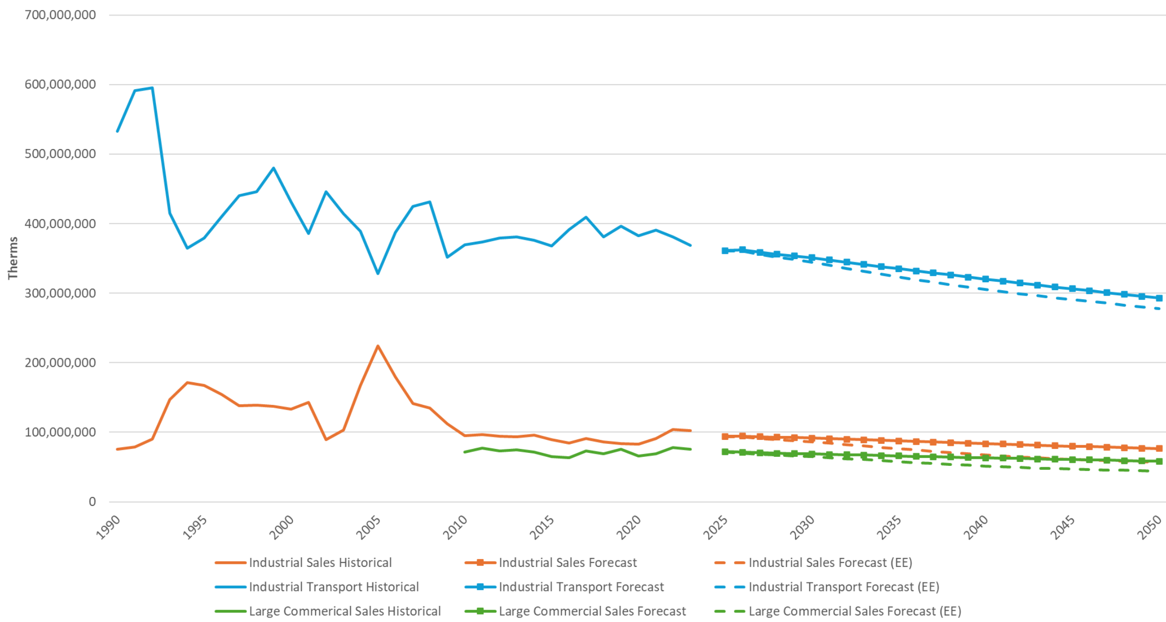
$$Annual\ Large\ Commercial\ Load = \sum_{i} L_{i} - EE_{i} \quad (7)$$

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

Figure 4.25 presents the system-wide annual forecast for industrial sales, industrial transport, and large commercial sales. Like the residential and small commercial forecast, the solid lines represent historical data, the lines with the square markers represent the load forecast with no energy efficiency decrements, and the dashed lines represent the load forecast with energy efficiency estimates incorporated. Over the forecast horizon there is a modest declining trend across the board. This updated trajectory is largely in line with the 2022 IRP forecast. For the industrial categories, the load decline after the first two years is principally a function of the load sensitivity to a modest growth forecast in U.S. industrial production through 2050.

Likewise, large commercial load is a function of the slight growth forecast in the Oregon information sector over the horizon.

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

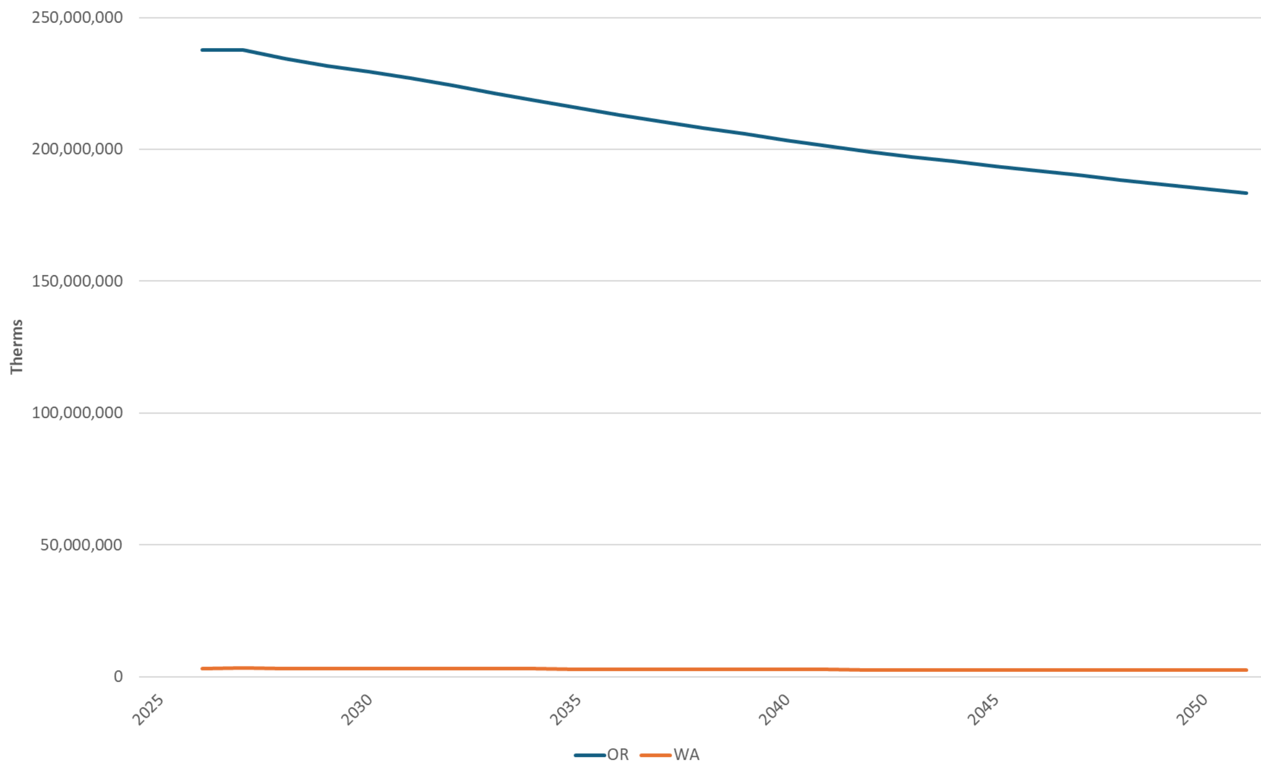



### *4.3.4.1 Forecast for EITE Customers*

NW Natural's Emissions-Intensive, Trade-Exposed (EITE) customers are industrial users in manufacturing sectors that produce large amounts of greenhouse gas (GHG) while facing significant competition for their products. This makes these entities particularly vulnerable to carbon compliance policies relative to competitors who face no restrictions at all.[32] Virtually all of NW Natural's EITE customers are transport customers.[33] For NW Natural's emissions reporting, for both CPP and CCA, the usage of these entities is removed, and the Company's compliance obligation is based on the total remaining throughput. Figure 4.26 shows the forecast for EITE load by state. For simplicity, following the short-term forecast by the SME, the EITE load is forecast to decline at the same rate as industrial transportation load in the reference case forecast.

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

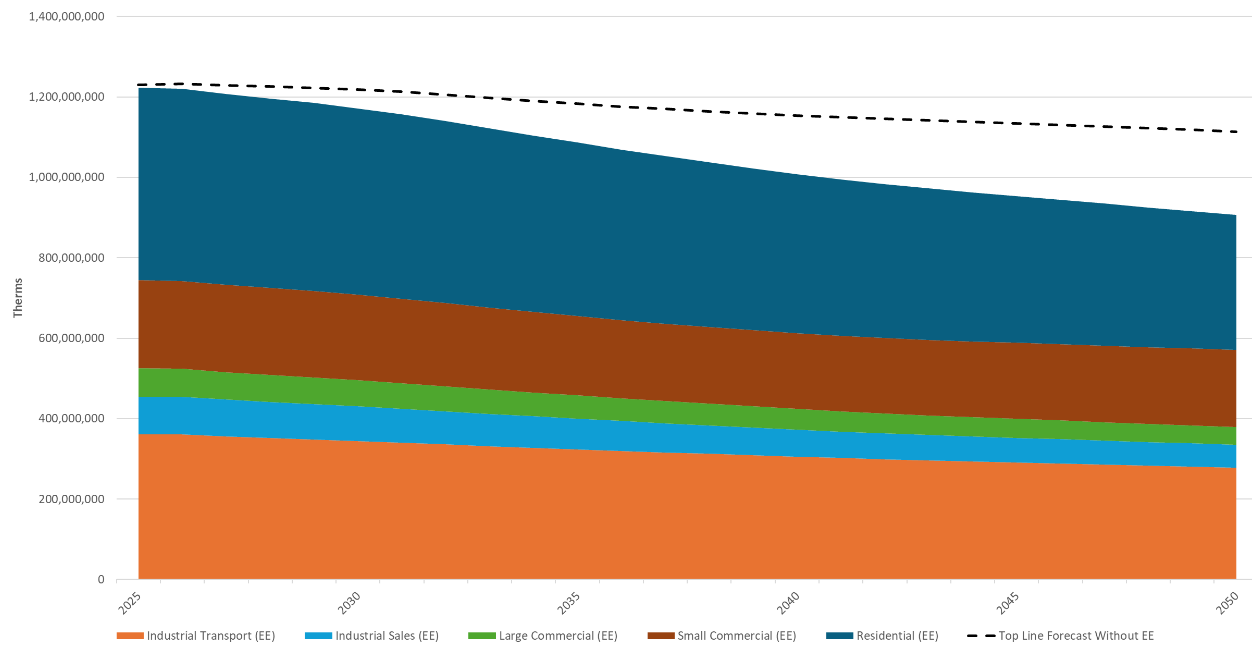
*Figure 4.26: EITE Load Forecast*




### 4.3.5 Annual Load – Annual Throughput Forecast

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

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




### *4.3.5.1 State Throughput Forecasts*

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

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

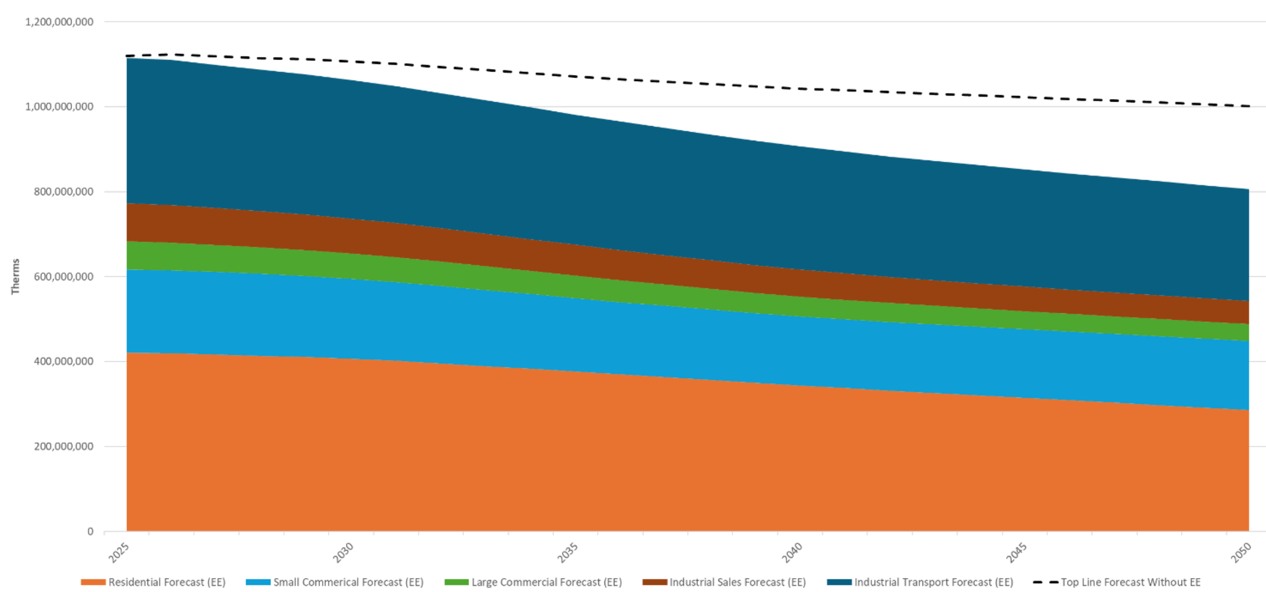
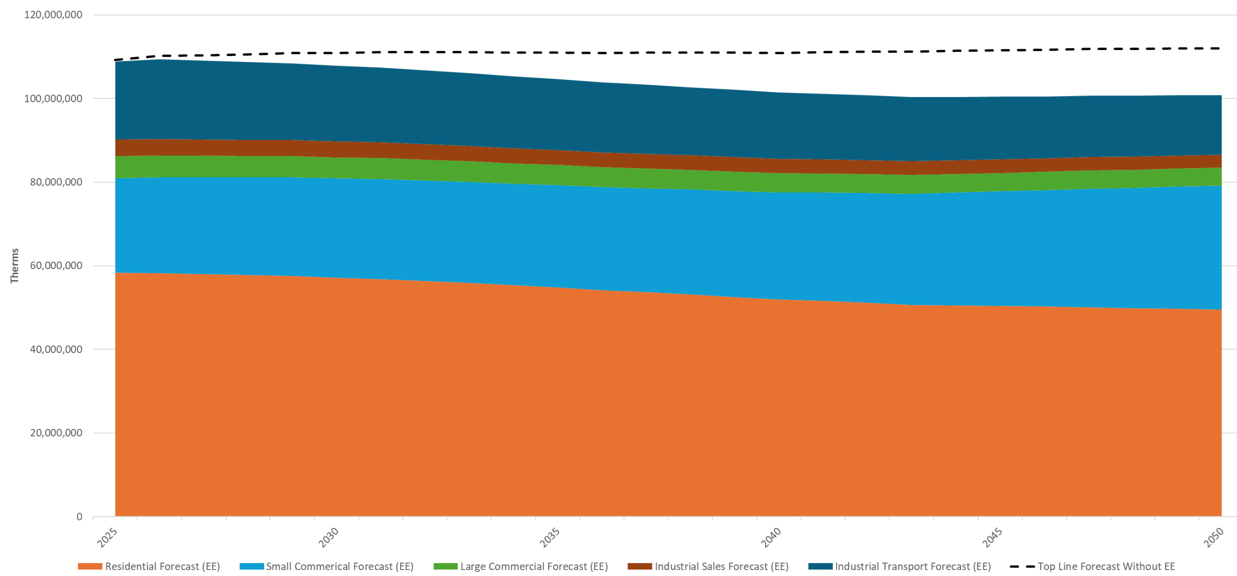


*Figure 4.29:Reference Case – State of Washington Natural Gas Usage Forecast*




## 4.4 Peak Day Load Forecast

### 4.4.1 Capacity Planning Standard

Developing a capacity planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure the reliability of service under design peak weather conditions.[34] NW Natural utilizes Monte Carlo simulations of demand predictors to establish a planning standard where the Company's resources can consistently serve the highest firm sales load going into each winter with 99 percent certainty, assuming all resources are available.[35] This standard is equivalent to planning for a 1-in-100-year weather event.[36]

### 4.4.2 Daily System Load Model

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

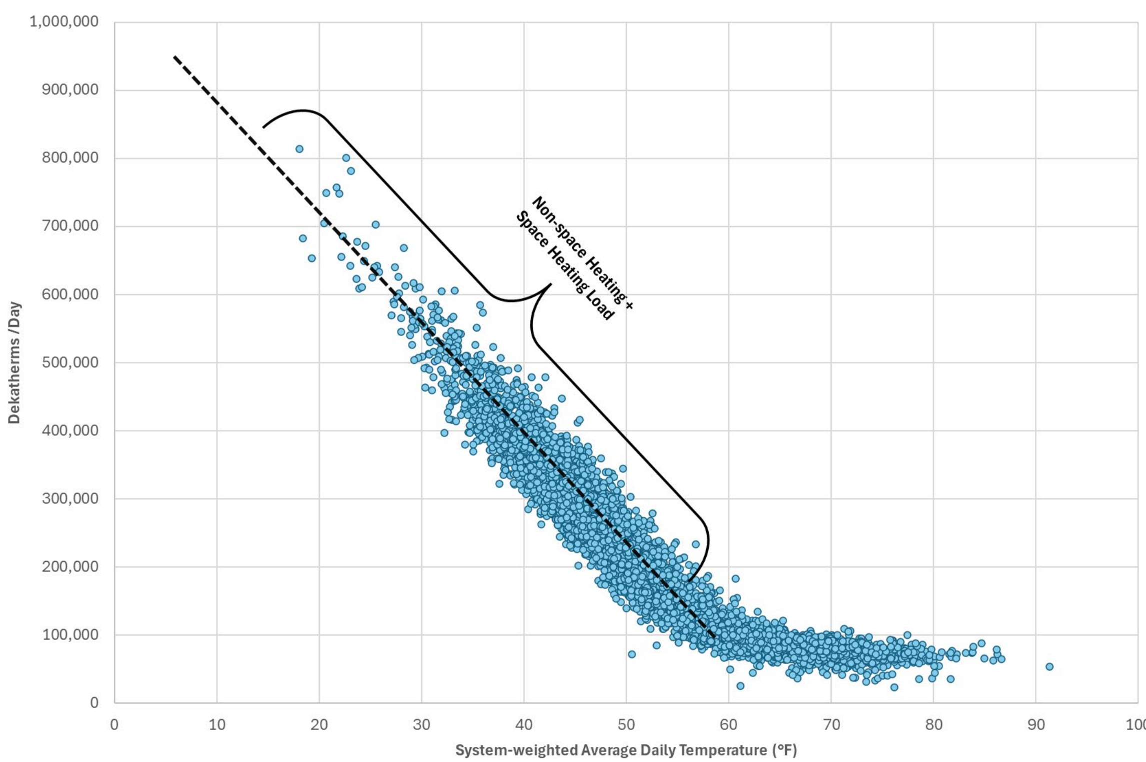
[34] Gas supply capacity requirements refer to the maximum daily volume of gas that the system can deliver to customers.
[35] This planning standard was first implemented in the 2018 IRP.
[36] A 1-in-100 winter is a measure of statistical likelihood. It does not mean that every 100 years a design winter occurs. It may be that two rare and cold winters occur within a 100-year time frame, or conversely, a design winter may not occur within a 100-year time frame.

detail in the sections immediately below. Equation (8) generalizes the linear model, in matrix notation:

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

where, $Y$ is a $n \times 1$ vector of daily system firm sales, $X$ is a $n \times 21$ matrix of explanatory variables and a constant term, $\beta$ is a $21 \times 1$ vector of estimated coefficients, $\epsilon$ is $n \times 1$ vector of residuals, and $n$ represents the number of daily observations. Specifically, the estimation of equation (8) only includes daily firm sales data for average temperatures less than, or equal to, 59°F.[37] Figure 4.30 shows a scatter plot of the average system-weighted temperature against the daily system firm sales load. Below 59°F a very clear negative linear relationship emerges between daily load and average temperature. The structural break in the relationship between average temperature and load at this 59°F inflection point is where space heating requirements ramp up.[38] This is analogous to the inflection point (K*) from the UPC modeling.

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




[37] Since this analysis focuses on modeling a design peak day, load data and respective explanatory variables where the daily average temperature is greater than 59°F is excluded when estimating the model coefficients.

[38] During a design winter peak event, it is predicted that more than 80% of NW Natural's firm sales would be used for space heating needs.

Ultimately, the estimated model coefficients are used in combination with Monte Carlo simulations of the explanatory variables to establish the peak day planning standard, discussed above, for resource capacity requirements.[39]

#### *4.4.2.1 Explanatory Variables – Main Effects*

Temperature is the predominant driver of load, but there are a variety of factors that can affect demand, particularly on a peak day. The daily system load model includes 12 explanatory variables—daily average temperature, previous day average temperature, customer count, wind speed, solar radiation, snow depth, a day-of-the-week indicator variable, a holiday indicator variable, a proxy for water heater inlet temperature, and an indicator variable for the COVID-19 pandemic shutdown beginning in March 2020.[40]

The remainder of this section discusses the rationale for the inclusion of these explanatory variables, referred to as the models “main effects,” as well as their economic influence on daily load. Table 4.3 summarizes the directional impacts of these variables on daily load. A negative sign indicates that the values of the explanatory variable and load move in opposite directions (e.g., as temperature decreases, peak load increases). In contrast, a positive sign indicates that the values of the explanatory variable and load move in the same direction (e.g., as customer count increases, peak load increases).

*Table 4.3: Main Effects on Daily Load*

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

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

The necessity of including a lag of the daily average temperature is due to the physical location of where data is collected and the speed at which gas flows through pipelines. Daily flow data is collected at NW Natural's gate stations and at on-system storage locations.[41] Since gas does not flow instantaneously, there is a delay between when customers use gas and when it flows and is measured through the gate stations.[42] Including the previous day's average temperature in the model helps capture this lagged response to changes in demand driven by temperature. Much like contemporaneous average temperature, a decline in the lagged average daily temperature will increase the estimated peak daily load.

Over time, NW Natural's customer count has increased, and this growth has resulted in an increase in the Company's peak daily load. The customer count variable captures the average effect of new (firm sales) customers joining the system. Relative to most of the weather and day-of-the-week variables, discussed below, the average impact of a single customer addition to daily load is economically, very small.[43]

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

Snow depth serves as a proxy for business and school closures. Accordingly, an increase in snow depth generally results in more closures, which at the system level results in a reduced estimated daily load since space heating needs are diminished.[44]

The day-of-the-week also impacts natural gas load. There is a statistically significant increase in average daily load during a weekday—defined as Monday through Thursday—relative to the weekend—defined as Saturday through Sunday. This weekend load reduction is mainly driven

[41] Any usage by non-firm sales customers is coincidently subtracted from flow data coming from the gate stations and on-system storage, but these customers may be located far from a gate station.
[42] The duration of the delay is dependent on several factors including the pipeline distance from the gate station and the speed of gas flow (which is dependent on the overall demand and pipeline pressure). This delayed response is applicable to all customers.
[43] The economic magnitude of a change in the explanatory variable on the (demand) response variable is determined by the coefficient estimates of the "main effects" and are reported in Appendix B.6. They can be interpreted as a one-unit change in the explanatory variable results in a x-unit change in the response variable, holding all else equal. For example, on average, a 1°F decrease in contemporaneous temperature results in an estimated increase of 11,464 dth/day, holding all else equal.
[44] Specific areas on NW Natural's system, particularly those with a high ratio of residential customers, may have a positive correlation with snow depth as residential customers are inclined to use more gas because of staying home, even after controlling for temperature.

by business and school closures for the weekend; its effect is akin to that of increased snow depth, though the magnitude of the weekend impact on average demand is much larger. Friday similarly shows a statistically and economically significant average daily load decline relative to other weekdays.[45] Similar effects are also observed on U.S. holidays.[46]

The COVID-19 economic shutdown reduced average daily load, as virtually all schools and most businesses were forced to close for social distancing protocols. While residential usage increased over this time frame, the aggregate effect on the system demand was negative.[47] While the world has long moved past this point in time, it is important to control for its historical effects on load, when modeling peak day conditions.

NW Natural uses the Bull Run River temperature as a proxy for water heater inlet temperature.[48] All else equal, colder inlet water temperatures require additional gas to heat the water to desired (warmer) temperatures and thus increases estimated peak day load.

#### *4.4.2.2 Explanatory Variables – Interaction Effects*

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

In total, there are eight "interaction effects" included in the model.[49] Table 4.4 summarizes the directional impacts of the interaction terms on daily load. The sign of the interaction term will typically take the opposite sign of the "main effects" variable. Hence, a negative interaction sign indicates that the effect of the directly related main variable on demand is dampened at higher

[45] For a gas day, Friday includes seven hours of Saturday. The inclusion of these hours into a Friday is a large driver as to why this weekday differs.
[46] U.S. holidays are defined as all U.S. Federal holidays.
[47] The COVID-19 pandemic indicator variable takes the value of one over the time span March 12, 2020, to December 31, 2021, and is zero otherwise.
[48] Portland is NW Natural's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).
[49] Not all "main effects" variables have a corresponding interaction term—this is due to either a reduction in model predictability or statistical insignificance.

average temperatures (i.e., the wind speed example). A positive interaction sign indicates that the effect of the inversely related main variable on demand is dampened at higher average temperatures.

*Table 4.4: Interaction Effects on Daily Load*

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

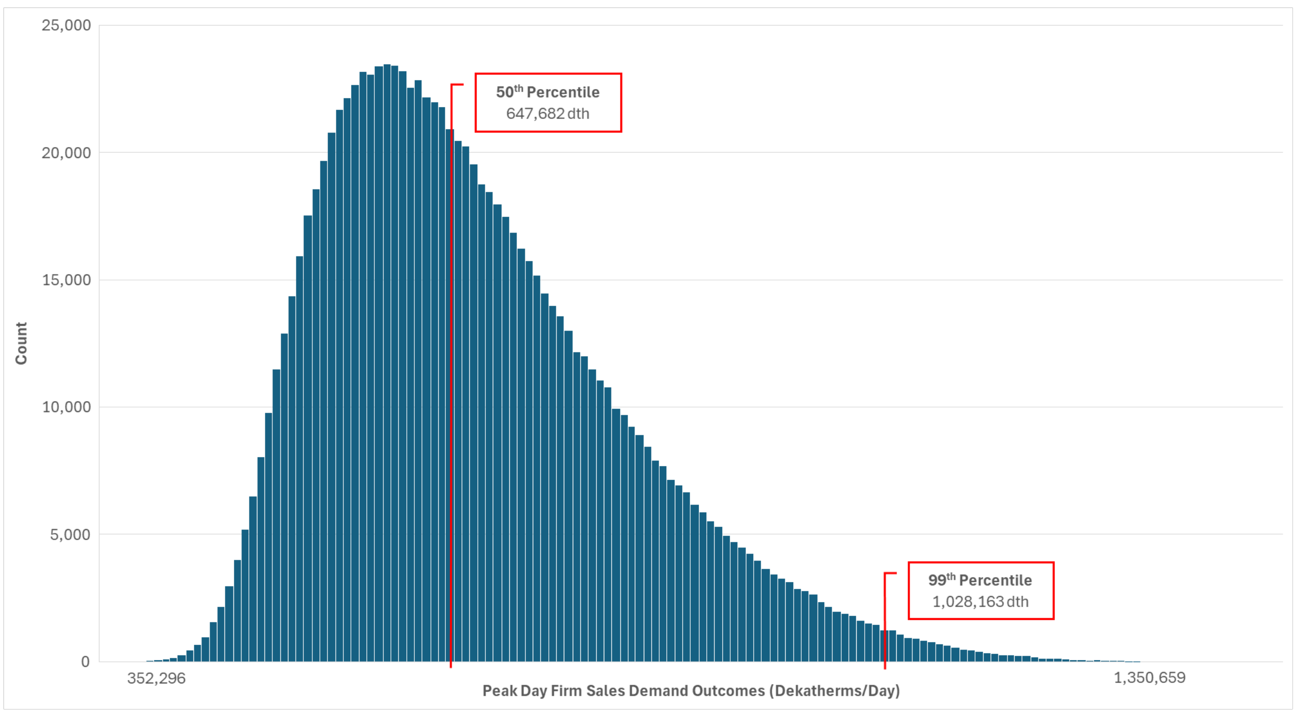
The interactions of contemporaneous average temperature with the one-day temperature lag, snow depth, the day-of-the-week indicator variable, and holiday indicator variable all take a positive sign. Thus, at higher average temperatures, the inversely related “main effects” of these variables on load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

#### *4.4.2.3 Design Peak Weather*

The regression coefficients from the firm sales daily system load model require input data to estimate a design peak day load. As discussed at the outset of this section, NW Natural implements Monte Carlo simulations of the explanatory variables of demand to establish the $99^{th}$ percentile planning standard. A Monte Carlo simulation is simply a method used to understand the behavior of system demand. It involves using random values for inputs to simulate many possible demand outcomes and then analyzing those outcomes to establish the capacity planning standard. In essence, Monte Carlo simulations are a way to model uncertainty and variability in NW Natural's complex system by repeatedly sampling random values and observing the impact on demand.[50]

Ultimately, the Monte Carlo simulations of the explanatory variables create a distribution of peak day demand. From this distribution the 99th percentile is calculated to establish the firm sales peak load that has a one percent chance of occurring (i.e., akin to a 1-in-100-year weather event). To illustrate the standard which NW Natural plans its system resources for peak day, Figure 4.31 shows the difference between a 1-in-2-year (50th percentile) and a 1-in-100-year (99th percentile) firm sales peak load from one million Monte Carlo simulations.[51] Note that the 1-in-2-year threshold indicates the level of peak demand that NW Natural would expect to exceed about 50 percent of the time.

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



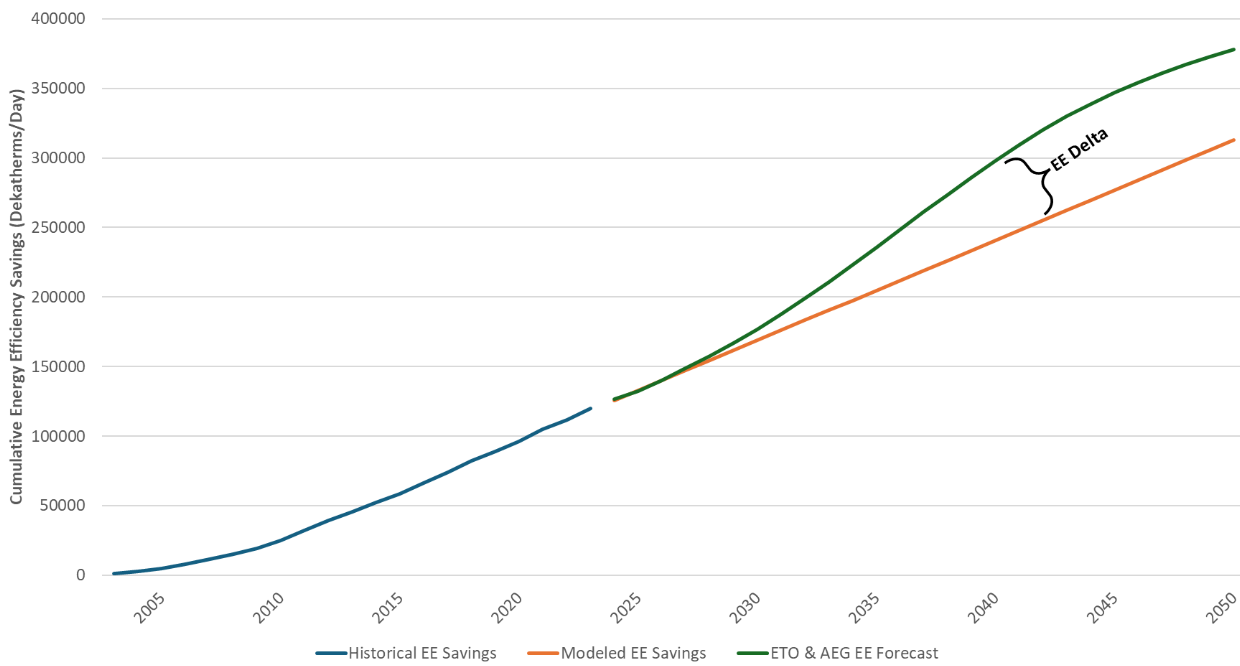

## 4.4.3 Design Peak Day Energy Efficiency

The 99th percentile demand for a peak day requires an adjustment based on the peak energy efficiency savings forecast. The peak day model utilizes SCADA data starting in 2009 to capture underlying trends in gas usage.[52] A cumulative increase in peak day savings from energy efficiency is one of these underlying trends. To account for this trend, NW Natural estimates a

[50] Details of the Monte Carlo simulation are provided in Appendix B.6.
[51] Since customer count is a model input, the percentiles are dynamic and change in the future as a function of changes in the customer count forecast.
[52] Data for peak day modeling spans 15 years (2009 – 2023).

time trend regression of historical cumulative system peak day energy efficiency savings, driven by energy efficiency programs. The delta between the forecasted time trend energy efficiency savings and the peak day efficiency savings forecasted in the CPAs is subtracted from the 99$^{th}$ percentile load. Figure 4.32 shows the plot of these values over the forecast horizon.

*Figure 4.32: Peak Day Savings Estimates*

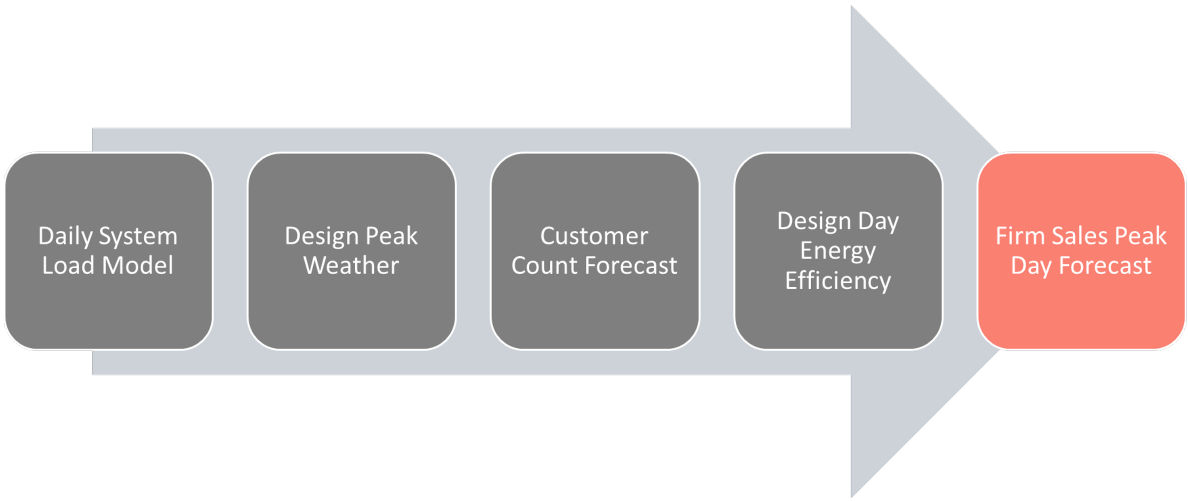



The design peak day therm savings are calculated using peak factors estimated by NW Natural for each end-use and are further discussed in detail in Chapter 6. These same factors are applied to the annual firm sales savings forecasted in the CPAs.

## 4.4.4 Peak Day Forecast

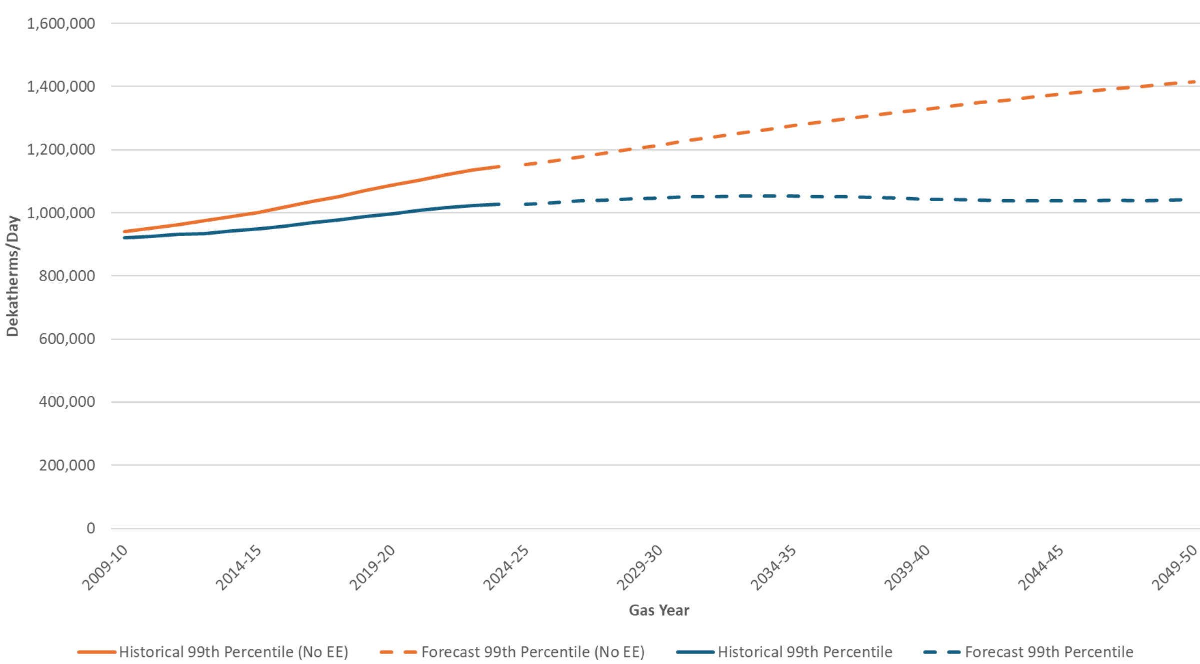
Following Figure 4.33, the daily system load model is estimated using historical cold weather data (i.e., less than 59°F). Next, Monte Carlo simulations are run for the explanatory variable inputs. Next, the randomly simulated model inputs and the customer count forecast are passed through the daily system load model to generate peak day firm sales demand outcomes, from which the 99$^{th}$ percentile is extracted as NW Natural's planning standard. Finally, the 99$^{th}$ percentile load is decremented by the estimated energy efficiency savings delta to arrive at the design peak day load forecast (see Figure 4.35).

*Figure 4.33: Flow Diagram of Peak Day Load Forecast*




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

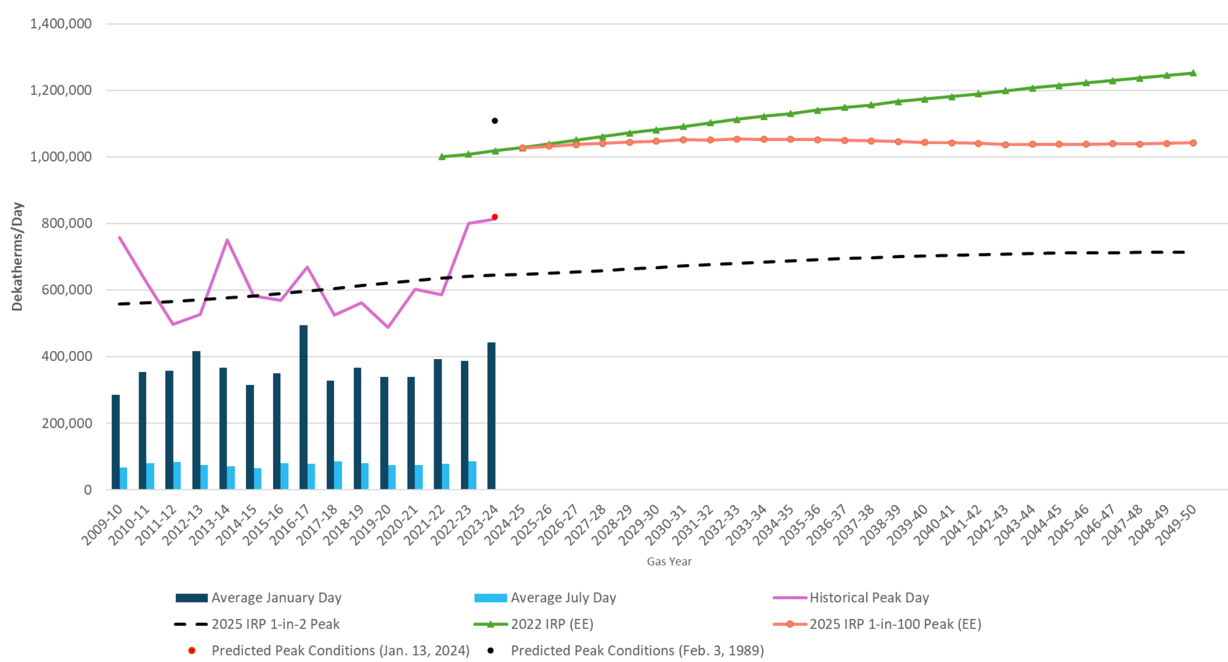
*Figure 4.34: Firm Sales Peak Day Load Forecast with and without Energy Efficiency*




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

Figure 4.35 captures a tremendous amount of useful information around historical and forecasted design peak days. To contextualize the seasonal demand change for natural gas, the vertical bars highlight the larger average daily load and volatility in a winter month (January) vs. a summer month (July). Further, the magenta line charts NW Natural's firm sales peak day demand, by gas year, relative to the 50th percentile winter estimate (black dashed line) from the model. The red dot marks the daily system load model peak day prediction for the prior winter (gas year 2023-24).[53] In contrast, the black dot represents the weather conditions of February 3, 1989, applied to our current customer base.[54] Its value corresponds to 1,108,331 dth/day and highlights the importance of having a high planning standard for peak day as the conditions which drive such a high peak load have occurred within the last 40 years.[55] Finally, the salmon line with circle markers is the 2025 IRP peak day planning standard (i.e., the 99th percentile planning standard inclusive of estimated peak day energy efficiency savings).[56] The green line with triangle markers is the analogous peak day forecast from the 2022 IRP. In the near-term, the 2025 IRP peak day planning standard is indistinguishable from the 2022 IRP planning standard. However, further out in time the two forecasts begin to diverge due to a few methodological changes in the peak day weather design simulation, in addition to downward customer count forecast revisions relative to the 2022 IRP.

*Figure 4.35: Historical and Forecast of Annual Peak Load*

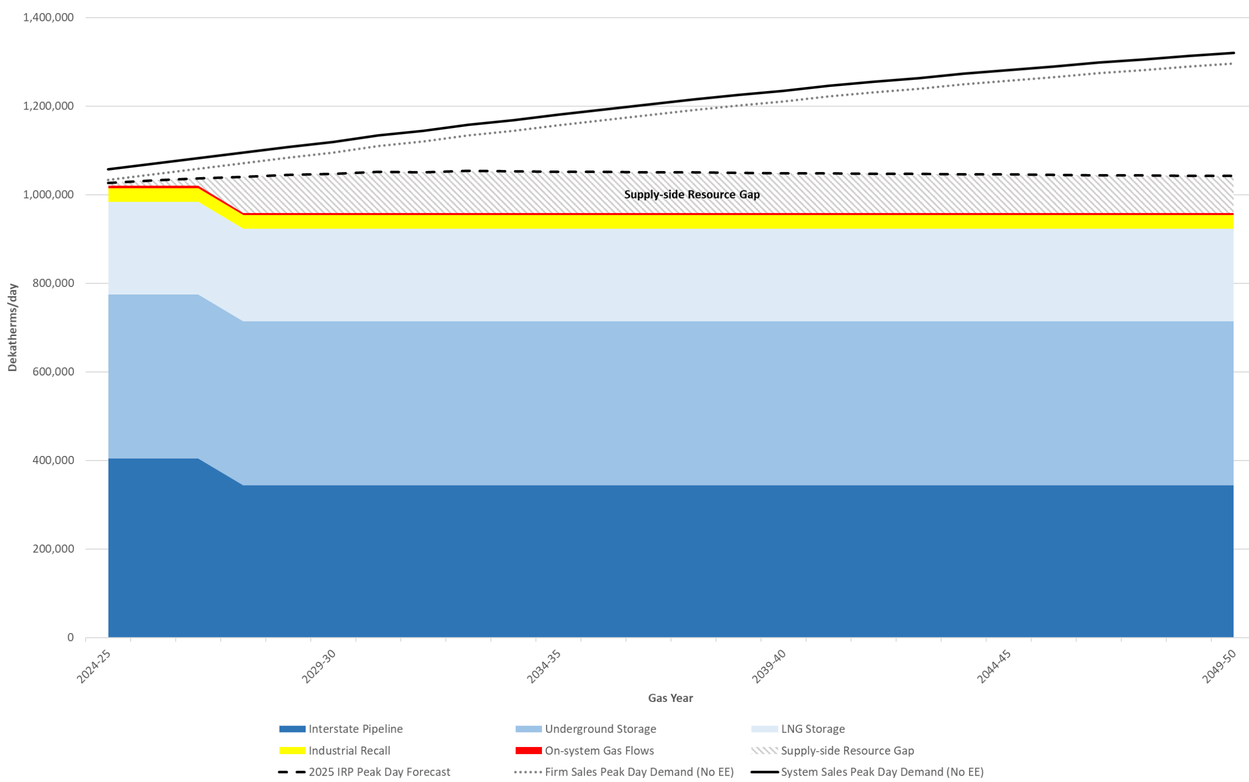



[53] The actual demand on January 13, 2024, was 813,860 dth/day vs. the model forecast of 818,948 dth/day.
[54] This is the coldest date on record for the state of Oregon.
[55] This estimated peak value is between the 99.7th and 99.8th percentile for the most recent gas year.
[56] The peak day forecast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

#### *4.4.4.1 Resource Stack/Capacity Needs*

Figure 4.36 illustrates NW Natural's resource stack to meet peak day needs. The gap between the design peak load net of energy efficiency and the expected resources represents the capacity needs for the Company to address.[57] The options to fill this gap are discussed in Chapter 8, and the least cost results for filling the gap for each scenario and across simulation draws are shown in Chapter 9.

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




## 4.5 Load Uncertainty and Scenario Development

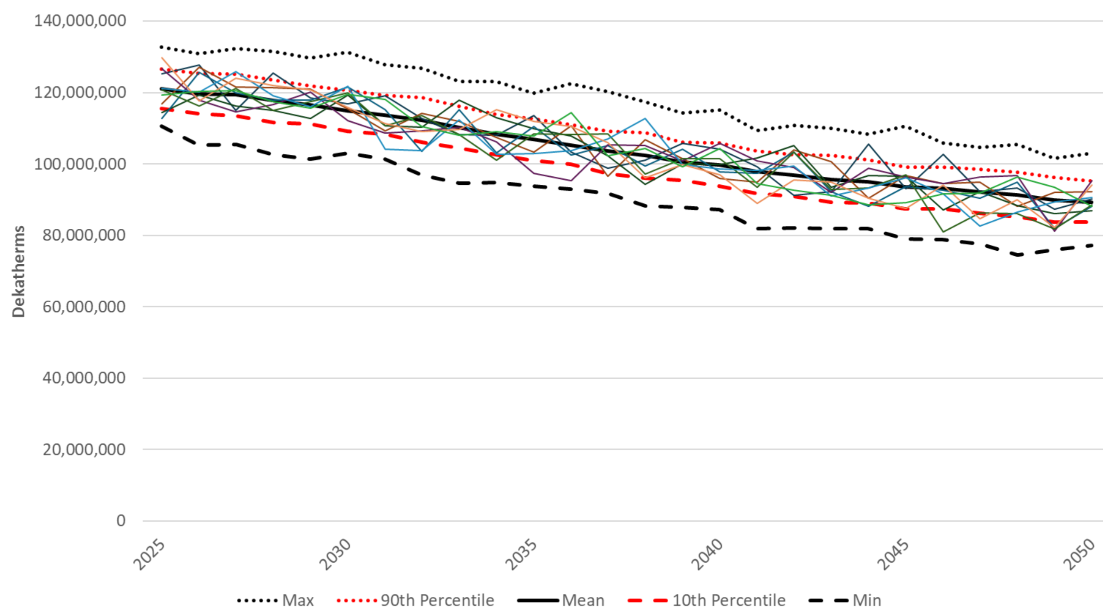
### 4.5.1 Reference Case Demand Stochastics

As discussed in prior sections, weather is a predominant driver of load. Given this, 500 stochastic weather simulations are run, and the resulting temperatures are input into the UPC model to estimate residential and small commercial load under those draws. Further, the industrial and large commercial econometric models are augmented with an HDD factor, so

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

that these loads also exhibit some level of temperature sensitivity.[58] Aggregating these loads across the 500 draws, by year, produces Figure 4.37. The average load profile, across the planning horizon, exhibits the same downward trend as seen in the Reference Case. However, the stochastic analysis reveals much higher (lower) demand under colder (warmer) weather conditions, while still maintaining the downward trend.[59]

*Figure 4.37: Total System Stochastic Weather Demand*




## 4.5.2 Demand Scenarios

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

[58] Both macroeconomic models yield significant betas when augmenting with annual log changes in HDDs. What is more, the sensitivity of these augmented factors to changes in HDDs is, economically, much smaller than the sensitivity to the models respective macroeconomic loading factor.
[59] The solid colored lines represent ten randomly selected stochastic draws.

*Table 4.5: Demand Scenarios*

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

## 4.6 Emissions Requirements

### 4.6.1 Oregon Emissions Requirements

Figure 4.38 shows Oregon's emissions requirements under the Climate Protection Program (CPP) with NW Natural's forecasted emissions from the annual load projection described in Section 4.3.

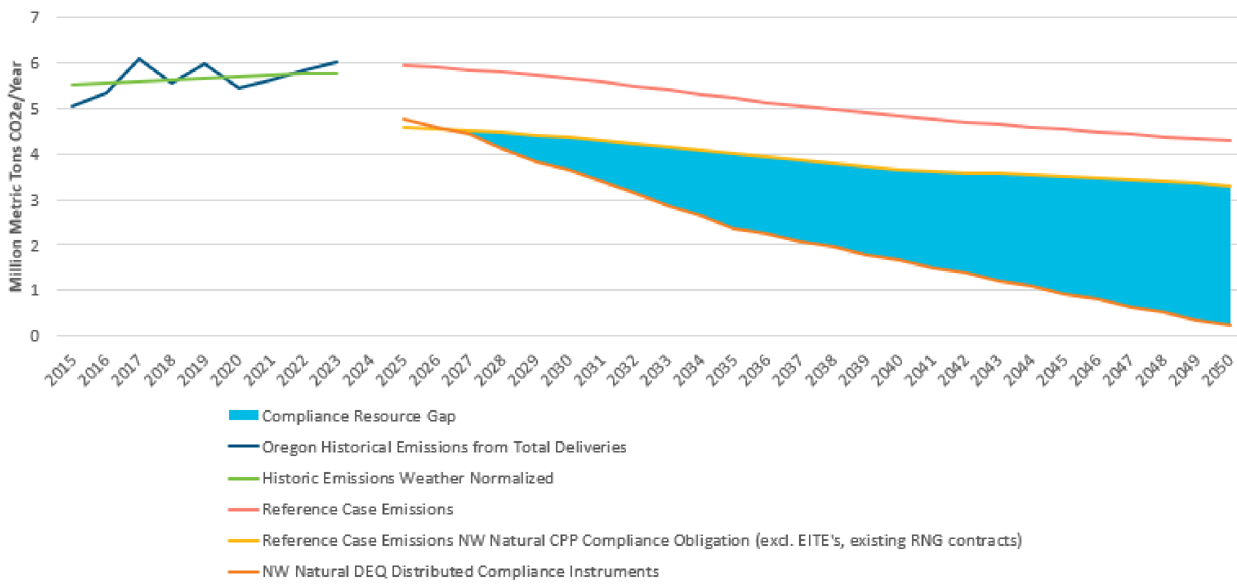
In the years before 2025, this figure contains two series. First, historical emissions from total deliveries between 2015 and 2023.[60] Historical emissions fluctuate due to variance in weather. Therefore, a second series that normalizes NW Natural's historical emissions is also shown.[61]

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

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

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

*Figure 4.38: Oregon Emissions Compliance Resource Requirements*




Between 2015 and 2023, NW Natural's emissions ranged from 5.05 million (2015) and 6.09 million (2017) MT $CO_2$e, with an average of 5.66 million and standard deviation of 0.33 million. In 2023, emissions were 6.02M MT$CO_2$e. NW Natural projects that from 2025 to 2050, Oregon emissions in the reference case will fall from 5.93 to 4.28 million MT $CO_2$e. Over the same period, compliance emissions (which excludes EITE's and existing RNG) is forecasted to fall from 4.57 to 3.31 million MTCO2e. On average, Oregon compliance emissions are 30 percent less than the total reference case forecasted emissions.

Starting in 2027, NW Natural does not expect to receive sufficient compliance instruments to cover compliance emissions. Between 2027 and 2050, the Company forecasts this gap will expand from 0.09 million (two percent) to 3.06 million MT $CO_2$e (93 percent)[62]. This gap is based on energy use projections from expected weather. Due to variance in winter weather, the size of the realized compliance gap will vary much more from year to year.

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

### 4.6.2 Washington Emissions Requirements

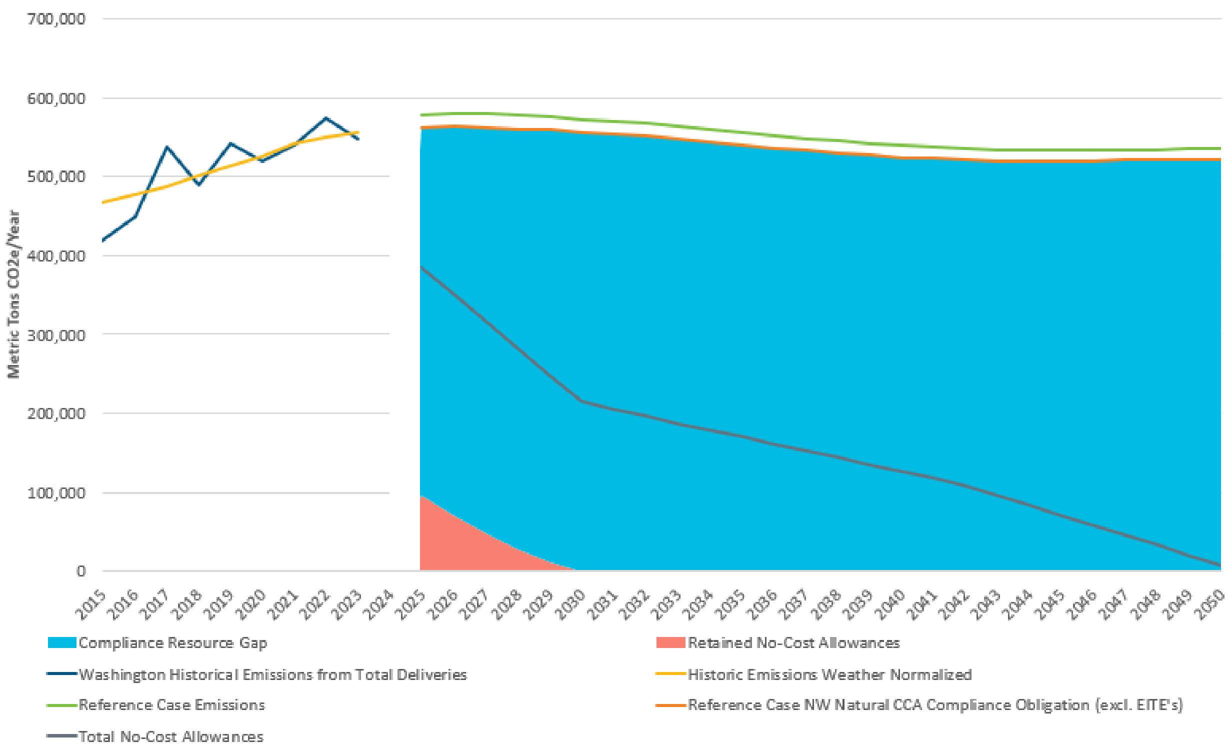
In similar fashion as Figure 4.38, Figure 4.39 contrasts Washington's emissions requirements under the Climate Commitment Act (CCA) with the NW Natural's forecasted emissions from the

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

annual load projection described in Section 4.3. It shows historic emissions and weather-normalized historic emissions from 2015 – 2023, as well as reference case emissions and reference case emissions without emissions from EITEs.

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

*Figure 4.39: Washington Emissions Compliance Resource Requirements*




Between 2015 and 2023, NW Natural's emissions ranged from 419,862 (2015) and 573,619 (2022) MT $CO_2e$, with an average of 513,223 and standard deviation of 47,725. In 2023, emissions were 547,472 MT $CO_2e$. NW Natural projects that from 2025 to 2050, Washington emissions in the reference case will fall from 578,247 to 535,536 MT $CO_2e$. Over the same period, compliance emissions (which excludes EITE's) is forecasted to fall from 561,236 to 522,544 MT $CO_2e$. On average, Washington compliance emissions are three percent less than the total reference case forecasted emissions.

The gap in compliance emissions ranges from 464,965 in 2025 to 522,544 in 2050. Though NW Natural will have to consign most of them at auction, NW Natural anticipates receiving 385,081 allowances in 2025.[63] That figure falls to 7,799 by 2050. During this period, the Company forecasts total allowances as a share of compliance emissions will decline from 69 percent (2025) to 1.5 percent (2050).

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

### 4.6.3 Emissions Under Various Load Scenarios

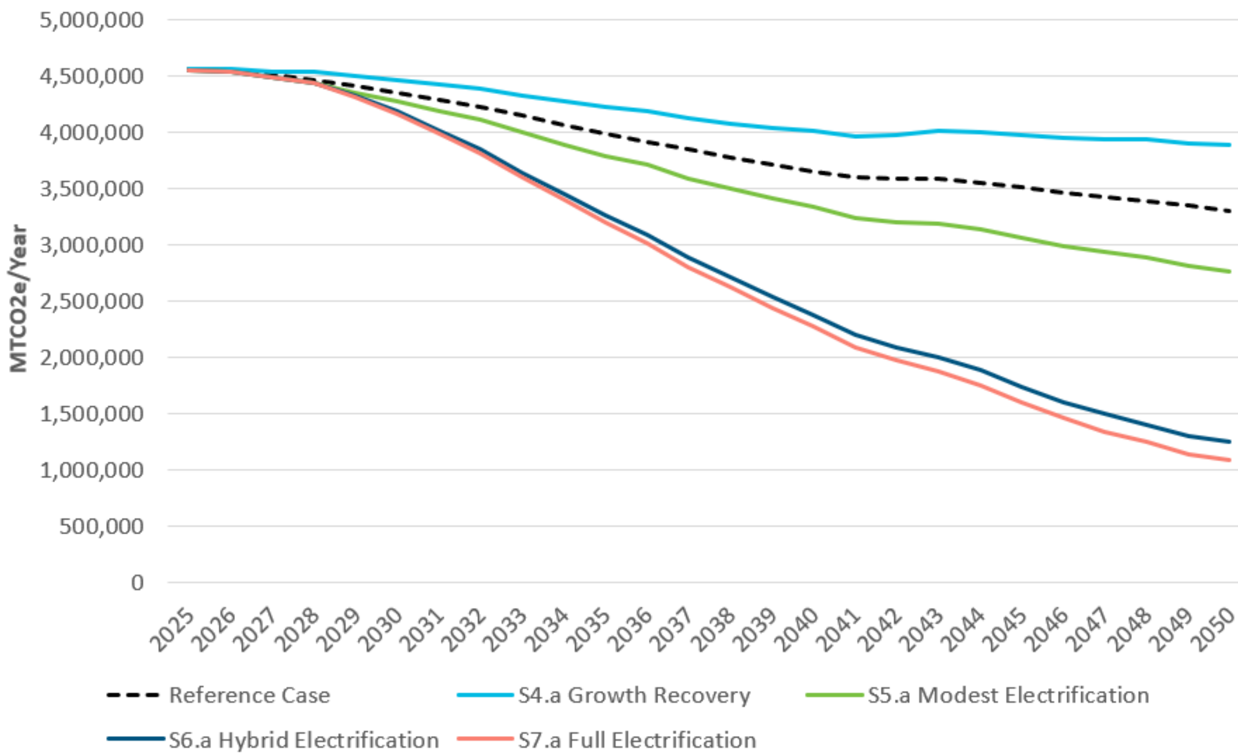
Figures 4.40 and Figure 4.41 compare the compliance obligations of five of the scenarios examined in this IRP for Oregon and Washington, respectively. They present emissions for the reference case, the growth recovery scenario, and three electrification scenarios: modest electrification, hybrid electrification,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

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

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

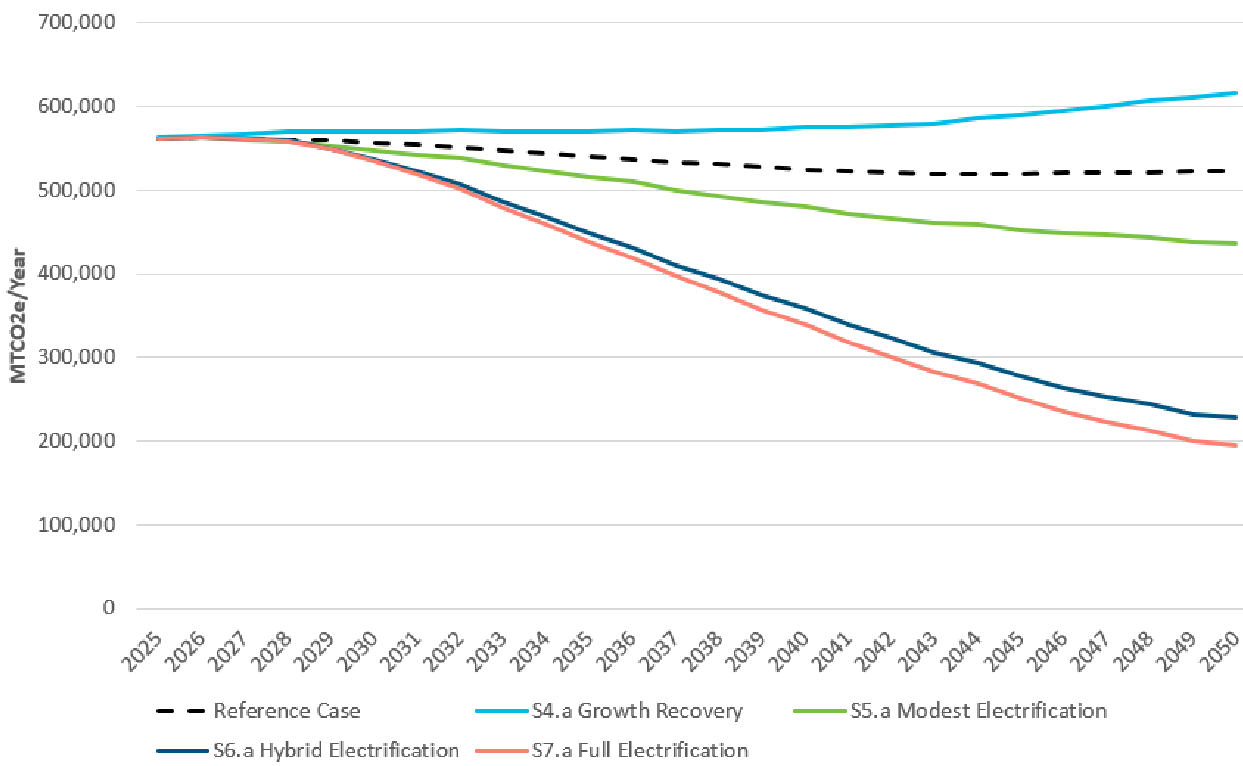
[63] Each allowance covers 1 $MTCO_2e$.

*Figure 4.40: Oregon Compliance Load Under Various Scenarios*




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

*Figure 4.41: Washington Compliance Load Under Various Scenarios*




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

# Chapter 5 - Avoided Costs

Choosing amongst resource options requires understanding the cost tradeoffs amongst resource options. Chapter 5 describes the methodologies used to determine the costs that are avoided when one resource is chosen over the other available options.

## 5.1 Avoided Costs

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

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

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

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

This chapter also presents the avoided costs results for both the demand-side and the supply-side resources to which the concept is applied. NW Natural continues to work on improving its methodologies and internal processes relative to avoided costs in a continuing effort to ensure that all resources, be they demand- or supply-side, are evaluated on a fair and consistent basis in a fully integrated process.

## 5.2 Avoided Cost Components

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

*Table 5.1: Avoided Costs Components and Application Summary*

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

### 5.2.1 Energy Related Avoided Costs

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

#### *5.2.1.1 Gas Purchase and Delivery Costs*

This component represents the cost of the natural gas commodity itself. The main driver of this cost is the base case natural gas price forecast detailed in Chapter 2.2, though it also includes the following minor costs: 1) "line losses," or the amount of gas that is used to deliver gas from where it is purchased to where it is consumed; 2) applicable variable transmissions costs; and 3) storage inventory carrying costs. On any given day in the forecast period, the avoided gas purchase and delivery costs represent the cost of the last unit of gas sold during that particular day[64], where that unit may be from an expected daily spot purchase or a storage withdrawal depending on the load that needs to be served and gas prices on that day. This daily figure comes from the resource planning optimization PLEXOS model and is aggregated to the monthly level. Note that avoided commodity and delivery costs varied not only through time but also across end uses. Therefore, each end use has its own gas purchase and delivery estimate based on the seasonal usage or supply portfolio of that resource and the seasonality of natural gas prices exhibited in the price forecast. The details of this calculation can be found in Appendix C.

#### *5.2.1.2 Greenhouse Gas Emissions Compliance Costs*

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

> Source 1. Combustion emissions costs by end use customers (Direct Use), calculated as the maximum of a or b in equation (9):

$$MAX\begin{cases} a.\,Social\ Cost\ of\ Carbon\left(\frac{\$}{MT}\right) * Emissions\ Intensity\ of\ Combustion\left(\frac{MT}{Dth}\right) \\ b.\,GHG\ Policy\ Compliance\ Cost\ \left(\frac{\$}{Dth}\right) \end{cases} \quad (9)$$

> Source 2. Equation (10) is gas supply chain emissions costs, calculated as:

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

$$Social\ Cost\ of\ Carbon \left(\frac{\$}{MT}\right) * Emissions\ Intensity\ of\ Gas\ Supply\ Chain\ \left(\frac{MT}{Dth}\right) (10)$$

The total avoided GHG compliance costs are the sum of the combustion emissions costs and the supply chain emissions costs. Note both emissions intensity of gas combustion and the emissions intensity of gas supply chain are estimated based on data sources including EPA Subpart W, GREET Model, and GHGenius. The emissions intensity of gas supply chain also includes lifecycle system leakage in the form of CH4. Social cost of carbon is based on Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, August 2016, as approved by WA HB 1257 and published on WUTC website.[65] Also, social cost of carbon per Dth in the calculation of avoided combustion emissions costs (Source 1) represents the lower bound of the GHG avoided costs of natural gas for this emissions source.

#### *5.2.1.3 Commodity Price Risk Reduction Value of DSM*

Natural gas prices are volatile and uncertain, particularly when analyzing long-term price forecasts as is necessary to: 1) forecast costs in IRPs; and 2) evaluate the cost-effectiveness of resource options that provide energy savings or gas supply for multiple years (and in the case of DSM, sometimes indefinitely). If price hedging is not used to remove or mitigate this price volatility and uncertainty, customers are exposed to changes in the trend of prices in the long-term, and price fluctuations around this long-term trend in the short-term. DSM savings are a type of long-term hedge: if the actual energy savings that are going to be acquired and the costs to obtain those savings are known with certainty, acquiring demand-side savings removes the price risk associated with unhedged supply resources that would be necessary if energy savings were not acquired. [66]

The hedge value of DSM represents the risk premium gas purchasers need to pay (i.e., the cost to fix the price) to obtain a long-term fixed price financial hedge at the time of the IRP analysis.[67] This IRP applies the same methodology as filed in the 2022 IRP to measure the commodity price risk reduction value as the portfolio risk-adjusted present value revenue requirement (rPVRR) calculated based on data from Monte Carlo gas price simulations equation (11):

*Risk Adjusted Cost of Gas = 75% × Mean Price + 25% × 95th Percentile Stochastic Price (11)*

[65] WUTC website https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon
[66] This component is thus also referred to as the "hedge value of DSM".
[67] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.

The second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the associated price risk. This is the risk that a hedge protects against, and hence the risk reduction value is calculated in equation (12):

*Risk Reduction Value = Risk Adjusted Cost of Gas – Mean Stochastic Price of Gas (12)*

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

#### *5.2.1.4 Greenhouse Gas Compliance Cost Risk Reduction Value of DSM*

In the 2025 IRP, NW Natural proposes the use of the approach to calculating the price risk reduction value described above to estimate risk reduction values for compliance costs given the uncertainty in environmental compliance costs. Environmental compliance costs are uncertain and even volatile for a couple of reasons. First, the social cost of carbon can be much higher than what is currently published on the WUTC website mentioned earlier per a recent report by U.S. Environmental Protection Agency (EPA).[68] Second, the costs of some environmental compliance resources such as renewable or low carbon natural gas are forecasts with uncertainty. PLEXOS based Monte Carlo compliance cost simulations are used to generate data for this risk reduction value calculation in equation (13):

*Risk adjusted cost of compliance = 75% × Base Case Compliance Cost + 25% × 95$^{th}$ Percentile Compliance Cost (13)*

Again, the second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the cost risk associated with compliance resources. This risk reduction value is calculated in equation (14):

*Compliance Risk Reduction Value = Risk adjusted cost of compliance – Mean Stochastic Cost of Compliance (14)*

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

[68] https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

## 5.2.2 Infrastructure Related Avoided Costs

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

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

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

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

### *5.2.2.1 Supply Capacity Costs*

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

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

Given the longstanding process of coordination between NW Natural and ETO/AEG (see Figure 5.1 for a visual depiction of this coordination) the DSM savings projections provided by ETO and AEG are completed before the supply resource optimization. Therefore, the incremental supply resources that would be saved for each year in the planning horizon with DSM need to be assumed before the supply resource optimization to assign a cost for the supply capacity costs being avoided based on prior IRP modeling output. The assumptions made about what supply portfolio resources would be acquired in each year can be different from the actual supply resource choices detailed in Chapter 12 Distribution System Planning.[69] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization. Different from prior IRPs, this IRP's modeling results show that avoided supply capacity costs exist from 2026 to 2033 and no avoided supply capacity costs at all from 2034 and onwards because there are no supply capacity expansion needs after 2033 as system peak day loads start to decline in 2034 till the end of the planning horizon (see Chapter 4 - Load Forecast).

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

To quantify the avoided supply capacity costs as benefits for DSM measures or supply resources, energy savings or supply on a peak day as well as the ratio of peak day savings or supply to normal weather annual energy savings or supply need to be estimated for each resource option. DSM measures or resources targeting at different end uses such as space heating, water heating or cooking have different peak day savings to annual savings or supply ratios that are defined in annual energy savings or supply shapes specific to each end use. Assuming the savings shape and the load shape are the same, these peak day to annual savings or supply can be obtained by estimating the peak day energy usage and annual usage of the end use to which a DSM measure or resource belongs with equation (15):

$$Peak\ Day\ to\ Annual\ Usage\ Ratio = \frac{Peak\ Day\ Energy\ Usage}{Normal\ Weather\ Annual\ Energy\ Usage} \quad (15)$$

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

As shown in Table 5.2, various approaches and sources of information were used to estimate the peak day to annual usage ratios for the end uses considered. The peak day to annual usage ratios for the largest contributor to peak day load, space heating, are estimated by the

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

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

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

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

#### *5.2.2.2 Distribution Capacity Costs*

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

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

In alignment with the guidance on the calculation of infrastructure avoided costs provided in OPUC Order No. 25-017,[70] this state-specific calculation relies on historical data of the costs to reinforce NW Natural's distribution system and is based on an average of the revenue

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

requirement of reinforcement projects that were completed over the previous 10 years from 2014 to 2023. Note that these costs do not include the costs associated with installing new services or meters, operation and maintenance costs, or with commodity purchases or our supply capacity resources. They represent only the cost of service revenue requirement of capital expenditures to reinforce the distribution system so that it is sufficient to reliably serve all our customers. The primary driver of these costs is growing peak hour load. Therefore, to estimate the cost of reinforcing NW Natural's distribution system as peak hour load grows, the growth in peak hour load for each of Oregon and Washington over the same 10 years was estimated using the peak hour load forecasting technique described in Chapter 12 Distribution System Planning. Dividing the revenue requirement from the sum of the reinforcement projects over the past 10 years by the growth in peak hour load over the same period, gives an estimate of the cost of incremental peak hour load on a per unit of peak hour load for the two states in our service territory. This is the estimate of the costs that would be avoided by serving or saving a unit of gas on a peak hour.

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

For each resource considered, the amount of natural gas it will supply or save on a peak hour is what is determined for each resource evaluated. Given that the peak hour is typically the hour starting at 8 a.m. on the peak day, this is done by estimating the share of peak day savings/supply that will occur during that hour and multiplying this factor by the peak day factors in Table 5.3. Take the largest contributor to peak hour load, space heating, as an example: dividing the peak hour space heating load (8 a.m.) by the total space heating load for the peak day, provides an estimate of the share of peak day load served during the peak hour that distribution system infrastructure is designed to serve. This estimate was made using two sources, NW Natural system hourly flow regressions and the Electric Power Research Institute (EPRI) residential peak space heating load shape. These sources were averaged to calculate the hourly to daily peak hour factor for residential space heating. Using NW Natural's hourly load forecasting methodology described in Chapter 4, subtracting summer loads from peak day loads for each hour of the day provides an estimate of space heating load on a peak day, which can then be turned into the peak hour factor described above. For space heating, this factor is 5.21 percent for residential and 6.02 percent for commercial.[71] Multiplying this factor times the peak day factor in Table 5.3 gives an estimate that the average residential NW Natural customer would use the equivalent of 0.092 percent of their normal weather *annual* residential space heating load on a peak hour. This figure, along with the peak hour to annual usage ratios for the other end uses considered in this IRP, is shown in Table 5.3.

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

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

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

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

#### *5.2.2.3 Unquantified Conservation Avoided Costs*

**Ten Percent Northwest Power and Conservation Council Conservation Credit**

In prior IRPs, this credit was applied for DSM and calculated from a summation of all the components of avoided costs except the risk reduction value of DSM and the GHG compliance cost components. Per Staff recommendations adopted in OPUC Order No. 24-119,[72] this IRP applies this 10 percent conservation credit to all avoided cost value streams including the risk reduction value and avoided GHG compliance costs. Note that even though the ten percent conservation credit is applied consistently across all DSM resources, the actual credit included in avoided costs varies since some of the avoided costs components vary by state, end use,

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

and/or time. While the credit was originally designed to apply to DSM, it is unclear whether it should also be applied to supply-side resources that also conserve the use of conventional natural gas (most notably renewable natural gas) so that demand- and supply-side resources are treated on a fair and consistent basis per Oregon PUC's IRP guidelines. NW Natural has not included the Conservation Credit in the avoided costs of any resources except DSM in this IRP, but it warrants consideration in future IRPs.

## 5.3 Demand Side Applications

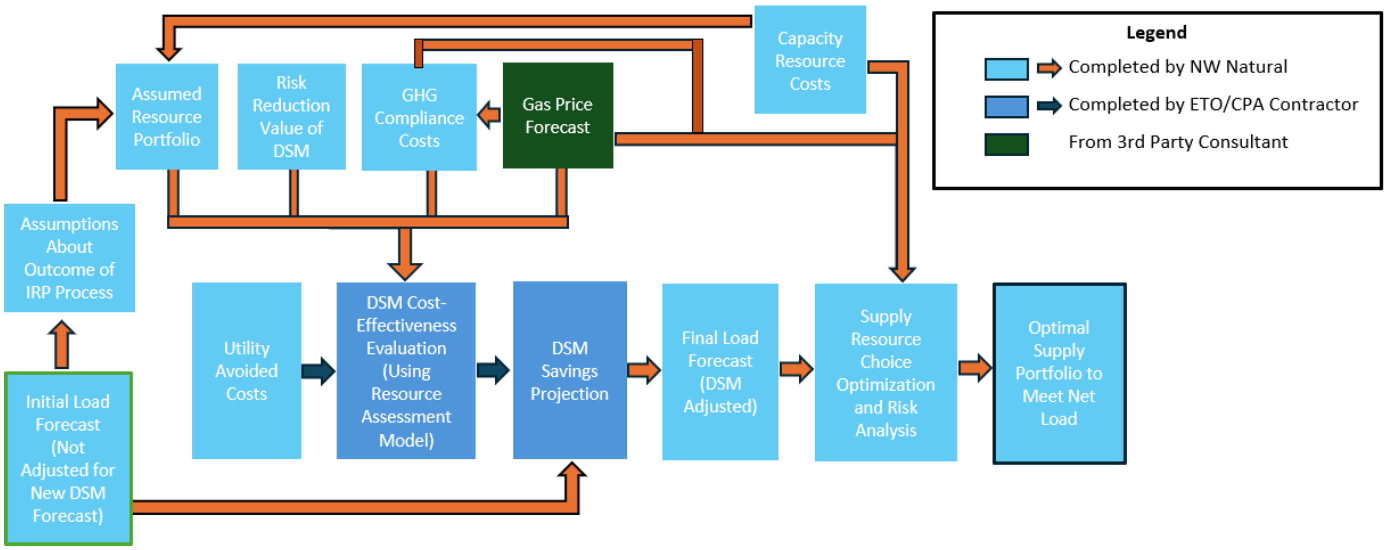
### 5.3.1 Avoided Costs and DSM in the Overall IRP Process

Figure 5.1 details how avoided costs and DSM energy savings forecasts, also referred as conservation potential assessments (CPAs), are integrated into the broader IRP process and what work is completed by NW Natural and what work is completed by ETO or other CPA contractors. Note that NW Natural has been using an avoided cost approach to compare demand-side and supply-side resources and this approach is necessarily an iterative process between IRPs or IRP updates and CPAs.[73] This iterative process is used because the CPA is conducted first based on the most up-to-date avoided costs and load forecasts (absent DSM energy savings). Ultimately, the savings forecasted in the CPA are netted out of the load forecast, an input to the Resource Planning Optimization Model (see section 9.2 for further details) that results in a new set of avoided costs.[74]

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

[74] The CPA work takes 6-12 months to complete and therefore the initial load forecast may not be the exact same as the final load forecast that the savings are netted from as the Company regularly updates components of the load forecast.

*Figure 5.1: NW Natural IRP Process*




An alternative and separate approach would be to compile bundles of DSM savings as selectable options within the Resource Planning Optimization Model. There are pros and cons to either approach. NW Natural raised key questions and discussion points about pursuing this alternative approach in the first round of reply comments in OPUC docket LC 79.[75] These reply comments discuss the pros, cons, and level of coordination with the DSM implementors needed to employ this alternative approach. The discussion around moving to an alternative approach has yet to be concluded. For this IRP, NW Natural continues to rely on the avoided cost framework that has been in place for the last several IRPs for evaluating demand-side resources.

### 5.3.2 Avoided Costs Component Breakdown Through Time

*TBD*

### 5.3.3 Avoided Costs Across Integrated Resource Plans

*TBD*

### 5.3.4 Avoided Costs for Carbon Emissions Compliance

*TBD*

[75] See section 1.5 Energy Efficiency and Demand Response as Selectable Resources in the Resource Optimization Model in NW Natural's reply comments filed February 3, 2023 in OPUC docket LC 79.

## 5.4 Supply Side Applications

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

### 5.4.1 Avoided Costs of Low Carbon Gas Supply

Natural gas supply alternatives that have a carbon intensity lower than conventional natural gas avoid expected GHG compliance costs, and under some regulatory frameworks the costs avoided depend upon the carbon intensity of the resource. For example, if a source of renewable natural gas has a carbon intensity of zero, it would avoid all of the expected GHG compliance costs associated with conventional natural gas. Chapter Seven Supply-Side and Compliance Resources details the average carbon intensities of different types of renewable natural gas. The specific avoided cost items applied to these lower carbon gas supply resources are shown in Table 5.4, which shows that GHG compliance costs avoided are applied to all low carbon gas resources.

*Table 5.4: Costs Avoided by Low Carbon Resource Type*

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

### 5.4.2 Avoided Costs of On-System Gas Supply

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

# Chapter 6 - Demand-Side Resources

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

## 6.1 Energy Efficiency

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

NW Natural has energy-efficiency programs for residential, commercial, and industrial customers. Program overviews and achievements are published in public reports filed with the OPUC and WUTC for programs in the respective states. Oregon results are included in Energy Trust's 2024 Annual Report[76] and all Washington reports are posted on the Company's regulatory activity page.[77]

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

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

[76] Energy Trust 2024 Annual Report: https://www.energytrust.org/2024-annual-report/

[77] NW Natural Regulatory Activity Page: https://www.nwnatural.com/about-us/rates-and-regulations/regulatory-activity

## 6.2 Oregon Energy Efficiency and Conservation Programs

*As the administrator for NW Natural energy efficiency programs, the Energy Trust provides the following information specific to NW Natural territory in Oregon[78] (shown in maroon text).*

### 6.2.1 Energy Trust Background

In 2002, as part of an agreement that allowed NW Natural to implement a decoupling mechanism, the Public Utility Commission of Oregon directed the Company to collect a public purpose charge for the funding of its residential and commercial energy efficiency programs and low-income programs, and to transfer the responsibility of energy efficiency programs to a third party.[79]

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

After NW Natural's 2008 IRP[80] identified that cost-effective industrial savings were available, the Company worked with Energy Trust to launch an Industrial demand-side management (DSM) program in Oregon. This program is available to large Firm and Interruptible Sales customers. Costs for the program, described in Schedule 360 of the Company's tariff, are deferred for recovery a year later through the charge published annually in Schedule 188. NW Natural worked with Energy Trust to launch a DSM program for Transportation customers beginning in 2024.

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

Since October 1, 2009, NW Natural has provided energy efficiency programs to its Washington Residential and Commercial customers in compliance with the direction provided by the WUTC in the Company's 2008 rate case.[81] The programs were developed and continue to evolve

[78] Energy Trust administers NW Natural's energy efficiency programs in both Oregon and Washington. The methodology and results in this chapter are provided by Energy Trust and are Oregon specific. NW Natural's Washington energy efficiency forecast was performed by a different entity and the results of which are described in a separate section.
[79] See Order No. 02-634 in Docket No. UG 143.
[80] See Docket No. LC 45.
[81] See Order No. 4 in Docket UG-080546.

under the oversight of the Energy Efficiency Advisory Group (EEAG), which is comprised of interested parties to the Company's 2008 rate case. Energy Trust administers the programs, leveraging the offerings available in Oregon to customers located in Washington.[82]

## 6.2.2 Energy Trust Forecast Overview and High-Level Results

Energy Trust developed a 20-year DSM resource forecast for NW Natural territory in Oregon using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost-effective modeled savings potential. Energy Trust then deploys @this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to NW Natural for inclusion in the Company's forecasts. The 2025 IRP results show that NW Natural can save over 30 million therms[83] in Oregon in the next five years from 2025 to 2029 and over 149 million therms by 2044. These results represent an 8 percent decline and a 5 percent increase respectively in cost-effective DSM potential over the prior IRP in 2022. The main drivers of these changes in deployed potential are:

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

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

[82] The program's parameters are provided in the Company's Schedule G and its Energy Efficiency Plan, which by reference is part of the Tariff. The program is funded through a charge collected in accordance with Schedule 215.
[83] The savings discussed in this chapter and appendices, depicted in all tables and the following figures showing savings projections are in gross savings for Oregon unless otherwise explicitly noted. Energy Trust publicly reports its Oregon savings and goals in gross savings as determined in consultation with OPUC and stakeholders in 2019. Energy Trust public reports prior to 2020 included net savings which are adjusted for market effects including free ridership and spillover. Prior Energy Trust DSM chapters for NWN IRP were in gross savings. Gross savings are not adjusted for market effects and most accurately reflect the reductions NW Natural will see on their system.

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

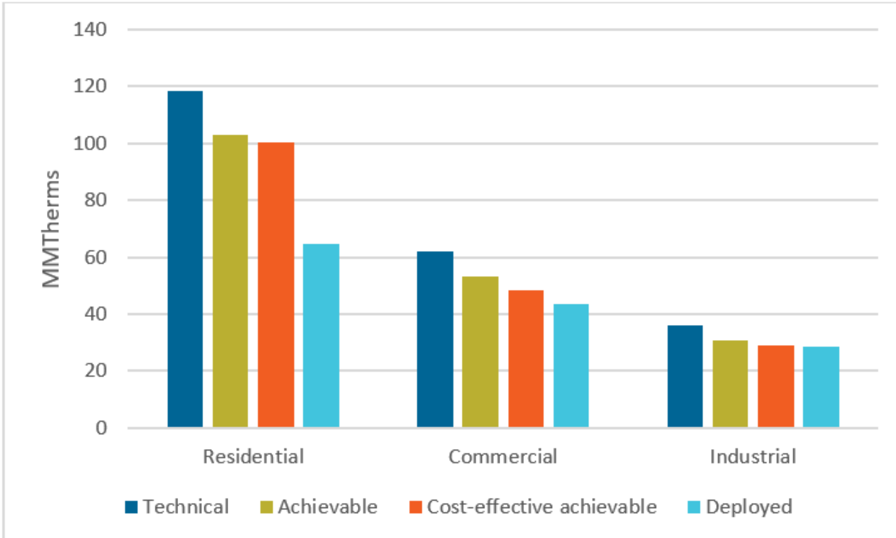
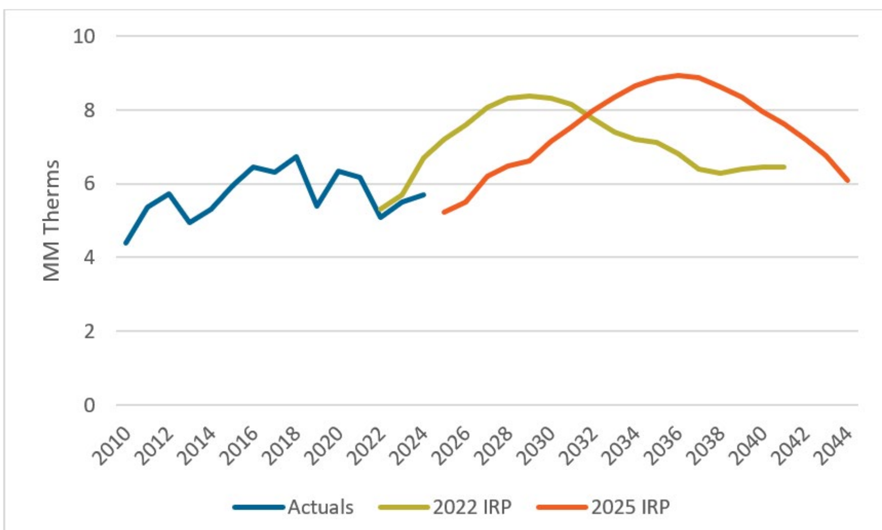



Figure 6.2 links actual historical savings going back to 2010 to the new deployed savings projection for the 2025 IRP. It also compares the current 2025 IRP deployed savings forecast to the 2022 IRP deployed savings forecast.

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




## 6.2.3 Energy Trust Resource Assessment Economic Modeling Tool

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

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

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

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

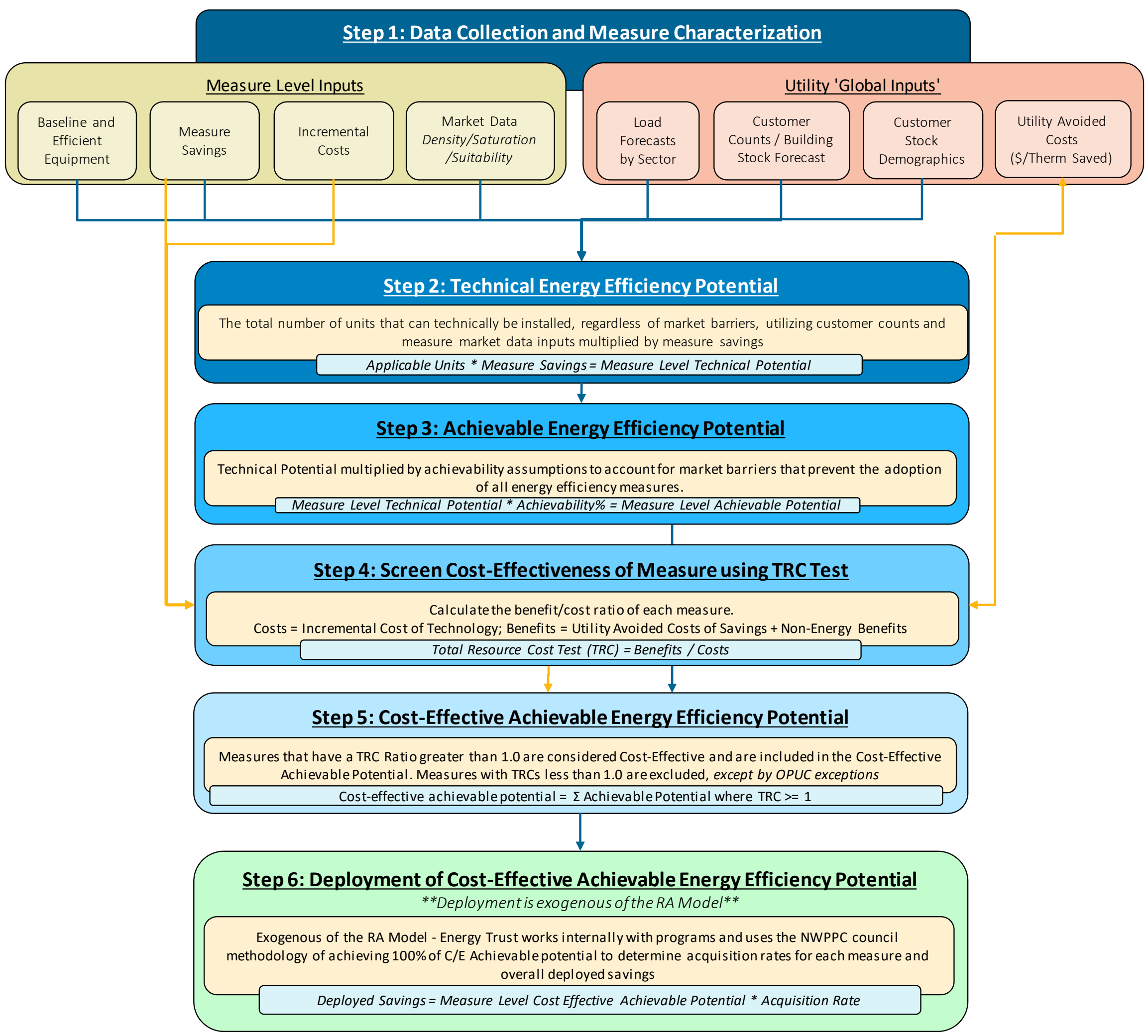
*Table 6.1: Three categories of savings potential identified by RA Model*

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

## 6.2.4 Methodology for Determining the Cost-Effective DSM Potential

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

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



**Step 1: Model and Measure Input Identification/Calculations**

The first step of the modeling process is to identify and characterize the list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of all commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[84] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[85], and engineering analysis. There are over 30 measure level inputs that feed into the model, but at a high level, the inputs are put into the following categories:
  1. *Measure Definition and Equipment Identification*: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a 70+ percent EF gas storage water heater replacing an 60 percent EF baseline gas water heater).
  2. *Measure Savings:* The therm savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. *Incremental Costs:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a Retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a Replace on Burnout or New Construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. *Market Data:* Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of

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

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

showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50 percent of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs are all generally derived from regional market data sources such as RBSA and CBSA.

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

**Step 2: Calculate Technical Energy Efficiency Potential**

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

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

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

**Step 3: Calculate Achievable Energy Efficiency Potential**

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

| | |
|---|---|
| *Achievable Potential =* | *Technical Potential * Achievability %* |

**Step 4: Determine Cost Effectiveness of Measure using TRC Test**

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

*TRC = Present Value of Benefits / Present Value of Costs*

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

a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by NW Natural's avoided cost per therm.[86] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[87]

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

Where the *Present Value of Costs* includes:

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

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

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

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then *achievable savings* from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions: 1) the OPUC has granted an exception to offer non-cost-effective measures under strict conditions or 2) the measure is cost-effective when using blended gas avoided costs[88] and is therefore offered by Energy Trust programs.

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

After determining the cumulative 20-year[89] cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on NW Natural's system. Energy Trust ramp rates are based on Northwest Power and Conservation Council methodology but are calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100 percent of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost

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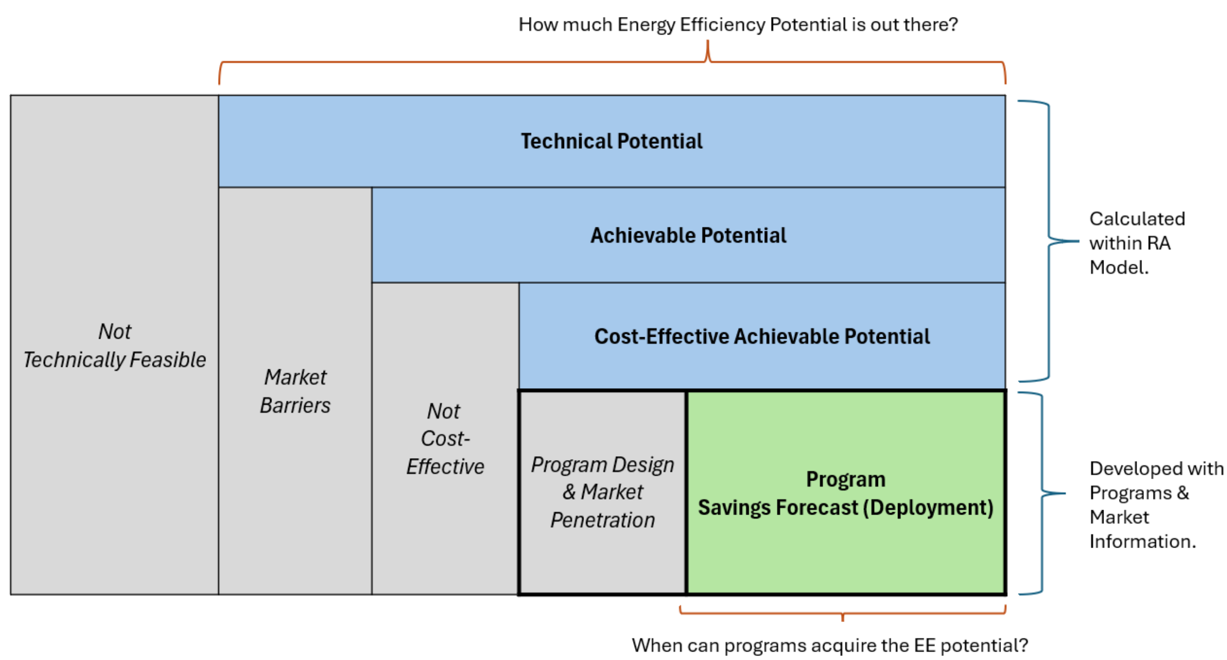
[86] See Chapter 5 for a discussion of NW Natural's avoided cost.
[87] NW Natural's real after-tax annual discount rates used by Energy Trust in the 2025 IRP is 3.39 percent.
[88] Energy Trust uses blended avoided costs for measure development and cost-effectiveness screening to provide uniform gas offerings throughout Oregon. Utility specific avoided costs are used in RA modeling to align inputs with utility IRPs.
[89] Energy Trust provided NW Natural with a final savings projection extended to 2050. These results are discussed in Section 6.2.10.

opportunity measures continue to ramp up to 100 percent of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100 percent. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy Trust is describing as a 'large project adder', savings that account for large unidentified projects that consistently appear in Energy Trust's historical savings record and have been a source of overachievement against IRP targets in prior years. The evolution from modeled technical potential to savings projections is depicted in Table 6.2

*Table 6.2:The Progression to Program Savings Projections*




## 6.2.5 RA Model Results and Outputs

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

## 6.2.6 Forecasted Savings Potential by Type

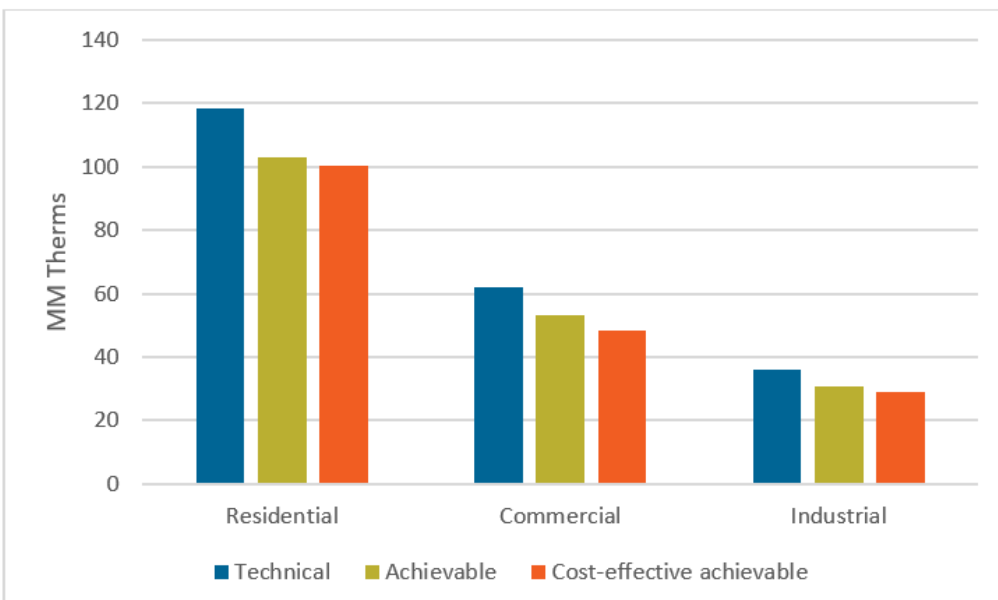
Table 6.3 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Table 6.1. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

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

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

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

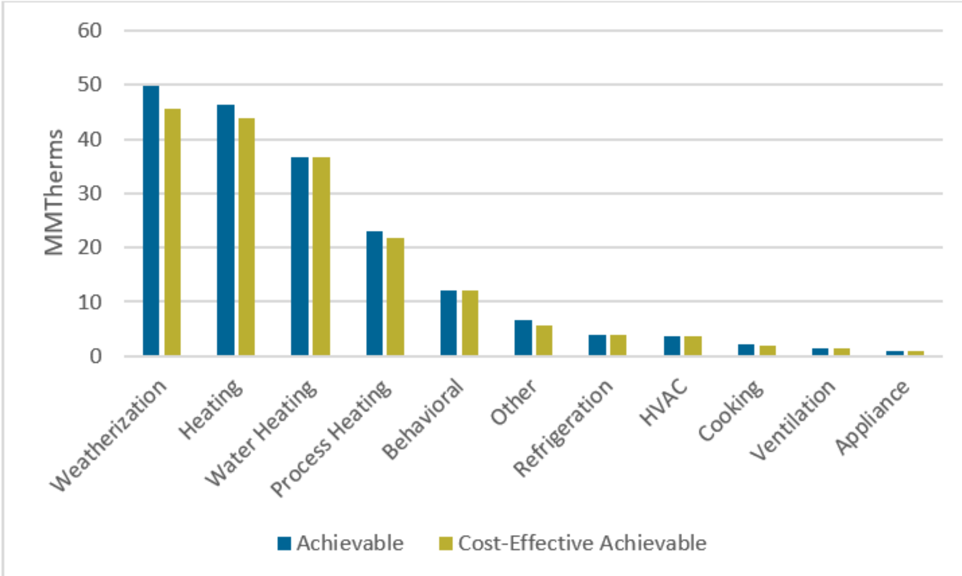
*Figure 6.4: Summary of Cumulative Modeled Savings Potential - 2025–2044 - by Sector and type of Potential*




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

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

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




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

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

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

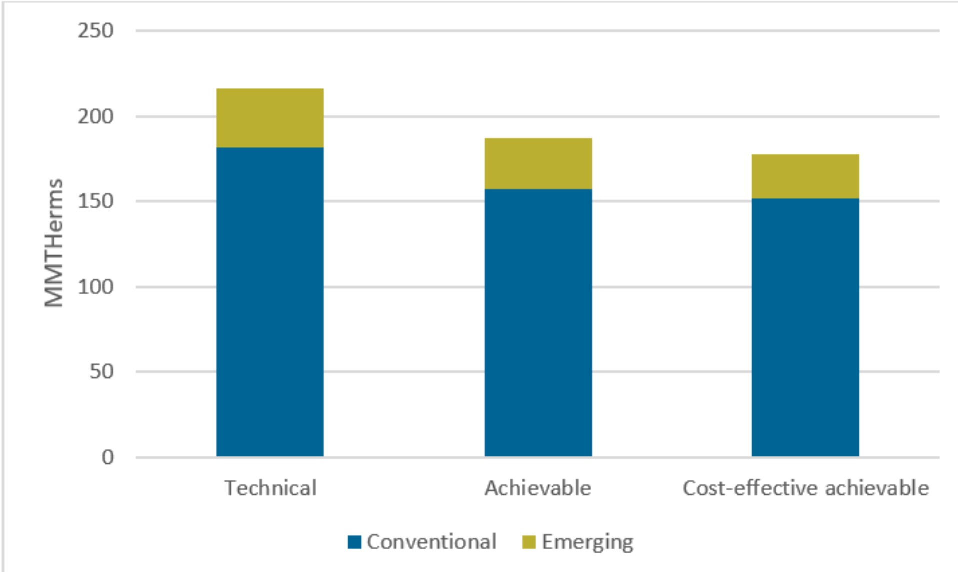



Table 6.4 shows the savings potential in the resource assessment model that was added by employing the cost-effectiveness override. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following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

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

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

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

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

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

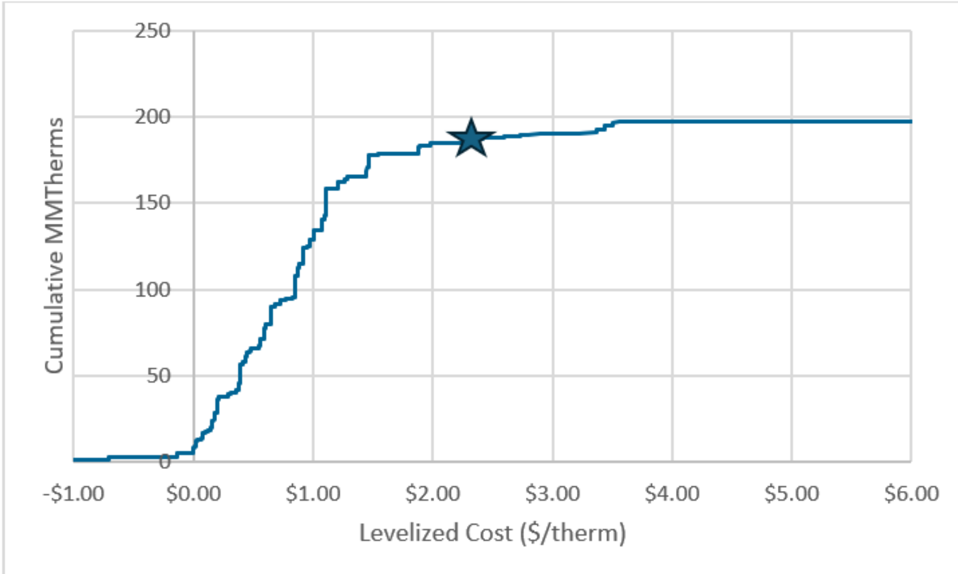
### 6.2.7 Supply Curve and Levelized Costs

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

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

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

*Figure 6.7: 20-year Gas Supply Curve*[90]




## 6.2.8 2025 Model Results Compared to 2022

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

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

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

Table 6.6 builds off Table 6.5 and details the key factors that drove the change in cost-effective potential for DSM compared to the prior IRP. Change components of opposite directionalities

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

net out to create a modest decrease in cost-effective achievable potential driven by model updates and increased avoided costs which partially offset the impacts of the lower load and building stock forecast seen in the 2025 IRP.

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

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

### 6.2.9 Final Savings Projection

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

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

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

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

| Sector | Technical | Achievable | Cost-effective | Energy Trust Savings Projection [91] |
|---|---|---|---|---|
| Residential | 118.29 | 103.11 | 100.30 | 64.67 |
| Commercial | 62.03 | 53.17 | 48.41 | 43.34 |
| Industrial | 36.03 | 30.62 | 29.10 | 28.74 |
| Other | - | - | - | 12.31 |
| All DSM | 216.35 | 186.90 | 177.81 | 149.07 |

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

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

*Figure 6.8: 20-Year Annual Savings Projection by Sector*

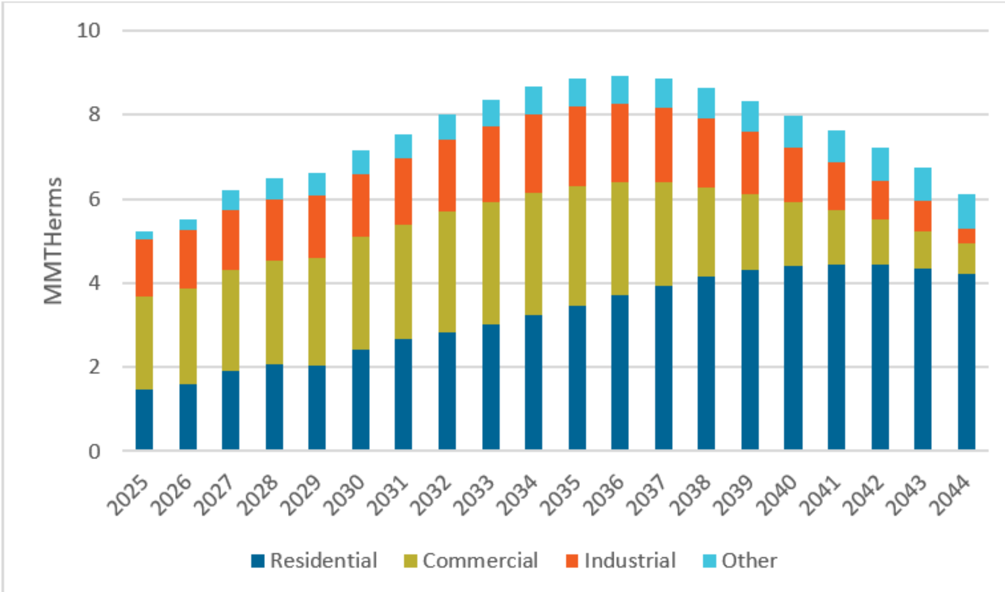
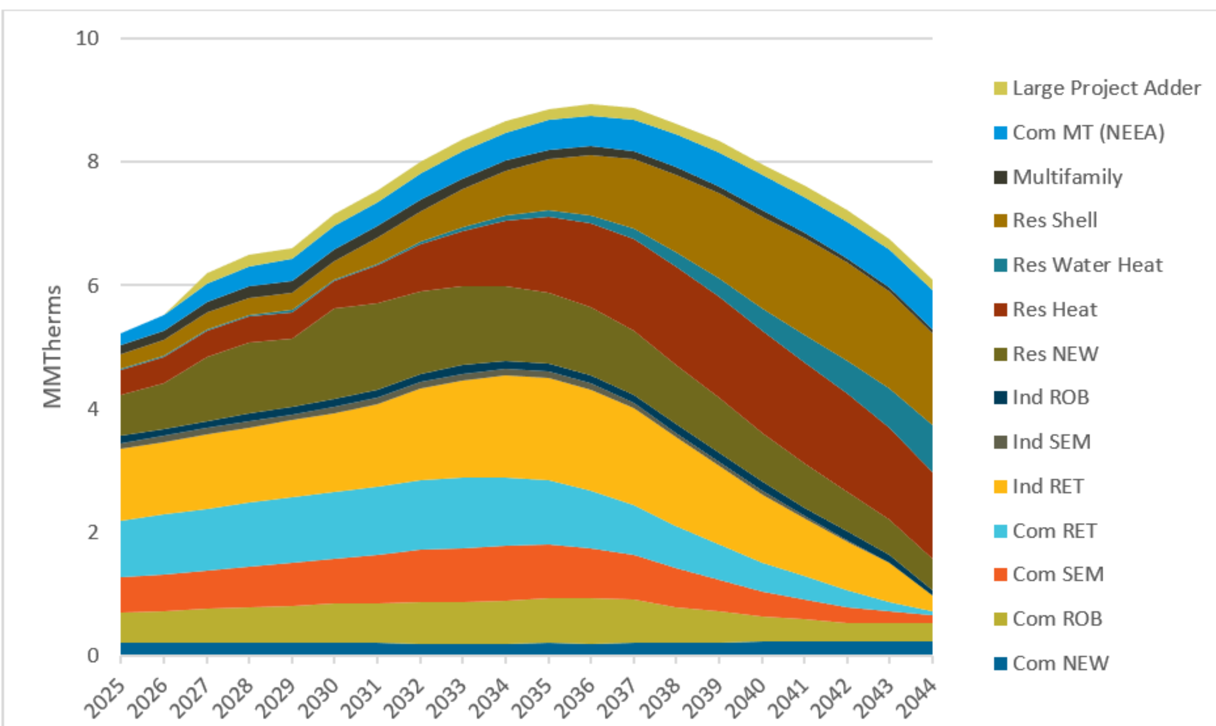



Figure 6.9 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

*Figure 6.9: Annual Savings Projection by Sector-Measure Type*



### 6.2.10 Final Savings Projection Extended to 2050

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

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

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

*Figure 6.10: Annual Savings Projection by Sector through 2050*

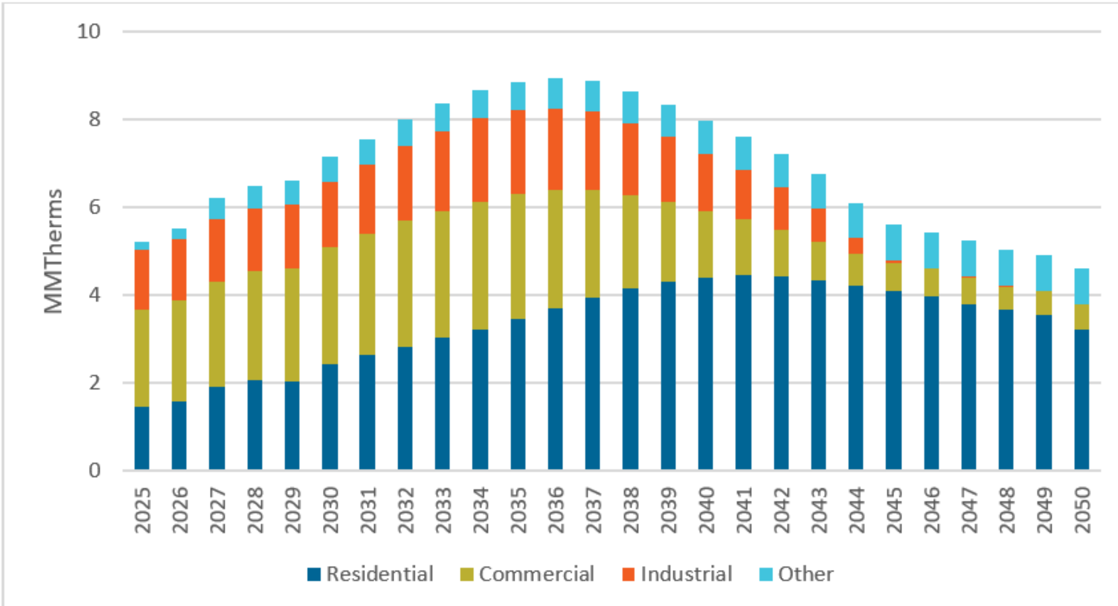
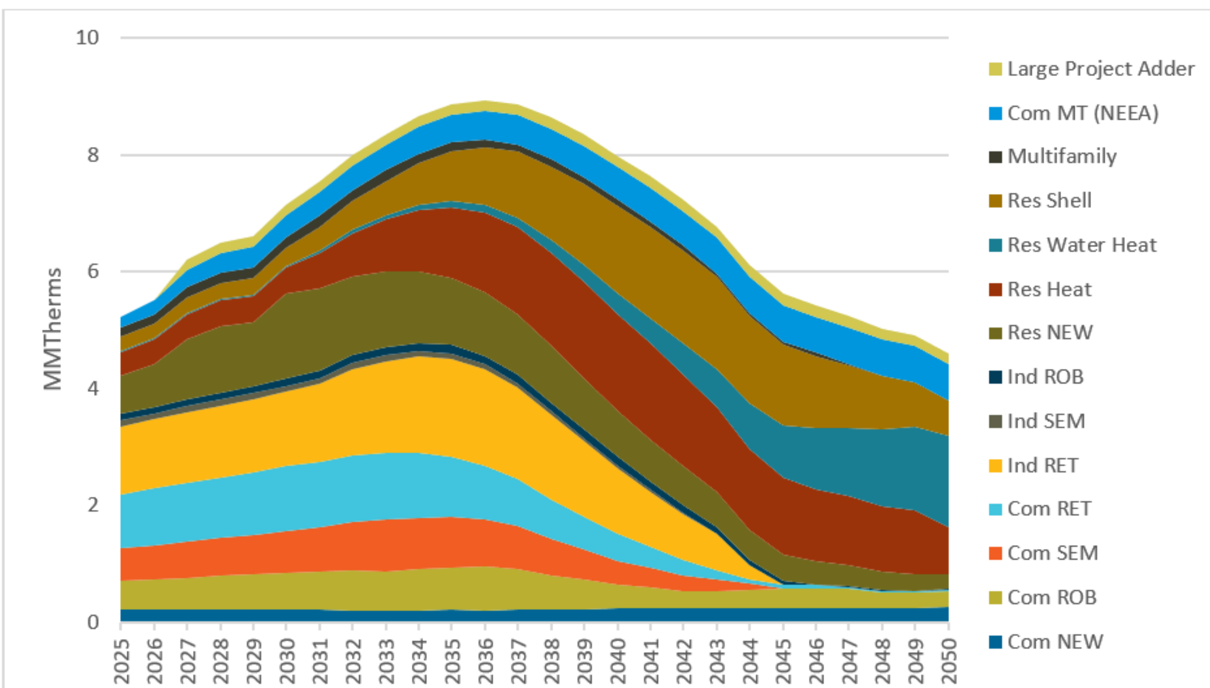



*Figure 6.11: Annual Savings Projection by Sector through 2050*




## 6.2.11 Peak Savings Deployment

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

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

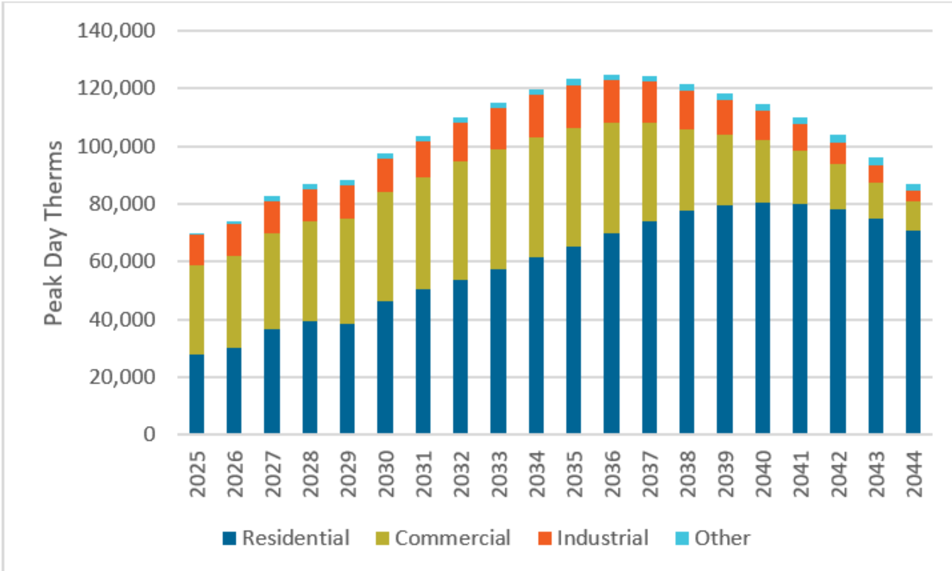
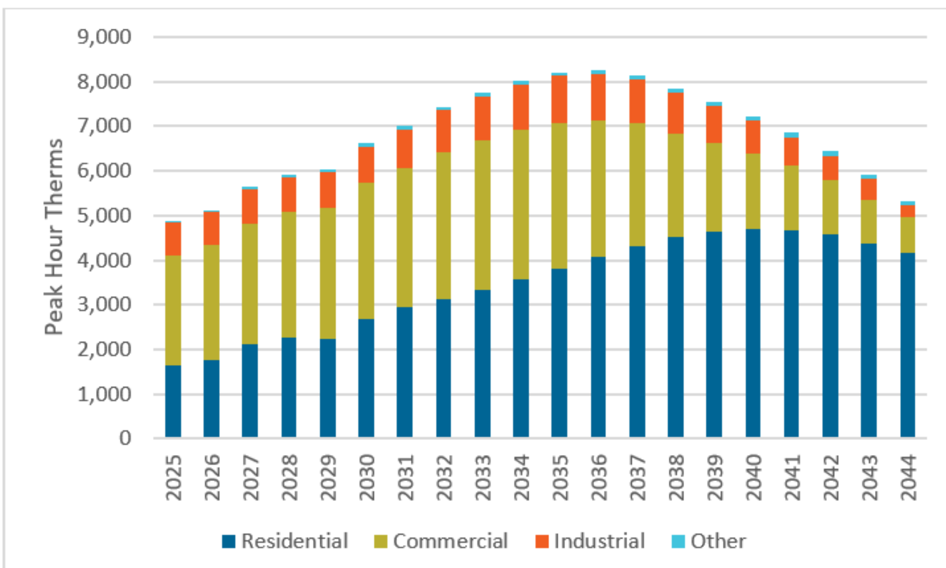



*Figure 6.13: NW Natural's Annual Peak-Hour Savings Projection by Sector*




Residential and Commercial heating measures have the greatest savings coincident with peak, and in this forecast contribute the most peak savings potential. The total peak-day savings over the 20-year savings projection is 2,070,691 peak-day therms or 1.4 percent of the 149.1 million therm savings projection. The total peak-hour savings over the 20-year savings projection is 136,191 peak-hour therms or 0.09 percent of the 149.1 million therm savings projection.

### 6.2.12 Avoided Costs Scenario Runs

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

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

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

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

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

Table 6.10 below shows how the different avoided costs scenarios impact the total amount of cost-effective achievable potential. The greatest impact is the high social cost of carbon

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

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

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

## 6.3 Washington Conservation Potential Assessment / Sales

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

### 6.3.1 Background

In early 2023, NW Natural contracted with Applied Energy Group (AEG), a consulting firm known for its services to the energy industry including gas utilities, to conduct an assessment of available conservation potential in its Washington service territory. This new iteration of the CPA refreshes key aspects of the 2021 CPA to assist NW Natural in developing the next iteration of the integrated resource plan (IRP).[92] Throughout this study, AEG worked with NW Natural to understand the baseline characteristics of their Washington service territory, including a detailed understanding of energy consumption in the territory, the assumptions and methodologies used in NW Natural's official load forecast, and recent programmatic accomplishments.

### 6.3.2 Analysis Approach

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

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

For this analysis, AEG used its Load Management Analysis and Planning tool (LoadMAP™) to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP

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

in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and potential studies since. Built in Excel, the LoadMAP framework is both accessible and transparent and possesses the following key features:

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

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.[93]

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

*Table 6.11: Levels of Potential*

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

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

### 6.3.3 Baseline Load Projection

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

AEG refined the baseline projection of annual natural gas use for 2024-2050 from the prior CPA to align with NW Natural's 2022 actual totals. The 2021 CPA reference case forecast was updated with the latest iteration of NW Natural's IRP customer growth projections and weather

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

data, and market based (naturally occurring) efficient purchase shares were reviewed considering changes to the efficiency options provided for equipment replacement.

Inputs to the baseline projection include:

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

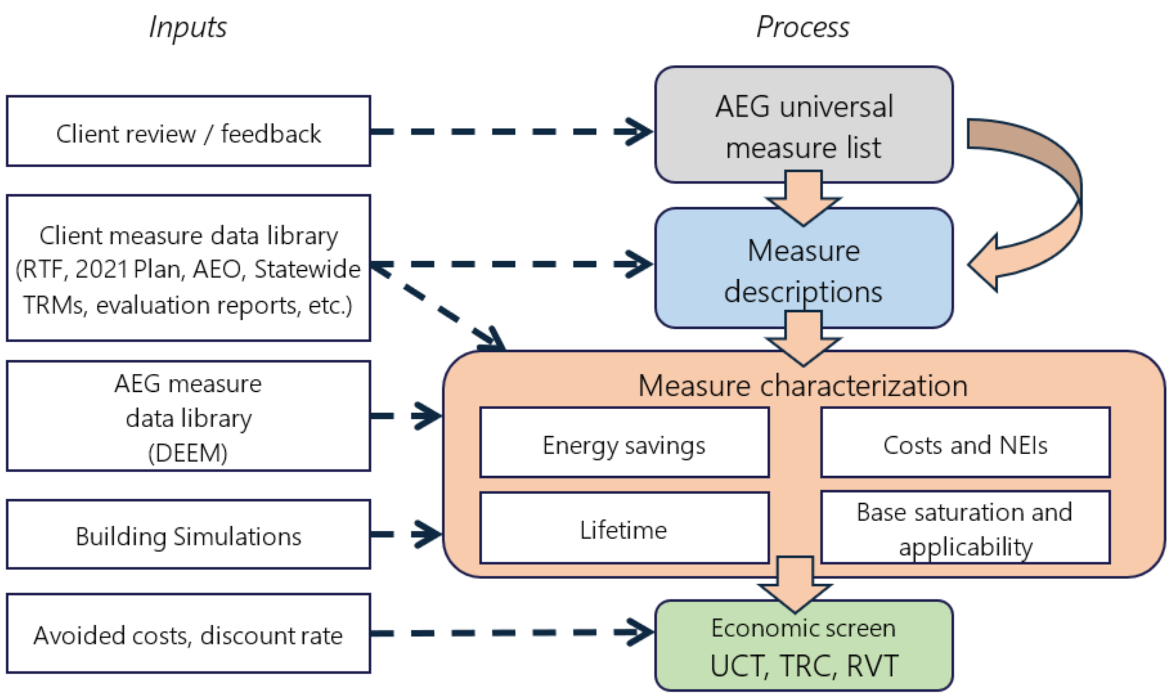
### 6.3.4 Energy Efficiency Measure Development

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

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

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

*Figure 6.14: Approach for Energy Efficiency Measure Characterization and Assessment*




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

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

without waiting for any existing equipment to malfunction and saves energy used by the furnace. Non-equipment measures typically fall into one of the following categories:

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

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

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

### 6.3.5 Energy Efficiency Potential

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

- **Technical Potential** reflects the adoption of all conservation measures regardless of cost-effectiveness. Technical potential is useful as a theoretical construct, applying an upper bound to the potential that may be realized in any one year. Other levels of potential are based off this level which makes it an important component in the estimation of potential. In this potential case, efficient equipment makes up all lost opportunity installations and all retrofit measures are installed, regardless of achievability.
- **Achievable Technical Potential** refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. For the 2024-2050 CPA, ramp rates from the 2021 Power Plan were customized for use in natural gas programs.
- **TRC Achievable Economic Potential** further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, the cost-effectiveness is

measured by the total resource cost (TRC) test, which compares lifetime energy benefits to the total customer and utility costs of delivering the measure through a utility program, including monetized non-energy impacts. AEG also applied benefits for non-gas energy savings, such as electric HVAC savings for weatherization and lighting savings for retro-commissioning. AEG also applied the Council's calibration credit to space heating savings to reflect the fact that additional fuels may be used as a supplemental heat source within an average home and may be accounted for within the TRC. Avoided costs of energy were provided by NW Natural, including ten percent conservation credit per the Council's methodology.

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

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

*Table 6.12: Summary of Energy Efficiency Potential (mTherms)*[94]

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

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

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

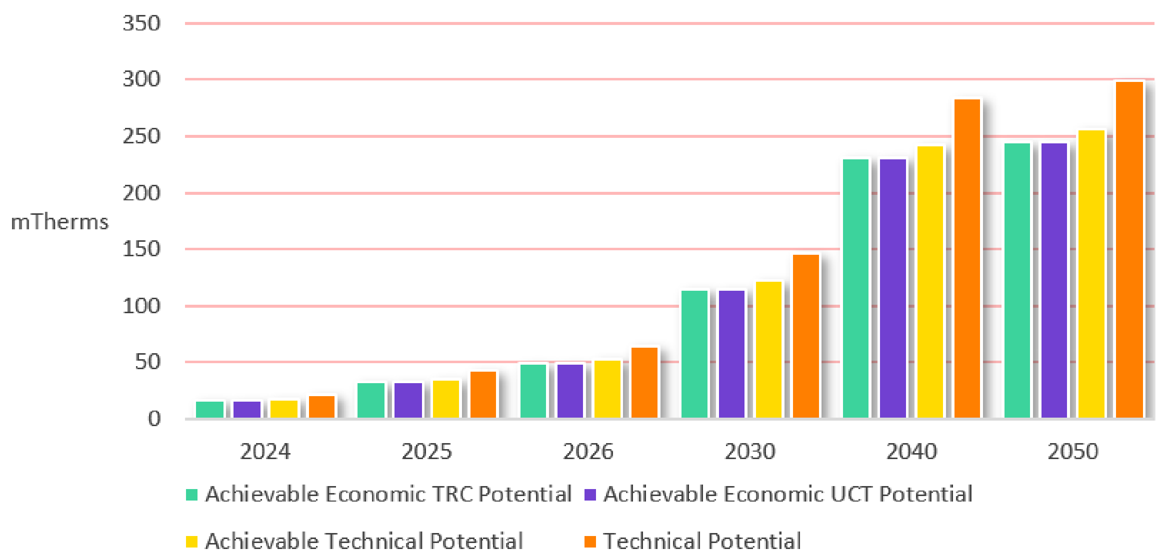



Table 6.13 summarizes TRC achievable potential by sector for selected years. While the precise distribution of savings among sectors shifts slightly over the course of the study, in general residential and commercial potential are well balanced. Since industrial sales customer consumption represents a small percentage of the baseline, potential for this sector makes up a lower percentage of the total. While residential and commercial potential ramps up, industrial potential is mainly retrofit in nature and is much flatter. This is because process equipment is highly custom and most potential comes from controls modifications or process adjustments rather than high-efficiency equipment upgrades. Additionally, AEG models retro-commissioning to phase in evenly over the next twenty years. This measure has a maintenance component, and not all existing facilities may be old enough to require the tune-up immediately but will be eligible at some point over the course of the study.

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

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

Table 6.14 and Table 6.15 present the total reference baseline and potential savings for the peak day and peak hour, respectively. Peak day and hour impacts are estimated using the

annual energy savings and conversion factors that relate peak day or hour consumption to annual consumption by end use, which were provided by NW Natural.

*Table 6.14: Peak Day Potential Summary (mTherms)*

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

*Table 6.15: Peak Hour Potential Summary (mTherms)*

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

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

## 6.4 Transportation Customers

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

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

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

### 6.4.1 Transportation – Oregon

NW Natural launched its initial Transportation energy efficiency program in partnership with the Energy Trust of Oregon (ETO) during the summer of 2024. At the time, Oregon's Climate Protection Program (CPP) had been invalidated and further rulemaking was undergoing. The 2024 program was intended to enable NW Natural and ETO to lay the groundwork for future program years.

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

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

### 6.4.2 Transportation – Washington

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

## 6.5 Income-based Energy Efficiency and Conservation Programs

### 6.5.1 Oregon Low Income Energy Efficiency

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

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

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

OLIEE funding is delivered through two primary channels:

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

#### *6.5.1.1 Community Action Program*

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

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

- Increased income eligibility threshold from 60 percent state median income (SMI) to 80 percent Area Median Income (AMI)
- Full funding of energy efficiency measures, along with necessary health, safety, and structural repairs

- Increased administrative support for program delivery agencies
- Enhanced funding for program and impact evaluation

*Table 6.16: Homes served through OLIEE program*

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

### *6.5.1.2 Open Solicitation Program*

The primary goal of the Open Solicitation Program (OSP) is to provide cost-effective, energy efficiency assistance to a greater number of low-income households in NW Natural's Oregon service territory. OSP is funded through the OLIEE program and enhances opportunities for dwellings that fall outside of the traditional single-family home program. This is achieved through a broad and diverse network of utility channels. To date OSP has seven established partnerships across the service territory that work on a diverse type of dwelling like multifamily building, new development, and shelters. Examples of projects conducted since 2022 are below in Table 6.17.

*Table 6.17: Examples of Projects Completed Since 2022*

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

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

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

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

#### *6.5.1.3 Oregon Low Income Energy Efficiency Advisory Committee*

Per Schedule 320, the Oregon Low Income Energy Efficiency (OLIEE) Advisory Committee (OAC) provides guidance to NW Natural on the implementation and evaluation of the OLIEE program. The committee includes representatives from NW Natural, Oregon Public Utility Commission staff, the Community Action Partnerships of Oregon (CAPO), and at least two members from community action agencies. Additional members include representatives from the Citizens' Utility Board (CUB) and the NW Energy Coalition (NWEC).

While the OAC does not hold decision making authority, it plays a critical role in shaping the delivery of the OLIEE programs. The committee meets a minimum of twice per program year to review progress and provide recommendations.

### 6.5.2 Washington Low Income Energy Efficiency

Launched in 2009, the Washington Low Income Energy Efficiency (WALIEE) program is modeled after Oregon's CAP programs and reimburses partner agencies for the installation of cost-effective weatherization measures. Currently, one agency administers the program in Washington, informed by the guidance of NW Natural's Energy Efficiency Advisory Group (EEAG).

Given that many homes in SW Washington are newer and have limited need for retrofits, program volume is low. Historically, WALIEE capped health and safety spending, but in 2024, NW Natural requested a tariff change that allows for greater project flexibility. Increased outreach efforts are also underway to enhance program visibility.

Table 6.18 shows the historical number of homes treated through the WALIEE program.

*Table 6.18: Historical WALIEE Homes*

| Program Year | Homes | Therms Saved |
|---|---|---|
| **2021** | 11 | 3,568 |
| **2022** | 11 | 2,581 |
| **2023** | 12 | 3,815 |
| **2024** | 9 | 666 |

#### *6.5.2.1 Outreach and Energy Education*

Outreach and Energy education are essential components of both the OLIEE and WALIEE programs, helping to connect eligible customers with available services and resources. These efforts take place through a variety of channels, including community events, partnerships with local organizations, and direct customer communication. NW Natural and its partner agencies have resumed in-person engagement activities that were paused during COVID-19, reflecting a renewed commitment to building trust and increasing awareness within underserved communities. Outreach strategies include participation in local events, the distribution of do-it-yourself (DIY) weatherization kits, and the use of customized bill inserts tailored to support partner organizations with program promotion and enrollment. The steady increase in outreach events in recent years highlights the growing emphasis on direct, community-based engagement. A communications plan outlining strategies for increasing program visibility across multiple platforms is provided in Appendix D.3.

Table 6.19 shows the number of outreach events attended by NW Natural.

*Table 6.19: Outreach Events Attended by NW Natural by Year*

| Program Year | # of Events |
| --- | --- |
| **2022-2023** | 8 |
| **2023-2024** | 12 |
| **2024-2025** | 15 |

### *6.5.2.2 Impact and Programs Evaluation*

In late 2024, NW Natural conducted a third-party impact and programs evaluation of its low-income energy efficiency programs, OLIEE and WALIEE. The evaluation identified a number of strengths and opportunities to improve program delivery and long-term impact.

Both programs were found to be accessible and responsive to community needs. In Oregon, OLIEE's decision to shift in eligibility from 200 percent Federal Poverty Level (FPL) to 80 percent Area Median Income (AMI) broadened eligibility to the program. Additionally, NW Natural expanded the scope of allowable health and safety measures, enabling more holistic home upgrades. These changes were driven by requests from community-based organizations (CBOs) that confirmed that the program offers a wide and effective range of services.

In both Oregon and Washington, most participants and non-participants were already engaged with local community action agencies or community-based organizations for energy bill assistance, highlighting the importance of leveraging existing service networks. However, program awareness remains a challenge. Non-participating households frequently cited costs as a barrier, despite upgrades being provided at no cost. This suggests that many income eligible non-participants are unaware of the program or unsure of the eligibility.

Another shared finding across both programs is the impact of workforce shortages. Agencies expressed concerns that while funding is available and demand is strong, they are limited by the ability of qualified contractors and auditors. This challenge is particularly acute in rural areas and threatens the long-term sustainability of program delivery. In Oregon, collaboration with Oregon Training Institute was recommended as support is needed to grow a diverse and skilled workforce.

Based on a billing analysis, both programs demonstrated clear and statistically significant energy savings. OLIEE participants saved on average 93 to 119 therms per year, a reduction of 16 percent to 19 percent of energy savings compared to non-participants. These savings are in line with or exceed typical benchmarks for weatherization and energy efficiency programs targeting low-income households.

The evaluation also revealed a reduction in arrearages among OLIEE participants, with an average annual decrease of $213 per household.

## 6.6 Energy Efficiency New Technologies

### 6.7 Natural Gas Heat Pumps

Energy efficiency is an important part of managing both emissions reductions and affordability. One key strategy in accomplishing emissions reductions is to improve efficiency utilizing emerging high-efficiency technologies. One such technology is natural gas heat pumps (GHPs), also known as gas-fired heat pumps. Natural gas heat pumps, like electric heat pumps share a commonality for achieving high efficiency through extracting heat from outside air to achieve efficiencies greater than 100 percent. A key advantage is that they have the potential to operate at sustained efficiency in lower ambient temperatures without the need for electric resistance backup.

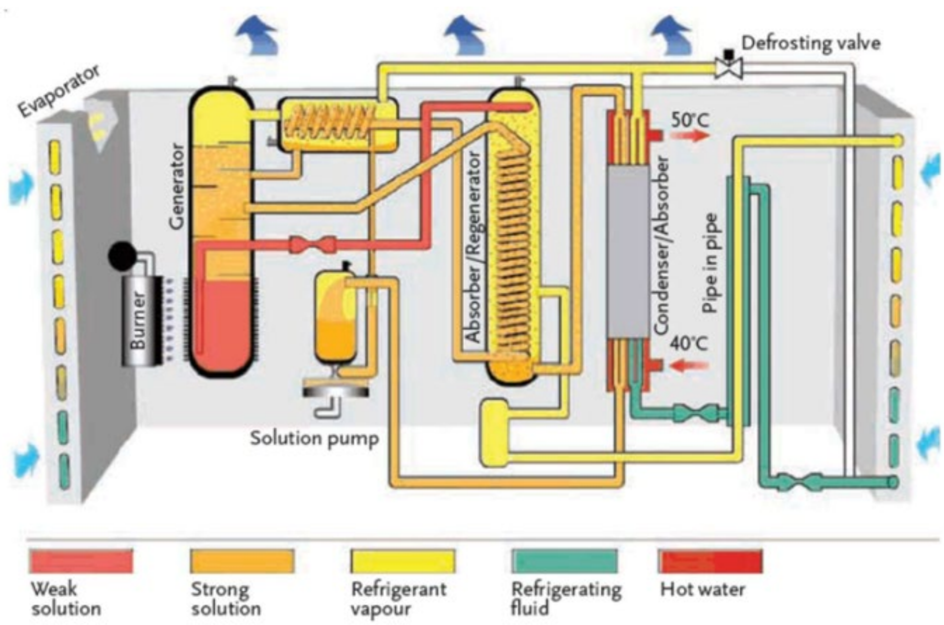
Similar to an electric heat pump, a gas-fired heat pump extracts heat from the outdoor ambient air and transfers it indoors for space and water heating. In the process, the gas heat pump creates more than one unit of heat for every unit of energy used, giving it more than 100 percent efficiency. The gas heat pump utilizes combustion at the site to drive the mechanical compression and expansion loop process in the heat pump. Because it utilizes some of the combustion heat, a GHP can operate with high efficiency at lower ambient temperatures.

A key benefit is the versatile use with traditional commercial HVAC applications:

> "GHPs can be utilized in a variety of applications. They can be combined with boilers, variable refrigerant flow (VRF) and domestic hot water (DHW) heaters for improved efficiency of existing systems and redundancy. In addition, GHPs can provide domestic hot water heating up to 140°F." [95]

[95] North American Gas Heat Pump Collaborative, Commercial HVAC Gas Heat Pump, Considerations for Installation, page 3. www.gasheatpumpcollab.org,

*Figure 6.16: Heat Pump Technology*




Source: Robur; roburcorp.com/technical_dossiers/heat_pumps_absorption_technology

### 6.7.1.1 Commercial Natural Gas Heat Pumps

For several years, commercial gas heat pumps have been commercially available from various manufacturers, most widely in North America from Robur Corporation.[96]

In 2020, Northwest Energy Efficiency Alliance (NEEA) performed a commercial GHP Pilot in Salem, OR installing a Robur commercial gas heat pump and achieving approximately a 50 percent improvement in efficiency compared to their existing gas space and water heating systems.[97]

The summary report indicated that the unit provided[98]:

- Efficiency improvement with "a significant improvement in performance above conventional gas-fired technologies"
- System reliability with minimal maintenance
- Excellent technical support

[96] For more information on commercial gas heat pumps, please see the following manufacturer websites:
www.robur.com/en-us/company/research-and-development/heat-pumps
www.vicot.com.cn/english/a/PRODUCT/Gas_system/2021/0312/GAP-V65.html
www.lsmenergysolutions.com/yanmar-gas-heat-pumps.html
www.yanmar.com/global/energy/ghp/vrf/merits.html
[97] Tierney, Jennifer, P.E., et al, Robur Heat Pump Field Trial, NEEA report #E20-309, March 11, 2020. Page 24.
[98] Tierney, Jennifer, P.E., et al, Robur Heat Pump Field Trial, NEEA report #E20-309, March 11, 2020. Page 19.

Pilot study recommendations for future pilots included applications for commercial pools, laundry facilities, multifamily buildings, and food processing as well as other sites with large year-round hot water loads.

#### *6.7.1.2 Residential Gas Heat Pumps*

Residential GHPs are newcomers to the HVAC market and are being supported and promoted by the North American Gas Heat Pump Collaborative – an international collaborative of utilities in the USA and Canada representing 37 percent of households using gas in those nations. The Northwest Energy Efficiency Alliance (NEEA) is also driving market transformation efforts around GHPs.

Currently there is one commercially available GHP product designed for residential single-family/single-dwelling unit applications. It is from Stone Mountain Technologies Inc. (SMTI)[99] and it is a combination "combi" space and water heating solution – meaning a single outdoor heat pump unit provides hot water to both a hot water tank and furnace style air-handler to heat the home.

Like Commercial Gas Heat Pump pilots, more residential pilots are needed in the Pacific Northwest region to gather data of seasonal performance in associated climate zones to help inform incentive development of this technology in our service area.

## 6.8 Demand Response

### 6.8.1 Residential and Small Commercial Bring Your Own Thermostat Demand Response Program

In NW Natural's 2022 IRP, docketed as LC 79 in Oregon and UG-210094 in Washington, the Company included an action item that focused on reducing load during peak demand period through a demand response program for residential and small commercial customers. Action Item 3 stated:

> "Scope a residential and small demand response program to supplement our large commercial and industrial programs and file by 2024."

In Order No. 23-281, the OPUC agreed with Staff's recommendation and acknowledged this action item to scope a residential and small commercial demand response (DR) program with the condition that NW Natural provides a discussion of how its general (system-wide) demand

[99] https://stonemountaintechnologies.com/wp-content/uploads/2024/01/Anesi_ResidentialForcedAirSpaceHeating_AppNote_24-01_RFA.pdf

response will interact with and support future locational (geographically targeted) DR programs.[100]

Upon receiving the Commission's acknowledgement on Action Item 3, the Company began scoping and developing a program plan. By the end of October 2023, the Company completed a DR program plan in which the scope, objectives, DR offerings, deliverables and timing for system-wide programs were developed. While several DR pathways were explored, a system-wide Bring Your Own Thermostat (“BYOT”, or “Thermostat Rewards” as branded) Program was identified as the best opportunity to create a demand response program that targets residential and small commercial customers and the platform created for the system-wide program can be leveraged to support future locational DR programs and hence to comply with the condition for action item acknowledgement as recommended by OPUC Staff.

Smart thermostats are required for a BYOT program. Energy Trust of Oregon (ETO) data showed that over 61,000 smart thermostats have already been installed across NW Natural’s service territory via ETO’s various energy efficiency programs. A separate survey by Northwest Energy Efficiency Alliance (NEEA) found that approximately 14 percent of single-family homes in the northwest region have installed certain types of smart thermostats.[101] The Company estimates that there are as many as 84,000 smart thermostats for single-family homes among the Company’s residential customers. Given so many smart thermostats are already installed in NW Natural’s service territory, the enrollment goal of the Thermostat Rewards Program was set to be 30,000 customers by the end of the three-year program period.

In February 2024 NW Natural issued a request for proposal (RFP) for the BYOT program. The Company hosted multiple rounds of interview sessions for each of the implementation vendors (RFP responders) during the RFP selection process from late March to May 2024 and eventually identified Resideo Grid Works (“Resideo”) as the implementor. NW Natural negotiated a scope of work and contract in July 2024. Resideo began to set up the BYOT program in their distributed energy resource management system (DERMS) in August 2024 and the program began enrolling eligible customers on December 9, 2024.

In addition, the Company issued an Evaluation, Measurement and Verification (EM&V) RFP for the DR program in March 2024, seeking a qualified third-party EM&V service vendor to conduct an independent EM&V analysis of the BYOT program. Five EM&V service vendors submitted their proposals. The Company selected ADM Associates for the EM&V vendor and negotiated a statement of work in August 2024.

[100] The Company received a letter from the WUTC on August 24, 2023 acknowledging compliance with WAC 480-90-238 along with Commission Staff comments. There was no discussion about this action item.

[101] See 2022 Residential Building Stock Assessment – Findings Report, published by NEEA in April 2024.

NW Natural's demand response program season is November 1 through March 31. The program DR event window will be from 7:00 AM through 11:00 AM. The maximum event duration is four hours and the number of events to be called is no more than ten in a season. Customers may opt in or out of an event anytime.

Each customer who enrolls in the Thermostat Rewards Program will receive an Enrollment Incentive in the form of a $25 Virtual Prepaid Mastercard®. In addition, customers enrolled may receive a $25 gift card as participation incentive after each season if they participate in 50 percent or more of the event hours during the DR season.

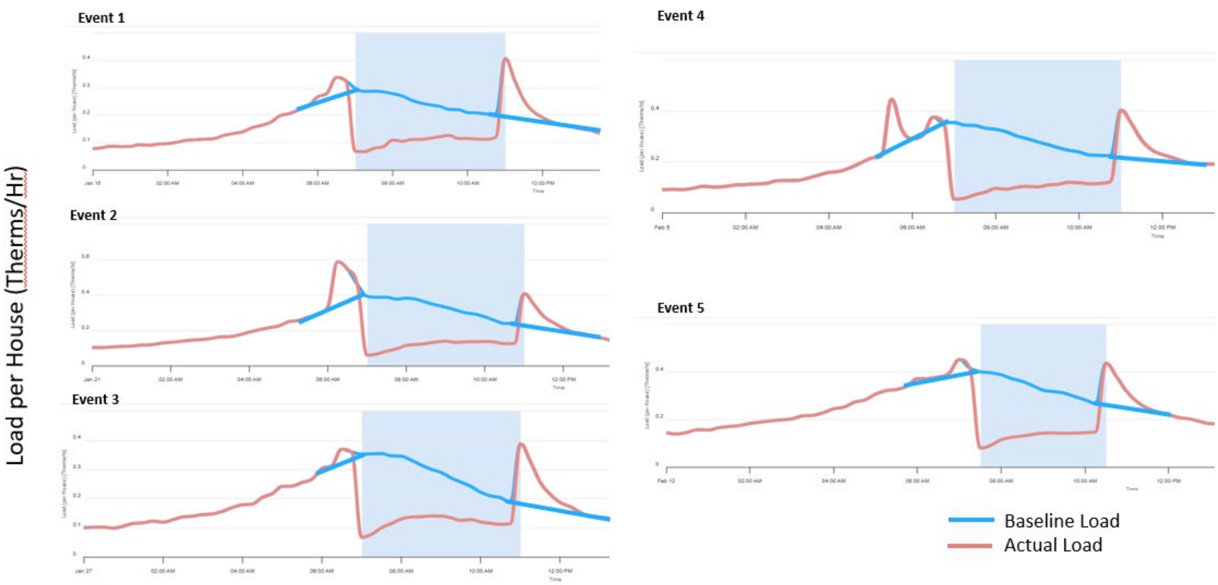
From the inception of the program through June 2, 2025, there are 11,065 customers/devices enrolled in the program. Over the past DR season, five DR events were dispatched between January 15 and February 12, 2025. Event parameters and preliminary performance stats are summarized in Table 6.20 and Figure 6.17.

*Table 6.20: DR Event Parameter and Preliminary Performance Summary*[102]

| Event Date | 1/15/25 | 1/21/25 | 1/27/25 | 2/5/25 | 2/12/25 |
|---|---|---|---|---|---|
| **Daily Temperature Range (F)** | 35-47 | 28-47 | 26-50 | 35-45 | 24-36 |
| **Event Start Time** | 7am | 7am | 7am | 7am | 7:30am |
| **Event End Time** | 11am | 11am | 11am | 11am | 10:30am |
| **Event Duration (Hours)** | 4 | 4 | 4 | 4 | 3 |
| **Setback Degrees (F)** | 3 | 4 | 4 | 4 | 4 |
| **Preheating Degrees (F)** | 0 | 2 | 0 | 1 | 0 |
| **Preheating Duration (Minutes)** | 0 | 45 | 0 | 90 | 0 |
| **Total Event Period Savings (Therms)** | 649 | 1,156 | 931 | 1,552 | 1,416 |
| **First Hour Savings (Therms)** | 245 | 423 | 362 | 574 | 645 |
| **Total Dispatched Devices (#)** | 3,515 | 4,834 | 4,649 | 6,081 | 5,970 |
| **Fully Participated Devices (#)** | 2,451 | 3,398 | 3,211 | 4,333 | 4,434 |
| **Average 1 Hour Savings/Device (Th/Tstat)** | 0.07 | 0.09 | 0.08 | 0.09 | 0.11 |

[102] Therm savings reported in the table are preliminary estimates by Resideo and will be measured and verified by ADM Associates.

*Figure 6.17: Average Load per Premise by Event*




NW Natural recognizes that the Thermostat Rewards Program is new and fast growing and that it is premature to assess the cost-effectiveness of the program at such an early stage, yet its overall performance in the test events dispatched aligns with industry expectations. Preliminary results indicate that the program has achieved comparable event capacity and participation rates to other gas BYOT programs. In terms of peak hour load reduction, per a DR potential study for NW Natural by Brattle, a BYOT program is expected to achieve an average reduction in peak hour demand by 0.09 therms/device/hour given the weather and load conditions in the Company's service territory.[103] The preliminary measurement and verification analysis by ADM Associates shows that over 0.1 therms/device/hour load savings may have been achieved in the program's first season with only five events. Participation rates for similar programs generally range between 51-74 percent across gas BYOT DR programs in the industry,[104] whereas Thermostat Rewards is averaging a 71 percent full participation rate. Additionally, the program has already reached its 2025 enrollment goal of 10,000 devices as of April 28, 2025, and is on track to achieving its three-year target of 30,000 devices.

As the Thermostat Rewards Program continues to develop, further testing will be conducted to optimize key DR event parameters such as setback degrees during events, preheating, event start times and durations. While initial testing was conducted during the first season, additional

[103] The Potential for Gas Demand Response in the NW Natural Service Territory, the Brattle Group, December 2019.
[104] Overview of Gas Demand Response Programs, Memorandum by the Brattle Group, October 2022.

assessments will be necessary to identify the best strategies to further improve the performance of the program.

# Chapter 7 - Emissions Compliance Resources

Once customer needs and compliance obligations are established, it is important to take a wide scope and assess what options are available to meet those needs. This chapter discusses resources that can be utilized to meet emissions compliance requirements.

## 7.1 Compliance Resources

The Oregon CPP and the Washington CCA each allow for a variety of resources to be utilized as compliance tools. While some of the compliance resources are accepted by both the CPP and CCA regulations, other resources are specific to either Oregon or Washington.

*Table 7.1: Allowed Compliance Resources by State*

| Compliance Resource | Oregon CPP | Washington CCA |
|---|---|---|
| Reduced usage through conservation/energy efficiency | ✓ | ✓ |
| Compliance Instruments issued from state or acquired from other covered entity | ✓ | |
| Allowances issued from state, acquired at auctions, or on the secondary market | | ✓ |
| Community Climate Investments (CCI) credits | ✓ | |
| Compliance Offsets | | ✓ |
| Compliance Offsets on tribal lands | | ✓ |
| Biomass derived fuels- renewable natural gas, synthetic methane | ✓ | ✓ |
| Hydrogen | ✓ | ✓ |
| Carbon Capture | ✓ | ✓ |

NW Natural's conservation and energy efficiency efforts are detailed in Chapter 6. The remaining compliance resources listed in Table 7.1 are detailed in this chapter.

## 7.2 Compliance Instruments and Allowances

As described in the Environmental Policy section each program has their own compliance tools that represent allocation of emissions from the program cap. The Compliance instruments under the Oregon CPP and the Allowances under the Washington CCA can be used as compliance resources. See the environmental policy section in Chapter 2 for additional details on these resources.

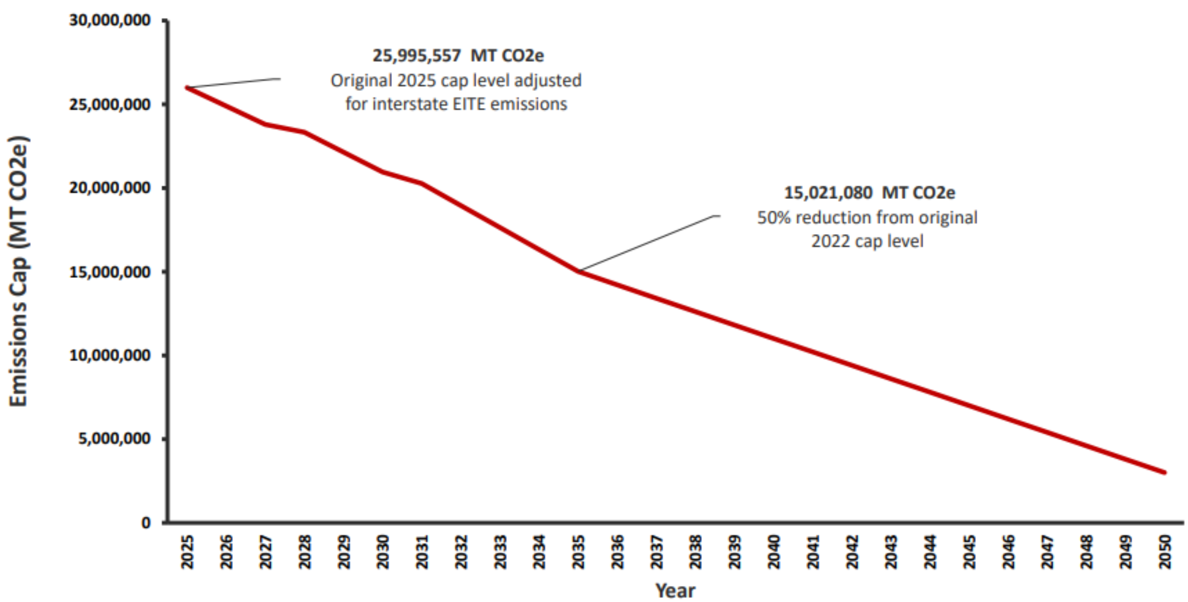
### 7.2.1 Oregon Compliance Instruments

In Oregon, allocations from the program cap are called compliance instruments. A compliance instrument is defined in OAR 340-273-0020 as an instrument issued by DEQ that authorized the emission of one MT $CO_2e$ of greenhouse gases. Annually, NW Natural is allocated a portion of the declining portion of the program cap using the procedure outlined in OAR 340-273-0420. DEQ will take the program cap, distribute compliance instruments to EITEs according to the percentages outlined in OAR 340-273-9000 Table 8, and then will apply the percentage for NW Natural listed in OAR 340-273-9000 Table 4.

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

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

*Figure 7.1: Oregon CPP Cap Trajectory*[105]




Oregon compliance instruments are bankable and tradable with other covered entities in the program. The modeling included in this IRP allows for banking of compliance instruments but does not include trading instruments with other parties. Since the CPP is not a market-based program and there is no pricing structure for these instruments or incentive to trade with such

[105] https://ormswd2.synergydcs.com/HPRMWebDrawer/Record/6768300/File/document

a steep program trajectory, it would be premature to assume a secondary market would develop that NW Natural would be able to participate in.

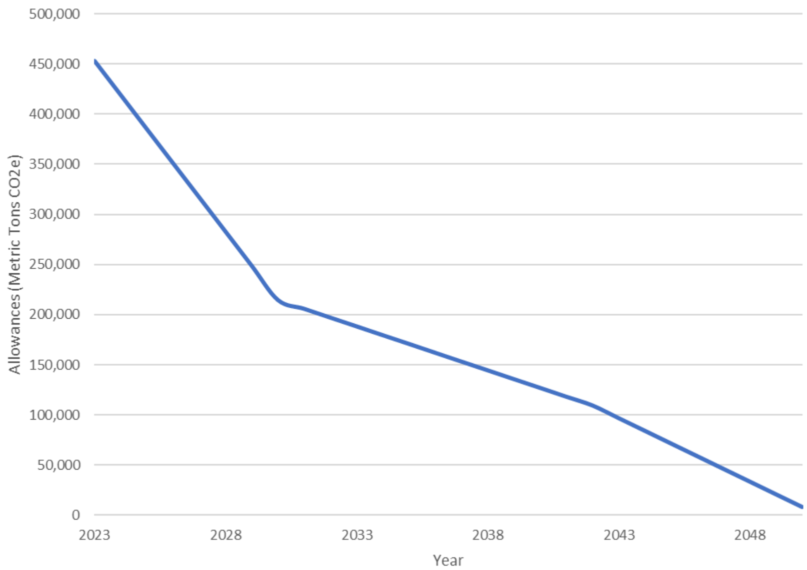
### 7.2.2 Washington Allowances

Like in Oregon, the Washington Climate Commitment Act (CCA) issues compliance tools that represent the amount of emissions allowed under the program's cap. These tools are called allowances in Washington. Each allowance authorizes the release of one metric ton (MT) of CO2e.

These allowances are acquired through a variety of pathways under the CCA. Certain categories of covered entities, like local distribution companies, are allocated "no cost" allowances annually from the Department of Ecology. Additional allowances can be purchased at auction or in a secondary market from other program participants.

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

*Figure 7.2: NW Natural Distribution of No Cost Allowances*




While these allowances are provided to the Company at no cost, they have some additional requirements on them compared to allowances purchased at auction or on the secondary market. These allowances are not allowed to be traded and are deposited in either the Company's compliance account or limited use account. Under the CCA program, local distribution companies are required to consign a specific percentage of their no cost allowances to auction each year. The following table outlines the percentage of allowances that NW Natural must consign to auction and the remaining may be retained and used for compliance.

*Table 7.2: Percentage Consigned to Auction*

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

NW Natural can purchase additional allowances at auction or on the secondary market. By rule, Ecology must hold four quarterly allowance auctions and one Allowance Price Containment Reserve (APCR) auction per year. Up to three additional APCR auctions can be held each year if the settlement price for the previous quarterly auction is about the APCR Tier 1 price. General market participants may purchase allowances in the quarterly auctions and sell them on the secondary market but are not allowed to participate in APCR auctions. Additionally, if covered entities are not able to secure enough compliance tools to cover their emissions by a compliance deadline, Ecology may issue additional allowances to that entity at the annual allowance ceiling price.

## 7.3 Offsets and Community Climate Investments

In addition to compliance tools that represent the emissions allowed under each state's program emission caps, the CPP and CCA allow for the use of an alternative compliance tool. In Oregon these tools are called Community Climate Investments and in Washington compliance offsets are allowed.

### 7.3.1 Oregon Community Climate Investments

The Oregon CPP does not allow for the use of traditional carbon offsets like other carbon compliance programs. Instead, Oregon DEQ created a tool unique to Oregon called a Community Climate Investment Credit (CCI). Under OAR 340-273-0020(5), Oregon DEQ defines a CCI Credit as "an instrument issued by DEQ to track a covered entity's payment of community climate investment funds, and which may be used in lieu of a compliance instrument." DEQ, with the assistance of an Equity Advisory Committee, will select at least one non-profit to be the CCI Entity and collect the CCI funds from covered parties. OAR 340-273-0020 defines a CCI Entity as a nonprofit organization that has been approved by DEQ and that has entered into a written agreement with DEQ consistent with OAR 340-273-0920 to implement projects supported by community climate investment funds. The CCI price is established by DEQ annually based on an initial value outlined in OAR 340-273-9000 Table 6 and adjusted by inflation.

CCI Credit Contribution Amount = CCI Credit Contribution Amount in Table 6 in OAR 340-273-9000 * (CPI-U West for January of the calendar year for the price in Table 6 in OAR 340-273-9000 that is currently in effect / CPI-U West for January 2024).

According to OAR 340-273-0900, the CCI funds are then supposed to be invested in projects that:

- Reduce anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT $CO_2e$ per CCI credit distributed by DEQ;
- Reduce emissions of other air contaminants that are not greenhouse gases, particularly in or near environmental justice communities in Oregon;

- Promote public health, environmental, and economic benefits for environmental justice communities throughout Oregon to mitigate impacts from climate change, air contamination, energy costs, or any combination of these; and
- Accelerate the transition of residential, commercial, industrial and transportation-related uses of fossil fuels in or near environmental justice communities in Oregon to zero or to other lower greenhouse gas emissions sources of energy in order to protect people, communities and businesses from increases in the prices of fossil fuels.

CCI credits can be issued by DEQ upon receipt that the funds were paid to the CCI Entity and can be used for compliance any time after their date of issue, regardless of whether the funds have been spent or accomplished the purposed outlined above.

Covered entities, like NW Natural, are limited in the amount of CCIs that may be used for compliance in each period. In compliance period one (2025-2027) CCI use is limited to 15 percent of NW Natural's compliance obligation. In compliance period two (2028-2029) and beyond, CCI use is limited to 20 percent of NW Natural's compliance obligation.

### 7.3.2 Washington Compliance Offsets

Under the Washington CCA, the Legislature authorized the use of compliance offsets as an alternative compliance tool. Compliance offsets must meet specific guidelines outlined in WAC 173-446-500. Until the CCA links with another cap and trade program, all compliance offsets must provide a direct environmental benefit to the state. After linkage, 50 percent of the compliance offsets may be located in a linked jurisdiction. All compliance offsets must adhere to approved offset protocol, as outlines in WAC 173-446-505, and be issued by an approved offset program registry.

Covered entities are limited in their ability to use offsets to cover their compliance obligation. In compliance period one (2023-2026) covered entities, such as NW Natural may only satisfy up to five percent of their compliance obligation. An additional three percent of its compliance obligation can be met by offset projects located on federally recognized tribal land. In compliance period two (2027-2030) and beyond, the amount of offsets allowed for compliance decreases to four percent with an additional two percent allowed from projects located on federally recognized tribal land.

## 7.4 Low to Zero Carbon Fuels

In recent years, there has been significant progress in the technologies and markets for various types of decarbonized gases. Biofuel-based resources, commonly known as Renewable Natural Gas (RNG), are one well-known type of low- or zero-carbon gas, as biogas has been utilized for decades for direct heating or power generation. However, new technologies have created new opportunities for decarbonized gases. Hydrogen generation from various sources has advanced significantly; projects are currently being developed to inject both pure hydrogen into gas lines and produce synthetic methane by combining clean hydrogen with waste CO2. Below is a discussion of the main types of low-carbon gases that NW Natural is currently considering as compliance resources.

### 7.4.1 Biofuels

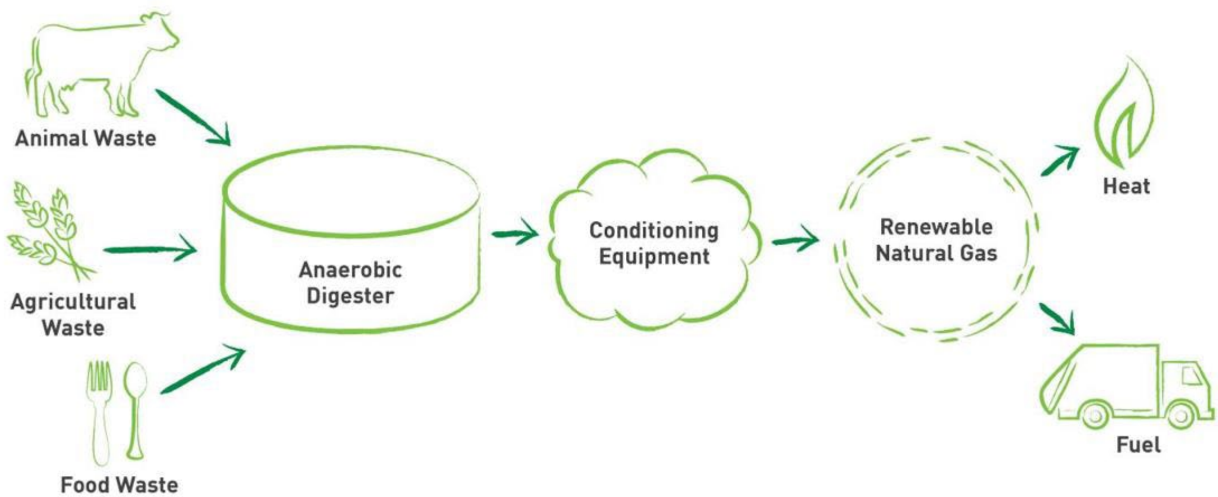
Biofuel gas or RNG is pipeline-quality gas derived by cleaning up the raw biogas emitted as organic material chemically breaks down. RNG entering NW Natural's system must adhere to specified quality standards, containing at least 97.3 percent methane and an energy content of at least 985 Btu/SCF. Once integrated into NW Natural's or any gas utility's system, RNG is interchangeable with conventional natural gas.


Oregon RNG was defined in 2019's Senate Bill 98 (SB 98) as:

> [A]ny of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural

> gas; Hydrogen gas derived from renewable energy sources; or Methane gas derived from any combination of: Biogas; Hydrogen gas or carbon oxides derived from renewable energy sources; or waste carbon dioxide[106].

In Washington, per 2019's House Bill 1257, RNG "means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters." The bill further notes that "the [WUTC] may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels[107]."




There are many policies that drive NW Natural to procure RNG for its customers. Table 7.3 identifies the key driving policies that establish RNG goals, define RNG, and define its role in NW Natural's emissions compliance activities to secure least cost RNG resources on behalf of its customers.

[106] Oregon Senate Bill 98: https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled
[107] Washington House Bill 1257: https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20220917151937

*Table 7.3: Policies Driving RNG Acquisitions*

| Policy | Relevance for RNG |
|---|---|
| **Oregon Senate Bill 98** | Volumetric targets for RNG procurement for Oregon sales customers |
| **Oregon Climate Protection Program (CPP)** | Compliance will include RNG and hydrogen (above and beyond Senate Bill 98 volumes) when cost-effective to procure |
| **Washington House Bill 1257** | Established both an option for delivery for RNG to all gas customers as well as a requirement to offer customers a voluntary RNG tariff |
| **Washington Climate Commitment Act (CCA)** | Sets emissions cap that applies to gas utilities, which can use RNG and hydrogen as a compliance tool |
| **Voluntary offerings to customers** | Building options in Oregon and Washington to procure greater amounts of RNG and hydrogen |

The policy that has had the largest impact to date on NW Natural's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG. The law allows gas utilities to procure RNG and invest in RNG projects, provided that the *incremental* cost of such procurement does not exceed five percent of the company's annual revenue requirement. The calculation for what costs are incremental is discussed later in this chapter.

Under Senate Bill 98 gas utilities can purchase RNG (including hydrogen) for all customers as part of the utility's resource mix. It also allows gas utilities to invest in and own the equipment necessary to bring raw biogas and landfill gas up to pipeline quality, as well as the facilities to connect to the local gas distribution system. Senate Bill 98 describes the voluntary volumetric targets for both large and small gas utilities (NW Natural is classified as a large gas utility). It is worth noting that although the volumetric targets increase by five percent every five years, there is no corresponding increase in the percentage of the revenue requirement for RNG spends in SB 98, thereby limiting the amount of RNG procured by spend vs. volume given today's RNG prices.

Senate Bill 98 has been instrumental in the Company being a leader in the procurement of RNG among gas utilities and to develop programs and build a team around the development and procurement of RNG. This technical and market knowledge can now be applied to NW Natural's compliance and planning under programs such as the Climate Protection Program, Washington House Bill 1257, and the Washington Climate Commitment Act.

#### *7.4.1.1 Emissions Benefits of RNG*

There are several ways to evaluate the emissions of RNG. Both Oregon and Washington's laws relating specifically to procurement of RNG by gas utilities do not set parameters around prescribed carbon intensity of RNG because the carbon dioxide that is emitted when RNG is combusted is biogenic—derived from and stored by organic matter—meaning that the combustion of it does not add any additional carbon into the carbon cycle. Therefore, under these legal frameworks, NW Natural treats RNG to be carbon neutral. NW Natural reports its emissions in both states on a "combustion basis," which reflects the view that the carbon in RNG is biogenic, and thus the carbon emitted when combusted is not reported. This same approach is used by the U.S. Environmental Protection Agency, the International Energy Agency, and the Intergovernmental Panel on Climate Change, which all recognize that because the CO2 in biogas is biogenic, it is appropriate to not report that carbon in RNG when reporting emissions.

There are other programs in the United States that use a different approach to measuring the emissions reduction benefits of RNG. These programs use lifecycle-based methodologies, which look at the total emissions embedded in the entire lifecycle of a fuel's production and utilization. These programs are mostly found in transportation fuels, which have several different types of fuels and use the lifecycle-based approach to evaluate these fuels on an apples-to-apples basis. This approach derives a carbon intensity (CI) of a fuel and includes considerations of the methane emissions that would have occurred had the RNG project not been constructed, how efficient the use of the fuel is in the end use (e.g., how efficient is a certain motor?) and other aspects. Each fuel is given a carbon intensity score, which can vary from month to month or year to year, depending on local policies that address methane emissions, project performance, etc. NW Natural does not use carbon intensity scores to evaluate RNG resources because the utility's compliance environment uses combustion-based emissions treatment. However, NW Natural does record the carbon intensity score of its resources and reports it in its annual Senate Bill 98 reports. Oregon's rules for Senate Bill 98 require annual reporting of the carbon intensity of RNG and reporting for Washington for RNG delivered as part of a House Bill 1257 program requires similar data.

The carbon intensity of a resource using the lifecycle-based approach will vary depending on the raw feedstock, the process used, the efficiency of the equipment, etc. State-level clean fuels programs are the most advanced programs in evaluating and tracking the carbon intensity of RNG using this approach.

In Oregon, NW Natural's compliance under the Climate Protection Program will be measured in part via the data reported in the Oregon Greenhouse Gas Reporting Program, which may include book and claim accounting in addition to RNG directly injected into NW Natural's system. Oregon DEQ notes that "…accounting for biomethane and hydrogen is done using "book and claim" accounting. Under the book and claim accounting model, the environmental attributes (either accounting for lifecycle or combustion basis) of the gas are detached from the physical molecules…"[108]. This approach—separating the environmental attributes of the RNG from the physical delivered gas—is the standard used throughout the RNG industry, including in the U.S. Environmental Protection Agency's Renewable Fuel Standard, the Oregon Clean Fuels Program, Oregon Senate Bill 98, and the California Low Carbon Fuel Standard. As noted earlier, under SB 98 and the OR GHG Reporting Program NW Natural is required to report the carbon intensity of all RNG resources utilizing the lifecycle approach, but carbon intensity is not used for compliance under the Climate Protection Program. Instead, the Climate Protection Program exempts the combustion emissions from biomass-derived fuels, including RNG.

#### *7.4.1.2 Other Benefits of RNG*

As shown in Figure 7.3, integrating renewable gases into a gas system offers numerous compound benefits beyond emissions reductions, such as:

- Displacing anthropogenic carbon dioxide emissions from fossil fuel combustion
- Enhancing energy security
- Providing additional environmental benefits through improved organic waste management
- Increasing resource value and income for rural areas
- Reducing the demand for conventional fertilizers

[108] https://www.oregon.gov/deq/ghgp/Documents/BiomethaneProtocol.pdf

*Figure 7.3: RNG's Role in the Circular Economy*[109]


### *7.4.1.3 Renewable Thermal Certificates*

To track the environmental attributes of RNG and ensure that the benefits are not being claimed by multiple parties, the RNG industry uses the generation of "renewable thermal certificates" (RTCs) to track and record RNG transactions. Regardless of whether RNG is purchased bundled with or without the underlying physical gas, RTCs are recorded to ensure the environmental attributes of the gas are appropriately tracked.

An RTC is a sole claim to the environmental benefits of a dekatherm (Dth) of thermal energy from sources such as RNG, hydrogen or synthetic methane, and is separate from the physical gas (i.e., unbundled RNG or hydrogen). Renewable Thermal Certificates are procured to meet compliance needs and to provide an auditable pathway of how NW Natural is procuring renewable resources on behalf of its customers. The Midwest Renewable Energy Tracking System (M-RETS), which has historically tracked the sale of electricity-based renewable energy credits (RECs) has emerged as the leading platform on which RTCs are tracked and recorded.

One RTC is created for every Dth of RNG produced and injected into the "common carrier" natural gas network or an LDC's distribution system. See Figure 7.4 for an illustration of how this separation occurs.

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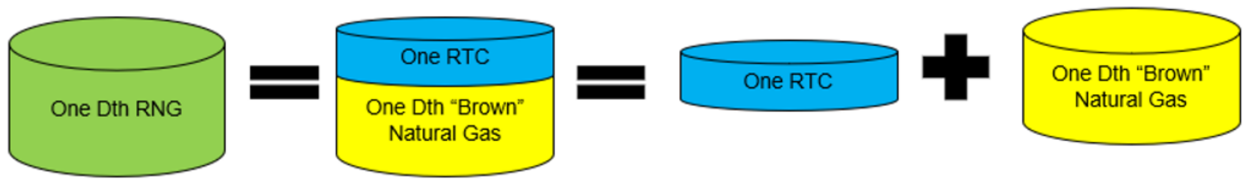
109
https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/6759c68149f2b8344218466e/1733936777572/RNG+Market+Today-+A+Primer.pdf

*Figure 7.4: Tracking RTCs*




NW Natural purchases both bundled and unbundled RNG resources. Bundled resources means that NW Natural is purchasing the physical molecules and the RTC together; unbundled means that NW Natural is purchasing the RTC only. Both are recognized as compliant resources under Senate Bill 98 and the Oregon Climate Protection Program. Contracts for RNG are either contracts for physical gas with special transaction confirmations and other elements that delineate what a producer will deliver, including RTCs entered into M-RETS as part of their contractual obligations, the RTCs only, or environmental attributes of RNG only.

### *7.4.1.4 Renewable Natural Gas Supply*

The supply of renewable natural gas (RNG) has recently become, and remains, a significant topic of research and evaluation as the industry matures. More potential buyers are seeking to understand the types, quantities, and economics of available RNG supplies.

The Coalition for Renewable Natural Gas announced in September 2024 a major milestone in the growth of the renewable natural gas industry, with 433 facilities now operational across North America. This achievement represents a significant leap from just a year ago, when the North American RNG industry celebrated the establishment of 300 facilities, marking a remarkable 44 percent growth within just one year.[110] While there has been healthy growth in the RNG market in recent years, there is still much more RNG that can be developed than what is already developed. Organizations such as the Oregon Department of Energy[111] and the American Gas Foundation[112] have published information regarding the potential for RNG development. In addition to these sources, a literature review on forecasts of RNG availability and price is available in Appendix E.1.

NW Natural is a leader in RNG procurement and project development among gas utilities in the United States and Canada. In previous years, NW Natural considered the transportation fuel sector to be its primary competitor for low-cost RNG, due to the highly lucrative credit markets available to those sectors. However, in recent years other gas utilities and large commercial and

[110] https://www.rngcoalition.com/news/2024/9/12/north-american-rng-surpasses-400-operational-facilities
[111] https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf
[112] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

industrial gas users have identified RNG as a critical resource for their decarbonization goals and targets and have begun to enter the market and buy RNG under both medium term (five years) and long term (ten years+) contracts. NW Natural has internal RNG origination resources and have maintained active project origination and development efforts for several years. These activities and the company's annual RFP process for RNG will continue to help the Company identify cost-effective RNG resources in the future. NW Natural is able to offer longer-term contracts than most other market participants, and its credit rating allows it to be viewed as an extremely low-risk offtaker or purchaser of RNG by project developers and owners.

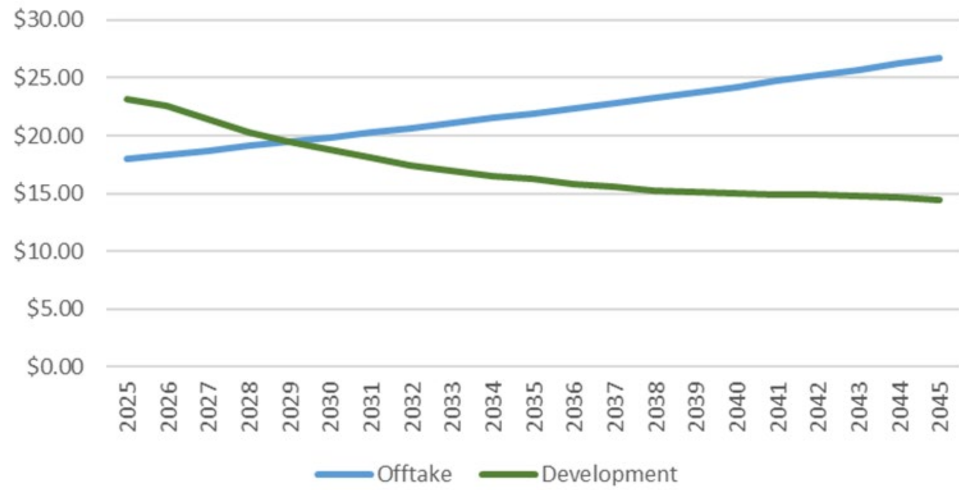
The cost of RNG on a dollar per MMBtu basis varies significantly depending on whether the project is a development by a utility itself or is an offtake-only opportunity. For utility development projects, the costs reflect the full scope of production, including financing, capital expenditures for equipment, ongoing operating expenses, and development costs such as legal and permitting fees. These projects benefit from economies of scale and avoid developer markups. Capital costs do increase with production volume; however, they do so at a slower pace, meaning the per-unit cost of RNG decreases as production capacity expands.

In contrast for offtake-only opportunities, the pricing is largely market-based. NW Natural typically purchases RNG from the non-vehicle fueling sector. However, the market lacks price transparency, making it difficult to assess costs directly. To mitigate this uncertainty, NW Natural relies on an annual RFP process to gather and analyze market data, allowing the company to make more informed decisions on the offtake opportunities it pursues. This approach helps ensure that NW Natural secures competitive pricing while maintaining flexibility in sourcing.

Figure 7.5 conveys the average cost of RNG, differentiating between development and offtake opportunities. Development opportunities are generally more cost effective than offtake opportunities as:

- Average RTC cost goes down over life with asset being depreciated
- Long term supply is enabled with development projects at low escalating price
- Revenue requirement to customers over life is substantially less
- Average RTC price goes up with offtake price increasing over life of contract

*Figure 7.5: Development versus Offtake RTC Cost*




### *7.4.1.5 Renewable Natural Gas Procurement*

Oregon Senate Bill 98, Washington HB 1257, the Oregon Climate Protection Program, and the Washington Climate Commitment Act all underscore the need for NW Natural to secure low carbon gases, including biofuel-based RNG and hydrogen resources. While each program takes a slightly different view of RNG definitions, cost caps, etc., NW Natural endeavors to secure resources that it believes will work within a variety of policies, regulations, and other programs. For instance, all the RNG procured to date under Senate Bill 98 will also offer compliance benefits under the Oregon CPP. As noted earlier, the Oregon DEQ has stated that off-system RNG, which is typically tracked via RTCs, will qualify as a resource under the Oregon CPP.

Renewable natural gas projects take several years to develop. NW Natural keeps track of projects at a variety of times in their lifespans. For instance, projects are sometimes in very early stages of development, with no definitive agreements or interconnection agreements signed, when they come to the company's attention. A developer may contact NW Natural about buying the RNG, and NW Natural will express interest but convey that NW Natural cannot enter true negotiations until the project has a clear pathway toward full development. NW Natural may enter non-binding letters of intent (LOIs) and non-binding term sheets with developers and project owners. Only a small number of these resources become actual contracted resources but entering into these non-binding agreements allows the Company to learn more about the resource, exercise its due diligence, and assess the costs and benefits of a project. This is similar to how other utility projects are assessed, where there is initial investigation/origination, targeted due diligence, and then recommendations for an investment or resource selection.

Projects must be continually evaluated, which makes it difficult to put specific resources into an IRP. Typically, NW Natural must decide to enter into definitive agreements within a set timeline (e.g., within 90-day exclusivity period, or in response to a formal bid process with a hard deadline). Additionally, all projects, regardless of timing or whether they are identified through the RFP process are evaluated on the same metrics, which include incremental cost to customers, project risks, volume availability, etc.

NW Natural utilizes in-house origination resources as well as its external relationships in the industry to identify new potential RNG resources. An annual request for proposal process is also used to evaluate offtake opportunities in the market and understand the breadth of renewable resources that might be available. Figure 7.6 and Table 7.4 summarize the 2024 RFP responses.

*Figure 7.6: 2024 RFP by Feedstock*

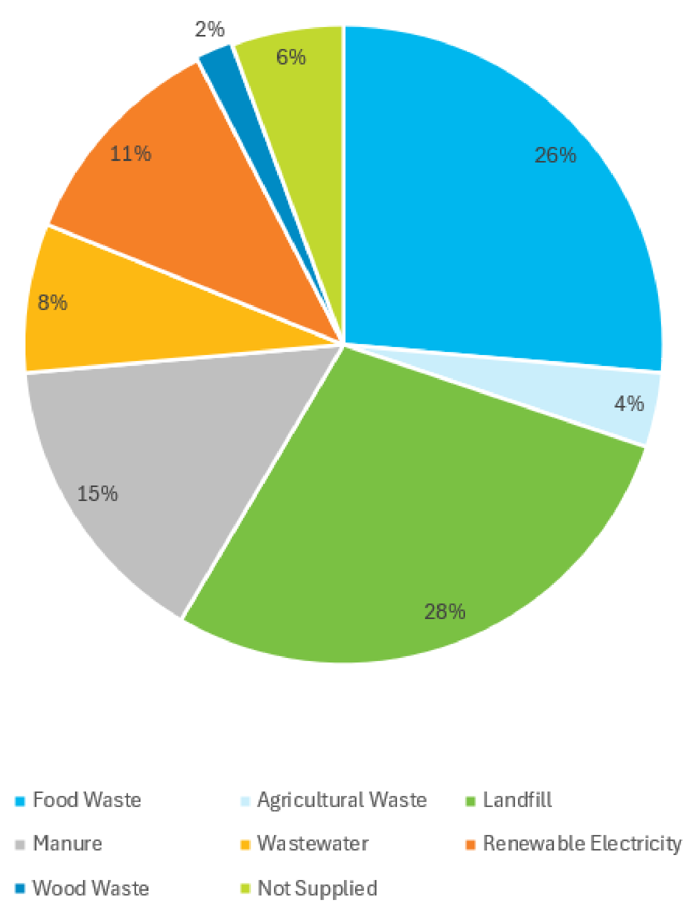


*Table 7.4: 2024 RFP Responses- Summary*

| 2024 RFP Response Summary | |
|---|---|
| **Total Responses** | 53 |
| **Average Contract Term** | 15 |
| **Average Annual Volume of Resource** | 716,363 MMBtu |
| **Bundled vs. Unbundled** | 38% / 62% |

The 2025 RFP, issued on May 15, 2025, marks NW Natural's sixth annual call for RNG resources. Shortlisted respondents will be notified in late July 2025 and further due diligence on these proposals will be conducted from July through August 2025. Final agreement negotiations will begin in the summer.

Between rounds of RFPs, NW Natural additionally evaluates resources on a rolling basis. This includes a rolling evaluation of other offtake resources as well as a rolling evaluation of RNG development opportunities. For development opportunities, the following agreements and activities are common during NW Natural's rolling evaluation process:

- Non-disclosure agreements signed to collect initial data
- Non-binding term sheets agreed to explore economic agreements with feedstock owners, developers, project owners, etc.
- Extensive diligence processes undertaken to assess project economics and risks, including technical, legal, regulatory, financial, environmental, etc.

Current RNG contracts will be discussed later in this chapter.

## 7.4.2 Hydrogen

Hydrogen is evaluated as a compliance resource option as it provides the needed emissions reductions for NW Natural customers similarly to RNG. The use of hydrogen has many benefits including: its compatibility with current gas system operations, increasing the diversity of supply sources, the ability to deliver high temperature energy (critical for industrial process loads), the potential to support new vehicle fuel demand (trucking, aviation, marine), and the ability to store energy long term at a low cost.

### *7.4.2.1 The Hydrogen Rainbow*

Hydrogen can be sourced from many feedstocks and processes, including electrolysis of water, gasification or pyrolysis of woody biomass, reforming or pyrolysis of methane, and cracking of imported ammonia. There are many types of hydrogen, and the colors (see Table 7.4) represent the base source, production method, and products.

NW Natural is open to exploring all low-carbon sources of hydrogen inside and outside the region.[113]

*Table 7.5: Hydrogen Sources*[114]

| | Gray Hydrogen | Blue Hydrogen | Turquoise Hydrogen | Green Hydrogen | Pink Hydrogen |
|---|---|---|---|---|---|
| Process | Steam methane reforming | Steam methane reforming with carbon capture sequestration | Reforming methane into hydrogen gas and elemental (solid) carbon | Electrolysis, electricity is used to split the molecule into hydrogen and oxygen | Electrolysis, electricity is used to split the molecule into hydrogen and oxygen |
| Source | Methane | Methane | Methane | Renewably-generated electricity | Nuclear electricity generation |

Regardless of the type of hydrogen that is produced or purchased, hydrogen molecules can be blended into existing pipelines and used by buildings, and commercial appliances. Studies and testing of hydrogen blends show a 20 percent by volume blend of hydrogen into natural gas distribution systems results in no significant safety, appliance compatibility, or leakage

[113] Gray hydrogen is presented for informational purposes only. As it is not a low-carbon source, NW Natural is not exploring this as an option.

[114] Each source of hydrogen carries a carbon footprint from a lifecycle perspective. Green hydrogen carries the carbon intensity of the energy used to create the electricity and build and maintain the associated generation infrastructure, blue and turquoise sources have up- and mid-stream methane emissions or CO2 sequestration efficiencies, etc. These carbon intensities depend on a number of design and production factors and can range from near-zero to the hundreds of grams of CO2 per MJ of energy. The Inflation Reduction Act provides hydrogen production tax credits (PTCs) based on the carbon intensity of the gas, as measure on a lifecycle basis using the GREET software created by Argonne National Laboratory. The PTCs are highly skewed towards the lowest carbon intensities possible:
Based on carbon intensity ($0.60/kg base credit, **5x** if prevailing wages & apprenticeship requirements met):

•0.45kgCO2/kgH2: 100% ($3.00/kg or $22/MMBtu)

•0.45-1.5kgCO2/kgH2: 33.4% ($1.00/kg or $7.43/MMBtu)

•1.5-2.5kgCO2/kgH2: 25% ($0.75/kg or $5.57/MMBtu)

•2.5-4.0kgCO2/kgH2: 20% ($0.60/kg or $4.46/MMBtu)

Any given hydrogen production pathway could be anywhere in this range of carbon intensities depending on the capital costs of the project. For example, electrolytic hydrogen using electricity from a coal generation plant could be on the lower end of carbon intensities using significant carbon capture infrastructure. The incentives to minimize the carbon intensity to obtain the maximize PTC are very high, and at a minimum, all hydrogen projects are expected to meet the definition of Clean Hydrogen as outlined in the Inflation Reduction Act, with the highest level being produced with emissions of $4kgCO_2e/kgH_2$ or less.

issues.[115,116] In addition to the distribution systems servicing homes and business, there is potential for hydrogen to have dedicated systems for large industrial processes currently relying on natural gas. These dedicated systems would flow 100 percent hydrogen that is completely separated from existing distribution systems delivering hydrogen/natural gas blends and would continue to provide the required energy for a large industrial customer.

Several natural gas distribution companies are exploring 100 percent hydrogen distribution systems as a natural evolution of the gas system:

- Northern Gas Networks (UK)[117]
- ATCO (Alberta, Canada)[118]
- Alliander (The Netherlands)[119]
- Clean Energy, part of the Holthausen Group (The Netherlands)[120]

One-hundred percent hydrogen distribution systems generally require new appliances and equipment for customers; however, the low distribution system pressures and material may well be compatible with 100 percent hydrogen, and the systems themselves create interesting opportunities for large amounts of decarbonization, distributed hydrogen generation not reliant on natural gas flows (blending), and customer net metering for production of hydrogen and storage in the gas system for later use when needed.

#### *7.4.2.2 Power-to-gas*

Power-to-gas (P2G), also referred to as green hydrogen or electrolytic hydrogen, describes a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen. Power-to-gas produces useful hydrogen that can be used as an energy source onsite (as in a fuel cell) or as mentioned above, blended into a gas grid to produce energy that is very similar to typical natural gas.

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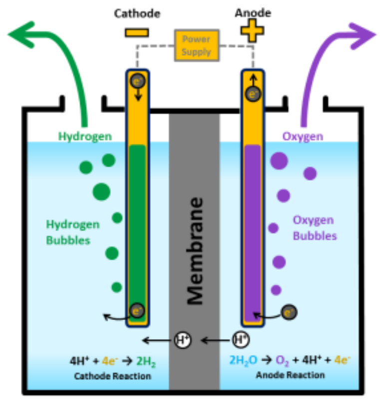
[115] Oxford Institute for Energy Studies, *Oxford Energy Forum: The Role of Hydrogen in the Energy Transition, Issue 127*, May 2021. Available at: https://www.oxfordenergy.org/publications/oxford-energy-forum-the-role-of-hydrogen-in-the-energy-transition-issue-127/ [Accessed 13 Feb. 2025].
[116] MacKinnon, M., et al., *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure*, 2020. Available at: https://www.researchgate.net/publication/339420288_Hydrogen_leaks_at_the_same_rate_as_natural_gas_in_typical_low-pressure_gas_infrastructure [Accessed 13 Feb. 2025].
[117] https://www.northerngasnetworks.co.uk/about-us/current-business-plan/our-hydrogen-home-welcome-to-green-gas/
[118] https://gas.atco.com/en-ca/community/projects/albertas-first-hydrogen-home.html
[119] https://www.bdrthermeagroup.com/stories/bdr-thermea-hydrogen-pilot-lochem
[120] https://northerntimes.nl/pilot-programme-to-heat-homes-with-hydrogen-to-begin-in-wagenborgen-in-groningen/

Figure 7.7 shows the basic reaction that occurs within an electrolyzer during electrolysis. An electrolyzer uses electricity to conduct this process, and if the electricity is sourced from zero-carbon resources, the entire production of hydrogen and oxygen is virtually zero-emissions.

*Figure 7.7: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis*[121]




### *7.4.2.3 Power-to-gas Existing Technologies and Trends*

There are three primary electrolyzer technologies that are available today for power-to-gas applications. These are:

- Alkaline
- Proton exchange membrane (PEM)
- Solid oxide (SOE)

Of these technologies, alkaline electrolyzers have been in operation much longer than the other two. They are also less expensive than the other technologies, and more efficient in their production of hydrogen. However, PEM technologies have advantages over alkaline electrolyzers such as faster ramp-up times and a smaller footprint. SOE technology is less developed but offers the distinct advantage of using heat as one of the inputs to generate hydrogen, so it could potentially offer a productive use for existing waste heat resources. The choice of electrolyzer depends on the situation and the way it will be operated.

Europe and Asia have been leading the way with power to gas installations; some notable electrolyzer installations recently include:

- 24MW PEM electrolyzer installed at Herøya, Norway for decarbonization of ammonia in 2024
- 10MW PEM electrolyzer installed near Wesseling, Germany for decarbonization of chemicals
- 2MW PEM electrolyzer installed in Yokohama, Japan for e-methane production

[121] U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

- Five 5MW alkaline and one 2MW PEM electrolyzers (total of 27MW) installed in Daye, China for industrial decarbonization

#### *7.4.2.4 The Economics of Power-to-gas for the Direct-use Natural Gas System*

When P2G is utilized as a supply-side resource for the direct-use natural gas system, its economics are driven primarily by technology costs (i.e., electrolyzer and methanation facility costs), the price of electricity used as a feedstock, and how often the built facility is used to produce deliverable gas. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

The previously mentioned Alt Fuels Study and Offsets report goes into great detail around the various inputs that influence hydrogen production from Power-to-gas. The report outlines the various technologies, electricity sources, and applicable tax credits and ultimately provides cost estimates for green hydrogen. These estimates were refined and simplified for use in the PLEXOS modeling presented later in this IRP.

#### *7.4.2.5 Methane Pyrolysis*

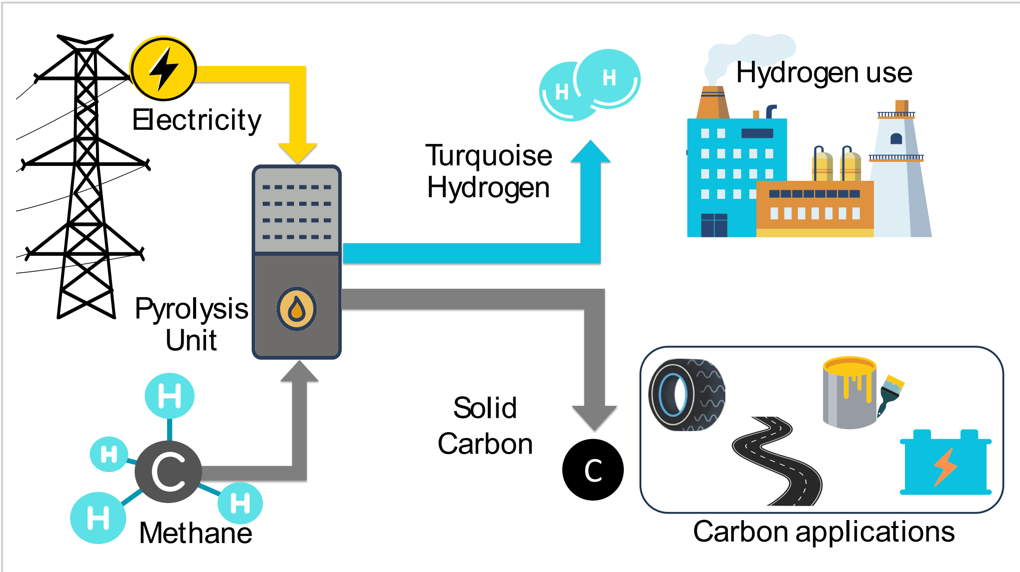
Methane pyrolysis (also referred to as turquoise hydrogen), is a method of producing hydrogen from natural gas. In traditional steam methane reforming (SMR), natural gas is combined with high-temperature steam to produce hydrogen, but this process also generates carbon dioxide as a byproduct, contributing to greenhouse gas emissions. Methane pyrolysis, on the other hand, involves breaking down methane into its constituent elements in the absence of oxygen typically at temperatures above 700°C to produce hydrogen and solid carbon, without the production of carbon dioxide.

The high temperatures needed to pyrolyze the natural gas can be achieved through different processes, including thermal, microwaves, and plasma torches, further adding catalysts to decrease the amount of energy needed and to increase efficiency.

- Thermal processes use heat from the combustion of natural gas, hydrogen, or other fuels, and can use electricity as well.
- Microwaves and plasma torches use electricity to heat natural gas and typically have the advantage of ramping up and down quickly, which is advantageous for changing customer demands.

Hydrogen produced from fossil natural gas using methane pyrolysis is therefore a low-emission resource, since no/minimal amounts of CO2 are emitted. The hydrogen can even have negative emissions when paired with RNG as the source of energy. The solid carbon produced as a byproduct can potentially be used in various applications and products, including asphalt and roofing materials, concrete, batteries, tires, aerospace materials, and more. This usefulness can create additional revenue to reduce the overall cost of the hydrogen; however, the value is directly tied to the type of carbon produced.

*Figure 7.8: Hydrogen Schematic*




The methods of methane pyrolysis and associated reaction conditions (e.g., pressure, temperature, on a surface or in the gas flow, etc.) dictate the molecular structure and consistency, which leads to the carbon classification. Graphene, Nanotubes, Carbon Black, and other types of carbon can be produced. There are a wide range of values; graphene can sell for $2,000/kg or more, while Carbon Black sees prices at around $2/kg.

There are significant advantages to turquoise hydrogen compared to other clean hydrogen production methods.

The existing gas system can be used to deliver energy to customers as it does today with hydrogen being produced on-site just before or behind the meter. Hydrogen blending or 100 percent dedicated hydrogen pipelines can deliver energy to customer equipment depending on their process needs and available equipment directly by the gas utility. This can lead to much more efficient decarbonization and decreased technology risk for NW Natural and its customers. It enables quicker scale up of hydrogen usage and can enable waste heat recovery for various processes on-site as well. Turquoise hydrogen requires no sequestration geology and is therefore not limited by geography. It also does not require any water usage, it is flexible in its input energy supplies, and initial modeling suggests it could be a very cost effective decarbonization resource compared to other options available to NW Natural.

There are considerations to turquoise hydrogen that NW Natural is analyzing, including increased system capacity demands, carbon management and markets, and technology maturity. The solid carbon that is removed from the natural gas stream has potential chemical energy; the carbon could be burned, thereby releasing its potential chemical energy as heat. This stored chemical energy that is locked into the solid carbon is energy that would have been delivered to customers in the form of natural gas. Therefore, more natural gas is required to deliver the same amount of energy to any given customer as the energy from combusted natural gas. The total amount of energy needed on the input side is approximately double the original amount due to this removal of energy. This increases the required natural gas delivered to the methane pyrolysis site, which increases demands on distribution infrastructure, pipeline capacity, and purchased molecules. If these resources are not available all the time, in lieu of modifying them it is conceivable that designs and customer equipment would need to be able to accommodate switching back and forth from using hydrogen back to natural gas.

Efficient and safe carbon management is critical to the success of turquoise hydrogen projects. The carbon often exists as a fine powder and significant on-site storage, or frequent removal needs to be available. For every kg of hydrogen produced, three kg of carbon is produced, and at utility scales significant amounts of carbon are produced, which can have downward pricing effects on existing carbon commodities. However, these large amounts of various types of carbon create opportunities for new carbon markets that can take advantage of low-cost carbon and favorable physical and chemical characteristics.

There are approximately 30 turquoise hydrogen technology companies and entities in the world today, with more coming online every month. These start-up companies are in various stages of product development, funding, and commercialization. Some of these companies will succeed whereas some will fail due to market forces and their abilities to access funding, technical resources, and being at the right place at the right time. This nascent market structure presents risk when gas utilities are considering deployment of turquoise hydrogen and benefiting from its low cost of decarbonization. Technology and commercial risk can be mitigated by using third parties to test the equipment before it is delivered to customer sites and have payments based on meeting performance goals. In addition, minimal capital deployments are being planned for the concrete pads, utility connections, etc. to accommodate the turquoise hydrogen units. Carbon removal service agreements will be put in place to create pay-for-performance transactions and ownership of the units will remain with the technology providers. Coupling this with having multiple technology providers at the ready decreases commercial and technology risk even further.

#### *7.4.2.6 Modern Hydrogen Pilot*

In 2022, NW Natural entered into an agreement with Modern Hydrogen (then Modern Electron) to host one of its pilot units for evaluation. This will help the company evaluate additional methane pyrolysis technologies and help mature and grow the technology to enable wide-spread usage to decarbonize its largest customers as efficiently as possible. The equipment was designed to produce five kg of hydrogen per day and the total term of the lease agreement is three years. During this time, NW Natural is evaluating the following:

- Availability and reliability of the technology
- Capabilities of Modern Hydrogen as a company to produce and support methane pyrolysis technology
- Efficiency of the natural gas to hydrogen conversion process
- Carbon storge and handling
- Safety of the technology
- Hydrogen metering and greenhouse gas reporting

The project has been well-supported by Modern Hydrogen to date and has been presented to numerous groups, including labor, elected officials, visiting utilities, etc. to educate them on the technology and decarbonization benefits for gas utilities.

The pilot project is expected to wrap up in 2026 and depending on what is learned and future developments in the methane pyrolysis space, NW Natural may pursue additional pilots.

*Figure 7.9: Modern Hydrogen Pilot*

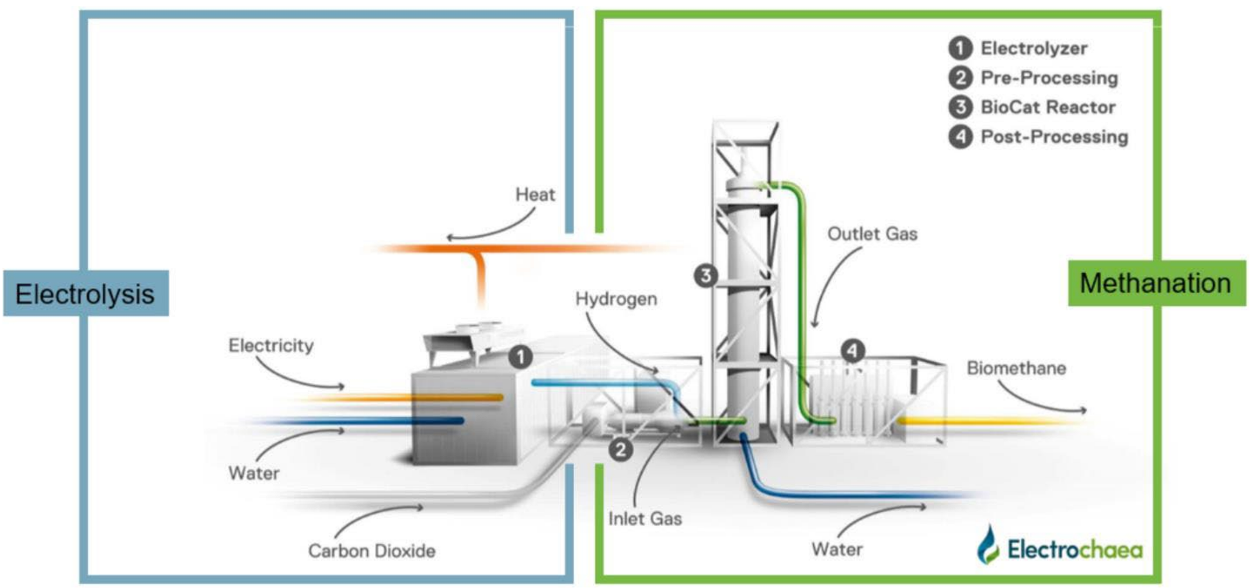
## 7.4.3 Synthetic Methane

Synthetic methane is a manufactured fuel that is designed to be a substitute for natural gas. It can be produced from biomass and hydrogen through different processes, each with unique advantages for sustainability and carbon neutrality.

### *7.4.3.1 Synthetic Methane - Hydrogen*

Green hydrogen can be combined with waste CO2 to produce synthetic methane (also referred to as synthetic natural gas, methanated hydrogen, power-to-X, or e-methane) using chemical or biological processes, as depicted in Figure 7.10. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15 percent of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

*Figure 7.10: Synthetic Methane Production Process Using Biogenic Methanation*




Synthetic methane does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection into transmission lines have; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found.

In addition, RNG projects which have low-cost electricity nearby are also being explored for synthetic methane “bolt-on” projects, as RNG has the requisite low-cost and steady waste CO2 supply. By adding synthetic methane to RNG projects, almost twice the amount of gas can be produced at the site while leveraging the existing gas interconnect and compression infrastructure, thereby significantly decreasing the cost of low-carbon energy at the site.

Green hydrogen can be combined with waste CO2 to produce synthetic methane (also referred to as synthetic natural gas, methanated hydrogen, power-to-X, or e-methane) using chemical or biological processes, as depicted in Figure 7.8. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15 percent of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

#### *7.4.3.2 Synthetic Methane - Woody Biomass*

Synthetic Methane (and RNG) can be produced from woody biomass through thermochemical or biochemical processes that break down lignocellulosic materials into hydrogen-rich gases. The primary methods include:

- Gasification – Biomass is heated in a controlled oxygen environment to produce syngas (a mix of hydrogen, carbon monoxide, and methane). The hydrogen is then separated and purified.
- Pyrolysis with Reforming – Biomass is heated in the absence of oxygen to produce bio-oil, which is then reformed into hydrogen.
- Biological Processes – Certain microorganisms produce hydrogen through fermentation, though this method is less commercially viable.

Woody biomass, including forest residues, logging slash, and mill waste, is an abundant and renewable feedstock, making it a promising resource for hydrogen production. Oregon is well-positioned for hydrogen production from woody biomass due to several key factors, including abundant biomass supply, need and willingness to address wildfire risks, and aggressive natural gas system decarbonization goals.

Woody biomass plants could be positioned to take full advantage of the 45V tax credit, as the biogenic feedstock should elicit the full $3/kg$H_2$ amount (approximately $22/MMBtu). This tax credit would likely be needed to make this pathway viable due to the high capital costs of the production plants and the relatively high feedstock costs. Gathering and transporting forest floor detritus and slash to a central location would be required.

Woody biomass projects could provide multiple wins for the state and NW Natural is monitoring pilots throughout the country to understand the costs and opportunities for this resource in the future.

### 7.4.4 RNG and Hydrogen Evaluation Methodology

The 2018 IRP included the nation's first comprehensive methodology to evaluate the cost-effectiveness of low-carbon gas supply resources and sought acknowledgement of this methodology in Oregon. This request resulted in the OPUC opening a docket (OPUC Docket No. UM 2030) for review of the proposed methodology. This process resulted in a modified methodology that was approved by the OPUC to evaluate low carbon gas supply resources. Also, as was previously mentioned a voluntary renewable gas portfolio standard (SB 98) passed in Oregon, and the resulting rules to implement the program included a placeholder for the evaluation methodology based upon the methodology acknowledged in the most recent IRP. NW Natural has been using this methodology to evaluate the incremental cost of potential resources to comply with climate policy in both Oregon and Washington.

As NW Natural has gained experience in the RNG market, NW Natural has made improvements to the methodology and modeling tools, resulting in a process that aligns with the realities of the RNG market. The following improvements have been made to the Incremental Cost Workbook: Avoided costs are updated annually, a new scenario tab was created where critical variables can be adjusted outside of the fifth and 95$^{th}$ percentile (capital expenditures, operations and maintenance costs, production), an investment tax credit scenario was created, and an on-system bundled model was created to simplify inputs and outputs which reduces the amount of formulas to track. The methodology is included in detail in Appendix K.

In addition, NW Natural added a risk scoring matrix to the offtake evaluation process which is designed to not only assess the risk of an opportunity but also help determine if contractual remedies might be warranted if the opportunity progressed to contract execution. Each opportunity is evaluated and assigned a score for seven risk categories as outlined in Figure 7.11. Those scores are then combined for a total risk score and risk categorization as outlined in Figure 7.12.

*Figure 7.11: RNG & Hydrogen Opportunity Risk Matrix*

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Finance risk** | Fully financed | Funding has been secured and project is currently under development | Project can be internally financed by developer. Alternatively, project has financing agreement (e.g., primary lender, and tax equity as appropriate) with credible funding source with joint commitment to proceed | Negotiations underway for financing | Not financed |
| **Constructability risk** | In operation | COD within 12 months | In construction and/or major equipment is ordered | Design complete | Design not complete |
| **Counterparty risk** | Counterparty has bond rating in good standing, no legal issues | Counterparty does not have bond rating but can supply positive financial records | minimal data available, but no negative reports | Legal issues have been identified or poor bond rating | Unknown entity or bankrupt |
| **Marketability** | D3 RINs eligible and negative CI score | D3 RINs eligible | D5 eligible and negative CI score | D5 RIN eligible | No other market eligibility |
| **Commercial Terms/ Legal risk** | Fixed volumes that can be supplied by seller's portfolio at same price | Minimum volumes that can be supplied by seller's portfolio at same price | remedies included | Ability to exit contract if minimum quantities are not met for an extended period of time | No contract minimums, no remedies |
| **Bidder Experience** | Multiple successful projects and experienced staff | Minimum of on operating project and experienced staff | Minimum of one operating project | Similar projects in construction | No successful projects |
| **Gas/Interconnect/Feedstock rights** | All rights obtained | 2/3 rights obtained, third in progress | 2/3 rights obtained | 1/3 rights obtained | No rights obtained |

*Figure 7.12: RNG & Hydrogen Opportunity Risk Score*

| Total | Color | Result |
|---|---|---|
| 23 to 30 | Red | Not moving forward |
| 13 to 22 | Yellow | Must have minimums or contract remedies |
| <12 | Green | Would sign without contractual remedies |

## 7.5 Current RNG Projects

NW Natural has six current renewable natural gas RTC offtake agreements and two development projects (see Table 7.6 for details). In 2024 NW Natural retired 739,487 RTCs from RNG project(s) on behalf of customers.

*Table 7.6: Current RNG Contracts*

| Projects [122] | Feedstock | Type | Start Date | Term (yr.) | CI Score (gCO2e/ MJ) | Projected Volumes (MMBtu/year) | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | 2025 | 2026 | 2027 |
| **Offtake #1 (Western US)** | Food Waste | Offtake | 2022 | 5 | 27 | 73,000 | 66,800 | |
| **Offtake #2** | Wastewater | Offtake | 2022 | 4 | 45 | 264,780 | 66,195 | |
| **Offtake #3** | Landfill | Offtake | 2022 | 21 | Various | 1,000,000 | 1,000,000 | 1,000,000 |
| **Offtake #4** | Landfill | Offtake | 2025 | 1 | TBD | 660,000 | | |
| **Offtake #5** | Landfill | Offtake | 2025 | 15 | TBD | 208,404 | 441,550 | 489,262 |
| **Offtake #6** | Synthetic Methane & Dairy Manure | Offtake | 2025 | 2 | TBD | 3,650 | 7,300 | 3,650 |
| **Tyson-Dakota City** | Food & Brewery | Develo pment | 2023 | 20 | 21.99 | 98,994 | 116,464 | 116,464 |
| **Tyson-Lexington** | Food & Brewery | Develo pment | 2022 | 20 | 32.57 | 79,112 | 83,067 | 87,221 |

For more information on current RNG offtakes, see Appendix E.3.

## 7.6 Carbon Capture Utilization and Storage/Sequestration

Carbon Capture, Utilization, and Storage (CCUS) encompasses a suite of technologies aimed at capturing $CO_2$ emissions from sources such as industrial processes, power generation, renewable fuels production, direct air capture (DAC), etc., transporting the captured $CO_2$ and either using it directly in products or as an industrial gas or storing it underground to prevent its release into the atmosphere. CCUS is emerging as a key decarbonization pathway in the portfolio of solutions to reduce greenhouse gas emissions, particularly from hard-to-abate sectors.

The process of capturing $CO_2$ typically involves separating it from other gases produced during industrial activities. The primary methods include:

[122] At the request of the vendor, the Project Name has been redacted.

- **Post-Combustion Capture**: This technique captures $CO_2$ from the flue gases emitted after fossil fuels are burned. It is commonly applied in power plants and involves the use of chemical solvents, such as amines, to absorb $CO_2$ from the exhaust stream.
- **Pre-Combustion Capture**: In this method, fossil fuels are partially oxidized to produce a synthesis gas (syngas), consisting mainly of hydrogen and carbon monoxide. The carbon monoxide is then converted to $CO_2$, which is separated, leaving hydrogen that can be used as a clean fuel. This process is used in producing blue hydrogen. Turquoise hydrogen can also be considered pre-combustion carbon capture, however, it is in a solid form and is sequestered in products or other permanent disposal methods other than injection underground as is being discussed here.
- **Direct Air Capture (DAC)**: DAC technologies extract $CO_2$ directly from ambient air using chemical processes. Although currently more energy-intensive and costly, DAC offers the potential for negative emissions by removing existing $CO_2$ from the atmosphere.

The chemicals (usually amine solvents) used in carbon capture systems absorb $CO_2$ from flue gases. This reaction occurs in an absorber column where $CO_2$-rich gas contacts the amine. The $CO_2$-loaded solvent is then heated in a separate unit, releasing pure $CO_2$ for storage and regenerates the amine for reuse.

The cost of capturing $CO_2$ is significantly influenced by its concentration in the emission stream. High-purity $CO_2$ streams, such as those from ethanol production or natural gas processing are less expensive to capture. In contrast, dilute $CO_2$ streams from power plants or cement production are more challenging and costly to process. The energy required for capture contributes to higher operational costs, as additional fuel may be needed to power the capture systems.

Gaseous $CO_2$ is typically converted to a liquid or a supercritical fluid for more efficient handling, storage, and transport. This step is done by compressing the gas and changing its temperature as needed. Supercritical $CO_2$ behaves similarly to $CO_2$ gas but has a higher density and lower viscosity than liquid $CO_2$, which is beneficial for pipeline use and geological storage.

## 7.6.1 Utilization

Once captured, the $CO_2$ is typically transported to another location where it can be used or permanently sequestered. The primary modes of transportation include:

- **Pipelines**: The most cost-effective and widely used method for transporting large volumes of $CO_2$ over long distances. The United States has over 5,000 miles of $CO_2$ pipelines, transporting approximately 80 million metric tons annually. Pipelines are regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to ensure safety and environmental protection.

- **Trucks and Rail**: Suitable for smaller quantities or regions lacking pipeline infrastructure. While offering flexibility, these methods are more expensive and less efficient for large-scale transport. Innovations like mobile carbon capture systems are being explored to capture and transport $CO_2$ directly from vehicles.

Safety in $CO_2$ transportation is paramount. Regulations exist for transport of supercritical $CO_2$ through the Department of Transportation (DOT), Federal Railroad Administration (FRA), the American Petroleum Institute (API), and Pipeline and Hazardous Materials Safety Administration (PHMSA).

### 7.6.2 Sequestration

Effective and permanent storage of $CO_2$ necessitates suitable geological formations that can securely contain the gas over extended periods. The primary types of geological formations used for $CO_2$ sequestration include:

- **Deep Saline Aquifers**: These are porous rock formations saturated with brine, offering vast storage potential. They are widely distributed and can accommodate significant volumes of $CO_2$.
- **Depleted Oil and Gas Reservoirs**: These formations have proven their ability to trap hydrocarbons for millions of years and can similarly store injected $CO_2$. Utilizing these reservoirs can also leverage existing infrastructure.
- **Basalt Formations**: Rich in reactive minerals, basalts can facilitate the mineralization of $CO_2$, converting it into stable carbonate minerals. This method is still in the early stages of development but offers promising long-term storage solutions.

The selection of a suitable storage site involves assessing factors such as depth (typically greater than 2,600 feet to maintain $CO_2$ in a supercritical state), porosity, permeability, and the integrity of cap rocks to prevent leakage.

The concept of $CO_2$ sequestration has evolved over several decades. One of the earliest applications was in Enhanced Oil Recovery (EOR) during the 1970s, where $CO_2$ was injected into oil fields to increase oil production. Dedicated $CO_2$ storage projects began to emerge in the 1990s. Various pilot and commercial-scale projects have been implemented worldwide, contributing to the maturation of CCUS technologies.

The Environmental Protection Agency (EPA) regulates the underground injection of $CO_2$ through the Underground Injection Control (UIC) program. Class VI wells are specifically designated for the geologic sequestration of $CO_2$ and must meet stringent criteria to ensure the protection of underground sources of drinking water, including:

- **Site Characterization**: Comprehensive analysis of the geology, hydrology, and potential pathways for $CO_2$ migration.
- **Well Construction Standards**: Requirements for materials and construction techniques to prevent leaks.
- **Monitoring and Reporting**: Continuous monitoring of $CO_2$ movement and pressure, with regular reporting to the EPA.
- **Post-Injection Site Care**: Ongoing surveillance after injection ceases to ensure long-term containment.

There are currently four Class VI wells permitted by the EPA and four additional draft permits are pending. As of March 2024, there are now 130 individual well permit applications for a total of 44 projects that are currently pending at EPA[123].

While $CO_2$ sequestration is generally considered safe, potential risks include leakage through faults, fractures, or improperly sealed wells. To mitigate these risks, several strategies are employed:

- **Site Selection**: Choosing locations with favorable geology and minimal seismic activity.
- **Well Integrity**: Ensuring robust construction and maintenance of injection wells.
- **Monitoring Systems**: Deploying technologies to detect $CO_2$ movement and pressure changes.
- **Regulatory Oversight**: Adhering to EPA guidelines and obtaining necessary permits.

CCUS offers a pathway to decarbonize sectors where emissions are challenging to eliminate, such as cement, steel, and chemical manufacturing. While the initial costs of implementing CCUS can be high, economies of scale, technological advancements, and supportive policies can enhance its economic viability. Government incentives, such as tax credits and funding for demonstration projects, play a crucial role in promoting CCUS deployment. The United States has announced significant investments in CCUS, including $1.7 billion for carbon capture demonstration projects and $1.2 billion for direct air capture hubs under the Infrastructure Investment and Jobs Act. The 45Q tax credit currently incentivizes CCUS at the following rates:

- $85 per metric ton of $CO_2$ permanently sequestered in:
  - Geologic storage (e.g., Class VI wells)
  - Enhanced oil recovery (EOR) (with some restrictions)
  - Utilization in certain qualified products (e.g., concrete, chemicals)

[123] https://carboncapturecoalition.org/wp-content/uploads/2024/05/Class-VI-Fact-sheet-5.pdf

- \$60 per metric ton of $CO_2$ captured and utilized in:
    - Enhanced oil recovery (EOR) operations
    - Certain beneficial uses of $CO_2$ (such as in algae production or chemical manufacturing)

Identifying and evaluating suitable sites for $CO_2$ storage is essential for planning and implementing CCUS projects. The U.S. Geological Survey (USGS) and the National Energy Technology Laboratory (NETL) have developed comprehensive maps and atlases detailing potential storage formations across the country[124]. These resources provide insights into the capacity, geology, and feasibility of various regions for $CO_2$ sequestration.

Interactive tools and databases allow stakeholders to assess storage options, plan infrastructure, and make informed decisions regarding CCUS investments. Continuous research and data collection are vital to refine these assessments and ensure the safe and effective deployment of CCUS technologies.

Carbon Capture, Utilization, and Storage represents a multifaceted approach to reducing $CO_2$ emissions and mitigating climate change. While challenges remain in terms of cost, infrastructure, and public perception, advancements in technology, supportive policies, and increased awareness of climate imperatives are driving the growth and maturation of CCUS. As part of a comprehensive strategy, CCUS holds the potential to play a significant role in achieving global emissions reduction targets.

Oregon has favorable geology for $CO_2$ sequestration; however, the level of exploration risk requires third party or state participation to make this happen. In addition, state decarbonization programs, such as the Climate Protection Program, would need to allow for applying these additional decarbonization activities directly to the hydrogen or RNG produced.

## 7.7 Compliance Resource Study and IRP Modeling

Alongside Cascade Natural Gas and Avista Natural Gas, NW Natural worked with ICF to develop the *Low Carbon Fuel Alternative Resources and Offsets for IRP Evaluation* study (see Appendix E.2 for full report). This study (Alt Fuels Study) developed forecasts for levelized cost, technical potential, resource life, and carbon intensity for various energy resources, including renewable natural gas, hydrogen, synthetic methane, carbon capture utilization and sequestration (CCUS), and renewable thermal credits (RTC) for Oregon and Washington. This collaboration aimed to provide a comprehensive analysis of these resources to support future energy planning and policy decisions. Understanding these factors is crucial for making informed decisions about the viability and sustainability of available decarbonization resources.

[124] https://www.usgs.gov/tools/geologic-carbon-dioxide-sequestration-interactive-map

The Alt Fuels Study covered five categories of alternatives:

- RTC Purchase
- Renewable Natural Gas
- Hydrogen
- Synthetic Methane
- Carbon Capture, Utilization, and Sequestration

Within each of these five categories the Alt Fuels Study further examined different types of feedstocks, technologies, facility sizes, and production pathways. Table 7.6 provides a more detailed breakout of the types of alternatives examined within each of these categories.

The Alt Fuels Study embedded 45V and 45Q tax credit[125] values into the costs of hydrogen and CCUS respectively, including the Department of the Treasury 45V final rules from January of 2025. It is assumed that these credits will be available to taxpayers in the foreseeable future. These tax credits are important for leveraging federal support to enhance the economic feasibility of clean hydrogen and carbon capture projects.

From the Alt Fuels Study, the IRP model uses both expected results as well as stochastic results for both prices and available quantities. NW Natural will use these outcomes to model potential resource integration futures for planning consideration, ensuring that their energy strategies are robust and adaptable to various scenarios. Considering both expected and stochastic results helps NW Natural to prepare for a range of possible futures, enhancing the resilience and flexibility of their energy planning.

### 7.7.1 Alternative Fuels Study Price Projections Background

The cost of Renewable Natural Gas (RNG) spans a wide range due to differences in production methods, feedstock types, and regional policy treatment. RNG production costs are primarily driven by the type of feedstock used, facility design, and the technology required for upgrading and injecting gas into pipelines. However, RNG Renewable Thermal Certificate (RTC) offtake prices- the prices buyers pay- are largely determined by market dynamics, including supply and demand, regulatory policy, and the value of associated environmental credits.

Programs like California’s Low Carbon Fuel Standard (LCFS) and Oregon’s Clean Fuels Program assign value to RNG based on its lifecycle carbon intensity. These policy-driven markets create strong competition for environmental attributes, such as RTCs, which can be traded through book-and-claim systems. As a result, the price of RNG in the market can be significantly higher—or lower—than the cost to produce it, depending on the market value of these

[125] For more information on 45V and 45Q tax credits, see https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

attributes. This divergence highlights the importance of distinguishing between RNG's production cost and its market price.

The ICF study focused on production cost modeling for each of the alternative fuel options to develop levelized costs that incorporates a utility weighted average cost of capital. These costs reflect the production costs of direct utility investment in a project, which eliminates the additional margin layer developers would require in their prices, and allow utilities to leverage lower costs of capital. These production costs models provide a bottom-up calculation of levelized costs of energy measured as $2024/MMBTU.

The levelized cost of energy (LCOE) is a measure of the average net present cost of production for a facility over its anticipated lifetime and enables the ability to compare costs across RNG feedstocks and other energy types on a consistent per unit energy basis. The LCOE can also be considered the average revenue per MMBtu produced that would be required to recover the costs of constructing and operating the facility during an assumed lifetime. The LCOE calculated as the discounted costs over the lifetime of an energy producing facility divided by a discounted sum of the actual energy amounts produced. The LCOE is calculated using the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where $I_t$ is the capital cost expenditures (or investment expenditures) in year t, $M_t$ represents the operations and maintenance expenses in year t, $F_t$ represents the feedstock costs in year t (where appropriate), $E_t$ represents the energy (i.e., MMBtu) produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

The ICF study also examined RTC offtake pricing which can deviate from production costs. To supplement the RTC offtake analysis, NW Natural also used information from the Company's 2024 RFP which solicits bids for RTC offtake agreements for near-term RTC purchase opportunities. This IRP uses these production costs and a forecast for D3 RIN prices as the basis for pricing used in the resource optimization model, however; this is a simplistic modeling approach, and the Company recognizes real world opportunities will range in cost, scale, and contract structure.

## 7.7.2 Aggregating Resource Options for IRP Modeling

The Alt Fuels Study provided 73 separate low carbon alternative options. This includes both downscaled national and regional quantities that could be available to the Pacific NW and their corresponding prices (i.e., levelized costs), which are described in Appendix E.3.[126] Using the downscaled national and regional quantities, NW Natural further reduced those values as the Company applied a customer weighted value between Avista, Northwest Natural, Puget Sound Energy, and Cascade. This value is calculated to be approximately 33 percent.

In order to model these resources, NW Natural grouped resources provided by the Alt Fuels Study into 20 proxy resources for evaluation in PLEXOS. Table 7.7 lists all the resources that are modeled in PLEXOS and their respective price in 2040. The resource groupings that were created from the Alt Fuel Study are indicated by the left-side column.

[126] Footnote 12 in the Alt Fuels Study, discusses how domestic RNG production is downscale to what would be available to Pacific NW utilities.

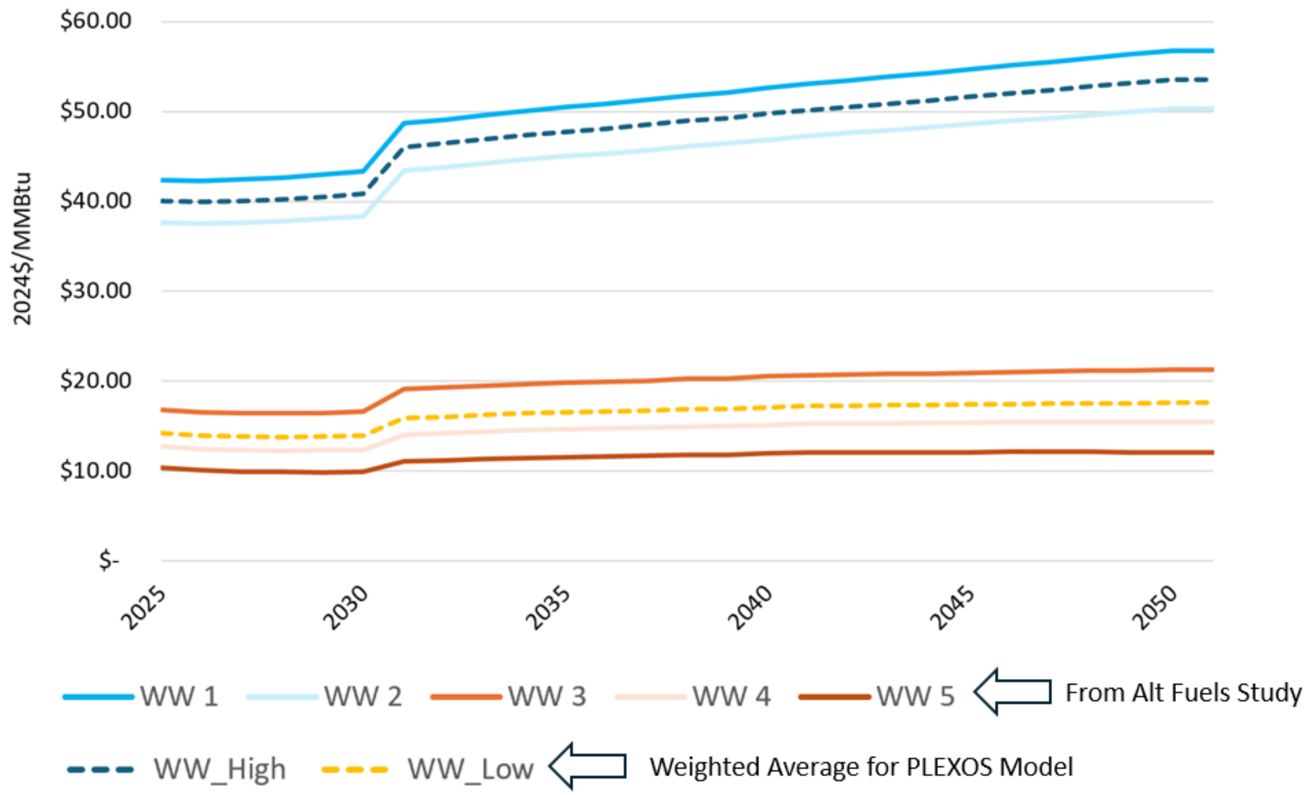
*Table 7.7: Resources Modeled in PLEXOS*

| | Category | Type | Costs Differentiation | 2040 Costs ($2024 / Unbundled MMBtu) |
|---|---|---|---|---|
| | Compliance Instruments | Offsets | Base Cost | $5.32 |
| | | CCA Allowance Purchases | Base Cost | $10.40 |
| | | Community Climate Investments | Base Cost | $7.60 |
| | Near Term RTC Opportunities | Local Water Resource Recovery Facility | Specific Cost | Not Available |
| | | Short Term Contracts | Low Cost | Not Available |
| | | | High Cost | Not Available |
| | | Long Term Contracts | Low Cost | Not Available |
| | | | High Cost | Not Available |
| Informed by Alt Fuels Study | Long Term RTC Opportunities | RTC Purchases | Base Cost | $27.32 |
| | Renewable Natural Gas | Land Fill Gas | Low Cost | $8.46 |
| | | | Mid Cost | $16.14 |
| | | | High Cost | $35.85 |
| | | Animal Manure | Low Cost | $48.88 |
| | | | High Cost | $120.23 |
| | | Wastewater | Low Cost | $13.97 |
| | | | High Cost | $48.62 |
| | | Food Waste | Low Cost | $56.05 |
| | | | High Cost | $90.40 |
| | Hydrogen | Green from Solar | Base Cost | $23.72 |
| | | Green from Wind | Base Cost | $36.05 |
| | | Blue Hydrogen | Base Cost | $22.57 |
| | | Turquoise Hydrogen | Base Cost | $44.10 |
| | Synthetic Methane | Biomass | Low Cost | $19.55 |
| | | | High Cost | $36.83 |
| | | Green from Solar | Base Cost | $43.15 |
| | | Green from Wind | Base Cost | $61.65 |
| | Carbon Capture Utilization and Storage | Industrial Customers | Base Cost | $8.21 |
| | | Direct Air Capture | Base Cost | $30.79 |

Notes: Not Available indicates that the resource is not available for resource selection in 2040

As an example, the Alt Fuels Study provided five resources for Wastewater (WW) that represent various facility sizes. Rather than modeling five WW resources, NW Natural summed the quantities for WW 1-2 and WW 3-5 to create WW High and WW Low, respectively. The granular resource quantities and prices were used to create weighted prices for WW High and WW Low. Figure 7.13 illustrates how the granular resources are grouped to inputs that are used in the PLEXOS® modeling.

*Figure 7.13: WW RNG Gas Groups for PLEXOS Model*

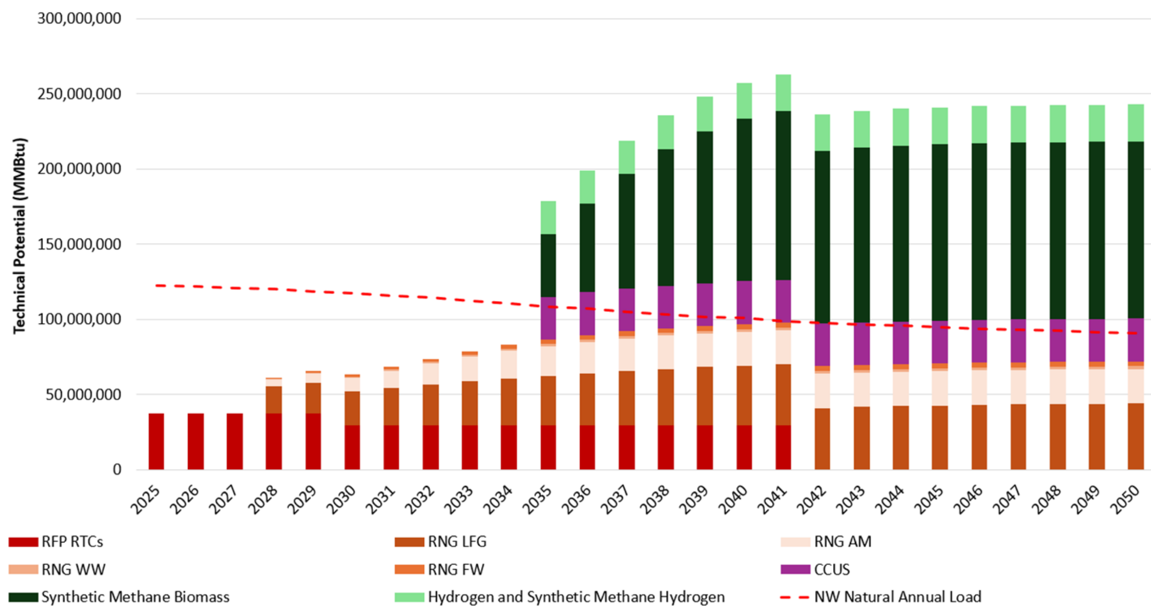



After the resources are grouped and the weighted average price is calculated, the commodity price of methane is subtracted out.[127] This yields an unbundled price, that represents the cost of the environmental attribute, which can be compared to other compliance resources such as offsets or RTC offtake purchases.

Figure 7.14 illustrates the total resources that are available for selection in the PLEXOS® model. These represent the downscaled quantities that could be available to NW Natural. In these quantities, hydrogen is capped of 20% of load by energy which accounts for both blending hydrogen into the system and industrial customers using 100% hydrogen. Synthetic Methane from Green Hydrogen is capped at the volumes available from green hydrogen (wind and solar respectively). PLEXOS® further constrains the models that the sum of Synthetic Methane and Hydrogen is also capped at the volumes available from Green Hydrogen. These constraints ensure that the availability of hydrogen is not double counted in the model.

[127] The Company notes that RNG projects may receive varying commodity prices depending on where in the country a project is located, however; this IRP does not speculate on project locations and uses the forecasted annual average Henry Hub gas price, a nation price benchmark for natural gas pricing, for this step.

*Figure 7.14: Resource Quantities Available for Selection in PLEXOS Model*

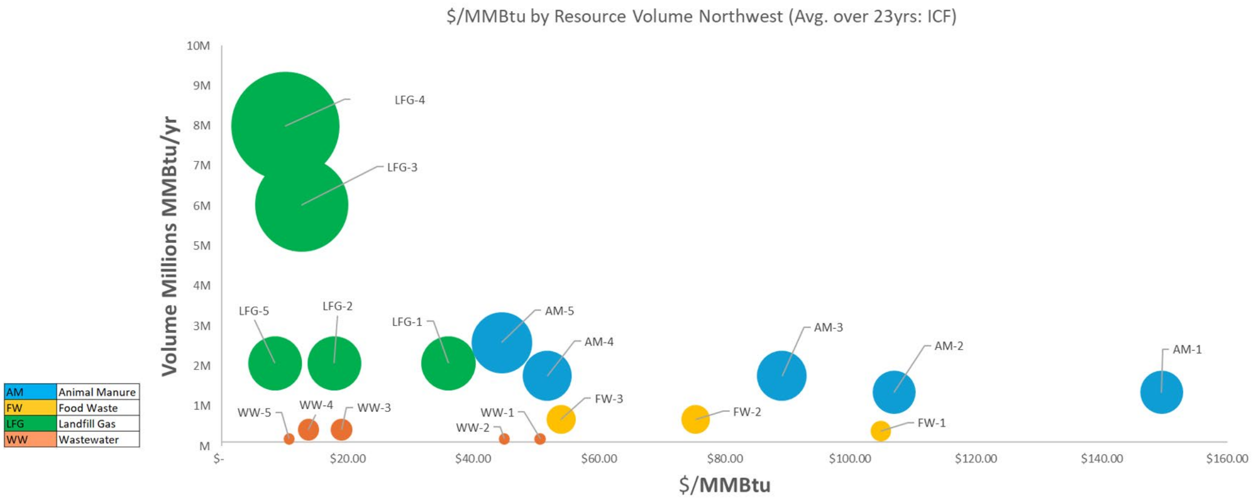



## 7.7.3 Renewable Natural Gas

Renewable natural gas (RNG) presents significant potential due to its interchangeability with conventional natural gas. RNG can be produced from a variety of feedstocks including animal manure (AM), food waste (FW), landfill gas (LFG), and water resource recovery facilities (WRRF; also abbreviate as wastewater (WW)). The successful implementation of RNG is largely contingent on the accessibility of biomass feedstocks as well as advancements in production technologies.

Figure 7.15 summarizes the granular results from the Alt Fuels Study where the size of each circle helps convey the total volumes associate with each type.

*Figure 7.15: ICF RNG Potential*

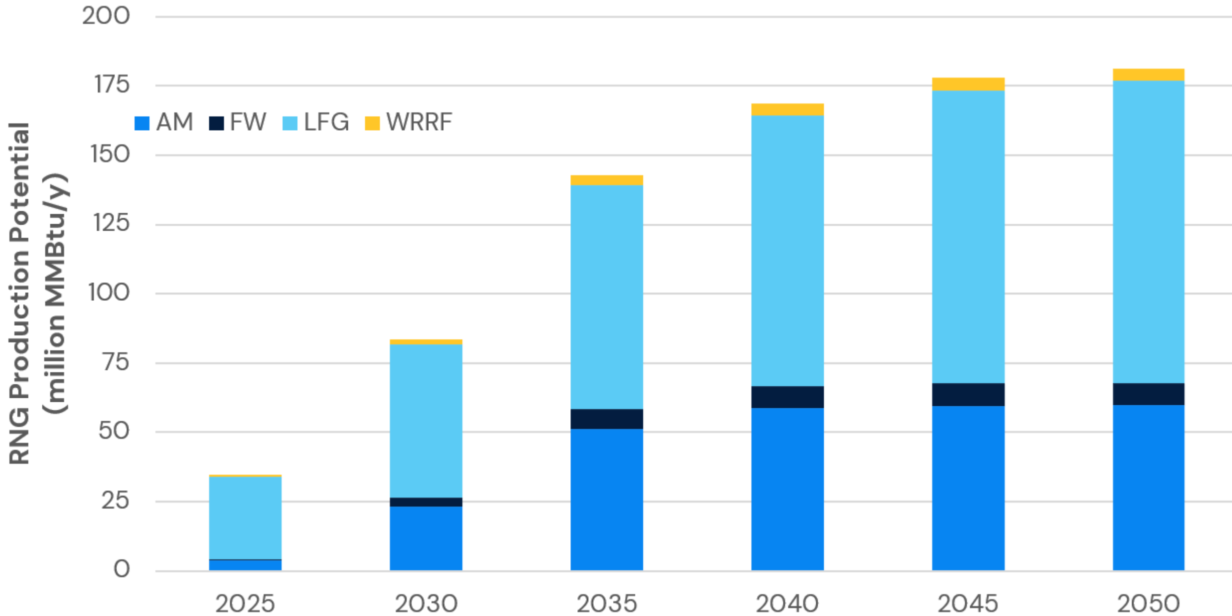



Different sized RNG facilities were modeled and are indicated by the numbers besides each resource with one (e.g., *LFG-1*) representing smaller facilities and higher numbers (e.g., *LFG-5*) representing larger facilities. This graph helps illustrate the economies of scale from larger scale RNG production sites.

### *7.7.3.1 Renewable Natural Gas Potential*

The Alt Fuels Study assumed that the Utilities would have substantial access to the resources designated for RNG development in Oregon and Washington. Additionally, ICF assumed that the Utilities would have a population-weighted share of first-mover access to national resources. Note that British Columbia and Québec were included as first movers as well due to their strong RNG policies and significant procurement of US-based RNG. Based on these assumptions, it is concluded that the Utilities are likely able to access roughly 13 percent of the total domestic RNG production. Figure 7.16 summarizes the maximum RNG potential for each feedstock (Animal Manure, Food Waste, Landfill Gas, and Water Resource Recovery Facilities) and production technology in Oregon and Washington.

*Figure 7.16: RNG Resource Potential Projection Base Case Results (OR & WA)*[128]




### *7.7.3.2 Renewable Natural Gas Levelized Cost*

Tables 7.8 and 7.9 summarize the maximum RNG LCOE for each feedstock and production technology in Oregon and Washington and at the national level. These tables reflect how the range of facility sizes that can drive a wide range of per unit prices. The Alt Fuel Study assumed the investment tax credit (ITC) for RNG production is available and extended through 2030.

*Table 7.8: RNG Levelized Cost Projection Base Case Results (Oregon and Washington, $/MMBtu)*[129]

| RNG Feedstock | 2025 | 2050 |
|---|---|---|
| Animal Manure | $35-$119 | $50-$172 |
| Food Waste | $42-$81 | $61-$119 |
| Landfill Gas | $7-$30 | $10-$42 |
| Water Resource Recovery Facilities | $10-$44 | $12-$59 |

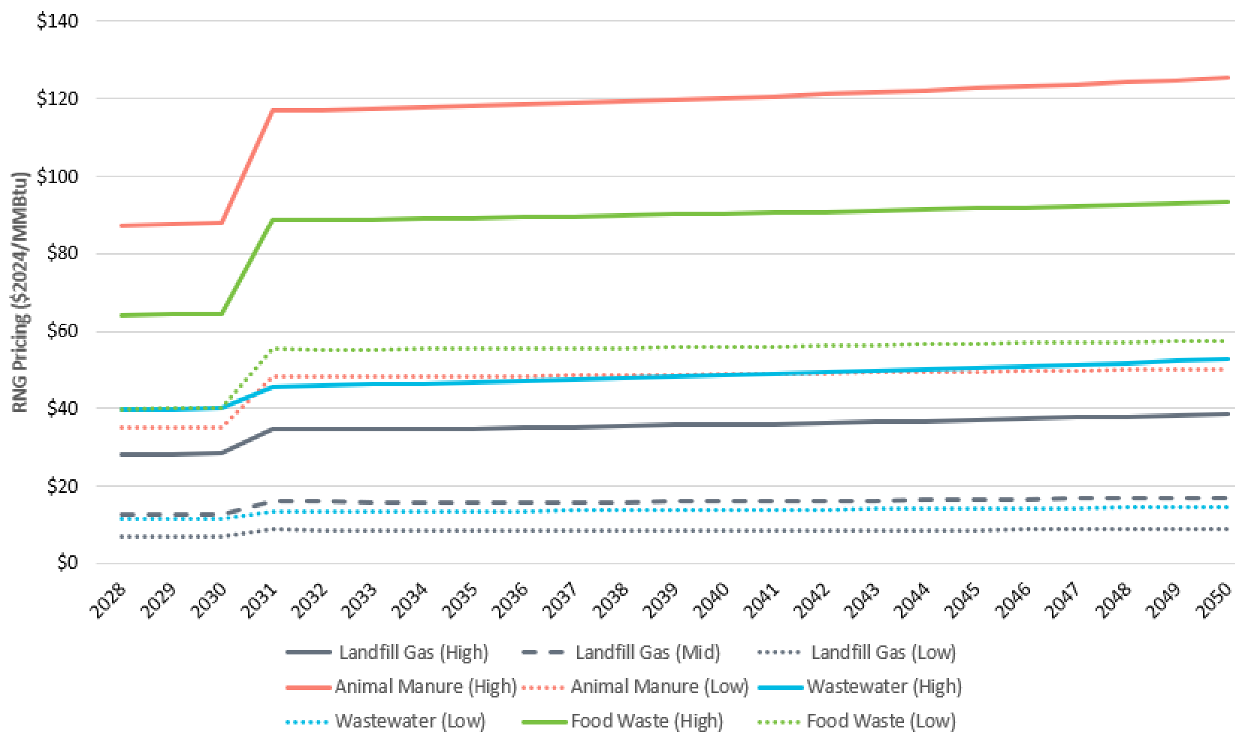
[128] Alt Fuels Study -Appendix E
[129] Alt Fuels Study -Appendix E

*Table 7.9: RNG Levelized Cost Projection Base Case Results (National, $/MMBtu)*[130]

| RNG Feedstock | 2025 | 2050 |
|---|---|---|
| Animal Manure | $36-$120 | $51-$172 |
| Food Waste | $43-$83 | $62-$120 |
| Landfill Gas | $8-$31 | $10-$43 |
| Water Resource Recovery Facilities | $11-$45 | $13-$60 |

While Tables 7.7 and 7.8 show the full costs for a bundled product, Figure 7.17 shows the unbundled prices paths for the aggregated categories for RNG being used in the Company's resource optimization model.

*Figure 7.17: ICF Estimated Pricing for RNG ($2024/Unbundled MMBtu)*[131]




This IRP also analyzed a specific local water resource recovery facility and is modeled to be available for resource selection in 2027. The unique timing of contract negotiations with this local water resource recovery facility has allowed NW Natural to be able to incorporate this specific project into the full IRP analysis.[132] This project would be connected directly to NW

[130] Alt Fuels Study -Appendix E
[131] Alt Fuels Study -Appendix E
[132] Contract negotiations are still on-going, and some contract specifics may still change.

Natural's system and provide approximately 0.05 percent of Oregon's sales load to NW Natural. Levelized costs for project are estimated to be similar the Wastewater (Low) category as shown in Figure 7.15. Relative to other RNG opportunities, via NW Natural's RFP process and current RNG portfolio, this project provides the lowest-cost RNG, while delivering local economic investment.

### 7.7.4 Hydrogen

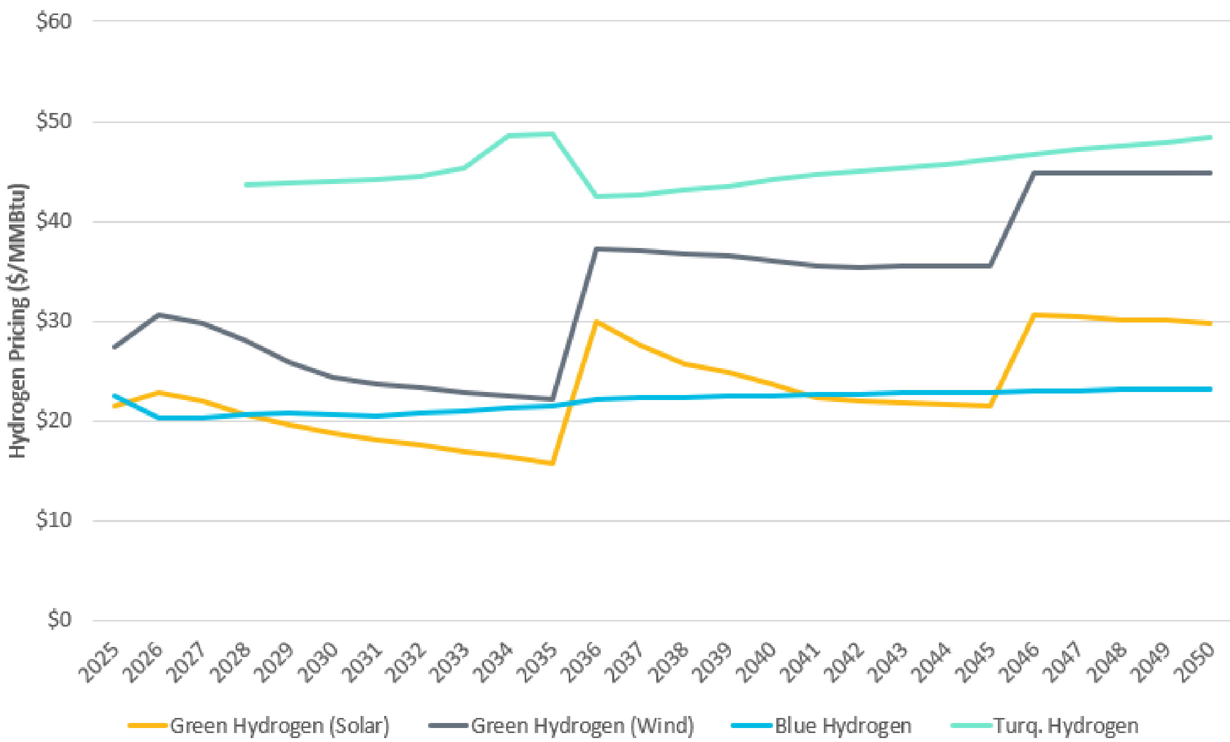
Hydrogen projections examined various feedstocks and carbon intensity ranges, denoted by different coloring scales; Green being from electrolysis using electricity from either solar or wind, Blue being natural gas or RNG from steam methane or autothermal reforming with 97 percent carbon capture and storage, Turquoise being natural gas and RNG from methane pyrolysis, and Pink being nuclear energy. Although Pink hydrogen was examined in the Alt Fuels Study, it was not considered as a compliance resource for this IRP.[133]

This detailed modeling helps to understand the potential environmental and economic impacts of different hydrogen production methods, which assists in the evaluation of hydrogen as a viable low-carbon energy source. Evaluating different hydrogen types allows for a more nuanced approach to integrating hydrogen into the energy mix as different sources may become available sooner than others with varying costs and supply locations.

Given the most recent Treasury guidance on 45V not allowing blends of decarbonized gas to qualify a hydrogen production facility for the 45V tax credit, Blue Hydrogen and Turquoise Hydrogen resources were reduced to the last tier of credits ($0.60 for CI scores between 2.5 and 4 kgCO2e/kg H2) in NW Natural's modeling. The Alt Fuels Study was complete prior to this ruling, however; NW Natural has updated the costs to reflect the significant decrease in tax incentives for Blue Hydrogen and Turquoise Hydrogen as depicted in Figure 7.18. Note the sudden price increases due to tax credits ending at times prescribed in statute.

[133] NW Natural will continue to monitor the development of pink hydrogen, but notes that the costs for pink hydrogen relative other alternatives are sufficiently high that it would not be selected as compliance resource even if it was included for any scenario or sensitivity.

*Figure 7.18: ICF Estimated Pricing for Hydrogen ($2024/ Unbundled MMBtu)*[134]



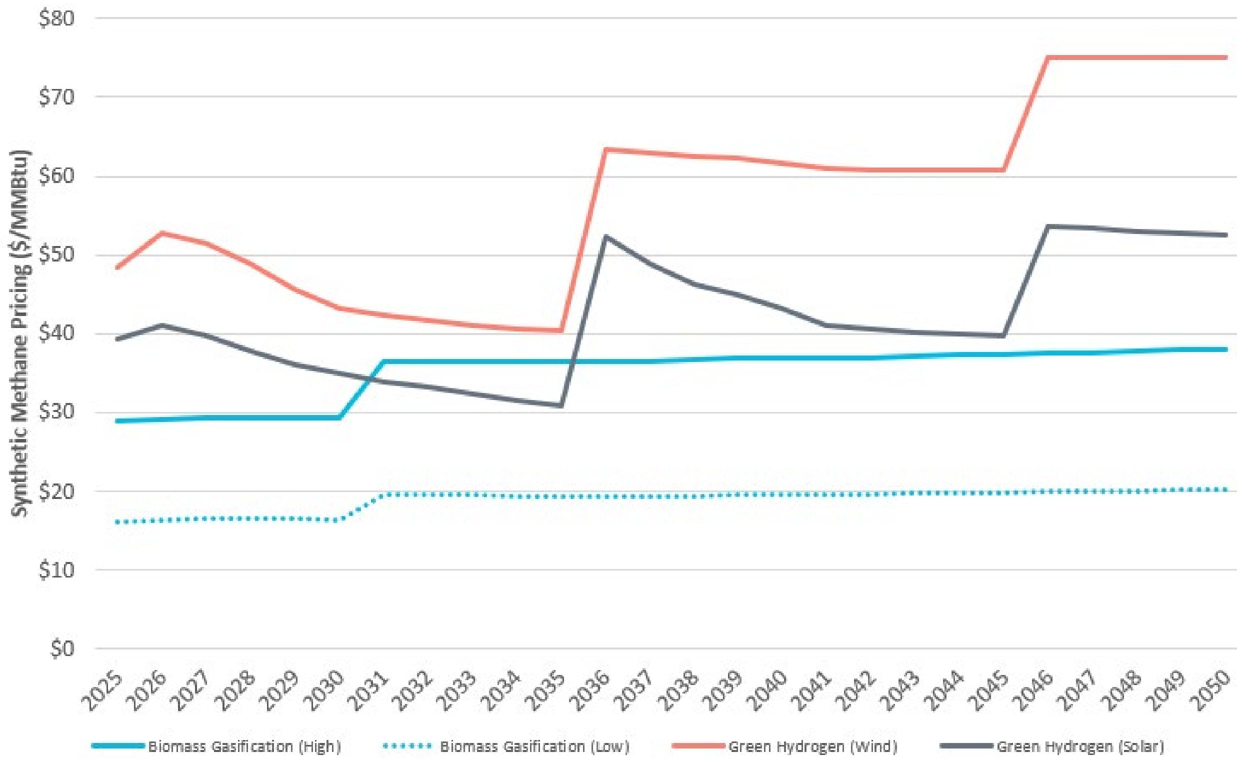

*Graph uses base case prices*

## 7.7.5 Synthetic Methane

Synthetic methane includes two different subcategories: methanation of syngas (CO and $H_2$) produced from gasification or pyrolysis of biomass, and catalytic methanation of green electrolytic hydrogen with biogenic $CO_2$. Limits were placed on the amounts of synthetic methane volumes based on biogenic feedstocks and renewable electricity availabilities. Similar to varying hydrogen sources, looking at different synthetic methane pathways provides a richer analysis of this resource given differing availabilities and volumes over time. Figure 7.19 shows the unbundled price paths for each type of synthetic methane being used in in the resource optimization model.

[134] Alt Fuels Study -Appendix E

*Figure 7.19: ICF Estimated Pricing for Synthetic Methane ($2024/Unbundled MMBtu)*[135]




## 7.7.6 Renewable Thermal Certificate

In renewable energy markets, a Renewable Thermal Certificate (RTC) verifies the environmental attributes of generating and using renewable thermal energy. M-RETS[136] issues one RTC for every Dth of verified renewable energy recorded on the platform. These certificates can be bought, sold, or retired by different organizations. NW Natural purchases RTCs to match the gas it supplies to customers, even though the actual renewable gas is used elsewhere. This is called a "book-and-claim" system -where the environmental benefit (or "green attribute") is separated from the physical gas and assigned to NW Natural through a contractual claim. The renewable gas is used locally near the production site, but the green attribute is applied to the traditional gas NW Natural delivers. The RTC projects are not developed by the utility and therefore include additional margins from other entities which increase costs.

It is challenging to readily identify pricing and volumes within the RTC market. To address this issue, ICF opted to use environmental commodity pricing from the Renewable Fuel Standard (RFS) as a benchmark. Under the RFS framework, RNG derived from most feedstocks qualifies

[135] Alt Fuels Study-Appendix E
[136] M-RETs is a nonprofit organization governed by an independent and multi-jurisdictional board of directors.

as a cellulosic biofuel and is categorized as a D3 RIN. According to multiple data sources, RTC prices have historically traded at a discount relative to D3 RIN values.

ICF leveraged the forecasted D3 RIN pricing to develop a range of pricing that may be used for RTC benchmarking for the foreseeable future. As RNG demand in the non-transportation sector (e.g., for Utilities) increases significantly above RNG demand for on-road transportation, the D3 RIN will no longer serve as predictive benchmark. However, the D3 RIN pricing shown is consistent with moderate pricing observed in the RNG supply curves and may be reflective of where pricing will fall in the mid- to long-term future. Based on this analysis, ICF's projected RTC pricing assumptions for this IRP are outlined in Figure 7.20 along with the bounds used to capture uncertainty in RTC pricing and simulated prices.

*Figure 7.20: ICF Estimated Pricing for RTCs ($/MMBtu)*[137]


RTC can be sourced from qualifying RNG, hydrogen, and synthetic methane projects that are injected into common carrier pipelines. While general more expensive, NW Natural does not foresee any technical limitations to procuring enough RTCs to meet compliance obligations, only cost limitations.

In addition to RTC purchase opportunities that are based on ICF's estimated pricing, NW Natural also includes in its resource optimization model options for near-term RTC contract opportunities with quantities, costs, and term lengths based on RTC offtake bids from the

[137] Alt Fuels Study-Appendix E

Company's 2024 RFP for RNG. Bids were aggregated into four categories. Table 7.10 outlines the specifics for these resource options.

*Table 7.10: Near-term RTC Contract Opportunities*

| Contract Type | Unbundled RTC Cost ($2024/MMBtu) | Quantity (MMBtu/year) | Term Length (years) |
|---|---|---|---|
| **Low-cost short term** | 19.00 | 3,800,000 | 3 |
| **Low-cost long term** | 19.00 | 17,400,000 | 15 |
| **High-cost short term** | 24.00 | 3,800,000 | 3 |
| **High-cost long term** | 32.00 | 12,400,000 | 15 |

## 7.7.7 Carbon Capture Utilization and Storage/Sequestration

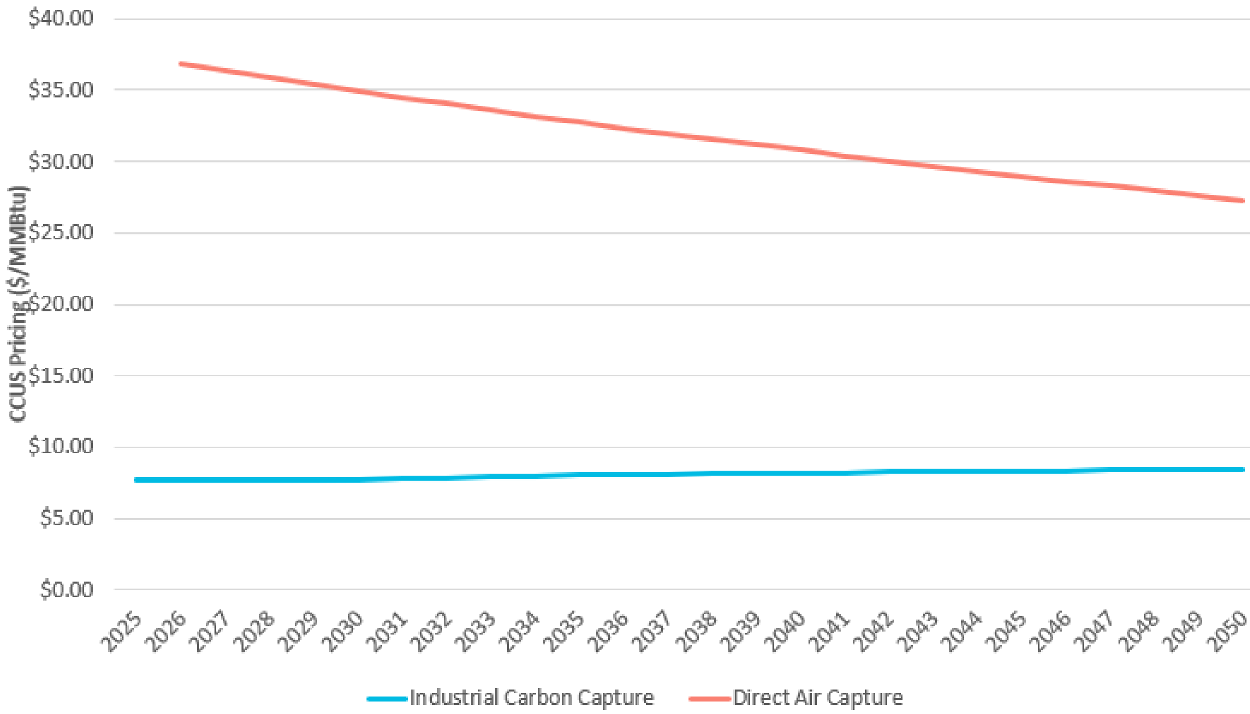
Carbon capture and storage/sequestration (CCUS) prices are generally the lowest for all of the low-carbon resources analyzed by the Alt Fuels Study. NW Natural assumed CCUS resources could be available in significant amounts as soon as by 2035 if not earlier. The Company includes the following types of CCUS into the resource optimization model; post-combustion capture and direct air capture.[138]

Post-combustion CCUS resources were modeled as being available to the load associated with NW Natural's largest 50 customers. As the study was being conducted in at the same time CPP rules were being finalized, this estimate ultimately included both EITE and non-EITE customers. Subsequent to completing the Alt Fuels Study, NW Natural excluded loads from EITE customers in all but one sensitivity explored in Chapter 9, as only non-EITE customers would be available for applying CCUS technology and reduce NW Natural's emissions liability. Distributed carbon capture may be viable from cost and technology perspectives for smaller customers as well (i.e., not limited to the top 50 customers), which could justify another case where CCUS can be applied to a wider portion of NW Natural customers. The CCUS pilot project being proposed in the Action Plan is specifically designed to answer this question.

The Alt Fuels Study also examined CCUS using direct air capture. Relative to post-combustion CCUS, CCUS from direct air capture is more expensive based on levelized costs as reflected in Figure 7.21.

[138] Note that pre-combustion CCUS, as discussed in a previous section, is used in the production of blue and turquoise hydrogen and is therefore not modeled separately in the resource optimization model.

*Figure 7.21: ICF Estimated Pricing for CCUS ($/MMBtu of Methane Equivalent)*[139]




*Graph uses base case prices*

The CCUS resource assumes geologic sequestration reservoirs and $CO_2$ pipelines are available for distributed carbon capture or direct customer connection. Oregon has favorable geology for $CO_2$ sequestration in the northwest corner of the state, which could be accessed relatively quickly should support for reservoir development arrive from public or private initiatives. Sequestration in basalt formations near the Gorge and across into Washington are also being explored by public and private entities alike that may be available for large-scale use in the near future.

[139] Alt Fuels Study-Appendix E

# Chapter 8 - Supply-Side Resources

This chapter of the IRP discusses both current and potential supply-side resources that NW Natural uses to deliver natural gas to customers. Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options.

## 8.1 Traditional Natural Gas Supply Options

This suite of supply-side resources focused on in this chapter are associated with serving customers at the system level in both Oregon and Washington. Supply-side resource options associated with alleviating constraints in specific areas of the distribution system are discussed in Chapter 12.

From a Gas Supply perspective, all resources vary across two dynamics as to the value for what each resource provides to NW Natural’s system: 1) the daily deliverability or capacity value, and 2) the overall energy a resource can provide throughout the year. For example, a year-round pipeline capacity contract provides capacity every day of the year but needs to be paired with gas purchases to provide energy. Storage LNG facilities are limited on the amount of energy they can provide but can provide deliverability for serving peak demand. Different resources also vary in costs, availability, and risks.

The rest of this chapter discusses general types of supply-side resources, NW Natural’s current resource portfolio, and future capacity resources options available for NW Natural to address resource need. These current and future options are inputs to the resource planning optimization model discussed in Chapter 9. The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a diversity of resources available. The portfolio of supply-side resources available to NW Natural can be categorized under various primary resource types:

**Natural gas supply contracts**: These are contract agreements for natural gas purchased from a producer or gas marketer for a specified volume for a given period and at a specific location known as a receipt point. Natural gas supply contracts are purchased on a term basis, for example baseload contracts- or purchased on the spot (daily) market and must be used in conjunction with other supply-side resources, such as interstate pipeline contracts, to ship the gas from the receipt point to a delivery point connected to NW Natural’s system, known as a citygate. See Appendix F.1 for further details about gas purchasing practices.

**Interstate/interprovincial pipeline capacity**: NW Natural contracts with pipeline companies in the US and Canada to ship natural gas from receipt points, where gas flows onto the interstate/interprovincial pipeline, to delivery points where NW Natural physically takes custody of the gas. These capacity rights are used to ship gas supplies purchased for NW Natural sales customers to NW Natural's system.

**On-system production resources**: On-system production resources are non-storage resources that produce gas and inject directly onto NW Natural's system. This primarily consists of injections from renewable methane sources, but also includes a minimal amount of Mist production gas still being collected from producing wells next to the underground Mist storage facility (a.k.a. Miller Station). The current on-system resources from renewable methane sources do not have environmental attributes, or RTCs, associated with the injected gas; however; future on-system renewable methane source could be bundled with the RTCs and used for emissions compliance for NW Natural customers.

**Underground storage**: There are 387 active underground natural gas storage fields in the Lower 48 states. These facilities utilize depleted oil or gas production wells, natural aquifers, or salt caverns to store gas supplies. The geological properties of each of these underground facilities offers an effective means of storing large amounts of natural gas which can be accessed relatively quickly to meet seasonal demand shifts throughout the year. Utilities, gas marketers, and other shippers of natural gas contract with the storage facility owners for both storage capacity (the total amount of gas stored underground) and storage deliverability (the amount of gas that can be withdrawn from storage in a day). While the storage capacity is a function of the geological properties of each facility, the storage deliverability is a function of the wells drilled into the formation and the piping and compression infrastructure used to withdraw stored gas. Note that storage capacity helps meet annual energy requirements, whereas storage deliverability helps meet daily system requirements as discussed at the start of this chapter.

In addition, deliverability from underground storage can be a function of the storage inventory level (i.e., how full the storage facility is at any given time). When the facility is full, the pressure of the gas underground is high and therefore will flow freely out of the ground. As the facility empties, pressure declines and deliverability will also decline. Due to the physics of these facilities, storage contracts often include clauses known as "ratchets", which specify the deliverability as a function of a customer's capacity inventory level.

**Above-ground LNG storage**: Above-ground LNG tanks and facilities super-cool natural gas into a liquid, known as liquefaction, and are an effective way to store more energy per volumetric unit (e.g., cubic foot) compared to its gaseous form. LNG storage facilities reverse the process, known as vaporization, to quickly inject gas back into the system to meet spikes in demand.

Compared to underground storage, these facilities have a higher ratio of storage deliverability to their overall storage capacity and are well-suited as "peaker" units to help meet demand spikes when temperatures plumet.

**Industrial recall options**: NW Natural contracts with two industrial counterparties for recall options wherein we would pay an industrial company to switch to an alternative fuel source and provide us with the natural gas supplies that they would have otherwise consumed. Note that these contracts are not with sales customers; therefore they would not be considered demand response. These contracts are agreements that provide additional interstate pipeline capacity and natural gas supplies if called upon. These contracts are limited to the number of days we can call on them in a winter season.

**Citygate deliveries**: The "citygate" is the point of delivery at which gas is transferred from an interstate or intrastate pipeline to a local distribution company's custody. Citygate contracts are for gas supplies delivered directly to NW Natural's service territory by the counterparty utilizing their own NW Pipeline capacity. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of NW Natural.

NW Natural has utilized citygate delivery agreements, on occasion, when cost effective. Such agreements usually take the form of swing arrangements that allow up to five days' usage during the period of December through February. As a near-term capacity resource, city gate deliveries are relatively inexpensive, but if the option for deliveries is utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high. The long-term reliability of citygate deliveries is too uncertain to be evaluated as a long-term option for IRP analysis, but these options are evaluated as an alternative for meeting design peak demand going into each winter.

## 8.2 Current Resources

NW Natural's current portfolio of resources sufficiently meets energy and capacity requirements for customers. This section discusses NW Natural's current resource portfolio.

### 8.2.1 Gas Supply Contracts

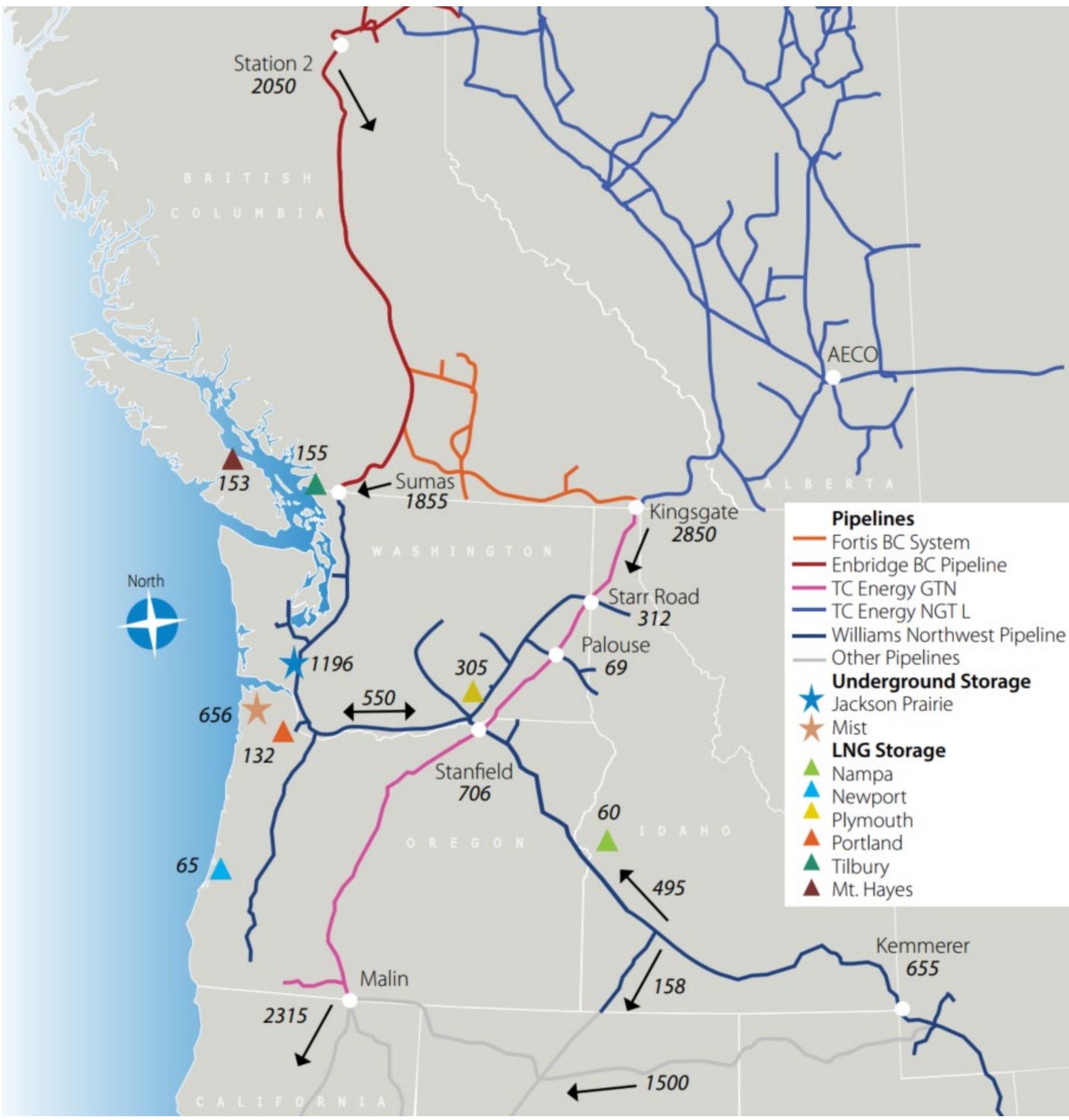
NW Natural has a portfolio of term supply contracts for each year, which are presented and reviewed in the annual purchased gas adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contracts — for the 2024-25 PGA period — is included in Appendix F.3. Contracts volumes are designated using the term "Baseload Quantity," which refers to a contractual obligation for daily delivery and payment.

In addition to term contracts, NW Natural buys certain gas volumes on the "spot" market, meaning the volumes, pricing and delivery points are negotiated on a real-time basis for delivery the following day or other near-term period, but no more than a month in advance. NW Natural maintains a diversified array of suppliers from whom gas can be bought on a spot or term basis.

## 8.2.2 Pipeline Capacity

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 8.1. Total pipeline capacities in the map are shown in thousands of Dths per day (MDth/day).

*Figure 8.1: Pacific Northwest Infrastructure and Capacities (MDth/day)*




Source: Northwest Gas Association, 2024 Gas Outlook

### 8.2.3 Firm Pipeline Transport Contracts

NW Natural holds firm transportation contracts for capacity on Williams Northwest Pipeline (NWP), over which all of NW Natural's supplies must flow except for the small amount of natural gas that comes from on-system resources, which are less than one percent of annual purchases.

For gas sourced in the U.S. Rockies, transportation over NWP is all that is needed to bring the supplies to NW Natural's territory.

For gas sourced in British Columbia, purchases are either made directly into the NWP system at the international border (called Sumas on the U.S. side and Huntingdon on the Canadian side) or purchased in Northern British Columbia at a trading hub called Station 2. Extending northward from the international border is the T-South pipeline system (owned by and referred to as Enbridge BC Pipeline in Figure 8.1), which creates a connection between Station 2 and Sumas/Huntington. Purchases made at Station 2 first require transportation by Enbridge before reaching the Sumas/Huntington interconnection point and movement onward by NWP to NW Natural.

For gas sourced in Alberta, purchases are made at the trading hub known as AECO. Gas sourced at the AECO hub reaches the NW Natural system via four pipeline systems, three owned by TC Energy, and the fourth being NWP. Starting in Alberta with NOVA Gas Transmission Limited (NGTL or NOVA), the molecules, then travel along the Foothills pipeline in southeastern British Columbia. The molecules continue south on this pipeline to the international border, at the Kingsgate point in northern Idaho, into Gas Transmission Northwest (GTN) pipeline, which extends southward and connects to NWP at Starr Road, in eastern Washington (near Spokane) and at Stanfield, in northeastern Oregon.

NW Natural has released a small portion of our NWP capacity to one customer but has retained certain heating season recall rights, discussed above as an Industrial recall option. Details of the current portfolio of pipeline transportation contracts are provided in Appendix F.3.

Since the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized, i.e., capacity can be bought and sold like other commodities. These acquisitions and releases occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have standardized many definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades can also occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

Except for a small percentage of on-system supply, all the gas supplied to NW Natural customers must be transported over the NWP system, which is fully subscribed in the areas served by NW Natural. Usage among NWP capacity holders tends to peak in a nearly coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, NWP capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions.

Given the dynamics of market growth and pipeline expansion, NW Natural will continue to monitor and leverage the capacity release mechanism whenever appropriate, but this will primarily mean continuing to use our asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

### 8.2.4 Exposure to Sumas

About 30 percent of our contracts on the NWP system are sourced through Sumas. We can fill these contracts either with purchases directly at Sumas or with purchases further upstream at West Coast Station 2 (Station 2), which is a supply point where the commodity is being produced. Sumas on the other hand is a trading point where natural gas trading occurs but supplies at Sumas first must be transported there from a production source, such as Station 2. We have long-term Enbridge BC Pipeline (T-South) contracts that allow us to procure about half of the gas we need to ship from Sumas at Station 2. The other half of the supplies we ship from Sumas must be purchased directly at Sumas.

Historically, Sumas has been a high-priced, volatile trading point when compared to other trading points throughout North America. We are expecting this to be further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online. Woodfibre LNG, which is being constructed in Squamish, B.C. will convert about 300,000 Dth/day of natural gas per day to LNG which will then be shipped overseas. Woodfibre LNG already holds the T-South pipeline capacity they need for their operations and this capacity is currently used to ship Station 2 gas down to Sumas where these supplies are sold.

When the LNG facility is operational, currently forecasted to be in 2027, these supplies will be pulled from the Sumas market and used in the liquefaction process. This loss of gas supply equates to approximately 15 percent of the total available winter capacity to Sumas on the T-South system and will represent a fundamental shift in the region's gas supply availability to serve existing demand. It will have significant adverse implications for customers relying on purchasing gas supply at Sumas unless there is an upstream pipeline expansion or another solution that would benefit the market at Sumas. In fact, if a regional peak cold weather event were to occur after Woodfibre is in service and before a solution could be found, we could possibly see supply shortages in the Pacific Northwest.

There are several pipeline solutions that are being marketed as a solution for this supply leaving the market at Sumas. One project is moving through the Canadian regulatory process but would not be in service until at least one year after Woodfibre starts liquefying. NW Natural did not participate in this first project, but we will evaluate participation in future projects as the opportunities present themselves. We will also evaluate longer-term physical purchases at Sumas or Mist Recall as solutions for the market disruption at Sumas.

Due to the expectation that Woodfibre LNG will begin operations in late 2027, thus tightening the Sumas market, we do not expect that we will be able to procure large volumes of Sumas spot gas during a cold weather event. While we are confident that gas supplies shipped on segmented capacity would flow, our ability to find these supplies will be restricted and that is why we are no longer relying on segmented capacity for a peak day starting in the 2027-28 winter, as is discussed in the segmented capacity section.

### 8.2.5 Segmented Capacity

Segmented capacity is secondary firm capacity on NWP that is deemed reliable due to the high probability that it will be available during times of peak usage. This reliability assumption is validated through an analysis of NWP flow data through the Chehalis Compressor Station along the I-5 corridor. The analysis uses flow data to validate that there is sufficient North to South capacity available as the weather gets colder.[140] These assumptions are based on current market dynamics as the ability to schedule segmented capacity is more reliable as weather becomes colder.[141]

For many years now, NW Natural has relied on segmented capacity and flexed the receipt and delivery points to create useful, albeit secondary, firm transportation on the NWP system. This segmented capacity flows from the north (Sumas) in a path that has not experienced constraints, during the coldest weather events in recent years. Utilizing segmented capacity does not incur an additional demand charge and only incurs NWP's variable and fuel charges in addition to the Sumas commodity costs. Because of this low opportunity cost, segmented capacity can be a very valuable resource for customers.

Modeling of segmented capacity began in 2014 with 43,800 Dth/day included in the analysis. Another 16,900 Dth/day of segmented capacity was subsequently created in 2016. This combined amount of 60,700 Dth/day was included in the 2016 and subsequent IRPs. This amount remains in the current IRP planning until 2027 when certain constraints in the Sumas

[140] For more detail on the Chehalis flow analysis please see Appendix E, section E.4 of the 2022 IRP.
[141] For more details on the process of segmentation see Chapter 6, section 3.3 in the 2018 IRP.

market are expected to increase the risk of being able to procure spot gas on a peak day. This IRP does not rely on segmented capacity to meet peak demand starting in the 2027-28 gas year but does allow it to be used on colder non-peak days at 30,000 Dth/day the rest of the year.

### 8.2.6 Storage Assets

NW Natural relies on four existing storage facilities in and around our market area to augment the supplies shipped from British Columbia, Alberta and the U.S. Rockies. These consist of underground storage at Mist and Jackson Prairie, and LNG plants located in Portland and Newport, Oregon.

NW Natural owns and operates Mist, Portland LNG, and Newport LNG, all of which reside within NW Natural's service territory. Hence, gas typically is injected into storage at these facilities during warm periods and withdrawn when needed during cold periods directly onto NW Natural's system.

In contrast, Jackson Prairie underground storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside NW Natural's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. NW Natural contracts for Jackson Prairie storage service from NWP. Several separate contracts with NWP provide for the pipeline transportation service from Jackson Prairie to the NW Natural citygate.

Table 8.1 shows the maximum storage capacity and deliverability of these four firm storage resources.

*Table 8.1: Firm Storage Resources*

| Facility | Maximum Daily Deliverability (Dth/day)* | Maximum Seasonal Storage Working Capacity (Dth)* |
|---|---|---|
| **Mist** | 325,000 | 13,322,920 |
| **Newport LNG** | 78,000 | 866,014 |
| **Portland LNG** | 132,840 | 405,959 |
| **Jackson Prairie** | 46,030 | 1,082,517 |

***Notes:** Volumes adjust each year based on heat content. These volumes are derived from 2024-25 PGA filing. Newport LNG available capacity takes into account a minimum 20% tank level needed for normal operations. Portland LNG maximum capacity currently de-rated due to seismic analysis, and the available capacity also considers a minimum 20% tank level needed for normal operations.

The Mist storage deliverability and seasonal capacity shown in Table 8.1 represents the portion of the facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum daily deliverability of 501.47 million cubic feet per day (MMcf/day) with peak hourly deliverability at a rate of 515 MMcf/day, and a total working gas capacity of 17.5 billion cubic feet (Bcf). These volumetric figures are converted to energy values (Dth) using the heat content of the injected gas. That heat content conversion factor had been relatively constant at 1,010 Btu/cf in prior years but has increased to around 1,060 Btu/cf to 1,080 Btu/cf over the past several years.

Storage capacity and deliverability in excess of core needs is made available for the non-utility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist recall discussed later in this chapter.

### 8.2.7 On-system Production Resources

On-system production resources produce methane and do not require upstream capacity resources. In other words, these resources produce and inject gas directly onto NW Natural's system.

### 8.2.8 Mist Production

Natural gas wells owned by a third-party in the Mist area continue to produce small quantities of low Btu gas which NW Natural purchases and blends into larger volumes of gas supplies at Miller Station. Over time these wells continue to deplete, and new wells have not been drilled for several years. Unless there is a renewed interest in exploration and production of natural gas in the Mist area, it is expected that these volumes will continue to decline over time.

### 8.2.9 On-system Production

RNG projects owned by third parties are interconnected to the NW Natural distribution system. Currently, NW Natural only purchases the underlying commodity from these projects and does not have rights to the environmental attributes associated with this RNG. Expected volumes from these projects are included as gas supplies in the IRP as they do provide a capacity benefit, but not a compliance benefit.

### 8.2.10 Industrial Recall Options

NW Natural has contracts with two industrial companies located on or near our distribution system wherein we can call on natural gas supplies if needed in the winter. The price of these contracts is either fixed or tied to an alternate fuel source that the industrial company could use if we were to call on their flowing natural gas supplies. If called upon, these supplies would be delivered to NW Natural at our citygate on the industrial customers' capacity with NWP. Each contract has specific terms outlining when we can call on the capacity and at what volume. Contract volumes range from 1,000 Dth/day to 30,000 Dth/day.

## 8.3 Future Resource Alternatives (On-System)

### Future Capacity Resource Options

NW Natural considers additional gas supply resource options including Mist recall and increases to Newport take-away. On the other side, if less resources are needed in the future, we evaluate non-renewal of our existing pipeline capacity. These alternatives are described in more detail below.

### 8.3.1 Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core utility sales customers (see Table 8.1), NW Natural has developed additional capacity in advance of core customer needs. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire.

Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet load requirements in the Portland area, which can then free up other capacity resources to meet incremental system requirements.

There are three practical considerations that apply to Mist recall:

1. Recall decisions to transition capacity to the utility portfolio are made roughly a year prior to the core utility's forecasted capacity need. On or about May 1, NW Natural wants to start filling any recalled storage capacity over the summer months to have the maximum inventory in place by the start of the following heating season. Working backwards from May 1, ISS customers need advance notice to empty their gas inventory accounts if their capacity is going to be recalled by NW Natural. NW Natural informs the ISS customer of a recall before the heating season if their contract will not be renewed. Accordingly, we have established the prior summer as the time at which operationally we must make our recall decisions. This timeline is depicted in Figure 8.2.

*Figure 8.2: Mist Recall Decision Timeline*

| Summer This Year | Winter Season | Next Year |
|---|---|---|
| Core recall decision made<br>Inform applicable ISS customer(s) if contract will not be renewed | Applicable ISS customer(s) empty inventory if contract is terminating | Core recall is effective May 1<br>Core injections spring/summer/fall<br>Core withdrawals available Nov. 1 |

2. Mist ISS contracts are of various durations. While limiting Mist ISS contracts to 1-year terms would maximize the capacity available for recall each year, it also would limit ISS revenues, which utility customers share in a portion of those revenues. Accordingly, ISS contracts have staggered start dates and durations that create a profile of capacity available for recall that increases over time, in effect mirroring expectations of rising resource requirements.

3. Recalls are rounded (up or down) to the closest 5,000 Dth/day of deliverability. This is done to simplify the administration of recalls and the marketing of ISS service but are modeled as a completely divisible product in the resource planning optimization model discussed in Chapter 9. For scale, 5,000 Dth/day is roughly 0.5 percent of the current resource stack daily deliverability. The ability to recall Mist in such small increments is a very valuable option that allows customers to pay for a capacity resource only as needed.

## 8.3.2 Newport Takeaway

### *8.3.2.1 Newport Takeaway Options*

As previously mentioned, the daily deliverability of the Newport LNG facility provides 73 MMscfd (78,000 Dth/day when adjusted for heat content) of system capacity under design peak conditions. This is due to pipeline infrastructure limitations flowing gas out from Newport back through the Central Coast feeder back towards Salem. However, the Newport LNG facility has the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To match the pipeline takeaway capability to Newport's vaporization capacity of 100 MMcf/day, infrastructure additions would be needed on the Newport to Salem pipeline, known as the Central Coast feeder and other related pipelines. This would provide an incremental 27 MMcf/day (29,025 Dth/day). The 2018 IRP identified a three phased approach that could be done separately and sequentially at various costs to achieve the full incremental takeaway capability. Since then, we've improved our modeling capabilities and determined that the 100 MMscfd could be achieved differently, with less expense, and in a single phase or we could increase the take-away capability, without achieving the full 100 MMscfd for a lower cost. For the two options below, it is not necessary to do the first before the second, they are standalone, independent options.

1. Newport Take-away 1 – would increase the maximum pressure rating of 15 miles of the Central Coast Feeder, adding 11.12 MMscfd (11,954 Dth/day) at an estimated cost range of $6.5-12.9 million.

2. Newport Take-away 2 –would add a new compressor station near and west of Grand Ronde, Oregon, adding 27.4 MMscfd (29,455 Dth/day) at an estimated cost of roughly $55-75 million.

As the increased throughput created by the addition of a compressor (2.), would cause the pressure to be less than 600 psig where the Central Coast feeder currently transitions to 600 psig, option 1 above does not need to be done prior to option 2. They are two independent options, with independent and different take-away increases.

## 8.3.3 Pipeline Capacity Non-Renewal

### *8.3.3.1 Pipeline Capacity Non-Renewal*

NW Natural holds contract and gate station capacity on: 1) NWP's mainline serving our service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington; and 2) NWP's Grant's Pass Lateral serving our loads in the Willamette Valley region of Oregon from Portland south to the Eugene area, as well as the central coast (e.g., Lincoln City, Newport) and south coast (e.g., Coos Bay) areas. We also hold contractual capacity on various upstream pipelines including GTN, Foothills, NGTL and T-South. The Company analyzes the future utilization, need, and value to customers of these contracts in our portfolio optimization modeling (i.e., PLEXOS), which selects whether to continue these capacity contracts beyond their current expiration date.[142]

### *8.3.3.2 Capacity Resources Comparison*

NW Natural uses cost-of-service modeling, which captures the capital costs, operation and maintenance costs, taxes, construction and overhead, and all other estimated costs associated with an option over the planning horizon. Using the cost-of-service modeling, each option has a present value revenue requirement. These costs become an input into the resource planning optimization model, and they are incurred when a capacity option is selected.

Table 8.2 lists the capacity options, costs in terms of dollars per Dth per day, the daily deliverability, and the years each option is available for selection. These are fixed costs that are incurred everyday throughout the planning horizon if a capacity resource is selected. Note that only Mist Recall is a non-binary option, and the model can select as much Mist Recall as needed in each year. All other options must be selected at the full amount. Once an option is selected it remains in the resource stack and incurs the cost for the rest of the planning horizon.

[142] This is an improvement in the resource optimization modeling from previous IRP modeling in response to OPUC Staff recommendation #4 from Staff's final report for LC-79.

*Table 8.2: Capacity Resource Cost and Deliverability*

| Capacity Resource | Deliverability (Dth/day) | Levelized Cost ($/Dth/Day) |
|---|---|---|
| **Mist Recall** | Up to 185,000 | $0.177 |
| **Newport Take-away 1** | 12,000 | $0.181 |
| **Newport Take-away 2** | 17,500 | $1.587 |

# Chapter 12 - Distribution System

Chapters 2 through 11 focus on ensuring enough resources are available and secured to get enough energy on NW Natural's gas grid every day of the year to meet customer needs. This chapter discusses how needs and options are assessed to distribute gas on the grid so that each customer can be serve reliably during any weather that could be reasonably expected.

## 12.1 Distribution System Planning

Distribution System Planning is this IRP is separate (but not fully independent) from the system-wide planning and PLEXOS modeling discussed throughout the rest of the IRP. It involves identifying system needs at the distribution system level, assessing both demand-side and supply-side solutions, and making risk-adjusted resource selections. Some of the unique aspects of distribution system planning include:

- **Location Dependent Demand Forecasting:** Predicts peak hour usage for an area, net of demand side actions
- **Supply Modeling:** Simulates flows and pressures from gas sources on the gas network based on actual pipeline alignments and attributes
- **System Modeling:** Use of different software/modeling tools to simulate system under peak conditions and/or use field measurements during cold periods
- **Planning Criterial Application:** Applies a consistent approach to identify areas of concern on the distribution network

NW Natural historically used a "just-in-time" distribution system planning approach, responding to low pressure system issues as they occurred. The "just-in-time" reactive approach introduces risks to customers because customers being served in these areas may experience service interruptions before mitigation measures are in place. NW Natural has shifted from a "just-in-time" to a forward-looking distribution system planning process that looks at least five years ahead, allowing NW Natural to anticipate future needs. The forward-looking planning approach allows for improved integration of non-pipeline demand-side solutions as these projects take longer to implement and produce reliable peak load reductions. The transition began with NW Natural's Geographically Targeted Energy Efficiency (GeoTEE) pilot and has been a lengthy transition over several years. Although the forward looking planning process has been implemented, the system will continuously improve as more data is collected, and customer usage patterns are characterized.

NW Natural has improved its system modeling capabilities. A major improvement involves completing the implementation of Customer Management Module (CMM) into the Company's pressure system modeling software, Synergi™ Gas. CMM acts as a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ Gas, enabling more efficient planning and system analysis. This improvement was successfully implemented across NW Natural's entire service territory in the third quarter of 2023. Details on the integration of CMM are provided in Section 12.4.2.

NW Natural conducts an annual review and updates a Forward Looking Distribution System Plan, which focuses on larger projects that may exceed design capacity in the future due to growth. This plan provides budgetary forecasts and establishes a Company-wide vision for prioritizing the distribution system planning process. The Forward Looking Distribution System Plan plays a key role in selecting projects for inclusion in the Integrated Resource Plan (IRP). Project selection is based on factors such as estimated cost, prioritization needs, supply implications, and timing considerations. NW Natural's Forward Looking Distribution System Plan is included in Appendix J of this document. Further details on this process will be discussed later in the document.

This chapter provides an overview of NW Natural's distribution system planning process, including the needs assessment process and tools used. It highlights improvements in engineering and computer modeling methods that support distribution system planning. Additionally, the chapter discusses existing and future distribution system resources, including both pipeline and non-pipeline solutions. The chapter concludes with an analysis of both pipeline and non-pipeline alternatives for areas identified in the Forward Looking Distribution System Plan.

## 12.2 Distribution System Planning Process

NW Natural's distribution system planning process is designed to provide reliable service by:

- Operating a distribution system capable of safely meeting firm service customers' peak hour demands
- Minimizing system reinforcement costs by selecting the most cost-effective alternative
- Proactively planning for future needs in a timely fashion
- Addressing distribution system needs related to localized customer demand

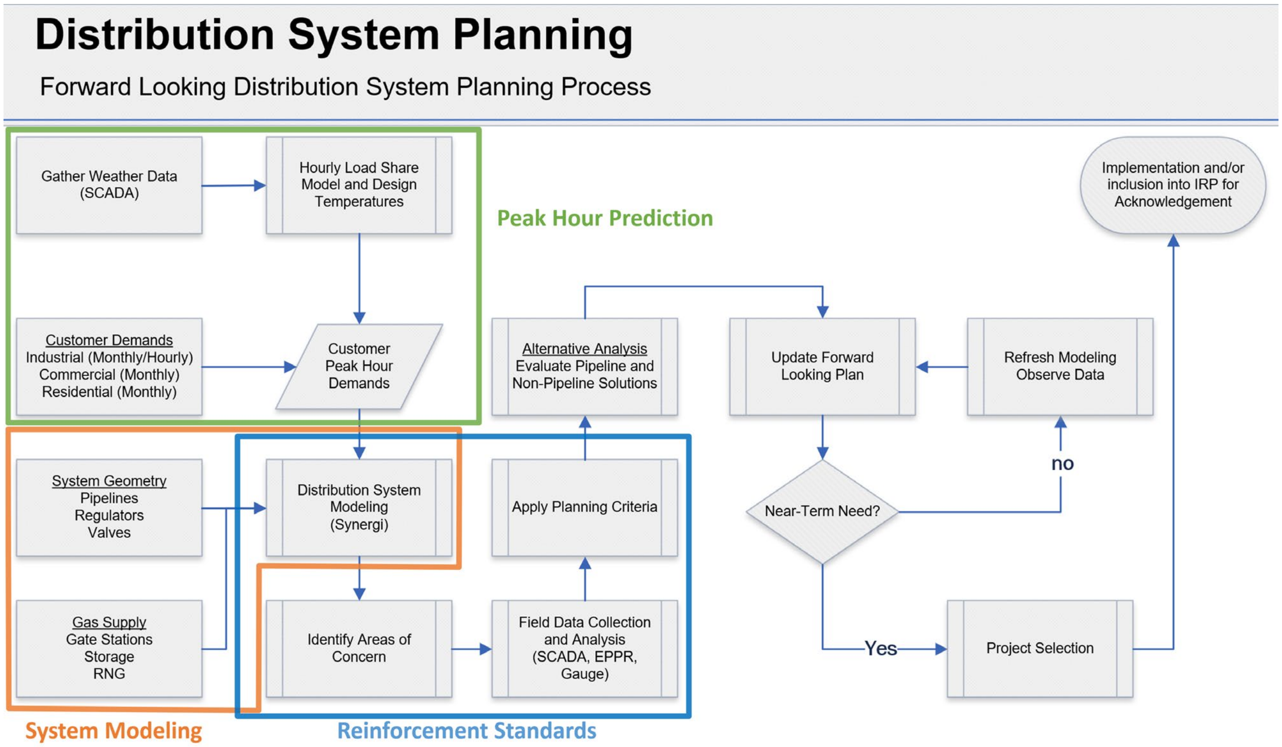
The goal of the distribution system planning is to ensure that the system can reliably meet peak hour gas demands for firm sales and firm transportation service customers, and to identify capacity constraints before service to customers is impacted. The planning process evaluates deficiencies during peak winter hour conditions, providing solutions, either demand-side or supply-side, to serve current localized forecasted firm energy requirements. Distribution system planning plays a critical role in identifying capacity constraints within the Company's gas network and develops solutions to address those weaknesses on the system. By knowing where and under what conditions pressure problems may occur, NW Natural can incorporate necessary projects into annual budgets and project planning. These planned solutions avoid costly reactive and disruptive emergency solutions.

NW Natural works closely with a variety of internal and external stakeholders including marketing departments, large customer account representatives, construction crews, external economic development and planning agencies, energy efficiency program administrators, and engineering design and construction firms, to develop feasible and reliable solutions for distribution system reliability concerns. These solutions can be either *non-pipeline* or *pipeline* solutions. Typical pipeline solutions include various forms of reinforcements, replacements, or expansions of NW Natural's distribution system. Non-pipeline solutions can be either supply-side solutions, for example deployment of a mobile CNG supply vehicle, or demand-side solutions, for example geographically targeted interpretability agreements. The costs, timing, and reliability varies across each of these options for distribution system planning and the suite of these options is discussed later in this chapter.

Distribution system planning follows the same overall process as system resource planning. The first step is identifying a need for additional resources. This step involves predicting peak hour customer demand and identifying potential constraints on the existing distribution system. After a need is identified, potential solutions are proposed that are capable of addressing the distribution system deficiency. A cost benefit analysis is conducted assessing the costs, risks, and benefits of the viable alternatives. The planning process is continuous and incorporates known public works projects, anticipated customer growth, and other relevant factors into NW Natural's construction forecasts.

Distribution system planning uses a pressure modeling software, Synergi™ Gas, to model pressure dynamics of actual pipe placement, specifications, and geographic location, along with peak hour usage estimates for the area in question (net of expected energy efficiency savings and demand response resources). Essentially this simulates the system under peak conditions, calibrates this simulation with actual field measurements during cold weather events, and is evaluated using a system planning criteria to identify areas of concern. This process helps identify areas at risk before those criteria are exceeded under actual peak conditions. Figure 12.1 presents a flow diagram for the distribution system planning process.

*Figure 12.1: Distribution System Planning Process*




As discussed in the introduction section of this chapter, NW Natural develops a Forward Looking Distribution System Plan that outlines areas of the distribution system under investigation. Areas for investigation do not currently violate system reinforcement criteria but are areas where the gas distribution system is approaching these thresholds and/or is showing evidence of growth in demand that could reach system monitoring thresholds within the next five years or beyond as will be discussed below. These areas are being monitored based on distribution system modeling under peak conditions, where growth may lead to safety or reliability concerns if system reinforcement standards are exceeded. In addition to identifying areas for cold weather observation, the Forward Looking Distribution Plan outlines the best (i.e., least-cost least-risk) solution for each geographic area being monitored.

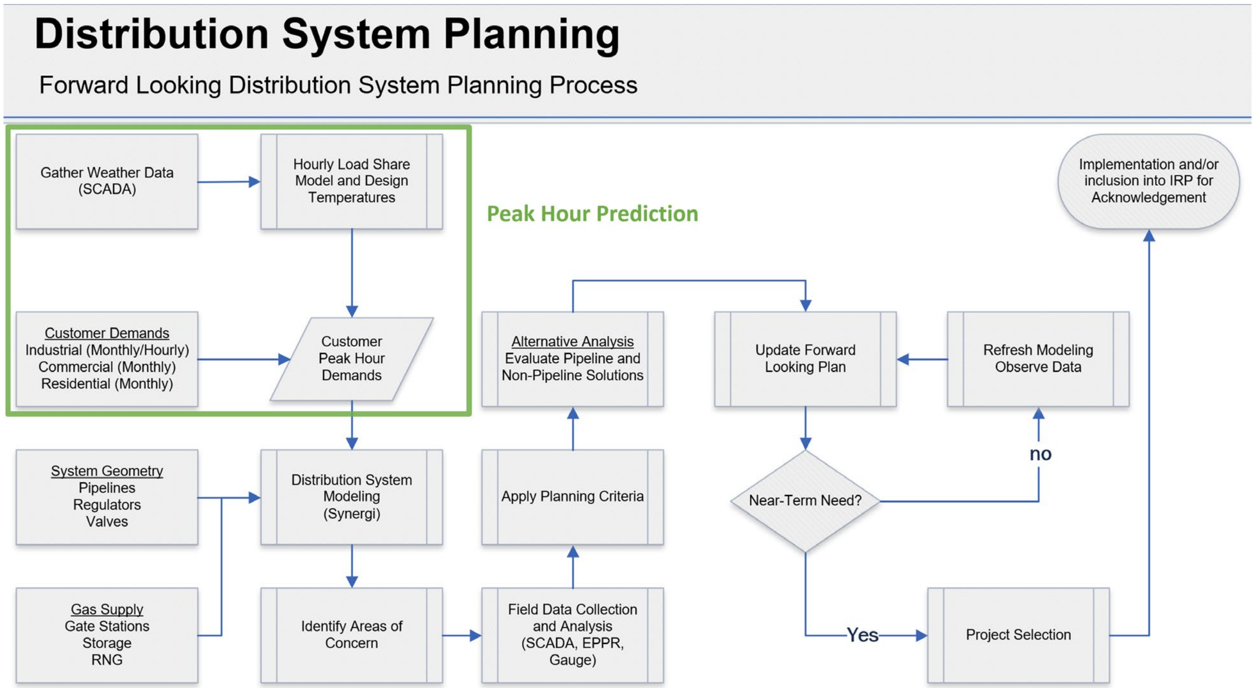
Areas can be categorized as a near term or long-term potential need. Areas identified as long-term needs are projected to exceed design capacity of the distribution system within a four to ten year timeframe. For long-term need areas, NW Natural prepares preliminary modeling documentation and high-level cost estimates for potential non-pipeline and pipeline solutions. At the long-term stage project planning remains conceptual. Areas facing a near-term need are projected to have capacity constraints within a one to three year timeframe. For areas with near-term needs, NW Natural conducts a detailed planning process that includes system modeling, pressure read documentation, the most feasible pipeline solution with more precise cost estimates and an evaluation of more non-pipeline alternatives, which are discussed later in this chapter.

Depending on the scope, magnitude of the investment, or the lead time needed to implement a pipeline solution; any project on the Forward Looking Distribution Plan may be included for a full IRP evaluation. Generally, this happens to be the higher priority near-term violation areas being monitored. However, regardless of the lead times needed to implement a distribution system solution (either demand-side or supply-side), detailed cost and risk assessments, along with a robust alternatives analysis are conducted for any solutions that would be included in an IRP Action Plan.

## 12.3 Peak Hour Prediction and Forecasting

As shown in Figure 12.2, peak hour modeling methodology generally follows that of the peak day forecasts while incorporating more granular geographic and time dimensions. NW Natural designs its gas distribution system to meet predicted peak hourly demands, ensuring reliable supply for firm customers during the highest usage periods. Designing for peak hourly usage is essential because natural gas consumption varies throughout the day, with demand typically peaking during the morning burn period between 6:00 AM and 10:00 AM, when firm customers have the highest energy needs. During the morning burn, increased flow rates lead to higher gas velocities, which in turn produces greater pressure drops across gas facilities. If the pressure on the distribution system falls below the minimum pressures required for customer equipment, outages can occur. By designing the system to handle peak hourly demand, NW Natural can maintain adequate pressure levels, minimizing the risk of service disruptions due to insufficient system capacity.

*Figure 12.2: Forward Looking Plan Peak Hour Prediction*




Synergi™ Gas demand forecasting incorporates distinct load centers, each defined by a unique weather zone. Each weather zone represents a specific geographical area where customers experience similar weather patterns, allowing for more precise demand forecasting for peak hour system planning. These weather zones account for variations in peak design temperatures across NW Natural's service territory, ensuring that the distribution system is designed to the specific demand characteristics of each weather zone.

Table 12.1 illustrates the peak HDDs for each weather zone, which demonstrates how peak design temperatures differ across NW Natural's service territory.[143] Each weather zone has a unique non-coincidental design peak HDD, reflecting localized climate conditions. Typically, individual customers within weather zones with higher HDDs experience greater peak gas demand, as colder temperatures lead to increased heating needs. Conversely, areas with lower HDDs generally exhibit lower peak demand. NW Natural can optimize system reliability by forecasting customer demands based on specific HDD. The benefit of analyzing the distribution system for unique weather zones is that it allows NW natural to propose solutions to meet the specific needs of each region based on a unique peak HDD.

[143] The NW Natural engineering team assumes an average outside temperature of 65°F when calculating HDDs for distribution system planning.

*Table 12.1: Peak HDDs by Weather Zone*

| Weather Zone | HDD |
|---|---|
| Clark County | 57.4 |
| Columbia River Gorge | 66.8 |
| Portland | 57.0 |
| Astoria | 49.4 |
| Salem | 54.8 |
| Lincoln City | 45.7 |
| Albany | 54.5 |
| Eugene | 56.2 |
| Coos County | 41.9 |

The table of region-specific HDDs are derived from historical localized coldest average daily temperatures each year. Specifically, a normal distribution is developed around the mean and standard deviation, of the coldest average daily temperatures in each historical winter for each location (i.e., non-coincident). The first percentile temperature is then used as the distribution planning standard for calculating HDDs for each location.

NW Natural relies on two data sources for forecasting individual customer demands for Distribution System Modeling. These two data sources are the Industrial Billing Reports and the Customer Management Module (CMM).

Industrial Billing Reports contain hourly consumption for approximately 450 industrial and commercial customers. The customers included in the industrial billing reports are typically large consumers of gas, whose firm demands have the greatest impact on distribution system pressures. An analysis is conducted for each one of these customers to determine consumption during the morning burn when gas demands are at the highest levels.

NW Natural does not collect hourly usage for all customers on the distribution system. Therefore, other tools have to be incorporated to forecast individual firm customer demands. The Customer Management Module (CMM) is used to forecast peak hour gas demands on the distribution system for firm customers without hourly consumption data. CMM plays a key role in demand forecasting by estimating daily individual customer usage based on their unique historical consumption patterns and weather data. CMM calculates daily demand estimates for customers by using historical monthly usage and daily weather data sourced from NW Natural's Customer Information System (CIS). CMM is discussed more in depth later in this chapter.

A peak hourly factor is calculated to convert CMM daily Demands into hourly data. The peak hour factor is a function of the systemwide peak hour demand (see Appendix J.1), Industrial

Billing Reports, and CMM daily forecasted demands. The equation below provides how the peaking factor is used to convert CMM daily demands to peak hourly demands.

$$Peak\ Hour\ Factor\ = \frac{Systemwide\ Peak\ Hour\ Demand - \sum(\text{Industrial Billing Hourly Demands})}{\sum(\text{CMM Forecasted Peak Daily Demand})}$$

Modeling results, based on the calculated peak factor, are compared with data from cold weather events to validate the peak hour factor used in the demand predictions. This involves adjusting the Heating Degree Days (HDD) to align with actual weather conditions and comparing the modeled pressures to actual pressure readings during the morning burn, when gas consumption is at its highest. For a given HDD, actual pressures may be higher or lower than the modeled values. The peak hour modeling results for a specific area are considered valid if the majority of recorded pressures are reasonably close to the modeled results.

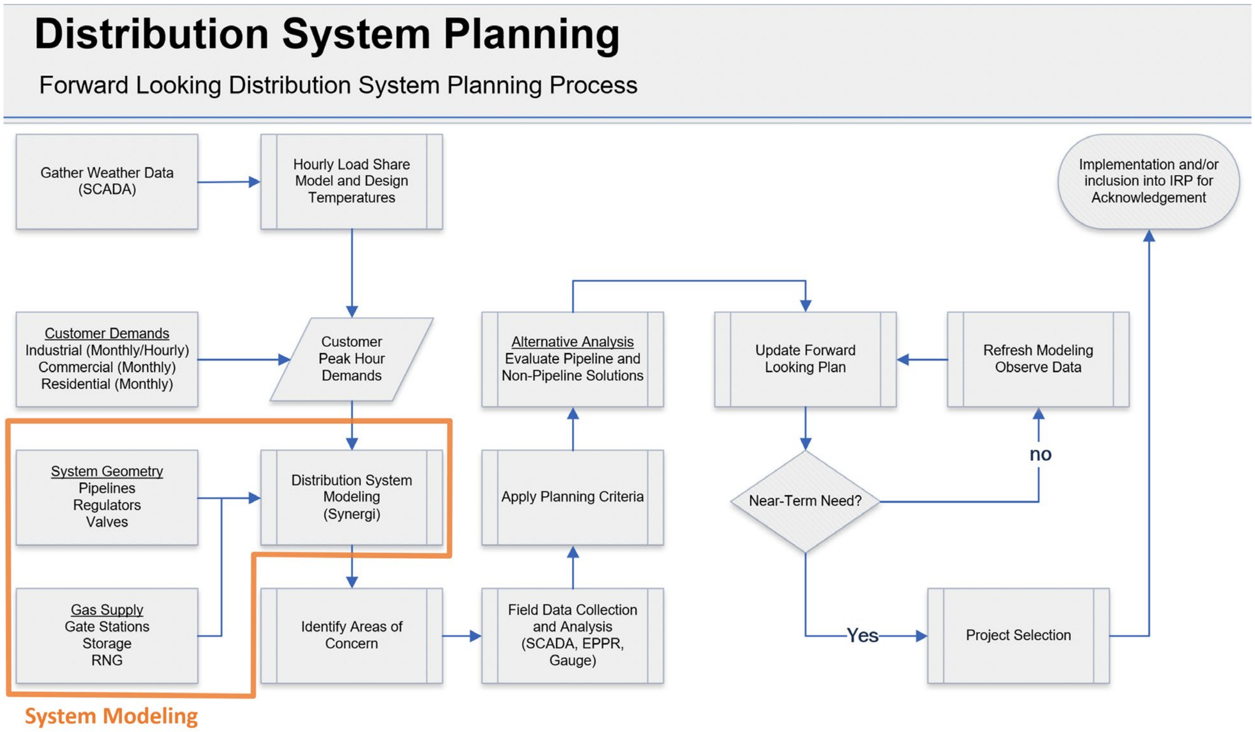
## 12.4 Distribution System Planning Tools and Standards

The following sections describe the planning tools and standards utilized for Distribution System Planning on NW Natural’s system.

### 12.4.1 System Modeling

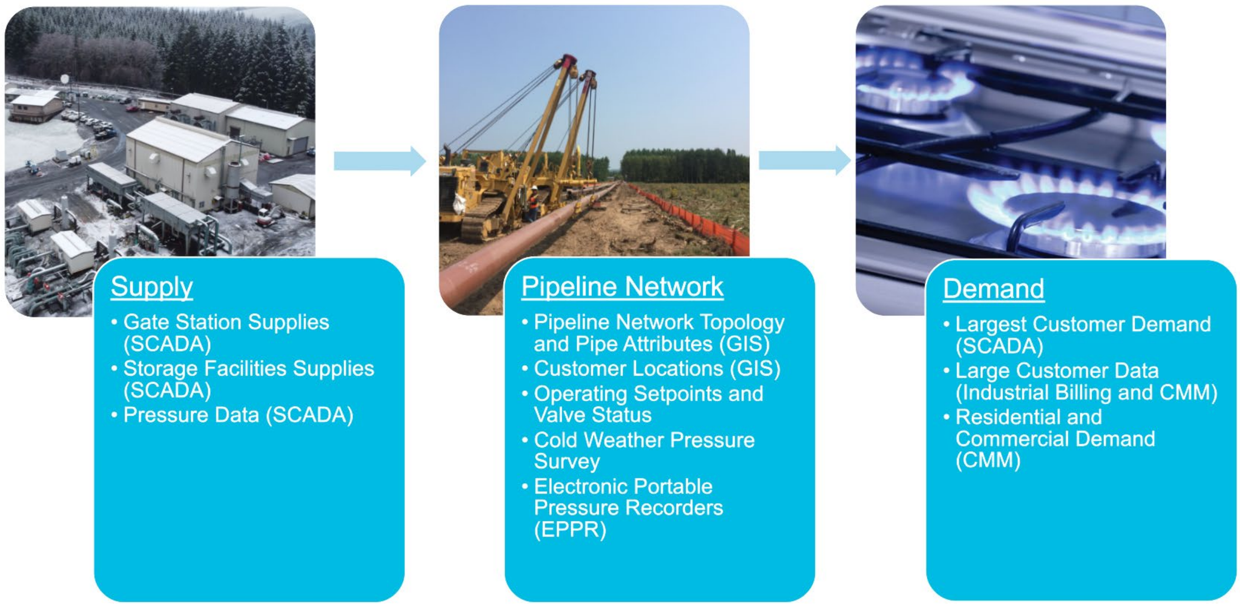
Figure 12.3 provides the components involved in System Modeling. System modeling is an important part of the distribution system planning process. Modeling allows accurate simulation of different aspects of NW Natural’s system, from the receipt of natural gas from supplies, through NW Natural’s pipeline networks, ending at customer locations. The purpose of System Modeling is to ensure adequate supply and pressure to customers, identify potential capacity constraints, and evaluate system performance under peak hourly conditions.

*Figure 12.3: Forward Looking Plan System Modeling*




Building the gas distribution network model is the first step in the System Modeling process. NW Natural develops Synergi™ Gas models in-house which represent the infrastructure found on the distribution system. Models are typically updated quarterly and completely rebuilt every two to four years. As shown in Figure 12.4, each model contains detailed information such as gas supply sources, pipe attributes (diameter, length, material, and roughness), regulator settings and characteristics, valve positions, customer demands, and other supporting information. These models are constructed using data from NW Natural's Geographic Information System (GIS) for pipe configuration and characteristics, the Customer Information System (CIS) for customer load sizing, and the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, and supply flow data. By integrating these data sources, the SynergiTM Gas model provides a comprehensive and accurate representation of the network, supporting the goals of providing reliable service to end-use customers.

*Figure 12.4: SynergiTM Gas Modeling Needs*




Synergi™ Gas applies user identified network data to construct a set of mathematical equations that form the model of the piping system. The solution of these equations provides predictions of pressures, flows, and other unknown values in models. A model is considered *balanced* when the relationship between flows and pressures at all points in the modeled system are within tolerance. A properly designed Synergi™ Gas model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi™ Gas models rely on assumptions about the actual system, and therefore modeling results may vary from actual results. Synergi™ Gas models are a representation of the actual system, and the outputs of these steady-state models are a static snapshot of expected system conditions.

A validation process is conducted for the Synergi™ Gas models to ensure that the predicted pressures fall within acceptable tolerance levels of actual pressures recorded during winter events. Synergi™ Gas may either underpredict or overpredict system pressures for a given HDD. CMM Demands loaded into Synergi™ Gas only applies a single independent variable (temperature) to predict customer demands. The variability between modeling pressures and actual pressures exists because other factors including wind speed, solar radiation, snow depth, day of the week, and water temperature are not included in CMM demand forecasting. A model is assumed to have accurate results if recorded pressures are within ±20 percent of actual pressures.

NW Natural uses three distinct data collection tools to validate the resulting pressures of its Synergi™ Gas models:

1. **Supervisory Control and Data Acquisition (SCADA) Flow/Pressure Data**: SCADA sites are located throughout the gas distribution system. These locations include Williams gate stations, regulator stations, regional stations, and various customer locations. These sites provide two-minute monitoring and control capabilities. Flow and/or pressure data can be viewed or exported in two-minute intervals, providing high granularity data related to system performance.

2. **Electronic Portable Pressure Recorders (EPPRs):** Battery operated temporary deployable devices placed in areas where low pressures are suspected. EPPRs collect pressure and temperature readings in hourly intervals, transmitting the recorded data using cellular technology. Their portable design allows them to be relocated as needed to satisfy data collection requirements.

3. **Cold Weather Survey Pressure Data:** Surveys may be conducted during cold weather events. This type of survey involves deploying NW Natural field personnel to specific sites to manually record pressures. These readings are then submitted to the Engineering team for analysis. Survey locations are selected to track system performance trends, identify potential low pressure areas, and assess the effectiveness of system reinforcements.

Synergi™ Gas software simulates gas pipeline operations and does not have the ability to perform automated pipeline route selection. Automated route selection for pipeline construction would require data with quality and coverage that are not available at this time. Instead, system planners perform an iterative process incorporating multiple economic, geologic, and infrastructure factors to draft the least cost, feasible route option. An identified route is further refined through field validation and right-of-way acquisition considerations.

Synergi™ Gas simulation capability allows NW Natural to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak hour delivery requirements to both planned and unplanned temporary service interruptions. Synergi™ Gas modeling allows NW Natural to evaluate various scenarios designed to stress test the system's response to alternative demand forecasts, future demand forecasts, emergency situations, new customer demands, customer growth, non-pipeline alternatives, and much more.

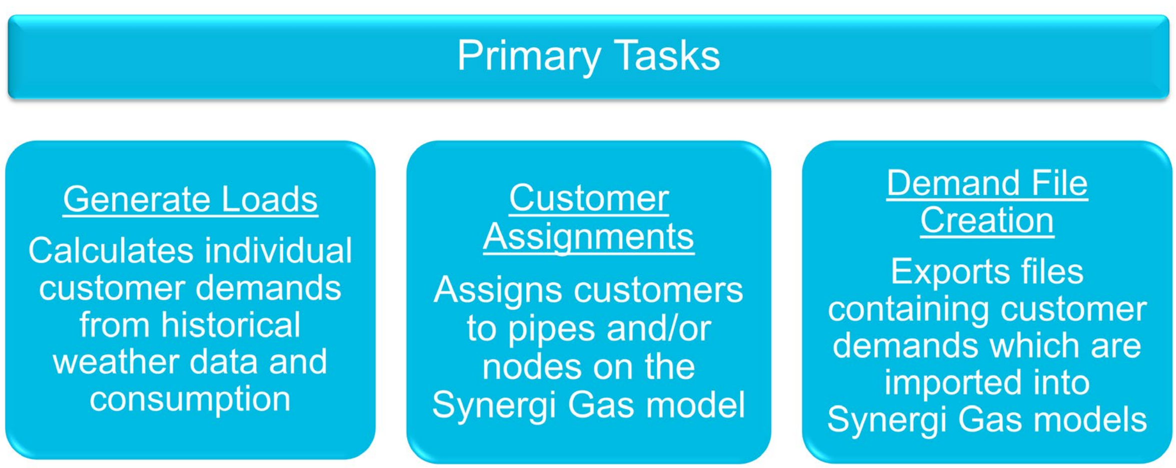
## 12.4.2 Customer Management Module

In 2021, NW Natural implemented the Customer Management Module (CMM) to predict demand for each individual customer on the system. Previous modeling methods utilized area-specific averages for residential and small commercial customers. For example, all residential customers in the Portland metropolitan area were previously assigned the same demand in the Synergi™ Gas models, whereas CMM allows customer-specific usages for each customer in the model based on historical consumption.

Part of integrating CMM into Synergi™ Gas modeling required all NW Natural models to be recreated. CMM based models are required to have the same coordinate system as the Geographical Information System (GIS) system. CMM models rely on NW Natural's current GIS coordinate standard, which was not utilized in previous models. Creating new models ensured alignment of spatial data between CMM demand locations and Synergi™ Gas. As of the third quarter of 2023, NW Natural has recreated all models to take advantage of CMM demand forecasting.

CMM is a forecasting software tool that works with Synergi™ Gas. CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ Gas. CMM is developed by DNV, which is the same developer who produces the Synergi™ Gas software. In summary, CMM provides three primary tasks as shown in Figure 12.5.

*Figure 12.5: CMM Primary Tasks*




**Generate Loads**: CMM uses a combination of historical monthly billing and temperature data to calculate a base load factor and a heat temperature-dependent load factor for each customer. The heating usage factors are determined through regression analyses that use monthly consumption data and the average daily temperature experienced.

**Customer Assignments**: Synergi™ Gas models consist of pipes and nodes representing the distribution system network. Synergi™ Gas models require that customer demands be assigned to a nearby pipe or node within the gas distribution system. When demands are correctly assigned to the correct position in Synergi™ Gas, it allows modelers to accurately evaluate localized system pressure conditions. CMM's customer assignment functionality matches each customer's load to the nearest node or pipe using geographic coordinates sourced from NW Natural's GIS system.

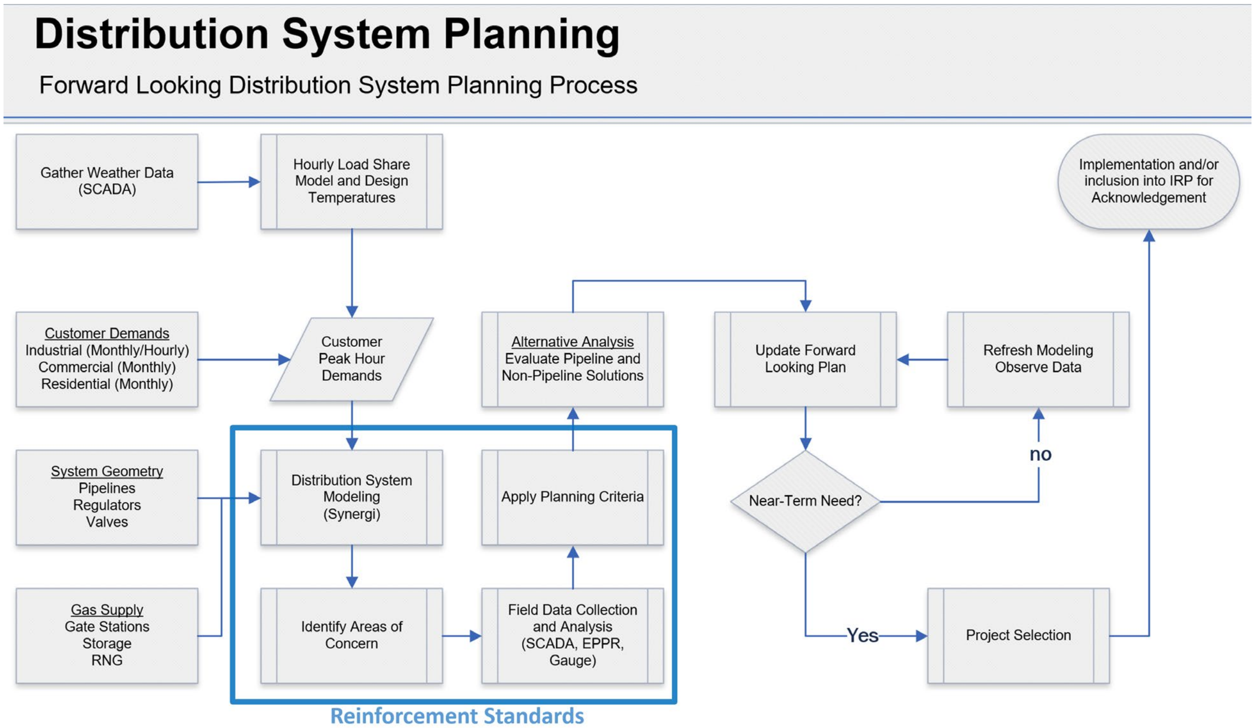
**Demand File Creation**: The purpose of the demand file is to import CMM calculated loads into the Synergi™ Gas model for accurate system simulation. Demand files generated from CMM include the relationship between customer location (pipe or node) in Synergi™ Gas models with corresponding calculated demands. These demand files contain pipe or node assignments as well as the base and heat load components for each customer, as well as whether the load is for residential, commercial, industrial, or interruptible use.

In addition to the primary tasks provided in Figure 12.5, CMM allows NW Natural to update modeling demands if a customer changes their status or service type, including whether customers are identified as active or inactive and if they are on a firm or interruptible rate schedule. Identifying customer status and rate schedule allows NW Natural to model active customers on the system. Firm customers are included in peak models, whereas interruptible customers are assumed to be curtailed during extreme cold weather. These qualities are important because having incorrect customer rate schedules and statuses would affect Synergi™ Gas pressures.

### 12.4.3 Distribution System Planning Criteria

As shown in Figure 12.6, system reinforcement standards are a required component of the distribution system planning process. These standards are developed based on suboptimal conditions such as a pipeline nearing peak capacity, a regulator near failure, or customers not being served with adequate pressure or volume. The system reinforcement standards represent trigger points indicating systems under stress and in need of imminent attention to reliably serve customers.

*Figure 12.6: Forward Looking Plan Reinforcement Standards*




### *12.4.3.1 System Reinforcement Standards*

Transmission and high-pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well.

System reinforcement parameters for these systems include:

- For systems with nominal diameters less than six inches, or have a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less:
  - Experiencing or modeling a greater than 30 percent pressure drop from a source to the lowest pressure indicates an **investigation** will be initiated.
  - Experiencing or modeling a greater than 40 percent pressure drop from a source to the lowest pressure indicates reinforcing the facility is **critical**, as a 40 percent pressure drop equates to an 80 percent level of capacity utilization[144]
- For systems with nominal diameters of six inches or greater or have a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig:
  - Experiencing or modeling a pressure below 210 psig on the system indicates an **investigation** will be initiated

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

    - Experiencing or modeling a pressure below 180 psig on the system indicates reinforcing the facility is **critical**
- Consider the minimum inlet pressure requirements for proper regulator function, in addition to total pressure drop for pipelines that feed other high-pressure systems
- The ability to meet firm-service customer delivery requirements (flow or pressure)
- Identified in the IRP associated with supply requirements or needs

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

- Experiencing a minimum distribution pressure of 15 psig or less that indicates an **investigation** will be initiated
- Experiencing or modeling minimum distribution pressure of 10 psig or less that indicates reinforcement is **critical**
- Firm service customer delivery requirements (flow or pressure)

#### *12.4.3.2 System Reinforcement Standard Updates*

Since the last IRP, the Company has modified the 40 percent pressure drop system reinforcement criteria to apply to pipelines less than six-inches in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less. NW Natural adopted a new standard for pipelines six-inches and larger or systems with an MAOP of greater than 300 psig allowing flexibility to exceed the 40 percent pressure drop.

Under the revised standard, for pipelines six-inches or larger in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig, a system reinforcement is considered critical when the lowest pressure on the system drops below 180 psig. This change ensures that district regulators feeding Class B systems continue to operate at adequate inlet pressures while lowering the necessary system reinforcement projects to comply with the previous standard. At 180 psig, Class B District Regulators can reliably serve downstream demand. However, if inlet pressure falls below 180 psig, Class B district regulators may experience pressure droop, also known as starving a district regulator. A starved district regulator leads to reduced regulator and B-system capacity, which can result in lower downstream pressures and potential system reliability concerns because the district regulator cannot provide enough gas to meet the downstream demand.

Despite the increased flexibility in pressure drop for high-pressure mains, the updated System Reinforcement standards preserves system reliability by maintaining the performance threshold needed to support Class B district regulator operations.

The original 40 percent pressure drop criteria continues to apply to transmission and high pressure systems operating at or below an MAOP of 300 psig or with a nominal diameter less than six-inches. These systems remain at greater risk of not providing sufficient inlet pressure for Class B district regulators to operate. Smaller diameter and lower MAOP system pressures are more sensitive to changes in demand because increases in demand causes a much higher pressure drop on the system. These greater fluctuations increase the likelihood of system reliability issues. The more volatile swings in system pressures for lower MAOP and smaller diameter pipelines make it important to preserve the 40 percent pressure drop criteria for these systems.

The reinforcement criteria for Class B systems, or systems operating at or below 60 psig, remain unchanged.

##### *12.4.3.3 Distribution System Planning Criteria – 40 percent Pressure Drop / 80 percent Capacity Utilization*

The Company established a system reinforcement criteria action threshold for systems where the pressure drop exceeds 40 percent from the source to the end of the system for pipelines less than six-inches in diameter or systems with a Maximum Allowable Operating Pressure (MAOP) less than 300 psig. This is because a system with a pressure reduction of 40 percent equates to an 80 percent level of capacity utilization (100 percent utilization means 0 psig at the end of the pipe). The Company needs to ensure that its gas distribution system will meet the demands of our firm load customers during peak cold weather events.

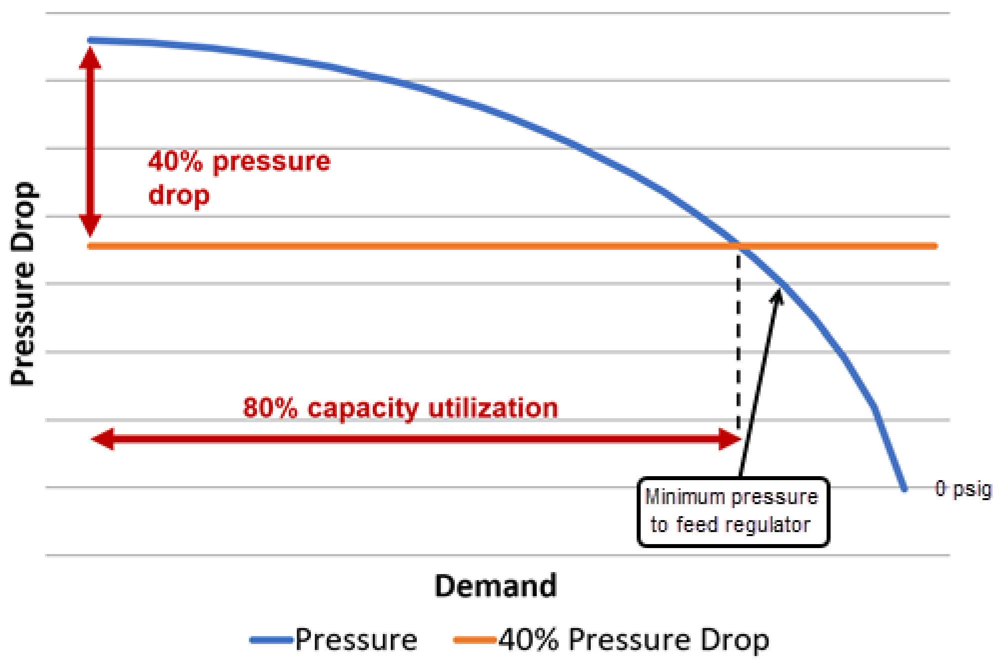
Although the models provide a good representation of system pressures, like any model they are not perfect at predicting real-world conditions, although we endeavor to make them as good as we practically can. Multiple uncertainties that pose risks are not accounted for in our system modeling. These risks that could cause unplanned use of the usable portion of the remaining 20 percent capacity. Should one or more of these modeling uncertainties be realized, it can result in equipment issues or even customer outages. These limitations highlight the need to maintain a buffer to ensure system reliability. Below are some of the factors that the Company cannot account for in its peak demand system modeling:

- **Variability in gas energy content**: If the actual energy content of gas during a peak weather event falls below the assumed average (1040 Btu/scf), the system will experience greater pressure drop, because it would require greater volumes of gas to deliver the same amount of energy.
- **Deviations in customer usage:** Customer usage behavior may differ from CMM calculated demands sourced from recent historical usage patterns (CMM calculated demands are based on the prior two years of customer usage).

- **Sudden spikes in demand:** Spikes in gas demand caused by restoration of electrical power to a large area of affected gas and electric customers.
- **Customer equipment changes:** Added customer equipment may not be accounted for in our system modeling as the Company may not have been notified about changes in customer equipment, and the install may have been recent enough to not properly register with CMM calculated demands.
- **Equipment malfunctions:** On-system equipment issues may occur during a peak weather event.
- **Interruptible customer usage:** Interruptible customers may continue to consume gas during a peak day (for which they will pay a penalty), which is not considered in peak day modeling.
- **Other independent variables:** CMM only considers temperature as an independent variable but other factors such as wind speed, solar radiation, snow depth, day of the week, holidays, water temperature, electrical outages, and differences in human behavior can cause variances in demand.
- **Modeling may predict lower pressures:** A model is considered validated when predicted pressures are within ±20 percent of field recorded pressures. If the model overestimates pressures (underestimates load), then actual pressures may be lower than peak modeling results.

Figure 12.7 below illustrates the nonlinear relationship between system demand and pressure drop. The image shows that pressure drop across a pipeline is not linear with respect to increasing demand. At lower levels of capacity utilization, pressure decreases gradually with increased demand. As the system approaches higher capacity utilization levels, it experiences larger pressure drops for the same demand increase. When a system is operating at or above 40 percent, small demand increases may cause pressures to fall below the minimum required pressures for district regulators to properly operate. If the pressure drops below the required minimum pressure for the regulator to flow the amount of gas the system needs, then the outlet pressure from the regulator drops below setpoint, resulting in a lower capacity of the system the regulator is feeding. The decreased district regulator capacity can lead to system reliability issues, especially during extreme cold weather events. Therefore, maintaining a sufficient pressure buffer is essential for maintaining gas service to customers during cold weather events.

*Figure 12.7: Pressure Loss Illustration*



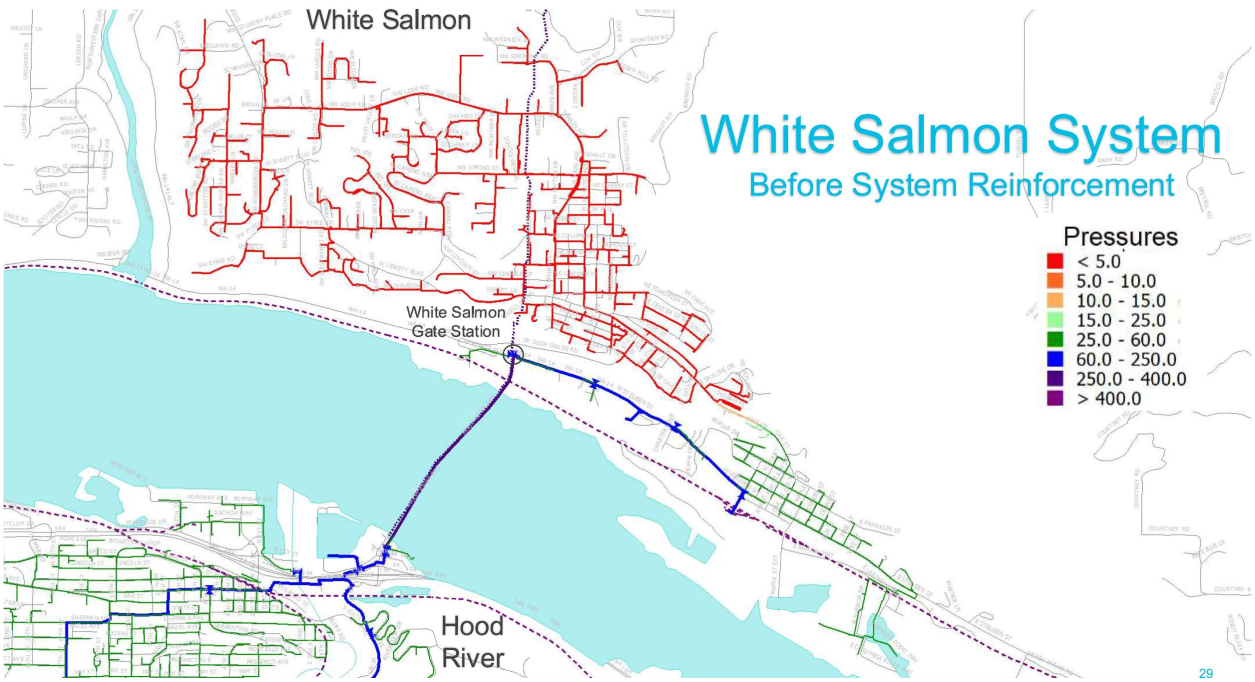

As can be seen in Figure 12.7, all of the remaining 20 percent of pipeline capacity is not available for utilization, as there needs to be sufficient remaining pressure to flow through the pressure regulating equipment then into the downstream system and ultimately to the customer. One hundred percent utilization of the pipes capacity would result in 0 psig at the end of the pipe. Utilization of 100 percent of the pipes capacity would lead to a loss of service to all customers affected.

Loss of service requires a lengthy 3-step process to restore service to customers, and service cannot be restored until the gas distribution system pressures stabilize above five psig for our residential customers. The Company must dispatch field service technicians to shut in the customer’s service, purge any air that may have entered our gas lines and then reintroduce gas to the customer’s gas service and appliances and relight the equipment. Air purging, and customer equipment relights, cannot begin until the pressures in the gas distribution pipelines permanently stabilize above five psig and relighting could take several days to weeks depending on the size of the affected area. If this loss of service were to happen in the midst of a multi-day cold weather event, the system would continue to lose pressure each day of the multi-day event and customer service could not be restored until distribution pipeline pressures permanently stabilize above five psig.

### 12.4.4 Identification of System Distribution Needs

Accurate modeling and forecasted level of peak hour demand combine to indicate how the distribution system would operate during a predicted peak hour. The system reinforcement standards are then applied to the model results to identify specific areas of NW Natural's system that need reinforcement. Such areas are typically much smaller than the load center in which they are located. In the following Synergi™ Gas example, and as shown in Figure 12.8, an area of the Class B distribution system in White Salmon, WA is forecasted, by modeling, to experience low system pressures or outages on a peak hour. Areas with pressure below ten psig are indicated in orange and red colors, while areas with more satisfactory pressure are indicated with shades of green. This modeling was validated in January of 2018 when SCADA revealed that the White Salmon distribution system experienced a pressure of 6.8 psig under non-peak conditions.

*Figure 12.8: Synergi™ Gas example*



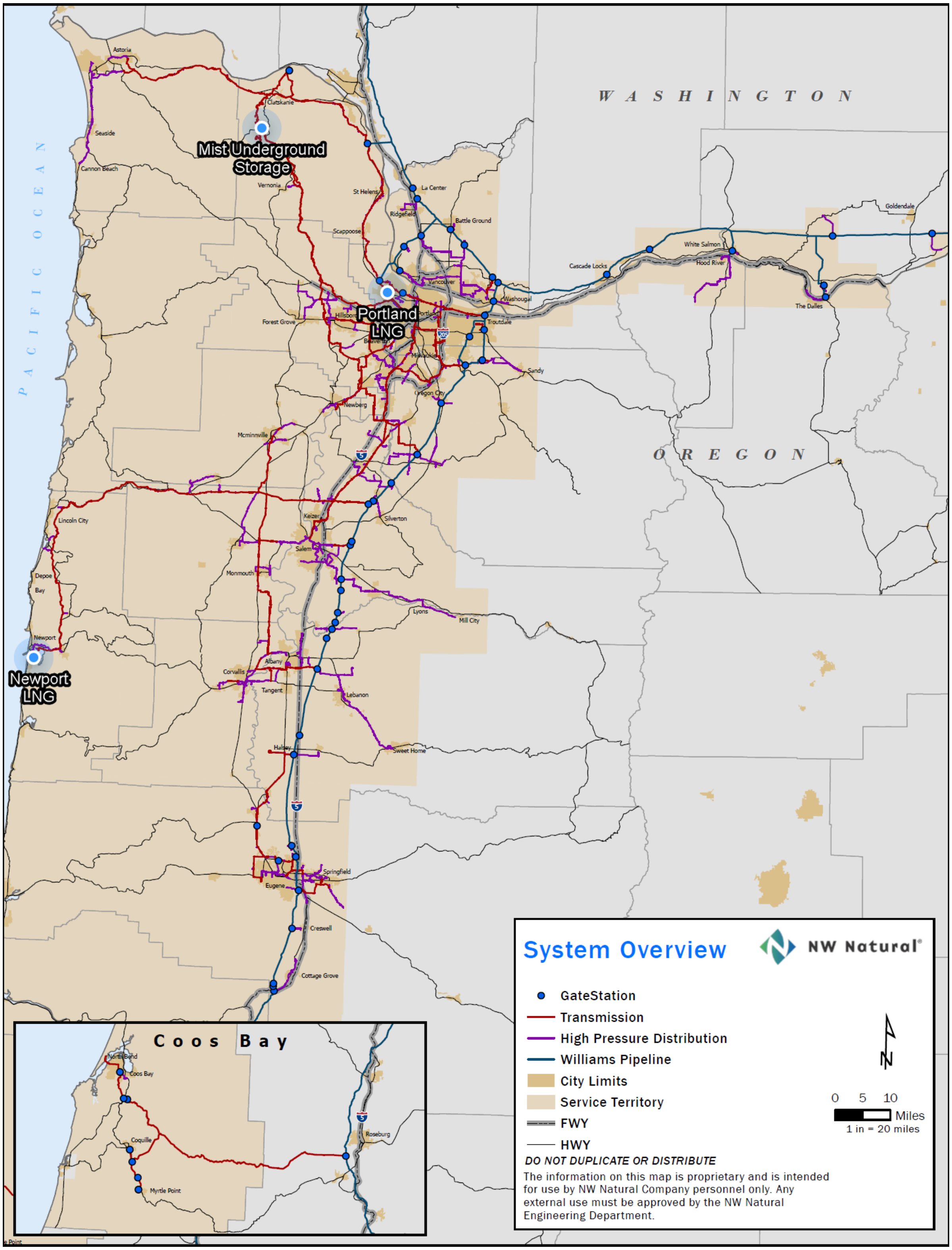

## 12.5 Distribution System Resources

### 12.5.1 Existing Distribution System

NW Natural's gas distribution system consists of approximately 14.4 thousand miles of transmission and distribution mains, of which approximately 86 percent are in Oregon with the remaining 14 percent in Washington. NW Natural has replaced all identified Aldyl-A, cast iron, and bare steel mains with modern polyethylene and coated steel.

NW Natural's Oregon service area includes 39 gate stations and approximately 954 district regulator stations. NW Natural owns and operates two liquefied natural gas (LNG) storage plants and the Mist underground storage facility in Oregon, which are discussed in Chapter 8. NW Natural's Washington service area includes 15 gate stations and approximately 78 district regulator stations. Figure 12.9 provides a high-level system overview of the Company's natural gas network.

*Figure 12.9: NW Natural Gas Network*



NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of individual customers, or small localized systems during cold weather operations, or while conducting pipeline maintenance procedures.

## 12.6 Alternative Analysis/Solutions

As shown in Table 12.2, NW Natural evaluates various alternatives when faced with a potential system reinforcement. A discussion of pipeline alternatives will be presented below followed by non-pipeline alternatives.

*Table 12.2: Distribution System Planning Alternatives*

| **Distribution System Planning Alternatives (not all options are possible or applicable in all situations)** | | | | **Option Currently Considered for Cost-Effectiveness Evaluation** |
|---|---|---|---|---|
| Supply-Side Alternatives | Pipeline Related Capacity Options | | Loop existing pipeline | ✓ |
| | | | Replace existing pipeline | ✓ |
| | | | Install pipeline extension | ✓ |
| | | | Uprate existing pipeline infrastructure | ✓ |
| | | | Add or upgrade regulator to serve area of weakness | ✓ |
| | | | Add or upgrade gate station | ✓ |
| | | | Add compression to increase capacity of existing pipelines | ✓ |
| | Non-Pipeline Solutions | Distributed Energy Resources (DER) | Mobile/fixed geographic targeted CNG storage | ✓ |
| | | | Mobile/fixed geographic targeted LNG storage | ✓ |
| | | | On-system gas supply (e.g. RNG, H2) | ✓ |
| | | | Geographically targeted underground storage | ✓ |
| Demand-Side Alternatives | | Demand Response | Interruptible schedules (DR by rate design) | ✓ |
| | | | Geographically targeted interruptible agreements | ✓ |
| | | | Geographically targeted Res & Com demand response (GeoDR) | ✓ |
| | | Energy Efficiency | Peak hour savings from normal statewide EE programs | ✓ |
| | | | Geographically targeted peak-focused energy efficiency (GeoTEE) | ✓ |

### 12.6.1 Pipeline Solutions (Supply-Side Resources)

Once NW Natural identifies a distribution system issue, in addition to demand-side alternatives, the Company evaluates multiple traditional pipeline solutions for addressing low pressures. NW Natural considers a variety of traditional pipeline solutions including:

- Constructing new pipelines
    - Distribution Pipeline Extensions
    - Distribution Pipeline Replacements

    - Distribution Pipeline Looping
- System pressure uprates
- New or improvements to regulator stations
- New or improvements to gate stations
- Constructing a new compressor station

The objective is to determine the most efficient, least cost, highly reliable, and low risk solution for the identified issue. Potential pipeline solutions are validated with hydraulic modeling and field testing to verify effectiveness.

Maintaining adequate pressure throughout the distribution system is essential for reliably serving customers on the distribution system. If pressures on the system are too low, it can lead to customer outages. Pipeline solutions are an important step in the alternative analysis to find feasible solutions to address areas experiencing low pressures.

### 12.6.2 Constructing New Pipelines

A common industry approach to resolve low pressure areas is to construct new distribution pipelines to reduce pressures losses through the existing gas network. The proposed distribution pipeline would allow more gas to flow to areas with weak pressures, thereby improving their pressures. Newly constructed pipelines can raise pressures in weak areas, reducing the likelihood of customer outages.

The Company conducts pipeline feasibility studies to evaluate potential pipeline projects. These pipeline feasibility studies assess various selection criteria including pipeline distance, ease of construction, operating pressure, material, pipeline diameter, load type, and existing network connectivity. The three primary types of new pipeline reinforcements include:

1. **Distribution Pipeline Extensions**: Installation of a gas distribution pipeline using a new alignment. A new distribution pipeline delivers higher pressure gas to an area of need, increasing the pressure and reliability of a distribution system. Depending on the relative operating pressures this could also include pressure regulation and overpressure protection equipment.

2. **Distribution Pipeline Replacements**: Replacing an existing pipeline with a new pipeline. Typically, the replacement distribution pipeline is larger in diameter than the original distribution pipeline, which reduces the pressure drop across the alignment.

3. **Distribution Pipeline Looping**: A new distribution pipeline is constructed parallel to an existing distribution pipeline. The looped mains are tied-in and work together to carry the gas, reducing pressure drop along the original pipeline alignment because of load sharing.

NW Natural considers alternative characteristics for a pipeline solution to the identified issue as a first step in developing supply-side solutions. These alternative characteristics include proposed pipeline alignments, the size of the pipe, the material used in the pipe, and the probable methods – or combination of methods – of pipeline construction. The feasibility study incorporates all three scenarios as well as these alternative characteristics. The least cost option is provided as an input in the alternatives analysis to address an area in need.

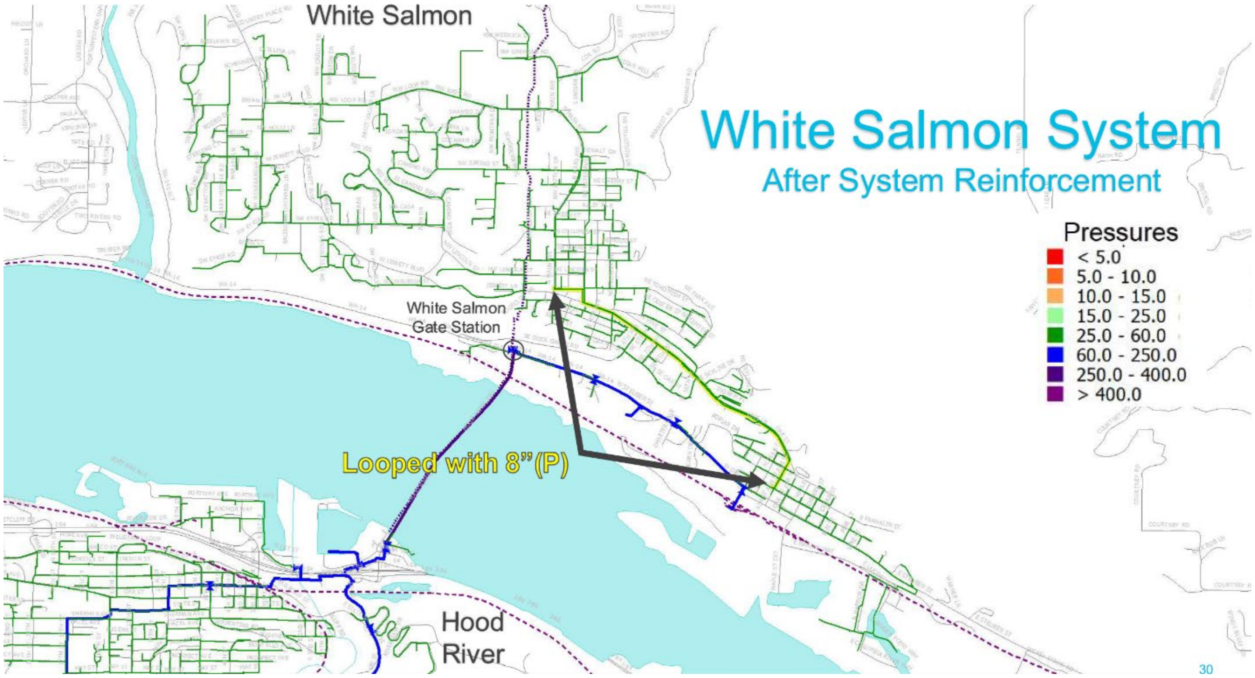
Table 12.3 provides the design capacity for a five-mile pipeline for various pipe sizes. The table shows that a 12-inch, 300 psig pipeline has approximately 6 times more carrying capacity than a six-inch 300 psig pipeline. Increasing pipe diameter does not increase capacity linearly, doubling pipeline diameter of gas main equates to increasing the flow capacity by approximately six times.

*Table 12.3: Comparative Pipeline Capacity Based on Diameter*

| Nominal Diameter | Beginning Pressure | Ending Pressure | Pipeline Capacity[1,2] |
|---|---|---|---|
| **2"** | 300 psig | 180 psig | 340 Th/hr |
| **4"** | 300 psig | 180 psig | 1,956 Th/hr |
| **6"** | 300 psig | 180 psig | 5,713 Th/hr |
| **8"** | 300 psig | 180 psig | 12,257 Th/hr |
| **12"** | 300 psig | 180 psig | 34,797 Th/hr |

[1]40% Pressure Drop Pipeline Capacity
[2]Calculated using a Heating Value of 1040 Btu/scf

In the White Salmon example discussed earlier in section 12.4.4, the primary weakness in the existing gas system was due to a single one-way feed serving the area to the north. This created a bottleneck, as nearly all gas supplied to customers had to pass through a small 3-inch diameter pipe, which had inadequate capacity to meet the demand in the northern part of the system. To address this issue, the implemented solution involved looping the existing 3-inch pipe with a new 8-inch pipeline. This significantly increased the system’s capacity and provided adequate pressures to customers in the north. The majority of the gas is now delivered through the new 8-inch pipeline, which loops the existing 3-inch pipe, providing greater capacity than the 8” by itself, and reduces construction costs since the previously existing services and pipe laterals did not have to be tied over to the new 8-inch pipe. As a result, overall system pressures improved significantly. Areas that previously showed low pressure (indicated in red) are now operating at sufficient pressures (indicated in green).




## 12.6.3 System Pressure Uprates

In many, but not all cases, the cost of uprating a portion of a distribution system is generally less than installing a new pipeline. Uprating pipelines is another form of increasing the capacity of a distribution system, by increasing the pipeline's Maximum Allowable Operating Pressure (MAOP). Before an uprate can be executed, a pipeline system must comply with Local and Federal Regulations. The uprating effort may include, but is not limited to, key activities such as reviewing records, pressure testing, replacements, field verification, inspections for all pipes and components on the portion of the distribution system being uprated, multiple leakage surveys before, during and after the pressure uprate process. Not all pipelines are eligible to be uprated, a system may have design or material limitations that prevent a distribution system pipeline from operating at a higher MAOP.

Table 12.4 shows the capacity for a five-mile, four-inch steel pipeline for varying operating pressures. The table shows that a pipeline operating at 600 psig with a 40 percent pressure drop along its length has approximately six times more capacity than a pipeline operating at 100 psig, also with a 40 percent pressure drop. A major benefit of uprating is; that incremental capacity can be provided through existing distribution pipelines by safely operating them at higher pressures.

*Table 12.4: Comparative Pipeline Capacity Based on Operating Pressure*

| Beginning Pressure | Ending Pressure | Pipeline Capacity[1,2] |
|---|---|---|
| **100 psig** | 60 psig | 662 Th/hr |
| **200 psig** | 120 psig | 1,304 Th/hr |
| **300 psig** | 180 psig | 1,956 Th/hr |
| **400 psig** | 240 psig | 2,617 Th/hr |
| **500 psig** | 300 psig | 3,289 Th/hr |
| **600 psig** | 360 psig | 3,971 Th/hr |

[1]40% Pressure Drop Pipeline Capacity
[2]Calculated using a Heating Value of 1040 Btu/scf

### 12.6.4 District Regulator Stations

If an area is experiencing low pressures and is located near a higher-pressure distribution or transmission system, then installing a new district regulator may be a viable solution. District regulators reduce higher-pressure gas to a lower pressure, suitable for the lower operating pressure system. By strategically placing a district regulator, the higher-pressure system can feed gas into the lower-pressure system, providing an additional source of gas and reducing pressure drop on the existing gas network. In some cases, a high-pressure main extension may be required to site the district regulator at an optimal location.

District regulator stations may also need to be rebuilt if the existing equipment or piping is undersized. Regulators are designed to maintain consistent outlet pressure within a specific flow range. However, if the station is undersized, it can experience pressure droop. Pressure droop occurs when the outlet pressure drops below the regulator set point, due to insufficient inlet pressure or equipment capacity. There are two primary ways to address pressure droop. One method is to increase the inlet pressure, which may involve system reinforcements such as a pipeline uprate or new pipeline construction. Another option is to rebuild the regulator station with appropriately sized equipment. However, all district regulators introduce some level of impedance (pressure loss), and rebuilding the regulator station may not be a viable option if the upstream system lacks the capacity to support the needed flow through the station.

### 12.6.5 Compressor Stations

Although NW Natural does not currently have inline compressor stations, construction of a new inline compressor station can be an option to ensure reliable pressures or increase gas sendout out of NW Natural's existing storage assets. By boosting pressures along the pipeline, compressor stations increase the capacity of the system to help meet energy needs. The optimal location and operating pressure of a compressor station are dependent on several factors including system MAOP, required horsepower, pipeline length, load placement along the system, potential need for additional compression in the future, availability of electrical power and communication capabilities, and surrounding site conditions. Balancing these factors are essential when designing a greenfield compressor station that meets performance, cost consideration goals, environmental and other regulatory requirements.

## 12.7 Non-pipeline Alternatives

The following sections provide a summary of the various non-pipeline alternatives (NPAs) NW Natural considers.

### 12.7.1 Trucking and Satellite Liquid Natural Gas and Compressed Natural Gas

*TBD*

### 12.7.2 Geographically Targeted Renewable Natural Gas

Geographically Targeted Renewable Natural Gas (GeoRNG) is another potential non-pipeline solution. As previously mentioned, RNG can be produced from a variety of feedstocks including animal manure, food waste, landfill gas, and water resource recovery facilities. If any of these feedstocks are available within the constrained areas, the Company could pursue GeoRNG. A strategically located RNG interconnection on NW Natural's system could have a similar impact in a constrained area of the distribution system as any targeted demand-side option. The additional RNG supply would be injected directly into a weak area of the system which can help avoid or delay a pipeline reinforcement project. The likelihood of an RNG facility providing the biogas needed in the perfect location as a specific alternative to a specific pipeline reinforcement project is small, but possible. However, after evaluation, the current constrained areas do not present any feasible GeoRNG project opportunities. The Company will continue to look at GeoRNG for NPA efforts within constrained areas.

### 12.7.3 Geographically Targeted Underground Storage

Similar to Satellite Liquid Natural Gas (LNG) and Compressed Natural Gas (CNG) , Geographically Targeted Underground Storage (GeoUnderground) storage would be an alternative if there was local underground storage strategically located near enough to the NW Natural system so that an interconnection could be constructed and add supplies in a constrained area. The likelihood of this being a realistic option for the capacity constrained areas is quite small after evaluation.

### 12.7.4 Geographically Targeted Demand-Side Management Programs

Geographically targeted demand-side management (GeoDSM) is a general term for geographically targeted energy efficiency (GeoTEE) and geographically targeted demand response (GeoDR), both of which can be specifically designed to achieve incremental peak hour savings from distinctive energy efficiency and demand response (DR) offerings to customers in a targeted area where the distribution system is expected to be constrained in the near future. The Company started the investigation of GeoTEE as a potential non-pipeline alternative (NPA) in the 2016 IRP, partnered with Energy Trust to implement a GeoTEE pilot from 2019 to 2022, and concluded the pilot with a detailed summary report in the 2022 IRP Update filed in 2024. [145] For GeoDR, the Company filed an action item in the 2022 IRP to scope a residential and small demand response program to supplement its large commercial and industrial interruptible rate schedule program, and OPUC acknowledged this action item with the condition that NW Natural provides a discussion of how its general demand response will interact with and support future GeoDR programs. In compliance with OPUC's guidance, the Company has evaluated several DR offerings as potential NPAs in the targeted areas. All these GeoDSM NPAs are discussed separately and their impacts on peak load and cost effectiveness as well as the time delay for engineering investments that can be achieved from the combination of the GeoDSM efforts are summarized below.

#### *12.7.4.1 Geographically Targeted Energy Efficiency Program*

Leveraging the data and experience gained from the 2019-2022 Geographically Targeted Energy Efficiency (GeoTEE) pilot, Energy Trust of Oregon (ETO) assessed the potential peak load and annual energy savings and costs based on historical trends and generalized assumptions for each of the three targeted areas. ETO's GeoTEE savings and costs estimates feature the historical trend in energy efficiency program implementation by customer segment in these areas since 2017 while increasing marketing/outreach as well as incentive levels to increase energy efficiency uptake. The Company has used the highly likely achievable potential annual and peak-hour therm savings and the corresponding costs to achieve these savings through a targeted approach.[146]

#### *12.7.4.2 Interruptible Rate Schedule Program*

NW Natural already relies upon substantial demand response resources in the form of interpretability to manage peak loads and save capacity resource costs on its distribution system, where about ten percent would-be peak load can be interrupted at the system level during peak events. This existing DR resource comes from 174 large industrial and transportation customers, having saved substantial infrastructure investments needed to serve the would-be peak load. In the GeoDSM targeted areas, two industrial and transportation customers are already enrolled in this rate schedule program and NW Natural is working with AWEC to explore opportunities to expand the program for other large commercial and

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[145] For more details about the GeoTEE pilot, see NW Natural's 2022 IRP Update in OPUC docket LC 79: https://edocs.puc.state.or.us/efdocs/HAH/lc79hah330506025.pdf

[146] For more details about ETO's GeoTEE peak load saving and cost estimates, see NW Natural's TWG #8 available at the following site: https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan.

industrial customers in these areas with area-specific rate schedules that provide higher incentives than the existing rate.

#### *12.7.4.3 Behavioral Demand Response Program*

As reported in the 2022 IRP Update filed in 2024, NW Natural ran a proof-of-concept effort from 2023 into 2024 that focused on a localized geographical demand response engagement in our Eugene area with a small subsection of our customer base. The Company partnered with a third-party vendor, Copper Labs, to enable our customers to see their current energy usage and receive notifications encouraging conservation during peak load times. Customers' usage data was available on both a customer app and a utility portal. Copper Lab's app allowed customers and NW Natural to see, in detail, their energy consumption patterns, peaks and valleys. The utility portal allowed NW Natural to send out notifications through the app during peak load times to customers encouraging them to reduce their usage.

Relying on similar technologies of the kind tested in the pilot mentioned above, NW Natural is working with AWEC to explore opportunities to enroll other large commercial and industrial customers in these areas in a behavioral demand response program. Unlike the interruptible rate schedule under which customers are required to completely shut down their natural gas usage for a whole day, customers enrolled in this behavioral demand response just need to reduce their usage by an agreed upon percentage or quantity during a DR event period of no more than four hours. The Company will work with individual prospective customers to identify measures to reduce peak hour load, set reasonable load reduction goals, and determine the size of incentives for the load reductions achieved. An independent third-party EM&V vendor, ADM Associates, has been contracted to verify the load reduction for each of participating customers using the time-interval usage data collected from metering devices developed by technology vendors like Copper Labs.

#### *12.7.4.4 Bring Your Own Thermostat Demand Response Program*

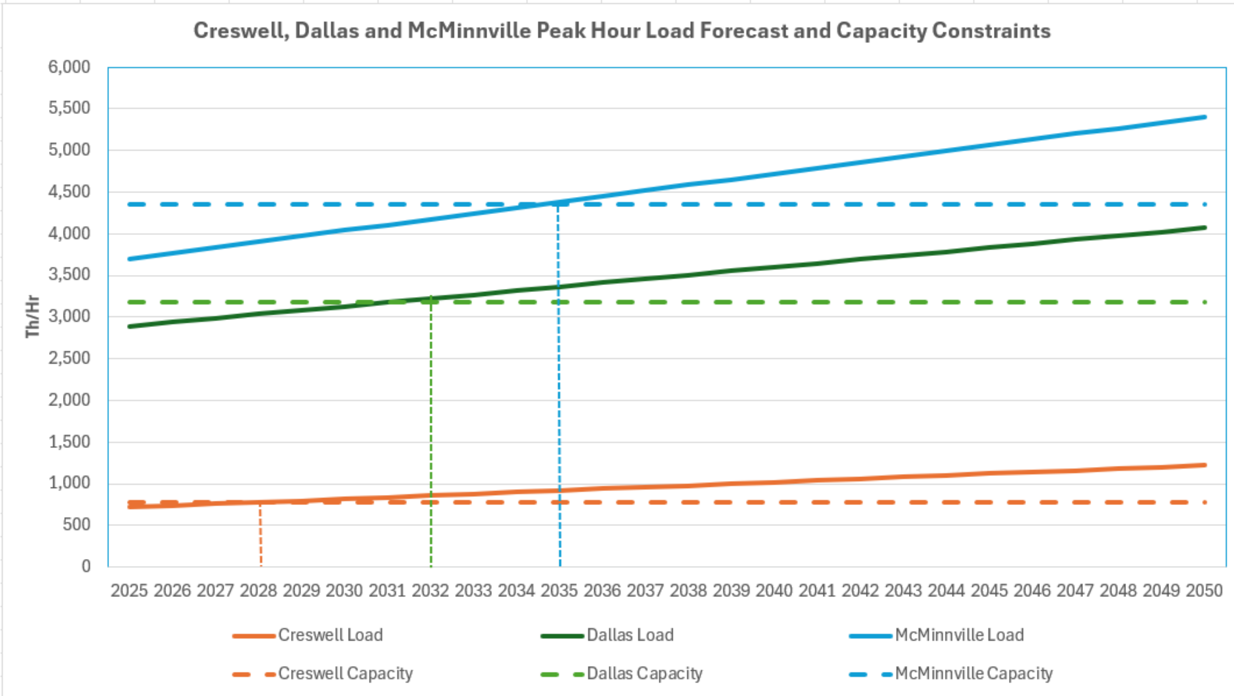
The Company will leverage the distributed energy resource management system (DERMS) established for the system-wide Bring Your Own Thermostat (BYOT) Demand Response Program ("Thermostat Rewards", as branded) and work with ETO to promote the program with area-specific increased enrollment and participation incentives along with ETO's smart thermostat energy efficiency program in the targeted areas. Since its rollout in December 2024, the numbers of smart thermostats that have been enrolled to date in the system-wide BYOT Demand Response Program in Creswell, Dallas, and McMinnville are 15, 45, and 66, respectively. Depending on the contribution of this geographically targeted demand response offering to the benefits obtained from delaying the corresponding pipeline solutions, the enrollment and participation incentives to be offered in these areas will be higher than those offered by the system-wide BYOT program while still ensuring the cost effectiveness of the offering in each of the targeted areas. Increased enrollment and participation incentives combined with ETO's intensified co-marketing and outreach for the smart thermostat energy efficiency and demand response programs are expected to significantly increase the uptake of both ETO's smart thermostat energy efficiency and NW Natural's BYOT demand response programs in the targeted areas.

## 12.8 Forward Looking Plan

NW Natural's Forward Looking Distribution System Plan is intended to proactively identify areas on the distribution network that may require a solution five years or more into the future, either through traditional pipeline solutions or non-pipeline alternatives (NPAs) to continue to provide reliable service to firm customers.

The 2025 Forward Looking Distribution System Plan focuses on three areas in Oregon, which are Creswell, McMinnville, and Dallas. These areas were selected because forecasted demand growth could cause the distribution system to operate above design capacity at some time in the future between 2028 and 2050. The 2024 Forward Looking Distribution System Plan included Lebanon, Oregon. After further review, it was determined that Lebanon no longer needs to be included in the plan, as current projections do not indicate that demand growth will result in capacity constraints within the current planning horizon. There are no areas in Washington identified in the Forward Looking Distribution Plan at this time, though the system is continuously being monitored.

*Figure 12.10: Peak Hour Load Forecast for Distribution Capacity Constrained Areas (No GeoDSM)*



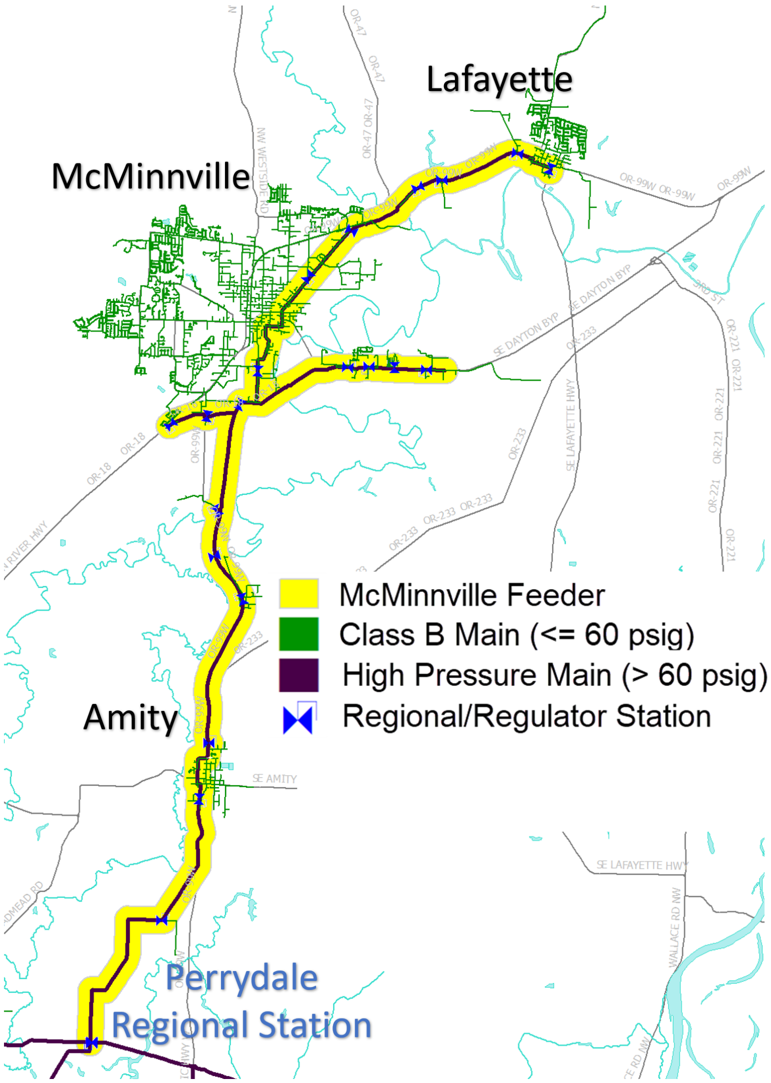

The pipeline solutions outlined in the plan are conceptual and may never be constructed. Construction of a pipeline solution is dependent on localized growth and the effectiveness of non-pipeline alternatives. These solutions will be reassessed annually, and their scope may be adjusted based on changes in demand and system performance. Available capacities provided in the Forward Looking Distribution Plan are an approximation. The values could differ depending on where the location of the demand growth occurs. A pipeline can serve higher demand growth closer to sources (Gate Station, Pressure Reducing Equipment), than demand further downstream.

NW Natural will continue to monitor system pressures in all areas of concern and determine the appropriate level of response. Should a large project be selected as the preferred solution, it will be included in the action plan of NW Natural's Integrated Resource Plan (IRP) for acknowledgement.

## 12.8.1 McMinnville

The McMinnville Feeder is a 17.2-mile, 6-inch high-pressure pipeline operating at 400 psig MAOP. The system is fed from the south from the Perrydale Regional Station. It includes two 4-inch laterals with a combined length of approximately 3.9 miles. The McMinnville Feeder provides service to Amity, McMinnville, and Lafayette. Synergi™ Gas modeling shows that the pipeline can support up to an additional 650 Th/hr of firm load. An image of the McMinnville Feeder is shown in Figure 12.11.

*Figure 12.11: McMinnville Feeder*




### *12.8.1.1 Supply Side Option*

The McMinnville Feeder has two pipeline solutions to increase distribution system capacity. Both options would increase the available capacity on the system from approximately 650 Th/hr to approximately 1740 Th/hr.

- **Option A** – Adding approximately 500 horsepower of compression along the existing pipeline between Perrydale Regional Station and Amity.
- **Option B** – Looping the existing 6-inch High Pressure Main from Perrydale Regional Station to Amity.

### *12.8.1.2 Demand Side Option – GeoDSM Non-Pipe Alternatives*

As mentioned above that NW Natural will continue to work with AWEC on recruiting large commercial and industrial customers in the interruptible rate schedule in the targeted areas, due to the huge uncertainties in the number of customers that might be enrolled and the peak load impact that might be resulting from the program, the focus of the non-pipe alternative (NPA) analysis of the demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

- **GeoTEE** – Pursuing the highly likely level of GeoTEE effort along with the corresponding implementation costs as identified in ETO's analysis.
- **BYOT DR** – Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.
- **Behavior DR** – Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

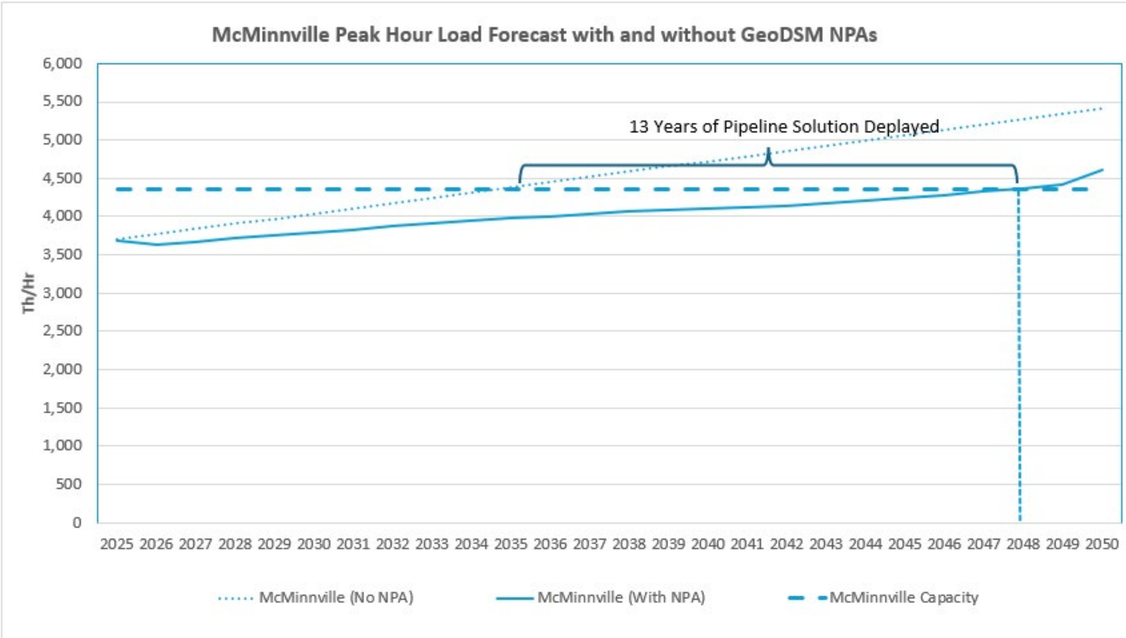
Table 12.5 summarizes the GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the McMinnville area, and Figure 12.5 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDSM NPA efforts in McMinnville from 2026 to 2048 together can cost-effectively delay the pipeline solution by 13 years. Note that the benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delayed pipeline investments in McMinnville.

*Table 12.5: GeoDSM Summary for McMinnville*

| GeoDSM | Peak Hour Load Savings, Therms/Hour | | Annual Energy Savings, Therms/Year | | Benefit/Cost Ratio |
|---|---|---|---|---|---|
| | Start Year - 2026 | End Year - 2048 | Start Year - 2026 | End Year - 2048 | |
| **GeoTEE**[147] | 23 | 540 | 25,944 | 596,712 | 4.08 |
| **BYOT DR** | 11 | 230 | 389 | 8,265 | 2.36 |
| **Behavioral DR** | 102 | 137 | 1,017 | 1,373 | 1.08 |

[147] ETO's GeoTEE efforts will start in 2027 and the peak hour load and annual energy savings in 2026 in the table represent the savings that can be achieved at the historical level of EE efforts in this area.

*Figure 12.12: McMinnville Peak Hour Load Forecast With and Without GeoDSM NPAs*



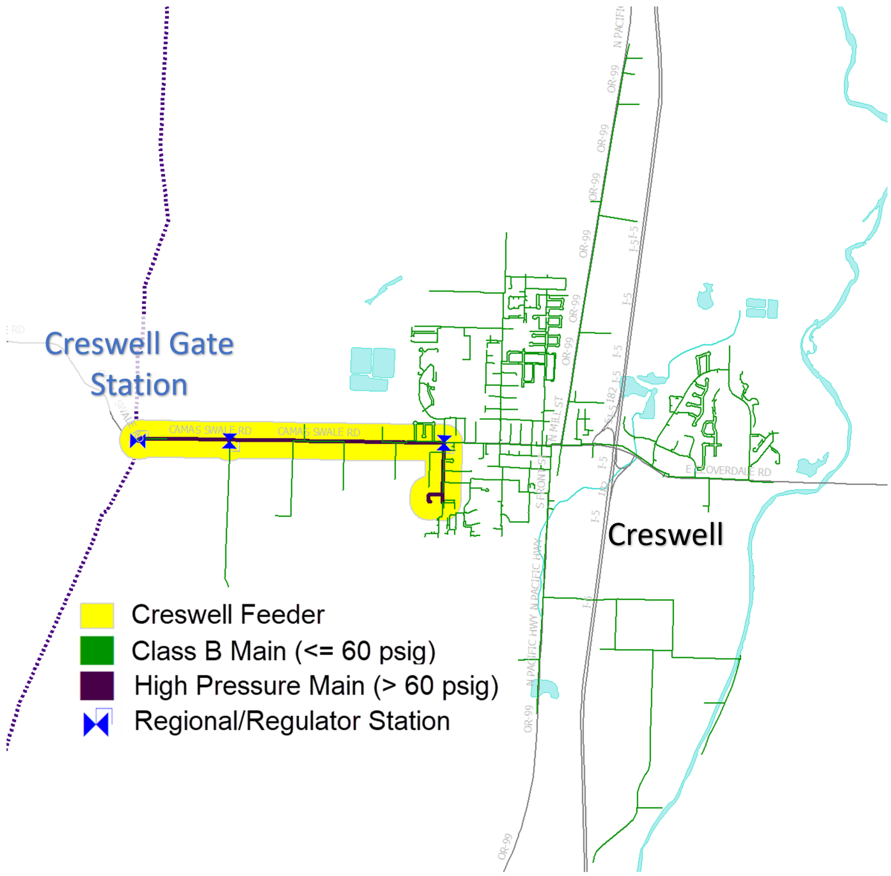

### *12.8.1.3 Preferred Option*

The distribution capacity in McMinnville is projected to be exceeded in 2035. To defer or avoid the supply side pipeline solution, the Company's preferred option is to deploy the GeoDSM NPAs as described above starting from 2026 while keeping monitoring load and system pressures and updating the GeoDSM NPA analysis annually. The GeoDSM NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure monitoring and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.

## 12.8.2 Creswell

The Creswell Feeder is a 1.9-mile-long, 3.5-inch high-pressure steel pipeline with a Maximum Allowable Operating Pressure (MAOP) of 150 psig. The system has a single source of gas, Creswell Gate Station, and supplies gas to the city of Creswell. Synergi™ Gas modeling shows that the pipeline can support up to an additional 80 Th/hr load. An image of the Creswell Feeder is shown in Figure 12.13.

*Figure 12.13: Creswell Feeder*




### *12.8.2.1 Supply Side Option*

The proposed pipeline solution for Creswell involves uprating the 1.9 miles of 3.5-ich wrapped steel from Creswell Gate Station to the end of the high pressure main. This uprate includes increasing the MAOP from 150 psig to 300 psig. The project would increase available capacity from 80 Th/hr to approximately 900 Th/hr.

### *12.8.2.2 Demand Side Option – GeoDSM Non-Pipe Alternatives*

For the same reason mentioned in the McMinnville section, the focus of the non-pipe alternative (NPA) analysis of the demand side options demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

- **Historical EE** – No GeoTEE effort is recommended by ETO given the time and resource constraints in this area; but the historical level of EE effort will be pursued along with the corresponding implementation costs as identified in ETO's analysis.
- **BYOT DR** – Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.

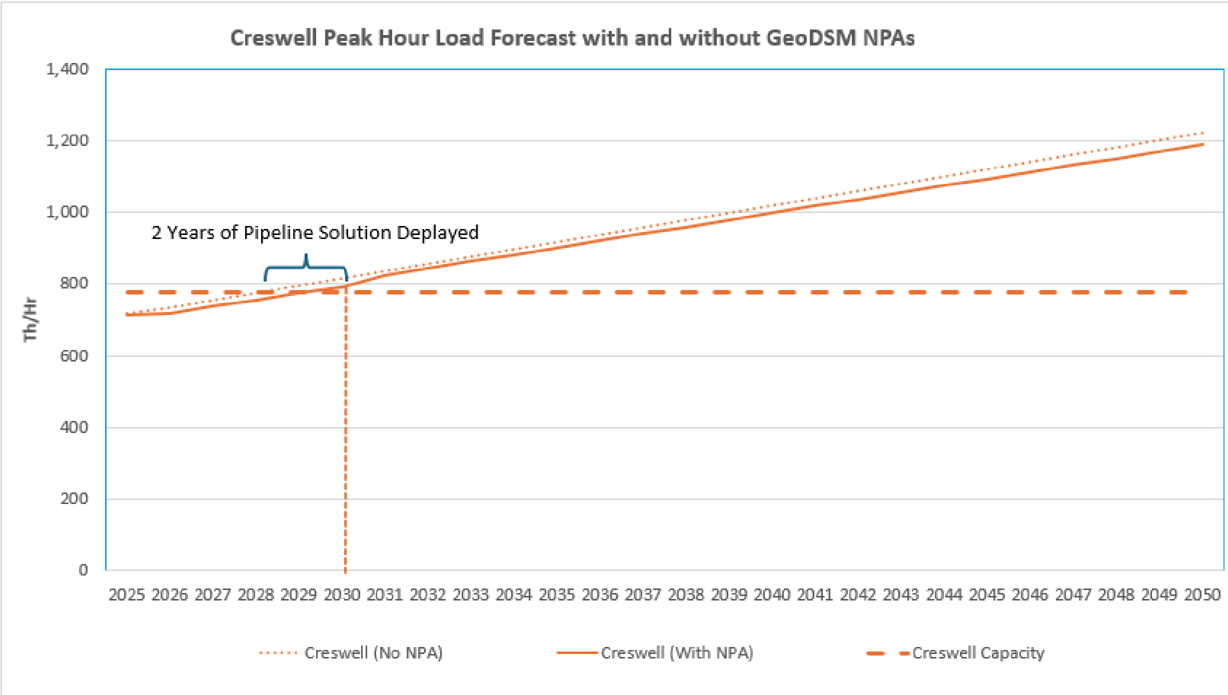
- **Behavior DR** – Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

Table 12.6 summarizes the GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the Creswell area, and Figure 12.14 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDR efforts in Creswell from 2026 to 2030 together with a historical level of EE can cost-effectively delay the pipeline solution by two years. Again, the benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter XX and the time value of delaying pipeline investments in Creswell.

*Table 12.6: GeoDSM Summary for Creswell*

| GeoDSM | Peak Hour Load Savings, Therms/Hour | | Annual Energy Savings, Therms/Year | | Benefit/Cost Ratio |
|---|---|---|---|---|---|
| | Start Year - 2026 | End Year - 2030 | Start Year - 2026 | End Year - 2030 | |
| **Historical EE** | 2 | 6 | 1,726 | 5,178 | 1.54 |
| **BYOT DR** | 3 | 5 | 91 | 188 | 2.19 |
| **Behavioral DR** | 12 | 15 | 119 | 148 | 6.43 |

*Figure 12.14: Creswell Peak Hour Load Forecast With and Without GeoDSM NPAs*



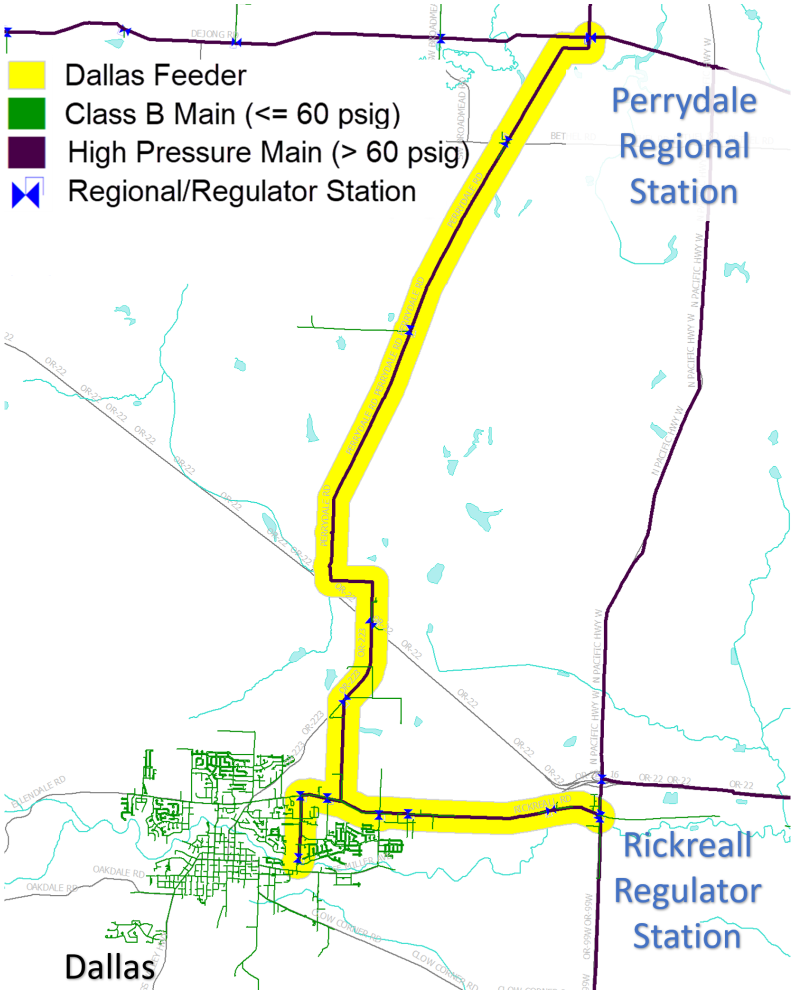

### *12.8.2.3 Preferred Option*

The distribution capacity in Creswell is projected to be exceeded in 2028 and the GeoDSM efforts can delay the pipeline solution by only two years to 2030. The Company's preferred option in this area is to deploy the GeoDSM NPAs and make all necessary preparations for the pipeline solution as described above starting from 2026 since both the GeoDSM NPAs and the pipeline solution take time to implement. In the meantime, the Company will keep monitoring the load and system pressure and update the pipeline and GeoDSM NPA analysis annually. Both the pipeline and the NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure monitoring and pipeline and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.

## 12.8.3 Dallas

The Dallas Feeder is a 6-inch high-pressure pipeline rated at 175 psig MAOP, serving the community of Dallas, Oregon. It is a bi-directional pipeline, receiving gas from both Perrydale (via the Central Coast Feeder) and Rickreall (via the Mid-Willamette Valley Feeder). System modeling indicates that, under peak-day conditions the lowest pressure on the Dallas Feeder would be approximately 115.6 psig, which is 32 pressure drop. An image of the Dallas Feeder is shown in Figure 12.15.

*Figure 12.15: Dallas Feeder*




### *12.8.3.1 Supply Side Option*

The Dallas Feeder pipeline solution includes two upgrades aimed to increase capacity to address potential growth. The first project includes replacing approximately 1100 ft of high pressure 4-inch wrapped steel with 6-inch wrapped steel. The second project is to uprate 15 miles of 6-inch wrapped steel from an MAOP of 175 psig to 300 psig. The two projects would increase the available capacity from 80 Th/hr to approximately 900 Th/hr.

### *12.8.3.2 Demand Side Option – GeoDSM Non-Pipe Alternatives*

For the same reason mentioned in the McMinnville section, the focus of the non-pipe alternative (NPA) analysis of the demand side options demand side options is on the GeoTEE, BYOT DR, and Behavioral DR.

- **GeoTEE** – Pursuing the highly likely level of GeoTEE effort along with the corresponding implementation costs as identified in ETO's analysis.
- **BYOT DR** – Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by providing enrollment and participation incentives higher than the system-wide BYOT program.
- **Behavioral DR** – Enrolling large commercial and industrial customers in the program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of $ per therm of peak hour load reduced.

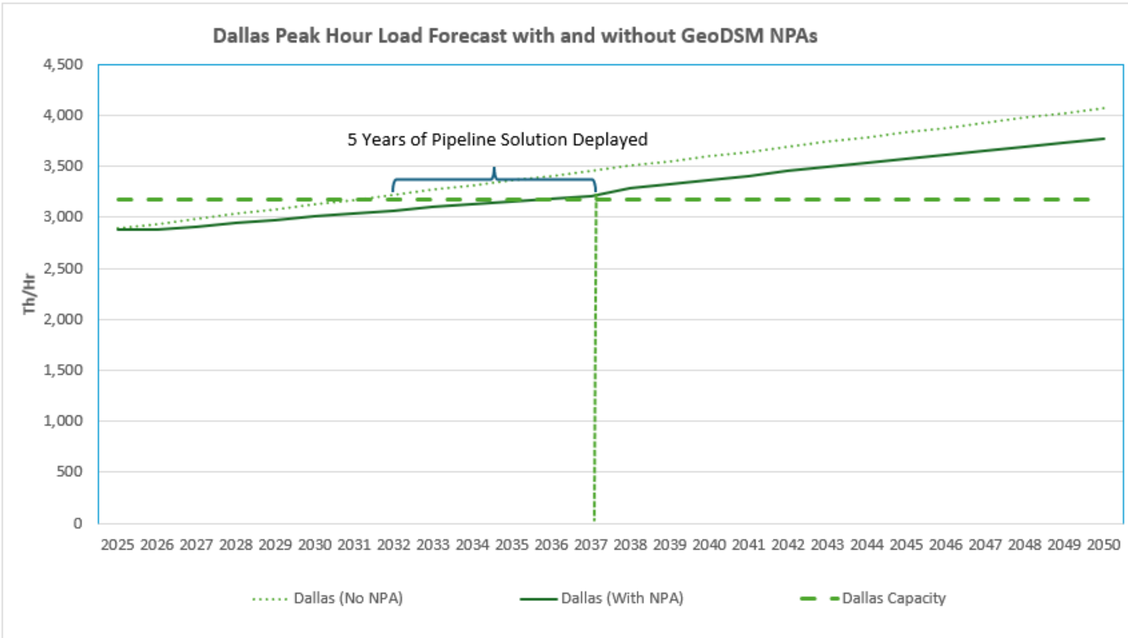
Table 12.7 summarizes the GeoDSM's timeline, peak load and energy savings and benefit/cost ratios by program in the Dallas area, and Figure 12.16 depicts the peak hour load forecasts for the area with and without GeoDSM NPA efforts. It can be seen that the proposed GeoDSM NPA efforts in Dallas from 2026 to 2037 together can cost-effectively delay the pipeline solution by five years. The benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delayed pipeline investments in Dallas.

*Table 12.7: GeoDSM Summary for Dallas*

| GeoDSM | Peak Hour Load Savings, Therms/Hour | | Annual Energy Savings, Therms/Year | | Benefit/Cost Ratio |
|---|---|---|---|---|---|
| | Start Year - 2026 | End Year - 2037 | Start Year - 2026 | End Year - 2037 | |
| **GeoTEE[148]** | 13 | 159 | 13,619 | 163,430 | 4.13 |
| **BYOT DR** | 7 | 51 | 246 | 1,830 | 2.67 |
| **Behavioral DR** | 38 | 43 | 380 | 432 | 2.57 |

[148] ETO's GeoTEE efforts will start in 2027 and the peak hour load and annual energy savings in 2026 in the table represent the savings that can be achieved at the historical level of EE efforts in this area.

*Figure 12.16: Peak Hour Load Forecast With and Without GeoDSM NPAs*




### *12.8.3.3 Preferred Option*

The distribution capacity in Dallas is projected to be exceeded in 2032 and the GeoDSM efforts can delay the pipeline solution by five years to 2037. The Company's preferred option in this area is to deploy the GeoDSM NPAs as described above starting from 2026 since the GeoDSM NPAs take time to implement. In the meantime, the Company will keep monitoring the load and system pressures and update the pipeline and GeoDSM NPA analysis annually. Both the pipeline and the NPA efforts will therefore be adjusted accordingly based on the outcome of annual load and system pressure monitoring and pipeline and NPA analysis update to deliver safe, reliable and affordable services to the customers in this area.