
NW Natural®
*We grew up here.*

## Forward Looking Statement

This and other presentations made by NW Natural from time to time, may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “assumes,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects”, “will”, and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: plans; objectives; assumptions, estimates; expectations; timing; goals; strategies; commitments; future events; investments; models; forecasts; timing and amount of capital expenditures; risks and risk profile; utility system and infrastructure investment; reliability and resiliency; third-party projects; storage, pipeline and other infrastructure investments; commodity costs; competitive advantage; customer service; customer and business growth; forecasts of customers’ future energy; capacity and environmental compliance needs; projected demand-side, supply-side, and other resources; resource options; emissions; energy requirements; environmental policy; effects of the global pandemic; economic uncertainty and future economic expectations; population growth; effects of global unrest; natural gas market volatility; weather and weather volatility; local, state and federal requirements relevant to energy or climate change and NW Natural’s ability to comply with, and costs related to, such requirements, as well as the efficacy of those requirements in reducing emissions; development and delivery of renewable energy; current and potential changes to building codes; load forecasting methodology; emissions compliance options; population trends; housing trends; gas supply levels, characteristics and areas of origin; natural gas production and market dynamics; renewable natural gas and hydrogen development, availability and markets; ability to use and blend renewable natural gas and hydrogen into existing gas systems; characteristics and feasibility of end-use equipment, and innovation and timing of readiness related thereto; avoided costs; energy efficiency; environmental attributes and availability and markets relating thereto; avoided costs; system planning and modeling; business risk; gas storage development, costs, timing or returns related thereto; financial positions and performance; liquidity, strategic goals, greenhouse gas emissions, carbon savings, gas reserves and investments and regulatory recoveries related thereto, hedge efficacy, cash flows and adequacy thereof, return on equity, capital structure, return on invested capital, revenues and earnings and timing thereof, margins, operations and maintenance expense, dividends, credit ratings and profile, the regulatory environment, effects of regulatory disallowance, timing or effects of future regulatory proceedings or future regulatory approvals, regulatory prudence reviews, effects of legislation, and other statements that are other than statements of historical facts.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements, so we caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A “Risk Factors,” and Part II, Item 7 and Item 7A “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and “Quantitative and Qualitative Disclosure about Market Risk” in the Company’s most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk”, and Part II, Item 1A, “Risk Factors”, in the Company’s quarterly reports filed thereafter.

## S&P Global Commodity Insights Gas Price Forecast Disclaimer

# Table of Contents and Figures

## Introduction

**Chapter 2: Planning Environment and Environmental Policy**

**Chapter 4:**

## Chapter 8: Distribution System Planning

# Glossary

| | |
|---|---|
| AECO | Alberta Energy Company |
| AEG | Applied Economics Group |
| AGA | American Gas Association |
| AMA | Asset Management Agreement |
| ARIMA | Autoregressive integrated moving average |
| Base Case | An analytical scenario (e.g., forecast scenario) in which currently expected conditions are assumed to occur |
| Baseload demand | Refers to utility customer demand that is constant over the year |
| Bcf | A billion cubic feet |
| Biogas | Gaseous fuel, especially methane, produced by fermentation of organic matter |
| Biomethane | A naturally occurring gas which is produced by anaerobic digestion of organic matter such as dead animal or plant material, manure, sewage, organic waste, etc. |
| Boiler | A large furnace in which water-filled tubes are heated to produce steam |
| Book and Claim Accounting | A chain of custody model which recognizes that environmental attributes (e.g., RTCs) can be separated from physical product and possession of environmental attribute can be used to deliver sustainable product |
| Brown Gas | The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included |
| Btu | British thermal unit |
| Bundled RNG | RNG including the physical gas molecules and renewable thermal certificate (RTC) |
| CAGR | Compounded Annual Growth Rate |
| Capacity | The maximum load that a gas pipeline or gas storage facility can carry under existing service conditions |

| | |
|---|---|
| Cap-and-Invest Program | Section of Washington's CCA, regulated by the Department of Ecology, which sets emissions caps, allowances, and trading mechanisms |
| Carbon cap | A limit on the amount of allowable carbon produced in a given region for a defined time period |
| Carbon Cap and Trade | A market mechanism to limit carbon emissions. Carbon emissions are capped at a certain level. Allowances are provided to companies and these allowances can be traded. The market sets the price of the allowances, creating a market incentive to reduce carbon emissions |
| Carbon credits or allowances | A fixed amount of carbon emissions to be produced is set for a period of time, and allowances or credits are allocated to carbon generators. The idea is that entities producing less carbon than their allowed amount can sell their allowances to other parties who are producing more than their allowed credit allowance. Often these can be traded or re-sold |
| CCA | Washington Climate Commitment Act |
| CCA allowances | A Cap-and-Invest Program mechanism for covered entities to obtain such allowances to cover emissions not reduced within a particular compliance period |
| CCI 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." Or. Admin. R. 340-271-0020 |
| CHP | Combined Heat and Power |
| CIS | Customer Information System |
| Citygate | 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 |
| CNG | Compressed natural gas |
| $CO^2$ | Carbon dioxide |
| $CO^2e$ | Carbon dioxide equivalent |
| Common Carrier Pipeline | A pipeline that is connected to the continent-wide natural gas pipeline grid |

| | |
|---|---|
| Compliance obligation | "Total quantity of covered emissions from a covered fuel supplier rounded to the nearest metric ton of CO2e." Or. Admin. R. 340-271-0020 |
| 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 |
| CMM | Customer Management Module |
| CPI | Consumer Price Index |
| CPP | Oregon Climate Protection Program |
| CUB | Oregon Citizens' Utility Board |
| City gate | The point of delivery at which a local gas distribution company takes custody of gas from an interstate pipeline |
| Class B (pipeline system) | A pipeline system operating at 60 psig or less |
| 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. |
| 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 |
| 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 |

| | |
|---|---|
| DSM | Demand-side management |
| Dth | Dekatherm (or dekatherm) |
| 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. |
| EE | Energy efficiency<br>EE is a reduction in energy use, production, or distribution as a result of greater efficiency. |
| EFRC | Energy Frontier Research Center |
| EIA | U.S. Energy Information Administration |
| 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 |
| EPA | Environmental Protection Agency |
| EPPR | Electronic Portable Pressure Recorder |
| ERU | Emission Reduction Unit |
| ETO | Energy Trust of Oregon |
| Entitlement | An event during which gas shippers must not take delivery of more than a specified volume of gas in a day |
| Exogenous (variable) | A variable that is independent or determined outside of the model |
| FERC | Federal Energy Regulatory Commission |
| Firm (Sales, Service, Customers) | Service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. |

| | |
|---|---|
| GAP; GASP | Gas Acquisition Plan; Gas Acquisition Strategy and Policies |
| Gasco | 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 |
| GeoTEE | Geographically Targeted Energy Efficiency |
| GIS | Geographical information system |
| GHG | Greenhouse gas |
| GTI | Gas Technology Institute |
| HDD | Heating degree day |
| Hedging | Any method of minimizing the risk of price change. |
| Henry Hub | A natural gas referencing price point |
| 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 3rd 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. |
| Jackson Prairie | A gas storage facility near Centralia, Washington, contracted by NW Natural |
| LDC | Local distribution company |
| Least-cost planning | Method of meeting future energy needs by acquiring the lowest cost resources first, considering all possible means of meeting energy needs and all resource costs including construction, operation, transmission, distribution, fuel, waste |

| | |
|---|---|
| | disposal, end-of-cycle, consumer, and environmental costs |
| Levelized (cost) | Equal periodic cost where the present value is equivalent to that of an unequal stream of periodic costs (typically expressed as a periodic rate; e.g., levelized cost per year) |
| 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 |
| Mcf/day | A thousand cubic feet per day |
| MDDO | Maximum daily delivery obligation |
| MDT | A thousand dekatherms |
| MMcf/day | A million cubic feet per day |
| MMDT | A million dekatherms |
| MPH (or mph) | Velocity in miles per hour |
| MSA | Metropolitan Statistical Area: a geographical area as defined by the U.S. Office of Management and Budget (OMB) |
| $MTCO^2e$ | A metric ton 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 |
| 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 |
| Non-pipeline alternatives | Strategies to use natural gas more efficiently so that new pipeline capacity is not needed |
| 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 |
| NWIGU | Northwest Industrial Gas Users |
| 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 |
| Outage | A period, scheduled or unexpected, during which the transmission of power stops or a particular power-producing facility ceases to provide generation |
| PGA | Purchased gas adjustment |
| P2G | Power-to-gas |
| PST | Pacific Standard Time |
| PVRR (also NPVRR) | Present value of revenue requirement |

| | |
|---|---|
| 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. |
| PLEXOS® | Optimization modeling software used by NW Natural |
| PSIG | Pounds per square inch gauge |
| REC | Renewable energy certificate |
| Reference Case | An analytical scenario (e.g., forecast scenario) to which other scenarios are compared |
| RIN | Renewable identification number |
| RMSE | Root mean squared error |
| 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 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>**Washington definitions per RCW 54.04.190(6):** "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. |

| | |
|---|---|
| | "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process. |
| RPS | Renewable portfolio standards |
| RTC | Renewable thermal certificate<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) |
| Sales (service, customers) | Service provided whereby NW Natural acquires gas supply and delivers it to customers |
| SCADA (system) | Supervisory Control and Data Acquisition |
| SME panel | A panel composed of subject matter experts |
| Stochastic | The property of being randomly distributed or including a random component; a stochastic variable often feeds into a forecast, property or constraint providing a range of outcomes; contrasts with deterministic |
| Synergi$^{TM}$ | A computer-based model used to simulate the physical natural gas system |
| 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 measurement<br>1 Therm = 29.3 KWh |
| 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 |
| UPC | Use per customer |
| WACOG | Weighted average cost of gas |

| | |
|---|---|
| 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 |
| W & P | Woods & Poole forecasting service |
| WUTC | Washington Utilities & Transportation Commission |

# Common Acronyms and Abbreviations

**AECO** Alberta Energy Company

**AEG** Applied Economics Group

**AGA** American Gas Association

**AMA** Asset Management Agreement

**ARIMA** Autoregressive Integrated Moving Average

**Bcf** Billion cubic feet

**Btu** British thermal unit

**CAGR** Compound growth rate

**CCA** Climate Commitment Act

**CCI** Community Climate Investment

**CD** Contract Demand

**CHP** Combined heat & power

**CIS** Customer Information system

**CMM** Customer Management Module

**CNG** Compressed natural gas

**$CO^2$** Carbon Dioxide

**$CO^2e$** Carbon Dioxide equivalent

**CPI** Consumer Price Index

**CPA** Conservation Potential Assessment

**CPP** Climate Protection Program

**CUB** Oregon Citizens' Utility Board

**DEQ** Department of Environmental Quality

**DR** Demand response

**DSM** Demand side management

**Dth** Dekatherm

**EE** Energy efficiency

**EFRC** Energy Frontier Research Center

**EIA** US Energy Information Administration

**EPA** US Environmental Protection Agency

**ERU** Emission reduction unit

**ETO** Energy Trust of Oregon

**FERC** Federal Energy Regulatory Agency

**GAP** Gas Acquisition Plan

**GASP** Gas Acquisition Strategy and Policies

**GIS** Geographic Information Systems

**GHG** Greenhouse gas

**GTI** Gas Technology Institute

**HDD** Heating degree day

**IRP** Integrated Resource Plan

**LDC** Local distribution company

**LNG** Liquefied natural gas

**MAOP** Maximum allowable operating pressure

**MAPE** Mean absolute percentage error

**Mbtu -** Thousand British thermal unit

**Mcf** Thousand cubic feet

**MDDO** Maximum daily delivery obligation

**MDT** Thousand dekatherms

**MMbtu** Million British thermal unit

**MMcf** Million cubic feet

**MMDT** Million dekatherms

**MPH** Miles per hour

**MSA** Metropolitan Statistical Area

**NEEA** Northwest Energy Efficiency Alliance

**NGL** Natural gas liquids

**NWIGU** Northwest Industrial Gas Users

**NWGA** Northwest Gas Association

**NWPCC** Northwest Power Council

**NWPL** Northwest Pipeline

**NPVRR (also PVRR)** Net present value revenue requirement

**ODOE** Oregon Department of Energy

**OEA** Oregon Office of Economic Analysis

**OFO** Operational flow order

**OLIEE** Oregon Low Income Energy Efficiency

**OPUC** Oregon Public Utility Commission

**PGA** Purchased Gas Agreement

**P2G** Power-to-gas

**PSIG** Pounds per square inch gauge

**PST** Pacific Standard Time

**REC** Renewable Energy Certificate

**RIN** Renewable Identification Number

**RMSE** Root mean squared error

**RNG** Renewable Natural Gas

**RPS** Renewable Portfolio Standards

**RTC** Renewable Thermal Certificate

**SCADA** Supervisory Control and Data Acquisition

**SME** Subject matter expert

**T-DSM** Targeted demand side management

**UPC** Use per customer

**WACOG** Weighted average cost of gas

**W & P** Woods and Poole forecasting service

**WUTC** Washington Utilities and Transportation Commission

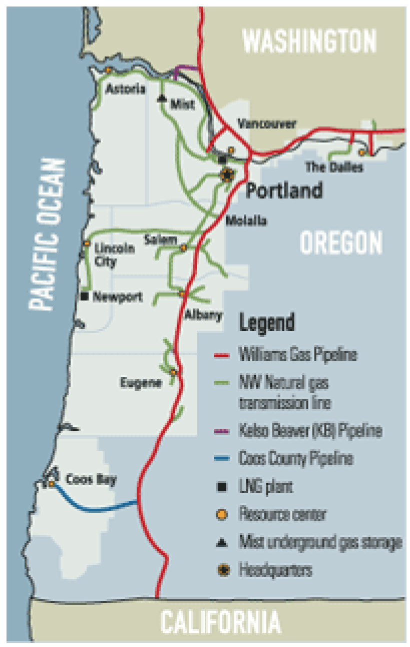
# Chapter 1
# Executive Summary

## 1.1 Overview

### 1.1.1 About NW Natural

NW Natural is a natural gas local distribution and storage utility headquartered in Portland, Oregon with a 163-year history. NW Natural serves approximately 2.5 million people in Oregon and Washington via nearly 800,000 customer accounts. The service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, much of the Oregon Coast, and a portion of the Columbia River Gorge. Approximately 89% of NW Natural's customers reside in Oregon, with the other 11% in the state of Washington. Residential customers account for roughly 90% of our customer accounts.

**Figure 1.1: NW Natural's Service Territory**



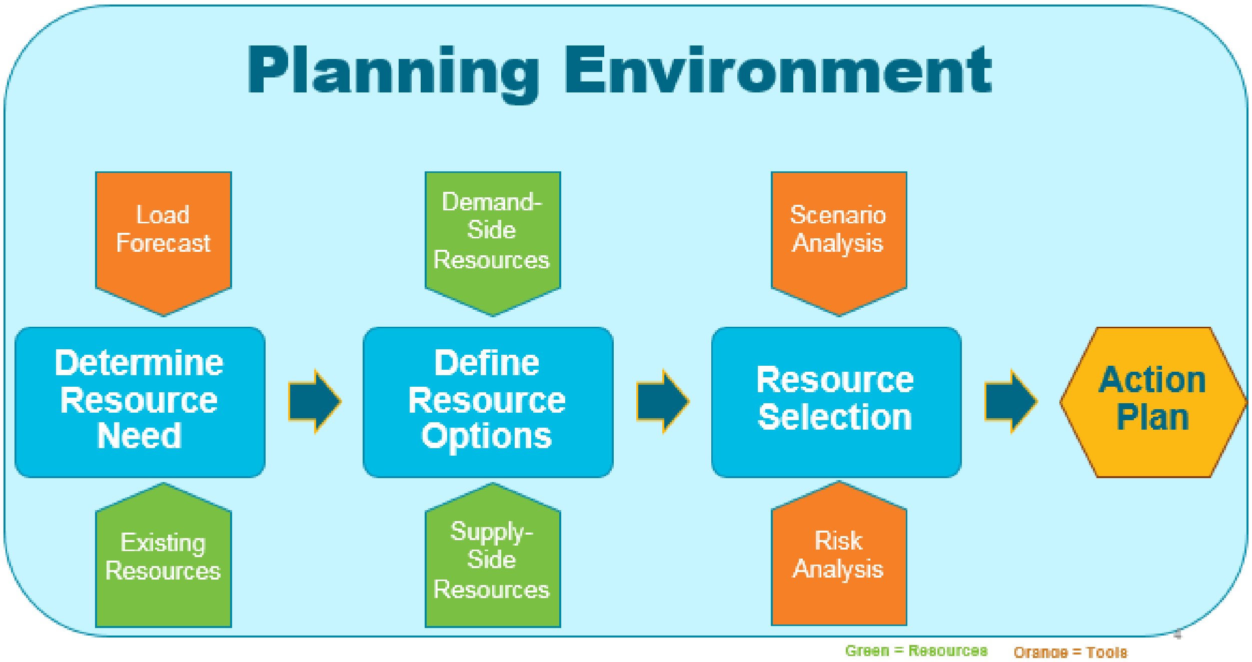

### 1.1.2 IRP Planning Process

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

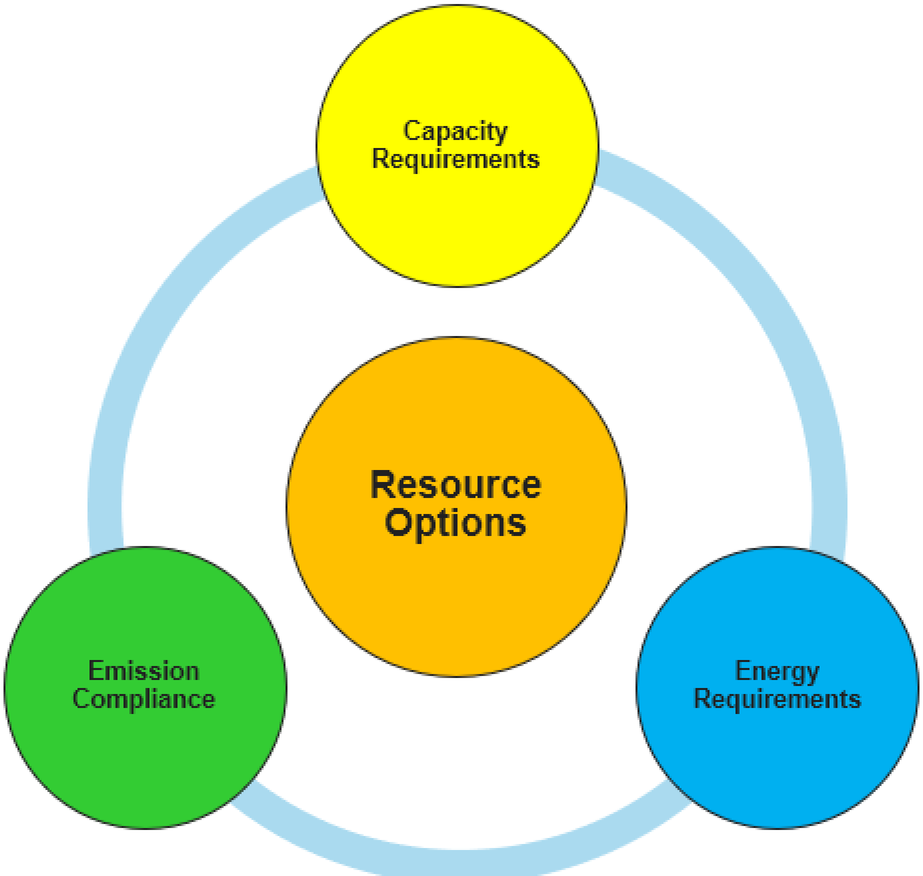
The IRP is the result of a rigorous analytical process that follows three broad steps:
1) forecasting our customers' future energy, capacity, and environmental compliance needs; 2) determining the options available to meet those needs, inclusive of both resource options that

help reduce the amount of gas our customers use (demand-side resources) and options that help us serve their natural gas needs (supply-side resources); and 3) identifying the portfolio of resources with the best combination of cost and risk for our customers (see Figure 1.2).

**Figure 1.2: Integrated Resource Planning Process**




NW Natural conducts this involved analytical process to ensure that we have adequate gas supply to meet customer needs on each day and across a year (energy planning) and during the coldest days we might experience (system capacity planning), that we can distribute the gas we bring onto our system so that each of our customers can be served reliably (distribution system planning), and that we acquire resources that will allow us to comply with environmental compliance laws and rules (environmental compliance planning).




Given the iterative nature of IRPs through time, this IRP should not be viewed as a "set it and forget it" plan, but rather a snapshot of the resource portfolio that shows as the "least cost-least risk" way to meet customers' needs going forward with the information currently available. While each IRP has a long planning horizon the primary output of each IRP is the Action Plan, which details the activities we propose taking before the next IRP (the next two to four years). As such, the actions detailed in the Action Plan are the near-term activities that are needed to serve customer needs now while allowing the utility to remain on a path that supports longer-term needs, noting that the next IRP will also include an Action Plan that will rely upon updated analysis.

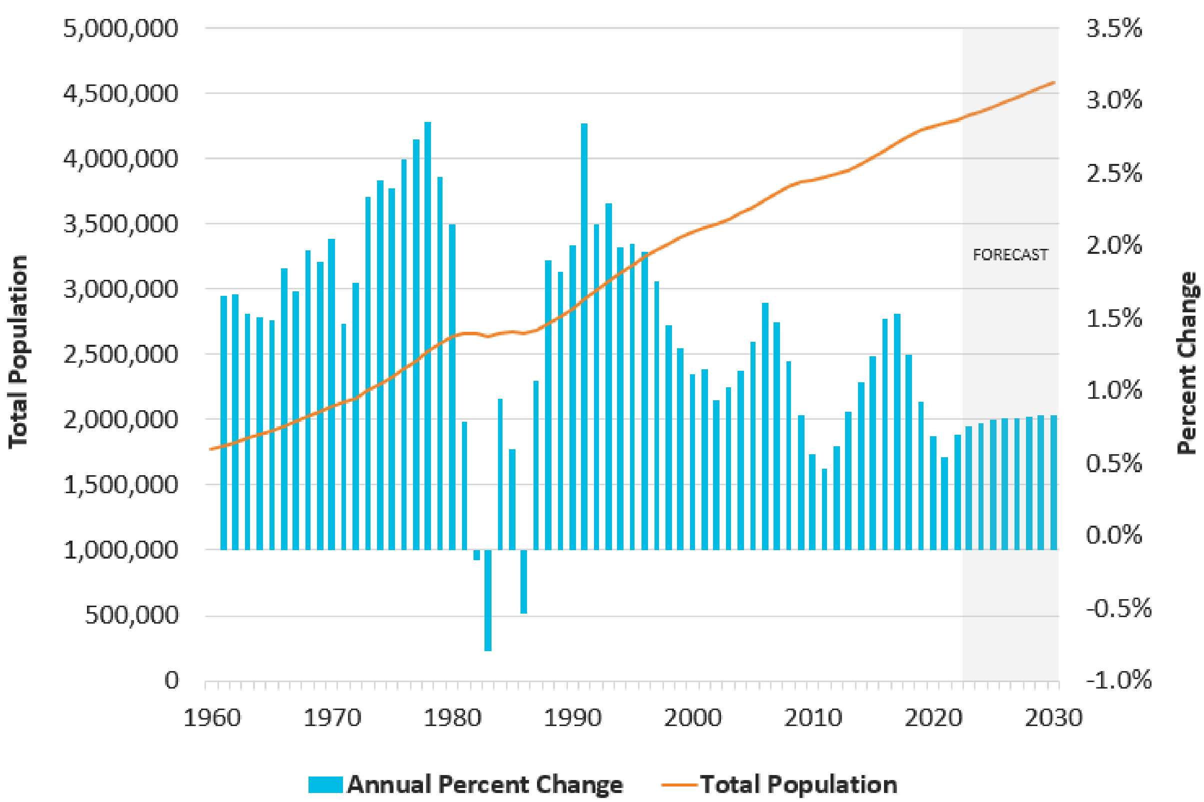
## 1.2 Planning Environment

Broader market and policy conditions and developments influence our customer's gas needs and the resource options that are suitable for us to serve those needs. While the planning environment presents analytical challenges and uncertainty in every IRP, the combination of the dynamic environmental policy associated with the energy transition in the Pacific Northwest, the current uncertainty in energy markets and the broader economy, and adjustments associated with the COVID-19 pandemic make the current planning environment particularly challenging.

### 1.2.1 Economic Outlook and Energy Markets

The broader economy is an important driver of the expected customer growth and gas use of NW Natural customers. When NW Natural completed its last IRP in 2018 our service territory, like the rest of the United States, was roughly a decade into the recovery from the Great Recession of the 2007-2009 period. While the 2018 IRP did not contemplate the COVID-19 pandemic or the current environment of high inflation and the acuteness of the housing shortage in our service territory, the customer growth projected in the 2018 IRP has largely materialized. As we draft this IRP a high level of economic uncertainty has settled on the Pacific Northwest, the United States, and the globe. While employment in NW Natural's service territory has largely recovered to pre-pandemic levels, high inflation, increasing interest rates, housing affordability, a potential recession on the horizon, and living preferences in the context of less employees tied to an office changed by the pandemic all could impact NW Natural customer growth and residential, commercial, and industrial gas usage moving forward. These and other factors have slowed expected population growth in our service territory.

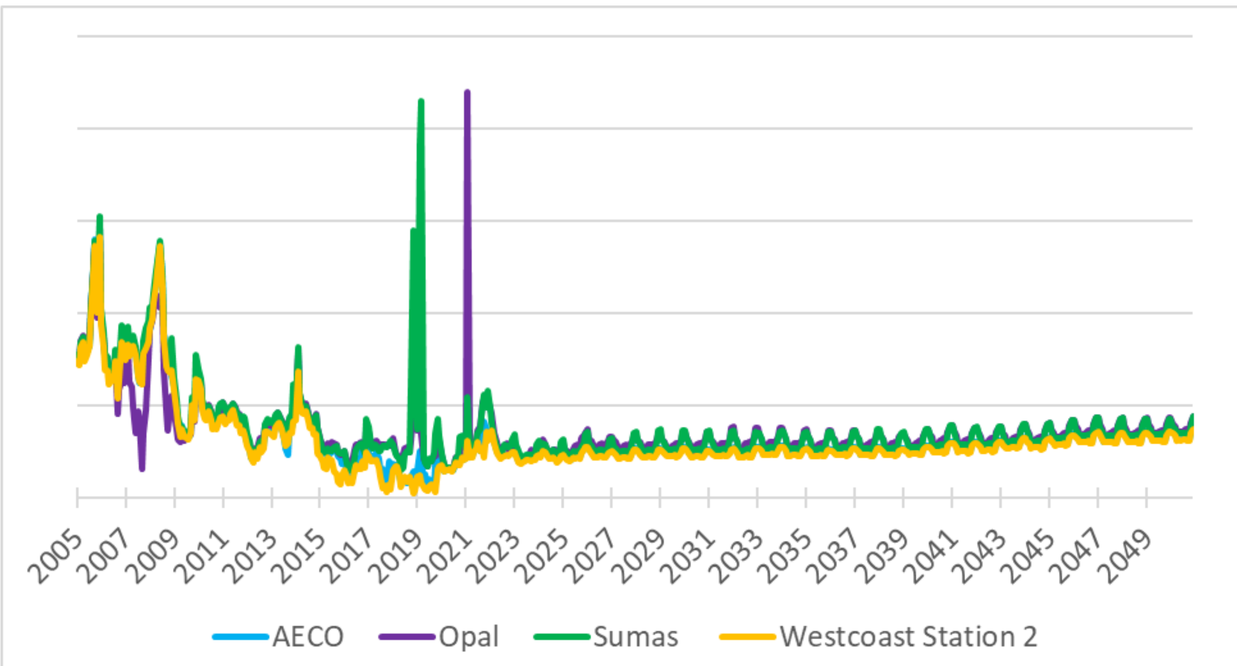
**Figure 1.3: Oregon Population Growth Slowing**




*Source: U.S. Census Bureau, Portland State University Population Research Center, Oregon Office of Economic Analysis.*

While the conventional natural gas markets NW Natural purchases gas on behalf of our customers are currently experiencing prices higher than in recent years due primarily to the shock to global energy markets due largely to Russia's invasion of Ukraine, prices of conventional gas are expected to return to levels consistent with prices in recent years over the medium- and long-term. However, while long-term expectations in conventional gas prices have not changed substantially compared to the 2018 IRP, limited capacity in regional and national natural gas infrastructure is driving an increase in price *volatility*, particularly during extreme weather events when NW Natural customers' gas needs are highest. Market dynamics suggest this current environment of more volatile prices during extreme weather is likely to continue, even as prices fall back to those in line with recent years.

**Figure 1.4: Historical Natural Gas Prices and Forecasts by Trading Hub[1]**




## 1.3 Environmental Policy

The single largest driver of change in this IRP is climate policy established in Oregon and Washington in recent years, and uncertainty about potential additional policies that could impact NW Natural's resource planning. NW Natural has implemented changes over recent IRP cycles to assess and evaluate low-GHG emissions supply resources, forecast emissions, and analyze demand- and supply-side resources on an apples-to-apples basis within the context of

[1] Source: ©2022 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

not only energy needs but also GHG emissions. These innovations, along with new analytical tools developed for this IRP, are needed to evaluate customer needs given newly established climate policy under which for the first time, NW Natural is a covered entity with compliance obligations under GHG emissions cap programs. Also, while NW Natural plans its resources on a service-territory wide basis for energy and capacity needs to the benefit of customers in both Oregon and Washington, differing climate policy in the two states requires that our emissions planning be conducted at the state level.

### 1.3.1 Climate Policy Enacted Since Last IRP

#### *Oregon*

1. **SB 98-** Passed in 2019 SB 98 encourages the development of renewable natural gas (RNG) and allows natural gas utilities to procure RNG at the following voluntary targets as a percentage of natural gas sales with:

| Year | RNG Target (% of gas sales) |
|---|---|
| **2020-2024** | **5%** |
| **2025-2029** | **10%** |
| **2030-2034** | **15%** |
| **2035-2039** | **20%** |
| **2040-2044** | **25%** |
| **2045-2050** | **30%** |

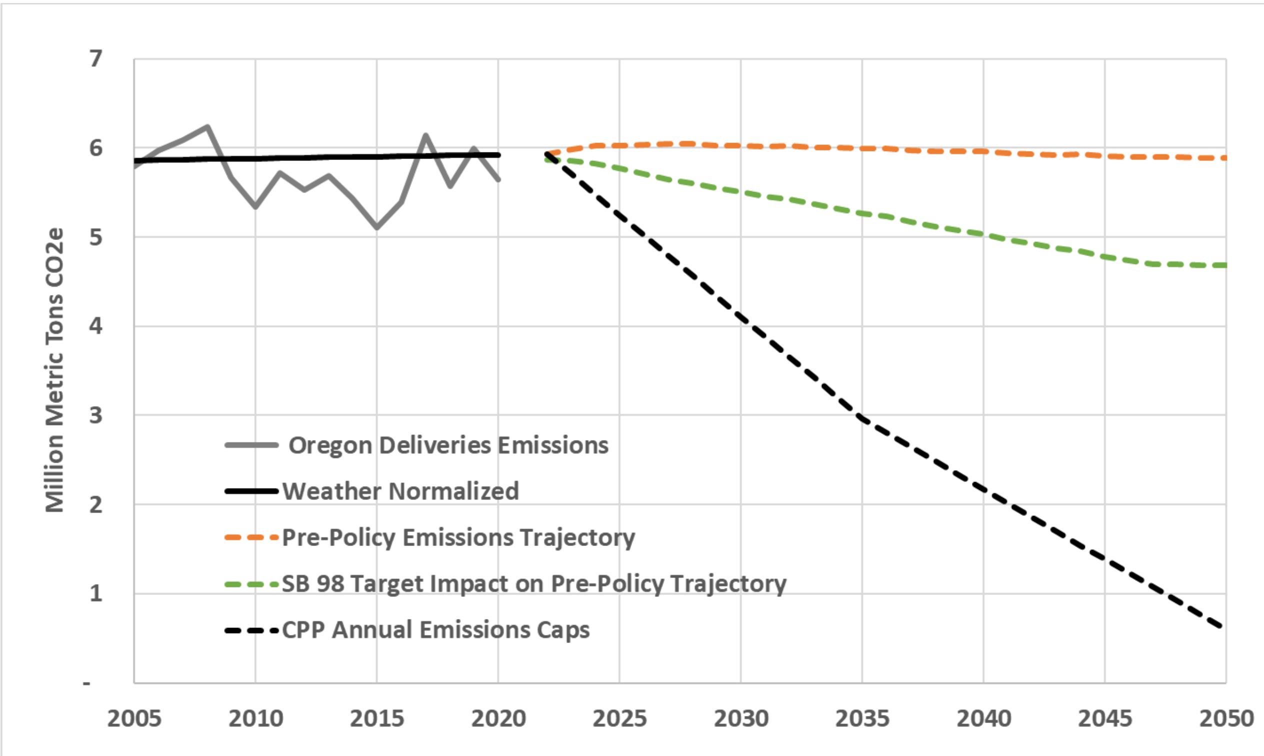
   Rules for program implementation were established at the Oregon Public Utility Commission in 2020 and NW Natural has begun delivering RNG to its customers for the targets in SB 98. The law states that it may not be allowed to continue to pursue additional RNG qualified investments if the incremental cost of RNG exceeds 5 percent of total revenue requirement in a given year.

2. **Climate Protection Program (CPP)-** GHG emissions cap program established with an initial compliance year of 2022 administered by the Oregon Department of Environmental Quality (ODEQ). The CPP was established from direction from Executive Order 20-04 issued by Gov. Brown in 2020. The program includes roughly half of the state’s emissions and primarily covers the transportation and natural gas utility sectors. The CPP has three-year compliance periods and sets annual emissions compliance limits for natural gas utilities and emissions associated and establishes gas utilities as the covered party for the emissions associated with the use of gas on utility transportation

rate schedules. The CPP is not a typical cap-and-trade system that include state-sanctioned allowance auctions.

Figure 1.5 shows the expected impact of SB 98 and the CPP relative to a pre-policy emissions trajectory to show the requirements of the CPP relative to historical trends and detail the emissions reductions requirement that is a key driver of the activities in this IRP.

**Figure 1.5: NW Natural OR Emissions- Historical Trend and Impact of SB 98 and CPP**




*Washington*

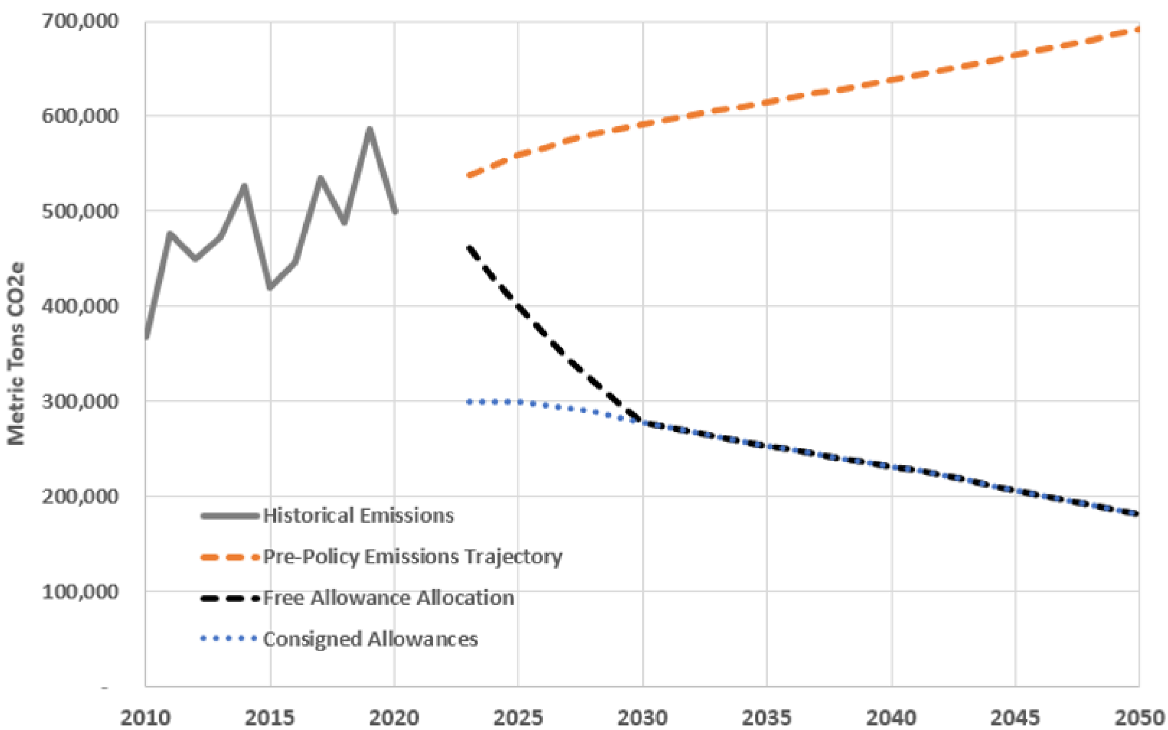
1. **HB 1257**- Passed in 2019. Established a requirement for natural gas utilities to establish a voluntary renewable natural gas option for customers, conduct energy efficiency forecasts (or conservation potential assessments (CPAs)) with economically incented targets, and use the social cost of carbon for resource planning.

2. **Climate Commitment Act (CCA)-** Passed in 2021. Directs establishment of a cap-and-invest program with similar provisions as the trading program currently in practice in California. The cap-and-invest program is currently in rulemaking. Covered parties need to demonstrate they have compliance instruments equal to their emissions over 4-year compliance periods. The program will establish a state-sanctioned allowance trading program and provides free and consigned emissions allowances to natural gas utilities

for some of their customers' expected emissions. Gas utilities are established as the point of regulation for most customers on gas transportation schedules.

3. **Building Codes Updates-** Residential building codes were updated in 2018 and commercial codes in 2022. Both updates made it more challenging to meet energy and emissions standards with the most common natural gas equipment installed in homes and businesses today.

**Figure 1.6: NW Natural WA Emissions- Historical Trend and Free Allowances in CCA**




For gas utilities the climate policies established since the filing of our last IRP are transformative policies that have generated transformative changes in NW Natural's resource planning and the Action Plan in this IRP. In fact, waiting for the OR-CPP rules to be finalized was the primary driver of NW Natural delaying its IRP until 2022. While these programs have provided certainty by establishing emissions reduction requirements with natural gas utilities as covered parties, they also create substantial uncertainty in resource planning and a heightened focus on resources that can help reduce GHG emissions.

Furthermore, there is still substantial policy uncertainty given that additional local, state, or federal climate policies are currently being considered could restrict growth and incent electrification. This policy uncertainty manifests in key planning assumptions important to conducting IRP analysis and requires different tools to analyze in detail outcomes that represent large changes from current trends.

The climate policies enacted since our last IRP, current uncertainty, and stakeholder feedback though the IRP process were the impetus for the following changes in this IRP:

1. Switching to the PLEXOS software for the resource planning optimization model
    - The change to the far more flexible PLEXOS software allowed NW Natural to develop the complex model needed to conduct robust emissions compliance planning to develop appropriate strategies for emissions compliance in both Oregon and Washington.
2. More detailed assumptions about low-GHG emitting resources
    - While NW Natural has analyzed both low carbon supply-side (e.g. RNG, clean hydrogen, etc.) and demand-side (e.g. natural gas heat pumps) resources in prior IRPs, these resources did not show as cost-effective resources in the near term given that we did not have authority to procure these resources if they were more expensive than conventional gas. Emissions cap programs change this dynamic and put greater reliance on understanding these resources in as much detail as is possible.
3. Change in load forecasting methodology
    - Given the transformative emissions policies that have been established and the current policy uncertainty, we have decided it is no longer appropriate to project forward historical trends to project our customers' needs. We have deployed forecasting techniques that project a change from historical trends. Additionally, we have modeled dual-fuel (or hybrid) gas-electric space heating for the first time in this IRP.
4. Including transportation schedule loads in our optimization modeling
    - In previous IRPs NW Natural's gas supply and emissions planning did not include loads on gas transportation rate schedules (though transportation loads were included in distribution system planning) since NW Natural does not need to supply (only distribute) gas to these customers. However, given that gas utilities were made the point of regulation for transportation schedule emissions in both the OR-CPP and WA-CCA it is required that these loads be included in our resource modeling to appropriately model emissions compliance.
    - Furthermore, given that there are not currently utility affiliated energy efficiency programs that serve transportation schedule customers there is discussion in both Oregon and Washington about establishing energy efficiency programs for transportation schedule customers to be part of the utilities'

emissions compliance options. In anticipation that energy efficiency programs for transportation customers might be established, and to better understand what cost-effective energy efficiency might be available to contribute to emissions compliance obligations, NW Natural had an independent consultant conduct the CPA for its transportation customers. Like existing energy efficiency programs, this CPA showed meaningful cost-effective savings in the context of compliance with the OR-CPP and WA-CCA.

To account for the uncertainty detailed above, utilizing insights and recommendations from stakeholders NW Natural developed multiple scenarios to understand the least-cost resource portfolio under a wide range of "what if" potential futures to supplement the reference case. Complying with the provisions of the OR-CPP and the WA-CCA is required of all scenarios.

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|---|
| **2022 IRP Scenarios- Summary Version** | | **Base Case - Balanced Approach** | **Carbon Neutral by 2050** | **New Direct Use Gas Customer Moratorium in 2025** | **Building Electrification** | **RNG and H2 Production Tax Credit** | **Limited RNG Availability** | **Supply-Focused Decarbonization** |
| **Demand-Side** | **Customer Growth** | Current Expectations | | No New Customers After 2025 | | Current Expectations | | |
| | **Space and Water Heating Equipment** | Moderate gas powered heat pump and hybrid heating adoption | | High electrification of existing residential and small commercial load | Full electrification of existing residential and small commercial load by 2050 | Moderate gas heat pump and hybrid heating adoption | | No gas powered heat pumps and low levels of hybrid heating |
| | **Industrial Load Efficiency** | Moderate increase | High increase | Moderate increase | | | | Limited increase |
| | **Building Shell Improvement** | Energy Trust projection | Energy Trust high sensitivity projection | Ajusted Energy Trust projection | | Energy Trust projection | | |
| **Supply-Side** | **Renewable Natural Gas** | Moderate availability and cost assumption | Moderately-high availability and moderate cost assumption | Moderate availability and cost | | Moderate availability and low cost to customers | Low availability and moderately high cost | Moderate availability and cost assumption |
| | **Hydrogen** | Moderate blending and dedicated system deployment allowed; moderate cost assumption | | | | | | |
| **OR- Community Climate Investements** | | Costs and limits defined in CPP rule | | | | | | |

## 1.4 Determining Resource Needs

### 1.4.1 Energy and Capacity Needs

On an annual basis, NW Natural's sales load[2] consists predominantly of space heating. During peak conditions, sales load and total deliveries are driven by space heat. Because of the needs for space heating, our loads are very seasonal and have peaks that are much higher than average daily loads. After adjusting for expected energy efficiency acquisition over the planning

[2] "Sales" load is a bundled service where NW Natural provides a bundled service that includes both the natural gas commodity and delivery services, whereas "transportation" load does not include sale of the natural gas commodity, simply delivery of the gas purchased by another gas supplier

horizon, peak capacity needs are expected to grow 0.4% annually over the planning horizon while annual deliveries are expected to fall 1.1% annually. However, load expectations over the next 2-4 years differ with the trend out to 2050 and align closely with current trends. While these forecasts represent our base case expectations, there is uncertainty in load forecasting – particularly in the later years of the 20-year planning horizon – so expected resource decisions are tested for robustness using a wide range of peak capacity and annual load forecasts.

**Figure 1.7: Monthly Sales Load by End Use**

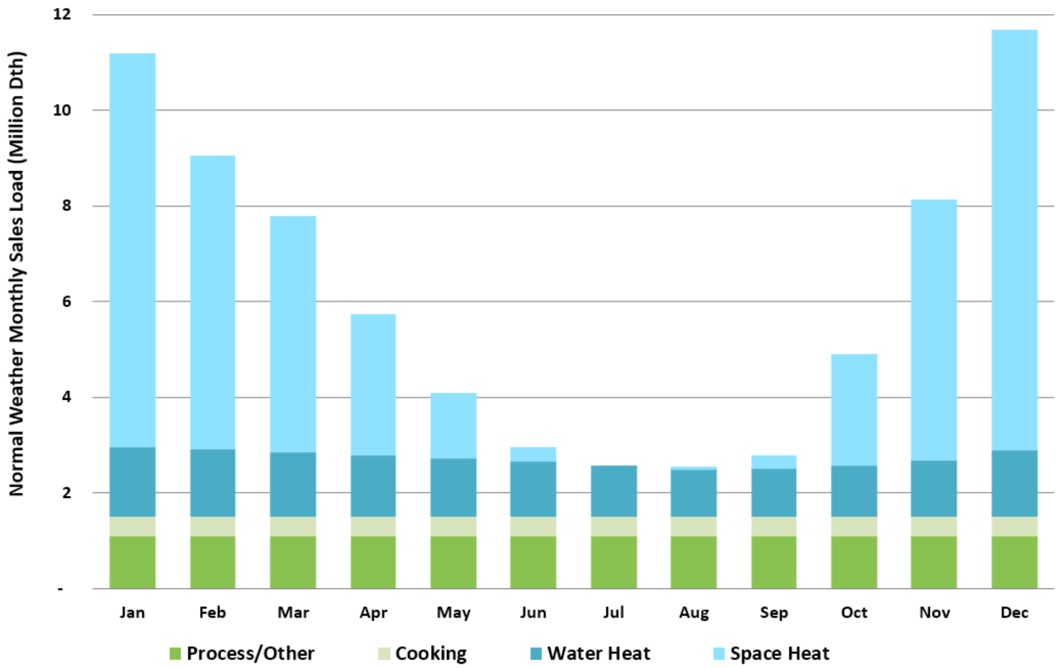
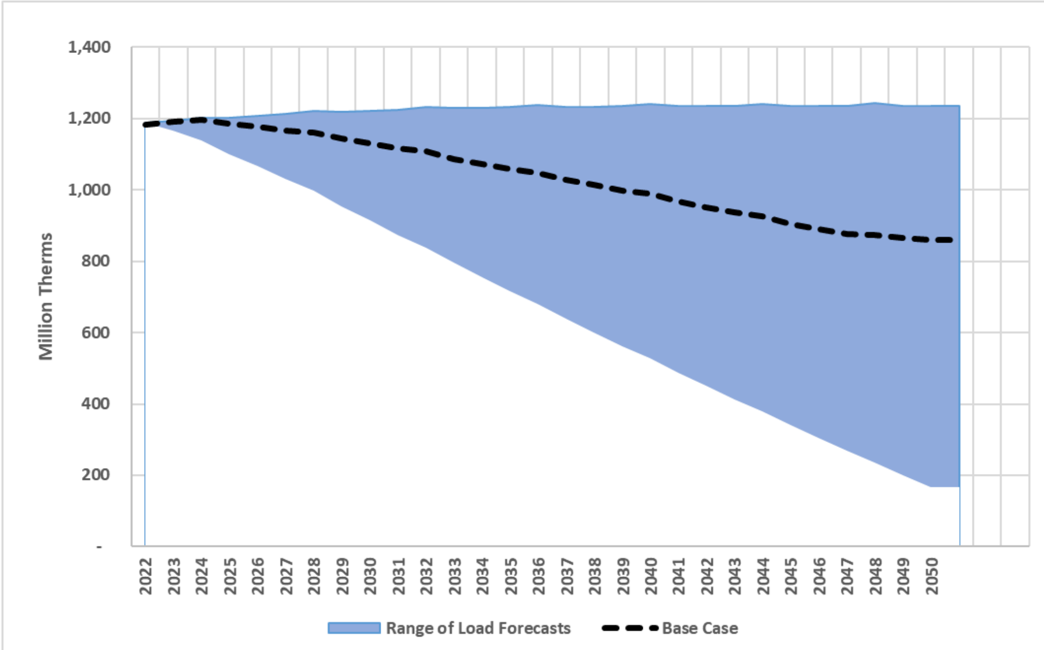
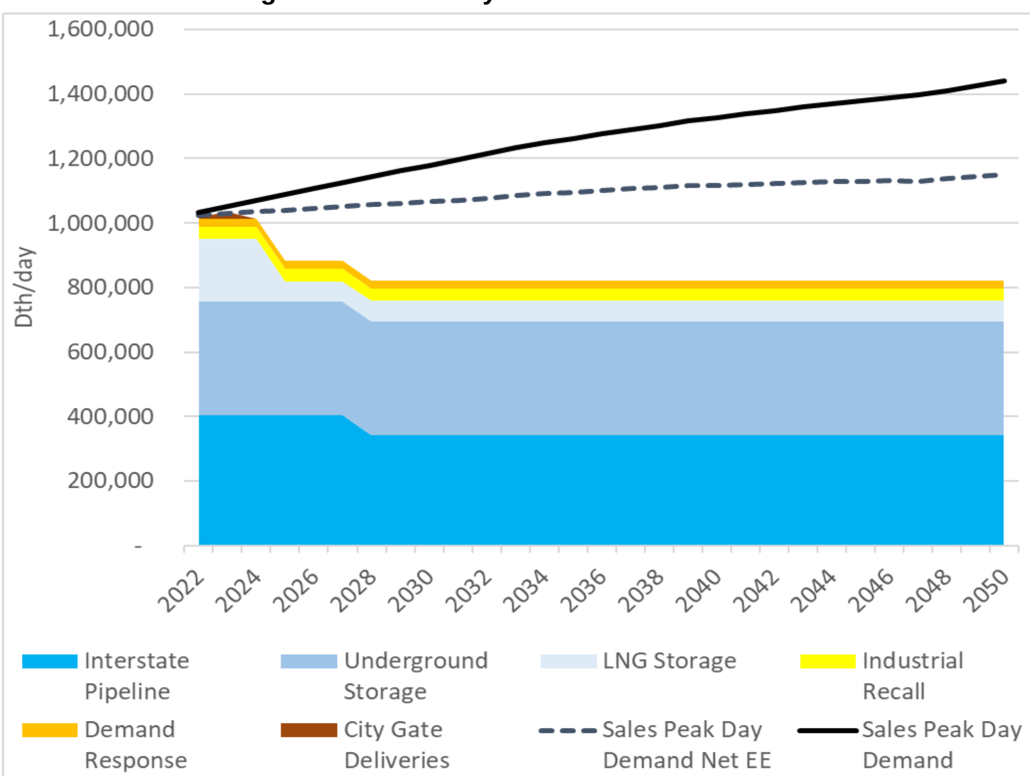


**Figure 1.8: Annual Deliveries (Including Transportation) Forecast Range**




The base case peak load forecast, in coordination with assumptions about the availability of shown above translates to the capacity load-resource balance shown in Figure 1.9.

**Figure 1.9: Peak Day Load Resource Balance**



## 1.5 Resource Options to Meet Needs

### 1.5.1 Energy and Capacity Options

Figure 1.9 shows the peak capacity load resource balance that NW Natural needs to fill to ensure that it can reliably serve customers in the event of an extreme cold event. As the figure shows, without action to replace the Cold Box at the Company's Portland liquified natural gas (LNG) facility a resource that NW Natural relies upon from to serve customers during peak periods would no longer be available and its capabilities would need to be replaced. The table below shows the capacity resource options analyzed to fill the resource deficiency depicted in for the base case Figure 1.9 and the scenarios shown above.

| Capacity Resource | Cost ($/Dth/day) | Daily Deliverability (Dth/day) |
|---|---|---|
| Mist Recall | $ 0.09 | As needed<br>Max: 203,800 |
| Newport Takeaway 1 | $ 0.14 | 16,125 |
| Newport Takeaway 2 | $ 1.00 | 13,975 |
| Newport Takeaway 3 | $ 1.41 | 12,900 |
| Mist Expansion | $ 0.62 | 100,000 |
| Upstream Pipeline Expansion | $ 2.12 | 50,000 |
| Portland LNG - Cold Box | $ 0.06 | 130,800 |
| Interstate Pipeline Looping Plus Required Mist Recall | $ 0.39 | 130,800 |
| Central" NWN System Pipeline Plus Required Mist Recall | $ 0.35 | 130,800 |

### 1.5.2 Emissions Policy Compliance Options

The options that can be used to reduce or offset emissions for compliance vary between the OR-CPP and the WA-CCA. In addition to resources like energy efficiency, RNG, clean hydrogen, and hydrogen derived synthetic gas that directly reduce emissions and contribute to compliance. Some emissions reduction options are more flexible than others and can be procured to and used for emissions compliance on short timeframes, while others require a longer lead time for construction (e.g., development of a new RNG or hydrogen project) or attrition through time (e.g., energy efficiency). The table below shows the options evaluated by NW Natural for compliance with the OR-CPP and WA-CCA.

| Emissions Compliance Options | Long-term Compliance Option | Short-term Compliance Flexibility |
|---|---|---|
| Energy Efficiency | ✓ | |
| Development RNG | ✓ | |
| RNG offtake from existing project | ✓ | ✓ |
| Development Hydrogen | ✓ | |
| Development Synthetic Gas | ✓ | |
| Community Climate Investements** | ✓ | ✓ |
| Banking | ✓ | ✓ |
| Allowance Trading at Auction* | ✓ | ✓ |
| Bilateral Allowance Trading** | ✓ | |
| Offsets* | ✓ | ✓ |

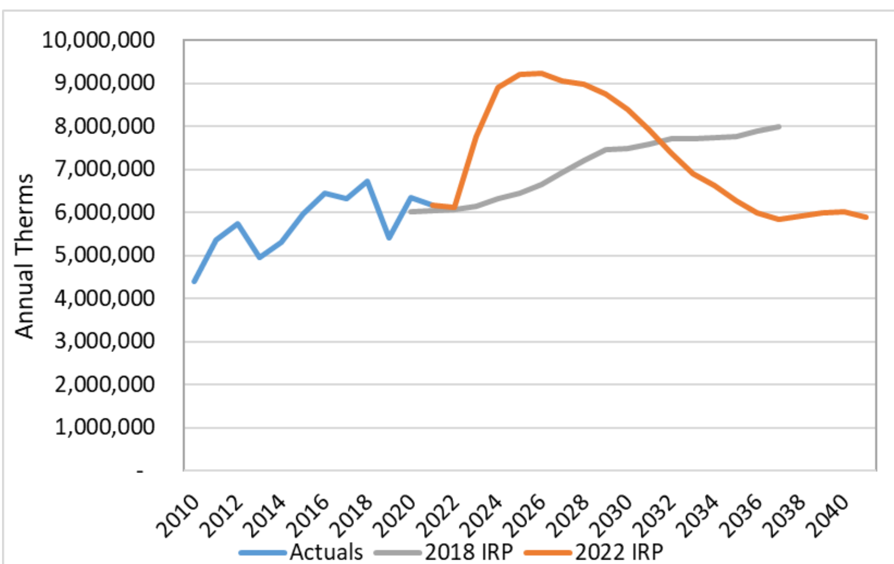
*** Only an option under Washington Cap-and-Invest**

**** Only an option under Oregon Climate Protection Program**

### 1.5.3 Energy Efficiency

The OR-CPP substantially changed avoided GHG emissions costs compared to the last IRP, leading to a sizeable increase in near- to mid-term energy efficiency expectations for customers with a bundled gas sales service, as can be seen in Figure 1.10:

**Figure 1.10: Oregon Sales Customer Energy Efficiency Forecast: 2022 vs 2018 IRP**




### 1.5.4 Supply-Side Low GHG Resources

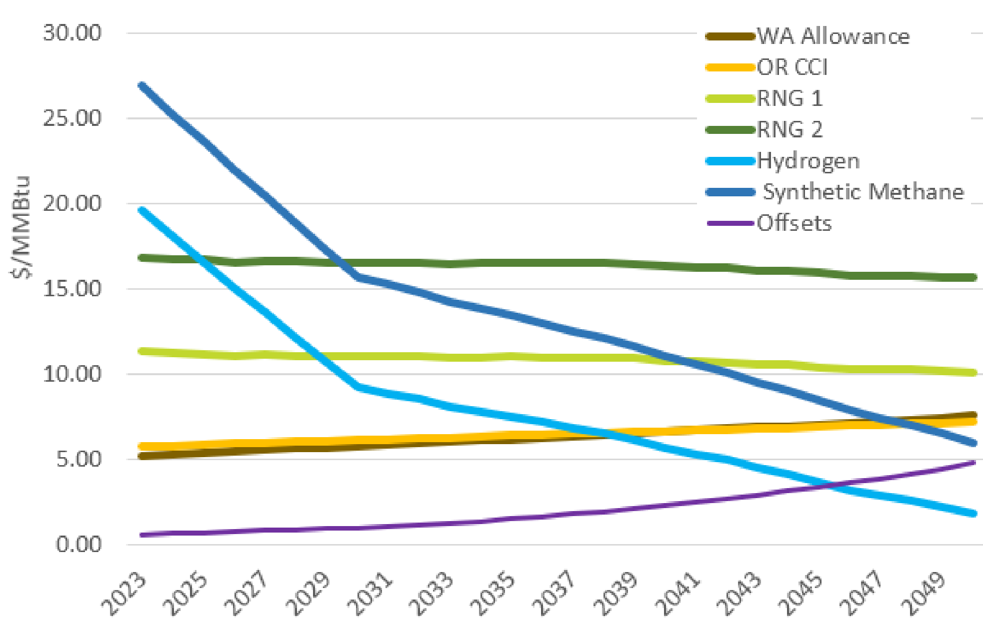
This IRP focuses on assessing the cost and availability of RNG, clean hydrogen and synthetic gas derived from clean hydrogen combined with carbon capture. Independent third parties served as the primary source for establishing many of these assumptions, where NW Natural's experience in the biofuel RNG market served a key role in understanding prices and validating availability.

### 1.5.5 Compliance Mechanisms

Both the OR-CPP and the WA-CCA have options that are allowed for compliance that are not direct emissions reductions from NW Natural customers. In simplistic terms, from NW Natural's customers' perspective, these options can be thought of as offsets. In the OR-CPP the purchase of CCIs serve this role, whereas emissions offsets and emissions allowances can be used for compliance in the WA-CCA. Prices for CCIs are set in rule, where offsets need to be acquired by covered parties in the WA-CCA and the allowance trading market, with bounds set in rule, determine the prices of allowances in the program (noting that the Social Cost of Carbon replaces the cost of allowances for resource decision-making purposes in complying with the WA-CCA).

Like other key inputs, these prices and availabilities are somewhat uncertain, and ranges for these assumptions are deployed in both scenario and stochastic risk assessment, where base case assumptions for these resources are shown in Figure 1.11.

**Figure 1.11: Emissions Compliance Option Base Case Cost Trajectories**




## 1.6 Resource Selection and Preferred Portfolio

Using the newly developed PLEXOS model least-cost portfolio optimization was conducted on the reference case, the base case, and the other scenarios. While there is substantial long-term uncertainty in the levels of capacity needed and what (and how much) emissions reduction resources are the lowest cost options for customers, this work resulted in the emergence of clear paths forward in terms of ensuring reliability (capacity planning) and meeting emissions compliance obligations in the near-term (i.e., the period covered by the action plan in this IRP). In other words, the results show that an Action Plan in this IRP can be developed that represents a low regret path forward.

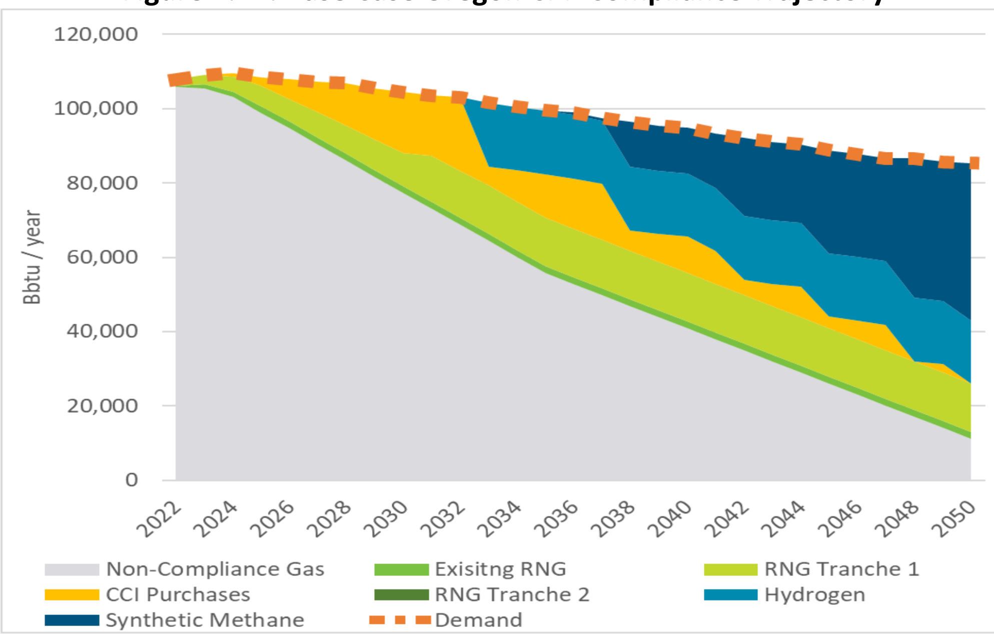
### 1.6.1 Capacity Results

All scenarios show that replacing the Cold Box at the Portland LNG facility to retain its capabilities moving forward is the cheapest way to serve customer needs. Additionally, all scenarios rely upon recalling deliverability from NW Natural's Mist storage facility to serve and expected capacity needs over the next 20 years.

### 1.6.2 Emissions Compliance Results

Figures 1.12 and 1.13 show the least-cost compliance options in the base case.

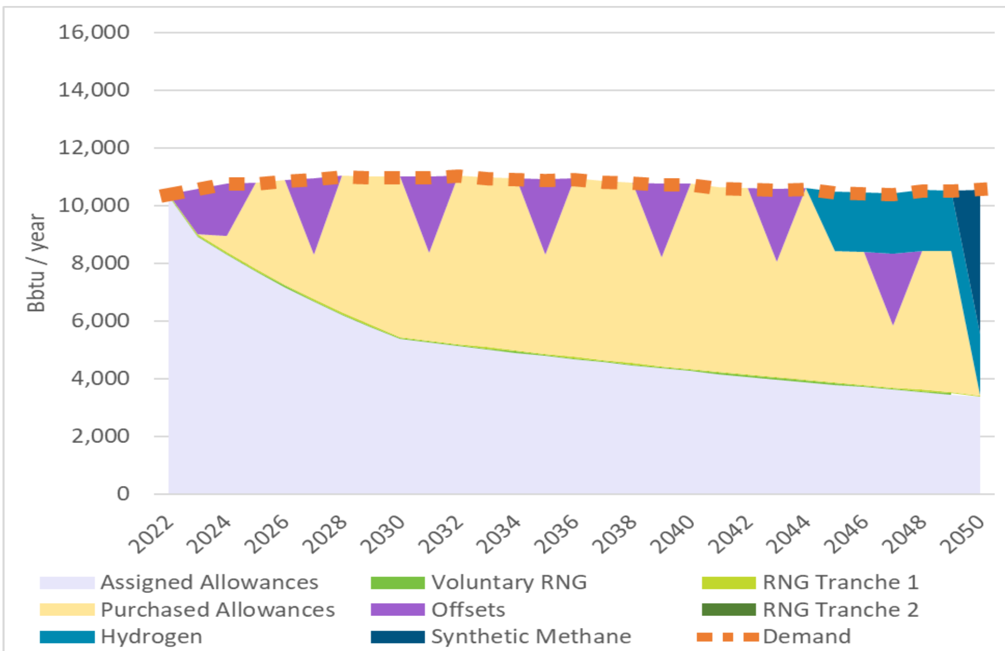
**Figure 1.12: Base Case Oregon CPP Compliance Trajectory**




The base case shows that in the OR-CPPs first compliance period (2022-2024) expected SB 98 RNG – of which biofuels are shown as the lowest cost option – make up the majority of the needed compliance action. In the base case a small amount of the lowest cost incremental option – CCIs – are needed in 2024. This result, that SB 98 RNG is supplemented by CCIs as needed is seen in all scenarios. In no scenario does the CCIs projected approach the limit for CCIs in the first compliance period. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e., not "wasted" in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs, in excess of SB 98, a robust option.

Looking at the base case and across scenarios shows a consistent trend in expected emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resources, expected to become cheaper than CCIs and WA allowances in later years in the planning horizon.

**Figure 1.13: Base Case Washington Cap-and-Invest Compliance Trajectory**




For compliance with the Washington Cap-and-Invest program the results show that it is expected that offsets are the lowest cost compliance option, and if compliance offsets can be procured at prices seen in today's market that they should be acquired to the maximum amount and used for compliance. There is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance. Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. As such a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios.

## 1.7 Action Plan Covering the Next Two to Four Years

The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment.

**Capacity Resource Action Items**

1. Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Acquire an incremental 5,000 Dth/Day of deliverability from either recalling Mist, a city gate deal, or a combination of both for each of the 2024-25 and 2025-26 gas years.
2. Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.
3. Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

**Emissions Compliance Action Items**

4. Working through Energy Trust of Oregon acquire 8.2 million therms of first year savings in 2023 and 9.4 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.
5. In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of a low sensitivity of normal weather sales load in 2024 and 2025.
6. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.
7. In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.
8. In Washington, acquire carbon offsets compliant with the Climate Commitment Act's Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance on tribal lands, and if they can be acquired for a lower

price than the program allowance price floor for years 2023 and 2024, acquire these offsets.

9. In Washington, purchase emissions allowances equal to emissions at an estimate of the 95$^{th}$ percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.

**Distribution System Action Items:**

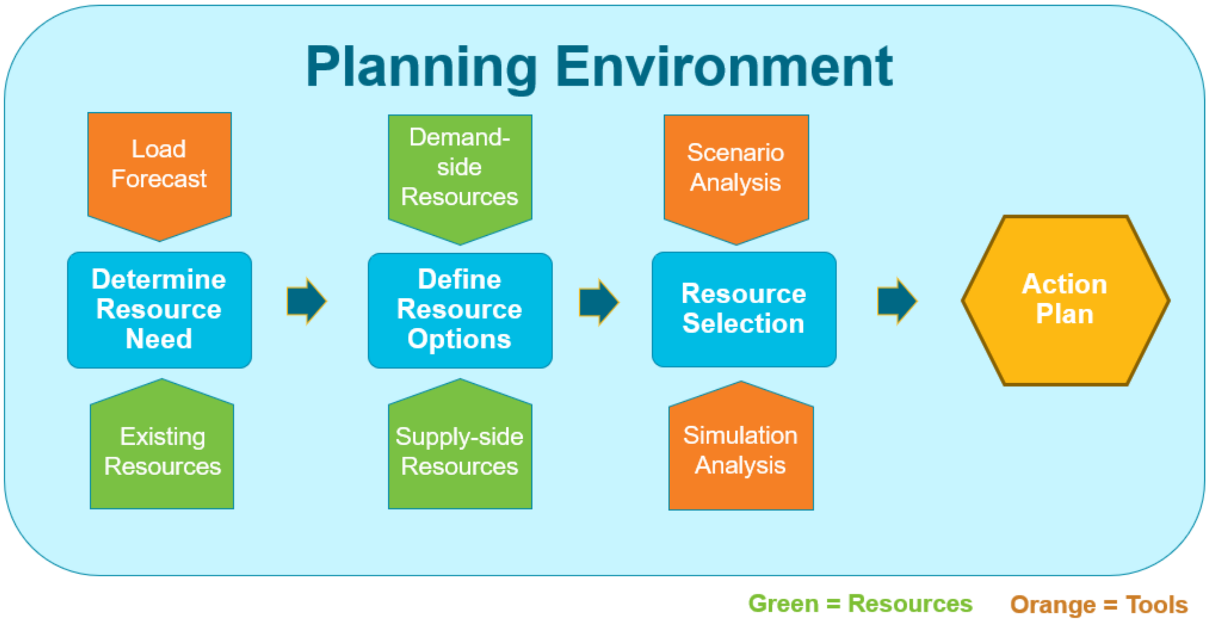
10. In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.

# Chapter 2
# Planning Environment and Environmental Policy

## 2.1 Planning Environment Overview

Fundamental in developing an IRP is an understanding of the planning environment and potential impacts to the plan now and in the future. The planning environment is a holistic review of potential risks, opportunities and important factors that can impact the IRP. As shown in Figure 2.1, it is the backdrop that informs our planning:

**Figure 2.1: Integrated Resource Planning Process Diagram**




When evaluating the planning environment NW Natural considers:

- Economic and demographic factors
- Commodity price forecast
- Environmental policy
- New technology or game changers
- Load service environment

NW Natural takes these factors into consideration for our load forecast, potential future resources, and risk analysis. These factors are discussed in more detail below.

## 2.2 Economic and Demographic Factors

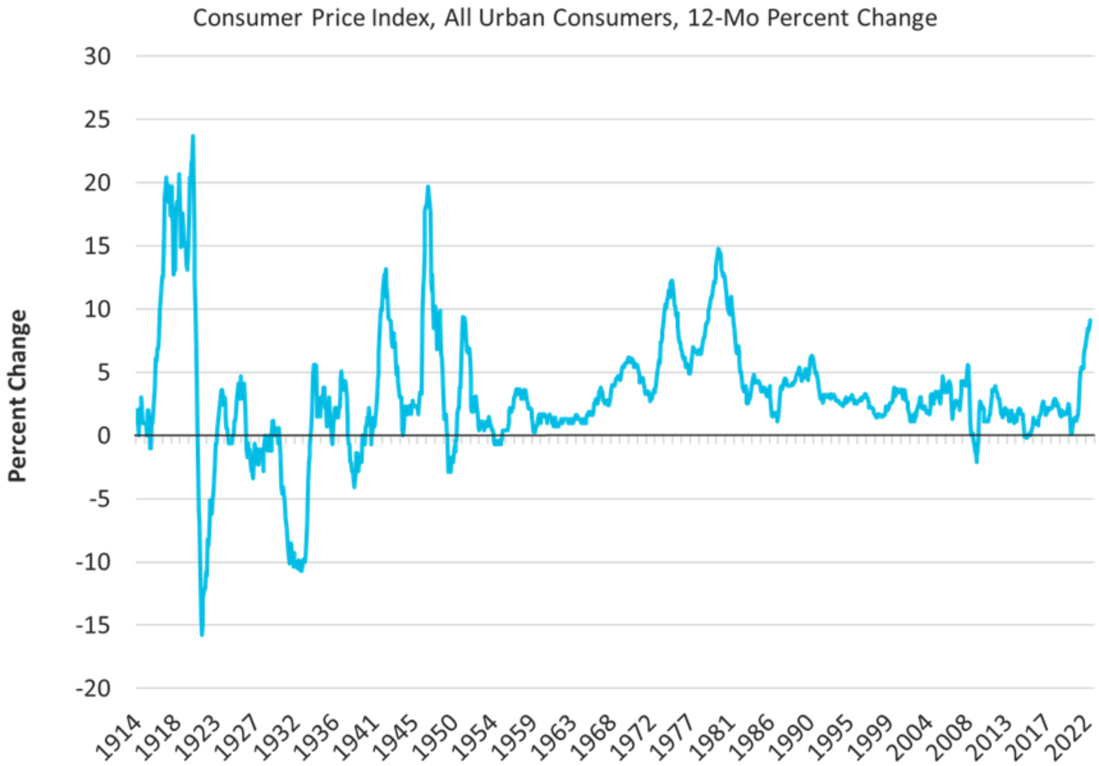
Economic and demographic factors are important underlying drivers of load growth. Changes in customer volume and usage patterns, especially for industrial customers, are impacted by broader trends in the economy and changing demographics.

### 2.2.1 U.S. Economic and Demographic Outlook

The U.S. economy continues its recovery from the COVID-19 pandemic, but inflation and uncertainty are slowing growth. In May 2022, the unemployment rate was 3.6 percent, virtually the same rate as the 3.5 percent rate from February 2020 before the COVID-19 pandemic. Similarly, total nonfarm employment in May 2022 was 99.5 percent of employment in February 2020. The labor market appears to be back at full employment, and while leisure and hospitality employment is still down 7.9 percent from pre-COVID-19 levels, employment has grown and shifted to other industries like transportation and warehousing, and professional and business services, making up the difference. The labor force participation rate is increasing, but remains below pre-COVID-19 levels, contributing to the extremely tight labor market.

But the economy is slowing. On one hand, economic growth ought to slow given labor constraints, but beyond the labor market, inflation, supply chain issues, and uncertainty surrounding monetary and fiscal policy, as well as geopolitical risks and energy supply shocks from the war in Ukraine, are putting downward pressure on growth. Massive deficit spending in the wake of COVID-19 and expansionary monetary policy by the Federal Reserve boosted the money supply in the U.S. to unprecedented levels in 2020 and 2021, which led to inflation. Energy price increases caused by the war in Ukraine further exacerbated inflation in early 2022. The Consumer Price Index in June 2022 was 9.1 percent higher year-over-year, following 8.6, 8.3, and 8.5 percent increases the previous three months. This is the highest year-over-year inflation since 1981 (Figure 2.2).

**Figure 2.2: Inflation at a 40-Year High**




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

The Federal Reserve has the unenviable task of trying to engineer a “soft landing” from this high inflationary environment. Historically, this rarely happens, and it has never happened with inflation this high, and the unemployment rate this low. Nonetheless, the Federal Open Market Committee (FOMC) has begun raising interest rates, with a 25-basis point increase in March 2022, a 50-point hike in May, and a 75-point hike in June, the highest increase since 1994. The Fed is also beginning to reduce its holdings of Treasury securities and mortgage-backed securities, shrinking the Fed’s balance sheet and further shifting from a policy of quantitative easing to one of tightening. Forward guidance from the FOMC indicates more rate increases in 2022, up to 50 or 75-basis points at a time.

First quarter GDP in 2022 declined 1.5 percent, after increasing 6.9 percent in the fourth quarter of 2021. The drop in GDP was due to decreased inventories, higher imports, and decreased federal spending. Consumer spending, business investment, and the labor market remain strong, however, so market response to the lower GDP reading was tepid. GDP is projected to turn positive in the second quarter of 2022, but economists and business leaders have increased their probability of recession in their forecasting, with the chance of recession over the next 12-24 months as high as 50 percent.[1] The spreads between short and long-term

[1] National Association for Business Economics, “NABE Outlook Survey, May 2022,” www.nabe.com, May 23, 2022, https://nabe.com/NABE/Surveys/Outlook_Surveys/May-2022-Outlook-Survey-Summary.aspx; Reade Pickert and Kyungjin Yoo, “U.S. Recession Odds Within the Next Year Now 30%, Survey Shows,” www.bloomberg.com, May 13, 2022, https://www.bloomberg.com/news/articles/2022-

Treasuries have shrunk significantly, a potential signal of recession. The yield on two-year Treasuries was briefly higher than ten-year Treasuries in April 2022 and again in June 2022, but the yield curve inversions did not last long. The S&P 500 officially fell into bear market (decline of 20 percent or more from previous peak) territory in June 2022. Stagflation – high inflation coupled with little to no economic growth – is a real possibility in the near-term, especially if efforts by the Fed do not lead to significantly lower inflation, but slow growth.

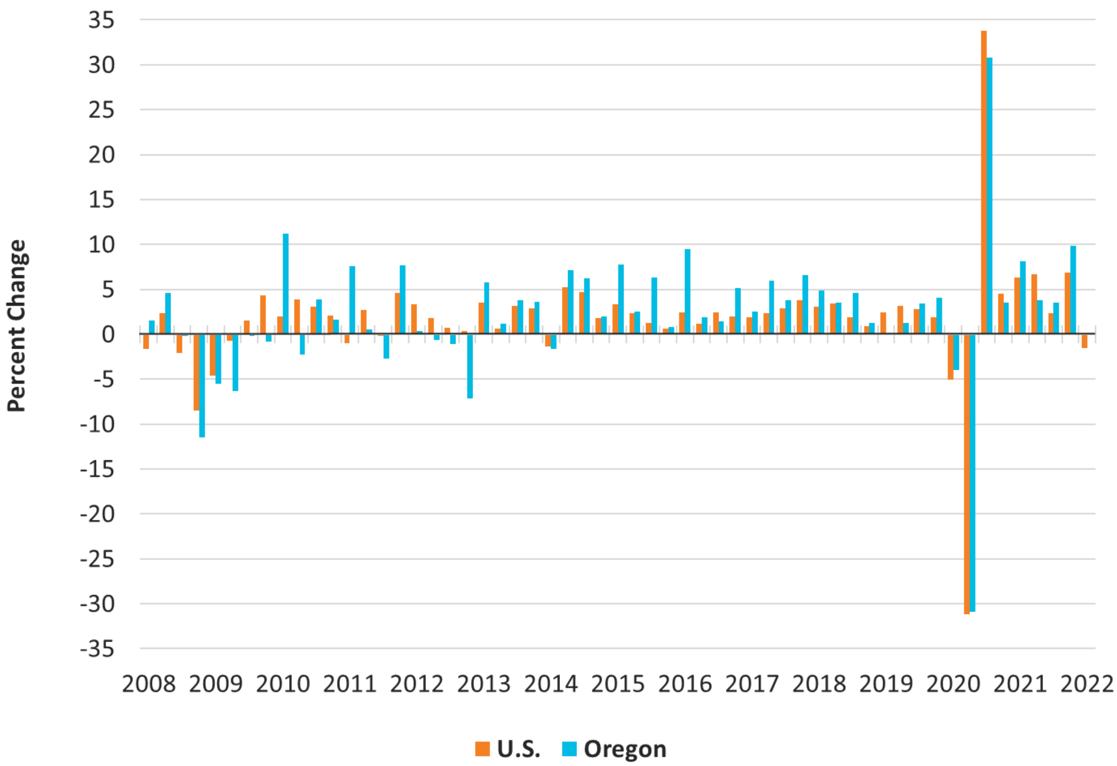
### 2.2.2 Oregon Economic and Demographic Outlook

During and after the recession of 2008 and 2009, Oregon GDP and employment followed similar trends to past economic cycles of greater loss during recession and greater gains in expansion years (Figure 2.3). Oregon's more cyclical economy is the result of larger-than-average durable goods manufacturing and related industries. Oregon's economy benefits from this industry concentration over time, with stronger GDP growth across cycles than the U.S. The recession caused by COVID-19 was different, though, since job losses were concentrated in industries like leisure and hospitality, air transportation, and retail trade – service industries that all states have in similar concentrations. As a result, negative GDP and employment impacts across states were more similar than a typical recession. Oregon's economic recovery coming out of the COVID-19 pandemic largely mirrors trends nationally.

---

05-13/odds-of-a-us-recession-within-next-year-now-30-survey-shows#xj4y7vzkg; Prerane Bhat and Indradip Ghosh, "No Respite from Fed Rate Hikes This Year, Chances Rising of Four 50 bps in a Row – Reuters poll," www.reuters.com, June 9, 2022, https://www.reuters.com/markets/us/poll-no-respite-fed-rate-hikes-this-year-chances-rising-four-50-bps-row-2022-06-10/; Isabella Simonetti and Jason Karaian, "'Uncomfortably high': What economists say about the chance of recession," *The New York Times*, June 28, 2022, https://www.nytimes.com/2022/06/28/business/recession-probability-us.html#:~:text=S%26P%20Global%20Ratings%3A%20Beth%20Ann,walking%20out%20of%202023%20unscathed.%E2%80%9D.

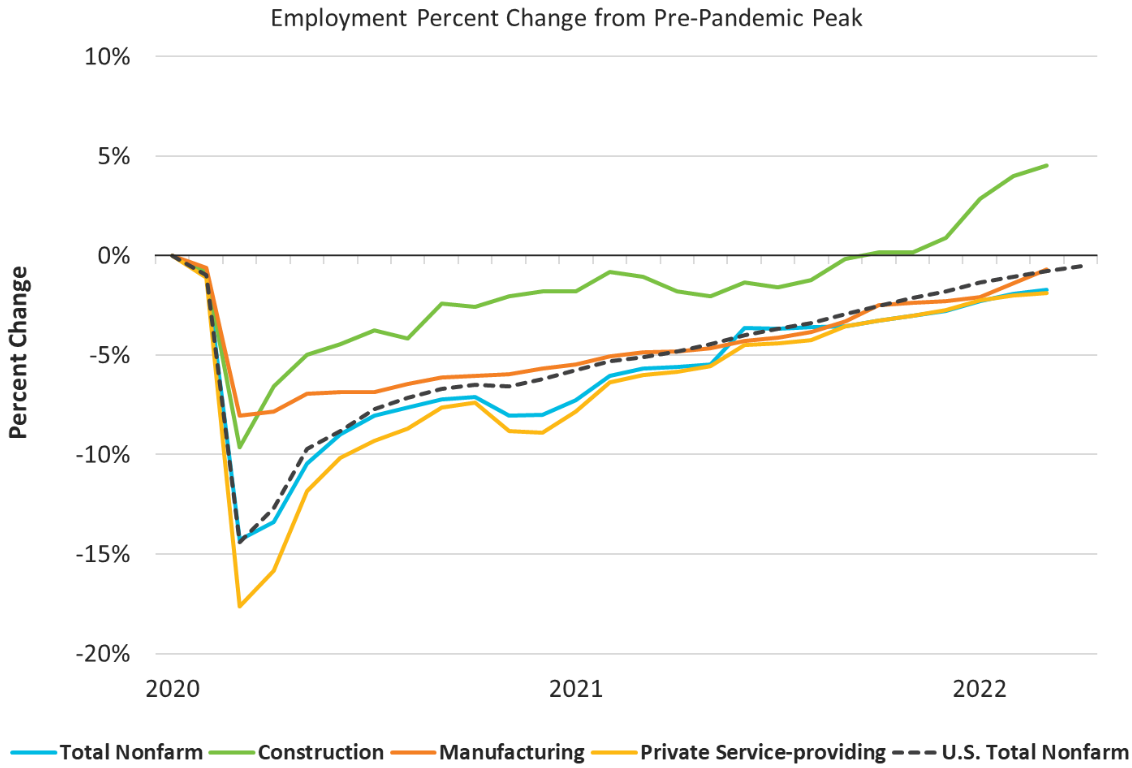
**Figure 2.3: Real Gross Domestic Product, Percent Change, Annualized**




*Source: U.S. Bureau of Economic Analysis.*

Oregon manufacturing employment declined 8 percent in April 2020 and has nearly recovered all jobs lost two years later. This is welcome news for Oregon's economy since jobs lost in manufacturing during recessions do not all come back historically. Some amount of structural job loss is typically realized, which reduces hard-to-replace, accessible, middle-wage jobs for Oregonians. Construction employment in Oregon is well above its pre-pandemic peak thanks to a strong rebound in residential building and related specialty trade contractors. Service industries experienced the largest employment declines during the pandemic and have recovered 89 percent of jobs lost through April 2020.

**Figure 2.4: Oregon Employment Nearly Recovered**




*Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series; U.S. Bureau of Labor Statistics.*

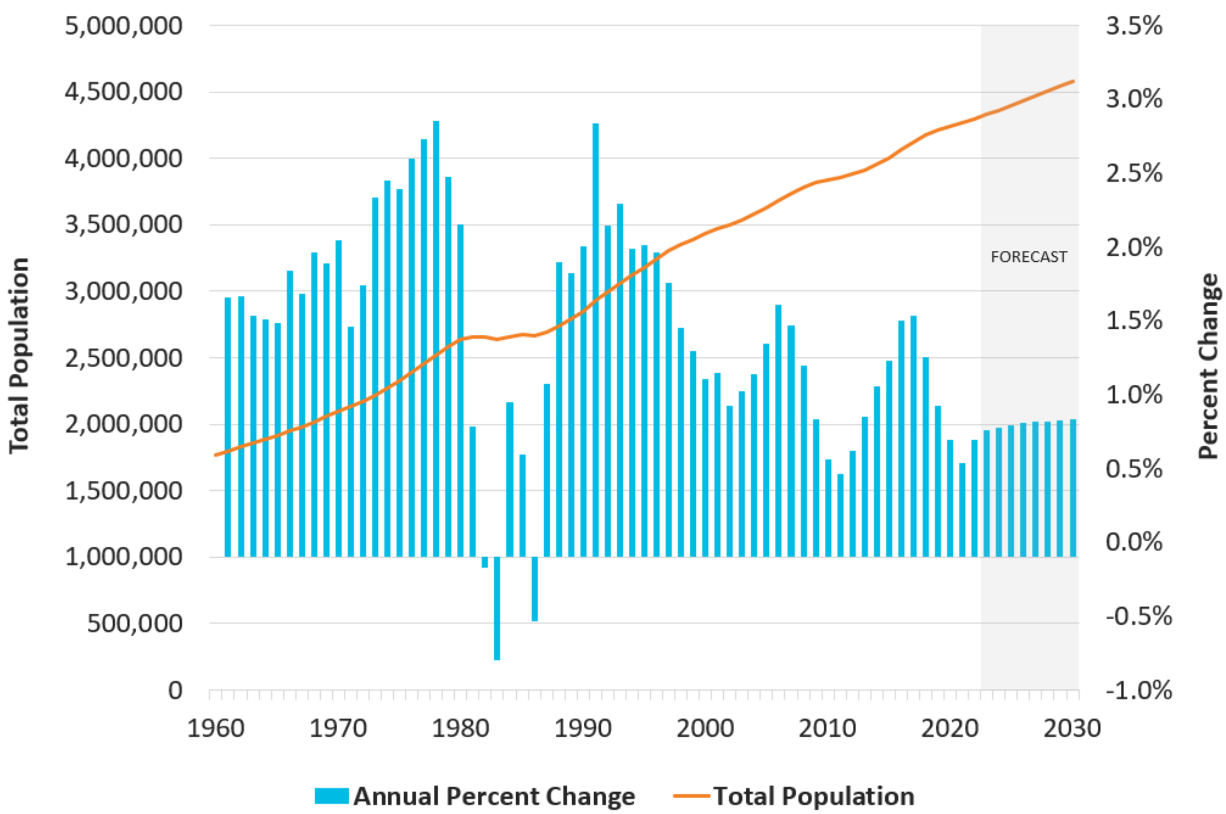
The Oregon Office of Economic Analysis (OEA) June 2022 forecast projects Oregon will return to pre-pandemic peak employment in the fall of 2022. All major industries are expected to have regained all jobs lost by the end of 2022, except leisure and hospitality, where employment is projected to return to its pre-pandemic peak in 2026. The baseline forecast calls for continued growth over the next five years, but at a slower rate. Employment growth is forecasted to be 3.8 percent in 2022, 2.3 percent in 2023, and down to 1.1 percent in 2024. Unfortunately, since the June 2022 forecast was published, inflation has only gotten worse. The 75-point interest rate increase prescribed by the FOMC at its June meeting is an indication the Fed is, perhaps, serious about getting rid of inflation. With interest rates on the rise, economic activity is slowing, such as building permits and home sales. So far, the labor market remains solid, but further contractionary monetary policy moves are expected to lead to higher unemployment going forward as the economy cools.

Recent demographic trends in Oregon have created some uncertainty for demographic forecasters in the state. Demographics are typically easier to forecast than the economy, especially in Oregon, which has enjoyed strong population growth for many years. That changed with COVID-19, and perhaps to a lesser degree, with the perceived lower quality of life experienced by Oregonians in the wake of protests, increased homelessness, and increased crime throughout the state, particularly in Portland. Immigration into the U.S. and migration between states slowed dramatically during the pandemic. Net migration into the U.S. dropped to 247,000 in 2021 – a 48 percent decline from 2020 – and was down 76 percent from last decade's high in 2016.[2] Similarly, Oregon's number of foreign-born prime working age adults was 90,000 lower in the first half of 2022 than it was in 2016, a decline of nearly one-third.[3] While migration between states will increase with the pandemic largely behind us, it is unclear what immigration into the U.S. will look like going forward due to uncertainty surrounding immigration policies at the federal level. Another wrinkle is the impact of increased remote workers in the U.S. It is an open question whether a larger share of remote workers in the U.S. could have a positive, negative, or net zero impact on Oregon's population and economy (or no impact at all). Oregon has historically attracted young, educated workers who see Oregon as a lower cost, higher quality of life destination than other places on the west coast. However, Oregon has a high personal income tax that remote workers may want to avoid. It is the 12th most expensive state in the U.S., up 8 spots from 2010 when it ranked 20th, and had the fourth highest increase in prices between 2015 and 2020.[4] That said, California and Washington are still more expensive than Oregon.

The latest demographic forecast from the OEA shows Oregon's population continuing to grow over the next decade, but at a slower rate than it has over the past three decades (Figure 2.5). Factors in the lower growth rate include slower growth trends since 2015, reduced migration during the pandemic, an aging population, and declining birth rate. A slower growing population will constrain potential labor force in Oregon, limiting economic growth as well. One of the potential barriers to higher growth is Oregon's affordability, in particular, its lack of affordable housing.

[2] Jason Schachter, Pete Borsella, and Anthony Knapp, "New Population Estimates Show COVID-19 Pandemic Significantly Disrupted Migration Across Borders," U.S. Census Bureau, December 21, 2021, https://www.census.gov/library/stories/2021/12/net-international-migration-at-lowest-levels-in-decades.html.
[3] IPUMS-CPS, University of Minnesota, www.ipus.org, retrieved June 21, 2022.
[4] U.S. Bureau of Economic Analysis, Regional Economic Accounts, Regional Price Parities by state, www.bea.gov, retrieved June 21, 2022.

**Figure 2.5: Oregon Population Growth Slowing**



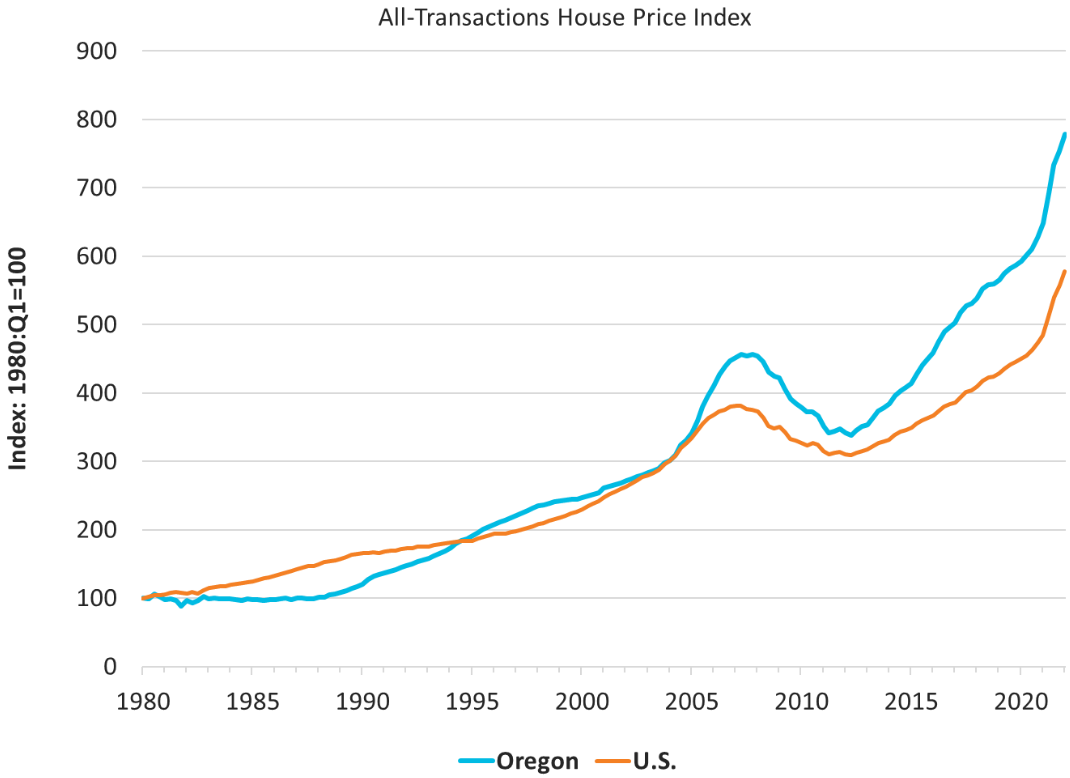

*Source: U.S. Census Bureau, Portland State University Population Research Center, Oregon Office of Economic Analysis.*

Housing affordability continues to be a problem in Oregon, as supply is not keeping up with demand. Oregon has underproduced about 110,000 housing units as of 2021, which is 19 percent of total units needed in the state.[5] Demand remains strong, with prices at record highs and inventories at record lows.[6] Oregon house prices increased at a much faster rate than prices in the U.S. over the past decade (Figure 2.6). Oregon prices were 20 percent higher in the first quarter of 2022 than they were the year before, which was equal to the highest quarterly year-over-year percent change experienced before the Great Recession in the first quarter of 2006.

[5] ECONorthwest. *Implementing a Regional Housing Needs Analysis Methodology in Oregon: Approach, Results, and Initial Recommendation*. Portland, Oregon: ECONorthwest, 2021. Accessed June 30, 2022. https://www.oregon.gov/ohcs/about-us/Documents/RHNA/RHNA-Technical-Report.pdf.

[6] Realtor.com. Housing Inventory Core Metrics. Accessed June 30, 2022 via Federal Reserve Bank of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/ACTLISCOUOR.

**Figure 2.6: Oregon House Prices Increasing Much Faster than U.S.**




*Source: Federal Housing Finance Agency, FHFA House Price Index.*

Growth appears to be slowing, though, as a result of increasing interest rates brought on by the Federal Reserve's actions to tamp down inflation. At the end of June 2022, the 30-year fixed rate mortgage average in the U.S. was 5.7 percent, almost double what it was a year earlier.[7] In May 2022, active residential listings in Oregon were up to 7,252 from 5,400 in May 2021. This is still a very low number of listings, but the increase year-over-year is a sign the market is becoming less tight. This trend is likely to continue as further interest rate increases are expected from the Fed in 2022. The OEA also expects housing starts in Oregon to decline in 2022. Housing starts are forecasted to grow from 2023 to 2030, but at a slower rate than they did pre-pandemic. Most of the slower growth in starts is tied to slower population growth.

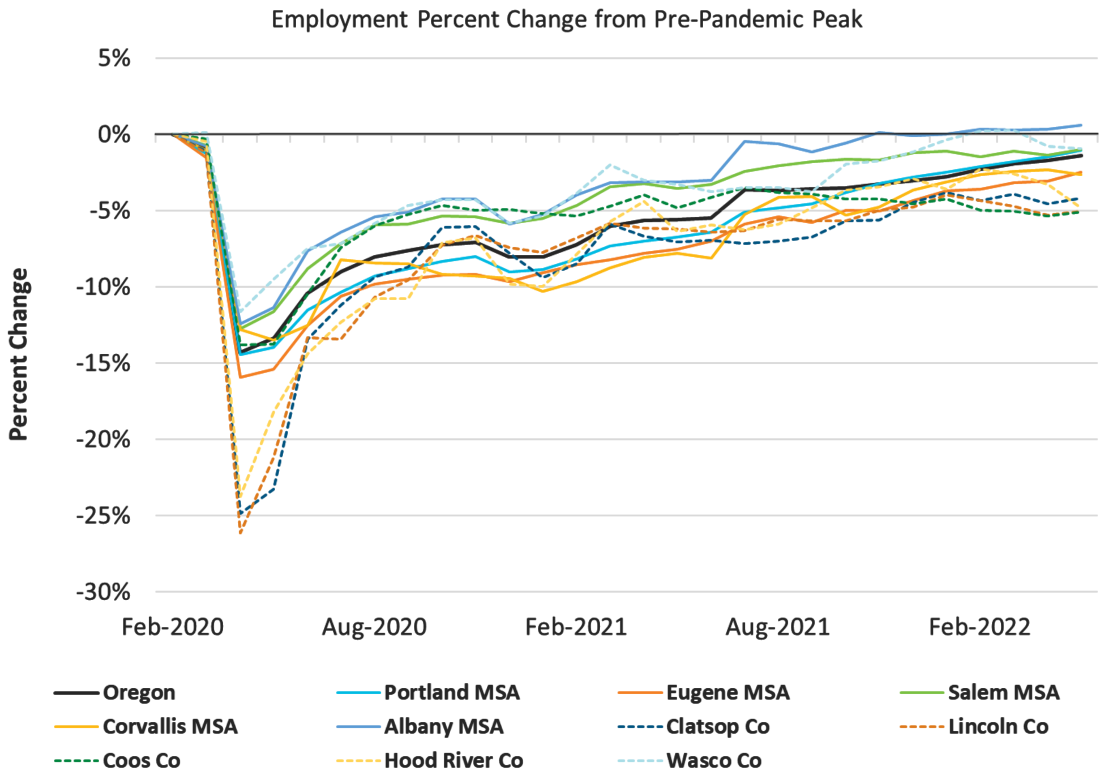
### 2.2.3 NW Natural System Area Economic and Demographic Outlook

The COVID-19 pandemic impacted cities and counties differently across the Company's service territory. In the service territory, as well as across the U.S., the pandemic had a larger negative impact in communities with above average concentrations of service sector employment in leisure and hospitality, arts, entertainment, and recreation, personal services, and air transportation. Employment in these industries is typically more concentrated in metropolitan areas than rural areas and in areas with significant tourism. Throughout the Company's service territory, employment declined the most in Lincoln, Clatsop, and Hood River counties – rural

[7] Freddie Mac. Primary Mortgage Market Survey. Accessed June 30, 2022 via Federal Reserve Back of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/MORTGAGE30US.

areas with significant tourism (Figure 2.7). The Portland and Eugene metro areas also experienced larger employment declines than average across the state.

**Figure 2.7: Pandemic Employment Impacts Across NW Natural Territory**




*Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series.*

Employment was 95-100 percent recovered in all areas as of May 2022. Wasco County, Albany, and Salem, which experienced the least amount of job loss during the pandemic, have nearly recovered all jobs lost. Coos, Lincoln, and Hood River counties were still down 5 percent from their pre-pandemic peaks. The Portland MSA has recovered 99 percent of jobs lost. Oregon is forecasted to recover all jobs lost during the pandemic by the fall of 2022, but areas that experienced larger job losses in the most impacted industries will take longer to recover.[8]

The pandemic led to lower rates of migration across the nation and migration out of larger cities. Total population in the Portland metro area declined by about 4,600 in 2021 from 2020. More significantly, Multnomah County's population dropped by 12,500, a decline of 1.5 percent. It remains to be seen how much this population shift out of larger cities and into suburbs and less populated areas will influence growth patterns going forward, but forecasters expect population growth to return to the Portland metro area, albeit at slower rates than experienced over the decade preceding the pandemic.[9] Population forecasts for metro areas

[8] Oregon Office of Economic Analysis, *Oregon Economic and Revenue Forecast, June 2022*. Salem, Oregon: Department of Administrative Services, 2022. Accessed July 6, 2022. https://www.oregon.gov/das/OEA/Documents/forecast0622.pdf.

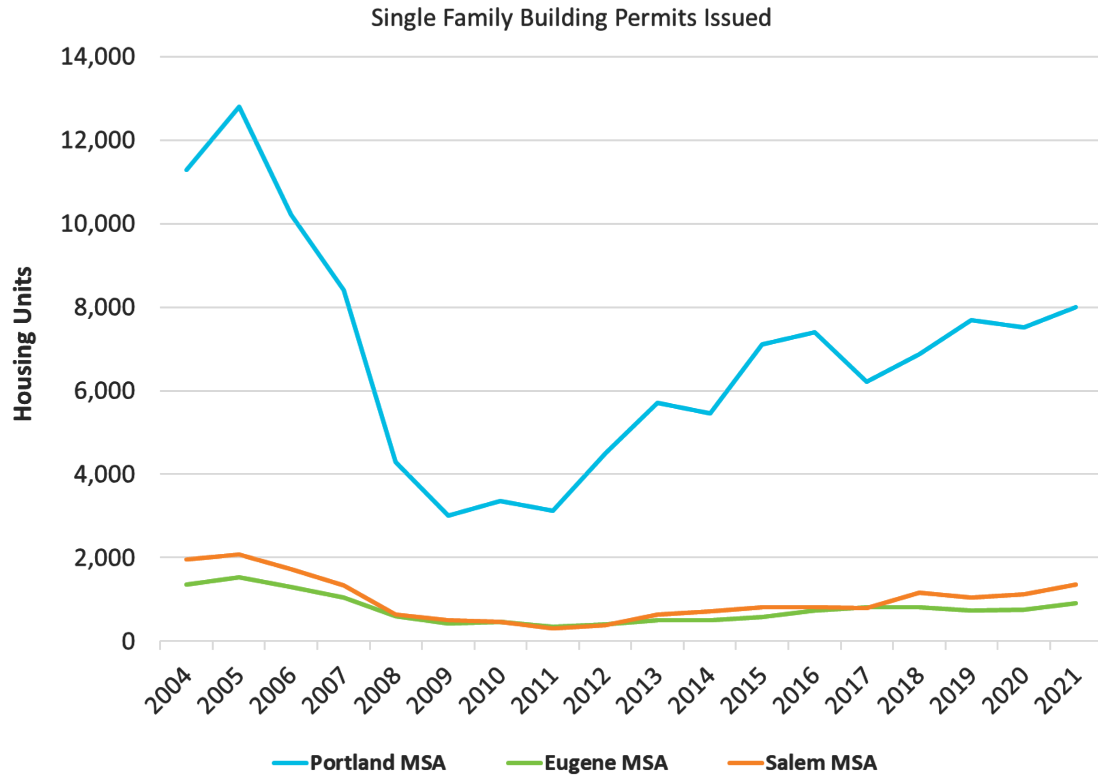
[9] Metro (MPO), *Portland-area 2045 Population and Housing Forecasts by City and County*. Portland, Oregon: Metro, 2021. Accessed July 5, 2022. https://www.oregonmetro.gov/sites/default/files/2021/03/26/2045-regional-population-housing-forecast-by-city-county.pdf.

and counties in the Company’s service territory have not been developed since the onset of the pandemic. Based on the current population forecast for Oregon developed by the OEA, population growth across the service territory will be slower between 2020 and 2030 than it was between 2010 and 2020.

Like Oregon, housing affordability in the service territory is an area of concern. Figure 2.8 shows recent trends in single family building permits in the territory’s three largest metro areas and, while growth in permits has continued to rise from lows experienced after the Great Recession, the pace of housing construction does not appear to be meeting increased demand in the area based on price and inventory trends. This was the case before the pandemic, but the situation worsened even more during the pandemic with extraordinarily low mortgage rates, migration out of cities to suburbs, and higher household incomes. The S&P CoreLogic Case-Shiller Portland Home Price Index increased at an annualized rate of 5.2 percent between April 2010 and April 2020. In the two years since, it increased at a 17.4 annualized rate. Increasing mortgage rates, brought on by interest rate increases by the Fed, have begun to dampen sales and prices in region. In the Portland metro area, pending sales were down 27.5 percent in June 2022 from a year ago.[10] The median sale price appears to have topped out as well and inventory is beginning to rise. Similar trends are occurring in Eugene, Salem, and other areas of the service territory.

[10] RMLS, *Market Action, June 2022*. Portland, Oregon: RMLS, 2022. Accessed July 11, 2022. https://www.rmlsweb.com/v2/public2/loadfile.asp?id=12507.

**Figure 2.8: Single Family Building Permits in Key Metro Areas Growing**

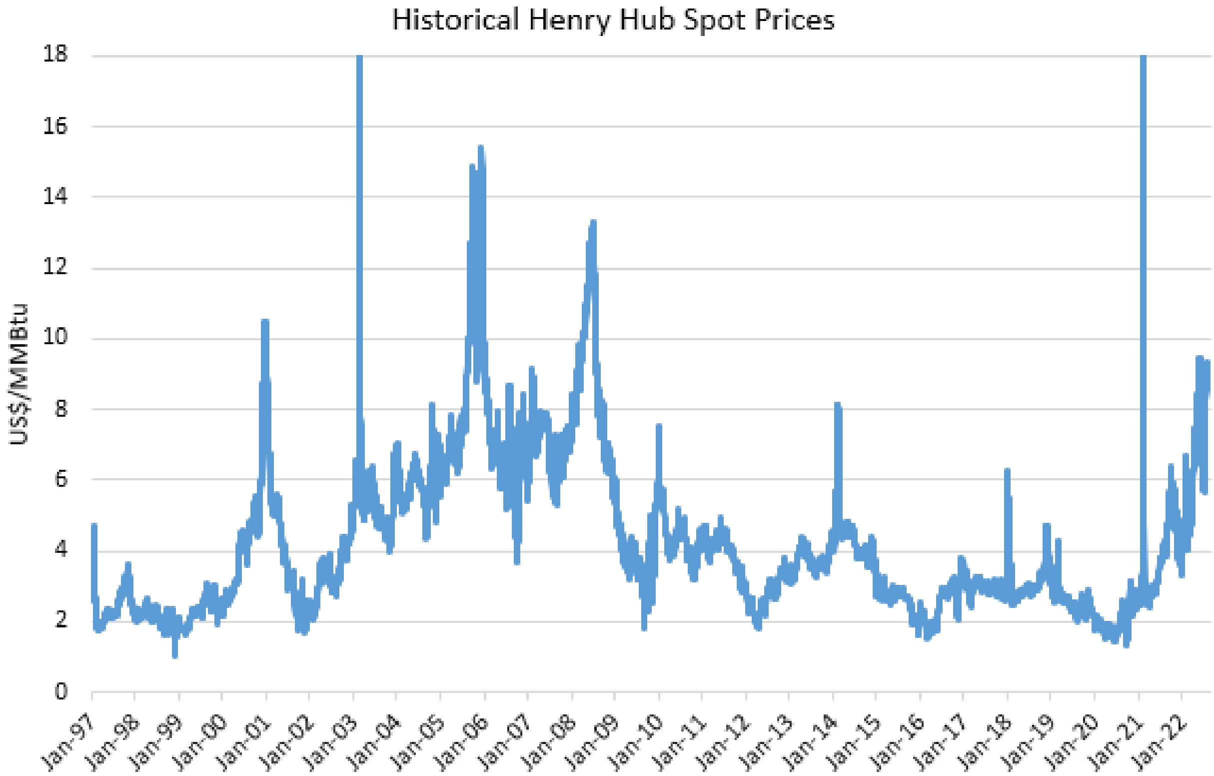



*Source: U.S. Census Bureau, Building Permits Survey.*

## 2.3 Natural Gas Prices

Like many commodities, volatility in natural gas prices are influenced by numerous factors, including macro-economic factors, weather, power generation demand, and production constraints and development in new and traditional supplies — such as more efficient extraction technologies or additional access to RNG. Figure 2.9 depicts how natural gas prices have been changing over time.

**Figure 2.9: Historical Natural Gas Prices**




Source: Morningstar

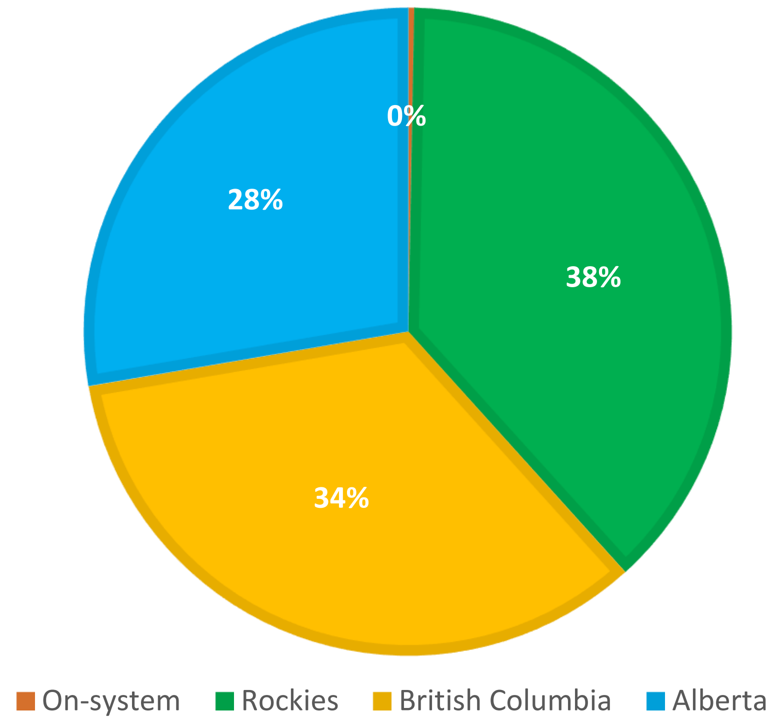
### 2.3.1 Natural Gas Supply Sources

NW Natural purchases natural gas on behalf of all sales customers. Purchasing natural gas from producers located in Canada or the Western US 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 conventional 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 2021, these contracts enabled us to purchase roughly 38% of our supplies from Rockies, 28% from Alberta and 34% from British Columbia (See Figure 2.10).[11] Looking forward, gas from RNG sources, either with or without environmental attributes, will become a larger share of the Company's supply purchases.

[11] There is a small amount of gas being produced at Mist that comes onto our system through a third-party producer and new RNG interconnections that began to flow onto our system in 2021.

**Figure 2.10: Supply Diversity by Location January 2021-December 2021**



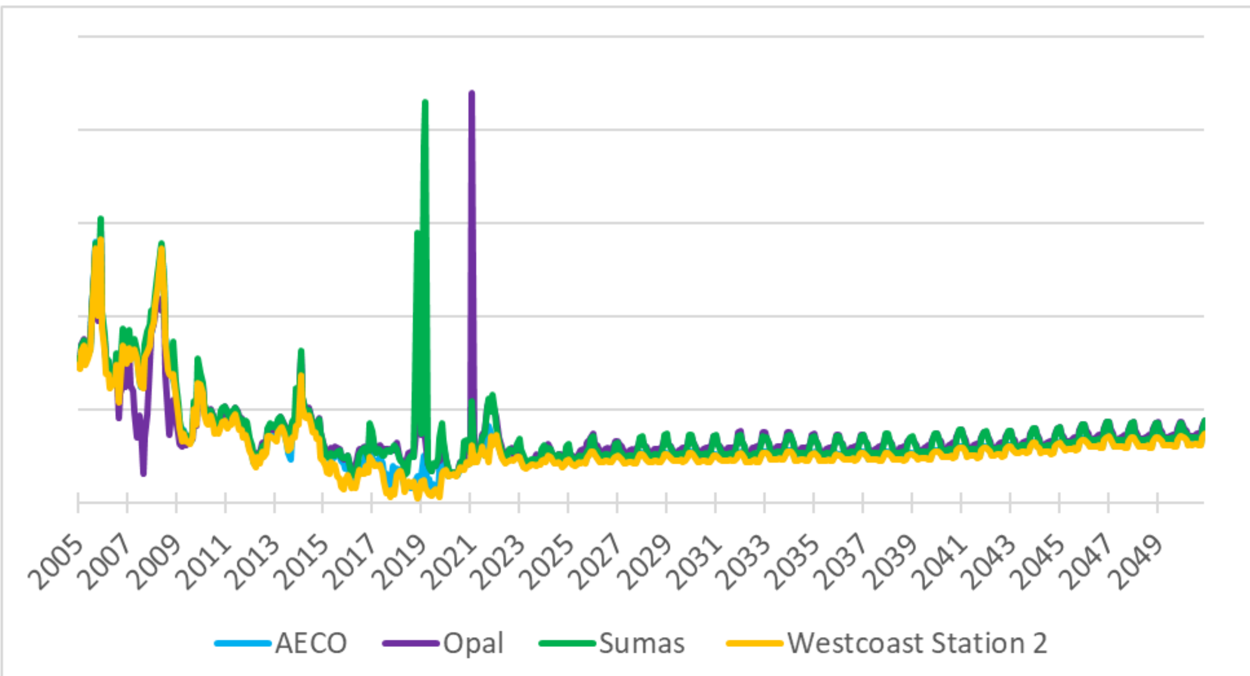

While our contracts allow us to access various points along the interstate/interprovincial pipelines, the gas prices we pay for gas produced in these basins are closely correlated with three major natural gas trading hubs in the corresponding production areas: AECO (Alberta), Opal (Rockies), and Westcoast 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 is no major production operations associated with Sumas.[12]

[12] Purchases at Sumas are group together with British Columbia in Figure 2.10, however; Sumas is a trading hub and most of the gas being bought and sold at this location is likely being transported from either Alberta or Northern British Columbia.

### 2.3.2. Natural Gas Price Forecast

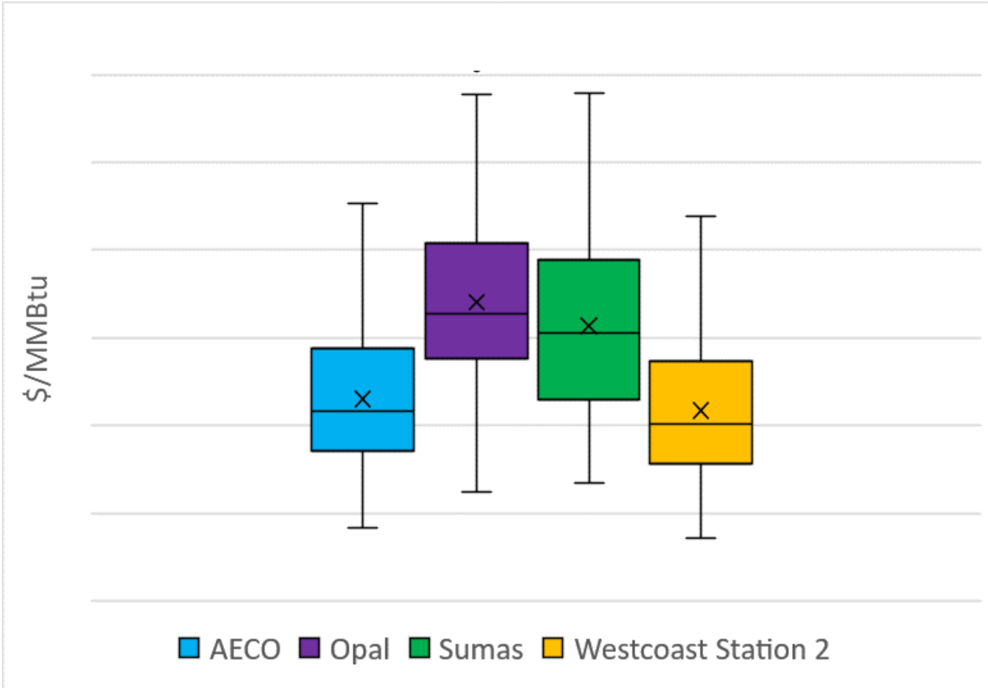
NW Natural subscribes to a gas market fundamentals forecasting service through a third-party, IHS Markit.[13] IHS Markit implements a nation-wide supply and demand fundamentals model for the natural gas sector. Using this model IHS Markit publishes a long-term gas price forecasts for numerous natural gas hubs around the U.S. and Canada. The IRP uses these gas price forecasts as the expected gas price for the four natural gas price hubs where the company purchases gas, AECO, Opal (i.e., Rockies), Sumas and West Coast Station 2. Natural gas prices will vary by location and time of year. As demand increases in a specific region and pipeline capacity to ship gas into that area becomes constrained, prices in the constrained region can spike. Figure 2.11 shows both historical prices and forecasted prices for these four hubs. Figure 2.12 shows average and range of gas prices in the forecast.

**Figure 2.11: Historical Natural Gas Prices and Forecasts by Trading Hub[14]**




[13] IHS now owned by S&P Global.
[14] Source: ©2022 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

**Figure 2.12: Mean and Range of Natural Gas Price Forecasts by Trading Hub[15]**




### 2.3.3 Current Conditions

While demand has continued to recover following the impact of the COVID-19 pandemic, production growth has lagged as producers have focused on capital discipline. The market has been additionally strained with an increase in LNG and Mexico pipeline exports, strong demand for natural gas generation, and a low storage inventory. Without additional supply to balance demand, the market has faced sustained high prices.

With new LNG export facilities and expansions, the seven big U.S. export plants are expected to have a capacity of 13.8 Bcf/d by the end of 2022. LNG exports have hit record levels due to the capacity additions along with strong global demand as a result of Russia's invasion of Ukraine. While a June 8 fire at Freeport LNG has taken the facility offline until late 2022, the additional 2 Bcf/d of supply added to the market has been swallowed up by strong demand for natural gas generation and injections into storage. LNG exports have increased from an average of 6.5 Bcf/d in 2020 to 9.8 Bcf/d in 2021 to 11.2 Bcf/d for the first half of 2022. The EIA expects LNG exports to increase to 12.7 Bcf/d in 2023.[16] LNG export growth will be constrained until the Golden Pass LNG Terminal is online in 2024, which will increase export capacity to 16.3 Bcf/d.

Despite high prices, power sector demand for natural gas generation is near record levels from 2020 as gas-to-coal fuel switching for electric generation is less flexible and new renewable

[15] Source: ©2022 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.
[16] Source: EIA, Short Term Energy Outlook, July 12, 2022

generating capacity is facing construction delays due to supply-chain issues.[17] Coal generation is constrained due to low coal stockpiles resulting from low production and increased exports, rail transport issues, and coal plant retirements. More than 100 GW of coal retired across the US over the past 10 years and an estimated 90 GW of retirements have been announced or are planned by 2030.[18] Demand for natural gas in the electric power sector is expected to grow through 2025 even as new renewable energy resources come online.[19]

Storage inventory is expected to head into the winter of 2022-23 below average. The EIA is forecasting that storage will end the 2022 injection season around 6% below the five-year average. This creates anxiety in the market in the event of a colder-than-normal winter.

An increase in crude oil and natural gas prices have contributed to increased drilling activity. Dry gas production is growing in the Haynesville region and the Permian Basin. Associated gas production, which is dependent on the crude oil market, is also expected to grow in the Permian Basin as high oil prices have led to plans to increase oil production. The EIA forecasts that dry natural gas production will increase 2.7 Bcf/d or 3% compared to 2021 and 3.7 Bcf/d or 4% in 2023.[20] Gas production from the Montney region in northern British Columbia and Alberta, Canada has also been increasing. Canadian production is currently just below the April 2006 all-time record high as Canadian producers were in better financial shape than U.S. producers and were able to boost production when prices began to rise.[21]

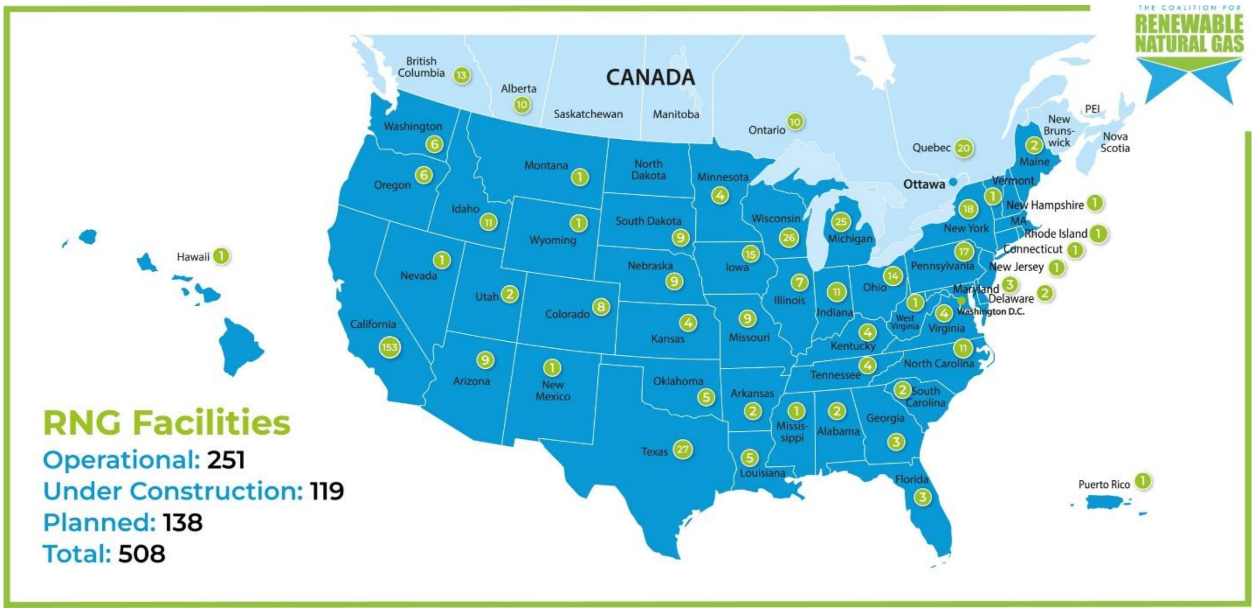
Volatility has been up due to the continual shifts in the market. Volatility of U.S. natural gas futures prices reached a record-high level in February with the 30-day historical volatility of gas futures reaching 179.1%. Upward price pressure and volatility will remain until supply and demand are balanced.

## 2.4 RNG and Hydrogen Markets

The renewable natural gas (RNG) market in the United States has matured significantly over the last several years. Whereas in previous years, most of the financing of new RNG projects came from private equity, this year saw substantial development and acquisition activities from large established players in the oil and natural gas and asset management space, such as Kinder Morgan and BlackRock. As can be seen in Figure 2.13, this year the RNG industry reached the milestone of over 250 operational projects in the U.S. and Canada[22], up from 100 projects just three years ago in 2019.[23]

[17] Source: Platts Gas Daily, "Gas demand from US power generators continues at record pace in July", July 11, 2022
[18] Source: IHS Markit, North American Power Market Outlook, July 14, 2022
[19] Source: IHS Markit, North American Natural Gas Short-Term Outlook, June 2022
[20] Source: EIA, Short Term Energy Outlook, July 12, 2022
[21] Source: Platts Gas Daily, "West Canada spot gas prices plummet as production soars to 16-year highs", July 11, 2022
[22] https://www.rngcoalition.com/media-room
[23] https://www.rngcoalition.com/renewable-natural-gas-market-surpasses-100-project-pinnacle-in-north-america

**Figure 2.13: RNG Projects**[24]




The key markets that have historically driven RNG project development are transportation fuel-driven, such as the federal United States Environmental Protection Agency's Renewable Fuel Standard and the California Low Carbon Fuel Standard and Oregon Clean Fuels Program. The value of certain RNG that can qualify for the generation of credits under the federal program has been hovering around $35/mmbtu, and the value for certain RNG that is selling into the Oregon Clean Fuels Program has been $50/mmbtu and up, depending on the resource. These revenue opportunities have driven the strong growth in project development and have helped to grow a more established RNG industry. An increasing number of engineering and construction firms now have RNG experience, and NW Natural has seen a growing number of traditional energy project engineering and construction firms building out dedicated RNG teams.

NW Natural issues annual RFPs for RNG resources. Our 2022 RFP process is currently ongoing, but we received 20 individual bids from RNG developers and brokers and are currently reviewing the bids. There continues to be a strong response to our annual RFPs and a clear interest in selling RNG into markets such as gas utilities that can offer revenue opportunities separate and distinct from the transportation fuel credit markets. Those markets, while lucrative, are also highly volatile, and very hard to forecast or hedge against.

Hydrogen markets continue to be based on the lowest-cost available feedstocks and direct on-site use of the commodity for processes such as liquid fuels refining and fertilizer production. There is minimal large-scale use of non-fossil sources due to costs and limited carbon policies

[24] https://www.rngcoalition.com/infographic

incentivizing lower-carbon sources. For off-site hydrogen use, costs are higher due to liquifying and truck transportation costs.

That said, there are signs the hydrogen market is changing. NW Natural has received responses in its annual RNG RFP for hydrogen at competitive prices, even lower than many RNG sources. Hydrogen developers are finding sources of low-cost electricity in regions outside of Oregon to use for electrolytic hydrogen production. Direct injection of hydrogen into interstate pipelines has yet to become widespread; developers are therefore exploring methanation to produce synthetic methane still at competitive prices. Transmission system hydrogen blending is predicted to become available in the future, at which time these methanation plants can be re-purposed to produce hydrogen only at lower production costs.

NW Natural and many other gas utilities are predicting increased hydrogen production in their regions and are preparing for wide-scale hydrogen blending. Hydrogen developers have expressed interest in developing projects in our region and by preparing for blending, NW Natural is positioning itself to accept large volumes of clean hydrogen to reduce the carbon intensity of its energy and potential enable other segments to decarbonize, such as heavy-duty transport, aviation, and maritime shipping. Economies of scale generated through large hydrogen production projects for utility use can decrease the costs of hydrogen for these other industries.

## 2.5 Efficient End Use Equipment

To accelerate the development and market adoption of efficient natural gas products, practices, and services, NW Natural partners with the Energy Trust of Oregon and natural gas utilities in Oregon and Washington through the Northwest Energy Efficiency Alliance (NEEA) to create a long-term market transformation strategy to ultimately increase consumer choices for the efficient use of natural gas in the Northwest.

There are three initiatives currently in NEEA's portfolio representing a technical savings potential of over 360 million annual therms in the Northwest. The specific technologies and associated saving anticipated to deliver those savings are outlined below.

### 2.5.1 Efficient Gas Water Heaters

The Efficient Gas Water Heater program seeks to transform the residential gas water heating market, making gas-fired heat pump water heaters the standard in gas water heating appliances. These units use half the energy of today's standard tanked gas water heaters and therefore represent tremendous savings opportunity. NEEA's 2020-2024 Business Plan[25] indicates a significant market for this product in the Northwest (1.7 million customers) and a high cumulative savings potential (over 200 million annual therms). NEEA is working to achieve this goal through exploring opportunities to accelerate adoption of currently available efficient products while driving manufacturers to develop and commercialize heat pump water heater

[25] NEEA's 2020-2024 Business Plan can be found at: [NEEA-2020-2024-Strategic-and-Business-Plans.pdf]

technology, and ultimately influencing federal manufacturing standards for natural gas water heaters. Broad commercialization of heat pump water heaters is estimated by 2025.

### 2.5.2 Efficient Rooftop Units

Rooftop units (RTUs) are heating and air conditioning appliances fueled by natural gas and are prevalent in low rise commercial buildings in the Northwest. RTUs are often purchased as a like-for-like replacement based on cost and availability and, therefore, strategic efficiency improvements may achieve savings without onerous customer adaptation.

NEEA identified best practices for effectively adopting RTU's with more efficient furnace components. Through additional modeling in 2020, NEEA staff identified several other, commercially available efficiency measures beyond the furnace (heating component of the RTU system) that could provide significant whole system efficiency gains and are not currently valued by existing metrics or widely used by manufacturers.

Current efficiency metrics and specifications focus only on some of the energy used by RTUs; for example, TE (thermal efficiency that measures a gas furnace's efficiency in converting fuel to energy) only accounts for the efficiency of the burner in the gas furnace (which is only one component of the RTU), and does not consider the efficiency of controls, insulation, damper leakage, and performance in different climates. To meet the need for a more comprehensive view of efficiency, updated metrics and specifications for RTUs are needed. To this end, NEEA is developing and promoting a new efficient Gas RTU national specification, comprehensive test procedure and associated Qualified Products List (QPL) that recognizes the efficiency improvements provided by these additional RTU characteristics that voluntary programs can reference and will provide modes to value higher system efficiency in the market. Ultimately, the program aims to lock in this efficiency shift through state codes and Federal Standards to represent a 10% efficiency gain above 2020 standards. This effort has the potential to save over 80 million annual therms in the Northwest.

### 2.5.3 High-Performance Windows

New technology advancements in ultra-thin glass production and low-conductivity gases that are inserted in between the panes of glass, have created the opportunity for a new caliber of high-performance windows. Designed to be the same width and virtually the same weight as existing double-glazed windows, new triple-paned windows offer a sleek and non-invasive retrofit solution for existing homes with poor-performing windows. They can also help builders in the new construction market reach above-code program targets more easily than other options. NEEA's High-Performance Windows program will focus on stimulating national builder and consumer demand, influencing the ENERGY STAR® specification to reach higher performance levels, and including high-performance windows in building codes. The efficiency of windows is measured in U-Values, the lower the U-Value number, the better the thermal performance of the window.[26] Today ENERGY STAR® rated windows for the northern climate

[26] The typical U-Values on windows is **a measurement of heat loss and the rate at which it is lost**. U-Values indicate the overall performance in retaining heat and preventing it from escaping to the outside. U-Values are measure in Watts per square metre Kelvin, or W/m2 K.

zone have a U-Value of 0.27; the long-term goal of this program is for windows with a 0.20 U-Value, or less, to reach over 50% share of sales in the Northwest which will benefit both natural gas- and electrically-heated homes and have the potential to save over 80 million annual therms in the Northwest.

### 2.5.4 Other Portfolio Activities

NEEA also recognizes the necessity of other activities to advance the portfolio, such as scanning for new technologies and codes and standards work, the activities for which are closely coordinated with the strategies and activities of the alliance's Market Transformation programs. For additional detail, please refer to NEEA's 2020-2024 Business Plan.[27]

## 2.6 Environmental Policy- Overview

Both Oregon and Washington have adopted climate policies that call for transformative change in energy systems. While state policy is driving much of the change, federal and local policies continue to influence NW Natural investments. The emission reduction targets in both states are aggressive but the policy structures are quite different. Most notably options for compliance and compliance periods in state carbon goals are not the same across both states. This requires greater differentiation as the company works to decarbonize the system at large and to comply with the laws in both states. Each law is detailed more completely below in Sections 2.6.2 and 2.6.3.

In addition to the transformative climate policy that sets carbon emission reduction goals, the environmental policy landscape in each state includes additional important elements including such factors as policy movement in building codes and renewable energy procurement.

### 2.6.1. Environmental Policy – Federal

At the federal level, greenhouse gas emissions from the natural gas supply chain continue to be a focus of the Environmental Protection Agency (EPA) agenda. 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 for operations in both Oregon and Washington. At this time, there is not a federal carbon market or cap on emissions. NW Natural emissions are limited by policy at the state level.

To spur innovation in alternative fuels there is ongoing work at the federal level for financial incentives for the development of hydrogen and renewable natural gas (RNG). Much like incentives that were provided to alternative electricity generation projects, hydrogen and RNG projects would benefit greatly from federal investments as these markets develop. One example of such investments is the Regional Clean Hydrogen Hub program administered by the US Department of Energy (US DOE). As part of the 2021 Bipartisan Infrastructure Law, $8,000,000,000 was allocated to the US DOE to support the development of at least 4 regional

[27] https://neea.org/img/documents/NEEA-2020-2024-Strategic-and-Business-Plans.pdf https://neea.org/img/documents/NEEA-2020-2024-Strategic-and-Business-Plans.pdf

clean hydrogen hubs to improve clean hydrogen production, processing, delivery, storage, and end use.

### 2.6.2. Environmental Policy / Codes – OR

#### *Oregon Climate Protection Program (CPP)*

On March 10th, 2020, Governor Kate Brown issued Executive Order 20-04 directing state agencies to take actions and regulate greenhouse gas emissions. The Climate Protection Program (CPP) was developed as an outcome of this executive order with Department of Environmental Quality (DEQ) as the administrator and regulator. Following a formal rulemaking process, the program went into effect on January 1, 2022.

The CPP sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout the state of Oregon, including diesel, gasoline, natural gas and propane, used in transportation, residential, commercial and industrial settings (the program is not inclusive of fossil fuel used in electric generation). The CPP also regulates site-specific greenhouse gas emissions at large stationary sources, such as emissions from industrial processes. The program baseline is set at average greenhouse gas emissions from covered entities from years 2017-2019. Reductions from this baseline are set at 50% by 2035 and 90% by 2050.

NW Natural is the entity responsible for decarbonizing all load delivered on the company's system. This includes not only sales customers- those customers for whom the company purchases and delivers the commodity but also transportation schedule customers. Transport schedule customers purchase the commodity they use directly from marketers and suppliers and pay NW Natural for delivery via the distribution system. This customer segment has not historically had rate funded energy efficiency programs.

Covered entities emissions are reported annually through the existing DEQ greenhouse gas reporting program and compliance will be demonstrated by each covered entity at the end of each three-year compliance period. To comply, covered entities like NW Natural can work to reduce usage through efficiency measures, introduce renewable and low carbon alternative fuels, trade for additional compliance instruments with other covered entities, or purchase a limited amount of Community Climate Investments (CCI).

CCI are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. In the rulemaking, DEQ established a set dollar amount that a regulated entity must invest in an approved project to earn a credit. The regulated entities using this compliance tool will pay a DEQ designated third party to invest in projects that reduce or remove greenhouse gas emissions in Oregon's communities.

These instruments are not conventional offsets. The program requires all CCI investments be located in Oregon and intends to prioritize investments in environmental justice and other impacted communities. CCIs are not available for purchase in the first year of the CPP as that part of the program and its administration is still under development. CCI's are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $71/ton for the first compliance period and raise over time. Use of CCI's as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

### *Senate Bill 98 (SB 98)*

NW Natural worked collaboratively with legislators and renewable natural gas (RNG) stakeholders to create SB 98, a groundbreaking bill that was signed into law by Oregon Governor Kate Brown in 2019. In 2020, rulemaking for SB 98 was completed and NW Natural was able to begin procuring RNG for our customers. SB 98 sets the following voluntary targets of 5% RNG for 2020-2024 period, 10% for 2025-2029, 15% by 2030, 20% by 2035 and 30% by 2050. It enables utilities to procure RNG through offtake contracts or invest and own cleaning and conditioning equipment required to bring raw biogas ad landfill gas up to pipeline quality, as well as allowing the facilities to connect to the local distribution system. The rule does contain cost containment measures that only allow for up to 5% of the utility's revenue requirement to be used to cover the incremental cost of investments in RNG infrastructure. The RNG procured under SB 98 may be acquired locally or from sources across the nation.

### *Status of Oregon Codes*

The 2021 Oregon Residential Specialty Code (ORSC) went into effect in April 2021 and is based on the 2018 International Residential Code. The current ORSC is fuel neutral. The next residential code cycle process began in June 2022 and will be effective in the fall of 2023. Review of proposals and the discussion process is expected to begin in August 2022.

Oregon commercial energy code is currently based on the national ASHRAE 90.1 – 2019 standard. The ASHRAE 90.1 – 2019 standard became effective in 2021 and is fuel neutral. The Oregon Building Codes Division has expressed intent to continue use of the national ASHRAE standard for the next commercial energy code cycle.

We expect future code cycles to continue to encourage electric heat pump technology adoption with opportunities for hybrid and gas heat pump technologies as well. For example, commercial and industrial gas heat pumps are available now and are comparable in price to their electric counterparts. We fully anticipate residential gas heat pumps, now in late-stage pilots, to be commercially available soon. In turn, we would expect building codes to reflect these high-efficiency options, as they lower emissions while reducing grid reliability risks.

### *Potential Impacts of Oregon House Bill 3055*

Oregon House Bill (HB) 3055, effective September 25, 2021, creates new provisions and amends numerous Oregon Revised Statutes (ORS) including ORS Chapter 757 - Utility Regulation Generally. The majority of HB 3055 focuses on State programs outside of natural gas planning, however, Section 23 creates allowances and pathways for natural gas utilities to recover costs for expenses for investments in infrastructure to support the adoption and service of alternative fuel vehicles if particular conditions are met.[28] Such conditions are as follows:

*Allows natural gas utilities to recover costs from investments related to infrastructure to support the adoption and service of alternative fuel vehicles if they can reasonably be expected to:*

- *Support vehicles that are powered by renewable natural gas or hydrogen;*
- *Support reductions in transportation sector greenhouse gas emissions over time; and,*
- *Benefit the natural gas utility system; or that revenues from natural gas utilities from fueling alternative forms of transportation vehicles offset utilities' fixed costs that may otherwise be charged to retail natural gas customers*

It is unclear at this point to what extent this legislation will have on the CNG market locally and regionally.

### 2.6.3. Environmental Policy / Codes – WA

#### *Washington Climate Commitment Act (CCA)*

In 2021, the Washington Legislature passed the Climate Commitment Act (or CCA) which establishes a state-wide program to reduce carbon pollution and achieve greenhouse gas limits set in state law (RCW 70A.45.020). The Climate Commitment Act (CCA) caps and sets reduction targets for greenhouse gas emissions from identified emitting sources and industries. The program will start Jan. 1, 2023.

The primary regulator of the CCA is Washington Department of Ecology (Ecology). The agency is in the process, throughout 2022, of developing rules to implement the cap on carbon emissions, including mechanisms for the sale and tracking of tradable emission allowances, along with compliance and accountability measures. Long term, the program is intended to allow for linkage with similar programs in other states/jurisdictions. California has been identified as the most likely first partner.

The cap-and-invest program works by setting a limit, or 'cap', on greenhouse gas emissions in the state, and then lowering that cap over time to ensure Washington meets the greenhouse gas targets. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

When it launches on Jan. 1, 2023, the cap-and-invest program will cover industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual greenhouse gas emissions above 25,000 metric tons of carbon dioxide equivalent. Over time additional portions of the economy will be moved under the program. On Jan. 1, 2027, the program adds waste-to-energy facilities and on Jan. 1, 2031, the program adds railroad companies.

[28] https://www.oregon.gov/puc/Documents/2021-Legislative-Summary.pdf

All participating entities must obtain allowances equal to their covered emissions. The Legislature determined that 'emissions-intensive, trade exposed' entities (EITEs), natural gas utilities, and electric utilities will be issued some allowances at no cost. Businesses can also buy and sell allowances on a secondary market. The total number of allowances issued each year will be equal to the 'emissions cap' and will decrease over time to meet statutory limits. Most businesses will purchase their allowances at auction. Ecology will host quarterly emission allowance auctions for covered entities. Funds from the auction of emission allowances are intended to support new investments in climate resiliency programs, lower carbon transportation, and addressing health disparities across the state. Ecology is proposing floor and ceiling prices for allowances to prevent allowance prices from going too high.

A portion of a covered entity's compliance obligation can be covered by credits generated by projects that reduce, remove, or avoid greenhouse gas emissions, called offset projects. Covered entities can meet up to 5% of their obligations with offset credits through 2026 (plus an additional 3% for offset projects on tribal lands), and 4% from 2027 to 2030 (plus an additional 2% for projects on tribal lands). To qualify under the CCA, offset projects must result in greenhouse gas reductions that are real, permanent, quantifiable, verifiable, and enforceable. They must also be in addition to emissions reductions that are required by law.

The cap-and -invest program is still in the final stages of rulemaking and will not be complete before the publication of this plan. As such it is possible that some details included may shift before implementation.

### *House Bill 1257 (HB 1257)*

House Bill 1257, The Washington Clean Buildings Bill, passed in 2019. HB 1257 adopts energy performance standards, aimed at reducing the energy intensity of Washington's commercial building stock, for commercial buildings exceeding 50,000 square feet. Buildings that fit this category will be required under the law to meet Energy-Use Intensity targets (EUIt) to reduce greenhouse gas emissions.

HB 1257 also adopts two new programs directly applicable to Washington's natural gas distribution utilities. Firstly, the legislation requires utilities to identify and acquire all natural gas conservation measures that are available and cost-effective. To achieve this goal, the legislation requires the utilities to establish a conservation acquisition target every two years (also referred to as a biennial energy efficiency plan). To identify all conservation measures the company contracted the consulting firm AEG to conduct a conservation potential assessment (CPA).

Secondly, the legislation required all Washington natural gas utilities to offer a voluntary renewable natural gas tariff and the legislation permits natural gas utilities to propose a renewable natural gas program for a portion of the gas delivered to all retail customers. NW Natural's voluntary renewable natural gas offering was approved by the Washington commission in March of 2022 and went live for customer participation in July of 2022.

### *Status of Washington Codes*

Washington's new residential code went into effect in February 2021. This change made it more expensive to build a single-family home with gas compared to electric – with the cost deferential varying depending on the home size, equipment choices, and shell measures selected. Despite this change, many homebuilders are opting to build with gas cooking and fireplaces, although some continue to build with gas space heating as well. New residential code development began in May 2022 and includes a prohibition on gas furnaces and water heating for residential new construction but allows for gas heat pumps and hybrid systems. The code draft will not be decided on until after the public comment period, which takes place from September to October 2022. The State Building Codes Council (SBCC) will take action on the new code in November 2022.

Washington commercial code changes were approved in April 2022 by the SBCC (with a final vote scheduled for November 2022) and will prohibit gas space and water heating in new construction and retrofits, with very limited exceptions beginning July 2023.

However, we are proposing and anticipate gas heat pumps and hybrid systems will be permitted through a Washington commercial building codes amendment to be consistent with Residential codes and reflect the efficiency and operating costs benefits of these systems.

## 2.6.4. Environmental Policy – Local

In NW Natural's service territory several local jurisdictions (e.g. cities and counties) have or are in the process of creating Climate Action Plans as a means of addressing and reducing carbon emissions within the jurisdiction. The plans vary across the territory between direct actions that municipal facilities and operations can take to reduce emissions to plans that encompass the activities of all citizens, institutions, and businesses. Most plans include a focus on a number of activities to reduce the use of fossil fuels in transportation and buildings. Within this spectrum of options, some municipalities consider banning natural gas or in some way limiting the growth of natural gas infrastructure.

# Chapter 3
# Resource Needs

This chapter examines the future resource requirements for NW Natural's system. This includes resources needed for capacity, energy, and emissions compliance. Establishing resource need begins with the load (i.e., demand) forecast, which is the focus of this Chapter. The resources needed are ultimately determined by demand specific type of customer. Table 3.1 lays out how system resources are planned to meet capacity, energy, and emissions compliance needs by customer type.

**Table 3.1: System Resource Planning by Customer Type**

| | Gas Supply System Resource Planning | | |
|---|---|---|---|
| **Customer Type** | **Design Winter Weather Energy Requirements** | **Peak Day Capacity Requirements** | **Emissions Compliance** |
| Firm Sales | ✓ | ✓ | ✓ |
| Interruptible Sales | ✓ | | ✓ |
| Firm Transport | | | ✓ |
| Interruptible Transport | | | ✓ |

## 3.1 Overview

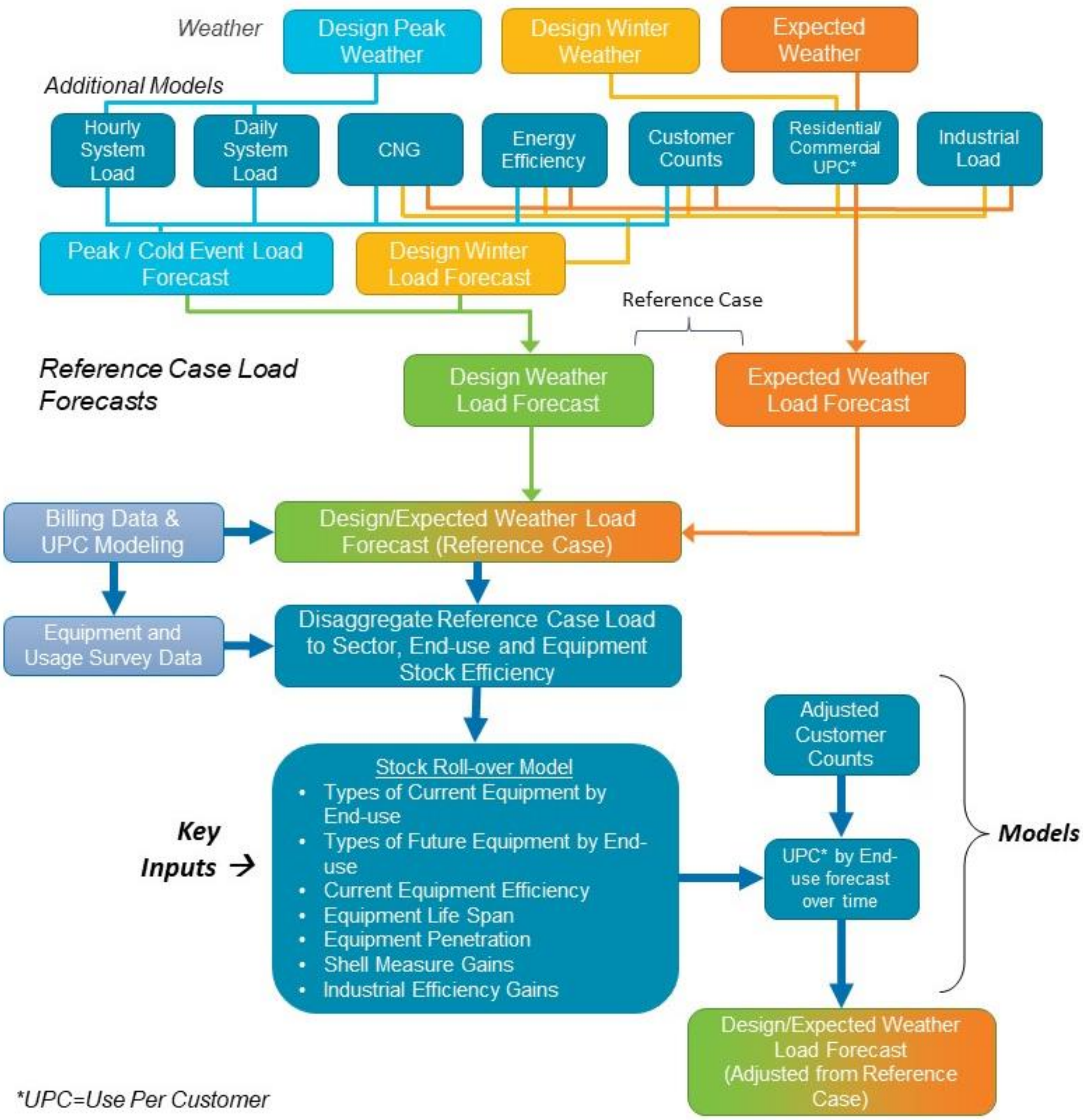
Given the planning environment as outlined in the previous chapter, this IRP develops a range of load forecasts over a 28-year planning horizon from 2022 to 2050. The resulting demand and emissions reduction requirements from these load forecasts determine the need for *gas supply and compliance resources*, which include options for both demand-side and supply-side resources and are discussed in detail in the following chapters). Developing a range of load forecasts and understanding the potential uncertainty of the load is a critical first step to determining the resource need.

NW Natural's load forecasts are compiled from several bottom-up modeling components including customer count forecast, use per customer modeling, industrial load forecast, and energy efficiency projections, and are combined with a top-down daily/hourly system load modeling approach. Each of these components of the load forecast is done at a selected granularity of time, geography, and customer type and allocated to lower levels where necessary. This component-by-component approach to load forecasting provides a deep understanding of the demand drivers, while balancing model complexity with accuracy and precision.

NW Natural's load forecasts start with historical data, input from subject matter experts (SME), and econometric models to project historical trends into the future. The combination of these historical trend models builds a *reference case* load forecast, which serves as a starting point for developing a range of load forecasts. The reference case represents a business-as-usual perspective, where the future looks like the past. Given the changing policy landscape, the imperative to address climate change, and the company's own carbon commitment goals, load forecasts are likely to deviate from these historical trends. To adequately model changes to these historical trends, NW Natural implements an end-use load forecasting model using the reference case as an anchoring point to adjust for changing expectations. This IRP's base case, scenarios, and stochastic forecasts all require the reference case as a starting point.

NW Natural first implemented end-use load forecasting in the 2018 IRP to analyze several scenarios. This IRP expands the use of the end-use load forecasting model to all scenarios (to be discussed in more detail later in this chapter) in combination with Monte Carlo simulations to create a range of potential load forecasts. Figure 3.1 illustrates a high-level flow chart for the various models needed to develop the reference case for a given weather pattern and how it then feeds into the end-use load forecasting model. The rest of this chapter is arranged by following this diagram through the different components of the load forecasting model.

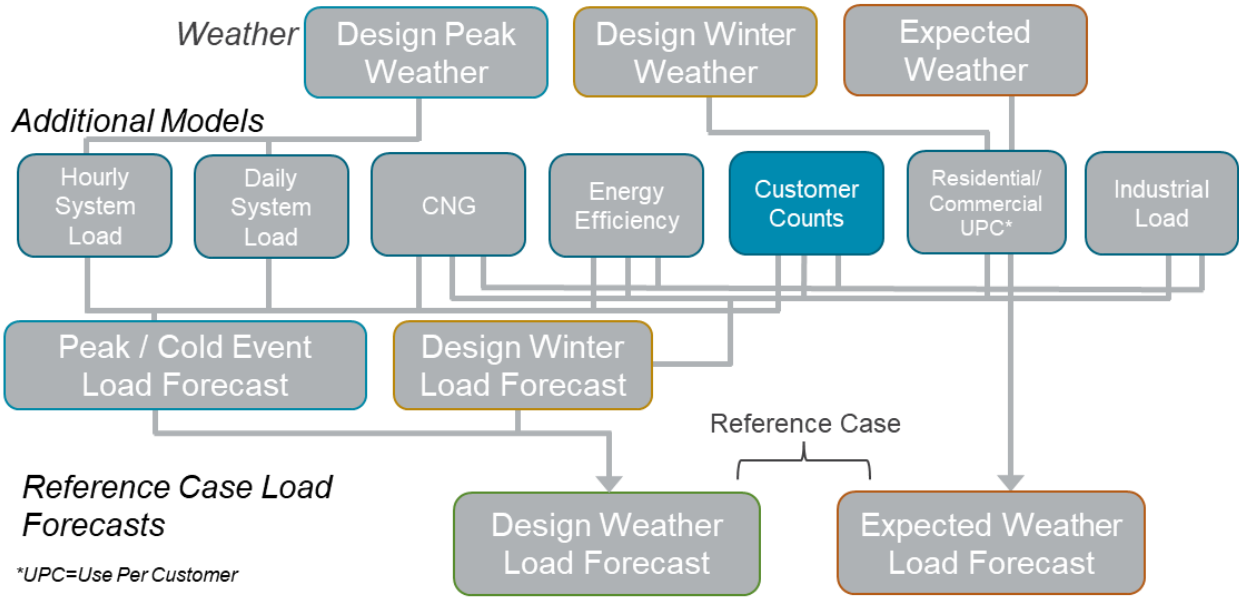
**Figure 3.1: Load Forecast Model Flow Diagram**




## 3.2 Customer Forecast – Reference Case

NW Natural serves a wide variety of homes and businesses where multiple people typically live in a single home and hundreds of consumers may patron a single business. As a common practice, the IRP defines a single customer as a natural gas meter in service. The customer count (i.e., meter count) forecast for residential and commercial customers is a critical input of the load forecast models (see Figure 3.2).

**Figure 3.2: Load Forecast Model Flow Diagram – Customer Counts**




NW Natural develops separate customer count forecasts for residential customers and commercial customers with four and three sub-classes, respectively. Each sub-class is allocated across ten load centers, which comprise NW Natural's service territory (see Table 3.2). In total, 70 separate customer count series are generated from the sub-class and load center combination. The customer count forecast is developed at this granular level as customer usage profiles are distinctly different across both sub-class and location (e.g., gas usage for the average residential house on the Pacific coast is very different than the average residential home in Portland).

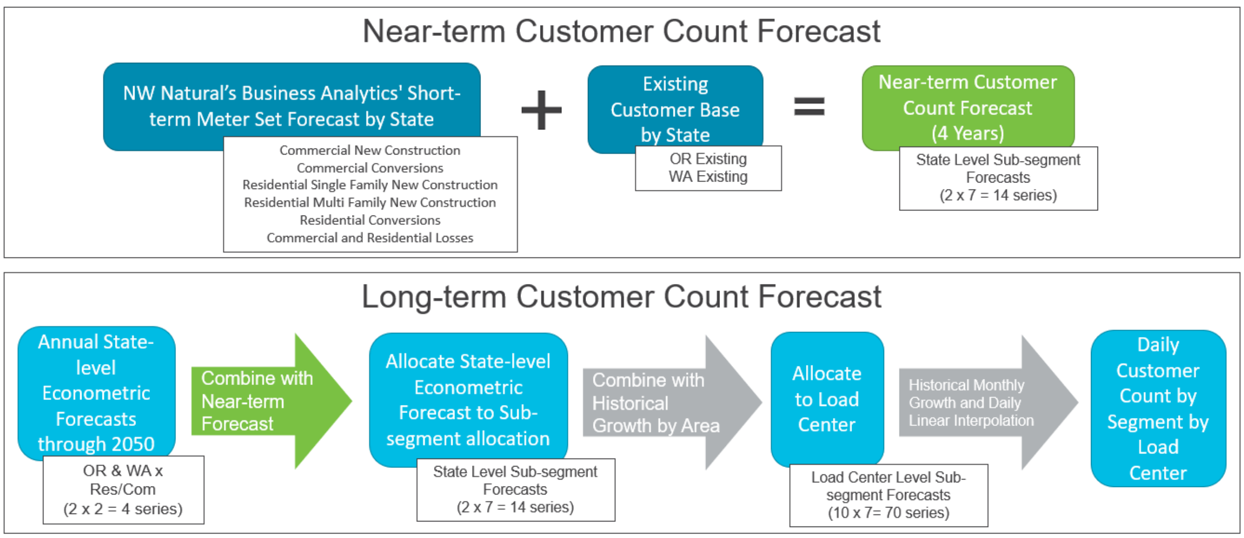
**Table 3.2: Customer Count Series**

| Class | Sub-class | | Load Center† |
|---|---|---|---|
| **Residential** | Existing<br>New Construction – Single Family<br>New Construction – Multi Family<br>Conversions | X | Albany<br>Astoria<br>The Dalles OR<br>The Dalles WA<br>Coos Bay<br>Eugene<br>Lincoln City<br>Portland<br>Salem<br>Vancouver |
| **Commercial** | Existing<br>New Construction<br>Conversions | | |

†The 10 Load centers include a broader area than indicated by its name (e.g., the Vancouver load center includes all of NW Natural's service territory in Clark County).

The IRP customer count forecast for the planning horizon combines a near-term customer count forecast provided by internal subject matter experts (SME), with an econometric model that captures long-term trends. The near-term forecast is projected by state and sub-class, while the econometric model is estimated by class (residential and commercial) and by state. Using historical data and growth rates, these forecasts are combined and allocated to each load center as illustrated in Figure 3.3.[1] Note that the IRP models do not forecast the number of industrial or large commercial customers due to the extreme difference in usage profiles among these customers. Load forecasting for these large usage customers is discussed later in this chapter.

**Figure 3.3: Customer Count Forecast Process Diagram**




## 3.2.1 Subject Matter Expert Panel

NW Natural's customer forecasts blend two different types of forecasts, that is, econometric method-based long-term trend forecasts as detailed in the following section and near-term forecasts provided a panel of internal subject matter experts (SME panel). The SME panel is composed of NW Natural employees from multiple departments across the company. The panel meets quarterly to update its previous forecast and prepares a budgetary forecast in the fourth quarter. The panel uses quantitative macroeconomic information such as the number of Oregon housing starts forecasted by Oregon's Office of Economic Analysis (OEA) or state immigration numbers, and qualitative information including up-to-date intel about potential multifamily new construction housing customer additions or information gathered directly from the trade ally community. Using information from departments across the company, the panel develops a near-term annual forecast for residential and commercial customer counts.

[1] See NW Natural's 2018 IRP, Chapter 3, Section 2.2 in which NW Natural evaluated several alternative bottoms-ups approaches for the customer count forecast including estimating sub-segments (referred to as components in the 2018 IRP) at the load center level. For a variety of reasons, including data availability and predictive power, NW Natural concluded that a top down statewide forecast for residential and commercial customer counts was the appropriate methodology.

### 3.2.2 Econometric Models

NW Natural used some of the same steps in its approach to developing and evaluating econometric models for customer forecasts in the 2022 IRP as in the 2018 IRP Update #3, 2018 IRP and 2016 IRP. These include the use of annual data, ensuring stationarity of dependent variables, and evaluating multiple explanatory variables and their transformations.
Annual data is used for two primary reasons. First, a much longer time series is available for customer data at an annual frequency than at a monthly frequency. Second, potential explanatory variables are typically not available at a monthly frequency, but at quarterly or annual frequencies. This is often the case for both historical and forecast values.

NW Natural tested dependent variables for stationarity and differenced where stationarity was not indicated. The Company assessed econometric models with alternative autoregressive integrated moving average (ARIMA) structures for each forecast, generally selecting the structure with the best information criterion value.

NW Natural also evaluated multiple potential explanatory variables for each customer forecast. These included transformations of values, such as differencing, moving averages, leads/lags, and their combinations. The Company eliminated from further consideration explanatory variables with less satisfactory results, such as limited correlation with the dependent variable or an indication of a non-normal distribution of model errors.

Econometric models are developed by class and by state. Table 3.3 shows the explanatory variables and source used in the econometric customer forecasting models. Technical details for the econometric forecast can be found in Appendix B.

**Table 3.3: Exogenous Variables used in Econometric Customer Forecast Models**

| Model | Oregon Models (Source) | Washington Models (Source) |
| --- | --- | --- |
| Residential | U.S. Housing Starts (OEA) | U.S. Housing Starts (OEA) |
| Commercial | Oregon Population (OEA) | Oregon Nonfarm Employment (OEA) |

### 3.2.3 SME and Econometric Blending

Timing requirements of the IRP process are such that NW Natural finalized customer forecasts in the 2022 IRP before 2021 annual data was available. Therefore, the first forecast year is 2021. The Company used the SME panel forecast for years between 2021 and 2023 as demonstrated in the 2018 IRP that the SME panel forecast is arguably more accurate than the econometric forecast in the near term.[2] For year 2024, the Company blends the two types of customer forecasts, with the SME panel forecast and the econometric forecast receiving a one-

[2] See NW Natural's 2018 IRP, Chapter 3 pages 3.8-3.10 for a detailed comparison.

half weight each. For years 2025 forward, the Company added the rate of change from the econometric customer forecast to the value of the customer forecast of the prior year. This merges the state by class econometric model to the state by sub-class SME forecast. Counts are then allocated to load center and daily counts.

### 3.2.4 Residential and Commercial Customer Count Forecast – Reference Case

As shown in Table 3.2 the customer count forecast models develop 70 separate series by load center and sub-class. Figure 3.4 and Figure 3.5 aggregates those series for the system residential and system commercial counts respectively. See Appendix B for state specific breakouts.

**Figure 3.4: System Residential Customers – Reference Case**

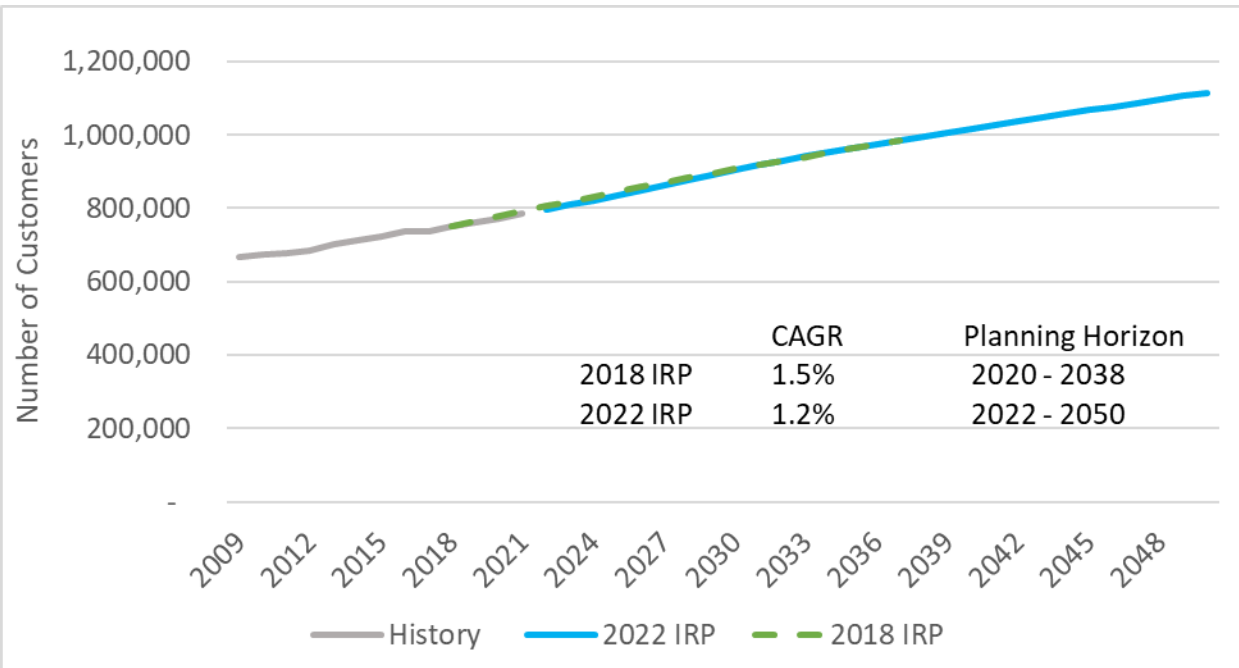


**Figure 3.5: System Commercial Customers– Reference Case[3]**

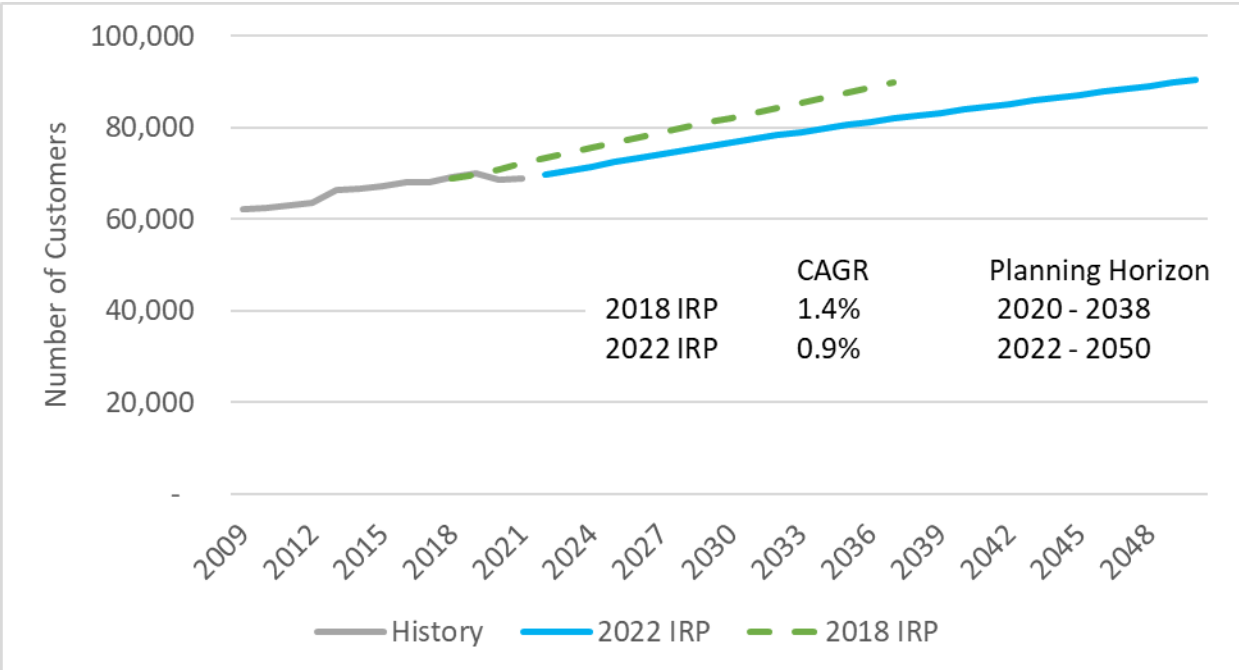



Table 3.4 summarizes the primary similarities and differences between customer forecasts in the 2022 IRP and the 2018 IRP.[4]

[3] Figure 3.5 includes customer counts for large commercial customers on rate schedules 31/32/41/42, but these customer counts are subtracted from the commercial customer count that is used in the use-per-customer model, which estimates small commercial customer usage. This is discussed later in this chapter.
[4] These are the same changes made for the 2018 IRP Update #3. There were no changes in methodology between the 2018 IRP Update #3 and the 2022 IRP. Only data was updated.

**Table 3.4: Customer Forecasting Comparison between the 2022 and 2018 IRP**

| | 2022 IRP | 2018 IRP Update |
|---|---|---|
| Econometric Models | State by Class<br>Oregon Residential<br>Oregon Commercial<br>Washington Residential<br>Washington Commercial | State by Class<br>Oregon Residential<br>Oregon Commercial<br>Washington Residential<br>Washington Commercial |
| **Left-hand side variable** | **Right-hand side variable (source)** | |
| Residential customers (OR) | OR Housing Starts (OEA) | U.S. Housing Starts (OEA) |
| Residential customers (WA) | U.S. Housing Starts† (OEA) | U.S. Housing Starts (OEA) |
| Commercial customers (OR) | OR Population‡ (OEA) | OR Population (OEA) |
| Commercial customers♠ (WA) | OR Nonfarm Employment (OEA) | OR Nonfarm Employment (OEA) |
| Year of SME panel and econometric forecast blending | Year 4 - 2024 | Year 4 - 2020 |

† Right-hand side variable for WA residential model – US Housing Starts – transformed to log form from level form
‡ Right-hand side variable for OR commercial model – Oregon population – transformed to log form from level form
♠ Autoregressive terms in 2018 WA commercial model no longer statistically significant and were dropped

## 3.3 Climate Change Adjusted Weather Forecasts

Climate change is impacting weather patterns across the globe, including here in the Pacific Northwest. As weather is a primary driver for gas usage and a critical input for forecasting load, the long-term trends in weather are important to consider for NW Natural's long-term resource planning. This section explains how the Company incorporates climate change trends into our load forecast modeling.[5]

NW Natural develops weather forecasts, which incorporates data from climate models from the Intergovernmental Panel on Climate Change (IPCC). These climate model predictions are available on a coarse grid of about 300 square kilometers. The coarse grid predictions are further downscaled using a local weather to get weather projections for NW Natural's service territory. The downscaled projections of the IPCC climate models are available through a website maintained by the Lawrence Livermore National Laboratory (LLNL) and are matched to weather stations for each load center.[6] The IPCC publishes numerous models from several different agencies around the world. For a robust outlook of weather trends, the IPCC recommends

**IPCC Climate Models**

- ccsm4.6
- cnrm-cm5.1
- gfdl-cm3.1
- hadgem2-cc.1
- miroc5.1

[5] NW Natural has included climate change models into our long-term load forecasts for several years, but first presented these changes to external stakeholder through the IRP Update #3.

[6] Downscaling of the IPCC data to NW Natural's service territory if 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

using an ensemble of climate models. We selected the five climate models to inform the long-term trends in annual HDDs forecasted out to 2050.

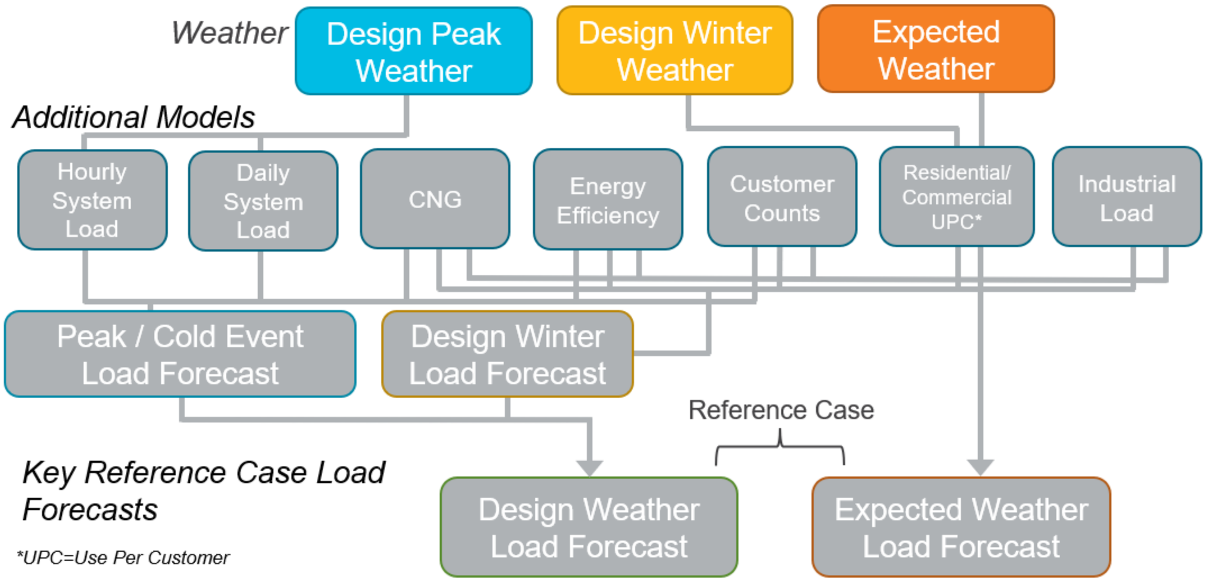
The IRP implements several deterministic and stochastic weather pattern forecasts as inputs into the demand models to establish resource requirements. Table 3.5 describes the three primary deterministic weather patterns.

**Table 3.5: Planning Standard Descriptions**

| Weather Pattern | Description | Purpose |
|---|---|---|
| Expected Weather | Expected weather is similar to "normal weather" uses in previous IRPs, however; expected weather is now incorporating long-term climate change trends based on cumulative annual HDDs. The expectation into the future is that on average weather would be reflected by expected weather. | Expected weather is the baseline used for emissions compliance planning and resource portfolio evaluation as expected weather will be a primary driver for expected natural gas and compliance costs. |
| Design Winter Weather | Cold winter weather adjusted from the expected weather based as a 90th percentile severe winter, based on cumulative winter HDDs (November-April). | The design winter weather drives annual energy requirements, ensuring resources are planned adequetly to meet annual energy requirement to sufficiently manage a colder than usual winter. |
| Design Peak Weather | The design peak day uses historical data to simulate a 1-in-100 year winter event. | Peak day weather drives the system capacity requirement for each forecasted winter in NW Natural's IRP. Peak hour weather drives the distribution capaacity requirement for a specfic area on NW Natural's distribution system. |

Figure 3.6 shows the load forecast flow chart illustrating how different weather inputs are used in demand forecasting models. See Appendix B for technical details on how these weather forecasts are generated.

**Figure 3.6: Load Forecast Model Flow Diagram – Weather Patterns**




### 3.3.1 Expected Weather

Since NW Natural's load is primarily driven by heating requirements, the expected weather forecast focuses on the expected level of annual HDDs out to 2050. The expected annual HDDs is based on the average of the annual HDDs from the five selected IPCC climate models for each load center. Intra-year shaping is then applied for each month and then intra-month shaping is applied to each day to generate a daily forecasted temperature. This daily shaping is developed using a representative temperature pattern that is applied to each year in the forecast. In other words, each year in the forecast will have the same shape, but overall temperatures are increasing (i.e., HDDs are decreasing) over the planning horizon. Using a representative weather pattern, creates realistic volatility in daily temperatures, which is important for modeling resource dispatching.

### 3.3.2 Design Winter Weather

Design winter weather is generated to ensure our resource plan is adequate to serve customers during a colder than normal winter. This is particularly important for storage resource planning, such that the storage facilities maintain a sufficient inventory level to serve customers throughout colder than normal winter. NW Natural uses a 90th percentile design winter planning standard based on cumulative winter (Nov-April) HDDs. The design winter weather is developed as an adjustment to the expected weather forecast for the winter months, thus incorporating climate change trends for those winter months.

### 3.3.3 Design Peak Weather

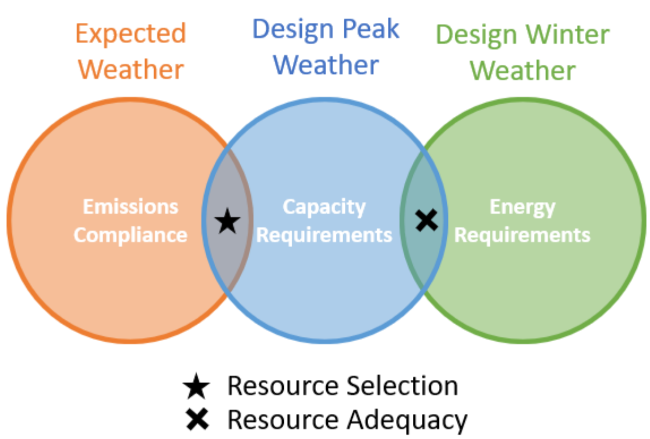
Design peak weather includes a five-day cold event where NW Natural's system experiences a peak day on the third day of the five-day cold snap. Temperatures for this design peak weather for each location is based on temperatures from February 3, 1989, where system weighted temperatures fell to 10°F. Note that the peak day sales load forecast is discussed in more detail later in this chapter and is a function of many more drivers than temperature, but the design peak weather describe here is used in combination with the UPC model to allocate the peak day to each load center. For gas supply planning in the IRP design peak weather is modeled from February 1st to February 5th for each year over the planning horizon.

### 3.3.4 Weather Patterns for Resource Planning

In previous IRPs, NW Natural has used the combination of design winter weather and design peak weather to ensure the selected resource portfolio could meet both capacity requirements and total annual energy requirements. Capacity requirements, specifically the ability to serve customers on a peak day, has been the primary driver for resource selection in previous IRPs. Resource selection for this IRP will need to fulfill an additional emission reduction requirement to comply with the state legislated emissions targets for utilities. Due to modeling limitations, a single weather pattern, and therefore daily demand profile, must be used per run in the cost minimizing resource selection model.

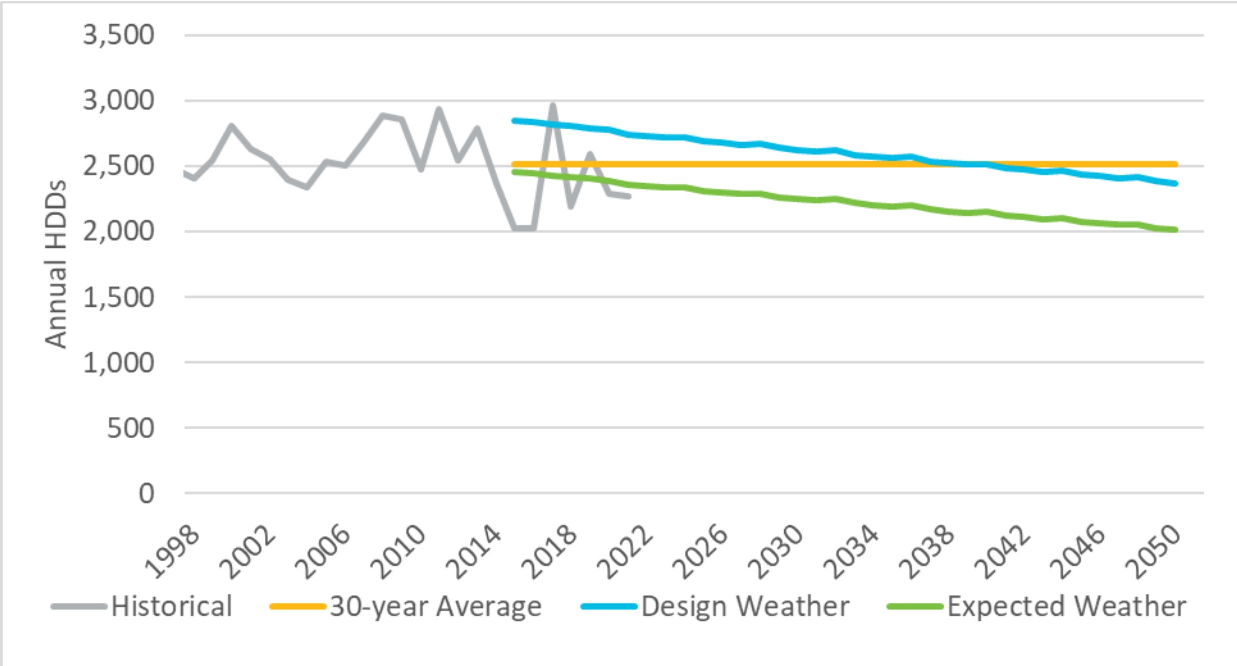
As emissions compliance and capacity requirements are critical to the long-term resource plan, this IRP uses expected weather with a single design peak day for resource selection. This will ensure that the model selects a least cost resource portfolio that meets both capacity and emission reduction requirements. The combination of design peak and design winter weather is still used to test the resource adequacy of preferred portfolio of resources as illustrated by Figure 3.7.

**Figure 3.7: Weather Patterns for Resource Planning**




The climate change models predict as substantial decrease in annual HDDs over the planning horizon. Figure 3.8 illustrates the annual HDDs for expected weather and design weather for the Portland load center used for this IRP. The 30-year average is simply shown for historical context.

**Figure 3.8: Portland Example Annual Expected and Design HDDs**



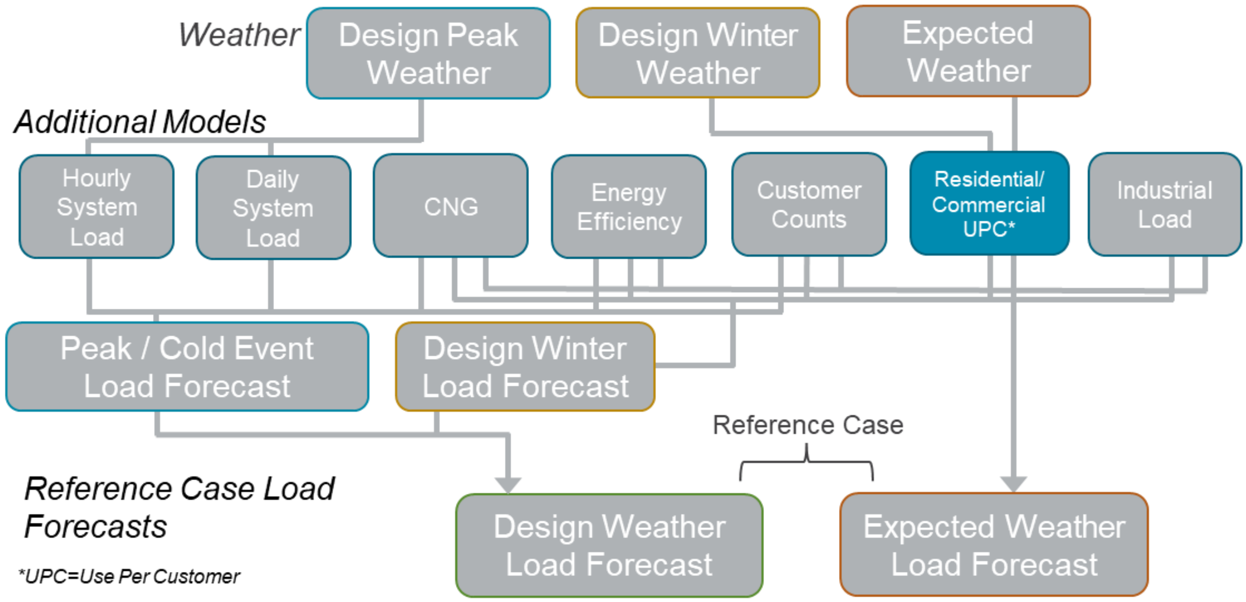

## 3.4 Residential and Small Commercial Use per Customer – Reference Case

The reference case demand for residential and small commercial customers is developed by first modeling daily use per customer (UPC) demand as a function of daily temperatures.[7] UPC models match up historical billing data with historical weather data and are estimated for each sub-class of customer by location. The daily weather patterns then feed into these UPC models (see Figure 3.9) which are then are multiplied by the customer count forecast to create daily residential and commercial load forecasts. Energy efficiency adjustments are made at the state and customer class level to create the reference case demand for residential and small commercial.

[7] Load from large commercial customer on rate schedules 31/32/41/42 is estimate along-side the industrial load and is discussed in the industrial load section.

### 3.4.1 Use per Customer Regression Model

**Figure 3.9: Load Forecast Model Flow Diagram – UPC Models**



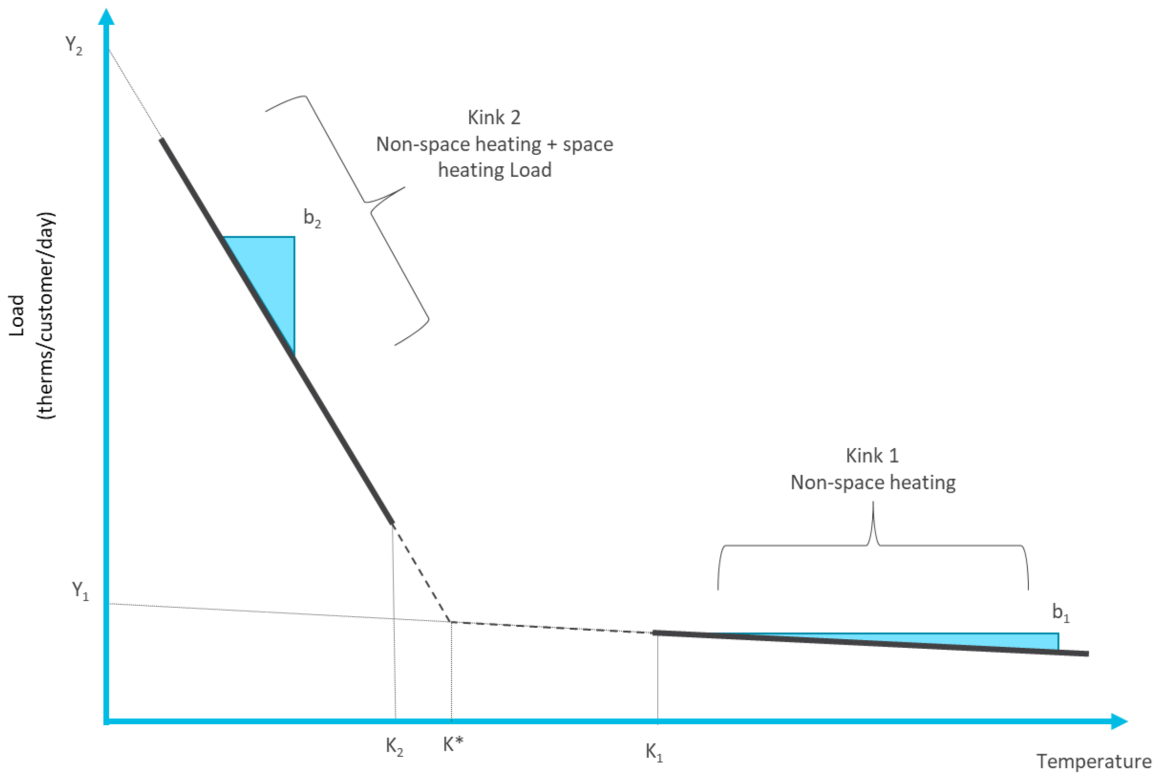

The UPC models estimates a two-segment piece-wise demand function for each customer sub-class and location. Demand functions for existing customers are estimated by load center and demand functions for new construction and conversion customers are estimated by state. Table 3.6 lays out the details of the billing data used in each UPC model.

**Table 3.6: UPC Regression Data Details**

| Sub-class | Bills Used In Regression Model | Geographic Grouping |
|---|---|---|
| **Residential Existing** | All current residential customers | Load Center |
| **Residential Conversion** | Residential new construction/conversions since 2018 | State |
| **Residential Single-family New Construction** | | |
| **Residential Multi-family New Construction** | | |
| **Commercial Existing** | All current commercial customers | Load Center |
| **Commercial Conversion** | Small commercial new construction/conversions since 2018 | State |
| **Commercial New Construction** | | |

The two segments of the piece-wise demand function represent customer demand as 1) non-heating load at warmer temperatures and 2) heating + non-heating load at colder temperatures. A simplified model is illustrated by Figure 3.10.

**Figure 3.10: UPC model**




The temperature point (K*) for when heating load starts for the average customer varies by location and customer sub-class. K* is calculated based on where the two regression lines intersect.[8] Regression models are used to estimate the parameters $b_1$, $b_2$, $Y_1$, and $Y_2$ for each of the models outlined by Table 3.2. Given these parameters, use per customer demand as a function of temperature (T) is specified as:

$$\underline{Use\ Per\ Customers\ (UPC)}$$

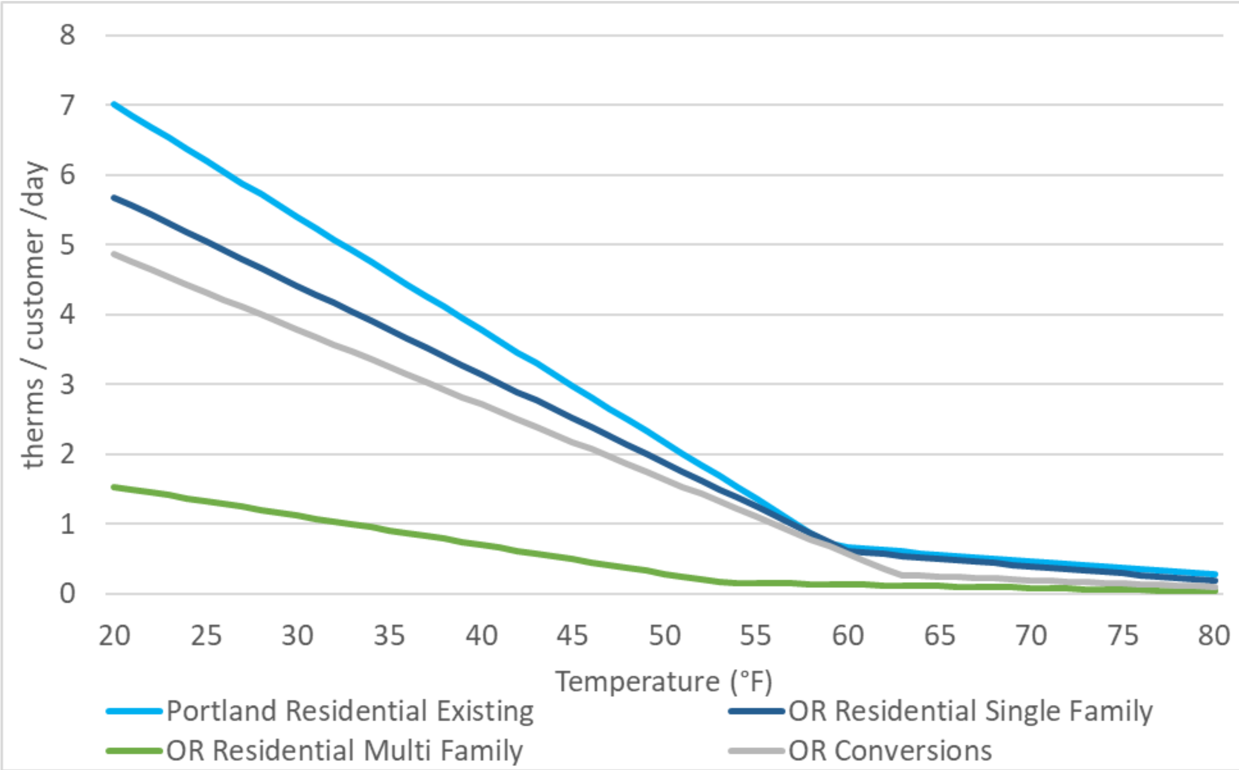
$$= Y_1 + b_1 * (T) \qquad if : T \geq K^*$$

$$= Y_2 + b_2 * (T) \qquad if : T < K^*$$

A table with $b_1$, $b_2$, $Y_1$, $Y_2$, $K_1$, $K_2$, and K* parameters for each model is listed in Appendix B. Figure 3.11 shows the predicted values for four of the residential UPC models as an example.

[8] Due to the nature of the monthly billing data used in the UPC model, data points with temperatures above $K_1$ are used for kink 1 regressions and data points with temperatures below $K_2$ are used for kink 2 regressions.

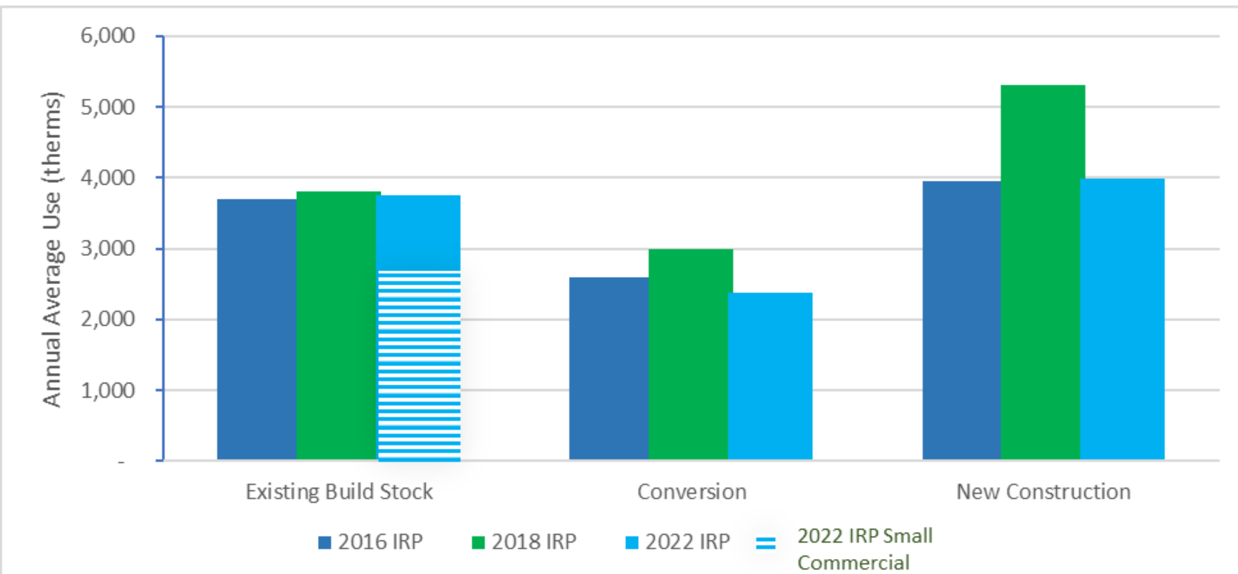
**Figure 3.11: UPC Model Predicted Values**




Figures 3.12 and 3.13 show the forecasted first year estimates of usage per customers for residential and commercial customer classes, respectively. While residential existing customer usage has remained almost unchanged over several IRPs, residential conversion, and new construction in the 2022 IRP have seen a reduction of 30% and 41%, respectively, in estimated annual usage compared with the 2016 IRP. In contrast, commercial customer usage is slightly lower (about 9% lower for the commercial conversion customers) between the 2022 and the 2016 IRPs.

**Figure 3.12: First Year Residential Annual Usage per Customer**


**Figure 3.13: First Year Commercial Annual Usage per Customer**




By multiplying the customer count forecast by the UPC model conditional on a given weather pattern (i.e., temperature) provides daily load for each sub-class and load center.

### 3.4.2 Cost-Effective Energy Efficiency – Reference Case

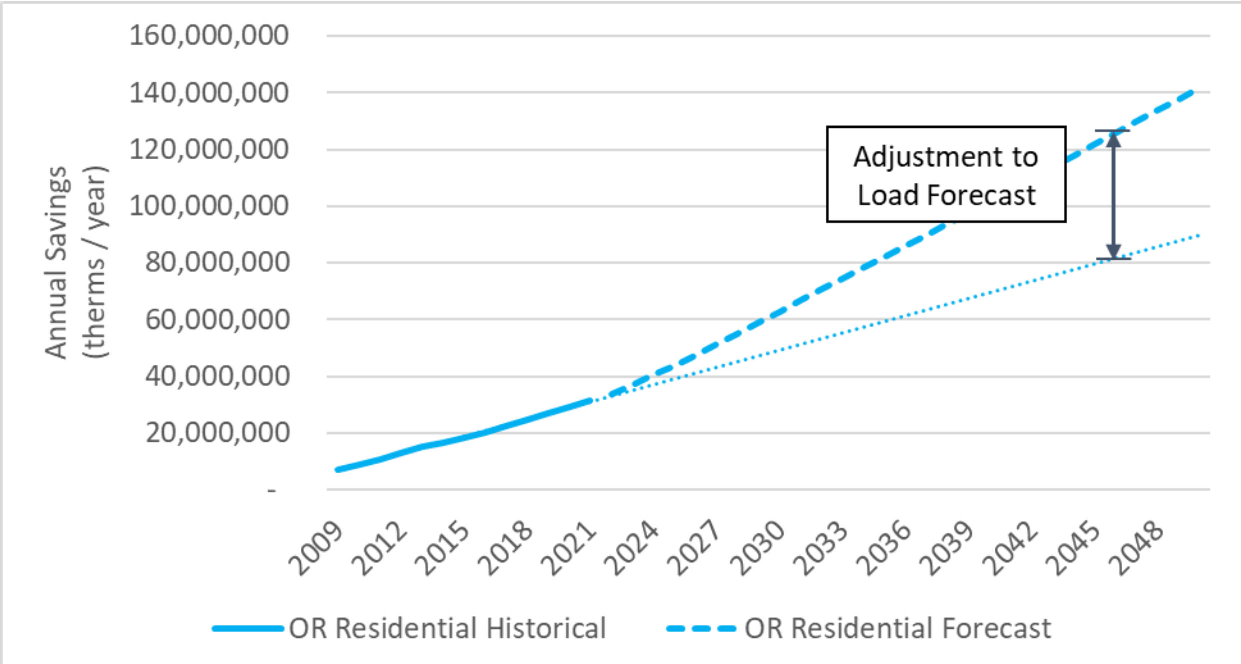
The Energy Trust of Oregon (Energy Trust) currently administers energy efficiency programs for residential, commercial, and industrial sales customers in Oregon and residential and commercial sales customers in Washington. NW Natural is working to establish energy efficiency programs for industrial sales customers in Washington and transportation customers across the system to further the therm savings, and therefore maximize emission reductions from energy efficiency for the whole gas system.

Energy Trust provides NW Natural with a therm savings forecast, known as a resource assessment (RA) or conservation potential assessment (CPA), for the incentive programs currently being offered in Oregon. Additionally, NW Natural hired a third-party consultant, Applied Energy Group (AEG), to conduct a CPA for Washington sales customers. AEG also conducted two high-level CPAs for transport customers in NW Natural's system, one for Oregon and one for Washington. See Chapter 5 for details for these various CPAs.

| Customer Type | CPA Developer |
|---|---|
| **Oregon** | |
| **Sales**<br>Residential<br>Commercial<br>Industrial | Energy Trust |
| **Transport** | AEG |
| **Washington** | |
| **Sales**<br>Residential<br>Commercial<br>Industrial<br>**Transport** | AEG |

Historical billing data used in the UPC models will reflect underlining trends in customer usage, but the UPC models by themselves will not reflect forecasted ramping up of incentivized energy efficiency programs. NW Natural uses the CPAs provided by Energy Trust and AEG to adjust output from the UPC models by the difference between the historical energy efficiency trend and the forecast from the CPA for cumulative therm savings. Figure 3.14 illustrates this difference and the adjustment made to the UPC modeled forecast for Oregon residential savings. These adjustments are done by state and customer type. Annual savings predictions are allocated to the day and load center based on load. A similar adjustment is made for design peak day savings to the peak day forecast discussed later in this chapter.

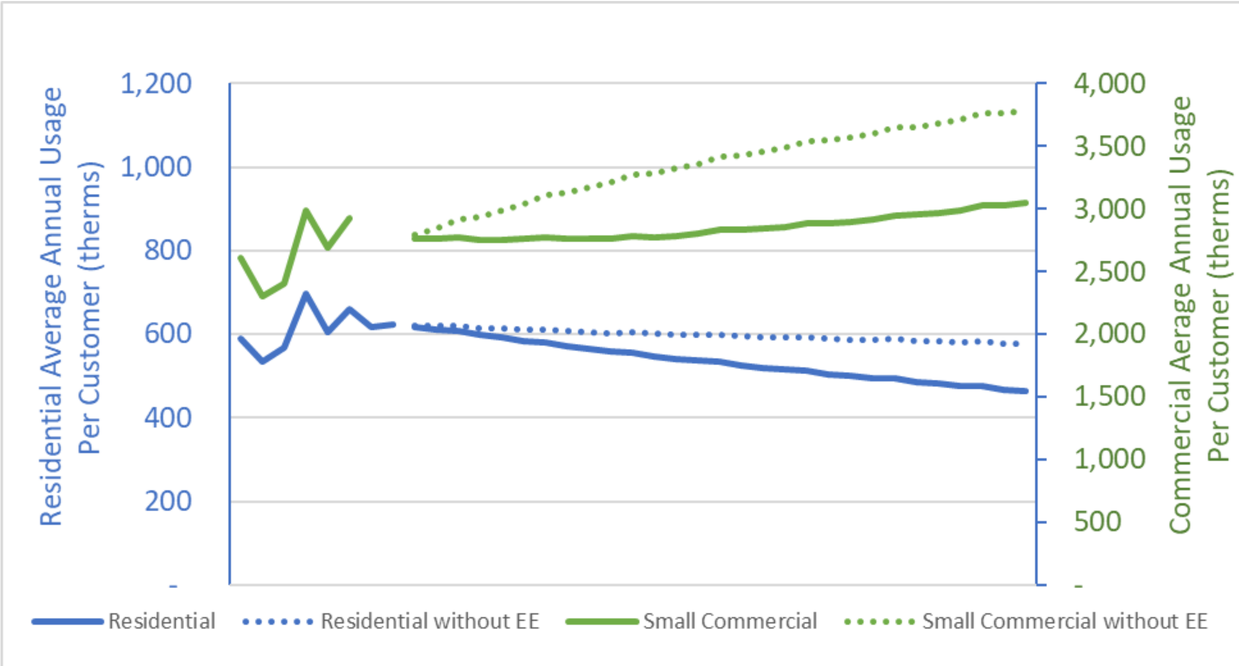
**Figure 3.14: OR Residential Cumulative Annual Savings and UPC Adjustment**




### 3.4.3 Annual Use per Customer and Annual Forecast – Reference Case

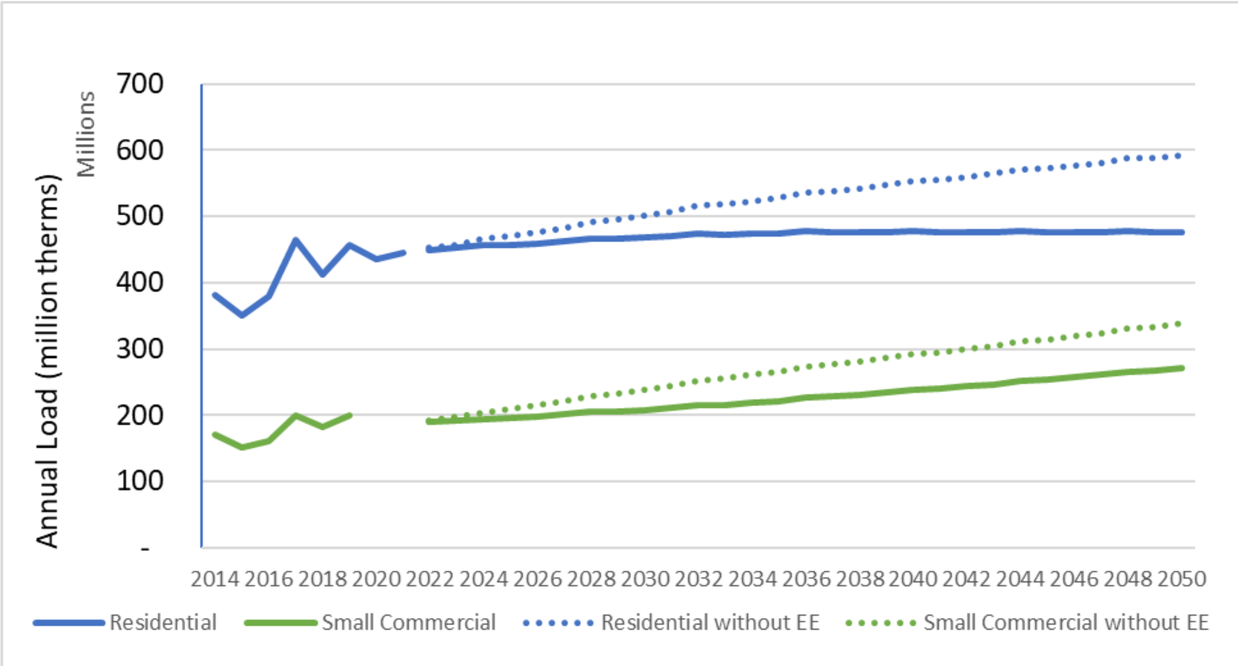
Figure 3.15 shows NW Natural's forecast of average annual use per customer for residential and commercial customers before and after incentivized energy efficiency savings. Residential average annual use per customer for the reference case declines, while commercial average annual use per customer for the reference case increases over the planning horizon. This increase in the reference case commercial UPC is reflective of the new construction commercial customers on average using more gas than existing customers.

**Figure 3.15: Trend in Use per Customer With and Without Energy Efficiency – Reference Case**




Multiplying the customer count forecast and the daily use per customer forecast provides a daily residential and small commercial forecast. Aggregating the daily number for each year provides the annual load forecasts for residential and small commercial customers (Figure 3.16). Due to declines in residential UPC and increases in residential customers over the planning horizon, the annual residential reference case demand grows slowly till 2040 before beginning to decline. Small commercial reference case total demand increases throughout the planning horizon driven by increases in commercial customers.

**Figure 3.16: Residential and Small Commercial Annual Demand Forecast**

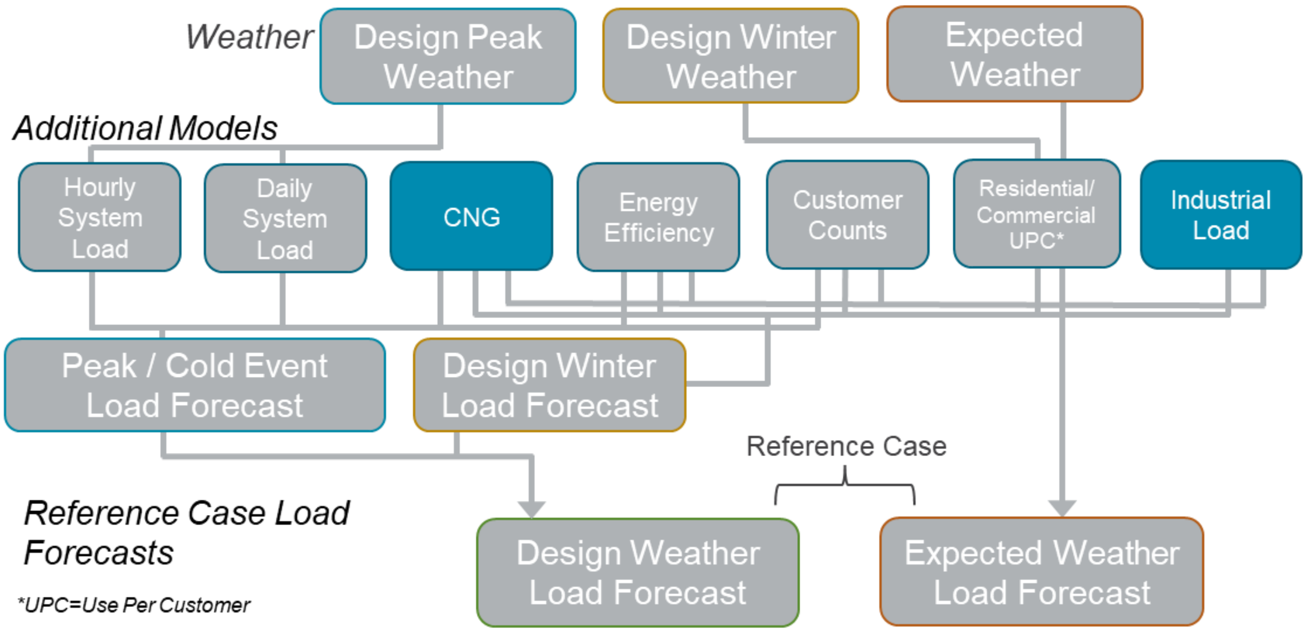



## 3.5 Industrial, Large Commercial and Compressed Natural Gas (CNG) Load Forecast – Reference Case

As noted earlier, NW Natural does not forecast Industrial load by forecasting use per customer and multiplying by forecasted customers due to the extreme differences in usage levels by these customers. Instead, we directly forecast the annual load of all industrial customers and large commercial customers. NW Natural's industrial load can then be allocated into four categories of service: firm sales, firm transportation, interruptible sales, and interruptible transportation.[9] Large commercial sales load is forecasted separately but is include as a part of the industrial load box in the Figure 3.17 flow chart.

[9] 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 transport load forecast.

**Figure 3.17: Load Forecast Model Flow Diagram – Industrial, Large Commercial and CNG Load Forecast**




### 3.5.1 Econometric Forecasts

NW Natural uses methods to develop an econometric forecast of industrial load like the methodology for the long-term econometric models implemented for residential and commercial customer counts, including an ARIMA structure and exogenous variable selection. Forecasting approaches involving separately forecasting loads for each industrial class of service were generally unsuccessful. [10] Therefore, NW Natural forecasts the aggregate industrial load (for all classes of service) and allocates the total to individual classes of service as well as to month and load center. Large commercial sales load is forecasted separately. See Appendix B for technical details related to the econometric models used to forecast industrial load.

### 3.5.2 SME Panel Forecasts

Similar to customer forecasts, NW Natural also uses an SME panel forecast of industrial load to blend with the econometric forecast discussed above. More specifically, NW Natural uses the SME panel forecast for 2022 and 2023, an equally weighted blend of the two forecasts for 2024, and the econometric forecast for 2025 forward.

### 3.5.3 Compressed Natural Gas Service

The 2022 IRP load forecast includes a load forecast associated with NW Natural's compressed natural gas (CNG) service, which NW Natural has previously labeled as an emerging market in previous IRPs. NW Natural's relies on SME who work with CNG customers to develop the CNG

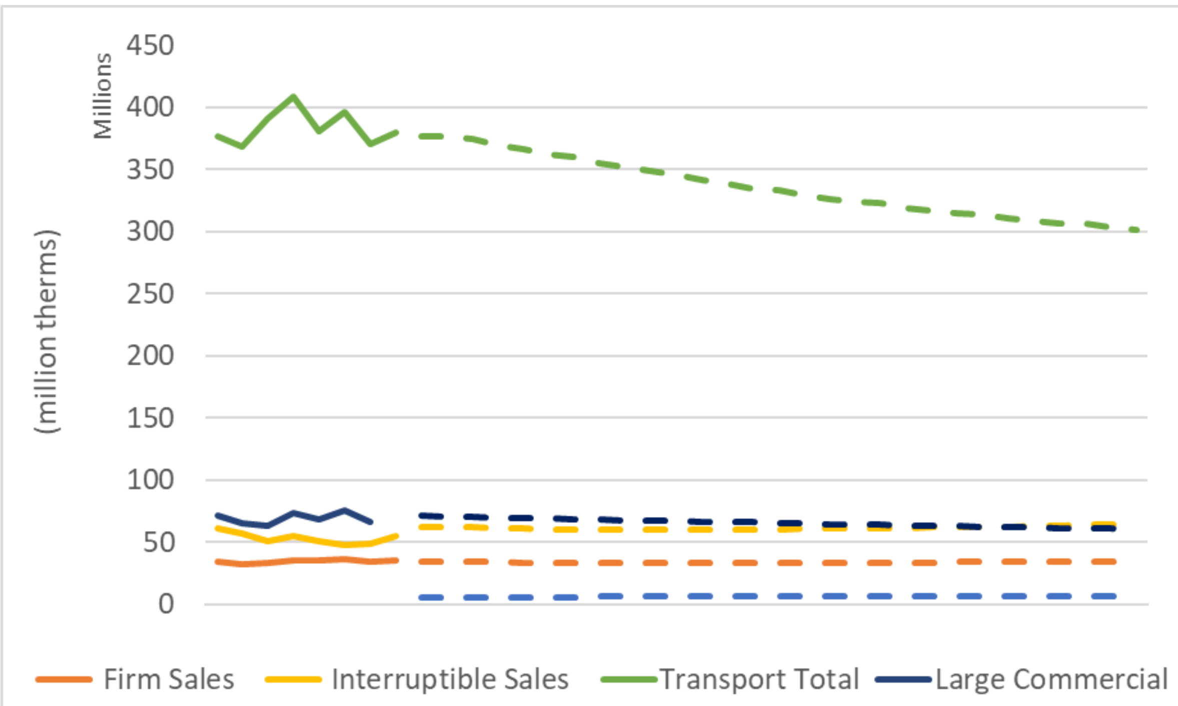
[10] The industrial classes of service are firm sales, interruptible sales, firm transportation, and interruptible transportation.

load forecast. CNG customer load is forecasted to be less than 0.5% of NW Natural's annual throughput for any year over the planning horizon (see Figure 3.21).

### 3.5.4 Industrial, Large Commercial Load, and CNG Forecast - Reference Case

NW Natural uses the composition of the SME panel industrial load forecast, which is by service category, to allocate the total industrial load to the four classes of service for 2022 forward. Figure 3.18 shows the annual industrial load by service category and large commercial sales load.

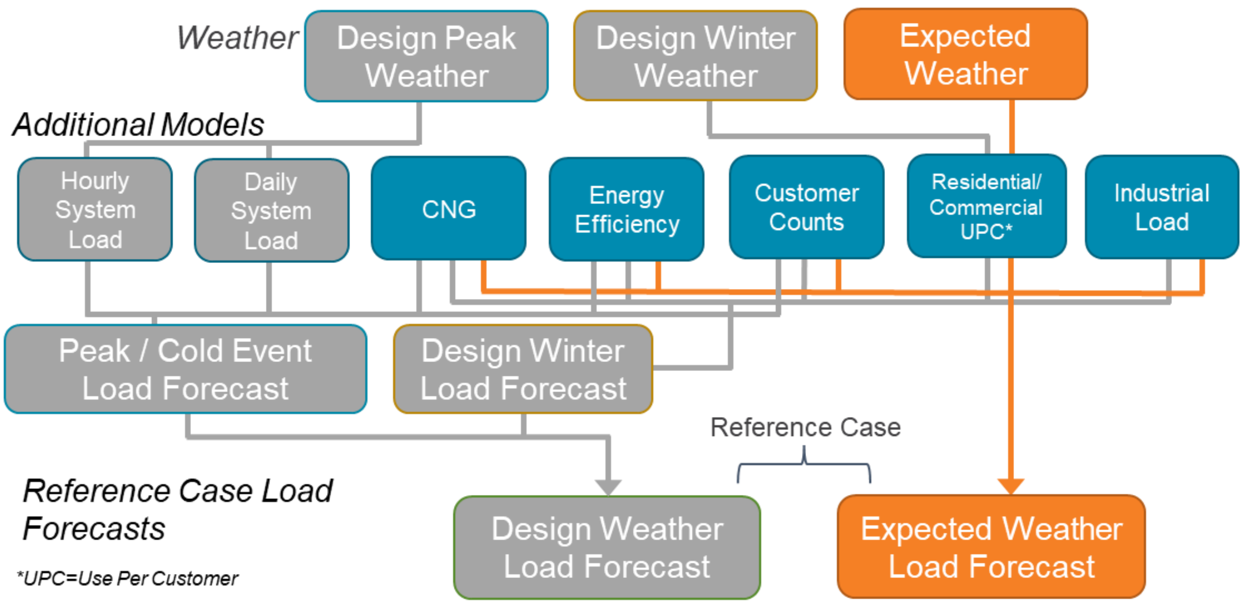
**Figure 3.18: System Industrial Load by Service – Reference Case**




NW Natural uses details provided in the SME panel forecast of industrial load to allocate these load forecasts by service type from annual to monthly and from system totals to load centers.

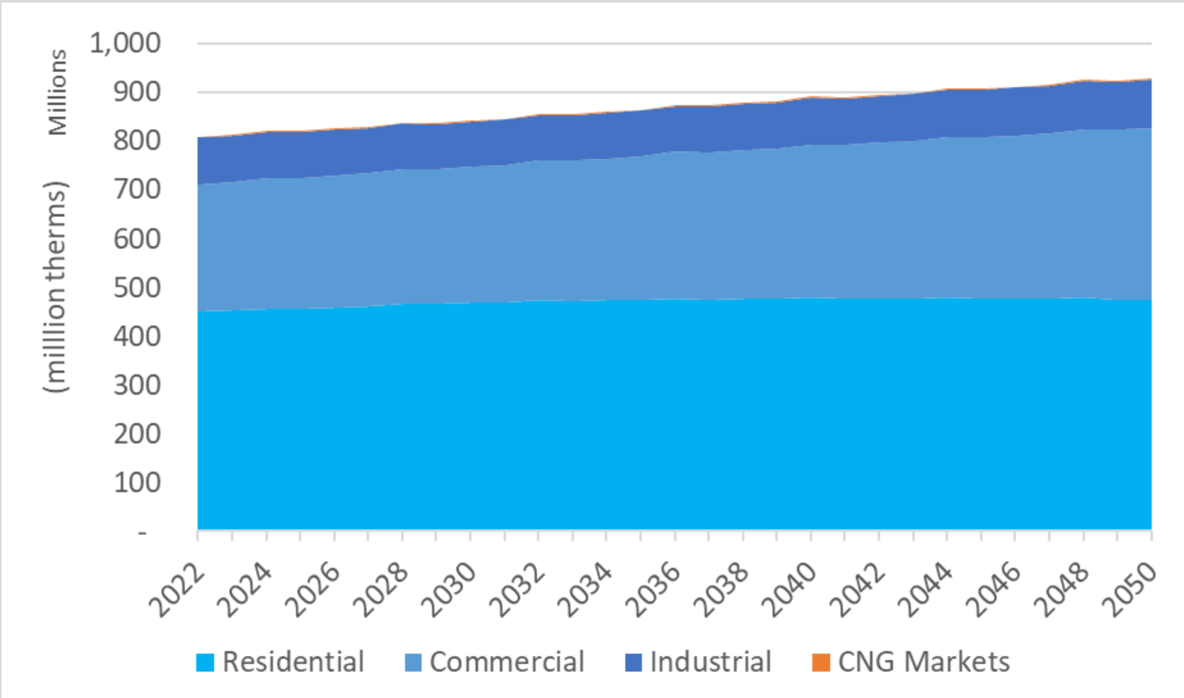
## 3.6 Expected Weather Annual Load Forecast – Reference Case

**Figure 3.19: Load Forecast Model Flow Diagram – Expected Annual Load Forecast**




Combining the expected weather, the customer counts, the residential UPC models, the small commercial UPC models, the industrial load, the large commercial sales load, the CNG market forecasts and energy efficiency forecast provides the total reference case expected weather load forecast (Figure 3.20).

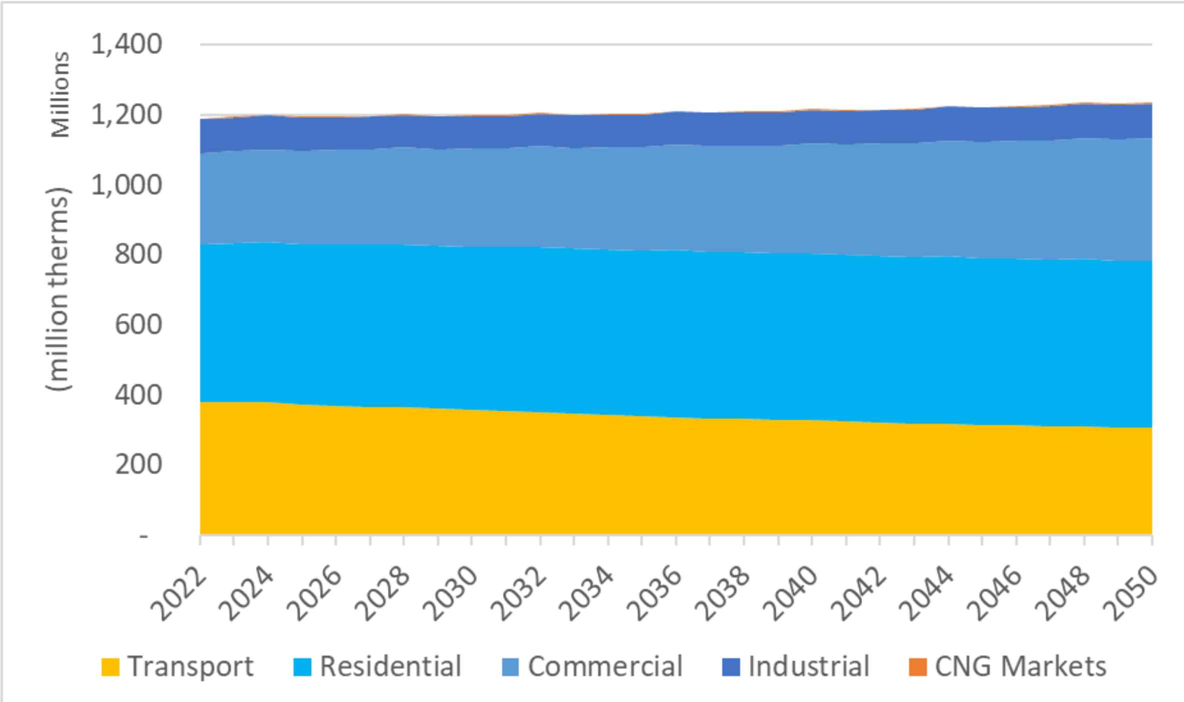
**Figure 3.20: Expected Weather Annual Sales – Reference Case[11]**




Emission compliance will be based on total throughput (i.e., sales load plus transport).

[11] Similar to Figure 3.21, the forecast is adjusted for energy efficiency forecasts.

**Figure 3.21: Expected Weather Annual Throughput – Reference Case[12]**



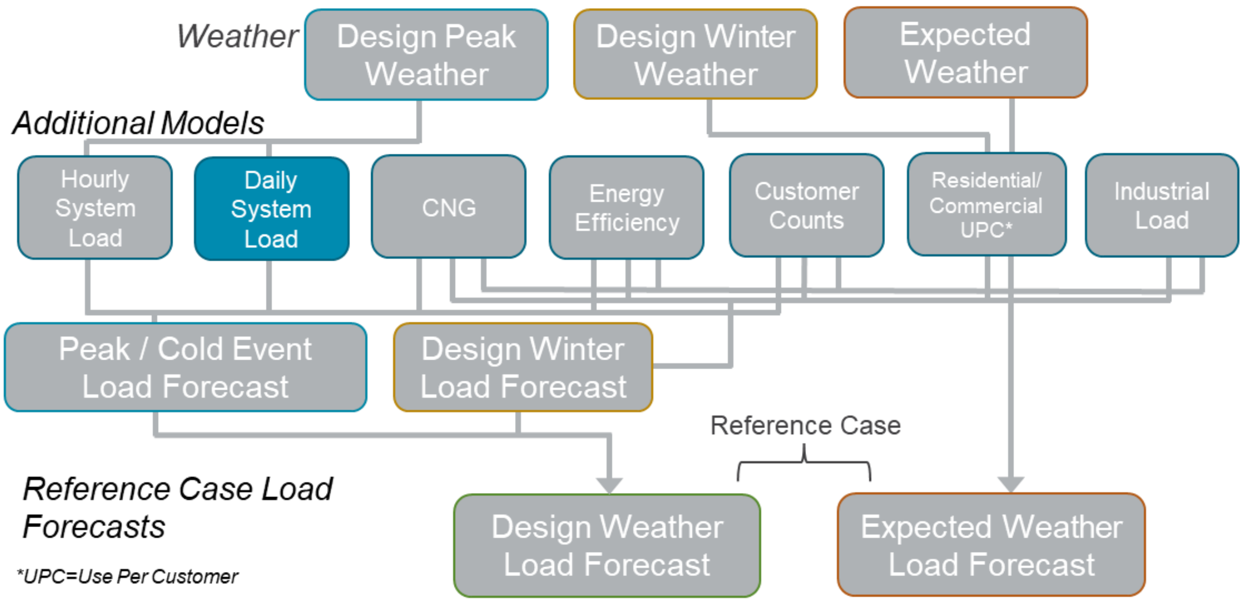

## 3.7 Daily System Load Model

The daily system load model is an econometric model that measures the relationship between daily firm sales load and its drivers such as temperature. Using historical data of daily firm sales load and drivers, the model statistically estimates coefficients, which represent the effect of each daily driver.[13] These coefficients are subsequently used as an input into the peak day planning standard, discussed in the next section. The daily system load model for resource planning is used to predict daily firm sales during peak demand conditions created from a combination of several factors. Ultimately, the daily system load model used for the peak day firm sales load forecast that determines the daily capacity requirements for resource planning (see Figure 3.22).

[12] The total annual throughput forecast is adjusted for energy efficiency forecasts.

[13] The daily system load model focuses on daily firm sales as NW Natural must buy the gas and have enough capacity resources to bring that gas on system during a peak day. Daily load for a gas day (7 a.m. - 7 a.m.) is used as gas is typically scheduled for an entire day in a day-ahead market. Hourly load is relevant for distribution system planning, but not necessary for supply planning and gas scheduling.

**Figure 3.22: Load Forecast Model Flow Diagram – Daily System Load**

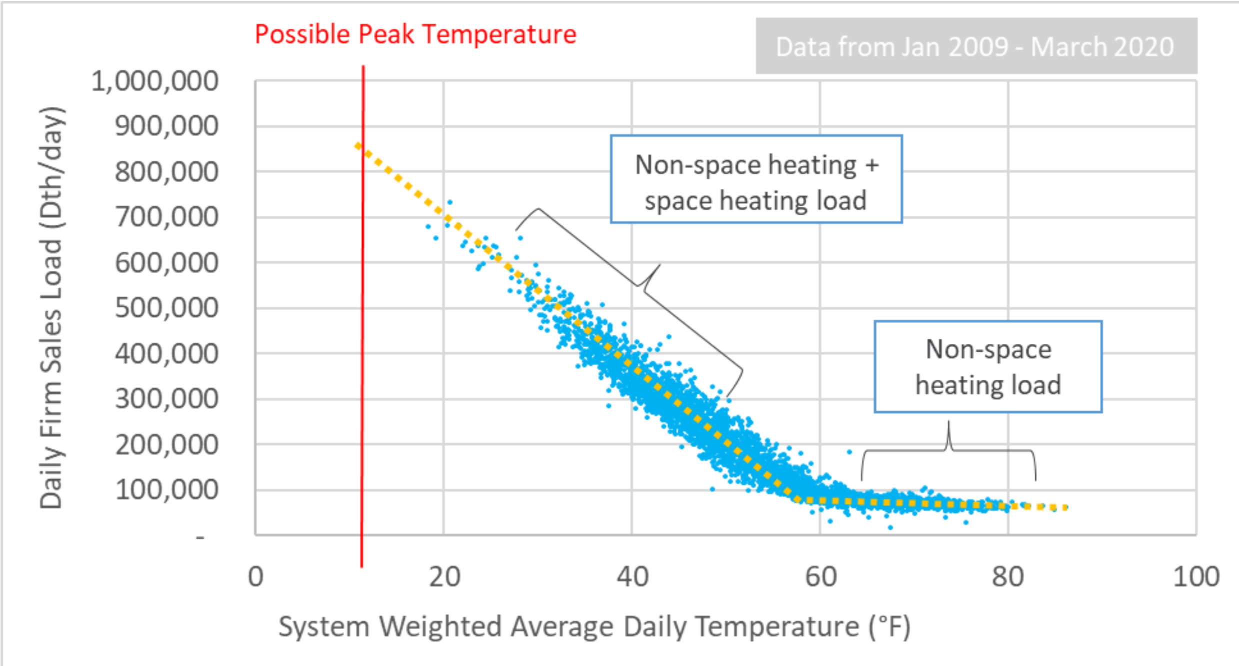



### 3.7.1 Daily Demand Drivers

The daily system load model includes 11 drivers: temperature, daily lagged temperature, solar radiation, wind speed, snow depth, customer count, day of the week indicator variables, a holiday indicator variable, a time trend, water heater water inlet temperature and a indicator variable for the pandemic shutdown in March of 2020. During peak conditions roughly 84% of NW Natural's sales throughput is used for space heating. Therefore, weather is a prominent driver of peak load and peak conditions. Peak conditions take place on very cold and windy winter weekdays when temperature drops and gas demand for space heating spikes. Figure 3.23 shows a scatter plot of temperature and a daily firm sales load. This figure illustrates that a negative linear relationship exists between daily load and temperature. There is a structural break in this relationship at 58°F as space heating equipment (e.g., furnaces) kicks on at temperatures less than 58°F. To capture this relationship the daily system load model is estimated in two versions: average daily temperature less than 59°F and average daily temperature greater than 59°F.[14] The coefficients from the less than 59°F model version are used as inputs into the peak day planning standard.

[14] Daily temperatures are calculated as system-weighted daily averages from hourly weather data.

**Figure 3.23: Daily Firm Sales Load and Temperature**




In addition to temperature, NW Natural includes a daily lagged temperature variable into the model. The necessity of including a temperature lag is due to the physical location of where data is collected and the speed at which gas flows through pipelines. Data on daily flow is collected at NW Natural's gate stations and at our on-system storage locations. Additionally, data is collected at the end use location for interruptible sales and transportation customers who have higher frequency meters that record their daily usage. Non-firm sales customer usage is subtracted coincidently from the flow coming from the gate stations and on-system storage, but these customers could be located far from the gate station. Since gas does not flow instantaneously, there is a delay between when customers use gas and when it flows through the gate stations.[15] Including a lagged temperature variable helps capture this lagged data response to changes in weather.

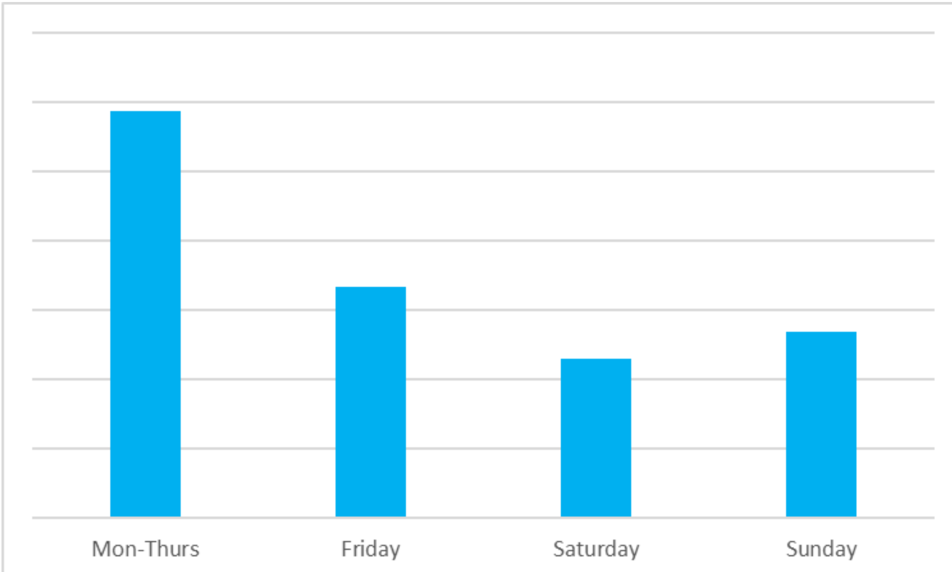
Wind and solar radiation have positive and negative impacts on daily load, respectively. High winds cool building structures, which in turn require additional gas to maintain space heating. Conversely, higher solar radiation heats buildings and hence reduces heating demand.

The day of the week also impacts natural gas load. The data shows a statistically significant increase in daily load during a weekday relative to a Saturday or Sunday. This is mainly driven by schools and businesses closing for the weekend. Daily load on Friday also shows a significant

[15] 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, i.e., firm sales customers as well.

decrease in daily load relative to Monday through Thursday.[16] Figure 3.24 shows daily average use for Monday–Thursday, Friday, Saturday, and Sunday. To capture this effect the model includes Friday, Saturday, and Sunday indicator, or dummy, variables.[17] A similar effect is captured by a holiday indicator variable.[18]

**Figure 3.24: Average Winter (Nov-Feb) Firm Sales Daily Use by Weekday**




Snow depth and water heater inlet temperature were first introduced in the 2018 IRP daily system load model and are used again in the 2022 IRP model. Snow depth is a proxy for business closures and the effect is like the effect of a weekend or holiday. Since snow depth is often correlated with cold weather, this effect is less intuitive. After controlling for other weather drivers, additional snow depth causes more schools and businesses to shut down and has a statistically significant negative impact on load.[19] NW Natural uses Bull Run River water temperature as a proxy for water heater inlet temperature.[20] Colder inlet water temperature requires additional heat to warm and thus has a negative effect on load meaning that load will increase.

The impact from the COVID-19 economic shutdown was overall negative as school and business closed for social distancing. It is likely that residential usage increased from people spending more time at home, either from unemployment or remote working, but the system data used for this model indicates an overall decrease in firm sales load. As the data for this model ends in

[16] For a 7 a.m. - 7 a.m. gas day, Friday includes 7 hours of Saturday. Including these hours into a Friday is a primary reason why Friday is different than other weekdays.
[17] Throughout this section weekday refers to a Monday through Thursday.
[18] Holidays are identified as federal holidays where most business and schools close. If the holiday falls on weekend the following Monday is considered a holiday as this a typical practice for schools and businesses to grant the following Monday as a holiday.
[19] NW Natural initially tried to attain data on school closures, but could not find sufficient data.
[20] Portland is NW Natural's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).

March of 2021, the longer-term impacts of COVID-19 on load is yet to be discovered, however; by including an indicator variable for the COVID-19 shutdown we account for its immediate impact during the 2020-2021 winter.

The last two drivers include customer counts and a time trend. Customer growth has increased over the past decade and has a positive impact on NW Natural's daily load.[21] Counter to customer growth, through energy efficiency efforts and changes in customer profiles,[22] use per customer is declining. To account for this change over time the model includes a time trend.

| Driver Variable | Impact on Load |
|---|---|
| Temperature | (-) |
| Previous Day Temperature | (-) |
| Solar Radiation | (-) |
| Wind Speed | (+) |
| Snow Depth | (-) |
| Water Heater Inlet Temperature | (-) |
| Fri/Sat/Sun or Holiday | (-) |
| Customer Count | (+) |
| Time Trend | (-) |
| COVID 19 | (-) |

### 3.7.2 Interaction Effects

Beginning with the 2018 IRP daily system load model, we have been incorporating interaction effects between variables, primarily temperature and other independent variables. The reason for including interaction effects starts with recognizing that a single driver alone fails to sufficiently explain changes in daily demand primarily used for space heating. For example, demand on a warm summer day with no wind will not be very different from demand on a windy summer day. However, the impact of wind greatly increases as temperatures decrease. In other words, demand on a cold windy day will be much greater than demand on a day with the same temperature and no wind. For more technical details on the daily system load model see Appendix B.

### 3.7.3 Firm Sales Daily System Load Regression Model

Daily load drivers constitute the independent, or right-hand-side, variables in the econometric model and daily system firm sales is the dependent, or left-hand-side, variable.

$$System\ Firm\ Sales_t = \alpha + \sum_{i=1}^{23} \beta_i\ Drivers_{it} + \epsilon_t$$

Where α is a constant, $\beta_i$ are the estimated coefficients, *i* is an index for drivers, *t* is a daily index and ε is a random error.

[21] A negative impact means that the values of the attribute go in the opposite direction as load. Whereas a positive impact means the values of the attribute go in the same direction as load. As an example, as temperature increases, load decreases and correspondingly, as temperatures drop, load increases.

[22] For example, the addition of higher efficiency new construction homes.

The right-hand-side variables include the previous day's temperature, solar radiation, wind speed, snow depth, customer count, Friday, Saturday, Sunday and holiday dummy variables, a time trend, and the Bull Run River water temperature. Temperature interacts with each dependent variable except for the Bull Run River water temperature. The data shows that the efficiency of insulated water heaters is independent of the outside temperature and therefore an interaction between temperature and the water heater inlet water temperature is not considered in this model.

## 3.8 Capacity Requirement Planning Standard

Developing a planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure the reliability of the service under design peak weather conditions. Gas supply capacity requirements refers to the daily maximum volume of gas that the system can deliver to customers. In the 2018 IRP, NW Natural implemented a new planning standard that uses statistics and Monte Carlo simulation of the demand drivers to set a standard that the company's resource capacity can serve the highest firm sales demand day going into each future winter with 99% certainty. This is equivalent to planning for a 1-in-a-100-year weather event.[23] This IRP uses the same planning standard as the 2018 IRP.

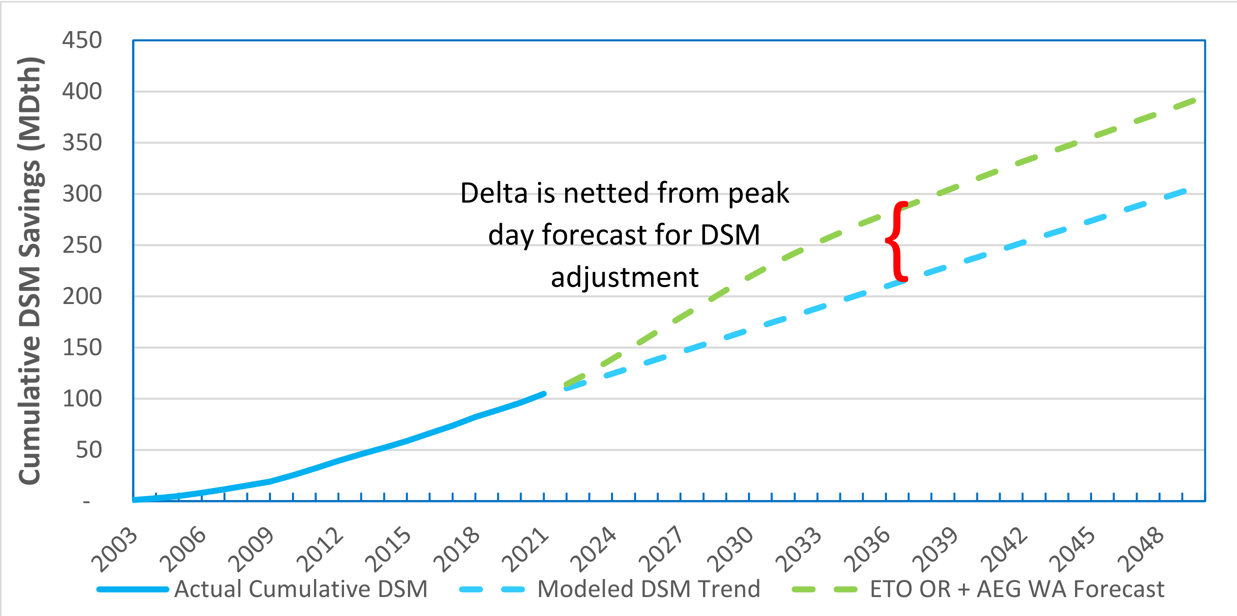
Using the regression coefficients from the firm sales daily system load model and the Monte Carlo simulation of the demand drivers create a distribution of peak day demand under potential peak conditions. Using this distribution and accounting for model error the 99$^{th}$ percentile pulled from this distribution.

## 3.9 Design Day Peak Savings from Energy Efficiency

The 99$^{th}$ percentile load requirement includes a time trend capturing underlying trends in the data, part of which is driven by past energy efficiency programs. There is an adjustment to the 99$^{th}$ percentile to account for design peak therm energy savings forecast, similar to the adjustment discussed for annual therm savings. These design peak therm savings are calculated using peak factors estimated by NW Natural for each end-use and are further discussed in Chapter 4, Section 3. These factors are applied to the annual sales savings forecasted by the Energy Trust (Oregon sales) and AEG (Washington sales). Figure 3.25 illustrates the adjustment made to the 99$^{th}$ percentile load requirement.

[23] As weather is random, a 1-in-a-100-year event has a probability of occurring more often than once every 100 years. On the other side of the coin, this type of event also has the probability of not occurring within a 100-year timeline. See the 2018 IRP Chapter 3, Section 7.2 for a detail discussion on this topic.

**Figure 3.25: DSM Peak Day Savings Trend and Forecast**




## 3.10 Peak Day Forecast – Reference Case

The peak day load forecast, which is modeled as the third day of a cold event, combines the customer forecast, peak day therm savings energy efficiency forecast, the daily system load model, and the peak day planning standard.[24] The combination of these models results in a forecast of the gas supply capacity requirements over the planning horizon (see Figure 3.26).[25]

[24] Note that peak day contribution from CNG markets are included in the peak day forecast, but are de minimis.

[25] Peak day is defined, per the peak day planning standard, as the firm resource requirement needed to have a 99% chance to be able to meet the highest firm sales demand day in a gas year.

**Figure 3.26 Load Forecast Model Flow Diagram – Peak Day Load Forecast**

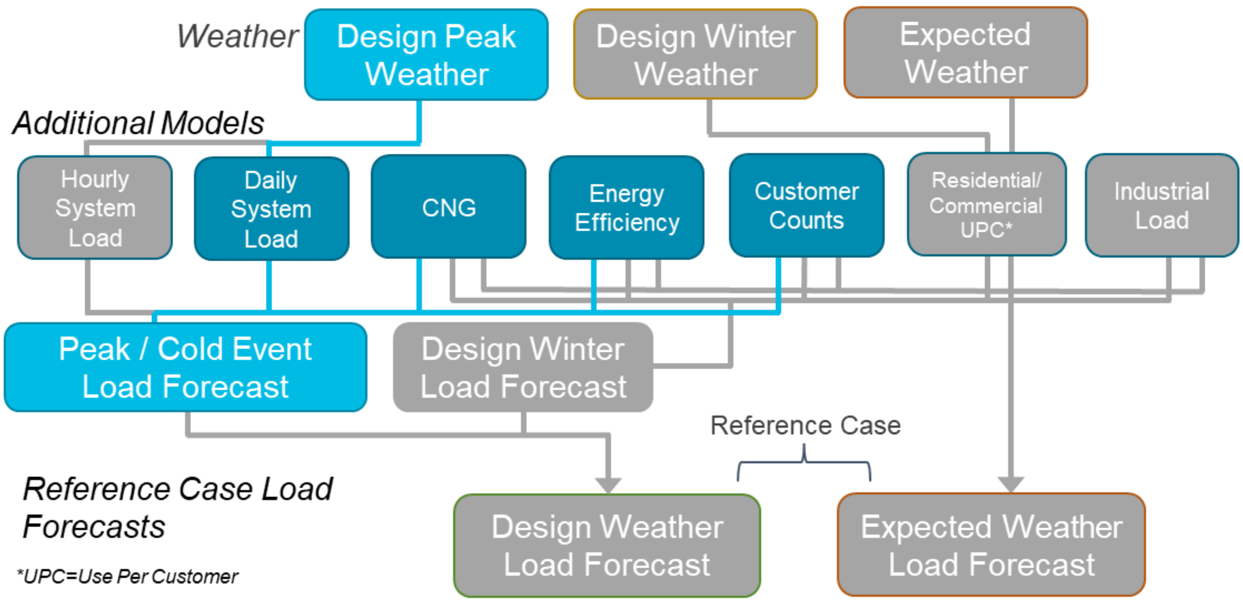
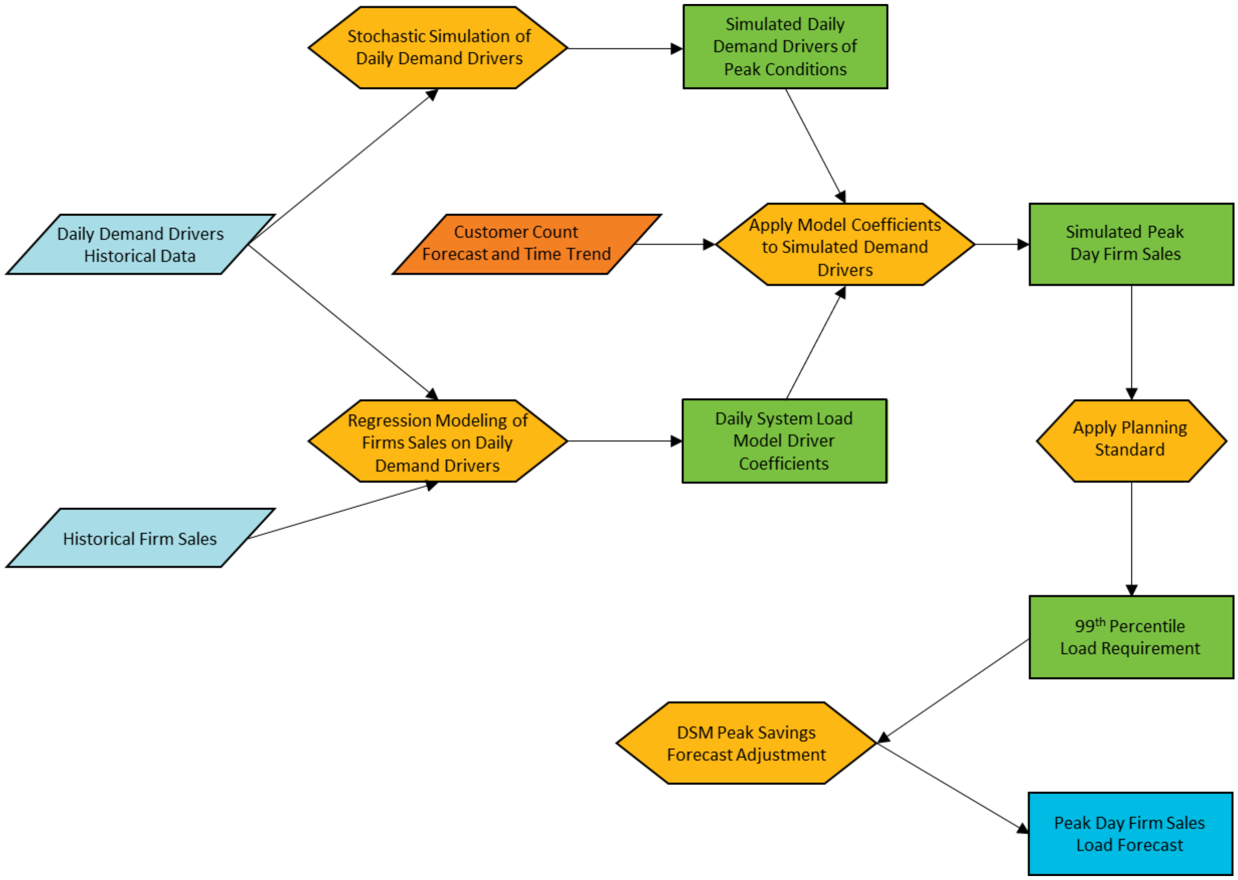


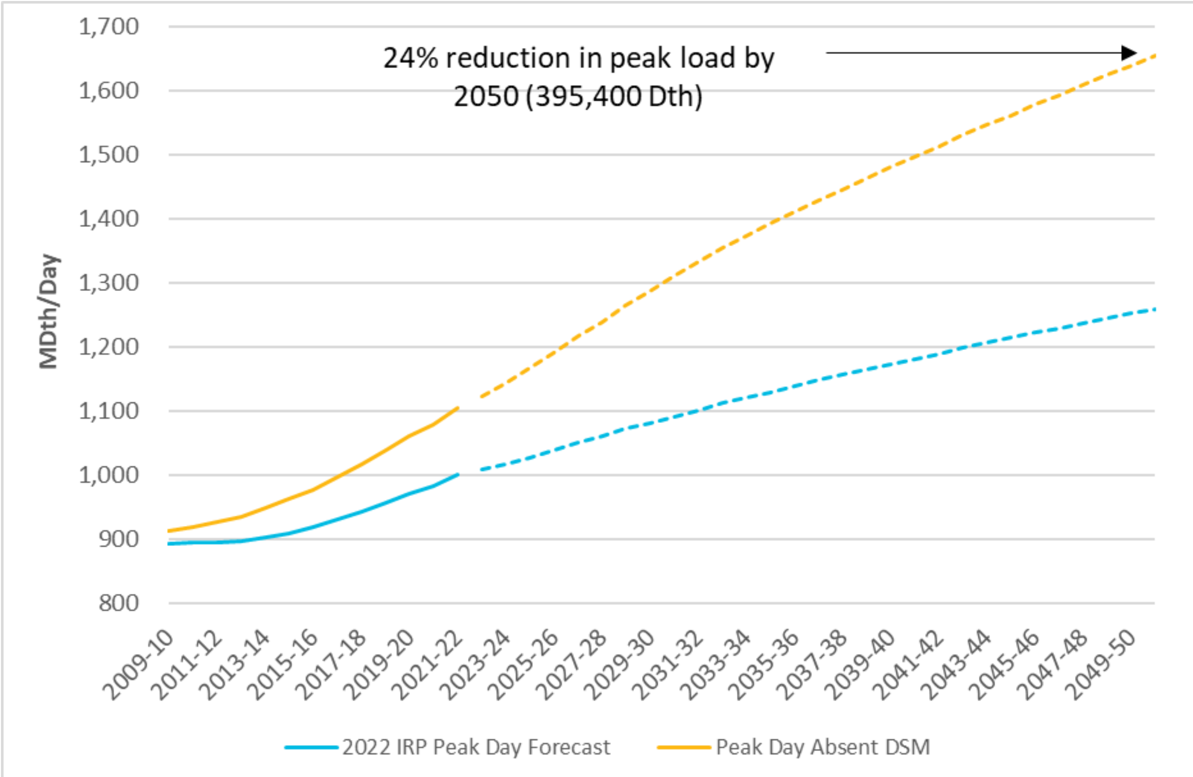

Figure 3.27 illustrates a flow chart for how the daily system load model, forecast of design peak day therm savings, and the planning standard are combined to develop the peak day forecast.

**Figure 3.27: Peak Day Load Forecast Flow Chart**



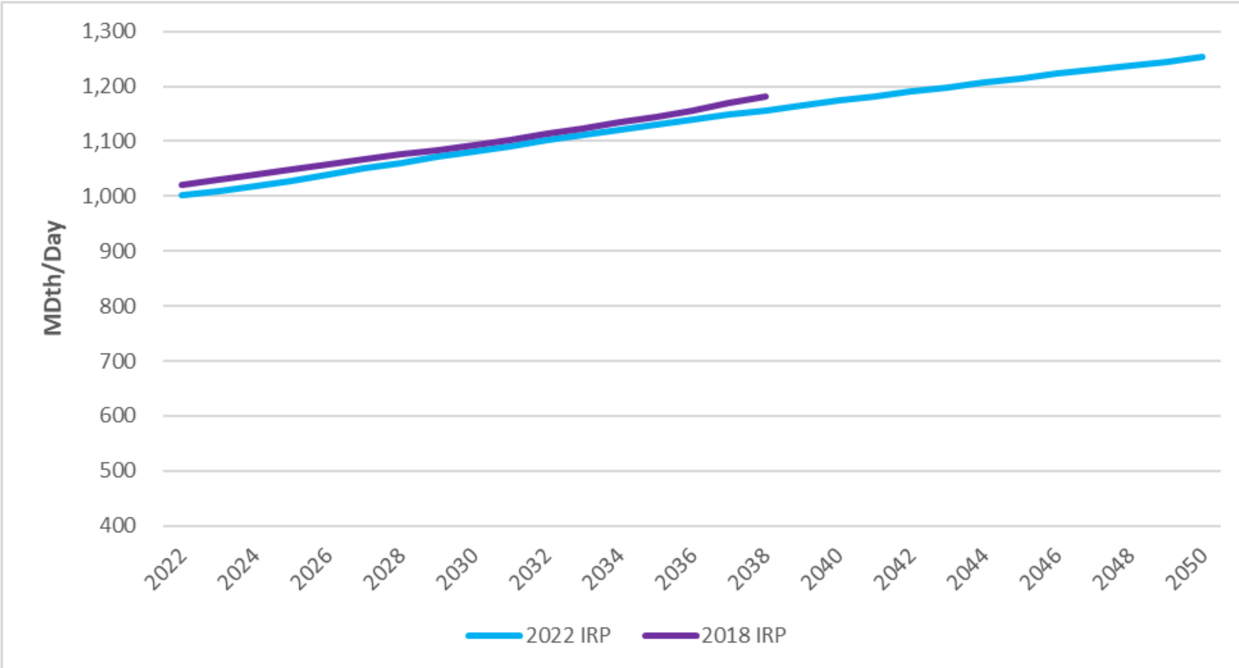

The impact of DSM programs has been and will continue to be a significant way to reduce annual load, but also generates significant savings on peak, particularly measures related to space heating. Figure 3.28 shows the peak day forecast, absent any DSM programs relative to the 2022 IRP peak day forecast adjusted for ETO and AEG's DSM forecast.

**Figure 3.28: Peak Day Load Forecast Without DSM**



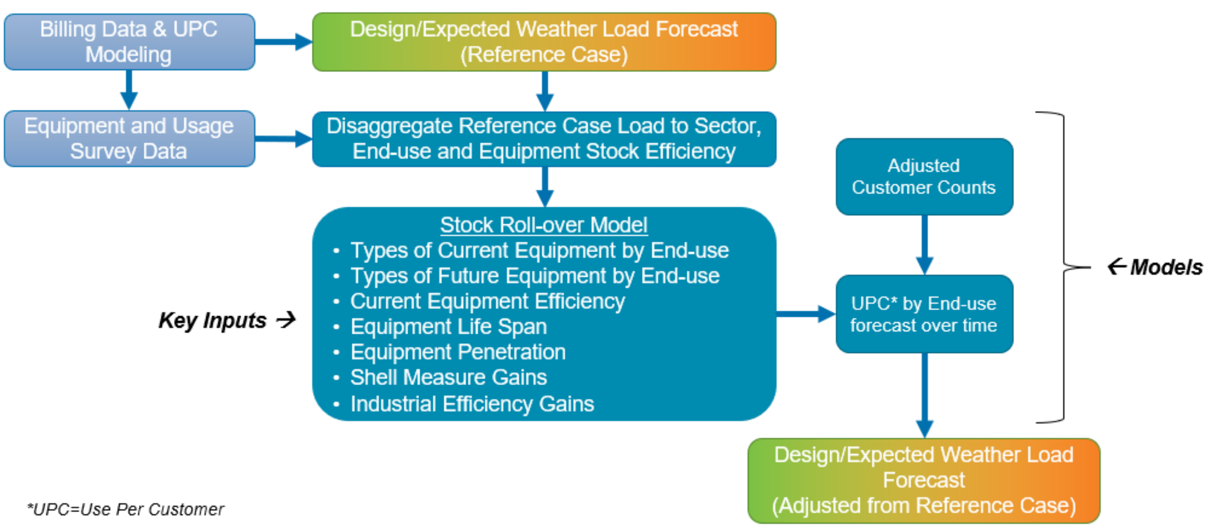

By 2050, DSM programs will reduce peak day load by about 395,400 Dth or 24% of peak load. This is roughly the capacity equivalent of three Portland LNG facilities. Compared to the 2018 IRP, the reference case peak day forecast is lower by 1.5% by in 2038 as shown in Figure 3.29.

**Figure 3.29: Peak Day Load Comparison 2018 IRP to 2022 IRP**




## 3.11 End Use Load Forecast Model

**Figure 3.30: End Use Load Forecast Model**



## End-Use Forecasting Context

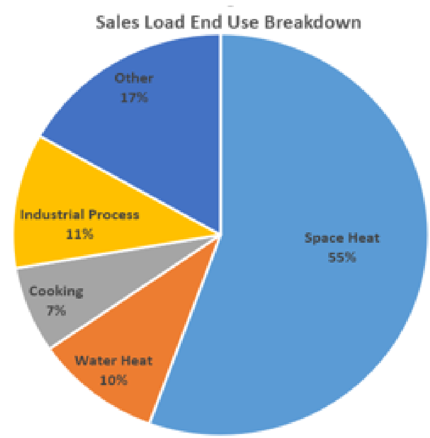
NW Natural®

- End-use load forecasting still relies on previous models to develop the reference case and implements a stock roll-over model to obtain estimated use per customer by sector and end-use
- The stock roll-over model is the tool to adjust the reference case to reflect shifts from historical trends
  - For a given sector and end-use, the reference case can become the forecast (either for the base case or a scenario) if no shifts from historical trends are expected
  - The stock roll-over model gives us the flexibility to incorporate potential shifts caused by fundamental changes in policy
- While being a more flexible tool to make adjustments to the reference case, the stock roll-over model requires assumptions regarding key inputs
  - Adoption rates of new or more equipment
  - Equipment life span
  - Assumptions about improvement in building shells and/or industrial process efficiency gains

## Sales by End-use

- Roughly 2/3 of gas delivered is to sales customers
- Space heating drives sales load, accounting for more than half of sales load
- The average efficiency of the installed equipment within the building stock is a major determinant of the load within each end-use category
- The average efficiency is determined by the make up of the equipment in the building stock
- Newly installed equipment, typically replaced when old equipment dies or installed for new customers, changes the average efficiency over time

tural®




| Space Heating Equipment Example | Relative Efficiencies |
|---|---|
| Furnace Stock Efficiency | 89% |
| High Efficiency Furnace Install | 95% |
| Gas-fired Heat Pump | 140% |
| Dual Fuel System | 90% when used |

# End-Use Load Disaggregation-Residential Example

NW Natural®

| End Use | Time Period | All Customer Annual Average Usage | Annual Average Usage by Customers who Have Space or Water Heating | All Customer Average Peak Share of Annual Usage |
|---|---|---|---|---|
| Primary Space Heating | Normal Weather Annual Usage | 494 | 565 | 0.768719 |
| | Peak Day | 7.26 | 8.31 | 0.011311 |
| | Peak Hour | 0.356 | 0.407 | 0.000554 |
| Water Heating | Normal Weather Annual Usage | 117 | 176 | 0.181856 |
| | Peak Day | 0.38 | 0.57 | 0.000592 |
| | Peak Hour | 0.025 | 0.038 | 0.000039 |
| Other Load | Normal Weather Annual Usage | 32 | N/A | 0.049425 |
| | Peak Day | 0.410 | N/A | 0.000639 |
| | Peak Hour | 0.021 | N/A | 0.000032 |
| Total | Normal Weather Annual Usage | 642 | N/A | 1.000000 |
| | Peak Day | 8.05 | N/A | 0.012541 |
| | Peak Hour | 0.401 | N/A | 0.000625 |

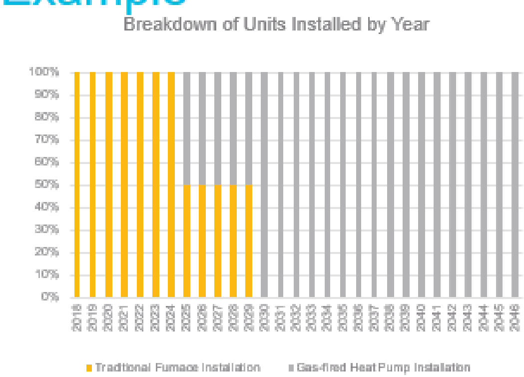
**End use load forecasting requires determining:**

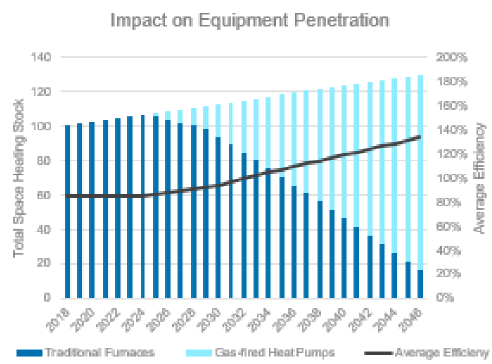
1. **What share of NW Natural customers use natural gas for the end use?**
2. **What is the average efficiency of the equipment used for the end use?**

| | Space Heating | Water Heating |
|---|---|---|
| Share of Customers gas is primary source: | 87% | 65% |
| Average efficiency of equipment for end use: | 89% | 73% |

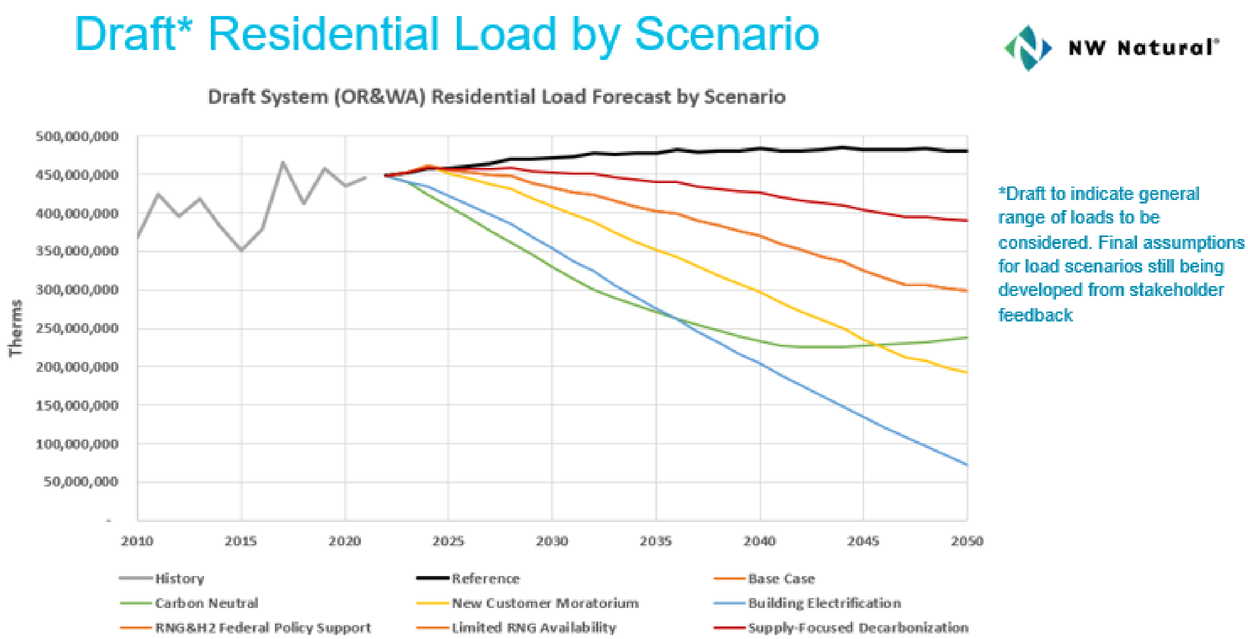
# Stock Turnover Model – Space Heat Example

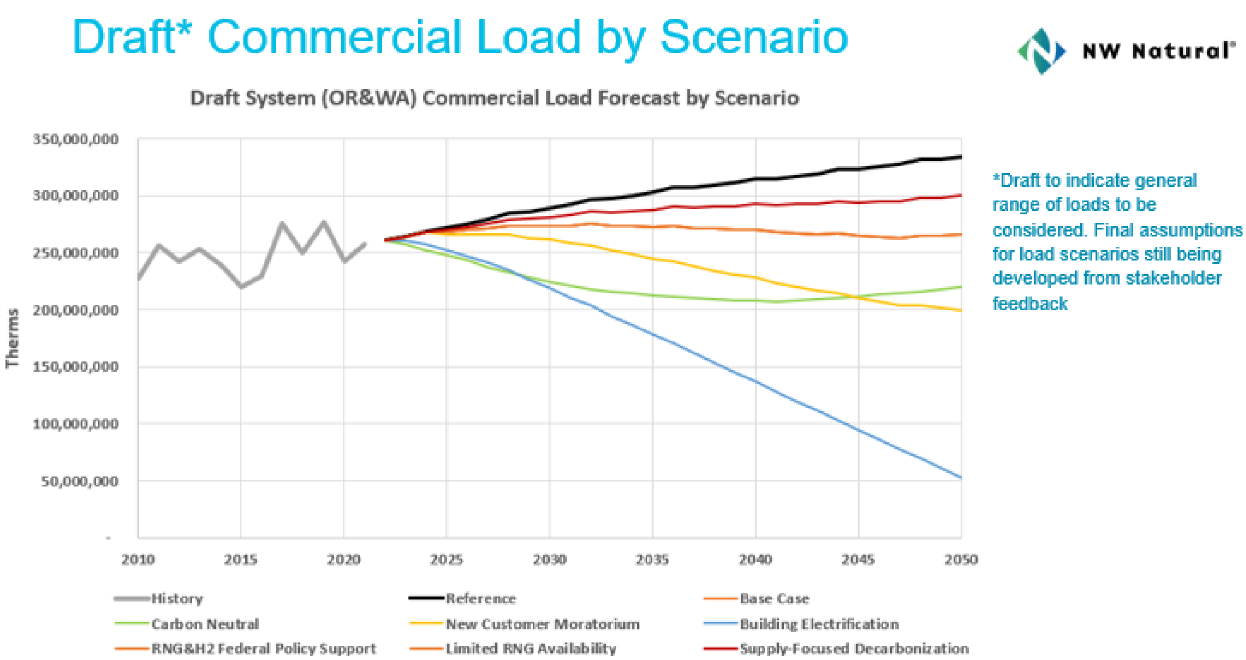
NW Natural®

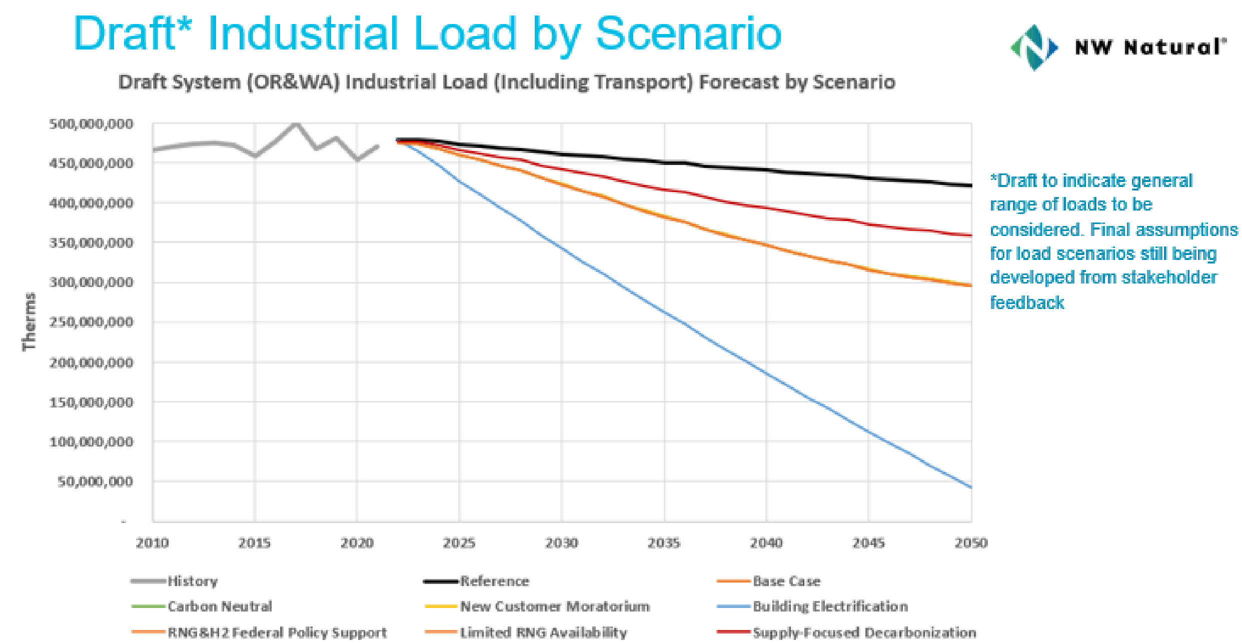


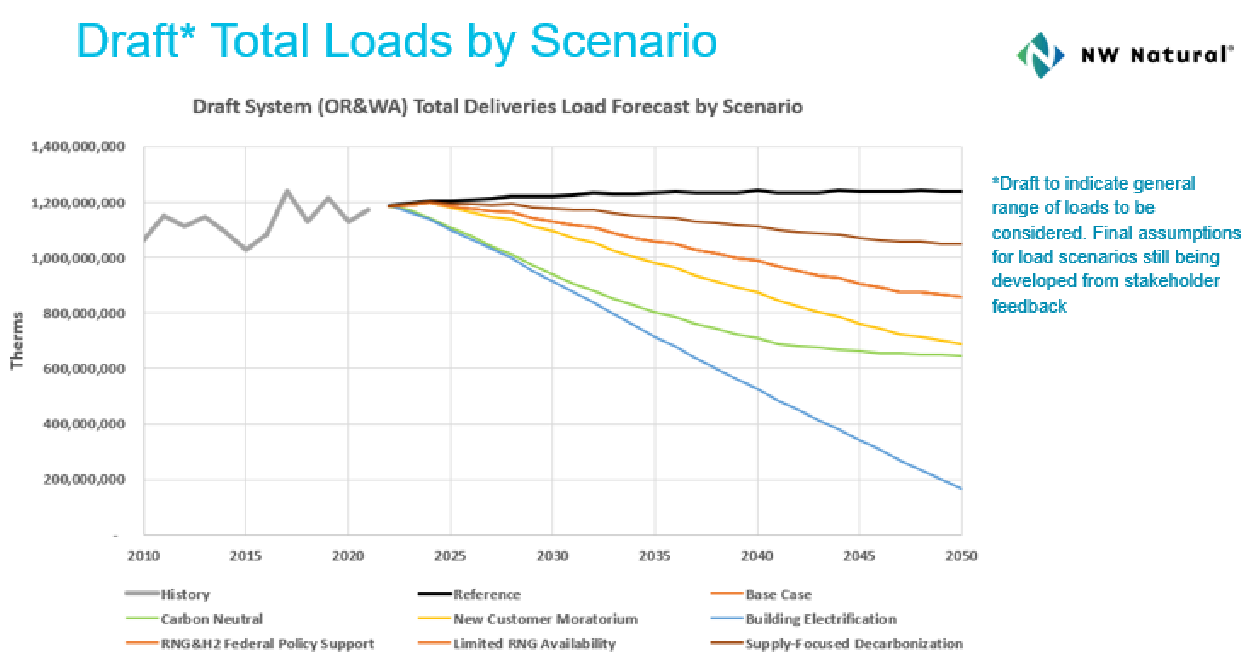




- As the new equipment is installed, the total stock mix and average efficiency of equipment providing energy services within the building stock changes over time
- Changes in efficiency different from historical trends are largely not accounted for in our reference case
- End-use load forecasting methodology starts with the reference case, but can account for shifts in trends due to things like emerging technologies and the policy environment


Draft* Residential Load by Scenario
NW Natural
Draft System (OR&WA) Residential Load Forecast by Scenario
Therms
500,000,000
450,000,000
400,000,000
350,000,000
300,000,000
250,000,000
200,000,000
150,000,000
100,000,000
50,000,000
-
2010
2015
2020
2025
2030
2035
2040
2045
2050
History
Reference
Base Case
Carbon Neutral
New Customer Moratorium
Building Electrification
RNG&H2 Federal Policy Support
Limited RNG Availability
Supply-Focused Decarbonization
*Draft to indicate general range of loads to be considered. Final assumptions for load scenarios still being developed from stakeholder feedback


Draft* Commercial Load by Scenario
NW Natural
Draft System (OR&WA) Commercial Load Forecast by Scenario
Therms
350,000,000
300,000,000
250,000,000
200,000,000
150,000,000
100,000,000
50,000,000
-
2010
2015
2020
2025
2030
2035
2040
2045
2050
History
Reference
Base Case
Carbon Neutral
New Customer Moratorium
Building Electrification
RNG&H2 Federal Policy Support
Limited RNG Availability
Supply-Focused Decarbonization
*Draft to indicate general range of loads to be considered. Final assumptions for load scenarios still being developed from stakeholder feedback


Draft* Industrial Load by Scenario
NW Natural®
Draft System (OR&WA) Industrial Load (Including Transport) Forecast by Scenario
Therms
500,000,000
450,000,000
400,000,000
350,000,000
300,000,000
250,000,000
200,000,000
150,000,000
100,000,000
50,000,000
-
2010
2015
2020
2025
2030
2035
2040
2045
2050
History
Reference
Base Case
Carbon Neutral
New Customer Moratorium
Building Electrification
RNG&H2 Federal Policy Support
Limited RNG Availability
Supply-Focused Decarbonization
*Draft to indicate general range of loads to be considered. Final assumptions for load scenarios still being developed from stakeholder feedback


Draft* Total Loads by Scenario
NW Natural®
Draft System (OR&WA) Total Deliveries Load Forecast by Scenario
Therms
1,400,000,000
1,200,000,000
1,000,000,000
800,000,000
600,000,000
400,000,000
200,000,000
-
2010
2015
2020
2025
2030
2035
2040
2045
2050
History
Reference
Base Case
Carbon Neutral
New Customer Moratorium
Building Electrification
RNG&H2 Federal Policy Support
Limited RNG Availability
Supply-Focused Decarbonization
*Draft to indicate general range of loads to be considered. Final assumptions for load scenarios still being developed from stakeholder feedback

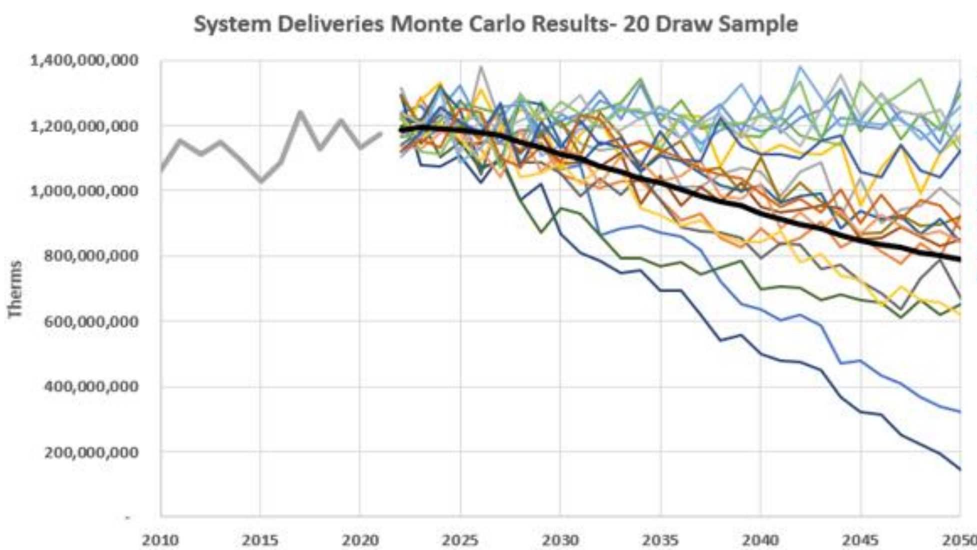
## Stochastic Monte Carlo Load Simulation

NW Natural®

- Long-term variance in load determined by load scenarios
  - Current assumptions
    - Path deviation for a load scenario can start any year between 2022 and 2028
    - All scenarios equally likely
- Short-term variance in load determined by weather and economic uncertainties
  - Current assumptions
    - Standard deviation in annual heating degree days from weather modeling combined with economic deviation
    - Economic deviation from history of non-weather

## Load Simulations for Optimization

NW Natural®




*Draft to indicate general range of loads to be considered and show how each forecast draw will deviate in the short-term around a long-term trend. Final assumptions for load scenarios still being developed from stakeholder feedback.

# Chapter 4
# Avoided Costs

## 4.1 Avoided Costs – Overview

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

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

Chapter Four details the methodology used to calculate each component of NW Natural's avoided costs. The methodology we used to calculate our avoided cost forecast has seen continued improvement since the 2014 IRP, and we are working with ETO and AEG to make additional improvements implementable within the broader distribution planning and IRP processes. For the 2022 IRP, NW Natural's avoided cost forecast features the following key methodological improvements:

- Avoided costs have been applied to more diversified on-system and low carbon supply-side resources so the entire value these resources provide to customers is included when they are evaluated against conventional resources.
- Environmental incremental policy compliance costs for recent Climate Protection Program (CPP) and Community Climate Investments (CCI) for Oregon and Climate Compliance Act (CCA) for Washington have been explicitly included in its portfolio modeling assumptions to generate state-specific avoided costs in NW Natural's territory.

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.

## 4.2. Avoided Cost Components

Table 4.1 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 4.1 shows which values of the avoided costs components vary by end use or supply resource.

**Table 4.1 Avoided Costs Components and Application Summary**

| Costs Avoided | | Resource Option Application | | | | | |
|---|---|---|---|---|---|---|---|
| | | Demand-Side Resources | | | Supply-Side Resources | | |
| | | Energy Efficiency | Demand Response | | Low-Carbon Gas Supply | | Recall Agreements |
| | | | Interruptible Schedules | Other DR | On-System Resources | Off-System Resources | |
| Commodity Related Avoided Costs | Natural Gas Purchase and Transport Costs | ✓ | | | ✓ | ✓ | |
| | Greenhouse Gas Compliance Costs | ✓ | | | ✓ | ✓ | |
| | Commodity Price Risk Reduction Value | ✓ | | | ✓ | ✓ | |
| Infrastructure Related Avoided Costs | Supply Capacity Costs | ✓ | ✓ | ✓ | ✓ | | ✓ |
| | Distribution System Costs | ✓ | ✓ | ✓ | ✓ | | |
| Unquantified Conservation Costs | 10% Northwest Power & Conservation Council Credit | ✓ | | | | | |

### 4.2.1. Commodity Related Avoided Costs

These avoided costs are those that apply equally on a per unit of natural gas saved or supplied basis. This is to say that for these components it is either irrelevant or somewhat unimportant when the energy is saved or supplied.[1] For example, it is irrelevant from a greenhouse gas (GHG) emissions compliance cost perspective whether the emissions occur during a peak period or any other time of the year.

#### *Gas and Transport Costs*

This component represents the cost of the natural gas commodity itself. The main driver of these costs is the base case natural gas price forecast detailed in Chapter Two, 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 and transport costs represent the cost of the last unit of gas sold during that particular day,[2] 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 model and is aggregated to the monthly level. Note that avoided commodity and transport costs varied not only through time but also across end uses since each end use has its own 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.

---

[1] Noting that seasonality of natural gas prices and the storage resources in NW Natural's portfolio make it inaccurate to claim that when the energy is saved or served has no impact on these avoided costs.

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

### *Greenhouse Gas Emissions Compliance Costs*

NW Natural explicitly includes environmental incremental policy compliance costs for the CPP in Oregon and the CCA in Washington in its portfolio modeling assumptions (in addition to the current policies embedded in the gas price forecasts provided by a third-party consultant). Potential compliance costs are hence separately generated by state to meet environmental policy requirements specific to each state in NW Natural's territory.

### *Commodity Price Risk Reduction Value or the Hedge Value of DSM*

While the "cost to achieve natural gas price certainty" is a more descriptive name for this component of avoided costs, this component is more commonly referred to as the "hedge value of DSM."[3] 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.

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.[4] When the hedge 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. In practical terms this combination replaces the spot price forecast as the price of gas for evaluating demand-side resources. The same hedge value is applied in both states and to all end uses and is the least significant component of avoided costs. In the current natural gas market, dynamics are such that long-term hedges can be procured at a price that is lower than forecasted spot prices over the hedge period. However, when market forces lead to a calculated hedge value that is negative, a value of zero is assigned.

## 4.2.2. Infrastructure Related Avoided Costs

Infrastructure needs are driven by peak loads. Consequently, the extent to which resources reduce or supply energy on peak determines the infrastructure costs they avoid. To estimate infrastructure costs avoided for any resource there are two pieces that need to be calculated:

1) the incremental cost of serving additional peak load; and
2) the amount energy that would be saved or supplied during a peak

[3] See OPUC docket No. UM 1622 for a lengthy discussion of the hedge value of DSM in avoided costs. Also, see page 10 and Appendix 1 of NW Natural's reply comments in the Company's 2016 IRP proceeding (OPUC docket No. LC 64) for a detailed history on how the hedge value of DSM came to be included in the NW Natural's avoided costs starting with the 2016 IRP. (https://edocs.puc.state.or.us/efdocs/HAC/lc64hac115929.pdf).

[4] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.

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.[5] 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. 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 the vast 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 our 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.

### *Supply Capacity Costs*

NW Natural's methodology for estimating supply capacity costs has not changed since the last IRP and has been applied to the end uses considered for DSM and the on-system supply resources discussed in Chapter Six.

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 4.2 in Section 4.3 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. The assumptions made about what supply portfolio resources would be acquired in each year were not significantly different from the actual supply

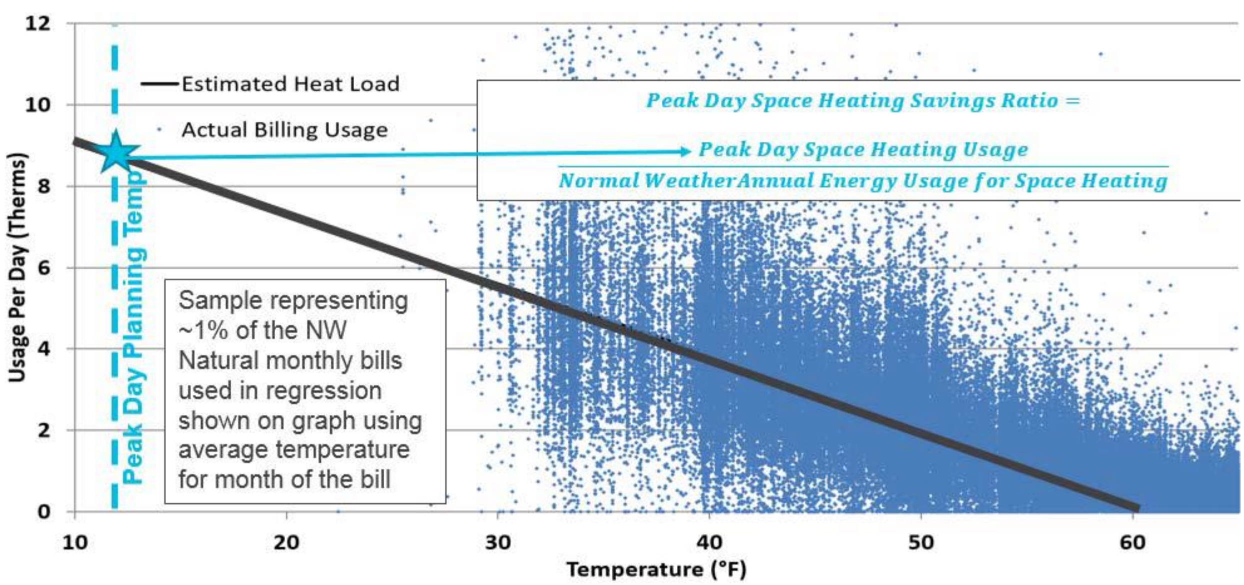
[5] Note that interruptible customers pay a lower rate than firm customers, with the difference in rate being the estimated infrastructure costs that are saved by interrupting customers during peak events.

resource choices detailed in Chapter Seven.[6] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization.

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

To give an idea of how this calculation works, the largest contributor to peak day load — residential space heating — is used as an example. Figure 4.1 shows daily usage for NW Natural residential customers who use natural gas to heat their homes.[7] While there is much variation in usage due to differences in customer equipment efficiency, behavior, home type and size, and relative shell efficiency, the average NW Natural residential customer's space heating usage across temperatures is depicted by the black line. As the graph shows, using an estimate of the temperature that corresponds with NW Natural's peak day planning standard (see Chapter Three), an average residential customer would use roughly nine therms of gas for space heating on a peak day.

**Figure 4.1: Residential Space Heating Peak Day Savings Estimate and Peak to Annual Ratio**




In conjunction with an estimate of the average annual usage for space heating under normal Weather, this peak day usage estimate can be used to determine the share of annual space heating load that occurs on a planning peak day. Assuming the savings shape and the load shape are the same, this ratio can be multiplied by the ETO and AEG's annual savings estimated for each residential space heating measure to estimate the peak savings for that measure. This can then be used to calculate the supply infrastructure avoided costs on an energy basis. Similarly, the peak day to annual usage ratios were calculated for all the end uses considered. These ratios are shown in Table 4.2.

[6] Note that the avoided cost figures have been updated and will be used by Energy Trust for budgeting if the avoided costs in the 2018 IRP are acknowledged.

[7] Note that if a thermostat is set to a fixed temperature and the efficiency of the customer's space heating equipment is not a function of temperature (which is generally true of any natural gas space heating equipment currently used by NW Natural customers) usage will be linear in temperature.

**Table 4.2: 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) | **0.01983** | NW Natural Regressions |
| Commercial Space Heating | **0.01769** | 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 |

### *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:

This state-specific calculation relies on historical data of the costs to reinforce NW Natural's distribution system and is based on an average of the revenue requirement of reinforcement projects that were completed over the previous five years. 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 five years was estimated using the peak hour load forecasting technique described in Chapter Eight. Dividing the revenue requirement from the sum of the reinforcement projects over the past five 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. This methodology has been applied since the 2018 IRP.

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 7 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 4.2. Take again the largest contributor to peak hour load — residential space heating — as an example: dividing the peak hour space heating load (7 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 Eight, 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 residential space heating, this factor is 5.79%.[8] Multiplying this factor times the peak day factor in Table 4.2 gives an estimate that the average residential NW Natural customer would use the equivalent of 0.115% 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 4.3.

**Table 4.3: 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 | **0.00115** | NWN System Hourly Flows & EPRI Load Shape |
| Hearths and Fireplaces | **0.00058** | EPRI Load Shape |
| Commercial Space Heating | **0.00139** | NWN System Hourly Flows & EPRI Load Shape |
| Water Heating | **0.00026** | NWN System Hourly Flows & Ecotope Water Heating Study |
| Cooking | **0.00071** | EPRI Load Shape |
| Process Load | **0.00011** | Daily/24 |

Multiplying the factor shown in Table 4.3 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.

### 4.2.3. Unquantified Conservation Avoided Costs

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

This credit is applied for DSM and is calculated from a summation of all the components of avoided costs except the hedge value of DSM and the GHG compliance cost components. Note that even though the 10% conservation credit is applied consistently across all DSM resources, the actual credit included in avoided costs varies since some of the avoided costs components vary by state, end use, and/or time. While the credit was originally designed to apply to DSM, it is unclear whether it should also be applied to supply-side resources that also conserve the use of conventional natural gas (most notably renewable natural gas) so that demand- and supply-side resources are treated on a fair and consistent basis per Oregon PUC's IRP guidelines. NW Natural has not included the Conservation Credit in the avoided costs of any resources except DSM in this IRP, but it warrants consideration in future IRPs.

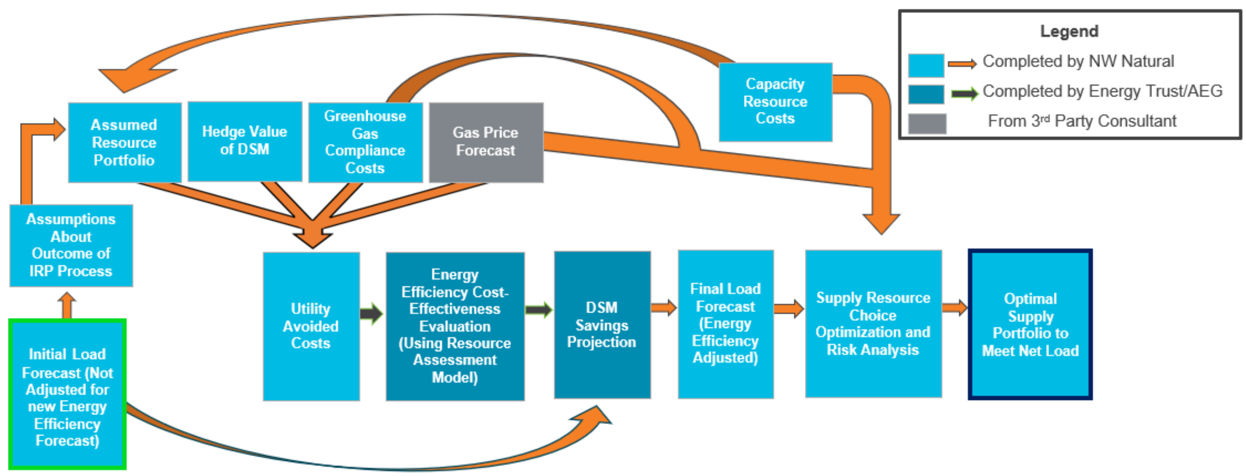
[8] Note that a flat load has a factor of 1/24, or 4.17%.

## 4.3. Demand-side Applications of Avoided Costs

### 4.3.1. Avoided Costs and DSM in the Overall IRP Process

Figure 4.2 details how avoided costs and DSM energy savings are integrated into the broader IRP process and shows what work is completed by NW Natural and what work is completed by ETO or AEG. Note that estimating the infrastructure (capacity) costs that can be avoided with DSM complicates the general process of obtaining the DSM savings projections from ETO and AEG. This complexity arises because the DSM savings projection has to be made before supply-side resource choice modeling to net the DSM savings projection out of load and start the supply-side resource optimization. That is, assumptions about what supply-side capacity resources to choose need to be made before the resource optimization process has begun for ETO and AEG to complete their cost-effectiveness test and savings projections for DSM required by the IRP.[9]

**Figure 4.2: NW Natural IRP Process**



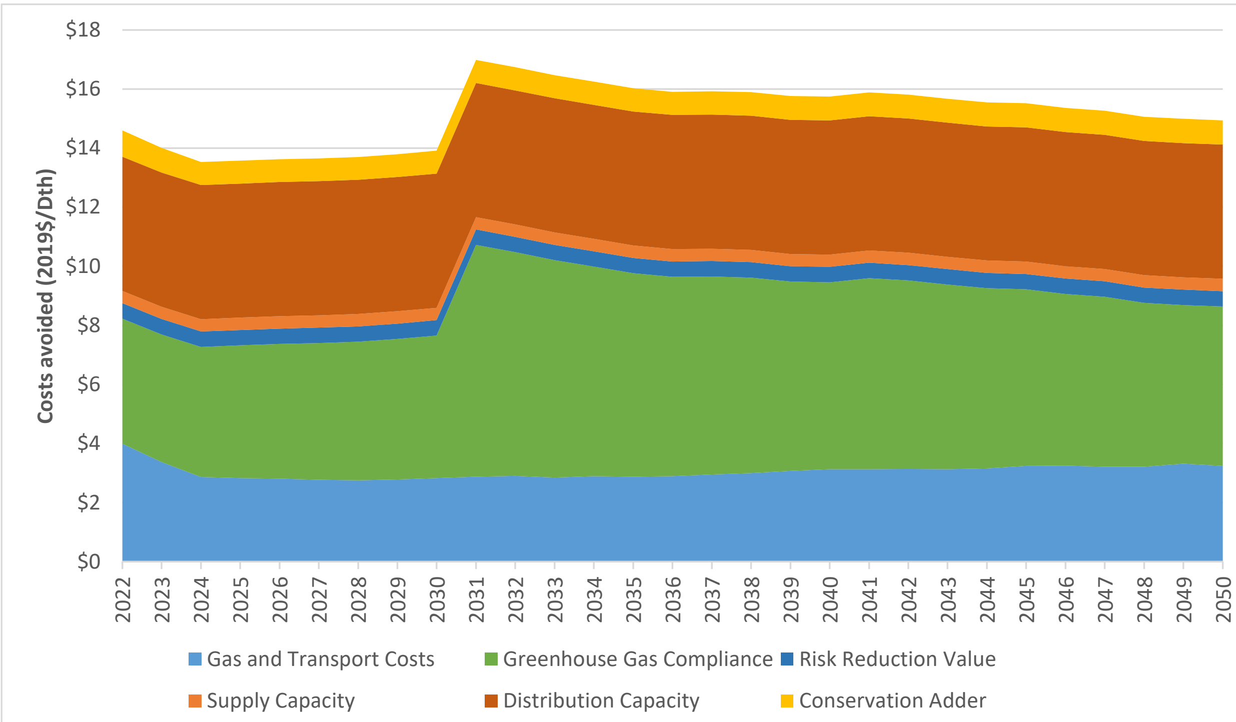

### 4.3.2. Avoided Cost Component Breakdown Through Time

For each end use, avoided costs vary through time (and by state). Figure 4.3 uses Oregon residential space heating as an example to show the component breakdown of avoided costs through time for this end use.[10] It is interesting to note that in contrast to the 2018 IRP, a similar sharp increase in avoided costs is perceived in 2031 but due to different reasons. In the 2018 IRP the sharp increase in avoided costs was due to supply capacity costs increasing dramatically as the Mist storage was expected to be exhausted in 2030. In this IRP, assumption about Mist Recall has changed: the Mist storage capacity may be recalled and transferred for use by core utility customers so this avoided costs component is forecasted to be small and steady throughout the planning horizon.[11] As shown in Figure 4.3, the sharp increase in avoided costs in this IRP comes from a significant increase in avoided GHG compliance costs. This is

[9] Note that 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 Five.
[10] See Appendix C for the same graph for each end use and also for Washington State.
[11] See Chapter Six for a more detailed discussion regarding the Mist storage recall.

because when RNG becomes the marginal resource for acquisition rather than the price of CCIs in the modeling system, so DSM will at the point go from offsetting purchases of CCIs to purchases of renewable supply. Note that space heating has the largest impact on peak loads so the distribution infrastructure costs avoided are largest for space heating relative to the other end uses.

**Figure 4.3: Example Avoided Cost Breakdown Through Time – Oregon Residential Space Heating**




Figures 4.4 (Oregon), 4.5 (Washington) and Table 4.4 summarize the component breakdown of avoided costs by end use and by state. The values are presented in levelized terms to provide a more succinct summary of the results. Note that the first bar (far left) in Figure 4.4 is a levelized representation of the time path shown in Figure 4.3.

**Figure 4.4: Oregon 30-year Levelized Avoided Costs by End Use**

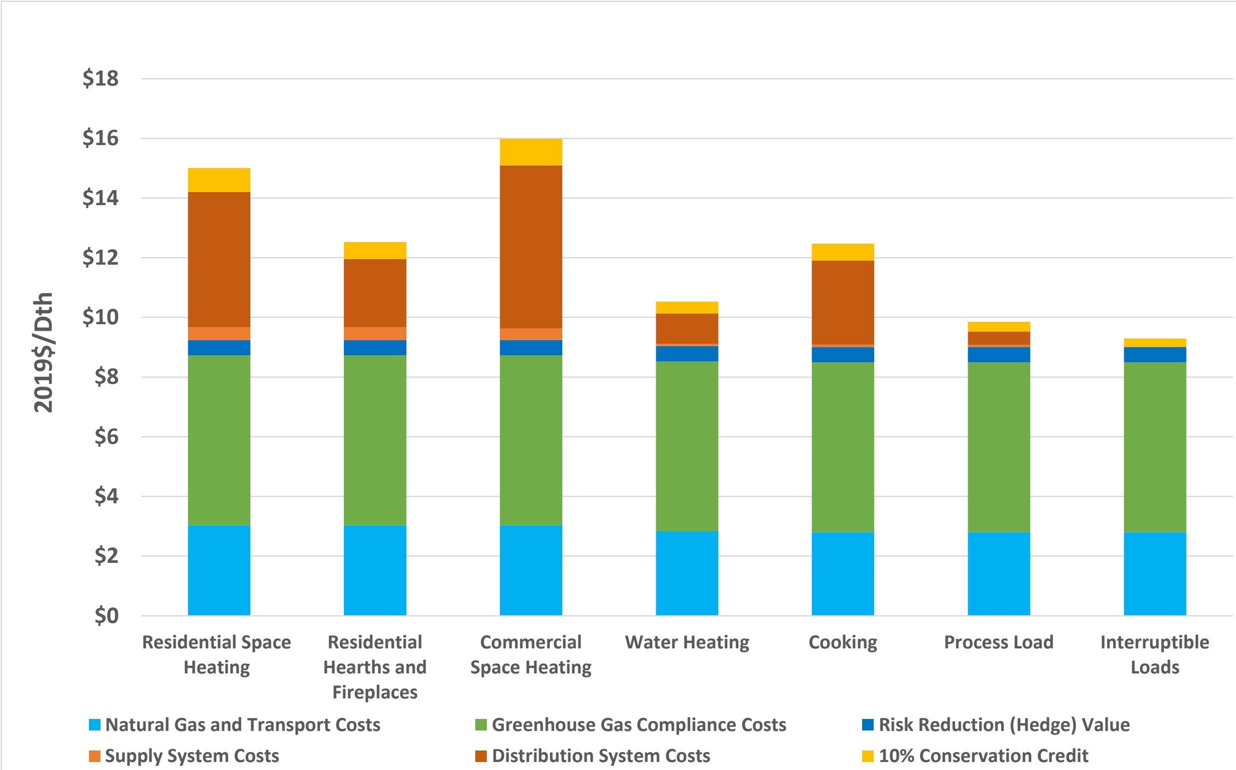


**Figure 4.5: Washington 30-year Levelized Avoided Costs by End Use**

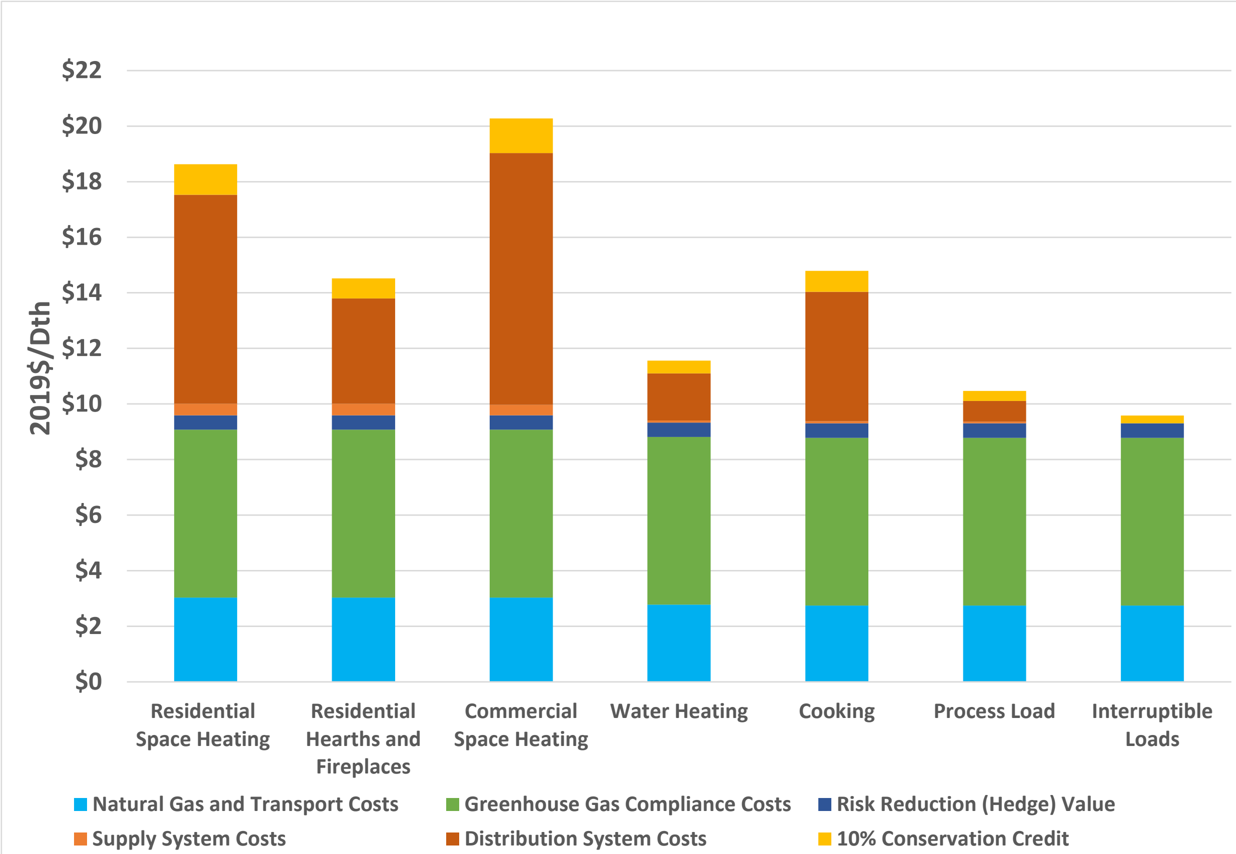



**Table 4.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2019$/Dth)**

| | | Commodity Costs | | | Capacity Costs | | | |
|---|---|---|---|---|---|---|---|---|
| | | Natural Gas Commodity and Transport | Greenhouse Gas Compliance Costs | Risk Reduction (Hedge) Value | Supply Capacity Costs Avoided | Distribution System Resources | 10% Conservation Credit | **Total Avoided Costs** |
| Oregon | Residential Space Heating | $3.04 | $5.69 | $0.52 | $0.42 | $4.54 | $0.80 | **$15.01** |
| | Residential Hearths and Fireplaces | $3.04 | | | $0.42 | $2.28 | $0.57 | **$12.52** |
| | Commercial Space Heating | $3.04 | | | $0.37 | $5.47 | $0.89 | **$15.98** |
| | Water Heating | $2.83 | | | $0.07 | $1.03 | $0.39 | **$10.53** |
| | Cooking | $2.80 | | | $0.08 | $2.81 | $0.57 | **$12.47** |
| | Process Load | $2.80 | | | $0.06 | $0.45 | $0.33 | **$9.85** |
| | Interruptible Loads | $2.80 | | | X | X | $0.28 | **$9.29** |
| Washington | Residential Space Heating | $3.04 | $6.04 | $0.52 | $0.42 | $7.52 | $1.10 | **$18.63** |
| | Residential Hearths and Fireplaces | $3.04 | | | $0.42 | $3.78 | $0.72 | **$14.52** |
| | Commercial Space Heating | $3.04 | | | $0.37 | $9.07 | $1.25 | **$20.28** |
| | Water Heating | $2.78 | | | $0.07 | $1.70 | $0.46 | **$11.56** |
| | Cooking | $2.75 | | | $0.08 | $4.66 | $0.75 | **$14.79** |
| | Process Load | $2.75 | | | $0.06 | $0.75 | $0.36 | **$10.47** |
| | Interruptible Loads | $2.75 | | | X | X | $0.28 | **$9.58** |

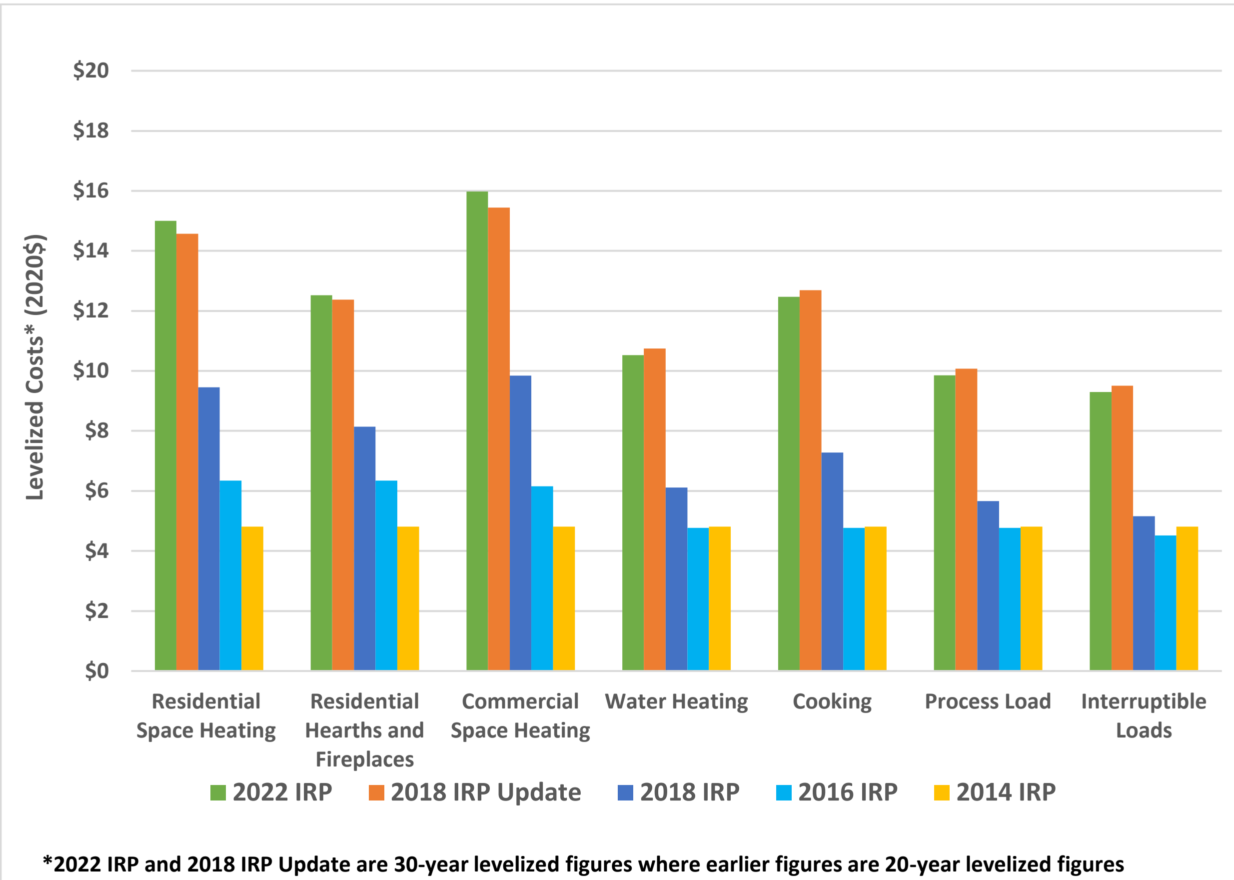
Table 4.4. shows that Washington avoided costs are generally higher than Oregon avoided costs, due largely to the differences in distribution capacity costs across the states and higher emissions compliance costs. Relative to Oregon, Washington avoided costs are more than 24%

higher for residential space heating, 27% higher for commercial space heating, and 10% higher for water heating.

### 4.3.3. Avoided Costs Results Across IRPS

Figure 4.6 shows avoided costs for Oregon by end use evaluated in the 2022 IRP, the avoided costs from the 2018 and 2016 IRPs, and those filed in the 2014 IRP (which were constant across end uses). Improvements to NW Natural's methodology for calculating peak savings from DSM are visible in the marked increase in estimated avoided costs for space heating measures.

**Figure 4.6: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Oregon Example[12]**



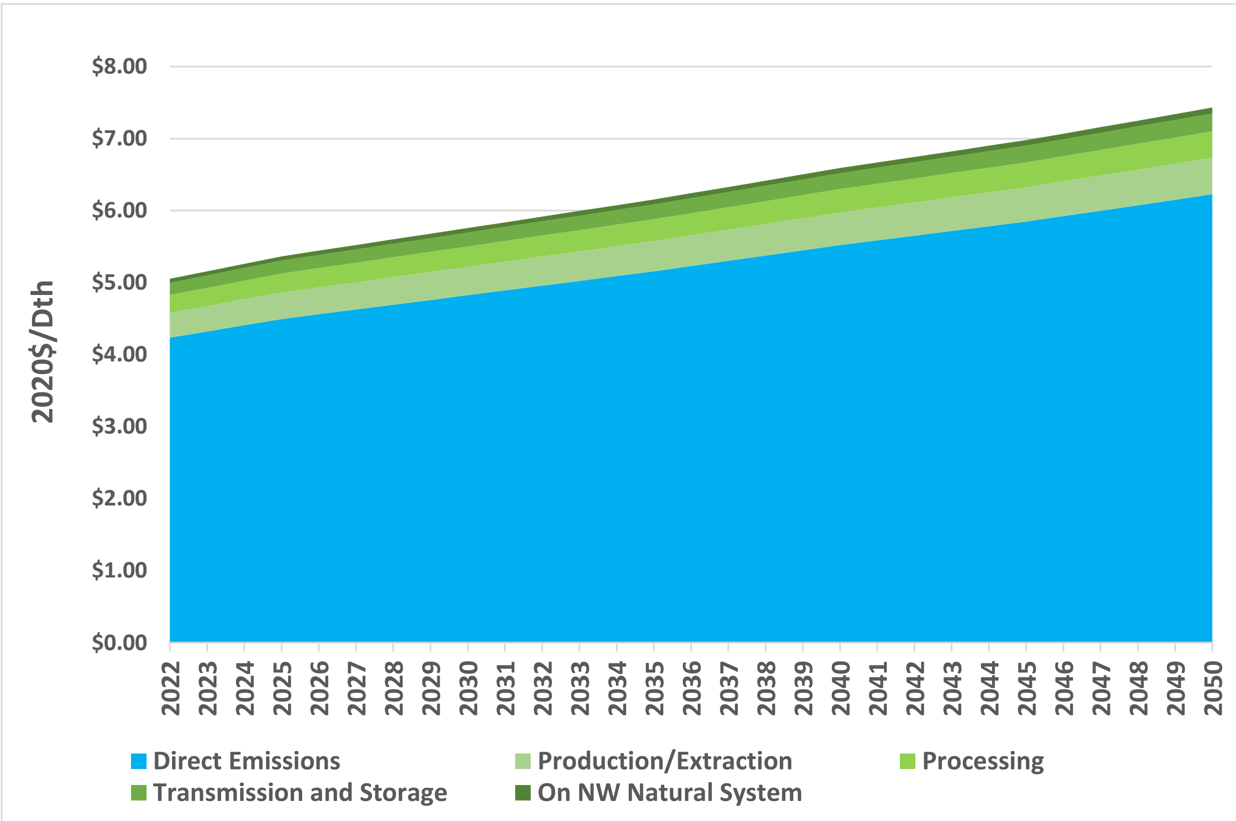

### 4.3.4. Avoided Costs for Carbon Emissions Reductions

As is discussed in Chapters Two, full compliance with the federal and state climate and environmental policies and regulations is a key requirement for this IRP. Potential GHG emissions compliance costs are consequently an important component of avoided costs. Figure 4.7 shows how avoided costs for emissions reduction across the life cycle of natural gas change over the planning horizon 2022-2050. Note that the avoided costs for GHG emissions reduction

[12] Please refer to Appendix C for Washington system estimates.

come mostly from direct emissions (i.e., combustion of natural gas), accounting for 84 percent of the total. The GHG costs avoided from production/extraction, processing, transportation and storage, and on NW Natural system are seven, five, three, and one percent in the total, respectively.

**Figure 4.7: Avoided Costs by Life Cycle of Natural Gas and Year**




## 4.4. Supply-side Applications of Avoided Costs

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.

### 4.4.1. 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 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 Six 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 4.5, which shows that GHG compliance costs avoided are applied to all low carbon gas resources.

**Table 4.5: 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 | Gas Supply displacement from bundled product | Distribution Capacity Costs |
|---|---|---|---|---|---|
| On-System Bundled RNG Purchase | X | X | X | | X |
| RNG with Delivery to NW Natural- Bundled | X | X | X | X | |
| RNG with Sale of Brown Gas- Bundled - Choose Sales Hub | X | X | | | |
| Unbundled Environmental Attribute Purchase | | X | | | |

### 4.4.2. 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 5
# Demand-Side Resources

## 5.1 Energy Trust Background

*As the administrator for NW Natural energy efficiency programs, the Energy Trust provides the following information (shown in maroon text).*

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.[1]

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[2] 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, but not transportation 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.

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 targets derived through the biannual IRP analysis of the available, cost-effective DSM potential.

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.[3] The programs were developed and continue to evolve under the oversight of the Energy Efficiency Advisory Group (EEAG), which is comprised of interested parties to the Company's 2008 rate case. Energy Trust administers the programs, leveraging the offerings available in Oregon to customers located in Washington.[4]

## 5.2 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

[1] *See* Order No. 02-634 in Docket No. UG 143.
[2] *See* Docket No. LC 45.
[3] *See* Order No. 4 in Docket UG-080546.
[4] 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.

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 2022 IRP results show that NW Natural can save 41.2 million therms[5] in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.[6] These results represent a 37% and 6% increase respectively in cost-effective DSM potential over the prior IRP in 2018. The two main drivers of this increased potential are:

1) *Increased budgets and program forecast:* 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 of the IRP.
2) *Measure additions and updates:* Energy Trust added several new emerging technologies to the model and updated measure level assumption for several of the existing measures

Figure 5.1 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.

[5] 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.
[6] Includes over 6.6 million therms of market transformation savings resulting from code changes driven by Energy Trust's New Buildings Program. Also includes 4.5 million therms from a large project adder incorporated into the savings forecast; more details on this adder are included later in this chapter.

**Figure 5.1: 20-year Savings Potential by Sector and Potential Type**

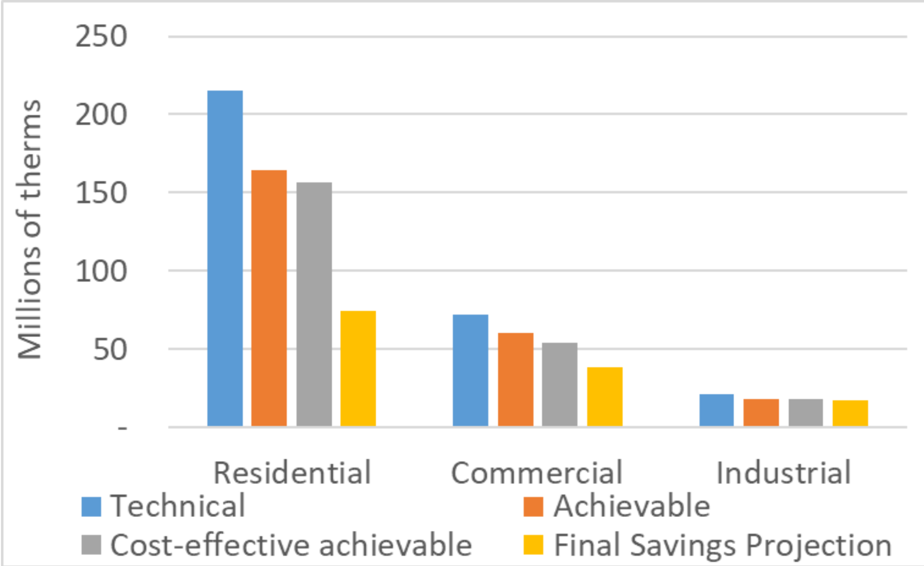
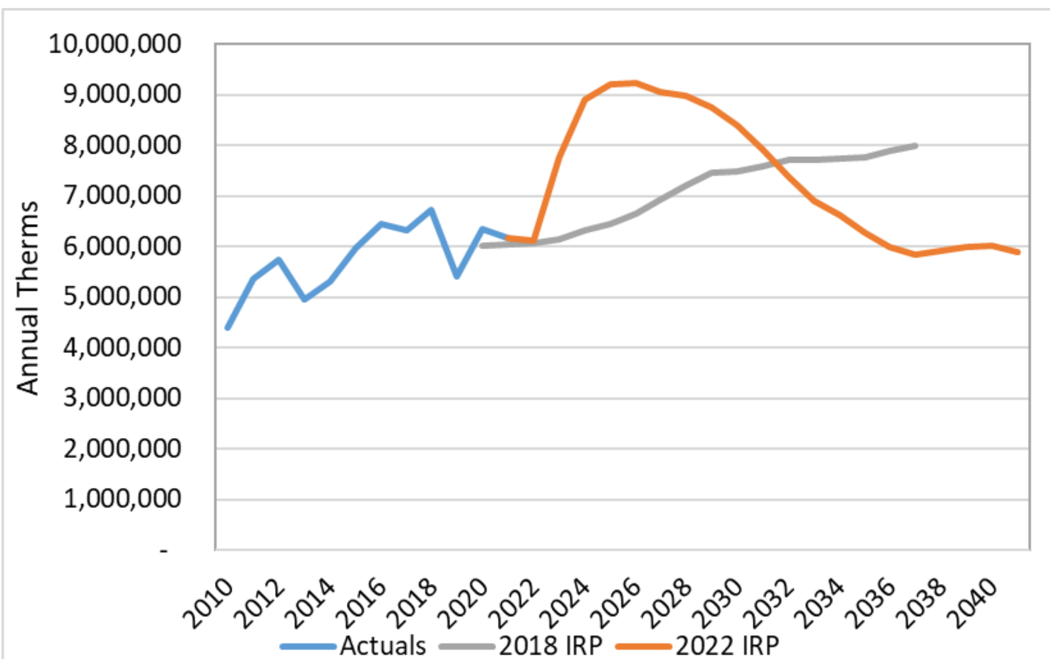



Figure 5.2 links actual historical savings going back to 2010 to the new savings projection for the 2022 IRP. It also compares the 2022 IRP forecast to the 2018 IRP forecast.

**Figure 5.2: Annual Savings Projection Comparison for 2018 and 2022 IRPs, with Actual savings since 2010**



## 5.3 Energy Trust Resource Assessment Economic Modeling Tool

Energy Trust owns, operates, and maintains a 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 2018 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.
- *Lost opportunity measures and unconstrained potential to replace failed equipment* – Lost opportunity measures are constrained in each year by the assumed failed equipment burnout rate as a percentage of total stock. Energy Trust has aligned how the RA model treats lost opportunity measures to be consistent with Northwest Power and Conservation Council (NWPCC) methodology, constraining replace on burnout turnover exogenously to the RA model and allowing lost opportunities to recycle throughout the forecast period.
- *Updated achievability assumptions to align with NWPCC methodology* – Energy Trust has updated achievability assumptions to be consistent with what was used in the most recent power plan. Historically achievability rates were assumed to be 85% for all measures. NWPCC has updated these rates for some measures based on market research. At a high level these changes result in greater achievability for market transformation and codes and standards, and lower achievability for shell measures.

Table 5.1 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.

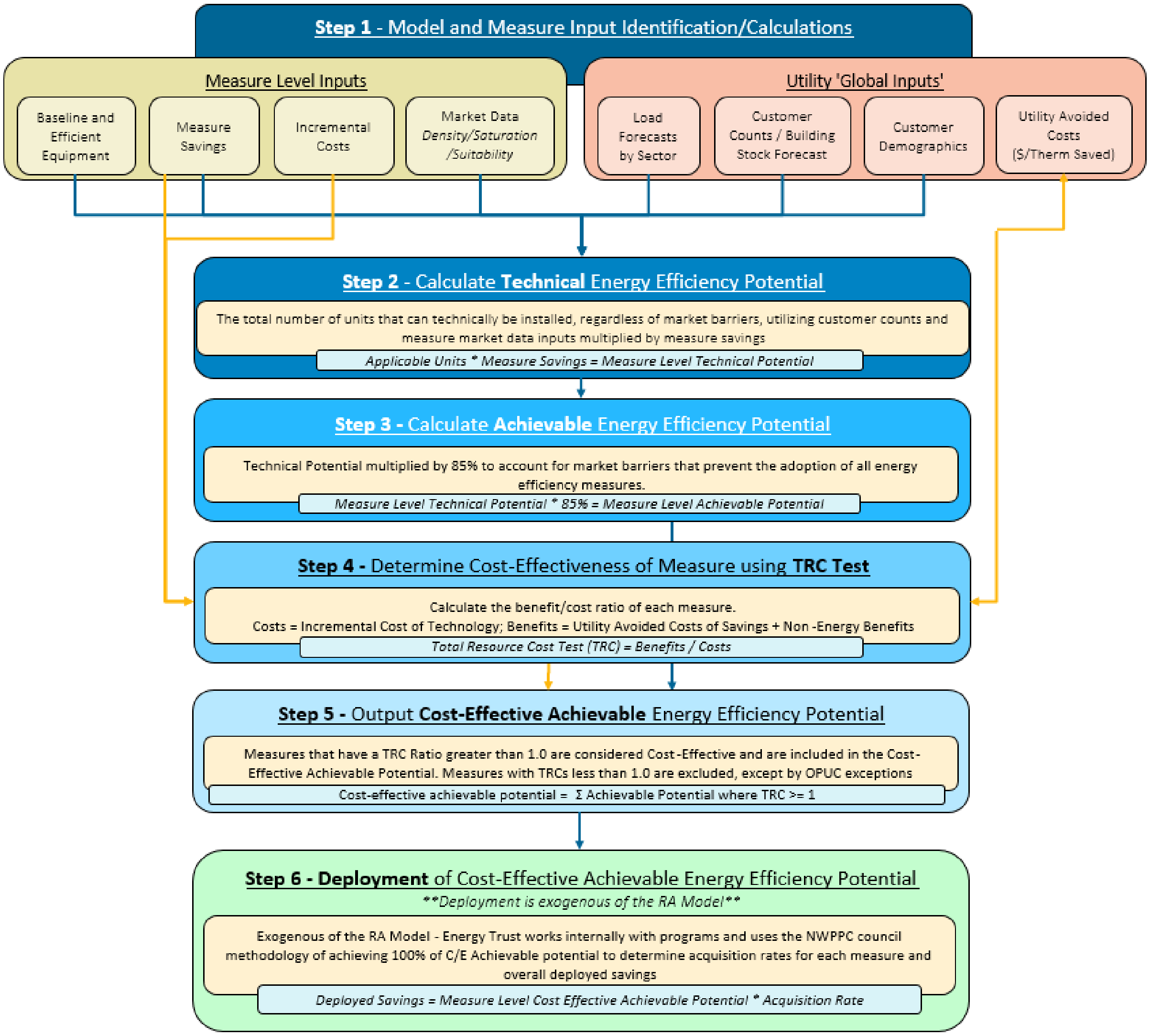
**Table 5.1: Three categories of savings potential identified by the RA Model**

<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>

## 5.4 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 5.3. Steps 1 through 5 (Measure Identification/Input Development to Cost Effective Achievable Output) are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the forecast horizon. The actual deployment of these savings (the acquisition percentage of the total potential each year – Step 6 of Figure 4.3) 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 5.3.

**Figure 5.3: 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.[7]

[7] 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

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

---

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.

[8] 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)

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. Please see Chapter 4 for more detail. 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 <u>not</u> 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 closer to 100% achievable while shell measures are closer to 60% 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.[9] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[10]
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (ex. water savings from low-flow showerheads, Operations and Maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

a) Incentives paid to the participant; and

[9] See Chapter Four for a discussion of NW Natural's avoided cost.

[10] NW Natural's real after-tax annual discount rates used in the 2018 IRP are 3.83 percent for Oregon.

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[11] and is therefore offered by Energy Trust programs.

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

After determining the cumulative 20-year[12] 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 method and ramp rates, but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and saving potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%. This savings forecast includes savings from 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 5.2.

[11] 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.

[12] Energy Trust provided NW Natural with a final savings projection extended to 2050. These results are discussed in section 5.8.

**Table 5.2: The Progression to Program Savings Projections**

<table>
<tr><td>Not Technically Feasible</td><td colspan="4">Technical Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td colspan="3">Achievable Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td>Not Cost Effective</td><td colspan="2">Cost Effective Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td>Not Cost Effective</td><td>Program Design, Market Penetration</td><td>Final Savings Projection</td></tr>
</table>

## 5.5 RA Model Results and Outputs

The RA Model outputs 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.

### 5.5.1 Forecasted Savings Potential by Type

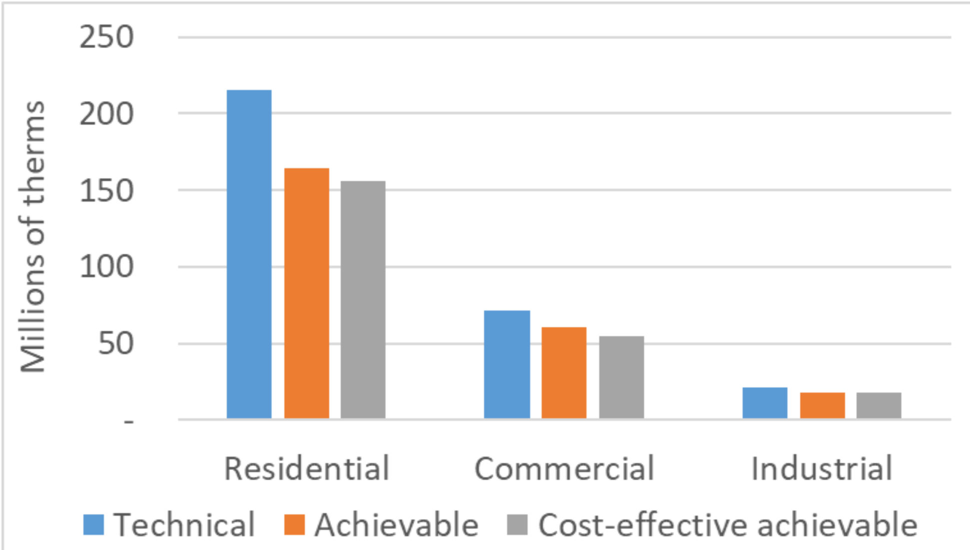
Table 5.3 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Table 5.1. Modeled savings represent the 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 5.3: Summary of Cumulative Modeled Savings Potential - 2022–2041**

| Sector | Technical Potential (Therms) | Achievable Potential (Therms) | Cost-effective achievable Potential (Therms) |
|---|---|---|---|
| Residential | 215,276,957 | 164,364,887 | 156,369,194 |
| Commercial | 71,737,121 | 60,455,169 | 54,208,488 |
| Industrial | 21,290,701 | 18,097,096 | 18,097,096 |
| **Total** | **308,304,779** | **242,917,152** | **228,674,778** |

Figure 5.4 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.

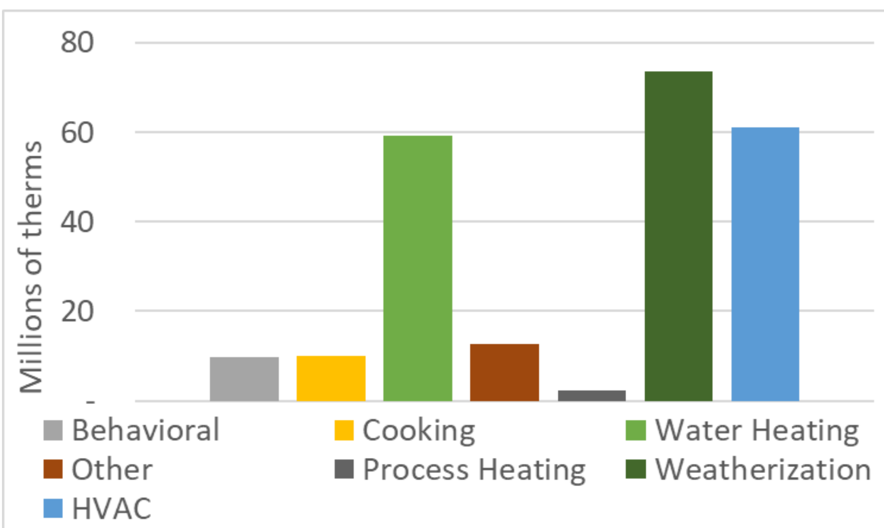
**Figure 5.4: Summary of Cumulative Modeled Savings Potential - 2022–2041 - by Sector and type of Potential**




These results show that for the Residential and Commercial Sectors, approximately 73 and 76 percent of the technical 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, 85 percent of the achievable potential identified is found to be cost effective.

Figure 5.5 provides a breakdown of NW Natural's 20-year cost-effective DSM savings potential by end use.

**Figure 5.5: 20-year Cumulative Cost-Effective Potential by End Use**




The weatherization and HVAC end uses top the list and represent all measures that save space heat. Water heating includes water heating equipment from all sectors. 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 5.6 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 over 66 million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, over 42 million, or 64 percent of that potential remains. For commercially available measures, of the 241 million therms of technical potential, over 185 million, or 77 percent of the potential remains. 19 percent of the total cost-effective potential identified in the model is from emerging technology measures including gas heat pump water heaters for both residential and commercial.

**Figure 5.6: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology.**

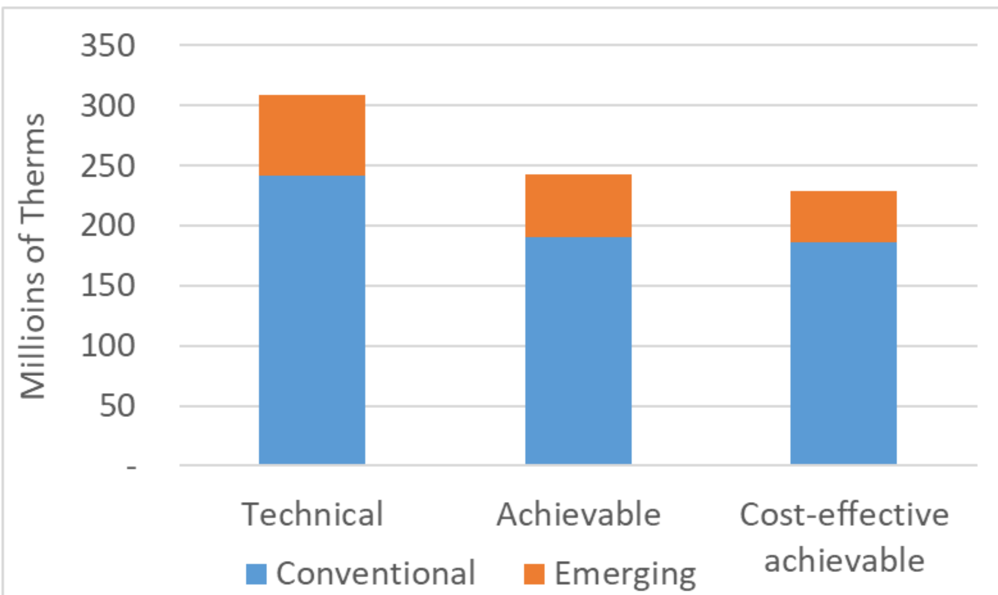



Table 5.4 shows the savings potential in the resource assessment model that was added by employing the cost-effectiveness override option in the model. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets 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 5.4: Cumulative Cost-Effective Potential (2022-2041) due to use of Cost-effectiveness override**

| Sector | Yes CE Override | No CE Override | Difference |
|---|---|---|---|
| **Residential** | 156.37 | 125.04 | 31.33 |
| **Commercial** | 54.21 | 47.19 | 7.01 |
| **Industrial** | 18.10 | 18.10 | 0 |
| **Total** | **228.67** | **190.33** | **38.35** |

In this IRP, 17 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.

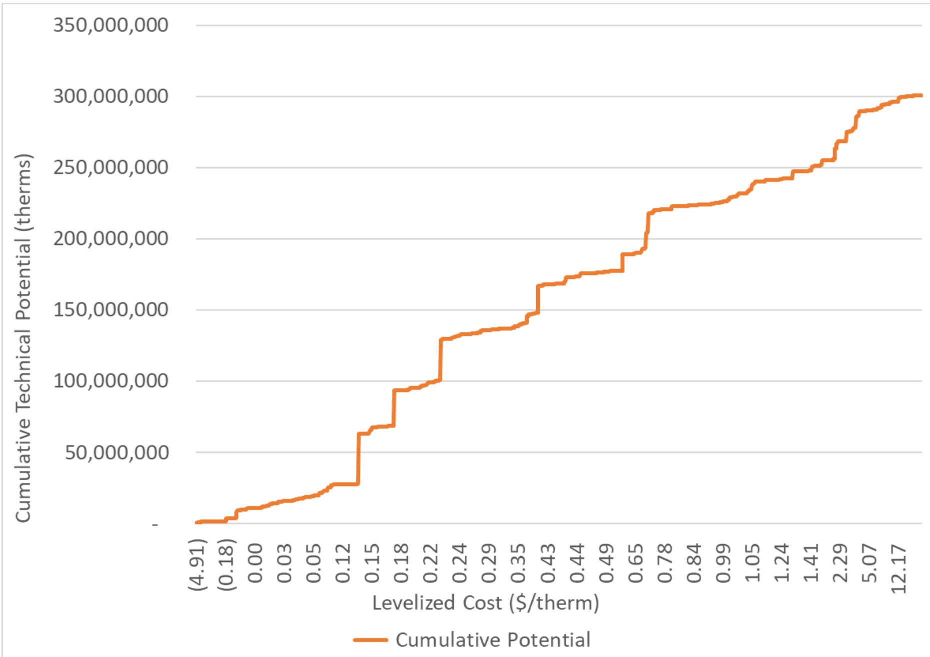
### 5.5.2 Supply Curve and Levelized Costs

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 3.83 percent. The annualized measure cost is then divided by the annual energy savings, in therms.

Figure 5.7 shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources.

**Figure 5.7: 20-year Gas Supply Curve.**[13]




## 5.6 2022 Model Results Compared to 2018

Table 5.5 shows the total modeled potential for DSM in this IRP compared to the prior IRP in 2018. The increased potential is primarily found in the residential sector and is primarily driven by emerging technology, new measures that are being offered by programs, and changes in modeling assumptions. This modeled savings amount is mitigated by the amount of savings potential selected for deployment as shown in the final savings projection beginning on page 5.17. Only a portion of the cost-effective potential from lost opportunity measures, such as new construction and replacement of end-of-life equipment, is expected to be acquired given program budgets, incentive levels, and customer decision making preferences. Assumptions based on historical program performance are considered when generating the final annual savings projection. The final savings projection relies on program input and forecasts of what amount of the modeled cost-effective potential Energy Trust anticipates acquiring through programs, code improvements and market transformation.

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

**Table 5.5: Total 2022 IRP Cost-Effective Modeled Potential compared to 2018 and IRP modeled potential by Sector**

| | Total Cost-Effective Potential 2018 OR IRP (Millions of therms) 2018-2037 | Total Cost-Effective Potential 2022 IRP (Millions of therms) 2022-2041 |
|---|---|---|
| Residential | 115.8 | 156.4 |
| Commercial | 62.8 | 54.2 |
| Industrial | 16.5 | 18.1 |
| All DSM | 195.1 | 228.7 |

Table 5.6 builds off Table 5.5 and details the key factors that drove the change in cost-effective potential for DSM in this IRP compared to the prior IRPs in 2018. The primary emerging technologies, Gas Heat Pump Water Heaters and Gas Fired Heat Pumps, are broken out separately in the table below and make up 13.56 MM therms of the total 23.02 MM therm savings from emerging technologies.

**Table 5.6: Key Changes in Model that Increased Potential from 2018 IRP to 2022 IRP**

| Change Component | Change in DSM Savings (Millions of Therms) from 2018 to 2022 IRPs | % of Total |
|---|---|---|
| Emerging Technology[14] | 23.02 | 69% |
| *Gas Heat Pump Water Heater* | *13.11* | |
| *Gas Heat Pump* | *0.45* | |
| New Measures | 25.01 | 75% |
| Removed Measures | -25.08 | -75% |
| CE override | 29.98 | 89% |
| Change in Model Assumptions | -21.02 | -63% |
| **Total Change from 2018 to 2022 IRP** | **33.56** | **95%** |

## 5.7 Final Savings Projection

The results of the final savings projection show that Energy Trust can save 41.2 million therms across NW Natural's system in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.

[14] Emerging technology is made up of condensing gas rooftop units, gas absorption heat pump water heaters, gas fired heat pumps, industrial advanced wall insulation, and thin triple pane windows. Gas heat pump water heaters constitute 13.11 million therms of the emerging technology potential.

The final savings projection of 147.1 million therms by 2041 in NW Natural's service territory in Oregon, contains a reduction to the full cost-effective potential shown in Table 5.7. 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 5.7 depicts savings projections for NW Natural's Oregon system. The 'Other' sector referenced in the savings projections include the large project adder, Commercial New Buildings market transformation savings, and code savings from several commercial cooking measures that result in a market baseline equivalent to efficient technology. Both Commercial market transformation and cooking savings were forecasted outside of that Sector's standard savings as Energy Trust does not claim those savings.

**Table 5.7: 20-Year Cumulative Savings Potential by type, including final savings projection**

| | Technical | Achievable | Cost-effective | Energy Trust Savings Projection |
|---|---|---|---|---|
| Residential | 215.28 | 164.36 | 156.37 | 74.14 |
| Commercial | 71.74 | 60.46 | 54.21 | 38.09 |
| Industrial | 21.29 | 18.10 | 18.10 | 16.74 |
| Other | 0 | 0 | 0 | 18.12 |
| All DSM | 308.30 | 242.92 | 228.67 | 147.08 |

Figure 5.8 shows the annual savings projection by Sector. The growth in savings from 2022 to 2025 is a result of discussions with NW Natural to increase efficiency spending to accelerate cost effective potential acquisition in the near forecast term. These increases reflect Energy Trust's best attempt to estimate increased savings potential without running these estimates through the more comprehensive planning that accommodates our annual budgeting process. Energy Trust will use these savings targets as a starting point for constructing savings goals for the 2023-2024 budget and presenting the anticipated budget needs that will accompany these savings goals. The eventual savings goals and the revenue needed to fund the budget will be negotiated, per usual practice, as a component of the budget process. Furthermore, the magnitude of the savings increases reflected in the attached savings targets for 2023-2026 are subject to evolving program designs and offerings that will need to be tested to validate their resulting efficacy.

**Figure 5.8: 20-Year Annual Savings Projection by Sector**

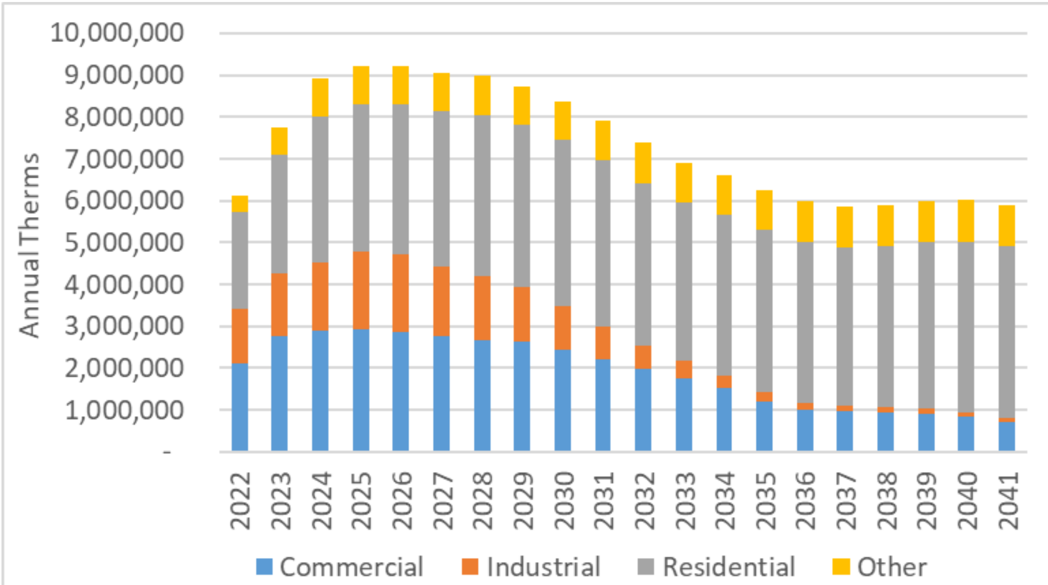
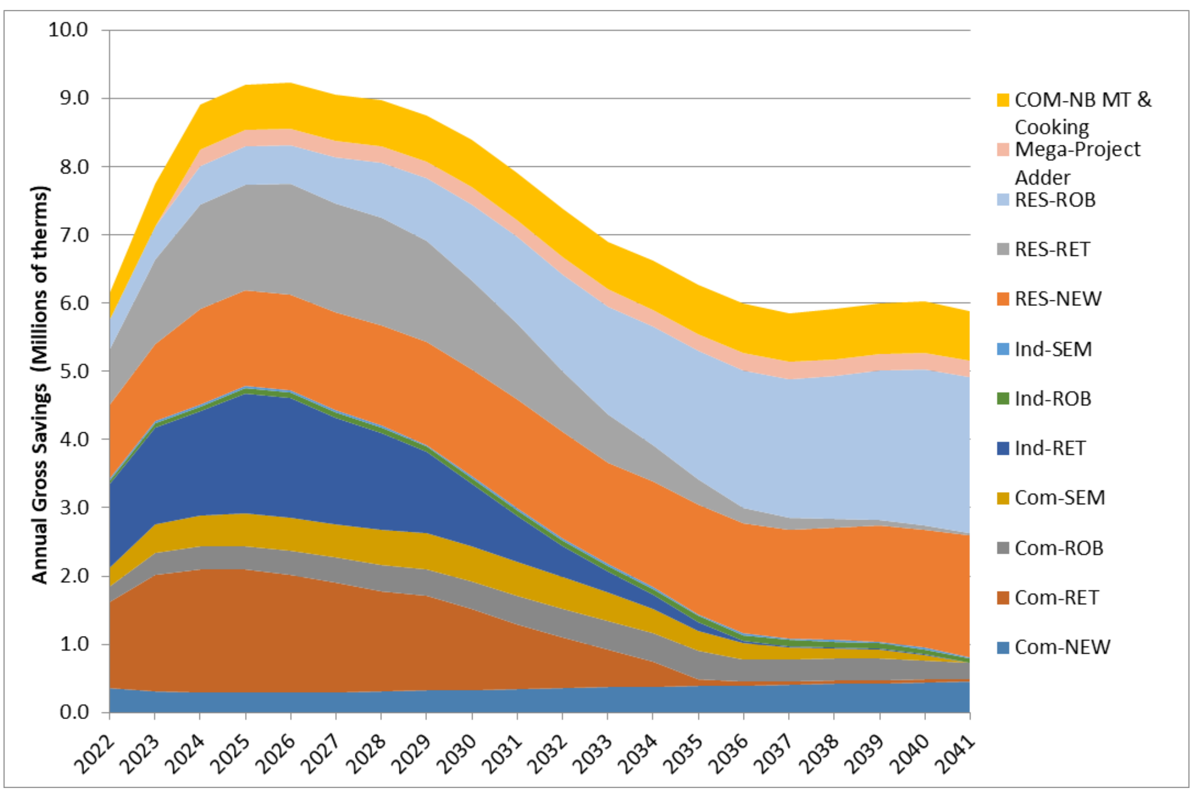



Figure 5.9 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

**Figure 5.9: Annual Savings Projection by Sector-Measure Type**



## 5.8 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 section 5.7 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 nine 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 calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%.

**Table 5.8: 20-year and 29-year Final Savings Projection**

| | 20-Year Savings Projection | 9-Year Savings Extension | Total Final Savings through 2050 |
|---|---|---|---|
| Residential | 74.14 | 35.92 | 110.05 |
| Commercial | 38.09 | 6.66 | 44.75 |
| Industrial | 16.74 | 0.21 | 16.95 |
| Other | 18.12 | 5.86 | 23.97 |
| All DSM | 147.08 | 48.65 | 195.73 |

**Figure 5.10: Annual Savings Projection by Sector through 2050**

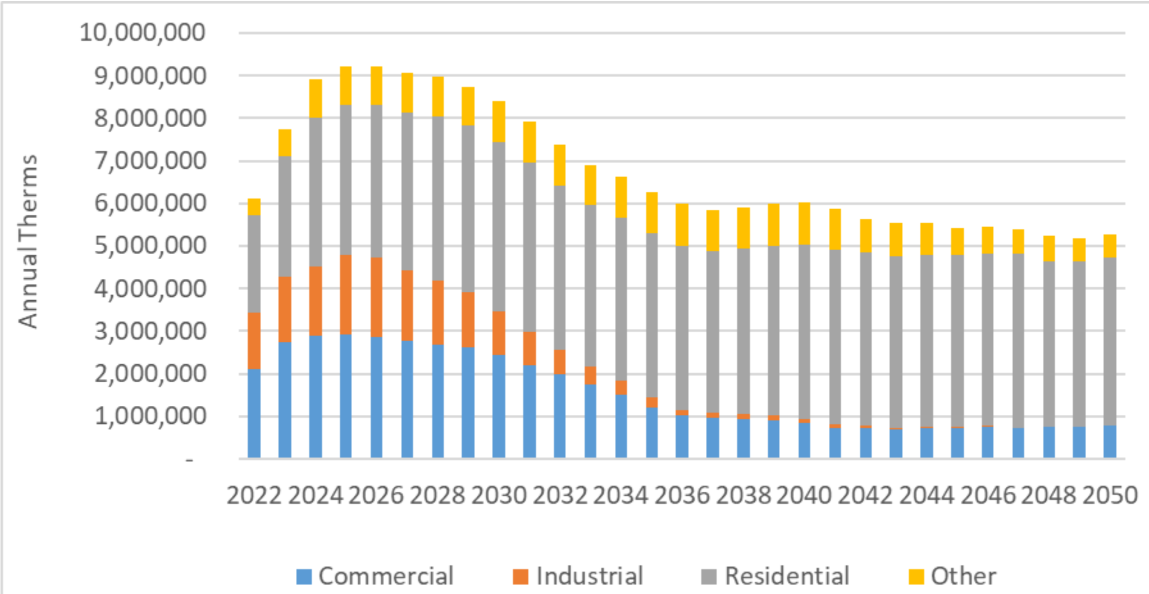
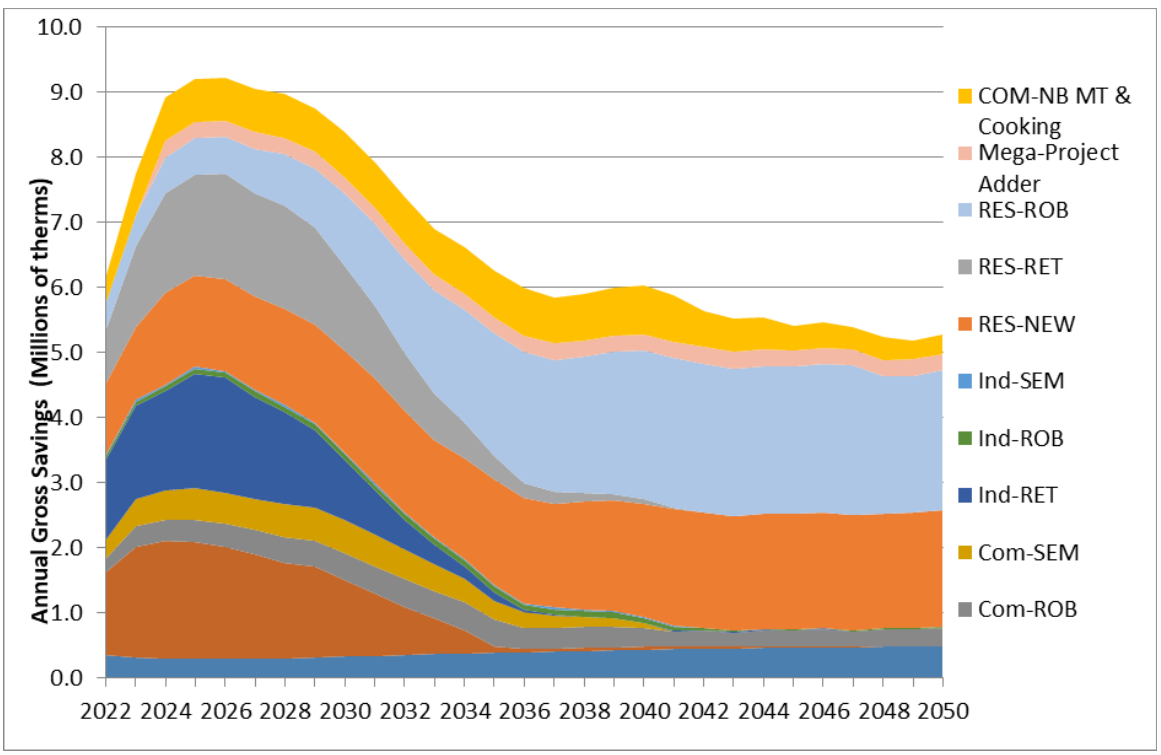



**Figure 5.11: Annual Savings Projection by Sector through 2050**




## 5.9 Peak Savings Deployment

Figures 5.12 and 5.13 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 5.12: NW Natural's Annual Peak-Day Savings Projection by Sector**

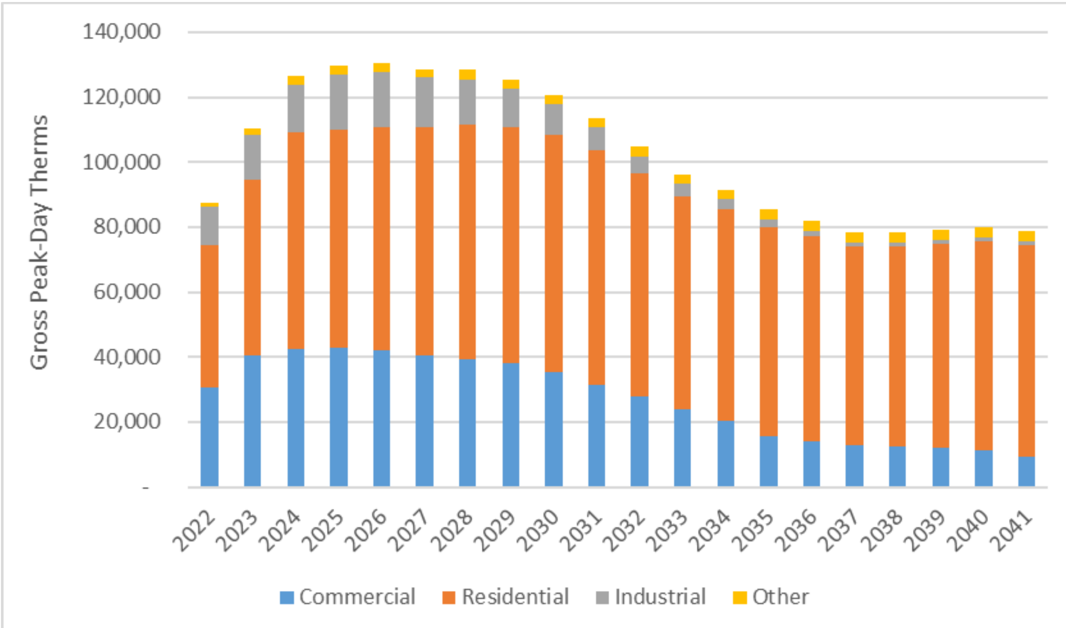
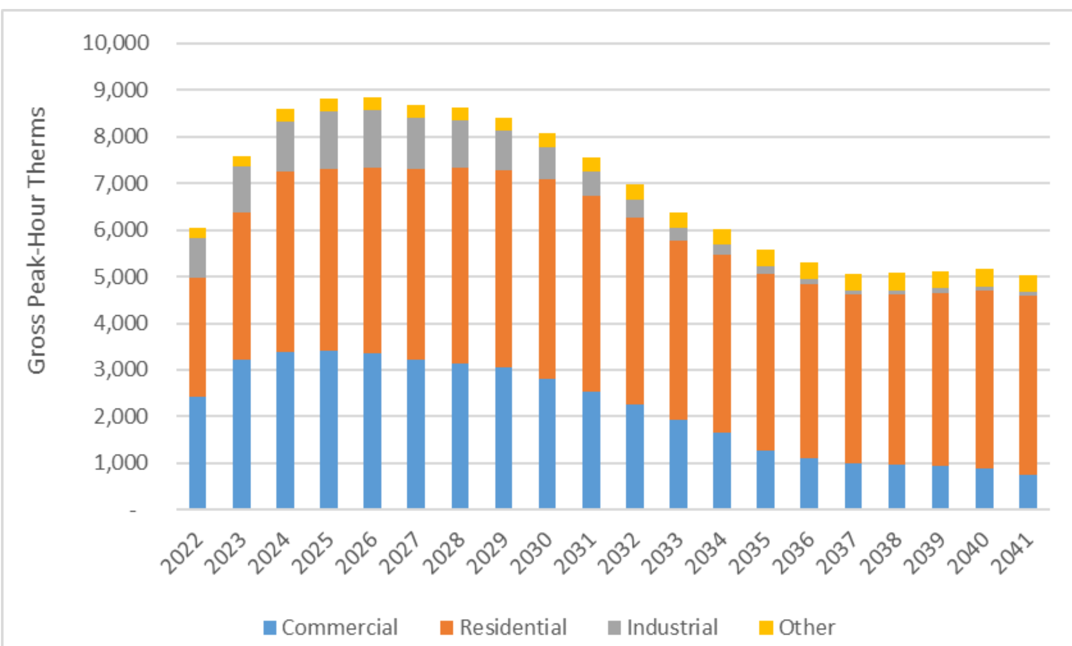



**Figure 5.13: NW Natural's Annual Peak-Hour Savings Projection by Sector**




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 2,055,067 therms or 1.4% of the 147.1 million therm savings projection. The total peak-hour savings over the 20-year savings projection is 136,898 therms or 0.09% of the 147.1 million therm savings projection.

## 5.10 Conservation Potential Assessment in Washington

*This section is extracted and summarized from the final report of the 2021 NW Natural Washington Conservation Potential Assessment submitted by Applied Energy Group (AEG) to NW Natural.* [15]

### 5.10.1 Background

In early 2021, 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. AEG applied standard industry and northwest regional methodologies to develop reliable estimates of technical, achievable technical, and achievable economic potential from two different cost-effectiveness perspectives for the period from 2022-2051. AEG completed the assessment in collaboration with NW Natural and ETO using information specific to NW Natural's customers and existing energy efficiency programs wherever possible and delivered the final study report to NW Natural in July 2021.

### 5.10.2 Analysis Approach

To perform the conservation potential analysis, AEG used a bottom-up approach following the major steps:

1) Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2019. This included extensive use of NW Natural data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
2) Developed a baseline projection of energy consumption by sector, segment, end use, and technology for 2022 through 2051.
3) Defined and characterized several hundred EE measures to be applied to all sectors, segments, and end uses.
4) Estimated technical, achievable technical, and achievable economic energy savings at the measure level for 2022-2051. Achievable economic potential was assessed using both the Total Resource Cost (TRC) and Utility Cost Test (UCT) screens.

More specifically, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop both the baseline projection and the estimates of potential. Built in Excel, the LoadMAP framework possesses key features that embody basic principles of rigorous end-use models, accommodates different levels of segmentation, includes algorithms that independently account for new and existing appliances and building stock, and balances the competing needs of simplicity and robustness. The LoadMAP model provides projections of

[15] 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

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.[16]

Three types of potential were analyzed in this AEG study: technical, achievable technical, and achievable economic. Table 5.9 provides detailed definitions on each type of potential.

**Table 5.9: Types of Potential and Definitions**

| 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 |

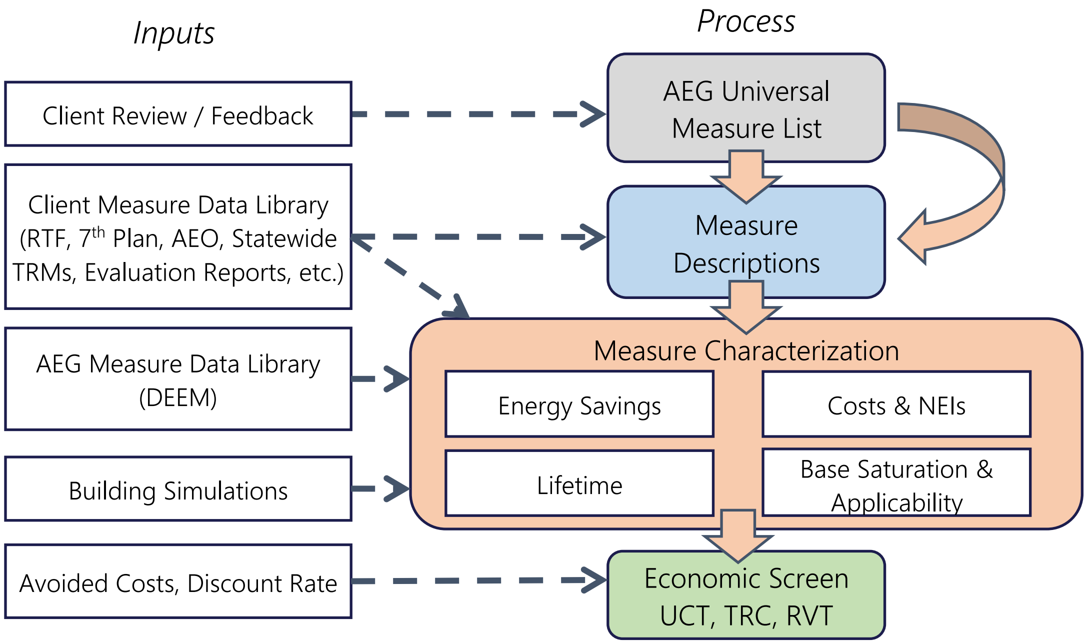
AEG developed the reference baseline in alignment with NW Natural's long-term demand forecast, but some modifications to account for known future conditions were also made. Inputs to the baseline projection include:

1) Current economic and load growth forecasts (i.e., customer growth, climate change assumptions)
2) Trends in fuel shares and equipment saturations
3) Existing and approved changes to building codes and equipment standards

To develop NW Natural's DSM measure list, in addition to its own databases, AEG also used datasets provided by NW Natural and ETO. As shown in Figure 5.13, first, a 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.

[16] 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).

**Figure 5.13: Approach for Energy Efficiency Measure Characterization and Assessment**




### 5.10.3 Baseline Projection

Prior to developing estimates of energy conservation potential, baseline projections of annual natural gas use for 2022 through 2051 by customer segment and end use in the absence of new utility energy-efficiency programs were developed. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future to avoid double counting potential opportunities. Thus, the potential analysis captures all possible savings from future programs.

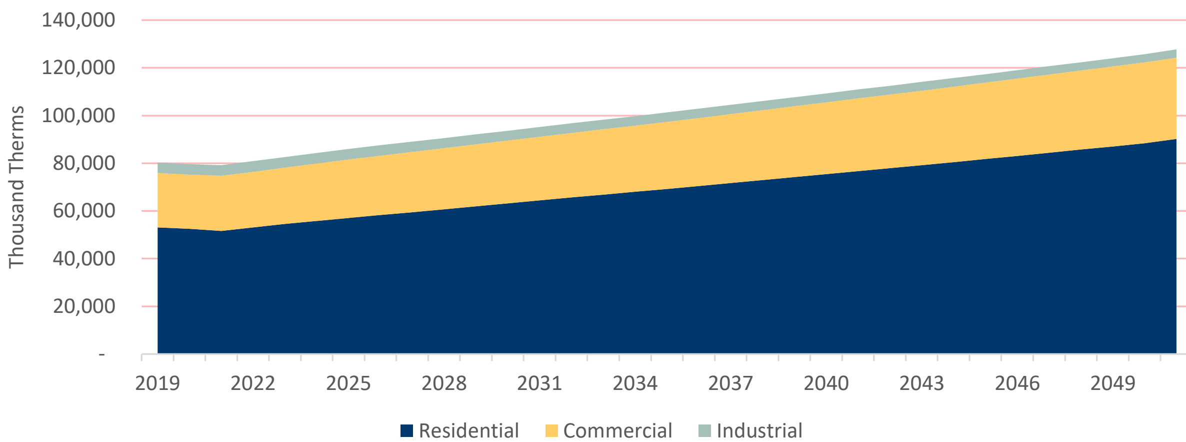
Table Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here. and **Error! Reference source not found.** provide a summary of the baseline projection for annual use by sector for the entire NW Natural Washington service territory. Base year (2019) values[17] are weather normalized using HDD data provided by NW Natural's load forecast department. Years 2021 forward include the impact of climate trends through projected heating degree days (HDDs) supplied by NW Natural. Overall, the forecast shows modest growth in natural gas consumption, at an average rate of about 1.4% per year.

[17] NW Natural also provided 2020 consumption data for AEG's consideration in aligning the baseline projection with NW Natural's forecast

**Table** Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here.**5.10: Baseline Projection Summary by Sector, Selected Years (mTherms)**

| Sector | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2031 | 2040 | 2050 | % Change ('19-'50) | Avg. Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 53,096 | 52,500 | 51,552 | 53,041 | 54,507 | 55,765 | 64,452 | 75,477 | 88,376 | 66.4% | 1.6% |
| Commercial | 22,840 | 22,754 | 23,213 | 23,350 | 23,623 | 24,112 | 26,657 | 30,083 | 33,935 | 48.6% | 1.3% |
| Industrial | 4,382 | 4,379 | 4,400 | 4,440 | 4,450 | 4,405 | 4,120 | 3,753 | 3,435 | -21.6% | -0.8% |
| **Total** | **80,319** | **79,633** | **79,166** | **80,831** | **82,581** | **84,282** | **95,229** | **109,312** | **125,747** | **56.6%** | **1.4%** |

**Figure 5.14: Baseline Projection Summary by Sector (mTherms)**



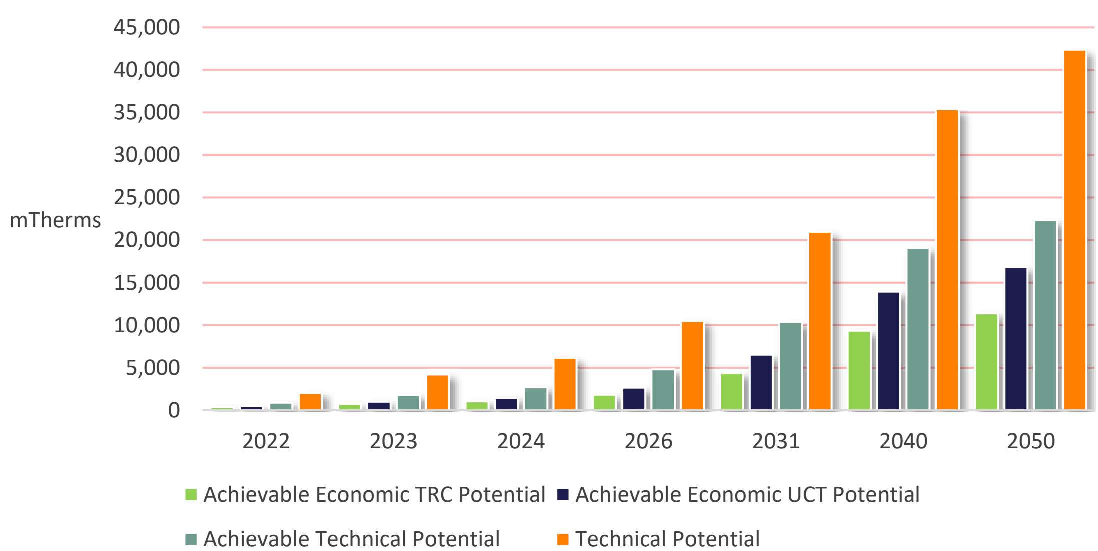

## 5.10.4 DSM Potential

**Error! Reference source not found.** and **Error! Reference source not found.** 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.

**Table** Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here.**5.11: Summary of Energy Efficiency Potential (mTherms)**

| Scenario | 2022 | 2023 | 2024 | 2026 | 2031 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **Baseline Load Projection (mTherms)** | 80,831 | 82,581 | 84,282 | 87,530 | 95,229 | 109,312 | 125,747 |
| **Cumulative Savings (mTherms)** | | | | | | | |
| TRC Achievable Economic Potential | 354 | 725 | 1,036 | 1,827 | 4,390 | 9,345 | 11,392 |
| UCT Achievable Economic Potential | 477 | 992 | 1,470 | 2,671 | 6,523 | 13,936 | 16,818 |
| Achievable Technical Potential | 874 | 1,799 | 2,702 | 4,808 | 10,350 | 19,102 | 22,321 |
| Technical Potential | 2,033 | 4,189 | 6,160 | 10,491 | 20,957 | 35,383 | 42,373 |
| **Cumulative Savings (% of Baseline)** | | | | | | | |
| TRC Achievable Economic Potential | 0.4% | 0.9% | 1.2% | 2.1% | 4.6% | 8.5% | 9.1% |
| UCT Achievable Economic Potential | 0.6% | 1.2% | 1.7% | 3.1% | 6.8% | 12.7% | 13.4% |
| Achievable Technical Potential | 1.1% | 2.2% | 3.2% | 5.5% | 10.9% | 17.5% | 17.8% |
| Technical Potential | 2.5% | 5.1% | 7.3% | 12.0% | 22.0% | 32.4% | 33.7% |

**Figure 5.15: Summary of Annual Cumulative Energy Efficiency Potential (mTherms)**




**Error! Reference source not found.** summarizes TRC achievable potential by market sector for selected years. In general, residential and commercial potential are well balanced and dominant since industrial sales customer consumption represents a small percentage of the baseline and potential for this sector is also relatively small in size. In 2022, TRC achievable economic potential is 182 mTherms, or 0.3% of the baseline projection for the residential sector, 155 mTherms, or 0.7% of the baseline projection for the commercial sector, and 16 mTherms, or 0.4% of the baseline projection for the industrial sector, respectively. By 2050, cumulative savings are 6,612 mTherms, or 7.5% of the baseline for the residential sector, 4,526 mTherms, or 13.7% of the baseline for the commercial sector, and 254 mTherms, or 7.4% of the baseline for industrial sector, respectively. Overall, in 2022, first-year savings are 354 mTherms, or 0.4% of the baseline projection. Cumulative savings in 2031 are 4,390 mTherms, or 4.6% of the baseline. By 2050 cumulative TRC achievable economic potential reaches 11,392 mTherms, or 9.1% of the baseline.

**Table** Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here.**5.12: Cumulative TRC Achievable Economic Potential by Sector, Selected Years (mTherms)**

| Sector | 2022 | 2023 | 2024 | 2026 | 2031 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| Residential | 182 | 369 | 478 | 837 | 2,250 | 5,380 | 6,612 |
| Commercial | 155 | 323 | 509 | 908 | 1,979 | 3,713 | 4,526 |
| Industrial | 16 | 33 | 49 | 82 | 162 | 253 | 254 |
| **Total** | **354** | **725** | **1,036** | **1,827** | **4,390** | **9,345** | **11,392** |

**Error! Reference source not found.** and **Error! Reference source not found.** 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 obtained from NW Natural.

**Table** Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here.**5.13: Peak Day Potential Summary (mTherms)**

| Scenario | 2022 | 2023 | 2024 | 2026 | 2031 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **Peak Day Savings (mTherms)** | | | | | | | |
| TRC Achievable Economic Potential | 5 | 11 | 16 | 27 | 60 | 124 | 148 |
| UCT Achievable Economic Potential | 7 | 15 | 22 | 38 | 85 | 179 | 208 |
| Achievable Technical Potential | 11 | 23 | 34 | 60 | 127 | 238 | 272 |
| Technical Potential | 27 | 55 | 79 | 134 | 265 | 473 | 563 |
| **Energy Savings (% of Baseline)** | | | | | | | |
| TRC Achievable Economic Potential | 0.5% | 1.1% | 1.4% | 2.4% | 4.9% | 8.9% | 9.3% |
| UCT Achievable Economic Potential | 0.7% | 1.4% | 2.0% | 3.4% | 6.9% | 12.8% | 13.0% |
| Achievable Technical Potential | 1.1% | 2.2% | 3.2% | 5.4% | 10.3% | 17.0% | 17.0% |
| Technical Potential | 2.6% | 5.2% | 7.3% | 11.9% | 21.6% | 33.8% | 35.3% |

**Table** Error! Use the Home tab to apply Heading 1,Chap Num to the text that you want to appear here.**5.14: Peak Hour Potential Summary (mTherms)**

| Scenario | 2022 | 2023 | 2024 | 2026 | 2031 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **Peak Hour Savings (mTherms)** | | | | | | | |
| TRC Achievable Economic Potential | 0.4 | 0.7 | 1.1 | 1.9 | 4.5 | 9.6 | 11.5 |
| UCT Achievable Economic Potential | 0.5 | 1.0 | 1.5 | 2.8 | 6.8 | 14.5 | 17.5 |
| Achievable Technical Potential | 0.9 | 1.9 | 2.8 | 5.0 | 10.9 | 20.1 | 23.4 |
| Technical Potential | 2.1 | 4.4 | 6.5 | 11.1 | 22.3 | 37.4 | 44.8 |
| **Energy Savings (% of Baseline)** | | | | | | | |
| TRC Achievable Economic Potential | 0.5% | 0.9% | 1.3% | 2.2% | 4.8% | 8.8% | 9.2% |
| UCT Achievable Economic Potential | 0.6% | 1.2% | 1.8% | 3.2% | 7.3% | 13.4% | 14.0% |
| Achievable Technical Potential | 1.1% | 2.3% | 3.4% | 5.8% | 11.6% | 18.5% | 18.8% |
| Technical Potential | 2.7% | 5.4% | 7.8% | 12.9% | 23.6% | 34.5% | 35.9% |

Key opportunities for savings include residential 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 2021 Washington Conservation Potential Study.[18]

## 5.11 DSM Potential for Oregon Transportation Customers

### 5.11.1 Background

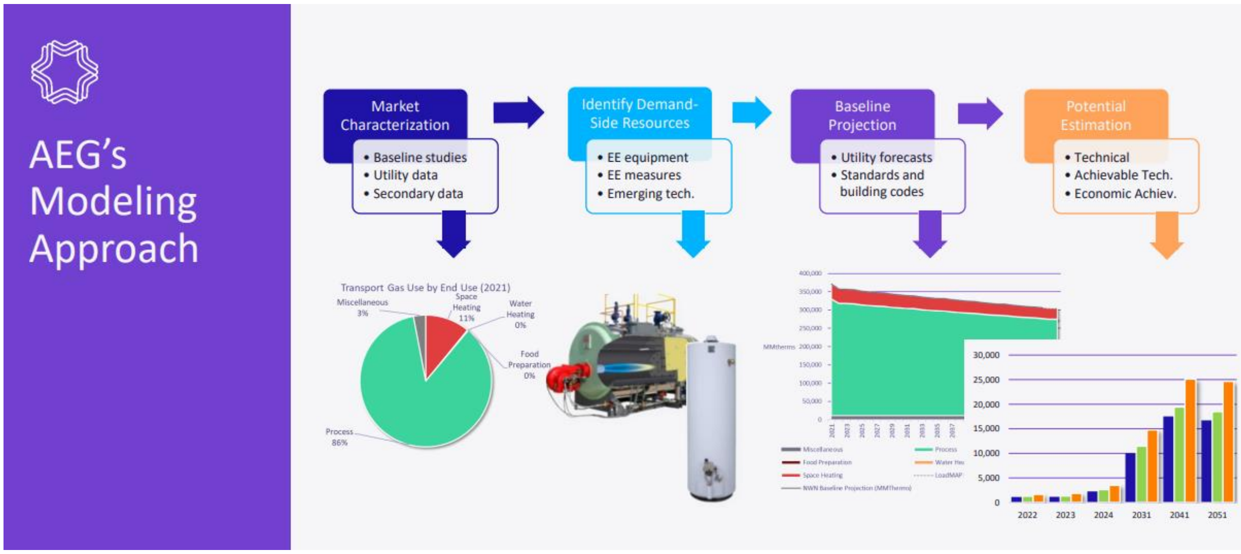
With the passing of Executive Order 20-04 in March 2020, statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels will be limited by new goals from the Oregon Department of Environmental Quality (DEQ). The resulting Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emission of natural gas transportation customers.[19] NW Natural's transportation customers have not historically paid into the public purpose charge and thus are currently not eligible to participate in natural gas energy efficiency programs administered by ETO. NW Natural engaged AEG to assess the potential that exists with Oregon transportation customers and inform what DSM programs for transportation customers could look like in the future.

[18] 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

[19] Transportation customers are non-residential natural gas consumers, typically large industrial users, who purchase natural gas from an alternate supplier, but use NW Natural's distribution system to deliver the fuel to their sites.

The Washington Conservation Potential Assessment (CPA) that AEG completed for NW Natural in 2021 provided a starting point to assess the potential for energy efficiency to reduce greenhouse gas (GHG) emissions at transportation customer sites.[20] AEG used many of the same data sources from the Washington CPA, updated as appropriate to capture Oregon transportation customer characteristics.

### 5.11.2 Methodology




## Key Data Sources

### NW Natural Data

- Customer account data including SIC codes
- Customer equipment database including nameplate BTU
  - Vetted and adjusted by NW Natural field techs
- Transport customer class energy totals and forecast
- Washington CPA conducted by AEG served as a starting point for many measure characterizations and applicable market/adoption rate assumptions

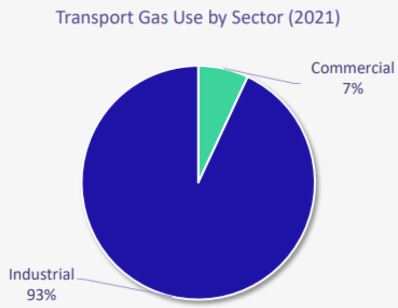
### Additional Data Sources:

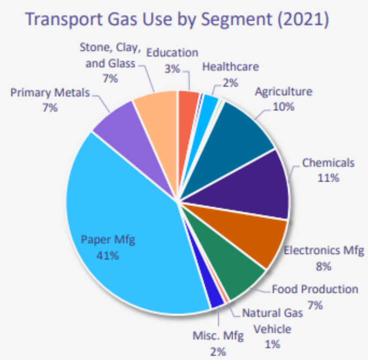
- Benchmarking/comparison:
  - NEEA's Commercial Building Stock Assessments (2014 and 2019)
  - US Energy Information Administration (EIA) Manufacturing Energy Consumption Survey (MECS)
- Projections
  - US EIA Annual Energy Outlook (AEO) reference case forecast (equipment stock turnover assumptions)
  - Northwest Power and Conservation Council measure adoption ramp rates

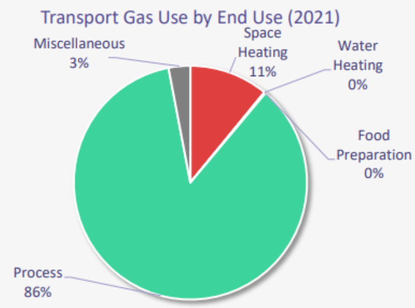
[20] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

# Market Characterization

- Define energy-consumption characteristics in the base year of the study (2021).
- Incorporates NW Natural's actual consumption and customer counts to develop "Control Totals" – values to which the model will be calibrated.
- Grounds the analysis in NW Natural data and provides enough detail to project assumptions forward to develop a baseline energy projection.
- After separating gas consumption into sectors and segments, it is allocated to specific end uses and technologies.




# Considerations for this Analysis

- Available potential is largely a function of baseline consumption – segments with the highest baseline consumption are likely to have the highest potential
- Potential studies rely on average information, which may not reflect conditions or opportunities for any single customer
  - This is particularly relevant for this study, where a small number of customers represent a large share of transport load
  - Ramp rates are derived from the Northwest Power and Conservation Council's 2021 Power Plan and reflect expected adoption across a broad set of customers. Actual adoption of energy efficiency for large transport customers may be lumpier based on cycles for implementing large capital projects
- Equipment data provided from NW Natural's system contain some uncertainty around frequency of use which could affect the actual impact of measures

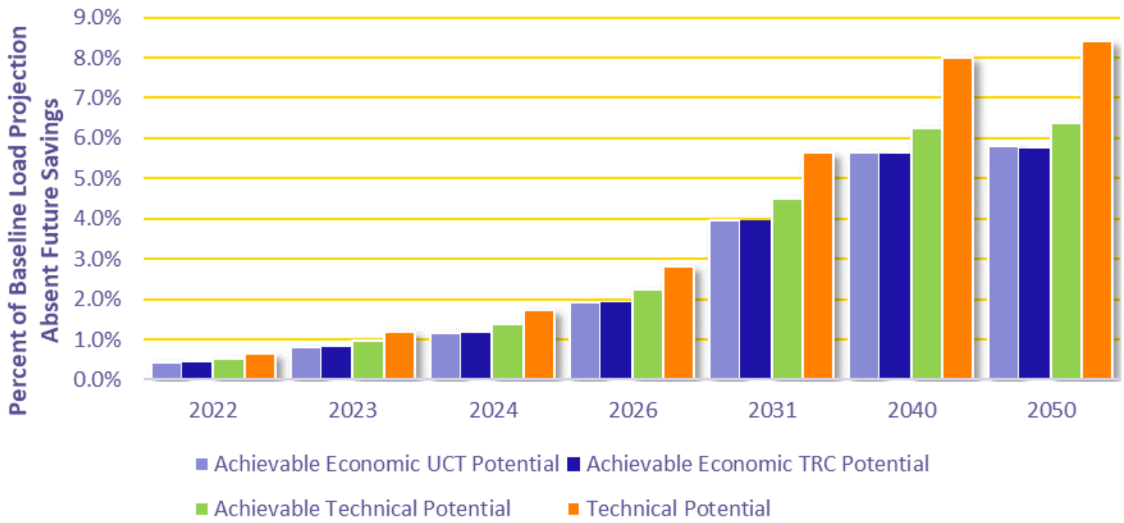
### 5.11.3 Results Summary

A summary of the identified DSM potential for the reference case at Oregon transportation customer sites is presented in Table 5.15 and Figure 5.16. It can be seen that a majority of the potential is assumed to be acquired over 10 years, and almost all over 20 years. Only a small amount of potential remains for acquisition from 2042-2051, primarily for equipment that was not assumed to be upgraded during the first 20 years of the forecast period. More specifically, in 2022, first-year TRC achievable economic potential savings are 1,531 mTherms, or 0.43% of the baseline projection. Cumulative savings in 2031 are 13,424 mTherms, or 3.95% of the baseline. By 2050 cumulative TRC achievable economic potential slowly increases to 17,481 mTherms, or 5.75% of the baseline.

**Table 5.15: Summary Potential Results – Reference Case**

| Scenario | 2022 | 2023 | 2024 | 2026 | 2031 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **Baseline Load Projection Absent Future Savings (mTherms)** | 357,025 | 357,418 | 355,616 | 350,191 | 340,047 | 323,605 | 304,190 |
| **Cumulative Savings (mTherms)** | | | | | | | |
| TRC Achievable Economic Potential | 1,531 | 2,883 | 4,155 | 6,721 | 13,424 | 18,166 | 17,481 |
| UCT Achievable Economic Potential | 1,537 | 2,894 | 4,170 | 6,746 | 13,480 | 18,287 | 17,655 |
| Achievable Technical Potential | 1,844 | 3,448 | 4,929 | 7,867 | 15,346 | 20,220 | 19,392 |
| Technical Potential | 2,291 | 4,298 | 6,158 | 9,842 | 19,167 | 25,882 | 25,622 |
| **Cumulative Savings (% of Baseline)** | | | | | | | |
| TRC Achievable Economic Potential | 0.43% | 0.81% | 1.17% | 1.92% | 3.95% | 5.61% | 5.75% |
| UCT Achievable Economic Potential | 0.43% | 0.81% | 1.17% | 1.93% | 3.96% | 5.65% | 5.80% |
| Achievable Technical Potential | 0.52% | 0.96% | 1.39% | 2.25% | 4.51% | 6.25% | 6.37% |
| Technical Potential | 0.64% | 1.20% | 1.73% | 2.81% | 5.64% | 8.00% | 8.42% |

**Figure 5.16: Reference Case Cumulative Potential**




## 5.12 Potential Widespread Deployment of Emerging End-Use Equipment

As discussed in Chapter Two- Planning Environment- there are enabling technologies that can help NW Natural meet both its resource and compliance needs. Those technologies include but are not limited to:

- Gas Heat Pumps/Gas Heat Pump Water Heaters
- Hybrid Heating Systems

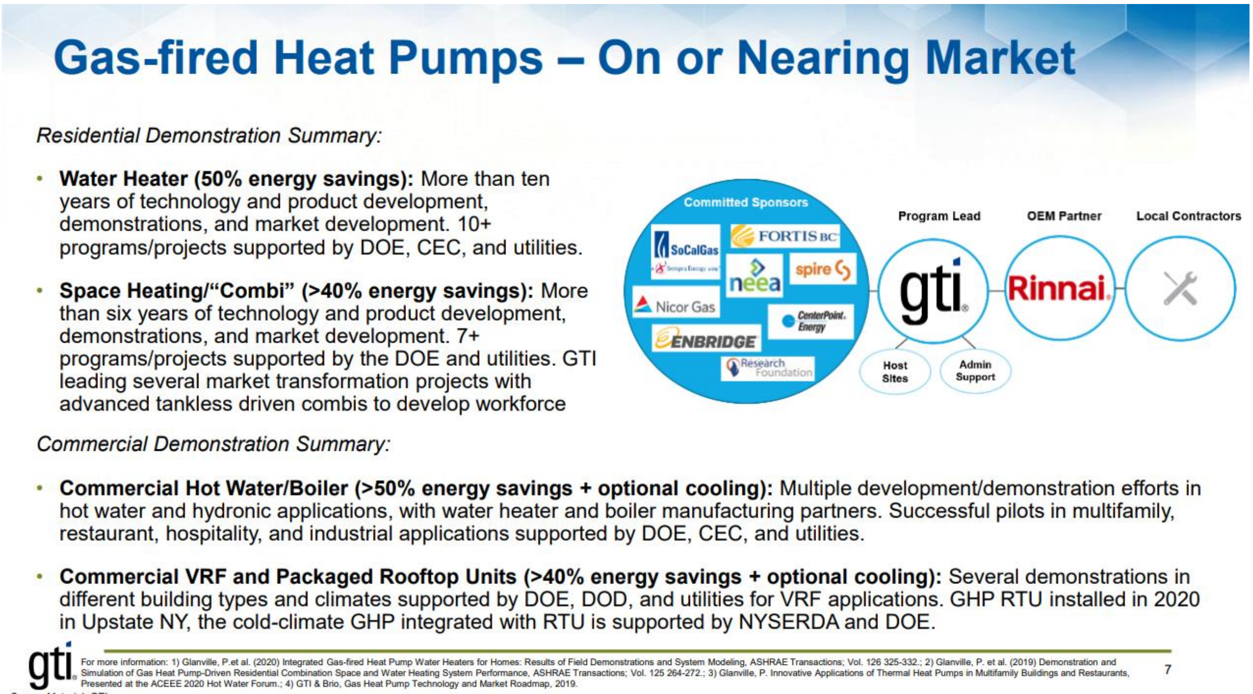
### 5.12.1 Gas Heat Pumps/Gas Heat Pump Water Heaters

Gas heat pumps are similar to heat pump technology on the electric side but are thermally driven using natural gas. They have the potential to reduce emissions and energy consumption by 40% or greater than existing natural gas furnaces and as they typically do not require back up heating, provide good opportunities for peak load management.

As shown in Figure 5.17[21], GTI identified gas heat pumps that are either on or near the market for both residential and commercial applications. In both markets, gas heat pumps can be used for space heating and cooling, for water heating or as "Combi" systems providing both hot water and space heating.

[21] NW Natural 2022 IRP Third Technical Working Group, April 13, 2022. This presentation and others may be found at https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

**Figure 5.17 Gas-Fired Heat Pumps**



Source Material: GTI

Figure 5.18 also shows the technology readiness of heat pumps from different manufacturers.

**Figure 5.18 Gas Heat Pump Technology Readiness by Manufacturer**

## Technology Readiness

Green: Commercially available in North America

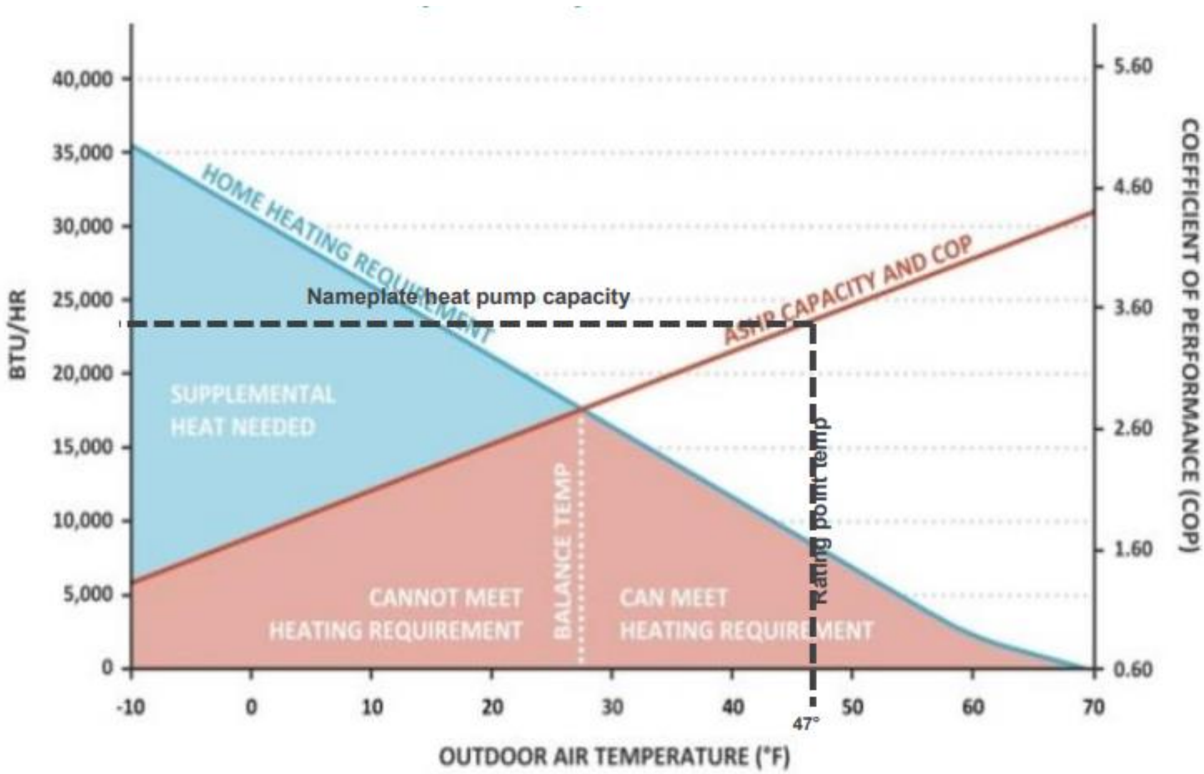
Source: Enbridge, NEEA, GTI

| Manufacturer | Type | Primary Applications | Primary Sectors | Technology Readiness for North America |
|---|---|---|---|---|
| ROBUR | Absorption | Space and DWH heating<br>Cooling (possible) | • Commercial<br>• Residential | • Commercial size unit commercially available<br>• Residential unit available in Europe. Efforts underway to bring it to NA |
| YANMAR | Engine driven | Space heating and cooling | • Commercial | • Commercially available |
| SMTI / ANESI | Absorption | Space and DHW heating | • Residential<br>• Small commercial | • Field trials of pre-production unit underway |
| VICOT | Absorption | Space and DHW heating | • Residential<br>• Commercial | • Commercially available in China<br>• Lab testing and field trials of production unit underway in NA |
| ThermoLift | Thermal compression | Space heating, cooling and DHW heating | • Residential<br>• Small commercial | • Lab testing and field trials of pre-production unit underway |
| HeatAmp | Adsorption | Space and DHW heating | • Residential<br>• Small commercial | • Lab testing in Europe |
| Rinnai | Absorption | DHW heating | • Residential | • Lab testing and field trials planned |

### 5.12.2 Hybrid Heating Systems

While not a new technology, hybrid systems use electric heat pumps with direct use natural gas as back up for peak periods. Typically, electric heat pumps use resistance heating as back-up systems to heat pumps to help maintain comfort during cold temperatures. As can be seen in Figure 5.20, electric heat pumps are efficient, but efficiencies decline as temperatures decrease due to the use of resistance back up heating. This contributes to large peaks to utility loads and is expensive to customers.

**Figure 5.19 Efficiency of Electric Heat Pumps and Ambient Temperature**




Hybrid heating systems consist of using an electric heat pump as the main source of space heating, but it is teamed with a natural gas furnace for back up heat. The benefit of using both energy systems is that it helps with energy system resource adequacy. With the natural gas energy system providing peak heat, these dual-fuel systems serve as demand response for the electric grid and allows the existing seasonal storage infrastructure to serve peak needs in a region that is capacity constrained. By displacing resistance back up heat and using natural gas only in times of cold temperatures not only does this help with resource adequacy but it also supports energy efficiency and decarbonization efforts. Decarbonization efforts are further supported as both energy systems use more renewable energy or low carbon energy.

## 5.13 Key Demand-Side Input Assumptions

NW Natural's primary driver of our demand-side assumptions are based on the forecasts that are discussed above and have been provided by both ETO and AEG. We adjust our load forecasts for these projections in the recognition that there is also DSM included in our historical data used to train our load forecasting models. These DSM efforts are material and NW Natural expects a reduction of roughly 20% in load in its reference case by 2050 from programs for sales customers. Assuming that DSM programs for our transportation schedule customers begins in 2024, NW Natural expects a reduction of 10% of its transportation load in its reference case by 2050. All load sensitivities and simulation draws adjust for electrification assumptions so that savings are not being claimed from an energy need not served by NW Natural.

The following figure and table set forth the key assumptions NW Natural used for the enabling equipment penetration and costs in both its reference case and scenarios. Figure 5.21 shows the percent of installations per year of gas heat pumps for residential space heating, gas heat pump water heaters for residential water heating, gas heat pumps for commercial space heating, and hybrid heating for both residential and commercial applications.

**Figure 5.20 Assumptions on Enabling Technology Adoption Over Time**


Table 5.16 represents NW Natural's assumptions of cost for these enabling technologies.

**Table 5.16 Assumptions on Cost for Enabling Technologies**

| Incremental Demand-Side Measure Costs | Incentive | Total Cost to Utility | Cost Range (5th and 90th Percentile) |
|---|---|---|---|
| Residential Hybrid Heating Incremental Incentive (2020$/System Install) | $1,200 | $1,600 | +/- 30% |
| Residential Hybrid Heating Share of Incentive paid by non-CCI funds (%) | 25% | $400 | +/- 50% |
| Residential Gas Heat Pump Incentive (2020$/System Install) | $3,000 | $4,000 | +/- 40% |
| Residential Gas Heat Pump Water Heater Incentive (2020$/System Install) | $1,200 | $1,600 | +/- 40% |
| Commercial Hybrid Heating Incremental Incentive (2020$/System Install) | $3,000 | $4,000 | +/- 30% |
| Commercial Hybrid Heating Share of Incentive paid by non-CCI funds (%) | 25% | $1,000 | +/- 40% |
| Commercial Gas Heat Pump Incentive (2020$/System Install) | $10,000 | $13,333 | +/- 30% |
| First Year Transport Load Savings Cost (2020$/1st year therm saved) | | $1.79 | +/- 100% |

## 5.14 Low Income Programs

### 5.14.1. Oregon Low-Income Energy Efficiency Program (OLIEE)

Since 2002, a portion of the public purpose funding collected by NW Natural has been allocated for Oregon Low-Income Energy Efficiency (OLIEE) through a surcharge to Oregon Residential and Commercial customers' energy bills. The OLIEE program attempts to provide equitable access to DSM by funding high-efficiency equipment and weatherization measures to income qualified homes. The program consists of two parts: The Community Action Program (CAP), and the Open Solicitation Program (OSP).

The CAP provides energy evaluations of low-income dwellings and funding for qualifying DSM measures. In conjunction with DSM, health, safety, and repair (HSR) projects like improving ventilation may also receive funds through the CAP. The program is administered by 10 CAP agencies throughout the Oregon service territory.

OSP focuses on projects that do not fit into the CAP framework, including but not limited to, new affordable housing or temporary living space retrofits. NW Natural invites proposals that serve low-income qualified customers and allocates funds based on availability. Bi-annual meetings are held with both the CAP agencies and OLIEE Advisory Committee (OAC) to ensure proper implementation of the programs. Historical engagement in the OLIEE program is shown in Table 5.17.

**Table 5.17: Homes Served through OLIEE Program**

| Homes Served through OLIEE Program | | |
|---|---|---|
| Program Year | Homes | Therms Saved |
| 2015-2016 | 231 | 52,817 |
| 2016-2017 | 260 | 59,232 |
| 2017-2018 | 299 | 103,708 |
| 2018-2019 | 260 | 73,441 |
| 2019-2020 | 248 | 68,320 |
| 2020-2021 | 341 | 60,394 |

### 5.14.2 Washington Low-Income Energy Efficiency Program (WA-LIEE)

In 2009, NW Natural launched a revised low-income program identified as WA-LIEE (Washington Low-Income Energy Efficiency). Modeled after Oregon's low-income CAP program, the WA-LIEE program reimburses administering agencies for installing weatherization measures that are cost-effective when analyzed in aggregate.

In Washington, two agencies co-administer the program. The program is informed by input from NW Natural's Energy Efficiency Advisory Group (EEAG). Homes with gas in SW Washington tend to be newer construction with less of a need for weatherization, and only 2% of NW Natural's customers in Washington qualify as low-income. Barriers such as these limit participation. NW Natural continues to evaluate how to support agencies and adjust the program to increase the number of homes served per year. Table 5.18 shows the historical number of homes treated through the WA-LIEE program.

**Table 5.18: Homes Served through WA-LIEE Program**

| Homes Served through WA-LIEE Program | | |
|---|---|---|
| Program Year | Homes | Therms Saved |
| 2016 | 16 | 6,132 |
| 2017 | 13 | 6,048 |
| 2018 | 16 | 7,578 |
| 2019 | 22 | 20,170 |
| 2020 | 3 | 1,132 |
| 2021 | 11 | 3,568 |

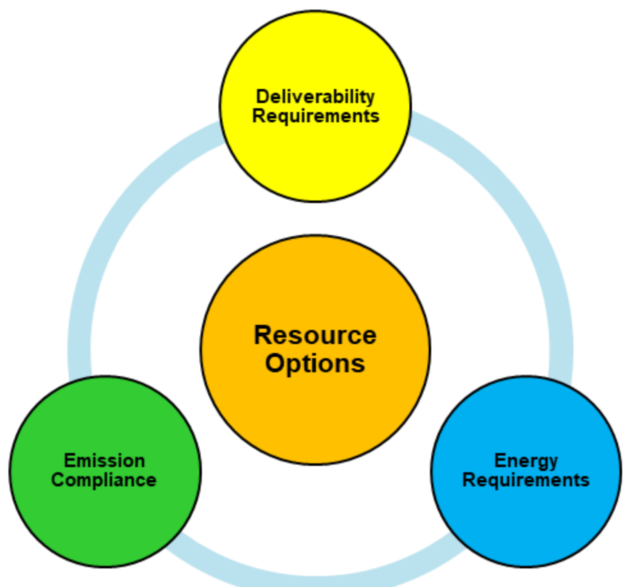
# Chapter 6

# Supply-Side and Compliance Resources

## 6.1 Overview

This chapter of the IRP discusses both current and potential supply-side resources that NW Natural uses to deliver conventional natural gas and renewable 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. Additionally, agreements for acquiring renewable thermal certificates (RTCs) on the behalf of customers and other emissions compliance resources, such as community climate investments (CCIs) are discussed in this chapter. Meeting compliance obligations in both Oregon and Washington over the planning horizon is a major focus for this IRP. While these compliance resources may not actually provide gas supply to the system, they are discussed in this supply-side resource chapter of this IRP.[1]

This suite of supply-side resources focused on in this chapter are associated with serving customers at the system level and meeting emissions requirements in both Oregon and Washington. Supply-side resource options associated with alleviating constraints in specific areas of the distribution system are discussed in Chapter 8.




All resources vary across three dynamics as to the value for what each resource provides to NW Natural's system; 1) the daily deliverability or capacity value, 2) the overall energy a resource can provide throughout the year, and 3) the contribution to emissions reduction under an emissions constraint. 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 a lot of capacity for serving peak demand. Off-system RNG gas contracts provide emissions compliance requirements, but by themselves do not provide any capacity to the system. All these different resources also vary in costs, availability, and risks.[2]

[1] Future discussion could help assess if resources needed for emissions compliance should be classified under a separate category as compliance resources such as CCIs do not clearly fall under the binary classification of demand-side or supply-side resources.
[2] Also, as done previously, potential resources are discussed in this chapter that ultimately are deemed too speculative to include in the portfolio choice analysis in Chapter Seven, with explanations for why they ended up on the "cutting room floor."

The rest of this chapter discussion includes general types of supply-side resources, NW Natural's current resource portfolio, future emissions compliance resource options, 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 discuss in Chapter 7.

## 6.2 Supply-side Resource Types

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, RNG, or hydrogen supply contracts*** – these are contract agreements for natural gas or RNG to be 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.[3] 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.[4] See Appendix E for further details about gas purchasing practices. RNG and Hydrogen are discussed in further detail later in this chapter.

***Unbundled environmental attribute purchases*** – these purchases do not provide capacity nor energy to NW Natural's system but are a pathway for reducing carbon emissions or meeting state carbon reduction targets on behalf of NW Natural customers. One example is the purchasing of renewable thermal certificates (RTCs) that give NW Natural's customers the rights to emissions reductions from RNG. In other words, other parties cannot claim the emissions reductions for RTCs purchased by NW Natural. Another example is NW Natural's smart energy program that allows customer to sign up to offset their natural gas usage.

***Interstate/interprovincial pipeline capacity*** – NW Natural contracts with pipeline companies in the US and Canada to ship natural gas from receipt points, where gas is injected into 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.[5]

***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

[3] Receipt points are commonly locations or gate stations on an interstate pipeline.
[4] The term ship is use purposefully here to refer to either physically flowing gas or moving gas via displacement on the interstate/interprovincial pipeline, as the pipeline contracts commonly refer to their customers, such as NW Natural as shippers.
[5] Transport customers are responsible for their own capacity and gas purchases upstream of NW Natural's system.

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.[6] 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.[7] 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).[8] 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 system capacity 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.

[6] https://www.eia.gov/naturalgas/storagecapacity
[7] For more information: https://www.eia.gov/naturalgas/storage/basics/

***Industrial recall options*** – NW Natural contracts with several industrial counterparties for recall options wherein we would pay the replacement fuel price for an industrial company to switch to an alternative fuel source to propane, fuel oil or diesel and provide us with the natural gas supplies that they would have otherwise consumed. Note that these contracts are not with sales customers therefore 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.

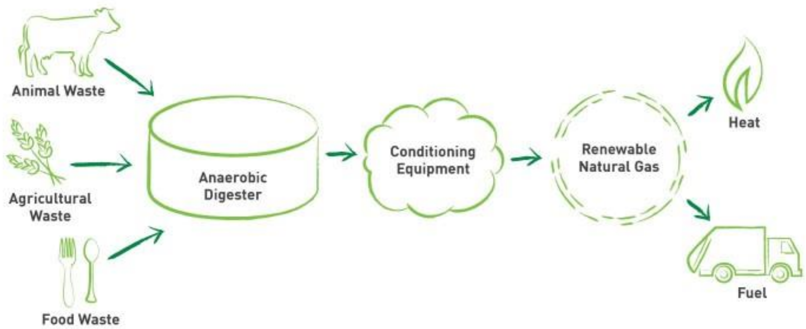
***Citygate deliveries*** – The "citygate" is the point of delivery at which gas is transferred from an interstate or intrastate pipeline to a local distribution company's custody. Citygate contracts are for gas supplies delivered directly to NW Natural's service territory by the counterparty utilizing their own NWP 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 very 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.

## 6.3 Renewable Natural Gas

As discussed in Chapter two, there has been a lot of activity in the RNG space. A good place to start is with how natural gas is made as shown in the below slide *How is RNG Made* and while covered in Chapter Two, the slides below revisit the policy backdrop that is supporting RNG and Hydrogen resources.

## How is RNG made?






## Policy Environment for Procuring RNG and Hydrogen

- 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
  - Establishes both an option for delivery for RNG to all gas customers as well as a requirement to offer customers voluntary RNG tariff
- Washington Climate Commitment Act (CCA)
  - Sets emission cap that applies to gas utilities, which can use RNG and hydrogen as a compliance tool
- Voluntary offerings to customers
  - Building options for customers in Oregon and Washington to procure greater amounts of RNG and hydrogen

## Oregon Senate Bill 98

NW Natural®

- Gas utilities can purchase RNG (including hydrogen) for all customers as part of our utility resource mix. This is a significant change, as prior to the passage of the bill, we could only buy the least-cost gas, which was not RNG.
- Gas utilities can 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.
- We must adhere to a spending limit to protect customers: we can spend up to 5% of our annual Revenue Requirement on the incremental cost of RNG.

**Large Gas Utility Volumetric Targets**

| | % Target |
|---|---|
| | |
| 2020 - 2024 | 5% |
| 2025 - 2029 | 10% |
| 2030 - 2034 | 15% |
| 2035 - 2039 | 20% |
| 2040 - 2044 | 25% |
| 2045 - 2050 | 30% |

*Prepared for IRP Working Group - Not to be used for investment purposes .*

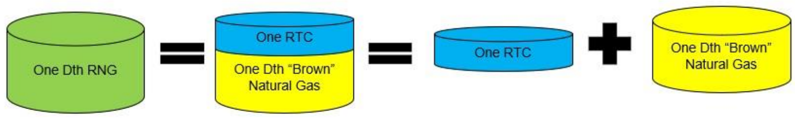
70

### 6.3.1 Renewable Thermal Certificates (RTCs)

An RTC is a sole claim to the environmental benefits of a dekatherm 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). RTCs are procured in order to meet compliance needs, to show how NW Natural is procuring renewable resources on behalf of its customers. Contracts for RTCs are typically between NW Natural and either a direct producer of RNG or a broker/marketer looking to sell RTCs. The below slides talk more about RTCs and the mechanism for tracking RTCs.

# How is RNG Transacted?

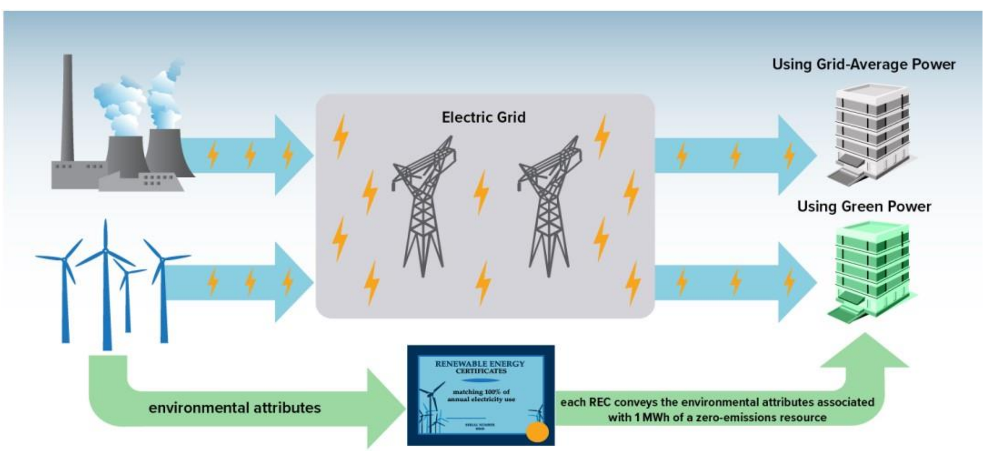
- Renewable Thermal Certificates (RTCs) are instruments that represent the legal property rights to the 'renewable -ness' (i.e. environmental attributes) of RNG
  - One RTC is created for every Dth of RNG produced and injected into the "common carrier" network or an LDC's distribution system. RTCs can be unbundled from the underlying gas and sold separately.




  - RTCs are issued, tracked, transferred, and retired through M -RETS, an online certificate system
  - To satisfy SB98 goals, we will need to show how many RTCs are retired each year

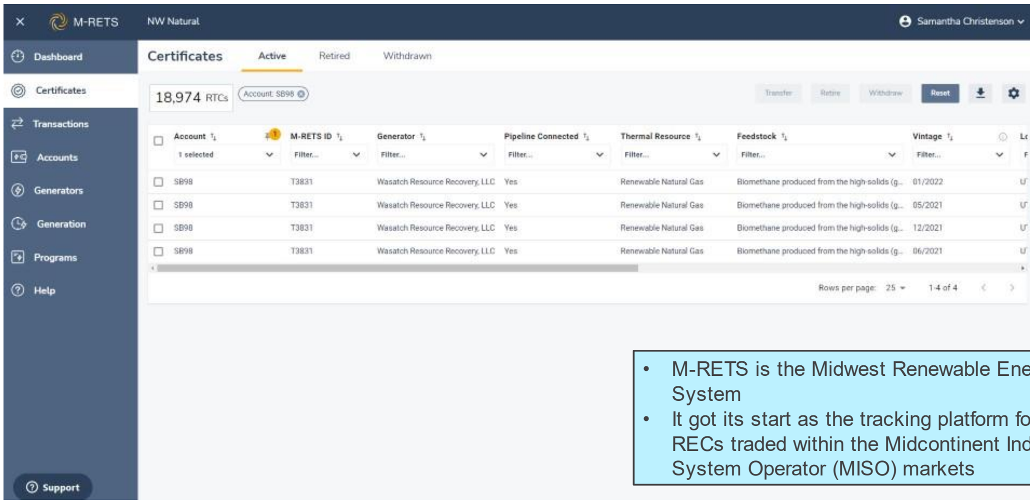


# RTCs: Same Structure as Electric Renewable Energy Certificates (RECs)



## Transacting RTCs: M-RETS

NW Natural




- M-RETS is the Midwest Renewable Energy Tracking System
- It got its start as the tracking platform for electricity RECs traded within the Midcontinent Independent System Operator (MISO) markets

*Prepared for IRP Working Group - Not to be used for investment purposes* .

74

### *6.3.2 Renewable Natural Gas Procurement*

NW Natural uses an request for proposal process for determining what renewable resources might be available. The below slides discuss our procurment process, considerations, and due diligence.

## RNG Procurement and Development Timeline Considerations

NW Natural

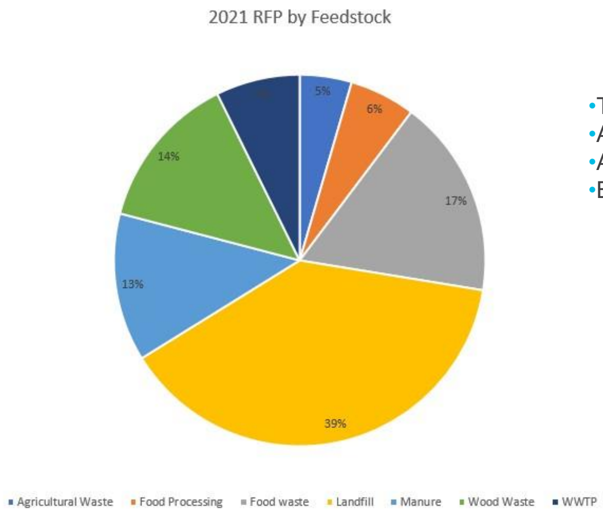
- 3rd Annual RFP for RNG Resources
  - Planned Release: April 14th
  - Short-listed respondents notified: mid-June
  - Diligence conducted on short-listed respondents: June-July
  - Final agreements negotiated throughout 3Q and 4Q 2022
- Rolling evaluation of other offtake resources in between RFP processes
- Rolling evaluation of RNG development opportunities
  - Non-disclosure agreement to collect initial data
  - Non-binding term sheet to explore economic agreements with feedstock owner, developer, etc.
  - Extensive diligence process to assess project economics and risks, including technical, legal, regulatory, financial, environmental, etc.
- Projects must be continually evaluated and acted on, which makes it hard to put specific resources into an IRP:
  - Typically must decide about whether to enter into definitive agreements within a set timeline (e.g., within 30-day exclusivity period, or in response to a formal bid process with a hard deadline)
  - 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.

*Prepared for IRP Working Group - Not to be used for investment purposes* .

75

## 2021 Request for Proposal Responses

NW Natural®




- Total number of responses: 27
- Average term of contract: 14 years
- Average annual volume of resource: 597,806 mmbtu
- Bundled vs. unbundled: 52% / 48%

*Prepared for IRP Working Group - Not to be used for investment purposes*

76

## Example: Diligence on RNG Resources

NW Natural®

| Team | Diligence Findings | Outstanding |
|---|---|---|
| Accounting | No concerns | None |
| Tax | Tax outcomes are consistent with expectations | None |
| Financial Risk/Credit | Brown gas marketer may require further credit support | Review of brown gas offtake proposal |
| Legal | Risks are mitigated through investment agreements and contracts | Finalize and execute Interconnection Agreement |
| Strategic Planning | No concerns | None |
| Rates/Regulatory | Will need to file in WA prior to effective date | Finalize timing of WA filing |
| Investor Relations | No significant concerns | None |
| Financial Planning/Treasury | No concerns | None |
| Environmental/Environmental Policy | No concerns | None |
| Engineering | No significant concerns | None |
| Gas Supply | No significant concerns | Finalize offtake w/ 3rd party marketer |
| Risk/Land | No concerns | |
| Corp. Communications/Public Affairs | No concerns | Finalize communications plan |

*Prepared for IRP Working Group - Not to be used for investment purposes*

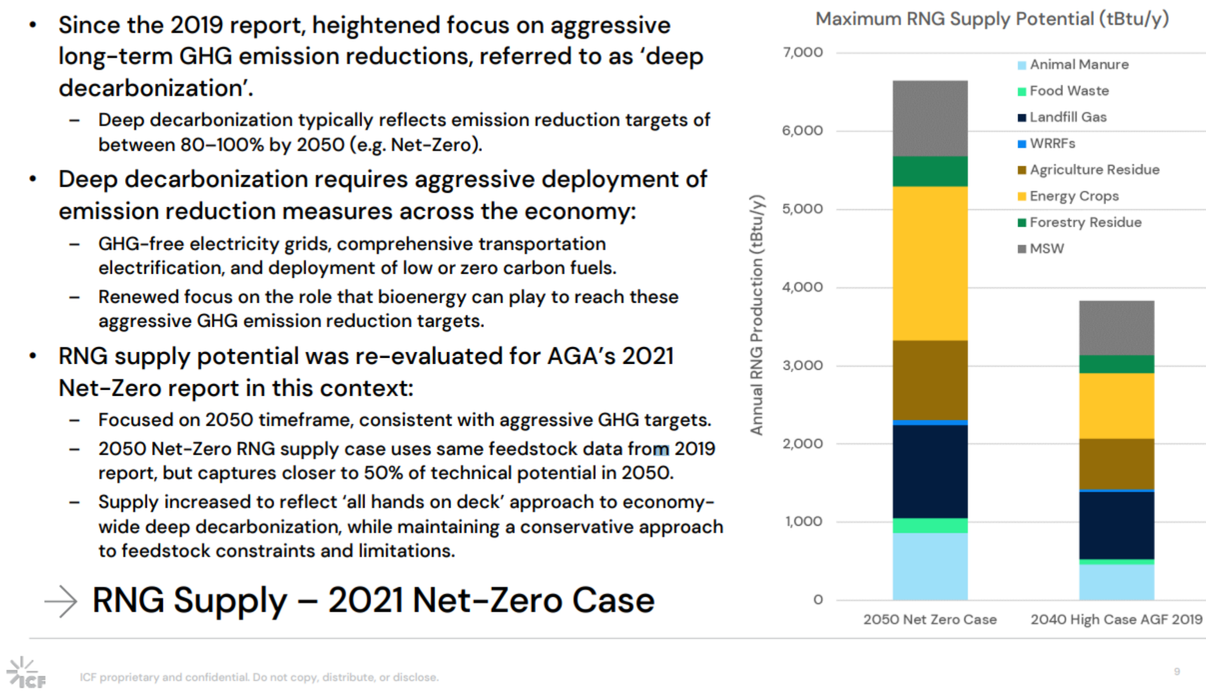
77

### 6.3.3. RNG Supply

RNG Supply has been and continues to be a topic of conversation. The American Gas Foundation in 2019[9] and the RNG supply potential was re-evaluated for AGA's 2021 Net-Zero report. The results of

[9] https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

these reports was presented at one of NW Natural's Technical Working Groups[10]. A key slide from the presentation is provided below.




## 6.3.3 National RNG Supply

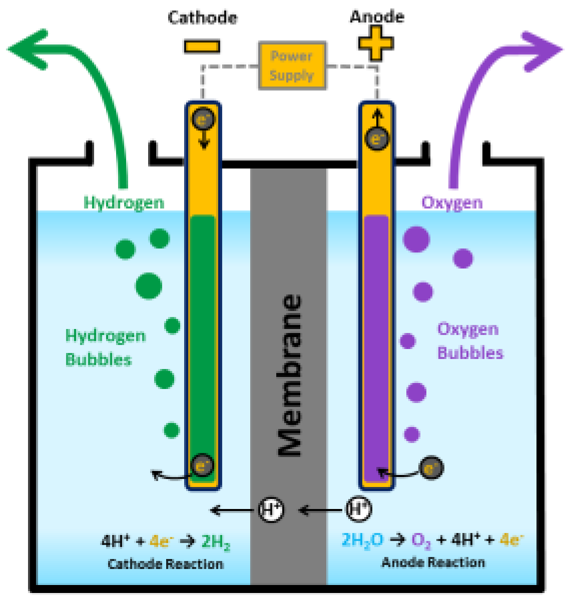
## 6.4 Power-to-gas

Power-to-gas (P2G) describes a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen. P2G produces useful hydrogen that can be used as an energy source onsite (as in a fuel cell) or injected into a gas grid to produce energy that is very similar to typical natural gas. There are limitations in the amount of hydrogen that can be blended into the natural gas system, but current pilots are exploring blending up to 20% hydrogen within existing natural gas grids.[11] A discussion of P2G as a potential resource option is new to NW Natural's IRP process.

Figure 6.X 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.

[10] For more information, please see TWG 3, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning
[11] See, e.g., the HyDeploy project: https://hydeploy.co.uk/.

**Figure 6.1: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis**



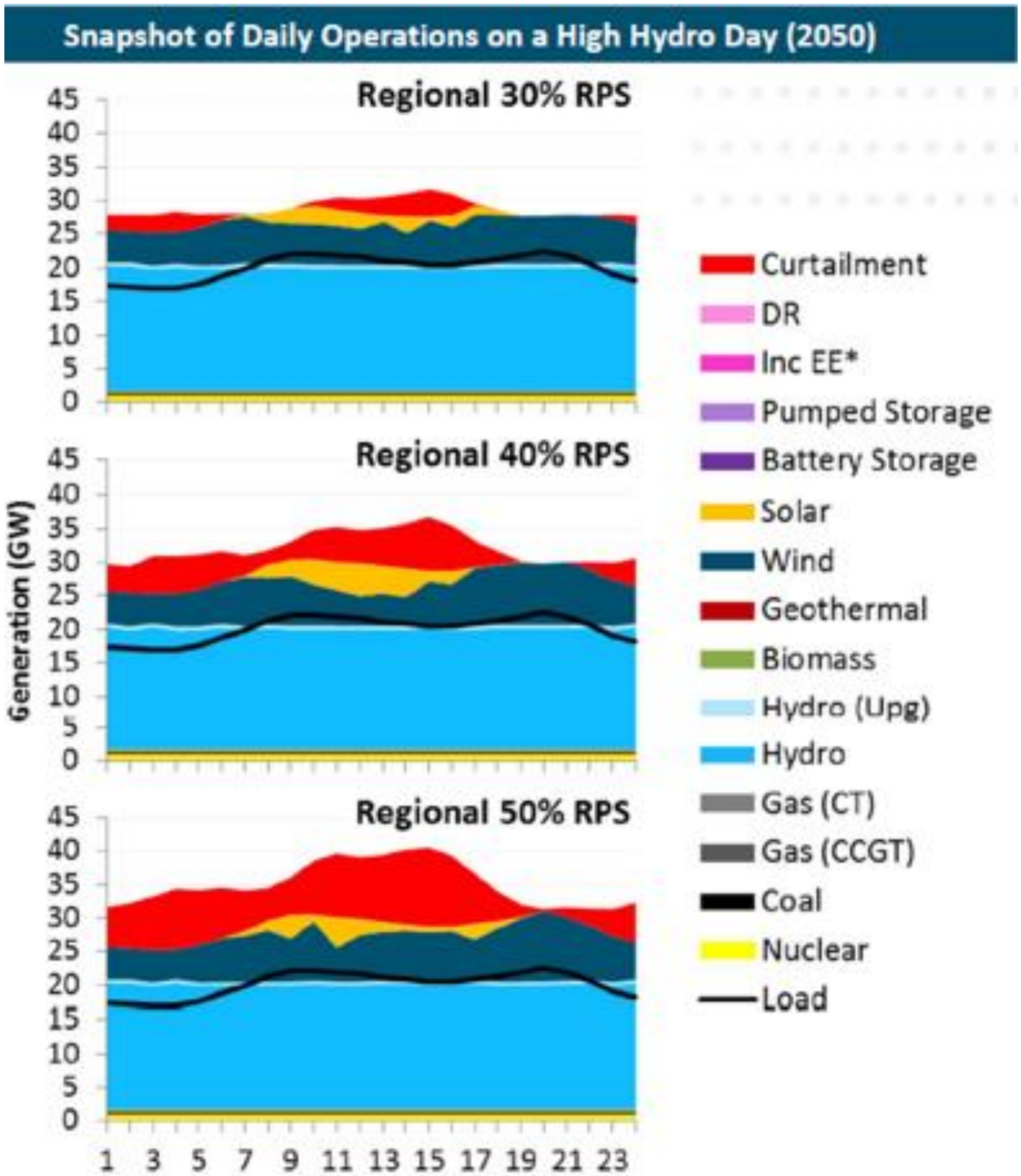

Source: U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

NW Natural is currently considering P2G projects that would blend hydrogen directly into the pipeline, at overall percentages likely far below 20%. NW Natural is reviewing research related to the impacts of varying percentages of hydrogen on system components and end use appliances to better understand the maximum potential of using hydrogen to meet different energy demands on our system with zero emissions.

### *6.4.1 Power-to-gas and the Need for Seasonal Energy Storage*

As renewable electricity goals and targets in the region ramp up over time, the amount of electricity that will need to be curtailed due to oversupply is expected to rise. See Figure 6.X for one analysis of the impact of rising renewable portfolio standards on the overall amount of curtailed power.

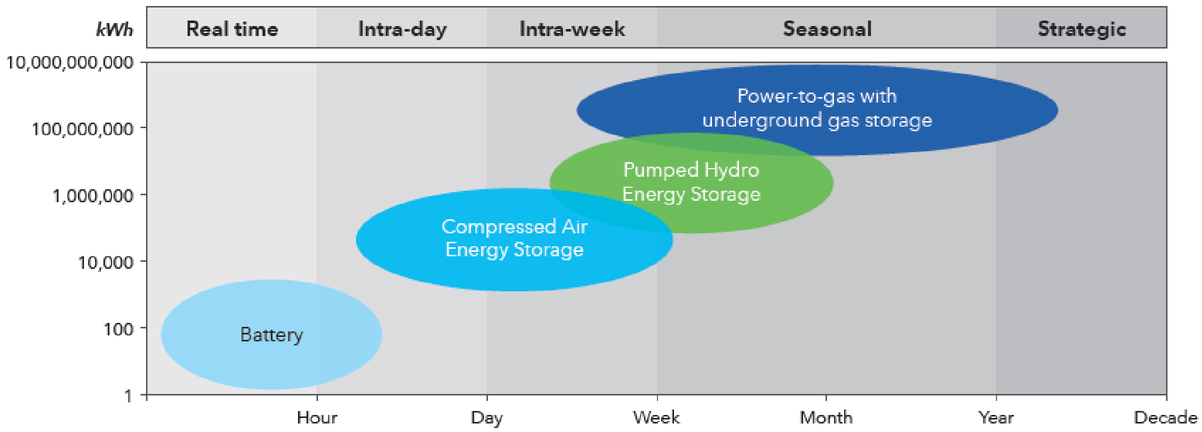
**Figure 6.2: Expected Curtailed Power in Future High-renewable Electricity Scenarios**




Source: https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf.

Curtailment events and the consequent energy storage needs are very different in the Pacific Northwest compared to other regions. In our region, excess generation occurs over a longer time period, and is less predictable day-to-day, due to the nature of the region's renewable resources. Thus, shorter-duration energy storage resources, such as batteries, which are well-equipped to handle energy storage needs over the course of several hours, are less well-suited to handle the energy storage needs we will experience in our region, which will stretch over weeks or perhaps months.[12] For this reason, energy storage resources that can store energy over longer time periods are necessary.

**Figure 6.3: Comparative Energy Storage Resources: Size and Duration**




Source: http://www.europeanpowertogas.com/media/files/European%20Power%20to%20Gas_White%20Paper.pdf

As seen in Figure 6.X, power-to-gas is one technology that can help store energy over much longer time periods than batteries and other shorter-duration energy storage resources. Hydrogen generated by excess power can be used immediately in the natural gas system, displacing natural gas purchases and turning what would otherwise be wasted energy into usable energy. A power-to-gas system can run for days, weeks, and months at a time, providing an energy storage service to the grid for very long durations. The overall amount of energy that can be stored is dependent on the size of the natural gas system to which it is connected, and the available gas storage technologies attached to that system. In the case of NW Natural, energy can be stored and withdrawn from the existing distribution system as well as our significant underground storage resources, including Mist.

### *6.4.2 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

[12] See pp. xiii – xv in the Pacific Northwest Low Carbon Scenario Analysis: https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf.

hydrogen. However, PEM technologies have advances 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 manner in which it will be operated.

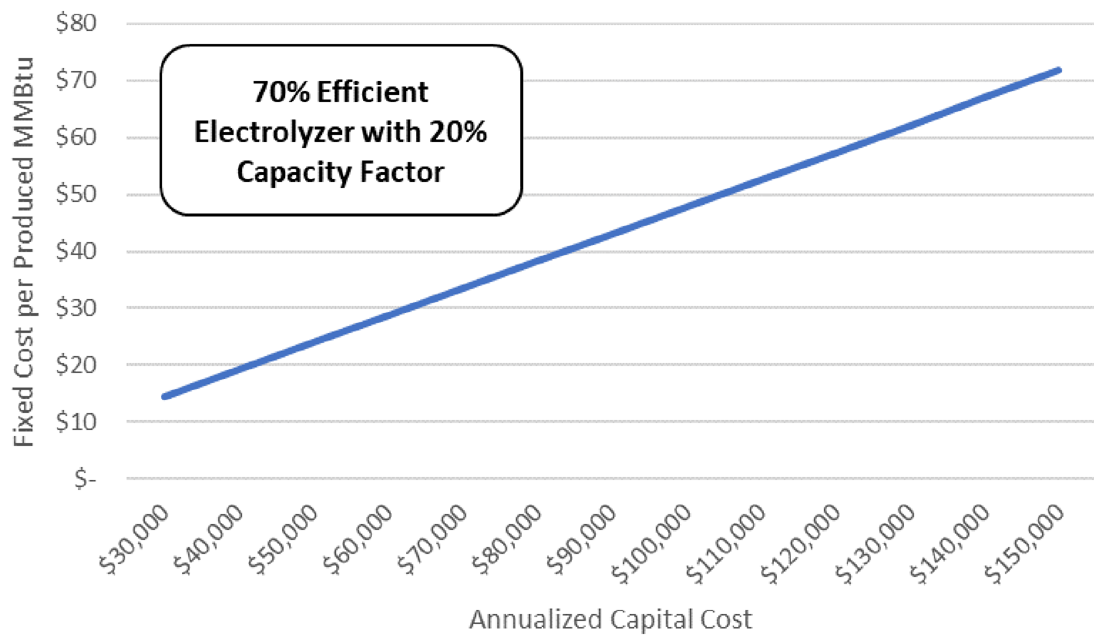
Today most P2G projects are located in Europe, where P2G has been identified as a critical component of a low-carbon future. In the U.S., several demonstration projects exist, and several projects are being designed in Canada.

### *6.4.3 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 — its utilization factor. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

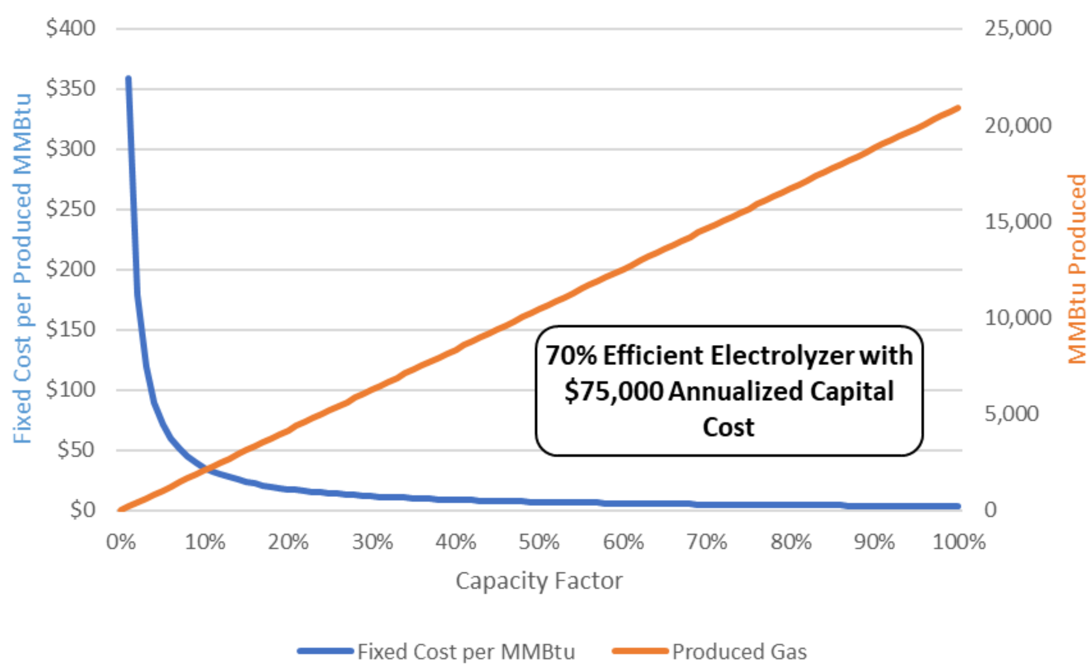
A 2018 report commissioned by NW Natural found recent commercial-scale electrolyzer projects with construction costs between $500 and $1000 per kW of capability, a range consistent with other recent industry estimates. As with most emerging technologies, these costs are expected to decline through time. At a given facility cost level, the ultimate costs of hydrogen delivered to the natural gas system on a per-unit basis depends on the extent to which a built facility is utilized, often referred to as its capacity factor or utilization factor. For illustration, Figures 6.10 and 6.11 isolate the impact of these two factors on the per-unit cost to produce gas. First, Figure 6.X summarizes a range of per-MMBtu costs associated with varying facility capital costs, assuming a facility with 1 MW capability, 70% efficiency in turning electricity into gas energy, and a 20% capacity factor.

**Figure 6.4: Electrolyzer Fixed Cost per MMBtu vs. Facility Capital Costs**




And below, Figure 6.5 illustrates the cost impact of capacity factor on a 70% efficient 1 MW electrolyzer with a $75,000 annualized capital cost. If the facility is operated at capacity for an entire year, the capital (fixed) cost per MMBtu of produced gas would be $3.59. If the facility were operated during only half the hours of the year, this cost would double to $7.18/MMBtu.

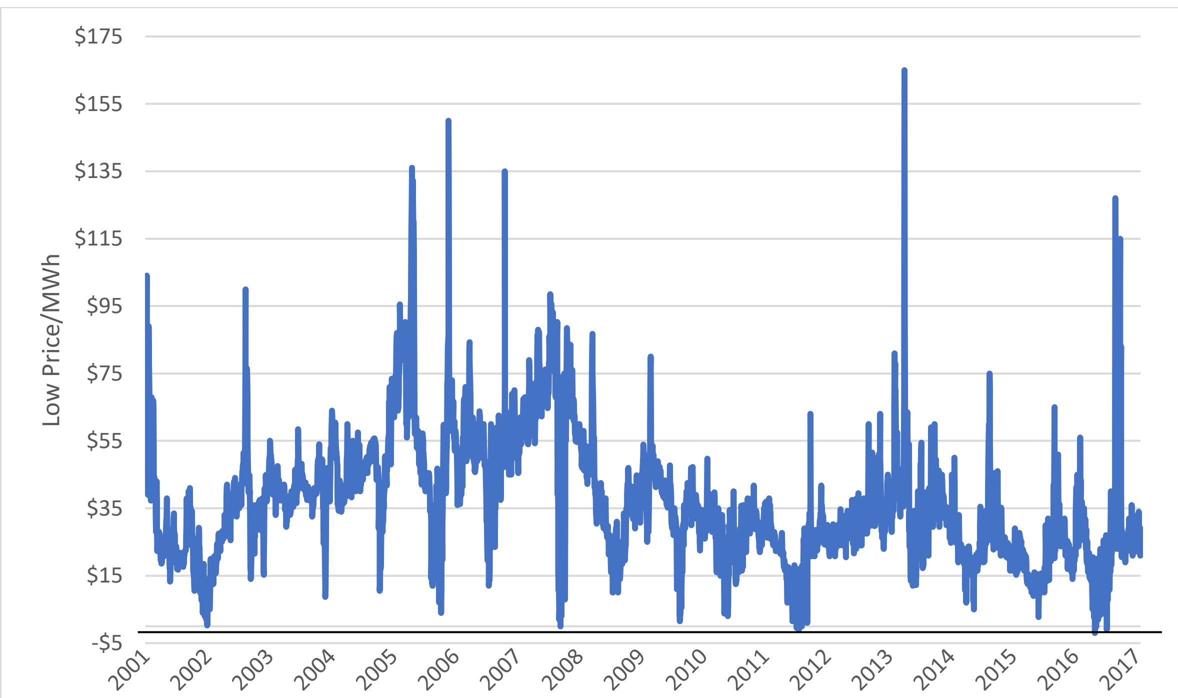
**Figure 6.5: Electrolyzer Fixed Cost per MMBtu vs. Utilization Factor**



While hydrogen produced by P2G technology must be blended with conventional natural gas to be used directly by most appliances, an additional conversion to methane (methanation) produces gas that is fully interchangeable with pipeline natural gas. Electrolysis may currently have more visibility in research and pilot programs in the U.S. and elsewhere, but several methanation facilities are in use in the U.S. and Europe, and the technology costs associated with this additional step in the P2G process are expected to fall over the coming decades.

For a direct-use natural gas system, P2G is essentially an opportunistic resource — by taking advantage of transitory surpluses in electricity markets, a gas utility can produce low-cost, carbon-neutral fuel for its customers. Thus, the availability of low-cost (or no-cost) electricity directly affects a P2G facility's utilization factor and overall economics. In the Pacific Northwest, electricity prices often fall to very low (and sometimes negative) levels during the spring season, as snowmelt increases hydro flows and electricity demand wanes with warming weather. At the Mid-Columbia power market, for reference, peak wholesale power prices have dropped below $0.01 per kWh on an average of roughly nine days per year over the last decade (Figure 6.6).

**Figure 6.6: Mid-Columbia Trading Hub Peak Wholesale Electricity Prices, Daily Low**




As the penetration of renewable generation resources increases in the region as a result of both market and policy forces, periods of curtailment (excess generation) are expected to increase in duration and frequency, and both power-to-hydrogen and power-to-methane technologies are recognized as well positioned for large scale and extended-duration storage. For NW Natural, the utilization rates of our power-to-gas facilities used for direct-use energy will likewise depend on this growing availability of low-cost electricity.

Given the opportunistic nature of P2G as a direct-use supply resource for the natural gas system, and limits on the amount of hydrogen that can be blended with conventional gas, it is worth noting that gas storage would likely play a key role in the integration of the two. At modest levels of hydrogen production, the product could be injected directly into local distribution networks; at higher levels, a combination of dispersed production/injection sites and storage would likely be used to incorporate hydrogen gas into the system.

A final but significant contributing factor in the cost-effectiveness of P2G for a natural gas utility is that its value would not be limited to that of the commodity it produces — its energy value. On-system P2G facilities would also serve as capacity resources, providing options for peak day production and delivery, and distribution system support during peak hours of the year, providing similar value to demand-side resources like energy efficiency measures.

### *6.4.4 Power-to-gas as a Direct-use Natural Gas Supply Resource*

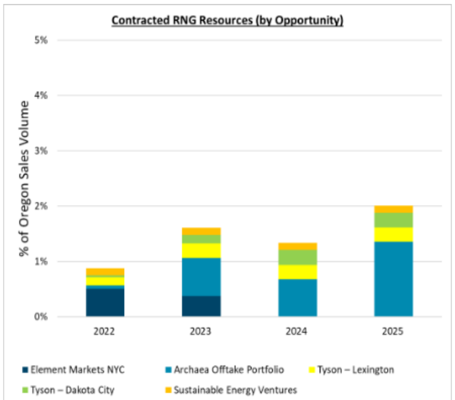
P2G is a relatively new and evolving technology, and as noted above its economics are substantially changing over time. As such, NW Natural draws from existing literature, industry reports, and internal consultants' reports for modeling purposes.

For portfolio analysis in the 2018 IRP, NW Natural models electrolyzer technology with construction capital costs declining over the planning horizon, and utilization factor modestly rising as policy-compliant renewable resources increase as a share of electricity generation. Electricity "feedstock" prices are assumed to be zero but limited in availability, which constrains the assumed capacity factor of the modeled resource. However, we will continue to investigate the economics of purchasing low-cost (but not free) electricity for use in P2G production — the cost-effectiveness threshold in this regard depends on expected pipeline gas prices and transport costs, rather than a requirement that electricity be absolutely free. To capture the value of on-system P2G to NW Natural's distribution system, avoided costs described in Chapter Four are applied to the modeled resource.

The slide *Summary: Current Committed RNG Portfolio* shows a summary of current committed RNG Portfolio as March 2022. As our actual experience with RNG grows, we are able to build and refine the supply curve shown in slide *Building a Supply Curve for RNG.*

## Summary: Current Committed RNG Portfolio

NW Natural



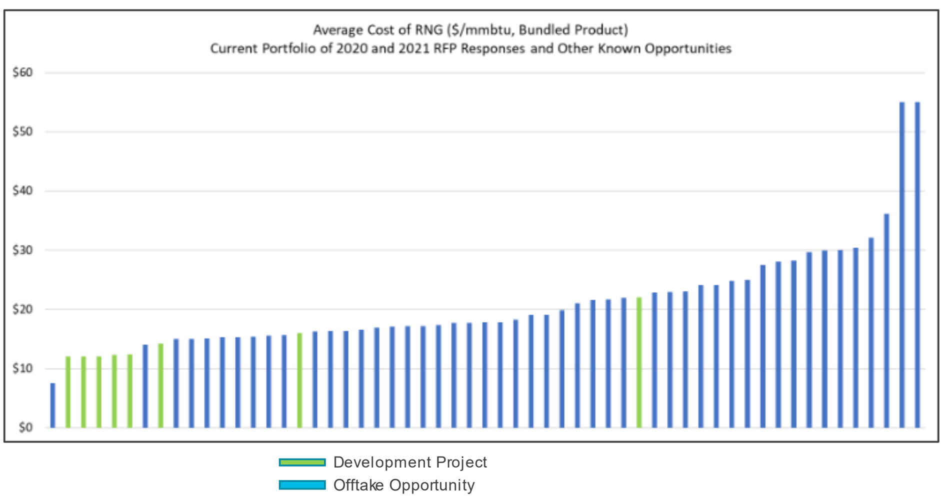

For these 5 resources, the weighted risk-adjusted incremental cost is projected to be $7.38/ mmbtu

81

Prepared for IRP Working Group - Not to be used for investment purposes .

## Building a Supply Curve for RNG

NW Natural




- Chart: 2020 and 2021 RFP responses, as well as the development projects NW Natural is currently evaluating
- Total production represented in chart: 35.3 million mmbtu/year (about 49% of all of NW Natural's annual sales in Oregon in 2021)
- New RFP to be issued next month
- Proposed supply tranches, +/- variability:
  - $14.00/mmbtu
  - $19.00/mmbtu

82

Prepared for IRP Working Group - Not to be used for investment purposes .

### *6.5 RNG and Hydrogen Evaluation Methodology*

Given SB98 and knowing that NW Natural was planning to acquire RNG resources on behalf of customers, NW Natural included an evaluation methodology in its 2018 IRP. In response, the Oregon OPUC opened up several dockets that inform the RNG evaluation process. The below slides discuss the history, methodology, and more detailed aspects of the methodology itself.

## Renewable Resource Evaluation Methodology History

NW Natural®

- In Oregon and Washington specific resources evaluated in Integrated Resource Plans (IRPs)
- Opportunities to acquire specific RNG resources do not align with infrequent IRP timing
- Low-GHG gas supply resources are evaluated using NW Natural's renewable resource evaluation methodology
  - First proposed in 2018 Integrated Resource Plan (Included as Appendix H in 2018 IRP)
    - Discussed at stakeholder workshops held by NW Natural
    - Deliberated in rounds of comments informed by data request process
  - Methodology updated and approved in Oregon Public Utility Commission (OPUC) Docket No. UM 2030
    - Stakeholder workshops held by Oregon Public Utility Commission
    - Updated proposal presented by NW Natural
    - Further deliberation and rounds of comments and data requests
  - OPUC rules resulting from RNG bill SB 98 require methodology to be updated in each IRP
  - NW Natural is now using methodology to evaluate RNG resources and procuring RNG
  - Small modifications to streamline implementation are being proposed in 2022 IRP

*Prepared for IRP Working Group - Not to be used for investment purposes* .

17

## Oregon SB 98 Rules (AR 632)

NW Natural®

- OAR 860-150-0200 Incremental Costs
- (1) For the purposes of ORS 757.396, a large natural gas utility must calculate its total incremental annual cost as follows: (a) A large natural gas utility must apply a cost-effectiveness calculation to all RNG that the utility acquires for its retail natural gas customers. The cost-effectiveness calculation must be consistent with the methodology used to evaluate RNG resources in the utility's most recently acknowledged integrated resource plan, or integrated resource plan update, or as the utility may otherwise be directed by order of the Commission;
- (b)-(e) For each purchase of RNG …. the dollar value of the difference between the levelized cost of the purchased RNG and the levelized cost of a … purchase of a comparable quantity of geologic natural gas of the same vintage and contract duration represents the incremental cost of that purchased RNG

*Prepared for IRP Working Group - Not to be used for investment purposes* .

18

# Key Aspects of RNG Evaluation Methodology

NW Natural®

- Application of numerous resource planning and rate -making concepts and accounting:
  - Comparing resources on a fair and consistent basis
  - Least cost/least risk planning standard
  - Incremental costs
  - Avoided costs
  - Cost of service
  - Levelized costs
  - Accounting for risk/risk-adjustment

Prepared for IRP Working Group - Not to be used for investment purposes .

19

# Key Terms

NW Natural®

- **RNG** = Renewable Natural Gas
  - While this methodology is a way to evaluate all low-GHG sources of gas including biofuels, clean hydrogen and synthetic methane, to avoid using the mouthful "low-GHG gas supply evaluation methodology" we will colloquially refer to the methodology as the RNG methodology in this presentation (noting that definitions for "RNG" sometimes means biofuels and sometimes can include other sources of renewable gases)
- **RTC** = Renewable thermal certificate
  - An RTC is a *sole* claim to the environmental benefits of a decatherm of RNG, separate from the physical gas of RNG (i.e. **unbundled RNG**)
  - Gaseous fuel version of electric REC (renewable energy credit)
- **Bundled RNG** = RNG including the physical gas molecules (i.e. physical gas molecules + RTC)
- **Brown Gas** = The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included
  - Note brown gas not RNG even though it comes from an RNG project as the environmental claims are not included. Brown gas is equivalent to conventional gas on the natural gas market
- **Book and Claim Accounting-** recognition that environmental attributes (e.g. RTCs) can be separated from physical product and possession of environmental attribute can be used to deliver sustainable product
  - Relative to RNG this means that "retirement" of an RTC represents delivery of a unit RNG to customers
- **Common Carrier Pipeline**- a pipeline that is connected to the continent-wide natural gas pipeline grid

Prepared for IRP Working Group - Not to be used for investment purposes .

20

# Project Types of Low-GHG Resources

NW Natural®

- There can be many variations of these general groupings of RNG project types:

| | RTC Acquired | Attach physical gas to obtain bundled RNG for Incrmental Cost | Sale of "Brown" gas | Avoided Commodity Costs | Avoided Capacity Costs |
|---|---|---|---|---|---|
| Unbundled Environmental Attribute (RTC) Purchase | ✓ | ✓ | | | |
| Bundled RNG Delivered to NW Natural's System | ✓ | | | ✓ | |
| Bundled RNG with Brown Gas Sales | ✓ | ✓ | ✓ | ✓* | |
| On-System Bundled RNG | ✓ | | ✓ | ✓ | ✓ |

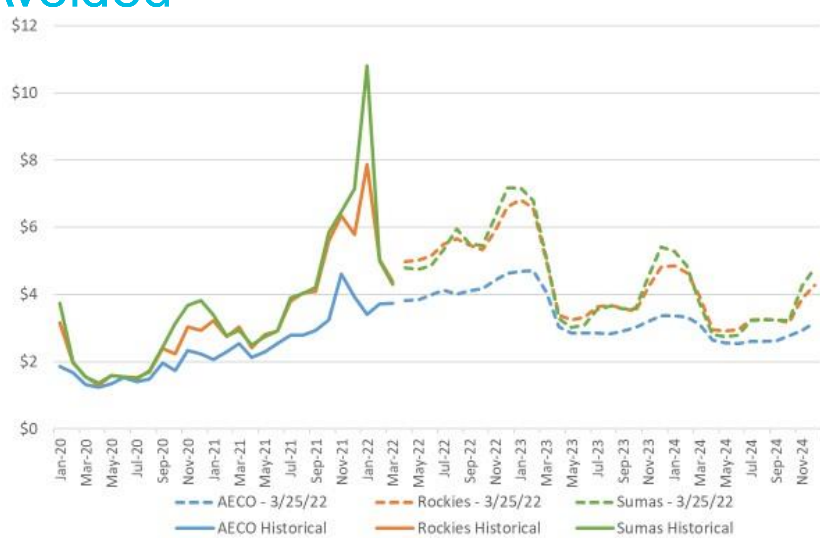
*net impact to customers is the difference between the price of the marginal unit of conventional gas purchased by NW Natural to serve its load and the price of the brown gas sold from the bundled RNG

Prepared for IRP Working Group - Not to be used for investment purposes .

21

# Energy and Transport Costs Avoided

NW Natural®



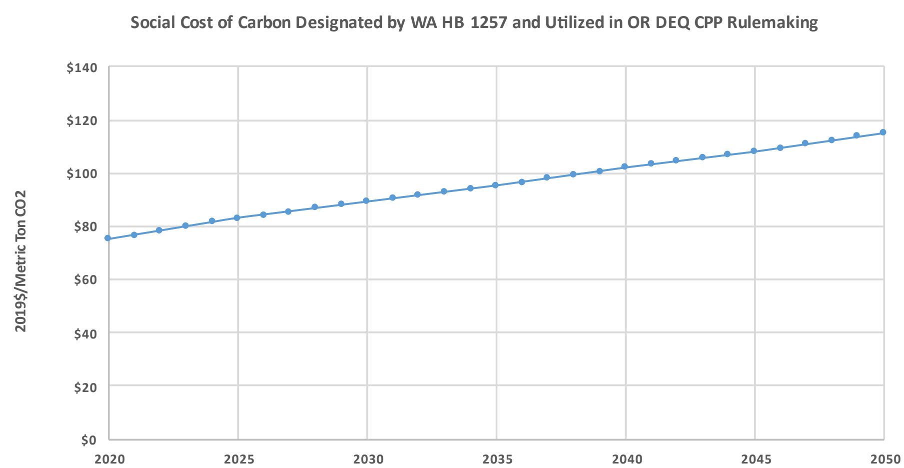

Avoided energy costs on each day is the associated with the **marginal** purchase on that day

Prepared for IRP Working Group - Not to be used for investment purposes .

23

# Avoided Greenhouse Gas Compliance Costs

NW Natural®




https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx

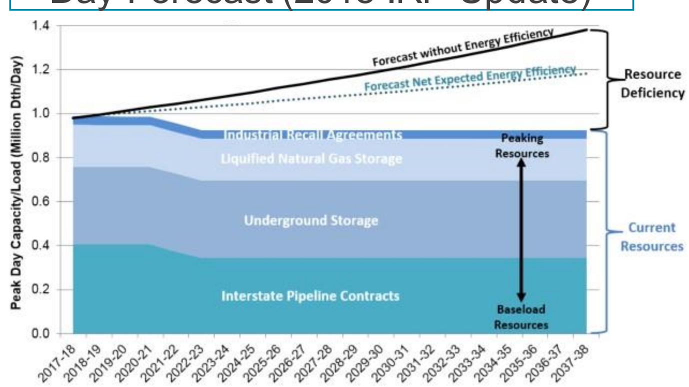
*Prepared for IRP Working Group - Not to be used for investment purposes.*

24

# Infrastructure Costs Avoided with Peak Saving

NW Natural®

Supply Capacity Resources & Peak Day Forecast (2018 IRP Update)




- Capacity resources are procured based upon peak day (supply capacity) and peak hour (distribution capacity) needs

  Gas injected onto or delivered on the system on a peak day contributes to capacity resource portfolio and avoids infrastructure costs

- Often referred to as a "capacity deferral"

*Prepared for IRP Working Group- Not to be used for investment purposes.*

25

## Comparing the Cost of RNG with Conventional Gas

NW Natural®

- **All-in Cost of Gas= Commodity cost of gas + GHG Compliance costs + Supply Infrastructure Costs + Distribution System Capacity Costs**

- The first inclination in comparing the cost of RNG with the cost of conventional gas is to compare the commodity cost of the two types of natural gas
- This is not a complete comparison, as energy, *environmental and capacity costs* should be considered and account for risk
- Comparing the “all-in” cost of different natural gas supply resources is more appropriate
- “All-in” cost represents the total cost to deliver a unit of natural gas to customers (i.e. what customers pay for a unit of gas)
- Comparing the “all-in” cost of different gas resources complies with IRP Guidelines
- Incremental cost of RNG = All-in cost of RNG – All-in Cost of Conventional Gas

*Prepared for IRP Working Group - Not to be used for investment purposes.*

26

## Cost Calculations

NW Natural®

- In general, “all-in costs” of RNG projects calculated with the following equation:

$$\textit{Annual all-In cost of RNG } (R) = \textit{Cost of biomethane } (M) + \textit{Emissions compliance costs } (E) - \textit{Avoided infrastructure costs } (I)$$

- Calculation will examine the entire lifespan of the project with the simplified equation:

$$R_T = M_T + E_T - I_T$$

Cost

Cost/Benefit

Benefit*

*$I_T$=0 for Off-system RNG

*Prepared for IRP Working Group - Not to be used for investment purposes.*

27

## Detailed Methodology and Tools

NW Natural®

- Summary equation:

$$R_T = M_T + E_T - I_T$$

- Detailed RNG cost equation is with substitution:

$$\underbrace{R_T}_{\text{All-in Costs}} = X_T - S_T A_T - DH_T + \sum_{t=1}^{365} \left[ P_{T,t} + Y_{T,t}^{RNG} + N^{RNG} G_T \right] Q_{T,t}$$

- Compared to the conventional supply:

$$\underbrace{C_T}_{\text{All-in Costs}} = \sum_{t=1}^{365} \left[ \underbrace{V_{T,t} + Y_{T,t}^{CONV}}_{\text{Commodity Costs}} + N^{CONV} G_T \right] Q_{T,t}$$

*Prepared for IRP Working Group - Not to be used for investment purposes* .

28

## Components Zoomed In

NW Natural®

| Term | Units | Description | Source | Project Specific? | Input or Output of Optimization? | Treated as Uncertain? |
|---|---|---|---|---|---|---|
| ***R*** | $/Year | Annual all-in cost of prospective renewable natural gas project | Output of RNG evaluation process | Yes | Output | Yes |
| ***C*** | $/Year | Annual all-in cost of conventional natural gas alternative | Output of RNG evaluation process | Yes | Output | Yes |
| ***M*** | $/Year | Annual costs of natural gas and the associated facilities and operations to access it | Output of RNG evaluation process | Yes | Output | Yes |
| ***E*** | $/Year | Annual greenhouse gas emissions compliance costs | Output of RNG evaluation process | Yes | Output | Yes |
| ***I*** | $/Year | Annual infrastructure costs avoided with on-system supply | Output of RNG evaluation process | Yes | Output | Yes |
| ***Q*** | Dth | Expected or contracted daily quantity of RNG supplied by project | Project evaluation or RNG supplier counterparty | Yes | Input | If no contractual obligation |
| ***P*** | $/Dth | Contracted or expected volumetric price of RNG | Project evaluation or RNG supplier counterparty; Max cost-effective price determined in SENDOUT if NWN initiating negotiations | Yes | Input if responding to offer, Output if NWN initiating offer | If no contractual obligation |
| ***T*** | Year | Year relative to current year, where the current year T = 0, next year T = 1, etc. | Project evaluation or RNG supplier counterparty | Yes | Input if responding to offer, Output if NWN initiating offer | If no contractual obligation |
| ***k*** | Year | When the RNG purhcase starts in # of years in the future; k = RNG start year - current year | Project evaluation or RNG supplier counterparty | Yes | Input if responding to offer, Output if NWN initiating offer | If no contractual obligation |

*Prepared for IRP Working Group - Not to be used for investment purposes* .

29

## Components Zoomed In

NW Natural®

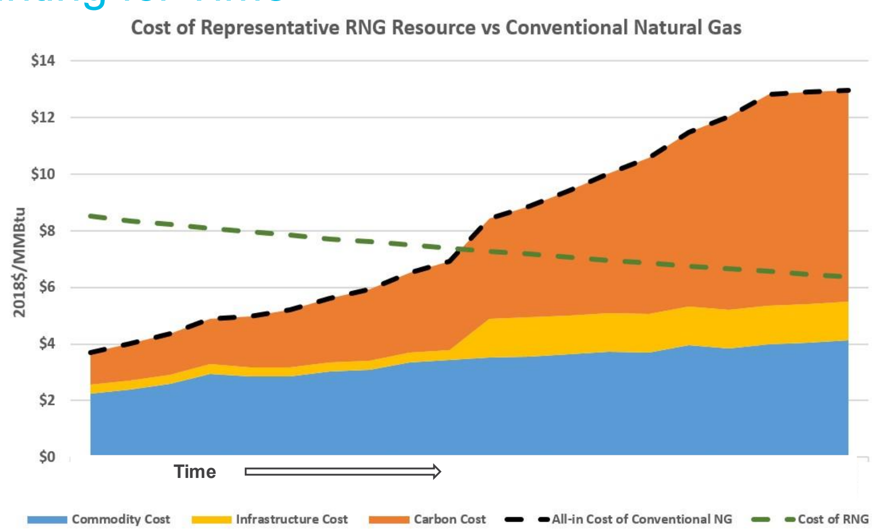
| Term | Units | Description | Source | Project Specific? | Input or Output of Optimization? | Treated as Uncertain? |
|---|---|---|---|---|---|---|
| *z* | Years | Duration of RNG purchase in years | Project evaluation or RNG supplier counterparty | Yes | Input if responding to offer, Output if NWN initiating offer | If no contractual obligation |
| *t* | Days | Day number in year *T* from 1 to 365 | N/A | No | Input | No |
| *V* | \$/Dth | Price of conventional gas that would be displaced by RNG project | Average price of last *Q* quantity of conventional gas dispatched in SENDOUT run without RNG project | Yes | Output | Yes |
| *Y* | \$/Dth | Variable transport costs to deliver gas to NWN's system; superscripted with R for RNG | *For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from last gas dispatched in SENDOUT | Yes | Output | No |
| *X* | \$/Year | Annual revenue requirement of capital costs to access resource | Engineering project evaluation or RNG supplier counterparty | Yes | Input | If no contractual obligation |
| *N* | Tons $CO_2e$ /Dth | Greenhouse gas intensity of natural gas being considered | From actual project certification if available, from California Air & Resources Board by biogas type if no certification has been completed | Yes | Input | No |
| *G* | \$ /Ton$CO_2e$ | Volumetric Greenhouse gas emissions compliance costs/price | Expected greenhouse gas compliance costs from the most recently acknowledged IRP | No | Input | Yes |
| *S* | \$/Dth | System supply capacity cost to serve one Dth of peak DAY load | Calculated within SENDOUT based upon marginal supply capacity resource that is being deferred using Base Case resource availability from the last IRP | No | Output | Yes |
| *A* | Dth | Minimum natural gas supplied on a peak DAY by project | Project evaluation or contractual obligation from RNG supplier counterparty | Yes | Input | If no contractual obligation |
| *D* | \$/Dth | Distribution system capacity cost to serve one DTH of peak HOUR load | Distribution system cost to serve peak hour load from avoided costs in most recently acknowledged IRP | No | Input | No |
| *H* | Dth | Minimum natural gas supplied on a peak HOUR by project | Project evaluation or contractual obligation from RNG supplier counterparty | Yes | Input | If no contractual obligation |
| *d* | % rate | Discount Rate | Discount rate from most recently acknowledged IRP | No | Input | No |

*Prepared for IRP Working Group - Not to be used for investment purposes* .

30

## Comparing RNG vs Conventional Gas Costs: Accounting for Time

NW Natural®




*Prepared for IRP Working Group - Not to be used for investment purposes* .

31

# Risks Accounted for in RNG Methodology

NW Natural®

- There are two main types of risks for NW Natural's customers
  1. Market Risks
  2. Policy Risks

Market risks are easier to quantify and include:

| | | Risk | Source of Base Case | Source of Risk Distribution |
|---|---|---|---|---|
| Market Risks | RNG Project | RNG Volumes/Production | Contract/Renewables Team | Renewables Team |
| | | Project Delay | Contract/Renewables Team | Renewables Team |
| | | Early Project Closure | Contract/Renewables Team | Renewables Team |
| | | Capital Investment Costs | Contract/Renewables Team | Renewables Team |
| | | Price of Brown Gas Sales | 3rd Party Consultant | Historic Data per IRP |
| | | Biogas Supply/Offtake Pric | Contract/Renewables Team | Renewables Team |
| | | Fixed O&M Costs | Contract/Renewables Team | Renewables Team |
| | | Variable O&M Costs | Contract/Renewables Team | Renewables Team |
| | | | | |
| | Avoided Costs | Price of Conventional Gas | 3rd Party Consultant | Historic Data per IRP |
| | | GHG Compliance Costs | CPP and CCA Rules Forecast | Scenarios per IRP |
| | | Capacity Costs | Avoided Costs in IRP | Historical Data |

- Unresolved policy decisions also represent risk to NW Natural customers and are generally around complicated issues regarding "carbon" accounting

34

*Prepared for IRP Working Group - Not to be used for investment purposes* .

## Incremental Cost: Accounting for Risk

NW Natural®

- Mathematically, the incremental cost of the RNG project is represented by:

$$\boldsymbol{Incremental\ Cost(IC)} = \boldsymbol{rPVRR(R)} - \boldsymbol{rPVRR(C)}$$

- rPVRR = risk adjusted present value of revenue requirement
- While the base case estimate of incremental cost is the best estimate of the cost of the project and is used for RNG portfolio cost estimates and SB 98 compliance filings, prospective projects are compared for decision making using risk-adjusted incremental costs

## Accounting for Risk Cont.

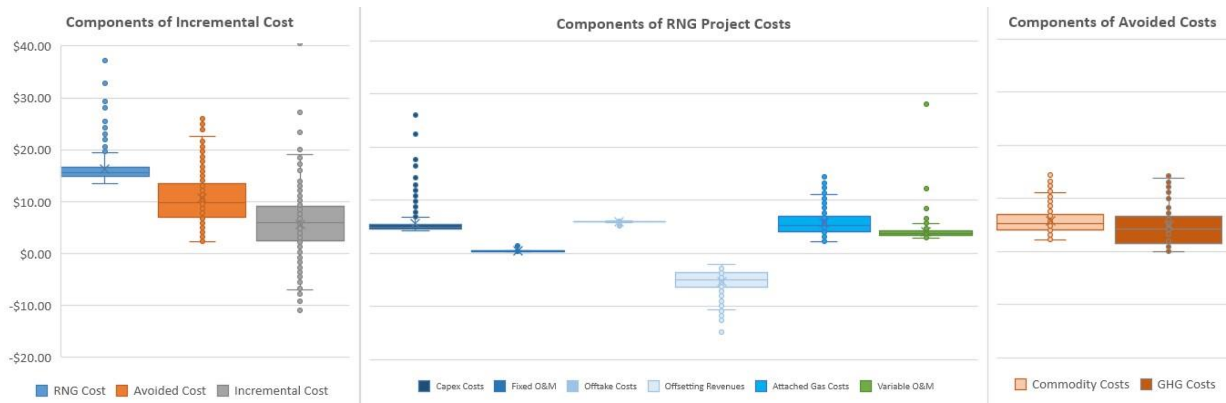
NW Natural®

- Stochastic simulation (Monte Carlo) is used to estimate 500 incremental costs for each RNG project
- NW Natural's risk-adjusted metric based upon assumption that customers are risk-averse in terms of their utility bills
- RALIC = [Base Case IC x 0.75] + $\underbrace{\text{[95}^{\text{th}}\text{ Percentile IC x 0.25]}}_{\text{Risk-Adder}}$

- RALIC= Risk-adjusted Levelized Incremental Cost
- Prospective projects are compared against each other using first-year RALIC (FYRALIC) for decision making purposes
- Note it is always the case the RALIC > IC

# Accounting for Uncertainty

All components that are not contractually obligated are treated as uncertain




*Prepared for IRP Working Group - Not to be used for investment purposes* .

35

# Methodology Implementation

- Key Questions:
  - How do we align the evaluation methodology with a RNG resource decision process that works in the RNG market?
  - How do compare potential RNG resources while maintaining an updated comparison that is on an apples-to-apples basis?
- The Low-GHG Gas Supply Resource Incremental Cost Evaluation Model was developed to apply the concepts just discussed and align with RNG resource decision making while allowing for many resources to be evaluated and compared at any given time

*Prepared for IRP Working Group - Not to be used for investment purposes* .

36

## 6.6 Current Resources

NW Natural's current portfolio of resources sufficiently meets energy and capacity requirements for customers and are on track to achieve RNG targets outlined by SB 98. This section discusses NW Natural's current resource portfolio.

### 6.6.1. Gas Supply Contracts

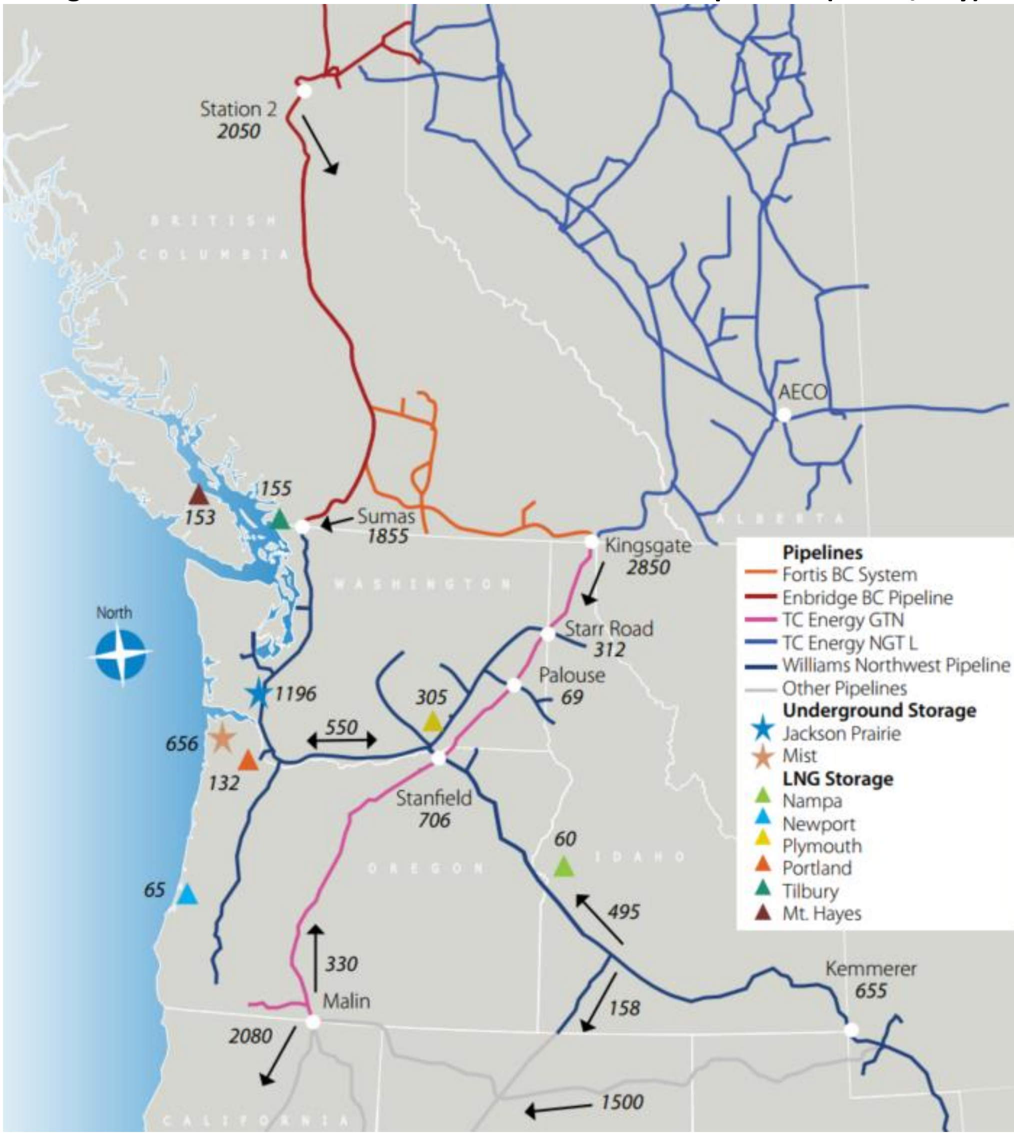
NW Natural has a portfolio of term supply contracts for each year, which are presented and reviewed in the annual purchased gas adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contracts — for the 2021-22 PGA period — is included in Appendix E, Table E.2. Some contracts are designated using the term "Baseload Quantity," which refers to a contractual obligation for daily delivery and payment, while contracts designated as "Swing Supply" mean one party has an option to deliver or receive all, some, or none of the indicated volumes at its sole discretion.

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.

### 6.6.2 Pipeline Capacity

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 6.7. Total pipeline capacities in the map are shown in thousands of Dths per day (MDth/day).

**Figure 6.7: Pacific Northwest Infrastructure and Capacities (MDth/day)**




Source: Northwest Gas Association, 2022 Gas Outlook

## *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 1% 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 6.1), 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.[13] 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 E, Table E.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

[13] The small section of Foothills pipeline in southeastern BC is shows as a part of the NGTL system in Figure 6.1

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 primarily this will mean continuing to use our asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

### *Segmented Capacity*

Segmented capacity is secondary firm capacity that is deemed reliable due to the high probability that it will be available during times of peak usage. This reliability assumption is validated every IRP cycle through an analysis of NWP flow data through the Chehalis Compressor Station along the I-5 corridor. The analysis uses the prior three to five winters to validate that there is sufficient North to South capacity available as the weather gets colder. These assumptions are based on current market dynamics as the ability to schedule segmented capacity is more reliable as weather becomes colder (see Appendix E for the Chehalis compressor analysis). For more details on the process of segmentation see Chapter 6 section 3.3 in the 2018 IRP.

For many years now, NW Natural has 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 segment capacity does not incur an additional demand charge and only incurs NWP's variable and fuel charges in additional to the Sumas commodity costs. Because of this low opportunity cost, segmented capacity is 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 both the 2016 and 2018 IRPs. This amount remains in the current IRP planning until 2027 when certain constraints in the Sumas market are expected to increase the risk of being able to procure spot gas on a peak day. This IRP does not rely on segmented capacity to meet peak demand starting in the 2027-2028 gas year, but does allow it to be used on colder non-peak days at 30,000 Dth/day the rest of the year (see Table 6.1).

**Table 6.1: Segmented Capacity Availability Assumption**

| Timeframe | Design Peak Day Availability | Non-Design Peak Day Availability |
|---|---|---|
| 2022 – Oct 2027 | 60,700 Dth/day | 60,700 Dth/day when temperature is < 40 |
| Nov 2027 – 2050 | 0 Dth/day | 30,000 Dth/day when temperature is < 40 |

### 6.6.3 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 transportation service from Jackson Prairie to the NW Natural citygate.

Table 6.2 shows the maximum storage capacity and deliverability of these four firm storage resources.

**Table 6.2: Firm Storage Resources[14]**

| Facility | Maximum Daily Deliverability (Dth/day) | Maximum Seasonal Storage Working Capacity (Dth) |
|---|---|---|
| **Mist (reserved for Utility Sales Customers)** | 305,000 | 12,213,605 * |
| **Newport LNG** | 64,500 * | 752,500 * |
| **Portland LNG** | 130,800 * | 368,776 * |
| **Jackson Prairie** | 46,030 | 1,120,288 |

Notes: Newport LNG tank maximum capacity currently de-rated pending results of the CO2 removal project, and the available capacity also 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 6.2 represent the portion of the facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum daily deliverability of 480 million cubic feet[15] per day (MMcf/day) with peak hourly deliverability at a rate of 515 MMcf/day, and a total working gas capacity of 17.3 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 and stabilized at around 1,060 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.

[14] The numbers in this table marked with an asterisk (*) originated from volumetric units (e.g., Bcf) and have been converted to energy units (Dth) using the heat content (Btu per cf) of the applicable facility, which may differ very slightly from the assumed heat content factors used in other portions of this IRP. The other numbers in this table do not need to be adjusted for heat content because they originate from contracts (Jackson Prairie) or deliverability calculations (Mist) that are specified in energy units. These values based on the heat content are firm storage resources as of Nov 2021.

[15] All uses of cubic feet in this chapter assume "standard conditions" of gas measurement, i.e., temperature of 60oF and pressure of 14.7 pounds per square inch absolute.

### 6.6.4 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.

#### *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.

#### *On-system production*

Currently two producing RNG projects are interconnected to the NW Natural distribution system and another one is expected to come online later in 2022. NW Natural currently only purchases the underlying 'brown gas' from these projects and does not have rights to the environmental attributes associated with this RNG. Expected volumes from these projects are modeled into our gas supplies in the IRP.

### 6.6.5 Industrial Recall Options

NW Natural has contracts with three 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 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. Contracts range from 1,000 Dth/day to 30,000 Dth/day.

### *6.6.6 Renewable Natural Gas RTC (Renewable Thermal Certificates) Offtakes*

NW Natural has entered into three offtake agreements to purchase RNG from operating RNG projects. Current agreements total about 938,000 in 2022 (over 1% of Oregon sales volume). Most will be delivered to Oregon customers and will be a part of the Oregon PGA, but some RNG will likely be used for other programs, such as those in Washington and future voluntary tariffs. The below slides discuss these Offtake agreements.

- Offtake #1
    - Five-year term
    - About 200 Dth/day
    - Organic waste processing facility in Utah
    - Fixed price per RTC; purchase what is delivered

- Offtake #2
    - Two-year term, with option for one year extension
    - About 1,000 Dth/day
    - Wastewater treatment plant in New York plus dairy-based agricultural waste in Wisconsin
    - Fixed price per RTC; only purchase what is delivered

- Offtake #3
    - 21-year term
    - Production ranges from 500,000-1,000,000 Dth/year
    - Landfill facilities (multiple)
    - Fixed price per RTC; only purchase what is delivered; required minimums, damages for failure to deliver

### *6.6.7 Renewable Natural Gas Development*

NW Natural partnered to develop an RNG upgrading and conditioning facility at the Tyson Fresh Meats facility in Lexington, Nebraska.

- The plant and RNG facility
    - Beef packaging plant built in 1990
    - Employs 2,700 people
    - The facility is expected to produce 84,587 MMBtu in 2022
- Scope of RNG Project
    - Utilize biogas off existing lagoons
    - Implement biogas flow balancing control systems
    - Invest in upgrading technology (membrane technology)
    - Develop interconnection to local gas pipelines
    - NW Natural buys the RNG from this project and retires the RTCs on behalf of NW Natural customers.

**Figure 6.8: Tyson Lexington Skid** *1*

## 6.7 Future Compliance Resource Options

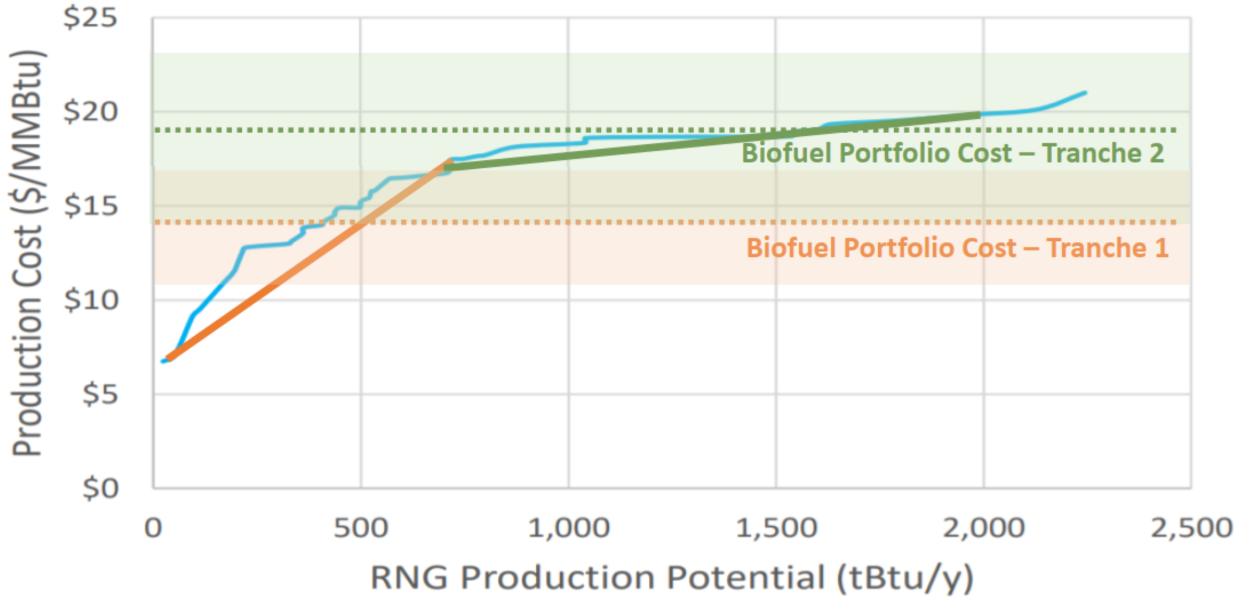
As 2022 is the first compliance year for Oregon and 2023 is the first compliance year for Washington, acquiring resources to meet compliance obligations is an immediate issue. This section outlines the various non-demand-side resources available to meet emissions compliance obligations.

### 6.7.1 Biofuel RNG Assumptions

As discussed in detail above and through participation in the RNG market and our annual RFP process, NW Natural maintains a deep understanding of the RNG market. Additionally, through origination and evaluation processes, NW Natural tracks production, equipment costs, and development costs for potential projects that might develop in the future. This understanding has shaped our assumptions for this IRP, including:

- Maximum available RNG to NW Natural is 75% of our customers' population weighted share of the national RNG supply potential.
- Not all RNG resources are available at all times, so using a traditional supply curve is inappropriate; we are employing a tranched portfolio approach.
- 1/3 of resource available to NW Natural (~13 million MMBtu per year) can be acquired for a portfolio cost of $14/MMBtu +/- $3/MMBctu (Tranche 1).
- The remaining 2/3 of the resource can be acquired for a portfolio cost of $19/MMBtu +/- $5/MMBtu (Tranche 2)

**Table 6.3: Biofuels Supply Curve and Tranched Portfolio Cost[16]**




## 6.7.2 Green Hydrogen

Hydrogen can serve as an emissions compliance resource depending on the feedstock source. Hydrogen produced from *green* sources, such as renewable electricity or biomass, and utilized by NW Natural customers displaces conventional natural gas that would have been used otherwise. Green hydrogen can be sourced from many sources, including electrolysis of water (electricity is used to split the molecule into hydrogen and oxygen), gasification or pyrolysis of woody biomass, cracking of imported ammonia, etc. These sources are becoming increasingly economically viable to produce hydrogen and are predicted to lower the production cost of hydrogen over the planning horizon.

## 6.7.3 Synthetic Methane

Green hydrogen can be combined with waste CO2 to produce synthetic methane using chemical or biological processes. 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. Producing synthetic methane uses approximately 15% 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. Synthetic methane does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection has; 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. NW Natural is pursuing synthetic methane projects where low-cost green hydrogen is available and direct hydrogen blending is not possible. In addition,

[16] Supply Curve (Blue Line) Source: "Renewable Source of Natural Gas." American Gas Foundation Study Prepared by ICF (2019). RNG supply potential adjusted for update in "Net Zero Emissions Opportunities for Gas Utilities." American Gas Association Prepared by ICF (2022).

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 by produced at the site while leveraging the existing gas interconnect and compression infrastructure.

### 6.7.4 Community Climate Investments (CCIs)

As was discussed in Chapter Two, CCIs are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. CCIs are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $71/ton for the first compliance period and raise over time. Use of CCIs as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

### 6.7.5 Tradable Emission Allowances

Discussed further in Chapter Two, rules are being developed by the Washington Department of Ecology to implement a cap on carbon emissions. Mechanisms for the sale and tracking of tradable emissions allowances are included in that rule making. Long term, the program is intended to link with similar programs in other states/jurisdictions, such as California. The cap-and-invest program works by setting a limit on greenhouse gas emissions in state, and then lowering that cap over time. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

NW Natural will be assigned some free allowances over the planning horizon but will be required to hold total allowances equal to the company's covered Washington customer's emissions. This will likely require the utility to purchase allowances at the quarterly allowance auctions. As NW Natural is a relatively small participant in the allowance market, the utility should be able to purchase as many allowances as needed.

### 6.7.6 Offsets

The CCA allows covered parties to purchase offsets up-to 5% of their emission within the first compliance period. An additional 3% of offsets can be purchased for project on tribal lands. For a total of 8% in the first compliance period (2023-2026). This decreases to 4% of offsets and 2% for projects on tribal lands, total 6% for all subsequent compliance periods.

### 6.7.7 Compliance Resource Comparison

**Table 6.4: Biofuels Cost and Quantity Assumptions**

| Resource | Cost | | | Volumes Available | | |
|---|---|---|---|---|---|---|
| | 10th Percentile | Base | 90th Percentile | 10th Percentile | Base | 90th Percentile |
| **Biofuels RNG Tranche 1** | $10.50 | $14.00 | $16.50 | -50% | 13 Million Dekatherms | +100% |
| **Biofuels RNG Tranche 2** | $14.00 | $19.00 | $24.00 | -50% | 27 Million Dekatherms | +100% |
| **Hydrogen** | | | | 10% Combined | 20% combined blending and dedicated systems | 40% Combined |
| **2022** | -20% | $23.00 | +40% | | | |
| **2050** | -50% | $6.00 | +70% | | | |
| **Synthetic Methane** | | | | | Unlimited | |
| **2022** | -20% | $32.00 | +40% | | | |
| **2050** | -50% | $9.00 | +70% | | | |

**Table 6.5: Long-term Compliance vs Short-term Flexibility**

**Table 6.5:**

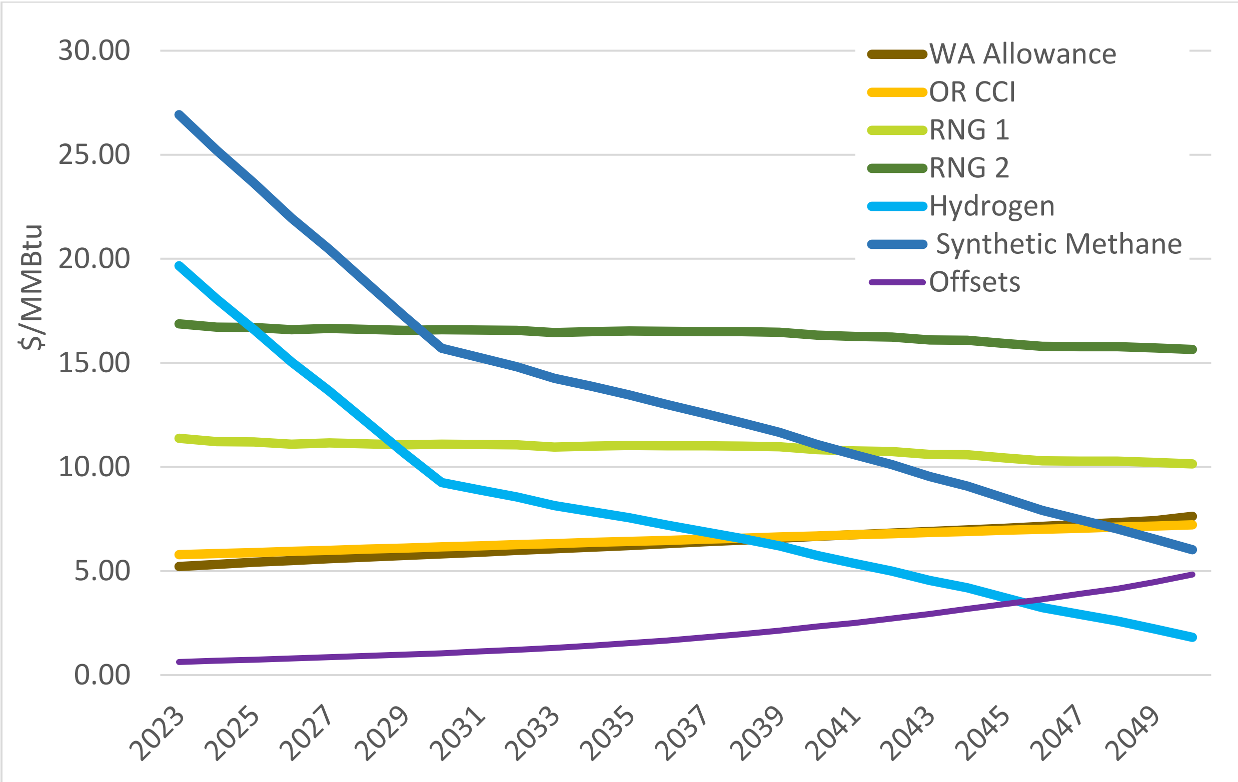
| Emissions Compliance Options | Long-term Compliance Option | Short-term Compliance Flexibility |
|---|---|---|
| Energy Efficiency | ✓ | |
| Development RNG | ✓ | |
| RNG offtake from existing project | ✓ | ✓ |
| Development Hydrogen | ✓ | |
| Development Synthetic Gas | ✓ | |
| Community Climate Investements** | ✓ | ✓ |
| Banking | ✓ | ✓ |
| Allowance Trading at Auction* | ✓ | ✓ |
| Bilateral Allowance Trading** | ✓ | |
| Offsets* | ✓ | ✓ |

*** Only an option under Washington Cap-and-Invest**

**** Only an option under Oregon Climate Protection Program**

Figure 6.9 shows the price paths for the compliance resources over the planning horizon.

**Figure 6.9: Compliance Resource Price Paths**




## 6.8 Future Capacity Resource Options

NW Natural considers additional gas supply resource options including Mist recall, further Mist expansion, and the acquisition of new interstate pipeline capacity. The primary alternatives are described in more detail below.

### 6.8.1 On-system production for Capacity

RNG and Hydrogen projects located within NW Natural service territory can inject molecules directly onto the system and provide energy to the system without needing upstream or storage capacity resources. NW Natural is applying for project approval of a 1MW hydrogen electrolyzer using the Senate Bill 844 voluntary emissions reduction program. The electrolyzer would produce approximately 4,300MMBtu of hydrogen to be blended into the natural gas distribution system. This is a small amount of energy that does not significantly impact supply side resource planning today; however, the learnings will be used to enable much larger scale projects connected to directly onto NW Natural's system in the coming years.

As we better understand the costs and availability of these utility-scale projects, future IRP will be able to evaluate them as a potential capacity resource option but are not being considered for capacity in this IRP. Depending on the economics, on-system production resources could be selected as an emissions compliance resource and the value of being on-system and providing capacity is included in the cost evaluation.

### 6.8.2 Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core utility sales customers (see Table 6.2), NW Natural has developed additional capacity in advance of core customer need. 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 6.10.

**Figure 6.10: 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 customer's 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 modelled as a completely divisible product in the resource planning optimization model discussed in Chapter 7. For scale, 5,000 Dth/day is roughly 0.5% of the current resource stack daily deliverability. The ability to recall Mist in such small increments is a very valuable property that allows customers pay for a capacity resource as needed.

### 6.8.3 Portland Cold Box Investment

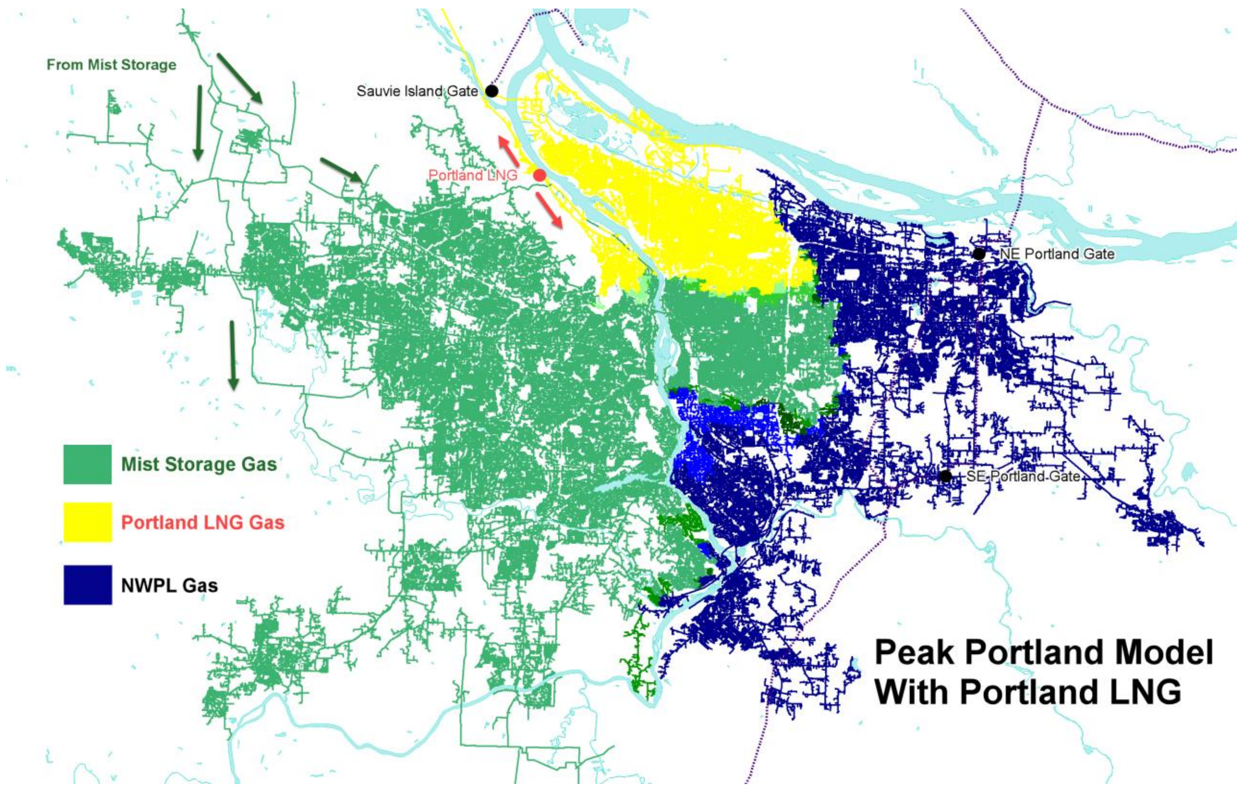
The Portland LNG Plant is a liquified natural gas production and storage facility located in Portland, Oregon. The Portland LNG Plant serves as a winter peak shaving facility to address gas supply and system pressure needs on the coldest winter days. This facility in NW Portland is ideally located to assure reliable gas service to Portland area customers under peak demand conditions. The facility provides 130,800 Dth/day of capacity to NW Natural's system and is in need of investment in a new cold box.

The current cold box at Portland LNG is 54 years old. This places it well past its design life and it is currently showing signs of performance issues. Without an investment in the cold box the Portland LNG facility would not be able to liquify natural gas to be ready to be withdrawn during a peak event. This investment is critical for the Portland LNG plant to remain in NW Natural's capacity resource stack and is modelled in the IRP as an option for selection in 2024. Without the cold box investment, the Portland LNG facility becomes unavailable. Further details on the Portland LNG cold box investment and the alternatives to having the facility operational are discussed later in this chapter.

### *6.8.4 Alternatives to Portland LNG Cold Box Investment*

During a peak event, the gas being withdrawn from Portland LNG supports the pressures on the distribution system serving Northern Portland (see yellow area in Figure 6.11).

**Figure 6.11: Portland LNG Gas Flow Diagram**




Without the Portland LNG facility additional pipeline enhancements would be required to support pressure on the distribution system in addition to recalling Mist deliverability. There are two primary alternatives explored in this IRP. Firstly, there is a Central NWN system pipeline whereby NW Natural would build a pipeline itself combined with 130,800 of Mist Recall. The second alternative would be a contract with NW Pipeline to loop their current interstate pipeline, also combing with 130,800 of Mist Recall (See Table 6.6).

**Table 6.6: Cold Box Alternatives**

| Alternative | Installation Cost | Additional Resources Required |
|---|---|---|
| Central NWN System Pipeline | $111 Million | Mist Recall |
| Interstate Pipeline Looping | $87 Million | Mist Recall |

### 6.8.5 Newport Takeaway Options

As previously mentioned, the daily deliverability of the Newport LNG facility provides 60 MMcf/day (64,500 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 the central coast 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 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 40 MMcf/day (43,000 Dth/day). The 2018 IRP identified a three phased approach that could be done separately and sequentially at various costs to achieve the full 40 MMcf/day of incremental takeaway capability.[17]

1. Central Coast Feeder 1 – would increase the maximum pressure rating of 40 miles of the Central Coast Feeder, adding 15 MMcf/day (16,125 Dth/day) at an estimated cost range of $7-16 million.
2. Central Coast Feeder 2 –would add a new compressor station near Lincoln City, Oregon, adding 13 MMcf/day (13,975 Dth/day) at an estimated cost of roughly $29-66 million.
3. Central Coast Feeder 3 – would boost the Lincoln City compressor horsepower, add another new compressor station to the west of Salem, and make piping improvements between Salem and Albany, all to add 12 MMcf/day (12,900 Dth/day) at an estimated cost of roughly $39-86 million.

The physical gas flow would require that these three improvement projects would have to be undertaken sequentially in the above order. If this were not the case, selection of these

[17] The 2016 IRP and the 2014 IRP evaluated a similar single project call the Christensen Compressor project.

projects would still proceed in this order due to the increase costs of each phase (see Table 6.7 for an apples-to-apples cost comparison for resource capacity).

### 6.8.6 Mist Expansion

The storage currently in service at Mist for core customers, the capacity already developed for future Mist recall that currently serves the ISS market, and the capacity recently developed as North Mist for PGE, collectively do not exhaust the Mist gas field's storage potential. That is, other Mist production reservoirs remain that could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move additional gas from a new Mist storage reservoir(s) to NW Natural's load centers.

A Mist expansion project which could be developed for core customer use, , which would involve 100 MMcf/day (rounded to 100,000 Dth/day) of maximum delivery capacity coupled with a maximum storage capacity of around 4.0 billion cubic feet (4 Bcf, or 4 million Dth). Any Mist Expansion would require new compressor stations, additional wells, pipelines and associated infrastructure. If shown to be a least costs least risk resource a Mist expansion would be developed exclusively for utility use.

While design of a new storage facility itself is relatively straightforward, a larger consideration is transporting the stored gas to NW Natural's load centers during the heating season — the "takeaway" pipeline(s). With exhaustion of all available Mist recall capacity, the existing primary takeaway pipelines from Mist will be at their maximum capacities and incapable of transporting additional gas during the heating season.

A Mist expansion project involves expanding the storage capacity and sharing the pipeline constructed for PGE northbound from Mist to the Kelso-Beaver Pipeline (KB Pipeline) and onto NWP's system near Kelso, Washington. NW Natural would contract with NWP for transport to NW Natural's load centers.

The analysis assumes NWP is willing to offer a storage-related transportation service on its mainline, and on the GPL moving upstream of Molalla, on a firm basis and at a cost reflective of similar offerings that have occurred in the recent past.

NW Natural estimates the investment cost of a Mist expansion with 100 MMcf/day of deliverability and roughly 4 Bcf of storage capacity to be in the range of $150 to $240 million.[18]

[18] A regulatory concern has been raised in the past regarding the utility's direct movement of gas stored at Mist out of Oregon to serve our load centers in Washington; specifically, the concern involves the potential violation of NW Natural's Hinshaw Exemption with FERC. However,

### 6.8.7 Upstream Pipeline Expansion

NW Natural holds existing contract demand 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 Grants Pass Lateral (GPL) 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. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for NW Natural's assessment of incremental interstate pipeline capacity in this IRP.

Since NW Natural effectively is interconnected only to NWP, a subscription to more NWP mainline capacity traditionally has been a prerequisite to holding more upstream capacity of equivalent amounts (e.g., from GTN). There could be exceptions when market dynamics indicate some advantage to holding more or less upstream capacity. For example, as upstream pipelines continue to expand into new supply regions and/or to serve new markets, an evolution of trading hubs may occur; opening up the more liquid trading points while others fade into disuse. The construction of an LNG export terminal in the Pacific Northwest or British Columbia and/or the construction of a new pipeline transporting Arctic gas (either from Alaska or the Mackenzie Delta) are examples of market developments that could cause NW Natural to reconfigure or add to our upstream pipeline contracts. Under these market conditions, it may be beneficial to hold transportation capacity upstream of NWP leading to these new supply points and trading hubs.

The timing for new regional pipelines will be driven by the growth in regional gas demand. From NW Natural's perspective, new regional pipelines could improve gas system resiliency and enhance reliability, which may be particularly important given the convergence and interdependencies of the electric and gas systems. Some proposed projects could provide the additional benefit of mitigating Sumas price risks potentially arising from future British Columbia LNG export terminals. By comparison, meeting regional demand growth via incremental NWP expansions from Sumas essentially "doubles down" on an existing pathway and, at the same time, is a potential lost opportunity to protect customers from a risk management perspective.

---

preliminary legal analysis has indicated that a viable structure could be created to make this arrangement work without adversely impacting NW Natural's Hinshaw Exemption.

In this IRP, NW Natural has evaluated the potential acquisition of interstate pipeline capacity via an expansion of the NWP system between Sumas and Portland. This incremental NWP capacity from Sumas is designed to serve only NW Natural's load growth needs. Accordingly, it would have a relatively small scale and would not benefit from the economies of scale from an expansion built to serve the whole region.[19] Having a NW Natural specific expansion as any option enables the IRP to select the resource at the point in time when customers would be need.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It would be dependent on the length of regulatory permitting times, and the time required to construct the required facilities, which could include restrictive periods due to environmental considerations. A pipeline expansion for NW Natural from Sumas to Portland is restricted from being selected for at least 5 years in the resource planning optimization model.

### 6.8.8 Capacity Resource Comparison

**Table 6.7: Capacity Resource Cost and Deliverability**

| Capacity Resource | Cost ($/Dth/day) | Daily Deliverability (Dth/day) |
|---|---|---|
| Mist Recall | $ 0.09 | As needed<br>Max: 203,800 |
| Newport Takeaway 1 | $ 0.14 | 16,125 |
| Newport Takeaway 2 | $ 1.00 | 13,975 |
| Newport Takeaway 3 | $ 1.41 | 12,900 |
| Mist Expansion | $ 0.62 | 100,000 |
| Upstream Pipeline Expansion | $ 2.12 | 50,000 |
| Portland LNG - Cold Box | $ 0.06 | 130,800 |
| Interstate Pipeline Looping Plus Required Mist Recall | $ 0.39 | 130,800 |
| Central" NWN System Pipeline Plus Required Mist Recall | $ 0.35 | 130,800 |

[19] Such as in the case when a pipeline expansion is being proposed and an open season is held to solicit interest from perspective customers.

## 6.9 Portland LNG Cold Box Project

Portland LNG was constructed by Chicago Bridge & Iron (CB&I) and commissioned in 1968 as one of the first LNG utility facilities used for LNG liquefaction, storage, and LNG vaporization for supplemental winter supply.

The Portland LNG facility's nominal capacity includes:

- One single containment LNG storage tank with a capacity of 175,000 barrels (7,350,000 gallons) of LNG.
- One flow-by-expander liquefaction cycle with a net LNG liquefaction capacity of 2.15 MMCFD (26,000 gpd).
- A net of 15.06 MMCFD tail gas is sent to the distribution system from pretreatment, LNG liquefaction, and vapor recovery operations during LNG liquefaction mode.
- Three submerged combustion vaporizers (SCVs) have a combined peak send-out capacity of 120,000 MCFD at 400 psig.
- One LNG truck loading bay using LNG tank pumps with a 506 gpm max rate.

### 6.9.1 Primary Role Played by Portland LNG

Due to its location, Portland LNG is a critical resource for meeting our customer's peak needs in the Portland Metro Area. As mentioned above, Portland LNG is considered an 'on-system' gas supply resource. Gas is typically placed into storage at this facility during off-peak periods, which is also known as 'liquefaction' (for the LNG facilities). When needed, this on-system resource does not require further transportation on the NW Pipeline interstate pipeline system, but rather uses vaporization from the LNG facility to supply gas directly to NW Natural's system. Portland LNG's central location and proximity to Portland makes it a valuable peaking resource. As discussed above, the facility is in need of investment in a new cold box.

### 6.9.2 Cold Box Project Background

The Cold Box is an essential component in an LNG liquefaction plant, and it is where natural gas is cooled to cryogenic temperatures to convert the gas to liquid. Once liquefied, it is pumped from the Cold Box to the onsite insulated storage tank where it can later be used in the winter. The Portland Cold Box, see Figure 6.12, is made up of multiple aluminum heat exchangers, which are encased in a single unit measuring approximately 15 feet in height.

**Figure 6.12 Portland LNG Cold Box**

The Cold Box at Portland LNG is 54 years old. This places it well past its design life and it is currently showing signs of performance issues. Accordingly, NW Natural engaged Sanborn, Head, and Associates, who specialize in LNG, to provide a report and recommendation specific to the Cold Box at the Portland facility ("Sanborn Cold Box Report"). The Sanborn Cold Box Report determined that the Cold Box is proposed for replacement to improve safety and reliability.

The Cold Box replacement is necessary in order to continue to rely upon Portland LNG as a firm resource to serve NW Natural's current needs. Should the Cold Box fail, the ramifications to the plant would be significant. For example, if a failure occurred at the beginning of the production season, this would leave the facility without a reasonable means to refill the storage tank, because a replacement unit would require approximately two years to install. As described by Sanborn and Head, repairs to this type of equipment can be very costly or even impractical. As a result, all remaining LNG may boil off prior to equipment replacement (depending on the tank level at the time of failure), which in turn, would allow the large LNG tank to warm significantly, inducing stress on the tank due to thermal expansion. Customers would also be left without the benefit of backup storage to support periods of peak demand during cold weather or other supply constraints.

**Figure 6.13: Overview Map of Project Area**


### 6.9.3 Cost Estimate of Cold Box Replacement

Table 6.8 lists the major project components as well as their costs. These capital costs include a 50% contingency.

**Table 6.8: Portland Cold Box Cost Estimates**

| Project Components | Cost |
|---|---|
| Engineering, Design, & Construction Management | $1,340,000 |
| Major Equipment | $4,310,000 |
| Cold Box System Integration | $1,330,000 |
| Civil/Site Construction | $390,000 |
| Permitting | $120,000 |
| Subtotal | $ 7,490,00 |
| Total +50% Contingency | $11,235,000 |

# Chapter 7
# Portfolio Selection

# Gas Supply Resource Portfolio Selection

A primary purpose of an IRP is to evaluate near-term decisions over a long-term planning horizon and how those decisions would be viewed under a range of circumstances. Some of these near-term decisions involve investments in long lived assets or signing long term contracts, such as an RNG off-take agreement. The long-term view of varying futures allows a robust evaluation of any near-term decision that require action before engaging stakeholders again in the next IRP process. The aim of a least cost least risk IRP is to put forth an action plan with low regret outcomes. All the material discussed in the previous chapters accumulate to this chapter, which discusses the cost minimizing resource selection and risk analysis.

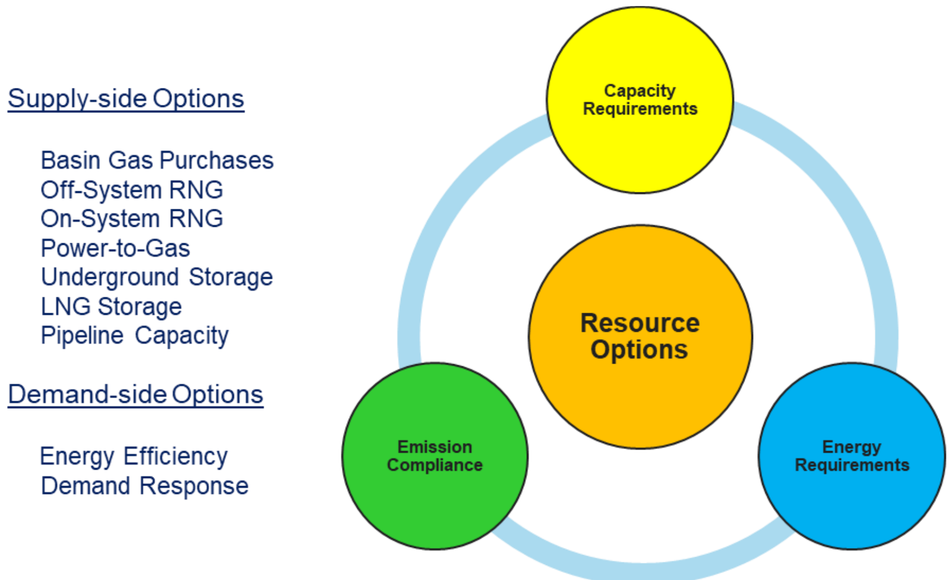
## 7.1 Portfolio Selection -Overview

Gas supply resource planning must acquire the appropriate mix of resources with the best combination of cost and risk to meet three primary requirements:

1. Emissions reduction requirements, emission compliance following the rules of the CPP in Oregon and the CCA in Washington
2. Capacity requirements, being able to reliably serve customers during a design peak cold event when loss of customers service due to resource constraints occurs at the same time when it is the most dangerous time for customers to lose service
3. Annual energy requirements, having the resources to reliably serve customers throughout the year.

Resource options offer very different emissions, capacity, and energy services. Additionally, resource options all vary in costs and availability. For example, NW Natural's Newport LNG facility provides a significant amount of capacity, but limited amount of total energy before being completely emptied. On the other hand, upstream pipeline capacity with conventional gas purchases can provide 365 days of both capacity and energy, some of which is needed during the summer to fill NW Natural's storage facilities. Off-system purchases of RNG help meet emission compliance, but do not provide either capacity nor energy to the system, whereas an on-system RNG can help meet all three requirements.

**Figure 7.1: Resource Requirement**




Due to the complexity of these various options and how they interact with each other, NW Natural must implement an optimization software called PLEXOS to select the least cost portfolio of resources. For this IRP NW Natural uses expected weather load with a single peak day in the resource planning optimization model to select least cost portfolio of resources that fulfils the capacity and emission reduction requirements. Design weather load is used as secondary check to ensure the preferred resource portfolio can meet total annual energy requirements.

## 7.2 Resource Planning Optimization Model (PLEXOS)

PLEXOS implements a mixed integer program (MIP) algorithm, which triangulates a least cost solution that minimizes net present value system costs of the entire resource portfolio over the planning horizon.[1] The software does this by making operational selections, known as decision variables, but is constrained based on the inputs of the model that represent real world limitations. Table 7.1 provides a high-level list of the decision variables and constraints of the model.

[1] PLEXOS is new for this IRP and provides superior flexibility and software support over the previous software being used for NW Natural's IRPs. The previous software and modeling implemented a linear program (LP) algorithm for cost minimization optimization. MIP algorithms are more complex, but allow for integer-based decisions, such as a binary build or not build decisions.

**Table 7.1: Decision Variables and Constraints**

| Decision Variable | Constraints |
| --- | --- |
| • Daily purchases for RNG, hydrogen, synthetic methane, and conventional gas<br>• Acquisition of resources required to serve demand<br>• Daily storage operations (injections and withdrawals) | • All demand is served<br>• NW Natural meets emissions compliance<br>• Pipeline constraints<br>• Storage constraints<br>• Supply constraints |

The PLEXOS model takes in all the information discussed in the previous chapters. This includes demand forecast, resources options, price forecasts, compliance obligations, etc. Given these inputs, the cost minimization algorithm of the PLEXOS model has perfect foresight of the future and optimizes across time accordingly. In other words, it can choose to inject into storage in one period to avoid paying high costs in the future. The reality is that we do not have perfect foresight and face a lot of uncertainty and risk across several factors which could impact the decisions the company makes on behalf of customers. Using the model in combination with a risk analysis cost least risk set of resource choices robust to many future outcomes.

**Defining Resource Needs**

Figures 7.2 shows the projected peak day resource deficiency when the base case peak day load forecast is shown along with capacity resources.

**Figure 7.2: Peak Day Capacity Load Resource Balance**

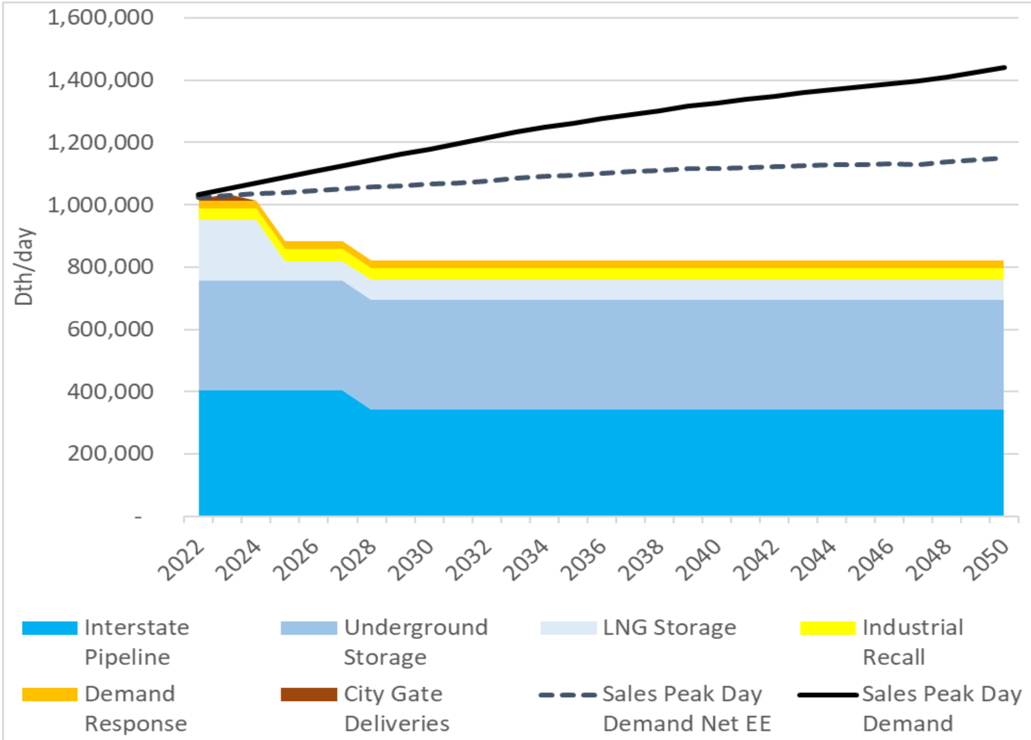



**Figure 7.3 Oregon CPP Emission Compliance Needs**

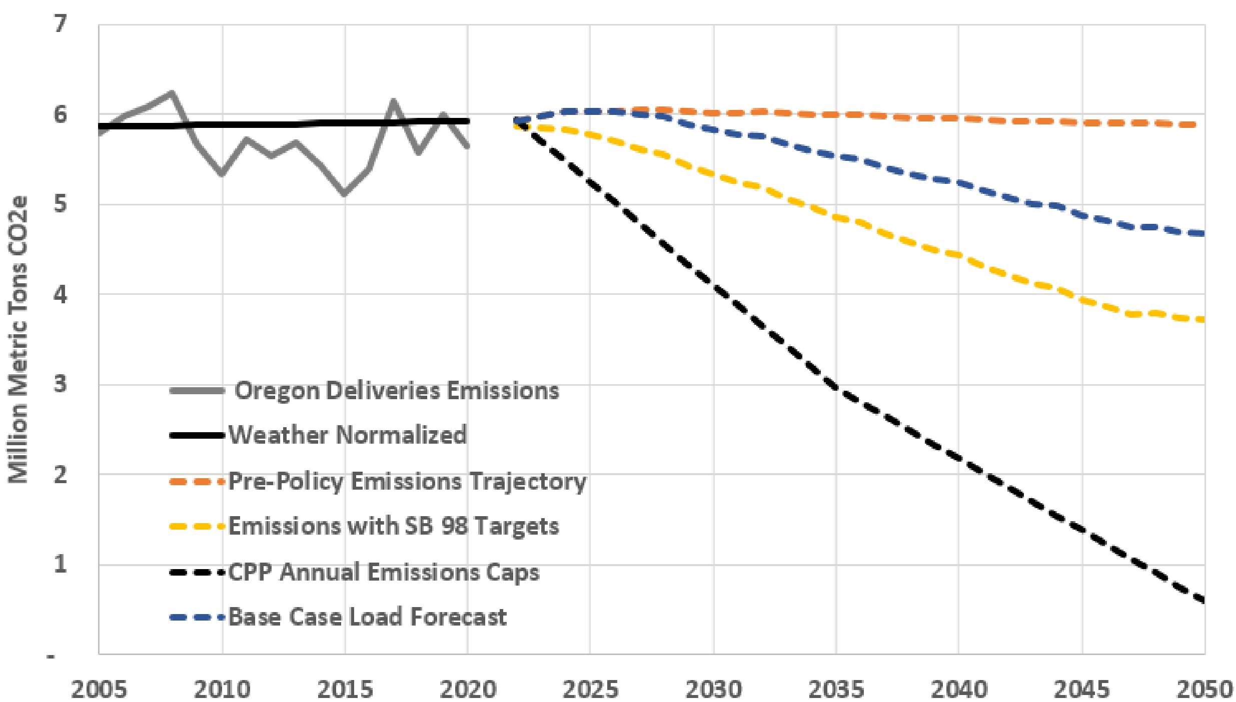
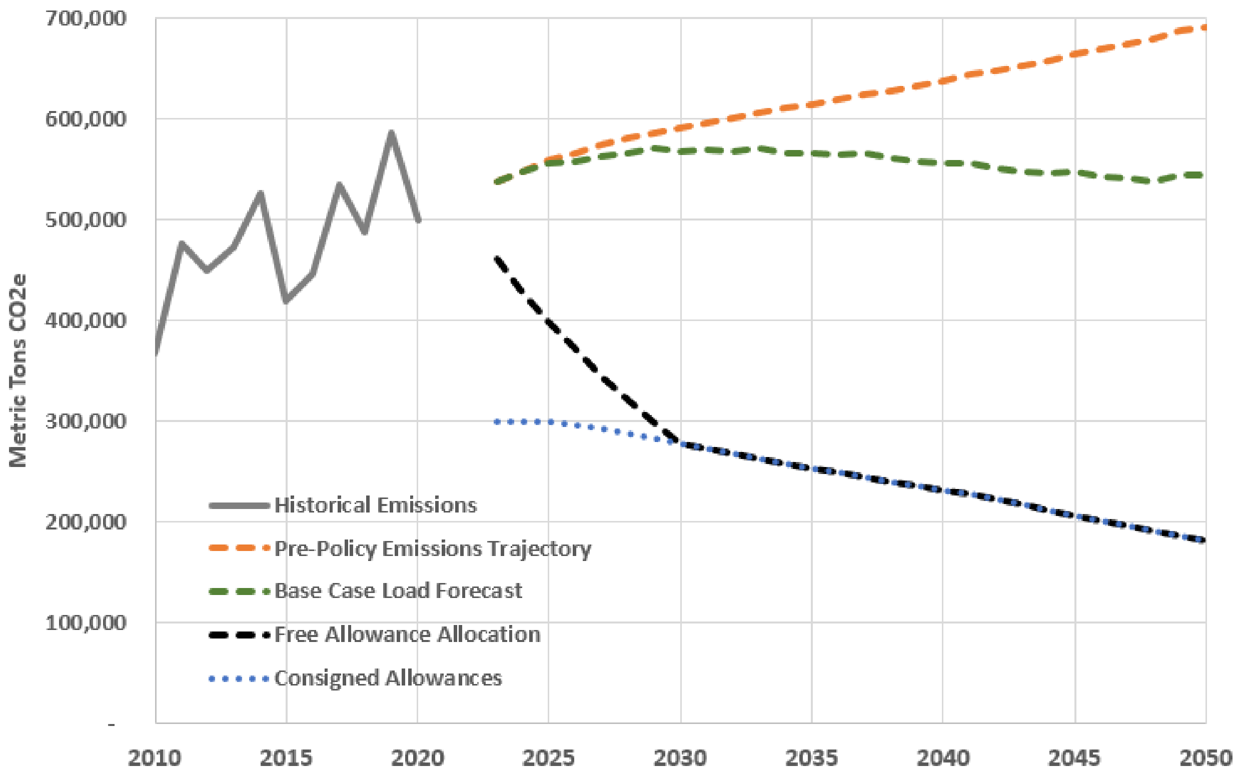
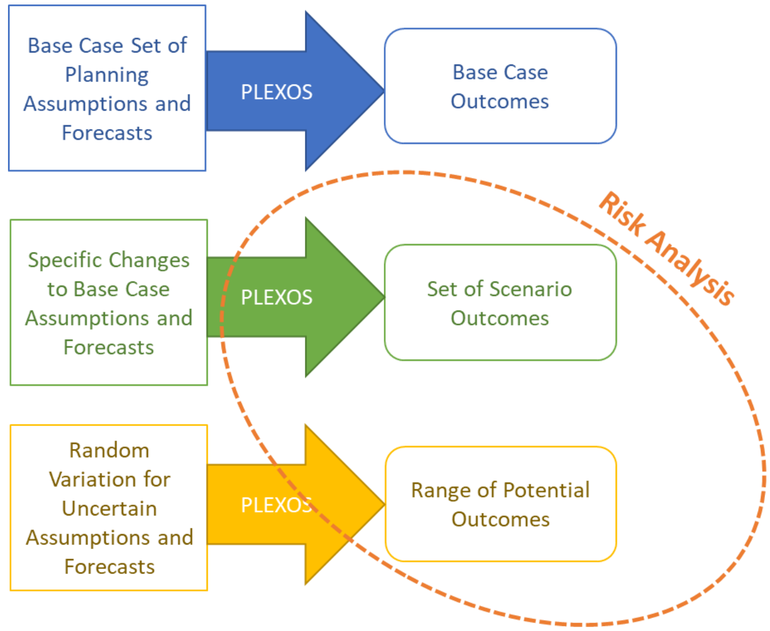


**Figure 7.4: Washington Cap-and-Invest Emissions Compliance Situation**




## 7.3 Base Case and Risk Analysis Overview

For this IRP, our base case is different than the reference case (see Chapter 3) and is a change from previous IRPs. The base case represents the company's expectation of the future for the key set of planning assumptions and forecasts. The PLEXOS takes in all the base case information and produces a least cost solution. This solution includes daily purchases of conventional gas, annual low-GHG supply resource contract decisions, daily storage operations, and capacity resource investments, along with the emissions and costs associated with each of components.




Our risk analysis includes two approaches to testing resource selection. The first approach is to view the world through a specific set of circumstances, known as scenarios. The benefit of using scenarios allows stakeholders to understand the implications for resource planning given a specific set of circumstances, for example building electrification, which can be bookend set of circumstances. Each scenario makes one or two significant deviations from the base case to understand the implication of that change. For example, scenario 5 examines the impact of a federal policy aimed at reducing the costs of RNG and Hydrogen. How the future ultimately unfolds will not be a single scenario, but likely a combination of all scenarios.

The second approach for risk analysis uses stochastic simulations that randomly varies independent factors that could impact resource decisions. This is done for many simulations (a.k.a. draws) that produces a wide range of outcomes.[2] Table 7.2 lists the factors that are varied in the stochastic risk analysis for this IRP. The base case outcomes, scenario outcomes, and range of outcomes from the stochastic analysis are used to inform the action plan.

[2] One of the benefits of moving to PLEXOS is the ability to optimize the resource selection for each individual draw. Due to the limitations of the previous software, prior IRPs ran Monte Carlo simulation of only costs and demand for a fixed resource portfolio. PLEXOS has the flexibility to input simulations for any key assumption, forecast or constraint and will optimize resource selection for that specific draw.

**Table 7.2: Stochastic Variables for Risk Analysis**

| Stochastic Variables |
| --- |
| **Demand** |
| Weather |
| Customer Growth Rates |
| Growth Moratorium Start Dates |
| Customer Losses |
| Gas Heat Pump and Hybrid Heating Penetration |
| Building Shell Improvements |
| Industrial Energy Efficiency |
| **Supply Costs** |
| Capacity Resource Costs |
| Price of Conventional Natural Gas |
| Price of RNG Tranche 1 |
| Price of RNG Tranche 2 |
| Price of Hydrogen |
| Cost of Methanation |
| Washington Allowance Prices |
| Washington Offset Prices |
| **Supply Availability** |
| Maximum Allowable Hydrogen Blend onto the System |
| Maximum Quantity of RNG Tranche 1 Available |
| Maximum Quantity of RNG Tranche 2 Available |

## 7.4. Reference Case

**Table 7.5: Oregon Reference Case - Compliance Resources**

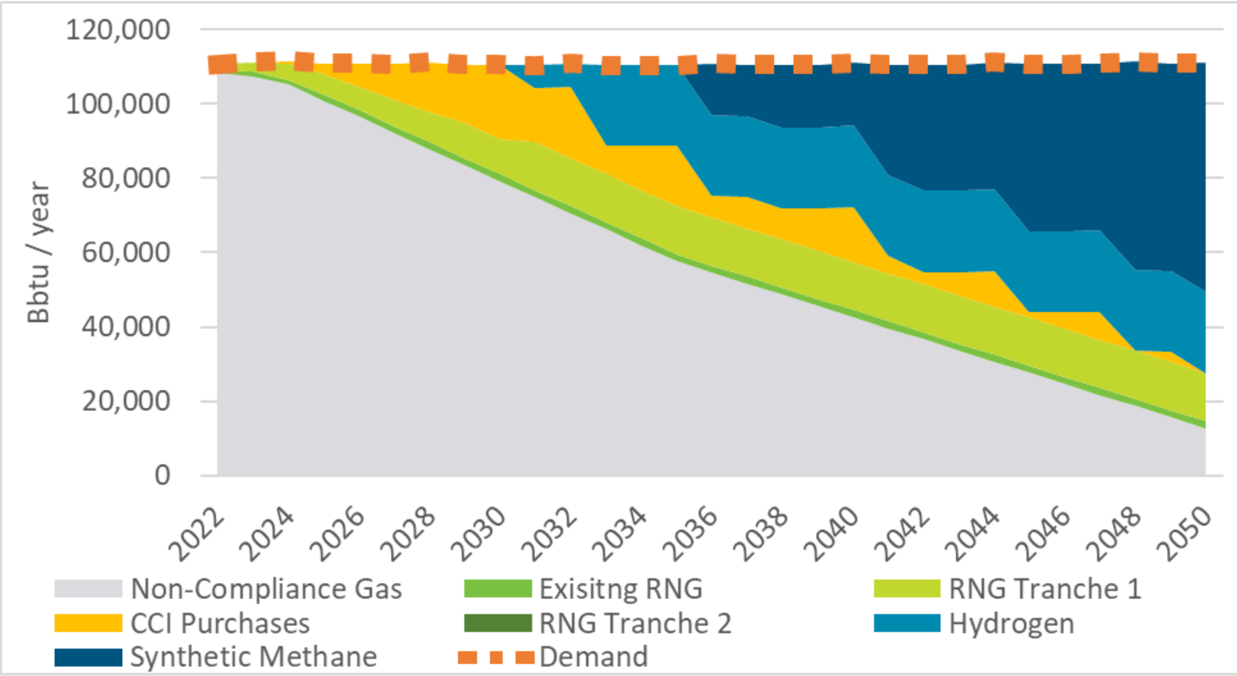
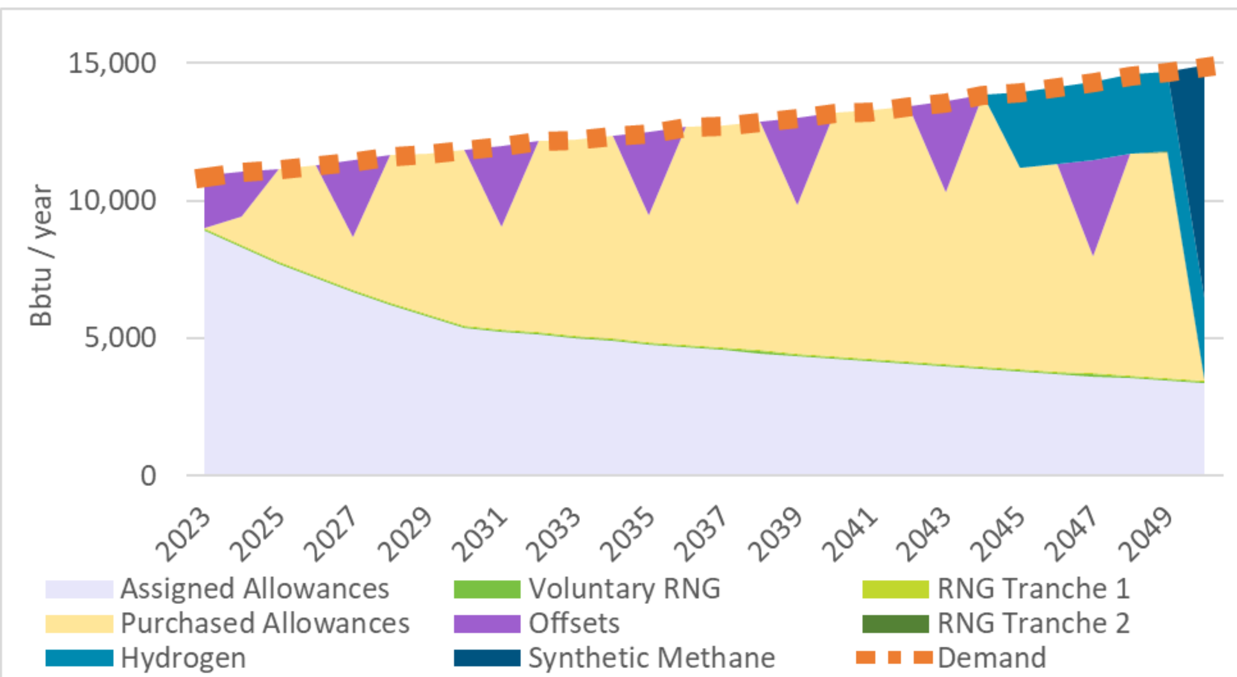



**Table 7.6: Washington Reference Case - Compliance Resources**



## 7.5 Base Case

**Figure 7.7: Oregon Base Case - Compliance Resources**

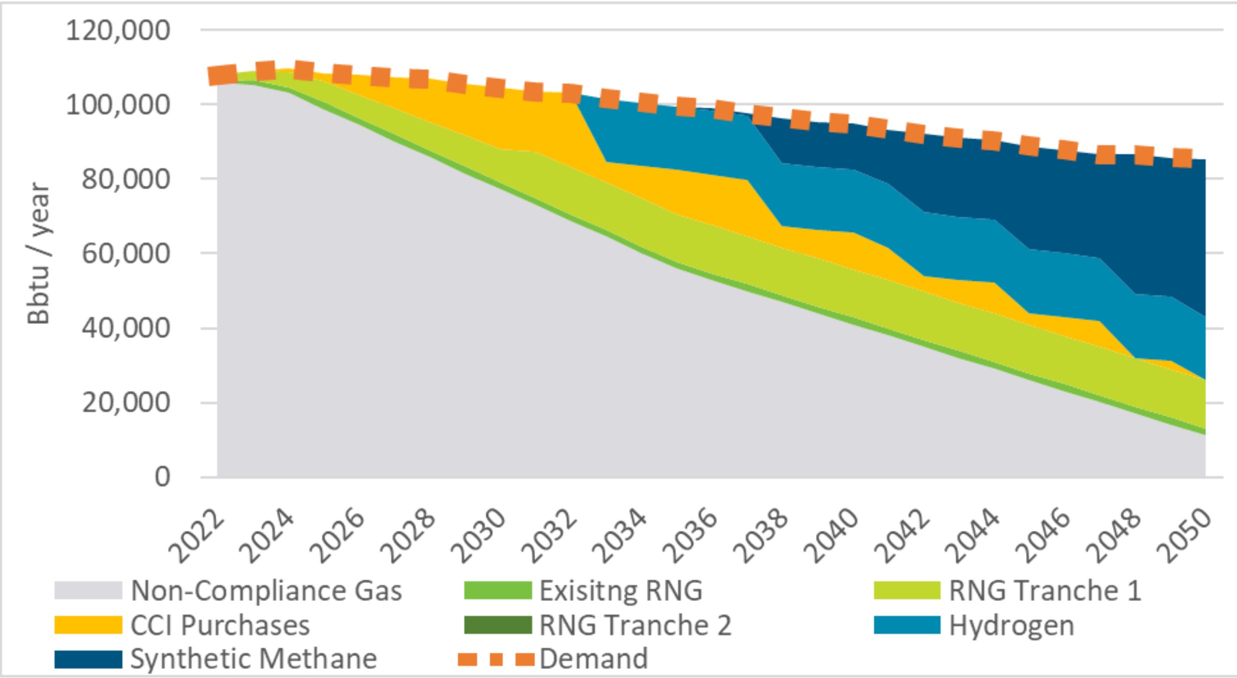
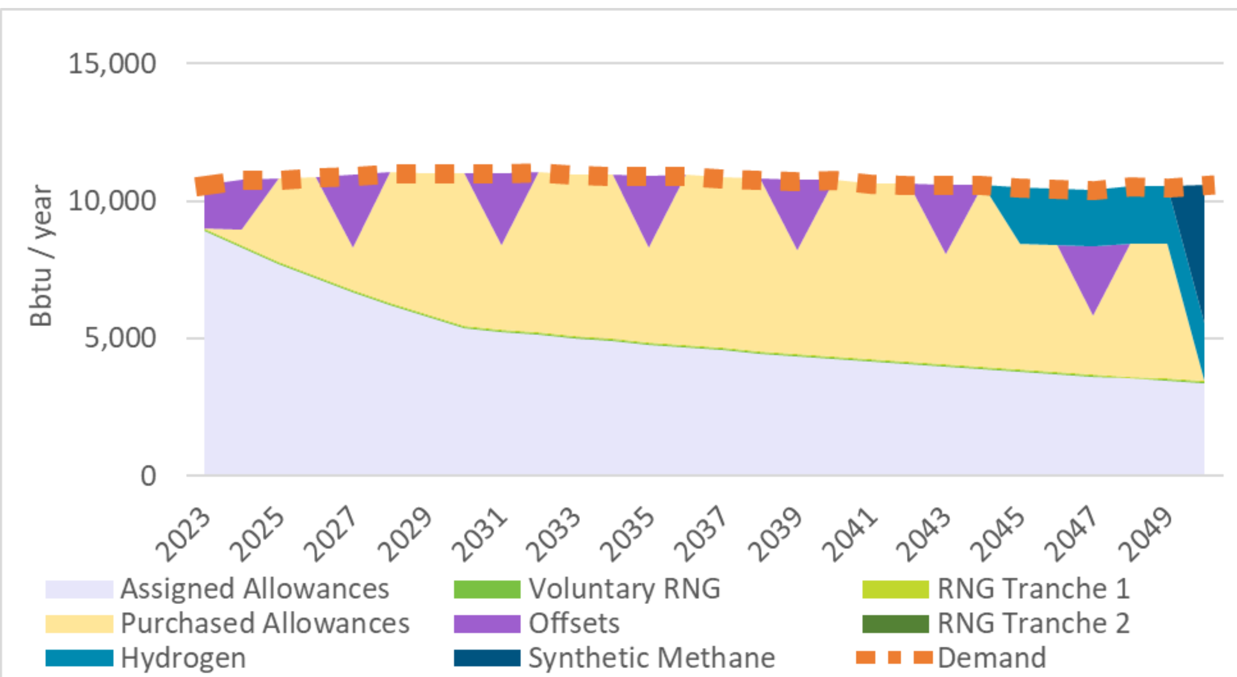



**Figure 7.8: Washington Base Case - Compliance Resources**



## 7.6 Carbon Neutral

**Figure 7.9: Oregon Carbon Neutral - Compliance Resources**

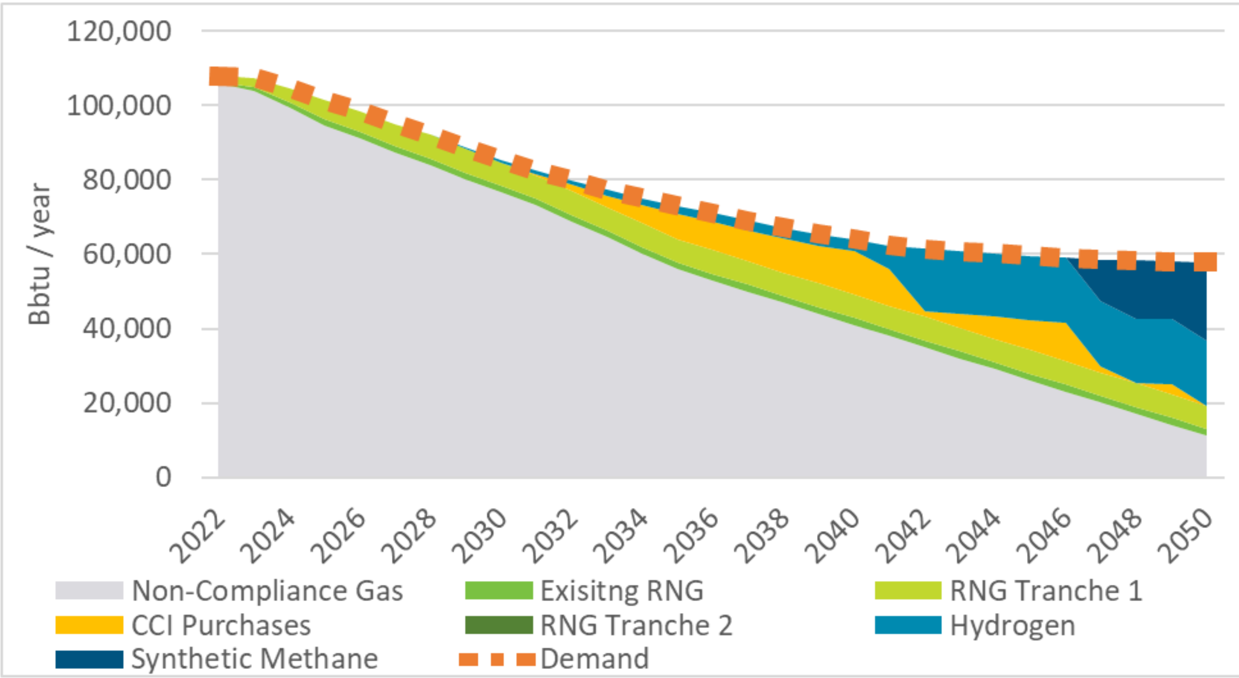
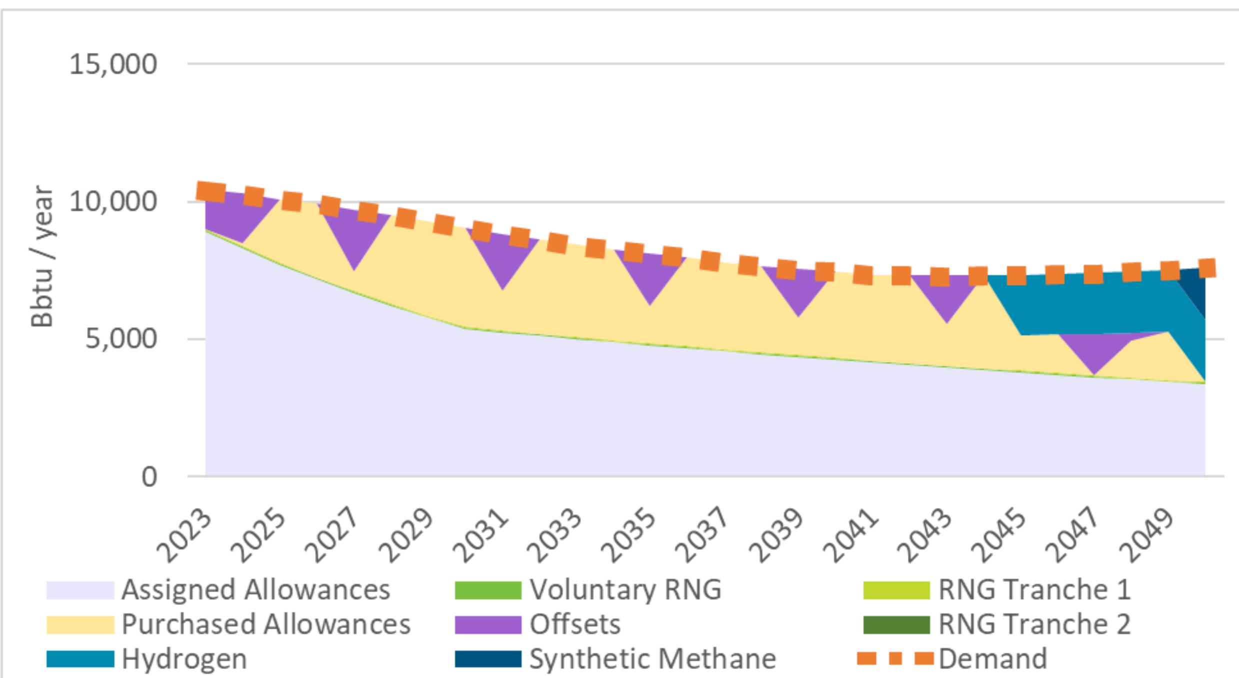



**Figure 7.10: Washington Carbon Neutral - Compliance Resources**



## 7.7 New Customer Moratorium

**Figure 7.11: Oregon New Customer Moratorium - Compliance Resources**

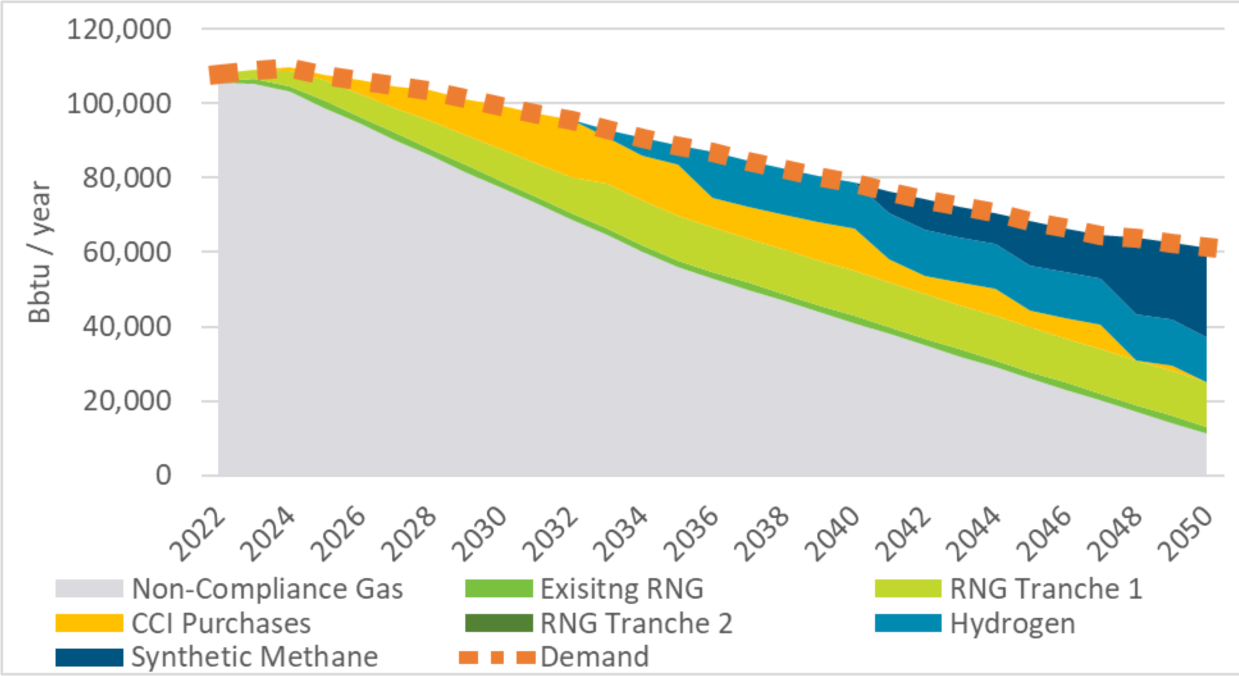
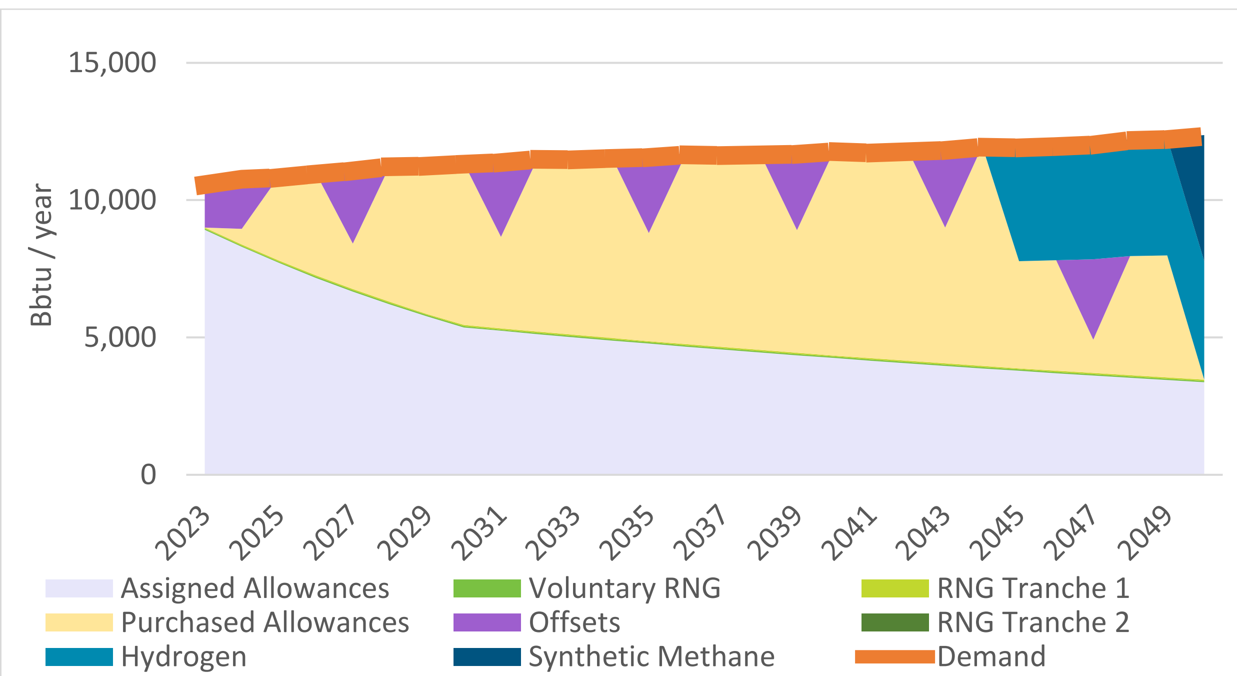



**Figure 7.12: Washington New Customer Moratorium - Compliance Resources**



## 7.8 Building Electrification

**Figure 7.13: Oregon Building Electrification - Compliance Resources**

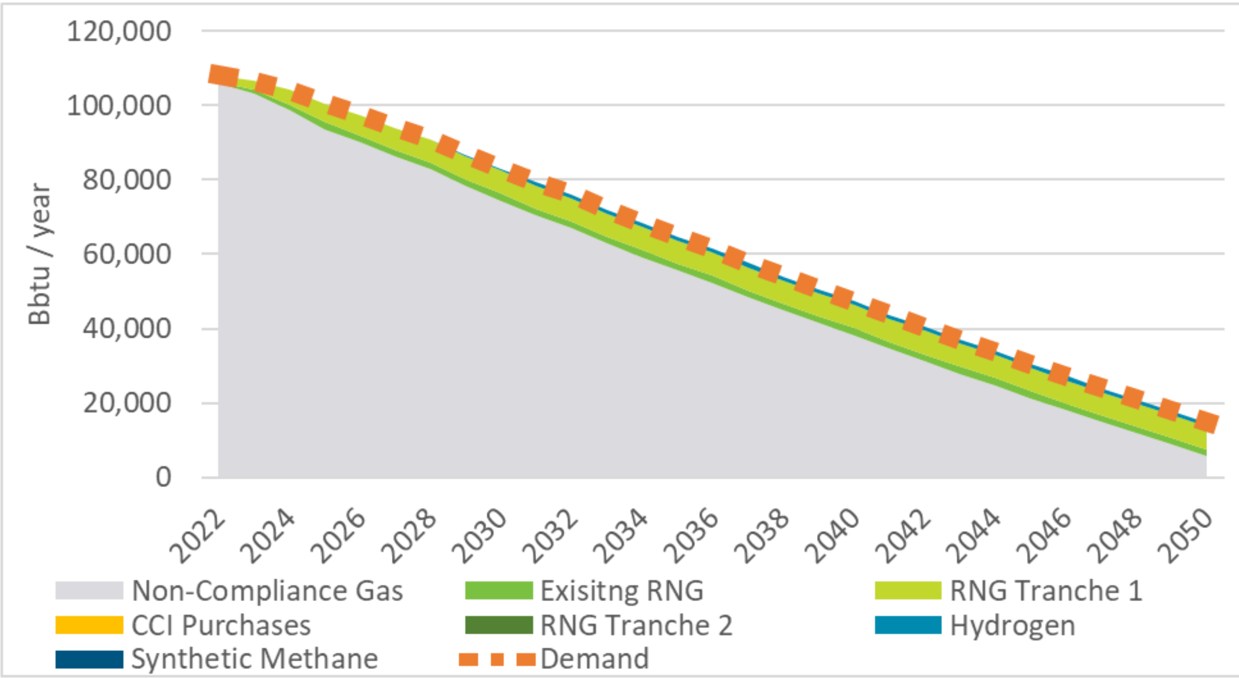
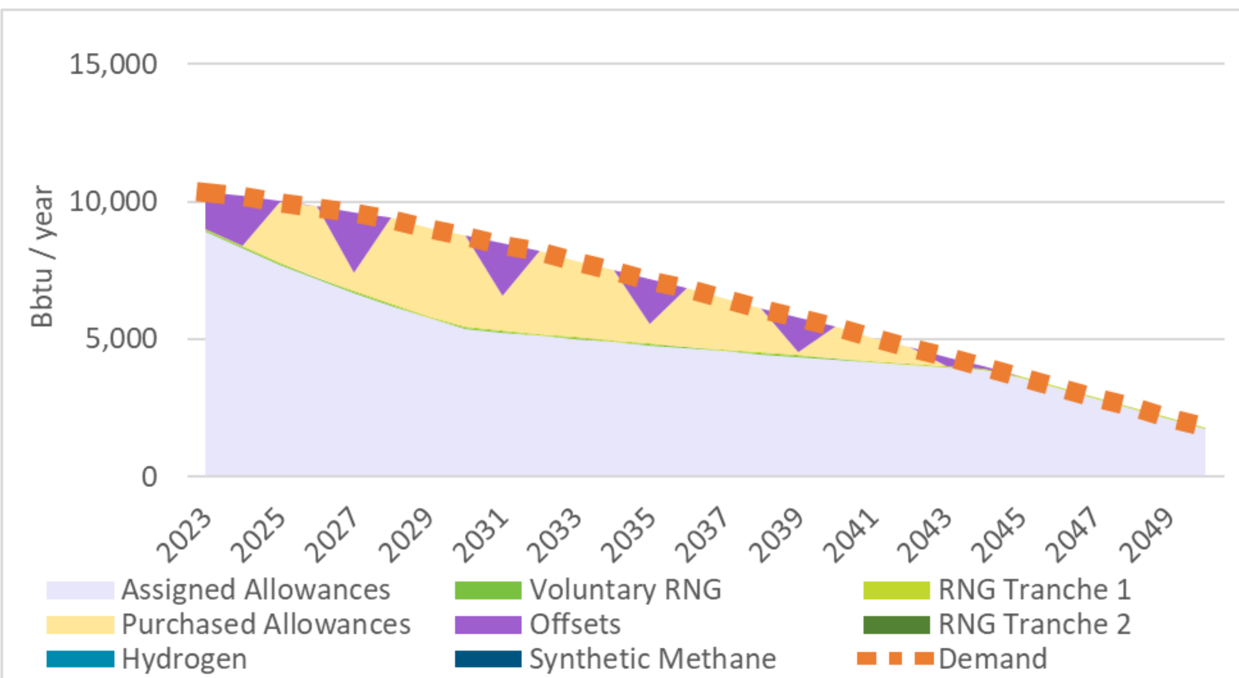



**Figure 7.14: Washington Building Electrification - Compliance Resources**



## 7.9 RNG&H2 Federal Policy Support

**Figure 7.15: Oregon RNG&H2 Federal Policy Support - Compliance Resources**

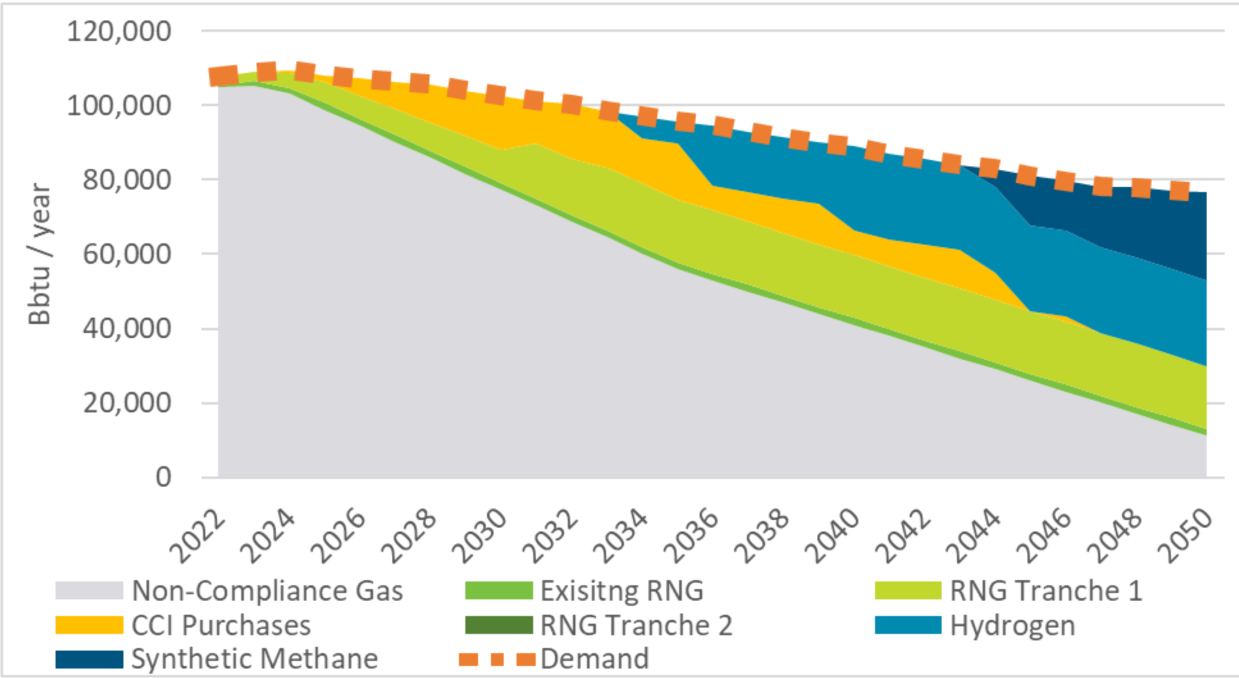
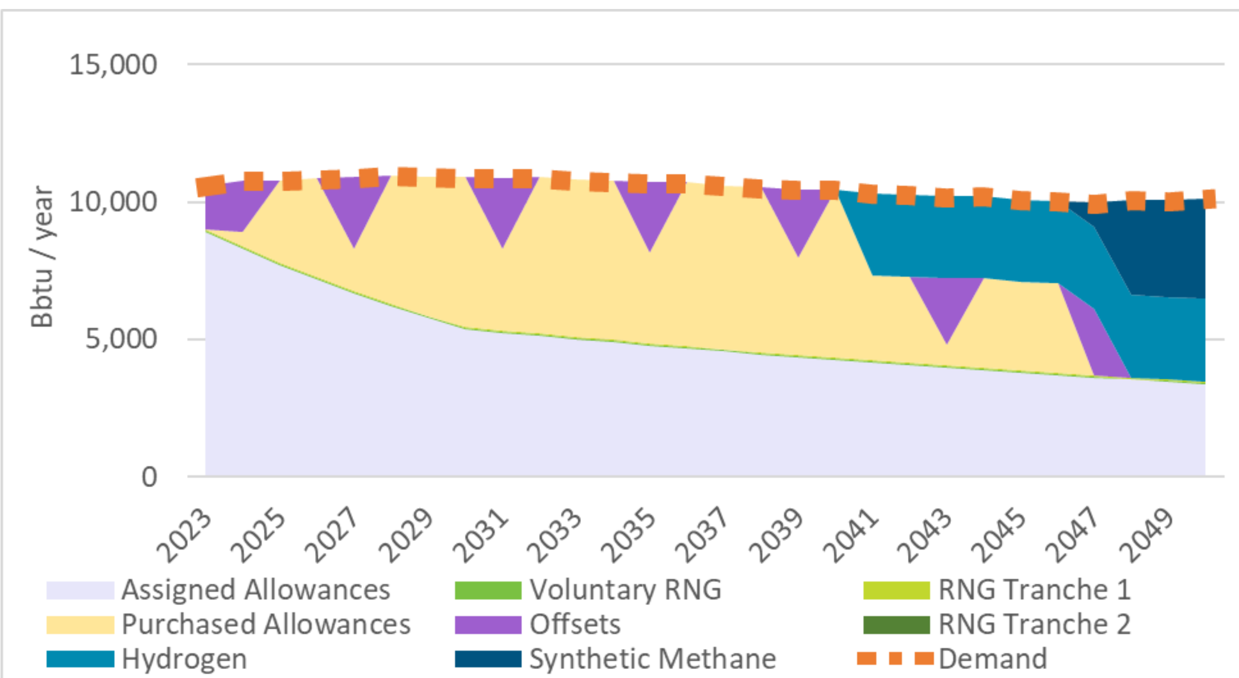



**Figure 7.16: Washington RNG&H2 Federal Policy Support - Compliance Resources**



## 7.10 Limited RNG Availability

**Figure 7.17: Oregon Limited RNG Availability - Compliance Resources**

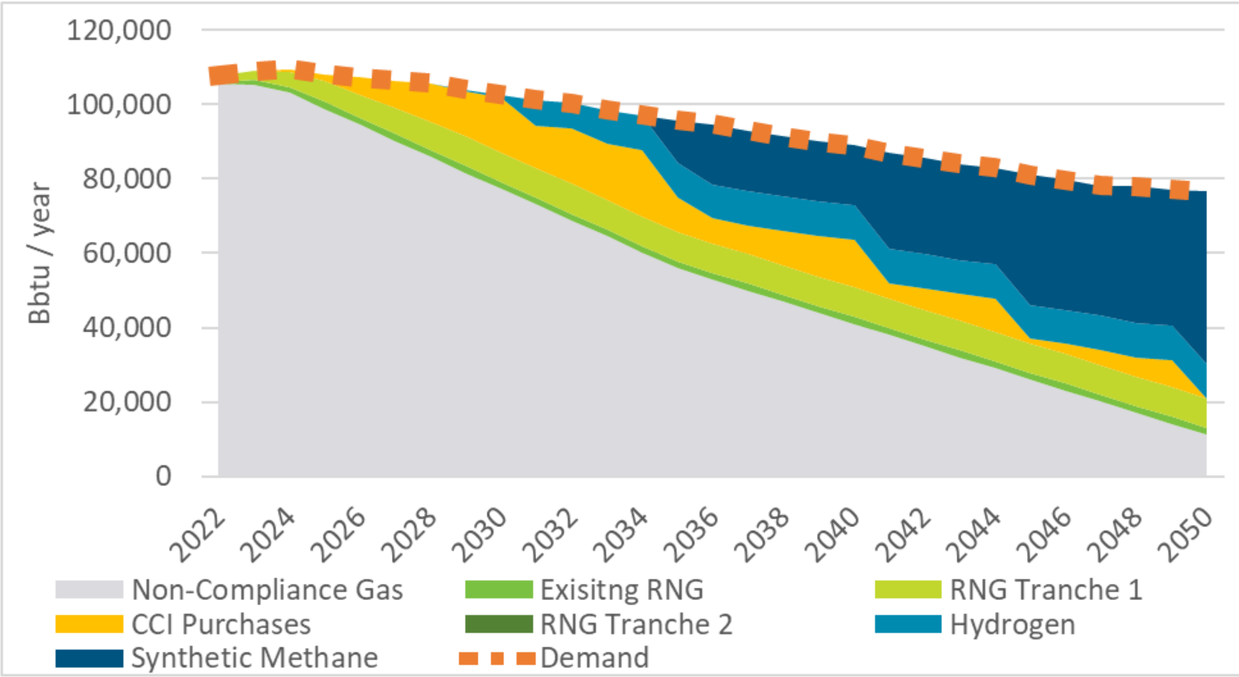
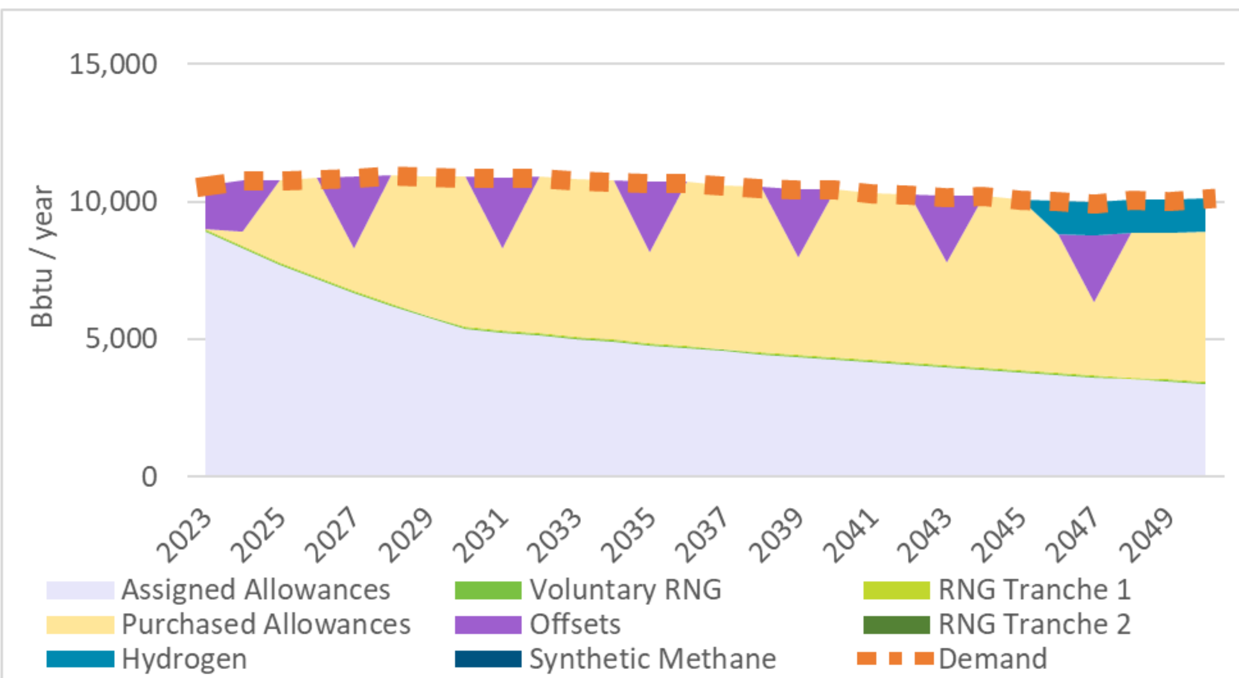



**Figure 7.18: Washington Limited RNG Availability - Compliance Resources**



## 7.11 Supply-Focused Decarbonization

**Figure 7.19: Oregon Supply-Focused Decarbonization - Compliance Resources**

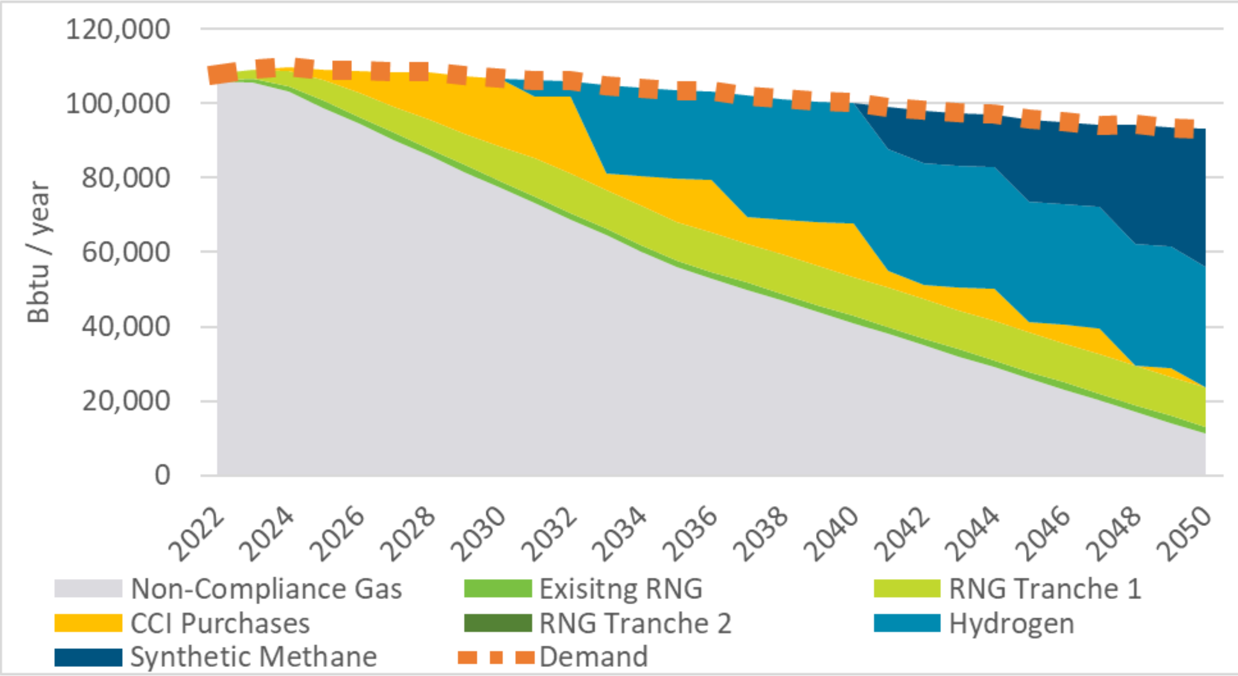
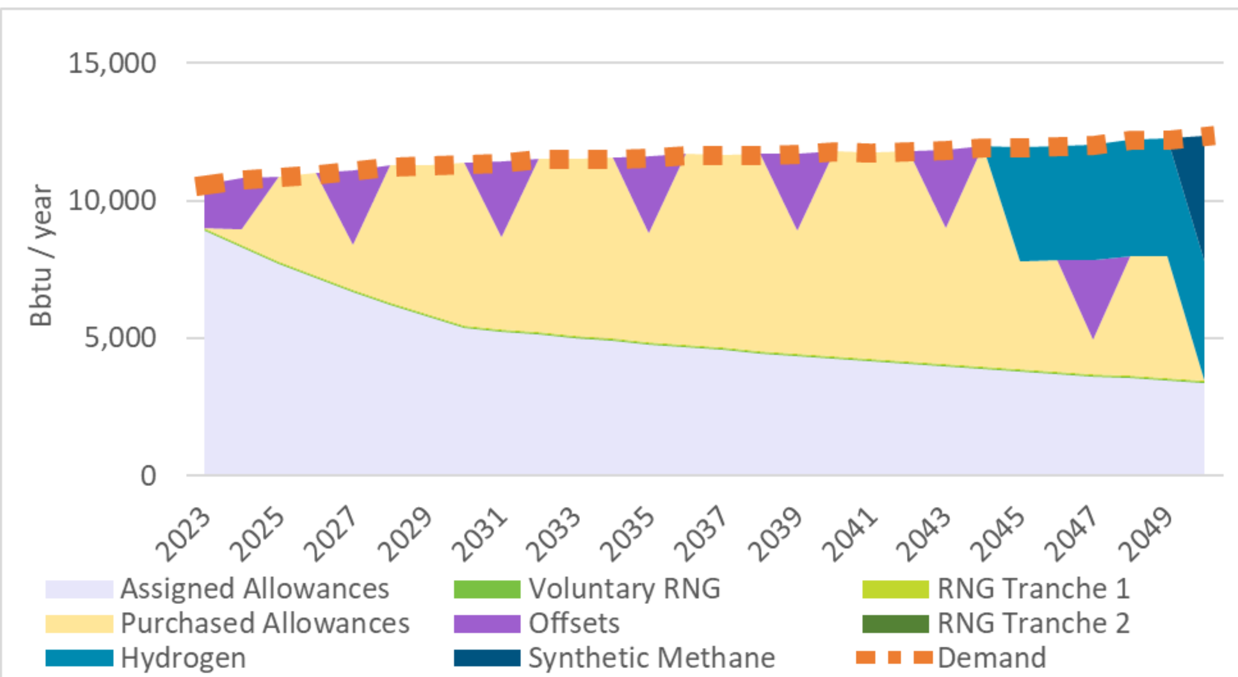



**Figure 7.20: Washington Supply-Focused Decarbonization - Compliance Resources**



The base case shows that in the OR-CPPs first compliance period (2022-2024) expected SB 98 RNG – of which biofuels are shown as the lowest cost option – make up the majority of the needed compliance action. In the base case a small amount of the lowest cost incremental option – CCIs – are needed in 2024. This result, that SB 98 RNG is supplemented by CCIs as needed is seen in all scenarios. In no scenario does the CCIs projected approach the limit for CCIs in the first compliance period. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e. not “wasted” in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs in excess of SB 98 a robust option.

Looking at the base case and across scenarios shows a consistent trend in expected emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resources, expected to become cheaper than CCIs and WA allowances in later years in the planning horizon.

For compliance with the Washington Cap-and-Invest program the results show that it is expected that offsets are the lowest cost compliance option, and if compliance offsets can be procured at prices seen in today’s market that they should be acquired to the maximum amount and used for compliance. There is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance.  Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. As such a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios.

# Chapter 8
# Distribution System Planning

## 8.1 Introduction

Distribution System Planning is an IRP unto itself. It requires a very similar process of identification of needs at the distribution level, identification of resources both demand-side and distribution supply side, and then a risk-adjusted resource selection. Some of the unique aspects of distribution system planning include:

- Demand: Forecast peak hour usage for the area in question net of demand-side actions
- Supply: Model distribution system based on actual pipe placement and specifications
- Modeling: Use of different software/modeling tools to simulate system under peak conditions and/or use field measurements during cold periods
- Apply system planning criteria to identify areas of concern before planning criteria are exceeded – Ongoing field monitoring of pressures and customer growth informs which areas to investigate

This chapter discusses NW Natural's distribution system planning process and includes an overview of our needs assessment process and tools including our improved engineering and computer modeling methods that allow for more forward-looking distribution system planning. This is followed by a discussion about our distribution system resources both existing and future options in addition to pipeline and non-pipeline solutions. The chapter concludes with the identification and discussion of a distribution project included in the action plan.

## 8.2 Distribution System Planning Process

NW Natural's distribution system planning process ensures that NW Natural:

- Operates a distribution system capable of meeting firm service customers' peak hour demands
- Minimizes system reinforcement costs by selecting the most cost-effective alternative
- Plans for future needs in a timely fashion
- Addresses distribution system needs related to localized customer demand

The goals of distribution system planning are the design of a distribution system meeting firm service customers' current natural gas needs under peak hour conditions[1] and to plan for reinforcement to serve future firm service requirements. Distribution system planning identifies operational problems and areas within the distribution system requiring reinforcement due to existing requirements and/or future requirements based on load indicators. By knowing where and under what conditions pressure problems may occur, NW Natural can incorporate

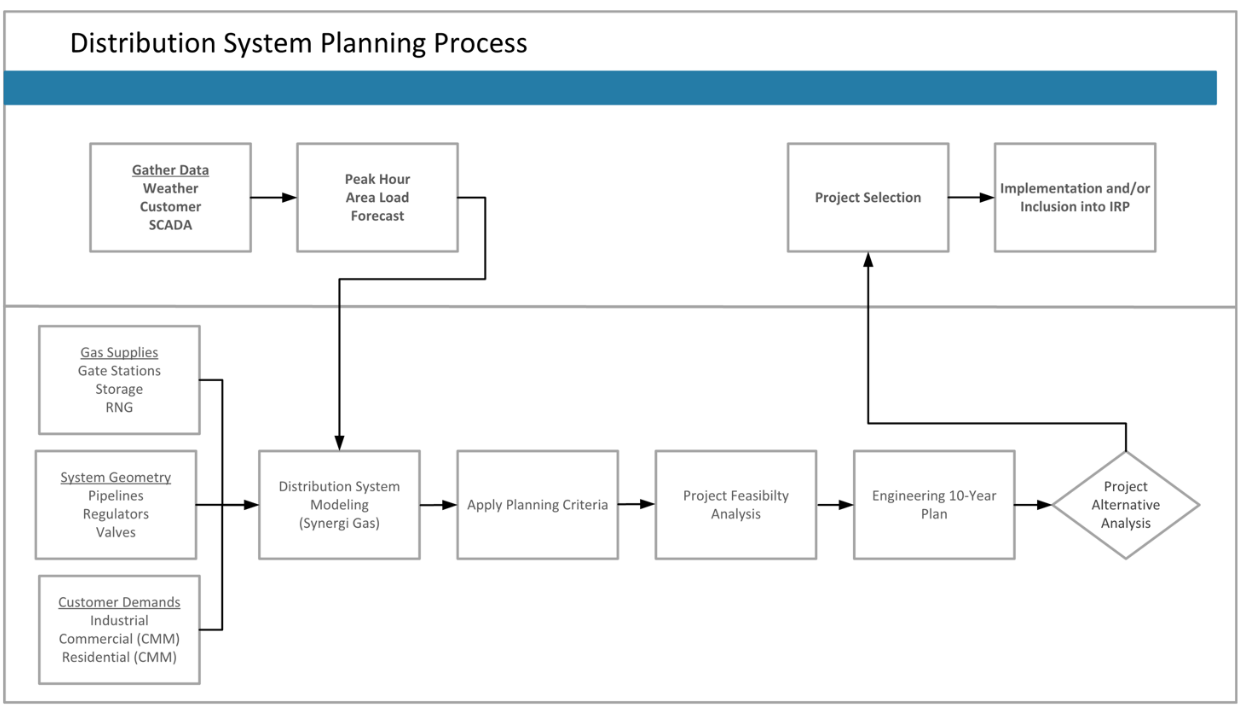
[1] NW Natural uses a peak hour standard for distribution system planning, as usage by firm service customers over a 24-hour period in colder weather has a diurnal pattern that includes an hour in which use is maximal. NW Natural discussed its peak hour standard with stakeholders in the fifth Technical Working Group meeting. See also the discussion of use of peak day load forecasts in Chapter Three.

necessary reinforcement projects into annual budgets and distribution project planning thereby avoiding costly reactive and potential emergency solutions.

NW Natural's engineering department—collaborating with the construction and marketing departments and incorporating input from external economic development and planning agencies—plans the expansion, reinforcement, and replacement of NW Natural's distribution system facilities. This planning process requires forecasting customer peak hour demand, determining potential distribution system constraints, analyzing potential solutions, and assessing the costs of viable alternatives. Planning is ongoing and integrates the requirements associated with known public works projects, customer growth, and other aspects into NW Natural's construction forecasts.

NW Natural's engineering department annually reviews and updates a forward looking 10-year plan for larger projects. The 10-year plan provides budgetary forecasts and company-wide vision and prioritization to the distribution system planning process. NW Natural selects projects from the 10-year plan for inclusion in the IRP based on estimated cost, system needs, supply implications, as well as timing considerations related to the IRP.

**Figure 8.1: Distribution System Planning Process**




For projects that will be completed within one to three years, NW Natural's distribution system engineers complete a planning process that documents system modeling and modeling results, selects an initial route where a new pipeline facility is indicated, provides an associated high-level cost estimate, and includes an analysis of alternatives, which NW Natural discusses in Section 8.5. These projects may be included in the IRP action plan. Figure 8.1 shows the distribution system planning process in a flow chart diagram.

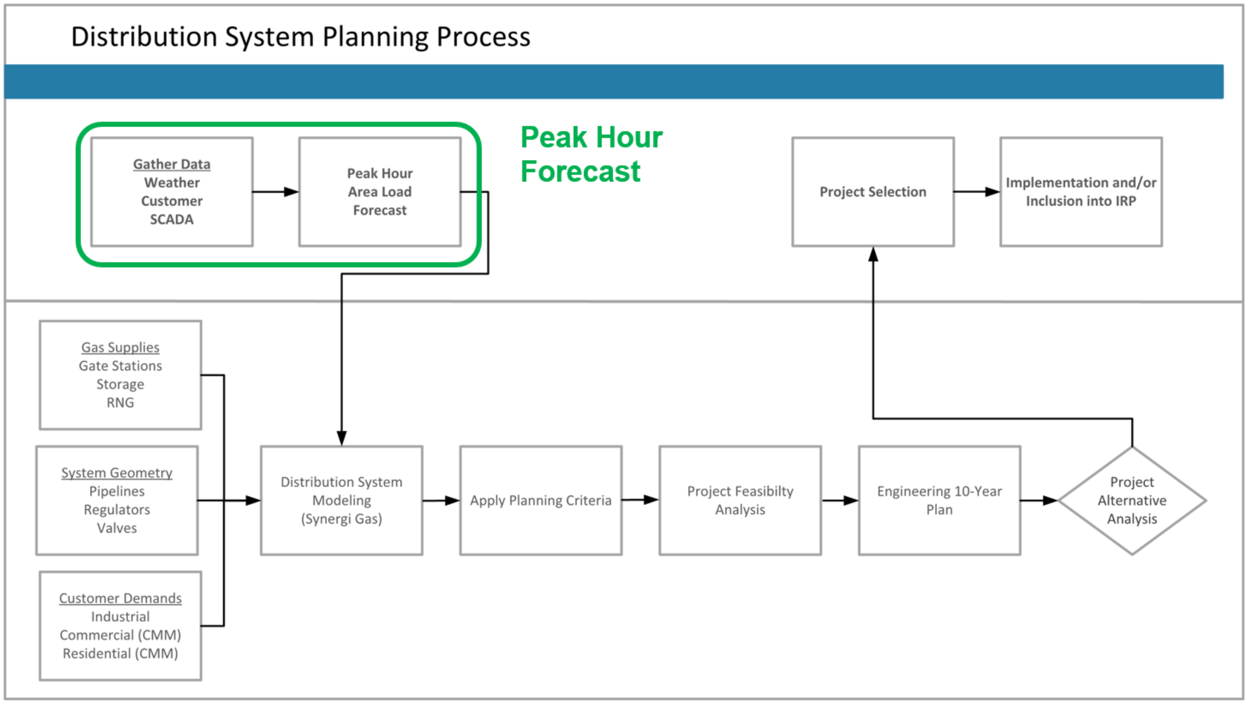
Projects that are forecasted to be completed within a four-to-seven-year timeframe include a project description, preliminary modeling documentation, preliminary schedule, and a high-level cost estimate. A project to be completed in the fourth year is likely to be an action item in the current IRP, while a project targeted for completion in years five through seven may be an action item in a future IRP.

Projects to be completed in the eight-to-ten-year timeframe include preliminary modeling documentation and a high-level cost estimate. Project planning associated with issues having this timeframe for resolution is at the conceptual level only and discussion of such projects are not typically included in an IRP unless very significant investments are indicated.

## 8.3 Forecasting Peak Hour Load

As can be seen in Figure 8.2, determining peak hour load/demand is a critical part of distribution system planning as it establishes the minimum criterion for meeting customer needs. The peak hour load forecast is the goal which must be met by the capacity of the piping network.

**Figure 8.2: Distribution System Planning Process – Peak Hour**




Much as NW Natural's peak day load forecast informs our supply resource planning, peak hour load forecasting provides an input into distribution system planning. Peak hour forecasts augment the daily system load model process with forward-looking, statistically derived forecasts of hourly load in specific geographic areas of NW Natural's service territory. NW Natural included peak hour load forecasts in its 2016 IRP process,[2] redefined its peak planning standard for both peak day and peak hour forecasts in the 2018 IRP and has applied the same peak planning standard in the 2022 IRP. NW Natural monitors, updates, and works to improve NW Natural's peak load forecast models and aspires to synchronize and adapt its peak hour load modeling process to optimally support an overall transition to a fully forward-looking distribution system planning process.

### 8.3.1 Estimating Peak Hour Load

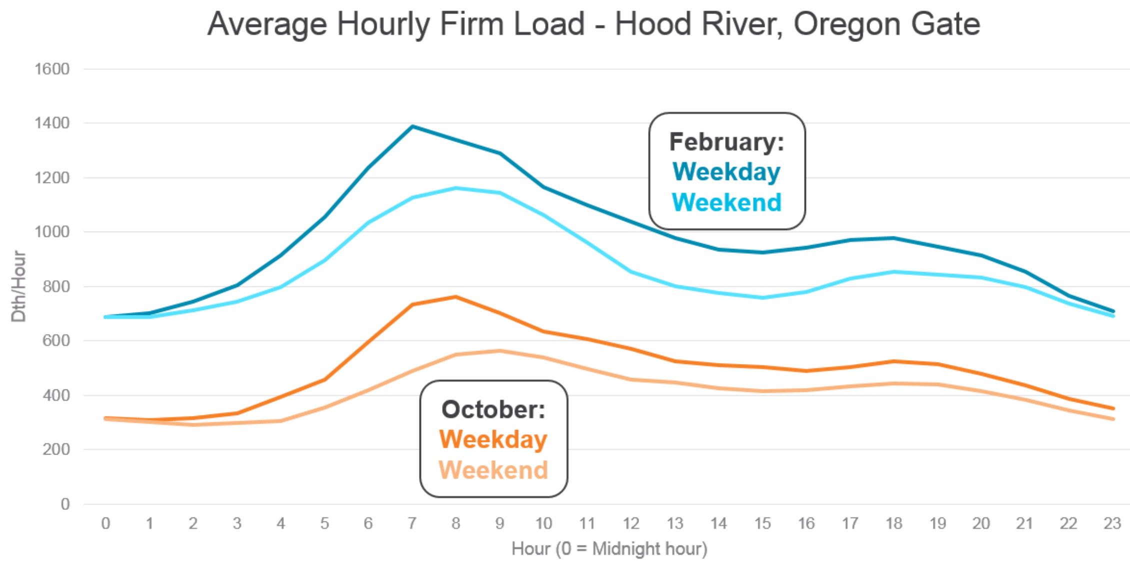
The peak hour modeling methodology generally follows that of the peak day forecasts while incorporating more granular geographic and time dimensions. Regression analysis is used to establish the statistical relationships between measured firm sales and firm transportation load in a given area with local weather variables—temperature, wind, sunshine, source water temperature, and snow depth—as well as customer counts, day of the week, holiday occurrences, and time trends. Because distribution system planning involves relatively small geographic areas, peak hour load forecasts use similarly localized input data—weather and customer counts, for example. These regression models also derive historical relationships

[2] See Chapter Three and Appendix C in NW Natural's 2016 IRP.

between hourly geographic load and global variables (such as holiday occurrences) that do not vary across locations.

One of the primary differences between peak hour and peak day models is the presence of time-of-day effects. The intraday load shape of the natural gas system typically exhibits an early morning peak followed by a midday taper, before a smaller peak in the late afternoon (see Figure 8.3 as an example). The morning peak is typically lower and later on weekend days.

**Figure 8.3: Hood River Area Intraday Load Shapes**



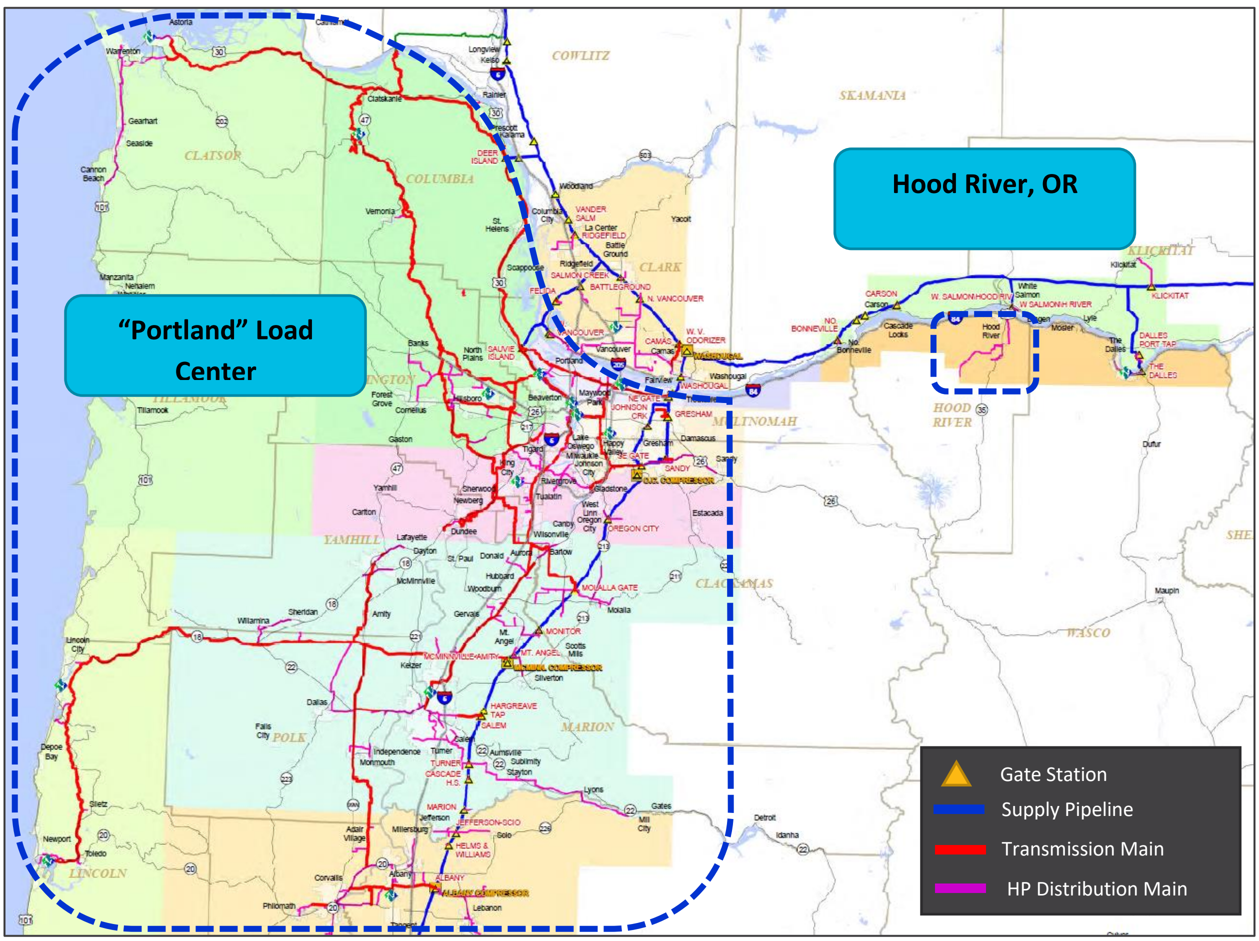

Temperature alters hourly effects, as it does the effects of other weather variables.[3] When temperatures stay cold on average throughout the day—on dark, wintry days in February, for example—the intraday load shape is less pronounced than one during the shoulder season, when midday high temperatures diverge further from nighttime lows and space heating needs fluctuate more substantially. To capture these nuanced dynamics, peak hour load models incorporate effects that are specific to the hour and day of the week (i.e., 72 indicator variables for each hour of a weekday, Saturday, and Sunday), which interact with temperature.

The second unique feature that differentiates peak hour load from peak day load is the narrower geographic relevance of the former concept. Whereas load on a peak day defines the resource capacity required to ensure that adequate gas resources be delivered on NW Natural's system, the ability to deliver gas to customers at any moment depends on very specific segments of NW Natural's distribution system, as outlined earlier in this chapter. Thus, area-specific hourly load and granular weather data is required in place of the system-level inputs of

[3] For a full discussion of load forecasting variables and their interactions, please see Chapter Three, Load Forecast.

the peak day model. Although gas demand must be met in any given instant, the time dimension granularity is constrained to hourly due to data limitations.[4] The geographic granularity of peak hour modeling is constrained by the availability of data. For example, the area served downstream of the Hood River, Oregon, gate station (Figure 8.4) represents a "system within a system" along a single distribution main, where hourly flow measured at the gate station can be isolated from the rest of NW Natural's distribution system. In contrast, customers in the broader Portland, Oregon, metropolitan area draw gas past multiple SCADA meters at receipt points that also serve other areas of the distribution system (as distant as Salem, Oregon), making it impossible to isolate the hourly load of just those customers within a given neighborhood within the metro area.

**Figure 8.4: Hood River and Portland, Oregon, Distribution Systems**




At this time, most of NW Natural's distribution system is oriented and metered more like the Portland metro area than like Hood River. Hood River's internal interconnectivity, while

---

[4] High frequency meters for customers on interruptible or transportation rate schedules record hourly flows. Additionally, weather data is at best available on an hourly frequency. Hourly data is sufficient for the needs of the distribution system planning process.

necessary and beneficial from an operations standpoint, limits the ability to isolate small areas for econometric load forecasting. A summary of peak hour load standards and latest available forecast for the feasible portions of the NW Natural distribution center follows in the next section.

### 8.3.2 Peak Hour Loads

Generally, the isolatable areas within NW Natural's distribution system are at least as large as (and often larger than) its constituent load centers. However, there are smaller areas for which econometric load forecasting is feasible, such as the area served by the Hood River gate. Forecasts are thus defined by the narrowest possible geography from which hourly data is obtainable. Table 8.1 summarizes the broad areas for which econometric peak hour load forecasting is currently feasible; smaller exceptions are omitted. Note that several load centers are subsumed by a functionally interlinked "Portland" area.

**Table 8.1: Areas with a Peak Hour Load Forecast**

| Area | Description |
|---|---|
| Vancouver load center | NW Natural's service areas in Clark County Washington |
| "Portland" | NW Natural service areas in Benton, Clackamas, Clatsop, Columbia, Lincoln, northern Linn, Marion, Multnomah, Polk, Washington, and Yamhill counties in Oregon |
| Eugene load center | NW Natural's service areas in Lane and southern Linn counties in Oregon |
| Columbia River Gorge-OR load center | NW Natural service areas in Hood River and Wasco counties in Oregon |
| Columbia River Gorge-WA load center | NW Natural service areas in Skamania and Klickitat counties in Washington |
| Coos Bay load center | NW Natural service areas in Coos County Oregon |

The conditions that produce peak hour loads across NW Natural's system clearly vary by location, necessitating area-specific peak hour planning standards. Analogous with the statistically-based approach of NW Natural's peak day planning standard,[5] an area's peak hour is defined by the level of firm resources that provide a 99% probability of meeting the highest firm hourly load in a gas year. Once area-specific relationships between hourly flow and its driver variables are estimated, they are applied to the area-specific peak planning standard, producing a benchmark that is incorporated into a forward-looking distribution system planning process.

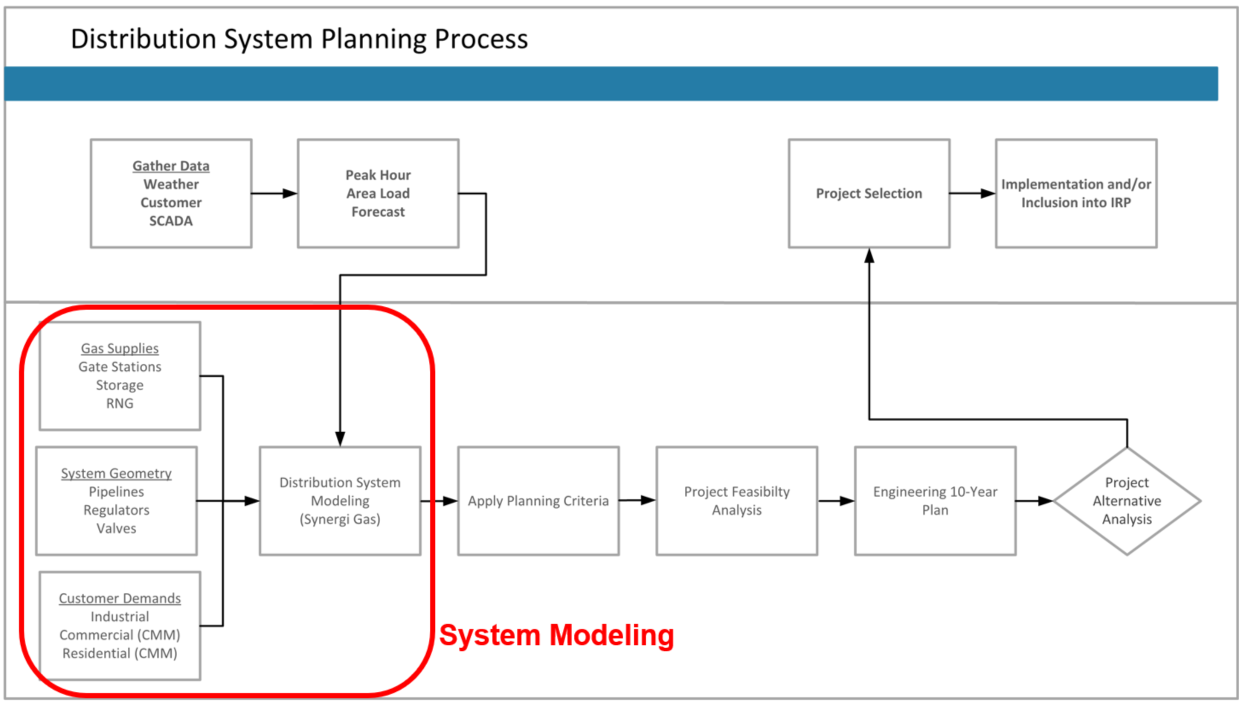
[5] See Chapter Three for a detailed discussion of NW Natural's peak day planning standard.

## 8.4 Distribution System Planning Tools and Standards

### 8.4.1 System Modeling

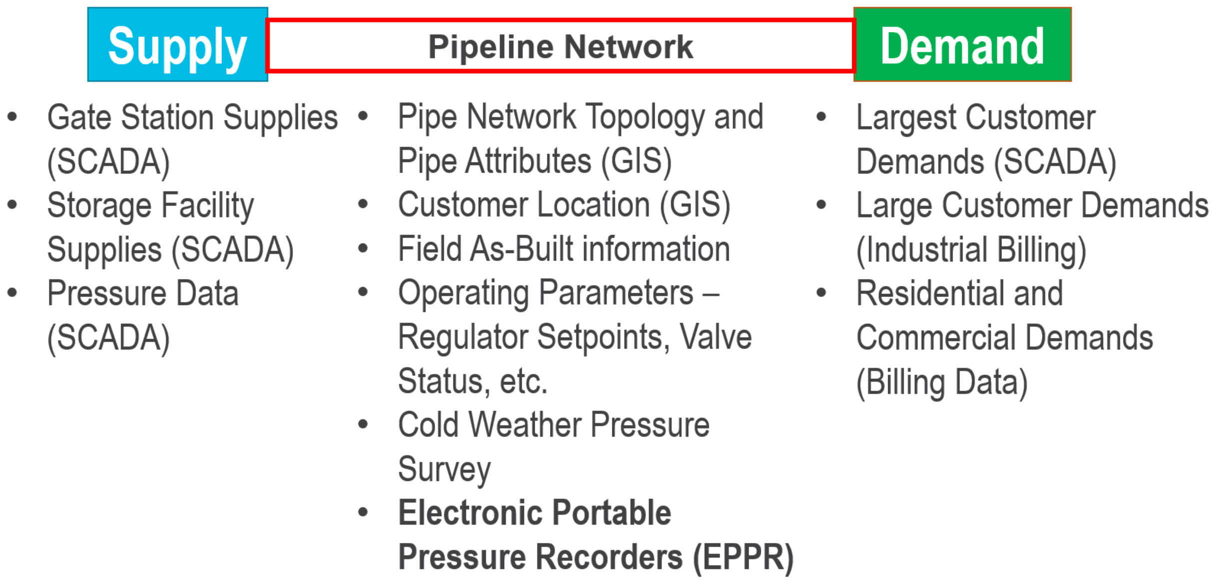
As shown in Figure 8.5, system modeling is an important part of the distribution system planning process. Modeling allows accurate simulation of different aspects of NW Natural's system, from the delivery of natural gas from supplies, through NW Natural's pipeline networks, to customer locations.

**Figure 8.5: Distribution System Planning Process – System Modeling**




As is shown in Figure 8.6, a Synergi Gas™ model contains detailed information regarding a specific portion of NW Natural's system, such as pipe size, length, pipe roughness, and configuration; customer loads; source gas pressures and flow rates; regulator settings and characteristics; and more. The model is based on information from NW Natural's Geographical Information System (GIS) for the piping system configuration and pipe characteristics; from the Customer Information System (CIS) for customer load sizing; and from the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, and supply flows and pressures.

**Figure 8.6: Data Used in Synergi™ Models**




Synergi™ uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A Synergi™ model shows flows and pressures at every point in the modeled system and, when balanced, the relationship between flows and whether pressures at all points in the modeled system are within tolerances specified by NW Natural's engineering staff. A properly designed Synergi™ model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi™ models rely on assumptions about the actual system, and therefore modeling results may vary from actual results. Synergi™ models are a representation of the actual system and the outputs of these models are a static snapshot of expected system conditions under the provided data.

NW Natural will occasionally run a field data collection process called a Cold Weather Survey to collect system pressures during cold weather conditions. Additionally, NW Natural has approximately a dozen Electronic Portable Pressure Recorders (EPPR) which are sited at locations with suspected low pressures. EPPR data includes pressure and temperate reads summarized in hourly intervals. NW Natural uses both EPPR data and Cold Weather Survey pressure data to validate Synergi™ modeled results.

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™ 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™ 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.

### 8.4.2 Customer Management Module (CMM)

In 2021, NW Natural completed the implementation of the Customer Management Module (CMM). CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi Gas™. CMM is created by DNV, which is the same developer who produces the Synergi Gas™ software. In summary, CMM provides the ability to:

- Import each customer's billing data from CIS and calculate a per customer demand based on daily temperature
- Update customer information such as rate schedule, status (active or inactive), and changes in forecasted consumption
- Assign each customer's load to the closest appropriate facility

CMM can apply historical billing and temperature data to calculate the demands of each customer. CMM has an option that allows Synergi Gas™ users to provide their own model demands for each customer. Previous modeling methods utilized area-specific averages for residential and small commercial customers. For example, residential and small commercial customers in the Portland metropolitan area were previously assigned the same demand in the Synergi Gas™ models, whereas CMM allows customer-specific usages based on historical consumption. The benefits of providing billing data are related to accurately modeling local system pressures because consumption is now based on historical usage, rather than localized averages.

Being connected to the CIS system allows NW Natural to update customer information in the production models, including whether customers are identified as active or inactive. 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 conditions. The connection to the CIS system provides updates to add or remove demand based on whether the customer is assigned a firm or interruptible rate schedule. CMM allows NW Natural to generate new demands from real-time data if a customer changes their usage patterns.

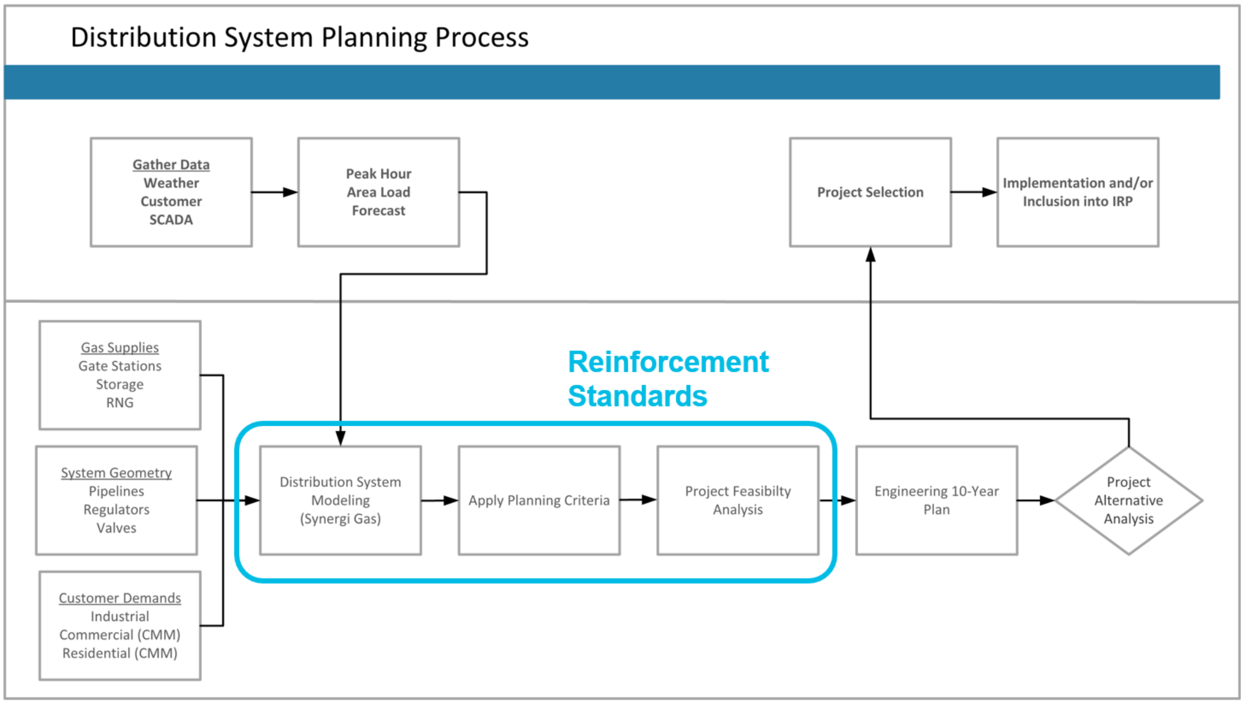
The modeling software requires that customer demands be properly assigned to the correct location in the gas distribution system. When demands are accurately assigned to the correct position in Synergi Gas™, it allows modelers to evaluate localized system pressure conditions. Previous models do not utilize the same coordinated system as the GIS system. CMM based models are required to have the same coordinate system as the GIS system. This requirement makes it mandatory for new models to be developed in order to take advantage of CMM features.

Model creation using CMM data was prioritized based on locations that were identified to have near-term needs. The distribution planning project introduced later in this chapter was modeled using CMM. NW Natural is in the process of updating all models to incorporate the benefits provided by CMM.

### 8.4.3 System Reinforcement Standards

As shown in Figure 8.7, system reinforcement standards are a required component of the distribution system planning process. The standards are based on multiple indicating 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 8.7: Distribution System Planning Process – Reinforcement Standards**




Transmission and high-pressure distribution systems (systems operating at greater than 60 psig[6]) 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:

- Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated
- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization
- Considering minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high-pressure systems
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- The ability to meet firm service customer delivery requirements (flow or pressure)
- Being identified in the IRP associated with supply requirements or needs

[6] Pounds per square inch gauge: a standard measure of pressure within a pipeline facility.

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:

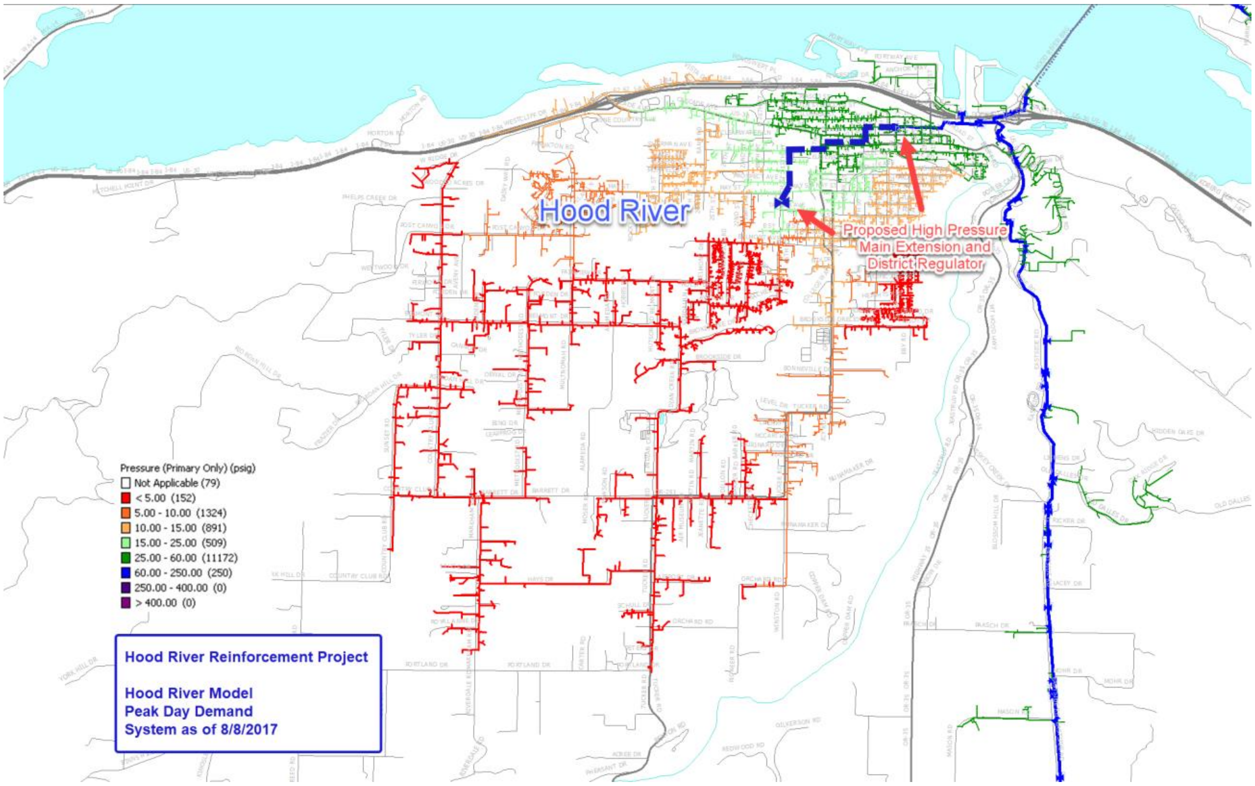
- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated
- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- Firm service customer delivery requirements (flow or pressure)

### 8.4.4 Identification of Distribution System Needs

Accurate modeling and forecasted level of peak hour demand combine to indicate how the distribution system would operate on a 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 example, and as shown in Figure 8.8, an area of the Class B distribution system[7] in Hood River is forecasted, by modeling, to experience low system pressures or outages on a peak hour. This modeling was validated in January of 2017 when several customer outages occurred in the Hood River area under non-peak conditions. Areas with pressure below 10 psig are indicated in orange and red colors, while areas with more satisfactory pressure are indicated with shades of green. Note that the Hood River Class B distribution system is located within the Columbia River Gorge-Oregon load center, is served by a single gate station on Northwest Pipeline (NWPL) and is not connected to other parts of NW Natural's distribution system.

[7] Class B systems are those operating at 60 psig or less.

**Figure 8.8: Illustration of Hood River Area Pressure Issues**




## 8.5 Distribution System Resources

### 8.5.1 Existing Distribution System

NW Natural's gas distribution system consists of approximately 14.6 thousand miles of transmission and distribution mains, of which approximately 87% are in Oregon with the remaining 13% in Washington.

Coos County Pipeline located in Oregon consists of approximately 86 miles of transmission main. Coos County Pipeline is operated by NW Natural on behalf of Coos County.

NW Natural's Oregon service area includes 39 gate stations[8], approximately 954 district regulator stations and 2 renewable natural gas (RNG) production sites. 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 Six. NW Natural's Washington service area includes 15 gate stations and approximately 78 district regulator stations.

[8] Gate station values for both Oregon and Washington include all upstream pipeline interconnections, including farm taps.

NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, a liquefied natural gas (LNG) trailer rated at 900 Dth capacity, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of cold weather operations, or while conducting pipeline maintenance procedures.

### 8.5.2 Future Distribution System Planning Resources

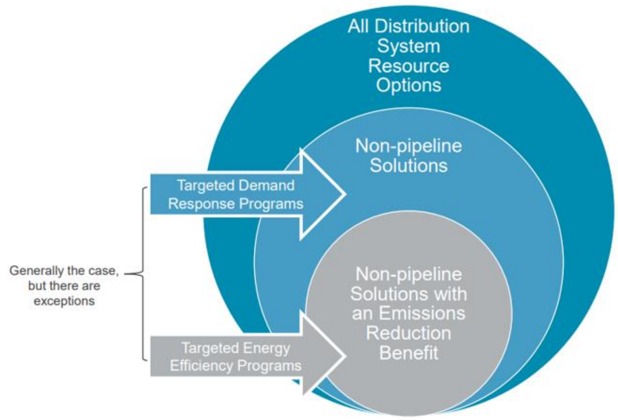
Similar to system planning, alternatives both demand-side and supply-side are evaluated. Distribution System Planning Resource Options can be seen in Figure 8.9.

**Figure 8.9: Distribution System Planning Alternatives**

<table>
<tr><th colspan="4">Distribution System Planning Alternatives<br>(not all options are possible or applicable in all situations)</th><th>Option Currently Considered for Cost-Effectiveness Evaluation</th></tr>
<tr><td rowspan="11">Supply-Side Alternatives</td><td colspan="2" rowspan="7">Pipeline Related Capacity Options</td><td>Loop existing pipeline</td><td>✓</td></tr>
<tr><td>Replace existing pipeline</td><td>✓</td></tr>
<tr><td>Install pipeline from different source location into area</td><td>✓</td></tr>
<tr><td>Uprate existing pipeline infrastructure</td><td>✓</td></tr>
<tr><td>Add or upgrade regulator to serve area of weakness</td><td>✓</td></tr>
<tr><td>Gate station upgrades</td><td>✓</td></tr>
<tr><td>Add compression to increase capacity of existing pipelines</td><td>✓</td></tr>
<tr><td rowspan="9">Non-Pipeline Solutions</td><td rowspan="4">Distributed Energy Resources (DER)</td><td>Mobile/fixed geographically targeted CNG storage</td><td>✓</td></tr>
<tr><td>Mobile/fixed geographically targeted LNG storage</td><td>✓</td></tr>
<tr><td>On-system gas supply (e.g. renewable natural gas, H2)</td><td>✓</td></tr>
<tr><td>Geographically targeted underground storage</td><td>✓</td></tr>
<tr><td rowspan="5">Demand-Side Alternatives</td><td rowspan="3">Demand Response</td><td>Interruptible schedules (DR by rate design)</td><td>✓</td></tr>
<tr><td>Geographically targeted interruptibility agreements</td><td>✓</td></tr>
<tr><td>Geographically targeted Res & Com demand response (GeoDR)</td><td></td></tr>
<tr><td rowspan="2">Energy Efficiency</td><td>Peak hour savings from normal statewide EE programs</td><td>✓</td></tr>
<tr><td>Geographically targeted peak-focused energy efficiency (GeoTEE)</td><td></td></tr>
</table>

As shown in Figure 8.9, non-pipeline solutions are alternative distribution resource solutions to distribution system planning identified needs. These solutions can be both supply-side and demand-side resources and will be discussed in each section. These solutions must reliably serve customers by helping to either serve or reduce load during a peak event. These solutions are evaluations for cost effectiveness along with other solutions. As shown in Figure 8.10, some non-pipeline solutions (such as Targeted Energy Efficiency) also have an emissions benefit but not all (as in the case of demand response).

**Figure 8.10 Purpose of Non-pipeline Solutions**




### 8.5.3 Supply-side Options – Pipeline-related Resources

Once NW Natural identifies a distribution system issue, in addition to Demand-Side alternatives, the Company considers multiple traditional pipeline solutions for addressing the issue. These traditional pipeline solutions may include:

- Pipeline construction
- Equipment addition (district regulators, compressor stations)
- Additional gas supply (gate station changes)
- Operating pressure uprates

The objective is to identify the most efficient, least cost, least risk solution for the identified issue. NW Natural validates the identified solution with models and field testing to verify effectiveness.

Having adequate pressure on the distribution system is crucial for reliably delivering gas to customers. Traditional pipelines are included in the alternative analysis as a solution to improve system pressures in areas with low pressures by installing new distribution pipelines or uprating existing distribution pipelines.

#### *Pipelines*

One option to remediate low pressures is installing new distribution pipelines to increase the capacity of a distribution system. The proposed distribution pipeline would transport higher pressure gas to areas with weak pressures. A distribution pipeline system reinforcement increases pressures in weak areas, lowering the potential for customer outages.

NW Natural's Engineering Department completes pipeline feasibility studies to develop potential pipeline projects to address low pressure areas. The selection criteria include: distribution pipeline distance, operating pressure, material, pipeline diameter, load type, and existing network architecture. The three major types of distribution pipeline installations related to system reinforcements are provided below:

1. Distribution Pipeline Extensions – Installation of gas distribution pipeline using a new alignment. A new distribution pipeline delivers higher pressure gas to an area of need, increasing the pressure and reliably 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 that is constructed parallel to an existing distribution pipeline. The looped mains are tied-in, decreasing the flow on the original pipeline, which reduces pressure drop along the original pipeline.

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 the path a pipeline solution might take, 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.

### *Uprating*

Typically, 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 operating at a higher 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 limitations that prevent a distribution system pipeline from operating at a higher MAOP.

Table 8.2 shows the capacity for a five-mile, six-inch steel pipeline for varying operating pressures. The table shows that a pipeline operating at 600 psig has approximately six times more capacity than a pipeline operating at 100 psig. A major benefit of uprating is that incremental capacity can be provided through existing distribution pipelines by operating them at higher pressures.

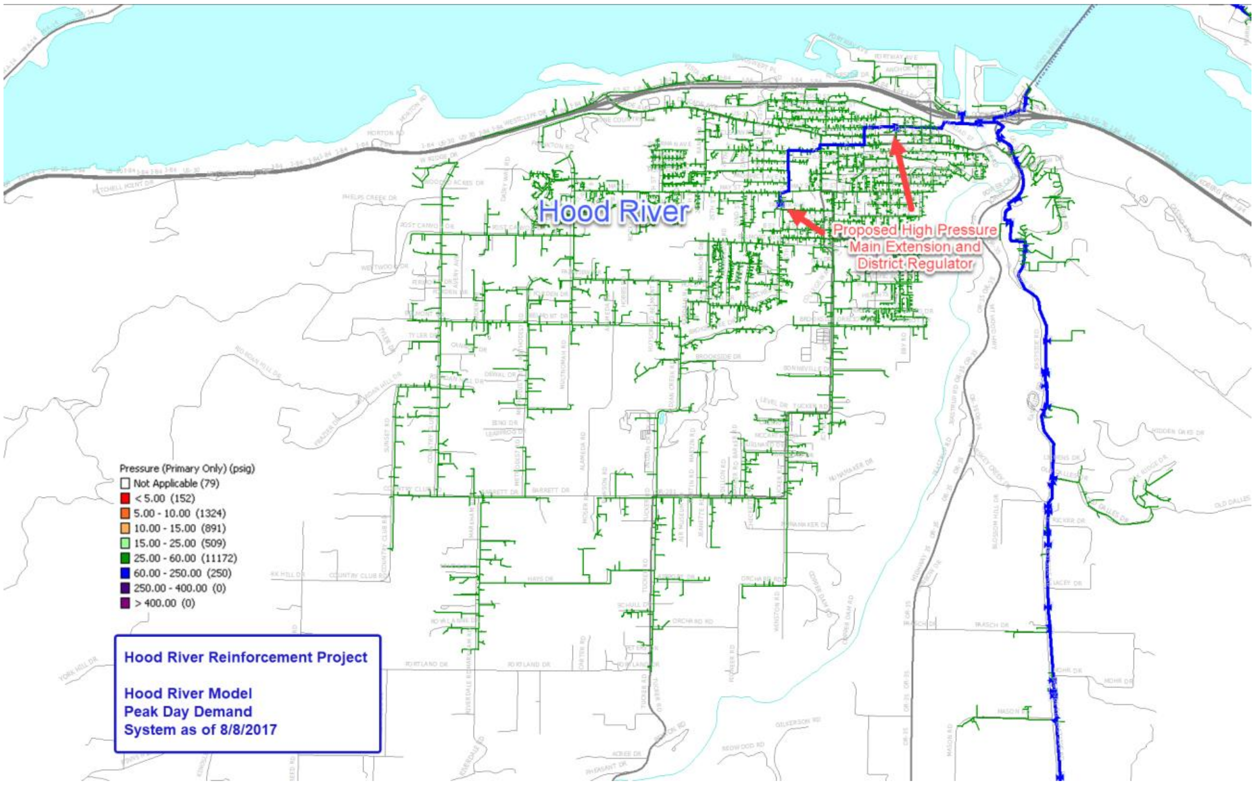
**Table 8.2: Pipeline Uprate Capacity Example**

| Starting Pressure (psig) | Ending Pressure (psig) | Pipeline Capacity* (th/hr) |
|---:|---:|---:|
| 100 | 60 | 1,820 |
| 200 | 120 | 3,569 |
| 300 | 180 | 5,341 |
| 400 | 240 | 7,163 |
| 500 | 300 | 8,956 |
| 600 | 360 | 10,800 |

*Pipeline Capacity Identified by 40% Pressure Drop

In the Hood River example discussed in section 8.4.4, the weakness in the existing system centered around a single point of gas feed from the northeast. This created system bottlenecks, as nearly all gas required by customers must go through a very small number of pipes. The final solution extended the existing high-pressure distribution main on Cascade Street and 6th Street. A new district regulator was installed on the end of the high-pressure main extension reducing the pipeline pressure drop through the bottleneck pipelines in the north. The result was that the system pressures overall were greatly improved (note the red areas in Figure 8.8 are green in Figure 8.11). Effective pipeline routes from the south could have been constructed, but the construction would have been much longer than the identified solution which avoided a costly river crossing.

**Figure 8.11: Illustration of Hood River Area Pressure Issues and Resolution**




## 8.5.4 Supply-side Options - Non-pipeline Resources

Non-pipeline supply-side options may be an option when customer demands grow beyond the capacity of the pipeline which currently serves this system. Instead of addressing weak areas with pipeline system reinforcement projects, non-pipeline alternatives are also assessed and include augmenting the capacity of the existing pipeline with a local peaking asset and the use of geo-targeted demand-side management means for reducing the local demand on peak, amongst other possible solutions, in lieu of traditional pipeline solutions. Essentially, non-pipeline supply-side options introduce a new source of gas into a constrained area of the system, thereby propping up pressure in the area to address reliability concerns.

### *GeoRNG*

On-system RNG interconnections are a form of distributed resources that can help maintain reliability within NW Natural's distribution system. 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 onto 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. Additionally, if more on-system RNG interconnections are developed, then the aggregate of the on-system RNG injections could result in system reinforcement projects that never materialize.

### *Satellite Storage*

A satellite storage facility delivers locally stored gas to the nearby customers, which temporarily reduces the volume of gas that flows on the existing upstream pipeline. Satellite storage works in tandem with existing pipelines to serve customer demand during very cold or peak demand conditions. Unlike the pipeline options, which provide permanent pressure benefits, satellite storage plants are peak shavers which are designed to be dispatched during extreme weather. The satellite storage has a limited supply of gas on site based on the size of the facility and is usually difficult to replenish under peak conditions. Two common types of satellite storage are Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG).

1. Satellite LNG Facility – LNG is natural gas that has been cooled to a liquid state reducing its volume by about 600 times. A satellite LNG facility is a tank that stores liquified natural gas along with the associated pumping, vaporization, meter, control, fire protection, standby power and odorization systems until the energy is required during peak or emergency conditions. Withdrawal rates are determined by the tank size, vaporizing equipment capacity, and the quantity of gas that can be absorbed by customers and local piping. A satellite LNG facility does not typically include a liquefaction process. LNG is generally brought in via tank trucks or occasionally trains.
2. Satellite CNG Facility – CNG is natural gas that is compressed to less than 1% of the volume it occupies at standard atmospheric pressure. The natural gas is stored in compressed form until dispatched to a lower pressure pipeline system. The storage facility is refilled during non-peak periods when system pressures are not a concern. These facilities normally have compressors to increase the pressure of the gas coming from the pipeline.

The option to site a CNG or LNG storage facility depends on many parameters including cost, flow rates capability, volume, commodity source, permitting requirements and tank size. Typically, the option between LNG and CNG facilities are determined by how much gas is required to serve an area. The biggest advantage of LNG storage is that the total storage capacity is greater than CNG storage. A satellite LNG facility can sustain an area experiencing low pressures for a longer duration. Both options generally require acres of land, and both processes can be noisy, limiting siting or increasing costs to remediate noise generation.

Liquefied natural gas (LNG), compressed natural gas (CNG), underground storage, and propane air facilities have all been used successfully for peaking in various parts of the country. CNG applications do not scale very well and quickly become cost prohibitive. Potentially viable underground storage structures are extremely rare and very expensive to develop. Propane air presents a risk of injecting oxygen into natural gas pipelines and producing a combustible mixture and is a safety risk NW Natural is hesitant to take. NW Natural's experience with LNG as a viable peaking asset facilitates assessment of a satellite LNG facility as an alternative to traditional pipelines. NW Natural has historically utilized mobile CNG and LNG as an emergency or best-efforts measure to support firm customers. Mobile solutions for natural gas delivery have significant risk, capacity, security, and siting issues, and a high cost per therm delivered. Thus, NW Natural routinely examines satellite LNG facilities in the alternatives analysis process and whereas other peaking assets may be considered if deemed appropriate.

### 8.5.5 Demand Side Resources

Demand-side management comes in many forms. NW Natural currently has many large interruptible customers who can be curtailed upon formal notice from NW Natural. This is one form of demand-side management. Another demand-side approach is to contractually arrange for voluntary service curtailment by large firm service customers within the area impacted. NW Natural begins the assessment of this alternative by examining historical loads of current large non-residential firm service customers in the area of impact for the proposed pipeline solution. If the estimated peak hour usage by these customers could be of sufficient volume to defer (or eliminate) the need to implement a supply-side solution, NW Natural would conduct additional analysis regarding whether customer-specific geographically targeted interruptible agreements[9] could be negotiated with these customers. Other demand-side management alternatives may be considered for future projects as new technologies and capabilities evolve. If the alternatives analysis indicates that a more effective and lower cost equivalent solution may be available, the proposed project will be revised to reflect the best alternative.

#### *Demand-side Resources- Non-pipeline Solutions*

A primary benefit of moving to a more forward-looking distribution system is to allow for better use of non-pipeline solutions. The early identification of distribution system issues as discussed above is necessary to go beyond supply-side options. More specifically, Figure 8.12 shows the value of the known time component associated with a supply-side solution but also the chunkiness of using this just-in-time supply side solutions.

[9] NW Natural also refers to such agreements as "localized interruptibility agreements."

**Figure 8.12: Just in Time Supply-side Solutions**

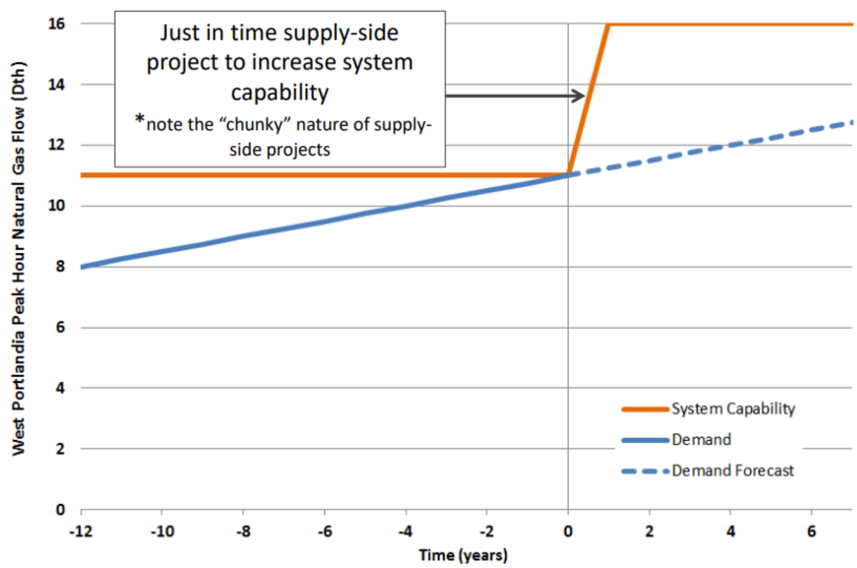
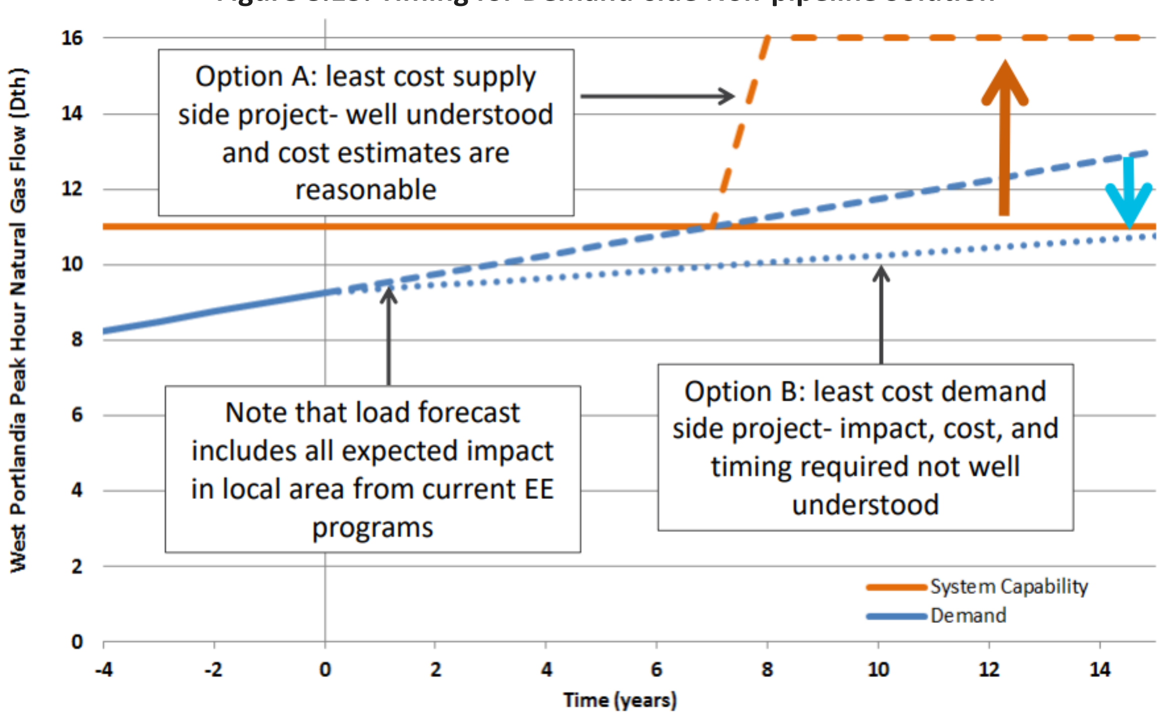


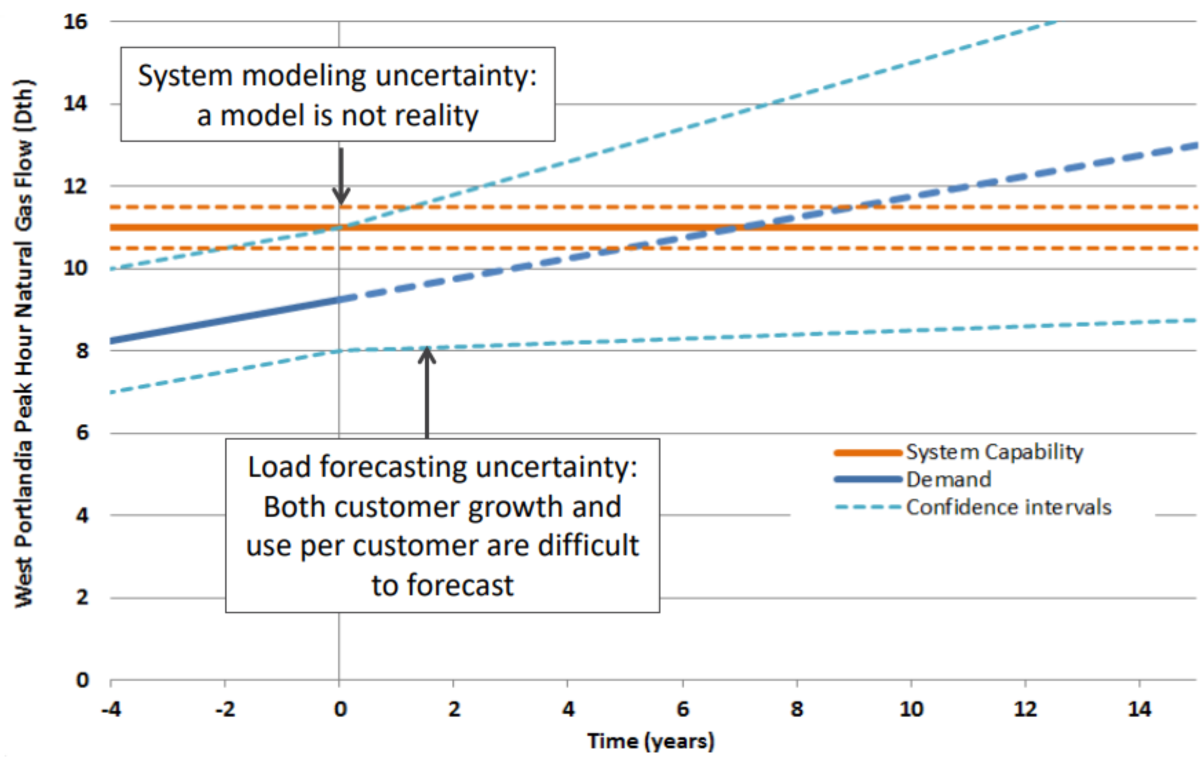

Figure 8.13 shows the timing needed for a demand-side non-pipeline solution.

**Figure 8.13: Timing for Demand-side Non-pipeline Solution**




As shown in Figure 8.14, the timing needed for demand-side projects is not well understood and there is still quite a bit of uncertainty. This is one of the reasons, NW Natural is currently piloting an innovative non-pipeline alternative known as GeoTEE or **Geo**graphically **T**argeted **E**nergy **E**fficiency. Partnering with Energy Trust of Oregon, one of the key objectives of this pilot is to develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options. GeoTEE is discussed in detail below.

**Figure 8.14: Distribution System Planning with Uncertainty**



### *GeoTEE*

GeoTEE stands for **Geo**graphically **T**argeted **E**nergy **E**fficiency, and it is a non-pipeline solution to distribution capacity constraints.[10] More specifically, GeoTEE is defined as savings from offerings that are distinctive to certain locations within a state to achieve additional savings specifically from customers that contribute to the peak load of an area where the distribution system is experiencing weakness and a supply-side project is projected to be needed to meet local peak demand. Geographically targeted DSM savings can be obtained from DSM programs with measures not being offered in other areas of the state or from programs that intensify/accelerate the deployment of measures available elsewhere but different from what is offered in the state at large. Given the current method for evaluating DSM cost-effectiveness, special consideration must be given to the design and deployment of a geographically targeted DSM program to meet the economic/cost-effectiveness criteria.

Specifically, GeoTEE is designed to be achieved by either "accelerating" or "enhancing," or accelerating *and* enhancing, DSM offerings:

*"Accelerated" DSM* is defined as savings acquired by speeding up the deployment of measures that meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs in an area with location specifically targeted marketing and/or increased incentives. In other words, accelerating DSM is acquiring savings that would be eventually achieved through statewide operations but faster in the locality in question.

*"Enhanced" DSM* is defined as savings obtained from measures that do not meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs but are cost-effective if location-specific avoided costs[11] are used to represent the value of achieving peak hour savings from DSM in the area that is experiencing a distribution system weakness. In other words, enhancing DSM is savings that are cost-effective based on local avoided costs but are not cost-effective under current statewide avoided costs.

Accelerated and/or Enhanced DSM will be required in a geographically targeted area to achieve the required peak hour savings since the "business as usual" process for acquiring conventional DSM savings is already accounted for in the peak hour distribution system planning that shows additional DSM is needed to address the peak hour demand. The demand-side options to evaluate against supply-side options to address weaknesses in NW Natural's distribution system will be referred to as "geographically targeted DSM via accelerated and/or enhanced offerings" or "Targeted DSM" for short. Allowing for Targeted DSM to be a viable option is breaking new ground for LDCs operating in the region and requires major changes to the way NW Natural plans distribution system upgrades and the way Energy Trust evaluates cost-effectiveness and deploys its programs.

[10] For more information on GeoTEE, please refer to NW Natural's 2016 IRP, Chapter 6, Section 7, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning
[11] Inclusive of the expected costs of the potential supply-side distribution enhancement.

Additionally, like supply-side options, if multiple enhanced *and/or* accelerated DSM programs are projected to be cheaper than the best supply-side option, the lowest cost option of the demand-side options would be selected and deployed to meet the best combination of cost and risk planning standard for addressing resource acquisitions.

As part of our 2016 IRP, we proposed the following action item:

*Work with Energy Trust of Oregon to further scope a geographically targeted DSM pilot via accelerated and/or enhanced offerings ("Targeted DSM" pilot) to measure and quantify the potential of demand-side resources to cost-effectively avoid/delay gas distribution system reinforcement projects in a timely manner and make a Targeted DSM pilot filing with the Oregon Public Utility Commission in late 2017 or early 2018.*

The Public Utility Commission of Oregon (OPUC) acknowledged this item in Order No. 17-059 dated February 21, 2017.[12]

On April 17, 2019, NW Natural filed an update to its 2018 Integrated Resource Plan[13] that included its GeoTEE pilot filing. It also noted at that time that while the filing of the pilot was delayed, the actual pilot was still on schedule.

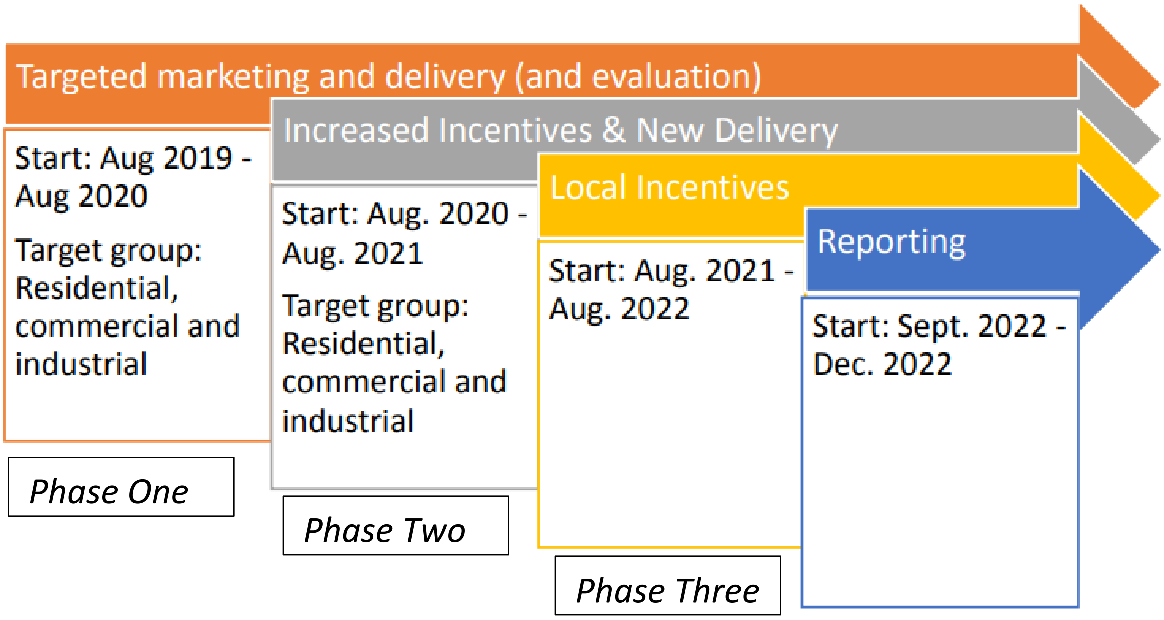
The objectives of the pilot include:

(1) Develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options.
(2) Determine whether GeoTEE represents a socially desirable tool to serve LDC customers if it shows the potential to be a cost-effective capacity resource in some situations.
(3) Explore and discuss with key stakeholders the appropriate funding mechanism for future GeoTEE projects should they show as a potentially cost-effective way to address distribution system weaknesses.

To achieve these objectives the pilot is being conducted in Cottage Grove and Creswell, Oregon and using various phases. The phases and anticipated timing are shown in Figure 8.15:

[12] The Washington Utility and Transportation Commission does not acknowledge specific action plans but did acknowledge that NW Natural's 2016 IRP compliance with WAC 480-90-238in their letter dated December 19, 2016.
[13] https://edocs.puc.state.or.us/efdocs/HAH/lc71hah134047.pdf

**Figure 8.15: GeoTEE Phases**




As of this writing, Phase One with increased marketing and outreach has been completed along with Phase Two which involved increased incentives but still within the current cost-effective parameters. Phase Three with the incentives increased even further by applying local avoided costs values for cost effectiveness screening is currently underway and will continue through August 2022. Upon completion of Phase Three, and as shown in Figure 8.15, the reporting and evaluation of the pilot will begin. It is important to note that the results will take time to process as a full year of consumption data will be required in order to compare with the baseline.

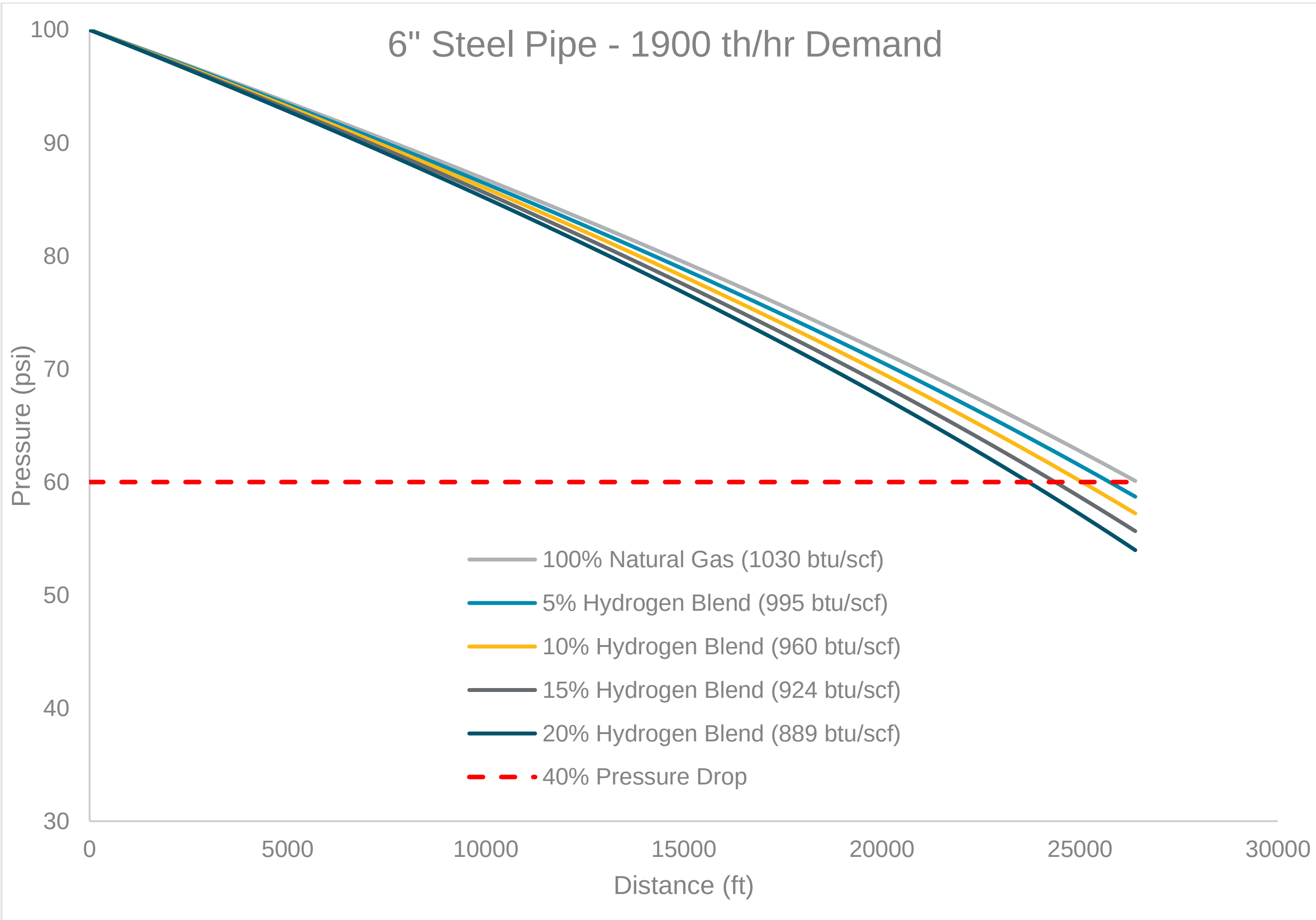
### *Hydrogen Blended with Natural Gas*

Blending hydrogen into an existing natural gas system has benefits related to emission reductions. Systems are included in the alternative analysis because of system reliability concerns due to low system pressures. Injecting hydrogen into a natural gas stream does not improve pressures on a gas distribution system, and hence is not presented as an option in NW Natural's alternative analysis. In fact, blending natural gas with Hydrogen reduces system pressures because it raises the volume of gas required to deliver to customers.

The British thermal units (Btu) Value for gas is defined as the amount of energy release by a unit volume when combusted. NW Natural measures Btu values per a standard cubic foot (Btu/scf). Btu Value on NW Natural's system typically ranges from 985 Btu/scf to 1155 Btu/scf. The Btu Value of hydrogen is approximately 325 Btu/scf. When hydrogen is blended with natural gas, the energy content of the gas stream is lowered because the Btu Value of hydrogen is approximately 1/3 that of natural gas. Btu Value is an important attribute on pipeline system because it determines the volumes of gas required to serve energy needs. Consumption on a natural gas network is determined by the amount of energy consumed, typically expressed in therms or Btus. If the energy needs remain constant while the Btu Value decreases, then it requires a higher volume of gas to meet the same energy demand. Higher volume of gas required equates to additional pressure drop along a pipeline system.

Figure 8.16 illustrates the pressure drop for natural gas compared to hydrogen blends. The graph shows that the pressure drops across a pipeline are proportional to the volume of hydrogen injected into the natural gas stream. Natural gas without hydrogen has less pressure drop than the hydrogen blends because it has a higher Btu Value. As more hydrogen is injected into the gas stream, more pressure drop occurs on the pipeline because the blend has a lower BTU Value. The main takeaway of Figure 8.8 is that it shows that hydrogen blending makes a distribution system with low pressures even weaker.

**Figure 8.16: Hydrogen Blending Pressure Drop**



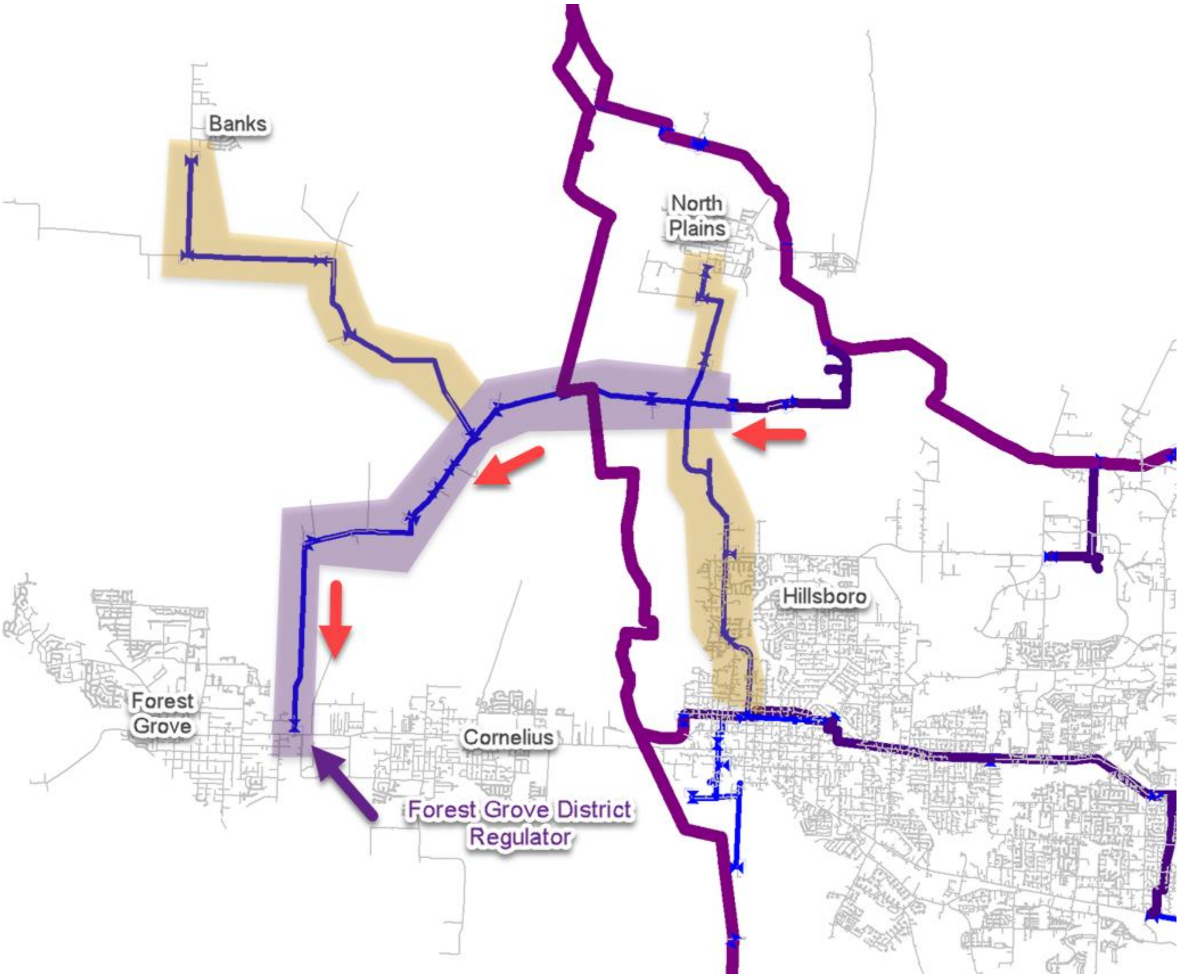

## 8.6 Distribution System Projects – 2022 IRP Action Item

This section describes a proposed distribution system project, which addresses an area of identified weakness within the distribution system.

### 8.6.1 Forest Grove Feeder Uprate

The Forest Grove Feeder (also known as the McKay Creek Feeder) is the primary supply pipeline for the western portion of the Portland metropolitan area. Customers in the communities of Hillsboro, Cornelius, Forest Grove, North Plains, and Banks are supplied by this pipeline. The Forest Grove Feeder is fed from the 720 MAOP Rock Creek Feeder and South Mist Feeder and has historically operated at 175 MAOP. Most of this pipeline was constructed in 1989 and other sections were installed in 1994. The segment that serves Banks was installed in 1997. Significant demand growth has occurred in this area and modeling results indicate that this pipeline is operating beyond its design capacity during extreme conditions. The Forest Grove Feeder is shown in Figure 8.17. The section of the Forest Grove Feeder that is operating over the original design capacity is indicated by the purple polygon.

**Figure 8.17: Forest Grove Feeder System Identification**

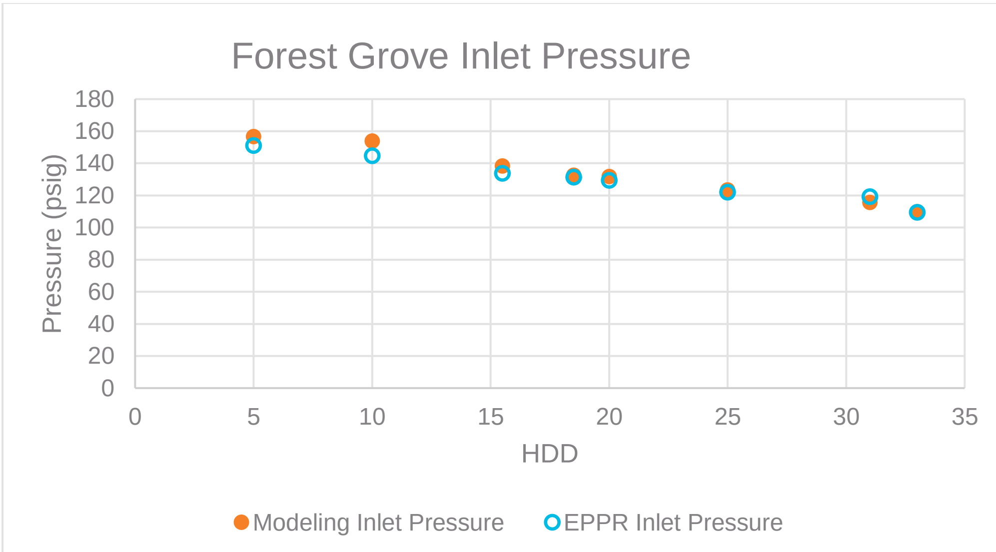



*Customer Management Module (CMM)*

For the following analysis, residential and commercial customer demands for Cornelius, Forest Grove, North Plains, and Banks were imported using CMM.

Nine data points collected between 2020 to 2022 were used to measure the variances between actual pressure reads from data extracted from an Electronic Portable Pressure Recorders (EPPR) sited at the inlet of the Forest Grove district regulator and the Synergi Gas™ model results. Because curtailments were not issued during the sample period, all interruptible customers remained enabled in Synergi Gas™ models for these data points. The Figure 8.18 illustrates the difference between EPPR reads and the Synergi Gas™ model results. The average percent difference for the nine samples is 1.8%. This validation provides supporting data that CMM is producing demands that resemble actual consumption for residential and commercial customers.

**Figure 8.18: Forest Grove District Regulator Inlet Pressure - CMM vs EPPR**




### *Analysis*

Peak hour analysis assumptions:

- Supplies set at peak hour
    - Customer demands set at Peak Hour
    - Largest customers estimated based on high frequency meter data (SCADA, Industrial Billing System)
- Commercial and residential customers peak hour demand estimated based on CMM Interruptible customers off as requested at peak hour
- Modeled System Configuration and Customers as of August 2021

During peak conditions, a severe pressure drop occurs on the last segment of the Forest Grove Feeder, which is approximately 5.3 miles of 6” steel pipeline operating at 175 MAOP. To force the model to solve during peak conditions, the Forest Grove district regulator had to be bypassed. Bypassing is performed in the model when regulators do not have sufficient inlet pressure to operate correctly. In field operations, bypassing a district regulator is typically performed by an operator who physically opens a valve that connects the district regulator inlet piping to the outlet piping. When bypassing occurs, gas does not flow through the regulator, avoiding pressures losses from the regulator. Figure 8.19 displays the model results for the Forest Grove area. Even with the Forest Grove district regulator bypassed, model results indicate customers may experience outages during a cold event. Customer connected pipes shown in red are those that may experience outages during extreme weather. During a peak hour event, the pressure drop in this segment of the pipeline is so high that Synergi Gas™ provides infeasible solutions. Infeasible solutions occur when the piping network is running out of pressure.

**Figure 8.19: Existing System Peak Model**

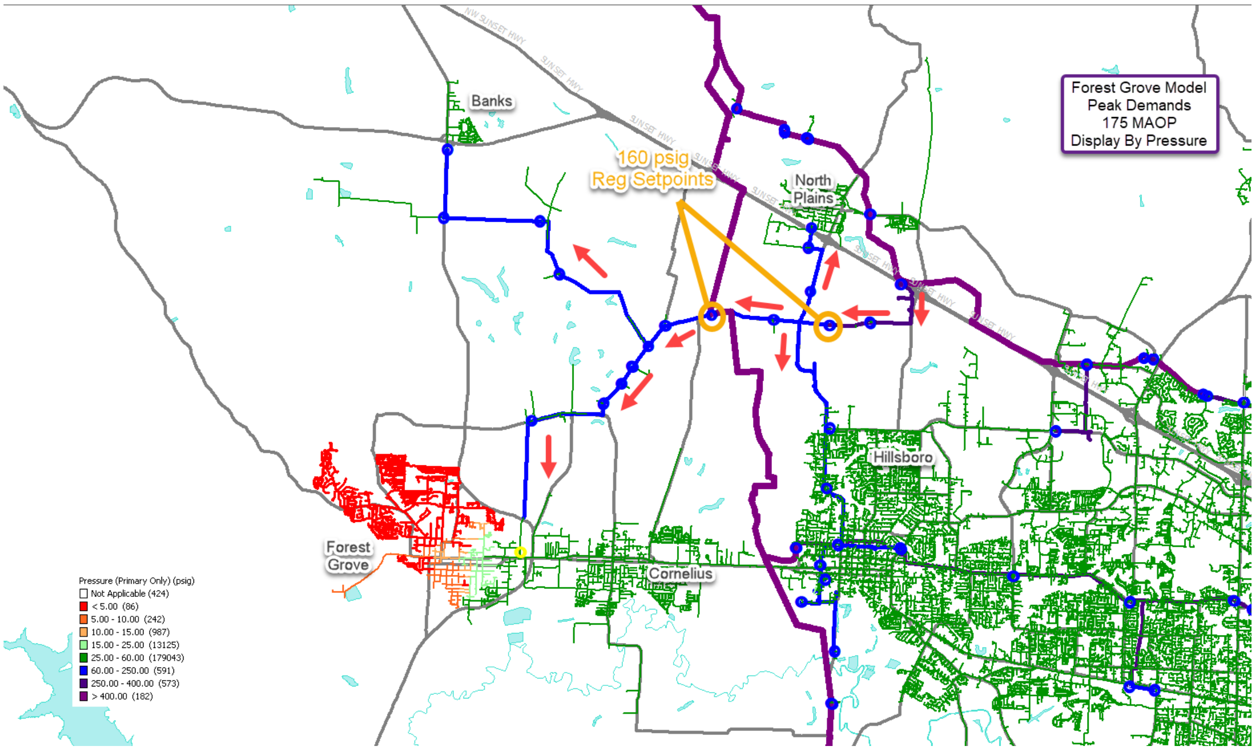
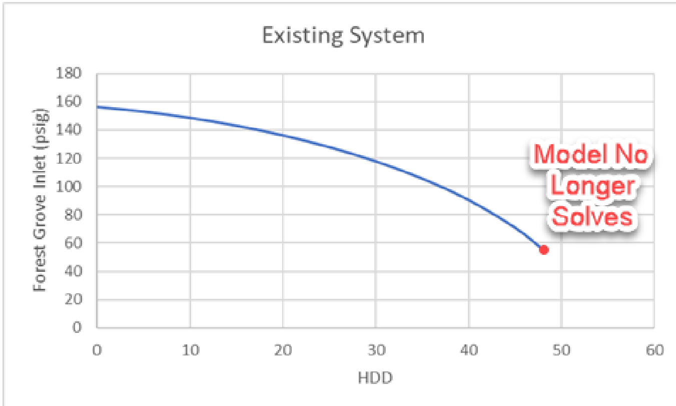


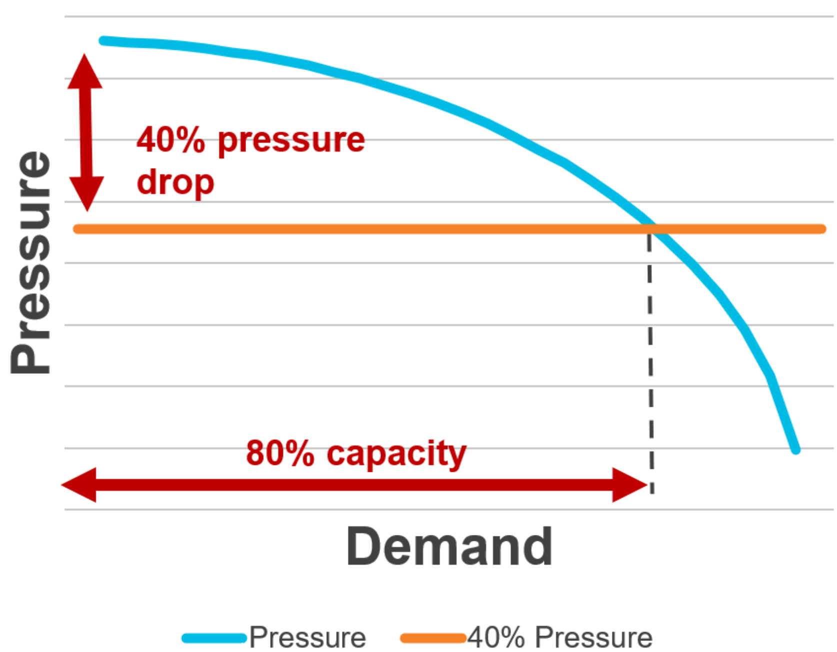

Figure 8.20 shows Synergi Gas™ results for the Forest Grove district regulator inlet pressures against various Heating Degree Days (HDDs). As the weather gets colder, the Forest Grove district regulator inlet pressure decreases. The graph illustrates that the relationship between pressure and capacity is nonlinear. The nonlinear relationship means that as demands are added in Forest Grove, the system becomes more sensitive to pressure loss. The graph terminates at 49 HDD. At 49 HDD, the model does not solve because of insufficient inlet pressure to the Forest Grove district regulator. Regulators require adequate inlet pressure to operate properly and deliver gas to downstream customers, which is typically 25 psig higher than the outlet pressure.

**Figure 8.20: Forest Grove District Regulator Inlet Pressure Over Various Temperatures**



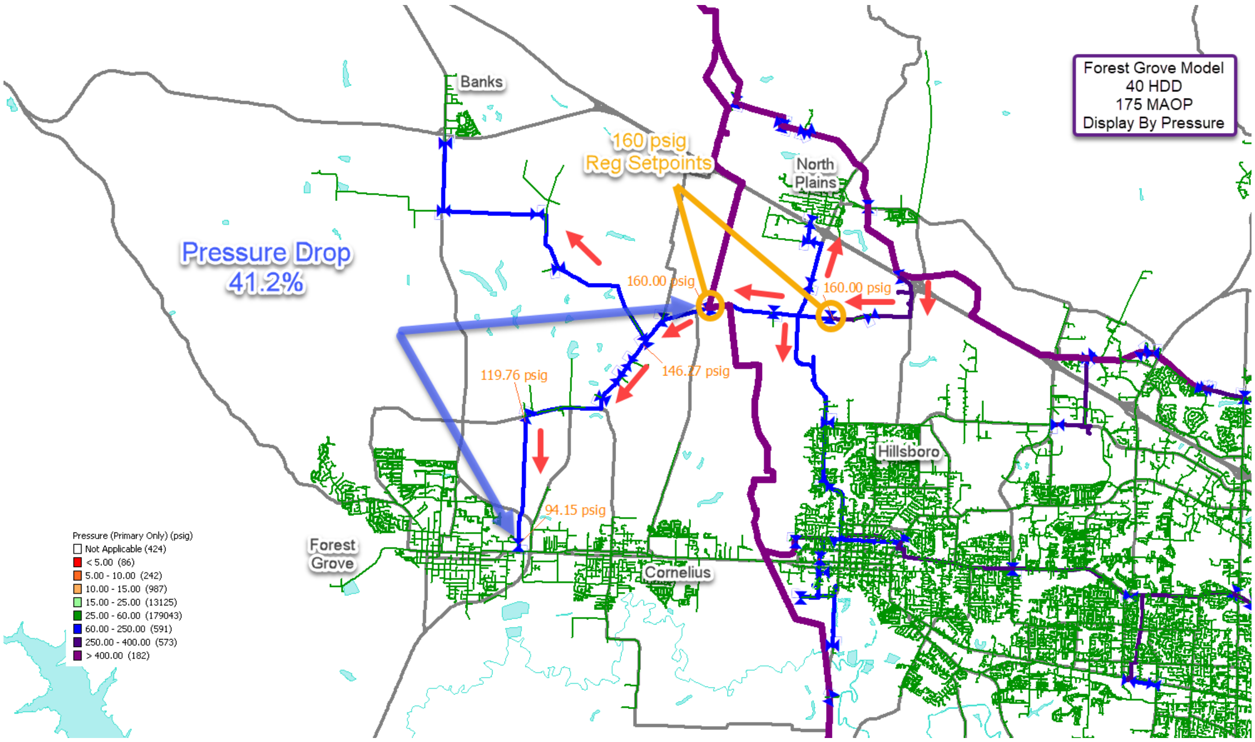

As mentioned in earlier in this Chapter, NW Natural's high pressure reinforcement criteria include addressing pressure drops that exceed 40% from the source to the end of the system. A system with a pressure reduction of 40% equates to an 80% level of capacity utilization. Small increases in demand from weather or growth can lead to outages when pipelines operate above 80% capacity. As shown in Figure 8.21, increases in demand from colder weather or growth increases the probability of outages when pipelines operate above 80% capacity as pipeline pressure decreases rapidly.

**Figure 8.21: Pressure Drop Vs Demand**



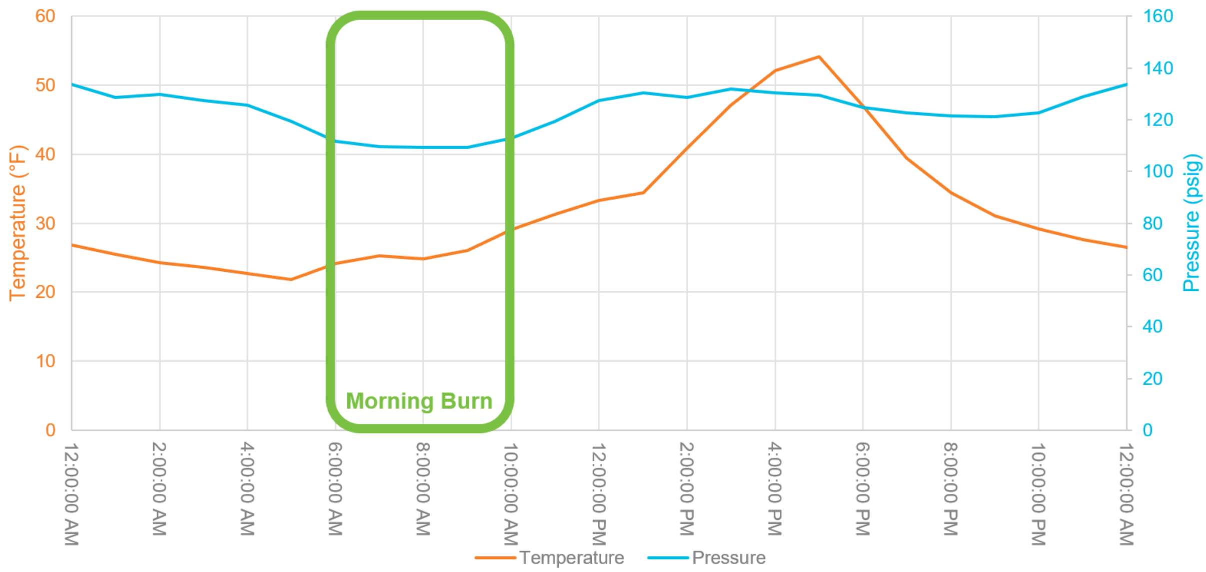
As displayed in Figure 8.22, the model results indicate that an average temperate of 25°F would cause the pressures on the Forest Grove Feeder to drop by over 40%. This area experiences a cold event with an average daily temperature less than 25°F about once every 3 years. The last cold event occurred in January of 2017.

**Figure 8.22: 40% Pressure Drop for the Existing System**



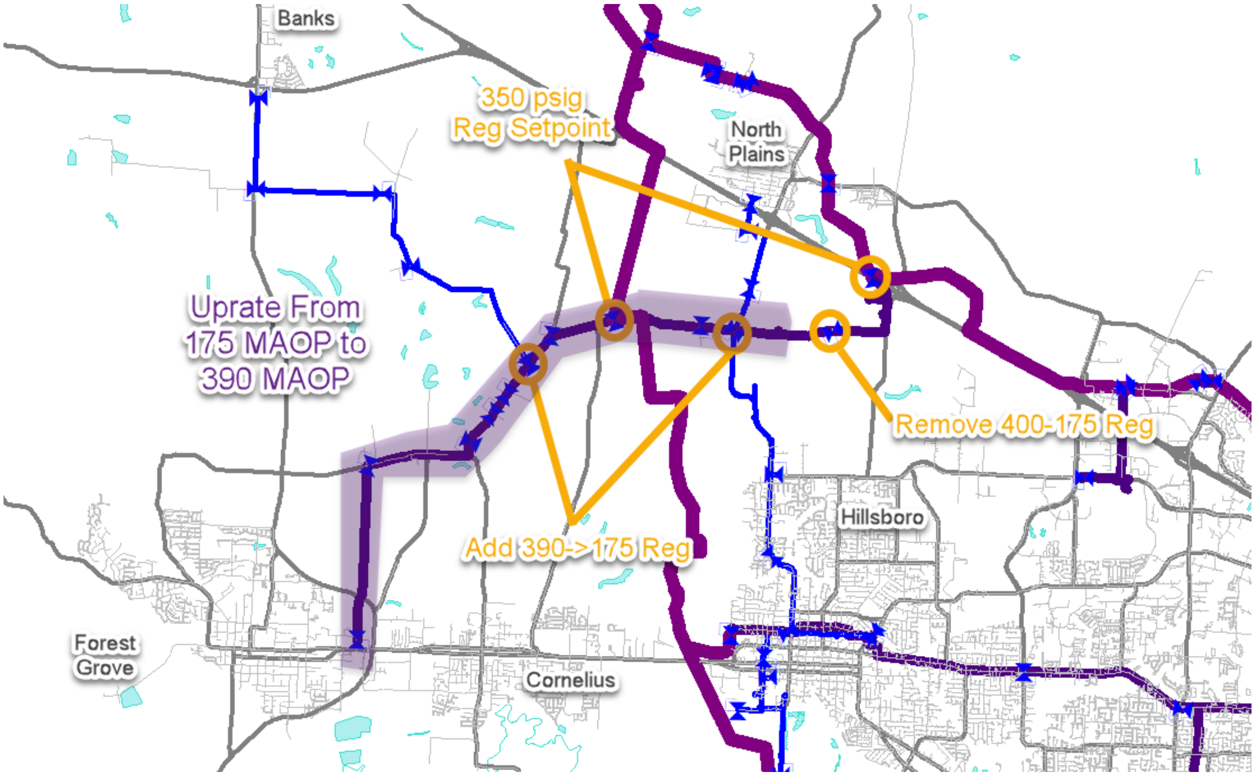

NW Natural began collecting EPPR pressure data in November 2020. During the sample period, the highest pressure drop occurred on February 23, 2022. Data retrieved from the EPPR revealed that the Forest Grove district regulator inlet pressure fell below 109 psig while the district regulators feeding the Forest Grove Feeder were set to 160 psig. Although the pressure drop was not greater than 40%, the pressure reads were within 1% of the modeled value of 110 psig. The EPPR case temperature during this day revealed that Forest Grove average daily temperature was 32°F.  Figure 8.23 shows the recorded pressures and temperatures during the February 23, 2022, event. One area highlighted in Figure 8.23 is the morning burn. The morning burn is defined as the peak usage hour when businesses open, and where gas use increases as customers cook, adjust thermostats, and use hot water as they prepare for the day.

**Figure 8.23: EPPR Data - February 23, 2022**




The high pressure main on the Forest Grove Feeder was originally tested to allow a pressure uprate to an MAOP higher than the current 175 MAOP. As a general rule, the easiest and least expensive way to increase the capacity of a pipeline is to increase its operating pressure. Uprating a portion of the Forest Grove Feeder to an MAOP of 390 psig increases the capacity of this pipeline to deliver gas reliably to Forest Grove. The 175 MAOP laterals to Banks, North Plains, and Hillsboro do not have capacity constraints and would remain at their current 175 MAOP. Two new 390 to 175 district regulators must be installed to isolate these laterals from the newly uprated feeder. An existing 400 to 175 district regulator would be removed. All other district regulators and service regulators along the newly uprated line would be certified to operate at the new MAOP. Figure 8.24 shows the modifications required for the high-pressure system to uprate the pipeline.

**Figure 8.24: Proposed System Reinforcement**




As depicted in Figure 8.25, under peak conditions, the inlet pressure at the Forest Grove district regulator would be 303 psig with the Forest Grove Feeder Uprate in place. The corresponding pressure drop across the high-pressure system is 13.4% (based on upstream regulator setpoint of 350 psig), which is below the 40% pressure drop criterion to identify weak high-pressure systems. The model results show that pressure on the Forest Grove low-pressure system would be above 5 psig with the uprated pipeline. With the reinforcement in place, the Forest Grove Feeder would have adequate capacity to serve demands in the area.

**Figure 8.25: Uprated System Peak Model**

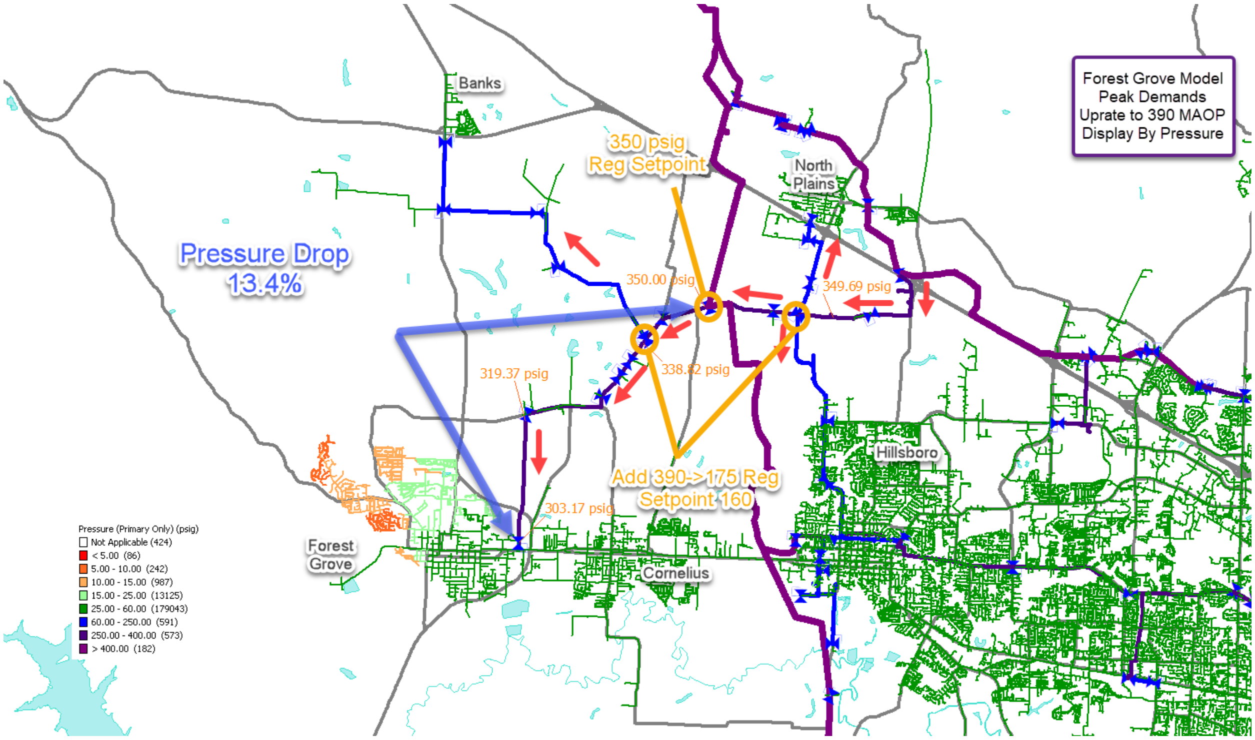
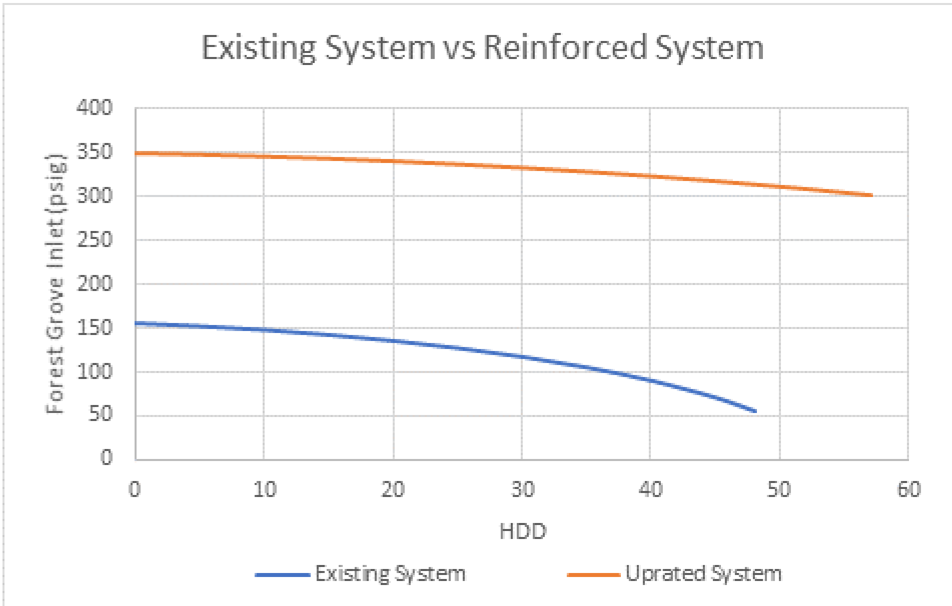



Figure 8.26 shows the pressures "before" and "after" the improvement. The "before" curve is the existing system applying current peak demands with interruptible customers disabled. The existing system curve shown in blue stops at 49 HDD because we do not have adequate inlet pressure at the Forest Grove district regulator for the model to solve. The "after" curve is the model results of the uprated system using existing demands with interruptible customers disabled. The difference between the curves captures the pressure benefits from the uprate.

**Figure 8.26: Pressure Improvement**




### *Uprate Scope*

The items below would have to be completed in order to safely operate the Forest Grove Feeder at 390 MAOP:

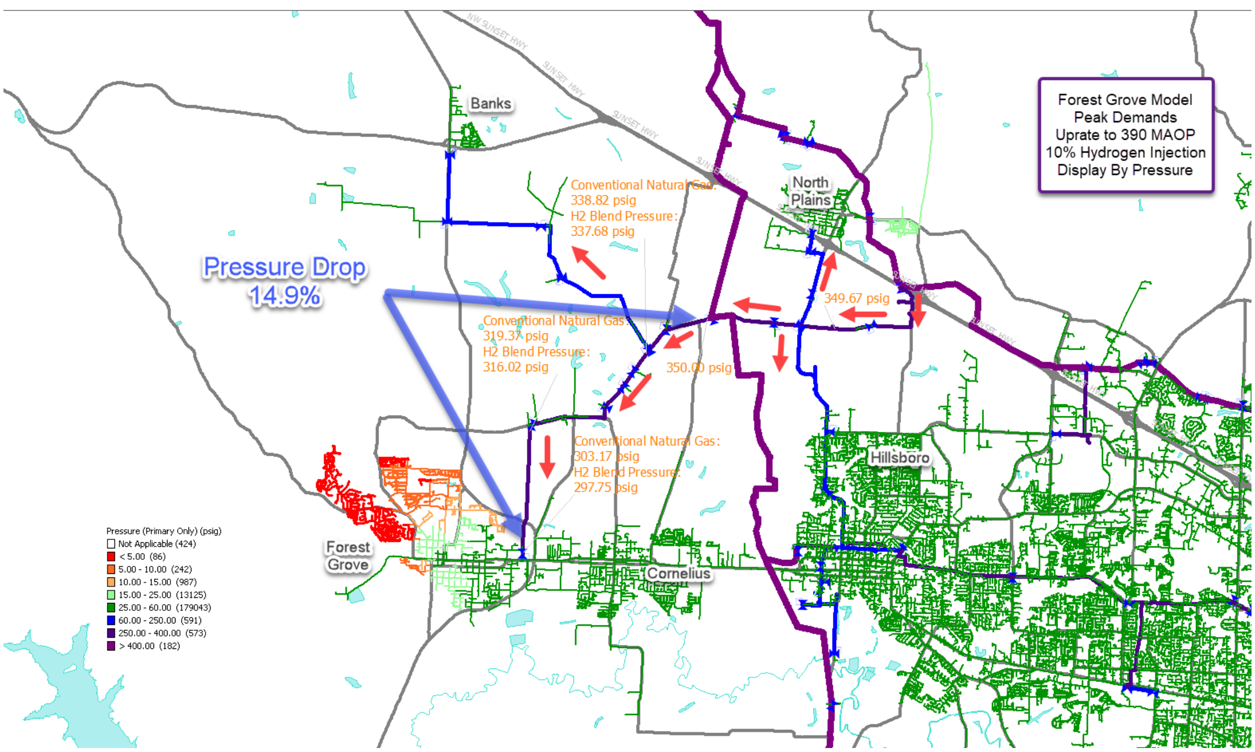
- Uprate approximately 6.3 miles of high-pressure main from an MAOP of 175 to an MAOP of 390
- Potentially uprate/replace 12 service regulator inlets
- Potentially uprate/replace 4 district regulator inlets
- Abandon 1 district regulator
- Install 2 district regulators

### *Hydrogen Compatibility*

NW Natural is seeking opportunities for blending hydrogen with natural gas to lower carbon emissions. Hydrogen blended with conventional natural gas lowers the BTU values of the gas on a pipeline system. Lower BTU value gas requires higher volumes to serve the same demand because each volumetric unit of gas contains a smaller amount of energy. The higher volume of gas required to serve the same demand increases velocities in the pipeline, resulting in increased frictional losses and higher pressure drops compared to gas with higher BTU values.

Because the pressure loss across a pipeline would be higher for hydrogen blends, the existing system could not receive a hydrogen blend without further worsening the inlet pressure of the Forest Grove district regulator. Synergi Gas™ was used to model the implications of introducing hydrogen blends into the Forest Grove Feeder after uprating the pipeline from an MAOP of 175 to an MAOP of 390. The model results compare the pressures at the inlet of the Forest Grove Feeder for conventional natural gas with a gas blend that includes 10% hydrogen by volume. Model results show that flowing conventional natural gas during a peak event would cause the inlet pressure at the Forest Grove district regulator to be 303 psig. Comparatively, with hydrogen blended gas, the pressure at the inlet of the Forest Grove district regulator would be 298 psig. If a hydrogen blend were introduced onto the Forest Grove Feeder, the proposed uprate of the system would satisfy existing and future peak demands on the Forest Grove Feeder. Figure 8.27 shows the Synergi Gas™ model results for the 10% by volume hydrogen model run.

**Figure 8.27: Uprated System Peak Model with 10% Hydrogen Blend**



### *Project Alternatives*

In addition to the tradition pipeline solution, NW Natural considered targeted interruptible schedule agreements by estimating the technically potential load savings from large firm industrial loads in the affected area switching to interruptible service.  Even with all firm industrial loads curtailed in the model, Synergi Gas™ results demonstrate that the 175 MAOP system will continue to experience a greater than 40% pressure drop during peak hourly conditions indicating that there is insufficient technical potential available.

NW Natural also considered a satellite LNG Facility. The estimated cost to site LNG facility to serve affected area was estimated to cost significantly higher than pipeline uprate (more than double uprate project.

Lastly, NW Natural also considered geographically targeted RNG/Synthetic Methane but the site was not conducive to a cost-effective RNG interconnection project.

The Forest Grove Feeder Uprate shown in Table 8.3 is the sole project which will have an action item for which NW Natural is requesting acknowledgement by the Public Utility Commission of Oregon. Following NW Natural's final investment decision, this project will be implemented between 2024 and 2025.

Estimated costs for this project are stated in $2022and do not include construction overhead.  A project's estimated cost may change over time, as it moves from a conceptual design to its final engineering specification. Additionally, both updated cost estimates and the actual cost of a project when constructed may differ from preliminary cost estimates due to actual inflation (cost escalation) differing from projected inflation; i.e., differences due to changes in the real price of a project between the preliminary cost estimate to a refined cost estimate to actual cost.

**Table 8.3: Distribution System Project**

| Project | Schedule | Estimated Cost (Millions of $2021) | Estimated PVRR (Millions of $2021) |
|---|---|---|---|
| **Forest Grove Feeder Uprate** | 2025 | $3.0 - $6.2 | $3.0 -$7.0 |

# Chapter 9

# Public Participation

## 9.1. Public Participation

Public involvement and input are essential to the IRP development. In accordance with guidelines from both Oregon and Washington and to encourage an open and transparent process, the public is encouraged to attend IRP workshops and meetings, and to submit comments during public comment periods. The public can find information about the IRP and associated workshops on the NW Natural IPR site. Members of the public can request to be included in upcoming meetings or workshop by contacting the IRP team.

The public is made aware of the IRP draft release through announcements on the NW Natural website and via a bill insert sent to all NW Natural customers. The Company additionally invited customers to participate in the resource planning process by hosting a meeting for the public on the evening of July 18, 2022. A bill insert notice, sent to all customers beginning on May 24, 2022, informed customers about the IRP process, draft release, welcomed customers to submit feedback, and invited customers to attend the meeting for the public.

Appendix H contains a copy of the bill insert notice that was sent out to all customers.

## 9.2. Technical Working Groups

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans. During this planning cycle, NW Natural worked with representatives from Citizens' Utility Board of Oregon; Energy Trust of Oregon; Alliance of Western Energy Consumers; Public Utility Commission (PUC) of Oregon Staff; Washington Utilities and Transportation Commission (WUTC) Staff; Northwest Gas Association; Washington's Office of the Attorney General; Enbridge Pipeline; Fortis BC; Avista; Cascade Natural Gas; Puget Sound Energy; Northwest Energy Coalition; Green Energy Institute at Lewis & Clark Law School; and other stakeholders.

NW Natural held six TWG meetings and one meeting for the public as part of its 2022 IRP process. A final TWG meeting is to be scheduled after the draft filing. Prior to the 2022 IRP TWG series, NW Natural held two supplemental TWGs pursuant to Oregon Public Utility Commission Order No. 21-013 in docket LC-71. Below is a brief summary of each meeting.

**Supplemental TWG No. 1, Load Considerations – September 29, 2021**

Held virtually via Microsoft Teams. NW Natural reviewed modeling tools used within load forecasting and discussed with stakeholders the potential implications to modeling and forecasting from recent policies enacted in Oregon and Washington. Stakeholders were asked to provide feedback to NW Natural regarding key demand-side inputs needed for end-use load forecasting.

**Supplemental TWG No. 2, Emission Considerations – December 9, 2021**

Held virtually via Microsoft Teams. NW Natural used the first portion of this supplemental TWG to allow stakeholders that opportunity to ask questions related to NW Natural's presentation through UM 2178, Natural Gas Fact Finding Per EO 20-04.

During the second half to the TWG, NW Natural presented the modeling challenges and considerations created by emissions compliance policies in both Oregon and Washington. TWG participants discussed challenges and potential solutions utilizing the tools available. Feedback was requested from stakeholders on additional thoughts to modeling challenges.

**TWG No. 1, Planning Environment and Environmental Policy – January 14, 2022**

Held virtually via Microsoft Teams. During the first half of TWG No. 1, NW Natural provided an introduction to NW Natural. During this introduction, the IRP team reviewed, at a high-level, gas purchases, customer types and rate schedules, emissions context, system capacity resources, and distribution system planning options. This portion of the TWG also included NW Natural's view on the scope and role of the IRP, the regulatory basis for IRP process, IRP timelines, least cost-least risk considerations, and the interplay of the parts within the planning environment which culminate in the Action Plan. The IRP team additionally provided updates on actions since the 2018 IRP and 2018 IRP Update, and new challenges for the 2022 IRP.

The second portion of the TWG was dedicated to the Planning Environment and Scenario Development. The IRP team reviewed changes in the policy landscape which impact the IRP in either or both Oregon and Washington. The team discussed with stakeholders the challenges associated with new policies and the compliance mechanisms associated with each. Lastly, the IRP team reviewed the development of scenarios and types of analysis within such scenarios. Scenario analysis used in the 2018 IRP was reviewed and draft scenarios for the 2022 IRP were presented. TWG attendees discussed draft scenarios and provided initial feedback during the presentation. Stakeholders were provided further time to provide feedback on scenarios with feedback requested back to the IRP team by February 4, 2022.

**TWG No. 2, Load Forecasting – February 11, 2022**

Held virtually via Microsoft Teams. NW Natural discussed the goals, purpose, and framework within which load forecasts are developed, including the differences in the 2022 IRP compared to previous years. The TWG focused on understanding several concepts about load forecasting including (1) when forecasting there is a trade-off between model parsimony and accuracy/precision (2) historical trends establish our reference case, which is a key starting point for understanding how structural changes to customer growth and stock turnover of end-use equipment impact overall demand (3) the importance for peak planning in IRPs and the trade-off of between costs for reliable service and the risks of resource constraints during an extreme cold event and (4) load uncertainty and an overview of stakeholder feedback on draft scenarios as well as a preview of the draft load forecasts within such scenarios.

Each part of load forecast modeling was reviewed with detailed discussion related to each section including the differences between the types of load forecasts; residential and commercial customer count and use per customer (UPC), and industrial, large commercial, and compressed natural gas (CNG). This discussion included accounting for impacts from energy efficiency and total sales and transportation loads. NW Natural also reviewed the reference case for the expected weather load forecast and the design weather load forecast (inclusive of a cold event and peak day load forecast).

Lastly, NW Natural gave an overview of stakeholder feedback on draft scenarios presented in TWG No. 1 as well as a preview of the draft load forecasts within such scenarios.

**TWG No. 3, Supply-Side Resources – March 28, 2022**

Held virtually via Microsoft Teams. The first portion of this TWG was dedicated to reviewing feedback received from stakeholders on the 2022 IRP scenarios and NW Natural's proposal to utilize the average of simulation draws as the base case to account for uncertainty in load scenarios. The remainder of the TWG focused on supply-side resources.

During the presentation on supply-side resources, the IRP team discussed the differences and overlap between gas supply capacity and distribution capacity resources; existing supply-side resources and an overview of conventional market fundamentals; Portland LNG; and RNG and hydrogen resources. The team went into a detailed discussion of Portland LNG's contribution to serving current load and its requirements to serve including an overview of the required cold box to continue operations at Portland LNG, and an overview of alternatives to the cold box to maintain reliable service for current peak day operations.

Lastly, ICF reviewed and discussed the availability of RNG and hydrogen resources at a national level. The IRP expanded upon this review with a discussion of the policy environment and markets for RNG and hydrogen, as well as current NW Natural projects. The IRP team also briefly reviewed NW Natural's methodology for evaluating the incremental cost of RNG resources.

**TWG No. 4, Avoided Costs and Demand-Side Resources– April 13, 2022**

Held virtually via Microsoft Teams. The first portion of the TWG focused on understanding several concepts about Avoided Costs. The IRP team reviewed what avoided costs are; principles of and standard industry approaches to avoided costs; applications of avoided costs in cost-effectiveness evaluations, as well as the components of avoided costs and their associated resource option application; energy and environmental related avoided costs including CPP and CCA compliance costs and calculating GHG price components; Risk Reduction Value and commodity price risk reduction costs; and infrastructure and capacity avoided costs including their relation to peak load and peak savings. NW Natural also shared avoided cost results by end-use for both OR and WA.

The second portion of the TWG focused on OR And WA Conservation Potential Assessments (CPAs) and emerging technologies. Energy Trust of Oregon (ETO) presented a section on OR CPA for Sales Customers, including forecast results. Applied Energy Group (AEG) presented a section on WA CPA for Transport Customers, including draft conservation potential results. The IRP team reviewed the WA CPA for sales load completed by AEG in 2021 and presented results for CPA for WA Transport Customers also conducted by AEG in 2021. GTI gave a presentation on thermal (gas) heat pumps and the status of new technologies coming to the market for residential and/or commercial customers. Finally, NEEA spoke to market transformation and the partnerships between various organization which can accelerate the adoption of emerging technology.

**TWG No. 5, Distribution System Planning– April 25, 2022**

Held virtually via Microsoft Teams. The IRP team reviewed distribution system planning (DSP) processes, modeling, and standards as they are applied within the IRP process. This includes the deployment of both “pipeline” and “non-pipeline” solutions. The Technical Working Group focused on (1) peak hour demand including that the design of system is based on peak hour customer demand and how weather is a major driver, and (2) non-pipeline solutions and the criteria they must meet in order to be an alternative distribution system resource, and (3) distribution system planning objectives.

During the discussion of DSP objectives, NW Natural reviewed meeting peak hour requirements, addressing localized system needs, and choosing the cost-effective alternative while accounting for risk. Points of consideration included that NW Natural's DSP is in a transition from a "just-in-time" planning process to a forward-looking planning process and that this transition is assisted by the improvements in system modeling through the Customer Management Module (CMM) project. Tools for system modeling and planning such as SCADA, and Synergi™, as well as reinforcement standards were also reviewed in detail.

Lastly, NW Natural discussed alternative analysis, the Geographically Targeted Energy Efficiency (GeoTEE) pilot, and the proposed Forest Grove Feeder system reinforcement project based upon principles and modeling as discussed.

**TWG No. 6, Low Carbon Gas Evaluation Methodology and Emissions Compliance Mechanisms – June 1, 2022**

Held virtually via Microsoft Teams. The first portion of the TWG focused on low carbon gas, (i.e., RNG) evaluation methodology, beginning with a review of IRP related activities and policies since filing the 2018 IRP update, as well as the evolution of NW Natural's evaluation methodology and key terminology related to low carbon/ renewable resources. The IRP team then reviewed and discussed:

- Project types of low-GHG resources including the differences between bundled and unbundled purchases
- Application of avoided costs, utilizing examples to illustrate the various types of costs avoided such as Transport, Compliance, Infrastructure, and Capacity
- How the cost of RNG is evaluated against conventional gas and the calculations used
- An in depth look at the components within the cost calculations and evaluation methodology
- Accounting for risk and uncertainty, including the tools and calculations utilized; NW Natural accounts for two main types of risk in its RNG methodology- Market and Policy

The second portion of the TWG was dedicated to reviewing PLEXOS®, the system resource planning model. The IRP team discussed how the model incorporates new policies including emissions compliance, as well as previously accounted for inputs such as weather and climate change, and the social cost of carbon. The IRP team then led stakeholders through modeling examples and a demonstration of NW Natural's complex model within the modeling software.

**TWG No. 7, Portfolio Results and Actions - TBA**

Appendix G contains the (virtual) attendance lists for each TWG meeting.

## 9.3. Community and Equity Advisory Group

The Company's IRP process was the driving force behind the formation of NW Natural's inaugural Community and Equity Advisory Group (CEAG). NW Natural recognized particular communities and customer groups have historically not been included or engaged in the resource planning process. The Company additionally recognized that many issues related to resource planning intersect with other areas of operations and community needs. Thus, the CEAG has been formed to advise the Company on various programs and processes, including, but not limited to the resource planning process. Members of the CEAG are recruited from community-based organizations representing historically underrepresented voices in the energy planning environment. Member organizations are compensated for participation in the CEAG. NW Natural expects the CEAG will assist with increasing and improving upon current public participation in its future IRPs.

# Appendix A
# IRP Requirements

To be filed with NW Natural's Final 2022 Integrated Resource Plan

# Appendix B
# Resource Needs

## B.1 Customer Count Forecast Technical Details

Oregon's Office of Economic Analysis (OEA) was the data source of the exogenous variables used in the four econometric customer forecasting models as specified in Equations from (1) to (4) in the 2022 IRP. As OEA forecasts U.S. housing starts and Oregon's nonfarm employment 10 years ahead, NW Natural used Population Research Center (PRC) at Portland State University (PSU)'s long-term forecast of Oregon's population to project U.S. housing starts[1] and Oregon's nonfarm employment beyond 2030, respectively.

**Residential:**

$$\Delta OR\ customer\ rate_t = \alpha + b_1 \frac{(\Delta OR\ starts_t + \Delta OR\ starts_{t-1})}{2} \tag{1}$$

$$\Delta WA\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln(US\ starts_t) + \Delta \ln(US\ starts_{t-1}))}{2} \tag{2}$$

**Commercial:**

$$\Delta OR\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln(OR\ pop_t) + \Delta \ln(OR\ pop_{t-1}) + \Delta \ln(OR\ pop_{t-2}))}{3} \tag{3}$$

$$\Delta WA\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln(OR\ emp_t) + \Delta \ln(OR\ emp_{t-1}) + \Delta \ln(OR\ emp_{t-2}))}{3} \tag{4}$$

The dependent and independent variables used in the equations are defined in Table B.1 while the estimated parameters of the equations are reported in Table B.2.

**Table B.1: Dependent and Independent Variables used in Equations (1) – (4)**

| Equation | Dependent Variable | Independent variable |
|---|---|---|
| (1) OR Residential | OR Residential Customer Growth | Change in housing stock (OR housing Starts) |
| (2) WA Residential | WA Residential Customer Growth | Change in housing stock (US housing Starts) |
| (3) OR Commercial | OR Commercial Customer Growth | Population growth (OR population) |
| (4) WA Commercial | WA Commercial Customer Growth | Local economic activity (Total employment growth in OR) |

[1] NW Natural projected U.S. housing starts by first using PRC at PSU's forecast of Oregon's population and the 1991–2021 average historical relationship between the annual average rates of growth of U.S. and Oregon's population to project U.S. population beyond 2027. The Company then used the average annual rate of change in projected U.S. population growth to project U.S. housing starts.

**Table B.2: Parameter Estimates for Equations (1) – (4)**

| Equation # | $\alpha$ | $b_1$ |
|---|---|---|
| 1 – OR Residential | -158 | 405** |
| 2 – WA Residential | 37 | 1,768** |
| 3 – OR Commercial | 29 | 64,625* |
| 4 – WA Commercial | 158** | 1.3* |

*Note that significance levels are indicated by asterisks: *p<0.1, **p<0.05, and ***p<0.01.*

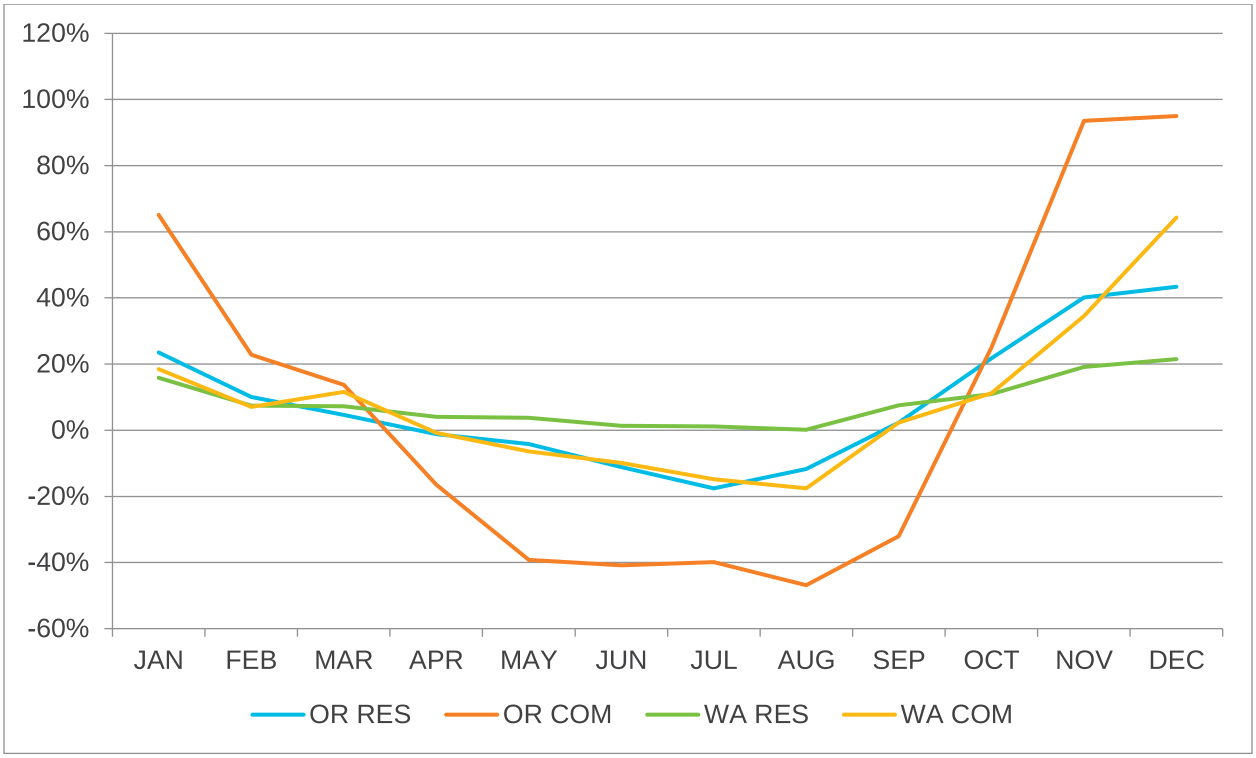
## B.1.2 Allocations

As shown in Table 3.2 Customer Count Series, for purposes of planning associated with the 2022 IRP, NW Natural has 10 load centers: eight in Oregon and two in Washington. The analysis of alternative approaches to forecasting customers described above results in four customer forecasts, each at the state-level: Oregon residential, Oregon commercial, Washington residential, and Washington commercial. As NW Natural has a need to forecast customers not only at the system or state-levels, but also at a more granular distribution level, the Company uses allocation methods to transform the four state-level forecasts into load center forecasts. Additionally, the customer forecasts at the state-level are for year-end and peak load forecasts require monthly forecasts of customers and NW Natural uses allocation methods to transform year-end customer values into monthly values. Methods used for allocations are described below.

### *Allocation to Months*

Figure B.1 shows the estimated monthly share of calendar year-over-year change in customers represented by each calendar month. Note that monthly share values for Oregon and Washington residential customers and for Washington commercial customers are similar, while those for Oregon Commercial are more extreme.

**Figure B.1: Monthly Shares of Calendar Year-over-Year Change in Customers**




## *Allocation to Load Centers*

NW Natural allocates month-over-month changes from state-level by month to load center by month on the basis of the contribution of each load center within the state to the increase in state-level customers over the September 2008 through December 2019 timeframe. These allocations are made separately for each of the four customer forecasts; i.e., Oregon residential, Oregon commercial, Washington residential, and Washington commercial.

Table B.3 shows the average annual rates of customer change by load center and state for residential customers and commercial customers over the 2022-2050 planning horizon. Note that NW Natural has provided service to Coos Bay for only two decades and there may be a relatively greater potential for customer change through conversions from other fuels in this load center than in other parts of the Company's service area.

**Table B.3: Average Annual Customer Reference Case Change Rates – 2022-2050**

| Load Center | | Residential | Commercial |
|---|---|---|---|
| OREGON | | | |
| Albany | | 0.7% | 0.6% |
| Astoria | | 1.2% | 0.4% |
| Coos Bay | | 4.7% | 4.2% |
| Columbia River Gorge – OR | | 1.5% | 0.8% |
| Eugene | | 1.2% | 0.9% |
| Lincoln City | | 1.0% | -0.1% |
| Portland | | 1.0% | 0.8% |
| Salem | | 1.0% | 1.1% |
| **Total Oregon** | | **1.0%** | **0.8%** |
| WASHINGTON | | | |
| Columbia River Gorge – WA | | 1.7% | 0.3% |
| Vancouver | | 2.6% | 1.9% |
| **Total Washington** | | **2.6%** | **1.8%** |

### *Allocation to Components of Customer Change*

NW Natural models separate usage profiles for existing customers, new construction customer additions, and conversion customer additions. Customer losses are accounted for by a declining existing customer count through time.

NW Natural used the "components" forecasts at state-level and projected customer loss rates based on the SME forecast for 2021-2024 and the new construction rate forecast for 2025 forward to allocate month-end customer levels at the load center level to these components. This was done by state and separately for residential and commercial customers. As the SME panel forecast includes the component detail, these allocations are for 2025 and subsequent years.

**Table B.4: UPC Model Coefficients**

| State | Load Center | Class | Sub-class | k0 | k1 | y0 | b1 | b2 | y2 |
|---|---|---|---|---|---|---|---|---|---|
| OR | ALB | C1 | com_exist | 55 | 65 | 6.669179 | -0.06265 | -0.55237 | 34.88348 |
| OR | AST | C1 | com_exist | 50 | 61 | 3.808998 | 0 | -0.43536 | 28.33427 |
| OR | COOS | C1 | com_exist | 53 | 63 | 4.247724 | 0 | -0.75662 | 49.61732 |
| OR | DALO | C1 | com_exist | 55 | 64 | 6.312669 | -0.04816 | -0.51628 | 33.47306 |
| WA | DALW | C1 | com_exist | 55 | 64 | 6.312669 | -0.04816 | -0.51628 | 33.47306 |
| OR | EUG | C1 | com_exist | 52 | 64 | 9.264012 | -0.08986 | -0.66883 | 41.67186 |
| OR | LC | C1 | com_exist | 52 | 60 | 5.314521 | 0 | -0.50649 | 32.63146 |
| OR | POR | C1 | com_exist | 50 | 64 | 8.348593 | -0.07674 | -0.69673 | 43.95235 |
| OR | SAL | C1 | com_exist | 54 | 64 | 6.269305 | -0.05467 | -0.66637 | 41.07671 |
| WA | VAN | C1 | com_exist | 50 | 64 | 8.754356 | -0.08192 | -0.64224 | 40.70289 |
| OR | ALB | R1 | res_exist | 52 | 68 | 1.233887 | -0.01193 | -0.14742 | 9.162369 |
| OR | AST | R1 | res_exist | 50 | 60 | 2.208741 | -0.02694 | -0.15716 | 9.543513 |
| OR | COOS | R1 | res_exist | 55 | 63 | 0.37091 | 0 | -0.15725 | 9.658525 |
| OR | DALO | R1 | res_exist | 50 | 64 | 1.322217 | -0.0121 | -0.10839 | 7.129867 |
| WA | DALW | R1 | res_exist | 50 | 64 | 1.322217 | -0.0121 | -0.10839 | 7.129867 |
| OR | EUG | R1 | res_exist | 51 | 67 | 1.064213 | -0.00879 | -0.13879 | 8.674684 |
| OR | LC | R1 | res_exist | 53 | 60 | 2.737316 | -0.03725 | -0.15457 | 9.122087 |
| OR | POR | R1 | res_exist | 50 | 65 | 1.798423 | -0.01901 | -0.1616 | 10.24808 |
| OR | SAL | R1 | res_exist | 52 | 68 | 1.060155 | -0.0087 | -0.1594 | 9.927056 |
| WA | VAN | R1 | res_exist | 50 | 66 | 1.687177 | -0.0162 | -0.16209 | 10.23714 |
| OR | | C1 | com_nc | 55 | 67 | 4.634968 | 0 | -0.89078 | 63.75738 |
| OR | | C1 | com_conv | 55 | 67 | 3.197445 | 0 | -0.59551 | 40.3124 |
| WA | | C1 | com_nc | 50 | 65 | 3.737502 | 0 | -0.59568 | 43.12067 |
| WA | | C1 | com_conv | 50 | 65 | 3.937895 | 0 | -1.03514 | 56.96523 |
| OR | | R1 | res_sfnc | 50 | 67 | 1.874433 | -0.02113 | -0.12682 | 8.2212 |
| OR | | R1 | res_mfnc | 50 | 67 | 0.414328 | -0.00475 | -0.04175 | 2.370682 |
| OR | | R1 | res_conv | 50 | 67 | 0.877146 | -0.00973 | -0.10727 | 7.004857 |
| WA | | R1 | res_conv | 53 | 68 | 0.265548 | 0 | -0.12328 | 7.740597 |
| WA | | R1 | res_sfnc | 53 | 68 | 0.25363 | 0 | -0.13705 | 8.493505 |
| WA | | R1 | res_mfnc | 53 | 68 | 0.156704 | 0 | -0.04737 | 2.869121 |

**Table B.5: Model Coefficients – Daily System Load**

| Driver | Units | Coefficients | Standard Error |
|---|---|---|---|
| Temperature | Hourly Average (°F) | 15,852.05 | 6,749.16 |
| Previous Day Temperature | Hourly Average (°F) | -8,615.11 | 318.22 |
| + Temperature Interaction | | 138.14 | 6.83 |
| Solar Radiation | Daily Sum (watts/$m^2$) | -12.72 | 2.38 |
| + Temperature Interaction | | 0.15 | 0.05 |
| Wind Speed | Hourly Average (mph) | 5,341.27 | 662.89 |
| + Temperature Interaction | | -44.84 | 15.43 |
| Snow Depth | Daily Measure (inches) | -24,821.04 | 5,350.68 |
| + Temperature Interaction | | 636.52 | 174.26 |
| Customer Count | N/A | 2.67 | 0.47 |
| + Temperature Interaction | | -0.05 | 0.01 |
| Friday Indicator | N/A | -35,274.63 | 7,015.24 |
| + Temperature Interaction | | 576.74 | 154.40 |
| Saturday Indicator | N/A | -52,131.89 | 7,665.59 |
| + Temperature Interaction | | 708.40 | 172.08 |
| Sunday Indicator | N/A | -44,956.72 | 6,960.35 |
| + Temperature Interaction | | 677.02 | 156.96 |
| Holiday Indicator | N/A | -26,295.56 | 3,353.69 |
| Annual Time Trend | Years after 2008 | -16,419.67 | 4,454.15 |
| + Temperature Interaction | | 381.99 | 100.01 |
| Bull Run Creek Temperature | Daily Measure (°F) | -1,539.93 | 128.64 |
| COVID-19 Indicator | | (69,350.23) | 19140.87 |
| + Temperature Interaction | | 1,526.86 | 429.7813 |
| Constant | | -504,550.50 | 299,508.80 |

# Appendix C
# Avoided Costs

## C.1 Levelized Avoided Costs by State and End Use

### Table C.1: Avoided Cost Summary by State, Year, and Policy

| Year | Real (2020$) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Infrastructure Costs | | | | Commodity Costs | | Environmental Compliance Costs | | | |
| | Supply ($/Dth/Day) | Washington Distribution ($/Dth/Hour) | Oregon Distribution ($/Dth/Hour) | System Distribution ($/Dth/Hour) | Gas and Transport Costs ($/Dth) | Hedge Value ($/Dth) | Oregon Carbon Policy Scenarios ($/Dth) | | | Washington Carbon Price: Social Cost of |
| | | | | | | | Base Case | SCC | High Sensitivity | |
| **2022** | $0.058 | $0.747 | $0.451 | $0.485 | $3.589 | $0.520 | $4.235 | $4.235 | $8.698 | $5.054 |
| **2023** | $0.058 | $0.747 | $0.451 | $0.485 | $3.133 | $0.520 | $4.322 | $4.322 | $8.900 | $5.158 |
| **2024** | $0.058 | $0.747 | $0.451 | $0.485 | $2.672 | $0.520 | $4.409 | $4.409 | $9.103 | $5.261 |
| **2025** | $0.058 | $0.747 | $0.451 | $0.485 | $2.602 | $0.520 | $4.496 | $4.496 | $9.305 | $5.365 |
| **2026** | $0.058 | $0.747 | $0.451 | $0.485 | $2.567 | $0.520 | $4.562 | $4.562 | $9.494 | $5.444 |
| **2027** | $0.058 | $0.747 | $0.451 | $0.485 | $2.546 | $0.520 | $4.628 | $4.628 | $9.683 | $5.523 |
| **2028** | $0.058 | $0.747 | $0.451 | $0.485 | $2.538 | $0.520 | $4.694 | $4.694 | $9.871 | $5.602 |
| **2029** | $0.058 | $0.747 | $0.451 | $0.485 | $2.535 | $0.520 | $4.760 | $4.760 | $10.060 | $5.681 |
| **2030** | $0.058 | $0.747 | $0.451 | $0.485 | $2.609 | $0.520 | $4.826 | $4.826 | $10.249 | $5.759 |
| **2031** | $0.058 | $0.747 | $0.451 | $0.485 | $2.672 | $0.520 | $7.848 | $4.892 | $10.465 | $5.838 |
| **2032** | $0.058 | $0.747 | $0.451 | $0.485 | $2.663 | $0.520 | $7.578 | $4.958 | $10.681 | $5.917 |
| **2033** | $0.058 | $0.747 | $0.451 | $0.485 | $2.601 | $0.520 | $7.359 | $5.025 | $10.896 | $5.996 |
| **2034** | $0.058 | $0.747 | $0.451 | $0.485 | $2.631 | $0.520 | $7.093 | $5.091 | $11.112 | $6.075 |
| **2035** | $0.058 | $0.747 | $0.451 | $0.485 | $2.652 | $0.520 | $6.888 | $5.157 | $11.328 | $6.154 |
| **2036** | $0.058 | $0.747 | $0.451 | $0.485 | $2.648 | $0.520 | $6.748 | $5.230 | $11.530 | $6.241 |
| **2037** | $0.058 | $0.747 | $0.451 | $0.485 | $2.673 | $0.520 | $6.709 | $5.303 | $11.732 | $6.329 |
| **2038** | $0.058 | $0.747 | $0.451 | $0.485 | $2.729 | $0.520 | $6.622 | $5.376 | $11.935 | $6.416 |
| **2039** | $0.058 | $0.747 | $0.451 | $0.485 | $2.818 | $0.520 | $6.411 | $5.450 | $12.137 | $6.504 |
| **2040** | $0.058 | $0.747 | $0.451 | $0.485 | $2.867 | $0.520 | $6.330 | $5.523 | $12.339 | $6.591 |
| **2041** | $0.058 | $0.747 | $0.451 | $0.485 | $2.891 | $0.520 | $6.468 | $5.588 | $12.528 | $6.669 |
| **2042** | $0.058 | $0.747 | $0.451 | $0.485 | $2.894 | $0.520 | $6.382 | $5.653 | $12.717 | $6.746 |
| **2043** | $0.058 | $0.747 | $0.451 | $0.485 | $2.902 | $0.520 | $6.260 | $5.718 | $12.906 | $6.824 |
| **2044** | $0.058 | $0.747 | $0.451 | $0.485 | $2.947 | $0.520 | $6.101 | $5.783 | $13.094 | $6.901 |
| **2045** | $0.058 | $0.747 | $0.451 | $0.485 | $3.064 | $0.520 | $5.975 | $5.848 | $13.283 | $6.979 |
| **2046** | $0.058 | $0.747 | $0.451 | $0.485 | $3.047 | $0.520 | $5.816 | $5.924 | $13.486 | $7.069 |
| **2047** | $0.058 | $0.747 | $0.451 | $0.485 | $3.044 | $0.520 | $5.756 | $5.999 | $13.688 | $7.160 |
| **2048** | $0.058 | $0.747 | $0.451 | $0.485 | $3.027 | $0.520 | $5.547 | $6.075 | $13.890 | $7.250 |
| **2049** | $0.058 | $0.747 | $0.451 | $0.485 | $3.158 | $0.520 | $5.375 | $6.151 | $14.092 | $7.341 |
| **2050** | $0.058 | $0.747 | $0.451 | $0.485 | $3.184 | $0.520 | $5.400 | $6.227 | $14.295 | $7.431 |
| **Levelized** | **$0.058** | **$0.747** | **$0.451** | **$0.485** | **$2.802** | **$0.520** | **$5.692** | **$5.059** | **$10.982** | **$6.037** |

**Figure C.1: Oregon 30-year Levelized Avoided Costs by End Use**

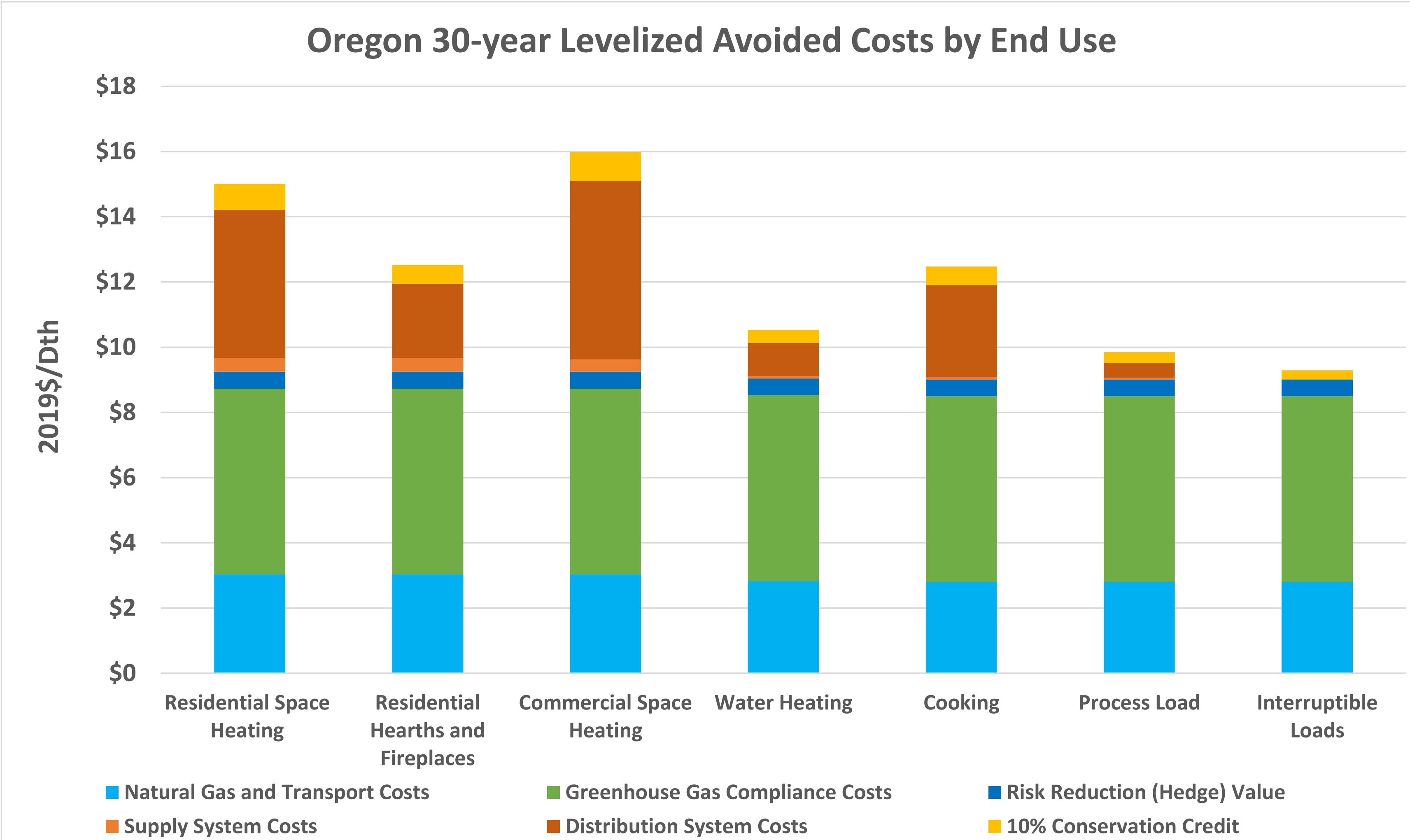
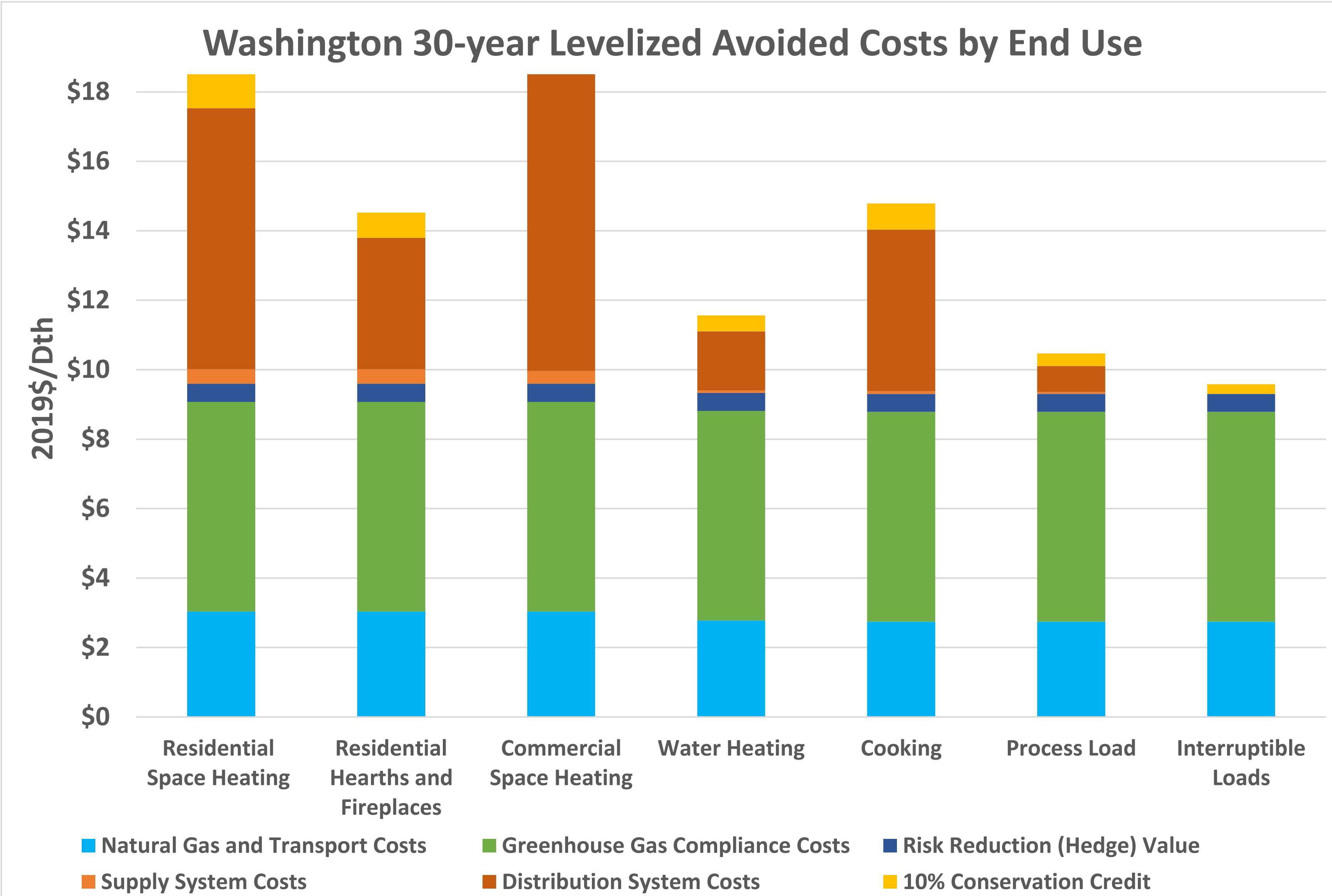


**Figure C.2: Washington 30-year Levelized Avoided Costs by End Use**



## Table C.2: Avoided Cost by Year and End Use

| | Oregon Total Avoided Costs by End Use (2019$) | | | | | | | Washington Total Avoided Costs by End Use (2019$) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Residential Space Heating | Residential Hearths and Fireplaces | Commercial Space Heating | Water Heating | Cooking | Process Load | Interruptible Load | Residential Space Heating | Residential Hearths and Fireplaces | Commercial Space Heating | Water Heating | Cooking | Process Load | Interruptible Load |
| **2022** | $14.60 | $12.12 | $15.58 | $9.98 | $11.88 | $9.26 | $8.70 | $18.70 | $14.59 | $20.35 | $11.54 | $14.73 | $10.41 | $9.52 |
| **2023** | $14.01 | $11.52 | $14.98 | $9.54 | $11.47 | $8.85 | $8.29 | $18.12 | $14.01 | $19.77 | $11.12 | $14.33 | $10.01 | $9.12 |
| **2024** | $13.53 | $11.05 | $14.51 | $9.10 | $11.04 | $8.43 | $7.87 | $17.66 | $13.55 | $19.31 | $10.69 | $13.93 | $9.61 | $8.72 |
| **2025** | $13.58 | $11.10 | $14.56 | $9.11 | $11.06 | $8.44 | $7.88 | $17.72 | $13.62 | $19.38 | $10.72 | $13.96 | $9.63 | $8.75 |
| **2026** | $13.63 | $11.15 | $14.60 | $9.14 | $11.08 | $8.47 | $7.91 | $17.78 | $13.68 | $19.44 | $10.76 | $14.00 | $9.67 | $8.79 |
| **2027** | $13.65 | $11.17 | $14.63 | $9.18 | $11.13 | $8.51 | $7.95 | $17.82 | $13.72 | $19.48 | $10.82 | $14.05 | $9.73 | $8.84 |
| **2028** | $13.70 | $11.21 | $14.67 | $9.24 | $11.18 | $8.56 | $8.01 | $17.88 | $13.77 | $19.53 | $10.88 | $14.12 | $9.80 | $8.91 |
| **2029** | $13.79 | $11.31 | $14.77 | $9.30 | $11.25 | $8.63 | $8.07 | $17.99 | $13.88 | $19.64 | $10.97 | $14.20 | $9.87 | $8.99 |
| **2030** | $13.91 | $11.43 | $14.89 | $9.45 | $11.39 | $8.78 | $8.22 | $18.12 | $14.02 | $19.78 | $11.12 | $14.36 | $10.03 | $9.15 |
| **2031** | $16.99 | $14.51 | $17.97 | $12.54 | $14.48 | $11.87 | $11.31 | $18.25 | $14.15 | $19.91 | $11.27 | $14.51 | $10.18 | $9.30 |
| **2032** | $16.74 | $14.26 | $17.72 | $12.26 | $14.20 | $11.59 | $11.03 | $18.36 | $14.25 | $20.01 | $11.34 | $14.57 | $10.25 | $9.37 |
| **2033** | $16.47 | $13.98 | $17.44 | $11.98 | $13.92 | $11.30 | $10.74 | $18.38 | $14.27 | $20.03 | $11.35 | $14.58 | $10.26 | $9.38 |
| **2034** | $16.25 | $13.77 | $17.23 | $11.75 | $13.68 | $11.07 | $10.51 | $18.51 | $14.40 | $20.16 | $11.47 | $14.70 | $10.37 | $9.49 |
| **2035** | $16.02 | $13.54 | $17.00 | $11.56 | $13.50 | $10.89 | $10.33 | $18.56 | $14.46 | $20.22 | $11.56 | $14.80 | $10.48 | $9.59 |
| **2036** | $15.91 | $13.43 | $16.88 | $11.42 | $13.36 | $10.74 | $10.18 | $18.67 | $14.57 | $20.33 | $11.65 | $14.88 | $10.56 | $9.67 |
| **2037** | $15.92 | $13.44 | $16.90 | $11.41 | $13.35 | $10.73 | $10.17 | $18.82 | $14.71 | $20.47 | $11.77 | $15.00 | $10.67 | $9.79 |
| **2038** | $15.89 | $13.41 | $16.87 | $11.38 | $13.32 | $10.70 | $10.14 | $18.96 | $14.85 | $20.61 | $11.92 | $15.15 | $10.82 | $9.94 |
| **2039** | $15.76 | $13.28 | $16.74 | $11.26 | $13.21 | $10.59 | $10.03 | $19.13 | $15.02 | $20.78 | $12.10 | $15.33 | $11.01 | $10.12 |
| **2040** | $15.74 | $13.26 | $16.72 | $11.24 | $13.18 | $10.56 | $10.00 | $19.28 | $15.17 | $20.93 | $12.24 | $15.47 | $11.15 | $10.27 |
| **2041** | $15.88 | $13.40 | $16.86 | $11.40 | $13.35 | $10.73 | $10.17 | $19.36 | $15.25 | $21.01 | $12.34 | $15.58 | $11.25 | $10.37 |
| **2042** | $15.81 | $13.33 | $16.79 | $11.32 | $13.26 | $10.64 | $10.09 | $19.45 | $15.34 | $21.10 | $12.42 | $15.66 | $11.33 | $10.45 |
| **2043** | $15.67 | $13.19 | $16.65 | $11.20 | $13.15 | $10.53 | $9.97 | $19.51 | $15.40 | $21.16 | $12.51 | $15.74 | $11.42 | $10.54 |
| **2044** | $15.55 | $13.07 | $16.52 | $11.09 | $13.04 | $10.42 | $9.86 | $19.62 | $15.51 | $21.28 | $12.63 | $15.87 | $11.55 | $10.66 |
| **2045** | $15.52 | $13.04 | $16.50 | $11.09 | $13.04 | $10.42 | $9.86 | $19.80 | $15.69 | $21.45 | $12.83 | $16.08 | $11.75 | $10.87 |
| **2046** | $15.36 | $12.88 | $16.34 | $10.92 | $12.86 | $10.25 | $9.69 | $19.89 | $15.78 | $21.54 | $12.91 | $16.15 | $11.83 | $10.94 |
| **2047** | $15.27 | $12.79 | $16.24 | $10.85 | $12.80 | $10.18 | $9.62 | $19.95 | $15.84 | $21.60 | $12.99 | $16.24 | $11.91 | $11.03 |
| **2048** | $15.06 | $12.58 | $16.03 | $10.63 | $12.57 | $9.96 | $9.40 | $20.04 | $15.93 | $21.69 | $13.07 | $16.31 | $11.99 | $11.10 |
| **2049** | $14.99 | $12.51 | $15.97 | $10.59 | $12.55 | $9.93 | $9.37 | $20.23 | $16.13 | $21.89 | $13.30 | $16.54 | $12.22 | $11.33 |
| **2050** | $14.94 | $12.46 | $15.91 | $10.64 | $12.60 | $9.98 | $9.42 | $20.24 | $16.13 | $21.90 | $13.41 | $16.66 | $12.34 | $11.45 |
| **Levelized** | **$15.01** | **$12.52** | **$15.98** | **$10.53** | **$12.47** | **$9.85** | **$9.29** | **$18.63** | **$14.52** | **$20.28** | **$11.62** | **$14.85** | **$10.52** | **$9.64** |

## C.2 Avoided Costs by IRP and State

**Figure C.3: Oregon Levelized Costs by IRP**

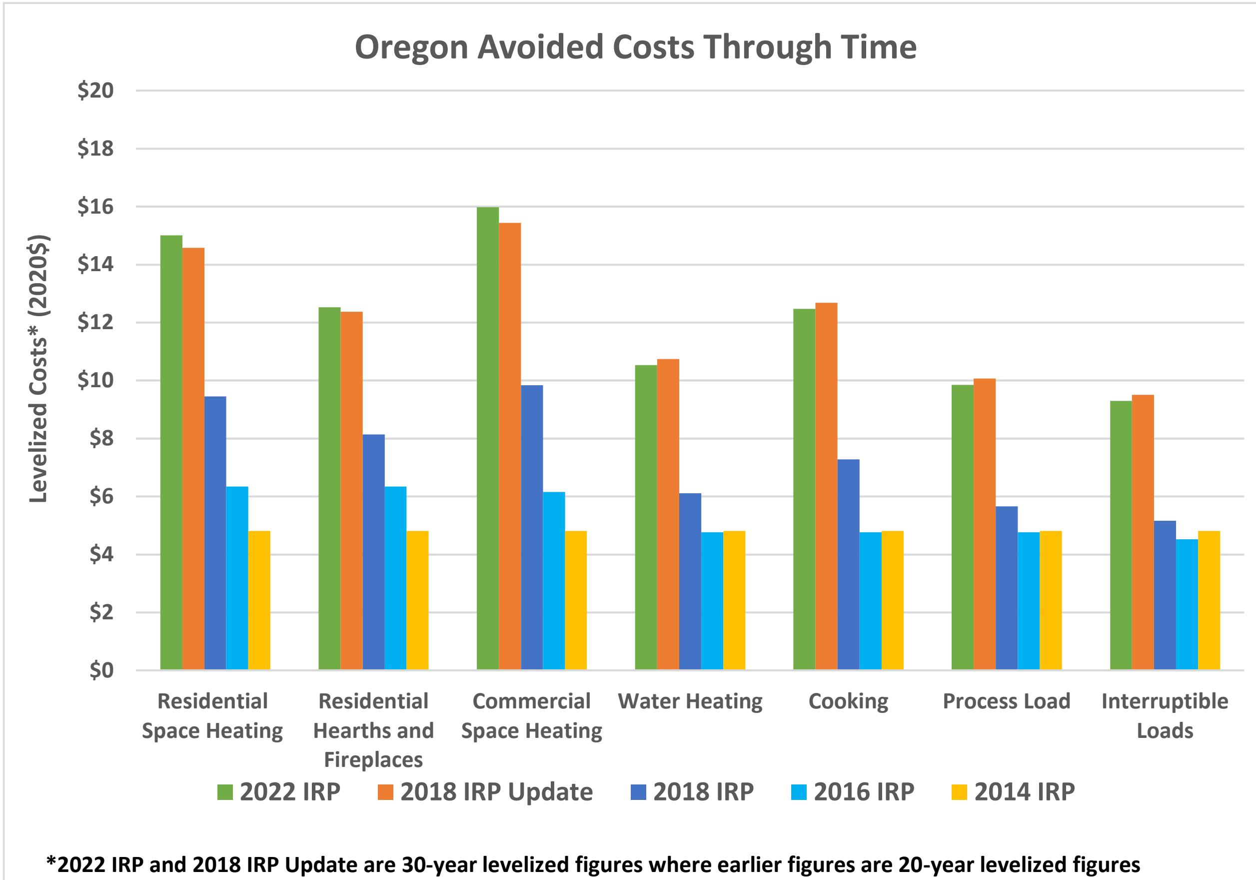


**Figure C.4: Washington Levelized Costs by IRP**

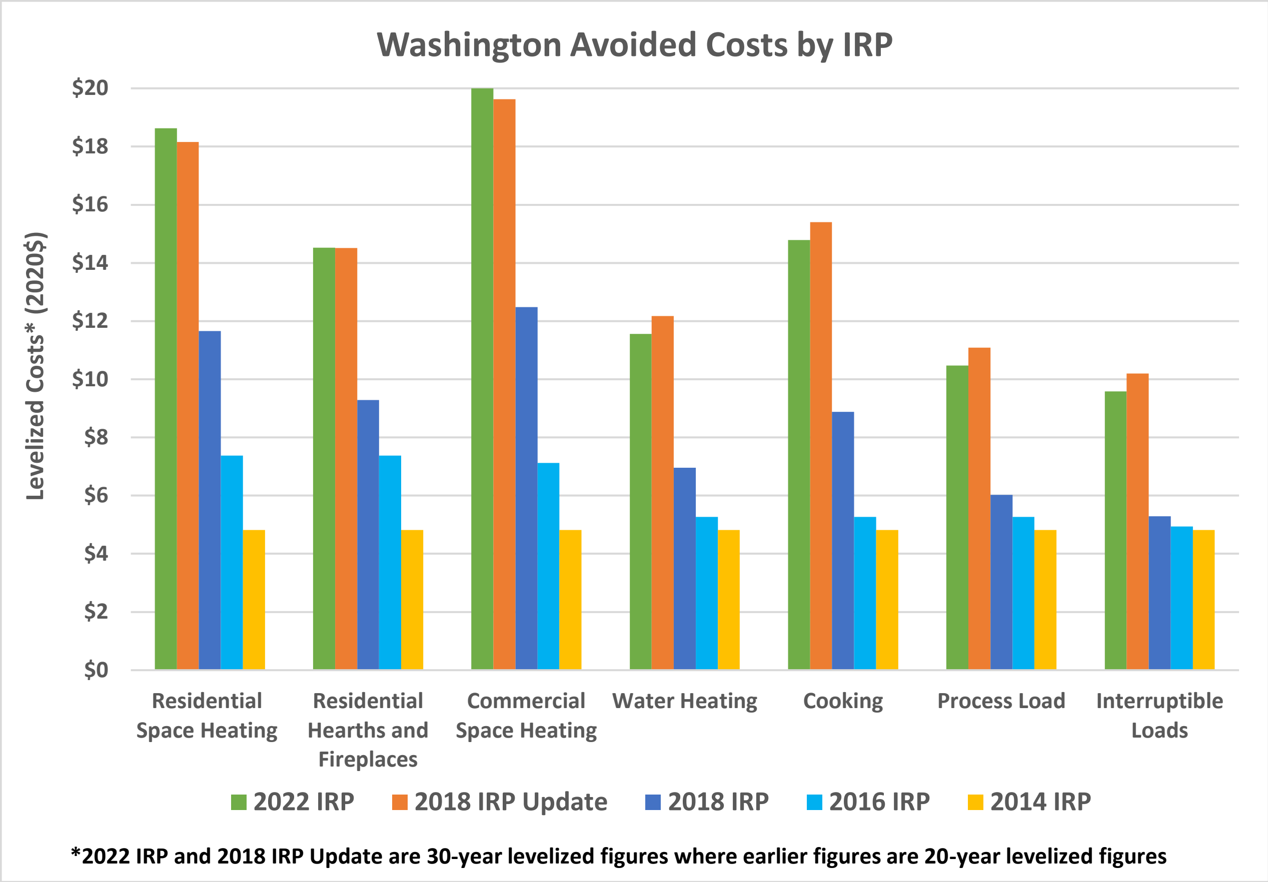


**Figure C.5: Oregon Change in Levelized Costs: 2022 IRP vs 2018 IRP Update**

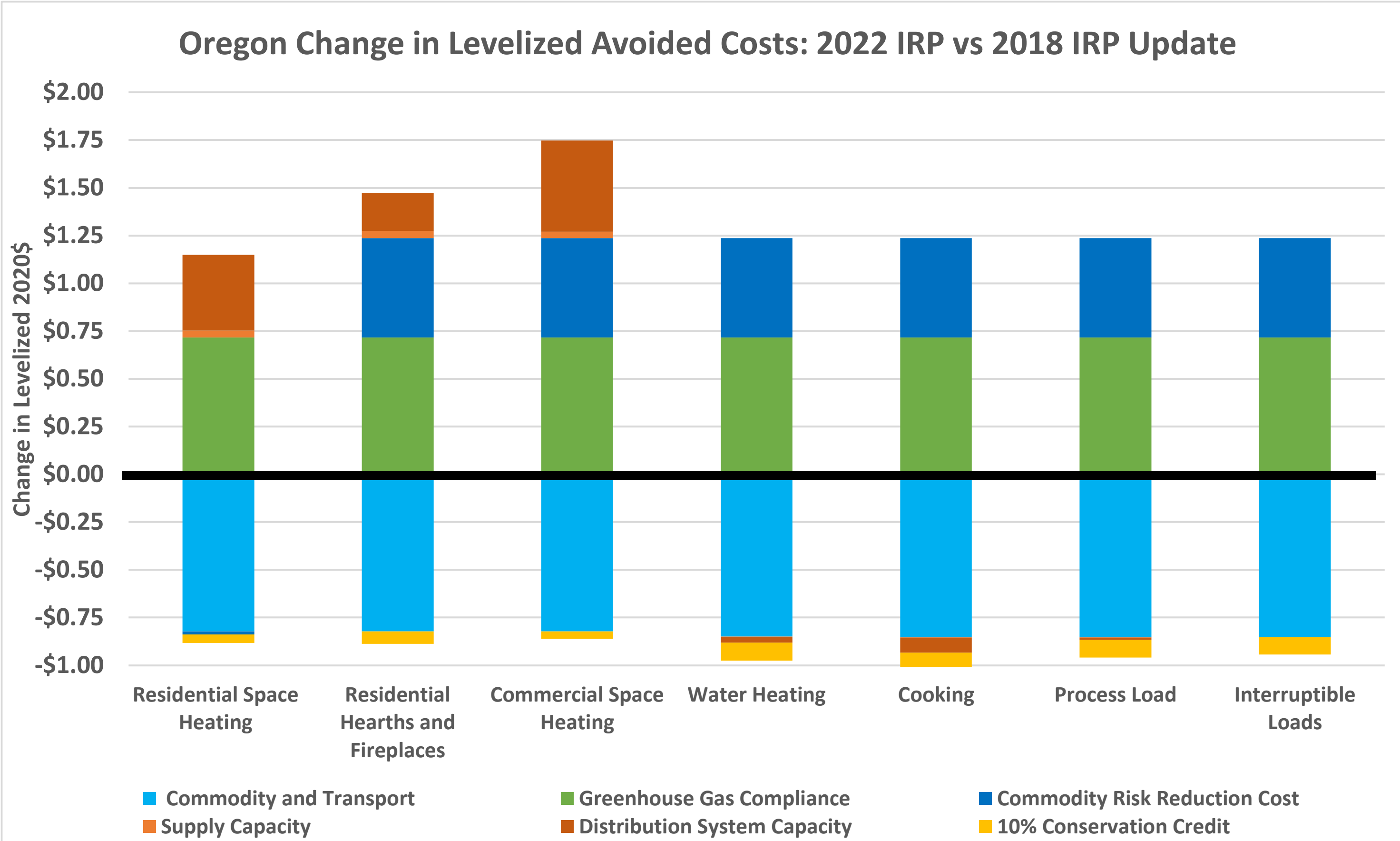
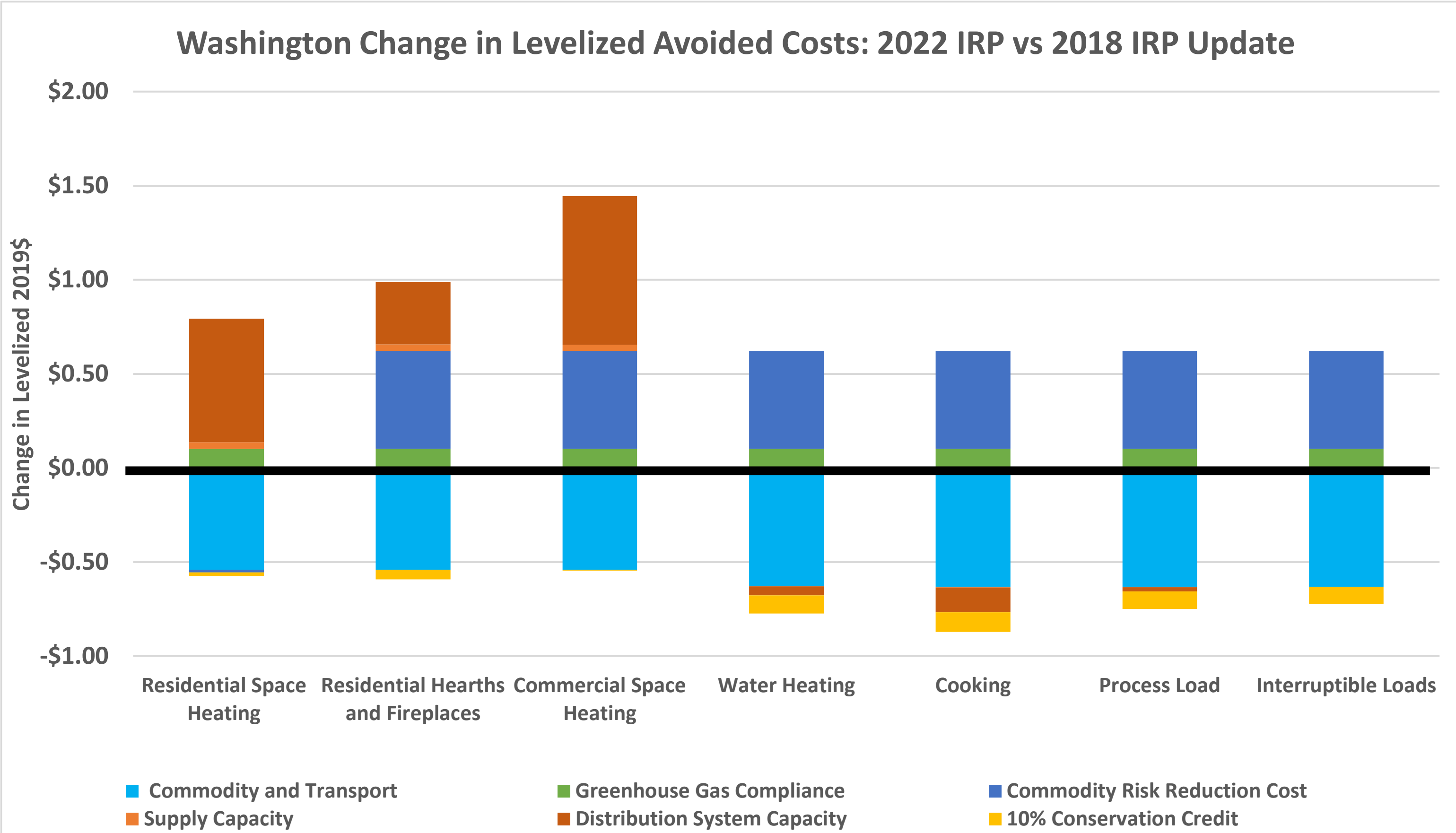


**Figure C.6: Washington Change in Levelized Costs: 2022 IRP vs 2018 IRP Update**



## C.3 Total Avoided Costs by End Use and Year

**Figure C.7: Oregon Total Avoided Costs by End Use and Year**

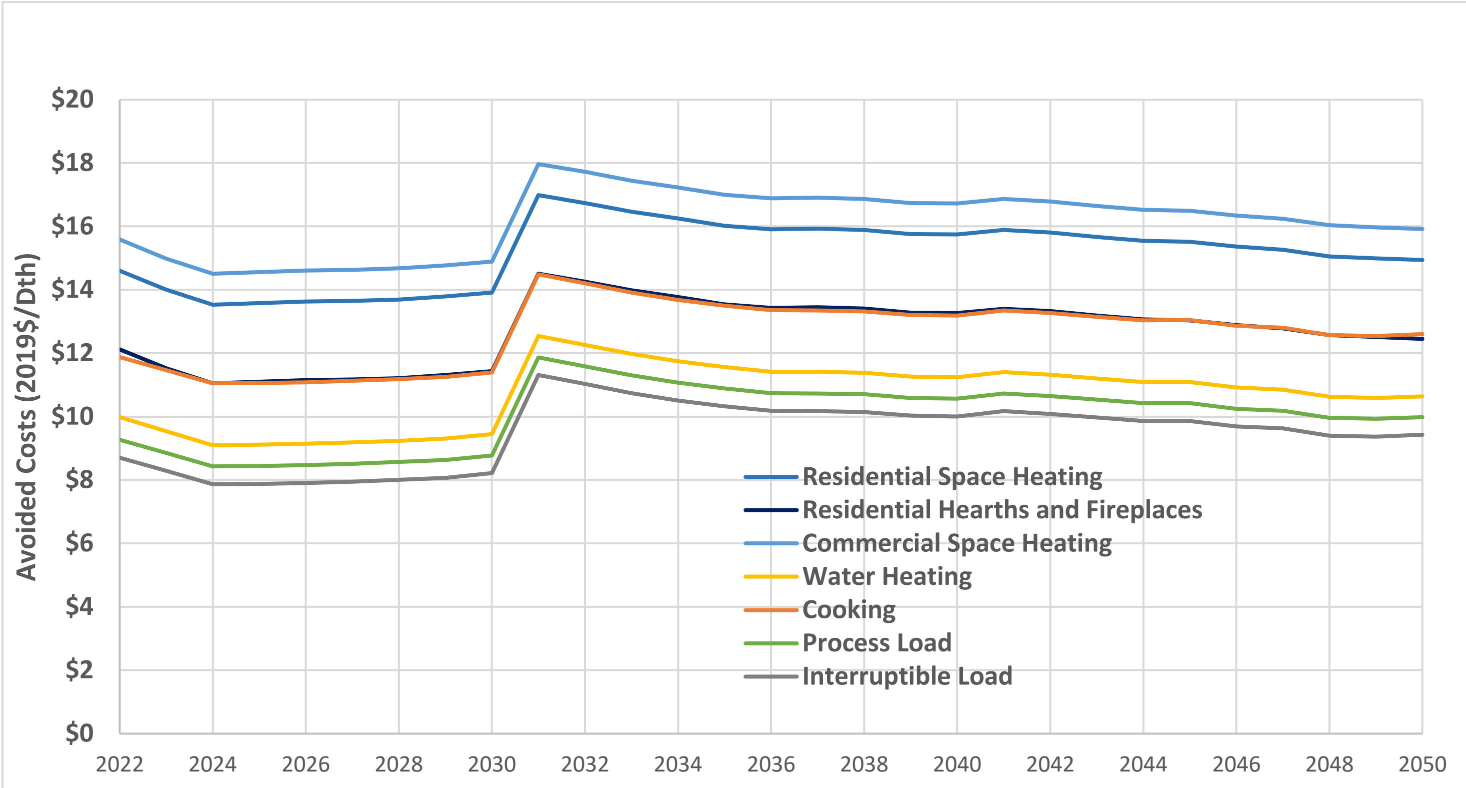


**Figure C.8: Washington Total Avoided Costs by End Use and Year**

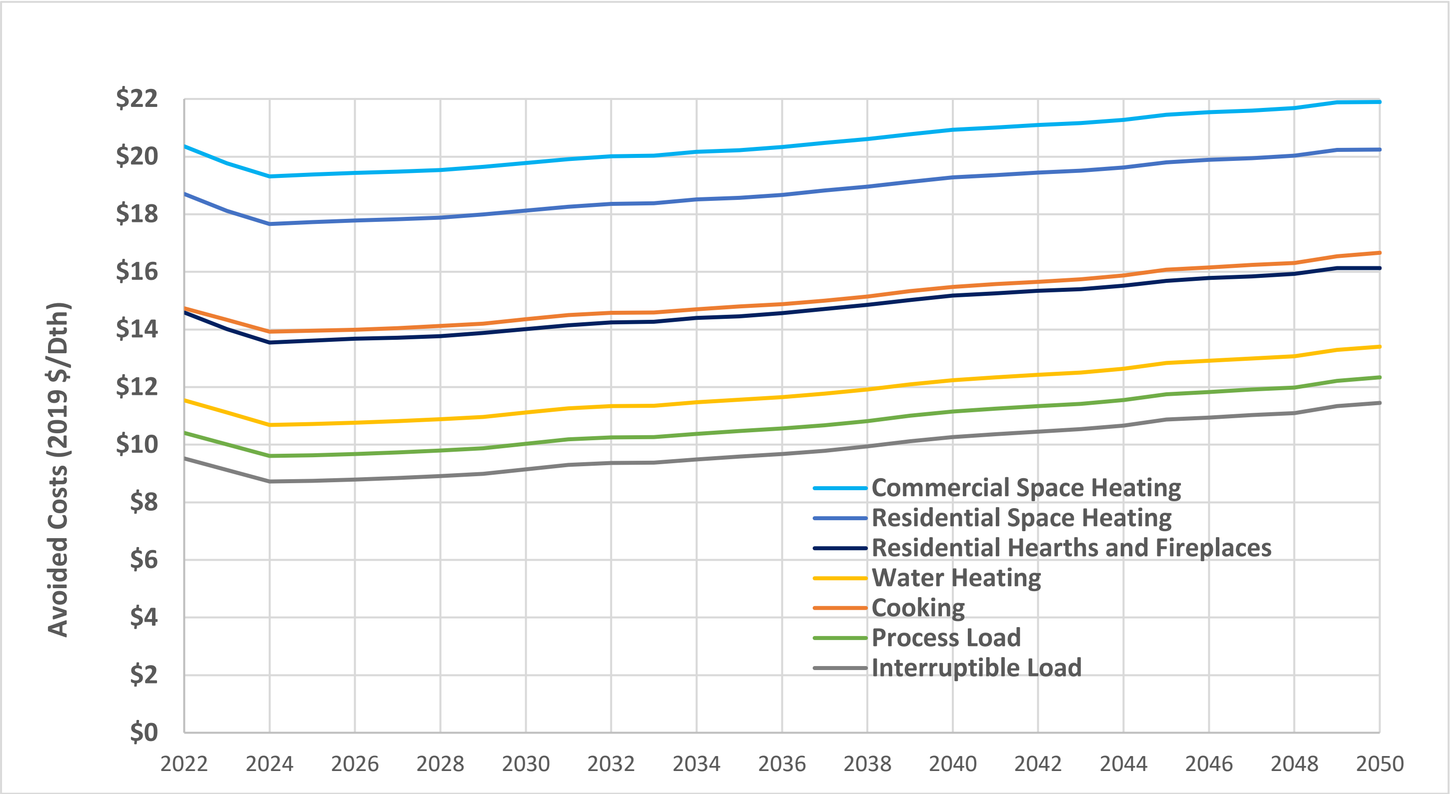


**Figure C.9: Residential Space Heating Avoided Cost Breakdown – Oregon**

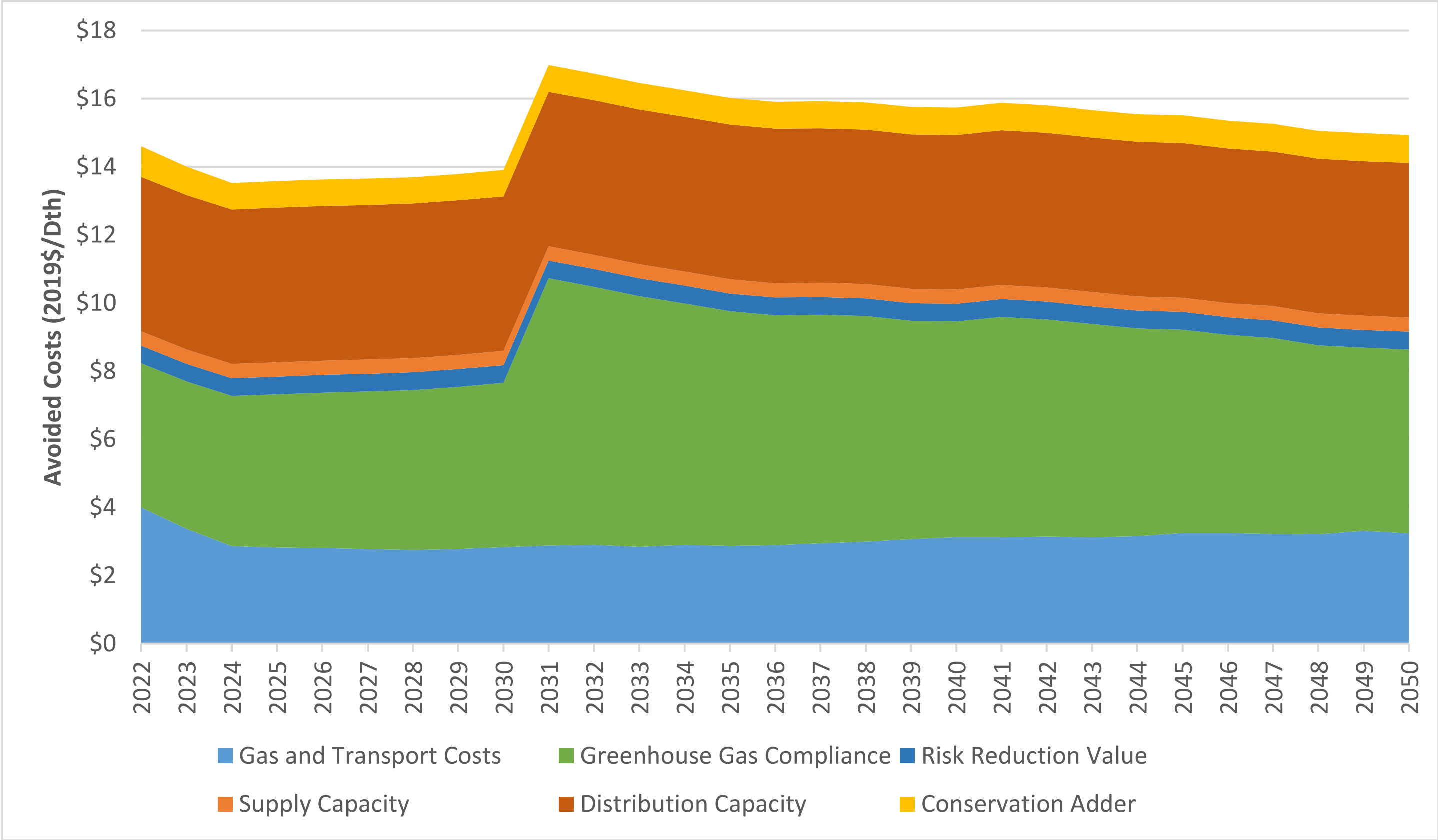
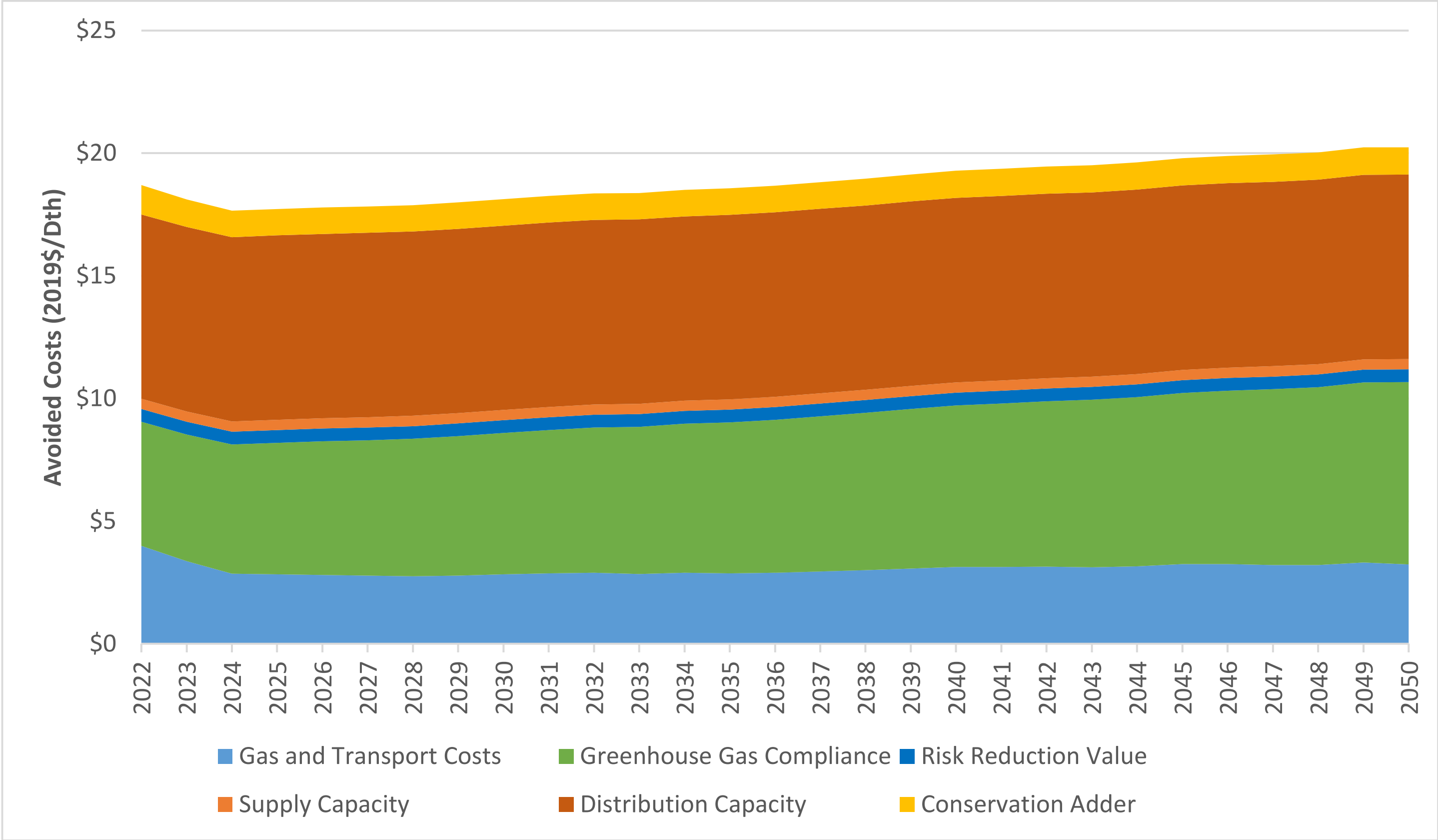


**Figure C.10: Residential Space Heating Avoided Cost Breakdown– Washington**



# Appendix D
# Demand-Side Resources

## D.1 Deployment Summary

See following pages

## Table D.1: Oregon Deployment Summary 2022-2031

| Gross Savings (Therms) | | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| New Buildings (Includes MF) | Com-New | 359,446 | 311,166 | 299,823 | 295,903 | 298,584 | 293,030 | 306,078 | 320,806 | 332,610 | 345,016 |
| | NEEA-MartetTX | 122,242 | 367,872 | 385,638 | 385,638 | 385,638 | 378,826 | 372,135 | 365,561 | 359,104 | 352,761 |
| Existing Buildings (No MF) | Com-ROB | 221,743 | 320,669 | 333,054 | 347,365 | 348,776 | 367,482 | 383,907 | 398,060 | 410,154 | 420,707 |
| | Com-SEM | 285,575 | 418,683 | 444,633 | 479,044 | 485,792 | 482,760 | 511,022 | 524,242 | 519,899 | 497,621 |
| | Com-RET | 1,252,113 | 1,706,450 | 1,804,364 | 1,794,076 | 1,719,743 | 1,615,804 | 1,472,899 | 1,386,060 | 1,177,535 | 951,104 |
| Industrial | Ind-RET | 1,218,366 | 1,422,372 | 1,527,633 | 1,754,348 | 1,756,483 | 1,560,709 | 1,415,177 | 1,183,336 | 916,988 | 665,824 |
| | Ind-SEM | 27,988 | 30,000 | 30,000 | 30,000 | 30,000 | 29,622 | 29,345 | 29,069 | 28,792 | 28,404 |
| | Ind-ROB | 54,910 | 64,936 | 69,741 | 80,091 | 80,189 | 81,257 | 81,752 | 82,212 | 82,686 | 83,163 |
| Residential New | Res-ManufNH | 1,590 | 3,394 | 3,394 | 3,394 | 3,394 | 3,340 | 3,280 | 3,215 | 3,147 | 3,076 |
| | Res-NewHomes | 255,034 | 247,674 | 145,991 | 145,991 | 145,991 | 186,669 | 234,560 | 288,258 | 358,029 | 426,311 |
| | Res-MarketTx | 820,903 | 870,834 | 1,261,157 | 1,261,156 | 1,261,157 | 1,246,781 | 1,236,441 | 1,219,839 | 1,201,150 | 1,179,261 |
| Residential Existing | Res-Tstat | 574,496 | 705,768 | 1,013,410 | 1,064,081 | 1,117,285 | 1,057,379 | 1,004,745 | 880,335 | 711,649 | 534,480 |
| | Res-TstatOpt | 40,390 | 3,527 | 4,341 | 4,341 | 4,341 | 24,462 | 42,551 | 58,467 | 72,064 | 83,194 |
| | Res-WaterHeat | 37,539 | 32,986 | 41,232 | 41,232 | 41,232 | 78,543 | 124,096 | 178,502 | 241,961 | 312,936 |
| | Res-Shell | 186,605 | 464,534 | 444,344 | 411,719 | 434,444 | 475,058 | 525,361 | 558,933 | 569,174 | 552,569 |
| | Res-Heat-ROB | 257,703 | 317,791 | 376,317 | 376,317 | 376,317 | 430,711 | 487,492 | 546,150 | 658,470 | 729,087 |
| Multi-family Existing | MF-RET | 48,845 | 65,329 | 68,060 | 68,775 | 66,396 | 53,386 | 44,556 | 33,898 | 23,782 | 15,649 |
| | MF-ROB | 87,791 | 126,957 | 131,860 | 137,526 | 138,084 | 142,490 | 145,887 | 135,532 | 138,790 | 140,288 |
| Other | Large-Project Adder | - | - | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 |
| | Com-Cooking | 269,935 | 269,229 | 274,888 | 273,136 | 280,248 | 288,500 | 304,584 | 298,608 | 329,099 | 339,447 |
| | **Total** | **6,123,213** | **7,750,168** | **8,910,070** | **9,204,324** | **9,224,283** | **9,046,998** | **8,976,058** | **8,741,271** | **8,385,273** | **7,911,087** |

## Table D.2: Oregon Deployment Summary 2032-2041

| Gross Savings (Therms) | | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| New Buildings (Includes MF) | Com-New | 356,429 | 368,124 | 378,712 | 389,431 | 397,989 | 411,209 | 418,551 | 427,635 | 436,882 | 446,892 | 7,194,314 |
| | NEEA-MartetTX | 346,530 | 340,409 | 334,396 | 328,489 | 322,687 | 316,987 | 311,388 | 305,888 | 300,485 | 295,177 | 6,677,850 |
| Existing Buildings (No MF) | Com-ROB | 427,461 | 423,704 | 424,381 | 417,961 | 314,368 | 313,100 | 321,174 | 324,487 | 280,479 | 229,951 | 7,028,983 |
| | Com-SEM | 459,479 | 409,603 | 353,234 | 295,580 | 240,877 | 191,911 | 150,099 | 115,649 | 75,851 | - | 6,941,554 |
| | Com-RET | 736,533 | 553,203 | 364,862 | 93,825 | 61,697 | 45,676 | 47,463 | 47,971 | 47,020 | 44,623 | 16,923,018 |
| Industrial | Ind-RET | 459,807 | 306,262 | 200,905 | 131,482 | 32,547 | 13,632 | 14,298 | 14,551 | 14,350 | 13,637 | 14,622,706 |
| | Ind-SEM | 27,961 | 27,343 | 26,791 | 26,220 | 25,668 | 25,021 | 24,453 | 23,612 | 23,612 | 23,124 | 547,028 |
| | Ind-ROB | 83,663 | 83,979 | 84,527 | 85,048 | 85,665 | 85,978 | 86,593 | 87,235 | 71,564 | 52,964 | 1,568,151 |
| Residential New | Res-ManufNH | 3,101 | 3,028 | 2,955 | 2,929 | 2,855 | 2,829 | 2,755 | 2,729 | 2,656 | 2,582 | 59,640 |
| | Res-NewHomes | 466,792 | 501,887 | 575,577 | 651,840 | 702,185 | 744,127 | 810,597 | 872,941 | 929,569 | 988,534 | 9,678,559 |
| | Res-MarketTx | 1,080,834 | 984,912 | 969,147 | 953,242 | 902,688 | 851,020 | 834,420 | 817,960 | 801,362 | 791,860 | 20,546,124 |
| Residential Existing | Res-Tstat | 377,392 | 254,040 | 165,202 | 67,683 | - | - | - | - | - | - | 9,527,945 |
| | Res-TstatOpt | 91,706 | 105,028 | 117,817 | 130,024 | 141,596 | 39,690 | - | - | - | - | 963,537 |
| | Res-WaterHeat | 390,302 | 471,231 | 552,111 | 629,201 | 699,413 | 760,905 | 813,239 | 857,110 | 893,851 | 924,975 | 8,122,597 |
| | Res-Shell | 510,309 | 448,373 | 375,770 | 301,802 | 232,598 | 174,699 | 128,272 | 92,517 | 65,851 | 31,639 | 6,984,574 |
| | Res-Heat-ROB | 795,126 | 860,256 | 923,720 | 984,821 | 1,042,959 | 1,097,649 | 1,148,532 | 1,195,384 | 1,238,102 | 1,276,696 | 15,119,602 |
| Multi-family Existing | MF-RET | 9,830 | 3,454 | - | - | - | - | - | - | - | - | 501,960 |
| | MF-ROB | 141,173 | 143,040 | 136,555 | 136,869 | 131,023 | 130,050 | 128,637 | 129,697 | 141,977 | 86,404 | 2,630,630 |
| Other | Large-Project Adder | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 4,503,423 |
| | Com-Cooking | 365,716 | 351,959 | 379,521 | 387,447 | 413,574 | 391,257 | 417,357 | 423,554 | 450,636 | 425,190 | 6,933,882 |
| | **Total** | **7,380,334** | **6,890,025** | **6,616,373** | **6,264,086** | **6,000,579** | **5,845,930** | **5,908,019** | **5,989,110** | **6,024,436** | **5,884,439** | **147,076,076** |

## Table D.3: Oregon Deployment Summary 2041-2050

| Gross Savings (Therms) | | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **New Buildings (Includes MF)** | Com-New | 453,346 | 456,341 | 462,099 | 466,565 | 470,927 | 477,998 | 482,517 | 486,536 | 490,536 | 11,441,179 |
| | NEEA-MartetTX | 289,963 | 284,841 | 279,810 | 274,867 | 270,012 | 265,243 | 260,557 | 255,955 | 251,434 | 9,110,532 |
| **Existing Buildings (No MF)** | Com-ROB | 233,847 | 211,126 | 246,036 | 241,161 | 267,003 | 223,846 | 255,330 | 253,444 | 278,312 | 9,239,088 |
| | Com-SEM | - | - | - | - | - | - | - | - | - | 6,941,554 |
| | Com-RET | 40,999 | 36,447 | 31,445 | 26,398 | 21,636 | 17,373 | 13,714 | 10,676 | 8,220 | 17,129,926 |
| **Industrial** | Ind-RET | 12,573 | 11,222 | 9,724 | 8,166 | 6,715 | 5,409 | 4,286 | 3,336 | 2,577 | 14,686,714 |
| | Ind-SEM | - | - | - | - | - | - | - | - | - | 547,028 |
| | Ind-ROB | 33,794 | 11,452 | 12,233 | 12,953 | 13,704 | 14,437 | 15,160 | 15,786 | 16,429 | 1,714,100 |
| **Residential New** | Res-ManufNH | 2,514 | 2,490 | 2,423 | 2,356 | 2,294 | 2,272 | 2,210 | 2,149 | 2,092 | 80,441 |
| | Res-NewHomes | 996,269 | 1,003,108 | 1,008,698 | 1,022,373 | 1,038,722 | 1,053,814 | 1,067,282 | 1,089,063 | 1,112,612 | 19,070,499 |
| | Res-MarketTx | 776,415 | 761,099 | 745,654 | 736,813 | 722,441 | 708,190 | 693,819 | 685,593 | 672,220 | 27,048,368 |
| **Residential Existing** | Res-Tstat | - | - | - | - | - | - | - | - | - | 9,527,945 |
| | Res-TstatOpt | - | - | - | - | - | - | - | - | - | 963,537 |
| | Res-WaterHeat | 895,528 | 870,346 | 851,982 | 820,999 | 805,125 | 734,146 | 510,433 | 489,622 | 511,518 | 14,612,296 |
| | Res-Shell | - | - | - | - | - | - | - | - | - | 6,984,574 |
| | Res-Heat-ROB | 1,311,264 | 1,341,983 | 1,365,778 | 1,388,218 | 1,408,805 | 1,536,035 | 1,555,628 | 1,571,729 | 1,592,070 | 28,191,111 |
| **Multi-family Existing** | MF-RET | - | - | - | - | - | - | - | - | - | 501,960 |
| | MF-ROB | 77,704 | 49,887 | 56,307 | 55,737 | 58,611 | 33,319 | 37,867 | 34,034 | 37,747 | 3,071,843 |
| **Other** | Large-Project Adder | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 250,190 | 6,755,134 |
| | Com-Cooking | 263,108 | 237,452 | 212,814 | 99,473 | 120,885 | 64,519 | 86,132 | 40,722 | 49,509 | 8,108,496 |
| | **Total** | **5,637,513** | **5,527,985** | **5,535,192** | **5,406,270** | **5,457,072** | **5,386,789** | **5,235,125** | **5,188,835** | **5,275,467** | **195,726,325** |

## D.2 Measure Levels

See following pages

## Table D.4: Oregon 20-Year Cumulative Potential (Commercial)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Commercial | Com - SEM GAS SPHT | Retrofit | Behavioral | 8,166,534 | 6,941,554 | 6,941,554 | 13% | $1.05 |
| Commercial | Com - Zero Net Energy | New Construction | Other | 5,363,675 | 4,559,124 | - | 0% | $7.87 |
| Commercial | Com - Gas Fryer | Replace on Burnout | Cooking | 5,334,679 | 4,534,477 | 4,534,477 | 8% | $0.37 |
| Commercial | Com - Gas Absorption HPWH GAS WHT | Replace on Burnout | Water Heating | 4,438,716 | 3,772,909 | 3,772,909 | 7% | $0.08 |
| Commercial | Com - Demand Controlled Ventilation GAS SPHT | Retrofit | Ventilation | 4,421,679 | 3,758,427 | 3,758,427 | 7% | $0.15 |
| Commercial | Com - NC Package (10% Better than Code) | New Construction | Other | 4,393,399 | 3,734,389 | 3,277,208 | 6% | $1.23 |
| Commercial | Com - Condensing Boiler GAS SPHT | Replace on Burnout | Heating | 4,372,284 | 3,716,441 | 3,716,441 | 7% | $0.44 |
| Commercial | Com - EMS GAS SPHT | Retrofit | Behavioral | 3,218,829 | 2,736,005 | 2,736,005 | 5% | $1.00 |
| Commercial | Com - Condensing Gas RTU GAS SPHT | Replace on Burnout | Heating | 2,438,840 | 2,073,014 | 2,073,014 | 4% | $0.74 |
| Commercial | Com - Refrig - Retrofit Doors to Open Display Cases GAS SPHT | Retrofit | Refrigeration | 2,326,388 | 2,210,068 | 2,210,068 | 4% | $0.69 |
| Commercial | Com - Gas RTU Advanced Tier 1 Package Upgrade GAS SPHT | Retrofit | Heating | 2,137,330 | 1,816,730 | 1,816,730 | 3% | $1.03 |
| Commercial | Com - WiFi Connected Thermostat GAS SPHT | Retrofit | Heating | 2,124,080 | 1,805,468 | 1,805,468 | 3% | $0.88 |
| Commercial | Com - Pipe Insulation DHW GAS WHT | Retrofit | Water Heating | 1,995,338 | 1,696,038 | 1,696,038 | 3% | $0.36 |
| Commercial | Com - Gas Absorption HPWH GAS WHT - NEW only | New Construction | Water Heating | 1,754,052 | 1,490,944 | 1,490,944 | 3% | $0.07 |
| Commercial | Com - Automatic Conveyor Broiler Gas | Replace on Burnout | Cooking | 1,716,965 | 1,459,420 | 1,459,420 | 3% | -$0.18 |
| Commercial | Com - Roof Insulation R0 Base GAS SPHT, Z1 | Retrofit | Weatherization | 1,535,486 | 921,292 | 921,292 | 2% | $0.19 |
| Commercial | Com - Pipe Insulation Space Heating Boiler | Retrofit | Heating | 1,468,966 | 1,248,621 | 1,248,621 | 2% | $0.28 |
| Commercial | Com - Condensing Boiler GAS SPHT - NEW only | New Construction | Heating | 1,334,287 | 1,134,144 | 1,134,144 | 2% | $0.65 |
| Commercial | Com - Gas Combination Oven | Replace on Burnout | Cooking | 1,259,948 | 1,070,956 | 1,070,956 | 2% | $0.00 |
| Commercial | Com - Gas Fryer - NEW Only | New Construction | Cooking | 1,198,603 | 1,018,812 | 1,018,812 | 2% | $0.37 |
| Commercial | Com - Efficient Windows GAS SPHT - NEW only | New Construction | Weatherization | 1,108,481 | 665,088 | 299,328 | 1% | $2.09 |
| Commercial | Com - Gas Fired Heat Pump GAS SPHT | Replace on Burnout | Heating | 1,013,909 | 963,214 | 963,214 | 2% | $0.94 |
| Commercial | Com - WiFi Connected Thermostat GAS SPHT - NEW only | New Construction | Heating | 914,956 | 869,209 | 854,457 | 2% | $0.85 |
| Commercial | Com - Gas Griddle | Replace on Burnout | Cooking | 883,149 | 750,676 | 750,676 | 1% | $1.04 |
| Commercial | Com - VFD Kitchen Vent Hood GAS SPHT | Retrofit | Heating | 878,859 | 747,030 | 747,030 | 1% | $1.24 |
| Commercial | Com - Efficient Windows GAS SPHT | Retrofit | Weatherization | 683,398 | 410,039 | - | 0% | $16.33 |
| Commercial | Com - Condensing Gas Furnace GAS SPHT | Replace on Burnout | Heating | 612,406 | 520,545 | 520,545 | 1% | $0.84 |
| Commercial | Com - Gas Fired Heat Pump GAS SPHT - NEW only | New Construction | Heating | 567,365 | 538,997 | 538,997 | 1% | $0.89 |
| Commercial | Com - DHW Circulator Pumps/Controls GAS WHT | Retrofit | Water Heating | 554,569 | 526,841 | 526,841 | 1% | $0.30 |
| Commercial | Com - Gas Convection Oven | Replace on Burnout | Cooking | 393,598 | 334,558 | 334,558 | 1% | $0.41 |
| Commercial | Com - Automatic Conveyor Broiler Gas - NEW Only | New Construction | Cooking | 382,986 | 325,538 | 325,538 | 1% | -$0.18 |
| Commercial | Com - Hot Water Temperature Reset GAS SPHT | Retrofit | Heating | 333,108 | 283,142 | 283,142 | 1% | $0.26 |
| Commercial | Com - Thin Triple Pane Windows GAS SPHT - NEW only | New Construction | Weatherization | 332,852 | 199,711 | - | 0% | $16.62 |

## Table D.4 – continued: Oregon 20-Year Cumulative Potential (Commercial)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Commercial | Com - Gas Combination Oven - NEW Only | New Construction | Cooking | 248,411 | 211,150 | 211,150 | 0% | $0.00 |
| Commercial | Com - Thin Triple Pane Windows GAS SPHT | Retrofit | Weatherization | 216,469 | 129,881 | - | 0% | $16.38 |
| Commercial | Com - Gas Griddle - NEW Only | New Construction | Cooking | 191,529 | 162,800 | 162,800 | 0% | $1.03 |
| Commercial | Com - VFD Kitchen Vent Hood GAS SPHT - NEW Only | New Construction | Heating | 188,413 | 160,151 | 160,151 | 0% | $1.24 |
| Commercial | Com - PreRinse Spray Valve GAS WHT | Retrofit | Water Heating | 184,751 | 157,039 | 157,039 | 0% | -$3.07 |
| Commercial | Com - Wall Insulation GAS SPHT, Z1 | Retrofit | Weatherization | 180,468 | 108,281 | - | 0% | $0.54 |
| Commercial | Com - Roof Insulation R5 Base GAS SPHT, Z1 | Retrofit | Weatherization | 180,161 | 108,097 | 108,097 | 0% | $1.38 |
| Commercial | Com - Gas Steamer | Replace on Burnout | Cooking | 141,034 | 119,879 | 119,879 | 0% | -$2.43 |
| Commercial | Com - Modulating Burner GAS SPHT | Retrofit | Heating | 108,283 | 92,041 | 92,041 | 0% | $0.47 |
| Commercial | Com - Gas Convection Oven - NEW Only | New Construction | Cooking | 79,743 | 67,782 | 67,782 | 0% | $0.41 |
| Commercial | Com - Pool Heaters Indoor | Replace on Burnout | Water Heating | 67,056 | 56,997 | 56,997 | 0% | $0.40 |
| Commercial | Com - Eff. Gas Clothes Washer | Replace on Burnout | Appliance | 65,730 | 62,443 | 62,443 | 0% | $0.79 |
| Commercial | Com - Condensing Gas Storage Water Heater GAS WHT - NEW only | New Construction | Water Heating | 54,311 | 46,164 | 46,164 | 0% | $0.01 |
| Commercial | Com - Steam Trap Maintenance GAS SPHT | Retrofit | Heating | 44,478 | 37,806 | 37,806 | 0% | $0.18 |
| Commercial | Com - Pool Heaters Outdoor | Replace on Burnout | Water Heating | 41,159 | 34,985 | 34,985 | 0% | $0.38 |
| Commercial | Com - Gas Steamer - NEW Only | New Construction | Cooking | 29,313 | 24,916 | 24,916 | 0% | -$2.43 |
| Commercial | Com - Roof Insulation R0 Base GAS SPHT, Z2 | Retrofit | Weatherization | 23,430 | 14,058 | 14,058 | 0% | $0.13 |
| Commercial | Com - Condensing Gas Instantaneous Water Heater GAS WHT - NEW only | New Construction | Water Heating | 15,549 | 13,217 | 13,217 | 0% | $0.01 |
| Commercial | Com - Eff. Gas Clothes Washer - NEW Only | New Construction | Appliance | 10,831 | 10,289 | 10,289 | 0% | $0.79 |
| Commercial | Com - Wall Insulation GAS SPHT, Z2 | Retrofit | Weatherization | 3,255 | 1,953 | - | 0% | $0.30 |
| Commercial | Com - Roof Insulation R5 Base GAS SPHT, Z2 | Retrofit | Weatherization | 3,033 | 1,820 | 1,820 | 0% | $0.83 |

## Table D.5: Oregon 20-Year Cumulative Potential (Industrial)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Industrial | Ind - Custom Boiler | Retrofit | Process Heating | 3,342,520 | 2,841,142 | 2,841,142 | 16% | $0.22 |
| Industrial | Ind - Custom Primary Process (Gas) | Retrofit | Process Heating | 2,760,206 | 2,346,175 | 2,346,175 | 13% | $0.24 |
| Industrial | Ind - Boiler Heat Recovery | Retrofit | HVAC | 2,164,508 | 1,839,832 | 1,839,832 | 10% | $0.01 |
| Industrial | Ind - Ceiling/Roof Insulation | Retrofit | Weatherization | 1,707,045 | 1,450,988 | 1,450,988 | 8% | $0.05 |
| Industrial | Ind - Wall Insulation (Gas) | Retrofit | Process Heating | 1,673,435 | 1,422,420 | 1,422,420 | 8% | $0.05 |
| Industrial | Ind - Gas-fired HP Water Heater | Replace on Burnout | Water Heating | 1,130,192 | 960,663 | 960,663 | 5% | $0.22 |
| Industrial | Ind - Radiant Heating (Gas) | Replace on Burnout | Process Heating | 1,012,643 | 860,747 | 860,747 | 5% | $0.27 |
| Industrial | Ind - Steam Trap Maintenance | Retrofit | Process Heating | 1,008,196 | 856,967 | 856,967 | 5% | $0.02 |
| Industrial | Ind - Custom HVAC (Gas) | Retrofit | HVAC | 866,822 | 736,799 | 736,799 | 4% | $0.44 |
| Industrial | Ind - Boiler Load Control | Retrofit | Process Heating | 792,879 | 673,948 | 673,948 | 4% | $0.00 |
| Industrial | Ind - Water Heating | Replace on Burnout | Process Heating | 750,093 | 637,579 | 637,579 | 4% | $0.49 |
| Industrial | Ind - Advanced Wall Insulation | Retrofit | Weatherization | 655,713 | 557,356 | 557,356 | 3% | $1.41 |
| Industrial | Ind - Custom O&M | Retrofit | Process Heating | 643,562 | 547,028 | 547,028 | 3% | $0.03 |
| Industrial | Ind - SEM (Gas) | Retrofit | Process Heating | 643,562 | 547,028 | 547,028 | 3% | $0.24 |
| Industrial | Ind - Steam Pipe Insulation | Retrofit | Process Heating | 605,919 | 515,031 | 515,031 | 3% | $0.05 |
| Industrial | Ind - Process Insulation | Retrofit | Process Heating | 353,441 | 300,425 | 300,425 | 2% | $0.16 |
| Industrial | Ind - Greenhouse - Under Bench Heating | Retrofit | Process Heating | 326,801 | 277,781 | 277,781 | 2% | $0.17 |
| Industrial | Ind - Custom Secondary Process (Gas) | Retrofit | Process Heating | 297,442 | 252,826 | 252,826 | 1% | $0.47 |
| Industrial | Ind - Greenhouse - Thermal Curtain | Retrofit | Process Heating | 173,208 | 147,227 | 147,227 | 1% | $0.32 |
| Industrial | Ind - Greenhouse - IR Poly Film | Retrofit | Process Heating | 171,604 | 145,863 | 145,863 | 1% | $0.12 |
| Industrial | Ind - Greenhouse - Controller | Retrofit | Process Heating | 82,411 | 70,050 | 70,050 | 0% | $0.11 |
| Industrial | Ind - Condensing Greenhouse Boiler | Replace on Burnout | Process Heating | 73,750 | 62,688 | 62,688 | 0% | $0.74 |
| Industrial | Ind - Greenhouse - Condensing Unit Heater | Retrofit | Process Heating | 54,747 | 46,535 | 46,535 | 0% | $0.22 |

## Table D.6: Oregon 20-Year Cumulative Potential (Residential)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Residential | Res - Window Replacement Tier 2 (U ≤ 0.27) GAS SPHT | Replace on Burnout | Weatherization | 35,250,116 | 21,150,070 | 21,150,070 | 13% | $0.14 |
| Residential | Res - Gas Absorption Heat Pump Water Heater GAS WHT | Replace on Burnout | Water Heating | 28,338,580 | 24,087,793 | 24,087,793 | 15% | $0.26 |
| Residential | Res - Window Tier 3 GAS SPHT | Replace on Burnout | Weatherization | 24,805,637 | 14,883,382 | 14,883,382 | 9% | $0.17 |
| Residential | Res - Market Transformation NH GAS SPHT DHW - Gas Only - NEW only | New Construction | Weatherization | 22,261,413 | 22,261,413 | 22,261,413 | 14% | $0.41 |
| Residential | Res - Smart Tstat - Gas FAF GAS SPHT | Retrofit | Heating | 11,428,475 | 9,714,203 | 9,714,203 | 6% | $0.58 |
| Residential | Res - AFUE 90 to 95 Furnace GAS SPHT | Replace on Burnout | Heating | 11,145,676 | 9,473,825 | 9,473,825 | 6% | $0.74 |
| Residential | Res - Thin Triple Pane Windows GAS SPHT | Replace on Burnout | Weatherization | 10,803,940 | 6,482,364 | 6,482,364 | 4% | $0.74 |
| Residential | Res - Path 4 Advanced Whole Home GAS SPHT DHW - Gas Only - NEW only | New Construction | Heating | 9,822,459 | 8,349,090 | 8,349,090 | 5% | $2.76 |
| Residential | Res - Path 2 MECH + DHW GAS WHT Space Heat - Gas Only - NEW only | New Construction | Water Heating | 8,274,243 | 7,033,107 | 7,033,107 | 4% | $2.99 |
| Residential | Res - Path 3 MECH + DHW GAS WHT Space Heat - Gas Only - NEW only | New Construction | Water Heating | 7,798,140 | 6,628,419 | 6,628,419 | 4% | $2.55 |
| Residential | Res - Gas Fireplace - 70-74 FE GAS SPHT | Replace on Burnout | Heating | 4,344,120 | 3,692,502 | 3,692,502 | 2% | $0.00 |
| Residential | Res - AFUE 96+ Furnace GAS SPHT | Replace on Burnout | Heating | 3,950,339 | 3,357,788 | 3,357,788 | 2% | $1.85 |
| Residential | Res - Wall insulation GAS SPHT, Z1 | Retrofit | Weatherization | 3,588,872 | 2,153,323 | 2,153,323 | 1% | $1.93 |
| Residential | Res - Wall insulation R-30 GAS SPHT, Z1 | Retrofit | Weatherization | 3,306,873 | 1,984,124 | - | 0% | $3.58 |
| Residential | Res - Floor insulation GAS SPHT, Z1 | Retrofit | Weatherization | 3,044,577 | 1,826,746 | 1,826,746 | 1% | $2.28 |
| Residential | Res - AFUE 90 to 95 Furnace GAS SPHT - NEW only | New Construction | Heating | 2,852,699 | 2,424,794 | 2,424,794 | 2% | $0.74 |
| Residential | Res - Attic insulation (R13-R18 starting condition) GAS SPHT, Z1- RET | Retrofit | Weatherization | 2,755,127 | 1,653,076 | 1,653,076 | 1% | $1.45 |
| Residential | Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Gas Only - NEW only | New Construction | Heating | 2,189,545 | 1,861,113 | 1,861,113 | 1% | $10.22 |
| Residential | Res - Gas Fired HP (>100% Eff) GAS SPHT | Replace on Burnout | Heating | 2,164,390 | 1,839,732 | - | 0% | $9.56 |
| Residential | Res - Attic insulation (R0-R11 starting condition) GAS SPHT, Z1- RET | Retrofit | Weatherization | 2,065,894 | 1,239,537 | 1,239,537 | 1% | $0.79 |
| Residential | Res - Market Transformation NH GAS SPHT DHW - Elec Only - NEW only | New Construction | Weatherization | 2,038,472 | 2,038,472 | 2,038,472 | 1% | $0.46 |
| Residential | Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT - NEW only | New Construction | Water Heating | 1,279,576 | 1,087,639 | 1,087,639 | 1% | $0.08 |
| Residential | Res - Tankless Gas Hot Water Heater GAS WHT - NEW only | New Construction | Water Heating | 1,267,253 | 1,077,165 | - | 0% | $2.21 |
| Residential | Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT | Replace on Burnout | Water Heating | 1,237,874 | 1,052,193 | 1,052,193 | 1% | $0.08 |
| Residential | Res - Tankless Gas Hot Water Heater GAS WHT | Replace on Burnout | Water Heating | 1,225,953 | 1,042,060 | - | 0% | $2.55 |
| Residential | Res - Tstat Optimization GAS SPHT | Retrofit | Heating | 1,133,573 | 963,537 | 963,537 | 1% | $0.26 |
| Residential | Res - Gas Fireplace - 75+ FE GAS SPHT | Replace on Burnout | Heating | 1,071,263 | 910,574 | 910,574 | 1% | $0.00 |
| Residential | Res - Attic insulation R-60 GAS SPHT, Z1 | Retrofit | Weatherization | 1,039,136 | 623,482 | - | 0% | $9.49 |
| Residential | Res - Elec Hi-eff Clotheswasher GAS WHT | Replace on Burnout | Water Heating | 952,284 | 809,442 | 809,442 | 1% | -$4.91 |
| Residential | Res - AFUE 96+ Furnace GAS SPHT - NEW only | New Construction | Heating | 801,747 | 681,485 | 453,402 | 0% | $1.52 |
| Residential | Res - Path 4 Advanced Whole Home GAS SPHT DHW - Elec Only - NEW only | New Construction | Heating | 738,329 | 627,579 | 627,579 | 0% | $3.83 |
| Residential | Res - Gas Fired HP (>100% Eff) GAS SPHT - NEW only | New Construction | Heating | 711,018 | 604,365 | - | 0% | $11.16 |

## Table D.6 – continued: Oregon 20-Year Cumulative Potential (Residential)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Residential | Res - Path 2 MECH + DHW ER WHT Space Heat - Gas Only - NEW only | New Construction | Water Heating | 520,608 | 442,517 | 442,517 | 0% | $6.25 |
| Residential | Res - Path 3 MECH + DHW ER WHT Space Heat - Gas Only - NEW only | New Construction | Water Heating | 506,535 | 430,555 | 430,555 | 0% | $4.79 |
| Residential | Res - Condensing Furnaces (MF) GAS SPHT | Replace on Burnout | Heating | 416,886 | 354,353 | 354,353 | 0% | $0.38 |
| Residential | Res - Cellular Shades GAS SPHT | Retrofit | Weatherization | 380,644 | 323,547 | - | 0% | $9.56 |
| Residential | Res - Hot Water Condensing Boiler for Space Heat (MF) GAS SPHT | Replace on Burnout | Heating | 350,327 | 297,778 | 297,778 | 0% | $0.30 |
| Residential | Res - Path 2 MECH + DHW GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only | New Construction | Water Heating | 326,329 | 277,379 | 277,379 | 0% | $6.35 |
| Residential | Res - Path 3 MECH + DHW GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only | New Construction | Water Heating | 292,541 | 248,660 | 248,660 | 0% | $7.48 |
| Residential | Res - Market Transformation NH AVG ELEC SPHT DHW - Gas Only - NEW only | New Construction | Weatherization | 275,210 | 275,210 | - | 0% | $3.59 |
| Residential | Res - Path 4 Advanced Whole Home AVG ELEC SPHT DHW - Gas Only - NEW only | New Construction | Heating | 273,691 | 232,637 | 232,637 | 0% | $9.34 |
| Residential | Res - Multifamily Pipe Insulation GAS WHT | Retrofit | Water Heating | 176,614 | 150,122 | 150,122 | 0% | $0.29 |
| Residential | Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Elec Only - NEW only | New Construction | Heating | 162,711 | 138,304 | 138,304 | 0% | $14.33 |
| Residential | Res - Gas Fireplace - Ignition System GAS SPHT | Replace on Burnout | Heating | 151,827 | 129,053 | 129,053 | 0% | $0.99 |
| Residential | Res - Thermostatic Radiator Valves | Retrofit | Water Heating | 140,362 | 119,308 | 119,308 | 0% | $0.33 |
| Residential | Res - Hot Water Condensing Boiler for Space Heat (MF) GAS SPHT - NEW only | New Construction | Heating | 128,677 | 109,375 | 109,375 | 0% | $0.20 |
| Residential | Res - Elec Hi-eff Clotheswasher MF GAS WHT - NEW only | New Construction | Water Heating | 122,842 | 104,415 | 104,415 | 0% | -$3.32 |
| Residential | Res - Elec Hi-eff Clotheswasher MF GAS WHT | Replace on Burnout | Water Heating | 118,838 | 101,013 | 101,013 | 0% | -$3.32 |
| Residential | Res - 0.70+ EF Gas Storage Water Heater GAS WHT - NEW only | New Construction | Water Heating | 114,854 | 97,626 | 97,626 | 0% | $0.49 |
| Residential | Res - 0.70+ EF Gas Storage Water Heater GAS WHT | Replace on Burnout | Water Heating | 111,111 | 94,445 | 94,445 | 0% | $0.49 |
| Residential | Res - Steam trap replacement GAS SPHT- ROB | Replace on Burnout | Heating | 103,696 | 88,142 | 88,142 | 0% | $0.18 |
| Residential | Res - Condensing Furnaces (MF) GAS SPHT - NEW only | New Construction | Heating | 103,627 | 88,083 | 88,083 | 0% | $0.38 |
| Residential | Res - New MH - Energy Star GAS SPHT, Z1 - NEW only | New Construction | Weatherization | 73,085 | 62,122 | 62,122 | 0% | $1.08 |
| Residential | Res - Energy Star Gas Clothes Dryer | Replace on Burnout | Appliance | 66,677 | 63,343 | 63,343 | 0% | $1.05 |
| Residential | Res - Path 5 Emerging Super Efficient Whole Home AVG ELEC SPHT DHW - Gas Only - NEW only | New Construction | Heating | 62,778 | 53,361 | 53,361 | 0% | $33.60 |
| Residential | Res - Wall insulation R-30 GAS SPHT, Z2 | Retrofit | Weatherization | 51,284 | 30,770 | - | 0% | $2.33 |
| Residential | Res - Duct Sealing MH GAS SPHT | Retrofit | Weatherization | 43,926 | 37,337 | 37,337 | 0% | $0.97 |
| Residential | Res - Wall insulation GAS SPHT, Z2 | Retrofit | Weatherization | 39,737 | 23,842 | 23,842 | 0% | $1.76 |
| Residential | Res - Window Replacement Tier 2 (U ≤ 0.27) GAS SPHT - NEW only | New Construction | Weatherization | 39,078 | 23,447 | 23,447 | 0% | $0.14 |
| Residential | Res - Elec Hi-eff Clotheswasher GAS WHT - NEW only | New Construction | Water Heating | 36,062 | 30,653 | 30,653 | 0% | -$4.91 |
| Residential | Res - Floor insulation GAS SPHT, Z2 | Retrofit | Weatherization | 33,682 | 20,209 | 20,209 | 0% | $2.08 |
| Residential | Res - Attic insulation (R13-R18 starting condition) GAS SPHT, Z2- RET | Retrofit | Weatherization | 29,970 | 17,982 | 17,982 | 0% | $1.34 |
| Residential | Res - Window Tier 3 GAS SPHT - NEW only | New Construction | Weatherization | 27,499 | 16,500 | 16,500 | 0% | $0.17 |
| Residential | Res - Attic insulation (R0-R11 starting condition) GAS SPHT, Z2- RET | Retrofit | Weatherization | 20,868 | 12,521 | 12,521 | 0% | $0.79 |

## Table D.6 – continued: Oregon 20-Year Cumulative Potential (Residential)

| Sector | Measure Name | Measure Type | End Use | 20-year Cumulative Technical Potential (therms) | 20-year Cumulative Achievable Potential (therms) | 20-year Cumulative Cost-Effective Potential (therms) | % of Total Sector C/E Potential | Average Levelized Cost ($/therm) |
|---|---|---|---|---|---|---|---|---|
| Residential | Res - Wall insulation MF GAS SPHT, Z1 | Retrofit | Weatherization | 17,029 | 10,217 | 10,217 | 0% | $1.93 |
| Residential | Res - Attic insulation R-60 GAS SPHT, Z2 | Retrofit | Weatherization | 16,115 | 9,669 | - | 0% | $6.18 |
| Residential | Res - Ceiling insulation - side by side R49 GAS SPHT, Z1 | Retrofit | Weatherization | 14,955 | 8,973 | 8,973 | 0% | $0.92 |
| Residential | Res - Ceiling insulation - stacked R49 GAS SPHT | Retrofit | Weatherization | 13,175 | 7,905 | 7,905 | 0% | $0.82 |
| Residential | Res - Floor insulation - 2-4 & side by side GAS SPHT, Z1 | Retrofit | Weatherization | 12,675 | 7,605 | 7,605 | 0% | $2.15 |
| Residential | Res - Dmd Ctrl Recirc. GAS WHT | Retrofit | Water Heating | 2,026 | 1,722 | 1,722 | 0% | $1.06 |
| Residential | Res - Showerhead, 1.5 GPM GAS WHT - NEW only | New Construction | Water Heating | 1,977 | 1,681 | 1,681 | 0% | -$0.11 |
| Residential | Res - Energy Star Gas Clothes Dryer - NEW only | New Construction | Appliance | 1,620 | 1,539 | 1,539 | 0% | $1.05 |
| Residential | Res - Bathroom Faucet Aerators, 0.5 gpm GAS WHT - NEW only | New Construction | Water Heating | 1,612 | 1,371 | 1,371 | 0% | -$0.18 |
| Residential | Res - New MH - Energy Star GAS SPHT, Z2 - NEW only | New Construction | Weatherization | 738 | 627 | 627 | 0% | $1.08 |
| Residential | Res - Kitchen Faucet Aerators, 1.0 gpm GAS WHT - NEW only | New Construction | Water Heating | 662 | 563 | 563 | 0% | -$0.15 |
| Residential | Res - Wall insulation MF GAS SPHT, Z2 | Retrofit | Weatherization | 189 | 113 | 113 | 0% | $1.74 |
| Residential | Res - Ceiling insulation - side by side R49 GAS SPHT, Z2 | Retrofit | Weatherization | 151 | 91 | 91 | 0% | $0.92 |
| Residential | Res - Floor insulation - 2-4 & side by side GAS SPHT, Z2 | Retrofit | Weatherization | 140 | 84 | 84 | 0% | $1.98 |

# Appendix E
# Supply-side Resources

## E.1 Gas Purchasing Common Practices

NW Natural also utilizes financial derivative hedges (mainly swaps) to manage cost risks. The physical baseload supply contracts mentioned in Chapter 6, which are priced at a variable index price, can be fixed using financial swaps. This is done for a large portion of our portfolio to lock in prices and decrease the volatility of costs in our gas supply portfolio for customers.

In addition to the long-term supply planning done in this IRP, NW Natural prepares a Gas Acquisition Plan (GAP) each year. The GAP is reviewed and approved by NW Natural's Gas Acquisition Strategy and Policies (GASP) Committee, but such plans are always subject to change based on market conditions. The primary objective of the Gas Acquisition Plan (GAP) is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, our primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery all while reducing the carbon content of the energy we deliver. The focus of the GAP is on the upcoming gas contracting year (November through October); however, this focus extends several years into the future for multi-year hedging considerations. Longer-term resource planning is the focus of the IRP and is not covered in the GAP, except of course to assure consistency in the transition from near-term to longer-term planning decisions.

## E.2 Pipeline Charges

There are three primary costs components associated with pipeline contracts, one that is a fixed charge and two variable components. Table E.1 outlines these three components.

**Table E.1: Three Cost Components for Pipeline Charges**

| Component | Description |
|---|---|
| Demand Charge | This is a fix cost associated with holding the capacity rights to ship gas on a pipeline. Often specified in $/Dth/day, this price multiplied by the capacity amount held by the shipper and 365 would provide the annual payment to the interstate pipeline regardless of how much gas is shipped over the course of that year. Also known as a reservation charge. |
| Variable Charge | This a variable charge associated with how much gas is scheduled on the pipeline each day. Some pipelines have postage-stamp variable charges that are independent of the receipt and delivery points, whereas other pipelines charge based not only the amount of gas scheduled but the distance that it is scheduled. |
| Fuel Charge | This is a secondary indirect variable charge that takes a percentage of the natural gas that is shipped on the pipeline. |

## E.3 Gas Supply Contracts

**Table E.2: NW Natural Firm Off-System Gas Supply Contracts for the 2021/2022 Tracker Year**

| | | | **Baseload Qty** | **Swing Qty** | **Contract** |
|---|---|---|---|---|---|
| | Supply Location | Duration | (Dth/day) | (Dth/day) | Termination Date |
| | ***British Columbia:*** | | | | |
| | MacQuarie Energy Canada Ltd. | Nov-Jan | 5,000 | | 1/31/2022 |
| | TD Energy Trading Inc | Nov-Feb | 5,000 | | 2/28/2022 |
| | Direct Energy Marketing Limited | Nov-Mar | 5,000 | | 3/31/2022 |
| | IGI Resources | Nov-Mar | 5,000 | | 3/31/2022 |
| | J. Aron & Company | Nov-Mar | 11,000 | | 3/31/2022 |
| | MacQuarie Energy Canada Ltd. | Nov-Mar | 10,000 | | 3/31/2022 |
| | Powerex Corp | Nov-Mar | 6,000 | | 3/31/2022 |
| | TD Energy Trading Inc | Nov-Mar | 11,000 | | 3/31/2022 |
| | Canadian Natural Resources | Nov-Oct | 10,000 | | 10/31/2022 |
| | ConocoPhillips Canada Marketing | Nov-Oct | 3,000 | | 10/31/2022 |
| | TD Energy Trading Inc | Nov-Oct | 5,000 | | 10/31/2022 |
| | Powerex Corp | Apr-May | 5,000 | | 5/31/2022 |
| | ConocoPhillips Canada Marketing | Apr | 10,000 | | 4/30/2022 |
| | J. Aron & Company | Apr | 2,000 | | 4/30/2022 |
| | MacQuarie Energy Canada Ltd. | Apr | 5,000 | | 4/30/2022 |
| | J. Aron & Company | Oct | 5,000 | | 10/31/2022 |
| | | | | | |
| | ***Alberta:*** | | | | |
| | ConocoPhillips Canada Marketing | Nov-Jan | 5,000 | | 1/31/2022 |
| | Direct Energy Marketing Limited | Nov-Jan | 5,000 | | 1/31/2022 |
| | PetroChina International (Canada) Trading | Nov-Jan | 10,000 | | 1/31/2022 |
| | J. Aron & Company | Nov-Feb | 5,000 | | 2/28/2022 |
| | Castleton Commodities | Nov-Mar | 5,000 | | 3/31/2022 |
| | ConocoPhillips Canada Marketing | Nov-Mar | 5,000 | | 3/31/2022 |
| | EDF Trading North America, LLC | Nov-Mar | 5,000 | | 3/31/2022 |
| | Powerex Corp | Nov-Mar | 5,000 | | 3/31/2022 |
| | Suncor Energy Marketing Inc | Nov-Mar | 15,000 | | 3/31/2022 |
| | BP Canada Energy Group | Nov-Oct | 10,000 | | 10/31/2022 |
| | Shell North America (Canada) Inc | Nov-Oct | 5,000 | | 10/31/2022 |
| | J. Aron & Company | Dec-Feb | 5,000 | | 2/28/2022 |
| | J. Aron & Company | Dec-Jan | 5,000 | | 1/31/2022 |
| | Powerex Corp | Dec-Jan | 5,000 | | 1/31/2022 |
| | Castleton Commodities | Apr-Jun | 3,000 | | 6/30/2022 |
| | Castleton Commodities | Apr-May | 5,000 | | 5/31/2022 |
| | Direct Energy Marketing Limited | Apr-May | 5,000 | | 5/31/2022 |

| | | | | | |
|---|---|---|---|---|---|
| | J. Aron & Company | Apr-May | 5,000 | | 5/31/2022 |
| | Direct Energy Marketing Limited | Feb-Mar | 5,000 | | 3/31/2022 |
| | Suncor Energy Marketing Inc | Apr | 11,000 | | 4/30/2022 |
| | ConocoPhillips Canada Marketing | Apr | 6,000 | | 4/30/2022 |
| | Powerex Corp | Feb | 5,000 | | 2/8/2022 |
| | J. Aron & Company | Mar | 3,000 | | 3/31/2022 |
| | BP Canada Energy Group | Oct | 5,000 | | 10/31/2022 |
| | Castleton Commodities | Oct | 13,000 | | 10/31/2022 |
| | IGI Resources | Oct | 5,000 | | 10/31/2022 |
| | Suncor Energy Marketing Inc | Oct | 5,000 | | 10/31/2022 |
| | Shell North America (Canada) Inc | Oct | 5,000 | | 10/31/2022 |
| | | | | | |
| | ***Rockies:*** | | | | |
| | CIMA Energy LTD | Nov-Mar | 5,000 | | 3/31/2022 |
| | ConocoPhillips Company | Nov-Mar | 16,000 | | 3/31/2022 |
| | Koch Energy Services, Inc | Nov-Mar | 10,000 | | 3/31/2022 |
| | MacQuarie Energy, LLC | Nov-Mar | 5,000 | | 3/31/2022 |
| | XTO Energy Inc | Nov-Mar | 5,000 | | 3/31/2022 |
| | Citadel Energy Marketing, LLC | Nov-Oct | 15,000 | | 10/31/2022 |
| | ConocoPhillips Company | Nov-Oct | 5,000 | | 10/31/2022 |
| | MacQuarie Energy, LLC | Nov-Oct | 4,000 | | 10/31/2022 |
| | Spotlight Energy, LLC | Nov-Oct | 5,000 | | 10/31/2022 |
| | CIMA Energy LTD | Dec-Jan | 10,000 | | 1/31/2022 |
| | Citadel Energy Marketing, LLC | Dec-Jan | 5,000 | | 1/31/2022 |
| | MacQuarie Energy, LLC | Dec-Jan | 5,000 | | 1/31/2022 |
| | CIMA Energy LTD | Dec-Feb | 5,000 | | 2/28/2022 |
| | ConocoPhillips Company | Dec-Feb | 5,000 | | 2/28/2022 |
| | IGI Resources, Inc | Dec-Feb | 15,000 | | 2/28/2022 |
| | ConocoPhillips Company | Feb | 5,000 | | 2/28/2022 |
| | MacQuarie Energy, LLC | Mar | 7,000 | | 3/31/2022 |
| | MacQuarie Energy, LLC | Apr | 6,000 | | 4/30/2022 |
| | ConocoPhillips Company | Nov-Mar | | 10,000 | 3/31/2022 |
| | ConocoPhillips Company | Apr-Oct | | 10,000 | 10/31/2022 |
| | | | | | |
| | | | | | |
| | | | Baseload Qty | Baseload + Swing | |
| | | Month | (Dth/day) | (Dth/day) | |
| | | Nov-21 | 221,000 | 231,000 | |
| | | Dec-21 | 281,000 | 291,000 | |
| | | Jan-22 | 281,000 | 291,000 | |
| | | Feb-22 | 241,000 | 251,000 | |

| | | | | | |
|---|---|---|---|---|---|
| | | Mar-22 | 201,000 | 211,000 | |
| | | Apr-22 | 125,000 | 135,000 | |
| | | May-22 | 85,000 | 95,000 | |
| | | Jun-22 | 65,000 | 75,000 | |
| | | Jul-22 | 62,000 | 72,000 | |
| | | Aug-22 | 62,000 | 72,000 | |
| | | Sep-22 | 62,000 | 72,000 | |
| | | Oct-22 | 100,000 | 110,000 | |
| | | | | | |
| **Notes:** | | | | | |
| **1** | Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption. | | | | |
| **2** | Nov-Mar "Swing" contracts represent physical call options at NWN's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion. | | | | |

### Table E.3: NW Natural Firm Transportation Capacity for the 2021/2022 Tracker Year

| | Pipeline and Contract | **Contract Demand** (Dth/day) | Termination Date |
|---|---|---|---|
| | **Northwest Pipeline:** | | |
| | Sales Conversion (#100005) | 214,889 | 10/31/2031 |
| | 1993 Expansion (#100058) | 35,155 | 9/30/2044 |
| | 1995 Expansion (#100138) | 102,000 | 10/31/2030 |
| | Occidental cap. acq. (#139153) | 1,046 | 10/31/2030 |
| | Occidental cap. acq. (#139154) | 4,000 | 10/31/2030 |
| | International Paper cap. acq. (#138065) | 4,147 | 10/31/2030 |
| | March Point cap. acq. (#136455) | 12,000 | 12/31/2046 |
| | Total NWP Capacity | 373,237 | |
| | less recallable release to - | | |
| | Portland General Electric | (30,000) | 10/31/2022 |
| | Net NWP Capacity | 343,237 | |
| | **TransCanada - GTN:** | | |
| | Sales Conversion (#00180) | 3,616 | 10/31/2030 |
| | 1993 Expansion (#00164) | 46,549 | 10/31/2030 |
| | 1995 Rationalization (#11030) | 56,000 | 10/31/2030 |
| | Total GTN Capacity | 106,165 | |
| | **TransCanada - Foothills:** | | |
| | 1993 Expansion | 47,727 | 10/31/2022 |
| | 1995 Rationalization | 57,417 | 10/31/2022 |
| | Engage Capacity Acquisition | 3,708 | 10/31/2022 |
| | 2004 Capacity Acquisition | 48,669 | 10/31/2025 |
| | Total Foothills Capacity | 157,521 | |

| | | | |
|---|---|---|---|
| | less release to - | | |
| | Shell Energy North America (Canada) Inc | (48,669) | 10/31/2025 |
| | Net Foothills Capacity | 108,852 | |
| | **TransCanada - NOVA:** | | |
| | 1993 Expansion | 48,135 | 10/31/2025 |
| | 1995 Rationalization | 57,909 | 10/31/2025 |
| | Engage Capacity Acquisition | 3,739 | 10/31/2025 |
| | 2004 Capacity Acquisition | 49,138 | 10/31/2025 |
| | Total NOVA Capacity | 158,921 | |
| | less release to - | | |
| | Shell Energy North America (Canada) Inc | (49,138) | 10/31/2025 |
| | Net NOVA Capacity | 109,783 | |
| | **T-South** | | |
| | Capacity (through Tenaska) | 19,000 | 3/31/2026 |
| | Capacity (through FortisBC) | 47,391 | 10/31/2025 |
| | 2021 Expansion | 25,511 | 10/31/2061 |
| | Total T-South Capacity | 91,902 | |
| | | | |
| **Notes:** | | | |
| **1** | All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contracts with Tenaska and Fortis, which have no renewal rights. | | |
| **2** | The T-South contract with FortisBC is for 47,391 Dth from 11/1/2020 through 10/31/2023, and then is reduced to 28,435 Dth from 11/1/2023 through 10/31/2025. | | |
| **3** | The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day. | | |
| **4** | Segmented capacity has not been included in this table. | | |
| **5** | T-South capacity includes the new T-South Expansion contract awarded in 2017, which begins November 1, 2021. | | |
| **6** | The 2004 Capacity Acquisition on NOVA and Foothills totaling about 49,000 Dth/day has been released to a third party through 10/31/2025. The revenues related to this arrangement are being credited back to customers as outlined in Schedule P. | | |

### Table E.4: NW Natural Firm Storage Resources for the 2021/2022 Tracker Year

| | | Max. Daily Rate | Max. Seasonal Level | |
|---|---|---|---|---|
| | Facility | (Dth/day) | (Dth) | Termination Date |
| | **Jackson Prairie:** | | | |
| | | | | |
| | SGS-2F | 46,030 | 1,120,288 | 10/31/2025 |
| | | | | |
| | TF-2 (primary firm portion) | 23,038 | 839,046 | 10/31/2025 |
| | TF-2 (primary firm portion) | 9,467 | 281,242 | 10/31/2025 |
| | TF-1 | 13,525 | n/a | 10/31/2031 |
| | | | | |
| | **Firm On-System Storage Plants:** | | | |
| | | | | |
| | Mist (reserved for core) | 305,000 | 12,258,591 | n/a |
| | Portland LNG Plant | 130,800 | 499,656 | n/a |
| | Newport LNG Plant | 64,500 | 967,500 | n/a |
| | Total On-System Storage | 500,300 | 13,725,747 | |
| | Total Firm Storage Resource | 546,330 | 14,846,035 | |
| | | | | |
| **Notes:** | | | | |
| **1** | The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date. | | | |
| **2** | The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning. | | | |
| **3** | On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full. | | | |
| **4** | Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate storage customers. | | | |
| **5** | The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1060 Btu/cf. The current heat content used for Newport is 1075 Btu/cf and Portland LNG is 1090 Btu/cf. | | | |
| **6** | Newport LNG tank de-rated to 90% of the tank capacity pending CO2 removal project. | | | |
| **7** | Due to an Engineering analysis of the Portland LNG tank, liquifaction will be limited to 76% of the tank's capacity. | | | |
| **8** | NW Natural has no supply-basin storage contract for the coming year. | | | |

**Table E.5: NW Natural Other Resources: Recall Agreements, City Deliveries and Mist Production for the 2021/2022 Tracker Year**

| | | Max. Daily Rate | Max. Availability | |
|---|---|---|---|---|
| | Type | (Dth/day) | (days) | Termination Date |
| | Recall Agreements: | | | |
| | | | | |
| | PGE | 30,000 | 30 | 10/31/2022 |
| | International Paper | 8,000 | 40 | Upon 1-year notice |
| | Georgia Pacific-Halsey mill | 1,000 | 15 | Upon 1-year notice |
| | Total Recall Resource | 39,000 | | |
| | | | | |
| | | | | |
| | Citygate Deliveries: | | | |
| | | | | |
| | Citygate Delivery | 5,000 | 5 | 2/28/2022 |
| | On-System Supplies: | | | |
| | | | | |
| | Renewable Natural Gas | ≈2,000 | n/a | Varying Terms |
| | Mist Production | ≈1,000 | n/a | Life of the wells |
| | Total On System Supplies | 3,000 | | |
| | | | | |
| **Notes:** | | | | |
| 1 | There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system. | | | |
| 2 | Citygate deal has been negotiated for 5 days peaking at 5,000 dth/day. | | | |
| 3 | Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells. | | | |
| 4 | Assumes three Renewable Natural Gas (RNG) projects are online this winter. | | | |

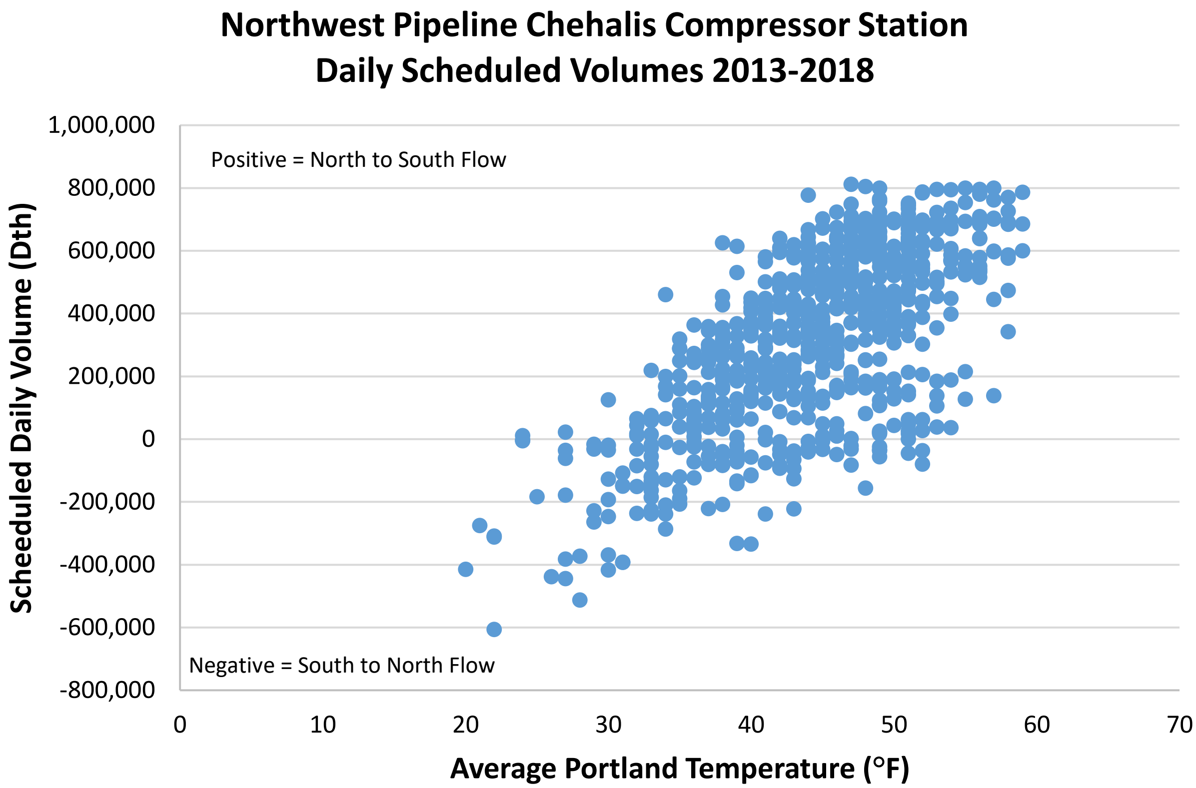
**Table E.6: NW Natural Peak Day Resource Summary for the 2021/2022 Tracker Year**

| | | | | Max. Daily Rate |
|---|---|---|---|---|
| | Resource Type | | | (Dth/day) |
| | | | | |
| | Net Deliverability over Upstream Pipeline Capacity | | | 343,237 |
| | Off-System Storage (Jackson Prairie only) | | | 46,030 |
| | On-System Storage (Mist, Portland LNG and Newport LNG) | | | 500,300 |
| | Recallable Capacity and Supply Agreements | | | 39,000 |
| | Citygate Deliveries | | | 5,000 |
| | On-System Supplies | | | 3,000 |
| | | | | |
| | Segmented Capacity (not primary firm) | | | 60,700 |
| | | | | |
| | Total Peak Day Resources | | | 997,267 |
| | | | | |
| Notes: | | | | |
| 1 | Per 2018 IRP Update #3, Segmented Capacity currently is included as a firm resource through 2021-2025 gas years. Afterwards reliance reduces to 30,000 dth/day into the future. | | | |

## E.4 Chehalis Compressor Analysis

In the 2016 IRP, an analysis of NWP flow data along the I-5 corridor over the prior five winters showed that as the weather gets colder, the predominant flow direction is south to north through the main constraint point at NWP's Chehalis compressor station. Hence, gas flowing south from Sumas on segmented capacity should have greater pipeline reliability as design day conditions are approached. This analysis is shown in Figure E.1 below.

**Figure E.1 Implied Reliability of Segmented Capacity**




Experience over the past several winters continues to support our use of segmented capacity during cold weather events.

Table E.7 (Jackson Prairie Related Transportation Agreements) shows the configuration of agreements that transport gas from Jackson Prairie on NWP's system.

**Table E.7 Jackson Prairie Related Transportation Agreements**

| Service Type | Primary Firm Rate (Dth/day) | Subordinate Firm Rate (Dth/day) |
|---|---|---|
| **TF-1** | 13,525 | - |
| **TF-2** | 23,038 | 9,586 |
| **TF-2** | 9,467 | 3,939 |
| Total | 46,030 | 13,525 |

# Appendix F
# Portfolio Selection

To be filed with NW Natural's Final 2022 Integrated Resource Plan

# Appendix G
# TWG Attendance

| | Supplemental TWG Load Considerations, September 9, 2021 | |
|---|---|---|
| Organization | Attendence 9/29/21 | Email |
| Avista | Tom Pardee | Tom.Pardee@avistacorp.com |
| AWEC | Chad Stokes | cstokes@cablehuston.com |
| Cascade Natural Gas | Devin McGreal | Devin.McGreal@cngc.com |
| Cascade Natural Gas | Mark Sellers- Vaughn | Mark.Sellers-Vaughn@cngc.com |
| CUB | Mike Goetz | mike@oregoncub.org |
| CUB | Sudeshna Pal | sudeshna@oregoncub.org |
| Energy Trust | Ben Cartwright | ben.Cartwright@energytrust.org |
| Energy Trust | Gini Saraswati | Gina.Saraswati@energytrust.org |
| Energy Trust | Kyle Morrill | Kyle.morrill@energytrust.org |
| Energy Trust | Spencer Moersfelder | Spencer.Moersfelder@energytrust.org |
| Fortis BC | Ken Ross | Ken.Ross@fortisbc.com |
| Green Energy Institute, Lewis & Clark Law School | Carra Sahler (GEI) | sahler@lclark.edu |
| NW Energy Coalition | Lauren McCloy | Lauren@nwenergy.org |
| NW Gas Association | Dan Kirshner | dkirschner@nwga.org |
| NW Natural | Kruti Pandya | Kruti.Pandya@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Matt Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Rick Hodges | Rick.Hodges@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Ryan Sigurdson | Ryan.Sigurdson@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Ted Drennan | Ted.Drennan@nwnatural.com |
| NW Natural | Zach Kravtiz | Zachary.Kravitz@nwnatural.com |
| OPUC | Anna Kim | Anna.Kim@puc.oregon.gov |
| OPUC | Kim Herb | Kim.herb@puc.oregon.gov |
| OPUC | Rose Anderson | rose.anderson@puc.oregon.gov |
| Pilot Strategies | Scott Peterson | dspeterson@pilotstrat.com |
| Public Counsel | Corey Dahl | Corey.dahl@atg.wa.gov |
| Puget Sounds Energy | Gurvinder Singh | gurvinder.singh@pse.com |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |

| Key: * = attended only morning Office Hours<br>**= attended only afternoon Presentation | Supplemental TWG Office Hours and Emissions Considerations, December 9, 2021 | |
|---|---|---|
| **Organization** | **Attendence 12/9/21** | **Email** |
| Avista | Michael Brutocao ** | |
| Avista | Tom Pardee ** | Tom.Pardee@avistacorp.com |
| AWEC | Jason Frank * | |
| Cascade Natural Gas | Ashton Davis | Ashton.Davis@cngc.com |
| Cascade Natural Gas | Brian Robertson | Brian.Robertson@cngc.com |
| Cascade Natural Gas | Devin McGreal | Devin.McGreal@cngc.com |
| Cascade Natural Gas | Mark Sellers- Vaughn ** | Mark.Sellers-Vaughn@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| CUB | Sudeshna Pal ** | sudeshna@oregoncub.org |
| Energy Trust | Ben Cartwright ** | ben.Cartwright@energytrust.org |
| Energy Trust | Gini Saraswati ** | Gina.Saraswati@energytrust.org |
| Energy Trust | Kyle Morrill ** | Kyle.morrill@energytrust.org |
| Energy Trust | Spencer Moersfelder ** | Spencer.Moersfelder@energytrust.org |
| Fortis BC | Ken Ross | Ken.Ross@fortisbc.com |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Amelia Schlusser ** | |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | sahler@lclark.edu |
| Metro Climate Action Team (OLCV) | Pat Delaquil | |
| NRDC | Alejandra Mejia Cunningham * | |
| NW Natural | Cecelia Tanaka ** | Cecelia.Tanaka@nwnatural.com |
| NW Natural | Dan Kizer | Daniel.Kizer@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Kruti Pandya | Kruti.Pandya@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Matt Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Rick Hodges | Rick.Hodges@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Samantha Christenson | Samantha.Christenson@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| OPUC | Curtis Dloughy * | Curtis.DLOUHY@puc.oregon.gov |
| OPUC | JP Batmale | jp.batmale@puc.oregon.gov |
| OPUC | Kim Herb | Kim.herb@puc.oregon.gov |
| OPUC | Zachariah Baker | Zachariah.Baker@puc.oregon.gov |
| Puget Sound Energy | Gurvinder Singh | gurvinder.singh@pse.com |
| Regulatory Assistance Project (RAP) | Elaine Prause ** | |
| Regulatory Assistance Project (RAP) | Jessica Shipley * | |
| Renewable NW | Jeff Bissonnette *** | |
| Sierra Club | Rose Monahan * | |
| WUTC | Andrew Rector ** | andrew.rector@utc.wa.gov |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |

| | TWG #1 Planning Environement & Environmental Policy, January 14, 2022 | |
|---|---|---|
| **Organization** | **Attendence 1/14/22** | **Email** |
| Adelante Mujeres | Maria Dolores Torres | |
| AWEC | Chad Stokes | cstokes@cablehuston.com |
| Cascade Natural Gas | Ashton Davis | Ashton.Davis@cngc.com |
| Cascade Natural Gas | Mark Sellers- Vaughn | Mark.Sellers-Vaughn@cngc.com |
| Cascade Natural Gas | Brian Robertson | Brian.Robertson@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| Climate Solutions | David Vant Hof | |
| Columbia Riverkeeper | Erin Saylor | erin@columbiariverkeeper.org |
| CUB | Bob Jenks | bob@oregoncub.org |
| CUB | Mike Goetz | mike@oregoncub.org |
| CUB | Sudeshna Pal | sudeshna@oregoncub.org |
| Metro Climate Action | Pat DeLaquil | pdelaquil@gmail.com |
| Enbridge | Sue Mills | suzette.mills@enbridge.com |
| Energy Trust | Kyle Morrill | Kyle.Morrill@energytrust.org |
| Energy Trust | Gina Saraswati | Gina.Saraswati@energytrust.org |
| Energy Trust | Hannah Cruz | Hannah.Cruz@energytrust.org |
| Fortis BC | Ken Ross | Ken.Ross@fortisbc.com |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | sahler@lclark.edu |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NW Gas Association | Natasha Jackson | |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Anna Chittum | Anna.Chittum@nwnatural.com |
| NW Natural | Dan Kizer | Daniel.Kizer@nwnatural.com |
| NW Natural | Kruti Pandya | Kruti.Pandya@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Matt Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Natash Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Rick Hodges | Rick.Hodges@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Brian Harney | Brian.Harney@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Kristel Muirhead | Kristel.Muirhead@nwnatural.com |
| NW Natural | Kevin McVay | Kevin.McVay@nwnatural.com |
| NW Natural | Ryan Sigurdson | Ryan.Sigurdson@nwnatural.com |
| NW Natural | Holly Braun | Holly.Braun@nwnatural.com |
| NW Natural | Zach Kravitz | Zachary.Kravitz@nwnatural.com |
| OPUC | Rose Anderson | rose.anderson@puc.oregon.gov |
| OPUC | Kim Herb | Kim.herb@puc.oregon.gov |
| OPUC | Zachariah Baker | Zachariah.Baker@puc.oregon.gov |
| OPUC | JP Batmale | jp.batmale@puc.oregon.gov |
| Portland Energy Conservation Inc (PECI) | Tim Miller | tim.miller@peci.org |
| Puget Sound Energy | Gurvinder Singh | gurvinder.singh@pse.com |
| Public Counsel | Aaron Tam | aaron.tam@atg.wa.gov |
| SAFE Cities at Stand.earth | Anne Pernick | |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| Member of the Public | Michael Mitton | |
| Member of the Public/ Industry Professional (NWEC) | Jeff Bissonnette | jeff@jeffbissonnette.com |
| Member of the Public | Bill Harris | |
| Member of the Public | Katherine Moyd | |
| Member of the Public /NRDC | Angus | |
| Member of the Public | Melanie Plaut | |
| Member of the Public | Robert Hunter | |
| Member of the Public | Brett Baylor | |

| | TWG #2 Load Forecast, February 11, 2022 | |
|---|---|---|
| **Organization** | **Attendence 2/11/22** | **Email** |
| Avista Corp | Tom Pardee | Tom.Pardee@avistacorp.com |
| Cascade Natural Gas | Ashton Davis | Ashton.Davis@cngc.com |
| Cascade Natural Gas | Mark Sellers-Vaughn | Mark.Sellers-Vaughn@cngc.com |
| Cascade Natural Gas | Devin McGreal | Devin.McGreal@cngc.com |
| Cascade Natural Gas | Brain Robertson | Brian.Robertson@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| Community Energy Project | Alma Pinto | alma@communityenergyproject.org |
| CUB | Bob Jenks | bob@oregoncub.org |
| CUB | Sudeshna Pal | sudeshna@oregoncub.org |
| Metro Climate Action Team | Pat Delaquil | pdelaquil@gmail.com |
| Enbridge | Sue Mills | suzette.mills@enbridge.com |
| Energy Trust | Kyle Morrill | Kyle.Morrill@energytrust.org |
| Energy Trust | Gina Saraswati | Gina.Saraswati@energytrust.org |
| Energy Trust | Spencer Moersfelder | Spencer.Moersfelder@energytrust.org |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | sahler@lclark.edu |
| Natural Resources Defense Coucil (NRDS) | Angus Duncan | angusduncan99@gmail.com |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NW Energy Coalition | Jeff Bisonette | jeff@jeffbissonnette.com |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Matt Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Kruti Pandya | Kruti.Pandya@nwnatural.com |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Dan Kizer | Daniel.Kizer@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Ryan Sigurdson | Ryan.Sigurdson@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Rick Hodges | Rick.Hodges@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| OPUC | Kim herb | Kim.herb@puc.oregon.gov |
| OPUC | Zachariah Baker | Zachariah.Baker@puc.oregon.gov |
| Portland Energy Conservation Inc (PECI) | Tim Miller | tim.miller@peci.org |
| Public Counsel | Aaron Tam | aaron.tam@atg.wa.gov |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| Member of the Public - Monitoring for LWV-OR | Kathy Moyd | kmoyd11@gmail.com |

| | TWG #3 Supply Side Resources, March 28, 2022 | |
|---|---|---|
| **Organization** | **Attendence** | **Email** |
| Awec | Chad Stokes | cstokes@cablehuston.com |
| Cascade Natural Gas | Ashton Davis | Ashton.Davis@cngc.com |
| Cascade Natural Gas | Devin McGreal | Devin.McGreal@cngc.com |
| Cascade Natural Gas | Brian Roberston | Brian.Robertson@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| Community Energy Project | Alma Pinto | |
| CUB | Bob Jenks | |
| CUB | Mike Goetz | |
| CUB | Sudeshna Pal | |
| Metro Climate Action Team | Pat Delaquil | |
| Enbridge | Sue Mills | Suzette.Mills@enbridge.com |
| Energy Trust | Kyle Morrill | Kyle.Morrill@energytrust.org |
| Energy Trust | Spencer Moersfeld | Spencer.Moersfelder@energytrust.org |
| Energy Trust | Gina Saraswati | Gina.Saraswati@energytrust.org |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | carrasahler@yahoo.com |
| ICF (Presenter) | Peter Narbaitz | Peter.Narbaitz@icf.com |
| ICF (Presenter) | Maurice Oldham | Maurice.Oldham@mulliongroup.com |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NW Energy Coalition | Jeff Bissonnette | jeff.bissonnette@nwenergy.org |
| NW Energy Coalition | Marli Klass | marli@nwenergy.org |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Matt Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Anna Chittum | Anna.Chittum@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Ryan Sigurdson | Ryan.Sigurdson@nwnatural.com |
| NW Natural | Chris Kroeker | Chris.Kroeker@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Gail Hammer | Gail.Hammer@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Zach Kravitz | Zach.Kravitz@nwnatural.com |
| NW Natural | Doug Tilner | doug.tilgner@nwnatural.com |
| NW Natural | Ed Thurman | Edward.Thurman@nwnatural.com |
| NW Natural | Sam Christenson | Samantha.Christenson@nwnatural.com |
| NW Natural | Ryan Weber | Ryan.Weber@nwnatural.com |
| NW Natural | Tom Carl | Tom.Carl@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| OPUC | JP Batmale | JP.BATMALE@puc.oregon.gov |
| OPUC | Zach Baker | Zachariah.BAKER@puc.oregon.gov |
| OPUC | Curtis Dlouhy | Curtis.DLOUHY@puc.oregon.gov |
| Portland Energy Conservation Inc (PECI) | Tim Miller | timmiller@climatesolutions.org |
| PSE | Gurvinder Singh | gurvinder.singh@pse.com |
| Public Counsel | Aaron Tam | |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| Member of the Public - Monitoring for LWV-OR | Kathy Moyd | |
| Member of the Public - NW Natural Customer | Melanie Plaut | |
| Member of the Public | Bill Harris | |

| | TWG # 4 Avoided Costs and Demand Side Resources, April 13, 2022 | |
|---|---|---|
| **Organization** | **Attendence** | **Email** |
| AEG (Presenter) | Eli Morris | EMorris@appliedenergygroup.com |
| AEG (Presenter) | Neil Grigsby | NGrigsby@appliedenergygroup.com |
| AEG (Presenter) | Ken Walter | kwalter@appliedenergygroup.com |
| Avista Corp | Michael Brutocao | Michael.Brutocao@avistacorp.com |
| AWEC | Chad Stokes | cstokes@cablehuston.com |
| Cascade Natural Gas | Devin McGreal | Devin.McGreal@cngc.com |
| Cascade Natural Gas | Brian Robertson | Brian.Robertson@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| CUB | Sudeshna Pal | |
| CUB | Jennifer Hill-Hart | jennifer@oregoncub.onmicrosoft.com |
| Metro Climate Action Team | Pat DeLaquil | |
| Enbridge | Sue Mills | Suzette.Mills@enbridge.com |
| Energy Trust (Presenter) | Kyle Morrill | Kyle.Morrill@energytrust.org |
| Energy Trust (Presenter) | Spencer Moersfelder | Spencer.Moersfelder@energytrust.org |
| Energy Trust | Gina Saraswati | Gina.Saraswati@energytrust.org |
| Energy Trust | Laura Schaefer | Laura.Schaefer@energytrust.org |
| Energy Trust | Adam Bartini | Adam.Bartini@energytrust.org |
| Energy Trust | Fred Gordon | Fred.Gordon@energytrust.org |
| Energy Trust | Jackie Goss | Jackie.Goss@energytrust.org |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | |
| GTI (Presenter) | Ryan Kerr | RKerr@gti.energy |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NEEA (Presenter) | Peter Christeleit | PChristeleit@neea.org |
| NW Energy Coalition | Jeff Bissonnette | jeff.bissonnette@nwenergy.org |
| NW Energy Coalition | Fred Heutte | |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Matthew Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Edward Thurman | Edward.Thurman@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Holly Braun | Holly.Braun@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Brown | Rebecca.Brown@nwnatural.com |
| NW Natural | Douglas Tilgner | Douglas.Tilgner@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Cecelia Tanaka | Cecelia.Tanaka@nwnatural.com |
| NW Natural | Jen Yocom | Jennifer.Yocom@nwnatural.com |
| NW Natural | Sam Christenson | Samantha.Christenson@nwnatural.com |
| NW Natural | Anna Chittum | Anna.Chittum@nwnatural.com |
| NW Natural | Nels Johnson | Nels.Johnson@nwnatural.com |
| OPUC | Kim herb | Kim.herb@puc.oregon.gov |
| OPUC | Anna Kim | Anna.KIM@puc.oregon.gov |
| OPUC | Zach Baker | Zachariah.Baker@puc.oregon.gov |
| Portland Energy Conservation Inc (PECI) | Tim Miller | |
| Public Counsel | Aaron Tam | |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| Member of the Public - Monitoring for LWV-OR | Kathy Moyd | |
| Call In (unknown) | 15037576222 | |

| | TWG # 5 - Distribution System Planning, April 25, 2022 | |
|---|---|---|
| Organization | Attendence | Email |
| AWEC | Chad Stokes | cstokes@cablehuston.com |
| Cascade Natural Gas | Brian Robertson | Brian.Robertson@cngc.com |
| Climate Solutions | Greer Ryan | greer.ryan@climatesolutions.org |
| CUB | Jennifer Hill-Hart | jennifer@oregoncub.onmicrosoft.com |
| CUB | Sudeshna Pal | |
| DEQ | Matt Steele | Matt.STEELE@deq.oregon.gov |
| Enbridge | Whitney Wong | WWong@Spectraenergy.com |
| Enbridge | Amrit Kunera | kunera@enbridge.com |
| Energy Trust | Spencer Moersfelder | spencer@etoo.org |
| Energy Trust | Gina Saraswati | Gina_Saraswati@etoo.org |
| Energy Trust | Kyle Morrill | Kyle_Morrill@etoo.org |
| Energy Trust | Quinn Cherf | Quinn_Cherf@etoo.org |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | |
| Metro Climate Action Team | Pat Delaquil | |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NW Energy Coalition | Jeff Bissonnette | jeff.bissonnette@nwenergy.org |
| NW Energy Coalition | Fred Heutte | |
| NWGA | Dan Kirschner | dkirschner@nwga.org |
| NWGA | Natasha Jackson | njackson@nwga.org |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Matthew Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Doug Tilner | Douglas.Tilgner@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Trujillo | Rebecca.Brown@nwnatural.com |
| NW Natural | Ed Thurman | Edward.Thurman@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Sebastian Weber | Sebastian.Weber@nwnatural.com |
| NW Natural | Nels Johnson | Nels.Johnson@nwnatural.com |
| Oregon Environmental Council | Angus Duncan | |
| OPUC | Kim herb | Kim.herb@puc.oregon.gov |
| OPUC | Zach Baker | Zachariah.Baker@puc.oregon.gov |
| OPUC | Abe Abdallah | abe.abdallah@puc.oregon.gov |
| Portland Energy Conservation Inc (PECI) | Tim Miller | timmiller@climatesolutions.org |
| Public Counsel | Aaron Tam | |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| WUTC | Byron Harmon | byron.harmon@utc.wa.gov |
| Member of the Public - Monitoring for LWV-OR | Kathy Moyd | |
| Call-in (unknown) | 15037576222 | |

| | TWG #6 RNG Methodology and System Resource Planning, June 1, 2022 | |
|---|---|---|
| **Organization** | **Attendence** | **Email** |
| Avista Corp | Tom Pardee | Tom.Pardee@avistacorp.com |
| Avista Corp | Michael Brutocao | Michael.Brutocao@avistacorp.com |
| Cascade Natural Gas | Brian Robertson | Brian.Robertson@cngc.com |
| Cascade Natural Gas | Ashton Davis | Ashton.Davis@cngc.com |
| Cascade Natural Gas | Mark Sellers-Vaughn | Mark.Sellers-Vaughn@cngc.com |
| CUB | Jennifer Hill-Hart | jennifer@oregoncub.onmicrosoft.com |
| CUB | Sudeshna Pal | |
| DEQ | Matt Steele | Matt.STEELE@deq.oregon.gov |
| Enbridge | Sue Mills | millss@enbridge.com |
| Energy Exemplar | Mark Sklar-Chik | mark.sklar-chik@energyexemplar.com |
| Energy Exemplar | Jonathan Surls | jonathan.surls@energyexemplar.com |
| Energy Trust | Spencer Moersfelder | spencer@etoo.org |
| Energy Trust | Gina Saraswati | Gina_Saraswati@etoo.org |
| Energy Trust | Kyle Morrill | Kyle_Morrill@etoo.org |
| Green Energy Institute, Lewis & Clark Law School (GEI) | Carra Sahler | |
| Metro Climate Action Team | Pat Delaquil | |
| Nature Conservancy in OR | Laura Tabor | laura.tabor@TNC.ORG |
| NW Energy Coalition | Jeff Bissonnette | jeff.bissonnette@nwenergy.org |
| NW Natural | Tamy Linver | Tamy.Linver@nwnatural.com |
| NW Natural | Matthew Doyle | Matthew.Doyle@nwnatural.com |
| NW Natural | Melissa Martin | Melissa.Martin@nwnatural.com |
| NW Natural | Ryan Bracken | Ryan.Bracken@nwnatural.com |
| NW Natural | Haixiao Huang | Haixiao.Huang@nwnatural.com |
| NW Natural | Andy Fortier | Andy.Fortier@nwnatural.com |
| NW Natural | Laney Ralph | Delaney.Ralph@nwnatural.com |
| NW Natural | Kellye Dundon | Kellye.Dundon@nwnatural.com |
| NW Natural | Doug Tilner | Douglas.Tilgner@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Natasha Siores | Natasha.Siores@nwnatural.com |
| NW Natural | Rebecca Trujillo | Rebecca.Brown@nwnatural.com |
| NW Natural | Ed Thurman | Edward.Thurman@nwnatural.com |
| NW Natural | Scott Johnson | Scott.Johnson@nwnatural.com |
| NW Natural | Steven Reinholtz | Steven.Reinholtz@nwnatural.com |
| NW Natural | Sebastian Weber | Sebastian.Weber@nwnatural.com |
| NW Natural | Mary Moerlins | Mary.Moerlins@nwnatural.com |
| NW Natural | Mike Meyers | Michael.Meyers@nwnatural.com |
| NW Natural | Taylor Nickel | Taylor.Nickel@nwnatural.com |
| NW Natural | Anna Chittum | Anna.Chittum@nwnatural.com |
| NW Natural | Dan Kizer | Daniel.Kizer@nwnatural.com |
| NW Natural | Cecelia Tanaka | Cecelia.Tanaka@nwnatural.com |
| Oregon Environmental Council | Angus Duncan | |
| OPUC | Kim herb | Kim.herb@puc.oregon.gov |
| OPUC | Nick Sayen | Nick.SAYEN@puc.oregon.gov |
| OPUC | JP Batmale | JP.BATMALE@puc.oregon.gov |
| Physicians for Social Responsibility | Melanie Plaut | |
| Portland Energy Conservation Inc (PECI) | Tim Miller | timmiller@climatesolutions.org |
| Puget Sound Energy | | gurvinder.singh@pse.com |
| Public Counsel | Aaron Tam | |
| WUTC | Jade Jarvis | jade.jarvis@utc.wa.gov |
| Member of the Public - Monitoring for LWV-OR | Kathy Moyd | |

## Appendix H
## Meeting for the Public Bill Insert

# NW NATURAL'S 2022 INTEGRATED RESOURCE PLAN (IRP)

The IRP is NW Natural's long-term plan to serve customers and answer questions, such as: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?

Please join us for a discussion of these and other topics to help develop the IRP:

| | |
|---|---|
| **DATE:** | Monday, July 18, 2022 |
| **TIME:** | 6 p.m. to 8 p.m. |
| **ONLINE OR BY PHONE:** | See meeting information at nwnatural.com/IRP |

**You can also mail any questions or comments about the plan to:**

NW Natural
Attn: Integrated Resource Plan
250 SW Taylor Street
Portland, OR 97204

A copy of the draft 2022 Integrated Resource Plan will be available on our website in early July, at **nwnatural.com/IRP**.

NW Natural®

At NW Natural, we have a responsibility to reliably and affordably meet our customers' current and future energy needs. Every few years, Integrated Resource Planning (IRP) develops a plan that best meets customers' forecasted long-term energy requirements with the goal of minimizing the combination of costs and risks for NW Natural customers. This robust planning process evaluates many factors, including but not limited to:

- Environmental policy
- Customer growth
- Consumption trends
- Demand-side resources, such as energy efficiency and demand response
- Supply-side resources, such as renewable natural gas and storage options

The NW Natural IRP is developed through a process open to the public and informed by feedback and a formal review by a diverse set of interested parties. For more information, please visit **nwnatural.com/IRP**.

NW Natural®

# Appendix I
# Draft Comments

To be filed with NW Natural's Final 2022 Integrated Resource Plan