2025

Natural Gas Integrated Resource Plan

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Production Credits

Primary Gas IRP Team

Name	Title	Contribution
Tom Pardee	Natural Gas Planning Manager	IRP Core Team
Michael Brutocao	Natural Gas Analyst	IRP Core Team
James Gall	Manager of Integrated Resource Planning	IRP Core Team
John Lyons	Sr. Resource Policy Analyst	IRP Core Team
Lori Hermanson	Sr. Power Supply Analyst	IRP Core Team
Mike Hermanson	Sr. Power Supply Analyst	IRP Core Team
Grant Forsyth	Chief Economist	Load Forecast
Kim Boynton	Mgr. of Energy Efficiency Analytics	Energy Efficiency
Lisa McGarity	Sr. Energy Efficiency Program Manager	Oregon Energy Efficiency
Leona Haley	Sr. Energy Efficiency Program Manager	Energy Efficiency
Terrence Browne	Principal Gas Planning Engineer	Gas Engineering
Justin Dorr	Natural Gas Resources Manager	Energy Supply

Gas IRP Contributors

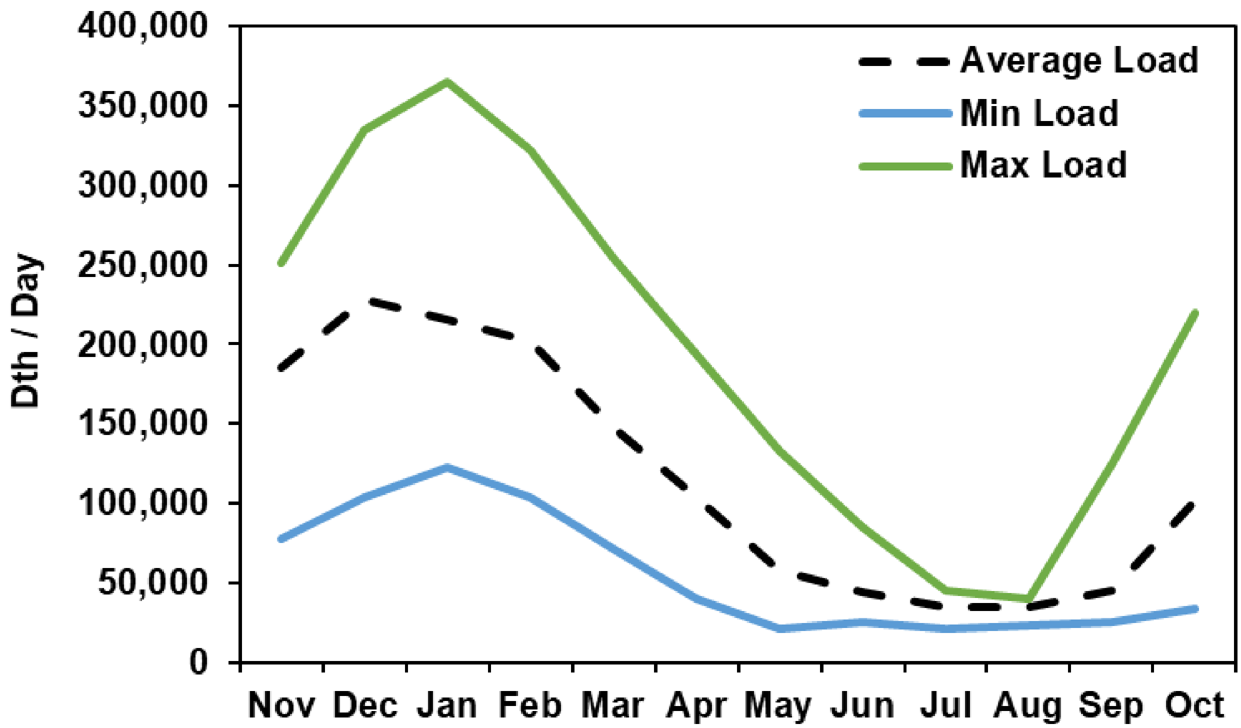
Name	Title	Contribution
Scott Kinney	VP of Energy Resources and Integrated Planning	Energy Supply
Mike Magruder	Director of Integrated Planning and Clean Energy	Integrated Planning
Kevin Holland	Director of Energy Resources	Energy Supply
Shawn Bonfield	Sr. Manager of Regulatory Policy	Regulatory Policy
Amanda Ghering	Regulatory Affairs Analyst	Regulatory Policy
Jared Webley	Sr. Communications Manager	Communications
John Gross	Manager of System Planning	Gas Engineering
Michael Whitby	Renewable Natural Gas Program Manager	Clean Energy

Contact contributors via email by placing their names in this email address format: first.last@avistacorp.com

2025 Natural Gas IRP
Executive Summary

Avista's 2025 Natural Gas Integrated Resource Plan (IRP) identifies a Preferred Resource Strategy (PRS) to meet system energy demand and emissions compliance in Washington under the Climate Commitment Act (CCA) and in Oregon under the Climate Protection Plan (CPP). Avista considers resource capacity needs on a peak day combined with weather futures considering a warming trend and its impact on demand. The total system load is illustrated in Figure 1 by month for 2025 to depict the seasonality of firm customer demand on the natural gas distribution infrastructure.

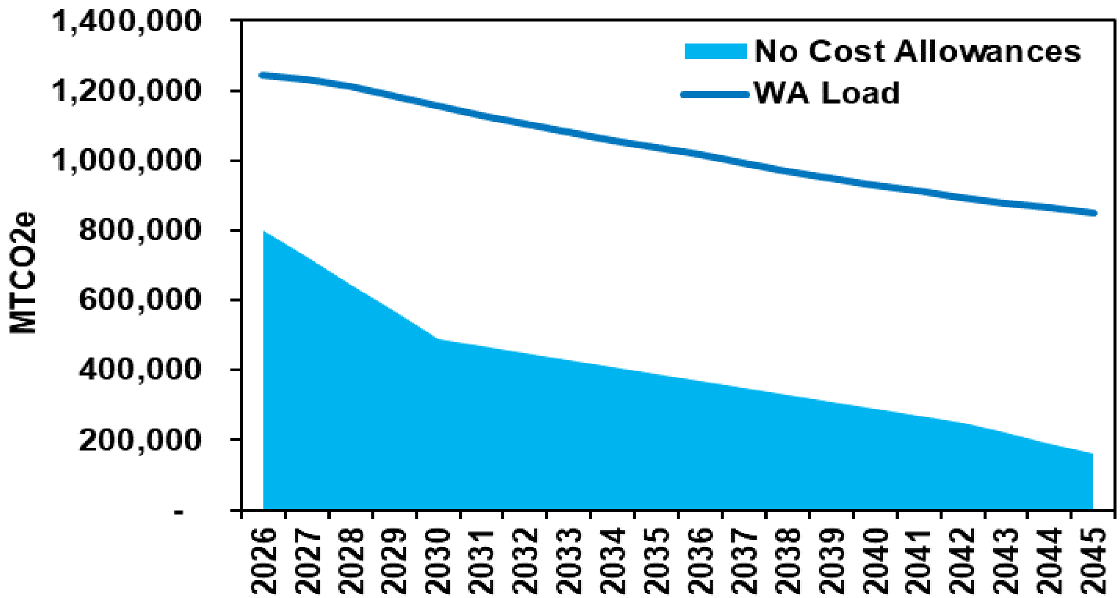
Figure 1: Total System Average Daily Load (Average, Minimum and Maximum)



Customer estimates are increasingly difficult to forecast due to the variety of rules and codes passed by Oregon, Washington and the federal administrations. In Washington, building codes went into effect on July 1, 2023, requiring heat pump technology for space and water heating in all new residential and commercial buildings. This IRP maintains these building codes in the Washington customer and demand forecasts. In November 2024, voters passed Initiative 2066 allowing for the continued use of natural gas. Line extension programs to financially assist customers with natural gas connections have been decreased or planned for elimination and new programs have been passed to help customers consider more efficient equipment. With the risk of uncertainty brought into the future state of customers and demand, 19 scenarios were developed to consider a range of different futures and resource selections. Avista controls sufficient gas transportation rights, consistent with prior IRP expectations during Peak Day criteria. These protect our customers and their structures during extreme weather.

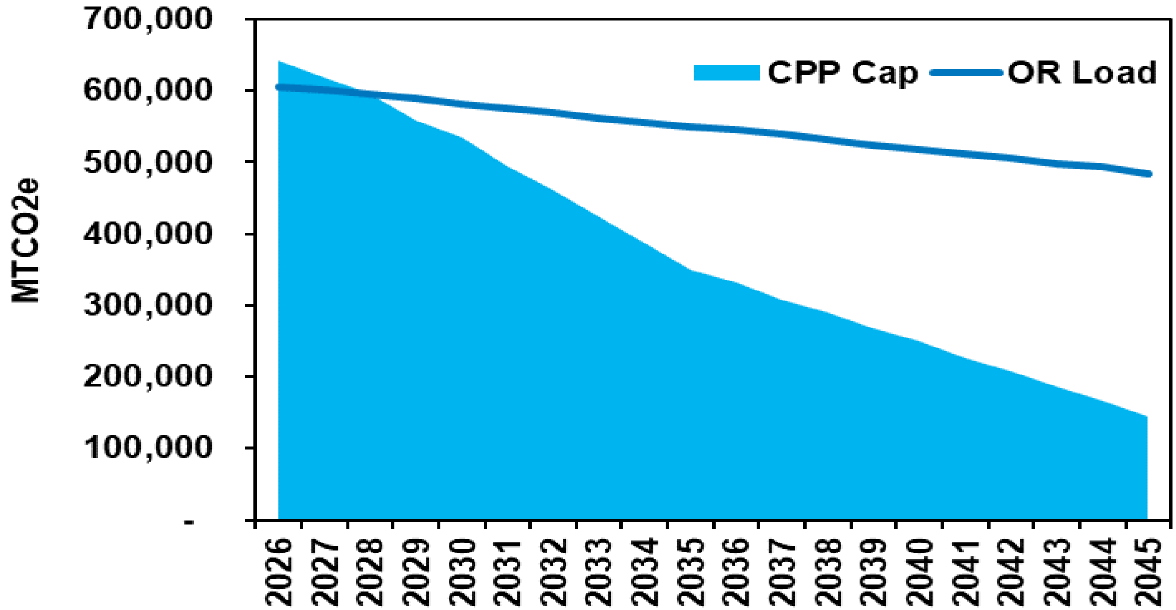
Emissions compliance under Washington's CCA and Oregon's CPP indicates a different story for resource need compared to historical IRPs focusing on securing transportation rights. This IRP focuses on greenhouse gas emissions compliance program constraints of the CCA and CPP, along with these regulations requiring planning for some transport customers. In Figure 2, for Washington's CCA the line demonstrates the equivalent greenhouse gas emissions from customer load and the blue area is the amount of no-cost allowances from the program, the difference between the amounts must be secured either using purchased allowances or emission reductions.

Figure 2: Washington Emissions Forecast Compared to CCA Cap



In Figure 3, the chart for Oregon's CPP is similar, but Avista is covered under program compliance instruments for expected emissions until 2029. After that, it must look to reduce emissions to meet program requirements.

Figure 3: Oregon Emissions Forecast Compared to CPP Cap

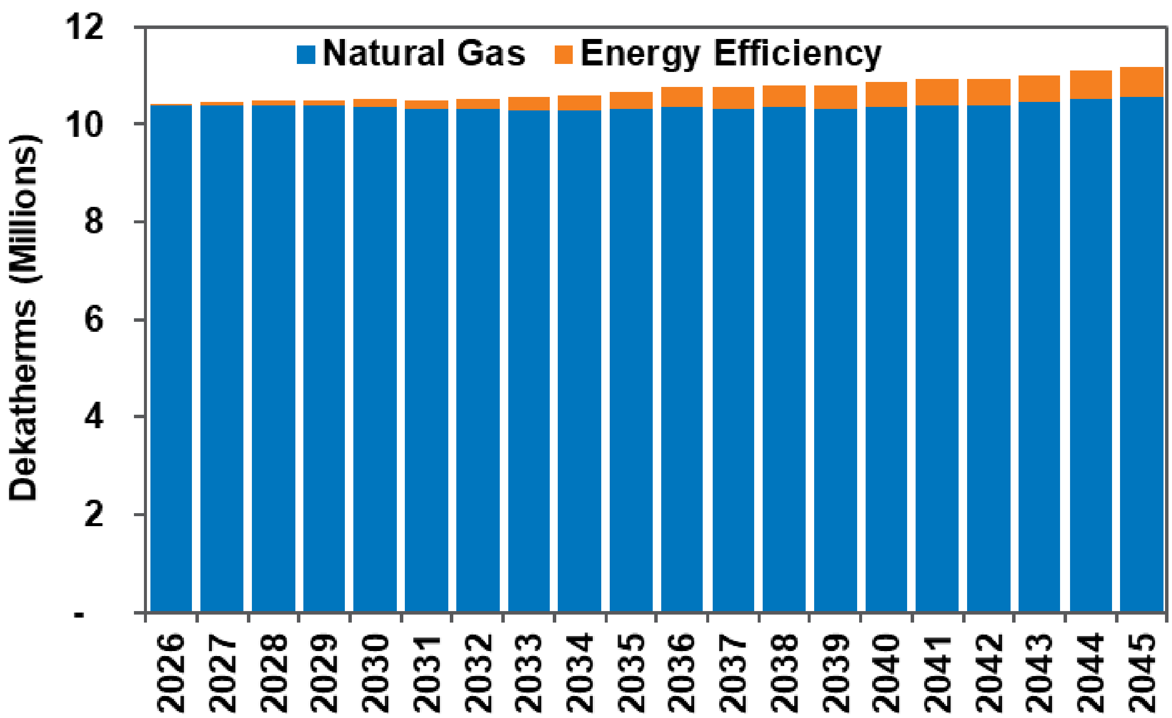


Both charts clearly indicate noncompliance if no measures are taken to offset emissions or utilize other compliance options as per program rules.

Idaho Preferred Resource Strategy

Currently the state of Idaho does not have any greenhouse gas emissions reduction policies and requires utilities to plan for the least cost resource portfolio meeting projected customer demand. Also, it is the only state with growth expectations in energy demand, yet based on expected efficiency offsets does not require new resources to meet increased loads. Based on these factors, the Idaho PRS continues to utilize natural gas from existing access to supply basins, and our existing storage. Avista also found minimal energy efficiency programs are economic to meet energy demand as illustrated in Figure 4. Natural gas will be acquired on a least cost basis from the available hubs. Avista's projection of fuel acquisition considers providing reliability on days with average demand and peak day demand based on our customers' needs. The Idaho PRS combines available resources, demand expectations and current resource needs to select a least cost and least risk portfolio to serve customers in a safe and reliable strategy.

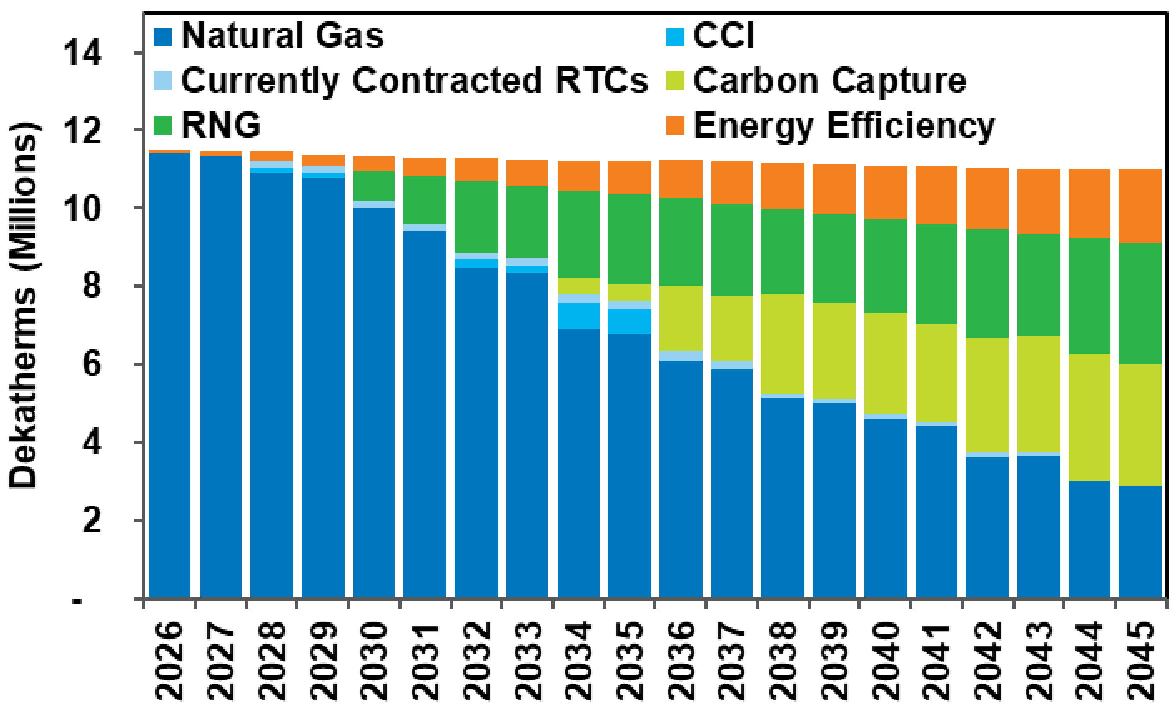
Figure 4: Idaho Preferred Resource Strategy



Oregon Preferred Resource Strategy

Oregon's PRS, shown in Figure 5, has changed as compared to the 2023 IRP. Changes adhere to the new environmental goals of the 2024 CPP and the estimated energy demand. Natural gas continues to be used to provide the primary energy source in the near term and continues through the forecast horizon. It will be sourced based on a least cost supply basin, or resource, to help provide the lowest costs of energy to Oregon customers. In 2030, Alternative resources like Renewable Natural Gas (RNG) is selected in the first year of availability with over 1.1 million dekatherms and ramps up to over 3 million dekatherms by 2045. This resource is expected to provide both the energy and emission offsets to the CPP. Energy Efficiency investments are expected to offset 18.5% of demand by 2045 and are the least cost as compared to the expected costs of CPP compliance and energy demand. Compliance instruments (CI) given to Avista from the CPP are expected to cover emissions in the first compliance period (2025-2027), while Community Climate Investments (CCI) are necessary beginning in 2028 through the next decade. In the mid-term, Carbon Capture (CCUS) is selected in 2035 and increases annually through 2045 to help offset carbon used from natural gas. These combined resources provide the least cost and least risk selection to meet customer energy needs and comply with CPP program requirements.

Figure 5: Oregon Preferred Resource Strategy



Washington Preferred Resource Strategy

Washington's PRS has also changed from the 2023 IRP. The CCA program rules allow covered entities to meet program requirements by procuring an allowance or offset. Allowance and offset prices may drive a different PRS than the one illustrated in Figure 6 and are bound by the floor and ceiling price per year. The current prices for the floor and ceiling in 2025 are $25.85 to $94.85, respectively. The PRS shows conventional natural gas and energy efficiency as the primary energy source options until the end of the study horizon in 2045. Small portions of RNG may be used as a system least cost solution in individual years. The darker blue bars in the chart, when combined, are the CCA program cap and would not require any additional type of program instruments. The lightest blue bar represents natural gas as an energy source, requiring an offset or an allowance as it is above the CCA cap. Energy efficiency is expected to provide the least cost resource through the planning horizon. By 2045, energy efficiency is expected to offset 11% of Washington demand. New resource costs and offsets will continually be compared to allowance prices to select a least cost resource as costs become available. All natural gas procured and delivered to Washington customers will continue to be based on a least cost and risk supply basin or resource.

Figure 6: Washington Preferred Resource Strategy

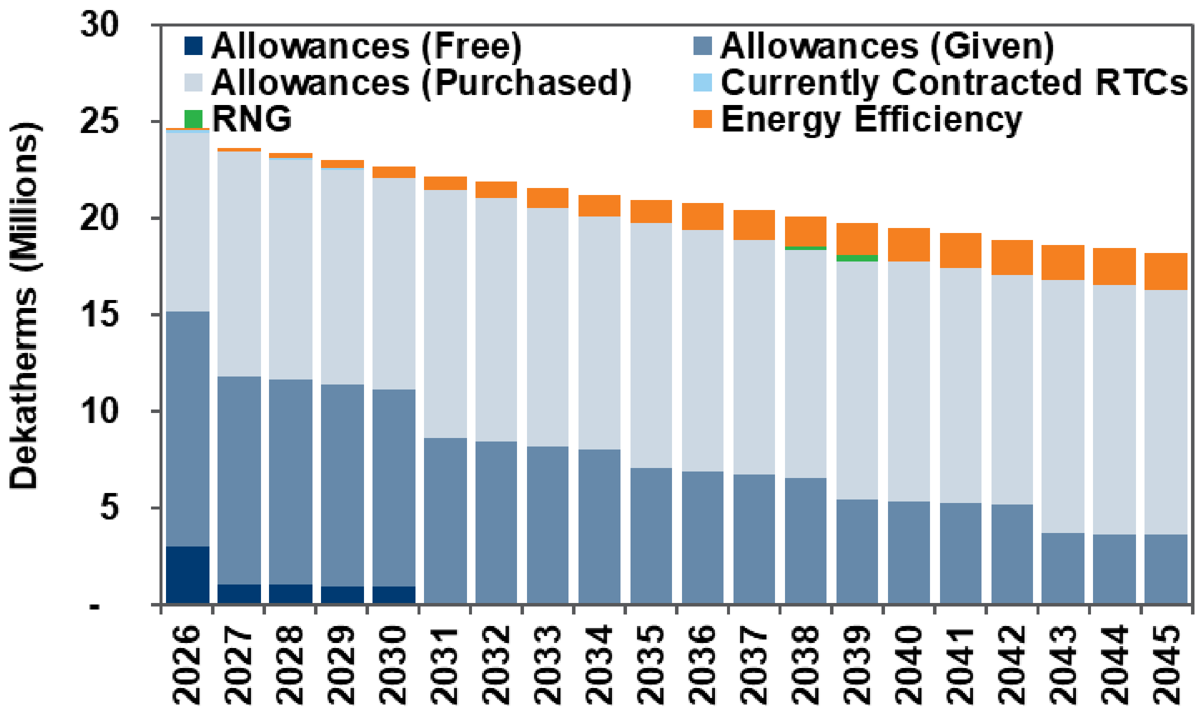


Table of Contents

Table of Figures

Table of Tables

Acronym List

AEG: Applied Energy Group
AMI: Automated Meter Infrastructure
ATR: Autothermal Reforming
BCF: Billion Cubic Feet
BCP: Biennial Conservation Plan
BTU: British Thermal Unit
CCA: Climate Commitment Act
CBO: Community Based Organizations
CCA: Climate Commitment Act
CC&B: Customer Care and Billing
CCI: Community Climate Investments
CCUS: Carbon Capture Utilization and Storage
CDD: Colling Degree Day
CETA: Clean Energy Transformation Act
CBI: Customer Benefit Indicator
CH4: Methane
CPA: Conservation Potential Assessment
CPI: Consumer Price Index
CPP: Climate Protection Plan
CNG: Compressed Natural Gas
CROME: Comprehensive Resource Optimization Model in Excel
DOE: Department of Energy
DOH: Department of Health
DLC: Direct Load Control
DNG: Direct Natural Gas
DR: Demand Response
DSM: Demand Side Management
DTh: Dekatherm
EAG: Equity Advisory Group
EAAG: Energy Assistance Advisory Group
EEAG: Energy Efficiency Advisory Group
EITE: Emission Intensive and Trade Exposed
ETO: Energy Trust of Oregon
FERC: Federal Energy Regulatory Commission
GTN: TC Energy Pipeline
H2: Hydrogen
HDD: Heating Degree Day
HG: Mercury
IAQ: Indoor Air Quality
ICF: ICF Consulting
IOU: Investor-Owned Utility
IP: Industrial Production Index of the U.S. Federal Reserve
IPCC: Intergovernmental Panel on Climate Change

IRP: Integrated Resource Plan
kWh: Kilowatt-hour(s)
GDP: Gross Domestic Product
GHG: Greenhouse Gas
GWh: Gigawatt-hour(s)
LCFS: Low Carbon Fuel Standard
LDC: Local Distribution Center
LFG: Landfill Gas
MACA: Multivariate Adaptive Constructed Analogs
MIP: Mixed Integer Program
MSA: Metropolitan Statistical Area
MW: Megawatt(s)
MWh: Megawatt-hour(s)
N2O: Nitrous Oxide
NDR: Natural Gas Demand Response
NEEA: Northwest Energy Efficiency Alliance
NEI: Non-Energy Impact
NOAA: National Oceanic and Atmospheric Administration
NOx: Nitrous Oxide
NREL: National Renewable Energy Laboratory
OPUC: Oregon Public Utility Commission
O&M: Operations and Maintenance
PGA: Purchase Gas Adjustment
PSE: Puget Sound Energy
PRS: Preferred Resource Strategy
RCP: Representative Concentration Pathway
RCW: Revised Code of Washington
RFP: Request for Proposal
RIN: Renewable Identification Number
RNG: Renewable Natural Gas
RTC: Renewable Thermal Credit
SBCC: State Building Code Council
SM: Synthetic Methane
SMR: Steam Methane Reforming
SO2: Sulfur Dioxide
TAC: Technical Advisory Committee
TRC: Total Resource Cost
UCT: Utility Cost Test
UEC: Unit Energy Consumption
UPC: Use Per Customer
UTC: Washington Utilities and Transportation Commission
WAC: Washington Administrative Code
WCSB: Western Canadian Sedimentary Basin
WWTP: Waste-Water Treatment Plant

This Page is Intentionally Left Blank

1. Introduction and Planning Environment

Section Highlights:

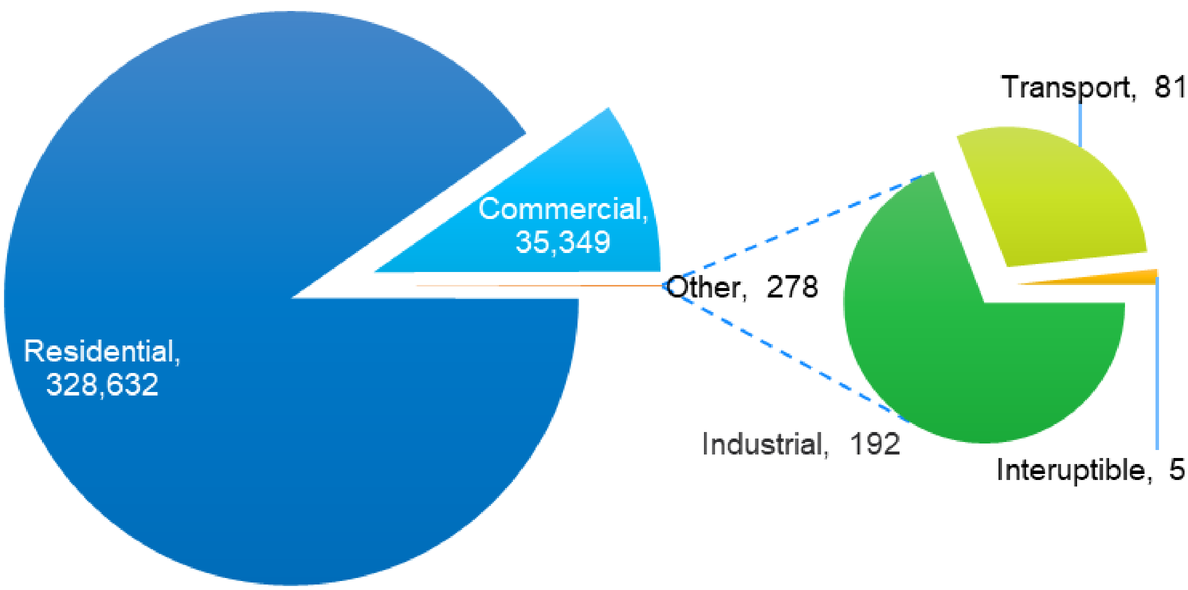
- A total of 11 Technical Advisory Committee (TAC) meetings were held.
- TAC participation included a representation from over 24 organizations and the public.
- A customer focused public meeting was held on March 5, 2025.
- Avista is using a new model for the 2025 IRP (CROME).

Avista is an investor-owned utility involved in the production, transmission, and distribution of natural gas and electricity, as well as other energy-related businesses.

Avista, founded in 1889 as Washington Water Power, has been providing reliable, efficient, and reasonably priced energy to customers for over 135 years. Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970, it expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (its interest subsequently purchased by Northwest Pipeline) to develop the Jackson Prairie natural gas underground storage facility located near Chehalis, Washington. In 1991, Avista added 63,000 customers with the acquisition of CP National Corporation’s Oregon and California properties. Avista sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Figure 1.1 shows where Avista currently provides natural gas service to approximately 377,000 customers in eastern Washington, northern Idaho, and several communities in northeast and southwest Oregon. Figure 1.2 shows the number of firm natural gas customers by state.

Figure 1.1: Avista's Natural Gas Service Territory

Figure 1.2: Avista's Natural Gas Customer Counts



Avista's natural gas operations covers 30,000 square miles, with a population of 1.6 million people. Avista manages its natural gas operation through the North and South operating divisions:

- The North Division includes Avista's eastern Washington and northern Idaho service areas. It includes urban areas, farms, timberlands, and the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 551,000[1] followed by the Lewiston, Idaho/Clarkston, Washington, and Coeur d'Alene, Idaho, areas. The North Division has about 75 miles of natural gas transmission pipeline and 6,300 miles in the distribution system in Washington and 3,700 miles in Idaho. The North Division receives natural gas at more than 40 connection points along interstate pipelines for distribution to over 260,000 customers.

- The South Division serves four counties in southern Oregon and one county in eastern Oregon. The combined population of these areas is over 585,000 residents. The South Division includes urban areas, farms, and timberlands. The Medford, Ashland and Grants Pass areas, located in Jackson and Josephine Counties, are the largest part of this division with a regional population of approximately 312,000. The South Division consists of approximately 15 miles of natural gas transmission main and 3,900 miles of distribution pipelines. Avista receives natural gas at more than 20 connection points along interstate pipelines and distributes it to nearly 102,000 customers.

Customers

Avista provides natural gas services to both core and transportation-only customer classes. Core or retail customers purchase natural gas directly from Avista with delivery to their home or business at a bundled rate. Core customers on firm rate schedules are entitled to receive any volume of natural gas they require. Some core customers are on interruptible rate schedules. These customers pay a lower rate than firm customers because their service can be interrupted. Interruptible customers are not considered in peak day IRP planning.

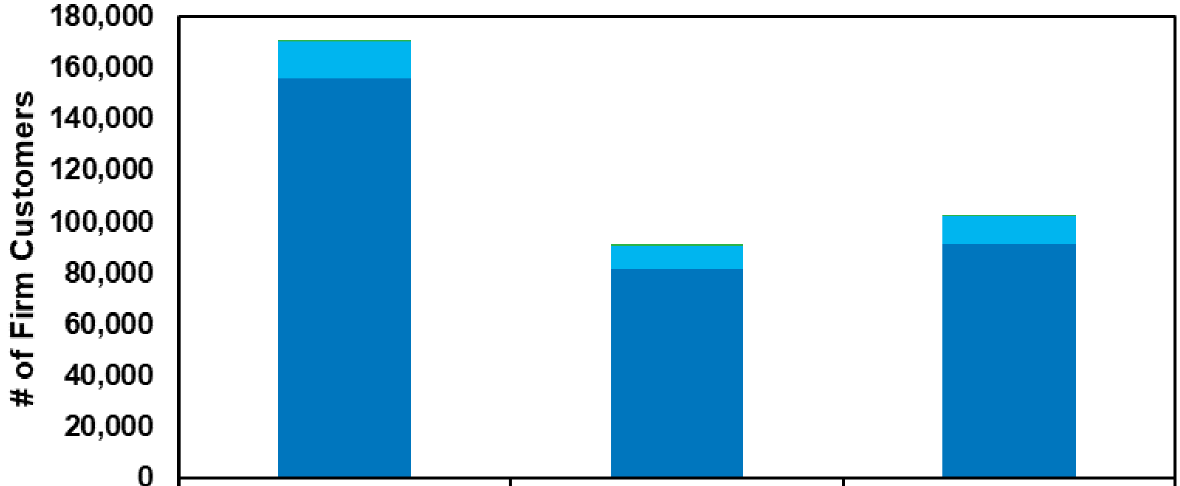
Transportation-only customers purchase natural gas from third parties who deliver the purchased gas to our distribution system. Avista delivers this natural gas to its customers charging a distribution rate only. Avista can interrupt the delivery service when following the priority of service tariff. However, new environmental programs in Oregon and Washington include Avista interruptible and transport customers within our compliance requirements. These environmental programs are discussed in Chapter 6 with resource selection in Chapter 2. Further, changes in policy (Chapter 7) may impact a customer's decision to remain in a specific class like transport due to effects of environmental programs. In the event Avista is required to procure alternative fuels to meet climate

[1] https://www.census.gov/quickfacts/fact/table/spokanecountywashington,WA/PST045221

program requirements it would change the meaning of being a transportation supplier and place these users in a commercial or industrial class

Avista's core or retail customers include residential, commercial, and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

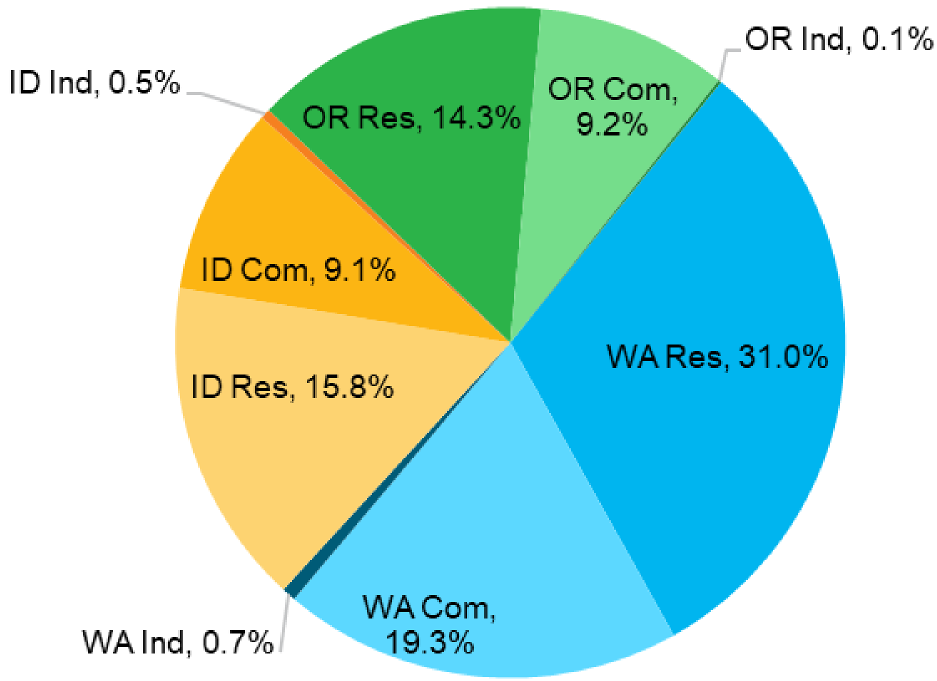
Figure 1.3: Firm Customer Mix



	WA	ID	OR
Ind	86	59	47
Com	14,777	9,203	11,369
Res	155,816	81,772	91,044

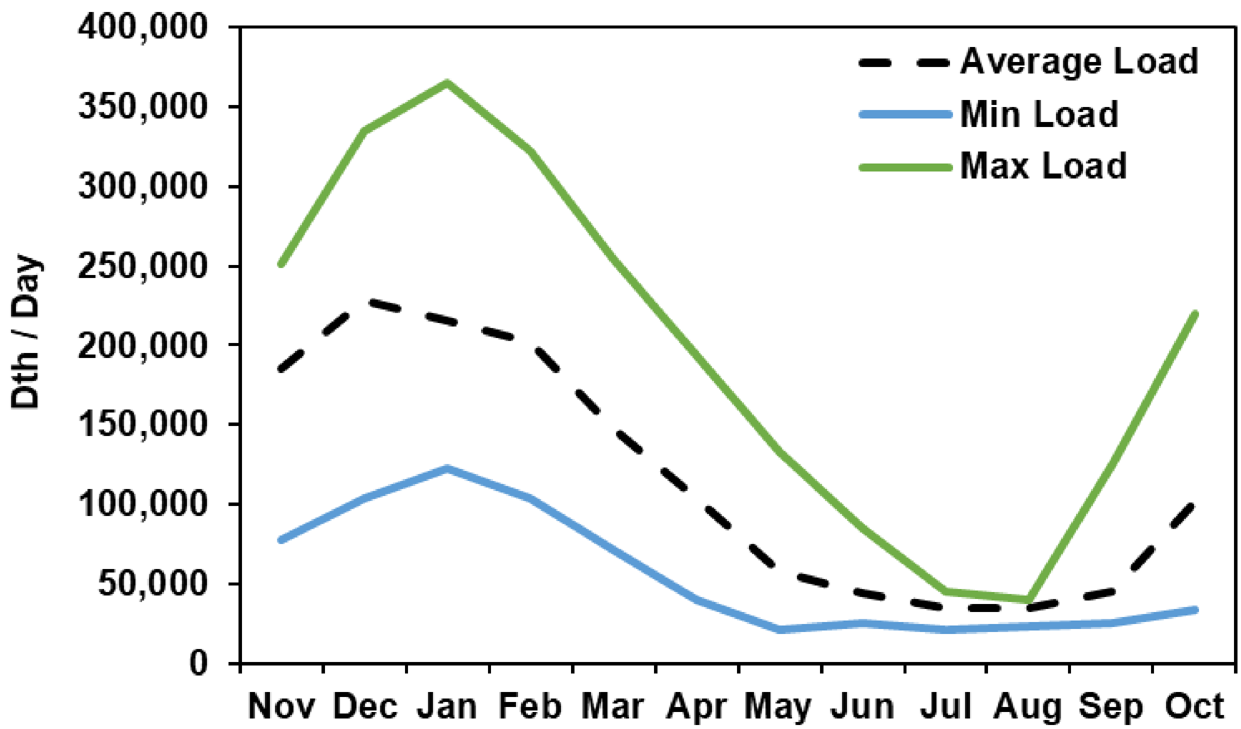
The customer mix is found mostly in the residential and commercial accounts on an annual volume basis (Figure 1.4). The volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers. These customers, however, will still require a compliance mechanism or alternative fuels to meet emissions targets if their emissions are lower than the environmental program requirements as discussed in Chapter 7.

Figure 1.4: 2023 Percent of Firm Demand by Class



The seasonal nature of weather in the Pacific Northwest can drastically alter the amount of energy demanded from the natural gas system for the 2024-2025 PGA year (Figure 1.5). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, the La Grande service territory has several industrially classified agricultural processing facilities producing a late summer seasonal demand spike.

Figure 1.5: Total System Average Daily Load



Integrated Resource Planning

Avista's IRP involves a comprehensive analytical process to ensure our core firm customers can receive long-term reliable natural gas service in extreme weather. The IRP evaluates, identifies, and plans for the acquisition of an optimal combination of existing and future resources using expected costs and associated risks to meet state environmental policies, average daily and peak-day demand delivery requirements over a 20-year planning horizon.

Purpose of the Natural Gas IRP

- Provides a comprehensive long-range planning tool;
- Fully integrates forecasted requirements with existing and potential resources;
- Determines the most cost-effective and risk-adjusted means for meeting future demand requirements; and
- Meets Washington, Idaho, and Oregon regulations, commission orders, environmental programs, and other applicable guidelines.

Avista's IRP Process Considerations

- Customer growth and expected usage;
- Weather planning standard;
- Weather futures;

- Energy Efficiency opportunities;
- Existing and potential supply-side resource options;
- Current and known legislation/regulation;
- Greenhouse gas emissions reductions and compliance mechanisms;
- Risk; and
- Least-cost mix of supply and conservation.

Public Participation

Avista's Technical Advisory Committee (TAC) members play a key role and have a significant impact in developing the IRP. TAC members include Commission staff, peer utilities, government agencies, and other interested parties. TAC members provide input on modeling, planning assumptions, and the general direction of the planning process.

Avista sponsored eleven public TAC meetings to facilitate stakeholder involvement in the 2025 IRP. The first meeting was convened in February 2024 and the last meeting occurred in January 2025. Each meeting was on-line and approximately 2 hours in length to make meetings more accessible and included a broad spectrum of interested parties. The TAC meetings focused on specific planning topics, reviewing the progress of planning activities, and soliciting input on IRP development and results. Avista appreciates the time and effort TAC members contributed to the IRP process as they provided valuable input through their participation. A list of organizations participating in at least one TAC meeting can be found in Table 1.1.

Table 1.1: TAC Member Participation

Cascade Natural Gas	Northwest Energy Coalition	Oregon Public Utility Commission
Fortis	Northwest Natural Gas	Alliance of Western Energy Consumers
Idaho Public Utilities Commission	Biomethane, LLC	Washington State Office of the Attorney General
Northwest Gas Association	Washington Utilities and Transportation Commission	Citizens Utility Board of Oregon
Interested Public Parties	Northwest Power and Conservation Council	Energy Trust of Oregon
Puget Sound Energy	Energy Strategies	Oregon Department of Energy
Lewis and Clark Law School	Eastern Washington University	Applied Energy Group
Oregon Department of Energy	Sierra Club	City of Spokane

Public Meetings

A public meeting was held on March 5, 2025 at noon lasting an hour. In this meeting, Avista reviewed the preferred resources selected in the natural gas IRP to meet energy demand and/or energy policy compliance. An email was sent to TAC members and customers in all jurisdictions informing them of the opportunity to participate and provide feedback. During the public meeting, summary level results by jurisdiction were presented to the participants. The public meeting structure is important as one does not have to be versed in the technical topics discussed in TAC meetings to participate. It also provides direct access to Avista subject matter experts to ask questions and provide feedback about topics most important to each customer. These comments and questions can be found in Appendix 1 and the recordings for each session are available on the Avista IRP website.[2]

Regulatory Requirements

Avista submits a natural gas IRP to the public utility commissions in Idaho, Oregon, and Washington every two years as required by state law or rule. There is a statutory obligation to provide reliable natural gas services to customers at rates, terms, and conditions that are fair, just, reasonable, and sufficient. Avista regards the IRP as a means for identifying methodologies and processes for the evaluation of potential resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis, and research may result in determining alternative resources to be more cost effective than resources reviewed and selected in this IRP. Avista will continue to review and refine its understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

Planning Model

New to the 2025 IRP, Avista used an internally developed planning model named CROME (Comprehensive Resource Optimization Model in Excel) to perform comprehensive natural gas supply planning and analysis in place of the prior software from Energy Exemplar named PLEXOS® and ABB's SENDOUT. At a lower cost to customers, CROME provides the flexibility to properly model unique physical and periodic constraints necessitated by new resources and environmental compliance regulations. This model uses a nodal and zonal analysis with:

- Customer growth, energy intensity and usage patterns to form demand forecasts net of energy efficiency savings as provided by AEG and ETO;
- Future weather forecasts;
- Electrification and demand response options;
- Existing and potential natural gas and alternative fuel supply availability and pricing;
- Existing and potential transportation and storage options and associated costs;
- Existing and potential environmental compliance mechanism supply availability and pricing; and
- Revenue requirements on all new asset additions.

[2] https://www.myavista.com/about-us/integrated-resource-planning

Avista incorporated stochastic modeling in CROME to measure risk around weather, supply and price uncertainty. Some examples of the types of stochastic analysis provided include:

- Price and weather probability distributions;
- Volumetric availability of alternative fuels and compliance mechanisms;
- Probability distributions of costs (i.e., system and commodity costs); and
- Resource mix (optimally sizing a contract or asset level of competing resources).

These computer-based planning tools were used to develop the optimal least-cost, risk-adjusted 20-year resource portfolio plan to serve customers.

Planning Environment

Even though Avista publishes an IRP every two years, the planning process is ongoing with new information and industry related developments occurring regularly. In normal circumstances, the process can become complex as underlying assumptions evolve, impacting previously completed analyses. Widespread agreement on the availability of shale gas and the ability to produce it at lower prices has increased interest in the use of natural gas for LNG and exports to Mexico as well as for industrial uses across North America. Policies meant to decrease the use of natural gas are outlined in Chapter 5 and represent one of the most prominent risks evaluated in this IRP; however, there is uncertainty around the timing and size of the impacts of these policy decisions.

IRP Planning Strategy

Planning for an uncertain future requires robust analysis encompassing a wide range of possibilities. Avista has determined the planning approach needs to:

- Adhere to new environmental laws and policies in Oregon and Washington;
- Recognize historical trends may be fundamentally altered;
- Critically review all modeling assumptions;
- Pursue a spectrum of scenarios and sensitivities;
- Develop a flexible analytical framework to accommodate changes; and
- Maintain a long-term perspective combined with a near-term resource plan.

With these objectives in mind, Avista developed a strategy encompassing all required planning criteria. This produced an IRP that effectively analyzes risks and resource options, which sufficiently ensures customers will receive safe and reliable energy delivery services with the best-risk, least-cost long-term solutions. The following chart summarizes significant changes from the 2023 IRP (Table 1.2).

Table 1.2: Summary of Changes from the 2023 IRP

Subject	Area	2025 Gas IRP	2023 Gas IRP
Demand	System Growth	0.68%	1.10%
Demand	Weather and Design Day Peak	Trended coldest on record to the % of overall weather future reduction in heating degree days by 2045	99% probability of a temperature occurring based on the coldest temperature each year for the past 30 years combined with weather forecasted temperatures and trended from the historic peak day
Demand	Energy Efficiency	ID: 6 Million Therms	ID: 12.7 Million Therms
Demand	Energy Efficiency	OR: 17.6 Million Therms	OR: 16.1 Million Therms
Demand	Energy Efficiency	WA: 19.5 Million Therms	WA: 25.3 Million Therms
Demand	Energy Efficiency	ID: No Carbon Cost	ID: National Carbon Tax beginning in 2030 ($12.00 - $62.08) per MTCO2e
Demand	Energy Efficiency	WA: Social Cost of Carbon @ 2.5% discount rate ($109 - $215) per MTCO2e	WA: Social Cost of Carbon @ 2.5% discount rate ($92.68 - $185.07) per MTCO2e
Supply	Natural Gas Price Forecast	A higher price curve at $4.94 / Dth levelized cost in real 2024 US $	A price curve at $4.50 / Dth levelized cost in real 2022 US $
Policy	Program Instruments for Compliance	CCA (WA): $44 - $117 per Allowance (MTCO2e)	CCA (WA): $46 - $83 per Allowance (MTCO2e)
Policy	Program Instruments for Compliance	CPP (OR): Cost of compliance to 2025 CPP ($141 - $241) per MTCO2e	OR: Cost of Carbon ($92.68 - $185.07) per MTCO2e
Policy	CPP	2025 Climate Protection Plan (CPP) - Oregon	2022 Climate Protection Plan (CPP) - Oregon

2. Preferred Resource Strategy

Section Highlights:
- Energy Efficiency reduces demand by over 4.35 million dekatherms by 2045.
- No new fuel transportation is required to meet firm customer loads.
- Idaho's preferred resource continues to be natural gas as it is the least cost resource.
- Renewable natural gas is needed by 2030 along with over 112,000 CCIs to meet Oregon's CPP requirements.
- To meet Washington's CCA - the lowest cost option is to purchase allowances for compliance.
- Avista is considering Liquefied Natural Gas Storage to increase resiliency of the system.

This chapter combines the previously discussed IRP components used to derive a 20-year resource plan to meet Avista's resource deficiencies and state environmental policy objectives. The foundation for integrated resource planning is the criteria used for developing demand forecasts. For peak capacity planning, Avista transitioned from using the coldest day on record to a 99th percentile, or 1 out of 100 chances, methodology applied to forecasted temperatures for each area within Avista's system; this is described further in Chapter 3. Avista plans to serve the expected peak day demand in each region by maintaining firm pipeline transportation rights along with purchasing natural gas from the market. Firm energy resources include natural gas, and distributed renewable supplies, firm pipeline transportation, and storage resources. In addition to peak requirements, Avista plans for demand occurring in non-peak periods such as winter, shoulder months (April and October) and summer. The modeling process includes optimization for every day of the 20-year planning period.

Avista does not make firm commitments to serve interruptible customers and therefore assumes these loads would be curtailed on a peak day to serve firm customers. However, these customers are considered in this IRP for compliance with the CPP and CCA. Transport customers have their own interstate pipeline contracts to flow natural gas to Avista's city gates and are not considered in peak day planning, unless necessary for greenhouse gas program compliance purposes. A weather planning standard, blended price curve of three studies developed by industry experts and an academically backed customer forecast all work together to develop stringent planning criteria to test resource needs.

The forecasted level of demand represents the amount of energy needed to be delivered; however, on both an annual and peak-day basis, an additional 1% to 3% is needed to account for additional natural gas used primarily for pipeline compressor station fuel to move the gas from different areas of demand on each interstate pipeline. The range of 1% to 3%, known as fuel, varies by delivery route and can change monthly depending on the specific pipeline and tariff. This fuel is used to move the natural gas from point A on the pipeline to point B or the delivery point. The FERC and National Energy Board approved tariffs govern the percentage of required additional fuel supply.

Other fuels like RNG may or may not require this additional fuel as it is location dependent. If a renewable fuel is within Avista's distribution system, the current design does not include any compressors needed to move the gas and is pressure driven (Chapter 10).

CROME Planning Model

CROME is an internally developed mixed integer programming model used to solve natural gas supply and transportation optimization questions. Mixed integer programming is a proven technique to solve minimization/maximization problems. CROME analyzes the complete problem at one time within the study horizon, while accounting for physical limitations, carbon equivalent emissions, and contractual constraints. The software analyzes thousands of variables and evaluates possible solutions to generate a least-cost solution satisfying a given set of constraints. CROME considers the following variables:

- Demand data, such as customer count forecasts and energy intensity by customer type (e.g., residential, commercial, industrial, and transport).
- Weather data, including minimum, maximum, and average temperatures.
- Existing and potential transportation data describes the network for physical movement of natural gas and associated pipeline costs.
- Existing and potential supply options include supply basins, revenue requirements as the key cost metric for all asset additions and prices.
- Natural gas storage options with injection/withdrawal rates, capacities, and costs.
- Energy Efficiency potential.
- Daily energy demand by location and customer type (e.g., residential, commercial, industrial, and transport)

Figures 2.1 through 2.3 are CROME network diagrams of Avista's demand centers and resources (including supply resource options) for Idaho, Washington and Oregon. These diagrams illustrate current and potential transportation and storage assets, flow paths and constraint points.

Figure 2.1: CROME Idaho System Map

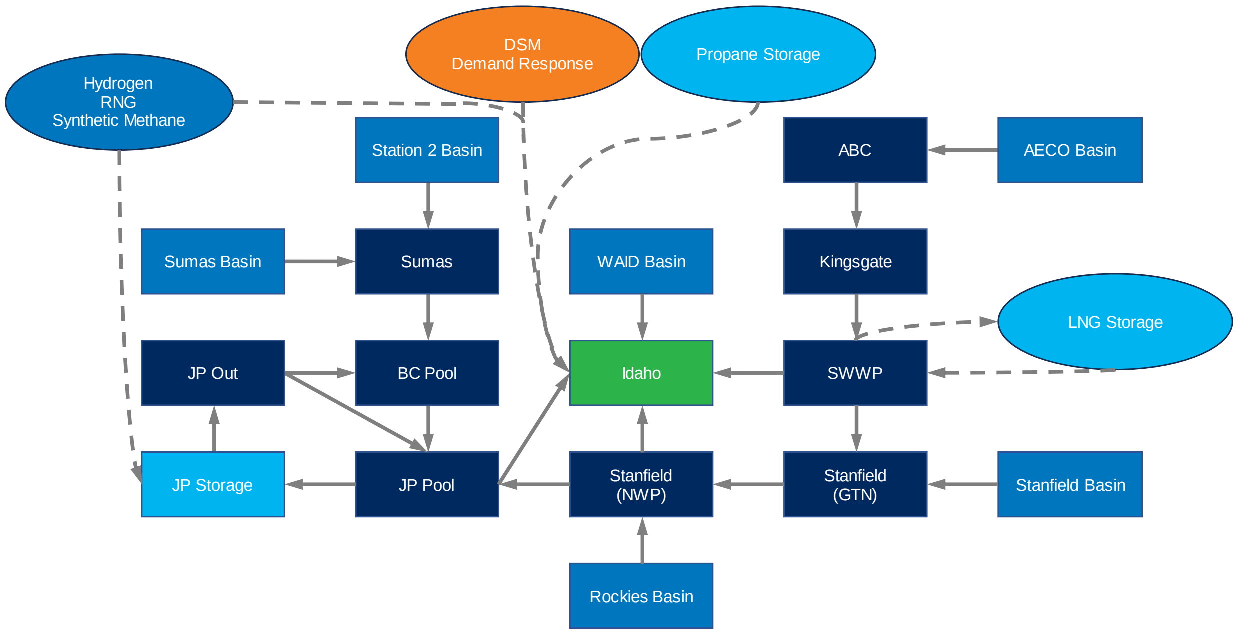


Figure 2.2: CROME Washington System Map

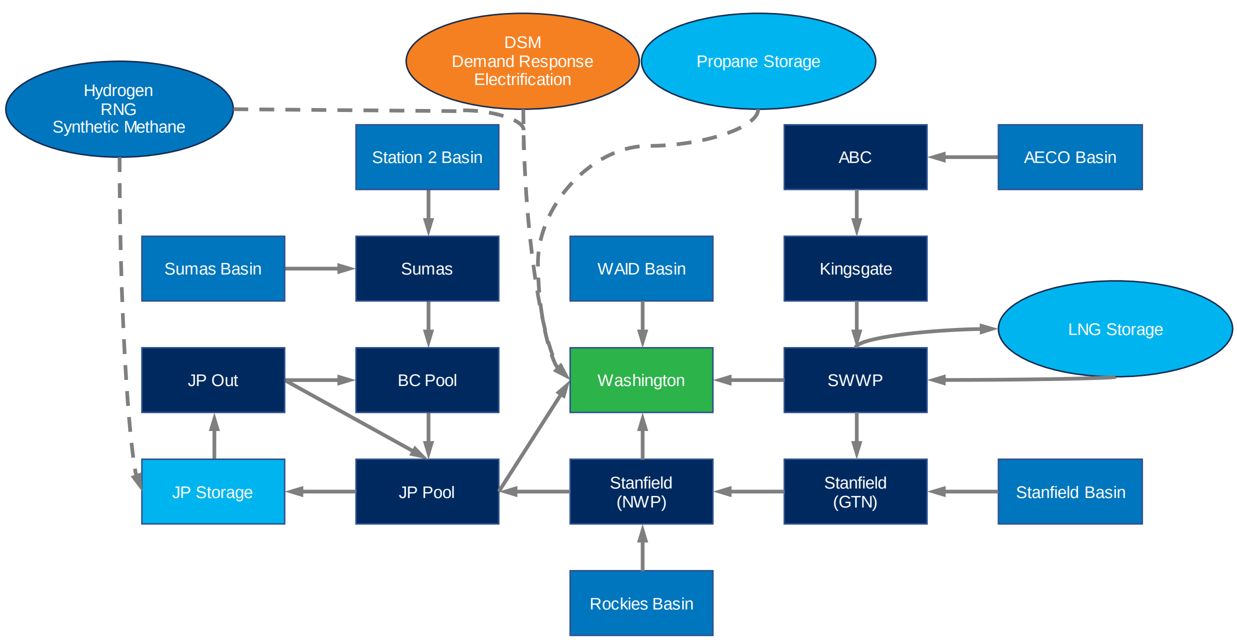
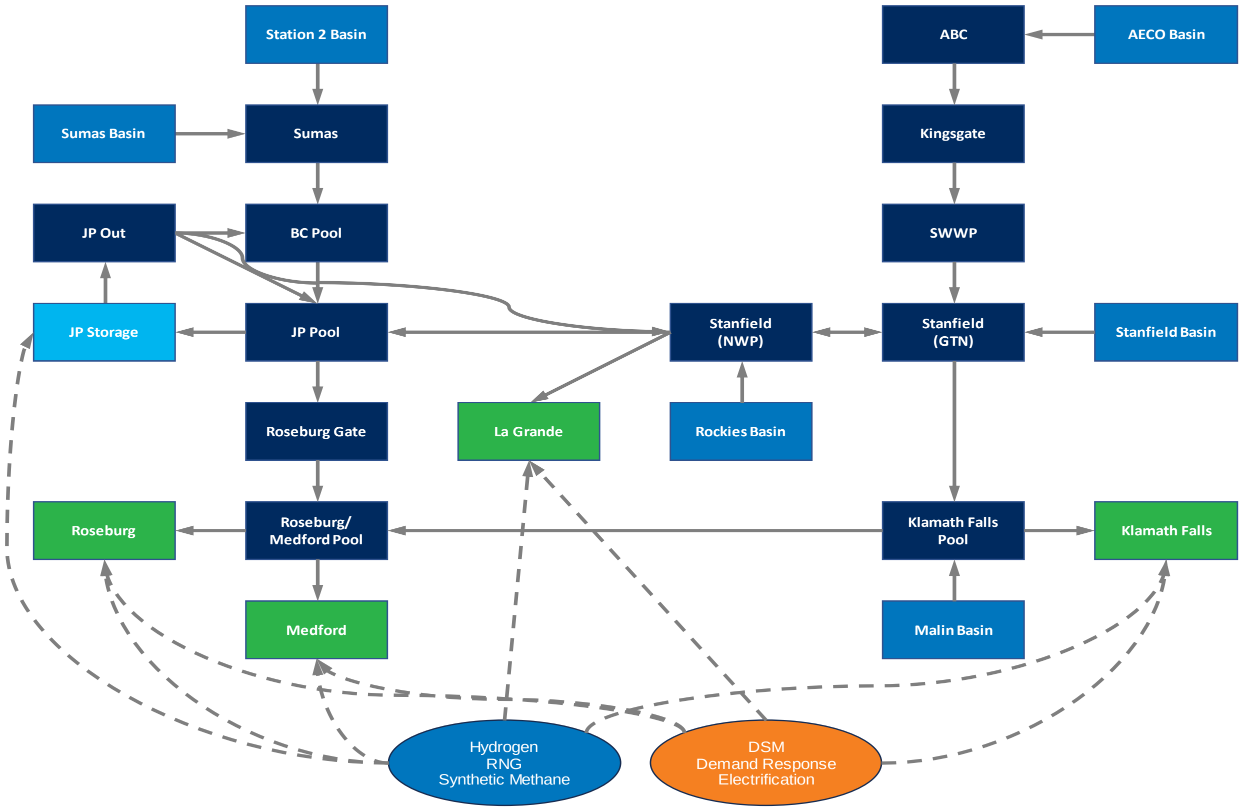


Figure 2.3: CROME Oregon System Map



The CROME model provides a flexible tool to analyze scenarios such as:

- Pipeline capacity needs and capacity releases;
- Effects of different weather patterns upon demand;
- Effects of natural and renewable gas price increases upon total gas costs;
- Emission constraints by planning zone;
- Storage optimization studies;
- Resource mix analysis for conservation;
- Weather pattern testing and analysis;
- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

CROME also includes stochastic modeling and Monte Carlo capabilities to facilitate price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions.

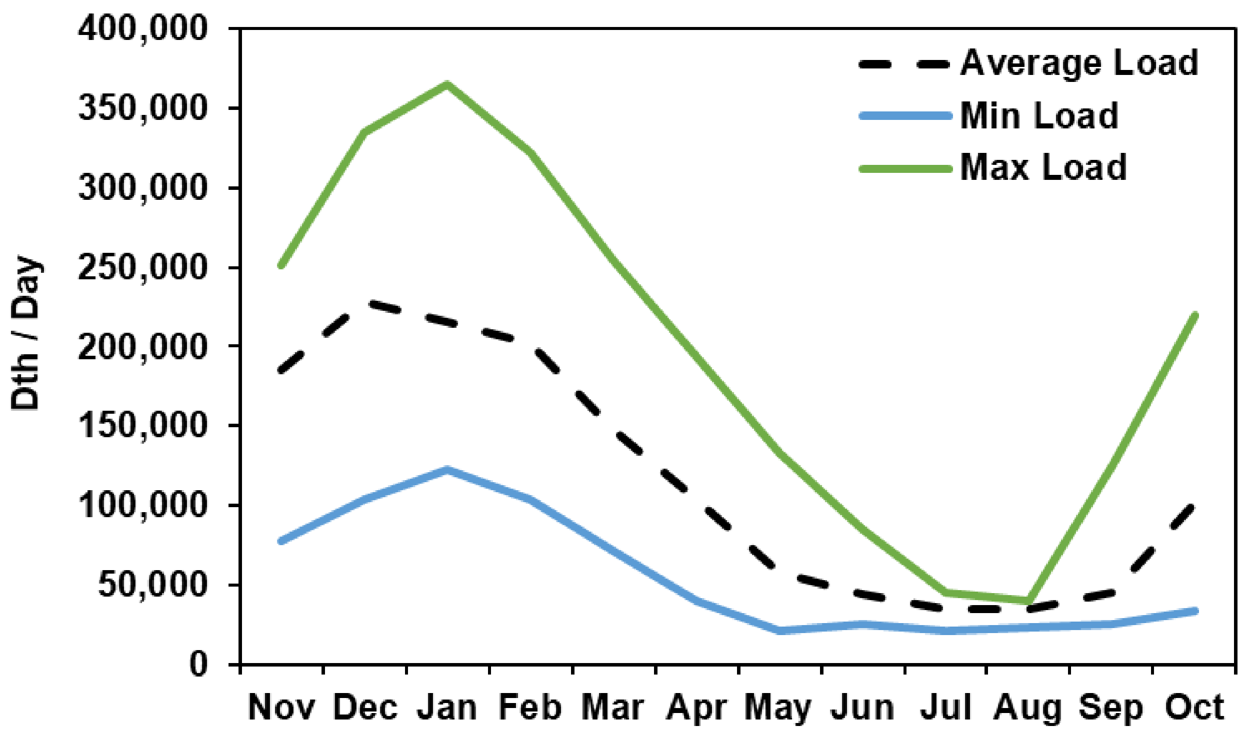
Resource Integration

The following sections summarize the comprehensive analysis bringing demand forecasting and existing and potential supply and demand-side resources together to form the 20-year, least-cost plan.

Avista forecasts 11 service areas with distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The areas are Washington and Idaho (each state is disaggregated into three sub-areas because of pipeline flow limitations and the ability to physically deliver natural gas to an area); Medford (disaggregated into two sub-areas because of pipeline flow limitations); and Roseburg, Klamath Falls, and La Grande. In addition to area distinction, Avista also models demand by customer class and by end use within each service area. The relevant firm customer classes are residential, commercial, and industrial.

Customer demand is highly weather-sensitive. Avista's customer demand is not only extremely seasonal but also highly variable. Figure 2.4 captures this historic variability showing firm customer monthly system-wide average demand, minimum demand, and maximum demand.

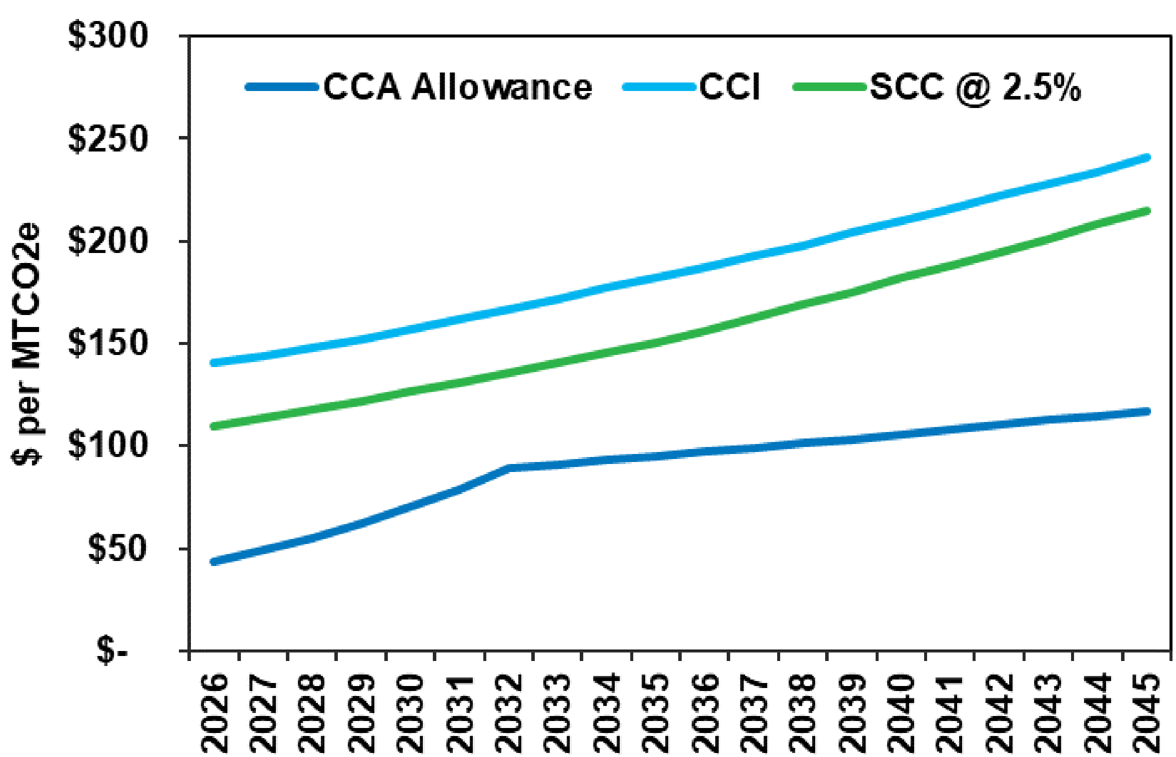
Figure 2.4: Total System Average Daily Load (Average, Minimum and Maximum)



Carbon Policy Resource Utilization Summary

Avista uses an estimated greenhouse gas (GHG) pricing as an incremental adder to address state climate policies. GHG price adders increase the price of a dekatherm of natural gas and impact resource selections and are summarized in Figure 2.5. In Washington, the Climate Commitment Act (CCA) requires the use of allowances issued by the Department of Ecology to be added to all consumption of natural gas consumed within the state above the cap with prices starting at $44 per metric ton in 2026 and moving to $117 per metric ton by 2045. Each CCA credit provides for one metric ton of CO2e GHG emissions. CCA credits are received as an allotment to the utility, purchased in the quarterly state auctions, or bought in the open market. A limited percentage of GHG emissions reductions can also be from carbon offsets. Additionally, Washington's energy efficiency cost effective selection analysis considers the social cost of greenhouse gas (SCGHG), determined by the Interagency Working Group on Social Cost of Greenhouse Gas using the 2.5% discount rate for future costs as required by RCW 80.28.395. For the State of Oregon, Avista considers a proxy value of a community climate investment (CCI) for meeting the Climate Protection Plan (CPP). As discussed in Chapter 7, this value is only an estimate as the quantity of available CCIs is fixed, and other resources are required to meet annual climate emissions requirements. Compliance to the CCA) and CPP occur through instruments in each program, with the attributed costs of compliance valued against supply side resources.

Figure 2.5: Carbon Legislation Sensitivities

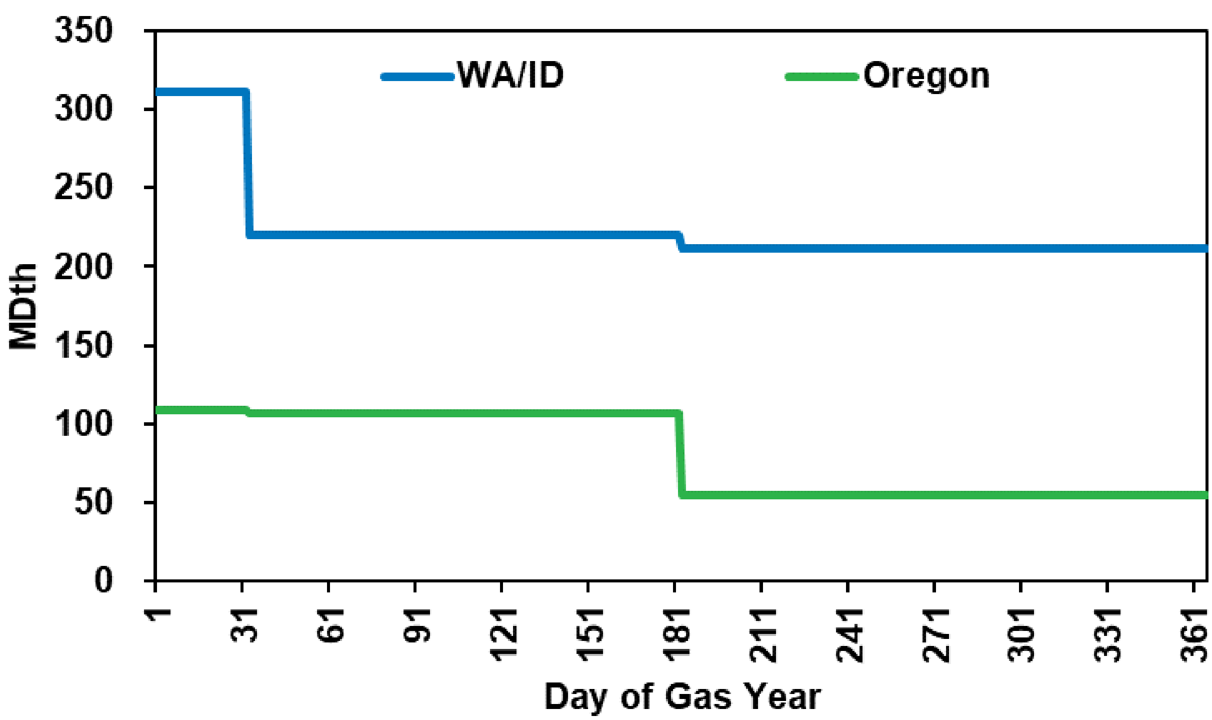


Transportation and Storage

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all of the costs necessary to deliver the natural gas to customers. Daily capacity of existing transportation resources (described in Chapter 5) is represented by the firm resource duration curves depicted in Figure 2.6. These volumes drop as seasonal contracts are in place with GTN as discussed in Chapter 5. The gas year begins on November 1, when all available transportation contracts begin allowing for higher volumes throughout the winter heating season.

Current rates for capacity are also available in Appendix 5. Forecasting future pipeline rates can be challenging because of the need to estimate both the amount and timing of rate changes. Avista's estimates and timing of future pipeline rate increases are based on knowledge obtained from industry discussions and participation in pipeline rate cases. This IRP assumes pipelines will file to recover costs at rates equal to inflation.

Figure 2.6: Existing Firm Transportation Resources



Demand and Deliverability Balance

After incorporating the system data into the CROME model, Avista generated an assessment of demand compared to existing deliverability resource sources (Transport Right) for several scenarios. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management, of both long- and short-term resources, ensures the goal to meeting firm customer demand in a reliable and cost-effective manner as described in Chapter 3.

Average Case demand, represented by the black line in Figures 2.7 and 2.8, is compared to existing storage and transport rights on a peak day. This demand is net of energy efficiency savings and shows the adequacy of Avista's transport rights under normal weather conditions. For this case, current transportation resources exceed demand needs over the planning horizon. Considerations to the importance of average demand are discussed above when optimizing resources and releasing capacity to mitigate costs along with contract type and terms for delivering natural gas in times of need. These resources vary in ownership by state and by area and must match or exceed the volume of expected demand.

Figure 2.7: Average Demand - Storage & Transport Rights for February 28th

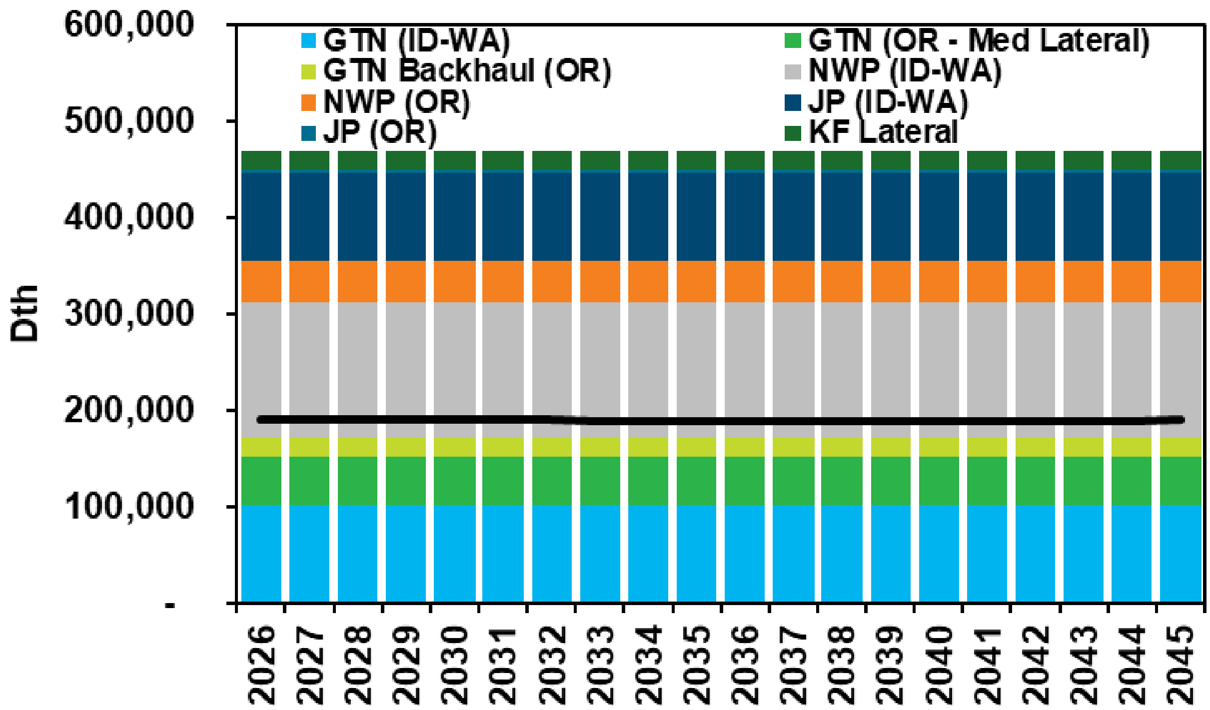


Figure 2.8: Average Demand - Storage & Transport Rights for December 20th

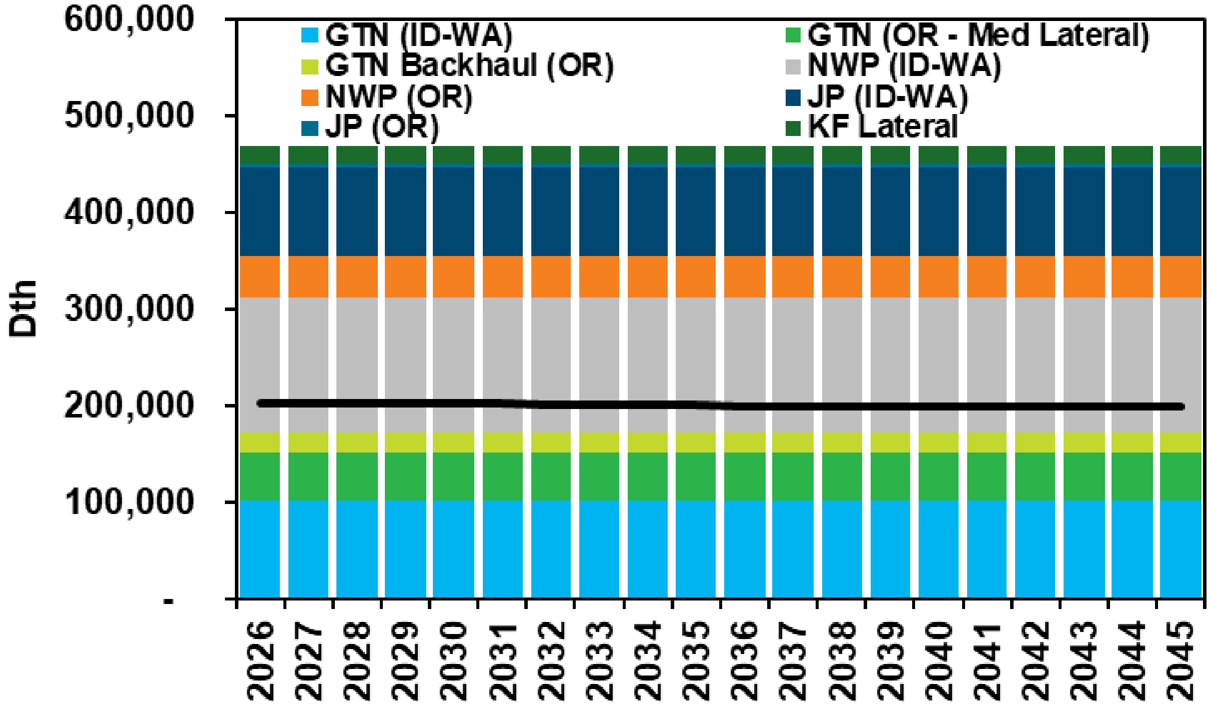


Figure 2.9 shows system peak day demand compared to existing resources when Idaho, Washington and La Grande experience peak days. In Figure 2.10, the Klamath Falls, Medford and Roseburg planning regions all experience peak days; the loads for these areas account for much less demand in comparison, including peak days. Peak day demand is also net of energy efficiency savings. Avista is still long on transport rights, consistent with prior IRP expectations. Peak day criteria is important as it protects our customers and their structures during extreme weather. Avista will evaluate future capacity releases or allocation between states as demand projections materialize. Currently, Avista is not proposing any change to its transportation rights.

Figure 2.9: Peak Day Demand - Storage & Transport Rights for February 28th

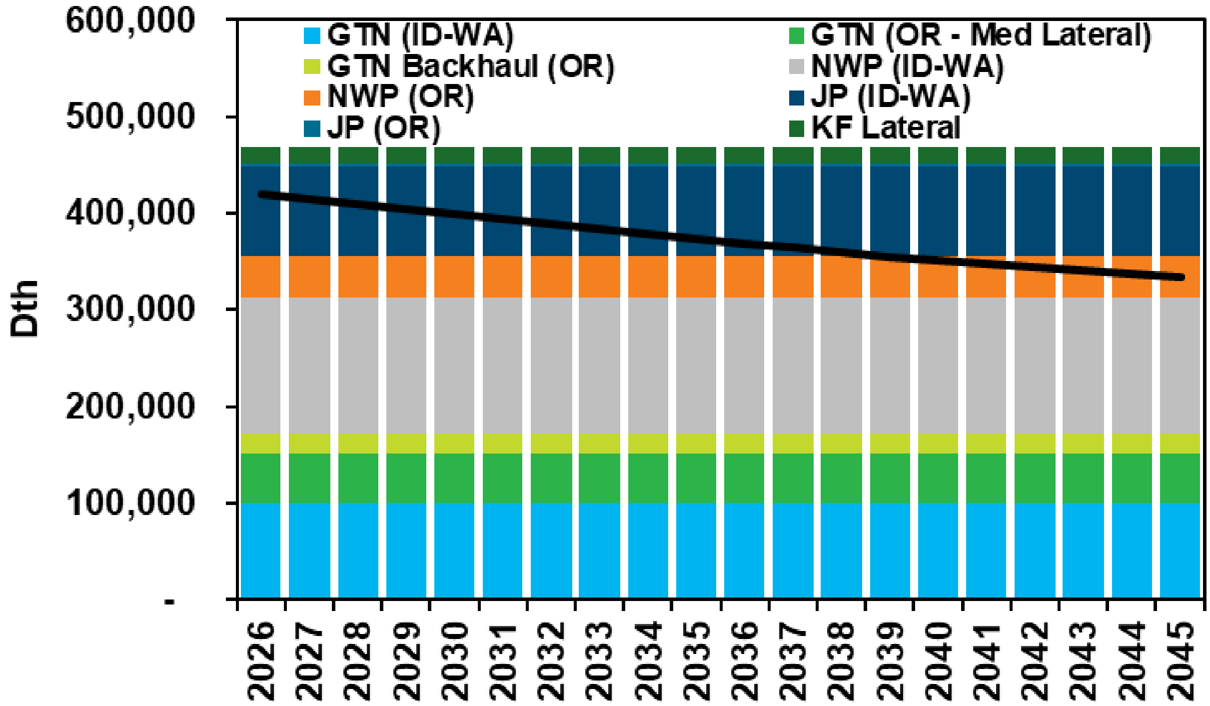
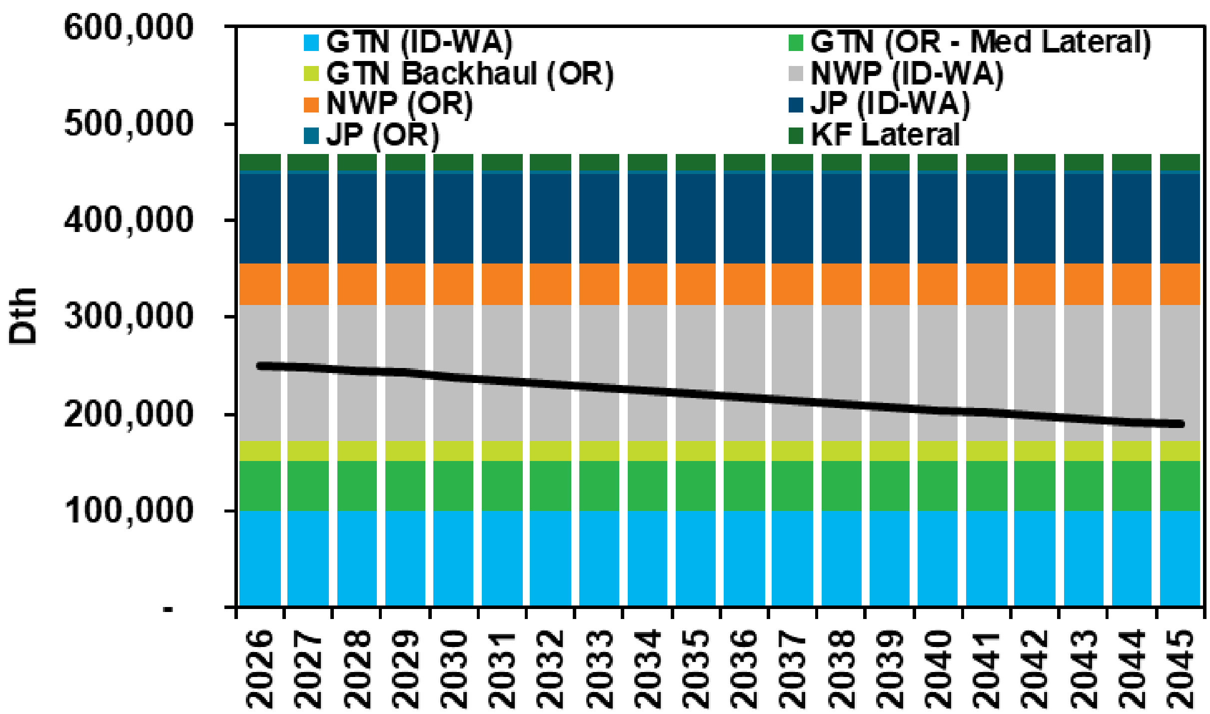


Figure 2.10: Peak Day Demand - Storage & Transport Rights for December 20th



Avista’s interstate pipeline transportation position is strong compared to existing peak demand; the IRP must also consider meeting emissions reductions for future demand changes. New capacity resources, such as on-system storage for resiliency in the event short term energy supplies are interrupted due to transportation outages, is a viable resource addition that Avista will further study. This Resiliency scenario is described in detail in Chapter 8 and will be an action item of this IRP to determine if Avista should pursue additional natural gas storage.

State Environmental Compliance

When considering emissions compliance under the CCA and CPP, Avista requires additional resources or compliance instruments. GHG emissions compliance addresses program constraints of the CCA and CPP, plus these regulations require planning for transport customers where past plans did not. In both Figure 2.11 and Figure 2.12, equivalent GHG emissions from all customer demand can be found in the line chart compared to the areas of each chart indicating the quantity of compliance instruments received from each program. The white area between these chart elements displays the resource needs for program compliance and clearly shows noncompliance will occur if no actions are taken to offset emissions or utilize other options per program rules, where the total emissions exceed the annual limits. These shortages occur in 2026 in Washington and continue through the end of the study in 2045. Oregon shortages begin in the second compliance period (2028-2029). Further analysis is required to determine demand and price in an unknown future and will be discussed and compared to other sensitivities and scenarios, where appropriate, in Chapter 8.

Figure 2.11: Washington Emissions Forecast Compared to No Cost Allowances

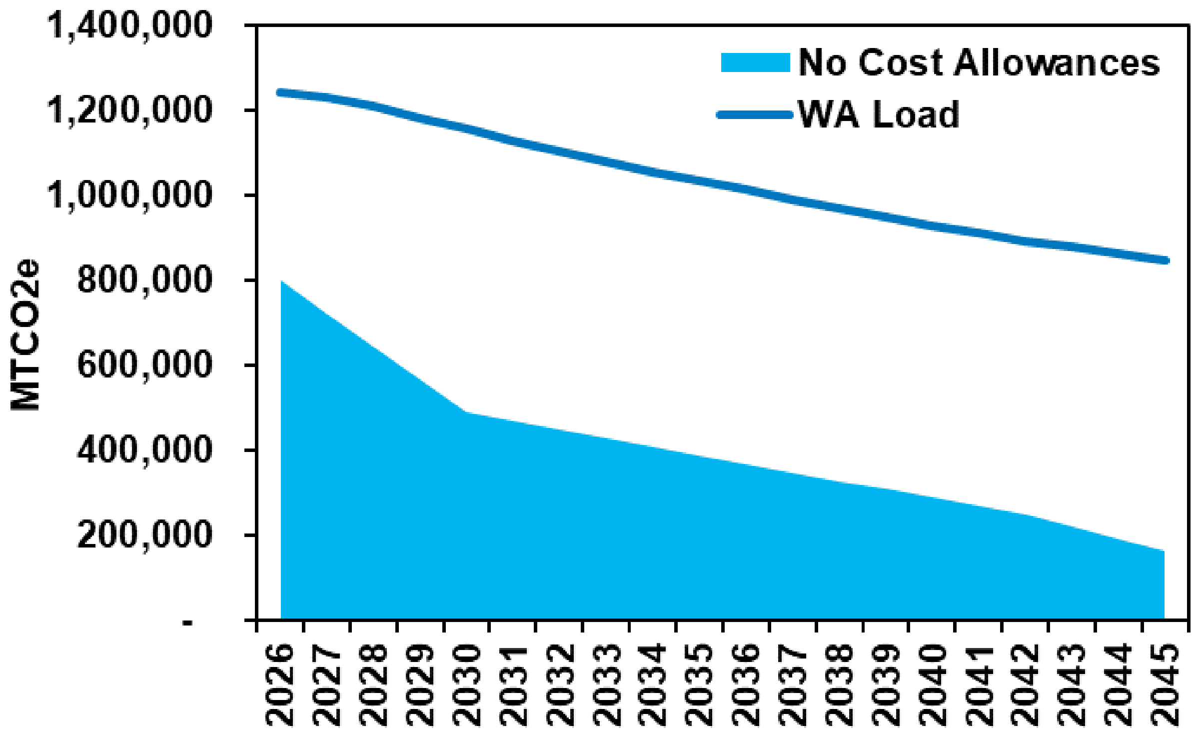
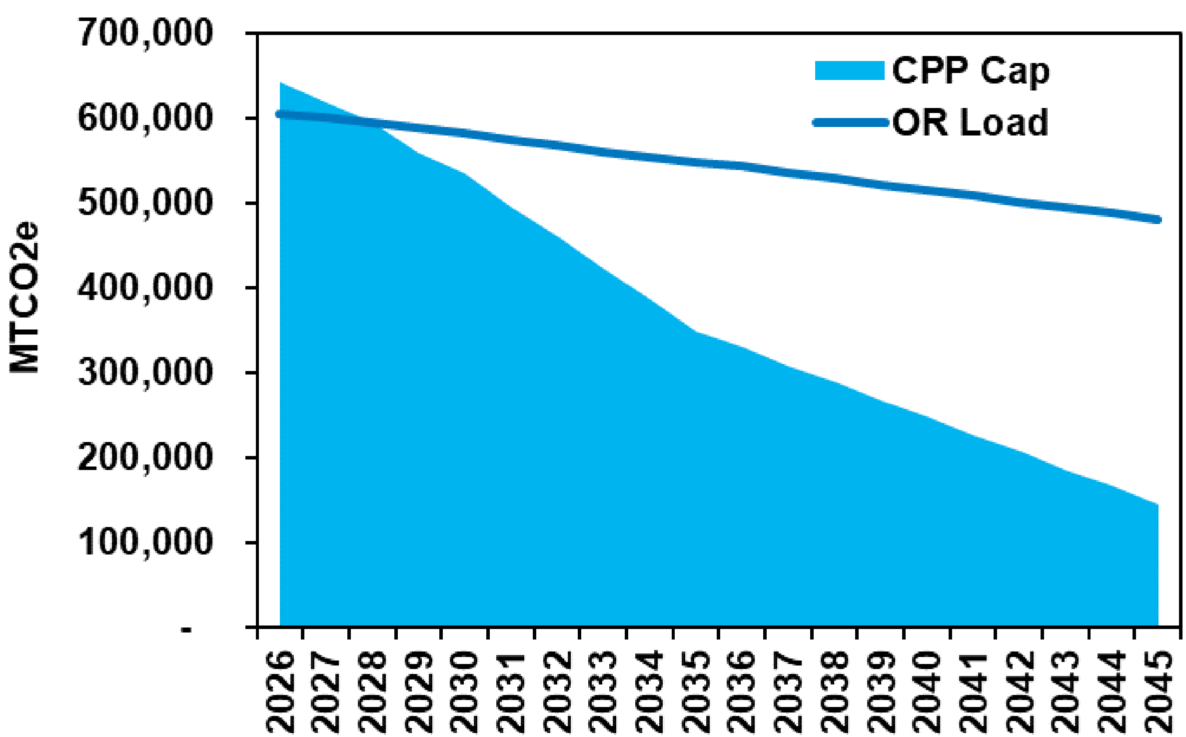


Figure 2.12: Oregon Emissions Forecast Compared to CPP Cap



New Resource Options and Considerations

All scenarios analyzed in this IRP process consider resource needs based on the climate policies in Oregon and Washington. These options have been input into the CROME model to help solve the energy demand and emissions reduction requirements. Table 2.1 highlights supply-side and demand-side resource options as discussed in later chapters.

Table 2.1: New Supply-Side and Demand-Side Resource Options

Supply-Side Resource Options	Demand-Side Resource Options
Natural Gas + Compliance Instrument in OR (CCI) and WA (allowance or offset)	Demand Response by program
Blue, Green and Pyrolysis Hydrogen	Space Heat, Water Heat, Other - Electrification
RNG by source (Dairy, Landfill, Food Waste, and Wastewater)	Carbon Capture, Utilization and Storage (CCUS)
Biomass and Electrolysis - Synthetic Methane	Energy Efficiency (CPA from AEG and ETO)
Renewable Thermal Credits (RTC) by source (as described in RNG)	Natural Gas

Resource cost is the primary consideration when evaluating resource options, although other factors mentioned below also influence resource decisions. Newly constructed resources are typically more expensive than existing resources, but existing resources are in exceedingly short supply. Newly constructed resources provided by a third party, such as a pipeline, may require significant contractual commitment. However, newly constructed resources are often less expensive per unit if a larger facility is constructed because of economies of scale. Resource cost estimates are in Chapter 6. A full set of resource options is provided in Table 2.2 to show when resources are available to select in the CROME model and if there are any limitations.

Table 2.2: New Resources Availability

Resource Type	Volumetric Restriction	First Year of Availability
Allowances	10% of Market per program rules (CCA)	2026
Community Climate Investments	15% (2025-2027), 20% 2028+ (CPP)	2026
Demand Response	CPA from AEG for potential	2026
Electrification	No constraints, up to total energy demanded on LDC by area/class/year	2026
Energy Efficiency	CPA from AEG and ETO	2026
Renewable Thermal Credit	NW Technical Potential (ICF)	2026

Propane Storage	30,000 Dth	2028
Hydrogen	NW Technical Potential to Avista (ICF) & 20% by volume	2030
Synthetic Methane	NW Technical Potential to Avista (ICF)	2030
Renewable Natural Gas	NW Technical Potential (ICF) for allocation of 1.5MM Dth Total Availability	2030
Liquified Natural Gas	1 Bcf Total & 0.1 Bcf Daily W/D	2030
Carbon Capture, Utilization and Storage	Constraints to Avista high volume customers (ICF)	2030

Lead Time Requirements

New resource options can take up to five or more years to put in service, with the exception being the propane storage option of two years. Open season processes to determine interest in proposed pipelines, planning and permitting, environmental review, design, construction, and testing contribute to longer lead time requirements for new facilities. Recalls of released pipeline capacity typically require advance notice of up to one year. Even energy efficiency programs can require significant amounts of time from program development and rollout to the realization of natural gas savings.

Peak Versus Base Load

Avista's planning efforts include the ability to serve firm natural gas loads on a peak day, as well as all other demand periods. Avista's core loads are considerably higher in the winter than in the summer. Due to the winter-peaking nature of Avista's demand, resources that cost-effectively serve the winter load without an associated summer commitment may be preferable. Alternatively, it is possible that the costs of a winter-only resource may exceed the cost of annual resources after capacity release or optimization opportunities are considered.

Resource Usefulness

Available resources must effectively deliver supply to the intended region. Given Avista's dispersed service territories, it is often impossible to deliver resources from a resource option, such as storage, without acquiring additional pipeline transportation. Pairing resources with transportation increases cost. Other key factors that can contribute to the usefulness of a resource are viability, capacity, and reliability along with carbon intensity. If the potential resource is either not available currently (e.g., new technology) or not reliable on a peak day (e.g., non-firm), they may not be considered as an option for meeting unserved demand.

"Lumpiness" of Resource Options

Newly constructed resource options are often only available in "lumpy" sizes. This means the new resources may only be available in larger-than-needed quantities and only available every few years. This lumpiness of resources is driven by the cost dynamics of new construction, where lower per unit costs are available with larger expansions and the economics of the expansion of existing pipelines, or the construction of new resources dictate additions infrequently. The lumpiness of new resources provides a cushion for future growth. Economies of scale for pipeline construction provide the opportunity to secure resources to serve future demand increases. Part of this problem can be met by contracting out the excess resources until needed to serve load growth.

Competition

LDCs, end-users and marketers compete for regional resources. The Northwest has efficiently utilized existing resources and has an appropriately sized system. Currently, the region can accommodate the regional energy demand needs. However, future needs are expected to vary, and regional LDCs may find they are competing with other parties to secure the same firm resources for their customers. RNG resources specifically will have an increased amount of competition as the drive for carbon-reducing supplies increases with associated policies in different states.

Risks and Uncertainties

Investigation, identification, and assessment of risks and uncertainties are critical considerations when evaluating supply resource options. For example, resource costs are subject to degrees of estimation, partly influenced by the expected timeframe of the resource need and rigor determining estimates, or estimation difficulties because of the uniqueness of a resource. Lead times can have varying degrees of certainty ranging from securing currently available transport (high certainty) to building underground storage (low certainty).

Energy Efficiency Resources

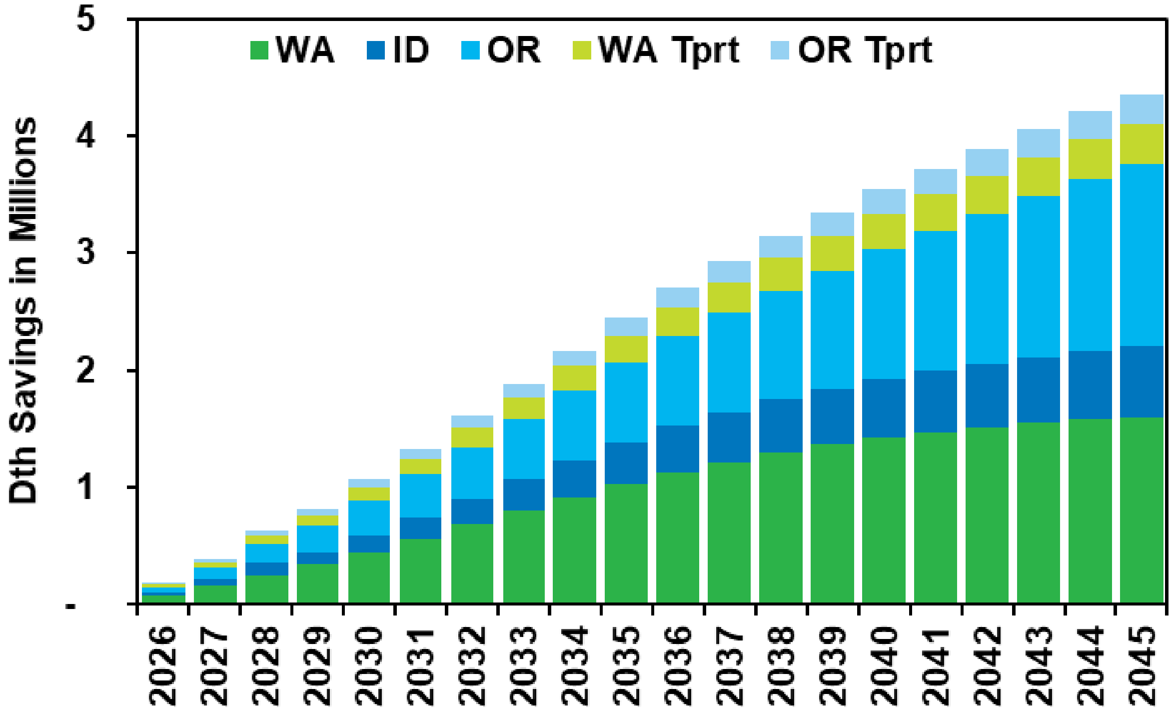
Integration by Price

As described in Chapter 4, Avista determines energy efficiency cost effectiveness without future energy efficiency programs in the load forecast. This preliminary study provides an avoided cost curve for use by both Applied Energy Group (AEG) and the Energy Trust of Oregon (ETO) to evaluate the cost effectiveness of energy efficiency programs against the initial avoided cost curve using the Utility Cost Test and Total Resource Cost Test. The therm savings and associated program costs are incorporated into the CROME model thereby reducing the load forecast.

Energy Efficiency Selection

Using the avoided cost thresholds, AEG selected all potential cost-effective energy efficiency programs for the Idaho and Washington service areas, while ETO performed the CPA study for Oregon excluding transport and residential low income which were also completed by AEG. Figure 2.13 shows the potential energy efficiency savings in dekatherms for each jurisdiction from the resource potential for the PRS. The total cumulative energy savings by 2045 could offset over 4 million dekatherms.

Figure 2.13: Cumulative Demand Served by Energy Efficiency



Preferred Resource Strategy (PRS)

The PRS considers current supply-side resources and new resource options to solve the energy and environmental policy program objectives. The resources Avista models for in the IRP include five types of RNG, four types of hydrogen, two types of synthetic methane, and industrial and direct carbon capture. Each of these resources and their associated costs are discussed in Chapter 6. The alternative fuel sources vary by the size of resource and cost estimates based on the facility type. Electrification of major end uses is also included for Oregon and Washington based on environmental policy and GHG reduction goals as an option and is included by planning region for space heat, water heating and cooking as detailed in Chapter 3. All options discussed above are treated so if any amount is taken, future years must also take this same amount and cost of the year selected as a minimum. Demand Response is treated in a similar fashion as if a program is selected, program costs and demand savings must be used going forward. Renewable thermal credits (RTC), allowances, community climate investments, and natural gas are all variable from year-to-year except for natural gas or physical alternative fuels as they can be carried from season to season by injecting into storage. Propane and LNG storage are also considered as if it is selected it carries forward across the forecast horizon.

To solve unserved demand and emissions goals, a set of resource options are available to meet the requirements of energy, capacity and emissions constraints. Chapter 8 includes summaries of weather and demand. Prices and volumes of resources will vary as shown historically, as planning for new resources must be considered on a stochastic basis. A final PRS will be chosen based on all modeling results and comparisons and may change from the selections discussed in this chapter.

Idaho PRS

The Idaho PRS continues to utilize natural gas as the least cost resource alternative from Avista's currently available supply basins and storage. In addition to maintaining natural gas as the least cost fuel, new energy efficiency programs are selected to reduce energy demand as shown in Figure 2.14. Energy efficiency lowers demand by over 4% by 2045. Natural gas will be acquired for Idaho on a least cost basis from the available hubs as illustrated in Figure 2.15. This figure displays a combination of purchases from the connected hubs available with the primary choice coming from the AECO basin. This basin is geographically closest to Avista's Idaho territory and is where the Company's largest pipeline capacity is located. Recent changes regarding tariffs on Canadian sourced natural gas started occurring after the completion of the modeling for the 2025 IRP. The timing and size of the potential new tariffs is still in development. However, the cost differential for AECO natural gas should remain the lowest cost supply basin. Tariffs will be analyzed more thoroughly in the 2027 IRP when more details are known.

Figure 2.14: Idaho Preferred Resource Strategy

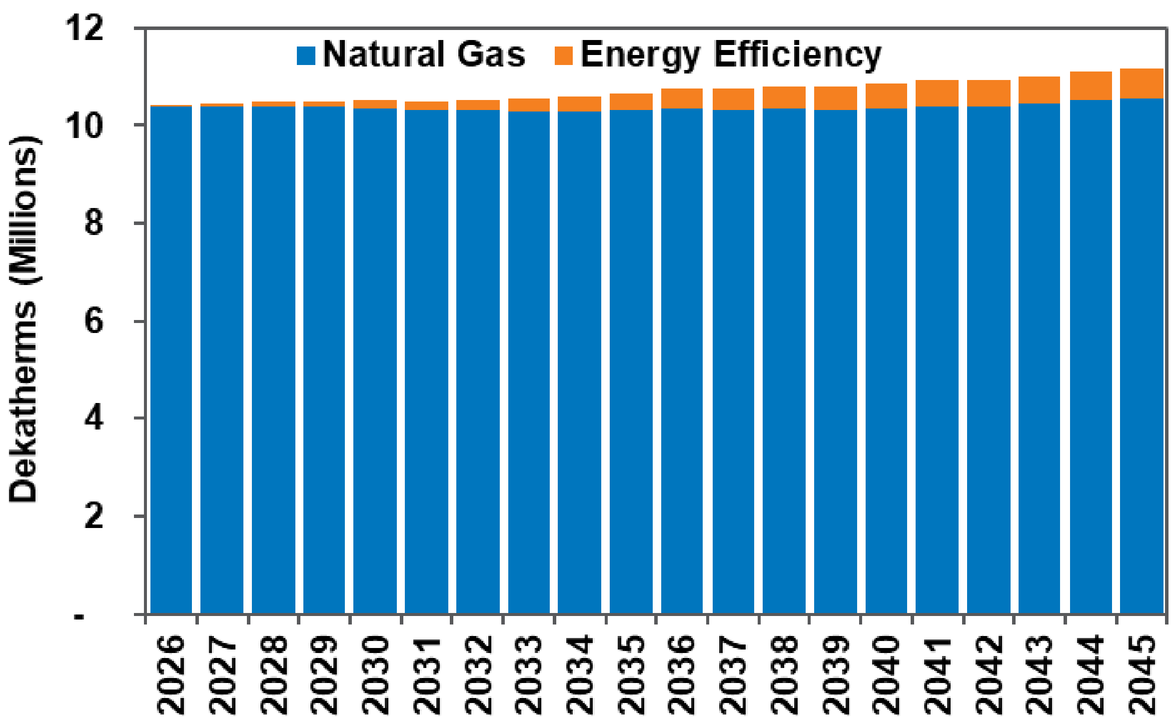
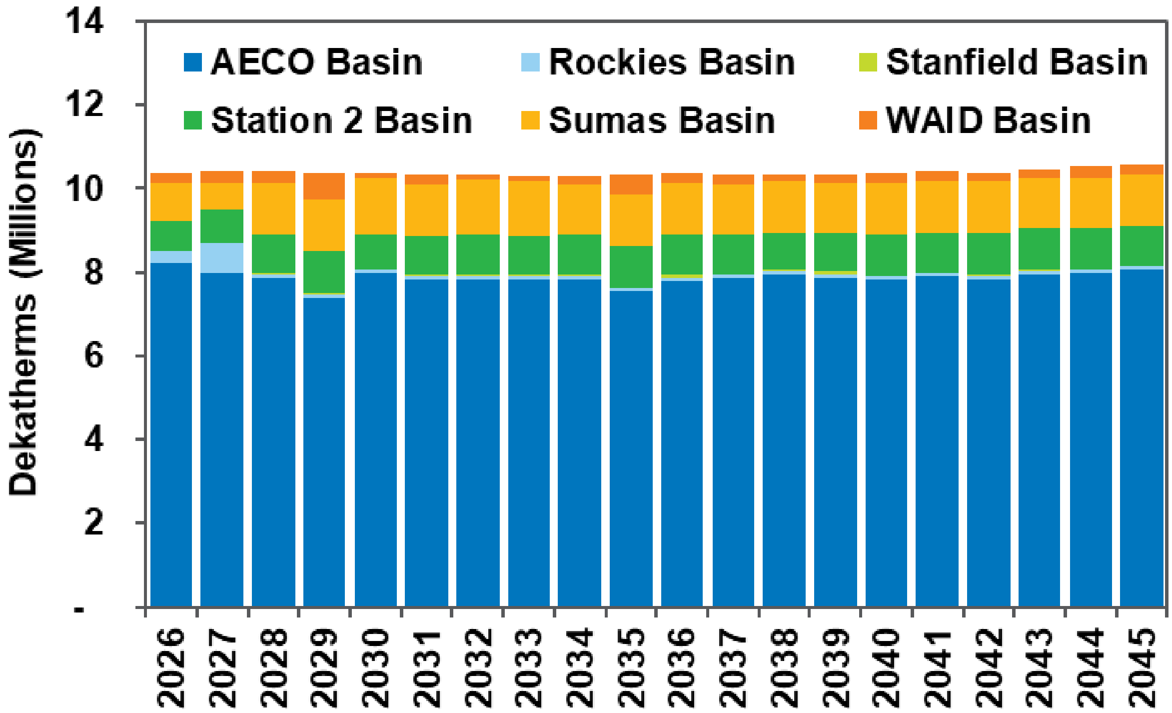


Figure 2.15: Idaho Natural Gas Basin Supply



Oregon PRS

Oregon's PRS has changed as compared to previous plans. Changes adhere to the new environmental goals of the 2024 CPP and the estimated energy demand. In the near-term, the new resource need is met via a combination of RNG from Landfill Gas (LFG), Wastewater Treatment Plants (WWTP), energy efficiency, Community Climate Investments (CCIs), RTCs procured to date, carbon capture, and conventional natural gas. RNG is added to the resource mix beginning in the 2030s, as illustrated in Figure 2.16. By 2045, customer demand will be met by 12.8% energy efficiency and 26% RNG. The remaining demand will utilize natural gas from the basins shown in Figure 2.17 and indicates a declining utilization of natural gas over the forecast horizon. In each figure, the dark blue area at the bottom of the chart depicts natural gas with no emissions instrument for compliance.

Figure 2.16: Oregon Preferred Resource Strategy – Firm Customers

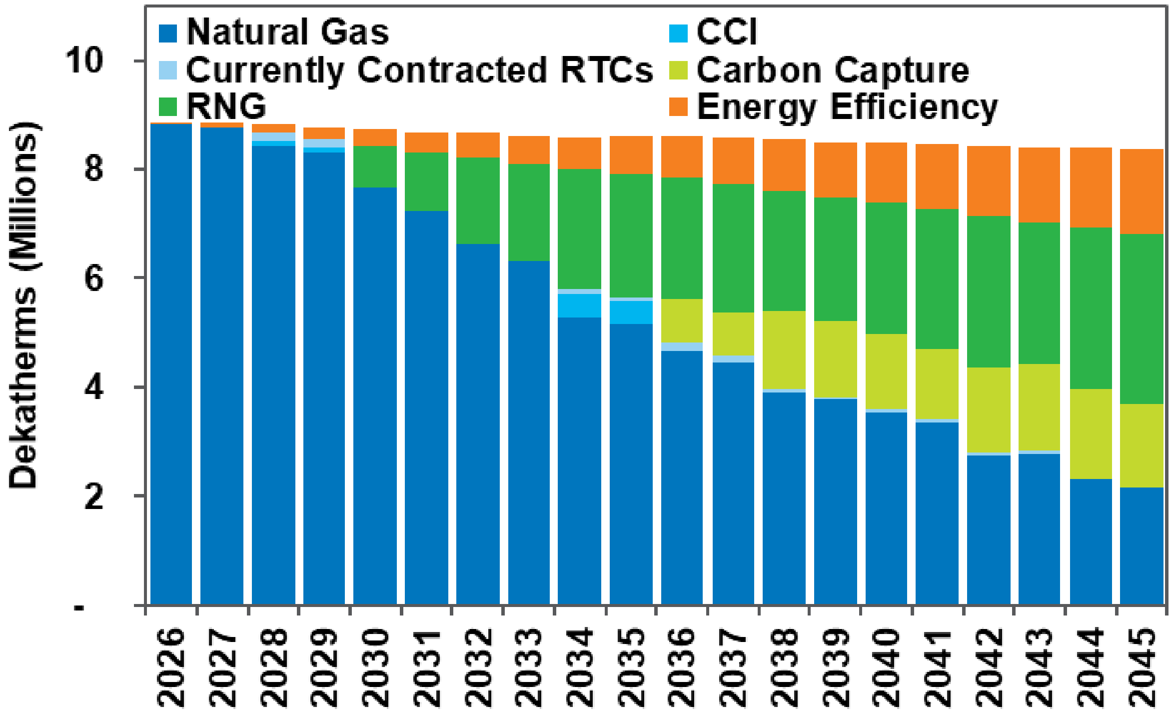
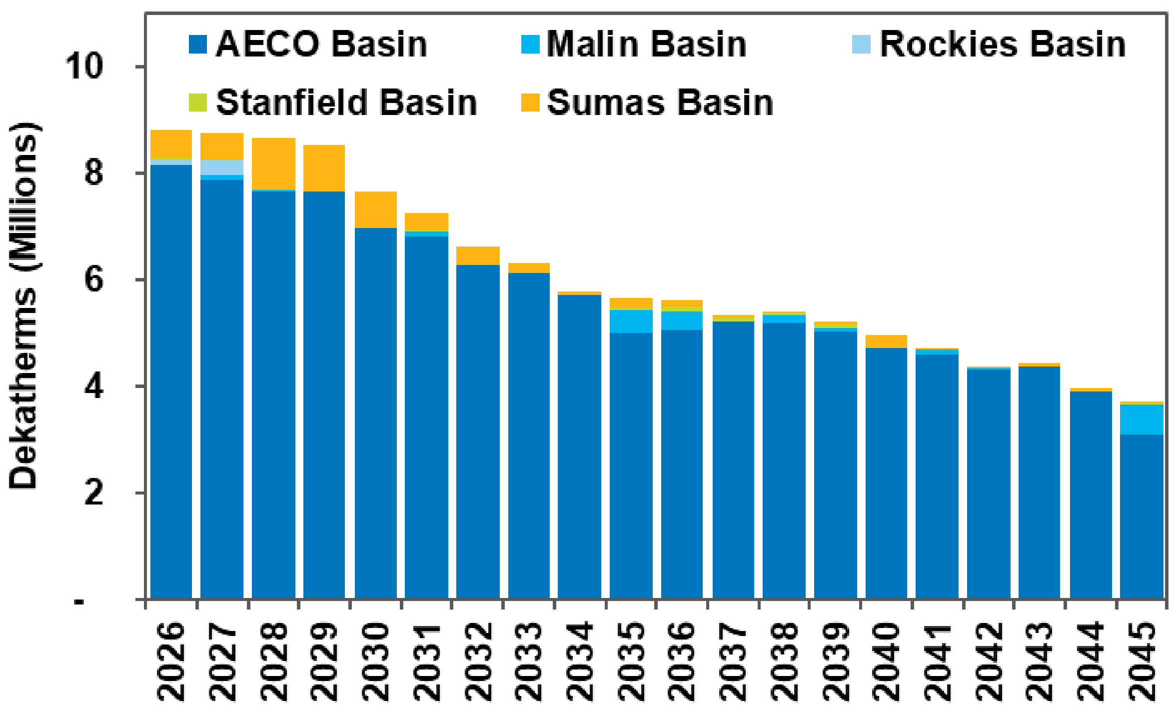


Figure 2.17: Oregon Natural Gas Basin Supply – Firm Customers



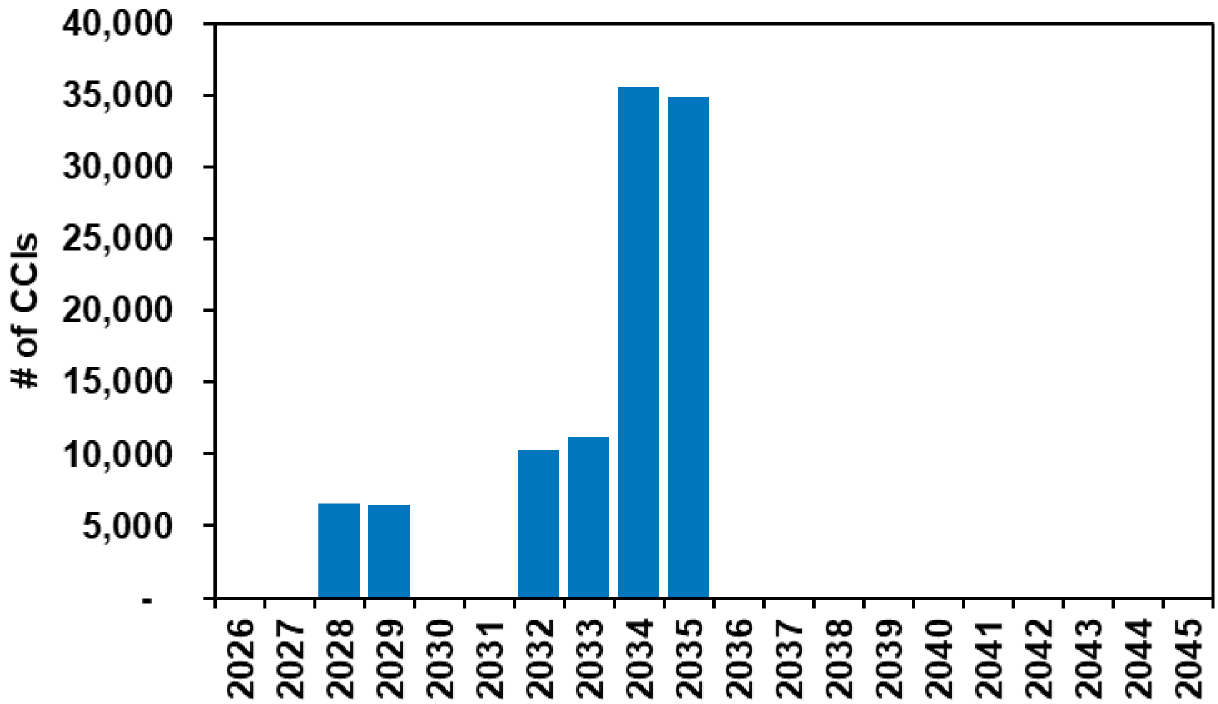
The number of CCIs available to Avista declines with the cap each year. Also, due to the rising costs of CCIs, alternative resources become cost effective in comparison. This leads to additional resources being brought onto the system on an annual basis through the end of the study timeframe, as depicted in Table 2.3.

Table 2.3: Average Daily Resource Quantities by Year

Year	Natural Gas	RNG	EE	Carbon Capture	CCI	Currently Contracted RTCs
2026	24,170	0	133	0	0	0
2027	23,970	0	288	0	0	0
2028	23,664	0	454	0	238	417
2029	23,410	0	618	0	236	412
2030	20,992	2,133	806	0	0	0
2031	19,846	2,947	1,002	0	0	0
2032	18,097	4,373	1,203	0	0	0
2033	17,296	4,901	1,417	0	0	0
2034	15,855	6,043	1,633	0	1,216	201
2035	15,483	6,220	1,855	0	1,187	197
2036	15,340	6,118	2,075	2,206	0	370
2037	14,678	6,511	2,308	2,111	0	354
2038	14,827	6,034	2,539	3,973	0	145
2039	14,306	6,185	2,773	3,833	0	140
2040	13,594	6,566	3,002	3,751	0	142
2041	12,907	7,000	3,253	3,561	0	135
2042	11,995	7,558	3,502	4,309	0	148
2043	12,122	7,123	3,755	4,355	0	150
2044	10,804	8,124	4,002	4,452	0	0
2045	10,129	8,545	4,241	4,174	0	0

Also, due to the divergent weather locations, the risk of the amount of needed CCIs is volatile. The coldest weather is found in La Grande and Klamath Falls where peak days have been observed in the past 30 years. In contrast, Medford and Roseburg have warmer climates and do not get extreme temperatures. Figure 2.18 illustrates the quantity of CCIs required in the PRS. Compliance instruments of the CPP are expected to cover Avista's emissions for the first compliance period (2025-2027). Beginning in the second compliance period (2028-2029) CCIs are chosen to help bridge the gap to when the model is offered alternative fuels like RNG. Additional CCIs are selected from 2032 to 2035 until enough RNG, load reduction and carbon capture are in place to meet emissions goals through the planning horizon.

Figure 2.18: Community Climate Investment Quantity – All Customers (MTCO2e)



Washington PRS

Washington's PRS is like previous IRP results except for lower projected demand. The PRS shown in Figure 2.19 shows conventional natural gas and energy efficiency as the primary energy source options until the end of the study horizon (2045). Energy efficiency reduces demand by 11% while small portions of RNG are utilized to cover energy and emissions reductions when cost competitive against CCA pricing. Natural gas will continue to be procured from the least cost supply basin for Washington as shown in Figure 2.20.

The specific resource selection by year is shown in Table 2.4. Avista does not expect a significant reduction in traditional natural gas utilization as the primary fuel in Washington with the CCA allowance prices assumed in this expected case. Chapter 8 identifies how a reduction in traditional natural gas use may occur by way of higher reliability, higher costs of supply, higher cost of allowances, or lower alternative volumes available.

Figure 2.19: Washington Preferred Resource Strategy – Firm Customers

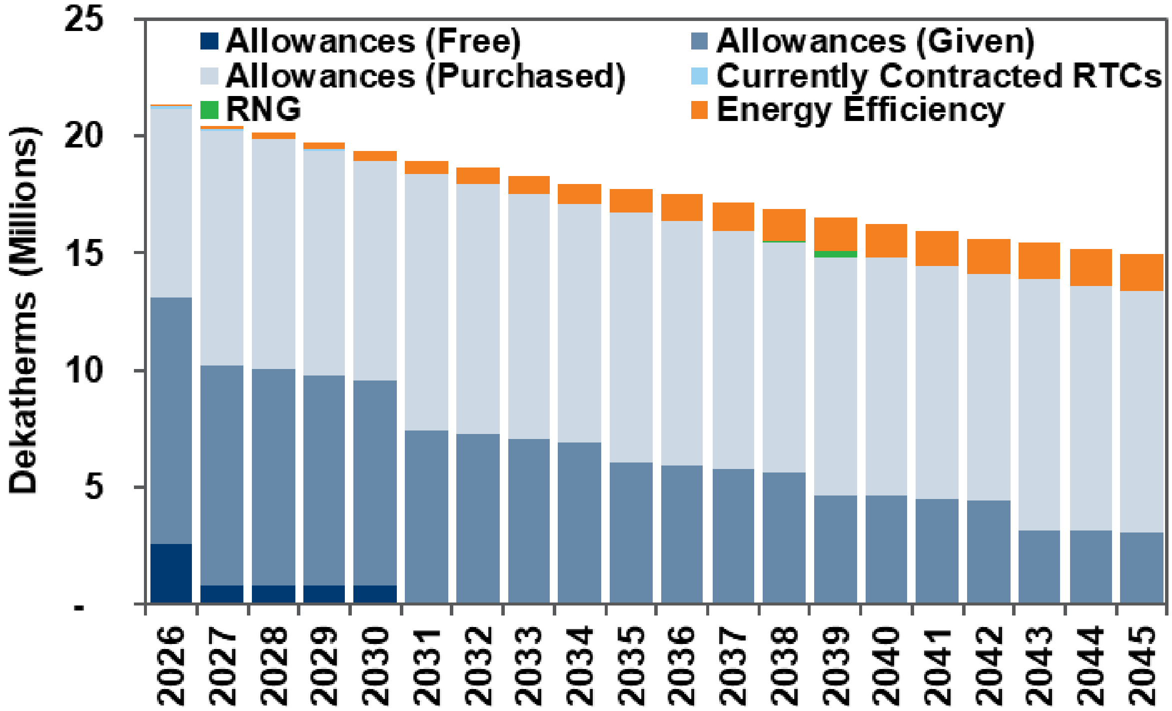


Figure 2.20: Natural Gas Basin Supply – Washington – Firm Customers

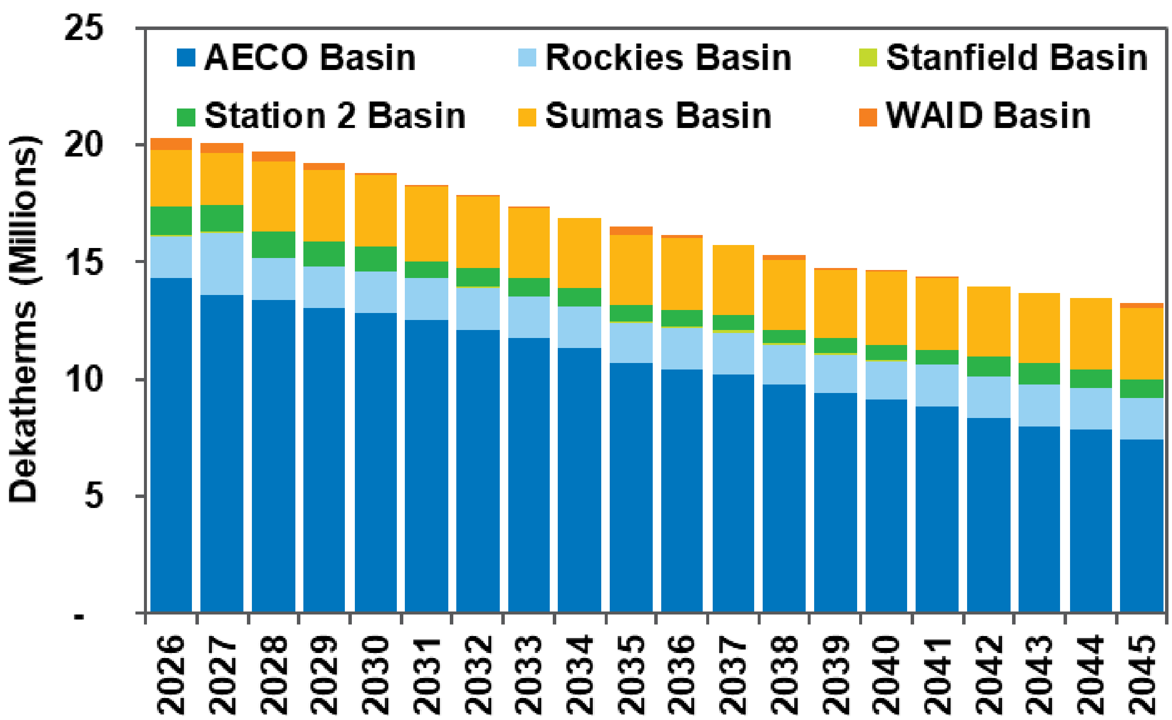
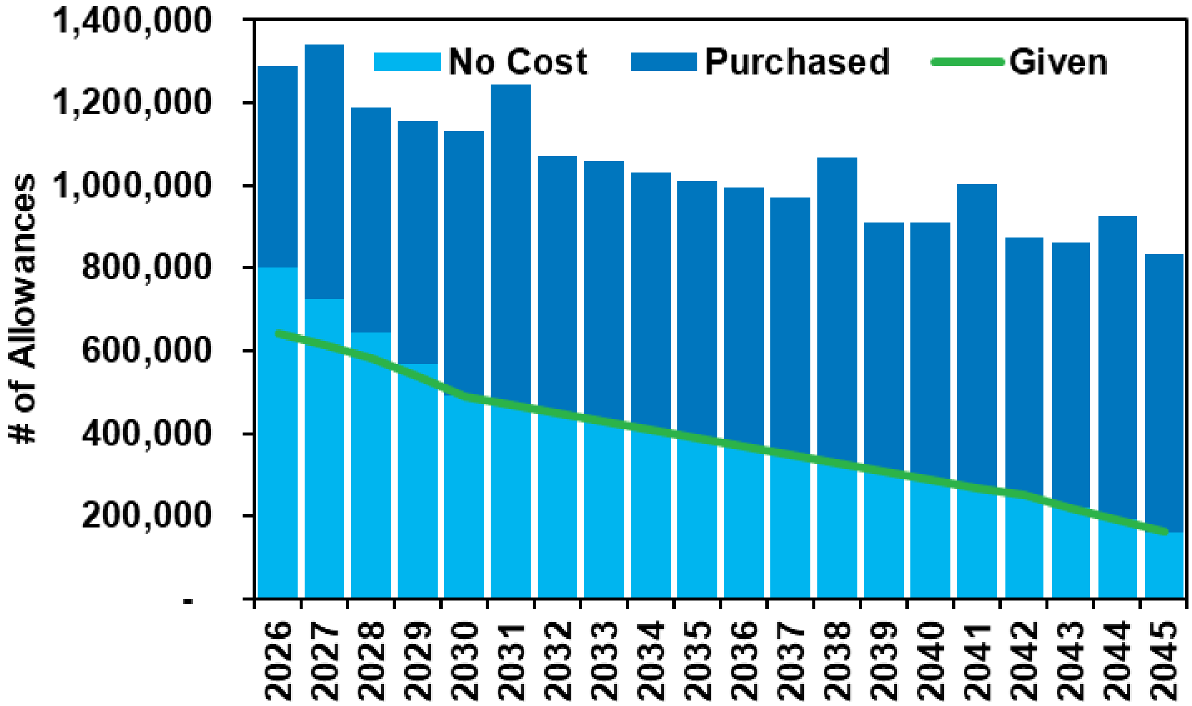


Table 2.4: Average Daily Resource Quantities by Year – Washington

Year	Natural Gas	RNG	EE	Allowances (Free)	Allowances (Given)	Allowances (Purchased)	Currently Contracted RTCs
2026	55,635	0	197	7,172	28,687	22,165	391
2027	54,967	0	425	4,856	27,517	22,989	86
2028	53,812	0	687	2,881	25,927	25,441	96
2029	52,645	0	936	1,270	24,130	27,720	104
2030	51,397	0	1,228	0	21,914	29,997	113
2031	49,969	0	1,539	0	21,017	29,398	0
2032	48,656	0	1,862	0	20,066	29,031	0
2033	47,493	0	2,189	0	19,224	28,705	0
2034	46,329	0	2,511	0	18,328	28,433	0
2035	45,364	0	2,819	0	17,431	28,391	0
2036	44,271	0	3,096	0	16,490	28,238	0
2037	43,226	0	3,339	0	15,639	28,041	0
2038	41,891	283	3,552	0	14,742	27,595	0
2039	40,232	795	3,732	0	13,846	26,814	0
2040	40,010	0	3,892	0	12,914	27,535	0
2041	39,263	0	4,037	0	12,053	27,651	0
2042	38,273	0	4,143	0	11,156	27,556	0
2043	37,582	0	4,247	0	9,861	28,147	0
2044	36,797	0	4,321	0	8,543	28,689	0
2045	36,227	0	4,387	0	7,271	29,401	0

Allowances and offsets for this plan are considered interchangeably and are compared to one another with available options at the time of purchase. If Avista can obtain offsets at a lower price than allowances, offsets will be purchased. The PRS selects program instruments each year as shown in Figure 2.21. The delta between the “Given” line and “No Cost” bar is the free CCA allowances Avista can use directly for compliance purposes.

Figure 2.21: CCA Allowances/Offsets Quantities by Type (MTCO2e)



Transport Customer State Environmental Compliance

Figure 2.22 shows the PRS for Washington transport customers where allowances are broken out by the percentage of load for their share of the “Free” and “Given” CCA allowances. Demand side management, or energy efficiency, portion is from the achievable economic potential analysis (TRC) Conservation Potential Assessment provided by AEG. Figure 2.23 shows the same breakout for Oregon transport customers with a share of Oregon resources for carbon capture and RNG, including the amount of CCIs in dekatherm equivalency.

A paradigm shift occurs with the current methods and tariff structure of transport customers as they currently provide their own fuel and resources to deliver their supply to Avista city gates. These charts do not predict which entities will purchase the alternative fuels, but rather that it may be the least cost solution to meet the climate goals given model inputs.

Figure 2.22: Washington Preferred Resource Strategy – Transport Customers

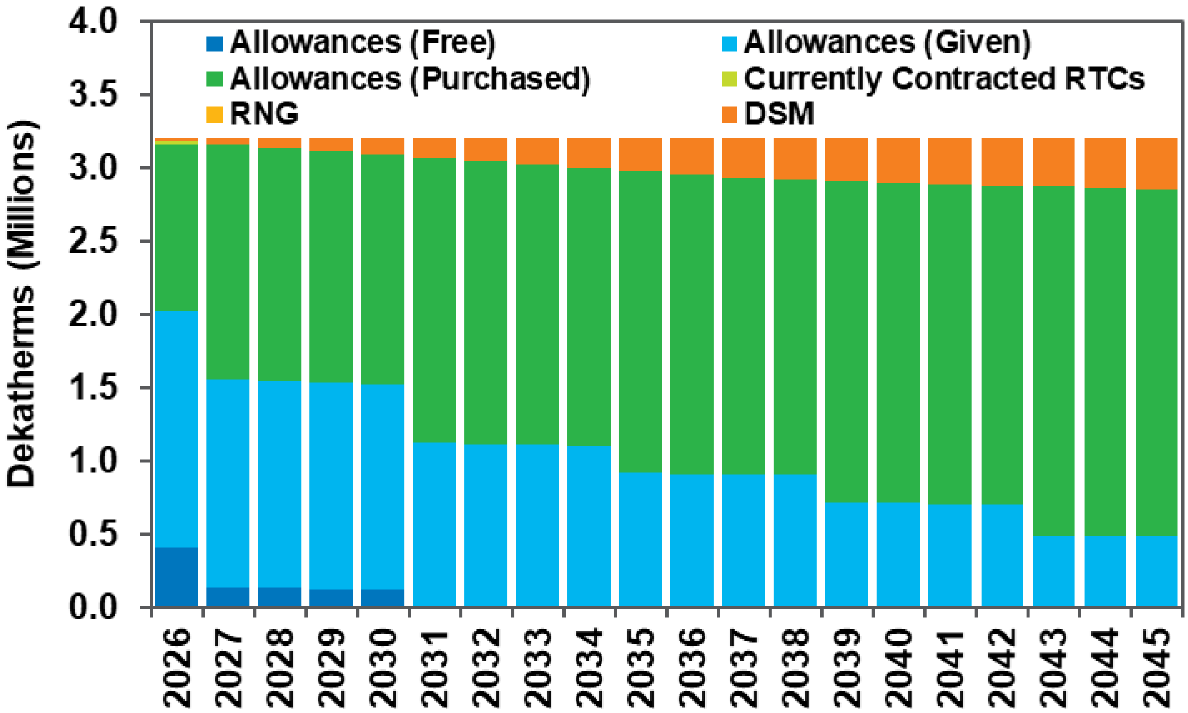
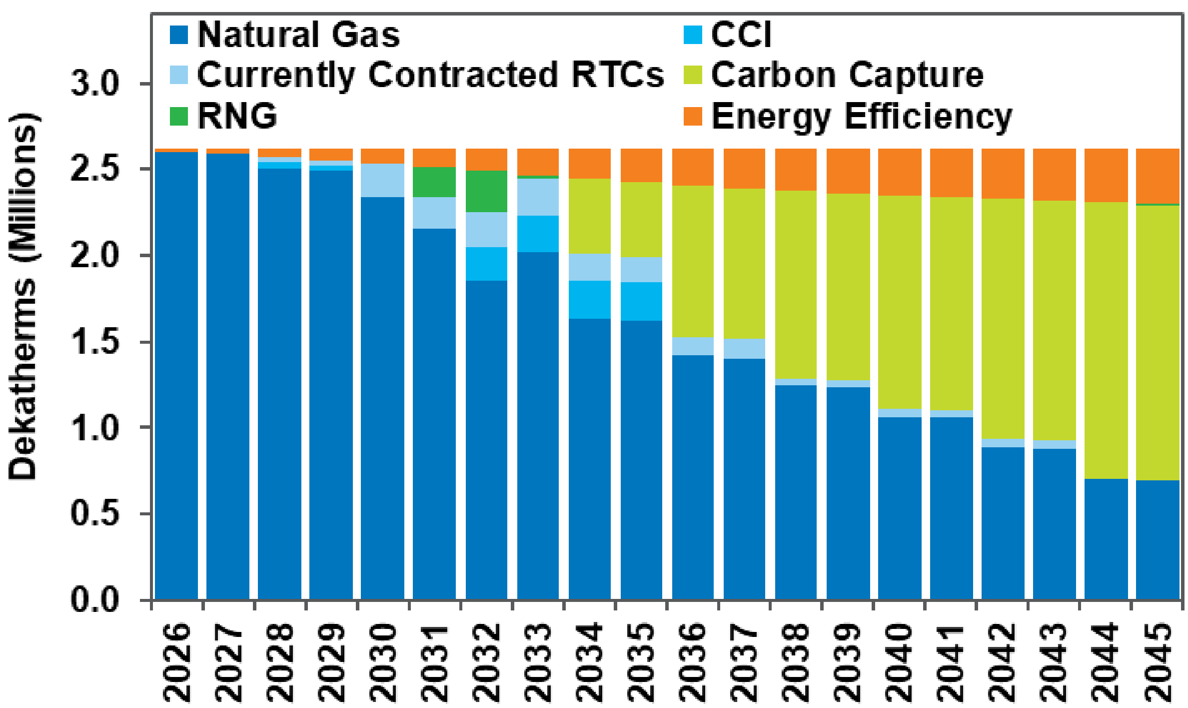


Figure 2.23: Oregon Preferred Resource Strategy - Transport Customers



All Customer Summary

Figures 2.24 to 2.25 show Washington and Oregon's PRS considering all customer classes and resources selected. Quantities selected are spread around compliance period and may differ slightly from modeled selection. Figure 2.26 is a summary illustration for the system including all areas and classes modeled for information discussed above.

Figure 2.24: Washington Preferred Resource Strategy – All Customers

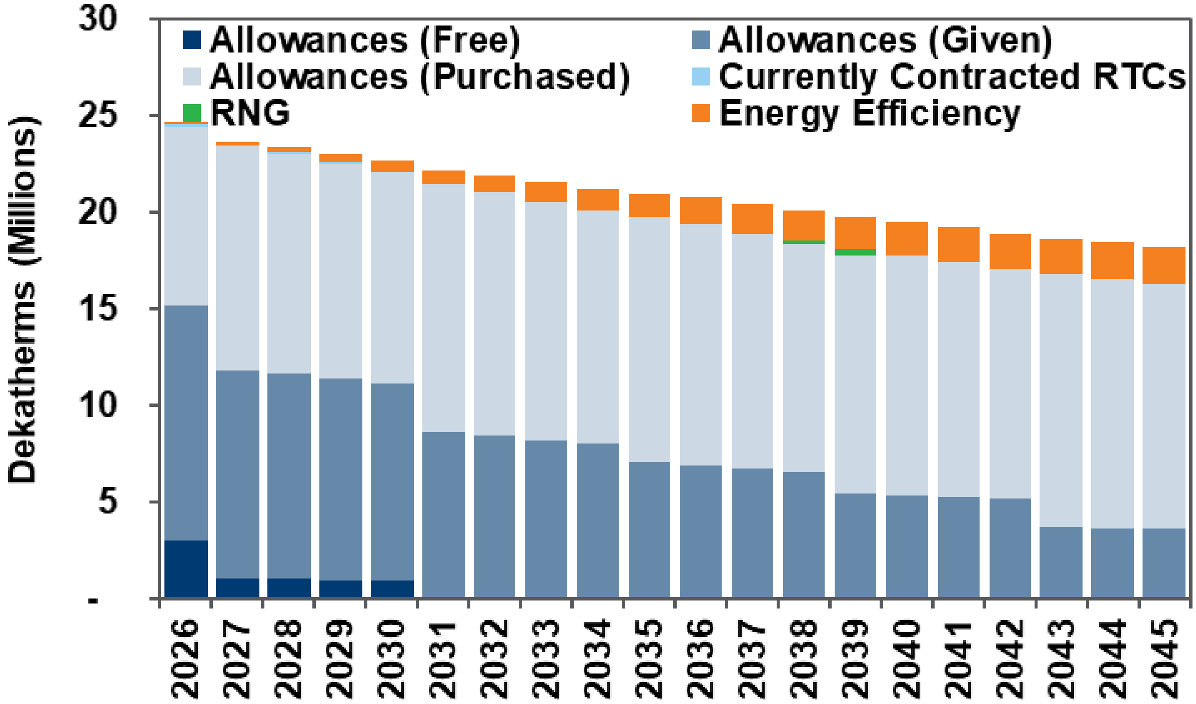


Figure 2.25: Oregon Preferred Resource Strategy - All Customers

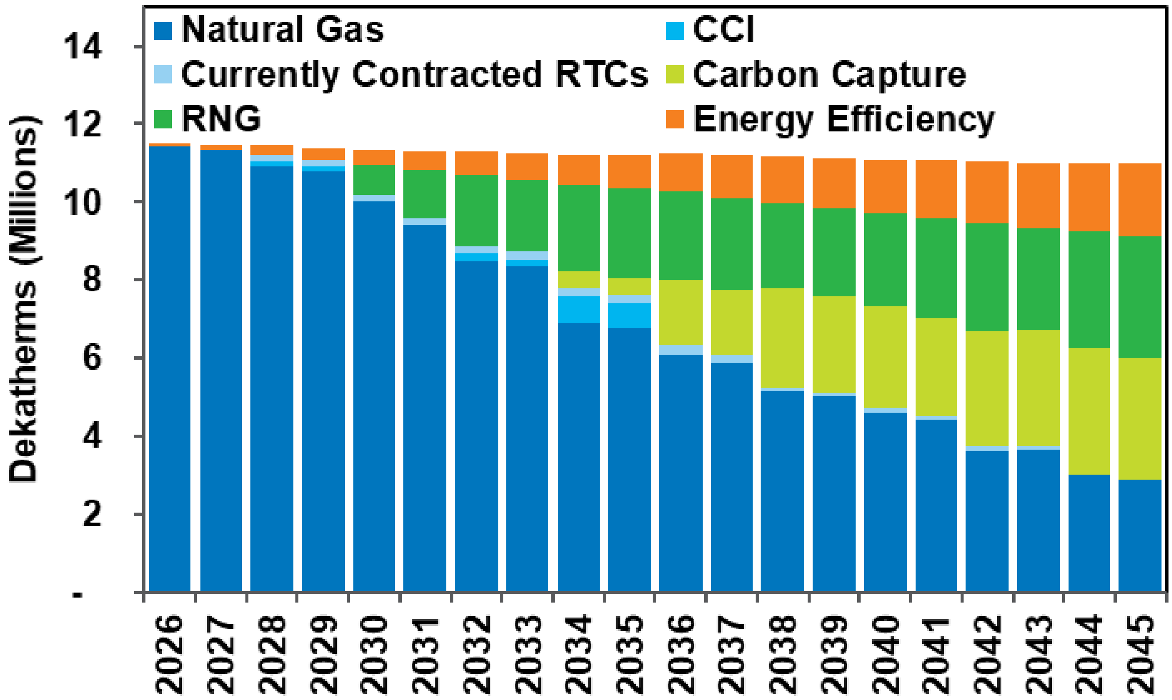
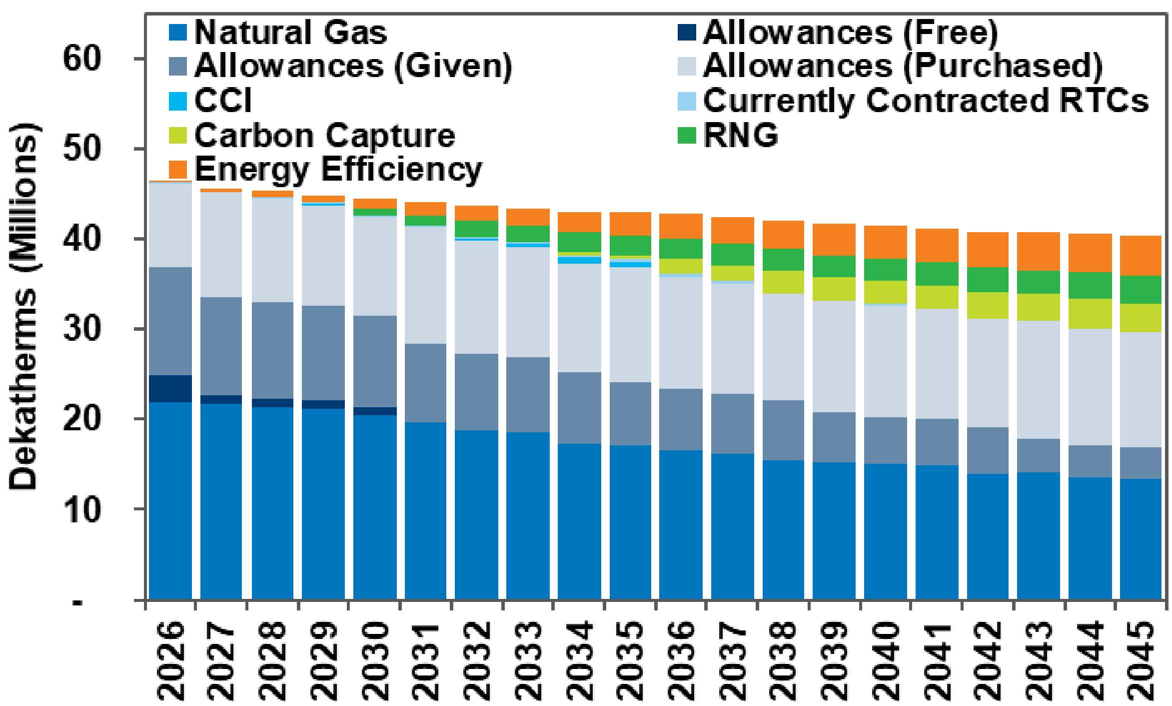


Figure 2.26: System Preferred Resource Strategy - All Customers



Avista's Aspirational Clean Energy Goals[1]

In 2021, Avista announced an aspirational goal to be carbon neutral by 2045. Natural gas has played a key role in reducing greenhouse gas emissions in the United States as electrical power plants have converted from coal to cleaner burning natural gas. In addition, the direct use of natural gas by customers in their homes is a more efficient use of natural gas as compared to its use for generating electricity to meet the same need. And when compared to burning wood, heating oil and other combustible fuel sources, natural gas emits fewer air pollutants. While natural gas may be a cleaner fuel than some other sources, we recognize there is an opportunity to further improve and lower our natural gas emissions going forward. We have developed a strategy for carbon reduction from our natural gas operations and have identified several pathways to get us there. The three primary pathways included in our strategy are:

- Diversify and transition from conventional fossil fuel natural gas to renewable natural gas (RNG), hydrogen, and other renewable biofuels.
- Reduce consumption via conservation, energy efficiency, and new technologies. Purchase carbon offsets as necessary. Avista remains committed to meeting the needs for reliable and affordable energy while advancing environmental stewardship, and our actions demonstrate these values.

To help achieve our aspirational goal and to reduce our carbon emissions from our natural gas operations, we have been actively pursuing renewable natural gas (RNG) projects in alignment with our strategies. Avista has recently entered into long-term purchase agreements to acquire the environmental attributes associated with the RNG from the following regional and national projects on behalf of our customers:

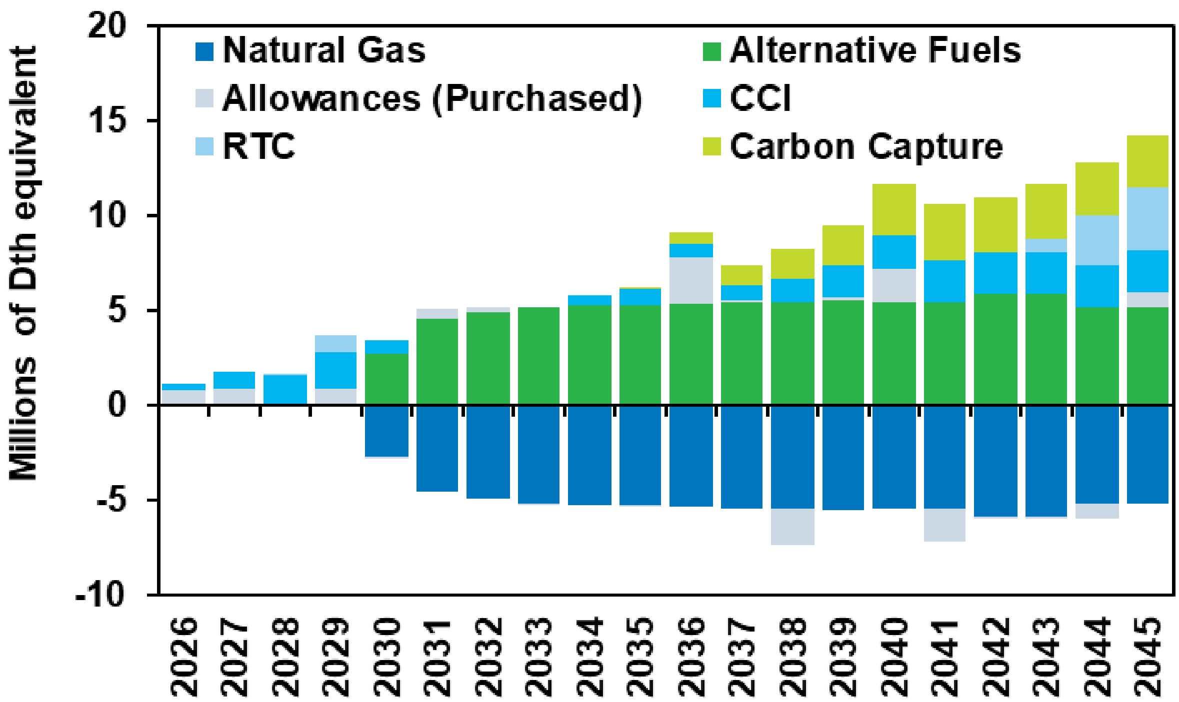
- Horn Rapids Landfill (Richland, WA)—project producing 1.6 million annual therms of RNG.
- Blackhawk Landfill (Waterloo, IA)—project producing 2.6 million annual therms of RNG.
- Bayview Landfill (Elberta, UT)—project producing 2.5 million annual therms of RNG.
- Quad Cities Landfill (Milan, IL)—project producing 3 million annual therms of RNG.

In all, Avista has contracted for the Renewable Thermal Certificates (RTCs) associated with 9.7 million therms of produced RNG on an annual basis from these landfill projects, which is equivalent to the annual amount of natural gas used by approximately 17,500 of our customers.

[1] Corporate Responsibility Report

Reaching our aspirational natural gas goal will require further improvements in costs, technology, and reliability associated with renewable fuels and green hydrogen. If these required improvements are not realized or not affordable in the future, we may not meet our aspirational goal in the desired timeframe. Meeting our aspirational natural gas goal may also require accommodation from regulatory agencies insofar as we may need to acquire carbon offsets to meet our aspirational goal. The natural gas industry has served a vital and essential role in delivering reliable and affordable energy to millions of customers, businesses and industries throughout our country and the world. This industry has evolved and will need to continue evolving to meet the real climate change challenges confronting us all. We will continue to engage in collaborative, solutions-oriented discussions with interested parties to highlight the importance of maintaining our natural gas pipeline assets and fuels as a reliable, affordable consumer choice and as a valuable resource for handling our region's peak energy demand. We anticipate natural gas will be a vital part of our energy mix as we continue our transition to a lower carbon future, and both our electric and natural gas IRPs demonstrate the role of natural gas in serving our customers and communities into the future. When compared to the PRS, the adjustment of resources necessary to meet this trended (2026-2045) carbon neutral goal can be found in Figure 2.27.

Figure 2.27: PRS Changes to Meet Carbon Neutral Goal of 100% by 2045



This Page is Intentionally Left Blank

3. Demand Forecast

Section Highlights:

- Washington annual average load growth is -1.68%
- Idaho annual average load growth is +0.37%
- Oregon annual average load growth is -0.31%
- In contrast to previous IRP, Avista used end-use modeling techniques to develop the long-term load forecast.
- Between warming temperature expectations, electric heat pump additions, and energy efficiency, Avista expects a decrease in demand per customer, with minimal customer additions in Oregon and Washington

The IRP development begins with a demand forecast. Understanding and analyzing key demand drivers and their potential impact on forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline; however, forecasting will always have uncertainties regardless of methodology and data integrity. This IRP mitigates the uncertainty by considering a range of scenarios to evaluate and prepare for a broad spectrum of potential outcomes.

Demand Areas

Avista defines eleven demand areas, structured around the pipeline's ability to serve them within the CROME model (Table 3.1). These demand areas are aggregated into five service territories and further summarized as North or South divisions for presentation throughout this IRP.

Table 3.1: Geographic Demand Classifications

Demand Area	Service Territory	Division
Washington NWP	Spokane	North
Washington GTN	Spokane	North
Washington Both	Spokane	North
Idaho NWP	Coeur D' Alene	North
Idaho GTN	Coeur D' Alene	North
Idaho Both	Coeur D' Alene	North
Medford NWP	Medford/Roseburg	South
Medford GTN	Medford/Roseburg	South
Roseburg	Medford/Roseburg	South
Klamath Falls	Klamath Falls	South
La Grande	La Grande	South

Customer Forecasts

Avista's customer load base includes firm residential, commercial, and industrial categories. For each of the customer categories, Avista develops customer forecasts incorporating national economic forecasts and regional economies. The key economic drivers to forecast customer growth are U.S. Gross Domestic Product (GDP) growth, national and regional employment growth, and regional population growth expectations. Avista combines this data with local knowledge about sub-regional construction activity, age and other demographic trends, and historical data to develop the 20-year customer forecasts. Forecasted residential customers by state are shown in Figure 3.1. Customer forecasts for commercial load are estimated based on historic customer counts divided by the number of square feet as provided by the AEG forecast and shown in Figure 3.2. To convert AEG's forecasted industrial customers, which use the number of employees per facility, Avista applied the same estimate using historic industrial customers to imply an estimated industrial customer count shown in Figure 3.3.

Figure 3.1: Residential Customer Forecast

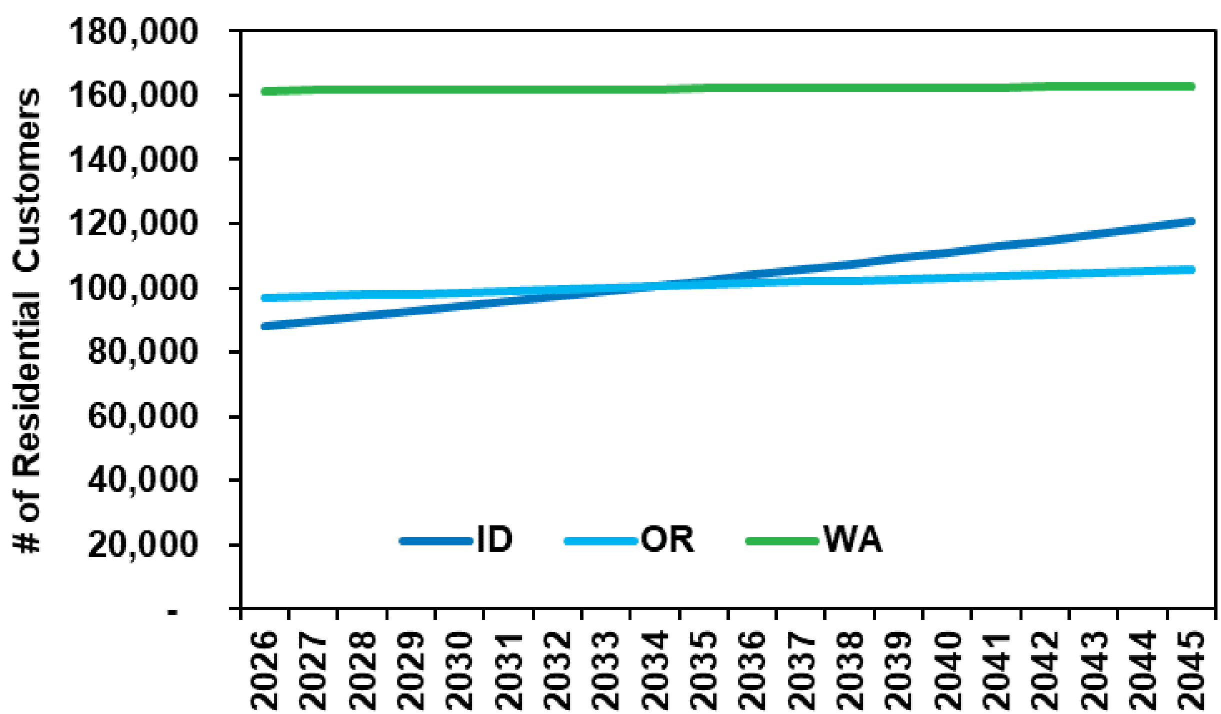


Figure 3.2: Commercial Customer Forecast

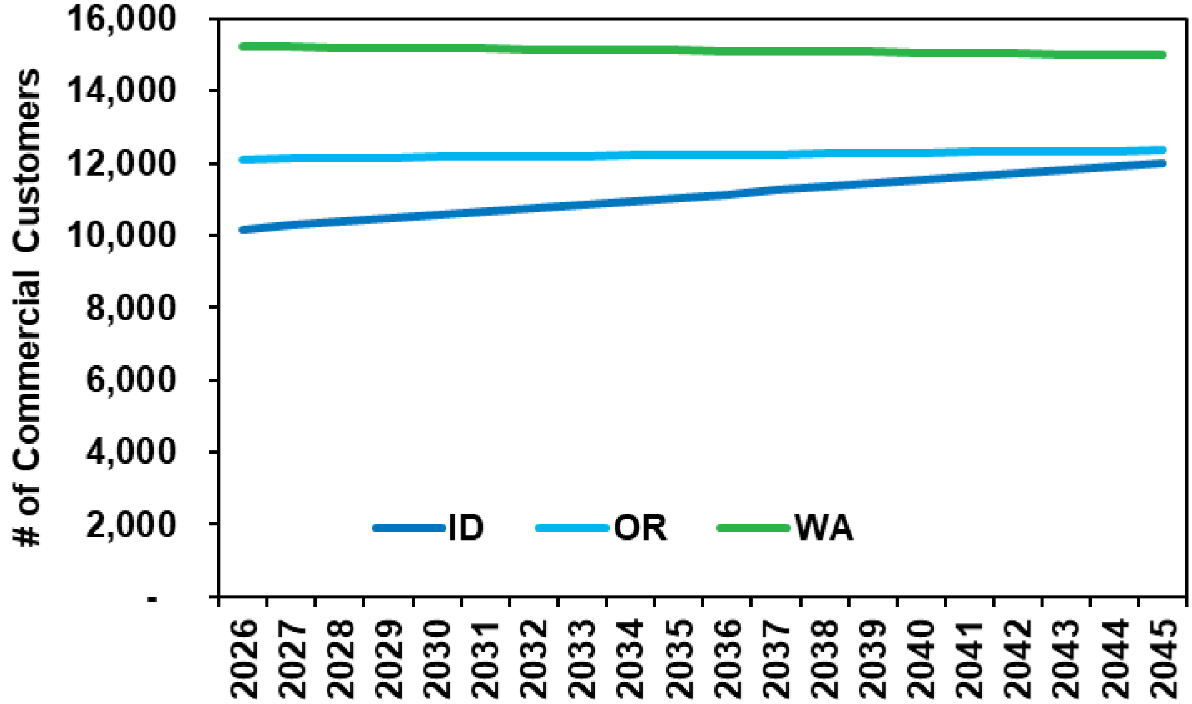


Figure 3.3: Industrial Customer Forecast

The customer forecast in the 2025 IRP assumes growth based on an end use forecast developed by Applied Energy Group (AEG) using the same tool to provide conservation potential assessments (CPA) named LoadMAP™. This model is used to directly inform the official load forecast, including effects of state energy codes, potential electrification, and market trends. Other major modeling inputs and sources are illustrated in Figure 3.4.

Figure 3.4: Loadmap™ Inputs and Sources

Avista foundational data

- Avista power sales by schedule
- Current and forecasted customer counts
- Retail price forecasts by class

Survey data showing presence of equipment

- Avista: Residential customer survey conducted in 2013
- NEEA: Residential and Commercial Building Stock Assessments (RBSA 2016 and CBSA 2019)
- US Energy Information Administration: Residential, Commercial, and Manufacturing Energy Consumption Surveys (RECS 2020, CBECS 2018, and MECS 2015)

Technical data on end-use equipment costs and energy consumption

- Regional Technical Forum workbooks
- Northwest Power and Conservation Council's 2021 Power Plan workbooks
- US Department of Energy and ENERGY STAR technical data sheets
- Energy Information Administration's Annual Energy Outlook/National Energy Modeling System data files

State and Federal energy codes and standards

- Washington State Energy Code
- Idaho Energy Code
- Federal energy standards by equipment class

Market trends and effects

- RTF market baseline data
- Annual Energy Outlook purchase trends (in base year)

The forecast process includes market characterization (segmentation, end use and technology list) and are allocated between electric loads and gas loads by the expected customer behavior of fuel choice. The baseline projection is then run on an annual basis based upon the customer forecast, stock turnover, purchasing decisions for equipment, and the weather forecast. The system total load forecast from the model includes a combination of electrification, building codes, and naturally occurring energy efficiency causing overall natural gas loads to decline by 7% across the forecast period. Washington specifically has a much stronger downward trend in isolation but is offset by growth in Idaho. A weather forecast by planning area is included in these projected load demands and is discussed in detail later in this chapter. Results of this demand forecast excluding Avista sponsored energy efficiency programs are shown by state and by end use in Figures 3.5 to 3.8 (excludes transport customer loads).

Figure 3.5: Idaho Demand by End Use

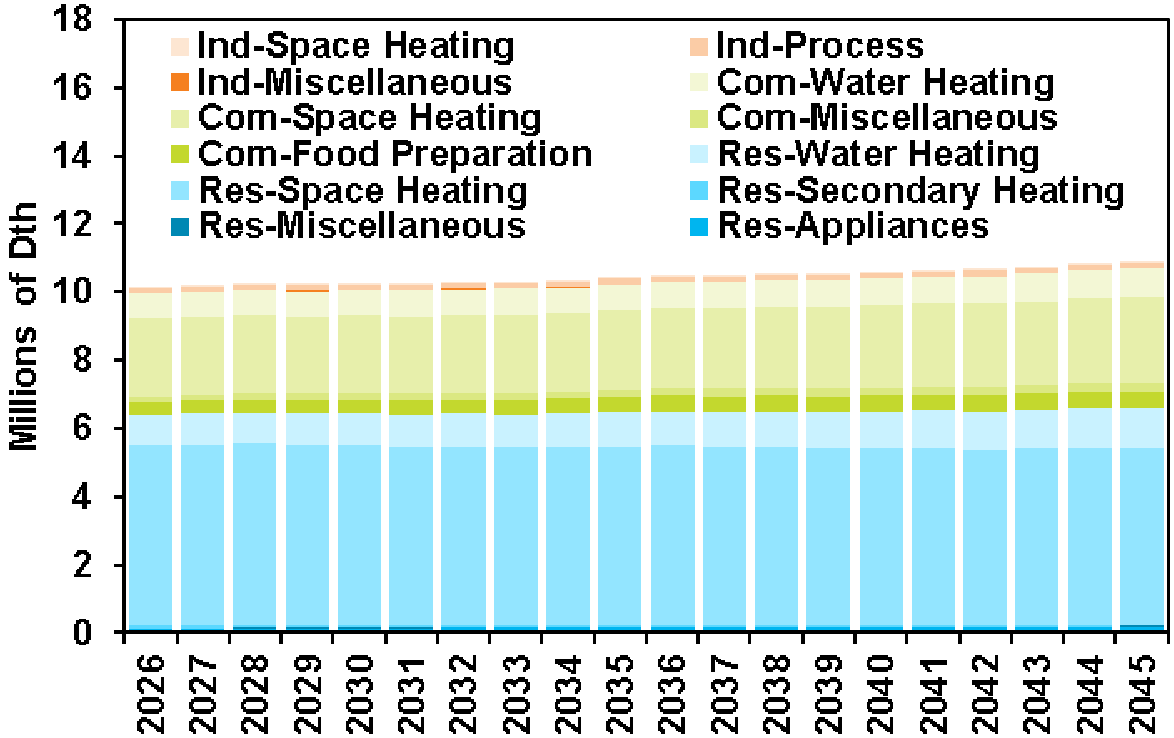


Figure 3.6: Oregon Demand by End Use

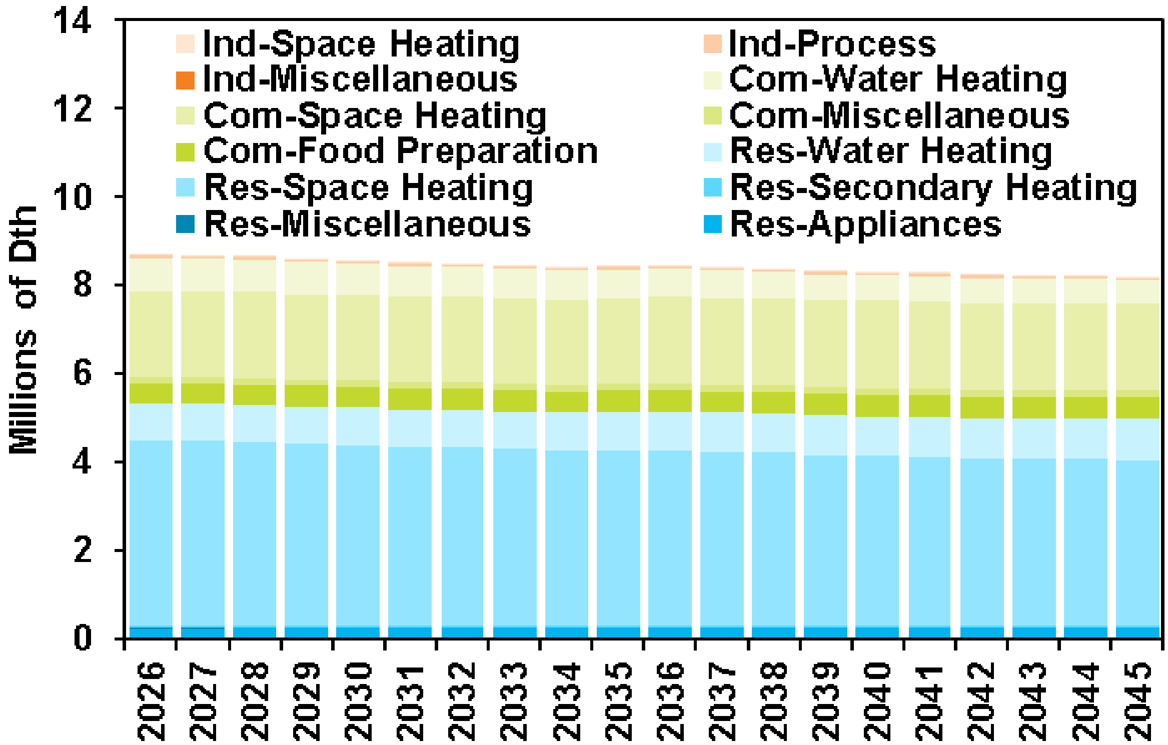


Figure 3.7: Washington Demand by End Use

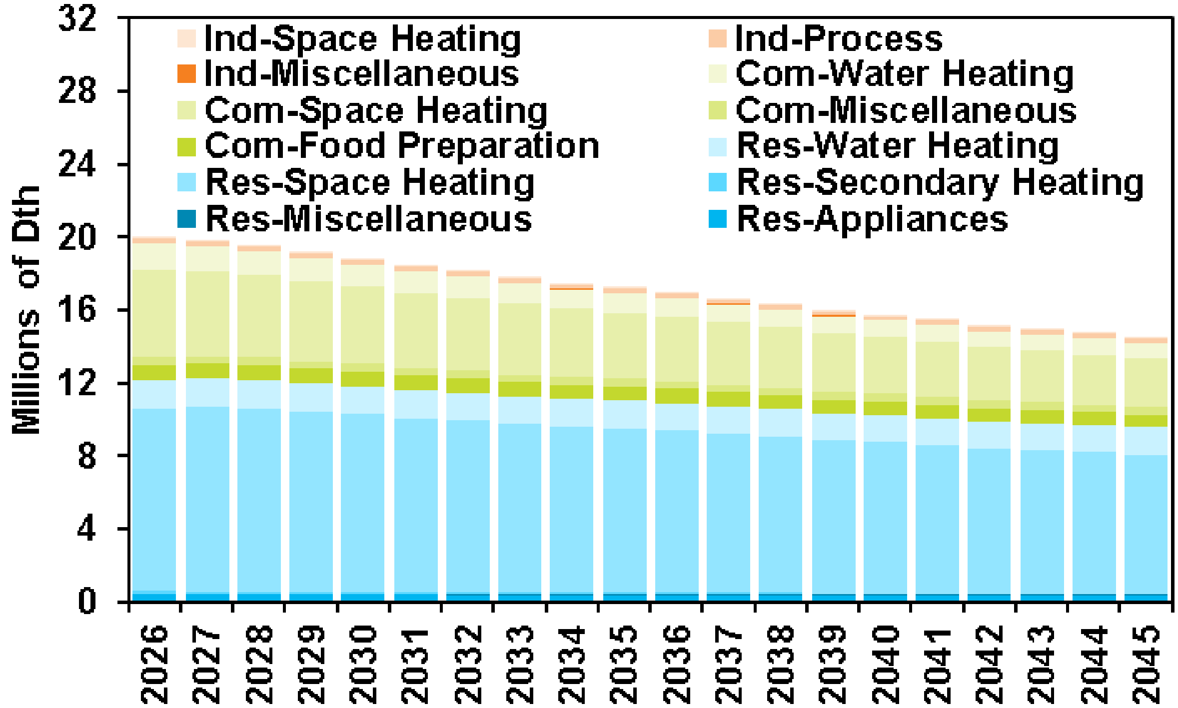
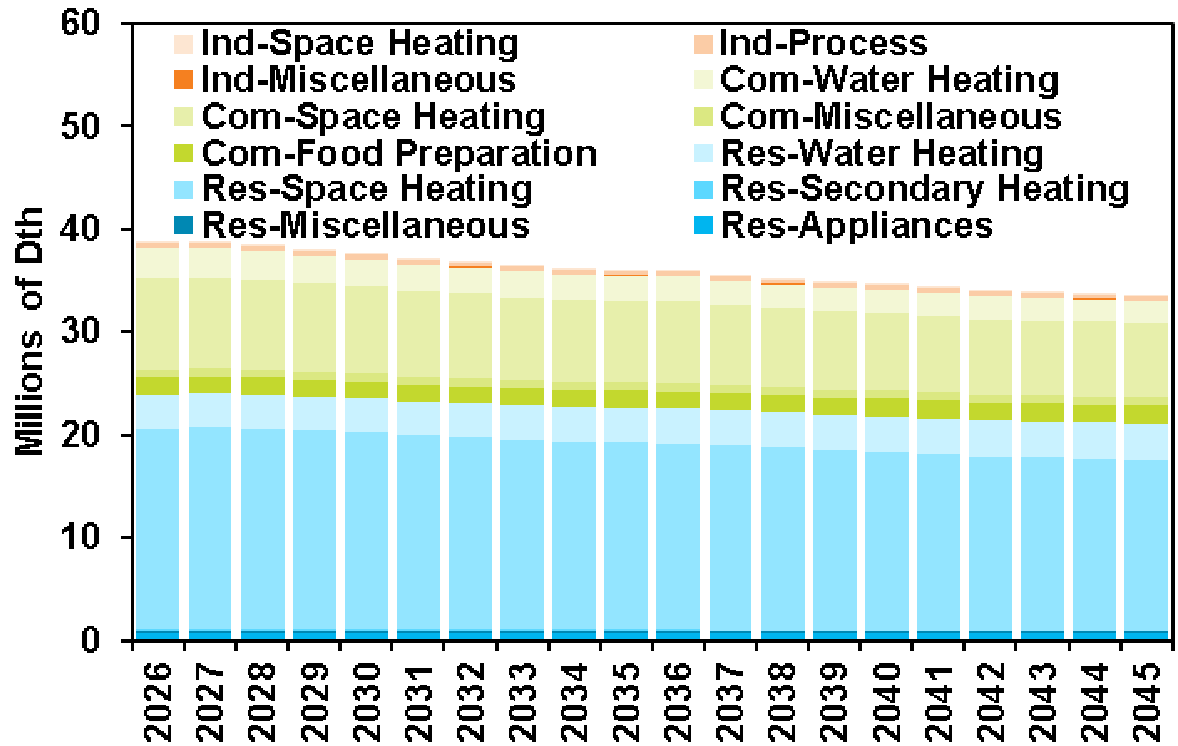


Figure 3.8: System Demand (Firm Customers)



Customer Electrification Forecast

Avista includes two types of electrification decision making within this IRP. The first is electrification initatied by Avista. This electrifcation is selected within the PRS modeling to meet either load or state enivormental policy. The second form of electrificaiton is the organic electrifcication from customer choice. Avista assumes some customers will choose electrification of appliances during new constuction or retrofit of their building. The demand forecast only includes customer driven electrifcation decisions, where a customer has the option to replace the existing natural gas space or water heating equipment with electric alternatives, and includes purchase decision logic copied from the U.S. DOE's National Energy Modeling System. The conversion costs include the possibility of an electric panel upgrade and associated labor. The model compares the lifetime cost of ownership including lifetime fuel costs, upfront costs and associated labor along with the tax benefits form the Inflation Reduction Act (IRA), but do not include any state incentives (as these are not known). Figures 3.9 to 3.14 show the amount of demand reduction expected to occur naturally by jurisdiction for residential and commercial customers.

Figure 3.9: Idaho Residential - Load Reduction Occurring Naturally

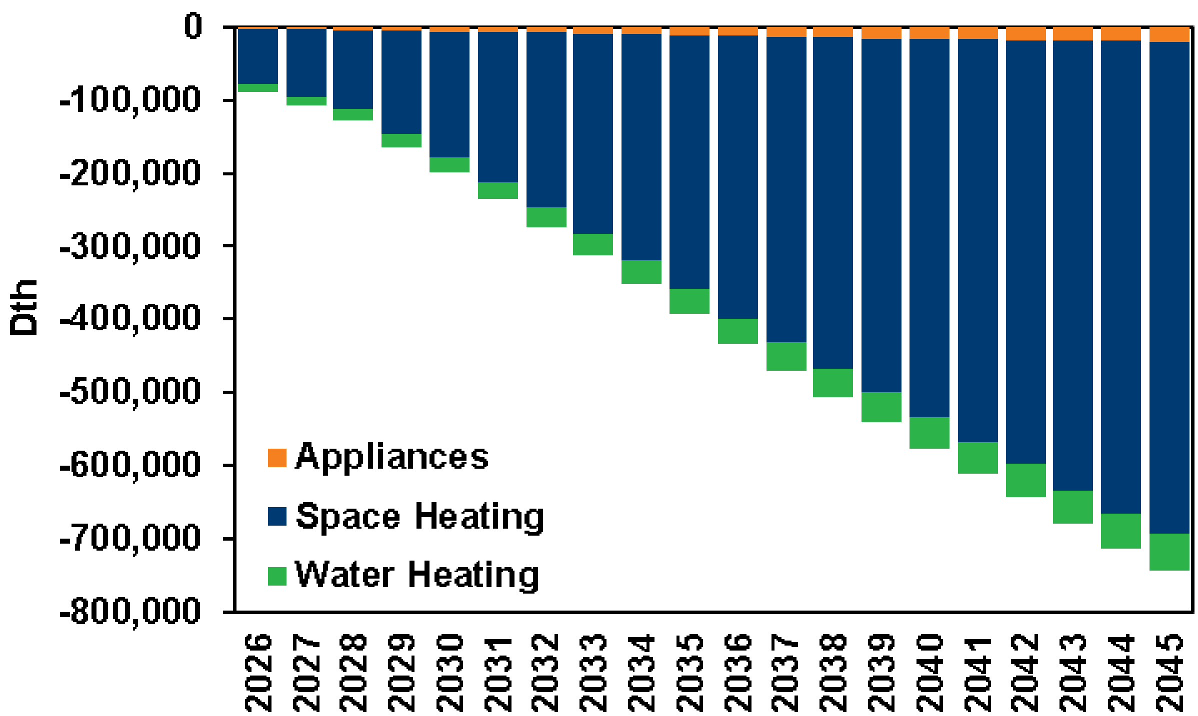


Figure 3.10: Oregon Residential - Load Reduction Occurring Naturally

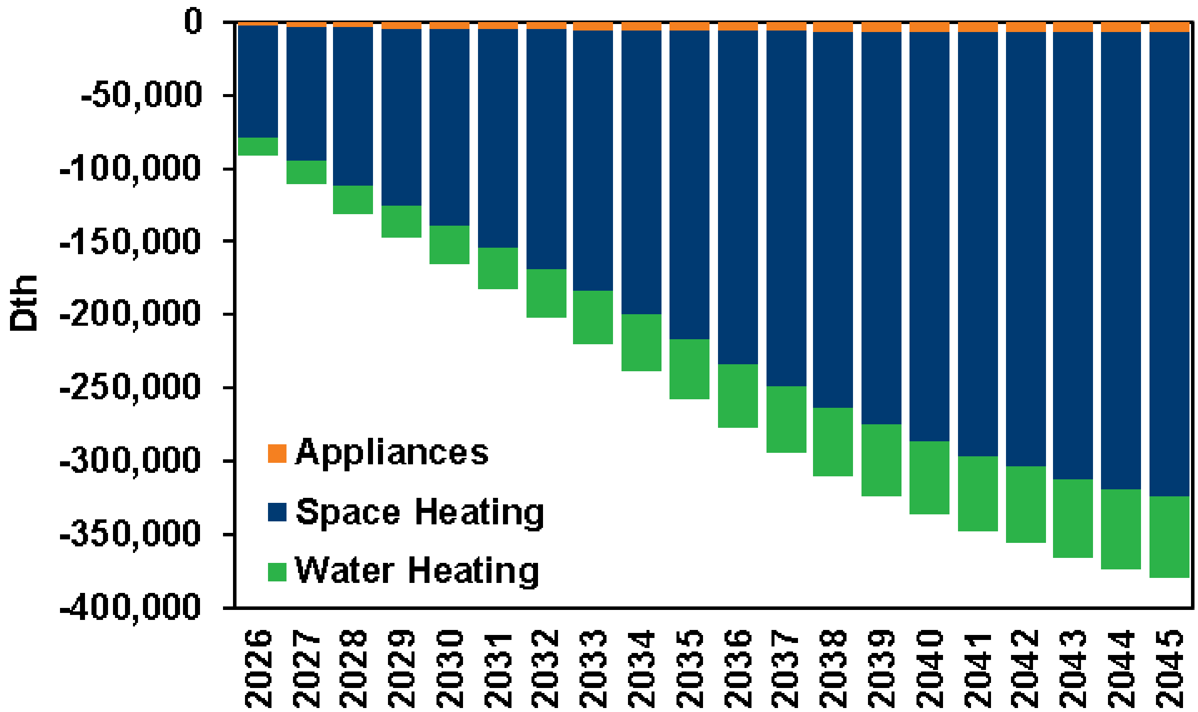


Figure 3.11: Washington Residential - Load Reduction Occurring Naturally

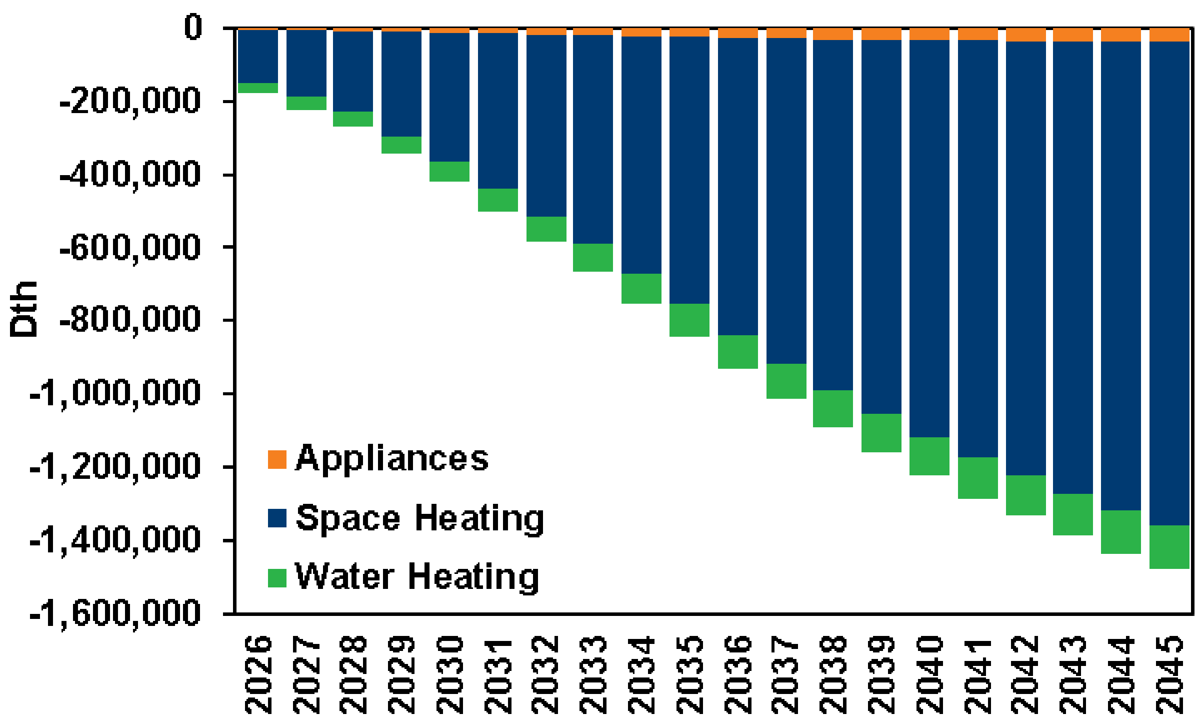


Figure 3.12: Idaho Commercial - Load Reduction Occurring Naturally

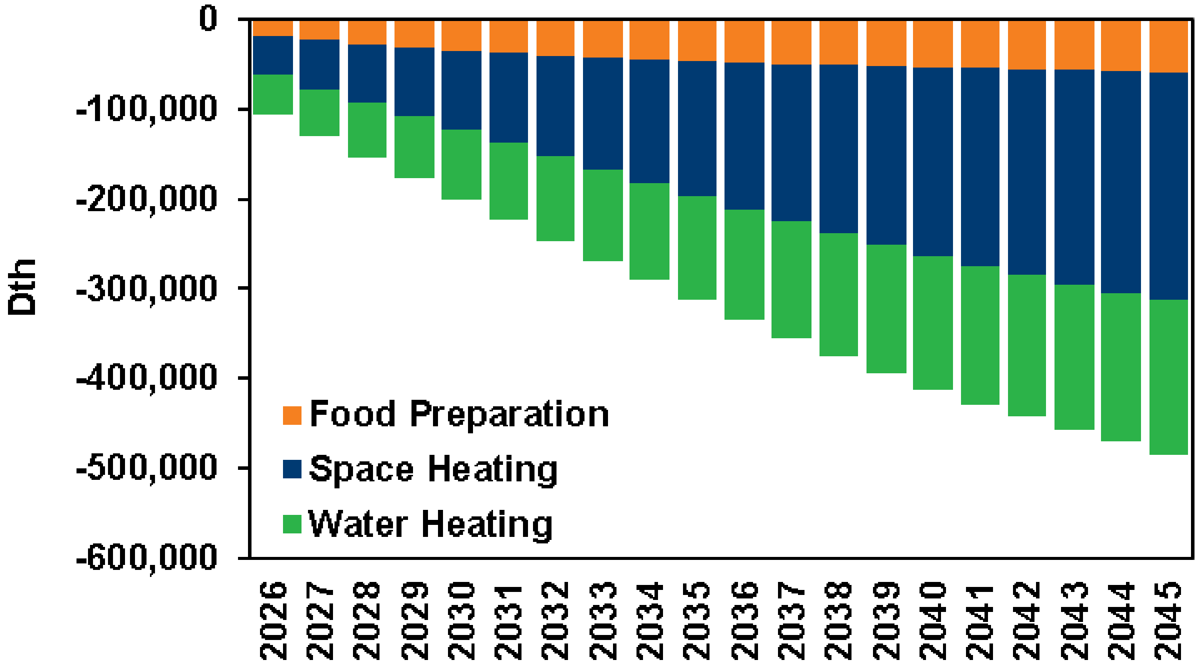


Figure 3.13: Oregon Commercial - Load Reduction Occurring Naturally

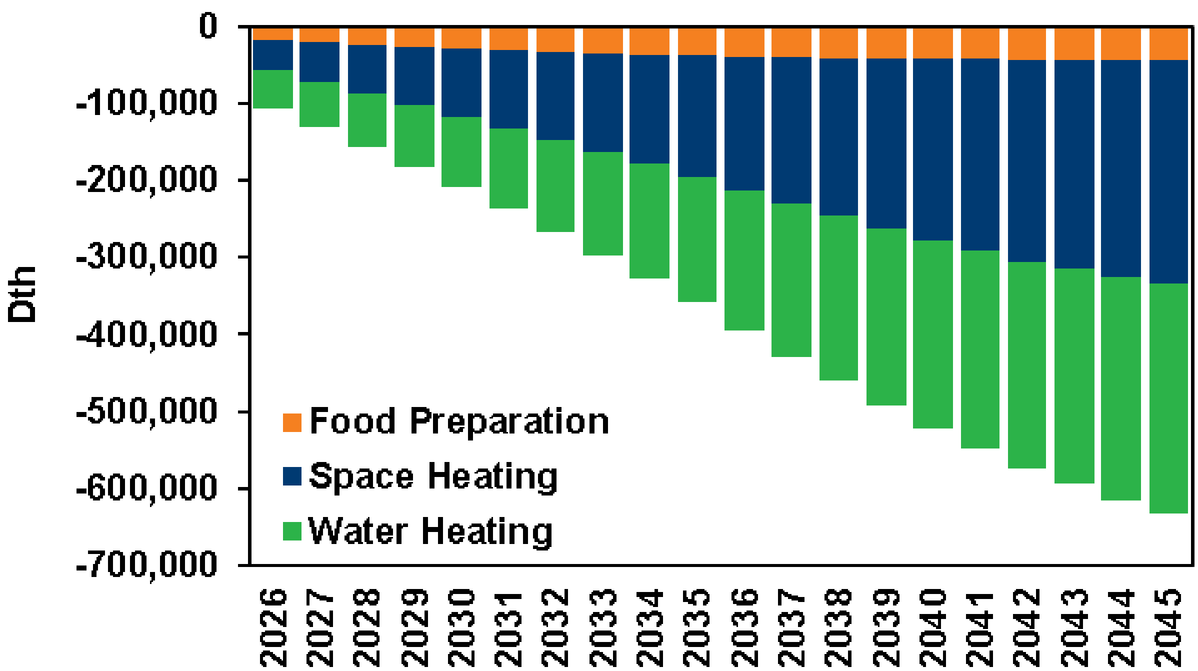
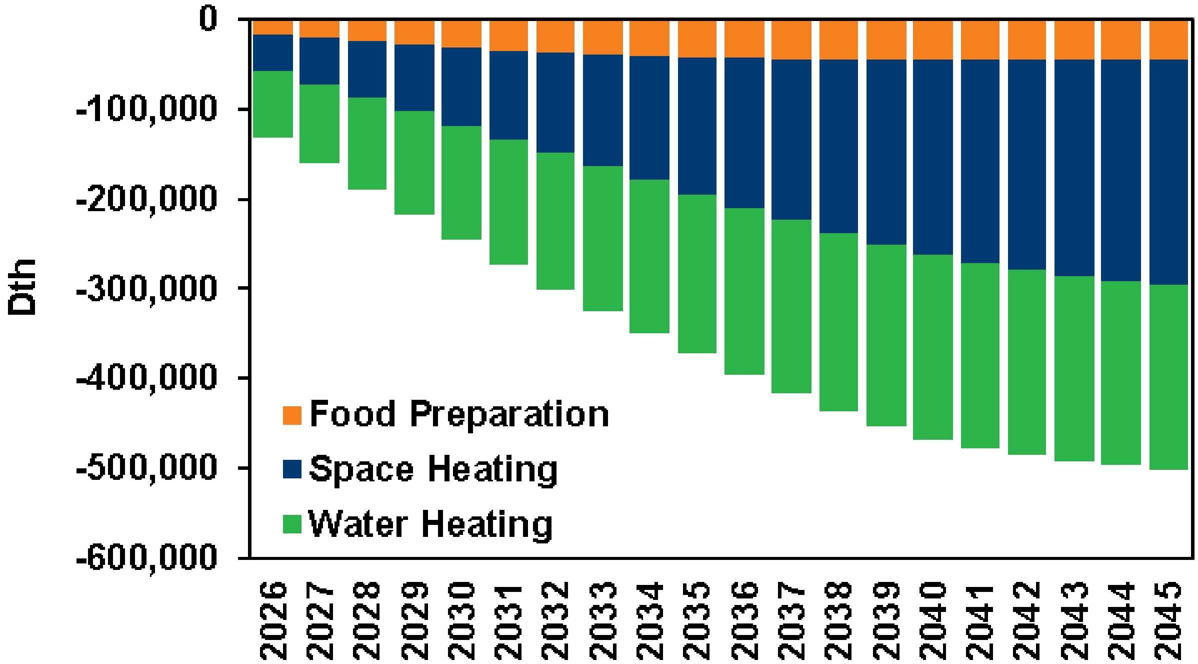


Figure 3.14: Washington Commercial - Load Reduction Occurring Naturally



Idaho is the only state with an expected increase in customers, specifically in the residential and commercial classes. With a 1.64% average customer growth rate, the residential class in Idaho has the fastest growth, followed by the commercial class with an average growth rate of 1.5%. The average customer growth rates in Oregon are 0.46% for residential customers and 0.37% for commercial customers. Washington follows a more muted trend of customer growth rates of 0.04% for residential customers and 1.35% in the commercial class. Industrial customers in Idaho and Oregon have a negative growth rate while Washington is nearly flat at 0.005%.

Although some of these classes estimate some growth, the overall energy use is expected to be declining in Oregon and Washington (-0.31% and -1.68%) with a slight average increase of 0.37% across firm customer classes in Idaho as shown in Table 3.2.

Table 3.2: Annual Average Demand Change by State (2026-2045)

State	Residential	Commercial	Industrial	Total
Idaho	0.18%	0.74%	-0.13%	0.37%
Oregon	-0.37%	-0.23%	-0.06%	-0.31%
Washington	-0.98%	-1.70%	-0.06%	-1.68%
System	**-0.65%**	**-0.98%**	**-0.09%**	**-0.76%**

The primary cause for decreased load in most jurisdictions can be explained through energy intensity. It is a use per customer metric where demand over time is measured per customer or unit (square feet). It considers upgrades of equipment and building shells along with end use technology efficiency gains from higher building code standards and a change in future temperatures. When viewed over the forecast period it produces a declining use per customer as shown in Figures 3.15 to 3.16.

Figure 3.15: Residential Customers Energy Intensity per Customer in Washington

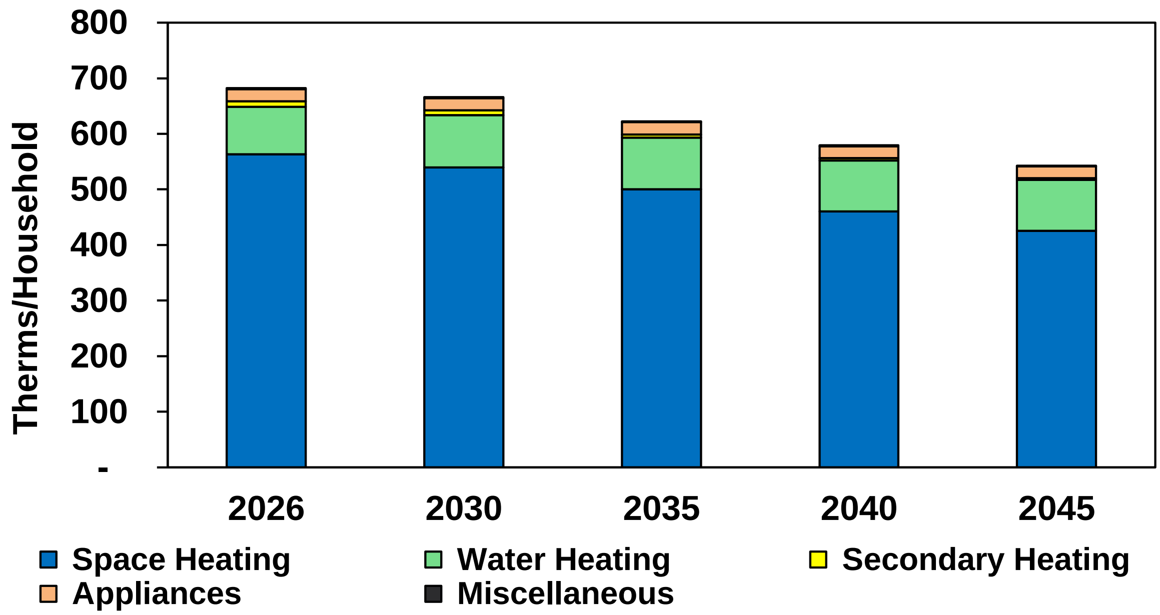
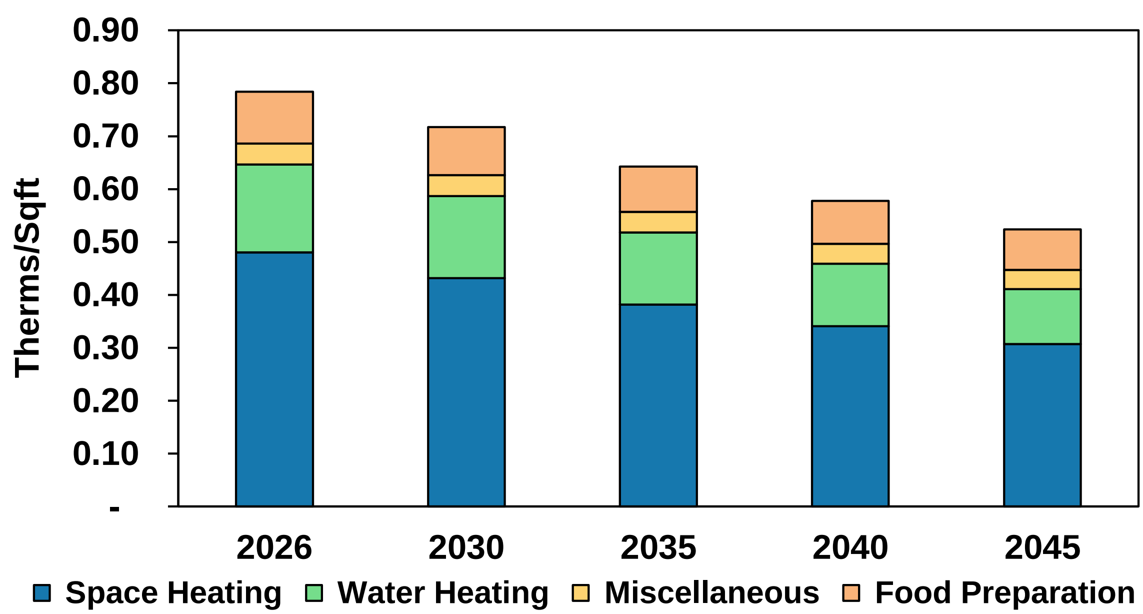
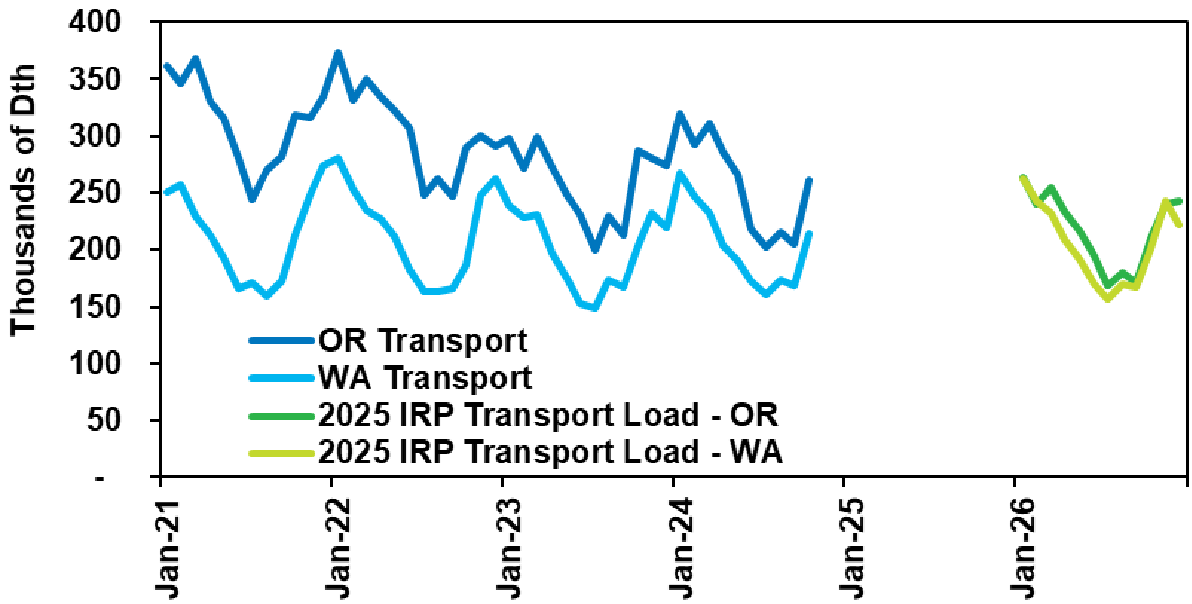


Figure 3.16: Commercial Energy Intensity (Therms/Sqft) in Washington



Avista only includes transportation tariff customer demand for emissions compliance programs in Oregon and Washington. This demand excludes transport customers larger than 25,000 metric tons of carbon dioxide equivalent (MTCO2e) in Washington and those specific customers removed in the final rules of the CPP larger than 15,000 MTCO2e. Avista then uses the average demand based on the three years of monthly historic demand in Oregon and Washington. Figure 3.17 is an example of demand for transport customers used in this plan. Beginning in 2026, monthly demand is carried forward for the forecast horizon as the gross demand prior to energy efficiency.

Figure 3.17: Monthly Demand of Transport Customers (MMBTU)



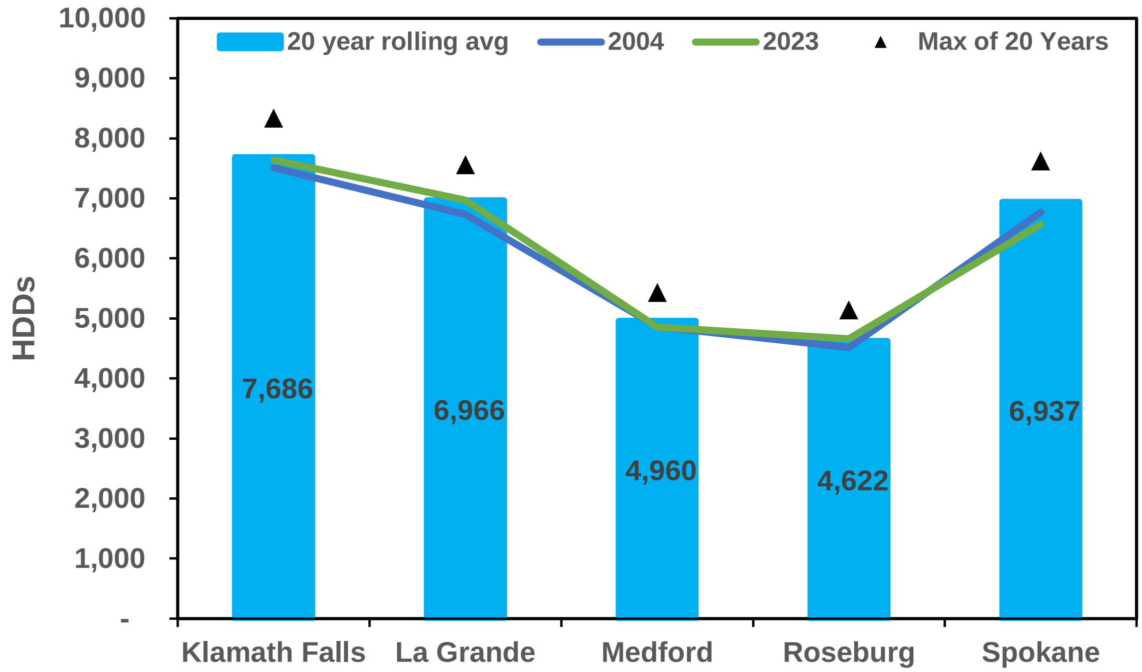
Weather Forecast

The weather forecast is a critical piece of the planning process. It is used to calculate expected demand by planning area when combined with use per customer and number of customers and it drives the resource strategy selection to meet energy and emissions requirements. The 2025 IRP combines historic temperatures and a temperature forecast to create a daily temperature by planning area. These sets of historic and forecasted temperature data are then used to create a design day peak.

Historic Temperature

The most current 20 years of daily weather data (minimums and maximums) from the National Oceanic and Atmospheric Administration (NOAA) is used to compute an average for each day. NOAA data is obtained from five weather stations, corresponding to the areas where Avista provides natural gas services (four in Oregon and one for Washington and Idaho), where this same rolling 20-year daily average weather computation is completed for all five areas. A comparison of a rolling 20-year average from 2004 and 2023 is illustrated in Figure 3.18. The Oregon weather stations in Roseburg and Medford have correlated weather patterns, while those in the Klamath Falls and La Grande areas are uncorrelated. HDD weather patterns amongst eastern Washington and northern Idaho portions of the service area are also correlated.

Figure 3.18: 20 Year Rolling Average by Weather Station



The NOAA 20-year average weather serves as the base weather forecast to prepare the annual average demand forecast. The peak day demand forecast includes adjustments to average weather to reflect a five-day cold weather event.

Forecasted Temperatures

There is significant uncertainty in projecting future temperatures and precipitation. This IRP uses temperature forecast data from Oregon State University's Institute of Natural Resources and uses a Multivariate Adaptive Constructed Analogs (MACA)[1]. The MACA method is a statistical downscaling method for removing biases from global climate model outputs. The MACA dataset is unique due to how it downscales a large set of variables (temperature, precipitation, humidity, wind, radiation) making it ideal for different kinds of modeling of future temperatures (i.e., hydrology, ecology, vegetation, fire, wind). These models also include representative concentration pathways (RCPs). RCPs represent different greenhouse gas (GHG) emission scenarios varying from no future GHG reductions to significant GHG reductions. The Intergovernmental Panel on Climate Change (IPCC) describes the following scenarios:

- RCP 2.6 – stringent GHG mitigation scenario
- RCP 4.5 & RCP 6.0 – intermediate GHG scenarios
- RCP 8.5 – very high GHG scenarios.

[1] MACA Statistical Downscaling Method

Table 3.3 provides a comparison of the temperature increases projected under the various scenarios by RCP.

Table 3.3: Comparison of Temperature Increases by RCP

	Scenario	2046-2065		2081-2100	
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (°C)	RCP 2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP 4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP 6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP 8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

The RCP 4.5 and RCP 6.0 scenarios are similar during the current IRP planning horizon. Avista selected modeling results based on the RCP 4.5 for this IRP due to:

- RCP 8.5 is at the high end of potential future GHG emissions,
- there are significant worldwide efforts to mitigate GHG emissions,
- the intermediate scenarios are similar during the IRP planning horizon,
- using RCP 4.5 temperatures for planning protects against the risk of the future not warming as anticipated,
- RCP 4.5 and 8.5 have overestimated winter temperatures on average (except for January).

Avista applied this information using the following methods:

- Median HDD values of available studies by planning region, using the average of daily min/max.
- Trended HDDs from 2026 to 2045 to calculate an average increase or decrease over the planning horizon.
- Rolling daily 20-year blend (historic and MACA HDDs).

MACA 4.5 and 8.5 weather median futures trended from 2026 to 2045 by planning area and combine with historical actual data into a rolling 20-year average. In the absence of a RCP 6.0 climate future, an average of the 4.5 and 8.5 models were used to produce a proxy for a RCP 6.5 scenario. Each planning region is entered by longitude and latitude with the data extracted corresponds to the average over the grid cell that contains your selected point. MACA 4.5 and MACA 6.5 represent growth in greenhouse gas emissions, but the growth is lower in comparison to RCP 8.5 due to mitigation strategies. Warming temperatures will impact average demand yet Avista maintains a severe cold weather risk and requires flexible resources to meet these extreme temperatures in each planning area. Specifically, we expect less heating demand in the winter.

A 20-year moving average of the HDDs is used, combining the historical and forecasted temperatures. In this analysis, the median daily average temperature of the MACA models isa used as the temperature data set compared to the 20-year moving average for each forecast year. Figure 3.19 shows the HDDs used by year and by planning region under RCP 4.5. The overall impact is hard to distinguish in a line chart so to help with this we have included Figure 3.20 showing the overall decrease from 2026 to 2045.

Figure 3.19: RCP 4.5 Blended with 20 Year Historic Temperatures

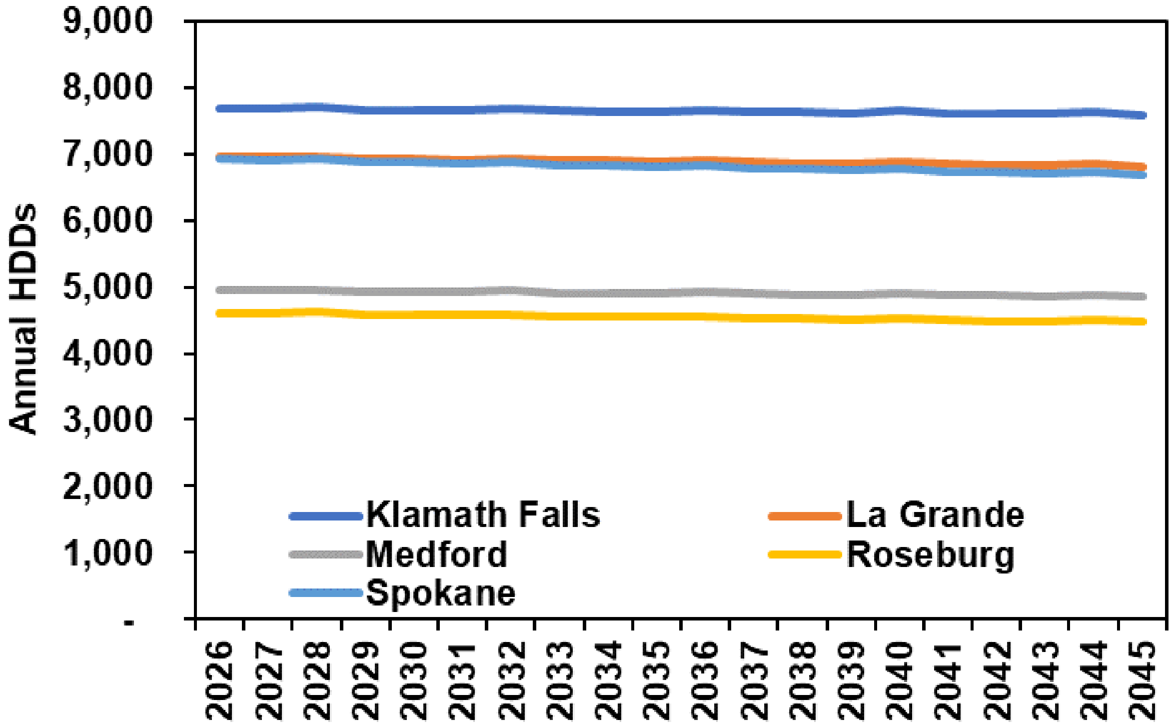
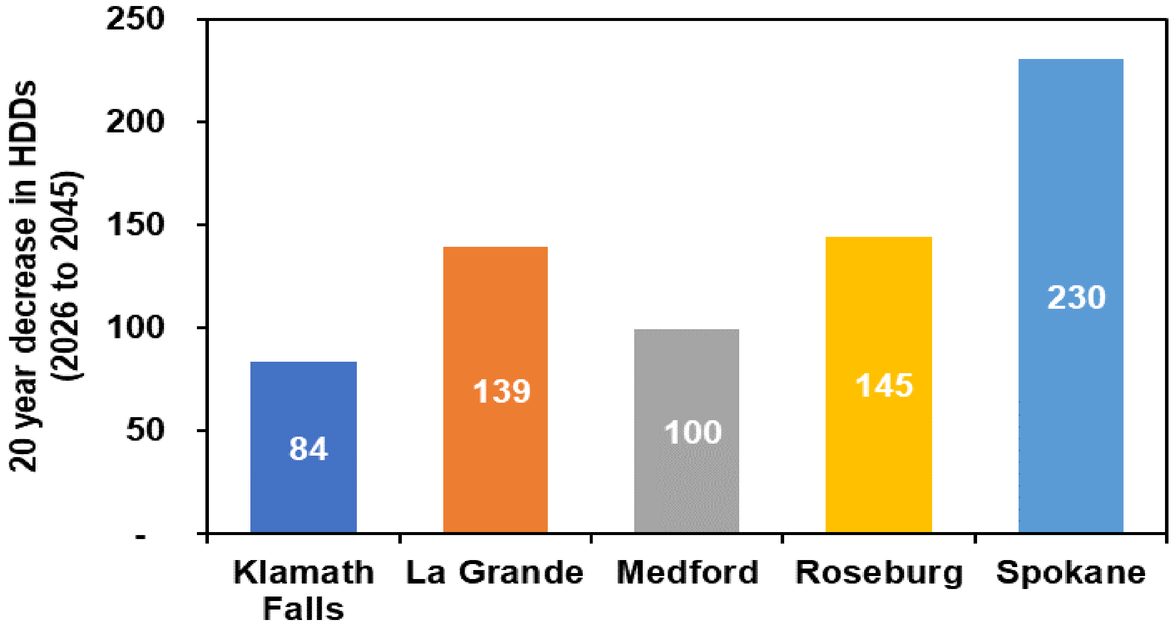


Figure 3.20: 20-Year Decrease of HDDs by Planning Region



Peak Day Design Temperature

The weather planning standard is an important piece of system planning for resources in an IRP because it sets the amount of firm delivery requirements to procure or construct. For most historical IRPs, the coldest day on record was used as the design day. In the 2023 IRP, Avista attempted to include future temperature forecasts within its design day calculations. For this IRP, the design day methodology is further evolved by calculating the design day by taking the coldest day on record for each area and adjusting it based upon the RCP 4.5 annual expected change in temperatures over the next 20 years. This temperature adjustment is shown in blue within Figure 3.21 for the Medford weather station. The orange line represents the coldest day on record, while the grey line is the 99th percentile coldest day from the MACA weather future temperatures between 2026 and 2045.

The 99th percentile, or 1-in-100 events, temperature forecast is colder than Avista's design day temperature for all locations. This temperature implies there is potential for overall HDDs to increase when comparing the historical coldest day on record according to global climate models. Given this uncertainty in projecting future temperatures, Avista will continue to improve upon its design day methodology in future IRPs. Table 3.4 is a summarizes each areas design day temperature in 2045, the current coldest day on record, and the 99th percentile coldest day of the weather futures from global climate models assuming RCP 4.5.

Figure 3.21: Medford Weather Station – Weather Planning Standard Comparison

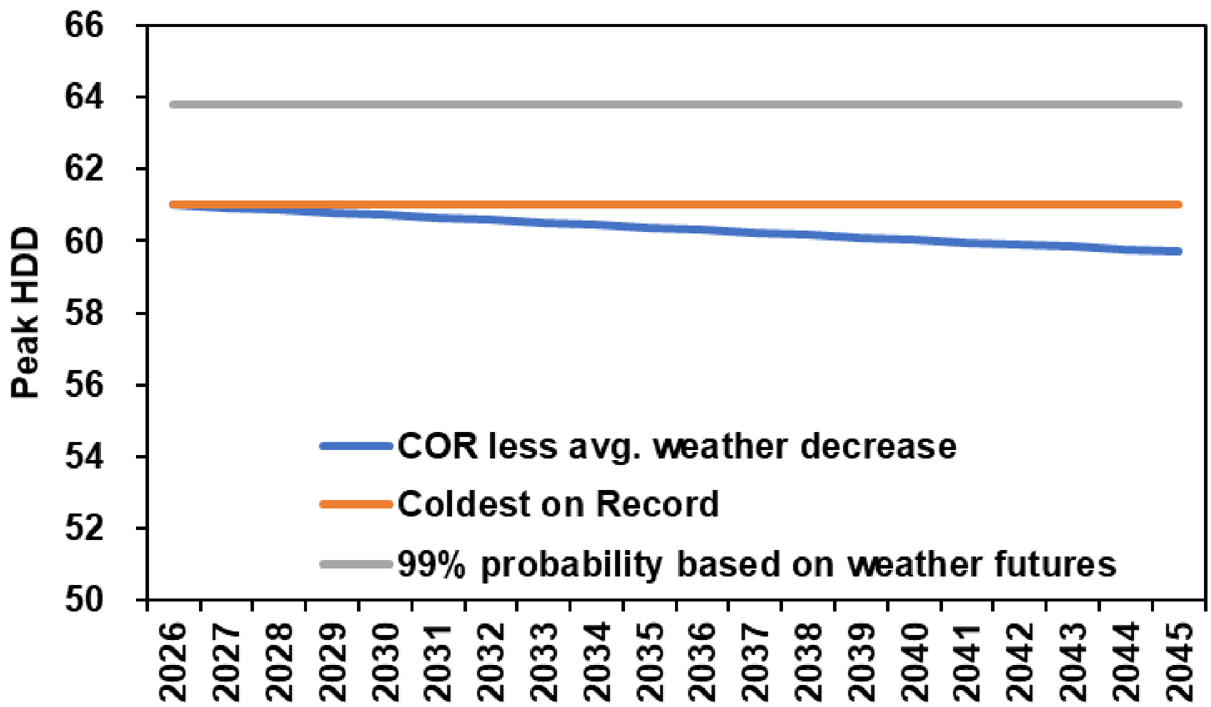


Table 3.4: Peak Day Design Temperature

Area	Coldest on Record (Prior IRP's)	99th Percentile Coldest Day Forecast	2045 Design Day
La Grande	-10	-19	-8.0
Klamath Falls	-7	-14	-6
Medford	4	1	5
Roseburg	10	1	12
Spokane	-17	-24	-14

Beyond a single cold day, the weather planning standard utilizes a five-day cold weather event by service territory while adjusting the two days on either side of the planning standard to temperatures colder than average. For the Washington, Idaho, and La Grande service territories, the model assumes this event on and around February 28th each year to safeguard the availability of storage resources to serve customers in late season cold weather events. With pipeline and storage resources in the Pacific Northwest constrained, managing supply along with the ability to serve cold days is paramount. For the southwestern Oregon service territories (Medford, Roseburg, and Klamath Falls), the plan assumes this event occurs on and around December 20th each year.

When considering changing weather in our service territories, a historic comparison is helpful as shown in Figures 3.22 to 3.26. This Z-statistic analysis is used to compare the deviation from an average temperature over each stated timeframe. Distributions of these daily changes compared to the average daily weather over the timeframe will emerge. The Spokane weather area maintains the same shape from a reference period where the coldest on record set of temperatures occurred. A slight deviation to the positive side of the Z-statistic points to a general warming trend compared to the reference period. Movement towards the right on the X-axis points to an increased deviation compared to the reference period indicating a shift to warmer weather. These figures illustrate a period of 30-year weather compared to recent weather by planning region for December, January, and February. An important piece of this analysis is to determine the tail to the left of each graph as this confirms cold weather is still occurring as seen historically.

Figure 3.22: Spokane Historical Temperature Distribution

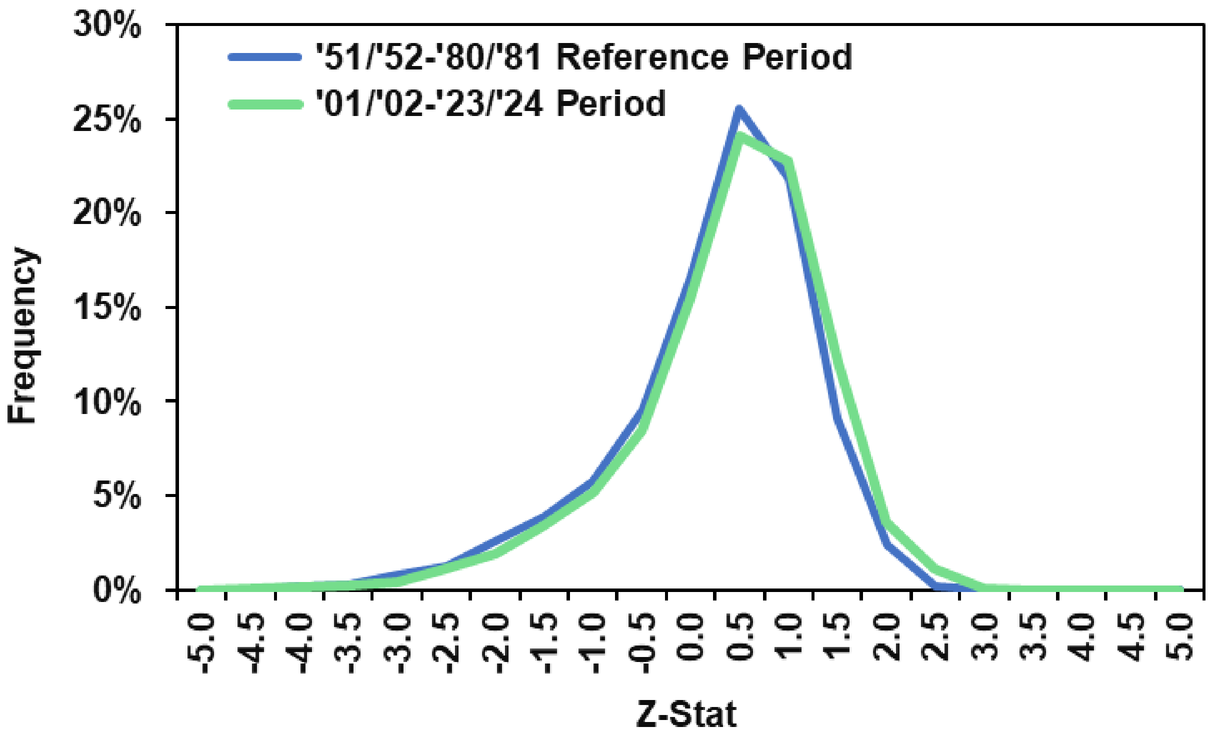


Figure 3.23: Medford Historical Temperatures

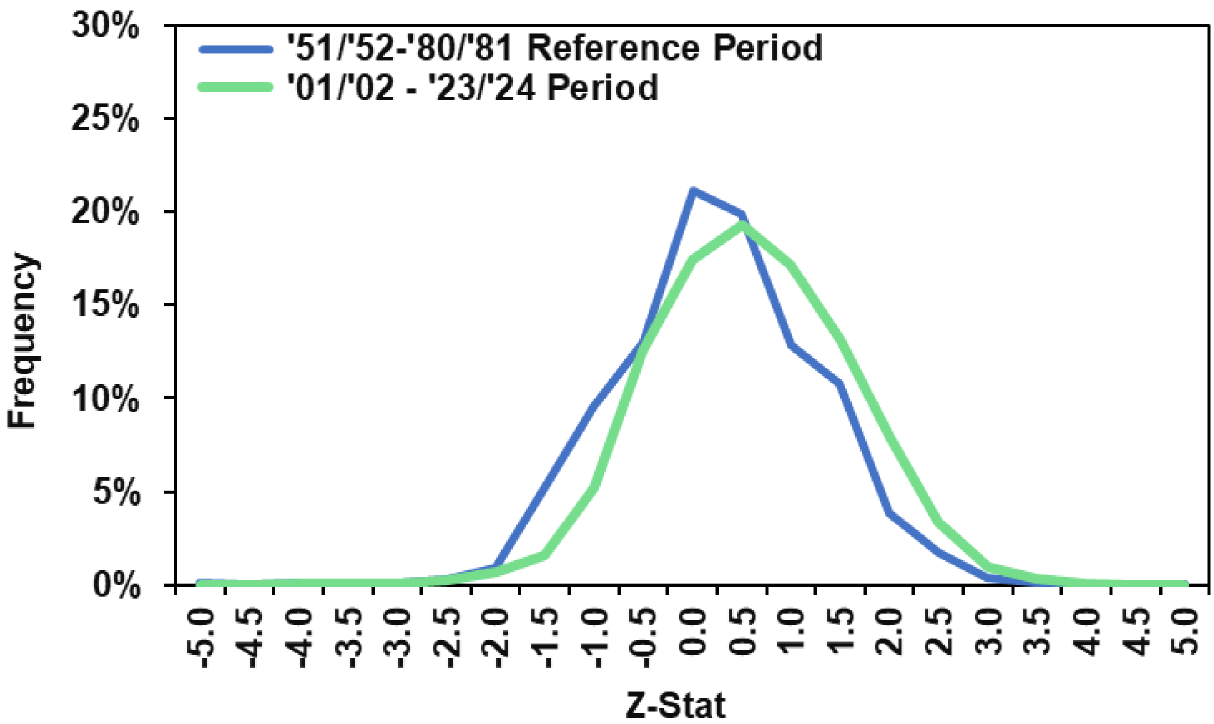


Figure 3.24: La Grande Historical Temperatures

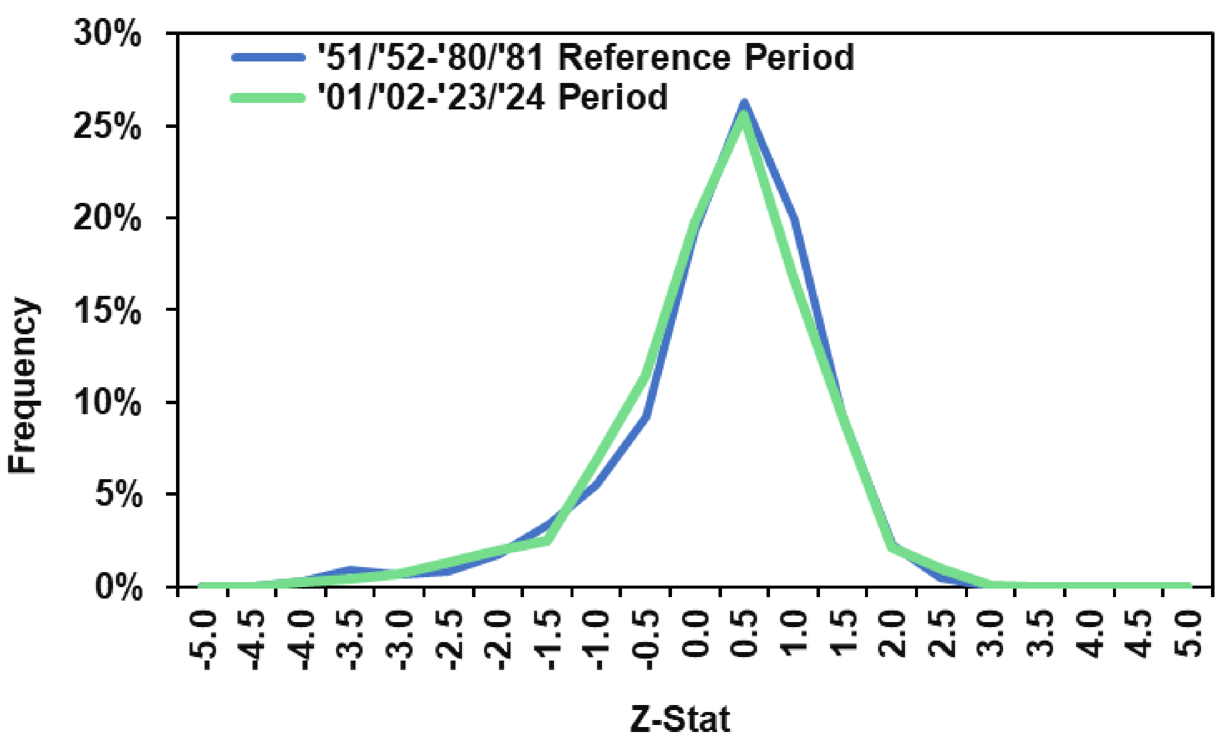


Figure 3.25: Klamath Falls Historical Temperatures

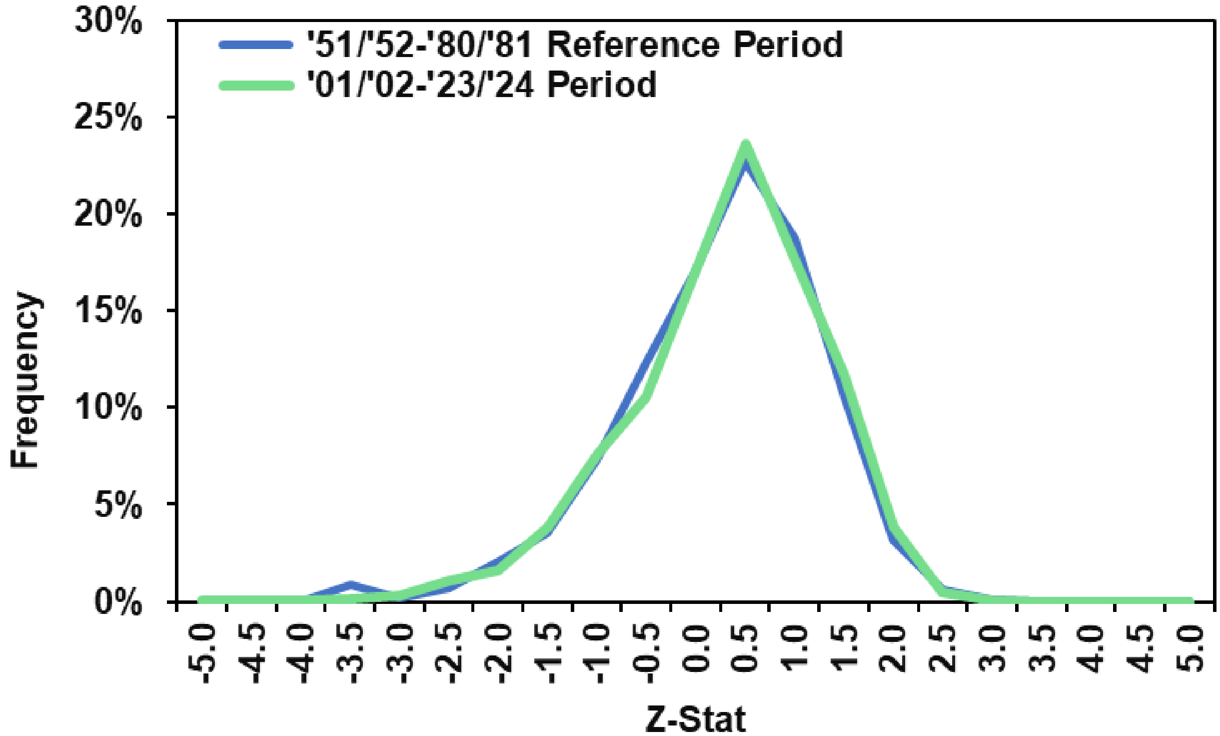
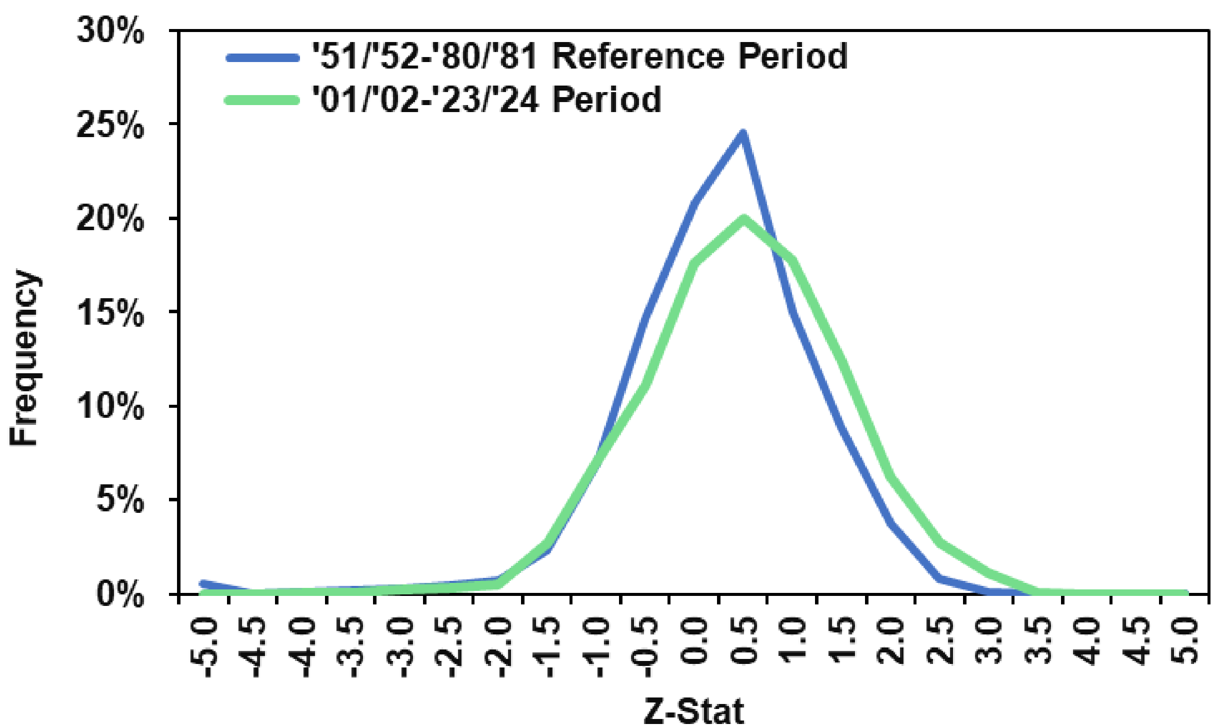


Figure 3.26: Roseburg Historical Temperatures



Weather Stochastics

Avista developed 500 simulations (draws) to evaluate weather and its effect on the portfolio. Unlike deterministic scenarios or sensitivities, the stochastic draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 3.5) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides a more robust basis for stress testing the deterministic analysis. These inputs are derived from the expected monthly temperatures from 2026 to 2045 as discussed above as the HDD mean, min and max. Historic temperatures are used as the standard deviation of these values as there is more data to draw information from with actual temperature variation to measure these mean HDD expectations variability.

Table 3.5: Example of Monte Carlo Weather Inputs – Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	867	1,110	1,170	935	799	541	318	140	31	40	194	523
HDD Std Dev	111	133	179	129	99	87	81	51	26	31	73	86
HDD Max	1,374	1,519	1,759	1,389	1,059	740	494	260	168	144	363	695
HDD Min	609	839	850	703	561	269	146	12	-	-	59	334

The model considers five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. See Figure 3.27 through Figure 3.31 for the number of annual heating degree days by weather area. These distributions help stress test the model for different load profiles and needed resources based on varying weather. These Monte Carlo simulations combine weather futures and historic data to obtain randomly generated weather events.

Figure 3.27: Frequency of Annual HDDs (2026-2045) – Spokane

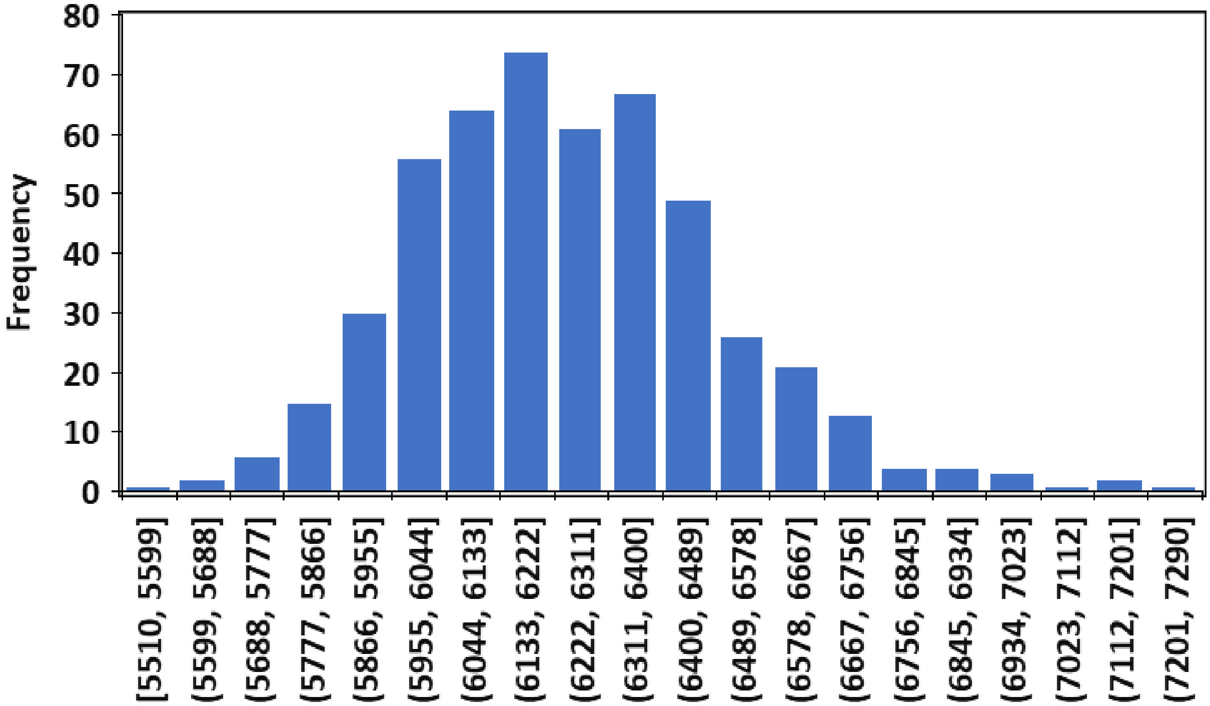


Figure 3.28: Frequency of Annual HDDs (2026-2045) – Medford

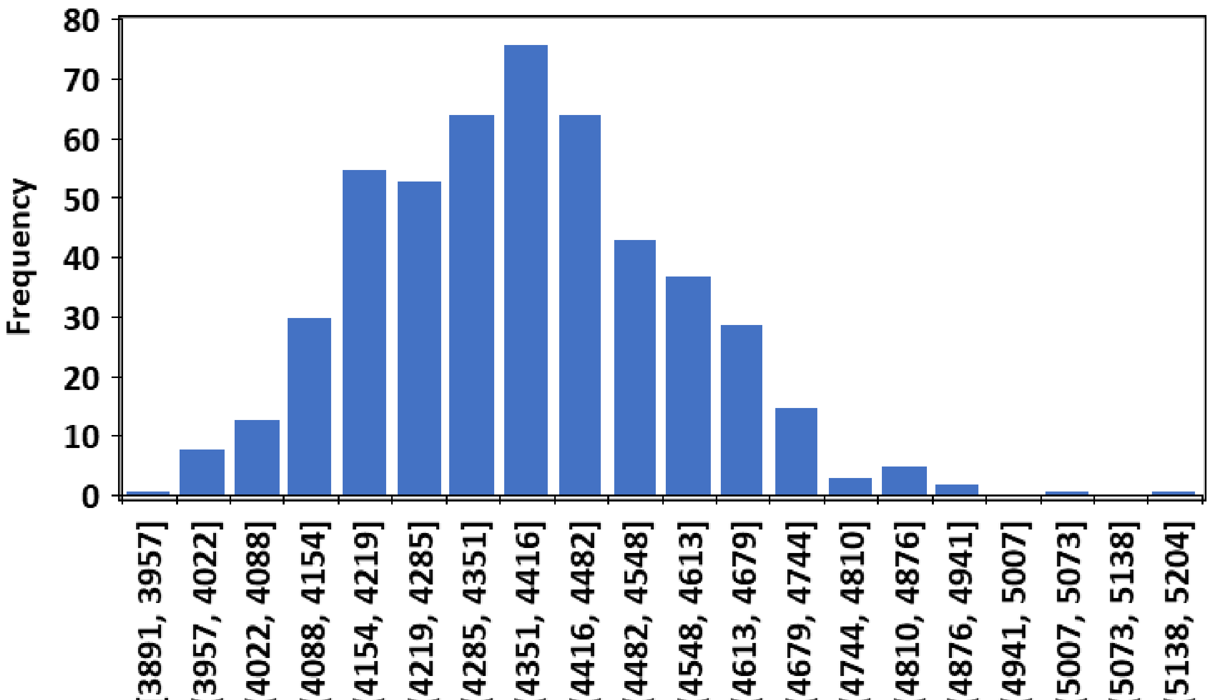


Figure 3.29: Frequency of Annual HDDs (2026-2045) – Roseburg

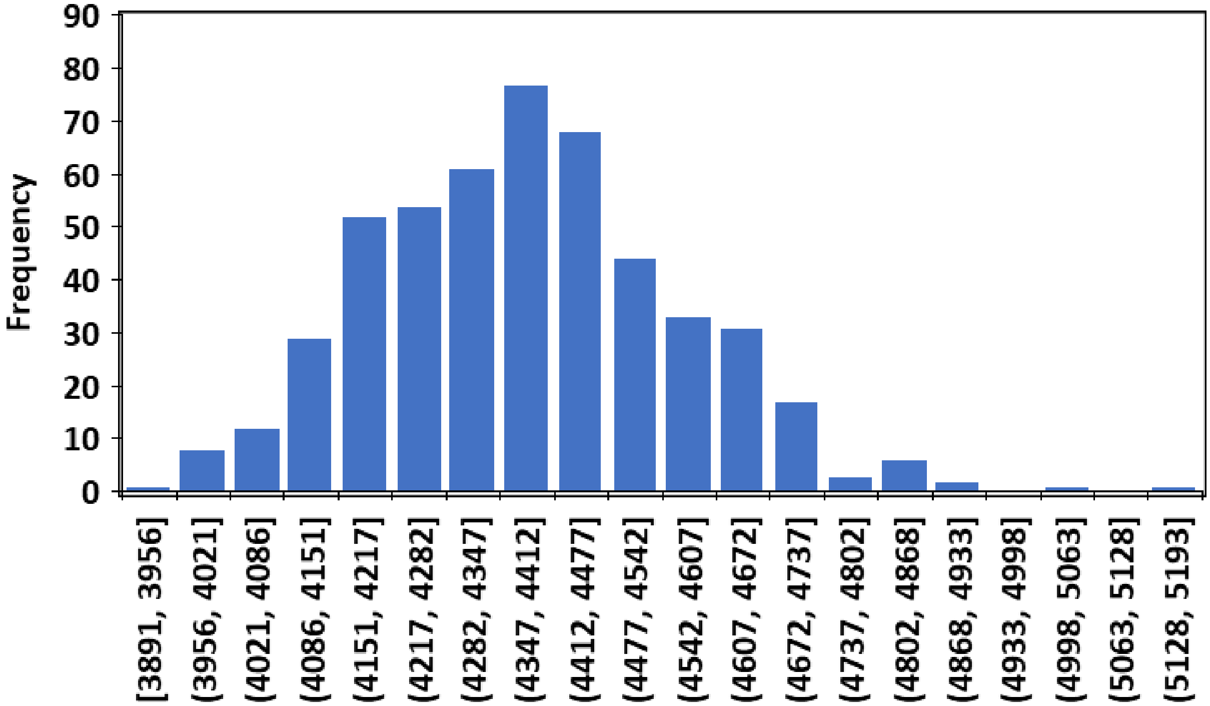


Figure 3.30: Frequency of Annual HDDs (2026-2045) – Klamath Falls

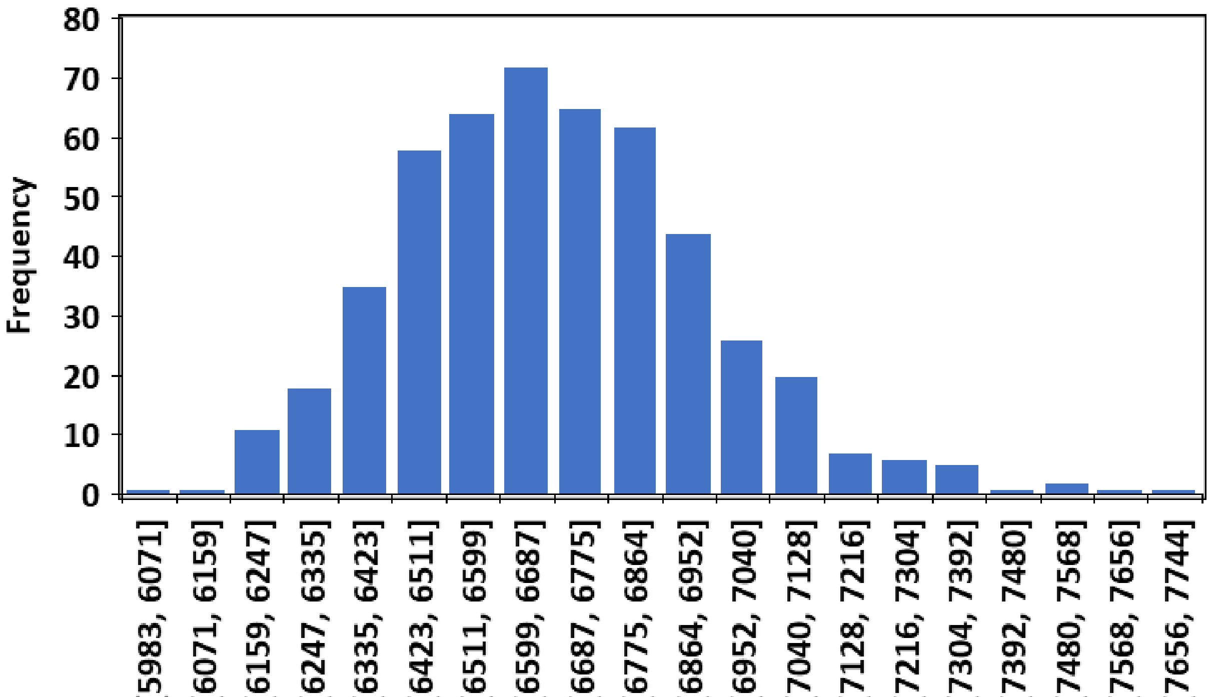
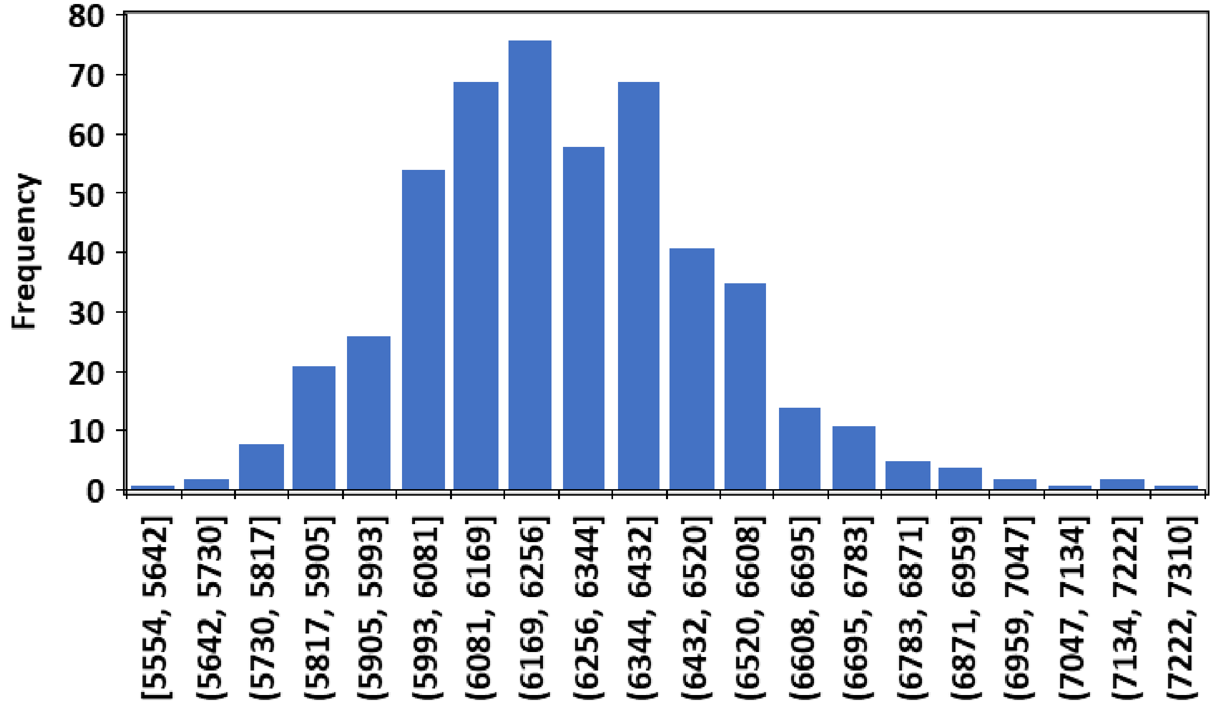


Figure 3.31: Frequency of Annual HDDs (2026-2045) – La Grande



Load Forecast

The combination of the elements discussed in this chapter produces an estimated energy need as illustrated in Table 3.6. The forecast is broken out by jurisdiction, separated by firm and transport only expectations. This represents the expected loads used in the Preferred Resource Strategy (PRS) and includes the reduction in demand from energy efficiency.

Table 3.6: Load Forecast (Thousand Dekatherms)

Year	Washington	Idaho	Oregon	Washington Transport	Oregon Transport	Total Firm	Total w/Transport
2026	20,307	10,377	8,823	3,181	2,603	39,507	45,291
2027	20,063	10,401	8,749	3,159	2,586	39,213	44,958
2028	19,695	10,396	8,661	3,137	2,569	38,752	44,458
2029	19,216	10,389	8,545	3,114	2,551	38,150	43,815
2030	18,760	10,373	8,441	3,090	2,531	37,574	43,195
2031	18,239	10,321	8,320	3,066	2,510	36,880	42,456
2032	17,808	10,319	8,224	3,041	2,489	36,351	41,881
2033	17,335	10,289	8,102	3,017	2,467	35,726	41,210
2034	16,910	10,286	7,993	2,994	2,445	35,189	40,628
2035	16,558	10,325	7,922	2,972	2,424	34,805	40,201
2036	16,203	10,364	7,853	2,952	2,405	34,420	39,777

2037	15,777	10,333	7,734	2,936	2,388	33,844	39,168
2038	15,393	10,345	7,614	2,921	2,373	33,352	38,646
2039	14,975	10,327	7,479	2,909	2,360	32,781	38,050
2040	14,644	10,363	7,379	2,897	2,347	32,386	37,630
2041	14,331	10,398	7,266	2,886	2,336	31,995	37,217
2042	13,970	10,391	7,137	2,878	2,326	31,498	36,702
2043	13,717	10,455	7,025	2,869	2,315	31,197	36,381
2044	13,468	10,515	6,928	2,860	2,306	30,911	36,077
2045	13,151	10,509	6,781	2,846	2,289	30,441	35,576

The peak demand forecast, net of energy efficiency, is included in Table 3.7. This forecast is analyzed to measure capacity needs on a peak day by demand area. Firm service customers rely on this capacity on the coldest of days to deliver the necessary energy to keep customers and their assets safe.

Table 3.7: Peak Day Load Forecast by Area (Thousand Dekatherms)

Year	Washington	Idaho	Oregon	Washington Transport	Oregon Transport	Total Firm	Total w/ Transport
2026	238.13	136.61	101.43	8.61	8.34	476.17	493.12
2027	233.66	136.56	100.28	8.56	8.31	470.50	487.37
2028	229.11	136.41	99.09	8.20	8.00	464.61	480.81
2029	224.69	136.79	97.89	8.43	8.25	459.37	476.06
2030	220.13	136.74	96.58	8.37	8.22	453.45	470.03
2031	215.52	136.63	95.22	8.30	8.18	447.37	463.85
2032	210.91	136.48	93.83	7.95	7.87	441.22	457.04
2033	206.35	136.34	92.40	8.17	8.11	435.09	451.38
2034	201.87	136.17	90.94	8.11	8.07	428.98	445.16
2035	197.54	136.05	89.45	8.05	8.04	423.04	439.12
2036	193.35	135.99	87.93	7.72	7.73	417.26	432.71
2037	189.36	136.00	86.37	7.95	7.98	411.73	427.66
2038	185.53	136.07	84.78	7.91	7.95	406.38	422.24
2039	181.84	136.18	83.16	7.88	7.93	401.18	416.99
2040	178.31	136.32	81.53	7.58	7.64	396.16	411.37
2041	174.98	136.51	79.87	7.82	7.89	391.36	407.06
2042	171.75	136.69	78.18	7.79	7.87	386.62	402.29
2043	168.69	136.91	76.47	7.77	7.85	382.07	397.69
2044	165.75	137.12	71.02	7.48	7.57	373.89	388.93
2045	162.98	137.36	69.25	7.72	7.82	369.60	385.14

Scenario Analysis

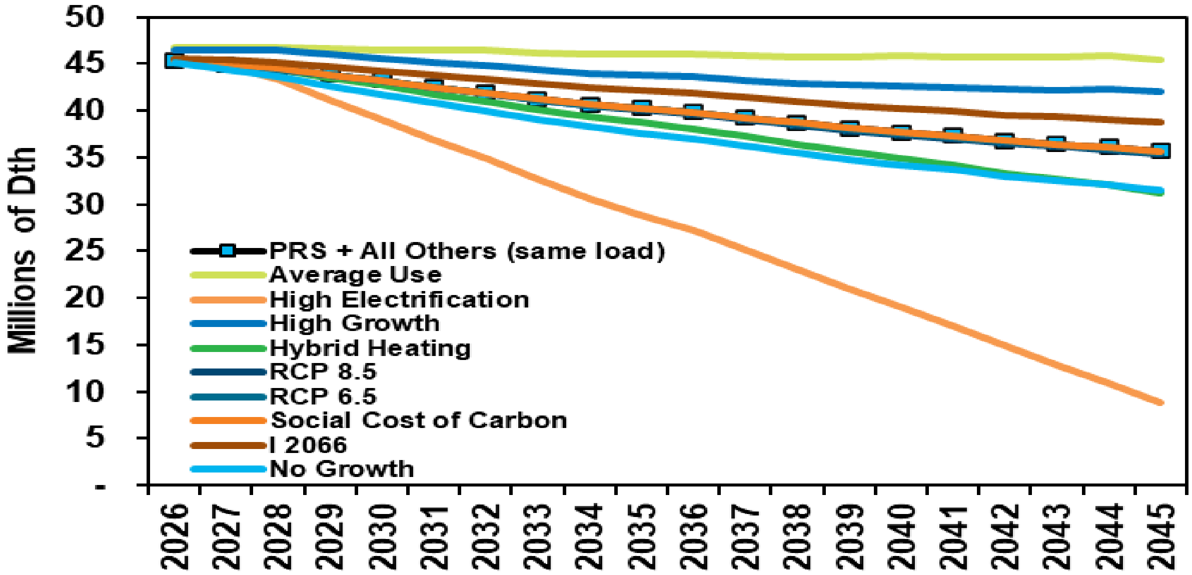
Demand is becoming more difficult to forecast due to the policy updates in both Oregon and Washington and building code updates in Washington. Changes in total demand can drastically change both the timing and resources selected, making it necessary to look at different future expectations based on demand, costs, and resource availability. Table 3.8 identifies the scenarios and sensitivities developed for this IRP. The PRS reflects the expected demand and available costs and resources Avista believes is most likely given expected peak weather conditions. All other scenarios represent a different set of future expectations and range of possible outcomes based on current policies, codes, and customer demand. Each scenario provides a “what if” analysis of a different future assumption given the volatile nature of key assumptions, including weather and price.

Table 3.8: Demand Scenarios and Sensitivities

Preferred Resource Strategy Scenario – Our expected case based on assumptions and costs with a least risk and least cost resource selection	**High Customer Scenario** – A high demand case to measure risk of additional customer and meeting our emissions and energy obligations
High Electrification Scenario – Scenario to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system	**Average Case Sensitivity** – Non climate change projected 20-year history of average daily weather and excludes peak day
Hybrid Heating Scenario – Natural Gas used for space heat below 38º F while transferring all other usage to electricity.	**Low Natural Gas Use Scenario –** A lower than expected use case using RCP 8.5 weather futures along with high costs for compliance
RCP 8.5 Weather Sensitivity – Expected case scenario assumptions with RCP 8.5 weather futures.	**RCP 6.5 Weather Sensitivity -** expected case scenario assumptions with RCP 6.5 weather futures.
Initiative 2066 Sensitivity – Expected case assumptions with a pause of Washington State commercial customers loads building codes.	**No Growth –** no new customers in OR & WA after line allowances expire in 2026 and 2025, respectively.

The total estimated system loads across scenarios and sensitivities address starkly different load scenarios as shown in Figure 3.32 and further discussed in Chapter 8, these forecasts include energy efficiency. RCP 6.5 and 8.5 sensitivities follow closely with the PRS scenario and are hard to distinguish in the figure within the forecast horizon and alternative loads. These loads encapsulate varying plausible futures and potential outcomes based on shifting policies, standards, and possible incentives. These policies are further discussed in Chapter 8.

Figure 3.32: System Load Forecast by Scenario/Sensitivity



This Page is Intentionally Left Blank

4. Demand Side Resources

Section Highlights:

- Energy efficiency is expected to offset 11% of demand by 2045.
- Heat pumps can provide great efficiency, but conversion costs remain a primary barrier.
- Higher avoided cost in Oregon and Washington drive higher efficiency targets compared to Idaho.

Avista is committed to offering natural gas energy efficiency (EE) programs to residential, low income, commercial, and industrial customer segments when it is feasible and cost-effective within each jurisdiction. Avista began offering natural gas EE programs in 1995. Program delivery has grown over the years with an emphasis on increasing customer participation. Avista's program design includes both prescriptive and site-specific offerings. Recent expansion includes additional programs such as On-Bill Repayment, Home Energy Audits, and incentives offered through midstream channels. Programs are designed to provide cash incentives for products such as the installation of qualifying high efficiency heating equipment, building weatherization, smart controls, and data informed approaches to saving energy.

Over the years, Avista has seen the most significant impacts in the residential market with the installation of high efficiency HVAC measures, such as furnaces, tanked and tankless water heaters, and the use of smart thermostats. These programs have historically produced the highest levels of EE, however, Avista strives to continue offering programs appealing to all customer segments. With the introduction of the House Bill 1444 in Washington, known as the Clean Buildings Act, Avista anticipates more non-residential programs and increased participation in the future.

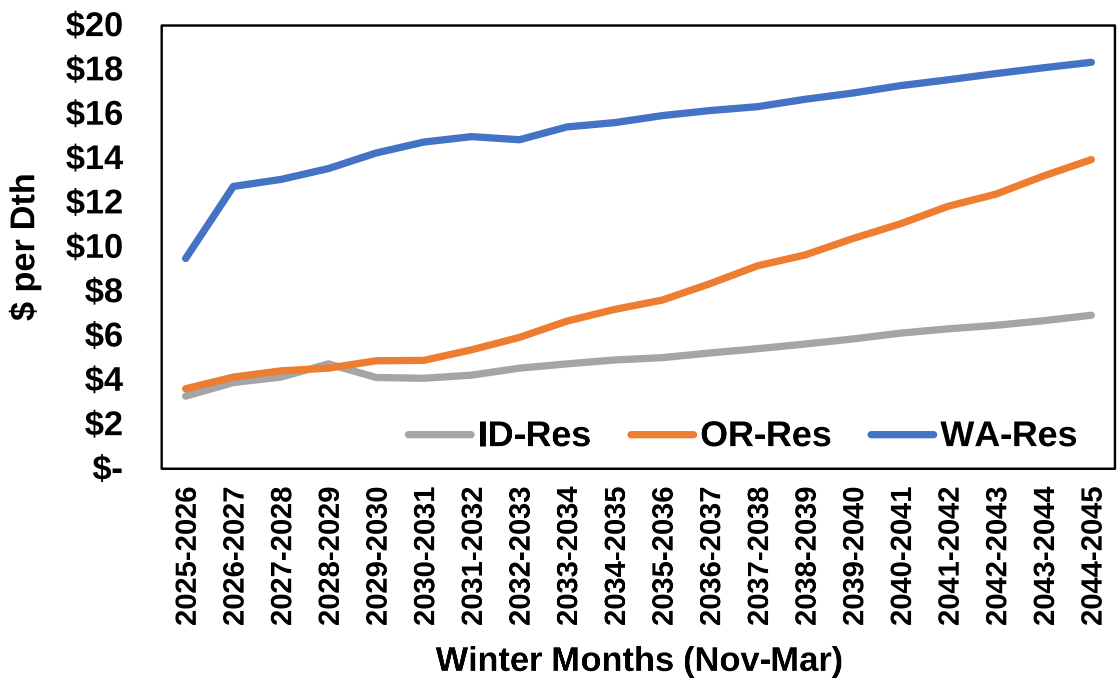
Avoided Cost

The preliminary cost-effective EE potential is determined by applying the stream of annual natural gas avoided costs to the Avista-specific supply curve of EE resources. These costs include commodity costs, distribution deferral values, storage costs, social cost of greenhouse gas at the 2.5% discount rate (Washington only), fuel costs to move the natural gas from point A to point B, and a 10% preference adder for EE for Washington and Oregon among others discussed in Chapter 4.

Avista's contractor, Applied Energy Group (AEG), for Idaho and Washington, with input from Avista's EE team, determines the initial technical EE acquisition values through the Conservation Potential Assessment (CPA) process, and the Energy Trust of Oregon (ETO) handles this process for Oregon for non-transport customers. The initial estimates from AEG and ETO are then decremented from Avista's load forecast. As the model changes based on updated assumptions and costs, updated avoided costs are considered by AEG and ETO to calculate the cost-effective EE potential within Avista's service territories, also known as economic potential. In Oregon and Washington, cost-effectiveness is calculated using the Total Resource Cost (TRC) methodology and in Idaho the Utility Cost Test (UTC) methodology is used. These methodologies are described below. Cost effective EE measures reduce customer demand and provide benefits by avoiding commodity, storage, transportation, and other supply resource costs while reducing the risk of unserved demand in peak weather.

The avoided-cost values represent the unit cost to serve the next incremental unit of demand with a supply-side resource option during a given period. CROME calculates marginal cost data by day, month, and year for each demand area. A summary graphical depiction of avoided winter costs for each jurisdictional area is in Figure 4.1.

Figure 4.1: Residential Winter Avoided Cost (By Jurisdiction)



Idaho and Washington Conservation Potential Assessment

As part of its process for identifying its CPA, Applied Energy Group (AEG) was contracted to perform an independent CPA for Washington and Idaho natural gas. The CPA is Avista's tool to identify the level of EE it anticipates achieving over a 20-year period. Moreover, the CPA is used to identify the EE target for each jurisdiction. The entire CPA report including the methodology used can be found in Appendix 4.

AEG's CPA report documents this effort and provides estimates of the potential reductions in annual energy usage for natural gas customers in Avista's Washington and Idaho service territories from EE efforts from 2026 to 2045. To produce a reliable and transparent estimate of EE resource potential, the AEG team performed the following tasks to meet Avista's key objectives:

- Used information and data from Avista, as well as secondary data sources, to describe how customers currently use natural gas by sector, segment, end use and technology.
- Develop a baseline projection of how customers are likely to use natural gas absent future EE programs.
- Define the metrics future program savings are measured against. This projection used up-to-date technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local EE legislation that will impact EE potential.
- Estimate the technical, achievable technical, and achievable economic potential at the measure level for EE within Avista's service territory over the 2026 to 2045 planning horizon.
- Focused on the potential study to provide a solid foundation for the development of Avista's energy savings targets.

Pursuing Cost-Effective Energy Efficiency

Avista's approach is to pursue all cost-effective EE with reliable and feasible program opportunities for the benefit of our customers and the system. Resource planning relies on the EE program's ability to reach its targets but also to ensure they contribute to an optimized strategy of providing the lowest cost resource.

Cost-effectiveness analysis considers the net benefit derived from EE programs with both the definition of "benefits" and "costs" differing between jurisdictions. The cost-effectiveness of EE programs can be viewed from a variety of perspectives, each of which leads to a specific standardized cost-effectiveness test. The section below outlines and describes various perspectives.

Total Resource Cost Test

Total resource cost (TRC) is from the cost perspective of the entire customer class of a particular utility. This includes not only what customers individually and directly pay for efficiency (through the incremental cost associated with higher efficiency options) but also the utility costs customers will indirectly bear through their utility bill. The TRC considers the impacts from energy benefits, non-energy benefits, greenhouse gas emission costs, administrative costs, and the incremental costs between standard and high efficiency equipment.

Utility Cost Test

1. The Utility Cost Test (UCT) or Program Administrator Cost Test (PAC) compares the reduced utility avoided cost and the full cost (incentive and non-incentive cost) of delivering the utility program.
2. As part of the CPA, each cost test is applied according to the jurisdiction’s primary cost test methodology. Idaho uses the UCT while Oregon and Washington use a modified TRC Test.

Washington and Idaho Energy Efficiency Potential

First-year TRC achievable economic potential in Washington is 92,492 dekatherms. This increases to a cumulative total of 197,255 dekatherms in the second year and 1,950,280 dekatherms by 2045. Figures 4.2 to 4.5 summarize the results for Avista’s Washington service territory by customer class. In these figures EE savings are cumulative for all prior years in the study and the costs are based on the annual cost estimate by year. AEG analyzed EE potential for all segments in the residential, commercial, industrial and transportation classes where Avista has obligations for compliance with the Climate Commitment Act (CCA) as discussed in Chapter 7.

Figure 4.2: Washington Residential - Energy Efficiency Savings and Costs

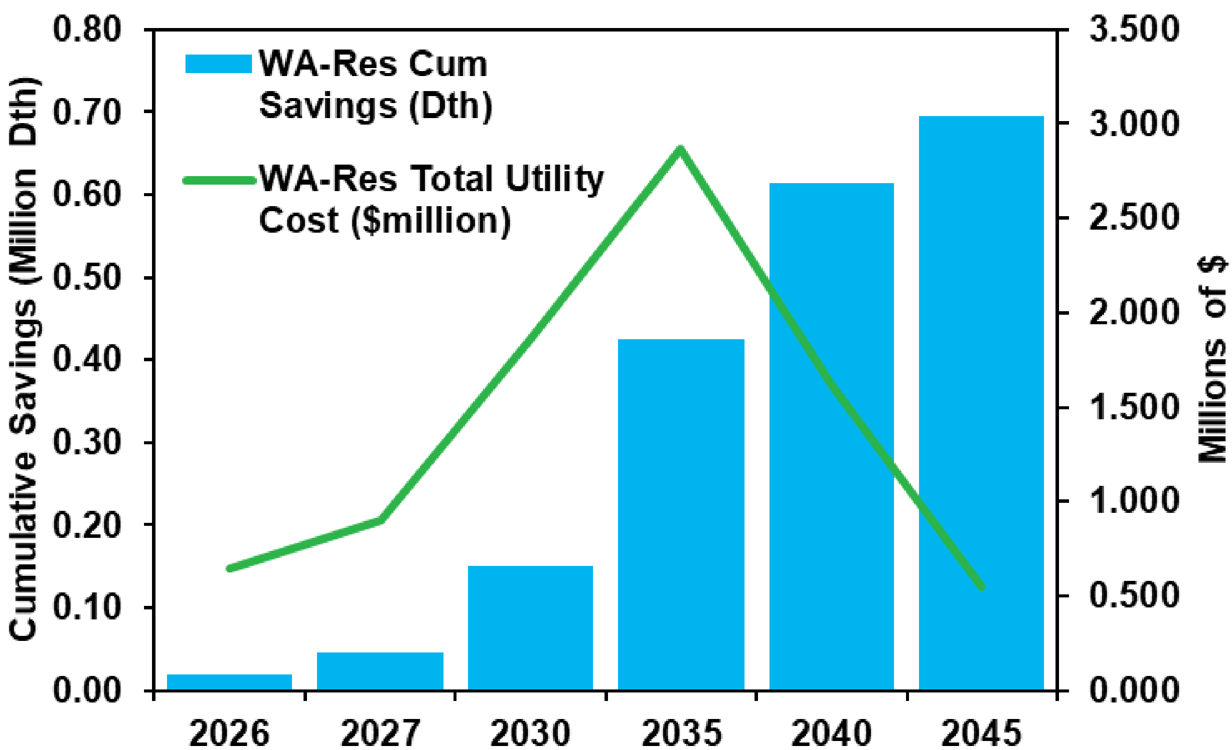


Figure 4.3: Washington Commercial - Energy Efficiency Savings and Costs

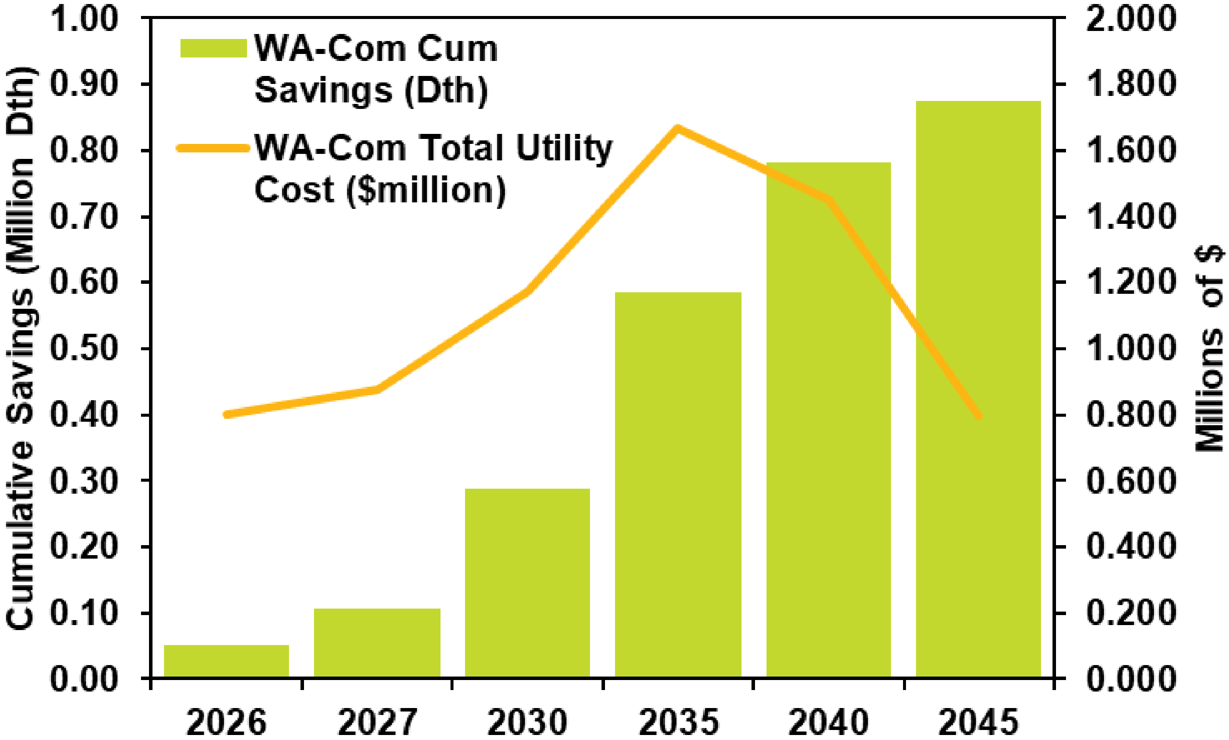


Figure 4.4: Washington Industrial - Energy Efficiency Savings and Costs

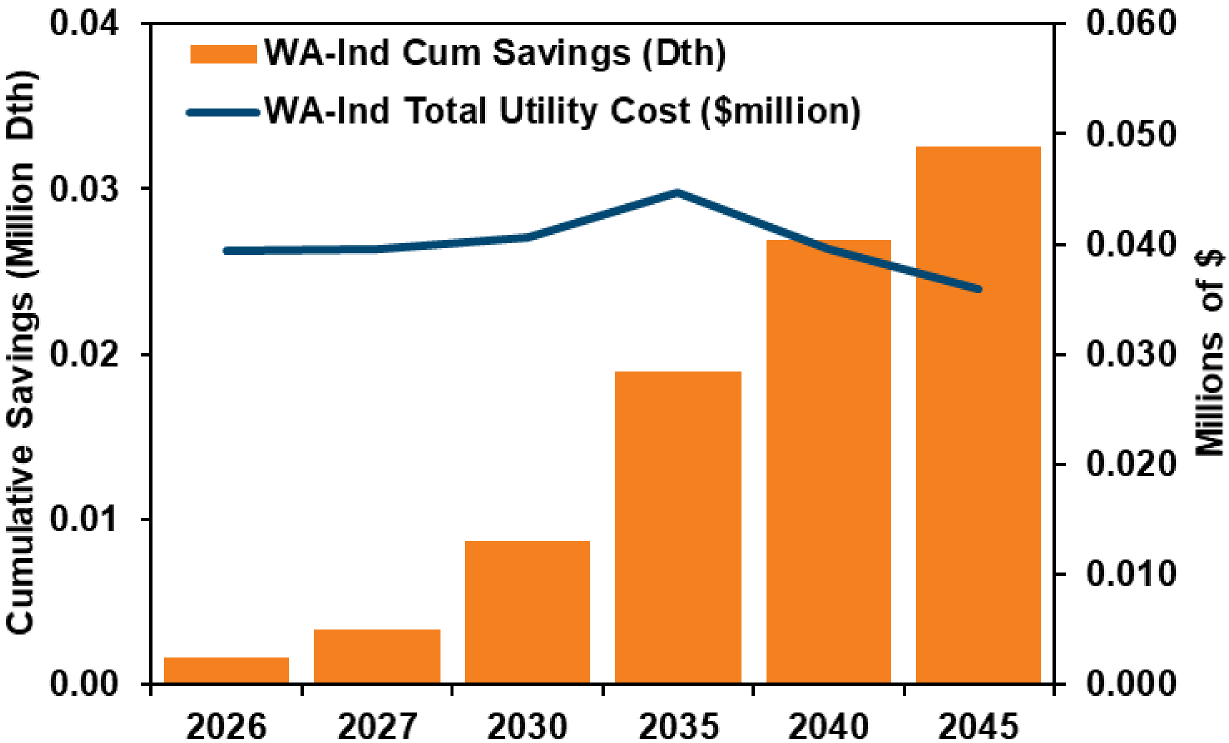
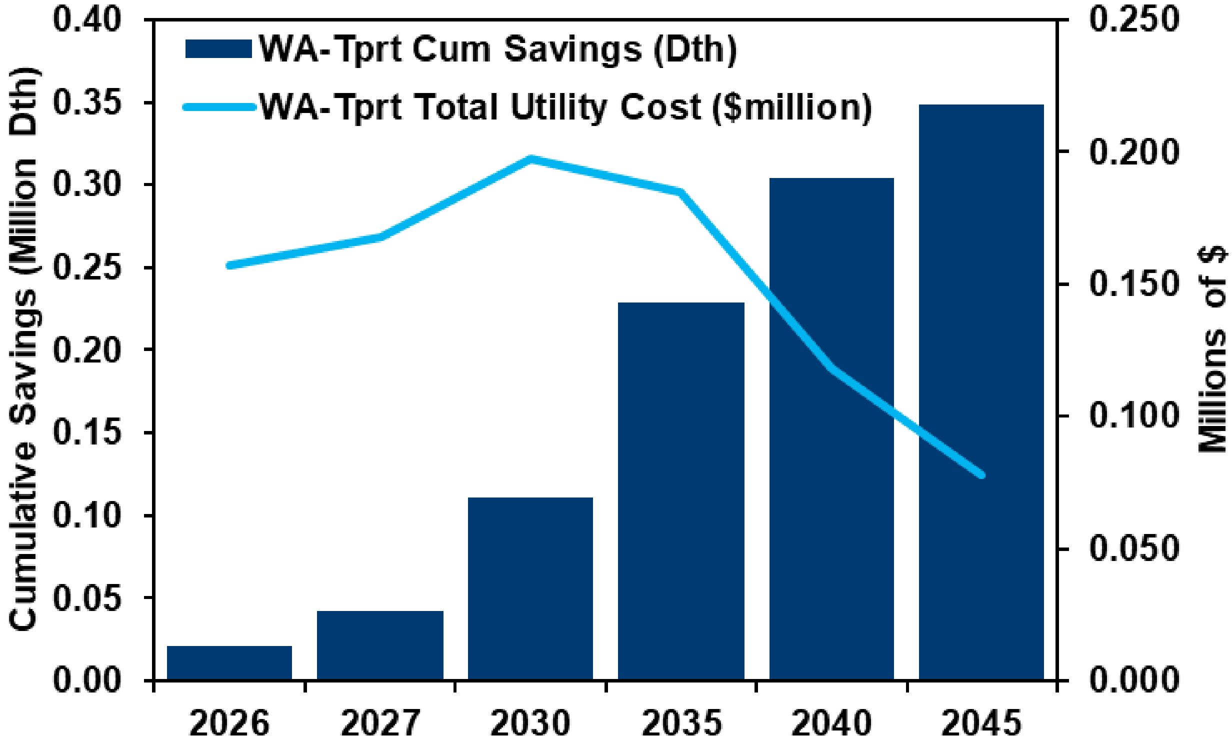


Figure 4.5: Washington Transport - Energy Efficiency Savings and Costs



First-year UCT achievable economic potential in Idaho is 26,257 dekatherms. This increases to a cumulative total of 60,181 dekatherms in the second year and 600,730 dekatherms by 2045. Figure 4.6 summarizes results for residential customers in Avista's Idaho service territory for both cumulative savings in dekatherms (Dth) and annual costs. Figure 4.7 shows the same metrics for commercial customers and Figure 4.8 shows the results for industrial customers.

Figure 4.6: Idaho Residential - Energy Efficiency Savings and Costs

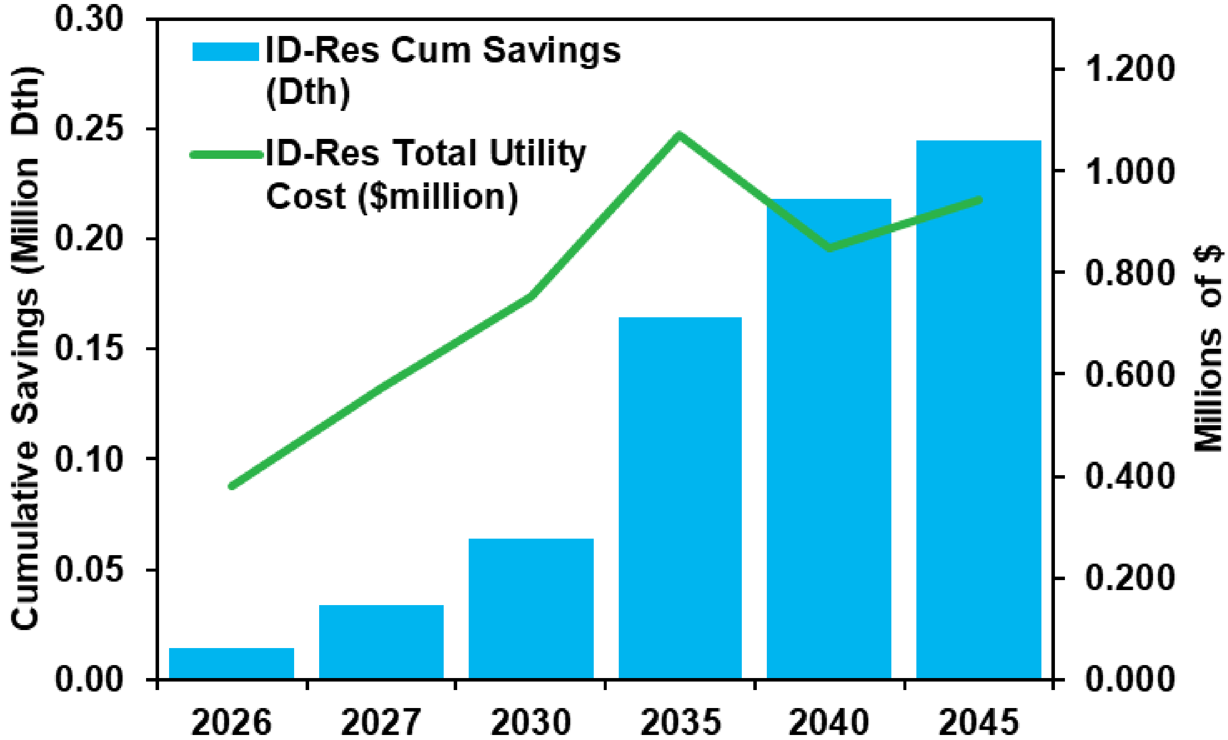


Figure 4.7: Idaho Commercial - Energy Efficiency Savings and Costs

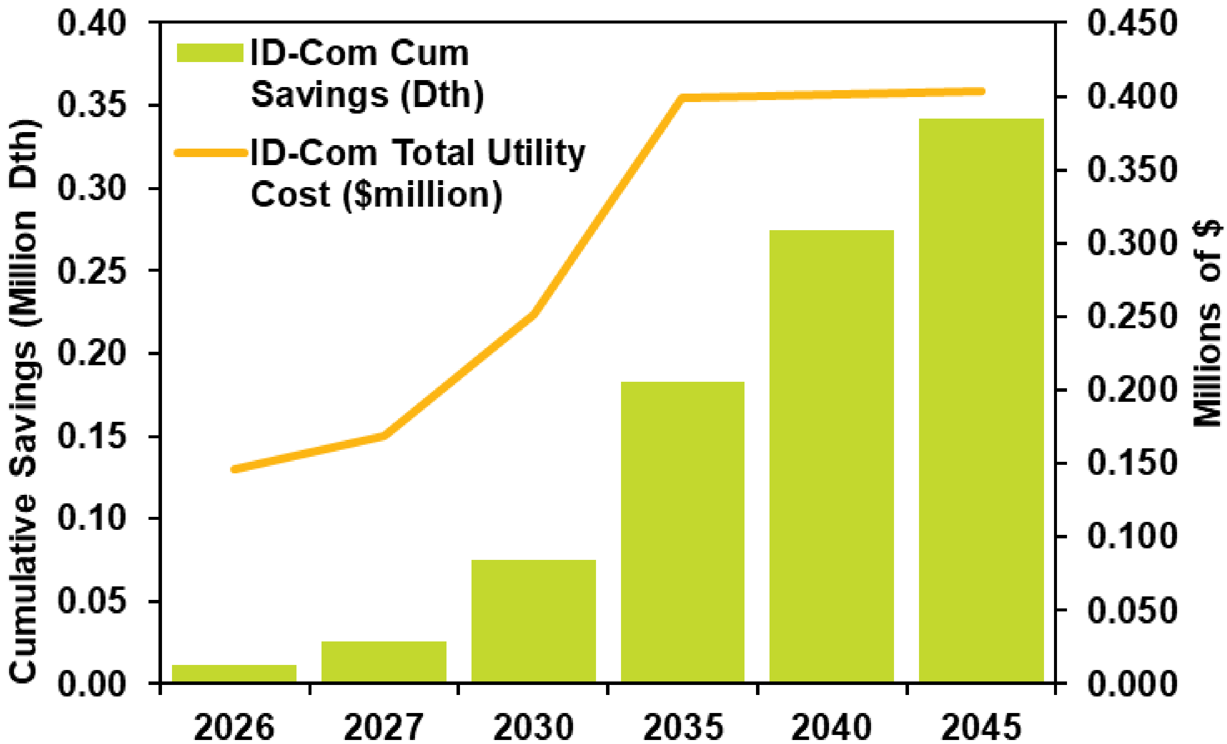
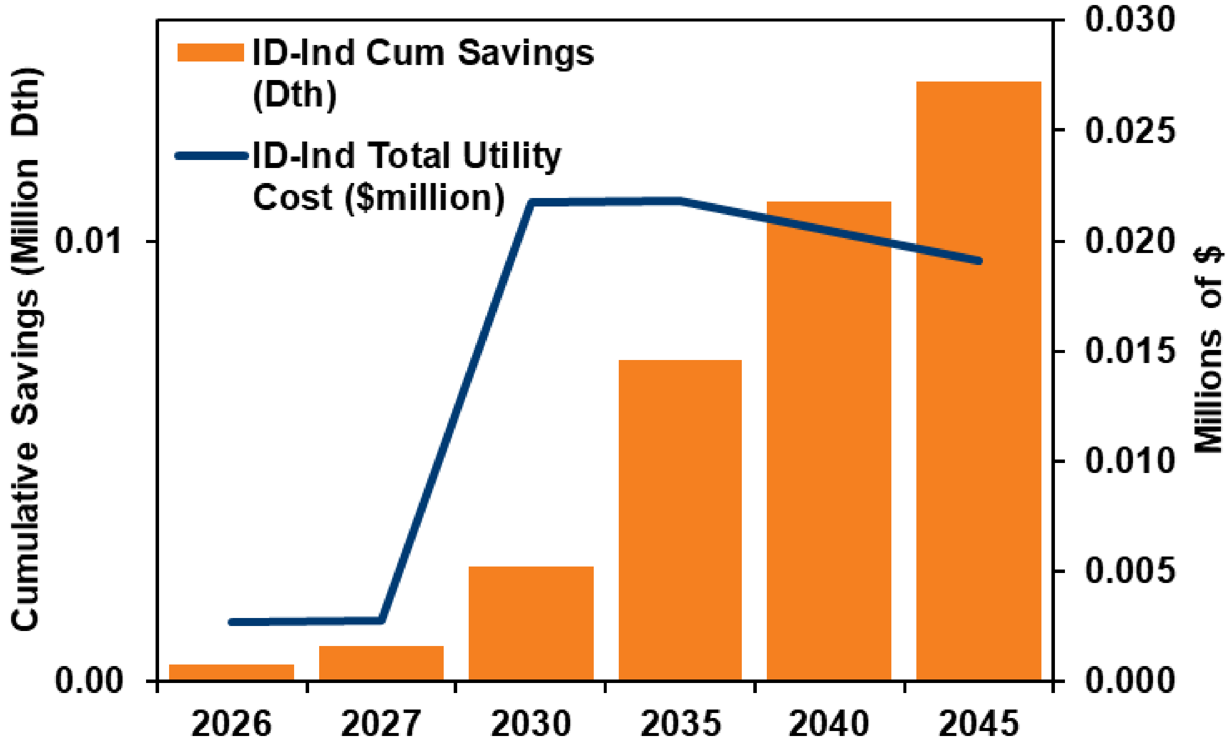


Figure 4.8: Idaho Industrial - Energy Efficiency Savings and Costs



Washington and Idaho Energy Efficiency Targets

The methodology for setting EE targets in Washington and Idaho are consistent with the most immediate two years of the study used to set EE targets. While the current CPA includes 2025 in its analysis, the next cycle for establishing annual EE targets begins in 2026 and runs through 2027 as a biennial period. Therefore, for the purpose of EE target setting, cumulative values are used with the first year of the study, 2025, removed. An additional CPA for Avista's Washington transport customer group was also conducted by AEG.

Tables 4.1 and 4.2 summarize the 2026 and 2027 targets for Washington and Idaho respectively based on results of the CPA.

Table 4.1: Washington 2026-2027 Conservation Target by Sector, (Dth)

Class	2026	2027	Total
Residential	19,132	45,189	64,321
Commercial	50,960	106,715	157,675
Industrial	1,649	3,322	4,971
Total	71,741	155,226	226,967

Table 4.2: Idaho 2026-2027 Conservation Target by Sector, (Dth)

Class	2026	2027	Total
Residential	13,858	33,833	47,691
Commercial	11,998	25,531	37,528
Industrial	401	818	1,219
Total	26,257	60,182	86,439

As measures are identified by the model for potential savings they are ranked by their relative contribution. A thorough review process is utilized to provide context; including a review of assumed ramp rates, availability of the measure, likelihood of adoption within Avista's service territory and previous experience with programs utilizing the selected measures. Based on the review and input from the Company and AEG, measures are either accepted as presented, modified, or removed prior to finalizing the overall targets.

Oregon Energy Efficiency Targets

As technologies and EE policies evolve over the IRP timeline, the Company worked with the Oregon Public Utility Commission (OPUC), Community Action Agencies, ETO of Oregon, and other interested parties to adjust offerings to maximize EE savings. AEG conducted a CPA for Avista's Oregon low-income, and transport customer groups to enable the Company to better understand the potential when designing programs for these customers. Energy Trust of Oregon (ETO) conducted a CPA for Avista's residential, commercial, and interruptible customers which they have served with EE programs since 2017, and interruptible customers starting in 2023. The entire CPA report including the methodology can be found in Appendix 4.

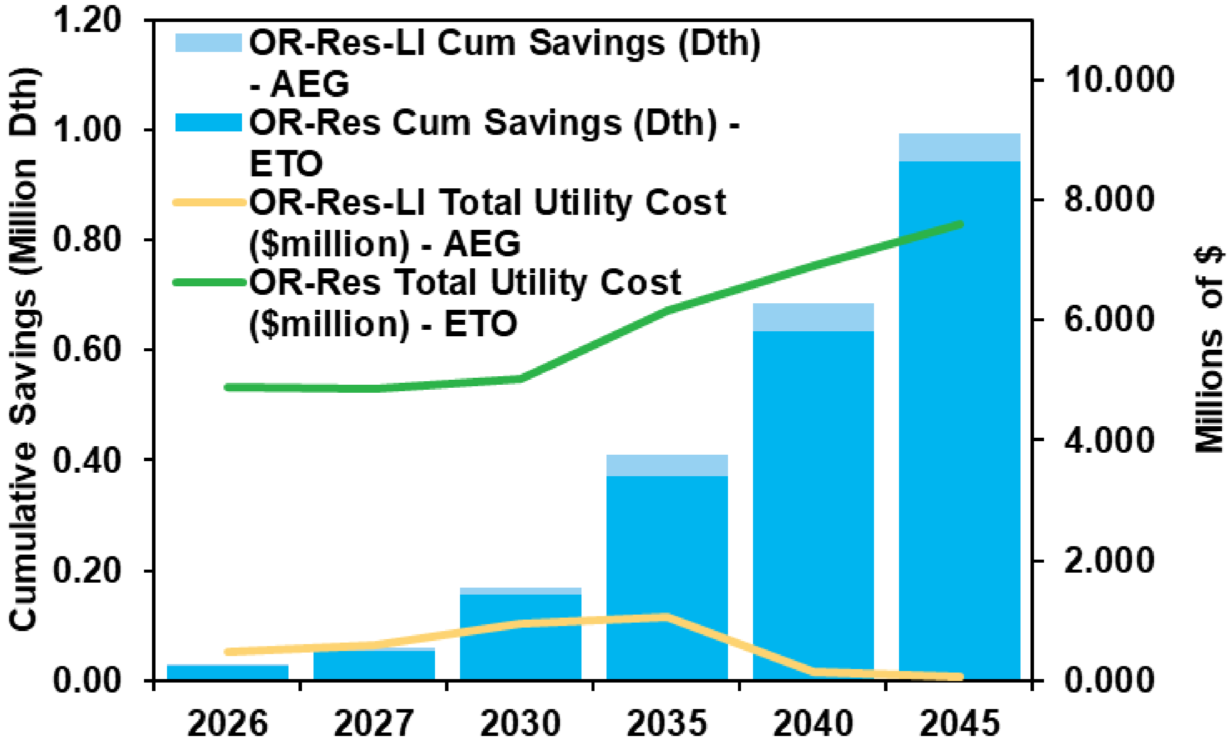
The Company has exclusively worked with Community Action Agencies (Agencies) to implement the Avista Oregon Low Income Energy Efficiency (AOLIEE) Program and is working to expand to other implementing organizations to reach more customers. Agencies primarily install insulation, air sealing, duct sealing, and provide needed health, safety, and minor repair for our low-income customers. The results of identified top EE measures are discussed with the Agencies and ETO to determine the measures that are readily deployable in the near term, but no measures are removed from the overall potential. Throughout 2024, Avista engaged the Agencies administering the AOLIEE Program, the Company's newly formed Equity Advisory Group, ETO, and OPUC staff to discuss new ways to possibly increase customer participation in the Program.

These engagements provide the basis for the Company's requested modifications to its AOLIEE Program for 2025, which were approved by the OPUC in Docket No. ADV 1656/Advice No. 24-08-G[1]. These modifications for the 2025 program year are intended to expand the reach of the existing program and to prioritize energy burdened customers within these communities to ensure EE services available are reaching those that need

[1] https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=24309

them most. Avista will continue to work with interested parties including ETO to ramp up EE programs to reduce the energy burden for low-income customers. Figure 4.9 summarizes the cumulative savings potential results and annual costs for residential customers as estimated by ETO and residential low-income customers as estimated by AEG.

Figure 4.9: Oregon Residential Energy Efficiency Savings and Costs



Avista offers a carbon reduction program via EE for transport customers and began in 2023 and 2024. The results of top efficiency measures are shared and discussed with ETO. Measures such as boiler pipe insulation, steam trap replacement, and strategic energy management[2] were available. The Company will continue to work with interested parties to determine appropriate EE programs for transport customers in 2025. Results for commercial, industrial and transport customers' cumulative energy savings potential and annual costs are shown in Figures 4.10 to 4.12.

[2] https://www.energytrust.org/industry-agriculture/

Figure 4.10: Oregon Commercial Energy Efficiency Savings and Costs

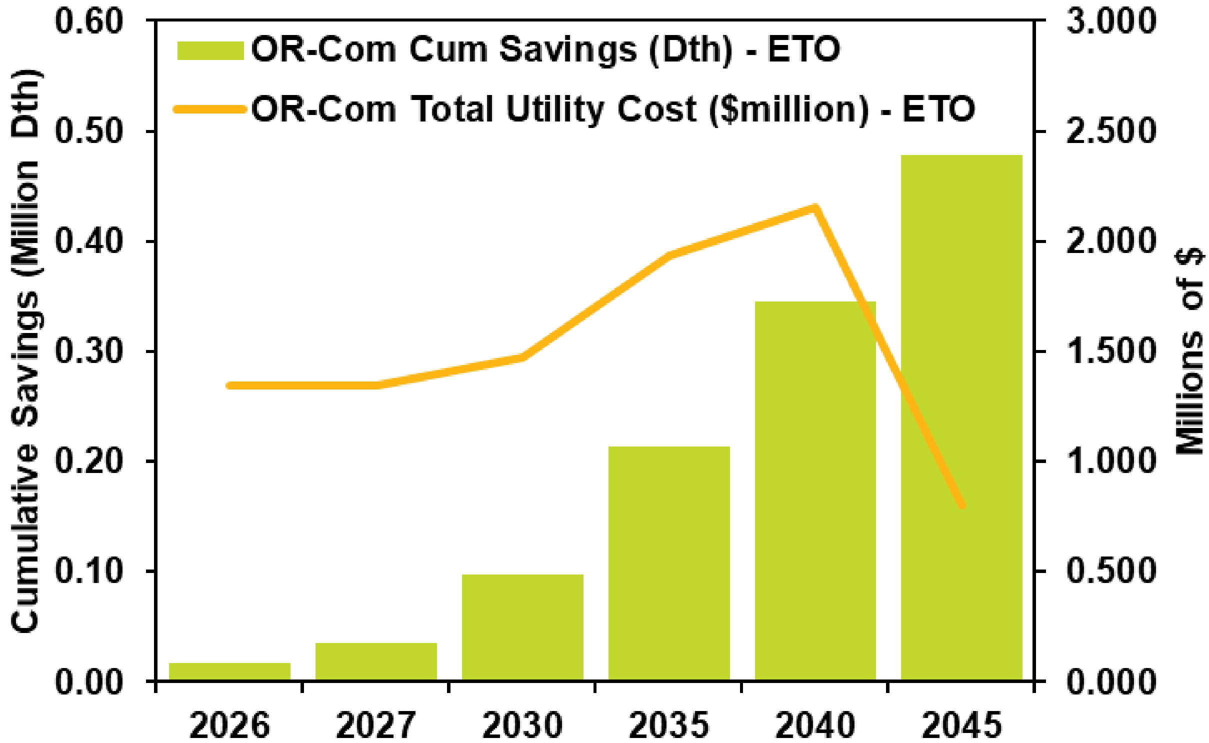


Figure 4.11: Oregon Industrial Energy Efficiency Savings and Costs

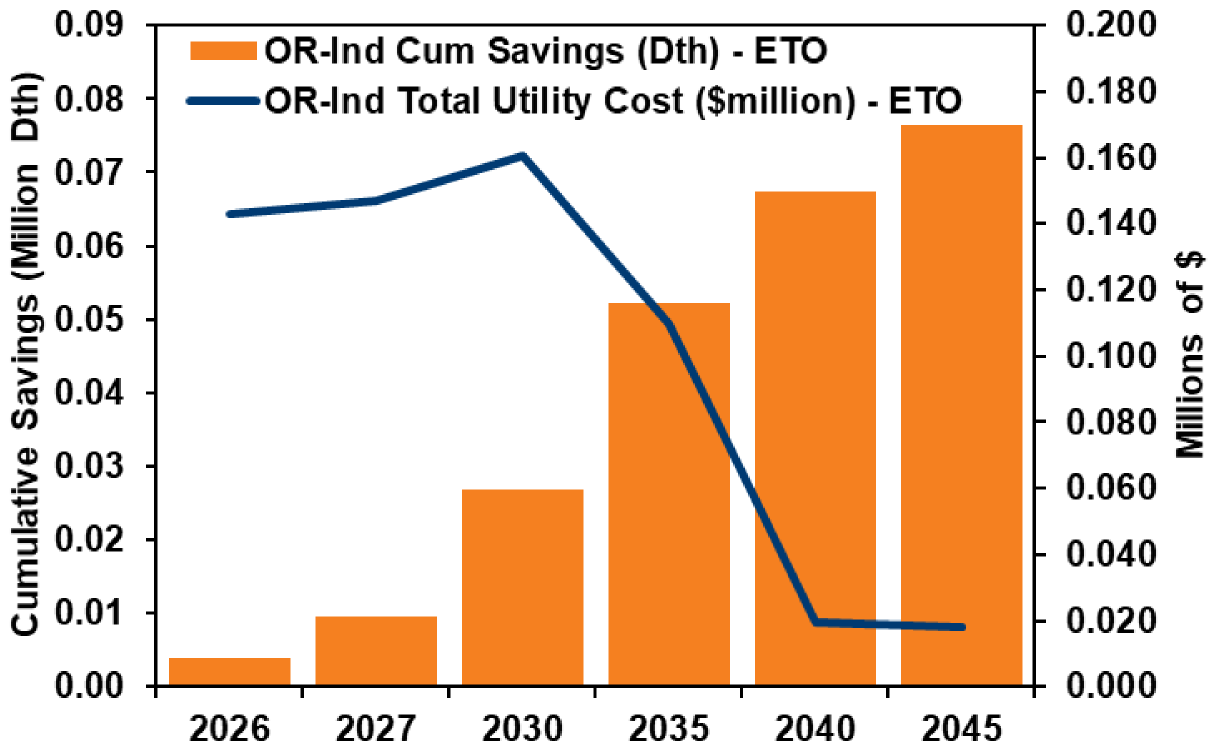
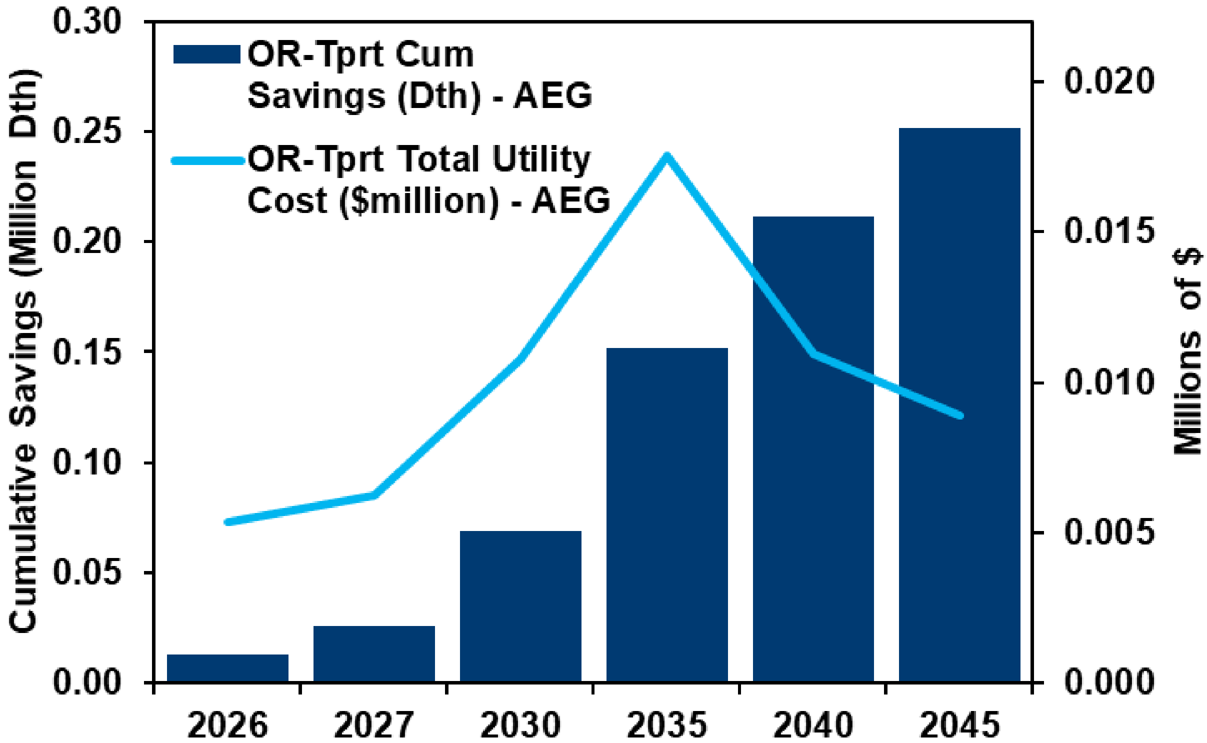


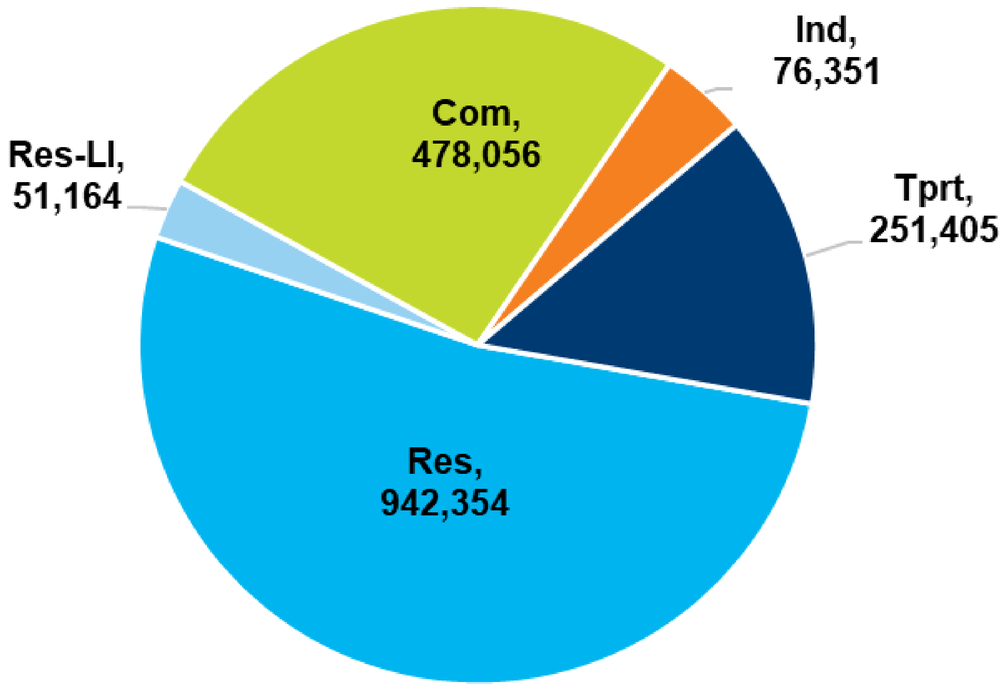
Figure 4.12: Oregon Transport Energy Efficiency Savings and Costs



As implementor of EE programs for the Company's residential, commercial, and interruptible customers. ETO provides a full suite of energy efficiency measures[3], including a moderate-income residential program. Avista supports acquiring all cost-effective potential identified in the CPA and approved by the ETO Board of Directors in the annual Budget and Action Plan.[4] Figure 4.13 shows cumulative potential savings results by 2045 for all customer classes and studies.

[3] https://www.energytrust.org/
[4] https://www.energytrust.org/about/reports-financials/budget-action-plan/

Figure 4.13: 20-Year Cumulative Savings Potential by Type (Dth)



ETO is continuing to implement a dual fuel heating pilot. The Company continues to monitor the need for a targeted EE distribution project in the natural gas system which is discussed further in Chapter 10 of the IRP. A presentation on this effort and status is included in Appendix 11 under TAC presentations[5].

Demand Response

Electric demand response (DR) programs are well known in electricity markets to provide capacity at times when wholesale prices are unusually high, when a shortfall of generation or transmission occurs, or during an emergency grid-operation situation. These types of programs have not garnered much interest in the natural gas markets. However, some pilot programs have emerged throughout the U.S. generating industry attention. The same reasons hold true for considering Natural Gas Demand Response (NGDR) programs as electric DR programs.

Avista retained AEG, who also performs the electric DR potential assessment, to perform the NGDR potential assessment study for Avista's Oregon, Washington, and Idaho service territories.

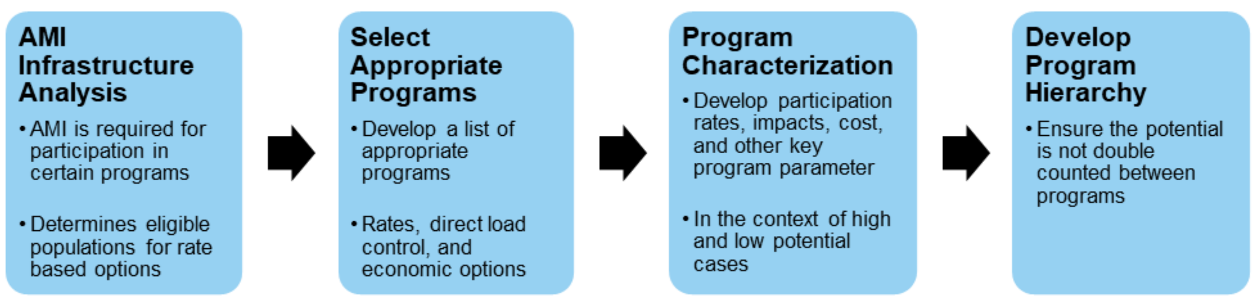
[5] TAC 10

Demand Response Potential Assessment Study

AEG's study estimates the potential magnitude, timing, and cost of a variety of NGDR programs likely available to Avista during winter peak loads over the 20-year planning horizon (2026-2045). These estimates are then modeled in the IRP to determine the value and cost effectiveness of each program on Avista's system. Figure 4.14 outlines AEG's approach to determine potential DR programs in Avista's service territories. The NGDR behavioral program and DLC Smart thermostat program included in this study require Advanced Metering Infrastructure (AMI) as an enabling technology for program performance tracking. Currently Washington is the only state in Avista's service territory with AMI.

AEG used the same market characterization for this potential assessment study as used in the CPA. This became the basis for customer segmentation to determine the number of eligible customers in each market segment for potential NGDR program participation and provides consideration for NGDR program interactions with EE programs. The study then compares Avista's market segments to national NGDR programs to identify relevant NGDR programs for analysis.

Figure 4.14: Program Characterization Process



This process identified the five NGDR program options shown in Table 4.3. Curtailable/controllable NGDR programs represent firm, dispatchable and reliable resources to meet peak-period loads. Overall, DR potential compared to the system peak is very low, even if all DR programs were implemented, it would only reduce peak demand by 0.006% in the first year and 0.047% by 2045.

Table 4.3: NGDR Program Options by Market Segment

DR Program		Participating Market Segment		
Program Type	Program Option	Residential	Commercial	Industrial
Curtailable Controllable DR	DLC Smart Thermostat	X	X	
	Third Party Contracts		X	X
	Behavioral*	X	X	

Demand Response Program Descriptions

Direct Load Control Smart Thermostats

Direct Load Control (DLC) Smart Thermostat programs leverage residential and commercial customer's smart thermostat installation to cycle heating end uses. This program relies on the customer's WiFi for communications. Typically, DLC programs take five years to ramp up to maximum participation levels. Customer participation rate assumptions along with program costs and potential are detailed in Tables 4.4 and 4.5.

Third Party Contracts - Firm Curtailment

Customers participating in a firm curtailment program agree to reduce demand by a specific amount or to a pre-specified consumption level during the event in exchange for fixed incentive payments. Customers receive payments while participating in the program even if they never receive a load curtailment request while enrolled in the program. The capacity payment typically varies with the firm reliability-commitment level. In addition to fixed capacity payments, participants receive compensation for reduced therm consumption. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads have the potential to be counted toward installed capacity requirements. Customer participation rate assumptions along with program costs and potential are detailed in Tables 4.4 and 4.5.

Customers with large process and heating loads that have flexibility in their operations are attractive candidates for firm curtailment programs. However, customers with operations requiring continuous processes, or with relatively inflexible obligations, such as schools and hospitals, generally are not good candidates for curtailment programs. The NGDR study factors in these assumptions to determine the eligible population for participation in this program and assumes a third party would administer all aspects of the program.

Behavioral

A behavioral program is a voluntary usage reduction in response to digital behavioral messaging. These programs typically occur in conjunction with EE home energy report behavioral programs and communicate the request to customers to reduce usage via text or email messages. Customer participation rate assumptions along with program costs and potential are detailed in Tables 4.4 and 4.5.

Natural Gas Demand Response Program Participation

The steady-state participation assumptions rely on AEG's database of existing program information and insights from market research results representing national "best-practice" estimates for program participation.

Once initiated, NGDR options require time to ramp up to a steady state because of the time needed for customer education, outreach, and recruitment; in addition to the physical implementation and installation of any hardware, software, telemetry, or other enabling equipment. NGDR programs included in the AEG study have ramp rates generally with a three- to five-year timeframe before reaching a steady state.

Table 4.4 shows the steady-state participation rate assumptions for each NGDR program option. Eligible customers are calculated by AEG based on market characterization and equipment end-use saturation. The values shown are considered maximum participation rates derived from derated usage, like electric DR programs' participation rates.

Table 4.4: NGDR Program Winter Peak Reduction (Dth)

DR Program	2026	2027	2030	2035	2040	2045
Behavioral	6.68	10.90	27.81	28.38	29.00	29.66
DLC Smart Thermostats - BYOT	9.71	29.26	98.99	101.55	103.85	104.57
Third Party Contracts	10.00	16.12	20.27	20.49	20.72	20.95

Cost and Potential Assumptions

Each NGDR program used in this evaluation was assigned an average load reduction per participant per event, an estimated duration of each event, and a total number of event hours per year. Costs were also assigned to each NGDR program for annual marketing, recruitment, incentives, program development, and administrative support. These resulted in potential demand savings and total cost estimates, as shown in Table 4.5, for each program independently and on a standalone basis. Details on NGDR resource assumptions can be found in AEG's Natural Gas CPA report, Appendix 4.

Table 4.5: System Program Cost (Capital and O&M)

DR Program	2026	2027	2030	2035	2040	2045
Behavioral	$138,932	$157,490	$362,969	$367,038	$371,401	$376,081
DLC Smart Thermostats - BYOT	$279,577	$445,076	$690,351	$625,426	$633,010	$636,258
Third Party Contracts	$70,232	$78,717	$84,521	$84,847	$85,191	$85,553

Building Electrification

State policies in Oregon and Washington may lead customers to electrify their natural gas space and water heating to reduce greenhouse gas emissions. This IRP includes natural gas customer choice fuel switching within the demand forecast and offers specific fuel use electrification as an alternative to natural gas supply as a resource option for both commercial and residential customers. Industrial customers are not considered in this analysis due to the variety of processes and needs of the product being produced. Avista does not have many industrial customers in its territories, with the overall system use of industrial customers around 1% of system demand. Electrification, if cost effective, must always be selected for the remaining study horizon. This is built on the assumption of a customer switching end uses and equipment is unlikely to return to the natural gas system within the study horizon.

Estimating building electrification costs is not a simple analysis as electrification costs vary by structure size, efficiency, shell efficiency, and geographical location in respect to weather. Individual homes at a discrete level and factors may find costs lower than these estimates, while others may be higher based on home size, location, or complexity of heating systems. Further, customers may find extrinsic value in natural gas for resilience benefits and its superior performance compared to electric options. Also, customers may choose to continue to use natural gas fireplaces, clothes dryers, and stoves, even if uneconomic. Another concern with fuel switching is affordability, where low-income customers may not have the ability to pay for an end use conversion creating an equity issue. A second equity issue concerns if higher income customers leave the system, the cost per customer for those that remain on the system would go up, resulting in low-income customers paying a higher cost per customer.

To begin the analysis, the customer type, class and major end use must be separated. Residential and commercial customers' electrification choices are broken into three separate categories.

- Space Heat
- Water Heat
- Other (Cooking, clothes dryer)

End Use Efficiency

The estimated values for these sources are used from the CPA studies provided by AEG and ETO. The second set of assumptions are built around demand variability and certain sets of temperature groupings. As an example, if a customer's furnace is running constantly at 65 Heating Degree Days (HDD's), it does not run more if the HDD's increase with colder temperatures. Climate zone requirements for heating needs differ depending on geographical location as shown in Figure 4.15.

Figure 4.15: Climate Zone Map[6]

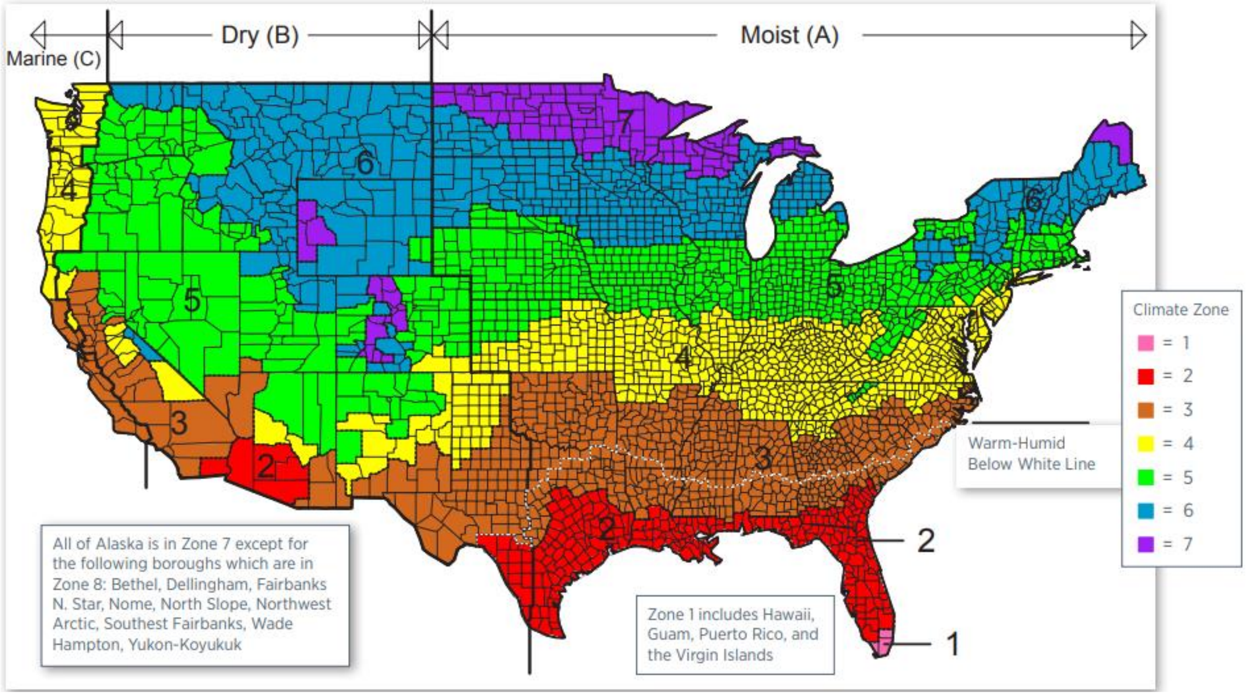
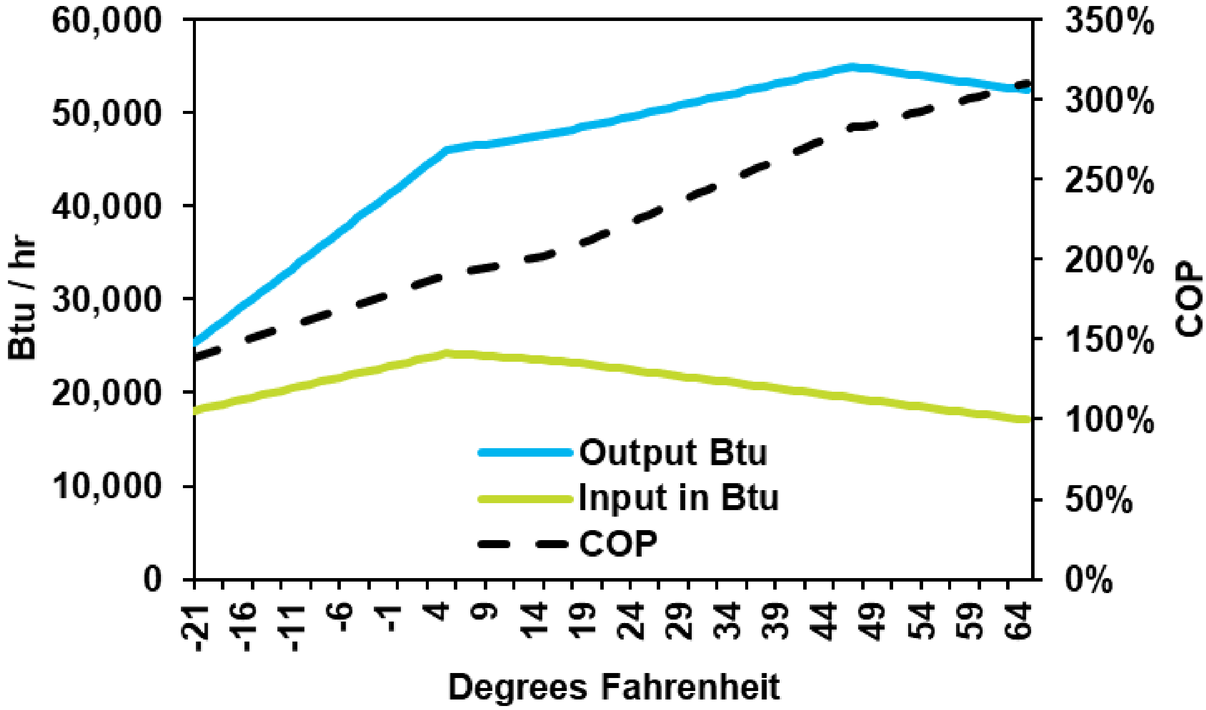


Figure 4.16 shows the modeled heat pump efficiency for a range of temperatures based on the amount of energy needed in the form of kWh (Input Btu) and the amount of energy generated through the heat pump process (Output Btu). While efficiency continues across all temperatures, the Btu per hour of output shows a declining amount of energy provided by heat pumps where auxiliary or backup systems are necessary to provide the necessary energy to fully heat a structure.

[6] International Energy Conservation Code (IECC) Climate Regions

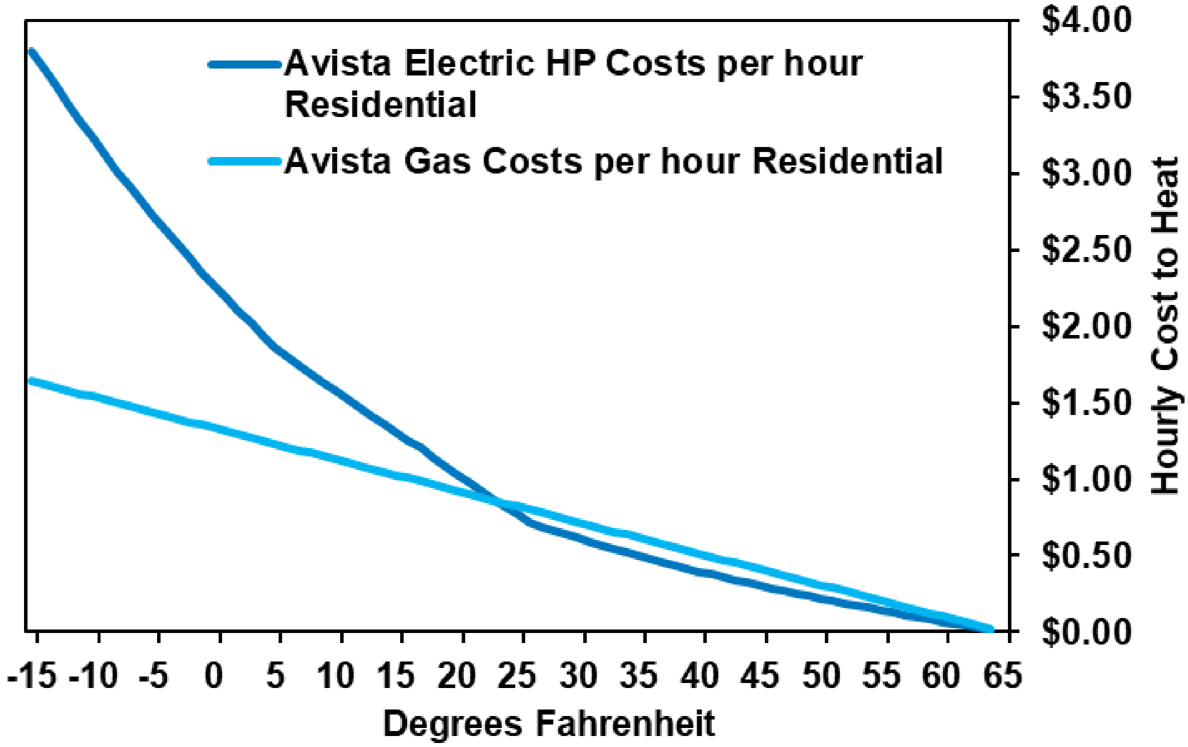
Figure 4.16: Modeled Heat Pump Efficiency[7]



Avista combines this estimate with current Avista rates as of November 1, 2024[8] to estimate costs of using a heat pump as compared to a 95% efficient natural gas furnace at different temperatures of operation as shown in Figure 4.17. Although a heat pump can operate efficiently at low temperatures, the amount of heat output and increased costs may change the customers' use of heat pumps depending on climate in the region. Implications of these efficiencies will come into focus when paired with weather regions, expected energy costs, and conversion costs.

[7] ASHP
[8] Avista Energy Rates and Tariffs in WA, ID, & OR | Avista

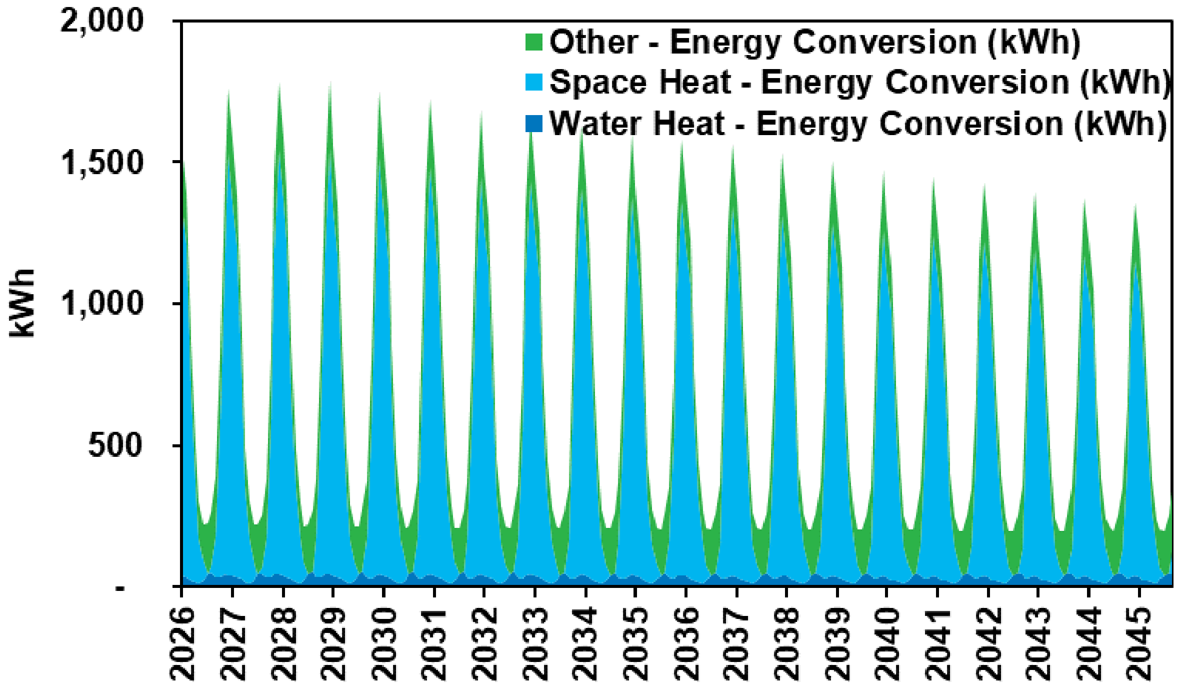
Figure 4.17: Electric and Gas Rate Comparison – WA Residential



Energy Demand

A daily demand forecast is important when considering electrification, otherwise the capacity to serve a peak day is ignored and the system value is not measured appropriately. This method considers daily temperatures as explained in Chapter 3. A demand per customer class and area considers a use per customer energy needed in therms and utilizes the conversion coefficient to estimate efficiency gains from switching to electricity. Efficiency is considered as a generic value across equipment and does not represent ultra-high efficiency units or old lower-efficiency units. These values are then rolled up into a monthly average to consider conversion efficiency and demand by planning area. In Figure 4.18, the bars indicate average monthly use per Washington residential customers in kilowatt hours. These totals include the average customer monthly demand, and all end uses to illustrate the energy needed from the electric grid per customer and end use.

Figure 4.18: Washington Residential Energy Demand - kWh



Conversion Costs

Conversion costs can vary widely by study, location, building size, and structure. Avista used a study by the Rocky Mountain Institute[9] to understand estimated costs by area to help address these ranges. Although the study provides an estimate by major area, no areas were in Avista's natural gas service territory. To help account for these wide-ranging study estimates, Avista considered the generic cost "total to a remodeler". The cost information from this study is illustrated in Table 4.6. For space heating, we assumed a 3-ton heat pump would be required on average for a 2,000 square foot house. Sizing needs estimates for space heat range from a 2.5 ton to a 4 ton for climate zone 4 or 5.[10]

Incentives and grants are estimated based on known programs such as the Inflation Reduction Act. These costs are treated as being removed from the overall conversion cost. Also, these conversion costs are estimated to be recovered over a five-year timeframe with an interest rate by jurisdiction (OR – 6.1%, WA – 6.58%). Payments are recovered monthly and in equal amounts like a mortgage payment. The estimated impact within the study is roughly half of the cost by end use and would be discounted, recovered by the customer or refundable and removed from the total before the monthly payment is estimated.

[9] The Economics of Electrifying Buildings – December 2022
[10] [What Size Heat Pump Do I Need (Heat Pump Size Calculator) - PICKHVAC]

Table 4.6: Estimated Conversion Costs (Dth)[11] – Real 2026$

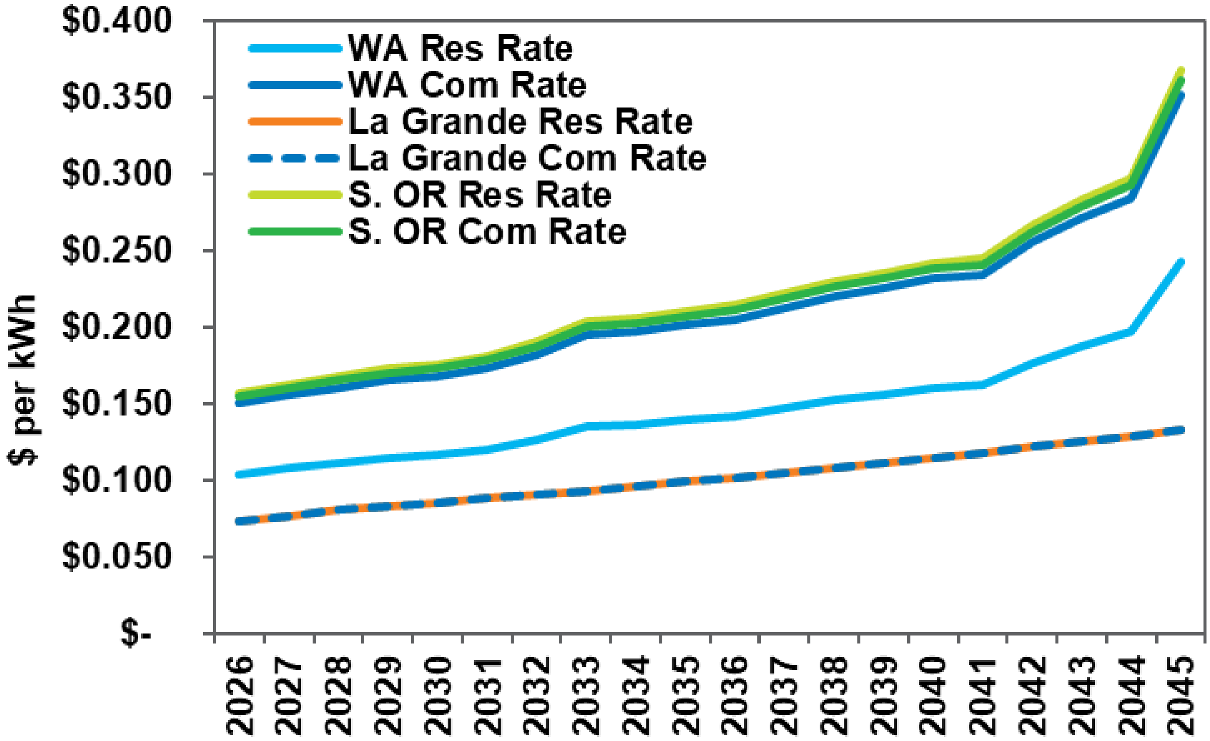
End Use	Equipment	Cost
Space Heating	Air source heat pump, ducted (per ton)	$ 1,998
Water Heating	heat pump water heater	$ 3,528
Cooking	electric range	$ 2,038
Clothes Dryer	electric dryer	$ 1,602

Energy Costs

Monthly costs from conversions are included with the energy demand per kWh. The rate per kWh uses current rates by area and inflates the average of both City of Ashland electric and Pacific Power customers, Klamath Falls-Medford-Roseburg, by the same estimated percentage Avista rates would see in meeting 100% clean goals by 2045. La Grande is served by Oregon Trail Electric and is mainly powered by hydro power from the Bonneville Power Administration (BPA) and assumes a lower rate increase of 3% annually after average rate increases in 2026-2028 of 10.8% for power rate and transmission rate increase of 24%[12] for an estimated total of 5% impact based on their offtake agreement. After 2029, a 3% estimate is broken out as 2% inflation and 1% for new transmission and distribution projects. The Washington territory estimates include 81% of natural gas customers moving to Avista for their electricity needs and 19% lost to other public power providers such as Inland Power & Light, Modern Electric, and VERA. The assumed escalation curves for energy per kWh are included in Figure 4.19. Base costs are not included as it is assumed a natural gas customer is currently using the local electric provider. These costs also include estimated generation, distribution and transmission resources to serve the additional load from the 2025 Avista Electric IRP.

[11] Economics of Electrifying Buildings - RMI
[12] PR-23-24 Increased investments in infrastructure lead to proposed rate increases

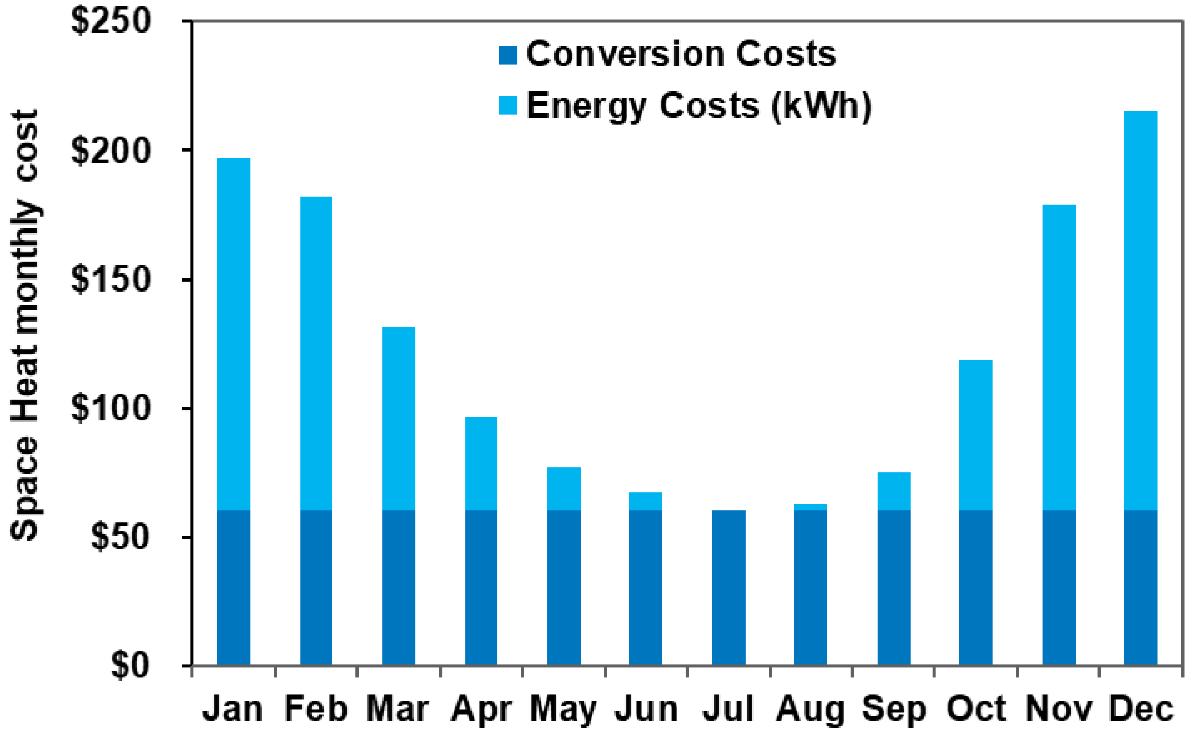
Figure 4.19: Electric Rate Assumption by Area by Class (Nominal $)



Rate Impact

When pairing the cost of energy with the conversion rate in the initial 5 years, a consistent monthly charge is included, even when energy is not being used in times of low demand, such as July and August, as illustrated in Figure 4.20. In the warmer months, the cost for electrification of space heat is from converting the equipment over. In the colder months when more energy is used, the efficiency of electric end uses help to conserve energy.

Figure 4.20: Conversion and Energy Costs - Space Heat WA Residential (2026 $)



Each step of the analysis process is summarized below:

1. Estimated demand by area by customer class by end use of natural gas.
2. Conversion efficiency by area and class by temperature.
3. Conversion cost of the building by class.
4. Rate impact by area and class to meet regional carbon reduction goals and includes additional supply resources, transmission, and distribution cost estimates to provide the energy.
5. Levelized costs per year to consider conversion costs specific to that year for 5 years repayment and expected energy costs for the study horizon.

Levelized Costs

The figures below (Figures 4.21 to 4.24) illustrate the final costs used in the model by end use and class. These costs consider the energy and conversion costs and place into a net present value monthly payment for each year the full costs over the 20-year forecast horizon. This helps to capture changing energy costs and IRA incentives expiring after 2032 or before based on government actions.

Figure 4.21: Space Heat Levelized Costs by Area for Residential Electrification

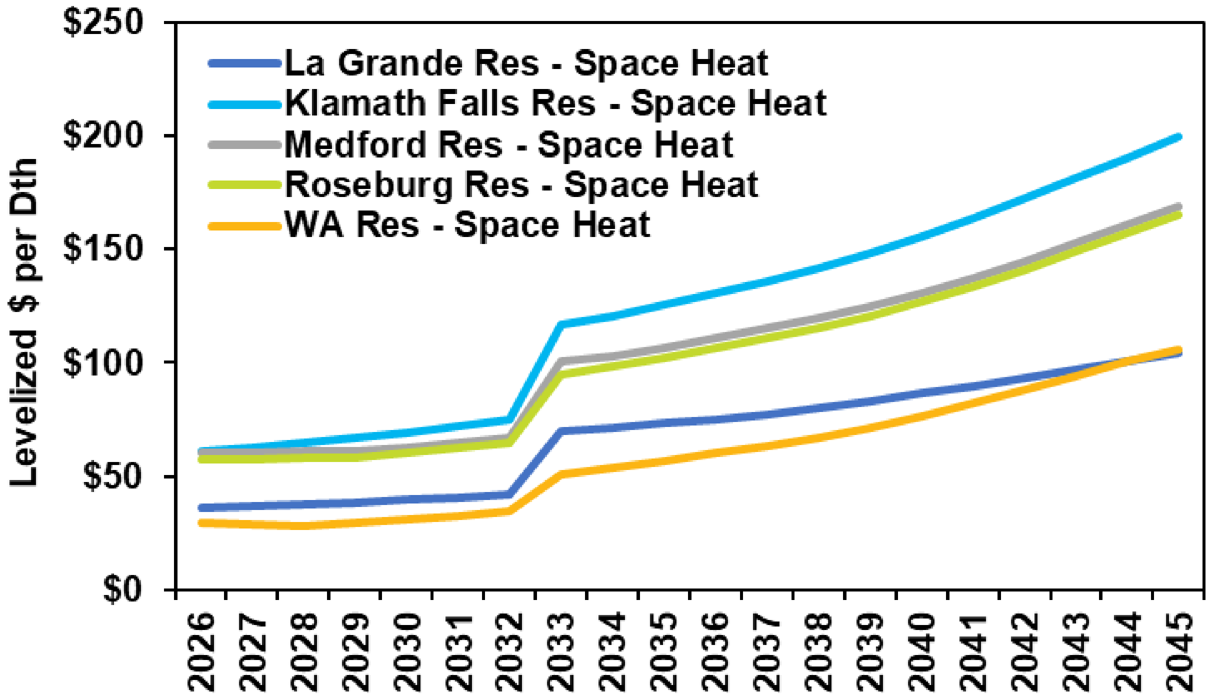


Figure 4.22: Water Heat Levelized Costs by Area for Residential Electrification

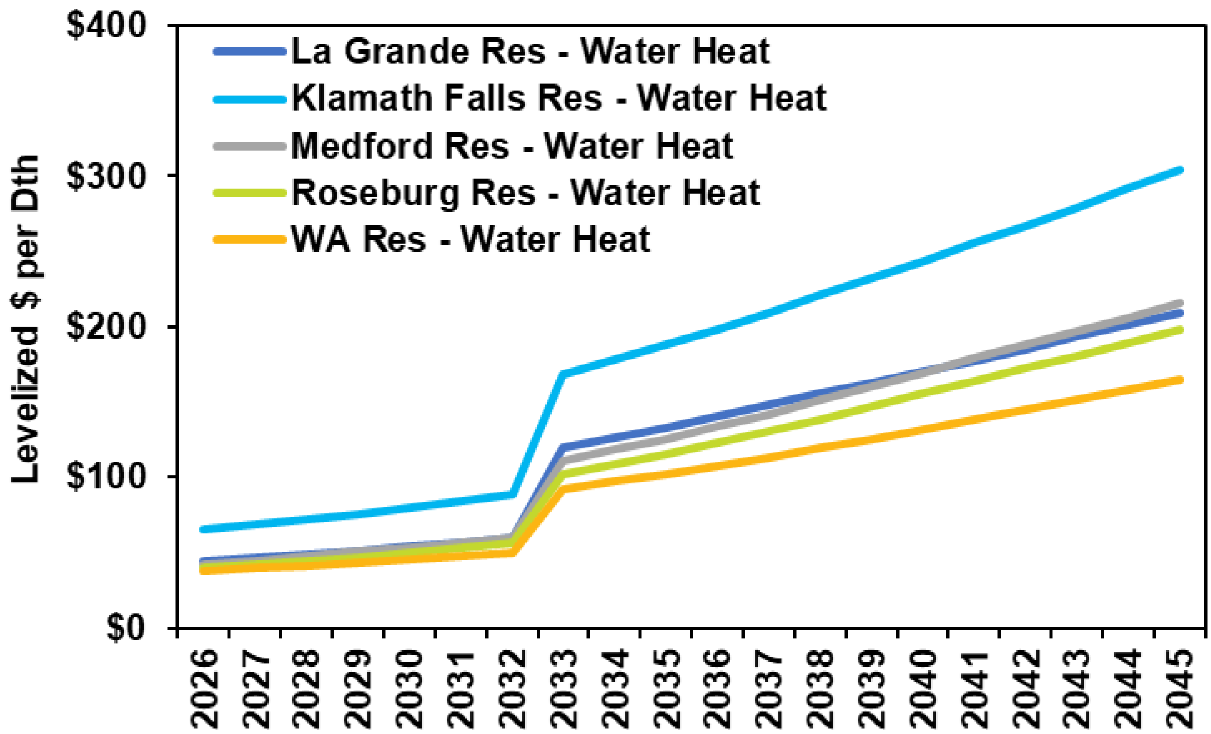


Figure 4.23: Space Heat Levelized Costs by Area for Commercial Electrification

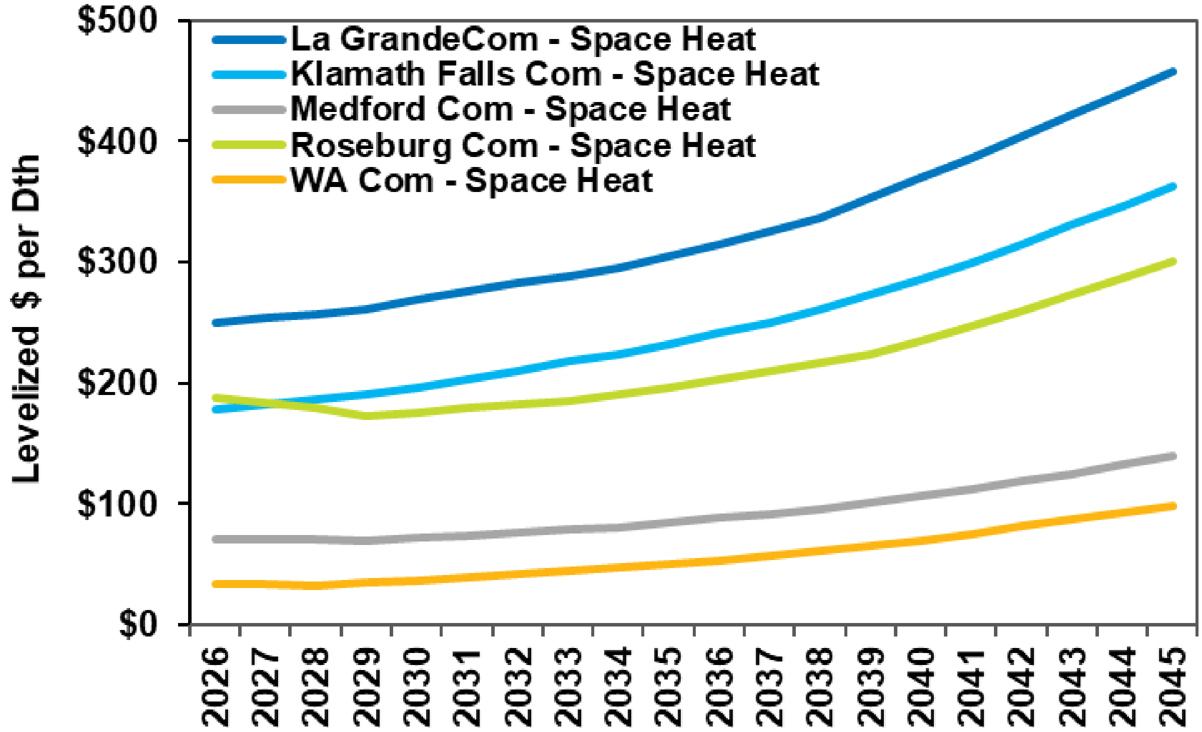
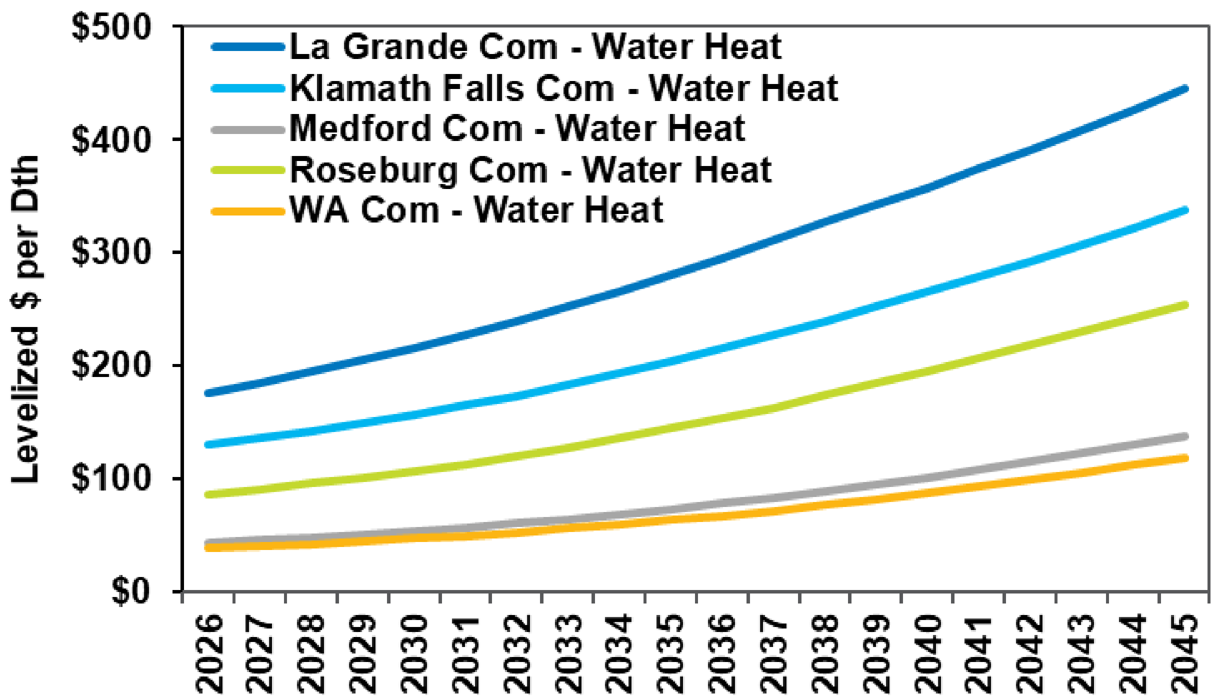


Figure 4.24: Water Heat Levelized Costs by Area for Commercial Electrification



5. Gas Markets and Current Resources

Section Highlights:

- The 20 year levelized price of gas is forecasted to be $4.94 per dekatherm at Henry Hub and $3.66 per dekatherm at AECO.
- Avista procures 83% of its natural gas from Canada.
- Jackson Prairie can supply Avista's normal winter demand for over 30 days.
- Avista's owned and subscribed assets are optimized to help reduce costs to customers.

Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve customers. Supply options include both firm and non-firm natural gas supplies using both firm and interruptible transportation on six interstate pipelines and natural gas storage. Because Avista's customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customer needs. The utilization of these resources varies depending on demand and operating conditions. This chapter discusses the available regional commodity natural gas resources and Avista's procurement plan strategies. The regional pipeline resource options available to deliver the commodity to customers and the storage resources available to provide additional supply diversity enhance reliability, flexibility and favorable price opportunities to meet demand.

Natural Gas Commodity Resources

Supply Basins

The Northwest continues to enjoy a low-cost commodity environment with abundant supply availability, especially when compared to other regions across the globe. This is primarily due to the production in the Northeast and Southern United States. This supply is serving an increasing amount of demand in heavily populated areas in the middle and eastern portions of Canada and the U.S. This dynamic displaces supplies previously delivered from the Western Canadian Sedimentary Basis (WCSB).

Current price forecasts show a long-term regional price advantage for the Western Canada and Rockies natural gas basins as the need for natural gas in the east diminishes. Higher Canadian production paired with limited options for flowing natural gas into demand areas has created a generally discounted commodity in the Northwest when compared to the Henry Hub. Access to these abundant supplies of natural gas and to major markets across the continent has also led to the construction of multiple LNG plants. These LNG plants will be a large addition to North American demand and are on track to more than double by 2028.[1]. A Canadian project (LNG Canada), located in Kitimat

[1] North America's LNG export capacity is on track to more than double by 2028 - U.S. Energy Information Administration (EIA)

B.C. represents one of the largest investments in Canadian history and is expected to export up to 14 million tonnes of LNG per year, or 2 Bcf per day, by 2025. Another Canadian project (Woodfibre LNG), located in Squamish, B.C., plans to come online in 2027, removing potentially 0.3 Bcf from supply available to the Pacific Northwest. It is stated to be the first net zero LNG facility in the world. Due to the limited infrastructure in the Pacific Northwest, the large increase of natural gas demand by either of these facilities moving forward could cause pressure on commodity prices.

Exports to Mexico continue to impact U.S. natural gas demand forecasts. In 2013, Mexico reformed its energy sector allowing new market participants, innovative technologies, and foreign investments. Additionally, this market reformation opened new opportunities for natural gas export to Mexico. Since these market changes, Mexican imports reached as much as 7 Bcf per day on average as compared to less than 2 Bcf per day prior to these changes.

Recent changes to tariffs with Canada and Mexico may impact regional natural gas prices. The modeling work for this IRP was substantially completed prior to the tariff proposals that are still being developed. These costs will be analyzed in the 2027 IRP when they should be finalized.

Regional Market Hubs

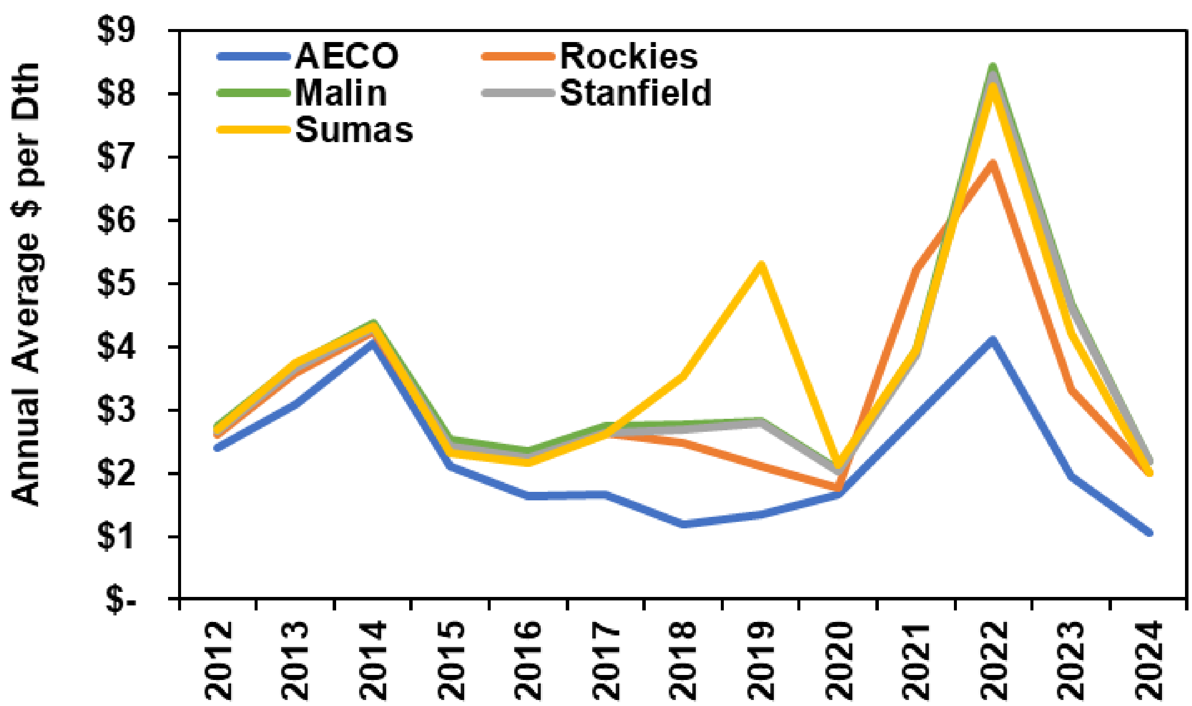
There are numerous regional market hubs in the Pacific Northwest where natural gas is traded extending from the two primary basins. These regional hubs are typically located at pipeline interconnects. Avista’s service area and pipeline rights are near most of the Pacific Northwest regional market hubs enabling flexible access to geographically diverse supply points. These supply points include:

- **AECO** – The AECO-C/Nova Inventory Transfer market center located in Alberta is a major connection region to long-distance transportation systems taking natural gas to points throughout Canada and the United States. Alberta is the primary Canadian exporter of natural gas to the U.S. and historically produces 90% of Canada's natural gas.
- **Rockies** – This pricing point represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain natural gas-producing areas clustered in areas of Colorado, Utah, New Mexico, and Wyoming.
- **Sumas/Huntingdon** – The Sumas, Washington pricing point is on the U.S./Canadian border where the northern end of the NWP system connects with Enbridge’s Westcoast Pipeline and predominantly markets Canadian natural gas from Northern British Columbia.
- **Malin** – This pricing point is at Malin, Oregon, on the California/Oregon border where TransCanada’s Gas Transmission Northwest (GTN) and Pacific Gas & Electric Company connect.

- **Station 2** – Located at the center of the Enbridge's Westcoast Pipeline system connecting to northern British Columbia natural gas production.
- **Stanfield** – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines.
- **Kingsgate** – Located at the U.S./Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Natural gas pricing is often compared to the Henry Hub price given the ability to transport natural gas across North America. Henry Hub, located in Louisiana, is the primary natural gas pricing point in the U.S. and is the trading point used in the New York Mercantile Exchange (NYMEX) futures contracts. Figure 5.1 shows historic annual natural gas prices since 2012 at AECO, Rockies, Malin, Stanfield and Sumas. Hub prices have changed in recent years due to shifts in flows of natural gas specifically coming from Western Canada.

Figure 5.1: Average Annual Index Prices



Northwest regional natural gas prices typically move together; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints, and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts, Avista can often purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

Liquidity is generally sufficient in the day-markets at most Northwest supply points. AECO continues to be the most liquid supply point, especially for longer-term transactions. Sumas has historically been the least liquid of the four major regional supply points (AECO, Rockies, Sumas, and Malin). This relative illiquidity contributes to generally higher comparative prices in the high demand winter months.

Avista procures natural gas with contracts. Contract specifics vary from transaction-to-transaction, and many of those terms or conditions affect commodity pricing. Some of the terms and conditions include:

- **Firm versus Non-Firm:** Most term contracts specify the supply is firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that the supply can be cut for reasons other than force majeure conditions.
- **Fixed versus Floating Pricing:** The agreed-upon price for the delivered natural gas may be fixed or based on a daily or monthly index.
- **Physical versus Financial:** Certain counterparties, such as investment banking institutions, may not trade physical natural gas, but are still active in the natural gas markets. Rather than managing physical supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge prices.
- **Load Factor/Variable Take:** Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a discount or premium compared to standard terms.
- **Liquidated Damages:** Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For this IRP, Avista assumes natural gas purchases under a firm, physical, fixed-price contract, regardless of contract execution date and type of contract. Avista pursues a variety of contractual terms and conditions to capture the most value for customers. Avista‘s natural gas buyers actively assess the most cost-effective way to meet customer demand and optimize unutilized resources.

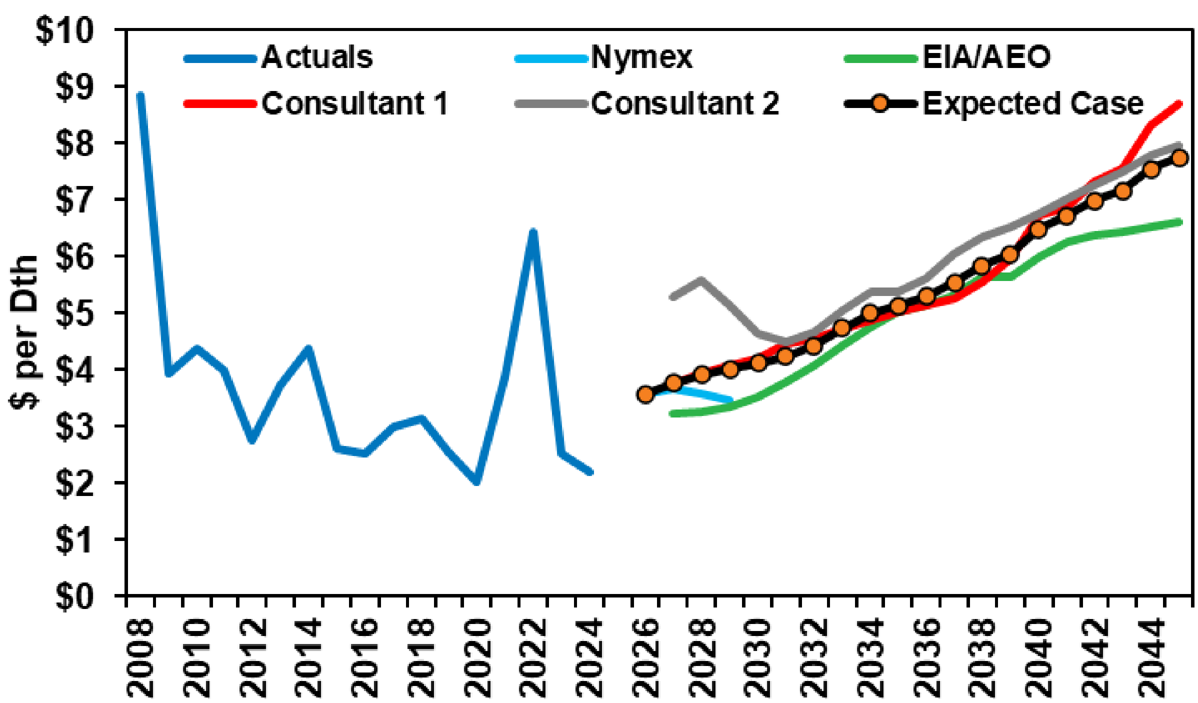
Natural Gas Price Forecasts

Natural gas prices play an integral role in the development of the IRP. It is the most significant variable in determining the cost-effectiveness of energy efficiency measures and of procuring new resources. The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry, including improved drilling methods and technology used in oil and natural gas production, increasing exports to Mexico, and ever-growing LNG exports as discussed above. These factors, in addition to more stringent renewable energy standards and increased need for natural gas-fired generation to back up such resources, are contributing to the rapidly changing natural gas market environment. The uncertainty in predicting future events and trends requires modeling a range of forecasts.

Many additional factors influence natural gas pricing and volatility, such as regional supply and demand issues, weather conditions, storage levels, natural gas-fired generation, infrastructure disruptions, and infrastructure additions, such as new pipelines and LNG terminals. Renewable fuels used in place of fossil natural gas and demand loss from policy implications will alter the variables affecting future natural gas prices. Estimates of these supply resource changes vary between studies as the study date and ultimately drive the primary differences between sources in pricing expectations.

Although Avista closely monitors these factors, we cannot accurately predict future prices across the 20-year horizon of this IRP. As a result, several price forecasts from credible industry experts were used in developing the price forecasts considered in this IRP. Figure 5.2 depicts the annual average prices of these combined forecasts in nominal dollars and includes the expected price resulting from a blending technique.

Figure 5.2: Henry Hub Forecasted Price Study Forecasts (Nominal $/Dekatherm)

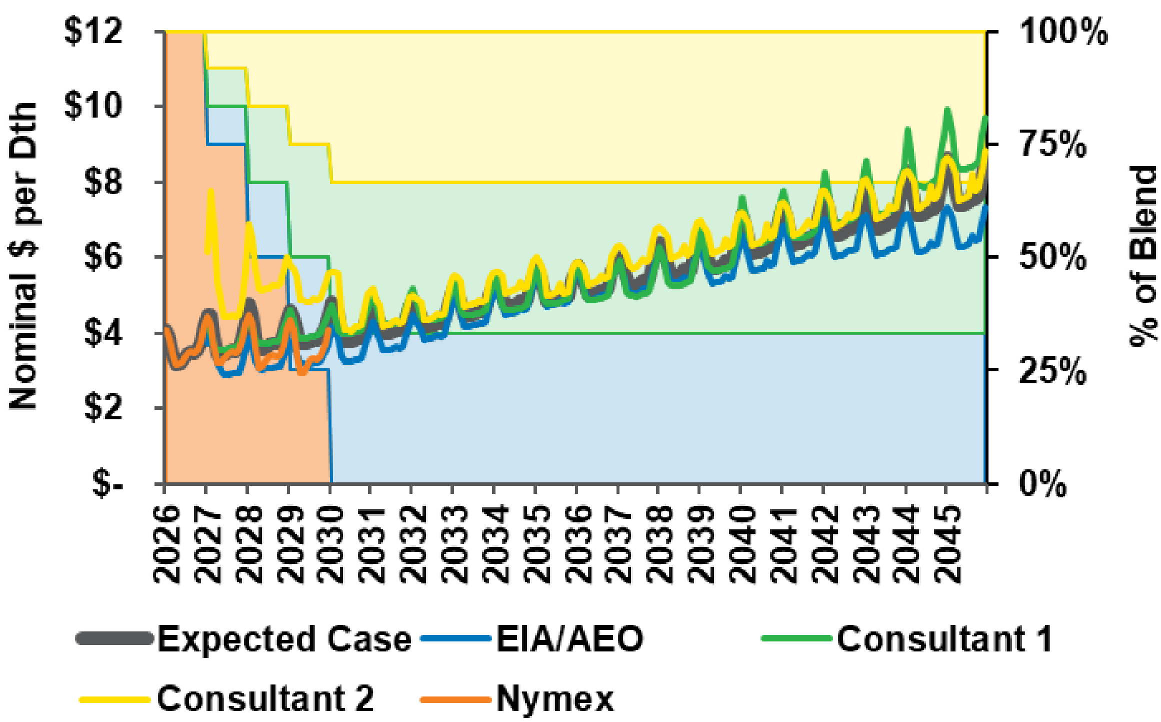


Expected prices at Henry Hub were derived through a blend of forecasts from four sources, including the NYMEX forward strip on November 11, 2025, and the Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO), and the fundamentals based forecasts from two reputable energy market consultants. Combining multiple forecasts improves the accuracy of models because the aggregate market discerns more information than any single entity or model. The weightings applied to each source vary throughout the 20-year forecasting horizon. Due to the high volume of market transactions, expected prices align completely with those of the NYMEX forward strip in the first year. From 2027 through 2029, market activity and speculation on the NYMEX deteriorate significantly, so forecasts from the other three sources, proportionally, are applied by incrementally more weighting. By the year 2030, and through the end of the forecasting horizon, the expected price is the result of an equally weighted blend of forecasts from the EIA's AEO and Avista's two market consultants. The specific weightings applied are described in Table 5.1 and the resulting annual average expected price at Henry Hub is depicted in Figure 5.3. On a levelized basis the real Henry Hub price is $4.94 per dth between 2026 and 2045.

Table 5.1 : Price Blend Methodology

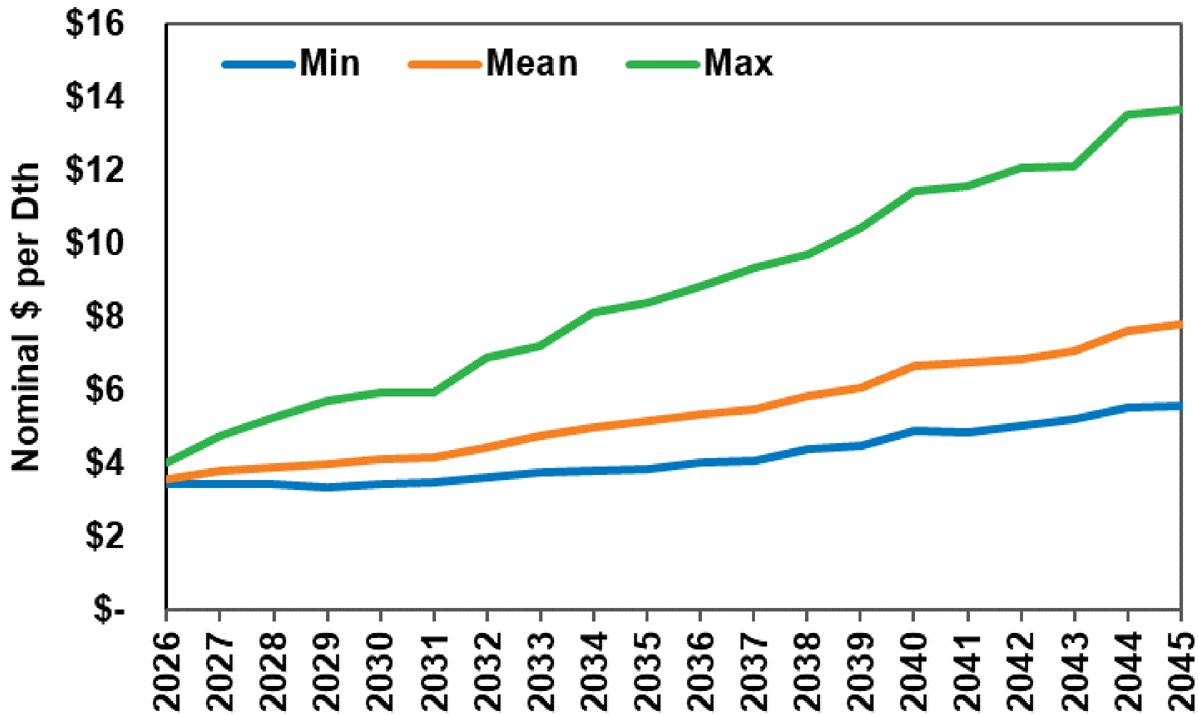
Years	Price Blend Methodology
2026	forward price only
2027	75% forward price / 25% average consultant forecasts
2028	50% forward price / 50% average consultant forecasts
2029	25% forward price / 75% average consultant forecasts
2030 - 2045	100% average consultant forecasts

Figure 5.3: Expected Price with Allocated Price Forecast



To accommodate for the likelihood, the expected prices at Henry Hub do not perfectly reflect future natural gas prices and to help measure price risk in resource planning, a stochastic analysis of 500 possible futures was modeled based on the expected price forecast. Each future contains unique monthly price movements throughout the 20-year forecasting horizon. With the assistance of the TAC, Avista selected the 95th and 25th highest prices in each month from the stochastic results to determine high and low-price curves, respectively. The high, expected, and low-price curves in nominal dollars are illustrated in Figure 5.4.

Figure 5.4: Henry Hub Prices for Low/ Expected/ High Price Scenarios



Henry Hub is in southeastern Louisiana, near the Gulf of Mexico. It is recognized as the most important pricing point in the U.S. due to its proximity to large production basins for U.S. natural gas production and the sheer volume traded in the daily, spot, and forward markets via the NYMEX futures contracts. Consequently, prices at other trading points tend to follow Henry Hub with a positive or negative basis differential. Of the two market consultants Avista uses, only one forecasts basis pricing at the gas hubs modeled throughout the 20-year horizon as a percentage of basis to Henry Hub for all modeled basins as discussed above. This percentage basis is an important consideration, in terms of stochastics, as when Henry Hub pricing gets low enough, simply using a differential can create negative prices at local hubs and is not a reasonable assumption.

The natural gas hubs at Sumas, AECO, and the Rockies (and other secondary regional market hubs) determine Avista's costs. Prices at these points typically trade at a discount in the summer, or negative basis differential, and flip to a higher cost as compared to the Henry Hub in the winter. This is based on supply constraints in the major demand areas such as Seattle, WA and Portland, OR. Figure 5.5 shows the resulting regional prices compared to Henry Hub and Figure 5.6 shows the resulting price distribution for AECO for the 500 future simulations. Table 5.2 shows the annual natural gas price by basin in nominal dollars.

Figure 5.5: Regional and Henry Hub Pricing Comparison

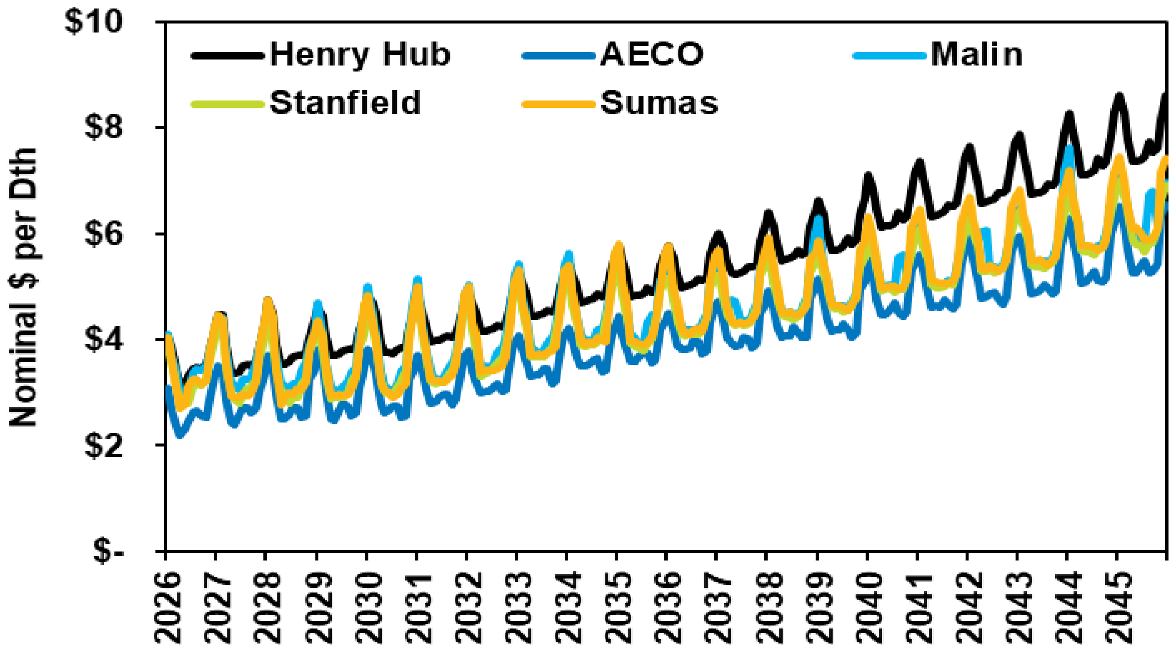


Figure 5.6: AECO - $ per Dth (500 Draws)

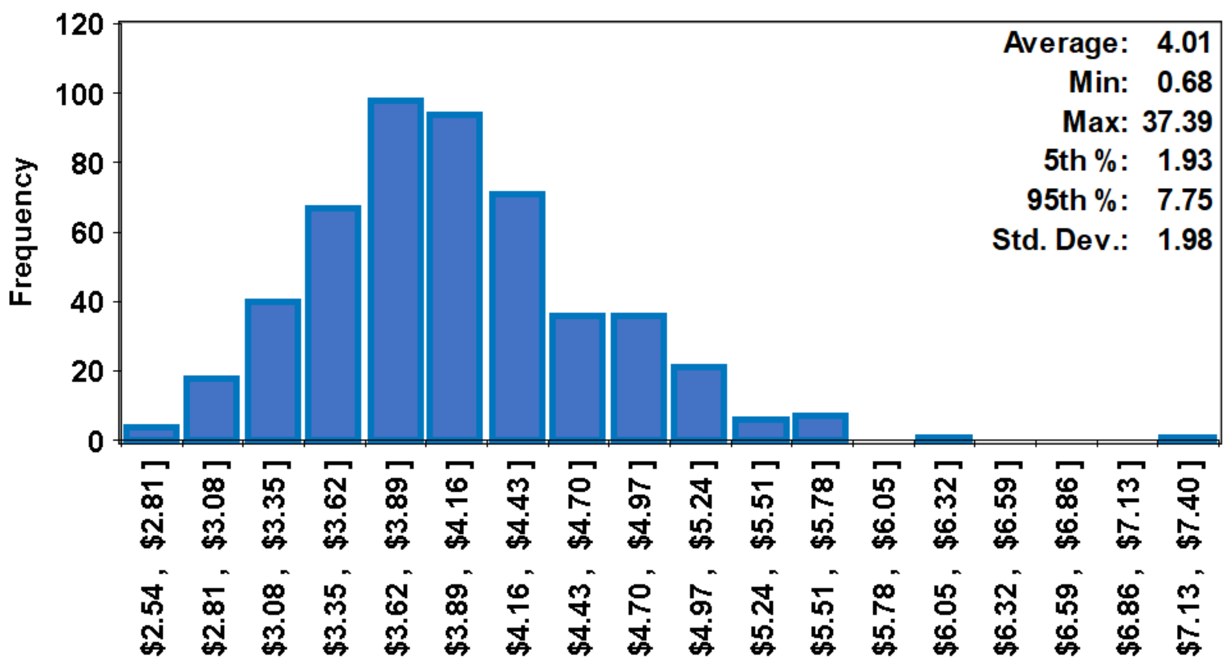


Table 5.2 : Annual Natural Gas Price by Basin (Nominal $)

Years	Henry Hub	AECO	Rockies	Sumas	Malin	Stanfield
2026	$3.57	$2.64	$3.44	$3.35	$3.50	$3.27
2027	$3.77	$2.85	$3.66	$3.45	$3.62	$3.38
2028	$3.92	$2.90	$3.75	$3.47	$3.58	$3.39
2029	$4.01	$2.94	$3.77	$3.46	$3.61	$3.37
2030	$4.12	$3.01	$3.91	$3.60	$3.77	$3.63
2031	$4.25	$3.10	$4.06	$3.75	$3.85	$3.71
2032	$4.44	$3.27	$4.24	$3.92	$4.05	$3.88
2033	$4.74	$3.55	$4.49	$4.21	$4.35	$4.16
2034	$5.00	$3.72	$4.73	$4.42	$4.52	$4.33
2035	$5.14	$3.87	$4.86	$4.52	$4.55	$4.36
2036	$5.30	$4.04	$5.01	$4.63	$4.59	$4.47
2037	$5.54	$4.15	$5.18	$4.75	$4.80	$4.64
2038	$5.84	$4.35	$5.38	$4.93	$4.93	$4.80
2039	$6.04	$4.47	$5.51	$5.05	$5.06	$4.93
2040	$6.50	$4.82	$5.92	$5.43	$5.46	$5.28
2041	$6.72	$4.96	$6.03	$5.55	$5.45	$5.38
2042	$6.99	$5.14	$6.23	$5.80	$5.83	$5.64
2043	$7.16	$5.26	$6.33	$5.93	$5.90	$5.76
2044	$7.54	$5.50	$6.62	$6.22	$6.20	$6.05
2045	$7.83	$5.72	$6.83	$6.46	$6.45	$6.22
Levelized	**$4.94**	**$3.66**	**$4.61**	**$4.29**	**$4.37**	**$4.20**

Transportation Resources

Although proximity to liquid market hubs is important from a cost perspective, supplies are only as reliable as the pipeline transportation from the hubs to Avista’s service territories. Capturing favorable price differentials and mitigating price and operational risk can also be realized by holding multiple pipeline transportation options. Avista contracts for enough diversified firm pipeline capacity from various receipt and delivery points (including storage facilities), to ensure firm deliveries will meet peak day demand. This combination of firm transportation rights to Avista’s service territory, storage facilities and access to liquid supply basins ensure peak supplies are available to serve core customers. The regional map, from the Northwest Gas Association (NWGA), shows the relative capacity of the pipelines and storage capacity (Figure 5.7).

Figure 5.7: Regional Pipeline and Storage Capacity

The major pipelines servicing the region include:

- **Williams - Northwest Pipeline (NWP):**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the U.S./Canadian border in Washington and from the U.S. Rocky Mountain region.
- **TransCanada Gas Transmission Northwest (GTN):** A natural gas transmission pipeline originating at Kingsgate, Idaho, (Canadian/U.S. border) and terminating at the California/Oregon border close to Malin, Oregon.
- **TransCanada Alberta System (NGTL): This** natural gas gathering and transmission pipeline in Alberta, Canada, delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.

- **TransCanada Foothills System: This** natural gas transmission pipeline delivers natural gas between the Alberta - British Columbia border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TransCanada Tuscarora Gas Transmission: This** natural gas transmission pipeline originates at Malin, Oregon, and terminates at Wadsworth, Nevada.
- **Enbridge - Westcoast Pipeline: This** natural gas transmission pipeline originates at Fort Nelson, British Columbia, and terminates at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Washington.
- **El Paso Natural Gas - Ruby pipeline: This** natural gas transmission pipeline brings supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Oregon.

Avista has contracts with all the above pipelines (except for the Ruby Pipeline) for firm transportation to serve customers. Table 5.3 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages with different expiration dates; however, all have the right to be renewed by Avista. This gives Avista, and its customers, the available capacity to meet existing demand now and in the future.

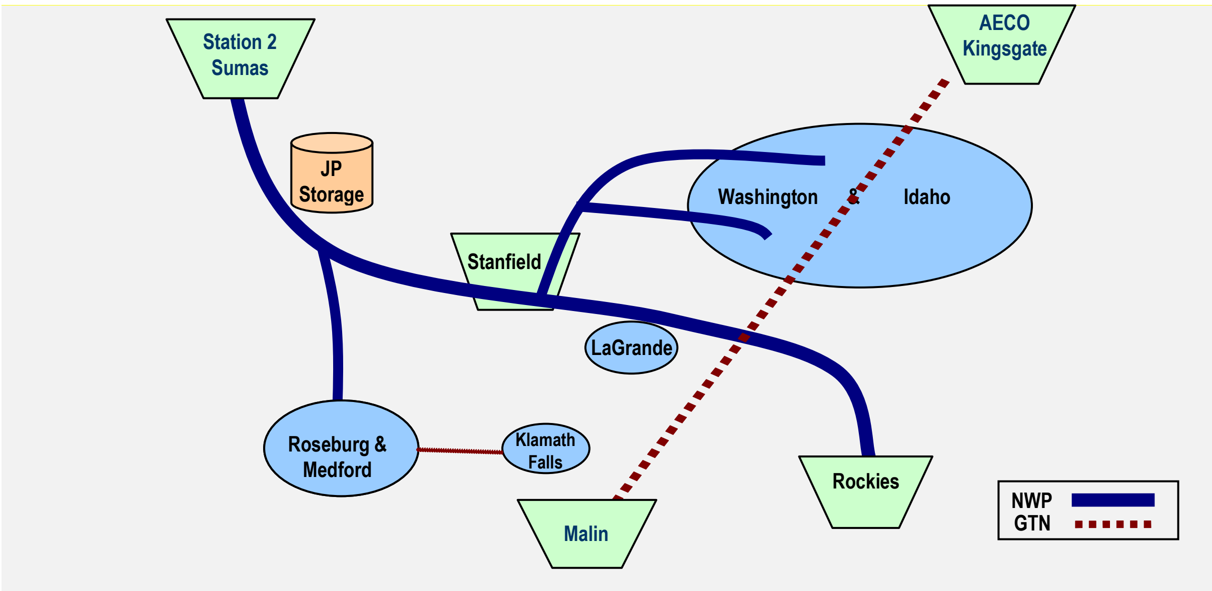
Table 5.3: Firm Transportation Resources Contracted (Dth/Day)

	Avista North		Avista South	
Firm Transportation	Winter	Summer	Winter	Summer
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie	346,667		54,623	

**Represents original contract amounts after releases expire*

Avista defines two categories of interstate pipeline capacity. Direct-connect pipelines deliver supplies directly to Avista's local distribution system from production areas, storage facilities, or interconnections with other pipelines. Upstream pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out-of-area storage facilities. Firm Storage Resources - Max Deliverability is specifically tied to Avista's withdrawal rights at the Jackson Prairie storage facility and is based on the Company's one third ownership rights. This number only indicates how much Avista can withdraw from the facility, as transport on NWP is needed to move it from the facility itself. Figure 5.8 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[2]

Figure 5.8: Direct-Connect Pipelines



Supply-side resource decisions focus on where to purchase natural gas and how to deliver it to customers. Each LDC has distinct service territories and geography relative to supply sources and pipeline infrastructure. Solutions delivering supply to service territories among regional LDCs are similar but are rarely identical.

The NWP system is effectively a fully contracted pipeline. Except for La Grande, OR, Avista's service territories lie at the end of NWP pipeline laterals. The Spokane, Coeur d'Alene, and Lewiston laterals serve Washington and Idaho load, and the Grants Pass lateral serves Roseburg and Medford. Capacity expansions of these laterals would be lengthy and costly endeavors resulting in Avista customers likely bearing most of the incremental costs.

The GTN system, also fully contracted, runs from the Kingsgate trading point on the Idaho-Canadian border to Malin on the Oregon-California border. This pipeline runs directly through or near most of Avista's service territories. Mileage based rates provide an attractive option for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. The NWP and GTN pipelines directly serve Avista's two largest service

[2] Avista has a small amount of pipeline capacity with TransCanada Tuscarora Gas Transmission, a natural gas transmission pipeline originating at Malin, Oregon, to service a small number of Oregon customers near the southern border of the state.

territories, providing diversification and risk mitigation with respect to supply source, price and reliability. NWP provides direct access to Rockies and British Columbia supplies and facilitates optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to serve Avista's service territories.

The rates used in the planning model start with filed rates currently in effect (See Appendix 5 – Current Transportation/Storage Rates and Assumptions). Forecasting future pipeline rates is challenging. Assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience, and informal discussions with regional pipeline owners. Pipelines will file new tariffs with FERC to recover costs at rates equal to their cost of service.

NWP and GTN also offer interruptible transportation services. Interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of natural gas that may be moved. Although the commodity cost per dekatherm transported is generally the same as firm transportation, there are no demand or reservation charges in these interruptible transportation contracts. Avista does not rely on interruptible capacity to meet peak day demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve customers on a peak day in the planning horizon. Since contracts for pipeline capacity are often lengthy and customer demand needs can vary over time, determining the appropriate level of firm transportation is a complex analysis. The analysis includes the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions, and relative costs between pipelines and upstream supplies. This analysis is done on a semi-annual basis and through the IRP. Active management of underutilized transportation capacity either through the capacity release market or engaging in optimization transactions to recover some transportation costs, keeps Avista's portfolio flexible while minimizing costs to customers. Timely analysis is also important to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise (See Chapter 6 for a description of the management of underutilized pipeline resources).

Avista manages existing resources through optimization to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of transportation costs is often market based with rules governed by FERC. The management of long- and short-term resources ensures the goal of meeting firm customer demand in a reliable and cost-effective manner. Unutilized resources like supply, transportation, storage, and capacity can be combined to create products that capture more value than the individual pieces. Avista has structured long-term arrangements with other utilities allowing available resource utilization and provides products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources. Another strategy to mitigate transportation costs is to participate in the daily market to assess if any unutilized capacity has value. Avista seeks daily opportunities to purchase natural gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the natural gas purchased and recover some pipeline charges. The recovery is market dependent and may or may not recover all pipeline costs but mitigates pipeline costs to customers.

Storage Resources

Storage is a valuable strategic resource enabling Avista to manage seasonal and varied demand profiles. Storage benefits include:

- Flexibility to serve peak period needs;
- Access to typically lower cost off-peak supplies;
- Reduced need for higher cost annual firm transportation;
- Improved utilization of existing firm transportation via off-season storage injections; and
- Additional supply point diversity.

While there are several storage facilities available in the region, Avista's existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie Storage facility. Avista optimizes storage as part of its asset management program. This helps to ensure a controlled cost mechanism is in place to manage the large supply found within the storage facility. An example of this storage optimization is selling today at a cash price and buying a forward month contract or selling between different forward months. Since forward months have risks or premiums built into the price the result is Avista locking in the spread. Storage optimization takes place while maintaining the peak day deliverability, at a not to exceed level, to plan for this cost-effective resource to serve customer needs. All benefits of optimization directly help to reduce the costs to our customers.

Jackson Prairie Storage (JP)

Avista is one-third owner, with Williams (NWP)[3] and Puget Sound Energy (PSE), of the Jackson Prairie Storage Project for the benefit of its customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Washington approximately 30 miles south of Olympia, Washington. The total working natural gas capacity of the facility is approximately 25 Bcf. Avista's current share of this capacity for customers is approximately 8.5 Bcf and includes 398,667 Dth of daily deliverability rights. Besides ownership rights, Avista leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

[3] Northwest Pipe

Avista's Natural Gas Procurement Plan

Avista's foundational purpose/goal of the natural gas procurement plan is to provide a diversified portfolio of reliable supply while managing cost volatility. Avista manages the procurement plan by layering in purchases over time based on expected demand per month. Avista does not measure the success of this plan based on a certain cost or loss risk, rather it is considered successful when Avista has secured firm load at a reasonable price while addressing risk inherent within these markets. The measurable objectives monitored toward this goal include a daily financial position of the overall portfolio, tracking of all new and previously transacted hedges, and the tracking of remaining hedges yet to be purchased based on a percentage of forecasted load as specified in the procurement plan.

No company can accurately predict future natural gas prices; however, market conditions and experience help shape Avista's overall approach to natural gas procurement. Avista's procurement plan seeks to acquire natural gas supplies while reducing exposure to short-term price and load volatility. This is done by utilizing a combination of strategies to reduce the impacts of changing natural gas prices in a volatile market. A portion of hedges will be focused on the concentration risk of fixed-price natural gas purchases by utilizing hedge windows, and another portion of hedges will target reducing risk in a volatile market by utilizing risk responsive methods. This allows Avista to set a risk level to help reduce exposure to events outside of the Company's control, such as the Energy Crisis in the early 2000s, the Enbridge pipeline rupture in 2018, or most recently the COVID-19 pandemic and subsequent oil price collapse.

Hedge transactions may be executed for a period of one month through thirty-six months prior to delivery period and are for the Local Distribution Customer (LDC) only. Due to Avista's geographic location, transactions may be executed at different supply basins to reduce overall portfolio risk. This procurement plan is disciplined, yet flexible, allowing for modifications due to changing market conditions, demand, resource availability, or other opportunities. Should economic or other factors warrant, any material changes are communicated to senior management and Commission Staff.

In addition to hedges, the Company's procurement plan includes storage utilization and daily/monthly index purchases. It is diversified through time, location, and counterparty in accordance with Risk Management credit terms.

Market-Related Risks and Risk Management

There are several types of risk and approaches to risk management. The 2025 IRP focuses on three areas of risk: 1) the financial risk of the cost of natural gas system fuel options to supply customers will be unreasonably high or volatile, 2) emissions compliance cost and options in Oregon and Washington and, 3) the physical risk that there may not be enough natural gas system resources (either transportation capacity or the commodity) to serve customers.

Avista's Risk Management Policy describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

Two internal organizations assist in the establishment, reporting, and review of Avista's business activities as they relate to management of natural gas business risks:

- The Risk Management Committee includes corporate officers and senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group coordinates natural gas matters among internal natural gas-related participants and serves as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Gas Supply, Accounting, Regulatory, Credit, Power Resources, and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Strategic Oversight Group provides input and advice.

Strategic Initiatives

Strategic Initiatives are generally defined as the means by which a vision is translated into practice. These initiatives are a group of projects and programs that are outside of the organization's daily operational activities and help an organization achieve a targeted performance.

The two primary roles of the Energy Resources Department (including Natural Gas Supply) are now two-fold:

- Serve Load – Assure adequate and reliable energy supplies for Avista's natural gas customers.

- Manage Resources – Exercise prudent stewardship of Avista's energy supply facilities and related Company resources.

A thorough review and filing is done annually by Avista for a retrospective hedging report submitted to each requesting commission. This report provides a detailed summary of current plan elements and performance over the past year and is filed along with a tariff revision filing of the annual PGA rates.

Resource Utilization

Avista plans to meet firm customer demand requirements in a cost-effective manner. This goal encompasses a range of activities from meeting peak day requirements in the winter to acting as a responsible steward of resources during periods of lower resource utilization. As the analysis presented in this IRP indicates, Avista has ample transportation resources to meet highly variable energy demand under multiple scenarios, including peak weather events.

Avista acquired most of its upstream pipeline capacity during the deregulation, or unbundling, of the natural gas industry. Pipelines were required to allocate capacity and costs to their existing customers as they transitioned to transportation only service providers. The FERC allowed a rate structure for pipelines to recover costs through a Straight Fixed Variable rate design. This rate structure is based on a higher reservation charge to cover pipeline costs whether natural gas is transported or not, and a much smaller variable charge which is incurred only when natural gas is transported. An additional fuel charge is assessed to fuel the compressors required to move the natural gas to customers. Avista maintains enough firm capacity to meet peak day requirements under the PRS in this IRP. This requires pipeline capacity contracts at levels more than the average and above minimum load requirements. Given this load profile and the Straight Fixed Variable rate design, Avista incurs ongoing pipeline costs during non-peak periods.

Avista chooses to have an active, hands-on management of resources to mitigate upstream pipeline and commodity costs for customers when the capacity is not utilized for system load requirements. This active management simultaneously deploys multiple long- and short-term strategies to meet firm demand requirements in a cost-effective manner. The resource strategies addressed are:

- Emissions compliance;
- Pipeline contract terms;
- Pipeline capacity;
- Storage;
- Commodity and transport optimization; and
- Combination of available resources.

Pipeline Contract Terms

Some pipeline costs are incurred whether the capacity is utilized or not. Winter demand must be satisfied, and peak days must be met. Ideally, capacity could be contracted from pipelines only for the time and days needed. Unfortunately, this is not how pipelines are contracted or built. Long-term agreements at fixed volumes are usually required for building or acquiring firm transport. This assures the pipeline of long-term, reasonable cost recovery.

Avista has negotiated and contracted for several seasonal transportation agreements. These agreements allow volumes to increase during the demand intensive winter months and decrease over the lower demand summer period. This is a preferred contracting strategy because it reduces costs when demand is low. Avista refers to this as a front-line strategy because it attempts to mitigate costs prior to contracting the resource. Not all pipelines offer this option. Avista seeks this type of arrangement where available. Avista currently has some seasonal transportation contracts on TransCanada GTN in addition to contracted volumes of TF2 on NWP. This is a storage specific contract and matches up the withdrawal capacity at Jackson Prairie with pipeline transport to Avista's service territories. TF2 is a firm service and allows for contracting a daily amount of transportation for a specified number of days rather than a daily amount on an annual basis as is usually required. For example, one of the TF2 agreements allows Avista to transport 91,200 Dth/day for 31 days. This is a more cost-effective strategy for storage transport than contracting for an annual amount. Through NWP's tariff, Avista maintains an option to increase or decrease the number of days this transportation option is available. More days increases transport costs, so balancing storage, transport, and demand is important to blend of lower cost and reliability.

Pipeline Capacity

After contracting for pipeline capacity, its management and utilization determine the actual costs. The worst-case economic scenario is to do nothing and simply incur the costs associated with this transport contract over the long-term to meet current and future peak demand requirements. Avista develops strategies to ensure this does not happen on a regular basis if possible.

Capacity Release

Through the pipeline unbundling of transportation, the FERC establishes rules and procedures to ensure a fair market developed to manage pipeline capacity as a commodity. This evolved into the capacity release market, and it is governed by FERC regulations through individual pipelines. The pipelines implement the FERC's posting requirements to ensure a transparent and fair market is maintained for the pipeline capacity. All capacity releases are posted on the pipeline Bulletin Boards and, depending on the terms, may be subject to bidding in an open market. This provides the transparency sought by the FERC in establishing the release requirements. Avista utilizes the capacity release market to manage both long-term and short-term transportation capacity needs.

For capacity under contract that may exceed current demand, Avista seeks other parties that may need it and arranges for capacity releases to transfer rights, obligations, and costs. This shifts all or a portion of the costs away from Avista's customers to a third party until it is needed to meet customer demand.

Many variables determine the value of natural gas transportation. Certain pipeline paths are more valuable, and this can vary by year, season, month, and day. The term, volume and conditions present also contribute to the value recoverable through a capacity release. For example, a release of winter capacity to a third party may allow for full cost recovery; while a release for the same period that allows Avista to recall capacity for up to 10 days during the winter may not be as valuable to the third party, but of high value to the Company. Avista may be willing to offer a discount to retain the recall rights during high demand periods. This turns a seasonal-for-annual cost into a peak-only cost. Market terms and conditions are negotiated to determine the value or discount required by both parties.

Avista has several long-term releases, some extending multiple years, providing full recovery of all the pipeline costs. These releases maintain Avista's long-term rights to the transportation capacity without incurring the costs of waiting until demand increases and the capacity is required. At the end of these release terms, Avista surveys the market against the IRP to determine if these contracts should be reclaimed or released, and for what duration. Through this process, Avista retains the rights to vintage capacity without incurring the costs or having to participate in future pipeline expansions that will cost more than current capacity.

On a shorter term, excess capacity not fully utilized on a seasonal, monthly, or daily basis can also be released. Market conditions often dictate less than full cost recovery for shorter-term requirements. Mitigating some costs for an unutilized, but required resource reduces costs to customers.

Segmentation

Through a process called segmentation, Avista creates new firm pipeline capacity for the service territory. This doubles some of the capacity volumes at no additional cost to customers. With increased firm capacity, Avista can continue some long-term releases, or even reduce some contract levels, if the release market does not provide adequate recovery. An example of segmentation is if the original receipt and delivery points are from Sumas to Spokane. Avista can alter this path from Sumas to Sipi, Sipi to Jackson Prairie, Jackson Prairie to Spokane. This segmentation allows Avista to flow three times the amount of natural gas on most days or non-peak weather events. In the event of a peak day, and the transport needs to be firm, the transportation can be rolled back up to ensure the natural gas will be delivered into the original firm path.

Storage

As a one-third owner of the Jackson Prairie Storage facility, Avista holds an equal share of capacity (space available to store natural gas) and delivery (the amount of natural gas that can be withdrawn daily).

Storage allows lower summer-priced natural gas to be stored and used in the winter during high demand or peak day events. Like transportation, unneeded capacity and delivery can be optimized by selling into a future higher priced market. This allows Avista to manage storage capacity and delivery to meet growing peak day requirements when needed.

The injection of natural gas into storage during the summer utilizes existing pipeline transport and helps increase the utilization factor of pipeline agreements. Avista employs several storage optimization strategies to mitigate costs. Revenue from this activity flows through the annual PGA process and passed back to customers.

Commodity and Transportation Optimization

Another strategy to mitigate transportation costs is to participate in the daily market to assess if unutilized capacity has value. Avista seeks daily opportunities to purchase natural gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the natural gas purchased and recover some pipeline charges. The amount of recovery is market dependent and may or may not recover all pipeline costs but does mitigate pipeline costs to customers.

Combination of Resources

Unutilized resources like supply, transportation, storage, and capacity can combine to create products that capture more value than the individual pieces. Avista has structured long-term arrangements with other utilities that allow available resource utilization and provide products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources while maintaining the rights to utilize the resource for future customers' needs.

Resource Utilization Summary

Avista manages the existing resources to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of costs is often market-based with rules governed by the FERC. Avista is recovering full costs on some resources and partial costs on others. The management of long- and short-term resources meets firm customer demand in a reliable and cost-effective manner.

Renewable Natural Gas

Avista currently purchases renewable natural gas using Renewable Thermal Credits (RTCs). Avista contracts using a project construct where Avista is the purchaser of a smaller volume of a total project's RTCs, and the remaining environmental benefits are sold. In this agreement a certain percentage can be claimed and transferred to Avista when called upon while the remainder are sold into the Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) markets to help offset the total cost of the RTCs obtained. Using this construct, Avita's percentage of RTCs is adjustable and can be optimized depending on market conditions in the RIN and LCFS markets in addition to Avista's needs based on climate programs, although pricing is subject to the value of alternative markets. Avista's expected RTC greenhouse gas reduction volumes from these arrangements are shown in Figure 5.9 and the expected pricing per metric ton is shown in Figure 5.10 and reduces greenhouse gas emissions as per the final rules of the CCA and CPP.

Figure 5.9: Avista Contracted RTCs Total Volume

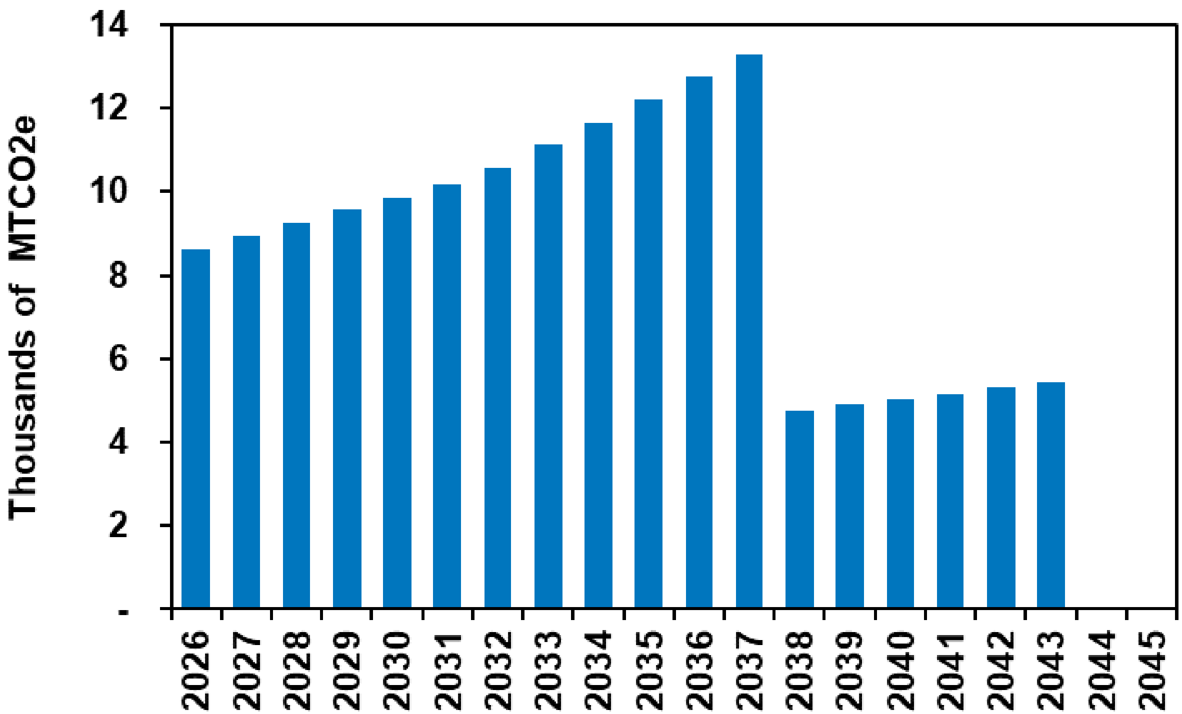
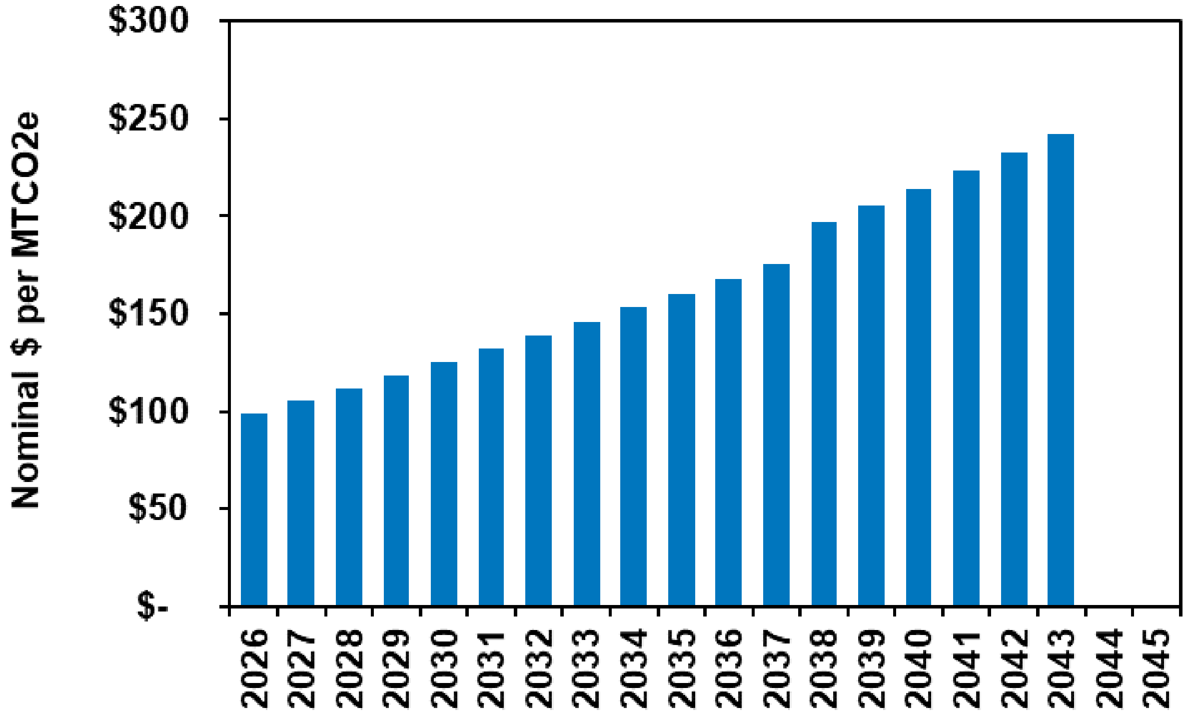


Figure 5.10: Avista Average Expected Price of RTCs Under Contract



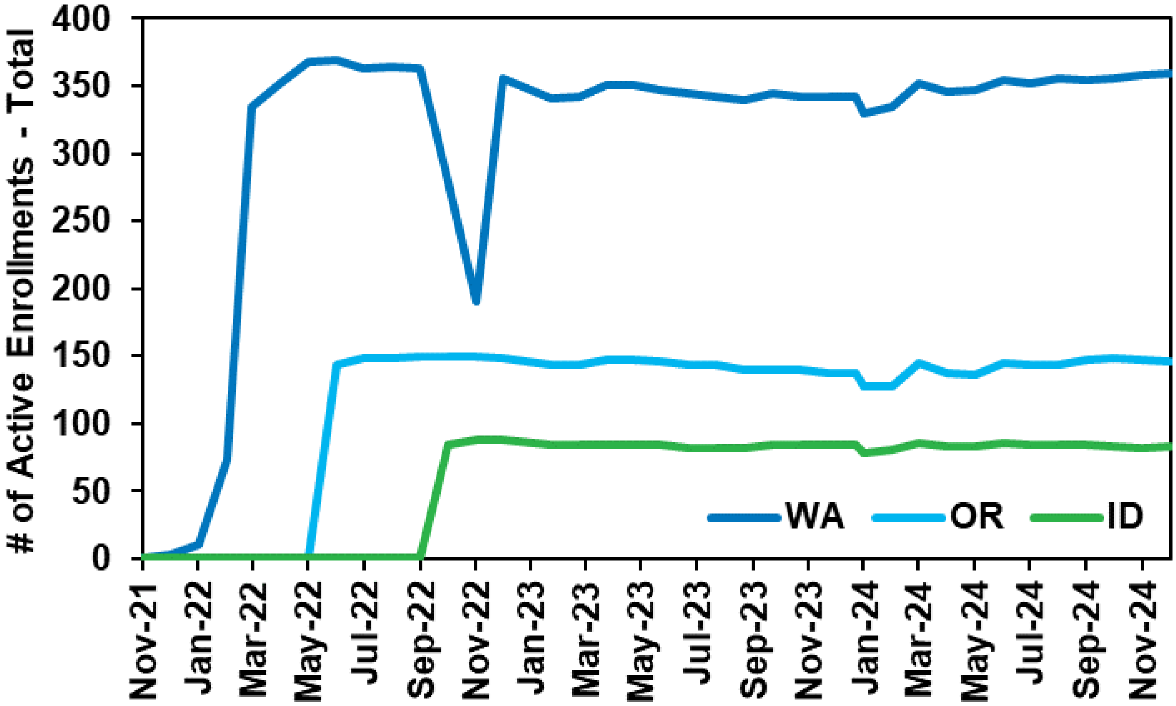
Voluntary Renewable natural gas allows Washington, Idaho, and Oregon natural gas customers to:

- Continue to enjoy the reliability and comfort of natural gas
- Tap into a local carbon-neutral resource
- Help repurpose existing waste streams
- Subscribe for as little as $5 per month
- Start or stop at any time, with no contract, while supplies last

Avista's RNG program supports RNG suppliers, including local and regional farms, landfills, green energy companies and municipalities, to capture the methane associated with these waste streams and purify it to make RNG.

Figure 5.11 illustrates the number of customers participant by state in Avista's voluntary RNG program, as of November 2024. The program started in 2021 in Washington and 2022 in Idaho and Oregon. Each state appears to show active enrollments have flattened off to levels reached in the initial program year.

Figure 5.11: Participants by State



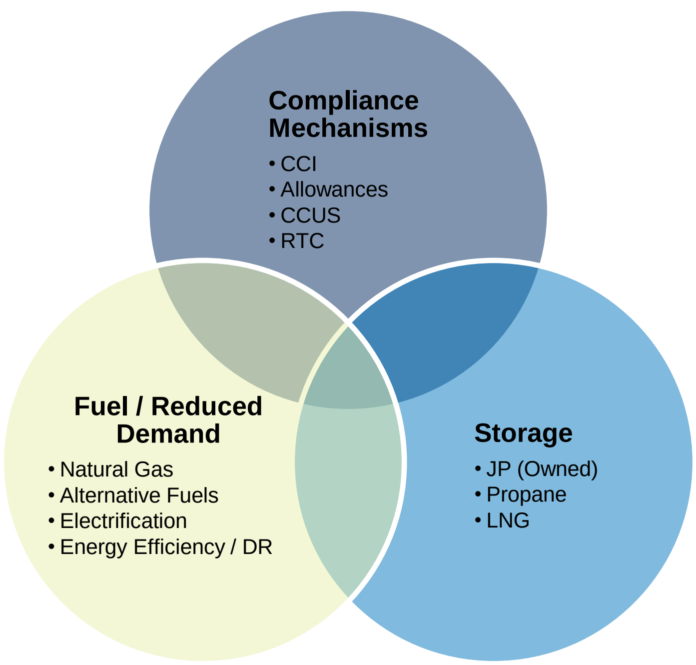
This Page is Intentionally Left Blank

6. Supply-Side Resource Options

Section Highlights:
- Avista models both gas supply options and storage resources.
- Future competitive acquisition processes may identify new or existing resources using different technologies with differing costs, sizes, or operating characteristics.
- Avista contracted with ICF to develop inputs for alternative fuel costs and volumes.
- The Inflation Reduction Act (IRA) tax incentives are included in resource costs.
- Renewable natural gas is modeled as a purchase gas agreement rather than utility ownership.

This chapter discusses fuel supply and delivery options to meet future net energy demand. Avista's objective is to provide a reliable gas service at reasonable prices. To help achieve this objective, Avista evaluates a variety of supply-side resources to build a diversified gas supply portfolio. In addition, Avista must be able to deliver fuels to customers via access to pipelines or storage within the system. Figure 6.1 is an illustration of the three components of the IRP's selection process, where demand and resource options meet in the darker shades with compliance, storage, and fuels. There is not a single solution to meeting these elements and all options, therefore a combination of options is considered within the IRP analysis, but this chapter focuses on alternative fuels to natural gas and storage. A summary of the alternative fuel options can be found at the end of this chapter in Table 6.7.

Figure 6.1: Demand and Resource Options



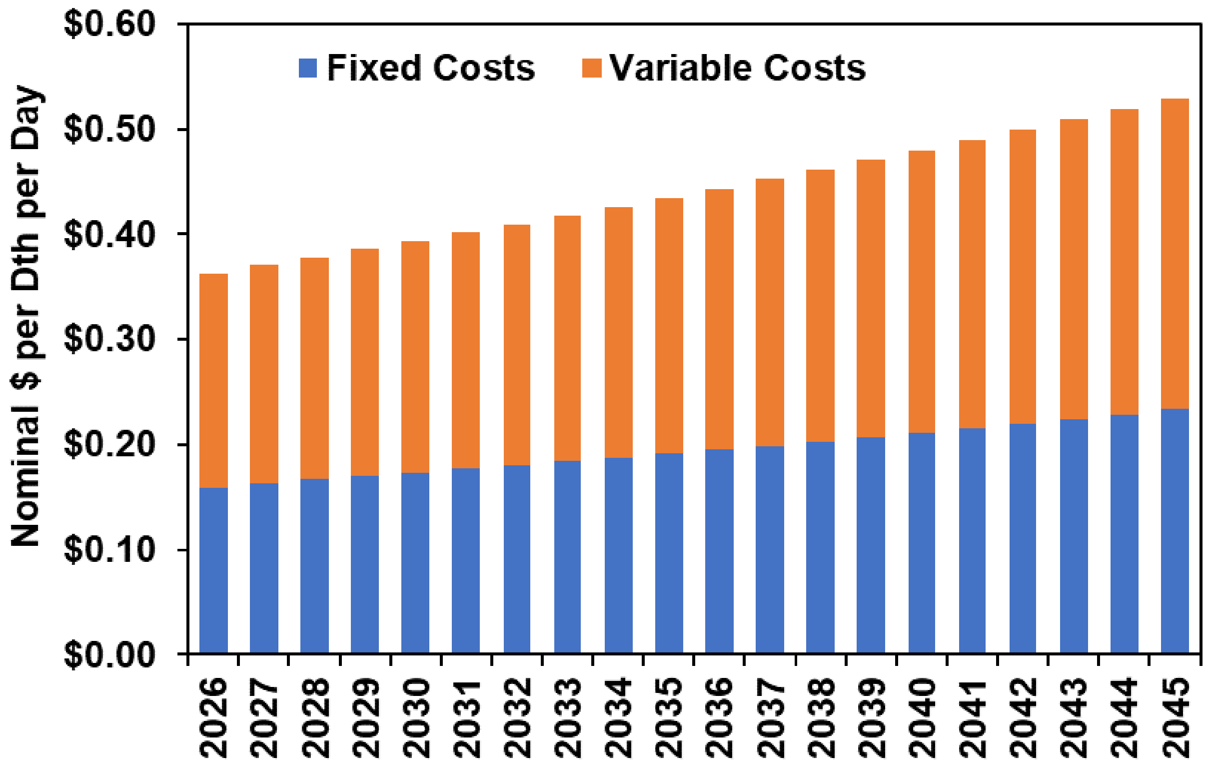
Gas Storage Options

For this IRP, Avista is modeling storage options to address reliability and resiliency issues recently seen in January 2024. This weather event brought a new set of challenges to the Northwest on both the electric and natural gas systems. Weather across Avista's LDC service territory reached near peaks in the Northern system and combined with freezing equipment issues at Crowsnest compressor feeding GTN led to a reduced capacity of volumes. Jackson Prairie (JP) storage also had a communications line issue over a few hours with mitigation leading to opening the gate station from JP to "free flow" as needed. A new communication line was run to the equipment and the facility was back to normal operating capabilities later in the day on January 13, 2024. Avista includes both Propane and Liquified Natural Gas (LNG) as a capacity option to address resiliency for high demand scenarios. These resources are selectable within the optimization model if found to be cost effective but may also be considered to address the risk of lost pipeline capacity as a resiliency solution.

Propane Storage

A propane storage facility is being modeled with a single day deliverability of 30,000 Dth equivalent energy. This storage facility could be placed on land currently owned by Avista, pending site and environmental approvals, and uses air injection to bring down the energy content to a pipeline quality standard. Each tank is considered at 10,000 Dth of capacity equivalent and could be filled concurrently as withdrawals take place dependent on supply availability. A total of roughly 328,000 gallons of propane would be required to fill this facility considering a low heating value of 91,500 btu per gallon or 10.93 gallons per dekatherm. This facility assumes two full-time equivalent employees per the manufacturer's estimates. Plant and air injection electricity cost is also included and is based on EIA national electricity costs and emissions per MWh. Capital costs are placed into a revenue requirement model where taxes, fees and cost of capital are included to estimate a yearly revenue requirement over its assumed 20-year life. An environmental benefit of propane is it is considered zero emissions in the Clean Air Act, Climate Commitment Act and the Climate Protection Plan meaning no offsets are needed to use the facility other than the fixed and variable costs as shown in 6.2.

Figure 6.2: Propane Storage Fixed and Variable Costs - Dth per Day (nominal $)



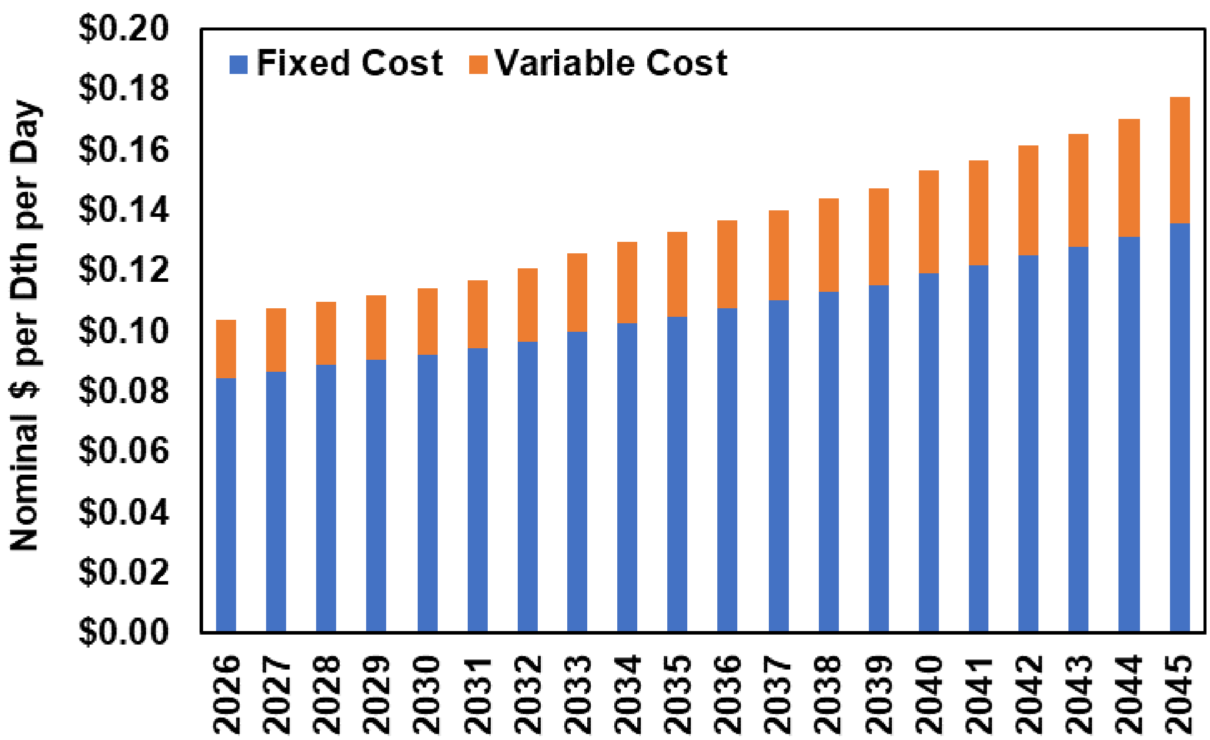
Liquified Natural Gas (LNG)

Avista could construct or partner to build a liquefaction LNG facility in the service area. Doing so could use excess transportation during off-peak periods to fill the facility, avoid tying up transportation during peak weather events, and it may avoid additional annual pipeline charges.

Construction would depend on regulatory and environmental approval as well as cost-effectiveness requirements. Preliminary estimates of the construction, environmental, right-of-way, legal, operating and maintenance, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. As noted above, liquified natural gas provides the ability to store multiple times the volume of natural gas or RNG into a much smaller footprint. This energy can be used on peak days or where supply is constrained. In the event of a deliverability constraint, it may be used for either Avista's electric generation resources or the LDC. The model assumes only LDC, but a cost sharing mechanism between these services may be considered in an integrated system planning type model where this is a shared storage resource. Further, Avista could offer existing pipeline capacity releases or other storage resource releases to lessen the cost of such a facility. Avista did not include these benefits in this IRP at this time but will evaluate these opportunities prior to the 2027 plan or when making a decision on acquiring storage capacity. To estimate the capital costs for LNG, there are three[1] recently built or planned facilities to use as proxy estimates, resulting in $200 million for an applicable facility.

As with the propane storage, a revenue requirement is estimated, but in this case an asset life of 50 years is used, producing an annual revenue requirement for the capital invested. Withdraw and injection estimates, plant and liquefaction electricity, maintenance, pipeline and interconnect, days to fill, daily liquefaction amounts, and plant operations are all considerations involving LNG. The storage facility modeled is 1 Bcf and can deliver 1/10th of this volume per day. Figure 6.3 illustrates the revenue requirement for this capital investment through the forecast timeframe on a capacity basis of dollars per dekatherm per day. Fuel costs are available within CROME for the alternative resources as discussed in this chapter and natural gas resources as discussed in Chapter 5. Plant cycling would help to reduce these costs as would market optimization but are not considered in the cost forecast below but are not considered within the optimization model for this plan.

Figure 6.3: LNG Storage Fixed and Variable Priced – Dth per Day (nominal $)



[1] Two projects from We® Energies - Ixonia and Bluff Creek (WI) and a proposal by nmgco (NM)

Capacity Options Considered Outside the IRP

In addition to the capacity options for storing gas discussed above, Avista does consider other options when they are available. These options are generally not modeled in the IRP unless specific information is available regarding the opportunity to select these resources.

Capacity Release Recall

Pipeline capacity not utilized to serve core customer demand is available to sell to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be on a short-term (month-to-month) or long-term basis. Avista actively participates in the capacity release market with short-term and long-term capacity releases. Avista assesses the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process evaluates if or when to recall some or all long-term releases.

Existing Regional Pipeline Capacity

The GTN interconnection with the Ruby Pipeline provides GTN the physical capability to provide a limited amount of firm back-haul service from Malin with minor modifications to their system. Fees for utilizing this service are under the existing Firm Rate Schedule (FTS-1) and currently include no fuel charges. Additional requests for back-haul service may require additional facilities and compression (i.e., fuel).

This service can provide an interesting solution for Oregon customers. For example, Avista can purchase supplies at Malin, Oregon and transport those supplies to Klamath Falls or Medford. Malin-based natural gas supplies typically include a higher basis differential to AECO supplies but are generally less expensive than the cost of forward-haul transporting traditional supplies south and paying the associated demand charges. The GTN system is a mileage-based system, so Avista pays only a fraction of the rate if it is transporting supplies from Malin to Medford and Klamath Falls. The GTN system is approximately 612 miles long and the distance from Malin to the Medford lateral is only about 12 miles.

In-Ground Storage

In-ground storage provides advantages when natural gas from storage can be delivered to Avista's city gates. It enables deliveries of natural gas to customers during peak cold weather events. It also facilitates potentially lower-cost supply for customers by capturing peak/non-peak pricing differentials and potential arbitrage opportunities within individual months. Although additional storage can be a valuable resource, without deliverability to Avista's service territory, this storage cannot be an incremental firm peak serving resource.

Jackson Prairie

Jackson Prairie is a potential resource for expansion opportunities. Any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, Avista will continue to look for exchange and transportation release opportunities to fully utilize these additional resource options. When an opportunity presents itself, Avista assesses the financial and reliability impact to customers. Due to the growth in the region, and the need for new resources, a future expansion is possible, though a robust analysis would be required to determine feasibility. Currently, there are no plans for immediate expansion of Jackson Prairie.

Other In-Ground Storage

Other regional storage facilities exist and may be cost effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, Ryckman Creek in Uinta County, Wyo., and northern California storage are all possibilities. Transportation to and from these facilities to Avista's service territories continues to be the largest impediment to these options. Avista will continue to look for exchange and transportation release opportunities while monitoring daily metrics of load, transport, and the market environment.

Compressed Natural Gas (CNG)

CNG is another resource option for meeting demand peaks and is operationally similar to LNG. Natural gas could be compressed offsite and delivered to a distribution supply point or compressed locally at the distribution supply point if sufficient natural gas supply and power for compression is available during non-peak times. Avista does not consider this option in higher level resource planning due to the small facility size but could be an alternative for a non-pipe alternative to distribution expansion.

Alternative Fuels Resource Supply Options

A coordinated study between Avista, Cascade Natural Gas, and Northwest Natural utilized ICF[2] to develop resource potential volumes and prices for Carbon Capture, Utilization and Storage (CCUS), Hydrogen (H2), Renewable Natural Gas (RNG), Renewable Thermal Credit (RTC), and Synthetic Methane (SM) in their various production types, facility sizes, volumes and any incentives offered to assist with the costs of their production. A full report is included in Appendix 6 summarizing methodologies and assumptions. High level summaries of this report are also included herein.

Technical Potential Resource Volumes

Technical potential resource volumes were estimated by ICF for estimated availability in the Northwest and Nationally. Split by estimated number of customers for each local distribution company (LDC) in Oregon and Washington. The volumes were then modeled by Avista in CROME with local availability potential in the Northwest for all alternative

[2] ICF: Strategic Consulting & Communications for a Digital World | ICF

resources except RTCs as National potentials were the only estimates requested. Volumes are considered local and within Avista's distribution system with the ability to be injected into storage in days of lower demand with rates and tariffs associated with the pipelines to get the gas to the storage destination.

Pricing

Expected prices are broken down between Northwest and national technical potential. All prices consider the Inflation Reduction Act (IRA) incentives and are shown in nominal dollars. Additional assumptions are as follows:

- Prices assume a first mover access to alternative fuels.
- Prices are for the Northwest located alternative fuels and Nationally located Renewable Thermal Credits (RTC).
- Hydrogen (H2) & Synthetic Methane (SM) prices will be treated as a purchase gas agreement where Avista would sign a term contract, each year, with the producer for these prices through the forecast.
- Renewable Natural Gas (RNG) assumes a proxy ownership with costs levelized over 20 years.
- RTC considers a production cost plus, where prices cover all costs.

Volumes

Expected fuel volumes are broken down between Northwest and National technical potential. These volumes assume a first mover access to alternative fuels and are weighted by US population for states where some form of climate policy is in place or demand is expected. Avista modeled physical potential volumes are from Avista's weighted share in the Northwest and intended to represent all volumes available to Avista in the United States. RTCs are the only National located resource potential considered in the plan and assumes physical pipeline accessibility to meet Washington's Climate Commitment Act (CCA) and Oregon's Climate Protection Program (CPP) program rules. The fuel volumes for Avista's potential are based on our pro-rata share of Northwest meters. This calculation is demonstrated in Table 6.1 and is broken out by the number of meters between LDCs in Oregon and Washington as of the year 2023. Figure 6.4 shows the total technical potential of Avista's share of the technical potential compared to the percentage of actual share modeled. Figure 6.5 shows the fuel type share by percentage of modeled total volume. Whereas Figure 6.6 demonstrates the percentage of available total volumes in dekatherm equivalent.

Table 6.1: Volumetric Breakout by LDC in the Northwest

Company	2023 # of Meters	Share
Avista	379,223	15.8%
Cascade	316,929	13.2%
Northwest Natural	799,250	33.4%
Puget Sound Energy	900,000	37.6%
Total	2,395,402	100.0%

Figure 6.4: Modeled Volumes Compared to Technical Potential Volumes

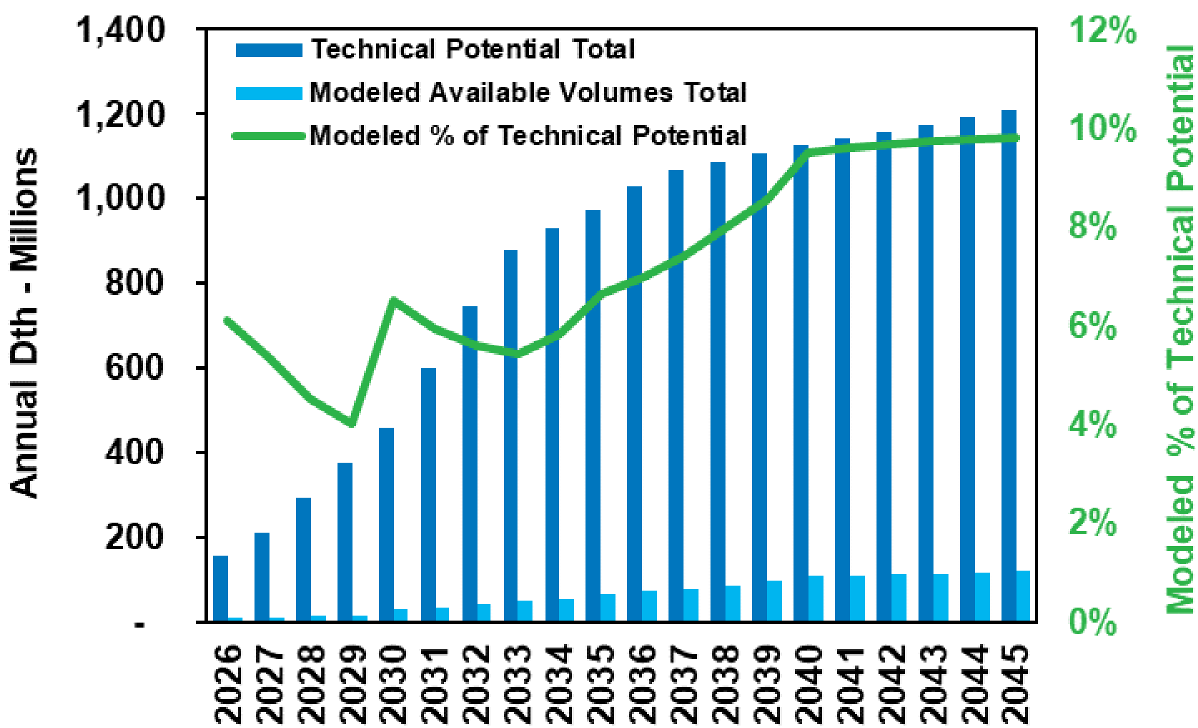


Figure 6.5: Percentage of Total Volumetric Availability by Source

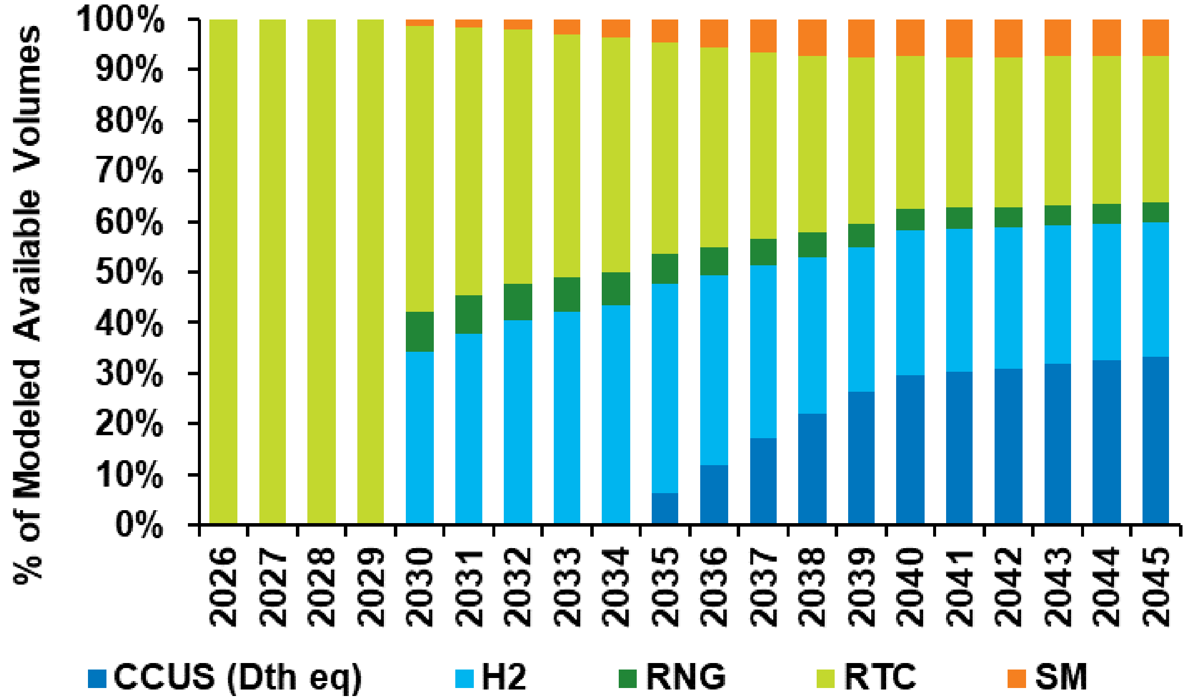
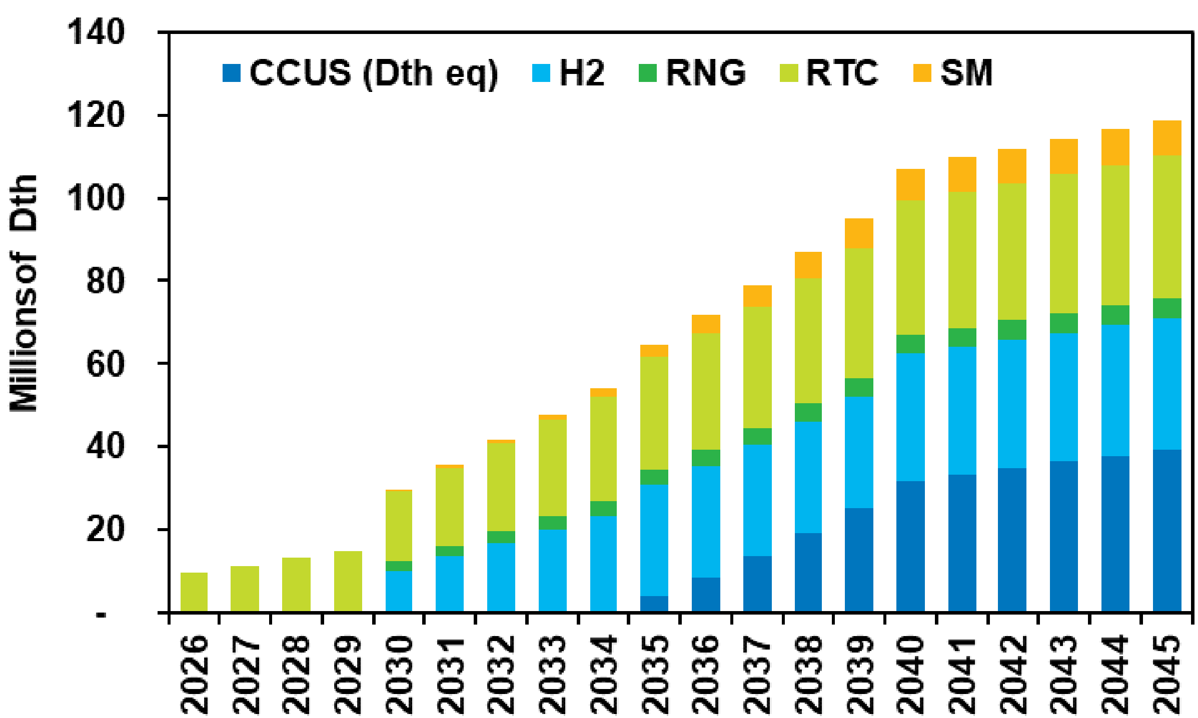


Figure 6.6: Annual Modeled Volumes by Alternative Fuel Type



Renewable Natural Gas (RNG)

Renewable Natural Gas, or biogas, typically refers to a mixture of gases produced by the biological breakdown of organic matter in the absence of oxygen. RNG can be produced by anaerobic digestion or fermentation of biodegradable materials such as woody biomass, manure or sewage, municipal waste, green waste, and energy crops. Depending on the type of RNG there are different factors to quantify methane saved by its capture as methane up to 34[3] times the greenhouse gas intensity as compared to carbon dioxide. Each type of RNG has a different carbon intensity as compared to natural gas as shown in Table 6.2.

Table 6.2: Carbon Intensity (lbs per mmbtu)[4]

RNG Feedstock (NW)	2025	2030	2035	2040	2045	2050
Animal Manure	-212.24	-212.24	213.33	213.33	213.43	213.43
Food Waste	-71.94	-71.94	-73.03	-73.03	-73.13	-73.13
Landfill Gas	14.08	14.08	13.01	13.01	12.91	12.91
Waste Water	14.54	14.54	13.17	13.17	13.04	13.04

RNG is a renewable fuel, so it may qualify for renewable energy subsidies. Once processed, RNG can be used by boilers for heat, as power generation, compressed natural gas vehicles for transportation or directly injected into the natural gas grid. The further down this line, the greater the need for pipeline quality gas. Avista modeled RNG with the option to inject into JP rather than use in low demand months and will help with the intrinsic value compared to natural gas. Geography is also generic as understanding exact location is problematic due to the unknown locations of these potential projects.

RNG projects are unique, so reliable cost estimates are difficult to obtain. Project sponsorship has many complex issues, and the more likely participation in such a project is as a long-term contracted purchaser. Avista considered biogas as a resource in this planning cycle and depending on the location of the facility it may be cost effective. This is especially the case when found within Avista's internal distribution system where transportation and fuel costs can be avoided. For more information about RNG and its potential uses in energy policy within Avista territories please see Chapter 7.

Each RNG project will vary in size, location, and distance to interconnection with the pipeline, feedstock type, gas conditioning equipment and requirements and operating costs. In general terms, new RNG projects can take two to three years to develop depending on project size and scope. This IRP considers the first year of availability to any RNG resource in 2030.

[3] https://www.ipcc.ch/
[4] ICF Alternative Fuels Study – Appendix 6

To bridge the gap between ownership or purchasing from a producer, it was made available in the model to assume a quantity taken each year carries forward thru the end of the study. Table 6.3 shows the RNG options and reference name as well as a description of each type of feedstock.

Table 6.3: Renewable Natural Gas Options

Feedstock for RNG		Reference Name	Description
Anaerobic Digestion	Animal manure	AM 4, AM 5	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	FW 3	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
	Landfill gas (LFG)	LFG 1, LFG 2, LFG 3, LFG 4, LFG 5	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	WW 1, WW 2, WW 3, WW 4, WW 5	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.

ICF developed assumptions for the capital expenditures and operation costs for RNG production from the various feedstock and technology pairings. ICF characterized costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. ICF also included operational costs for each technology type. Price estimates are illustrated in Figure 6.7, 6.8, and 6.9 assume both the RTC and brown gas (energy) as a bundled price.

Figure 6.7: Higher Cost RNG Price by Source (nominal $)

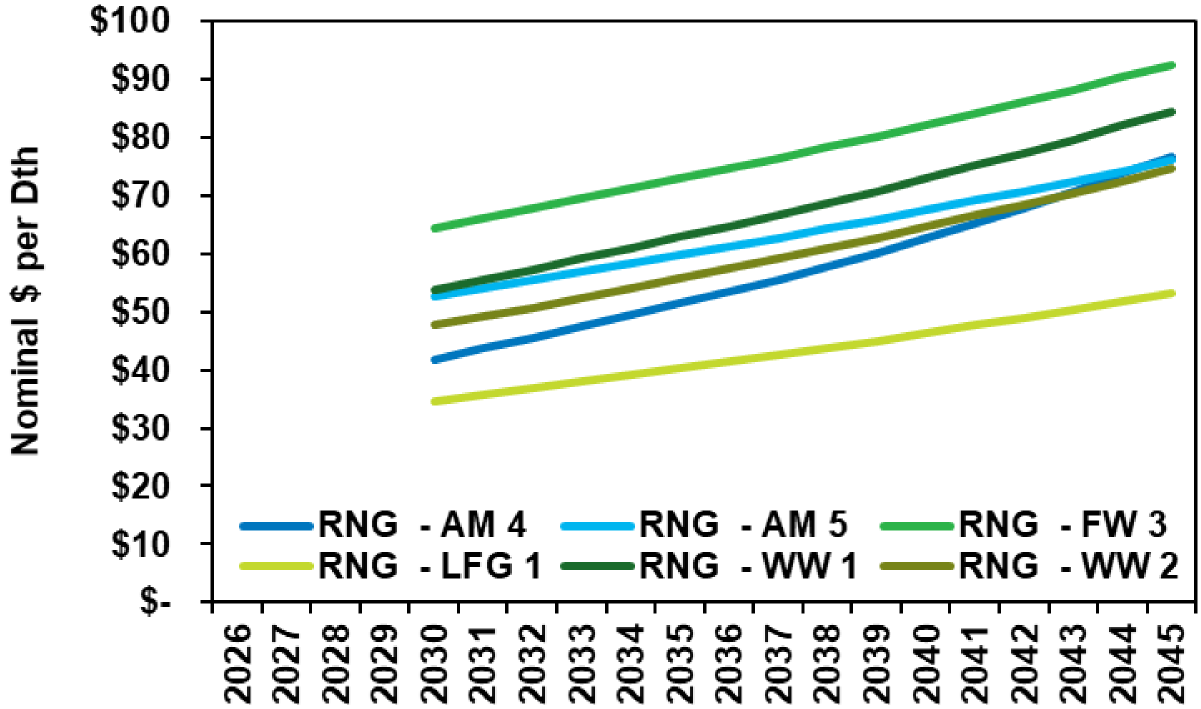


Figure 6.8: Lower Cost RNG Price by Source (nominal $)

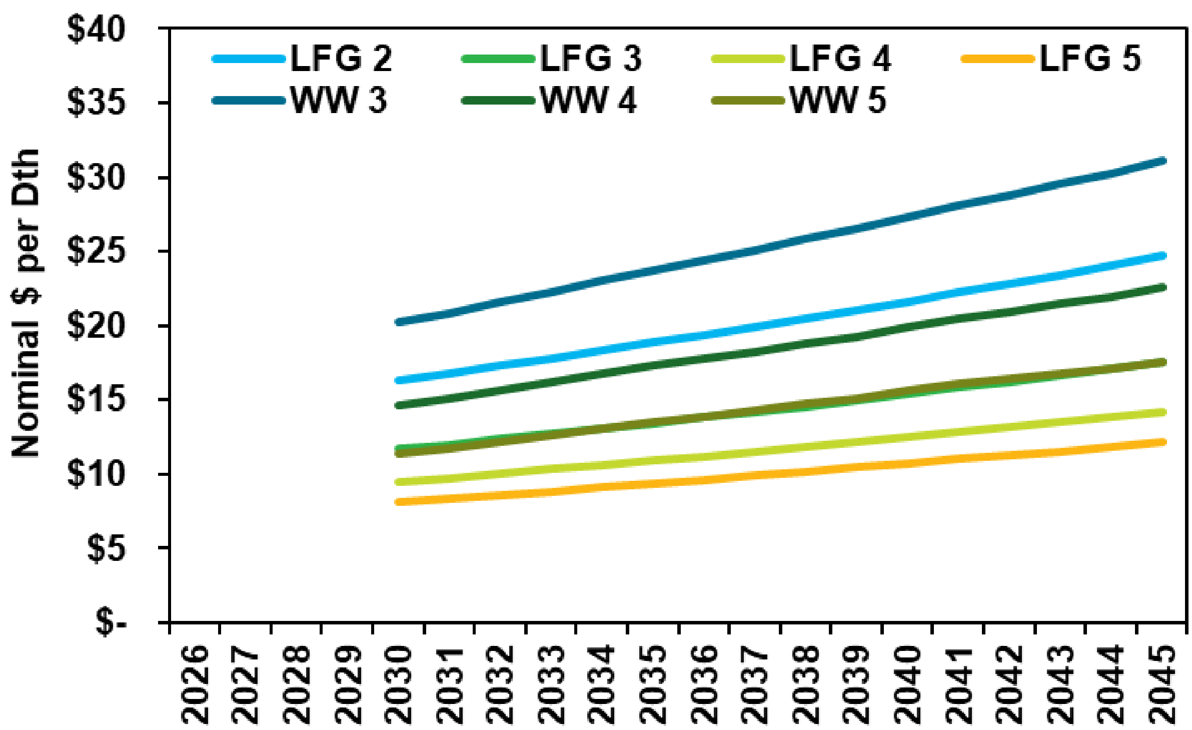
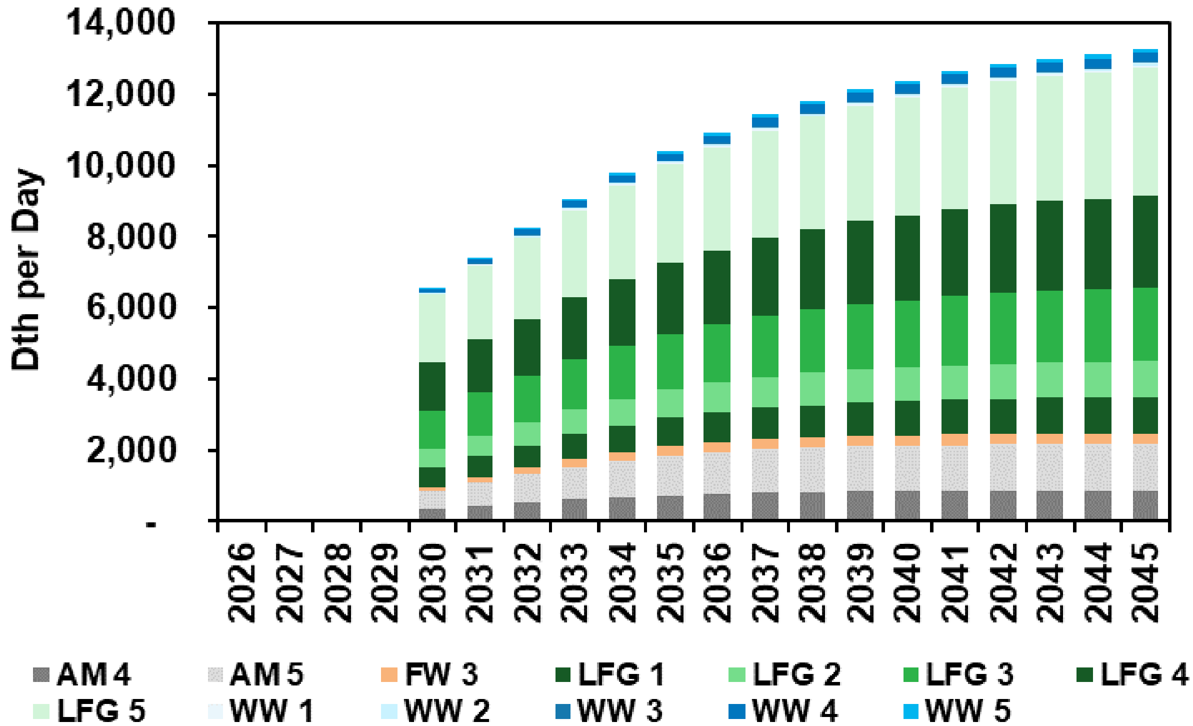


Figure 6.9: RNG Modeled Resource Potential Volumes



Renewable Thermal Certificate (RTC)

RTCs are the certified volume of energy that provides proof of production of renewable gas but is not directly delivered to Avista's system. This gas can be in the form of any of the alternative fuel options covered in this chapter but modeled based on the production of RNG. The energy from the production volumes is not delivered gas to Avista customers, but rather an offset for the use of natural gas. Program requirements for Washington's CCA and Oregon's CPP describe compliance can be achieved by fuels where a physical pathway beginning at the production site and to the area of use can be identified. Avista does not assume compliance with RTCs where the gas is physically stranded or impossible to use based on location and interconnection. Avista's assumptions for RTC pricing for this IRP are included in Figure 6.10 and Figure 6.11 with the same RNG types of production and feedstock as discussed above.

Figure 6.10: Higher Cost RTCs Price by Source (nominal $)

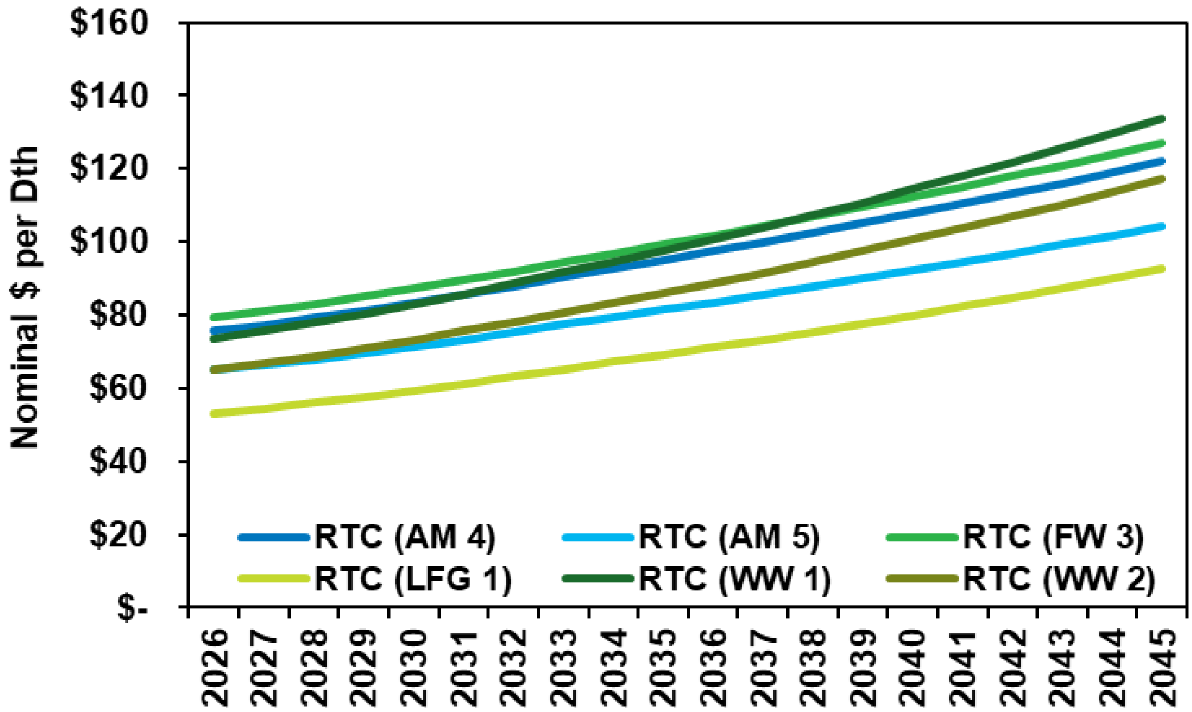
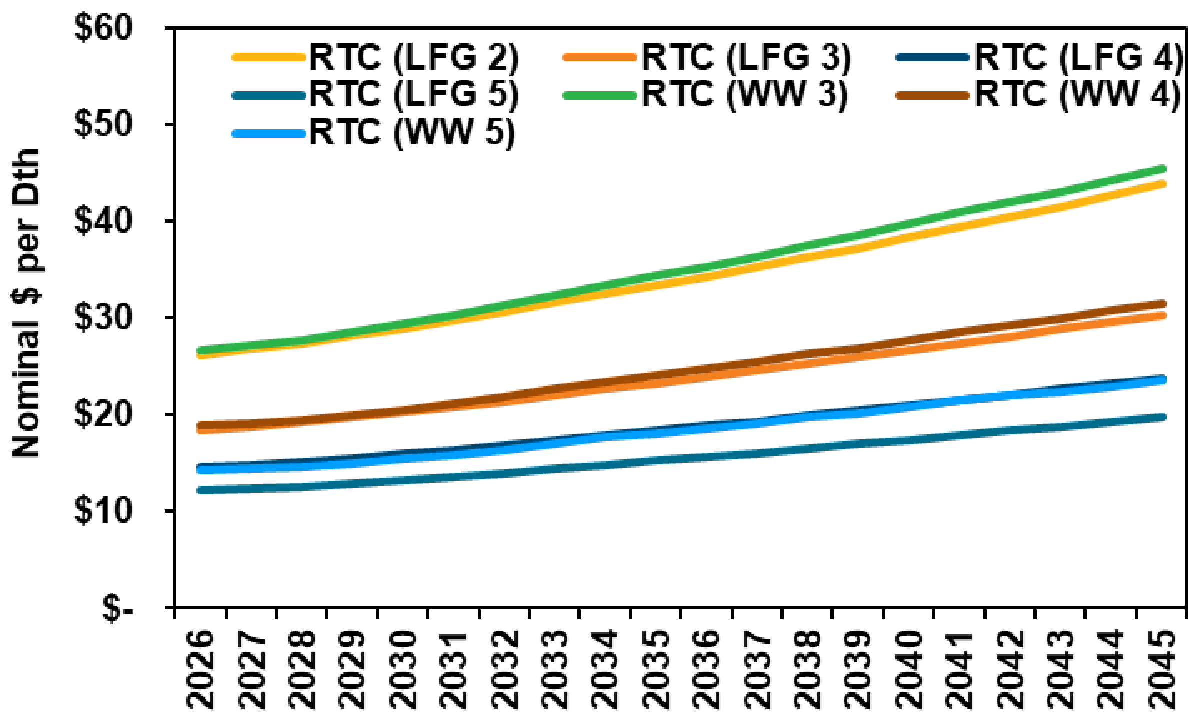


Figure 6.11: Lower Cost RTCs Price by Source (nominal $)



Hydrogen

Hydrogen (H_2) is a fuel source with a long history and great potential to help solve future energy needs. Its energy factor, as measured in a kilogram (kg) of low heating value (LHV), is roughly equivalent to a gallon of gasoline. Hydrogen can be made from any energy source including nuclear (pink H_2) and electric renewable energy (green H_2). With expanding renewable electricity production, the ability to create green hydrogen from this energy is moving from concept to market throughout the world. Some drawbacks to hydrogen include needing three times the volume of pipeline capacity to provide the same energy as natural gas. Avista assumes a maximum blend rate with natural gas in the pipelines system to be 20%[5], but the energy blend can reduce current pipeline capacity and may not be possible to obtain this limit if the underlying delivery system is constrained. Hydrogen can also impact functionality of appliances and end uses based on the ability to contain the lightest element on earth combined with less energy delivered on a cubic foot basis when compared to natural gas. This process of using power to separate water into hydrogen and oxygen is known as power to gas (P2G) through electrolysis and can provide energy storage, a critical piece to electric grid decarbonization yet to be developed on a large enough or cost-effective scale. Most hydrogen is currently made by reforming natural gas, also known as grey H_2. The emission ranges shown in Table 6.4 include all types of hydrogen production and qualified facilities, which are to be required to meet certain wage and apprenticeship requirements as defined in the IRA.

Table 6.4: Production Types of Hydrogen:

Hydrogen Feedstock	Production Technology	CI range kg CO_2e/kg H_2	Former Color
Natural Gas	Hydrogen produced from SMR, no carbon capture	10 – 14	Gray
Coal	Hydrogen produced from coal gasification	20 – 30	Brown
Natural Gas	Hydrogen produced from SMR/ATR with 97%+ CCS	1.8 – 2.6	Blue
Natural Gas & RNG	Hydrogen produced from SMR/ATR with 97%+ CCS	0 – 0.45	Blue
RNG	Hydrogen produced from methane pyrolysis (Microwave Pyrolysis)	<0	Turquoise
Natural Gas	Hydrogen produced from methane pyrolysis (Microwave Pyrolysis)	<2.5	Turquoise
Renewable Electricity	Hydrogen produced via electrolysis from renewable energy[16]	0 – 2.6[17]	Green
Nuclear Energy	Hydrogen produced via electrolysis from nuclear energy	<1	Pink

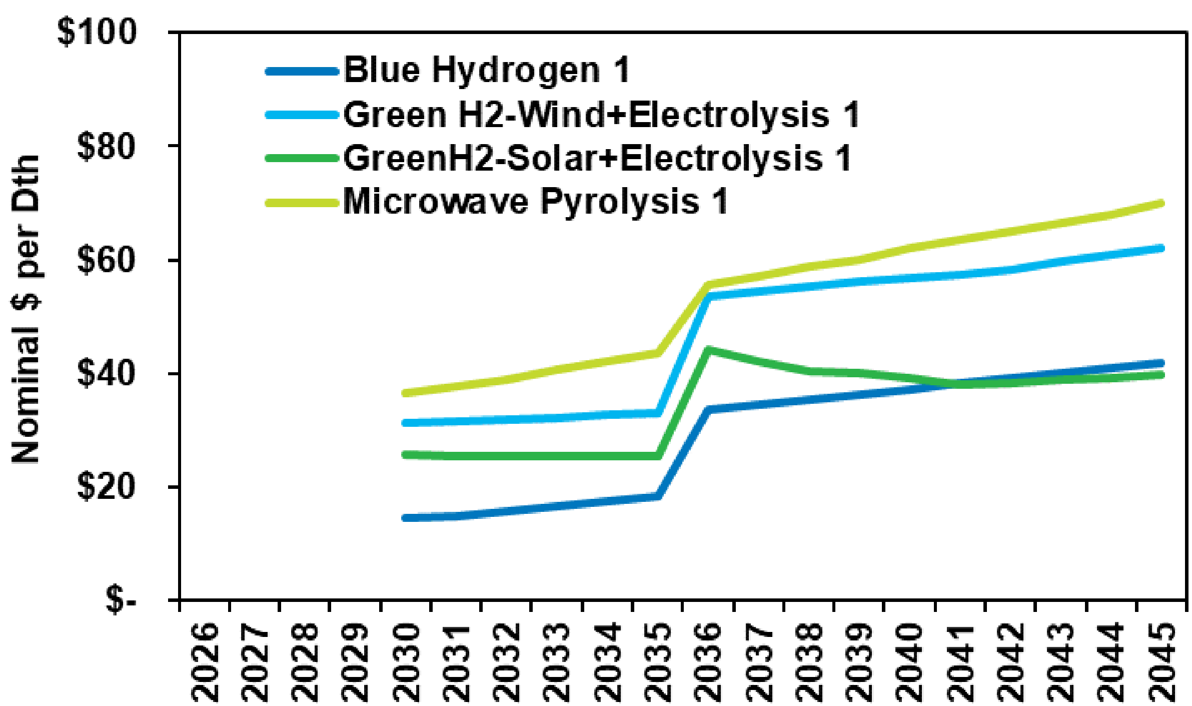
Several governing bodies have begun to define “Clean Hydrogen” according to its carbon intensity. In the US, the definition of Clean Hydrogen was established to be less than 4

5 https://www.prnewswire.com/news-releases/socalgas-among-first-in-the-nation-to-test-hydrogen-blending-in-real-world-infrastructure-and-appliances-in-closed-loop-system-301389186.html

kg CO2e/kg H2 under the Bipartisan Infrastructure Law and further defined by categories under the Inflation Reduction Act (IRA) which created a new hydrogen production tax credit under Section 45V of the tax code. Only projects demonstrating life cycle GHG emissions of less than 4 kg CO2e/kg H2 produced are to qualify, as demonstrated in the Figure 6.12 and Figure 6.13 below. Further details of the IRA are discussed in Chapter 7. These costs are assumed to be located at or near load centers in Avista owned distribution.

Two new types of hydrogen have been modeled in the 2025 IRP. The first is blue hydrogen and like gray hydrogen can use steam methane reforming (SMR) using steam from electricity to split water. Blue hydrogen adds additional production capabilities with autothermal reforming (ATR) using chemical reactions (partial oxidation and steam reforming) to generate the heat needed to split water through electrolysis and adds in carbon capture and storage. The second type of hydrogen modeled is turquoise, using microwave radiation[6], and produces a solid form of carbon known as carbon black, this bi-product can be sold to manufacturers for other products such as tires. Gray, brown, and pink forms of hydrogen were not modeled in this IRP as adding emissions to Avista's supply does not help with climate goals (gray, brown) and pink hydrogen or hydrogen produced from nuclear electricity is unlikely in our region as the power would more likely be used directly by the electric grid.

Figure 6.12: Hydrogen Cost Estimates



6 Microwave Pyrolysis - an overview | ScienceDirect Topics

Figure 6.13: Hydrogen Daily Modeled Volumes

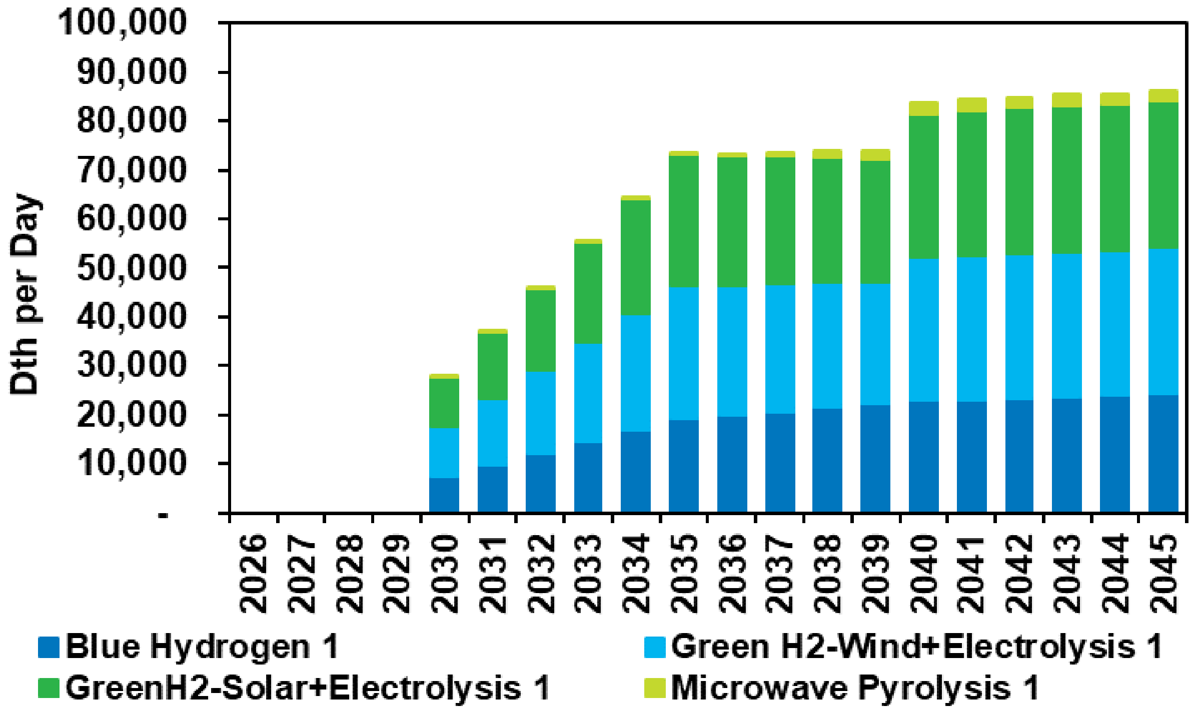


Table 6.5 shows cost inputs from ICF assumptions involving the use of electrolyzers in the production of hydrogen to derive the costs as shown above and include electrolyzer size, energy consumption rate per kWh and water costs among others.

Table 6.5: Electrolyzer Facility Production Cost Inputs

Input	Value	Comments
Sample Facility Size		
Electrolyzer Size	220 MW	Based on projects with which ICF is familiar
Annual Production Target	20,000,000 kg	Based on projects with which ICF is familiar
Energy and Water Inputs		
Renewable Power Capacity Factor	Dependent on energy resource and location (national vs. regional averages)	Assuming energy from solar, wind and nuclear sources
Electrolyzer Energy Consumption Rate	53 kWh/kg	Based on projects with which ICF is familiar and ranges from original equipment manufacturers (OEMs)
BoP Energy Consumption Rate	8 kWh/kg	Based on projects with which ICF is familiar and ranges from OEMs

Electricity Cost	Dependent on resource type (solar, wind, nuclear or renewable energy certificates [RECs])	Based on AEO projections for solar and wind LCOEs and ICF estimates from NREL for nuclear LCOE; RECs assumed to come at a placeholder value of 5% premium to the LCOE which is varied in the Monte Carlo analysis due to the regulatory uncertainties
Water Intake Rate	2.64 gal/kg	Based on projects with which ICF is familiar and ranges from OEMs
Water Cost	$5.63/kgal	Industrial utility water with approximately 1% annual escalation from DOE's Office of Scientific and Technical Information (OSTI)
Operation Inputs		
Stack Membrane Life	10 years	Based on projects with which ICF is familiar
Life of Electrolyzer Equipment	80,000 hours	Based on projects with which ICF is familiar
Annual Degradation Rate	1%	Conservative estimate; levelized degradation factor was assumed to have minimal impact and not included in analysis
Operating year	333-353 days	Based on projects with which ICF is familiar
Annual Labor Costs	$2.95MM	ICF's estimate for standalone electrolyzer facility with ~25 staff
Membrane Replacement Cost as % of Direct Capex	30%	Based on projects with which ICF is familiar
Annual Maintenance as % of Capex	3%	Based on projects with which ICF is familiar
Project Finance and Capital Costs		
PEM Electrolyzer	$1050/kW	Based on projects with which ICF is familiar and bids from OEMs
Total Installed Cost Factor	2	Based on projects with which ICF is familiar; can range from 2 – 2.7 depending on BOP
Learning Curve Rate for Total System	22%	ICF's internal model
WACC	4%	Provided by utilities; varied in the Monte Carlo analysis
Loan Duration	20 years	Based on projects with which ICF is familiar

Synthetic Methane

Synthetic Methane is the creation of natural gas through an artificial process. This analysis considers two primary forms of creation:

3. Biomass gasification includes energy crops with high energy content, like agricultural residues or forestry residues. The material goes through a thermal gasification process to produce RNG. Thermal gasification generates synthesis gas containing hydrogen and carbon monoxide.
4. Power to Gas, for this IRP analysis, green hydrogen is created using water electrolysis with solar energy, then the hydrogen is bonded with a carbon source. The carbon source could be from an industrial facility, power plant, or air capture. For this IRP a biogenic carbon source is assumed. The capacity of the electrolyzer needed to produce the synthetic methane is summarized in Table 6.6 where a 220 MW solar facility combined with a carbon source producing 188,553 metric tons of CO_2 can produce 3.8 million dekatherm equivalent energy per year.

Table 6.6: Green H2-Biogenic CO_2

Variable	Units	Values
GreenH2-Solar (NW)-BiogenicCO₂		
Electrolyzer	MW	220
Capacity factor, methanation/electrolysis	%	95%
Electrolyzer Energy Consumption	kWh/kg	53.00
H_2 Production / Consumption	t/y	34,544
CO_2 Consumption	t/y	188,553
$SynCH_4$ Production	t/y	68,732
$SynCH_4$ Production	mmBtu/y	3,831,161

Synthetic methane is considered pipeline quality and acceptable for use in the current natural gas system infrastructure without any upgrades or alterations as it is, in essence, natural gas. This fuel can also help bridge the gap for excess electricity if produced from an electrolyzer and act as a form of energy storage during period of low demand to a period of higher demand. Green hydrogen costs are discussed above and provide the energy portion of synthetic methane. Synthetic methane is a combination of green hydrogen and carbon capture costs per dekatherm. Cost estimates for synthetic methane are included in Figure 6.14 and volumes can be found in 6.15. For this IRP, Avista is modeling three different production levels for the biomass options to represent the project scale required if the fuel alternative is selected.

Figure 6.14: Synthetic Methane Cost Estimates

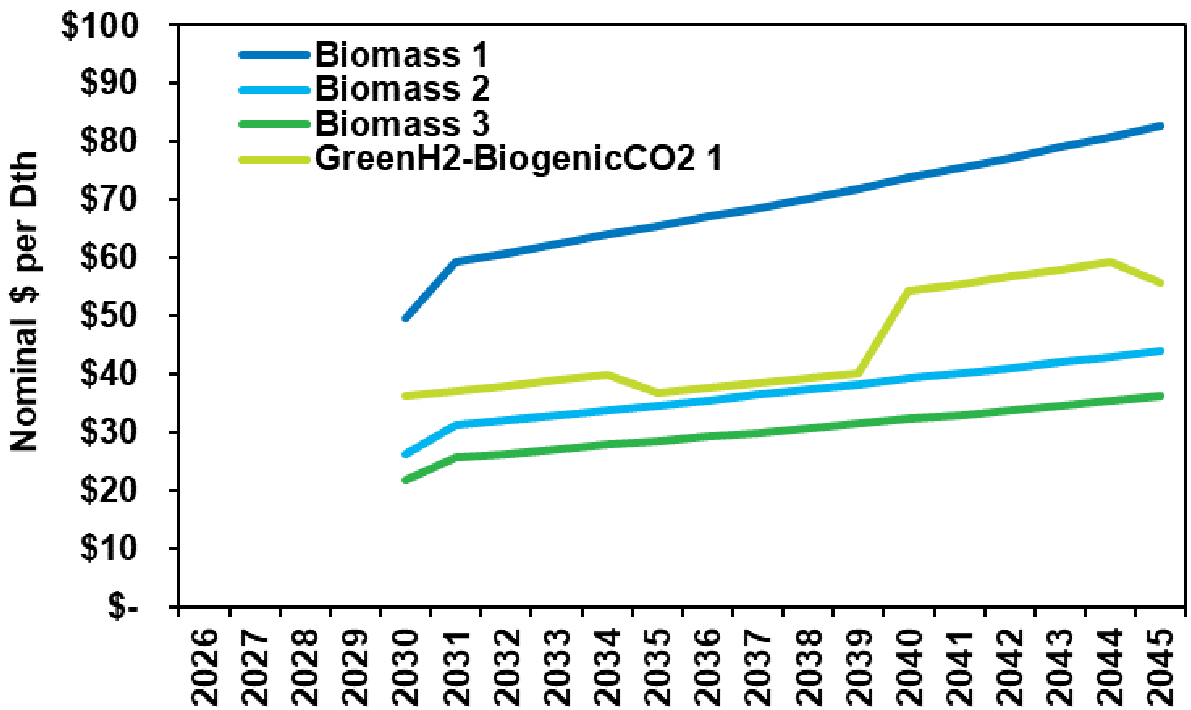
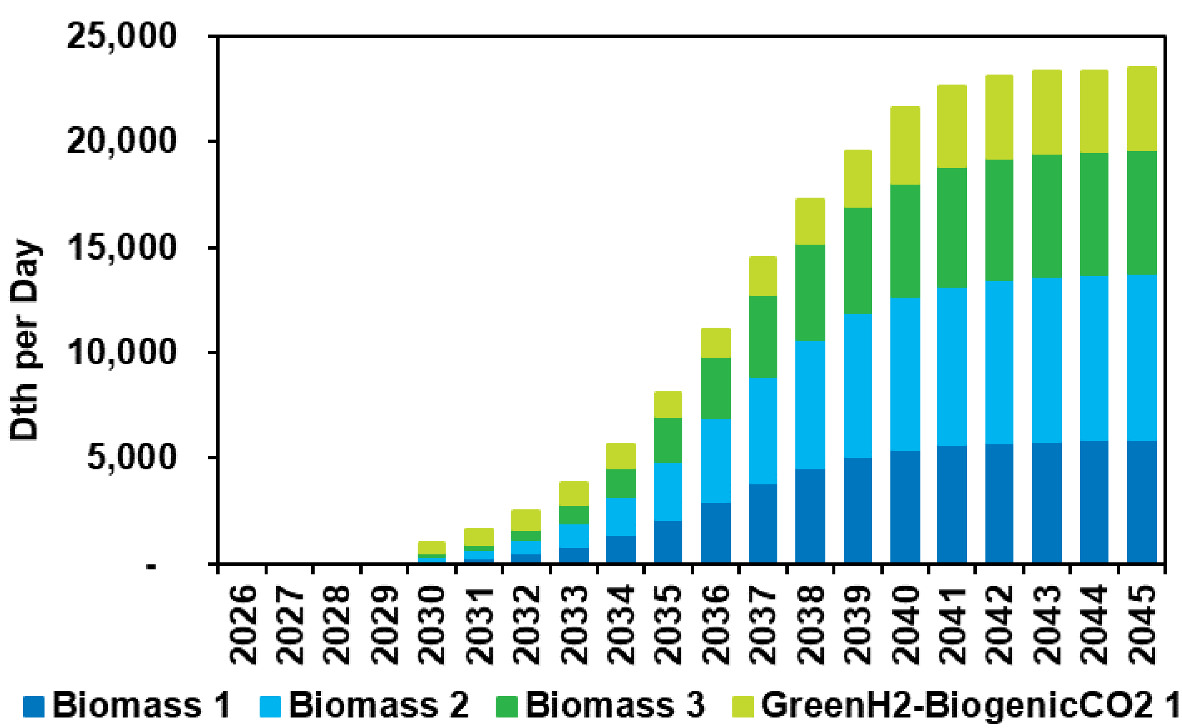


Figure 6.15: Synthetic Methane Daily Modeled Volumes



Alternative Fuel Supply Price Risk

While weather is an important driver for the IRP, fuel price is also important. As seen in recent years, significant price volatility can affect the resource portfolio. In deterministic modeling, a single price curve for each scenario is used for analysis, these prices are shown in the price forecasts above. There is uncertainty with new technology prices, therefore, Avista used Monte Carlo simulation to test the resource portfolio and quantify the risk to customers when prices do not materialize as forecast. Avista performed a simulation of 500 draws to include varying fuel supply prices, to investigate whether the Preferred Resource Strategy's total portfolio costs from the deterministic analysis are within the range of occurrences in the stochastic analysis. This simulation of prices is done for natural gas, RNG by anaerobic production type (dairy, landfill, solid waste, and waste- water), hydrogen, and synthetic methane. Figure 6.16 to Figure 6.21 show the average yearly price per dekatherm for the largest and most cost-effective units from the ICF analysis, per draw and resource for the years 2030 through 2045, for each of the 500 draws. Statistics are also provided with each histogram and represent the raw data results. This dataset can also be found in Appendix 6 for all modeled resources. An annual request for proposal (RFP) will help to value these resources and availability to obtain the least cost resource as compared to other available resources as bid into this process. Other proposals outside of this process may arrive and will be valued under the same methodology considering the least cost and risk solution.

Figure 6.16: RNG Landfill RNG (LFG 5) - $ per Dth (500 Draws)

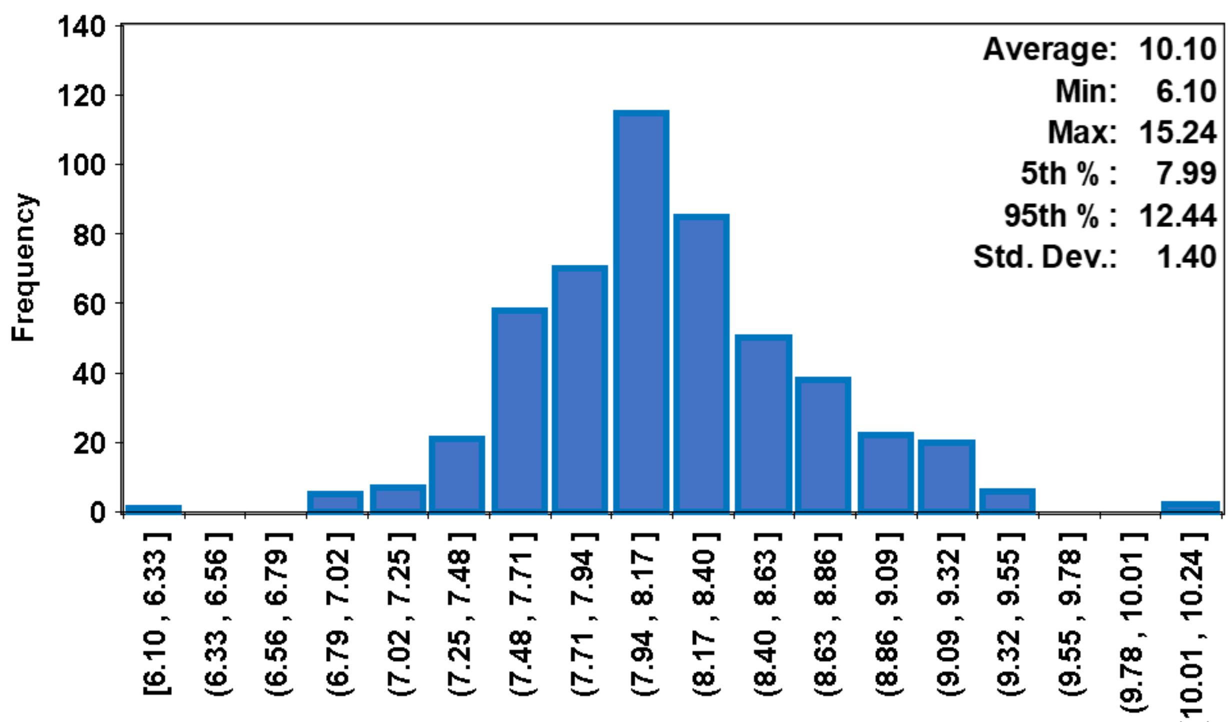


Figure 6.17: Dairy RNG (AM 5) - $ per Dth (500 Draws)

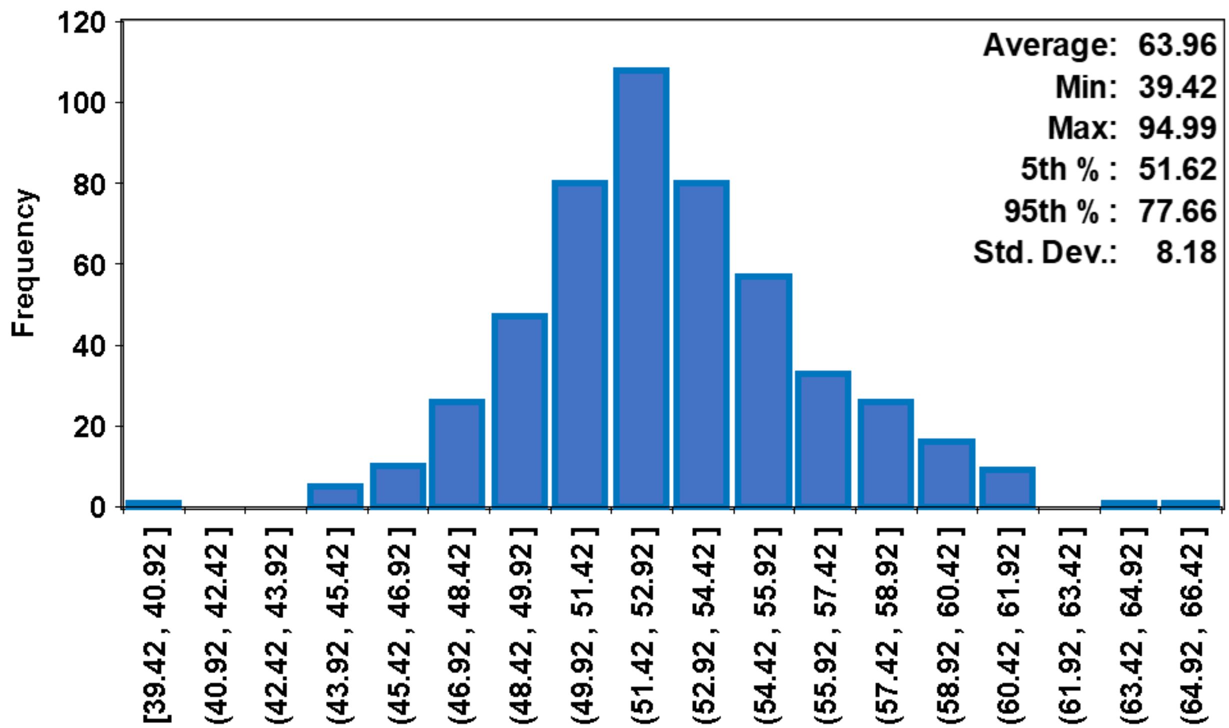


Figure 6.18: Food Waste RNG (FW 3) - $ per Dth (500 Draws)

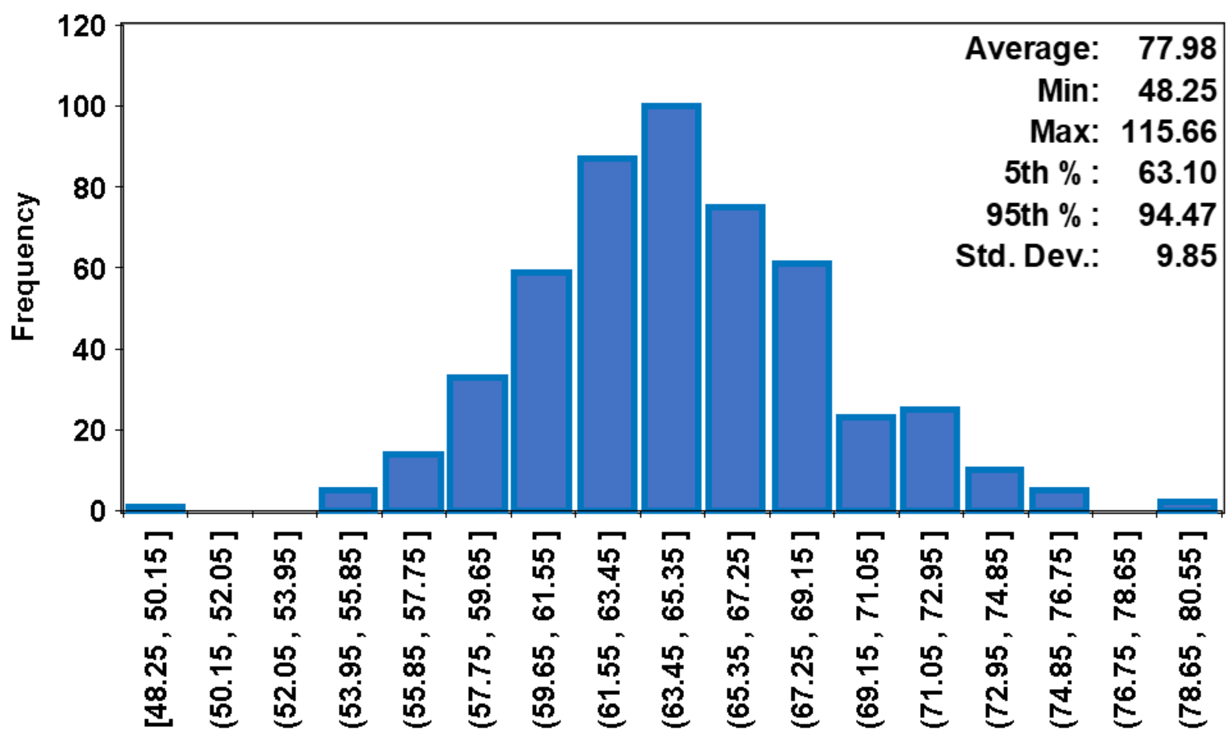


Figure 6.19: Wastewater Treatment RNG (WW 5) - $ per Dth (500 Draws)

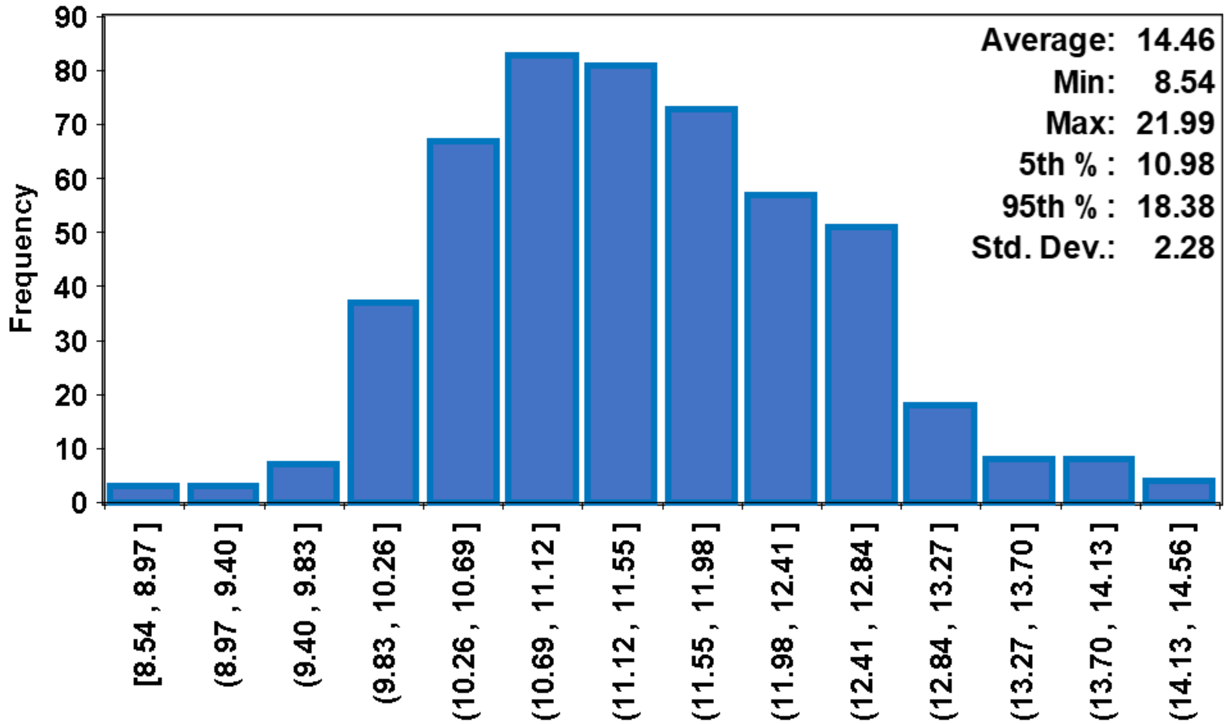


Figure 6.20: Hydrogen (GreenH2-Solar + Electrolysis1) - $ per Dth (500 Draws)

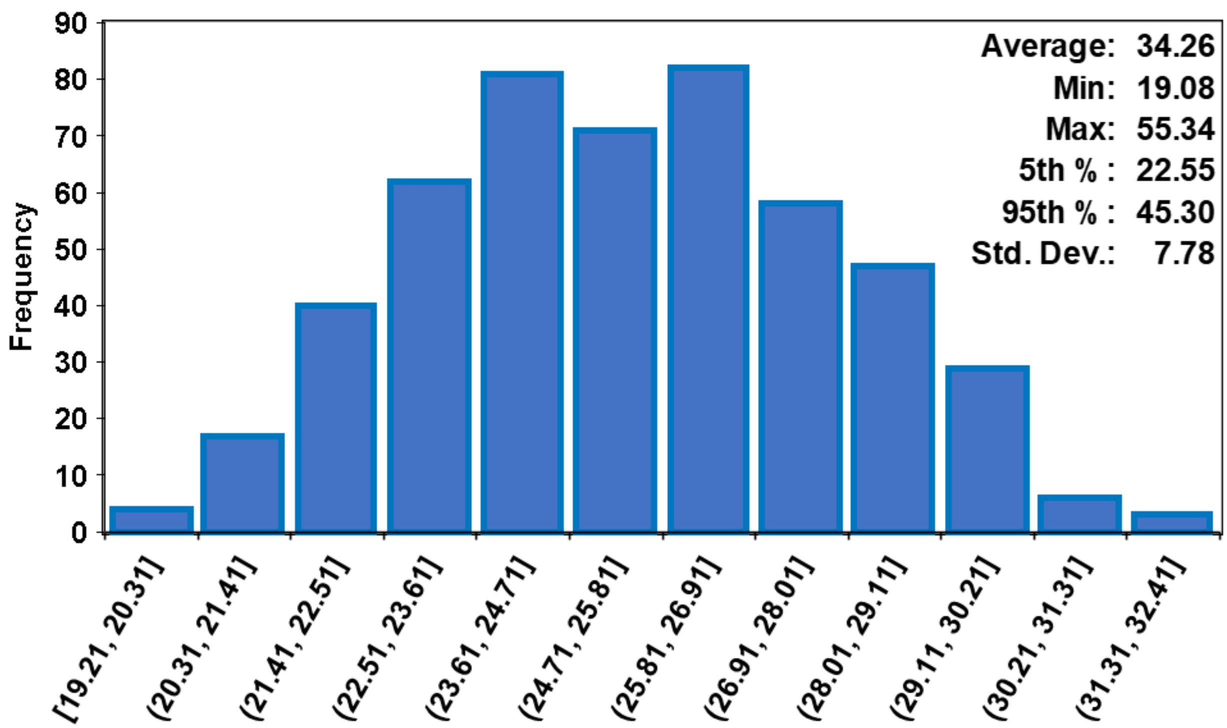
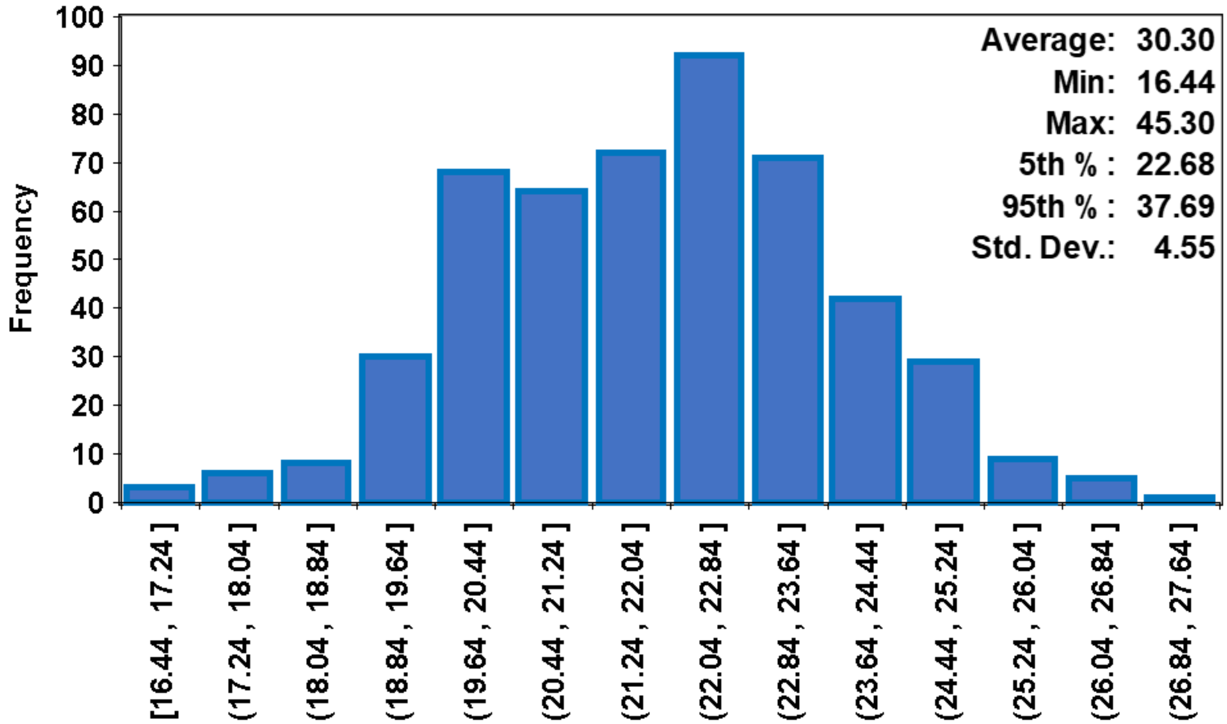


Figure 6.21: Synthetic Methane (Biomass 3) - $ per Dth (500 Draws)



Finally, Table 6.7 summarizes the alternative fuel costs per dekatherm discussed above in nominal dollars. These resources represent the fuels and unit specific values included in the CROME model by type and incremental year to help show changes in cost over the forecast horizon.

Table 6.7: Alternative Fuels Costs per Dth (Nominal $)

Alt Fuel Type	2026	2030	2035	2040	2045
Blue Hydrogen 1	$ 12.86	$ 14.43	$ 18.22	$ 37.27	$ 41.82
Green H2-Wind+Electrolysis 1	$ 36.41	$ 31.26	$ 33.16	$ 56.77	$ 62.13
GreenH2-Solar+Electrolysis 1	$ 28.19	$ 25.61	$ 25.44	$ 39.28	$ 39.79
Microwave Pyrolysis 1	$ 33.40	$ 36.61	$ 43.59	$ 61.93	$ 69.92
AM 4	$ 35.86	$ 41.88	$ 51.36	$ 62.60	$ 76.80
AM 5	$ 47.90	$ 52.56	$ 59.85	$ 67.52	$ 75.99
FW 3	$ 58.61	$ 64.34	$ 73.00	$ 82.22	$ 92.53
LFG 1	$ 31.14	$ 34.72	$ 40.20	$ 46.32	$ 53.31
LFG 2	$ 14.79	$ 16.36	$ 18.86	$ 21.64	$ 24.70
LFG 3	$ 10.60	$ 11.68	$ 13.46	$ 15.44	$ 17.55
LFG 4	$ 8.63	$ 9.48	$ 10.92	$ 12.54	$ 14.22
LFG 5	$ 7.42	$ 8.13	$ 9.38	$ 10.77	$ 12.19
WW 1	$ 47.95	$ 53.65	$ 62.89	$ 73.00	$ 84.48
WW 2	$ 42.66	$ 47.63	$ 55.78	$ 64.64	$ 74.64
WW 3	$ 18.38	$ 20.23	$ 23.73	$ 27.35	$ 31.12
WW 4	$ 13.41	$ 14.66	$ 17.29	$ 19.94	$ 22.56
WW 5	$ 10.48	$ 11.39	$ 13.52	$ 15.62	$ 17.59
Biomass 1	$ 45.44	$ 49.68	$ 65.52	$ 73.71	$ 82.78
Biomass 2	$ 24.08	$ 26.31	$ 34.73	$ 39.22	$ 44.08
Biomass 3	$ 20.09	$ 21.93	$ 28.55	$ 32.26	$ 36.24
GreenH2-BiogenicCO2 1	$ 41.54	$ 36.30	$ 36.81	$ 54.40	$ 55.87
RTC (AM 4)	$ 75.67	$ 83.26	$ 95.08	$ 107.70	$ 121.93
RTC (AM 5)	$ 64.92	$ 71.34	$ 81.46	$ 92.23	$ 104.31
RTC (FW 3)	$ 79.31	$ 87.23	$ 99.33	$ 112.32	$ 127.02
RTC (LFG 1)	$ 53.15	$ 59.41	$ 69.08	$ 79.91	$ 92.49
RTC (LFG 2)	$ 26.17	$ 28.91	$ 33.35	$ 38.26	$ 43.80
RTC (LFG 3)	$ 18.41	$ 20.21	$ 23.26	$ 26.62	$ 30.32
RTC (LFG 4)	$ 14.59	$ 15.94	$ 18.33	$ 20.95	$ 23.78
RTC (LFG 5)	$ 12.17	$ 13.24	$ 15.22	$ 17.39	$ 19.69
RTC (WW 1)	$ 73.58	$ 82.85	$ 97.75	$ 114.35	$ 133.66
RTC (WW 2)	$ 65.11	$ 73.12	$ 86.13	$ 100.54	$ 117.21
RTC (WW 3)	$ 26.63	$ 29.32	$ 34.35	$ 39.66	$ 45.41
RTC (WW 4)	$ 18.83	$ 20.53	$ 24.09	$ 27.74	$ 31.51
RTC (WW 5)	$ 14.25	$ 15.38	$ 18.11	$ 20.82	$ 23.49

Carbon Capture Utilization and Storage (CCUS)

CCUS considers the capturing and utilization of carbon or the storage of the physical carbon elements. This is a form of carbon mitigation where the sources of capture can vary between:

- Flue gases of power plants and industrial facilities burning fossil fuels or biomass/biofuel,
- Process gas streams from industrial facilities (natural gas processing plants, ammonia plants, methanol plants, petroleum refineries, steel mills, cement plants, ethanol plants, etc.)
- Hydrogen plants using fossil fuels or biomass as feedstocks
- Air (through the application of direct air capture).

After capturing CO_2, the next step is to purify and dehydrate the CO_2, compress it for transportation and then either (a) to inject it underground into an appropriate geological storage site, where it is trapped and permanently stored in porous rock or (b) utilize it in one or more of the ways shown in the chart below in Figure 6.22. The prices assumed for carbon capture by type and total volumes for this IRP can be found in Figures 6.23 and 6.24. The costs include incentives from the IRA to help offset the total costs of production. The volumes represent Avista specific large users of natural gas. Stochastic variability was not wide enough to use in the risk portion of the model (Chapter 8) as provided by ICF for CCUS. Avista will work on determining a reasonable stochastic variability for CCUS for future planning documents. More work is needed to understand the capturing of carbon at these large facilities to account for the possibility of additional costs and resources (pipelines, storage) needed for a full set of costs. For these reasons we have pushed out CCUS as a resource potential until 2035. Additional description of carbon capture and all alternative fuels can be found in Appendix 6.

Figure 6.22. Options for CO_2 Utilization (via NETL)

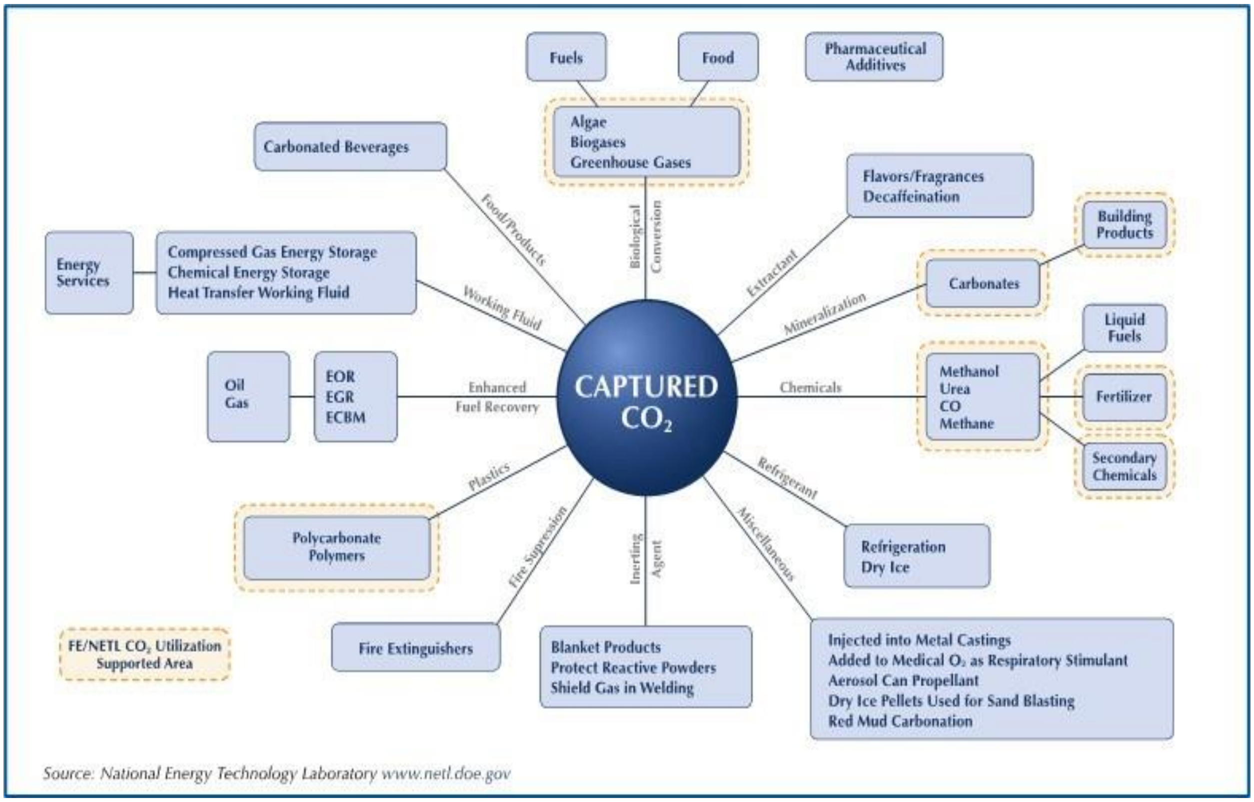


Figure 6.23: CCUS Fixed and Variable Priced per Dth (nominal $)

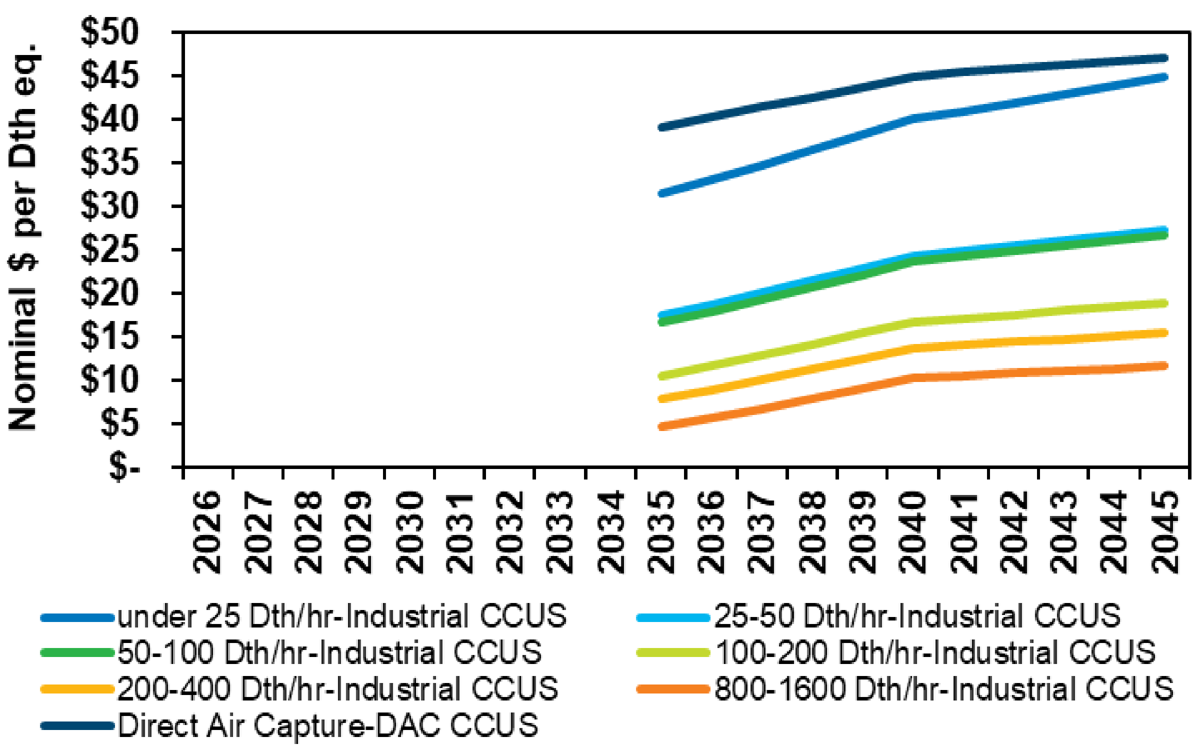
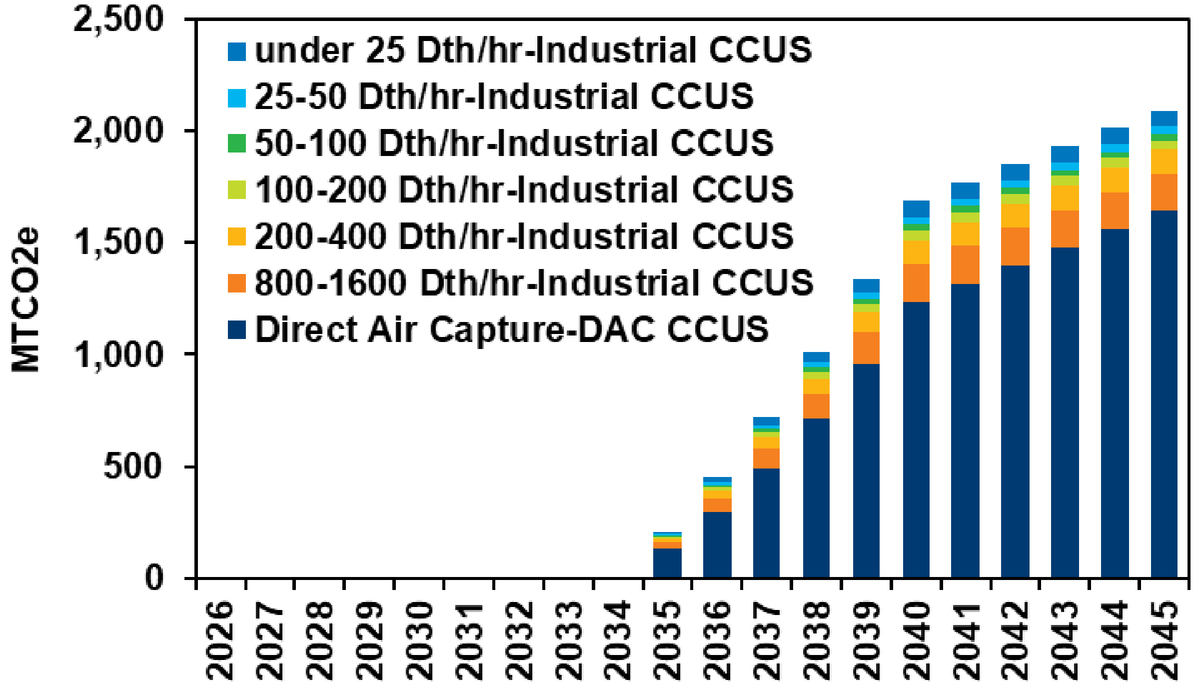


Figure 6.24: CCUS Volumes Modeled MTCO2e



RNG Program Considerations

As Avista prepares to move forward with new RNG supplies, some of the primary considerations given are as follows:

- Evaluate available RNG procurement options.
- Pursue potential RNG development opportunities from local RNG feedstock resources under new legislation (Washington House Bill 1257 & Oregon Senate Bill 98).
- Develop an understanding of RNG development cost, cost recovery impacts to customers, resulting supply volumes and RNG costs.
- Evaluate potential RNG customer market demands vs. supply.
- Participation in RNG rule making and policy determinations, such as:
    - Participation in House Bill 1257 Policy development.
    - Participation in Senate Bill 98 Policy Rulemaking via OPUC Docket AR 632 informal and formal.
- Cost recovery proposal led by NWGA with input from all four Washington LDC’s.
- Collaborative RNG Gas Quality Framework established across four Washington LDC’s.

Utility RNG Projects

Fuel feedstocks are not always readily available nor are feedstock owners who are willing to partner with an LDC to develop renewable natural gas. Even with potential willing feedstock partners, Avista recognizes many practical complexities associated with developing RNG projects as well as the many benefits. The following examples are based on what the Company has learned during its business development efforts;

- Legislation allows LDC's to invest in RNG infrastructure projects with feedstock partners.
- LDC's are credit worthy partners offering long term off-take contracts to feedstock owners.
- Each RNG project is unique with respect to capital development costs & resulting RNG costs.
- Each RNG project will vary in size, location, and distance to interconnection pipeline, feedstock type, gas conditioning equipment and requirements, and operating costs.
- Low volume biogas opportunities face economic challenges because of economies of scale.
- The utility cost of service model is typically a foreign concept to feedstock owners, requiring an educational process to get them comfortable.
- Feedstock owners over-valuing their biogas can degrade project economics.
- New RNG projects can take three to four years to develop given myriad factors. A new RNG project is a multi-year endeavor involving the usual phases expected for major capital construction projects, coupled with many first ever discussions between the utility and the feedstock owner, a new regulatory process and program requirements, the identification of customer cost impacts, environmental benefits, and the tracking process just to name a few.
- Customers have paid for pipeline infrastructure re-usable for a lower carbon intensive fuel.

Project Evaluation - Build or Buy

Avista recognizes the two primary options to procure RNG; build RNG project(s) or buy RNG. In the build scenario, new RNG facilities are developed, and the costs are recovered through the General Rate Case. Avista can also buy RNG from other RNG producers and pass the costs through the Purchase Gas Adjustment (PGA).

Build

Both Oregon's Senate Bill 98 and Washington's House Bill 1257 are focused on decarbonization and support the development of new RNG infrastructure and resources by allowing LDC's to build RNG resources and deliver the RNG. Also, local projects contribute to improved local air quality and support the local economy during construction and operations as discussed in Chapter 9.

Naturally, feedstock biogas royalties are expected to be a key factor in project economics, as well as operating costs including power, conditioning equipment type, interconnection pipeline distance and cost. Since utilities companies are institutional credit worthy partners with the ability to be a long term off-taker for biogas, it is expected these types of build arrangements will be desirable with feedstock owners, and long-term arrangements will temper biogas royalty pricing.

Buy

Competition for environmental attributes pits utility companies against the transportation sector for credits such as the LCFS[7] and RIN[8] markets. These markets create a cost competition for producers where selling RNG volumes into these markets can be lucrative yet risky if markets for these credits move lower than expected.

At Avista, the voluntary RNG program demands will likely have limited volume requirements and be short-term in nature. Since a short-term, low-volume off-take purchase scenario is unlikely to be attractive to producers typically seeking long-term off-take agreements, the expectation is higher RNG costs. Given the nature of this temporary interim situation, a short-term voluntary pilot program in which off-take volumes may be procured from a local producer with excess supply, at a negotiated price, may be advantageous.

This strategy allows Avista to ramp-up and learn more about the demand from its voluntary RNG program in the near-term, while minimizing risk until the Company can supply RNG under a longer-term purchase at a lower price.

[7] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard
[8] https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-numbers-rins-under-renewable-fuel-standard

Environmental Attribute Tracking

Oregon Senate Bill 98 specifies M-RETS[9] as the third-party entity designated to manage environmental attribute tracking and banking for RNG. M-RETS will utilize a proprietary transparent electronic certificate tracking system where one renewable thermal certificate (RTC) is equal to one dekatherm (Dth) of RNG. Given the Oregon requirement and in lieu of contracting with another vendor for the tracking and banking of Washington environmental attributes, Avista will likely use M-RETS for Washington RNG attributes.

The California RNG market will continue to be a major demand for renewable resources due to the low carbon fuel standard (LCFS) in addition to the federal Renewable Identification Number (RIN)[10] market. These incentives can drive the value of these specific renewable resource attributes to many multiples of conventional natural gas prices. While the market has volatility based on demand, the primary issue of bringing additional projects into the market is based on the unknowns as it is related to the market itself. There are currently no forward prices for these renewable credits and the environmental attribute value for local markets is unidentified. These are some of the major obstacles potential producers may encounter when looking for financing of their projects. A potential solution to some of these unknowns in the market is through utility RNG projects. Feedstock owners would now be able to partner with LDC's to cultivate new RNG projects. Financing becomes less of an issue as most LDC's are credit worthy and can provide a measure of certainty with long term offtake agreements.

[9] https://www.mrets.org/

[10] https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-numbers-rins-under-renewable-fuel-standard

This Page is Intentionally Left Blank

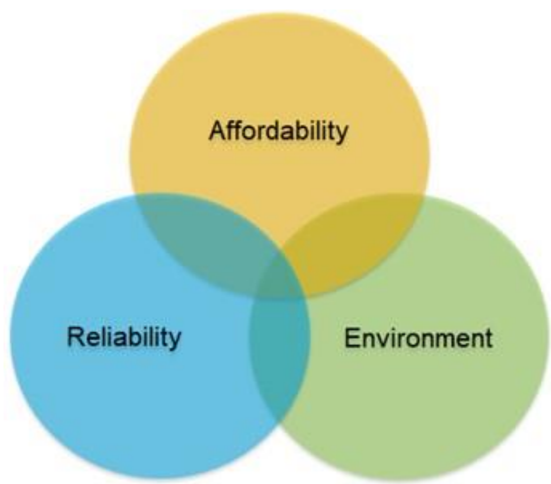
7. Policy Considerations

Section Highlights:

- The Oregon 2024 Climate Protection Plan is the basis for resource decision making to serve Oregon customers.
- Washington's Climate Commitment Act's regional cap and trade is the basis for resource decision making to serve Washington customers.
- Potential tariffs for natural gas purchased from Canada is not considered in this plan.

Regulatory environments regarding energy topics such as renewable energy, carbon reduction, carbon intensity, and greenhouse gas regulation continue to evolve since publication of the last IRP. Current and proposed regulations by federal and state agencies, coupled with political and legal efforts, have implications for the reduction of carbon in the natural gas stream. Avista is challenged with trying to balance affordability, reliability, and the environment with its resource planning solution (Figure 7.1).

Figure 7.1: Resource Planning Balancing Act



Avista has always been at the forefront of clean energy and innovation. Founded on clean, renewable hydro power on the banks of the Spokane river, Avista has maintained an electric generation portfolio with more than half the generation from renewable resources, while continuously making investments in new renewable energy, advancing the efficient use of electricity and natural gas, and driving technology innovation that has enabled and will continue to become the platform and gateway to a clean energy future.

The evolving and sometimes contradictory nature of environmental regulation from state and federal perspective creates challenges for resource planning. The IRP cannot add renewables or reduce emissions in isolation from topics such as system reliability, least cost requirements, price mitigation, financial risk management, and meeting changing environmental requirements. All resource choices have costs and benefits requiring careful consideration of the utility and customer needs being fulfilled, their location, and the regulatory and policy environment at the time of procurement.

The lack of a comprehensive federal greenhouse gas policy has encouraged states, such as California, Oregon, and Washington to develop their own climate change policies and regulations. The climate policies in Oregon and Washington have added state policies, impacting the overall trajectory of Avista's resource needs and future rates. Comprehensive climate change policies can include multiple components, such as renewable portfolio standards, energy efficiency standards, and emission performance standards.

Oregon

Oregon's Climate Protection Program

The State of Oregon has a history of greenhouse gas emissions and renewable portfolio standards legislation. For this IRP, the Climate Protection Program (CPP) is the driving greenhouse gas reduction policy.

In March of 2020, Governor Brown signed Executive Order (EO) 20-04 requiring the reduction of greenhouse gas emissions to at least 45% below 1990 levels by 2035 and 80 percent below 1990 levels by 2050. EO 20-04 requires statewide reductions by all carbon emitting sources and managed by the respective emissions sources governing agencies. State agencies are directed to exercise all authority to achieve GHG emissions reduction goals expeditiously.

CPP 2021 - The initial CPP was invalidated due to the state's Environmental Quality Commission not fully complying with disclosure requirements in 2021 when it voted to create emissions rules that exceed federal rules and affect entities holding industrial air pollution permits under the federal Clean Air Act.

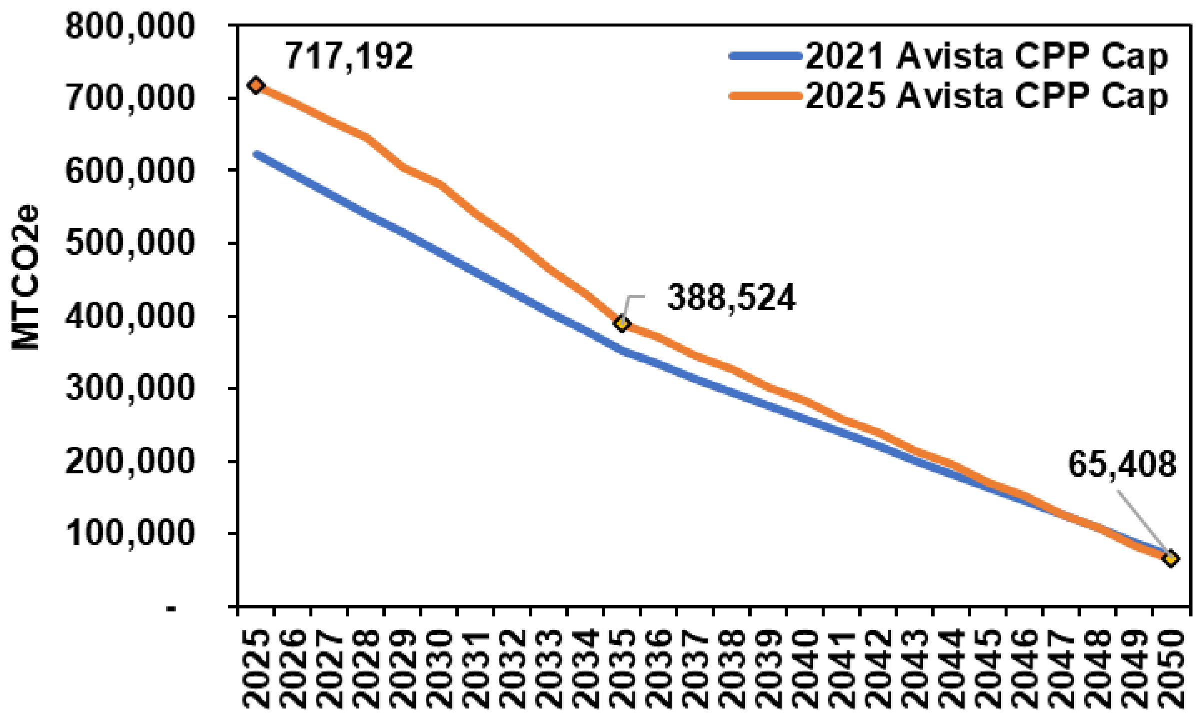
The CPP is the primary program being used to meet EO 20-04 and is being administered by the Oregon Department of Environmental Quality (DEQ) under rule DEQ-18-2024, Chapter 340[1]. This new version of the CPP was adopted on November 21, 2024[2], after a restart of rules process with the rule advisory committee (RAC) in 2024. The CPP is designed to reduce 50% of emissions by 2035 and a 90% reduction by 2050. Figure 7.2 compares 2021 program rules in 2026 with the 2024 updated rule guidelines. Emissions-Intensitve and Trade Exposed (EITE) and Direct Natural Gas (DNG) customers are independantly responsible for complying with CPP and may be excluded from the cap

[1] Department of Environmental Quality: Climate Protection Program 2024: Rulemaking at DEQ: State of Oregon

[2] cppFS2024.pdf

depending on usage above 15,000 MTCO2e[3]. Avista considers in it's modeling within the analysis.

Figure 7.2: Oregon Customers Annual Emissions Compliance Cap Comparison



CPP Program Compliance

Oregon DEQ's rules assume a carbon footprint of roughly 117 pounds per MMBtu for natural gas. For other fuels such as RNG with its renewable thermal credit (RTC) or obtaining just the RTC is assumed to be a non-emitting source with greenhouse gas emissions, regardless of its actual emissions intensity profile. The CPP does not include carbon intensity by source so higher emitting sources such as dairies do not provide additional emissions benefits over a landfill, as other programs do, e.g. the California program. Further, RNG/RTCs do not have to be physically sourced in the state of Oregon. With this provision Avista has greater potential opportunities to seek these resources as compared to if Avista had to physically deliver the fuel to our system. Another element of the program is compliance instruments known as Community Climate Investments (CCI). These instruments allow an entity such as Avista to offset a portion of actual emissions through the purchase of CCIs. The quantity of CCIs available to Avista is directly related to the allowed emissions under the CPP as shown in Figure 7.3. In the years 2025 to 2027, the quantity of CCIs available is equal to 15% of the LDC emissions, and 20% for

[3] https://ormswd2.synergydcs.com/HPRMWebDrawer/Record/6795229/File/document

all compliance periods thereafter. Avista may purchase CCIs at the nominal prices shown in Figure 7.4, with an additional adder of 4.5% for DEQ administration.

Figure 7.3: Maximum Available CCI Compared to the Expected Load

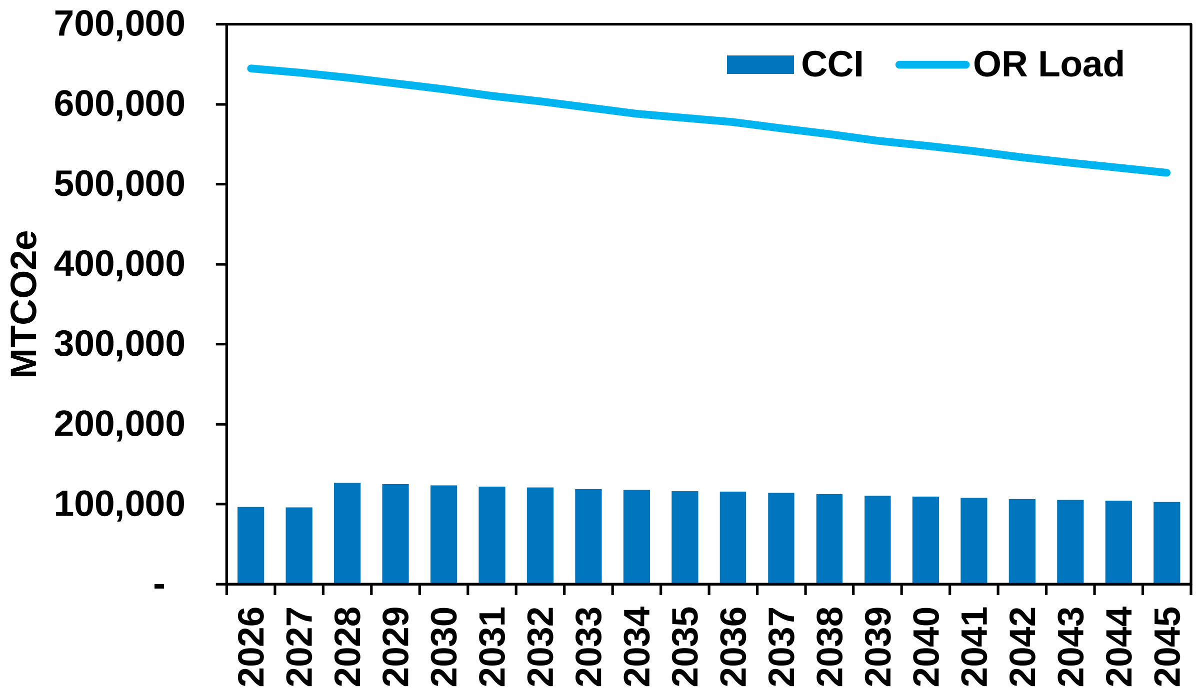


Figure 7.4: Community Climate Investment ($ per MTCO2e)

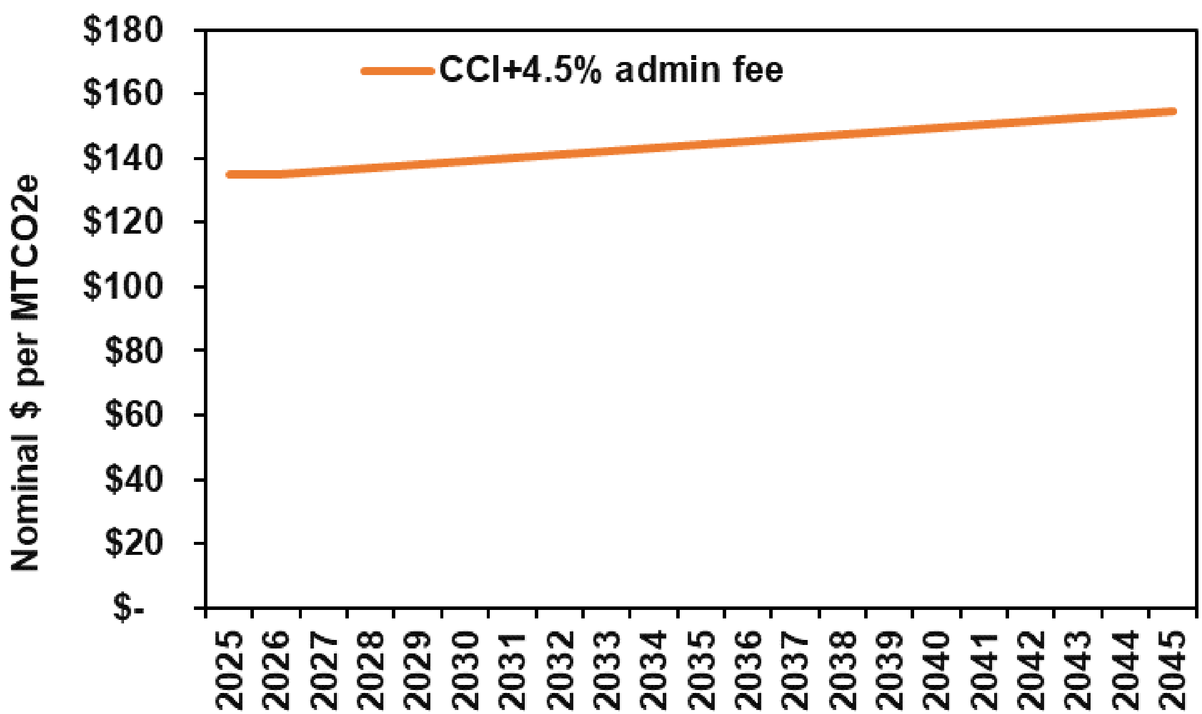
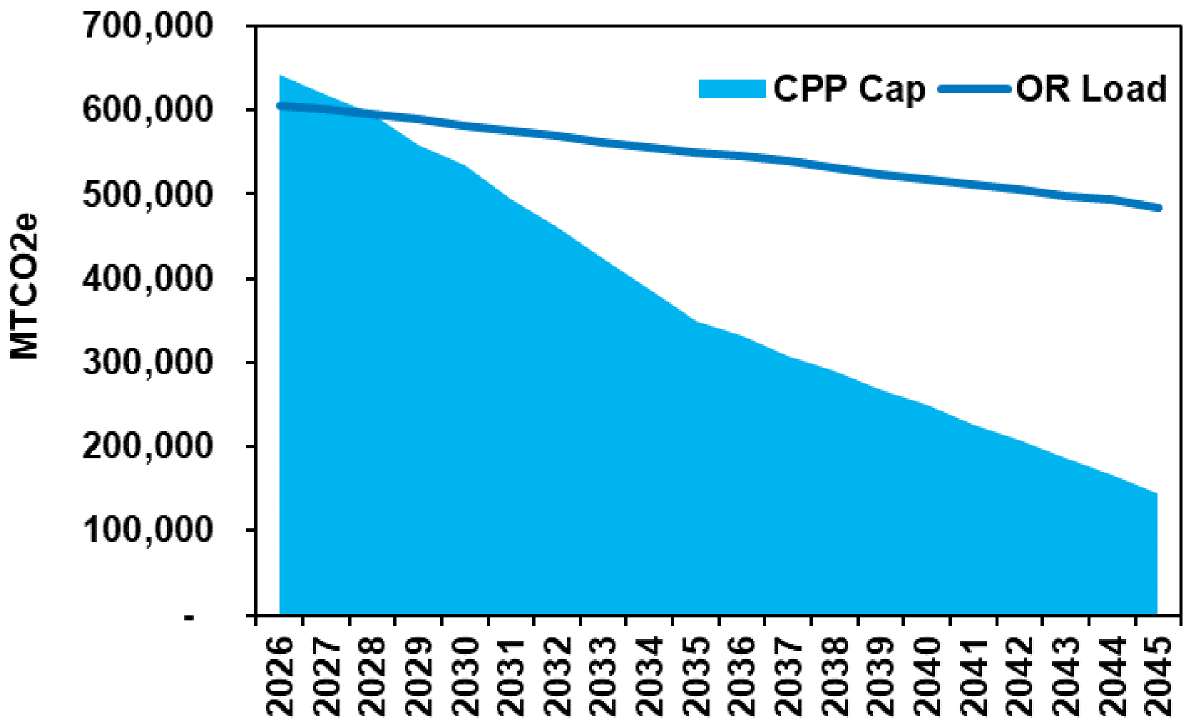


Figure 7.5 combines expected emissions from serving load with natural gas as compared to the number of compliance instruments (CI) given through the CPP to offset these emissions. The net delta would be where resources are needed to meet Avista's CPP targets. The resource mix to meet the greenhouse reduction goals of the CPP is discussed in Chapter 2. All customers are included in the load estimate where Avista hold responsibility for compliance.

Figure 7.5: Expected Load Forecast Emissions Compared to CPP Emissions Target



Oregon Senate Bill 334

Senate Bill 334 was passed in 2017 to develop, update, and maintain the biogas inventory available to Oregon customers. This includes the sites and potential production quantities available in addition to the quantity of RNG available for use to reduce greenhouse gas emissions. This bill also promotes RNG and identifies the barriers and removal of barriers to develop and utilize RNG. In September 2018 the Oregon Department of Energy issued the report to the Oregon legislature titled "Biogas and Renewable Natural Gas Inventory.[4]"

Oregon Senate Bill 844

Senate Bill 844 passed in 2013, with OPUC rules going into effect in December 2014. This bill directed the OPUC to establish a voluntary emission reduction program and

---

[4] 2018-RNG-Inventory-Report.pdf

criteria for the purpose of incentivizing public natural gas utilities to invest in emission reducing projects providing benefits to their respective customers. The public utility, without the emission reduction program, would not invest in the project in the ordinary course of business.

To date, this legislation has not yielded any emission reducing projects. Avista is aware that Governor Brown's Executive Order 20-04 has the OPUC reconsidering the usefulness of SB 844.

Oregon Senate Bill 98

Senate Bill 98 was passed during the 2019 regular session and mandates the OPUC "to adopt by rule a renewable natural gas program for natural gas utilities to recover prudently incurred qualified investments in meeting certain targets for including renewable natural gas purchases for distribution to retail natural gas customers."

The OPUC initiated a rulemaking to implement Senate Bill 98 under Docker AR 632 in late 2019 with final rules taking effect on July 17, 2020. To participate in a SB 98 RNG Program, a petition to participate is required. Small utilities desiring to participate are required to define their respective percentage of revenue requirement per year needed to support potential project investment costs. The bill allows investment in gas conditioning equipment without RFP process. Per the OPUC's rules, the RNG attributes will be tracked by the M-RETS system as renewable thermal certificates (RTC) in which (1) RTC = (1) Dekatherm of RNG.

Washington

Washington State Policy Considerations[5]

In 2008, Washington's Legislature introduced a framework for reducing greenhouse gas emissions with HB 2815[6]. In December 2020, Washington State's Energy Strategy was released as a roadmap to meet Washington's laws of reducing greenhouse gas emissions, as follows:

- By 2030 a 45% reduction below 1990 levels
- By 2040 a 70% reduction below 1990 levels
- By 2050 a 95% reduction below 1990 levels and net-zero emissions

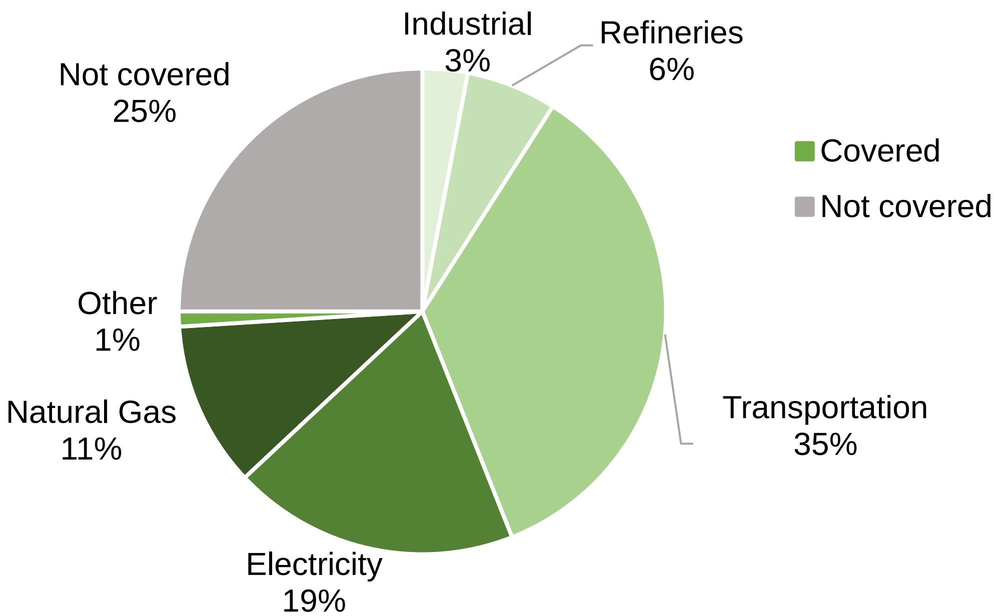
Climate Commitment Act

The Washington legislature passed into law its largest environmental program in 2021, the Climate Commitment Act (CCA) (RCW 70A.45.020). The CCA is administered by Washington Department of Ecology with the program beginning January 1, 2023. The CCA creates a state-wide emissions cap and invest program where statewide emissions

5 https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/
6 Washington State Greenhouse Gas Emissions Inventory

are to be reduced by 95 percent by 2050. The CCA will also expand the air quality monitoring in overburdened communities with evaluation every two years to ensure pollutants and greenhouse gases are being reduced. Initial covered entities under the CCA include industrial facilities, certain fuel suppliers, natural gas distributors, and in state electricity suppliers. Figure 7.6 illustrates the CCA coverage by percentage of emissions and industry type for included covered entities.

Figure 7.6: Climate Commitment Act Coverage[7]



Future emitting participants will be added in 2027, for example the inclusion of the City of Spokane's Waste-to-Energy plant. The emission allowance cap for the CCA reduces emissions beginning 2023 by 7 percent annually until 2030. The cap then decreases by 1.8 percent annually from 2031 to 2042. Carbon dioxide emissions from biomass or biofuels are exempt from this program.[8] Finally, the cap decreases by 2.6 percent in the years 2043 to 2049 to fully meet the 95 percent below 1990 reduction state goal noted above. For modeling purposes, we fully exclude any emissions from RNG for compliance with the CCA in the resource selection described in Chapter 2. A summary of the pro rata share of this reduction to Avista's LDC emissions is shown in Figure 7.7.

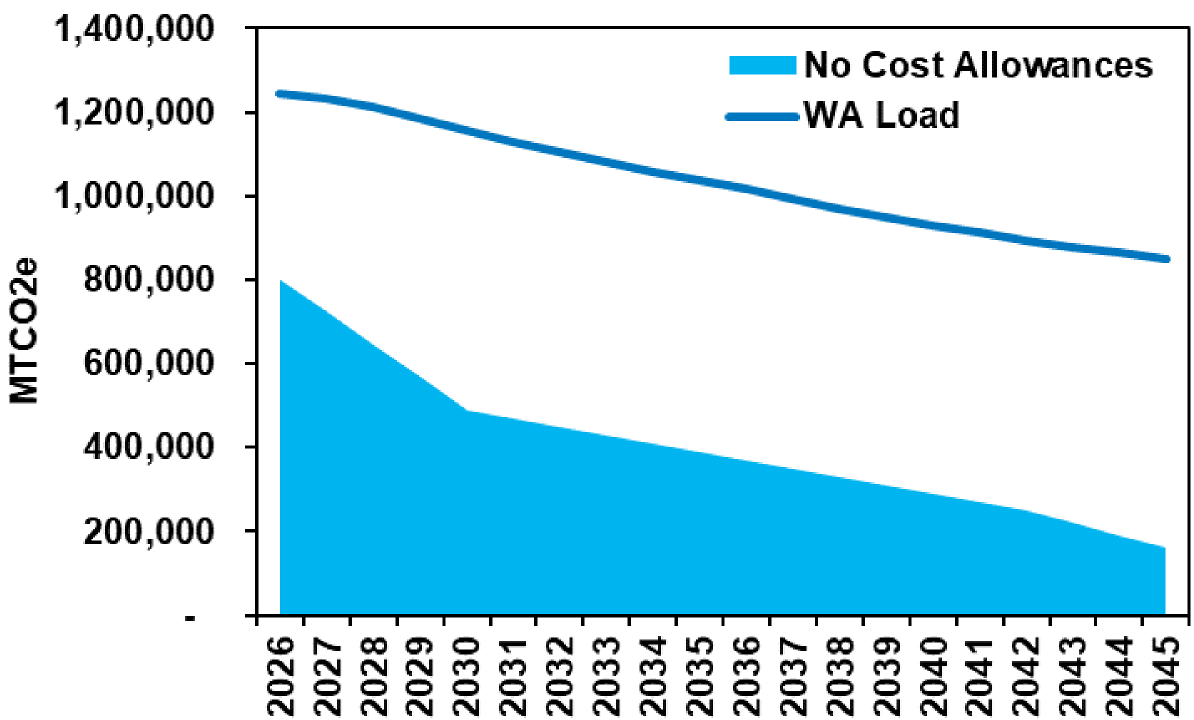
All covered entities are required to obtain allowances or offsets to cover their emissions. Offsets are projects reducing, removing, or avoiding greenhouse gas emissions and are verified through audits. Offsets can be used in place of allowances beginning in the first compliance period of 2023 – 2026, with limit of a total of 5% of their emissions from general offset projects and 3% from Tribally supported projects. These offset projects include four protocols adopted from the California program and include U.S. Forestry,

[7] Washington State Department of Ecology produced graphic
[8] RCW 70A.65.080 (1)(iii)(7)(d)

Urban Forestry, Livestock Projects, and Ozone Depleting Substances. As of December 2024, three projects have been approved for offset credits totaling 310,000 MTCO2e[9] of credits.

Offsets are below the cap meaning allowances and offsets are interchangeable and should be procured on a least cost or least risk basis. Also, if offsets are used for compliance, less CCA credits will be available to other participants. These offsets drop after this initial timeframe to 4% general offsets and 2% of Tribal offsets going forward starting 2027. Transport customers outside of Avista's obligations have access to the allowance market. For those transport customers within Avista's compliance obligations, Avista purchases allowances for all customers, regardless of class, for compliance.

Figure 7.7: Expected Load Forecast Emissions Compared to CCA Emissions Target



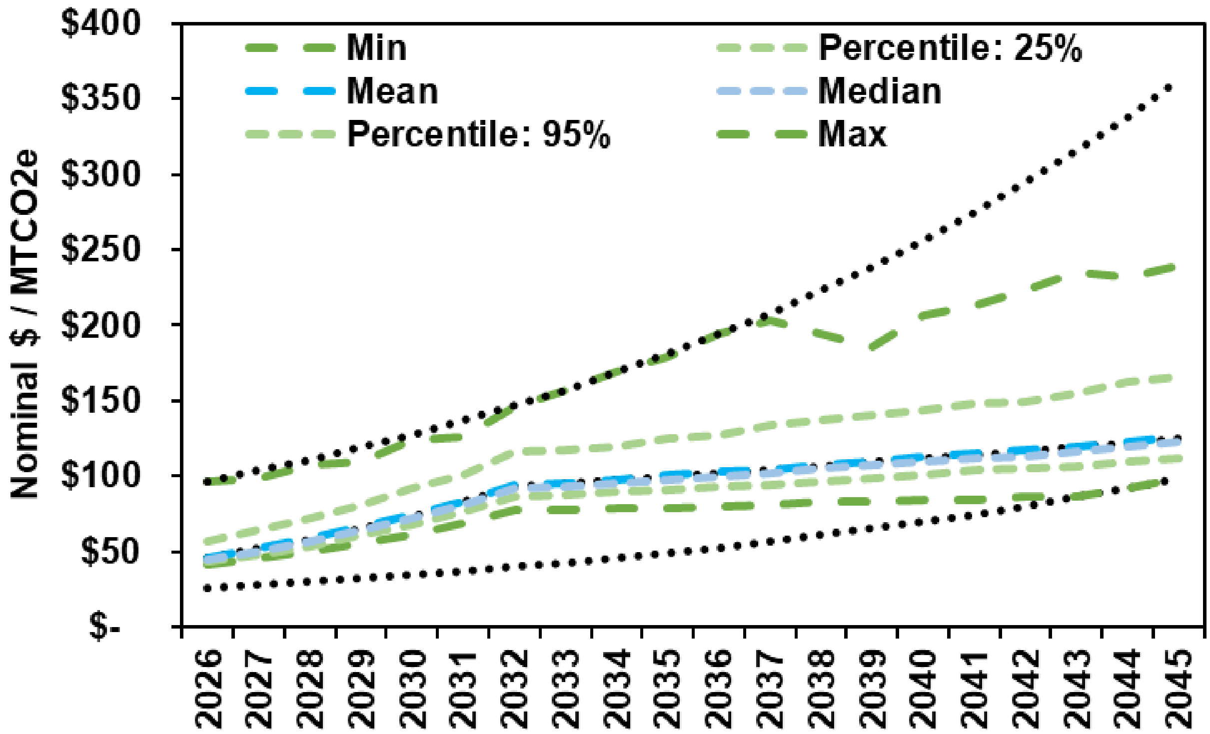
Program participants will be required to cover their emissions by the purchase of "allowances" acquired through state auction or by purchasing offsets in the secondary market. Electric utilities are also required to offset their emissions but will be given free allowances to cover most of their emissions. Electric utilities are already covered under the Clean Energy Transformation Act which requires 100% clean energy by 2045. The full impacts of the CCA to Avista's customers are not known at this time.

[9] Ecology Offset Credit Issuance Table

The CCA allows for Washington to join California and the Quebec markets to increase "allowance" liquidity possibly as early as 2026. California and Quebec still need to approve the addition of Washington to their program.[10] The law also focuses on using proceeds from state allowance auctions to improve over-burdened communities and tribes but also incent a clean energy transformation of Washington to electrify transportation and heating. This plan assumes linkage with California and Quebec to determine our forecast of emission pricing.

Allowances are available through quarterly auctions or traded on a secondary market. Allowances will decrease over time to meet goals state statutory limits. All proceeds from allowances must be used for clean energy transition. This transition includes bill assistance, clean transportation, and climate resiliency projects promoting climate justice with a minimum of 35 percent of funds to provide direct benefit to overburdened communities. Allowances price estimates used for evaluation are illustrated in Figure 7.8 where the floor and ceiling prices are in the dotted black lines.

Figure 7.8: Expected CCA Allowance Prices



Washington HB 1257

HB 1257 was passed during the 2019 Regular Session, coined the "Building Energy Efficiency" bill, mandating each gas company to offer by tariff a voluntary renewable natural gas service. The bill also allows LDCs to create an RNG program to supply a

---

10 Cap-and-Trade Program | California Air Resources Board

portion of the natural gas it delivers to its customers. Any such program is subject to review and approval by the WUTC. Regarding natural gas distribution companies, this bill was designed for the purpose of establishing the following:

> *"efficiency performance requirements for natural gas distribution companies, recognizing the significant contribution of natural gas to the state's greenhouse gas emissions, the role that natural gas plays in heating buildings and powering equipment within buildings across the state, and the greenhouse gas reduction benefits associated with substituting renewable natural gas for fossil fuels."*

Section 12 of the bill "finds and declares:

a) Renewable natural gas provides benefits to natural gas utility customers and to the public;
b) The development of RNG resources should be encouraged to support a smooth transition to a low carbon energy economy in Washington;
c) It is the policy of the state to provide clear and reliable guidelines for gas companies that opt to supply RNG resources to serve their customers and that ensure robust ratepayer protections."

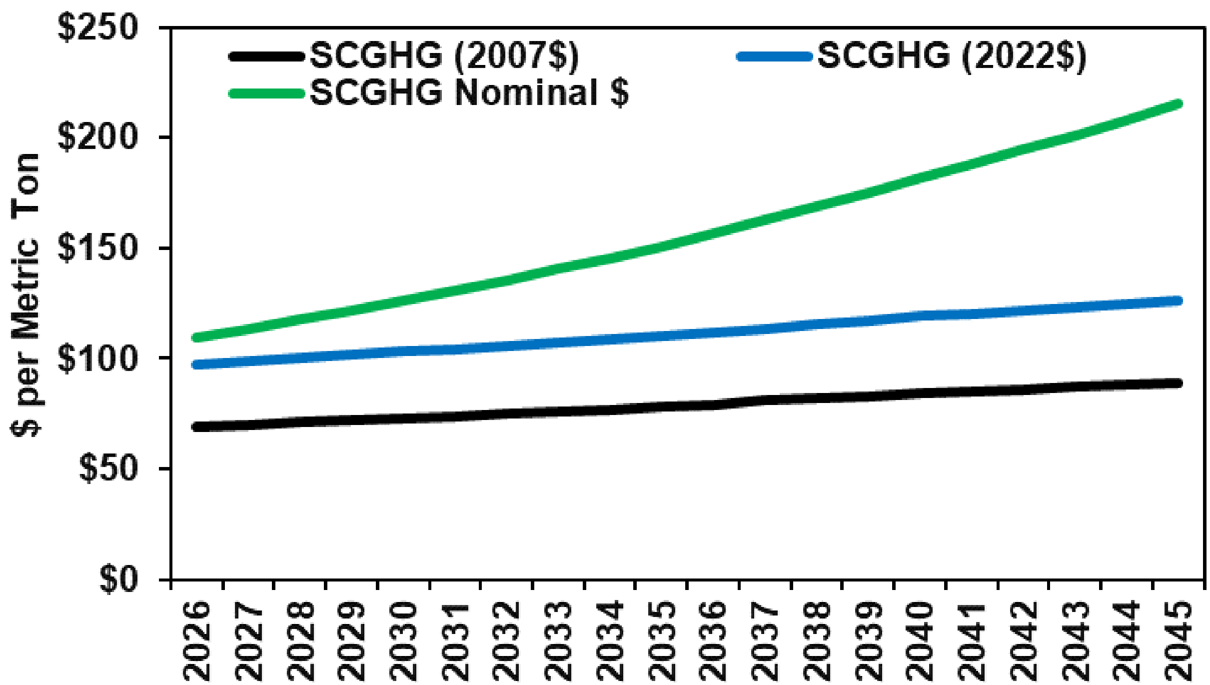
Section 13 of the bill allows LDC's to propose an RNG program under which the company would supply RNG for a portion of the natural gas sold or delivered to its retail customers. Section 14 of the bill states that LDC's must offer by tariff a voluntary RNG service available to all customers to replace any portions of the natural gas that would otherwise be provided by the gas company.

HB 1257 provided limited direction and the necessary details to advance RNG programs and projects. As such, there has been an effort on behalf of the impacted utilities to provide the commission with feedback and clarity with respect to gas quality and cost treatment. More specifically, the Northwest Gas Association (NWGA) has collaborated with Washington LDC's to develop a common Gas Quality Standard Framework, and proposed language defining the treatment of RNG program costs.
On December 16, 2020, the Washington UTC issued a Policy Statement to provide guidance with respect to the following elements of HB 1257 as follows; General Program Design, RNG Program cost cap, Voluntary Program cost treatment, gas quality standards, and pipeline safety, environmental attributes and carbon intensity, renewable thermal credit (RTC) tracking, banking, and verification.

Social Cost of Greenhouse Gas

Figure 7.9 shows the social cost of greenhouse gas at 2.5%, this price represents the marginal cost of the impacts caused by carbon emissions per metric ton at any point in time. This price forecast is used in two specific areas of the 2025 Gas IRP. The first is for the evaluation of energy efficiency in Washington in the Total Resource Cost test in combination of upstream emissions. The second way these costs are incorporated is through the Social Cost of Greenhouse Gas scenario found in Chapter 8. In this scenario, this price is used for Washington's resource decision making. The "SCGHG Nominal $" is what is employed in this IRP where Social Cost of Carbon is mentioned.

Figure 7.9: Social Cost of Carbon at 2.5% Modeled Costs



Initiative 2066

In 2022, Washington's[11] Building Council passed new commercial and residential construction building code changes to require heat pumps for space and water heat beginning July 1, 2023 for new construction. For residential buildings, codes do not require a specific fuel source if heat pump technology is utilized.

In response to these building code changes, Initiative 2066 was passed into law on December 5, 2024 and was aimed at a 2024 law that stops a large combination utility, Puget Sound Energy (PSE), from incentivizing the use of natural gas. This law prevented PSE from offering any customers a rebate for installing gas-powered appliances. The initiative reverses these code changes and ultimately written to protect natural gas access and prohibit state and local governments from discouraging natural gas use. This initiative allows local utility services to continue to offer gas as an option to customers who request it.

11 Digital Codes (iccsafe.org)

While those against the measure, No on I-2066, have conceded the race, they are exploring possible legal challenges to the measure. The Building Industry Association of Washington has also filed a lawsuit to declare that the Washington State Building Council must comply with I-2066. While the outcome of these legal challenges is unknown, a higher load forecast is considered through scenario analysis to understand the impact if the law changes remain and can be found in Chapter 8. Due to timing of the initiative passing and the modeling process, this load forecast is not available for the Preferred Portfolio Analysis. Oregon and Idaho do not currently have any codes or policies requiring building electrification.

Thermal Energy Networks (TENs)

TENs provide thermal energy for space heating, cooling or process uses from a central plant or combined heat and power facility. This thermal energy is distributed to two or more buildings through a network of pipes. ESHB 2131[12] authorizes gas and most electrical companies to own or operate a TENs, subject to oversight from the WUTC. These networks may be considered depending on the availability of a specific area and estimated costs to develop and administer the network, subject to WUTC approval.

Federal Legislation

Various federal agencies, including the Consumer Product Safety Commission, Department of Energy, Department of Housing and Urban Development and Environmental Protection Agency, have been petitioned to, or are either considering new regulation of natural gas appliances, or are considering banning the use of fossil fuels in federal buildings and subsidized public housing. To date, no new regulations from the federal level have been adopted in this regard.

Inflation Reduction Act

Signed into law in August 2022, the Inflation Reduction Act (IRA) provides support in the form of grants, loans, rebates, incentives, and other investments for clean energy and climate action. The IRA includes over $300 billion in available funding and tax credits to be used for climate and energy programs starting in 2023 to 2032. This program both extends and expands the renewable electricity production tax credit and the energy tax credit and provides for a “technology neutral” clean electricity production and investment credit. Credits range from zero-emissions nuclear power production credit, carbon capture and storage, clean hydrogen to energy manufacturing credits.

There are bonus credits with projects meeting certain prevailing wage and apprenticeship requirements with an additional 10 percent credit bonus if produced domestically with domestic products. The credits discussed below assume direct impact on prices and technology maturity as discussed in Chapter 4.

[12] 2131-S.E SBR ENET OC 24

Various tax credits may apply to renewable energy production including wind, geothermal, solar, RNG, hydropower and all forms of renewable energy for facilities placed into service after December 25, 2022. Additionally, these facilities must have begun construction prior to January 1, 2025. This is assumed to impact the overall build of renewable sources and green hydrogen production and the availability of carbon to react synthetic methane. Carbon capture technologies include ranges of incentives based on type.

Direct Carbon Capture Facilities must capture a minimum of 1,000 metric tons of carbon dioxide during the tax year. The base rate starts at $36 per metric ton with a higher rate of $180 for carbon dioxide captured for storage in geologic formations. If the carbon is captured and used by the taxpayer a rate of $26 to $130 per metric ton is applicable. A final credit is available for carbon captured and used for enhanced oil recovery or other use but is not included or considered in this IRP.

A credit applies to clean hydrogen production after December 31, 2022, for a facility with construction beginning before 2033. The credit includes a base of 60 cents per kilogram and is multiplied by the lifecycle greenhouse emissions rate percentage with a bonus credit for prevailing wages, domestic materials, and investment. A full credit in the amount of $3 per kilogram is attainable considering meeting each credit criteria. Avista assumes this $3 per kilogram in its price forecast for green hydrogen.

Finally, a buildings and end use efficiency credit in the IRA includes incentives for homeowners' investment in energy efficiency. It includes a tax credit for upgrading end use equipment including insulation, windows, doors, and end use equipment. We assume a 50% direct credit to the homeowner for costs to convert from natural gas to electric end use. All resource options in Chapter 6 have incentives from the IRA included in estimated costs where applicable.

Due to changes in the Federal Administration, Avista is not confident all provisions in the IRA will remain. Avista will re-evaluate these assumptions in the 2027 IRP as new policy is enacted.

Tariffs

Avista is not including any effects of potential tariffs from Canadian natural gas within this plan. Avista purchases approximately 83% of natural gas from Canada. Due to lower prices of Canadian fuel compared to US sources in the Rockies, there will be minimal switching between Canadian and US gas basins as Avista's interstate pipeline contracts from the Rockies supply is limited. Finally, the cost of natural gas commodity ranges between 20% and 50% of the customer prices, therefore tariffs on imported natural gas may have a minimal impact on customer rates.

This Page is Intentionally Left Blank

8. Alternative Scenarios

Section Highlights:

- Future demand remains the most uncertain assumption in this plan.
- Portfolio risk of the PRS is dependent on quantity, availability, and price of alternative resources.
- Recent peak weather events and diversification of resources are increasingly important to consider in a future resource mix.
- The system benefits from a local storage and fuels to improve resilience if interstate pipelines become unavailable.

This chapter identifies the resource portfolios for alternative future assumptions, such as differing demand and supply resource scenarios as compared to the Preferred Resource Strategy (PRS). Scenarios consider different underlying assumptions vetted with the Technical Advisory Committee (TAC) members to develop a consensus about the number and types of cases to model. These scenarios help in the understanding of the PRS results and provide insights into the costs and benefits of future policy changes.

Alternate Demand Scenarios and Sensitivities

As discussed in Chapter 2, Avista identifies alternate scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. All cases identified as a scenario (Table 8.1) are studied using 500 Monte Carlo or stochastic simulations to identify risks and outcomes by various weather, price, and alternative fuel volume availability. These scenarios may represent a major change with forecasted demand or policy. Alternative sensitivities (Table 8.2) help in the understanding of how resources selections may change based on adjustments to expected inputs and use deterministic assumptions. A guide to these assumptions and how all cases compare to one another is included in Table 8.3.

Monte Carlo runs are helpful to understand risks for the selected resources based on the specific changes. When comparing scenarios and sensitivities, a deterministic model is useful to help show cost variability based on different assumptions. If Avista were to compare all scenarios and sensitivities, based on statistics, the costs would average out to roughly those costs as depicted in the deterministic scenarios. For this reason, using Monte Carlo on all cases evaluated is not helpful as they use the same values. The PRS is the most reasonable to run a Monte Carlo for risk of differing prices, loads and volumes available as it is the expected future.

Table 8.1: IRP Scenarios

Scenario	Description
Diversified Portfolio	Forces alternative fuels on system in 2030 to begin system decarbonization.
No Climate Programs	Assumes less climate programs to help quantify PRS cost impacts.
Preferred Resource Strategy	All expected assumptions and preferred resource selection based on expectations.
Resiliency	An outage occurs over peak day weeks (Feb. 28th and Dec. 20th) and assumes 50% availability of transport and storage resources on the west side (Sumas, JP) as unavailable.
Social Cost of Greenhouse Gas	PRS assumptions and resource selection based on Social Cost of Greenhouse Gas.

Table 8.2: IRP Sensitivities

Sensitivity	Description
Average Case Weather	PRS assumptions using average 20-year historic weather and 3- year customer usage coefficients.
High Alternative Fuel Costs	Higher than expected costs for alternative fuels using 95th percentile of prices from all Monte Carlo draws.
High CCA Pricing	95th percentile of all 500 Monte Carlo draws for Climate Commitment Act (CCA) prices.
High Growth on Gas System	Highest growth scenario for loads with corresponding increased energy efficiency forecast.
High Natural Gas Prices	95th percentile of all 500 Monte Carlo draws for natural gas prices.
High Electrification	Highest loss of customers due to building electrification includes corresponding decreased energy efficiency forecast.
Hybrid Heating	Assumes customers add an electric heat pump to their existing natural gas furnace over forecast horizon.
Initiative 2066	Adds Washington's new commercial customers usage to the expected load forecast.
Low Alternative Fuel Costs	5th percentile of all 500 Monte Carlo draws for natural gas prices.
Low Natural Gas Use	Lower than expected demand on the as compared to the PRS. Also includes the RCP 8.5 weather, high alternative fuel prices and low volumetric availability. High natural gas prices. High CCA allowance prices.
RCP 6.5 Weather	Assumes RCP 6.5 weather futures rather than RCP 4.5.
RCP 8.5 Weather	Assumes RCP 8.5 weather futures rather than RCP 4.5.
No Purchased Allowances After 2030	Assumes no Allowances are purchased after 2030.
No Growth	Assumes no new customers after phaseout of gas line extension subsidies in Washington (2025) and Oregon (2026).

Table 8.3: Scenario and Sensitivity Input Guide

2025 IRP Cases	Load Forecast	Peak Days	Weather	DSM	Natural Gas Prices	Allowance Prices	Alternative Fuel Prices	RTC Prices	Alternative Fuel Volumes	RTC Volumes	Carbon Intensity	Social Cost of Carbon
PRS	Expected											None
Hybrid Heating	Hybrid Heating											
Initiative 2066	Initiative 2066											
No Growth	No Growth											
RCP 6.5 Weather	RCP 6.5											
RCP 8.5 Weather	RCP 8.5											
Average Case Weather	3-Year UPC	No Peak Days	20 Year Average									
High Electrification	Electrification			Low Quantities								
High Growth on Gas System	High Growth			High Quantities								
Low Natural Gas Use Case	Low Growth				High	High	High	High	Low	Low		
High Natural Gas Prices					High							
High CCA Costs						High						
High Alternative Fuel Costs							High	High				
Low Alternative Fuel Costs							Low	Low				
Social Cost of Carbon											Upstream Emissions Included	SCC Included
Diversified Portfolio	Alternative fuels forced onto system in 2030; 40% of CCA and CPP compliance met with Hydrogen (20), RNG (17), and Synthetic Methane (3).											
No Climate Programs	CCA and CPP programs are removed from consideration.											
No Purchased Allowances After 2030	No Allowances are available for purchase after 2030.											
Resiliency	Sumas, Station 2, and JP capacities limited to 50% during week of peak day.											

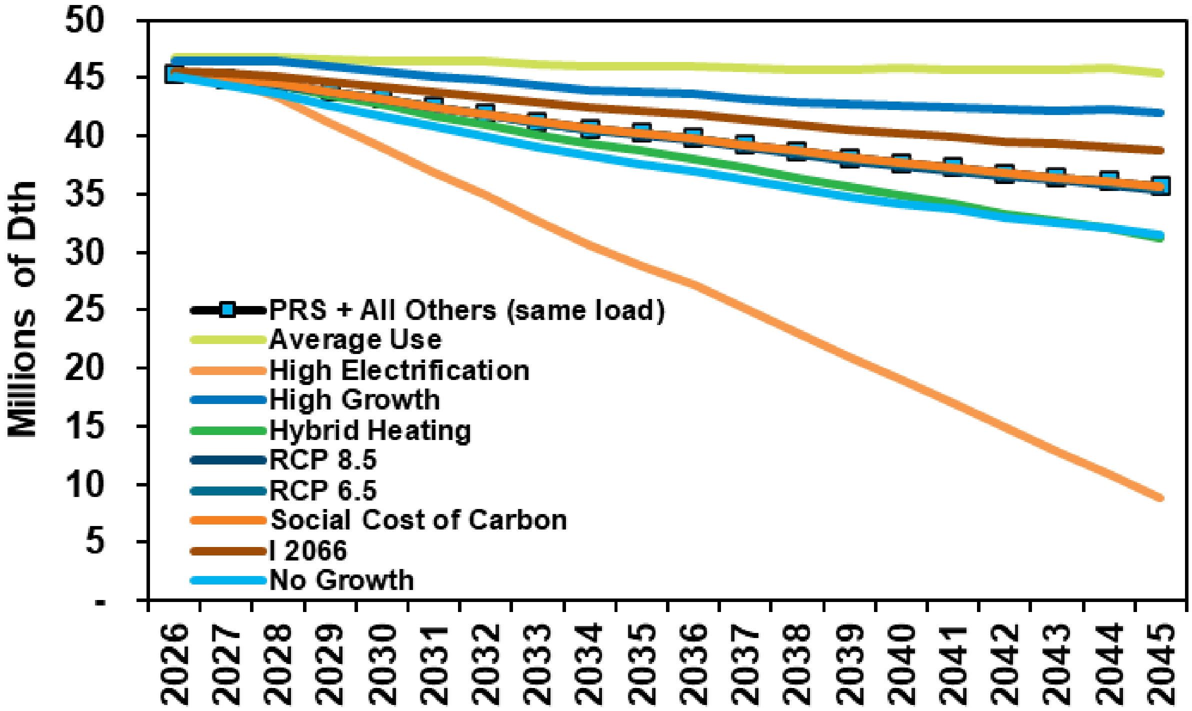
Deterministic Evaluation

A deterministic evaluation was used to consider alternative cases. These alternate demand and supply scenarios are placed in the model as predicted future conditions for supply portfolio to satisfy with least cost and least risk resources. This creates bounds for analyzing the Preferred Resource Selection by creating high and low boundaries for customer usage, weather, alternative fuels volumetric availability and pricing. Each portfolio is simulated through CROME where the supply resources, demand resources and energy efficiency are compared and selected on a least cost basis. Results are not all directly comparable as different demand and price assumptions change the least cost results.

Demand

Demand profiles for firm customers, or customers where Avista complies with a climate program, are net of energy efficiency measures shown in Figure 8.1 illustrate the demand risks from the alternate scenarios. The demand for our Average case shows the greatest expected system demand using historic use per customer and weather. The High Electrification case indicates the lowest expected demand using the end-use modeling methodology as discussed in Chapter 3. As discussed in previous chapters, demand is the greatest risk in this IRP and has fundamentally changed due to building codes, clean energy policies, and lowering expected energy use intensity. These demand forecasts show a decreasing demand throughout the study horizon. Further analysis will be necessary to carefully consider the impacts to future demand expectations and resources to meet those needs.

Figure 8.1: System Annual Demand Scenarios



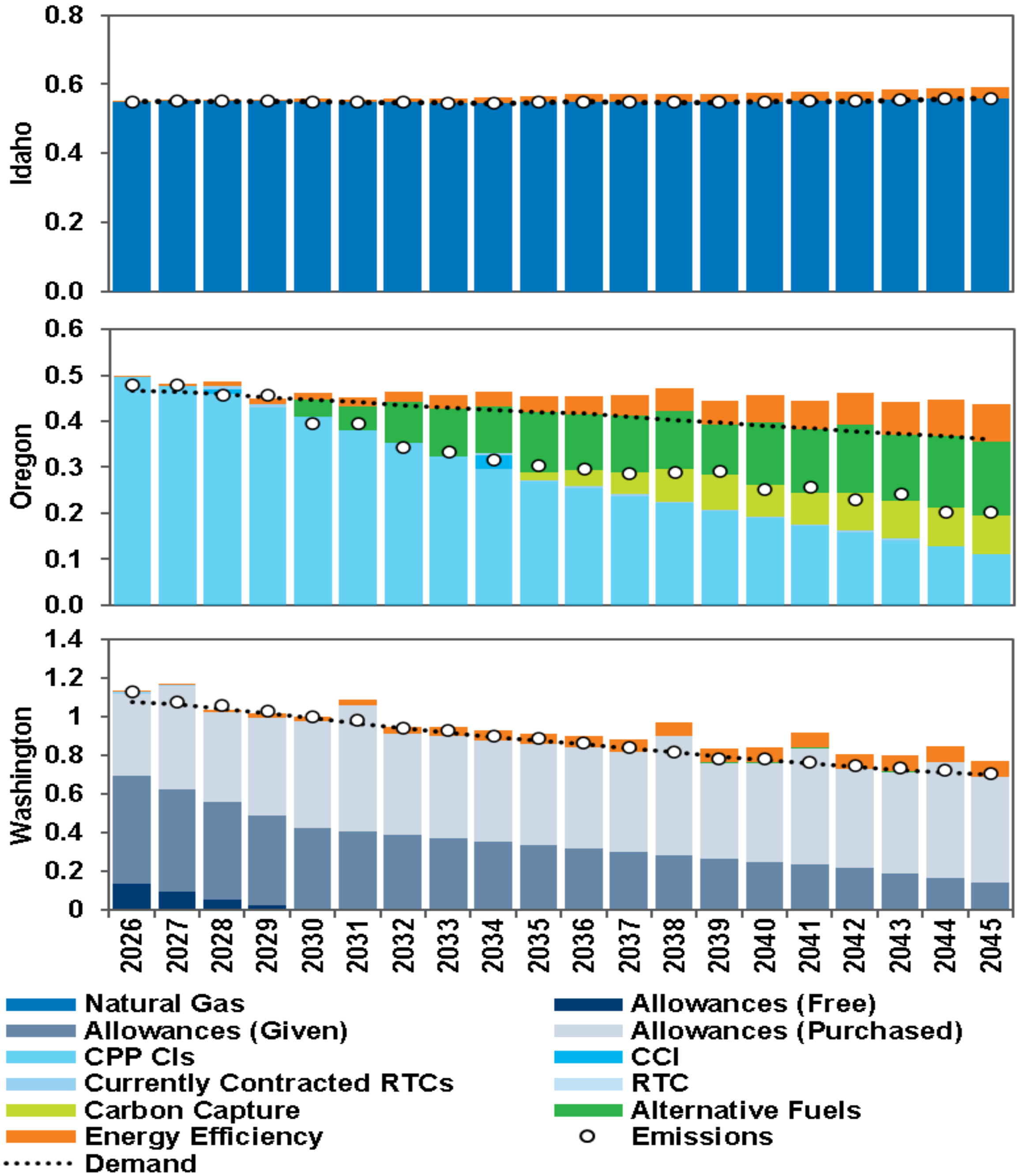
Scenario Forecasts

Scenarios include future combinations of inputs to measure implications of alternative possible outcomes. The scenarios evaluated consider a quantitative approach to look for the best and worst outcomes of key model inputs. These scenarios consider plausible futures with critical uncertainties and are useful to determine resource selections to compare directly with the PRS results. These scenarios are run both deterministically and through 500 Monte Carlo simulations where a daily selection is made for each year of the 20-year forecast. The results shown in this section are shown in metric tonne equivalents of greenhouse gas emissions, it includes a forecast for Washington's CCA allowances, Oregon's CCIs, RTCs, Alternative Fuels, demand side options and carbon sequestration to comply with Washington and Oregon's clean energy policy objectives. Also included in the total greenhouse gas emissions forecast, this forecast includes the actual emissions from all states excluding the state policy offsets. The term "CPP Cis", found in each figure below, are the given compliance instruments from the CPP program and adjust annually with the cap.

Preferred Resource Strategy

The PRS is covered in detail in Chapter 2 and included herein for reference and comparison to other scenarios and sensitivities below. This scenario is based on expected future conditions and stochastic modeling as discussed further in this chapter. In Figure 8.2 the PRS deterministic run is shown for comparative purposes to other scenarios as discussed below.

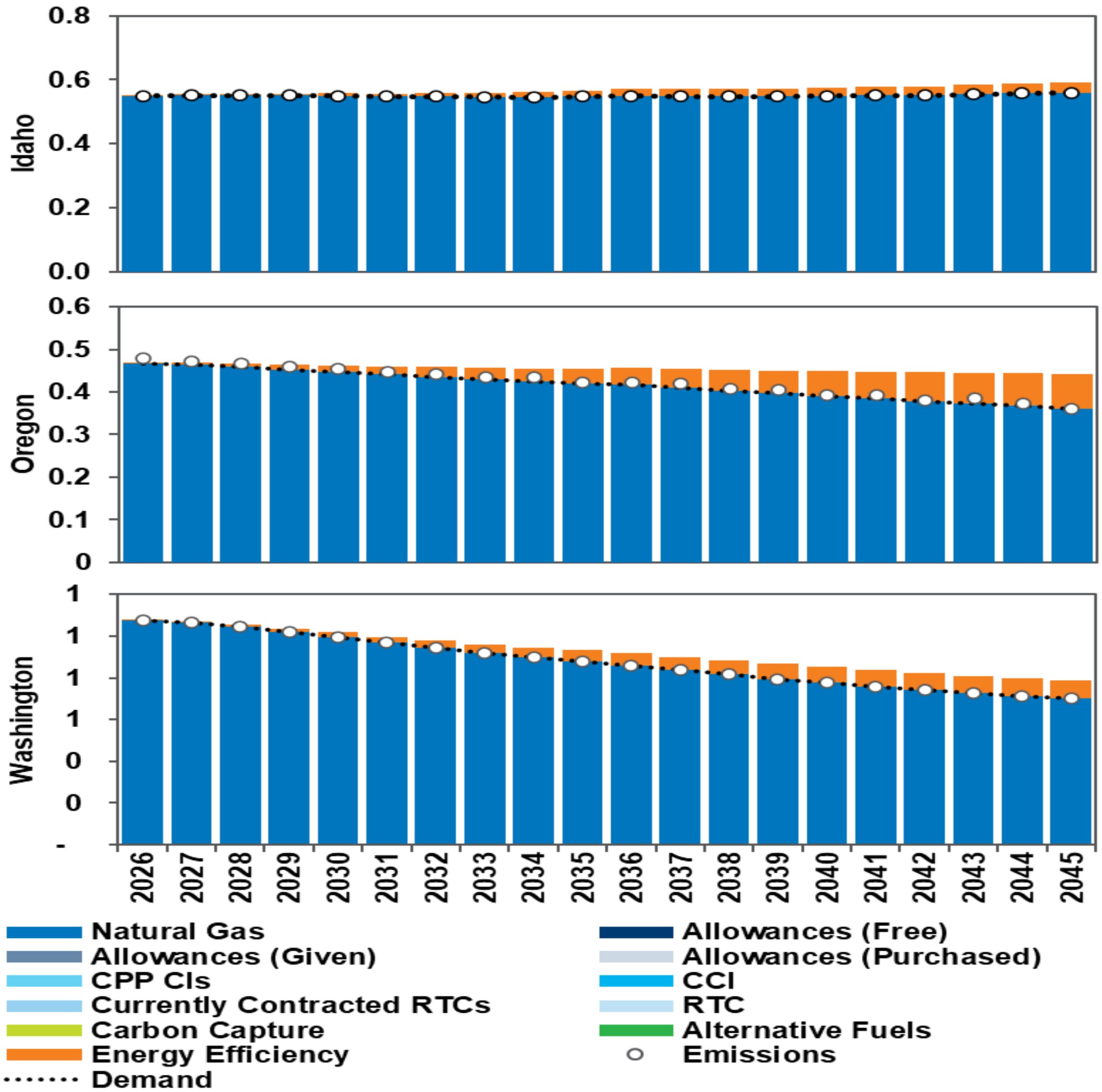
Figure 8.2: Preferred Resource Strategy (MTCO2e)



No Climate Programs

This scenario considers a future with no climate programs or clean energy policies. The intent of this scenario is to use the results to help with cost implications of these programs in comparison to other scenarios to help estimate total cost impacts. All other inputs and elements discussed remain the same as the PRS. In the absence of climate programs, Avista would only procure RTCs from current offtake contracts. These RTCs could be used for Avista's voluntary RNG program or sold into the RIN and LCFS markets as discussed in Chapter 5. All energy acquired is from natural gas, as this fuel is the least cost option to serve customers. The resulting emissions from this scenario is shown in Figure 8.3. No offsets or alternative fuels are procured to offset these total natural gas emissions. Due to the reduction in expected sales, Avista does not assume any additional pipeline transportation is required to meet future demand.

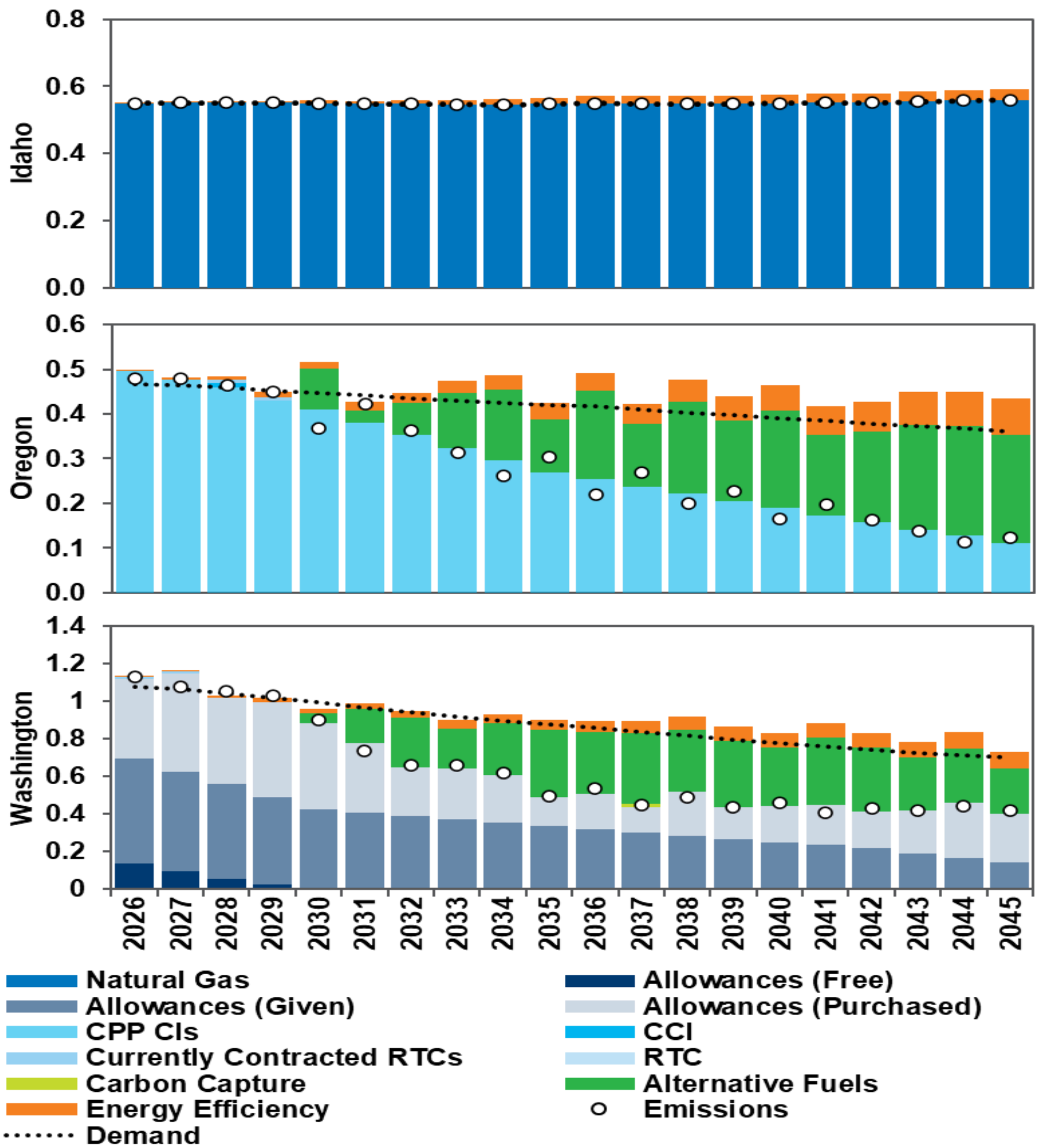
Figure 8.3: No Climate Programs (MTCO2e)



Social Cost of Greenhouse Gas

This scenario generally assumes the same assumptions as those in the PRS, but uses SCGHG pricing at the 2.5% discount rate for all resource selections including upstream emissions for all jurisdictions. This cost is for resource selection only and is not included in total costs comparisons. The scenario considers this adjustment to all jurisdictions based on the full emission cost adder from production to customer use. Alternative fuels selected in year 2045 are nearly 10.5 million Dth and decrease the number of CCIs and allowances needed by 89% and 38%, respectively, when compared to the PRS. CCUS also declines by 59% of total quantities. Selected resources are shown in Figure 8.4.

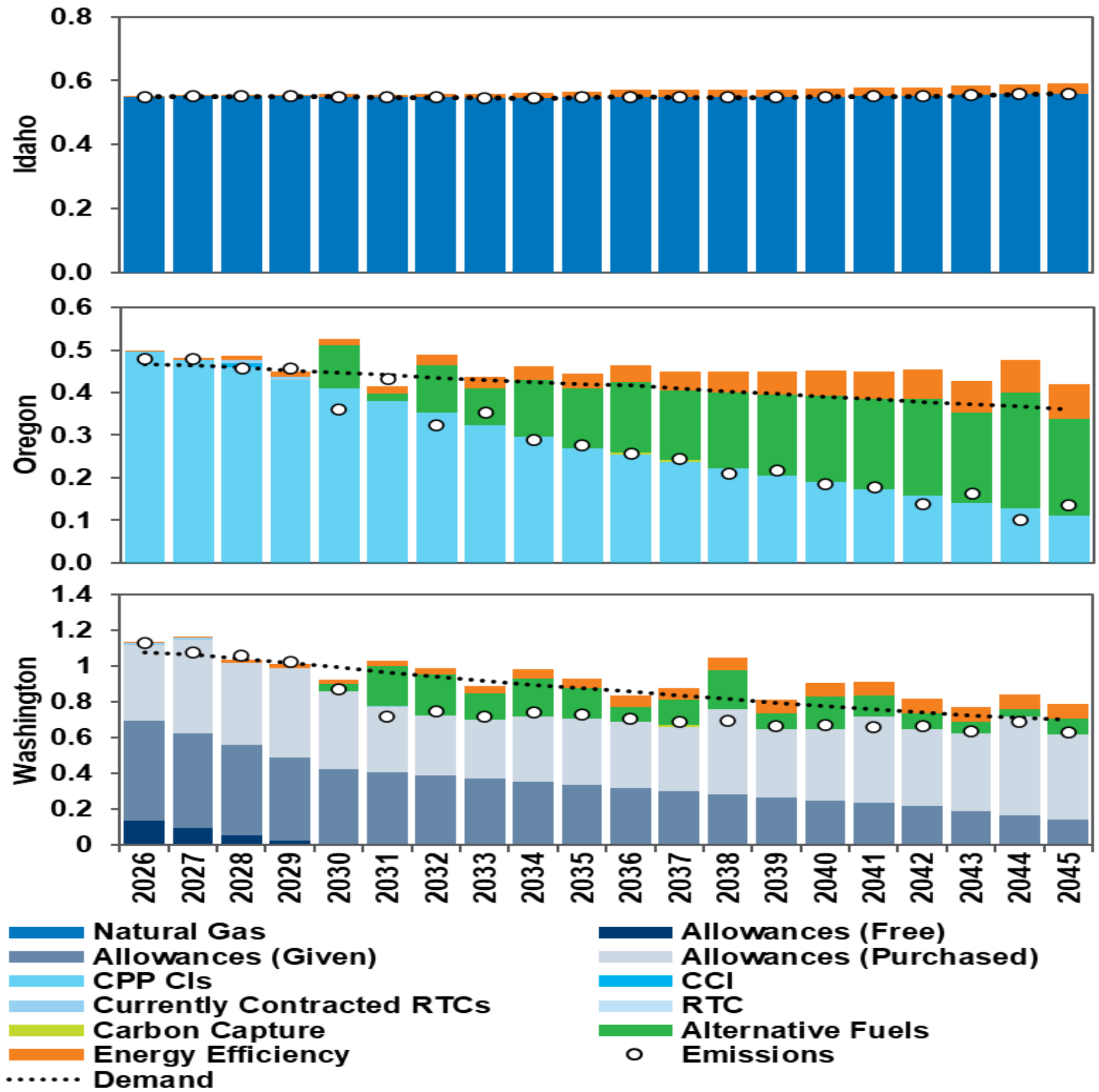
Figure 8.4: Social Cost of Greenhouse Gas (MTCO2e)



Diversified Portfolio

In the Diversified Portfolio case, all elements of the PRS's assumptions are used, but in this case, resources selection is a mix of alternative fuels regardless of a least cost test for Washington and Oregon. This sensitivity measures the potential costs of requiring decarbonization to the resource stack through physical fuels rather than other compliance instruments. RNG is added based on availability by resource occurring across all RNG production sources at 42% of alternative fuels in year 2030. Synthetic methane is added across all available production types at 51% of the alternative fuels while the remainder of the 2030 was hydrogen with 7% of total alternative fuels. Alternative fuels account for over 13% of total load in 2030. Carbon capture is selected in 2035 while prior contracted RTCs, Allowances and CCIs round off the resource selections over the forecast horizon as shown in Figure 8.5.

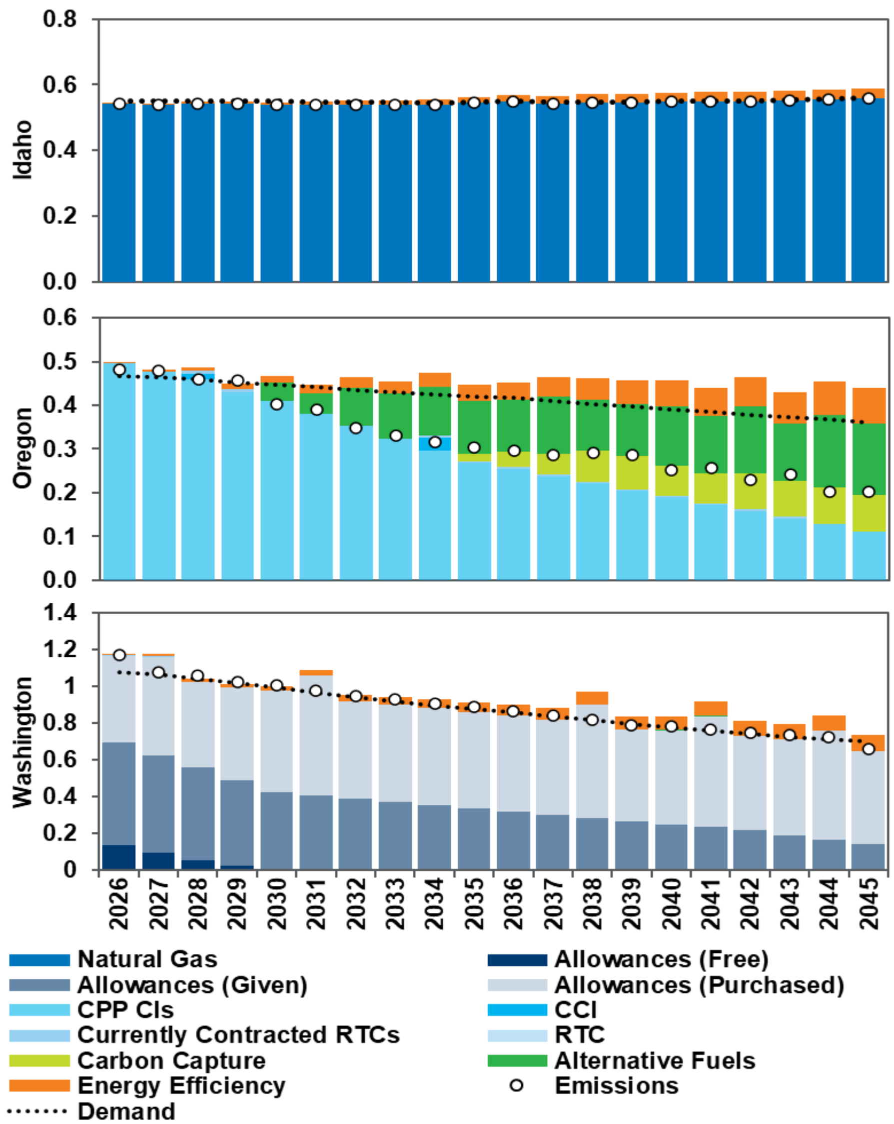
Figure 8.5: Diversified Portfolio Resource Selection (MTCO2e)



Resiliency

The Resiliency case assumes 50% availability of Sumas and JP supply points over peak demand weeks as discussed in Chapter 3. This scenario solves for the least cost resource mix assuming either pipeline outages, equipment failure such as compressor failures or pipeline incidents like those experienced in 2018 with the Enbridge pipeline and 2024 Martin Luther King Jr. weekend. Avista tested 30 unique model runs and constraints to determine alternative methods to optimally serve this load with available resource timing, however no optimal solutions could be found. To solve this scenario within this IRP, Avista included a one BCF LNG storage facility in 2026 to allow for a solution without unserved energy considering new energy storage is not selectable until 2030. Further study on this scenario is required to determine the most optimal method of preventing unserved load in the event of this scenario. Avista will further study this scenario for the 2027 IRP. Resource selections are shown in Figure 8.6 and remain mostly in line with the PRS.

Figure 8.6: Resiliency (MTCO2e)



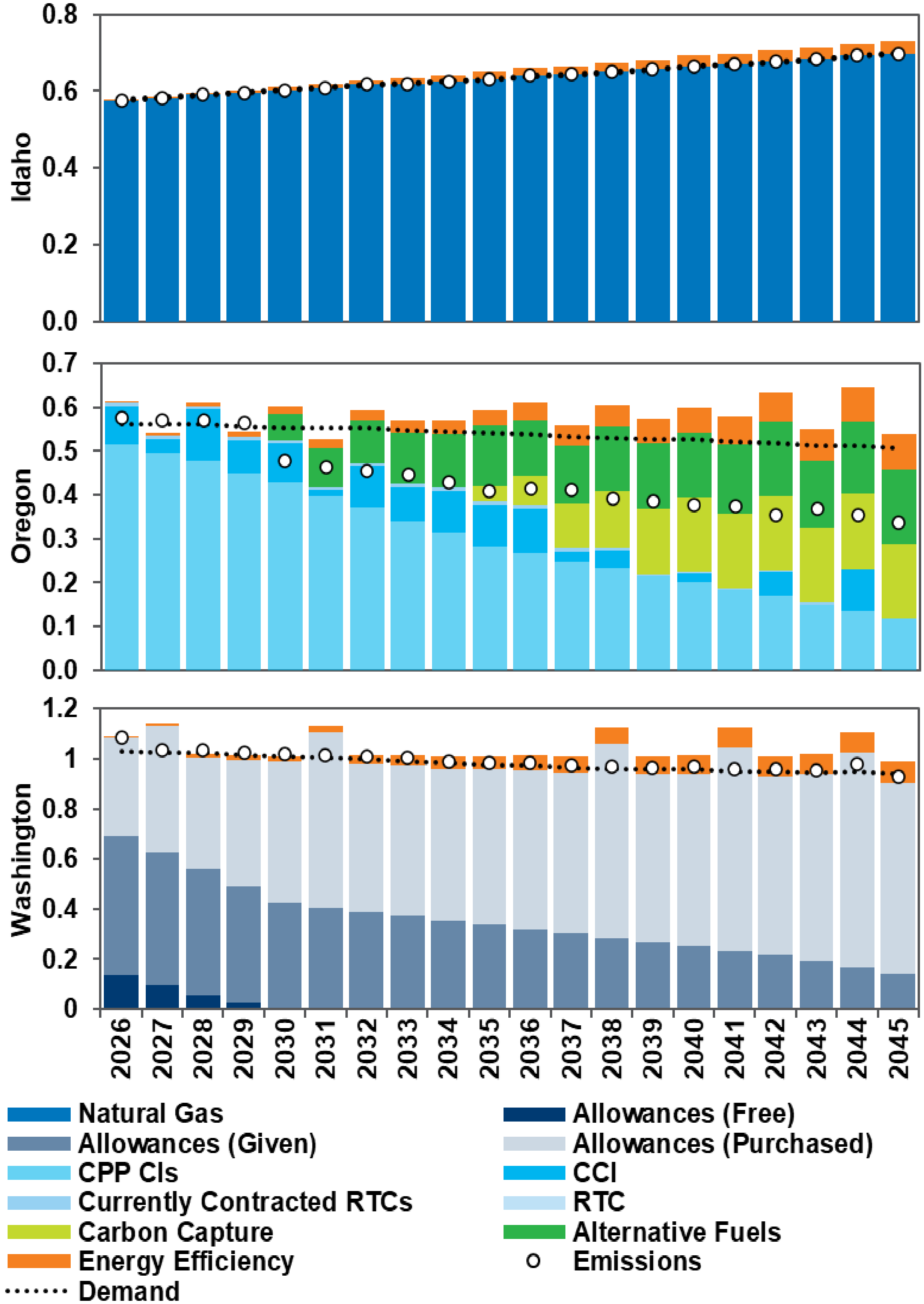
Sensitivity Forecasts

Sensitivities help illustrate implications of physical impacts to the system, impacts to program compliance or resource availability. These include outages and expected volumetric availability of resources such as RNG pose a risk to serving demand as well as meeting emissions compliance. The following sensitivities show different futures in comparison to the PRS by changing individual elements like prices, volumetric availability of fuels, weather, or demand. The results presented here are like the scenarios above illustrating the portfolio selections in metric ton equivalents to greenhouse gas emissions.

Average Case

The Average Case uses the average daily weather for the past 20 years and a three-year historical use per customer data for space and heating needs. This scenario assumes the status quo of customer demand does not change in the future, where demand is not impacted from significant energy efficiency, weather forecasts, or customer use decisions. All other assumptions are the same as the PRS, excluding a peak day. Figure 8.7 shows a need for more energy resources to comply with clean energy policies in comparison to all other futures outcomes discussed in this chapter as energy intensity per customer does not decline as the PRS assumes. One of the most significant changes compared to the PRS is Carbon Capture Utilization or Storage (CCUS) increases by over 50%, allowances purchased totaling an additional 17% and CCIs increasing by a staggering 1,400% even with the additional 11% of alternative fuels brought on to the system. Even with this higher load scenario, Avista does not assume any additional transportation requirements are needed.

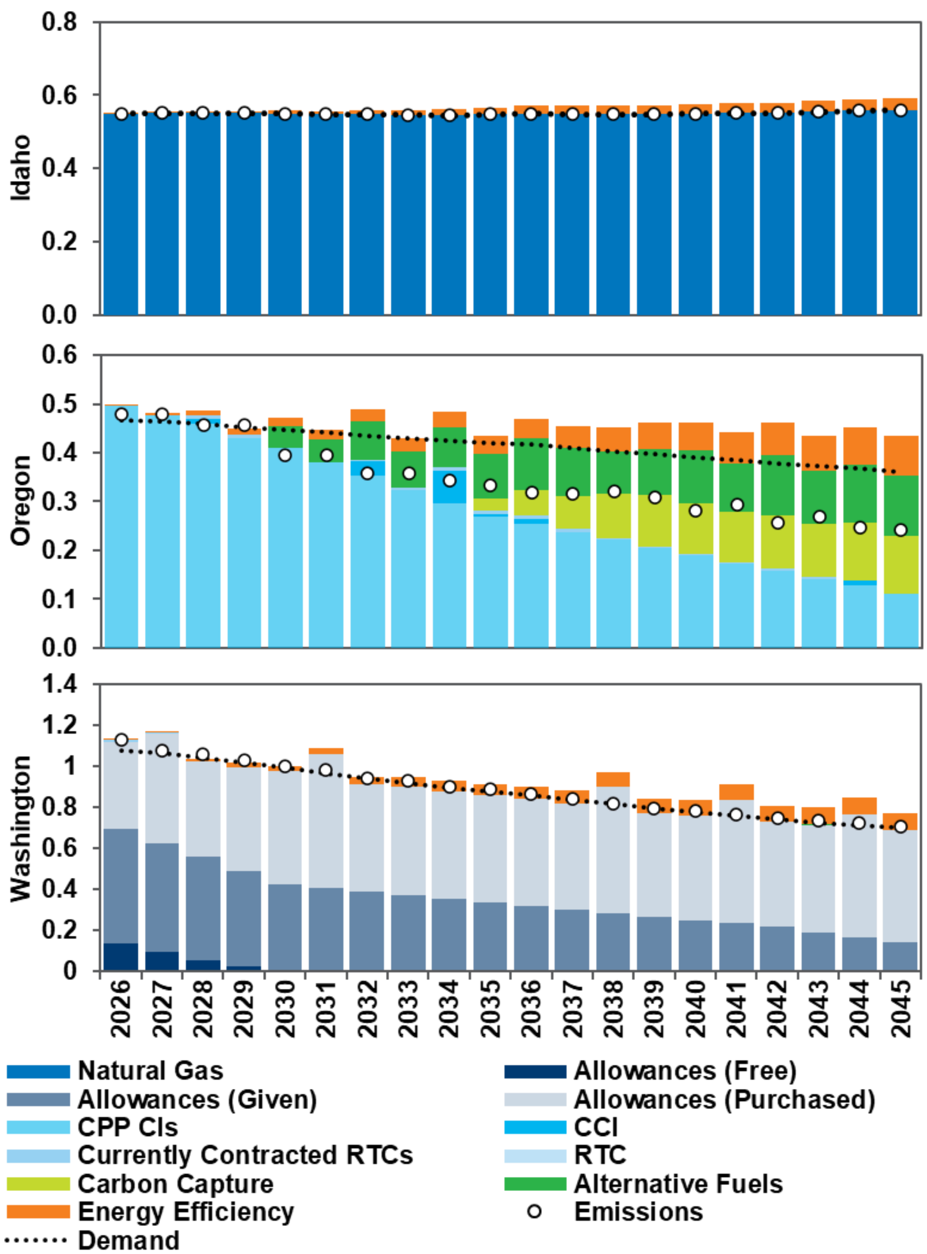
Figure 8.7: Average Case (MTCO2e)



High Alternative Fuel Costs

The High Alternative Fuel Costs case considers alternative fuel costs using the 95th percentile of 500 pricing simulations. All other inputs are the same as the PRS. The resource selection, compared to the PRS, shows a 21% decline in total alternative fuels. To offset this loss, CCI procurements for Oregon double and an additional 16% of Washington's CCA allowances would need to be purchased. CCUS also increases by 19% to capture emissions from natural gas due to the higher prices to comply with the standards in Oregon. Figure 8.8 shows the resource selections. Idaho's procurement strategy does not change.

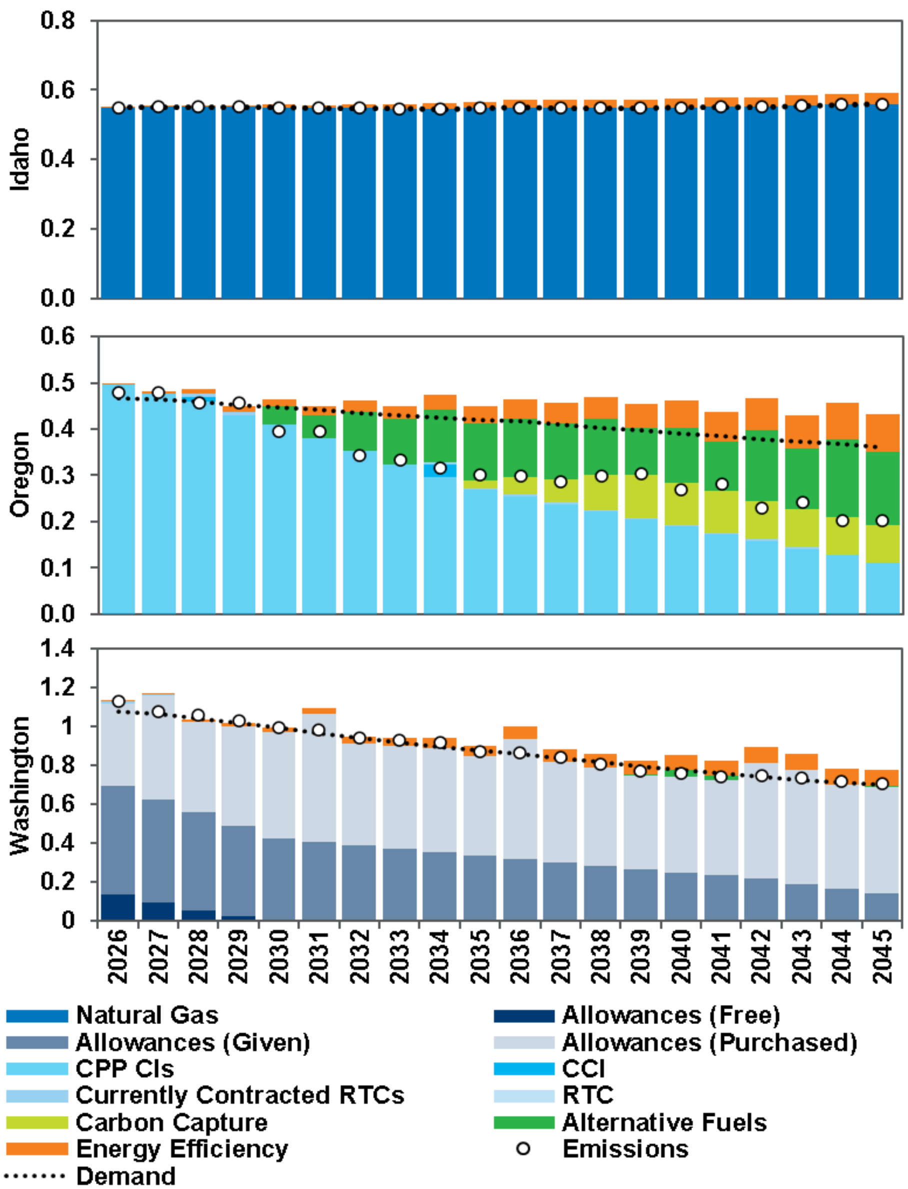
Figure 8.8: High Alternative Fuel Costs (MTCO2e)



High CCA Allowance Pricing

If higher CCA allowance pricing persists then the PRS's forecast of the resource selections will change. For this sensitivity, the 95th percentile of 500 stochastic pricing simulations (from the PRS) of the forecasted allowance prices is used. All other input assumptions are the same as the PRS. The impacts, as shown in Figure 8.9, of resource selections include a 3% drop in the total selection in CCIs and a less than 1% change in purchased allowances. Increases in CCUS selection of 5% is necessary to offset impacts of these decreased program instruments. This implies that even at a higher cost, compliance instruments maintain their overall selections as they continue to offer a least cost resource in meeting the greenhouse emission reduction requirements.

Figure 8.9: High CCA Allowance Pricing (MTCO2e)



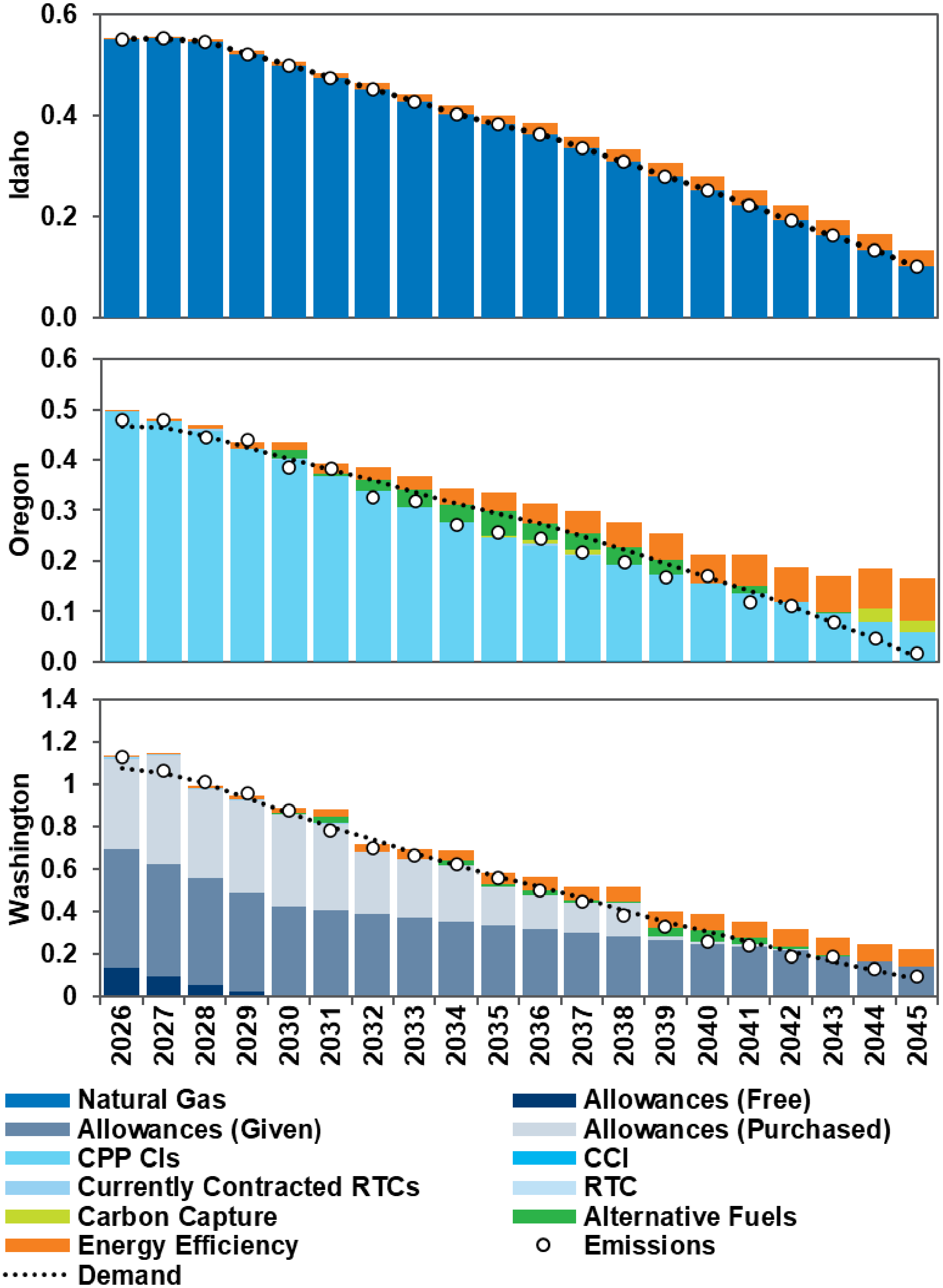
High Electrification

This sensitivity considers a loss of system demand due to building electrification, using an average decline of 4% load loss per year. All remaining assumptions remain consistent with the PRS. Additional building electrification beyond what is included in this load forecast is available for the model to further reduce loads to comply with the state's clean energy policies but are not selected. The resulting resource selections indicate RNG is selected at 1.15 million Dth, or 56% of the PRS's selection, and CCUS declines by 3% compared to the PRS by 2045. CCA allowances needed decrease by 53% and no CCIs are selected as shown in Figure 8.10.

What is not included within these results is the effect to Avista's and other electric utilities resource needs. These utilities will have higher costs to meet this higher load with additional generation, transmission, and distribution system enhancements. These costs are included in the "cost comparison" section below. For example, in Avista's Electric IRP[1], it conducted a Washington building electrification scenario indicating its 2045 winter peak load would increase by 356 MW, resulting in a rate increase in 2045 from 24.8 c/kWh to 27.8 c/kWh. This analysis only includes the impact on Avista's service area and not other utilities where Avista serves gas in their area. Further, this scenario goes beyond the Electric's IRP's analysis to look at other impacts to the system including Idaho and Oregon. In this case Avista would have greater impacts due to transmission system limitations- basically requiring the utility to need up to 475 MW of additional nuclear generation to cover this load if natural gas generation is not available. Further, Avista does not serve the Oregon service territory with electric service. This makes it difficult to estimate the financial impacts to those customers and would need to be analyzed by each electric provider by planning region to get accurate costs. A forecast was estimated for these costs based on current rates as used in the electrification estimate described in Chapter 4. These results do not consider decreased capacity or distribution costs as the necessary detail to understand where and when customers electrify is not possible to model in CROME. Further, these costs could decrease if all customers on a distribution line electrify but would likely remain if even a single customer was left on the line. For safety and reliability reasons, Avista would still be required to maintain this distribution line.

[1] https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2025/2025-avista-electric-irp.pdf

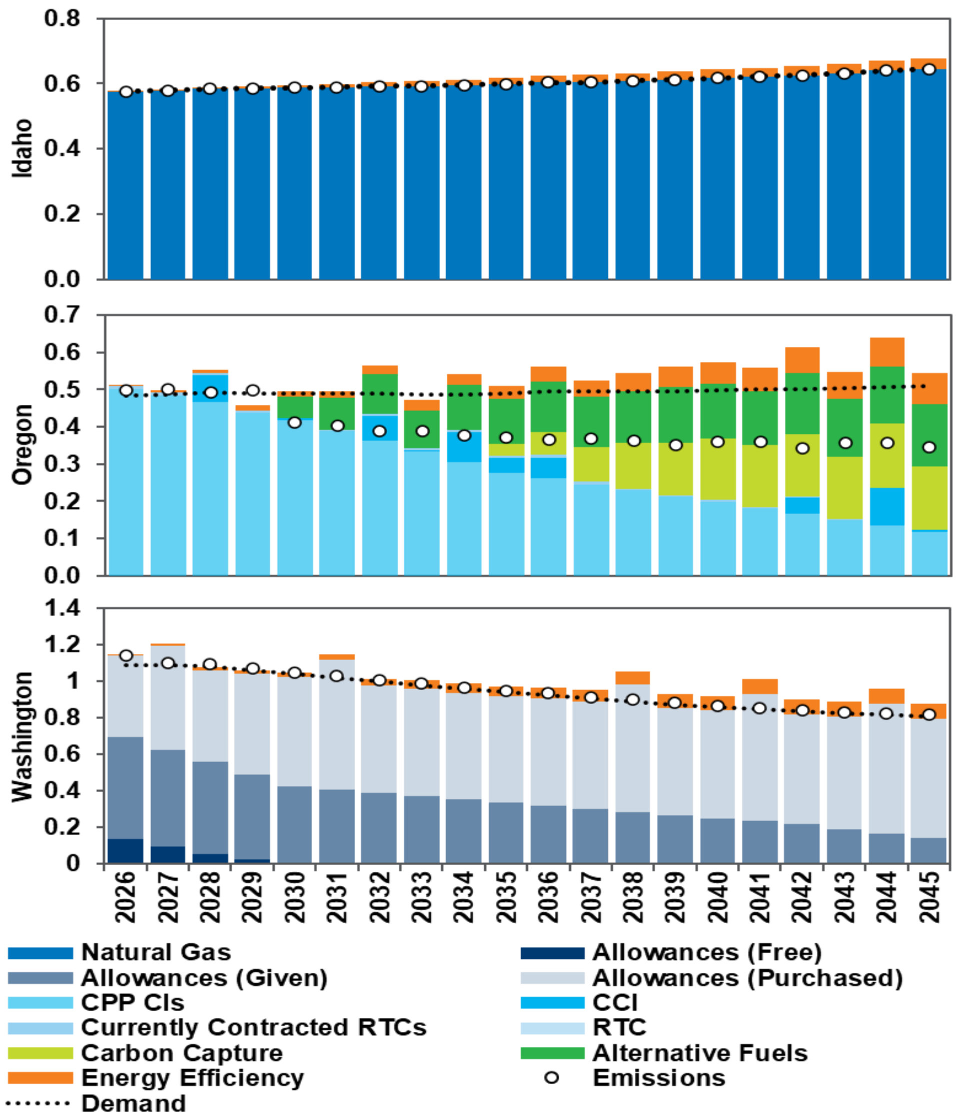
Figure 8.10: High Electrification (MTCO2e)



High Growth on the Gas System

Measuring risk includes a higher-than-expected case for customer growth in our natural gas territories. The overall growth in this case increases by 18% by 2045 as compared to the PRS resulting from a higher than expected number of customers, leading to an increase in overall demand. This high growth case maintains the same demand decline, like most scenarios and sensitivities, and is based on energy efficiency savings and higher efficiency in end uses. While Oregon and Washington have policies and programs making this case unlikely, Idaho is experiencing strong growth as discussed in Chapter 3. When compared to the PRS, CCUS has a 51% increase in total quantities selected, and an 11% increase in total CCA allowances purchased. CCIs drastically increase to nearly 760,000 over the planning horizon where the PRS selects slightly more than 112,000 CCIs. Alternative fuels also increase by 6% to meet this high growth case as shown in Figure 8.11.

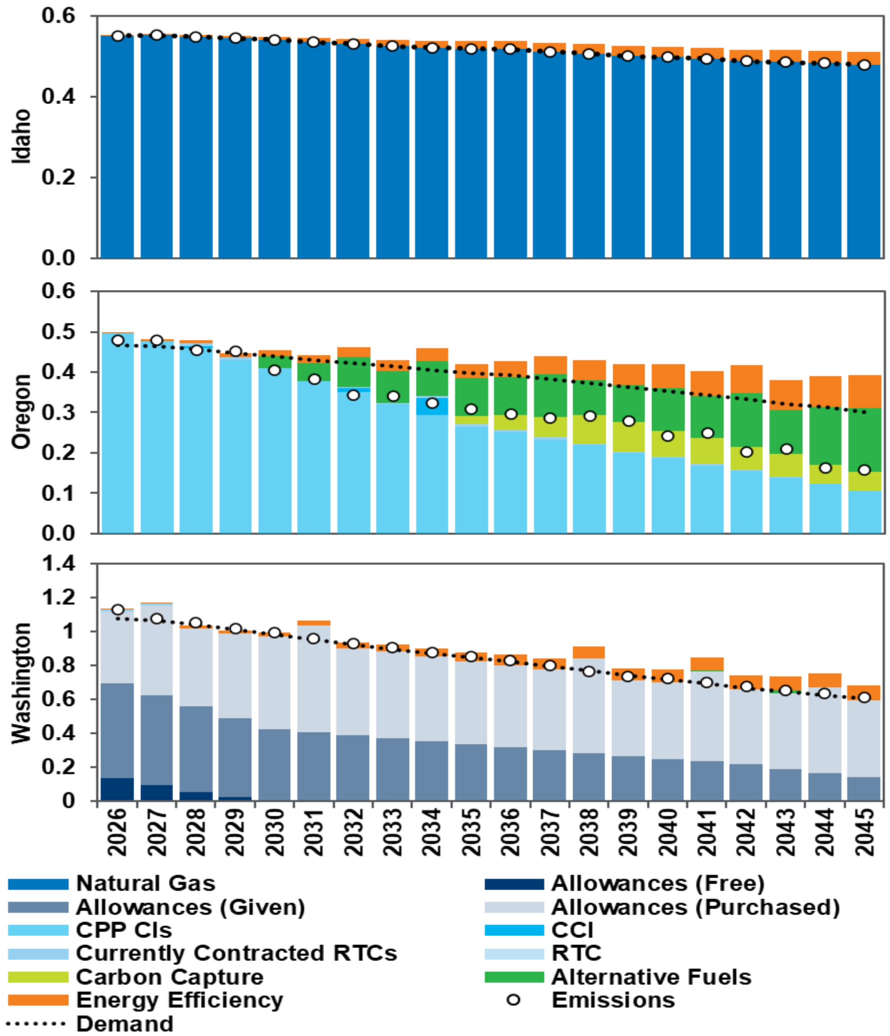
Figure 8.11: High Growth on the Gas System (MTCO2e)



Hybrid Heating

The Hybrid case assumes electric heat pumps are added to existing natural gas furnaces. Effectively the natural gas system provides heating needs during colder temperatures with non-peak impact to the electric system as the heating source switches to gas when the outdoor temperature goes below 38 degrees Fahrenheit[2]. By 2045 the annual energy forecast is 13% lower than the PRS's forecast. This scenario results in lower demand overall for Oregon and Washington. Rather than a total loss of these customers like the previous electrification sensitivity, a customer would remain on the natural gas system. All other assumptions remain consistent with the PRS. Total CCIs purchased increased by 26% to cover emissions in place of alternative fuels or CCUS, which decreased by 18% and 12%, respectively, as compared to the PRS. Finally, allowances slightly decrease by only 6% as primary heating needs would continue to be met by the gas system. Selected resources are shown in Figure 8.12.

Figure 8.12: Hybrid Heating (MTCO2e)

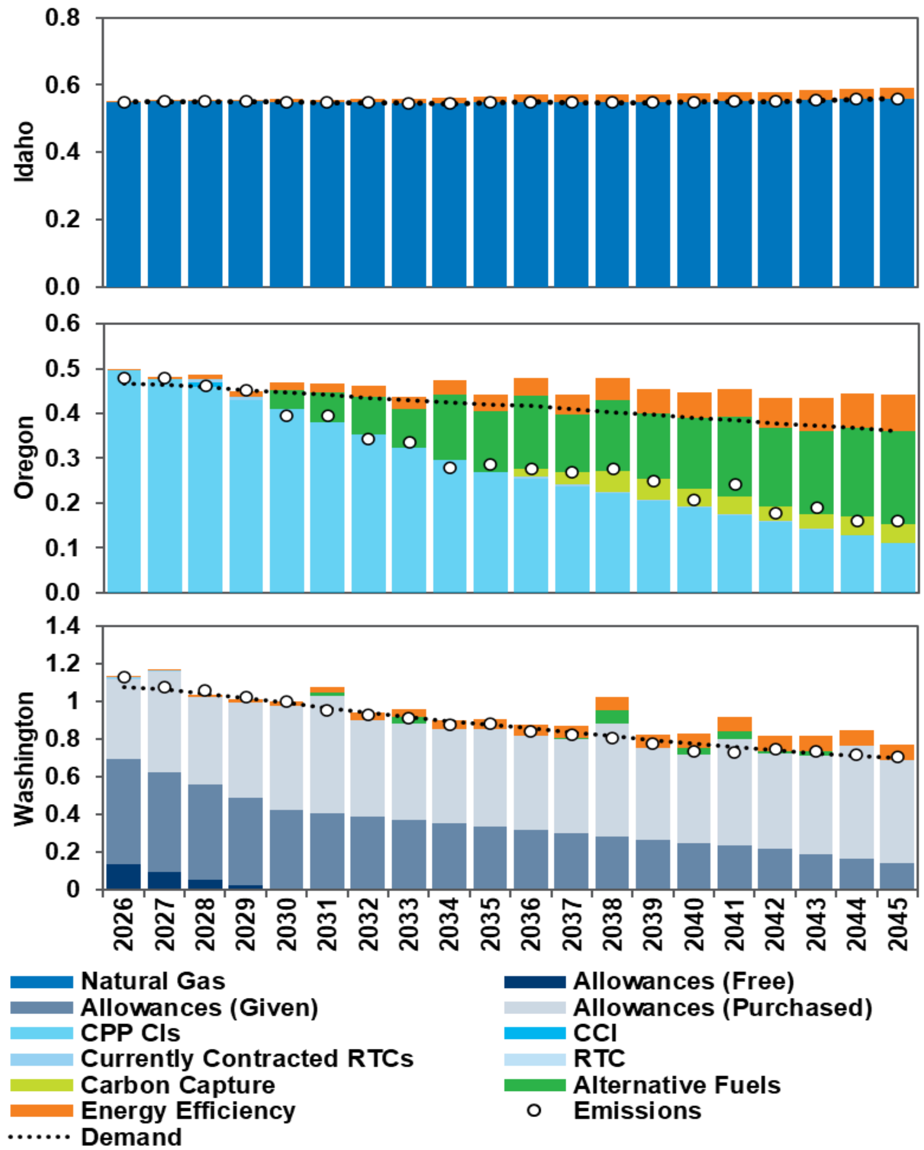


2 [Residential Code Amendments | SBCC]

High Natural Gas Prices

For most cases evaluated in this IRP, all of them continue to rely on natural gas as a form of energy. Evaluating resource selections based on high natural gas prices is evaluated in this sensitivity. Figure 8.13 shows resource selections based on the 95th percentile of 500 stochastic simulations to estimate higher natural gas costs. The resulting natural gas prices are 57% higher in 2030, 104% in 2045. All other inputs are the same as the PRS. As expected, the number of allowances selected in total has decreased due to an increase in alternative fuels selected of 34% as compared to the PRS. CCUS selection decreased by a significant amount with 25% less carbon capture and a slight reduction in purchased CCA allowances of 2%. Finally, a drastic reduction of 87% for CCIs is primarily based on the large increase in alternative fuels fulfilling both energy and emission reduction requirements.

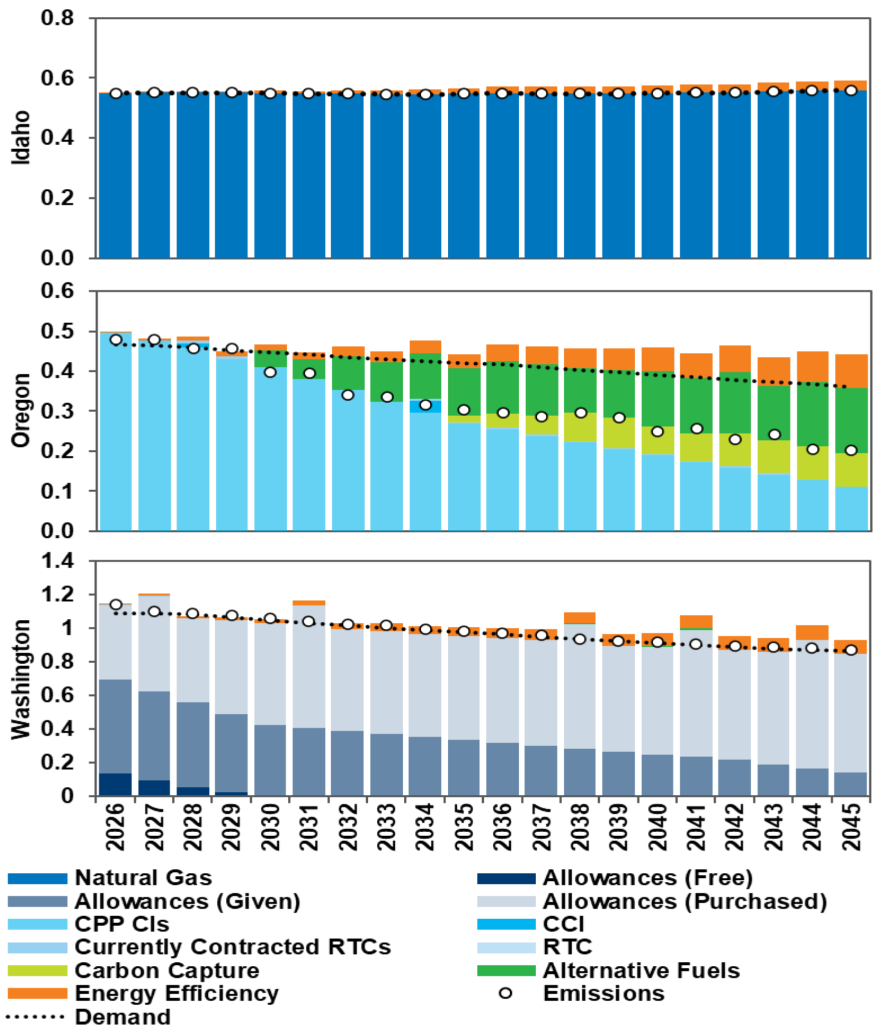
Figure 8.13: High Natural Gas Prices (MTCO2e)



I-2066

Initiative 2066 considers a future where the building code is changed to allow new commercial customers to use natural gas for heating in Washington. This initiative passed in the state's election in November 2024 and the currently being challenged. This sensitivity does increase the load expectation in Washington for only commercial customers to reflect historical use per customer rates. There are no changes to residential usage in this analysis. The impact of load increases the 2045 system demand by 9% as compared to the PRS. Avista did not use this sensitivity, as the PRS, due to the certification of the election, was not completed in time to update all the processes for the PRS specifically for energy efficiency. Also due to the legal challenges of the initiative and the minimal change to resource acquisition these changes could be completed as a sensitivity. If this initiative survives legal challenges, changes will be considered in the 2027 IRP. Figure 8.13 shows overall impact with the selection of an additional 16% of purchased allowances combined with more natural gas purchased to supply this higher load. All other resource selections stay the same compared to the PRS.

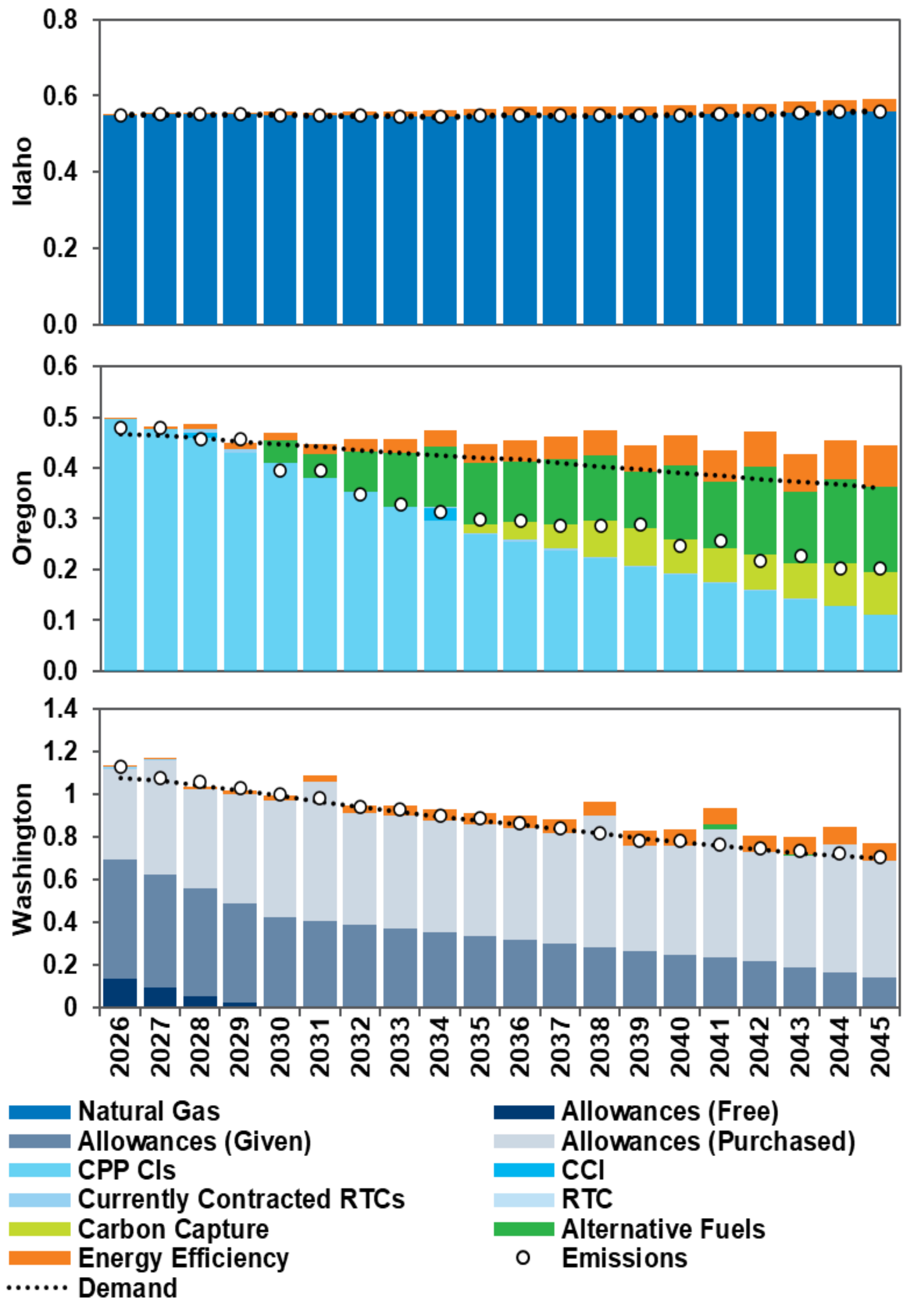
Figure 8.14: I-2066 (MTCO2e)



Low Alternative Fuel Costs

This sensitivity considers lower than expected alternative fuel pricing from 500 stochastic simulations to estimate low natural gas costs using the 25th percentile of prices by fuel type. This assumption change reduces prices of alternative fuels by 11%. The resources selected include an increase of alternative fuels procured over the planning horizon of 3% and primarily impact Oregon as allowances remain the least cost resource in Washington. There are no changes in Idaho selections. CCIs decrease by 10% and a similar reduction in selected quantities of CCUS. These selections are shown in Figure 8.15.

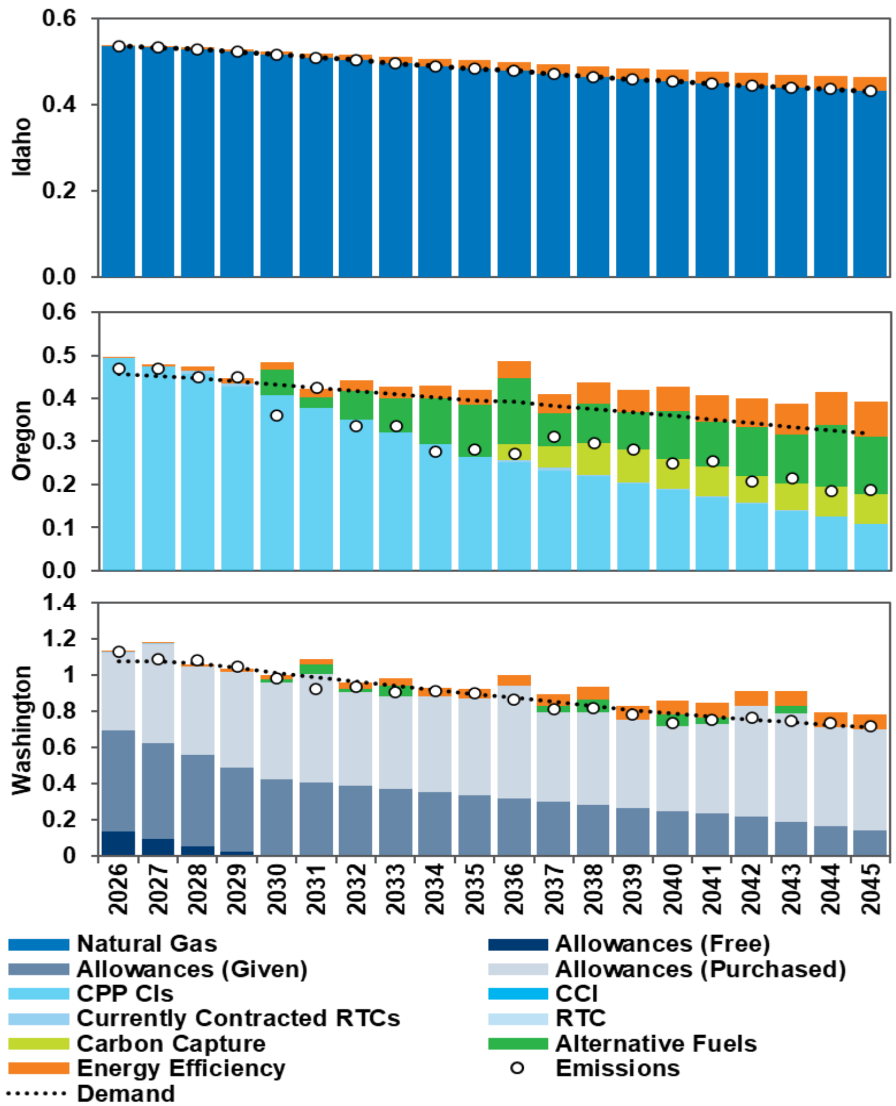
Figure 8.15: Low Alternative Fuel Costs (MTCO2e)



Low Natural Gas Use

The low natural gas use case analyzes an alternative warmer weather future using RCP 8.5, higher prices for natural gas and alternative fuels, low availability of alternative fuel volumes, and high CCA allowance pricing. RCP 8.5 is considered due to less heating degree days pushing cost per therm to a higher rate to recover base rates of delivering energy to the customer and higher costs of energy. This scenario creates a near worst case scenario for natural gas fuel to test whether electrification becomes cost effective. When compared to the PRS the selections include 6% less CCUS, a higher selection of alternative fuels of 6% leading to a system total emission decline of 7%, and no building electrification selections. Although, high natural gas prices drive the selection of alternative fuels when combining compliance instruments in Washington and create a higher cost than alternative fuels. No CCIs are selected for Oregon based on higher alternative fuel volumes used to reduce emissions. Resource selections are shown in Figure 8.16.

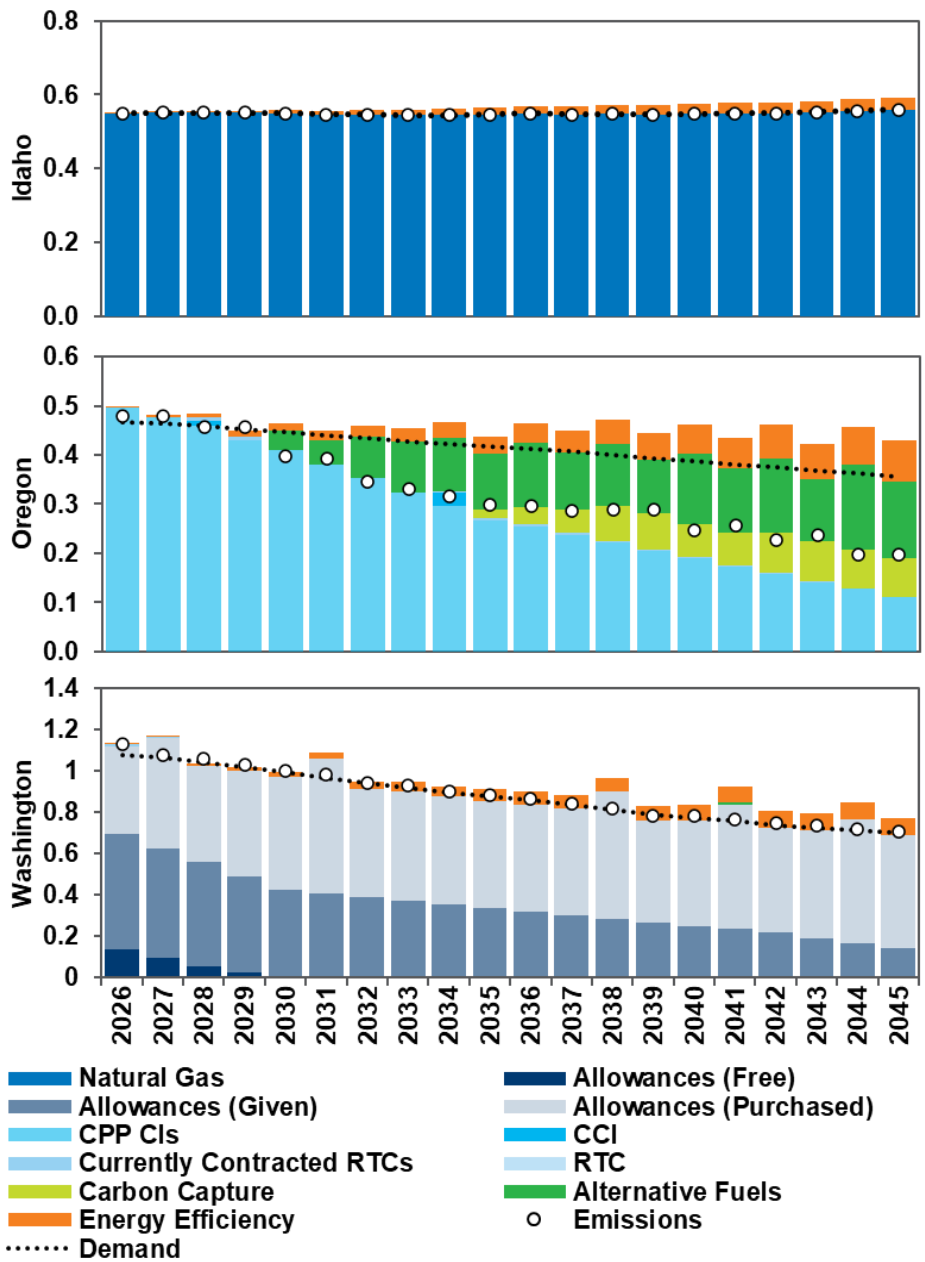
Figure 8.16: Low Natural Gas Use (MTCO2e)



RCP 6.5 Weather

The RCP 6.5 weather sensitivity considers PRS inputs with a mid-range warmer weather future (RCP 6.5) as compared to the PRS. Further information on the assumption of this forecast is found in Chapter 3. RCP 6.5 does not drastically change the total HDDs as compared to the PRS in the forecast horizon considering this IRP. If Avista were to extend the forecast to the year 2100, more significant changes would be apparent. Because of this, the resources selected include a 1% decline in alternative fuels and allowances, and a 7% reduction of total CCIs. All changes are due to a 0.04% reduction in demand over the planning horizon. These selected resources are shown in Figure 8.17.

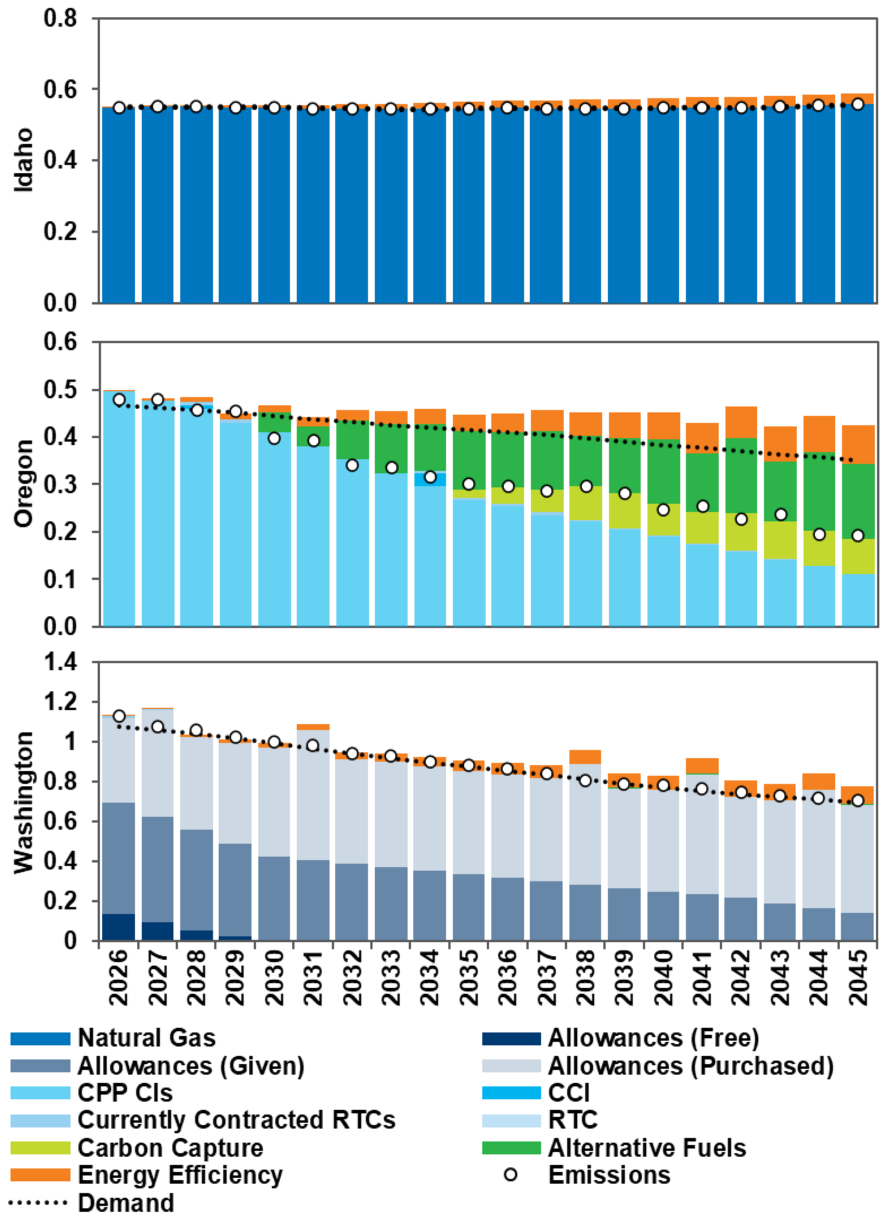
Figure 8.17: RCP 6.5 Weather (MTCO2e)



RCP 8.5 Weather

RCP 8.5 is warmer weather sensitivity considers a separate weather scenario to understand different futures with declining HDDs. This sensitivity uses the RCP 8.5 weather futures and shows resources selected around a decreased demand in a warming climate. Like RCP 6.5, the changes in the forecast horizon do not overly deviate from RCP 4.5 by 2050. Further information on the assumption of this forecast is found in Chapter 3. The selected resources, in comparison to the PRS, include a 3% decrease in CCUS and alternative fuels. CCIs have an overall decrease of 6% while allowances stay mostly the same with slight percentage decreases of less than 1%. Selected resources for this sensitivity are shown in Figure 8.18.

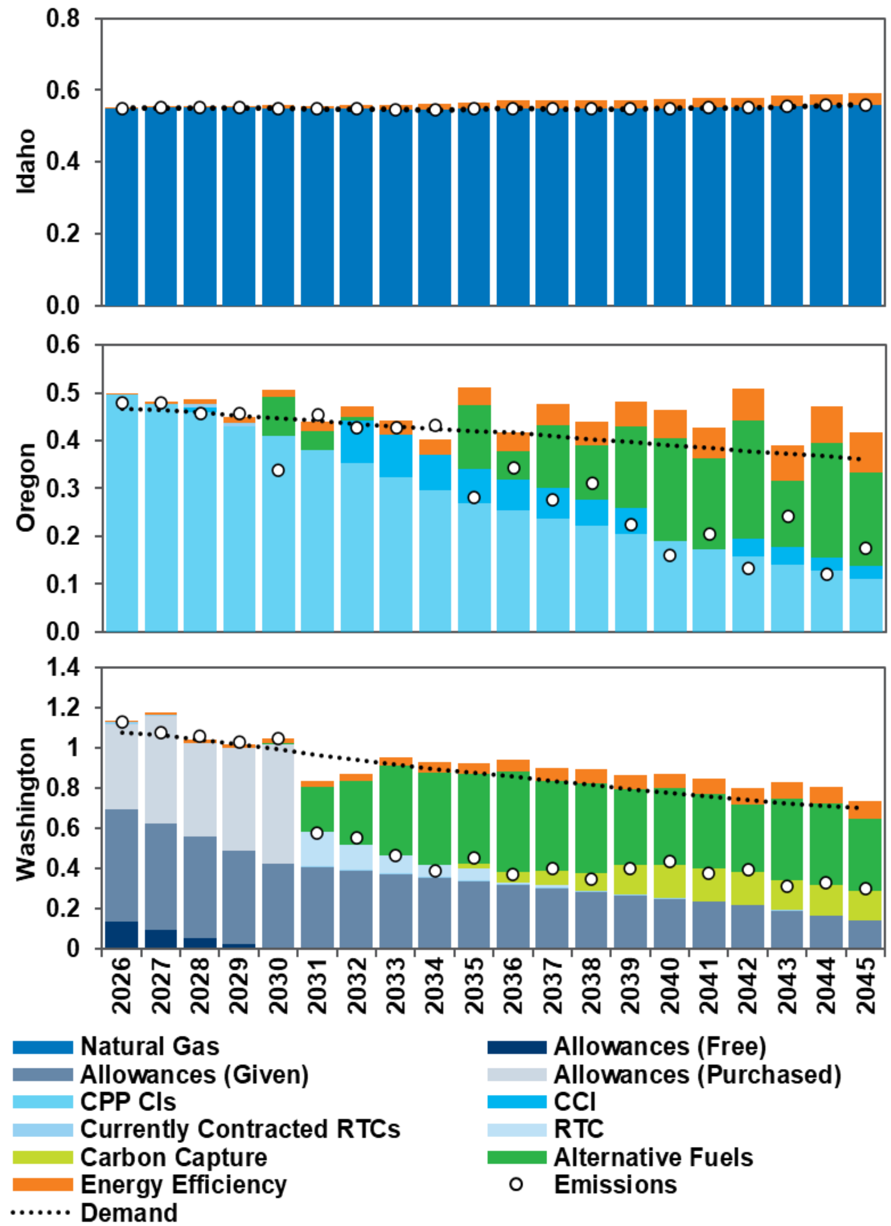
Figure 8.18: RCP 8.5 Weather (MTCO2e)



No Allowances 2030+

The No Purchased Allowances After 2030 case mirrors the PRS but does not consider Washington CCA allowances for purchase after 2030. The selected resources, in comparison to the PRS, include increases of 66% in CCUS and 324% in alternative fuels primarily as a resource to replace allowances in Washington for CCA compliance. Total selected CCIs increased 1,303% while allowances unsurprisingly decreased by 77% over the 20 years. Selected resources for this sensitivity are shown in Figure 8.19. This sensitivity demonstrates the constraints of scarce qualifying fuels and how alternative compliance mechanisms such as buying allowances or CCI's will help control compliance costs when emission reduction may have significant cost increases.

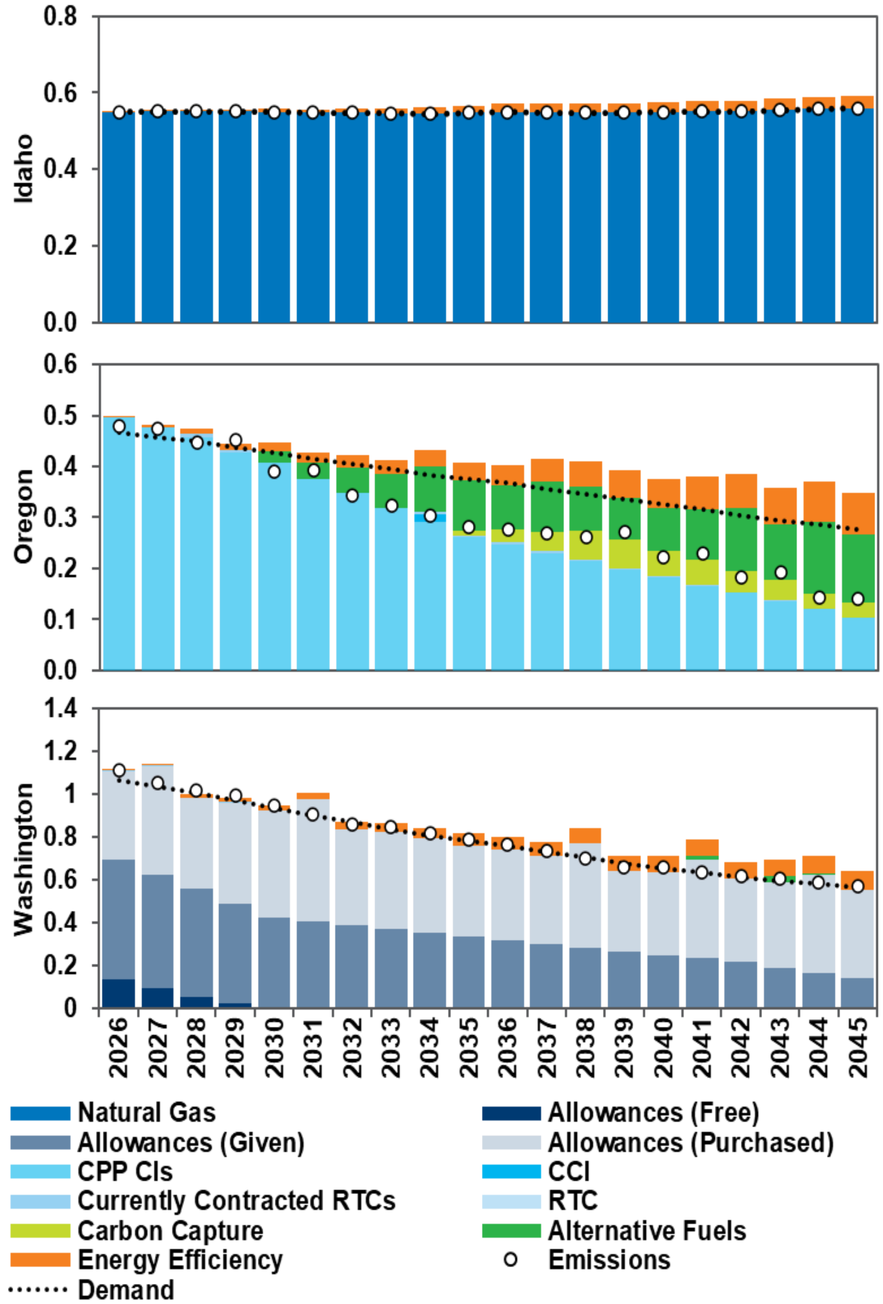
Figure 8.19: No Purchased Allowances After 2030 (MTCO2e)



No Growth

The No Growth case assumes no new customers are added to the natural gas system after 2025 and 2026 in Washington and Oregon, respectively. This assumption aligns with the phasing out of subsidized gas line hookups in each state. A declining customer curve results in lower demand and necessitates fewer alternative fuels and compliance mechanisms in aggregate when compared to the PRS. By 2045, selected CCIs decrease by 31%, purchased allowances decrease by 14%, CCUS decreases by 26% and alternative fuels decrease by 23% as shown in Figure 8.20.

Figure 8.20: No Growth (MTCO2e)

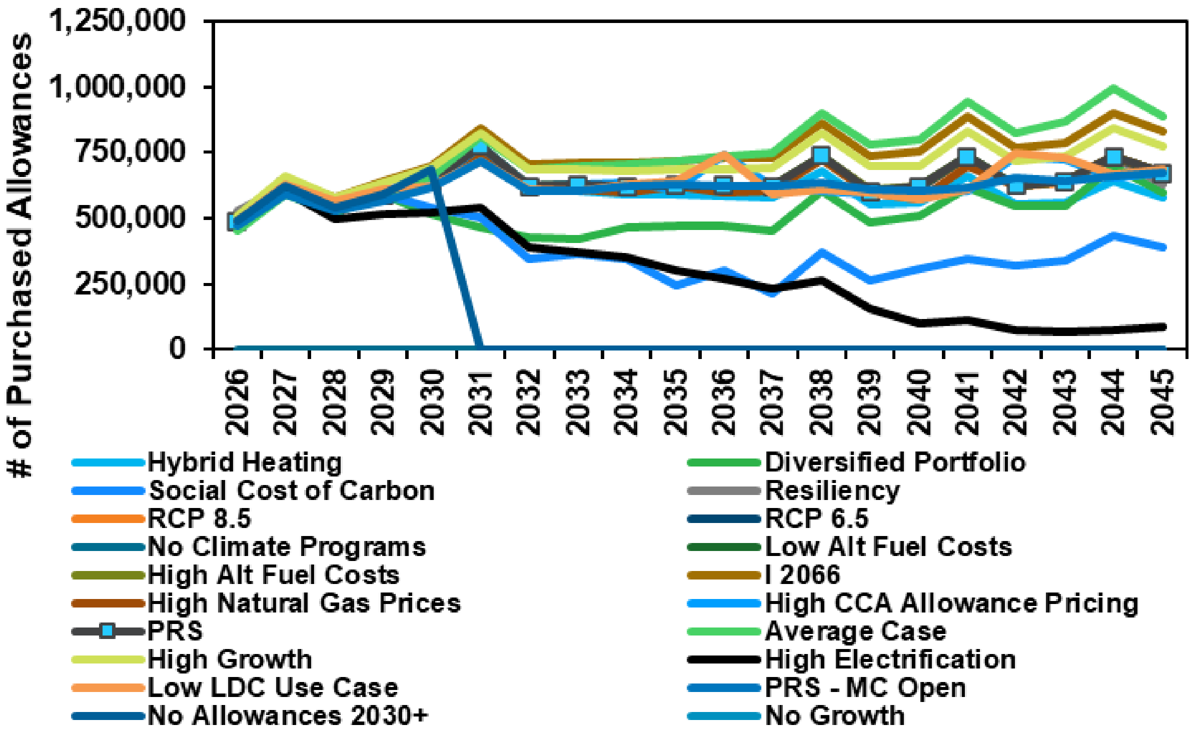


Washington Climate Commitment Act Allowances

Comparison of the total purchased allowances across scenarios and the consideration of availability needs to be carefully examined. As mentioned in Chapter 7, Washington is currently investigating linkage with the California and Quebec cap and trade program. In the event Washington does join this program a higher likelihood of sufficient quantities of allowances will enable the strategy to offset Washington emissions with program instruments. This remains a risk and will be carefully considered in an ongoing basis to ensure the risk of non-compliance does not occur.

The Average Case has the highest requirement for allowances through 2045 followed by the High Growth Case, while the High Electrification scenario has the lowest total allowances purchased (excludes the “No Climate Programs” scenario. The average total quantity, across all cases, of allowances purchased across the forecast horizon is just over 11 million allowances. The variability of purchased allowances by case is illustrated in Figure 8.21.

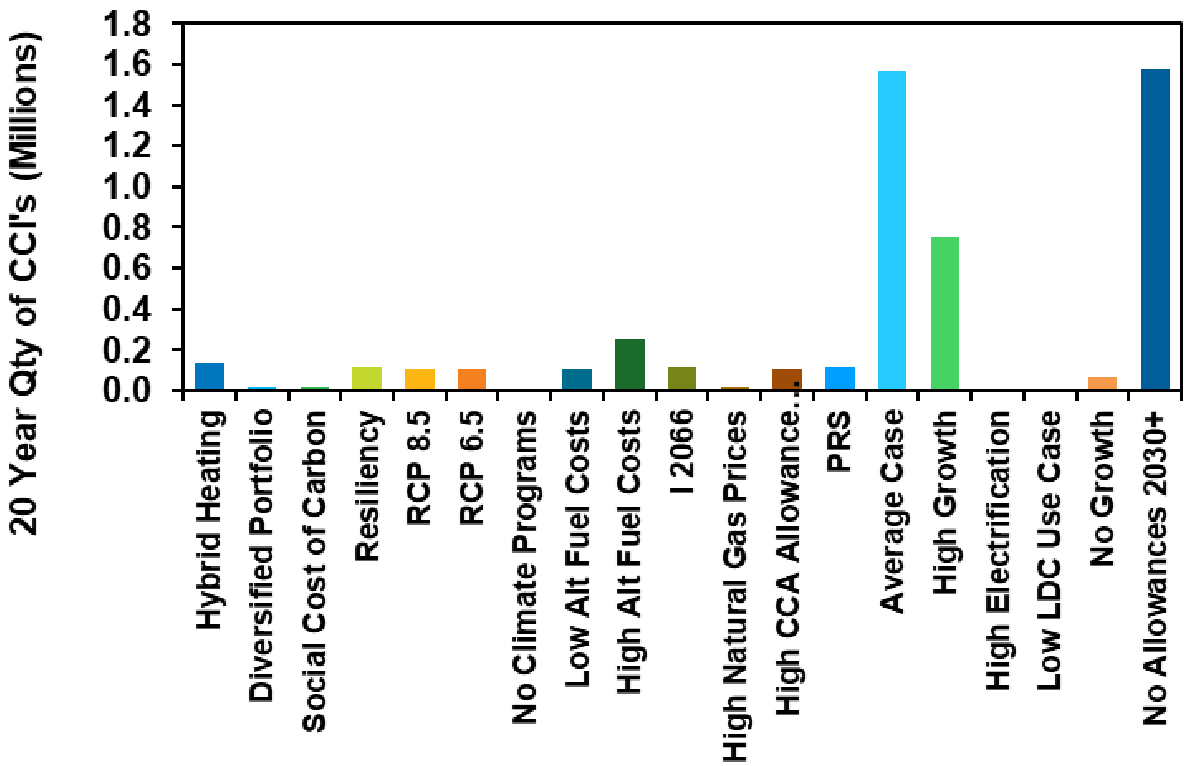
Figure 8.21: Annual Allowance Demand by Case – Washington CCA



Oregon’s Community Climate Investments

Community Climate Investments show a greater range of required quantities for compliance. In Figure 8.22 illustrates the total CCIs purchased for the 20-year forecast horizon. No Climate Programs, High Electrification and Low LDC Use Case all select zero CCIs over the time horizon. The “No Allowances after 2030” case selects the highest number of CCIs with over 1.57 million instruments and illustrates the implications to Oregon of this consideration. The “Average Case” selects the second most CCIs in total at just under 1.57 million instruments. The average selection across all scenarios and sensitivities of 266,000 CCIs.

Figure 8.22: CCI Demand by Case – Oregon CPP



Cost Comparison

When considering the costs of these scenarios and sensitivities, there are three with a lower cost than the PRS. These cases include RCP 6.5 and RCP 8.5 where weather is trending warmer and creating less demand to serve, and No Climate Programs. All other cases have a higher cost deterministically than the PRS. Levelized costs help to depict an average cost per year over the planning horizon and remove weather volatility. Figure 8.25 shows these levelized costs and includes Avista’s discount rate to show a form of a weather normalized annual payment. The total system costs are shown in Figure 8.23 and compare the 20-year cost, present valued to 2026 dollars, for each scenario. The Average Case costs are higher than the PRS as it only considers 20-year historic weather by area and a three-year use per customer. The Low LDC Use Case has a lower demand from RCP 8.5 combined with much higher costs of natural gas, alternative fuels, and allowances. The Hybrid scenario is the second most expensive case and includes calculations for estimated electric side additions of generation, transmission, and distribution to handle this increased overall load. Finally, the High Electrification case is 130% higher in total costs as compared to the Hybrid case or 580% more expensive as compared to the PRS and includes estimates for electric generation, transmission and distribution. Figure 8.24 shows total costs per case across the 20-year planning horizon.

Figure 8.23: PRS Alternative Scenario Cost Comparison
Annual Levelized Costs

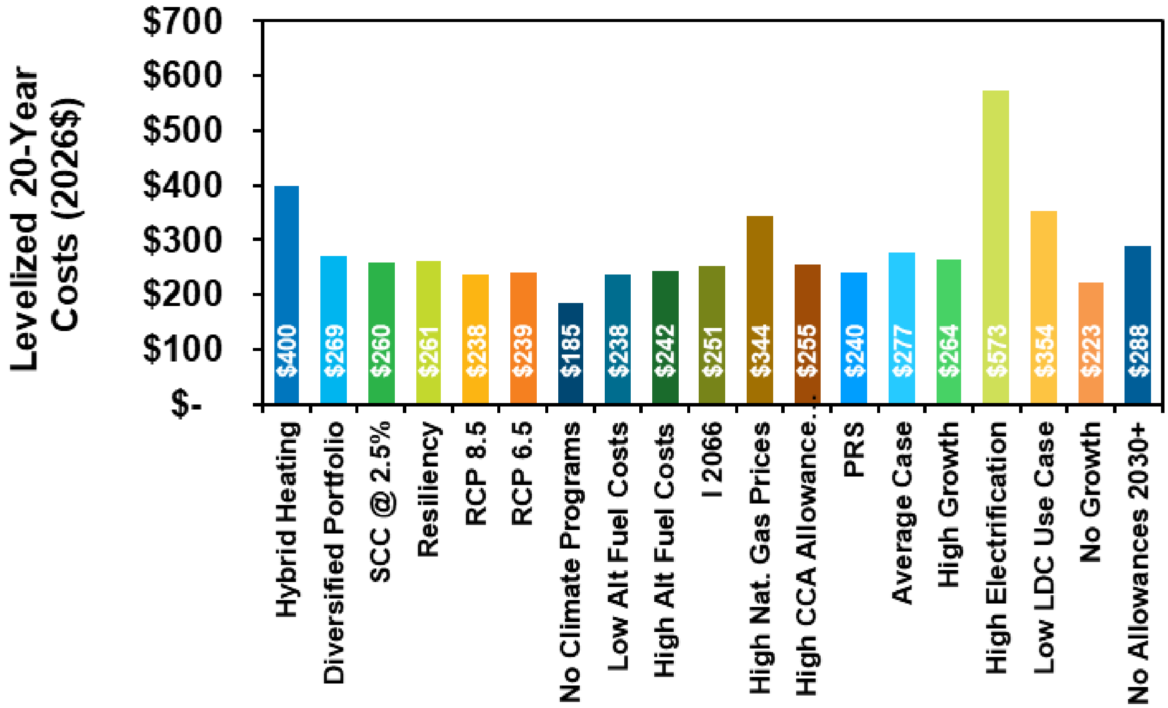
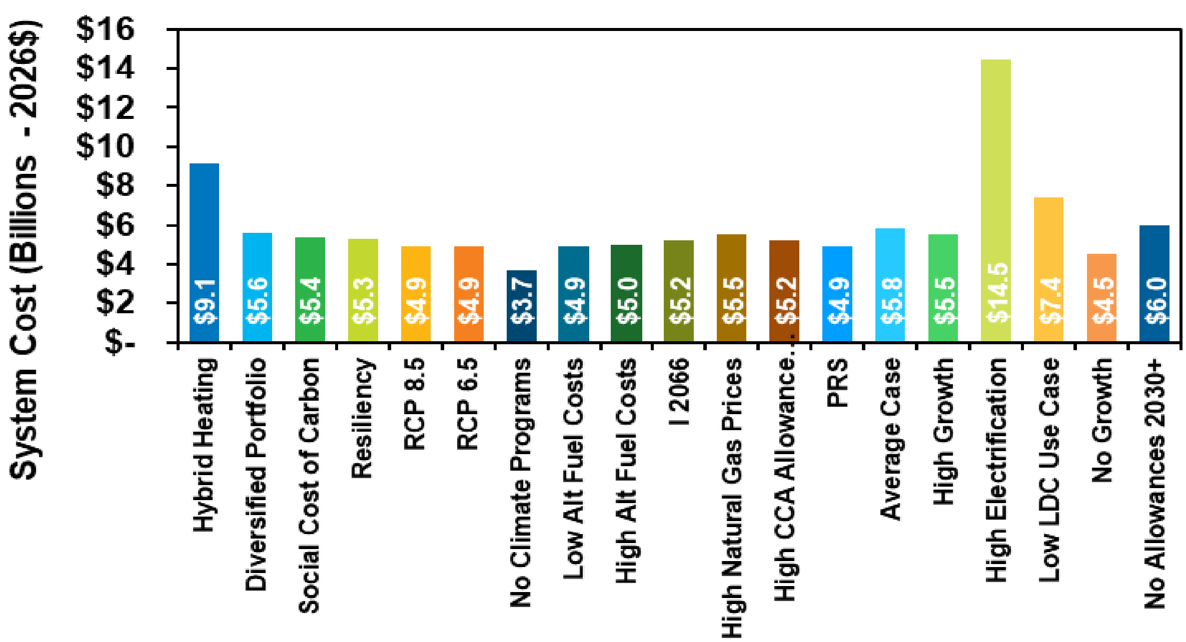


Figure 8.24: All Scenarios and Sensitivities 20-Year Costs (2026$)



The estimated price impact by scenario by generic class and area are included in Figures 8.4 to 8.7. These figures show the implications of each case in respect to commodity and supply costs and exclude base and other tariffs. For electrification scenarios, these costs do not include the impacts to the electric utility.

Table 8.4: Residential Customer Price Impact ($ per dekatherm)

Case	Idaho			Oregon			Washington		
	2026	2035	2045	2026	2035	2045	2026	2035	2045
Average Case Weather	3.86	5.02	6.92	5.28	9.20	12.33	4.74	8.31	11.28
Diversified Portfolio	3.94	5.10	6.96	5.00	11.34	15.20	4.71	10.02	12.14
High Alternative Fuel Costs	3.94	5.09	6.96	5.01	9.20	11.83	4.71	8.00	10.84
High CCA Costs	3.94	5.09	6.96	5.01	8.94	11.21	4.97	8.83	12.48
High Electrification	3.98	18.70	247.53	5.01	8.41	12.92	4.73	25.38	412.04
High Growth on Gas System	3.90	5.03	6.87	4.79	9.15	12.51	4.70	8.07	10.98
High Natural Gas Prices	4.43	9.05	13.38	5.52	11.51	13.52	5.25	11.86	16.96
Hybrid Heating	3.94	10.84	21.73	5.01	8.35	11.31	4.71	12.28	34.30
Initiative 2066	3.94	5.09	6.96	5.01	8.58	11.36	4.71	8.10	10.98
Low Alternative Fuel Costs	3.94	5.09	6.96	5.01	8.25	11.08	4.71	8.00	10.85
Low Natural Gas Use Case	4.45	9.17	13.31	5.58	12.04	14.48	5.51	12.85	18.57
No Allowances 2030+	3.94	5.09	6.96	5.01	10.66	13.80	4.71	11.90	13.66
No Climate Programs	3.94	5.09	6.96	4.98	6.65	8.22	3.84	5.25	6.93
No Growth	3.94	5.09	6.96	5.01	8.58	10.14	4.71	7.88	10.63
PRS	3.94	5.09	6.96	5.01	8.71	11.47	4.71	8.00	10.84
RCP 6.5	3.94	5.10	6.96	5.01	8.45	11.07	4.71	8.00	10.83
RCP 8.5	3.94	5.09	6.96	5.01	8.57	11.28	4.71	8.00	10.87
Resiliency	4.81	6.08	7.92	5.01	8.58	11.46	5.71	8.86	11.21
Social Cost of Carbon	3.94	5.11	6.92	5.00	9.64	12.66	4.71	9.93	11.70

Table 8.5: Commercial Customer Price Impact ($ per dekatherm)

Case	Idaho			Oregon			Washington		
	2026	2035	2045	2026	2035	2045	2026	2035	2045
Average Case Weather	3.99	5.08	7.00	4.86	8.64	11.43	4.92	8.60	11.81
Diversified Portfolio	4.17	5.21	7.07	4.65	10.48	13.97	5.07	10.30	13.27
High Alternative Fuel Costs	4.17	5.21	7.07	4.66	8.51	10.67	5.07	8.85	12.39
High CCA Costs	4.17	5.21	7.07	4.67	8.25	10.08	5.35	9.88	14.45
High Electrification	4.22	18.65	243.43	4.66	7.55	7.93	5.10	25.99	404.09
High Growth on Gas System	4.14	5.15	6.98	4.42	8.61	11.73	5.06	8.89	12.51
High Natural Gas Prices	4.68	9.25	13.44	5.19	10.89	12.26	5.61	12.77	18.81
Hybrid Heating	4.17	12.34	25.91	4.66	7.66	10.22	5.07	14.17	43.00
Initiative 2066	4.17	5.21	7.07	4.66	7.87	10.30	5.07	8.83	12.23
Low Alternative Fuel Costs	4.17	5.21	7.07	4.66	7.66	10.02	5.07	8.85	12.38
Low Natural Gas Use Case	4.74	9.48	13.53	5.23	11.44	13.21	5.89	13.86	20.84
No Allowances 2030+	4.17	5.21	7.07	4.66	9.65	12.37	5.07	11.71	13.75
No Climate Programs	4.17	5.21	7.07	4.64	6.05	7.15	4.13	5.52	7.37
No Growth	4.17	5.21	7.07	4.67	7.96	8.91	5.07	8.89	12.52
PRS	4.17	5.21	7.07	4.66	8.11	10.26	5.07	8.85	12.40
RCP 6.5	4.17	5.21	7.07	4.67	7.78	9.88	5.07	8.85	12.40
RCP 8.5	4.17	5.21	7.08	4.67	7.95	10.20	5.07	8.85	12.42
Resiliency	5.06	6.24	8.03	4.67	7.95	10.33	6.15	9.71	12.79
Social Cost of Carbon	4.17	5.22	7.04	4.65	8.73	11.01	5.07	9.79	11.84

Table 8.6: Industrial Customer Price Impact ($ per dekatherm)

Case	Idaho			Oregon			Washington		
	2026	2035	2045	2026	2035	2045	2026	2035	2045
Average Case Weather	4.20	5.24	7.14	6.41	10.21	11.86	5.60	10.13	14.23
Diversified Portfolio	4.76	5.68	7.53	7.44	12.33	13.83	5.96	10.89	15.55
High Alternative Fuel Costs	4.76	5.67	7.53	7.47	10.84	11.27	5.96	10.86	15.58
High CCA Costs	4.76	5.67	7.53	7.46	10.56	10.39	6.30	12.40	18.60
High Electrification	4.81	15.42	56.44	7.47	9.53	12.00	5.99	21.91	80.17
High Growth on Gas System	4.71	5.56	7.34	7.04	10.43	12.27	5.96	10.90	15.56
High Natural Gas Prices	5.30	9.91	13.72	8.06	12.84	11.98	6.48	14.93	22.70
Hybrid Heating	4.76	12.42	23.44	7.48	9.68	11.32	5.96	16.13	42.53
Initiative 2066	4.76	5.67	7.53	7.48	9.78	10.63	5.96	10.69	14.84
Low Alternative Fuel Costs	4.76	5.68	7.53	7.49	9.78	10.27	5.96	10.86	15.55
Low Natural Gas Use Case	5.41	10.29	14.07	8.15	13.37	13.04	6.84	16.57	26.34
No Allowances 2030+	4.76	5.67	7.53	7.47	11.30	13.39	5.96	10.88	13.62
No Climate Programs	4.76	5.67	7.53	7.47	7.95	7.91	4.80	6.00	8.05
No Growth	4.76	5.67	7.53	7.49	10.04	9.22	5.97	10.98	16.03
PRS	4.76	5.67	7.53	7.47	9.92	10.66	5.96	10.86	15.60
RCP 6.5	4.76	5.68	7.53	7.47	9.58	9.95	5.96	10.85	15.60
RCP 8.5	4.76	5.68	7.53	7.47	9.90	10.42	5.96	10.85	15.60
Resiliency	5.71	6.82	8.48	7.50	10.50	10.71	7.25	11.72	16.09
Social Cost of Carbon	4.76	5.69	7.51	7.45	9.54	9.23	5.96	9.17	11.86

Table 8.7: Transport Only Customer Price Impact ($ per dekatherm)

Case	Oregon			Washington		
	2026	2035	2045	2026	2035	2045
Average Case Weather	3.17	7.56	11.30	3.50	6.78	9.64
Diversified Portfolio	2.57	7.04	10.64	3.52	6.78	9.66
High Alternative Fuel Costs	2.57	6.48	10.12	3.52	6.78	9.65
High CCA Costs	2.57	6.34	9.69	3.75	7.84	11.49
High Electrification	2.57	4.72	4.49	3.52	6.77	11.17
High Growth on Gas System	2.38	7.15	11.36	3.50	6.78	9.65
High Natural Gas Prices	3.11	8.84	15.36	4.13	10.17	15.38
Hybrid Heating	2.57	6.21	9.00	3.52	6.78	9.64
Initiative 2066	2.57	6.35	9.84	3.51	6.78	9.65
Low Alternative Fuel Costs	2.57	6.32	9.89	3.52	6.78	9.65
Low Natural Gas Use Case	3.11	9.13	15.35	4.37	11.23	17.23
No Allowances 2030+	2.57	6.86	13.18	3.52	9.72	11.73
No Climate Programs	2.57	3.48	4.93	2.69	3.63	5.03
No Growth	2.57	5.91	8.76	3.52	6.78	9.65
PRS	2.57	6.35	9.84	3.52	6.78	9.65
RCP 6.5	2.57	6.32	9.78	3.52	6.78	9.65
RCP 8.5	2.57	6.30	9.70	3.52	6.78	9.65
Resiliency	2.57	6.35	9.84	3.51	6.78	9.64
Social Cost of Carbon	2.57	6.19	9.74	3.52	6.79	9.66

Finally, to understand cost risks for residential customers, a full rate has been estimated by scenario as shown in Table 8.8. These costs include current base rates, grown by inflation through 2045, and are added to the estimated costs per dekatherm as described above to show a total estimate of customer impacts. Some things to note are the spiraling of rates in the high electrification scenario and Hybrid Heating scenario. These costs assume base rates would not be spread by some other instrument such as accelerated depreciation of the assets in the near term to pay down costs more quickly or some other combination like spreading these rates through power costs. In the event customers begin to see these higher rates it is plausible that customers would look to convert their end use equipment over to electric.

Table 8.8: Estimated Residential Customer Cost Impact ($per Therm)

Case	Idaho			Oregon			Washington		
	2026	2035	2045	2026	2035	2045	2026	2035	2045
Average Case Weather	1.04	1.27	1.61	1.56	2.20	2.84	1.38	2.02	2.80
Diversified Portfolio	1.05	1.28	1.62	1.53	2.41	3.13	1.37	2.19	2.88
High Alternative Fuel Costs	1.05	1.28	1.62	1.53	2.20	2.79	1.37	1.99	2.75
High CCA Costs	1.05	1.28	1.62	1.53	2.17	2.73	1.40	2.07	2.92
High Electrification	1.05	2.95	28.75	1.53	2.62	9.25	1.38	4.31	48.85
High Growth on Gas System	1.01	1.20	1.49	1.47	2.00	2.45	1.36	1.94	2.56
High Natural Gas Prices	1.10	1.68	2.26	1.58	2.43	2.96	1.43	2.38	3.37
Hybrid Heating	1.05	2.00	3.49	1.53	2.16	2.95	1.37	2.54	5.75
Initiative 2066	1.05	1.28	1.62	1.53	2.14	2.75	1.37	2.00	2.77
Low Alternative Fuel Costs	1.05	1.28	1.62	1.53	2.10	2.72	1.37	1.99	2.75
Low Natural Gas Use Case	1.10	1.75	2.45	1.61	2.51	3.16	1.46	2.48	3.51
No Allowances 2030+	1.05	1.28	1.62	1.53	2.34	2.99	1.37	2.38	3.04
No Climate Programs	1.05	1.28	1.62	1.53	1.94	2.43	1.29	1.71	2.36
No Growth	1.05	1.28	1.62	1.53	2.22	2.84	1.37	2.01	2.82
PRS	1.05	1.28	1.62	1.53	2.15	2.76	1.37	1.99	2.75
RCP 6.5	1.05	1.28	1.62	1.53	2.12	2.72	1.37	1.99	2.75
RCP 8.5	1.05	1.28	1.62	1.53	2.13	2.74	1.37	1.99	2.76
Resiliency	1.14	1.38	1.71	1.53	2.14	2.76	1.47	2.08	2.79
Social Cost of Carbon	1.05	1.28	1.61	1.53	2.24	2.88	1.37	2.18	2.84

Monte Carlo Risk Analysis

Avista employed Monte Carlo risk analysis for estimating probability distributions of potential outcomes by allowing for random variation in natural and renewable gas prices, allowance prices, and weather based on fluctuations in historical data. This statistical analysis, in conjunction with the deterministic analysis, enabled statistical quantification of risk from reliability and cost perspectives related to resource portfolios under varying price and weather conditions. Figures 8.25 to 8.30 show the annual costs and frequency of these costs along with statistics of the 500 draws for each scenario. Figure 8.38 shows all scenarios run through a Monte Carlo analysis and compare costs and frequency of the results.

Figure 8.25: PRS – Millions (500 Draws)

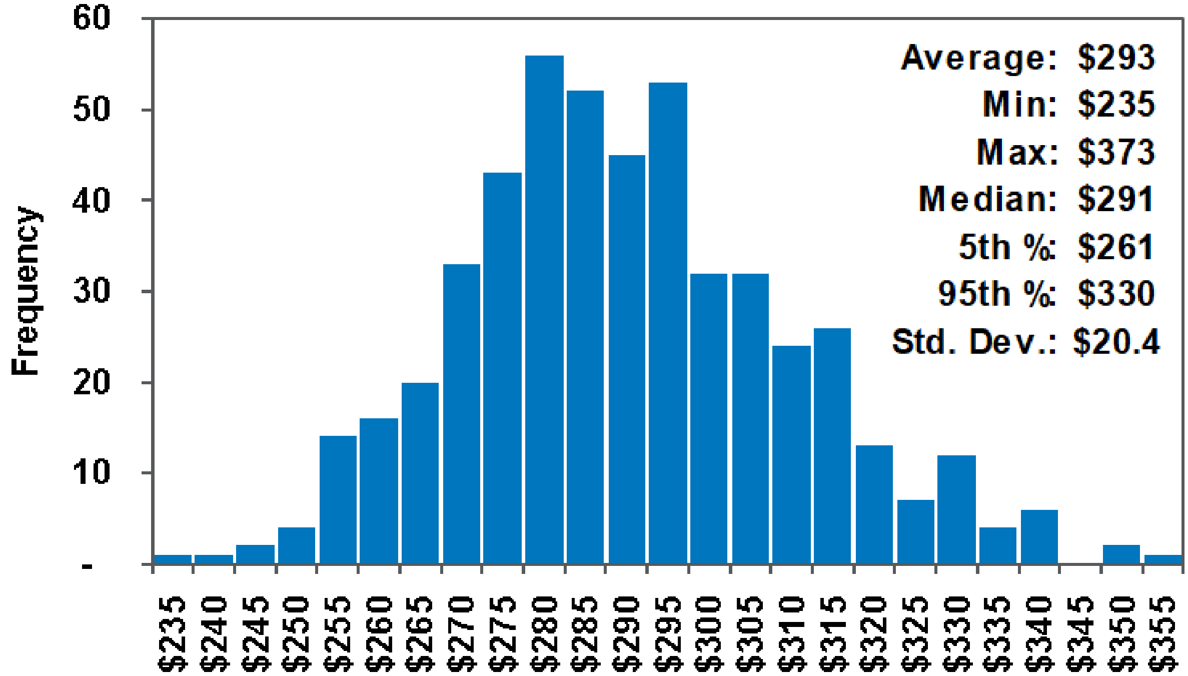


Figure 8.26: Diversified Portfolio – Millions (500 Draws)

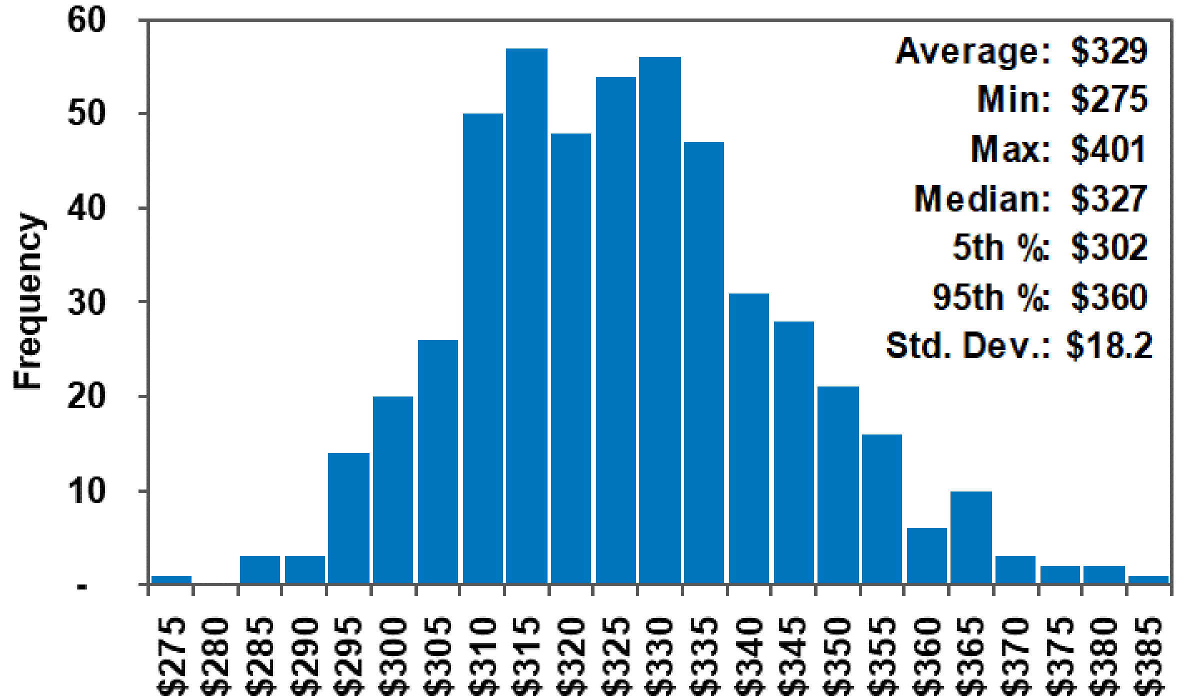


Figure 8.27: No Climate Programs – Millions (500 Draws)

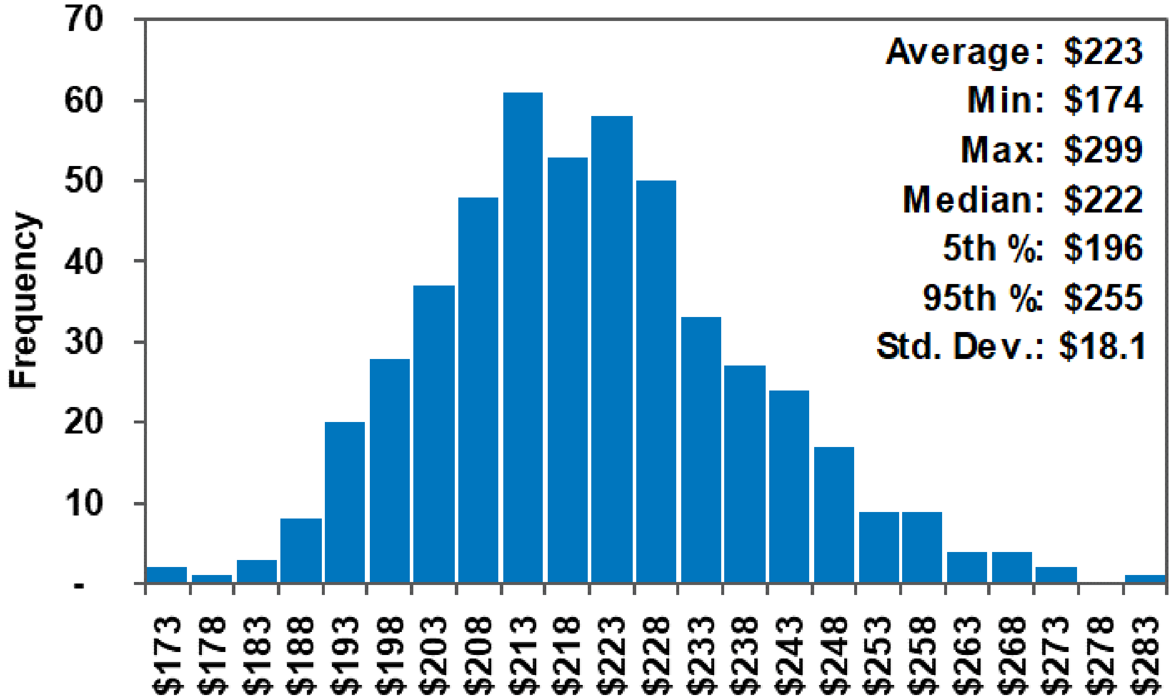


Figure 8.28: Resiliency – 1,000 of $ (500 Draws)

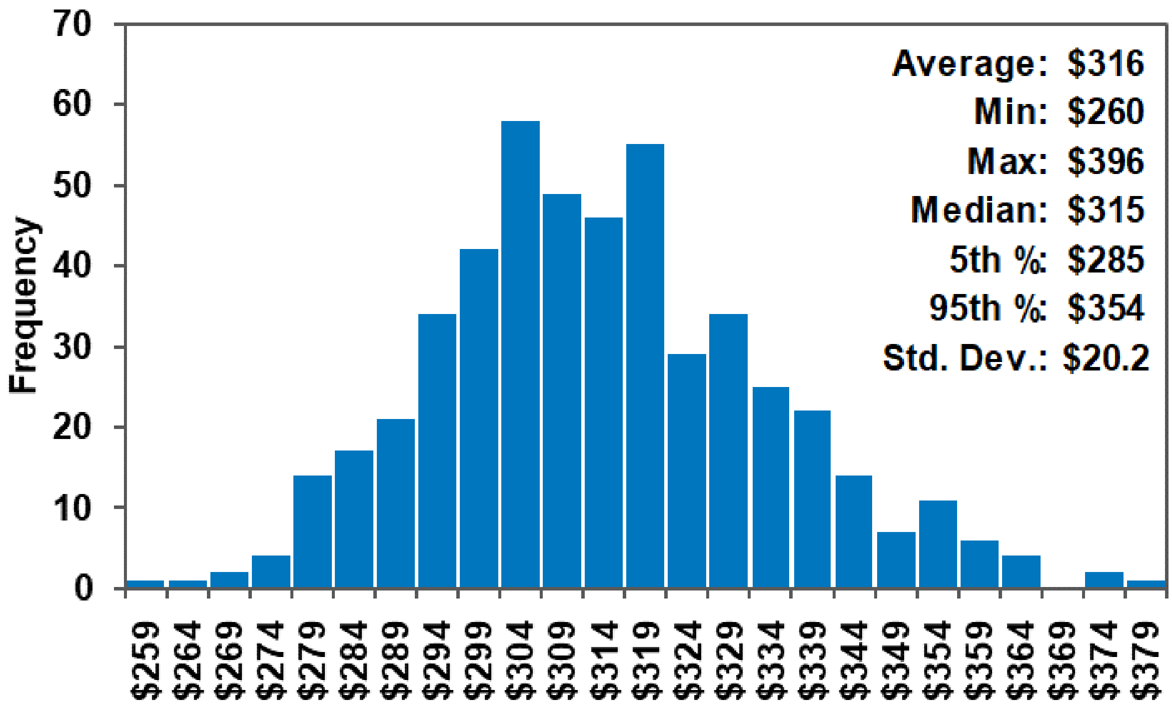


Figure 8.29: Social Cost of Carbon – $ Millions (500 Draws)

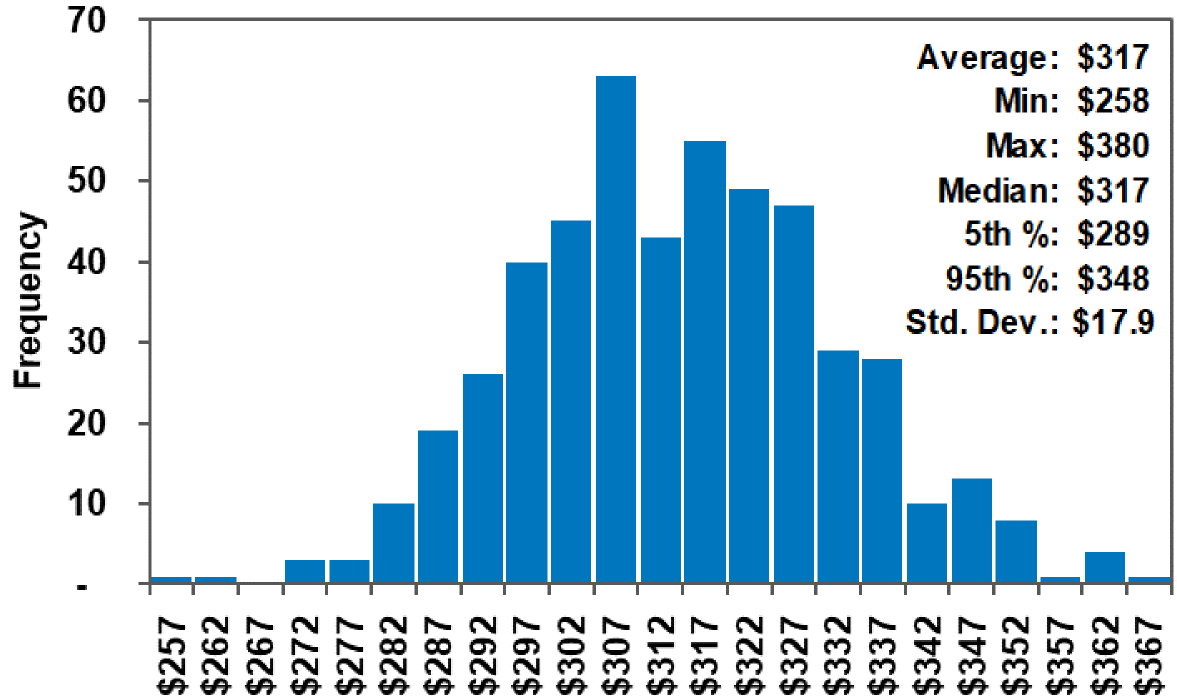
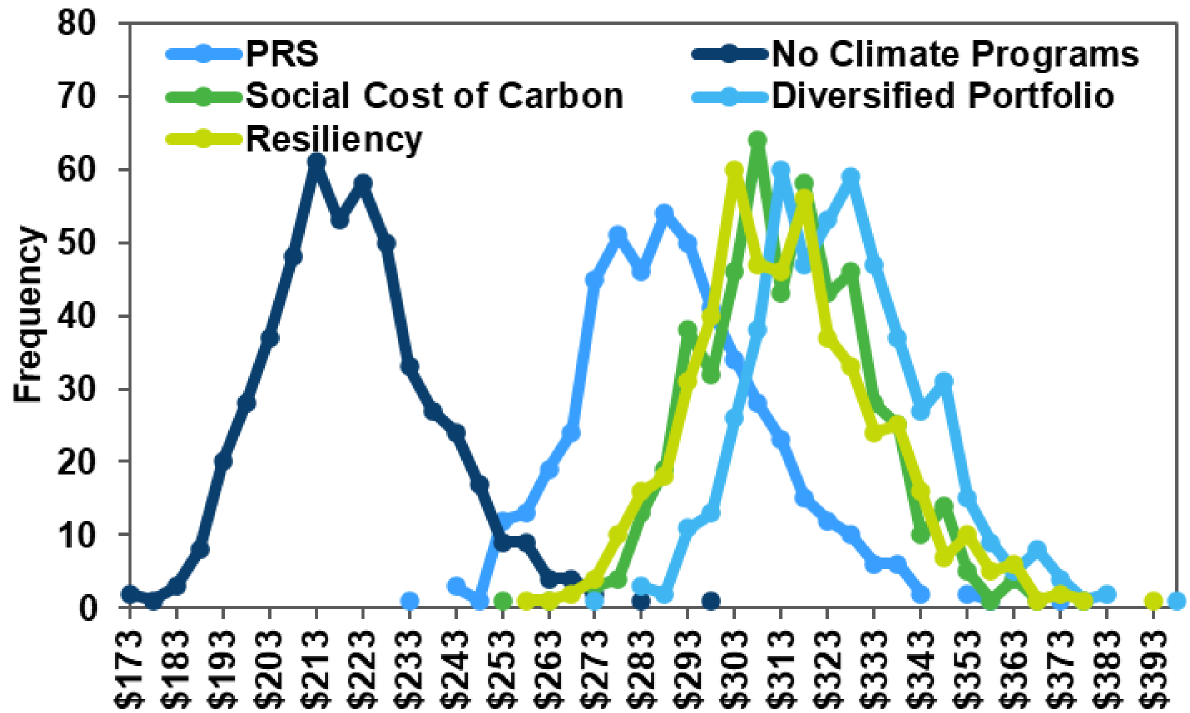


Figure 8.30: Scenario - Monte Carlo Results Comparison - $ Millions

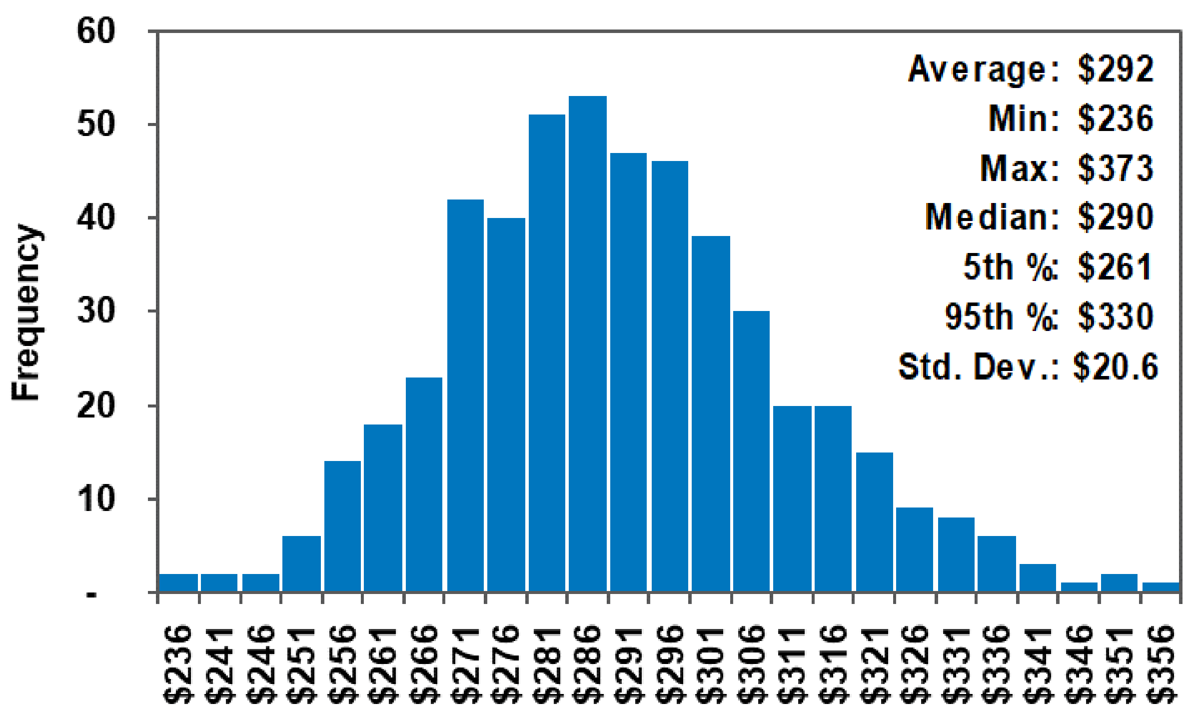


Portfolio Selection

Understanding risk and least cost resources to meet customer demand and state climate programs requires further analysis of the PRS. All alternative portfolios utilize the same stochastic inputs in these Monte Carlo simulations allowing a user to appropriately compare results. Avista used the following methodology to compare risks:

1. Consider resources selected in these cases to identify availability and cost risks including potential impacts to our customers.
2. Consider policy risks and the likelihood of a future like the "No Climate Programs" scenario.
3. Utilize all alternative scenarios from the 500 draws (2026-2045) to estimate risk and costs of each portfolio.
4. Include an additional Monte Carlo simulation, named "Optimized Portfolio", for the PRS where each individual 20-year draw can select the least cost resource daily. This occurs across all 500 draws. This general methodology can be compared to a deterministic analysis running 500 times. These results are shown in Figure 8.31.
5. Compare all scenarios against these levelized costs and risk (standard deviation of costs) in year 2045.
6. Select the least cost and risk scenario based on results. (Figure 8.32)

Figure 8.31: Optimized Portfolio – $ Millions (500 Draws)



There are tradeoffs between risk and cost in an approach similar to finding an optimal mix of risk and return in an investment portfolio, like the efficient frontier[3]; as potential returns increase, so do risks. Conversely, reducing risk generally increases overall cost. Figure 8.32 presents the change in cost and risk from these five different portfolios. Lower gas cost variability comes from investments in more expensive, but less risky, resources such as RNG and CCUS.

The “No Climate Programs” is not considered as the PRS based on voter approval to keep the CCA program. Also, the CPP was passed in November of 2024 so this scenario and results should be used for cost comparison only for greenhouse gas emissions programs. The results show an average annual levelized cost reduction of $69 million dollars as compared to the PRS.

The Social cost of carbon has a higher average annual cost of $24 million dollars as compared to the PRS, yet only reduces cost risk in 2045 by $15 million. Residential rate impacts per therm between 2026 and 2035 estimate increases of 46% in Oregon and 59% in Washington.

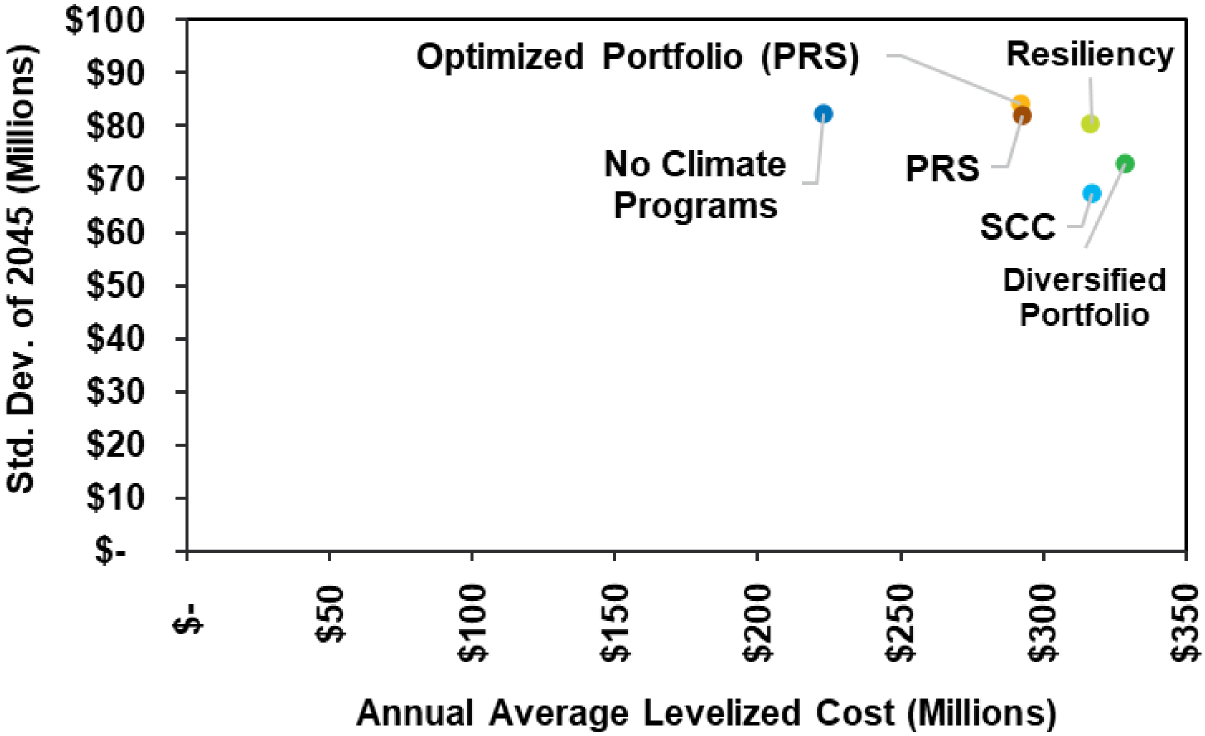
The “Diversified Portfolio” costs an additional $36 million dollars per year as the PRS, yet only reduces risk by $9 million dollars in 2045 as compared to the PRS. With a large number of resources added in 2030 this leads to residential customers in Oregon and Washington experiencing a 58% and 60% increase, respectively, by 2035. In comparison to the PRS, where rates are less dramatic and show a rate increase of 41% in Oregon and 45% in Washington between 2026 and 2035. For these reasons this portfolio was not considered as a preferred resource.

“Resiliency”, as discussed above may not fully consider all cost reductions and risk reduction benefits of on system storage and will be refined in the 2027 IRP. The results of the Resiliency scenario show an average annual cost impact of $24 million, yet only a reduction to the 2045 cost risk of $2 million.

This leaves the “Optimized Portfolio (PRS)” and the “PRS” risks for comparison as they are both relatively the levelized costs, $292 million and $293 million respectively, but the PRS has a lower level of risk in 2045 by $2 million. With the lowest cost and risk combination, the PRS portfolio is selected. Resource acquisition and market availability of the selected resources of an RFP may alter resources when considering actual costs.

[3] Efficient Frontier: What It Is and How Investors Use It

Figure 8.32: Annual Levelized Costs and Risks - All Portfolios



This Page is Intentionally Left Blank

9. Customer Equity and Metrics

Section Highlights:

- Non energy impacts such as social cost of greenhouse gases, upstream emissions, safety and direct air emissions are considered in resource selection for fuels in Washington and Oregon.
- Today the use of natural gas is the lowest cost to heat residential homes.
- 19% of Oregon and 18% of Washington Customers are expected to be energy burdened in 2026.
- Economic impacts were estimated for induced spend for RNG projects and EE.

In recent years, energy equity has emerged as a critical consideration for electric and natural gas utilities, reflecting a growing recognition of the need to address the diverse needs of all communities, particularly those historically underserved or vulnerable to energy-related inequities. Illustrating Avista's Commitment to infusing equity into operations as directed by both Washington and Oregon Commissions, this chapter explores the proactive steps taken by Avista to consider and integrate energy equity into the IRP processes and demonstrating metrics to measure change. By implementing a comprehensive strategy encompassing community engagement, equitable resource access, environmental concerns, and continuous evaluation, Avista is setting the foundation for ensuring natural gas operations are done in a socially responsible manner. This chapter applies to analysis for Washington and Oregon service territories only, limited information will be provided for Idaho customers in this section due to its policy objectives.

Understanding Energy Justice

Energy justice refers to the "goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic and health burdens on marginalized communities. Energy justice explicitly centers the concerns of frontline communities and aims to make energy more accessible, affordable and demographically managed for all communities"[1] Consideration for energy justice creates a broader consideration for benefit types, increase input of interested parties regarding equity issues, and promote continuous process for resource evaluations and the overall delivery of the energy system within the traditional planning process. To ensure Avista is effectively planning for equitable outcomes, the four tenets of energy justice – recognition, procedural, distributive and restorative – are considered in the natural gas IRP.

[1] Shalanda Baker, Subin DeVar, and Shiva Prakash, "The Energy Justice Workbook" (Boston, MA: Initiative for Energy Justice, December 2019), https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf.

Recognition Justice

Recognition justice primarily focuses on whose energy service has been, or is currently, impacted in a disproportional manner. It is primarily concerned with the historical context and seeks to understand how previous actions or policies have resulted in disproportional outcomes. This "… requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequalities". Unlike Avista's electric business which is required to incorporate equity through the Clean Energy Transformation Act, the natural gas business has not been required to formally identify Named Communities. Understanding recognition justice sets the foundation for procedural justice, distributive justice and ultimately restorative justice, several steps were recently taken to identify those equity determinants such as unemployment, age or education level that commonly result in energy-related inequities.

Initially, the Company built upon its Washington Named Communities map, based on the Washington State's Department of Health Environmental Disparities Map by expanding the electric map to include information on communities served by natural gas. "disadvantaged" from the White house's Justice 40 initiative map. Through this map the Company can identify community burdens in the areas of climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development. These maps provide insight into the identification of communities who may have, or continue to, receive a disproportionate benefit or burden. For the purposes of this IRP, these communities identified to be susceptible to energy related inequities will be referred to as "Named Communities".

Beyond a contextual understanding of disparities, recognition justice also validates lived experiences, encourages constructive dialogue regarding methods for addressing inequities, and ensures new policies do not exacerbate existing situations or create unintended consequences. The Equity Advisory Group (EAG) was established in 2021 to support these efforts. While initially limited only to characteristics specific to electric operations, this lens was broadened to represent any customers with characteristics or circumstances that may lead to inequities in process or disparities in energy access or affordability. The EAG members have been instrumental in validating inequalities in known electric Named Community areas and identifying additional communities or individuals who have or are experiencing disparities within Avista's Washington service territory.

In addition, Avista is taking the necessary steps to ensure inclusive, diverse representation through the establishment of an Oregon Equity Advisory group. This group is currently under development and kicks off initial meetings in early 2025. The Company will consider additional input regarding socioeconomic or demographics contributing to energy inequities in Oregon from this group.

Although the preferred resource strategy does not directly include consideration for these communities, the very act of actively seeking out an understanding of where and why there are disparities sets a solid foundation from which Avista may grow its future planning efforts.

Procedural Justice

Procedural justice focuses on impartial, accessible, and inclusive decision-making. Incorporating procedural justice into the IRP process involves ensuring all interested parties, especially those from Named Communities, have meaningful opportunities to provide input to the decisions impacting them.

Throughout the natural gas IRP development, Avista promoted procedural equity in a variety of ways:

- Engaged several advisory groups and encouraged participation in the areas of equity, energy efficiency/demand response, energy assistance, resource planning and the IRP's Technical Advisory Committee (TAC).
- Modified the TAC meeting's frequency and duration based on feedback from participant's feedback.
- Reviewed and modified presentations to ensure more use of common language (non-technical) where possible.
- Recorded presentations for ease of access at later dates/times.
- Posted IRP calculation workpapers to provide transparency.
- Emailed presentations before meetings to provide more time to develop questions and share concerns.
- Invited customer advocates to represent customers who may not be able to attend.
- Developed customer metrics in relation to resource planning to track.
- Invited all customers to participate in an open meeting to learn about the plan and ask questions and provide comments.
- Posted input received from public meetings to support transparency of feedback.

Avista's Public Participation Plan (PPP)[2] informed tactics and strategies to facilitate meaningful engagement. The PPP supports broad representation from interested parties and customer advocates, providing additional opportunities for identifying and considering policies or procedures going forward. Although this plan was intended for Washington's CETA compliance, learnings from it may be applied to natural gas operations in all states.

[2] See Docket No. UE-210295 for Avista's 2021 Public Participation Plan and Docket UE-210628 for its 2023 Public Participation Plan.

Distribution Justice

Distribution equity in the natural gas IRP pertains to the allocation of advantages and disadvantages of goals and targets and ensures they are allocated between different communities or across generations. It not only focuses on the actions taken but also on the communities affected, considering variations among them, such as between the subset of customers described above and the general customer base.

The foundation of energy equity emphasizes identifying benefits going beyond traditional energy-related benefits. In IRP modeling, resource selection is based on either a constraint (forcing an action) or a financial driver (cost or benefit) to incentivize resource selection. Recent IRP’s resource selection used additional modeling of non-financial benefits, or Non-Energy Impacts (NEIs), to highlight the interconnectedness of economic, social, and environmental issues from resource selection.

To measure the distributional impacts of resource selection, energy burden is also being monitored as a transparent, consistent, and measurable way to track progress and ensure accountability in equity areas specific to affordability. Importantly, this is an initial step taken by the Company to evaluate disparities in natural gas service.

Avista's approach to distributional justice is in its infancy stages and will continue to be evaluated on an ongoing basis to determine the most optimal manner to capture this important aspect of energy equity.

Restorative Justice

Restorative justice focuses on systematic approaches to prevent harm from occurring or continuing in the future. Striving to minimize disparities between Named Communities and all customers, particularly in relation to areas of affordability, availability, and accessibility, amongst others. Avista incorporates restorative equity mainly through energy efficiency and accounting for non-energy impacts. Energy efficiency specifically for lower income households include additional economic value compared to other energy efficiency programs by accounting for additional non-energy impacts. Furthermore, Avista includes other non-energy impacts discussed later leading to higher avoided cost to enable higher levels of energy efficiency and lower emitting options.

Achieving equity in operations is not limited to IRP planning. A broader, Company-focused effort is being made to ensure an equitable transition – one that is fair, impartial, and provides opportunities for all customers regardless of their unique circumstance. Avista has several efforts in progress to help incorporate equity throughout Avista’s operations. These efforts include an equity focus on capital planning, energy efficiency and weatherization, affordability, and distribution planning.

Non-Energy Impacts

To account for societal cost of Avista's resource decisions the use of non-energy impacts (NEI) is included in resource decision making. These impacts may alter resource decisions away from the utilities lowest cost but allow for a portfolio of resources representing the lowest reasonable cost given the impacts of Avista decision on its customers. Avista includes these NEIs differently between each of the states.

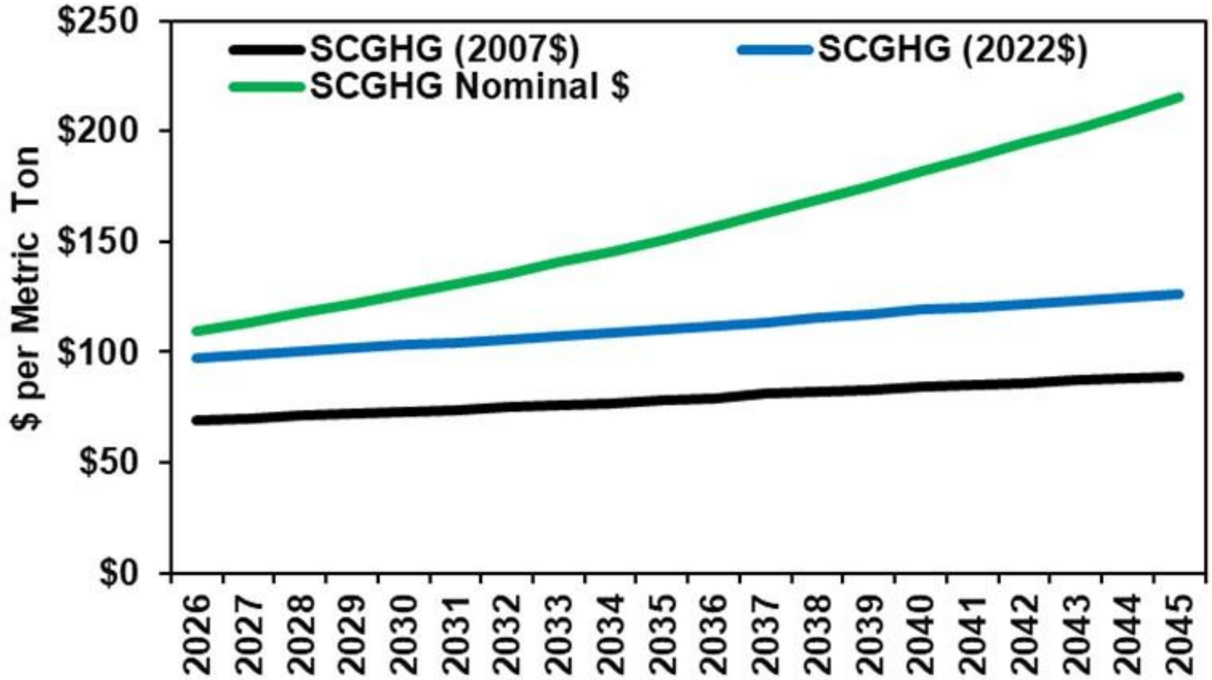
Avista during its February 1, 2024 TAC meeting[3], Avista presented the potential items a full NEI study may entail including the impacts of public health, safety, land use, water use, economic impacts, community odor pollution, process bi-products, and pipeline construction for renewable natural gas, hydrogen/synthetic methane, and natural gas fuels. Avista ultimately decided against conducting a full study due to the cost of such a study for Avista customers to carry. Although, Avista was able to conduct its own analysis using public available sources for the following NEIs, included is a description of the NEI and how it is used within the resource decision making process.

Social Cost of Greenhouse Gas (SCGHG)

The SCGHG is used as a cost adder to natural gas resources for determining the avoided cost of gas for the energy efficiency in Washington state. This cost increases the avoided cost of gas and therefore increases the number of cost-effective programs. Avista does not include this cost for other resource selections. Although, a scenario described in Chapter 8 demonstrates the impact if Avista used this cost adder for all resource decisions. The SCGHG is determined by the Interagency Working Group on Social Cost of Greenhouse Gas using the 2.5% discount rate for future costs. Figure 9.1 illustrates the prices used for this analysis.

[3] See Appendix 11

Figure 9.1: Social Cost of Carbon



Upstream Emissions

System emissions include any emissions from combustion including those emissions upstream of the point of combustion like production, processing, transmission, and equipment. This designation becomes important when placing a tax or cost of emissions on the price per MMBtu. Avista assumes these upstream emissions are measured at the standard 100-year Global Warming Potential (GWP) meaning a 29.8 multiplier of methane from natural gas for the same mass of carbon dioxide. The levels of upstream emissions in this plan are determined by production region, specifically in Canada and the Rockies in the United States and multiplied by the associated emissions estimate.

Avista assumes a 0.77% upstream emissions rate for Canadian production[4] and 2.64% rate from the Rockies as calculated by an EDF study. From 2019 to 2023, nearly 83% of Avista's natural gas was sourced from Canadian production leaving roughly 17% of estimated upstream emissions to the Rockies region. Additionally, Avista adds 0.51% from its local distribution lost and unaccounted for estimates. This estimate compares billed data to metered data from June to July of each year. These estimates can be overstated as the most likely case of losses are from meter reading issues or billing timeframes or the dates a meter is read and billed compared to the specific calendar month a bill is sent. Meter reading dates are specific to the days the information is collected meaning one could be read on the 1st of the month, while another could be read on the 20th. These upstream emissions are included in the Social Cost of Greenhouse

[4] as calculated in a study for the Tacoma LNG project

Gas scenario and for estimating energy efficiency avoided cost as explained in Chapter 4 and are used to consider all emissions from production to the burner tip for use. The Climate Protection Plan and Climate Commitment Act do not consider upstream emissions for compliance, but rather site source emissions only.

The final upstream emissions from methane (CH_4) in carbon equivalents add nearly 12.09 pounds per MMBtu as shown in Table 9.1:

Table 9.1: Avista Specific LDC Natural Gas Emissions

Combustion	Avista Specific Natural Gas	
	lbs. GHG/MMBtu	lbs. CO2e/MMBtu
CO_2	116.88	116.88
CH_4	0.0022	0.06556
N_2O	0.0022	0.6006
Total Combustion		117.61
Upstream		
CH_4	0.406	12.55
Total		130.09

Table 9.2 illustrates the Global Warming Potential; the Intergovernmental Panel on Climate Change released their 6th assessment study defining these impacts to global warming in units of CO_2e.

Table 9.2: Global Warming Potential (GWP) in CO_2 Equivalent[5]

Greenhouse Gas	GWP – 100 Year	GWP – 20 Year
CO_2	1	1
CH_4	29.8	83
N_2O	273	268

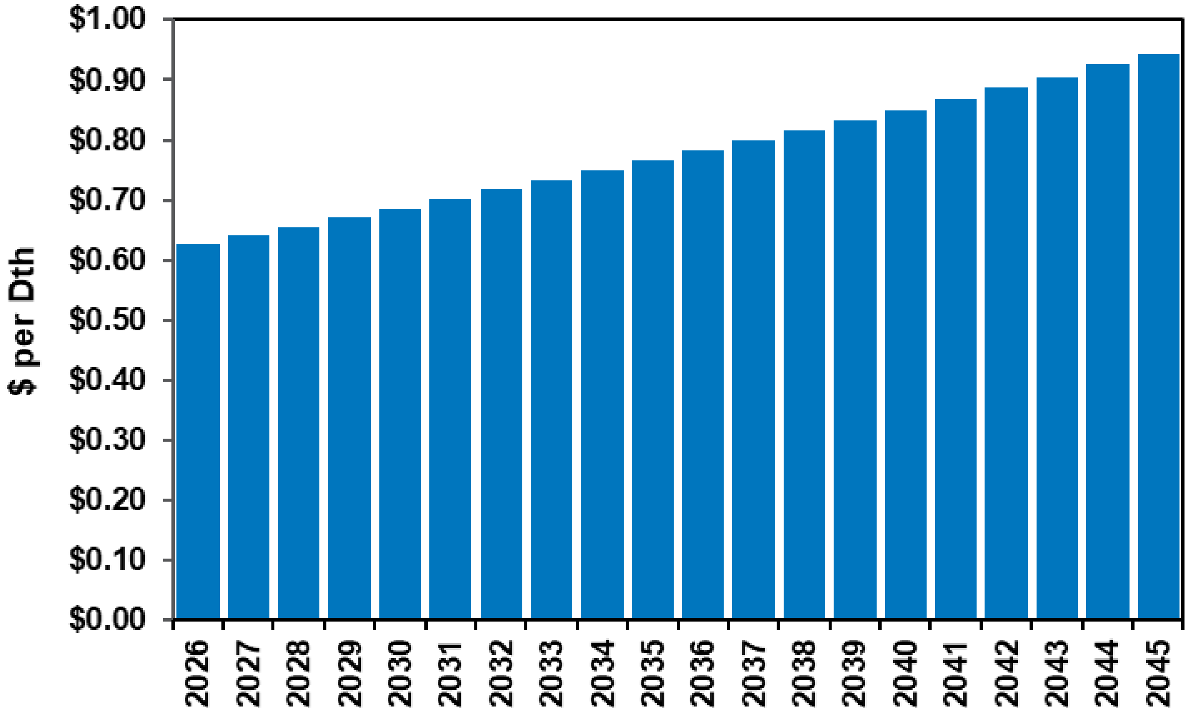
Safety

Avista is considering customer safety to add a financial value to the cost of natural gas resources for resource selection. Avista estimates this value by considering the potential deaths related to carbon monoxide poisoning as a population share of overall deaths[6]. Safety incidents from the natural gas system is also included in this estimate as provided by PHMSA7 and is based on Avista's percentage of total throughput of natural gas in Idaho, Oregon and Washington and the value of a human life. Avista uses this NEI only

[5] From the 6th Assessment of the Intergovernmental Panel on Climate Change
[6] Non-Fire Carbon Monoxide Deaths Associated with the Use of Consumer Products 2020 Annual Estimates
[7] US DOT Pipeline and Hazardous Materials Safety Administration

for Washington and Oregon resource decision making. Figure 9.2 demonstrates the safety cost adder starting \$0.63 per Dth in 2026 escalating to \$0.95 per Dth by 2045.

Figure 9.2: Customer Safety Impact



Air Emissions

Avista also includes a financial adder for air emissions from the combustion of natural gas for resource selection in Washington and Oregon, these include N_2O, CH_4 and CO_2. Figures 9.3 to 9.5 represent these costs based on the direct use of natural gas. These estimates are derived from the Interagency Working Group on Social Cost of Greenhouse Gas. Although the cost of CO_2 price adder is only included in the energy efficiency potential analysis and the Social Cost of Greenhouse Gas Scenario, this is due to the Climate Commitment Act's carbon allowance prices accounts for the actual financial value of these emissions as directed by Washington State's legislature.

Figure 9.3: CO_2 Cost per Dth (Nominal $)

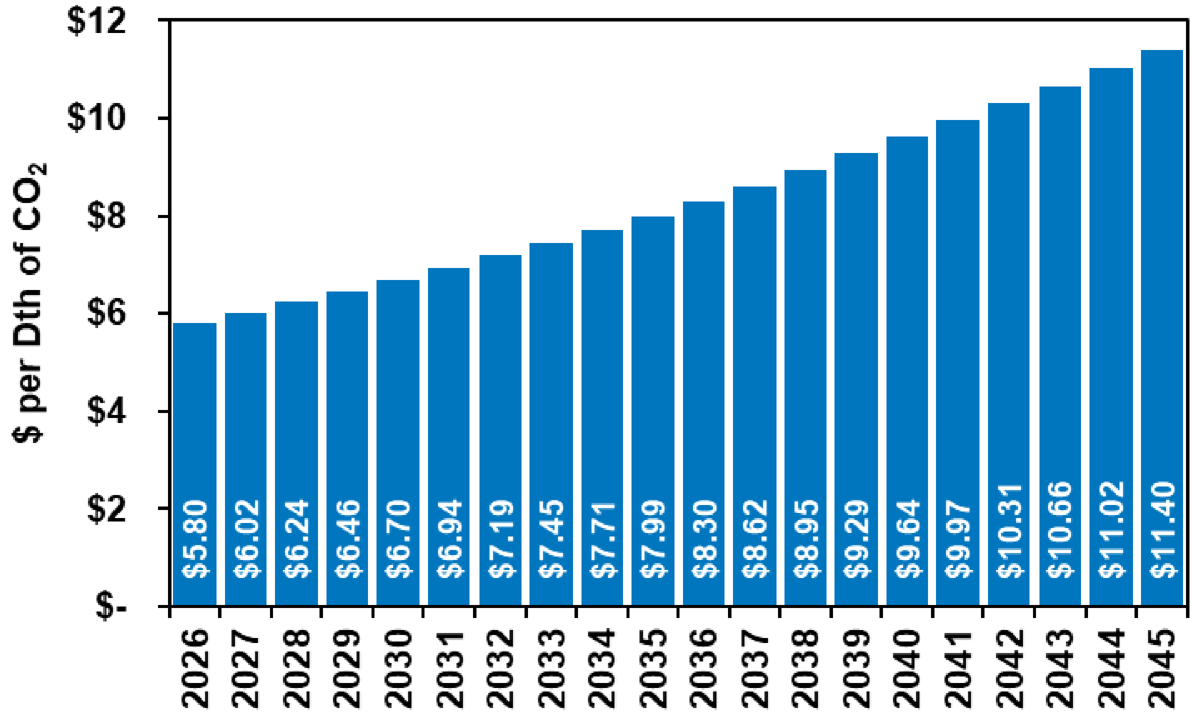


Figure 9.4: CH_4 Cost per Dth (Nominal $)

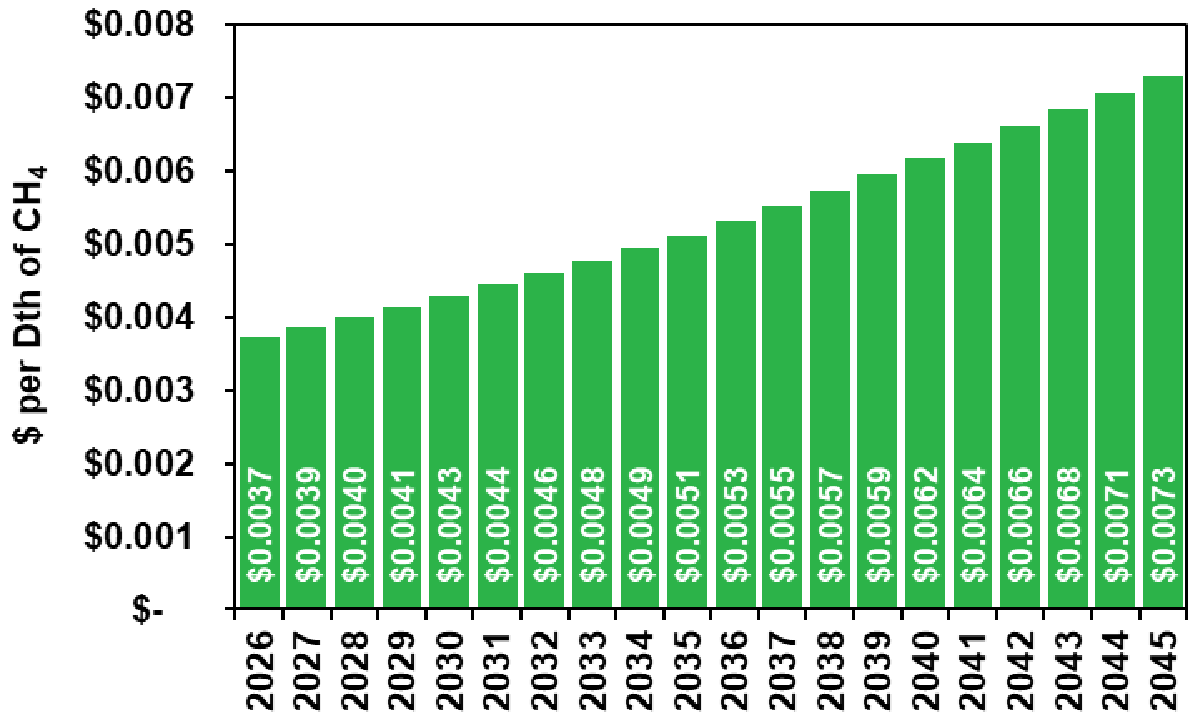
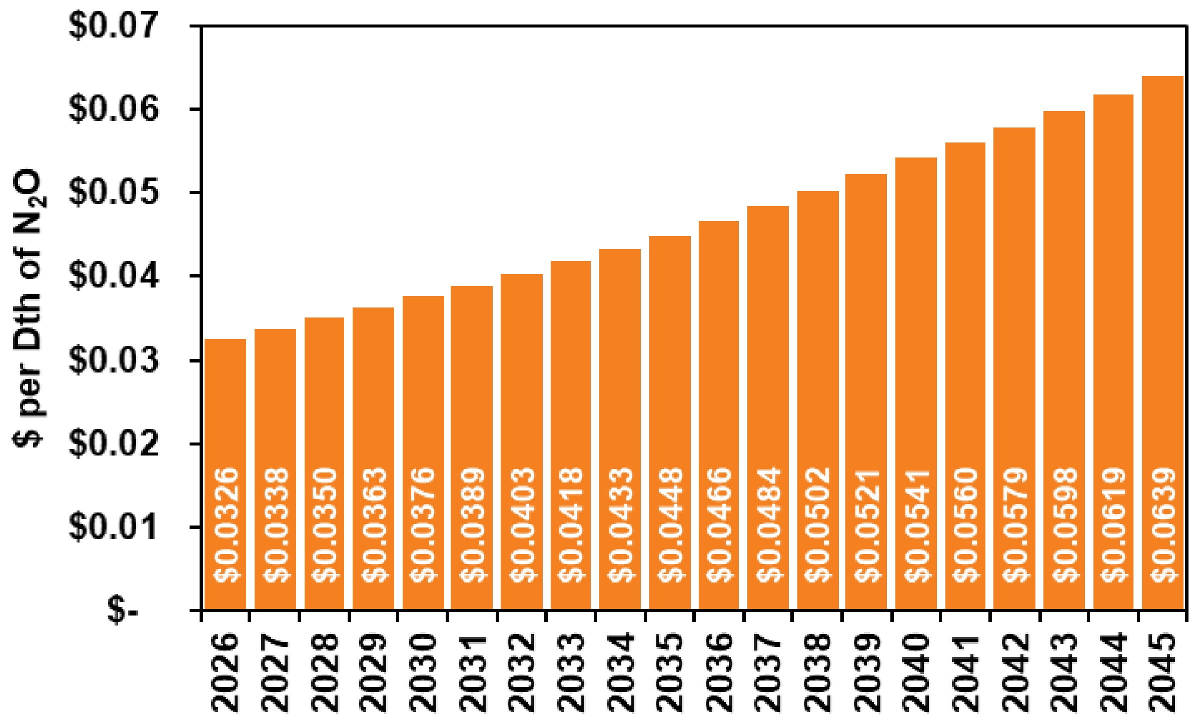


Figure 9.5: N_2O Cost per Dth (Nominal $)



Energy Efficiency Programs

Avista engaged with DNV (formerly DNV-GL) to develop and quantify a list of NEIs for Avista's electric and natural gas programs, along with a gap analysis of areas for future NEI development. These efforts identified several NEIs for low-income, residential, and commercial/industrial customers, including those affecting participants, society, and the utility.

While basic conservation efforts consider the effect of energy efficiency measures on the utility's system by deferring capital investments, NEIs provide an opportunity to assign value to what is received by the customer, providing a link between an efficiency measure and a measurable customer benefit. As such, NEI values are included in Avista's TRC cost-effectiveness test as a benefit to the customer. Avista started utilizing NEI values in its benefits calculations for TRC and PCT cost-effectiveness tests starting with Avista's 2022 Annual Conservation Report, which was filed on June 1, 2023. Avista has incorporated updated NEI values into its TRM and continues to utilize NEI values in its cost-effectiveness calculations. NEI values are tracked on a per-measure basis and range from less than $.01 per therm up to $1.91 per therm. Low-Income Program measures have the highest non-energy benefit value to customers because of the health and safety benefits provided to qualified customers at no cost.

Other categories of non-energy impact values that are quantified in Avista's NEI values include avoided illness from pollution; reductions in noise, increases in productivity, ease of selling or leasing a space based on improvements, avoided costs of insurance/fire damage, and NEIs related to energy burden reduction. Examples include reductions in bad debt write-offs' reductions in calls to the utility' reductions for utility carrying costs on arrearages, and thermal comfort and operations savings for customers. For each measure in Avista's portfolio, the NEI value for each identified category is aggregated and then matched against an NEI database to create an Avista-specific NEI value for that measure.

Power Act Adder

Avista's avoided cost for energy efficiency includes the Northwest Power Act's 10% energy efficiency preference. This adder is applied to energy efficiency selection in Washington only to further encourage energy efficiency.

Economic

Avista acquired IMPLAN[8] to estimate the economic benefits of added natural gas infrastructure and supply. IMPLAN is a leading national economic impact analysis tool used to gain precise insights into local, regional, and national economies. Avista's intent was to use this information to influence resource decisions by including the induced economic benefits as NEI. Avista ultimately decided to not include this as an NEI and rather measure the economic benefit and induced jobs as a metric.

Customer Equity Metrics

Avista committed in its first Technical Advisory Committee meeting to include metrics regarding customer impacts like Customer Benefit Indicators (CBI's) used in other forums. These metrics are used to determine the impacts of the Preferred Resource Strategy to our customers. In this first meeting Avista agreed to estimate future greenhouse gas emissions, customer rates, energy burden, and other air emissions. In addition to these metrics Avista is also including induced economic benefits and job creation of the plan.

Air Emissions

The PRS expects natural gas and renewable natural gas to service customers into the future to assist in complying with state greenhouse reduction goals. Although, even if Avista uses all direct use renewable natural gas to serve customers, there is likely emissions from the combustion of the fuel regardless of climate program rules of accounting for those emissions. The following Figures (9.6 to 9.11) show the actual air emissions (carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) from the PRS's resource selection rather than the estimated emissions based upon compliance of state programs. Avista's reductions shown in the estimates are from energy efficiency, changes in customer use, and expected carbon capture and does not include the emission reductions for any Renewable Thermal Credits (RTCs) purchased.

[8] IMPLAN | Economic Impact Analysis Software

Figure 9.6: Washington Direct CO_2 Emissions

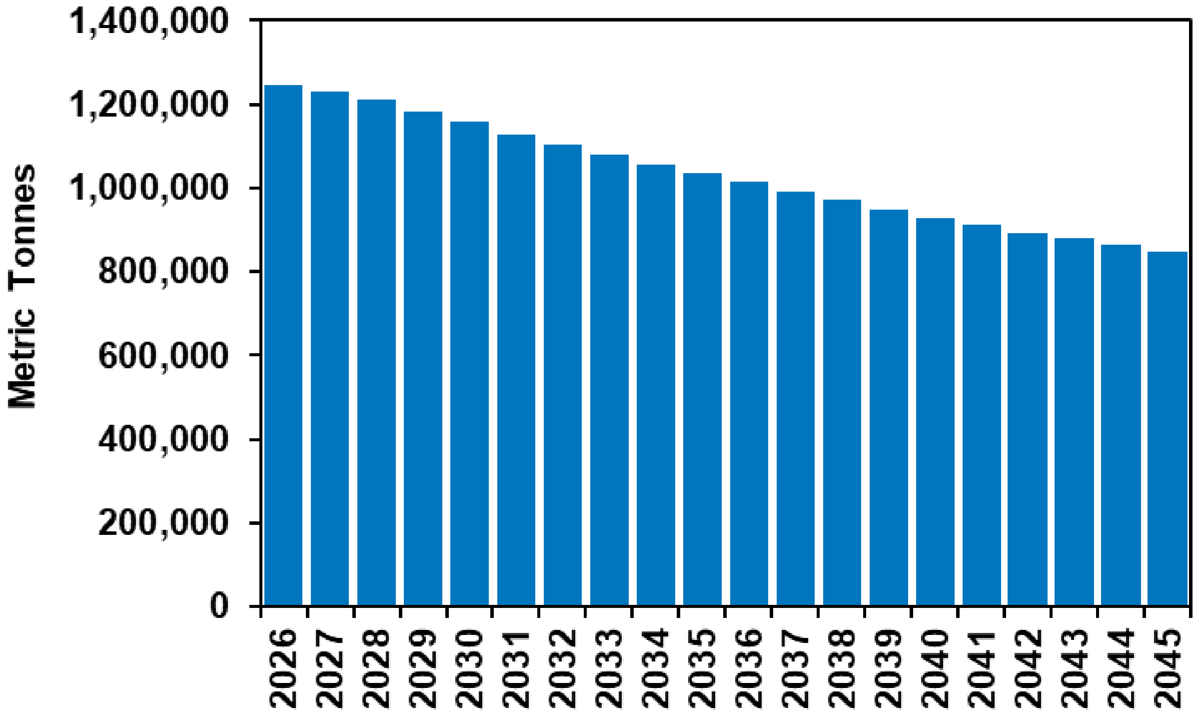


Figure 9.7: Oregon Direct CO_2 Emissions

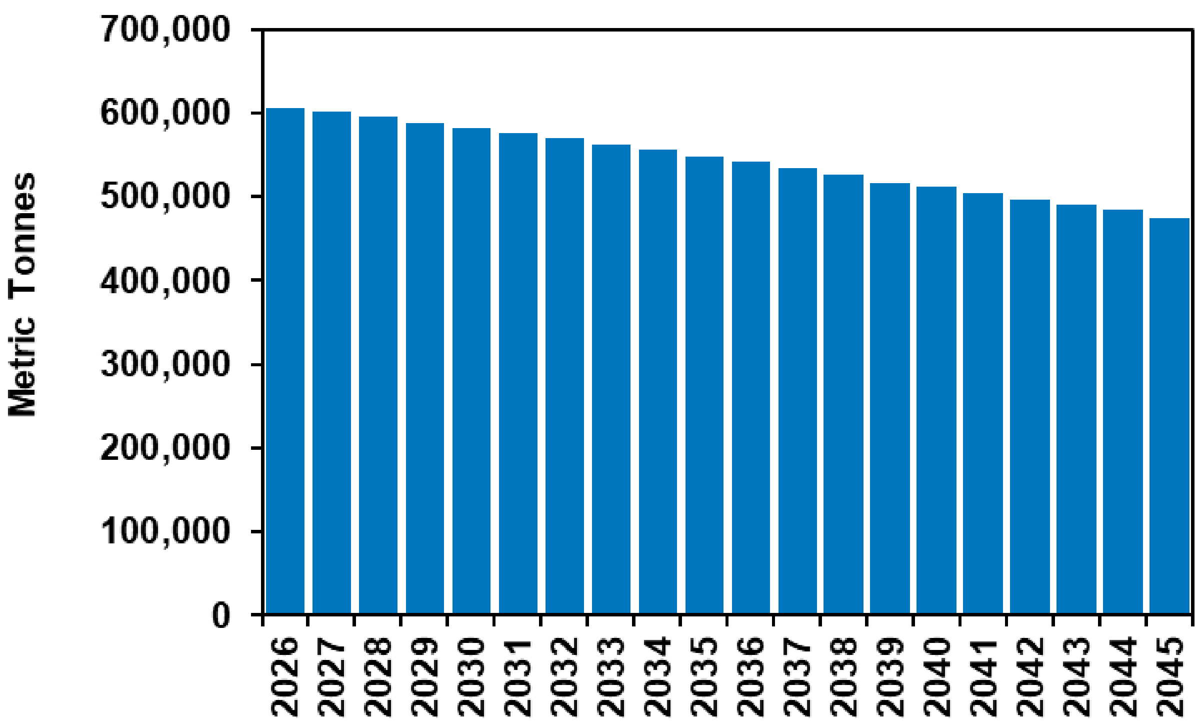


Figure 9.8: Washington Direct N_2O Emissions

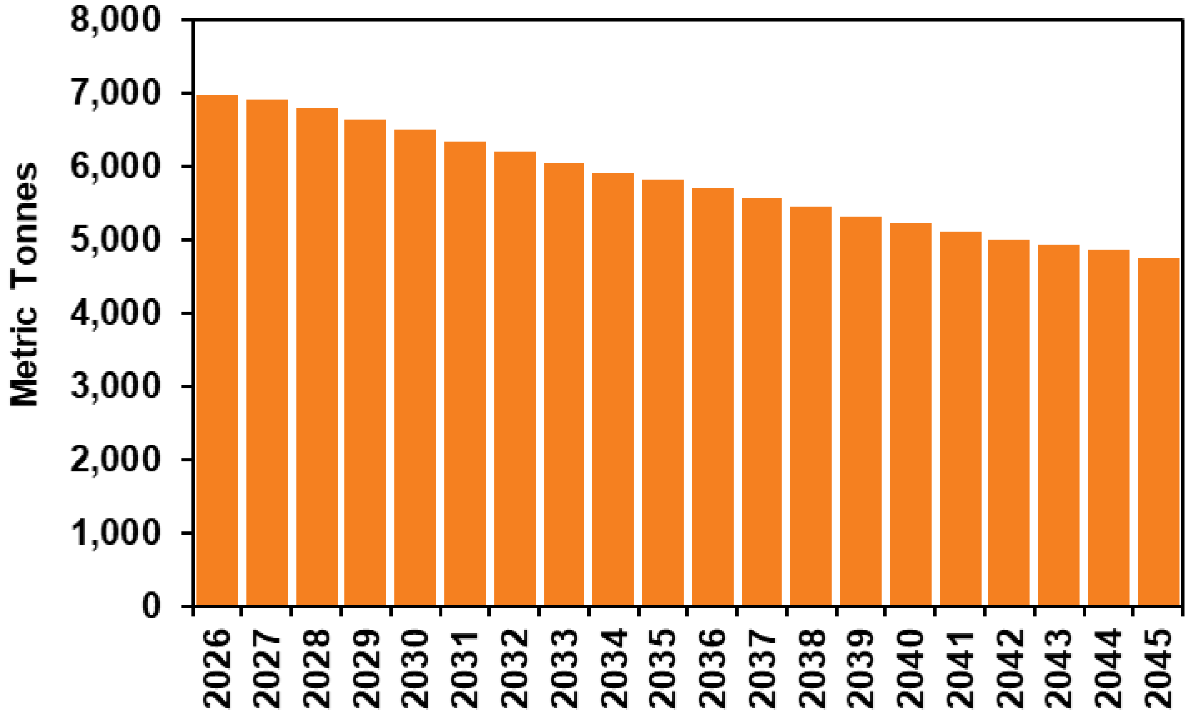


Figure 9.9: Oregon Direct N_2O Emissions

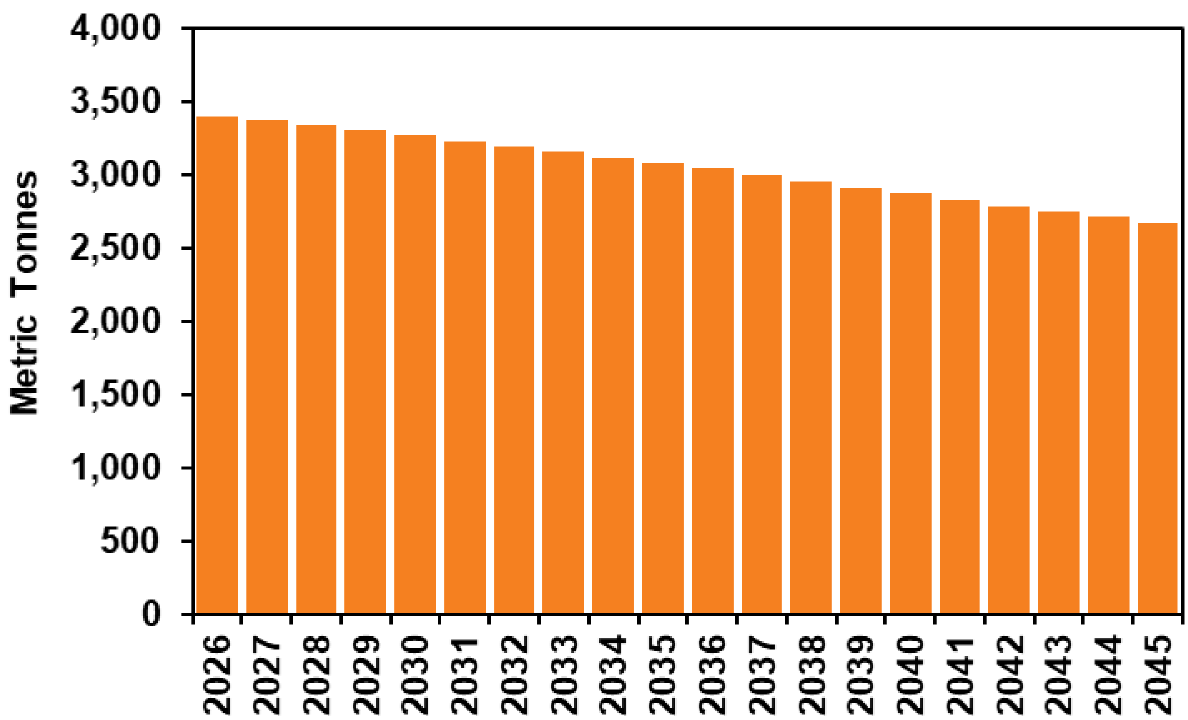


Figure 9.10: Washington Direct CH_4 Emissions

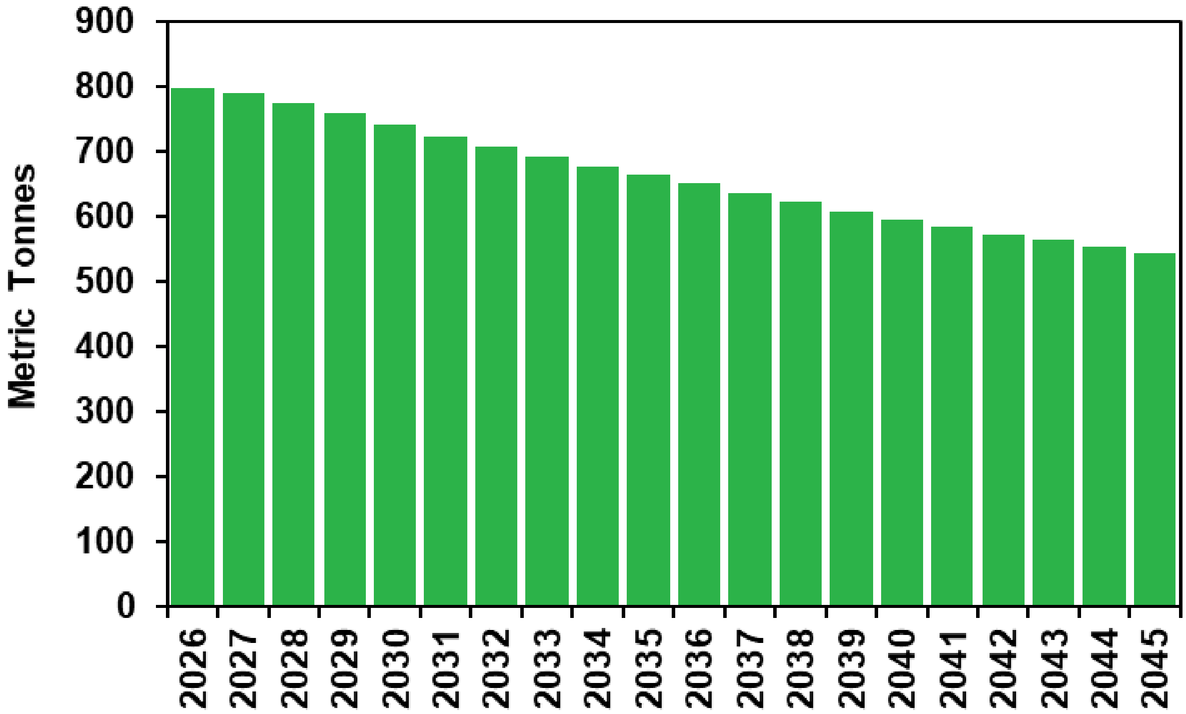
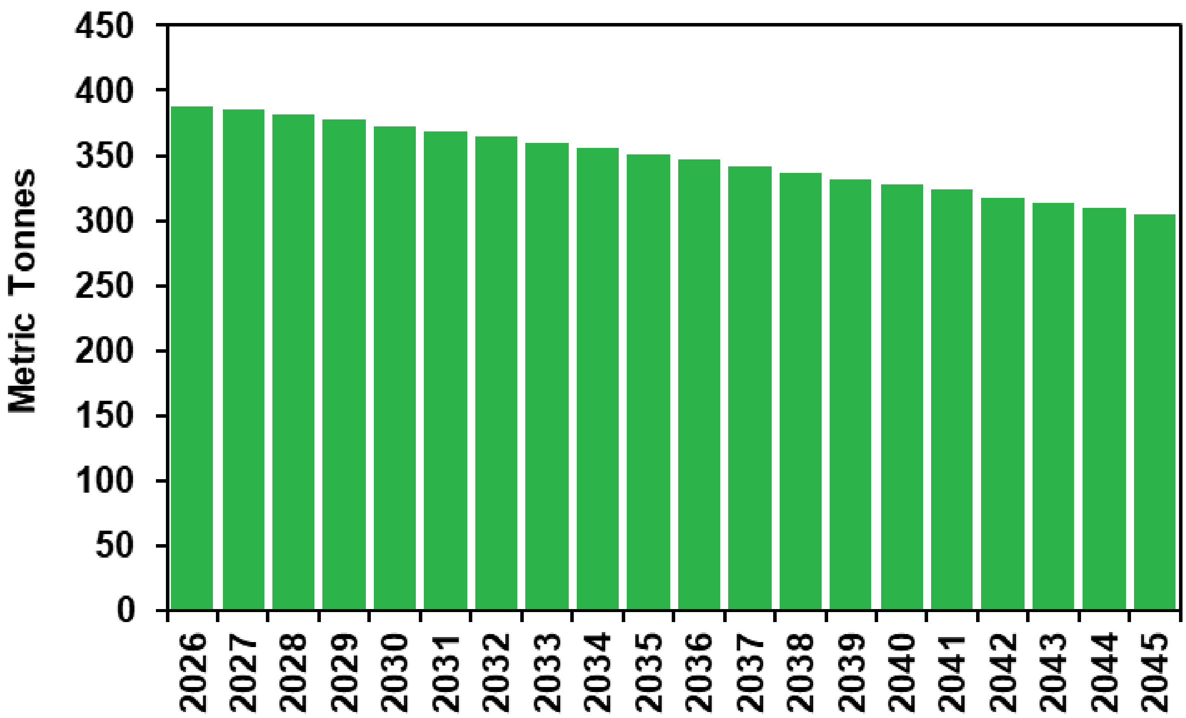


Figure 9.11: Oregon Direct CH_4 Emissions



Economic Impacts

Avista's resource choices of acquiring fuel and energy efficiency within the local economy will improve community vitality, this is mainly accomplished through capital investment and job creation. Using the IMPLAN model, Avista estimates the following economic activity from Avista resource choices of RNG and Energy Efficiency. Oregon selects nearly all RNG in the PRS so no other states are shown in Figure 9.12 for economic impacts. On average, each dekatherm of capital spend creates an additional 28% of induced economic growth in Oregon. Figures 9.13 and 9.14 show the number of job creations based on annual energy efficiency spend and in Oregon the total induced jobs including those from RNG.

Figure 9.12: Oregon Induced Economic Growth from RNG

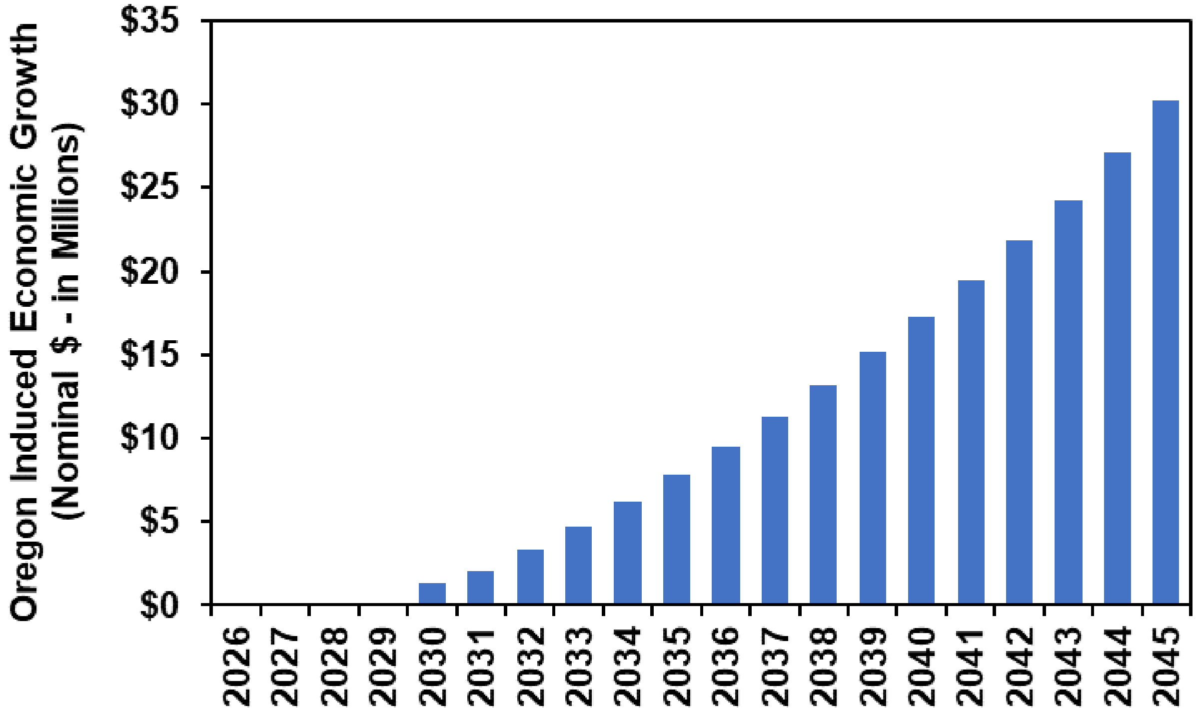


Figure 9.13: Oregon Induced Job Creation from RNG/Energy Efficiency

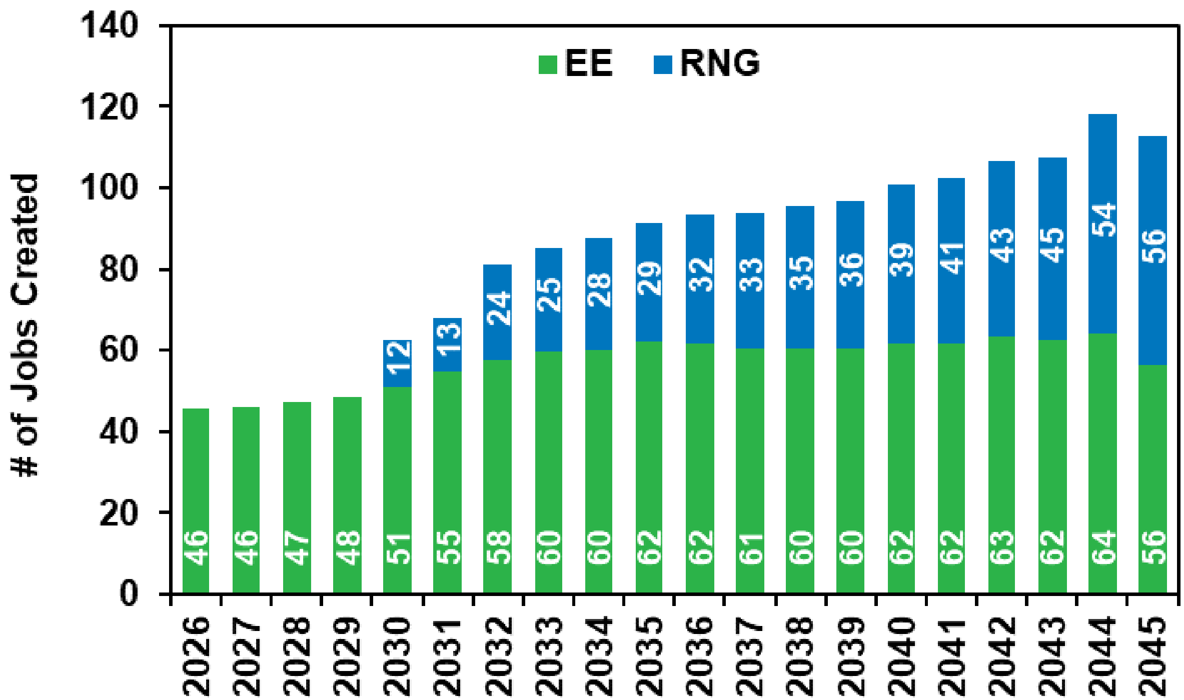
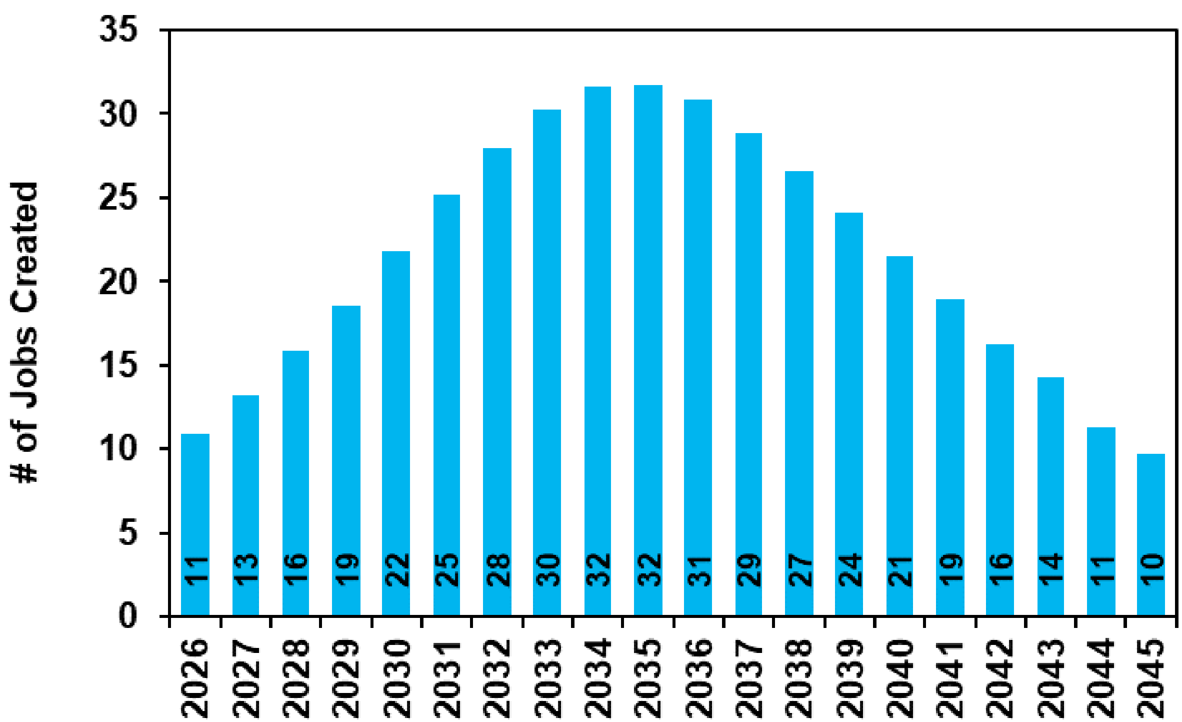


Figure 9.14: Washington Induced Job Creation from Energy Efficiency



Affordability

The first consideration of understanding customer's energy equity is to comprehend the current landscape of residential customer's gas cost. This analysis describes the components of the customer bill on a winter monthly perspective and an annual cost perspective to give understanding to typical bill size and what makes up a customer's natural gas energy cost. Following this analysis is an estimate of customers with an energy burden exceeding 6% of gross income is performed to identify the quantity of customers who may have challenges paying their energy bills.

Current Customer Space Heating Costs

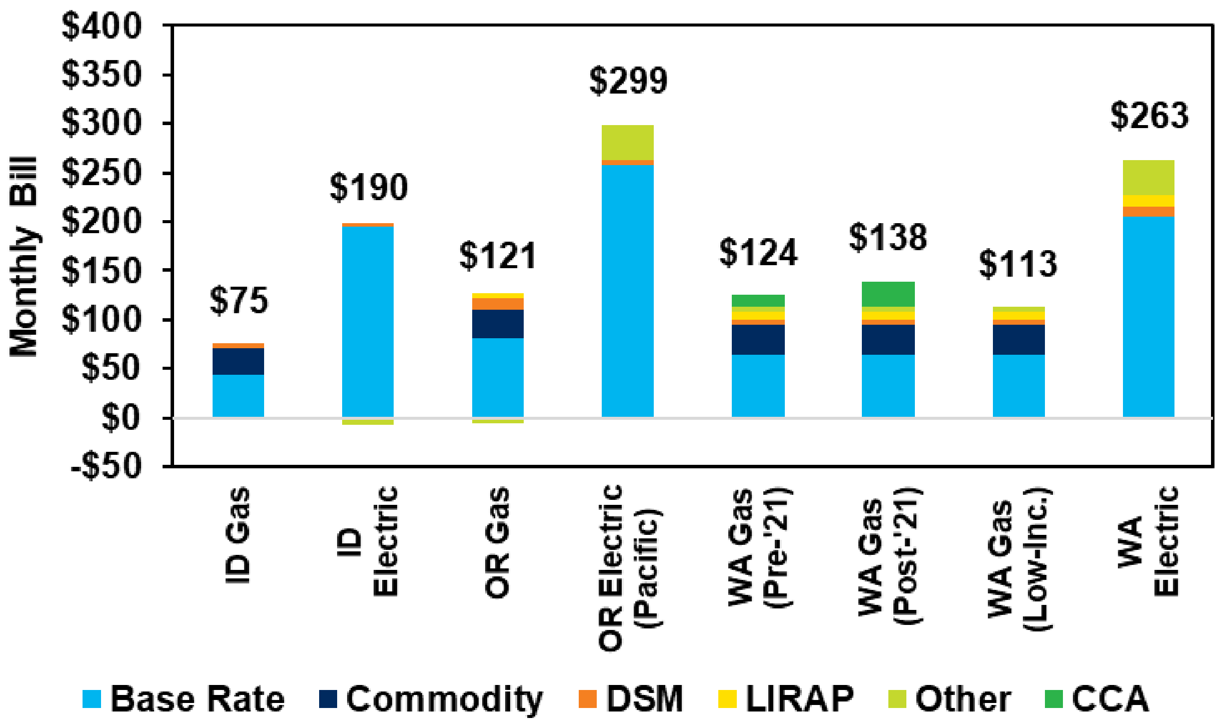
Residential customers use natural gas for space heating, water heating, cooking, and other purposes, but the main purpose is space heating. The intention of this analysis focuses on the cost of residential space heating as it's the major component of a customer bill and is a necessity in Avista's climate zones. Winter monthly bills are the greatest challenge for customers, this analysis demonstrates a comparison of current rates for each of Avista's jurisdictions for the same natural gas consumption using actual tariff rates as of February 2025[9]. The analysis demonstrates the highest monthly bill in is typically in the month of January and the total cost over a year for customer's space heating needs. This analysis does not include water heating or any other use of natural gas service. In addition, this analysis shows the alternative cost if the customer was heating with an electric furnace and heat pump for comparison if the customer electrified their home's heating system.

Figure 9.15 shows an example of the January bill for a customer using 90 therms of natural gas for each jurisdiction's residential rate class[10]. Also included is a comparative electric heating bill if the customer uses electricity for heating[11]. The main charges for natural gas is the Base Rate in light blue and the Commodity in dark blue. The Commodity is the price of the physical gas purchased for the customer, whereas the Base Rate includes pipelines, transport, and utility administration. The amount paid for DSM (energy efficiency), LIRAP (low-income subsidy), and "other" is also included to separate utility costs versus other costs. The "Other category includes items such as insurance, decoupling, taxes, and other small or temporary adjustments and in many cases can be a rate reduction[12]. Lastly, for Washington customers, the CCA is the direct cost of the Climate Commitment Act[13]. For the electric bill comparison, Avista's electric rates are used, except in Oregon, where Pacific Power is used as the primary electric provider in

[9] Excludes the temporary Washington CCA adjustment, schedule 162.
[10] Washington includes multiple rate schedules due to CCA requirements for different rates due to either income or age of home.
[11] Avista estimates kWh demand by using 77% of the 293 kWh to equal an mmBTU. The 77% is used for January to account for the efficiency of a heat pump vs a natural gas furnace. The cost of installing or switching to electric heat is not included.
[12] See Avista Energy Rates and Tariffs in WA, ID, & OR | Avista for compete list of tariff adjustments for both electric and natural gas rates.
[13] The CCA prices for the pre 2021 residence will increase over time to match the post 2021 customer rates.

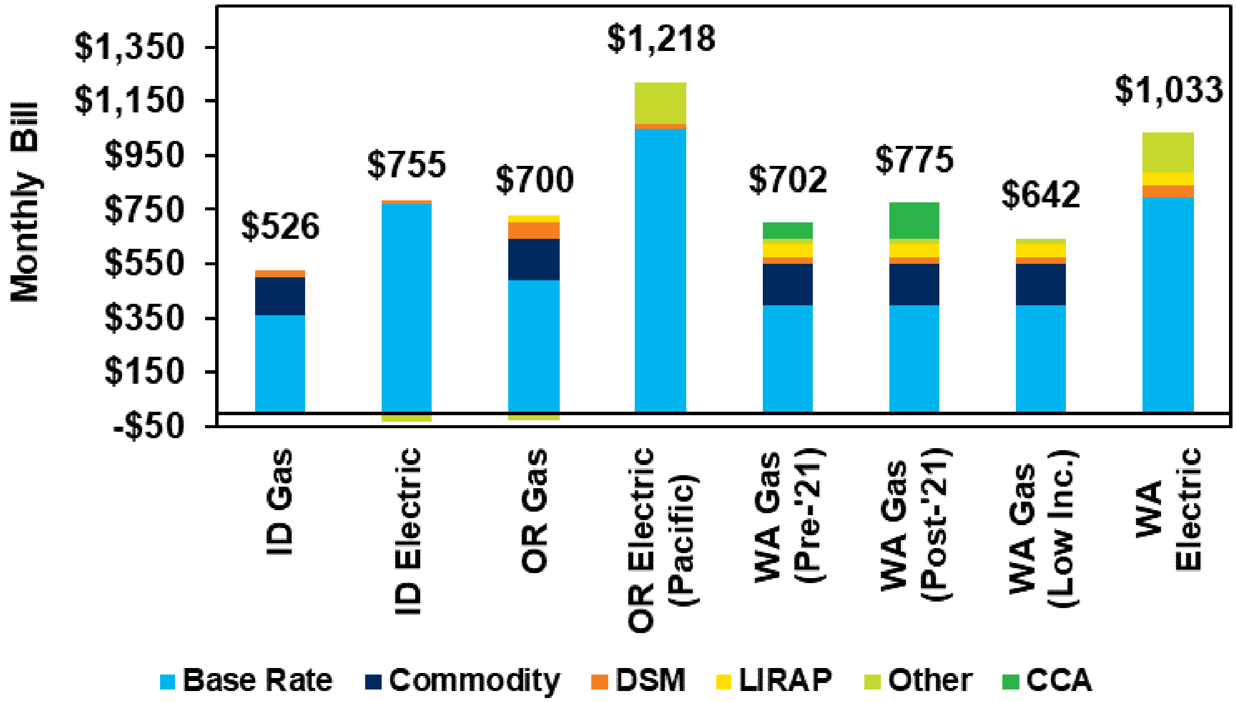
Avista's gas service area, although some customers in any of the jurisdictions may have different rates depending on the electric provider. Also, regarding the electric heating alternative, the basic charge is not included as the customer would have this charge regardless of its space heating choice. This analysis shows a significant lower cost for customer heating using natural gas as compared to electric alternatives in each jurisdiction during the heating season.

Figure 9.15: Example Space Heating Winter Month Bill by Jurisdiction (80 therms)



Due to jurisdictions having different monthly customer charges, another way to look at the cost of service is the annual bill shown in Figure 9.16. A customer may opt for levelized billing to address bill spikes seen in the monthly perspective, so this view shows an overall impact on pricing. When comparing the annual bill for space heating (assumes 465 therms over the year), natural gas heating remains the lowest cost option. Also notable is the Idaho cost on an annual basis is like Washington when excluding Washington's tariff adders for LIRAP, Other, and CCA. This is different than the monthly view in Figure 9.16 due to Idaho's higher fixed monthly charge.

Figure 9.16: Example Space Heating Annual Bill by Jurisdiction (465 therms)



Energy Burden

There are three forecastable metrics[14] related to household energy burden included within resource selection modeling, each excluding energy assistance funds:

- The number of households with energy burden exceeding 6% of income,
- Percentage of customers with excess energy burden, and
- Average excess energy burden.

To assess current and future energy burden, data for customer income, energy usage, and energy rates is required. Customer income data was derived from the LEAD tool. Total energy burden includes all fuels, natural gas, electricity, wood, propane and heating oil, at a specific location. Forecasting this CBI requires assumptions regarding individual customer income and usage along with the cost of non-electric household fuels. To forecast energy burden in this analysis, customers are grouped by income by general customers and disadvantaged customers. Households using wood, propane, or heating oil were included based on data in the 2022 RBSA and are considered in this analysis. Customer income is escalated using inflationary expectations in this IRP. Lastly, the cost of the energy used by the customer is estimated using a rate forecast based on the

[14] Separate tracking on a forecasted basis for known low-income and Named Communities cannot be completed until additional data is gathered.

resources selected through the IRP or estimated costs of wood, propane or heating oils combined with inflation.

The first metric illustrates the forecast of the number of customers with excess energy burden (see Figure 9.17 and 9.18) over the IRP planning horizon. These customers have a combined energy bill exceeding 6% of their income to be included in this metric. Customers can fall into this metric due to high usage or low income. In 2026, approximately 38,000 customers in Washington out of 250,000 will be energy burdened. The absolute number of customers stays relatively flat until 2040 (Oregon) and 2045 (Washington), but as a percentage of energy total, customers with energy burden decreases until clean energy targets are enforced along with the higher expected costs to comply with the 100% clean baseline emissions goals. when significant resources are retired, and additional clean generation is added to ensure reliability and 100% clean energy in all hours. Forecasted energy burden estimates show a significant increase compared to the 2020 LEAD study, where only 3.2% of Washington and 3.6% of Oregon customers were considered energy burdened. The only other way to address energy burden within a resource plan is to use energy efficiency to lower energy use and develop dedicated resources for low-income customers. Both strategies are presumed in this plan, but all result in financial energy assistance, further creating pressures on retail energy pricing.

Figure 9.17: OR Customers with Excess Energy Burden (Before Energy Assistance)

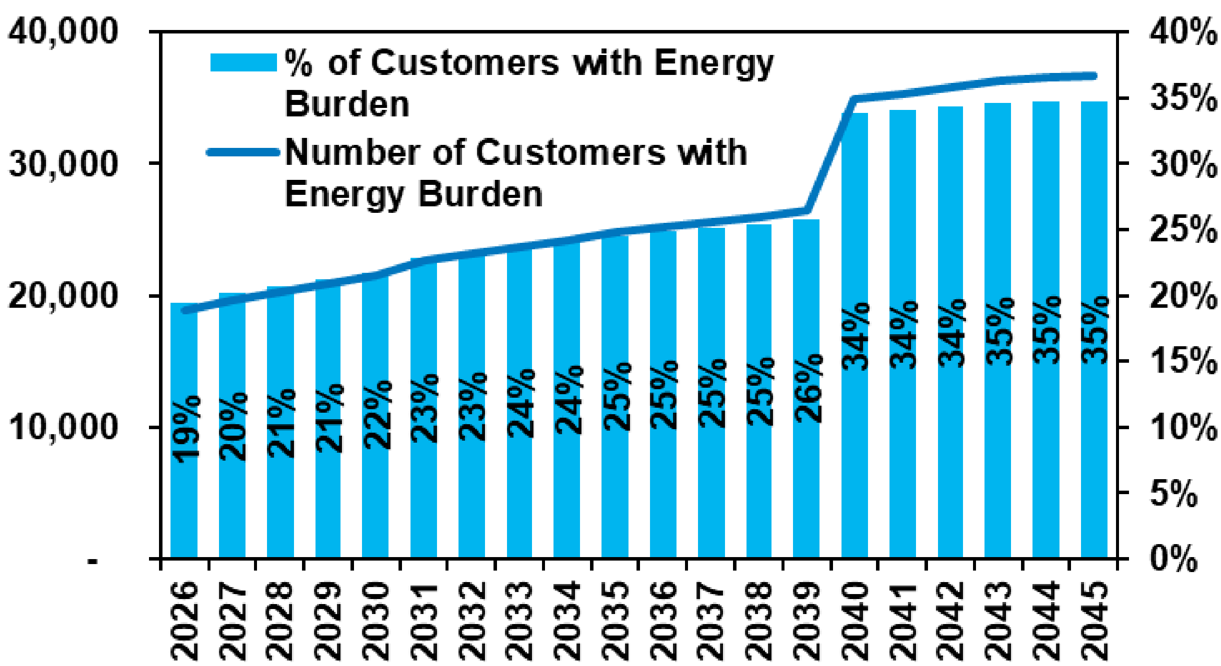
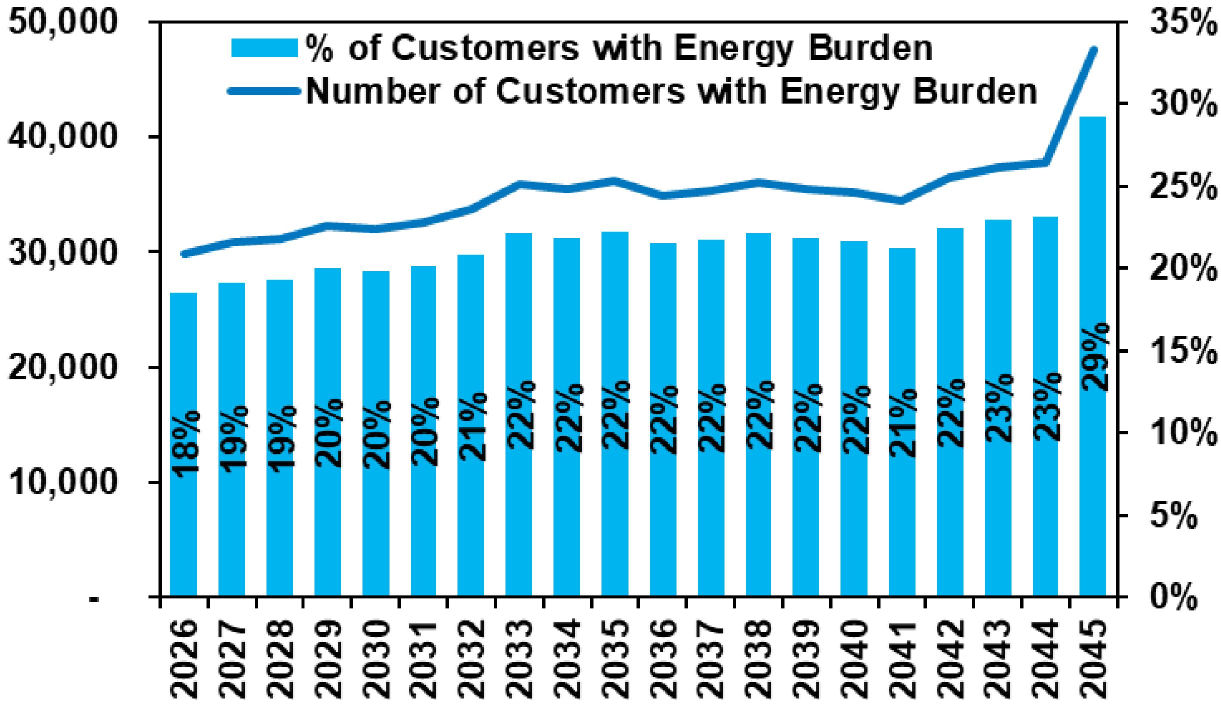


Figure 9.18: WA Customers with Excess Energy Burden (Before Energy Assistance)



The last customer energy burden metric is the amount of dollars per year of energy assistance the customer would need to reduce their energy burden to achieve the 6% level. The average excess energy burden growth is shown in Figure 9.19 and 9.20. This metric is expected to increase both in nominal and real (2026 dollars) values though the real increase is modest compared to the nominal increase at 1% a year in Oregon and 0.6% a year in Washington above inflation. The difference between the two demonstrates the impact of inflation compared to the impact of rate increases. Oregon has a goal for electric utilities to be 100 percent[15] below baseline emissions by 2040. This impacts rates 5 years earlier than Washingtons goal of 100 percent supply free of greenhouse gas emissions by 2045[16].

[15] Department of Environmental Quality : Oregon Clean Energy Targets : Action on Climate Change : State of Oregon

[16] Clean Energy Transformation Act (CETA) – Washington State Department of Commerce

Figure 9.19: OR Customers with Excess Energy Burden (Before Energy Assistance)

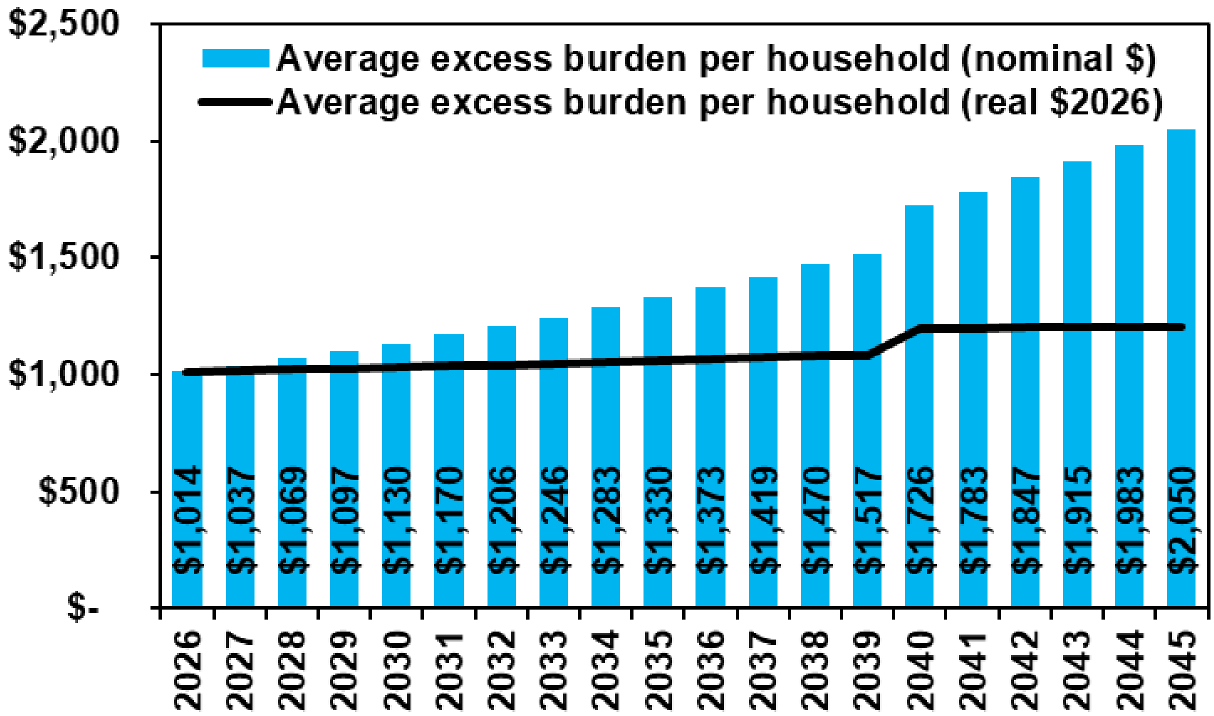
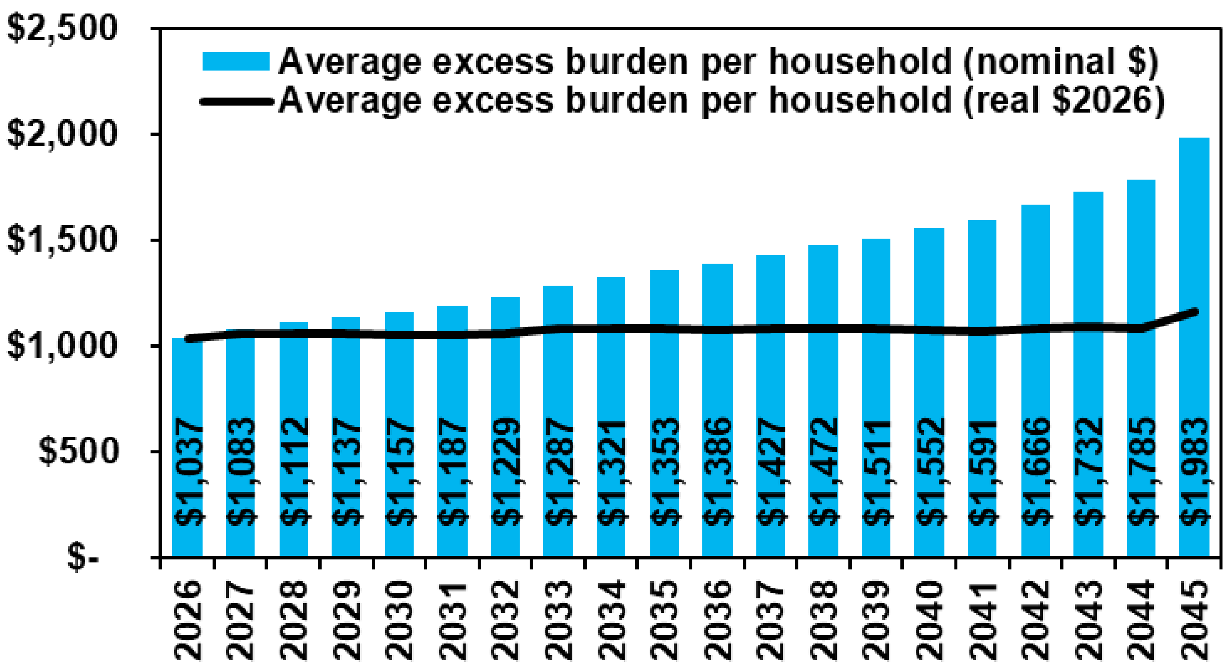


Figure 9.20: WA Customers with Excess Energy Burden (Before Energy Assistance)



10. Distribution Planning

Section Highlights:

- A Non-Pipeline Alternative analysis will be considered going forward for all projects meeting cost criteria in Oregon and Washington.
- Distribution planning is a continual process used to incorporate detailed operating conditions to maintain a safe and reliable resource.
- Two projects have been identified for NPA in Washington for 2025 completion.

Avista's IRP evaluates the safe, economical, and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to Avista's city gates become secondary issues if distribution system growth behind the city gates increases faster than expected and the system becomes severely constrained. Important parts of the distribution planning process include forecasting local demand and growth, determining potential distribution system constraints, analyzing possible solutions and estimating costs for eliminating constraints.

Analyzing resource needs to this point has focused on ensuring adequate capacity to the city gates, especially during a peak event. Distribution planning focuses on determining if there will be adequate pressure during a peak hour, downstream of the city gates within the distribution system. Despite this altered perspective, distribution planning shares many of the same goals, objectives, risks, and solutions as integrated resource planning.

Avista's natural gas distribution system consists of approximately 3,700 miles of distribution main and service pipelines in Idaho, 3,900 miles in Oregon and 6,300 miles in Washington; as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within Avista's distribution system. Distribution network pipelines and regulating stations operate and maintain system pressure solely from the gas provided by the interstate transportation pipelines.

Distribution System Planning

Avista conducts two primary types of evaluations in its distribution system planning efforts: capacity requirements and integrity assessments.

Capacity requirements include distribution system reinforcements and expansions. Reinforcements are upgrades to existing infrastructure or new system additions to increase system capacity, reliability, and safety. Expansions are new system additions to accommodate new demand. Collectively, these reinforcements and expansions are distribution enhancements.

Ongoing evaluations of each distribution network in the five primary service territories identify strategies for addressing local distribution capacity requirements resulting from customer growth. Customer growth assessments are made based on factors including IRP demand forecasts, monitoring gate station flows and other system metering, new service requests, field personnel discussion, and inquiries from major developers.

Avista regularly conducts integrity assessments of its distribution systems. Ongoing system evaluation can indicate distribution-upgrading requirements for system maintenance needs rather than customer and load growth. In some cases, the timing for system integrity upgrades coincides with growth-related expansion requirements. These planning efforts provide a long-term planning and strategy outlook and integrate into the Company’s capital planning and budgeting process.

Gas planning models are also compared with capacity limitations at each city gate station. Referred to as city gate analysis, the design day hourly demand generated from planning analyses must not exceed the actual physical limitation of the city gate station. A capacity deficiency found at a city gate station establishes a potential need to rebuild or add a new city gate station.

Network Design Fundamentals

Natural gas distribution networks rely on pressure differentials to flow natural gas from one place to another. When pressures are the same on both ends of a pipe, the natural gas does not move. As natural gas exits the pipeline network, it causes a pressure drop due to its movement and friction. As customer demand increases, pressure losses increase, reducing the pressure differential across the pipeline network. If the pressure differential is too small across the regulator, flow stalls and the network could run out of pressure.

It is important to design a distribution network to ensure intake pressure from gate stations and/or regulator stations within the network is high enough to maintain an adequate pressure differential when natural gas leaves the network.

Not all natural gas flows equally throughout a network. Certain points within the network constrain flow and restrict overall network capacity. New network constraints can occur as demand requirements evolve. Anticipating these demand requirements, identifying potential constraints, and forming cost-effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design.

Computer Modeling

Developing and maintaining effective network design is aided by computer modeling for network demand studies. Demand studies have evolved with technology to become a highly technical and powerful means of analyzing distribution system performance. Using a pipeline fluid flow formula, a specified parameter for each pipe element can be simultaneously solved. Many pipeline equations exist, each tailored to a specific flow behavior. These equations have been refined through years of research to the point where modeling solutions closely resemble actual system behavior.

Avista conducts network load studies using DNV GL's Synergi Gas software. This modeling tool allows users to analyze and interpret solutions graphically.

Determining Peak Demand

Avista's distribution network is comprised of high pressure (90-500 psig) and intermediate pressure (5-60 psig) mains. Avista operates its intermediate networks at a maximum pressure of 60 psig or less for ease of maintenance and operation, public safety, reliable service, and cost considerations. Since most distribution systems operate through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations. Line pack is the difference between the natural gas contents of the pipeline under packed (fully pressurized) and unpacked (depressurized) conditions. Line pack is negligible in Avista's distribution system due to the smaller diameter pipes and lower pressures. In transmission and inter-state pipelines, line-pack contributes to the overall capacity due to the larger diameter pipes and higher operating pressures.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and the peak hour demand for these customers can be as much as 50% above the hourly average of daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for distribution systems uses peak hour demand.[1]

Distribution System Enhancements

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification and corresponding optimum combinations of pipe modification, and pressure modification solutions to maintain adequate pressures throughout the network. Distribution system enhancements do not reduce demand, nor do they create additional supply. However, enhancements increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Pipelines

Pipeline solutions consist of looping, upsizing, and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. Looping involves constructing new pipe parallel to an existing pipeline to relieve the constraint point. Constraint points inhibit flow capacities downstream of the constraint creating inadequate pressures during periods of high demand. When the parallel line connects to

[1] This method differs from the approach for IRP peak demand planning, the IRP focuses on peak "day" requirements to the city gate.

the system, this alternative path allows natural gas flow to bypass the original constraint and bolsters downstream pressures. Looping can also involve connecting previously unconnected mains. The feasibility of looping a pipeline depends upon the location where the pipeline will be constructed. Installing natural gas pipelines through private easements, residential areas, existing paved surfaces, and steep or rocky terrain can increase the cost to a point where alternative solutions are more cost effective.

Pipeline upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity due to increased cross-sectional area of the pipe, results in less friction, and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or where pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition, looping augments existing pipe, which remains in use.

Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional facilities. However, safety considerations and pipe regulations may prohibit the feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating costly repairs. A thorough review is conducted to ensure pipeline integrity and safety are accounted for before pressure is increased.

Regulators

Regulators, or regulator stations, reduce pipeline pressure at various stages in the distribution system. Regulation provides a specified and constant outlet pressure before natural gas continues its downstream travel to a city's distribution system, customer's property, or natural gas appliance. Regulators also ensure flow requirements are met at a desired pressure regardless of pressure fluctuations upstream of the regulator. Regulators are at city gate stations, district regulator stations, farm taps and customer services.

Compression

Compressor stations present a capacity enhancing option for pipelines with significant natural gas flow and the ability to operate at higher pressures. Most often these are used on interstate transportation pipeline systems, upstream of Avista's gas facilities. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline will boost downstream pressure.

A second option is the installation of smaller compressors located close together or strategically placed along a pipeline. Multiple compressors accommodate a large flow range and use smaller and very reliable compressors. These smaller compressor stations are well suited for areas where natural gas demand is growing at a slower and steady pace, allowing for installation of less expensive compressors over time to serve growing customer demand into the future.

Compressors are an option to resolving system constraints; however, regulatory, and environmental approvals to install a compressor station, along with engineering and construction time can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Avista's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Distribution Scenario Decision-Making Process

After achieving a working load study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur due to inadequate capacity.

Avista's design Heating Degree Day (HDD) for distribution system modeling is determined using a 99% statistical probability method for each given service area as discussed in Chapter 3. This practice is consistent with the peak day demand forecast utilized in other sections of Avista's Natural Gas IRP.

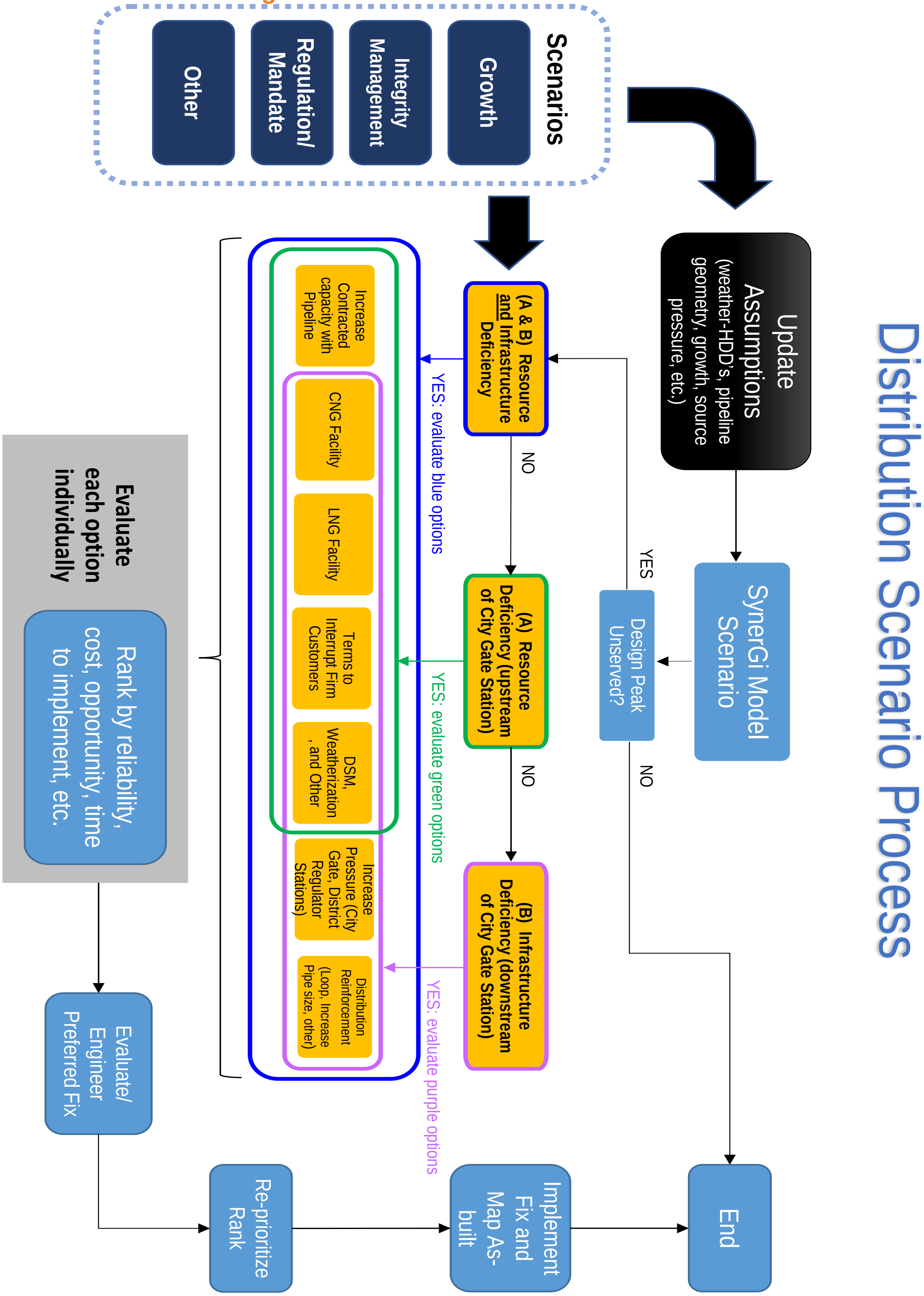
Utilizing a peak planning standard based on a statistical probability method of historical temperatures is sensible even though extreme temperatures are rare. Given the potential impacts of an extreme weather event on customers' personal safety and potential damage to customer's appliances and Avista's infrastructure, it is a prudent and regionally accepted planning standard.

These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient part of the distribution system.
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights or traffic issues.
- Minimal to no water, railroad, major highway crossings.
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, the design engineer or construction project coordinator begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of the above project/reinforcement selection criteria. Figure 10.1 provides a schematic representation of the distribution scenario process.

Figure 10.1: Distribution Scenario Process



Non-Pipe Alternatives

An evaluation of non-pipe alternatives (NPAs) is considered against pipeline capacity reinforcements, when not related to safety, compliance, or road moves. NPAs will only be considered when the cost of an upgrade is at a level high enough where a NPA may be cost effective, can be accomplished prior to the time the upgrade is needed, and can lead to a great enough reduction of demand to defer or eliminate the need for the upgrade. Total project cost consideration for cost effectiveness differ between jurisdictions. In Washington a $500,000[2] or greater cost estimate requires a NPA where in Oregon a million-dollar threshold this analysis is required[3].

Avista's methodology for NPA analyses, as directed by the OPUC[4] and adopted by the WUTC, is as follows:

a. NPA analysis will be performed for supply-side resources (these include but are not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts) and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects (a group of projects that are interdependent or interrelated).
b. NPA analysis will include cost benefit analysis that reflects an avoided GHG compliance cost element consistent with a high cost estimate of future alternative fuels prices. Non-Energy Impacts must be included as part of the NPA analysis.
c. NPA analysis will include electrification, targeted energy efficiency, targeted demand response, and other alternative solutions.
d. NPA analysis should look forward five years to allow ample time for evaluation and implementation.
e. NPA analysis will include an explanation of solutions considered and evaluated including a description of the projected timeline and annual implementation rate for the solutions evaluated, the technical feasibility of the solutions, and the strategy to implement the solutions evaluated.
f. NPA analysis should include an explanation of the resulting investment selection (either NPA or a traditional investment) including the costs and ranking of the solutions, and the criteria used to rank or eliminate them.
    i. If a NPA is not selected and the reason is insufficient implementation time, it should include steps the Company will take to perform NPA analysis to provide sufficient implementation time for future projects.

Specific to Washington, the WUTC required that:

[2] WUTC Docket UE-240006 and UG-240007 (Consolidated), Order 08, December 20, 2024 at ¶309.
[3] OPUC Docket UG 461, Order No. 23-384, October 26, 2023 – Appendix B, Second Settlement Stipulation #21.
[4] OPUC Docket LC 81, Order No. 24-156, May 31, 2024 – Attachment C.

- Avista must examine the relationship between any NPA and the Climate Commitment Act (CCA) but may not assume that all CCA allowances will be purchased at the ceiling price.
- Avista must provide an explanation of the resulting investment selection (either the NPA or a traditional investment) that compares the costs of both projects, but Avista is not required to rank or score any NPA in its evaluation process.[5]

To date, Avista has not had a project that meets the criteria to perform an NPA analysis. However, Avista will be performing an NPA analysis on at least two projects related to customer grown in Washington that exceed $500,000 in 2025, as required by the WUTC.[6] The two projects identified for NPA analysis in Washington are discussed below.

Conservation Resources

The evaluation of distribution system constraints includes consideration of targeted conservation resources to reduce or delay distribution system enhancements. The consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, Avista attempts to influence energy efficiency through the measures discussed in Chapter 4 but does not depend on estimates of peak day demand reductions from energy efficiency to eliminate near-term distribution system constraints. Over the longer-term, targeted energy efficiency programs may provide a cumulative benefit that could offset potential constraint areas and may be an effective strategy.

Planning Results

Table 10.1 summarizes the cost and timing, as of the publication date of this IRP, of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of expenditures.

The Distribution Planning Capital Projects criteria includes:

- Prioritized need for system capacity (necessary to maintain reliable service to firm sales gas customers);
- Scale of project (large in magnitude and will require significant engineering and design support);
- Budget approval (will require approval for capital funding); and,
- Projects are subject to change and will be reviewed on a regular basis.

These projects are preliminary estimates of timing and costs of major reinforcement solutions whose costs exceed the limits as discussed above. The scope and needs of distribution system enhancement projects generally evolve with new information requiring

[5] WUTC Docket UE-240006 and UG-240007 (Consolidated), Order 08, December 20, 2024 at ¶309.
[6] Ibid ¶311.

ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment and timing of planned completion may change based on the ongoing reassessment of information. The following discussion provides information about key near-term projects.

Kettle Falls, WA High Pressure Reroute: The Kettle Falls high pressure line is approximately 80 miles long and serves the communities of Addy, Chewelah, Colville, Deer Park, Kettle Falls, and some additional rural towns. This project is considered an integrity driven project, not a capacity project. Sections of this high-pressure pipeline are currently classified as “transmission” due to the operating conditions and physical pipe characteristics. This pipeline is in close proximity to high occupancy dwellings and businesses (high consequence areas or HCA’s), making it necessary for Avista to either lower the pressure or reroute these sections. This project will introduce a new high-pressure pipeline along a different route, allowing Avista to maintain capacity needs and eliminate “transmission” high pressure mains in any HCA’s. Project design will begin in 2026-27 with construction anticipated in 2027-28. An NPA analysis will be completed on this project and will include targeted energy efficiency analysis. Avista will complete this analysis in 2026.

Airway Heights, WA High Pressure Reinforcement: Although recently enhanced, the Airway Heights high pressure gas main has provided natural gas to one of the fastest growing regions in all of Avista’s service territories. Currently there are several industrial customers considering the Airway Heights location for new facilities or expansion. A reinforcement will provide additional capacity for industrial growth and ensure reliable pressure at the end of the gas main. This main also supplies a major regulator station supporting the Downtown Spokane neighborhoods. An NPA analysis will be completed on this project in 2025 along with the Kettle Falls High Pressure Reroute above in 2025.

Schweitzer, ID High Pressure Reinforcement: Recent growth in the Schweitzer Resort Community is causing the distribution to approach maximum capacity. Additional growth is planned and preliminary studies recommend extending the existing high pressure further up Mountain Road to be closer to the Schweitzer growth areas. Design and construction will be determined after growth expectations are confirmed.

Table 10.1: High Pressure - Distribution Planning Capital Projects

Location	2026	2027	2028	2029+
Kettle Falls High Pressure Reroute, WA (compliance-driven)	---	$100,000	$2,000,000	---
Airway Heights High Pressure Reinforcement, WA (growth-driven)	TBD	TBD	TBD	TBD
Schweitzer High Pressure Reinforcement, ID (growth-driven)	TBD	TBD	TBD	TBD

Table 10.2 shows city gate stations identified as possibly over utilized or under capacity. Estimated cost, year, and the plan to remediate the capacity concern are shown.

These projects are preliminary estimates of timing and costs of city gate station upgrades. The scope and needs of each project generally evolve with new information requiring ongoing reassessment. Final solutions may change due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment. The city gate station projects in Table 10.2 are periodically reevaluated to determine if upgrades need to be accelerated or delayed. Those assigned a TBD year have relatively small capacity constraints, and thus will be monitored.

Table 10.2: City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
Malin, OR	Malin #27T01	TBD	-	TBD
Medford, OR	Medford #2431	TBD	-	TBD
Pullman, WA	Pullman #350	TBD	-	TBD
Colton, WA	Colton #315	TBD	-	TBD

This Page is Intentionally Left Blank

11. Action Plan

Action items position Avista to provide the best cost/risk resource portfolio to support and improve IRP planning going forward. The Action Plan identifies supply and demand side resource needs and highlights key analytical needs in the near term. It also highlights essential ongoing planning initiatives and natural gas industry trends Avista will monitor as a part of its planning processes.

2023 Avista Action Items

1. Purchase allowances or offsets for compliance to the Climate Commitment Act for years 2023, 2024, 2025 and 2026 to comply with emissions reduction targets.

   Result: Avista procured allowances in 2023 and 2024 based on expected number of instruments needed to offset total emissions in Washington.

2. Begin to offer a Washington transport customer EE program by 2024 with the goal of saving 35,000 therms.

   Result: This program was delayed due to the initiative to repeal the CCA. Avista stood up a carbon reduction program in 2025 and will begin offering this program to eligible transport customers where Avista has the responsibility to cover emissions for compliance to the CCA (Less than 25,000 tonnes of emissions).

3. Explore methods for using Non-Energy Impact (NEI) values in future IRP analysis to account for social costs in Oregon and Washington to ensure equitable outcomes.

   Result: Avista has included induced safety and emissions impacts estimates for new resources. Avista also created job creation and economic impacts estimates based on these resources as selected in the PRS. This information can be found in Chapter 9.

4. Explore using end use modeling techniques for forecasting customer demand.

   Result: Avista utilized an end use forecast as developed by AEG in all analysis included within the 2025 IRP and discussed in detail in Chapter 3.

5. Consider contracting with an outside entity to help value supply side resource options such as synthetic methane, renewable natural gas, carbon capture, and green hydrogen.

   Result: Avista contracted with ICF to estimate alternative resources including various production methods for synthetic methane, renewable natural gas, hydrogen, carbon capture utilization and sequestration and renewable thermal credits. These inputs and results can be found in Chapter 6 with the final report in Appendix 6.

6. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:

    - Natural gas infrastructure investment not included as discrete projects in IRP
        - Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
            - Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
        - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely require additional capital to comply
            - Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
        - Other special contract projects not known at the time the IRP was published
    - Other non-IRP investments common to all jurisdictions that are ongoing, for example:
        - Enterprise technology projects & programs
        - Corporate facilities capital maintenance and improvements

    Result: Avista holds quarterly meetings with OPUC Staff where information such as this is discussed. This list of projects was also formally presented to TAC members during the TAC 4 meeting in June 2024. Please refer to Chapter 10 for a full listing of projects Avista is currently monitoring.

Oregon (OPUC-Actions)

1. For the IRP Update the Company should update the load forecast with a GCM downscaling methodology using Multivariate Adaptive Constructed Analogs as employed by Oregon State University's Institute of Natural Resources. (Recommendation 2)

   Result: Avista utilized the MACA downscaling data for RCP 4.5 and 8.5 in addition to blending the two for an RCP 6.5 weather future. This is discussed in detail in Chapter 3.

2. New program offered by ETO for interruptible customers in 2023 to save 15,000 therms. (Recommendation 3)

   Result: Energy Trust of Oregon helped interruptible customers save 66 therms in 2023. The second year of the of the program offering in 2024 resulted in preliminary savings of 122,603 therms of natural gas saved and will be finalized in their annual report.

3. Engage Oregon stakeholders to explore additional new offerings for interruptible, transport, and low-income customers to work towards identified savings of 375,000 therms in 2024, 381,000 therms in 2025 and 371,000 therms in 2026. (Recommendation 4)

   Result: Energy Trust of Oregon has offered energy efficiency programs to Avista interruptible customers since 2023. Avista continued to offer its low-income energy efficiency program through the Community Action Agencies for whole home retrofits. The Company began providing ETO data in 2023 that indicates customers that participate in bill assistance so that energy efficiency programs can be targeted to these customers. The data received from ETO does not contain Account or Customer ID number, so the Company is unable to fully verify low-income participation and is working with ETO to update data received in 2025. Preliminary 2024 savings for interruptible and low-income programs totaled 126,500 therms with ETO low-income targeted efforts estimated at 23,949 therms. The Company began standing-up an Equity Advisory Group in 2024 to gain insights to help reduce customer energy burden through low-income programs. Currently, a low-income whole home energy efficiency program is being designed with ETO, and Bidgely Home Energy Reports will be launched in 2025 to educate residential customers about how they use energy and energy efficiency programs available to reduce usage.

4. Include the modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios. (Recommendation 5)

   Result: Avista included distribution cost estimates for current projects anticipated to be needed in the next 5 years and are included in the avoided costs and will include these costs in NPA analysis going forward. It is difficult to model distribution level capacity and costs in a resource selection model as pressure, needed capacity and cost increase are difficult to estimate.

5. Avista work with the TAC to develop additional scenarios and sensitivities for the next IRP, including for example: greater price variation for low carbon resources, high cost for low carbon resources, omission of any highly uncertain resource, or utilization of only existing resources. (Recommendation 6)

   Result: Avista requested assistance and input beginning in TAC 2 in April 2024. Each meeting had space for feedback prior to the individual presentations prepared with this topic discussed throughout the process. Feedback was given by the TAC members and included in the analysis included in this document.

6. Avista should update its distribution system planning practices and its future IRP processes as outlined in Attachment C. (Expectation 22)

   Result: Avista has updated its planning practices as discussed in Chapter 10.

7. ETO identified 546,000 therms in the 2023 IRP verses 427,000 therms of planned savings in the 2023 ETO Budget and Action Plan. Avista will work with the ETO to meet the IRP gross savings target of 568,000 therms in 2024, 590,000 therms in 2025 and 614,000 therms in 2026.

   Result: Avista fully funded ETO's board approved budget in 2023 Budget and Action Plan. The budget was increased in September 2024 due to the programs performing better than expected. ETO saved 446,880 therms in 2023 and 477,906 therms in 2024.

2025-2026 Action Plan

1. Purchase Community Climate Investments for compliance to the Climate Protection Plan for years 2025, 2026, 2027, 2028 and 2029 to comply with emission reduction targets.
2. Avista will work with ETO to meet IRP gross savings target of 463,410 therms in 2026.
3. Engage Oregon's stakeholders to explore additional new offerings for interruptible, transport, and low-income customers to work towards identified savings of 147,250 therms in 2026.
4. Acquire all estimated potential energy efficiency savings for Idaho and Washington.
5. In Washington purchase allowances or offsets for compliance to the Climate Commitment Act for years 2025, 2026, 2027 and 2028 to comply with emissions reduction targets.
6. Release an annual RFP to investigate options of acquiring the necessary amount of RNG chosen in the PRS in 2030 of 1.184 million dekatherms.
7. Investigate adding liquified natural gas storage to improve resiliency in the North Idaho/Eastern Spokane region.
8. Investigate carbon capture technologies for further understanding of processes and costs needed for capturing and removal of carbon in large industry and direct air capture.
9. Perform at least two NPA analysis for Washington in 2025 and 2026.
10. Perform an NPA analysis for any distribution project with an estimated cost greater than $1 million in Oregon.