Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

April 6, 2023

Public Utility Commission of Oregon
Attn: Filing Center
201 High St SE, Suite 100
Salem, Oregon 97301

RE: UG 461 – Avista Corporation's Request for General Rate Revision

Enclosed for filing with the Commission in Docket No. UG-461 is the Supplemental Exhibit No. 402 of Mr. Kevin Holland. Supplemental Exhibit No. 402 is the 2023 Natural Gas Integrated Resource Plan (IRP) that was filed with the Commission on March 31, 2023 under Docket No. LC-81.

Please direct any questions regarding this filing to Paul Kimball at (509) 495-4584.

Sincerely,

/s/ David J. Meyer

David J. Meyer
Vice President and Chief Counsel for Regulatory and Governmental Affairs

Enclosure

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-461

KEVIN HOLLAND
Exhibit No. 402

Natural Gas Supply

AVISTA

2 0 2 3

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 Natural Gas IRP Team

Name	Title	Contribution
James Gall	Manager of Integrated Resource Planning	IRP Core Team
Tom Pardee	Natural Gas Planning Manager	IRP Core Team
Michael Brutocao	Natural Gas Analyst	IRP Core Team
John Lyons	Sr. 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
Ryan Finesilver	Mgr. of Energy Efficiency, Planning & Analysis	Energy Efficiency
Lisa McGarity	Energy Efficiency Program Manager	Oregon Energy Efficiency
Leona Haley	Energy Efficiency Program Manager	Demand Response
Terrence Browne	Sr. System Planning Engineer	Gas Engineering
Justin Dorr	Natural Gas Resources Manager	Power Supply

Natural Gas IRP Contributors

Name	Title	Contribution
Scott Kinney	VP of Energy Resources	Power Supply
Kevin Holland	Director of Energy Supply	Power Supply
Clint Kalich	Sr. Manager of Resource Analysis	Power Supply
Shawn Bonfield	Sr. Manager of Regulatory Policy	Regulatory
Amanda Ghering	Regulatory Affairs Analyst	Regulatory
Annie Gannon	Communications Manager	Communications
Mary Tyrie	Manager Corporate Communications	Communications
Jeff Webb	Manager of Gas Design, Measuring and 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

Table of Contents

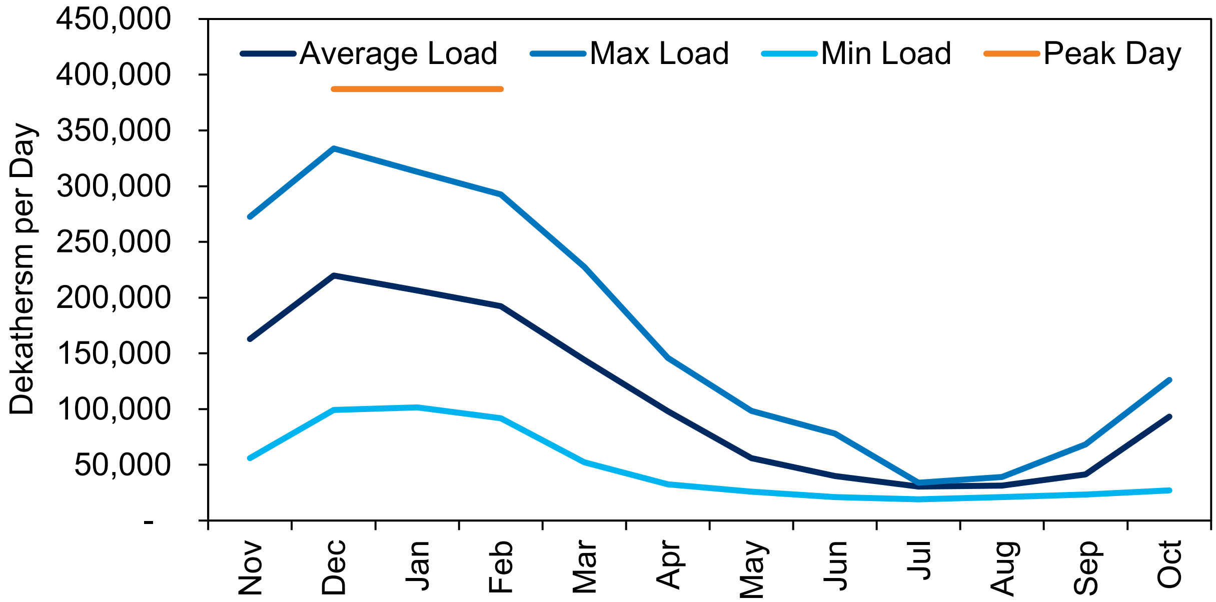
Table of Figures

Table of Tables

Executive Summary

Avista's 2023 Natural Gas Integrated Resource Plan (IRP) identifies a Preferred Resource Portfolio (PRS) to meet system energy demand and emissions compliance in Washington under the Climate Commitment Act (CCA) and Oregon under Climate Protection Plan (CPP). Avista considered resource capacity needs on a peak day combined with weather futures to consider a warming trend and its impact on demand. The total system load is illustrated in Figure 1 by month to help 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 forecasts are increasingly difficult to model based on a variety of rules and codes passed since the 2021 IRP. In Washington, a building code update will go into effect on July 1, 2023, requiring heat pump technology for space and water heating in all new residential and commercial buildings. Line extension programs to assist customers with natural gas 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, fourteen scenarios were developed to consider a range of different futures and resource selections. Avista is still long transport rights, consistent with prior IRP expectations. Peak Day criteria is important as it protects our customers and their structures during extreme weather.

Emissions compliance under the CCA and CPP tells a different story for resource need. Greenhouse gas emissions compliance considers program constraints of the CCA and CPP, plus these regulations require planning for transport customers where past plans did not. In both Figure 2 and Figure 3, equivalent emissions from Firm customers and transport customers can be found in the stacked bar chart with the cap for the respective program as a line. These charts clearly show noncompliance if no actions are taken to offset emissions or other options per program rules, where the total emissions in the blue and green bars exceed the cap shown in orange. These shortages occur in 2023 and continue through the end of the study in 2045.

Figure 2: Washington Emissions Forecast Compared to CCA Cap

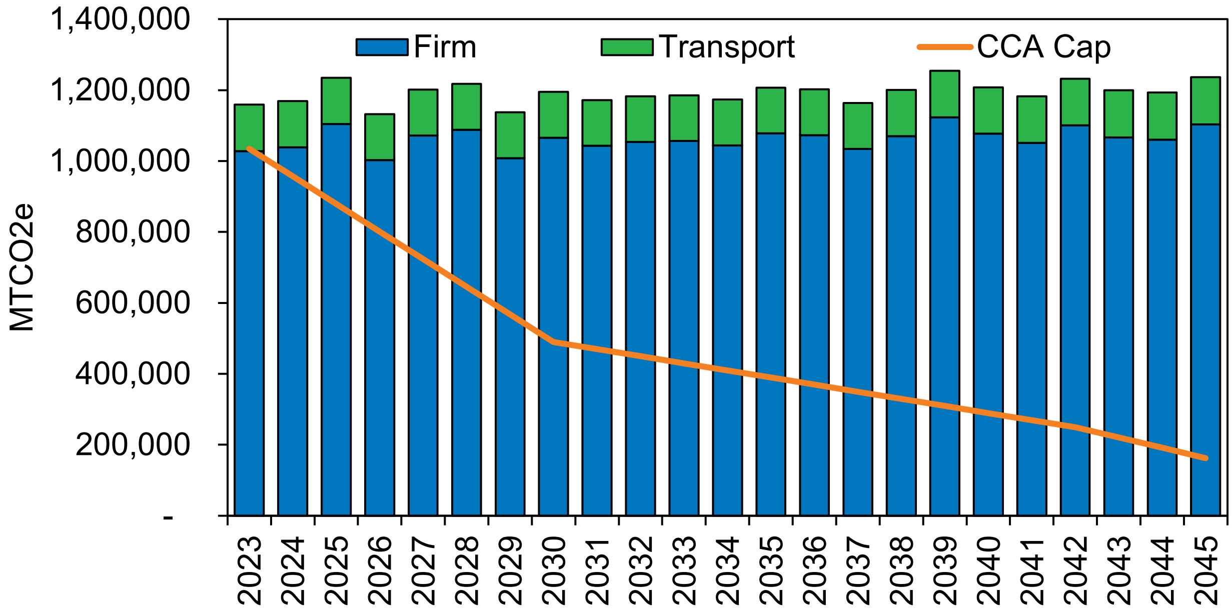
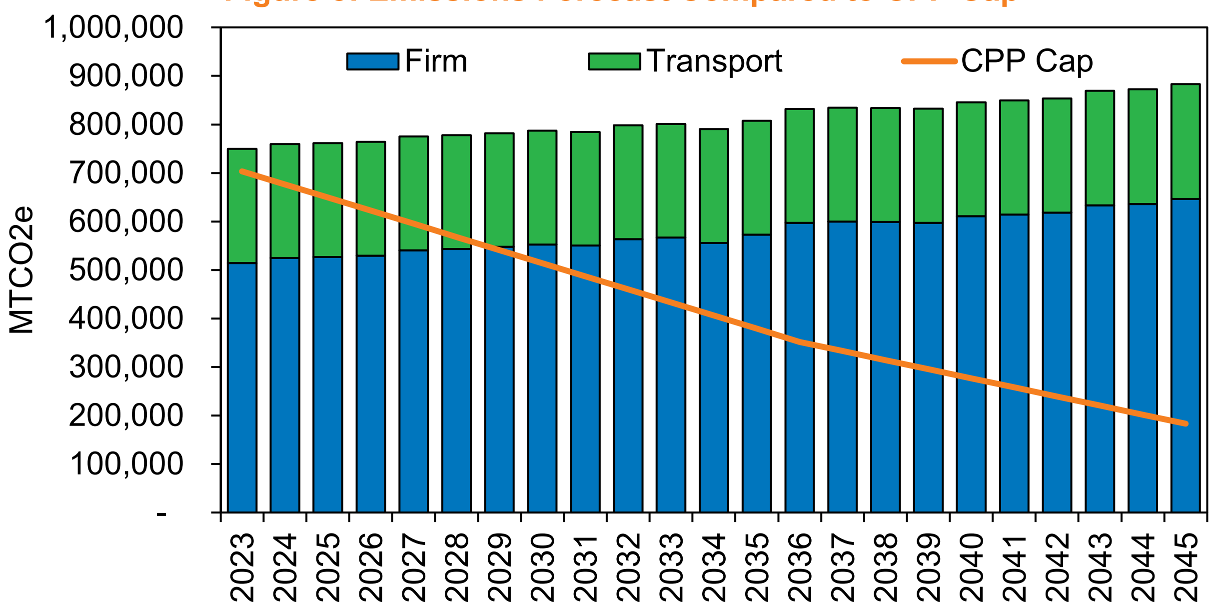


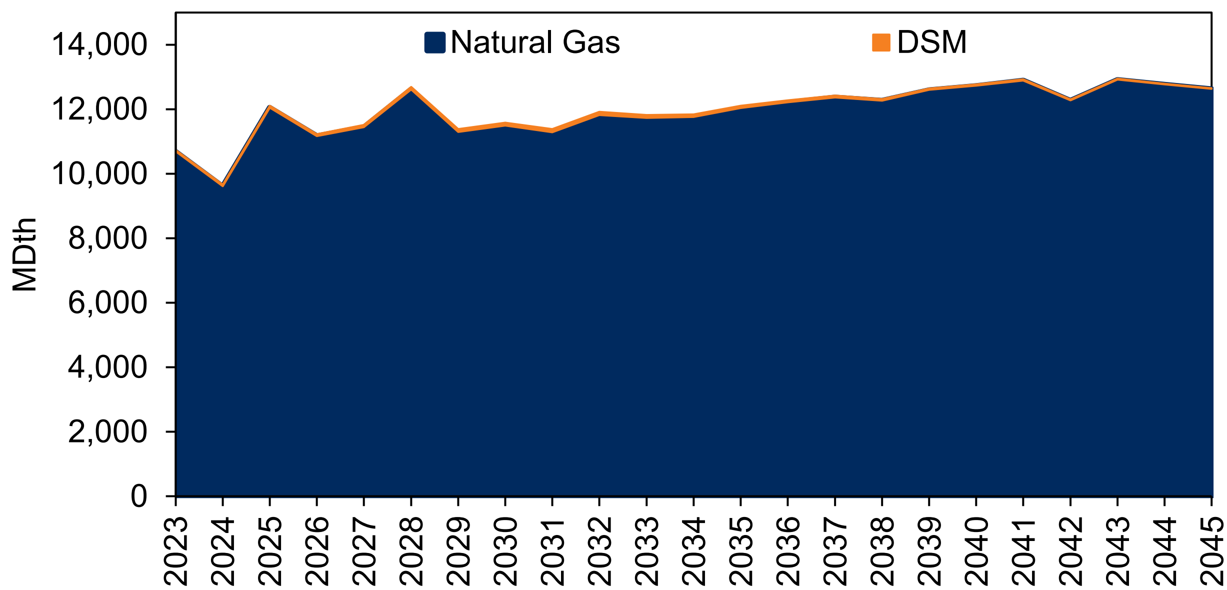
Figure 3: Emissions Forecast Compared to CPP Cap



Idaho Preferred Resource Strategy

The Idaho PRS continues to utilize the least cost natural gas basin, and storage, combined with energy efficiency to meet energy demand as illustrated in Figure 4. Natural gas will be acquired on a least cost basis from the available hubs.

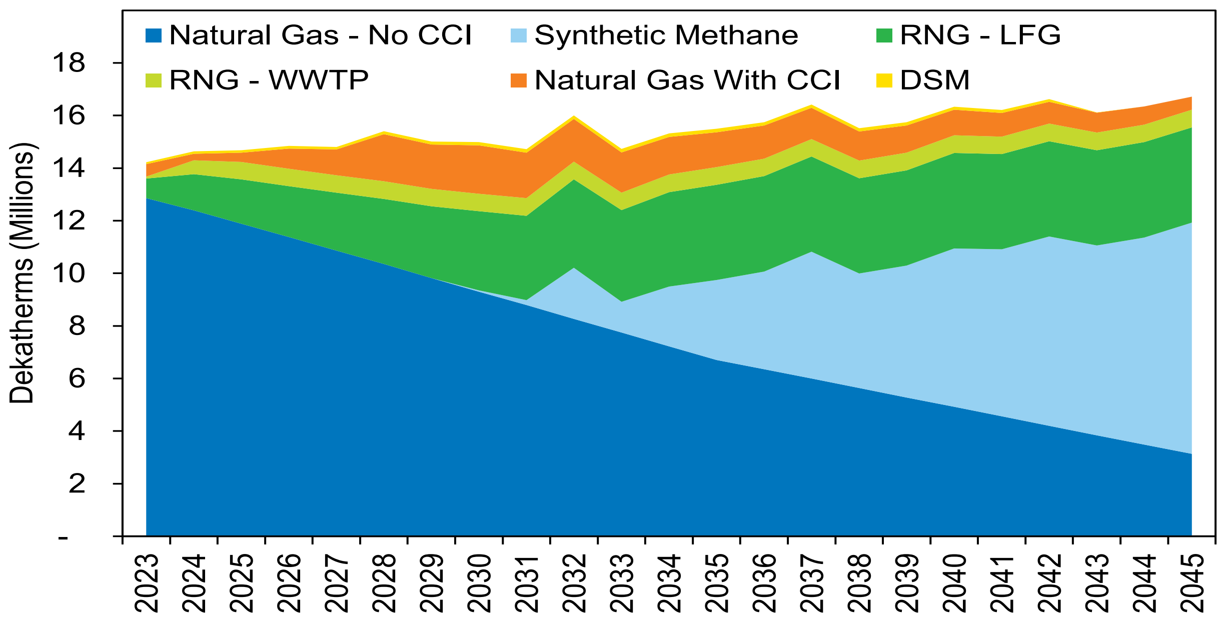
Figure 4: Idaho Preferred Resource Strategy



Oregon Preferred Resource Strategy

Oregon's PRS has drastically changed as compared to the 2021 IRP. Changes adhere to the new environmental goals of the CPP and the estimated energy demand. In the near-term, the new resource need is acquired via a combination of RNG from Landfill Gas (LFG), Wastewater Treatment Plants (WWTP), energy efficiency, Community Climate Investments (CCIs), and conventional natural gas. Synthetic methane is added to the resource mix beginning in the 2030's, as illustrated in Figure 5. In each figure, the dark blue area at the bottom of the chart depicts natural gas with no emissions instrument for compliance, essentially the cap of the CPP.

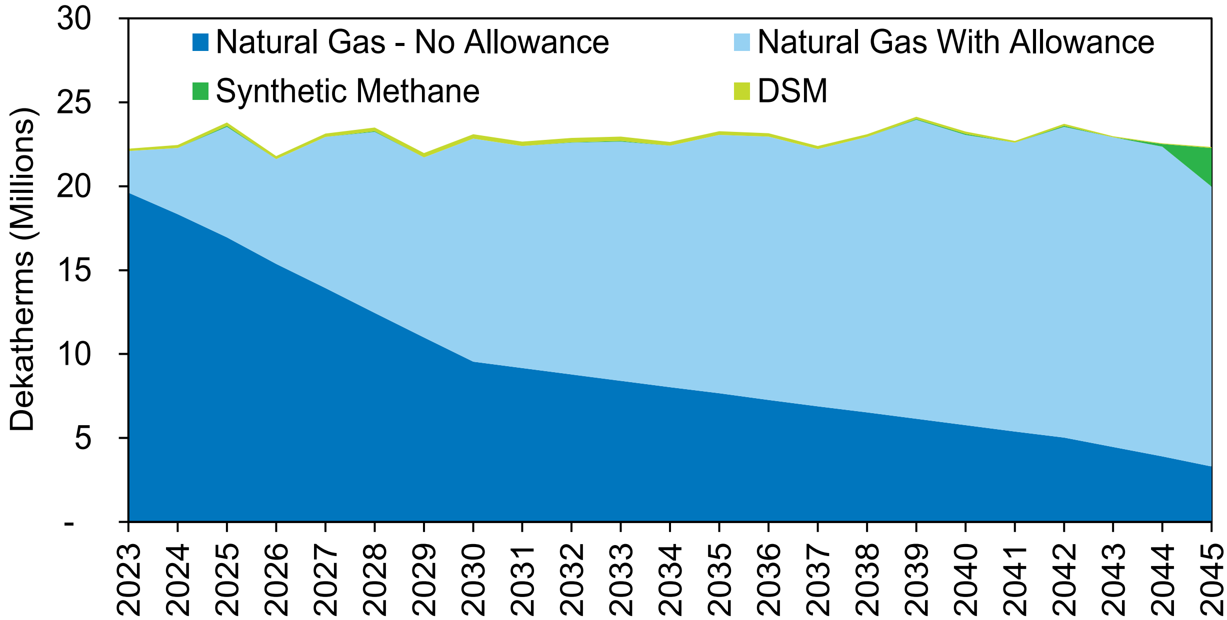
Figure 5: Oregon Preferred Resource Strategy



Washington Preferred Resource Strategy

Washington's PRS has also changed dramatically from the 2021 IRP. The CCA has introduced a cap-and-trade program with the ability to cover emissions with an allowance or offset. Allowance and offset prices may drive a different PRS than the one illustrated in Figure 6. The range of allowance prices for 2023 is $22 to $82 USD. The PRS shows conventional natural gas and energy efficiency as the primary energy source options until the end of the study horizon (2044), when synthetic methane is chosen. The darker blue area in the chart is the CCA program cap and would not require any type of program instruments. The lighter blue area represents natural gas as an energy source, requiring an offset or an allowance as it is above the cap. Natural gas will continue to be procured from the least cost supply basin.

Figure 6: Washington Preferred Resource Strategy



This Page Intentionally Left Blank

1. Introduction and Planning Environment

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 130 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 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

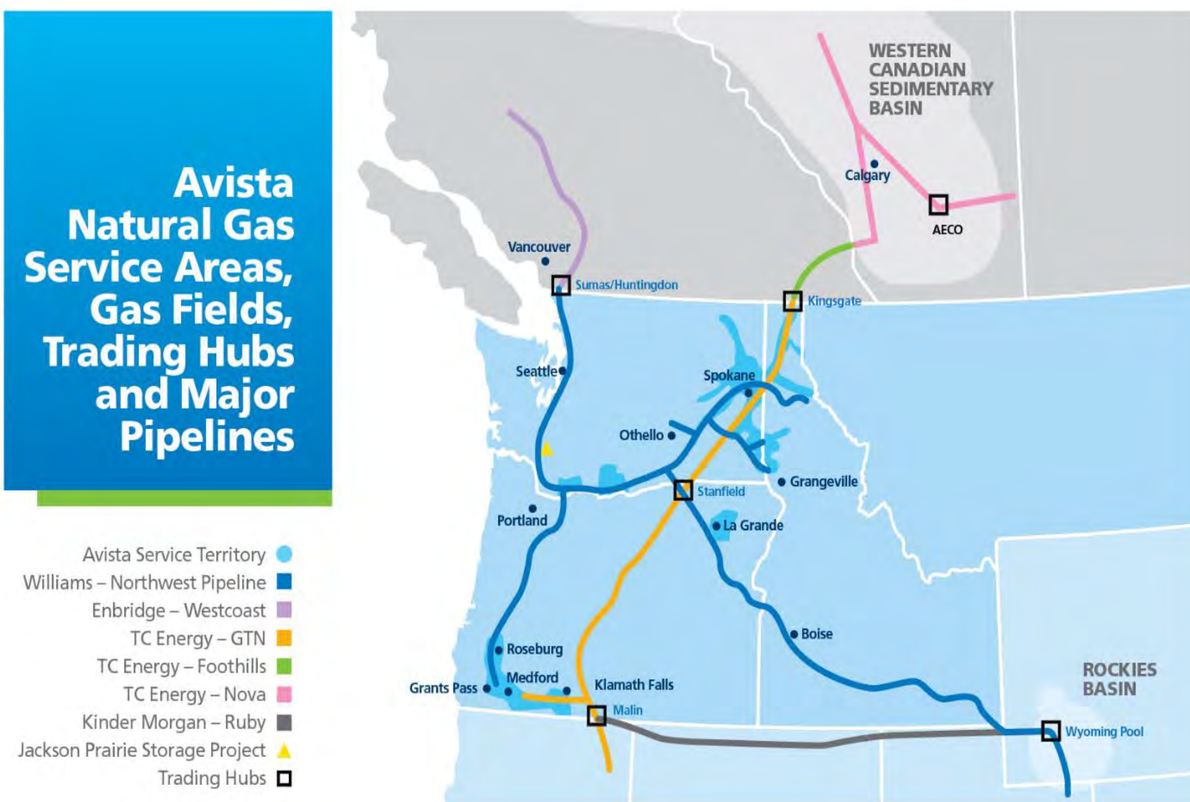
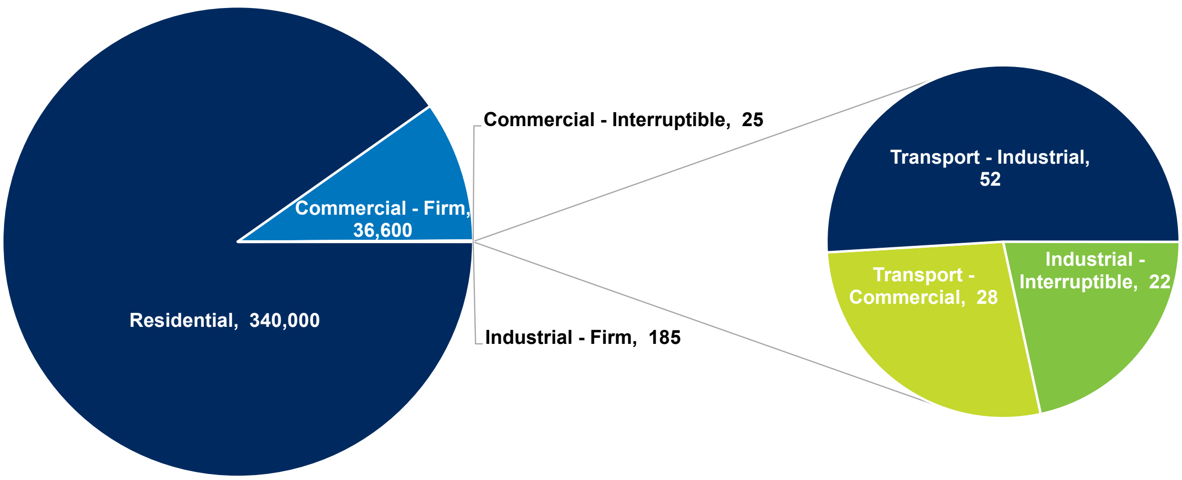


Figure 1.2: Avista's Natural Gas Customer Counts



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 area. 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 546,000[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 5,800 miles in the distribution system in Washington and 3,300 miles in Idaho. The North Division receives natural gas at more than 40 connection points along interstate pipelines for distribution to over 270,000 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, is the largest single area served in this division with a regional population of approximately 312,000. The South Division consists of approximately 15 miles of natural gas transmission main and 3,700 miles of distribution pipelines. Avista receives natural gas at more than 20 connection points along interstate pipelines and distributes it to nearly 106,000 customers.

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

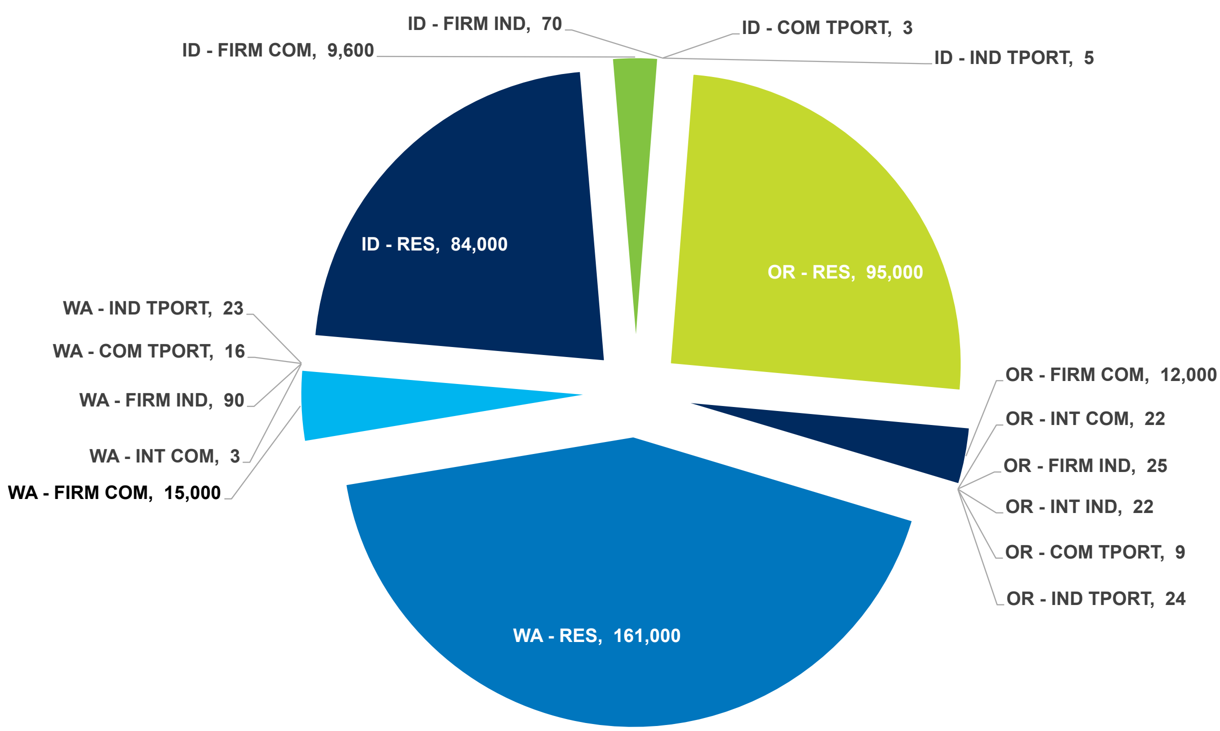
Customers

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 under 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 business 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 require Avista to comply for these emissions for the interruptible and transport customers. These new programs are discussed in Chapter 5 with resource selection in Chapter 6.

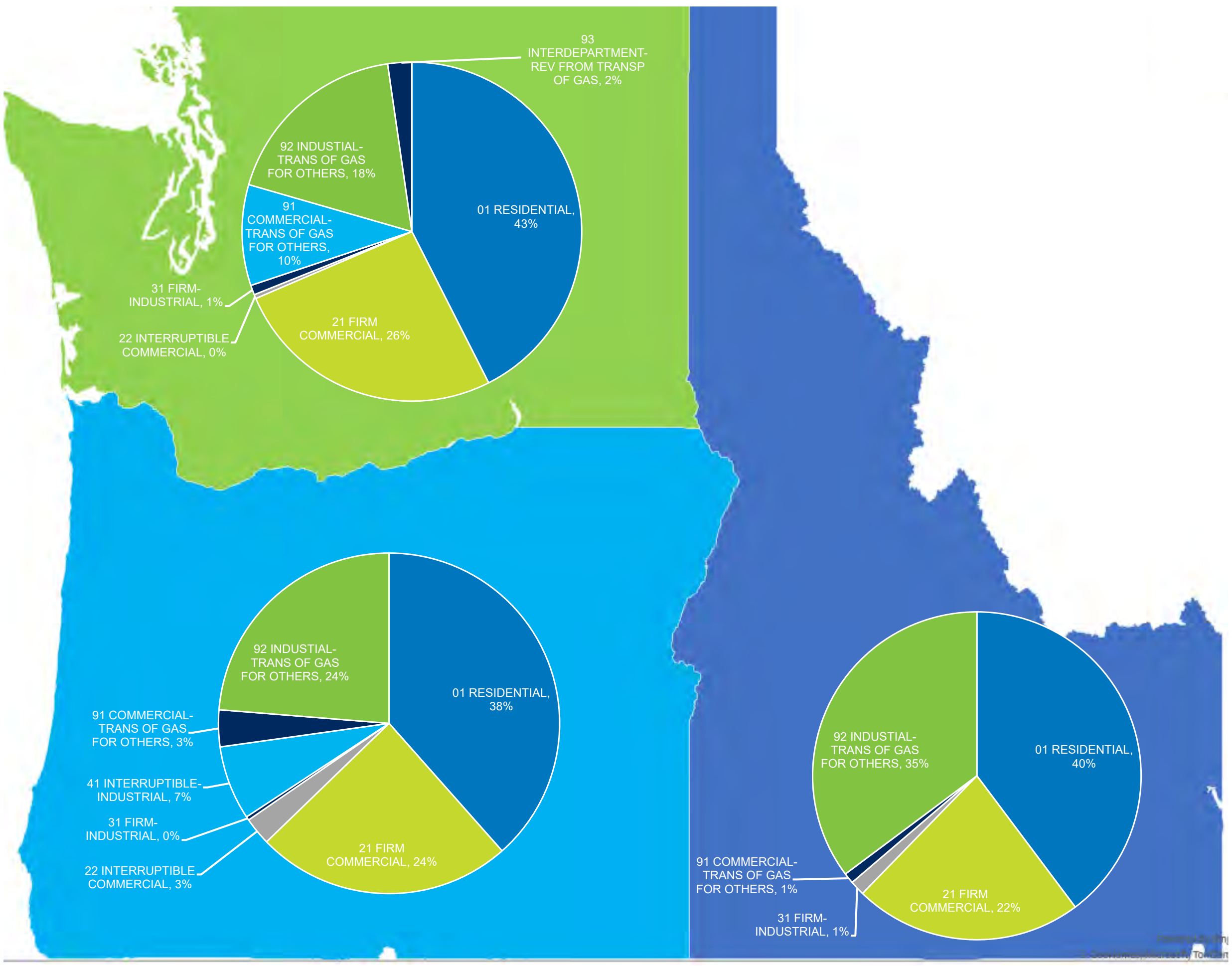
Avista's core or retail customers include residential, commercial, and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

Figure 1.3: Firm Customer Mix



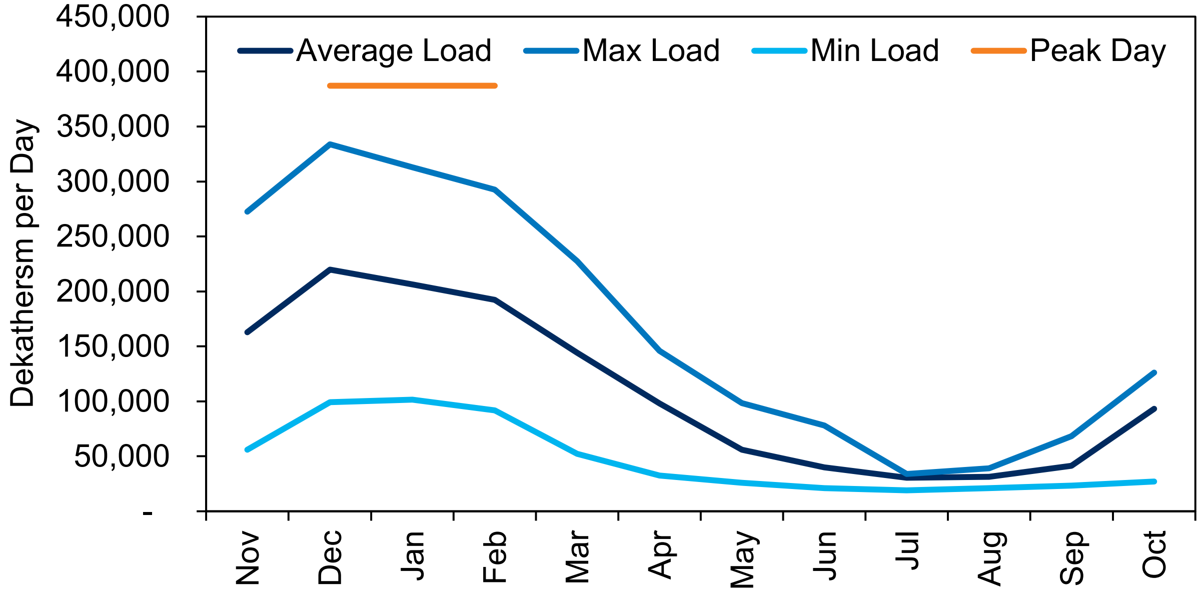
The customer mix is found mostly in the residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.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

Figure 1.4: 2021 Percent of Demand by Area and Class



The seasonal nature of weather in the Pacific Northwest can drastically alter the amount of energy demanded from the natural gas system (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 the core firm customers 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 stage 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;
- Meets Washington, Idaho, and Oregon regulations, commission orders, environmental programs and other applicable guidelines.

Avista's IRP Process Considerations

- Customer growth and usage;
- Weather planning standard;
- Energy Efficiency opportunities;
- Existing and potential supply-side resource options;
- Current and potential 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 five public TAC meetings to facilitate stakeholder involvement in the 2023 IRP. The first meeting convened in February 2022 and the last meeting occurred in December 2022. Each meeting included a broad spectrum of stakeholders. The 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 these organizations can be found below (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
Washington State Department of Commerce	Northwest Power and Conservation Council	Energy Trust of Oregon
Intermountain Gas Company	Energy Strategies	RNG Coalition
Lewis and Clark Law School	Eastern Washington University	Applied Energy Group
Oregon Department of Energy	San Francisco Bay Area Planning and Urban Research Association (SPUR)	DecisionWare Group

Public Meetings

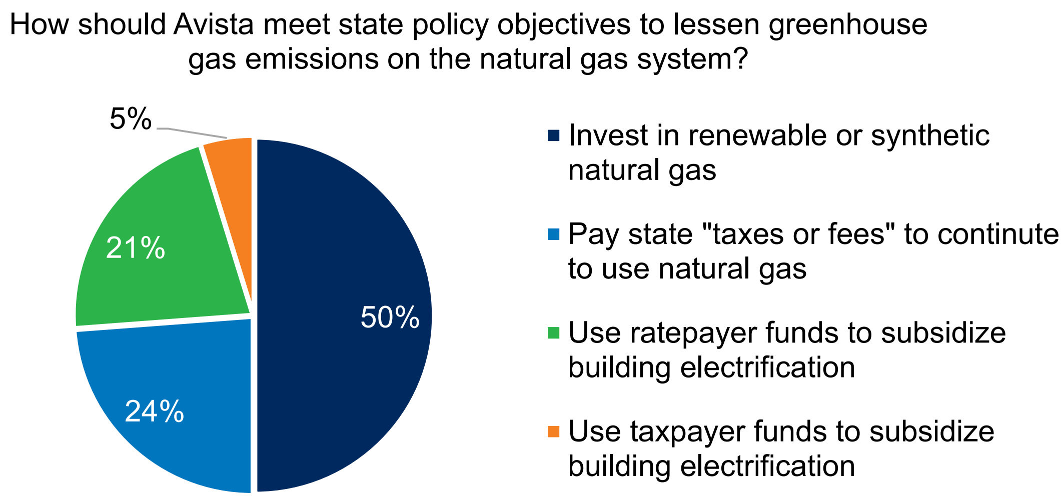
Two public meetings were held on March 8th, 2023 at noon and 5 pm lasting an hour each. In each meeting Avista reviewed the preferred resources selected in both the electric and natural gas IRPs to meet energy demand and/or energy policy compliance.

An email was sent to TAC members and customers in all jurisdictions informing them of the opportunity to participate and provide feedback. Avista also included a recorded video of its resource planning process and resource strategies. 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 side of energy, statistics, math, chemistry, or other potential topics as discussed in TAC meetings. 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].

A set of five poll questions were asked to meeting participants surrounding topics including emissions compliance pathways for natural gas, equity, demand response, and ranking the overall importance of planning considerations when compared with a variety of options valued in IRPs. The two poll questions directly related to natural gas are illustrated in Figure 1.6 and 1.7.

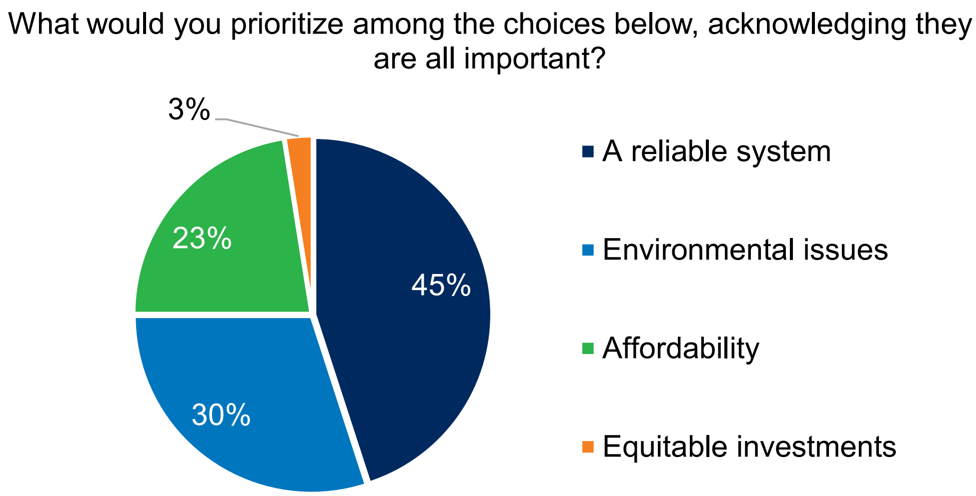
Generally, participants were engaged in the conversation representing many viewpoints of how Avista serves its customers. A common theme of concerns are related to cost impacts of environmental policy, how other states policies effect non-participating states, and whether or not natural gas will continue to be available.

Figure 1.6: Poll Question 1



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

Figure 1.7: Poll Question 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 service 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 are 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 2023 IRP, Avista used the PLEXOS® planning model to perform comprehensive natural gas supply planning and analysis in place of the old software from ABB Sendout. PLEXOS®, from Energy Exemplar, provides unlimited flexibility in its ability to run scenarios, constraints, variables, horizons, and environmental constraints. This model uses a nodal and zonal analysis with:

- Customer growth and customer natural gas usage to form demand forecasts;
- Existing and potential transportation and storage options and associated costs;
- Existing and potential natural gas supply availability and pricing;
- Revenue requirements on all new asset additions;
- Weather assumptions; and
- Conservation.

Avista incorporated stochastic modeling in PLEXOS® to incorporate weather and price uncertainty. Some examples of the types of stochastic analysis provided include:

- Stochastics futures where five future scenarios are solved simultaneously with a single set of resource selections;
- Price and weather probability distributions;
- Probability distributions of costs (i.e. system costs, storage costs, 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 20-year best cost/risk resource portfolio plan to serve customers.

Planning Environment

Even though Avista publishes an IRP every two years, the 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 Mexico exports as well as industrial uses. One of the most prominent risks in the IRP involves policies meant to decrease the use of natural gas as outlined in Chapter 5. However, there is uncertainty about the timing and size of those 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;
- 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, lease-cost, long-term solutions. The following chart summarizes significant changes from the 2021 IRP (Table 1.2).

Table 1.2: Summary of Changes from the 2021 IRP

Subject	Area	2023 Natural Gas IRP	2021 Natural Gas IRP
Demand	System Growth	1.10%	1.00%
Demand	System Growth	Washington building code requirements for residential and commercial homes to use a heat pump for space and water heat beginning in July 2023	None
Demand	Weather and Design Day Peak	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	99% probability of a temperature occurring based on the coldest temperature each year for the past 30 years
Demand	Weather and Design Day Peak	Climate Change future weather predictions incorporated into analysis	20 year rolling average weather utilized
Demand	Energy Efficiency	Cumulative Savings over 20 years:	Cumulative Savings over 20 years:
Demand	Energy Efficiency	ID: 12.7 Million Therms	ID: 21.4 Million Therms
Demand	Energy Efficiency	OR: 16.1 Million Therms	OR: 14.8 Million Therms
Demand	Energy Efficiency	WA: 25.3 Million Therms	WA: 37.7 Million Therms
Demand	Energy Efficiency	A higher price curve with less potential	A lower price curve and slightly less conservation potential
Demand	Energy Efficiency	CPA for Demand Response (DR)	None
Demand	Energy Efficiency	CPA for Transport Customers in Oregon and Washington	None
Demand	Energy Efficiency	CPA for Low Income Customers in Oregon	None
Demand	Energy Efficiency	ID: National Carbon Tax beginning in 2030 ($12.00 - $62.08) per MTCO2e	No Program or Cost
Demand	Energy Efficiency	OR: Social Cost of Carbon @ 2.5% discount rate ($92.68 - $185.07) per MTCO2e	California Cap and Trade - ($15.83 – $97.90)
Demand	Energy Efficiency	WA: Social Cost of Carbon @ 2.5% discount rate ($92.68 - $185.07) per MTCO2e	WA – Social Cost of Carbon @ 2.5% discount rate ($79.86 - $158.06)
Supply	Energy Prices	Synthetic Methane Evaluated	None

Supply	Energy Prices	Electrification by Area and End Use Evaluated	None
Supply	Energy Prices	RNG by type evaluated combined with volumetric expectations	None
Supply	Energy Prices	A higher price curve at $4.50 / Dth levelized cost in real 2022 US $	A lower price curve at $3.73 / Dth levelized cost in real 2019 US $
Policy	CCA	Climate Commitment Act (CCA) - Washington	No Program
Policy	CCA	Allowance Floor Price of CCA	No Program
Policy	CCA	Allowance Ceiling Price of CCA	No Program
Policy	CCA	Emissions Compliance to CCA	No Program
Policy	CPP	Climate Protection Plan (CPP) - Oregon	No Program
Policy	CPP	Community Climate Investment (CCI)	No Program
Policy	CPP	Emissions Compliance to CPP	No Program
Policy	IRA	Inflation Reduction Act included	No Program
Scenario	Resource Shortage	Due to the new climate policies in Oregon and Washington all scenarios require new resources.	There are two cases where resource deficiencies occur, the High Growth/Low Price scenario and the Carbon Reduction scenario. The High Growth/Low Price scenario is solved by adding RNG landfill within the city gate. The Carbon Reduction scenario looks to reduce emissions and Dairy RNG provides the greatest amount of carbon intensity/carbon capture of RNG sources.
Scenario	New Scenario	Electrification Scenarios	None
Scenario	New Scenario	Hybrid Scenario	None

This Page Intentionally Left Blank

2. Demand Forecasts

The IRP process 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 PLEXOS® model (Table 2.1). These demand areas are aggregated into five service territories and further summarized as North or South divisions for presentation throughout this IRP.

Table 2.1: 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 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. A detailed description of the customer forecast is found in Appendix 2.1. 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.

The customer forecast in the 2023 IRP assumes growth based on historic trends. These trends were evaluated against electrification end uses to consider conversion based on economics. A price elasticity was not incorporated in this analysis so there may be additional movement from natural gas customers to electric end uses simply due to increases in price to comply with climate programs.

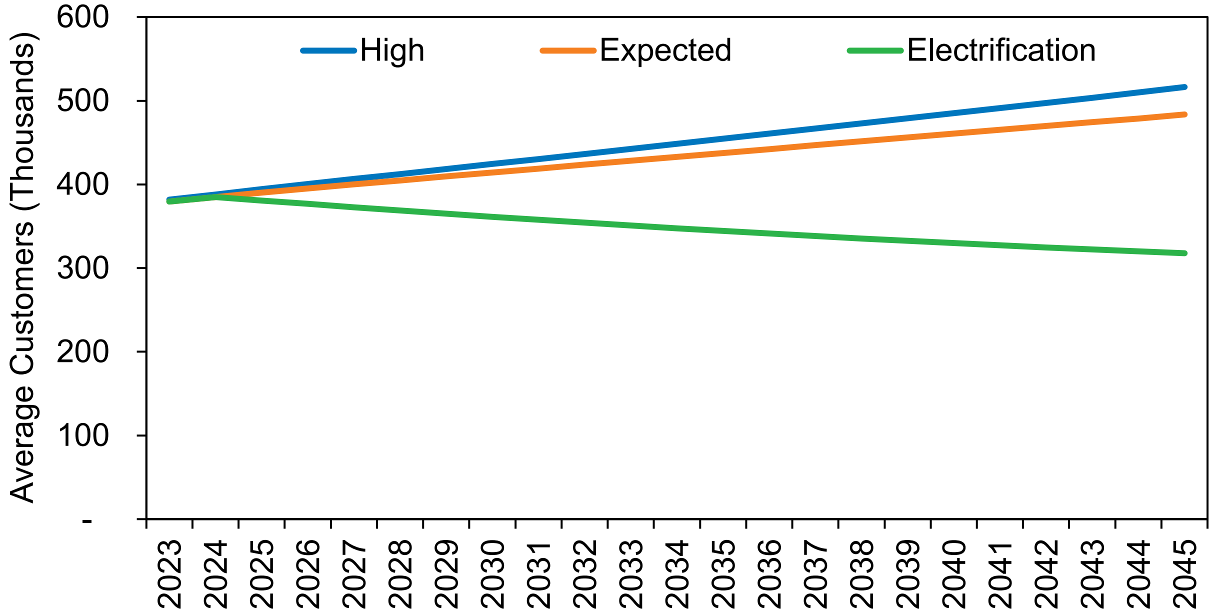
Forecasting customer growth is an inexact science, so it is important to consider different forecasts. Two alternative growth forecasts were developed for this IRP. Avista developed High and Low Growth forecasts to provide potential paths and test resource adequacy. Appendix 2.1 contains a description of how these alternatives were developed. However, it is important to understand these forecasts reflect the “status quo” and do not fully reflect emerging natural gas connection restrictions in Washington and Oregon. Avista added a customer scenario to measure building electrification to consider potential impacts based on movement from natural gas to an alternative fuel source. After the completion of this forecast Washington added restrictions to new residential and commercial natural gas connects through new construction building codes. It is unclear at this point how those new codes will impact the accumulation of new gas customers. Avista will carefully follow implications for these codes and incorporate a forecast in the 2025 IRP to better reflect these fundamental changes.

Table 2.2 shows the three customer growth forecasts. The expected case customer counts are lower than the last 2021 IRP. Lower customer growth relates to lower forecasted demand from both the average and peak day perspective. Detailed customer count data by region and class for all three scenarios is in Appendix 2.2. In comparison to Avista’s 2021 IRP, the base forecast for customer growth increases by just over 22,000 new customers. This sharp change reflects (1) a stronger than expected recovery from the 2020 pandemic induced recession; (2) stronger than expected in-migration, especially to our Washington and Idaho service territories; and (3) higher population growth forecasts compared to the 2021 IRP, especially in Avista’s Washington and Idaho service territories. Rules and policy are changing quickly with natural gas usage as discussed in Chapter 5. In consideration of these fundamental changes in Oregon and Washington, a scenario for electrification was developed to consider a lower than expected customer growth based on historic trends. Figure 2.1 illustrates the average annual customer forecasts used in the 2023 IRP.

Table 2.2: Customer Growth Scenarios

Variable	Base Growth	High Growth	Low Growth
Customers	1.1%	1.4%	0.7%
Population	0.7%	0.9%	0.3%

Figure 2.1: Customer Forecast Scenarios



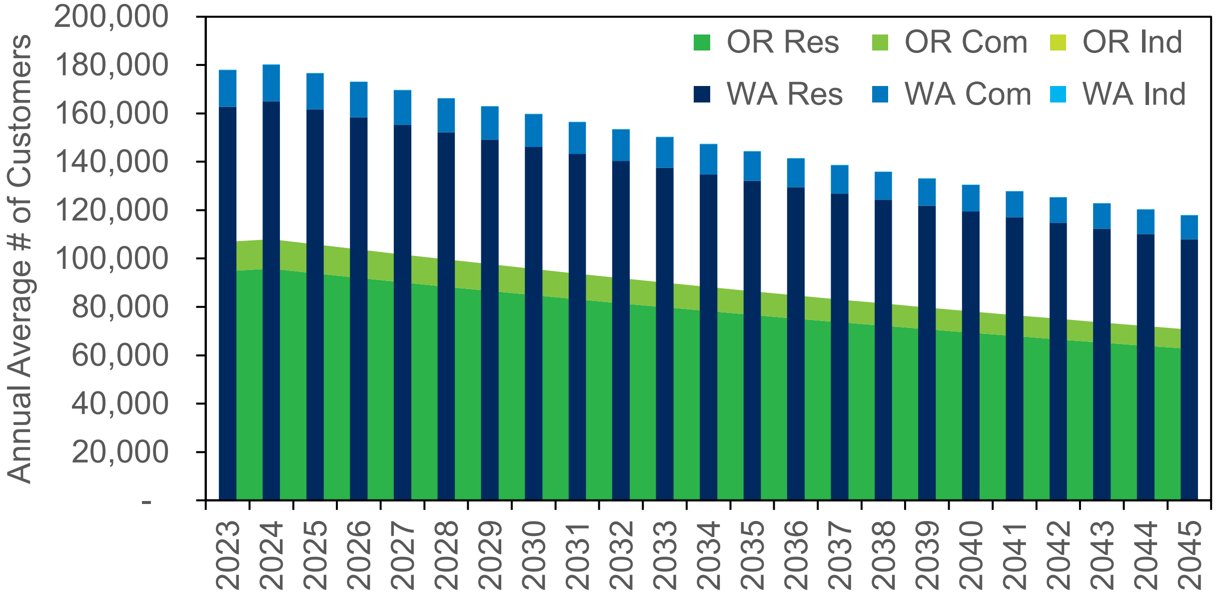
Electrification of Natural Gas Customers

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

To help quantify a loss of demand on the natural gas system, a building electrification scenario was created to consider a loss of customers as compared to the expected number of customers in Oregon and Washington with an average reduction of 98% from the prior year for the same month, by area and class as illustrated in Figure 2.2. In total an estimated 33% reduction in residential customers occurs in both jurisdictions by 2045. This equates to a loss of natural gas system demand of 6.9 million dekatherms per over the 23-year timeframe. Further discussion of this scenario is discussed in Chapter 7.

1 Digital Codes (iccsafe.org)

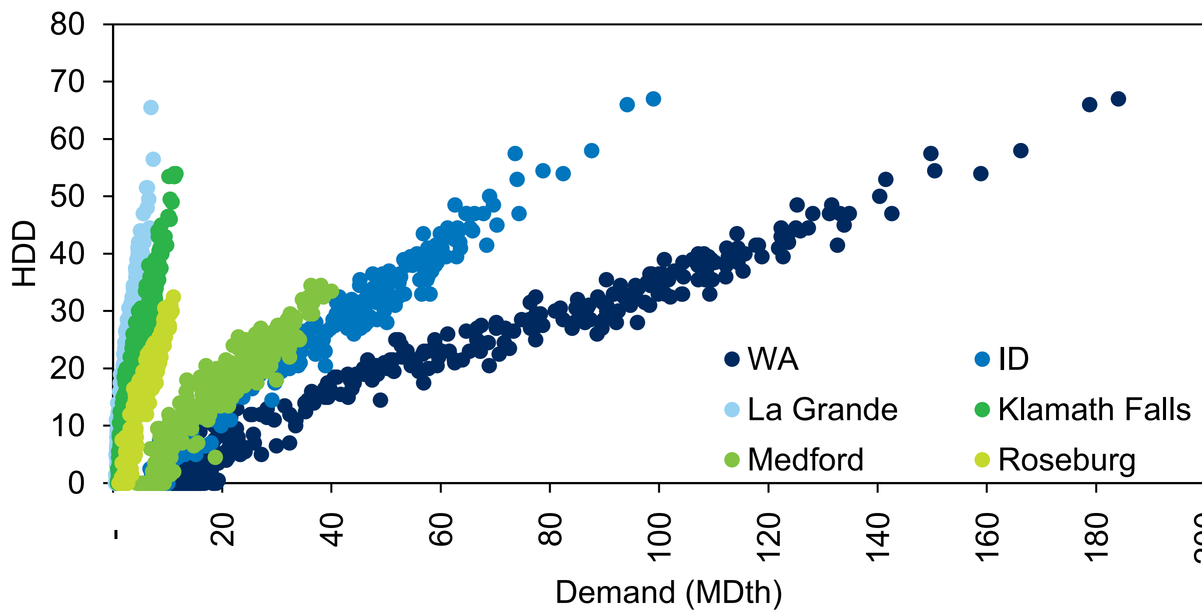
Figure 2.2: Electrification Scenario Customer Forecast



Use-per-Customer Forecast

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients to be applied to heating degree day (HDD) weather parameters to reflect average use-per-customer. This produces a reliable forecast because of the high correlation between usage and temperature as depicted in the scatter plot in Figure 2.3. This figure is intended to show how linear the relationship in usage with increased HDDs but may look skewed as it considers total load by area instead of a use per customer per HDD.

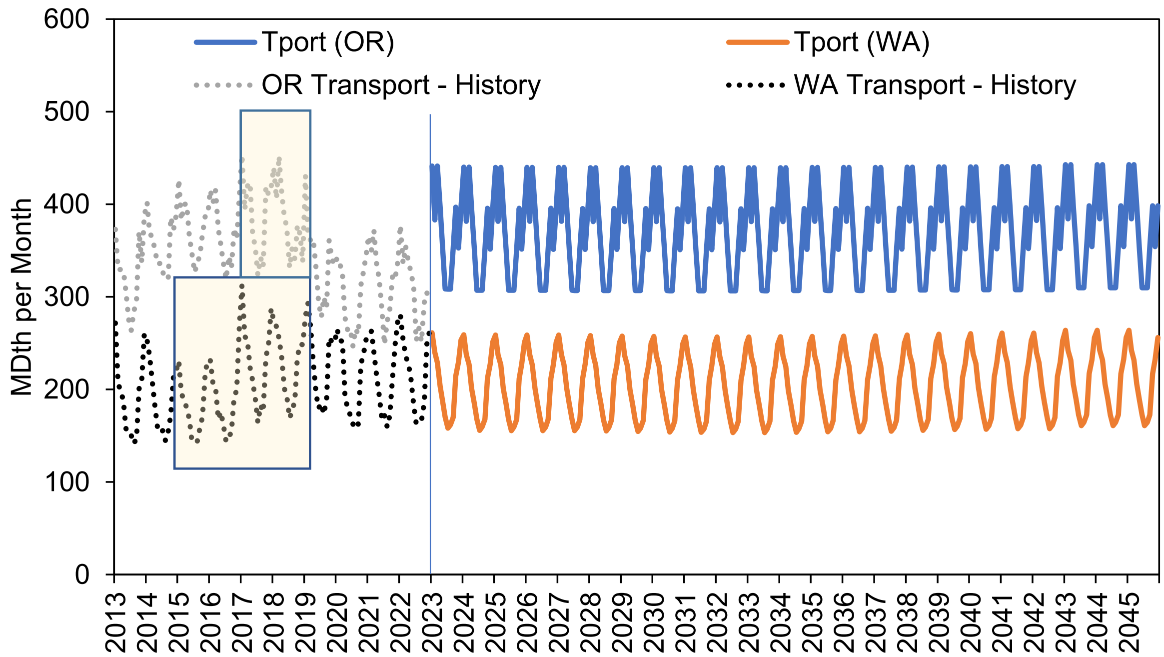
Figure 2.3: Example Demand vs. Temperature – 2022



This forecast considers up to five years of historical city gate data, sorted by service territory/temperature zone, and then by month. The three-year coefficient most closely aligns with economic expectations and use within Avista's territories in the short-term forecasting in Idaho, Oregon, and Washington. However, Oregon territories include a five-year demand coefficient based on the OPUC staff's recommendation 1 discussed in Chapter 9. Specifically, the Oregon five-year coefficient is lower than expected usage by over four hundred thousand dekatherms annually from 2023 to 2027. Without this action item, Avista would have utilized a three-year coefficient across all jurisdictions.

Avista only includes Transportation tariff customer demand for emissions compliance programs in Oregon and Washington. Avista assumes the average usage based on the historic baseline in each program. Figure 2.4 is an example of demand for transport customers from the PLEXOS® model.

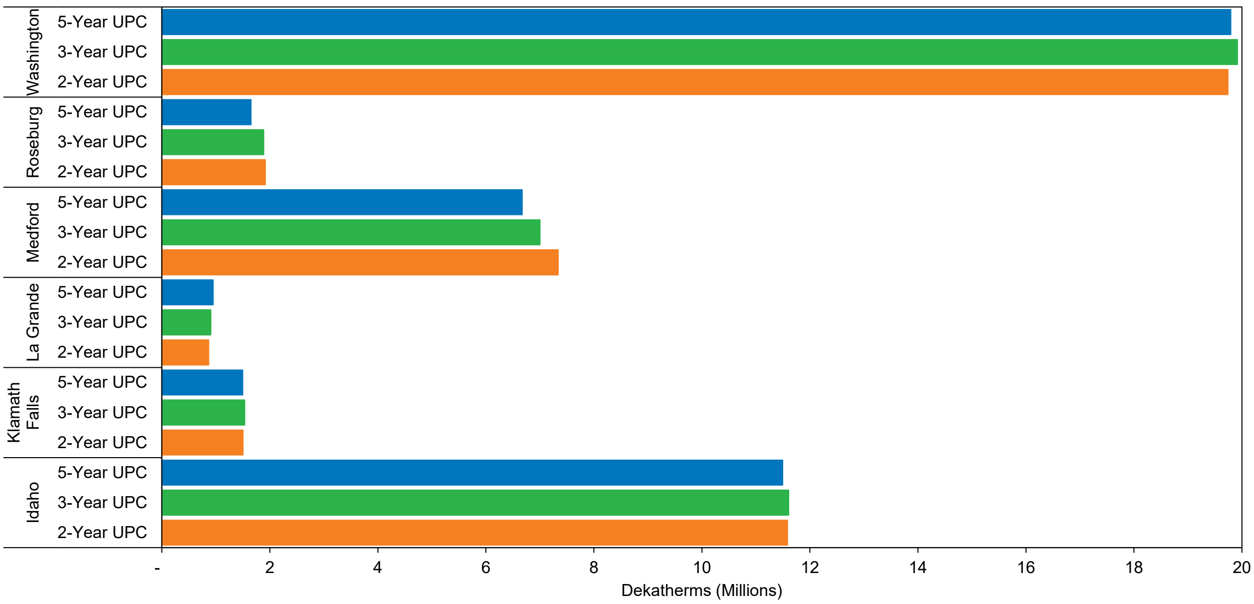
Figure 2.4: Monthly Demand of Transport Customers (MMBTU)



The forecast uses coefficients for each degree day plus base usage. The base usage per customer calculation uses three or five years of July and August data, depending on the jurisdiction. Average usage in these months divided by the average number of customers provides the base usage coefficient input into PLEXOS®. This calculation is done for each area and customer class based on customer billing data demand ratios to reflect demand without a weather sensitivity.

To derive weather sensitive demand coefficients for each month, Avista removed base usage from the total and plotted usage by HDD in a scatter plot chart to verify correlation visually. The process included the application of a linear regression to the data by month to capture the linear relationship of usage to HDD. The slopes of the resulting lines are the monthly weather sensitive demand coefficients inputs for PLEXOS®. Again, this calculation is done by area and by customer class using allocations based on customer billing data demand ratios. Demand by location is illustrated in Figure 2.5.

Figure 2.5: Usage Based on 2-year, 3-year, and 5-year Coefficient



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 drives the resource strategy selection to meet energy and emissions requirements. The 2023 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. The HDD weather patterns between the Oregon areas are uncorrelated, while the HDD weather patterns amongst eastern Washington and northern Idaho portions of the service area are correlated. Thus, Spokane Airport weather data is used for all Washington and Idaho demand areas.

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. The weather history for the Avista territories modeled within this IRP uses over 70 years of historical temperatures and contains minimum, maximum, and average weather data.

Forecasted Temperatures

The temperature forecast uses data developed for the Columbia River Basin by the River Management Joint Operating Committee (RMJOC)[2] comprised of the Bonneville Power Administration (BPA), United States Army Corps of Engineers, and United States Bureau of Reclamation. There is significant uncertainty in projecting future temperature. The RMJOC used an ensemble approach to capture a range of potential outcomes.

Given the sheer volume of data, a method to select a representative set from the 172 modeling combinations was needed. Fortunately, BPA conducted this exercise and selected a subset of modeling combinations representing a sufficient cross section of outcomes to calculate generation. The subset represents 19 modeling combinations for both RCP 4.5 and RCP 8.5.

Representative Concentration Pathways (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 scenarios as follows:

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

RCP 4.5 and RCP 6.0 represent growth in greenhouse gas emissions, but the growth is lower in comparison to RCP8.5 due to mitigation strategies. In the time horizon of the IRP the increase in global mean surface temperature for RCP4.5 and RCP6.5 are 1.4 and 1.3 degrees Celsius, respectively, and therefore have a similar impact on the IRP analysis.

Table 2.3 provides a comparison of the temperature increases projected under the various scenarios.

[2] Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II)

Table 2.3: Comparison of Temperature Increases by Representative Concentration Pathway

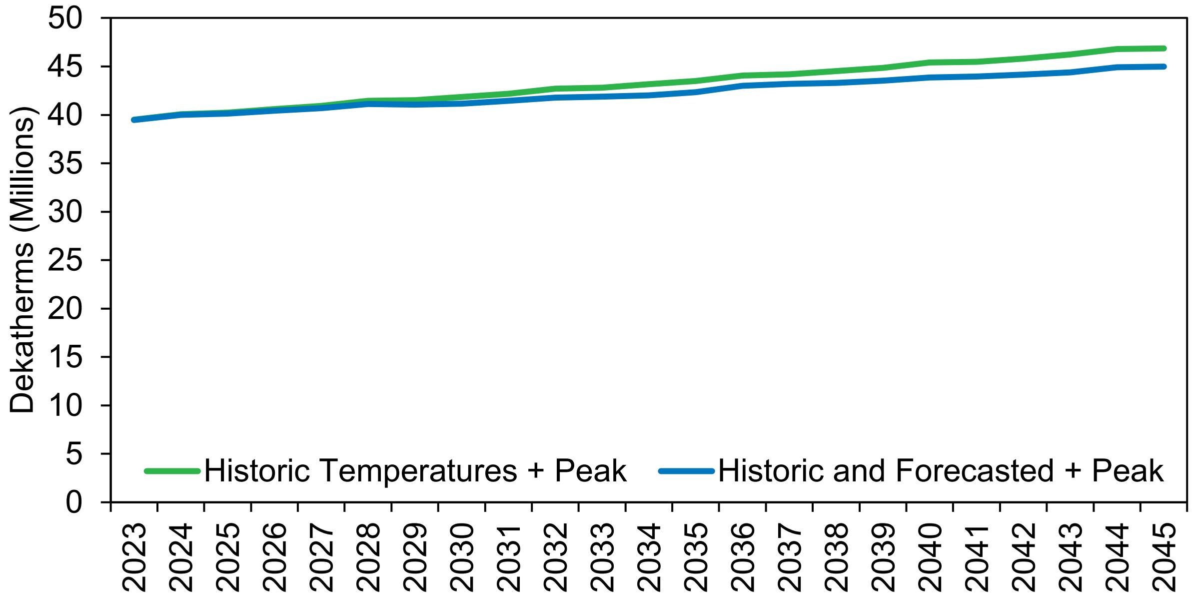
	Scenario	2046-2065	2081-2100		
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (°C)	RCP 2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP 4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP 6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP 8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

The results of the RCP 4.5 and RCP 6.0 scenarios are similar during the 2023 IRP planning horizon. Given the RCP 8.5 is at the high end of potential future GHG emissions where there are significant worldwide efforts to mitigate GHG emissions removes this future as a realistic option. The lower RCP 2.6 was not chosen due to the extreme levels of emission reductions which did not seem probable, therefore the intermediate scenarios with similar results during the 2023 IRP planning horizon were the focus. Avista selected the RCP 4.5 modeling for use in this IRP.

Warming temperatures will impact average demand yet maintain a peak risk and require flexible resources to meet these extreme temperatures in each planning area. Specifically, there will be less heating required in the winter.

HDDs are inputs to the PLEXOS® model. A 20-year moving average of the HDDs is used. The 2021 IRP the baseline forecast used the average of the most recent 20 years as a static input for all forward forecast years. In this analysis, the median daily average temperature of the RCP 4.5 model is used as the temperature data set compared to the 20-year moving average for each forecast year. Figure 2.6 presents the net change in load resulting from using the RCP 4.5 data in the forecast model compared to using the most recent 20-year average held constant over all future years. The net change is presented in Figure 2.6. The demand decreases as warming temperatures are incorporated into the 20-year moving average.

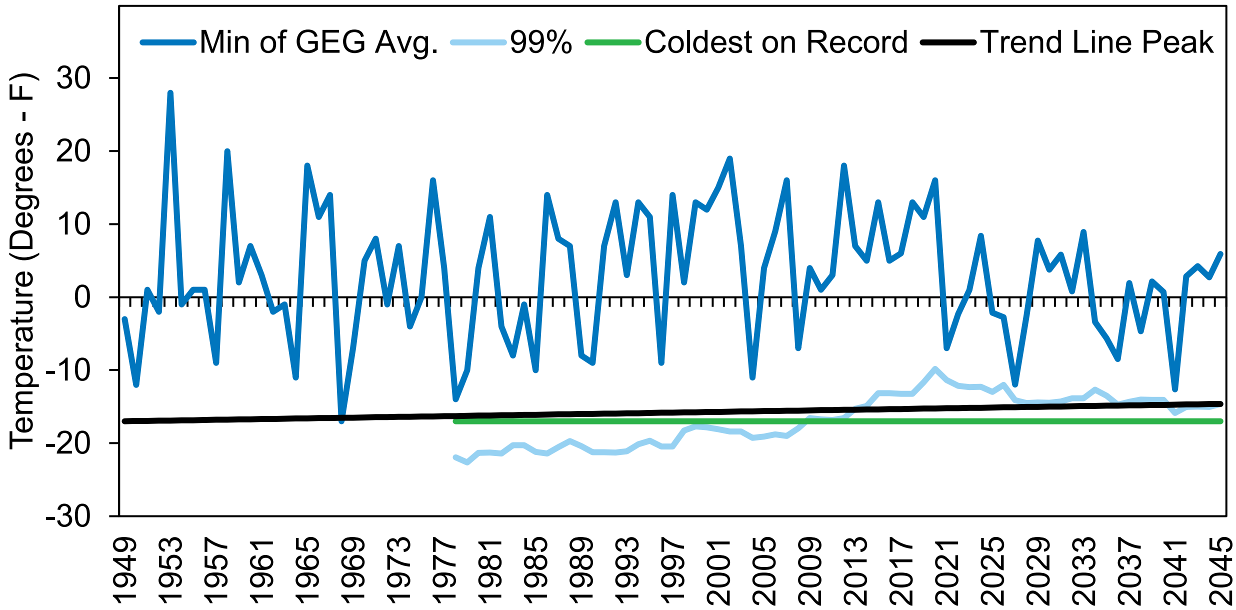
Figure 2.6: Impact of RCP 4.5 Temperature Data on Load Forecast



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. In prior IRP's a coldest on record approach was considered the planning standard. This IRP uses a different approach, first the coldest average daily temperature for each year is calculated for the past thirty years, by planning area. For future years, the 99th percentile of the cold weather daily temperature from the RCP 4.5 model is used to reflect probable cold days. Then the forecasted peak day uses a rolling 30 years of data and including both historic temperature and forecasted peak day temperatures. As shown in Figure 2.7. the volatile nature of the 99th percentile as calculated for each year with the prior 30 years of data creates volatility in future planning temperatures. For example, the 2024 the calculated peak temperature for Spokane is -12 degrees Fahrenheit but drops to -14 degrees Fahrenheit in 2027. To smooth out the whipsaw effect of these values, and subsequent overbuilding or underbuilding of the required resources, a smoothing calculation was used which utilizes the coldest on record temperature and the peak temperature calculation in 2045 and connects the two linearly.

Figure 2.7: Spokane Weather Station – Weather Planning Standard Comparison



The new 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 resources to serve customers in late season cold weather events. With supply side resources in the Pacific Northwest growing further 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 model assumes this event on and around December 20th each year. The following section provides a comparison of prior IRP planning standard versus the updated methodology (Table 2.4).

Table 2.4: Peak Day Design Temperature

Area	Coldest on Record (Prior IRP's)	99% Probability Avg. Temp (by 2045)
La Grande	-10	-8.0
Klamath Falls	-7	-5.1
Medford	4	11.7
Roseburg	10	11.7
Spokane	-17	-14.6

When considering changing weather in our service territories, a historic comparison is helpful. This Z-statistic analysis is used to compare the deviation from an average temperature over each stated timeframe. Distributions of these daily deltas as compared to the average daily weather over the timeframe will emerge. The Spokane weather area maintains the same shape from reference period where a coldest on record set of temperatures occurred. A slight deviation to the positive side of the Z-statistic points to a general warming trend as compared to the reference period. Movement towards the right on the X axis points to an increased deviation as compared to the reference period indicating a shift to warmer weather. The following figures illustrate a period of 30-year weather compared to recent weather by planning region for December, January, and February.

Figure 2.8: Spokane Historical Temperature Distribution

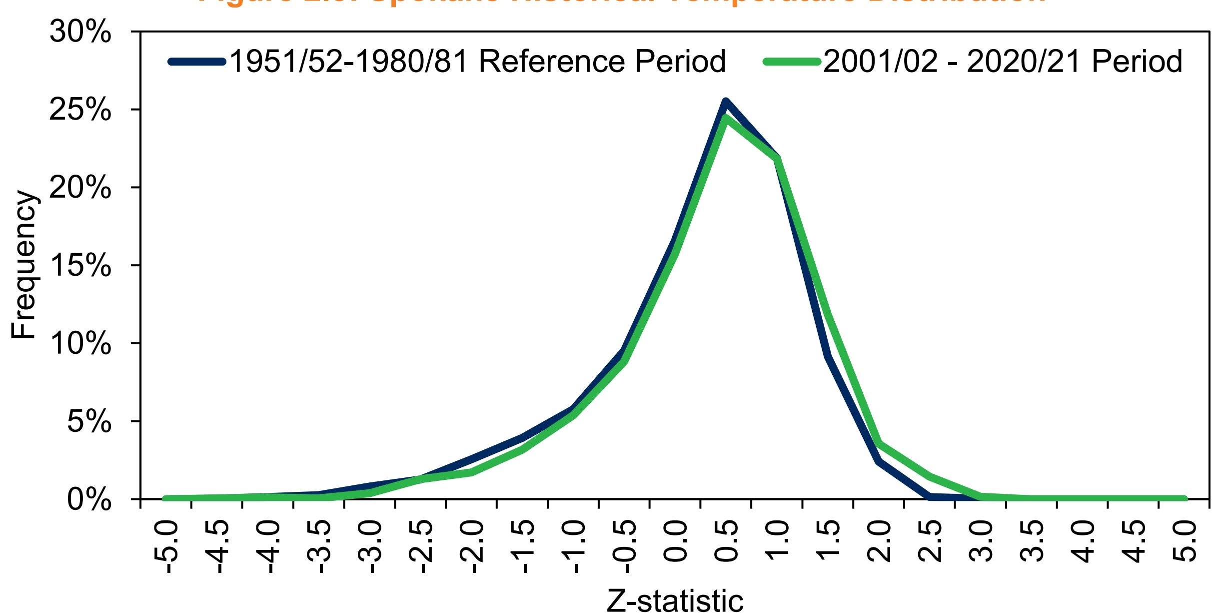


Figure 2.9: Medford Historical Temperatures

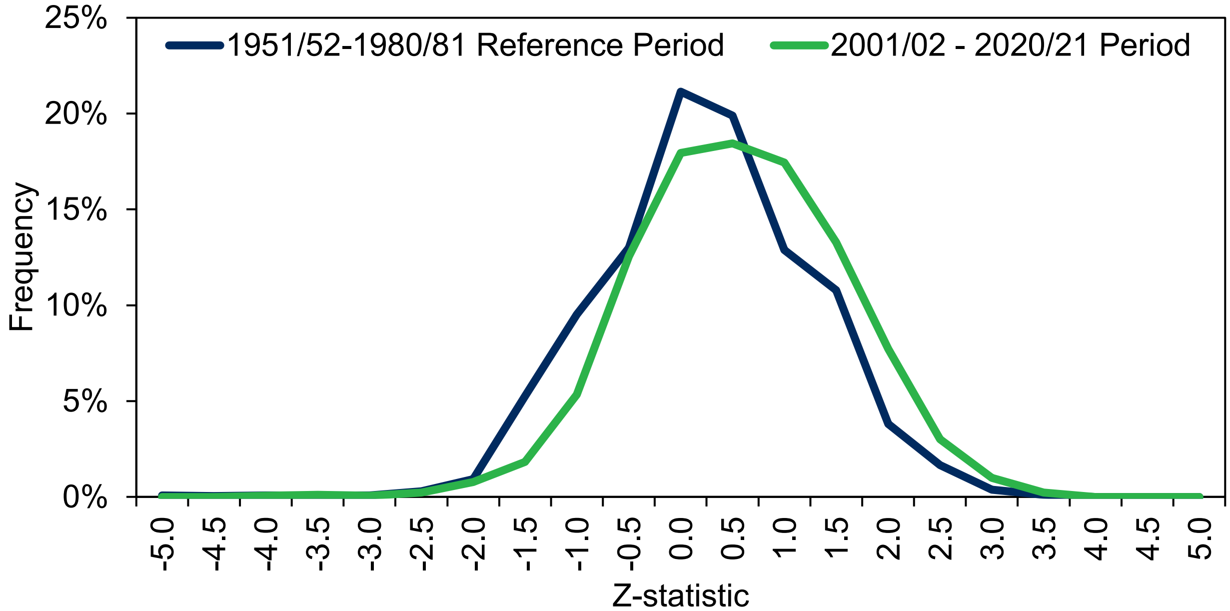


Figure 2.10: La Grande Historical Temperatures

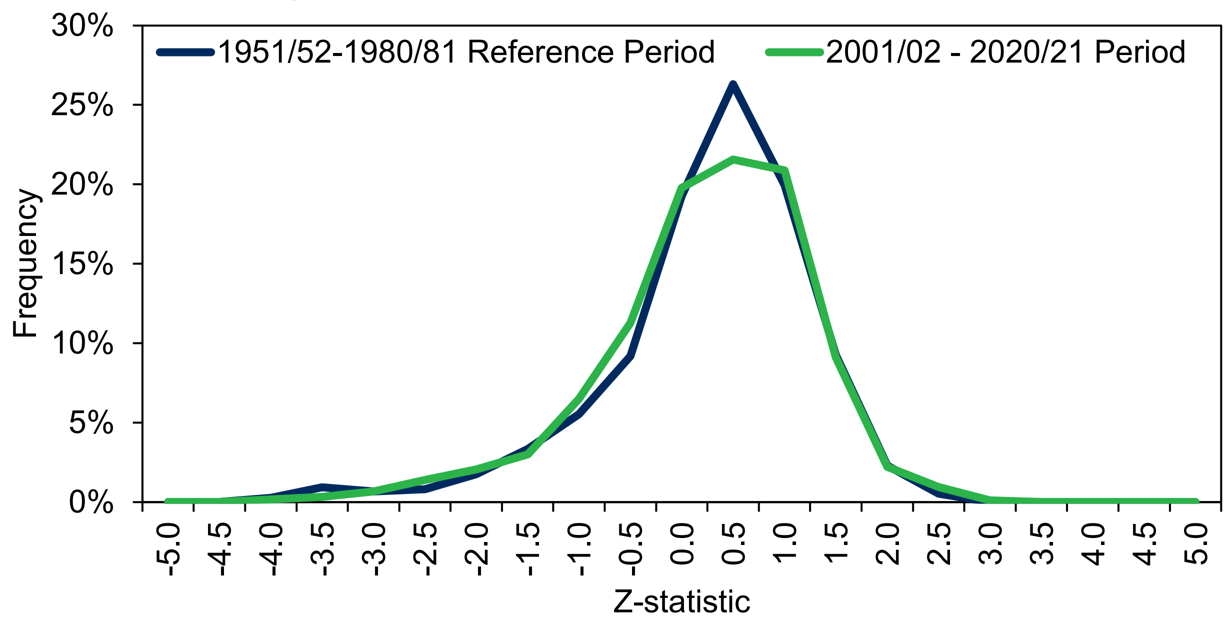


Figure 2.11: Klamath Falls Historical Temperatures

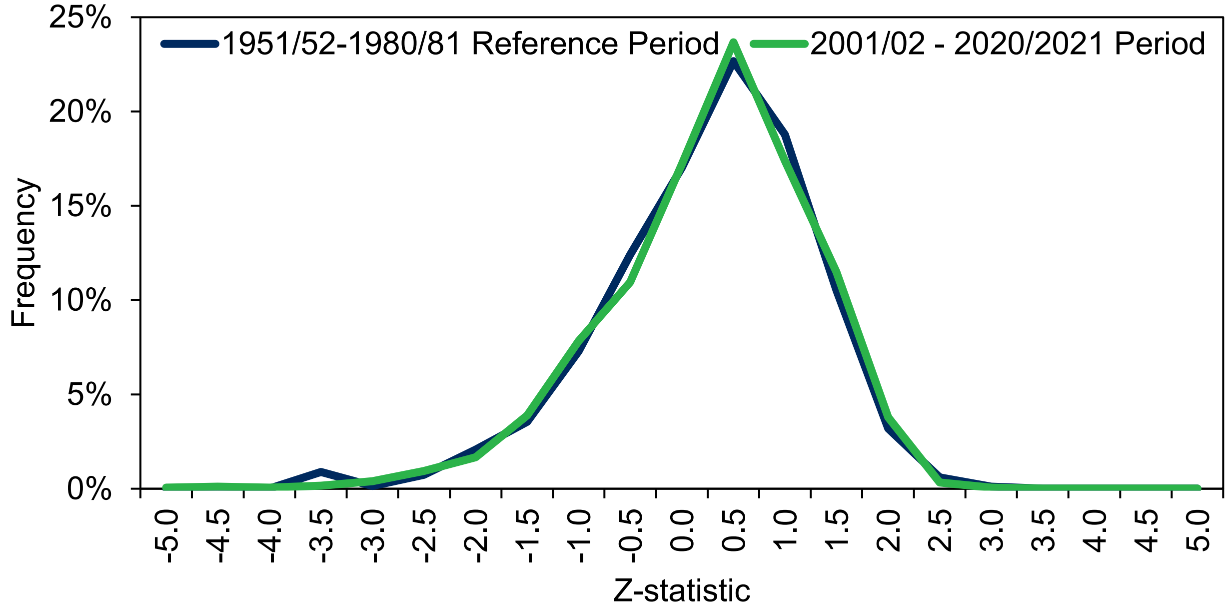
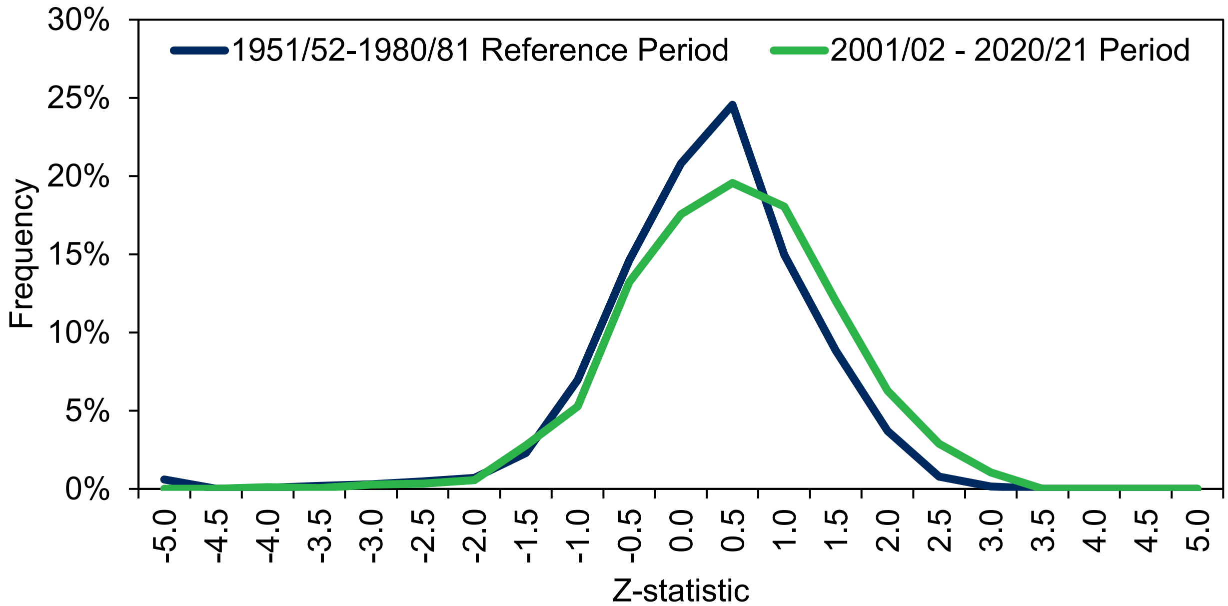


Figure 2.12: Roseburg Historical Temperatures



Weather

In order to evaluate weather and its effect on the portfolio, Avista developed 500 simulations (draws) using PLEXOS®'s stochastic capabilities. 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 2.5) 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.

Table 2.5: 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. A new weather planning standard was introduced in the 2021 IRP, and Avista assessed the frequency of when the weather planning standard peak day occurs in each area from the simulation data. The stochastic analysis shows that in over 500, 20-year simulations, a peak day (or more) occurs with enough frequency to utilize the new planning standard for this IRP. This topic remains a subject of continued analysis.

See Figure 2.13 through Figure 2.17 for the number of peak day occurrences by weather area. To help explain the number of peak day occurrences, Avista looks to the process itself. Monte Carlo simulations use historic data to obtain randomly generated weather events. Due to the change in planning standard, no peak days were simulated above the historic coldest on record temperature. Though due to the number of peak days occurring in the past 30 years, probability sees it is a higher likelihood of occurrence.

Figure 2.13: Frequency of Peak Day Occurrences – Spokane

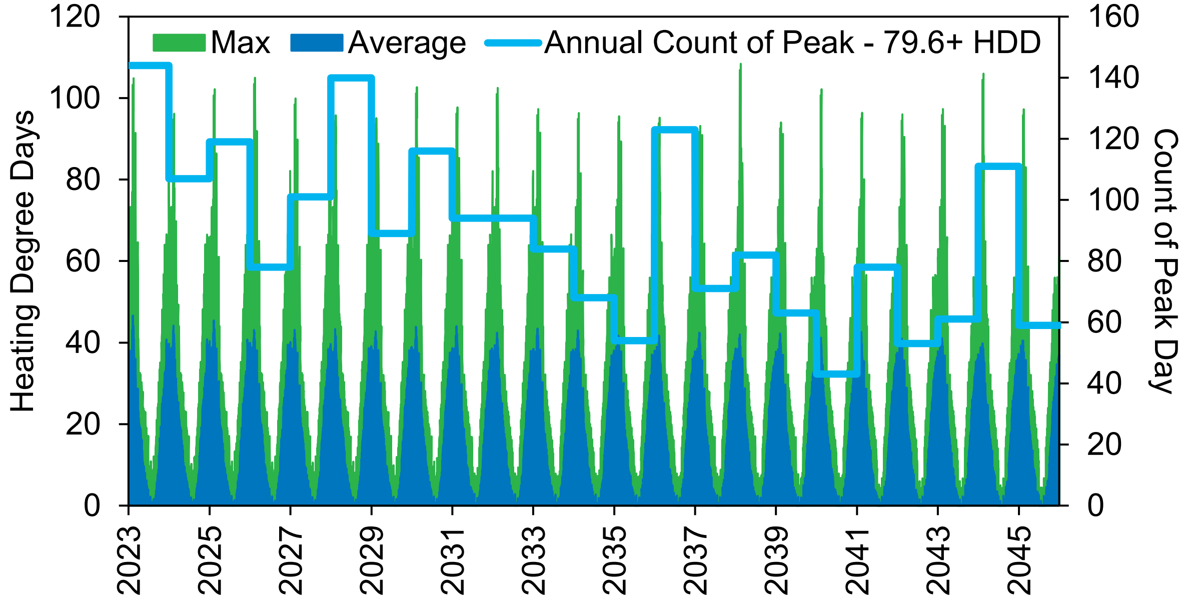


Figure 2.14: Frequency of Peak Day Occurrences – Medford

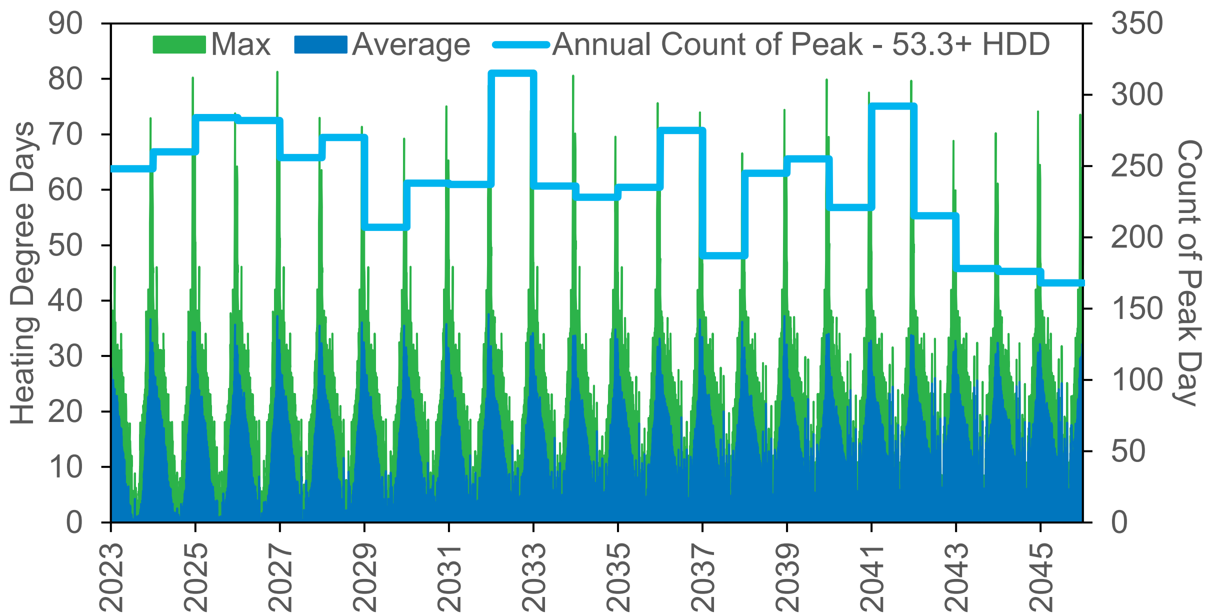


Figure 2.15: Frequency of Peak Day Occurrences – Roseburg

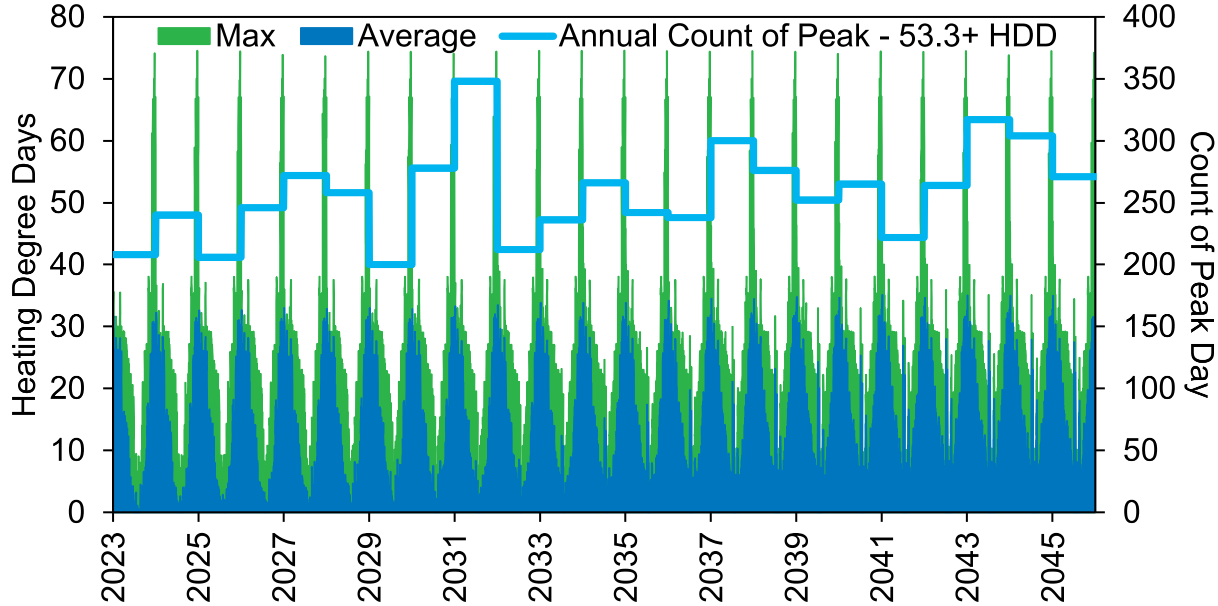


Figure 2.16: Frequency of Peak Day Occurrences – Klamath Falls

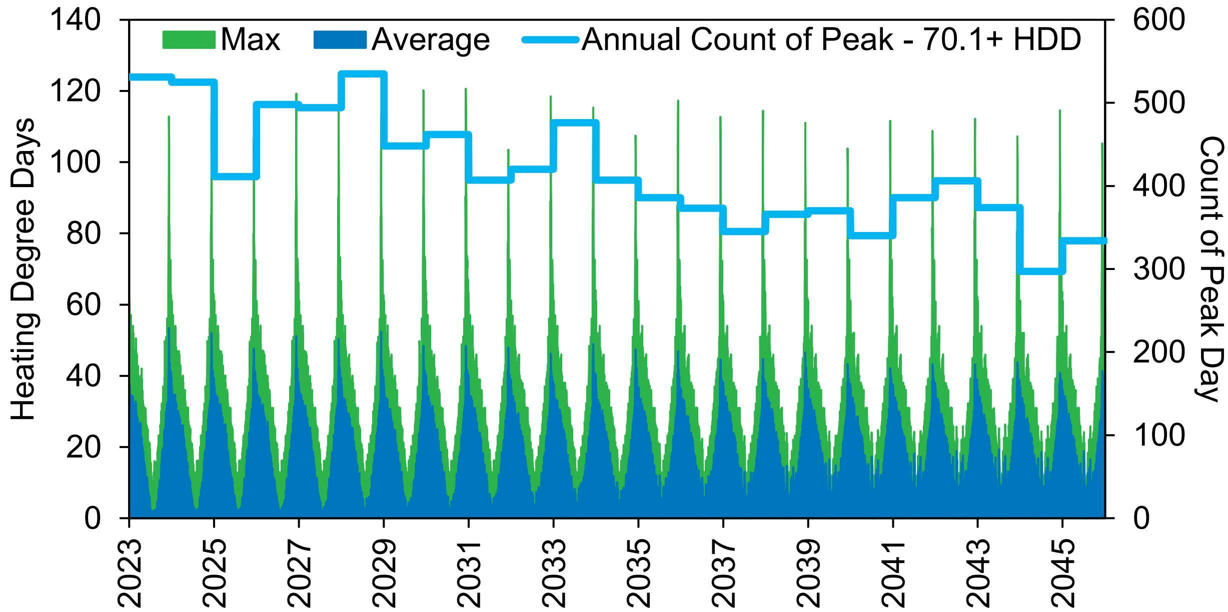
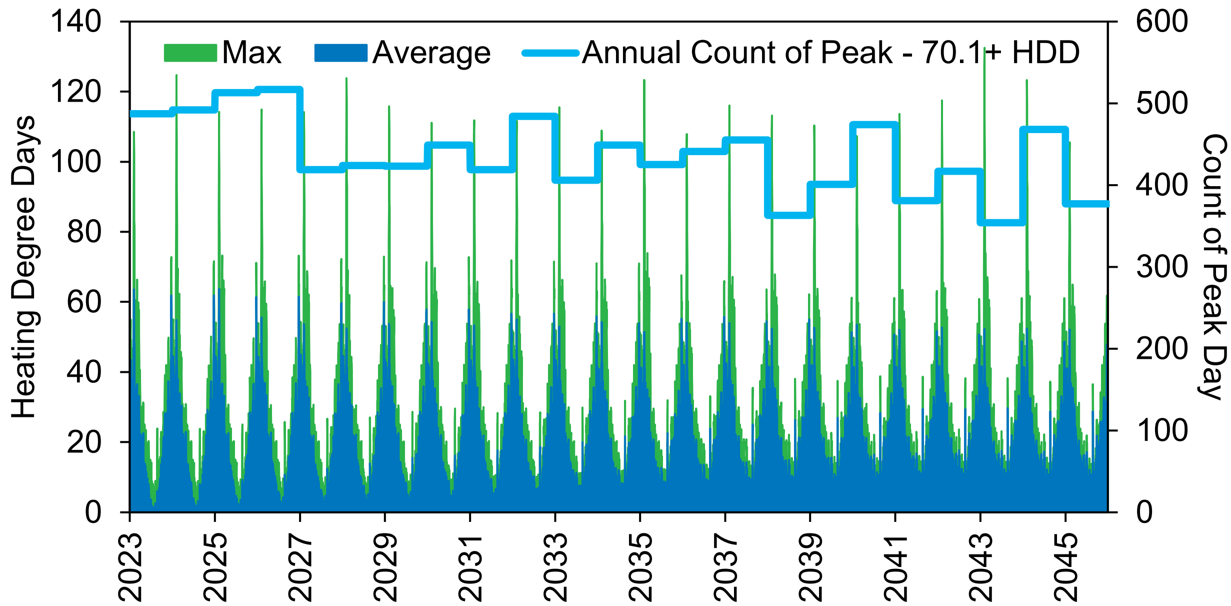


Figure 2.17: Frequency of near Peak Day Occurrences – La Grande



Load Forecast

The combination of the elements discussed in this chapter produce an estimated energy need as illustrated in Table 2.6: Load Forecast. The forecast is broken out by jurisdiction, separated by firm and transport only expectations.

Table 2.6: Load Forecast (Thousand Dekatherms)

Year	Washington	Idaho	Oregon	Washington Transport	Oregon Transport	Total	Total w/ Transport
2023	19,436	10,441	9,597	2,479	4,441	39,475	46,394
2024	19,604	10,644	9,759	2,451	4,425	40,007	46,884
2025	19,549	10,724	9,845	2,448	4,424	40,118	46,990
2026	19,620	10,855	9,968	2,448	4,424	40,443	47,315
2027	19,657	10,956	10,069	2,448	4,423	40,682	47,553
2028	19,816	11,118	10,202	2,443	4,421	41,136	48,000
2029	19,675	11,128	10,237	2,435	4,420	41,040	47,895
2030	19,652	11,192	10,316	2,430	4,419	41,159	48,008
2031	19,726	11,295	10,429	2,426	4,418	41,451	48,295
2032	19,821	11,422	10,544	2,424	4,418	41,786	48,628
2033	19,790	11,475	10,604	2,425	4,419	41,869	48,713
2034	19,785	11,549	10,672	2,427	4,420	42,006	48,854
2035	19,864	11,665	10,819	2,432	4,422	42,348	49,203
2036	20,122	11,867	11,014	2,434	4,423	43,003	49,860
2037	20,130	11,947	11,109	2,440	4,425	43,186	50,051
2038	20,082	12,005	11,201	2,450	4,427	43,289	50,167
2039	20,128	12,106	11,300	2,461	4,430	43,533	50,424
2040	20,209	12,216	11,436	2,466	4,431	43,861	50,758
2041	20,173	12,270	11,507	2,473	4,432	43,950	50,855
2042	20,193	12,356	11,607	2,474	4,433	44,155	51,062
2043	20,210	12,440	11,732	2,510	4,457	44,382	51,348
2044	20,424	12,624	11,864	2,510	4,457	44,912	51,879
2045	20,398	12,698	11,885	2,510	4,457	44,981	51,948

The peak load demand forecast is included in Table 2.7. 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 2.7: Peak Day Load Forecast (Thousand Dekatherms)

Year	Washington	Idaho	Oregon	Washington Transport	Oregon Transport	Total	Total w/ Transport
2023	219.89	111.89	90.11	8.57	14.24	378.37	400.62
2024	221.98	113.86	90.96	8.35	14.20	382.50	403.86
2025	224.00	115.68	91.76	8.48	14.19	387.11	409.22
2026	226.17	117.40	92.59	8.49	14.19	391.42	413.54
2027	228.09	118.91	93.25	8.48	14.19	395.42	417.53
2028	230.01	120.40	94.03	8.33	14.18	398.71	420.03
2029	231.84	121.83	94.62	8.45	14.18	402.47	424.54
2030	233.77	123.22	95.36	8.44	14.18	406.13	428.18
2031	235.75	124.63	95.94	8.42	14.18	410.08	432.12
2032	237.77	126.10	96.58	8.28	14.18	413.76	435.02
2033	239.76	127.55	97.24	8.42	14.18	417.06	439.10
2034	241.80	129.02	97.91	8.43	14.18	421.29	443.33
2035	243.83	130.49	98.65	8.44	14.19	425.34	447.40
2036	245.85	131.97	99.23	8.31	14.19	429.59	450.89
2037	247.83	133.42	99.89	8.46	14.19	433.40	455.49
2038	249.84	134.87	100.46	8.49	14.20	436.76	458.89
2039	251.80	136.32	101.13	8.52	14.21	439.47	461.64
2040	253.75	137.75	101.86	8.39	14.21	442.56	463.98
2041	255.68	139.15	102.55	8.55	14.21	446.40	468.61
2042	257.58	140.55	103.14	8.56	14.22	450.20	472.41
2043	259.53	141.99	104.08	8.65	14.28	454.17	476.55
2044	261.44	143.42	104.65	8.51	14.28	457.25	478.85
2045	263.32	144.92	105.23	8.65	14.28	460.21	482.59

Measuring risk in weather is done through a statistical approach of analyzing each of these measures to reflect the uncertain nature of a future outcome. Risk can be measured by the variation of cost outcome of resources in addition to unknown weather events and the ability to serve customer demand. This analytical perspective provides confidence in the conclusions and stress tests the robustness of the selected portfolio of resources, thereby mitigating analytical risks. The system demand for these 500 futures from 2023 to 2045 is illustrated in Figure 2.18 with demand by jurisdiction in Figures 2.19 to 2.21.

Figure 2.18: System Demand – 1,000 Dth (500 Draws)

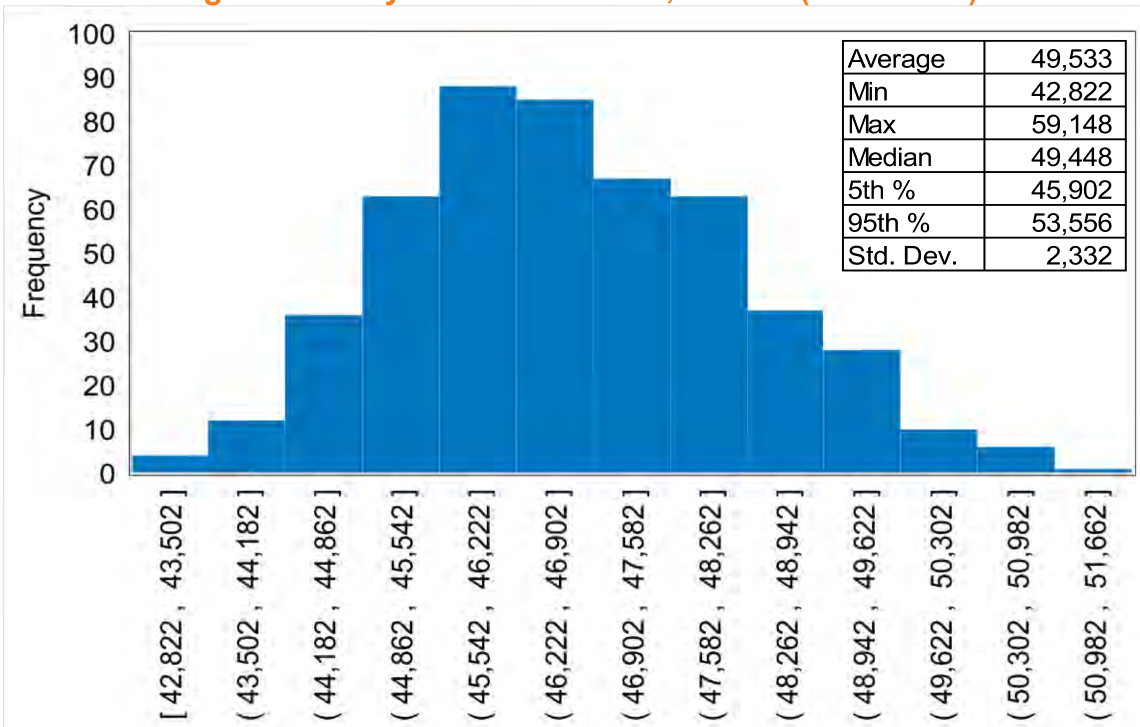


Figure 2.19: Idaho Demand – 1,000 Dth (500 Draws)

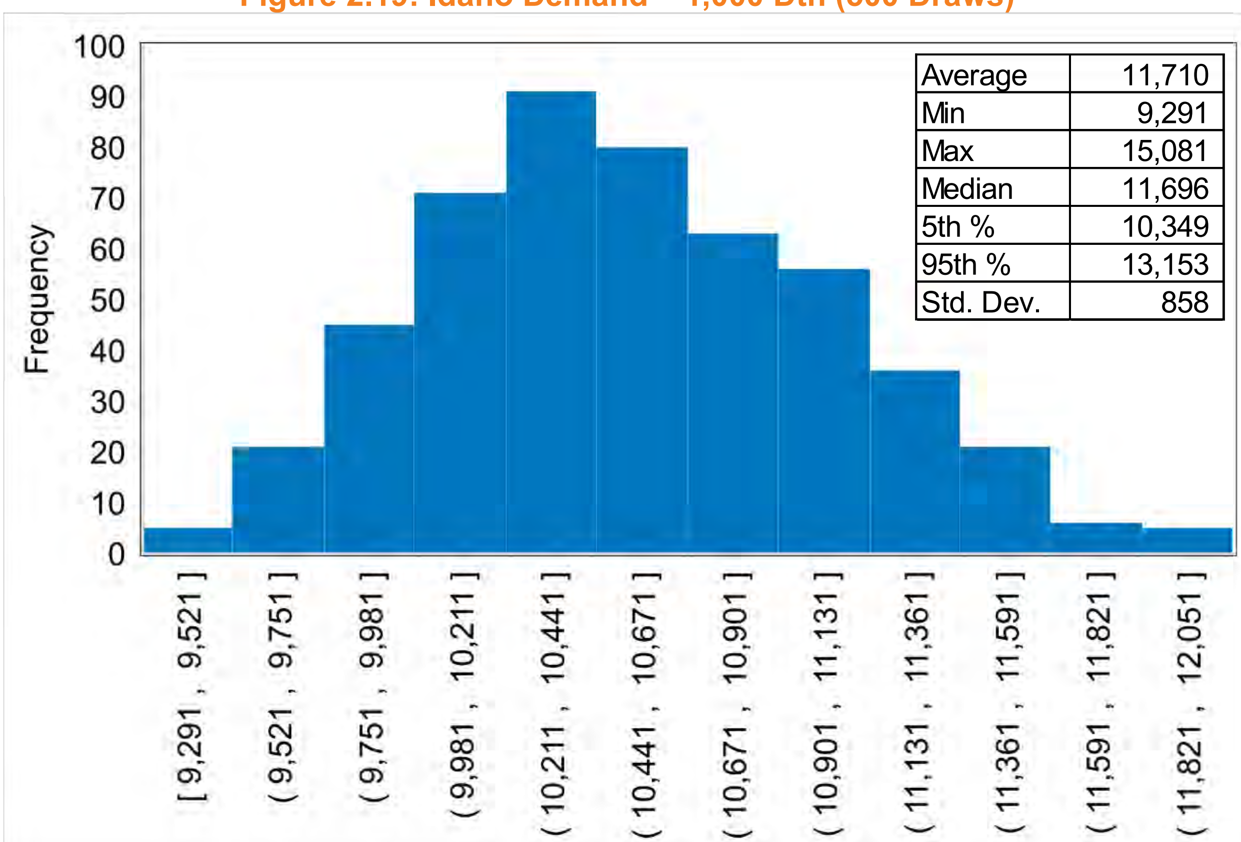


Figure 2.20: Oregon Demand – 1,000 Dth (500 Draws)

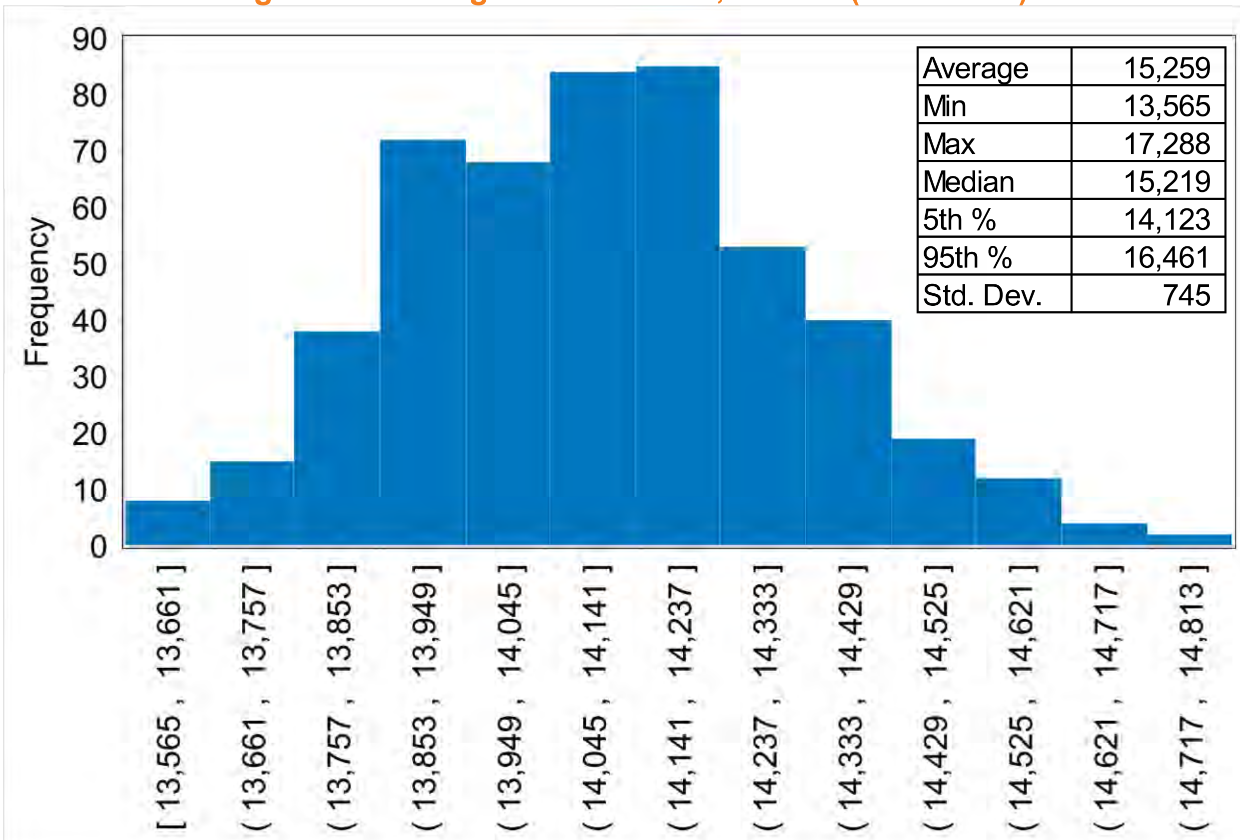
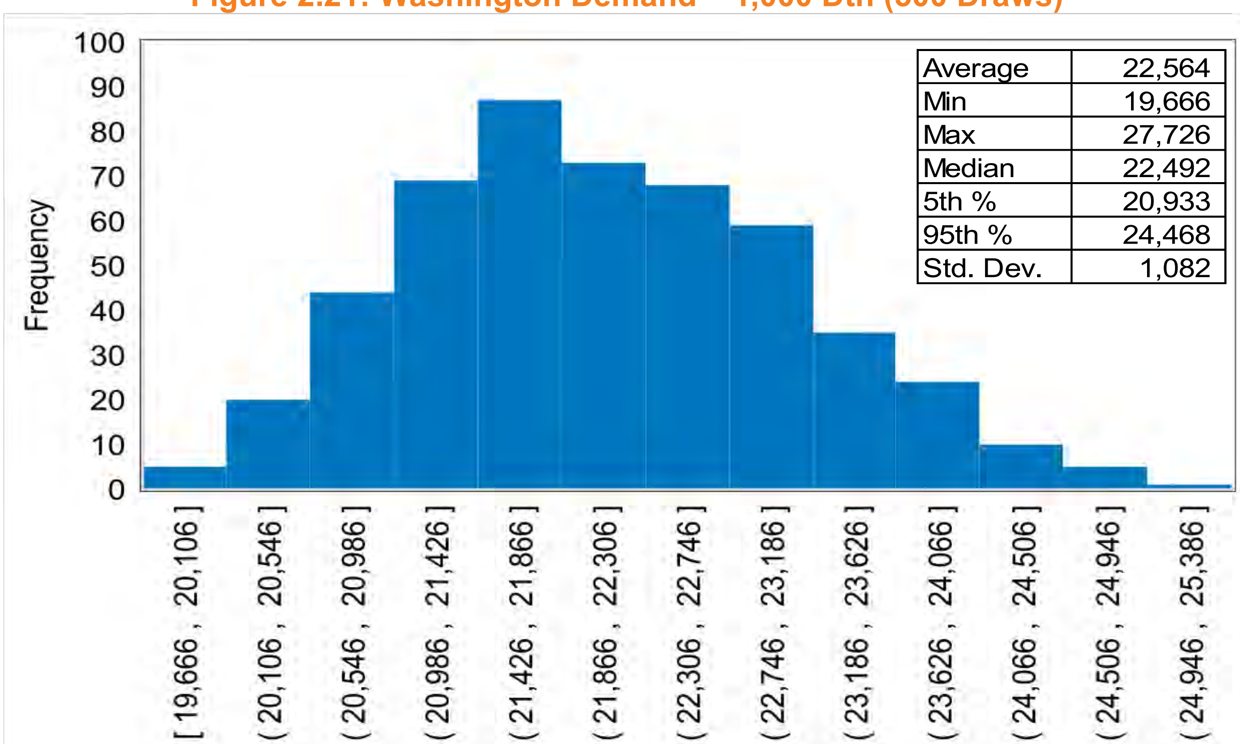


Figure 2.21: Washington Demand – 1,000 Dth (500 Draws)



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 2.7 identifies the scenarios developed for this IRP. The Average Case represents the case used for normal planning purposes, such as corporate budgeting, procurement planning, PGAs, and General Rate Cases. The Preferred Resource Case 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 given the volatile nature of key assumptions, including weather and price.

Table 2.8: Demand Scenarios

Preferred Resource Case – Our expected case based on assumptions and costs with a least risk and least cost resource selection	**High Customer Case** – A high demand case to measure risk of additional customer and meeting our emissions and energy obligations
Electrification Expected Conversion Costs – Expected conversion costs case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system	**Average Case** – Non climate change projected 20-year history of average daily weather and excludes peak day
Hybrid Case – Natural Gas used for space heat below 40º F while transferring all other usage to electricity.	

During 2023, the Average Case demand forecast indicates Avista will serve an average of 379,669 core natural gas customers with 38,871,519 Dth of natural gas. By 2042, Avista projects 469,703 core natural gas customers with an annual energy demand of 45,082,213 Dth. In Washington/Idaho, the projected number of customers increases at an average annual rate of 1.22%, with demand growing at a compounded average annual rate of 0.78%. In Oregon, the projected number of customers increases at an average annual rate of 0.89%, with demand growing 0.80% per year.

The Expected Case demand forecast indicates Avista will serve an average of 379,669 core natural gas customers with 39,518,082 Dth of natural gas in 2023. By 2042, Avista projects 469,703 core natural gas customers with an annual demand of 44,199,537 Dth.

Table 2.8 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[3]

[3] Appendix 2.1 shows gross demand, conservation savings and net demand.

Table 2.9: Annual Demand – 2023 IRP Scenarios (000 dth)

<table>
<tr><th>Scenario</th><th>2025</th><th>2035</th><th>2045</th></tr>
<tr><td>Hybrid Case</td><td>46,702</td><td>45,155</td><td>44,772</td></tr>
<tr><td>Average Case</td><td>46,406</td><td>49,612</td><td>53,042</td></tr>
<tr><td>Electrification - Expected Conversion Costs</td><td rowspan="3">46,270</td><td rowspan="3">41,447</td><td rowspan="3">38,368</td></tr>
<tr><td>Electrification - High Conversion Costs</td></tr>
<tr><td>Electrification - Low Conversion Costs</td></tr>
<tr><td>PRS - High Prices</td><td>46,933</td><td>49,122</td><td>51,909</td></tr>
<tr><td>PRS</td><td rowspan="6">46,990</td><td rowspan="6">49,203</td><td rowspan="6">51,948</td></tr>
<tr><td>PRS - Allowance Price Ceiling</td></tr>
<tr><td>Limited RNG Availability</td></tr>
<tr><td>Carbon Intensity</td></tr>
<tr><td>Social Cost of Carbon</td></tr>
<tr><td>Interrupted Supply</td></tr>
<tr><td>PRS - Low Prices</td><td>47,011</td><td>49,217</td><td>51,950</td></tr>
<tr><td>High Customer Case</td><td>47,456</td><td>50,913</td><td>55,089</td></tr>
</table>

The IRP balances forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which reduce demand reduction, the demand forecasts prepared and described in this section include existing energy efficiency standards and normal market acceptance levels. The methodology for modeling energy efficiency initiatives is in Chapter 3.

Alternative Forecasting Methodologies

There are many forecasting methods available and used throughout different industries. Avista uses methods to enhance forecast accuracy, facilitate meaningful variance analysis, and allows for modeling flexibility to incorporate different assumptions. Avista believes the IRP statistical methodology to be sound and provides a robust range of demand considerations while allowing for the analysis of different statistical inputs by considering both qualitative and quantitative factors unless there are fundamental changes to the industry. These factors come from data, surveys of market information, fundamental forecasts, and industry experts. Avista is always open to new methods of forecasting natural gas demand and will continue to assess alternative methodologies for possible inclusion in the dynamic demand forecasting methodology.

Key Issues

Demand forecasting is a critical component of the IRP requiring careful evaluation of the current methodology and use of scenario planning to understand how changes to the underlying assumptions will affect the results. The evolution of demand forecasting over recent years has been dramatic, causing a heightened focus on variance analysis and trend monitoring. Current techniques have provided sound forecasts with appropriate variance capabilities. However, Avista is mindful of the importance of the assumptions driving current forecasts and understands there will be change over time. Therefore, monitoring key assumptions driving the demand forecast is an ongoing effort and will be shared with the TAC as they develop. Avista intends to explore the use of an end-use model to help forecast demand in future IRPs.[4]

[4] Action # 9 in Chapter 9 - Action Plan

3. Demand Side Resources

Avista is committed to offering natural gas energy efficiency (EE) programs to residential, low income, commercial and industrial customer segments when it is feasible to do so in a cost-effective manner as prescribed 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 savings 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 future years.

Avoided Cost

The preliminary cost-effective energy efficiency potential is determined by applying the stream of annual natural gas avoided costs to the Avista-specific supply curve for EE resources. These costs include commodity costs, distribution cost adders, storage costs, social cost of greenhouse gas at 2.5%, fuel costs to move the gas from point A to point B, and a 10% preference adder for EE among others discussed in Chapters 4 & 5. A quantity of EE acquisition is provided by Applied Energy Group (AEG) for Idaho and Washington and while the Energy Trust of Oregon (ETO) handles the analysis and program delivery for Oregon. The estimated results 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 estimate total potential in the CPA. The resulting avoided costs were provided to AEG to use in selecting cost-effective EE potential within Avista's service territories.

The avoided-cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If an energy efficiency measure's total resource cost (Oregon and Washington), or utility cost (Idaho), is less than this avoided cost, it will be cost effective to reduce customer demand and Avista can avoid commodity, storage, transportation, and other supply resource costs while reducing the risk of unserved demand in peak weather.

PLEXOS® calculates marginal cost data by day, month, and year for each demand area. A summary graphical depiction of avoided annual and winter costs for each jurisdictional area is in Figure 3.1 and 3.2. The detailed data is in Appendix 6.4. Appendix 3.2 describes this concept more fully and includes specific requirements required in modeling for the Oregon service territory.

Figure 3.1: Annual Avoided Cost (by jurisdiction)

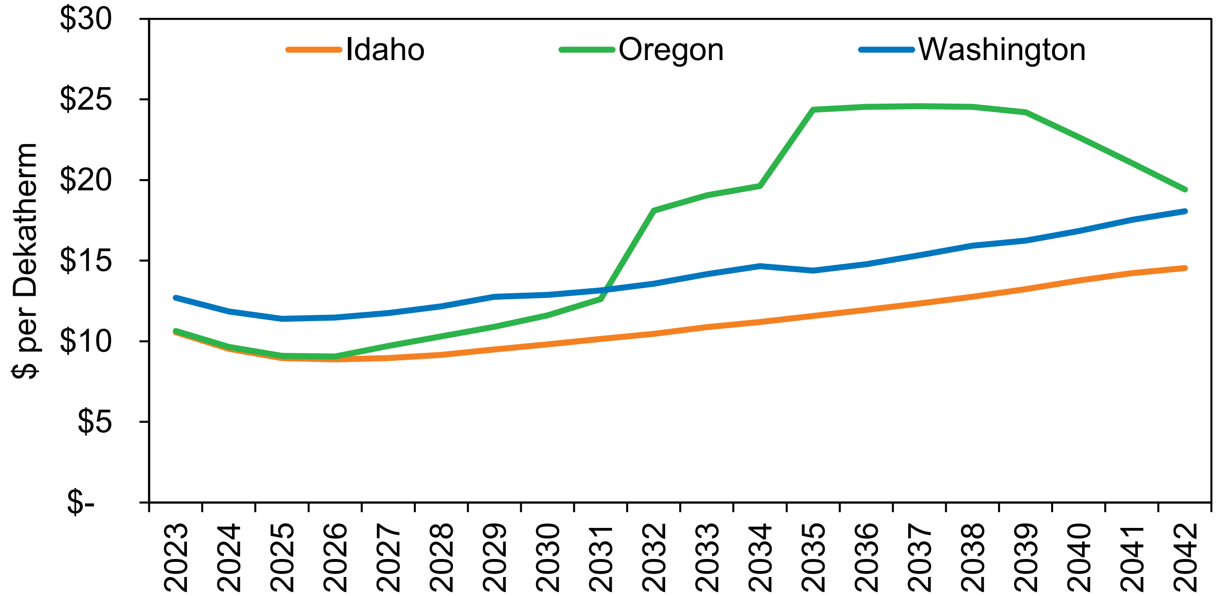
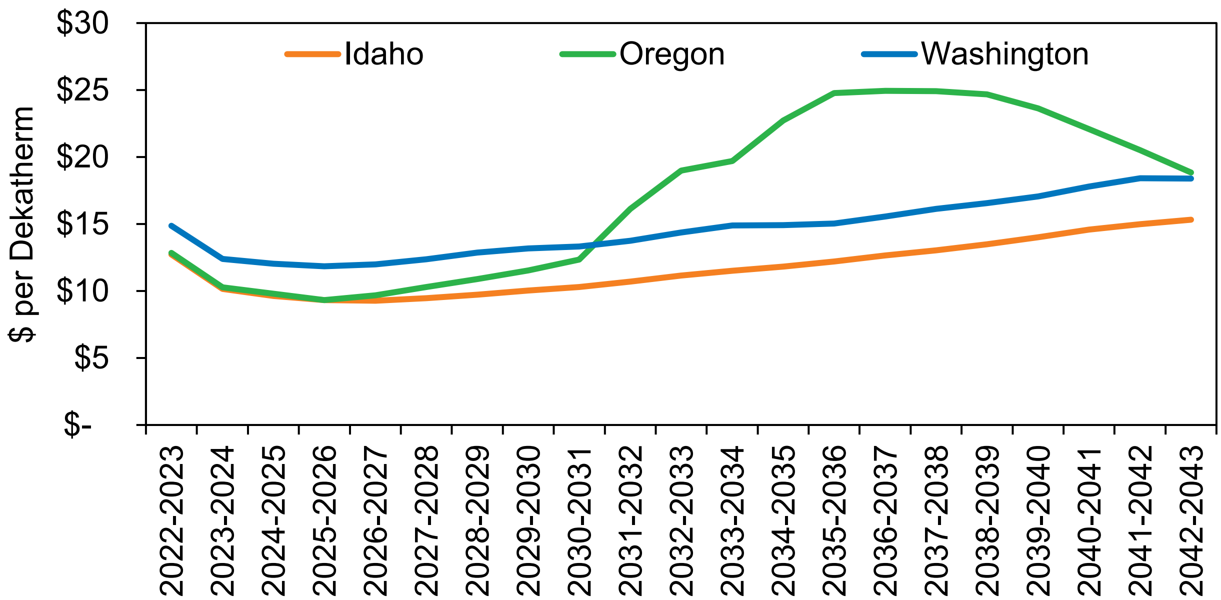


Figure 3.2: Winter Avoided Cost (by jurisdiction)



Idaho and Washington Conservation Potential Assessment

As part of its process for identifying its Conservation Potential Assessment (CPA), also known as an EE potential assessment, Avista issued an RFP to identify qualified third parties to estimate potential EE savings opportunities. Avista chose Applied Energy Group (AEG) to perform an independent CPA for Washington and Idaho natural gas. The CPA is Avista's tool to identify the level of energy efficiency it anticipates achieving over a 20-year period. Moreover, the CPA is used to identify the conservation target for each jurisdiction that it operates in.

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 of 2023 to 2042. 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 in absence of 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 2023 to 2045 planning horizon.
- Deliver a fully configured end-use conservation planning model, LoadMAP, for Avista to use in future potential and resource planning initiatives.
- 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 to 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 lead to a specific standardized cost-effectiveness test. The section below outlines and describes the 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, administrative costs, and the incremental costs between standard and high efficiency equipment.

Utility Cost Test

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. The UCT is also known as the program administrator cost test (PAC). As part of the CPA, each cost test is applied to the jurisdictions according to the jurisdictions primary cost test methodology. Idaho and Washington have traditionally use the UCT while Oregon has used a modified TRC Test.

Washington's EE program evaluation will transition away from the UCT to the TRC method as its primary cost effectiveness test. As a condition to Avista's 2022-23 Natural Gas Biennial Conservation Plan[1], Avista agreed to conduct a TRC analysis assesses all costs and all benefits of EE measures. Also included in the conditions is the requirement to include the costs of greenhouse gas emissions per RCW 80.28.380. Since the UCT does not include these in their calculation, the requirement necessitates a change in the primary cost-effectiveness test. Therefore, for this CPA, Avista requested that AEG prepare the Washington level of EE on the TRC basis. Table 3.1 summarizes the cost tests used by each jurisdiction.

Table 3.1: Cost Effectiveness Test

State	Total Resource Cost	Utility Cost Test
Idaho		X
Oregon	X	
Washington	X	

Washington and Idaho Energy Efficiency Potential

First-year TRC achievable economic potential in Washington is 111,992 dekatherms. This increases to a cumulative total of 225,734 dekatherms in the second year and 2,497,540 dekatherms by 2045. Table 3.2 summarizes the results for Avista's Washington service territory at a high level. AEG analyzed the EE potential for the residential, commercial, and industrial market sectors.

[1] UG-210827 Order No. 01, Attachment A.

Table 3.2: Washington Energy Efficiency Potential by Case (dekatherms)[2]

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	19,632,329	19,782,233	19,934,947	21,966,934	24,576,214
Cumulative Savings (Dth)					
TRC Economic Potential	111,992	225,734	361,485	1,833,863	2,497,540
Achievable Technical Potential	191,654	423,238	686,518	3,774,115	4,938,238
Technical Potential	429,564	884,194	1,375,956	6,455,295	8,637,218
Energy Savings (% of Baseline)					
TRC Economic Potential	0.6%	1.1%	1.8%	8.3%	10.2%
Achievable Technical Potential	1.0%	2.1%	3.4%	17.2%	20.1%
Technical Potential	2.2%	4.5%	6.9%	29.4%	35.1%

Table 3.3 summarizes the results for Avista's Idaho service territory at a high level. First-year UCT achievable economic potential in Idaho is 46,414 dekatherms. This increases to a cumulative total of 96,705 dekatherms in the second year and 1,278,511 dekatherms by 2045.

Table 3.3: Idaho Energy Efficiency Potential by Case (dekatherms)

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	9,781,790	9,893,452	10,003,402	11,501,243	13,451,001
Cumulative Savings (Dth)					
UCT Economic Potential	46,414	96,705	155,748	906,240	1,278,511
Achievable Technical Potential	105,612	228,853	371,295	2,144,539	2,885,725
Technical Potential	254,213	498,497	772,091	3,673,174	5,060,646
Energy Savings (% of Baseline)					
UCT Economic Potential	0.5%	1.0%	1.6%	7.9%	9.5%
Achievable Technical Potential	1.1%	2.3%	3.7%	18.6%	21.5%
Technical Potential	2.6%	5.0%	7.7%	31.9%	37.6%

[2] See Appendix Chapter 3

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 2023 in its analysis, the cycle for establishing annual EE targets begins in 2024 and runs through 2025 as a biennial period. Therefore, for the purpose of target setting, cumulative values are used with the first year of the study, 2023, removed. An additional CPA for Avista's Washington transport customer group was conducted. The entire CPA report including the methodology can be found in Appendix 3.

Table 3.4 and 3.5 summarizes the 2024 and 2025 targets for Washington and Idaho respectively as a result of the CPA. As stated above the 2023 estimates were removed from the overall cumulative value to arrive at the 2024 and 2025 incremental targets.

Table 3.4: Washington 2024-2025 Conservation Target by Sector, (therms)

Customer Segment	2024	2025	Total
Low Income	119,407	160,534	279,941
Residential	368,556	498,644	867,199
Commercial	627,625	676,226	1,303,851
Industrial	19,874	20,193	40,067
Total	**1,135,461**	**1,355,596**	**2,491,058**

Table 3.5: Idaho 2024-2025 Conservation Target by Sector, (therms)

Customer Segment	2024	2025	Total
Low Income	25,176	31,788	56,964
Residential	256,634	319,784	576,418
Commercial	204,566	222,235	426,802
Industrial	15,422	15,530	30,952
Total	**501,799**	**589,337**	**1,091,136**

Avista made one adjustment to the CPA impacting its overall EE target. The measure "Gas Furnace – Maintenance" was included in the study provided by AEG and was also included in the economic screen to inform the overall targets for each state. While other measures included in the study focus on efficiency, controls, commissioning or weatherization, the maintenance measure is intended to return existing equipment to its "nameplate" or as-designed efficiency level. The feasibility of reaching the level of potential outlined in the study is unlikely since there are no available sources for a deemed savings value for this measure that can be vetted and relied upon. In addition, the evaluation of a maintenance-type program creates difficulty since individual unit service needs vary substantially from project to project, and in many cases, may not result in efficiency gains. Since savings values within the potential do not have an adequate level of certainty, the maintenance measure has been removed from the economic potential.

The impact of this adjustment is a reduction of 386,757 therms for Washington over the two-year period and 220,820 therms for Idaho over the two-year period.

Oregon Energy Efficiency Targets

As technologies and EE policies evolve over the IRP timeline the Company works with the Oregon Public Utility Commission, Community Action Agencies, Energy Trust of Oregon, and other stakeholders to adjust offerings to maximize EE savings. AEG conducted a CPA for Avista's Oregon low-income, interruptible and transport customer groups to enable the Company to better understand potential when designing programs for these customers. Energy Trust of Oregon (ETO) conducted a CPA for Avista's residential, small, and large commercial customer groups which they have served with energy efficiency programs since 2017. The entire CPA report including the methodology can be found in Appendix 3.

The Company has exclusively worked with Community Action Agencies (CCAs) to implement the Avista Oregon Low Income Energy Efficiency (AOLIEE) Program. Agency primarily install shell measures, air and duct sealing for our low-income customers. The results of identified top EE measures were discussed with the CCAs and ETO to determine the measures that are readily deployable in the near term, but no measures have been removed from the overall potential. Throughout 2022, Avista engaged the CCAs that administer the AOLIEE Program, as well as several other organizations to serve its low-income households,[3] via meetings, email correspondence, and telephone conversations to gain community perspective and collaboratively discuss new ways to possibly increase customer participation in the Program. As noted in the Company's 2021 AOLIEE Report, Avista also partnered with a third-party contractor, *Empower Dataworks*,[4] to complete an Energy Burden Assessment (Assessment) in 2022.[5] This Assessment informs the Company of existing gaps in Program structure and provides data needed to better target Avista's energy burdened customers needing weatherization services.

These engagements provide the basis for the Company's requested modifications to its AOLIEE Program for 2023, which were approved by the Commission in Docket No. ADV 1452/Advice No. 22-11-G. These modifications for the 2023 Program year, are intended to expand the reach of the existing Program and to prioritize energy burdened customers within these communities to ensure energy efficiency services available are reaching those that need them most. Avista will continue to work with interested parties including Energy Trust of Oregon to ramp up EE programs to reduce the energy burden for low-income customers. Table 3.6 summarizes the potential results for low-income customers.

---

[3] Such organizations include Federally Recognized Tribes and Saint Vincent de Paul.

[4] *Empower Dataworks*, a third-party consultant specializing in data, informed marketing, and engineering analytical services, was hired by the Company in 2021 to perform an Energy Burden Assessment. See https://empowerdataworks.com/ for more detail regarding *Empower Dataworks*.

[5] https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAH&FileName=um2211hah135626.pdf&DocketID=23122&numSequence=66

Table 3.6: Summary of Oregon Low-Income Energy Efficiency Potential

	2023	2024	2025	2035	2045
Baseline Projection (Dth)[1]	914,784	919,566	924,873	999,238	1,128,049
Cumulative Savings (Dth)					
Achievable Economic Potential	3,816	7,383	12,114	60,487	99,838
Achievable Technical Potential	8,877	18,471	30,274	165,088	205,045
Technical Potential	14,319	28,147	44,987	226,689	295,472
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.4%	0.8%	1.3%	6.1%	8.9%
Achievable Technical Potential	1.0%	2.0%	3.3%	16.5%	18.2%
Technical Potential	1.6%	3.1%	4.9%	22.7%	26.2%

Avista has not offered carbon reduction programs via EE for transport and interruptible customers in previous years. The results of top efficiency measures were shared and discussed with ETO; Through these discussions, the ETO will offer EE programs to interruptible customers starting in March of 2023. Measures such as shell measures, equipment upgrades, strategic energy management, and custom projects[6] are available. The Company will continue to work with interested parties to determine appropriate EE programs for transport customers with an estimated start date mid-2023. Interruptible and transport customers' energy savings potential is shown in Table 3.7, 3.8, and 3.9 below.

Table 3.7: Summary of Oregon Interruptible Industrial Energy Efficiency Potential

Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	1,509,283	1,507,701	1,503,695	1,499,146	1,494,147
Cumulative Savings (Dth)					
Achievable Economic	7,690	20,982	63,008	141,741	252,992
Achievable Technical	8,252	22,265	66,441	148,323	262,025
Technical Potential	12,571	31,598	89,499	189,969	322,829
Energy Savings (% of Baseline)					
Achievable Economic	0.5%	1.4%	4.2%	9.5%	16.9%
Achievable Technical	0.5%	1.5%	4.4%	9.9%	17.5%
Technical Potential	0.8%	2.1%	6.0%	12.7%	21.6%

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

Table 3.8: Summary of Oregon Interruptible Commercial Energy Efficiency Potential

Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	389,600	386,846	380,130	373,268	367,372
Cumulative Savings (Dth)					
Achievable Economic	904	2,441	8,398	23,243	47,598
Achievable Technical	1,336	3,499	11,632	30,283	58,455
Technical Potential	5,998	12,666	32,618	66,549	103,852
Energy Savings (% of Baseline)					
Achievable Economic	0.2%	0.6%	2.2%	6.2%	13.0%
Achievable Technical	0.3%	0.9%	3.1%	8.1%	15.9%
Technical Potential	1.5%	3.3%	8.6%	17.8%	28.3%

Table 3.9: Summary of Oregon Transport Industrial Energy Efficiency Potential

Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	2,782,962	2,782,624	2,781,477	2,779,303	2,775,037
Cumulative Savings (Dth)					
Achievable Economic	9,534	28,080	84,925	184,338	361,139
Achievable Technical	9,531	28,086	84,876	183,737	359,563
Technical Potential	12,498	35,485	105,602	225,654	436,548
Energy Savings (% of Baseline)					
Achievable Economic	0.3%	1.0%	3.1%	6.6%	13.0%
Achievable Technical	0.3%	1.0%	3.1%	6.6%	13.0%
Technical Potential	0.4%	1.3%	3.8%	8.1%	15.7%

As implementor of EE programs for the Company's residential, small, and large commercial customers. ETO provides a full suite of energy efficiency measures[7] . 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[8]. Table 3.10 below shows potential results over a 20-year horizon.

[7] https://www.energytrust.org/

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

Table 3.10: 20-Year Cumulative Savings Potential by Type (Millions of Therms)

	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Energy Trust Deployed Savings Projection
Residential	20.3	16.2	15.9	9.9
Commercial	6.9	5.8	5.5	3.8
Industrial	0.4	0.3	0.3	0.3
Exogenous[9]	-	-	-	1.4
Total	**27.6**	**22.3**	**21.6**	**15.3**

Additionally, in 2023 Avista will meet with ETO, and other utilities to explore a hybrid heating pilot with planning beginning during the second quarter. The company will also explore during 2023 whether to implement in 2024 a targeted EE distribution project in the natural gas system which is discussed further in Chapter 8 of the IRP.

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.

While Avista has historical electric DR experience, NGDR programs have not been reviewed prior to this IRP. Avista retained AEG to perform the first NGDR potential assessment study for Avista's Oregon, Washington, and Idaho service territories.

Demand Response Potential Assessment Study

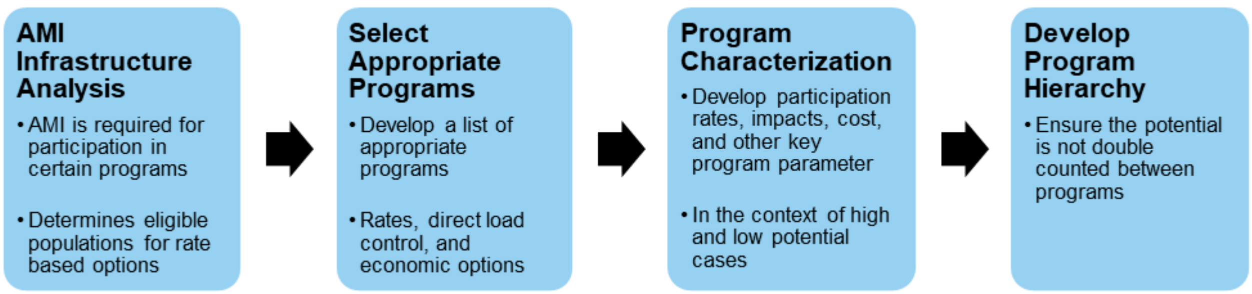
AEG's study estimates the potential magnitude, timing, and cost of a variety of NGDR programs likely available to Avista during winter peak loads over the 23-year planning horizon (2023-2045). These estimates are then modeled in the IRP to determine the value and cost effectiveness of each program on Avista's system.

Figure 3.1 outlines AEG's approach to determine potential DR programs in Avista's service territories. All NGDR pricing programs and behavioral programs included in this study require Advanced Metering Infrastructure (AMI) as an enabling technology. Currently Washington is the only state in Avista's service territory with AMI.

[9] The final deployed savings projection includes savings calculated outside of the modeling process consisting of the large project adder and unclaimed market savings.

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 provided 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 3.3: Program Characterization Process



This process identified the five NGDR program options shown in Table 3.11. The different types of NGDR programs include two broad classifications: curtailable/controllable NGDR and rate design programs. Except for the behavioral program, curtailable/controllable NGDR programs represent firm, dispatchable and reliable resources to meet peak-period loads. Rate design options offer non-firm load reductions that might not be available when needed but create a reliable pattern of potential load reduction. Pricing options include time-of-use and variable peak pricing. Each option requires a new rate tariff for each state in Avista's service territories.

Table 3.11: 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	
Rates	Time-of-Use Opt-in*	X	X	X
	Variable Peak Pricing Rates*	X	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 3.9 and 3.10.

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 3.9 and 3.10.

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 behavioral reporting 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 3.9 and 3.10.

Time of Use Rates (Opt-In)

A Time of Use (TOU) rate is a time-varying rate. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with an incentive to shed or shift consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not an NGDR option, per se, but rather a permanent load shedding or shifting opportunity. Large price differentials are generally more effective than smaller differentials for TOU programs. This study assumes an opt-in rate, where participants voluntarily enroll in the rate program. Customer participation rate assumptions along with program costs and potential are detailed in Tables 3.9 and 3.10.

Variable Peak Pricing

The Variable Peak Pricing (VPP) amount changes daily to reflect system conditions and costs for peak hours. Under a variable peak pricing program, on-peak prices for each weekday are made available the previous day. Through a VPP program customers are billed for their actual consumption during the billing cycle at these prices. Over time, establishment of event-trigger criteria enables customers to anticipate events based on extreme weather or other factors. System contingencies and emergency needs are good candidates for VPP events. VPP program participants are required to be enrolled in a TOU rate option. Customer participation rate assumptions along with program costs and potential are detailed in Tables 3.9 and 3.10.

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 "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 3.12 shows the steady-state participation rate assumptions for each NGDR program option. Eligible customers for each customer class are calculated based on market characterization and equipment end use saturation. The values shown are considered maximum participation rates with a ramp rate of 5 years. AEG used derated electric participation rates for natural gas DR programs rather than a direct comparison to the pilot programs described above.

Table 3.12: NGDR Program Steady-State Participation Rates (Percentage of Eligible Customers)

DR Program	Residential	Commercial	Industrial
Smart Thermostats DLC Heating	9%	9%	-
Third Party Contracts	-	5%	13%
Behavioral*	12%	12%	-
Time-of-Use*	8%	8%	8%
Variable Peak Pricing*	15%	15%	15%

*Requires AMI and only available in WA State

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 for each program independently and on a standalone basis.

If Avista offers more than one program, the potential for double counting exists. To address this possibility, a participation hierarchy was assumed and defines the order customers take the programs for an integrated approach. These savings and costs results were then used in Avista's modeling. Additional detail on NGDR resource assumptions can be found in AEG's Natural Gas CPA report, Appendix 3.

The estimated savings for reach program and its levelized costs are shown in Table 3.13. The cost of the programs within these tables represents the on-going operations and capital cost required to start and maintain these programs. The capital costs are amortized and recovered over a 10-year period. These tables include the estimated potential dekatherm savings for 2030 and 2045 for illustrative purposes of program potential. These estimates are the expected amount of demand reduction and net savings from all program participants.

Table 3.13: System Program Cost and Potential

Program	Costs $/Dth year	Winter (Dth) Potential	
		2030	2045
Smart Thermostats DLC Heating	$5,756	3,336.53	4,000.84
Third Party Contracts	$135,937	25.38	29.71
Behavioral*	$11,849	304.66	364.53
Time-of-Use*	$18,883	232.21	280.69
Variable Peak Pricing*	$4,474	1,192.69	1,440.26
Total Potential		**5,091.47**	**6,116.02**

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 does not include fuel switching in the demand forecast, but rather includes specific fuel use electrification 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 toward the product being produced. Avista does not have many industrial customers in its territories, with the overall system use of industrial customer around one percent 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 concern is 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. This will be further discussed in Chapter 7.

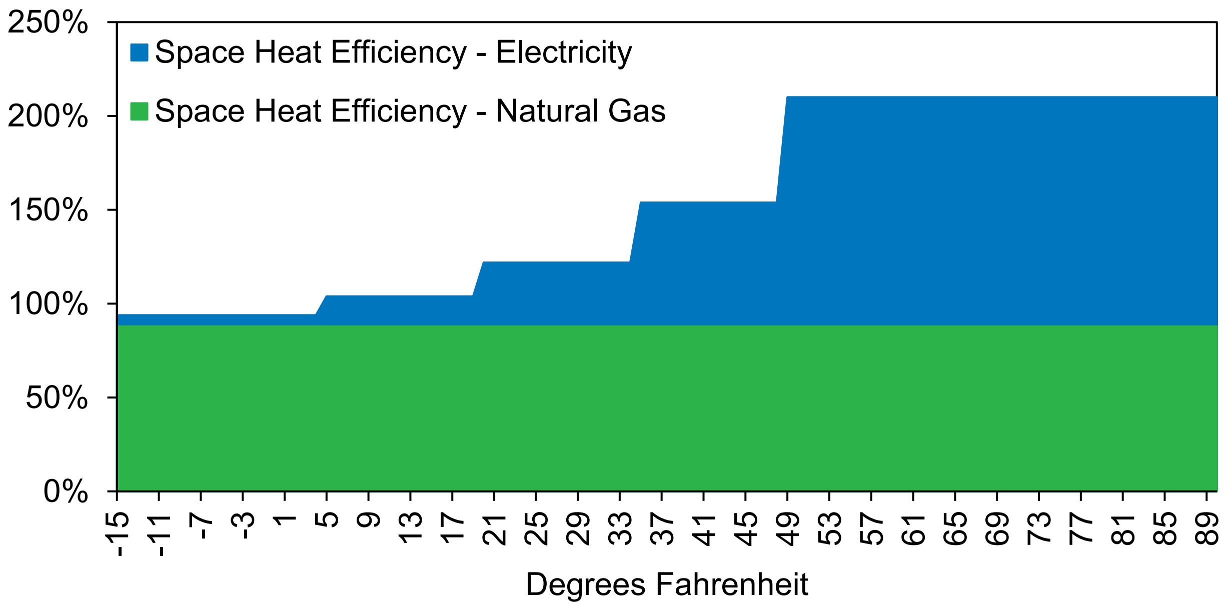
To begin the analysis the customer type, class and major end use must be separated. Residential and Commercial customers electrification choices are broken into three separate categories.

- 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 is 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. Efficiency estimates are illustrated in Figure 3.4 and indicate expected electric space heating efficiency is higher than natural gas space heat efficiency. Implications of these efficiencies will come into focus when paired with weather regions, expected energy costs, and conversion costs.

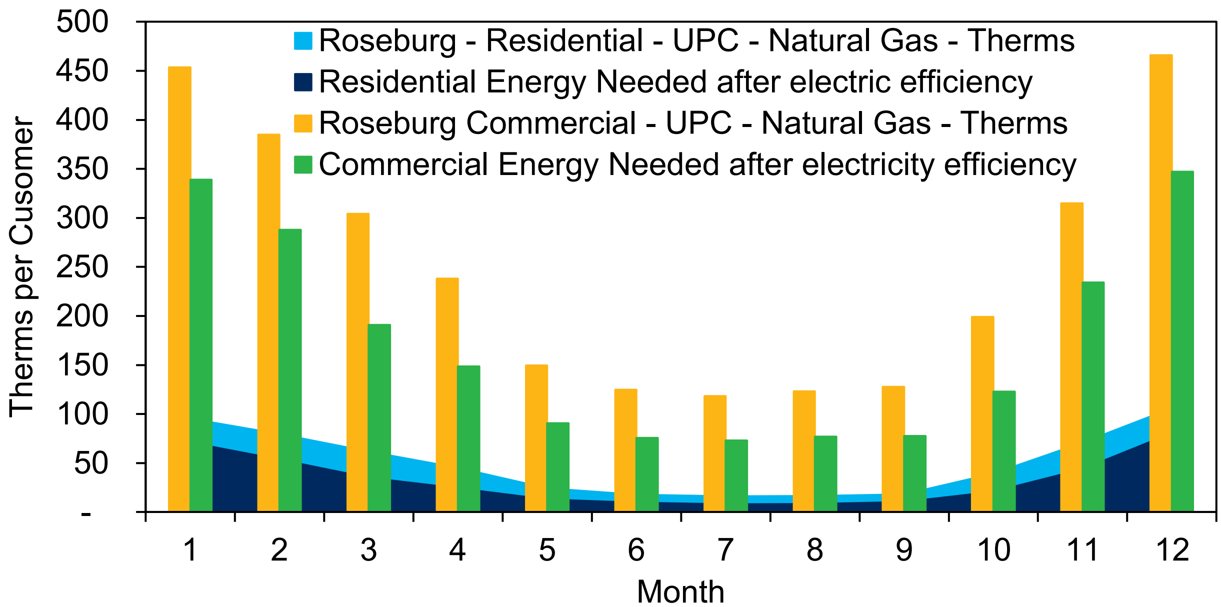
Figure 3.4: Space Heat Efficiency by Degrees Fahrenheit and Fuel



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 2. 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 3.5, the bars indicate before and after efficiencies in Roseburg, Oregon in 2023 per Commercial customer while the area chart illustrates before and after efficiencies per Residential customer. These totals include the average customer monthly demand and all end uses to illustrate the energy needed on the electric grid versus the natural gas system.

Figure 3.5: Energy Conversion Efficiency therms to kWh Roseburg, Oregon



Conversion Costs

Conversion costs can vary widely by study, location, building size, and structure. Avista used a study by Home Innovation Research Labs[10] to understand estimated costs by area to help address these ranges. Although the study provides an estimate by major area, no areas were in the Avista natural gas service territory. To help account for these wide-ranging study estimates, Avista considered the generic cost "total to a remodeler". The low-cost conversion is 50% of this estimated remodel cost and the high cost of

[10] Cost and Other Implications of Electrification Policies on Residential Construction, February 2021

conversion is 150%. This cost information from this study is illustrated in Figure 3.6 along with the specific efficiency considerations.

Incentives and grants are estimated based on known programs such as the Inflation Reduction Act which is discussed further in Chapter 5. These costs are treated as being removed from the overall conversion cost. Also, these conversion costs are estimated to be recovered over a 5- 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 is removed from the total before the monthly payment is estimated.

Figure 3.6: Estimated Conversion Costs

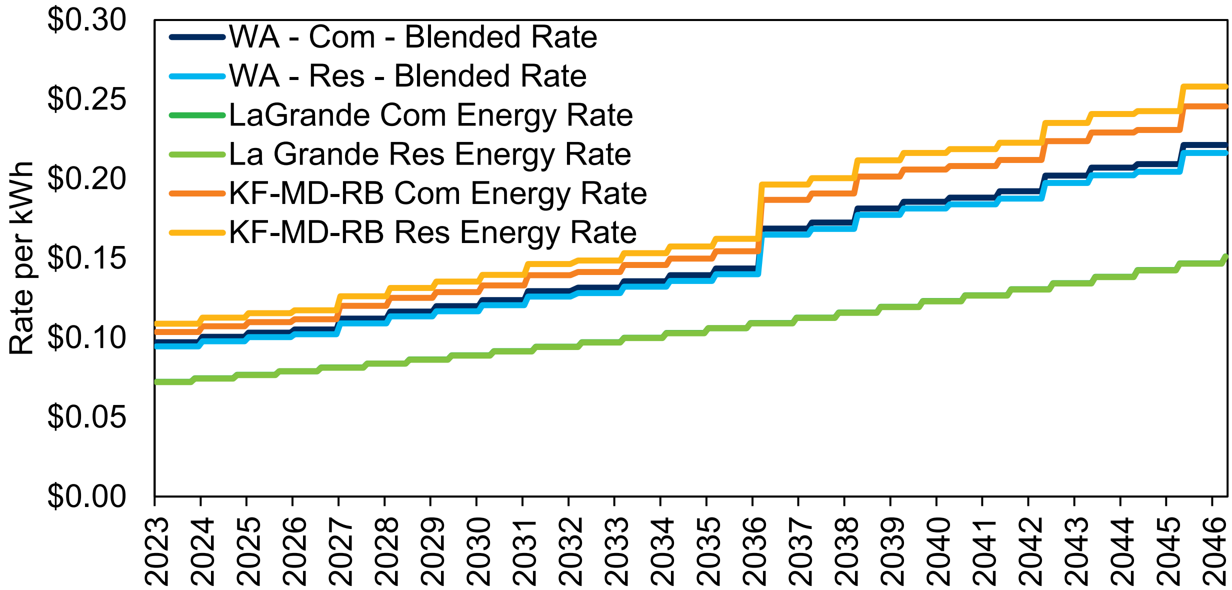
**Retrofit Cost of Gas Equipment and Appliances for an Existing Gas Baseline House:
96 AFUE GF; 16 SEER AC; Tankless Condensing 0.93 UEF WH**

Component	Unit	Material	Labor	Total	w/O&P	Quantity	Cost
Demo and Install GF, labor	EA				377.00	1	377
Demo and Install AC system, labor	EA				943.00	1	943
Demo and Install WH, labor	EA				499.00	1	499
Reclaim old refrigerant	LB		8.40	8.40	13.75	5	69
Install new Refrigerant piping	EA	204.00	21.50	225.50	261.00	1	261
GF materials, est.	EA	200.00		200.00	220.00	1	220
AC materials, est.	EA	200.00		200.00	220.00	1	220
WH materials, est.	EA	100.00		100.00	110.00	1	110
96 AFUE GF	EA	1,295.00		1,295.00	1,424.50	1	1,425
GF Vent piping, PVC, 2" dia.	LF	3.45	2.97	6.42	8.65	40	346
GF 2" concentric vent kit	EA	59.95		59.95	65.95	1	66
16 SEER AC	EA	1,346.00		1,346.00	1,480.60	1	1,481
Coil	EA	439.00		439.00	482.90	1	483
Tankless condensing 0.93 UEF WH	EA	1,039.00		1,039.00	1,142.90	1	1,143
WH Vent piping, PVC, 2" dia.	LF	3.45	2.97	6.42	8.65	20	173
WH 2" PVC concentric vent kit	EA	22.49		22.49	24.74	1	25
WH Gas piping, 1"	LF	7.80	6.15	13.95	18.60	7	130
WH 15-amp circuit, toggle, 40' #14/2 NM	EA	57.00	83.50	140.50	199.00	1	199
WH GFCI 15-amp, 1-pole breaker	EA	41.99		41.99	46.19	1	46
Remove and install range, labor	EA				138.00	1	138
Remove and install dyer, labor	EA				297.90	1	298
Gas Range	EA	542.00		542.00	596.20	1	596
Gas Dryer	EA	528.00		528.00	580.80	1	581
Total to Remodeler							**9,828**
Total to Consumer							**12,786**
Houston						0.99	**12,658**
Baltimore						1.02	**13,041**
Denver						1.05	**13,425**
Minneapolis						1.00	**12,786**

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 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. This 3% estimate is broken out as 2% inflation and 1% for new transmission and distribution projects. The Washington territory estimates include 75% of natural gas customers moving to Avista for their electricity needs and 25% lost to other public power providers such as Inland Power & Light. The assumed escalation curves for energy per kWh are included in Figure 3.7. Base costs are not included as it is assumed a gas customer is currently using the local electric provider.

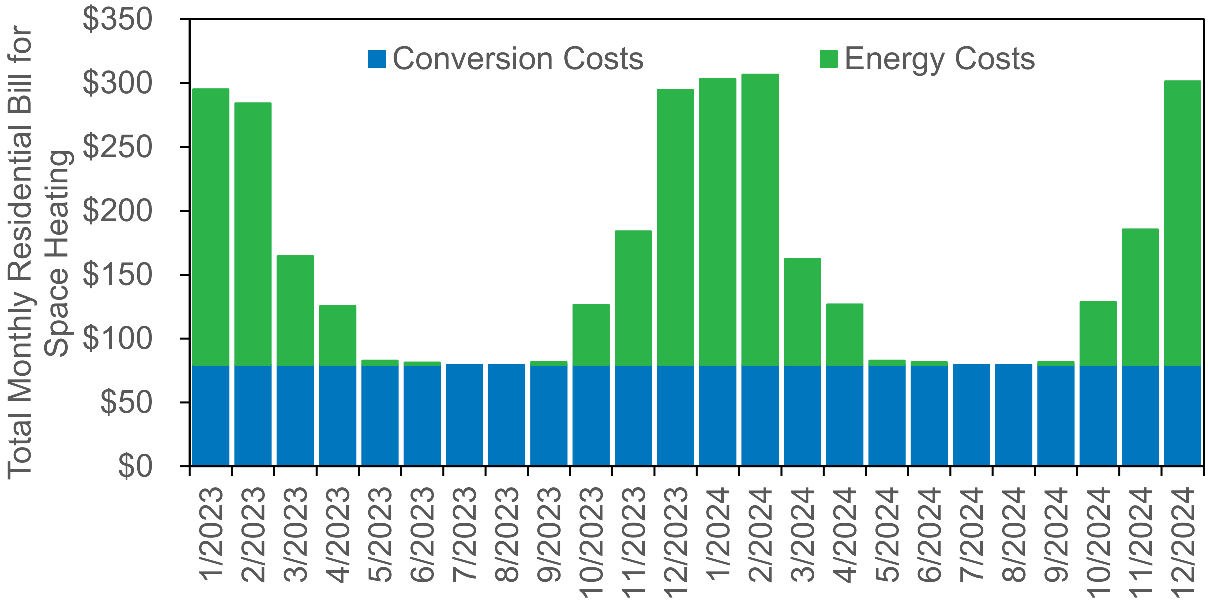
Figure 3.7: Electric Rate Assumption by Area by Class



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 3.8. 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 3.8: Conversion Costs and Energy Costs for Space Heat Washington Residential



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 (Figure 3.9 to 3.12) illustrate the final costs used in the model by end use and class.

Figure 3.9: Space Heat Levelized Costs by Area for Residential Electrification

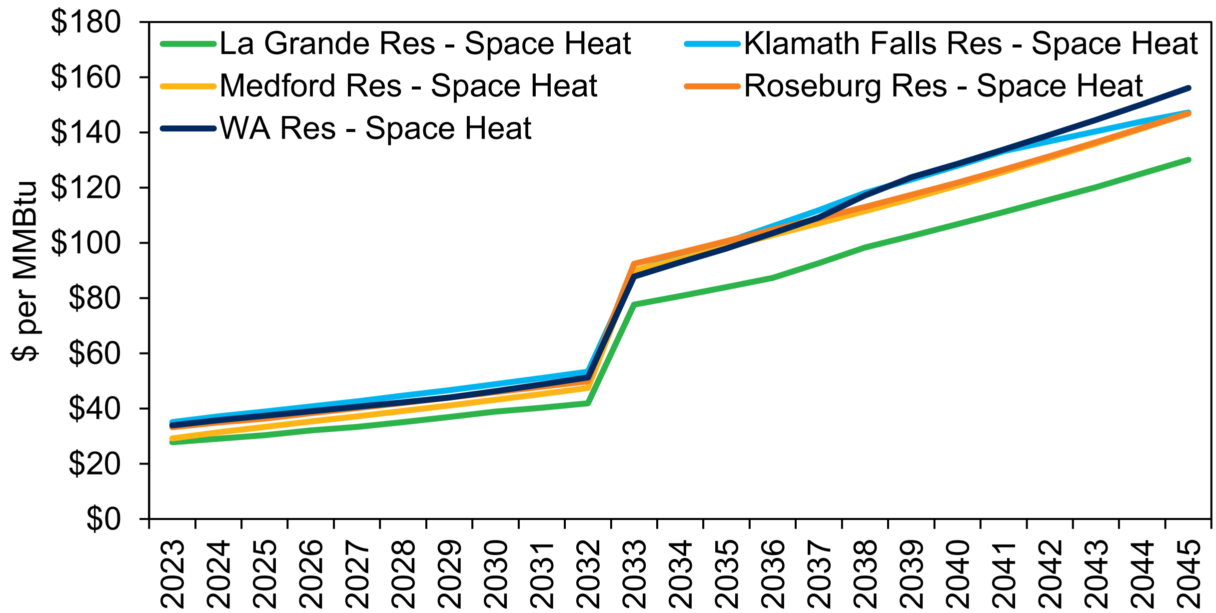


Figure 3.10: Water Heat Levelized Costs by Area for Residential Electrification

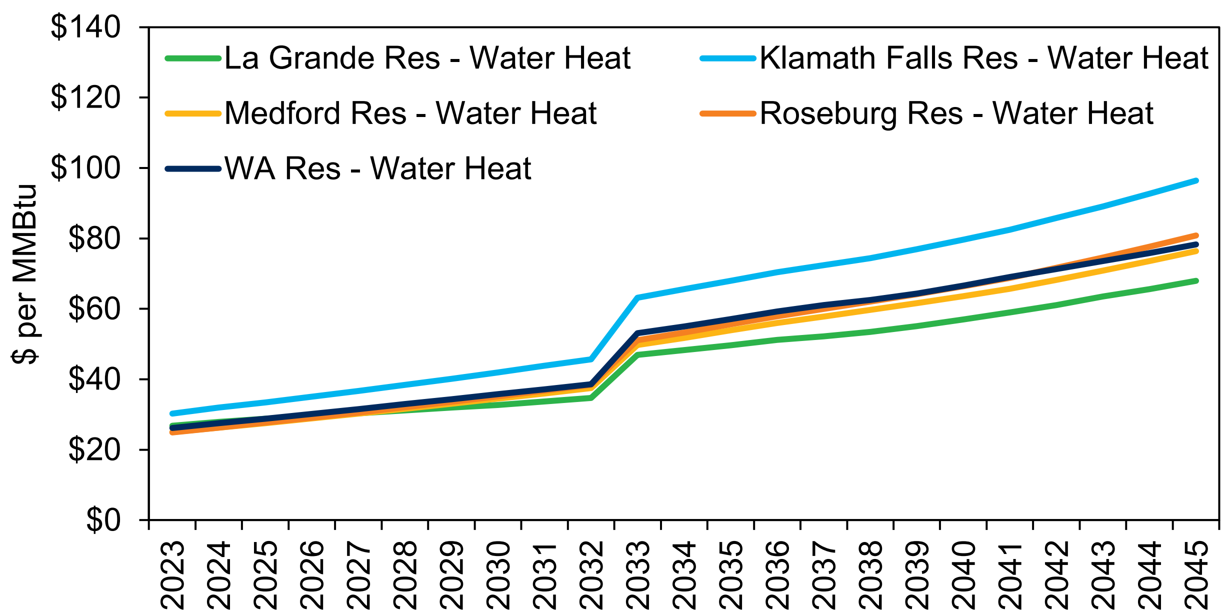


Figure 3.11: Space Heat Levelized Costs by Area for Commercial Electrification

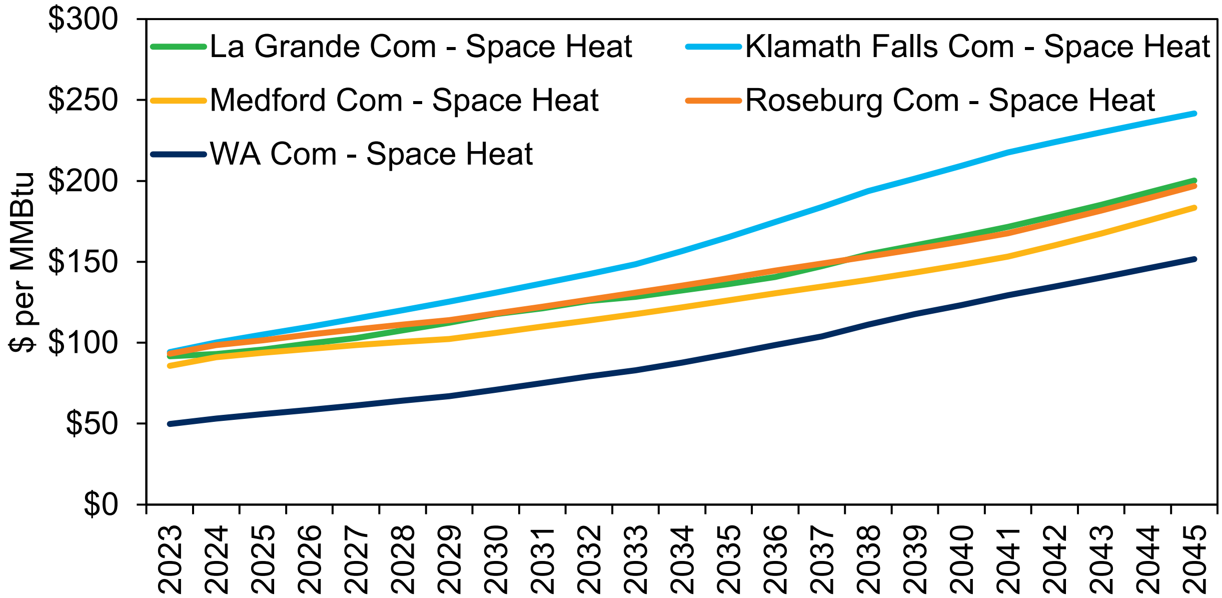
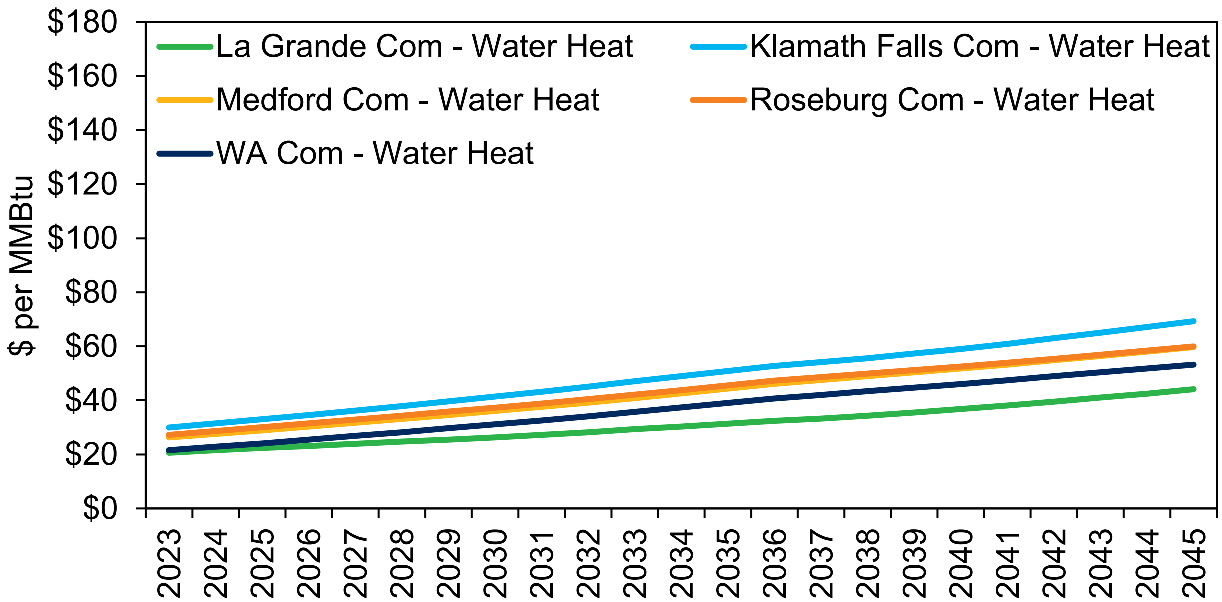


Figure 3.12: Water Heat Levelized Costs by Area for Commercial Electrification



This Page Is Intentionally Left Blank

4. Current Resources and New Resource Options

This chapter discusses fuel supply options to meet future net energy demand. Avista's objective is to provide reliable natural gas service at reasonable prices. To help achieve this objective, Avista evaluates a variety of supply-side resources and attempts to build a diversified natural gas supply portfolio. The resource acquisition and commodity procurement programs resulting from the evaluation of physical and financial risks, market-related risks, and procurement execution risks; and identifies methods to mitigate these risks.

Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve core customers. Supply options include firm and non-firm supplies, firm, and interruptible transportation on six interstate pipelines, and storage. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these resources varies depending on demand and operating conditions. This chapter discusses the available regional commodity resources and Avista's procurement plan strategies, the regional pipeline resource options available to deliver the commodity to customers, and the storage resource options available to provide additional supply diversity, enhanced reliability, favorable price opportunities, and flexibility to meet a varied demand profile. Carbon reducing supplies, such as renewable natural gas (RNG) and hydrogen (H_2) are also considered.

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 areas of the Northeast and Southern United States. This supply is serving an increasing amount of demand in the population heavy areas in the middle and eastern portions of Canada and the U.S displacing supplies previously delivered from the Western Canadian Sedimentary Basis (WCSB).

Current forecasts show a long-term regional price advantage for Western Canada and Rockies natural gas basins as the need for this gas diminishes. High 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 demand addition to North American supply. The Canadian project is known as LNG Canada and is in Kitimat B.C. This facility is one of the largest investments in Canadian history and is currently under construction. Its initial capacity is, roughly 1 Bcf per day, but contains an option for up to 3.5 Bcf per day in total. Additionally, WoodFibre LNG located in Squamish, BC will come online in 2027 removing potentially 0.3 Bcf from supply to the Pacific Northwest. The large increase of natural gas demand by either of these facilities moving forward could cause pressure on commodity prices with the limited infrastructure in the Pacific Northwest. An LNG facility in Oregon known as Jordan Cove was approved by FERC, however, was officially abandoned in December 2021 due to the continued uncertainties around state environmental permits.

Exports to Mexico continue to impact US natural gas demand forecasts. In 2013, Mexico reformed its energy sector allowing new market participants, innovative technologies, and foreign investment. This market reformation opened new opportunities for natural gas export to Mexico. Since these market changes, Mexican imports which were historically less than 2 Bcf per day have more than doubled to over 5.5 Bcf per day on average.

Regional Market Hubs

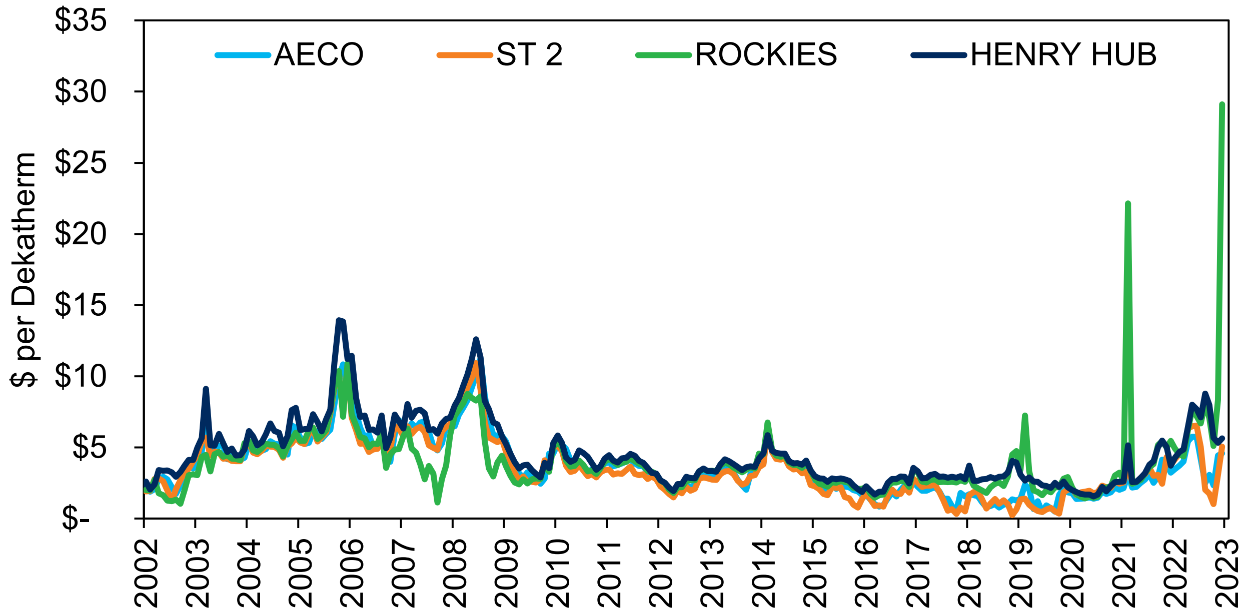
There are numerous regional market hubs in the Pacific Northwest where natural gas is traded extending from the two primary basins. These regional hubs are typically located at pipeline interconnects. Avista is located near, and transacts at, most of the Pacific Northwest regional market hubs, enabling 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 percent 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 NYMEX futures contracts.

Figure 4.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Station 2, Rockies, and Henry Hub. The figure has changed in recent years due to an alteration in flows of natural gas specifically coming from Western Canada.

Figure 4.1: Monthly 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 illiquidity contributes to generally higher relative 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 the supply can be cut for reasons other than force majeure conditions.
- **Fixed versus Floating Pricing:** The agreed-upon price for the delivered gas may be fixed or based on a daily or monthly index.

- **Physical versus Financial:** Certain counterparties, such as 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 price.
- **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.

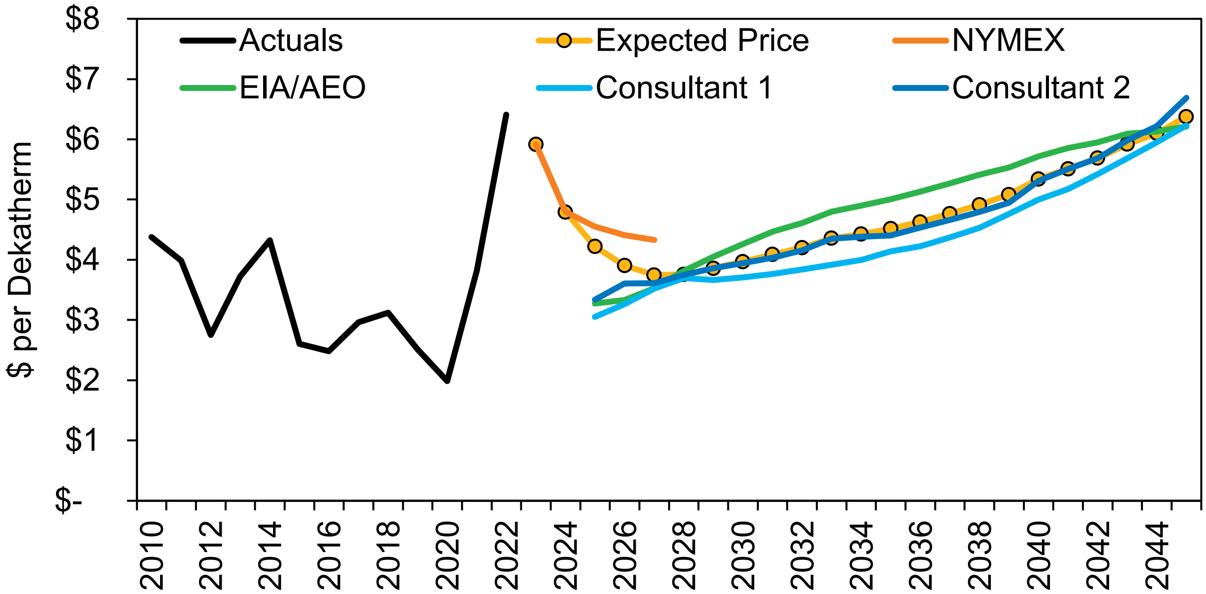
Natural Gas Price Forecasts

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 LNG, and policies towards the continued use of natural gas. 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 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 does 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 4.2 depicts the annual average prices of these combined forecasts in nominal dollars and includes the expected price resulting from a blending technique.

Figure 4.2: Henry Hub Forecasted Price (Nominal $/Dekatherm)



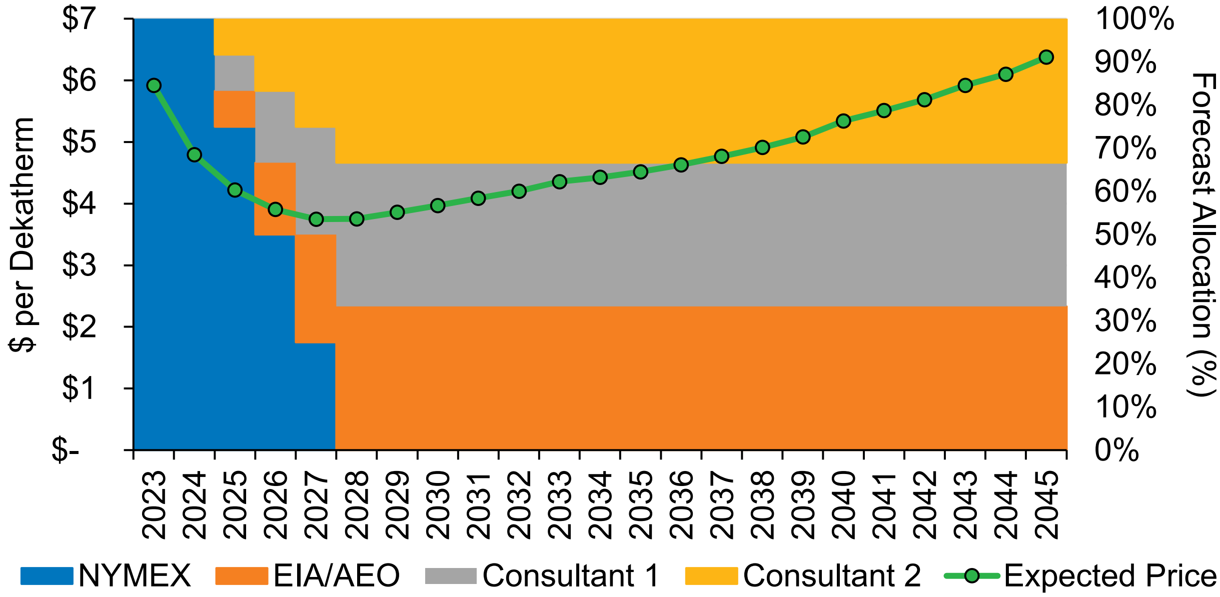
Expected prices at Henry Hub were derived through a blend of forecasts from four sources, including the New York Mercantile Exchange (NYMEX) forward strip on July 26, 2022, the Energy Information Administration's (EIA) 2022 Annual Energy Outlook (AEO), and two reputable market consultants. Combining multiple forecasts improves the accuracy of our model based on the aggregate market knows more than any single entity or model.

The weightings applied to each source vary throughout the twenty-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 two years. From 2025 through 2027, market activity and speculation on the NYMEX deteriorate significantly, so forecasts from the other three sources, proportionally, are applied incrementally more weighting. By the year 2028, and through the end of our forecasting horizon, the expected price is the result of an equally weighted blend of forecasts from the EIA's AEO and our two market consultants. The specific weightings applied are described in Table 4.1 and the resulting annual average expected price at Henry Hub is depicted in Figure 4.3 below.

Table 4.1 : Price Blend Methodology

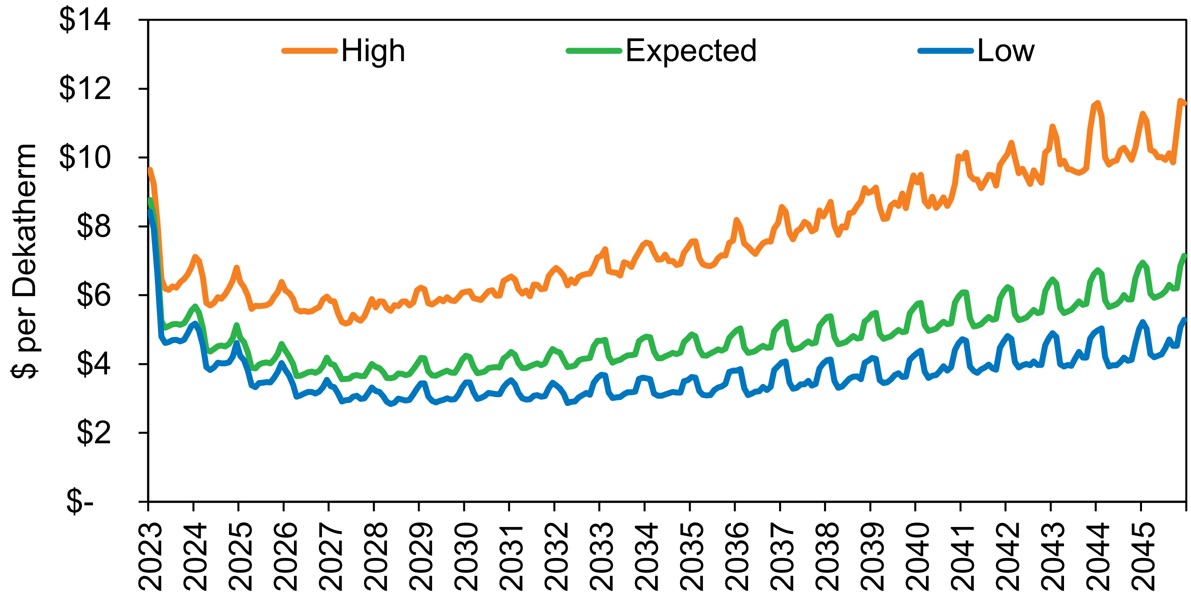
Years	Price Blend Methodology
2023 & 2024	forward price only
2025	75% forward price / 25% average consultant forecasts
2026	50% forward price / 50% average consultant forecasts
2027	25% forward price / 75% average consultant forecasts
2028 - 2042	100% average consultant forecasts

Figure 4.3: 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 were modeled based on the expected price forecast. Each future contains unique monthly price movements throughout the twenty-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 4.4.

Figure 4.4: Henry Hub Forecasts for IRP Low/ Expected/ High Forecasted Price



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 a large portion of 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 the 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 twenty-year horizon.

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 4.5 below shows the resulting regional prices as compared to the Henry Hub and Figure 4.6 shows the resulting price distribution for AECO for the 500 future simulations

Figure 4.5: Regional Price as a compared to the Henry Hub Price

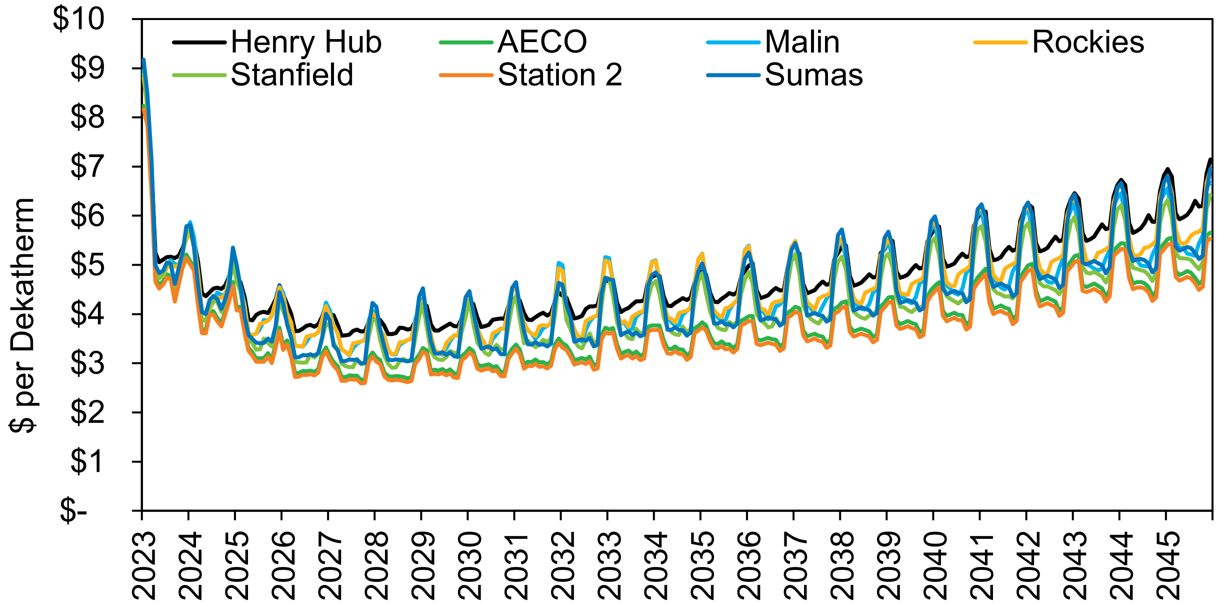
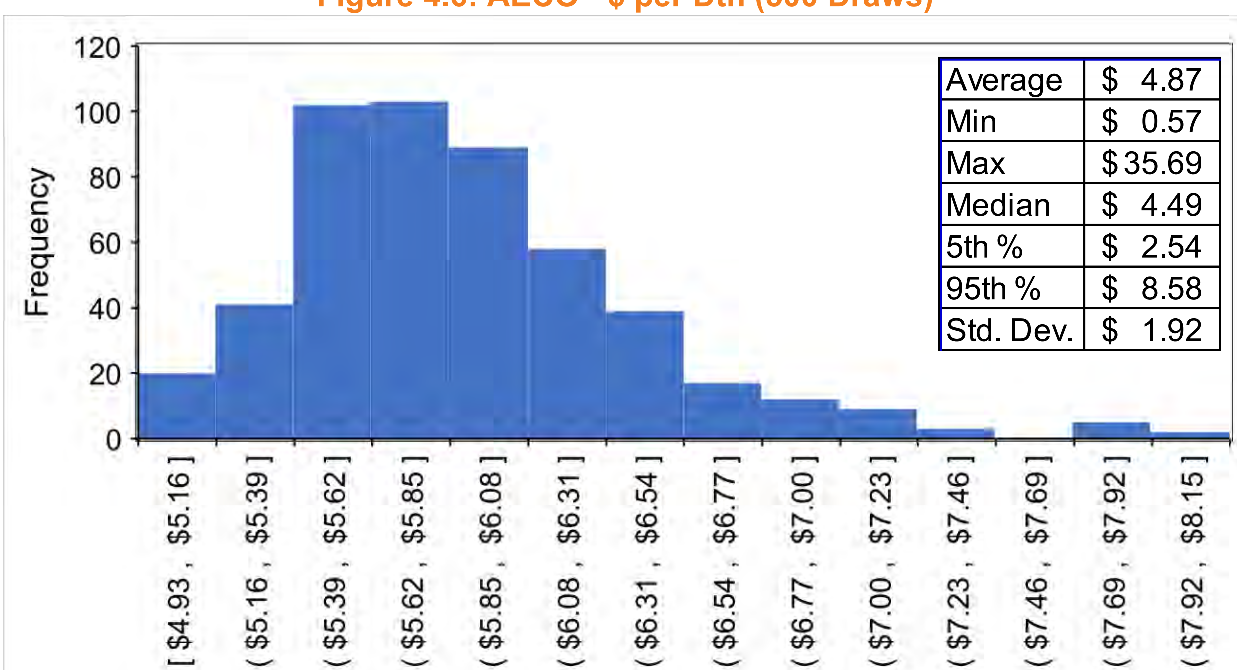


Figure 4.6: AECO - $ per Dth (500 Draws)



Average	$ 4.87
Min	$ 0.57
Max	$ 35.69
Median	$ 4.49
5th %	$ 2.54
95th %	$ 8.58
Std. Dev.	$ 1.92

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 4.7).

Figure 4.7: 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 Rocky Mountain region of the U.S.
- **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 (with the exception of Ruby Pipeline) for firm transportation to serve core customers. Table 4.2 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 customer's available capacity to meet existing core demand now and in the future.

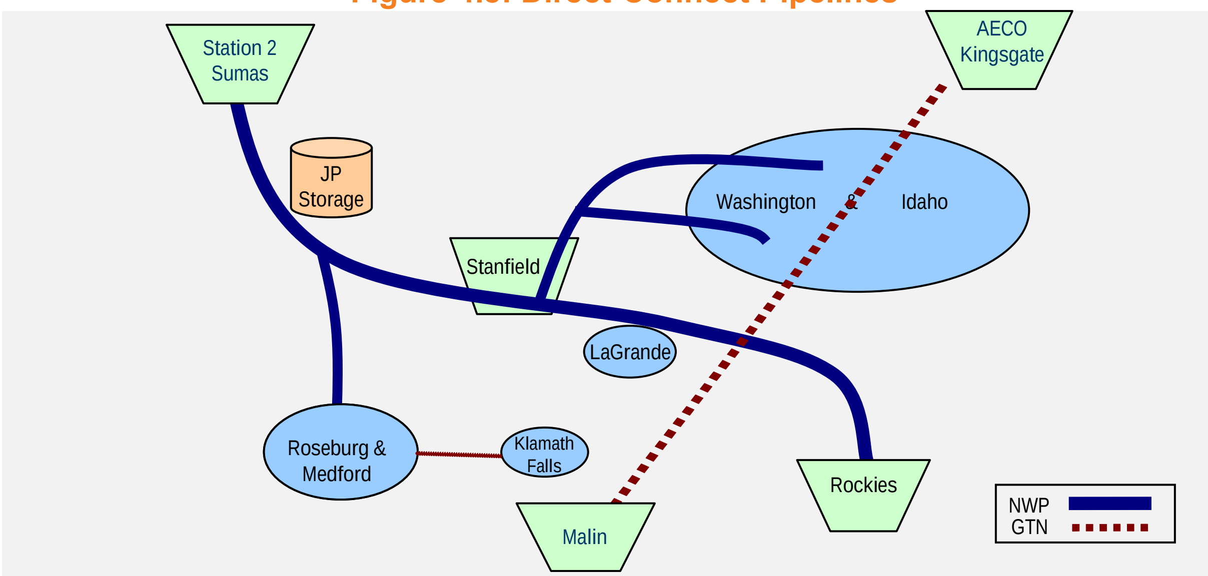
Table 4.2: Firm Transportation Resources Contracted (Dth/Day)

	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 4.8 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[1]

Figure 4.8: 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 to likely bear most of the incremental costs.

[1] 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.

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 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 Avista's service territories.

The rates used in the planning model start with filed rates currently in effect (See Appendix 4.1 – 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 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 transportation contracts. Avista does not rely on interruptible capacity to meet peak day core demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers on a peak day in the planning horizon. Since contracts for pipeline capacity are often lengthy and core 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 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 to meet 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's utilization and provide 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;
- 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 optimization of assets directly reduce customers monthly billing.

Jackson Prairie Storage (JP)

Avista is one-third owner, with Williams (NWP[2]) and Puget Sound Energy (PSE) of the Jackson Prairie Storage Project for the benefit of its core 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 core 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

[2] Northwest Pipe

Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

Incremental Supply-Side Resource Options

Avista's existing portfolio of supply-side resources provides a mix of assets to manage demand requirements for average and peak day events. Avista monitors the following potential resource options to meet future requirements in anticipation of changing demand requirements. When considering or selecting a transportation resource, the appropriate natural gas supply pairs with the transportation resource and the PLEXOS® model prices the resources accordingly.

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 Available 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-Owned Liquefaction LNG

Avista could construct 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. Due to the changing direction in policy and fossil fuels, Avista did not model this resource in the current IRP.

Alternative Fuel Supply Options

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 4.3.

Table 4.3: Carbon Intensity[4]

Source	Current Carbon Intensity (g CO2e/MJ)	Estimated Percent of Carbon reduction as compared to natural gas
Natural Gas	78.37	
Landfill	46.42	41%
Dairy	-276.24	-452%
Wastewater	19.34	75%
Solid Waste	-22.93	-129%

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 geographically as understanding exact location and instruments will be modeled in a detailed manner.

RNG projects are unique, so reliable cost estimates are difficult to obtain. However, Avista has released a Request For Proposal (RFP) for RNG resources in Q4 of 2022 and pricing will come into focus for environmental attributes or as a bundled product including both energy and the environmental attributes. 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 5.

[3] https://www.ipcc.ch/
[4] California Air Resources Board

RNG Program Considerations

As Avista prepares to move forward with RNG, 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 that can be utilized for a cleaner future by transitioning to cleaner fuel and keeping the pipeline infrastructure.

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 the through General Rate Case. Avista can also buy RNG from other RNG producers and pass the costs through the Gas Purchase Adjustment (GPA).

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.

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[5] and RIN[6] 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.

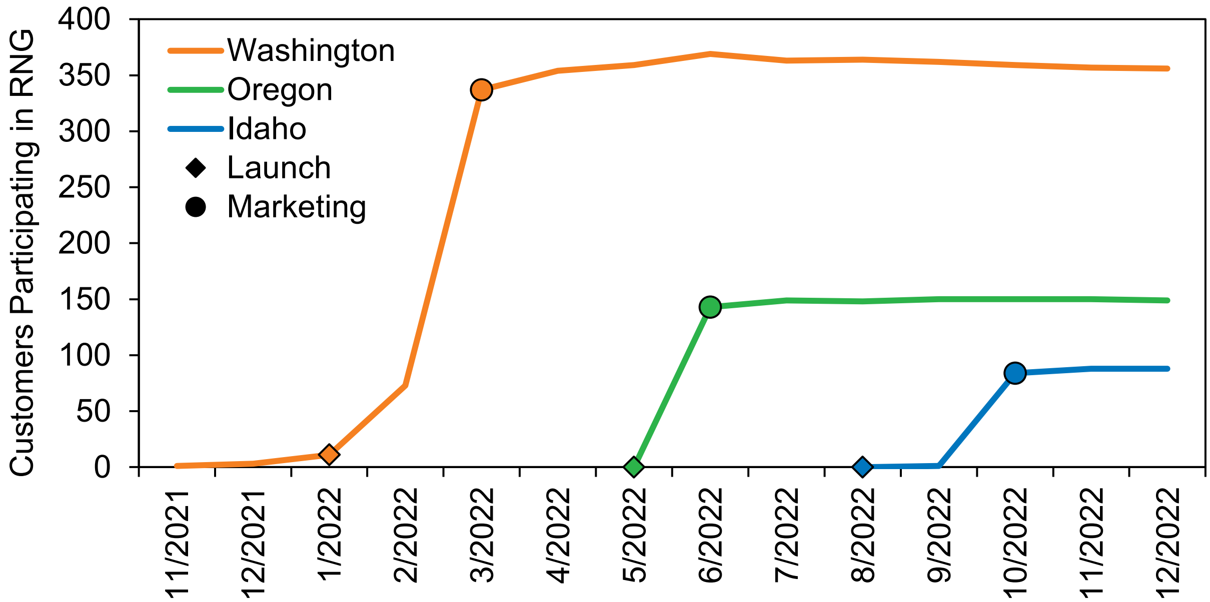
At Avista, the voluntary RNG program demands will likely have limited volume requirements and be short-term in nature. Since a short-term, low-volume off-take purchase scenario is unlikely to be attractive to producers typically seeking long-term off-take agreements, the expectation is higher RNG costs. 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

---

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

supply RNG under a longer-term purchase at a lower price. Figure 4.9 illustrates the number of participants by state in Avista's voluntary RNG program, as of November 2022

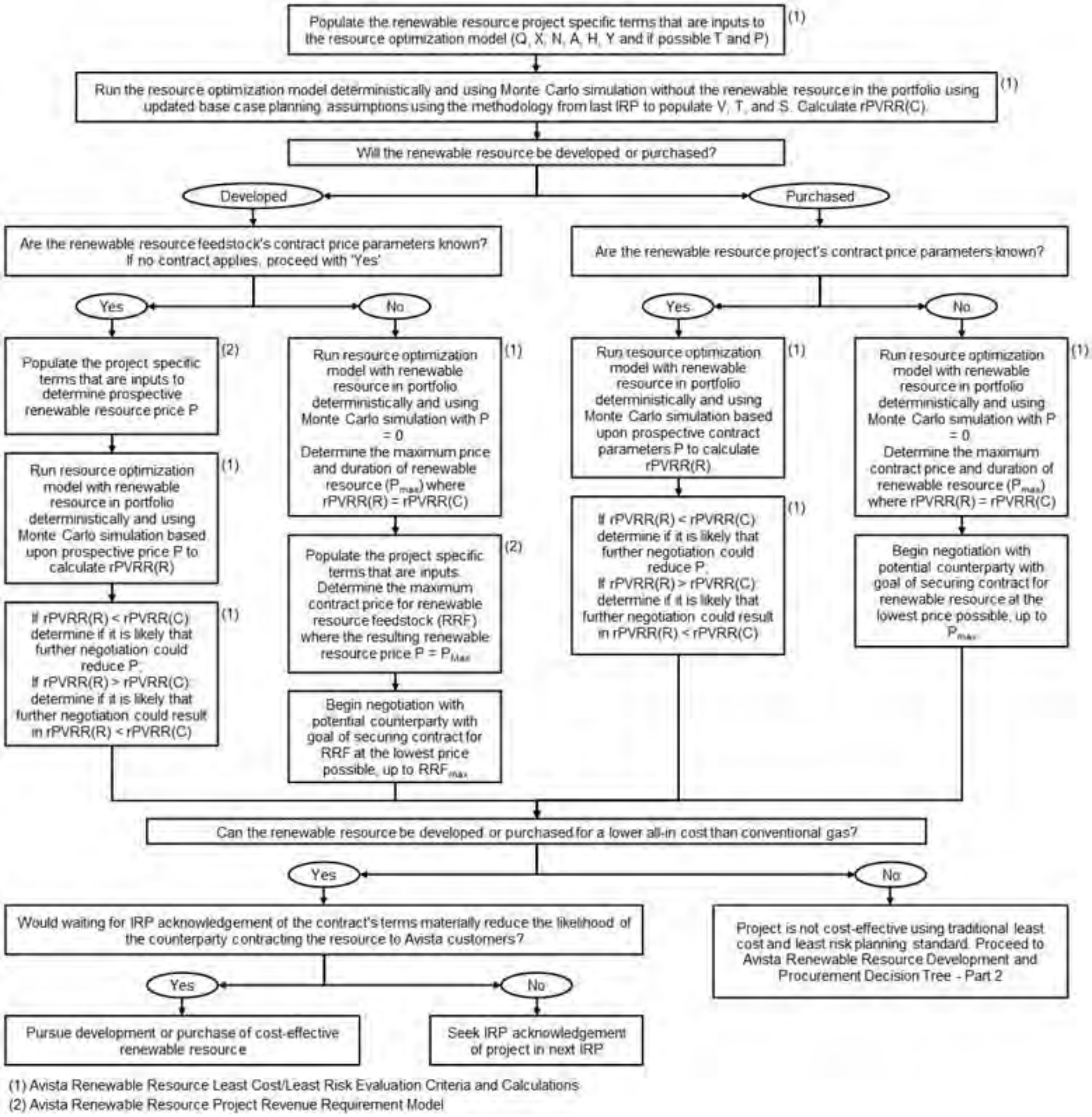
Figure 4.9: Participants by State



Cost Effective Evaluation Methodology

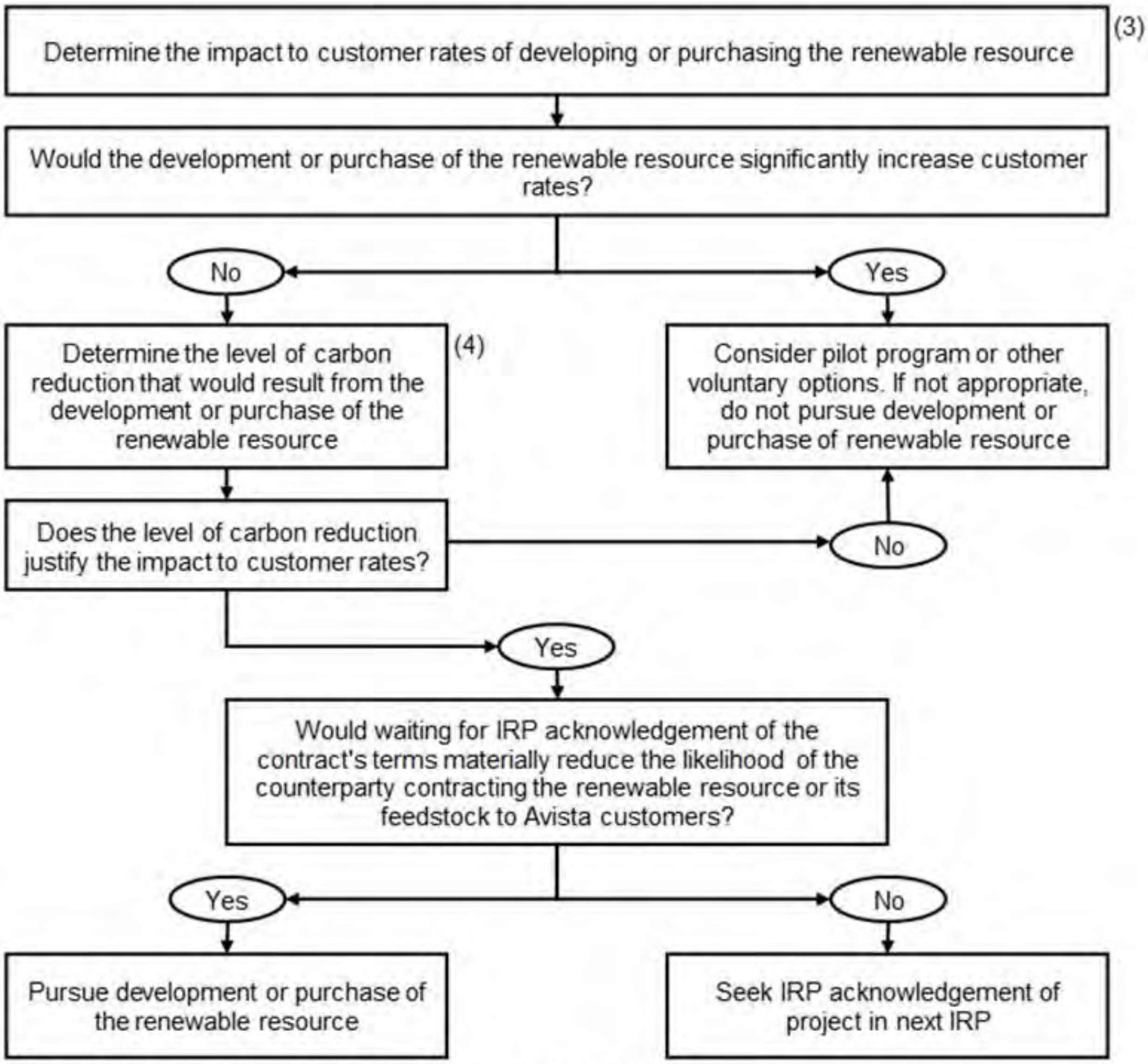
Avista's methodology utilizes costs for projects on a levelized basis as compared to other resources as found in the Plexos model for the IRP. Incorporating just the attribute of RNG requires a pairing with the energy such as brown gas or gas that has no associated environmental attribute. To date, the methodology shown is derived from OPUC Docket UM2030, also referenced in the OPUC Senate Bill 98 rulemaking as described in Chapter 5. The evaluation method shown herein is subject to input, refinement, and reconsideration (Figure 4.10 and Figure 4.11). In-depth descriptions of the calculations and components used in the Avista Renewable Resource Development and Procurement Decision Tree are in Appendix 5.

Figure 4.10: Avista RNG Development and Procurement Decision Tree – Part 1[7]



7 The Avista Renewable Resource Development and Procurement Decision Tree described above is a work in progress and is subject to change at any time.

Figure 4.11: Avista RNG Development and Procurement Decision Tree – Part 2



(3) Avista Renewable Resource Project Rate Impact Analysis
(4) Avista Renewable Resource Project Carbon Reduction Calculation

Environmental Attribute Tracking

Oregon Senate Bill 98 specifies M-RETS[8] 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)[9] 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 are based on the unknowns as it 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.

Developing a generic cost for RNG based on feedstock will require several assumptions as each specific RNG project will have its own capital development costs. 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.

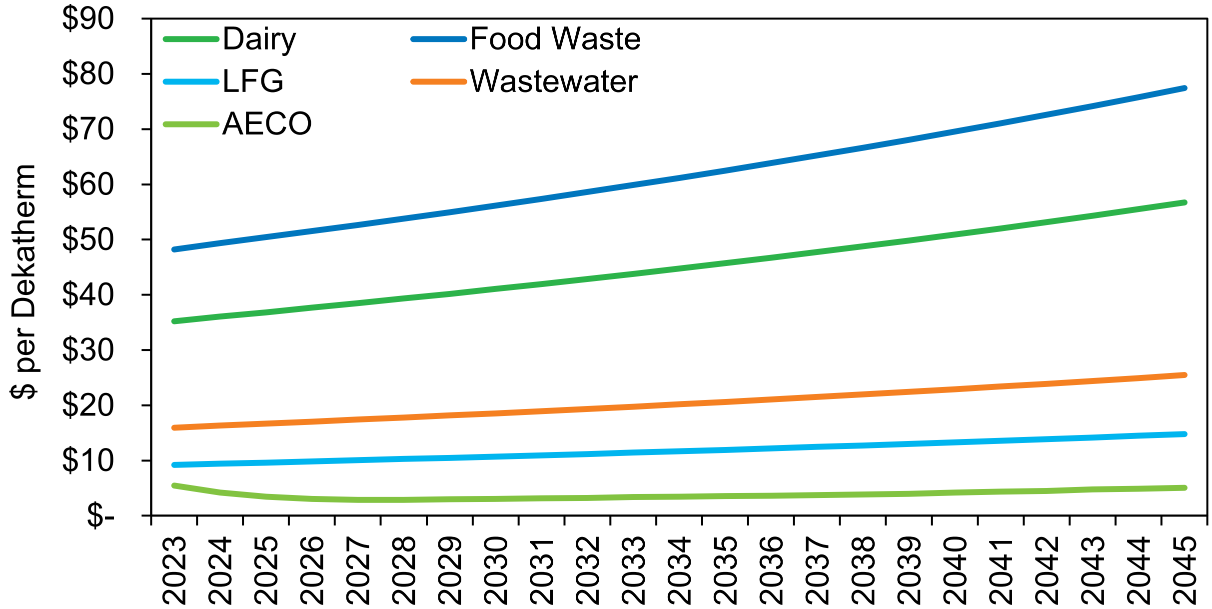
RNG costs can deviate greatly by source, location, and capital costs. These RNG costs are considered by research done for Avista by Black and Veach. This paper considers cost estimates for averages by RNG type and Hydrogen project size. RNG is considered an option at increments of twenty environmental attributes known as Renewable Thermal Credits in the PLEXOS model. To bridge the gap between ownership or purchasing from a producer, it was made available in the model to assume a quantity taken in a given year carries forward thru the end of the study. Price estimates are illustrated in Figure 4.12 and assume both the RTC and brown gas as a bundled price. It should be noted that RTCs can be purchased separately from the energy. The current RFP should help value RTCs compared with a bundled product.

---

8 https://www.mrets.org/

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

Figure 4.12: RNG Price by Source (nominal $)

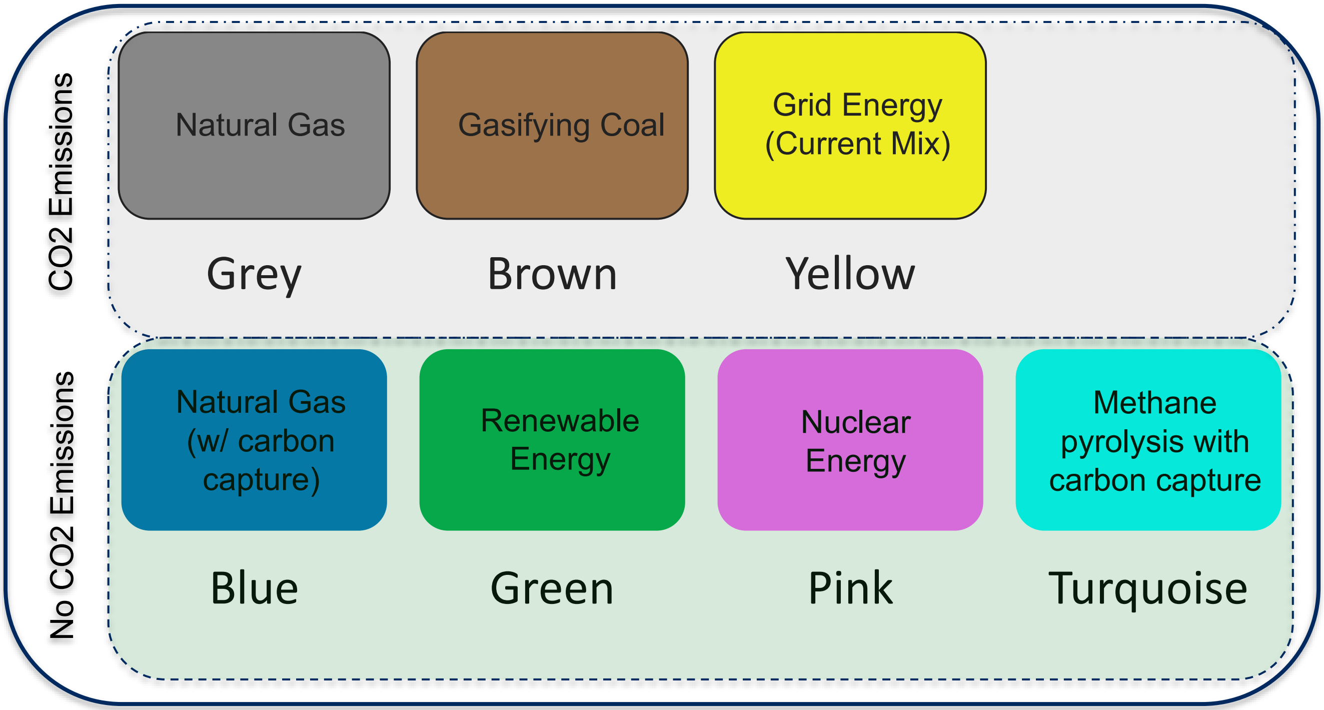


Hydrogen

Hydrogen (H_2) is a fuel source with a long history and a 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 renewables (green H_2). With expanding renewable electricity production, the ability to create green H_2 from this energy is moving from concept to market throughout the world. Some drawbacks to hydrogen include needing 3 times the volume to provide the same energy as natural gas. With a maximum blend rate in the pipelines assumed at 20%[10], the energy blend can reduce current pipeline capacity. 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 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 as shown in Figure 4.13. Further, implications for demand from highly intensive processes altering the availability of supply have not been studied at this time.

[10] 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

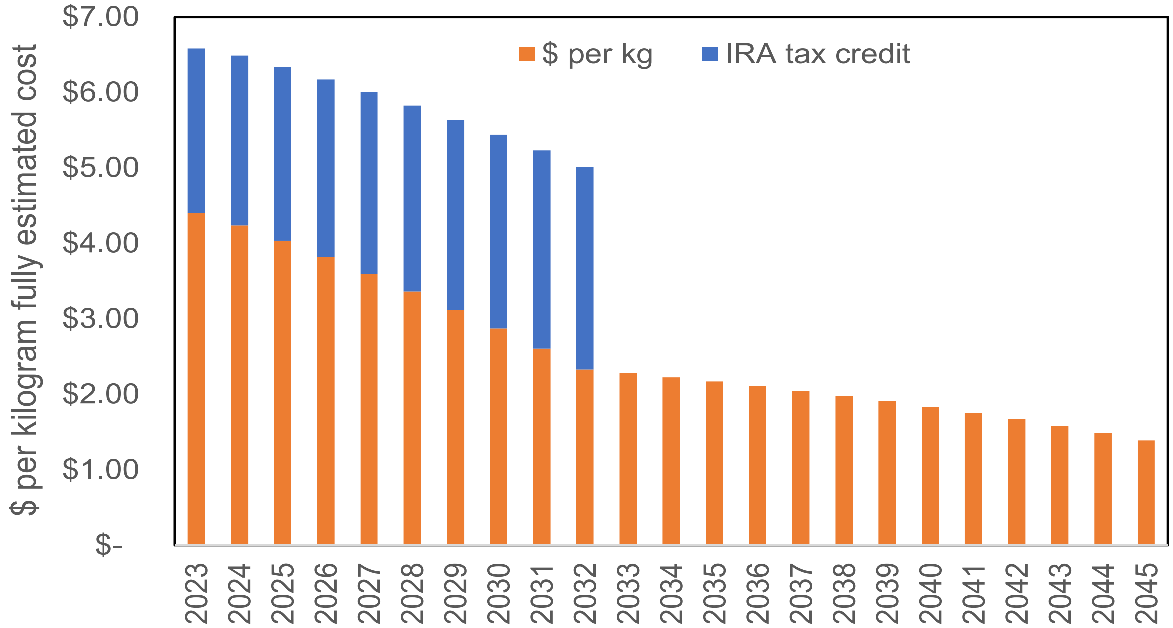
Figure 4.13: Production Types of Hydrogen:



The high cost of hydrogen has been the primary barrier to an accelerated use and adoption. Maturation of these technologies is assumed based on the federal policy known as Inflation Reduction Act (IRA) and other potential state and county policy. Cost estimates include a reduction from these renewable energy technologies as seen in wind and solar[11]. Incentives from the IRA are assumed in these costs at a full level of $3 per kg of green hydrogen. Further details of the IRA are discussed in Chapter 5. Several studies[12] were considered to value the cost of green hydrogen in the model as depicted in Figure 4.14. These costs are assumed to be located at or near load centers in Avista owned distribution.

[11] https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/
[12] Lazard, Black & Veatch, Bloomberg

Figure 4.14: Green Hydrogen Cost Estimates



Synthetic Methane

Synthetic methane is a fuel beginning to come into focus as an option for cleaner supply side resources. This fuel can be used in the current natural gas system infrastructure without any upgrades or alterations as it is, in essence, natural gas. The process would use a form of carbon capture either directly from the air or from waste and combines green hydrogen and reacted to create synthetic methane. The potential for new sources of grants, loans, or funds from programs such as the CCA, CPP or IRA should help drive the costs of these sources further down as seen in solar and wind projects over the past 30 years. The potential size of this resource is limited to the quantify of hydrogen available, a carbon source, and cost. Depending on if those elements are available, the economic synthetic methane has the potential to supply a 1:1 conversion from the natural gas from fossil sources. This fuel can also help bridge the gap for excess electricity and act as a storage of energy to a period of higher demand. Carbon capture costs are estimated between $94 and $414 per MTCO2e depending on source and technology[13]. 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 4.15. Finally, a summary of all new resource options is illustrated in Table 4.4.

[13] Science Direct, Science Daily

Figure 4.15: Synthetic Methane cost estimates

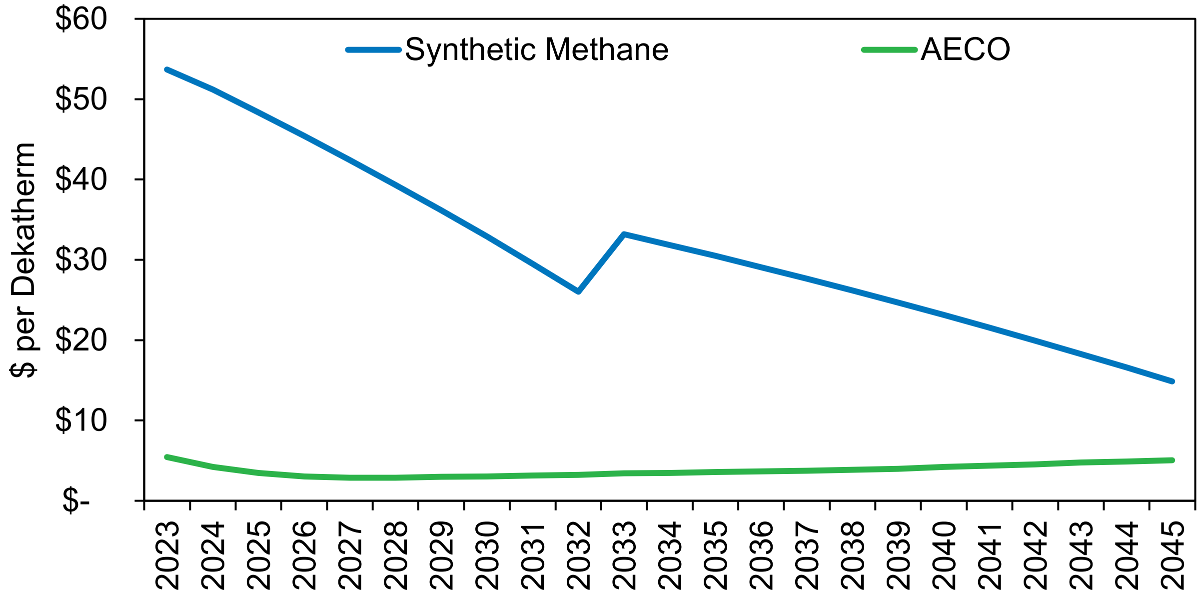


Table 4.4: All resource price comparison $/Dth

Year	Hydrogen	Dairy	Food Waste	LFG	Wastewater	Synthetic Methane	AECO
2025	$35.43	$36.84	$50.43	$9.62	$16.68	$48.35	$3.43
2030	$25.20	$41.05	$56.15	$10.72	$18.54	$32.90	$3.03
2035	$19.05	$45.72	$62.49	$11.93	$20.60	$30.48	$3.55
2040	$16.09	$50.92	$69.56	$13.28	$22.91	$23.13	$4.19
2045	$12.19	$56.71	$77.43	$14.79	$25.47	$14.84	$5.05

Alternative Fuel Supply Price Risk

While weather is an important driver for the IRP, price is also important. As seen in recent years, significant price volatility can affect the portfolio. In deterministic modeling, a single price curve for each scenario is used for analysis. There is risk that the price curve in the scenario will not reflect actual results.

Avista used Monte Carlo simulation to test the portfolio and quantify the risk to customers when prices do not materialize as forecast. Avista performed a simulation of 500 draws, varying prices, to investigate whether the PRS Case total portfolio costs from the deterministic analysis is 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 4.16 to Figure 4.21 show the average yearly price per dekatherm, per draw and resource, for each of the 500 draws. Statistics are also provided with each histogram and represent the raw data results.

Figure 4.16: RNG Landfill RNG - $ per Dth (500 Draws)

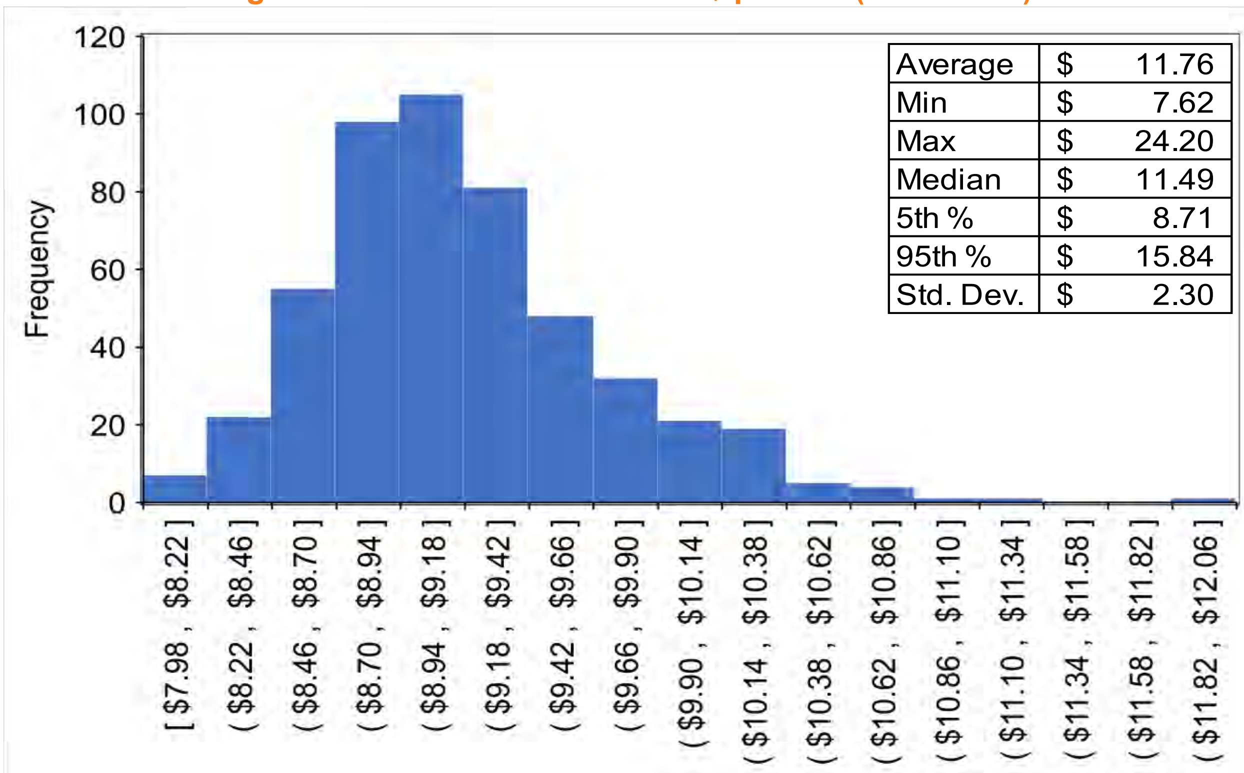


Figure 4.17: Dairy RNG - $ per Dth (500 Draws)

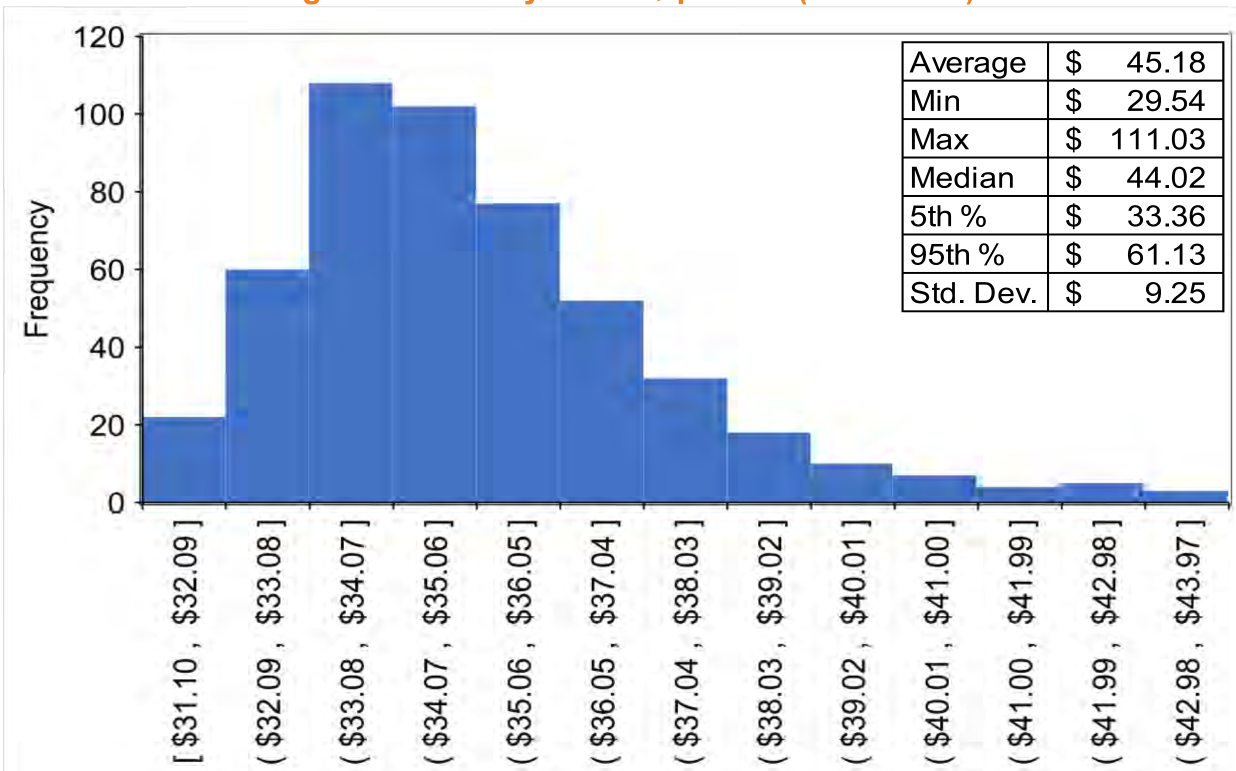


Figure 4.18: Food Waste RNG - $ per Dth (500 Draws)

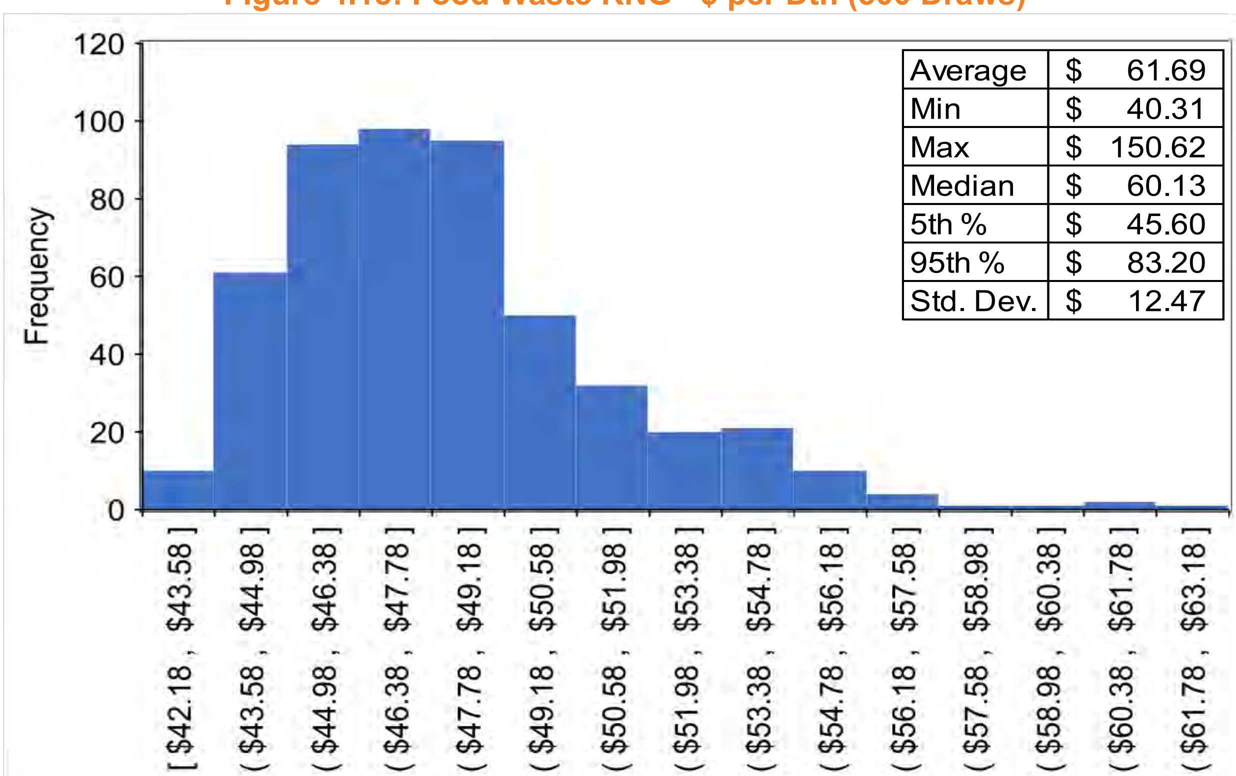


Figure 4.19: Wastewater Treatment RNG - $ per Dth (500 Draws)

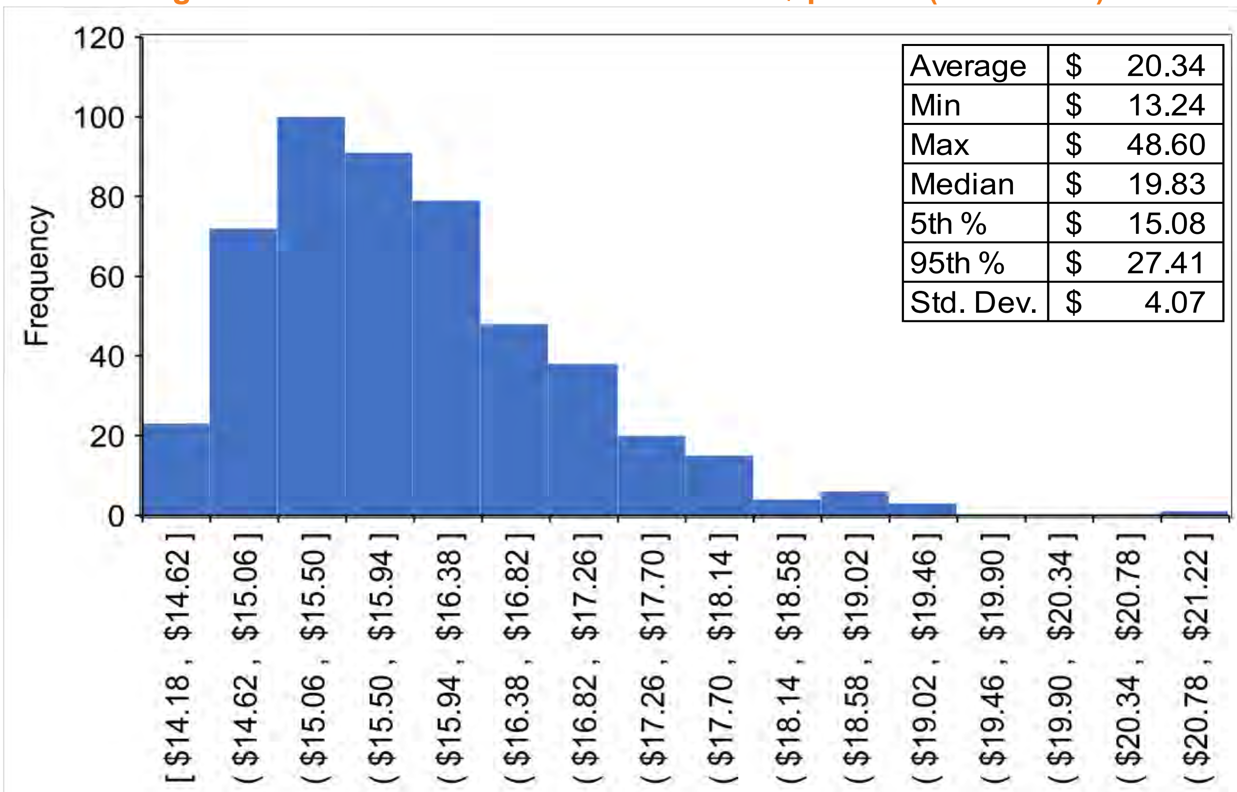


Figure 4.20: Hydrogen (500 Draws)

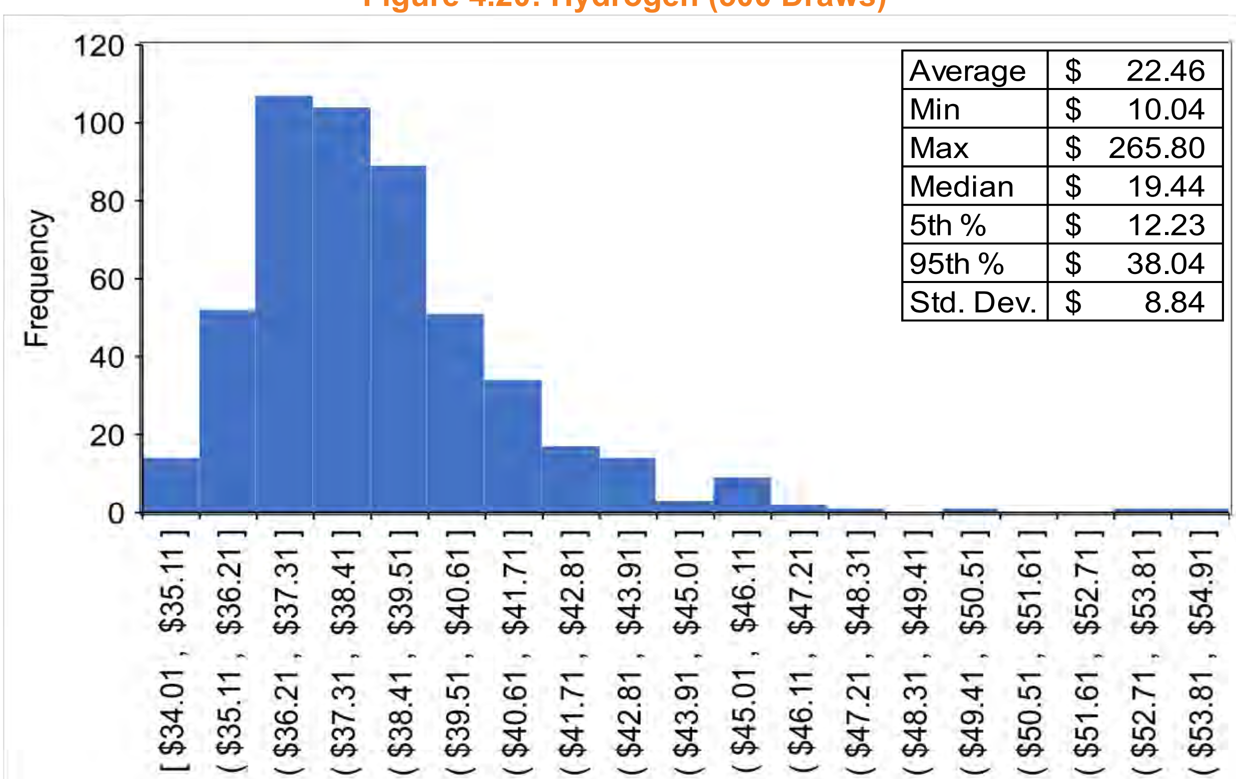
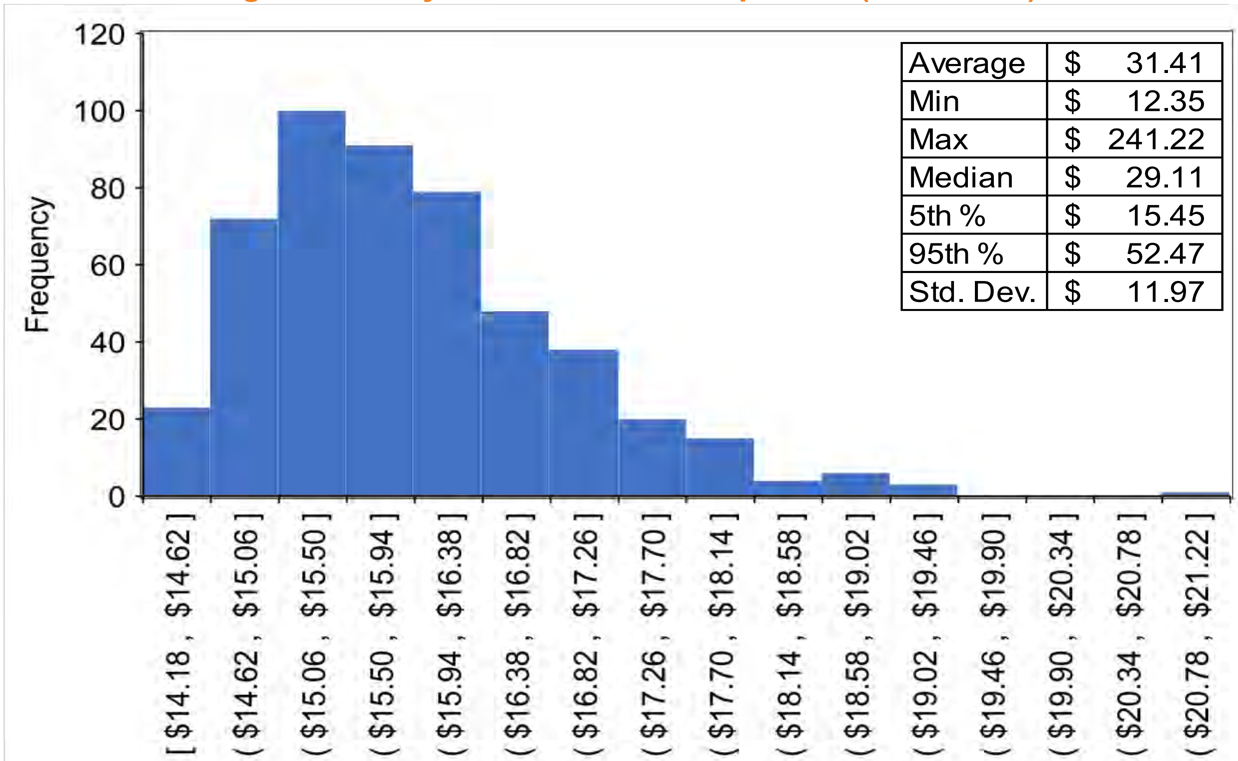


Figure 4.21: Synthetic Methane - $ per Dth (500 Draws)



Average	$	31.41
Min	$	12.35
Max	$	241.22
Median	$	29.11
5th %	$	15.45
95th %	$	52.47
Std. Dev.	$	11.97

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 at the same time 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. The Avista 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 our control such as the Energy Crisis in the early 2000's or the Enbridge pipeline rupture in 2018 or most recently the COVID-19 pandemic and the 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 in order reduce our 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 2023 IRP focuses on three areas of risk: the financial risk of the cost of natural gas system fuel options to supply customers will be unreasonably high or volatile, emissions compliance cost and options in Oregon and Washington and the physical risk that there may not be enough natural gas system resources (either transportation capacity or the commodity) to serve core 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 stakeholders 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 a vision is translated into practice. These initiatives are a group of projects and programs that are outside of the organizations daily operational activities and help an organization achieve a targeted performance.

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

- Serve Load – Assure adequate and reliable energy supplies for Avista Utilities natural gas customers.
- Manage Resources – Exercise prudent stewardship of Avista Utilities energy supply facilities and related Company resources.

A thorough review and filing is done annually by Avista for a retrospective hedging report submitted to the Washington Utilities and Transportation Commission[14] (2022 filing UG-220670). 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.

[14] https://apiproxy.utc.wa.gov/cases/GetDocument?docID=5&year=2022&docketNumber=220670

5. Policy Issues

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.

Avista's Environmental Objective

Avista has always been on 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.

Environmental Issues

The evolving and sometimes contradictory nature of environmental regulation from state and federal perspectives 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.

Natural Gas Greenhouse Gas System Emissions

System emissions include any emission found upstream of the point of combustion and includes 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 emissions are measured at the standard 100-year Global Warming Potential (GWP) meaning a 34 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[1] and 1.0% rate from the Rockies as calculated in the EIA sinks and emissions estimates. Over the past five years, nearly 90% of Avista's natural gas was sourced from Canadian production leaving roughly 10% of estimated upstream emissions to the Rockies region. The EIA upstream emissions estimate[2] is updated on a yearly basis and will show gains and losses as they occur as compared to a point in time study. These upstream emissions are included in the Carbon Intensity and Social Cost of Carbon scenarios as emissions in Oregon and Washington are governed and valued against the CPP and CCA respectively other than for energy efficiency as explained in Chapter 3.

The final upstream emissions from methane (CH_4) in carbon equivalents add nearly 10.66 pounds per MMBtu as shown in Table 5.1:

Table 5.1: 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	0.0748
N_2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH_4	0.313406851	10.66
Total		128.27

Table 5.2 illustrates the Global Warming Potential; the Intergovernmental Panel on Climate Change released their 5th assessment study defining these impacts to global warming in units of CO_2e.

Table 5.2: Global Warming Potential (GWP) in CO2 Equivalent[3]

Greenhouse Gas	GWP – 100 Year	GWP – 20 Year
CO_2	1	1
CH_4	34	86
N_2O	298	268

[1] as calculated in a study for the Tacoma LNG project
[2] Inventory of U.S. Greenhouse Gas Emissions and Sinks | Greenhouse Gas (GHG) Emissions | US EPA
[3] From the 5th Assessment of the Intergovernmental Panel on Climate Change

Local Distribution Pipeline Emissions - Methane Study

In a study led by Washington State University (WSU) and sponsored by the Environmental Defense Fund (EDF) and others, an estimate of utility pipeline distribution systems leakage found the overall levels of leakage were around 0.1% to 0.2% of methane delivered nationwide. The study goes on to state the Eastern regions of the United States contribute much more methane to the total as compared to the Western regions, where Western regions account for only 5% of total emissions. The study theorizes eastern US system's older infrastructure and material types are the likely culprit, but also goes on to attribute regulations and better infrastructure and monitoring by utilities for these decreased Western emissions. It found that "out of 230 measurements, three large leaks accounted for 50 percent of the total measured emissions from pipelines leaks. In these types of emission studies, a few leaks accounting for a large fraction of total emissions are not unusual."[4] Such levels within Avista's distribution system from July 2019 – June 2022 average 0.51%.

State and Regional Level Policy Considerations

The lack of a comprehensive federal greenhouse gas policy has encouraged states, such as California, to develop their own climate change laws and regulations. Over the past few years both 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.

Idaho

Avista does not anticipate any greenhouse gas policies in Idaho for the planning horizon. Although, Idaho customers are at risk of a federal policy regulating of greenhouse gas emissions, therefore, this plan includes a risk adder of a federal policy. This risk is evaluated by the inclusion of a national carbon tax beginning in 2030 and increases yearly through 2045 as shown in Table 5.3. The national pricing is based on a national energy consultant's estimate of a nationally accepted price passed by congress. As implications from programs in California, Oregon and Washington come into focus, a better idea of indirect cost impacts will be measured through national or regional natural gas prices. This may include a lower demand for natural gas with a potential to push against high natural gas prices and lack of pipeline infrastructure growth.

[4] https://methane.wsu.edu

Table 5.3: National Greenhouse Gas Pricing Forecast

Year	$ per MTCO2e
Pre-2030	$0
2030	$12.00
2031	$15.03
2032	$17.69
2033	$20.47
2034	$23.36
2035	$26.38
2036	$29.52
2037	$32.79
2038	$36.19
2039	$39.74
2040	$43.43
2041	$46.63
2042	$50.08

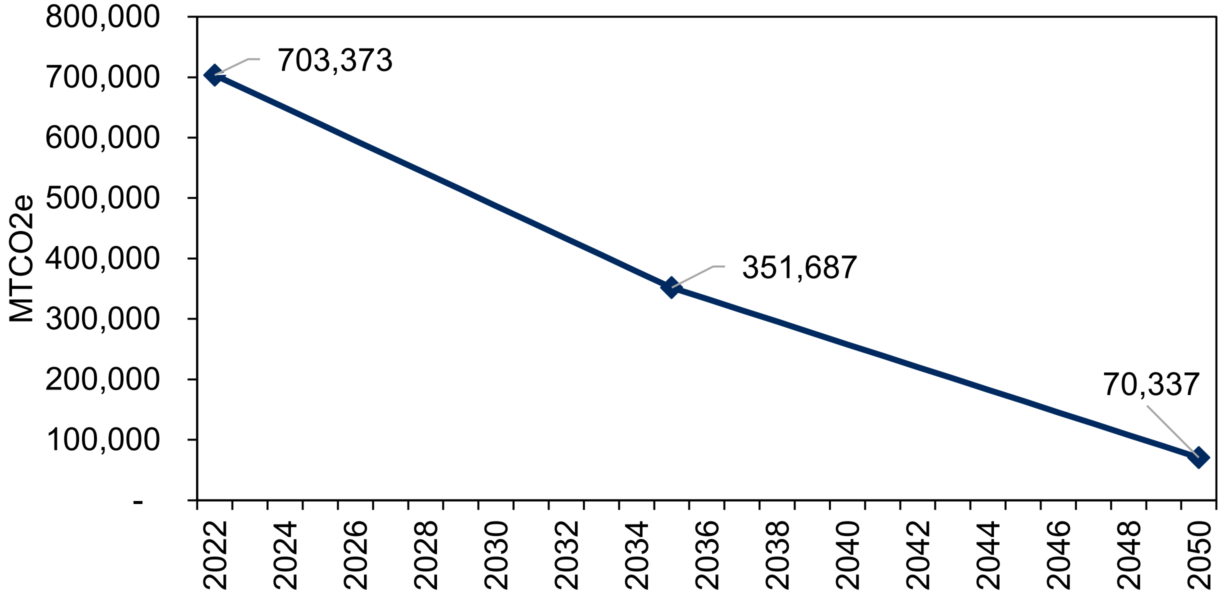
Oregon

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. 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 27-2021, Chapter 340 (effective on December 17, 2021)[5]. In it, annual reduction amounts between 2022 and 2035 is equal to 27,000 metric tons of carbon equivalent (MTCO2e) or 50% of Avista's natural gas customer's emissions. In the following timeframe, 2036 – 2050, nearly 19,000 MTCO2e annually reductions leads to the final 40% reduction from the program baseline goal leaving a 10% total carbon emissions equivalent by 2050. This program will require natural gas utilities to meet annual emissions goals in Oregon as illustrated in Figure 5.1.

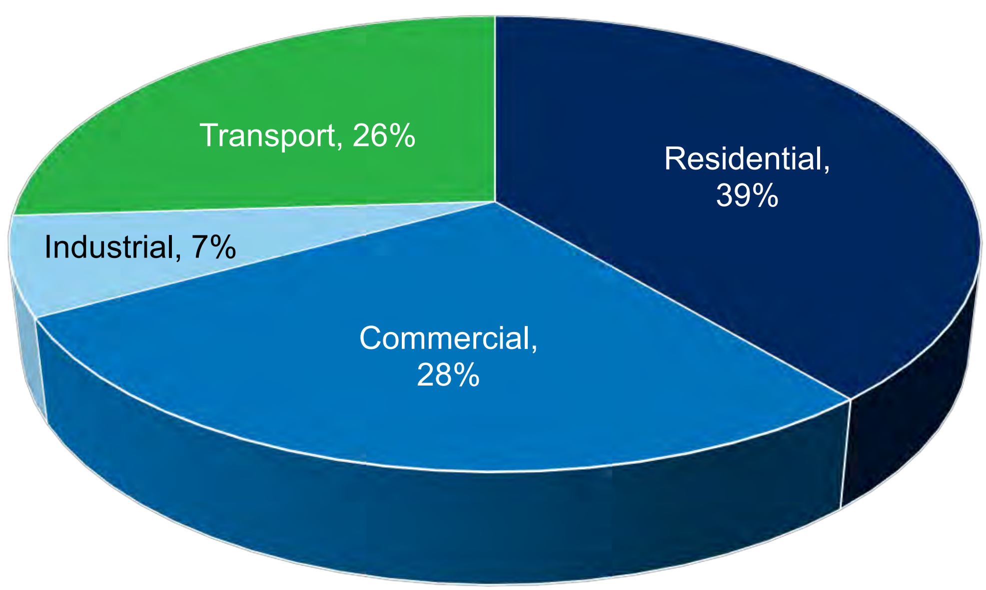
[5] https://www.oregon.gov/deq/rulemaking/Pages/rghgcr2021.aspx

Figure 5.1: Oregon Customers Annual Emissions Compliance Cap



DEQ's final rules declare Avista's annual carbon compliance levels. Within these final rules, the CPP directs Avista with compliance responsibility for all emissions from our infrastructure regardless of customer class or source natural gas. This requirement includes transport customer class emissions where, historically speaking, Avista only charges a small fee for use of the distribution system but does not procure the energy or resources to get this energy to the city gate. As such, the requirement adds an additional 48.81% to Avista's emissions. Refer to Figure 5.2, for an understanding of emissions by class in 2022.

Figure 5.2: Oregon Emissions by Class for 2022[6]



[6] Emission percentages are from 2022 billed data actuals

Program Compliance

DEQ's rules assume a carbon footprint of 117 pounds per MMBtu for natural gas, but bundled RNG with renewable thermal credit (RTC) or obtaining just the RTC does not include any greenhouse gas emissions regardless of its actual emissions intensity profile. Unlike the California program, 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. Further, RNG does not have to be physically sourced in the state of Oregon, so the total potential volume drastically increases with the increase in geography. Another element of the program are 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 available is directly related to the allowed emissions under the CPP. In years 2022 to 2024 the quantity of CCIs available is equal to 10 percent of the emissions limit, followed by 15% in 2025 to 2027 and finally 20% of the emissions cap from 2028 going forward as show in Figure 5.3. Avista must purchase these CCI's at the nominal prices shown in Figure 5.4.

Figure 5.3: Maximum Available CCI Compared to the Reduction Goal

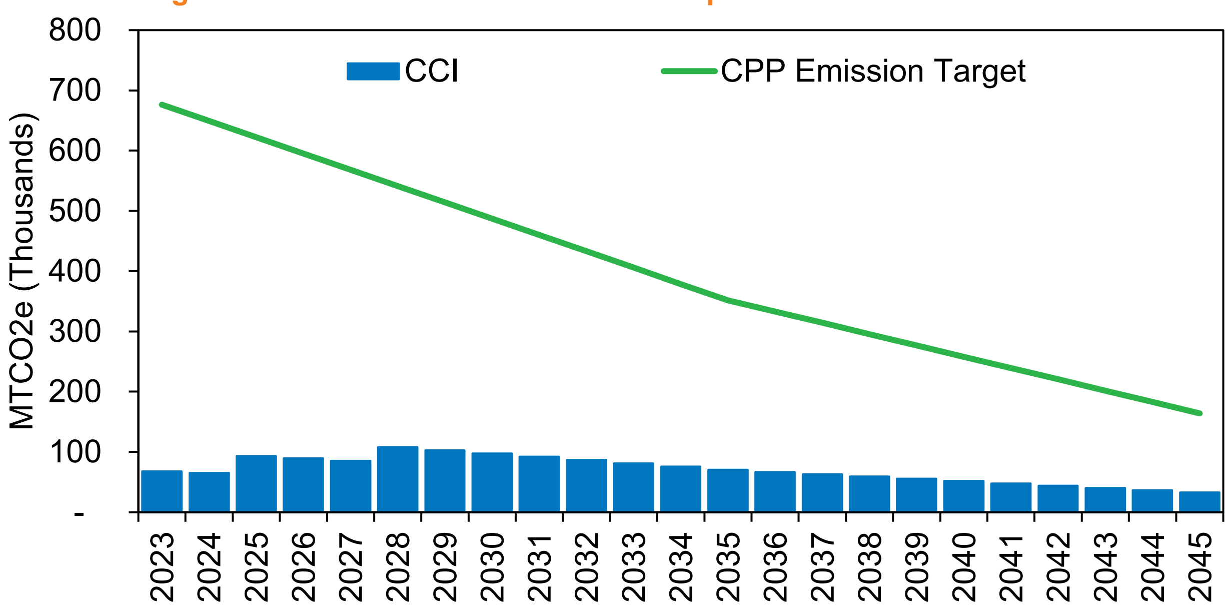


Figure 5.4: Community Climate Investment ($ per MTCO2e)

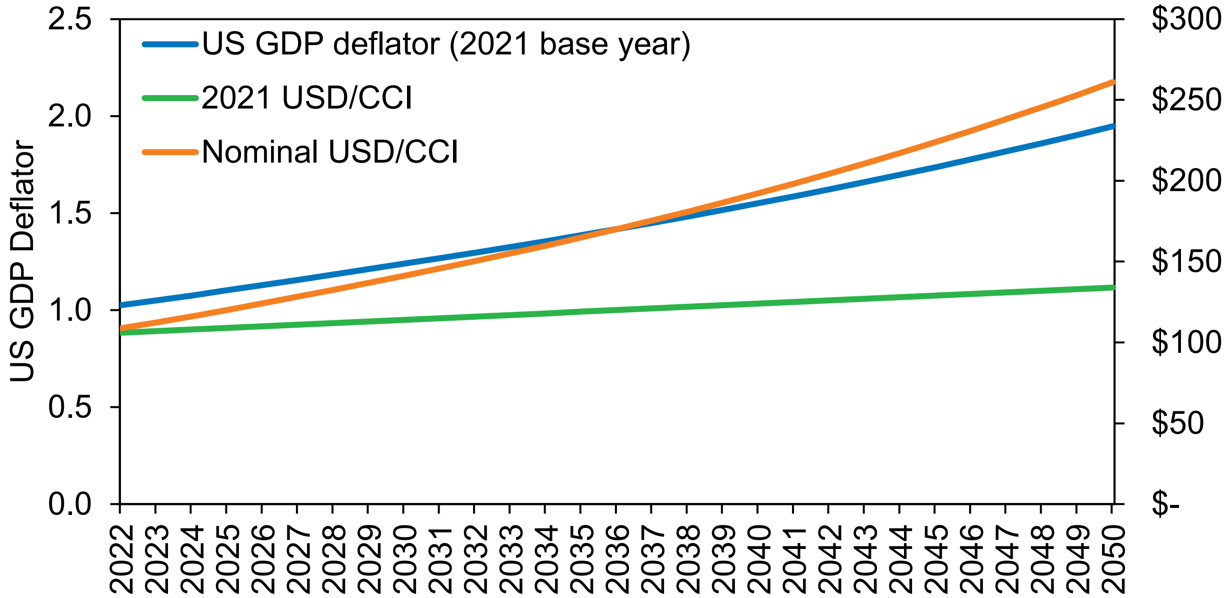
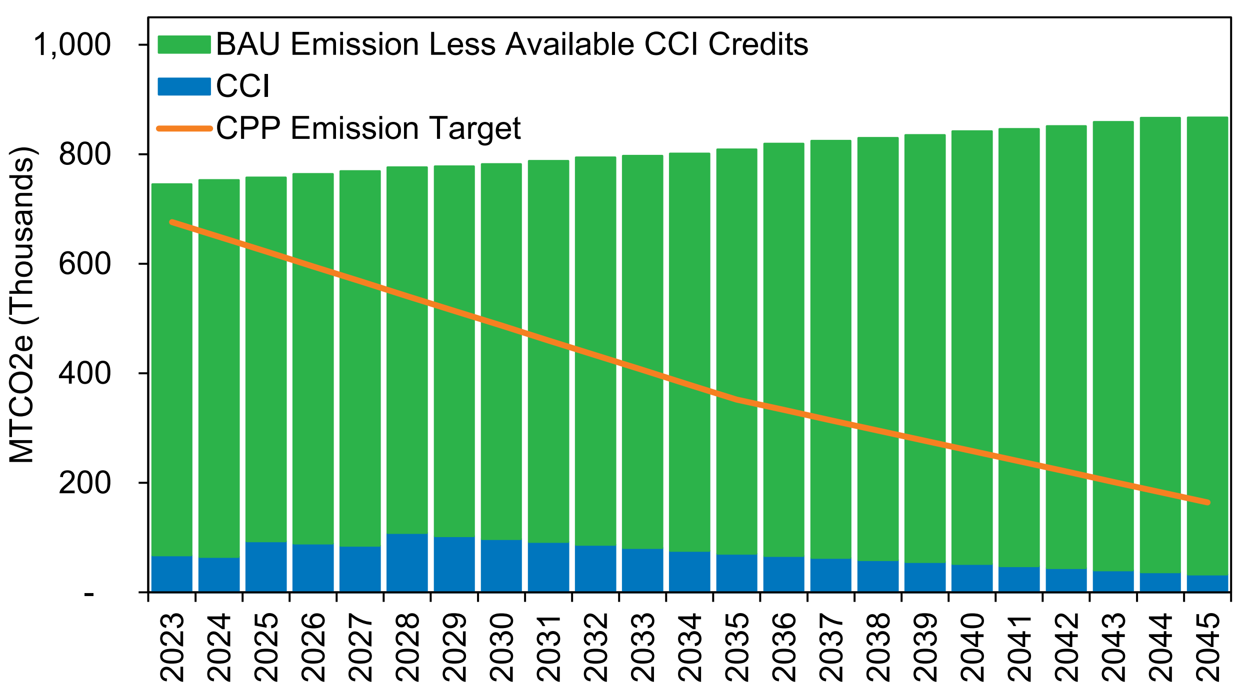


Figure 5.5 combines expected emissions from serving load with natural gas as compared to the comparative number of CCI instruments available to offset these emissions. In Figure 5.5, the area above the "CPP Emissions Target" line will require additional reduction instruments, load reduction, or alternative natural gas sources to meet CPP goals. The resource mix to meet these carbon emissions cap will be discussed in Chapter 6.

Figure 5.5: Business as Usual Emission Forecast vs. Utility Goal



Oregon Senate Bill 334

Senate Bill 334 was passed in 2017 to help develop, update, and maintain the biogas inventory available. 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 will also help promote RNG and identify 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."

Oregon Senate Bill 844

Senate Bill 844 passed in 2013 with rulemaking following OPUC Docket AR 580, with rules going into effect in December of 2014. This bill directed the OPUC to establish a voluntary emission reduction program and 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 SB844.

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. In order 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 percent 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[7]

In December 2020 a Washington State Energy Strategy was released as a roadmap committing Washington to reducing greenhouse gas emissions, as follows:

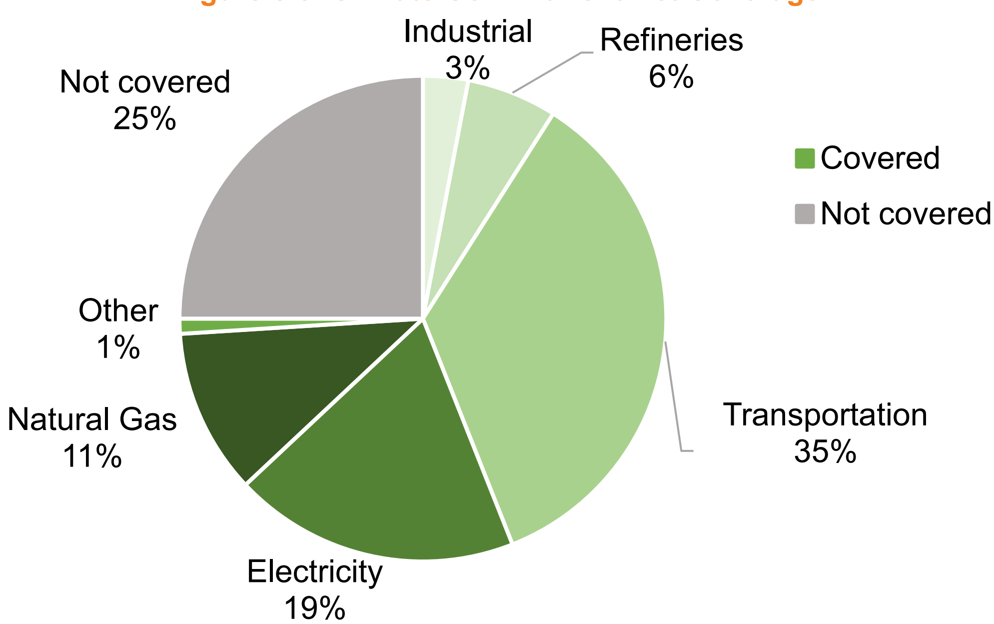
- By 2030 a 45% reduction below 1990 levels
- By 2040 a 70% reduction below 1990 levels
- By 2050 a 95% reduction below 1990 levels and net-zero emissions

[7] https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/

Climate Commitment Act

The Washington legislature passed its largest environmental program in 2021, the Climate Commitment Act (CCA) into state law (RCW 70A.45.020). This CCA is administered by Washington Department of Ecology with the program beginning January 1, 2023. The CCA creates a state-wide emissions cap and trade program where emissions 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 5.6 illustrates the CCA coverage by percent of emissions and industry type for included covered entities.

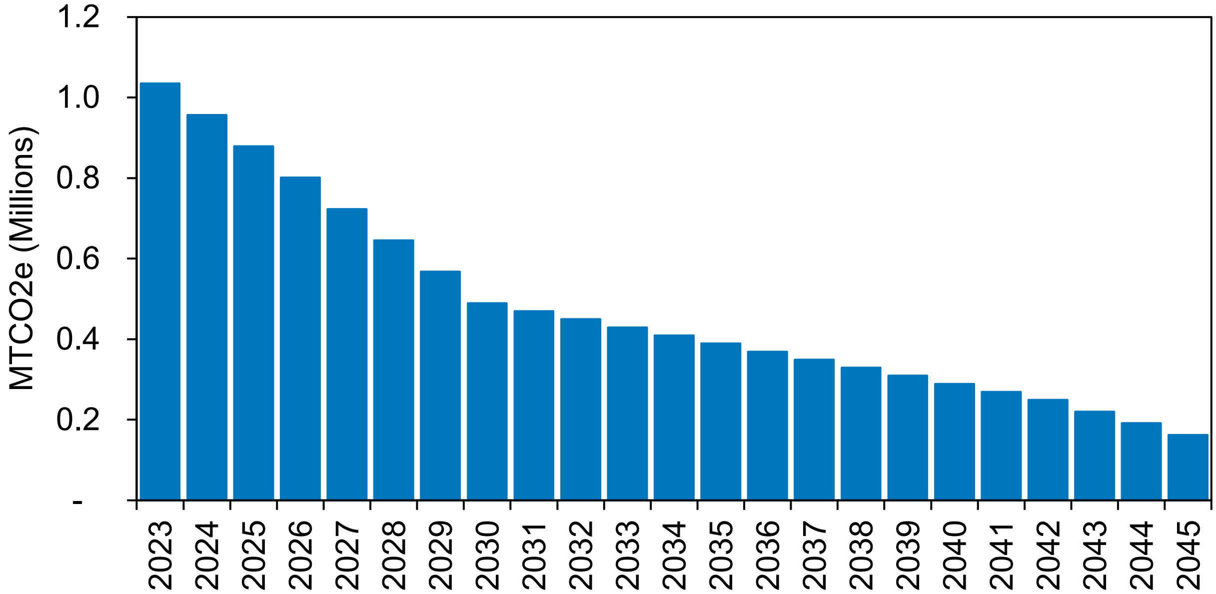
Figure 5.6: Climate Commitment Act Coverage[8]



Future participants will be added in 2027 with the inclusion of waste-to-energy plants and in 2031 with railroad companies, and solar and wind power at the Wild Horse wind farm. The cap for the CCA reduces emissions beginning 2023 by 7 percent annually until 2030. The cap decreases by 1.8 percent annually from 2031 to 2042. 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. A summary of the prorata share of this reduction to Avista's LDC emissions are shown in Figure 5.7.

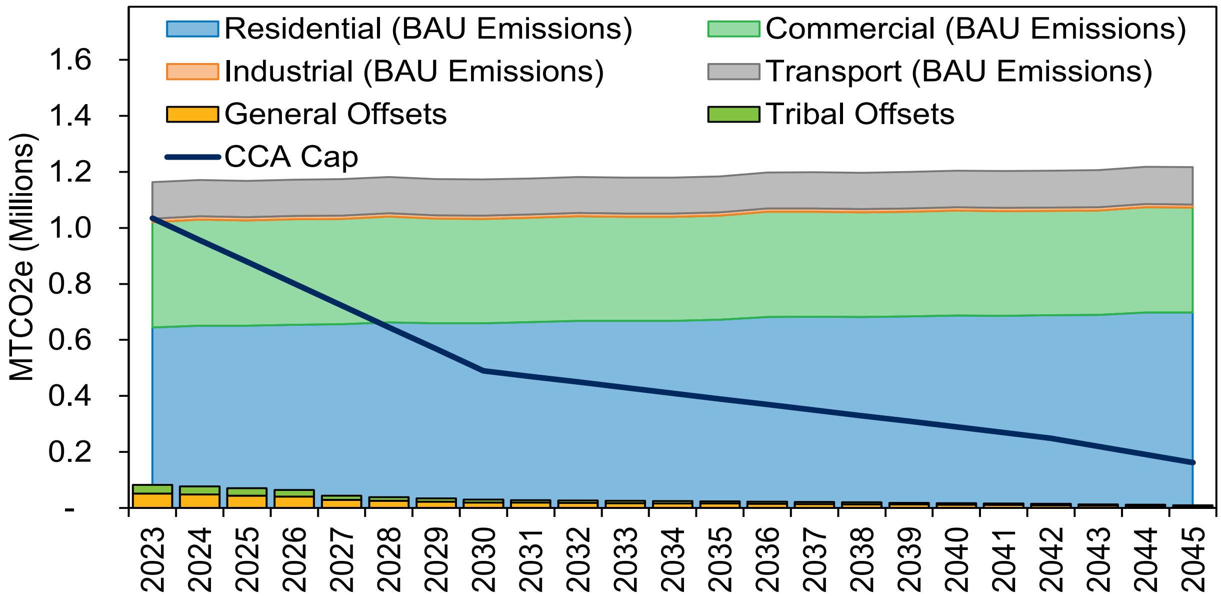
[8] Washington State Department of Ecology produced graphic

Figure 5.7: Avista's Estimated Annual Emissions Cap



All covered entities are required to obtain allowances or offsets to cover their emissions. Offsets are projects that reduce, remove, or avoid 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 5 percent of their emissions from general offset projects and 3% from Tribally support projects. Offsets are below the cap meaning allowance and offsets are interchangeable and should be procured on a least cost or least risk basis. Program design elements are intended to provide linkage to similar programs in other jurisdictions. These offsets drop after this initial timeframe to 4% general offsets and 2% Tribal offsets going forward starting 2027. Please see Figure 5.8 to understand potential emissions offsets available to Avista through Offset projects.

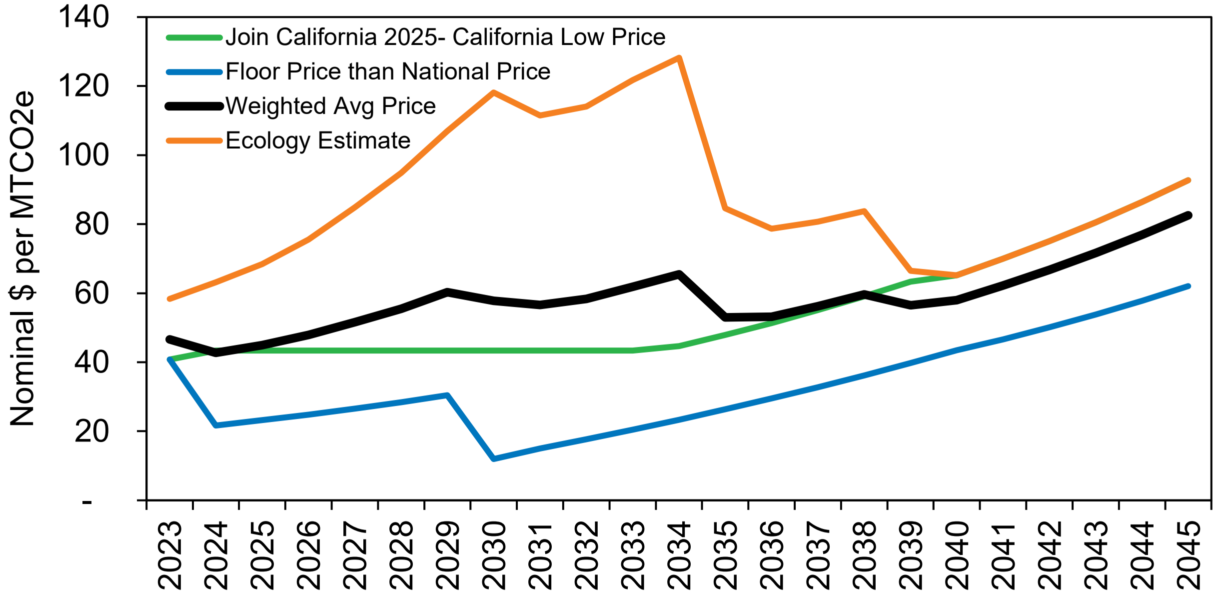
Figure 5.8: Emissions Reductions from Offset Projects



These 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 are not known at this time. The intent of this legislation allows for the Washington State program to join California and the Quebec markets to increase “allowance” liquidity possibly as early as 2025. California and Quebec still need to approve the addition of Washington to their program. 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.

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 5.9.

Figure 5.9: Expected CCA Allowance Prices



Washington HB 2580

House Bill 2580 was signed by Governor Jay Inslee on March 22, 2018 and became effective on July 1, 2018 bringing into law a bill to help encourage production of RNG. This bill requires the Washington State University Extension Energy Program and the Department of Commerce (DOC) along with the consulting of the WUTC, to submit recommendations on promoting the sustainable development of RNG. The DOC will consult with natural gas utilities and other state agencies to explore developing voluntary gas quality standards for the injection of RNG into natural gas pipeline systems in the state.

Washington HB 1257

The bill was passed during the 2019 Regular Session, coined the “Building Energy Efficiency” bill, mandating that each gas company must offer by tariff a voluntary renewable natural gas service. The bill also allows for LDCs to create an RNG program to supply a portion of the natural gas it delivers to its customers. This program is subject to review and approval by the WUTC. With regard to 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.

House Bill 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.

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 thru 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.

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 that began construction 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 forecasts 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.

Customer Market study

In the 2021 Natural Gas IRP a recommendation was included, from OPUC, to conduct market research with Avista customers for sentiments around costs and carbon policies. "Recommendation 9: Prior to the next IRP, conduct market research to reflect the willingness of Oregon customers to pay for various carbon reduction strategies. Present results at a TAC meeting."

In light of climate policy and the potential impact to all jurisdictions served with natural gas or electricity by Avista, the study was broadened to understand these elements in

Idaho, Oregon, and Washington. Some study highlights are below and with the entire study available on Avista's IRP website.[9]

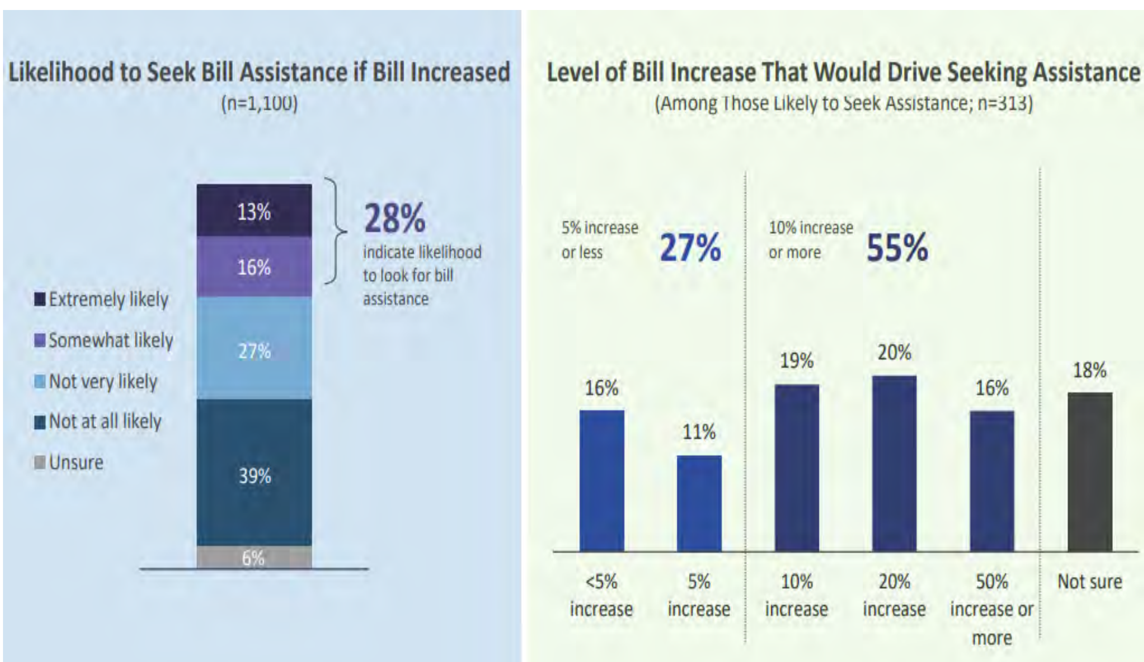
The overall objective of this study was to determine the willingness to pay for the implementation of clean energy among Avista customers. Establishment of a baseline of environmental concerns, tradeoffs between bill increases and carbon emissions goals, explore perceptions specific to natural gas preferences and tradeoffs and perceptions associated with Avista and investing in carbon-neutral or carbon-free emissions sources. This survey was delivered through the web with Avista customers and sourced randomly by email and was conducted in April of 2022. The sample size was 1,100 participants. Participants were required to be above 18 years of age, responsible for household finance or utility bill and cannot be employed or affiliated by Avista.

Key Takeaways

Price is Important

"When faced with tradeoffs, price is the prevailing factor. While the majority of customers find importance in sourcing green or local energy, they are only willing to pay so much. Anything beyond a 10% monthly bill increase shows significant declines in popularity. If bill increases to invest in carbon-free or carbon-neutral options are kept below 10%, the specific energy goal, timeframe, local vs. regional source are less important." An example of one question related to price is illustrated in Figure 5.10.

Figure 5.10: Bill Increase and Carbon-Neutral or Carbon-Free Options

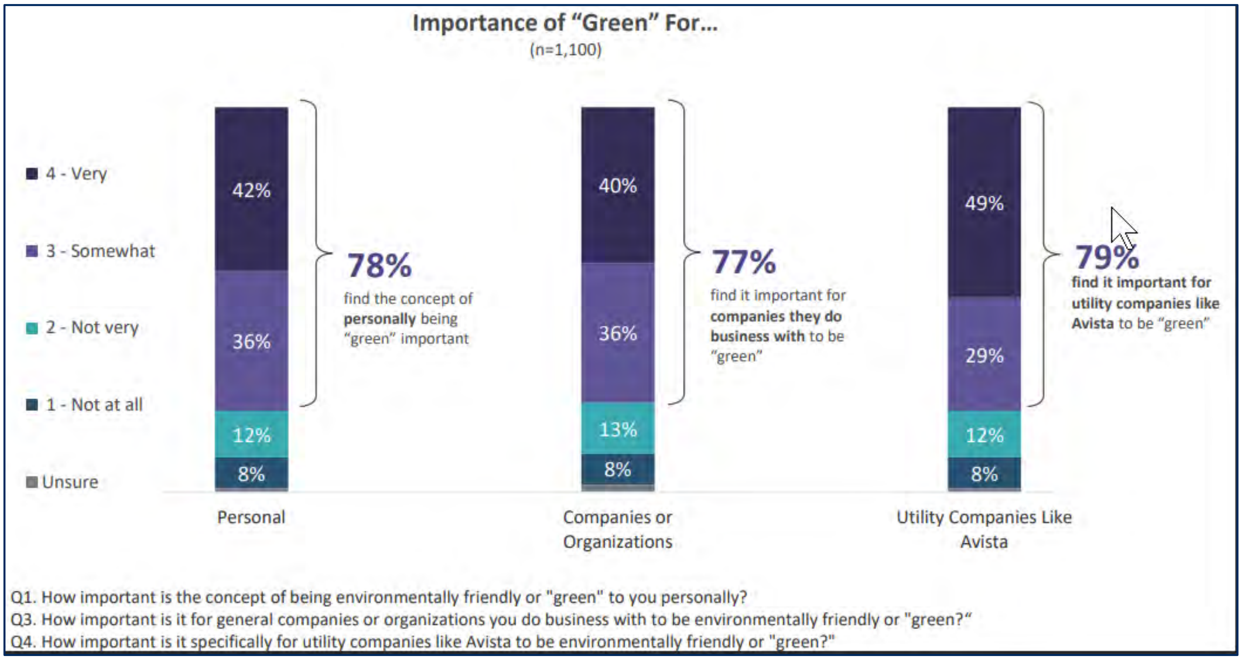


[9]https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/natural-gas-irp-documents/avista-irp-clean-energy-research-tac.pdf

Some Customers See Beyond Price

"Increases beyond 10% monthly still appeal to a certain subset of customers, particularly those who place great importance on "green," and/or when the goal can be achieved within the next 10 years." Figure 5.11 provides an example of customers seeing beyond price.

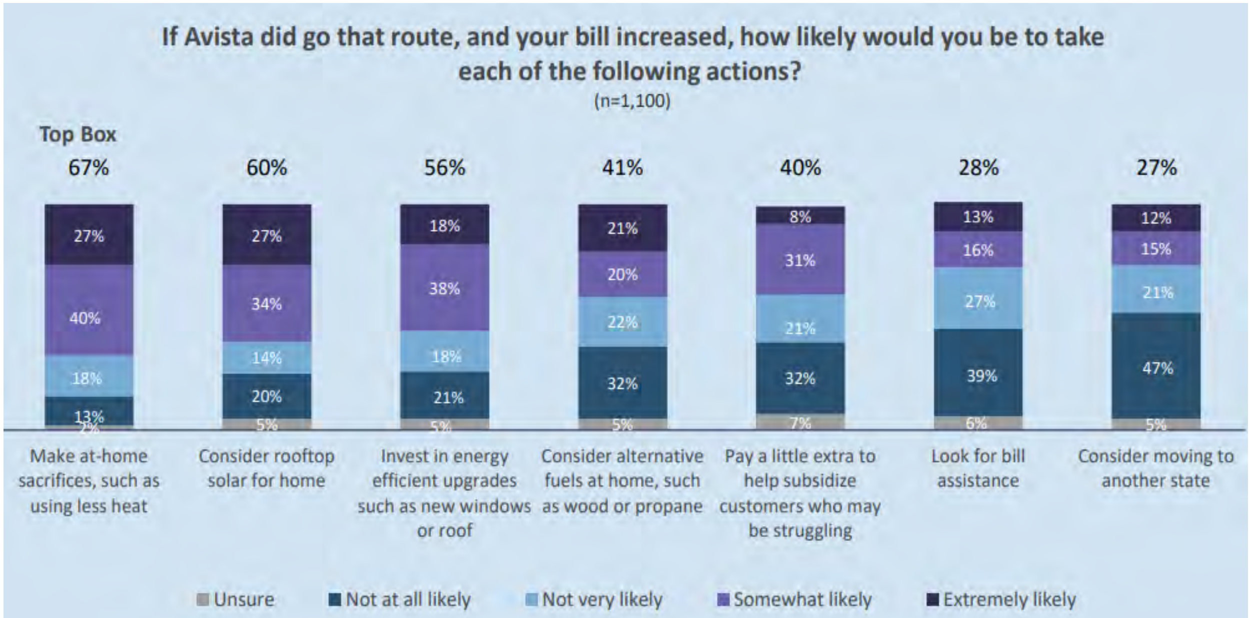
Figure 5.11: Importance of "Green"



Any increase to invest in "green" energy will alienate some customers.

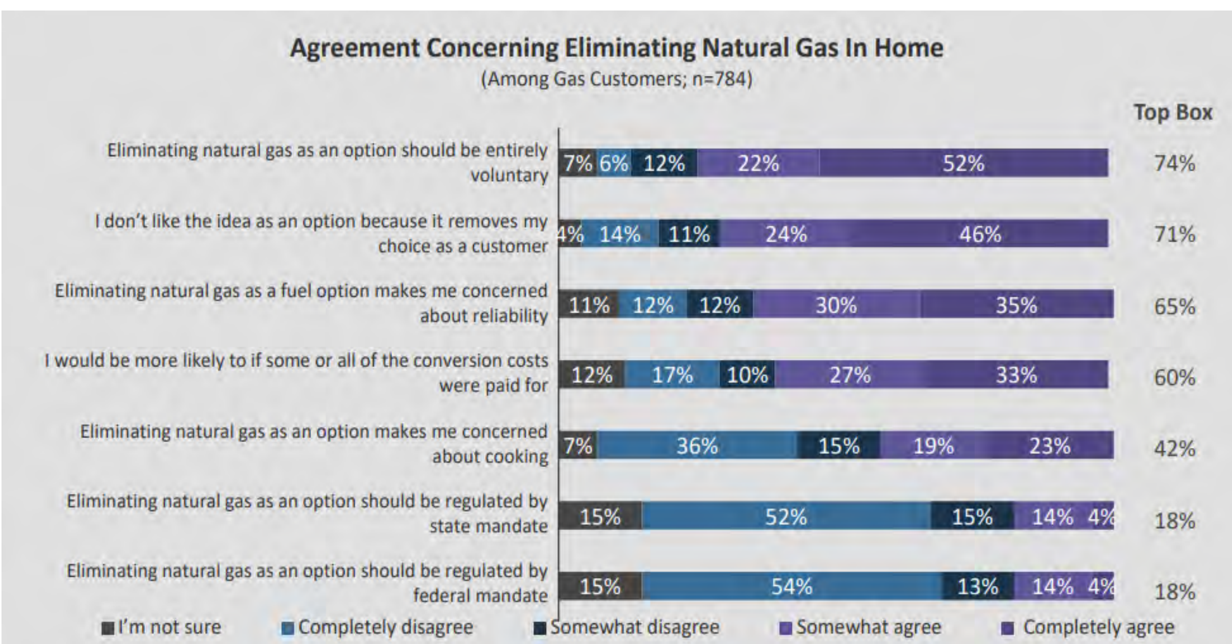
"Overall, roughly one in five do not find importance in being "green" When evaluating various green investment options, 17 percent reject all, including more ambitious outcomes for just a 2 percent increase. Three in ten say they would be likely to seek bill assistance or consider moving to another state if bill were to increase due to Avista investing in carbon-free or carbon-neutral energy."

Figure 5.12: An Increased Bill and Possible Actions from Customers



Finally, we have nearly half of our customers that would not consider switching from natural gas to help reduce carbon emissions. While nearly 75 percent of these customers agree that eliminating natural gas should be entirely voluntary as shown in Figure 5.13.

Figure 5.13: Customer Concerns with Fuel Switching



Equity Considerations

Equity has been a newer piece of the IRP process in Washington, for electric investor-owned utilities, as introduced from Clean Energy Transformation Act (CETA) and other legislation or WUTC policies. Equity focuses on the energy justice, through metrics, to consider benefits and burdens of living near resources. Avista intends to incorporate increased equity considerations in the 2025 natural gas IRP and utilize lessons from our electric IRP process to assist in the development of metrics and use in analytics.

6. Preferred Resource Strategy

This chapter combines the previously discussed IRP components within the PLEXOS® model to determine resource deficiencies during the 20 plus years planning horizon. The foundation for integrated resource planning is the criteria used for developing demand forecasts. The weather planning standard is updated in this IRP. The new planning standard has Avista moving away from coldest day on record and into a 99% probability of a daily temperature occurring. This new standard has been combined with forecasted future weather data for each planning area as discussed in Chapter 2. Avista plans to serve the expected peak day in each demand region with firm resources. Firm resources include natural gas and distributed renewable supplies, firm pipeline transportation, and storage resources. In addition to peak requirements, Avista also plans for non-peak periods such as winter, shoulder months (April and October) and summer demand. The modeling process includes an optimization for every day of the 20-year planning period.

The IRP assumes on a peak day all interruptible customers have left the system to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers, therefore this IRP analysis only includes the firm residential, commercial, and industrial classes. Using the weather planning standard, a blended price curve of three studies developed by industry experts, and an academically backed customer forecast all work together to develop stringent planning criteria.

Forecasted demand represents the amount of energy needed. Delivering this forecasted demand requires an additional 1% to 3% on both an annual and peak-day basis to account for additional natural gas supplies purchased primarily for pipeline compressor station fuel. The range of 1% to 3% (known as fuel), varies depending on the pipeline. This fuel is used to move the 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 and is pressure driven (Chapter 8).

PLEXOS® Planning Model

PLEXOS® is a 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. PLEXOS® 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 given a set of constraints. The model considers the following variables:

- Demand data, such as customer count forecasts and demand coefficients 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 including 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.

Figures 6.1 through 6.5 are PLEXOS® network diagrams of Avista's demand centers and resources (including supply resource options). This diagram illustrates current transportation and storage assets, flow paths and constraint points.

Figure 6.1: PLEXOS® Idaho System Map

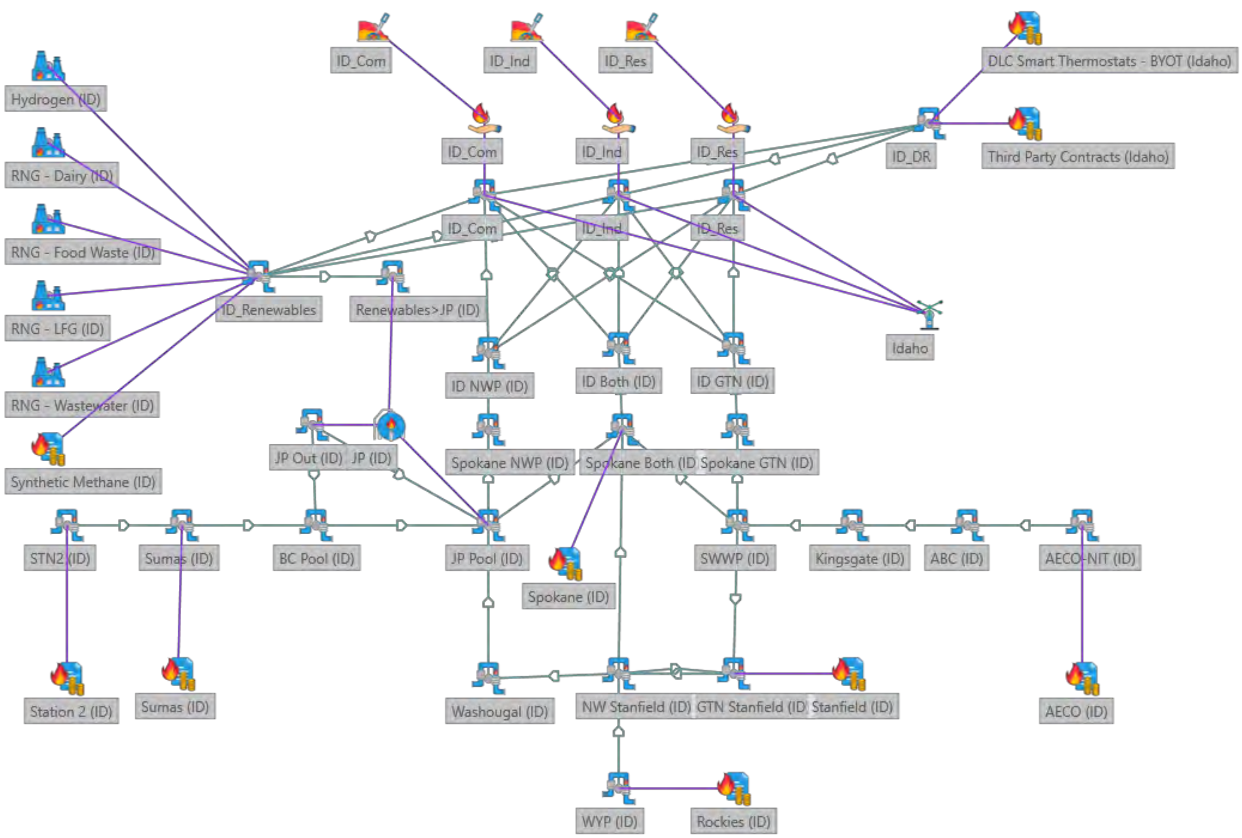


Figure 6.2: PLEXOS® Washington System Map

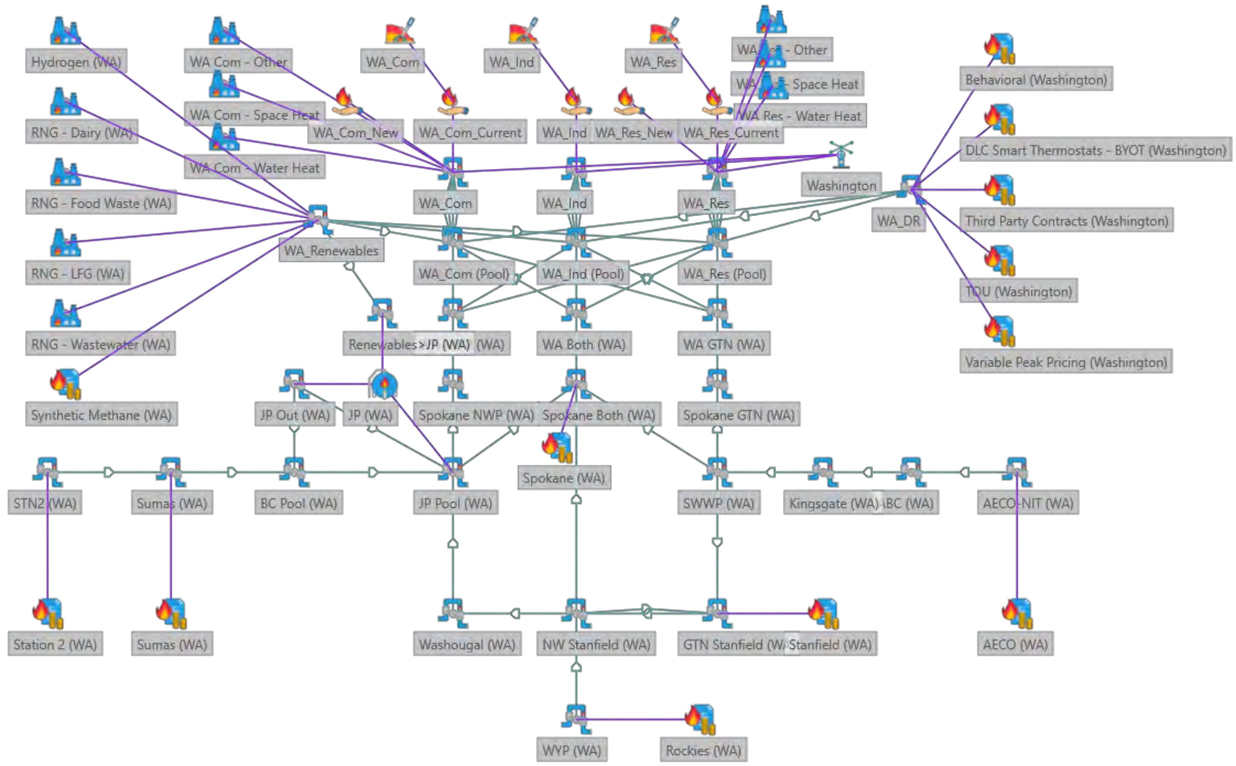


Figure 6.3: PLEXOS® Oregon System Map

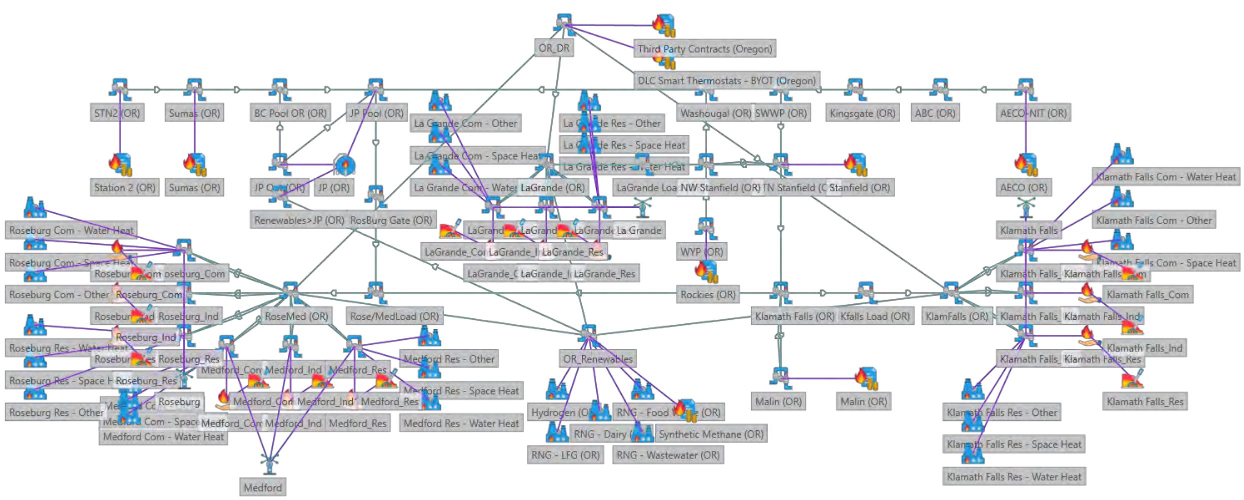


Figure 6.4: PLEXOS® Washington Transport Customer Map

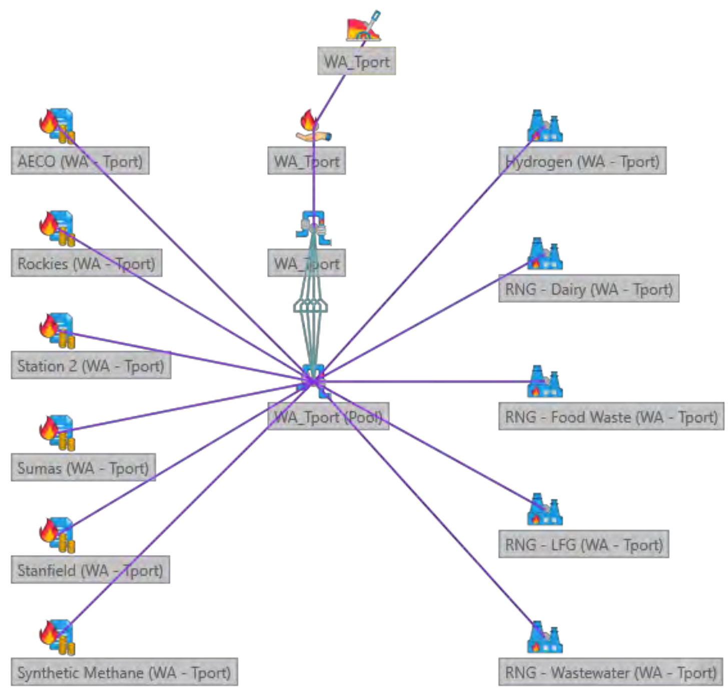
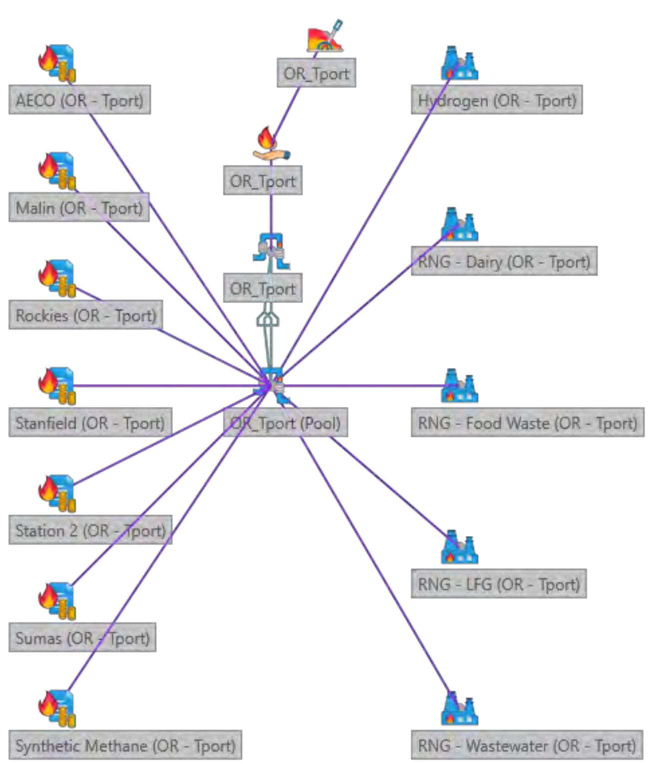


Figure 6.5: PLEXOS® Oregon Transport Customer Map

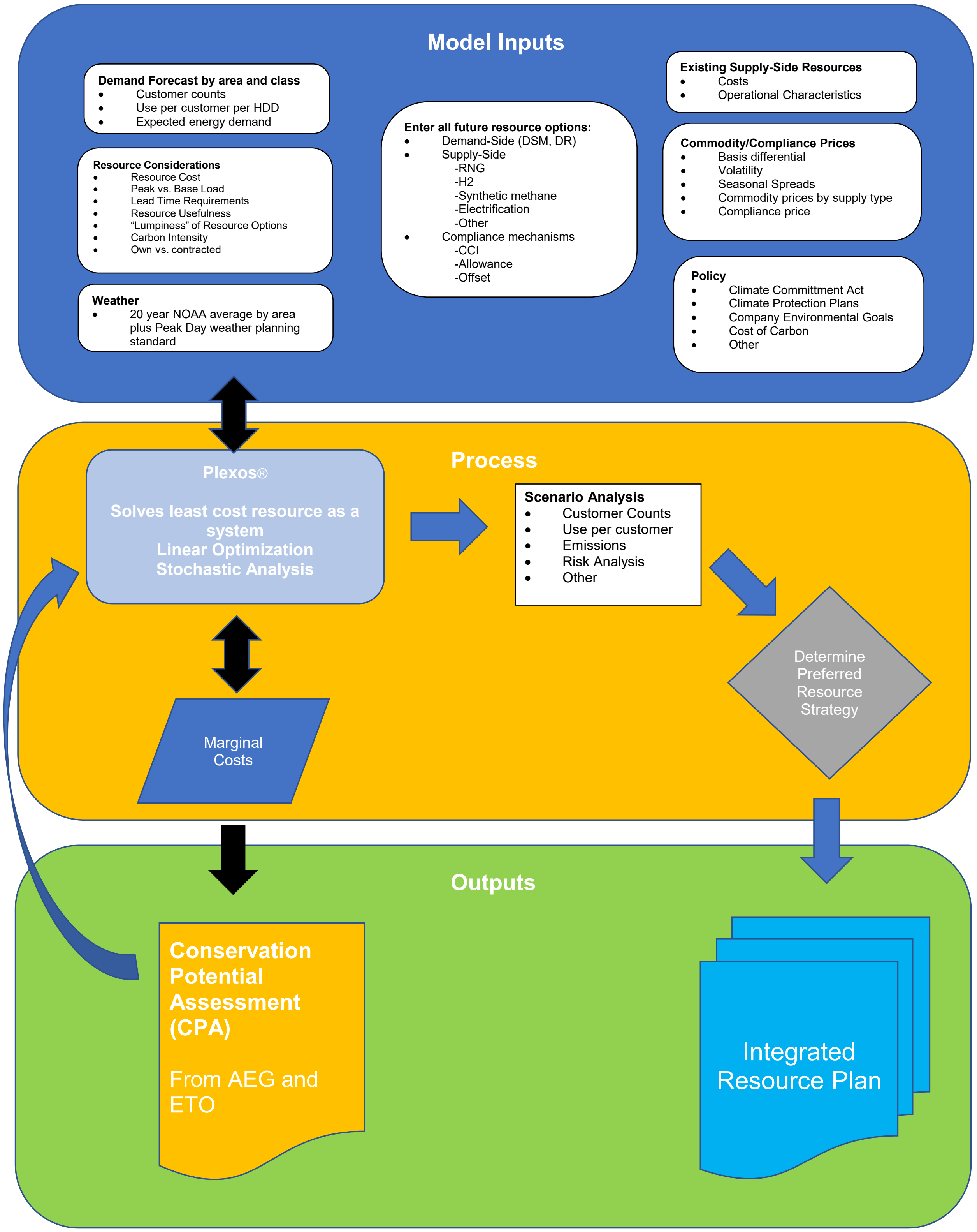


The PLEXOS® model provides a flexible tool to analyze scenarios such as:

- 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.

PLEXOS® also includes Stochastic modeling and Monte Carlo capabilities to facilitate price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. The PLEXOS® model is used by LDC's across the U.S. and has replaced Avista' use of SENDOUT®, as it became increasingly outdated for the current regulatory environment when it comes to greenhouse gas reduction. Figure 6.6 provides a summary view of inputs and modeling flow.

Figure 6.6: Modeling Workflow Diagram



Stochastic Analysis[1]

The scenario (deterministic) analysis described earlier in this chapter represents specific what if situations based on predetermined expected assumptions, including price and weather. These factors are an integral part of scenario analysis. To understand how each scenario will respond to cost and risk, through price and weather, Avista applied stochastic analysis to generate a variety of price and weather events.

Deterministic analysis is a valuable tool for selecting an optimal portfolio yet only considers one set of data such as the most probably future. The model selects resources to meet peak weather conditions in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the planning horizon can be overstated because of annual recurrence of design conditions and the recurrence of price increases in the forward price curve. As a result, deterministic analysis does not provide a comprehensive look at future events. Utilizing stochastic simulation and Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of portfolio variability of price risk and weather created risks.

A deterministic resource mix is performed allowing the model to solve the demand based on the optimal least cost solution for the system. Avista then performs five stochastic simulations on the Preferred Resource Strategy (PRS) where PLEXOS® solves for all five futures at the same time occurring in a single best set of resources to solve the energy and emissions goals.

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. Chapter 2 describes Avista's demand forecasting approach.

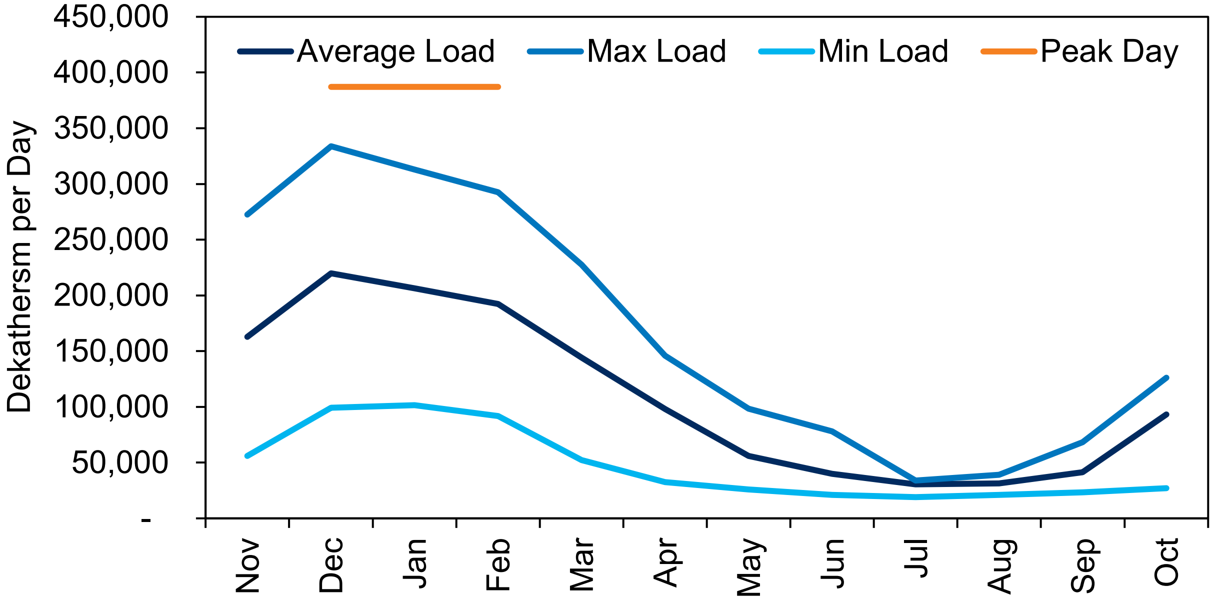
Avista forecasts eleven service areas with distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The areas are Washington and Idaho (each state is disaggregated into three sub-areas because of pipeline flow limitations and the ability to physically deliver gas to an 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 within each area. The relevant firm customer classes are residential, commercial, and industrial customers.

Customer demand is highly weather-sensitive. Avista's customer demand is not only highly seasonable, but also highly variable. Figure 6.7 captures this variability showing firm customer monthly system-wide average demand, minimum demand day observed

[1] PLEXOS® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate future possibilities that exist with a real-life system.

by month, maximum demand day observed in each month, and winter projected peak day demand for the first year of the PRS forecast as determined in PLEXOS®.

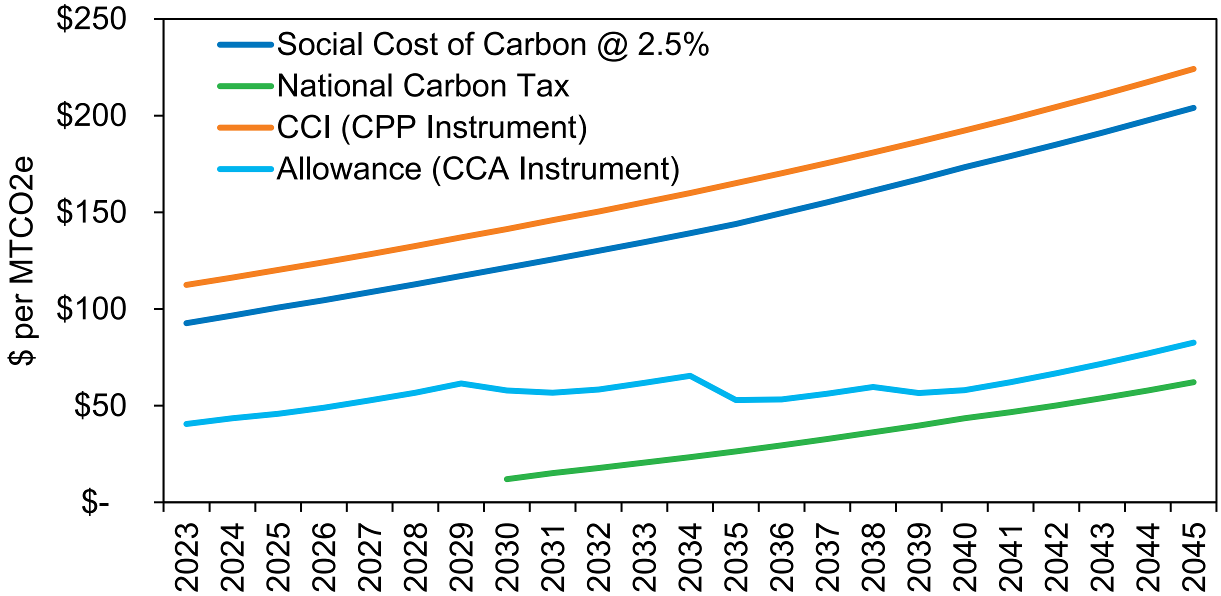
Figure 6.7: Total System Average Daily Load (Average, Minimum and Maximum)



Carbon Policy Resource Utilization Summary

Avista uses an estimated carbon price as an incremental adder to address any potential policy. Carbon price adders increase the price of a dekatherm of natural gas and impact resource selections and are summarized in Figure 6.8. Oregon and Washington were assumed to have a social cost of carbon (SCC) at a 2.5% carbon adder price and based on carbon tax figures built on the requirement to utilize SCC at 2.5% discount estimates from the Environmental Protection Agency (EPA), as required by RCW 80.28.395 and per the 2021 IRP Chapter 9, Recommendation 7. For the State of Idaho, Avista considered a national carbon tax beginning in 2030 running through the end of study timeframe in 2045. SCC is used to value energy efficiency (EE) as described in Chapter 3. Compliance to the Climate Commitment Act and Climate Protection Plan (CPP) occurs through instruments in each program, with the attributed carbon costs of compliance valued against supply side resources.

Figure 6.8: Carbon Legislation Sensitivities

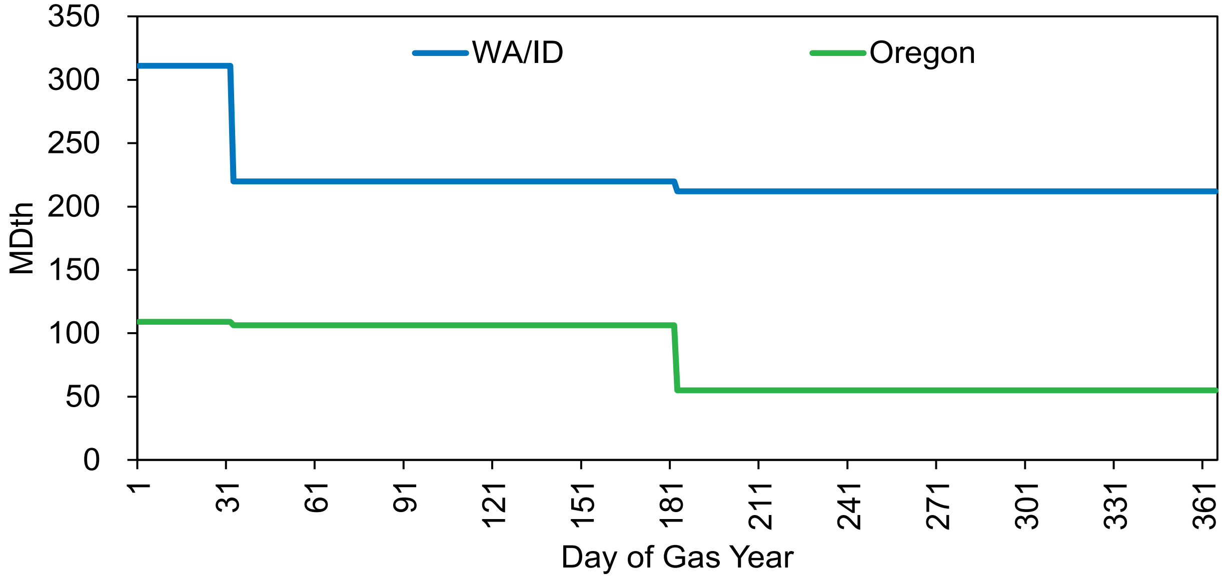


Transportation and Storage

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the natural gas to customers. Daily capacity of existing transportation resources (described in Chapter 4) is represented by the firm resource duration curves depicted in Figures 6.9 and 6.10.

Current rates for capacity are in Appendix 6.1. Forecasting future pipeline rates can be challenging because of the need to estimate 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 increases in GDP (see Appendix 6.2).

Figure 6.9: Existing Firm Transportation Resources



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. New to the 2023 IRP is the requirement to meet greenhouse emissions targets in both Oregon and Washington creating a resource clean energy deficiency.

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 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 account for the compressors required to move the natural gas to customers. Avista maintains enough firm capacity to meet peak day requirements under the Expected Case 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 management simultaneously deploys multiple long-and short-term strategies to meet firm demand requirements in a cost-effective manner. These strategies and plan are discussed in detail in Chapter 4. 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 it is required. 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 eliminates 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 and decrease the number of days this transportation option is available. More days correspond to increased costs, so balancing storage, transport, and demand is important to ensure an optimal blend of 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 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 capacity. All capacity releases are posted on the pipelines 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.

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 the capacity for up to 10 days during the winter may not be as valuable to the third party, but of high value to us. 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 peaking-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. As the end of these release terms near, 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 our 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.

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 customer 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.

Demand and Deliverability Balance

After incorporating the above data into the PLEXOS® 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 meet firm customer demand in a reliable and cost-effective manner as described in Chapter 4.

Figures 6.10 and 6.11 provide graphic summaries of the deterministic results for the Average Scenario and Preferred Resource Strategy (PRS). Average Case demand (black line) as 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 resources exceed demand needs over the planning horizon. Considerations as 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 gas in times of need. These resources vary in ownership by state and area and must match or exceed volume of expected demand.

Figures 6.12 and 6.13 details peak day demand compared to existing resources. This demand is also net of energy efficiency savings. Avista is still long transport rights, consistent with prior IRP expectations. Peak Day criteria is important as it protects our customers and their structures during extreme weather.

Figure 6.10: Average Demand Compared to Storage & Transport Rights for February 28th

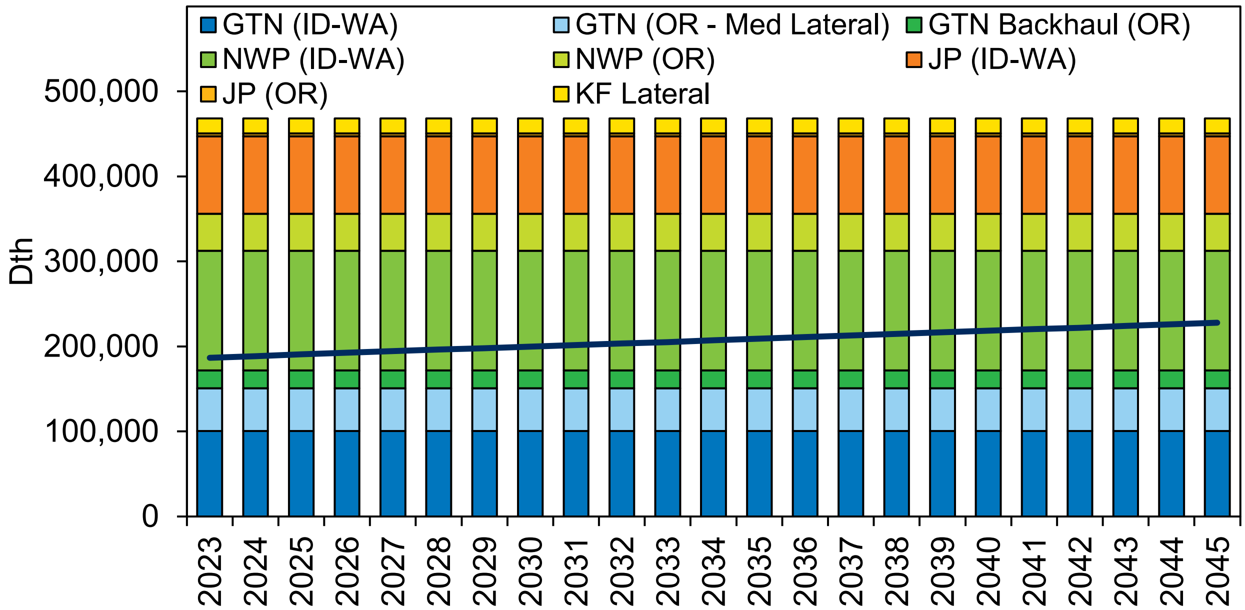


Figure 6.11: Average Demand Compared to Storage & Transport Rights for December 20th

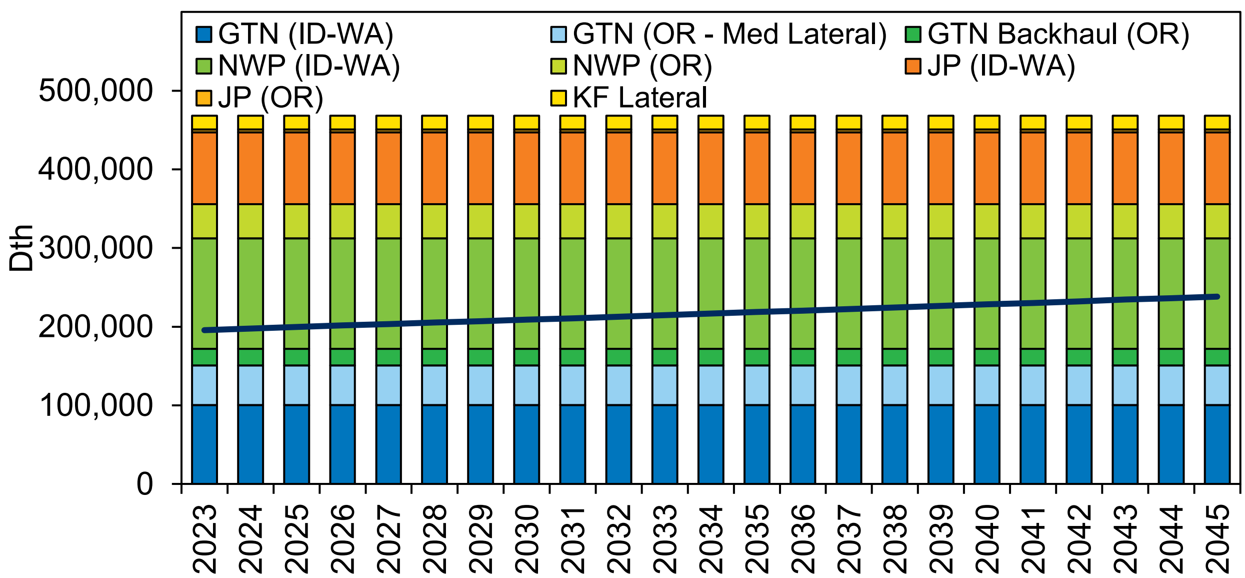


Figure 6.12: Expected Peak Day Demand Compared to Storage & Transport Rights for February 28th

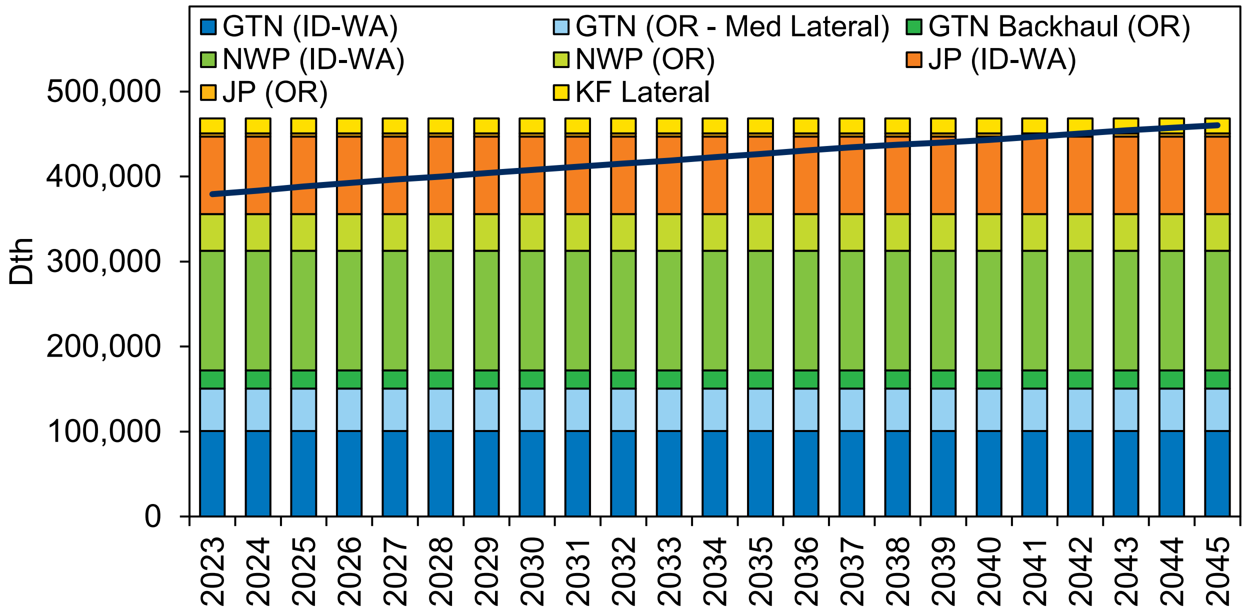
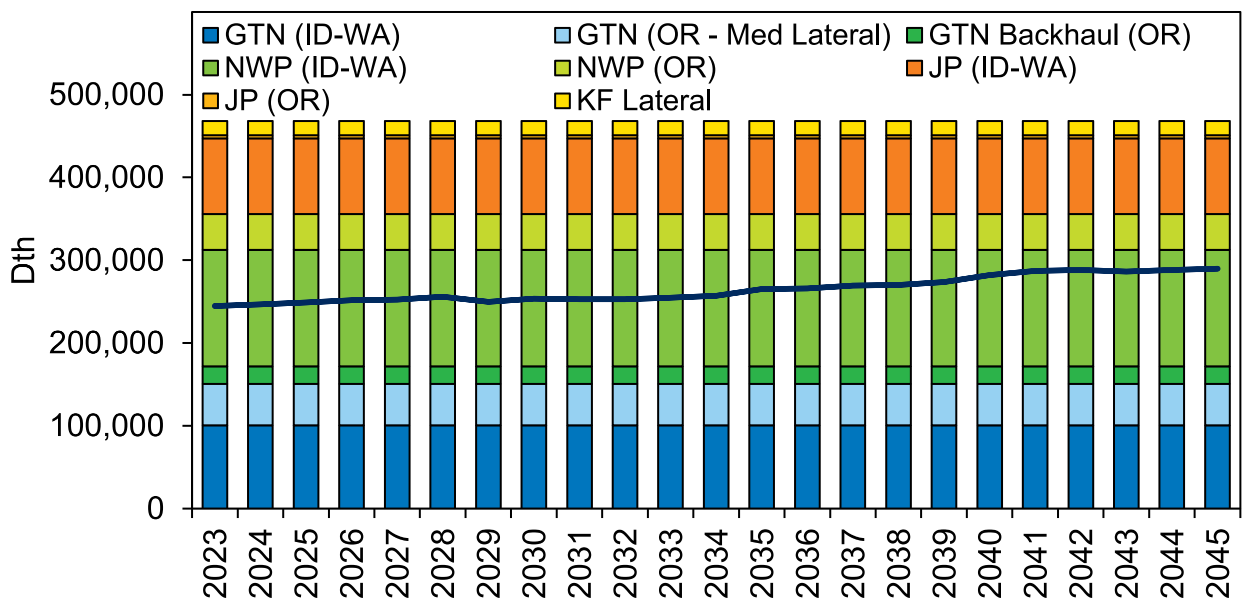


Figure 6.13: Expected Peak Day Demand Compared to Storage & Transport Rights for December 20th



When considering emissions compliance under the CCA and CPP, a different story emerges when comparing to transportation rights. Greenhouse gas 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 6.14 and Figure 6.15, equivalent emissions from firm customers and transport customers can be found in the stacked bar chart with the cap for the respective program as illustrated in by the line. These charts clearly show noncompliance if no actions are taken to offset emissions or other options per program rules, where the total emissions in the blue and green bars exceed the cap shown in orange. These shortages occur in 2023 and continue through the end of the study in 2045. Further study is required to determine demand and price in an unknown future.

Figure 6.14: Washington Emissions Forecast Compared to CCA Cap

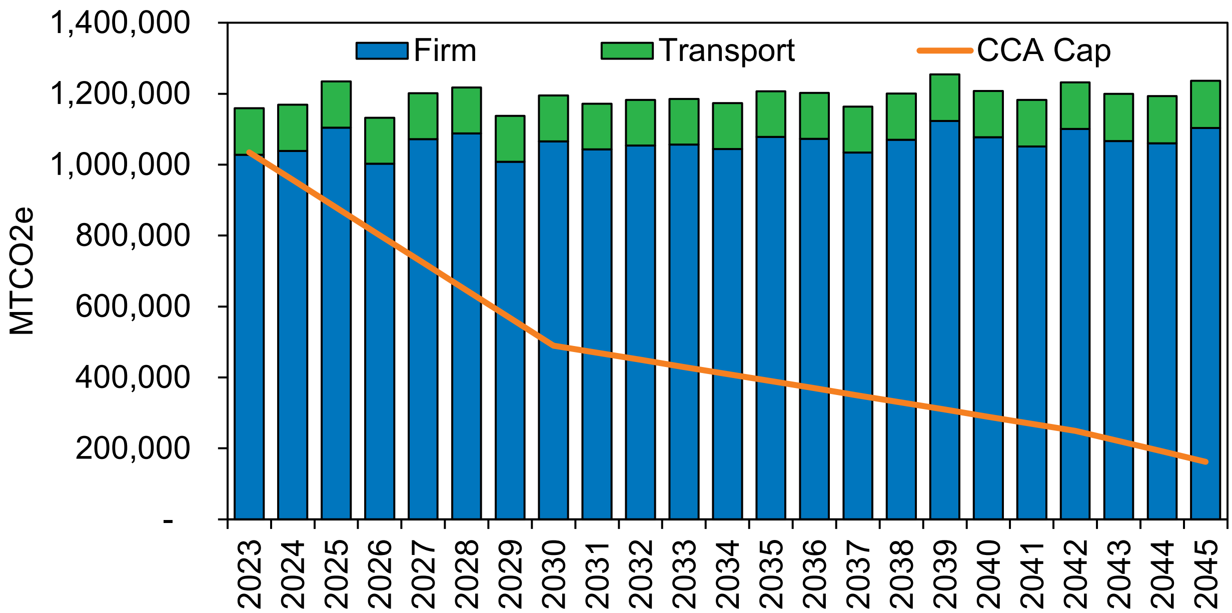
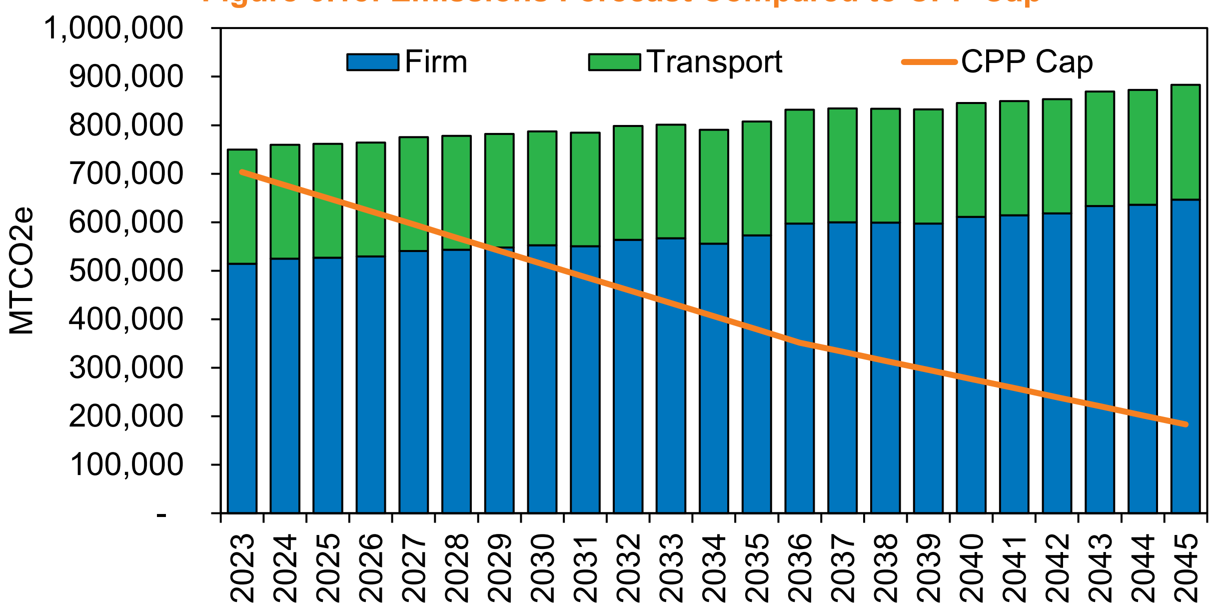


Figure 6.15: Emissions Forecast Compared to CPP Cap



New Resource Options and Considerations

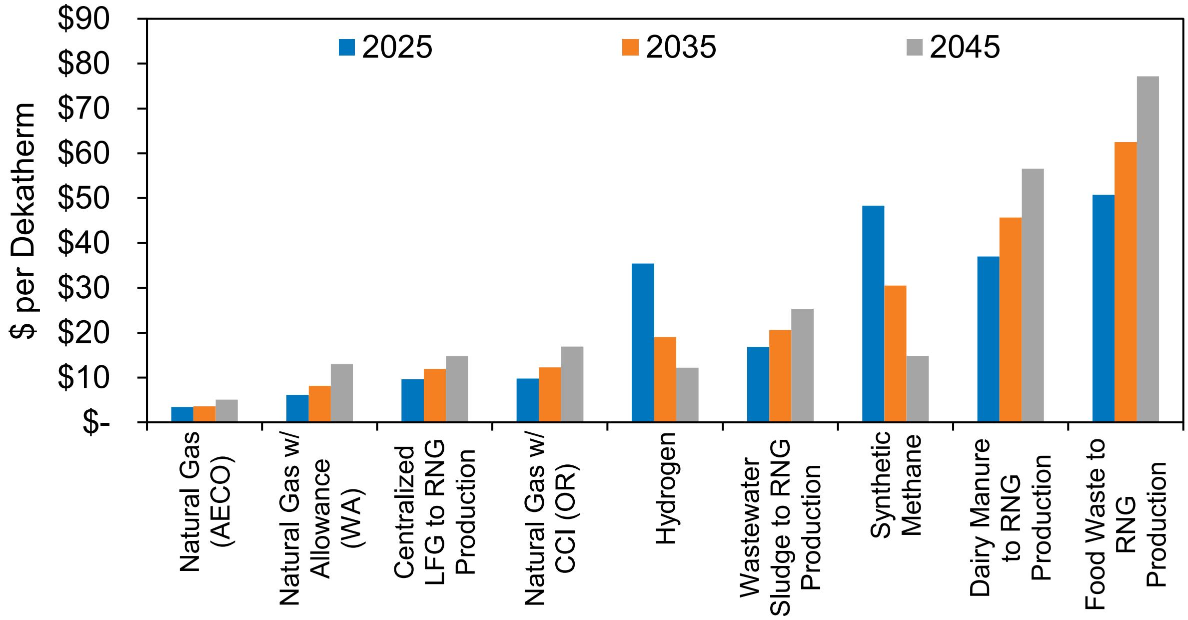
All scenarios analyzed in this IRP process contain resource needs based on the climate policy in Oregon and Washington. These options have been input into the PLEXOS® model to help solve the energy demand and emissions goals. Table 6.1 highlights supply-side and demand-side resource options as discussed in prior chapters.

Table 6.1: 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
Green Hydrogen	Electrification – Space Heat
Synthetic Methane	Electrification – Water Heat
RNG by source (Dairy, Landfill, Solid Waste, and Waste Water)	Electrification - Other
Natural Gas	Energy Efficiency (CPA from AEG and ETO)

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 shorter supply. Newly constructed resources provided by a third party, such as a pipeline, may require a 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 can be found in Chapter 4. A full set of resource options is provided in Figure 6.16 to help illustrate resource costs in comparison to one another over time. These costs exclude electrification options as found in Chapter 3, mostly as they skew the chart making the natural gas options difficult to view.

Figure 6.16: Resource Options and Costs in PLEXOS Model



Lead Time Requirements

New resource options can take up to five or more years to put in service. Open season processes to determine interest in proposed pipelines, planning and permitting, environmental review, design, construction, and testing contribute to 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 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 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 unique 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 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., firm), they may not be considered as an option for meeting unserved demand.

"Lumpiness" of Resource Options

Newly constructed resource options are often "lumpy." 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 unit costs are available with larger expansions and the economics of 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 vary, and regional LDCs may find they are competing with other parties to secure firm resources for customers. RNG resources specifically will have an increased amount of competition as the drive for carbon-reducing supplies increases with associated policy.

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 3, Avista determines energy efficiency cost effectiveness without future energy efficiency programs in the load forecast. This preliminary study provides an avoided cost curve for both Applied Energy Group (AEG) and 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, Program Administrator Costs Test, Total Resource Cost Test, and Participant Cost Test. The therm savings and associated program costs are incorporated into the PLEXOS® model therefore 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. Tables 6.2 and 6.3 show potential energy efficiency savings in dekatherms for each region from the resource potential for the Expected Case. The energy efficiency annual demand served begins to decline after reaching a peak in 2032 as a total system as measures require replacement.

Table 6.2: Annual Demand Served by Energy Efficiency

Case	Year	Klamath Falls	La Grande	Medford/Roseburg	Oregon	Idaho	Washington	Total System
PRS	2023	8,194	4,466	44,889	57,549	46,414	111,991	273,503
PRS	2024	8,504	4,635	46,586	59,725	52,700	122,712	294,863
PRS	2025	8,864	4,831	48,555	62,249	59,890	137,682	322,070
PRS	2026	9,008	4,909	49,347	63,264	55,234	123,902	305,664
PRS	2027	9,431	5,140	51,661	66,232	64,711	139,450	336,624
PRS	2028	10,110	5,510	55,382	71,002	74,970	152,821	369,795
PRS	2029	10,914	5,948	59,786	76,647	83,106	171,273	407,674
PRS	2030	11,614	6,330	63,622	81,566	89,337	177,730	430,199
PRS	2031	12,288	6,697	67,317	86,302	91,496	175,688	439,788
PRS	2032	12,839	6,997	70,332	90,168	90,704	171,846	442,886
PRS	2033	13,263	7,228	72,656	93,147	85,561	160,872	432,727
PRS	2034	13,521	7,369	74,066	94,955	78,470	146,895	415,276
PRS	2035	13,307	7,252	72,898	93,458	71,431	131,483	389,830
PRS	2036	13,059	7,117	71,535	91,711	64,587	119,970	367,979
PRS	2037	12,805	6,979	70,147	89,930	56,419	107,079	343,358
PRS	2038	12,610	6,872	69,078	88,561	49,196	91,981	318,299
PRS	2039	12,375	6,744	67,793	86,913	43,787	82,345	299,957
PRS	2040	12,210	6,654	66,886	85,750	40,163	76,356	288,019
PRS	2041	12,032	6,557	65,913	84,503	35,109	67,940	272,055
PRS	2042	11,753	6,405	64,384	82,543	34,459	64,851	264,396

Table 6.3: Average Daily Demand Served by Energy Efficiency

Case	Year	Klamath Falls	La Grande	Medford/Roseburg	Oregon	Idaho	Washington	Total System
PRS	2023	22.45	12.24	122.98	157.67	127.16	306.83	749.32
PRS	2024	23.24	12.66	127.28	163.18	143.99	335.28	805.64
PRS	2025	24.28	13.23	133.03	170.55	164.08	377.21	882.38
PRS	2026	24.68	13.45	135.20	173.33	151.33	339.46	837.44
PRS	2027	25.84	14.08	141.54	181.46	177.29	382.05	922.26
PRS	2028	27.62	15.05	151.32	193.99	204.84	417.54	1,010.37
PRS	2029	29.90	16.30	163.80	209.99	227.69	469.24	1,116.92
PRS	2030	31.82	17.34	174.31	223.47	244.76	486.93	1,178.63
PRS	2031	33.67	18.35	184.43	236.44	250.67	481.34	1,204.90
PRS	2032	35.08	19.12	192.16	246.36	247.83	469.53	1,210.07
PRS	2033	36.34	19.80	199.06	255.20	234.41	440.74	1,185.55
PRS	2034	37.04	20.19	202.92	260.15	214.99	402.45	1,137.74
PRS	2035	36.46	19.87	199.72	256.05	195.70	360.23	1,068.03
PRS	2036	35.68	19.44	195.45	250.58	176.47	327.79	1,005.41
PRS	2037	35.08	19.12	192.18	246.38	154.57	293.37	940.71
PRS	2038	34.55	18.83	189.26	242.63	134.78	252.00	872.05
PRS	2039	33.91	18.48	185.73	238.12	119.97	225.60	821.80
PRS	2040	33.36	18.18	182.75	234.29	109.74	208.62	786.94
PRS	2041	32.97	17.97	180.58	231.51	96.19	186.14	745.36
PRS	2042	32.20	17.55	176.40	226.14	94.41	177.67	724.37

Preferred Resource Strategy (PRS)

The PRS considers current supply-side resources and new resource options to solve the energy and carbon program goals. The resources Avista modeled for the current IRP include five types of RNG, hydrogen, synthetic methane, and demand side options of demand response (DR) as discussed in Chapter 4, and electrification of major end uses such as space heat, water heating and cooking detailed in Chapter 3. The cost risk for each of these selected resources can be found in Chapter 4.[2] Electrification end uses are treated as a resource and if any amount is taken, future years must take this same amount as a minimum as it's considered permanent demand loss. Demand Response is treated in a similar fashion as if a program is selected, program costs, and demand savings must be used going forward.

To solve for unserved demand and emissions goals, a set of resources options are available to meet the requirements of energy, capacity and emissions constraints as determined from these stochastic draws. This stochastic evaluation is a deviation from prior resource plans and has been introduced to not over procure new resources, while maintaining compliance to emission reduction programs. Using deterministic results would create a yearly energy peak and may increase risks in the over investment in resources. As discussed in Chapter 2, weather and demand will vary as shown historically, and planning for new resource must be considered on a stochastic basis.

Idaho PRS

The Idaho PRS continues to utilize the least cost natural gas basin, and storage, combined with energy efficiency to meet energy demand as illustrated in Figure 6.17. Natural gas will be acquired on a least cost basis from the available hubs as illustrated in Figure 6.18. 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 amount of pipeline capacity is located.

[2] Chapter 4 – Current Supply-Side Resources and New Resource Options.

Figure 6.17: Idaho Preferred Resource Strategy

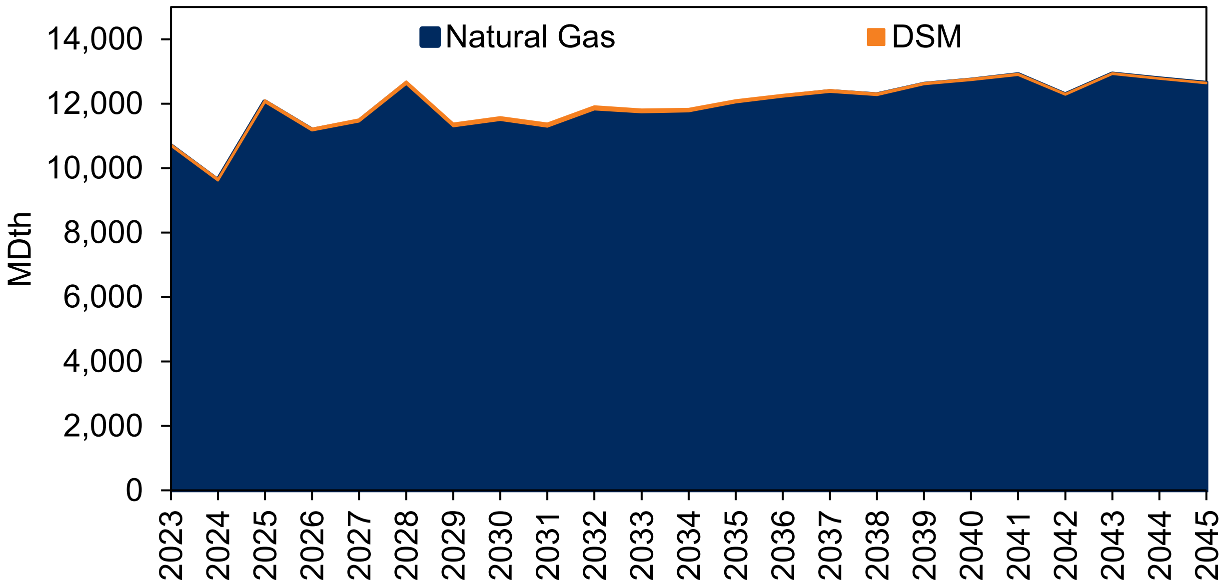
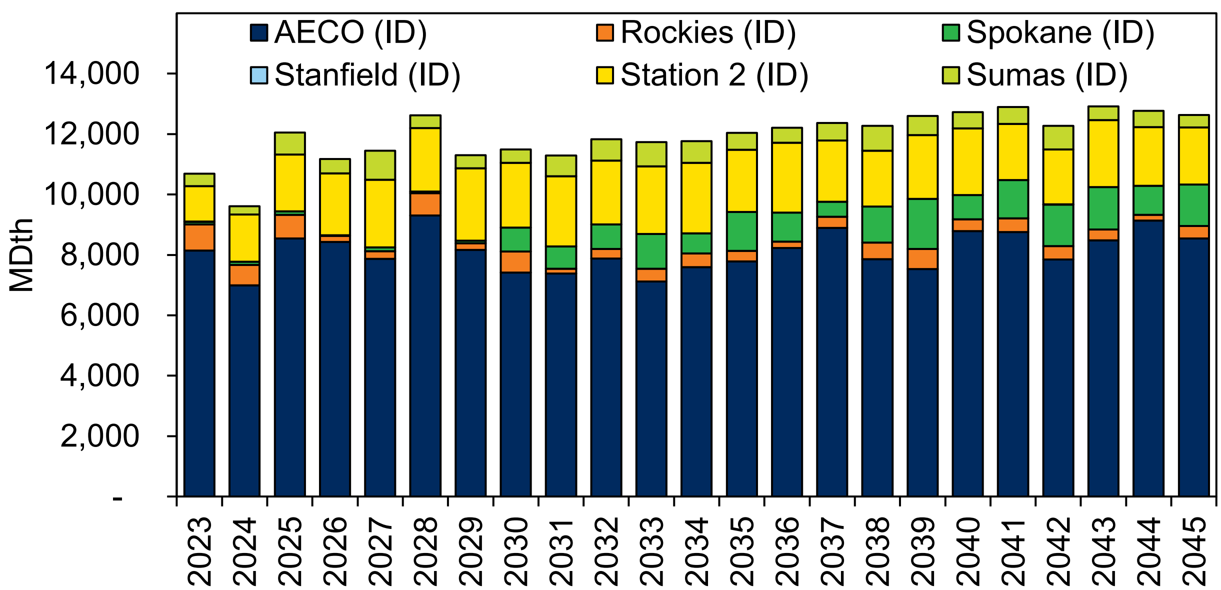


Figure 6.18: Natural Gas Basin Least Cost - Idaho



Oregon PRS

Oregon's PRS has drastically changed as compared to the 2021 IRP. Changes adhere to the new environmental goals of the CPP and the estimated energy demand. In the near-term, the new resource need is acquired via a combination of RNG from Landfill Gas (LFG), Wastewater Treatment Plants (WWTP), energy efficiency, Community Climate Investments (CCIs), and conventional natural gas. Synthetic methane is added to the resource mix beginning in the 2030's, as illustrated in Figure 6.19. Least cost natural gas basin is illustrated in Figure 6.20. In each figure, the dark blue area at the bottom of the chart depicts natural gas with no emissions instrument for compliance, essentially the cap of the CPP.

Figure 6.19: Oregon Preferred Resource Strategy

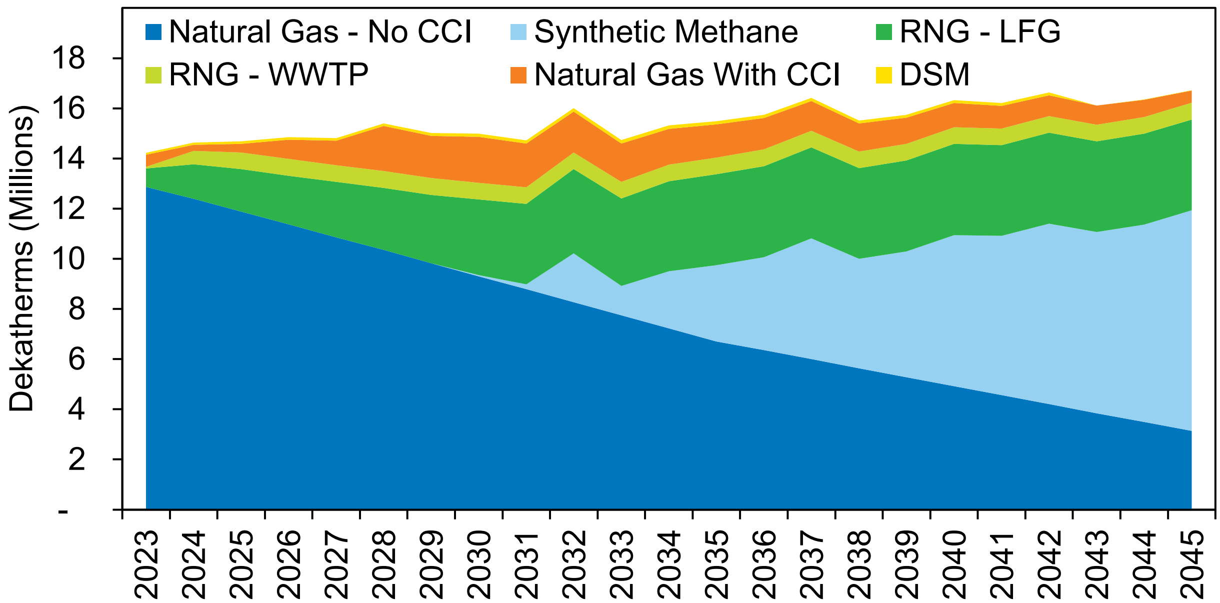
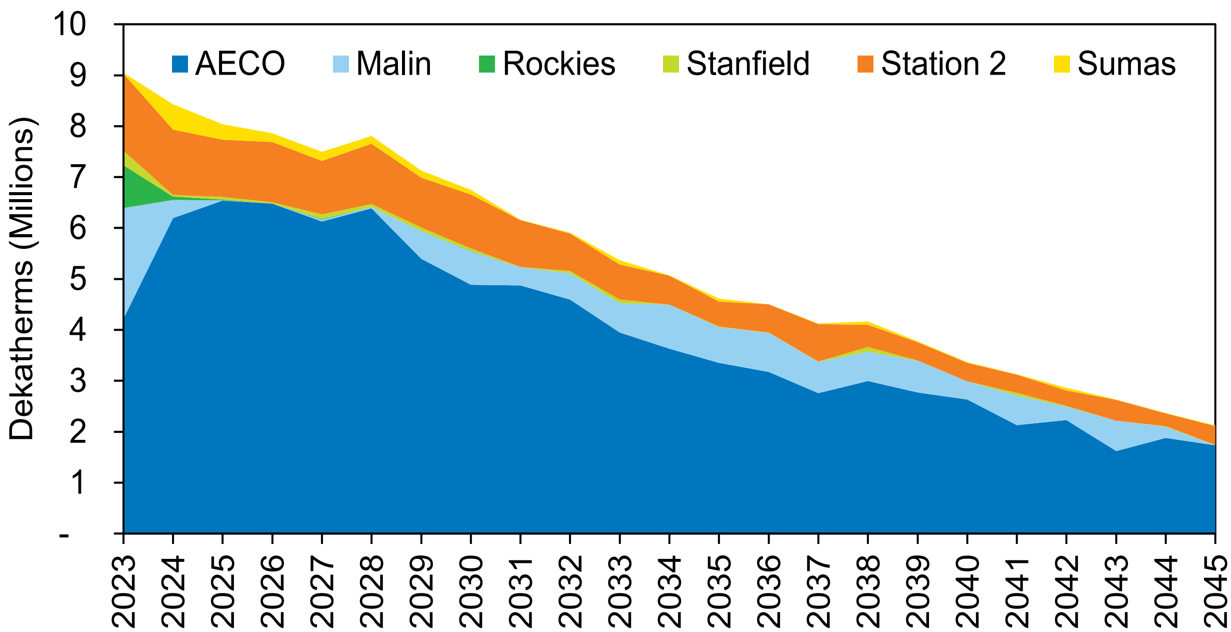


Figure 6.20: Natural Gas Basin Least Cost – Oregon



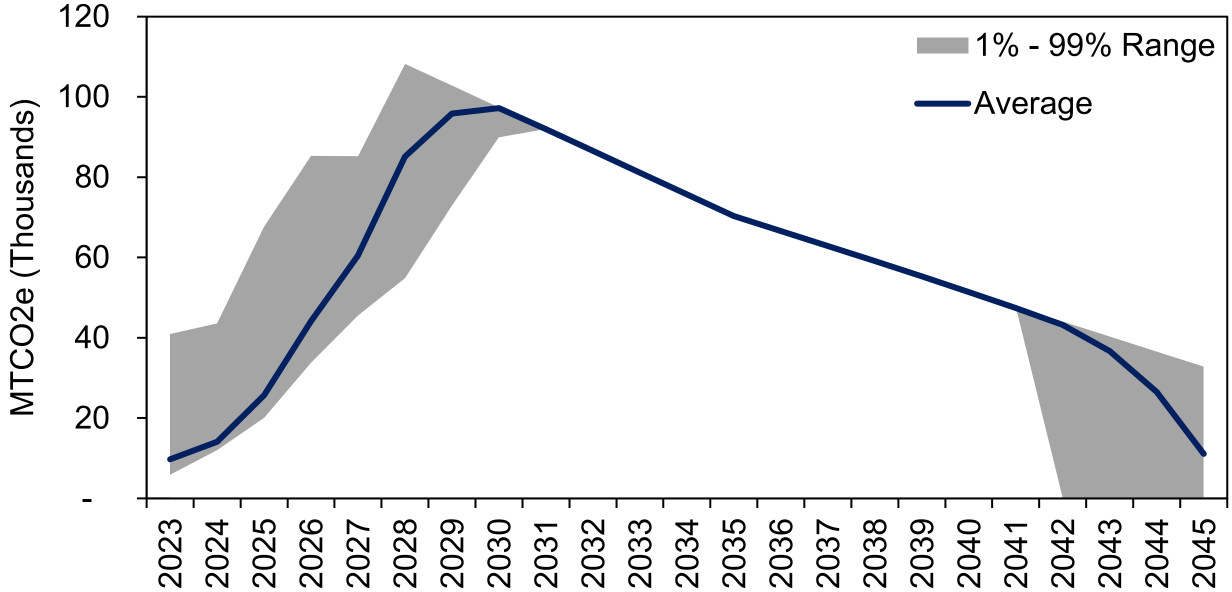
As discussed in Chapter 5, the number of CCIs available to Avista declines with the cap each year. To backfill these lost CCIs additional resources need to be brought onto the system on an annual basis through the end of the study timeframe. This will lead to an increased number of renewable energy sources needed as depicted in Table 6.4.

Table 6.4: Average Daily Resource Quantities by Year

Year	Natural Gas - No CCI	Synthetic Methane	RNG - LFG	RNG - WWTP	Natural Gas with CCI (Dth equivalent)
2023	35,237	-	2,024	196	1,310
2024	33,960	-	3,762	1,460	666
2025	32,568	-	4,619	1,824	955
2026	31,173	-	5,306	1,824	2,095
2027	29,747	-	6,038	1,824	2,681
2028	28,375	-	6,773	1,829	4,923
2029	26,908	-	7,474	1,824	4,613
2030	25,491	138	8,240	1,824	5,028
2031	24,082	517	8,800	1,824	4,748
2032	22,654	5,329	9,208	1,829	4,469
2033	21,219	3,205	9,559	1,823	4,190
2034	19,795	6,229	9,837	1,824	3,910
2035	18,377	8,337	9,918	1,824	3,631
2036	17,405	10,172	9,947	1,827	3,437
2037	16,430	13,210	9,920	1,823	3,244
2038	15,448	11,936	9,920	1,824	3,050
2039	14,462	13,748	9,920	1,824	2,856
2040	13,486	16,507	9,946	1,828	2,663
2041	12,491	17,401	9,920	1,824	2,469
2042	11,523	19,717	9,920	1,824	2,276
2043	10,533	19,778	9,920	1,824	2,082
2044	9,563	21,552	9,947	1,829	1,888
2045	8,597	24,093	9,920	1,824	1,356

CCIs are expected to be a least cost solution when compared to renewable resource options, due to the ability to pair CCIs with natural gas as a low quantity solution. Low carbon resource fuels will be needed to serve a consistent demand of energy and emissions. Also, due to the divergent weather locations, the risk 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 are warmer climates and do not get the extreme temperatures. Figure 6.21 illustrates the range in CCIs required given the potential for weather variance. In the near term the CCIs have a wide range of volumes required. Beginning in 2030, the range disappears as the certainty of the demand for these instruments in meeting CPP emission compliance is necessary to procure the entire amount available within the program. Finally, the study points to more uncertainty for CCIs as alternative fuels may become more cost effective in the 2042 and beyond time horizon.

Figure 6.21: Community Climate Investment Quantity – (MTCO2e)



Washington PRS

Washington's PRS has also changed dramatically from the 2021 IRP. The CCA has introduced a cap-and-trade program with the ability to cover emissions with an allowance or offset. Allowance and offset prices may drive a different PRS than the one illustrated in Figure 6.22. The range of allowance prices for 2023 is $22 to $82 USD. The PRS shows conventional natural gas and energy efficiency as the primary energy source options until the end of the study horizon (2044), when synthetic methane is chosen. The darker blue area in the chart is the CCA program cap and would not require any type of program instruments. The lighter blue area represents natural gas as an energy source, requiring an offset or an allowance as it is above the cap. Natural gas will continue to be procured from the least cost supply basin as shown in Figure 6.23.

Figure 6.22: Washington Preferred Resource Strategy

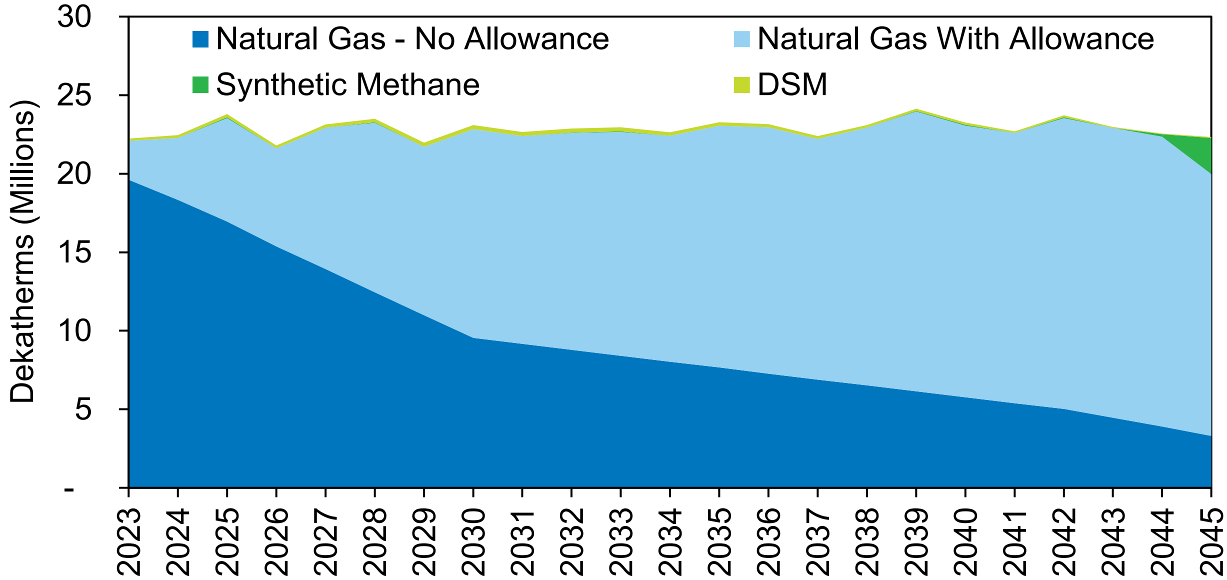
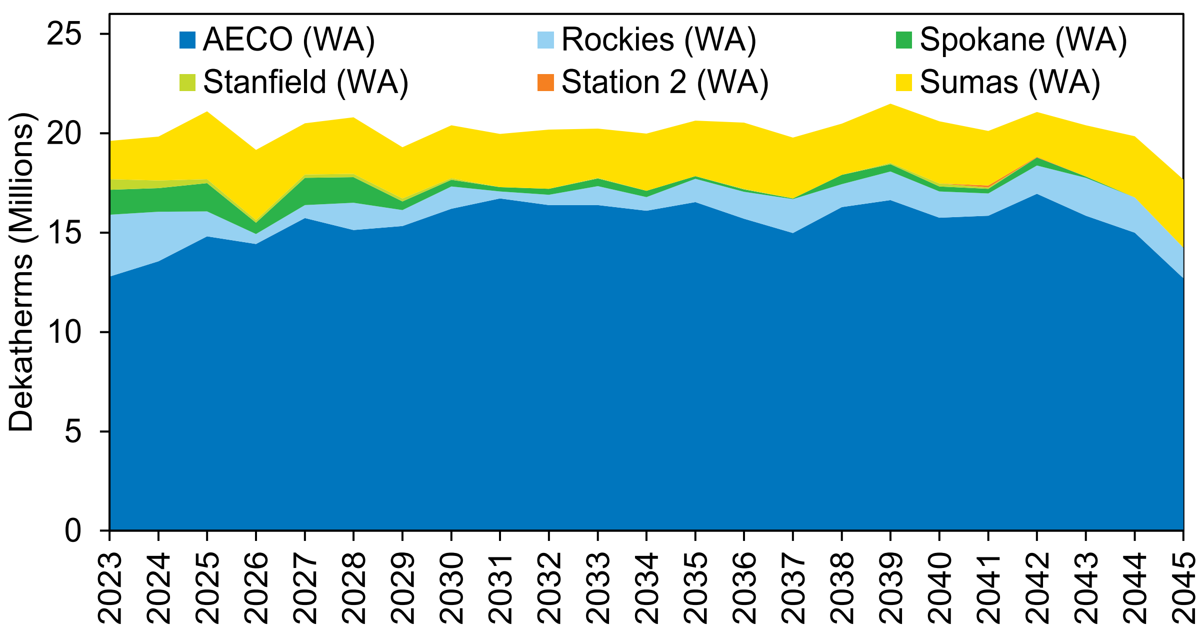


Figure 6.23: Natural Gas Basin Least Cost - Washington



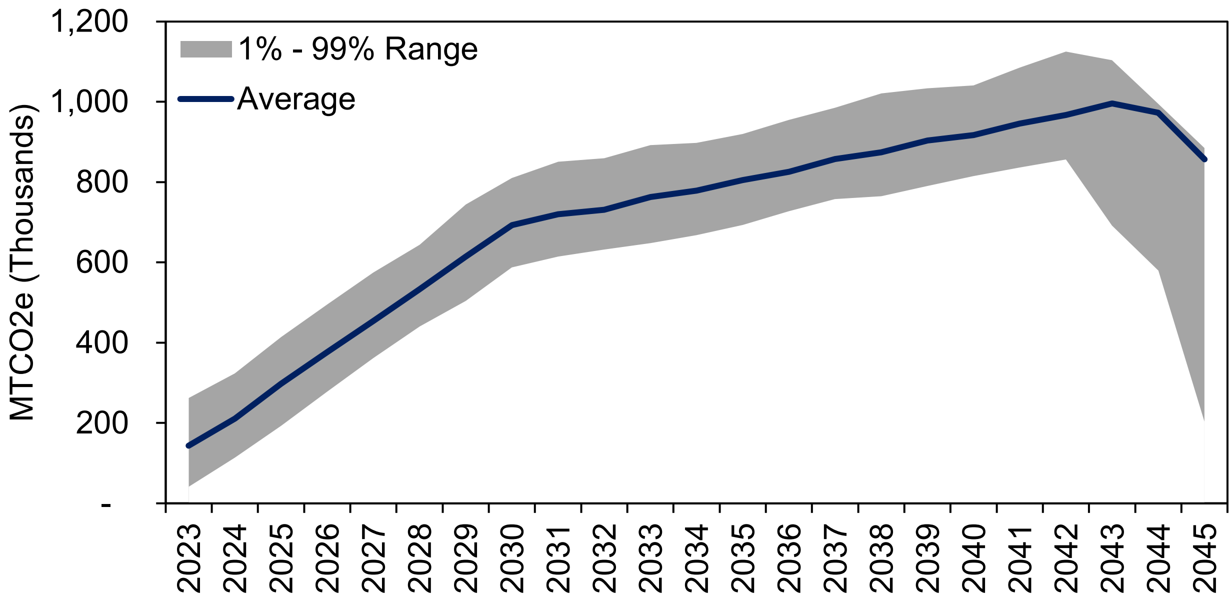
The specific resource selection by year is shown in Table 6.5. Avista does not expect a significant reduction in traditional natural gas use with the CCA prices assumed in this expected case. Chapter 7 identifies how reduction in traditional natural gas may occur either by way of higher CCA prices or non-cost-effective electrification.

Table 6.5: Average Daily Resource Quantities by Year – Washington

Year	Energy Efficiency	Natural Gas	Synthetic Methane	Allowances DTh Equivalent	Natural Gas - No allowance	Natural Gas with allowance
2023	404	60,537	-	6,807	53,730	6,807
2024	507	60,881	-	10,804	50,077	10,804
2025	558	64,507	136	18,075	46,432	18,075
2026	519	59,228	-	17,105	42,122	17,105
2027	563	62,859	-	24,688	38,171	24,688
2028	612	63,497	119	29,472	34,026	29,472
2029	685	59,521	3	29,412	30,109	29,412
2030	717	62,552	0	36,417	26,135	36,417
2031	723	61,364	-	36,236	25,128	36,236
2032	717	61,759	52	37,748	24,011	37,748
2033	686	62,066	141	39,023	23,043	39,023
2034	641	61,415	-	39,422	21,994	39,422
2035	585	63,193	3	42,210	20,983	42,210
2036	546	62,735	-	42,884	19,851	42,884
2037	496	60,887	5	42,055	18,833	42,055
2038	427	62,836	20	44,967	17,869	44,967
2039	372	65,626	157	48,772	16,854	48,772
2040	340	63,017	177	47,287	15,730	47,287
2041	300	61,895	20	47,151	14,744	47,151
2042	287	64,523	159	50,754	13,769	50,754
2043	154	62,775	14	50,559	12,217	50,559
2044	136	61,087	428	50,438	10,649	50,438
2045	129	54,741	6,313	45,678	9,063	45,678

Allowances and offsets will be considered interchangeably and compared to one another with available options at the time of purchase. In the event Avista can obtain offsets at a lower price than allowances, offsets will be purchased in place of allowances. The PRS selects program instruments each year as shown in Figure 6.24 with bounds to address the potential need for more or less allowances. Similar to CCIs in Oregon, the range of allowance volumes beginning in 2040 becomes volatile as alternative resources become cost effective in comparison to natural gas paired with an allowance.

Figure 6.24: CCA Allowances/Offsets Quantity Needed (MTCO2e)



Monte Carlo Risk Analysis

Avista uses 500 Monte Carlo draws (23-year futures, 2023 – 2045) to measure the statistical risk of varying elements such as price and demand based on the new resources selected from the five stochastic simulations. Weather and price risk related to costs of our PRS case are put through a Monte Carlo simulation based on the stochastic scenario solve. The Monte Carlo simulation in PLEXOS® can vary index price and weather simultaneously. This simulates the effects each have on the other. Monte Carlo solves resources and demand need for each year based on least cost pricing.

Avista performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural and renewable gas prices, Allowance prices, the occurrence of a national carbon tax applied to Idaho beginning in 2030, 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.

Annual system demand costs are summarized in Figure 6.25 and illustrate the cost volatility across the system. Some costs such as CCIs for compliance with the CPP are known, other than inflation, so there is little risk in the movement of costs from year to year. The costs of allowances or offsets to comply with the CCA are not known and can move between the floor and ceiling on an annual basis. Figures 6.25 through 6.28 illustrate the specific cost information based on jurisdiction.

Figure 6.25: System Annual Costs – 1,000 of $ (500 Draws)

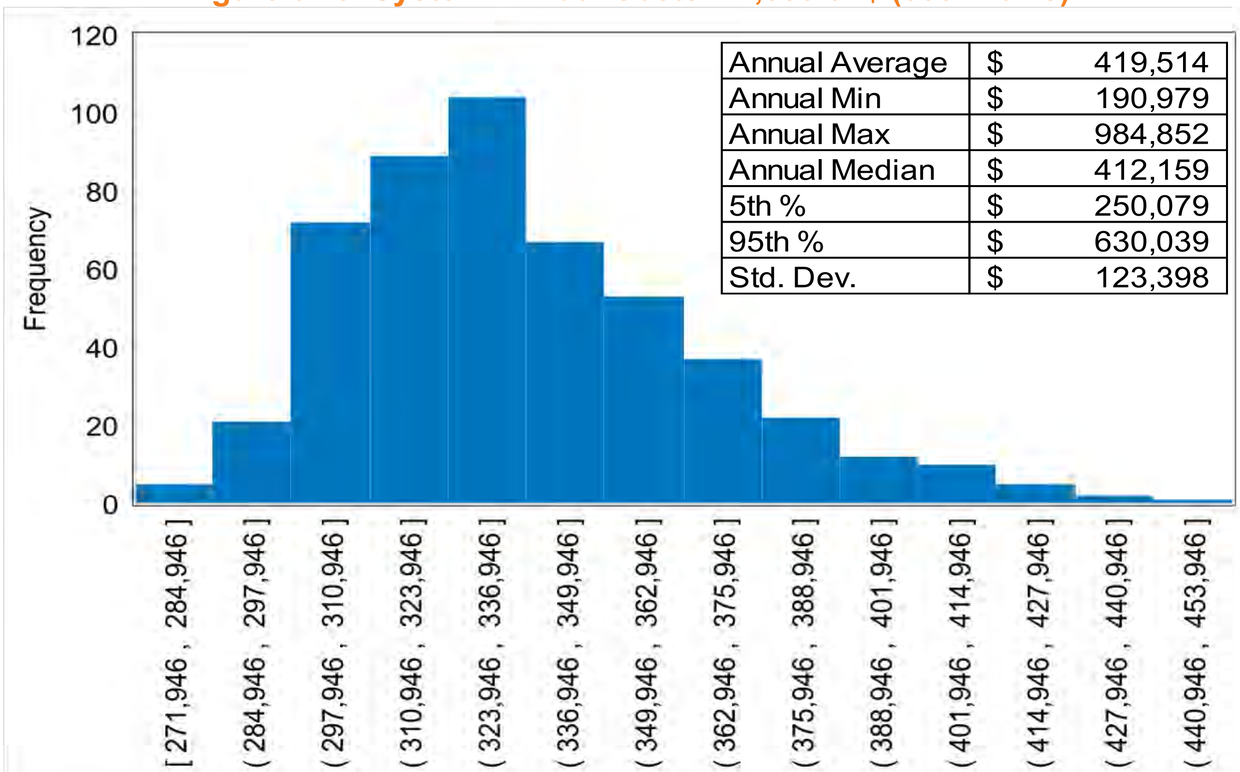


Figure 6.26: Idaho Annual Costs – 1,000 of $ (500 Draws)

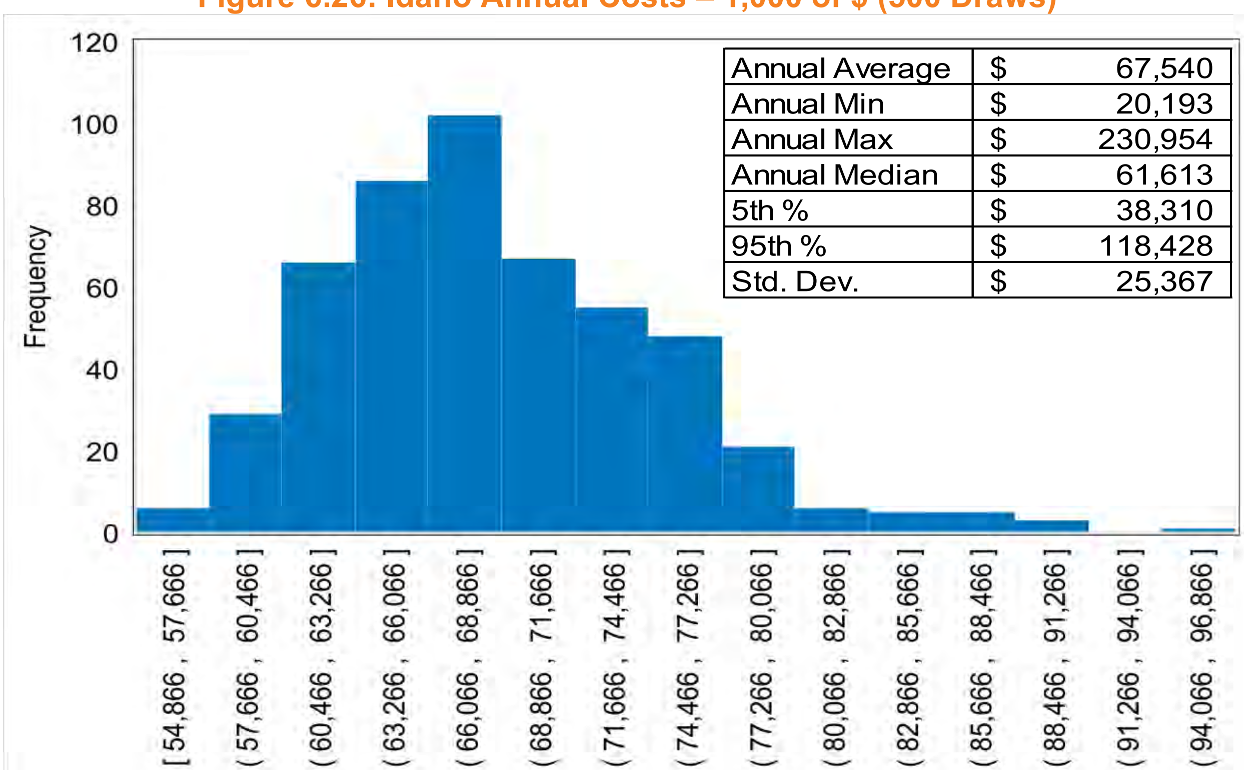


Figure 6.27: Oregon Annual Costs – 1,000 of $ (500 Draws)

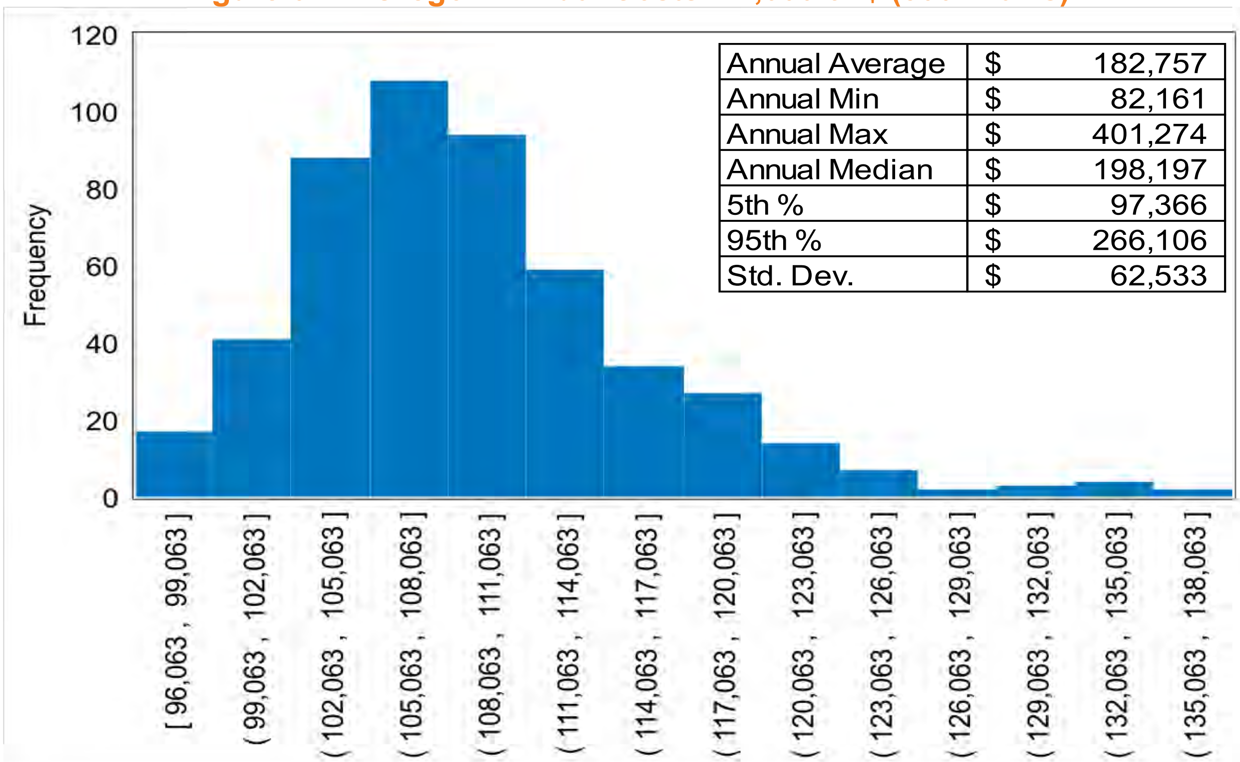
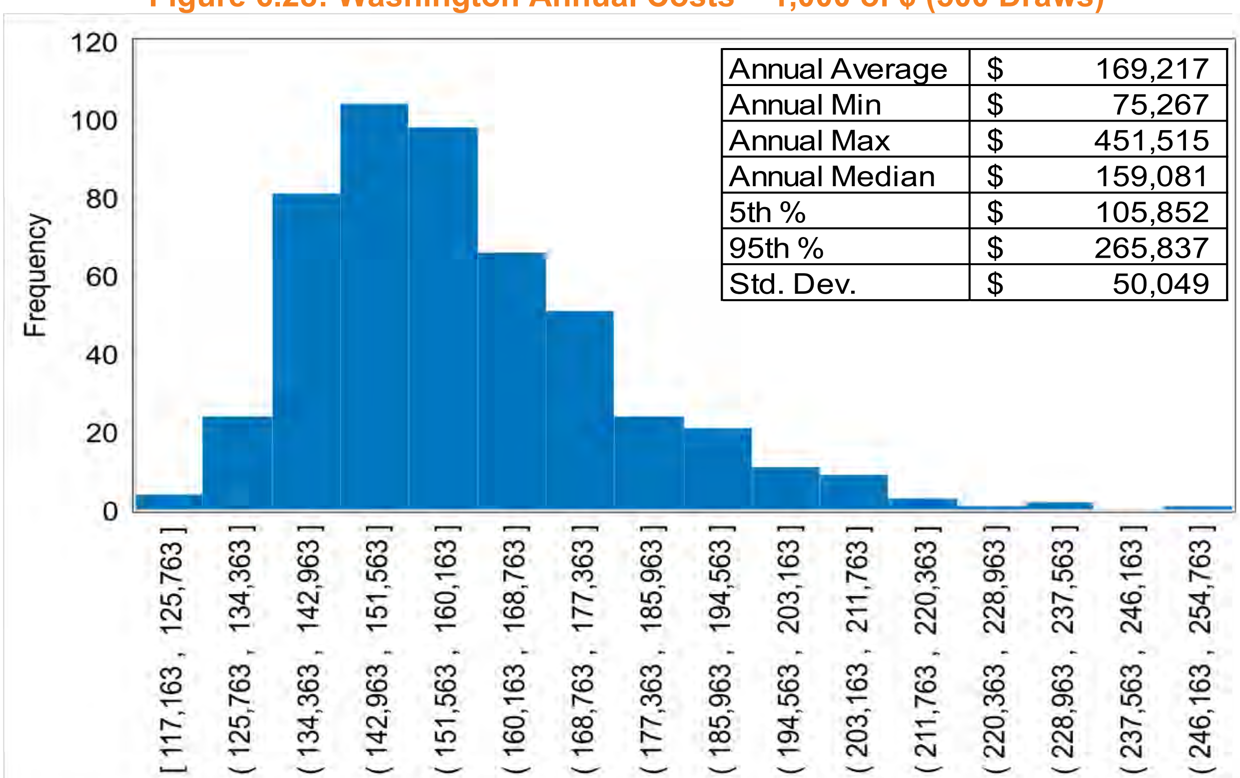


Figure 6.28: Washington Annual Costs – 1,000 of $ (500 Draws)



Estimated Price Impacts

The estimated rate impacts are intended to give a commodity only estimate of impacts to meet the energy demand and emissions goals. Specifically, these price estimates include contracted, owned, or leased infrastructure resources, the energy and any fuel needed to move the energy (if required). The price impacts by specific customer class, like low-income residential customers in Washington, will differ from non-low-income customers. These are just for illustrative purposes to general area and class. General and administrative costs of providing energy, office support, and its infrastructure are not included in these overall estimates. Figure 6.29 through Figure 6.32 illustrate price impacts by generic class and jurisdiction.

Figure 6.29: Residential Price Impact ($ of therm)

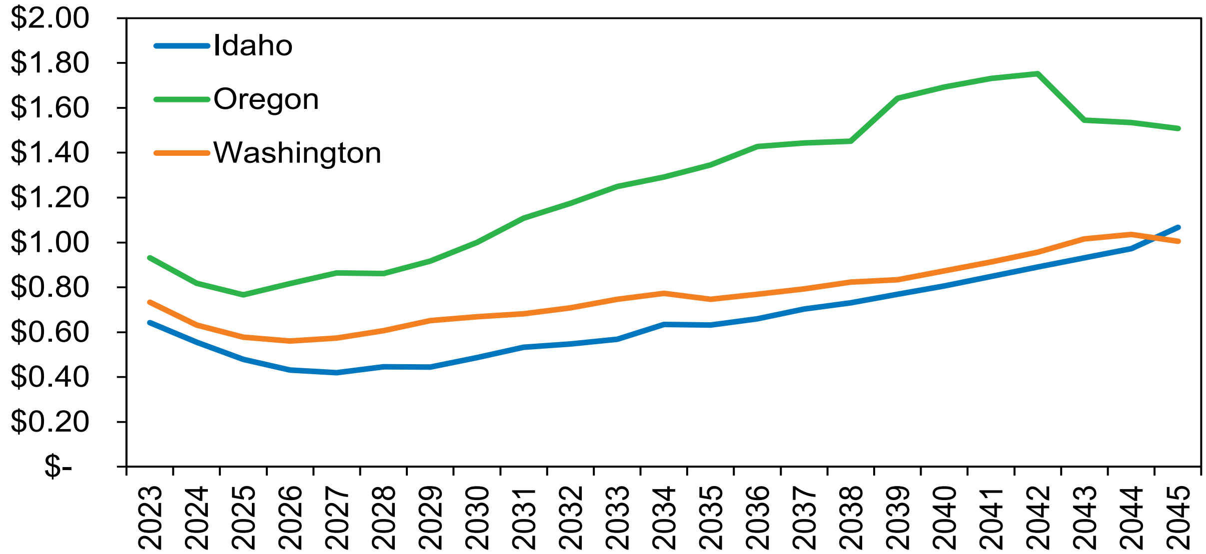


Figure 6.30: Commercial Price Impact ($ per therm)

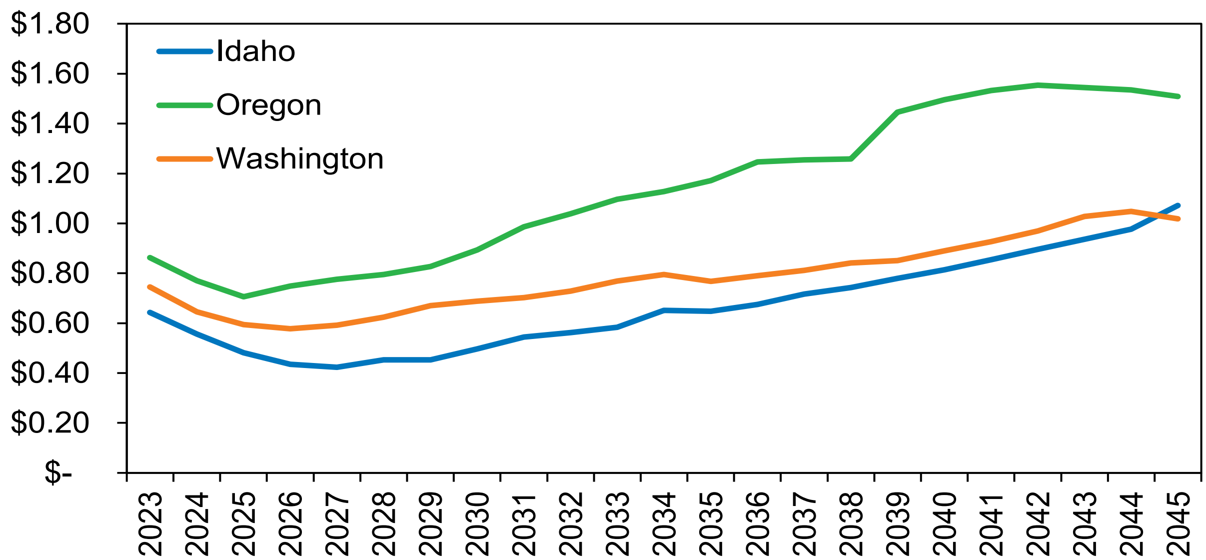


Figure 6.31: Industrial Price Impact ($ per therm)

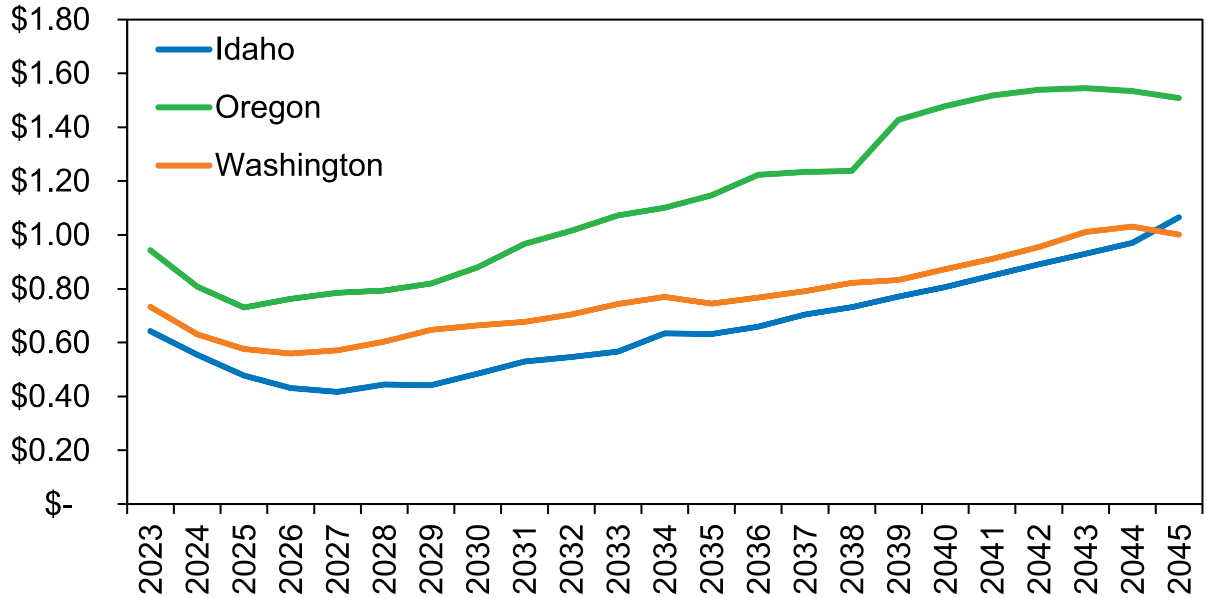
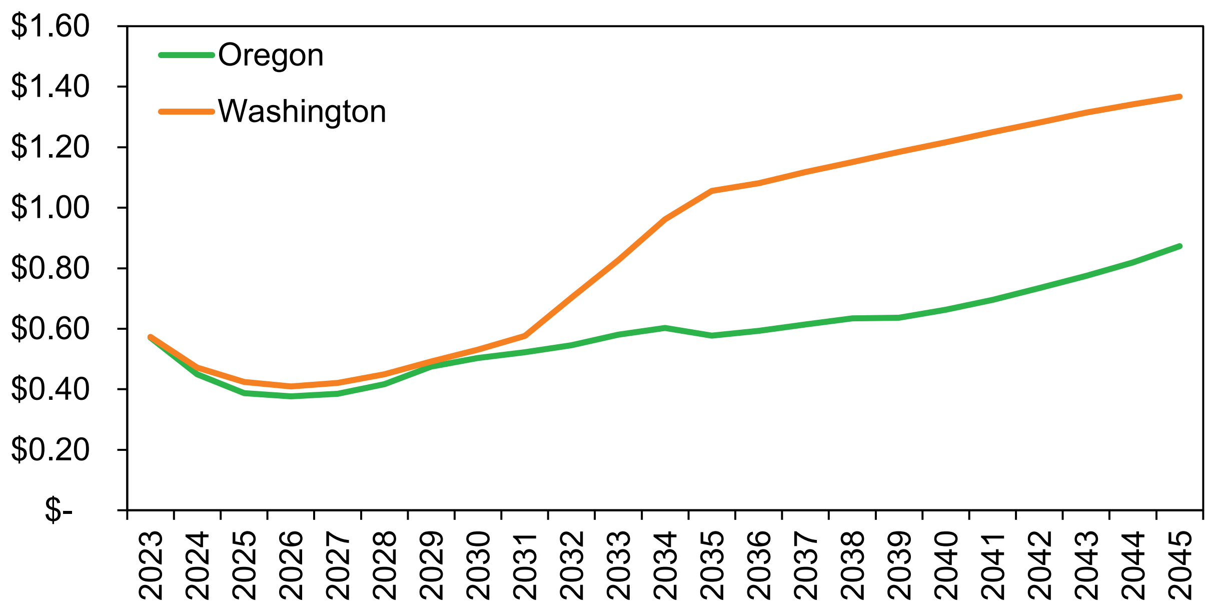


Figure 6.32: Transport Price Impact ($ per therm)



This Page Intentionally Left Blank

7. Alternate Scenarios

Avista applied the Preferred Resource Strategy and Risk analysis in Chapter 6 to alternate demand and supply resource scenarios to develop a range of alternate portfolios. This modeling approach considered different underlying assumptions vetted with the TAC members to develop a consensus about the number of cases to model. These scenarios help in the understanding of the PRS results and to provide insight of the costs and benefits with policy changes.

Alternate Demand Scenarios

As discussed in Chapter 2, Avista identified alternate scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. The scenarios consider different demand and price-influencing factors as shown in Table 7.1.

Table 7.1: 2023 IRP Scenarios

<table>
<tr><th>2023 IRP Scenarios</th><th>Natural Gas Prices</th><th>DSM Potential</th><th>CCA</th><th>Customer Growth</th><th>Electrification Conversion Costs</th><th>Renewable Prices</th><th>Renewable Supply</th><th>Pipeline Outages</th><th>Carbon Intensity Natural Gas</th><th>Carbon Intensity Renewables</th><th>Cost of Carbon</th><th>Weather</th><th>UPC</th><th>CPP</th></tr>
<tr><td>PRS</td><td>Expected</td><td>Expected</td><td rowspan="3">Expected Price (Allowances)</td><td rowspan="4">Expected</td><td rowspan="5">Expected</td><td rowspan="8">Expected</td><td rowspan="8">Expected</td><td rowspan="9">None</td><td rowspan="10">117 lbs. per Dekatherm</td><td rowspan="10">0 lbs. per Dekatherm</td><td rowspan="11">Carbon Tax Beginning 2030 Idaho Only</td><td rowspan="12">Climate Change</td><td rowspan="13">5-Year UPC - OR
3-Year UPC - ID
3-Year UPC WA

Space Heat Demand Only for New Residential + New Commercial Customers in Washington</td><td rowspan="14">Emission Targets + CCI Prices</td></tr>
<tr><td>PRS - Low Prices</td><td>Low</td><td>Low</td></tr>
<tr><td>PRS - High Prices</td><td>High</td><td>High</td></tr>
<tr><td>PRS - Allowance Price Ceiling</td><td rowspan="11">Expected</td><td rowspan="11">Expected</td><td>Ceiling Price (Allowances)</td></tr>
<tr><td>Electrification - Expected Conversion Costs</td><td rowspan="10">Expected Price (Allowances)</td><td rowspan="3">Electrification</td></tr>
<tr><td>Electrification - High Conversion Costs</td><td>High</td></tr>
<tr><td>Electrification - Low Conversion Costs</td><td>Low</td></tr>
<tr><td>High Customer Case</td><td>High</td><td rowspan="7">Expected</td></tr>
<tr><td>Limited RNG Availability</td><td rowspan="6">Expected</td><td>High</td><td>Low</td></tr>
<tr><td>Interrupted Supply</td><td rowspan="5">Expected</td><td rowspan="5">Expected</td><td>50% Capacity Station 2, Sumas, and Rockies</td></tr>
<tr><td>Carbon Intensity</td><td rowspan="4">None</td><td>128.27 lbs. per Dekatherm</td><td>Carbon Intensity</td></tr>
<tr><td>Social Cost of Carbon</td><td rowspan="3">117 lbs. per Dekatherm</td><td rowspan="3">0 lbs. per Dekatherm</td><td>Social Cost of Carbon @ 2.5%</td></tr>
<tr><td>Average Case</td><td rowspan="2">Carbon Tax Beginning 2030 Idaho Only</td><td>20 Year Average</td></tr>
<tr><td>Hybrid Case</td><td>Climate Change</td><td>Space Heat Demand Only for Hybrid Customers</td></tr>
</table>

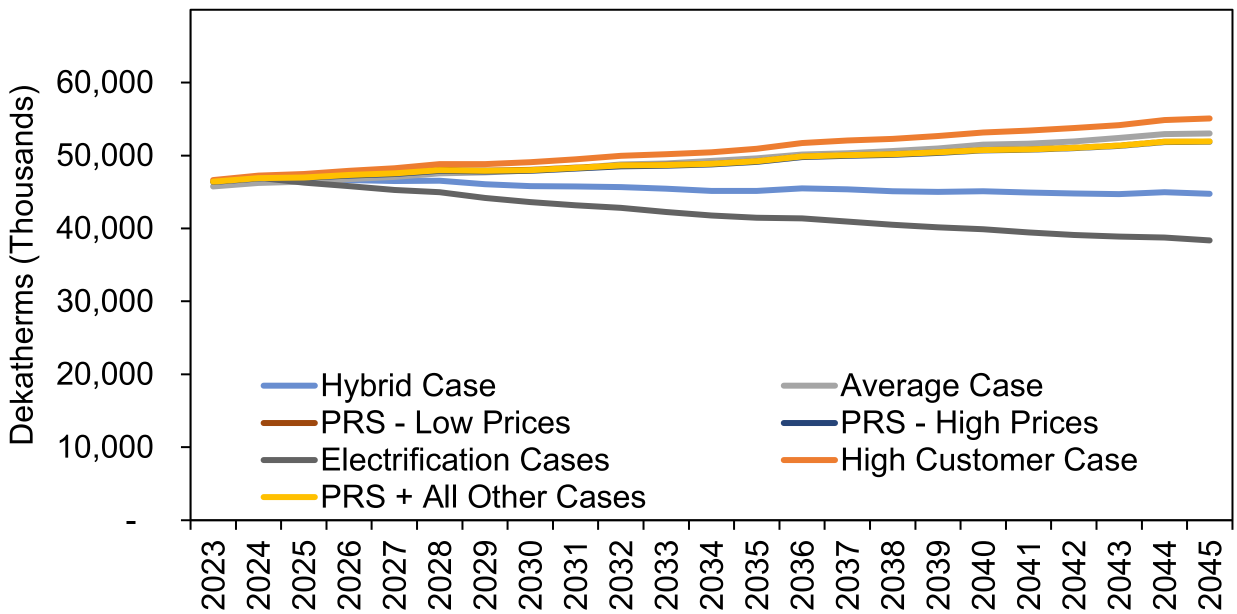
Deterministic – Portfolio Evaluation and Scenario Results

A deterministic evaluation was used to consider alternative scenarios. 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 Scenario by creating high and low boundaries for customer count, weather, and pricing. Each portfolio runs through PLEXOS® 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 least cost results.

Demand

Demand profiles, for firm customers and net of DSM measures, over the planning horizon for each of the scenarios shown in Figure 7.1. illustrate the demand risks from the alternate scenarios. The demand for our High Customer Case shows the greatest expected system demand with the Electrification Cases showing the lowest expected demand. As discussed in previous chapters, demand is the greatest risk in this IRP and has fundamentally changed due to building codes and climate programs. The PRS, and associated scenarios, all show an increasing demand through the study horizon while the Electrification scenarios assume a steady conversion of natural gas customers to the electric grid. Further analysis will be necessary to carefully consider impacts to future demand expectations and resources to meet those needs.

Figure 7.1: Demand by Scenario



PRS Scenarios

The PRS Alternative Scenarios measure the same basic assumptions as the PRS, but study different cost implications for modeled resources options. These scenarios consider lower and higher natural gas prices and the ceiling price for the CCA to help determine a crossover point for different resources. The costs for these resources can vary for a myriad of reasons such as supply issues, inflation, or policy. Individual descriptions are provided below by scenario. Figure 7.2 illustrates the alternative PRS scenarios as compared to the PRS costs.

Preferred Resource Strategy (PRS)

Included in Chapter 7 to illustrate the different outcomes for prices and demand based on different scenarios. A full description of the PRS can be found in Chapter 6.

Preferred Resource Strategy – Low Prices

Considers both lower price expectations by resource, as discussed in Chapter 4 and a resulting lower avoided cost curve and DSM potential, as described in Chapter 3. This will help determine a least cost supply and demand side resource selection assuming natural gas prices are lower than our expected price curve.

Preferred Resource Strategy – High Prices

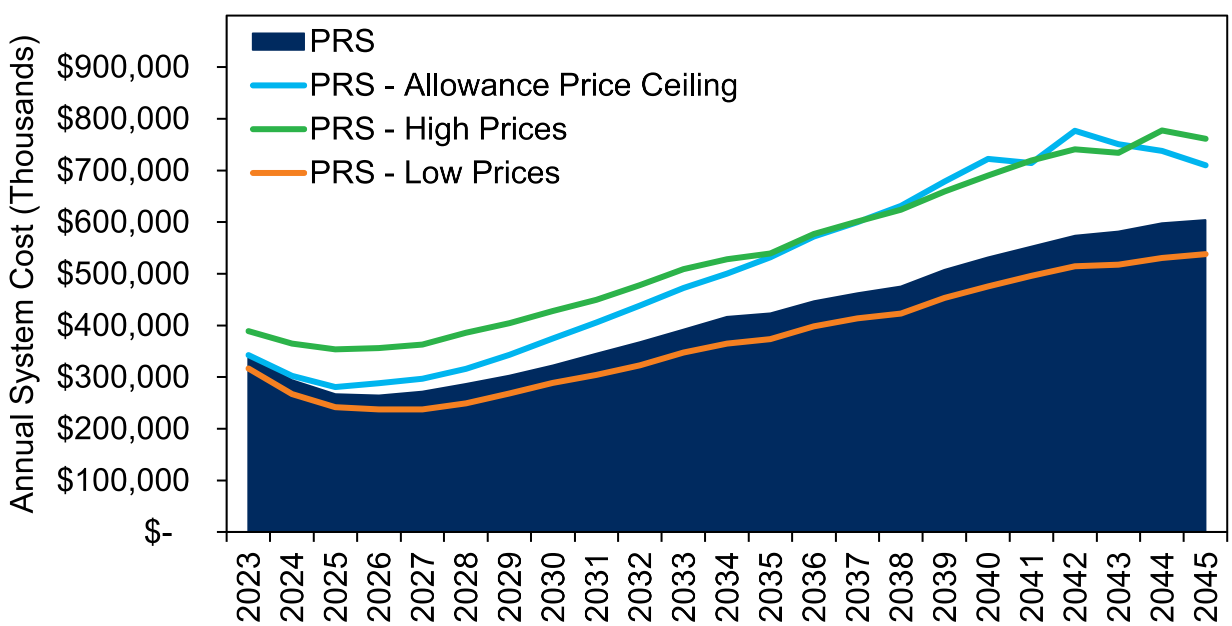
Considers a higher resource price combined with a higher DSM potential. A new set of supply and demand side resources and compliance instruments for the CCA and CPP are selected to maintain emissions compliance.

Preferred Resource Strategy – Allowance Price Ceiling

A scenario to consider a ceiling price in the CCA program in Washington State. The auction process and quantity of allowances available and an unknown amount of demand for these instruments creates a risk to the IRP considerations if the allowance price is higher than expected. This scenario considers a ceiling allowance price and resource selection alternatives to acquire a set of least cost and risk portfolio.

Annual system costs for alterative future scenarios compared to the PRS are illustrated in Figure 7.2.

Figure 7.2: PRS Scenarios - Annual System Costs



In Table 7.2, the portfolio selections for these alternative scenarios can be compared to the PRS where energy resources are in thousands of dekatherms and compliance instruments are in metric tons of carbon dioxide equivalent (MTCO2e). Quantities are similar across the three PRS scenario alternatives other than the quantity of natural gas selected.

Table 7.2: PRS Scenarios - Portfolio Selections

Scenario	Category	2025	2035	2045
PRS	Synthetic Methane (,000s of Dth)	93	146	5,191
PRS	OR - Renewables (,000s of Dth)	2,000	7,295	8,973
PRS	Natural Gas (,000s of Dth)	45,485	42,403	37,022
PRS	CCI (MTCO2e)	16,758	70,337	-
PRS	Allowances (MTCO2e)	283,273	793,898	884,819
PRS - Allowance Price Ceiling	Synthetic Methane (,000s of Dth)	93	146	24,009
PRS - Allowance Price Ceiling	OR - Renewables (,000s of Dth)	1,927	7,210	8,560
PRS - Allowance Price Ceiling	WA - Renewables (,000s of Dth)	29	24	555
PRS - Allowance Price Ceiling	Natural Gas (,000s of Dth)	45,685	42,676	18,645
PRS - Allowance Price Ceiling	CCI (MTCO2e)	16,758	70,337	-
PRS - Allowance Price Ceiling	Allowances (MTCO2e)	283,273	793,898	-
PRS - High Prices	Synthetic Methane (,000s of Dth)	91	145	6,913
PRS - High Prices	OR - Renewables (,000s of Dth)	2,621	7,225	8,966
PRS - High Prices	WA - Renewables (,000s of Dth)	-	-	-
PRS - High Prices	Natural Gas (,000s of Dth)	45,094	42,533	35,258
PRS - High Prices	CCI (MTCO2e)	-	70,337	-
PRS - High Prices	Allowances (MTCO2e)	282,841	792,175	860,762
PRS - Low Prices	Synthetic Methane (,000s of Dth)	94	146	5,175
PRS - Low Prices	OR - Renewables (,000s of Dth)	1,745	7,288	8,981
PRS - Low Prices	Natural Gas (,000s of Dth)	45,907	42,047	36,777
PRS - Low Prices	CCI (MTCO2e)	38,441	70,337	-
PRS - Low Prices	Allowances (MTCO2e)	283,889	794,288	884,819

Electrification Scenarios

Avista uses four scenarios to identify impacts to the natural gas and power system if space and water heating is electrified in the Oregon and Washington service areas, specifically for the residential and commercial customers. Industrial customers are not considered as each process would require an individual analysis to determine if electrification is possible or if an alternative fuel would be a better option.

A loss of demand is expected on the natural gas system in each scenario. These scenarios also estimate cost impacts to convert and replace the energy moved to the power grid combined with remaining costs for program compliance and energy on the natural gas system. Chapter 2 explains methodology to remove demand from the natural gas system and Chapter 3 explains methodology for conversion costs and power costs.

Electrification – Expected Conversion Cost

This scenario considers a loss of customers in Oregon and Washington at roughly 2% annually. All remaining assumptions remain consistent with the PRS scenario. Additional electrification is available to the model and compared to other resources available as a least cost option.

Electrification – Low Conversion Cost

An alternate scenario to our Electrification – Expected Conversion Cost, to consider the impacts of lower-than-expected conversion costs, 50% of expected costs, and the potential resources selected. The model is forced to reduce at 2% per year in Oregon and Washington. Additional electrification is available to the model in a least cost option.

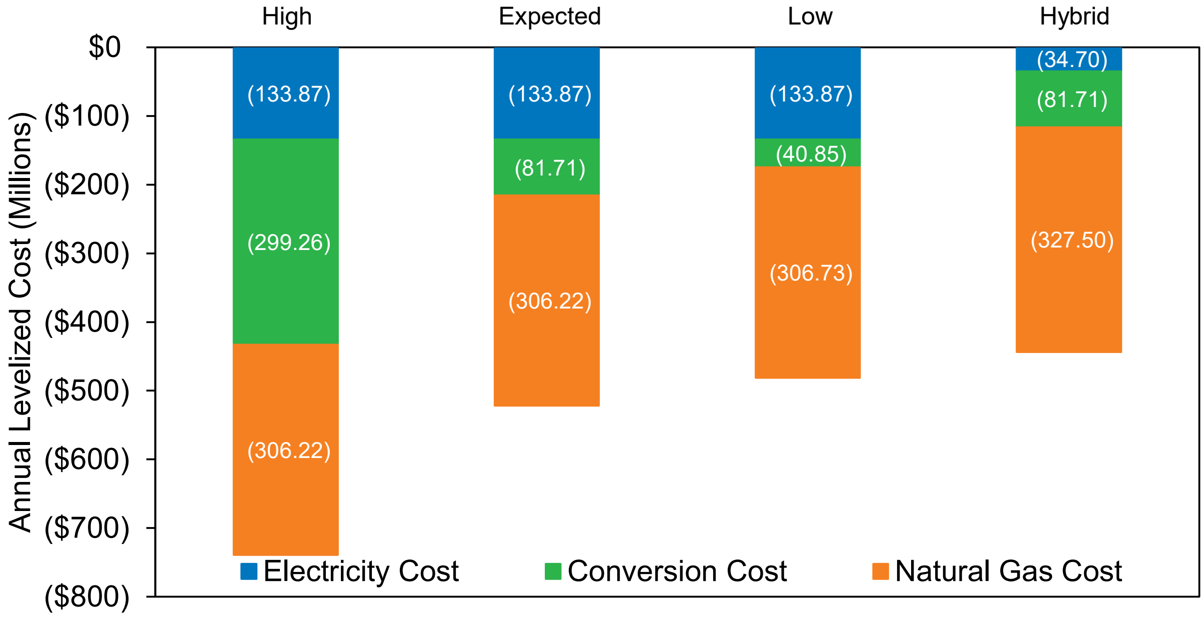
Electrification – High Conversion Cost

An alternate scenario to our Electrification – Expected Conversion Cost, to consider the impacts of higher-than-expected conversion costs, 150% of expected costs, and the potential resources selected. The model is forced to reduce at 2% per year in Oregon and Washington. Additional electrification is available to the model in a least cost option.

Hybrid Case

The Hybrid Case considers the use of the natural gas system for peak heating needs with non-peak electrified for heat sensitive usage below 40 degrees Fahrenheit. This scenario assumes the conversion to a hybrid system utilizing the same decreasing customer trajectory as the electrification scenarios and only for Oregon and Washington. Rather than a total loss of these customers, a customer would remain on the natural gas system for use with back up heating. Like the Electrification scenarios, after converting estimated demand from natural gas to electricity from Oregon and Washington with efficiencies estimated in Chapter 3, the remaining price impact is added to account for total costs of the electric and natural gas systems. All other assumptions remain consistent to the PRS. In Figure 7.3, the annual levelized costs by major end source are provided. These major end sources include costs from the natural gas system, conversion costs for incremental customers, and the cost of electricity for these converted end sources.

Figure 7.3: Annual Electrification Levelized Costs by Source



Portfolio selections by scenario and category are shown in Table 7.3. Energy is in thousands of dekatherms and allowances and CCIs are in Metric Tons of Carbon Dioxide equivalent (MTCO2e).

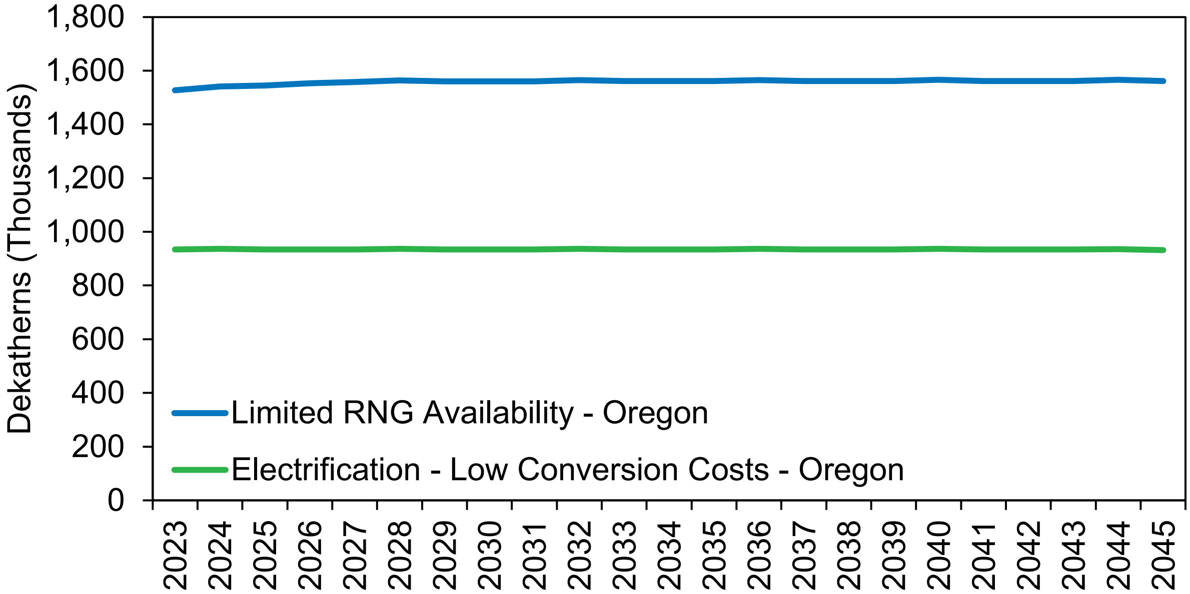
Table 7.3: Electrification Scenarios - Portfolio Selections

Scenario	Category	2025	2035	2045
Elec. - Expected Conversion Costs	Synthetic Methane (,000s of Dth)	81	42	2,057
Elec. - Expected Conversion Costs	OR - Renewables (,000s of Dth)	1,694	4,044	5,975
Elec. - Expected Conversion Costs	Natural Gas (,000s of Dth)	45,195	37,759	29,218
Elec. - Expected Conversion Costs	CCI (MTCO2e)	24,894	70,337	-
Elec. - Expected Conversion Costs	Allowances (MTCO2e)	260,407	538,955	555,307
Elec. - High Conversion Costs	Synthetic Methane (,000s of Dth)	81	42	2,057
Elec. - High Conversion Costs	OR - Renewables (,000s of Dth)	1,694	4,044	5,975
Elec. - High Conversion Costs	Natural Gas (,000s of Dth)	45,188	37,759	29,225
Elec. - High Conversion Costs	CCI (MTCO2e)	24,506	70,337	-
Elec. - High Conversion Costs	Allowances (MTCO2e)	260,407	538,955	555,705
Elec. - Low Conversion Costs	Synthetic Methane (,000s of Dth)	85	42	1,434
Elec. - Low Conversion Costs	OR - Electrification (,000s of Dth)	934	934	932
Elec. - Low Conversion Costs	OR - Renewables (,000s of Dth)	1,467	3,774	5,667
Elec. - Low Conversion Costs	Natural Gas (,000s of Dth)	44,711	37,453	29,151
Elec. - Low Conversion Costs	CCI (MTCO2e)	99	53,709	-
Elec. - Low Conversion Costs	Allowances (MTCO2e)	260,407	538,955	551,783
Hybrid Case	Synthetic Methane (,000s of Dth)	93	140	2,820
Hybrid Case	OR - Renewables (,000s of Dth)	1,694	4,570	6,459
Hybrid Case	Natural Gas (,000s of Dth)	45,541	40,831	34,820
Hybrid Case	CCI (MTCO2e)	24,506	70,337	-
Hybrid Case	Allowances (MTCO2e)	279,381	705,858	825,407

Electrification Selected as a Resource

Electrification as a selected resource occurred in two scenarios as illustrated in Figure 7.4. The first in the Limited RNG Availability with the second in our Electrification – Low Conversion Costs case, both selections are for Avista's Oregon territory. Limited RNG creates a resource issue to meet emissions goals and is the only scenario that selects electrification based on our estimated costs per Dth as described in Chapter 3. The model selected electrification in the first available year, removing 1.5 million dekatherms of demand per year for the study horizon. No additional electrification was selected after 2023 as the model is given a choice to add additional electrification to reduce load as a least cost, meaning no other electrification was least cost past the first year. The Electrification – Low Conversion Costs case shows the potential for electrification as a demand side resource. The Medford Residential customers select space heat electrification as a resource removing 934,400 dekatherms of demand annually beginning in 2023. As in the Limited RNG Availability Case, no additional electrification is selected after 2023 as a least cost option. These results show a potential to alter demand for electric end uses if conversion costs are lower than expected through grants, tax incentive or discounts.

Figure 7.4: Electrification as a Demand-Side Resource by Scenario and State



Supply Scenarios

The supply scenarios help to illustrate implications of physical impacts to the system, impacts to program compliance or resource availability. Outages and expected volume availability of resources such as RNG pose a risk to serving demand and meeting emissions compliance. These scenarios are Limited RNG availability, Interrupted supply and Carbon Intensity and help demonstrate potential pathways for program compliance with resource risk.

Carbon Intensity

Carbon Intensity is considered in the event the Washington CCA or Oregon CPP alter program methodologies or combine with the California Cap and Trade program. The only change from the PRS is the carbon intensity of RNG resources. Cost Impact and RNG source and quantity selected is a primary measure of this scenario. This scenario also considers carbon intensity in the natural gas fuel from upstream emissions at 128.27 pounds per dekatherm. In the California cap and trade program anaerobic sources are valued by carbon intensity meaning a dairy project may be considered as the value of reduced methane from the capture of these sources brings the cost down by over 400 percent (Chapter 4, Table 4.2 Carbon Intensity).

Limited RNG Availability

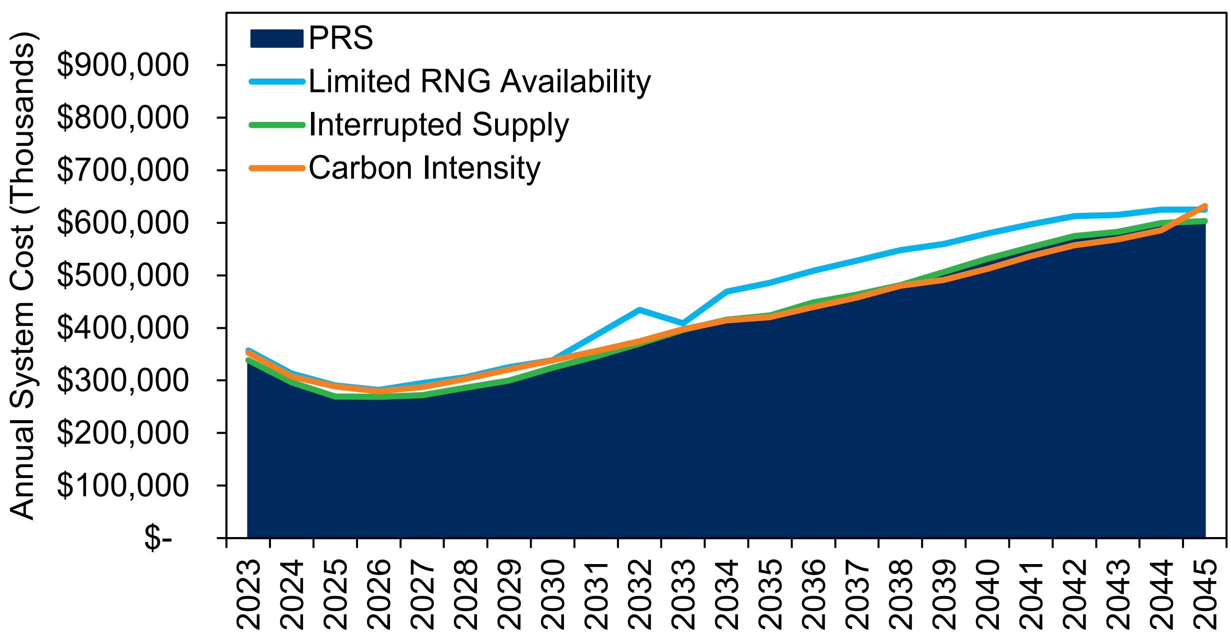
The availability of RNG in sufficient quantities to meet CCA and CPP emissions targets is measured in this scenario. This scenario constrains the expected RNG volumes to 50% with high RNG prices as discussed in Chapter 4.

Interrupted Supply

The Interruptible Supply case considers constraints of 50% availability at major supply points on the Northwest Pipeline system to measure risk of unserved demand. This scenario looks solve a least cost resource selection due to the risk of pipeline outages, equipment failure such as compressors or pipeline rupture as experienced in 2018 with the Enbridge pipeline. All other factors are consistent with PRS.

Figure 7.5 illustrates the annual system cost in comparison to the PRS. The Carbon Intensity scenario shows a lower system cost in the outer years but is not currently within CCA or CPP program rules and is included as an estimate of rule changes.

Figure 7.5: Supply Scenarios vs PRS - Annual System Costs



The portfolio selections for these Supply Scenarios include least cost resources provided to the model based on Carbon Intensity, Interrupted supply and Limited RNG as illustrated by Scenario and Category in Table 7.4. Energy is in thousands of dekatherms and allowances and CCIs are in MTCO2e.

Table 7.4: Supply Scenarios – Portfolio Selection

Scenario	Category	2025	2035	2045
Carbon Intensity	Synthetic Methane (,000s of Dth)	98	153	5,477
Carbon Intensity	OR – Renewables (,000s of Dth)	927	2,212	4,157
Carbon Intensity	WA – Renewables (,000s of Dth)	-	-	44
Carbon Intensity	Natural Gas (,000s of Dth)	47,126	47,799	42,385
Carbon Intensity	CCI (MTCO2e)	-	624	-
Carbon Intensity	Allowances (MTCO2e)	395,722	907,878	884,819
Interrupted Supply	Synthetic Methane (,000s of Dth)	120	181	5,137
Interrupted Supply	OR - Renewables (,000s of Dth)	1,993	7,232	8,982
Interrupted Supply	Natural Gas (,000s of Dth)	45,653	42,468	36,944
Interrupted Supply	CCI (MTCO2e)	17,146	70,337	-
Interrupted Supply	Allowances (MTCO2e)	283,273	793,898	884,819
Limited RNG Availability	Synthetic Methane (,000s of Dth)	98	2,552	9,075
Limited RNG Availability	OR - Electrification (,000s of Dth)	1,545	1,561	1,562
Limited RNG Availability	OR - Renewables (,000s of Dth)	774	3,368	3,526
Limited RNG Availability	Natural Gas (,000s of Dth)	45,479	42,642	37,023
Limited RNG Availability	CCI (MTCO2e)	16,758	70,337	-
Limited RNG Availability	Allowances (MTCO2e)	283,273	793,898	884,819

Other Scenarios

The Average Case is a key scenario to show peak demand versus the demand used to plan for an average use scenario. It considers average 20-year historic weather without climate futures to quantify the impacts of future temperatures and resource needs. This Average Case scenario uses historic temperatures from its planning areas to estimate demand based on weather and use per customer. The High Customer Case is exceedingly unlikely due to policy in Oregon and Washington but is also important as a perspective to understand costs of resources and environmental compliance given a higher than expected demand. Our Idaho territory may have a greater potential for this risk given the above system average growth combined with no current policy restricting the use of natural gas. Finally, the Social Cost of Carbon is considered as a method to value system costs using impacts as estimated through the Social Cost of Carbon at 2.5%.

High Customer Growth

Measuring risk includes a higher-than-expected case for customer growth in our natural gas territories. While Oregon and Washington have policy and programs making this unlikely, Idaho is experiencing strong growth as discussed in Chapter 2.

Social Cost of Carbon

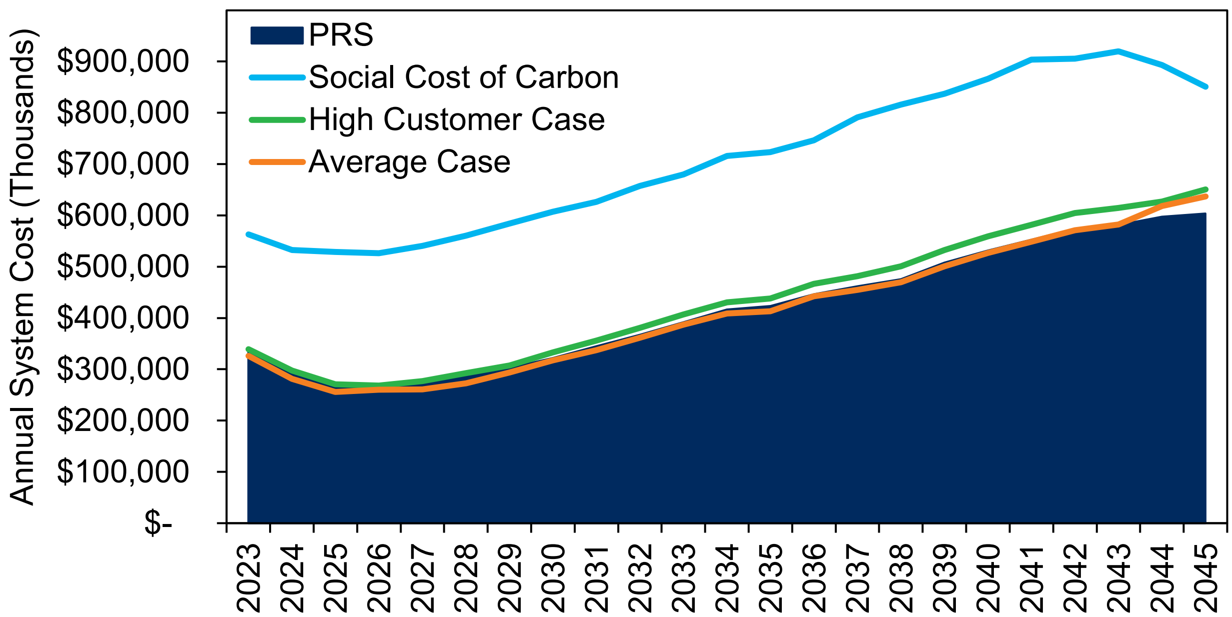
Assumes PRS inputs with a SCGHG at the 2.5% discount rate for all resources to compare in supply side resource selection. This cost overrides the costs of compliance in the CCA and CPP programs.

Average Case

The Average Case uses only the average daily weather for the past 20 years as compared to the PRS. All other assumptions are used from the PRS, excluding a peak day. This helps to show average demand as seen historically to compare to cases where demand is impacted from resources, weather forecasts, or peak day.

A cost comparison is provided in Figure 7.6 and compares these "Other" scenarios to the PRS annual system costs. In Table 7.5, selected resources by portfolio are included by Scenario and Category.

Figure 7.6: Other Scenarios vs PRS - Annual System Costs



A portfolio selection is provided in Table 7.5 for these other scenarios. Energy is in thousands of dekatherms and allowances and CCIs are in MTCO2e. Renewable energy increases drastically in the Social Cost of Carbon case as higher costs lead to greater demands for carbon free fuels. The model must take the same quantity of RNG once chosen for the remainder of the study. If, for example, 10 dekatherms were chosen in 2025, the model must take this same amount of volume through the end of the study. This method creates a more realistic consideration of obtaining RNG. Due to additional uptake in RNG, CCIs have less demand and is replaced by additional RNG.

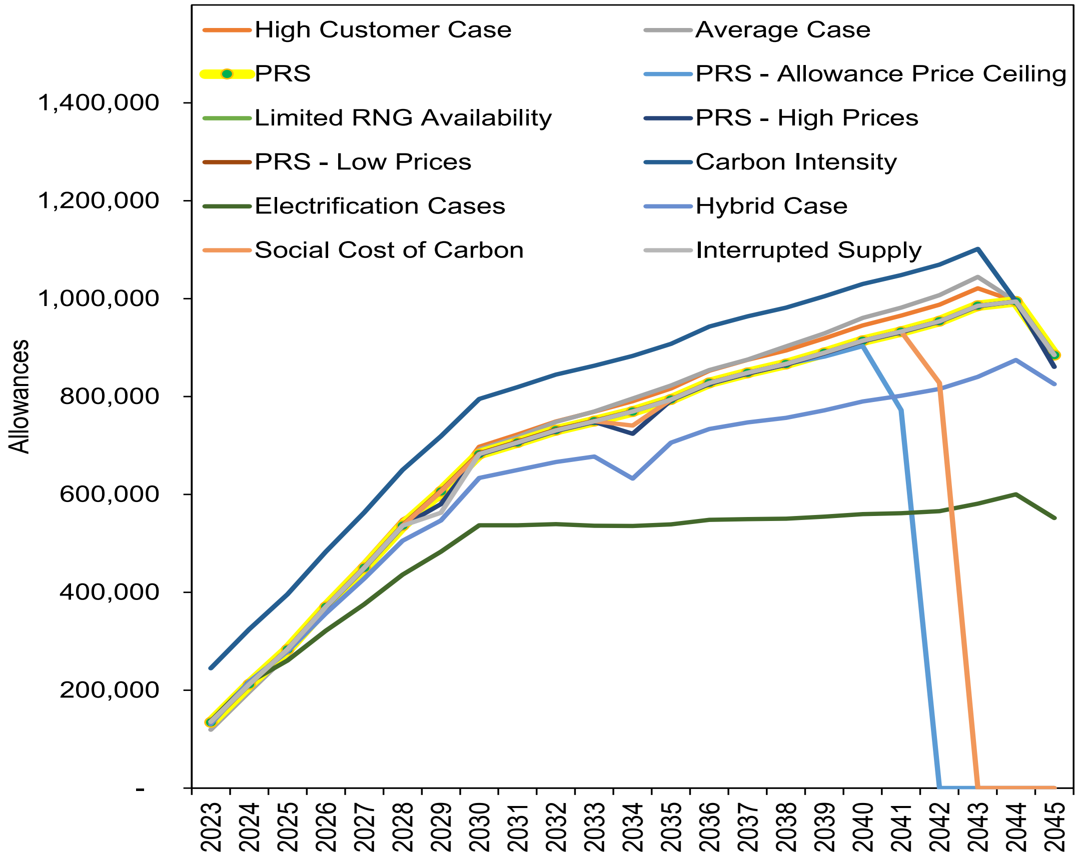
Table 7.5: Other Scenarios – Portfolio Selection

Scenario	Category	2025	2035	2045
Average Case	Synthetic Methane (,000s of Dth)	-	-	8,487
Average Case	OR - Renewables (,000s of Dth)	1,686	6,638	8,313
Average Case	WA - Renewables (,000s of Dth)	7	2	204
Average Case	Natural Gas (,000s of Dth)	45,249	43,506	36,140
Average Case	CCI (MTCO2e)	18,631	70,337	-
Average Case	Allowances (MTCO2e)	271,571	822,730	884,819
High Customer Case	Synthetic Methane (,000s of Dth)	99	181	6,901
High Customer Case	OR - Renewables (,000s of Dth)	2,139	7,672	9,514
High Customer Case	Natural Gas (,000s of Dth)	45,818	43,582	38,436
High Customer Case	CCI (MTCO2e)	16,758	70,337	-
High Customer Case	Allowances (MTCO2e)	290,676	816,701	884,819
Social Cost of Carbon	Synthetic Methane (,000s of Dth)	87	146	42,344
Social Cost of Carbon	OR - Renewables (,000s of Dth)	3,482	7,299	9,028
Social Cost of Carbon	WA - Renewables (,000s of Dth)	-	-	497
Social Cost of Carbon	Natural Gas (,000s of Dth)	45,069	42,261	-
Social Cost of Carbon	CCI (MTCO2e)	-	70,337	-
Social Cost of Carbon	Allowances (MTCO2e)	283,273	793,898	-

Washington Climate Commitment Act Allowances

The Carbon Intensity scenario has the highest requirement for allowances through 2030, though the lines generally converge in the 2030 timeframe with similar quantity estimates. PRS is included to show the variation of resources needed to help reduce emissions or meet emissions targets. In the Social Cost of Carbon scenario, higher costs lead to a higher RNG demand by 2025 reducing the need for allowances. All other scenarios are generally within the blue area depicting the PRS results. The Hybrid Case has the lowest quantity of allowances due to the reduced demand and energy supplied by the natural gas system. By 2042 the PRS – Allowance Price Ceiling case and 2043 the Social Cost of Carbon case both show allowance requirements fall to zero as synthetic methane becomes the least cost resource for the CCA. The variability of allowances is illustrated in Figure 7.7.

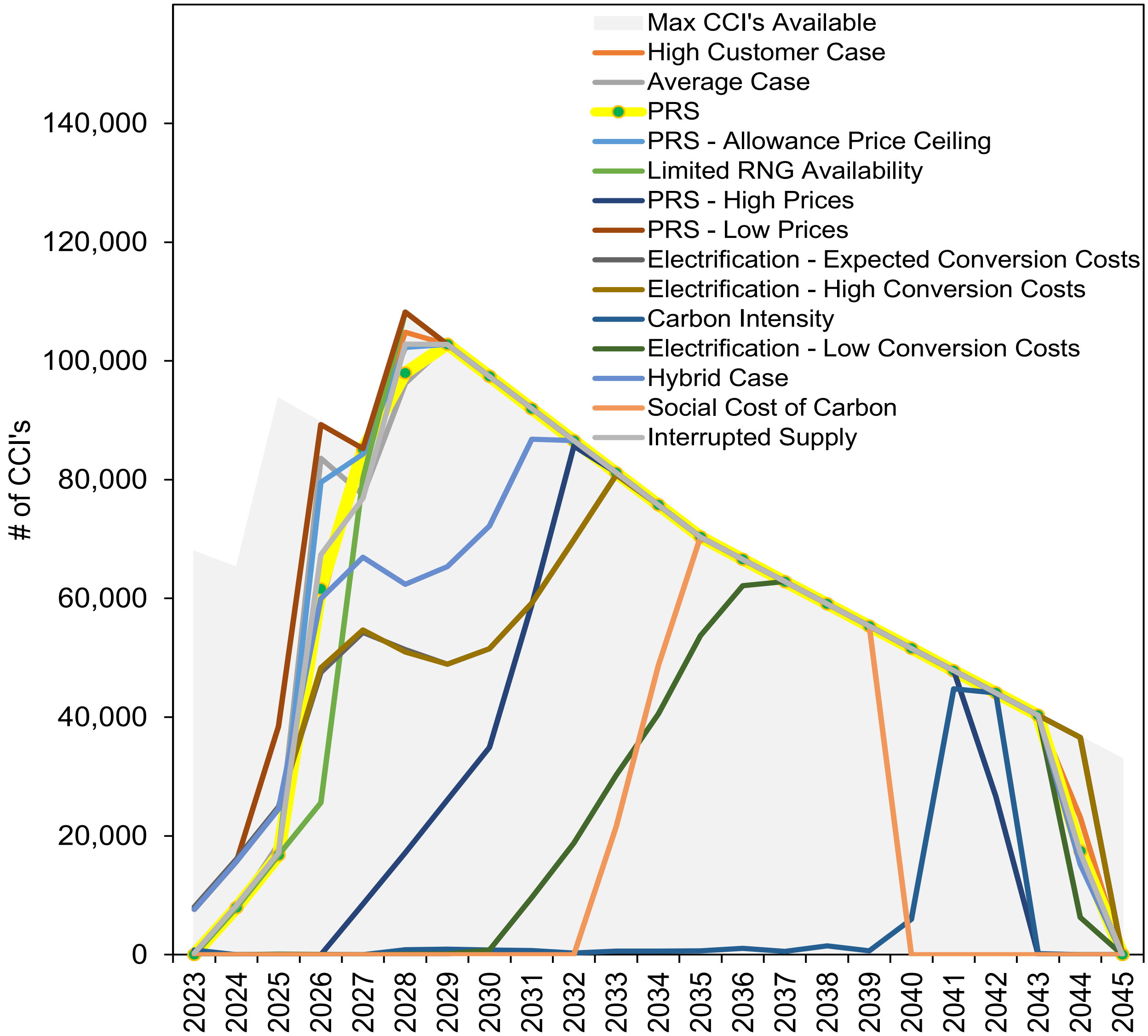
Figure 7.7: Allowance Demand by Scenario – Washington CCA



Oregon Community Climate Investments

Community Climate Investments show a greater range of required quantities for compliance. In Figure 7.8, the maximum amount of CCIs available beginning in 2023 can be found in the gray area. The steps are based on the quantity of CCIs available in each timeframe as allowed per the rules (Chapter 5). The PRS acquires near the cap by 2026 with many scenarios following a similar pathway. The Electrification scenarios generally require fewer instruments in the near term due to a loss of demand on the natural gas system which removes the larger CCIs needed. The Social Cost of Carbon scenario acquires a higher level of renewable fuels and removes the need for more CCIs to pair with natural gas. Finally, the most interesting result is from our Carbon Intensity scenario. The demand for CCIs does not generally come around until 2040 and only for a few years until future renewable resources are brought onto the system.

Figure 7.8: CCI Demand by Scenario – Oregon CPP

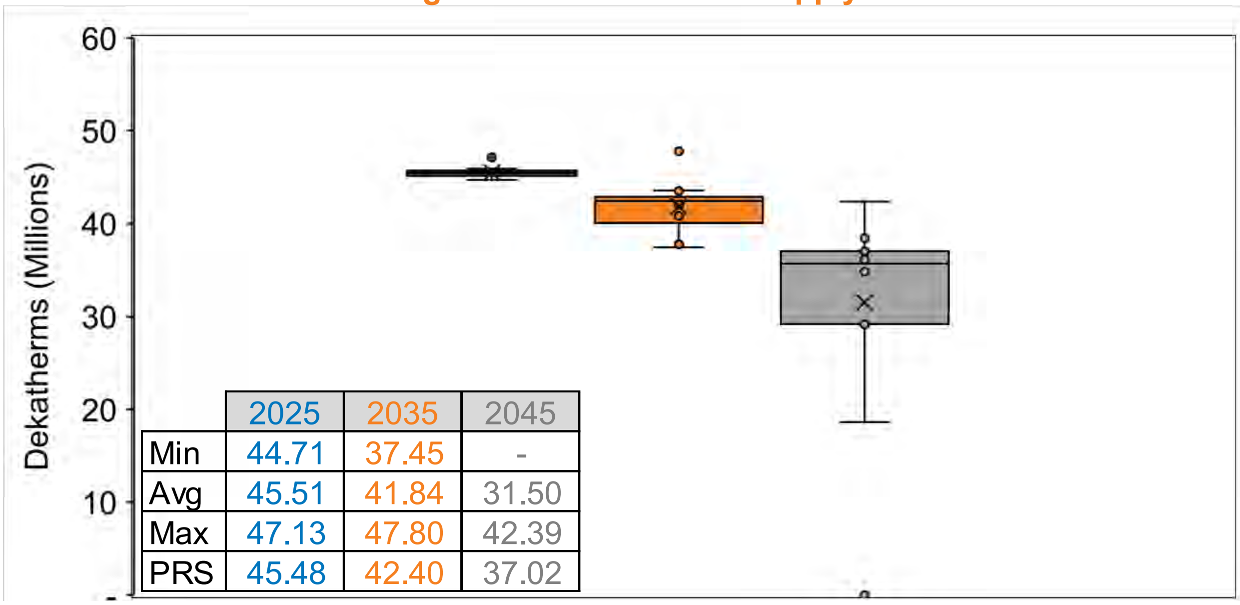


Natural Gas Use

The demand for natural gas decreases across all studied scenarios in this IRP. The scenario with the greatest decline is the Social Cost of Carbon case where by 2045 it eliminates natural gas from its resource selection. This case is followed by the PRS – Allowance Price Ceiling with only 41% of energy being filled by natural gas. The overall decrease across these fourteen scenarios is an average of 31% by 2045 as compared to 2025. Figure 7.9 illustrates the use of natural gas across all scenarios in 2025, 2035 and 2045. The future of natural gas is facing a fundamental change at Avista, the Pacific Northwest and nations in the climate pledge with the goal to reduce global emissions.[1]

[1] https://www.ipcc.ch/about/

Figure 7.9: Natural Gas Supply

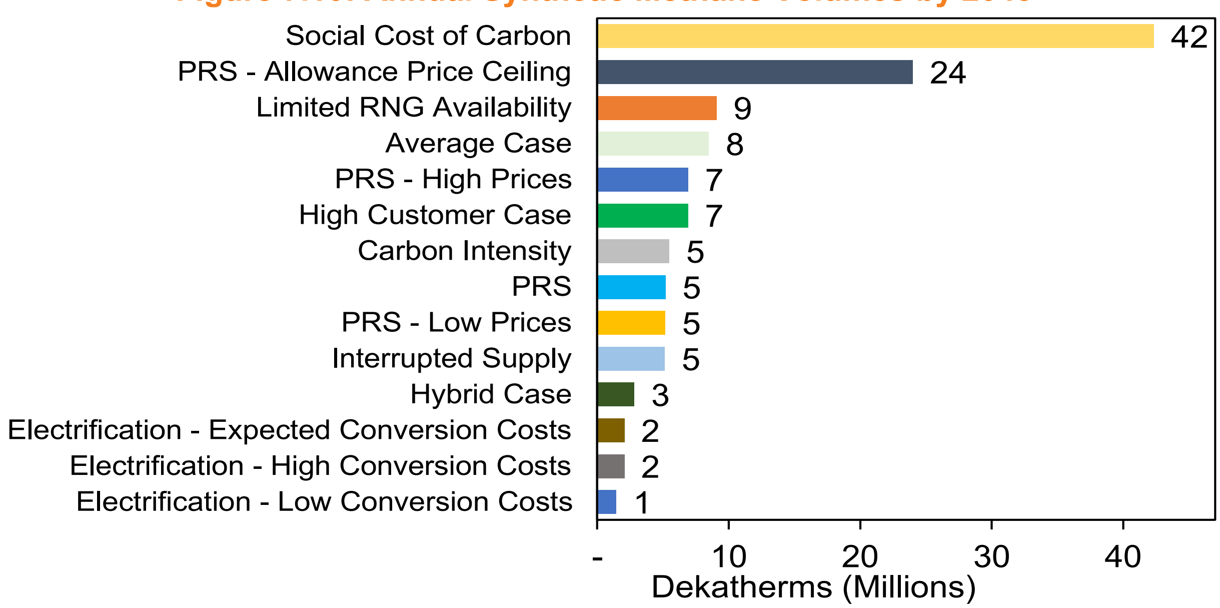


	2025	2035	2045
Min	44.71	37.45	-
Avg	45.51	41.84	31.50
Max	47.13	47.80	42.39
PRS	45.48	42.40	37.02

Synthetic Methane

Synthetic methane has been chosen as a resource across all scenarios as illustrated in Figure 7.10. Reducing emissions is key to the selection of synthetic methane with cost expectations around carbon capture and green hydrogen reducing over time as discussed in Chapter 4, this energy source may prove to be an important fuel in emissions compliance programs. Further studies and lifecycle analysis will be necessary if selected as a resource or through a request for procurement (RFP). Important pieces to consider include waste from the process to create hydrogen or carbon capture, permitting for a water supply in the electrolysis process and waste.

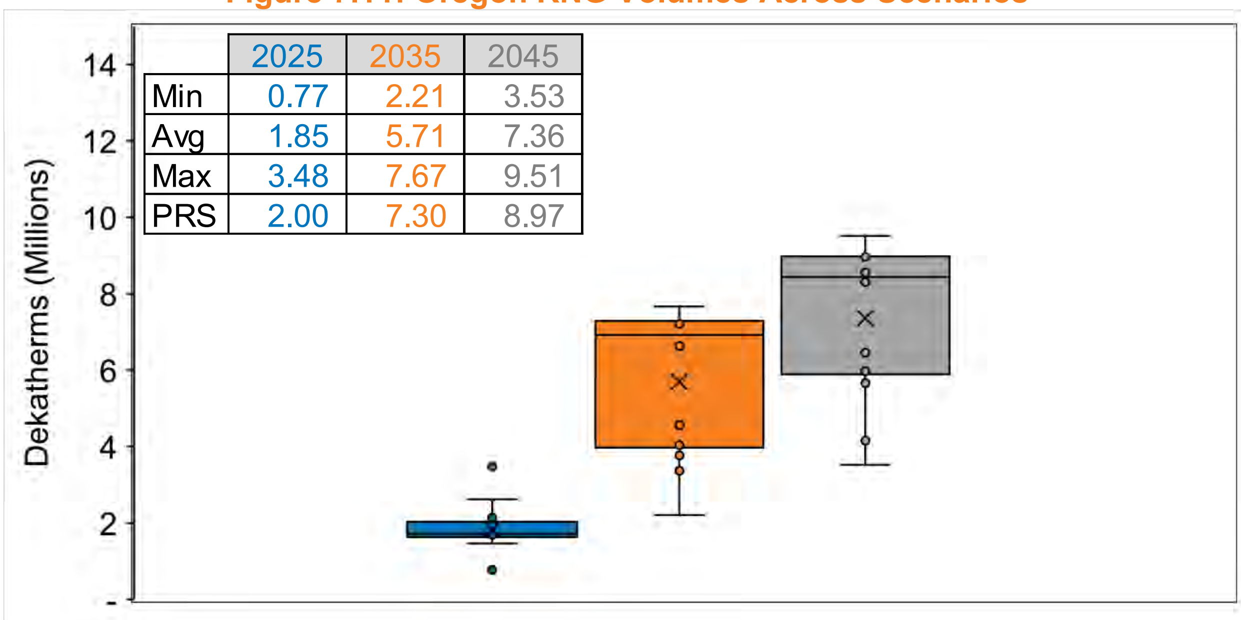
Figure 7.10: Annual Synthetic Methane Volumes by 2045



Renewable Natural Gas

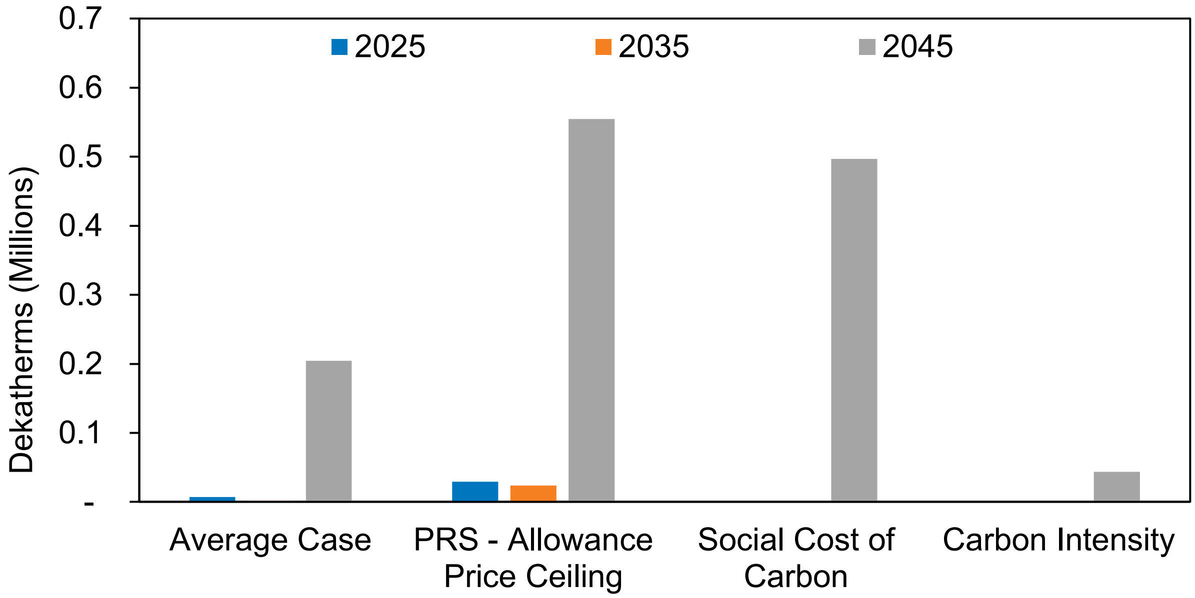
Renewable Natural Gas is considered a necessary energy and emissions reduction tool for the CCA and CPP. While costs vary by project, location, and size, RNG is necessary to meet initial needs of emissions reduction until other resource options can be further matured and advanced. Idaho does not select any RNG under any scenario even when considering a national carbon tax as discussed in in Chapter 5. Oregon, under the CPP, chooses RNG consistently across all scenarios as illustrated in Figure 7.11. The variability occurs with different costs and system customers. RNG is also considered an important fuel to consider for the replacement of natural gas in industrial processes as these processes can be more difficult to electrify.

Figure 7.11: Oregon RNG Volumes Across Scenarios



Currently, Washington is considering linkage to the California cap and trade program. In the event program rules change under the CCA or CPP, RNG may provide for the ability to reduced emissions program costs with the use of higher carbon intensive RNG sources. With the expected price of allowances relatively low in the first years of the CCA, RNG has a limited uptake across most scenarios. As previously discussed, if cost assumptions due to inflation and its impact on allowance prices, allowance availability, changes to compliance resources may change. Figure 7.12 illustrates all studied scenarios in this IRP where RNG was chosen.

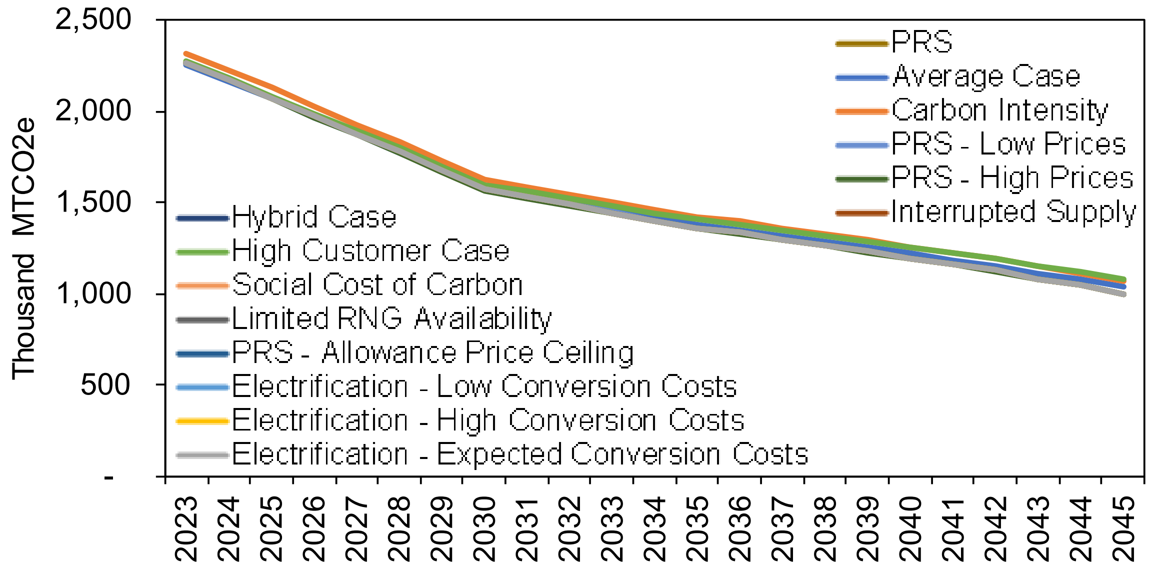
Figure 7.12: Washington RNG Volumes Across Scenarios



Emissions

Emissions compliance to the CCA and CPP have been met in all scenarios studied in the 2023 IRP. These scenarios consider a sizeable range of future outcomes including the loss of customers from policy, regulation, and customer choice. The resultant outcomes depict a varying level of emissions based on selected resources and demand reduction. When considering the primary reasons for reducing emissions, the cap in each program creates a requirement to meet stated targets. The Carbon Intensity scenario highlights additional carbon in Idaho from upstream emissions, while the other scenarios mostly follow a similar trajectory. This is illustrated in Figure 7.13 and only vary slightly based on the number of customers on the system with growth occurring in Idaho in all scenarios.

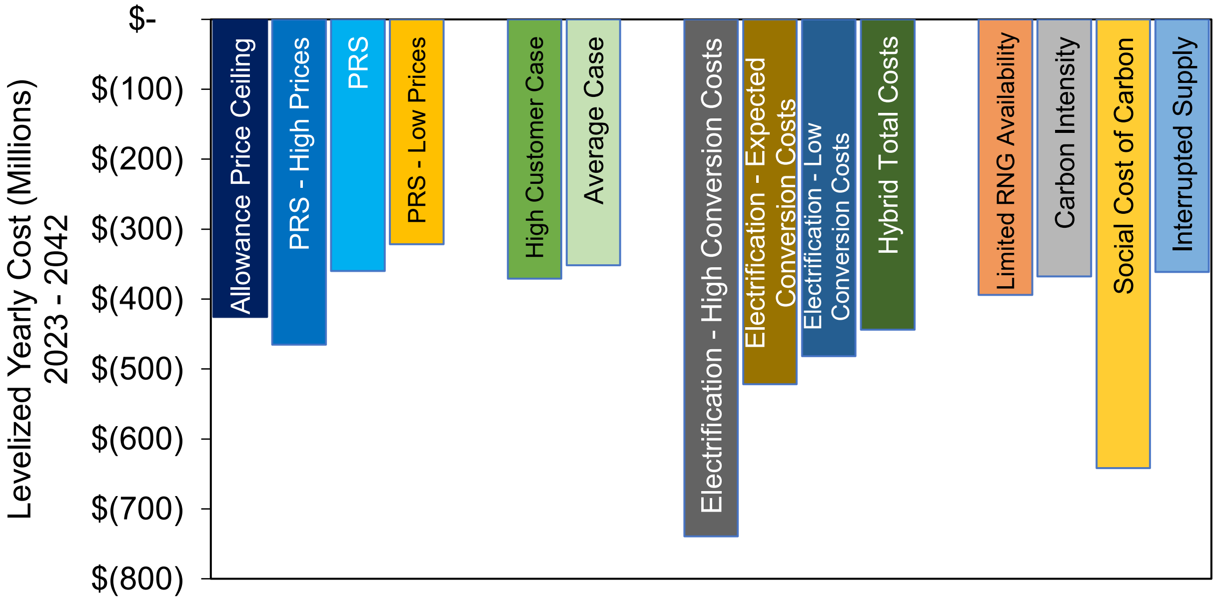
Figure 7.13: System Emissions by Scenario by 2030



Cost Comparison

When we consider costs of these scenarios, there are two with a cost lower than the PRS. The first is the Average Case and the second is PRS – Low Prices. The Average Case is like the PRS with two primary differences, price assumptions for energy and weather futures. Recall the Average Case does not include peak weather and should be used as a reference to all scenarios considered. The overall lower demand creates less energy supplied and lower emissions to meet compliance in compliance in the CCA and CPP. The PRS – Low Prices is measuring the same demand as the PRS with just lower costs than expected. Electrification costs include incremental conversion costs of customers and energy costs from the power grid as discussed in Chapter 3. These electrification costs are included in all three Electrification scenarios and the Hybrid Case. These levelized costs consider twenty years as CPA estimates are not available from the ETO past this mark as illustrated in Figure 7.14.

Figure 7.14: PRS Alternative Scenario Cost Comparison Annual Levelized Costs (2023 – 2042)



The estimated price impact by scenario by generic class and area are included in Figure 7.15 to 7.19.

Figure 7.15: Residential Customer Price Impact ($ per dekatherm)

	Idaho Residential			Oregon Residential			Washington Residential		
	2025	2035	2045	2025	2035	2045	2025	2035	2045
Average Case	3.76	5.54	8.75	10.06	25.28	14.37	6.28	7.06	14.66
Carbon Intensity	4.60	6.07	9.09	7.50	10.84	14.41	7.54	7.89	14.68
Electrification - Expected Conversion Costs	4.57	5.50	8.77	10.19	23.94	12.98	7.03	6.89	9.80
Electrification - High Conversion Costs	4.57	5.50	8.77	10.19	23.94	12.98	7.03	6.89	9.80
Electrification - Low Conversion Costs	4.57	5.50	8.78	5.06	12.47	13.22	7.03	6.89	9.81
High Customer Case	4.61	6.21	8.86	10.18	24.77	14.62	7.32	7.97	14.63
Hybrid Case	4.60	5.88	9.02	10.41	23.87	14.43	7.45	7.58	10.31
Interrupted Supply	4.60	6.20	8.96	10.17	24.72	14.58	7.31	7.96	14.40
Limited RNG Availability	4.60	5.84	8.94	9.15	30.14	14.74	7.32	7.59	14.39
PRS	4.60	5.95	8.94	10.19	24.82	14.59	7.31	7.64	14.39
PRS - Allowance Price Ceiling	4.45	5.85	8.70	10.17	24.94	14.61	9.72	14.77	14.81
PRS - High Prices	6.32	8.65	13.27	9.77	24.93	14.51	9.02	10.33	14.50
PRS - Low Prices	4.06	4.82	7.19	9.69	24.74	14.61	6.78	6.52	14.37
Social Cost of Carbon	9.93	12.17	14.79	9.42	24.03	14.34	12.62	15.24	14.82

Figure 7.16: Commercial Customer Price Impact ($ per dekatherm)

	Idaho Commercial			Oregon Commercial			Washington Commercial		
	2025	2035	2045	2025	2035	2045	2025	2035	2045
Average Case	3.72	5.49	8.69	10.02	25.11	14.18	6.27	7.05	14.64
Carbon Intensity	4.49	5.98	9.02	7.44	10.80	14.35	7.51	7.87	14.66
Electrification - Expected Conversion Costs	4.46	5.44	8.69	10.16	23.91	12.93	6.98	6.86	9.76
Electrification - High Conversion Costs	4.46	5.44	8.69	10.16	23.91	12.93	6.98	6.86	9.76
Electrification - Low Conversion Costs	4.46	5.44	8.71	5.03	12.45	13.19	6.98	6.86	9.77
High Customer Case	4.50	6.10	8.78	10.13	24.59	14.55	7.30	7.96	14.61
Hybrid Case	4.49	5.79	8.93	10.40	23.85	14.33	7.38	7.56	10.29
Interrupted Supply	4.49	6.09	8.87	10.11	24.57	14.48	7.29	7.94	14.38
Limited RNG Availability	4.49	5.69	8.85	9.10	29.65	14.58	7.29	7.55	14.37
PRS	4.49	5.86	8.86	10.13	24.66	14.49	7.29	7.63	14.37
PRS - Allowance Price Ceiling	4.36	5.77	8.63	10.11	24.81	14.52	9.70	14.75	14.81
PRS - High Prices	6.21	8.56	13.16	9.72	24.80	14.39	9.00	10.31	14.47
PRS - Low Prices	3.95	4.73	7.11	9.64	24.58	14.52	6.75	6.50	14.35
Social Cost of Carbon	9.83	12.10	14.77	9.36	23.84	14.14	12.60	15.22	14.81

Figure 7.17: Industrial Customer Price Impact ($ per dekatherm)

	Idaho Industrial			Oregon Industrial			Washington Industrial		
	2025	2035	2045	2025	2035	2045	2025	2035	2045
Average Case	3.62	5.38	8.55	9.83	24.23	13.24	6.06	6.76	14.32
Carbon Intensity	4.09	5.72	8.88	7.11	10.58	14.06	6.84	7.28	14.33
Electrification - Expected Conversion Costs	4.07	5.29	8.53	9.81	23.79	12.56	6.59	6.70	9.57
Electrification - High Conversion Costs	4.07	5.29	8.53	9.81	23.79	12.56	6.59	6.70	9.57
Electrification - Low Conversion Costs	4.07	5.29	8.55	4.67	12.31	12.52	6.59	6.70	9.59
High Customer Case	4.09	5.77	8.62	9.81	23.89	14.24	6.61	7.22	14.23
Hybrid Case	4.09	5.52	8.72	9.81	23.56	12.76	6.61	6.96	9.76
Interrupted Supply	4.09	5.77	8.69	9.79	23.85	14.03	6.61	7.22	13.94
Limited RNG Availability	4.09	5.32	8.66	9.01	29.69	14.55	6.62	6.77	13.91
PRS	4.09	5.59	8.68	9.81	23.91	14.04	6.61	7.02	13.93
PRS - Allowance Price Ceiling	4.01	5.55	8.49	9.81	24.22	14.11	9.10	14.23	14.71
PRS - High Prices	5.83	8.29	12.96	9.40	24.16	13.82	8.34	9.72	13.98
PRS - Low Prices	3.55	4.45	6.93	9.31	23.84	14.11	6.07	5.89	13.91
Social Cost of Carbon	9.47	11.88	14.72	9.09	22.93	13.20	11.98	14.72	14.73

Figure 7.18: Transport Only Customer Price Impact ($ per dekatherm)

	Oregon Transport			Washington Transport		
	2025	2035	2045	2025	2035	2045
Average Case	9.56	24.93	14.21	5.85	6.30	13.97
Carbon Intensity	3.39	12.77	14.11	6.08	6.57	13.98
Electrification - Expected Conversion Costs	9.56	23.51	14.62	5.85	6.30	9.20
Electrification - High Conversion Costs	9.56	23.51	14.62	5.85	6.30	9.20
Electrification - Low Conversion Costs	9.56	12.17	14.21	5.85	6.30	9.23
High Customer Case	9.56	24.42	14.21	5.85	6.30	13.80
Hybrid Case	9.56	23.27	14.22	5.85	6.30	9.23
Interrupted Supply	9.56	24.26	14.21	5.85	6.30	13.44
Limited RNG Availability	9.56	29.76	14.65	5.85	5.95	13.41
PRS	9.56	24.42	14.21	5.85	6.30	13.44
PRS - Allowance Price Ceiling	9.56	24.42	14.61	8.44	13.56	14.67
PRS - High Prices	5.11	6.14	14.07	7.56	8.97	13.47
PRS - Low Prices	9.02	24.37	14.24	5.31	5.17	13.44
Social Cost of Carbon	8.74	23.56	14.68	11.19	13.93	14.69

Regulatory Requirements

IRP regulatory requirements in Idaho, Oregon, and Washington call for several key components. The completed plan must demonstrate that the IRP:

- Examines a range of demand forecasts.
- Examines feasible means of meeting demand with both supply-side and demand-side resources.
- Treats supply-side and demand-side resources equally.
- Describes the long-term plan for meeting expected demand growth.
- Describes the plan for resource acquisitions between planning cycles.
- Takes planning uncertainties into consideration.
- Involves the public in the planning process.

Avista addressed the applicable requirements throughout this document. Appendix 1.2 – IRP Guideline Compliance Summaries lists the specific requirements and guidelines of each jurisdiction and describes Avista's compliance.

The IRP is also required to consider risks and uncertainties throughout the planning and analytical processes. Avista's approach in addressing this requirement was to identify factors that could cause significant deviation from the expected outcomes in planning conclusions. From this, Avista created a total of fourteen demand scenario alternatives, which incorporated different customer growth, resource availability, use-per-customer, weather, and price assumptions.

Avista analyzed peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather-planning standard using the coldest day in 20 years. Stochastic analysis using Monte Carlo simulations in PLEXOS® supplemented this analysis. Avista also used simulations from PLEXOS® to analyze price uncertainty and the effect on total portfolio cost.

Avista examined risk factors and uncertainties that could affect expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, Avista assessed the expected available supply-side resources and potential conservation savings for evaluation.

The investigation, identification, and assessment of risks and uncertainties in our IRP process should reasonably mitigate surprise outcomes.

This Page Intentionally Left Blank

8. Distribution Planning

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 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. 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 3,300 miles of distribution main and service pipelines in Idaho, 3,700 miles in Oregon and 5,800 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 pressure 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, which 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 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 capital planning and budgeting process, which incorporates planning for other types of distribution capital expenditures and infrastructure upgrades.

Gas Engineering 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, 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 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 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.

---

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

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. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline boosts 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 can be a cost-effective 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.

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 3 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.

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 2. This practice is consistent with the peak day demand forecast utilized in other sections of Avista’s Natural Gas IRP.

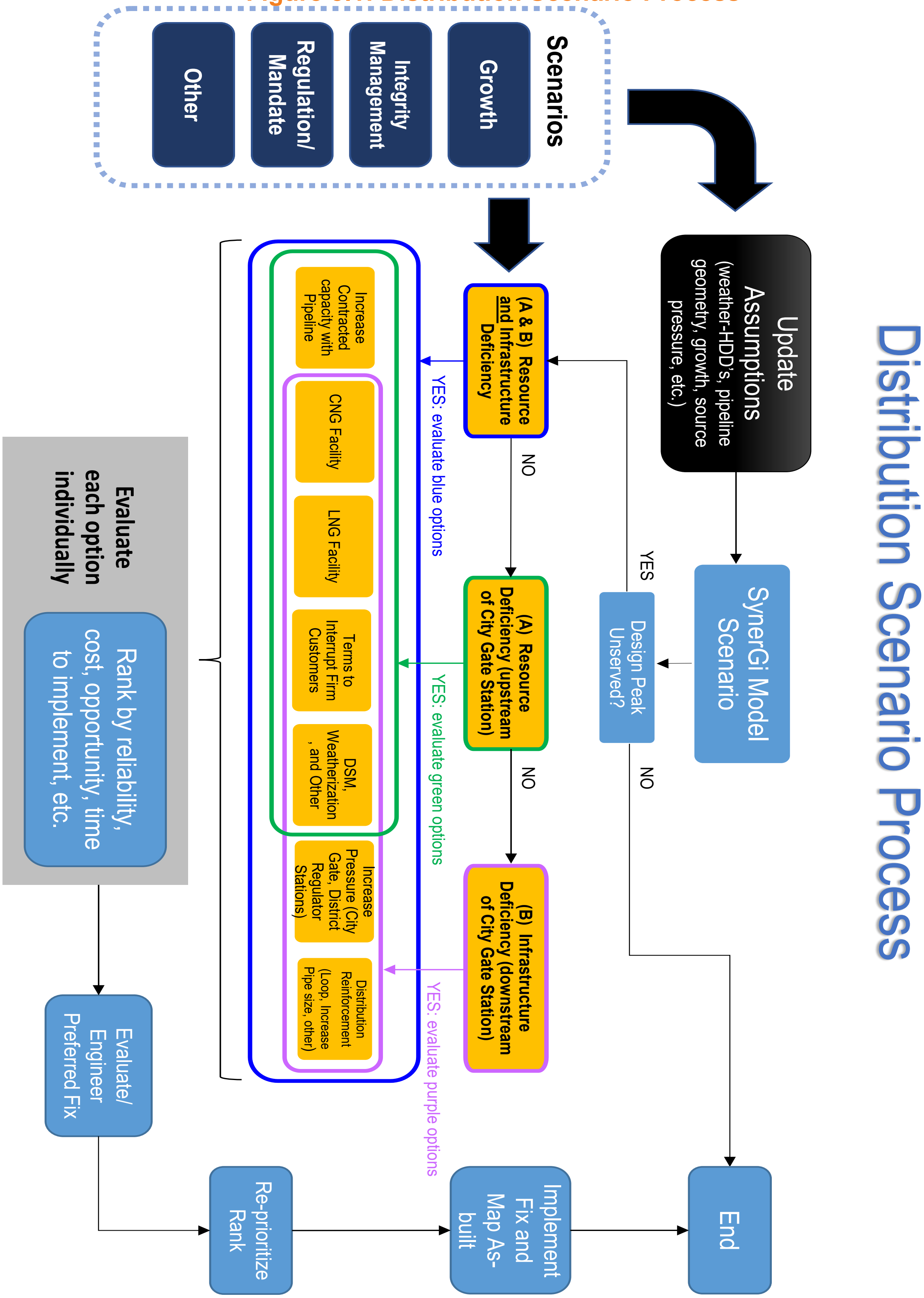
Utilizing a peak planning standard based on a statistical probability method of historical temperatures may seem aggressive since extreme temperatures are rare. Given the potential impacts of an extreme weather event on customers’ personal safety and potential damage to customer’s appliances and Avista’s 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 8.1 provides a schematic representation of the distribution scenario process

Figure 8.1: Distribution Scenario Process



Planning Results

Table 8.1 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);
- 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 $500,000 in any year. The scope and needs of distribution system enhancement projects generally evolve with new information requiring 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 High Pressure Reroute, WA: 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 with construction anticipated in 2027.

Pullman High Pressure Reinforcement, WA: The Pullman high pressure reinforcement will connect both the Moscow and Pullman’s high-pressure systems. This would bring Moscow gas to Pullman, avoiding the need to rebuild the Pullman City Gate Station which is currently exceeding its physical capacity. Additionally, this interconnection would increase reliability as both Moscow and Pullman would then have two sources of gas. Design is tentatively scheduled for 2023 with construction anticipated in 2024. Construction timelines may change due to customer growth expectations.

Table 8.1: High Pressure - Distribution Planning Capital Projects

Location	2023	2024	2025	2026	2027+
Kettle Falls High Pressure Reroute, WA (compliance-driven)	---	---	---	$100,000	$2,000,000
Pullman High Pressure Reinforcement, WA	$100,000	$6,700,000	---	---	---

Table 8.2 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 8.2 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. There are no plans to rebuild or upgrade TBD city gate stations at this time.

Table 8.2: City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
Rathdrum ID	Chase #5000	Increase capacity	$1,000,000	2023
Coeur d'Alene, ID	CDA East #221	Rebuild for reliability	$200,000	2023
Colton, WA	Colton #315	TBD	-	TBD
Medford, OR	Medford #2431	TBD		TBD
Pullman, WA	Pullman #350	Pullman High Pressure Reinforcement, WA	$6,800,000	2024
Sutherlin, OR	Sutherlin #2626	TBD	-	TBD

Non-Pipe Alternatives

An evaluation of non-pipe alternatives is considered against pipeline capacity reinforcements, when not related to safety, compliance, or road moves. Non-pipe alternatives will only be considered when the cost of an upgrade is at a level high enough where a non-pipe alternative may be cost-effective (i.e., greater than $500,000), 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. Possible non-pipe alternatives include, but are not limited to, the following: uprating (raising) the existing pipeline pressure, energy efficiency efforts including encouraging customers to adopt more efficient appliances and equipment, and potentially electrification of natural gas appliances. A non-pipe alternative must address any capacity concerns at a lower cost versus the pipeline reinforcement to be considered a viable strategy.

This Page Intentionally Left Blank

9. 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. The Oregon Public Utility Commission (OPUC) provided a majority of the recommendations based on the Company's 2021 IRP, while others were derived from Washington and Idaho Commission Staff and Avista's proposed Action Plan items.

2021 IRP OPUC Recommendations

Recommendation 1: In the next IRP, use at least five years of historic data for modeling use per customer.

> *This IRP utilizes a five-year use per customer coefficient for all Oregon territories in the 2023 IRP across all scenarios. For reference, a three-year coefficient was used for Idaho and Washington.*

Recommendation 2: Include a No Growth scenario in the next IRP.

> *Four scenarios were studied with no growth. These scenarios consider Electrification with no new customers starting in 2024 and a hybrid heating scenario where electric heat pumps are used with natural gas supplying supplemental heat in cold temperatures. The results of these scenarios are in Chapter 7.*

Recommendation 3: In future IRPs, provide a comparison between the current CPA and the last CPA, including a narrative explanation of major changes in the potential.

> *Please refer to Chapter 3 for a complete description of current and prior IRP CPA reports.*

Recommendation 4: Discuss demand response as a demand side resource option at a TAC meeting before filing the next IRP.

> *Demand response studies were completed by Applied Energy Group (AEG) and presented to the August and December 2022 TAC meetings. At this time demand response is not cost effective and is not selected in any scenario. Please refer to Chapters 6 and 7 for results of this analysis.*

Recommendation 5: Discuss long-term transport procurement strategies at a TAC meeting before the next IRP.

Long-term transport procurement strategies were discussed in TAC 2 on May 3, 2022. This discussion included current supply side resources and contract expiration dates along with renewal strategies.

Recommendation 6: Host a workshop within two months of the publishing of DEQ's Clean Power Plan Rules, to discuss challenges and opportunities to incentivize near-term actions to reduce GHGs to meet Clean Power Plan targets, including consideration of SB 98 and SB 844 programs.

Avista held a TAC meeting in February 2022 to review the final CPP and its implications to Avista including the challenges and opportunities of this program.

Recommendation 7: Provide a workshop in the next IRP development process to discuss the possibility of using the social cost of carbon to help inform carbon risks in its portfolios.

Avista utilized the social cost of greenhouse gas (SCGHG) for its energy efficiency CPA in all three states. Additionally, a scenario using the SCC to value natural gas versus other supply side resource options was performed and analyzed. Results are in Chapter 7 and were presented during the TAC 4 meeting within the Demand Side Management (DSM) and CPA presentations.

Recommendation 8: Include a non-zero carbon risk value for its Idaho customers.

In the 2023 IRP considers a national carbon cost for Idaho beginning in 2030. Materials were presented in the TAC 4 meeting in September 2022. The values used in this study are in Chapter 5.

Recommendation 9: Prior to the next IRP, conduct market research to reflect the willingness of Oregon customers to pay for various carbon reduction strategies. Present results at a TAC meeting.

Market research was conducted by Clean Energy Research and shared with our TAC members in the August 10, 2022, meeting. The more significant results are shown in Chapter 5.

Recommendation 10: Work with stakeholders and Staff to identify information that should be included in an RNG project pipeline update and provide an update on the Company's RNG project pipeline as part of the next IRP Update, including, but not limited to consumer risks and costs assessment associated with buy vs build RNG options.

The TAC was updated at the February 16, 2022 and December 15th, 2022 TAC meetings. TAC members provided no feedback at those times. Chapter 4 provides details around the project pipeline and process.

Recommendation 11: In the next IRP, provide an analysis of the capabilities of Avista's system to accommodate hydrogen, where upgrades would be required to accommodate hydrogen, and estimated costs of those upgrades.

As discussed during TAC meeting 5 held in December 2022, Avista can accommodate a hydrogen supplier if the resultant gas meets existing tariff quality standards and industry maximum blending percentages. Avista may inject the hydrogen supply into a contained system where the end use customers have equipment capable of accepting a hydrogen-blended gas. Avista will also require metering and pressure regulation equipment at any interconnect point to measure volume and gas quality and control supply pressure. Avista has an Interconnection Agreement and application process ready for a hydrogen supplier. Avista has not had any committed suppliers at this time. Any cost and/or upgrade will depend on the proximity of the supplier to our distribution system.

Recommendation 12: In the next IRP, describe the assumptions for changes to renewable technologies and their impact on future levelized costs in the text of the next IRP.

Avista anticipates a reduction in green hydrogen and synthetic methane costs over tie. Demand for these renewable technologies from state and federal policies along with industry demand should increase overall demand for these carbon free options. Also supporting programs and incentives such as the IRA, CCA, and CPP all help to provide grants, loans, incentives, or equipment to help meet these goals.

Recommendation 13: Work with TAC to develop a scenario with a future large scale supply interruption, like the October 2018 Enbridge incident

This IRP includes a supply interruption scenario, where an outage starting north of Sumas at Enbridge and dropping down through Sumas. The scenario assumes North capacity at 50% of available transport capacity rights. Included in this scenario is an additional outage from the South at the Rocky Mountain region with a 25% assumed outage. Results are found in Chapter 7. These scenarios were discussed throughout the majority of the 2023 TAC meetings with additional attention provided during the TAC 4 and 5 meetings.

Recommendation 14: In the next IRP, Avista should continue to keep the Commission apprised of the Sutherlin and Klamath Falls city gate projects. The Company should also provide a list of areas or projects where the Company is monitoring for capacity or pressure issues.

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 5 meeting in December 2022. Please refer to Chapter 8 for a full listing of projects Avista is monitoring at this time.

Avista's 2021 IRP Action Items

1. Further model carbon reduction in Oregon and Washington.

   The PLEXOS model includes all carbon zero fuels and options in addition to program elements to meet climate goals in Oregon and Washington.

2. Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout.

   Avista procured a commercial off the shelf product called PLEXOS® from Energy Exemplar in May 2021. This software was built and verified using Sendout for initial model build. As mentioned during the TAC process the additional complexity brought into the natural gas model with the climate policies in Oregon and Washington made a parallel run impossible. The additional functionality of PLEXOS® to model these new program requirements was a primary reason Avista made the investment in the PLEXOS® application.

3. Model all requirements as directed in Executive Order 20-04

   This plan includes the CPP by including yearly emission constraints, community climate investments and zero carbon fuels as energy choices.

4. Avista will ensure the Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.

   The ETO has received the necessary funding to acquire therm savings as identified and then approved by the OPUC and ETO Board.

5. Explore the feasibility of using projected future weather conditions in its design day methodology.

   Avista utilizes a rolling 20-year average for both the demand and peak forecasts using average temperatures projected for future weather conditions from the River Management Joint Operating Committee (RMJOC). The RMJOC includes BPA, US Army Corps of Engineers and the US Bureau of Reclamation. The research team for these studies included the University of Washington and Oregon State University. The data for these studies were provided for Spokane, Medford, La Grande, and Klamath Falls to develop 19 different weather futures.

6. Provide an update to the Oregon distribution projects referenced in Table 9.1 from the 2021 IRP to understand capital costs outside of 2021 IRP expectations.

Table 9.1: Oregon Distribution Projects

Location	Gate Station	Project to Remediate	Cost	Year
Klamath Falls, OR	Klamath Falls #2703	TBD	-	2023+
Sutherlin, OR	Sutherlin #2626	TBD	-	2023+

Large High-pressure distribution and City Gas projects did not occur since the 2021 IRP. Quarterly updates with OPUC Staff and other interested parties will occur to ensure any change in projects is known along with reasons for any major changes in expected capital expenditures.

2023-2024 Action Plan

1. Purchase Community Climate Investments for compliance to the Climate Protection Plan for years 2022, 2023, 2024, 2025 and 2026 to comply with Executive Order 20-04.
2. 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 ETO to meet IRP gross savings target of 568,000 therms in 2024.
3. New program offered by ETO for interruptible customers in 2023 to save 15,000 therms.
4. 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.
5. In Oregon, acquire 8.64 million therms of RNG in 2023 and 21.80 million therms of RNG in 2024.
6. In Washington purchase allowances or offsets for compliance to the Climate Commitment Act for years 2023, 2024, 2025 and 2026 to comply with emissions reduction targets.
7. Begin to offer a Washington transport customer EE program by 2024 with the goal of saving 35,000 therms
8. Explore methods for using Non-Energy Impact (NEI) values in future IRP analysis to account for social costs in Washington to ensure equitable outcomes.
9. Explore using end use modeling techniques for forecasting customer demand.
10. 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.

11. 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 in order 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

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-461

KEVIN HOLLAND
Exhibit No. 402

Natural Gas Supply

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 Natural Gas IRP Team

Name	Title	Contribution
James Gall	Manager of Integrated Resource Planning	IRP Core Team
Tom Pardee	Natural Gas Planning Manager	IRP Core Team
Michael Brutocao	Natural Gas Analyst	IRP Core Team
John Lyons	Sr. 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
Ryan Finesilver	Mgr. of Energy Efficiency, Planning & Analysis	Energy Efficiency
Lisa McGarity	Energy Efficiency Program Manager	Oregon Energy Efficiency
Leona Haley	Energy Efficiency Program Manager	Demand Response
Terrence Browne	Sr. System Planning Engineer	Gas Engineering
Justin Dorr	Natural Gas Resources Manager	Power Supply

Natural Gas IRP Contributors

Name	Title	Contribution
Scott Kinney	VP of Energy Resources	Power Supply
Kevin Holland	Director of Energy Supply	Power Supply
Clint Kalich	Sr. Manager of Resource Analysis	Power Supply
Shawn Bonfield	Sr. Manager of Regulatory Policy	Regulatory
Amanda Ghering	Regulatory Affairs Analyst	Regulatory
Annie Gannon	Communications Manager	Communications
Mary Tyrie	Manager Corporate Communications	Communications
Jeff Webb	Manager of Gas Design, Measuring and 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

TABLE OF CONTENTS: APPENDICES

APPENDIX 0.1: TAC MEMBER LIST

Organization	Representatives	
Applied Energy Group	Kenneth Walter	
Avista	Terrence Browne	Heather Rosentrater
	Amanda Ghering	Tom Pardee
	Ryan Finesilver	Michael Brutocao
	Grant Forsyth	Jason Thackston
	James Gall	Jaime Majure
	Justin Dorr	Michael Whitby
	John Lyons	Shawn Bonfield
	Lisa McGarity	Jeff Webb
	Annette Brandon	Annie Gannon
	Clint Kalich	Scott Kinney
Biomethane, LLC	Kathlyn Kinney	
Cascade Natural Gas Company	Ashton Davis	Brian Robertson
	Mark Sellers-Vaughn	
Citizens Utility Board of Oregon	Sudeshna Pal	Will Gehrke
Eastern Washington University	Erik Budsberg	
Energy Trust of Oregon	Ben Cartwright	Spencer Moersfelder
	Ted Light	Hannah Cruz
Department of Energy	Michael Freels	
DEQ	Nicole Singh	
Energy Strategies	Jeff Burks	
Fortis	Ken Ross	
Idaho Public Utility Commission	Donn English	Kevin Keyt
	Terri Carlock	Mike Louis
	Joseph Terry	Rick Keller
	Taylor Thomas	Jason Talford

Intermountain Gas	Raycee Thompson Dave Swenson	Lori Blattner
Lewis and Clark Law School	Carra Sahler	
Northwest Energy Coalition	Amy Wheeless	
Northwest Gas Association	Dan Kirschner	
Northwest Natural Gas	Michael Meyers	
Northwest Power and Conservation Council	Steve Simmons	
Oregon Public Utility Commission	JP Batmale Sudeshna Pal	Kim Herb Ted Drennan
RNG Coalition	Vincent Morales	
Sierra Club	Jim Dennison	
Washington State Office of the Attorney General	Shay Bauman Chuck Murray	Corey J Dahl
Washington Utilities and Transportation Commission	Jennifer Snyder	Jim Woodward

Appendix 0.2: OPUC Staff Draft Comments

Avista Draft 2023 IRP: OPUC Staff Feedback Comments

Staff wants to thank Avista for providing a Draft IRP for stakeholder comment. At a high level Staff is pleased with the elements being considered in this IRP, including consideration of the IRP Guidelines, past orders, and issues raised in UM 2178, such as electrification and applicable scenarios. We look forward to reviewing the Final IRP and remind the Company that Staff's review of the IRP will be delayed until the summer of 2023.

This document contains comments made by Oregon Public Utility Commission Staff (Staff) with regards to Avista (the Company) 2023 Draft IRP (Draft). Grouped by topic, the comments mainly focus on Staff's suggestions and recommendations for the upcoming filed 2023 IRP.

General

Staff asks that the company plan to provide the workpapers for all tables in the IRP, including appendices, with formulae intact, as well as all supporting graphs and charts exhibited in the IRP upon filing the IRP.

Response: All workpapers have been provided with the final IRP.

Staff notices and appreciates Avista's efforts to incorporate some of the IRP suggestions from Docket No. UM 2178. Staff would appreciate the Company identifying which of the NGFF recommendations it has incorporated in this IRP, as well as which ones will it not be incorporating and why. See Table 2 in the Natural Gas Fact Finding Report and respond to at least each of the following recommendations (table 2 in the report includes other recommendations that may not be applicable):[1]

UM 2178 Topic	Recommendation	Comments	Avista Response
Protecting Customers	Estimated ratepayer bill impact	Staff appreciates the inclusion of the discussion on rate impacts, and especially considering these from a bill impact perspective, with regard to electrification. Staff encourages Avista to include further descriptions about how bill impacts are considered across the different scenarios, especially where scenario assumptions might significantly alter cost of gas, fixed costs, and compliance cost associated with transport customers associated with compliance with CPP. This would ideally include, at a minimum, general approaches it is considering for rate spread as well as \$/GHG emission reduction, where possible.	Chapter 7 includes examples by scenario
	EE programs to include transport	Staff looks forward to learning more about the opportunities for EE programs for transport / transportation customers in Oregon and appreciates Avista's activities described to date.	N/A

	Target IRA Incentives	Consider including a section on how IRP incentives are modeled and whether the Company is pursuing federal incentives.	Chapters 3 and 5 describe these assumptions
	Align near-term investments with CPP compliance	Avista should include in the IRP whether and how action plan items align with CPP compliance.	Chapter 6 for the preferred resource selection and Chapter 9 for Action Plan

[1] See Docket No. UM 2178, Natural Gas Fact Finding Final Report, January 2023, page 2, available at: https://edocs.puc.state.or.us/efdocs/HAU/um2178hau111621.pdf

UM 2178 Topic	Recommendation	Comments	Avista Response
Full Cost	Develop marginal abatement cost curve	Staff is interested in developing a full understanding of the cost of compliance with CPP of different strategies. How does Avista anticipate analyzing the cost of compliance of different strategies, and what value might the Company see in developing marginal abatement cost curves to illustrate compliance cost and options?	Supply Curves included in Appendix 4. Future outcome is dependent on customers and demand on system.
	Utilities articulate electrification assumption in IRPs	Staff greatly appreciates Avista's work in characterizing electrification cost and assumptions, and especially its work on having electrification be a selectable resource. Staff will be very interested in engaging closely with the company on electrification assumptions and the impact it had on resource selection in the various scenarios. Staff will be interested in understanding limitations of this approach, especially with regard to modeling in territories for which Avista is not the utility providing electricity.	N/A
	Electrification info and data from DSP	As applicable, Avista should work with Oregon investor-owned electric utilities with which the Company has overlapping territory to develop electrification assumptions aligned with information and data being submitted in electric utility Distribution System Planning efforts.	Not included in the 2023 IRP, need more information prior to development and inclusion in future IRP

Decarb Planning & Cost-Recovery	Gas system maps with infrastructure age and depreciation information	Avista should provide, in digital map format, the location, age, size and type of pipe, as well as information indicating where distribution system upgrades are being considered and why.	Not included in 2023 IRP. Maps of the distribution system are not publicly available because they include sensitive/customer/confidential information. By suggesting this information be required to be made publicly available poses serious safety and security concerns. Overlaying depreciation data on maps does not provide additional information due to the use by utilities of mass (group) asset accounting. Distribution assets are accounted for at the jurisdictional level, thus depreciation rates and composite remaining life are identical for Company assets across Oregon. Lists of infrastructure and associated depreciation schedules can possibly be provided in the future, outside of the IRP, by general categorization but would be consistent with publicly available data from the Company's depreciation study, provided to the Commission and parties every five years.
	CPP as an acknowledgeable item in IRPs	Avista should ensure that the IRP demonstrates incremental progress toward meeting CPP GHG emission reductions through the actions taken in this IRP and should seek acknowledgement of these actions as those taken to meet CPP compliance.	These are included in Chapter 9 Action Plan
	Exploring IRP guidance from UM 2178	Avista should review Appendix B of the NGFF Final Report and identify which of the IRP recommendations it has incorporated, will incorporate, or plans to incorporate in this IRP. Which ones will it not be incorporating and why?	Included in Appendix
Monitoring, Tracking, and Reporting	Annual PUC report based on DEQ compliance filings Utilities host annual utility report on CPP compliance filings	Avista should demonstrate progress toward meeting CPP compliance through the plans articulated in the IRP with annual reports based on DEQ compliance filings and referencing associated action plan items as appropriate. These reports should also include the associated costs. These reports, where applicable, can be	Avista will include information on its CPP compliance within its IRP update and future IRPs.

	Enhance tracking of alternative supply of actual costs and report to planning	submitted as part of an IRP Update when the timing accommodates this or as a separate report. This report should clearly track and delineate alternative supply actual costs.	
Incentivize GHG reduction pathways	Explore use of SB 844 for emerging technologies	Avista should include a description of any/all SB 844 related activities.	Not included in the 2023 IRP. Avista will share in all future IRPs
	Pilot or joint pilots with electric utilities proposal by 2025	Avista should share opportunities it envisions, or progress made on pilots.	Not included in the 2023 IRP. Avista will share in all future IRPs

Chapter 1: Planning Environment
Staff very much appreciates Avista's inclusion of Table 1.2 showing the Summary of Changes from the 2021 IRP.

Response: N/A

Chapter 2: Demand Forecast
Avista forecasts an average annual load-growth of 1.1 percent in the Draft IRP. That is an increase from 1.0 percent in the previous IRP. While Staff has yet to see Appendix 2.1, Staff has three concerns regarding how this growth is considered in the IRP: 1) its reliance on the Status Quo 2) the impact of this assumption on near- and long-term planning, and 3) the additional compliance obligation and stranded asset risk that accompanies this growth.

Similar to Staff's concerns in response to NW Natural's 2022 IRP,[2] Avista's customer count predictions appear to use historical trends without regard to new clean energy policies and uncertainty. Page 2-2 notes that the "…forecasts reflect the "status quo" and do not fully reflect emerging natural gas connection restrictions in Washington and Oregon." Staff will be interested in understanding how status quo growth assumptions impact the Preferred Resource Strategy (PRS or preferred portfolio) and near- and long- term actions and whether the assumptions of status quo growth are reasonable.

Response: With a lack of building codes or policies to guide a different future level of growth in Oregon, Avista addressed this uncertainty through a variety of scenarios including electrification with three sets of different conversion costs and a hybrid scenario, among others. An end use model may help better forecast these unknown futures as discussed in action items in Chapter 9.

The Company should develop a sensitivity, to include in the filed IRP, that reflects the potential for declining customer counts, not just a decline in growth rates.
Response: Please refer to response 4a. scenarios to illustrate a loss of customers can be seen in the electrification scenarios and the hybrid scenario.

Additionally, Staff has expressed concerns in other gas IRP and in NW Natural's most recent General Rate Case UG 435 about how utilities are considering and addressing the impact of increased customer counts on CPP compliance risk. Please see Staff's Opening Comments Section 4.2.[3]

Response: Until such time clarification is provided in legislation or policy, Avista shares this concern and will attempt to address through scenarios. Increased customers are something Avista does not have direct control over at this time.

Given the CPP coverage of Transport Customers, please ensure either the body of the IRP or Appendix 3 includes Avista's plan for reducing these emissions and explain how it anticipates the costs of these emission reductions might affect cost of service customers.
Response: Avista is exploring new energy efficiency programs for transport customers to help find carbon emissions savings. As the State of Oregon sees these emissions as under Avista's control or obligation, costs of compliance will be spread across the system on a per therm basis.

Check Figure 2.2 to confirm that all customers are represented in the chart, it appears to show only two colors.

Response: Customers are accurately depicted in Figure 2.2. Industrial customers in both Oregon and Washington are small in comparison to Residential and Commercial customers. Please refer to Figure 1.3 for a detailed understanding of these customers.

Chapter 3: Demand Side Resources

While the Draft describes the Low-Income EE potential and references an appendix with more detail, the filed IRP should go a step further and include a description of the Company's plans, if any, to integrate these activities with Avista's programs designed to reduce energy burden.

Response: The IRP is not the document to discuss Avista's plans for programs designed to reduce energy burden. The IRP is focused on ensuring that the Company has adequate supply to deliver to its customers while meeting CPP compliance targets. Discussions of programs intended to reduce energy burden are best suited within the framework of HB 2475, the Company's Low-Income Rate Assistance Program (LIRAP), and the Company's annual report out on its Avista Oregon Low Income Energy Efficiency Program (AOLIEE).

Staff would appreciate the Company explaining in the filed IRP the extent to which PLEXOS could be allowed to select greater levels of energy efficiency – beyond Energy Trust's forecasts – versus RNG as part of a least-cost/least-risk portfolio. It may be helpful to review Staff's comments on this topic in NW Natural's 2022 IRP.[4]

Response: Avista will explore this in the 2025 IRP. Market saturation, costs, and other assumptions will be key to obtain from the Energy Trust of Oregon to model within Plexos.

Please explain why interruptible and transport energy efficiency potential are grouped (see Table 3.7).

Response: These results were completed under the same CPA. A detailed description and set of results can be found in the Appendix under Chapter 3.

Page 3-7 includes reference to demand response pilot programs. Please provide citations to these studies.

Response: Updated in Final IRP.

[2] See Docket No. LC 79, NW Natural 2022 IRP, Staff's Opening Comments, December 30, 2022, page 83.

[3] See Docket No. LC 79, NW Natural 2022 IRP, Staff's Opening Comments, December 30, 2022, Section 4.2.

[4] See Docket No. LC 79, NW Natural 2022 IRP, Staff's Opening Comments, December 30, 2022, Section 3

Table 3.9 shows NGDR participation rates. If available, please include information about how these participation rates compare to other regions. It would be helpful to understand if these are high, average, or low participation rates.

Response: Additional detail can be found in the CPA included in the Appendix for Chapter 3. The results are specific to Avista territories, but methodology and details are further explained.

Please provide references or sources for the information provided in Figure 3.2 – Space Heat Efficiency by Degrees Fahrenheit and Fuel.

Response: Estimates were obtained from internal subject matter experts based on knowledge and data seen in the industry and through multiple years of studies, experience, and data from sources such as Applied Energy Group (AEG).

Staff is grateful for the detail included regarding Conversion Costs. Staff has many questions about the assumptions and expects the IRP to include significant detail about the assumptions. Please provide this in workbook format and where possible, document the incentives considered that result in the final prices.

Response: A description is included in Chapter 3 in addition to Chapter 5 for the Inflation Reduction Act. Final prices in Figure 3.4 share a detailed breakout by end source. These end sources assume a consumer saving 50% of the "Total to Remodeler". Estimates and study reference are also included with these chapters of reference.

Please consider a scenario where just water and space heating conversions are done, or where the customer chooses to stay and use dual fuel heat pump and heat pump water heaters, but keep other gas appliances, if they have them.

Response: This is essentially the Hybrid Case. A very small portion of demand is estimated in the residential class for "Other" appliances such as stoves.
Regarding Rate Impacts, please clarify whether the model makes any assumptions about cooling.

Response: Avista does not forecast cooling in as it would be assumed cooling is supplied by the electric providers.

See Figure 3.6 – How do these bills compare to baseline? It would be valuable to see energy used, GHG emissions, and associated cost differences between pre and post conversion.

Response: Impacts by scenario have been added to the Final IRP in Chapter 4.

Regarding Figure 3.7 - is the 2032 increase associated with HB 2021 clean energy goals? Will modeling show bill impacts? Will there be any targeted electrification - or a distinction between the difference in moving from resistance to heat pump vs gas to heat pump? Has the Company identified the optimal conversion scenarios and associated costs? e.g., space heating costs deltas are A for resistance to heat pump, B for gas to heat pump, etc. and assumptions about changes in summer load regarding air conditioning, e.g., fans vs. window unit vs. other.

Response: This increase in 2032 is due to the IRA expiration. Modeling will show bill impacts. Electrification is not targeted in any of these scenarios as discussed in chapter 7. It is simply a demand side choice to the model. Varying levels of conversion have not been considered in the 2023 IRP.

Chapter 4: Current & New Resources

Renewable Natural Gas

Staff expects that a conversation about the Company's forecasted cost trajectories and availability for RNG, Hydrogen, and other emerging technologies will be an important part of the IRP review process. Supporting information that Avista can provide in the IRP document itself to help facilitate this conversation will be appreciated. If possible, a study and discussion of the risks and opportunities of a scenario with higher cost trajectories would be of interest to Staff, especially where technology readiness levels are low.

Response: Updated in Final IRP and supply curves added to Appendix 4.

When evaluating RNG and hydrogen availability, please include a discussion about the economic sectors competing for this resource and assumptions about availability to the power sector. What economic factors cause the company to expect RNG and hydrogen to be available to the power sector even while demand from other sectors is high?

Response: All sectors, including transportation, may be competing for these resources. Hydrogen being the most abundant element may help to alleviate this competition though the creation of hydrogen and the technology to do so may be the areas most constrained. RNG has been shown through multiple studies to contain enough resource potential to provide some level of clean fuels to programs and states containing these goals. Not all States have clean goals or programs so the availability of these fuels may be more available depending on this trajectory.

Per OAR 860-150-0400, Avista must file a petition to participate in the PUC RNG's program and Staff's understanding is that the methodology can be approved in an IRP process. Staff is unclear if the filed IRP's action plan can be acknowledgeable without this filing and Commission approval, given the levels of RNG acquisition the IRP calls for. The filed IRP should discuss how this filing will be made if the Company if it is not filing for acknowledgment of this methodology in this IRP. Further, it would be helpful to explore the rate cap it will attempt to establish in their petition filing.
Response: Avista will follow all rules as needed to bring on new resources under SB 98 if it pursues this path. If SB 98 is not used as the reason to acquire a new resource, filing a petition to participate in this process will not be necessary.

Staff appreciates the model notes of the proposed RNG Cost Effectiveness calculation. Avista should consider including additional information about the change in carbon compliance costs over time and how that could be reflected in the cost-effectiveness evaluation methodology.
Response: Changing carbon compliance costs are evaluated in comparison to RNG and other

resource costs in the Plexos model to understand RNG cost effectiveness.

Staff appreciates the inclusion of a conversation regarding buying versus building RNG projects. Staff requests that this section be expanded to include more discussion regarding whether and how risk is captured when considering RNG project type and finding ways to ensure that ratepayers are not negatively impacted by Avista's choice of deal structure.[5] Further, consider discussing whether there other risk mitigation aspects that a build option presents; and how customers are afforded equal, or increased protection from risks.[6]

Response: Updated in Final IRP.

Regarding Purchase Projects,[7] the descriptions include project design and construction aspects. Staff would also appreciate additional discussion regarding:

Avista's role in designing and building these projects and whether there are O&M costs;

The procurement process for these projects; and

If possible, the emissions impacts from these projects - both in terms of CPP compliance and carbon intensity - and the anticipated or known end use of the gas.

Response: Avista has not, to date, bought any project. Emissions from these projects per the CPP is all directly available through the program language itself as if a project is certified as RNG, it meets the compliance goals of offsetting an equivalent of natural gas meaning it gets excluded from emissions totals. Carbon intensity is not a part of the CPP in its current design.

For all RNG projects, please provide additional description about the benefits these projects provide to Avista and Avista's Oregon customers and which ones have Environmental Attributes that will apply to CPP compliance.

Response: All RNG as modeled in the IRP are considered a bundled product. Renewable Thermal Credits (RTCs), if purchased, would require a source of energy such as natural gas. RTCs offset the energy and carbon in a dekatherm of natural gas and all would apply toward CPP compliance.

Avista references some of the same sources for cost and availability used by NW Natural in its 2022 IRP. As Staff provided substantial comments on the cost and availability assumptions of RNG and Hydrogen in its comments in NW Natural's case,[8] it may be helpful to review Staff's comments to see if there are concerns or questions raised in that docket that are applicable to Avista and that the Company could address with additional clarification in its filed IRP.

Response: Avista utilized RNG curves from multiple sources. The supply curves included in the Appendix Chapter 4 include estimated supply availability from a consultant to Avista and are population weighted. An RFP was conducted and volumes in response to the RFP support and even eclipse these estimated totals in the IRP.

In the Draft, it appears the company anticipates acquiring more RNG for WA than for OR.[9] This was surprising to see given the constraints around environmental attributes in WA. Please provide more explanation about the difference in RNG potential volumes in WA and OR.

Response: Avista does not have RNG as a resource option in WA in the PRS. Oregon, however, has the highest demand for RNG in all scenarios for the 2023 IRP.

[5] See Docket No. LC 79, NW Natural 2022 IRP, Staff's Opening Comments, December 30, 2022, pages 49-51.
[6] Avista Natural Gas Corporation 2023 Integrated Resource Plan Draft, January 5, 2023, pages 4-18.
[7] Avista Natural Gas Corporation 2023 Integrated Resource Plan Draft, January 5, 2023, pages 4-11 to 4-13.
[8] See Docket No. LC 79, NW Natural 2022 IRP, Staff's Opening Comments, December 30, 2022, Section 11, pages 64-72.
[9] Avista Natural Gas Corporation 2023 Integrated Resource Plan Draft, January 5, 2023, Figure 4-4, page 4-16.

Synthetic Methane

Staff and CUB provided substantial comments in Opening Comments in LC 79 regarding synthetic methane assumptions. Concerns were around price and availability assumptions and the resulting modeling with the use of those assumptions.[10]

Response: Avista shares those concerns as it is a proven technology, but not readily available or used on a large scale. External studies were used to develop assumptions such as those from Lazards, Bloomberg, Black and Veach and others. The IRA should help to boost technology uptake, yet the quantity and availability is a risk as with any new technology.

Other

Recognizing that GTN Xpress has garnered attention from advocacy groups, please consider additional information about the role this project plays in the Company's planning, any anticipated impacts if this project didn't manifest, and alternative ways to meet the need this project addresses.

Response: Avista did not consider GTN Xpress in resource options as resources to deliver natural gas are long and nothing is needed to meet capacity. Emissions constraints drive the resource needs considered in the 2023 IRP. However, without GTN Xpress, the region may become resource constrained and the ability to meet a regional peak along with extreme price volatility has seen an increase in recent years. GTN does not serve solely one jurisdiction with a single climate policy, but rather crosses multiple jurisdictions with various climate policies. Idaho is Avista's fastest growing jurisdiction and does not have, nor is it expected to have, a climate policy in the future. With policy in California reducing operating storage fields, if a pipeline or gas infrastructure unexpectedly fails, the ability to provide energy demand is at serious risk.
Regarding Strategic Initiatives and the primary roles of the Energy Resources Department, Staff may be interested to hear more about how, if at all, the Company factors in new customers in its consideration of risk to serving existing load. When the company describes its strategic initiative with a primary role of serving load - is there differentiation drawn between existing and future load?

Response: Serving load, both existing and new, is a requirement to having a monopoly service in Oregon. Avista will follow all procedures, rules, and regulations in providing energy through its pipeline infrastructure. Until such time the requirement to serve new customers is removed, Avista is obligated to serve these customers. As such, Avista has not factored new customers in its consideration of risk to serving existing load.

On page 4-31 the company describes ongoing activity of optimizing underutilized resources to help reduce costs to customers. Can you provide more detail on the types of activities this includes?

Response: Optimization of these resources includes releasing pipeline capacity when it is not required. It also includes using the basin spreads to capture value between demand regions. This can include purchasing at the lower priced basin and selling at the highest priced basin. This would consider all costs and fuel to move the energy from one point to the next.

Chapter 5: Policy Issues

Staff really appreciates the level of detail provided around Direct Carbon Capture Facilities incentives. Staff would like to understand whether and how this incentive information is captured in modeling. Similarly, Staff will be interested in understanding how incentives for conversions from natural gas to electric are modeled and whether this policy is reflected in future load and customer growth.

Response: The expected costs of the IRA are included in conversion costs by end use. These costs are estimated as saving as much as 50 % of the total costs to convert. Load growth uses historic figures to estimate future load growth. Until an end use model is developed or obtained, understanding elasticity and future load growth based on the IRA is not directly available in the analysis. This is an action item in the 2023 IRP Action Plan to obtain an end use model.

Staff notes that the Company is also subject to Securities and Exchange Commission GHG and Climate-related Risk Disclosure. While Staff isn't suggesting that the Company include additional information in the IRP, it should anticipate that Staff will be interested in seeing any filings of the Company, either in the IRP itself or through the discovery process.

Response: Avista will provide all materials of interest that have been made publicly available, if requested to do so.

Chapter 6: Preferred Resource Strategy

Chapter 6 includes several charts that have little or no additional text explaining the importance of the information they contain.

Response: Avista has attempted to address this comment throughout the document and specifically Chapter 6.

Regarding Lead Time Requirements - please consider adding language about the lead time and information necessary to consider non-pipe alternatives to distribution system investments.

Response: Updated in Final IRP.

Regarding competition for RNG resources - Staff appreciates this mention and asks that the company explain and demonstrate how this competition is reflected in its availability and cost assumptions.

Response: The current market for competition dictates a price for RNG in the LCFS and RIN markets as discussed in Chapter 5. Prices analyzed by source provide estimates of a cost of ownership structure. Without ownership, costs of RNG may lean to a market based structure where competition is around compliance. Both pose risks as a cost risk may be evident in place of a loss risk if projects don't materialize as expected.

[10] Docket No. LC 79, Staff Opening Comments, December 30, 2022 Section 11. https://edocs.puc.state.or.us/efdocs/HAC/lc79hac162626.pdf and CUB Opening Comments, December 30, 2022

Regarding Risk and Uncertainty - consider the feedback provided to NWN regarding risk and uncertainty in Staff's Opening Comments in LC 79 and the assumptions used to represent conservative approaches.[11] Where assumptions stray from a conservative approach, provide the rationale and support for the assumptions used.
Response: Avista analyzed risk and uncertainty using factors specific to its specific system. There are many risks included in the 2023 IRP, more than any previous IRP, but in simple terms it all comes down to supply, demand and cost risks. Natural gas sources are abundant in our region so supply risk pending an unexpected outage is navigable. New carbon free resources present mostly a cost risk at this point as some technology is not scaled up and costs are still higher when compared to natural gas. Demand risk in Oregon and Washington is likely the greatest risk. For this we have to rely on estimates of how demand may shift based on the known facts. Electrification may take place at a faster level than anticipated. Electrification may take place at a slower level than anticipated. Policy may imply a fundamental change, but one that never takes place. Chapter 2 helps to describe these potential outcomes based on stochastic futures. More work is needed in future IRPs to understand these risks and have been added to the Action Plan.

Please provide more explanation for the information provided in figure 6.16.

Response: Updated and moved to Chapter 3-1.

Consider providing additional information about what is happening in table 6.2 and 6.3. In particular, please speak to the change(s) that occurs between 2035 and 2036.
Response: Updated in final IRP.

See page 6-24. Please explain and provide associated workpapers demonstrating about why synthetic methane appears before hydrogen in the Oregon PRS.
Response: Hydrogen can only provide 1/3 the energy for the same amount of space in the pipeline. Synthetic methane requires the same amount of space as natural gas meaning an equal amount of energy can be provided when needed. This insinuates an additional pipeline or expanded distribution would need to be created in order to utilize hydrogen to provide an equal amount of energy demand.

See page 6-24. Regarding Natural Gas Basin Least Cost, to what extent are the volumes procured via multi year contracts. Please consider explaining how these contracts reflect reductions in volume associated with CPP compliance.

Response: Natural gas supply basins are procured on a least cost basis where Avista has the ability to move natural gas from the supply point to city gate stations in its service territories. Volumes can be procured into the future as much as 36 months. Avista does not have multi-year contracts in its portfolio and procures hedges against average volumes in winter strips (November-March), summer strips (April – October), or in individual months. Avista does not have any RNG, synthetic methane, hydrogen, or other clean fuel on the system, but when these supplies are secured, they will be removed from average volume hedge plan targeted hedges. They would directly reduce obligations for energy in the form of natural gas. Program offsets would still be required if natural gas is purchased in compliance to the CCA and CPP where volumes are above the program cap.

See table 6.4. Considering the remarkable trajectory of synthetic methane acquisition, what are the consequences of this not materializing?
Response: Like all forms of clean energy, these supplies will take time and investments to materialize as expected. In the event these costs and available volume acquisition do not materialize, Avista will look to other forms of clean energy resources to meet customer demand. These could include RNG, hydrogen, carbon capture, among others.

Regarding Figure 6.21 – consider providing additional detail about what influences the ranges.

Response: Updated in final IRP.

Regarding Price Impacts on page 6-32 – the Company notes that these are a "commodity only estimate." Does this mean that this does not reflect the full anticipated bill impact? Please provide more explanation about what these values include or do not include.

Response: Updated in final IRP.

Avoided Costs

Staff looks forward to seeing more detail about Avista's avoided costs methodology and understanding the extent to which it captures the increased costs from RNG. To the extent that cost could be avoided by energy efficiency, would it be found in the methodology's Commodity Cost or in the Environmental Compliance Costs? If the preferred portfolio's forecasted 2028 RNG costs are not accounted for in energy efficiency's avoided costs, the filed IRP should detail the reasons.

Response: avoided costs include emissions compliance costs and energy costs. Any resource available, as outlined in Chapter 4, make up these costs. They are all included in the model which provides the avoided costs to AEG and ETO for evaluation.

Chapter 7: Alternative Scenarios

Consider a reorganization of the Tables in Chapter 7, with the categories in the first column and the scenarios and years in the following columns, like the Company did in the scenario comparisons in UM 2178. This would facilitate comparisons across the scenarios. Please also consider including the units in the tables themselves, instead of in the narratives about the tables.

Response: Additional comparisons have been provided in Chapter 7 to provide reference points across all scenarios.

Staff would like to have any easy way to compare key findings of the different scenarios in one place instead of flipping between scenarios (a summary table with key metrics – like what you did in UM 2178)

Response: Additional comparisons have been provided in Chapter 7 to provide reference points across all scenarios.

Regarding the Electrification Scenarios

Do they capture emission reductions and bill impacts? Is there any consideration of the payback on the conversion costs when considering energy saved on the gas side and energy consumed on the electric side? To the extent possible, it would be helpful to understand the shifts in costs and emissions or make it explicitly clear where those are not captured in the modeling.

Response: The electricity is considered green, though one could argue that maybe premature depending on the year selected combined with the electric provider. Avista does not know the source of power for the electricity provided to crossover areas. Emission reductions are captured and illustrated in Chapter 7, Figure 7.13. Conversion costs are assumed to have a payback of 5 years and charged in an annuity type monthly fee. Any customer loss to the electric provide helps meet emissions goals on the natural gas system as less demand is required to find a clean fuel or procure a CCI.

This section notes that Chapter 2 explains the methodology to remove demand from the gas system. Please consider including an additional discussion about how it considered reductions in O&M and infrastructure costs where demand on the gas side is reduced.

Response: Depending on where the line and customers are located, pruning of the system may created a cost savings in O&M. This is a detailed analysis where a SCADA system would be required in combination with software used to plan the distribution system. This is a good reason why Avista chose to only include cost impacts on the commodity rather than as an bill.

Be sure the electrifications cost clearly indicate how IRA and other federal incentives are considered.

Response: Updated in final IRP.

Staff is unclear about the Hybrid case. Please consider expanding the description of this scenario and the role it plays in this IRP modeling.
The Company says it assumes "immediate conversion." Please explain more about why this is reasonable.
This section would benefit from more explanation about what technologies are considered and support for the timeline of adoption considered.

Response: Avista agrees with this initial case and has adjusted the case to allow for a declining use or conversion of customers as in the electrification scenarios.

Electrification Selected as Resource – Staff is pleased to see the Company including electrification as a selectable resource. The outcomes of including electrification as a selected resource are interesting and warrant more explanation about the drivers and implications. For example, the Company notes that "electrification was selected in the first year, but not again after." It is not clear to Staff why or what this might mean. Please consider opining on this further.
Response: Updated in final IRP.

Interrupted Supply - please explain how this scenario plays out over the course of the planning

horizon. Is the 50 percent constraint over the entire planning horizon?
Response: In the scenario it is assumed the pipeline capacity is reduced by 50% from Sumas south at Northwest pipeline (NWP) and Westcoast pipeline which brings in supply from station 2. This is paired with a constraint at the Rockies point on NWP down to 75% of capacity. Both constraints are for the 23 year timeframe on a daily basis. The primary reason to not just model a daily outage is due to the models ability to just use storage to meet demand. These scenarios also have a hard time and are at a disadvantage as these expected futures would impact the region so the ability for the region to meet these capacity constraints would likely tell a more accurate story as to best mix of cost and risk.

Social Cost of Carbon - Please explain what is meant that the SCC overrides the cost of compliance in CCA and CPP. It's not entirely clear how this scenario handles the SCC as considered already.

Response: The social cost of carbon is higher than the program cost of carbon in both the CCA and CPP. To understand the costs of using the SCC for compliance rather than the costs as found in the CCA and CPP, an "override" of the costs in these programs are necessary. Another way to say this is the SCC is the cost of carbon in place of those costs included in the CCA and CPP to compare resource selections.

Oregon CCI Investments - please provide more explanation about why SCC scenario results in higher acquisition of renewable fuels and removes the need for more CCIs. Figure 7.8 The CCI demand by scenarios are very interesting, please consider providing a more discussion opining on these, including how they influence the PRS.

Response: Additional explanation has been provided to help add more detail to selections.

See Figure 7.9: System Emissions by Scenario by 2030 - Please provide more discussion around the emissions outcomes in figure 7.9. In particular, consider more discussion around the carbon intensity scenario and the hybrid case scenario.

Response: Updated in final IRP.

Chapter 8: Distribution System Planning (DSP)

Distribution system 'pruning' and electrification may be topics of conversation in the IRP review process. Any context the Company is inclined to provide on these issues could help develop a shared framework and knowledge base for this discussion.

Response: Avista would like to be part of the pruning and electrification discussion to learn more about how this potential strategy may mitigate near-term distribution constraints.

For future distribution system projects presented in an IRP Action Plan, Staff recommends Avista follow the Commission's endorsement, in Commission's Order 23-023, of encouraging the use of Attachment A in the Staff's Report when such projects appear in an IRP Action Plan. Staff uses the set of questions in Attachment A for requesting specific information that help build an analytical framework to be used for the assessment of proposed distribution system projects.

Response: Avista will review Commission Order 23-023 and consider the use of Attachment A in future IRP Action Plans for distribution system projects.

Non-Pipe Alternatives

On page 8-5 the company references "longer-term, targeted energy efficiency programs" that could offset constrained areas. Staff is interesting understanding how much advance lead time Avista would need to consider targeted energy efficiency or non-pipe alternatives, to mitigate the need for other distribution system constraints. Consider including more information about how non-pipe alternative are considered as options (or not) and why.

Response: As shown in Table 8.2 (City Gate Station Upgrades), Avista has some city gate stations that are reviewed periodically to determine the need and timing of any upgrade. Avista is exploring the possibility of using a targeted energy efficiency alternative as a means to mitigate or eliminate an upgrade project. However, until the need becomes imminent, it is prudent to wait before Avista dedicates resources to a targeted energy efficiency program or non-pipe alternative solution.

Table 8.2 shows City Gate Station Upgrades and lists two Oregon projects with TBD dates and notes that the Company is monitoring these constraints. Please describe the nature of the issues being monitored and whether non-pipe alternatives could address the issues. Please also explain why a location would be monitored and what characteristics warrant monitoring.

Response: The list in Table 8.2 (City Gate Station Upgrades), with TBD dates reflect those city gate stations that have projected capacities near to slightly above the physical capacity of the station. To determine if and when an upgrade is necessary, Avista continues to monitor peak-hour capacity flows during cold weather conditions. Non-pipe alternatives and targeted energy efficiency programs may be able to address the city gate station's physical capacity constraint. Avista feels it may be prudent to continue monitoring to determine the need and timing of any upgrade before dedicating resources to evaluate a non-pipe alternative solution.

Page 8-8 includes a description of the evaluation of non-pipe alternatives. Please describe whether and how stranded asset risks are considered in the evaluation of non-pipe alternatives.

Response: Avista has yet to employ a non-pipe alternative that involves the evaluation of stranded assets. When the first case is studied, the appropriate departments will be included (Regulatory, Property Accounting, and Engineering) to ensure the full financial impacts are included in the analysis.

Chapter 9: Action Plan

Staff expects the action plan to cover four years.

Response: The action plan is intended to cover four years.

Regarding Action Item 3 – please provide more details in the IRP about the ETO program for interruptible customers or reference program details in an appendix.

Response: Updated in the final IRP

Please provide more detail about the Company's anticipated RNG projects for 2023 and the pipeline of projects in development, as applicable.

Response: Avista is currently in an RFP and under an NDA. Currently Avista is evaluating options including bundled and unbundled RNG. Avista will inform each commission in its service territory as projects or resources are further considered.

Regarding Action Item 10 - specifically, the construction of gas infrastructure associated with growth. The Company lists these as a potential necessary capital investments that are not referenced in the IRP. This is disconcerting, especially regarding Staff's concerns about growth related investments and CPP risk. Please provide more discussion about these types of possible projects and please see Staff's Opening Comments in LC 79, section 4.2, and Order No. 23-023.

Response: The specific language was a carryover from prior IRPs. The line regarding expansions based on growth has been removed and is now accurately depicted in the Action Plan in Chapter 9.

[12] See Docket No. LC 76, Cascade's 2020 IRP Update, Staff Report, October 7, 2022, pages 19

Appendix 0.3: WUTC Staff Draft Comments

A table of contents with embedded links would be helpful.	Avista will include a table of contents in the final IRP.
Ch. 1 Introduction and Planning environment	
Fig 1.4 – Please make colors for each class match across states.	Primary colors match across each area and state now.
Ch. 2 Demand Forecasts	
Page 2-2, "However, it is important to understand these forecasts reflect the "status quo" and do not fully reflect emerging natural gas connection restrictions in Washington and Oregon. After the completion of this forecast Washington added restrictions to new residential and commercial natural gas connects through new construction building codes. It is unclear at this point how those new codes will impact the accumulation of new gas customers." Please indicate when Avista will provide this analysis.	Additional dialogue has been added to help explain assumptions in the final IRP. Also, Avista will carefully follow implications for these codes changes and incorporate them into the 2025 IRP.
The last sentence on page 2-3 is incomplete. Please include an internal link to the further discussion.	This has been addressed within the final IRP in section 2-3.
Page 2-5, Figure 2.3, staff would appreciate additional narrative explanation for the different HDD responses by region. Is this driven mostly by the number of users, end use load types, etc.?	See page 2-5 for additional narrative. This figure is intended to show how linear the relationship in usage is with increased HDDs but may look skewed as it considers total load by area instead of a use per customer per HDD.
Page 2-5, "This forecast uses three-years of historical city gate data, sorted by service territory/temperature zone, and then by month. The three-year coefficient most closely aligns with economic expectations and use within Avista's territories in the short-term forecasting in Idaho and Washington. Oregon territories include a five-year demand coefficient based on the OPUC staff's recommendation 1 discussed in Chapter 9." Why did Avista choose to use only 3 years of data for Washington and Idaho instead of aligning with Oregon? What differences are seen with 5 years of data?	This forecast considers up to five years of historical city gate data, sorted by service territory/temperature zone, and then by month. The three-year coefficient most closely aligns with economic expectations and use within short-term forecasting in Idaho, Oregon, and Washington. However, Oregon territories include a five-year demand coefficient based on the OPUC staff's recommendation 1 discussed in Chapter 9. Specifically, the Oregon five-year coefficient is lower than expected usage by over four hundred thousand dekatherms annually from 2023 to 2027. Without this action item, Avista would have utilized a three-year coefficient across all jurisdictions.

Page 2-5, "Avista assumes the average usage based on the historic baseline in each program. Figure 2.4 is an example of demand for transport customers from the PLEXOS® model" What does the historic trend/baseline look like?	This has been updated in the final IRP to show historic use for transport customers for Oregon and Washington
Page 2-7, "Given the sheer volume of data, a method to select a representative set from the 172 modeling combinations was needed. Fortunately, BPA conducted this exercise and selected a subset of modeling combinations representing a sufficient cross section of outcomes to calculate generation." What is the method? If possible provide link to BPA study.	The description of BPA's selection of 19 scenarios can be found in the following document: "Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part II: Columbia River Reservoir Regulation and Operations—Modeling and Analyses"
Page 2-7, "The subset represents 19 modeling combinations for both RCP 4.5 and RCP 8.5." How many of each?	There are 19 scenarios for RCP 4.5 and 19 scenarios for RCP 8.5.
Page 2-8, "Given the RCP 8.5 is at the high end of potential future GHG emissions where there are significant worldwide efforts to mitigate GHG emissions removes this future as a realistic option." NWPCC relies on RCP 8.5. Other than occasional dips correlated with economic crises, can Avista point to a global downward trend in emissions to support this position?	Avista chose to use the RCP4.5 Scenario because it represents a reasonable increase in GHG emissions over the planning horizon of interest. The Intergovernmental Panel on Climate Change (IPCC) describes the Representative Concentration Pathways (RCP) as follows: (https://ar5-syr.ipcc.ch/topic_futurechanges.php): • RCP2.6 – stringent mitigation scenario • RCP4.5 and RCP 6.5 – intermediate scenarios • RCP8.5 – very high GHG emissions. RCP 4.5 and RCP 6.0 represent growth in greenhouse gas emissions, but the growth is lower in comparison to RCP8.5 due to mitigation strategies. In the time horizon of the IRP the increase in global mean surface temperature for RCP4.5 and RCP6.5 are 1.4 and 1.3 degrees Celsius, respectively, and therefore have a similar impact on the IRP analysis.
Page 2-8, "Figure 2.6 presents the net change in load resulting from using the RCP 4.5 data in the forecast model compared to using the most recent 20-year average held constant over all future years." How does the figure differ under an RCP 8.5 model? How does this model combine with figure 2.2 and customer preference for furnaces over heatpumps?	As discussed, Avista did not model RCP 8.5 within this IRP. The method was selected based on an exercise conducted by BPA as discussed on page 2-8. Looking into these varying RCP data sets is a time intensive exercise and Avista chose to follow others in the Pacific Northwest rather than analyze every possible future. Understanding possible future changes will be addressed in the 2025 IRP as the timeseries methodology of

	forecasting use per customer no longer provides the necessary detail and nuances needed to analyze such an outcome.
Page 2-14, "For example, the Medford weather pattern over the 500 20-year draws (i.e, 10,000 years) HDDs at or above peak weather (53.3 HDDs) occur 4,986 times or once every two years." Please explain how peak weather can happen every other year? Does this suggest something is wrong with the model?	The correct way to read the chart would be to consider the total possible days in a year combined with 500 draws. The total days with a possible peak day for 2023 would be roughly 248 occurrences in 182,625 days or 0.14% of days. Avista believes the model is stochastically analyzing peak days correctly.
Page 2-21, "Scenario Analysis" It's not clear to Staff how demand goes up in most scenarios despite the Washington building code changes. The "hybrid case" scenario needs explanation, especially how it starts with such low demand.	Avista has tried to address this question throughout the final IRP. The basic explanation is that we do not know what to expect from building code changes. The changes occurred toward the end of the technical advisory committee meetings, and because the codes do not begin until July 2023, additional understanding of this fundamental shift and future customer expectations is necessary. Scenario analysis is an accepted form of measuring unknown futures to help address this concern of customer growth. Avista has included 14 total scenarios in the 2023 IRP to try to account for the various pathways of demand and future supply. The Hybrid Case was reanalyzed based on these similar concerns from Avista and is addressed in Chapter 7.
Page 2-21, "Electrification Expected Conversion Costs – Expected conversion costs case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system" Please explain the particular risks involved that are shown in this scenario.	The risk of electrification is expecting a level of demand on the natural gas system while and investing in resources to serve this expected demand. If fewer customers remain on the system than expected, fewer customers will pay for a greater share of the overall costs.
Page 2-22, Table 2.8 – Why is hybrid demand so much lower than electrification demand in 2025? (Explained on page 7-5, please provide explanation and/or embedded link in chapter 2)	The Hybrid Case was re-analyzed based on these similar concerns from Avista and is addressed in Chapter 7.
What does "PRS" mean? Please expand the acronym for the table or provide a footnote for easy reference.	PRS means "Preferred Resource Strategy". Chapter 6 goes into full detail of the strategy Avista is considering in the 2023 IRP.

Does the Electrification scenario consider IRA subsidies, cap and invest spending, and other subsidies that might ease electrification? What is the connection between "Electrification" here on Table 2.8 (decrease of 18% of demand) and Figure 2.2 (decrease of 33% of customers)?	The IRA is discussed in Chapter 3 and is included in expected costs as a degradation to the costs of electrification. The connection between Table 2.8 and Figure 2.2 shows the summary of decreasing 33% of customers by 2045 and the energy expected to serve load with future weather expectations net of these customer losses.
Ch. 3 Demand Side Resources	
Pg 3-1, "The resulting avoided costs are compared to those obtained from the previous iteration of PLEXOS® avoided costs. This process continues until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial." Staff requests Avista add a layperson-friendly explanation. This comment is applicable in many places, but we won't detail every instance. Please give a read through with an eye to, where possible, adding plain talk descriptions that are more widely accessible.	The IRP document is technical in nature, so is difficult to add in plain talk descriptions. We have added clarifications in the final IRP where possible.
Pg 3-4, Table 3.2, please provide a link in this text to the appendices and/or workpapers that contain data for each year.	A link has been provided to reference the appendices.
Pg 3-11, "This IRP does not include fuel switching in the demand forecast, but rather includes specific fuel use electrification as a resource option for both commercial and residential customers." Is this modelling assumption based on evidence? Are there any studies that consider what portion of customers are more likely to selectively swap out appliances or to electrify all at once?	This modeling assumption was a methodology to address electrification while providing the model an apples-to-apples comparison to switching over when valuing least cost options to serve customers demand and emissions compliance.
Pg 3-11, "Industrial customers are not considered in this analysis." Please include an explanation of why?	Avista has very few industrial customers and some customers end use needs require natural gas. Also, end use by industrial customers is not straight forward, rather depends on the specific industrial process itself.
Pg 3-11, "Further, customers may find extrinsic value in natural gas for resilience benefits and its superior performance compared to electric options." Do you mean intrinsic? Does Avista consider these values for cost-effectiveness of electrification?	Extrinsic is the correct terminology in this case. Intrinsic would refer to a customer finding natural gas rewarding because it is natural gas. Extrinsic refers to outside feelings or perceptions of a product, such as the use of a natural gas stove by a chef simply because others use them.

	Resiliency when electricity is out is another example. These values would be considered non-energy indicators and will be developed in the 2025 IRP process.
Pg 3-12, "The estimated values for these sources are used from the CPA studies provided by AEG and ETO." Please provide the source for heatpump/electric heating efficiency?	These efficiencies have been developed by experts at Avista and confirmed when possible by outside persons and technical advisory members.
Pg 3-12, Figure 3.2, why is the graph a stepwise function and not a continuous function? What assumptions underly the shape of the blue stepwise function? "The second set of assumptions is 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." Please add additional context.	Figure 3.2 includes a stepwise function based on assumptions built by our energy efficiency engineers and staff. A linear nature was not chosen, though could be, as different set points are estimated rather than an exact model by end unit type to understand how a unit may respond to 44 HDDs as compared to 43 HDDs. These assumptions assume it is roughly similar and mostly changes in steps.
Pg 3-12, "Efficiency is considered as a generic value across equipment and does not represent ultra-high efficiency units or old lower-efficiency units." Did Avista consider a scenario that looked at the savings and costs of highly efficient units?	Avista did not consider such a scenario in this IRP.
Pg 3-14, "The Washington territory estimates include 75% of natural gas customers moving to Avista for their electricity needs and 25% lost to other public power providers such as Inland Power & Light." Even quarters always elicit questions, is this an accurate estimate?	The estimate of 75% and 25% for the Washington territory is the best estimate available by Avista. Understanding where a gas customer would switch to would require a SCADA type system that geographically locates customers and their electric provider. Avista did not have this ability at the time of the analysis and would need to rely on the external entities to provide further detail if available.
Pg 3-14 and 15, Figure 3.5, what are the sources for "The assumed escalation curves for energy per kWh"?	Escalation curves include an expected inflation through time.
Pg 3-15, Figure 3.5, Why is there a larger jump in 2036?	This is an added cost based on Avista electric system upgrades needed to adhere to CETA requirements. This price increase is included in Oregon due to similar programs toward carbon reductions on the electric grid.

Pg 3-15 "When pairing the cost of energy with the conversion rate in the initial 5 years, a consistent monthly charge even when energy is not being used." This sentence could use editing.	This has been updated within the final IRP.
Pg 3-16, Figure 3.7, why is there a sizable jump in 2032?	As discussed in this section, the IRA is expected to expire making costs more expensive to covert as the incentives remove half of the cost of conversion.
Figures 3.7 to 3.10 - levelized cost per MMBTU – it is unclear if this is step 5 of the primary analysis detailed on page 3-16 or the combined single analysis.	A levelized cost is step 5 of the overall analysis outcome.
Ch. 4 Current Resources and New Resource Options	
Pg 4-4, "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." How representative is this assumption?	This is accurate to the methodologies employed in the natural gas hedging plan. Please see Purchased Gas Adjustment (PGA) filings by Avista. A retrospective hedging report is included in these annual filings. It provides great detail around the program and annual adjustments to help keep Avista gas customers rates as low as possible.
Pg 4-16, table 4.3, please explain the carbon intensity scores in more detail. What does a score of –276.24 mean? Does a percentage reduction of –452% mean that use of dairy-sourced RNG results in even more net emissions than not collecting the fuel?	This has been updated in Chapter 4. A negative carbon intensity indicates net benefit by collecting the RNG rather than allowing the RNG to emit directly into the air. The CCA nor CPP currently provide credit for the carbon intensity score, but other programs such as those in California do.
Pg 4-19, "Figure 4.9 illustrates the number of participants by state in Avista's voluntary RNG program, as of November 2022" Does Avista currently have RNG resources to meet this voluntary demand? Could Avista please provide narrative for the shape of the lines in the charts? Why do they increase and then flatten out instead of continuing to increase more steadily over time? Did Avista reach market saturation in 2 months?	These are the actual customers by jurisdiction by month. Avista contracts these volumes from the Roosevelt landfill through Puget Sound Energy owned volumes. Uptake in each jurisdiction was strong in the beginning months but has now leveled off. Whether customers will increase demand for this voluntary program is unknown, however, it may be an indicator of actual demand to these emission reducing programs as Avista has seen similar results on the electric side program for green energy.
Pg 4-19, "Avista is developing a methodology to evaluate RNG projects." When does Avista	The current methodology is provided in Chapter 4. Projects are included in the Plexos model used for the IRP to evaluate against all options.

expect this methodology be finalized/workable?	
Page 4-23, figure 4.12, Is the research from Black and Veatch available? Why do the prices go up over time?	This is included in the Appendix. Avista utilized this analysis to determine an estimated cost by RNG type. Prices go up in general due to inflation.
Page 4-23, "While it is assumed hydrogen can only be mixed and stored in a natural gas distribution pipeline system as a small percentage of the total volume of gas in the pipe," What evidence does Avista rely upon for this claim? What percentage? Staff has seen this claim repeated across the industry without citation.	Some sources include: 1. Layout 1 (osti.gov) 2. Injection of gaseous hydrogen into a natural gas pipeline - ScienceDirect 3. SoCalGas Among First in the Nation to Test Hydrogen Blending in Real-World Infrastructure and Appliances in Closed Loop System (prnewswire.com)
Page 4-23, "The high cost of hydrogen has been the primary barrier to an accelerated use and adoption." Does Avista see evidence this cost will come down?	Yes, please refer to Figure 4.4 and dialogue on page 4-23.
Page 4-23, "to produce methane" will system/fugitive emissions of synthetic methane hinder CCA compliance? Will hydrogen fugitive emissions hinder CCA compliance?	Avista submits yearly volumes of throughput in each of its jurisdictions. Further analysis will be required to understand resources chosen. In the current estimated PRS case, Synthetic methane is not selected in Washington until past the 20-year IRP timeframe, which will allow Avista to continue to research and estimate costs and risks of long-term resources.
Page 4-23, "separate water" How much water could be needed to meet demand? Will permits be needed to pump that volume of water? What about disposal of post-electrolysis precipitates/waste/biosolids?	4 gallons of water per kilogram will be necessary. Additional full lifecycle analysis will take place and is mentioned in the Action Plan in Chapter 9.
Page 4-24, "The process would use a form of carbon capture" What form(s)?	The process would use air capture.
Page 4-24, "The potential size of this resource is limited to the quantity of hydrogen available, a carbon source and cost." Is synthetic methane production not also limited by carbon capture technology?	This has been updated to correct this missed piece of critical technology.
Page 4-24, "Carbon capture costs are estimated between $94 and $414 per MTCO2e depending on source and technology" Is this expensive? Staff would appreciate additional context or analysis.	In comparison to compliance in CCA programs or CPP programs, it helps to provide perspective if other forms of compliance are not available such as allowances or offsets (CCA) or community climate investments (CPP). Depending on the penalty cost in the thousands of dollars per MTCO2e above the cap and how the state would apply this fine (daily or annually), this would still be considered least cost. It should be noted that

	carbon paired with hydrogen is not selected as least cost until the 2030's in Oregon and past the 20-year IRP planning horizon in Washington. This indicates other methods for compliance are preferred.
Page 4-24, "Synthetic methane is a combination of green hydrogen and carbon capture costs per dekatherm." Does Avista not account for the cost of combining hydrogen and CO2? The calculus appears to be the production cost of Hydrogen plus the cost of capturing CO2, without considering the further cost of combining these two products together.	The chemistry of hydrogen and carbon bonding is not discussed and requires more analysis to understand methods and additional costs not considered in the 2023 IRP. An action item is included in Chapter 9 to address this point.
Page 4-24, "This fuel can also help bridge the gap for excess electricity and act as a storage of energy to a period of higher demand." This sounds like a non-gas utility service. Does Avista consider competing/more efficient end uses for these fuels?	The IRP only considers ways to reduce demand or provide energy to natural gas customers considering a variety of pathways to test resource needs and potential supply side resources.
Page 4-25, figure 4.14, What is the cost estimate of hydrogen? Why does the cost of synthetic methane increase in 2032?	Please refer to the updated Figure 4.14 for H2 only cost estimate. The IRA impacts costs beginning in 2032 when the program is set to expire.
Page 4-25, table 4.4, by 2045 the marginal cost difference between hydrogen and synthetic methane is $2.65. This represents an 80% reduction in cost of carbon capture technology from 2025 to 2045. This reduction is, proportionately, greater than any other fuel's cost reduction. What is the basis for this assumption?	Refer to Page 4-25 and the associated studies indicated as footnotes.
Page 4-25, table 4.4, If offsets and auctions etc are included, what is the unit cost of natural gas?	Please refer to chapter 5, 6 and 7 for assumptions on the full price of natural gas by scenario and how these costs change. The model pairs allowances, environmental attributes, offsets, community climate investments with natural gas in its selection of least cost.
Ch. 5 Policy Issues	
Page 5-2, "assumes these emissions are measured at the standard 100-year Global Warming Potential (GWP) meaning a 34 multiplier of methane from natural gas for the same mass of carbon dioxide." Please provide a citation.	A citation can be found on page 5-2.
Page 5-2, Did Avista consider other fugitive emission estimates? Is there any risk that	This is a two-part answer:

actual emissions are considerably different than the assumptions in this IRP?	The risk of emissions is a sizeable one in the 2023 IRP. Emissions from fuel burned by our customers is considered through stochastic variability. Fugitive emissions is considered in the carbon intensity scenario. The compliance to climate programs in Oregon and Washington relies on throughput of natural gas and do not include fugitive emissions unless from within Avista owned distribution.
Utilities are asked to consider the social cost of greenhouse gases in their planning. How did Avista's incorporation of the SCGHG interact with the CCA? Did Avista apply the SCGHG the carbon intensity scores of RNG?	Avista utilized the SCGHG to value energy efficiency. Avista utilized the estimated costs of compliance through an allowance to value the costs to comply with the CCA. The CCA values RNG as either meeting the criteria for renewable natural gas or not. Carbon intensity is not considered as there is not applicable value in the program for such scores in either the CCA or CPP.
Page 5-12, Any update on where the process for developing RNG standards are?	RNG pipeline standards should meet pipeline quality by tariff by pipeline.
Page 5-14, it would be helpful to have a table of IRA impacts included in this IRP, how certain they are, and a general time frame of when and how we will know with more certainty (waiting for Treasury guidance, waiting for Commerce).	Impacts can be seen in the electrification scenario conversion costs, the cost of hydrogen and synthetic methane. Additional implications to resources and impacts from the IRA will be included in future IRPs.
Ch. 6 Preferred Resource Strategy	
Page 6-20 refers to using the utility cost test for WA but Chapter 3 indicates a total resource cost test for WA. Please clarify that in this IRP Avista has moved to the TRC for WA gas.	Avista moved to the TRC in WA. It has been corrected in the text.
Ch. 7 Alternate Scenarios	
Figure 7.9, Average case appears to be higher cost than PRS but the narrative below states that average case is lower cost. Also, please address why the hybrid case appears much lower.	This has been updated in the final IRP.
Ch. 8 Distribution Planning	
Page 8-8, has Avista ever identified a non-pipe alternative in an IRP?	Avista has not mentioned any non-pipe alternatives to eliminate near-term distribution constraints. Near-term distribution constraints and their respective proposed reinforcements mentioned in current and past IRP's were aimed at specific parts of the distribution system that were capacity constrained

	and were not possible candidates for non-pipe alternative solutions.

APPENDIX 1.1: AVISTA CORPORATION 2023 NATURAL GAS INTEGRATED RESOURCE PLAN WORK PLAN

IRP WORK PLAN REQUIREMENTS

Section 480-90-238 (4), of the natural gas Integrated Resource Plan ("IRP") rules, specify requirements for the IRP Work Plan:

> Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.

Additionally, Section 480-90-238 (5) of the WAC states:

> The work plan must outline the timing and extent of public participation.

OVERVIEW

This Work Plan outlines the process Avista will follow to complete its 2023 Natural Gas IRP by April 1, 2023. Avista uses a public process to obtain technical expertise and guidance throughout the planning period via Technical Advisory Committee (TAC) meetings. The TAC will be providing input into assumptions, scenarios, and modeling techniques.

PROCESS

This Work Plan is submitted in compliance with the Washington Utilities and Transportation Commission's Integrated Resource Planning (IRP) rules (WAC 480-90-238). It outlines the process Avista will follow to develop its 2023 IRP for filing with Washington, Idaho and Oregon Commissions by April 1, 2023. Avista uses a public process to solicit technical expertise and feedback throughout the development of the IRP through a series of public Technical Advisory Committee (TAC) meetings. Avista held its first TAC meeting for the 2023 IRP on February 16, 2022.

The 2023 IRP process will include a new linear modeling software, Plexos®, to model its natural gas system. This model includes the available supply basins for natural gas combined with the transportation of this supply to Avista's demand regions. Scenarios will help measure risk of outcomes in addition to the expected demand from our service territories on a peak day. The Plexos® model also includes the Climate Commitment Act (CCA) and new zero carbon resources options to help meet emissions requirements under this new rule. The model will use stochastic analysis to help select the Preferred Resource Strategy (PRS).

Avista will use both detailed site-specific and generic resource assumptions in development of the 2023 IRP. The assumptions combine Avista's research of similar supply-side resources, engineering studies and two third-party consultant analyses. This

IRP will study environmental costs, weather planning standard, peaking requirements and resource adequacy, energy efficiency programs, demand response programs, and renewable resources.

Avista will test the PRS against a range of scenarios and potential futures. The TAC meetings will help to develop and determine the underlying assumptions used in the scenarios and futures. The IRP process is very technical and data intensive; public comments are welcome but timely input and participation will be necessary for inclusion into the process so the plan can be submitted according to the tentative schedule identified in this Work Plan.

Additionally, Avista intends to incorporate action plan items identified in the 2021 Natural Gas IRP, including selecting resources to meet a zero-carbon future as laid out in the CCA and exploring the feasibility of using projected future weather conditions. Further details about Avista's process for determining the risk adjusted least-cost resource mix is shown in Exhibit 1.

The following topics and meeting times may change depending on the availability of presenters and requests for additional topics from the TAC members. The tentative timeline for the agenda and TAC schedule is as follows:

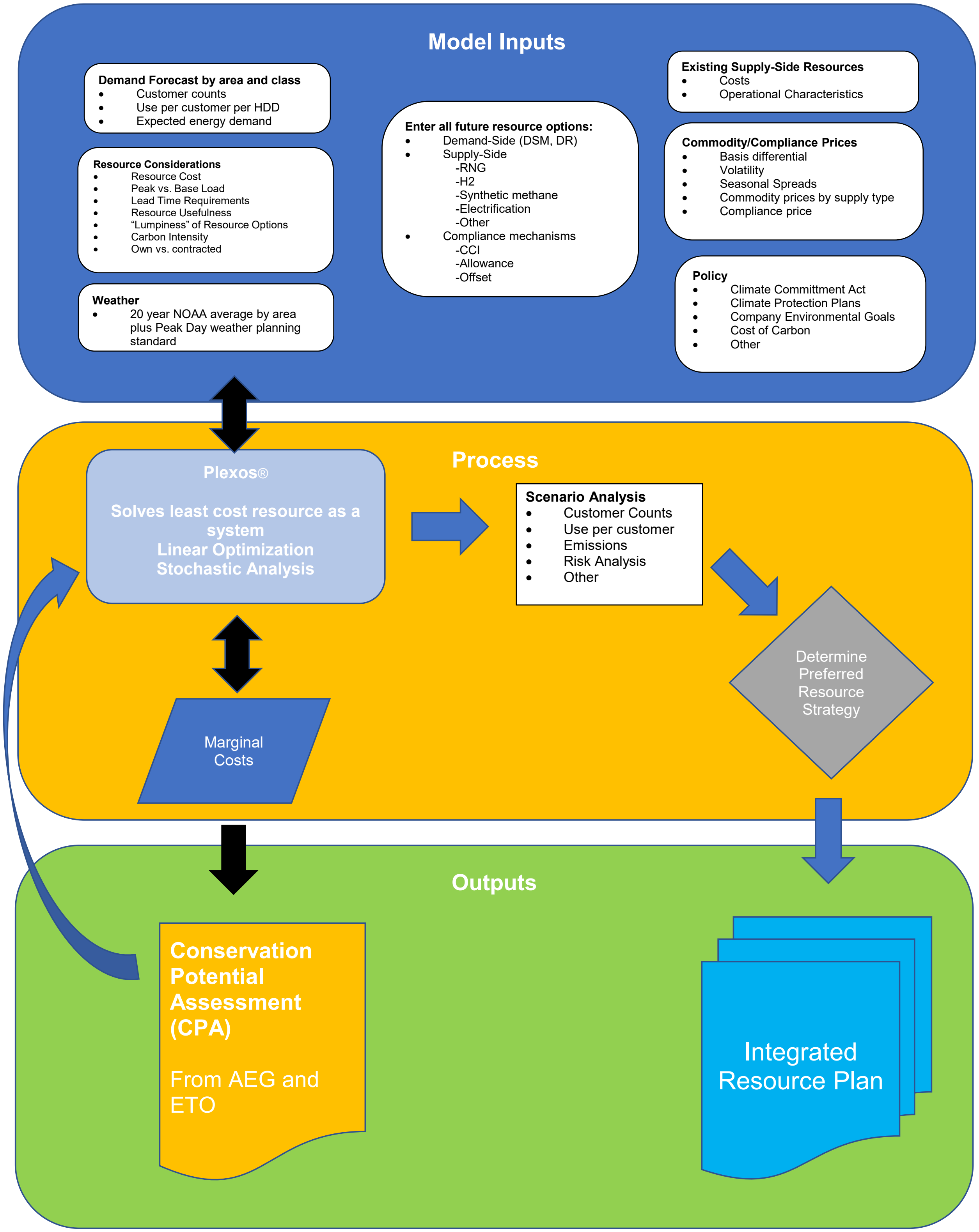
TIMELINE

The following is Avista's 2023 Natural Gas IRP timeline:

Major Milestone	Date	Topics
TAC 1	2/16/2022	RNG Discussion, compliance to EO 20-04, policy, Peak Day weather planning standard
TAC 2	4/19/2022	Use per customer, planned scenarios, Customer Forecast, current Supply Side Resources, Plexos Model Overview
TAC 3	8/10/2022	AEG results and Survey Results
TAC 4	9/27/2022	Future Supply Side Resource Options, ETO - CPA, CCA Overview, Market Dynamics, Climate Change Weather, load forecast
TAC 5	12/15/2022	Final Results / Stochastics, scenario results, distribution, energy efficiency comparison, DR
External Draft Feedback	1/25/2023	
Draft Feedback Due	2/25/2023	
File	3/31/2023	

Major Milestone	Date	Topics
TAC 1	May-2024	Use per customer, Policy, 2021 Action Item Review, price elasticity
TAC 2	July-2024	Customer Forecast, price forecast
TAC 3	Aug-2024	sensitivities, distribution, model overview
TAC 4	Sept-2024	Renewable Resources, New and Existing Resources, Demand Side Resources (CPA)
TAC 5	Nov-2024	Results / Stochastics, Action Items
Write IRP Draft	Dec-2024	
Draft Feedback Due	Feb-2025	
File	Apr-2025	

EXHIBIT 1: AVISTA'S 2021 NATURAL GAS IRP MODELING PROCESS



APPENDIX 1.2: WASHINGTON PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – WAC 480-90-238

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	Work plan submitted to the WUTC on April 1, 2022, See attachment to this Appendix 1.1.
WAC 480-90-238(4)	Work plan outlines content of IRP.	See work plan attached to this Appendix 0.1.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See Appendix 1.1.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	See Appendix 1.1.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	Last Integrated Resource Plan was submitted on April 1, 2021
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	TBD
WAC 480-90-238(5)	Commission holds public hearing.	TBD
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply resources.	See Chapter 4 on New and Existing Resources
WAC 480-90-238(2)(a)	Plan describes conservation supply.	See Chapter 3 on Demand Side Resources
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	See Chapter 4 on New and Existing Resources and Chapter 6 Preferred Resource Selection and Risk
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	See Chapters 3 and 4 for Demand and New and Existing Resources. Chapters 6 and 7 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	See Chapters 3 and 4 for Demand and New and Existing Resources. Chapters 6 and 7 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	See Chapter 4 on New and Existing Resources
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	See Chapter 2 Demand Forecasting
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	See Chapter 4 and Chapter 6
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	See Chapter 4 procurement plan section. We seek to minimize but cannot eliminate price risk for our customers. Chapter 6 and 7.

WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	See Chapter 2 demand scenarios
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See Chapters 2 and 6 on demand scenarios and Integrated Resource Portfolio
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	See Chapter 4 on New and Existing Resources
Rule	**Requirement**	**Plan Citation**
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	See Chapter 3 on Demand Side Resources
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	See Chapter 2 on Demand Forecast
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	See Chapter 2 on Demand Forecast
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	See Chapter 2 on Demand Forecast
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	See Chapter 3 on Demand Side Management including demand response section.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	See Chapter 3 and Appendix 3.1.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	See Chapter 4 on New and Existing Resources
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	See Chapter 4 on New and Existing Resources
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	See Chapter 4 on New and Existing Resources
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	See Chapter 3 on Demand Side Resources and Chapter 4 on New and Existing Resources
WAC 480-90-238(3)(g)	Plan includes at least a 10 year long-range planning horizon.	Our plan is a comprehensive 20 year plan.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Chapter 6 Integrated Resource Portfolio details how demand and supply come together to form the least cost/best risk portfolio.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	See Section 9 Action Plan

WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	See Section 9 Action Plan
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	See Section 1 Introduction
WAC 480-90-238(5)	Plan includes description of completion of work plan. (Description not required)	See Appendix 1.1.

APPENDIX 1.2: IDAHO PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – ORDER NO. 2534

	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
1	Purpose and Process. Each gas utility regulated by the Idaho Public Utilities Commission with retail sales of more than 10,000,000,000 cubic feet in a calendar year (except gas utilities doing business in Idaho that are regulated by contract with a regulatory commission of another State) has the responsibility to meet system demand at least cost to the utility and its ratepayers. Therefore, an ‘‘integrated resource plan’’ shall be developed by each gas utility subject to this rule.	Avista prepares a comprehensive 20 year Integrated Resource Plan every two years. Avista will be filing its 2023 IRP on or before April 1, 2023.
2	Definition. Integrated resource planning. ‘‘Integrated resource planning’’ means planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas customers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.	Avista's IRP brings together dynamic demand forecasts and matches them against demand-side and New and Existing Resources in order to evaluate the least cost/best risk portfolio for its core customers. While the primary focus has been to ensure customer's needs are met under peak or design weather conditions, this process also evaluates the resource portfolio under normal/average operating conditions. The IRP provides the framework and methodology for evaluating Avista's natural gas demand and resources.
3	Elements of Plan. Each gas utility shall submit to the Commission on a biennial basis an integrated resource plan that shall include:	The last IRP was filed on April 1, 2021.
	A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the effect of economic forces on the consumption of gas and that address changes in the number, type and efficiency of gas end-uses.	See **Chapter 2 - Demand Forecasts** and **Appendix 2 et.al.** for a detailed discussion of how demand was forecasted for this IRP.
	An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.	See **Chapter 3 - Demand Side Management** and **DSM Appendices 3 et.al.** for detailed information on the DSM potential evaluated and selected for this IRP and the operational implementation process.

	An analysis for each customer class of gas supply options, including: (1) a projection of spot market versus long-term purchases for both firm and interruptible markets; (2) an evaluation of the opportunities for using company-owned or contracted storage or production; (3) an analysis of prospects for company participation in a gas futures market; and (4) an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers.	See **Chapter 4 - New and Existing Resources** for details about the market, storage, and pipeline transportation as well as other resource options considered in this IRP. See also the procurement plan section in this same chapter for supply procurement strategies.
	A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method for calculating cost-effectiveness.	See Methodology section of **Chapter 3 - Demand-Side Resources** where we describe our process on how demand-side and New and Existing Resources are compared on par with each other in the PLEXOS® model. Chapter 3 also includes how results from the IRP are then utilized to create operational business plans. Operational implementation may differ from IRP results due to modeling assumptions.
	The integration of the demand forecast and resource evaluations into a long-range (e.g., twenty-year) integrated resource plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.	See **Chapter 6 – Preferred Resource Selection and Risk** for details on how we model demand and supply coming together to provide the least cost/best risk portfolio of resources.
	A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the integrated resource plan.	See **Chapter 9 - Action Plan** for actions to be taken in implementing the IRP.
4	Relationship Between Plans. All plans following the initial integrated resource plan shall include a progress report that relates the new plan to the previously filed plan.	Avista strives to meet at least bi-annually with Staff and/or Commissioners to discuss the state of the market, procurement planning practices, and any other issues that may impact resource needs or other analysis within the IRP.
5	Plans to Be Considered in Rate Cases. The integrated resource plan will be considered with other available information to evaluate the performance of the utility in rate proceedings before the Commission.	We prepare and file our plan in part to establish a public record of our plan.
6	Public Participation. In formulating its plan, the gas utility must provide an opportunity for public participation and comment and must provide methods that will be available to the public of validating predicted performance.	Avista held five Technical Advisory Committee meetings beginning in February and ending in December. See **Chapter 1 - Introduction** for more detail about public participation in the IRP process.

7	Legal Effect of Plan. The plan constitutes the base line against which the utility's performance will ordinarily be measured. The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that a gas utility, having made an integrated resource plan to provide adequate and reliable service to its gas customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in existing or earlier plans and not undermining the utility's reliability.	See section titled "Avista's Procurement Plan" in **Chapter 4 - New and Existing Resources**. Among other details we discuss plan revisions in response to changing market conditions.
8	In order to encourage prudent planning and prudent deviation from past planning when presented with opportunities for improving upon a plan, a gas utility's plan must be on file with the Commission and available for public inspection. But the filing of a plan does not constitute approval or disapproval of the plan having the force and effect of law, and deviation from the plan would not constitute violation of the Commission's Orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proceedings in which those issues have been noticed.	See also section titled "Alternate Supply-Side Scenarios" in **Chapter 6 – Preferred Resource Selection and Risk** where we discuss different supply portfolios that are responsive to changing assumptions about resource alternatives.

APPENDIX 1.2: OREGON PUBLIC UTILITY COMMISSION IRP STANDARD AND GUIDELINES – ORDER 07- 002

Guideline 1: Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis.	All resource options considered, including demand-side and supply-side are modeled in PLEXOS® utilizing the same common general assumptions, approach, and methodology.
1.a.2	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	Avista considered a range of resources including demand-side management, distribution system enhancements, capacity release recalls, interstate pipeline transportation, interruptible customer supply, renewable natural gas by source, hydrogen, electrification by end source and synthetic methane. Chapter 3 and Appendix 3.1 documents Avista's demand-side management resources considered. Chapter 4 and Appendix 6.3 documents New and Existing Resources. Chapter 6 and 7 documents how Avista developed and assessed each of these resources.
1.a.3	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 6 provides details about the modeling methodology and results. Chapter 4 describes resource attributes and Appendix 6.3 summarizes the resources' lead times, in-service dates and locations.
1.a.4	Consistent assumptions and methods should be used for evaluation of all resources.	Appendix 6.2 documents general assumptions used in Avista's PLEXOS® modeling software. All portfolio resources both demand and supply-side were evaluated within PLEXOS® using the same sets of inputs.
1.a.5	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	(See general assumptions at Appendix 6.2)
1.b.1	Risk and uncertainty must be considered. Electric utilities only	Not Applicable
1.b.2	Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions.	Risk has been considered as illustrated in chapter 2, 4, 5, 6 & 7. Risk is a cornerstone to Integrated Resource Planning and one measured in many facets including weather risk, commodity risk by source and policy risk including electrification or building code restrictions.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Risk has been considered as illustrated in chapter 2, 4, 5, 6 & 7. Risk is a cornerstone to Integrated Resource Planning and one measured in many facets including weather risk, commodity risk by source and policy risk including electrification or building code restrictions.

1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 6 and 7 plus supporting information in Appendix 2.6 for Avista's portfolio risk analysis and determination of the preferred portfolio.
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Avista used a 23-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs of all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Avista's PLEXOS® modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Avista, through its stochastic analysis, modeled 500 twenty three year futures via Monte Carlo iterations developing a distribution of Total 23 year cost estimates utilizing PLEXOS®'s PVRR methodology. Chapter 2 further describes this analysis. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95th percentile capture the severity of outcomes. Chapter 4 discusses Avista's physical and financial hedging methodology.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 4, 5, 6, and 7 describe various specific resource considerations and related risks, and describes what criteria we used to determine what resource combinations provide an appropriate balance between cost and risk.
1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Avista considered current and expected state and federal energy policies in portfolio modeling. Chapter 5 and 6 describe the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2: Procedural Requirements		
2a	The public, including other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan.	Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2023 IRP. Avista encourages participation in the development of the plan, as each party brings a unique perspective and the ability to exchange information and ideas makes for a more robust plan.

	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan.	The entire IRP, as well as the TAC process, and website includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The document and appendices will be available on the company website for viewing.
	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Avista distributed a draft IRP document for external review to all TAC members on January 25, 2023 and requested comments by February 25, 2023. All comments and responses are included in Appendix 1
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	The 2021 IRP was filed April 1, 2021 with acknowledgement in October 2021. The 2023 IRP will be filed March 31, 2023.
3b	Utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Avista will work with Staff to fulfill this guideline following filing of the IRP.
3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing	Pending
3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order	Pending
3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Pending
3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update	A waiver was requested as Avista was in process of IRP completion within 6 months between acknowledged 2021 IRP and 2023 IRP submittal date.
3g	Unless the utility requests acknowledgement of changes in	The updates described in 3f above explained changes since acknowledgment of the 2021 IRP and an update

	proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	of emerging planning issues. The updates did not request acknowledgement of any changes.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met each of the substantive and procedural requirements.	This table summarizes guideline compliance by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP.
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	Chapter 2 describes the demand forecast data and risk analysis of demand. Chapter 4 describes price risk. Chapter 7 provides the scenario and risk analysis results.
4c	For electric utilities only	Not Applicable
4d	A determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Chapter 2 and 6 describe peak demand expectations and resource selection.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapter 3 and Appendix 3.1 identify the demand-side potential included in this IRP. Chapter 4, 5 & 6 and Appendix 6.3 identify the New and Existing Resources.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 6 and 7 discuss the modeling tools, customer growth forecasting and cost-risk considerations used to maintain and plan a reliable gas delivery system. These Chapters also capture a summary of the reliability analysis process demonstrated in the four TAC meetings. Chapter 4 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks.
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs)	Chapter 7 considers alternative scenarios and future cost variability.

	and alternative scenarios considered.	
4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	This Plan documents the development and results for portfolios evaluated in chapter 6 and 7.
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	We evaluated our candidate portfolio by performing stochastic analysis using PLEXOS® varying price under 500 different scenarios. Additionally, we test the portfolio of options with the use of PLEXOS® under deterministic scenarios where demand and price vary.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 7 illustrates cost and risk variability of the 14 modeled scenarios in the 2023 IRP.
4k	Analysis of the uncertainties associated with each portfolio evaluated	See the responses to 1.b above.
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Avista evaluated cost/risk tradeoffs for each of the risk analysis in Chapter 6 and 7.
4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation	This IRP is presumed to have no inconsistencies.
4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 9 presents the IRP Action Plan with focus on the following areas: - Modeling - Policy - Supply/capacity/distribution - Forecasting - Regulatory communication - DSM - Distribution and/or capital needs
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote	Not applicable to Avista’s gas utility operations.

	locations, acquiring alternative fuel supplies, and improving reliability.	
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	ETO and AEG both performed a conservation potential assessment study for our 2023 IRP. A discussion of the study is included in Chapter 3. Each full study document is in Appendix 3.1. Avista incorporates a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process.
6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	A discussion on the treatment of conservation programs is included in Chapter 3 while selection methodology is documented in Chapter 6. The action plan details conservation targets, if any, as developed through the operational business planning process. These targets are updated annually, with the most current avoided costs. Given the challenge of the low cost environment, current operational planning and program evaluation is still underway and targets for Oregon have not yet been set.
6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	Not applicable. See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. Technology, customer characteristics and cost issues are hurdles for developing effective programs.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable.	Discussed in Chapter 5. The Environmental Externalities discussion in Appendix 3.2 describes our analysis performed. See also the guidelines addendum reflecting revised guidance for environmental costs per Order 08-339.

Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Not applicable to Avista’s gas utility operations.
Guideline 10: Multi-state utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2023 IRP conforms to the multi-state planning approach with a specific cost of compliance to Oregon and Washington for their respective climate compliance programs as discussed throughout the IRP.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility’s chosen portfolio achieves its stated reliability, cost and risk objectives.	Avista’s storage and transport resources while planned around meeting a peak day planning standard, also provides opportunities to capture off season pricing while providing system flexibility to meet swing and base-load requirements. Diversity in our transport options enables at least dual fuel source options in event of a transport disruption. For areas with only one fuel source option the cost of duplicative infrastructure is not feasible relative to the risk of generally high reliability infrastructure.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other New and Existing Resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Not applicable to Avista’s gas utility operations.
Guideline 13: Resource Acquisition		
13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan; Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party; identify any Benchmark Resources it plans to consider in competitive bidding.	Chapter 4 and 9 discuss resource need and ownership advantages and disadvantages.
13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	A discussion of Avista’s procurement practices is detailed in Chapter 4.
Guideline 8: Environmental Costs		

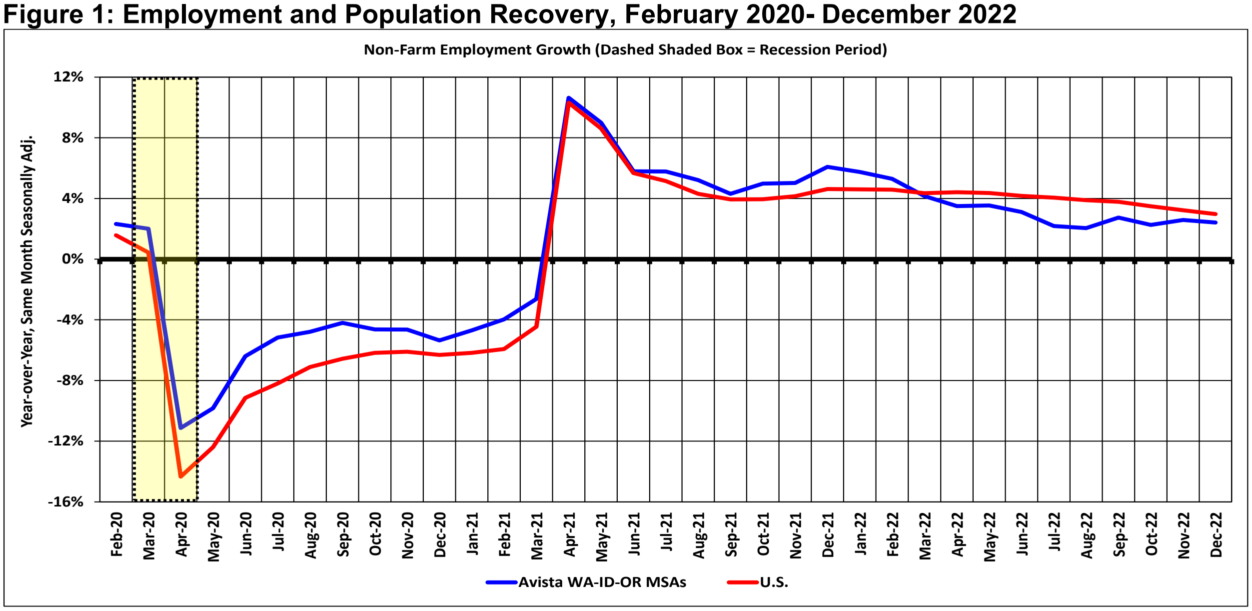
a.	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs", would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	Chapters 5, 6 and 7 summarize these environmental costs. The Environmental Externalities discussion in Appendix 3.2 describes our process for addressing these costs.
b.	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	The Environmental Externalities discussion in Appendix 3.2 describes our process for addressing these costs. Chapter 7

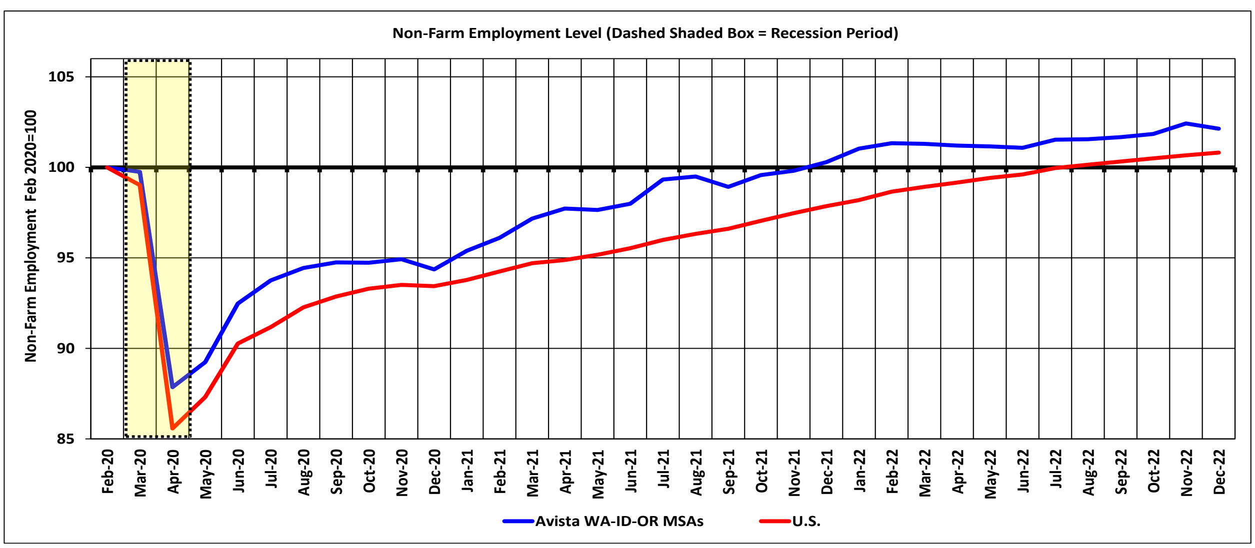
APPENDIX 2.1: ECONOMIC OUTLOOK AND CUSTOMER COUNT FORECAST

I. Service Area Economic Performance and Outlook

Avista's core service area for natural gas includes Eastern Washington, Northern Idaho, and Southwest Oregon. Smaller service islands are also located in rural South-Central Washington and Northeast Oregon. Our service area is dominated by four metropolitan statistical areas (MSAs): the Spokane-Spokane Valley, WA MSA (Spokane-Stevens counties); the Coeur d'Alene, ID MSA (Kootenai County); the Lewiston-Clarkson, ID-WA MSA (Nez Perce-Asotin counties); the Medford, OR MSA (Jackson County); and Grants Pass, OR MSA (Josephine County). These five MSAs represent the primary demand for Avista's natural gas and account for 75% of both customers (i.e., meters) and load. The remaining 25% of customers and load are spread over low density rural areas in all three states.

Figure 1: Employment and Population Recovery, February 2020- December 2022





Data source: Employment from the BLS, OR Labor, and WA ESD; population from the U.S. Census.

Figure 1 shows Avista's service areas did not escape the employment impacts of COIVD-19 induced recession at the start of 2020. Historically, service area population growth has slowed in one or more years following an employment shock; however, this did not occur in the case of the pandemic shock. In-migration to our service territory, especially in WA and ID, remained strong through the pandemic. This supported population growth, and therefore customer growth, from 2020 to 2022 (Figure 2). By the end of 2022, service area employment was 2% higher than the pre-pandemic level of February 2020.

Figure 2: Avista MSA Annual Population Growth, 2005-2022

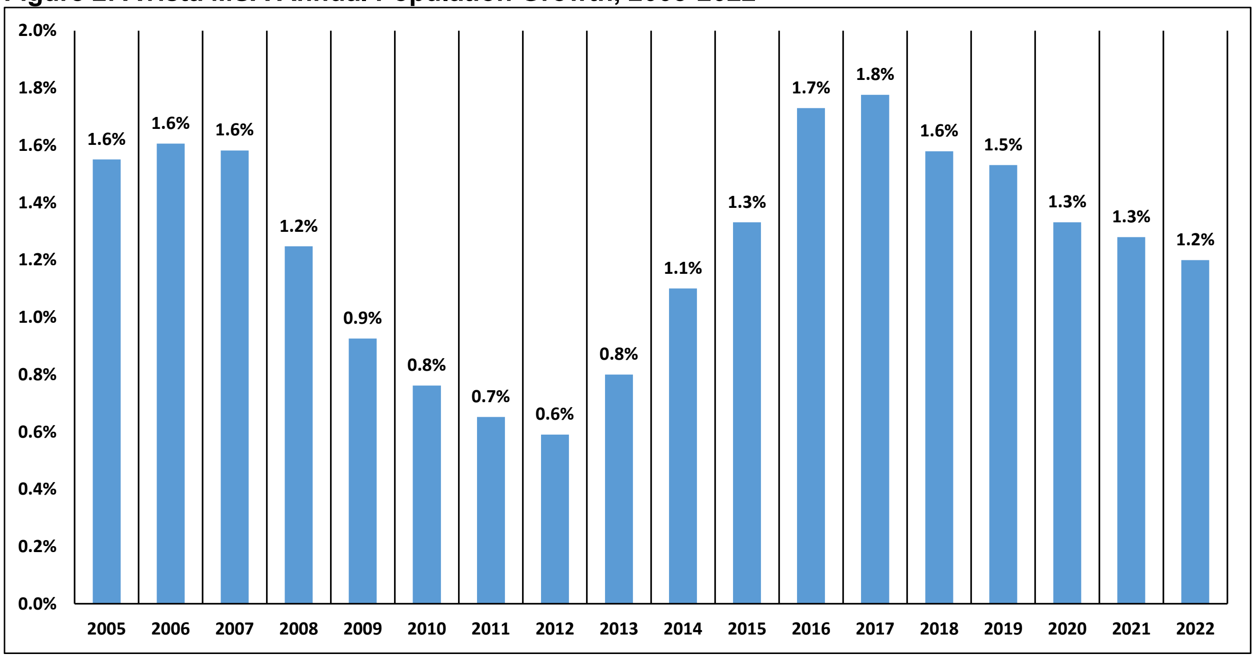
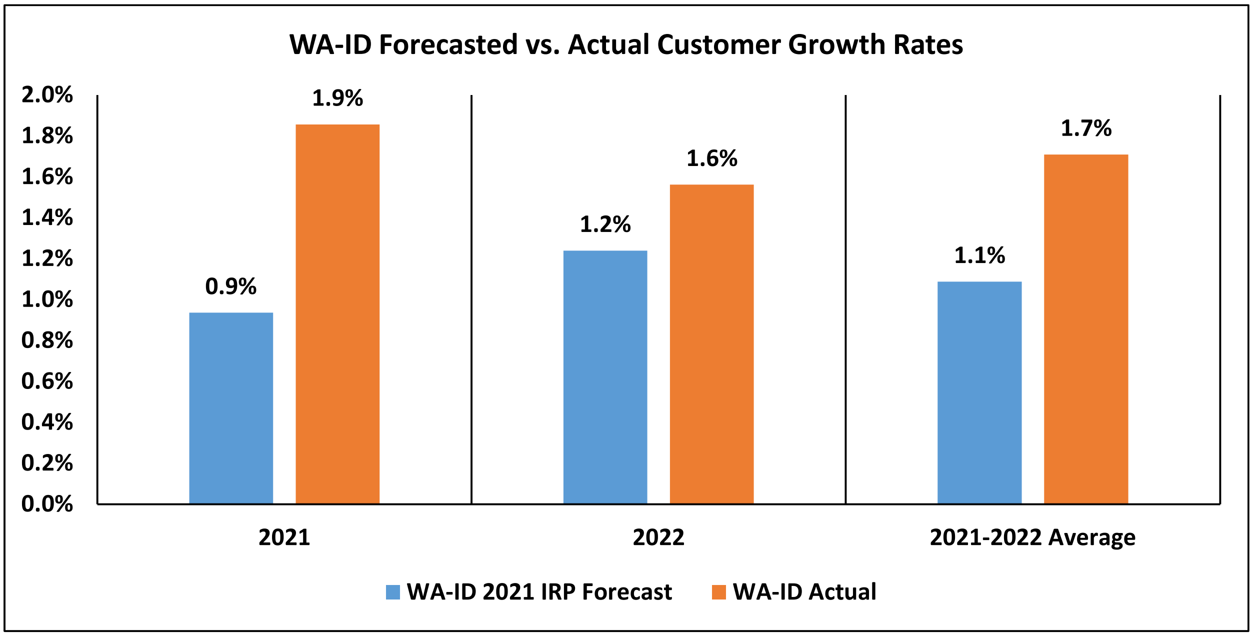
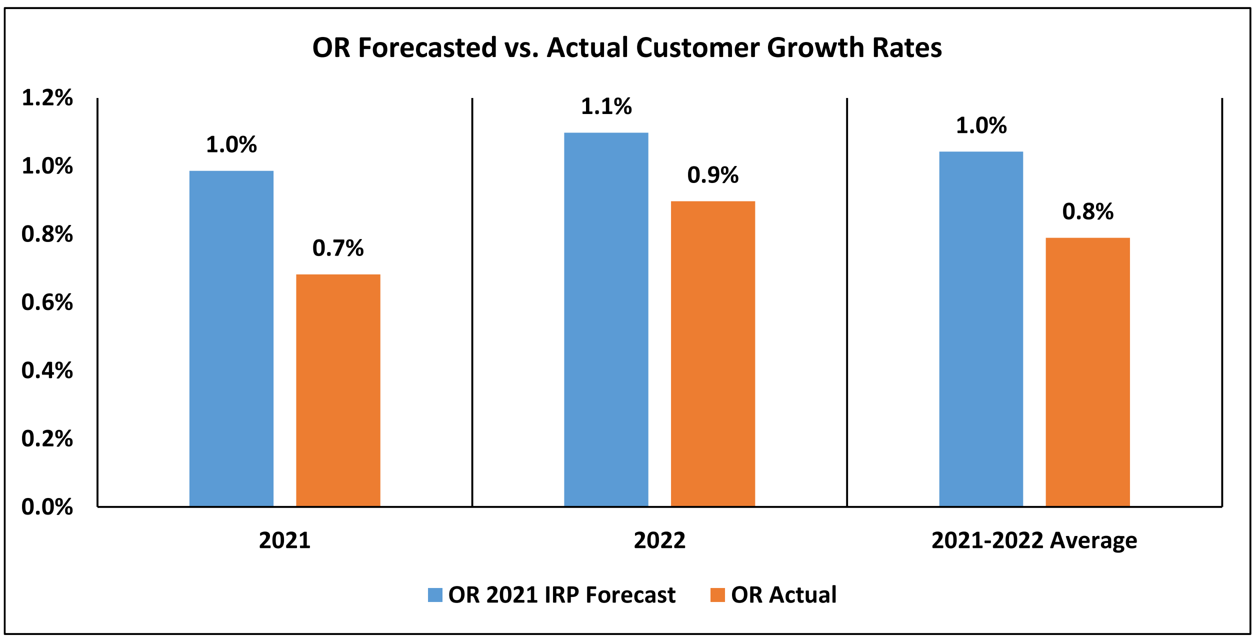


Figure 3 shows that compared to the 2021 IRP, actual average customer growth in WA-ID over the 2021-2022 period was considerably higher than forecasted. This reflects (1) a stronger than expected economic recovery from the pandemic induced recession in 2020 and (2) stronger than expected population growth over this period. In contrast, OR's actual growth rate is slightly lower than forecast over the same period. This reflects lower than expected population growth in OR. Figure 4 shows since the 2021 IRP, customer growth has significantly exceeded population growth, which reflects customer growth from existing homes converting to gas in addition to new construction installing gas.

Compared to the 2021 IRP, this IRP shows a system-wide upward revision of approximately 22,000 customers by 2045. This reflects the net impact of a 17,000-customer increase in WA-ID and 5,000 decrease in OR. Overall, the upward revision in all three jurisdiction reflects the stronger than expected economic recovery from the pandemic induced recession, higher than expected in-migration since the 2021 IRP, and higher expected long-run population growth. Figure 5 and Table 1 show the change in the customer forecast by for the system and by class between the 2021 and 2023 IRPs.

Figure 3: Comparison of 2021 IRP Customer Growth Forecasts to Actuals, 2021-2022





Data source: Company data.

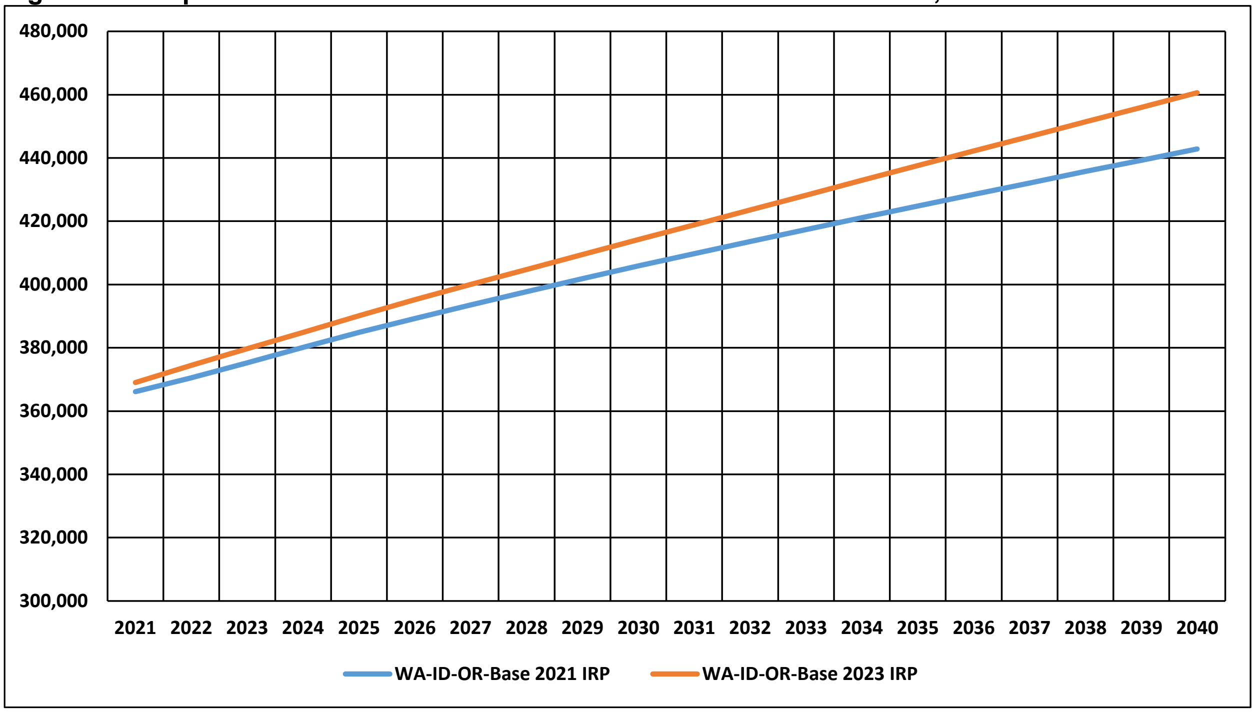
Figure 4: Customer and Population Growth, 2005-2022

Data source: Company data.

Table 1: Change in Forecast between the 2021 IRP and 2023 IRP in 2045

Area	Residential	Commercial	Industrial	Total Change
WA-ID	16,352	1,053	-11	17,394
OR	5,030	90	2	5,121
System	21,382	1,142	-9	22,516

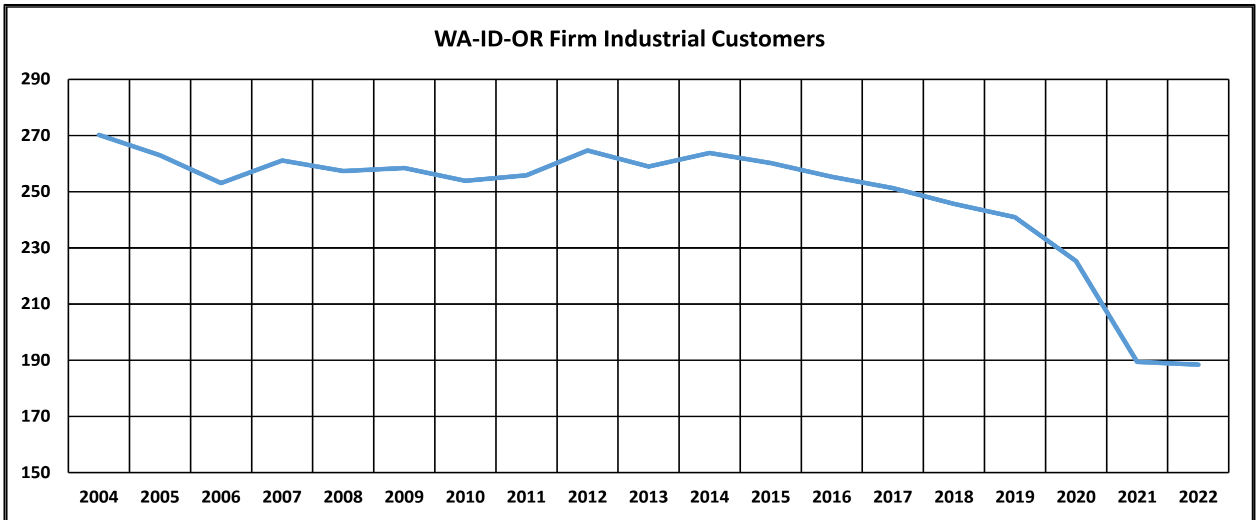
Figure 5: Comparison IRP Forecasted Customer Growth in WA-ID and OR, 2023-2045

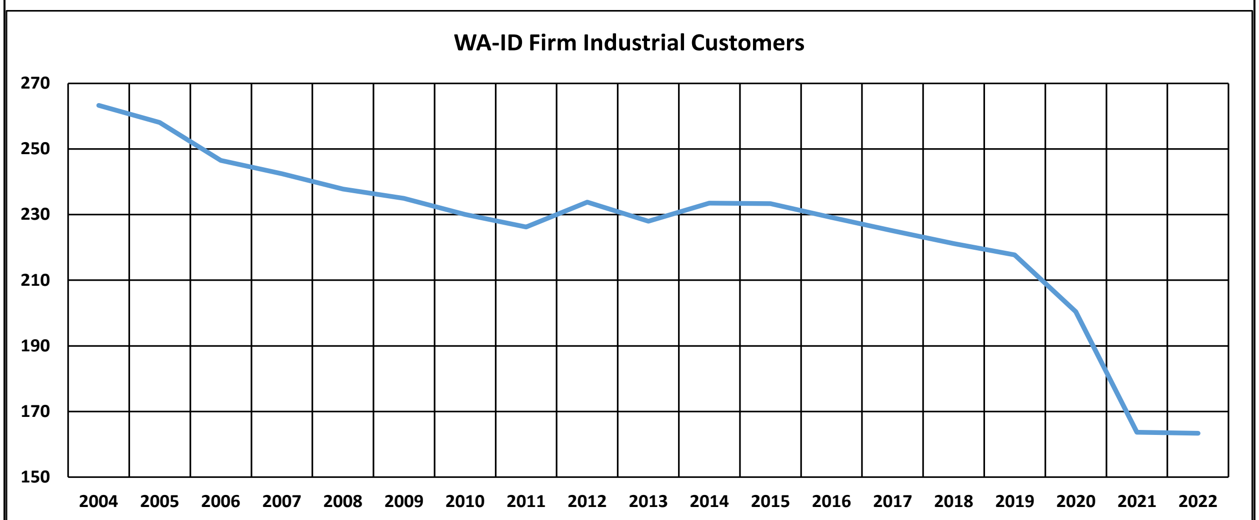


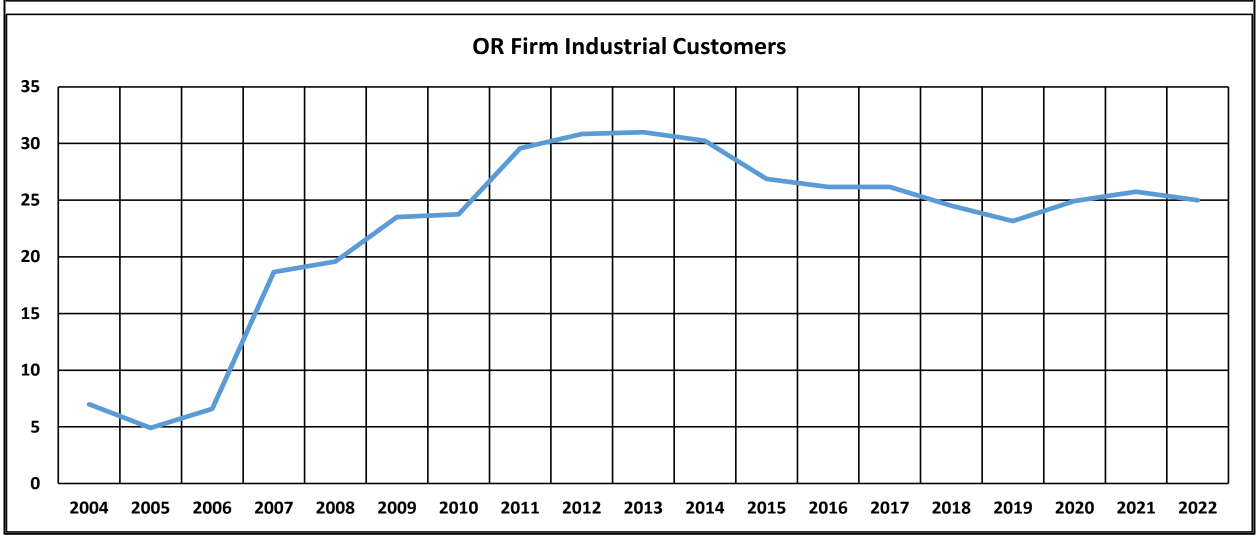
Data source: Company data.

In past IRPs, the modeling approach for the majority of commercial customers *assumed* that residential customer growth (WA-ID schedule 101 and OR schedule 410 in Medford and Klamath Falls regions) is a driver of commercial customer growth (WA-ID schedule 101 and OR schedule 420 in Medford and Klamath Falls). The use of residential customers as a forecast driver for commercial customers reflects the historically high correlation between residential and commercial customer growth rates. However, because of the LEAP program, schedule 101 residential customers are no longer the primary driver in the commercial forecast in WA. The LEAP program altered the historical relationship between residential and commercial customers because the program was not offered to commercial customers. As a result, population has replaced residential customers as the primary driver of commercial customer forecast. This is also the case for ID, but for different reasons. In ID, the relationship between residential and commercial customers is changing such that using population directly produces better model diagnostics.

The forecast for system-wide industrial customers is lower compared to the 2021 IRP. Approximately 90% of industrial customers are in WA-ID. Figure 6 (top graph) shows total system-wide firm industrial customers since 2004. Following a sharp drop over the 2004-2006 period, firm industrial customers started to decline starting in 2016. It should be noted that some of the decline between 2019 and 2022 reflects a reclassification of some WA-ID customers to firm commercial schedules. This reclassification reflects customers that were incorrectly placed in firm industrial schedules in years past. Separating out WA-ID and OR (middle graph), the number of firm customers in WA-ID continuously fell over the 2004-2011 period; stabilized over the 2012-15; and then started to decline again. In contrast, OR customers increased over the 2004-2011 period (bottom graph). However, after a period of stability during the 2011-2014 period, customers declined modestly. Therefore, like the 2021 IRP, the current IRP forecast shows a declining base.**Figure 7: Industrial Customer Count, 2004-2022**







Data source: Company data.

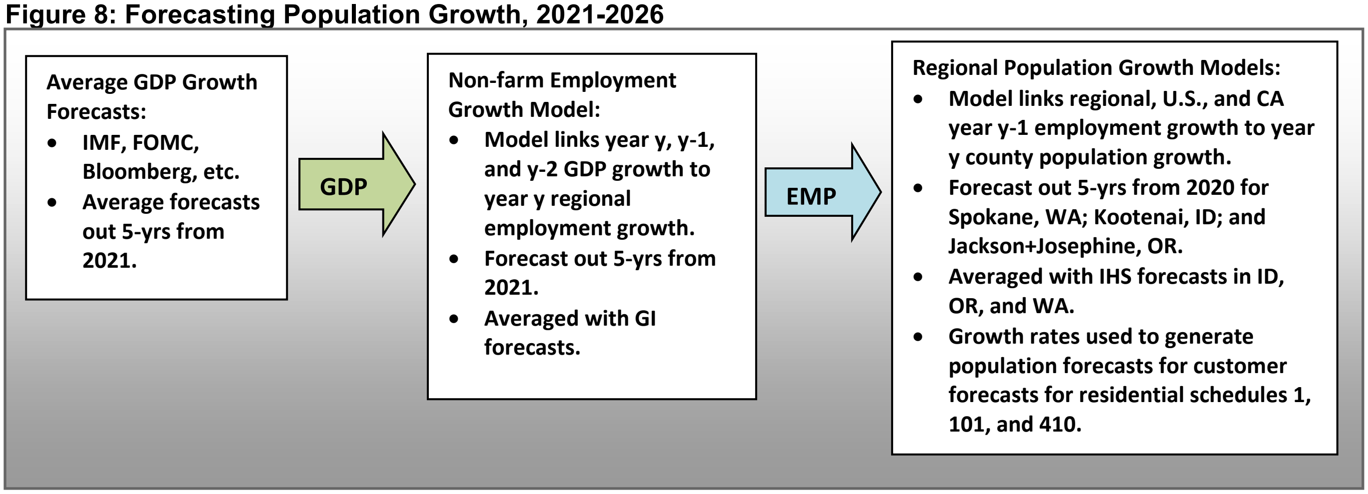
II. IRP Forecast Process and Methodology

The customer forecasts are generated from forecasting models that are either regression models with ARIMA error corrections or simple smoothing models. The ARIMA error correction models are estimated using SAS/ETS software. The customer forecasts are used as input into Plexos® to generate the IRP load forecasts.

Population growth is the key driver for the residential and commercial customer forecasts. Other variables include (1) seasonal dummy variables and (2) outlier dummy variables that control for extreme customer counts associated with double billing, software conversions, and customer movements from one billing schedule to another.

As noted above, the population growth forecast is the key driver behind the customer forecast for WA-ID residential schedules 101 and OR residential schedule 410. These two schedules represent the majority of customers and, therefore, drive overall residential customer growth. Because of their size and growth potential, a multi-step forecasting process has been developed for the Spokane-Spokane Valley, Coeur d'Alene, and Medford+Grants Pass MSAs. The process for forecasting population growth starts with a medium-term forecast horizon (2021-2026). This medium-term forecast is typically used for the annual financial forecast. However, during IRP years, this medium-term forecast is augmented with third party forecasts that cover the next twenty years. Starting with Figure 8, the five-year population forecast is a multi-step process that begins with a GDP forecast that drives the regional employment forecast, which in turn, drives a five-year population forecast.

Figure 8: Forecasting Population Growth, 2021-2026



The forecasting models for regional employment growth are:

[1] $GEMP_{y,SPK} = \vartheta_0 + \vartheta_1 GGDP_{y,US} + \vartheta_2 GGDP_{y-1,US} + \vartheta_3 GGDP_{y-2,US} + \omega_{SC} D_{KC,1998-2000=1} + \omega_{SC} D_{HB,2005-2007=1} + \epsilon_{t,y}$

[2] $GEMP_{y,KOOT} = \delta_0 + \delta_1 GGDP_{y,US} + \delta_2 GGDP_{y-1,US} + \delta_3 GGDP_{y-2,US} + \omega_{OL} D_{1994=1} + \omega_{OL} D_{2009=1} + \omega_{SC} D_{HB,2005-2007=1} + \epsilon_{t,y}$

[3] $GEMP_{y,JACK+JOS} = \phi_0 + \phi_1 GGDP_{y,US} + \phi_2 GGDP_{y-1,US} + \phi_3 GGDP_{y-2,US} + \omega_{SC} D_{HB,2004-2005=1} + ARIMA\epsilon_{t,y}\,(1,0,0)(0,0,0)_{12}$

SPK is Spokane, WA (Spokane MSA), KOOT is Kootenai, ID (Coeur d'Alene MSA), and JACK+JOS is for the combination of Jackson County, OR (Medford MSA) and Josephine County, OR (Grants Pass MSA). $GEMP_y$ is employment growth in year y, $GGDP_{y,US}$ is U.S. real GDP growth in year y. D_{KC} is a dummy variable for the collapse of Kaiser Aluminum in Spokane, and D_{HB}, is a dummy for the housing bubble, specific to each region. The average GDP forecasts are used in the estimated model to generate five-year employment growth forecasts. The employment forecasts are then averaged with IHS's forecasts for the same counties so that:

[4] $F_{Avg}(GEMP_{y,SPK}) = \frac{F(GEMP_{y,SPK}) + F(GIHSEMP)_{y,SPK}}{2}$

[5] $F_{Avg}(GEMP_{y,KOOT}) = \frac{F(GEMP_{y,KOOT})+F(GIHSEMP_{y,KOOT})}{2}$

[6] $F_{Avg}(GEMP_{y,JACK+JOS}) = \frac{F(GEMP_{y,JACK+JOS})+F(GIHSEMP_{y,JACK+JOS})}{2}$

Averaging reduces the systematic errors of a single-source forecast. The averages [8.4] through [8.6] are used to generate the population growth forecasts, which are described next.

The forecasting models for regional population growth are:

[7] $GPOP_{y,SPK} = \kappa_0 + \kappa_1 GEMP_{y-1,SPK} + \kappa_2 GEMP_{y-2,US} + \omega_{OL} D_{2001=1} + \epsilon_{t,y}$

[8] $GPOP_{y,KOOT} = \alpha_0 + \alpha_1 GEMP_{y-1,KOOT} + \alpha_2 GEMP_{y-2,US} + \omega_{OL} D_{1994=1} + \omega_{OL} D_{2002=1} + \omega_{SC} D_{HB,2007\uparrow=1} + \epsilon_{t,y}$

[9] $GPOP_{y,JACK+JOS} = \psi_0 + \psi_1 GEMP_{y-1,JACK+Jos} + \psi_2 GEMP_{y-2,CA} + \omega_{OL} D_{1991=1} + \omega_{SC} D_{HB,2004-2006=1} + \epsilon_{t,y}$

$D_{2001=1}$ and $D_{1991=1}$ are a dummy variables for recession impacts. $GEMP_{y-1,US}$ is U.S. employment growth in year y-1 and $GEMP_{y-2}$, and CA is California Employment growth in year y-1. Because of its close proximity to CA, CA employment growth is better predictor of Jackson, OR employment growth than U.S. growth. The averages [8.4] through [8.6] are used in [7] through [9] to generate population growth forecasts. These forecasts are combined with IHS's forecasts for Kootenai, ID; Jackson, OR; Josephine, OR, and the Office for Financial Management (OFM) for Spokane, WA in the form of a simple average:

[10] $F_{Avg}(GPOP_{y,SPK}) = \frac{F(GPOP_{y,SPK})+F(GIHSPOP_{y,SPK})}{2}$

[11] $F_{Avg}(GPOP_{y,KOOT}) = \frac{F(GPOP_{y,KOOT})+F(GIHSPOP_{y,KOOT})}{2}$

[12] $F_{Avg}(GPOP_{y,JACK+JOS}) = \frac{F(GPOP_{y,JACK+JOS})+F(GIHSPOP_{y,JACK+JOS})}{2}$

Here, $F_{Avg}(GPOP_y)$ is used to forecast population to forecast residential customers in WA-ID 101 and OR 410 schedules for the Spokane, Kootenai, and Jackson+Josephine areas. The population growth forecasts for the Douglas (Roseburg), Klamath (Klamath Falls); and Union (La Grande) counties come directly from IHS. Since all forecasted growth rates are annualized, they are converted to monthly rates. By way of example, the following is regression model for residential 101 customers for the Spokane region:

$$C_{t,y,WA101.r} = \alpha_0 + \tau POP_{t,y,SPK} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Sep\ 2018=1\uparrow} + \omega_{OL} D_{Oct\ 2015=1} + \omega_{OL} D_{Feb\ 2016=1} + \omega_{OL} D_{Mar\ 2018=1} + \omega_{OL} D_{Nov\ 2018=1} + \omega_{OL} D_{Sep\ 2020=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$$

Where:

$tPOP_{t,y,SPK}$ = t is the coefficient to be estimated and $POP_{t,y,SPK}$ is the interpolated population level in month t, in year y, for Spokane. The monthly interpolation of historical data assumes that between years, population accumulates following the standard population growth model: $POP_{y,SPK} = POP_{y-1,SPK}e^r$.

$w_{SD}D_{t,y}$ = w_{SD} is a vector of seasonal dummy (SD) coefficients to be estimated and $D_{t,y}$ is a vector monthly seasonal dummies to account of customer seasonality. $D_{t,y}$ = 1 for the relevant month.

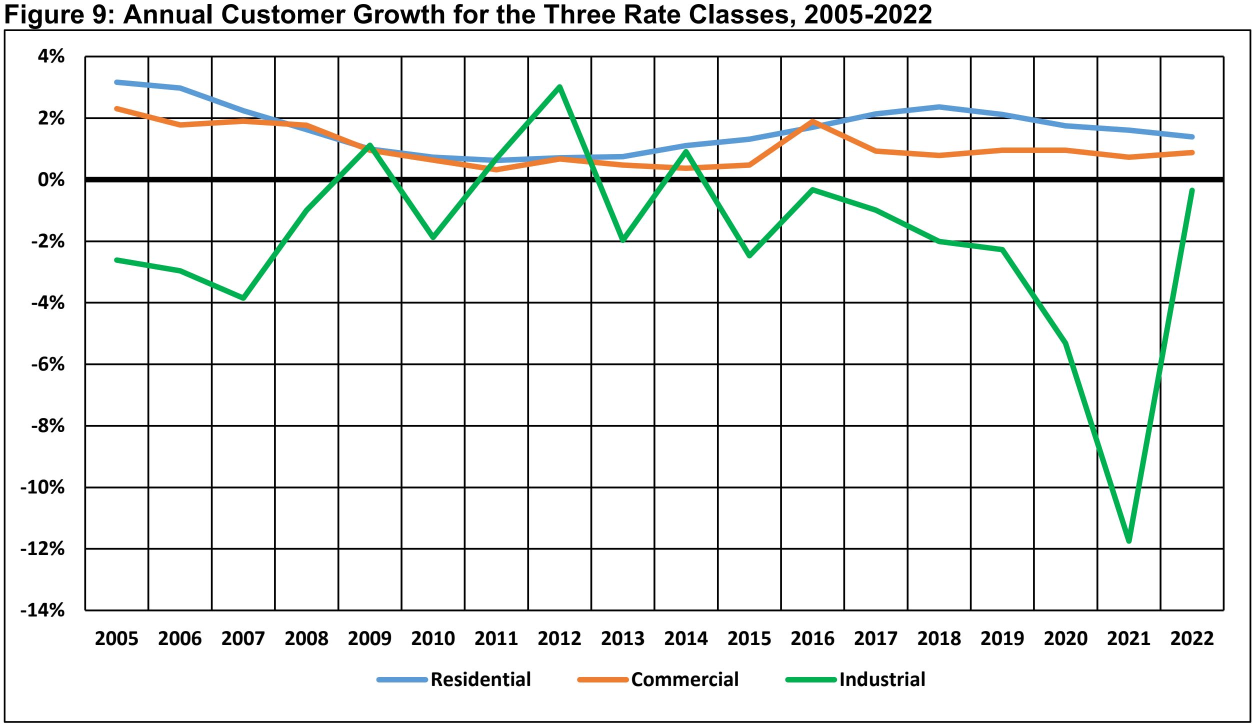
$w_{OL}D_{Oct\ 2015=1}$ = w_{OL} outlier (OL) coefficient to be estimated and D is a dummy that equals 1 for October 2015. There are three additional outlier dummies that follow August 2010. In some cases, the dummy variable may be a structural change (SC) dummy that takes the form, for example, $w_{SC}D_{Sep\ 2018\uparrow=1}$; in this case, the dummy takes the value of 1 for September 2018 forward.

$ARIMAe_{t,y}(12,1,0)(0,0,0)_{12}$ = is the error correction applied to the model's initial error structure. This term follows the following from $ARIMAe_{t,y}$ $(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the moving average (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values are related to "k," which is the frequency of the data. With the current data set, k = 12.

The customer forecast is generated by inputting forecasted values of $POP_{t,y,SPK}$ into the model estimated with historical data. All customer forecast equations are shown in the last section of this appendix.

The above describes the medium-term population forecast to 2025. For IRPs, the medium-term customer forecasts must be extended an additional 15+ years. This is done using the IHS population forecast for Kootenai, Spokane, Jackson+Josephine, Douglas, Klamath, and Union counties. That is, IHS is the sole source for forecasted population growth beyond the medium-term forecast horizon by [10] through [12]. For firm schedules without explicit regression drivers like population, the forecast model run to cover the entire forecast period of the IRP.

Figure 9: Annual Customer Growth for the Three Rate Classes, 2005-2022



Data source: Company data.

Figure 9 demonstrates that residential and commercial growth rates are highly correlated over the long-run. Over the period shown, residential and commercial averaged about 1.6% and 1.0%, respectively. Residential growth is, on average, higher than population growth because of existing households converting to natural gas at the same time new construction is installing gas. However, by 2009, with the Great Recession and increased natural gas saturation, the difference between customer growth and population growth almost disappears. As the economy improved in the 2015-2019 period, residential and commercial growth accelerated due to an improved economy and gas conversion incentives in Washington in the 2016-2019 period.

In contrast, the behavior of Industrial customer growth looks quite different. Customer growth is both lower and more volatile. The average growth rate since 2005 is -1.9%, reflecting a trend of nearly flat or slowly declining customers, depending on the jurisdiction. In addition, the standard deviation of year-over-year growth is 3% compared to 0.8% for residential and 0.6% for commercial growth. The current IRP forecast reflects this historical trend of weak growth.

Establishing High-Low Cases for IRP Customer Forecast

The customer forecasts for this IRP include high and low cases that set the expected bounds around the base-case. Table 2 shows the base, low, and high customer forecasts along with the underlying population growth assumption. The underlying population forecast is the primary driver for each of the three cases.

Table 2: Alternative Growth Cases, 2023-2045

Area	Low Growth	Base Growth	High Growth
WA-ID:			
WA-ID Customers	0.8%	1.2%	1.5%
WA Population	0.2%	0.6%	0.8%
ID Population	1.0%	1.7%	2.1%
WA-ID Population	0.9%	0.9%	1.2%
OR:			
OR Customers	0.6%	0.9%	1.1%
OR Population	0.2%	0.4%	0.6%
System:			
System Customers	0.7%	1.1%	1.4%
System Population	0.3%	0.9%	0.9%

III. IRP Customer Forecast Equations

<u>1. WA residential customer forecast models</u>:

[1] $C_{t,y,WA101.r} = \alpha_0 + \tau POP_{t,y,SPK} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Sep\ 2018=1\uparrow} + \omega_{OL} D_{Oct\ 2015=1} + \omega_{OL} D_{Feb\ 2016=1} + \omega_{OL} D_{Mar\ 2018=1} + \omega_{OL} D_{Nov\ 2018=1} + \omega_{OL} D_{Sep\ 2020=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$

[1] Model notes:
1. WA schedule 2 customers are schedule 1 customers that have been moved to a new low-income schedule.
2. SC dummy controls for step-up in customers starting September 2018.

[2] $C_{t,y,WA102.r} = C_{t-1} + \bar{\Delta},\ where\ \bar{\Delta} = \frac{\sum(C_{t,y} - C_{t-1,y})}{N} for\ N\ months\ between\ November\ 2015 - December\ 2021$

[2] Model notes:
1. WA schedule 102 customers are schedule 101 customers that have been moved to a new low-income schedule. The schedule started in October 2015, so there is insufficient data for a more complicated model. In the first years of the program, the number of customers in this schedule started slowly declining under the original cap of 300 customers. However, this schedule has had its cap removed and the number of customers has started to increase. In the spring 2022 forecast the average Δ = 5.

[3] $C_{t,y,WA111.r} = \alpha_0 + \omega_{SC} D_{Oct\ 2011\uparrow=1} + \omega_{SC} D_{Oct\ 2013\uparrow=1} + \omega_{SC} D_{Oct\ 2018\uparrow=1} + ARIMA\epsilon_{t,y}\ (8,1,0)(0,0,0)_{12}\ for\ t,y = September\ 2010\uparrow$

[3] Model notes:
1. SC dummies control for a step-up in customers starting in October 2011, October 2013, and October 2018.
2. Model restricted to September 2010↑ because of a significant change in trend and behavior starting in 2010.

<u>2. ID residential customer forecast models</u>:

[4] $C_{t,y,ID101.r} = \beta_0 + \tau POP_{t,y,KOOT} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2007\uparrow=1} + \omega_{SC} D_{Nov\ 2007\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2007} +$
$+ \omega_{OL} D_{Jul\ 2005=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Jun\ 2006=1} + \omega_{OL} D_{Jun\ 2007=1} + \omega_{OL} D_{Aug\ 2011=1} +$
$\omega_{OL} D_{Sept\ 2011=1} + \omega_{OL} D_{Oct\ 2018=1} + \omega_{OL} D_{Jun\ 2021=1} + ARIMA\epsilon_{t,y}\ (9,1,0)(0,0,0)_{12}$

[4] Model notes:

1. SC dummies and ramping time trend control for a change in the time-path of customer growth staring in January 2007.
2. The large number of OL dummies controls for a range of factors including changes in billing cycles, billing errors, and software changes.
3. May need to average June 2020 as an outlier in the next forecast; could be a billing error.

[5] $C_{t,y,ID111.r} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$

[5] Model notes:

1. Model changed to a 12-month moving average in fall 2020. There has been no customer growth since 2012.

<u>3. WA commercial customer forecast models</u>:

[6] $C_{t,y,WA101.c} = \alpha_0 + \alpha_1 POP_{t,y,SPK} + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_{RAMP} T_{Jan\ 2010} + \omega_{SC} D_{Dec\ 2015\uparrow=1} + \omega_{OL} D_{Nov\ 2005=1} +$
$\omega_{OL} D_{Feb\ 2007=1} + \omega_{OL} D_{Sep\ 2013=1} + + \omega_{OL} D_{Oct\ 2013=1} + \omega_{OL} D_{Jun\ 2017=1} + \omega_{OL} D_{Feb\ 2020=1} + ARIMA\epsilon_{t,y}\ (2,1,0)(0,0,0)_{12}$

[6] Model notes:

1. In the June 2017 forecast, $C_{t,y,WA101.r}$ (residential customers from residential schedule 101) was replaced with POP for Spokane. This was done to account for a new hookup tariff for residential gas customers in WA's LEAP program. This tariff is more generous than the previous long-standing tariff. In addition, any savings in the hookup process could be passed on to the customer for equipment purchases or replacement. Since this tariff change excluded commercial and industrial customers, this significantly accelerated residential hookups but not commercial hookups. As a result, this historical relationship between residential and commercial customer growth has been altered. See also Tables 5.1 and 5.2.
2. RAMP variable was added in June 2019 because of increasing evidence that the sensitivity of commercial customer growth to population growth fell after 2009. SC dummies control for step-ups in customers in starting in December 2015 and December 2018.
3. There is no SC dummy for the in-migration of customers from industrial schedule 101 starting in October 2020. The in-migration was relatively small to the total number of customers in commercial schedule 101. See also notes for UPC model.
4. May need to be adjusted for billing errors in the fall 2022 forecast.

[7] $C_{t,y,WA111.c} = \alpha_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_{RAMP} T_{Apr\ 2016} + \gamma_{RAMP} T_{Mar\ 2018} + \omega_{SC} D_{Nov\ 2011\uparrow=1} +$
$\omega_{SC} D_{Apr\ 2016\uparrow=1} + \omega_{SC} D_{Mar\ 2018\uparrow=1} + \omega_{OL} D_{Jan\ 2007=1} + \omega_{OL} D_{Nov\ 2013=1} + \omega_{OL} D_{Jun\ 2017=1} +$
$\omega_{OL} D_{Sep\ 2018=1} + \omega_{OL} D_{Oct\ 2018=1} + \omega_{OL} D_{Sep\ 2019=1} + \omega_{OL} D_{Oct\ 2019=1} + ARIMA\epsilon_{t,y}\ (1,1,0)(0,0,0)_{12}$

[7] Model notes:

1. SC dummies and RAMP variables control for a complex set of steps and slope changes in the customer count.

<u>4. ID commercial customer forecast model</u>s:

[8] $C_{t,y,ID101.c} = \beta_0 + \beta_1 POP_{t,y,Koot} + \omega_{SC} D_{Nov\ 2005\uparrow=1} + \omega_{SC} D_{Sep\ 2006\uparrow=1} + \omega_{SC} D_{Nov\ 2007\uparrow=1} + \omega_{OL} D_{Mar\ 2005=1} +$
$\omega_{OL} D_{Jun\ 2005=1} + \omega_{OL} D_{Oct\ 2005=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Mar\ 2007=1} + \omega_{OL} D_{Dec\ 2015=1} +$
$ARIMA\epsilon_{t,y}\ (5,1,0)(3,1,0)_{12}$

[8] Model notes:

1. In the spring 2020 forecast, $C_{t,y,ID101.r}$ (residential customers from residential schedule 101) was replaced with POP for Kootenai. This was done because POP produced a model with slightly improved diagnostic tests. Previously, $C_{t,y,ID101.r}$ was being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.
2. SC dummies control for a step-up in customers in November 2005, September 2006, and November 2007.
3. There is no SC dummy for the in-migration of customers from industrial schedule 101 starting in October 2020. The in-migration was relatively small to the total number of customers in commercial schedule 101. See also notes for UPC model.

[9] $C_{t,y,ID111.c} = \beta_0 + \gamma_{RAMP} T_{Jan\ 2012} + \omega_{SC} D_{Nov\ 2008\uparrow=1} + \omega_{SC} D_{Nov\ 2011\uparrow=1} + \omega_{SC} D_{Jan\ 2012\uparrow=1} + \omega_{OL} D_{Feb\ 2011=1} +$
$\omega_{OL} D_{Feb\ 2015=1} + \omega_{OL} D_{Dec\ 2015=1} + ARIMA\epsilon_{t,y}\ (7,1,0)(0,0,0)_{12}$

[9] Model notes:
1. SC dummies control for a large step-up in customers starting in November 2008 and November 2011.
2. Ramping time trend and SC dummy starting in Jan 2012 control for a slowdown in customer growth.

5. WA industrial customer forecasts models:

[10] $C_{t,y,WA101.i} = \frac{1}{6}\sum_{j=1}^{6} C_{t-j}$

[10] Model notes:
1. In late 2020 there was a large customer out-migration to schedule 1010 commercial. As with the electric side, this was due to customers not generating enough load to get the industrial rate. Number of customers dropped from around 70 to 16. Until a longer time-series is available, a simple averaging model will be used. See also notes for UPC model.

[11] $C_{t,y,WA111.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[11] Model notes:
1. In January 2019, all three customers in schedule 121 industrial were moved to schedule 111, in addition to Boise Cascade Arden, WA (under the company name Columbia Cedar) from schedule 146. This change of four customers falls within the normal variation of customers in schedule 111; therefore, no explicit adjustment is made to the model [7.40] to account for this shift. The customer count is now changing very slowly over time, so a 12-month moving average was applied starting with the winter 2020 forecast.

6. ID industrial customer forecast models:

[12] $C_{t,y,ID101.i} = \frac{1}{6}\sum_{j=1}^{6} C_{t-j}$

[12] Model notes:
1. In late 2020 there was a large customer out-migration to schedule 1010 commercial. As with the electric side, this was due to customers not generating enough load to get the industrial rate. Number of customers dropped from around 50 to 30. Until a longer time-series is available, a simple averaging model will be used. See also notes for UPC model.

[13] $C_{t,y,ID111.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[13] Model notes:
1. Period of restriction reflects the restriction on the UPC model for this schedule.
2. Customer count stabilized in 2012; customer count fluctuates between 31 and 34 without any clear trend or seasonality.

[14] $C_{t,y,ID112.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[14] Model notes:
1. Customer count tends to increase in steps following prolonged periods of stability. No clear seasonality present.

7. Medford, OR forecasting models:

The forecasting models for the Medford region (Jackson County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Customers:

[15] $C_{t,y,MED410.r} = \alpha_0 + \alpha_1 POP_{t,y,JACK+JOS} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D + \omega_{SC} D_{Nov\ 2004\uparrow=1} + \omega_{SC} D_{Oct\ 2020\uparrow=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Sep\ 2020=1} + \omega_{OL} D_{Oct\ 2018=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(1,0,0)_{12}$

[15] Model notes:

1. SC dummy and ramping time trend for January 2008 control for a change in the time-path of customer growth staring in January 2008. SC dummy for 2004↑ controls for a step-up in customers; SC dummy for October 2020↑ and OL dummy for September 2020 control for the impact of the 2020 wildfires which destroyed around 1,000 customers (both residential and commercial) in the Medford region.
2. POP is Jackson plus Josephine counties.

Commercial Sector, Customers:

[16] $C_{t,y,MED420.c} = \alpha_0 + \alpha_1 C_{t,y,MED410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Feb\ 2016\uparrow=1} + \omega_{OL} D_{Jan\ 2016=1} + \omega_{OL} D_{May\ 2020=1} + \omega_{OL} D_{Jun\ 2020=1} + ARIMA\epsilon_{t,y}\,(8,1,0)(0,0,0)_{12}$

[16] Model notes:
1. $C_{t,y,MED410.r}$ are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2. However, in the future, POP may become a better driver. Model results with POP are fairly close to model shown above.
2. OL dummies for May and June may reflect short-term impacts of the COVID shock.
3. Because the impact of the wildfires is reflected in $C_{t,y,MED410}$, they are controlled for through that variable and not an SC dummy.

[17] $C_{y,MED424.c} = C_{y-1} + (\widehat{\alpha_0} + \widehat{\alpha_1}\Delta EMP_{y-1,4County})$

[17] Model notes:
1. This model reflects a recommendation by Oregon staff in the 2016 rate case to include employment as an economic driver for schedule 424 commercial customers. The estimated equation in parenthesis reflects the regression estimated of $\Delta C_{y,MED424.c} = \alpha_0 + \alpha_1 \Delta EMP_{y-1,4County} + \varepsilon_t$ using annual customer data since 2004. Annual data is used to smooth over the sometimes volatile changes in the monthly customer number. In addition, customer increases and decreases around the long-run trend tend to occur in steps. The combination of steps and month-to-month volatility creates significant economic problems when trying to model around the monthly data. For example, even with intervention variables, tests for error normality always indicated non-normal error terms with the use of monthly data.
2. $\Delta C_{y,MED424.c}$ is the change in customers in year y (customer change between year y and y-1) and $\Delta EMP_{y-1,4County}$ is the change in total non-farm employment in Jackson+Josephine, Klamath, and Douglas counties in year y-1 (employment change between year y-1 and y-2). Staff originally suggested lagged total employment for Oregon, but the correlation between schedule 424 customers and employment for the four-county area is higher. The forecasted employment values for Jackson+Josephine County are derived from the employment growth forecasts used in the Jackson+Josephine County population forecast. The forecasts for Douglas and Klamath counties come from IHS. In IRP years, IHS forecasts all counties will be used for the out years.
3. The annual forecast value for each year, F(·), is assumed to hold for each month of that year. That is: $F(C_{y,MED424.c}) = F(C_{t,y,MED424.c})$. Given the step-like behavior of the monthly series, this is a reasonable assumption.
4. The forecast and regressions for this schedule can be found in the Excel file folder “OR 4County Sch 424c Cus.”

[18] $C_{t,y,MED444.c} = 1\ if\ (THM/C_{t,y})_{MED,444.c} > 0$

[18] Model notes:
1. There is typically only one customer served by this schedule. Therefore, the customer forecast is automatically set to one whenever the load forecast is greater than zero.

Industrial Sector, Customers:

[19] $C_{t,y,MED420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[19] Model notes:
1. Data starts November 2006. Excluding outliers in November 2006, November 2009, and February 2011, the customer count fluctuates between 9 and 16 without any clear trend or seasonality. Changes in the customer count occur in steps between prolonged periods of stability.

[20] $C_{t,y,MED424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[21] Model notes:
1. Data starts January 2009. Excluding a January 2009 outlier, the customer count fluctuates between 1 and 3 without any clear trend or seasonality. In March 2019, the schedule 447b (biomass plant) moved to schedule 424.

8. Roseburg, OR forecasting models:

The forecasting models for the Roseburg region (Douglas County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Customers:

[22] $C_{t,y,ROS410.r} = \varphi_0 + \varphi_1 POP_{t,y,DOUGLAS} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2005\uparrow =1} + \omega_{SC} D_{Dec\ 2005\uparrow =1} + \omega_{SC} D_{Nov\ 2006\uparrow =1} + \omega_{OL} D_{Oct\ 2004\ =1} + \omega_{OL} D_{Nov\ 2004\ =1} + \omega_{OL} D_{Dec\ 2007\ =1} + \omega_{OL} D_{Feb\ 2008\ =1} + \omega_{OL} D_{Nov\ 2009\ =1} + \omega_{OL} D_{Oct\ 2018\ =1} + \omega_{OL} D_{Mar\ 2019\ =1} + \omega_{OL} D_{Nov\ 2020\ =1} + ARIMA\epsilon_{t,y}\ (12{,}1{,}0)(0{,}0{,}0)_{12}$

[22] Model notes:
1. POP is population for Douglas County, OR.
2. SC dummies control for large step-ups in customers in 2005 and 2006.

Commercial Sector, Customers:

[23] $C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 POP_{t,y,DOUGLAS} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Dec\ 2005\uparrow =1} + \omega_{OL} D_{Jan\ 2005\ =1} + \omega_{OL} D_{Jan\ 2008\ =1} + \omega_{OL} D_{Mar\ 2019=1} + ARIMA\epsilon_{t,y}\ (9{,}1{,}0)(0{,}0{,}0)_{12}\ for\ y = 2005\uparrow$

[23] Model notes:
1. Model does not use schedule 410 customers as driver. This reflects the lack of correlation between residential 410 and commercial 420 customer growth. However, POP was added for the 2018 gas IRP and was significant at the 10% level; however, by the time of the spring 2022 forecast it had become insignificant but still consistently positive, so it was left in.
2. The lack of correlation noted above could reflect Roseburg's position between larger cities that offer a range of commercial activities. Competition from these cities may be inhibiting commercial growth in Roseburg. However, as noted above, it now appears the linkage to population is also weakening.
3. Model restricted to 2005↑ because the inclusion of the pre-2005 period produced unstable models starting in the spring 2022 forecast.4. SC dummy controls for a significant step-up in customers starting in December 2005.

[24] $C_{t,y,ROS424.c} = C_{y-1} + (\widehat{\varphi_0} + \widehat{\varphi_1} \Delta EMP_{y-1,4County})$

[24] Model notes:
1. This model reflects a recommendation by Oregon staff in the 2016 rate case to include employment as an economic driver for schedule 424 commercial customers. The estimated equation in parenthesis reflects the regression estimated of $\Delta C_{y,ROS424.c} = \alpha_0 + \alpha_1 \Delta EMP_{y-1,4County} + \varepsilon_t$ using annual customer data since 2004. Annual data is used to smooth over the sometimes volatile changes in the monthly customer number. In addition, customer increases and decreases around the long-run trend tend to occur in steps. The combination of steps and month-to-month volatility creates significant economic problems when trying to model around the monthly data. For example, even with intervention variables, tests for error normality always indicated non-normal error terms with the use of monthly data.
2. $\Delta C_{y,ROS424.c}$ is the change in customers in year y (customer change between year y and y-1) and $\Delta EMP_{y-1,4County}$ is the change in total non-farm employment in Jackson+Josephine, Klamath, and Douglas counties in year y-1 (employment change between year y-1 and y-2). Staff originally suggested lagged total employment for Oregon, but the correlation between schedule 424 customers and employment for the four-county area is higher. The forecasted employment values for Jackson+Josephine County are derived from the employment growth forecasts used in the Jackson+Josephine County population forecast. The forecasts for Douglas and Klamath counties come from IHS. In IRP years, IHS forecasts for all counties will be used for the out years.
3. The annual forecast value for each year, F(·), is assumed to hold for each month of that year. That is: $F(C_{y,ROS424.c}) = F(C_{t,y,ROS424.c})$. Given the step-like behavior of the monthly series, this is a reasonable assumption.
4. The forecast and regressions for this schedule can be found in the Excel file file folder “OR 4County Sch 424c Cus.”

Industrial Sector, Customers:

[25] $C_{t,y,ROS420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[25] Model notes:
1. Data starts September 2009. Excluding a February 2015 outlier, the customer count fluctuates between 1 and 2 without any clear trend or seasonality.
2. Due to the Compass software conversion, February 2015 is excluded from the historical data. The conversion resulted in a double counting of customers in February 2015. Therefore, including this month leads to a significant over-forecast of customers.

9. Klamath Falls, OR forecasting models:

The forecasting models for the Klamath Falls region (Klamath County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Customers:

[26] $C_{t,y,KLM410.r} = \beta_0 + \beta_1 POP_{t,y,KLAMATH} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}$

[26] Model notes:
1. POP is for Klamath County, OR.

Commercial Sector, Customers:

[27] $C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (11,1,0)(1,0,0)_{12}$

[27] Model notes:
1. $C_{t,y,KLM410.r}$ are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2. However, in as of the June 2019 forecast, the coefficient on $C_{t,y,KLM410.r}$ is positive but no longer statistically significant.

[28] $C_{t,y,KLM424.c} = C_{y-1} + (\widehat{\beta}_0 + \widehat{\beta}_1 \Delta EMP_{y-1,4County})$

[28] Model notes:
1. This model reflects a recommendation by Oregon staff in the 2016 rate case to include employment as an economic driver for schedule 424 commercial customers. The estimated equation in parenthesis reflects the regression estimated of $\Delta C_{y,KLM424.c} = \alpha_0 + \alpha_1 \Delta EMP_{y-1,4County} + \varepsilon_t$ using annual customer data since 2004. Annual data is used to smooth over the sometimes volatile changes in the monthly customer number. In addition, customer increases and decreases around the long-run trend tend to occur in steps. The combination of steps and month-to-month volatility creates significant economic problems when trying to model around the monthly data. For example, even with intervention variables, tests for error normality always indicated non-normal error terms with the use of monthly data.
2. $\Delta C_{y,KLM424.c}$ is the change in customers in year y (customer change between year y and y-1) and $\Delta EMP_{y-1,4County}$ is the change in total non-farm employment in Jackson, Josephine, Klamath, and Douglas counties in year y-1 (employment change between year y-1 and y-2). Staff originally suggested lagged total employment for Oregon, but the correlation between schedule 424 customers and employment for the four-county area is higher. The forecasted employment values for Jackson+Josephine County are derived from the employment growth forecasts used in the Jackson+Josephine County population forecast. The forecasts for Douglas and Klamath counties come from IHS. In IRP years, IHS forecasts for all counties will be used for the out years.
3. The annual forecast value for each year, F(·), is assumed to hold for each month of that year. That is: $F(C_{y,KLM424.c}) = F(C_{t,y,KLM424.c})$. Given the step-like behavior of the monthly series, this is a reasonable assumption.
4. The forecast and regressions for this schedule can be found in the Excel file folder "OR 4County Sch 424c Cus."

Industrial Sector, Customers:

[29] $C_{t,y,KLM420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[29] Model notes:
1. Data starts December 2006. The customer count fluctuates between 4 and 9 without any clear trend or seasonality.

[30] $C_{t,y,KLM424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[30] Model notes:
1. Data starts April 2009. The customer count fluctuates between 1 and 4 without any clear trend or seasonality.

<u>10. La Grande, OR forecasting models</u>:

The forecasting models for the La Grande region (Union County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Customers:

[31] $C_{t,y,LaG410.r} = \theta_0 + \theta_1 POP_{t,y,UNION} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2004=1} + \omega_{OL} D_{Jul\ 2006=1} + \omega_{OL} D_{Dec\ 2009=1} + ARIMA\epsilon_{t,y}\ (9,1,0)(1,0,0)_{12}$

[31] Model notes:
1. POP is population for Union County, OR.

Commercial Sector, Customers:

[32] $C_{t,y,LaG420.c} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Jul\ 2005=1} + \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Nov\ 2011=1} + \omega_{OL} D_{Nov\ 2019=1} + ARIMA\epsilon_{t,y}\ (13,1,0)(0,0,0)_{12}$

[32] Model notes:
1. $C_{t,y,LaG410.r}$, residential customers from residential schedule 410, are no longer used as a forecast driver. The estimated coefficient on $C_{t,y,LaG410.r}$ was no longer statistically significant and its sign flips between positive and negative, depending on the form of the model. POP for union county was also tried as a driver, but had the same issues as $C_{t,y,LaG410.r}$.

[33] $C_{t,y,LaG424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[33] Model notes:
1. Data starts January 2007. The customer count fluctuates between 2 and 4 without any clear trend or seasonality. Changes in the customer count appear as steps after prolonged periods of stability.

Industrial Sector, Customers:

[34] $C_{t,y,LaG420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[34] Model notes:
1. Since these customers appeared approximately, there has been no load activity. As a result, they have never been included in a forecast prior to fall 2021; it was assumed this schedule was simply a revenue reporting error. However, subsequent research of billing activity indicates the customers are paying fixed charges. The current forecast assumes no load over the forecast horizon.

[35] $C_{t,y,LaG444.i} = \frac{1}{N}\sum_{j=1}^{N} C_{t,y-j}\ for\ y-j = 2014 \uparrow$
$up\ to\ the\ most\ recent\ month, then\ repeat\ forecast\ values.$

[35] Model notes:
1. Even in the presence of seasonality, customer count can be highly erratic. Regression models produced poor diagnostics and required many OL dummies. As a result, a historical monthly average is used as the forecast.
2. Restricted to 20124 ↑ because of a significant change in behavior starting in 2014.

APPENDIX 2.2: CUSTOMER FORECASTS BY SCENARIO EXPECTED

EXPECTED	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WA_Res_Current	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664
WA_Res_New	1,075	3,313	5,534	7,719	9,813	11,886	13,966	16,048	18,130	20,211	22,285	24,351
WA_Com_Current	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241
WA_Com_New	36	108	179	250	321	391	462	532	603	673	743	814
WA_Ind	93	93	93	93	93	93	93	93	93	93	93	93
ID_Res	84,955	86,657	88,289	89,881	91,376	92,844	94,298	95,736	97,187	98,647	100,112	101,591
ID_Com	9,623	9,739	9,845	9,923	9,990	10,059	10,120	10,171	10,223	10,276	10,324	10,370
ID_Ind	68	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611
Medford_Res_New	325	1,109	1,933	2,752	3,539	4,315	5,085	5,849	6,604	7,351	8,089	8,818
Medford_Com_Current	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108
Medford_Com_New	28	96	167	238	305	373	438	503	568	633	695	758
Medford_Ind	14	14	14	14	14	14	14	14	14	14	14	14
Roseburg_Res_Current	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252
Roseburg_Res_New	30	104	180	256	330	403	477	551	621	690	758	826
Roseburg_Com_Current	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212
Roseburg_Com_New	2	7	11	16	20	24	29	33	37	41	45	50
Roseburg_Ind	2	2	2	2	2	2	2	2	2	2	2	2
Klamath Falls_Res_Current	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601
Klamath Falls_Res_New	56	186	319	442	550	652	749	841	931	1,023	1,114	1,203
Klamath Falls_Com_Current	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809
Klamath Falls_Com_New	6	18	28	40	51	61	71	82	91	102	112	123
Klamath Falls_Ind	6	6	6	6	6	6	6	6	6	6	6	6
LaGrande_Res_Current	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890
LaGrande_Res_New	14	51	89	128	168	208	249	290	331	371	411	451
LaGrande_Com_Current	943	943	943	943	943	943	943	943	943	943	943	943
LaGrande_Com_New	2	6	11	15	19	24	28	32	37	41	45	50
LaGrande_Ind	4	4	4	4	4	4	4	4	4	4	4	4

EXPECTED	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA_Res_Current	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664	161,664
WA_Res_New	26,406	28,455	30,494	32,523	34,542	36,555	38,562	40,555	42,547	44,532	46,514
WA_Com_Current	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241	15,241
WA_Com_New	884	954	1,024	1,094	1,164	1,234	1,304	1,374	1,444	1,514	1,583
WA_Ind	93	93	93	93	93	93	93	93	93	93	93
ID_Res	103,074	104,564	106,060	107,559	109,063	110,564	112,075	113,604	115,155	116,722	118,386
ID_Com	10,415	10,458	10,497	10,534	10,569	10,601	10,630	10,659	10,687	10,715	10,752
ID_Ind	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611	57,611
Medford_Res_New	9,538	10,252	10,960	11,658	12,349	13,034	13,713	14,386	15,055	15,719	16,366
Medford_Com_Current	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108	7,108
Medford_Com_New	819	880	940	999	1,058	1,116	1,173	1,230	1,286	1,343	1,396
Medford_Ind	14	14	14	14	14	14	14	14	14	14	14
Roseburg_Res_Current	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252	14,252
Roseburg_Res_New	892	957	1,023	1,089	1,156	1,222	1,287	1,352	1,416	1,480	1,543
Roseburg_Com_Current	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212
Roseburg_Com_New	54	57	62	65	70	74	77	82	85	90	93
Roseburg_Ind	2	2	2	2	2	2	2	2	2	2	2
Klamath Falls_Res_Current	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601
Klamath Falls_Res_New	1,290	1,376	1,463	1,551	1,641	1,730	1,816	1,899	1,979	2,057	2,135
Klamath Falls_Com_Current	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809
Klamath Falls_Com_New	132	142	153	163	172	183	193	203	213	223	233
Klamath Falls_Ind	6	6	6	6	6	6	6	6	6	6	6
LaGrande_Res_Current	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890	6,890
LaGrande_Res_New	491	530	568	607	645	683	721	759	797	835	873
LaGrande_Com_Current	943	943	943	943	943	943	943	943	943	943	943
LaGrande_Com_New	54	58	63	67	72	76	80	85	89	93	98
LaGrande_Ind	4	4	4	4	4	4	4	4	4	4	4

APPENDIX 2.2: CUSTOMER FORECASTS BY SCENARIO HIGH

HIGH	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WA_Res_Current	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189
WA_Res_New	1,250	3,846	6,435	8,998	11,478	13,947	16,433	18,930	21,438	23,953	26,472	28,991
WA_Com_Current	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291
WA_Com_New	52	157	262	366	470	575	680	785	891	997	1,103	1,210
WA_Ind	97	99	101	103	105	107	109	111	113	115	117	119
ID_Res	85,757	87,878	89,946	91,990	93,951	95,901	97,852	99,802	101,782	103,787	105,815	107,872
ID_Com	9,714	9,876	10,029	10,156	10,271	10,391	10,501	10,603	10,706	10,811	10,912	11,011
ID_Ind	70	71	72	73	74	75	76	77	78	79	80	81
Medford_Res_Current	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718
Medford_Res_New	361	1,216	2,115	3,012	3,877	4,733	5,586	6,434	7,276	8,110	8,938	9,759
Medford_Com_Current	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121
Medford_Com_New	32	109	189	269	346	423	498	574	648	722	796	869
Medford_Ind	15	15	16	16	17	17	18	18	19	19	20	20
Roseburg_Res_Current	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318
Roseburg_Res_New	51	169	290	411	530	650	771	892	1,010	1,127	1,244	1,361
Roseburg_Com_Current	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222
Roseburg_Com_New	6	17	28	39	50	62	73	84	96	107	118	129
Roseburg_Ind	3	3	4	4	5	5	6	6	7	7	8	8
Klamath Falls_Res_Current	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673
Klamath Falls_Res_New	79	258	441	614	773	926	1,075	1,220	1,364	1,510	1,656	1,801
Klamath Falls_Com_Current	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
Klamath Falls_Com_New	9	26	43	60	76	93	109	125	141	158	174	191
Klamath Falls_Ind	7	7	8	8	9	9	10	10	11	11	12	12
LaGrande_Res_Current	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920
LaGrande_Res_New	24	81	139	198	258	319	381	444	507	570	632	694
LaGrande_Com_Current	947	947	947	947	947	947	947	947	947	947	947	947
LaGrande_Com_New	3	10	17	25	32	39	46	53	61	68	75	83
LaGrande_Ind	5	6	6	7	7	8	8	9	9	10	10	11

HIGH	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA_Res_Current	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189	162,189
WA_Res_New	31,510	34,032	36,553	39,074	41,594	44,118	46,644	49,167	51,697	54,230	56,770
WA_Com_Current	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291	15,291
WA_Com_New	1,317	1,424	1,532	1,640	1,748	1,857	1,966	2,075	2,185	2,295	2,405
WA_Ind	121	123	125	127	129	131	133	135	137	139	141
ID_Res	109,952	112,055	114,183	116,330	118,501	120,686	122,898	125,150	127,443	129,774	132,230
ID_Com	11,110	11,207	11,301	11,393	11,484	11,571	11,657	11,742	11,828	11,913	12,010
ID_Ind	82	83	84	85	86	87	88	89	90	91	92
Medford_Res_Current	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718	57,718
Medford_Res_New	10,572	11,382	12,186	12,983	13,774	14,560	15,342	16,120	16,896	17,668	18,424
Medford_Com_Current	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121	7,121
Medford_Com_New	941	1,012	1,083	1,154	1,223	1,293	1,362	1,430	1,498	1,566	1,632
Medford_Ind	21	21	22	22	23	23	24	24	25	25	26
Roseburg_Res_Current	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318	14,318
Roseburg_Res_New	1,477	1,593	1,710	1,828	1,946	2,065	2,184	2,303	2,421	2,539	2,658
Roseburg_Com_Current	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222
Roseburg_Com_New	141	152	163	174	186	198	209	221	232	244	255
Roseburg_Ind	9	9	10	10	11	11	12	12	13	13	14
Klamath Falls_Res_Current	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673	15,673
Klamath Falls_Res_New	1,945	2,088	2,231	2,378	2,528	2,676	2,823	2,967	3,108	3,249	3,389
Klamath Falls_Com_Current	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
Klamath Falls_Com_New	208	224	241	258	275	292	309	326	343	360	377
Klamath Falls_Ind	13	13	14	14	15	15	16	16	17	17	18
LaGrande_Res_Current	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920	6,920
LaGrande_Res_New	757	819	881	943	1,006	1,068	1,131	1,194	1,257	1,320	1,383
LaGrande_Com_Current	947	947	947	947	947	947	947	947	947	947	947
LaGrande_Com_New	90	97	105	112	120	128	135	143	151	158	166
LaGrande_Ind	11	12	12	13	13	14	14	15	15	16	16

APPENDIX 2.2: CUSTOMER FORECASTS BY SCENARIO ELECTRIFICATION

ELECTRIFICATION	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WA_Res_Current	162,739	164,977	161,677	158,444	155,275	152,169	149,126	146,144	143,221	140,356	137,549	134,798
WA_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
WA_Com_Current	15,241	15,241	14,936	14,638	14,345	14,058	13,777	13,501	13,231	12,967	12,707	12,453
WA_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
WA_Ind	93	93	91	89	88	86	84	83	81	79	78	76
ID_Res	84,955	86,657	88,289	89,881	91,376	92,844	94,298	95,736	97,187	98,647	100,112	101,591
ID_Com	9,623	9,739	9,845	9,923	9,990	10,059	10,120	10,171	10,223	10,276	10,324	10,370
ID_Ind	68	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	57,937	58,720	57,546	56,395	55,267	54,161	53,078	52,017	50,976	49,957	48,958	47,978
Medford_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
Medford_Com_Current	7,136	7,204	7,060	6,918	6,780	6,645	6,512	6,382	6,254	6,129	6,006	5,886
Medford_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Medford_Ind	14	14	14	13	13	13	13	12	12	12	12	11
Roseburg_Res_Current	14,282	14,355	14,068	13,787	13,511	13,241	12,976	12,717	12,462	12,213	11,969	11,729
Roseburg_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Com_Current	2,213	2,218	2,174	2,131	2,088	2,046	2,005	1,965	1,926	1,887	1,850	1,813
Roseburg_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Ind	2	2	2	2	2	2	2	2	2	2	2	2
Klamath Falls_Res_Current	15,656	15,787	15,471	15,161	14,858	14,561	14,270	13,985	13,705	13,431	13,162	12,899
Klamath Falls_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Com_Current	1,815	1,826	1,789	1,754	1,719	1,684	1,650	1,617	1,585	1,553	1,522	1,492
Klamath Falls_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Ind	6	6	6	6	6	6	5	5	5	5	5	5
LaGrande_Res_Current	6,904	6,941	6,802	6,666	6,533	6,402	6,274	6,149	6,026	5,905	5,787	5,671
LaGrande_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Com_Current	945	949	930	912	893	875	858	841	824	807	791	775
LaGrande_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Ind	4	4	4	4	4	4	4	4	3	3	3	3

ELECTRIFICATION	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA_Res_Current	132,102	129,460	126,871	124,334	121,847	119,410	117,022	114,681	112,388	110,140	107,937
WA_Res_New	-	-	-	-	-	-	-	-	-	-	-
WA_Com_Current	12,204	11,960	11,721	11,486	11,257	11,032	10,811	10,595	10,383	10,175	9,972
WA_Com_New	-	-	-	-	-	-	-	-	-	-	-
WA_Ind	75	73	72	70	69	67	66	65	63	62	61
ID_Res	103,074	104,564	106,060	107,559	109,063	110,564	112,075	113,604	115,155	116,722	118,386
ID_Com	10,415	10,458	10,497	10,534	10,569	10,601	10,630	10,659	10,687	10,715	10,752
ID_Ind	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	47,019	46,079	45,157	44,254	43,369	42,501	41,651	40,818	40,002	39,202	38,418
Medford_Res_New	-	-	-	-	-	-	-	-	-	-	-
Medford_Com_Current	5,768	5,653	5,540	5,429	5,320	5,214	5,110	5,007	4,908	4,809	4,713
Medford_Com_New	-	-	-	-	-	-	-	-	-	-	-
Medford_Ind	11	11	11	11	10	10	10	10	10	9	9
Roseburg_Res_Current	11,495	11,265	11,040	10,819	10,603	10,390	10,183	9,979	9,779	9,584	9,392
Roseburg_Res_New	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Com_Current	1,776	1,741	1,706	1,672	1,638	1,606	1,574	1,542	1,511	1,481	1,451
Roseburg_Com_New	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Ind	2	2	2	2	1	1	1	1	1	1	1
Klamath Falls_Res_Current	12,641	12,388	12,140	11,898	11,660	11,426	11,198	10,974	10,754	10,539	10,328
Klamath Falls_Res_New	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Com_Current	1,462	1,433	1,404	1,376	1,348	1,321	1,295	1,269	1,244	1,219	1,195
Klamath Falls_Com_New	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Ind	5	5	5	5	4	4	4	4	4	4	4
LaGrande_Res_Current	5,558	5,447	5,338	5,231	5,126	5,024	4,923	4,825	4,728	4,634	4,541
LaGrande_Res_New	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Com_Current	760	745	730	715	701	687	673	660	647	634	621
LaGrande_Com_New	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Ind	3	3	3	3	3	3	3	3	3	3	3

APPENDIX 2.2: CUSTOMER FORECASTS BY SCENARIO HYBRID

HYBRID	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WA_Res_Current	162,739	164,977	161,677	158,444	155,275	152,169	149,126	146,144	143,221	140,356	137,549	134,798
WA_Res_New	-	-	5,521	10,939	16,202	21,381	26,504	31,568	36,574	41,519	46,400	51,217
WA_Com_Current	15,241	15,241	14,936	14,638	14,345	14,058	13,777	13,501	13,231	12,967	12,707	12,453
WA_Com_New	36	108	484	854	1,217	1,575	1,926	2,272	2,613	2,947	3,277	3,602
WA_Ind	93	93	91	89	88	86	84	83	81	79	78	76
ID_Res	84,955	86,657	88,289	89,881	91,376	92,844	94,298	95,736	97,187	98,647	100,112	101,591
ID_Com	9,623	9,739	9,845	9,923	9,990	10,059	10,120	10,171	10,223	10,276	10,324	10,370
ID_Ind	68	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	57,937	58,720	57,546	56,395	55,267	54,161	53,078	52,017	50,976	49,957	48,958	47,978
Medford_Res_New	-	-	1,998	3,969	5,883	7,765	9,618	11,443	13,239	15,005	16,742	18,451
Medford_Com_Current	7,136	7,204	7,060	6,918	6,780	6,645	6,512	6,382	6,254	6,129	6,006	5,886
Medford_Com_New	-	-	215	428	633	836	1,035	1,230	1,423	1,612	1,797	1,981
Medford_Ind	14	14	14	13	13	13	13	12	12	12	12	11
Roseburg_Res_Current	14,282	14,355	14,068	13,787	13,511	13,241	12,976	12,717	12,462	12,213	11,969	11,729
Roseburg_Res_New	-	-	364	721	1,071	1,414	1,753	2,086	2,411	2,729	3,041	3,348
Roseburg_Com_Current	2,213	2,218	2,174	2,131	2,088	2,046	2,005	1,965	1,926	1,887	1,850	1,813
Roseburg_Com_New	-	-	49	97	144	189	235	280	323	366	407	449
Roseburg_Ind	2	2	2	2	2	2	2	2	2	2	2	2
Klamath Falls_Res_Current	15,656	15,787	15,471	15,161	14,858	14,561	14,270	13,985	13,705	13,431	13,162	12,899
Klamath Falls_Res_New	-	-	449	881	1,293	1,691	2,079	2,457	2,827	3,192	3,552	3,905
Klamath Falls_Com_Current	1,815	1,826	1,789	1,754	1,719	1,684	1,650	1,617	1,585	1,553	1,522	1,492
Klamath Falls_Com_New	-	-	48	95	141	185	229	273	315	357	398	439
Klamath Falls_Ind	6	6	6	6	6	6	5	5	5	5	5	5
LaGrande_Res_Current	6,904	6,941	6,802	6,666	6,533	6,402	6,274	6,149	6,026	5,905	5,787	5,671
LaGrande_Res_New	-	-	177	352	525	696	865	1,031	1,195	1,356	1,514	1,670
LaGrande_Com_Current	945	949	930	912	893	875	858	841	824	807	791	775
LaGrande_Com_New	-	-	24	46	69	91	113	134	156	176	197	217
LaGrande_Ind	4	4	4	4	4	4	4	4	3	3	3	3

HYBRID	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA_Res_Current	132,102	129,460	126,871	124,334	121,847	119,410	117,022	114,681	112,388	110,140	107,937
WA_Res_New	55,968	60,659	65,287	69,853	74,359	78,809	83,204	87,538	91,823	96,056	100,241
WA_Com_Current	12,204	11,960	11,721	11,486	11,257	11,032	10,811	10,595	10,383	10,175	9,972
WA_Com_New	3,921	4,235	4,545	4,849	5,149	5,444	5,734	6,020	6,302	6,580	6,853
WA_Ind	75	73	72	70	69	67	66	65	63	62	61
ID_Res	103,074	104,564	106,060	107,559	109,063	110,564	112,075	113,604	115,155	116,722	118,386
ID_Com	10,415	10,458	10,497	10,534	10,569	10,601	10,630	10,659	10,687	10,715	10,752
ID_Ind	68	68	68	68	68	68	68	68	68	68	68
Medford_Res_Current	47,019	46,079	45,157	44,254	43,369	42,501	41,651	40,818	40,002	39,202	38,418
Medford_Res_New	20,131	21,785	23,414	25,016	26,592	28,144	29,673	31,179	32,664	34,128	35,559
Medford_Com_Current	5,768	5,653	5,540	5,429	5,320	5,214	5,110	5,007	4,908	4,809	4,713
Medford_Com_New	2,159	2,335	2,508	2,678	2,846	3,010	3,172	3,330	3,487	3,642	3,791
Medford_Ind	11	11	11	11	10	10	10	10	10	9	9
Roseburg_Res_Current	11,495	11,265	11,040	10,819	10,603	10,390	10,183	9,979	9,779	9,584	9,392
Roseburg_Res_New	3,649	3,944	4,235	4,522	4,805	5,083	5,356	5,625	5,888	6,148	6,403
Roseburg_Com_Current	1,776	1,741	1,706	1,672	1,638	1,606	1,574	1,542	1,511	1,481	1,451
Roseburg_Com_New	489	528	567	605	643	680	715	751	785	820	853
Roseburg_Ind	2	2	2	2	1	1	1	1	1	1	1
Klamath Falls_Res_Current	12,641	12,388	12,140	11,898	11,660	11,426	11,198	10,974	10,754	10,539	10,328
Klamath Falls_Res_New	4,250	4,589	4,923	5,254	5,582	5,904	6,218	6,526	6,825	7,119	7,408
Klamath Falls_Com_Current	1,462	1,433	1,404	1,376	1,348	1,321	1,295	1,269	1,244	1,219	1,195
Klamath Falls_Com_New	478	518	557	596	633	670	707	743	778	813	847
Klamath Falls_Ind	5	5	5	5	4	4	4	4	4	4	4
LaGrande_Res_Current	5,558	5,447	5,338	5,231	5,126	5,024	4,923	4,825	4,728	4,634	4,541
LaGrande_Res_New	1,823	1,973	2,121	2,266	2,409	2,550	2,688	2,824	2,959	3,091	3,221
LaGrande_Com_Current	760	745	730	715	701	687	673	660	647	634	621
LaGrande_Com_New	237	256	276	294	313	332	349	367	385	402	419
LaGrande_Ind	3	3	3	3	3	3	3	3	3	3	3

APPENDIX 2.3: HEAT DEMAND COEFFICIENTS

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2-Year	Klamath Falls_Com	0.0314	0.0302	0.0271	0.0181	0.0140	0.0088	0.0047	0.0045	0.0112	0.0235	0.0279	0.0305
	Klamath Falls_Ind	0.0904	0.0986	0.0585	0.0133	0.0296	0.0450	0.0852	0.2446	0.2895	0.4587	0.3168	0.2842
	Klamath Falls_Res	0.0086	0.0083	0.0075	0.0056	0.0048	0.0032	0.0013	0.0002	0.0017	0.0051	0.0076	0.0083
	LaGrande_Com	0.0408	0.0398	0.0329	0.0237	0.0170	0.0061	0.0003	0.0163	0.0017	0.0223	0.0324	0.0382
	LaGrande_Ind	-	-	-	-	-	-	4.5258	2.2558	1.6580	2.5837	0.0003	-
	LaGrande_Res	0.0091	0.0089	0.0074	0.0059	0.0049	0.0030	0.0010	0.0030	0.0002	0.0049	0.0082	0.0089
	Medford_Com	0.0473	0.0455	0.0372	0.0276	0.0207	0.0202	0.0258	0.0904	0.0227	0.0420	0.0422	0.0435
	Medford_Ind	0.0375	0.0546	0.0231	0.0198	0.0505	0.1270	0.1993	1.3995	0.2539	0.3423	0.1410	0.0544
	Medford_Res	0.0118	0.0112	0.0097	0.0083	0.0062	0.0053	0.0090	0.0108	0.0039	0.0083	0.0100	0.0112
	Roseburg_Com	0.0613	0.0487	0.0371	0.0353	0.0237	0.0169	0.0006	0.0790	0.0286	0.0342	0.0386	0.0405
	Roseburg_Ind	0.0355	0.0411	0.0026	0.0723	0.1453	0.2113	0.1925	0.7885	0.2225	0.1446	0.0274	0.0029
	Roseburg_Res	0.0139	0.0115	0.0095	0.0085	0.0062	0.0049	0.0015	0.0104	0.0065	0.0093	0.0109	0.0108
	ID_Com	0.0420	0.0437	0.0381	0.0256	0.0185	0.0206	0.0038	0.0148	0.0232	0.0308	0.0341	0.0411
	ID_Ind	0.2266	0.2060	0.2007	0.2185	0.3854	0.2479	0.1907	0.0506	0.1722	0.2098	0.2401	0.2024
	ID_Res	0.0106	0.0105	0.0089	0.0079	0.0056	0.0032	0.0026	0.0009	0.0032	0.0079	0.0097	0.0099
	WA_Com	0.0594	0.0595	0.0519	0.0357	0.0257	0.0149	0.0045	0.0083	0.0210	0.0444	0.0486	0.0551
	WA_Ind	0.1669	0.1865	0.1875	0.1898	0.1515	0.2054	0.0242	0.2696	0.2536	0.2258	0.1862	0.1750
	WA_Res	0.0103	0.0104	0.0083	0.0072	0.0045	0.0034	0.0014	0.0014	0.0031	0.0072	0.0093	0.0097
3-Year	Klamath Falls_Com	0.0323	0.0312	0.0282	0.0200	0.0146	0.0077	0.0050	0.0040	0.0150	0.0242	0.0278	0.0308
	Klamath Falls_Ind	0.0920	0.1060	0.0627	0.0214	0.0420	0.0314	0.0606	0.1882	0.3807	0.4084	0.3605	0.2396
	Klamath Falls_Res	0.0087	0.0084	0.0077	0.0060	0.0049	0.0030	0.0012	0.0002	0.0023	0.0055	0.0075	0.0084
	LaGrande_Com	0.0420	0.0409	0.0347	0.0265	0.0171	0.0055	0.0013	0.0201	0.0049	0.0244	0.0323	0.0386
	LaGrande_Ind	-	-	-	-	1.9182	2.0468	4.6388	1.7754	1.9218	2.5342	0.1874	-
	LaGrande_Res	0.0092	0.0090	0.0076	0.0063	0.0049	0.0025	0.0009	0.0033	0.0005	0.0054	0.0079	0.0089
	Medford_Com	0.0450	0.0447	0.0367	0.0274	0.0205	0.0158	0.0172	0.0603	0.0235	0.0400	0.0417	0.0423
	Medford_Ind	0.0263	0.0513	0.0224	0.0185	0.0479	0.0861	0.1329	0.9330	0.2694	0.2727	0.1164	0.0445
	Medford_Res	0.0114	0.0110	0.0096	0.0080	0.0058	0.0041	0.0060	0.0072	0.0036	0.0082	0.0099	0.0108
	Roseburg_Com	0.0556	0.0564	0.0389	0.0392	0.0193	0.0197	0.0009	0.0771	0.0311	0.0349	0.0415	0.0434
	Roseburg_Ind	0.0397	0.0456	0.0017	0.0483	0.1199	0.2149	0.1283	0.5257	0.1917	0.1094	0.0252	0.0023
	Roseburg_Res	0.0129	0.0132	0.0096	0.0091	0.0053	0.0044	0.0010	0.0090	0.0063	0.0095	0.0112	0.0114
	ID_Com	0.0418	0.0432	0.0389	0.0266	0.0181	0.0182	0.0096	0.0127	0.0256	0.0310	0.0354	0.0402
	ID_Ind	0.2061	0.1907	0.2128	0.2193	0.2912	0.2234	0.1932	0.0905	0.1851	0.1939	0.2355	0.2065
	ID_Res	0.0104	0.0103	0.0090	0.0078	0.0055	0.0032	0.0022	0.0007	0.0037	0.0082	0.0097	0.0099
	WA_Com	0.0581	0.0595	0.0512	0.0382	0.0248	0.0172	0.0095	0.0098	0.0280	0.0443	0.0515	0.0560
	WA_Ind	0.1527	0.1756	0.1848	0.1668	0.1386	0.1656	0.0162	0.1805	0.2713	0.1832	0.1700	0.1633
	WA_Res	0.0101	0.0102	0.0086	0.0071	0.0046	0.0029	0.0014	0.0011	0.0037	0.0076	0.0094	0.0096
5-Year	Klamath Falls_Com	0.0311	0.0307	0.0276	0.0207	0.0129	0.0089	0.0037	0.0028	0.0153	0.0223	0.0273	0.0313
	Klamath Falls_Ind	0.0721	0.0955	0.0549	0.0445	0.0267	0.0459	0.0364	0.1169	0.3357	0.3034	0.2657	0.1936
	Klamath Falls_Res	0.0084	0.0082	0.0076	0.0061	0.0045	0.0030	0.0008	0.0001	0.0021	0.0053	0.0075	0.0084
	LaGrande_Com	0.0431	0.0418	0.0360	0.0283	0.0133	0.0071	0.0008	0.0538	0.0046	0.0228	0.0326	0.0393
	LaGrande_Ind	0.0033	-	-	-	1.1509	1.2281	11.1715	4.6440	2.6618	2.3656	0.1126	-
	LaGrande_Res	0.0093	0.0090	0.0078	0.0066	0.0053	0.0027	0.0005	0.0086	0.0004	0.0051	0.0080	0.0090
	Medford_Com	0.0430	0.0426	0.0359	0.0273	0.0184	0.0149	0.0103	0.0362	0.0210	0.0350	0.0392	0.0410
	Medford_Ind	0.0214	0.0428	0.0229	0.0244	0.0327	0.0799	0.0797	0.5598	0.2331	0.2198	0.1062	0.0396
	Medford_Res	0.0111	0.0107	0.0097	0.0079	0.0057	0.0037	0.0036	0.0043	0.0031	0.0074	0.0095	0.0106
	Roseburg_Com	0.0495	0.0495	0.0369	0.0335	0.0157	0.0132	0.0005	0.0463	0.0202	0.0281	0.0374	0.0424
	Roseburg_Ind	0.0239	0.0275	0.0040	0.0524	0.0799	0.1379	0.0770	0.3154	0.1166	0.0797	0.0355	0.0134
	Roseburg_Res	0.0117	0.0116	0.0091	0.0080	0.0042	0.0029	0.0006	0.0054	0.0041	0.0080	0.0103	0.0110
	ID_Com	0.0419	0.0423	0.0382	0.0281	0.0187	0.0194	0.0087	0.0223	0.0225	0.0283	0.0352	0.0403
	ID_Ind	0.1933	0.2113	0.1848	0.1842	0.2640	0.2046	0.1772	0.1154	0.2189	0.1558	0.2098	0.1859
	ID_Res	0.0102	0.0100	0.0091	0.0080	0.0052	0.0028	0.0018	0.0005	0.0037	0.0080	0.0096	0.0099
	WA_Com	0.0566	0.0578	0.0501	0.0396	0.0254	0.0185	0.0085	0.0163	0.0272	0.0406	0.0503	0.0544
	WA_Ind	0.1485	0.1649	0.1698	0.1573	0.1416	0.1530	0.0266	0.1193	0.2650	0.1362	0.1478	0.1410
	WA_Res	0.0101	0.0099	0.0088	0.0075	0.0046	0.0028	0.0013	0.0016	0.0037	0.0075	0.0093	0.0097

APPENDIX 2.3: RESIDENTIAL BASE COEFFICIENT CALCULATION

	Idaho	Klamath Falls	La Grande	Medford	Roseburg	Washington
Average Residential Demand (July & August)						
2017	3,140	458	439	2,596	486	6,574
2018	3,506	495	478	2,603	474	7,074
2019	3,568	562	457	2,647	667	7,133
2020	4,122	599	456	3,463	977	7,514
2021	3,653	533	348	3,199	890	6,745
Average Residential Customers (July & August)						
2017	72,686	14,397	6,565	53,920	13,337	145,535
2018	74,722	14,619	6,660	54,837	13,518	149,924
2019	76,651	14,823	6,695	55,737	13,685	153,598
2020	78,641	15,207	6,778	56,659	13,973	155,954
2021	80,962	15,400	6,837	56,521	14,106	158,518
Residential Base Coefficients						
2 Year	0.0487	0.0370	0.0591	0.0589	0.0665	0.0453
3 Year	0.0480	0.0373	0.0621	0.0551	0.0606	0.0457
5 Year	0.0469	0.0355	0.0650	0.0523	0.0509	0.0459

APPENDIX 2.3: COMMERCIAL BASE COEFFICIENT CALCULATION

	Idaho	Klamath Falls	La Grande	Medford	Roseburg	Washington
Average Commercial Demand (July & August)						
2017	3,464	361	338	2,487	628	5,380
2018	3,328	401	367	2,481	597	5,605
2019	3,663	448	359	2,633	817	5,979
2020	3,198	417	269	2,929	988	5,020
2021	3,311	420	266	3,110	1,080	5,339
Average Commercial Customers (July & August)						
2017	8,881	1,762	914	6,850	2,141	14,551
2018	8,958	1,753	916	6,906	2,146	14,721
2019	9,092	1,770	923	6,987	2,150	14,863
2020	9,215	1,781	938	7,051	2,187	14,945
2021	9,365	1,791	932	6,952	2,188	15,120
Commercial Base Coefficients						
2 Year	0.3503	0.2345	0.2864	0.4313	0.4728	0.3446
3 Year	0.3676	0.2408	0.3202	0.4132	0.4423	0.3637
5 Year	0.3727	0.2312	0.3459	0.3926	0.3802	0.3682

APPENDIX 2.3: INDUSTRIAL BASE COEFFICIENT CALCULATION

	Idaho	Klamath Falls	La Grande	Medford	Roseburg	Washington
	Average Industrial Demand (July & August)					
2017	495	26	202	68	5	427
2018	520	28	86	49	3	421
2019	520	27	159	58	5	410
2020	424	25	126	65	11	424
2021	365	31	147	66	11	445
	Average Industrial Customers (July & August)					
2017	93	7	3	15	2	133
2018	92	7	3	14	1	130
2019	91	6	4	14	2	129
2020	87	6	3	14	2	128
2021	69	6	4	14	2	96
	Industrial Base Coefficients					
2 Year	5.0548	4.6530	39.0120	4.7388	5.6583	3.8875
3 Year	5.3096	4.6222	41.1053	4.5284	4.6714	3.6325
5 Year	5.3835	4.2819	46.4154	4.3175	4.0766	3.4596

APPENDIX 2.4: HEATING DEGREE DAY DATA MONTHLY TABLES

WA/ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2023	1,093	1,030	829	546	292	133	16	23	164	532	870	1,145	6,672
2024	1,097	1,094	794	541	287	133	16	23	162	535	856	1,141	6,681
2025	1,090	1,020	831	543	284	132	15	22	159	536	854	1,140	6,626
2026	1,088	1,019	831	542	283	127	15	20	152	536	851	1,132	6,596
2027	1,097	1,010	824	538	282	128	14	19	149	532	848	1,125	6,566
2028	1,099	1,072	792	534	283	124	14	17	144	528	841	1,122	6,571
2029	1,091	1,007	818	524	282	119	14	14	144	527	842	1,106	6,488
2030	1,087	1,001	809	517	279	117	13	13	144	517	841	1,097	6,436
2031	1,092	1,002	808	514	270	109	11	11	139	517	835	1,094	6,402
2032	1,089	1,056	770	502	263	102	9	11	141	514	828	1,090	6,375
2033	1,090	990	799	500	259	98	8	10	142	512	827	1,089	6,323
2034	1,077	983	799	498	260	92	8	10	137	507	824	1,078	6,274
2035	1,080	973	799	494	261	89	8	9	139	512	819	1,077	6,260
2036	1,077	1,038	771	490	267	94	8	9	132	517	817	1,078	6,296
2037	1,079	981	806	502	270	92	6	9	128	513	822	1,064	6,270
2038	1,065	970	803	497	269	91	7	8	122	508	819	1,056	6,215
2039	1,073	961	797	492	276	88	6	7	117	504	814	1,053	6,189
2040	1,074	1,004	749	487	278	86	5	6	110	490	811	1,056	6,158
2041	1,079	942	781	486	275	83	3	5	111	487	808	1,057	6,115
2042	1,082	929	780	484	272	80	3	3	107	484	809	1,050	6,084
2043	1,076	924	777	486	269	76	3	3	107	482	810	1,039	6,052
2044	1,079	983	743	486	267	75	2	3	103	479	811	1,038	6,071
2045	1,083	926	777	485	267	71	2	2	102	477	809	1,038	6,040

Medford	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2023	771	607	529	368	180	59	8	9	60	294	602	903	4,389
2024	778	624	530	364	185	69	14	16	71	302	596	906	4,456
2025	779	602	539	371	192	79	21	24	80	308	593	905	4,491
2026	777	604	543	374	199	84	28	30	89	314	591	907	4,539
2027	778	601	538	375	209	94	35	38	97	318	591	906	4,580
2028	771	617	542	378	218	103	42	45	104	320	588	904	4,631
2029	767	596	536	377	225	110	50	51	116	325	589	897	4,639
2030	764	595	535	377	234	119	57	57	126	327	584	891	4,666
2031	773	597	535	375	235	124	63	63	134	334	583	894	4,709
2032	771	613	533	371	235	131	70	70	146	339	581	887	4,746
2033	769	591	530	375	242	136	78	77	158	346	582	887	4,771
2034	762	584	534	381	253	144	84	83	165	347	582	871	4,789
2035	761	586	540	388	263	153	90	89	175	358	585	875	4,864
2036	761	611	548	392	274	162	96	96	184	369	583	880	4,956
2037	766	595	552	404	285	170	102	102	193	372	588	874	5,003
2038	760	594	554	406	294	177	108	109	200	376	586	873	5,037
2039	764	587	552	407	305	185	113	115	208	381	586	869	5,073
2040	767	597	551	413	314	193	120	121	214	380	588	868	5,126
2041	770	576	548	420	321	200	126	127	224	389	584	870	5,155
2042	771	571	548	426	330	207	132	134	233	392	584	868	5,194
2043	766	568	545	426	327	206	130	132	233	390	584	861	5,170
2044	767	588	547	426	326	205	130	131	232	390	586	863	5,190
2045	768	572	546	427	326	202	129	130	230	388	583	862	5,163

La Grande	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2023	1,007	923	776	551	334	152	28	43	200	512	785	1,045	6,358
2024	1,013	977	745	549	335	161	36	53	208	517	777	1,045	6,415
2025	1,008	910	784	551	335	168	45	60	211	518	776	1,046	6,411
2026	1,009	908	786	553	339	170	53	67	215	519	774	1,039	6,433
2027	1,014	900	782	551	343	178	62	74	219	515	774	1,033	6,446
2028	1,006	960	753	552	349	184	71	81	223	517	770	1,030	6,495
2029	999	905	780	545	352	186	79	88	229	517	774	1,020	6,474
2030	995	904	774	541	354	192	85	94	238	511	772	1,013	6,475
2031	1,001	903	772	539	350	194	91	100	242	512	768	1,011	6,482
2032	996	956	736	531	346	194	98	107	253	510	760	1,004	6,491
2033	998	896	768	534	347	197	106	115	260	508	762	1,002	6,493
2034	986	892	770	533	351	201	113	123	266	501	761	990	6,486
2035	985	889	772	531	354	205	120	129	275	509	754	992	6,515
2036	983	950	746	530	360	215	127	136	278	515	749	991	6,581
2037	985	897	779	539	366	220	133	143	282	515	756	973	6,590
2038	968	894	782	538	369	226	141	151	285	510	754	964	6,581
2039	976	887	777	537	378	230	147	155	285	506	746	958	6,582
2040	978	932	734	534	382	234	153	162	288	492	741	958	6,587
2041	981	874	763	533	383	237	159	168	295	490	736	957	6,574
2042	981	862	757	531	383	244	165	171	299	489	735	952	6,570
2043	976	858	756	531	381	242	165	169	298	488	736	942	6,540
2044	981	913	725	531	380	241	164	167	296	487	737	943	6,564
2045	982	860	755	532	380	238	162	166	295	485	735	942	6,532

Roseburg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2023	679	563	506	371	202	81	12	11	67	290	538	822	4,143
2024	691	582	511	370	208	90	18	18	78	298	536	827	4,225
2025	698	561	519	375	214	97	25	26	86	304	537	832	4,273
2026	701	563	525	378	219	102	32	32	94	311	538	837	4,331
2027	708	561	521	379	226	111	38	39	103	314	540	840	4,381
2028	704	581	526	381	232	117	45	46	109	317	537	844	4,439
2029	703	562	523	379	237	121	52	52	119	322	543	842	4,454
2030	703	562	521	378	245	129	59	58	128	325	544	840	4,493
2031	715	568	521	376	247	133	65	64	136	330	548	847	4,551
2032	721	585	522	373	246	138	72	71	147	334	548	845	4,600
2033	726	564	520	376	251	142	79	77	158	341	553	849	4,636
2034	724	562	527	383	260	150	85	84	165	344	556	841	4,679
2035	728	567	534	389	270	157	90	90	176	356	562	847	4,765
2036	735	594	543	393	280	167	97	96	183	368	564	856	4,876
2037	742	582	549	405	290	173	102	103	193	375	573	855	4,940
2038	741	581	551	406	298	179	108	109	200	378	575	856	4,984
2039	751	578	550	409	308	186	114	115	208	384	577	857	5,037
2040	754	592	550	415	317	195	120	122	214	383	578	861	5,100
2041	765	573	548	422	324	201	126	127	224	390	579	865	5,144
2042	771	571	548	426	330	207	132	134	233	392	584	868	5,194
2043	766	568	545	426	327	206	130	132	233	390	584	861	5,170
2044	767	588	547	426	326	205	130	131	232	390	586	863	5,190
2045	768	572	546	427	326	202	129	130	230	388	583	862	5,163

Klamath Falls	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2023	1,045	860	808	651	422	205	40	61	231	563	854	1,202	6,940
2024	1,054	886	804	639	421	212	46	68	238	564	844	1,198	6,973
2025	1,049	850	809	639	418	217	53	73	239	561	838	1,196	6,942
2026	1,042	849	808	633	416	212	61	80	238	557	835	1,194	6,925
2027	1,041	841	795	627	418	218	68	86	240	552	830	1,189	6,906
2028	1,035	866	794	622	422	221	76	93	240	545	826	1,177	6,916
2029	1,023	822	784	613	420	221	85	98	246	543	826	1,165	6,847
2030	1,024	820	778	603	422	223	91	103	253	536	805	1,156	6,814
2031	1,026	820	771	594	413	222	96	108	252	536	797	1,156	6,791
2032	1,023	838	765	583	402	219	101	116	261	531	788	1,150	6,777
2033	1,019	804	761	580	401	217	108	123	270	529	785	1,144	6,742
2034	1,002	795	761	579	404	221	115	127	270	520	783	1,126	6,704
2035	1,002	795	762	577	404	223	122	133	277	522	781	1,128	6,726
2036	1,007	827	764	572	406	232	129	140	277	525	774	1,125	6,778
2037	1,004	803	765	578	408	237	132	146	277	519	775	1,116	6,760
2038	991	801	764	573	410	241	140	154	278	512	772	1,112	6,748
2039	997	791	756	568	416	244	146	159	278	506	767	1,109	6,737
2040	999	806	750	568	416	248	151	167	276	496	764	1,105	6,745
2041	1,002	778	744	569	419	251	156	174	282	495	756	1,104	6,730
2042	1,002	771	739	566	418	255	164	178	284	489	753	1,099	6,718
2043	998	767	741	565	412	255	162	177	284	487	753	1,095	6,695
2044	1,001	792	743	565	408	253	160	174	282	488	756	1,097	6,719
2045	1,001	769	740	565	408	251	161	174	280	485	754	1,097	6,685

APPENDIX 2.4: AVERAGE DAILY HEATING DEGREE DAY BY MOTH BY AREA

WA/ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	36	34	59	21	14	4	1	0	1	11	23	31
2	36	33	41	20	12	5	1	0	2	12	23	31
3	37	32	29	19	12	4	1	0	2	12	23	32
4	35	31	28	20	11	5	0	0	2	13	24	34
5	35	31	27	19	10	5	1	0	3	12	25	35
6	34	31	27	19	11	5	0	0	3	12	25	35
7	34	31	28	18	11	5	0	0	2	12	25	35
8	34	31	28	18	10	5	1	0	3	13	25	36
9	34	32	27	19	11	5	0	0	2	14	26	36
10	34	32	26	18	11	5	0	0	2	15	26	34
11	35	32	24	20	10	4	0	0	3	16	27	33
12	34	31	24	20	10	3	0	0	3	16	28	34
13	35	32	24	19	11	4	0	0	3	15	29	34
14	35	32	24	19	9	5	0	0	3	16	27	34
15	36	31	24	19	9	5	0	0	3	16	28	35
16	36	30	23	17	8	5	0	0	5	15	28	35
17	35	31	24	16	8	4	0	0	5	16	28	35
18	34	32	23	17	8	3	0	0	5	17	29	34
19	36	31	23	16	8	3	0	0	6	17	29	34
20	37	32	22	15	9	3	0	0	7	17	29	35
21	36	32	22	14	9	2	0	0	7	18	30	35
22	34	31	23	14	9	1	0	1	6	19	30	35
23	34	32	23	14	8	2	0	1	6	19	30	36
24	35	32	23	15	7	2	0	1	5	19	30	36
25	35	32	22	16	7	2	0	1	5	20	31	37
26	36	48	23	14	7	1	0	1	6	20	30	39
27	36	64	22	13	6	1	0	1	8	21	31	38
28	35	80	22	14	5	1	0	1	8	21	31	37
29	34	63	22	13	5	1	0	1	8	23	32	36
30	34		21	14	5	2	0	1	9	23	31	37
31	32		21		4		0	2		22		39

Medford	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	26	22	20	16	11	5	3	2	4	8	14	24
2	26	22	19	15	10	5	3	2	4	8	15	23
3	27	22	20	15	9	5	3	2	4	9	15	24
4	26	22	20	14	9	5	2	2	4	10	16	24
5	25	21	20	14	9	5	2	2	4	10	17	25
6	25	20	20	14	10	6	3	2	5	9	17	24
7	25	20	21	14	9	6	3	3	4	9	18	26
8	24	20	20	14	9	6	3	2	4	9	18	25
9	25	21	18	14	9	6	3	2	4	10	19	24
10	25	22	18	14	9	6	3	2	4	10	18	25
11	25	21	17	14	9	6	2	2	4	11	19	26
12	24	21	16	14	9	5	2	2	4	11	19	25
13	25	21	17	14	8	5	2	2	5	11	19	25
14	26	21	18	15	8	5	2	2	4	11	19	25
15	26	19	17	14	8	5	2	2	5	11	19	26
16	25	20	17	13	8	5	2	3	5	11	20	26
17	26	21	17	12	8	5	2	3	5	10	20	26
18	25	21	17	12	8	4	3	2	6	11	22	36
19	25	21	16	12	8	4	3	2	6	12	21	45
20	26	22	16	12	8	4	3	2	6	12	21	54
21	25	22	15	12	9	4	2	2	6	12	21	45
22	24	22	17	12	9	4	2	2	6	12	22	36
23	23	22	18	12	8	4	2	2	6	13	21	26
24	24	21	17	12	7	4	2	3	6	13	22	27
25	24	21	17	12	8	4	2	3	6	13	21	27
26	24	22	17	12	7	3	2	3	5	13	22	28
27	24	21	16	11	7	3	2	3	6	14	23	27
28	24	20	16	11	6	3	2	2	6	14	23	26
29	23	20	16	11	6	3	2	3	7	14	24	26
30	23		16	11	6	4	3	3	7	14	24	26
31	23		16		6		3	4		14		28

La Grande	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	34	30	54	21	16	7	4	2	6	13	21	28
2	34	30	38	20	14	7	5	3	6	13	20	28
3	34	29	27	20	14	7	4	4	6	13	21	30
4	34	28	27	19	13	7	3	3	6	15	22	30
5	33	28	25	19	13	7	3	3	7	15	22	31
6	33	27	26	19	14	8	3	3	7	14	23	31
7	31	28	26	18	13	8	4	3	7	14	24	31
8	30	28	26	19	13	8	4	4	7	15	23	32
9	31	29	26	19	14	8	3	3	7	15	24	32
10	31	29	25	19	13	9	3	3	7	15	24	31
11	32	29	23	20	12	8	3	3	8	17	24	31
12	32	29	22	20	12	6	3	4	8	17	24	31
13	32	29	22	20	12	7	4	3	8	15	26	31
14	32	28	23	20	12	8	3	3	8	15	25	32
15	33	28	22	19	12	8	3	3	8	16	25	32
16	32	27	22	19	11	8	3	4	9	15	27	33
17	32	28	23	17	10	7	3	4	8	15	26	33
18	31	30	23	17	11	7	3	4	9	16	26	32
19	32	29	23	18	11	7	5	4	10	16	26	32
20	32	29	22	17	12	6	3	3	10	15	27	32
21	32	29	21	17	12	7	3	4	10	17	28	31
22	32	29	22	15	12	5	3	3	10	18	27	33
23	31	29	23	16	11	6	3	4	10	18	27	34
24	32	29	22	17	11	6	3	4	10	19	28	34
25	32	29	22	17	10	5	3	5	10	18	28	34
26	32	44	22	16	10	5	3	5	10	19	28	34
27	33	58	21	15	9	5	3	5	10	20	28	34
28	33	73	21	15	9	5	3	5	11	19	29	33
29	31	57	21	16	8	4	3	4	11	20	29	34
30	31		22	16	8	5	3	5	11	20	29	34
31	30		21		8		3	6		20		37

Roseburg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	25	21	20	15	11	6	3	2	4	8	14	23
2	25	21	19	15	10	5	3	2	4	9	14	23
3	25	21	20	15	10	6	3	2	4	9	15	22
4	25	21	19	14	10	6	2	2	4	10	15	23
5	24	20	19	14	10	6	3	2	4	10	16	24
6	23	19	20	13	10	6	3	3	5	9	16	24
7	23	19	20	14	10	6	3	3	4	9	18	24
8	23	19	19	14	10	6	3	2	4	9	17	24
9	24	20	17	14	9	6	3	2	5	10	18	23
10	24	21	18	14	9	7	3	2	5	11	18	24
11	24	19	16	15	9	6	2	2	5	11	18	24
12	23	20	16	14	9	5	2	2	5	11	18	24
13	24	21	17	14	9	5	2	2	5	11	18	24
14	25	20	17	15	9	5	2	2	4	11	18	24
15	25	19	16	14	9	6	2	2	5	11	18	25
16	24	20	17	13	8	6	2	3	5	11	19	25
17	24	19	17	12	8	5	2	3	5	11	19	25
18	23	21	17	12	8	5	3	2	6	11	20	35
19	24	21	16	12	9	4	3	2	6	11	19	45
20	25	21	16	12	8	4	3	2	6	11	20	54
21	24	21	15	12	9	4	2	3	6	12	20	44
22	23	21	16	12	9	4	2	2	6	12	21	35
23	22	21	17	12	8	4	2	2	6	13	20	25
24	23	21	16	12	7	4	2	3	6	13	21	26
25	23	21	16	12	8	4	2	3	6	13	20	26
26	23	21	16	12	7	4	2	3	5	13	20	27
27	23	20	16	11	7	3	2	3	6	14	22	25
28	23	20	15	11	7	3	2	2	6	13	22	25
29	22	20	16	11	6	3	2	3	7	14	23	25
30	21		16	12	6	4	3	3	7	14	22	25
31	22		16		6		3	4		14		26

Klamath Falls	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	35	30	28	22	17	8	5	3	6	14	21	30
2	35	30	28	22	16	8	4	3	6	14	23	30
3	34	29	29	22	14	8	4	3	6	14	22	30
4	34	29	27	21	14	9	3	3	6	15	24	31
5	33	28	26	21	14	9	3	4	7	15	25	32
6	34	27	28	20	15	9	4	4	7	13	24	32
7	33	28	28	21	15	10	5	4	6	14	25	32
8	31	27	28	20	14	10	5	3	7	15	25	33
9	34	28	27	21	15	10	4	3	6	15	26	32
10	33	29	26	21	15	9	4	3	7	16	25	32
11	34	28	24	21	14	8	3	3	7	17	26	33
12	33	29	23	21	13	8	4	3	7	17	26	32
13	33	29	24	22	13	9	4	3	8	16	25	32
14	34	29	24	22	14	9	3	3	8	16	25	33
15	34	28	24	21	14	10	3	4	9	16	26	33
16	33	28	24	20	13	9	3	3	10	15	27	34
17	33	30	25	19	14	8	3	4	10	16	27	34
18	32	30	24	19	14	8	4	3	11	17	28	46
19	32	29	23	19	14	7	4	4	11	17	27	58
20	33	31	23	19	14	7	4	4	11	17	27	70
21	33	29	22	17	15	6	3	4	11	18	28	58
22	32	29	24	17	14	6	3	4	11	18	28	47
23	31	30	25	17	13	5	3	5	11	19	28	35
24	31	29	24	19	12	6	3	5	10	19	29	35
25	33	29	24	20	13	7	2	5	10	19	28	35
26	33	30	24	18	12	5	3	5	10	19	29	37
27	33	30	23	17	12	5	3	5	10	21	30	35
28	32	29	22	18	10	5	3	4	10	21	30	35
29	31	29	23	18	9	5	3	5	11	22	31	35
30	31		23	18	9	5	3	6	12	21	30	35
31	31		23		9		4	7		21		37

APPENDIX 2.5: ANNUAL, AVERAGE DAY, AND PEAK DAY DEMAND (MDTH, NET OF DSM) – CASE PRS

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	1,453	3.98	14.47	898	2.46	8.37	5,742	15.73	56.07	1,505	4.12	15.43
2024	1,468	4.01	14.58	908	2.48	8.42	5,856	16.00	56.72	1,527	4.17	15.47
2025	1,469	4.02	14.68	910	2.49	8.47	5,930	16.25	57.37	1,536	4.21	15.51
2026	1,475	4.04	14.77	915	2.51	8.51	6,027	16.51	58.00	1,551	4.25	15.55
2027	1,478	4.05	14.86	920	2.52	8.55	6,110	16.74	58.59	1,562	4.28	15.59
2028	1,486	4.06	14.94	929	2.54	8.59	6,208	16.96	59.17	1,578	4.31	15.62
2029	1,477	4.05	15.02	928	2.54	8.63	6,252	17.13	59.73	1,580	4.33	15.66
2030	1,476	4.05	15.09	932	2.55	8.68	6,320	17.31	60.29	1,588	4.35	15.69
2031	1,479	4.05	15.16	936	2.57	8.72	6,410	17.56	60.84	1,604	4.39	15.72
2032	1,484	4.05	15.24	942	2.57	8.76	6,498	17.76	61.38	1,619	4.42	15.75
2033	1,481	4.06	15.32	944	2.59	8.80	6,555	17.96	61.91	1,625	4.45	15.78
2034	1,479	4.05	15.39	947	2.59	8.84	6,613	18.12	62.44	1,634	4.48	15.81
2035	1,487	4.07	15.47	953	2.61	8.88	6,724	18.42	62.96	1,654	4.53	15.85
2036	1,503	4.11	15.54	964	2.63	8.92	6,864	18.75	63.49	1,683	4.60	15.88
2037	1,503	4.12	15.62	966	2.65	8.96	6,943	19.02	64.00	1,697	4.65	15.91
2038	1,506	4.13	15.70	969	2.65	9.00	7,019	19.23	64.50	1,707	4.68	15.95
2039	1,509	4.13	15.77	973	2.66	9.05	7,097	19.44	65.00	1,721	4.72	15.98
2040	1,518	4.15	15.85	979	2.67	9.09	7,200	19.67	65.49	1,739	4.75	16.01
2041	1,518	4.16	15.92	979	2.68	9.12	7,261	19.89	65.97	1,748	4.79	16.04
2042	1,521	4.17	16.00	982	2.69	9.17	7,342	20.11	66.45	1,762	4.83	16.08
2043	1,536	4.21	16.13	990	2.71	9.24	7,430	20.36	67.18	1,776	4.86	16.18
2044	1,551	4.24	16.20	999	2.73	9.28	7,524	20.56	67.64	1,790	4.89	16.21
2045	1,550	4.25	16.26	998	2.73	9.31	7,550	20.68	68.08	1,787	4.90	16.24

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	9,597	26.29	90.11	19,436	53.25	219.89	10,441	28.61	111.89	39,475	108.15	378.37
2024	9,759	26.67	90.96	19,604	53.56	221.98	10,644	29.08	113.86	40,007	109.31	382.50
2025	9,845	26.97	91.76	19,549	53.56	224.00	10,724	29.38	115.68	40,118	109.91	387.11
2026	9,968	27.31	92.59	19,620	53.75	226.17	10,855	29.74	117.40	40,443	110.80	391.42
2027	10,069	27.59	93.25	19,657	53.85	228.09	10,956	30.02	118.91	40,682	111.46	395.42
2028	10,202	27.87	94.03	19,816	54.14	230.01	11,118	30.38	120.40	41,136	112.39	398.71
2029	10,237	28.05	94.62	19,675	53.90	231.84	11,128	30.49	121.83	41,040	112.44	402.47
2030	10,316	28.26	95.36	19,652	53.84	233.77	11,192	30.66	123.22	41,159	112.76	406.13
2031	10,429	28.57	95.94	19,726	54.04	235.75	11,295	30.95	124.63	41,451	113.56	410.08
2032	10,544	28.81	96.58	19,821	54.15	237.77	11,422	31.21	126.10	41,786	114.17	413.76
2033	10,604	29.05	97.24	19,790	54.22	239.76	11,475	31.44	127.55	41,869	114.71	417.06
2034	10,672	29.24	97.91	19,785	54.21	241.80	11,549	31.64	129.02	42,006	115.09	421.29
2035	10,819	29.64	98.65	19,864	54.42	243.83	11,665	31.96	130.49	42,348	116.02	425.34
2036	11,014	30.09	99.23	20,122	54.98	245.85	11,867	32.42	131.97	43,003	117.49	429.59
2037	11,109	30.44	99.89	20,130	55.15	247.83	11,947	32.73	133.42	43,186	118.32	433.40
2038	11,201	30.69	100.46	20,082	55.02	249.84	12,005	32.89	134.87	43,289	118.60	436.76
2039	11,300	30.96	101.13	20,128	55.14	251.80	12,106	33.17	136.32	43,533	119.27	439.47
2040	11,436	31.25	101.86	20,209	55.22	253.75	12,216	33.38	137.75	43,861	119.84	442.56
2041	11,507	31.53	102.55	20,173	55.27	255.68	12,270	33.62	139.15	43,950	120.41	446.40
2042	11,607	31.80	103.14	20,193	55.32	257.58	12,356	33.85	140.55	44,155	120.97	450.20
2043	11,732	32.14	104.08	20,210	55.37	259.53	12,440	34.08	141.99	44,382	121.59	454.17
2044	11,864	32.41	104.65	20,424	55.80	261.44	12,624	34.49	143.42	44,912	122.71	457.25
2045	11,885	32.56	105.23	20,398	55.89	263.32	12,698	34.79	144.92	44,981	123.24	460.21

APPENDIX 2.5: ANNUAL, AVERAGE DAY, AND PEAK DAY DEMAND (MDTH, NET OF DSM) – CASE AVERAGE

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	1,434	3.93	8.56	884	2.42	4.89	5,632	15.43	31.75	1,468	4.02	8.31
2024	1,452	3.97	8.63	892	2.44	4.92	5,726	15.64	32.12	1,481	4.05	8.35
2025	1,455	3.99	8.69	893	2.45	4.94	5,770	15.81	32.53	1,479	4.05	8.38
2026	1,465	4.01	8.75	897	2.46	4.96	5,840	16.00	32.95	1,484	4.07	8.41
2027	1,474	4.04	8.80	901	2.47	4.99	5,907	16.18	33.35	1,489	4.08	8.44
2028	1,490	4.07	8.85	909	2.48	5.01	5,999	16.39	33.72	1,501	4.10	8.47
2029	1,490	4.08	8.89	909	2.49	5.04	6,034	16.53	34.09	1,499	4.11	8.50
2030	1,498	4.10	8.94	913	2.50	5.06	6,096	16.70	34.45	1,503	4.12	8.53
2031	1,505	4.12	8.98	917	2.51	5.08	6,159	16.87	34.81	1,508	4.13	8.55
2032	1,521	4.15	9.03	925	2.53	5.11	6,250	17.08	35.17	1,520	4.15	8.58
2033	1,521	4.17	9.07	925	2.53	5.13	6,282	17.21	35.52	1,517	4.16	8.61
2034	1,529	4.19	9.12	929	2.55	5.16	6,343	17.38	35.88	1,522	4.17	8.64
2035	1,537	4.21	9.17	933	2.56	5.18	6,406	17.55	36.23	1,527	4.18	8.67
2036	1,552	4.24	9.22	941	2.57	5.21	6,499	17.76	36.59	1,540	4.21	8.70
2037	1,553	4.25	9.27	942	2.58	5.23	6,530	17.89	36.94	1,538	4.21	8.73
2038	1,561	4.28	9.31	946	2.59	5.26	6,591	18.06	37.29	1,543	4.23	8.76
2039	1,569	4.30	9.36	951	2.60	5.28	6,651	18.22	37.64	1,548	4.24	8.79
2040	1,586	4.33	9.41	959	2.62	5.31	6,742	18.42	37.98	1,561	4.26	8.82
2041	1,586	4.34	9.46	959	2.63	5.33	6,769	18.55	38.31	1,558	4.27	8.84
2042	1,594	4.37	9.51	963	2.64	5.35	6,828	18.71	38.65	1,564	4.28	8.88
2043	1,613	4.42	9.61	974	2.67	5.41	6,935	19.00	39.21	1,583	4.34	8.97
2044	1,628	4.45	9.65	982	2.68	5.44	7,025	19.19	39.54	1,595	4.36	9.00
2045	1,627	4.46	9.69	982	2.69	5.46	7,047	19.31	39.86	1,592	4.36	9.03

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	9,417	25.80	52.48	19,125	52.40	113.87	10,284	28.18	59.52	38,827	106.38	225.87
2024	9,550	26.09	53.00	19,315	52.77	114.87	10,498	28.68	60.49	39,364	107.55	228.36
2025	9,596	26.29	53.52	19,329	52.95	115.84	10,610	29.07	61.35	39,534	108.31	230.70
2026	9,687	26.54	54.02	19,454	53.30	116.93	10,766	29.49	62.22	39,907	109.33	233.17
2027	9,771	26.77	54.50	19,547	53.55	117.83	10,897	29.86	62.99	40,216	110.18	235.32
2028	9,899	27.05	54.96	19,729	53.90	118.74	11,073	30.25	63.73	40,701	111.21	237.43
2029	9,932	27.21	55.41	19,728	54.05	119.62	11,151	30.55	64.45	40,811	111.81	239.48
2030	10,010	27.43	55.85	19,829	54.33	120.57	11,275	30.89	65.18	41,114	112.64	241.60
2031	10,088	27.64	56.28	19,938	54.62	121.57	11,404	31.24	65.94	41,430	113.51	243.80
2032	10,215	27.91	56.72	20,140	55.03	122.58	11,586	31.66	66.71	41,941	114.59	246.02
2033	10,244	28.07	57.16	20,166	55.25	123.63	11,672	31.98	67.50	42,082	115.29	248.30
2034	10,323	28.28	57.60	20,286	55.58	124.69	11,809	32.35	68.31	42,419	116.22	250.61
2035	10,403	28.50	58.05	20,408	55.91	125.76	11,947	32.73	69.12	42,757	117.14	252.92
2036	10,533	28.78	58.50	20,619	56.34	126.80	12,136	33.16	69.92	43,288	118.27	255.22
2037	10,562	28.94	58.94	20,643	56.56	127.84	12,222	33.48	70.73	43,427	118.98	257.51
2038	10,641	29.15	59.38	20,762	56.88	128.89	12,358	33.86	71.53	43,761	119.89	259.80
2039	10,719	29.37	59.82	20,876	57.20	129.91	12,492	34.22	72.31	44,087	120.79	262.04
2040	10,847	29.64	60.25	21,083	57.60	130.91	12,677	34.64	73.08	44,607	121.88	264.23
2041	10,872	29.79	60.67	21,098	57.80	131.91	12,755	34.94	73.85	44,724	122.53	266.44
2042	10,948	29.99	61.10	21,204	58.09	132.88	12,883	35.30	74.62	45,036	123.39	268.59
2043	11,104	30.42	61.93	21,320	58.41	133.91	13,017	35.66	75.41	45,442	124.50	271.25
2044	11,230	30.68	62.34	21,529	58.82	134.89	13,207	36.08	76.21	45,966	125.59	273.44
2045	11,249	30.82	62.74	21,534	59.00	135.85	13,292	36.42	77.08	46,075	126.23	275.68

APPENDIX 2.5: ANNUAL, AVERAGE DAY, AND PEAK DAY DEMAND (MDTH, NET OF DSM) – CASE HIGH GROWTH

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	1,464	4.01	14.59	914	2.51	8.46	5,758	15.77	56.25	1,516	4.15	15.55
2024	1,483	4.05	14.75	945	2.58	8.53	5,879	16.06	56.96	1,543	4.21	15.64
2025	1,492	4.09	14.91	951	2.61	8.65	5,963	16.34	57.69	1,558	4.27	15.73
2026	1,502	4.12	15.06	977	2.68	8.71	6,067	16.62	58.39	1,577	4.32	15.82
2027	1,512	4.14	15.20	987	2.70	8.83	6,160	16.88	59.07	1,596	4.37	15.91
2028	1,525	4.17	15.33	1,017	2.78	8.89	6,267	17.12	59.73	1,617	4.42	15.99
2029	1,523	4.17	15.47	1,022	2.80	9.00	6,320	17.31	60.37	1,625	4.45	16.08
2030	1,527	4.18	15.60	1,047	2.87	9.07	6,396	17.52	61.01	1,639	4.49	16.16
2031	1,537	4.21	15.74	1,057	2.90	9.19	6,497	17.80	61.64	1,661	4.55	16.25
2032	1,547	4.23	15.87	1,085	2.96	9.25	6,595	18.02	62.26	1,682	4.60	16.33
2033	1,550	4.25	16.01	1,092	2.99	9.36	6,662	18.25	62.89	1,695	4.64	16.42
2034	1,552	4.25	16.13	1,117	3.06	9.43	6,729	18.44	63.50	1,710	4.68	16.50
2035	1,569	4.30	16.28	1,129	3.09	9.55	6,852	18.77	64.12	1,738	4.76	16.59
2036	1,589	4.34	16.41	1,164	3.18	9.62	7,003	19.13	64.73	1,774	4.85	16.67
2037	1,597	4.37	16.55	1,172	3.21	9.73	7,094	19.43	65.33	1,794	4.92	16.76
2038	1,604	4.40	16.68	1,198	3.28	9.80	7,180	19.67	65.93	1,811	4.96	16.85
2039	1,615	4.42	16.83	1,208	3.31	9.92	7,270	19.92	66.52	1,833	5.02	16.94
2040	1,630	4.45	16.96	1,238	3.38	9.99	7,385	20.18	67.10	1,858	5.08	17.02
2041	1,636	4.48	17.11	1,244	3.41	10.10	7,458	20.43	67.69	1,874	5.14	17.11
2042	1,644	4.50	17.24	1,271	3.48	10.17	7,550	20.68	68.26	1,895	5.19	17.20
2043	1,667	4.57	17.44	1,283	3.52	10.32	7,650	20.96	69.08	1,916	5.25	17.36
2044	1,688	4.61	17.57	1,315	3.59	10.38	7,756	21.19	69.64	1,937	5.29	17.44
2045	1,694	4.64	17.71	1,319	3.61	10.50	7,794	21.35	70.18	1,941	5.32	17.53

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	9,651	26.44	90.61	19,519	53.48	220.72	10,542	28.88	112.77	39,712	108.80	380.29
2024	9,850	26.91	91.67	19,715	53.87	223.29	10,799	29.50	115.30	40,363	110.28	385.56
2025	9,963	27.30	92.69	19,689	53.94	225.79	10,932	29.95	117.69	40,584	111.19	391.39
2026	10,124	27.74	93.74	19,787	54.21	228.46	11,119	30.46	120.00	41,030	112.41	396.90
2027	10,254	28.09	94.61	19,854	54.40	230.90	11,277	30.89	122.12	41,385	113.38	402.18
2028	10,426	28.49	95.62	20,045	54.77	233.34	11,499	31.42	124.24	41,970	114.67	406.71
2029	10,490	28.74	96.43	19,928	54.60	235.69	11,565	31.69	126.31	41,983	115.02	411.81
2030	10,608	29.06	97.40	19,932	54.61	238.17	11,688	32.02	128.36	42,228	115.69	416.77
2031	10,752	29.46	98.21	20,039	54.90	240.69	11,853	32.47	130.44	42,644	116.83	422.11
2032	10,908	29.80	99.08	20,163	55.09	243.27	12,043	32.90	132.60	43,114	117.80	427.14
2033	10,999	30.13	99.97	20,162	55.24	245.83	12,157	33.31	134.76	43,317	118.68	431.88
2034	11,108	30.43	100.88	20,184	55.30	248.43	12,293	33.68	136.95	43,585	119.41	437.52
2035	11,288	30.93	101.86	20,294	55.60	251.05	12,476	34.18	139.15	44,058	120.71	443.07
2036	11,530	31.50	102.69	20,593	56.26	253.66	12,752	34.84	141.39	44,874	122.61	448.79
2037	11,657	31.94	103.58	20,630	56.52	256.25	12,899	35.34	143.62	45,186	123.80	454.15
2038	11,794	32.31	104.40	20,606	56.45	258.86	13,022	35.68	145.86	45,422	124.44	459.02
2039	11,926	32.67	105.31	20,681	56.66	261.45	13,193	36.14	148.11	45,800	125.48	463.31
2040	12,110	33.09	106.30	20,796	56.82	264.02	13,376	36.55	150.36	46,282	126.45	467.95
2041	12,213	33.46	107.24	20,787	56.95	266.59	13,498	36.98	152.60	46,499	127.39	473.44
2042	12,359	33.86	108.09	20,836	57.09	269.14	13,657	37.42	154.86	46,852	128.36	478.87
2043	12,516	34.29	109.28	20,881	57.21	271.75	13,815	37.85	157.18	47,212	129.35	484.55
2044	12,696	34.69	110.12	21,138	57.75	274.33	14,085	38.48	159.50	47,919	130.93	489.28
2045	12,748	34.93	110.95	21,140	57.92	276.88	14,234	39.00	161.91	48,121	131.84	493.98

APPENDIX 2.5: ANNUAL, AVERAGE DAY, AND PEAK DAY DEMAND (MDTH, NET OF DSM) – CASE ELECTRIFICATION

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	1,453	3.98	14.47	898	2.46	8.37	5,742	15.73	56.07	1,505	4.12	15.43
2024	1,468	4.01	14.58	908	2.48	8.42	5,856	16.00	56.72	1,527	4.17	15.47
2025	1,429	3.91	14.28	889	2.43	8.25	5,739	15.72	55.50	1,499	4.11	15.14
2026	1,396	3.82	13.99	872	2.39	8.09	5,643	15.46	54.31	1,477	4.05	14.82
2027	1,362	3.73	13.71	855	2.34	7.92	5,542	15.18	53.14	1,453	3.98	14.50
2028	1,335	3.65	13.43	841	2.30	7.72	5,456	14.91	51.99	1,433	3.92	14.18
2029	1,290	3.53	13.13	820	2.25	7.56	5,324	14.59	50.86	1,400	3.84	13.87
2030	1,256	3.44	12.86	801	2.19	7.41	5,215	14.29	49.75	1,374	3.76	13.57
2031	1,227	3.36	12.60	781	2.14	7.26	5,128	14.05	48.68	1,355	3.71	13.28
2032	1,200	3.28	12.34	766	2.09	7.11	5,041	13.77	47.62	1,335	3.65	12.99
2033	1,167	3.20	12.09	748	2.05	6.96	4,932	13.51	46.59	1,309	3.59	12.71
2034	1,135	3.11	11.85	733	2.01	6.82	4,825	13.22	45.58	1,285	3.52	12.44
2035	1,114	3.05	11.61	721	1.97	6.69	4,762	13.05	44.61	1,271	3.48	12.17
2036	1,097	3.00	11.37	712	1.94	6.55	4,718	12.89	43.66	1,263	3.45	11.91
2037	1,070	2.93	11.14	697	1.91	6.42	4,633	12.69	42.73	1,243	3.41	11.66
2038	1,045	2.86	10.92	684	1.87	6.30	4,548	12.46	41.82	1,222	3.35	11.41
2039	1,019	2.79	10.68	669	1.83	6.17	4,464	12.23	40.93	1,201	3.29	11.16
2040	999	2.73	10.47	658	1.80	6.05	4,400	12.02	40.05	1,186	3.24	10.92
2041	975	2.67	10.26	644	1.76	5.92	4,311	11.81	39.20	1,164	3.19	10.69
2042	952	2.61	10.05	629	1.72	5.81	4,235	11.60	38.36	1,146	3.14	10.46
2043	943	2.58	9.91	620	1.70	5.72	4,187	11.47	37.80	1,133	3.10	10.31
2044	929	2.54	9.71	612	1.67	5.61	4,120	11.26	36.99	1,116	3.05	10.09
2045	906	2.48	9.51	595	1.63	5.50	4,020	11.01	36.20	1,089	2.98	9.88

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	9,597	26.29	90.11	19,459	53.31	219.89	10,441	28.61	111.89	39,498	108.21	378.37
2024	9,759	26.67	90.96	19,681	53.77	221.74	10,644	29.08	113.86	40,085	109.52	382.26
2025	9,556	26.18	89.02	19,118	52.38	217.12	10,724	29.38	115.68	39,398	107.94	378.84
2026	9,389	25.72	87.18	18,700	51.23	212.78	10,855	29.74	117.40	38,944	106.70	375.26
2027	9,211	25.24	85.25	18,254	50.01	208.37	10,956	30.02	118.91	38,420	105.26	371.59
2028	9,064	24.77	83.44	17,930	48.99	204.07	11,118	30.38	120.40	38,112	104.13	367.37
2029	8,834	24.20	81.55	17,359	47.56	199.78	11,128	30.49	121.83	37,321	102.25	363.73
2030	8,646	23.69	79.84	16,910	46.33	195.68	11,192	30.66	123.22	36,748	100.68	360.11
2031	8,490	23.26	78.07	16,536	45.30	191.70	11,295	30.95	124.63	36,322	99.51	356.83
2032	8,342	22.79	76.37	16,202	44.27	187.84	11,422	31.21	126.10	35,965	98.27	353.47
2033	8,155	22.34	74.75	15,770	43.21	184.05	11,475	31.44	127.55	35,400	96.99	349.93
2034	7,978	21.86	73.16	15,379	42.13	180.37	11,549	31.64	129.02	34,906	95.63	347.19
2035	7,867	21.55	71.69	15,061	41.26	176.79	11,665	31.96	130.49	34,593	94.77	344.45
2036	7,789	21.28	70.13	14,857	40.59	173.27	11,867	32.42	131.97	34,514	94.30	341.93
2037	7,643	20.94	68.66	14,499	39.72	169.80	11,947	32.73	133.42	34,090	93.40	339.18
2038	7,499	20.54	67.18	14,129	38.71	166.42	12,005	32.89	134.87	33,633	92.15	336.22
2039	7,353	20.15	65.76	13,819	37.86	163.09	12,106	33.17	136.32	33,278	91.17	332.94
2040	7,243	19.79	64.45	13,530	36.97	159.81	12,216	33.38	137.75	32,988	90.13	330.01
2041	7,093	19.43	63.15	13,184	36.12	156.61	12,270	33.62	139.15	32,547	89.17	327.65
2042	6,962	19.07	61.81	12,882	35.29	153.45	12,356	33.85	140.55	32,200	88.22	325.35
2043	6,883	18.86	60.89	12,589	34.49	150.39	12,440	34.08	141.99	31,912	87.43	323.41
2044	6,776	18.51	59.60	12,402	33.89	147.38	12,624	34.49	143.42	31,803	86.89	320.86
2045	6,609	18.11	58.32	12,095	33.14	144.40	12,698	34.79	144.92	31,401	86.03	318.37

APPENDIX 2.5: ANNUAL, AVERAGE DAY, AND PEAK DAY DEMAND (MDTH, NET OF DSM) – CASE HYBRID

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	1,453	3.98	14.47	898	2.46	8.37	5,742	15.73	56.07	1,505	4.12	15.43
2024	1,468	4.01	14.58	908	2.48	8.42	5,856	16.00	56.72	1,527	4.17	15.47
2025	1,451	3.98	14.65	898	2.46	8.45	5,779	15.83	57.18	1,501	4.11	15.47
2026	1,440	3.94	14.72	891	2.44	8.47	5,718	15.67	57.61	1,481	4.06	15.48
2027	1,425	3.90	14.78	883	2.42	8.49	5,655	15.49	58.02	1,460	4.00	15.48
2028	1,417	3.87	14.84	878	2.40	8.47	5,596	15.29	58.42	1,442	3.94	15.48
2029	1,387	3.80	14.87	865	2.37	8.49	5,492	15.05	58.81	1,412	3.87	15.48
2030	1,371	3.76	14.92	855	2.34	8.52	5,400	14.80	59.19	1,387	3.80	15.48
2031	1,356	3.71	14.97	843	2.31	8.54	5,360	14.69	59.56	1,376	3.77	15.47
2032	1,343	3.67	15.03	836	2.28	8.56	5,291	14.46	59.94	1,361	3.72	15.47
2033	1,321	3.62	15.08	827	2.27	8.58	5,210	14.27	60.30	1,339	3.67	15.47
2034	1,305	3.57	15.13	818	2.24	8.61	5,057	13.85	60.66	1,315	3.60	15.47
2035	1,297	3.55	15.19	813	2.23	8.63	5,014	13.74	61.03	1,305	3.58	15.47
2036	1,297	3.54	15.24	813	2.22	8.66	5,015	13.70	61.40	1,302	3.56	15.48
2037	1,285	3.52	15.30	805	2.21	8.68	4,970	13.62	61.76	1,285	3.52	15.48
2038	1,272	3.48	15.35	798	2.19	8.71	4,897	13.42	62.11	1,264	3.46	15.48
2039	1,258	3.45	15.39	789	2.16	8.73	4,816	13.20	62.46	1,258	3.45	15.49
2040	1,252	3.42	15.45	787	2.15	8.76	4,828	13.19	62.80	1,255	3.43	15.49
2041	1,237	3.39	15.50	778	2.13	8.78	4,775	13.08	63.14	1,249	3.42	15.49
2042	1,229	3.37	15.56	771	2.11	8.81	4,711	12.91	63.48	1,243	3.41	15.50
2043	1,229	3.37	15.67	767	2.10	8.86	4,631	12.69	64.06	1,224	3.35	15.57
2044	1,232	3.37	15.72	767	2.09	8.89	4,585	12.53	64.38	1,211	3.31	15.58
2045	1,220	3.34	15.76	754	2.06	8.91	4,517	12.38	64.69	1,190	3.26	15.58

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	9,597	26.29	90.11	19,467	53.33	219.89	10,441	28.61	111.89	39,505	108.23	378.37
2024	9,759	26.67	90.96	19,706	53.84	222.09	10,644	29.08	113.86	40,110	109.59	382.61
2025	9,630	26.38	91.48	19,476	53.36	223.80	10,724	29.38	115.68	39,830	109.12	385.87
2026	9,530	26.11	92.04	19,371	53.07	225.68	10,855	29.74	117.40	39,756	108.92	388.86
2027	9,423	25.82	92.44	19,245	52.73	227.33	10,956	30.02	118.91	39,623	108.56	391.59
2028	9,333	25.50	92.91	19,239	52.57	228.98	11,118	30.38	120.40	39,690	108.44	393.62
2029	9,157	25.09	93.23	18,927	51.86	230.52	11,128	30.49	121.83	39,212	107.43	396.12
2030	9,013	24.69	93.71	18,734	51.33	232.20	11,192	30.66	123.22	38,939	106.68	398.59
2031	8,935	24.48	94.05	18,665	51.14	233.92	11,295	30.95	124.63	38,895	106.56	401.32
2032	8,831	24.13	94.45	18,595	50.81	235.67	11,422	31.21	126.10	38,848	106.14	403.84
2033	8,697	23.83	94.88	18,429	50.49	237.43	11,475	31.44	127.55	38,601	105.76	406.12
2034	8,495	23.27	95.30	18,271	50.06	239.21	11,549	31.64	129.02	38,314	104.97	409.14
2035	8,429	23.09	95.82	18,205	49.88	241.01	11,665	31.96	130.49	38,300	104.93	412.06
2036	8,426	23.02	96.17	18,348	50.13	242.78	11,867	32.42	131.97	38,642	105.58	415.12
2037	8,345	22.86	96.61	18,221	49.92	244.54	11,947	32.73	133.42	38,513	105.52	417.87
2038	8,231	22.55	96.97	18,008	49.34	246.31	12,005	32.89	134.87	38,244	104.78	420.29
2039	8,120	22.25	97.39	17,914	49.08	248.06	12,106	33.17	136.32	38,140	104.49	422.28
2040	8,122	22.19	97.91	17,872	48.83	249.78	12,216	33.38	137.75	38,210	104.40	424.57
2041	8,040	22.03	98.40	17,705	48.51	251.50	12,270	33.62	139.15	38,015	104.15	427.38
2042	7,953	21.79	98.78	17,591	48.20	253.20	12,356	33.85	140.55	37,900	103.84	430.16
2043	7,852	21.51	99.53	17,470	47.86	254.93	12,440	34.08	141.99	37,762	103.46	433.26
2044	7,795	21.30	99.89	17,579	48.03	256.65	12,624	34.49	143.42	37,997	103.82	435.62
2045	7,681	21.04	100.23	17,426	47.74	258.33	12,698	34.79	144.92	37,805	103.58	437.93

APPENDIX 2.6: ANNUAL, AVERAGE DAY, AND PEAK DAY DSM – EXPECTED PRICES AND EXPECTED VOLUMES (MDTH)

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	8.194	0.022	0.042	4.466	0.012	0.023	34.932	0.096	0.179	9.956	0.027	0.051
2024	8.504	0.023	0.044	4.635	0.013	0.024	36.253	0.099	0.186	10.333	0.028	0.053
2025	8.864	0.024	0.045	4.831	0.013	0.025	37.785	0.104	0.194	10.770	0.030	0.055
2026	9.008	0.025	0.046	4.909	0.013	0.025	38.401	0.105	0.197	10.945	0.030	0.056
2027	9.431	0.026	0.048	5.140	0.014	0.026	40.203	0.110	0.206	11.459	0.031	0.059
2028	10.110	0.028	0.052	5.510	0.015	0.028	43.098	0.118	0.221	12.284	0.034	0.063
2029	10.914	0.030	0.056	5.948	0.016	0.031	46.525	0.127	0.239	13.261	0.036	0.068
2030	11.614	0.032	0.060	6.330	0.017	0.032	49.511	0.136	0.254	14.112	0.039	0.072
2031	12.288	0.034	0.063	6.697	0.018	0.034	52.386	0.144	0.269	14.931	0.041	0.077
2032	12.839	0.035	0.066	6.997	0.019	0.036	54.732	0.150	0.281	15.600	0.043	0.080
2033	13.263	0.036	0.068	7.228	0.020	0.037	56.541	0.155	0.290	16.115	0.044	0.083
2034	13.521	0.037	0.069	7.369	0.020	0.038	57.638	0.158	0.296	16.428	0.045	0.084
2035	13.307	0.036	0.068	7.252	0.020	0.037	56.729	0.155	0.291	16.169	0.044	0.083
2036	13.059	0.036	0.067	7.117	0.019	0.037	55.669	0.152	0.286	15.867	0.043	0.081
2037	12.805	0.035	0.066	6.979	0.019	0.036	54.588	0.150	0.280	15.559	0.043	0.080
2038	12.610	0.035	0.065	6.872	0.019	0.035	53.757	0.147	0.276	15.322	0.042	0.079
2039	12.375	0.034	0.063	6.744	0.018	0.035	52.756	0.145	0.271	15.037	0.041	0.077
2040	12.210	0.033	0.063	6.654	0.018	0.034	52.050	0.142	0.267	14.835	0.041	0.076
2041	12.032	0.033	0.062	6.557	0.018	0.034	51.293	0.141	0.263	14.620	0.040	0.075
2042	11.753	0.032	0.060	6.405	0.018	0.033	50.104	0.137	0.257	14.281	0.039	0.073
2043	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	57.549	0.158	0.295	111.991	0.307	0.646	46.414	0.127	0.259	214.988	0.589	1.033
2024	59.725	0.163	0.306	122.712	0.335	0.708	52.700	0.144	0.294	274.085	0.749	1.241
2025	62.249	0.171	0.319	137.682	0.377	0.795	59.890	0.164	0.335	294.063	0.806	1.340
2026	63.264	0.173	0.325	123.902	0.339	0.715	55.234	0.151	0.309	287.251	0.787	1.301
2027	66.232	0.181	0.340	139.450	0.382	0.805	64.711	0.177	0.362	307.982	0.844	1.413
2028	71.002	0.194	0.364	152.821	0.418	0.882	74.970	0.205	0.418	334.019	0.913	1.537
2029	76.647	0.210	0.393	171.273	0.469	0.988	83.106	0.228	0.464	361.911	0.992	1.667
2030	81.566	0.223	0.418	177.730	0.487	1.026	89.337	0.245	0.499	382.914	1.049	1.765
2031	86.302	0.236	0.443	175.688	0.481	1.014	91.496	0.251	0.511	395.143	1.083	1.817
2032	90.168	0.246	0.463	171.846	0.470	0.992	90.704	0.248	0.506	402.949	1.101	1.852
2033	93.147	0.255	0.478	160.872	0.441	0.928	85.561	0.234	0.478	397.414	1.089	1.825
2034	94.955	0.260	0.487	146.895	0.402	0.848	78.470	0.215	0.438	385.361	1.056	1.768
2035	93.458	0.256	0.479	131.483	0.360	0.759	71.431	0.196	0.399	363.892	0.997	1.667
2036	91.711	0.251	0.470	119.970	0.328	0.692	64.587	0.176	0.360	347.810	0.950	1.585
2037	89.930	0.246	0.461	107.079	0.293	0.618	56.419	0.155	0.315	320.985	0.879	1.457
2038	88.561	0.243	0.454	91.981	0.252	0.531	49.196	0.135	0.275	289.605	0.793	1.316
2039	86.913	0.238	0.446	82.345	0.226	0.475	43.787	0.120	0.245	260.047	0.712	1.187
2040	85.750	0.234	0.440	76.356	0.209	0.441	40.163	0.110	0.224	243.000	0.664	1.108
2041	84.503	0.232	0.433	67.940	0.186	0.392	35.109	0.096	0.196	219.832	0.602	1.001
2042	82.543	0.226	0.423	64.851	0.178	0.374	34.459	0.094	0.193	211.475	0.579	0.961
2043	-	-	-	51.673	0.142	0.298	30.149	0.083	0.168	57.270	0.157	0.305
2044	-	-	-	45.830	0.125	0.265	28.295	0.077	0.158	54.393	0.149	0.291
2045	-	-	-	42.857	0.117	0.247	27.538	0.075	0.154	53.751	0.147	0.287

APPENDIX 2.6: ANNUAL, AVERAGE DAY, AND PEAK DAY DSM – LOW PRICES AND LOW VOLUMES (MDTH)

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	8.194	0.022	0.042	4.466	0.012	0.023	34.932	0.096	0.179	9.956	0.027	0.051
2024	8.504	0.023	0.044	4.635	0.013	0.024	36.253	0.099	0.186	10.333	0.028	0.053
2025	8.864	0.024	0.045	4.831	0.013	0.025	37.785	0.104	0.194	10.770	0.030	0.055
2026	9.008	0.025	0.046	4.909	0.013	0.025	38.401	0.105	0.197	10.945	0.030	0.056
2027	9.431	0.026	0.048	5.140	0.014	0.026	40.203	0.110	0.206	11.459	0.031	0.059
2028	10.110	0.028	0.052	5.510	0.015	0.028	43.098	0.118	0.221	12.284	0.034	0.063
2029	10.914	0.030	0.056	5.948	0.016	0.031	46.525	0.127	0.239	13.261	0.036	0.068
2030	11.614	0.032	0.060	6.330	0.017	0.032	49.511	0.136	0.254	14.112	0.039	0.072
2031	12.288	0.034	0.063	6.697	0.018	0.034	52.386	0.144	0.269	14.931	0.041	0.077
2032	12.839	0.035	0.066	6.997	0.019	0.036	54.732	0.150	0.281	15.600	0.043	0.080
2033	13.263	0.036	0.068	7.228	0.020	0.037	56.541	0.155	0.290	16.115	0.044	0.083
2034	13.521	0.037	0.069	7.369	0.020	0.038	57.638	0.158	0.296	16.428	0.045	0.084
2035	13.307	0.036	0.068	7.252	0.020	0.037	56.729	0.155	0.291	16.169	0.044	0.083
2036	13.059	0.036	0.067	7.117	0.019	0.037	55.669	0.152	0.286	15.867	0.043	0.081
2037	12.805	0.035	0.066	6.979	0.019	0.036	54.588	0.150	0.280	15.559	0.043	0.080
2038	12.610	0.035	0.065	6.872	0.019	0.035	53.757	0.147	0.276	15.322	0.042	0.079
2039	12.375	0.034	0.063	6.744	0.018	0.035	52.756	0.145	0.271	15.037	0.041	0.077
2040	12.210	0.033	0.063	6.654	0.018	0.034	52.050	0.142	0.267	14.835	0.041	0.076
2041	12.032	0.033	0.062	6.557	0.018	0.034	51.293	0.141	0.263	14.620	0.040	0.075
2042	11.753	0.032	0.060	6.405	0.018	0.033	50.104	0.137	0.257	14.281	0.039	0.073
2043	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	57.549	0.158	0.295	103.866	0.285	0.599	39.165	0.107	0.219	206.679	0.566	0.986
2024	59.725	0.163	0.306	113.002	0.309	0.652	44.550	0.122	0.249	264.859	0.724	1.189
2025	62.249	0.171	0.319	126.073	0.345	0.728	50.578	0.139	0.283	283.647	0.777	1.281
2026	63.264	0.173	0.325	110.587	0.303	0.638	45.961	0.126	0.257	276.830	0.758	1.242
2027	66.232	0.181	0.340	124.397	0.341	0.718	54.512	0.149	0.305	296.578	0.813	1.350
2028	71.002	0.194	0.364	136.261	0.372	0.786	63.784	0.174	0.356	322.386	0.881	1.472
2029	76.647	0.210	0.393	145.375	0.398	0.839	71.380	0.196	0.399	349.720	0.958	1.598
2030	81.566	0.223	0.418	151.288	0.414	0.873	77.633	0.213	0.434	370.680	1.016	1.696
2031	86.302	0.236	0.443	150.738	0.413	0.870	80.537	0.221	0.450	383.616	1.051	1.753
2032	90.168	0.246	0.463	150.290	0.411	0.867	80.504	0.220	0.449	392.175	1.072	1.792
2033	93.147	0.255	0.478	143.926	0.394	0.831	76.701	0.210	0.429	388.001	1.063	1.772
2034	94.955	0.260	0.487	135.240	0.371	0.781	70.810	0.194	0.396	377.199	1.033	1.722
2035	93.458	0.256	0.479	124.138	0.340	0.716	64.929	0.178	0.363	356.938	0.978	1.628
2036	91.711	0.251	0.470	115.815	0.316	0.668	59.092	0.161	0.330	342.007	0.934	1.552
2037	89.930	0.246	0.461	104.797	0.287	0.605	51.757	0.142	0.289	316.245	0.866	1.430
2038	88.561	0.243	0.454	90.953	0.249	0.525	45.314	0.124	0.253	285.790	0.783	1.294
2039	86.913	0.238	0.446	81.607	0.224	0.471	40.492	0.111	0.226	256.938	0.704	1.170
2040	85.750	0.234	0.440	75.886	0.207	0.438	37.118	0.101	0.207	240.270	0.656	1.093
2041	84.503	0.232	0.433	67.701	0.185	0.391	32.719	0.090	0.183	217.858	0.597	0.991
2042	82.543	0.226	0.423	64.803	0.178	0.374	32.156	0.088	0.180	209.660	0.574	0.951
2043	-	-	-	51.769	0.142	0.299	28.171	0.077	0.157	55.810	0.153	0.297
2044	-	-	-	46.021	0.126	0.266	26.337	0.072	0.147	52.961	0.145	0.283
2045	-	-	-	43.100	0.118	0.249	25.585	0.070	0.143	52.309	0.143	0.279

APPENDIX 2.6: ANNUAL, AVERAGE DAY, AND PEAK DAY DSM – HIGH PRICES AND HIGH VOLUMES (MDTH)

	Klamath Falls			La Grande			Medford			Roseburg		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	8.196	0.022	0.042	4.467	0.012	0.023	34.938	0.096	0.179	9.958	0.027	0.051
2024	8.506	0.023	0.044	4.636	0.013	0.024	36.261	0.099	0.186	10.335	0.028	0.053
2025	8.865	0.024	0.045	4.832	0.013	0.025	37.793	0.104	0.194	10.772	0.030	0.055
2026	9.010	0.025	0.046	4.910	0.013	0.025	38.409	0.105	0.197	10.947	0.030	0.056
2027	9.431	0.026	0.048	5.140	0.014	0.026	40.202	0.110	0.206	11.458	0.031	0.059
2028	10.250	0.028	0.053	5.586	0.015	0.029	43.697	0.119	0.224	12.455	0.034	0.064
2029	11.183	0.031	0.057	6.095	0.017	0.031	47.673	0.131	0.245	13.588	0.037	0.070
2030	11.999	0.033	0.062	6.540	0.018	0.034	51.154	0.140	0.262	14.580	0.040	0.075
2031	12.676	0.035	0.065	6.908	0.019	0.035	54.036	0.148	0.277	15.401	0.042	0.079
2032	13.314	0.036	0.068	7.256	0.020	0.037	56.759	0.155	0.291	16.177	0.044	0.083
2033	13.740	0.038	0.070	7.488	0.021	0.038	58.572	0.160	0.300	16.694	0.046	0.086
2034	14.072	0.039	0.072	7.669	0.021	0.039	59.988	0.164	0.308	17.098	0.047	0.088
2035	13.833	0.038	0.071	7.539	0.021	0.039	58.971	0.162	0.303	16.808	0.046	0.086
2036	13.639	0.037	0.070	7.433	0.020	0.038	58.144	0.159	0.298	16.572	0.045	0.085
2037	13.379	0.037	0.069	7.292	0.020	0.037	57.036	0.156	0.293	16.256	0.045	0.083
2038	13.285	0.036	0.068	7.240	0.020	0.037	56.635	0.155	0.291	16.142	0.044	0.083
2039	13.034	0.036	0.067	7.103	0.019	0.036	55.563	0.152	0.285	15.837	0.043	0.081
2040	12.967	0.035	0.067	7.067	0.019	0.036	55.278	0.151	0.284	15.756	0.043	0.081
2041	12.863	0.035	0.066	7.010	0.019	0.036	54.836	0.150	0.281	15.629	0.043	0.080
2042	12.635	0.035	0.065	6.886	0.019	0.035	53.862	0.148	0.276	15.352	0.042	0.079
2043	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-

	Oregon			Washington			Idaho			System		
	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day	Annual	Daily	Peak Day
2023	57.559	0.158	0.295	116.782	0.320	0.674	81.479	0.223	0.455	250.316	0.686	1.230
2024	59.738	0.163	0.306	128.765	0.352	0.743	93.750	0.256	0.523	315.510	0.862	1.472
2025	62.262	0.171	0.319	145.821	0.400	0.842	108.215	0.296	0.605	343.347	0.941	1.615
2026	63.277	0.173	0.325	133.918	0.367	0.773	107.617	0.295	0.601	340.876	0.934	1.600
2027	66.231	0.181	0.340	154.203	0.422	0.890	123.992	0.340	0.693	368.902	1.011	1.754
2028	71.989	0.197	0.369	171.870	0.470	0.992	140.425	0.384	0.783	402.753	1.100	1.921
2029	78.539	0.215	0.403	187.574	0.514	1.083	154.764	0.424	0.865	438.194	1.201	2.092
2030	84.272	0.231	0.432	198.537	0.544	1.146	164.028	0.449	0.917	463.602	1.270	2.214
2031	89.021	0.244	0.457	200.106	0.548	1.155	164.883	0.452	0.921	475.080	1.302	2.263
2032	93.506	0.255	0.480	199.700	0.546	1.153	159.950	0.437	0.892	479.825	1.311	2.280
2033	96.494	0.264	0.495	191.143	0.524	1.103	147.576	0.404	0.825	467.622	1.281	2.216
2034	98.826	0.271	0.507	178.759	0.490	1.032	131.539	0.360	0.735	447.706	1.227	2.115
2035	97.152	0.266	0.498	163.955	0.449	0.946	116.488	0.319	0.651	418.085	1.145	1.969
2036	95.788	0.262	0.491	153.985	0.421	0.889	103.396	0.283	0.577	395.973	1.082	1.852
2037	93.963	0.257	0.482	139.444	0.382	0.805	90.323	0.247	0.505	363.913	0.997	1.695
2038	93.303	0.256	0.479	121.922	0.334	0.704	77.917	0.213	0.435	327.564	0.897	1.526
2039	91.537	0.251	0.470	110.153	0.302	0.636	69.678	0.191	0.389	295.003	0.808	1.381
2040	91.068	0.249	0.467	101.423	0.277	0.585	64.112	0.175	0.358	276.188	0.755	1.292
2041	90.338	0.248	0.463	90.776	0.249	0.524	56.924	0.156	0.318	250.972	0.688	1.173
2042	88.735	0.243	0.455	84.966	0.233	0.490	55.459	0.152	0.310	241.874	0.663	1.128
2043	-	-	-	70.480	0.193	0.407	49.282	0.135	0.275	79.216	0.217	0.428
2044	-	-	-	64.969	0.178	0.375	47.953	0.131	0.268	76.977	0.210	0.417
2045	-	-	-	62.260	0.171	0.359	47.656	0.131	0.266	76.892	0.211	0.416

APPENDIX 2.7: DETAILED DEMAND DATA (MDTH, NET OF DSM) – CASE PRS

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	3,607	3,660	3,671	3,690	3,702	3,734	3,716	3,714	3,722	3,740	3,733	3,733
ID_Ind	226	227	226	225	225	225	224	223	222	222	221	221
ID_Res	6,607	6,758	6,827	6,940	7,029	7,158	7,188	7,255	7,350	7,460	7,520	7,595
Klamath Falls_Com_Current	475	476	473	472	470	470	465	463	461	461	458	455
Klamath Falls_Com_New	2	5	7	10	13	16	18	21	23	26	29	31
Klamath Falls_Ind	14	15	14	15	15	15	15	15	15	15	15	15
Klamath Falls_Res_Current	958	960	954	951	946	945	934	927	924	921	913	907
Klamath Falls_Res_New	4	12	20	27	34	40	45	51	56	61	66	71
LaGrande_Com_Current	318	320	319	319	319	320	319	318	318	319	318	317
LaGrande_Com_New	1	2	4	5	6	8	9	11	13	14	15	17
LaGrande_Ind	83	85	85	86	86	87	88	88	89	90	90	91
LaGrande_Res_Current	495	497	495	495	495	497	494	492	492	492	490	489
LaGrande_Res_New	1	4	7	10	13	16	19	22	25	28	30	33
Medford_Com_Current	2,178	2,194	2,194	2,201	2,206	2,217	2,210	2,211	2,219	2,228	2,226	2,225
Medford_Com_New	9	30	52	75	96	118	138	159	180	201	220	240
Medford_Ind	22	23	23	23	24	24	24	25	25	25	26	26
Medford_Res_Current	3,515	3,541	3,541	3,555	3,562	3,578	3,561	3,559	3,572	3,581	3,574	3,569
Medford_Res_New	19	68	120	172	221	271	318	366	414	462	508	553
OR_Tport	4,441	4,425	4,424	4,424	4,423	4,421	4,420	4,419	4,418	4,418	4,419	4,420
Roseburg_Com_Current	662	669	670	673	676	680	679	680	684	689	689	691
Roseburg_Com_New	1	2	3	5	6	7	9	10	11	13	14	16
Roseburg_Ind	2	3	2	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	838	847	849	854	857	863	860	861	866	871	872	873
Roseburg_Res_New	2	6	11	16	20	25	30	34	39	43	47	52
WA_Com_Current	7,084	7,100	7,040	7,026	6,998	7,017	6,938	6,898	6,884	6,882	6,834	6,801
WA_Com_New	7	25	43	59	77	95	109	123	141	157	172	186
WA_Ind	227	227	226	226	225	225	224	223	222	222	221	221
WA_Res_Current	12,077	12,113	12,007	11,987	11,941	11,972	11,826	11,756	11,734	11,737	11,658	11,603
WA_Res_New	41	138	233	322	415	506	578	651	744	823	904	974
WA_Tport	2,479	2,451	2,448	2,448	2,448	2,443	2,435	2,430	2,426	2,424	2,425	2,427

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	3,746	3,786	3,788	3,787	3,796	3,808	3,803	3,804	3,805	3,831	3,826
ID_Ind	221	221	221	220	220	220	219	218	219	220	219
ID_Res	7,698	7,860	7,939	7,999	8,090	8,188	8,248	8,333	8,416	8,573	8,652
Klamath Falls_Com_Current	456	458	457	455	454	455	453	452	453	455	453
Klamath Falls_Com_New	33	36	39	41	43	46	49	51	53	56	58
Klamath Falls_Ind	15	15	15	15	15	15	15	15	15	15	15
Klamath Falls_Res_Current	907	912	907	904	901	901	897	893	901	905	901
Klamath Falls_Res_New	76	81	86	91	96	101	105	110	114	119	123
LaGrande_Com_Current	317	320	319	318	318	319	318	317	317	319	317
LaGrande_Com_New	18	20	21	23	24	26	27	28	30	31	33
LaGrande_Ind	92	92	93	93	94	94	95	95	95	95	95
LaGrande_Res_Current	489	493	491	490	489	490	488	487	490	493	490
LaGrande_Res_New	36	39	42	44	47	50	52	55	58	61	63
Medford_Com_Current	2,241	2,265	2,269	2,274	2,280	2,293	2,293	2,299	2,302	2,312	2,302
Medford_Com_New	261	283	303	322	342	362	381	400	417	437	453
Medford_Ind	26	26	26	26	27	27	27	27	28	28	28
Medford_Res_Current	3,594	3,635	3,643	3,649	3,656	3,677	3,676	3,685	3,712	3,730	3,713
Medford_Res_New	602	655	701	747	793	841	885	930	970	1,018	1,055
OR_Tport	4,422	4,423	4,425	4,427	4,430	4,431	4,432	4,433	4,457	4,457	4,457
Roseburg_Com_Current	697	706	709	712	715	720	721	725	725	728	725
Roseburg_Com_New	17	18	20	21	23	24	25	27	28	29	30
Roseburg_Ind	3	3	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	881	894	899	902	906	912	914	919	927	931	927
Roseburg_Res_New	56	61	66	70	75	80	84	89	93	97	101
WA_Com_Current	6,796	6,841	6,816	6,784	6,776	6,775	6,743	6,725	6,708	6,741	6,707
WA_Com_New	202	223	238	248	262	278	290	303	315	335	346
WA_Ind	221	221	221	220	219	219	218	218	219	219	219
WA_Res_Current	11,593	11,672	11,618	11,546	11,516	11,501	11,428	11,390	11,353	11,415	11,358
WA_Res_New	1,053	1,164	1,237	1,285	1,354	1,435	1,494	1,557	1,615	1,714	1,769
WA_Tport	2,432	2,434	2,440	2,450	2,461	2,466	2,473	2,474	2,510	2,510	2,510

APPENDIX 2.7: DETAILED DEMAND DATA (MDTH, NET OF DSM) – CASE AVERAGE

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	3,557	3,613	3,634	3,662	3,683	3,720	3,723	3,738	3,754	3,787	3,789	3,807
ID_Ind	225	226	225	225	225	226	225	225	225	226	225	225
ID_Res	6,502	6,660	6,751	6,879	6,989	7,127	7,204	7,313	7,425	7,573	7,658	7,777
Klamath Falls_Com_Current	469	471	469	469	469	471	469	468	468	471	468	468
Klamath Falls_Com_New	2	5	7	10	13	16	19	21	24	27	29	32
Klamath Falls_Ind	14	14	14	14	14	15	15	15	15	15	15	15
Klamath Falls_Res_Current	945	950	945	945	944	948	943	942	942	946	941	940
Klamath Falls_Res_New	3	12	20	27	34	40	46	51	57	63	68	73
LaGrande_Com_Current	313	314	313	313	313	314	313	313	312	314	312	312
LaGrande_Com_New	1	2	4	5	6	8	9	11	12	14	15	17
LaGrande_Ind	83	83	83	83	83	83	83	83	83	83	83	83
LaGrande_Res_Current	486	488	486	486	486	488	485	485	484	486	484	484
LaGrande_Res_New	1	4	7	10	13	16	19	21	24	27	30	33
Medford_Com_Current	2,142	2,151	2,141	2,141	2,140	2,149	2,139	2,138	2,138	2,147	2,138	2,138
Medford_Com_New	8	29	51	73	93	114	134	153	173	193	212	231
Medford_Ind	21	23	23	23	23	23	24	24	24	24	24	24
Medford_Res_Current	3,442	3,457	3,439	3,439	3,437	3,451	3,431	3,429	3,426	3,441	3,422	3,420
Medford_Res_New	18	66	116	166	213	261	306	352	397	444	486	530
OR_Tport	4,441	4,425	4,424	4,424	4,423	4,421	4,420	4,419	4,418	4,418	4,419	4,420
Roseburg_Com_Current	648	651	648	648	647	650	647	647	647	650	647	647
Roseburg_Com_New	0	2	3	5	6	7	8	10	11	12	13	15
Roseburg_Ind	2	3	2	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	816	819	815	815	814	818	813	812	811	815	810	809
Roseburg_Res_New	2	6	11	15	19	24	28	32	36	40	44	48
WA_Com_Current	6,974	6,997	6,961	6,964	6,957	6,983	6,947	6,944	6,943	6,972	6,943	6,945
WA_Com_New	8	25	43	61	78	96	113	130	148	166	182	200
WA_Ind	225	226	225	225	225	226	225	225	225	226	225	225
WA_Res_Current	11,877	11,927	11,865	11,875	11,867	11,911	11,844	11,842	11,844	11,904	11,860	11,871
WA_Res_New	42	139	235	329	420	512	599	688	778	873	957	1,046
WA_Tport	2,479	2,451	2,448	2,448	2,448	2,443	2,435	2,430	2,426	2,424	2,425	2,427

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	3,826	3,862	3,866	3,886	3,905	3,938	3,938	3,950	3,963	3,991	3,988
ID_Ind	225	226	225	225	225	226	225	225	226	227	226
ID_Res	7,896	8,048	8,131	8,247	8,362	8,513	8,591	8,708	8,828	8,989	9,078
Klamath Falls_Com_Current	469	471	469	470	470	472	470	470	473	475	473
Klamath Falls_Com_New	34	37	40	42	45	48	50	53	55	58	61
Klamath Falls_Ind	15	15	15	15	15	15	15	15	15	15	15
Klamath Falls_Res_Current	940	945	940	940	940	945	940	940	949	954	949
Klamath Falls_Res_New	79	84	89	94	100	106	110	116	120	126	130
LaGrande_Com_Current	313	314	313	313	313	315	314	314	315	316	315
LaGrande_Com_New	18	20	21	22	24	25	27	28	30	31	32
LaGrande_Ind	83	83	83	83	83	83	83	83	83	84	83
LaGrande_Res_Current	484	486	483	483	483	485	483	483	489	491	489
LaGrande_Res_New	36	39	41	44	47	50	52	55	57	60	63
Medford_Com_Current	2,140	2,151	2,142	2,144	2,145	2,155	2,146	2,147	2,156	2,166	2,156
Medford_Com_New	249	269	286	304	322	340	356	373	391	410	424
Medford_Ind	24	25	24	25	25	25	25	25	26	26	26
Medford_Res_Current	3,420	3,436	3,419	3,419	3,418	3,435	3,418	3,419	3,459	3,476	3,459
Medford_Res_New	573	619	658	700	742	786	823	864	904	948	982
OR_Tport	4,422	4,423	4,425	4,427	4,430	4,431	4,432	4,433	4,457	4,457	4,457
Roseburg_Com_Current	647	651	648	648	649	652	649	649	652	655	652
Roseburg_Com_New	16	17	18	19	21	22	23	24	25	26	27
Roseburg_Ind	3	3	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	809	813	809	809	809	813	809	809	820	824	820
Roseburg_Res_New	52	56	59	63	67	71	75	78	82	86	89
WA_Com_Current	6,951	6,987	6,965	6,975	6,984	7,021	6,999	7,003	7,009	7,040	7,010
WA_Com_New	217	236	252	269	286	306	321	338	355	375	390
WA_Ind	225	226	225	225	226	226	226	226	227	228	227
WA_Res_Current	11,880	11,941	11,891	11,896	11,896	11,949	11,895	11,895	11,900	11,959	11,909
WA_Res_New	1,134	1,230	1,310	1,397	1,484	1,581	1,657	1,743	1,828	1,926	1,999
WA_Tport	2,432	2,434	2,440	2,450	2,461	2,466	2,473	2,474	2,510	2,510	2,510

APPENDIX 2.7: DETAILED DEMAND DATA (MDTH, NET OF DSM) – CASE ELECTRIFICATION

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	3,607	3,660	3,671	3,690	3,702	3,734	3,716	3,714	3,722	3,740	3,733	3,733
ID_Ind	226	227	226	225	225	225	224	223	222	222	221	221
ID_Res	6,607	6,758	6,827	6,940	7,029	7,158	7,188	7,255	7,350	7,460	7,520	7,595
Klamath Falls_Com_Current	477	481	468	457	446	437	424	413	404	395	385	375
Klamath Falls_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Ind	14	15	14	15	15	15	12	12	12	12	12	12
Klamath Falls_Res_Current	962	972	946	924	901	882	854	831	811	792	770	749
Klamath Falls_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Com_Current	319	322	315	308	302	297	290	283	278	272	266	260
LaGrande_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Ind	83	85	85	84	83	81	80	78	73	72	70	71
LaGrande_Res_Current	496	501	489	480	470	462	450	439	430	422	412	402
LaGrande_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
Medford_Com_Current	2,187	2,224	2,179	2,143	2,104	2,072	2,023	1,983	1,951	1,919	1,878	1,840
Medford_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Medford_Ind	22	23	23	22	22	22	23	21	21	22	22	20
Medford_Res_Current	3,534	3,609	3,537	3,479	3,416	3,362	3,278	3,210	3,156	3,101	3,032	2,965
Medford_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
OR_Tport	4,441	4,425	4,424	4,424	4,423	4,421	4,420	4,419	4,418	4,418	4,419	4,420
Roseburg_Com_Current	663	671	658	648	638	629	615	604	595	587	575	565
Roseburg_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Ind	2	3	2	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	840	854	838	826	813	801	782	767	757	745	730	717
Roseburg_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
WA_Com_Current	7,084	7,100	6,898	6,745	6,582	6,466	6,264	6,101	5,965	5,842	5,684	5,541
WA_Com_New	-	-	-	-	-	-	-	-	-	-	-	-
WA_Ind	227	227	221	216	213	208	202	199	194	189	185	180
WA_Res_Current	12,148	12,353	11,999	11,739	11,458	11,256	10,894	10,611	10,378	10,172	9,901	9,658
WA_Res_New	-	-	-	-	-	-	-	-	-	-	-	-
WA_Tport	2,479	2,451	2,448	2,448	2,448	2,443	2,435	2,430	2,426	2,424	2,425	2,427

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	3,746	3,786	3,788	3,787	3,796	3,808	3,803	3,804	3,805	3,831	3,826
ID_Ind	221	221	221	220	220	220	219	218	219	220	219
ID_Res	7,698	7,860	7,939	7,999	8,090	8,188	8,248	8,333	8,416	8,573	8,652
Klamath Falls_Com_Current	368	362	354	346	338	332	324	316	312	307	299
Klamath Falls_Com_New	-	-	-	-	-	-	-	-	-	-	-
Klamath Falls_Ind	12	12	12	12	10	10	10	10	10	10	10
Klamath Falls_Res_Current	734	722	704	687	671	658	641	626	621	612	597
Klamath Falls_Res_New	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Com_Current	255	252	247	241	236	232	226	221	218	214	209
LaGrande_Com_New	-	-	-	-	-	-	-	-	-	-	-
LaGrande_Ind	71	71	71	71	70	70	70	68	66	66	62
LaGrande_Res_Current	394	389	380	371	363	356	347	340	337	332	323
LaGrande_Res_New	-	-	-	-	-	-	-	-	-	-	-
Medford_Com_Current	1,816	1,798	1,766	1,734	1,704	1,679	1,646	1,617	1,590	1,564	1,527
Medford_Com_New	-	-	-	-	-	-	-	-	-	-	-
Medford_Ind	20	20	20	21	19	19	19	19	20	18	18
Medford_Res_Current	2,926	2,899	2,847	2,794	2,742	2,702	2,646	2,599	2,577	2,537	2,475
Medford_Res_New	-	-	-	-	-	-	-	-	-	-	-
OR_Tport	4,422	4,423	4,425	4,427	4,430	4,431	4,432	4,433	4,457	4,457	4,457
Roseburg_Com_Current	559	555	546	537	529	522	512	504	495	488	476
Roseburg_Com_New	-	-	-	-	-	-	-	-	-	-	-
Roseburg_Ind	3	3	3	3	1	1	1	1	2	2	2
Roseburg_Res_Current	709	705	694	682	671	662	650	640	636	626	611
Roseburg_Res_New	-	-	-	-	-	-	-	-	-	-	-
WA_Com_Current	5,426	5,352	5,227	5,099	4,993	4,893	4,774	4,667	4,563	4,493	4,381
WA_Com_New	-	-	-	-	-	-	-	-	-	-	-
WA_Ind	178	173	170	165	162	157	154	152	148	146	143
WA_Res_Current	9,457	9,331	9,102	8,865	8,664	8,479	8,256	8,063	7,877	7,763	7,570
WA_Res_New	-	-	-	-	-	-	-	-	-	-	-
WA_Tport	2,432	2,434	2,440	2,450	2,461	2,466	2,473	2,474	2,510	2,510	2,510

APPENDIX 2.7: DETAILED DEMAND DATA (MDTH, NET OF DSM) – CASE HYBRID

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	3,607	3,660	3,671	3,690	3,702	3,734	3,716	3,714	3,722	3,740	3,733	3,733
ID_Ind	226	227	226	225	225	225	224	223	222	222	221	221
ID_Res	6,607	6,758	6,827	6,940	7,029	7,158	7,188	7,255	7,350	7,460	7,520	7,595
Klamath Falls_Com_Current	477	481	468	457	446	437	424	413	404	395	385	375
Klamath Falls_Com_New	-	-	6	12	18	24	28	33	38	42	45	50
Klamath Falls_Ind	14	15	14	15	15	15	12	12	12	12	12	12
Klamath Falls_Res_Current	962	972	946	924	901	882	854	831	811	792	770	749
Klamath Falls_Res_New	-	-	16	31	45	59	69	81	91	101	109	119
LaGrande_Com_Current	319	322	315	308	302	297	290	283	278	272	266	260
LaGrande_Com_New	-	-	3	7	10	14	17	20	23	26	29	31
LaGrande_Ind	83	85	85	84	83	81	80	78	73	72	70	71
LaGrande_Res_Current	496	501	489	480	470	462	450	439	430	422	412	402
LaGrande_Res_New	-	-	6	12	18	24	29	34	39	45	50	54
Medford_Com_Current	2,187	2,224	2,179	2,143	2,104	2,072	2,023	1,983	1,951	1,919	1,878	1,840
Medford_Com_New	-	-	12	22	33	41	49	55	68	73	82	68
Medford_Ind	22	23	23	22	22	22	23	21	21	22	22	20
Medford_Res_Current	3,534	3,609	3,537	3,479	3,416	3,362	3,278	3,210	3,156	3,101	3,032	2,965
Medford_Res_New	-	-	28	53	80	99	119	131	164	176	196	164
OR_Tport	4,441	4,425	4,424	4,424	4,423	4,421	4,420	4,419	4,418	4,418	4,419	4,420
Roseburg_Com_Current	663	671	658	648	638	629	615	604	595	587	575	565
Roseburg_Com_New	-	-	1	1	2	3	4	4	7	9	10	10
Roseburg_Ind	2	3	2	3	3	3	3	3	3	3	3	3
Roseburg_Res_Current	840	854	838	826	813	801	782	767	757	745	730	717
Roseburg_Res_New	-	-	1	3	4	6	8	8	14	17	20	20
WA_Com_Current	7,084	7,100	6,898	6,745	6,582	6,466	6,264	6,101	5,965	5,842	5,684	5,541
WA_Com_New	7	25	119	207	298	388	461	533	618	693	767	832
WA_Ind	227	227	221	216	213	208	202	199	194	189	185	180
WA_Res_Current	12,148	12,353	11,999	11,739	11,458	11,256	10,894	10,611	10,378	10,172	9,901	9,658
WA_Res_New	-	-	239	464	694	921	1,107	1,291	1,510	1,701	1,892	2,060
WA_Tport	2,479	2,451	2,448	2,448	2,448	2,443	2,435	2,430	2,426	2,424	2,425	2,427

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	3,746	3,786	3,788	3,787	3,796	3,808	3,803	3,804	3,805	3,831	3,826
ID_Ind	221	221	221	220	220	220	219	218	219	220	219
ID_Res	7,698	7,860	7,939	7,999	8,090	8,188	8,248	8,333	8,416	8,573	8,652
Klamath Falls_Com_Current	368	362	354	346	338	332	324	316	312	307	299
Klamath Falls_Com_New	54	59	63	67	71	75	78	82	85	90	93
Klamath Falls_Ind	12	12	12	12	10	10	10	10	10	10	10
Klamath Falls_Res_Current	734	722	704	687	671	658	641	626	621	612	597
Klamath Falls_Res_New	129	141	151	160	168	178	185	194	201	213	221
LaGrande_Com_Current	255	252	247	241	236	232	226	221	218	214	209
LaGrande_Com_New	34	37	40	42	44	47	49	52	54	57	59
LaGrande_Ind	71	71	71	71	70	70	70	68	66	66	62
LaGrande_Res_Current	394	389	380	371	363	356	347	340	337	332	323
LaGrande_Res_New	59	64	68	72	76	81	85	90	93	98	100
Medford_Com_Current	1,816	1,798	1,766	1,734	1,704	1,679	1,646	1,617	1,590	1,564	1,527
Medford_Com_New	74	87	99	102	103	125	136	139	130	136	145
Medford_Ind	20	20	20	21	19	19	19	19	20	18	18
Medford_Res_Current	2,926	2,899	2,847	2,794	2,742	2,702	2,646	2,599	2,577	2,537	2,475
Medford_Res_New	178	210	238	246	249	303	328	336	315	329	352
OR_Tport	4,422	4,423	4,425	4,427	4,430	4,431	4,432	4,433	4,457	4,457	4,457
Roseburg_Com_Current	559	555	546	537	529	522	512	504	495	488	476
Roseburg_Com_New	12	13	15	15	20	24	30	34	32	33	35
Roseburg_Ind	3	3	3	3	1	1	1	1	2	2	2
Roseburg_Res_Current	709	705	694	682	671	662	650	640	636	626	611
Roseburg_Res_New	23	25	27	28	37	45	56	64	59	62	66
WA_Com_Current	5,426	5,352	5,227	5,099	4,993	4,893	4,774	4,667	4,563	4,493	4,381
WA_Com_New	902	999	1,063	1,106	1,166	1,234	1,283	1,335	1,382	1,463	1,505
WA_Ind	178	173	170	165	162	157	154	152	148	146	143
WA_Res_Current	9,457	9,331	9,102	8,865	8,664	8,479	8,256	8,063	7,877	7,763	7,570
WA_Res_New	2,243	2,492	2,659	2,773	2,929	3,108	3,237	3,374	3,499	3,713	3,826
WA_Tport	2,432	2,434	2,440	2,450	2,461	2,466	2,473	2,474	2,510	2,510	2,510

AEG

AVISTA NATURAL GAS CONSERVATION POTENTIAL ASSESSMENT FOR 2023-2045

Prepared For: Avista Corporation
By: Applied Energy Group, Inc.
Date: December 21, 2022
AEG Key Contact: Eli Morris

This work was performed by

Applied Energy Group, Inc. (AEG)
2300 Clayton Road, Suite 1370
Concord, CA 94520

Project Director: E. Morris
Project Manager: A. Hudson

Project Team:

K. Marrin
K. Walter
F. Nguyen
T. Williams
K. Billeci
S. Chen
L. Khan
C. Struthers

CONTENTS

LIST OF FIGURES

LIST OF TABLES

2 | INTRODUCTION

In October 2021, Avista Corporation (Avista) engaged Applied Energy Group (AEG) to conduct a Conservation Potential Assessment (CPA) for its Washington and Idaho service areas. AEG first performed an electric CPA for Avista in 2013; since then, AEG has performed both electric and natural gas CPAs for Avista's planning cycles. This study represents the first assessment of the potential for natural gas demand response resources within Avista's service area, including Oregon. The CPA is a 20-year study of electric and natural gas conservation potential, performed in accordance with Washington Initiative 937 and associated Washington Administrative Code provisions. This study provides data on conservation resources to support the development of Avista's 2023 Integrated Resource Plan (IRP). For reporting purposes, the potential results are separated by fuel. This report documents the natural gas CPA.

Notable updates from prior CPAs include:

- The analysis base year was brought forward from 2019 to 2021.
- For the residential sector, the study still incorporates Avista's GenPOP residential saturation survey from 2012, which provides a more localized look at Avista's customers than regional surveys. The survey provided the foundation for the base year market characterization and energy market profiles. The Northwest Energy Efficiency Alliance's (NEEA's) 2016 Residential Building Stock Assessment II (RBSA) supplemented the GenPOP survey to account for trends in the intervening years.
- The residential segmentation was expanded to include household counts and energy characteristics of low-income customers by dwelling type.
- For the commercial sector, the analysis was performed for the major building types in the service territory. Results from NEEA's 2019 Commercial Building Stock Assessment (CBSA), including hospital and university data, provided useful information for this analysis.
- The list of energy conservation measures was updated with research from the Regional Technical Forum (RTF).
- Measure characterizations, which previously relied on data from the Northwest Power and Conservation Council's (NWPCC or Council) Seventh Power Plan, is now updated to the 2021 Power Plan, including measure data, adoption rates, and updated measure applicability.
- The study incorporates updated forecasting assumptions that align with the most recent Avista load forecast.

Summary of Report Contents

Volume 1, Final Report

The report is divided into seven chapters. Chapters 2 through 6 describe the analysis approach taken and the data sources used to develop the energy efficiency potential estimates and Chapter 7 discusses the demand response analysis.

- Chapter 2 – Energy Efficiency Analysis Approach and Data Development. A detailed description of AEG's approach to estimating the energy efficiency potential and documentation of data sources used.
- Chapter 3 – Energy Efficiency Market Characterization presents how Avista's customers use natural gas today and what equipment is currently being used.
- Chapter 4 – Energy Efficiency Baseline Projection presents the baseline end-use projections developed for each sector and state as well as a summary.
- Chapter 5 – Conservation Potential. Energy efficiency potential results for each state across all sectors and separately for each sector.

- Chapter 6 - Sector-Level Energy Efficiency Potential. Summary of energy efficiency potential for each market sector within Avista's service territory for both Washington and Idaho. This chapter includes a detailed breakdown of potential by measure type, vintage, market segment, end use, and state.
- Chapter 7 – Demand Response Potential. Demand response potential results for each state across all sectors and separately for each sector.

Volume 2, Appendices

The appendices for this report are provided in separate spreadsheets accompanying the delivery of this report and consist of the following:

- Market Profiles. Detailed market profiles for each market segment. Includes equipment saturation, unit energy consumption or energy usage index, energy intensity, and total consumption.
- Customer Adoption Factors. Documentation of the ramp rates used in this analysis. These were adapted from the 2021 Power Plan electrical power conservation supply curve workbooks for the estimation of achievable natural gas potential.
- Measure List. List of measures, along with example baseline definitions and efficiency options by market sector analyzed.
- Detailed Measure Assumptions. This dataset provides input assumptions, measure characteristics, cost-effectiveness results, and potential estimates for each measure permutation analyzed within the study.

Abbreviations and Acronyms

Table 2-1 shows the abbreviations and acronyms used in this report, along with an explanation.

Table 2-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	U.S. Census American Community Study
AEG	Applied Energy Group
AEO	EIA's Annual Energy Outlook
BEST	AEG's Building Energy Simulation Tool
C&I	Commercial and Industrial
CBSA	NEEA's Commercial Building Stock Assessment
COMMEND	EPRI's Commercial End-Use Planning System
CPA	Conservation Potential Assessment
DEEM	AEG's Database of Energy Efficiency Measures
DEER	California Database for Energy Efficient Resources
DR	Demand Response
DSM	Demand Side Management
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EUI	Energy Use Index
HDD	Heating Degree Day
HVAC	Heating Ventilation and Air Conditioning
IFSA	NEEA's Industrial Facilities Site Assessment
IRP	Integrated Resource Plan
LoadMAP	AEG's Load Management Analysis and Planning™ tool
NEEA	Northwest Energy Efficiency Alliance
NWPCC	Northwest Power and Conservation Council
O&M	Operations and Maintenance
RBSA	NEEA's Residential Building Stock Assessment
REEPS	EPRI's Residential End-Use Energy Planning System
RTF	NWPCC's Regional Technical Forum
TRC	Total Resource Cost test
TRM	Technical Reference Manual
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WSEC	2015 Washington State Energy Code

3 | ENERGY EFFICIENCY ANALYSIS APPROACH AND DATA DEVELOPMENT

This section describes the analysis approach and the data sources used to develop the energy efficiency potential estimates. The demand response analysis discussion can be found in Chapter 6.

Overview of Analysis Approach

AEG used a bottom-up approach to perform the potential analysis. The major steps are listed below and detailed detail throughout this section.

1. Perform a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2021. The market characterization included extensive use of Avista data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
2. Develop a baseline projection of energy consumption by sector, segment, end use, and technology for 2023 through 2045.
3. Define and characterize several hundred energy efficiency measures to be applied to all sectors, segments, and end uses.
4. Estimate technical, achievable technical, and achievable economic energy savings at the measure level for 2023 through 2045. Achievable economic potential was assessed using the Utility Cost Test (UCT) test for Avista's Idaho territory and the Total Resource Cost (TRC) test for Avista's Washington territory.

Comparison with NWPCC Methodology

It is important to note that electricity is the primary focus of the regionwide potential assessed in the NWPCC's Plans. Natural gas impacts are typically assessed when they overlap with electricity measures (e.g., gas water heating impacts in an electrically heated "Built Green Washington" home). Although Avista is a dual-fuel utility, this study focuses on natural gas measures and programs, which exhibit noticeable differences from electric programs, notably regarding avoided costs. To account for this, AEG sometimes adapted NWPCC methodologies rather than using them directly from the source. This adaptation is especially relevant in the development of ramp rates when achievability was determined not to be applicable to a specific natural gas measure or program.

A primary objective of the study was to estimate natural gas potential consistent with the NWPCC's analytical methodologies and procedures for electric utilities. While developing Avista's 2023- 2045 CPA, AEG relied on an approach vetted and adapted through the successful completion of CPAs referencing the NWPCC's Fifth, Sixth, Seventh, and now 2021 Power Plans. Among other aspects, this approach involves using consistent:

- Data sources: Avista surveys, regional surveys, market research, and assumptions
- Measures and assumptions: Avista TRM, 2021 Power Plan supply curves and RTF work products
- Potential factors: 2021 Power Plan ramp rates
- Levels of potential: technical, achievable technical, and achievable economic
- Cost-effectiveness approaches: assessed potential under the UCT for Idaho and TRC for Washington, including non-energy impacts (and non-gas energy impacts), which may be quantified and monetized, as well as operations and maintenance (O&M) impacts within the TRC.
- Conservation credit: applied NWPCC 10% conservation credit to avoided energy costs in Washington for energy benefits. This is incorporated into the TRC calculation.

LoadMAP Model

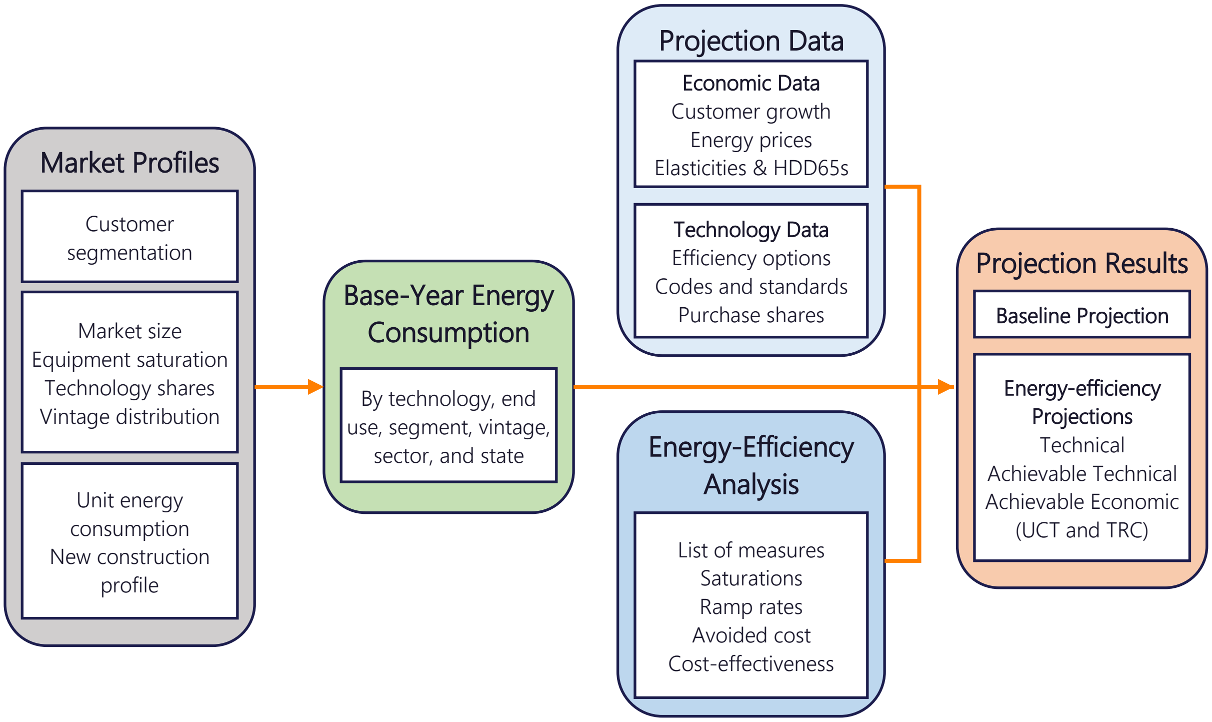
AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and potential studies since. Built in Excel, the LoadMAP framework (see Figure 3-1) is both accessible and transparent and has the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's Residential End-Use Energy Planning System (REEPS) and Commercial End-Use Planning System (COMMEND)) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately. This is especially relevant in the state of Washington where the 2015 Washington State Energy Code (WSEC) substantially enhances the efficiency of the new construction market.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex customer choice algorithms or diffusion assumptions. The model parameters tend to be difficult to estimate or observe, and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for water heating is distinct from furnaces and fireplaces.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, state, or income level).
- Natively outputs model results in a detailed line-by-line summary file, allowing for review of input assumptions, cost-effectiveness results, and potential estimates at a granular level. Also allows for the development of IRP supply curves, both at the achievable technical and achievable economic potential levels.

Consistent with the segmentation scheme and market profiles described below, LoadMAP provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It provides forecasts of total energy use and energy efficiency savings associated with the various types of potential.[1]

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

Figure 3-1 LoadMAP Analysis Framework



Definitions of Potential

AEG's approach for this study adheres to the approaches and conventions outlined in the National Action Plan for Energy Efficiency's Guide for Conducting Potential Studies[2] and is consistent with the methodology used by the Northwest Power and Conservation Council to develop its regional power plans. The guide represents the most credible and comprehensive industry practice for specifying conservation potential. Four types of potential were developed as part of this effort:

- Technical Potential is the theoretical upper limit of conservation potential. It assumes that customers adopt all feasible efficient measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers choose the efficient equipment option relative to applicable codes and standards. Non-equipment measures, which may be realistically installed apart from equipment replacements, are implemented according to ramp rates informed by the NWPCC 2021 Power Plan, applied to 100% of the applicable market. This case is provided primarily for planning and informational purposes.
- Achievable Technical Potential refines Technical Potential by applying market adoption rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of energy efficiency measures. AEG used achievability assumptions from the NWPCC's 2021 Power Plan, adjusted for Avista's recent program accomplishments, as the customer adoption rates for this study. For the achievable technical case, ramp rates are applied to between 85% - 100% of the applicable market, per NWPCC methodology. This achievability factor represents potential that all available mechanisms, including utility programs, updated codes and standards, and market transformation, can reasonably acquire. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs.[3] The market adoption factors can be found in Appendix B.

[2] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

[3] Council's 7th Power Plan applicability assumptions reference an "Achievable Savings" report published August 1, 2007. http://www.nwcouncil.org/reports/2007/2007-13/

  - Note that the previous CPA used ramp rates from the NWPCC's Seventh Power Plan, which assumed a fixed 85% achievability for all measures. In the 2021 Power Plan, some measures have this limit increased.

- UCT Achievable Economic Potential further refines achievable technical potential by applying a cost-effectiveness screen. The UCT test assesses cost-effectiveness from the utility's perspective. This test compares lifetime energy benefits to the costs of delivering the measure through a utility program, excluding monetized non-energy impacts. The costs are the incentive, as a percent of the incremental cost of the given measure, relative to the relevant baseline (e.g., the federal standard for lost opportunity and no action for retrofits), plus any administrative costs that are incurred by the program to deliver and implement the measure. If the benefits outweigh the costs (that is, if the UCT ratio is greater than 1.0), a given measure is included in the economic potential.
- TRC Achievable Economic Potential also refines achievable technical potential through cost-effectiveness analysis. The TRC test assesses cost-effectiveness from a combined utility and participant perspective. As such, this test includes the full cost of the measure and non-energy impacts realized by the customer (if quantifiable and monetized). AEG also assessed the impacts of non-gas savings following the NWPCC methodology. For the assessment, AEG used a calibration credit for space heating equipment consumption to account for secondary heating equipment present in an average home as well as other electric end-use impacts, such as cooling and interior lighting (as applicable), on a measure-by-measure basis.

Market Characterization

To estimate the savings potential from energy efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used. The characterization begins with a segmentation of Avista's natural gas footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies. To complete this step, AEG relied on information from Avista, NEEA, and secondary sources, as necessary.

Segmentation for Modeling Purposes

The market assessment first defined the market segments (building types, end uses, and other dimensions) relevant to Avista's service territory. The segmentation scheme is presented in Table 3-1.

Table 3-1 Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
0	State	Washington and Idaho
1	Sector	Residential, Commercial, Industrial
2	Segment	Residential: Single Family, Multifamily, and Mobile Home, by income group Commercial: Office, Restaurant, Retail, Grocery, School, College, Health, Lodging, Warehouse, Miscellaneous Industrial: Total
3	Vintage	Existing and new construction
4	End uses	Heating, secondary heating, water heating, food preparation, process, and miscellaneous (as appropriate by sector)
5	Appliances/end uses and technologies	Technologies such as furnaces, water heaters, and process heating by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, we then performed a high-level market characterization of natural gas sales in the base year, 2021. This information provided control totals at a sector level for calibrating the LoadMAP model to known data for the base-year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. The market profiles provide the foundation for the development of the baseline projection and the potential estimates. A market profile includes the following elements:

- Market size represents the number of customers in the segment. For the residential sector, it is the number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is the number of employees.
- Saturations indicate the share of the market that is served by a particular end use technology. Three types of saturation definitions are commonly used:
    - Conditioned space accounts for the fraction of each building that is conditioned by the end use, applying to cooling and heating end uses.
    - The whole-building approach measures shares of space in a building with an end use regardless of the portion of each building served by the end use. Examples are commercial refrigeration, food service, and domestic water heating and appliances.
    - The 100% saturation approach applies to end uses generally present in every building or home and are set to 100% in the base year.
- UEC (unit energy consumption) or EUI (energy use index) describes the amount of energy consumed in 2021 by a specific technology in buildings with the technology. UECs are expressed in therms/household for the residential sector and EUIs are expressed in therms/square foot for the commercial sector or therms/employee for the industrial sector.
- Annual Energy Intensity for the residential sector represents the average energy use for the technology across all homes in 2021 and is the product of the saturation. The commercial and industrial sectors represent the average use for the technology across all floor space or employees in 2021 and is the product of the saturation and EUI.
- Annual Usage is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in therms or dekatherms.

The market characterization and market profiles are presented in Chapter 3.

Baseline Projection

The next step was to develop the baseline projection of annual natural gas use for 2023 through 2045 by customer segment and end use in the absence of new utility energy efficiency programs. The baseline projection is the foundation for the analysis of savings in future conservation cases as well as the metric against which potential savings are measured. The end-use projection includes the impacts of future codes and standards that were effective as of May 2022.

Naturally occurring efficiency is energy conservation that is realized within the service area independent of utility-sponsored programs. It was incorporated into the baseline projection consistent with the EIA's Annual Energy Outlook (AEO) for the Pacific region.

Inputs to the baseline projection include:

- Avista's official forecast (Heating Degree Days base 65°F (HDD65)), calibrated to actual sales
- Current economic growth forecasts (i.e., customer growth, changes in weather (HDD65 normalization))
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards

We present the baseline projection for the system as a whole and for each sector in Chapter 4.

Washington HB 1444

Washington's HB 1444 established energy efficiency standards around equipment that exceed federal standards. These energy efficiency measures include but are not limited to showerheads, aerators, commercial food service equipment, and office equipment. This study's foundational setup included assumptions of HB-1444's impact on the available market for energy efficiency measures in Washington.

Conservation Measure Analysis

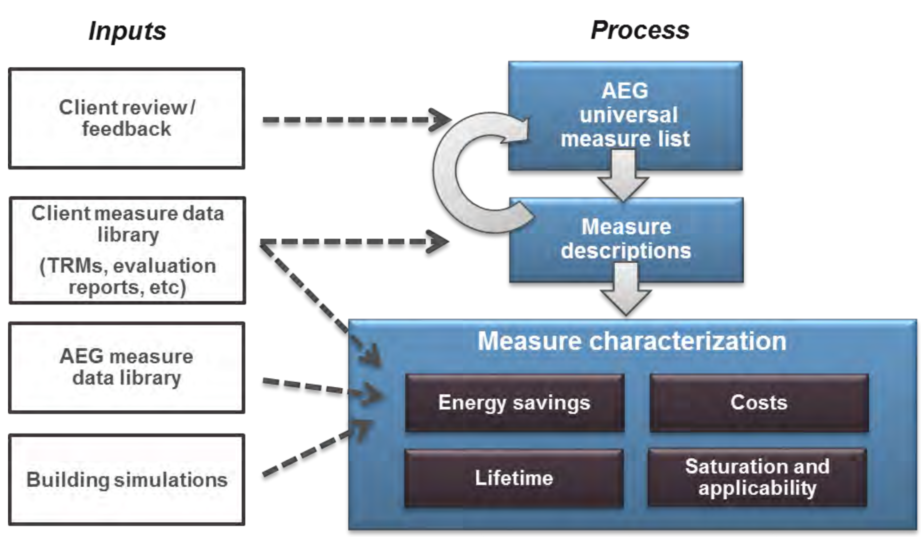
This section describes the framework used to assess conservation measures' savings, costs, and other attributes. These characteristics form the basis for measure-level cost-effectiveness analyses and determining measure-level savings. For all measures, AEG assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information combined with Avista's avoided cost data to inform the economic screens that determine economically feasible measures.

Conservation Measures

Figure 3-2 outlines the framework for conservation measure analysis. The framework involves identifying the list of measures to include in the analysis, determining their applicability to each sector and segment, and fully characterizing each measure. Finally, cost-effectiveness screening is performed. Avista provided feedback during each step to ensure measure assumptions and results lined up with programmatic experience.

AEG compiled a robust list of conservation measures for each customer sector, drawing upon Avista's Technical Reference Manual (TRM) and program experience, the RTF's Unit Energy Savings measure workbooks, and the 2021 Power Plan's electric power conservation supply curves, as well as a variety of secondary sources. This universal list of measures covers all major types of end use equipment, as well as devices and actions to reduce energy consumption.

Figure 3-2 Approach for Measure Development



The selected measures are categorized into the following two types according to the LoadMAP taxonomy:

- Equipment measures are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR® residential water heater (UEF 0.64) that replaces a standard efficiency water heater (UEF 0.58). For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by a code or standard) up to the most efficient product commercially available. These measures are applied on a stock-turnover basis and are generally referred to as lost opportunity measures by the NWPCC because once a purchase decision is made, there will not be another opportunity to improve the efficiency of the equipment until its effective useful life is reached.

- Non-equipment measures save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a furnace or water heater). An example would be low-flow showerheads that modify a household's hot water consumption. The showerhead can be replaced without waiting for the existing showerhead to malfunction, and saves energy used by the water heating equipment. Non-equipment measures typically fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (smart thermostats, water heater setback)
    - Whole-building design (ENERGY STAR homes)
    - Retrocommissioning and strategic energy management

We developed a preliminary list of efficient measures, which was distributed to Avista's project team for review. Once the measure list was finalized, AEG characterized measure savings, incremental cost, service life, non-energy impacts, and other performance factors. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential scenarios. Table 3-2 summarizes the number of measures evaluated within each sector.

Table 3-2 Number of Measures Evaluated

Sector	Total Measures	Measure Permutations w/ 2 Vintages	Measure Permutations w/ All Segments & States
Residential	61	122	1,464
Commercial	64	128	2,560
Industrial	34	68	136
Total Measures Evaluated	**159**	**318**	**4,160**

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied. Data sources included Avista, Northwest, and well-vetted national or other regional secondary sources. In general, data were adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Avista Data

Our highest priority data sources for this study were those that were specific to Avista.

- *Customer Data:* Avista provided billing data for development of customer counts and energy use for each sector. We also used the results of the Avista GenPOP survey, a residential saturation survey.
- *Load Forecasts:* Avista provided forecasts, by sector and state, of energy consumption, customer counts, weather actuals for 2020 and 2021, as well as weather-normal HDD65.
- *Economic Information:* Avista provided a discount rate as well as avoided cost forecasts consistent with those utilized in the IRP.
- *Program Data:* Avista provided information about past and current programs, including program descriptions, goals, and achievements to date.
- *Avista TRM:* Avista provided energy conservation measure assumptions within current programs. We utilized this as a primary source of measure information, supplemented secondary data.

Northwest Energy Efficiency Alliance Data

The NEEA conducts research for the Northwest region. The NEEA surveys were used extensively to develop base saturation and applicability assumptions for many of the non-equipment measures within the study.

The following studies were particularly useful:

- Residential Building Stock Assessment II, Single-Family Homes Report 2016-2017.
- Residential Building Stock Assessment II, Manufactured Homes Report 2016-2017.
- Residential Building Stock Assessment II, Multifamily Buildings Report 2016-2017.
- 2019 Commercial Building Stock Assessment, May 21, 2020.
- 2014 Industrial Facilities Site Assessment, December 29, 2014.

Northwest Power and Conservation Council Data

Several sources of data were used to characterize the conservation measures. We used the following regional data sources and supplemented with AEG's data sources to fill in any gaps.

- RTF Deemed Measures. The NWPCC RTF maintains databases of deemed measure savings data.
- NWPCC 2021 Power Plan and Regional Technical Forum Workbooks. To develop its Power Plan, the NWPCC maintains workbooks with detailed information about measures.
- NWPCC, MC and Loadshape File, September 29, 2016. The Council's load shape library was utilized to convert CPA results into hourly conservation impacts for use in Avista's IRP process.

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools has been incorporated into the analysis and deliverables for this study.

- AEG Energy Market Profiles: AEG maintains regional profiles of end-use consumption. The profiles include market size, fuel shares, unit consumption estimates, and annual energy use by fuel (electricity and natural gas), customer segment and end use for 10 regions in the U.S. The EIA surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- Building Energy Simulation Tool (BEST): AEG's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for HVAC-related measures.
- AEG's Database of Energy Efficiency Measures (DEEM): AEG maintains an extensive database of measure data, drawing upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.
- Recent studies: AEG has conducted numerous studies of energy efficiency potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies both within the region and across the country.

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources include:

- AEO: Conducted each year by the U.S. EIA, the AEO presents yearly projections and analysis of energy topics. For this study, we used data from the 2021 AEO.
- American Community Survey (ACS). The U.S. Census ACS is an ongoing survey that provides data every year on household characteristics.

- Local Weather Data: Weather from National Oceanic and Atmospheric Administration's National Climatic Data Center for Spokane, WA and Coure d'Alene in Idaho were used as the basis for building simulations.
- EPRI End-Use Models (REEPS and COMMEND): These models provide the elasticities we apply to prices, household income, home size and heating and cooling.
- DEER: The California Energy Commission and California Public Utilities Commission sponsor this database, which is designed to provide well-documented estimates of energy and peak demand savings values, measure costs, and effective useful life for the state of California.
- Other relevant regional sources: These include reports from the Consortium for Energy Efficiency, the Environmental Protection Agency, and the American Council for an Energy-Efficient Economy. This also includes technical reference manuals from other states. When using data from outside the region, especially weather-sensitive data, AEG adapted assumptions for use within Avista's territory.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of natural gas consumption and market size units (households for residential, floor space for commercial, and employees for industrial), we primarily used Avista's billing data as well as secondary data from AEG's Energy Market Profiles database.

- Residential Segments. Avista estimated the numbers of customers and average energy use per customer for each of the three segments, based on its GenPOP survey matched to billing data for surveyed customers. AEG compared the resulting segmentation with data from the ACS regarding housing types and income and found that the Avista segmentation corresponded well with the ACS data.
- C&I Segments. We relied upon the allocation from the previous energy efficiency potential study. For the previous study, customers and sales were allocated to building type based on SIC codes, with some adjustments between the C&I sectors to better group energy use by facility type and predominate end uses.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 3-3. To develop the market profiles for each segment, we used the following approach:

1. Developed control totals for each segment. These include market size, segment-level annual natural gas use, and annual intensity. Control totals were based on Avista's actual sales and customer-level information found in Avista's customer billing database.
2. Developed existing appliance saturations and the energy characteristics of appliances, equipment, and buildings using equipment flags within Avista's billing data; NEEA's RBSA, CBSA, and IFSA; U.S. EIA's surveys and AEO; AEG's Energy Market Profile for the Pacific region; and the American Community Survey.
3. Ensured calibration to control totals for annual natural gas sales in each sector and segment.
4. Compare and cross-checked with other recent AEG studies.
5. Worked with Avista staff to vet the data against their knowledge and experience.

Table 3-3 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	Avista 2020-2021 actual sales Avista customer account database
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	Avista customer account database AEG's Energy Market Profiles NEEA RBSA and CBSA AEO 2021 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Avista GenPOP Survey RBSA, CBSA, and IFSA ACS AEG's Energy Market Profiles
UEC/EUI for each end-use technology	UEC: Annual natural gas use in homes and buildings that have the technology EUI: Annual natural gas use per square foot/employee for a technology in floor space that has the technology	HVAC uses: BEST simulations using prototypes developed for Avista Engineering analysis AEG DEEM AEO 2021 Recent AEG studies
Appliance/equipment age distribution	Age distribution for each technology	RBSA, CBSA, and recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	Avista current program offerings AEG DEEM AEO 2021 DEER RTF and NWPCC 2021 Plan data Recent AEG studies

Data Application for Baseline Projection

Table 3-4 summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 3-4 Data Needs for the Baseline Projection and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial, and industrial sectors	Avista load forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipment data from AEO and ENERGY STAR AEO 2021 regional forecast assumptions[4] Appliance/efficiency standards analysis Avista program results and evaluation reports
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models

In addition, we implemented assumptions for known future equipment standards as of May 2022, as shown in

[4] We developed baseline purchase decisions using the EIA's *AEO* report (2016), which utilizes the National Energy Modeling System to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match distributions/allocations of efficiency levels to manufacturer shipment data for recent years.

Table 3-5 and

End-Use	Technology	2021	2022	2023	20
Space Heating	Furnace – Direct Fuel		AFUE 80%		
	Boiler – Direct Fuel			AFUE 80%	
Secondary Heating	Fireplace			N/A	
Water Heating	Water Heater <= 55 gal.			UEF 0.58	
	Water Heater > 55 gal.			UEF 0.76	
Appliances	Clothes Dryer			CEF 3.30	
	Stove/Oven			N/A	
Miscellaneous	Pool Heater			TE 0.82	
	Miscellaneous			N/A	

Table 3-6 Commercial and Industrial Natural Gas Equipment Standards

. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 3-5 Residential Natural Gas Equipment Standards[5]

End-Use	Technology	2021	2022	2023	2024	2025
Space Heating	Furnace – Direct Fuel	AFUE 80%			AFUE 90%	
	Boiler – Direct Fuel	AFUE 80%				
Secondary Heating	Fireplace	N/A				
Water Heating	Water Heater <= 55 gal.	UEF 0.58				
	Water Heater > 55 gal.	UEF 0.76				
Appliances	Clothes Dryer	CEF 3.30				
	Stove/Oven	N/A				
Miscellaneous	Pool Heater	TE 0.82				
	Miscellaneous	N/A				

Table 3-6 Commercial and Industrial Natural Gas Equipment Standards

End-Use	Technology	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 80% / TE 0.80			TE 0.90	
	Boiler	Average around AFUE 80% / TE 0.80 (varies by size)				
	Unit Heater	Standard (intermittent ignition and power venting or automatic flue damper)				
Water Heater	Water Heating	TE 0.80				
Food Preparation	Fryer	N/A	ENERGY STAR 3.0			
	Steamer	N/A	ENERGY STAR 1.2			
Miscellaneous	Pool Heater	TE 0.82				

[7] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Conservation Measure Data Application

Table 3-7 details the energy-efficiency data inputs to the LoadMAP model. It describes each input and identifies the key sources used in the Avista analysis.

Table 3-7 Data Needs for the Measure Characteristics in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Avista TRM NWPCC workbooks, RTF AEG BEST AEG DEEM AEO 2021 DEER Other secondary sources
Costs	Equipment Measures: full cost of purchasing and installing the equipment on a per-household, per-square-foot, or per employee basis for the residential, commercial, and industrial sectors, respectively. Non-Equipment Measures: Existing buildings – full installed cost. New Construction - costs may be either the full cost of the measure or, as appropriate, the incremental cost of upgrading from a standard level to a higher efficiency level.	Avista TRM NWPCC workbooks, RTF AEG DEEM AEO 2021 DEER RS Means Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Avista TRM NWPCC workbooks, RTF AEG DEEM AEO 2021 DEER Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector, or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	RBSA, CBSA WSEC for limitations on new construction AEG DEEM DEER Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Data Application for Cost-effectiveness Screening

All cost and benefit values were analyzed as real dollars, converted from nominal provided by Avista. We applied Avista's long-term discount rate of 5.21% excluding inflation. LoadMAP is configured to vary this by market sector (e.g., residential and commercial) if Avista develops alternative values in the future.

Estimates of Customer Adoption

Two parameters are needed to estimate the timing and rate of customer adoption in the potential forecasts.

- Technical diffusion curves for non-equipment measures. Equipment measures are installed when existing units fail. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules that generally align with the diffusion of similar equipment measures. For this analysis, we used the NWPCC's retrofit ramp rates, labeled "Retro".
- Adoption rates. Customer adoption rates or take rates are applied to technical potential to estimate Technical Achievable Potential. For equipment measures, the NWPCC's "Lost Opportunity" ramp rates were applied to technical potential with a maximum achievability of 85%-100% depending on the measure. For non-equipment measures, the NWPCC's "Retrofit" ramp rates have already been applied to calculate

technical diffusion. In this case, we multiply each of these by 85% (for most measures) to calculate Technical Achievable Potential.

4 | ENERGY EFFICIENCY MARKET CHARACTERIZATION

In this section, we describe how customers in the Avista service territory use natural gas in the base year of the study, 2021. It begins with a high-level summary of energy use across all sectors and then delves into each sector in more detail.

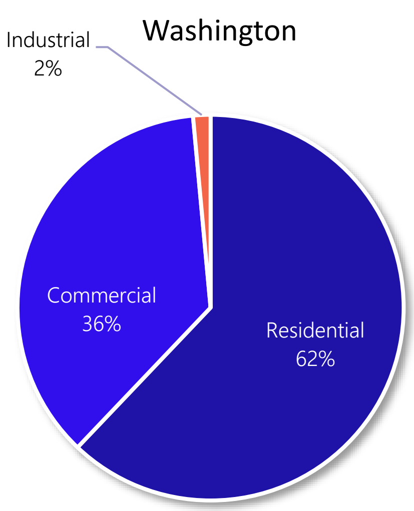
Energy Use Summary

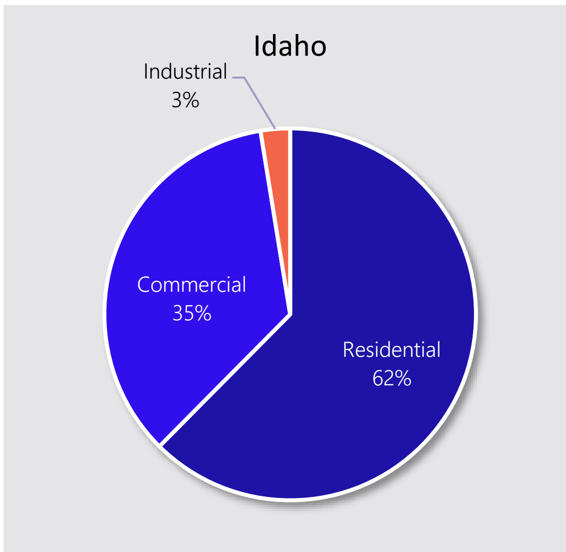
Avista's total natural gas consumption for the residential, commercial, and industrial sectors in 2021 was 27,285,801 dekatherms (dtherms or dth); 18,288,700 dtherms in Washington and 8,997,101 dtherms in Idaho. As shown in Table 4-1 and Figure 4-1, the residential sector accounts for the largest share of annual energy use at 62%, followed by the commercial sector at approximately 35%.

Table 4-1 Residential Sector Control Totals, 2021

	Washington		Idaho	
Sector	Natural Gas Usage (Dth)	% of Annual Use	Natural Gas Usage (Dth)	% of Annual Use
Residential	11,356,811	62.1%	5,617,143	62.4%
Commercial	6,665,122	36.4%	3,149,752	35.0%
Industrial	266,766	1.5%	230,206	2.6%
Total	18,288,700	100%	8,997,101	100%

Figure 4-1 Avista Sector-Level Natural Gas Use (2021)





Residential Sector

Washington Characterization

The total number of households and natural gas sales for the service territory were obtained from Avista's actual sales. In 2021, there were 157,808 households in the state of Washington that used a total of 11,356,811 dtherms, resulting in an average use per household of 720 therms per year. Table 4-2 and Figure 4-2 shows the total number of households and natural gas sales in the six residential segments for each state. These values represent weather actuals for 2021 and were adjusted within LoadMAP to normal weather using heating degree day, base 65°F, using data provided by Avista.

Table 4-2 Residential Sector Control Totals, Washington, 2021

Segment	Households	Natural Gas Use (dtherms)	Annual Use/Customer (therms/HH)
Single Family	84,836	7,324,885	863
Multi-Family	8,705	431,675	496
Mobile Home	5,136	305,566	595
Low Income - Single Family	39,810	2,481,707	623
Low Income – Multi-Family	15,263	546,435	358
Low Income – Mobile Home	4,057	266,544	657
Total	**157,808**	**11,356,811**	**720**

Figure 4-2 Residential Natural Gas Use by Segment, Washington, 2021

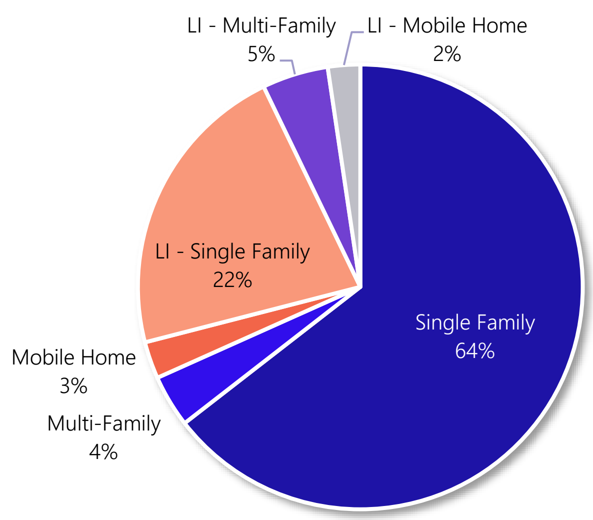


Figure 4-3 and Table 4-3 show the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises most of the load at 83%, followed by water heating at 12%. Appliances, secondary heating, and miscellaneous loads make up the remaining portion (5%) of the total load.

The market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector is presented in Table 4-3.

Figure 4-3 Residential Natural Gas Use by End Use, Washington, 2021

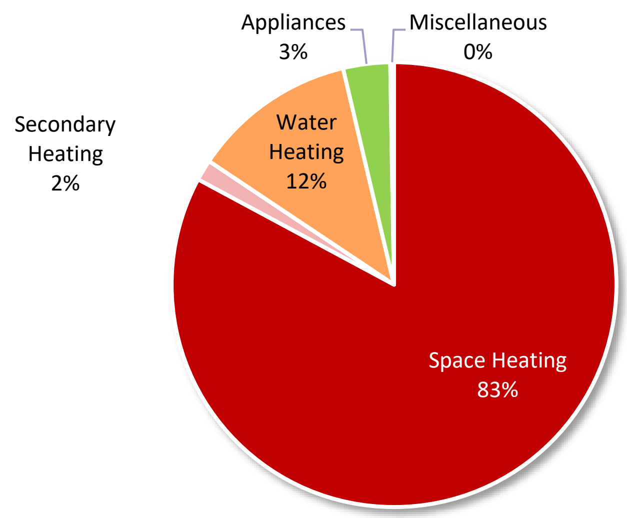
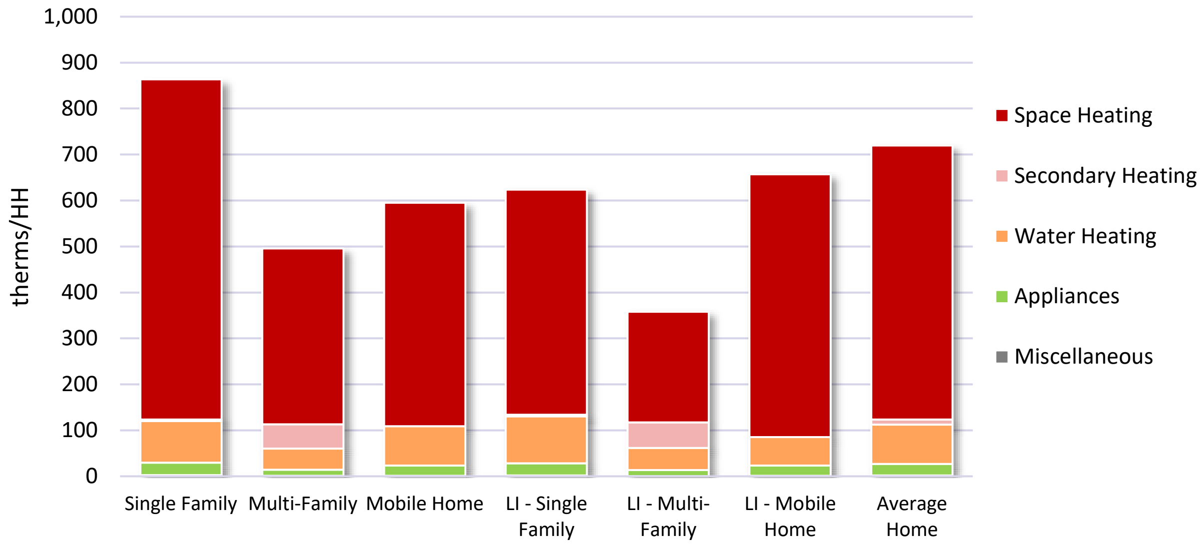


Table 4-3 Average Market Profile for the Residential Sector, Washington, 2021

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dtherms)
Space Heating	Furnace - Direct Fuel	84.8%	685	581	9,175,585
	Boiler - Direct Fuel	2.4%	628	15	233,076
Secondary Heating	Fireplace	5.1%	216	11	172,769
Water Heating	Water Heater (<= 55 Gal)	55.1%	156	86	1,356,503
	Water Heater (>55 Gal)	0.0%	148	0	457
Appliances	Clothes Dryer	28.4%	23	6	101,141
	Stove/Oven	58.6%	31	18	286,622
Miscellaneous	Pool Heater	0.9%	106	1	15,120
	Miscellaneous	100%	1	1	15,539
Total				**720**	**11,356,811**

Figure 4-4 presents average natural gas intensities by end use and housing type. Single family homes consume substantially more energy in space heating because single family homes are larger and more walls are exposed to the outside environment, compared to multifamily dwellings with many shared walls. Additional exposed walls increase heat transfer, resulting in greater heating loads. Water heating consumption is also higher in single family homes due to a greater number of occupants.

Figure 4-4 Residential Energy Intensity by End Use and Segment, Washington, 2021



Idaho Characterization

In 2021, there were 80,127 households in Avista's Idaho territory that used a total of 5,617,143 dtherms, resulting in an average use per household of 701 therms per year. Table 4-4 and Figure 4-5 shows the total number of households and natural gas sales in the six residential segments for each state.

Table 4-4 Residential Sector Control Totals, Idaho, 2021

Segment	Households	Natural Gas Use (dekatherms)	Annual Use/Customer (therms/HH)
Single Family	55,954	4,471,261	799
Multi-Family	8,690	379,050	436
Mobile Home	5,585	261,344	468
Low Income – Single Family	6,505	377,733	581
Low Income – Multi-Family	2,685	85,112	317
Low Income – Mobile Home	708	42,642	603
Total	**80,127**	**5,617,143**	**701**

Figure 4-5 Residential Natural Gas Use by Segment, Idaho, 2021

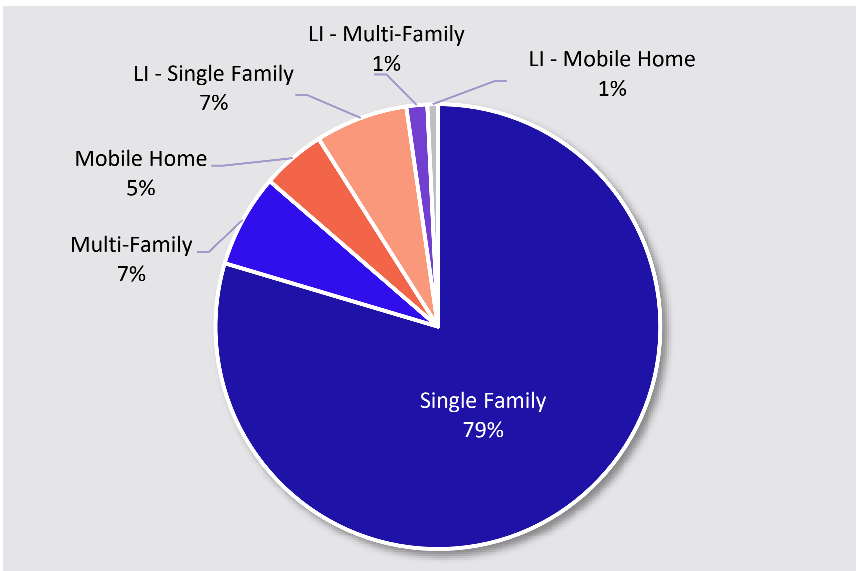


Figure 4-6 and Table 4-5 show the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises most of the load at 84%, followed by water heating at 12%. Appliances, secondary heating, and miscellaneous loads make up the remaining portion (4%) of the total load.

Figure 4-6 Residential Natural Gas Use by End Use, Idaho, 2021

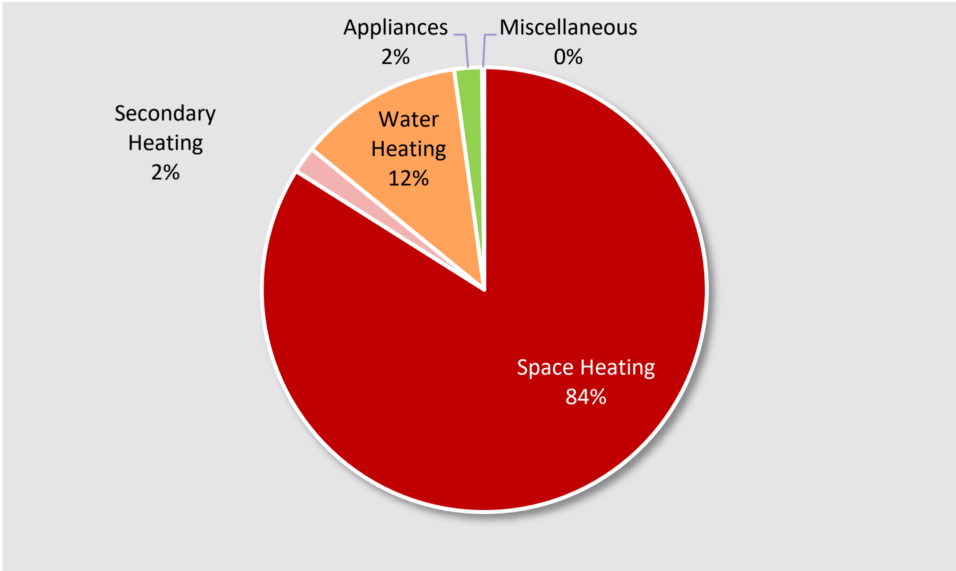
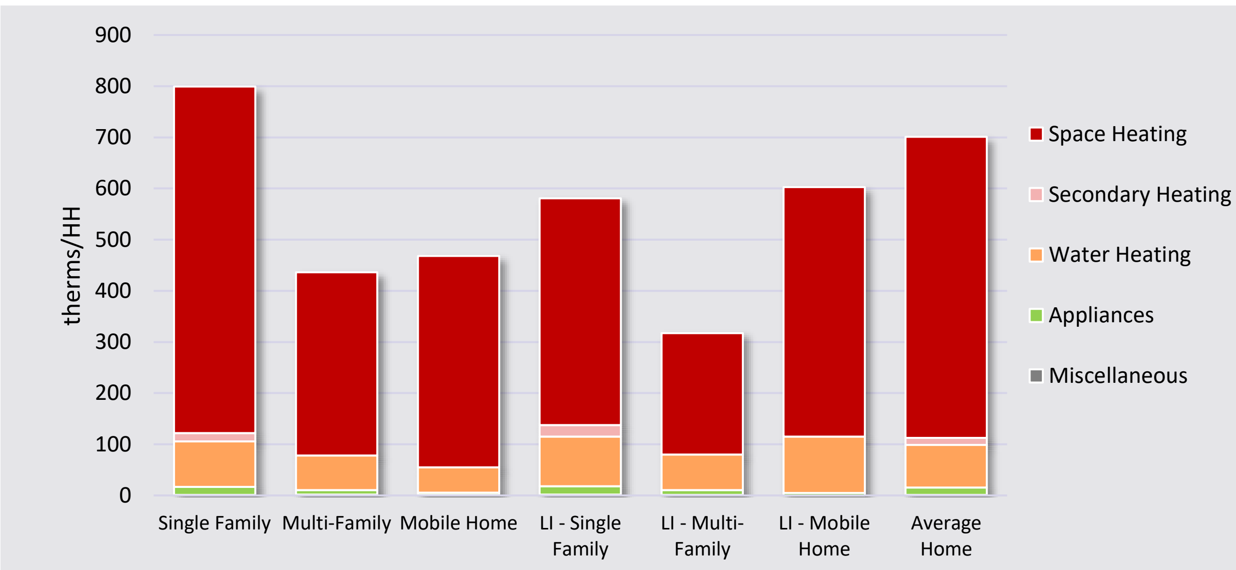


Table 4-5 Average Market Profile for the Residential Sector, Idaho 2021

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dtherms)
Space Heating	Furnace - Direct Fuel	88.0%	669	589	4,715,719
	Boiler - Direct Fuel	0.0%	-	-	-
Secondary Heating	Fireplace	6.0%	225	14	108,339
Water Heating	Water Heater (<= 55 Gal)	50.9%	152	77	618,978
	Water Heater (>55 Gal)	4.3%	151	7	52,229
Appliances	Clothes Dryer	16.2%	22	4	28,672
	Stove/Oven	34.7%	30	11	84,402
Miscellaneous	Pool Heater	0.3%	106	0	2,848
	Miscellaneous	100%	1	1	5,958
Total				**701**	**5,617,143**

Figure 4-7 presents average natural gas intensities by end use and housing type. Single family homes consume substantially more energy in space heating. Water heating consumption is higher in single family homes as well, due to a greater number of occupants, which increases the demand for hot water.

Figure 4-7 Residential Energy Intensity by End Use and Segment, Idaho, 2021 (Annual Therms/HH)



Commercial Sector

Washington Characterization

The total natural gas consumed by commercial customers in Avista's Washington service area in 2021 was 6,665,122 dtherm. The total number of non-residential accounts and natural gas sales for the Washington service territory were obtained from Avista's customer account database. AEG separated the commercial and industrial accounts by analyzing the SIC codes and rate codes assigned in the billing system. Energy use from accounts where the customer type could not be identified were distributed proportionally to all C&I segments. Once the billing data was analyzed, the final segment control totals were derived by distributing the total 2021 non-residential load to the sectors and segments according to the proportions in the billing data.

Table 4-6 shows the final allocation of energy to each segment in the commercial sector, as well as the energy intensity on a square-foot basis. Intensities for each segment were derived from a combination of the 2021 CBSA and equipment saturations extracted from Avista's database.

Table 4-6 Commercial Sector Control Totals, Washington, 2021

Segment	Description	Intensity (therms/Sq Ft)	Natural Gas Use (dekatherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.53	536,771
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.60	747,786
Retail	Department stores, services, boutiques, strip malls etc.	0.79	1,547,664
Grocery	Supermarkets, convenience stores, market, etc.	0.55	125,630
School	Day care, pre-school, elementary, secondary schools	0.28	187,678
College	College, university, trade schools, etc.	0.59	182,118
Health	Health practitioner office, hospital, urgent care centers, etc.	0.99	243,745
Lodging	Hotel, motel, bed and breakfast, etc.	0.67	370,063
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.57	688,567
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	0.95	2,035,100
Total		**0.78**	**6,665,122**

Figure 4-8 shows the distribution of annual natural gas consumption by segment across all commercial buildings. The three segments with the highest natural gas usage in 2021 are miscellaneous (30%), retail (23%), and restaurant (11%).

Figure 4-8 Commercial Natural Gas Use by Segment, Washington, 2021

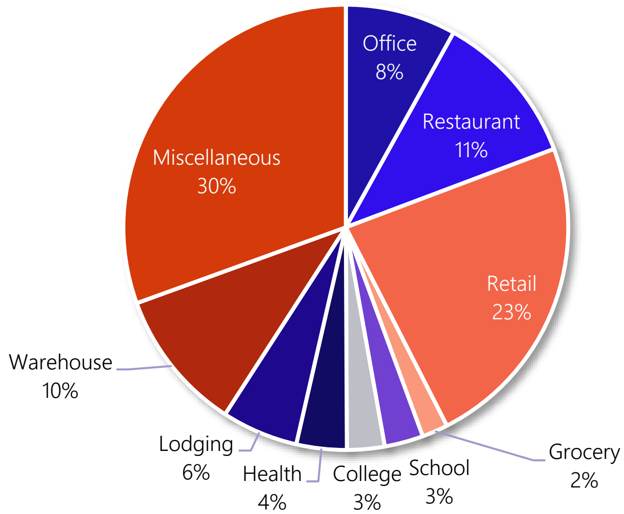


Figure 4-9 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed by water heating and food preparation. The miscellaneous end use is quite small, as expected.

Figure 4-9 Commercial Sector Natural Gas Use by End Use, Washington, 2021

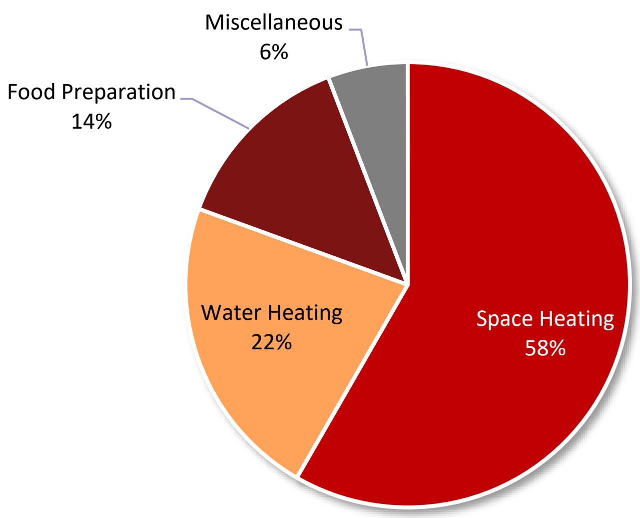


Figure 4-10 presents average natural gas intensities by end use and segment. In Washington, restaurants use the most natural gas in the service territory. Avista customer account data informed the market profile by providing information on saturation of key equipment types. Secondary data was used to develop estimates of energy intensity and square footage and fill in saturations for any equipment types not included in the database.

Figure 4-10 Commercial Energy Usage Intensity by End Use and Segment, Washington, 2021

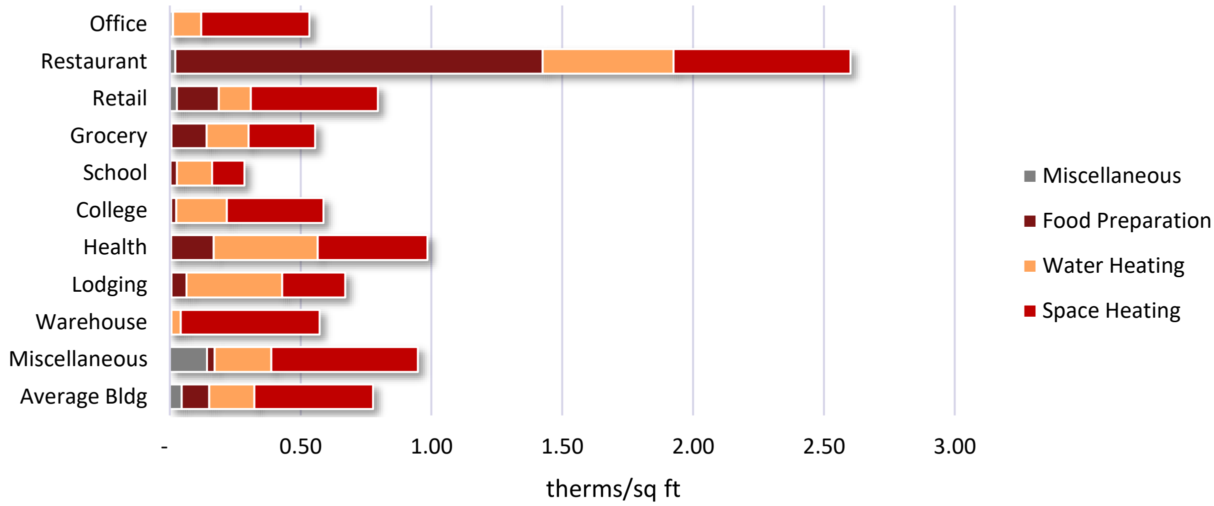


Table 4-7 shows the average market profile for the commercial sector as a whole, representing a composite of all segments and buildings.

Table 4-7 Average Market Profile for the Commercial Sector, Washington, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/Sq Ft)	Usage (dtherms)
Space Heating	Furnace	52.4%	0.55	0.29	2,485,626
	Boiler	21.9%	0.66	0.15	1,247,409
	Unit Heater	5.9%	0.31	0.02	156,793
Water Heating	Water Heater	58.7%	0.29	0.17	1,481,152
Food Preparation	Oven	11.3%	0.08	0.01	73,181
	Conveyor Oven	5.6%	0.13	0.01	62,609
	Double Rack Oven	5.6%	0.20	0.01	95,114
	Fryer	8.0%	0.44	0.04	300,472
	Broiler	13.3%	0.12	0.02	133,574
	Griddle	17.5%	0.08	0.01	118,981
	Range	17.8%	0.07	0.01	113,457
	Steamer	1.9%	0.07	0.00	10,828
	Commercial Food Prep Other	0.2%	0.02	0.00	221
Miscellaneous	Pool Heater	1.0%	0.06	0.00	5,419
	Miscellaneous	100%	0.04	0.04	383,287
Total				**0.78**	**6,665,122**

Idaho Characterization

The total natural gas consumed by commercial customers in Avista's Idaho service area in 2021 was 3,149,752 dtherm. Table 4-8 shows the final allocation of energy to each segment in the commercial sector, as well as the energy intensity on a square-foot basis. Intensities for each segment were derived from a combination of the 2021 CBSA and equipment saturations extracted from Avista's database.

Table 4-8 Commercial Sector Control Totals, Idaho, 2021

Segment	Description	Intensity (therms/Sq Ft)	Natural Gas Use (dekatherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.53	226,954
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.60	139,154
Retail	Department stores, services, boutiques, strip malls etc.	0.79	959,894
Grocery	Supermarkets, convenience stores, market, etc.	0.55	58,138
School	Day care, pre-school, elementary, secondary schools	0.28	184,533
College	College, university, trade schools, etc.	0.59	179,370
Health	Health practitioner office, hospital, urgent care centers, etc.	1.01	102,436
Lodging	Hotel, motel, bed and breakfast, etc.	0.67	170,255
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.57	334,864
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	0.95	794,154
Total		0.70	3,149,752

Figure 4-11 shows the distribution of annual natural gas consumption by segment across all commercial buildings. The three segments with the highest natural gas usage in 2021 are retail (31%), miscellaneous (25%), and warehouse (11%).

Figure 4-11 Commercial Natural Gas Use by Segment, Idaho, 2021

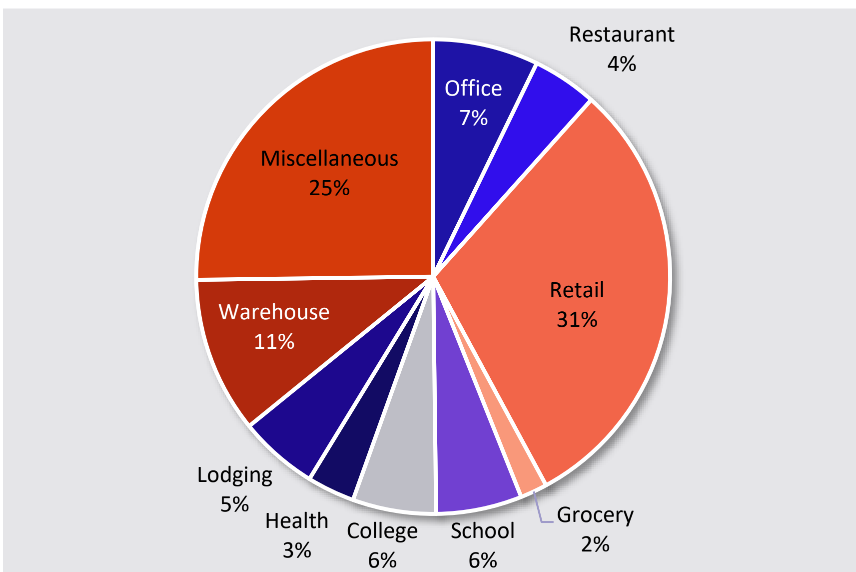


Figure 4-12 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed by water heating and food preparation. The miscellaneous end use is quite small, as expected.

Figure 4-12 Commercial Sector Natural Gas Use by End Use, Idaho, 2021

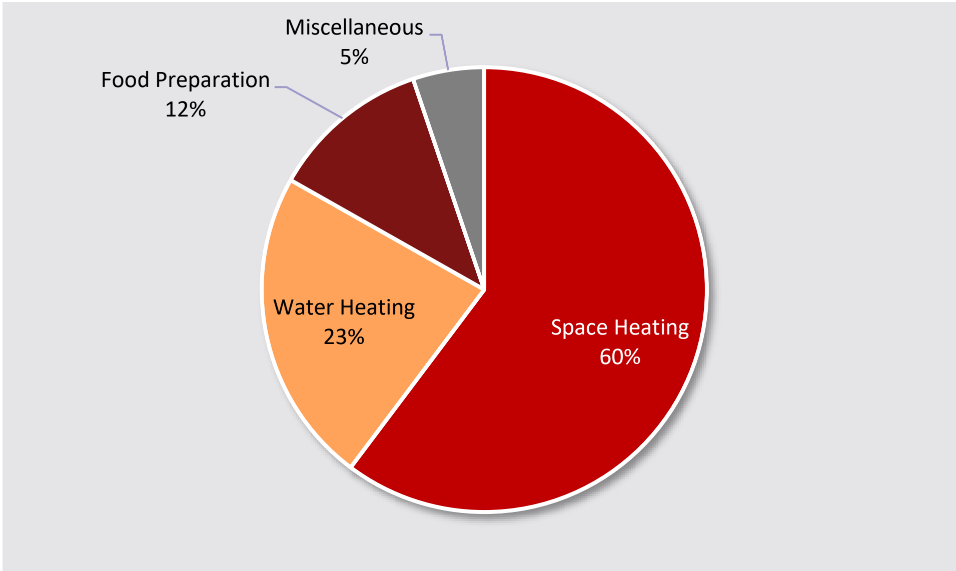


Figure 4-13 presents average natural gas intensities by end use and segment. In Idaho, restaurants use the most natural gas in the service territory. Avista customer account data informed the market profile by providing information on saturation of key equipment types. Secondary data was used to develop estimates of energy intensity and square footage and fill in saturations for any equipment types not included in the database.

Figure 4-13 Commercial Energy Usage Intensity by End Use and Segment, Idaho, 2021

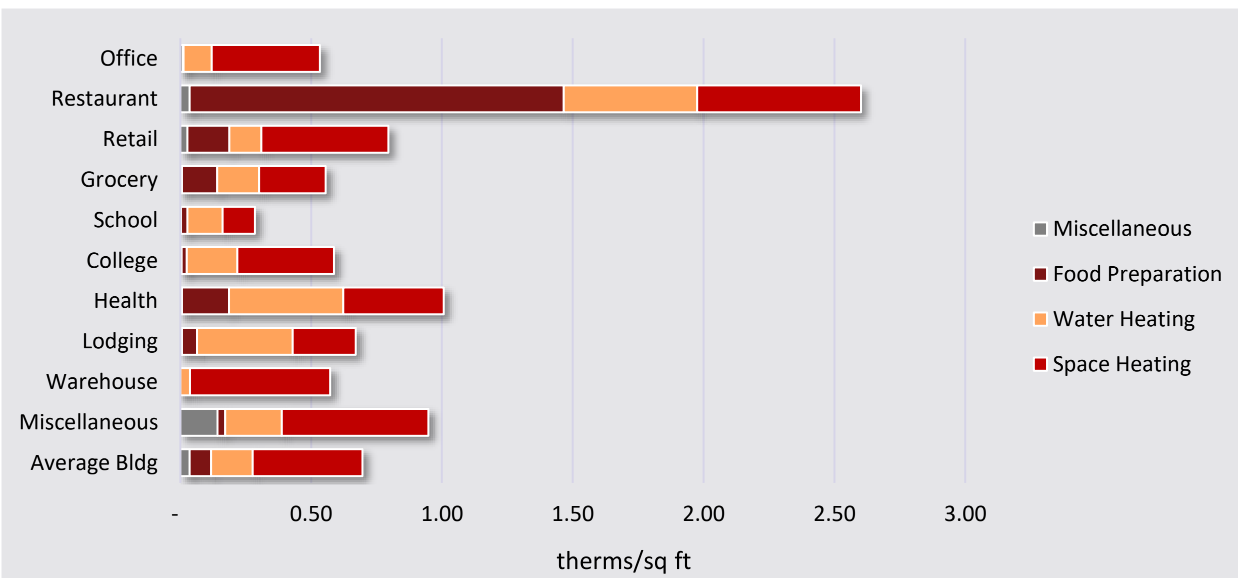


Table 4-9 shows the average market profile for the commercial sector as a whole, representing a composite of all segments and buildings.

Table 4-9 Average Market Profile for the Commercial Sector, Idaho, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/Sq Ft)	Usage (dtherms)
Space Heating	Furnace	50.1%	0.53	0.26	1,194,251
	Boiler	24.5%	0.56	0.14	621,861
	Unit Heater	6.2%	0.29	0.02	81,760
Water Heating	Water Heater	60.5%	0.26	0.16	722,590
Food Preparation	Oven	9.7%	0.09	0.01	40,281
	Conveyor Oven	4.8%	0.16	0.01	34,461
	Double Rack Oven	4.8%	0.24	0.01	52,353
	Fryer	6.8%	0.44	0.03	134,342
	Broiler	11.1%	0.07	0.01	33,837
	Griddle	15.2%	0.05	0.01	33,185
	Range	16.0%	0.05	0.01	32,941
	Steamer	2.6%	0.04	00.0	4,364
	Commercial Food Prep Other	0.3%	0.01	0.00	118
Miscellaneous	Pool Heater	0.9%	0.05	0.00	2,146
	Miscellaneous	100%	0.04	0.04	161,261
Total				**0.70**	**3,149,752**

Industrial Sector

Table 4-10 Industrial Sector Control Totals, 2021

Segment	Intensity (therms/employee)	Natural Gas Usage (dtherms)
Washington Industrial	1,699	266,766
Idaho Industrial	2,327	230,206

Washington Characterization

The total natural gas consumed by industrial customers in Avista's Washington service area in 2021 was 266,766 dtherms. Like in the commercial sector, customer account data was used to allocate usage among segments. Energy intensity was derived from AEG's Energy Market Profiles database. Most industrial measures are installed through custom programs, where the unit of measure is not as necessary to estimate potential.

Figure 4-14 shows the distribution of annual natural gas consumption by end use for all industrial customers. Two major sources were used to develop this consumption profile. The first was AEG's analysis of warehouse usage as part of the commercial sector. We begin with this prototype as a starting point to represent non-process loads. We then added in process loads using our Energy Market Profiles database, which summarizes usage by end use and process type.

Figure 4-14 Industrial Natural Gas Use by End Use, Washington, 2021

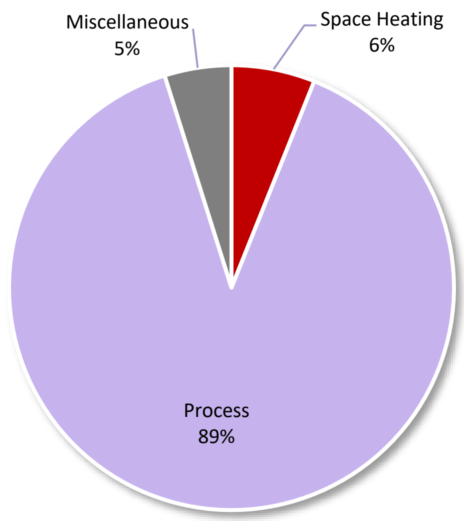


Table 4-11 shows the composite market profile for the Washington industrial sector. Process cooling is very small and represents niche technologies such as gas-driven absorption chillers.

Table 4-11 Average Natural Gas Market Profile for the Industrial Sector, Washington, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dtherms)
Space Heating	Furnace	32.3%	103.12	33.3	5,230
	Boiler	51.5%	103.12	53.2	8,346
	Unit Heater	16.2%	103.12	16.7	2,615
Process	Process Boiler	100%	750.42	750.4	117,823
	Process Heating	100%	686.11	686.1	107,725
	Process Cooling	100%	6.65	6.7	1,045
	Other Process	100%	70.14	70.1	11,012
Miscellaneous	Miscellaneous	100%	82.61	82.6	12,971
Total				**1,699.1**	**266,766**

Idaho Characterization

The total natural gas consumed by industrial customers in Avista's Idaho service area in 2021 was 230,206 dtherms.

Figure 4-15 shows the distribution of annual natural gas consumption by end use for all industrial customers. Two major sources were used to develop this consumption profile. The first was AEG's analysis of warehouse usage as part of the commercial sector. We begin with this prototype as a starting point to represent non-process loads. We then added in process loads using our Energy Market Profiles database, which summarizes usage by end use and process type.

Figure 4-15 Industrial Natural Gas Use by End Use, Idaho, 2021

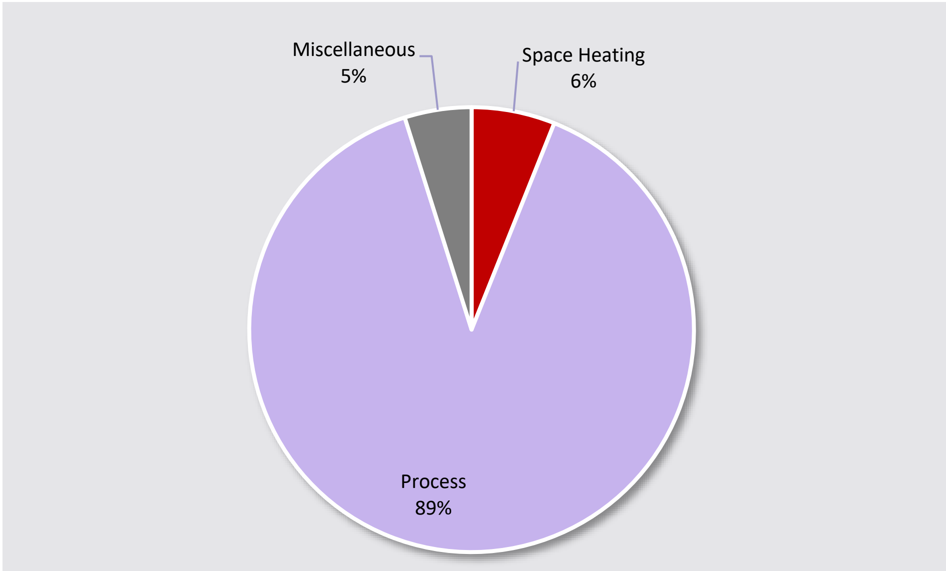


Table 4-12 shows the composite market profile for the industrial sector. Process cooling is very small and represents technologies such as gas-driven absorption chillers.

Table 4-12 Average Natural Gas Market Profile for the Industrial Sector, Idaho, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dekatherms)
Space Heating	Furnace	32.3%	141.24	45.6	4,513
	Boiler	51.5%	141.24	72.8	7,203
	Unit Heater	16.2%	141.24	22.8	2,257
Process	Process Boiler	100.0%	1,027.79	1,027.8	101,675
	Process Heating	100.0%	939.70	939.7	92,961
	Process Cooling	100.0%	9.11	9.1	901
	Other Process	100.0%	96.06	96.1	9,503
Miscellaneous	Miscellaneous	100.0%	113.14	113.1	11,193
Total				**2,327.0**	**230,206**

5 | BASELINE PROJECTION

Prior to developing estimates of energy efficiency potential, we developed a baseline end-use projection to quantify the likely future consumption in absence of any future conservation programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future. Possible savings from future programs are captured by the potential estimates.

The baseline projection incorporates assumptions about:

- 2021 energy consumption based on the market profiles
- Customer forecast and population growth
- Appliance/equipment standards and building codes and purchase decisions
- Trends in fuel shares and appliance saturations and assumptions about miscellaneous natural gas growth

This chapter presents the annual baseline natural gas projections developed for each sector and state. Although it aligns closely, the baseline projection is not Avista's official load forecast. It was developed to serve as the metric against which energy efficiency potentials are measured.

Overall Baseline Projection

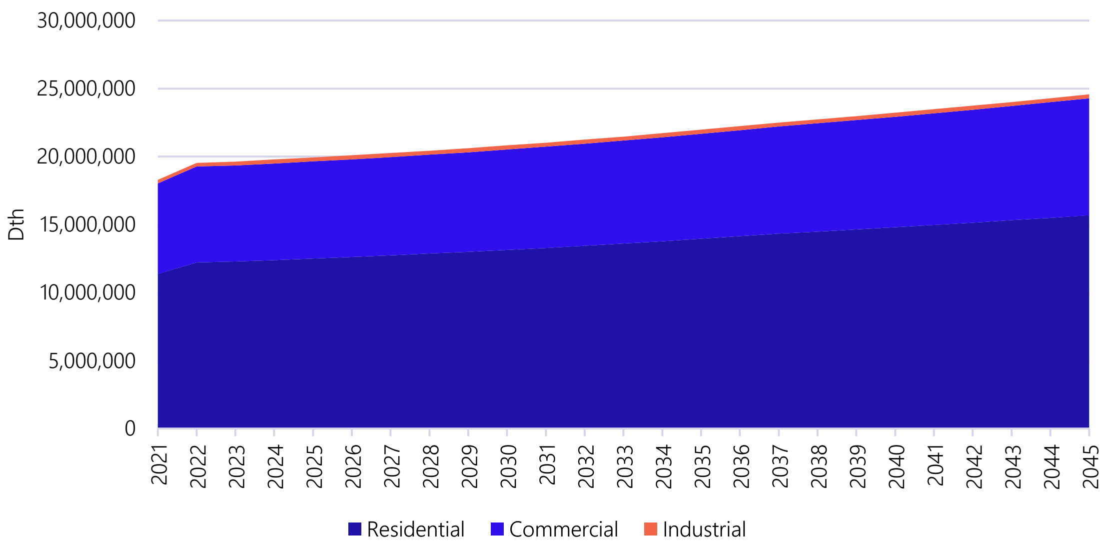
Washington

Table 5-1 and **Error! Reference source not found.** summarize the baseline projection for annual use by sector for Avista's Washington service territory. The forecast shows modest annual growth, driven by the residential and commercial sectors.

Table 5-1 Baseline Projection Summary by Sector, Washington (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Residential	11,356,811	12,274,400	12,387,892	12,501,697	13,948,186	15,683,198	38.10%
Commercial	6,665,122	7,069,971	7,101,191	7,136,906	7,720,617	8,594,749	28.95%
Industrial	266,766	287,959	293,150	296,345	298,131	298,267	11.81%
Total	**18,288,700**	**19,632,329**	**19,782,233**	**19,934,947**	**21,966,934**	**24,576,214**	**34.38%**

Figure 5-1 Baseline Projection Summary by Sector, Washington



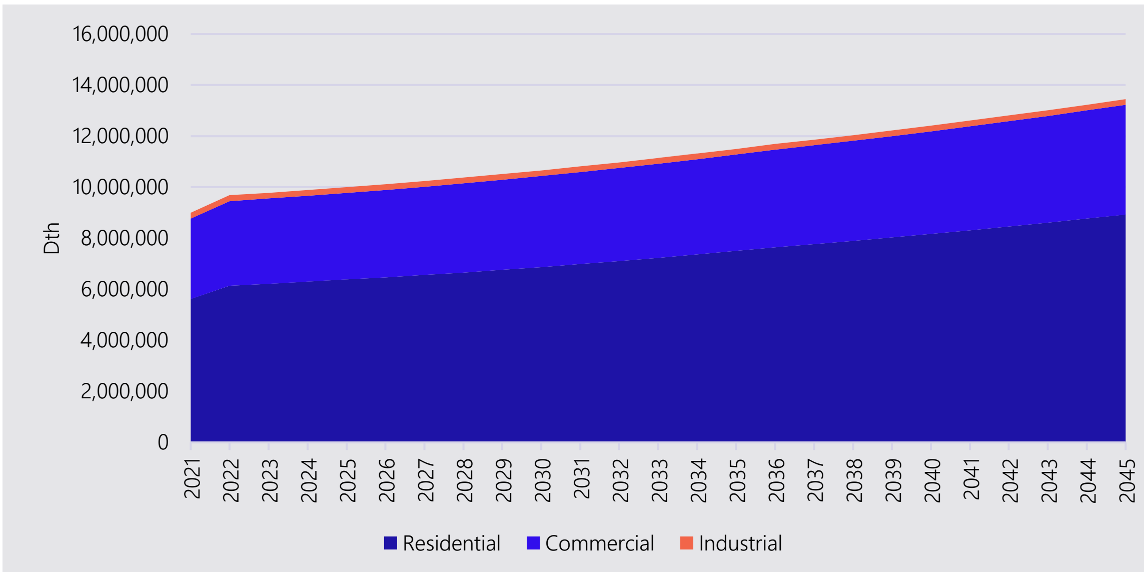
Idaho

Table 5-2 and Figure 5-2 summarize the baseline projection for annual use by sector for Avista's Idaho service territory. The forecast shows modest annual growth, driven by the residential and commercial sectors.

Table 5-2 Baseline Projection Summary by Sector, Idaho (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Residential	5,617,143	6,215,422	6,300,557	6,382,522	7,499,611	8,929,190	58.96%
Commercial	3,149,752	3,342,401	3,368,913	3,397,011	3,778,711	4,299,692	36.51%
Industrial	230,206	223,967	223,982	223,868	222,921	222,119	-3.51%
Total	**8,997,101**	**9,781,790**	**9,893,452**	**10,003,402**	**11,501,243**	**13,451,001**	**49.50%**

Figure 5-2 Baseline Projection Summary by Sector, Idaho



Residential Sector

Washington Projection

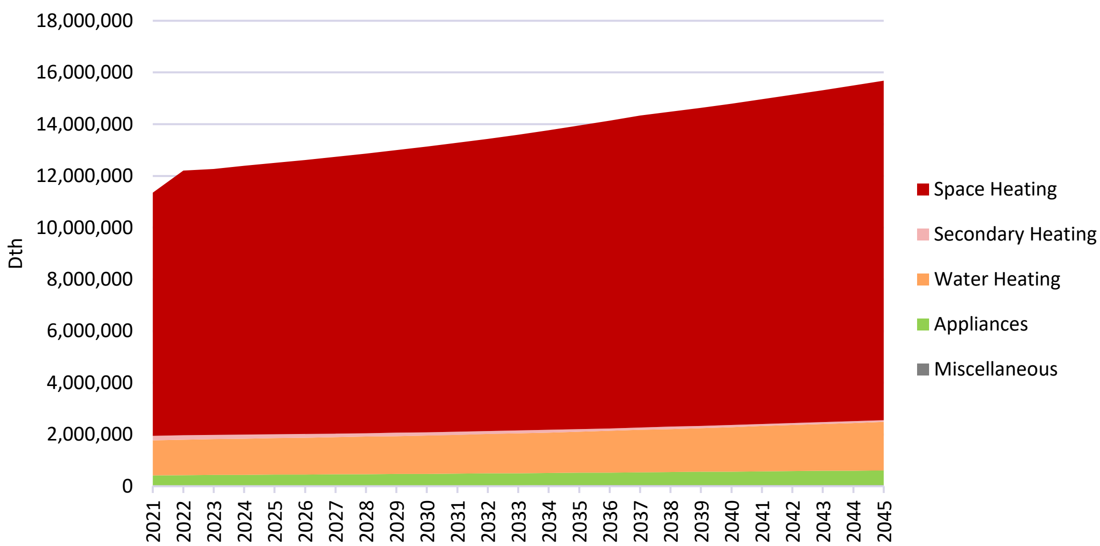
Table 5-3 and Figure 5-3 present the baseline projection for natural gas at the end-use level for the residential sector. Overall, residential use increases from 11,356,811 dtherms in 2021 to 15,683,198 dtherms in 2045 (38.1%). Factors affecting growth include a moderate increase in the number of households and customers as well as a decrease in equipment consumption due to standards and naturally occurring efficiency.

We model gas-fired fireplaces as secondary heating. These consume energy and may heat a space but are rarely used as the primary heating technology. As such, they are estimated to be more aesthetic and less weather-dependent. This end use grows faster than others since new homes are more likely to install a unit, increasing fireplace stock. Miscellaneous is a very small end use, including technologies with low penetration, such as gas barbeques.

Table 5-3 Residential Baseline Projection by End Use, Washington (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	9,408,661	10,290,384	10,391,860	10,493,546	11,739,189	13,126,445	39.5%
Secondary Heating	172,769	164,209	157,168	150,444	98,948	66,939	-61.3%
Water Heating	1,356,961	1,387,160	1,399,677	1,411,982	1,589,357	1,875,045	38.2%
Appliances	387,763	401,031	407,136	413,242	483,593	572,381	47.6%
Miscellaneous	30,658	31,616	32,051	32,482	37,100	42,388	38.3%
Total	**11,356,811**	**12,274,400**	**12,387,892**	**12,501,697**	**13,948,186**	**15,683,198**	**38.1%**

Figure 5-3 Residential Baseline Projection by End Use, Washington



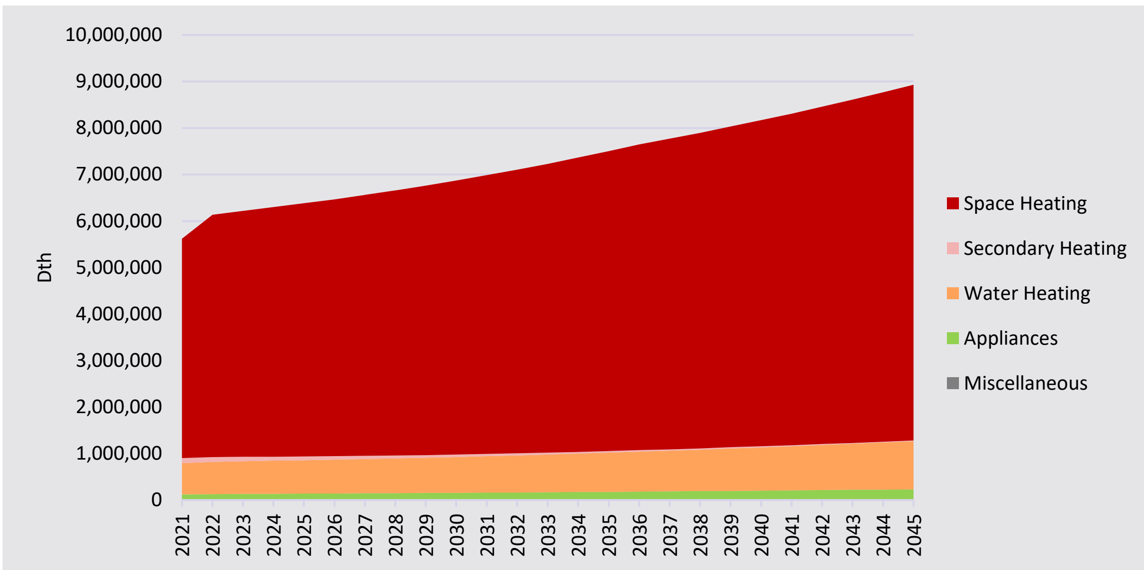
Idaho Projection

Error! Reference source not found. and Figure 5-4 present the baseline projection for natural gas at the end-use level for the residential sector. Overall, residential use increases from 5,617,143 dtherms in 2021 to 8,929,190 dtherms in 2045, an increase of 59.0%.

Table 5-4 Residential Baseline Projection by End Use, Idaho (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	4,715,719	5,287,189	5,367,732	5,445,288	6,446,442	7,649,958	62.2%
Secondary Heating	108,339	96,535	88,722	81,446	34,921	15,001	-86.2%
Water Heating	671,206	701,265	710,412	718,910	841,874	1,033,899	54.0%
Appliances	113,073	121,097	124,167	127,175	164,577	215,963	91.0%
Miscellaneous	8,806	9,336	9,523	9,703	11,797	14,369	63.2%
Total	**5,617,143**	**6,215,422**	**6,300,557**	**6,382,522**	**7,499,611**	**8,929,190**	**59.0%**

Figure 5-4 Residential Baseline Projection by End Use, Idaho



Commercial Sector

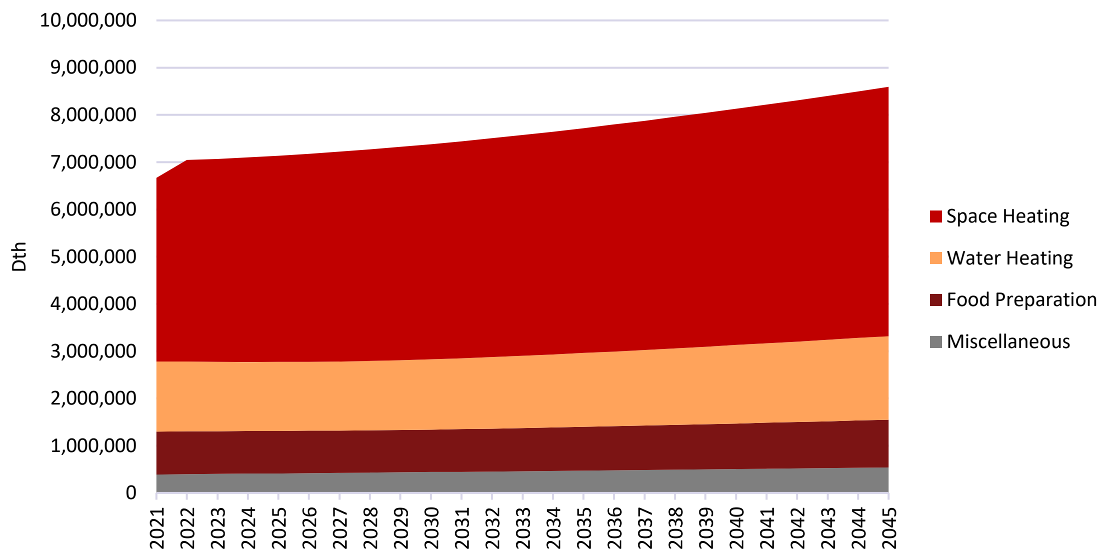
Washington Projection

Annual natural gas use in the commercial sector grows 29.0% during the overall forecast horizon, starting at 6,665,122 dtherms in 2021, and increasing to 8,594,749 dtherms in 2045. Table 5-5 and **Error! Reference source not found.** present the baseline projection at the end-use level for the commercial sector, as a whole. Similar to the residential sector, market size is increasing and usage per square foot is decreasing slightly.

Table 5-5 Commercial Baseline Projection by End Use, Washington (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	3,886,828	4,295,626	4,330,709	4,365,994	4,759,146	5,275,544	35.7%
Water Heating	1,481,152	1,467,668	1,461,346	1,458,458	1,563,969	1,770,182	19.5%
Appliances	908,437	903,690	900,737	898,613	925,243	1,009,887	11.2%
Miscellaneous	388,706	402,987	408,399	413,840	472,259	539,135	38.7%
Total	**6,665,122**	**7,069,971**	**7,101,191**	**7,136,906**	**7,720,617**	**8,594,749**	**29.0%**

Figure 5-5 Commercial Baseline Projection by End Use, Washington



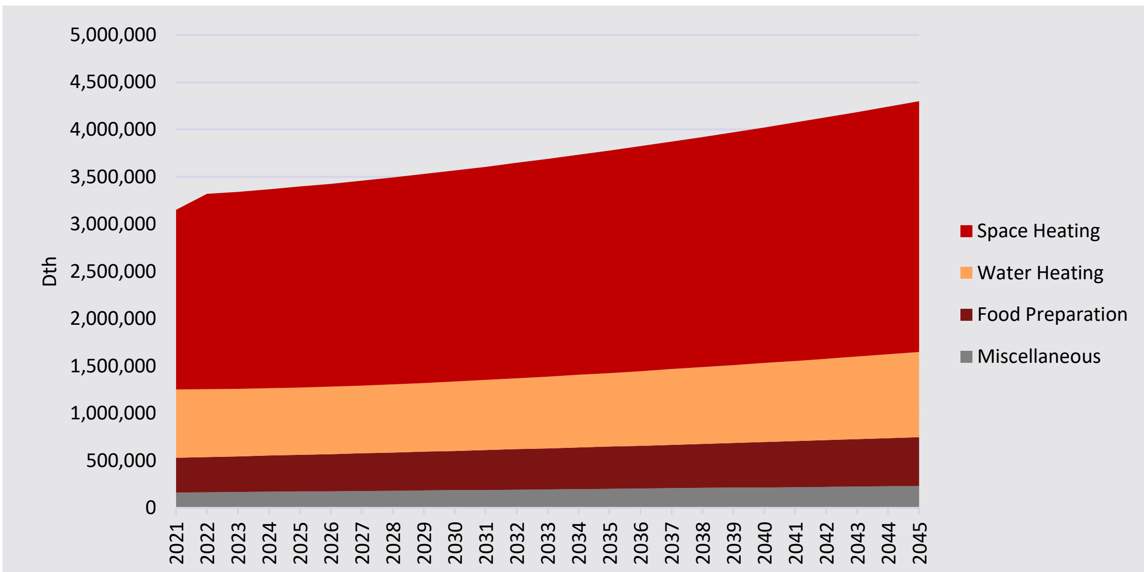
Idaho Projection

Annual natural gas use in the Idaho commercial sector grows 36.5% during the forecast horizon, starting at 3,149,752 dtherms in 2021, and increasing to 4,299,692 dtherms in 2045. Table 5-6 and Figure 5-6 present the baseline projection at the end-use level for the commercial sector. Similar to the residential sector, market size is increasing and usage per square foot is decreasing slightly.

Table 5-6 Commercial Baseline Projection by End Use, Idaho (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	1,897,872	2,083,872	2,104,055	2,124,262	2,352,655	2,653,169	39.8%
Water Heating	722,590	713,016	711,324	711,267	778,543	899,018	24.4%
Food Preparation	365,882	377,145	382,602	387,980	446,014	513,408	40.3%
Miscellaneous	163,408	168,369	170,932	173,502	201,500	234,097	43.3%
Total	**3,149,752**	**3,342,401**	**3,368,913**	**3,397,011**	**3,778,711**	**4,299,692**	**36.5%**

Figure 5-6 Commercial Baseline Projection by End Use, Idaho



Industrial Sector

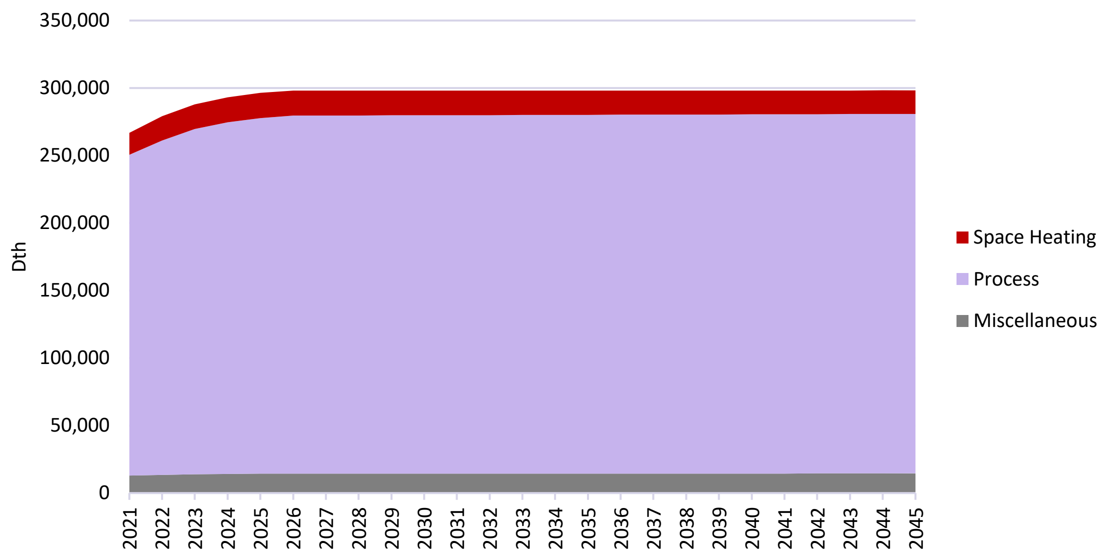
Washington Projection

Industrial sector usage increases throughout the planning horizon. Table 5-7 and Figure 5-7 present the projection at the end-use level. Overall, industrial annual natural gas use increases from 266,766 dtherms in 2021 to 298,267 dtherms in 2040, an increase of 11.8%.

Table 5-7 Industrial Baseline Projection by End Use, Washington (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	16,191	18,321	18,519	18,611	17,961	17,407	7.5%
Process	237,604	255,680	260,415	263,357	265,667	266,323	12.1%
Miscellaneous	12,971	13,957	14,216	14,376	14,502	14,538	12.1%
Total	**266,766**	**287,959**	**293,150**	**296,345**	**298,131**	**298,267**	**11.8%**

Figure 5-7 Industrial Baseline Projection by End Use, Washington



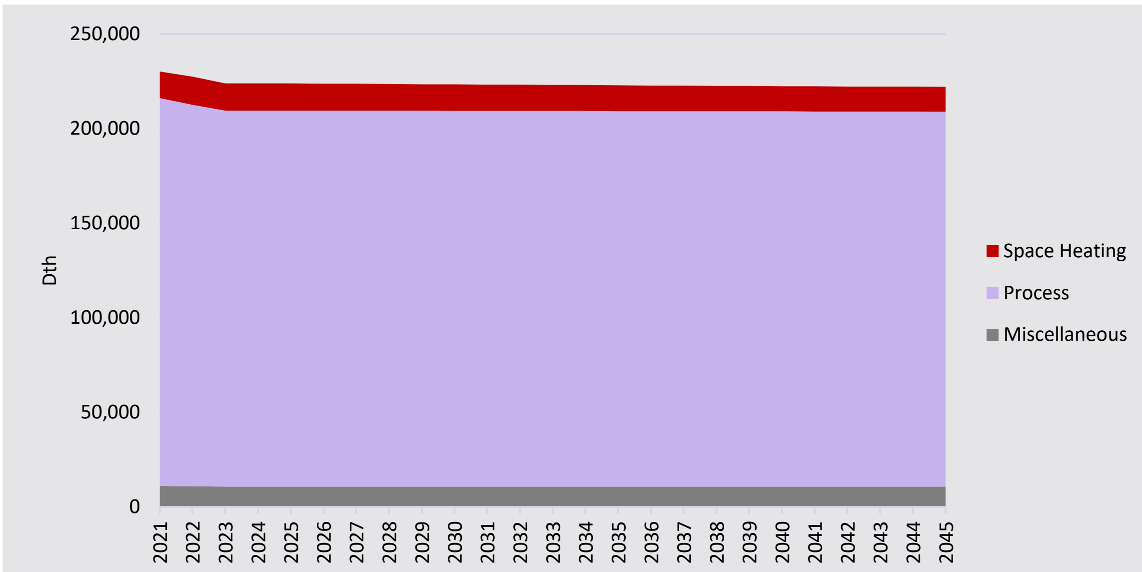
Idaho Projection

Industrial annual natural gas use decreases from 230,206 dtherms in 2021 to 222,119 dtherms in 2045, a decrease of 3.5%. Table 5-8 and Figure 5-8 present the projection at the end-use level.

Table 5-8 Industrial Baseline Projection by End Use, Idaho (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	13,972	14,459	14,392	14,317	13,624	13,111	-6.2%
Process	205,041	198,663	198,741	198,704	198,463	198,190	-3.3%
Miscellaneous	11,193	10,845	10,849	10,847	10,834	10,819	-3.3%
Total	**230,206**	**223,967**	**223,982**	**223,868**	**222,921**	**222,119**	**-3.5%**

Figure 5-8 Industrial Baseline Projection by End Use, Idaho



6 | CONSERVATION POTENTIAL

This chapter presents the conservation potential across all sectors for Avista's Washington and Idaho territories. Conservation potential includes every measure considered in the measure list, regardless of delivery mechanism (program implementation, etc.). Year-by-year annual energy savings are available in the LoadMAP model and measure assumption summary, provided to Avista at the conclusion of the study. Please note that all savings are at the customer site.

Washington Overall Energy Efficiency Potential

Error! Reference source not found. and Figure 6-1 summarize the conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection.

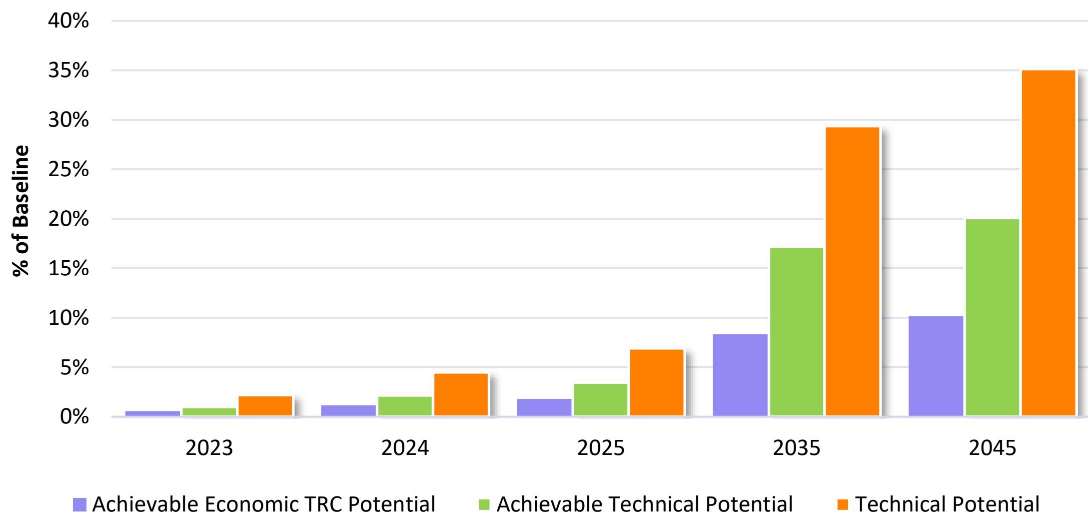


Figure 6-2 displays the cumulative energy conservation forecasts, which reflect the effects of persistent savings in prior years and new savings.

- Technical Potential reflects the adoption of all conservation measures regardless of cost-effectiveness. Efficient equipment makes up all lost opportunity installations and all retrofit measures are installed, regardless of achievability. First-year savings are 429,564 dtherms, or 2.2% of the baseline projection. Cumulative savings in 2045 are 8,637,218 dtherms, or 35.1% of the baseline.
- Achievable Technical Potential refines Technical Potential by applying market adoption rates to each measure. The market adoption rates estimate the percentage of customers who would be likely to select each measure given market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. First-year savings are 191,654 dtherms, or 1.0% of the baseline projection. Cumulative savings in 2045 are 4,938,238 dtherms, or 20.1% of the baseline.
- TRC Achievable Economic Potential refines Achievable Technical Potential by applying the TRC economic cost-effectiveness screen, which compares lifetime energy benefits to the total customer and utility costs of delivering the measure through a utility program, including monetized non-energy impacts. For the TRC, AEG also applied (1) benefits for non-gas energy savings, such as electric HVAC savings for weatherization, (2) the NWPCC's calibration credit to space heating savings to reflect that additional fuels may be used as a supplemental heat source within an average home, and (3) a 10% conservation credit to avoided costs per the NWPCC methodologies. First-year savings are 111,992 dtherms, or 0.6% of the baseline projection. Cumulative savings in 2045 are 2,497,540 dtherms, or 10.2% of the baseline.

Table 6-1 Summary of Energy Efficiency Potential, Washington

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	19,632,329	19,782,233	19,934,947	21,966,934	24,576,214
Cumulative Savings (Dth)					
TRC Achievable Economic Potential	111,992	225,734	361,485	1,833,863	2,497,540
Achievable Technical Potential	191,654	423,238	686,518	3,774,115	4,938,238
Technical Potential	429,564	884,194	1,375,956	6,455,295	8,637,218
Energy Savings (% of Baseline)					
TRC Achievable Economic Potential	0.6%	1.1%	1.8%	8.3%	10.2%
Achievable Technical Potential	1.0%	2.1%	3.4%	17.2%	20.1%
Technical Potential	2.2%	4.5%	6.9%	29.4%	35.1%

Figure 6-1 Cumulative Energy Efficiency Potential as % of Baseline Projection, Washington

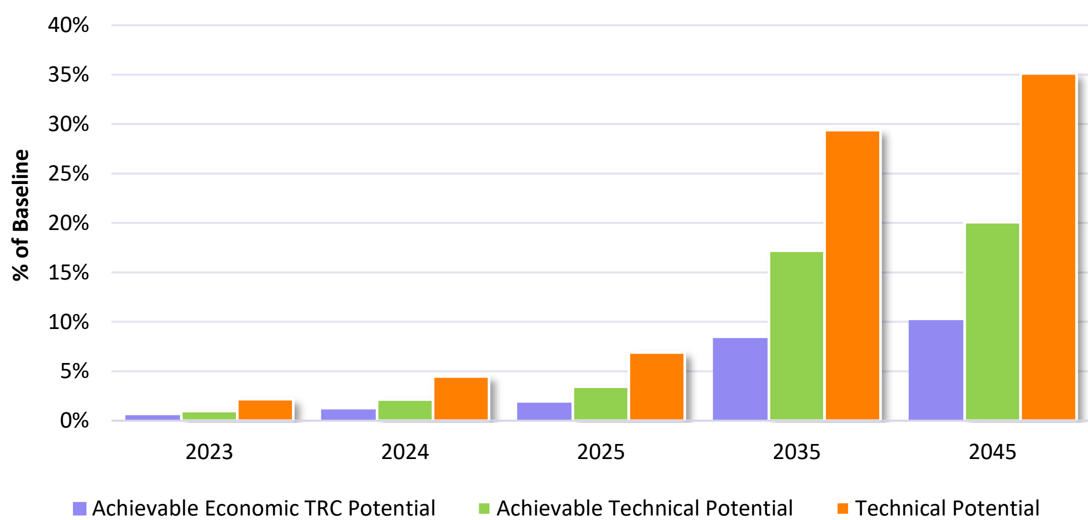
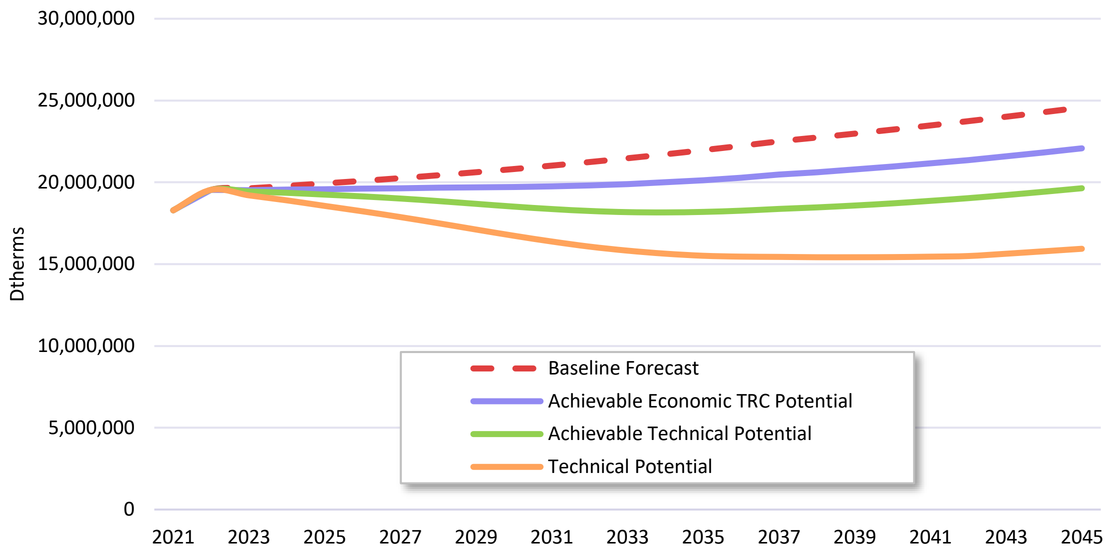


Figure 6-2 Baseline Projection and Energy Efficiency Forecasts, Washington



Idaho Overall Energy Efficiency Potential

Table 6-2 and Figure 6-3 summarize the conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Figure 6-4 displays the cumulative energy conservation forecasts, which reflect the effects of persistent savings in prior years in addition to new savings.

- Technical Potential first-year savings in 2023 are 254,213 dtherms, or 2.6% of the baseline projection. Cumulative savings in 2045 are 5,060,646 dtherms, or 37.6% of the baseline.
- Achievable Technical Potential first-year savings are 105,612 dtherms, or 1.1% of the baseline projection. Cumulative savings in 2045 are 2,885,725 dtherms, or 21.5% of the baseline
- UCT Achievable Economic Potential first-year savings are 46,414 dtherms, or 0.5% of the baseline projection. Cumulative savings in 2045 are 1,278,511 dtherms, or 9.5% of the baseline

Table 6-2 Summary of Energy Efficiency Potential, Idaho

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	9,781,790	9,893,452	10,003,402	11,501,243	13,451,001
Cumulative Savings (Dth)					
UCT Achievable Economic Potential	46,414	96,705	155,748	906,240	1,278,511
Achievable Technical Potential	105,612	228,853	371,295	2,144,539	2,885,725
Technical Potential	254,213	498,497	772,091	3,673,174	5,060,646
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.5%	1.0%	1.6%	7.9%	9.5%
Achievable Technical Potential	1.1%	2.3%	3.7%	18.6%	21.5%
Technical Potential	2.6%	5.0%	7.7%	31.9%	37.6%

Figure 6-3 Cumulative Energy Efficiency Potential as % of Baseline Projection, Idaho

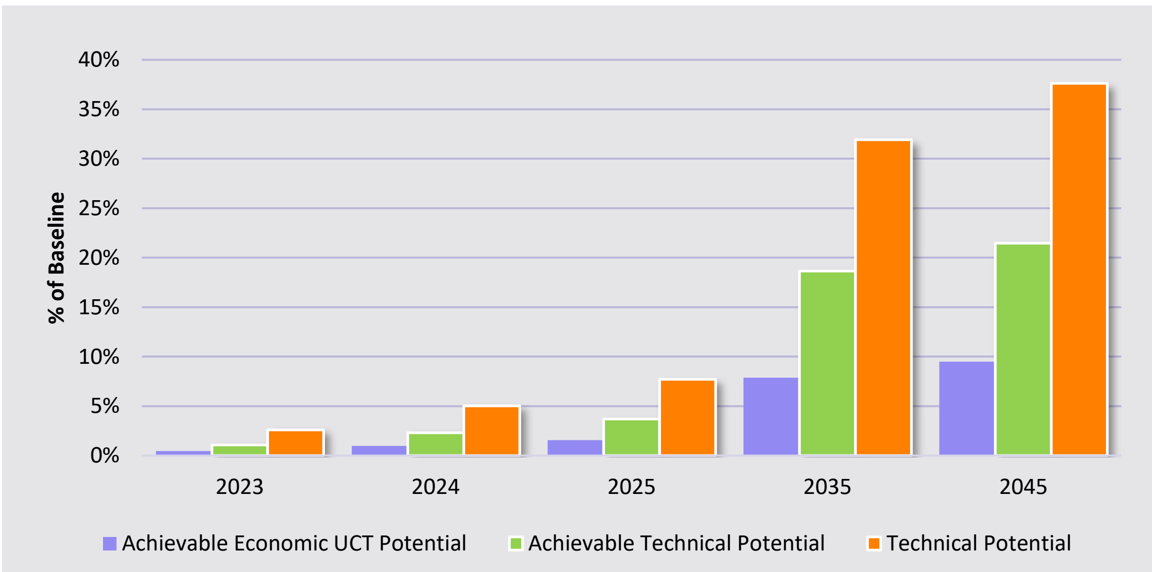
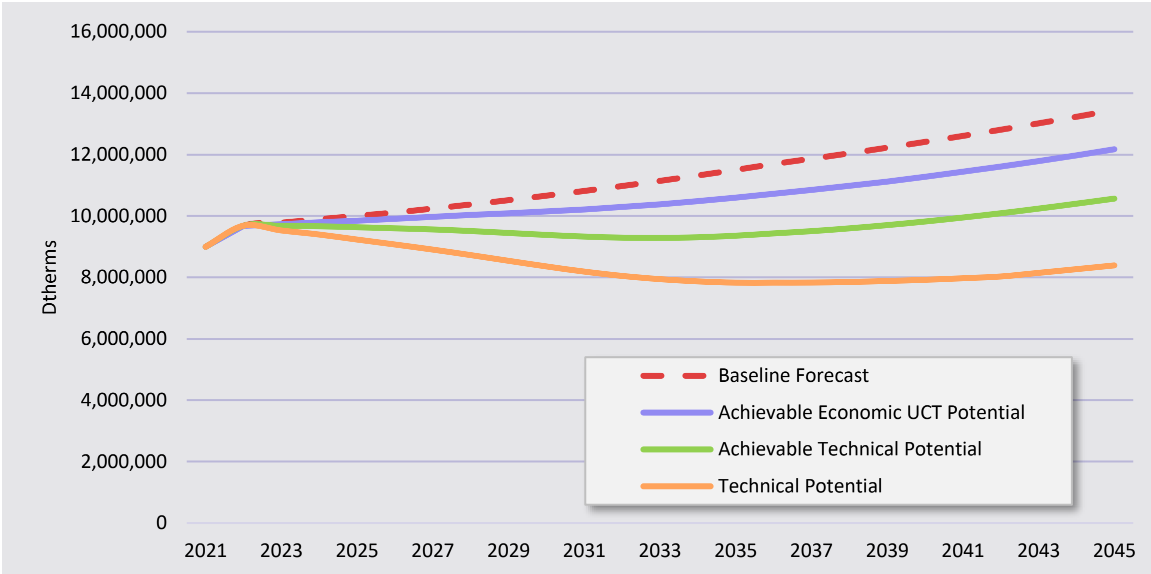


Figure 6-4 Baseline Projection and Energy Efficiency Forecasts, Idaho



7 | SECTOR-LEVEL ENERGY EFFICIENCY POTENTIAL

This chapter provides energy efficiency potential at the sector level.

Residential Sector

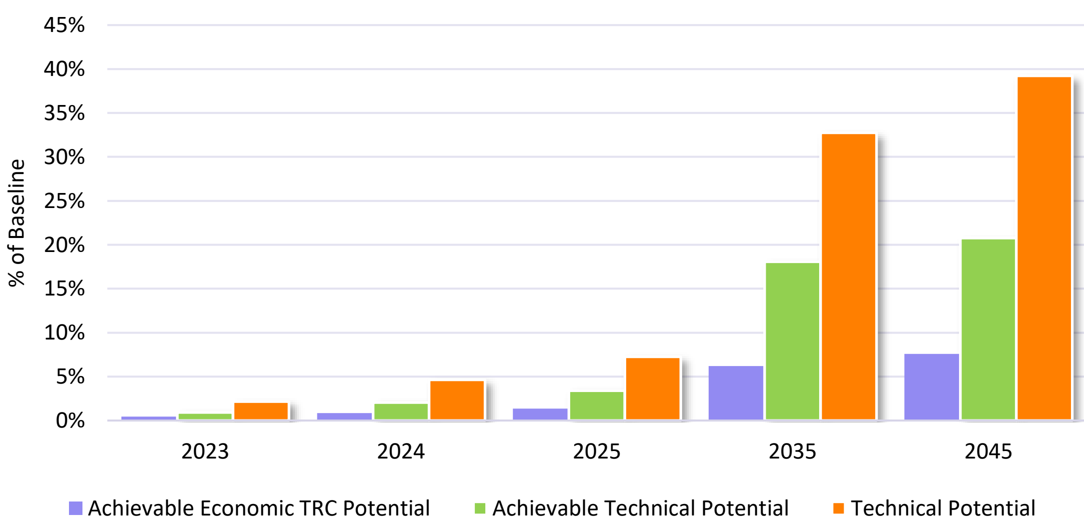
Washington Potential

Error! Reference source not found. and Figure 7-1 summarize the energy efficiency potential for the residential sector. In 2023, TRC achievable economic potential is 54,479 dtherms, or 0.4% of the baseline projection. By 2040, cumulative savings are 1,187,145 dtherms, or 7.6% of the baseline.

Table 7-1 Residential Energy Conservation Potential Summary, Washington

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	12,274,400	12,387,892	12,501,697	13,948,186	15,683,198
Cumulative Savings (Dth)					
TRC Achievable Economic Potential	54,479	103,469	169,578	866,240	1,187,145
Achievable Technical Potential	111,343	254,601	423,501	2,522,674	3,258,916
Technical Potential	264,105	573,696	906,085	4,569,190	6,154,164
Energy Savings (% of Baseline)					
TRC Achievable Economic Potential	0.4%	0.8%	1.4%	6.2%	7.6%
Achievable Technical Potential	0.9%	2.1%	3.4%	18.1%	20.8%
Technical Potential	2.2%	4.6%	7.2%	32.8%	39.2%

Figure 7-1 Cumulative Residential Potential as % of Baseline Projection, Washington



Error! Reference source not found. presents the forecast of cumulative energy savings by end. Space heating makes up a majority of potential followed by water heating.

Figure 7-2 Residential TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

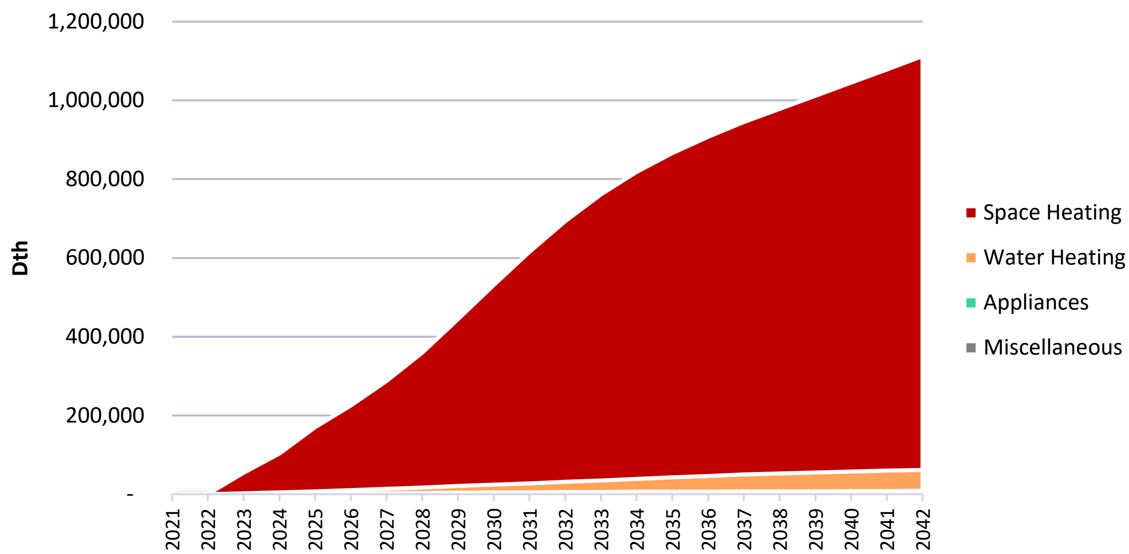


Table 7-2 identifies the top 20 residential measures by cumulative 2023 and 2035 savings. Furnaces, learning thermostats, insulation and water heating are the top measures.

Table 7-2 Residential Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Gas Furnace - Maintenance	19,639	36.0%	53,786	6.2%
2	Furnace	13,294	24.4%	248,091	28.6%
3	Connected Thermostat - ENERGY STAR (1.0)	7,426	13.6%	236,408	27.3%
4	Building Shell - Whole-Home Aerosol Sealing	6,216	11.4%	127,435	14.7%
5	Insulation - Ceiling Installation	3,478	6.4%	72,298	8.3%
6	Clothes Washer - ENERGY STAR (8.0)	2,161	4.0%	20,175	2.3%
7	Gas Boiler - Steam Trap Maintenance	637	1.2%	3,474	0.4%
8	Boiler	408	0.7%	11,449	1.3%
9	Behavioral Programs	298	0.5%	9,308	1.1%
10	Insulation - Wall Sheathing	271	0.5%	5,770	0.7%
11	ENERGY STAR Home Design	212	0.4%	25,408	2.9%
12	Building Shell - Liquid-Applied Weather-Resistive Barrier	130	0.2%	15,425	1.8%
13	Gas Boiler - Pipe Insulation	79	0.1%	646	0.1%
14	Gas Boiler - Thermostatic Radiator Valves	67	0.1%	1,374	0.2%
15	Ducting - Repair and Sealing - Aerosol	52	0.1%	2,314	0.3%
16	Water Heater - Drain Water Heat Recovery	38	0.1%	10,190	1.2%
17	Windows - Low-e Storm Addition	24	0.0%	5,184	0.6%
18	Circulation Pump - Timer	11	0.0%	2,719	0.3%
19	Windows - High Efficiency (Class 22)	11	0.0%	2,195	0.3%
20	Windows - High Efficiency (Class 30)	9	0.0%	1,798	0.2%
	Subtotal	54,462	100.0%	855,447	98.8%
	Total Savings in Year	**54,479**	**100.0%**	**866,240**	**100.0%**

Idaho Potential

Table 7-3 and

Figure 7-3 summarize the energy efficiency potential for the residential sector. In 3, UCT achievable economic potential is 27,232 dtherms, or 0.4% of the baseline projection. By 2045, cumulative savings are 658,730 dtherms, or 7.4% of the baseline.

Table 7-3 Residential Energy Conservation Potential Summary, Idaho

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (Dth)	6,215,422	6,300,557	6,382,522	7,499,611	8,929,190
Cumulative Savings (Dth)					
Achievable Economic UCT Potential	27,232	55,524	90,790	455,114	658,730
Achievable Technical Potential	65,493	144,748	240,091	1,466,014	1,972,483
Technical Potential	165,889	331,905	520,749	2,640,710	3,686,728
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.4%	0.9%	1.4%	6.1%	7.4%
Achievable Technical Potential	1.1%	2.3%	3.8%	19.5%	22.1%
Technical Potential	2.7%	5.3%	8.2%	35.2%	41.3%

Figure 7-3 Cumulative Residential Potential as % of Baseline Projection, Idaho

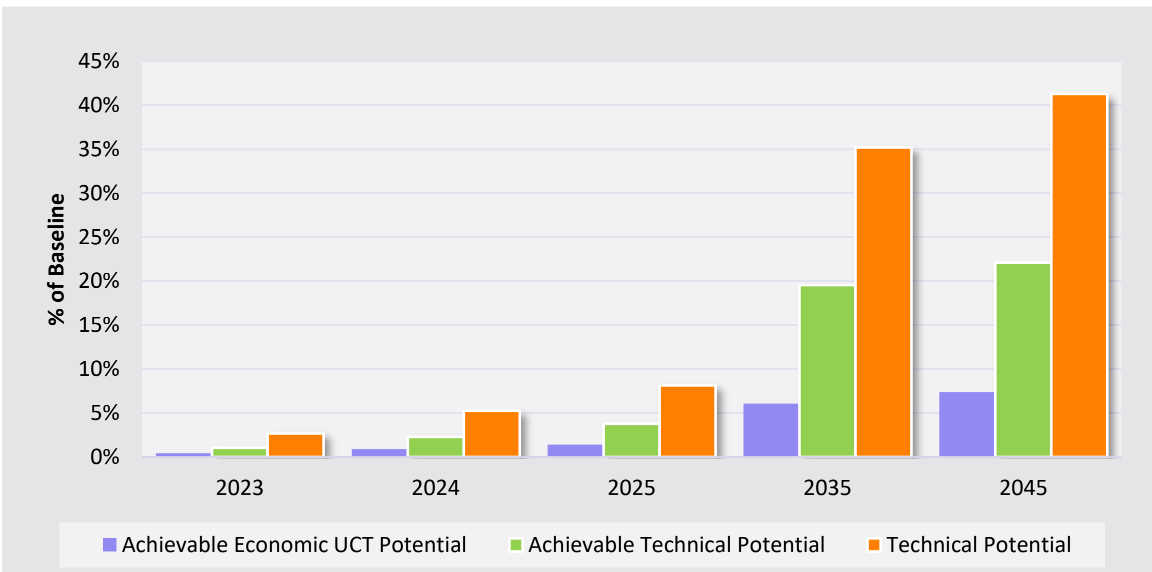


Figure 7-4 presents the forecast of cumulative energy savings by end use. Space heating makes up a majority of potential followed by water heating.

Figure 7-4 Residential UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

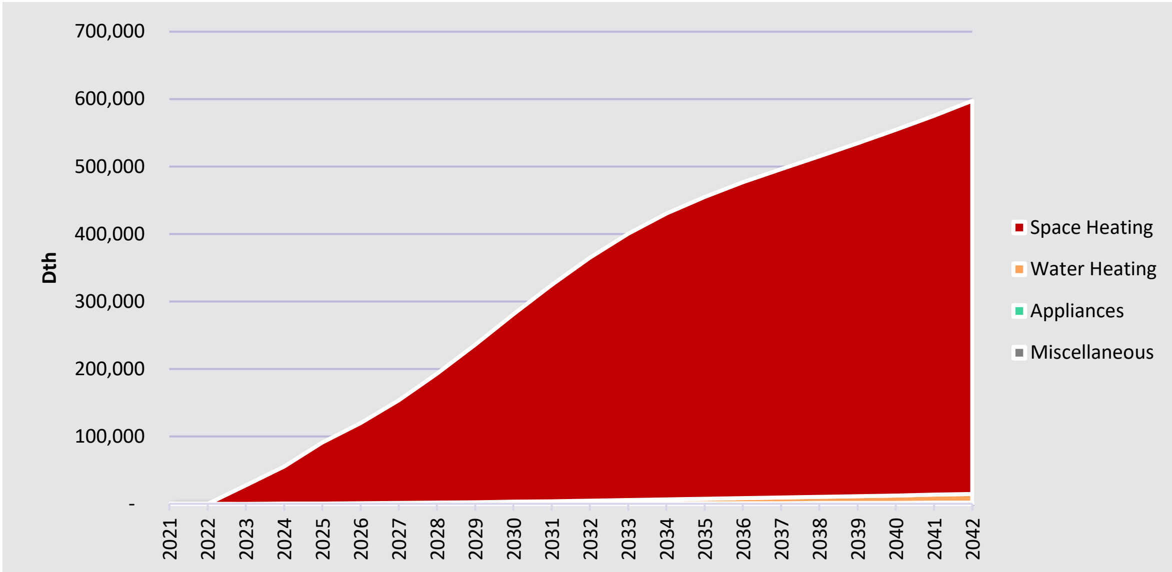


Table 7-4 identifies the top 20 residential measures by cumulative 2023 and 2035 savings. Furnaces, tankless water heaters, windows, and insulation are the top measures.

Table 7-4 Residential Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Idaho

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Gas Furnace - Maintenance	11,234	41.3%	11,234	41.3%
2	Connected Thermostat - ENERGY STAR (1.0)	6,439	23.6%	6,439	23.6%
3	Furnace	3,261	12.0%	3,261	12.0%
4	Building Shell - Whole-Home Aerosol Sealing	2,962	10.9%	2,962	10.9%
5	Insulation - Ceiling Installation	1,906	7.0%	1,906	7.0%
6	Windows - Low-e Storm Addition	791	2.9%	791	2.9%
7	ENERGY STAR Home Design	263	1.0%	263	1.0%
8	Behavioral Programs	150	0.6%	150	0.6%
9	Insulation - Wall Sheathing	117	0.4%	117	0.4%
10	Insulation - Wall Cavity Installation	57	0.2%	57	0.2%
11	Windows - High Efficiency (Class 22)	15	0.1%	15	0.1%
12	Windows - High Efficiency (Class 30)	12	0.0%	12	0.0%
13	Building Shell - Liquid-Applied Weather-Resistive Barrier	11	0.0%	11	0.0%
14	Circulation Pump - Timer	8	0.0%	8	0.0%
15	Water Heater - Pipe Insulation	5	0.0%	5	0.0%
	Subtotal	27,232	100.0%	27,232	100.0%
	Total Savings in Year	**27,232**	**100.0%**	**27,232**	**100.0%**

Commercial Sector

Washington Potential

Table 7-5 and Figure 7-5 summarize the energy conservation potential for the commercial sector. In 2023, TRC achievable economic potential is 55,557 dtherms, or 0.8% of the baseline projection. By 2045, cumulative savings are 1,273,615 dtherms, or 14.8% of the baseline.

Table 7-5 Commercial Energy Conservation Potential Summary, Washington

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (dtherms)	7,069,971	7,101,191	7,136,906	7,720,617	8,594,749
Cumulative Savings (dtherms)					
Achievable Economic TRC Potential	55,557	118,321	185,945	941,943	1,273,615
Achievable Technical	78,348	164,679	257,030	1,225,667	1,642,279
Technical Potential	162,823	305,303	462,087	1,853,896	2,436,763
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.8%	1.7%	2.6%	12.2%	14.8%
Achievable Technical	1.1%	2.3%	3.6%	15.9%	19.1%
Technical Potential	2.3%	4.3%	6.5%	24.0%	28.4%

Figure 7-5 Cumulative Commercial Potential as % of Baseline Projection, Washington

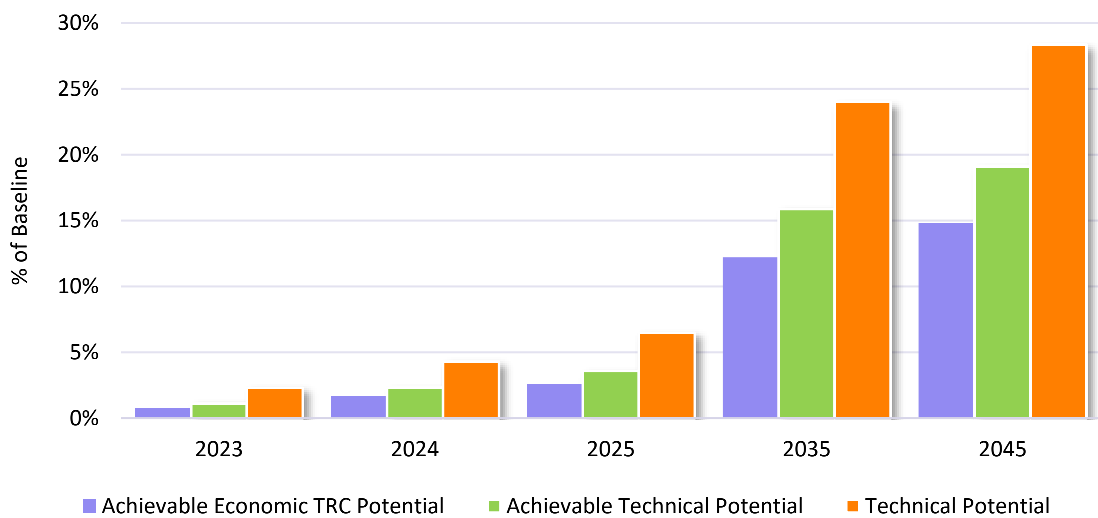


Figure 7-6 presents the cumulative forecast of energy savings by end. Space heating makes up a majority of the potential early, but water heating and food preparation equipment upgrades provide increased savings opportunities in the later years.

Figure 7-6 Commercial TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

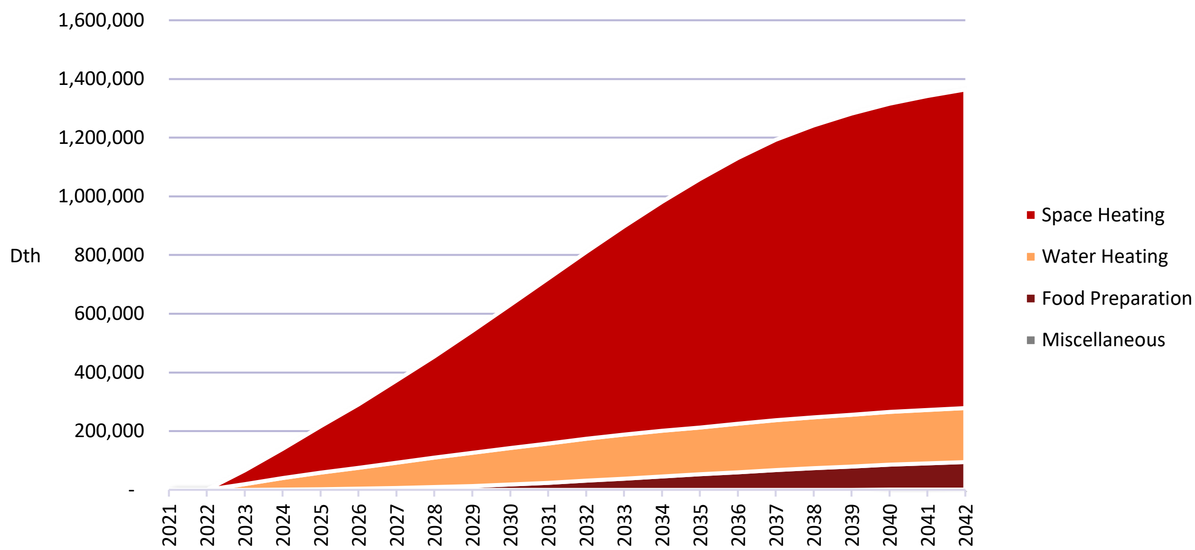


Table 7-6 identifies the top 20 commercial measures by cumulative savings in 2023 and 2035. Strategic Energy Management is the top measure, followed by Retrocommissioning and several HVAC and space heating measures, along with water heater controls.

Table 7-6 Commercial Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Strategic Energy Management	6,581	11.8%	44,626	4.7%
2	Retrocommissioning	5,777	10.4%	30,609	3.2%
3	Ventilation - Demand Controlled	5,364	9.7%	32,722	3.5%
4	HVAC - Energy Recovery Ventilator	4,613	8.3%	44,592	4.7%
5	Water Heater - Circulation Pump Controls	4,137	7.4%	32,785	3.5%
6	Boiler	3,630	6.5%	89,444	9.5%
7	Water Heater - Solar System	3,524	6.3%	23,836	2.5%
8	Water Heater - Temperature Setback	3,510	6.3%	6,799	0.7%
9	Thermostat - Connected	3,161	5.7%	13,233	1.4%
10	Water Heater - Tank Blanket/Insulation	1,875	3.4%	13,377	1.4%
11	Insulation - Wall Cavity	1,804	3.2%	127,530	13.5%
12	Water Heater - Efficient Dishwasher	1,793	3.2%	10,455	1.1%
13	Gas Boiler - Thermostatic Radiator Valves	1,750	3.1%	31,775	3.4%
14	Water Heater	1,743	3.1%	55,529	5.9%
15	Insulation - Ceiling	1,192	2.1%	76,887	8.2%
16	Water Heater - Pipe Insulation	896	1.6%	7,333	0.8%
17	Gas Boiler - High Turndown Burner	763	1.4%	5,194	0.6%
18	Gas Boiler - Hot Water Reset	747	1.3%	14,411	1.5%
19	Gas Boiler - Insulate Steam Lines/Condensate Tank	651	1.2%	6,552	0.7%
20	Advanced Kitchen Ventilation Controls	402	0.7%	8,883	0.9%
	Subtotal	53,913	97.0%	676,571	71.8%
	Total Savings in Year	**55,557**	**100.0%**	**941,943**	**100.0%**

Idaho Potential

Table 7-7 and Figure 7-7 summarize the energy conservation potential for the commercial sector. In 2023, UCT achievable economic potential is 17,641 dtherms, or 0.5% of the baseline projection. By 2045, cumulative savings are 591,777dtherms, or 13.8% of the baseline.

Table 7-7 Commercial Energy Conservation Potential Summary, Idaho

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (dtherms)	3,342,401	3,368,913	3,397,011	3,778,711	4,299,692
Cumulative Savings (dtherms)					
Achievable Economic UCT Potential	17,641	38,098	60,322	431,420	591,777
Achievable Technical	38,577	81,016	126,554	658,739	885,023
Technical Potential	86,399	162,707	245,484	1,007,830	1,338,703
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.5%	1.1%	1.8%	11.4%	13.8%
Achievable Technical	1.2%	2.4%	3.7%	17.4%	20.6%
Technical Potential	2.6%	4.8%	7.2%	26.7%	31.1%

Figure 7-7 Cumulative Commercial Potential as % of Baseline Projection, Idaho

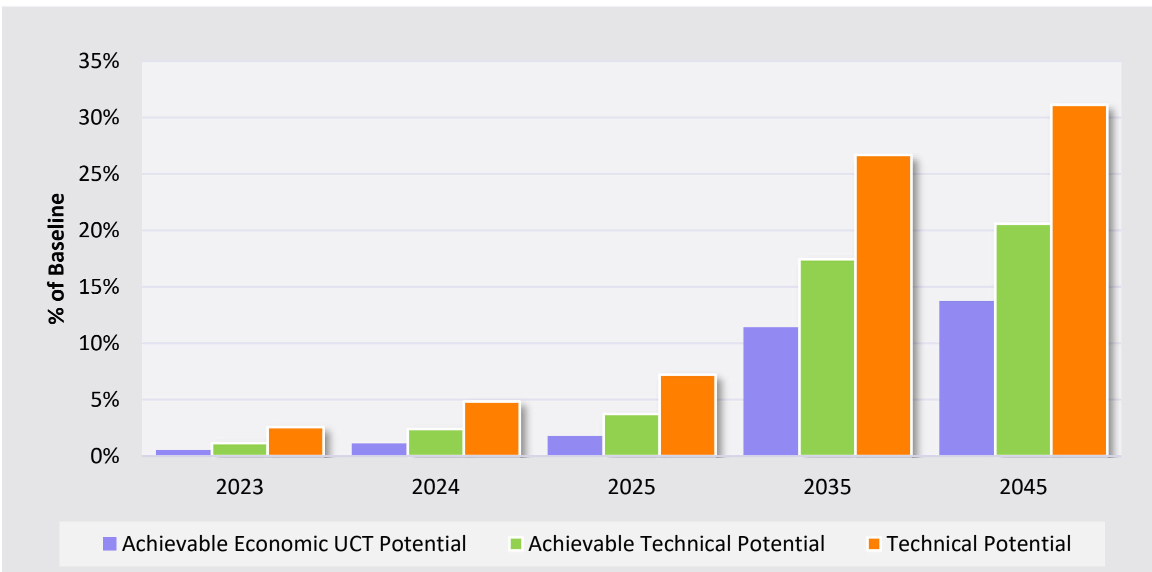


Figure 7-8 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of the potential early, but food preparation equipment upgrades provide substantial savings opportunities in the later years.

Figure 7-8 Commercial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

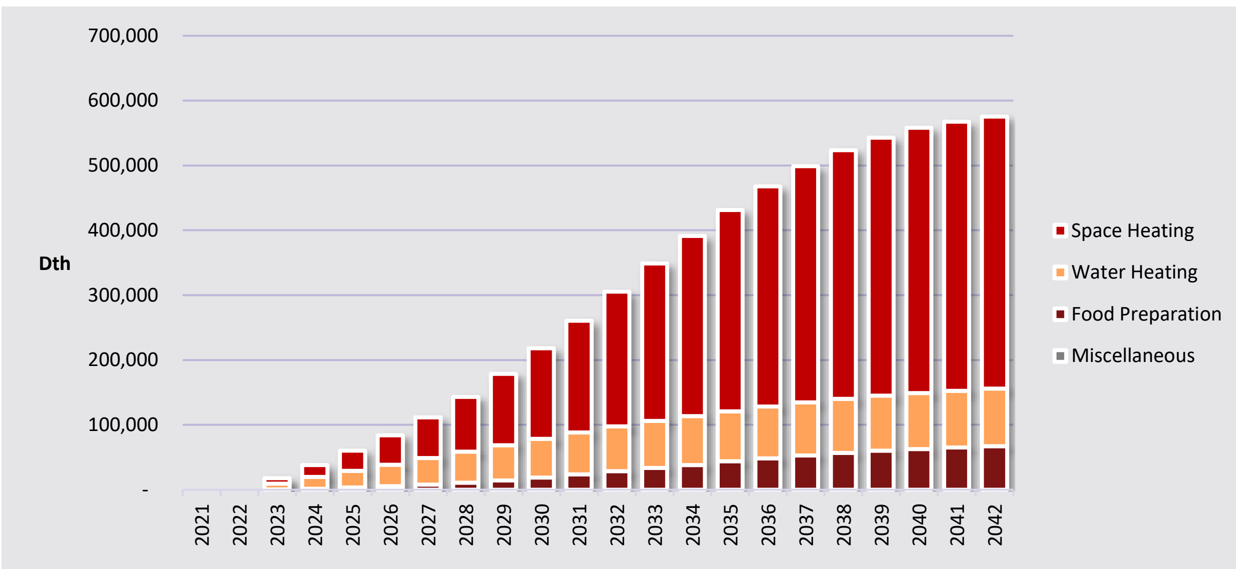


Table 7-8 identifies the top 20 commercial measures by cumulative savings in 2023 and 2035. Water Heaters are the top measure, followed by custom HVAC measures and insulation.

Table 7-8 Commercial Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Idaho

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Water Heater - Circulation Pump Controls	2,030	11.5%	16,022	3.7%
2	Water Heater - Temperature Setback	1,703	9.7%	3,301	0.8%
3	Strategic Energy Management	1,492	8.5%	10,327	2.4%
4	HVAC - Energy Recovery Ventilator	1,426	8.1%	14,038	3.3%
5	Retrocommissioning	1,084	6.1%	5,705	1.3%
6	Water Heater - Low-Flow Showerheads	1,071	6.1%	7,967	1.8%
7	Ventilation - Demand Controlled	1,028	5.8%	6,326	1.5%
8	Water Heater - Tank Blanket/Insulation	915	5.2%	6,526	1.5%
9	Insulation - Wall Cavity	907	5.1%	94,182	21.8%
10	Water Heater	868	4.9%	27,735	6.4%
11	Gas Boiler - Thermostatic Radiator Valves	866	4.9%	16,123	3.7%
12	Insulation - Ceiling	536	3.0%	50,921	11.8%
13	Fryer	501	2.8%	30,335	7.0%
14	Water Heater - Faucet Aerators	413	2.3%	3,132	0.7%
15	Water Heater - Pipe Insulation	383	2.2%	3,120	0.7%
16	Gas Boiler - Hot Water Reset	370	2.1%	7,266	1.7%
17	Water Heater - Thermostatic Shower Restriction Valve	314	1.8%	2,262	0.5%
18	Gas Boiler - Insulate Steam Lines/Condensate Tank	294	1.7%	3,020	0.7%
19	Gas Boiler - High Turndown Burner	290	1.6%	2,041	0.5%
20	Water Heater - Drainwater Heat Recovery	254	1.4%	1,707	0.4%
	Subtotal	16,745	94.9%	312,056	72.3%
	Total Savings in Year	**17,641**	**100.0%**	**431,420**	**100.0%**

Industrial Sector

Washington Potential

Table 7-9 and Figure 7-9 summarize the energy conservation potential for the industrial sector. In 2023, TRC achievable economic potential is 1,956 dtherms, or 0.7% of the baseline projection. By 2045, cumulative savings reach 36,780 dtherms, or 12.3% of the baseline. Industrial potential is a lower percentage of overall baseline compared to the residential and commercial sectors. While large, custom process optimization and controls measures are present in potential, these are not applicable to all processes which limits potential at the technical level. Additionally, since the largest customers were excluded from this analysis due to their status as transport-only customers making them ineligible to participate in energy efficiency programs for the utility, the remaining customers are smaller and tend to have lower process end-use shares, further lowering industrial potential.

Table 7-9 Industrial Energy Conservation Potential Summary, Washington

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (dtherms)	287,959	293,150	296,345	298,131	298,267
Cumulative Savings (dtherms)					
Achievable Economic TRC Potential	1,956	3,943	5,963	25,680	36,780
Achievable Technical	1,963	3,957	5,988	25,774	37,043
Technical Potential	2,637	5,195	7,784	32,209	46,291
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.7%	1.3%	2.0%	8.6%	12.3%
Achievable Technical	0.7%	1.3%	2.0%	8.6%	12.4%
Technical Potential	0.9%	1.8%	2.6%	10.8%	15.5%

Figure 7-9 Cumulative Industrial Potential as % of Baseline Projection, Washington

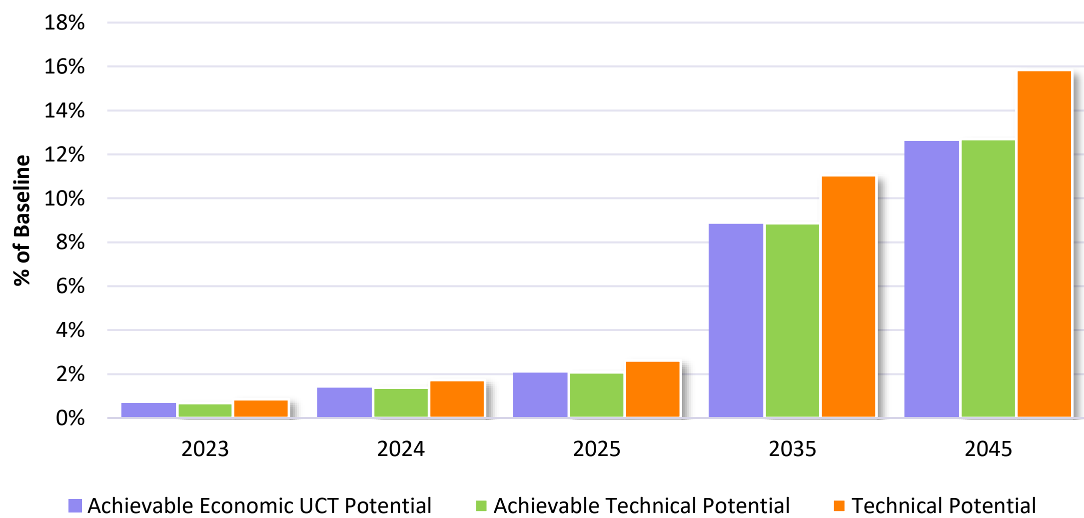


Figure 7-10 presents the forecast of cumulative energy savings by end use.

Figure 7-10 Industrial TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

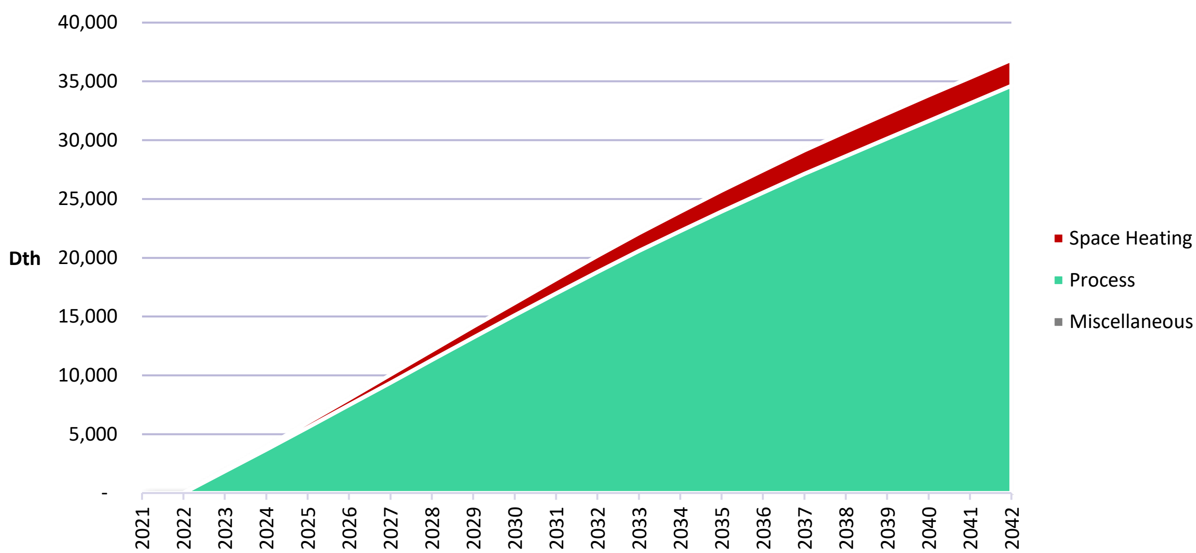


Table 7-10 identifies the top 20 industrial measures by cumulative 2023 and 2035 savings. Process Heat Recovery and Process Boiler control measures have the largest potential savings.

Table 7-10 Industrial Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Process - Heat Recovery	1,464.9	74.9%	19,327.6	75.3%
2	Process Boiler - Stack Economizer	135.7	6.9%	1,205.7	4.7%
3	Process Boiler - Insulate Steam Lines/Condensate Tank	69.6	3.6%	810.6	3.2%
4	Process Boiler - Hot Water Reset	66.5	3.4%	1,372.5	5.3%
5	Process Boiler - Insulate Hot Water Lines	46.6	2.4%	463.7	1.8%
6	Process Boiler - Maintenance	40.7	2.1%	87.6	0.3%
7	Destratification Fans (HVLS)	29.8	1.5%	375.3	1.5%
8	Thermostat - Connected	28.9	1.5%	146.6	0.6%
9	HVAC - Energy Recovery Ventilator	10.6	0.5%	111.2	0.4%
10	Gas Boiler - Stack Economizer	9.2	0.5%	64.7	0.3%
11	Ventilation - Demand Controlled	7.4	0.4%	47.6	0.2%
12	Retrocommissioning	7.3	0.4%	42.4	0.2%
13	Gas Boiler - High Turndown Burner	6.0	0.3%	45.0	0.2%
14	Gas Boiler - Insulate Steam Lines/Condensate Tank	5.2	0.3%	57.3	0.2%
15	Gas Boiler - Hot Water Reset	5.0	0.3%	97.1	0.4%
16	Process Boiler - Steam Trap Replacement	4.3	0.2%	26.9	0.1%
17	Process Boiler - Burner Control Optimization	4.1	0.2%	637.9	2.5%
18	Gas Boiler - Insulate Hot Water Lines	3.5	0.2%	31.8	0.1%
19	Gas Boiler - Maintenance	3.0	0.2%	5.7	0.0%
20	Unit Heater	2.3	0.1%	110.7	0.4%
	Subtotal	1,950.4	99.7%	25,067.8	97.6%
	Total Savings in Year	1,955.9	100.0 %	25,679.6	100.0 %

Idaho Potential

Table 7-11 and Figure 7-11 summarize the energy conservation potential for the industrial sector. In 2023, UCT achievable economic potential is 1,540 dtherms, or 0.7% of the baseline projection. By 2045, cumulative savings reach 28,004 dtherms, or 12.6% of the baseline. Industrial potential is a lower percentage of overall baseline compared to the residential and commercial sectors. While large, custom process optimization and controls measures are present in potential, these are not applicable to all processes which limits potential at the technical level. Additionally, since the largest customers were excluded from this analysis due to their status as transport-only customers making them ineligible to participate in energy efficiency programs for the utility, the remaining customers are smaller and tend to have lower process end-use shares, further lowering industrial potential.

Table 7-11 Industrial Energy Conservation Potential Summary, Idaho

Scenario	2023	2024	2025	2035	2045
Baseline Forecast (dekatherms)	223,967	223,982	223,868	222,921	222,119
Cumulative Savings (dekatherms)					
Achievable Economic UCT Potential	1,540	3,083	4,636	19,707	28,004
Achievable Technical	1,543	3,089	4,649	19,786	28,219
Technical Potential	1,925	3,886	5,857	24,634	35,215
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.7%	1.4%	2.1%	8.8%	12.6%
Achievable Technical	0.7%	1.4%	2.1%	8.9%	12.7%
Technical Potential	0.9%	1.7%	2.6%	11.1%	15.9%

Figure 7-11 Cumulative Industrial Potential as % of Baseline Projection, Idaho

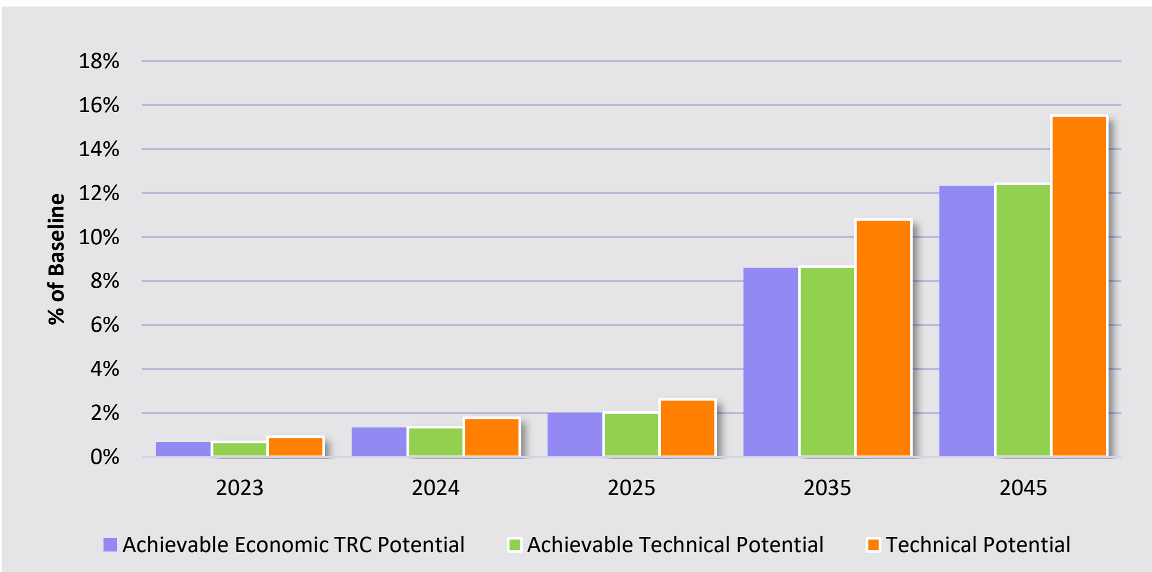


Figure 7-12 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings.

Figure 7-12 Industrial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

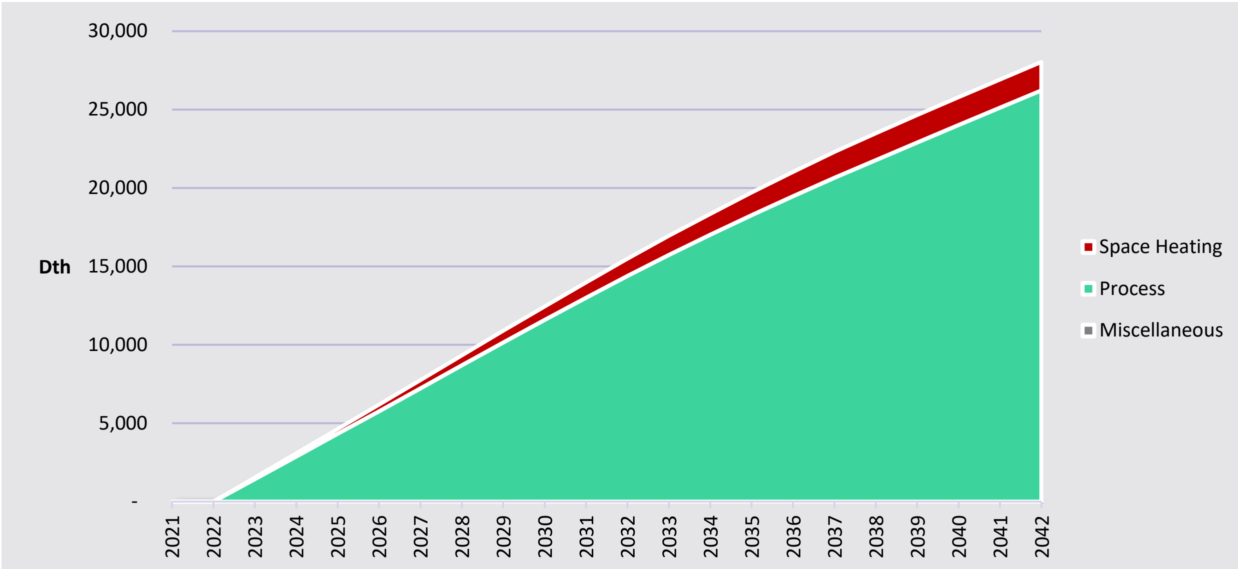


Table 7-12 identifies the top 20 industrial measures by cumulative 2023 and 2035 savings.

Table 7-12 Industrial Top Measures in 2023 and 2035, UCT Achievable Economic Potential, Idaho

Rank	Measure / Technology	2023 Cumulative dtherms	% of Total	2035 Cumulative dtherms	% of Total
1	Process - Heat Recovery	1,138.1	73.9%	14,508.6	73.6%
2	Process Boiler - Stack Economizer	105.4	6.8%	907.7	4.6%
3	Process Boiler - Insulate Steam Lines/Condensate Tank	59.4	3.9%	692.5	3.5%
4	Process Boiler - Hot Water Reset	57.4	3.7%	1,184.4	6.0%
5	Process Boiler - Insulate Hot Water Lines	39.8	2.6%	396.2	2.0%
6	Process Boiler - Maintenance	33.3	2.2%	71.7	0.4%
7	Destratification Fans (HVLS)	23.4	1.5%	285.5	1.4%
8	Thermostat - Connected	22.4	1.5%	111.9	0.6%
9	HVAC - Energy Recovery Ventilator	9.2	0.6%	96.0	0.5%
10	Gas Boiler - Stack Economizer	7.9	0.5%	55.8	0.3%
11	Ventilation - Demand Controlled	6.4	0.4%	41.1	0.2%
12	Retrocommissioning	6.3	0.4%	36.6	0.2%
13	Gas Boiler - High Turndown Burner	5.2	0.3%	38.9	0.2%
14	Gas Boiler - Insulate Steam Lines/Condensate Tank	4.5	0.3%	49.0	0.2%
15	Gas Boiler - Hot Water Reset	4.3	0.3%	83.8	0.4%
16	Process Boiler - Steam Trap Replacement	3.5	0.2%	21.7	0.1%
17	Process Boiler - Burner Control Optimization	3.2	0.2%	476.9	2.4%
18	Gas Boiler - Insulate Hot Water Lines	3.0	0.2%	27.2	0.1%
19	Gas Boiler - Maintenance	2.5	0.2%	4.7	0.0%
20	Gas Furnace - Maintenance	1.6	0.1%	2.9	0.0%
	Subtotal	1,536.7	99.8%	19,093.1	96.9%
	Total Savings in Year	**1,540.4**	**100%**	**19,702.8**	**100%**

8 | DEMAND RESPONSE POTENTIAL

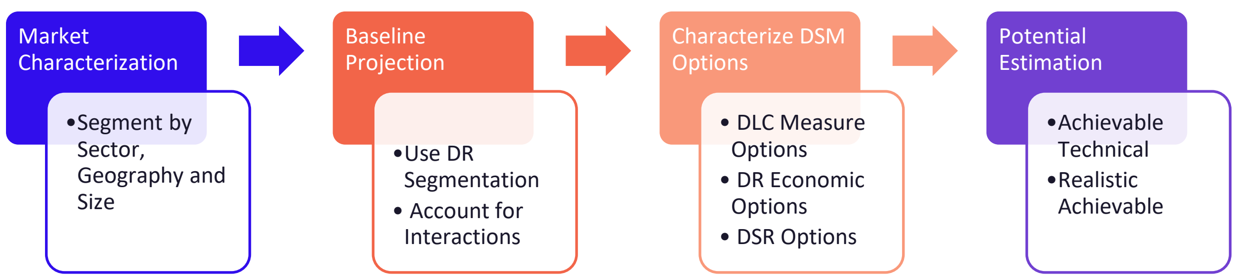
This study is the first time AEG estimated demand response (DR) potential for natural gas in the Avista territory. Natural gas DR is an emerging market with only a few programs offered in the US. To estimate potential, AEG referenced current natural gas DR program data and addressed gaps utilizing information from the electric DR study.

This study provides demand response potential and cost estimates for the 23-year planning horizon (2023-2045) across three states in the Avista territory (Washington, Idaho, and Oregon) to inform the development of Avista's 2023 IRP. Through this assessment, AEG sought to develop reliable estimates of the magnitude, timing, and costs of DR resources likely available to Avista over the planning horizon. The analysis focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics that may hinder resource acquisition. The DR potential will be incorporated into subsequent DR planning and program development efforts.

Study Approach

Figure 8-1 outlines the analysis approach used to develop potential and cost estimates, with each step described in more detail in the following subsections.

Figure 8-1 Demand Response Analysis Approach



AEG estimated demand response potential across the following scenarios:

- Achievable Technical Potential or Stand Alone. Program options are treated as the only programs running in the Avista territory and are viewed in a vacuum. Potential savings cannot be added since it does not account for program overlap.
- Achievable Potential or Integrated. Program options are treated as if they are run simultaneously, and a program hierarchy is applied to account for participation overlap across programs that use the same end-use. For programs that affect the same end use, the model selects the most likely program a customer would participate in, and eligible participants were chosen for that program first. The remaining pool of eligible participants will then be available to participate in the secondary program. This scenario allows for potential to be added as it removes any double counting of savings.

Market Characterization

The first step was to segment customers by service class and develop characteristics for each segment. The two relevant characteristics for the DR potential analysis are end-use saturations of the controllable equipment types in each market segment and coincident peak demand in the base year. The market characteristics are consistent with the natural gas energy efficiency analysis (see Chapter 2 for more information on market profiles).

AEG used Avista's rate schedules as the basis for customer segmentation by state and customer class. Table 8-1 summarizes the market segmentation developed for this study.

Table 8-1 Market Segmentation

Market Dimensions	Segmentation Variable	Description
1	State	Idaho Oregon Washington
2	Customer Class	Residential Commercial Industrial

Baseline Forecast

Once the customer segments were defined and characterized, AEG developed the baseline projection. Load and consumption characteristics, including customer counts and peak-hour demand values, were provided by Avista and aligned with the natural gas energy efficiency analysis.

Customer Counts

Avista provided actual customer counts by rate schedule for each state over the 2017-2021 timeframe and forecasted customer counts over the 2022-2026 period. AEG used this data to calculate the growth rates by customer class across the final two forecasted years and projected customer counts through 2045. The average annual customer growth rate for all sectors is 1.3% in Washington, 1.5% in Idaho, and 0.9% in Oregon. Table 8-2, Table 8-3, and Table 8-4 show the number of customers by state and customer class for selected years.

Table 8-2 Baseline Customer Forecast by Customer Class, Washington

Customer Class	2023	2024	2025	2035	2045
Residential	162,739	164,977	167,198	190,988	218,240
Commercial	15,277	15,349	15,421	16,154	16,922
Industrial	93	93	93	93	93

Table 8-3 Baseline Customer Forecast by Customer Class, Idaho

Customer Class	2023	2024	2025	2035	2045
Residential	84,954	86,656	88,289	106,441	128,443
Commercial	9,623	9,739	9,845	10,879	12,050
Industrial	68	68	68	68	68

Table 8-4 Baseline Customer Forecast by Customer Class, Oregon

Customer Class	2023	2024	2025	2035	2045
Residential	94,779	95,803	96,875	108,034	120,487
Commercial	12,110	12,197	12,289	13,226	14,234
Industrial	26	26	26	26	26

Winter Peak Load Forecasts by State

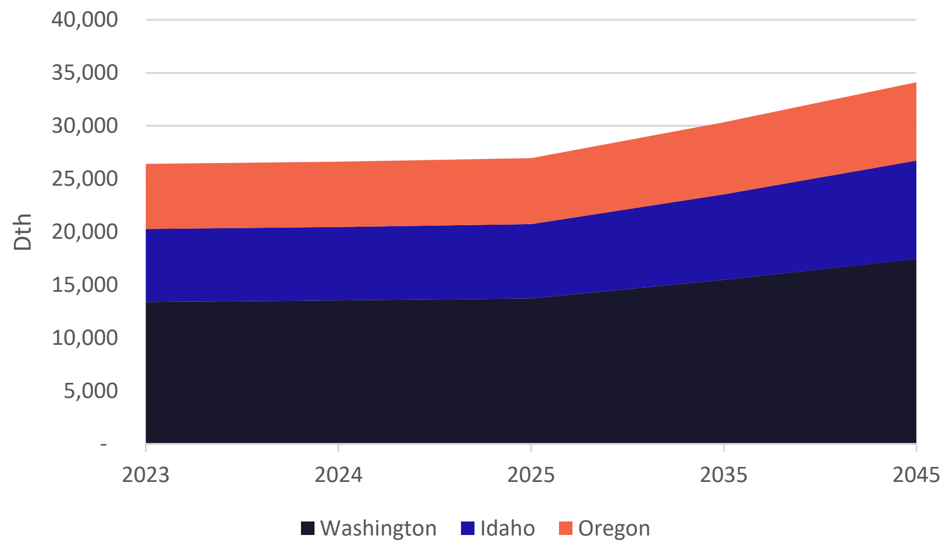
Winter peak load forecasts were developed by state and customer class by multiplying the per customer peak-hour demand values by class by the forecasted customer counts. Table 8-5 shows the winter system peak for selected future years. The system peaks are expected to increase by 33% between 2023-2045.

Table 8-5 Baseline February Winter System Peak Forecast (Dth @Generation) by State

State	2023	2024	2025	2035	2045
Washington	13,399	13,553	13,721	15,474	17,454
Idaho	6,877	6,909	7,026	8,077	9,273
Oregon	6,123	6,162	6,219	6,781	7,384
Grand Total	26,399	26,624	26,966	30,331	34,111

Figure 8-2 shows the contribution to the estimated system coincident winter peak by state. In 2023, system peak load for the winter is 26,399 dekatherms at generation. Washington contributes 51% to the winter system peak, while Idaho and Oregon contribute 26% and 23%, respectively. Winter coincident peak load is expected to grow by an average of 1.3% annually from 2023-2045.

Figure 8-2 Coincident Peak Load Forecast by State (Winter)



Characterize Demand Response Program Options

Next, AEG identified and described the viable DR programs for inclusion in the analysis and developed assumptions for key program parameters, including per customer impacts, participation rates, program eligibility, and program costs. AEG considered the characteristics and applicability of a comprehensive list of options available that could be feasibly run in Avista's territory. Once a list of DR options was determined, AEG characterized each option.

Each selected option is described briefly below.

Program Descriptions

DLC Smart Thermostats - Heating

These programs use the two-way communicating ability of smart thermostats to cycle heating end uses on and off during events. The program targets Avista's Residential and Commercial customers with qualifying equipment in Washington, Idaho, and Oregon. This was assumed to be a Bring Your Own Thermostat (BYOT) program; therefore, no equipment or installation costs were estimated.

Third Party Contracts

Third Party Contracts are assumed to be available for large commercial and industrial customers. This program is based on a firm curtailment strategy targeting large process and heating loads. It is also assumed that participating customers will agree to reduce demand by a specific amount or curtail consumption to a predefined level at the time of an event. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/therm-month or $/therm-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment typically varies with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for gas reduction during events. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity requirements. Penalties may be assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by load aggregators and is most attractive for customers with high natural gas demand and flexibility in their operations. Industry experience indicates that aggregation of customers with smaller-sized loads is less attractive financially due to lower economies of scale. In addition, customers with 24x7 operations, continuous processes, or with obligations to continue providing service (such as schools and hospitals) are not often good candidates for this option.

Time-of-Use Pricing

The TOU pricing rate is a standard rate structure where rates are lower during off-peak hours and higher during peak hours during the day, incentivizing participants to shift energy use to periods of lower grid stress. For the TOU rate, there are no events called, and the structure does not change during the year. Therefore, it is a good default rate for customers that still offers some load-shifting potential. This rate is assumed to be available to all service classes.

Variable Peak Pricing

The Variable Peak Pricing (VPP) rate is composed of significantly higher prices during relatively short critical peak periods on event days to encourage customers to reduce their usage. VPP is usually offered in conjunction with a time-of-use rate, which implies at least three time periods: critical peak, on-peak and off-peak. The customer incentive is a more heavily discounted rate during off-peak hours throughout the year (relative a standard TOU rate). Event days are dispatched on relatively short notice (day ahead or day of), typically for a limited number of days during the year. Over time, event-trigger criteria become well-established so that customers can expect events based on hot weather or other factors. Events can also be called during times of system contingencies or emergencies. This rate has been assumed to be offered to all service classes.

Behavioral DR

Behavioral DR is structured like traditional demand response interventions, but it does not rely on enabling technologies, nor does it offer financial incentives to participants. Participants are notified of an event and simply asked to reduce their consumption during the event window. Generally, notification occurs the day prior to the event and are deployed utilizing a phone call, email, or text message. The next day, customers may receive post-event feedback that includes personalized results and encouragement. This program is assumed to be offered to residential and commercial customers.

Program Assumptions and Characteristics

The key parameters required to estimate the potential for a DR program are participation rate, per-participant load reduction, and eligibility or end use saturations.[6] The development of these parameters is based on research findings and a review of available information on the topic, including national program survey

[6] End Use Saturations used in this study are provided in Appendix D.

databases, evaluation studies, program reports, and regulatory filings. AEG's assumptions of these parameters are described below.

Participation Rate Assumptions

Table 8-6 below shows the steady-state participation rate assumptions for each demand side management (DSM) option as well as the basis for the assumptions.

Table 8-6 Steady-State Participation Rate Assumptions (% of eligible customers)

DSM Option	Residential Service	Commercial Service	Industrial Service	Basis for Assumption
Behavioral	12%	12%	-	PG&E rollout with six waves (2017) - 60% of Electric Behavioral Program Participation
DLC Smart Thermostats - BYOT	9%	9%	-	NWPC Smart Thermostat cooling assumption - 60% of Electric Smart Thermostat Program Participation
Time-of-Use	8%	8%	8%	Industry experience - 60% of Electric TOU Program Participation
Variable Peak Pricing	15%	15%	15%	OG&E 2019 Smart Hours Study - 60% of Electric VPP Program Participation
Third Party Contracts	-	5%	13%	Industry Experience - 60% of Electric Third Party Contracts Program Participation. Commercial adjusted to reflect challenge of reducing heating loads

Load Reduction AssumptionsTable 8-7 presents the per participant load reductions for each DSM option and explains the basis for these assumptions.

Table 8-7 DSM Per Participant Impact Assumptions

DSM Option	Residential Service	Commercial Service	Industrial Service	Basis for Assumption
Behavioral	2%	2%	-	PG&E rollout with six waves (2017)
DLC Smart Thermostats - BYOT	15%	15%	-	SoCalGas 2019 Impact Evaluation
Time-of-Use	3%	1%	2%	Electric TOU Winter Program Impacts
Variable Peak Pricing	8%	4%	3%	OG&E 2019 Smart Hours Impact Evaluation
Third Party Contracts	-	8%	8%	De-rated BYOT Residential impact for Third Party accounting for less discretionary load

Other Cross-cutting Assumptions

In addition to the above program-specific assumptions, there are three that affect all programs:

- Discount rate. A nominal discount rate of 5.21% was used to calculate the net present value of costs over the useful life of each DR program. All cost results are shown in nominal dollars.
- Line losses. Avista provided a line loss factor of 6.16% to convert estimated demand savings at the customer meter level to the generator level. Results in the next section are reported at the generator level.
- Shifting and Saving. Each program varies in the way energy is shifted or saved throughout the day. For example, customers on the DLC Smart Thermostat program are likely to pre-heat their homes prior to the event and turn their heaters back on after the event (snapback effect). The results in this report only show

the savings during the event window and not before and after the event. However, shifting and savings assumptions were provided to Avista for each program to inform the IRP results.

Integrated DR Potential Results

This section presents analysis results for demand savings and levelized costs for all considered DR programs. In the interest of succinctness, AEG only presents the Integrated scenario results in this chapter. The integrated approach represents Realistic Achievable Potential and is the most realistic scenario allowing for multiple DR programs to be run at the same time employing a hierarchy that eliminates double counting of impacts. The stand-alone scenario (Achievable Technical Potential) results can be found in Appendix D. All potential results represent savings at the generator.[7]

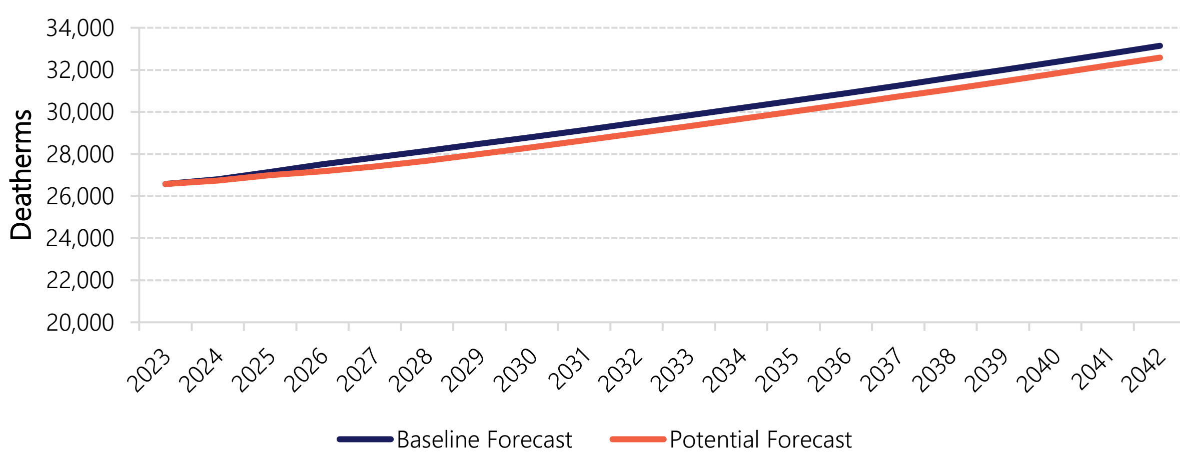
Integrated Results Summary

Table 8-8, and Figure 8-3 show the total winter demand savings for selected years. These savings represent total integrated savings from all available DR options in Avista's Washington, Idaho, and Oregon service territories. All programs are assumed to start in 2024 so there is zero potential across all programs in 2023. The total potential savings are expected to increase from 0 in 2023 to 614 dekatherms by 2045. The percentage of system peak goes from 0% in 2023 to 1.8% by 2045.

Table 8-8 Summary of Integrated Potential (Dekatherms @ Generator)

	2023	2024	2025	2035	2045
Baseline Forecast	26,574	26,801	27,145	30,533	34,338
Achievable Potential	-	72	176	545	614
Achievable Potential (% of baseline)	0%	0%	1%	2%	2%
Potential Forecast	26,574	26,729	26,969	29,988	33,724

Figure 8-3 Summary of Integrated Potential (Dekatherms @ Generator)



Integrated Results

Key findings from the integrated scenario include:

- The largest potential option is DLC Smart Thermostats - BYOT, contributing 403 dekatherms by 2045.
- The next largest projected savings comes from the Variable Peak Pricing Rate, contributing 120 dekatherms by 2045.

[7] Line losses were applied to all savings potential as well as demand forecasts to present the results in terms of generation as opposed to meter.

- The three remaining options contribute 92 dekatherms by 2045

Potential by DSM Option

Figure 8-4 and

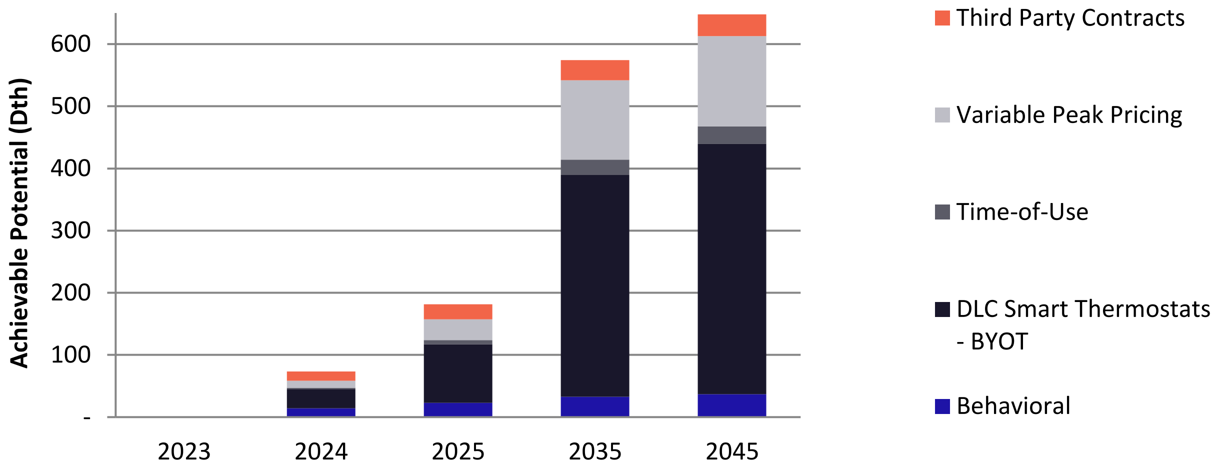
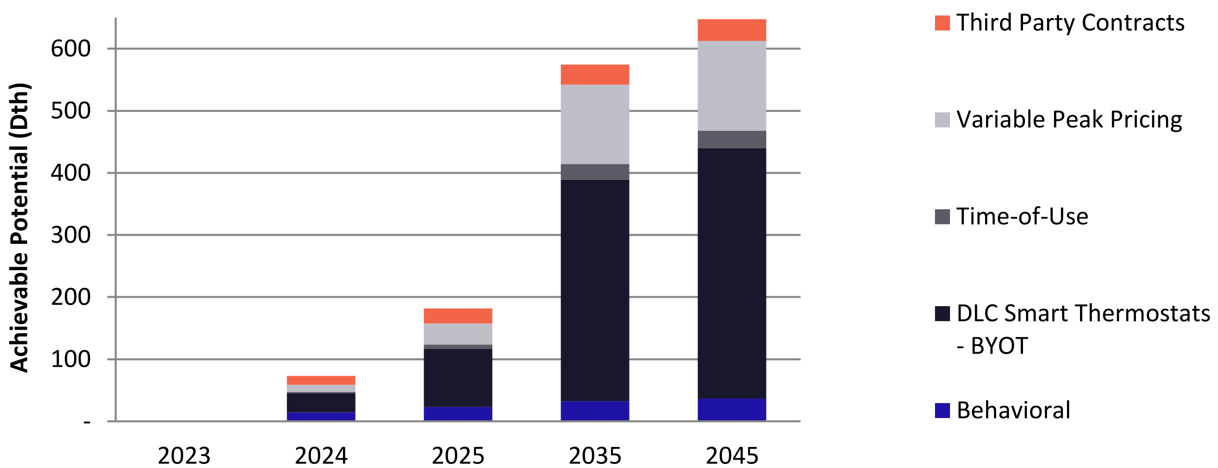


Table 8-9 show the total winter demand savings from individual DR options for selected years. These savings represent integrated savings from all available DR options in Avista's Washington, Idaho, and Oregon service territories. Several DR programs require Advanced Metering Infrastructure (AMI) such as rates (TOU and VPP) and behavioral options. Currently Washington is the only state in the Avista territory with AMI[8]. Therefore, DLC Smart Thermostats – BYOT and Third Party Contracts are the only two programs available to all three states. Across Avista's entire territory, The DLC Smart Thermostats – BYOT program is projected to save the most of all programs at 403 dekatherms by 2045 followed by Variable Peak Pricing at 120 dekatherms by 2045.

Figure 8-4 Summary of Potential by Option – (Dekatherms @ Generator)



[8] See Appendix Section A | for end use saturation details

Table 8-9 Summary of Potential by Option – (Dekatherms @ Generator)

	2023	2024	2025	2035	2045
Behavioral	-	14	22	30	33
DLC Smart Thermostats - BYOT	-	31	94	357	403
Time-of-Use	-	2	6	21	23
Variable Peak Pricing	-	10	30	105	119
Third Party Contracts	-	15	24	32	35

Potential by Class

Table 8-10, Table 8-11, and Table 8-12 show the total winter demand savings by class for Washington, Idaho, and Oregon respectively. Washington is projected to save 407 dekatherms (2.3% of winter system peak demand) by 2045, Idaho is projected to save 126 dekatherms (1.4% of winter system peak demand) by 2045, and Oregon is projected to save 80 dekatherms (1.1% of winter system peak demand) by 2045.

The residential sector contributes 69% of the total load across all three states while commercial and industrial contribute 44% and 2% respectively. This is due primarily to the low number of industrial natural gas customers in Avista's territory.

Table 8-10 Potential by Class – Dekatherms @Generator, Washington

	2023	2024	2025	2035	2045
Baseline Forecast	13,399	13,553	13,721	15,474	17,454
Achievable Potential	-	51	120	361	407
Residential	-	30	76	249	284
Commercial	-	20	43	110	121
Industrial	-	1	1	2	2

Table 8-11 Potential by Class – Dekatherms @Generator, Idaho

	2023	2024	2025	2035	2045
Baseline Forecast	6,877	6,909	7,026	8,077	9,273
Achievable Potential	-	12	32	110	126
Residential	-	6	19	76	91
General Service	-	6	13	33	35
Large General Service	-	0	1	1	1

Table 8-12 Potential by Class – Dekatherms @Generator, Oregon

	2023	2024	2025	2035	2045
Baseline Forecast	6,123	6,162	6,219	6,781	7,384
Achievable Potential	-	9	24	74	80
Residential	-	4	12	43	48
General Service	-	5	11	30	32
Large General Service	-	0	0	0	0

Figure 8-5 Potential by Class –Dekatherms @Generator, Washington

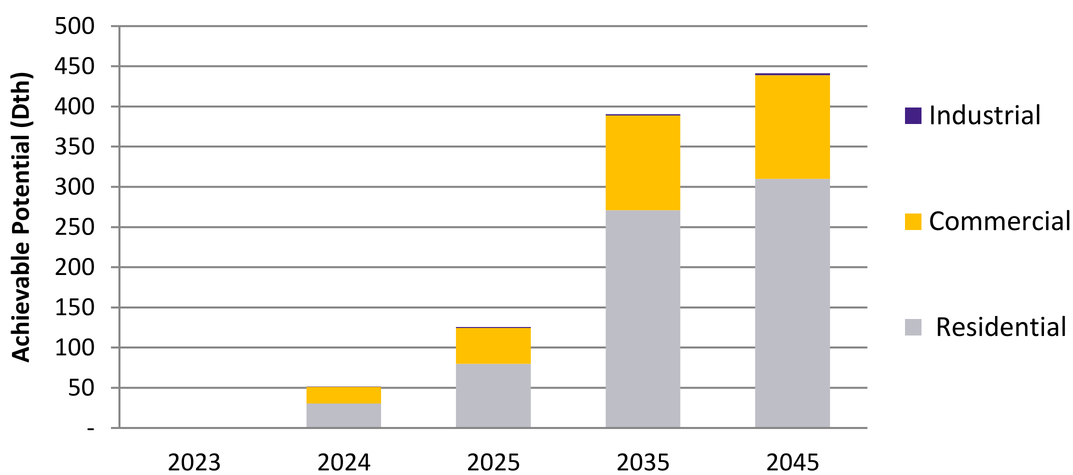


Figure 8-6 Potential by Class – Dekatherms @Generator, Idaho

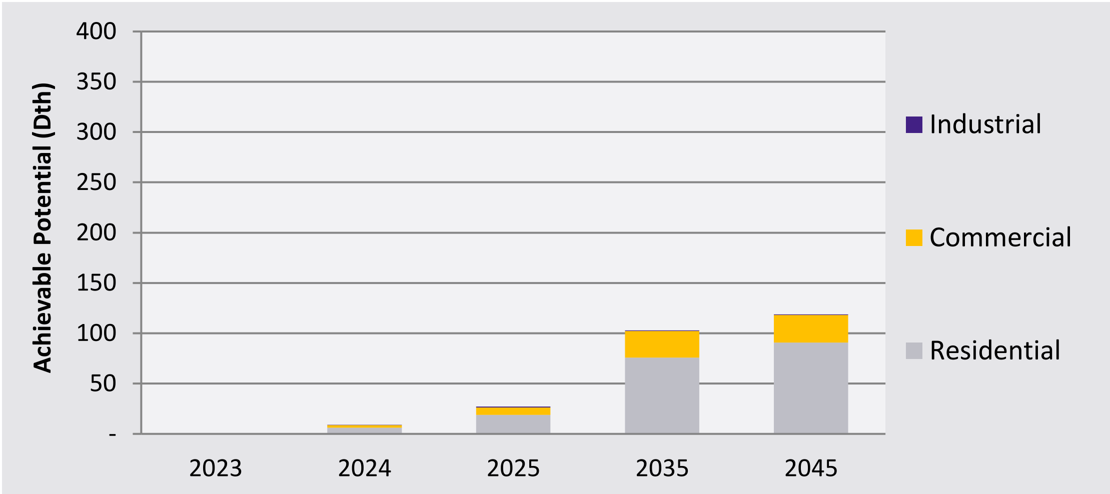
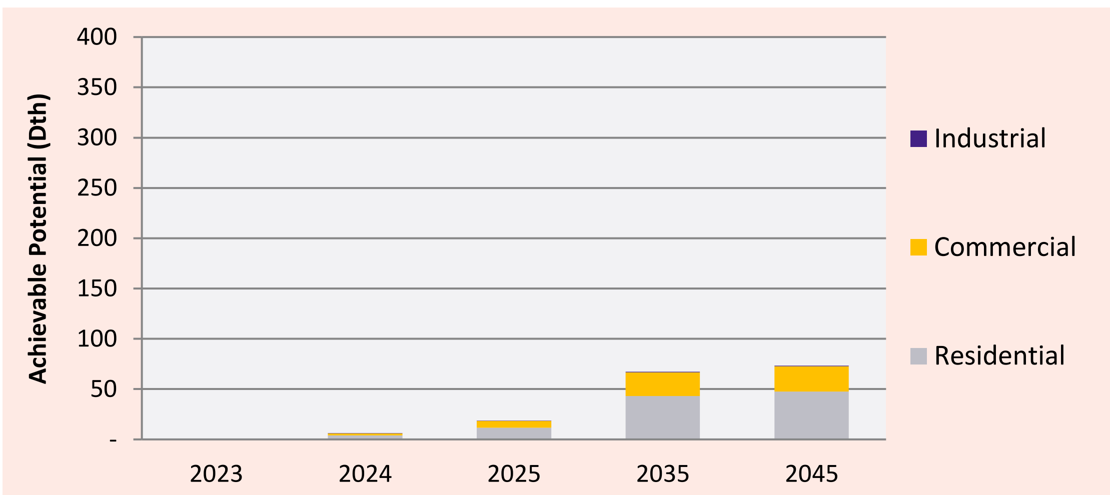


Figure 8-7 Potential by Class – Dekatherms @Generator, Oregon



Levelized Costs

Table 8-13 presents the levelized costs per dekatherm of equivalent generation capacity over 2023-2032 for Washington, Idaho, and Oregon. The ten-year NPV dekatherm potential by program is shown for reference in the first column.

Key findings include:

- The Third Party Contracts option is expected to be the cheapest program to run per dekatherm savings at approximately $2,568/Dth-year. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All development, O&M, and administrative costs are expected to be incurred by the representative third-party contractor.
- The Time-of-Use option has the highest levelized cost among all the DR options over ten years at $16,815/dekatherm-year system-wide. The main contributors to the high cost compared to low savings are marketing and recruitment and administrative costs.

Table 8-13 Levelized Program Costs and Potential (TOU Opt-In Winter)

Program	NPV Dth Potential	Levelized Costs ($/Dth)
Behavioral	168.48	$11,170.36
DLC Smart Thermostats - BYOT	1633.65	$4,924.69
Time-of-Use	94.94	$16,814.75
Variable Peak Pricing	487.42	$4,338.36
Third Party Contracts	186.21	$2,567.59

A | DEMAND RESPONSE POTENTIAL APPENDIX

Equipment End Use Saturation

The end use saturation data is required to further segment the market and identify eligible customers for direct control of different equipment options. Table A-1 below shows saturation estimates by state and customer class for Washington, Idaho, and Oregon. For Washington and Idaho, AEG used the end use saturation data from the energy efficiency study. In absence of saturation data, Oregon saturations use Washington saturations as a proxy. For AMI, Avista provided gas AMI saturation data for Washington, but AMI has yet to be rolled out in Idaho and Oregon.

Table A-1 End Use Saturations by Customer Class and State[9]

State	Customer Class	End Use Saturation	2023	2024	2025	2035	2045	Source
WA	Res	Gas Space Heat	87%	87%	87%	89%	89%	Baseline Survey
WA	Res	Gas Water Heat	55%	55%	55%	56%	56%	Baseline Survey
WA	Res	Behavioral	100%	100%	100%	100%	100%	Default
WA	Res	AMI	85%	85%	85%	85%	85%	AMI data from Avista
WA	Com	Gas Space Heat	77%	77%	77%	77%	77%	Baseline Survey
WA	Com	Gas Water Heat	58%	58%	58%	58%	58%	Baseline Survey
WA	Com	Behavioral	100%	100%	100%	100%	100%	Default
WA	Com	AMI	86%	86%	86%	86%	86%	AMI data from Avista
WA	Ind	Gas Space Heat	84%	84%	84%	84%	84%	Baseline Survey
WA	Ind	Gas Process Heat	100%	100%	100%	100%	100%	Baseline Survey
WA	Ind	AMI	97%	97%	97%	97%	97%	AMI data from Avista
ID	Res	Gas Space Heat	94%	94%	94%	94%	94%	Baseline Survey
ID	Res	Gas Water Heat	56%	56%	56%	56%	56%	Baseline Survey
ID	Res	Behavioral	100%	100%	100%	100%	100%	Default
ID	Res	AMI	0%	0%	0%	0%	0%	AMI data from Avista
ID	Com	Gas Space Heat	77%	77%	77%	77%	77%	Baseline Survey
ID	Com	Gas Water Heat	58%	58%	58%	58%	58%	Baseline Survey
ID	Com	Behavioral	100%	100%	100%	100%	100%	Default
ID	Com	AMI	0%	0%	0%	0%	0%	AMI data from Avista
ID	Ind	Gas Space Heat	84%	84%	84%	84%	84%	Baseline Survey
ID	Ind	Gas Process Heat	100%	100%	100%	100%	100%	Baseline Survey
ID	Ind	AMI	0%	0%	0%	0%	0%	AMI data from Avista
OR	Res	Gas Space Heat	87%	87%	87%	89%	89%	WA Proxy
OR	Res	Gas Water Heat	55%	55%	55%	56%	56%	WA Proxy
OR	Res	Behavioral	100%	100%	100%	100%	100%	WA Proxy
OR	Res	AMI	0%	0%	0%	0%	0%	AMI data from Avista
OR	Com	Gas Space Heat	77%	77%	77%	77%	77%	WA Proxy
OR	Com	Gas Water Heat	58%	58%	58%	58%	58%	WA Proxy
OR	Com	Behavioral	100%	100%	100%	100%	100%	Default
OR	Com	AMI	0%	0%	0%	0%	0%	AMI data from Avista
OR	Ind	Gas Space Heat	84%	84%	84%	84%	84%	WA Proxy
OR	Ind	Gas Process Heat	100%	100%	100%	100%	100%	WA Proxy
OR	Ind	AMI	0%	0%	0%	0%	0%	AMI data from Avista

Mechanism and Event Hours

Table A-2 lists the DSM options considered in the study, including the eligible sectors, the mechanism for deployment, and the expected annual event hours.

[9] Res = Residential, Com = Commercial, Ind = Industrial

Table A-2 DSM Program Event Hours

DSM Option	Eligible Sectors	Annual Seasonal Hours	Average Event Duration (hours)	Estimated Number of Events per Year
Behavioral	Res and Com	40	6	7
Third Party Contracts	C&I	30	4	8
Time-of-Use	All	528	6	88
Variable Peak Pricing Rates	All	80	4	20
DLC Smart Thermostats - BYOT	Res and Com	36	3	12

Stand Alone Results

Figure A-1 and Table A-3 show the winter demand savings from individual DR options. These savings represent stand-alone savings from all available DR options in Washington, Idaho, and Oregon service territories. The Smart Thermostats and Third Party Contracts programs are projected to save the same amount as in the integrated scenario due to the expectation that there won't be participation overlap across other programs for these offerings.

- Like in the integrated scenario, the largest potential option is DLC Smart Thermostats - BYOT, contributing 403 dekatherms by 2045.
- The next largest projected savings comes from the Variable Peak Pricing Rate, contributing 145 dekatherms by 2045.

Figure A-1 Summary of Potential by Option – Stand Alone (Dekatherms @Generator)

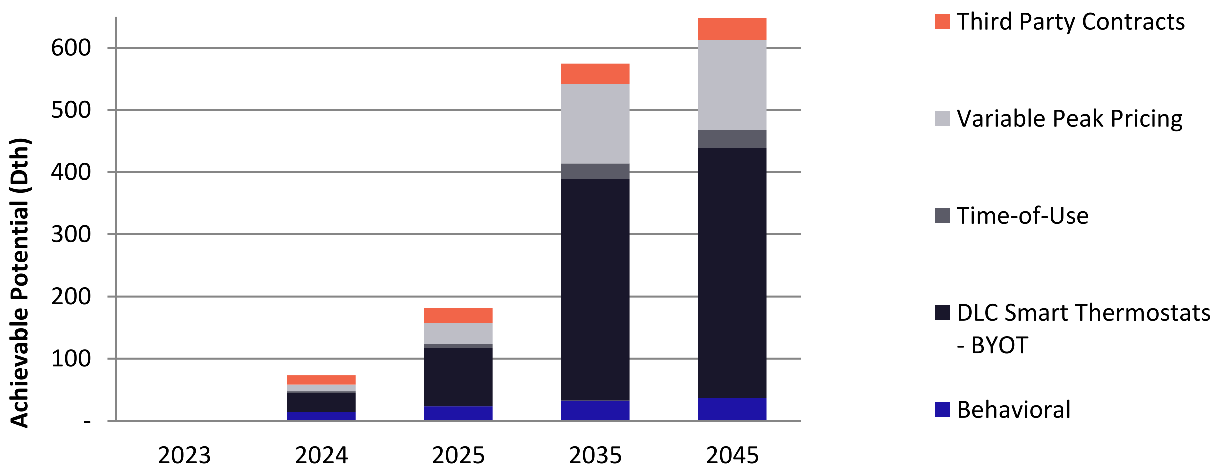


Table A-3 Summary of Potential by Option – Stand Alone (Dekatherms @ Generator)

	2023	2024	2025	2035	2045
Behavioral	-	14	23	33	37
DLC Smart Thermostats - BYOT	-	31	94	357	403
Time-of-Use	-	2	7	25	28
Variable Peak Pricing	-	11	34	128	145
Third Party Contracts	-	15	24	32	35

Applied Energy Group, Inc.
2300 Clayton Road, Suite 1370
Concord, CA 94520

Appendix 3.2: Oregon Firm-Customers

Energy Trust of Oregon Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping utility customers in Oregon and southwest Washington benefit from saving energy and generating renewable power. Energy Trust funding comes exclusively from utility customers and is invested on their behalf in lowest-cost energy efficiency and clean, renewable energy. In 1999, Oregon energy restructuring legislation (SB 1149) required Oregon's two largest electric utilities—PGE and Pacific Power—to collect a public purpose charge from their customers to support energy conservation in K-12 schools, low-income housing energy assistance, and energy efficiency and renewable energy programs for residential and business customers.[1]

In 2001, Energy Trust entered into a grant agreement with the Oregon Public Utility Commission (OPUC) to invest the majority of revenue from the 3 percent public purpose charge in energy efficiency and renewable energy programs. Every dollar invested in energy efficiency by Energy Trust will save residential, commercial, and industrial customers nearly $3 in deferred utility investment in generation, transmission, fuel purchase and other costs. Appreciating these benefits, natural gas companies asked Energy Trust to provide service to their customers—NW Natural in 2003, Cascade Natural Gas in 2006 and Avista in 2017. These arrangements stemmed from settlement agreements reached in Oregon Public Utility Commission processes.

Energy Trust's model of delivering energy efficiency programs as a single entity across the five overlapping service territories of Oregon's investor-owned gas and electric utilities has experienced a great deal of success. Since its inception, Energy Trust has saved more than 865 aMW of electricity and 84 million annual therms. This equates to more than 22.3 million metric tons of CO_2 emissions avoided and is a significant factor contributing to the relatively flat or lower energy sales observed by both gas and electric utilities from 2011 to 2020, as shown in OPUC utility statistic books.[2]

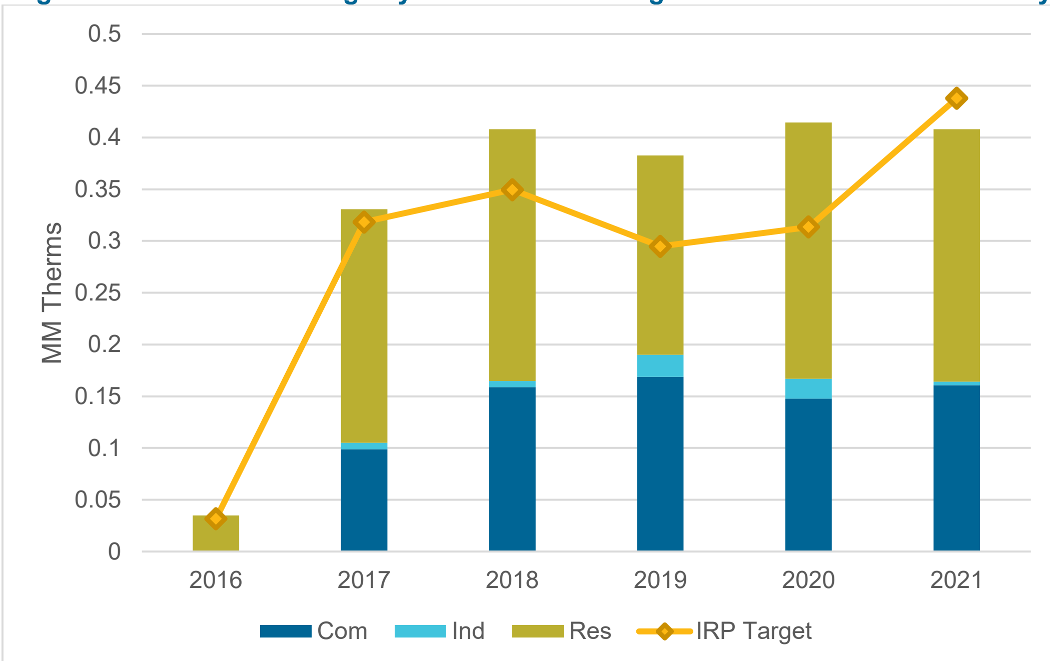
Energy Trust serves residential, commercial, and firm industrial customers in Avista's natural gas service territory in the areas of Medford, Klamath Falls, and La Grande, Oregon. In 2021, Energy Trust's programs achieved savings of 408,163 therms—equivalent to about 93% of the IRP target, as shown in

[1] In 2007, Oregon's Renewable Energy Act (SB 838) allowed the electric utilities to capture additional, cost-effective electric efficiency above what could be obtained through the 3 percent charge, thereby avoiding the need to purchase more expensive electricity. This new supplemental funding, combined with revenues from natural gas utility customers, increased Energy Trust revenues from about $30 million in 2002 to $190 million in 2021.

[2] OPUC 2020 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2020-Oregon-Utility-Statistics-Book.pdf

Figure ***1***. As seen in the figure, 2021 is the first year Energy Trust savings in Avista's Oregon service territory are below the IRP target. While savings remained relatively consistent with 2020, Energy Trust projected growth in 2021 as an extension of increased efficiency activities seen in 2020 as a result of pandemic related market conditions. However, supply chain and labor difficulties experienced in 2021 slowed down the rate of growth Energy Trust was able to achieve. Energy Trust is working with Avista to build program delivery infrastructure to accelerate savings acquisition to meet carbon reduction requirements in context with related least-cost planning principles.

Figure 1 – Achieved Savings by Sector vs. IRP Targets for Avista Service Territory



In addition to administering energy efficiency programs on behalf of the utilities, Energy Trust also provides each utility with a 20-year forecast of cost-effective energy efficiency savings potential expected to be achieved by Energy Trust. The results are used by Avista and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential in their territory that can be used in their resource mix to meet their customers' projected load.

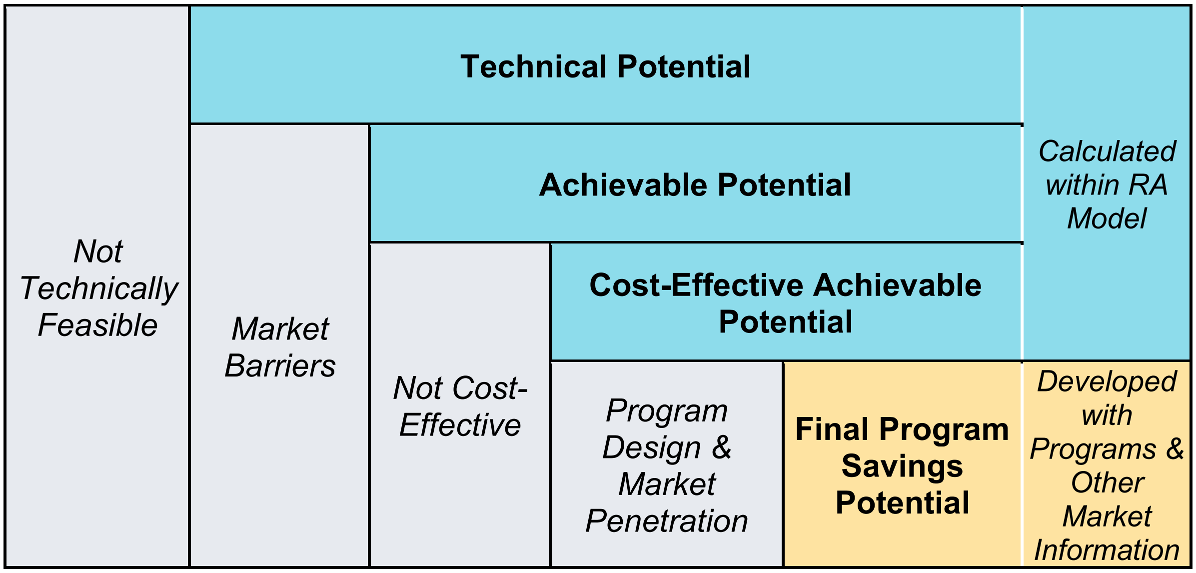
Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a DSM resource forecast for Avista using its resource assessment modeling tool (hereinafter the "RA Model") to identify the total 20-year cost-effective modeled savings potential. This potential is subsequently 'deployed' exogenously of the model to estimate the final savings forecast for each of the 20 years. There are four types of potential that are calculated to develop the final savings potential estimate. These are shown in

Figure ***2*** and discussed in greater detail in the sections below.

Figure 2 – Types of Potential Calculated in 20-year Forecast Determination



The RA Model utilizes the modeling platform Analytica®[3], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to Avista for inclusion in in their SENDOUT® Model as a reduction to demand on the system.

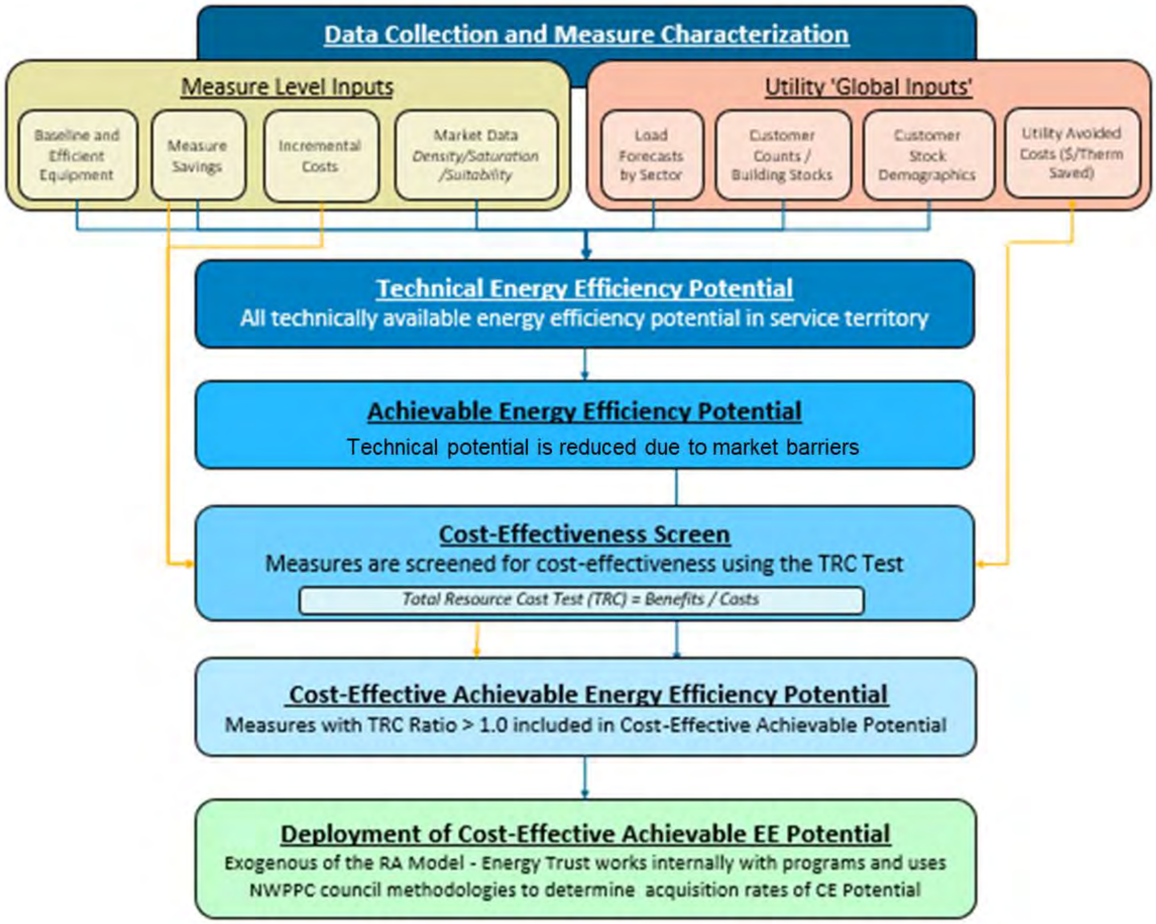
20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed savings, as shown in

[3] http://www.lumina.com/why-analytica/what-is-analytica1/

Figure ***3***. The first five steps in the varying shades of blue nodes - *Data Collection and Measure Characterization* to *Cost-Effective Achievable Energy Efficiency Potential* - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail on each of the steps shown below.

Figure 3 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart



1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of commercially available and emerging technology measures for residential, commercial, industrial, and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[4] In addition to identifying and characterizing applicable measures, Energy Trust collects necessary data to scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures have been identified for inclusion in the model, they must be characterized in order to determine their savings potential and cost-effectiveness.

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

The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[5], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are organized into the following categories:

1. ***Measure Definition and Equipment Identification***: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g., wall insulation greater than or equal to R11 replacing wall insulation with an R value of four or less). A measure's replacement type is also determined in this step – retrofit, replace on burnout, or new construction.
2. ***Measure Savings****:* natural gas savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
3. ***Incremental Costs****:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a replace on burnout or new construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline equipment.
4. ***Market Data****:* Market data of a measure includes the density, saturation, and suitability of a measure. The density is the number of measure units that can be installed per scaling basis (e.g., the average number of showers per home for showerhead measures). Saturation is the share of equipment that is already efficient (e.g., 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage that represents the percent of installation opportunities where the measure can actually be installed. These data inputs are generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments.

- ***Utility Global Inputs:***

  The RA Model requires several utility-level inputs to create the DSM forecast. These inputs include:

  1. ***Customer and Load Forecasts****:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a 'per home' scaling basis, so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that Avista has forecasted to scale the measure level potential to their entire service territory.
  2. ***Customer Stock Demographics****:* These data points are utility specific and identify the percentage of customer building stock that utilize different fuels for space and water heating. The RA Model uses these inputs to segment the total stock to the portion that is applicable to a measure (e.g., gas water heaters are only applicable to customers that have gas water heat).
  3. ***Utility Avoided Costs****:* Avoided costs are the net present value of avoided energy purchases and delivery costs associated with energy savings. Energy Trust calculates these values based on inputs provided

---

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

by Avista. The avoided cost components are discussed in other sections of this IRP. Avoided costs are the primary benefit of energy efficiency in the cost-effectiveness screen.

2. Calculate Technical Energy Efficiency Potential

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

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

This savings potential does <u>not</u> consider the various cost and market barriers that will limit the adoption of efficiency measures.

3. Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction of the technical potential to account for market barriers that prevent the adoption of the measures identified in the technical potential. This is done by applying a factor to reflect the maximum achievability for each measure. Energy Trust first updated its methodology in Avista's 2020 IRP to reflect the maximum achievability estimated by the Northwest Power and Conservation Council for the 2021 Power Plan, and has done so again for the 2023 IRP. While in past power plans a universal assumption of 85% was used, these factors now typically range from 85% to 95%.[6]

Achievable Potential =	*Technical Potential * Maximum Achievability Factor*

4. Determine Cost-effectiveness of Measure using TRC Screen

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

TRC = Present Value of Benefits / Present Value of Costs

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

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

[6] For details on this, see https://www.nwcouncil.org/sites/default/files/2019_0813_p5.pdf.

b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g., water savings from low-flow showerheads or operations and maintenance cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

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

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

5. Quantify the Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then the achievable savings from a measure is included in this potential. If the measure does not pass the TRC test above, the measure's potential is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions:

1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,
2) When the measure is not cost-effective using utility-specific avoided costs, but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

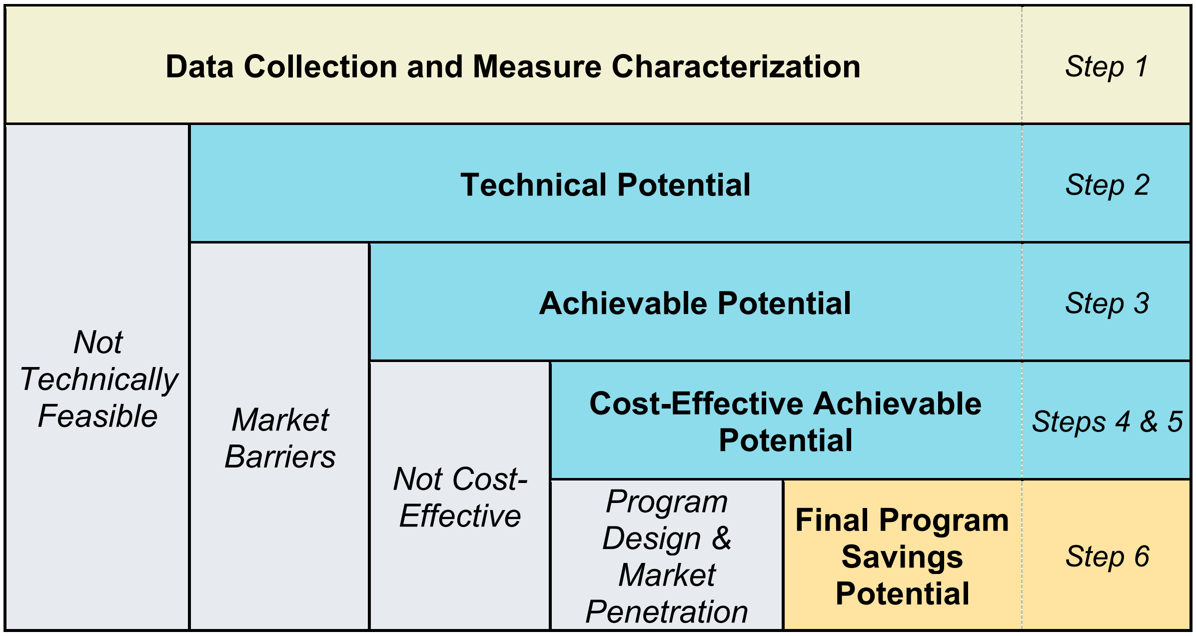
6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the 20-year cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on Avista's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of savings from very large projects that are not characterized in Energy Trust's RA Model but consistently appear in Energy Trust's historic savings record and have been a source of overachievement against IRP targets in prior years for other utilities that Energy Trust serves.

Figure ***4*** below reiterates the types of potential shown in

Figure ***2***, and how the steps described above and in the flow chart fit together.

Figure 4 - The Progression to Program Savings Projections



Forecast Results (Base Case)

The results of Energy Trust's forecast are shown below. Energy Trust performed two analyses for Avista's 2023 IRP – a base case using an expected load forecast with expected commodity prices, transport prices and carbon prices, and a high case using a high growth load forecast with high growth commodity prices, transport prices and carbon prices. The results presented below reflect the base case. The results from the high scenario are presented in a separate section at the end of this chapter.

RA Model Results – Technical, Achievable and Cost-Effective Achievable Potential

The RA Model produces results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve. These results do not include the application of ramp rates applied in Step 6 described above.

Forecasted Savings by Sector

Table 1 summarizes the technical, achievable, and cost-effective potential for Avista's system in Oregon. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in

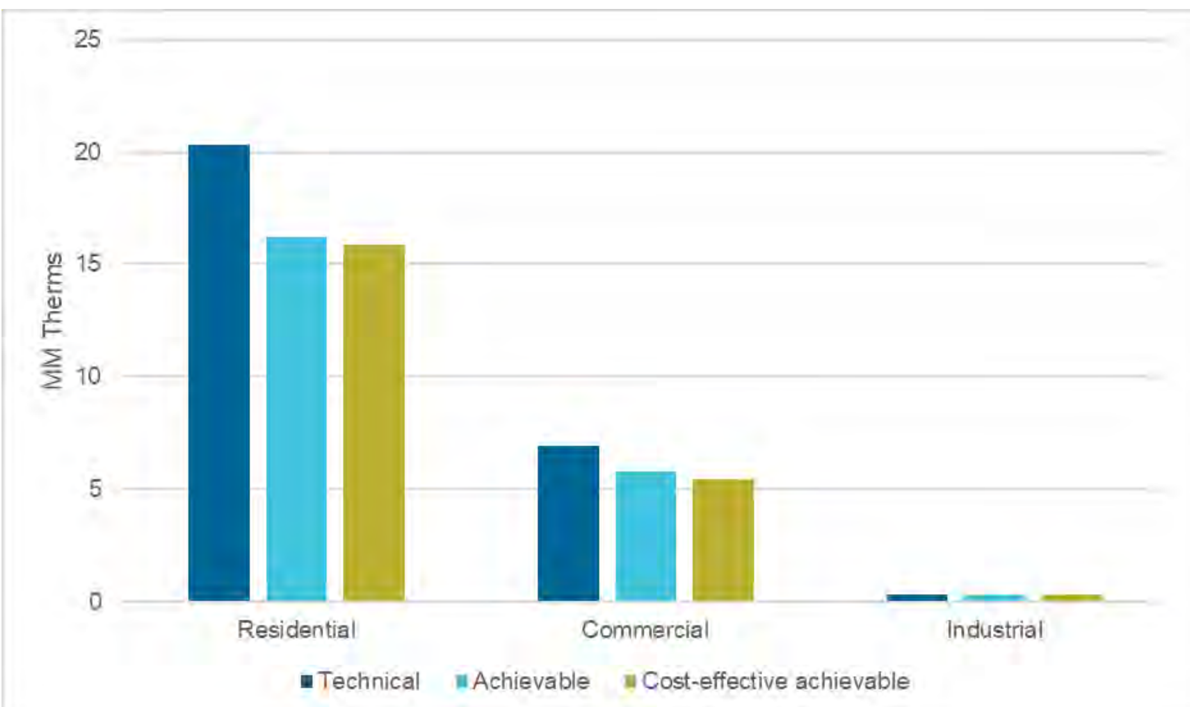
Figure ***4*** above. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 1 - Summary of Cumulative Modeled Savings Potential - 2023–2042

Sector	Technical Potential (Million Therms)	Achievable Potential (Million Therms)	Cost-Effective Achievable Potential (Million Therms)
Residential[7]	20.3	16.2	15.9
Commercial	6.9	5.8	5.5
Industrial	0.4	0.3	0.3
Total	**27.6**	**22.3**	**21.6**

Figure 5 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in Avista's service territory. Residential sales make up the majority of Avista's service in Oregon, which is reflected in the potential. Firm industrial sales represent a small percentage of the total sales in Oregon for Avista, and subsequently shows very little savings potential. Avista's interruptible and transport customers are not eligible to participate in Energy Trust programs. 85% of the industrial technical potential is cost-effective, while in the residential and commercial sectors, cost-effective achievable potential is 78% and 79% of technical potential, respectively.

Figure 5 - Savings Potential by Sector and Type – Cumulative 2023–2042 (Millions of Therms)

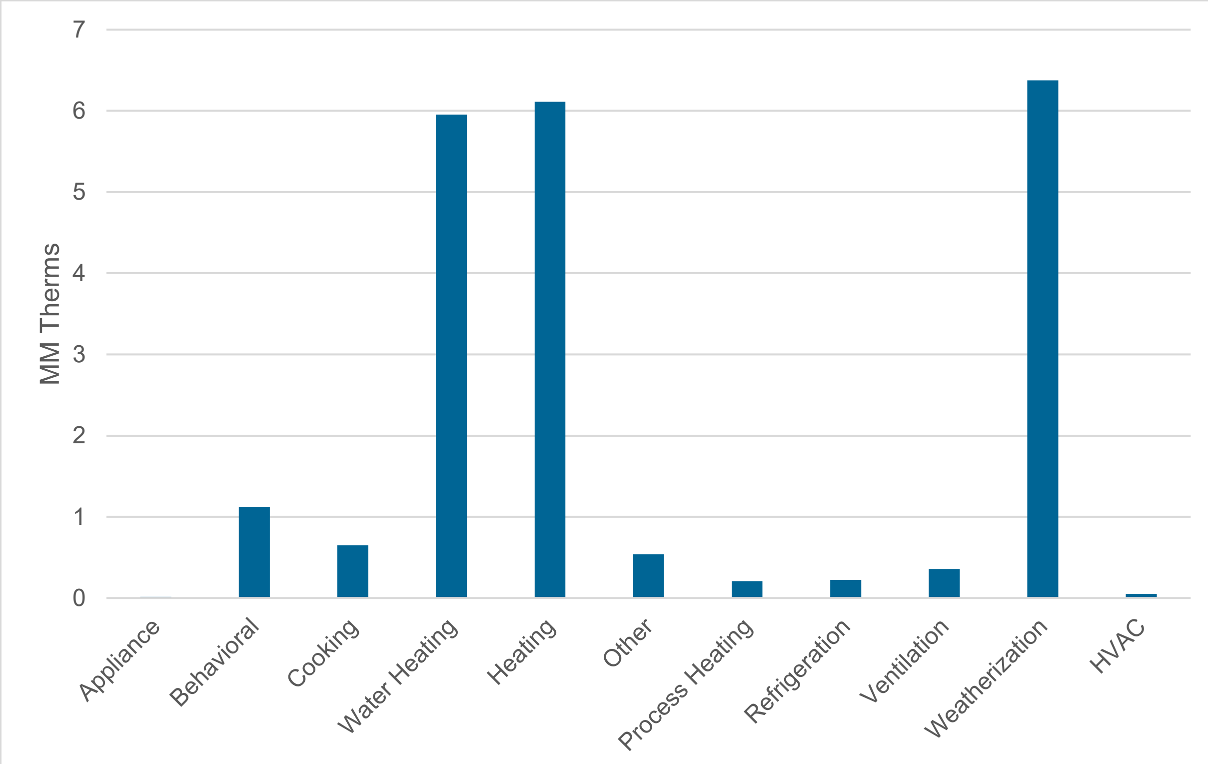


[7] Residential sector savings potential reflect the load and stock forecast from all of Avista's residential customers in Oregon, including low-income customers modeled separately by AEG.

Cost-Effective Achievable Savings by End-Use

Figure ***6*** below provides a breakdown of Avista's 20-year cost-effective savings potential by end use.

Figure 6 – 20-year Cost-Effective Cumulative Potential by End Use



As is typical for a gas utility, the top saving end uses are heating, water heating, and weatherization. A large portion of the water heating end-use is attributable to new construction homes due to how Energy Trust assigns end uses to the New Homes pathways offered through Energy Trust's residential programs. The New Home pathways are packages of measures in new construction homes with savings that span several end-uses. Energy Trust assigns an end-use to each of the New Homes pathways based on the end-use that achieves the most significant savings in the package. For example, the most cost-effective New Home pathway that was identified by the model (because it achieves the most savings for the least cost) was designated as a water heating end-use, though the package includes several other efficient gas equipment measures.

In addition to the New Homes pathway savings, the water heating end-use includes water heating equipment from all sectors, and HVAC end uses represent the savings associated with space heating equipment, retrofit add-ons, and new construction packages. The behavioral end use consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training and support to facilities teams and staff to identify operations and maintenance changes that make a difference in a building's energy use.

Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model

Residential	Commercial	Industrial

• Attic Insulation R-60 • Behavior Competitions • Cellular Shades • Gas Absorption Heat Pump Water Heater • Gas Fired Heat Pump • Thin Triple Pane Windows • Wall Insulation R-30	• Condensing Gas Rooftop unit • Gas Absorption Heat Pump Hot Water • Gas-fired Heat Pump • Gas RTU Advanced Tier 1 • Thin Triple Pane Windows • VHE DOAD/HRV • Zero Net Energy	• Advanced Wall Insulation • Gas Fired Heat Pump Water Heater

Energy Trust recognizes that emerging technologies are inherently uncertain and applies a risk factor to hedge against that uncertainty. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for emerging technologies to produce reliable future savings. This risk factor is determined based on qualitative risk categories, including:

- Market risk
- Technical risk
- Data source risk

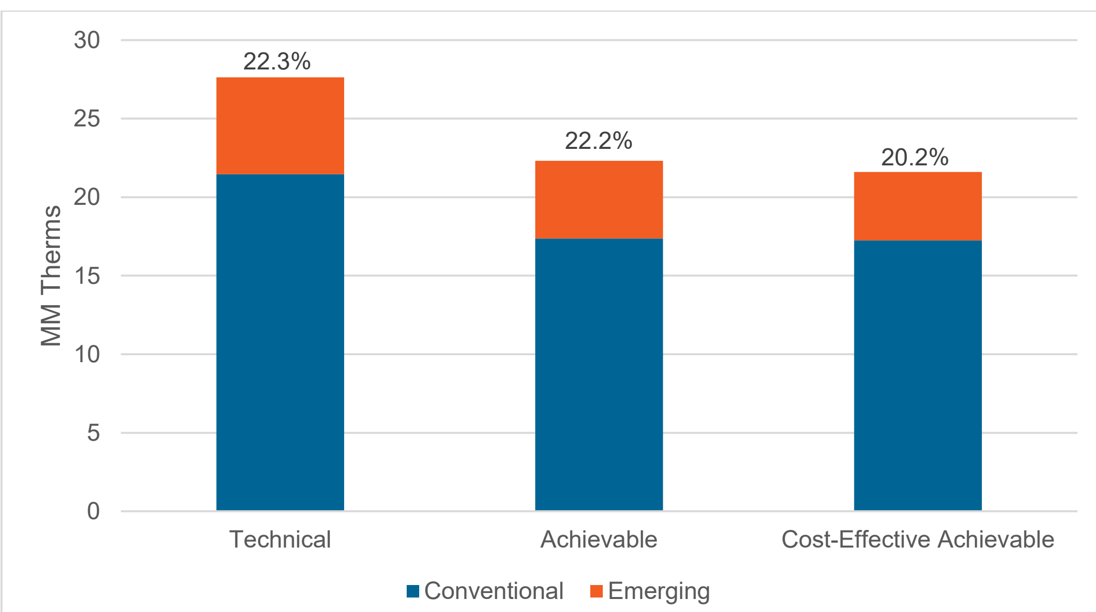
The framework for assigning the risk factor is shown in Table 3. Each emerging technology was assessed within each risk category and then a total weighted score was then calculated. Well-established and well-studied technologies have lower risk factors and nascent, unevaluated technologies (e.g., gas absorption heat pump water heaters) have higher risk factors. This risk factor is then applied as a multiplier to reduce the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

	Emerging Technology Risk Factor				
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk (25% weighting)	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist.			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk (25% weighting)	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third-party case studies

Figure 7 below shows the amount of emerging technology savings within each type of potential. While emerging technologies make up a relatively large percentage of the technical and achievable potential, nearly 23%, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to 20% of total cost-effective achievable potential. This is because some of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time where applicable, some are not cost-effective at any point over the planning horizon.

Figure 7 – Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 4 shows the savings potential in the RA model that was added by employing the cost-effectiveness override option in the model. As discussed in the methodology section, the cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria:

1. A measure is offered under an OPUC exception.
2. When the measure is not cost-effective using Avista-specific avoided costs, but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

Table 4 - Cumulative Cost-Effective Potential (2023-2042) due to Cost-Effectiveness Override (Millions of therms)

Sector	With Cost Effectiveness Override	Without Cost Effectiveness Override	Difference
Residential	15.9	15.0	(0.8)
Commercial	5.5	5.5	-
Industrial	0.3	0.3	-
Total	**21.6**	**20.8**	**(0.8)**

In this IRP, approximately 8% of the cost-effective potential identified by the model is due to the use of the cost-effective override. The measures that had this option applied to them included residential attic, floor, and wall insulation, gas heated new manufactured homes, clothes washers, and commercial wall and roof insulation[8].

Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential that could be saved at various costs. The levelized cost provides a consistent basis for comparing efficiency measures and other resources with different lifetimes. The levelized cost calculation starts with the incremental cost of a given measure. The total cost is amortized over the estimated measure lifetime using Avista's discount rate. The annualized measure cost is then divided by the annual natural gas savings. Some measures have negative levelized costs because these measures have non-energy benefits that are greater than the total cost of the measure over the same period.

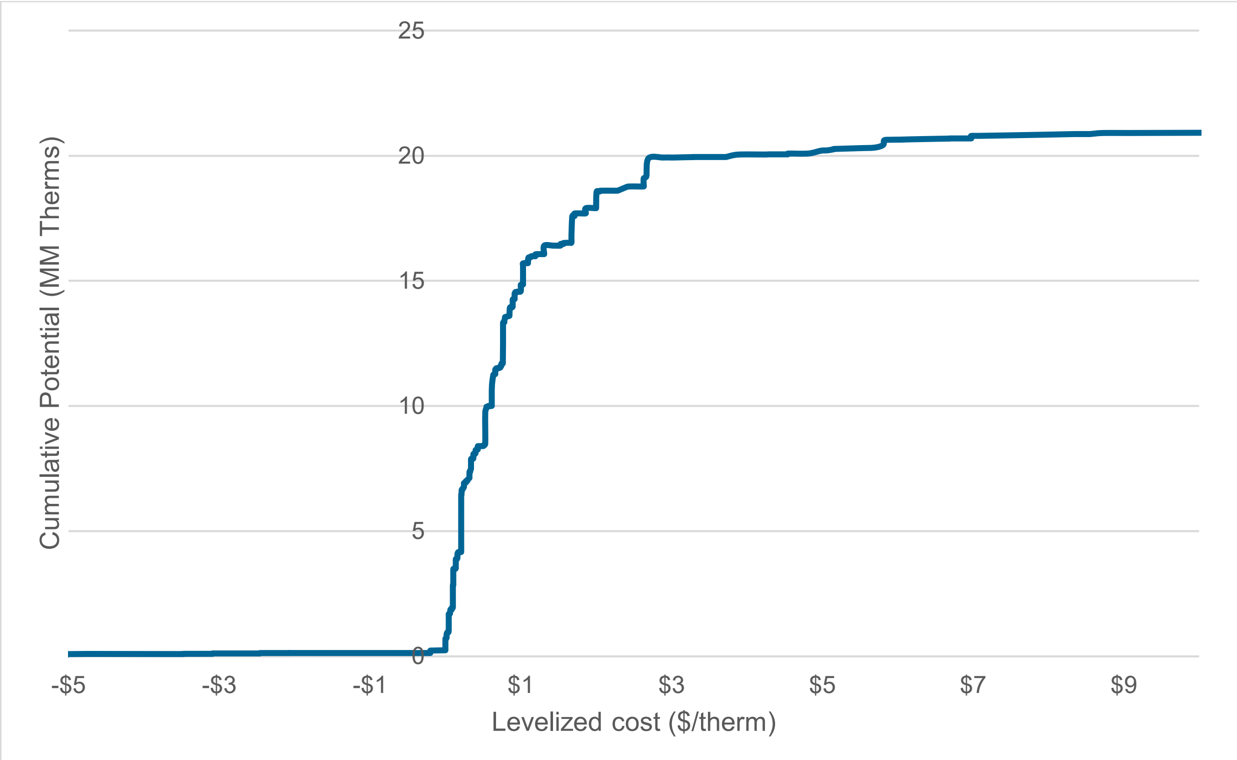
Figure ***8*** below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The cost-effective potential, without override, identified in this assessment is approximately 19.9 million therms, which translates to approximately $2.89/therm on this graph. This is not a precise point, however, since measures around this point will save natural gas at different times in relation to Avista's peak periods and therefore have varying capacity values that function to make them more or less cost-effective.

---

[8] Since the completion of Avista's 2023 IRP the Oregon Public Utility Commission has granted measure exceptions associated with measures which are being offered in 2023. The results presented in this chapter reflect measures under OPUC exception as of 2022. Notable changes include residential gas insulation measures becoming cost-effective and not under exception, and the addition of residential and multifamily windows as measures under exception.

Consequently, measures on either side of this point may or may not be cost effective. Finally, after approximately $3/therm, additional potential comes at rapidly increasing cost increments.

Figure 8 – Natural Gas Efficiency Supply Curve



Deployed Results – Final Savings Projection

The results of the final savings projection show that Energy Trust can achieve 2.1 million annual therm savings across Avista's system in Oregon from 2021 to 2025 and nearly 14.8 million therms by the end of 2040. This represents a 14.4 percent cumulative load reduction by 2040 and is an average of just under a 0.8 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 5, which compares the technical, achievable, and cost –effective achievable potential for comparison.

Table 5 - 20-Year Cumulative Savings Potential by Type (Millions of Therms)

	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Energy Trust Deployed Savings Projection
Residential	20.3	16.2	15.9	9.9
Commercial	6.9	5.8	5.5	3.8
Industrial	0.4	0.3	0.3	0.3
Exogenous[9]	-	-	-	1.4

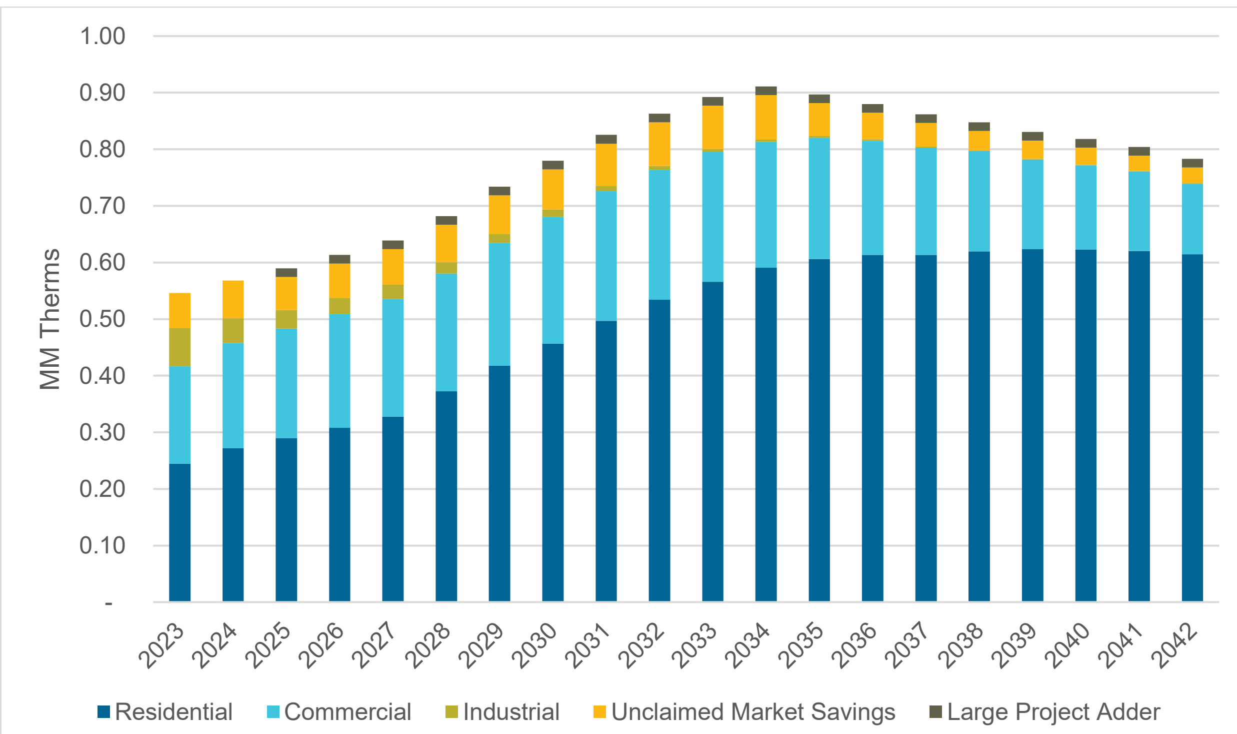
[9] The final deployed savings projection includes savings calculated outside of the modeling process consisting of the large project adder and unclaimed market savings.

Total	27.6	22.3	21.6	15.3

The final deployed savings projection is less than the modeled cost-effective achievable potential. The primary reason for this additional step down in savings is lost opportunity measures. These measures are meant to replace failed equipment or be installed in new construction. They are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if the efficient equipment is not installed, then the opportunity is lost until the equipment fails again. Energy Trust assumes that most lost opportunity measures have gradually increasing annual adoption rates as time passes due to increasing program influence and increasing codes and standards.

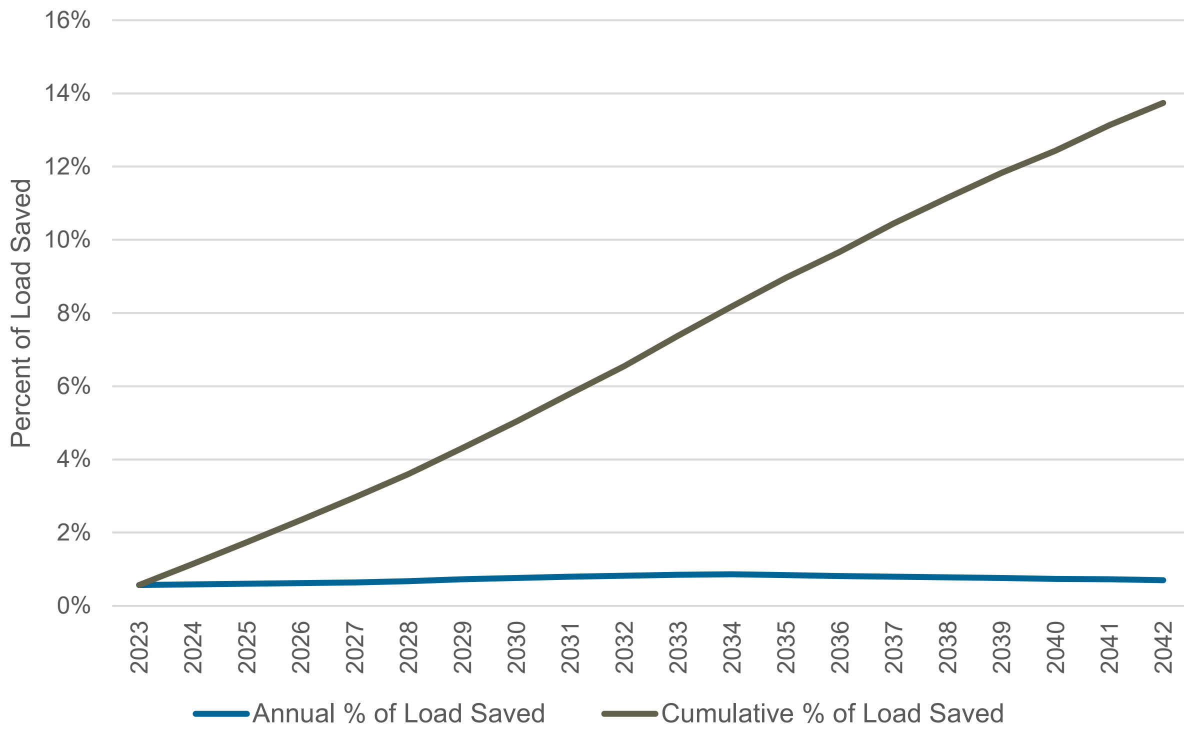
Figure 9 below shows the annual savings projection by sector. The savings acquisitions in the initial years are fairly flat due to expected market conditions. After this point, expected program savings ramp up over the forecast period, to achieve as much cost-effective potential as possible.

Figure 9 – Annual Deployed Final Savings Potential by Sector



Finally, Figure 10 shows the annual and cumulative savings as a percentage of Avista's load forecast in Oregon. Annually, the savings as a percentage of load varies from about 0.4% at its lowest to just under 1% at its highest, as represented on the left axis and the blue line. Cumulatively, the savings as a percentage of load builds to 13.7% by 2042.

Figure 10 – Annual and Cumulated Forecasted Savings as a Percentage of Avista Load Forecast



Comparison to 2020 IRP Savings Projection

Figure 11 below shows the annual deployed savings potential discussed above compared to Avista's previous IRP completed in 2020. In Avista's 2020 IRP savings peaked around year 2039, whereas Energy Trust's current forecast shows savings peaking in year 2034 reflecting acceleration in the near-term savings acquisition and thus acquiring more retrofit potential earlier in the forecast period. This is especially evident in the commercial and industrial sectors, whereas residential savings grow throughout the forecast horizon.

Figure 11 – Annual Deployed Final Savings Projection Compared to 2020

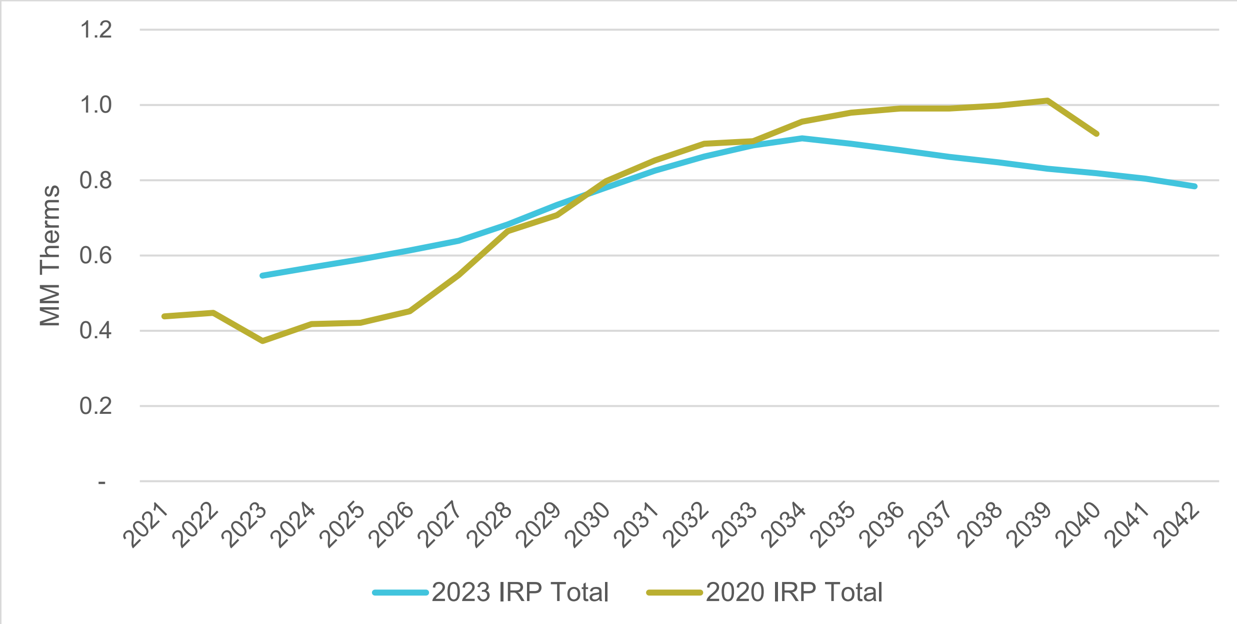


Table 6 below compares the modeled potential between this study and the 2020 IRP. Savings are up in each category of potential in the 2023 IRP compared to the 2020 IRP, however a lower share of cost-effective potential is reflected in the final deployment. This is primarily due to the 2023 IRP having a higher proportion of emerging technology potential. Energy Trust applies a different ramp rate to emerging technologies than the ramp rate applied to conventional technologies. The emerging technology ramp rate places emerging technologies at the beginning of an adoption curve when the model demonstrates that they become market ready and cost-effective.

Table 6 - 20-Year Cumulative Savings Potential by IRP vintage (Millions of Therms)

	2023 IRP	2020 IRP	Difference
Technical	27.6	24.9	2.7
Achievable	22.3	22.2	0.1
Cost-Effective	21.6	18.0	3.6
Deployed	15.3	14.8	0.5

Table 7 details the individual changes contributing to the 3.6 MM therm difference in cost-effective achievable potential shown above. Changes in load and stock forecast is the largest contributor, followed by emerging technology and measures updates.

Table 7 – Difference Between 2023 and 2020 Cost-Effective Achievable Potential (Millions of Therms)

	Difference	Share of Difference
Load and Stock Forecast	+ 1.29	36%

Emerging Technology	+ 0.84	23%
Measure Updates	+ 0.68	19%
Avoided Costs	+ 0.48	13%
Discount Rate	+ 0.34	9%
CE Override	- 0.01	0%
Total	**+ 3.63**	

Deployed Results – Peak Day Results

In the state of Oregon and around the region, there is an increased focus on the peak savings contributions of energy efficiency and the related impact on capacity investments. This new focus has led some utilities to embark on efforts to avoid or delay distribution system reinforcements. Therefore, Avista and Energy Trust have collaborated to develop estimates of peak day contributions from the energy efficiency measures in the Energy Trust forecast.

Peak day coincident factors are the percentage of annual savings that occur on a peak day and are shown in Table 8 below. Avista is still reviewing this methodology and for the purpose of this analysis, Energy Trust utilized the peak day factors that are used in the avoided costs used to screen measures for cost-effectiveness to determine the cost-effective achievable resource per the description above. These include residential and commercial space heating factors developed by NW Natural and hot water, process load (flat), and clothes washer factors sourced from load shapes developed by the Northwest Power and Conservation Council for electric measures that are analogous to gas equipment. The peak day factors are the highest for the space heating load shapes, which align with a winter system peak that is typical of natural gas utilities.

Table 8 - Peak Day Coincident Factors by Load Profile

Load Profile	Peak Day Factor	Source
Residential Space Heating	2.00%	NW Natural
Commercial Space Heating	1.77%	NW Natural
Water Heating	0.33%	NWPCC
Clothes Washer	0.20%	NWPCC
Process Load	0.27%	NWPCC

Figure below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast developed for this IRP. Each measure analyzed is assigned a load shape and the appropriate peak day factor is applied to the annual savings to calculate the overall DSM contribution to peak day capacity. Cumulatively, this is equal to 230,998 therms in Avista's Oregon service territory over the 20-year forecast, as shown in 9 below.

Figure 12 - Annual Deployed Peak Day DSM Savings Contribution by Sector[9]

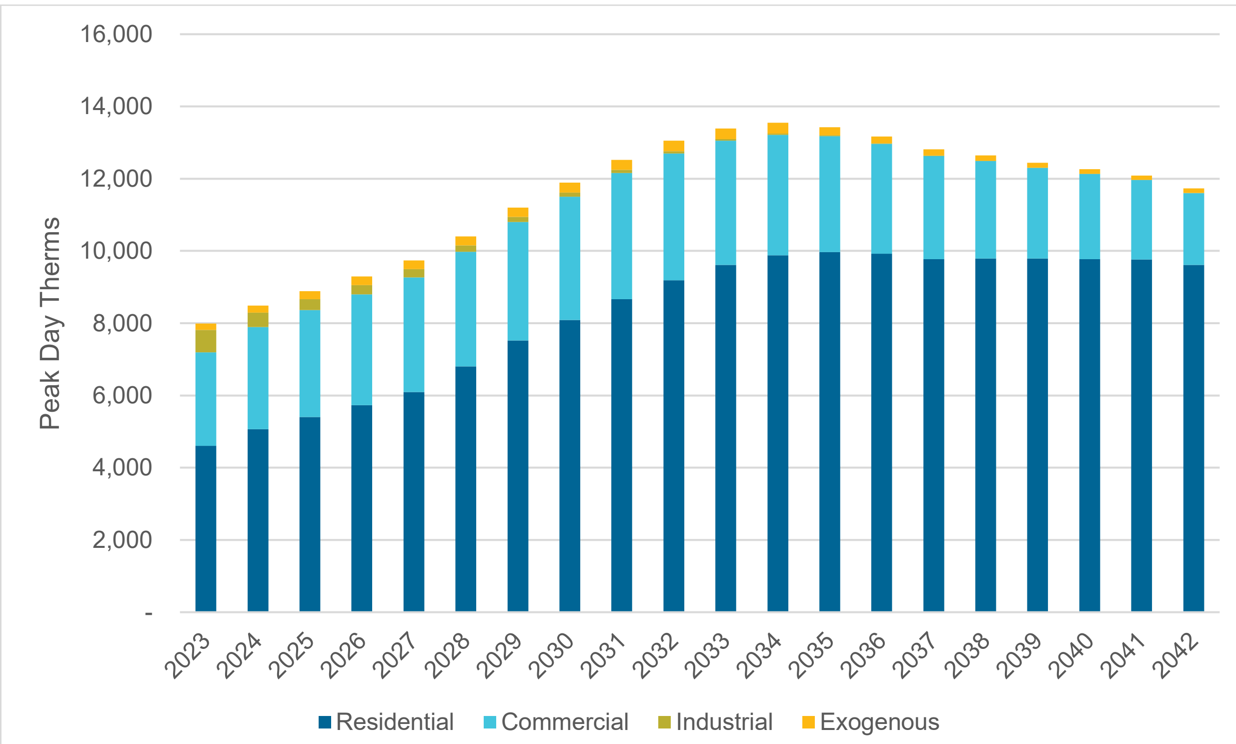


Table 9 - Cumulative Deployed Peak Day DSM Savings Contribution by Sector (Therms)

Sector	Cumulative Peak Day Savings (Therms)
Residential	165,069
Commercial	59,108
Industrial	2,571
Exogenous[9]	4,249
Total	**230,998**

Scenario Runs

For the 2023 IRP, Energy Trust modeled two scenarios for Avista. The two scenarios were designed to reflect differences in load growth and avoided costs. These scenarios are outlined in the bullets below:

- *Base Case:* Expected load forecast with expected commodity prices, transport prices and carbon prices.
- *High Case:* High growth load forecast with high growth commodity prices, transport prices and carbon prices.

Figure 13 provides a graphical view of the annual savings potential for the two scenarios. Table 10 provides the cumulative savings potential of each scenario.

Figure 13 - Annual Deployed Savings Comparison of Scenarios

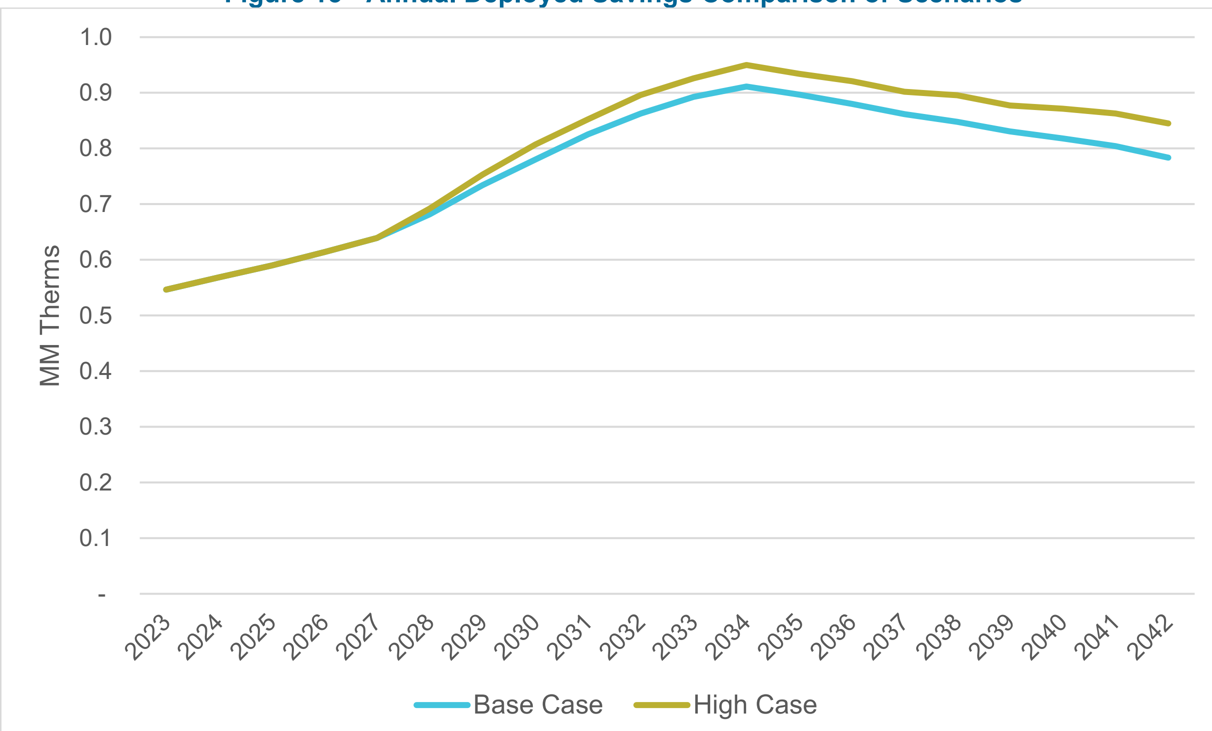


Table 10 - Cumulative 20-year Deployed Savings Potential by Scenario (Therms)

Sector	Cumulative Savings (Therms)
Base Case	15,368,375
High Case	15,942,609

The high case scenario results in an increase in deployed savings potential. This occurs through two channels. The amount of technical and achievable potential increases as a result of the higher load growth forecast, and, separately, increases in avoided costs result in more of that achievable potential being cost-effective. The high case results in about a 3.7% increase in the deployed savings forecast. As in the base case, the first five years of the forecast period are set by program budgets and expectations of market conditions, and therefore the high case increases begin in year six of the forecast period.

MEMORANDUM

To: Lisa McGarity and Ryan Finesilver – Avista Corporation

From: Eli Morris, Andy Hudson, Ken Walter, Stephanie Chen, Laraeb Khan - AEG

Date: December 16, 2022

Re: Avista Oregon Low-Income Conservation Potential Assessment

Background

To support initiatives to serve low-income customers and reduce energy burden in its Oregon natural gas service territory, Avista Corporation (Avista) engaged Applied Energy Group (AEG) to assess the energy efficiency potential for Oregon low-income households. This analysis leverages the natural gas conservation potential assessment (CPA) AEG was already performing for Avista's Washington and Idaho service territories, incorporating Oregon-specific data to ensure results are directly applicable to Avista's Oregon low-income customers.

This memo presents a high-level summary of potential results, followed by an overview of AEG's methodology, identification of key data sources, customer segmentation analysis, and more detailed potential results.

Results Summary

A summary of the energy efficiency potential for Oregon low-income customers is presented in Table 1. As shown, achievable and cost-effective energy efficiency potential represents approximately 9% of baseline sales by 2045.

AEG notes the following considerations in reviewing these results:

- The study relied on the best available data from Avista and secondary sources. Sources did not include on-site assessments of low-income customer equipment efficiency or practices. Therefore, current conditions and remaining opportunities were estimated using information about typical characteristics by market segment.
- Achievable economic potential was estimated from the Total Resource Cost (TRC) perspective, consistent with standard cost-effectiveness practices for energy efficiency in Oregon.
- Energy efficiency programs serving low-income customers are often not required to be cost-effective. Achievable technical potential provides an estimate of what could be possible if cost-effectiveness is not considered.

Table 1 – Summary of Energy Efficiency Potential

	2023	2024	2025	2035	2045
Baseline Projection (Dth)[1]	914,784	919,566	924,873	999,238	1,128,049
Cumulative Savings (Dth)					
Achievable Economic Potential	3,816	7,383	12,114	60,487	99,838
Achievable Technical Potential	8,877	18,471	30,274	165,088	205,045
Technical Potential	14,319	28,147	44,987	226,689	295,472
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.4%	0.8%	1.3%	6.1%	8.9%
Achievable Technical Potential	1.0%	2.0%	3.3%	16.5%	18.2%
Technical Potential	1.6%	3.1%	4.9%	22.7%	26.2%

Methodology

AEG used a bottom-up approach to perform the potential analysis, following the steps listed:

1. Perform a customer segmentation analysis to estimate the number of Avista Oregon residential customers in each housing type and considered low-income, and the energy consumption of each segment.
2. Perform a market characterization to describe sector-level natural gas use for residential low-income customers for the base year, 2021. The characterization included extensive use of Avista data and other secondary data sources from Northwest Energy Efficiency Alliance (NEEA) and the Energy Information Administration (EIA).
3. Develop a residential baseline projection of energy consumption by segment, end use, and technology for 2023 through 2045.
4. Define and characterize energy efficiency measures to be applied to all segments and end uses.
5. Estimate technical, achievable technical, and achievable economic energy efficiency potential at the measure level for 2023 through 2045.

Key Data Sources

AEG used Avista's 2022 Washington and Idaho CPA as the foundation for this assessment. Key updates from the Washington CPA assumptions to reflect the Oregon market and potential included:

- Input and market characterization data were specific to Avista's Oregon low-income customers. The CPA model generally formed the basis for measure cost assumptions and savings estimates.
- With the CPA measure list as the starting point, AEG worked with Avista to identify measures in active programs serving low-income customers, avoiding measures that are inappropriate for these segments due to costs or other concerns.
- The model reflects baseline conditions in alignment with Oregon's state building codes.

Where data gaps existed in Avista's data, AEG relied on national and regional data sources for assumptions in the potential model. Table 2 summarizes key data sources used and how they informed the study.

[1] 1 Dth = 1 dekatherm, or 10 therms

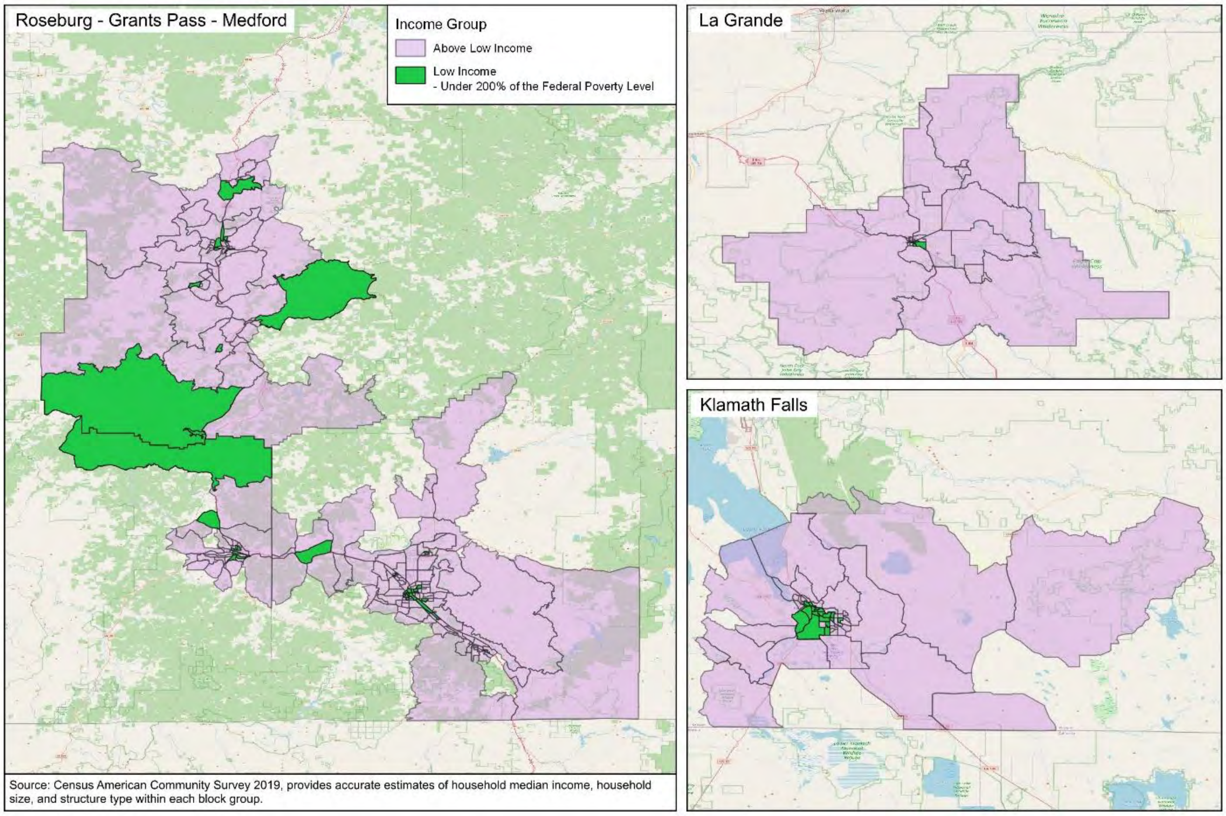
Table 2 – Key Data Source Summary

Data Source	Used for
Avista Data	Development of customer counts and energy use for each segment type, comparison baseline forecast, customer counts forecast, presence of equipment, end use load distribution, economics inputs, scenario development
US Census American Community Survey (ACS)	Household characteristics in block groups
Northwest Power and Conservation Council's 2021 Power Plan	Technical achievable ramp rate library and study methodology
NEEA's Residential Building Stock Assessment II (RBSA), Single-Family Homes Report 2016-2017	Benchmark equipment saturations, normalized end use and equipment intensity (therms per household)
US Energy Information Administration (EIA) 2015 Residential Energy Consumption Survey (RECS)	Estimated equipment use per unit, end use distribution of natural gas use by segment type, benchmarking equipment presence (saturation)
EIA's 2020 Annual Energy Outlook	Reference baseline purchase assumptions, equipment lifetimes and costs

Customer Segmentation Analysis

To estimate the number of Avista customers in Oregon to include in the low-income assessment, AEG mapped address data back to corresponding geographic "block groups" in the ACS census data. Each block groups was then processed to analyze average household size and income, producing a distribution of households into income buckets for places where Avista customers reside. The low-income threshold corresponds with 200% of the Federal Poverty Level. The maps in Figure 1 shows the distribution of different income groups through Avista's Oregon service territory.

Figure 1 – Income Group Map



Once the percentage of customers in each housing type and income group was known, AEG used RBSA data to investigate differences in energy consumption for each grouping, enabling a comparison of natural gas usage per household across categories. Combining the geographic/demographic analysis with RBSA data on usage differences by income level, AEG was able to produce an expanded residential profile with data-driven variation by income group. Table 3 shows the customer energy consumption by income level in the base year, 2021. While AEG fully characterized the residential customer populations, only low-income customers are included in the potential analysis.

Table 3 – Customer Counts and Energy Consumption by Dwelling Type and Income Level, 2021

Segment	Households	Natural Gas Consumption (Dth)	Intensity (Dth/household)
Single Family - Regular Income	58,913	3,770,739	64,006
Single Family - Low Income	12,289	662,559	53,917
Multi-Family - Regular Income	7,707	183,230	23,774
Multi-Family - Low Income	4,428	88,679	20,026
Mobile Home - Regular Income	7,066	253,416	35,864
Mobile Home - Low Income	2,197	113,191	51,514
Total	**92,600**	**5,071,813**	**54,771**

Potential Results

Figure 2 presents the annual potential savings relative to the baseline projection. Based on the ramp rates used, a majority of the identified potential is assumed to be acquired over 10 years.

Figure 2 – Cumulative Energy Efficiency Potential as % of Baseline Projection

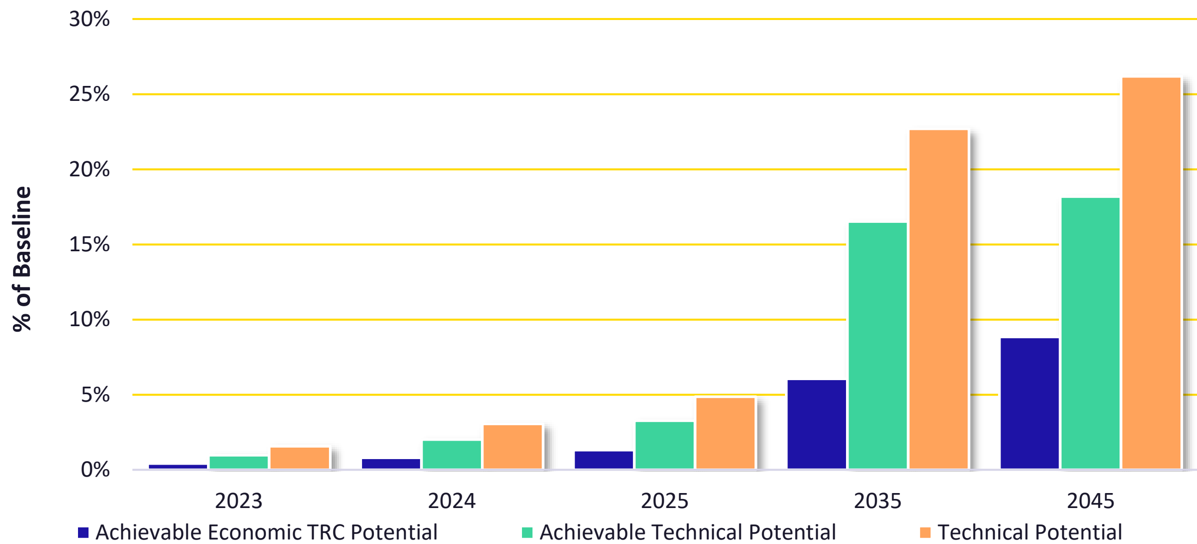


Figure 3 presents the percentage of achievable economic potential in 2045 by market segment and end use. Single family dwellings account for 77% of low-income achievable economic potential. Space heating accounts for 67% of low-income achievable economic potential.

Figure 3 - Achievable Economic Potential, 2045

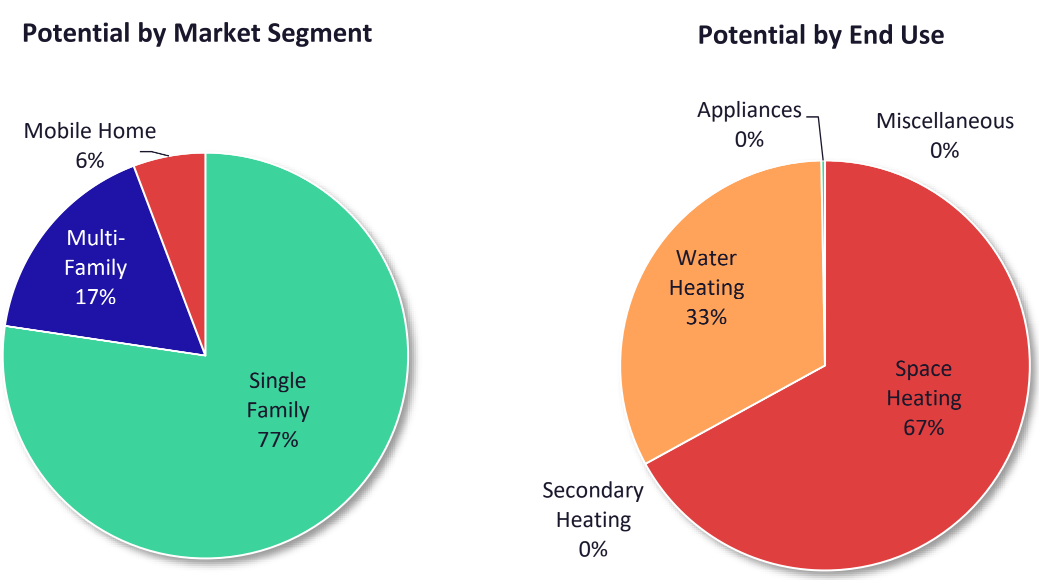


Figure 4 presents a forecast of cumulative achievable economic potential by end use. Space heating accounts for the majority of potential but declines slightly in the mid-2020s due to a future furnace standard.

Figure 4 – Cumulative TRC Achievable Economic Potential by End Use

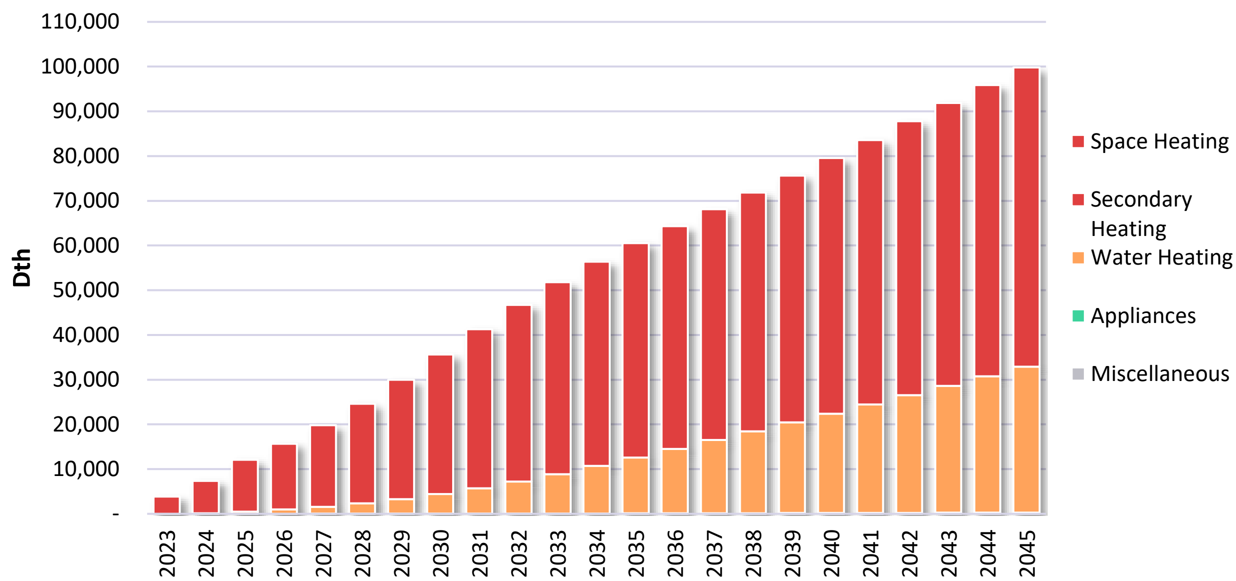


Table 4 identifies the top measures by cumulative 2023 and 2035 achievable economic potential. Furnaces, connected smart thermostats, and insulation are the top measures.

Table 4 – Top Measures in 2023 and 2035, Achievable Economic Potential

Rank	Measure / Technology	2023 Cumulative Dth	% of Total	2035 Cumulative Dth	% of Total
1	Gas Furnace - Maintenance	1,813	47.5%	5,115	8.5%
2	Connected Thermostat - ENERGY STAR (1.0)	860	22.5%	18,027	29.8%
3	Furnace	694	18.2%	8,829	14.6%
4	Insulation - Ceiling Installation	326	8.5%	6,915	11.4%
5	Insulation - Wall Sheathing	51	1.3%	1,118	1.8%
6	ENERGY STAR Home Design	26	0.7%	5,090	8.4%
7	Behavioral Programs	21	0.5%	764	1.3%
8	Insulation - Wall Cavity Installation	11	0.3%	238	0.4%
9	Circulation Pump - Timer	5	0.1%	1,208	2.0%
10	Water Heater - Pipe Insulation	3	0.1%	365	0.6%
11	ENERGY STAR Doors - Storm and Thermal	2	0.1%	581	1.0%
12	Windows - Low-e Storm Addition	2	0.1%	1,315	2.2%
13	Windows - High Efficiency (Class 22)	1	0.0%	395	0.7%
14	Windows - High Efficiency (Class 30)	1	0.0%	285	0.5%
	Subtotal	3,815	**100.0%**	50,245	**83.1%**
	Total Savings in Year	3,816	**100.0%**	60,487	**100.0%**

APPLIED ENERGY GROUP

MEMORANDUM

To: Ryan Finesilver and Tom Pardee – Avista Corporation

From: Eli Morris, Andy Hudson, Ken Walter, Fuong Nguyen - AEG

Date: December 16, 2022

Re: Avista Washington and Oregon Natural Gas Transportation Customer Conservation Potential Assessment

Background

Avista Corporation (Avista) engaged Applied Energy Group (AEG) to assess the conservation potential at Washington and Oregon natural gas transportation customer[1] facilities to inform the extent to which energy efficiency savings at these facilities could help Avista comply with new regulations. In Washington and Oregon, Avista's transportation customers are currently exempt from funding energy efficiency programs and thus are not eligible to participate in natural gas energy efficiency programs administered by Avista and the Energy Trust of Oregon in Washington and Oregon, respectively.

In Washington, the Washington Utilities and Transportation Commission continues to consider whether pursuing all cost-effective conservation, as required by Initiative 937, requires utilities to fund energy efficiency programs for natural gas transportation customers. In Oregon, Executive Order 20-04, passed in March 2020, limits statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels by new goals established by the Oregon Department of Environmental Quality (DEQ). The Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emissions of natural gas transportation customers.

The remainder of this memo presents high-level study results, followed by an overview of AEG's methodology, identification of key data sources, potential results, and considerations and recommendations as Avista considers new program options to reach these customers.

Results Summary

Table 1 and Table 2 summarize the energy efficiency potential at transportation customer sites in Washington and Oregon, respectively. AEG notes the following considerations in reviewing these results:

- The potential represents expected levels of savings using average assumptions across customers and equipment. However, a small number of customers represent a majority of transportation customer consumption (the top 21% of the largest Washington transportation customers make up roughly 76% of Avista Washington transportation load). Therefore, actual energy efficiency impacts may vary widely depending on whether these large customers choose to participate in potential programs and customer-specific characteristics. As such, these results should be viewed as planning assumptions that are likely to differ in practice.
- The study relied on the best available data from Avista and secondary sources, which did not include on-site assessments of transportation customer equipment efficiency or practices. Therefore, current conditions and

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

remaining opportunities were estimated using information about typical characteristics by market segment (i.e., business or industry type).

- Achievable economic potential was estimated from the Total Resource Cost (TRC) perspective, consistent with standard cost-effectiveness practices for energy efficiency in Washington and Oregon.
- In Washington, programs are anticipated to roll out halfway through 2024; therefore, there is zero achievable technical and achievable economic potential savings potential in 2023. In Oregon, programs are anticipated to roll out halfway through 2023.

Table 1 – Summary Potential Results – Reference Case, Washington

	2023	2024	2025	2035	2045
Baseline Projection (Dth)	7,948,528	7,926,395	7,906,170	7,784,947	7,734,852
Cumulative Savings (Dth)					
Achievable Economic Potential	0	35,247	97,553	821,836	1,234,253
Achievable Technical Potential	0	42,283	115,124	970,876	1,437,154
Technical Potential	37,603	121,842	239,931	1,417,264	2,031,971
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.0%	0.4%	1.2%	10.6%	16.0%
Achievable Technical Potential	0.0%	0.5%	1.5%	12.5%	18.6%
Technical Potential	0.5%	1.5%	3.0%	18.2%	26.3%

Table 2 – Summary Potential Results – Reference Case, Oregon

	2023	2024	2025	2035	2045
Baseline Projection (Dth)	4,681,846	4,677,171	4,672,870	4,646,028	4,633,981
Cumulative Savings (Dth)					
Achievable Economic Potential	18,128	51,503	86,078	459,802	665,887
Achievable Technical Potential	19,119	53,850	89,939	475,228	684,470
Technical Potential	31,066	79,749	129,326	615,631	874,975
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.4%	1.1%	1.8%	9.9%	14.4%
Achievable Technical Potential	0.4%	1.2%	1.9%	10.2%	14.8%
Technical Potential	0.7%	1.7%	2.8%	13.3%	18.9%

1. ## Methodology

2. AEG used a bottom-up approach to perform the potential analysis, following the steps listed:

3. Perform a customer segmentation analysis to estimate the number of Avista Washington and Oregon transportation customers in each market segment and the energy consumption of each segment.

4. 5. Perform a market characterization to describe sector-level natural gas use for transportation customers for the base year, 2021. The characterization included extensive use of Avista data and other secondary data sources from the US Energy Information Administration (EIA).

Develop a baseline projection of energy consumption by segment, end use, and technology for 2023 through 2045.

Define and characterize energy efficiency measures to be applied to all segments and end uses.

Estimate technical, achievable technical, and achievable economic potential for 2023 through 2045.

Key Data Sources

AEG used Avista's 2022 Washington Natural Gas Conservation Potential Assessment (CPA) as the foundation for this assessment. The Washington CPA assessed natural gas energy efficiency potential for Avista's residential, commercial, and industrial sales customers, but excluded transportation customers. Key updates AEG made to Washington CPA assumptions to reflect Washington and Oregon transportation customers, loads, and potential included:

- Input and market characterization data for this analysis were specific to Avista's Washington and Oregon transportation customers, including baseline sales, forecasts, and industry designations. The Washington CPA generally formed the basis for the measure cost assumptions and savings percentage estimates.
- AEG benchmarked the distribution of end use loads with data from the EIA's Commercial Building and Manufacturing Energy Consumption Surveys and discussed notable differences with Avista to ensure that they accurately reflected known aspects of those customers. For example, if a particular manufacturing sector showed a greater proportion of space heating load than expected compared to MECS data, Avista could confirm that their Oregon transportation customers was dominated by a facility with significant conditioned space and whose product line did not require as much natural gas use.
- The assessment leveraged the Washington CPA measure list.

Where data gaps existed in Avista data, AEG relied on national and regional data sources for assumptions in the potential model. Table 3 summarizes key data sources used for the analysis and how each informed the study.

Table 3 – Key Data Source Summary

Data Source	Used for
Avista Utility Data	Load segmentation by industry/building type, presence of equipment, end use load distribution, comparison baseline forecast, economics inputs, scenario development
Northwest Power and Conservation Council's 2021 Power Plan	Technical Achievable ramp rate library and study methodology
NEEA's 2019 and 2014 Commercial Building Stock Assessment (CBSA)	Benchmark equipment saturations, normalized end use and equipment intensity (therms per sq.ft)
EIA 2014 Manufacturing Energy Consumption Survey (MECS) and 2012 Commercial Building Energy Consumption Survey (CBECS)	Estimated equipment use per unit, end use distribution of natural gas use by business/industry type, benchmarking equipment presence (saturation)
EIA's 2022 Annual Energy Outlook	Reference baseline purchase assumptions, equipment lifetimes and costs

Potential Results

AEG developed achievable economic potential based on assumptions regarding the rate at which potential could be acquired. The achievable economic potential started with standard ramp rate assumptions from the Northwest Power and Conservation Council's (Council's) 2021 Power Plan, mapped to natural gas measures,[2] and accounting for the assumed timing of Avista's program offerings. In Washington, programs are anticipated to roll out halfway through 2024; therefore, there is zero potential savings in 2023 and fewer savings potential in 2024 before ramping up in future years. In Oregon, programs are anticipated to roll out halfway through 2023; therefore, reduced savings potential is identified in the first year before ramping up in future years.

Figure 1 presents the annual potential savings relative to the baseline projection. Based on the ramp rates used, a majority of the identified potential is assumed to be acquired over the first 10 years of the study period.

[2] The Council's 2021 Power Plan only covers electric measures. To adapt these ramp rates for this natural gas assessment, AEG mapped gas measures to the same or similar electric measure, consistent with the methodology from the Washington Natural Gas CPA.

Figure 1 – Reference Case Cumulative Potential, Washington

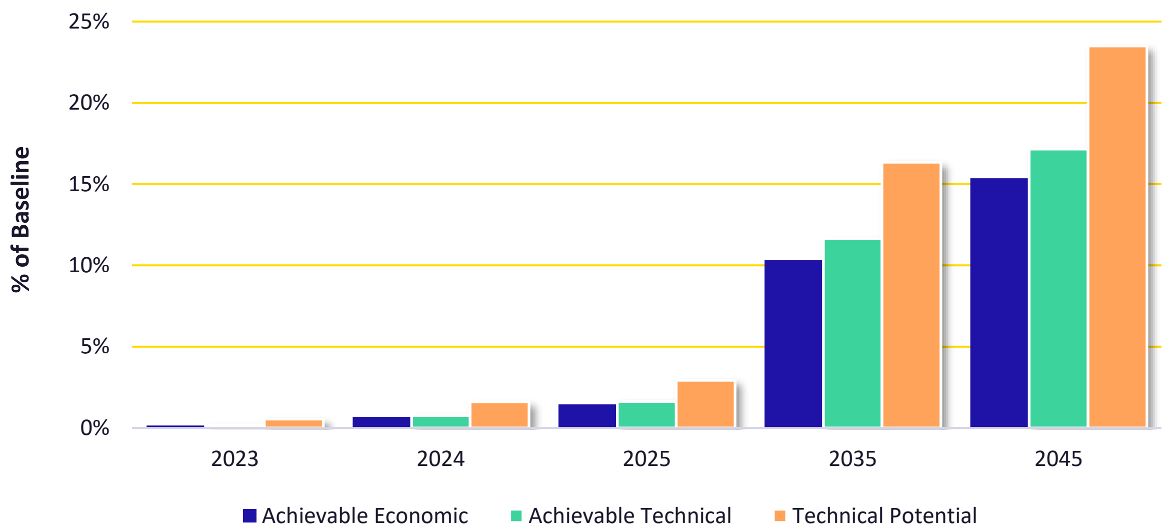
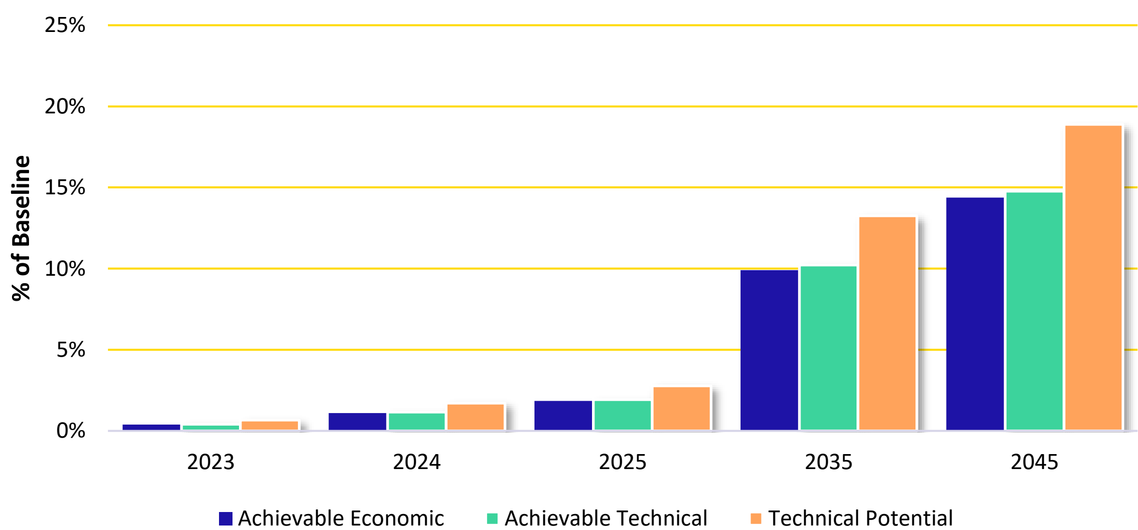


Figure 2 – Reference Case Cumulative Potential, Oregon



Commercial Potential Results

Figure 3 and Figure 4 present the percentage of achievable economic potential 2045 by market segment and end use, respectively. The majority of Avista's commercial transportation customers are college (52% in Oregon and 61% in Washington). Space heating accounts for the largest share of end use potential in both states, representing 60% and 76% of cumulative commercial achievable economic potential in Oregon and Washington, respectively.

Figure 3 – Commercial Achievable Economic Potential by Market Segment, 2045

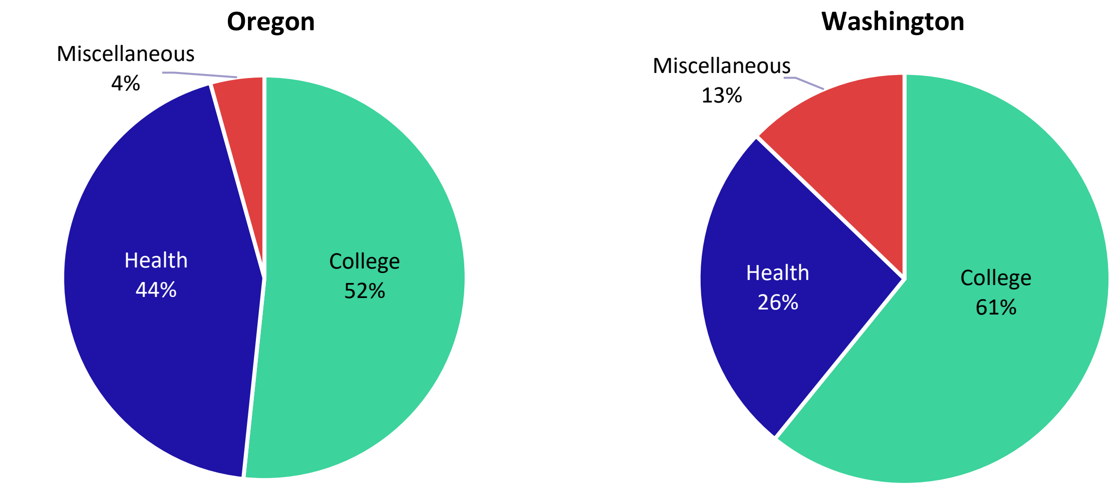
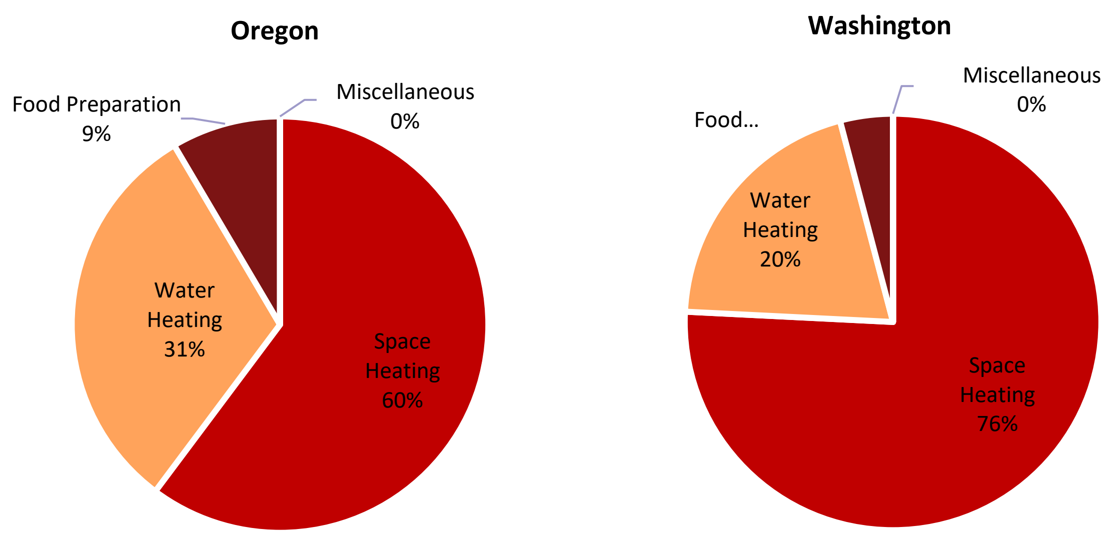


Figure 4 – Commercial Achievable Economic Potential by End Use, 2045



Cumulative commercial achievable economic potential is provided in Figure 5 for Oregon and Figure 6 for Washington.

Figure 5 - Cumulative Achievable Economic Commercial Potential by End Use, Oregon

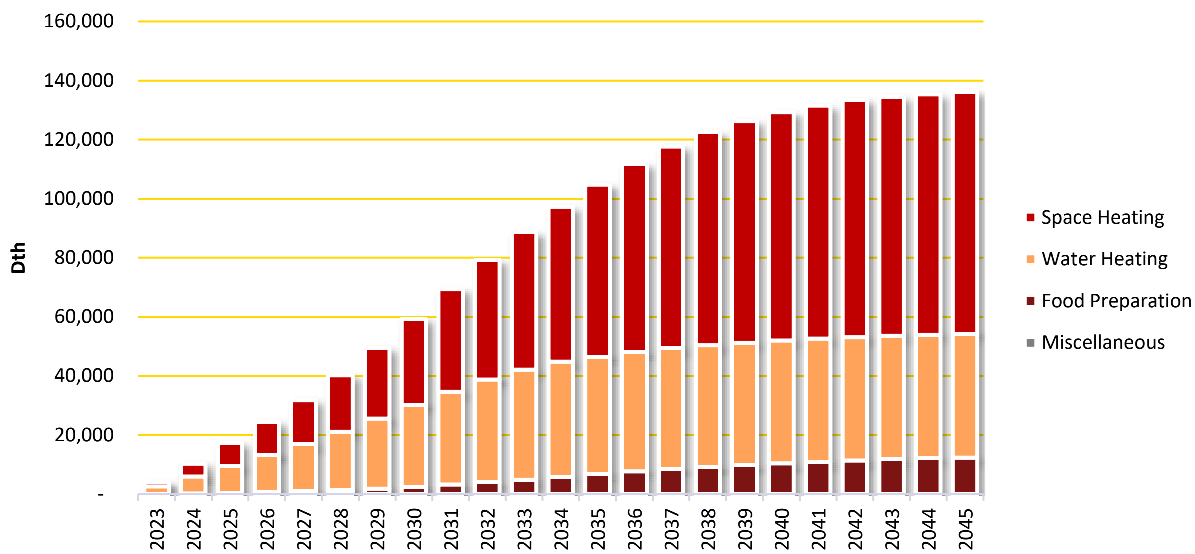
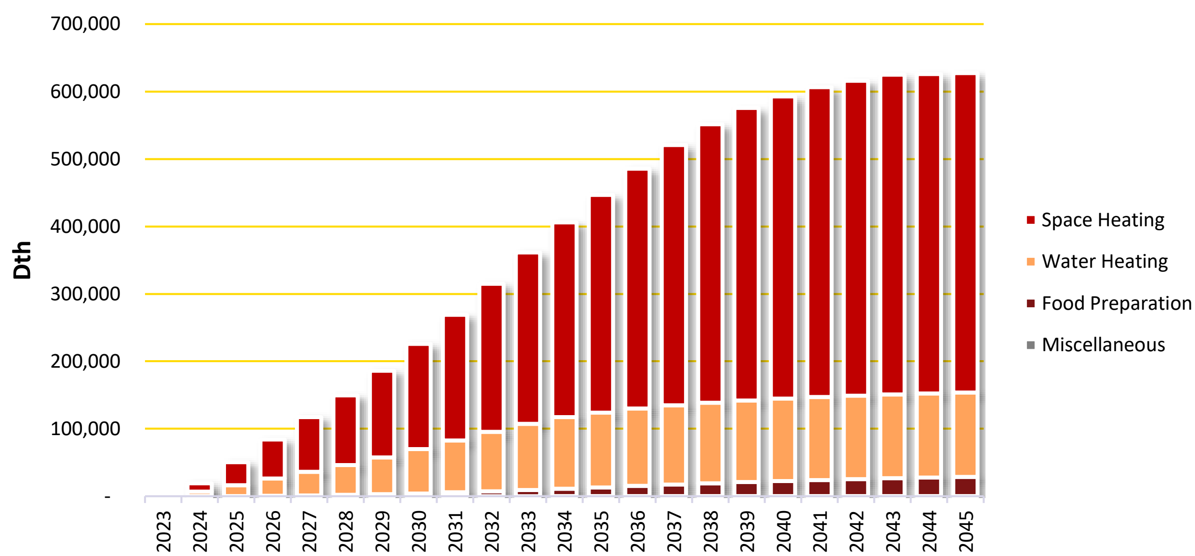


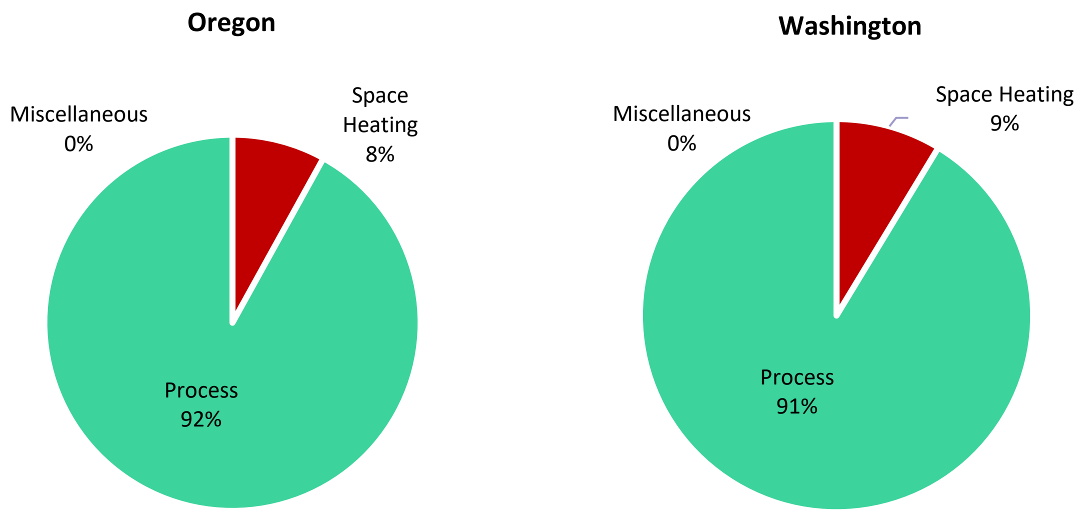
Figure 6 - Cumulative Achievable Economic Commercial Potential by End Use, Washington



Industrial Potential Results

Figure 7 presents the cumulative industrial potential in 2045 by end use. Industrial process end use accounts for 92% of Oregon's identified industrial achievable economic potential process and 91% of Washington's identified industrial achievable economic potential.

Figure 7 – Industrial Achievable Economic Potential by End Use, 2045



Cumulative industrial achievable economic potential is provided in Figure 8 for Oregon and Figure 9 for Washington.

Figure 8 – Cumulative Achievable Economic Industrial Potential by End Use, Oregon

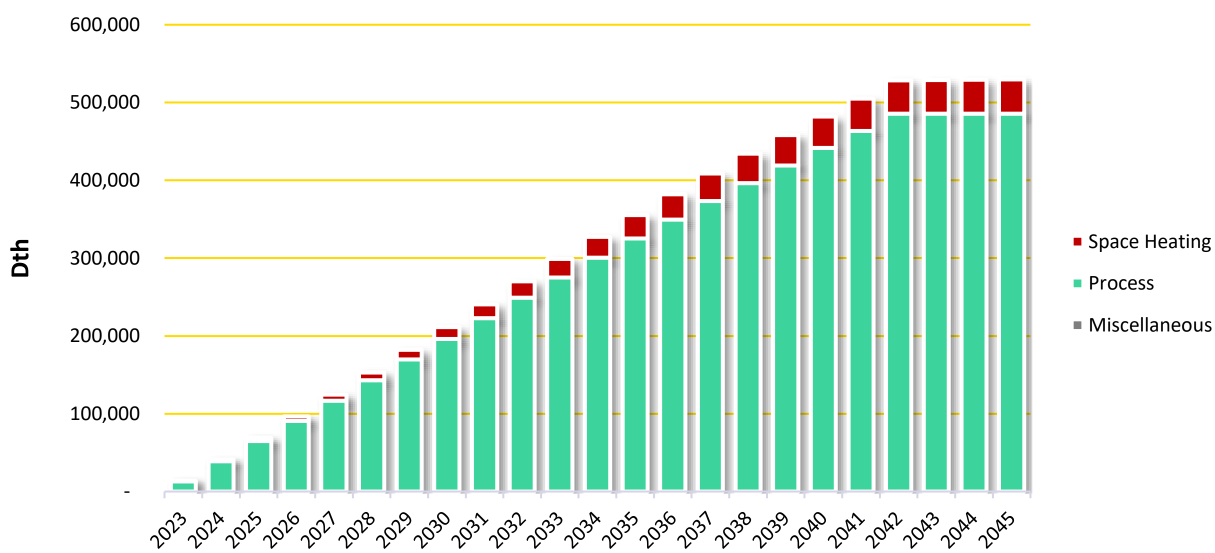
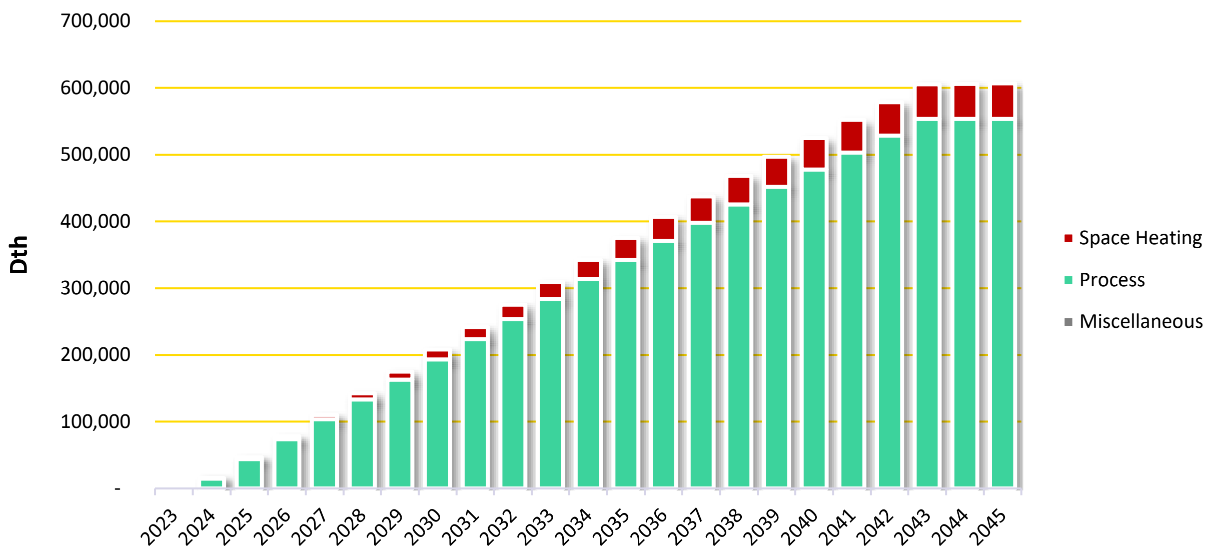


Figure 9 – Cumulative Achievable Economic Industrial Potential by End Use, Washington



Considerations and Recommendations

This assessment was a first step in identifying and realizing natural gas energy efficiency (and associated greenhouse gas emissions reductions) within Avista's transportation customer base. While program design is outside the scope of this assessment, AEG notes the following items for Avista as it determines the best way to achieve these savings:

- Many of the inputs into the analysis are averages across market segments based on the best available data sources and may not reflect the available potential at any individual site. **To address this, AEG recommends that Avista consider sponsoring audits of specific transportation customer sites to better understand current equipment and practices to refine estimates of available potential for these customers.**
- Because a small number of customers account for a large amount of transportation customer consumption, whether these customers choose to participate in future programs will significantly affect the amount of savings that Avista is able to achieve. This uncertainty could increase or decrease acquisition levels relative to the potential identified in this assessment. **As Avista considers new program designs for transportation customers, AEG recommends targeted outreach to the largest customers to understand their likelihood of participating in future programs, including to what extent and on what timeline.**

APPENDIX 3.2: ENVIRONMENTAL EXTERNALITIES OVERVIEW (OREGON JURISDICTION ONLY)

The methodology for determining avoided costs from reduced incremental natural gas usage considers commodity and variable transportation costs only. These avoided cost streams do not include environmental externality costs related to the gathering, transmission, distribution or end-use of natural gas.

Per traditional economic theory and industry practice, an environmental externality factor is typically added to the avoided cost when there is an opportunity to displace traditional supply-side resources with an alternative resource with no adverse environmental impact.

REGULATORY GUIDANCE

The Oregon Public Utility Commission (OPUC) issued Order 93-965 (UM-424) to address how utilities should consider the impact of environmental externalities in planning for future energy resources. The Order required analysis on the potential natural gas cost impacts from emitting carbon dioxide (CO_2) and nitric-oxide (NOx).

The OPUC's Order No. 07-002 in Docket UM 1056 (Investigation Into Integrated Resource Planning) established the following guideline for the treatment of environmental costs used by energy utilities that evaluate demand-side and supply-side energy choices:

> UM 1056, Guideline 8 - Environmental Costs
>
> *"Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur oxides (SO_2), and mercury (Hg) emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides (NOx), sulfur dioxide (SO2), and mercury (Hg), if applicable.*

In June 2008, the OPUC issued Order 08-338 (UM1302) which revised UM1056, Guideline 8. The revised guideline requires the utility should construct a base case portfolio to reflect what it considers to be the most likely regulatory compliance future for the various emissions. Additionally the guideline requires the utility to develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals and each scenario should include a time profile of CO2 costs. The utility is also required to include a "trigger point" analysis in which the utility must determine at what level of carbon costs its selection of portfolio resources would be significantly different.

ANALYSIS

Unlike electric utilities, environmental cost issues rarely impact a natural gas utility's supply-side resource options. This is because the only supply-side energy resource is natural gas. The utility cannot choose between say "dirty" coal-fired generation and "clean" wind energy sources. The supply-side implication of environmental externalities generally relates to combustion of fuel to move or compress natural gas. Avista's direct gas distribution system infrastructure relies solely on the upstream line pressure of the interstate pipeline transportation network to distribute natural gas to its customers and thus does not directly combust fuels that result in any CO_2, NOx, SO2, or Hg emissions.

Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems), however, do produce CO_2 emissions via compressors used to pressurize and move natural gas. Accessing CO_2 emissions data on these upstream activities to perform detailed meaningful analysis is challenging. In the 2009 Natural Gas IRP there was significant momentum regarding GHG legislation and the movement towards the creation of carbon cap and trade markets or tax structure. Additionally, the pricing level of the framework has been greatly reduced. Whichever structure ultimately gets implemented, Avista believes the cost pass through mechanisms for upstream gas system infrastructure will not make a difference in supply-side resource selection although the amount of cost pass through could differ widely.

Table 3.2.1 summarizes a range of environmental cost adders we believe capture several compliance futures including our expected scenario. The CO2 cost adders reflect outlooks we obtained from one of our consultants, and following discussion and feedback from the TAC, have been incorporated into our Expected Case, Average Case, Low Growth & High Prices, Electrification - Carbon Reduction, and High Growth & Low Prices portfolios.

The guidelines also call for a trigger point analysis that reflects a "turning point" at which an alternate resource portfolio would be selected at different carbon cost adders levels. Because natural gas is the only supply resource applicable to LDC's any alternate resource portfolio selection would be a result of delivery methods of natural gas to customers. Conceptually, there could be differing levels of cost adders applicable to pipeline transported supply versus in service territory LNG storage gas. From a practical standpoint however, the differences in these relative cost adders would be very minor and would not change supply-side resource selection regardless of various carbon cost adder levels. We do acknowledge there is influence to the avoided costs which would impact the cost effectiveness of demand-side measures in the DSM business planning process.

CONSERVATION COST ADVANTAGE

For this IRP, we also incorporated a 10 percent environmental externality factor into our assessment of the cost-effectiveness of existing demand-side management programs. Our assessment of prospective demand-side management opportunities is based on an avoided cost stream that includes this 10 percent factor.

Environmental externalities were evaluated in the IRP by adding the cost per therm equivalent of the externality cost values to supply-side resources as described in OPUC Order No. 93-965. Avista found that the environmental cost adders had no impact on the company's supply-side choices, although they did impact the level of demand-side measures that could be cost-effective to acquire.

REGULATORY FILING

Avista will file revised cost-effectiveness limits (CELs) based upon the updated avoided costs available from this IRP process within the prescribed regulatory timetable.

TABLE 3.2.1: ENVIRONMENTAL EXTERNALITIES COST ADDER ANALYSIS (2022$)

			2025	2030	2035	2040	2045
Social Cost of Carbon	NOx – Annual	$/short ton	$ 5.51	$ 5.51	$ 5.51	$ 5.51	$ 5.51
		$/lb	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003
		lbs/therm	0.066	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.145	$ 0.145	$ 0.145	$ 0.145	$ 0.145
		lbs/therm	0.066	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 100.68	$ 121.36	$ 143.95	$ 173.33	$ 203.99
		$/lb	$ 0.046	$ 0.055	$ 0.065	$ 0.079	$ 0.093
		lbs/therm	11.700	11.700	11.700	11.700	11.700
		CO2 Adder $/therm	$ 0.53	$ 0.64	$ 0.76	$ 0.92	$ 1.08

			2025	2030	2035	2040	2045
Community Climate Investments	NOx – Annual	$/short ton	$ 5.51	$ 5.51	$ 5.51	$ 5.51	$ 5.51
		$/lb	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003
		lbs/therm	0.066	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.145	$ 0.145	$ 0.145	$ 0.145	$ 0.145
		lbs/therm	0.066	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 120.15	$ 141.34	$ 164.98	$ 192.34	$ 224.09
		$/lb	$ 0.054	$ 0.064	$ 0.075	$ 0.087	$ 0.102
		lbs/therm	11.700	11.700	11.700	11.700	11.700
		CO2 Adder $/therm	$ 0.64	$ 0.75	$ 0.88	$ 1.02	$ 1.19

BLACK & VEATCH

Appendix 4.1: Black & Veatch Study

MEMORANDUM

Client: Avista Corporation	B&V Project 198930
Study: Hydrogen Study for Integrated Resource Planning (IRP)	B&V File 41.0000
Subject: Task 1 – Renewable Gas Technology Cost and Performance Data - Draft	May 18, 2018

To: Tom Pardee, James Gall Avista Corporation

From: Jonathan Cristiani, Frank Jakob, Elizabeth Waldren Black & Veatch

Introduction

Avista Corporation (Avista) is a major US energy company whose service territory includes customers in Washington, Idaho, and Oregon. As part of their commitment to their customers as well as requirements from each state's public utility commission (PUC), Avista periodically performs integrated resource planning (IRP) for their natural gas and electric power businesses. Avista is currently in the process of preparing their 2018 natural gas IRP documentation for PUCs in Washington, Idaho, and Oregon and will shortly begin preparing their 2019 electric power IRP documentation for PUCs in Washington and Idaho. Avista has engaged Black & Veatch to support the development of these IRP filing documents, specifically to assist with an increased understanding of the technical and economic forecasts for renewable gas production as well as the production of electricity from such renewable gaseous fuels.

As part of this memorandum, Black & Veatch has prepared a concise background for each of the renewable gas production investigated. Technical performance attributes reported comprise facility capacity, process efficiencies (i.e. units of output per units of input), feedstock and/or utility consumption, and expected lifetimes. Capital costs account for direct (e.g. equipment, piping, installation, etc.) and indirect (e.g. site preparation, engineering, permitting, contingency, etc.) costs and were developed on an engineering, procurement, and construction (EPC) basis exclusive of Owner's costs, escalation, financing, and interest. Fixed operations and maintenance (O&M) costs include labor, taxes, insurance, professional fees, etc. Variable O&M costs can consist of consumables, scheduled / unscheduled maintenance reserves, utilities, waste disposal fees, etc. All of these performance and cost characteristics are presented in a tabular format and projected every five years for the 2020 through 2040 timeframe. Costs that are presented in each table specify whether they are constant US dollars (USD) or nominal (current) USD.

A subsequent memorandum concerning electricity production from renewable gases will be issued in the near future and will be entitled "Task 2 – Electricity Production from Renewable Gas and Hydrogen."

Renewable Gas Production Technologies and Costs

The renewable gas technologies in which Avista has interest include hydrogen and renewable natural gas (RNG), the latter of which consists primarily of methane and meets applicable natural gas pipeline quality standards. Renewable gases can be produced via a number of different feedstocks and pathways, which complicates their synopsis for the purposes of an IRP report. To accommodate these factors, Black & Veatch recommended a number of the most promising feedstocks and pathways that show the greatest potential for commercialization and economically-viable operations from our perspective as an EPC company. Thus, low technology readiness pathways were not considered in this report. Accordingly, the following renewable gas production technologies were considered:

- Water electrolysis to hydrogen
- Landfill gas to RNG
- Dairy manure to RNG
- Wastewater sludge to RNG
- Food waste to RNG

Renewable Hydrogen

Electrolysis is the electrochemical decomposition of water into hydrogen and oxygen using electricity to drive the reaction. The two predominant types of electrolyzer technologies are polymer electrolyte membrane (PEM) and alkaline. In a PEM electrolyzer, water is oxidized at the anode into oxygen gas and hydrogen ions, which are transported across a solid polymer membrane (electrolyte) to the cathode where they combine with one another to form hydrogen gas. Conversely in an alkaline electrolyzer, water is reduced at the cathode into hydrogen gas and hydroxide ions, which are transported through a liquid electrolyte solution (typically potassium hydroxide) to the anode, where they combine to form oxygen gas and water. In both cases, the overall chemical reaction is as follows:

$$2H_2O(l) \xrightarrow{Electricity} 2H_2(g) + O_2(g)$$ [1]

When paired with renewable electricity resources, such as solar photovoltaic or wind power generation, water electrolysis is considered a renewable, carbon-free hydrogen production technology. The US Department of Energy (DoE) has created a number of targets and managed a host of research and development (R&D) programs for the production of renewable hydrogen. Much of that research has focused on renewable hydrogen as vehicle fuel; however, many of the technical objectives established under those programs can be extended to fuel cell power generation applications as well. As part of the DoE program, performance and cost goals were developed for two production scales: distributed and centralized. Distributed production corresponds with lower capacities where hydrogen is generated at or near the point of use (e.g. at a refueling station). Centralized facilities have larger capacities that take advantage of economies of scale but also require greater transportation and delivery costs.

Black & Veatch investigated performance and cost metrics for water electrolysis to renewable hydrogen at both distributed and centralized scales, which are displayed in Table 1 and Table 2, respectively.

---

[1] Hydrogen Production: Electrolysis. (2015, March). US Department of Energy. Retrieved May, 2018, from https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

Table 1 Performance and Cost Table for Distributed Renewable Hydrogen Production

PARAMETER	2020	2025	2030	2035	2040
Capacity	1,500 kg/day				
Capital Cost (2017 USD)	$1.94M	$1.79M	$1.64M	$1.59M	$1.54M
Fixed O&M Costs (Nominal USD/year)	$133K	$154K	$179K	$209K	$243K
Variable O&M Costs (Nominal USD/year)	$33K	$38K	$43K	$48K	$53K
Electricity Costs (2017 USD/kWh)	$0.047	$0.047	$0.047	$0.048	$0.047
Energy Use (kWh electricity / kg hydrogen)	50	49	48	47	45
Annual Availability Factor	97%				
Expected Life	20 years				
Water Usage	4.4 gallons/year				

Table 2 Performance and Cost Table for Centralized Renewable Hydrogen Production

PARAMETER	2020	2025	2030	2035	2040
Capacity	52,300 kg/day				
Capital Cost (2017 USD)	$83.6M	$77.5M	$71.9M	$70.1M	$68.4M
Fixed O&M Costs (Nominal USD/year)	$3.7M	$4.3M	$5.0M	$5.9M	$6.8M
Variable O&M Costs (Nominal USD/year)	$600K	$662K	$731K	$808K	$891K
Electricity Costs (2017 USD/kWh)	$0.047	$0.047	$0.047	$0.048	$0.047
Energy Use (kWh electricity / kg hydrogen)	50	49	48	47	45
Annual Availability Factor	97%				
Expected Life	40 years				
Water Usage	4.4 gallons/year				

Electrolysis plant capacities, annual availabilities, and expected lifetimes were selected based on published US DoE Fuel Cell Technologies Office (FCTO) plans and reports. [2] Capital and O&M costs, as well as process efficiency and water usage, were estimated using US DoE independent review reports and financial modeling by numerous US government agencies. [3,4] Electricity costs were estimated from

[2] Fuel Cell Technologies Office - Multi-Year Research Development and Demonstration Plan. (2015). US Department of Energy.
[3] Independent Review: Current State-of-the-Art Hydrogen Production Cost Estimate Using Water Electrolysis. (2009, September). US Department of Energy / National Renewable Laboratory.
[4] Techno-Economic Analysis of PEM Electrolysis for Hydrogen Production. (2014, February). Electrolytic Hydrogen Production Workshop, Strategic Analysis Inc. / National Renewable Energy Laboratory.

the latest US Energy Information Administration (EIA) Annual Energy Outlook (AEO) report [5] for the Pacific Northwest region as a proxy for future renewable electricity generation. Cost projections developed by Black & Veatch were made using the following assumptions:

- Capital cost compound annual reduction of 1.5 percent for 2020-2030 and 0.5 percent for 2031-2040. Reductions indicate the learning curve associated with the increased deployment of electrolysis systems. [6]
- Fixed O&M cost compound annual growth of 3.1 percent based on Oil & Gas Journal's Nelson-Farrar cost index for "Refinery Operations" as a proxy for RNG, a similar technology.
- Variable O&M cost compound annual growth of 2.0 percent based on consumer price index from the US Bureau of Labor Statistics.

Renewable Natural Gas

As mentioned, RNG is derived from an assortment of different feedstocks and pathways. Chiefly, it is produced through the anaerobic digestion (AD) of organic wastes sourced from agricultural (e.g. manure, energy crops) and municipal/industrial (e.g. wastewater sludge, food waste) resources. AD involves the microbiological degradation of organic matter in the absence of oxygen, which results in the production of biogas (e.g. a saturated, gaseous mixture of methane, carbon dioxide, and other contaminants). AD can occur in a digester or in a landfill, the latter of which creates a biogas that is often referred to as landfill gas (LFG). Solid and liquid residues that remain after AD has completed are referred to as digestate and can be used as a soil conditioner or filler material in certain applications, depending on quality. The principal types of AD digester types are plug-flow, complete-mix, and covered-lagoon. [7]

Once biogas is generated, it must be conditioned and purified of contaminants before it can be utilized. In many applications, such as power generation via a reciprocating engine, minimal biogas cleaning and upgrading is required. However, if the desire is for pipeline-quality RNG to be made, then more significant processing is needed. For example, contaminants such as particulates, hydrogen sulfide, ammonia, and siloxanes require removal to meet equipment protection and air emissions mandates. For RNG specifically, the removal of more benign diluents such as nitrogen, oxygen, and carbon dioxide is necessary so that stringent volumetric energy content and other quality requirements can be met. Furthermore, in some localities pipeline quality requirements cannot be met with purified methane alone, in which cases the cleaned and conditioned biogas must be blended with propane. The major biogas cleaning and conditioning techniques include membrane separation, water / solvent scrubbing, solid sorbents, and pressure swing adsorption, among others. To achieve RNG purity with mixtures of all of the aforementioned contaminants and diluents, biogas cleaning systems will frequently be designed with combinations of some or all of the processing technologies highlighted resulting in higher capital and operating costs.

---

[5] Annual Energy Outlook 2018, Table: Electric Power Projections by Electricity Market Module Region, Case: Reference Case, Region: Western Electricity Coordinating Council / Northwest Power Pool Area. (2018). US Energy Information Administration.
[6] E4tech. Study on Development of Water Electrolysis in the EU. (2014, April). Fuel Cells and Hydrogen Joint Undertaking.
[7] Livestock Anaerobic Digester Database. (2018). US Environmental Protection Agency. Retrieved May, 2018, from https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

Landfill Gas
LFG is one of the simplest feedstocks for the production of RNG since the biogas is made in a landfill. However, given the multitude of contaminants present due to the heterogeneity of the municipal solid waste (MSW) from which it formed, LFG also requires one of the most complex cleaning processes. As is the case with renewable hydrogen, LFG to RNG can be appropriate for large and small applications, corresponding to different sized landfills and loosely defined here as distributed and centralized. Performance and cost metrics for distributed and centralized LFG to RNG operations are shown in Table 3 and Table 4, respectively.

Table 3 Performance and Cost Table for Distributed LFG to RNG Production

PARAMETER	2020	2025	2030	2035	2040
Capacity (LFG Flowrate)			1,000 scfm		
Capacity (RNG Flowrate)			490 scfm		
Capital Cost (2017 USD)	$7.42M	$7.22M	$7.02M	$6.86M	$6.71M
Fixed O&M Costs (Nominal USD/year)	$71K	$81K	$96K	$111K	$130K
Variable O&M Costs (Nominal USD/year)	$609K	$672K	$742K	$819K	$904K
LFG Payments (2017 USD/mcf)	$0.34 - $4.66	$0.37 - $5.02	$0.38 - $5.17	$0.38 - $5.22	$0.40 - $5.46
Annual Availability Factor			90%		
Expected Life			20 years		

Table 4 Performance and Cost Table for Centralized LFG to RNG Production

PARAMETER	2020	2025	2030	2035	2040
Capacity (LFG Flowrate)			3,000 scfm		
Capacity (RNG Flowrate)			1,400 scfm		
Capital Cost (USD)	$15.1M	$14.7M	$14.4M	$14.0M	$13.7M
Fixed O&M Costs (USD/year)	$188K	$219K	$255K	$297K	$345K
Variable O&M Costs (USD/year)	$1.62M	$1.79M	$1.98M	$2.18M	$2.41M
LFG Payments (USD/scf)	$0.34 - $4.66	$0.37 - $5.02	$0.38 - $5.17	$0.38 - $5.22	$0.40 - $5.46
Annual Availability Factor			90%		
Expected Life			20 years		

Capacities (for LFG and RNG), availability factors, and expected project lifetimes are based on Black & Veatch experience and prior project work. LFG payments (from project developer to the landfill operator) can vary substantially depending on the type of project (i.e. power, combined heat and power, RNG, etc.), the public/private nature of the landfill owner/operator, and the terms and conditions of the specific supply agreement. Black & Veatch estimates that LFG payments could be as low as $0.30 per thousand cubic feet (/mcf) and as high as 85 percent of industrial delivered natural gas pricing, [8] which are estimated based on EIA AEO figures. [9] Capital, fixed O&M, and variable O&M costs are also based on prior project work and vendor quotes using the following:

- Capital cost compound annual reduction of 0.5 percent for 2020-2040 to indicate a modest learning curve associated with LFG project deployments.
- Fixed O&M cost compound annual growth of 3.1 percent based on Oil & Gas Journal's Nelson-Farrar cost index for "Refinery Operations."
- Variable O&M cost compound annual growth of 2.0 percent based on consumer price index from the US Bureau of Labor Statistics.

Dairy Manure to RNG

Organic agricultural waste (manure) from dairy cows kept in large feeding lots and confined animal feeding operations can be substantial in quantity and a challenging waste product to manage. Depending on the required capacity, geographical region, and local climate, there are benefits and disadvantages in selection of specific digester types. However, a discussion of this nature is beyond the scope of this report. For applications in the northwestern US, Black & Veatch has assumed that plug-flow type digester is used, given its prevalence in the marketplace and suitability in a variety of climates. Although the concentration of dairy farms in the Avista service territory is potentially not as significant as in states such as California, it is expected that the presence of the dairy industry in places like southwest Washington could offer opportunities for dairy manure to RNG projects.

An emerging concept in dairy manure AD for energy recovery applications is referred to as "clustering," whereby several farms in close proximity convey biogas to a central location, after which the biogas is upgraded to RNG and injected into a pipeline. [10] The purpose of a cluster configuration is to achieve improved project economics and meet other project requirements such as overcoming permitting challenges and achieving environmental compliance. Black & Veatch has assumed that a dairy manure cluster to RNG project is feasible in the Avista service territory and that five dairies are able to be connected in a cluster. Performance and cost figures are displayed for such a scenario in Table 5.

Table 5 Performance and Cost Table for Dairy Manure to RNG Production

PARAMETER	2020	2025	2030	2035	2040
Capacity (Dairy Size)	4,000 cows per dairy (20,000 total)				

[8] Landfill Methane Outreach Program: LFGcost-Web Economic Model, Version 3.2. (2017, May). US Environmental Protection Agency.

[9] Annual Energy Outlook 2018, Table: Natural Gas Delivered Prices by End-Use Sector and Census Division, Case: Reference Case, Region: Pacific. (2018). US Energy Information Administration.

[10] Economic Feasibility of Dairy Digester Clusters in California: A Case Study. (2013, June). United States Department of Agriculture, Rural Development Agency and California Dairy Campaign.

PARAMETER	2020	2025	2030	2035	2040
Capacity (Manure)	180,000 tons/year per dairy (900,000 tons/year total)				
Capacity (Biogas Flowrate)	200 scfm per dairy (1,000 scfm total)				
Capacity (RNG Flowrate)	98 scfm per dairy (490 scfm total)				
Capital Cost (2017 USD)	$40.6M	$39.6M	$38.6M	$37.7M	36.7M
Fixed O&M Costs (Nominal USD/year)	$238K	$277K	$323K	$376K	$438K
Variable O&M Costs (Nominal USD/year)	$2.05M	$2.26M	$2.50M	$2.76M	$3.05M
Annual Availability Factor	90%				
Expected Life	20 years				

Capacities listed include the dairy size (i.e. number of cows), the annual amount of manure digested, the expected biogas flowrate, and the resultant RNG flowrate. These capacities, availability factors, and expected project lifetimes are based on Black & Veatch experience and prior project work. It was assumed that no payments are made to farm operators by the project developer; however, in some circumstances Manure to RNG projects will include such payments. Capital, fixed O&M, and variable O&M costs are also based on prior project work and vendor quotes using the following:

- Capital cost compound annual reduction of 0.5 percent for 2020-2040 to indicate a modest learning curve associated with Manure to RNG project deployments.
- Fixed O&M cost compound annual growth of 3.1 percent based on Oil & Gas Journal's Nelson-Farrar cost index for "Refinery Operations."
- Variable O&M cost compound annual growth of 2.0 percent based on consumer price index from the US Bureau of Labor Statistics.

Wastewater Sludge to RNG

Wastewater treatment is a diverse field in which a variety of physical, chemical, and biological processes are used to remove contaminants from household sewage, resulting in treated effluent and sludge products. Wastewater sludge will then undergo further treatments, which often involve stabilization through digestion. In instances where AD is used, the resultant biogas can be recovered and upgraded to RNG, similar to the aforementioned manure AD scenario. Municipal wastewater treatment plants are ubiquitous across the US, thus Wastewater Sludge to RNG projects offer significant promise for widespread adoption.

Black & Veatch has significant experience with wastewater treatment, including the AD of wastewater sludge. In many cases for these projects, it is desirable to enhance biogas production by co-digesting municipal fats, oils, and greases (FOG) along with the sludge. Therefore, the performance and costs depicted herein are reported with respect to a typical municipal wastewater treatment plant upgrade to accommodate the co-digestion of FOG and the cleaning/upgrading of biogas to RNG. These parameters are shown in Table 6.

Table 6 **Performance and Cost Table for Wastewater Sludge to RNG Production**

PARAMETER	2020	2025	2030	2035	2040
Capacity (Sludge)	21,000 tons/year				
Capacity (FOG)	14M gal/year				
Capacity (Biogas Flowrate)	650 scfm				
Capacity (RNG Flowrate)	375 scfm				
Capital Cost (2017 USD)	$10.7M	$10.4M	$10.2M	$9.9M	$9.7M
Fixed O&M Costs (Nominal USD/year)	$175K	$204K	$238K	$277K	$323K
Variable O&M Costs (Nominal USD/year)	$1.10M	$1.22M	$1.35M	$1.49M	$1.64M
Annual Availability Factor	95%				
Expected Life	30 years				

Capacities listed include the annual amount of sludge digested, the expected biogas flowrate, and the resultant RNG flowrate. These capacities, availability factors, and expected project lifetimes are based on Black & Veatch experience and prior project work. O&M costs are exclusive of full operating staff for the overall wastewater treatment operation and only reflect the staff needed to accommodate the biogas production and upgrading to RNG portion. Capital, fixed O&M, and variable O&M costs are also based on prior project work and vendor quotes using the following:

- Capital cost compound annual reduction of 0.5 percent for 2020-2040 to indicate a modest learning curve associated with Wastewater Sludge to RNG project deployments.
- Fixed O&M cost compound annual growth of 3.1 percent based on Oil & Gas Journal's Nelson-Farrar cost index for "Refinery Operations."
- Variable O&M cost compound annual growth of 2.0 percent based on consumer price index from the US Bureau of Labor Statistics.

Food Waste to RNG

The digestion of organic waste such as food is relatively early in its deployment compared with other substrates discussed in this memorandum. Given the potential for contaminants if food waste is separated from a broader stream of MSW and high solids nature of food waste compared with manure/sludge, AD system designs can be more complex and expensive. Based on prior Black & Veatch experience, high-solids discontinuous (i.e. batch) digester designs tend to offer the proper level of robustness while balancing those attributes with lower capital and operating costs.

For the purposes of the current study, Black & Veatch has assumed that a batch digester is used in conjunction with a mixture of source-separated organic food waste (i.e. grocery store or restaurant discards) and yard waste. The biogas produced is then cleaned and upgraded in a similar manner as the other RNG technologies described herein. Depending on the prevalence of food waste separation / landfill diversion programs in the Avista service territory; such a project may be achievable. Most importantly with respect to a project of this nature, tipping fees are often charged by waste handlers for the acquisition of food waste, thereby representing an additional revenue stream to project developer. Performance and cost information for a representative Food Waste to RNG project is outlined in Table 7.

Table 7 Performance and Cost Table for Food Waste to RNG Production

PARAMETER	2020	2025	2030	2035	2040
Capacity (Food / Yard Waste)	55,000 tons/year				
Capacity (Biogas Flowrate)	400 scfm				
Capacity (RNG Flowrate)	230 scfm				
Capital Cost (2017 USD)	$23.0M	$22.5M	$21.9M	$21.4M	$20.8M
Fixed O&M Costs (Nominal USD/year)	$188K	$219K	$255K	$297K	$345K
Variable O&M Costs (Nominal USD/year)	$1.62M	$1.79M	$1.97M	$2.18M	$2.41M
Tipping Fee (2017 USD/ton)	$20				
Annual Availability Factor	90%				
Expected Life	20 years				

Capacities listed include the amount of annual food/yard waste processed, the expected biogas flowrate, and the resultant RNG flowrate. These capacities, availability factors, and expected project lifetimes are based on Black & Veatch experience and prior project work. Capital, fixed O&M, and variable O&M costs are also based on prior project work and vendor quotes using the following:

- Capital cost compound annual decay of 0.5 percent for 2020-2040 to indicate a modest learning curve associated with Food Waste to RNG project deployments.
- Fixed O&M cost compound annual growth of 3.1 percent based on Oil & Gas Journal's Nelson-Farrar cost index for "Refinery Operations."
- Variable O&M cost compound annual growth of 2.0 percent based on consumer price index from the US Bureau of Labor Statistics.

APPENDIX 4.2: AVISTA RENEWABLE RESOURCE DEVELOPMENT AND PROCUREMENT DECISION TREE

APPENDIX 5.1: AVISTA RENEWABLE RESOURCE LEAST COST/LEAST RISK EVALUATION CRITERIA AND CALCULATIONS

Annual all-in cost of RNG (R) =
Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

Or: $R_T = M_T + E_T - I_T$

Where:

$$M_T = X_T + \sum_{t=1}^{365}[P_{T,t} + Y_{T,t}^{RNG}]Q_{T,t}$$

$$E_T = \sum_{t=1}^{365} N^{RNG} G_T Q_{T,t}$$

$$I_T = S_T A_T + DH_T$$

Substituting leaves the annual all-in cost of RNG as:

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

Where the annual all-in cost of the conventional natural gas alternative (C) is:

$$C_T = \sum_{t=1}^{365}\left[V_{T,t} + Y_{T,t}^{CONV} + N^{CONV} G_T\right]Q_{T,t}$$

The present value of revenue requirement of all relevant years is used for evaluation where:

$$PVRR(R) = \sum_{T=k}^{T=k+z} \frac{R_T}{[1+d]^T}$$

$$PVRR(C) = \sum_{T=k}^{T=k+z} \frac{C_T}{[1+d]^T}$$

This is risk-adjusted to account for uncertainty in long-term forecasting where:

$$rPVRR(R) = 0.75 * \text{deterministic } PVRR(R) + 0.25 * \text{95th Percentile Stochastic } PVRR(R)$$

$$rPVRR(C) = 0.75 * \text{deterministic } PVRR(C) + 0.25 * \text{95th Percential Stochastic } PVRR(C)$$

The RNG project is a least cost/least risk resource to acquire if:

$$rPVRR(R) \leq rPVRR(C)$$

Term	Units	Description	Source	Project Specific?	Input or Output of Optimization?	Treated as Uncertain?
R	$/Year	Annual all-in cost of prospective renewable resource project	Output of renewable resource evaluation process	Yes	Output	Yes
C	$/Year	Annual all-in cost of conventional natural gas alternative	Output of renewable resource evaluation process	Yes	Output	Yes
M	$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of renewable resource evaluation process	Yes	Output	Yes
E	$/Year	Annual greenhouse gas emissions compliance costs	Output of renewable resource evaluation process	Yes	Output	Yes
I	$/Year	Annual infrastructure costs avoided with on-system supply	Output of renewable resource evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted dailyquantity of renewable resource supplied by project	Project evaluation or renewable resource supplier counterparty	Yes	Input	If no contractual obligation
P	$/Dth	Contracted or expected volumetric price of renewable resource	Project evaluation or renewable resource counterparty; Max xost-effective price determined by methodology if Avista initiating negotiations	Yes	Input if responding to offer; Output if Avista making offer	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or renewable resource supplier counterparty	Yes	Input if responding to offer; Output if Avista making offer	If no contractual obligation
k	Year	When the RNG purchase starts in # of years in the future; k = renewable resource start year - current year	Project evaluation or renewable resource supplier counterparty	Yes	Input if responding to offer; Output if Avista making offer	If no contractual obligation
z	Years	Duration of renewable resource purchase or development in years	Project evaluation or renewable resource supplier counterparty	Yes	Input if responding to offer; Output if Avista making offer	If no contractual obligation
t	Days	Day number in year **T** from 1 to 365	N/A	No	Input	No
V	$/Dth	Price of conventional gas that would be displaced by renewable resource project	Average price of last **Q** quantity of conventional gas dispatched without renewable resource project	Yes	Output	Yes
Y	$/Dth	Variable transport costs to deliver gas to Avista's system	*For off-system renewable resource* - based upon geographic location of project; *For conventional gas* - determined from the marginal unit of gas dispatched to meet demand	Yes	Output	No
X	$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or renewable resource supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e/Dth	Greenhouse gas intensity of natural gas being considered	Based on expected policy treatment of carbon intensity for reported emissions from renewable resource	Yes	Input	No
G	$/Ton$CO_2$e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recent update	No	Input	Yes
S	$/Dth	System gas supply capcaity cost to serve one dekatherm of peak day load	Based upon marginal supply capacity resource that is being deferred using Base Case resource availability from the most recent update	No	Output	Yes
A	Dth	Minimum natural gas injected on to Avista's system during a peak day by project	Project evaluation or contractual obligation from renewable resource supplier counterparty	Yes	Input	If no contractual obligation
D	$/Dth	Distribution system capacity cost to serve one dekatherm of peak hour load	Distribution system cost to serve peak hour load from avoided costs in most recent update	No	Input	No
H	Dth	Minimum natural gas injected on to Avista's system during a peak hour by project	Project evaluation or contractual obligation from renewable resource supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount rate	Discount rate from most recent update	No	Input	No

APPENDIX 4.3: AVISTA RENEWABLE RESOURCE PROJECT REVENUE REQUIREMENT MODEL

Term	Line Item	Calculation					
T	Project Year	1	2	3	4	5	...
A	Tax Basis of Project Investment	$TCapEx_T$					
B	Book Basis of Project Investment	$BCapEx_T$					
C	Book Depreciation on Tax Basis	$TDr_T * \sum B_{T=1 \text{ to current } T}$					
D	Book Depreciation on Book Basis	$BDr_T * \sum B_{T=1 \text{ to current } T}$					
E	Accumulated Book Depreciation	$\sum D_{T=1 \text{ to current } T}$					
F	Beginning Net Book Value	$F_{T-1} + B_T - D_{T-1}$					
G	Property Tax Expense	$F_T * PTr$					
H	Tax Depreciation	$TDr_T * \sum A_{T=1 \text{ to current } T}$					
I	Deferred Taxes	$(H_T - C_T) * FITr$					
J	Beginning Rate Base	$B_T + K_{T-1}$					
K	Ending Rate Base	$J_T - I_T - D_T$					
L	Average Rate Base	$(J_T + K_T)/2$					
M	Interest Expense	$DF * DFr * L_T$					
N	Shareholders' Equity Return	$EF * EFr * L_T$					
O	Feedstock, O&M, and A&G Expense	$RRF_T + O\&M_T + A\&G_T$					
R	Duplicate Revenue Requirement	$[D_T + M_T + N_T + O_T + G_T - (SITr + (1 - SITr) * FITr) * (C_T + M_T + O_T + G_T)] / CF$					
S	Miscellaneous Revenue Items	$R_T * MR$					
U	State Income Tax Expense	$(R_T - C_T - M_T - O_T - G_T - S_T) * SITr$					
V	Federal Income Tax Expense	$(R_T - C_T - M_T - O_T - G_T - S_T - U_T) * FITr$					
W	Revenue Requirement	$D_T + M_T + N_T + O_T + G_T + S_T + U_T + V_T$					
Q	Renewable Resource Quantity	Q_T					
P	Price of Renewable Resource	W_T / Q_T					

Term	Units	Description	Project Specific?	Input or Output	Treated as Uncertain?
A	$	Taxable basis of capital investment(s) in project asset(s) up to and including current project year	Yes	Input	Yes
B	$	Book basis of capital investment(s) in project asset(s) up to and including current project year	Yes	Input	Yes
C	$	Book depreciation of project assets on tax basis in project year	Yes	Output	Yes
D	$	Book depreciation of project assets on book basis in project year	Yes	Output	Yes
E	$	Accumulated book depreciation of project assets up to and including current project year	Yes	Output	Yes
F	$	Net book value of project assets at beginning of project year	Yes	Output	Yes
G	$	Property taxes paid in year of project	Yes	Output	Yes
H	$	Tax depreciation in year of project	Yes	Output	Yes
I	$	Deferred taxes in year of project	Yes	Output	Yes
J	$	Rate base at beginning of project year	Yes	Output	Yes
K	$	Rate base at end of project year	Yes	Output	Yes
L	$	Average rate base in year of project	Yes	Output	Yes
M	$	Interest paid in project year on project investment(s) financed with debt	Yes	Output	Yes
N	$	Shareholder return on equity in year of project	Yes	Output	Yes
O	$	Renewable resource feedstock, operating & maintenance, and administrative & general expenses in year of project	Yes	Output	Yes
P	$	Average revenue requirement per unit of renewable resource developed in year of project	Yes	Output	Yes
Q	$	Units of renewable resource created in year of project	Yes	Input	If no contractual obligation
R	$	Revenue Requirement in year of project; duplicated for purpose of calculating miscellaneous revenues and state and federal income tax expenses	Yes	Output	Yes
S	$	Miscellaneous revenues for items such as uncollectables, commission fees, excise taxes, and franchise fees	Yes	Output	Yes
T	$	Year of project, where first year T = 1, next year T = 2, etc.	Yes	Input	If no contractual obligation
U	$	State income taxes paid in year of project	Yes	Output	Yes
V	$	Federal income taxes paid in year of project	Yes	Output	Yes
W	$	Revenue requirement in year of project	Yes	Output	Yes
A&G	$	Administrative and general expense in year of project	Yes	Input	Yes
BCapEx	$	Book basis of project asset(s) in year of investment	Yes	Input	Yes
BDr	%	Project asset book depreciation rate in year relative to capital investment	No	Input	No
CF	%	Revenue conversion factor after accounting for miscellaneous revenue items and state and federal income taxes	No	Input	No
DF	%	Percentage of capital investment(s) in project asset(s) financed with debt	Yes	Input	No
DFr	%	Rate of return on debt financing	No	Input	No
EF	%	Percentage of capital investment(s) in project asset(s) financed with equity	Yes	Input	No
EFr	%	Shareholder rate of return on equity	No	Input	No
FITr	%	Federal income tax rate	No	Input	No
MR	%	Percentage of revenues allocated to items such as uncollectables, commission fees, excise taxes, and franchise fees.	No	Input	No
O&M	$	Operating and maintenance expense in year of project	Yes	Input	Yes
PTr	%	Property tax rate	Yes	Input	No
RRF	$	Feedstock expense of renewable resource in year of project	Yes	Input	If no contractual obligation
SITr	%	State income tax rate	No	Input	No
TCapEx	$	Tax basis of project asset(s) in year of investment	Yes	Input	Yes
TDr	%	Project asset tax depreciation rate in year relative to year of capital investment	No	Input	No

APPENDIX 4.4: AVISTA RENEWABLE RESOURCE PROJECT RATE IMPACT ANALYSIS

Avista will analyze all RNG-related investment costs and determine the appropriate rate recovery mechanism, which may include an impact on base rates, purchase gas adjustments or other cost recovery tariffs. This analysis considers, but is not limited to, factors such as the jurisdictions involved, expenditure types, cost recovery mechanisms, the spread of the investment to Avista's customer base and other potential impacts to ensure the appropriate treatment of the investment.

APPENDIX 5.4: AVISTA RENEWABLE RESOURCE PROJECT CARBON REDUCTION CALCULATION

$$G_T^{CONV} = Q_T * N^{CONV}$$

$$G_T^{RNG} = Q_T * N^{RNG}$$

Total annual greenhouse gas emissions without renewable resource:

$$E_T^{CONV} = A_T * N^{CONV}$$

Total annual greenhouse gas emissions with renewable resource:

$$E_T^{CONV, RNG} = E_T^{CONV} - (G_T^{CONV} - G_T^{RNG})$$

Term	Units	Description	Project Specific?	Input or Output	Treated as Uncertain?
N	TonsCO$_2$e/Dth	Greenhouse gas intensity of resource being considered	Yes	Input	No
G	TonsCo$_2$e	Greenhouse gas emissions of resource being considered	Yes	Output	Yes
Q	Dth	Expected or contracted quantity of renewable resource	Yes	Input	If no contractual obligation
E	TonsCo$_2$e	Avista greenhouse gas emissions	No	Output	No
A	Dth	Dekatherms delivered to Avista customers	No	Input	No
T	Year	Year relative to current year, where the current year T = 1, next year T =2, etc.	Yes	Input if responding to offer, Output if Avista making offer	If no contractual obligation

APPENDIX 5.1: WA GRC REQUIREMENTS

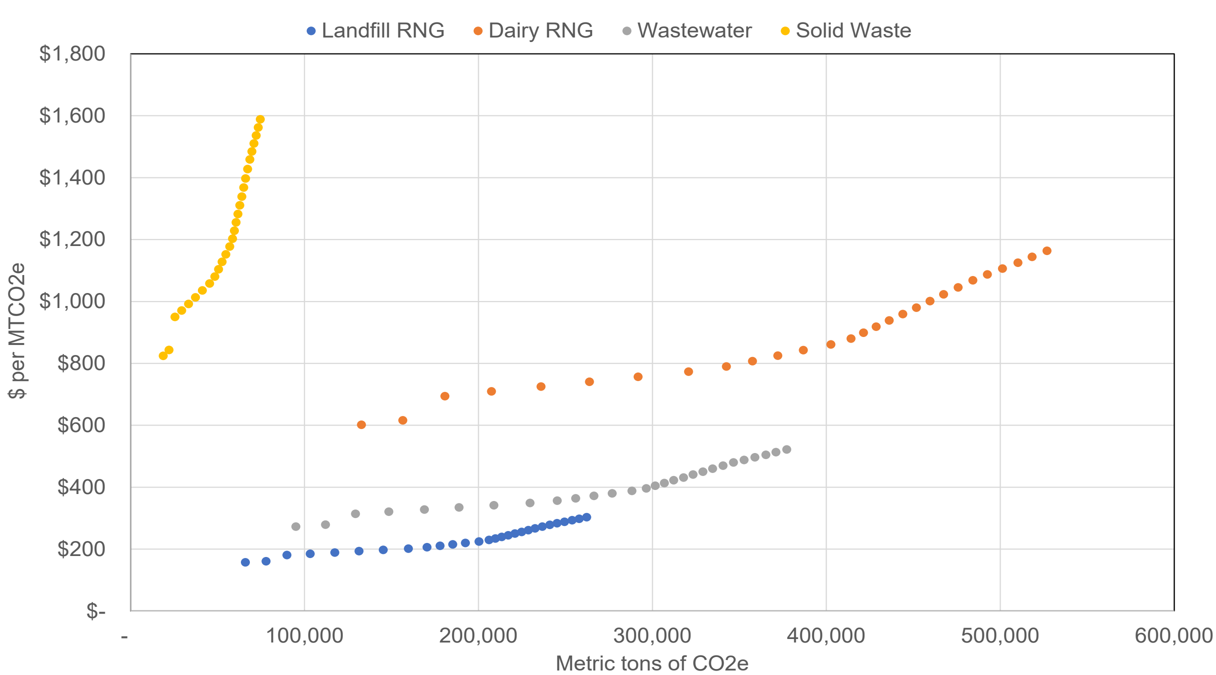
For its Washington service territory, Avista agreed to include in its 2023 Natural Gas IRP, a natural gas system decarbonization plan for complying with the Climate Commitment Act (CCA) with the following elements.

i. The Natural Gas IRP's decarbonization plan shall include a supply curve of decarbonization resources by price and availability, e.g. energy efficiency bundle 1 costs X$/ton of carbon dioxide equivalent (CO2e) reduction and can reduce Y tons of CO2e, dairy RNG costs A$/ton and can reduce B tons of CO2e.

The Avista 2023 Natural Gas IRP has included a variety of supplies to decarbonize its energy delivered to the end user. The resources in Figures 1 to Figure 5 below show those supply side or demand side options (energy efficiency) available to the model to meet climate goals as laid out in the CCA. Each figure represents the cost per metric ton of carbon dioxide equivalent combined with the estimated potential of the resource over time.

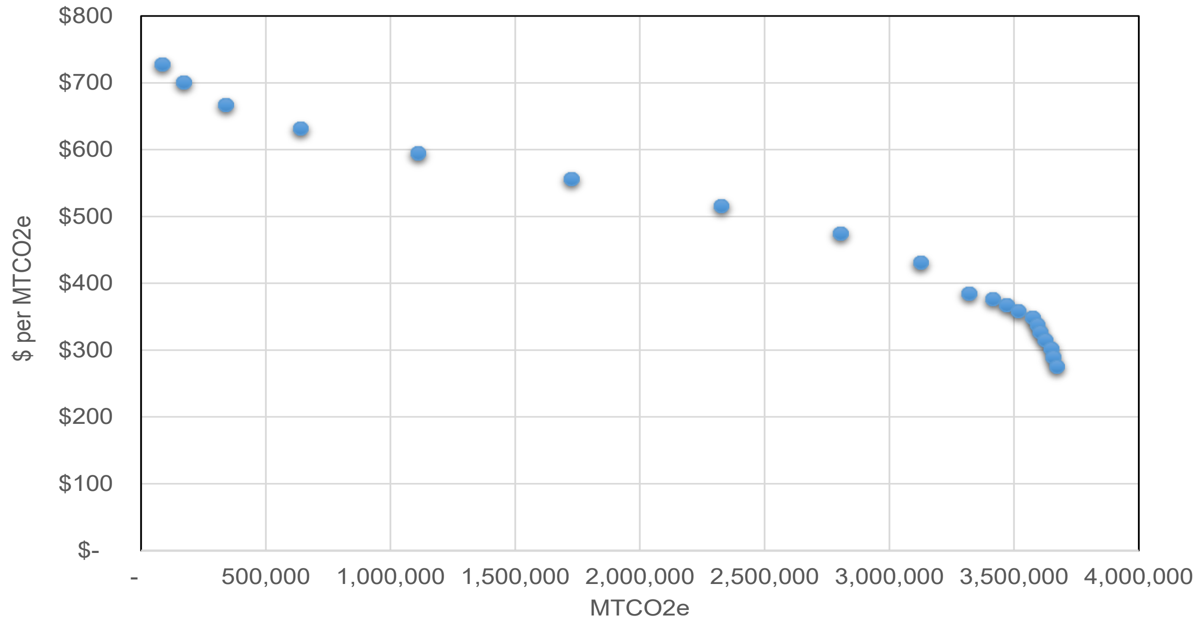
Renewable Natural Gas (RNG) was estimated based on a Black and Veatch study with the initial year estimated through a revenue model and decreased following expectations in 2050 based on estimates and papers as discussed in Chapter 4. These values are population weighted with a potential volume as developed by a consultant contracted by Avista.

Figure 1: Renewable Natural Gas by Type - Costs per Metric Ton of Carbon Dioxide and Estimated Volume of Availability



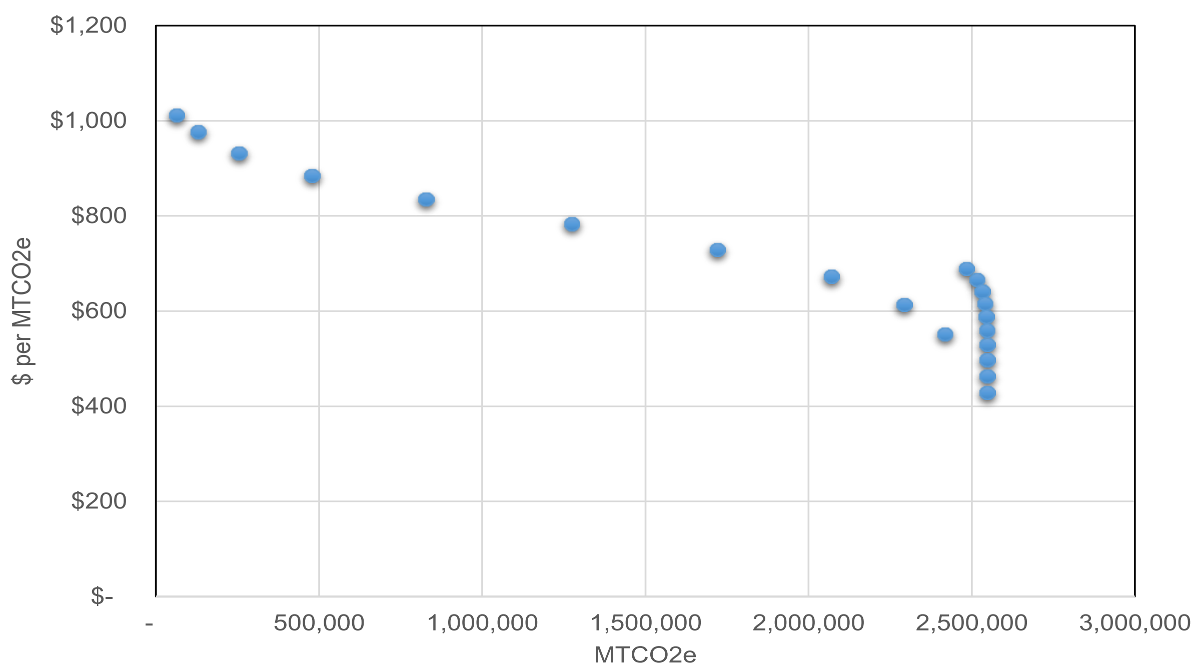
The potential for hydrogen and synthetic methane was developed using the Fischer-Pry Technology Substitution Model[1] with an estimated saturation curve of 20 years. This 20-year timeframe was chosen based on External Factor of Government Regulation as being a driving force of this conversion. The spike at 2.5 million MTCO2e is related to the expected end date of the Inflation Reduction Act as discussed in Chapters 3 and 5.

Figure 2: Green Hydrogen - Costs per Metric Ton of Carbon Dioxide and Estimated Volume of Availability



[1] https://www.sciencedirect.com/science/article/abs/pii/004016259500004T

Figure 3: Synthetic Methane - Costs per Metric Ton of Carbon Dioxide and Estimated Volume of Availability



Energy Efficiency is based on the 2023 year of the study provided by AEG as discussed in Chapter 3 and found in Appendix 3.

Figure 4: Energy Efficiency (Non-Space Heating) - Costs per Metric Ton of Carbon Dioxide and Estimated Volume of Availability

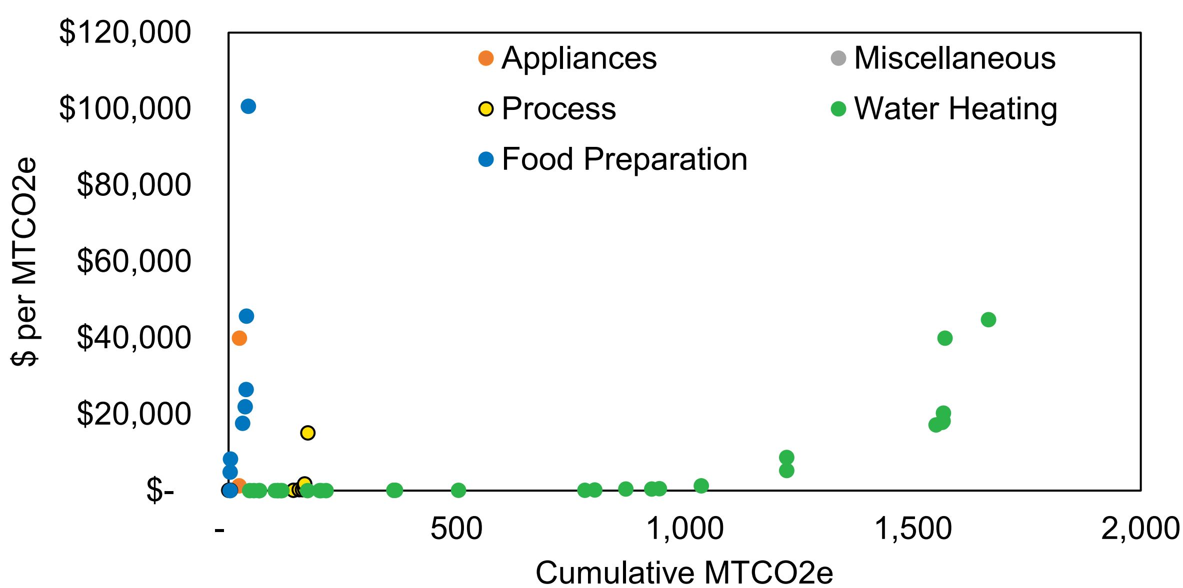
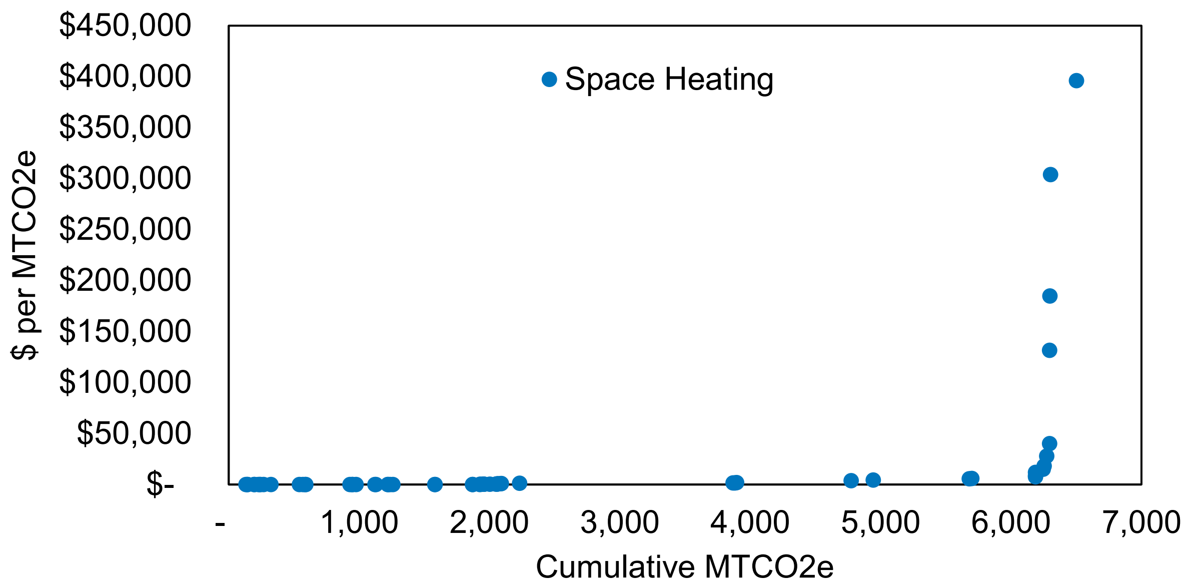


Figure 5: Energy Efficiency (Space Heating) - Costs per Metric Ton of Carbon Dioxide and Estimated Volume of Availability



ii. The decarbonization plan shall consider a comprehensive set of strategies, programs, incentives and other measures to encourage new and existing customers to adopt fully energy efficient appliances and equipment or other decarbonization measures, which could include electrification.

Chapter 3 includes a summary of the demand side resources considered in the 2023 IRP, including electrification. Chapter 6 discusses the Preferred Resource Strategy selected in the IRP to meet the CCA requirements, and ultimately the Company's decarbonization plan for this IRP. Additionally, the Appendix has all Conservation Potential Assessments (CPAs) included for a full analysis of considerations.

iii. The decarbonization plan shall include targets for the ratio of new gas customers added relative to new electric customers added in future years.

Due to the phase out of natural gas line extensions allowances by 2025 for Avista, and building codes set to take effect in 2023, Avista does not anticipate any new gas customers added to the system beginning in 2025, and potentially earlier. If no new gas customers are added to the system, the ratio would be 0 as the numerator would be 0 in the following equation.

$$\text{Ratio of New Gas Customers to New Electric Customers} = \frac{\text{New Gas Customers}}{\text{New Electric Customers}}$$

Because the ratio of new gas customers relative to new electric customers is already expected to be 0, any such future target would also be 0.

APPENDIX 6.1: MONTHLY PRICE DATA BY BASIN
EXPECTED PRICE PER DEKATHERM

AECO	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.24	$7.90	$6.51	$4.72	$4.59	$4.67	$4.81	$4.77	$4.31	$4.66	$5.01	$5.21
2024	$5.08	$4.97	$4.22	$3.68	$3.68	$4.06	$4.06	$3.92	$3.82	$4.06	$4.33	$4.65
2025	$4.14	$4.15	$3.68	$3.32	$3.22	$3.10	$3.10	$3.10	$3.21	$3.08	$3.39	$3.72
2026	$3.36	$3.47	$3.19	$2.80	$2.80	$2.84	$2.84	$2.85	$2.82	$2.88	$3.19	$3.32
2027	$3.15	$3.03	$2.93	$2.72	$2.72	$2.75	$2.74	$2.74	$2.66	$2.67	$3.11	$3.22
2028	$3.11	$3.06	$2.81	$2.74	$2.73	$2.74	$2.74	$2.72	$2.70	$2.71	$3.07	$3.16
2029	$3.31	$3.27	$2.85	$2.87	$2.85	$2.88	$2.83	$2.87	$2.79	$2.78	$3.15	$3.21
2030	$3.31	$3.24	$2.98	$2.94	$2.96	$2.98	$2.92	$2.94	$2.82	$2.82	$3.17	$3.29
2031	$3.38	$3.27	$2.97	$3.03	$3.02	$3.07	$3.02	$3.03	$2.98	$3.04	$3.38	$3.50
2032	$3.41	$3.36	$3.23	$3.06	$3.09	$3.11	$3.08	$3.13	$2.96	$2.99	$3.57	$3.72
2033	$3.69	$3.72	$3.38	$3.19	$3.23	$3.26	$3.19	$3.24	$3.16	$3.19	$3.74	$3.77
2034	$3.77	$3.77	$3.47	$3.29	$3.29	$3.34	$3.29	$3.28	$3.16	$3.22	$3.71	$3.76
2035	$3.83	$3.77	$3.55	$3.41	$3.40	$3.45	$3.38	$3.39	$3.30	$3.38	$3.87	$3.90
2036	$3.96	$3.96	$3.49	$3.46	$3.49	$3.52	$3.49	$3.48	$3.35	$3.40	$4.03	$4.08
2037	$4.15	$4.12	$3.67	$3.55	$3.57	$3.60	$3.56	$3.54	$3.42	$3.46	$4.11	$4.15
2038	$4.24	$4.26	$3.74	$3.65	$3.68	$3.71	$3.68	$3.64	$3.53	$3.58	$4.16	$4.23
2039	$4.33	$4.35	$3.87	$3.80	$3.82	$3.86	$3.82	$3.79	$3.63	$3.68	$4.36	$4.49
2040	$4.58	$4.65	$4.07	$3.96	$3.99	$4.03	$3.98	$3.98	$3.79	$3.85	$4.62	$4.75
2041	$4.83	$4.92	$4.34	$4.11	$4.14	$4.17	$4.13	$4.10	$3.90	$3.97	$4.76	$4.88
2042	$4.99	$5.02	$4.48	$4.26	$4.29	$4.33	$4.29	$4.25	$4.07	$4.13	$4.97	$5.07
2043	$5.18	$5.20	$4.58	$4.55	$4.58	$4.62	$4.58	$4.53	$4.36	$4.48	$5.29	$5.37
2044	$5.44	$5.43	$4.85	$4.62	$4.65	$4.65	$4.63	$4.55	$4.38	$4.46	$5.34	$5.43
2045	$5.53	$5.55	$4.88	$4.80	$4.83	$4.87	$4.84	$4.74	$4.61	$4.68	$5.60	$5.66

Malin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.96	$8.27	$6.82	$4.97	$4.76	$4.78	$4.95	$5.10	$5.02	$5.00	$5.26	$5.63
2024	$5.87	$5.56	$4.84	$4.05	$4.04	$4.10	$4.25	$4.44	$4.38	$4.40	$4.76	$5.25
2025	$4.87	$4.57	$4.20	$3.61	$3.57	$3.60	$3.70	$3.88	$3.86	$3.96	$4.25	$4.56
2026	$4.43	$4.02	$3.82	$3.36	$3.35	$3.34	$3.44	$3.56	$3.57	$3.63	$3.90	$4.23
2027	$4.08	$3.78	$3.61	$3.28	$3.23	$3.16	$3.31	$3.39	$3.45	$3.46	$3.87	$4.07
2028	$3.99	$3.66	$3.56	$3.28	$3.18	$3.18	$3.37	$3.43	$3.47	$3.50	$3.89	$4.10
2029	$4.32	$3.94	$3.57	$3.26	$3.22	$3.17	$3.30	$3.44	$3.57	$3.56	$3.94	$4.28
2030	$4.40	$4.03	$3.71	$3.52	$3.38	$3.30	$3.50	$3.59	$3.70	$3.70	$4.16	$4.53
2031	$4.65	$4.10	$3.82	$3.67	$3.60	$3.50	$3.58	$3.72	$3.76	$3.83	$4.29	$5.04
2032	$5.00	$4.10	$3.91	$3.68	$3.52	$3.44	$3.68	$3.84	$3.94	$3.97	$4.53	$5.16
2033	$5.14	$4.66	$4.05	$3.80	$3.82	$3.68	$3.70	$3.94	$4.02	$4.06	$4.64	$5.06
2034	$5.09	$4.65	$4.19	$3.94	$3.84	$3.76	$3.78	$3.99	$4.06	$4.14	$4.62	$5.12
2035	$5.23	$4.68	$4.27	$4.08	$3.93	$3.86	$3.87	$4.08	$4.21	$4.29	$4.76	$5.30
2036	$5.39	$4.89	$4.34	$4.10	$4.02	$3.89	$3.93	$4.16	$4.19	$4.31	$4.95	$5.37
2037	$5.47	$5.08	$4.48	$4.24	$4.11	$4.02	$3.99	$4.17	$4.31	$4.42	$5.07	$5.38
2038	$5.49	$5.13	$4.58	$4.27	$4.17	$4.11	$4.09	$4.20	$4.44	$4.51	$5.19	$5.33
2039	$5.46	$5.18	$4.70	$4.35	$4.33	$4.25	$4.22	$4.34	$4.62	$4.68	$5.41	$5.72
2040	$5.83	$5.39	$4.96	$4.59	$4.51	$4.43	$4.40	$4.51	$4.84	$4.91	$5.67	$6.01
2041	$6.12	$5.65	$5.10	$4.73	$4.63	$4.53	$4.50	$4.57	$4.87	$5.00	$5.74	$6.02
2042	$6.15	$5.66	$5.11	$4.86	$4.76	$4.66	$4.63	$4.67	$4.94	$5.14	$5.92	$6.11
2043	$6.24	$5.71	$5.25	$5.02	$4.98	$4.92	$4.89	$4.92	$5.14	$5.31	$6.19	$6.36
2044	$6.46	$5.98	$5.35	$5.14	$5.11	$4.99	$4.98	$4.96	$5.21	$5.37	$6.30	$6.44
2045	$6.56	$6.02	$5.51	$5.34	$5.35	$5.23	$5.21	$5.19	$5.44	$5.60	$6.60	$6.67

Rockies	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.80	$8.19	$6.79	$4.96	$4.75	$4.78	$4.95	$5.00	$4.96	$4.99	$5.26	$5.52
2024	$5.66	$5.36	$4.84	$4.04	$4.03	$4.09	$4.30	$4.34	$4.33	$4.40	$4.68	$5.15
2025	$4.72	$4.47	$4.15	$3.61	$3.57	$3.60	$3.80	$3.83	$3.86	$3.96	$4.24	$4.54
2026	$4.35	$4.02	$3.82	$3.36	$3.35	$3.34	$3.54	$3.56	$3.57	$3.63	$3.89	$4.16
2027	$3.98	$3.78	$3.60	$3.28	$3.23	$3.17	$3.41	$3.42	$3.45	$3.46	$3.82	$4.02
2028	$3.93	$3.66	$3.55	$3.28	$3.18	$3.20	$3.43	$3.44	$3.47	$3.50	$3.83	$4.04
2029	$4.26	$3.94	$3.57	$3.26	$3.22	$3.19	$3.41	$3.50	$3.57	$3.56	$3.89	$4.22
2030	$4.34	$4.03	$3.71	$3.52	$3.38	$3.30	$3.62	$3.65	$3.70	$3.70	$4.12	$4.46
2031	$4.58	$4.12	$3.82	$3.67	$3.60	$3.55	$3.76	$3.77	$3.76	$3.83	$4.23	$4.93
2032	$4.87	$4.16	$3.91	$3.68	$3.55	$3.50	$3.86	$3.91	$3.94	$3.97	$4.50	$5.09
2033	$5.06	$4.65	$4.05	$3.80	$3.86	$3.74	$3.95	$4.00	$4.04	$4.06	$4.62	$5.05
2034	$5.08	$4.72	$4.21	$3.94	$3.90	$3.83	$4.02	$4.05	$4.07	$4.14	$4.60	$5.11
2035	$5.22	$4.75	$4.33	$4.08	$3.99	$3.93	$4.12	$4.14	$4.21	$4.29	$4.74	$5.29
2036	$5.38	$4.95	$4.41	$4.10	$4.09	$3.96	$4.21	$4.25	$4.26	$4.31	$4.93	$5.36
2037	$5.49	$5.15	$4.54	$4.24	$4.18	$4.09	$4.31	$4.36	$4.38	$4.43	$5.05	$5.42
2038	$5.53	$5.27	$4.65	$4.33	$4.24	$4.21	$4.44	$4.47	$4.51	$4.56	$5.18	$5.39
2039	$5.52	$5.35	$4.77	$4.42	$4.40	$4.39	$4.61	$4.66	$4.69	$4.75	$5.40	$5.79
2040	$5.90	$5.64	$5.03	$4.64	$4.58	$4.57	$4.80	$4.87	$4.91	$4.99	$5.71	$6.09
2041	$6.19	$5.94	$5.18	$4.80	$4.70	$4.68	$4.92	$4.98	$5.01	$5.07	$5.81	$6.09
2042	$6.22	$6.00	$5.25	$4.93	$4.83	$4.82	$5.05	$5.11	$5.14	$5.21	$5.99	$6.26
2043	$6.39	$6.14	$5.43	$5.09	$5.05	$5.08	$5.24	$5.28	$5.32	$5.38	$6.26	$6.52
2044	$6.64	$6.40	$5.56	$5.21	$5.18	$5.23	$5.34	$5.36	$5.42	$5.49	$6.37	$6.66
2045	$6.79	$6.47	$5.73	$5.47	$5.42	$5.47	$5.60	$5.65	$5.67	$5.74	$6.67	$6.94

Stanfield	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.88	$8.21	$6.70	$4.88	$4.73	$4.81	$5.03	$5.05	$4.43	$4.83	$5.19	$5.67
2024	$5.73	$5.35	$4.40	$3.89	$3.86	$4.20	$4.27	$4.25	$4.04	$4.26	$4.57	$5.05
2025	$4.67	$4.46	$3.91	$3.51	$3.41	$3.28	$3.29	$3.50	$3.41	$3.34	$3.64	$4.29
2026	$4.06	$3.85	$3.50	$3.03	$3.02	$3.01	$3.02	$3.19	$3.12	$3.19	$3.50	$3.81
2027	$3.76	$3.42	$3.27	$2.99	$2.94	$2.92	$2.92	$3.09	$2.98	$3.00	$3.54	$3.88
2028	$3.88	$3.47	$3.16	$2.99	$2.91	$2.92	$3.04	$3.09	$3.05	$3.08	$3.51	$3.93
2029	$4.21	$3.74	$3.25	$3.12	$3.08	$3.06	$3.12	$3.25	$3.22	$3.21	$3.64	$3.93
2030	$4.29	$3.81	$3.41	$3.32	$3.21	$3.17	$3.30	$3.38	$3.28	$3.28	$3.75	$4.19
2031	$4.36	$3.88	$3.41	$3.46	$3.39	$3.33	$3.38	$3.48	$3.43	$3.51	$3.97	$4.63
2032	$4.56	$3.89	$3.69	$3.47	$3.34	$3.31	$3.47	$3.60	$3.42	$3.45	$4.15	$4.74
2033	$4.72	$4.39	$3.83	$3.59	$3.61	$3.51	$3.49	$3.71	$3.59	$3.64	$4.31	$4.60
2034	$4.68	$4.41	$3.94	$3.71	$3.64	$3.59	$3.57	$3.75	$3.63	$3.71	$4.29	$4.67
2035	$4.84	$4.43	$4.04	$3.84	$3.73	$3.69	$3.67	$3.84	$3.78	$3.85	$4.42	$4.70
2036	$4.86	$4.63	$3.99	$3.88	$3.82	$3.73	$3.75	$3.92	$3.76	$3.87	$4.60	$5.07
2037	$5.22	$4.82	$4.18	$3.99	$3.90	$3.84	$3.80	$3.93	$3.87	$3.97	$4.72	$5.07
2038	$5.16	$4.91	$4.25	$4.05	$3.97	$3.93	$3.90	$3.97	$3.99	$4.07	$4.74	$5.15
2039	$5.23	$4.96	$4.37	$4.15	$4.14	$4.08	$4.04	$4.11	$4.12	$4.18	$4.95	$5.45
2040	$5.54	$5.20	$4.59	$4.36	$4.30	$4.26	$4.21	$4.29	$4.28	$4.35	$5.22	$5.72
2041	$5.79	$5.48	$4.86	$4.51	$4.43	$4.40	$4.36	$4.36	$4.32	$4.44	$5.30	$5.75
2042	$5.85	$5.55	$4.92	$4.63	$4.56	$4.56	$4.52	$4.49	$4.40	$4.59	$5.48	$5.86
2043	$5.98	$5.65	$4.96	$4.84	$4.82	$4.86	$4.81	$4.77	$4.64	$4.80	$5.75	$6.12
2044	$6.21	$5.89	$5.23	$4.94	$4.92	$4.89	$4.87	$4.79	$4.68	$4.84	$5.85	$6.20
2045	$6.32	$5.96	$5.24	$5.14	$5.13	$5.13	$5.10	$5.00	$4.91	$5.06	$6.13	$6.43

Station 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.17	$7.83	$6.44	$4.65	$4.52	$4.60	$4.74	$4.71	$4.26	$4.60	$4.94	$5.14
2024	$5.01	$4.89	$4.15	$3.61	$3.61	$3.99	$3.99	$3.85	$3.75	$4.00	$4.26	$4.58
2025	$4.07	$4.08	$3.61	$3.25	$3.16	$3.03	$3.03	$3.03	$3.13	$3.00	$3.31	$3.65
2026	$3.27	$3.39	$3.11	$2.72	$2.73	$2.77	$2.76	$2.78	$2.76	$2.81	$3.11	$3.25
2027	$3.07	$2.95	$2.86	$2.65	$2.64	$2.67	$2.67	$2.67	$2.59	$2.60	$3.03	$3.14
2028	$3.03	$2.98	$2.73	$2.66	$2.65	$2.66	$2.66	$2.64	$2.62	$2.64	$2.99	$3.08
2029	$3.23	$3.18	$2.77	$2.79	$2.77	$2.80	$2.75	$2.79	$2.71	$2.70	$3.06	$3.12
2030	$3.22	$3.16	$2.89	$2.85	$2.88	$2.90	$2.84	$2.86	$2.74	$2.73	$3.09	$3.21
2031	$3.29	$3.19	$2.89	$2.95	$2.94	$2.99	$2.93	$2.94	$2.89	$2.95	$3.29	$3.41
2032	$3.32	$3.27	$3.14	$2.97	$3.00	$3.02	$2.99	$3.04	$2.87	$2.89	$3.48	$3.63
2033	$3.60	$3.62	$3.29	$3.10	$3.14	$3.17	$3.10	$3.15	$3.06	$3.10	$3.65	$3.68
2034	$3.68	$3.68	$3.37	$3.20	$3.20	$3.25	$3.19	$3.18	$3.07	$3.13	$3.61	$3.66
2035	$3.73	$3.67	$3.45	$3.31	$3.30	$3.35	$3.28	$3.30	$3.22	$3.29	$3.77	$3.80
2036	$3.86	$3.86	$3.39	$3.36	$3.39	$3.42	$3.39	$3.38	$3.25	$3.30	$3.93	$3.98
2037	$4.05	$4.02	$3.57	$3.45	$3.47	$3.50	$3.46	$3.44	$3.32	$3.36	$4.01	$4.05
2038	$4.13	$4.16	$3.64	$3.54	$3.57	$3.60	$3.58	$3.54	$3.43	$3.48	$4.05	$4.13
2039	$4.23	$4.25	$3.77	$3.69	$3.72	$3.75	$3.72	$3.69	$3.53	$3.57	$4.25	$4.38
2040	$4.47	$4.54	$3.96	$3.85	$3.89	$3.92	$3.88	$3.88	$3.68	$3.74	$4.51	$4.64
2041	$4.72	$4.81	$4.23	$4.00	$4.04	$4.07	$4.02	$4.00	$3.80	$3.86	$4.65	$4.77
2042	$4.88	$4.91	$4.37	$4.15	$4.19	$4.22	$4.18	$4.14	$3.96	$4.03	$4.86	$4.96
2043	$5.06	$5.09	$4.47	$4.45	$4.48	$4.51	$4.47	$4.42	$4.25	$4.37	$5.18	$5.25
2044	$5.33	$5.32	$4.73	$4.51	$4.54	$4.55	$4.52	$4.44	$4.26	$4.34	$5.22	$5.32
2045	$5.41	$5.43	$4.76	$4.68	$4.71	$4.76	$4.73	$4.62	$4.49	$4.56	$5.48	$5.53

Sumas	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$9.18	$8.47	$7.10	$4.99	$4.84	$4.88	$5.05	$5.02	$4.62	$4.93	$5.25	$5.79
2024	$5.81	$5.37	$4.57	$4.04	$4.00	$4.28	$4.37	$4.31	$4.10	$4.31	$4.58	$5.35
2025	$4.99	$4.55	$3.94	$3.58	$3.49	$3.42	$3.41	$3.42	$3.50	$3.44	$3.76	$4.45
2026	$4.21	$3.79	$3.52	$3.12	$3.12	$3.16	$3.16	$3.18	$3.16	$3.21	$3.52	$4.01
2027	$3.87	$3.36	$3.27	$3.05	$3.04	$3.08	$3.07	$3.07	$3.00	$3.01	$3.75	$4.23
2028	$4.15	$3.68	$3.33	$3.07	$3.06	$3.08	$3.07	$3.06	$3.04	$3.06	$3.71	$4.35
2029	$4.52	$3.96	$3.45	$3.21	$3.19	$3.23	$3.18	$3.22	$3.14	$3.13	$3.87	$4.34
2030	$4.47	$4.06	$3.64	$3.29	$3.32	$3.34	$3.28	$3.30	$3.19	$3.18	$3.99	$4.53
2031	$4.64	$4.15	$3.65	$3.39	$3.38	$3.43	$3.37	$3.38	$3.34	$3.40	$4.22	$4.64
2032	$4.59	$4.19	$3.94	$3.44	$3.46	$3.49	$3.46	$3.51	$3.34	$3.37	$4.41	$4.74
2033	$4.71	$4.69	$4.08	$3.57	$3.62	$3.65	$3.57	$3.63	$3.55	$3.58	$4.57	$4.79
2034	$4.85	$4.74	$4.24	$3.69	$3.68	$3.73	$3.68	$3.67	$3.56	$3.62	$4.55	$4.88
2035	$5.03	$4.78	$4.36	$3.81	$3.80	$3.85	$3.79	$3.80	$3.73	$3.81	$4.70	$5.13
2036	$5.25	$4.98	$4.34	$3.87	$3.90	$3.93	$3.90	$3.89	$3.77	$3.82	$4.89	$5.30
2037	$5.44	$5.18	$4.53	$3.97	$3.99	$4.02	$3.98	$3.96	$3.84	$3.89	$5.01	$5.61
2038	$5.72	$5.30	$4.59	$4.08	$4.11	$4.14	$4.11	$4.08	$3.97	$4.02	$5.03	$5.55
2039	$5.68	$5.38	$4.49	$4.22	$4.25	$4.29	$4.25	$4.23	$4.07	$4.12	$5.25	$5.88
2040	$5.99	$5.67	$4.52	$4.40	$4.44	$4.47	$4.43	$4.43	$4.24	$4.31	$5.56	$6.13
2041	$6.23	$5.97	$4.79	$4.55	$4.59	$4.62	$4.58	$4.55	$4.36	$4.42	$5.65	$6.15
2042	$6.27	$6.03	$4.94	$4.71	$4.74	$4.78	$4.74	$4.71	$4.53	$4.60	$5.82	$6.31
2043	$6.43	$6.12	$5.05	$5.01	$5.04	$5.08	$5.04	$4.99	$4.83	$4.95	$6.08	$6.57
2044	$6.67	$6.36	$5.32	$5.08	$5.11	$5.12	$5.10	$5.02	$4.85	$4.93	$6.20	$6.68
2045	$6.81	$6.35	$5.37	$5.29	$5.32	$5.37	$5.34	$5.24	$5.12	$5.18	$6.50	$6.96

APPENDIX 6.1: MONTHLY PRICE DATA BY BASIN
LOW PRICE PER DEKATHERM

AECO	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$7.90	$7.52	$6.09	$4.28	$4.14	$4.20	$4.35	$4.31	$3.83	$4.19	$4.55	$4.76
2024	$4.58	$4.46	$3.72	$3.17	$3.14	$3.52	$3.58	$3.40	$3.32	$3.53	$3.79	$4.13
2025	$3.61	$3.62	$3.15	$2.81	$2.68	$2.57	$2.53	$2.53	$2.65	$2.55	$2.86	$3.17
2026	$2.80	$2.92	$2.60	$2.20	$2.23	$2.28	$2.26	$2.26	$2.22	$2.28	$2.57	$2.67
2027	$2.51	$2.38	$2.30	$2.07	$2.10	$2.13	$2.13	$2.14	$2.01	$2.03	$2.43	$2.53
2028	$2.41	$2.37	$2.11	$2.04	$1.98	$2.00	$2.01	$1.97	$1.95	$1.97	$2.34	$2.45
2029	$2.57	$2.54	$2.12	$2.13	$2.08	$2.09	$2.03	$2.07	$2.01	$2.02	$2.35	$2.41
2030	$2.53	$2.51	$2.23	$2.19	$2.22	$2.27	$2.20	$2.19	$2.04	$2.04	$2.34	$2.51
2031	$2.55	$2.41	$2.12	$2.15	$2.11	$2.12	$2.11	$2.10	$2.06	$2.08	$2.42	$2.52
2032	$2.42	$2.32	$2.25	$2.02	$2.06	$2.06	$2.01	$2.08	$1.96	$1.91	$2.51	$2.66
2033	$2.71	$2.68	$2.32	$2.16	$2.18	$2.18	$2.12	$2.16	$2.08	$2.11	$2.64	$2.63
2034	$2.57	$2.55	$2.25	$2.20	$2.20	$2.23	$2.17	$2.14	$2.04	$2.05	$2.57	$2.55
2035	$2.59	$2.57	$2.34	$2.26	$2.24	$2.24	$2.26	$2.27	$2.25	$2.36	$2.87	$2.83
2036	$2.79	$2.79	$2.31	$2.24	$2.28	$2.33	$2.23	$2.29	$2.12	$2.25	$2.90	$2.94
2037	$3.00	$2.97	$2.52	$2.41	$2.43	$2.52	$2.39	$2.39	$2.20	$2.27	$2.87	$2.92
2038	$2.99	$3.00	$2.46	$2.39	$2.43	$2.54	$2.54	$2.47	$2.43	$2.38	$2.95	$3.01
2039	$3.06	$3.01	$2.54	$2.50	$2.52	$2.60	$2.59	$2.53	$2.34	$2.37	$3.01	$3.10
2040	$3.16	$3.26	$2.72	$2.59	$2.67	$2.67	$2.63	$2.69	$2.44	$2.58	$3.25	$3.39
2041	$3.48	$3.52	$2.94	$2.81	$2.78	$2.86	$2.75	$2.72	$2.49	$2.49	$3.33	$3.42
2042	$3.57	$3.59	$3.10	$2.89	$2.96	$2.99	$2.80	$2.76	$2.56	$2.60	$3.41	$3.50
2043	$3.62	$3.65	$2.94	$3.00	$3.04	$3.00	$3.04	$3.05	$2.82	$2.92	$3.64	$3.65
2044	$3.69	$3.85	$3.21	$2.89	$2.92	$2.88	$2.85	$2.73	$2.60	$2.71	$3.45	$3.65
2045	$3.80	$3.78	$3.12	$3.07	$3.10	$3.13	$3.19	$3.15	$2.96	$3.01	$3.81	$3.80

Malin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.62	$7.89	$6.40	$4.53	$4.31	$4.31	$4.49	$4.65	$4.54	$4.52	$4.80	$5.17
2024	$5.37	$5.05	$4.33	$3.53	$3.50	$3.56	$3.77	$3.92	$3.88	$3.87	$4.21	$4.73
2025	$4.35	$4.04	$3.67	$3.10	$3.03	$3.07	$3.13	$3.30	$3.31	$3.43	$3.73	$4.01
2026	$3.87	$3.47	$3.23	$2.75	$2.78	$2.77	$2.87	$2.97	$2.97	$3.03	$3.28	$3.58
2027	$3.44	$3.13	$2.97	$2.64	$2.61	$2.54	$2.70	$2.78	$2.79	$2.82	$3.19	$3.39
2028	$3.29	$2.96	$2.85	$2.58	$2.43	$2.44	$2.65	$2.68	$2.73	$2.75	$3.15	$3.38
2029	$3.58	$3.21	$2.84	$2.52	$2.45	$2.38	$2.50	$2.64	$2.78	$2.79	$3.14	$3.48
2030	$3.63	$3.29	$2.97	$2.77	$2.64	$2.59	$2.77	$2.84	$2.92	$2.93	$3.33	$3.75
2031	$3.82	$3.24	$2.96	$2.79	$2.69	$2.54	$2.67	$2.79	$2.84	$2.88	$3.33	$4.06
2032	$4.01	$3.05	$2.94	$2.64	$2.49	$2.39	$2.61	$2.79	$2.94	$2.90	$3.47	$4.09
2033	$4.15	$3.62	$2.99	$2.78	$2.77	$2.60	$2.63	$2.86	$2.94	$2.98	$3.54	$3.92
2034	$3.89	$3.43	$2.97	$2.85	$2.75	$2.66	$2.66	$2.85	$2.94	$2.96	$3.48	$3.90
2035	$3.99	$3.48	$3.06	$2.93	$2.77	$2.66	$2.76	$2.97	$3.16	$3.26	$3.76	$4.22
2036	$4.22	$3.71	$3.16	$2.88	$2.81	$2.70	$2.67	$2.97	$2.96	$3.16	$3.82	$4.23
2037	$4.32	$3.93	$3.33	$3.10	$2.97	$2.94	$2.81	$3.02	$3.09	$3.23	$3.83	$4.15
2038	$4.24	$3.88	$3.30	$3.01	$2.92	$2.94	$2.95	$3.03	$3.34	$3.31	$3.99	$4.12
2039	$4.18	$3.84	$3.37	$3.06	$3.03	$2.99	$3.00	$3.09	$3.32	$3.37	$4.06	$4.33
2040	$4.41	$4.00	$3.61	$3.22	$3.18	$3.08	$3.04	$3.22	$3.49	$3.64	$4.29	$4.66
2041	$4.77	$4.24	$3.71	$3.44	$3.26	$3.22	$3.13	$3.19	$3.45	$3.52	$4.32	$4.56
2042	$4.73	$4.23	$3.72	$3.48	$3.42	$3.32	$3.14	$3.18	$3.43	$3.61	$4.36	$4.55
2043	$4.68	$4.16	$3.61	$3.46	$3.43	$3.30	$3.36	$3.45	$3.60	$3.75	$4.54	$4.64
2044	$4.71	$4.40	$3.71	$3.42	$3.38	$3.21	$3.20	$3.14	$3.43	$3.62	$4.42	$4.65
2045	$4.83	$4.25	$3.76	$3.60	$3.62	$3.49	$3.56	$3.60	$3.78	$3.92	$4.81	$4.81

Rockies	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.46	$7.81	$6.37	$4.52	$4.30	$4.31	$4.49	$4.54	$4.48	$4.51	$4.80	$5.07
2024	$5.16	$4.85	$4.33	$3.52	$3.49	$3.55	$3.82	$3.82	$3.83	$3.87	$4.13	$4.63
2025	$4.19	$3.94	$3.62	$3.10	$3.03	$3.07	$3.23	$3.25	$3.31	$3.43	$3.72	$3.99
2026	$3.79	$3.47	$3.23	$2.75	$2.78	$2.77	$2.97	$2.97	$2.97	$3.03	$3.27	$3.51
2027	$3.34	$3.13	$2.97	$2.64	$2.61	$2.54	$2.80	$2.82	$2.79	$2.82	$3.14	$3.33
2028	$3.24	$2.96	$2.85	$2.58	$2.43	$2.46	$2.70	$2.69	$2.73	$2.75	$3.10	$3.32
2029	$3.51	$3.21	$2.84	$2.52	$2.45	$2.40	$2.61	$2.70	$2.78	$2.79	$3.09	$3.42
2030	$3.57	$3.29	$2.96	$2.77	$2.64	$2.59	$2.89	$2.90	$2.92	$2.93	$3.28	$3.68
2031	$3.75	$3.26	$2.96	$2.79	$2.69	$2.60	$2.85	$2.85	$2.85	$2.87	$3.27	$3.95
2032	$3.88	$3.12	$2.94	$2.64	$2.52	$2.45	$2.79	$2.85	$2.94	$2.90	$3.44	$4.02
2033	$4.07	$3.61	$2.99	$2.78	$2.80	$2.66	$2.88	$2.92	$2.96	$2.98	$3.52	$3.91
2034	$3.88	$3.49	$2.99	$2.85	$2.82	$2.72	$2.90	$2.91	$2.95	$2.96	$3.46	$3.89
2035	$3.98	$3.55	$3.12	$2.93	$2.84	$2.72	$3.00	$3.03	$3.16	$3.26	$3.74	$4.21
2036	$4.21	$3.78	$3.23	$2.88	$2.88	$2.77	$2.95	$3.06	$3.03	$3.16	$3.80	$4.22
2037	$4.34	$4.00	$3.39	$3.10	$3.04	$3.01	$3.14	$3.21	$3.16	$3.24	$3.81	$4.19
2038	$4.28	$4.01	$3.37	$3.07	$2.99	$3.04	$3.30	$3.30	$3.41	$3.36	$3.98	$4.18
2039	$4.24	$4.01	$3.44	$3.13	$3.10	$3.13	$3.38	$3.40	$3.39	$3.44	$4.05	$4.40
2040	$4.48	$4.25	$3.68	$3.28	$3.25	$3.22	$3.45	$3.58	$3.57	$3.71	$4.34	$4.73
2041	$4.84	$4.53	$3.79	$3.50	$3.33	$3.37	$3.55	$3.60	$3.60	$3.59	$4.39	$4.64
2042	$4.80	$4.57	$3.87	$3.55	$3.49	$3.48	$3.56	$3.61	$3.63	$3.68	$4.43	$4.70
2043	$4.83	$4.59	$3.78	$3.53	$3.50	$3.45	$3.71	$3.80	$3.78	$3.82	$4.61	$4.80
2044	$4.89	$4.82	$3.92	$3.49	$3.45	$3.45	$3.56	$3.54	$3.64	$3.74	$4.49	$4.87
2045	$5.06	$4.71	$3.97	$3.74	$3.69	$3.73	$3.94	$4.06	$4.02	$4.07	$4.88	$5.08

Stanfield	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.54	$7.83	$6.28	$4.44	$4.28	$4.34	$4.57	$4.59	$3.96	$4.36	$4.73	$5.22
2024	$5.23	$4.83	$3.89	$3.37	$3.32	$3.66	$3.79	$3.73	$3.54	$3.73	$4.03	$4.53
2025	$4.14	$3.92	$3.39	$3.00	$2.87	$2.74	$2.72	$2.93	$2.86	$2.81	$3.11	$3.73
2026	$3.49	$3.30	$2.91	$2.43	$2.44	$2.45	$2.45	$2.60	$2.52	$2.59	$2.88	$3.16
2027	$3.11	$2.77	$2.63	$2.34	$2.32	$2.30	$2.31	$2.48	$2.32	$2.36	$2.86	$3.19
2028	$3.18	$2.78	$2.45	$2.29	$2.16	$2.18	$2.32	$2.34	$2.30	$2.33	$2.78	$3.22
2029	$3.47	$3.01	$2.52	$2.38	$2.31	$2.27	$2.32	$2.45	$2.43	$2.44	$2.85	$3.13
2030	$3.51	$3.07	$2.67	$2.57	$2.47	$2.46	$2.57	$2.63	$2.50	$2.51	$2.91	$3.41
2031	$3.54	$3.02	$2.55	$2.58	$2.48	$2.37	$2.47	$2.55	$2.51	$2.56	$3.01	$3.65
2032	$3.57	$2.84	$2.72	$2.43	$2.31	$2.26	$2.39	$2.55	$2.42	$2.38	$3.09	$3.68
2033	$3.73	$3.35	$2.78	$2.56	$2.55	$2.43	$2.42	$2.63	$2.51	$2.56	$3.21	$3.45
2034	$3.47	$3.19	$2.73	$2.62	$2.55	$2.48	$2.46	$2.61	$2.51	$2.53	$3.15	$3.46
2035	$3.60	$3.23	$2.83	$2.70	$2.57	$2.48	$2.56	$2.73	$2.73	$2.83	$3.43	$3.63
2036	$3.69	$3.45	$2.81	$2.65	$2.61	$2.54	$2.49	$2.73	$2.54	$2.72	$3.48	$3.93
2037	$4.08	$3.67	$3.02	$2.86	$2.76	$2.77	$2.63	$2.78	$2.65	$2.78	$3.48	$3.84
2038	$3.91	$3.65	$2.97	$2.79	$2.72	$2.76	$2.76	$2.79	$2.89	$2.87	$3.53	$3.93
2039	$3.96	$3.62	$3.03	$2.86	$2.84	$2.82	$2.81	$2.85	$2.82	$2.87	$3.60	$4.06
2040	$4.13	$3.81	$3.25	$3.00	$2.98	$2.90	$2.86	$3.00	$2.93	$3.08	$3.84	$4.37
2041	$4.44	$4.07	$3.46	$3.21	$3.06	$3.09	$2.98	$2.98	$2.90	$2.96	$3.88	$4.29
2042	$4.43	$4.12	$3.54	$3.26	$3.23	$3.22	$3.03	$2.99	$2.89	$3.06	$3.92	$4.30
2043	$4.42	$4.10	$3.32	$3.28	$3.28	$3.24	$3.28	$3.29	$3.10	$3.25	$4.11	$4.40
2044	$4.46	$4.31	$3.59	$3.21	$3.19	$3.12	$3.09	$2.97	$2.90	$3.09	$3.97	$4.41
2045	$4.59	$4.19	$3.49	$3.41	$3.40	$3.39	$3.45	$3.41	$3.26	$3.39	$4.34	$4.58

Station 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$7.83	$7.45	$6.02	$4.21	$4.07	$4.13	$4.28	$4.25	$3.78	$4.13	$4.48	$4.69
2024	$4.51	$4.38	$3.64	$3.10	$3.07	$3.45	$3.51	$3.33	$3.25	$3.46	$3.71	$4.05
2025	$3.54	$3.55	$3.08	$2.74	$2.61	$2.50	$2.46	$2.46	$2.58	$2.47	$2.79	$3.09
2026	$2.71	$2.84	$2.52	$2.12	$2.16	$2.20	$2.19	$2.19	$2.16	$2.21	$2.49	$2.59
2027	$2.43	$2.30	$2.22	$2.00	$2.02	$2.05	$2.06	$2.06	$1.93	$1.95	$2.35	$2.45
2028	$2.33	$2.29	$2.03	$1.96	$1.90	$1.92	$1.93	$1.89	$1.88	$1.89	$2.26	$2.36
2029	$2.49	$2.46	$2.04	$2.05	$2.00	$2.01	$1.95	$1.99	$1.93	$1.93	$2.26	$2.32
2030	$2.45	$2.42	$2.15	$2.11	$2.14	$2.19	$2.11	$2.11	$1.95	$1.96	$2.26	$2.42
2031	$2.46	$2.33	$2.03	$2.07	$2.03	$2.03	$2.02	$2.01	$1.97	$2.00	$2.33	$2.43
2032	$2.33	$2.23	$2.16	$1.93	$1.97	$1.97	$1.92	$1.98	$1.87	$1.82	$2.42	$2.56
2033	$2.61	$2.59	$2.23	$2.07	$2.09	$2.09	$2.03	$2.07	$1.98	$2.02	$2.55	$2.53
2034	$2.47	$2.45	$2.16	$2.11	$2.11	$2.14	$2.08	$2.04	$1.95	$1.96	$2.47	$2.45
2035	$2.49	$2.47	$2.24	$2.17	$2.15	$2.14	$2.17	$2.18	$2.17	$2.26	$2.77	$2.73
2036	$2.69	$2.69	$2.21	$2.14	$2.18	$2.23	$2.13	$2.19	$2.02	$2.15	$2.80	$2.84
2037	$2.90	$2.87	$2.42	$2.31	$2.33	$2.42	$2.29	$2.29	$2.10	$2.17	$2.77	$2.82
2038	$2.88	$2.90	$2.36	$2.28	$2.32	$2.43	$2.44	$2.37	$2.33	$2.28	$2.85	$2.91
2039	$2.95	$2.91	$2.43	$2.40	$2.42	$2.50	$2.49	$2.43	$2.23	$2.27	$2.91	$2.99
2040	$3.05	$3.15	$2.61	$2.49	$2.56	$2.57	$2.52	$2.58	$2.33	$2.47	$3.14	$3.28
2041	$3.37	$3.41	$2.84	$2.71	$2.67	$2.75	$2.65	$2.62	$2.38	$2.38	$3.22	$3.31
2042	$3.46	$3.48	$2.99	$2.78	$2.85	$2.88	$2.69	$2.65	$2.46	$2.49	$3.30	$3.39
2043	$3.50	$3.54	$2.83	$2.89	$2.93	$2.89	$2.93	$2.94	$2.71	$2.81	$3.53	$3.53
2044	$3.58	$3.74	$3.10	$2.78	$2.81	$2.77	$2.74	$2.62	$2.48	$2.59	$3.34	$3.53
2045	$3.68	$3.67	$3.00	$2.95	$2.99	$3.01	$3.07	$3.03	$2.84	$2.89	$3.69	$3.68

Sumas	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$8.84	$8.08	$6.69	$4.55	$4.39	$4.41	$4.59	$4.57	$4.14	$4.46	$4.79	$5.33
2024	$5.31	$4.86	$4.06	$3.52	$3.47	$3.74	$3.89	$3.79	$3.61	$3.77	$4.03	$4.83
2025	$4.47	$4.02	$3.41	$3.07	$2.95	$2.88	$2.84	$2.84	$2.95	$2.90	$3.23	$3.89
2026	$3.64	$3.24	$2.92	$2.52	$2.55	$2.60	$2.59	$2.59	$2.56	$2.61	$2.90	$3.36
2027	$3.23	$2.71	$2.63	$2.40	$2.42	$2.46	$2.46	$2.47	$2.34	$2.36	$3.07	$3.55
2028	$3.45	$2.99	$2.63	$2.38	$2.31	$2.34	$2.35	$2.31	$2.30	$2.31	$2.98	$3.63
2029	$3.78	$3.24	$2.72	$2.47	$2.42	$2.44	$2.38	$2.42	$2.35	$2.36	$3.07	$3.54
2030	$3.69	$3.32	$2.90	$2.55	$2.58	$2.63	$2.55	$2.55	$2.40	$2.41	$3.16	$3.75
2031	$3.82	$3.29	$2.79	$2.51	$2.47	$2.48	$2.47	$2.46	$2.42	$2.45	$3.26	$3.65
2032	$3.60	$3.15	$2.97	$2.40	$2.43	$2.44	$2.39	$2.46	$2.35	$2.30	$3.35	$3.67
2033	$3.72	$3.65	$3.02	$2.54	$2.56	$2.56	$2.51	$2.55	$2.47	$2.50	$3.47	$3.65
2034	$3.64	$3.52	$3.02	$2.60	$2.59	$2.62	$2.57	$2.53	$2.44	$2.45	$3.41	$3.66
2035	$3.79	$3.58	$3.15	$2.67	$2.65	$2.65	$2.67	$2.69	$2.68	$2.78	$3.70	$4.05
2036	$4.08	$3.81	$3.16	$2.65	$2.69	$2.74	$2.64	$2.71	$2.54	$2.67	$3.76	$4.16
2037	$4.29	$4.03	$3.38	$2.83	$2.85	$2.94	$2.81	$2.82	$2.62	$2.70	$3.77	$4.39
2038	$4.47	$4.05	$3.31	$2.81	$2.86	$2.97	$2.97	$2.90	$2.87	$2.82	$3.83	$4.33
2039	$4.40	$4.04	$3.16	$2.93	$2.95	$3.03	$3.02	$2.97	$2.77	$2.81	$3.90	$4.49
2040	$4.57	$4.28	$3.17	$3.04	$3.11	$3.12	$3.08	$3.14	$2.89	$3.03	$4.18	$4.78
2041	$4.88	$4.56	$3.40	$3.25	$3.22	$3.31	$3.20	$3.17	$2.94	$2.94	$4.23	$4.69
2042	$4.85	$4.60	$3.55	$3.34	$3.41	$3.44	$3.25	$3.21	$3.02	$3.07	$4.26	$4.75
2043	$4.87	$4.57	$3.40	$3.45	$3.50	$3.46	$3.51	$3.52	$3.29	$3.39	$4.44	$4.85
2044	$4.92	$4.78	$3.68	$3.35	$3.39	$3.34	$3.32	$3.20	$3.07	$3.18	$4.32	$4.89
2045	$5.08	$4.58	$3.62	$3.56	$3.60	$3.63	$3.69	$3.65	$3.46	$3.51	$4.71	$5.11

APPENDIX 6.1: MONTHLY PRICE DATA BY BASIN
HIGH PRICE PER DEKATHERM

AECO	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$ 9.12	$ 8.81	$7.61	$5.95	$5.72	$5.71	$5.91	$5.82	$5.56	$5.95	$ 6.27	$ 6.47
2024	$ 6.52	$ 6.48	$5.69	$5.04	$5.01	$5.40	$5.48	$5.28	$5.32	$5.69	$ 6.00	$ 6.32
2025	$ 5.76	$ 5.75	$5.32	$5.03	$5.04	$4.80	$4.76	$4.76	$4.96	$4.90	$ 5.19	$ 5.53
2026	$ 5.11	$ 5.32	$5.09	$4.74	$4.68	$4.69	$4.60	$4.61	$4.68	$4.74	$ 5.12	$ 5.09
2027	$ 4.98	$ 4.87	$4.63	$4.39	$4.32	$4.38	$4.52	$4.37	$4.28	$4.41	$ 4.92	$ 5.10
2028	$ 4.84	$ 5.00	$4.86	$4.77	$4.68	$4.84	$4.69	$4.81	$4.83	$4.71	$ 5.01	$ 5.31
2029	$ 5.35	$ 5.27	$4.83	$4.93	$4.99	$5.07	$4.89	$5.00	$4.89	$4.87	$ 5.17	$ 5.16
2030	$ 5.17	$ 5.16	$4.96	$5.09	$5.07	$5.19	$5.15	$5.19	$4.90	$4.91	$ 5.43	$ 5.53
2031	$ 5.56	$ 5.47	$5.13	$5.19	$5.28	$5.11	$5.34	$5.30	$5.19	$5.21	$ 5.68	$ 5.76
2032	$ 5.83	$ 5.73	$5.68	$5.44	$5.62	$5.50	$5.51	$5.57	$5.42	$5.43	$ 5.89	$ 6.15
2033	$ 6.16	$ 6.35	$5.86	$5.81	$5.79	$5.71	$5.95	$5.90	$5.72	$5.99	$ 6.33	$ 6.48
2034	$ 6.51	$ 6.48	$6.35	$6.15	$6.16	$6.29	$6.01	$5.95	$5.75	$5.79	$ 6.31	$ 6.40
2035	$ 6.53	$ 6.53	$6.20	$6.05	$6.01	$5.99	$5.92	$6.04	$6.07	$6.09	$ 6.62	$ 6.61
2036	$ 7.17	$ 6.90	$6.51	$6.55	$6.43	$6.33	$6.40	$6.46	$6.44	$6.47	$ 7.01	$ 7.10
2037	$ 7.52	$ 7.32	$6.87	$6.75	$6.98	$7.05	$7.11	$6.95	$6.68	$6.77	$ 7.46	$ 7.19
2038	$ 7.36	$ 7.58	$6.99	$6.82	$7.08	$7.03	$7.34	$7.24	$7.38	$7.56	$ 8.03	$ 7.89
2039	$ 7.90	$ 8.00	$7.55	$7.28	$7.29	$7.66	$7.60	$7.39	$7.66	$7.27	$ 7.95	$ 8.35
2040	$ 8.11	$ 8.37	$7.68	$7.58	$7.87	$7.54	$7.50	$7.59	$7.22	$7.46	$ 8.08	$ 8.83
2041	$ 8.72	$ 8.98	$8.50	$8.39	$8.39	$8.13	$8.15	$8.24	$8.09	$7.83	$ 8.65	$ 8.71
2042	$ 8.86	$ 9.28	$9.04	$8.53	$8.66	$8.43	$8.06	$8.31	$8.03	$7.89	$ 9.00	$ 8.99
2043	$ 9.62	$ 9.44	$8.75	$8.98	$8.72	$8.70	$8.47	$8.26	$8.23	$8.42	$ 9.73	$10.25
2044	$10.30	$10.01	$9.00	$8.76	$8.85	$8.83	$9.00	$8.82	$8.62	$8.51	$ 9.12	$ 9.45
2045	$ 9.85	$ 9.82	$9.06	$9.04	$8.87	$8.87	$8.66	$8.56	$8.28	$9.27	$10.40	$10.09

Malin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$ 9.84	$ 9.18	$7.93	$6.20	$5.89	$5.83	$6.05	$6.16	$6.26	$ 6.28	$ 6.52	$ 6.89
2024	$ 7.31	$ 7.08	$6.31	$5.41	$5.37	$5.44	$5.68	$5.80	$5.89	$ 6.03	$ 6.42	$ 6.92
2025	$ 6.50	$ 6.17	$5.84	$5.32	$5.39	$5.30	$5.36	$5.54	$5.62	$ 5.78	$ 6.05	$ 6.37
2026	$ 6.18	$ 5.87	$5.72	$5.30	$5.22	$5.18	$5.20	$5.32	$5.43	$ 5.49	$ 5.82	$ 6.00
2027	$ 5.91	$ 5.62	$5.30	$4.95	$4.84	$4.79	$5.08	$5.02	$5.06	$ 5.20	$ 5.68	$ 5.96
2028	$ 5.72	$ 5.60	$5.60	$5.31	$5.14	$5.28	$5.33	$5.52	$5.61	$ 5.50	$ 5.82	$ 6.25
2029	$ 6.36	$ 5.95	$5.55	$5.33	$5.36	$5.36	$5.36	$5.57	$5.66	$ 5.65	$ 5.96	$ 6.23
2030	$ 6.26	$ 5.94	$5.70	$5.68	$5.48	$5.51	$5.73	$5.84	$5.78	$ 5.79	$ 6.41	$ 6.77
2031	$ 6.83	$ 6.29	$5.98	$5.83	$5.86	$5.54	$5.90	$5.99	$5.97	$ 6.00	$ 6.59	$ 7.30
2032	$ 7.42	$ 6.46	$6.36	$6.06	$6.05	$5.83	$6.11	$6.28	$6.40	$ 6.42	$ 6.84	$ 7.58
2033	$ 7.61	$ 7.29	$6.52	$6.43	$6.38	$6.13	$6.46	$6.61	$6.58	$ 6.86	$ 7.22	$ 7.77
2034	$ 7.83	$ 7.36	$7.07	$6.80	$6.71	$6.72	$6.50	$6.66	$6.65	$ 6.71	$ 7.22	$ 7.76
2035	$ 7.93	$ 7.45	$6.92	$6.72	$6.55	$6.41	$6.41	$6.73	$6.97	$ 6.99	$ 7.52	$ 8.00
2036	$ 8.60	$ 7.83	$7.37	$7.19	$6.97	$6.71	$6.84	$7.14	$7.29	$ 7.39	$ 7.93	$ 8.39
2037	$ 8.84	$ 8.29	$7.68	$7.44	$7.52	$7.47	$7.54	$7.57	$7.58	$ 7.72	$ 8.42	$ 8.42
2038	$ 8.61	$ 8.46	$7.83	$7.44	$7.57	$7.43	$7.75	$7.80	$8.29	$ 8.48	$ 9.06	$ 8.99
2039	$ 9.02	$ 8.82	$8.39	$7.84	$7.80	$8.05	$8.01	$7.95	$8.64	$ 8.27	$ 9.00	$ 9.58
2040	$ 9.36	$ 9.10	$8.57	$8.20	$8.38	$7.94	$7.92	$8.12	$8.28	$ 8.52	$ 9.13	$10.10
2041	$10.01	$ 9.71	$9.27	$9.01	$8.87	$8.49	$8.53	$8.71	$9.06	$ 8.87	$ 9.63	$ 9.86
2042	$10.02	$ 9.92	$9.67	$9.12	$9.13	$8.76	$8.41	$8.73	$8.90	$ 8.89	$ 9.96	$10.03
2043	$10.68	$ 9.95	$9.42	$9.44	$9.11	$9.00	$8.78	$8.65	$9.02	$ 9.26	$10.62	$11.24
2044	$11.32	$10.56	$9.50	$9.28	$9.31	$9.16	$9.35	$9.24	$9.45	$ 9.43	$10.09	$10.45
2045	$10.88	$10.29	$9.69	$9.58	$9.39	$9.23	$9.03	$9.01	$9.11	$10.19	$11.39	$11.10

Rockies	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$ 9.68	$ 9.10	$7.89	$6.19	$5.88	$5.82	$6.05	$6.05	$6.21	$ 6.27	$ 6.52	$ 6.79
2024	$ 7.10	$ 6.88	$6.30	$5.40	$5.36	$5.43	$5.72	$5.70	$5.84	$ 6.03	$ 6.34	$ 6.82
2025	$ 6.34	$ 6.07	$5.79	$5.32	$5.39	$5.30	$5.47	$5.49	$5.62	$ 5.78	$ 6.04	$ 6.35
2026	$ 6.10	$ 5.87	$5.72	$5.30	$5.22	$5.18	$5.31	$5.32	$5.43	$ 5.49	$ 5.82	$ 5.93
2027	$ 5.81	$ 5.62	$5.30	$4.95	$4.84	$4.80	$5.18	$5.05	$5.06	$ 5.20	$ 5.63	$ 5.90
2028	$ 5.67	$ 5.60	$5.60	$5.31	$5.14	$5.29	$5.39	$5.53	$5.61	$ 5.49	$ 5.76	$ 6.18
2029	$ 6.29	$ 5.94	$5.55	$5.33	$5.36	$5.37	$5.47	$5.63	$5.66	$ 5.65	$ 5.91	$ 6.17
2030	$ 6.20	$ 5.94	$5.69	$5.68	$5.48	$5.51	$5.85	$5.90	$5.78	$ 5.79	$ 6.37	$ 6.70
2031	$ 6.76	$ 6.31	$5.97	$5.83	$5.86	$5.59	$6.08	$6.05	$5.97	$ 6.00	$ 6.53	$ 7.19
2032	$ 7.29	$ 6.52	$6.36	$6.06	$6.08	$5.89	$6.29	$6.35	$6.40	$ 6.42	$ 6.82	$ 7.51
2033	$ 7.53	$ 7.28	$6.52	$6.43	$6.41	$6.20	$6.72	$6.67	$6.61	$ 6.86	$ 7.20	$ 7.76
2034	$ 7.82	$ 7.43	$7.09	$6.80	$6.78	$6.78	$6.74	$6.72	$6.66	$ 6.71	$ 7.20	$ 7.75
2035	$ 7.92	$ 7.51	$6.98	$6.72	$6.61	$6.47	$6.65	$6.80	$6.97	$ 6.99	$ 7.50	$ 7.99
2036	$ 8.59	$ 7.89	$7.43	$7.19	$7.03	$6.77	$7.12	$7.23	$7.35	$ 7.39	$ 7.91	$ 8.38
2037	$ 8.86	$ 8.35	$7.75	$7.44	$7.59	$7.53	$7.86	$7.77	$7.64	$ 7.74	$ 8.40	$ 8.46
2038	$ 8.66	$ 8.60	$7.90	$7.50	$7.64	$7.53	$8.10	$8.07	$8.36	$ 8.54	$ 9.05	$ 9.05
2039	$ 9.08	$ 8.99	$8.45	$7.90	$7.87	$8.19	$8.40	$8.26	$8.71	$ 8.34	$ 9.00	$ 9.65
2040	$ 9.43	$ 9.35	$8.64	$8.26	$8.45	$8.08	$8.33	$8.48	$8.35	$ 8.60	$ 9.18	$10.17
2041	$10.08	$10.00	$9.34	$9.08	$8.94	$8.63	$8.95	$9.11	$9.20	$ 8.94	$ 9.70	$ 9.93
2042	$10.09	$10.26	$9.81	$9.20	$9.20	$8.92	$8.83	$9.17	$9.10	$ 8.96	$10.03	$10.18
2043	$10.83	$10.38	$9.59	$9.51	$9.18	$9.16	$9.13	$9.01	$9.20	$ 9.33	$10.70	$11.40
2044	$11.50	$10.98	$9.71	$9.35	$9.38	$9.40	$9.72	$9.64	$9.66	$ 9.55	$10.16	$10.67
2045	$11.11	$10.74	$9.91	$9.72	$9.46	$9.47	$9.41	$9.47	$9.35	$10.33	$11.47	$11.37

Stanfield	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$ 9.76	$ 9.12	$7.80	$6.12	$5.86	$5.85	$6.13	$6.10	$5.68	$6.12	$ 6.45	$ 6.93
2024	$ 7.17	$ 6.86	$5.87	$5.24	$5.19	$5.54	$5.70	$5.61	$5.55	$5.89	$ 6.24	$ 6.72
2025	$ 6.29	$ 6.06	$5.55	$5.22	$5.23	$4.98	$4.95	$5.16	$5.17	$5.16	$ 5.44	$ 6.09
2026	$ 5.81	$ 5.70	$5.40	$4.97	$4.89	$4.86	$4.78	$4.95	$4.97	$5.05	$ 5.43	$ 5.58
2027	$ 5.59	$ 5.26	$4.96	$4.66	$4.55	$4.55	$4.69	$4.72	$4.60	$4.74	$ 5.35	$ 5.76
2028	$ 5.61	$ 5.41	$5.21	$5.02	$4.86	$5.01	$5.00	$5.18	$5.18	$5.07	$ 5.44	$ 6.08
2029	$ 6.25	$ 5.75	$5.23	$5.18	$5.22	$5.24	$5.18	$5.38	$5.31	$5.30	$ 5.67	$ 5.88
2030	$ 6.14	$ 5.72	$5.40	$5.48	$5.31	$5.37	$5.53	$5.63	$5.36	$5.37	$ 6.00	$ 6.43
2031	$ 6.55	$ 6.07	$5.56	$5.61	$5.65	$5.37	$5.70	$5.75	$5.64	$5.68	$ 6.27	$ 6.89
2032	$ 6.98	$ 6.25	$6.14	$5.84	$5.88	$5.70	$5.89	$6.04	$5.88	$5.89	$ 6.46	$ 7.17
2033	$ 7.19	$ 7.02	$6.31	$6.21	$6.17	$5.96	$6.25	$6.37	$6.16	$6.43	$ 6.89	$ 7.31
2034	$ 7.41	$ 7.12	$6.83	$6.57	$6.51	$6.55	$6.29	$6.42	$6.22	$6.28	$ 6.89	$ 7.31
2035	$ 7.53	$ 7.19	$6.69	$6.49	$6.34	$6.23	$6.21	$6.49	$6.54	$6.56	$ 7.18	$ 7.41
2036	$ 8.07	$ 7.57	$7.02	$6.96	$6.76	$6.55	$6.65	$6.90	$6.86	$6.94	$ 7.59	$ 8.09
2037	$ 8.59	$ 8.02	$7.38	$7.20	$7.31	$7.29	$7.35	$7.33	$7.14	$7.28	$ 8.07	$ 8.11
2038	$ 8.29	$ 8.23	$7.50	$7.22	$7.37	$7.25	$7.56	$7.57	$7.84	$8.04	$ 8.61	$ 8.80
2039	$ 8.80	$ 8.61	$8.05	$7.63	$7.60	$7.88	$7.83	$7.71	$8.14	$7.77	$ 8.54	$ 9.31
2040	$ 9.08	$ 8.91	$8.20	$7.98	$8.18	$7.77	$7.73	$7.90	$7.72	$7.96	$ 8.68	$ 9.80
2041	$ 9.68	$ 9.53	$9.02	$8.79	$8.68	$8.36	$8.38	$8.50	$8.51	$8.31	$ 9.19	$ 9.59
2042	$ 9.72	$ 9.81	$9.48	$8.90	$8.93	$8.66	$8.30	$8.55	$8.36	$8.35	$ 9.52	$ 9.78
2043	$10.42	$ 9.89	$9.13	$9.26	$8.96	$8.94	$8.71	$8.50	$8.52	$8.75	$10.19	$11.00
2044	$11.07	$10.47	$9.38	$9.08	$9.12	$9.07	$9.24	$9.07	$8.92	$8.89	$ 9.64	$10.21
2045	$10.64	$10.23	$9.42	$9.38	$9.17	$9.13	$8.91	$8.82	$8.58	$9.65	$10.93	$10.87

Station 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$ 9.05	$8.74	$7.54	$5.88	$5.65	$5.64	$5.84	$5.76	$5.50	$5.89	$ 6.20	$ 6.40
2024	$ 6.45	$6.40	$5.61	$4.97	$4.94	$5.33	$5.41	$5.21	$5.26	$5.62	$ 5.92	$ 6.25
2025	$ 5.69	$5.68	$5.25	$4.96	$4.97	$4.73	$4.70	$4.69	$4.89	$4.82	$ 5.11	$ 5.45
2026	$ 5.02	$5.24	$5.01	$4.67	$4.60	$4.61	$4.52	$4.54	$4.61	$4.67	$ 5.04	$ 5.02
2027	$ 4.91	$4.79	$4.55	$4.31	$4.25	$4.30	$4.44	$4.29	$4.21	$4.34	$ 4.84	$ 5.02
2028	$ 4.76	$4.92	$4.78	$4.69	$4.60	$4.76	$4.61	$4.73	$4.76	$4.63	$ 4.92	$ 5.23
2029	$ 5.27	$5.19	$4.75	$4.85	$4.91	$4.99	$4.81	$4.92	$4.81	$4.79	$ 5.08	$ 5.07
2030	$ 5.08	$5.07	$4.88	$5.01	$4.98	$5.10	$5.07	$5.11	$4.82	$4.82	$ 5.34	$ 5.44
2031	$ 5.48	$5.38	$5.04	$5.10	$5.20	$5.03	$5.25	$5.22	$5.10	$5.12	$ 5.59	$ 5.67
2032	$ 5.74	$5.63	$5.59	$5.35	$5.53	$5.41	$5.42	$5.48	$5.33	$5.34	$ 5.80	$ 6.05
2033	$ 6.07	$6.26	$5.76	$5.72	$5.70	$5.62	$5.86	$5.81	$5.63	$5.89	$ 6.23	$ 6.39
2034	$ 6.42	$6.39	$6.26	$6.06	$6.07	$6.20	$5.91	$5.86	$5.66	$5.70	$ 6.21	$ 6.30
2035	$ 6.43	$6.43	$6.10	$5.96	$5.92	$5.89	$5.82	$5.95	$5.98	$5.99	$ 6.53	$ 6.51
2036	$ 7.07	$6.80	$6.41	$6.45	$6.33	$6.23	$6.30	$6.36	$6.35	$6.38	$ 6.91	$ 7.00
2037	$ 7.41	$7.22	$6.77	$6.65	$6.88	$6.95	$7.01	$6.85	$6.58	$6.67	$ 7.36	$ 7.09
2038	$ 7.26	$7.48	$6.88	$6.72	$6.97	$6.93	$7.24	$7.14	$7.28	$7.45	$ 7.92	$ 7.78
2039	$ 7.80	$7.89	$7.45	$7.18	$7.19	$7.55	$7.50	$7.29	$7.56	$7.16	$ 7.85	$ 8.24
2040	$ 8.00	$8.26	$7.57	$7.47	$7.76	$7.43	$7.40	$7.49	$7.11	$7.35	$ 7.97	$ 8.72
2041	$ 8.61	$8.87	$8.39	$8.28	$8.29	$8.02	$8.05	$8.13	$7.99	$7.73	$ 8.54	$ 8.60
2042	$ 8.75	$9.17	$8.93	$8.42	$8.56	$8.32	$7.95	$8.21	$7.92	$7.78	$ 8.89	$ 8.88
2043	$ 9.51	$9.33	$8.64	$8.87	$8.61	$8.59	$8.36	$8.15	$8.13	$8.31	$ 9.61	$10.13
2044	$10.19	$9.90	$8.89	$8.65	$8.74	$8.72	$8.89	$8.71	$8.51	$8.40	$ 9.01	$ 9.33
2045	$ 9.73	$9.70	$8.94	$8.93	$8.76	$8.76	$8.54	$8.45	$8.17	$9.15	$10.27	$ 9.97

Sumas	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	$10.06	$ 9.37	$8.21	$6.22	$5.97	$5.93	$6.15	$6.08	$5.86	$6.22	$ 6.51	$ 7.05
2024	$ 7.25	$ 6.88	$6.03	$5.39	$5.34	$5.62	$5.79	$5.67	$5.61	$5.93	$ 6.24	$ 7.02
2025	$ 6.62	$ 6.15	$5.58	$5.29	$5.31	$5.11	$5.07	$5.08	$5.26	$5.26	$ 5.55	$ 6.25
2026	$ 5.96	$ 5.64	$5.41	$5.06	$5.00	$5.01	$4.92	$4.94	$5.01	$5.07	$ 5.45	$ 5.78
2027	$ 5.71	$ 5.20	$4.96	$4.71	$4.65	$4.71	$4.84	$4.70	$4.61	$4.75	$ 5.56	$ 6.12
2028	$ 5.88	$ 5.62	$5.38	$5.11	$5.02	$5.18	$5.03	$5.15	$5.18	$5.05	$ 5.65	$ 6.49
2029	$ 6.56	$ 5.97	$5.43	$5.27	$5.33	$5.41	$5.24	$5.35	$5.24	$5.21	$ 5.89	$ 6.29
2030	$ 6.33	$ 5.97	$5.63	$5.45	$5.42	$5.55	$5.51	$5.56	$5.27	$5.27	$ 6.24	$ 6.77
2031	$ 6.83	$ 6.34	$5.80	$5.54	$5.64	$5.47	$5.70	$5.66	$5.55	$5.57	$ 6.52	$ 6.90
2032	$ 7.02	$ 6.55	$6.40	$5.81	$6.00	$5.88	$5.89	$5.95	$5.81	$5.81	$ 6.72	$ 7.16
2033	$ 7.18	$ 7.32	$6.56	$6.19	$6.18	$6.10	$6.34	$6.29	$6.11	$6.38	$ 7.15	$ 7.50
2034	$ 7.59	$ 7.45	$7.12	$6.55	$6.56	$6.69	$6.40	$6.35	$6.15	$6.20	$ 7.15	$ 7.52
2035	$ 7.73	$ 7.54	$7.01	$6.46	$6.42	$6.40	$6.32	$6.45	$6.50	$6.51	$ 7.45	$ 7.83
2036	$ 8.46	$ 7.92	$7.37	$6.96	$6.84	$6.74	$6.81	$6.88	$6.86	$6.89	$ 7.87	$ 8.32
2037	$ 8.81	$ 8.38	$7.73	$7.17	$7.40	$7.47	$7.53	$7.37	$7.11	$7.20	$ 8.36	$ 8.66
2038	$ 8.85	$ 8.63	$7.83	$7.25	$7.51	$7.46	$7.77	$7.68	$7.82	$7.99	$ 8.90	$ 9.21
2039	$ 9.24	$ 9.03	$8.18	$7.71	$7.72	$8.09	$8.04	$7.83	$8.10	$7.71	$ 8.84	$ 9.74
2040	$ 9.52	$ 9.38	$8.13	$8.02	$8.31	$7.98	$7.95	$8.04	$7.67	$7.92	$ 9.02	$10.22
2041	$10.12	$10.03	$8.95	$8.83	$8.84	$8.57	$8.60	$8.69	$8.55	$8.29	$ 9.54	$ 9.98
2042	$10.14	$10.29	$9.50	$8.98	$9.11	$8.88	$8.52	$8.77	$8.49	$8.35	$ 9.86	$10.23
2043	$10.87	$10.35	$9.21	$9.43	$9.18	$9.16	$8.93	$8.72	$8.71	$8.90	$10.52	$11.45
2044	$11.53	$10.94	$9.47	$9.22	$9.31	$9.29	$9.47	$9.30	$9.09	$8.99	$ 9.99	$10.70
2045	$11.13	$10.62	$9.55	$9.53	$9.37	$9.37	$9.16	$9.06	$8.79	$9.77	$11.29	$11.40

APPENDIX 6.2: WEIGHTED AVERAGE COST OF CAPITAL

WA Discount Factor	6.58%
ID Discount Factor	6.56%
OR Discount Factor	6.71%

Appendix 6.3: Potential Supply Side Resource Options ($/Dekatherm)

	Hydrogen	Dairy	Food Waste	LFG	Wastewater	Synthetic Methane
2023	$ 38.64	$ 35.22	$ 48.22	$ 9.20	$ 15.96	$ 53.72
2024	$ 37.22	$ 36.05	$ 49.35	$ 9.42	$ 16.33	$ 51.20
2025	$ 35.43	$ 36.84	$ 50.43	$ 9.62	$ 16.68	$ 48.35
2026	$ 33.54	$ 37.66	$ 51.54	$ 9.83	$ 17.04	$ 45.43
2027	$ 31.58	$ 38.49	$ 52.67	$ 10.05	$ 17.41	$ 42.42
2028	$ 29.54	$ 39.32	$ 53.80	$ 10.27	$ 17.78	$ 39.34
2029	$ 27.41	$ 40.18	$ 54.96	$ 10.49	$ 18.15	$ 36.16
2030	$ 25.20	$ 41.05	$ 56.15	$ 10.72	$ 18.54	$ 32.90
2031	$ 22.88	$ 41.94	$ 57.36	$ 10.95	$ 18.94	$ 29.52
2032	$ 20.44	$ 42.86	$ 58.60	$ 11.19	$ 19.34	$ 26.02
2033	$ 20.01	$ 43.79	$ 59.87	$ 11.43	$ 19.75	$ 33.20
2034	$ 19.54	$ 44.74	$ 61.17	$ 11.68	$ 20.17	$ 31.86
2035	$ 19.05	$ 45.72	$ 62.49	$ 11.93	$ 20.60	$ 30.48
2036	$ 18.52	$ 46.71	$ 63.84	$ 12.19	$ 21.05	$ 29.08
2037	$ 17.97	$ 47.73	$ 65.22	$ 12.45	$ 21.50	$ 27.64
2038	$ 17.37	$ 48.77	$ 66.64	$ 12.72	$ 21.96	$ 26.17
2039	$ 16.75	$ 49.83	$ 68.08	$ 13.00	$ 22.43	$ 24.67
2040	$ 16.09	$ 50.92	$ 69.56	$ 13.28	$ 22.91	$ 23.13
2041	$ 15.39	$ 52.03	$ 71.06	$ 13.57	$ 23.40	$ 21.55
2042	$ 14.65	$ 53.16	$ 72.60	$ 13.87	$ 23.90	$ 19.94
2043	$ 13.87	$ 54.32	$ 74.18	$ 14.17	$ 24.41	$ 18.28
2044	$ 13.05	$ 55.50	$ 75.79	$ 14.48	$ 24.94	$ 16.58
2045	$ 12.19	$ 56.71	$ 77.43	$ 14.79	$ 25.47	$ 14.84

Appendix 6.4: Average Case Avoided Cost ($/Dekatherm)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.11	4.53	3.72	3.29	3.16	3.18	3.33	4.06	4.35	4.64	4.96	5.22
ID_Ind	5.80	4.41	3.62	3.21	3.09	3.10	3.24	3.97	4.26	4.53	4.85	5.11
ID_Res	6.19	4.57	3.76	3.32	3.19	3.21	3.36	4.09	4.39	4.68	5.01	5.27
Klamath Falls_Com	5.69	10.27	10.01	9.77	9.82	10.04	10.66	11.17	11.89	12.25	13.22	24.27
Klamath Falls_Ind	5.67	10.12	9.87	9.68	9.74	9.97	10.57	11.09	11.82	12.06	12.97	23.81
Klamath Falls_Res	5.74	10.31	10.05	9.79	9.84	10.06	10.68	11.19	11.92	12.31	13.31	24.44
LaGrande_Com	5.69	10.31	10.06	9.82	9.86	10.08	10.70	11.17	11.89	12.25	13.23	24.29
LaGrande_Ind	5.32	9.99	9.80	9.65	9.71	9.95	10.54	10.99	11.66	11.68	12.47	22.85
LaGrande_Res	5.72	10.34	10.09	9.84	9.87	10.10	10.72	11.18	11.91	12.29	13.28	24.38
Medford_Com	5.63	10.24	9.99	9.76	9.80	10.02	10.64	11.15	11.88	12.21	13.19	24.21
Medford_Ind	5.65	10.07	9.84	9.65	9.71	9.93	10.53	11.05	11.78	11.99	12.90	23.73
Medford_Res	5.73	10.30	10.05	9.79	9.84	10.06	10.68	11.19	11.92	12.29	13.29	24.39
OR_Tport	5.48	10.13	9.56	9.35	9.40	9.60	10.37	10.89	11.68	12.03	12.85	15.06
Roseburg_Com	5.65	10.26	10.00	9.76	9.80	10.02	10.64	11.15	11.88	12.21	13.18	24.21
Roseburg_Ind	5.65	10.05	9.84	9.64	9.70	9.92	10.52	11.05	11.76	11.97	12.87	23.69
Roseburg_Res	5.73	10.31	10.05	9.79	9.83	10.05	10.67	11.18	11.91	12.29	13.28	24.38
WA_Com	7.86	6.98	6.27	5.99	6.07	6.31	6.73	6.61	6.69	6.95	7.31	7.62
WA_Ind	7.98	6.73	6.06	5.81	5.88	6.11	6.51	6.39	6.46	6.68	7.03	7.32
WA_Res	7.88	6.99	6.28	6.00	6.08	6.32	6.74	6.62	6.69	6.96	7.32	7.63
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.49	5.78	6.12	6.39	6.74	7.15	7.47	7.77	8.20	8.40	8.69
ID_Ind	5.38	5.66	5.97	6.25	6.59	6.99	7.28	7.58	8.04	8.24	8.55
ID_Res	5.54	5.84	6.18	6.45	6.80	7.22	7.55	7.86	8.27	8.48	8.75
Klamath Falls_Com	25.13	24.68	24.86	24.86	23.45	21.93	20.36	18.80	17.29	15.67	14.19
Klamath Falls_Ind	24.56	23.58	23.74	23.74	22.40	20.91	19.36	17.87	16.48	14.91	13.54
Klamath Falls_Res	25.33	25.07	25.25	25.25	23.82	22.28	20.70	19.13	17.57	15.94	14.42
LaGrande_Com	25.17	24.83	25.01	25.01	23.60	22.06	20.47	18.91	17.38	15.75	14.26
LaGrande_Ind	23.40	21.51	21.65	21.66	20.42	19.04	17.56	16.18	15.01	13.53	12.35
LaGrande_Res	25.27	25.01	25.19	25.19	23.77	22.22	20.63	19.05	17.50	15.87	14.36
Medford_Com	25.07	24.62	24.80	24.80	23.39	21.86	20.28	18.72	17.22	15.60	14.13
Medford_Ind	24.51	23.64	23.80	23.81	22.46	20.95	19.36	17.86	16.48	14.89	13.55
Medford_Res	25.28	24.99	25.17	25.18	23.75	22.21	20.63	19.05	17.50	15.87	14.36
OR_Tport	24.93	15.26	25.13	25.13	23.70	22.07	20.40	18.79	17.28	15.83	14.21
Roseburg_Com	25.06	24.61	24.80	24.80	23.40	21.86	20.28	18.72	17.22	15.60	14.13
Roseburg_Ind	24.46	23.59	23.75	23.76	22.41	20.90	19.31	17.80	16.43	14.85	13.52
Roseburg_Res	25.26	24.96	25.14	25.14	23.72	22.18	20.59	19.02	17.48	15.84	14.33
WA_Com	7.05	7.22	7.55	7.82	7.82	8.14	8.53	8.89	9.34	16.32	14.64
WA_Ind	6.76	6.89	7.19	7.47	7.45	7.72	8.07	8.43	8.94	15.93	14.32
WA_Res	7.06	7.23	7.56	7.83	7.83	8.15	8.55	8.91	9.35	16.34	14.66
WA_Tport	6.30	6.40	6.66	6.94	6.92	7.16	7.49	7.87	8.44	15.49	13.97

APPENDIX 6.4: CARBON INTENSITY CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.70	4.49	3.99	3.78	4.03	3.88	4.60	4.81	5.17	5.49	5.70
ID_Ind	6.32	5.14	4.09	3.64	3.46	3.62	3.59	4.33	4.58	4.89	5.21	5.43
ID_Res	7.11	5.85	4.60	4.09	3.87	4.14	3.98	4.68	4.89	5.27	5.58	5.79
Klamath Falls_Com	8.21	7.53	7.27	7.18	7.30	7.51	8.15	8.65	9.39	9.73	10.08	10.34
Klamath Falls_Ind	8.17	7.38	7.12	7.09	7.22	7.44	8.07	8.57	9.32	9.65	9.99	10.24
Klamath Falls_Res	8.25	7.57	7.31	7.21	7.32	7.53	8.18	8.68	9.41	9.76	10.11	10.37
LaGrande_Com	8.62	8.50	8.00	7.89	7.99	8.36	8.71	9.15	9.83	10.26	10.60	10.83
LaGrande_Ind	7.98	7.45	7.18	7.18	7.32	7.56	8.11	8.60	9.36	9.69	10.01	10.26
LaGrande_Res	8.65	8.66	8.08	7.96	8.03	8.42	8.75	9.18	9.86	10.29	10.63	10.85
Medford_Com	8.14	7.50	7.24	7.16	7.28	7.49	8.13	8.63	9.37	9.71	10.05	10.31
Medford_Ind	8.14	7.32	7.08	7.04	7.18	7.38	8.00	8.50	9.26	9.58	9.92	10.17
Medford_Res	8.24	7.56	7.30	7.20	7.32	7.53	8.17	8.67	9.40	9.75	10.09	10.35
OR_Tport	11.81	4.17	3.39	2.97	2.81	10.25	10.61	10.92	11.29	11.63	12.07	12.39
Roseburg_Com	8.16	7.52	7.25	7.17	7.28	7.49	8.13	8.63	9.37	9.71	10.06	10.32
Roseburg_Ind	8.15	7.30	7.07	7.03	7.17	7.37	7.99	8.50	9.25	9.57	9.91	10.17
Roseburg_Res	8.24	7.57	7.30	7.21	7.32	7.53	8.17	8.67	9.40	9.75	10.10	10.36
WA_Com	8.52	8.62	7.51	7.21	7.21	7.80	7.85	7.62	7.55	7.91	8.26	8.51
WA_Ind	8.79	7.80	6.84	6.56	6.59	7.01	7.23	7.04	7.02	7.29	7.64	7.90
WA_Res	8.56	8.64	7.54	7.23	7.23	7.82	7.87	7.64	7.57	7.93	8.28	8.53
WA_Tport	7.89	6.73	6.08	5.83	5.88	6.10	6.49	6.33	6.37	6.56	6.94	7.19

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.98	6.42	6.71	6.95	7.28	7.68	8.00	8.28	8.62	8.87	9.02
ID_Ind	5.72	6.10	6.41	6.68	7.01	7.41	7.75	8.05	8.42	8.67	8.88
ID_Res	6.07	6.53	6.81	7.05	7.37	7.77	8.09	8.36	8.70	8.96	9.09
Klamath Falls_Com	10.70	11.07	11.50	11.96	13.16	15.70	16.24	16.79	16.51	16.14	14.39
Klamath Falls_Ind	10.62	10.98	11.39	11.85	13.05	15.57	16.08	16.64	16.35	15.96	14.22
Klamath Falls_Res	10.73	11.10	11.54	12.00	13.21	15.75	16.28	16.83	16.56	16.20	14.45
LaGrande_Com	11.15	11.57	11.94	12.35	13.48	15.92	16.39	16.89	16.52	16.13	14.37
LaGrande_Ind	10.63	10.96	11.35	11.80	12.96	15.45	15.93	16.50	16.07	15.63	13.89
LaGrande_Res	11.18	11.60	11.96	12.38	13.50	15.94	16.41	16.91	16.54	16.16	14.40
Medford_Com	10.67	11.03	11.46	11.93	13.12	15.65	16.18	16.74	16.46	16.07	14.32
Medford_Ind	10.55	10.89	11.30	11.76	12.94	15.46	15.97	16.54	16.25	15.84	14.08
Medford_Res	10.71	11.08	11.51	11.98	13.18	15.71	16.24	16.79	16.52	16.15	14.39
OR_Tport	12.77	13.15	13.55	13.96	14.42	14.95	15.46	16.05	16.51	15.91	14.11
Roseburg_Com	10.68	11.04	11.47	11.93	13.13	15.66	16.20	16.75	16.48	16.10	14.33
Roseburg_Ind	10.54	10.88	11.29	11.75	12.93	15.45	15.97	16.54	16.24	15.83	14.07
Roseburg_Res	10.72	11.09	11.52	11.99	13.19	15.73	16.26	16.81	16.54	16.17	14.41
WA_Com	7.87	8.22	8.47	8.70	8.62	8.88	9.24	9.54	9.93	14.75	14.66
WA_Ind	7.28	7.51	7.79	8.05	7.99	8.24	8.64	9.00	9.42	14.26	14.33
WA_Res	7.89	8.24	8.49	8.72	8.64	8.90	9.26	9.56	9.95	14.77	14.68
WA_Tport	6.57	6.67	6.95	7.25	7.21	7.49	7.91	8.34	8.82	13.70	13.98

APPENDIX 6.4: ELECTRIFICATION – EXPECTED CONVERSION COST CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.93	5.68	4.46	3.95	3.73	3.67	3.47	4.15	4.40	4.62	5.01	5.18
ID_Ind	6.31	5.12	4.07	3.61	3.42	3.38	3.30	3.99	4.26	4.48	4.84	5.02
ID_Res	7.09	5.83	4.57	4.04	3.81	3.75	3.53	4.20	4.45	4.67	5.07	5.24
Klamath Falls_Com	7.13	10.23	9.98	9.78	9.81	9.97	10.00	10.03	10.18	11.34	11.76	12.81
Klamath Falls_Ind	6.62	10.07	9.82	9.69	9.73	9.91	9.93	9.97	10.13	11.27	11.69	12.73
Klamath Falls_Res	7.21	10.26	10.02	9.80	9.83	9.98	10.02	10.05	10.20	11.36	11.79	12.84
LaGrande_Com	8.01	11.34	10.72	10.47	10.44	10.30	10.31	10.31	10.18	11.33	11.76	12.81
LaGrande_Ind	6.42	10.13	9.86	9.76	9.81	9.92	9.94	9.97	10.03	11.14	11.55	12.59
LaGrande_Res	7.99	11.34	10.72	10.48	10.45	10.31	10.32	10.31	10.18	11.34	11.77	12.82
Medford_Com	7.07	10.21	9.96	9.76	9.79	9.95	9.99	10.02	10.17	11.32	11.74	12.79
Medford_Ind	6.60	10.01	9.78	9.64	9.69	9.87	9.90	9.94	10.08	11.21	11.63	12.68
Medford_Res	7.21	10.27	10.01	9.80	9.82	9.98	10.02	10.04	10.20	11.35	11.78	12.83
OR_Tport	11.25	10.13	9.56	9.35	9.40	9.78	10.12	10.41	10.76	11.08	11.50	12.55
Roseburg_Com	7.11	10.21	9.97	9.76	9.79	9.95	9.99	10.02	10.17	11.32	11.75	12.80
Roseburg_Ind	6.60	9.99	9.78	9.63	9.68	9.86	9.90	9.94	10.08	11.21	11.62	12.68
Roseburg_Res	7.20	10.26	10.01	9.80	9.82	9.98	10.02	10.04	10.20	11.35	11.78	12.83
WA_Com	9.21	8.11	6.98	6.62	6.59	6.74	6.77	6.61	6.63	6.80	7.23	7.43
WA_Ind	8.57	7.56	6.59	6.28	6.28	6.45	6.59	6.44	6.48	6.64	7.04	7.26
WA_Res	9.28	8.18	7.03	6.66	6.63	6.78	6.80	6.63	6.65	6.82	7.26	7.46
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.44	5.70	5.97	6.23	6.52	6.92	7.25	7.58	8.00	8.33	8.69
ID_Ind	5.29	5.54	5.81	6.08	6.35	6.73	7.07	7.39	7.84	8.15	8.53
ID_Res	5.50	5.75	6.02	6.28	6.59	6.99	7.33	7.65	8.08	8.41	8.77
Klamath Falls_Com	23.92	24.02	23.49	22.90	22.71	22.57	21.02	19.43	17.76	15.85	12.90
Klamath Falls_Ind	23.85	23.95	23.39	22.80	22.58	22.42	20.77	19.16	17.48	15.39	12.53
Klamath Falls_Res	23.95	24.05	23.52	22.93	22.75	22.61	21.10	19.52	17.86	16.00	13.00
LaGrande_Com	23.92	24.03	23.50	22.91	22.71	22.57	21.04	19.44	17.78	15.88	13.02
LaGrande_Ind	23.71	23.81	23.24	22.65	22.35	22.11	20.32	18.67	16.94	14.57	12.16
LaGrande_Res	23.93	24.04	23.51	22.92	22.72	22.58	21.06	19.47	17.82	15.94	13.05
Medford_Com	23.90	24.00	23.47	22.88	22.67	22.52	20.95	19.35	17.69	15.73	12.88
Medford_Ind	23.80	23.90	23.35	22.76	22.51	22.33	20.67	19.05	17.38	15.26	12.74
Medford_Res	23.93	24.03	23.50	22.91	22.72	22.57	21.04	19.45	17.79	15.90	12.95
OR_Tport	23.51	23.65	23.10	22.28	22.04	21.86	20.43	18.91	17.35	15.88	14.62
Roseburg_Com	23.91	24.01	23.48	22.89	22.69	22.54	20.98	19.38	17.71	15.77	12.92
Roseburg_Ind	23.80	23.90	23.35	22.76	22.51	22.32	20.67	19.06	17.39	15.30	12.82
Roseburg_Res	23.94	24.04	23.51	22.92	22.73	22.59	21.06	19.47	17.80	15.91	12.93
WA_Com	6.86	6.96	7.22	7.48	7.41	7.69	8.08	8.46	8.94	9.33	9.76
WA_Ind	6.70	6.79	7.05	7.32	7.23	7.49	7.87	8.25	8.75	9.13	9.57
WA_Res	6.89	6.99	7.24	7.50	7.45	7.73	8.12	8.49	8.97	9.37	9.80
WA_Tport	6.30	6.40	6.66	6.94	6.84	7.09	7.48	7.87	8.39	8.76	9.20

APPENDIX 6.4: ELECTRIFICATION – HIGH CONVERSION COST CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.93	5.68	4.46	3.95	3.73	3.67	3.47	4.15	4.40	4.62	5.01	5.18
ID_Ind	6.31	5.12	4.07	3.61	3.42	3.38	3.30	3.99	4.26	4.48	4.84	5.02
ID_Res	7.09	5.83	4.57	4.04	3.81	3.75	3.53	4.20	4.45	4.67	5.07	5.24
Klamath Falls_Com	9.29	10.23	9.98	9.78	9.81	9.97	10.00	10.03	10.18	11.34	11.76	12.81
Klamath Falls_Ind	8.77	10.07	9.82	9.69	9.73	9.91	9.93	9.97	10.13	11.27	11.69	12.73
Klamath Falls_Res	9.37	10.26	10.02	9.80	9.83	9.98	10.02	10.05	10.20	11.36	11.79	12.84
LaGrande_Com	10.16	11.34	10.72	10.47	10.44	10.30	10.31	10.31	10.18	11.33	11.76	12.81
LaGrande_Ind	8.57	10.13	9.86	9.76	9.81	9.92	9.94	9.97	10.03	11.14	11.55	12.59
LaGrande_Res	10.15	11.34	10.72	10.48	10.45	10.31	10.32	10.31	10.18	11.34	11.77	12.82
Medford_Com	9.23	10.21	9.96	9.76	9.79	9.95	9.99	10.02	10.17	11.32	11.74	12.79
Medford_Ind	8.75	10.01	9.78	9.64	9.69	9.87	9.90	9.94	10.08	11.21	11.63	12.68
Medford_Res	9.37	10.27	10.01	9.80	9.82	9.98	10.02	10.04	10.20	11.35	11.78	12.83
OR_Tport	11.25	10.13	9.56	9.35	9.40	9.78	10.12	10.41	10.76	11.08	11.50	12.55
Roseburg_Com	9.27	10.21	9.97	9.76	9.79	9.95	9.99	10.02	10.17	11.32	11.75	12.80
Roseburg_Ind	8.75	9.99	9.78	9.63	9.68	9.86	9.90	9.94	10.08	11.21	11.62	12.68
Roseburg_Res	9.36	10.26	10.01	9.80	9.82	9.98	10.02	10.04	10.20	11.35	11.78	12.83
WA_Com	9.21	8.11	6.98	6.62	6.59	6.74	6.77	6.61	6.63	6.80	7.23	7.43
WA_Ind	8.57	7.56	6.59	6.28	6.28	6.45	6.59	6.44	6.48	6.64	7.04	7.26
WA_Res	9.28	8.18	7.03	6.66	6.63	6.78	6.80	6.63	6.65	6.82	7.26	7.46
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.44	5.70	5.97	6.23	6.52	6.92	7.25	7.58	8.00	8.33	8.69
ID_Ind	5.29	5.54	5.81	6.08	6.35	6.73	7.07	7.39	7.84	8.15	8.53
ID_Res	5.50	5.75	6.02	6.28	6.59	6.99	7.33	7.65	8.08	8.41	8.77
Klamath Falls_Com	23.92	24.02	23.49	22.90	22.71	22.57	21.02	19.43	17.76	15.85	12.90
Klamath Falls_Ind	23.85	23.95	23.39	22.80	22.58	22.42	20.77	19.16	17.48	15.39	12.53
Klamath Falls_Res	23.95	24.05	23.52	22.93	22.75	22.61	21.10	19.52	17.86	16.00	13.00
LaGrande_Com	23.92	24.03	23.50	22.91	22.71	22.57	21.04	19.44	17.78	15.88	13.02
LaGrande_Ind	23.71	23.81	23.24	22.65	22.35	22.11	20.32	18.67	16.94	14.57	12.16
LaGrande_Res	23.93	24.04	23.51	22.92	22.72	22.58	21.06	19.47	17.82	15.94	13.05
Medford_Com	23.90	24.00	23.47	22.88	22.67	22.52	20.95	19.35	17.69	15.73	12.88
Medford_Ind	23.80	23.90	23.35	22.76	22.51	22.33	20.67	19.05	17.38	15.26	12.74
Medford_Res	23.93	24.03	23.50	22.91	22.72	22.57	21.04	19.45	17.79	15.90	12.95
OR_Tport	23.51	23.65	23.10	22.28	22.04	21.86	20.43	18.91	17.35	15.88	14.62
Roseburg_Com	23.91	24.01	23.48	22.89	22.69	22.54	20.98	19.38	17.71	15.77	12.92
Roseburg_Ind	23.80	23.90	23.35	22.76	22.51	22.32	20.67	19.06	17.39	15.30	12.82
Roseburg_Res	23.94	24.04	23.51	22.92	22.73	22.59	21.06	19.47	17.80	15.91	12.93
WA_Com	6.86	6.96	7.22	7.48	7.41	7.69	8.08	8.46	8.94	9.33	9.76
WA_Ind	6.70	6.79	7.05	7.32	7.23	7.49	7.87	8.25	8.75	9.13	9.57
WA_Res	6.89	6.99	7.24	7.50	7.45	7.73	8.12	8.49	8.97	9.37	9.80
WA_Tport	6.30	6.40	6.66	6.94	6.84	7.09	7.48	7.87	8.39	8.76	9.20

APPENDIX 6.4: ELECTRIFICATION – LOW CONVERSION COST CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.93	5.68	4.46	3.95	3.73	3.66	3.47	4.15	4.40	4.62	5.02	5.19
ID_Ind	6.31	5.13	4.07	3.61	3.42	3.38	3.29	3.99	4.25	4.48	4.84	5.02
ID_Res	7.09	5.83	4.57	4.04	3.82	3.74	3.52	4.20	4.45	4.68	5.08	5.25
Klamath Falls_Com	6.17	4.81	4.84	5.37	5.49	6.12	6.95	8.20	9.37	11.34	11.75	12.05
Klamath Falls_Ind	5.67	4.66	4.68	5.28	5.42	6.06	6.88	8.13	9.32	11.27	11.68	11.97
Klamath Falls_Res	6.26	4.85	4.88	5.39	5.52	6.14	6.97	8.22	9.39	11.36	11.78	12.07
LaGrande_Com	7.06	5.98	5.62	6.12	6.19	6.76	7.30	8.50	9.62	11.54	12.01	12.30
LaGrande_Ind	5.47	4.73	4.73	5.37	5.51	6.12	6.90	8.15	9.33	11.24	11.65	11.96
LaGrande_Res	7.05	5.98	5.62	6.12	6.19	6.76	7.31	8.51	9.63	11.54	12.02	12.31
Medford_Com	6.11	4.79	4.81	5.35	5.48	6.11	6.94	8.18	9.35	11.32	11.73	12.03
Medford_Ind	5.64	4.59	4.63	5.23	5.37	6.02	6.84	8.09	9.27	11.21	11.63	11.92
Medford_Res	6.26	4.85	4.87	5.39	5.51	6.14	6.97	8.21	9.38	11.35	11.77	12.06
OR_Tport	5.48	4.17	9.56	9.35	2.81	9.60	9.93	10.22	10.56	10.88	11.30	11.60
Roseburg_Com	6.16	4.80	4.82	5.35	5.48	6.11	6.94	8.19	9.36	11.32	11.74	12.03
Roseburg_Ind	5.65	4.58	4.63	5.22	5.37	6.01	6.84	8.09	9.26	11.21	11.62	11.92
Roseburg_Res	6.25	4.85	4.87	5.39	5.51	6.14	6.97	8.21	9.39	11.35	11.77	12.06
WA_Com	9.21	8.11	6.98	6.62	6.59	6.73	6.77	6.61	6.63	6.80	7.24	7.44
WA_Ind	8.58	7.56	6.59	6.28	6.28	6.45	6.59	6.44	6.47	6.65	7.05	7.26
WA_Res	9.29	8.18	7.03	6.66	6.63	6.77	6.80	6.63	6.65	6.83	7.27	7.46
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.44	5.70	5.97	6.23	6.56	6.97	7.31	7.61	8.01	8.34	8.71
ID_Ind	5.29	5.54	5.81	6.08	6.41	6.82	7.16	7.44	7.85	8.16	8.55
ID_Res	5.50	5.75	6.03	6.29	6.61	7.03	7.37	7.67	8.08	8.42	8.78
Klamath Falls_Com	12.40	12.78	21.11	21.22	21.13	18.93	18.55	18.03	17.61	15.86	13.79
Klamath Falls_Ind	12.34	12.71	21.02	21.14	20.93	18.70	18.30	17.69	17.14	15.35	13.16
Klamath Falls_Res	12.42	12.81	21.13	21.25	21.19	19.01	18.63	18.15	17.77	16.04	14.00
LaGrande_Com	12.63	12.83	21.15	21.27	21.18	19.00	18.62	18.12	17.71	15.95	13.93
LaGrande_Ind	12.33	12.65	20.93	21.07	20.69	18.41	18.00	17.19	16.37	14.51	12.10
LaGrande_Res	12.64	12.84	21.15	21.28	21.21	19.02	18.64	18.16	17.77	16.02	14.01
Medford_Com	12.38	12.76	21.08	21.20	21.08	18.88	18.49	17.95	17.42	15.62	12.50
Medford_Ind	12.29	12.65	20.97	21.09	20.87	18.62	18.22	17.58	16.96	15.12	12.36
Medford_Res	12.41	12.79	21.12	21.23	21.16	18.96	18.58	18.06	17.57	15.70	12.35
OR_Tport	12.17	12.53	20.74	20.89	20.91	18.46	18.08	17.60	17.32	15.82	14.21
Roseburg_Com	12.39	12.76	21.09	21.21	21.10	18.90	18.51	17.98	17.45	15.66	12.54
Roseburg_Ind	12.29	12.65	20.96	21.09	20.88	18.64	18.24	17.60	17.00	15.18	12.47
Roseburg_Res	12.41	12.80	21.12	21.24	21.16	18.97	18.58	18.09	17.58	15.80	12.53
WA_Com	6.86	6.96	7.22	7.48	7.44	7.74	8.12	8.48	8.94	9.34	9.77
WA_Ind	6.70	6.79	7.05	7.32	7.28	7.57	7.96	8.30	8.76	9.13	9.59
WA_Res	6.89	6.99	7.24	7.51	7.47	7.76	8.15	8.52	8.98	9.38	9.81
WA_Tport	6.30	6.40	6.66	6.94	6.92	7.20	7.60	7.93	8.39	8.76	9.23

APPENDIX 6.4: HIGH CUSTOMER GROWTH CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.71	4.50	4.00	3.81	4.06	3.86	4.56	4.80	5.15	5.66	5.84
ID_Ind	6.31	5.14	4.09	3.64	3.48	3.65	3.56	4.28	4.54	4.85	5.30	5.50
ID_Res	7.11	5.86	4.61	4.10	3.90	4.18	3.95	4.65	4.89	5.25	5.77	5.95
Klamath Falls_Com	7.86	10.22	9.97	9.79	9.85	10.07	10.87	11.50	12.04	12.36	13.31	14.36
Klamath Falls_Ind	7.80	10.07	9.81	9.69	9.77	9.99	10.78	11.42	11.92	12.19	13.03	14.05
Klamath Falls_Res	7.91	10.26	10.01	9.81	9.87	10.09	10.89	11.53	12.08	12.42	13.41	14.46
LaGrande_Com	8.28	11.16	10.64	10.43	10.45	10.61	11.11	11.49	12.02	12.35	13.32	14.37
LaGrande_Ind	7.75	10.14	9.93	9.79	9.90	10.08	10.73	11.33	11.78	11.99	12.79	13.80
LaGrande_Res	8.30	11.25	10.70	10.48	10.48	10.64	11.13	11.51	12.05	12.38	13.37	14.42
Medford_Com	7.80	10.19	9.94	9.77	9.83	10.05	10.85	11.48	12.01	12.32	13.25	14.29
Medford_Ind	7.79	10.01	9.78	9.65	9.73	9.93	10.73	11.37	11.85	12.10	12.93	13.96
Medford_Res	7.90	10.26	10.00	9.81	9.87	10.08	10.89	11.52	12.06	12.39	13.37	14.41
OR_Tport	5.48	10.13	9.56	9.35	9.43	9.60	10.56	11.20	11.82	12.10	12.94	13.97
Roseburg_Com	7.81	10.20	9.95	9.77	9.83	10.04	10.85	11.49	12.01	12.32	13.26	14.30
Roseburg_Ind	7.72	9.99	9.75	9.64	9.72	9.92	10.72	11.37	11.84	12.09	12.93	13.96
Roseburg_Res	7.90	10.26	10.00	9.81	9.87	10.08	10.89	11.52	12.07	12.39	13.36	14.41
WA_Com	8.32	8.42	7.30	6.98	6.98	7.55	7.51	7.36	7.35	7.72	8.33	8.54
WA_Ind	8.58	7.58	6.61	6.32	6.34	6.75	6.89	6.76	6.78	7.05	7.55	7.78
WA_Res	8.36	8.44	7.32	7.00	7.00	7.57	7.52	7.38	7.37	7.74	8.35	8.56
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	6.10	6.37	6.65	6.86	7.15	7.47	7.76	8.03	8.39	8.61	8.78
ID_Ind	5.77	6.02	6.32	6.55	6.85	7.12	7.45	7.75	8.15	8.39	8.62
ID_Res	6.21	6.48	6.75	6.96	7.25	7.60	7.88	8.14	8.49	8.70	8.86
Klamath Falls_Com	24.62	24.29	24.79	24.80	23.46	21.89	20.45	19.11	17.59	16.12	14.57
Klamath Falls_Ind	24.02	23.13	23.56	23.64	22.43	20.87	19.56	18.50	17.12	15.77	14.32
Klamath Falls_Res	24.83	24.71	25.22	25.21	23.82	22.25	20.76	19.32	17.76	16.24	14.66
LaGrande_Com	24.69	24.50	25.01	25.02	23.65	22.04	20.58	19.18	17.64	16.15	14.58
LaGrande_Ind	23.66	22.50	22.99	23.06	21.96	20.22	19.03	18.04	16.75	15.46	14.12
LaGrande_Res	24.78	24.68	25.19	25.19	23.80	22.20	20.71	19.27	17.71	16.20	14.62
Medford_Com	24.52	24.14	24.63	24.64	23.31	21.71	20.29	18.98	17.48	16.03	14.51
Medford_Ind	23.93	23.06	23.50	23.56	22.35	20.70	19.43	18.35	16.99	15.66	14.24
Medford_Res	24.74	24.55	25.06	25.05	23.67	22.08	20.61	19.20	17.66	16.17	14.61
OR_Tport	24.42	24.61	25.13	25.12	3.87	21.94	20.39	18.82	17.25	15.84	14.21
Roseburg_Com	24.54	24.19	24.68	24.70	23.37	21.76	20.34	19.02	17.52	16.06	14.52
Roseburg_Ind	23.95	23.16	23.61	23.68	22.45	20.81	19.50	18.40	17.02	15.69	14.27
Roseburg_Res	24.72	24.51	25.01	25.01	23.64	22.06	20.59	19.20	17.67	16.17	14.61
WA_Com	7.96	8.08	8.32	8.53	8.44	8.68	8.99	9.28	9.66	14.52	14.61
WA_Ind	7.22	7.31	7.58	7.82	7.75	7.90	8.28	8.62	9.08	14.01	14.23
WA_Res	7.97	8.11	8.34	8.54	8.46	8.71	9.02	9.30	9.68	14.54	14.63
WA_Tport	6.30	6.40	6.66	6.93	6.90	7.04	7.47	7.88	8.41	13.42	13.80

APPENDIX 6.4: HYBRID CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.70	4.49	3.98	3.78	4.00	3.80	4.46	4.71	5.05	5.34	5.51
ID_Ind	6.32	5.14	4.09	3.63	3.45	3.60	3.52	4.20	4.46	4.76	5.06	5.23
ID_Res	7.11	5.86	4.60	4.08	3.87	4.12	3.89	4.54	4.79	5.14	5.44	5.59
Klamath Falls_Com	8.36	10.23	10.11	9.87	9.89	10.10	10.46	10.74	11.16	12.40	12.75	13.81
Klamath Falls_Ind	7.84	10.07	9.82	9.69	9.74	9.96	10.30	10.58	10.99	12.22	12.54	13.58
Klamath Falls_Res	8.44	10.26	10.13	9.88	9.90	10.11	10.48	10.75	11.17	12.41	12.77	13.82
LaGrande_Com	9.25	11.34	11.23	10.89	10.83	11.29	10.88	11.08	11.42	12.38	12.73	13.78
LaGrande_Ind	7.64	10.12	9.86	9.76	9.81	10.02	10.28	10.49	10.88	12.07	12.37	13.41
LaGrande_Res	9.23	11.34	11.18	10.87	10.80	11.26	10.87	11.07	11.42	12.38	12.74	13.79
Medford_Com	8.30	10.21	10.12	9.88	9.95	10.18	10.53	10.82	11.31	12.49	12.86	13.96
Medford_Ind	7.82	10.01	9.78	9.64	9.69	9.91	10.25	10.54	10.92	12.16	12.47	13.52
Medford_Res	8.44	10.27	10.15	9.90	9.96	10.19	10.55	10.84	11.33	12.51	12.88	13.98
OR_Tport	11.25	10.13	9.56	9.35	9.40	9.78	10.12	10.41	10.76	12.01	12.31	13.35
Roseburg_Com	8.34	10.21	10.15	9.96	10.05	10.30	10.64	10.96	11.50	12.57	12.96	14.05
Roseburg_Ind	7.82	9.99	9.78	9.63	9.68	9.90	10.25	10.54	10.91	12.16	12.46	13.51
Roseburg_Res	8.43	10.26	10.17	9.98	10.06	10.31	10.65	10.97	11.53	12.59	12.98	14.08
WA_Com	8.31	8.41	7.38	7.01	6.98	7.53	7.46	7.26	7.26	7.60	7.93	8.10
WA_Ind	8.59	7.58	6.61	6.30	6.32	6.70	6.84	6.67	6.70	6.96	7.29	7.49
WA_Res	9.30	8.21	7.45	7.05	7.01	7.56	7.48	7.28	7.27	7.62	7.95	8.12
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.79	6.22	6.34	6.53	6.85	7.36	7.66	7.95	8.31	8.62	8.93
ID_Ind	5.52	5.89	6.07	6.26	6.57	7.04	7.36	7.67	8.07	8.36	8.72
ID_Res	5.88	6.32	6.43	6.63	6.95	7.47	7.77	8.06	8.41	8.73	9.02
Klamath Falls_Com	23.81	23.97	23.77	23.59	23.49	22.81	21.17	19.52	17.89	16.12	14.36
Klamath Falls_Ind	23.62	23.75	23.47	23.21	22.98	22.25	20.37	18.57	17.04	15.02	13.18
Klamath Falls_Res	23.82	23.98	23.79	23.63	23.54	22.86	21.25	19.61	17.98	16.24	14.48
LaGrande_Com	23.79	23.95	23.75	23.59	23.48	22.83	21.19	19.54	17.92	16.16	14.40
LaGrande_Ind	23.47	23.59	23.22	22.81	22.48	21.70	19.60	17.61	16.12	13.85	11.80
LaGrande_Res	23.80	23.96	23.76	23.60	23.49	22.84	21.22	19.58	17.95	16.20	14.45
Medford_Com	23.89	24.07	23.82	23.63	23.55	22.80	21.14	19.47	17.86	16.06	14.27
Medford_Ind	23.57	23.69	23.40	23.11	22.86	22.13	20.24	18.42	16.90	14.86	12.99
Medford_Res	23.91	24.09	23.85	23.67	23.60	22.86	21.23	19.57	17.95	16.19	14.40
OR_Tport	23.27	23.41	22.96	22.74	22.62	21.97	20.40	18.79	17.23	15.82	14.22
Roseburg_Com	23.93	24.11	23.86	23.67	23.57	22.82	21.16	19.49	17.88	16.09	14.30
Roseburg_Ind	23.56	23.69	23.40	23.11	22.86	22.14	20.27	18.46	16.94	14.93	13.08
Roseburg_Res	23.94	24.13	23.89	23.71	23.63	22.87	21.23	19.58	17.95	16.18	14.39
WA_Com	7.56	7.92	7.94	8.15	8.11	8.55	8.89	9.22	9.58	9.97	10.29
WA_Ind	6.96	7.18	7.32	7.51	7.46	7.82	8.19	8.54	8.99	9.35	9.76
WA_Res	7.58	7.94	7.96	8.17	8.13	8.58	8.91	9.24	9.60	9.99	10.31
WA_Tport	6.30	6.40	6.66	6.86	6.81	7.09	7.48	7.87	8.39	8.76	9.23

APPENDIX 6.4: INTERRUPTED SUPPLY CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.95	5.71	4.49	4.01	3.83	4.07	3.88	4.58	4.80	5.15	5.66	5.84
ID_Ind	6.32	5.15	4.09	3.66	3.50	3.65	3.58	4.30	4.54	4.85	5.31	5.50
ID_Res	7.11	5.86	4.60	4.11	3.93	4.18	3.97	4.67	4.88	5.24	5.77	5.95
Klamath Falls_Com	5.72	10.25	9.95	9.79	9.84	10.09	17.54	18.28	18.91	19.38	20.07	20.98
Klamath Falls_Ind	5.68	10.10	9.80	9.69	9.76	10.01	17.45	18.20	18.84	19.19	19.69	20.58
Klamath Falls_Res	5.76	10.29	9.99	9.82	9.86	10.11	17.57	18.30	18.93	19.44	20.20	21.12
LaGrande_Com	6.14	11.16	10.63	10.44	10.45	10.86	17.72	18.27	18.89	19.36	20.09	21.00
LaGrande_Ind	5.52	10.16	9.85	9.77	9.83	10.11	17.36	18.06	18.71	18.84	18.99	19.86
LaGrande_Res	6.17	11.32	10.71	10.50	10.49	10.91	17.74	18.28	18.90	19.40	20.16	21.08
Medford_Com	5.65	10.22	9.93	9.77	9.82	10.06	17.52	18.26	18.89	19.33	19.99	20.90
Medford_Ind	5.65	10.04	9.76	9.65	9.71	9.95	17.40	18.14	18.78	19.10	19.58	20.47
Medford_Res	5.75	10.28	9.98	9.81	9.86	10.10	17.56	18.30	18.92	19.41	20.14	21.05
OR_Tport	11.25	10.13	9.56	9.35	9.40	9.78	17.13	17.85	18.50	19.01	19.68	20.58
Roseburg_Com	5.67	10.24	9.94	9.77	9.82	10.06	17.52	18.26	18.89	19.33	20.01	20.92
Roseburg_Ind	5.65	10.02	9.76	9.64	9.70	9.94	17.39	18.13	18.77	19.09	19.58	20.48
Roseburg_Res	5.76	10.29	9.99	9.81	9.86	10.10	17.56	18.30	18.92	19.41	20.14	21.05
WA_Com	8.33	8.41	7.29	6.98	7.01	7.56	7.52	7.38	7.35	7.70	8.32	8.53
WA_Ind	8.59	7.59	6.61	6.33	6.37	6.76	6.90	6.78	6.78	7.04	7.55	7.78
WA_Res	8.37	8.43	7.31	7.00	7.03	7.58	7.54	7.40	7.36	7.72	8.34	8.54
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	6.09	6.34	6.59	6.78	7.04	7.42	7.72	8.00	8.37	8.58	8.87
ID_Ind	5.77	6.00	6.28	6.48	6.73	7.09	7.42	7.72	8.13	8.37	8.69
ID_Res	6.20	6.45	6.70	6.89	7.16	7.55	7.84	8.11	8.47	8.68	8.96
Klamath Falls_Com	24.60	24.39	24.79	24.83	23.42	21.90	20.45	19.10	17.56	16.04	14.51
Klamath Falls_Ind	24.12	23.26	23.59	23.71	22.37	20.89	19.58	18.50	17.07	15.62	14.20
Klamath Falls_Res	24.77	24.79	25.22	25.23	23.80	22.26	20.76	19.32	17.74	16.20	14.62
LaGrande_Com	24.64	24.58	25.00	25.03	23.60	22.06	20.57	19.17	17.61	16.08	14.53
LaGrande_Ind	23.25	21.39	21.63	21.89	20.62	19.19	18.13	17.46	16.20	14.87	13.66
LaGrande_Res	24.73	24.77	25.20	25.22	23.77	22.22	20.71	19.27	17.69	16.15	14.59
Medford_Com	24.51	24.24	24.63	24.67	23.25	21.72	20.28	18.97	17.45	15.94	14.44
Medford_Ind	24.01	23.18	23.51	23.62	22.25	20.74	19.42	18.35	16.93	15.49	14.12
Medford_Res	24.69	24.65	25.05	25.07	23.63	22.09	20.60	19.20	17.64	16.10	14.56
OR_Tport	24.26	24.65	25.13	25.09	23.56	21.96	20.38	18.82	17.24	15.83	14.21
Roseburg_Com	24.53	24.30	24.70	24.74	23.32	21.79	20.34	19.02	17.49	15.97	14.46
Roseburg_Ind	24.03	23.28	23.63	23.73	22.34	20.84	19.51	18.40	16.97	15.53	14.15
Roseburg_Res	24.69	24.62	25.02	25.04	23.61	22.08	20.59	19.20	17.64	16.11	14.55
WA_Com	7.94	8.03	8.25	8.44	8.35	8.62	8.94	9.24	9.64	14.11	14.38
WA_Ind	7.22	7.28	7.54	7.75	7.63	7.87	8.24	8.60	9.06	13.59	13.94
WA_Res	7.96	8.06	8.27	8.46	8.37	8.64	8.96	9.26	9.66	14.14	14.40
WA_Tport	6.30	6.40	6.66	6.91	6.80	7.06	7.47	7.88	8.40	13.02	13.44

APPENDIX 6.4: LIMITED RNG AVAILABILITY CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.70	4.49	3.99	3.79	4.03	3.91	4.56	4.78	5.09	5.23	5.43
ID_Ind	6.32	5.14	4.09	3.64	3.47	3.62	3.61	4.29	4.53	4.81	4.83	5.04
ID_Res	7.11	5.86	4.60	4.09	3.89	4.14	4.00	4.65	4.86	5.19	5.39	5.59
Klamath Falls_Com	5.71	8.79	9.18	9.70	9.84	10.48	31.76	32.05	29.32	25.85	32.73	31.44
Klamath Falls_Ind	5.67	8.64	9.02	9.60	9.76	10.41	31.66	31.96	29.26	25.77	32.48	31.19
Klamath Falls_Res	5.75	8.83	9.22	9.72	9.87	10.50	31.79	32.07	29.34	25.87	32.82	31.53
LaGrande_Com	5.31	8.78	8.94	9.40	9.55	10.34	29.16	29.52	27.03	24.07	30.62	29.51
LaGrande_Ind	5.49	8.70	9.06	9.67	9.83	10.52	31.58	31.88	29.18	25.72	32.06	30.77
LaGrande_Res	5.93	9.60	9.65	10.18	10.33	11.29	31.90	32.11	29.34	25.89	32.74	31.45
Medford_Com	5.64	8.75	9.14	9.67	9.82	10.46	31.73	32.03	29.31	25.83	32.63	31.34
Medford_Ind	5.64	8.56	8.97	9.56	9.71	10.35	31.60	31.92	29.23	25.74	32.28	31.01
Medford_Res	5.20	8.11	8.53	9.16	9.56	10.43	31.78	32.07	29.33	25.86	32.74	31.45
OR_Tport	5.48	10.13	9.56	9.35	9.40	10.02	31.18	31.49	28.83	25.43	32.35	31.10
Roseburg_Com	5.66	8.77	9.16	9.68	9.82	10.46	31.74	32.04	29.31	25.83	32.63	31.35
Roseburg_Ind	5.65	8.54	8.97	9.55	9.70	10.34	31.59	31.92	29.22	25.74	32.26	30.99
Roseburg_Res	5.74	8.82	9.21	9.72	9.86	10.50	31.78	32.07	29.33	25.86	32.76	31.47
WA_Com	8.31	8.40	7.29	6.96	6.96	7.51	7.57	7.35	7.31	7.63	7.91	8.14
WA_Ind	8.59	7.58	6.62	6.31	6.33	6.72	6.93	6.76	6.77	7.00	7.08	7.32
WA_Res	8.35	8.43	7.32	6.98	6.98	7.53	7.59	7.37	7.33	7.65	7.95	8.17
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.25	6.49

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.69	6.10	6.24	6.61	6.92	7.34	7.66	7.93	8.30	8.55	8.85
ID_Ind	5.32	5.68	5.89	6.25	6.59	7.01	7.36	7.65	8.06	8.32	8.66
ID_Res	5.84	6.27	6.38	6.75	7.05	7.48	7.78	8.05	8.41	8.65	8.94
Klamath Falls_Com	30.11	28.67	27.27	25.81	24.35	22.82	21.35	19.74	18.16	16.46	14.73
Klamath Falls_Ind	29.88	28.44	27.06	25.61	24.17	22.65	21.21	19.61	18.06	16.36	14.64
Klamath Falls_Res	30.19	28.75	27.35	25.88	24.41	22.87	21.40	19.79	18.20	16.50	14.77
LaGrande_Com	28.46	27.28	26.07	24.75	23.49	22.05	20.64	19.08	17.54	15.90	14.22
LaGrande_Ind	29.48	28.04	26.66	25.22	23.81	22.31	20.94	19.34	17.85	16.15	14.45
LaGrande_Res	30.11	28.67	27.27	25.81	24.34	22.82	21.36	19.74	18.16	16.46	14.73
Medford_Com	30.01	28.57	27.18	25.72	24.27	22.75	21.30	19.69	18.12	16.42	14.69
Medford_Ind	29.71	28.26	26.89	25.45	24.03	22.52	21.12	19.51	17.99	16.29	14.56
Medford_Res	30.12	28.68	27.28	25.82	24.35	22.82	21.36	19.74	18.16	16.46	14.73
OR_Tport	29.76	28.30	26.91	25.46	24.01	22.46	21.16	19.55	18.07	16.36	14.65
Roseburg_Com	30.02	28.58	27.19	25.74	24.28	22.76	21.31	19.70	18.13	16.42	14.69
Roseburg_Ind	29.69	28.25	26.89	25.45	24.03	22.52	21.12	19.52	18.00	16.29	14.57
Roseburg_Res	30.13	28.69	27.30	25.83	24.37	22.84	21.37	19.76	18.17	16.47	14.74
WA_Com	7.55	7.87	7.91	8.31	8.24	8.54	8.89	9.18	9.57	14.08	14.37
WA_Ind	6.77	6.99	7.15	7.52	7.49	7.79	8.18	8.53	8.99	13.54	13.91
WA_Res	7.59	7.91	7.94	8.33	8.27	8.58	8.92	9.21	9.60	14.10	14.39
WA_Tport	5.95	6.08	6.37	6.68	6.69	7.00	7.42	7.82	8.35	12.97	13.41

APPENDIX 6.4: PRS CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.70	4.49	3.99	3.79	4.02	3.88	4.53	4.74	5.08	5.38	5.60
ID_Ind	6.32	5.14	4.09	3.64	3.46	3.62	3.58	4.26	4.50	4.80	5.10	5.32
ID_Res	7.11	5.85	4.60	4.09	3.88	4.14	3.97	4.62	4.82	5.18	5.47	5.69
Klamath Falls_Com	7.87	10.22	9.97	9.78	9.82	10.05	14.09	14.69	15.34	15.79	16.68	23.80
Klamath Falls_Ind	7.83	10.07	9.82	9.69	9.74	9.98	14.00	14.61	15.28	15.63	16.37	23.42
Klamath Falls_Res	7.92	10.27	10.01	9.81	9.84	10.07	14.12	14.72	15.36	15.85	16.78	23.94
LaGrande_Com	8.27	11.13	10.65	10.43	10.43	10.82	14.31	14.68	15.32	15.78	16.69	23.83
LaGrande_Ind	7.63	10.12	9.86	9.76	9.81	10.08	13.92	14.48	15.16	15.31	15.82	22.75
LaGrande_Res	8.31	11.29	10.73	10.49	10.47	10.87	14.33	14.70	15.33	15.81	16.74	23.89
Medford_Com	7.80	10.20	9.94	9.76	9.80	10.03	14.07	14.67	15.32	15.75	16.61	23.73
Medford_Ind	7.81	10.01	9.78	9.64	9.70	9.93	13.94	14.56	15.22	15.54	16.27	23.33
Medford_Res	7.90	10.26	10.00	9.80	9.83	10.07	14.11	14.71	15.35	15.82	16.74	23.87
OR_Tport	5.48	10.13	9.56	9.35	9.40	9.60	13.71	14.34	15.01	15.48	16.28	23.36
Roseburg_Com	7.83	10.21	9.96	9.76	9.80	10.03	14.07	14.67	15.32	15.75	16.62	23.75
Roseburg_Ind	7.81	9.99	9.78	9.64	9.69	9.92	13.94	14.55	15.21	15.54	16.27	23.34
Roseburg_Res	7.91	10.26	10.01	9.80	9.84	10.07	14.11	14.71	15.36	15.82	16.73	23.87
WA_Com	8.31	8.40	7.29	6.96	6.95	7.50	7.53	7.32	7.27	7.62	7.95	8.20
WA_Ind	8.59	7.58	6.61	6.31	6.33	6.72	6.90	6.74	6.73	6.99	7.32	7.58
WA_Res	8.35	8.43	7.31	6.98	6.96	7.52	7.55	7.33	7.28	7.64	7.97	8.22
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.86	6.28	6.40	6.73	6.99	7.39	7.69	7.97	8.33	8.57	8.86
ID_Ind	5.59	5.95	6.13	6.44	6.68	7.07	7.40	7.70	8.10	8.36	8.68
ID_Res	5.95	6.38	6.50	6.83	7.10	7.51	7.81	8.07	8.42	8.67	8.94
Klamath Falls_Com	24.69	24.35	24.67	24.83	23.41	21.89	20.48	19.10	17.60	16.04	14.52
Klamath Falls_Ind	24.18	23.24	23.48	23.71	22.36	20.89	19.64	18.49	17.11	15.61	14.21
Klamath Falls_Res	24.88	24.76	25.10	25.23	23.79	22.26	20.78	19.32	17.77	16.19	14.63
LaGrande_Com	24.74	24.55	24.88	25.03	23.59	22.05	20.59	19.17	17.65	16.08	14.54
LaGrande_Ind	23.26	21.38	21.53	21.88	20.61	19.19	18.24	17.46	16.26	14.86	13.67
LaGrande_Res	24.84	24.74	25.08	25.22	23.76	22.22	20.73	19.27	17.73	16.15	14.59
Medford_Com	24.60	24.21	24.51	24.67	23.24	21.72	20.32	18.97	17.49	15.94	14.44
Medford_Ind	24.08	23.16	23.40	23.62	22.24	20.73	19.48	18.34	16.98	15.49	14.13
Medford_Res	24.79	24.61	24.94	25.07	23.62	22.09	20.62	19.20	17.67	16.10	14.56
OR_Tport	24.42	24.65	25.01	25.09	23.56	21.96	20.38	18.82	17.33	15.83	14.21
Roseburg_Com	24.62	24.27	24.58	24.74	23.32	21.78	20.37	19.02	17.53	15.97	14.46
Roseburg_Ind	24.10	23.26	23.52	23.73	22.34	20.83	19.56	18.40	17.02	15.53	14.16
Roseburg_Res	24.78	24.58	24.90	25.04	23.61	22.07	20.62	19.20	17.68	16.10	14.56
WA_Com	7.63	7.96	8.00	8.37	8.28	8.58	8.91	9.20	9.59	14.09	14.37
WA_Ind	7.02	7.24	7.39	7.70	7.59	7.85	8.22	8.57	9.03	13.57	13.93
WA_Res	7.64	7.98	8.02	8.39	8.30	8.60	8.94	9.22	9.61	14.11	14.39
WA_Tport	6.30	6.40	6.66	6.91	6.80	7.06	7.47	7.88	8.40	13.01	13.44

APPENDIX 6.4: PRS – ALLOWANCE PRICE CEILING CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.81	5.51	4.36	3.87	3.69	3.87	3.77	4.42	4.64	4.92	5.28	5.48
ID_Ind	6.24	5.02	4.01	3.57	3.41	3.53	3.52	4.20	4.44	4.71	5.04	5.25
ID_Res	6.96	5.64	4.45	3.96	3.78	3.97	3.85	4.50	4.71	5.00	5.36	5.56
Klamath Falls_Com	5.71	10.22	9.97	9.78	9.83	10.07	10.87	11.52	12.05	12.54	13.43	14.48
Klamath Falls_Ind	5.67	10.07	9.82	9.69	9.75	10.00	10.78	11.44	11.99	12.40	13.15	14.17
Klamath Falls_Res	5.75	10.27	10.01	9.81	9.85	10.10	10.90	11.54	12.08	12.60	13.53	14.58
LaGrande_Com	6.04	11.04	10.58	10.36	10.38	10.75	11.09	11.51	12.03	12.53	13.44	14.49
LaGrande_Ind	5.44	10.11	9.85	9.75	9.81	10.08	10.69	11.31	11.86	12.11	12.64	13.63
LaGrande_Res	6.08	11.18	10.65	10.42	10.41	10.79	11.12	11.52	12.05	12.55	13.49	14.54
Medford_Com	5.64	10.20	9.95	9.76	9.81	10.05	10.85	11.49	12.03	12.50	13.37	14.41
Medford_Ind	5.65	10.01	9.78	9.64	9.70	9.94	10.71	11.38	11.93	12.31	13.06	14.08
Medford_Res	5.74	10.26	10.00	9.80	9.85	10.09	10.89	11.53	12.07	12.57	13.49	14.53
OR_Tport	5.48	10.13	9.56	9.35	9.40	9.60	10.52	11.20	11.76	12.25	13.06	14.09
Roseburg_Com	5.66	10.21	9.96	9.76	9.81	10.05	10.85	11.50	12.03	12.51	13.38	14.43
Roseburg_Ind	5.65	9.99	9.78	9.64	9.70	9.93	10.70	11.37	11.92	12.30	13.06	14.08
Roseburg_Res	5.74	10.26	10.01	9.80	9.85	10.09	10.89	11.53	12.07	12.57	13.49	14.53
WA_Com	10.42	10.54	9.70	9.58	9.80	10.47	10.75	11.21	11.75	12.46	13.28	13.95
WA_Ind	10.67	9.81	9.10	9.02	9.25	9.80	10.21	10.71	11.29	11.96	12.74	13.42
WA_Res	10.46	10.56	9.72	9.60	9.81	10.48	10.77	11.22	11.76	12.48	13.29	13.97
WA_Tport	5.53	8.88	8.44	8.37	8.60	8.99	9.55	10.08	10.70	11.34	12.10	12.78

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.77	6.13	6.31	6.59	6.86	7.21	7.41	7.42	7.88	8.23	8.63
ID_Ind	5.55	5.87	6.09	6.37	6.63	6.99	7.21	7.28	7.75	8.08	8.49
ID_Res	5.85	6.22	6.39	6.67	6.95	7.31	7.49	7.49	7.94	8.31	8.70
Klamath Falls_Com	24.84	24.49	24.81	24.90	23.43	21.95	20.56	19.12	17.63	16.07	14.55
Klamath Falls_Ind	24.45	23.37	23.61	23.84	22.40	21.00	19.80	18.50	17.16	15.66	14.27
Klamath Falls_Res	24.98	24.90	25.24	25.29	23.80	22.29	20.84	19.34	17.80	16.22	14.65
LaGrande_Com	24.87	24.69	25.02	25.10	23.62	22.12	20.67	19.17	17.66	16.09	14.55
LaGrande_Ind	23.74	21.49	21.66	22.12	20.70	19.41	18.52	17.43	16.31	14.93	13.78
LaGrande_Res	24.94	24.88	25.22	25.27	23.78	22.27	20.80	19.27	17.74	16.16	14.60
Medford_Com	24.76	24.35	24.65	24.76	23.27	21.80	20.42	18.97	17.51	15.97	14.48
Medford_Ind	24.34	23.29	23.53	23.76	22.29	20.87	19.66	18.32	17.00	15.52	14.18
Medford_Res	24.91	24.76	25.08	25.14	23.64	22.14	20.70	19.21	17.70	16.13	14.58
OR_Tport	24.42	24.77	25.15	25.15	17.89	22.02	20.43	18.87	17.37	15.86	14.61
Roseburg_Com	24.78	24.41	24.72	24.82	23.34	21.86	20.47	19.02	17.54	15.99	14.49
Roseburg_Ind	24.36	23.39	23.65	23.86	22.39	20.97	19.73	18.38	17.04	15.56	14.21
Roseburg_Res	24.91	24.73	25.04	25.11	23.62	22.12	20.69	19.21	17.70	16.13	14.58
WA_Com	14.75	15.71	16.46	17.39	18.37	19.48	20.47	19.89	18.24	16.54	14.81
WA_Ind	14.23	15.11	15.93	16.86	17.82	18.94	19.99	19.78	18.14	16.44	14.71
WA_Res	14.77	15.73	16.48	17.41	18.39	19.50	20.49	19.90	18.25	16.55	14.81
WA_Tport	13.56	14.37	15.26	16.18	17.14	18.30	19.47	19.74	18.09	16.39	14.67

Appendix 6.4: PRS – High Prices Case Avoided Cost ($/Dekatherm)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	8.06	7.20	6.21	5.84	5.58	6.04	5.89	6.63	6.98	7.52	8.02	8.31
ID_Ind	7.45	6.64	5.83	5.50	5.25	5.66	5.62	6.39	6.74	7.26	7.75	8.06
ID_Res	8.22	7.36	6.32	5.94	5.68	6.15	5.97	6.71	7.05	7.61	8.11	8.39
Klamath Falls_Com	8.05	8.95	9.56	10.08	10.64	11.13	11.80	12.66	13.31	13.86	14.71	15.79
Klamath Falls_Ind	7.99	8.78	9.42	9.99	10.54	11.07	11.74	12.62	13.23	13.73	14.40	15.45
Klamath Falls_Res	8.11	9.00	9.60	10.11	10.67	11.15	11.82	12.68	13.33	13.91	14.82	15.91
LaGrande_Com	8.44	9.87	10.23	10.44	10.95	11.12	11.80	12.65	13.30	13.85	14.72	15.82
LaGrande_Ind	7.79	8.80	9.44	9.98	10.45	10.98	11.66	12.53	13.09	13.48	13.83	14.90
LaGrande_Res	8.49	10.04	10.32	10.48	10.99	11.14	11.81	12.66	13.31	13.87	14.78	15.87
Medford_Com	7.98	8.91	9.53	10.06	10.61	11.11	11.79	12.65	13.28	13.82	14.64	15.72
Medford_Ind	7.94	8.68	9.36	9.94	10.47	11.01	11.70	12.58	13.17	13.65	14.30	15.38
Medford_Res	8.09	8.98	9.59	10.10	10.66	11.14	11.81	12.67	13.32	13.88	14.77	15.85
OR_Tport	6.60	5.64	5.11	4.81	11.13	11.60	11.99	12.32	12.97	13.50	14.31	15.39
Roseburg_Com	8.00	8.92	9.54	10.06	10.61	11.11	11.79	12.65	13.29	13.82	14.65	15.74
Roseburg_Ind	7.94	8.65	9.36	9.93	10.46	11.00	11.70	12.58	13.16	13.64	14.29	15.40
Roseburg_Res	8.09	8.99	9.59	10.10	10.66	11.14	11.82	12.68	13.33	13.88	14.77	15.85
WA_Com	9.51	9.94	9.00	8.79	8.77	9.50	9.49	9.39	9.50	10.03	10.58	10.86
WA_Ind	9.72	9.08	8.34	8.18	8.11	8.76	8.94	8.85	8.98	9.44	9.98	10.31
WA_Res	9.55	9.96	9.02	8.81	8.79	9.52	9.51	9.40	9.52	10.05	10.60	10.88
WA_Tport	6.66	7.99	7.56	7.42	7.35	7.81	8.23	8.14	8.29	8.68	9.22	9.59

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	8.56	9.33	9.72	10.20	10.62	11.01	11.69	12.02	12.61	12.88	13.16
ID_Ind	8.29	9.01	9.48	9.95	10.35	10.71	11.44	11.79	12.36	12.65	12.96
ID_Res	8.65	9.44	9.80	10.28	10.71	11.14	11.79	12.12	12.73	12.97	13.27
Klamath Falls_Com	24.83	24.43	24.42	24.61	23.40	21.93	20.56	19.19	17.58	16.10	14.43
Klamath Falls_Ind	24.41	23.42	23.26	23.55	22.35	20.91	19.71	18.55	17.07	15.67	14.04
Klamath Falls_Res	24.98	24.80	24.84	25.00	23.78	22.29	20.86	19.41	17.76	16.25	14.57
LaGrande_Com	24.86	24.60	24.64	24.79	23.58	22.08	20.68	19.27	17.61	16.15	14.45
LaGrande_Ind	23.64	21.74	21.36	21.73	20.58	19.21	18.31	17.53	16.17	14.94	13.36
LaGrande_Res	24.93	24.77	24.83	24.97	23.75	22.25	20.81	19.37	17.70	16.22	14.52
Medford_Com	24.74	24.29	24.27	24.45	23.23	21.75	20.40	19.05	17.45	16.00	14.33
Medford_Ind	24.29	23.33	23.19	23.42	22.21	20.76	19.57	18.41	16.91	15.58	13.93
Medford_Res	24.91	24.66	24.68	24.84	23.61	22.12	20.71	19.29	17.65	16.16	14.48
OR_Tport	6.14	6.57	6.96	7.24	23.57	21.98	20.45	18.90	17.39	15.56	14.07
Roseburg_Com	24.76	24.34	24.34	24.50	23.30	21.82	20.45	19.10	17.49	16.04	14.36
Roseburg_Ind	24.30	23.40	23.31	23.51	22.31	20.86	19.66	18.48	16.95	15.62	13.96
Roseburg_Res	24.90	24.64	24.65	24.82	23.60	22.10	20.69	19.28	17.66	16.16	14.48
WA_Com	10.31	11.00	11.28	11.77	11.87	12.18	12.83	13.20	13.91	14.44	14.47
WA_Ind	9.72	10.29	10.73	11.21	11.25	11.48	12.26	12.65	13.27	13.89	13.98
WA_Res	10.33	11.03	11.30	11.79	11.88	12.21	12.85	13.22	13.93	14.46	14.50
WA_Tport	8.97	9.41	9.96	10.43	10.47	10.69	11.50	11.96	12.63	13.29	13.47

APPENDIX 6.4: PRS – LOW PRICES CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.52	5.19	3.95	3.41	3.15	3.30	3.10	3.73	3.81	4.05	4.32	4.43
ID_Ind	5.88	4.62	3.55	3.05	2.82	2.89	2.80	3.47	3.56	3.75	4.02	4.15
ID_Res	6.69	5.34	4.06	3.51	3.24	3.42	3.20	3.82	3.89	4.14	4.41	4.52
Klamath Falls_Com	7.43	9.73	9.47	9.24	9.91	10.54	11.35	11.89	12.57	12.76	13.63	14.59
Klamath Falls_Ind	7.39	9.58	9.32	9.14	9.83	10.45	11.25	11.81	12.49	12.60	13.35	14.29
Klamath Falls_Res	7.47	9.77	9.51	9.26	9.93	10.56	11.37	11.91	12.60	12.81	13.72	14.69
LaGrande_Com	7.83	10.65	10.17	9.89	10.52	11.29	11.58	11.89	12.56	12.74	13.63	14.60
LaGrande_Ind	7.18	9.63	9.36	9.20	9.90	10.55	11.15	11.70	12.34	12.32	12.87	13.76
LaGrande_Res	7.87	10.81	10.24	9.96	10.56	11.34	11.61	11.90	12.57	12.77	13.68	14.65
Medford_Com	7.36	9.70	9.45	9.22	9.89	10.52	11.32	11.87	12.55	12.72	13.57	14.52
Medford_Ind	7.37	9.51	9.28	9.09	9.79	10.40	11.19	11.77	12.44	12.52	13.26	14.20
Medford_Res	7.46	9.76	9.50	9.26	9.93	10.55	11.36	11.91	12.59	12.79	13.68	14.64
OR_Tport	10.81	9.61	9.02	8.80	9.48	10.26	11.02	11.61	12.33	12.49	13.26	14.24
Roseburg_Com	7.38	9.72	9.46	9.22	9.89	10.52	11.33	11.88	12.56	12.72	13.58	14.54
Roseburg_Ind	7.37	9.50	9.28	9.08	9.78	10.39	11.18	11.77	12.43	12.51	13.26	14.21
Roseburg_Res	7.46	9.77	9.51	9.26	9.93	10.55	11.37	11.91	12.59	12.79	13.68	14.64
WA_Com	7.87	7.89	6.75	6.38	6.31	6.79	6.76	6.51	6.34	6.60	6.90	7.03
WA_Ind	8.15	7.06	6.07	5.72	5.69	5.99	6.13	5.94	5.80	5.95	6.25	6.41
WA_Res	7.91	7.92	6.78	6.40	6.33	6.81	6.78	6.53	6.36	6.62	6.91	7.05
WA_Tport	5.10	5.99	5.31	4.99	4.97	5.09	5.41	5.28	5.17	5.22	5.55	5.70

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	4.73	5.11	5.24	5.54	5.69	6.04	6.32	6.52	6.75	6.82	7.11
ID_Ind	4.45	4.77	4.97	5.25	5.38	5.70	6.01	6.25	6.51	6.60	6.93
ID_Res	4.82	5.23	5.34	5.63	5.81	6.17	6.43	6.63	6.84	6.92	7.19
Klamath Falls_Com	24.61	24.33	24.69	24.86	23.41	21.90	20.48	19.14	17.60	15.97	14.54
Klamath Falls_Ind	24.12	23.22	23.50	23.76	22.37	20.89	19.65	18.53	17.12	15.52	14.26
Klamath Falls_Res	24.79	24.74	25.12	25.25	23.79	22.26	20.78	19.36	17.77	16.13	14.65
LaGrande_Com	24.66	24.53	24.90	25.06	23.59	22.05	20.60	19.22	17.65	16.01	14.56
LaGrande_Ind	23.21	21.36	21.55	21.98	20.62	19.19	18.24	17.51	16.28	14.74	13.77
LaGrande_Res	24.75	24.72	25.10	25.24	23.76	22.22	20.74	19.31	17.73	16.08	14.61
Medford_Com	24.52	24.19	24.54	24.71	23.25	21.72	20.33	19.01	17.49	15.86	14.48
Medford_Ind	24.01	23.14	23.42	23.68	22.25	20.73	19.49	18.39	16.99	15.39	14.18
Medford_Res	24.71	24.59	24.96	25.10	23.62	22.09	20.63	19.24	17.67	16.03	14.58
OR_Tport	24.37	24.63	25.06	25.19	23.59	21.99	20.43	18.93	17.35	15.69	14.24
Roseburg_Com	24.54	24.25	24.60	24.77	23.32	21.78	20.38	19.06	17.53	15.90	14.49
Roseburg_Ind	24.02	23.24	23.55	23.80	22.35	20.83	19.58	18.45	17.03	15.42	14.22
Roseburg_Res	24.70	24.56	24.92	25.07	23.60	22.07	20.63	19.24	17.68	16.04	14.58
WA_Com	6.50	6.82	6.85	7.18	7.00	7.24	7.55	7.77	8.02	14.12	14.35
WA_Ind	5.89	6.06	6.22	6.51	6.29	6.48	6.84	7.12	7.44	13.59	13.91
WA_Res	6.52	6.84	6.87	7.19	7.02	7.27	7.58	7.79	8.04	14.14	14.37
WA_Tport	5.17	5.22	5.49	5.73	5.49	5.68	6.07	6.42	6.82	13.05	13.44

Appendix 6.4: Social Cost of Carbon Case Avoided Cost ($/Dekatherm)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	11.85	10.77	9.83	9.55	9.59	9.99	10.06	10.33	10.62	11.00	11.44	11.73
ID_Ind	11.26	10.27	9.47	9.24	9.31	9.64	9.82	10.11	10.42	10.78	11.20	11.51
ID_Res	12.01	10.91	9.93	9.64	9.68	10.09	10.14	10.41	10.69	11.08	11.52	11.81
Klamath Falls_Com	10.72	9.88	9.29	9.09	9.24	12.37	12.94	13.43	14.15	17.57	18.65	19.23
Klamath Falls_Ind	10.67	9.73	9.14	9.00	9.16	12.30	12.86	13.35	13.83	16.83	18.01	18.59
Klamath Falls_Res	10.76	9.93	9.33	9.12	9.26	12.39	12.96	13.45	14.26	17.83	18.88	19.46
LaGrande_Com	10.90	10.22	9.63	9.40	9.52	12.36	12.93	13.42	14.15	17.66	18.73	19.31
LaGrande_Ind	10.38	9.62	9.05	8.94	9.09	12.18	12.74	13.23	13.23	15.52	16.89	17.50
LaGrande_Res	10.95	10.30	9.69	9.45	9.55	12.38	12.95	13.43	14.21	17.80	18.85	19.42
Medford_Com	10.65	9.85	9.26	9.07	9.22	12.35	12.92	13.41	14.08	17.47	18.56	19.13
Medford_Ind	10.64	9.66	9.10	8.95	9.11	12.24	12.81	13.30	13.74	16.75	17.93	18.51
Medford_Res	10.75	9.92	9.32	9.11	9.26	12.38	12.95	13.45	14.21	17.74	18.80	19.37
OR_Tport	10.74	9.30	8.74	8.52	8.57	8.77	9.11	9.40	9.73	10.04	18.44	18.98
Roseburg_Com	10.67	9.87	9.27	9.07	9.22	12.35	12.92	13.41	14.10	17.50	18.58	19.16
Roseburg_Ind	10.64	9.64	9.09	8.94	9.10	12.23	12.80	13.30	13.73	16.78	17.96	18.54
Roseburg_Res	10.76	9.92	9.33	9.11	9.26	12.39	12.95	13.45	14.21	17.73	18.78	19.36
WA_Com	13.27	13.45	12.60	12.49	12.73	13.41	13.65	13.71	13.91	14.42	15.06	15.53
WA_Ind	13.52	12.69	11.98	11.90	12.16	12.73	13.13	13.22	13.46	13.92	14.52	15.02
WA_Res	13.31	13.47	12.62	12.50	12.74	13.43	13.67	13.73	13.92	14.43	15.07	15.55
WA_Tport	10.45	11.64	11.19	11.13	11.38	11.79	12.38	12.48	12.75	13.16	13.76	14.24

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	12.10	12.57	12.89	13.31	13.73	14.24	14.68	15.00	15.31	15.78	14.77
ID_Ind	11.88	12.31	12.67	13.10	13.54	14.05	14.50	14.82	15.17	15.63	14.72
ID_Res	12.17	12.65	12.96	13.39	13.81	14.31	14.74	15.08	15.37	15.86	14.79
Klamath Falls_Com	23.86	24.11	23.68	23.66	23.32	21.85	20.32	18.74	17.23	15.58	14.17
Klamath Falls_Ind	23.25	23.44	22.53	22.50	22.19	20.78	19.33	17.78	16.36	14.77	13.50
Klamath Falls_Res	24.09	24.35	24.10	24.07	23.73	22.24	20.68	19.09	17.54	15.87	14.41
LaGrande_Com	23.94	24.20	23.88	23.86	23.53	22.05	20.50	18.91	17.34	15.68	14.26
LaGrande_Ind	22.17	22.28	20.63	20.63	20.36	19.04	17.74	16.21	14.93	13.42	12.40
LaGrande_Res	24.05	24.31	24.07	24.05	23.71	22.22	20.65	19.05	17.49	15.81	14.37
Medford_Com	23.76	24.00	23.52	23.50	23.16	21.69	20.16	18.57	17.06	15.42	14.05
Medford_Ind	23.15	23.33	22.43	22.40	22.08	20.66	19.20	17.63	16.20	14.59	13.40
Medford_Res	23.99	24.25	23.94	23.91	23.56	22.07	20.52	18.92	17.38	15.72	14.29
OR_Tport	23.56	11.48	11.89	12.30	12.76	13.29	13.77	19.31	17.64	15.87	14.68
Roseburg_Com	23.79	24.03	23.59	23.56	23.23	21.75	20.22	18.64	17.11	15.47	14.08
Roseburg_Ind	23.17	23.36	22.55	22.52	22.21	20.79	19.32	17.74	16.30	14.68	13.49
Roseburg_Res	23.98	24.24	23.91	23.88	23.53	22.04	20.50	18.91	17.37	15.71	14.27
WA_Com	15.22	15.75	16.19	16.81	17.04	17.61	18.26	18.81	18.24	16.54	14.81
WA_Ind	14.72	15.18	15.68	16.30	16.56	17.15	17.82	18.38	18.14	16.43	14.73
WA_Res	15.24	15.77	16.20	16.83	17.06	17.63	18.28	18.83	18.25	16.55	14.82
WA_Tport	13.93	14.33	14.90	15.49	15.78	16.40	17.10	17.74	18.10	16.40	14.69

Appendix 6.5: Average Case Winter Avoided Cost ($/Dekatherm)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	7.71	5.01	4.30	3.57	3.33	3.31	3.43	3.95	4.36	4.70	5.08	5.37
ID_Ind	7.71	5.01	4.30	3.56	3.33	3.31	3.43	3.94	4.36	4.70	5.08	5.36
ID_Res	7.71	5.01	4.30	3.57	3.33	3.31	3.43	3.95	4.36	4.71	5.08	5.37
Klamath Falls_Com	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
Klamath Falls_Ind	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
Klamath Falls_Res	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
LaGrande_Com	7.84	8.51	10.40	9.98	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
LaGrande_Ind	7.84	8.51	10.40	9.98	9.89	10.04	10.53	11.07	11.70	12.26	13.17	20.33
LaGrande_Res	7.84	8.51	10.40	9.98	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
Medford_Com	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
Medford_Ind	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.17	20.33
Medford_Res	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
OR_Tport	7.48	8.40	10.20	9.64	9.55	9.70	10.19	10.79	11.43	12.01	12.81	14.44
Roseburg_Com	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
Roseburg_Ind	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.17	20.33
Roseburg_Res	7.84	8.51	10.40	9.97	9.89	10.04	10.53	11.07	11.70	12.26	13.18	20.33
WA_Com	9.86	7.26	6.68	6.10	6.05	6.24	6.60	6.71	6.65	6.87	7.25	7.57
WA_Ind	9.86	7.25	6.68	6.09	6.04	6.23	6.59	6.70	6.64	6.86	7.24	7.56
WA_Res	9.86	7.26	6.68	6.10	6.05	6.24	6.60	6.71	6.65	6.87	7.25	7.57
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	5.63	5.87	6.31	6.57	6.85	7.30	7.76	8.03	8.34	8.71	8.87	9.10
ID_Ind	5.63	5.87	6.30	6.57	6.85	7.30	7.76	8.03	8.34	8.71	8.87	9.10
ID_Res	5.63	5.87	6.31	6.57	6.85	7.30	7.76	8.03	8.34	8.71	8.87	9.10
Klamath Falls_Com	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Klamath Falls_Ind	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Klamath Falls_Res	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
LaGrande_Com	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
LaGrande_Ind	25.40	25.78	25.98	26.04	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
LaGrande_Res	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Medford_Com	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Medford_Ind	25.40	25.78	25.98	26.04	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Medford_Res	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
OR_Tport	21.18	19.34	21.47	25.41	24.52	23.05	21.54	19.92	18.30	16.95	15.36	14.84
Roseburg_Com	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Roseburg_Ind	25.40	25.78	25.98	26.04	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
Roseburg_Res	25.40	25.78	25.98	26.05	25.14	23.63	22.08	20.46	18.81	17.19	15.54	14.84
WA_Com	7.35	7.17	7.53	7.79	7.85	8.08	8.52	8.84	9.21	13.67	15.41	14.84
WA_Ind	7.34	7.16	7.52	7.78	7.84	8.07	8.51	8.84	9.21	13.67	15.40	14.84
WA_Res	7.35	7.17	7.53	7.79	7.85	8.08	8.52	8.84	9.21	13.67	15.41	14.84
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	13.17	15.03	14.64

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: CARBON INTENSITY CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.57	6.53	5.35	4.53	4.21	4.39	4.15	4.66	5.01	5.40	5.79	5.98
ID_Ind	9.33	6.35	5.20	4.40	4.08	4.25	4.05	4.56	4.93	5.32	5.70	5.89
ID_Res	9.65	6.58	5.39	4.58	4.25	4.44	4.19	4.69	5.04	5.43	5.82	6.00
Klamath Falls_Com	10.35	7.87	7.64	7.31	7.33	7.51	8.00	8.57	9.20	9.71	10.14	10.39
Klamath Falls_Ind	10.35	7.86	7.64	7.31	7.33	7.50	8.00	8.57	9.20	9.70	10.13	10.38
Klamath Falls_Res	10.35	7.87	7.64	7.31	7.33	7.51	8.00	8.57	9.20	9.71	10.14	10.39
LaGrande_Com	12.20	9.39	8.70	8.31	8.28	8.67	8.76	9.25	9.78	10.39	10.85	11.04
LaGrande_Ind	11.38	8.76	8.22	7.86	7.85	8.19	8.42	8.95	9.53	10.14	10.57	10.77
LaGrande_Res	12.22	9.40	8.72	8.32	8.29	8.68	8.77	9.26	9.78	10.40	10.86	11.04
Medford_Com	10.35	7.86	7.64	7.31	7.33	7.51	8.00	8.57	9.20	9.70	10.14	10.39
Medford_Ind	10.35	7.86	7.64	7.30	7.33	7.50	7.99	8.57	9.20	9.69	10.12	10.38
Medford_Res	10.35	7.87	7.64	7.31	7.33	7.51	8.00	8.57	9.20	9.71	10.14	10.39
OR_Tport	13.81	7.36	4.12	3.35	3.05	7.46	10.66	10.95	11.25	11.67	12.17	12.53
Roseburg_Com	10.35	7.87	7.64	7.31	7.33	7.51	8.00	8.57	9.20	9.71	10.14	10.39
Roseburg_Ind	10.35	7.86	7.64	7.30	7.32	7.50	7.99	8.56	9.19	9.69	10.12	10.38
Roseburg_Res	10.35	7.87	7.64	7.31	7.33	7.51	8.00	8.57	9.21	9.71	10.14	10.39
WA_Com	11.97	9.07	8.03	7.38	7.25	7.67	7.69	7.75	7.58	7.83	8.23	8.45
WA_Ind	11.75	8.86	7.86	7.21	7.09	7.49	7.54	7.61	7.46	7.71	8.09	8.32
WA_Res	12.00	9.08	8.04	7.39	7.26	7.68	7.69	7.76	7.59	7.83	8.24	8.45
WA_Tport	9.83	7.29	6.73	6.12	6.02	6.18	6.51	6.54	6.46	6.64	7.04	7.33

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.23	6.64	7.09	7.30	7.55	7.90	8.33	8.56	8.80	9.15	9.26	9.43
ID_Ind	6.15	6.55	6.98	7.21	7.46	7.84	8.27	8.51	8.77	9.14	9.26	9.43
ID_Res	6.26	6.67	7.12	7.34	7.58	7.92	8.35	8.58	8.82	9.16	9.26	9.43
Klamath Falls_Com	10.69	11.05	11.54	11.98	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
Klamath Falls_Ind	10.69	11.04	11.53	11.97	12.85	14.93	16.31	16.84	16.87	16.60	15.35	14.84
Klamath Falls_Res	10.70	11.05	11.54	11.98	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
LaGrande_Com	11.30	11.70	12.16	12.53	13.30	15.20	16.52	16.97	16.89	16.59	15.35	14.84
LaGrande_Ind	11.05	11.42	11.87	12.26	13.09	15.09	16.41	16.91	16.87	16.59	15.35	14.84
LaGrande_Res	11.31	11.71	12.17	12.54	13.31	15.21	16.52	16.97	16.89	16.59	15.35	14.84
Medford_Com	10.69	11.05	11.53	11.97	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
Medford_Ind	10.69	11.04	11.53	11.97	12.85	14.93	16.30	16.84	16.86	16.59	15.35	14.84
Medford_Res	10.70	11.05	11.54	11.98	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
OR_Tport	12.82	13.22	13.69	14.08	14.48	15.04	15.64	16.17	16.68	16.67	15.32	14.82
Roseburg_Com	10.69	11.05	11.53	11.97	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
Roseburg_Ind	10.68	11.03	11.52	11.97	12.84	14.93	16.30	16.84	16.86	16.59	15.35	14.84
Roseburg_Res	10.70	11.05	11.54	11.98	12.85	14.94	16.31	16.84	16.87	16.60	15.35	14.84
WA_Com	8.18	8.12	8.68	8.88	8.87	8.81	9.33	9.58	9.87	12.91	14.77	14.84
WA_Ind	8.05	7.99	8.34	8.56	8.58	8.71	9.11	9.42	9.74	12.88	14.76	14.84
WA_Res	8.18	8.13	8.69	8.89	8.88	8.81	9.33	9.58	9.87	12.91	14.77	14.84
WA_Tport	6.99	6.82	7.11	7.39	7.45	7.66	8.10	8.49	8.94	12.23	14.31	14.64

*2045-2046 avoided cost values include only November and December months.

Appendix 6. 5: Electrification – Expected Conversion Cost Case Winter Avoided Cost ($/Dekatherm)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.54	6.50	5.32	4.49	4.15	3.96	3.67	4.10	4.45	4.70	5.17	5.40
ID_Ind	9.30	6.32	5.19	4.35	4.03	3.86	3.61	4.04	4.40	4.66	5.11	5.34
ID_Res	9.61	6.55	5.37	4.53	4.19	3.99	3.69	4.12	4.47	4.71	5.19	5.42
Klamath Falls_Com	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Klamath Falls_Ind	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Klamath Falls_Res	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
LaGrande_Com	10.62	10.29	11.34	10.88	10.73	10.41	10.48	10.44	10.16	10.97	11.76	12.56
LaGrande_Ind	9.81	9.70	10.89	10.46	10.34	10.22	10.30	10.28	10.16	10.97	11.75	12.55
LaGrande_Res	10.64	10.31	11.35	10.89	10.74	10.42	10.49	10.45	10.16	10.97	11.76	12.56
Medford_Com	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Medford_Ind	8.80	8.86	10.34	9.95	9.88	10.02	10.11	10.12	10.16	10.97	11.75	12.56
Medford_Res	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
OR_Tport	13.25	10.71	10.20	9.64	9.55	9.75	10.13	10.40	10.68	11.07	11.56	12.34
Roseburg_Com	8.80	8.87	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Roseburg_Ind	8.80	8.86	10.34	9.95	9.88	10.02	10.11	10.12	10.16	10.97	11.75	12.55
Roseburg_Res	8.80	8.87	10.35	9.96	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
WA_Com	11.73	8.77	7.73	7.04	6.89	6.90	6.85	6.86	6.75	6.87	7.34	7.60
WA_Ind	11.51	8.62	7.61	6.92	6.77	6.81	6.79	6.81	6.70	6.83	7.29	7.55
WA_Res	11.76	8.80	7.75	7.06	6.90	6.91	6.86	6.87	6.75	6.87	7.35	7.61
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	5.56	5.79	6.13	6.37	6.63	7.04	7.46	7.76	8.10	8.55	8.82	9.10
ID_Ind	5.51	5.74	6.08	6.33	6.59	7.00	7.43	7.73	8.08	8.53	8.80	9.10
ID_Res	5.58	5.80	6.14	6.39	6.64	7.05	7.47	7.77	8.11	8.55	8.82	9.10
Klamath Falls_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.24
Klamath Falls_Ind	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.33	11.12
Klamath Falls_Res	19.60	24.12	23.90	23.30	22.94	22.84	21.97	20.41	18.78	17.12	15.33	11.28
LaGrande_Com	19.59	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.89
LaGrande_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.77
LaGrande_Res	19.59	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.89
Medford_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.33	11.16
Medford_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.88
Medford_Res	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.21
OR_Tport	19.27	23.75	23.55	22.91	22.44	22.35	21.51	20.00	18.42	17.03	15.52	14.84
Roseburg_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.16
Roseburg_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.82
Roseburg_Res	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.21
WA_Com	7.28	7.08	7.35	7.59	7.63	7.82	8.22	8.57	8.97	9.48	9.81	10.12
WA_Ind	7.23	7.04	7.31	7.55	7.59	7.78	8.19	8.54	8.95	9.46	9.80	10.12
WA_Res	7.29	7.09	7.36	7.59	7.64	7.82	8.23	8.58	8.98	9.48	9.82	10.12
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	9.13	9.49	9.88

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: ELECTRIFICATION – HIGH CONVERSION COST CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.54	6.50	5.32	4.49	4.15	3.96	3.67	4.10	4.45	4.70	5.17	5.40
ID_Ind	9.30	6.32	5.19	4.35	4.03	3.86	3.61	4.04	4.40	4.66	5.11	5.34
ID_Res	9.61	6.55	5.37	4.53	4.19	3.99	3.69	4.12	4.47	4.71	5.19	5.42
Klamath Falls_Com	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Klamath Falls_Ind	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Klamath Falls_Res	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
LaGrande_Com	12.78	11.16	11.34	10.88	10.73	10.41	10.48	10.44	10.16	10.97	11.76	12.56
LaGrande_Ind	11.97	10.57	10.89	10.46	10.34	10.22	10.30	10.28	10.16	10.97	11.75	12.55
LaGrande_Res	12.80	11.17	11.35	10.89	10.74	10.42	10.49	10.45	10.16	10.97	11.76	12.56
Medford_Com	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Medford_Ind	10.96	9.73	10.34	9.95	9.88	10.02	10.11	10.12	10.16	10.97	11.75	12.56
Medford_Res	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
OR_Tport	13.25	10.71	10.20	9.64	9.55	9.75	10.13	10.40	10.68	11.07	11.56	12.34
Roseburg_Com	10.96	9.73	10.35	9.95	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
Roseburg_Ind	10.96	9.73	10.34	9.95	9.88	10.02	10.11	10.12	10.16	10.97	11.75	12.55
Roseburg_Res	10.96	9.73	10.35	9.96	9.88	10.02	10.12	10.12	10.16	10.98	11.76	12.56
WA_Com	11.73	8.77	7.73	7.04	6.89	6.90	6.85	6.86	6.75	6.87	7.34	7.60
WA_Ind	11.51	8.62	7.61	6.92	6.77	6.81	6.79	6.81	6.70	6.83	7.29	7.55
WA_Res	11.76	8.80	7.75	7.06	6.90	6.91	6.86	6.87	6.75	6.87	7.35	7.61
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	5.56	5.79	6.13	6.37	6.63	7.04	7.46	7.76	8.10	8.55	8.82	9.10
ID_Ind	5.51	5.74	6.08	6.33	6.59	7.00	7.43	7.73	8.08	8.53	8.80	9.10
ID_Res	5.58	5.80	6.14	6.39	6.64	7.05	7.47	7.77	8.11	8.55	8.82	9.10
Klamath Falls_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.24
Klamath Falls_Ind	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.33	11.12
Klamath Falls_Res	19.60	24.12	23.90	23.30	22.94	22.84	21.97	20.41	18.78	17.12	15.33	11.28
LaGrande_Com	19.59	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.89
LaGrande_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.77
LaGrande_Res	19.59	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.89
Medford_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.33	11.16
Medford_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.88
Medford_Res	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.21
OR_Tport	19.27	23.75	23.55	22.91	22.44	22.35	21.51	20.00	18.42	17.03	15.52	14.84
Roseburg_Com	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.16
Roseburg_Ind	19.59	24.12	23.89	23.30	22.94	22.83	21.97	20.41	18.78	17.11	15.32	10.82
Roseburg_Res	19.60	24.12	23.90	23.30	22.94	22.83	21.97	20.41	18.78	17.12	15.33	11.21
WA_Com	7.28	7.08	7.35	7.59	7.63	7.82	8.22	8.57	8.97	9.48	9.81	10.12
WA_Ind	7.23	7.04	7.31	7.55	7.59	7.78	8.19	8.54	8.95	9.46	9.80	10.12
WA_Res	7.29	7.09	7.36	7.59	7.64	7.82	8.23	8.58	8.98	9.48	9.82	10.12
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	9.13	9.49	9.88

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: ELECTRIFICATION – LOW CONVERSION COST CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.55	6.51	5.33	4.49	4.15	3.96	3.67	4.09	4.45	4.70	5.18	5.41
ID_Ind	9.30	6.33	5.19	4.36	4.02	3.86	3.60	4.03	4.40	4.66	5.11	5.35
ID_Res	9.62	6.56	5.37	4.54	4.19	4.00	3.69	4.11	4.47	4.71	5.20	5.43
Klamath Falls_Com	7.84	5.22	5.09	5.26	5.52	5.99	6.75	7.81	8.95	10.66	11.76	12.10
Klamath Falls_Ind	7.84	5.22	5.09	5.26	5.52	5.99	6.74	7.80	8.95	10.65	11.76	12.10
Klamath Falls_Res	7.84	5.22	5.09	5.26	5.52	5.99	6.75	7.81	8.95	10.66	11.76	12.10
LaGrande_Com	9.68	6.73	6.14	6.25	6.45	6.79	7.17	8.17	9.25	10.86	12.06	12.38
LaGrande_Ind	8.86	6.11	5.66	5.80	6.03	6.43	6.95	7.98	9.09	10.76	11.90	12.23
LaGrande_Res	9.70	6.74	6.15	6.26	6.46	6.79	7.17	8.17	9.25	10.86	12.07	12.39
Medford_Com	7.84	5.22	5.09	5.26	5.52	5.99	6.74	7.80	8.95	10.66	11.76	12.10
Medford_Ind	7.84	5.22	5.09	5.25	5.52	5.98	6.74	7.80	8.94	10.65	11.75	12.10
Medford_Res	7.84	5.22	5.09	5.26	5.52	5.99	6.74	7.80	8.95	10.66	11.76	12.10
OR_Tport	7.48	4.83	7.82	9.64	5.60	7.07	9.99	10.26	10.54	10.93	11.41	11.74
Roseburg_Com	7.84	5.22	5.09	5.26	5.52	5.99	6.74	7.80	8.95	10.66	11.76	12.10
Roseburg_Ind	7.84	5.22	5.09	5.25	5.52	5.98	6.74	7.80	8.94	10.65	11.75	12.10
Roseburg_Res	7.84	5.22	5.09	5.26	5.52	5.99	6.75	7.81	8.95	10.66	11.76	12.10
WA_Com	11.74	8.78	7.74	7.05	6.88	6.90	6.84	6.86	6.75	6.87	7.35	7.62
WA_Ind	11.52	8.62	7.61	6.93	6.77	6.81	6.78	6.81	6.70	6.83	7.29	7.56
WA_Res	11.77	8.81	7.76	7.07	6.90	6.92	6.85	6.87	6.75	6.88	7.36	7.62
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	5.57	5.78	6.13	6.37	6.63	7.04	7.46	7.76	8.11	8.55	8.83	9.10
ID_Ind	5.51	5.74	6.08	6.33	6.59	7.00	7.43	7.73	8.08	8.54	8.81	9.10
ID_Res	5.59	5.80	6.14	6.39	6.65	7.05	7.48	7.77	8.11	8.56	8.84	9.10
Klamath Falls_Com	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.16	15.40	14.24
Klamath Falls_Ind	12.37	12.73	17.95	21.34	21.37	20.11	19.05	18.63	18.26	17.16	15.40	14.21
Klamath Falls_Res	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.16	15.40	14.25
LaGrande_Com	12.63	12.74	17.95	21.35	21.37	20.10	19.05	18.63	18.26	17.16	15.40	14.19
LaGrande_Ind	12.49	12.73	17.95	21.34	21.36	20.10	19.05	18.62	18.26	17.16	15.40	14.13
LaGrande_Res	12.63	12.74	17.95	21.35	21.37	20.10	19.05	18.63	18.26	17.16	15.40	14.19
Medford_Com	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.05	15.25	10.26
Medford_Ind	12.36	12.73	17.95	21.34	21.36	20.10	19.05	18.62	18.26	17.04	15.23	9.94
Medford_Res	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.05	15.25	10.32
OR_Tport	12.06	12.55	17.69	21.05	21.09	19.77	18.62	18.19	17.85	16.98	15.35	14.84
Roseburg_Com	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.05	15.25	10.26
Roseburg_Ind	12.36	12.73	17.95	21.34	21.36	20.10	19.05	18.62	18.26	17.03	15.23	9.87
Roseburg_Res	12.37	12.74	17.95	21.35	21.37	20.11	19.05	18.63	18.26	17.05	15.25	10.32
WA_Com	7.29	7.08	7.35	7.59	7.63	7.82	8.23	8.57	8.98	9.49	9.83	10.12
WA_Ind	7.24	7.04	7.31	7.55	7.60	7.78	8.20	8.55	8.95	9.47	9.81	10.12
WA_Res	7.30	7.09	7.36	7.60	7.64	7.82	8.23	8.58	8.98	9.49	9.83	10.12
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	9.13	9.49	9.88

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: HIGH CUSTOMER GROWTH CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.58	6.54	5.36	4.55	4.24	4.43	4.19	4.61	5.00	5.40	6.14	6.29
ID_Ind	9.33	6.36	5.22	4.41	4.11	4.29	4.08	4.51	4.92	5.31	5.99	6.15
ID_Res	9.65	6.60	5.41	4.59	4.28	4.48	4.22	4.64	5.03	5.43	6.19	6.34
Klamath Falls_Com	10.01	9.35	10.35	9.96	9.91	10.06	10.67	11.36	11.95	12.39	13.29	14.32
Klamath Falls_Ind	10.01	9.35	10.35	9.96	9.90	10.06	10.67	11.35	11.95	12.39	13.28	14.31
Klamath Falls_Res	10.01	9.35	10.35	9.96	9.91	10.06	10.68	11.36	11.95	12.39	13.29	14.32
LaGrande_Com	11.88	10.78	11.33	10.88	10.76	10.78	11.03	11.35	11.94	12.38	13.28	14.31
LaGrande_Ind	11.04	10.19	10.89	10.46	10.36	10.46	10.85	11.35	11.94	12.38	13.28	14.30
LaGrande_Res	11.90	10.80	11.35	10.89	10.77	10.79	11.04	11.35	11.94	12.38	13.28	14.31
Medford_Com	10.01	9.35	10.35	9.96	9.91	10.06	10.67	11.35	11.95	12.39	13.29	14.31
Medford_Ind	10.01	9.35	10.34	9.95	9.90	10.06	10.67	11.35	11.94	12.38	13.28	14.31
Medford_Res	10.01	9.35	10.35	9.96	9.91	10.06	10.67	11.36	11.95	12.39	13.29	14.32
OR_Tport	7.48	8.40	10.20	9.64	9.57	9.72	10.31	11.05	11.63	12.11	12.90	13.82
Roseburg_Com	10.01	9.35	10.35	9.96	9.91	10.06	10.67	11.36	11.95	12.39	13.29	14.31
Roseburg_Ind	10.01	9.35	10.34	9.95	9.90	10.06	10.67	11.35	11.94	12.38	13.28	14.31
Roseburg_Res	10.01	9.35	10.35	9.96	9.91	10.06	10.68	11.36	11.95	12.39	13.29	14.32
WA_Com	11.77	8.87	7.82	7.15	7.03	7.43	7.41	7.43	7.36	7.62	8.74	8.89
WA_Ind	11.55	8.66	7.65	6.98	6.86	7.25	7.27	7.29	7.23	7.50	8.19	8.38
WA_Res	11.80	8.88	7.83	7.16	7.03	7.44	7.42	7.44	7.36	7.63	8.75	8.90
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.52	6.64	7.09	7.25	7.48	7.78	8.22	8.40	8.65	8.90	9.05	9.20
ID_Ind	6.39	6.54	6.98	7.15	7.38	7.72	8.15	8.34	8.60	8.89	9.05	9.20
ID_Res	6.57	6.67	7.13	7.29	7.51	7.80	8.24	8.42	8.66	8.90	9.05	9.20
Klamath Falls_Com	21.08	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Klamath Falls_Ind	21.07	25.39	25.88	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Klamath Falls_Res	21.08	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Com	21.07	25.38	25.88	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Ind	21.06	25.38	25.88	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Res	21.07	25.38	25.88	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Com	21.07	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Ind	21.07	25.38	25.88	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Res	21.08	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
OR_Tport	20.44	24.75	25.22	25.41	12.64	15.13	21.54	19.93	18.31	16.95	15.35	14.84
Roseburg_Com	21.07	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Roseburg_Ind	21.06	25.38	25.88	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Roseburg_Res	21.08	25.39	25.89	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
WA_Com	8.61	7.99	8.59	8.73	8.71	8.60	9.16	9.36	9.65	12.64	14.66	14.80
WA_Ind	8.14	7.86	8.22	8.39	8.40	8.51	8.92	9.17	9.49	12.61	14.64	14.79
WA_Res	8.62	7.99	8.60	8.74	8.72	8.61	9.16	9.37	9.65	12.64	14.66	14.80
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	11.91	14.08	14.45

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: HYBRID CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.58	6.53	5.35	4.53	4.21	4.39	4.11	4.52	4.85	5.27	5.64	5.83
ID_Ind	9.33	6.35	5.21	4.39	4.08	4.24	4.00	4.43	4.77	5.18	5.54	5.74
ID_Res	9.65	6.59	5.40	4.57	4.25	4.43	4.14	4.55	4.88	5.30	5.67	5.86
Klamath Falls_Com	10.02	9.36	10.35	9.96	9.88	10.04	10.36	10.65	10.92	11.94	12.66	13.44
Klamath Falls_Ind	10.02	9.36	10.35	9.95	9.88	10.04	10.36	10.64	10.91	11.93	12.65	13.43
Klamath Falls_Res	10.02	9.36	10.35	9.96	9.88	10.04	10.36	10.65	10.92	11.95	12.66	13.44
LaGrande_Com	11.89	10.79	11.40	10.94	10.79	11.13	10.75	10.98	11.19	11.93	12.65	13.43
LaGrande_Ind	11.06	10.20	10.89	10.46	10.34	10.64	10.54	10.79	11.04	11.92	12.64	13.42
LaGrande_Res	11.91	10.80	11.40	10.95	10.80	11.14	10.75	10.98	11.20	11.93	12.65	13.43
Medford_Com	10.02	9.36	10.35	9.96	9.88	10.04	10.36	10.65	10.92	11.95	12.65	13.44
Medford_Ind	10.02	9.35	10.34	9.95	9.88	10.04	10.35	10.64	10.91	11.93	12.64	13.42
Medford_Res	10.02	9.36	10.35	9.96	9.88	10.04	10.36	10.65	10.92	11.95	12.65	13.44
OR_Tport	13.25	10.71	10.20	9.64	9.55	9.75	10.13	10.40	10.68	11.63	12.41	13.15
Roseburg_Com	10.02	9.36	10.35	9.97	9.90	10.06	10.38	10.67	10.94	11.98	12.67	13.46
Roseburg_Ind	10.02	9.35	10.34	9.95	9.88	10.04	10.35	10.64	10.91	11.92	12.64	13.42
Roseburg_Res	10.02	9.36	10.35	9.97	9.90	10.06	10.38	10.67	10.94	11.98	12.67	13.46
WA_Com	11.77	8.86	7.81	7.13	7.00	7.39	7.34	7.35	7.20	7.50	7.88	8.10
WA_Ind	11.55	8.65	7.64	6.96	6.83	7.21	7.19	7.21	7.07	7.37	7.73	7.96
WA_Res	11.80	8.84	7.82	7.14	7.01	7.40	7.35	7.36	7.21	7.50	7.88	8.10
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.03	6.46	6.62	6.84	7.09	7.64	8.05	8.29	8.58	8.90	9.19	9.27
ID_Ind	5.94	6.36	6.54	6.76	7.02	7.56	7.97	8.22	8.52	8.86	9.16	9.27
ID_Res	6.06	6.50	6.64	6.86	7.11	7.66	8.08	8.32	8.60	8.91	9.20	9.27
Klamath Falls_Com	19.85	23.93	23.92	23.75	23.61	23.27	22.05	20.44	18.80	17.15	15.41	14.84
Klamath Falls_Ind	19.83	23.91	23.91	23.74	23.59	23.25	22.04	20.43	18.79	17.15	15.40	14.84
Klamath Falls_Res	19.85	23.93	23.92	23.75	23.61	23.27	22.05	20.44	18.80	17.15	15.41	14.84
LaGrande_Com	19.84	23.92	23.91	23.74	23.60	23.26	22.05	20.44	18.80	17.16	15.41	14.84
LaGrande_Ind	19.82	23.90	23.90	23.73	23.59	23.24	22.04	20.43	18.79	17.15	15.40	14.84
LaGrande_Res	19.84	23.92	23.91	23.74	23.60	23.26	22.05	20.44	18.80	17.16	15.41	14.84
Medford_Com	19.86	23.92	23.92	23.74	23.60	23.27	22.04	20.43	18.79	17.15	15.40	14.74
Medford_Ind	19.83	23.90	23.90	23.73	23.59	23.24	22.04	20.43	18.79	17.15	15.40	14.61
Medford_Res	19.86	23.92	23.92	23.75	23.60	23.27	22.04	20.43	18.79	17.15	15.40	14.74
OR_Tport	19.45	23.51	23.45	23.16	23.02	22.65	21.53	19.92	18.30	16.95	15.36	14.84
Roseburg_Com	19.87	23.93	23.93	23.76	23.61	23.27	22.04	20.43	18.79	17.15	15.40	14.74
Roseburg_Ind	19.82	23.90	23.90	23.73	23.59	23.24	22.04	20.43	18.79	17.15	15.40	14.61
Roseburg_Res	19.87	23.93	23.93	23.76	23.61	23.27	22.04	20.43	18.79	17.15	15.40	14.74
WA_Com	7.81	7.83	7.90	8.12	8.15	8.48	9.03	9.30	9.63	9.86	10.30	10.29
WA_Ind	7.68	7.68	7.77	7.99	8.03	8.36	8.75	9.05	9.40	9.80	10.16	10.29
WA_Res	7.82	7.83	7.90	8.12	8.15	8.49	9.04	9.30	9.64	9.87	10.30	10.29
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	9.13	9.49	9.88

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: INTERRUPTED SUPPLY CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.57	6.55	5.35	4.57	4.25	4.46	4.19	4.62	5.03	5.37	6.14	6.31
ID_Ind	9.33	6.37	5.21	4.43	4.12	4.32	4.08	4.52	4.95	5.29	5.99	6.17
ID_Res	9.65	6.61	5.40	4.61	4.29	4.51	4.22	4.65	5.06	5.40	6.19	6.36
Klamath Falls_Com	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.08	18.75	19.34	20.21	21.09
Klamath Falls_Ind	7.84	8.51	10.34	9.95	9.90	10.07	14.69	18.08	18.75	19.33	20.20	21.09
Klamath Falls_Res	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.09	18.75	19.34	20.21	21.10
LaGrande_Com	9.71	9.93	11.33	10.88	10.75	11.10	14.95	18.08	18.74	19.33	20.20	21.09
LaGrande_Ind	8.87	9.34	10.89	10.46	10.36	10.67	14.81	18.08	18.74	19.33	20.20	21.09
LaGrande_Res	9.73	9.95	11.34	10.89	10.76	11.12	14.96	18.08	18.74	19.33	20.20	21.09
Medford_Com	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.08	18.75	19.34	20.20	21.09
Medford_Ind	7.84	8.50	10.34	9.95	9.90	10.06	14.68	18.08	18.74	19.33	20.20	21.09
Medford_Res	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.08	18.75	19.34	20.21	21.09
OR_Tport	13.25	10.71	10.20	9.64	9.55	9.75	14.33	17.67	18.31	18.93	19.71	20.49
Roseburg_Com	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.08	18.75	19.34	20.21	21.09
Roseburg_Ind	7.84	8.50	10.34	9.95	9.90	10.06	14.68	18.08	18.74	19.33	20.20	21.09
Roseburg_Res	7.84	8.51	10.34	9.96	9.90	10.07	14.69	18.09	18.75	19.34	20.21	21.10
WA_Com	11.76	8.88	7.81	7.17	7.04	7.47	7.42	7.45	7.39	7.59	8.74	8.92
WA_Ind	11.54	8.67	7.64	7.00	6.87	7.28	7.27	7.31	7.25	7.47	8.19	8.40
WA_Res	11.80	8.90	7.82	7.18	7.05	7.48	7.43	7.45	7.39	7.60	8.75	8.93
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.50	6.63	7.04	7.18	7.42	7.72	8.16	8.35	8.64	8.87	9.12	9.32
ID_Ind	6.37	6.53	6.92	7.08	7.32	7.66	8.08	8.29	8.59	8.86	9.11	9.32
ID_Res	6.55	6.66	7.08	7.22	7.45	7.75	8.18	8.37	8.66	8.88	9.12	9.32
Klamath Falls_Com	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Klamath Falls_Ind	23.66	25.39	25.92	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Klamath Falls_Res	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Com	23.66	25.38	25.92	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Ind	23.65	25.38	25.92	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
LaGrande_Res	23.66	25.39	25.92	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Com	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Ind	23.65	25.39	25.92	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Medford_Res	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
OR_Tport	22.99	24.71	25.23	25.41	24.52	23.05	21.54	19.93	18.31	16.95	15.35	14.84
Roseburg_Com	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Roseburg_Ind	23.65	25.38	25.92	26.06	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
Roseburg_Res	23.66	25.39	25.93	26.07	25.14	23.63	22.08	20.47	18.82	17.23	15.54	14.84
WA_Com	8.60	7.99	8.54	8.66	8.66	8.55	9.10	9.31	9.65	12.37	14.37	14.55
WA_Ind	8.12	7.85	8.17	8.32	8.34	8.45	8.86	9.11	9.48	12.34	14.34	14.55
WA_Res	8.61	7.99	8.55	8.67	8.66	8.56	9.11	9.32	9.65	12.38	14.37	14.55
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	11.68	13.71	14.09

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: LIMITED RNG AVAILABILITY CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.58	6.53	5.35	4.54	4.21	4.41	4.19	4.67	4.97	5.35	5.70	5.91
ID_Ind	9.33	6.35	5.21	4.41	4.09	4.27	4.08	4.57	4.89	5.27	5.61	5.82
ID_Res	9.66	6.59	5.40	4.59	4.25	4.46	4.22	4.70	5.00	5.38	5.73	5.93
Klamath Falls_Com	7.84	7.61	9.29	9.60	9.85	10.33	23.41	32.09	30.50	27.37	30.22	32.33
Klamath Falls_Ind	7.84	7.61	9.29	9.59	9.85	10.33	23.41	32.09	30.50	27.37	30.22	32.33
Klamath Falls_Res	7.84	7.61	9.29	9.60	9.85	10.33	23.41	32.09	30.51	27.37	30.22	32.33
LaGrande_Com	9.71	9.10	10.30	10.53	10.73	11.37	23.53	32.13	30.52	27.37	30.22	32.33
LaGrande_Ind	8.88	8.49	9.84	10.10	10.33	10.94	23.48	32.12	30.51	27.37	30.22	32.33
LaGrande_Res	9.74	9.11	10.31	10.54	10.74	11.38	23.53	32.13	30.52	27.37	30.22	32.33
Medford_Com	7.84	7.61	9.29	9.60	9.85	10.33	23.41	32.09	30.50	27.37	30.22	32.33
Medford_Ind	7.84	7.61	9.28	9.59	9.84	10.32	23.41	32.09	30.50	27.37	30.22	32.33
Medford_Res	7.84	7.61	9.29	9.60	9.85	10.33	23.41	32.09	30.50	27.37	30.22	32.33
OR_Tport	7.48	8.40	10.20	9.64	9.55	9.95	22.85	31.48	29.96	26.91	30.04	32.21
Roseburg_Com	7.84	7.62	9.29	9.60	9.85	10.33	23.41	32.09	30.50	27.37	30.22	32.33
Roseburg_Ind	7.84	7.61	9.28	9.59	9.84	10.32	23.40	32.09	30.50	27.37	30.22	32.33
Roseburg_Res	7.84	7.62	9.29	9.60	9.85	10.33	23.41	32.09	30.51	27.37	30.22	32.33
WA_Com	11.77	8.86	7.81	7.14	7.00	7.41	7.42	7.50	7.33	7.57	7.93	8.16
WA_Ind	11.55	8.65	7.64	6.98	6.84	7.23	7.27	7.36	7.20	7.45	7.80	8.04
WA_Res	11.81	8.88	7.82	7.15	7.01	7.42	7.42	7.50	7.33	7.58	7.94	8.17
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.14	6.53	6.67	7.08	7.32	7.63	8.09	8.29	8.56	8.85	9.09	9.32
ID_Ind	6.06	6.43	6.59	6.98	7.23	7.56	8.02	8.24	8.52	8.83	9.08	9.32
ID_Res	6.17	6.56	6.69	7.11	7.35	7.65	8.12	8.32	8.57	8.86	9.09	9.32
Klamath Falls_Com	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Klamath Falls_Ind	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Klamath Falls_Res	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
LaGrande_Com	30.96	29.54	28.15	26.69	25.21	23.68	22.18	20.58	18.94	17.26	15.54	14.84
LaGrande_Ind	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
LaGrande_Res	30.96	29.54	28.15	26.69	25.21	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Medford_Com	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Medford_Ind	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Medford_Res	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
OR_Tport	30.82	29.40	28.02	26.55	25.04	23.52	22.06	20.45	18.94	17.26	15.54	14.84
Roseburg_Com	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Roseburg_Ind	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
Roseburg_Res	30.96	29.54	28.15	26.68	25.20	23.68	22.18	20.58	18.94	17.26	15.54	14.84
WA_Com	7.92	7.88	7.94	8.55	8.55	8.46	9.03	9.26	9.56	12.36	14.34	14.55
WA_Ind	7.79	7.75	7.83	8.21	8.25	8.36	8.80	9.07	9.40	12.32	14.30	14.55
WA_Res	7.92	7.89	7.94	8.56	8.56	8.46	9.04	9.27	9.56	12.36	14.34	14.55
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	11.67	13.71	14.09

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: PRS CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.58	6.53	5.35	4.54	4.21	4.40	4.14	4.62	4.94	5.32	5.70	5.88
ID_Ind	9.33	6.35	5.21	4.41	4.09	4.25	4.03	4.53	4.85	5.23	5.60	5.79
ID_Res	9.65	6.59	5.40	4.58	4.25	4.44	4.18	4.65	4.96	5.34	5.73	5.91
Klamath Falls_Com	10.01	9.35	10.35	9.96	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.40
Klamath Falls_Ind	10.01	9.35	10.35	9.95	9.88	10.04	12.58	14.58	15.17	15.75	16.69	21.39
Klamath Falls_Res	10.01	9.35	10.35	9.96	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.40
LaGrande_Com	11.88	10.78	11.33	10.88	10.73	11.08	12.89	14.57	15.16	15.74	16.68	21.39
LaGrande_Ind	11.04	10.19	10.89	10.46	10.34	10.64	12.73	14.57	15.16	15.74	16.68	21.38
LaGrande_Res	11.90	10.79	11.35	10.89	10.74	11.09	12.90	14.57	15.16	15.74	16.68	21.39
Medford_Com	10.01	9.35	10.35	9.95	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.39
Medford_Ind	10.01	9.35	10.34	9.95	9.88	10.04	12.58	14.57	15.16	15.74	16.68	21.39
Medford_Res	10.01	9.35	10.35	9.96	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.40
OR_Tport	7.48	8.40	10.20	9.64	9.55	9.70	12.20	14.19	14.80	15.41	16.26	20.80
Roseburg_Com	10.01	9.35	10.35	9.96	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.39
Roseburg_Ind	10.01	9.35	10.34	9.95	9.88	10.04	12.57	14.57	15.16	15.74	16.68	21.38
Roseburg_Res	10.01	9.35	10.35	9.96	9.88	10.05	12.58	14.58	15.17	15.75	16.69	21.40
WA_Com	11.77	8.86	7.81	7.14	7.00	7.39	7.37	7.45	7.29	7.53	7.92	8.14
WA_Ind	11.55	8.65	7.63	6.97	6.84	7.21	7.23	7.31	7.16	7.41	7.79	8.01
WA_Res	11.80	8.87	7.82	7.15	7.01	7.40	7.38	7.46	7.29	7.54	7.93	8.15
WA_Tport	7.48	6.21	6.50	5.87	5.76	5.90	6.21	6.24	6.16	6.35	6.73	7.01

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	6.14	6.53	6.72	7.12	7.34	7.65	8.12	8.31	8.57	8.87	9.09	9.32
ID_Ind	6.05	6.44	6.65	7.02	7.25	7.58	8.05	8.25	8.53	8.85	9.08	9.32
ID_Res	6.16	6.56	6.74	7.15	7.37	7.67	8.14	8.33	8.59	8.87	9.09	9.32
Klamath Falls_Com	24.87	25.41	25.82	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Klamath Falls_Ind	24.86	25.41	25.81	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Klamath Falls_Res	24.87	25.41	25.82	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
LaGrande_Com	24.86	25.40	25.81	26.01	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
LaGrande_Ind	24.85	25.40	25.81	26.01	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
LaGrande_Res	24.86	25.40	25.81	26.01	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Medford_Com	24.86	25.41	25.81	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Medford_Ind	24.86	25.40	25.81	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Medford_Res	24.87	25.41	25.82	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
OR_Tport	24.20	24.78	25.16	25.37	24.52	23.05	21.54	19.93	18.36	16.98	15.35	14.84
Roseburg_Com	24.86	25.41	25.82	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Roseburg_Ind	24.86	25.40	25.81	26.01	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
Roseburg_Res	24.87	25.41	25.82	26.02	25.14	23.63	22.08	20.46	18.84	17.23	15.54	14.84
WA_Com	7.91	7.89	7.99	8.59	8.57	8.47	9.05	9.27	9.57	12.36	14.34	14.55
WA_Ind	7.79	7.75	7.88	8.25	8.27	8.38	8.83	9.08	9.41	12.33	14.30	14.55
WA_Res	7.92	7.89	8.00	8.60	8.58	8.48	9.06	9.27	9.57	12.37	14.34	14.55
WA_Tport	6.70	6.55	6.83	7.09	7.15	7.36	7.79	8.16	8.59	11.67	13.71	14.09

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: PRS – ALLOWANCE PRICE CEILING CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.27	6.28	5.17	4.37	4.06	4.19	4.01	4.46	4.80	5.11	5.55	5.73
ID_Ind	9.06	6.13	5.05	4.26	3.96	4.08	3.93	4.39	4.74	5.06	5.48	5.67
ID_Res	9.33	6.32	5.20	4.40	4.10	4.23	4.04	4.49	4.82	5.13	5.58	5.75
Klamath Falls_Com	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.44
Klamath Falls_Ind	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.39	11.93	12.48	13.42	14.43
Klamath Falls_Res	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.44
LaGrande_Com	9.40	9.75	11.22	10.77	10.65	10.95	10.97	11.39	11.92	12.47	13.41	14.43
LaGrande_Ind	8.70	9.23	10.83	10.40	10.30	10.57	10.81	11.39	11.92	12.47	13.41	14.42
LaGrande_Res	9.41	9.76	11.23	10.78	10.66	10.96	10.98	11.39	11.92	12.47	13.41	14.43
Medford_Com	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.43
Medford_Ind	7.84	8.48	10.34	9.95	9.90	10.05	10.65	11.39	11.92	12.47	13.41	14.43
Medford_Res	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.44
OR_Tport	7.48	8.40	10.20	9.64	9.55	9.70	10.28	11.03	11.60	12.18	13.03	13.95
Roseburg_Com	7.84	8.48	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.44
Roseburg_Ind	7.84	8.48	10.34	9.95	9.90	10.05	10.65	11.39	11.92	12.47	13.41	14.43
Roseburg_Res	7.84	8.49	10.35	9.96	9.90	10.05	10.66	11.40	11.93	12.48	13.42	14.44
WA_Com	13.63	10.88	10.11	9.67	9.74	10.28	10.53	11.06	11.53	12.21	13.09	13.73
WA_Ind	13.44	10.71	9.97	9.53	9.61	10.14	10.41	10.95	11.43	12.13	12.99	13.63
WA_Res	13.66	10.89	10.12	9.67	9.75	10.29	10.54	11.06	11.54	12.22	13.10	13.73
WA_Tport	7.48	7.63	9.00	8.58	8.67	9.01	9.51	10.01	10.56	11.24	12.05	12.76

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	5.99	6.34	6.59	6.89	7.10	7.42	7.77	7.68	7.93	8.42	8.72	9.10
ID_Ind	5.93	6.28	6.55	6.84	7.05	7.40	7.76	7.68	7.93	8.42	8.72	9.10
ID_Res	6.01	6.36	6.60	6.91	7.11	7.43	7.77	7.68	7.93	8.42	8.72	9.10
Klamath Falls_Com	21.12	25.52	25.98	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Klamath Falls_Ind	21.12	25.52	25.97	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Klamath Falls_Res	21.12	25.52	25.98	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
LaGrande_Com	21.11	25.51	25.97	26.08	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
LaGrande_Ind	21.11	25.51	25.97	26.08	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
LaGrande_Res	21.11	25.51	25.97	26.08	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Medford_Com	21.12	25.52	25.97	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Medford_Ind	21.11	25.51	25.97	26.08	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Medford_Res	21.12	25.52	25.98	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
OR_Tport	20.49	24.85	25.29	25.44	21.09	20.76	21.56	20.02	18.46	17.06	15.52	14.84
Roseburg_Com	21.12	25.52	25.97	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Roseburg_Ind	21.11	25.51	25.97	26.08	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
Roseburg_Res	21.12	25.52	25.98	26.09	25.14	23.63	22.09	20.49	18.85	17.24	15.54	14.84
WA_Com	14.48	15.37	16.20	17.25	18.10	19.08	20.25	20.17	18.94	17.26	15.54	14.84
WA_Ind	14.38	15.28	16.12	17.05	17.95	19.03	20.19	20.17	18.94	17.26	15.54	14.84
WA_Res	14.49	15.38	16.20	17.25	18.11	19.08	20.25	20.17	18.94	17.26	15.54	14.84
WA_Tport	13.43	14.24	15.17	16.07	17.03	18.20	19.46	19.96	18.94	17.26	15.54	14.84

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: PRS – HIGH PRICES CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	10.52	7.89	6.99	6.36	6.01	6.36	6.20	6.57	7.08	7.68	8.18	8.67
ID_Ind	10.28	7.71	6.85	6.23	5.89	6.22	6.10	6.48	7.00	7.60	8.09	8.59
ID_Res	10.60	7.94	7.03	6.40	6.05	6.40	6.23	6.60	7.11	7.70	8.21	8.70
Klamath Falls_Com	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.83
Klamath Falls_Ind	9.97	8.65	9.58	10.00	10.52	11.02	11.66	12.30	13.15	13.79	14.66	15.83
Klamath Falls_Res	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.84
LaGrande_Com	11.80	10.12	10.58	10.50	10.97	11.02	11.66	12.30	13.14	13.78	14.66	15.83
LaGrande_Ind	10.98	9.51	10.13	10.24	10.74	11.02	11.65	12.30	13.14	13.78	14.66	15.82
LaGrande_Res	11.82	10.14	10.59	10.50	10.98	11.02	11.66	12.30	13.14	13.78	14.66	15.83
Medford_Com	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.83
Medford_Ind	9.97	8.65	9.58	10.00	10.52	11.02	11.65	12.30	13.14	13.78	14.66	15.83
Medford_Res	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.83
OR_Tport	8.44	6.21	5.76	5.17	8.82	11.59	12.02	12.21	12.79	13.43	14.22	15.27
Roseburg_Com	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.83
Roseburg_Ind	9.97	8.65	9.58	9.99	10.51	11.02	11.65	12.30	13.14	13.78	14.66	15.82
Roseburg_Res	9.97	8.65	9.58	10.00	10.52	11.03	11.66	12.31	13.15	13.79	14.67	15.84
WA_Com	12.71	10.22	9.44	8.96	8.79	9.35	9.43	9.39	9.42	9.89	10.41	10.92
WA_Ind	12.49	10.01	9.27	8.80	8.64	9.18	9.29	9.26	9.31	9.78	10.28	10.80
WA_Res	12.74	10.23	9.45	8.97	8.80	9.36	9.43	9.40	9.43	9.89	10.42	10.93
WA_Tport	8.44	7.60	8.14	7.69	7.57	7.78	8.23	8.18	8.37	8.70	9.20	9.73

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	8.75	9.45	9.92	10.35	10.92	11.23	11.96	12.33	12.69	13.40	13.20	13.88
ID_Ind	8.67	9.36	9.86	10.26	10.85	11.18	11.90	12.28	12.65	13.39	13.20	13.88
ID_Res	8.77	9.47	9.94	10.38	10.95	11.25	11.98	12.34	12.70	13.40	13.21	13.88
Klamath Falls_Com	21.63	25.44	25.61	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Klamath Falls_Ind	21.62	25.44	25.60	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Klamath Falls_Res	21.63	25.44	25.61	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
LaGrande_Com	21.61	25.43	25.60	25.63	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
LaGrande_Ind	21.61	25.43	25.60	25.63	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
LaGrande_Res	21.62	25.43	25.60	25.63	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Medford_Com	21.62	25.44	25.60	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Medford_Ind	21.62	25.44	25.60	25.63	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Medford_Res	21.63	25.44	25.61	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
OR_Tport	10.01	6.66	7.06	7.21	17.45	23.08	21.65	20.03	18.46	17.06	15.08	14.84
Roseburg_Com	21.62	25.44	25.61	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Roseburg_Ind	21.61	25.43	25.60	25.63	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
Roseburg_Res	21.63	25.44	25.61	25.64	25.17	23.65	22.13	20.56	18.84	17.26	15.54	14.84
WA_Com	10.51	10.79	11.19	11.79	12.11	12.05	12.86	13.24	13.65	14.49	14.33	14.83
WA_Ind	10.40	10.67	11.09	11.49	11.86	11.97	12.68	13.11	13.53	14.47	14.30	14.83
WA_Res	10.52	10.80	11.19	11.80	12.12	12.05	12.86	13.25	13.66	14.49	14.33	14.83
WA_Tport	9.37	9.48	9.98	10.31	10.83	11.03	11.72	12.24	12.75	13.87	13.71	14.50

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: PRS – LOW PRICES CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	9.21	6.05	4.82	3.99	3.59	3.72	3.40	3.85	4.06	4.32	4.65	4.73
ID_Ind	8.96	5.87	4.68	3.85	3.46	3.57	3.29	3.75	3.98	4.22	4.55	4.63
ID_Res	9.28	6.11	4.87	4.03	3.64	3.77	3.43	3.88	4.09	4.34	4.69	4.76
Klamath Falls_Com	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.79	13.62	14.53
Klamath Falls_Ind	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.80	12.42	12.79	13.62	14.52
Klamath Falls_Res	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.80	13.63	14.53
LaGrande_Com	11.51	10.32	10.85	10.37	10.56	11.41	11.49	11.80	12.41	12.78	13.61	14.52
LaGrande_Ind	10.67	9.73	10.40	9.94	10.17	10.98	11.31	11.80	12.41	12.78	13.61	14.51
LaGrande_Res	11.53	10.34	10.86	10.38	10.57	11.42	11.49	11.80	12.41	12.78	13.61	14.52
Medford_Com	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.79	13.62	14.52
Medford_Ind	9.63	8.88	9.85	9.42	9.70	10.38	11.13	11.80	12.41	12.79	13.61	14.52
Medford_Res	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.80	13.62	14.53
OR_Tport	12.87	10.23	9.67	9.11	9.37	10.07	10.89	11.47	12.12	12.54	13.26	14.06
Roseburg_Com	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.79	13.62	14.52
Roseburg_Ind	9.63	8.88	9.85	9.42	9.70	10.38	11.13	11.80	12.41	12.78	13.61	14.51
Roseburg_Res	9.63	8.88	9.85	9.43	9.71	10.39	11.14	11.81	12.42	12.80	13.62	14.53
WA_Com	11.40	8.38	7.28	6.59	6.38	6.72	6.63	6.68	6.42	6.53	6.88	6.99
WA_Ind	11.17	8.17	7.11	6.42	6.21	6.54	6.48	6.54	6.28	6.41	6.74	6.85
WA_Res	11.43	8.40	7.29	6.60	6.39	6.73	6.63	6.69	6.42	6.54	6.89	7.00
WA_Tport	7.10	5.73	5.97	5.32	5.12	5.21	5.48	5.47	5.33	5.36	5.69	5.83

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	4.96	5.42	5.58	5.92	6.10	6.31	6.78	6.92	7.03	7.18	7.32	7.52
ID_Ind	4.87	5.32	5.50	5.81	6.00	6.24	6.71	6.86	6.98	7.16	7.31	7.52
ID_Res	4.99	5.46	5.60	5.96	6.13	6.34	6.81	6.95	7.05	7.18	7.32	7.52
Klamath Falls_Com	21.07	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Klamath Falls_Ind	21.06	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Klamath Falls_Res	21.07	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
LaGrande_Com	21.06	25.39	25.84	25.99	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
LaGrande_Ind	21.05	25.39	25.84	25.99	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
LaGrande_Res	21.06	25.39	25.84	25.99	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Medford_Com	21.06	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Medford_Ind	21.06	25.39	25.84	25.99	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Medford_Res	21.07	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
OR_Tport	20.45	24.79	25.22	25.37	24.55	23.05	21.59	20.02	18.37	16.91	15.25	14.84
Roseburg_Com	21.06	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Roseburg_Ind	21.05	25.39	25.84	25.99	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
Roseburg_Res	21.07	25.40	25.85	26.00	25.14	23.62	22.08	20.49	18.82	17.21	15.54	14.84
WA_Com	6.74	6.78	6.86	7.41	7.35	7.15	7.74	7.91	8.06	11.74	14.31	14.48
WA_Ind	6.61	6.64	6.74	7.05	7.02	7.04	7.48	7.69	7.87	11.71	14.28	14.48
WA_Res	6.75	6.79	6.86	7.42	7.36	7.15	7.75	7.91	8.06	11.74	14.31	14.48
WA_Tport	5.50	5.44	5.68	5.84	5.88	5.99	6.42	6.74	7.01	11.07	13.67	14.01

*2045-2046 avoided cost values include only November and December months.

APPENDIX 6. 5: SOCIAL COST OF CARBON CASE WINTER AVOIDED COST ($/DEKATHERM)

	2022 - 2023	2023 - 2024	2024 - 2025	2025 - 2026	2026 - 2027	2027 - 2028	2028 - 2029	2029 - 2030	2030 - 2031	2031 - 2032	2032 - 2033	2033 - 2034
ID_Com	14.36	11.47	10.57	9.95	9.89	10.26	10.26	10.51	10.73	11.15	11.68	11.94
ID_Ind	14.14	11.32	10.44	9.84	9.79	10.15	10.18	10.44	10.67	11.10	11.61	11.88
ID_Res	14.43	11.52	10.60	9.99	9.93	10.30	10.29	10.53	10.75	11.17	11.70	11.96
Klamath Falls_Com	12.87	10.29	9.81	9.28	9.25	11.22	12.84	13.33	14.07	16.81	19.02	19.72
Klamath Falls_Ind	12.87	10.29	9.81	9.27	9.25	11.22	12.84	13.33	14.06	16.81	19.02	19.72
Klamath Falls_Res	12.87	10.29	9.81	9.28	9.25	11.22	12.85	13.33	14.07	16.81	19.02	19.72
LaGrande_Com	13.76	10.79	10.31	9.74	9.68	11.22	12.84	13.33	14.06	16.80	19.01	19.72
LaGrande_Ind	13.32	10.55	10.06	9.50	9.46	11.22	12.84	13.33	14.06	16.80	19.01	19.71
LaGrande_Res	13.77	10.80	10.32	9.74	9.68	11.22	12.84	13.33	14.06	16.80	19.01	19.72
Medford_Com	12.87	10.29	9.81	9.27	9.25	11.22	12.84	13.33	14.06	16.81	19.02	19.72
Medford_Ind	12.87	10.29	9.81	9.27	9.25	11.22	12.84	13.33	14.06	16.80	19.01	19.72
Medford_Res	12.87	10.29	9.81	9.28	9.25	11.22	12.84	13.33	14.07	16.81	19.02	19.72
OR_Tport	12.74	10.01	9.38	8.81	8.73	8.88	9.17	9.44	9.71	10.09	15.36	19.03
Roseburg_Com	12.87	10.29	9.81	9.28	9.25	11.22	12.84	13.33	14.07	16.81	19.02	19.72
Roseburg_Ind	12.87	10.29	9.81	9.27	9.25	11.22	12.84	13.33	14.06	16.80	19.01	19.72
Roseburg_Res	12.87	10.29	9.81	9.28	9.25	11.23	12.85	13.33	14.07	16.81	19.02	19.72
WA_Com	16.54	13.79	13.01	12.54	12.66	13.25	13.47	13.70	13.81	14.25	14.93	15.38
WA_Ind	16.35	13.61	12.86	12.40	12.53	13.10	13.36	13.60	13.72	14.18	14.83	15.29
WA_Res	16.58	13.80	13.02	12.55	12.67	13.25	13.48	13.71	13.82	14.25	14.94	15.39
WA_Tport	12.40	11.26	11.76	11.34	11.44	11.80	12.33	12.58	12.74	13.15	13.77	14.29

*2022-2023 avoided cost values include only January, February, and March months.

	2034 - 2035	2035 - 2036	2036 - 2037	2037 - 2038	2038 - 2039	2039 - 2040	2040 - 2041	2041 - 2042	2042 - 2043	2043 - 2044	2044 - 2045	2045 - 2046
ID_Com	12.28	12.73	13.08	13.53	13.88	14.34	14.87	15.18	15.42	15.94	15.38	14.84
ID_Ind	12.22	12.66	13.04	13.48	13.84	14.31	14.84	15.17	15.42	15.94	15.38	14.84
ID_Res	12.30	12.75	13.10	13.55	13.90	14.35	14.87	15.18	15.42	15.94	15.38	14.84
Klamath Falls_Com	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Klamath Falls_Ind	22.70	24.73	24.92	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Klamath Falls_Res	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
LaGrande_Com	22.69	24.72	24.92	24.91	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
LaGrande_Ind	22.69	24.72	24.92	24.91	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
LaGrande_Res	22.69	24.72	24.92	24.91	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Medford_Com	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Medford_Ind	22.69	24.72	24.92	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Medford_Res	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
OR_Tport	21.93	16.53	12.02	12.42	12.82	13.39	13.96	17.50	18.76	17.14	15.52	14.84
Roseburg_Com	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Roseburg_Ind	22.69	24.72	24.92	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
Roseburg_Res	22.70	24.73	24.93	24.92	24.69	23.64	22.08	20.47	18.86	17.18	15.54	14.84
WA_Com	15.40	15.59	16.04	16.78	17.07	17.40	18.14	18.65	18.55	17.26	15.54	14.84
WA_Ind	15.31	15.50	15.97	16.58	16.92	17.36	18.06	18.62	18.54	17.26	15.54	14.84
WA_Res	15.41	15.59	16.04	16.78	17.08	17.40	18.14	18.65	18.55	17.26	15.54	14.84
WA_Tport	14.24	14.37	14.94	15.51	15.89	16.43	17.17	17.86	18.28	17.26	15.54	14.84

*2045-2046 avoided cost values include only November and December months.

APPENDIX 8.1: DISTRIBUTION SYSTEM MODELING

OVERVIEW

The primary goal of distribution system planning is to design for present needs and to plan for future expansion in order to serve demand growth. This allows Avista to satisfy current demand-serving requirements, while taking steps toward meeting future needs. Distribution system planning identifies potential problems and areas of the distribution system that require reinforcement. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly reactive and emergency solutions can be avoided.

COMPUTER MODELING

When designing new main extensions, computer modeling can help determine the optimum size facilities for present and future needs. Undersized facilities are costly to replace, and oversized facilities incur unnecessary expenses to Avista and its customers.

THEORY AND APPLICATION OF STUDY

Natural gas network load studies have evolved in the last decade to become a highly technical and useful means of analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. Through years of research, pipeline equations have been refined to the point where solutions obtained closely represent actual system behavior.

Avista conducts network load studies using GL Noble Denton's Synergi® 4.8.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically.

CREATING A MODEL

To properly study the distribution system, all natural gas main information is entered (length, pipe roughness and size) into the model. "Main" refers to all pipelines supplying services.
Nodes are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material, and to identify all large customers. A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

Regulators are treated like adjustable valves in which the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the expected flow passing through the actual regulator is determined and the modeled regulator is forced to accommodate such flows.

FLUID MECHANICS OF THE MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter and pipe length. For all models, the Fundamental Flow equation (FM) is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings and angle changes within the distribution system. Starting with a 95 percent factor, the efficiency can be changed to fine tune the model to match field results.

Pipe roughness, along with flow conditions, creates a friction factor for all pipes within a system. Thus, each pipe may have a unique friction factor, minimizing computational errors associated with generalized friction values.

LOAD DATA

All studies are considered steady state; all natural gas entering the distribution system must equal the natural gas exiting the distribution system at any given time.

Customer loads are obtained from Avista's customer billing system and converted to an algebraic format so loads can be generated for various conditions. Customer Management Module (CMM), an add-on application for Synergi, processes customer usage history and generates a base load (non-temperature dependent) and heat load (varying with temperature) for each customer.

In the event of a peak day or an extremely cold weather condition, it is assumed that all curtailable loads are interrupted. Therefore, the models will be conducted with only core loads.

DETERMINING NATURAL GAS CUSTOMERS' MAXIMUM HOURLY USAGE

Determining Design Peak Hourly Load

The design peak hourly load for a customer is estimated by adding the hourly base load and the hourly heat load for a design temperature. This estimate reflects highest system hourly demands, as shown in Table 1:

Table 1 - Determining Peak* Hourly Load

Peak Hourly Base Load	+	Peak Hourly Heat Load	=	Peak Hourly Load

This method differs from the approach that is used for IRP peak day load planning. The primary reason for this difference is due to the importance of responding to hourly peaking in the distribution system, while IRP resource planning focuses on peak day requirements to the city gate.

APPLYING LOADS

Having estimated the peak loads for all customers in a particular service area, the model can be loaded. The first step is to assign each load to the respective node or element.

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node or element, thus loads can be varied based on any temperature (HDD). Such a tool is necessary to evaluate the difference in flow and pressure due to different weather conditions.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

Several years ago Avista converted the natural gas facility maps to GIS. While the GIS can provide a variety of map products, the true power lies in the analytical capabilities. A GIS consists of three components: spatial operations, data association and map representation.

A GIS allows analysts to conduct spatial operations (relating a feature or facility to another geographically). A spatial operation is possible if a facility displayed on a map maintains a relationship to other facilities. Spatial relationships allow analysts to perform a multitude of queries, including:

- Identify electric customers adjacent to natural gas mains who are not currently using natural gas

- Display the number of customers assigned to particular pipes in Emergency Operating Procedure zones (geographical areas defined to aid in the safe isolation in the event of an emergency)

- Classify high-pressure pipeline proximity criteria

The second component of the GIS is data association. This allows analysts to model relationships between facilities displayed on a map to tabular information in a database. Databases store facility information, such as pipe size, pipe material, pressure rating, or related information (e.g., customer databases, equipment databases and work management systems). Data association allows interactive queries within a map-like environment.

Finally, the GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present complex analyses rapidly and in an easy-to-understand method.

BUILDING SYNERGI® MODELS FROM A GIS

The GIS can provide additional benefits through the ease of creation and maintenance of load studies. Avista can create load studies from the GIS based on tabular data (attributes) installed during the mapping process.

MAINTENANCE USING A GIS

The GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company's natural gas system are managed through Avista's Maximo tool. Once jobs are completed, the as-built information is automatically updated on GIS, eliminating the need to convert physical maps to a GIS at a later date. Because the facility is updated, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a present case model has to be developed that reflects what the system was doing when downstream pressures and flows are known. To establish the present case, pressure recording instruments located throughout the distribution system are used.

These field instruments record pressure and temperature throughout the winter season. Various locations recording simultaneously are used to validate the model. Customer loads on Synergi® are generated to correspond with actual temperatures recorded on the instruments. An accurate model's downstream pressures will match the corresponding field instrument's pressures. Efficiency factors are adjusted to further refine the model's pressures and better match the actual conditions.

Since telemetry at the gate stations record hourly flow, temperature and pressure, these values are used to validate the model. All loads are representative of the average daily temperature and are defined as hourly flows. If the load generating method is truly accurate, all natural gas entering the actual system (physical) equals total natural gas demand solved by the simulated system (model).

DEVELOPING A PEAK CASE LOAD STUDY

Using the calculated peak loads, a model can be analyzed to identify the behavior during a peak day. The efficiency factors established in the present case are used throughout subsequent models.

ANALYZING RESULTS

After a model has been balanced, several features within the Synergi® model are used to interpret results. Color plots are generated to depict flow direction, pressure, and pipe diameter with specific break points. Reinforcements can be identified by visual inspection. When user edits are completed and the model is re-balanced, pressure changes can be visually displayed, helping identify optimum reinforcements.

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig indicate a likelihood of distribution low pressure, and therefore necessitate reinforcements. For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter. Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

Using a peak day model, loads can be prorated at intervals until area pressures drop to 15 psig. At that point, the total amount of natural gas entering the system equals the maximum capacity before new construction is necessary. The difference between natural gas entering the system in this scenario and a peak day model is the maximum additional capacity that can be added to the system.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements. The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine the potential increase in capacity.

FIVE-YEAR FORECASTING

The intent of the load study forecasting is to predict the system's behavior and reinforcements necessary within the next five years. Various Avista personnel provide information to determine where and why certain areas may experience growth.

By combining information from Avista's demand forecast, IRP planning efforts, regional growth plans and area developments, proposals for pipeline reinforcements and expansions are evaluated with Synergi®.

Appendix 8.2

Oregon Public Utility Commission Order No. 16-109 (the Order) included the following language:

> Finally, as part of the IRP-vetting process and subsequent rate proceedings, we expect that Avista conduct and present comprehensive analyses of its system upgrades. Such analyses should provide: (1) a comprehensive cost-benefit analysis of whether and when the investment should be built; (2) evaluation of a range of alternative build dates and the impact on reliability and customer rates; (3) credible evidence on the likelihood of disruptions based on historical experience; (4) evidence on the range of possible reliability incidents; (5) evidence about projected loads and customers in the area; and (6) adequate consideration of alternatives, including the use of interruptibility or increased demand-side measures to improve reliability and system resiliency.

In order to address this portion of the Order, Avista has prepared this appendix, which includes documentation addressing the six points above for each of the natural gas distribution system enhancements included in the 2021 Natural Gas Integrated Resource Plan (IRP) for Avista's Oregon service territory. Each of these three enhancement projects represents a significant, discrete project which is out of the ordinary course of business (that is to say, different from <u>ongoing</u> capital investment to address Federal or State regulatory requirements, relocation of pipe or facilities as requested by others, failed pipe or facilities, etc., all of which occur routinely over time and which are discussed below).

The routine, ongoing capital investments can be loosely classified in the following categories (which are not mutually exclusive):

- Safety – Ongoing safety related capital investment includes the repair or replacement of obsolete or failed pipe and facilities. This category includes, but is not necessarily limited to, investment to address deteriorated or isolated steel pipe, cathodic protection, and the replacement of pipeline which has been built over, as well as the remedy of shallow pipe or the repair or replacement of leaking pipe.
- System Maintenance – Ongoing capital investment related to system maintenance includes replacement of facilities or pipe that has reached the end of their useful lives, as well as other general investment required to maintain Avista's ability to reliably serve customers.
- Relocation Requested by Others – Ongoing capital investment related to relocation requested by others falls primarily into two categories, relocation requested by other parties which is required under the terms of our franchise agreements (such as

relocations required to accommodate road or highway construction or relocation), or relocation requested by customers or others (in which case the customer would be responsible for the cost of the immediate request, but in which case Avista may perform additional work, such as the replacement of a steel service with polyethylene to reduce future maintenance or cathodic protection requirements on that pipe).

- Mandated System Investment – Ongoing capital investment in this category is driven by Federal or State regulatory requirements, such as investment that results from TIMP/DIMP programs, among other programs.

Avista's Aldyl-A replacement program has been addressed in substantial detail in Oregon Public Utility Commission Docket UG-246, Avista/500-501.

Natural Gas Integrated Resource Plan

Technical Advisory Committee (TAC) # 1

February 16, 2022

Agenda

Item	Time
Meeting Guidelines and reminders	9:00am – 9:10am
2023 IRP Topics and Timeline	9:10am – 9:30am
2021 IRP Review	9:30am – 9:45am
Weather Planning Standard	9:45am – 10:00am
Break	10:00am – 10:10am
RNG Supply Overview	10:10am – 11:00am
Climate Protection Plan (CPP) Overview	11:00am – 12:00pm

Meeting Guidelines

- IRP team is working remotely and is available for questions and comments
- Stakeholder feedback form
  - Responses shared with TAC at meetings, by email and in Appendix
  - Would a form and/or section on the web site be helpful?
- IRP data posted to web site – updated descriptions and navigation are in development
- Virtual IRP meetings on Microsoft Teams until able to hold large meetings again
- TAC presentations posted on IRP page
- This meeting is being recorded and an automated transcript made

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be documented and recorded

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- An IRP is submitted every 2 years in Idaho, Oregon and Washington
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Supply side resource choices
  - Conservation / demand response
  - Customer growth
- Market and portfolio scenarios for uncertain future events and issues

Technical Advisory Committee

- The public process piece of the IRP – input on what to study, how to study, and review of assumptions and results
- Wide range of participants involved in all or parts of the process
  - Please ask questions
  - Always soliciting new TAC members
- Open forum while balancing need to get through topics
- Welcome requests for new studies or different modeling assumptions.
- Available by email or phone for questions or comments between meetings

2023 IRP TAC Meeting Topics

- Weather forecast
  - Peak Weather
- 2021 IRP Action Items
- Climate Protection Plan (CPP)
- Renewable Natural Gas (RNG)

2023 IRP TAC Meeting Topics

- Natural gas market overview
- Natural gas price forecast
- Transportation contracts
- Current supply side resources
- Future supply side resource options
- Climate Commitment Act (CCA)
- Electrification

2023 IRP TAC Meeting Topics

- Clean energy survey study
- Conservation potential assessment
  - AEG (ID and WA)
    - Performing a low income and transportation customer study for Oregon
  - ETO (OR)
- Demand Response (AEG)
- Plexos model overview
- Distribution system planning

2023 IRP TAC Meeting Topics

- Preferred Resource Strategy
- Portfolio scenario analysis
- Risk assessment and stochastics
- Carbon Pricing
  - Social cost of carbon (OR and WA)
- Action Items for next IRP
- Other items of interest

2023 – Avista Natural Gas IRP

TAC #1
- February 2022

TAC #2
- April 2022

TAC #3
- June 2022

TAC #4
- August 2022

TAC #5
- October 2022

Draft IRP to TAC
- January 2023

TAC #6 (if necessary)
- February 2023

File IRP
- April 2023

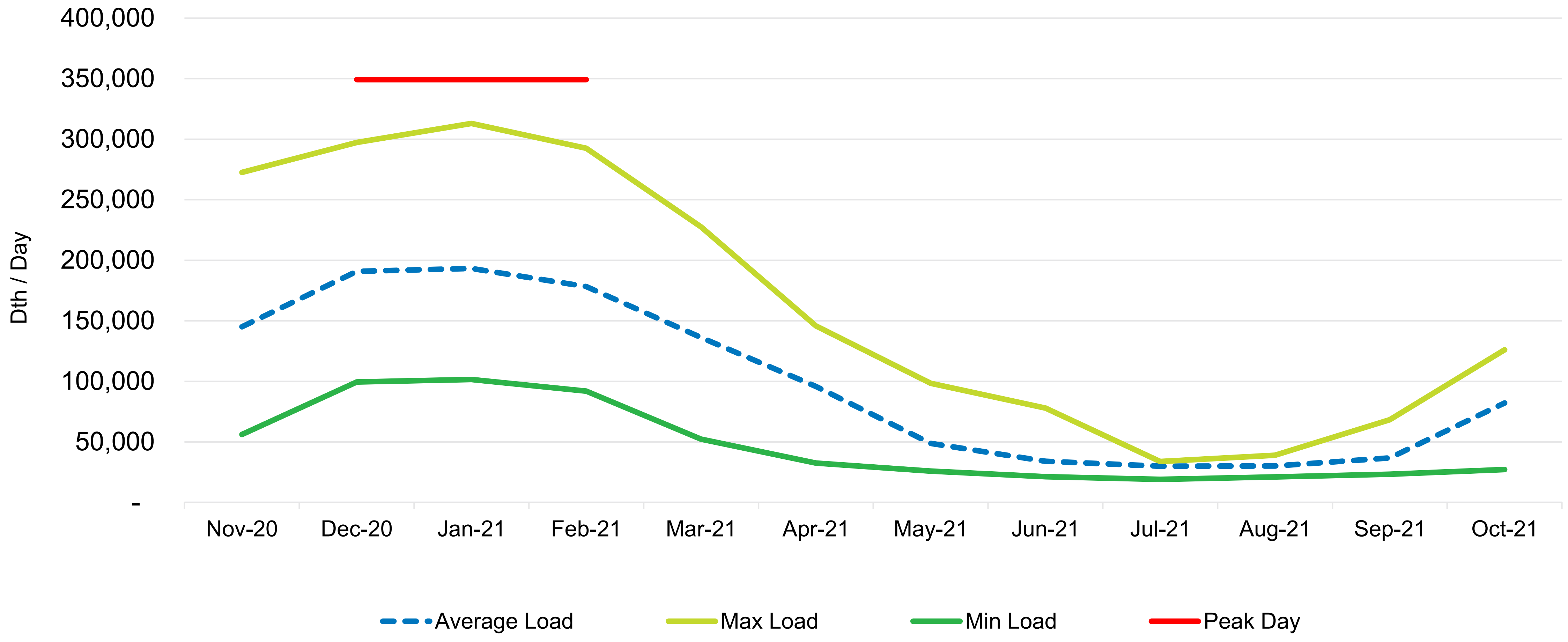
Avista 2021 IRP Review

ID	92,000
OR	105,000
WA	175,000
Total	**372,000**

Avista

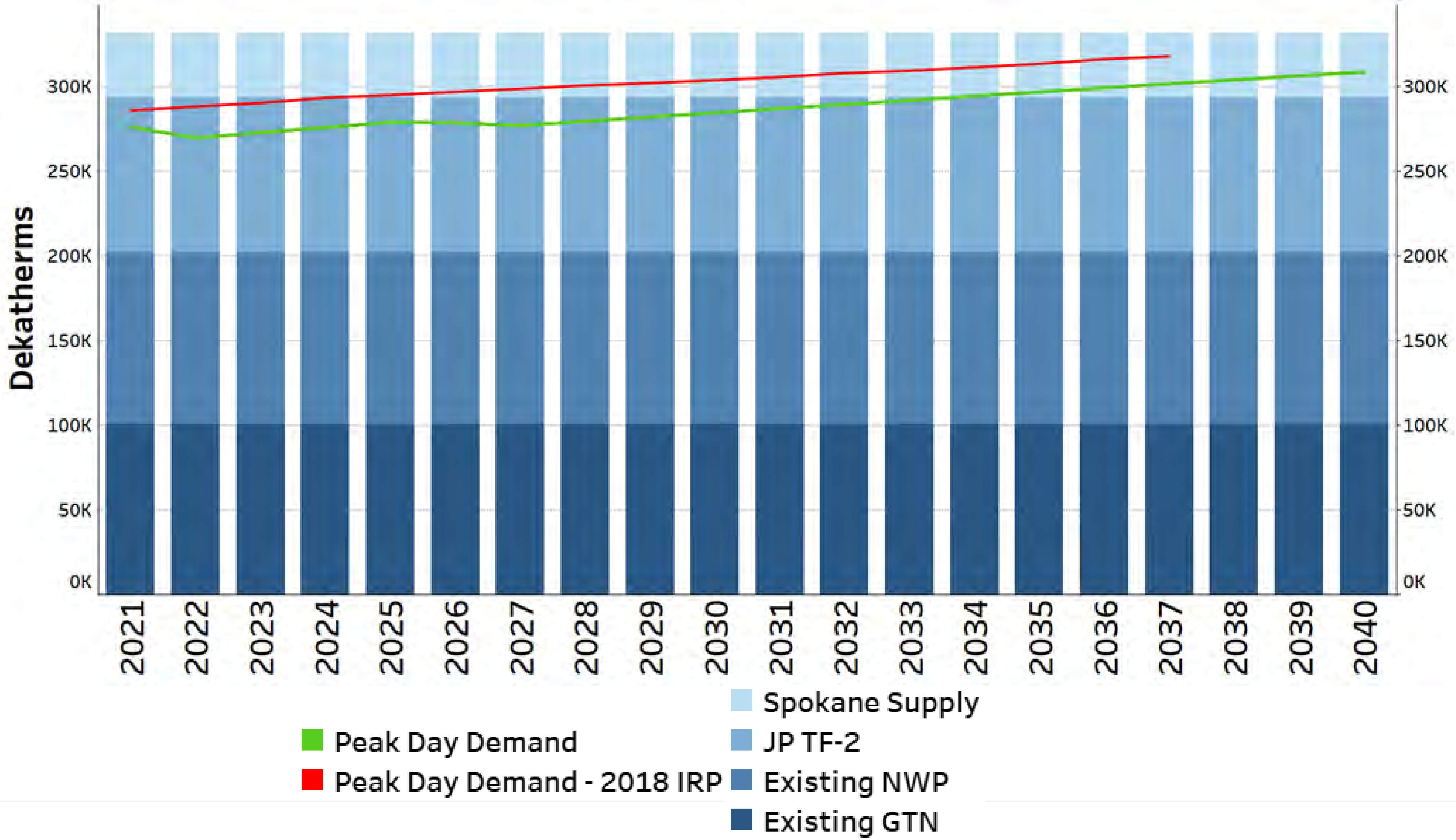
AVISTA

LDC - Total System Average Daily Load



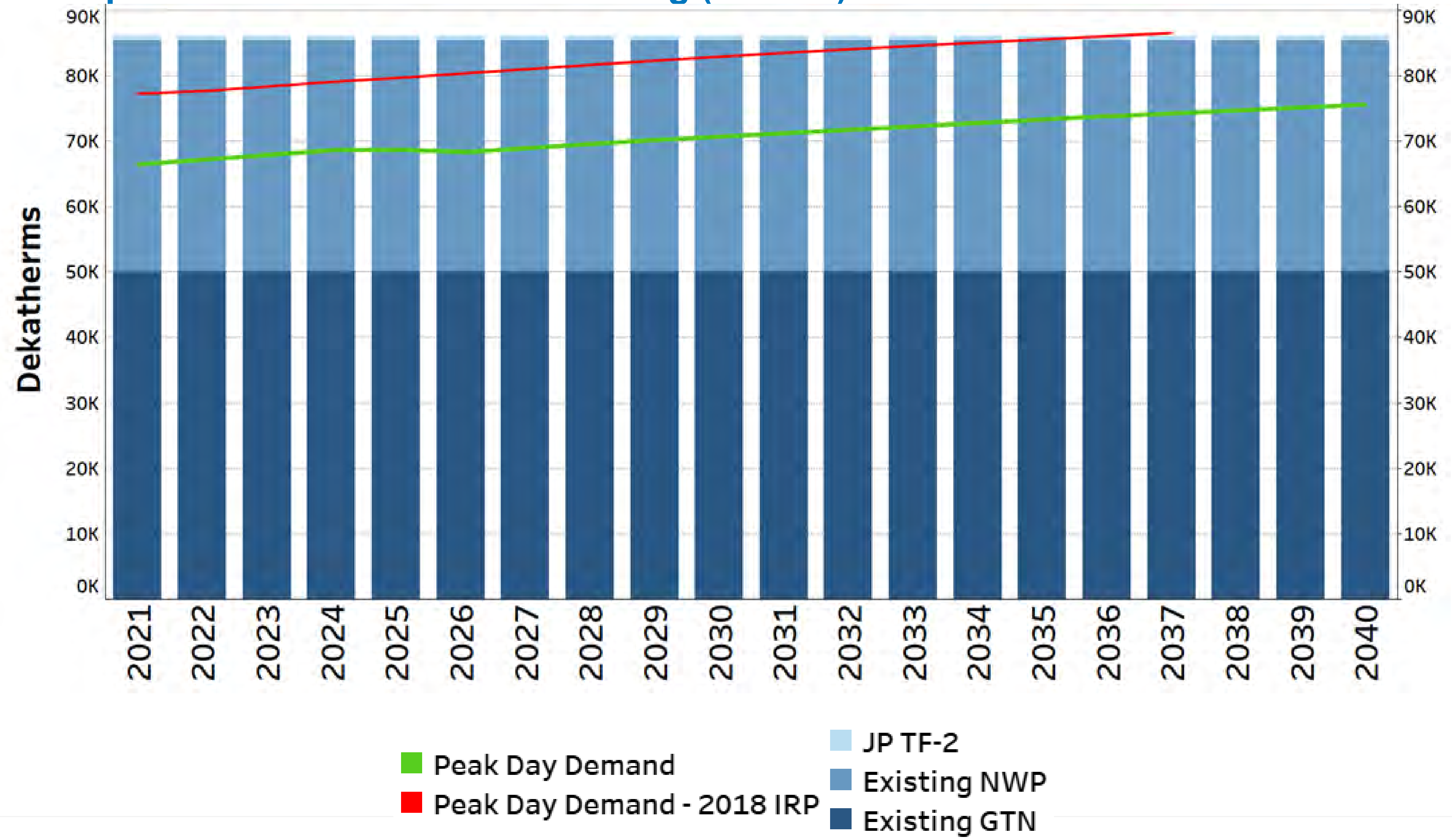
Existing Resources vs. Peak Day Demand

Expected Case – Washington/Idaho (DRAFT)



Existing Resources vs. Peak Day Demand

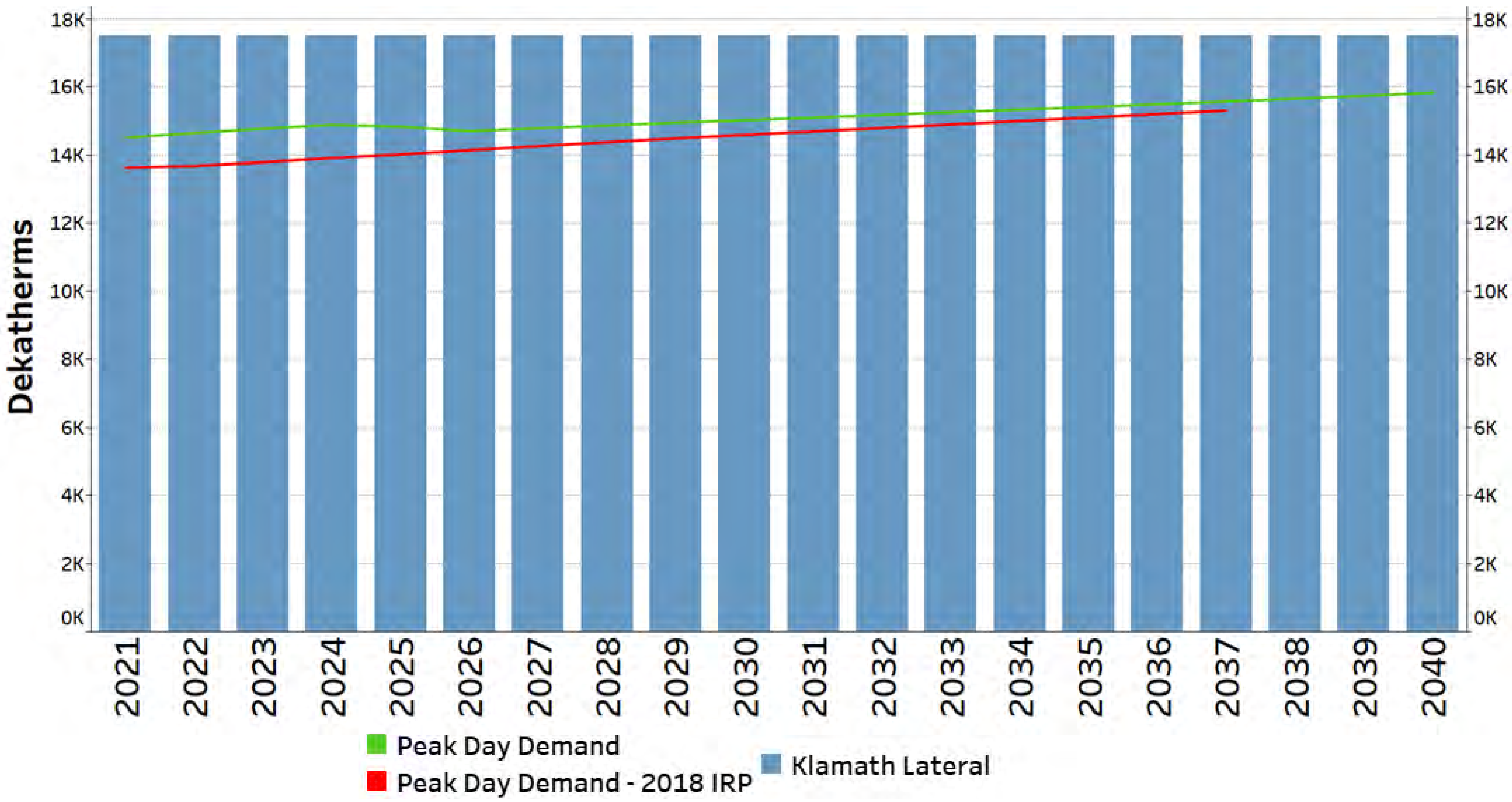
Expected Case – Medford/Roseburg (DRAFT)



AVISTA

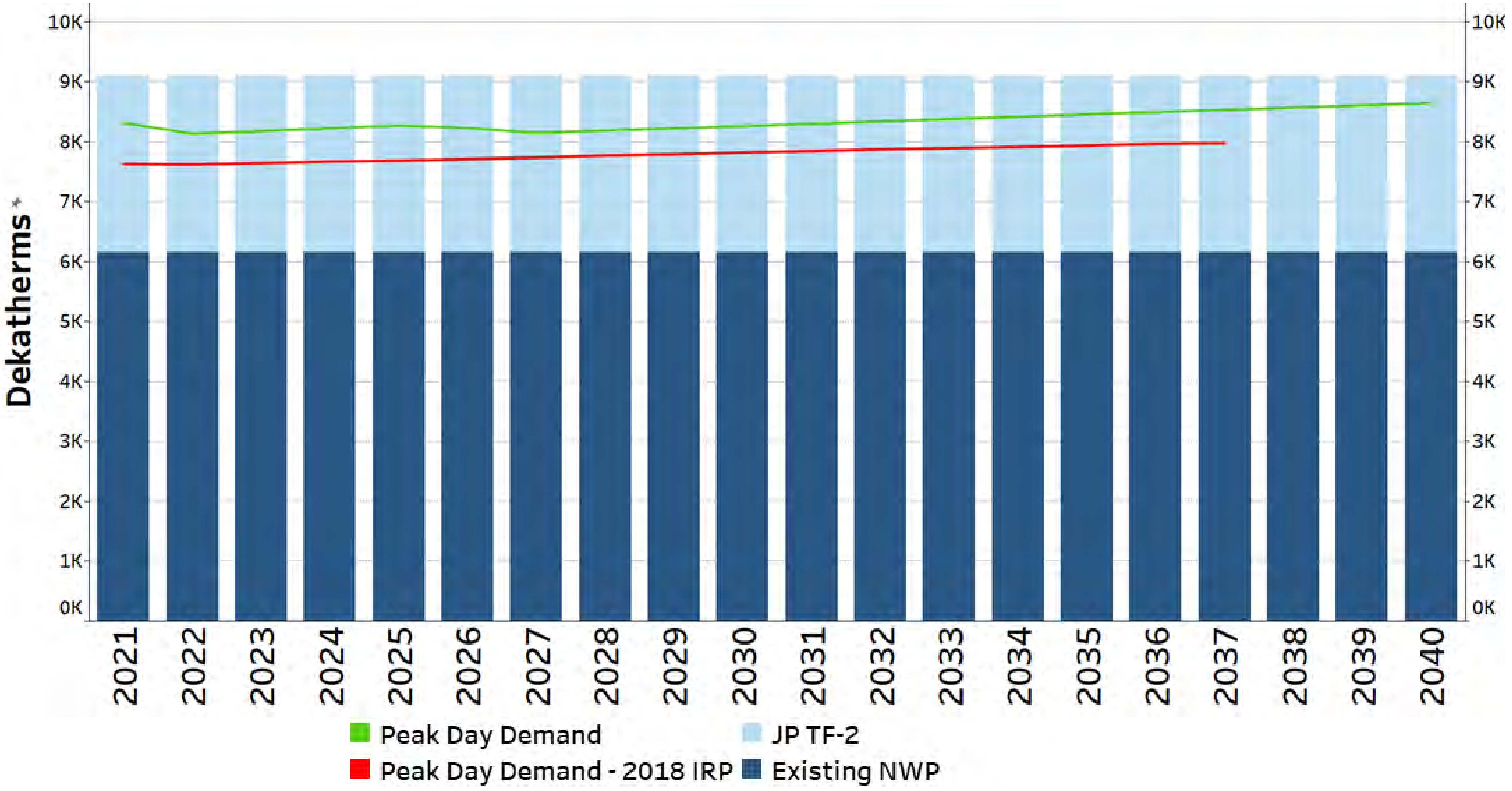
Existing Resources vs. Peak Day Demand

Expected Case – Klamath Falls (DRAFT)



Existing Resources vs. Peak Day Demand

Expected Case – La Grande (DRAFT)



AVISTA

Carbon Reduction scenario

- Carbon reduction goals to meet 2035 targets of 45% below 1990 emissions
- Any actual availability of physical RNG resources and rate impact by year can be further studied in future Integrated Resource Plans
- Actual projects will be considered on an ad-hoc basis to determine which costs and environmental attributes may make different RNG types a least cost solution
- Exact 1990 emissions are not known and are estimated based on prior 10k's
- Many of the rules from EO 20-04 will be coming out after this IRP is submitted
- Allowances are not considered

Major Changes since last IRP

- CCA (WA)
- CPP (OR)
- Clean Energy Costs
- Risk of Customer growth

2021 IRP Action Items

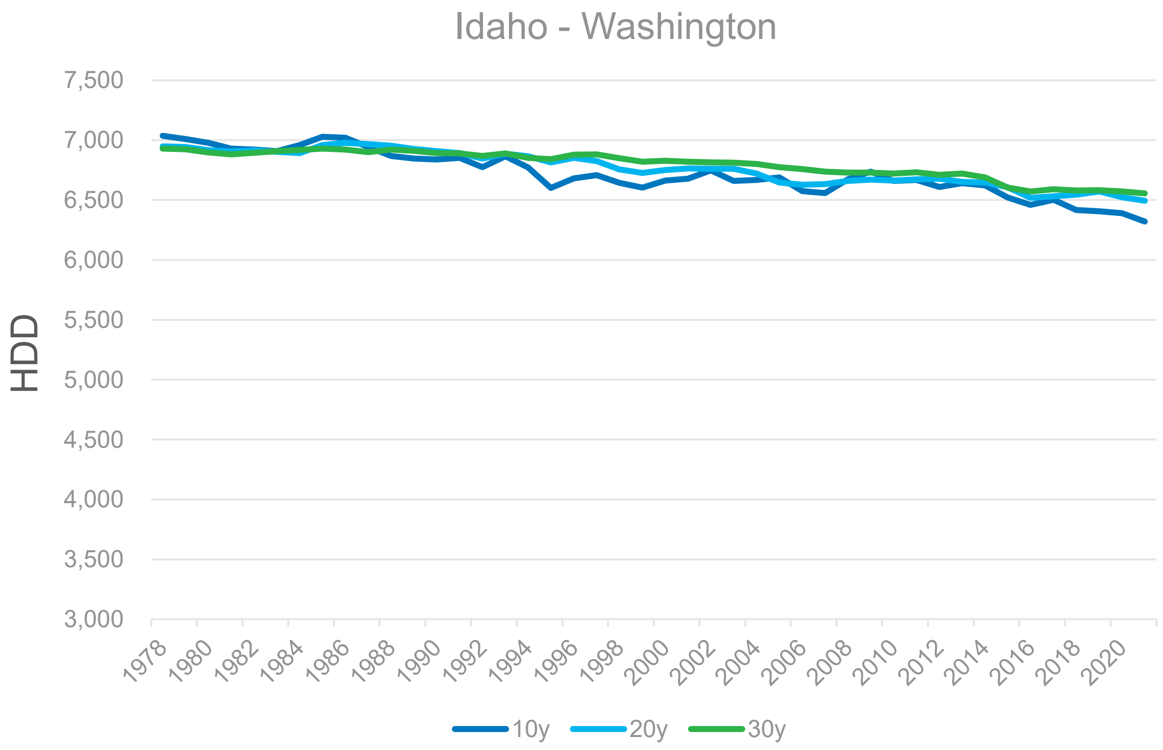
Action Item	Commission
Recommendation 1: In the next IRP, use at least five years of historic data for modeling use per customer	OPUC
Recommendation 2: Include a No Growth scenario in the next IRP	OPUC
Recommendation 3: In future IRPs, provide a comparison between the current CPA and the last CPA, including a narrative explanation of major changes in the potential	OPUC
Recommendation 4: Discuss demand response as a demand side resource option at a TAC meeting before filing the next IRP	OPUC
Recommendation 5: Discuss long-term transport procurement strategies at a TAC meeting before the next IRP	OPUC
Host a workshop within two months of the publishing of DEQ's Clean Power Plan Rules, to discuss challenges and opportunities to incentivize near-term actions to reduce GHGs to meet Clean Power Plan targets, including consideration of SB 98 and SB 844 programs.	OPUC
Recommendation 7: Provide a workshop in the next IRP development process to discuss the possibility of using the social cost of carbon to help inform carbon risks in its portfolios	OPUC
Recommendation 8: Include a non-zero carbon risk value for its Idaho customers	OPUC
Recommendation 9: Prior to the next IRP, conduct market research to reflect the willingness of Oregon customers to pay for various carbon reduction strategies. Present results at a TAC meeting	OPUC
Recommendation 10: Work with stakeholders and Staff to identify information that should be included in an RNG project pipeline update and provide an update on the Company's RNG project pipeline as part of the next IRP Update, including, but not limited to consumer risks and costs assessment associated with buy vs build RNG options	OPUC

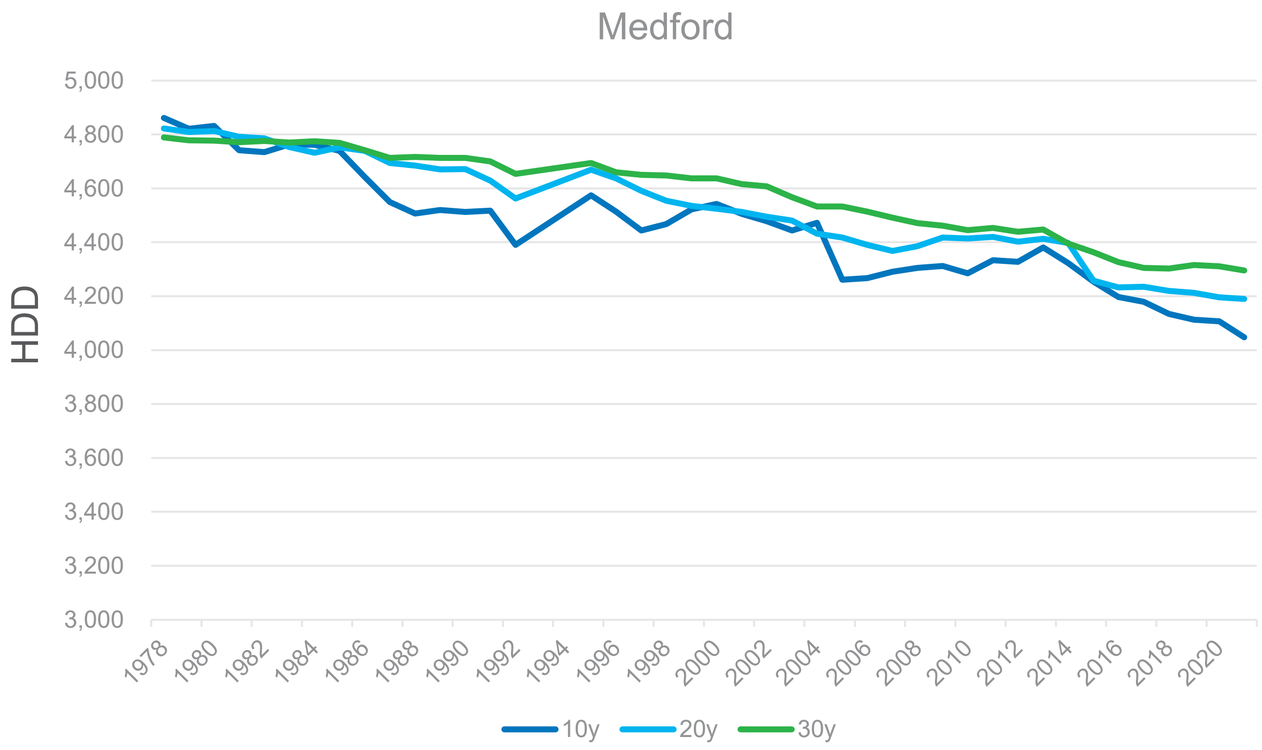
2021 Action Items cont.

Action Item	Commission
Recommendation 11: In the next IRP, provide an analysis of the capabilities of Avista's system to accommodate hydrogen, where upgrades would be required to accommodate hydrogen, and estimated costs of those upgrades	OPUC
Recommendation 12: In the next IRP, describe the assumptions for changes to renewable technologies and their impact on future levelized costs in the text of the next IRP	OPUC
Recommendation 13: Work with TAC to develop a scenario with a future large scale supply interruptions, like the October 2018 Enbridge incident	OPUC
Recommendation 14: In the next IRP, Avista should continue to keep the Commission apprised of the Sutherlin and Klamath Falls city gate projects. The Company should also provide a list of areas or projects where the Company is monitoring for capacity or pressure issues.	OPUC
Further model carbon reduction in Oregon and Washington	All
Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout	All
Model all requirements as directed in Executive Order 20-04	All
Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board	All
Explore the feasibility of using projected future weather conditions in its design day methodology	All
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	All

Weather Planning

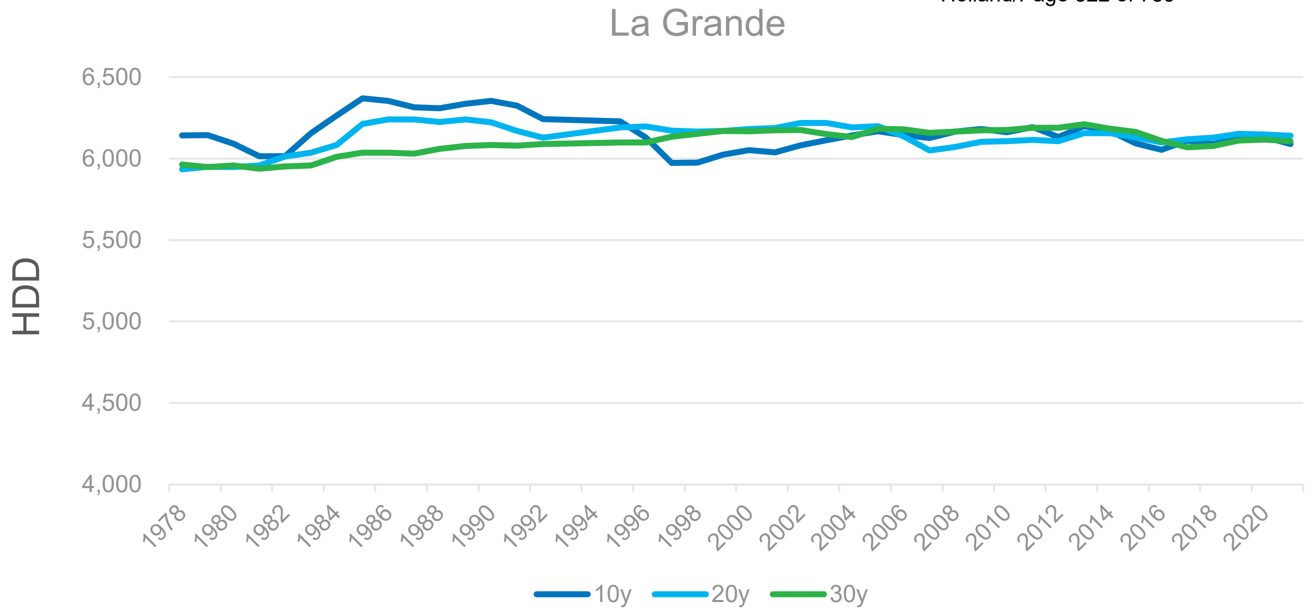
Weather Trend

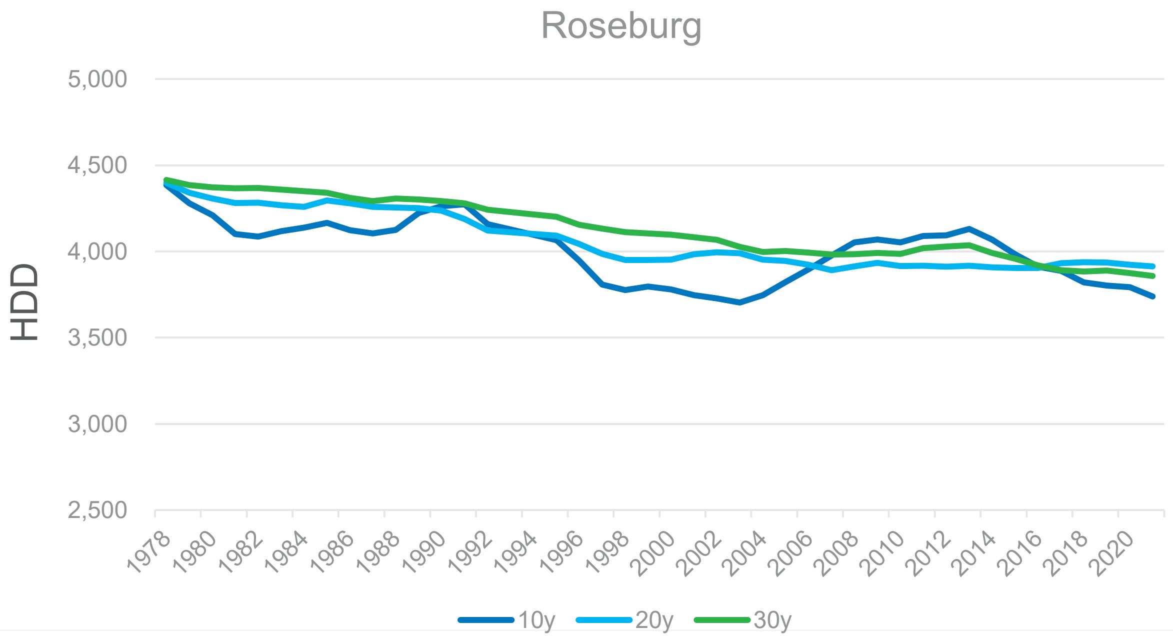


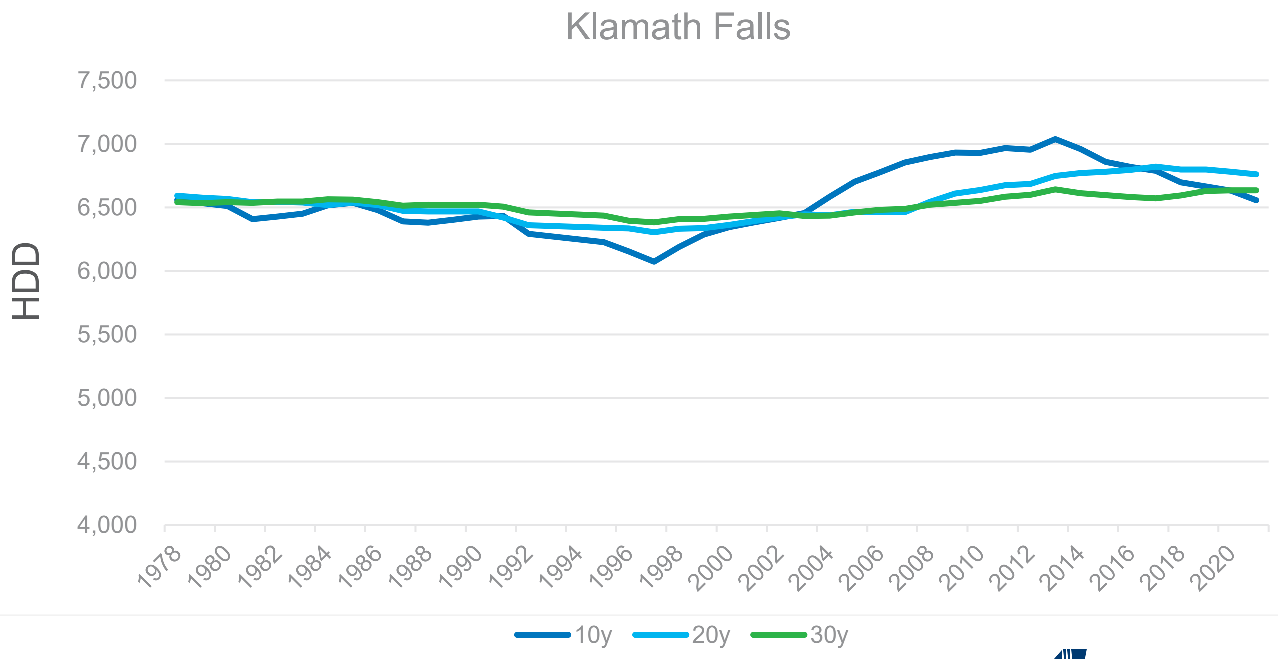


Heating Degree Day (HDD) begins at 65° F
Anything less than this beginning value would be 1 HDD for each degree of Fahrenheit reduction (e.g. 65-64=1 HDD)

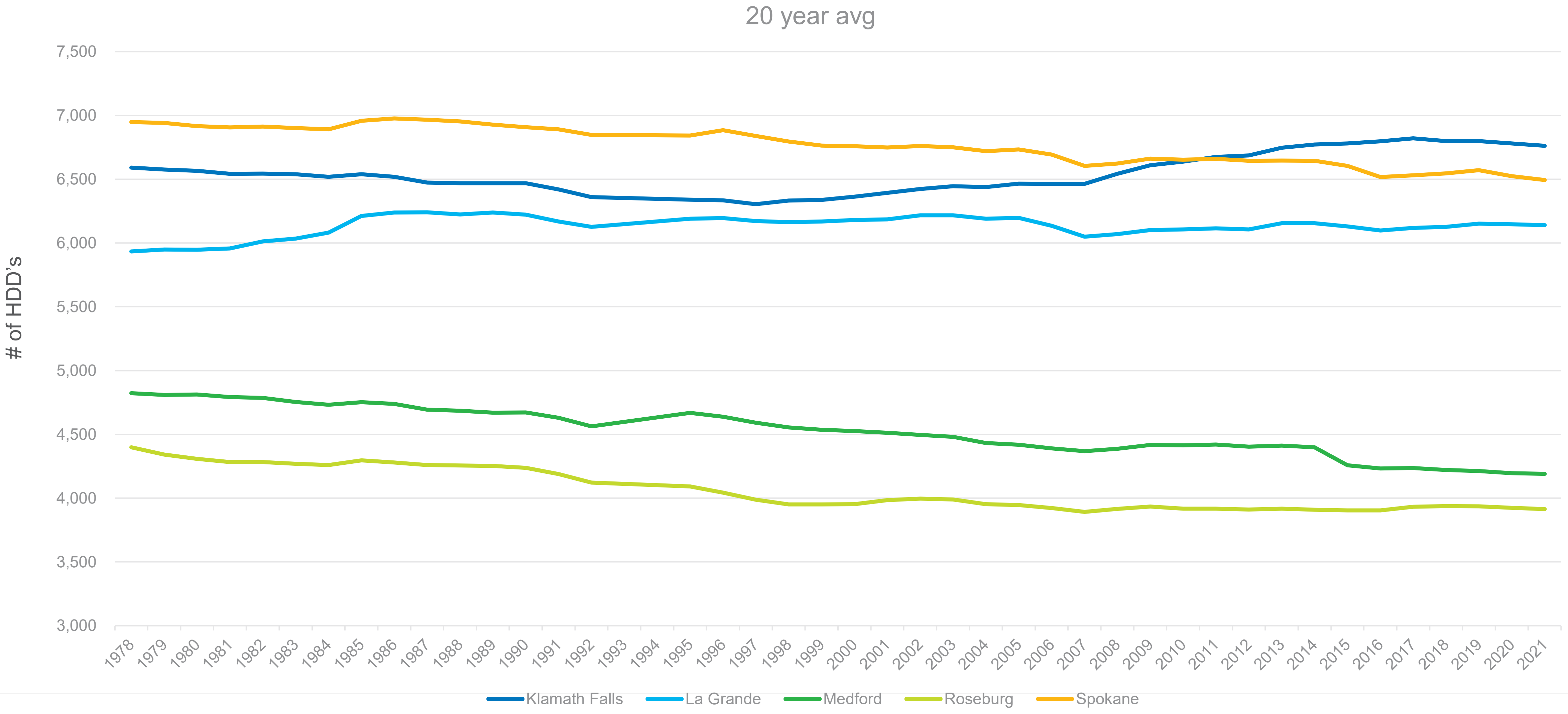
Weather Trend cont.





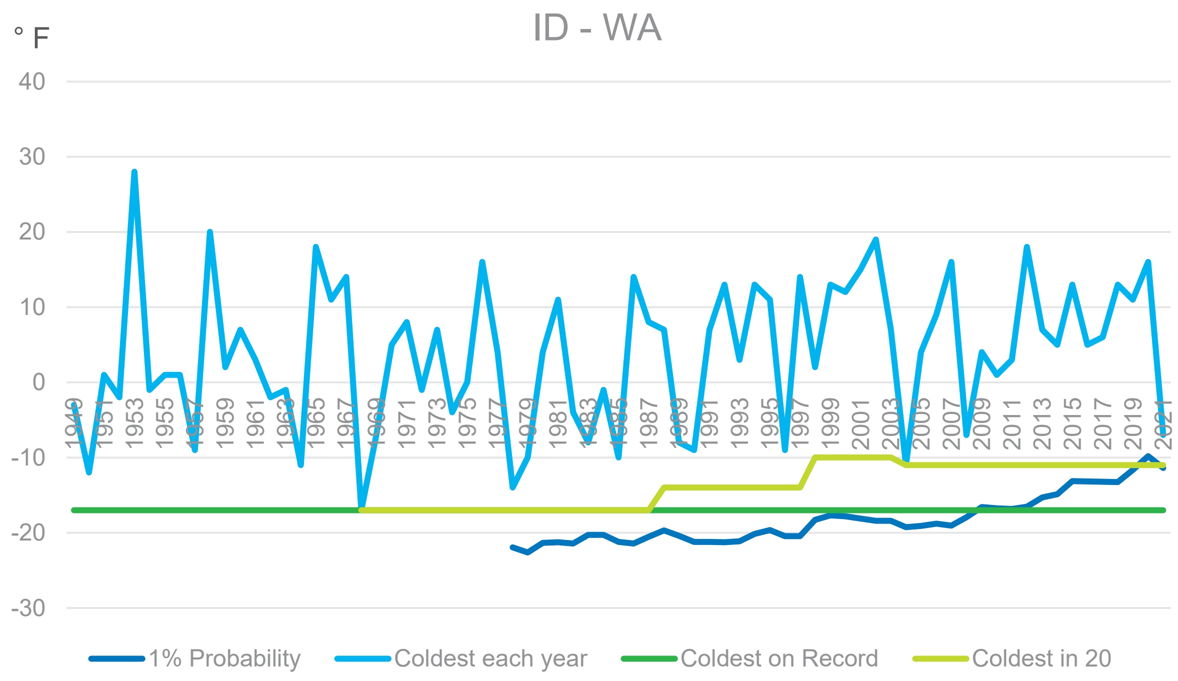


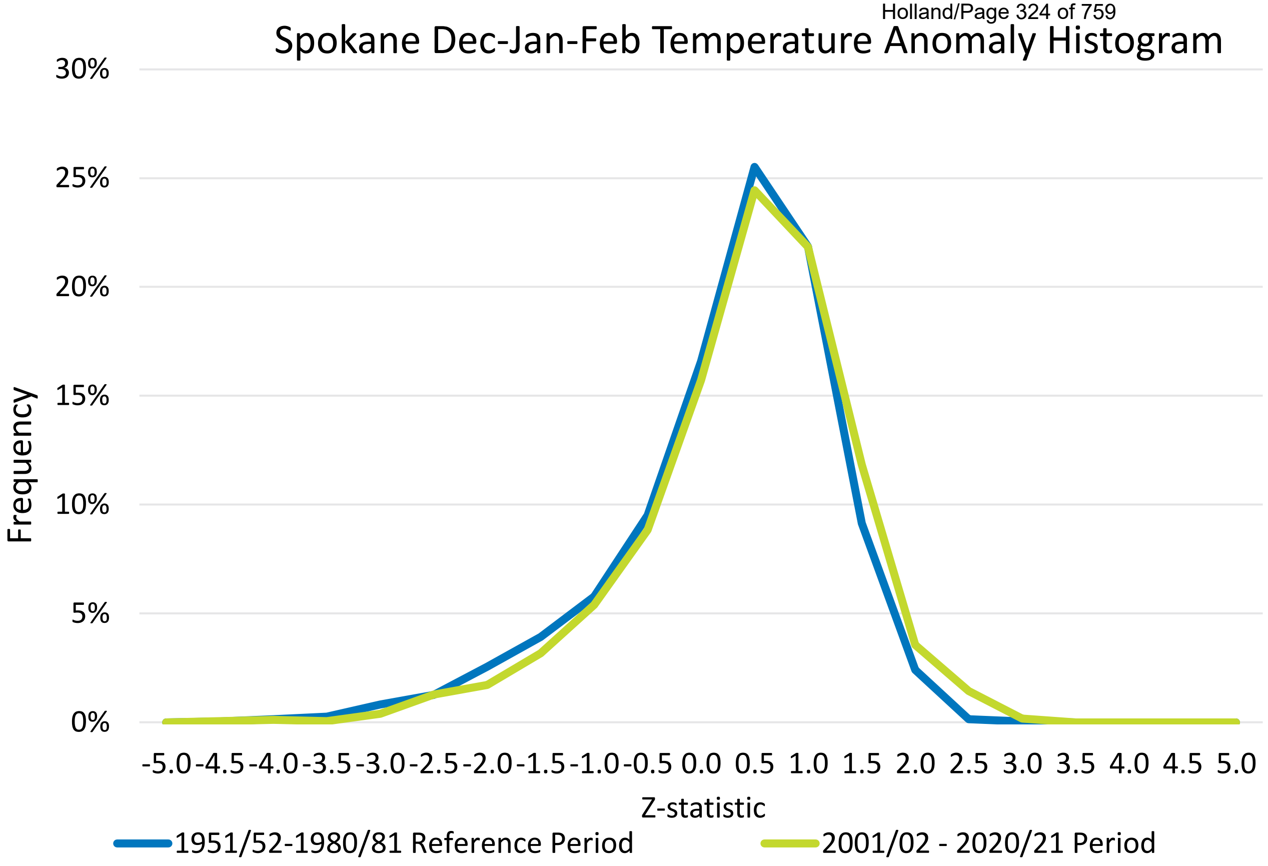
20-Year Average Daily Weather



Idaho - Washington

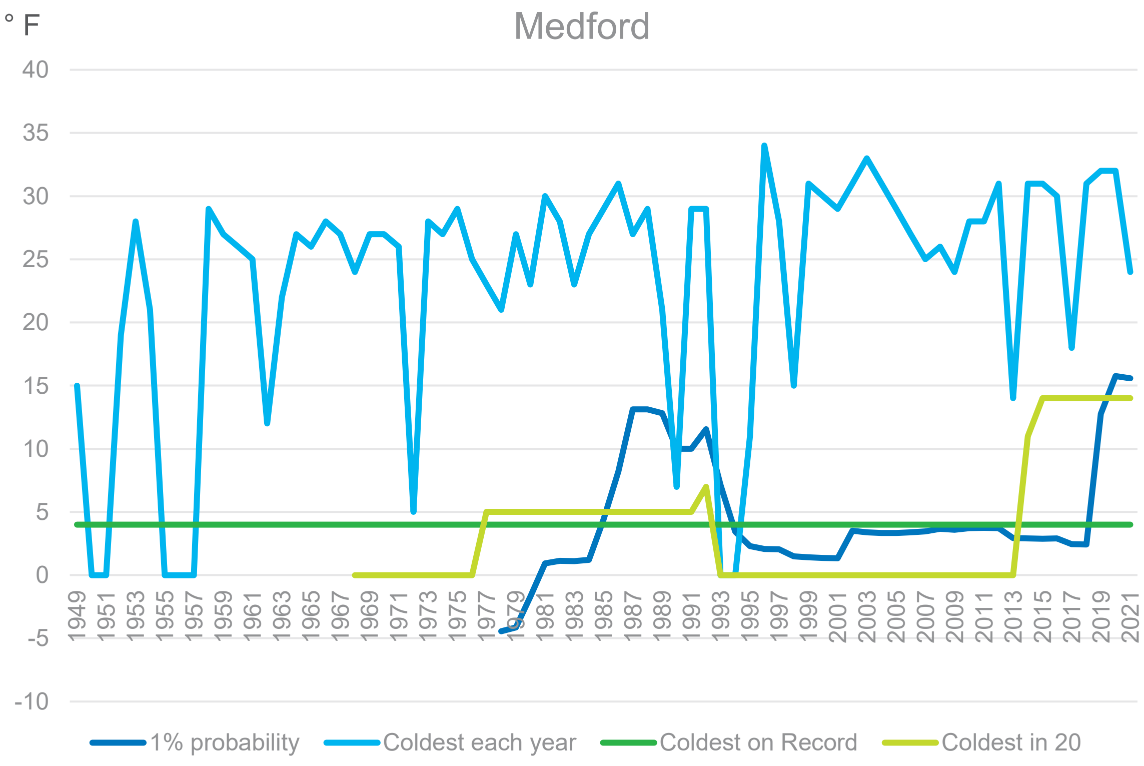
Peak Day -11° F

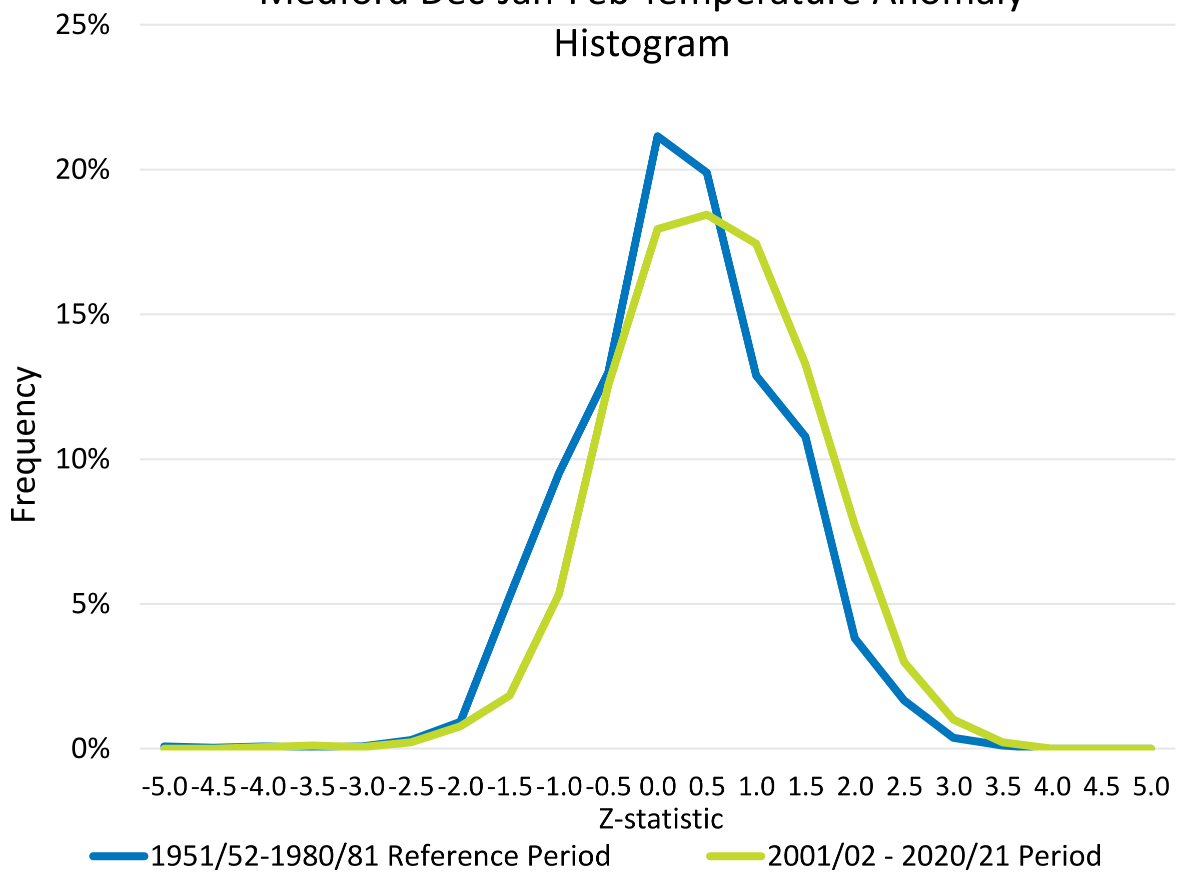




Medford

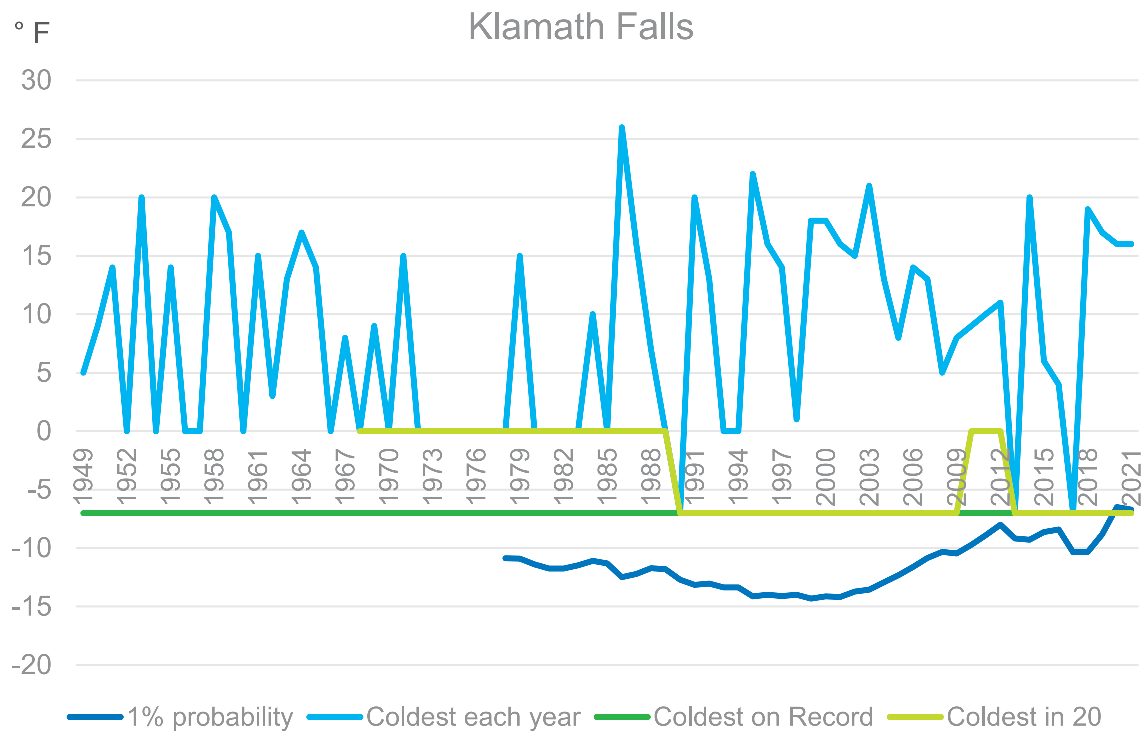
Medford Peak Day 16° F

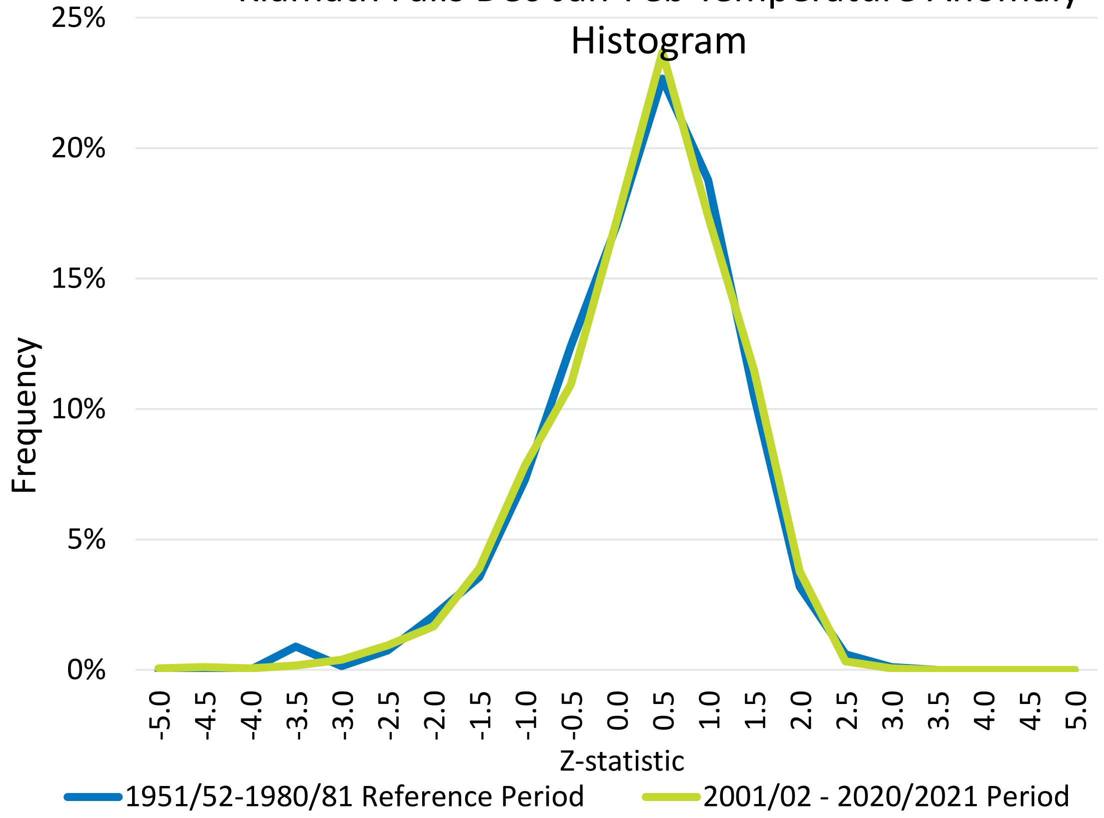




Klamath Falls

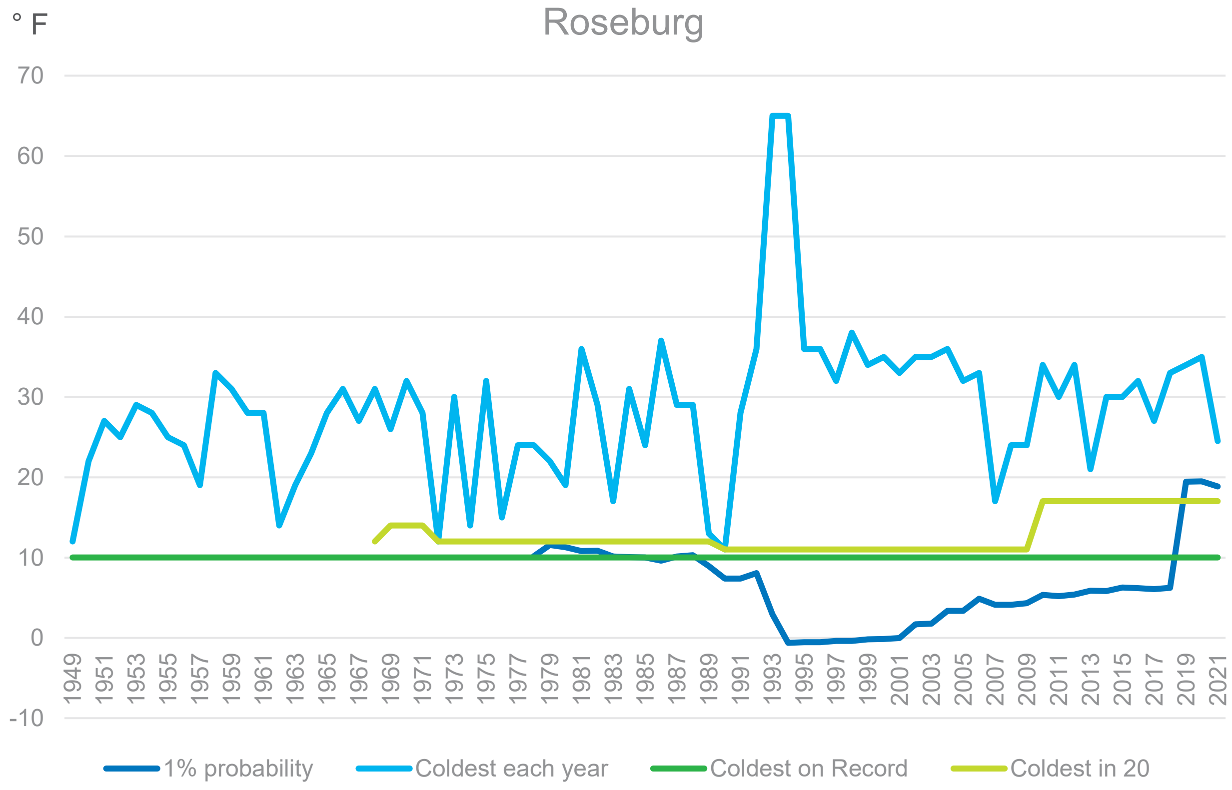
Peak Day -7° F

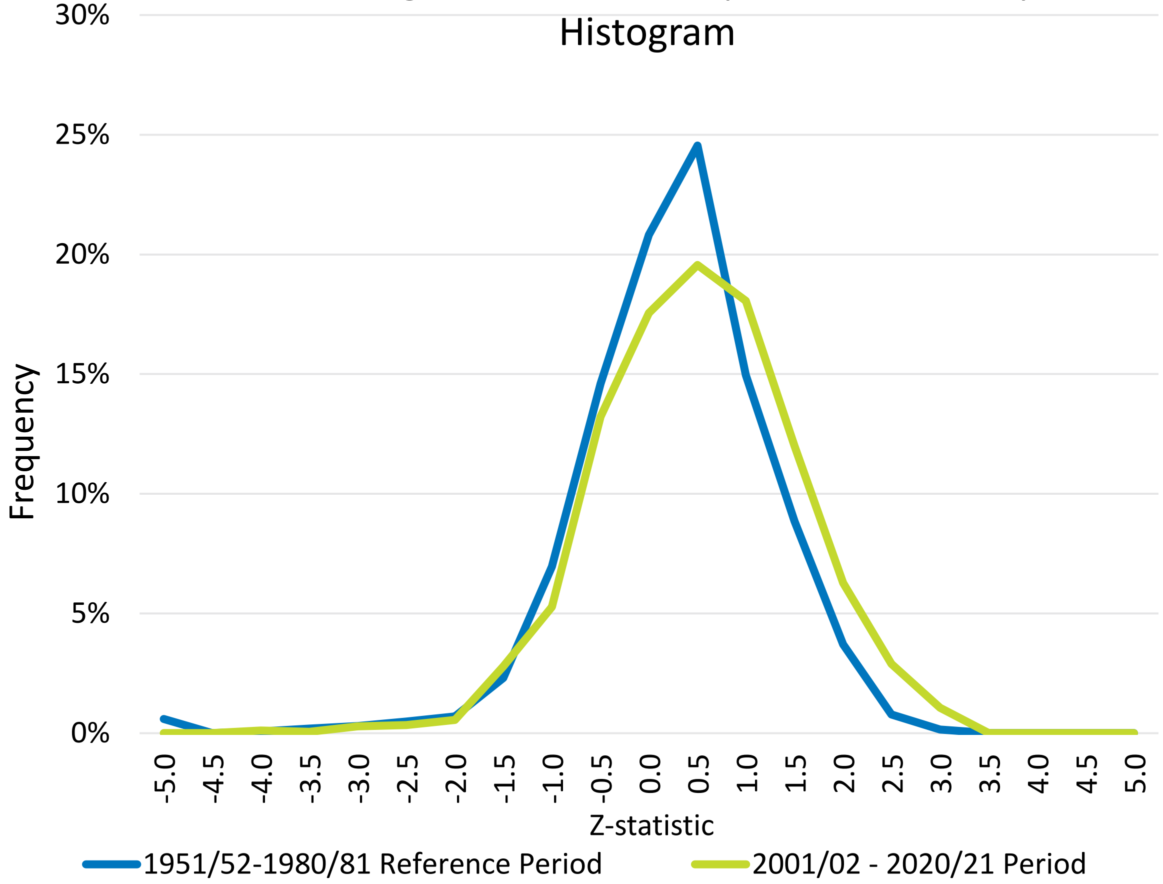




Roseburg

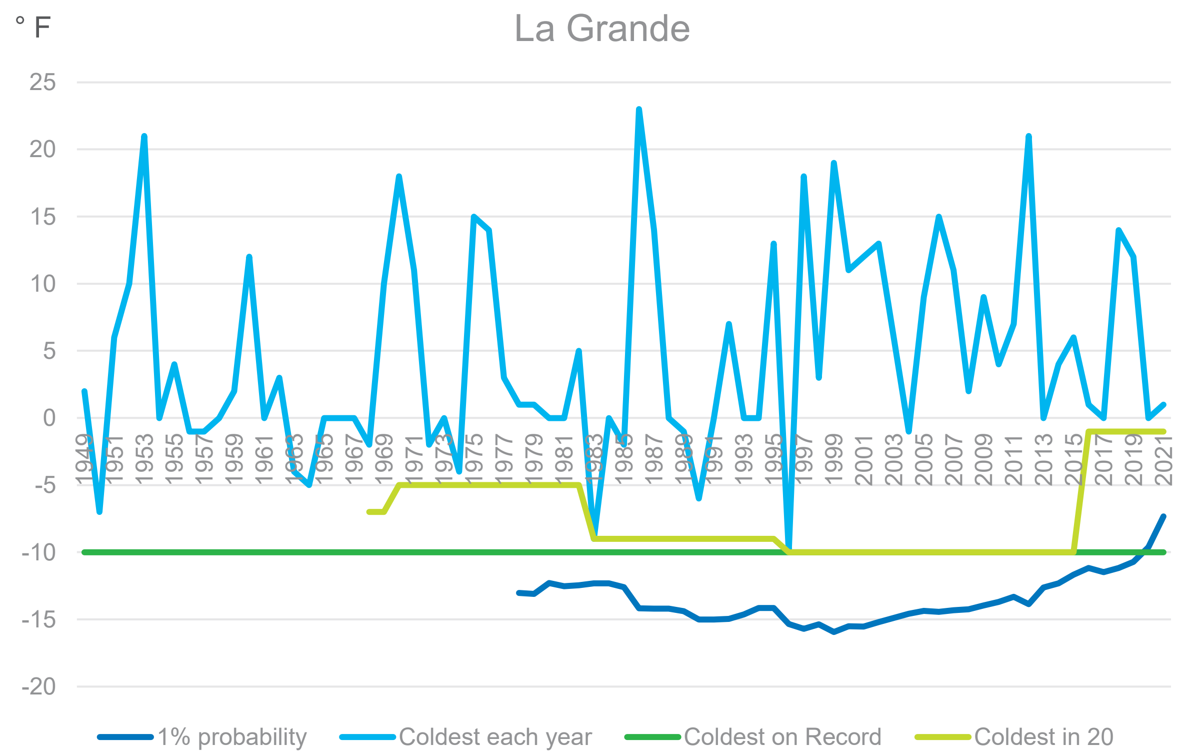
Peak Day 19° F

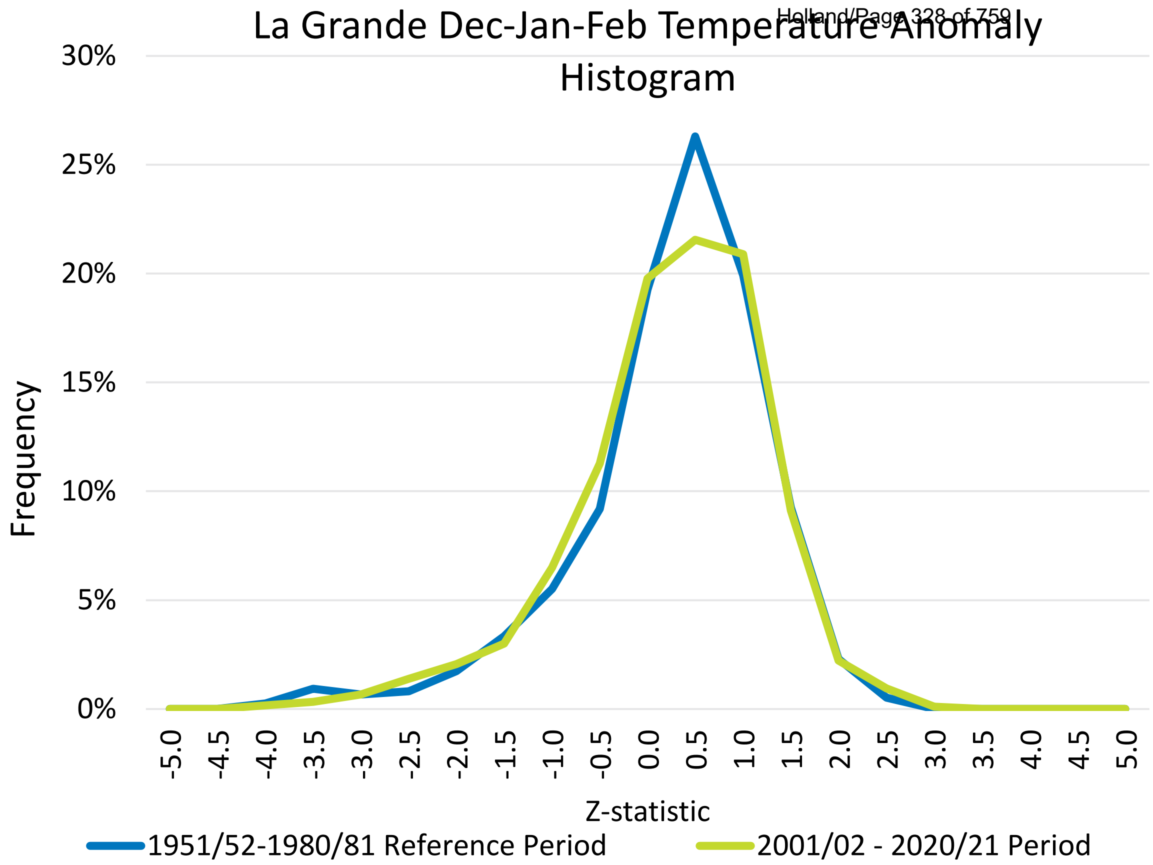




La Grande

Peak Day -7° F





Weather Summary

- Average daily weather by planning region for the past 20 years
- A peak event by planning region based on the past 30 years of the coldest average day, each year, combined with a 1% probability of a weather occurrence
- We are currently evaluating options for using projected weather in our forecasting

Renewable Natural Gas (RNG)

Michael Whitby, RNG Manager

Advancing RNG at Avista

Avista has been actively pursuing RNG. This section covers the following items:

- RNG: A Climate Change Solution
- RNG Procurement
- RNG Pathways & Technologies
- Build vs Buy
- RNG Project Development (Lessons learned)
- RNG Procurement & Potential Project Pipeline
- Voluntary RNG Customer Programs
- Decarbonization Pathways Analysis
- Steps to Decarbonization
- Decarbonization Pathways & CC&R Potential
- Industry Reports
- Policy

RNG: A Climate Change Solution

RNG is a drop-in fuel that has many benefits over alternative solutions

- RNG “Decarbonizes” the gas stream
- RNG is not a fossil fuel and does not add carbon emissions to the atmosphere
- RNG is seamless to our customers and does not require changes to appliances or equipment
- RNG is interchangeable with conventional gas and does not require utilities to make any changes to the existing infrastructure
- RNG leverages an efficient energy delivery system. From production to customer = 91% efficient
- RNG is a here and now solution, however further advancements & supportive policy to expand low carbon fuel pathways through innovation
- RNG supports and enhances the resiliency and reliability of our energy system and is more affordable than electrification scenarios
- RNG leverages the existing infrastructure’s energy storage capabilities that alternative electrification solutions cannot compete with.
- In the right applications, **direct use of natural gas is best use**
- Natural gas generation provides **critical capacity** as renewables expand until utility-scale storage is cost effective and reliable
- RNG **promotes customer fuel choice over choice elimination**

RNG Procurement

Exploring the Procurement Options

To make informed decisions on RNG procurement, Avista set out to understand the known and emerging procurement pathways available for RNG. This has included undertaking a process to research and seek out potential projects, as well as identify technologies and explore innovations that can help to achieve meaningful decarbonization.

Pathways & Technologies

Conventional RNG

Unconventional RNG

Innovative RNG

Primary Approaches

Build

vs.

Buy

RNG Pathways & Technologies

As Avista seeks to identify pathways to decarbonize our gas supply we have been exploring a range of technologies

Technology	Attributes/Comments
Conventional RNG	Amine scrub, membrane separation, H2o wash, pressure swing absorption
Pyro Catalytic Hydrogenation (PCH)	Woody waste to synthetic RNG
Thermal gasification	Plasma Enhanced Melter - Municipal waste to synthetic RNG
Mobile RNG Solution	Small scale remote RNG production & transport without a pipeline
Proprietary biocatalyzed methanation	Unconventional RNG that boosts RNG volumes
Carbon Capture & Recycle (CC&R)	Carbon Reduction
Carbon capture & recycle (CC&R) w/ proprietary biosynthesized methanation	Carbon Reduction & Synthetic RNG
Solar to hydrogen	Green hydrogen in support of CC&R & proprietary methanation

Build vs. Buy

RNG Development Projects (Build)

Avista has been pursuing several RNG projects with a variety of feedstock types to build a pipeline of potential RNG projects. The following list represents the pathways in the order in which they have been pursued:

- Conventional
- Unconventional (proprietary biocatalyzed methanation)
- Innovative Carbon Capture & Recycle (CC&R) solutions

Building RNG projects is complex and comes with a host of challenges.

- RNG projects can be delivered at a lower cost since they do not include the profit margins associated with the California market, however competition for, and influence on the biogas cost still exists.
- Having pursued RNG projects and having purchased RNG, Avista recognizes the value of developing projects on a utility cost of service model, which on a like to like basis is the best value for our customers.

Build vs. Buy

Purchasing RNG (Buy)

- This pathway is widely available with a lot of variations with respect to volumes, costs, and sell back/cost sharing options, however the pricing is influenced by the California transportation sector (Federal RIN & CA LCFS markets).

- Avista has procured an RNG supply for Avista's first ever Voluntary Customer RNG Program in the State of Washington.

RNG Project Development Challenges

Lessons learned from pursuing RNG projects directly with feedstock owners:

- Competition
- The California transportation market dominates the supply
- Federal RIN & California LCFS markets influence commercial terms
- Reaching commercial terms is challenging
- The utility cost of service model is a foreign concept
- Every RNG project is unique
- Economies of scale
- New RNG Projects can take 2-3 years to develop
- Limited feedstock supply
- Partnering strategy
- Picking partners

RNG Procurement & Potential Project Pipeline

Avista has been pursuing RNG projects with a host of feedstock owners for the past few years. The table below captures these efforts by type & volume

#	Project Pathway Type	In Service Avista Territory (Y/N)	Partnering Considered	Estimated Supply (Dth/YR) (Avista only)	Est. Online Date
1	Conventional RNG	Yes	Yes	~ 200K - 350K	2024
2	Unconventional RNG	Yes	Yes	~ 150K - 250K	TBD
3	Unconventional RNG	Yes	Yes	~ 70K - 120K	2024-25
4	Conventional RNG	Yes	Yes	~ 30K - 50K	TBD
5	Conventional RNG	Yes	Yes	~ 20K - 30K	TBD
6	Innovative CC&R RNG	Yes	Yes	~ 50K - 80K	2024-25
7	Thermal Gasification	Yes	Yes	~ 70K - 200K	TBD
8	Conventional RNG	Yes	Yes	~ 60K - 140K	TBD
9	Pyro Catalytic Hydrogenation	Yes	Yes	~ 70K - 150K	TBD
10	Purchased RNG	Yes	No	~ 5K - 10.8K	2022

Voluntary RNG Customer Programs

Q1 2022 - Avista's first ever Voluntary Customer RNG program launched in Washington

- This voluntary RNG subscription is much like Avista's My Clean Energy program, in which customers can elect to purchase pre-defined 'blocks' therms of energy generated from renewable sources.
- The M-RETS system has been selected to track RNG environmental attributes.
  - 1 Renewable Thermal Certificate (RTC) = 1 Dekatherm (Dth) of RNG
  - Transparent electronic certificate tracking

Market related challenges & opportunities:

- Customers lack understanding of RNG since it is a new product
- Customers like the environmental aspects of RNG
- Customers like to choose their level of participation to manage costs predictably

Q2 2022 - Avista will seek approval for a voluntary RNG tariff in Oregon & Idaho

Decarbonization Pathways Analysis

Avista engaged Guidehouse to evaluate and compare various pathways.
The takeaway is that a mix of pathways will be needed to reach decarbonization goals and mandated targets

Comparison of GHG Reduction Pathways

RNG leverages existing Avista infrastructure and allows customers to use existing equipment.

Legend: Favorable ● ◕ ◑ ◔ ○ Unfavorable

GHG Reduction Approaches

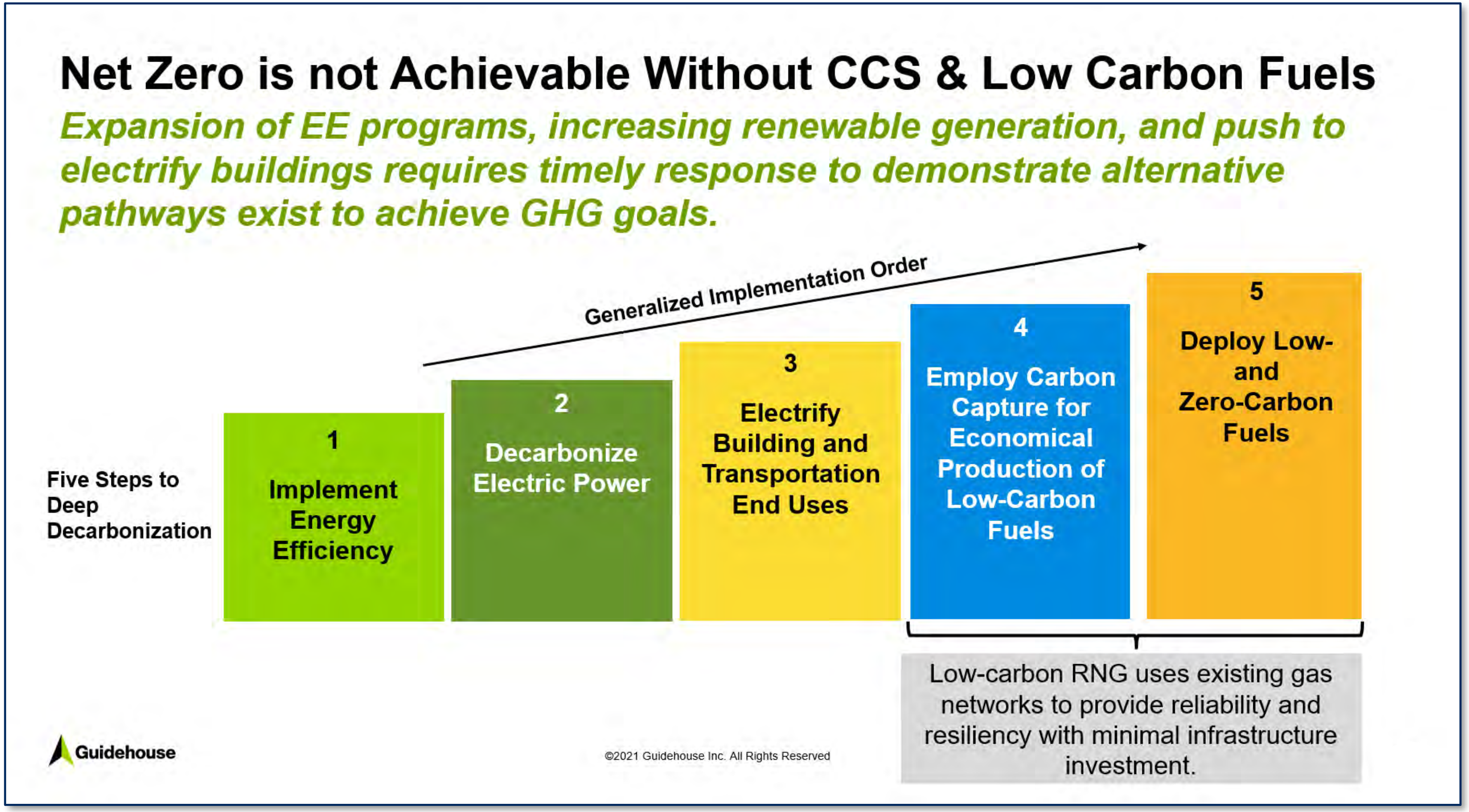
		Pure Hydrogen	Electrification	Gas-Powered Heat Pumps	H2 Blending (HENG)	Energy Efficiency	Biogenic RNG	Synthetic RNG
Customer	Customer Ease of Adoption	○	◔	◔	●	◔	●	●
Customer	Customer Costs	◔	◔	◔	◑	◑	◕	◕
Customer	Other Barriers to Adoption	◔	◔	○	◕	◕	◕	◕
Supplier	Infrastructure, Investment Needs	○	○	●	◔	●	◔	◑
Supplier	Regulatory Barriers	◑	●	●	◑	◕	◑	◑
Supplier	Gas Utility Impact	◑	○	●	◑	◑	◕	◕
	Emissions Impact	◕	◕	◑	◔	◑	◕	◕

Details supporting individual ratings are included as an appendix.

Guidehouse

Steps to Decarbonization – A mix of pathways

The Guidehouse analysis shows the logical decarbonization progression from energy efficiency to the deployment of low carbon fuels

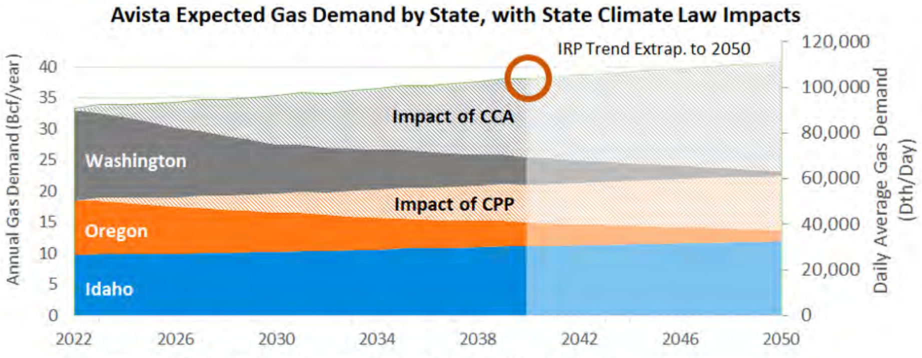


Decarbonization Pathways & CC&R Potential

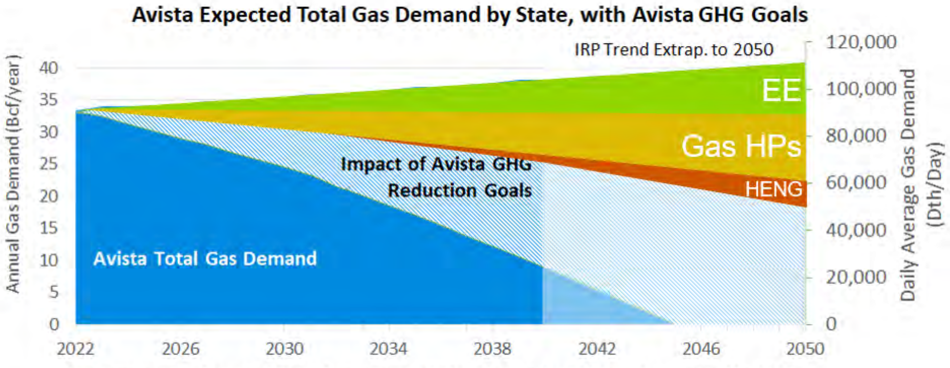
The Guidehouse analysis shows a range of pathways and how Low Carbon fuels including CC&R can help to achieve carbon reduction goals

Market Potential for CC&R – Demand Side

Managing the gap between IRP demand forecast and emission reduction goals requires low carbon fuels



Note: Impact of state climate laws is assessed based on draft rule language.



Note: Impact of Avista goals based on target of 30% reduction by 2030, carbon neutral by 2045.

- Avista IRP projects system-wide demand increase
- OR and WA will require emissions reductions to 2050

- Energy efficiency, gas heat pumps, and hydrogen blending can provide GHG reductions, but are not sufficient
- Low-carbon fuels such as RNG are required to meet Avista goals and state requirements

Sources:
2021 Avista Natural Gas IRP (link), p.3
Avista (2021). “Avista declares natural gas emission reduction goal.” (link)
Washington CCA draft rule (link); Oregon CPP draft rules (link)

Guidehouse

AVISTA

RNG Pathways Analysis

The Guidehouse analysis included a comparison of Electrification to Low Carbon Fuel pathways as a part of Avista's resource mix.

Scenario Modeling Findings

CC&R technology has higher CAPEX "price tag" than conventional RNG, but a low-carbon fuels pathway with CC&R will be less expensive than deep electrification.

Total CAPEX through 2050 for Oregon, Washington, and Idaho
Note: Estimates do not include OPEX, fuel costs, or stranded asset costs

GHG Reduction Interventions	Electrification Scenario	Low-Carbon Fuel Scenario, no CC&R	Low-Carbon Fuel Scenario, with CC&R
Downstream Electrification (Building heat + HW, EVs, industry)	◕	◑	◑
Efficiency (Buildings, transport, industrial process)	○	◑	◑
Low Carbon Fuels (RNG, hydrogen)	○	◔	◑
Electric Capacity (New generation and T&D)	●	◕	◕

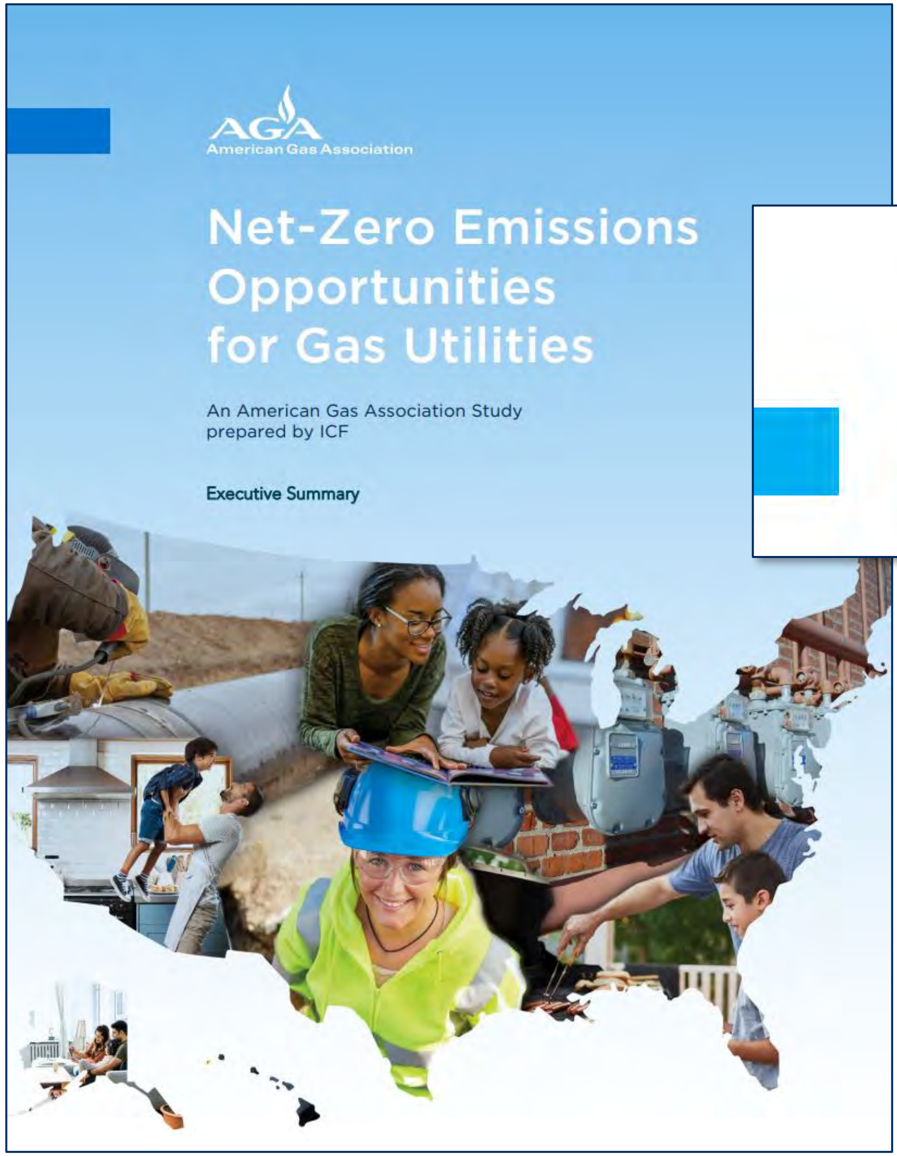
Legend
- ○ <$5 B
- ◔ $5 B - $10 B
- ◑ $10 B - $25 B
- ◕ $25 B - $50 B
- ● >$50 B

- Scenario modeling indicates that a high electrification scenario will incur a higher CAPEX cost per ton of GHG emissions abated, due to the sharp increase in infrastructure that will be needed for electric generation, transmission, and distribution.
- In comparison, a low-carbon fuel scenario incurs lower total CAPEX cost by utilizing gas infrastructure that is already in place.
- The introduction of CC&R technology increases gas system costs, but not to the order that high electrification would require.

Guidehouse

AVISTA

Industry Reports



Avista's experience in pursuing RNG comports with the findings found within AGA's latest report.

AGA Net-Zero Emissions Opportunities for Gas Utilities: **Executive Summary** **February 2022**

Large amounts of renewable and low-carbon electricity and gases, and negative emissions technologies, will be required to meet an economy-wide 2050 net-zero target

AGA Net-Zero Emissions Opportunities for Gas Utilities: **Executive Summary** **February 2022**

Using a range of different approaches and technologies, gas utilities can meet net-zero GHG emissions targets, and the appropriate mix of measures will vary by region and utility

Supportive policy and regulatory approval will be essential for gas utilities to achieve net-zero emissions

AVISTA

Policy

RNG leverages existing infrastructure and customer equipment. A mix of solutions including conventional & innovative low carbon fuels will be needed to reach decarbonization goals and targets.

Policy and Regulatory Drivers Impact Regional Operations

Legislation targets in Avista's service area require CO2 reduction;
LDCs must demonstrate the role for low-carbon fuels

Avista's Natural Gas Emissions Reduction Goals	
2030	30% Reduction
2045	Carbon Neutral

GHG reduction options for Gas LDCs:

1. Sell less gas (via efficiency, electrification)
2. Reduce carbon intensity of gas system
3. Purchase carbon offsets

WA Climate Commitment Act
GHG reductions:
45% by 2030, 95% by 2050.

No GHG Targets in Idaho

OR Executive Order 20-04
GHG reductions:
45% by 2035, **90%** by 2050

Guidehouse

Questions?

Climate Protection Plan (CPP) Overview

CPP Purpose and Scope

- Signed into Law on March 10, 2020 by Governor Kate Brown via Executive Order 20-04

- The purposes of the Climate Protection Program are to:
  - reduce greenhouse gas emissions that cause climate change from sources in Oregon
  - achieve co-benefits from reduced emissions of other air contaminants, and
  - enhance public welfare for Oregon communities, particularly environmental justice communities disproportionately burdened by the effects of climate change and air contamination.

- Local distribution companies, known as natural gas utilities
  - covered emissions do not include emissions from biomass derived fuels.

- Does not include emissions from landfills, electric power plants, and natural gas compressor stations on and owned by interstate pipelines.

OAR 340-271-0010

Program Coverage

- Local distribution companies
  - Covered emissions do not include emissions from biomass derived fuels.

- Covered emissions described as anthropogenic greenhouse gas emissions from combustion of natural gas, excluding natural gas used at large electricity generating facilities.

- Covered stationary sources include: Stationary sources for covered emissions described as anthropogenic greenhouse gas emissions from industrial processes and fuel combustion not otherwise regulated from a covered fuel supplier and that meet or exceed 25,000 MT CO2e.

- Does not include emissions from landfills, electric power plants, and natural gas compressor stations on and owned by interstate pipelines.
  - Does not include emissions from biomass-derived fuels
  - New stationary sources with the potential to emit covered emissions at or above 25,000 MT CO2e.

Compliance

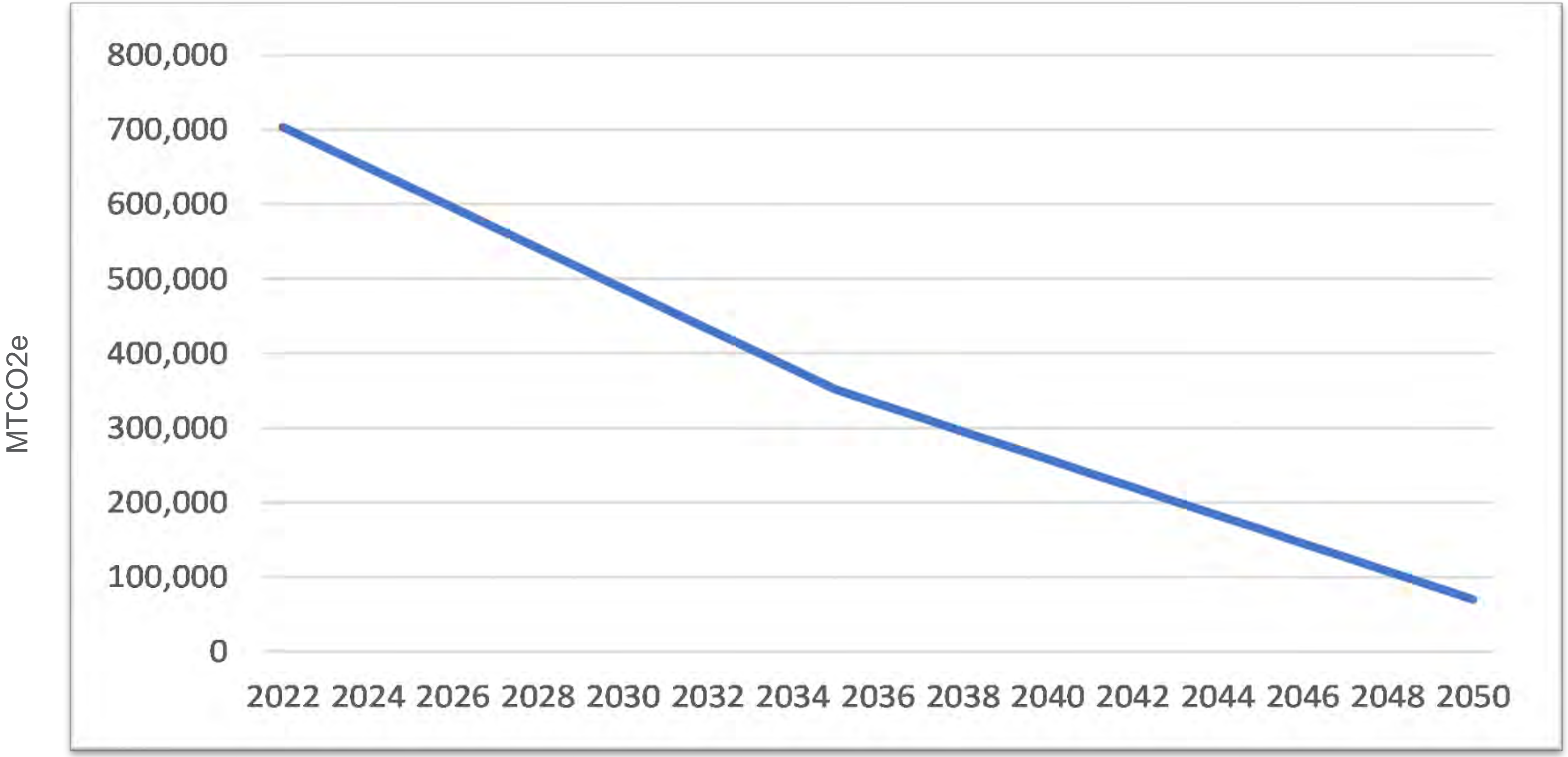
A compliance period is three years. This first compliance period begins with 2022 and includes calendar years 2023 and 2024.

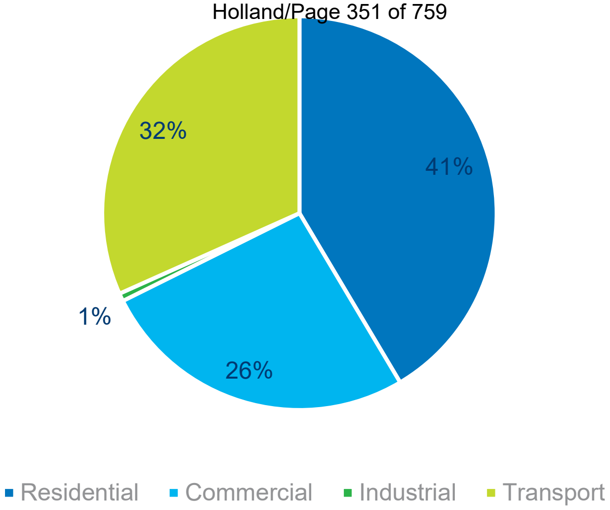
Demonstration of compliance is only required after a three-year compliance period.

OAR 340-271-9000
Table 1
Thresholds for applicability described in OAR 340-271-0110(3)

Applicability determination calendar year(s)	Threshold for applicability to compare to annual covered emissions	Calendar year a person becomes a covered fuel supplier
Any year from 2018 through 2022	200,000 MT CO2e	2022
2023	200,000 MT CO2e	2023
2024	200,000 MT CO2e	2024
Any year from 2021 through 2025	100,000 MT CO2e	2025
2026	100,000 MT CO2e	2026
2027	100,000 MT CO2e	2027
Any year from 2024 through 2028	50,000 MT CO2e	2028
2029	50,000 MT CO2e	2029
2030	50,000 MT CO2e	2030
Any year from 2027 through 2031	25,000 MT CO2e	2031
2032	25,000 MT CO2e	2032
Each subsequent year	25,000 MT CO2e	Each subsequent year

Avista Emissions Target





OAR 340-271-9000
Table 4
Compliance instrument distribution to covered fuel suppliers that are local distribution companies

Calendar year	Compliance instruments to distribute to Avista Utilities	Compliance instruments to distribute to Cascade Natural Gas Corporation	Compliance instruments to distribute to Northwest Natural Gas Company
2022	703,373	743,707	5,759,972
2023	676,320	715,103	5,538,434
2024	649,267	686,499	5,316,897
2025	622,214	657,895	5,095,359
2026	595,161	629,291	4,873,822
2027	568,109	600,687	4,652,285
2028	541,056	572,083	4,430,747
2029	514,003	543,478	4,209,210
2030	486,950	514,874	3,987,673
2031	459,897	486,270	3,766,135
2032	432,845	457,666	3,544,598
2033	405,792	429,062	3,323,061
2034	378,739	400,458	3,101,523
2035	351,686	371,854	2,879,986
2036	332,930	352,021	2,726,387
2037	314,173	332,189	2,572,787
2038	295,416	312,357	2,419,188
2039	276,660	292,525	2,265,589
2040	257,903	272,693	2,111,990
2041	239,147	252,860	1,958,390
2042	220,390	233,028	1,804,791
2043	201,633	213,196	1,651,192
2044	182,877	193,364	1,497,593
2045	164,120	173,532	1,343,993
2046	145,364	153,699	1,190,394
2047	126,607	133,867	1,036,795
2048	107,850	114,035	883,196
2049	89,094	94,203	729,596
2050 and each calendar year thereafter	70,337	74,371	575,997

DEQ will distribute compliance instruments to covered fuel suppliers by March 31 of each year as follows: Covered fuel suppliers that are natural gas utilities will receive an annual distribution of compliance instruments described in Table 4.

OAR 340-271-9000 – Table 4

Community Climate Investment (CCI)

(2) A CCI entity may use CCI funds only for:

(a) Implementing eligible projects in Oregon, which are actions that reduce anthropogenic greenhouse gas emissions that would otherwise occur in Oregon.

- Eligible projects include actions that reduce emissions in Oregon resulting from:
  - (A) Transportation of people, freight, or both;
  - (B) An existing or new residential use or structure;
  - (C) An existing or new industrial process or structure; and
  - (D) An existing or new commercial use or structure.

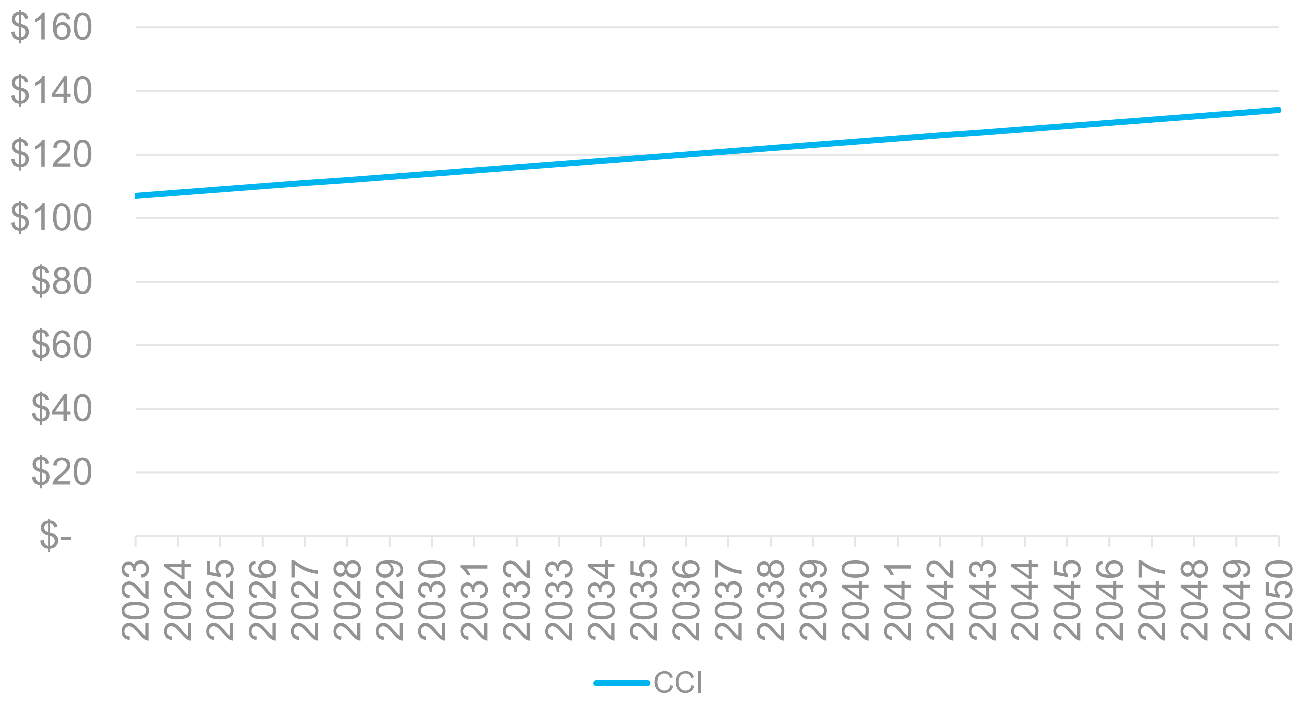
DEQ State of Oregon Department of Environmental Quality

OAR 340-271-9000
Table 6
Covered fuel supplier allowable usage of community climate investment credits to demonstrate compliance as described in OAR 340-271-0450(3)

Compliance period	Allowable percentage of total compliance obligation(s) for which compliance may be demonstrated with CCI credits
Compliance period 1 (2022 through 2024)	10%
Compliance period 2 (2025 through 2027)	15%
Compliance period 3 (2028 through 2030), and for each compliance period thereafter	20%

AVISTA

CCI Costs



OAR 340-271-9000
Table 7
CCI credit contribution amount

Effective date	CCI credit contribution amount in 2021 dollars, to be adjusted according to OAR 340-271-0820(3)
March 1, 2023	$107
March 1, 2024	$108
March 1, 2025	$109
March 1, 2026	$110
March 1, 2027	$111
March 1, 2028	$112
March 1, 2029	$113
March 1, 2030	$114
March 1, 2031	$115
March 1, 2032	$116
March 1, 2033	$117
March 1, 2034	$118
March 1, 2035	$119
March 1, 2036	$120
March 1, 2037	$121
March 1, 2038	$122
March 1, 2039	$123
March 1, 2040	$124
March 1, 2041	$125
March 1, 2042	$126
March 1, 2043	$127
March 1, 2044	$128
March 1, 2045	$129
March 1, 2046	$130
March 1, 2047	$131
March 1, 2048	$132
March 1, 2049	$133
March 1, 2050	$134

UM-2178

Scope: The purpose of this Fact Finding will be to analyze the potential natural gas utility bill impacts that may result from limiting GHG emissions of regulated natural gas utilities under the DEQ's Climate Protection Program and to identify appropriate regulatory tools to mitigate potential customer impacts. The ultimate goal of the Fact Finding will be to inform future policy decisions and other key analyses to be considered in 2022, once the CPP is in place.

- Presentations and modeling was provided to the OPUC and other stakeholders to understand the LDC's ability to meet EO 20-04

- Avista intends to build the findings and additional supply side resources into the 2023 IRP as a way of showing a more detailed path and analysis to compliance

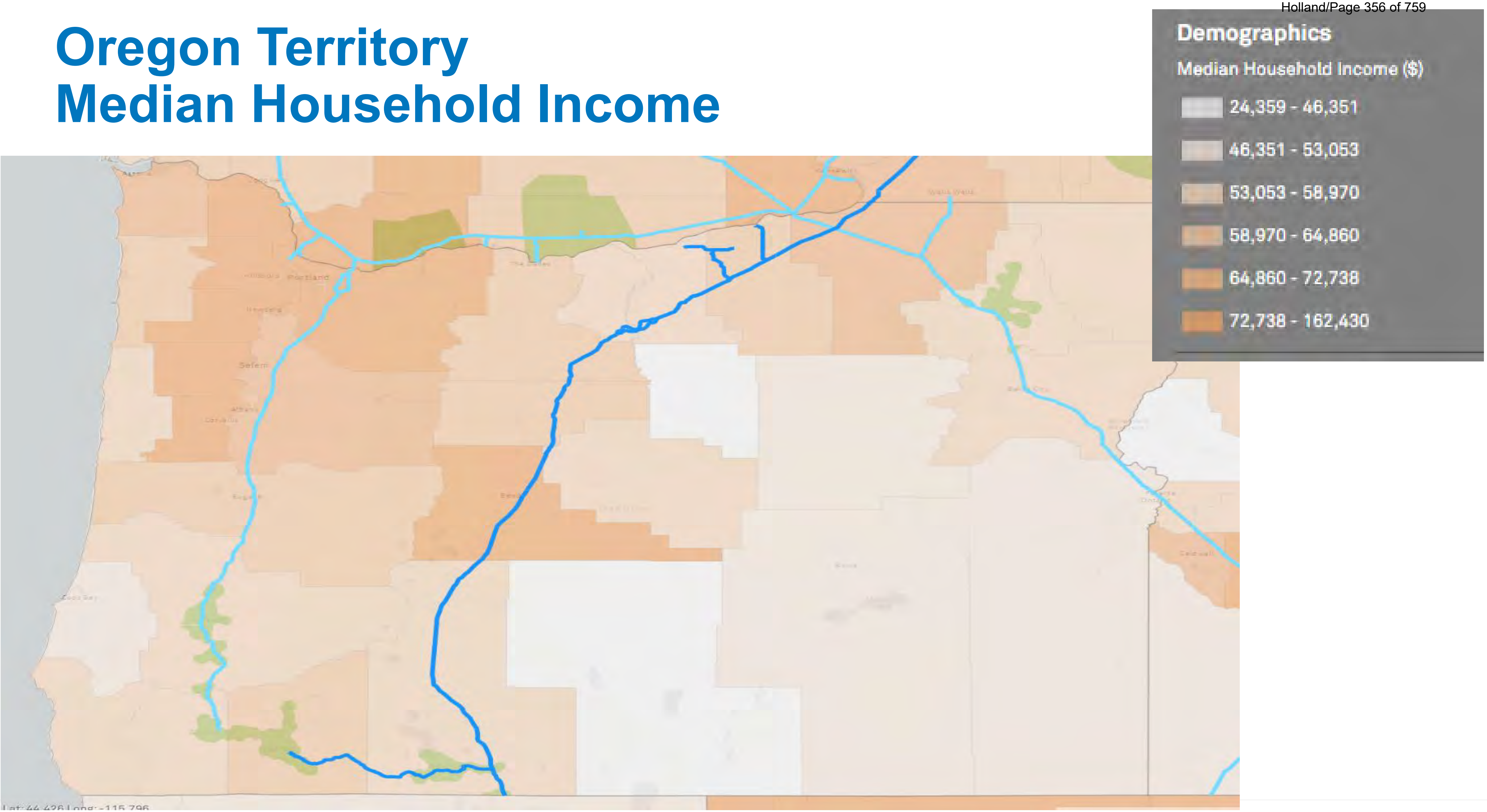
State of Oregon: Public Utility Commission of Oregon

Avista Compliance to CPP

Challenges to CPP	Opportunities of CPP
More entities looking for same resources	clean up grid
As a smaller LDC additional costs are spread across fewer customers	a specific directive to decarbonize with goals
Cost Equity, Avista's customers are generally less wealthy as compared to other Oregon counties	LDCs play an active role in Oregon's clean energy future
Increased demand for limited new resources drives higher prices	Utilize SB 98 to help projects online
Clean Fuel Supply Ramp up to match cap in near term	Increased Energy Efficiency Potential
Higher Costs	Gas continues to hold economic fuel choice to decarbonize the electric grid
Responsibility for transport customers emissions	
Technology Maturation	
Cost Recovery	
Reliability of Electric System with additional load	
Rate pressure will lead to the utilization of different heating fuels	
Limited ability to link to other state's clean energy programs	
Infrastructure Cost recovery – Electrification will result in costs being spread across a smaller customer base	

Host a workshop within two months of the publishing of DEQ's Clean Power Plan Rules, to discuss challenges and opportunities to incentivize near-term actions to reduce GHGs to meet Clean Power Plan targets, including consideration of SB 98 and SB 844 programs.

Oregon Territory
Median Household Income



Source: SNL maps

Questions?

Scenarios - Draft

- **Preferred Resource Case** – Our expected case based on assumptions and costs with a least risk and least cost resource selection
- **Avista company goal - Carbon Neutral by 2045** – Intended to move the 2050 state/federal goals up to the company goal of 2045
- **Electrification Push –** A low case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **High Customer Case** – A high case to measure risk of additional customer and meeting our emissions and energy obligations
- **Limited RNG Availability** – A scenario to show costs and supply options if RNG availability is smaller than expected
- **High Prices - Interrupted Supply** – A scenario to show the impacts and risks associated with large scale supply impacts and the ability for Avista to provide the needed energy to our customers
- **Other?**

2023 – Avista Natural Gas IRP

TAC #1
- February 2022

TAC #2
- April 2022

TAC #3
- June 2022

TAC #4
- August 2022

TAC #5
- October 2022

Draft IRP to TAC
- January 2023

TAC #6 (if necessary)
- February 2023

File IRP
- April 2023

Natural Gas Integrated Resource Plan

Technical Advisory Committee (TAC) # 2

May 3, 2022

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be documented and recorded

2023 – Avista Natural Gas IRP

Major Milestone	Date	Topics
TAC 1	Wednesday, February 16, 2022	RNG Discussion, Compliance To EO 20-04, Policy, Peak Day Weather Planning Standard
TAC 2	Tuesday, May 3, 2022	Use Per Customer, Planned Scenarios, Customer Forecast, Current Supply Side Resources, Plexos Model Overview, Baseline Demand Projections
TAC 3	Wednesday, June 22, 2022	Customer Survey Results,CCA Overview, Distribution
TAC 4	Tuesday, August 23, 2022	Future Supply Side Resource Options, CPA, Demand Response
TAC 5	Tuesday, October 25, 2022	Final Results / Stochastics, Scenario Results
Draft Feedback Due	Wednesday, February 1, 2023	
File	Friday, March 31, 2023	

Agenda

Item	Time
2023 Timeline / Agenda Overview	9:00am – 9:10am
Customer Forecast	9:10am – 9:40am
Use per Customer	9:40am – 10:10am
Break	10:10am – 10:20am
Current Supply Side Resources	10:20am – 11:00am
Plexos Model Overview	11:00am – 11:30am
Proposed Scenarios	11:30am – 12:00pm

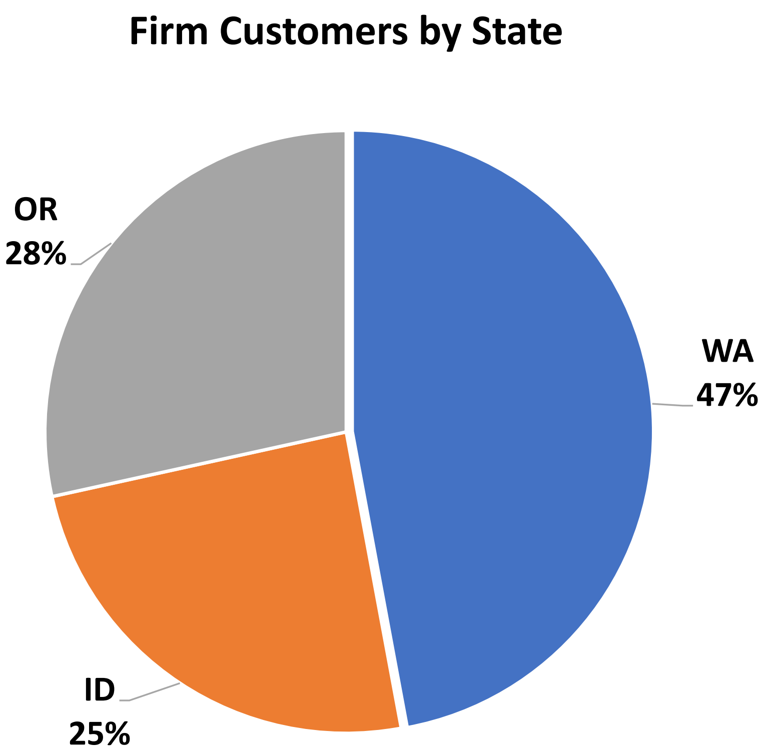
2023 IRP Long-Run Customer Forecast: Natural Gas

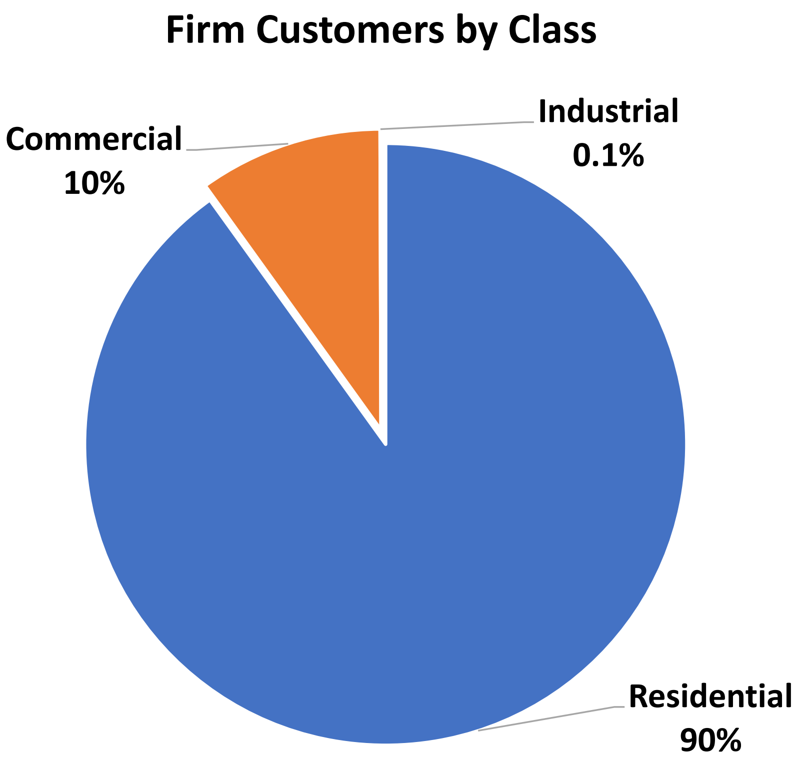
Grant D. Forsyth, Ph.D.

Grant.Forsyth@avistacorp.com

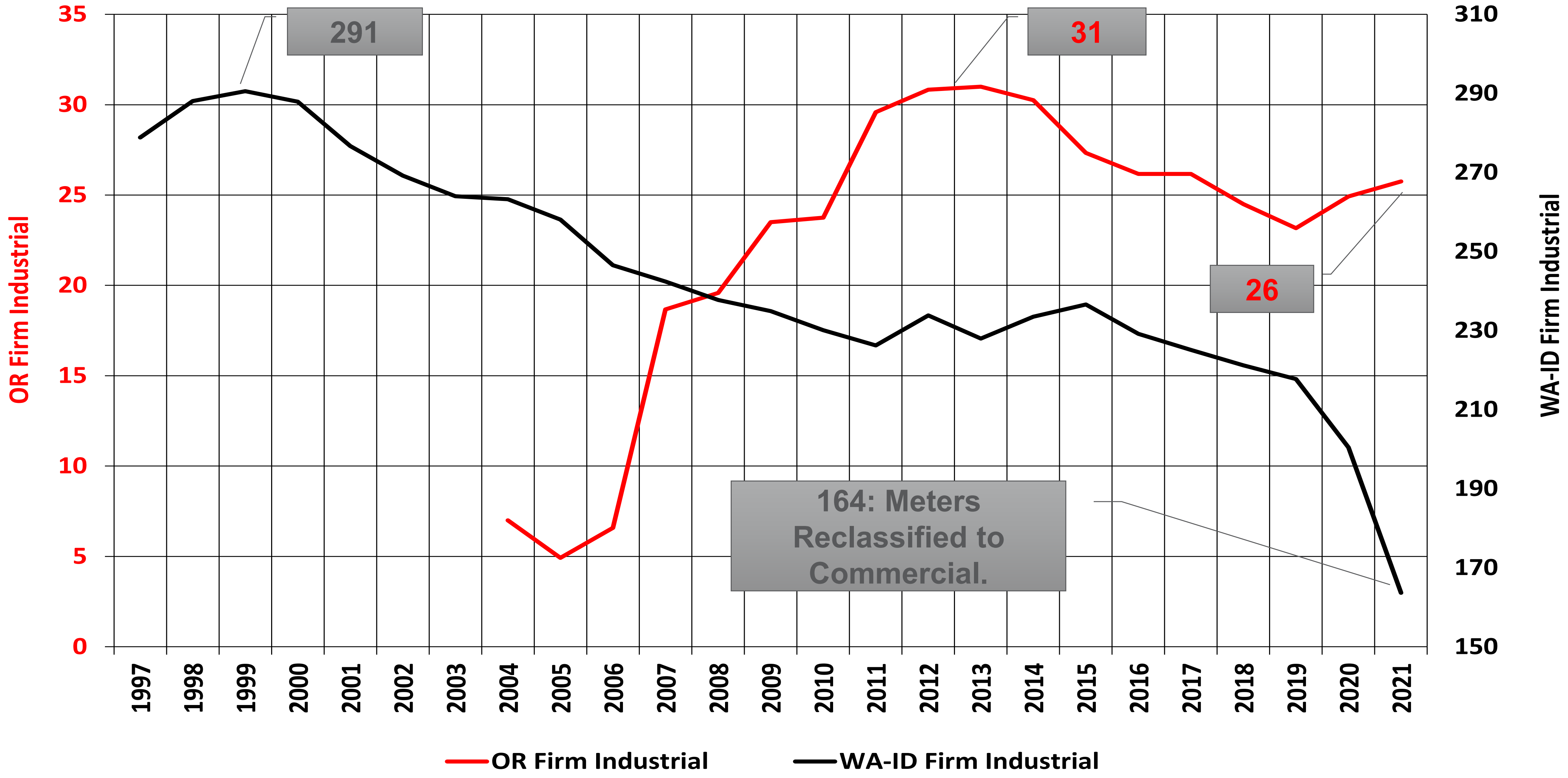
Chief Economist

Firm Customers (Meters) by State and Class, 2021





System Firm Industrial Customers, 1997-2021



Customer Forecast Models

- Forecast models are structured around each schedule, in each class, by jurisdiction. In the case of OR, this is done individually for each of Avista’s service islands.
- Time series transfer function models (models with regressions drivers and ARIMA error terms).
- Simple time series smoothing models (for schedules with little customer variation).
- Same models used for the bi-annual revenue model forecast pushed out to 2045. The forecasts for this IRP were generated from the “Spring 2022” forecast completed in March 2022.
- Customer forecasts are sent to Gas Supply for inclusion in the PLEXOS model.
- Example of transfer function model: WA sch. 101 residential customers…

Transfer Function Model Example

Monthly Customer (Meter Count)

Monthly Interpolated Population for Spokane MSA

Seasonal Dummies

Structural Change Dummy for a Step-up in Customers (Interventions for steps up or down).

$$C_{t,y,WA101.r} = \alpha_0 + \tau POP_{t,y,SPK} + \boldsymbol{\omega_{SD}\, D_{t,y}} + \omega_{SC} D_{Sep\ 2018=1} + \omega_{OL} D_{Oct\ 2015=1} + \omega_{OL} D_{Feb\ 2016=1} + \omega_{OL} D_{Mar\ 2018=1} + \omega_{OL} D_{Nov\ 2018=1} + \omega_{OL} D_{Sep\ 2020=1} + ARIMA\epsilon_{t,y}\,(12,1,0)(0,0,0)_{12}$$

Error Correction Component

Outlier Dummy (Interventions)

Getting to Population as a Driver, 2022-2026 & 2027-2045

2022-2026 For Spokane, WA; Kootenai, ID, and Jackson+Josephine, OR

Average GDP Growth Forecasts:
- WSJ, FOMC, Bloomberg, etc.
- Average forecasts out 5 full calendar years.

GDP →

Non-farm Employment Growth Model:
- Model links year y, y-1, and y-2 GDP growth to year y regional employment growth.
- Forecast out 5 full calendar years.
- Averaged with IHS employment growth forecasts.

EMP →

Regional Population Growth Models:
- Model links regional, U.S., and CA year y-1 employment growth to year y county population growth.
- Forecast out 5 full calendar years for Spokane, WA; Kootenai, ID; and Jackson+Josephine, OR.
- Averaged with IHS growth forecasts.
- Growth rates used to generate population forecasts for use in regression models—important driver for main residential and commercial schedules.

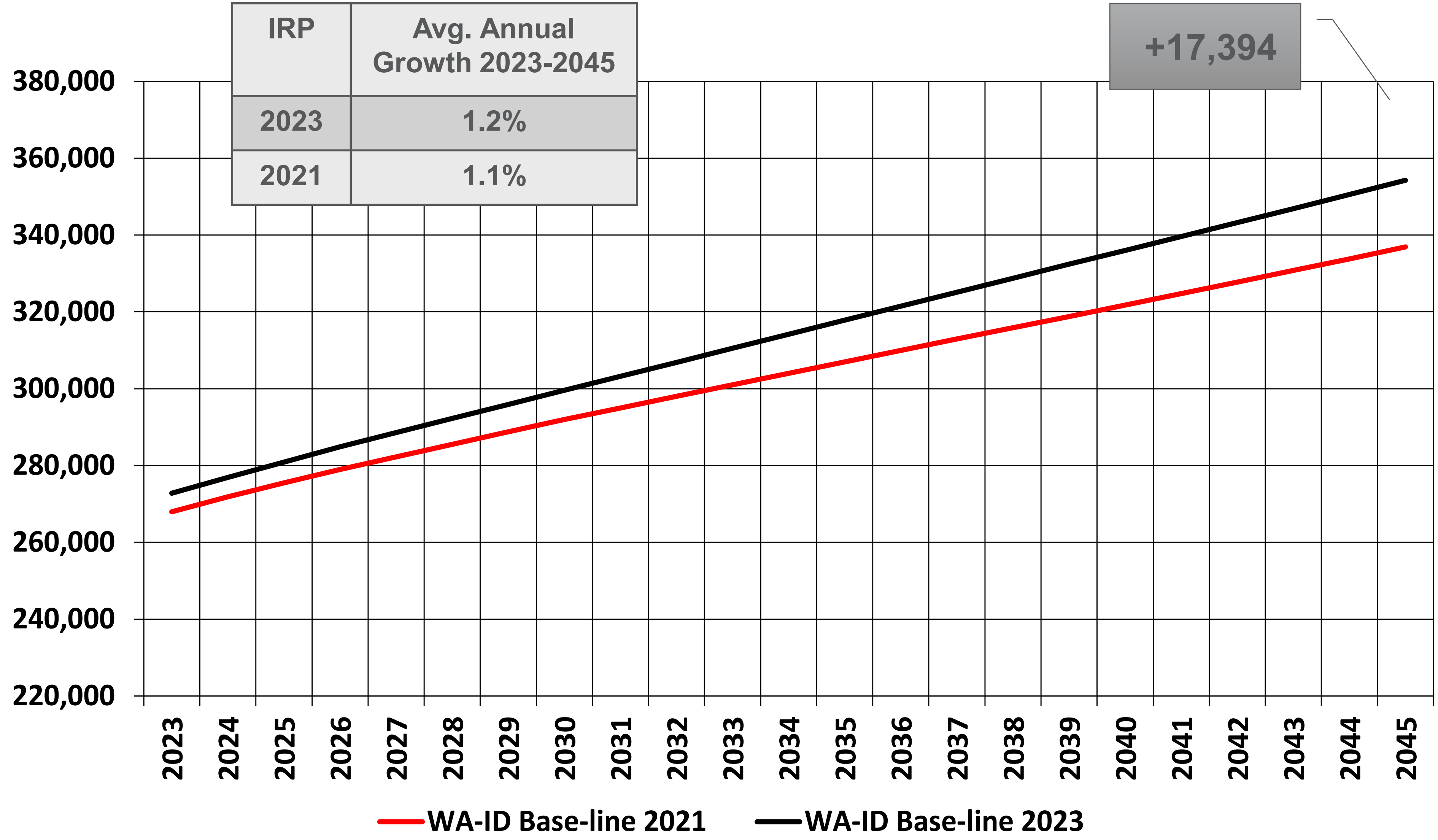
Kootenai and Jackson: IHS population growth forecasts for 2027-2045

Spokane: IHS population growth forecasts for 2027-2045

OR Douglas, Klamath, and Union counties: IHS population growth forecasts for 2027-2045

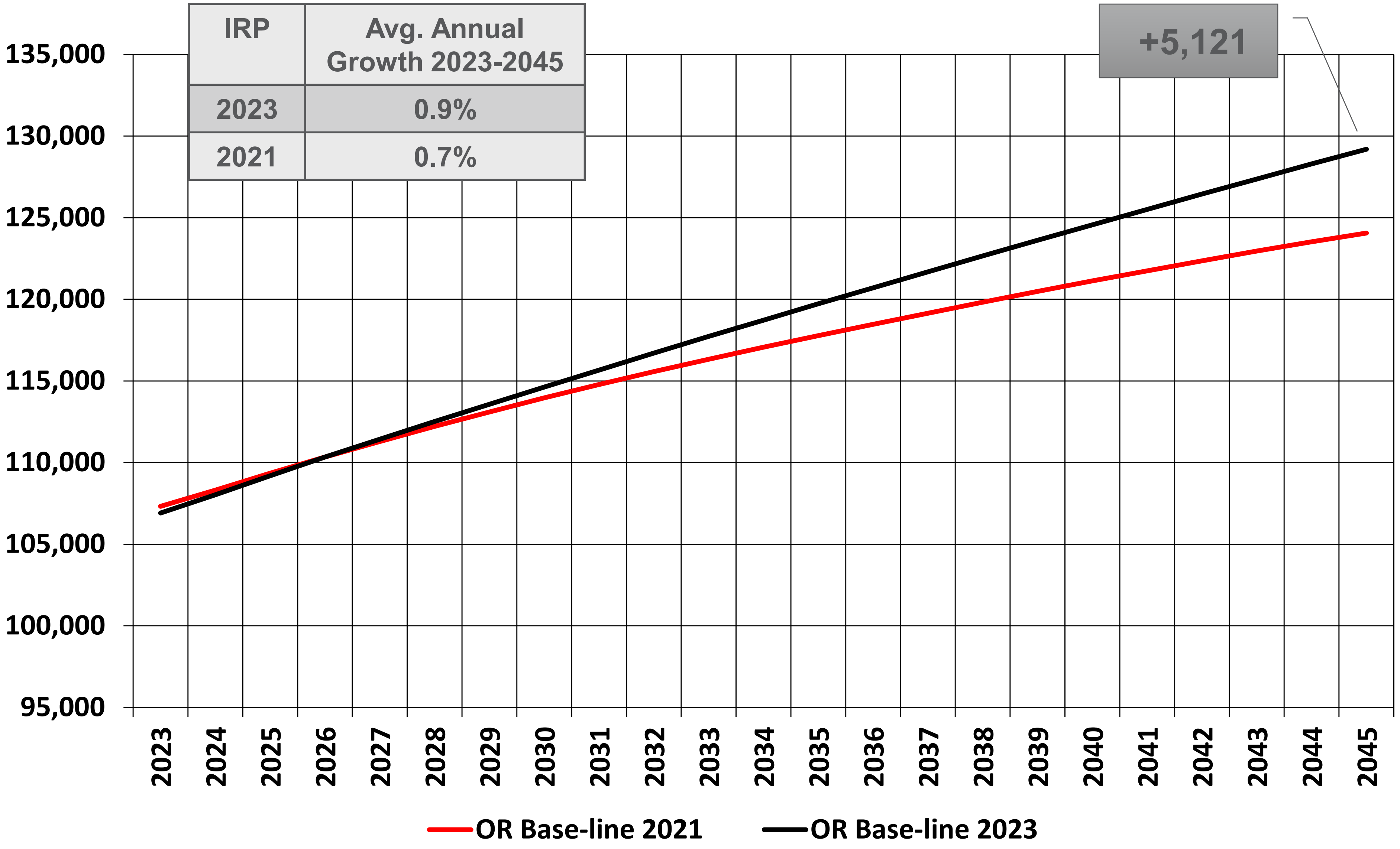
Monthly Interpolation assumes: $P_N = P_0 e^{rN}$

WA-ID Region Firm Customers (2023-2045)



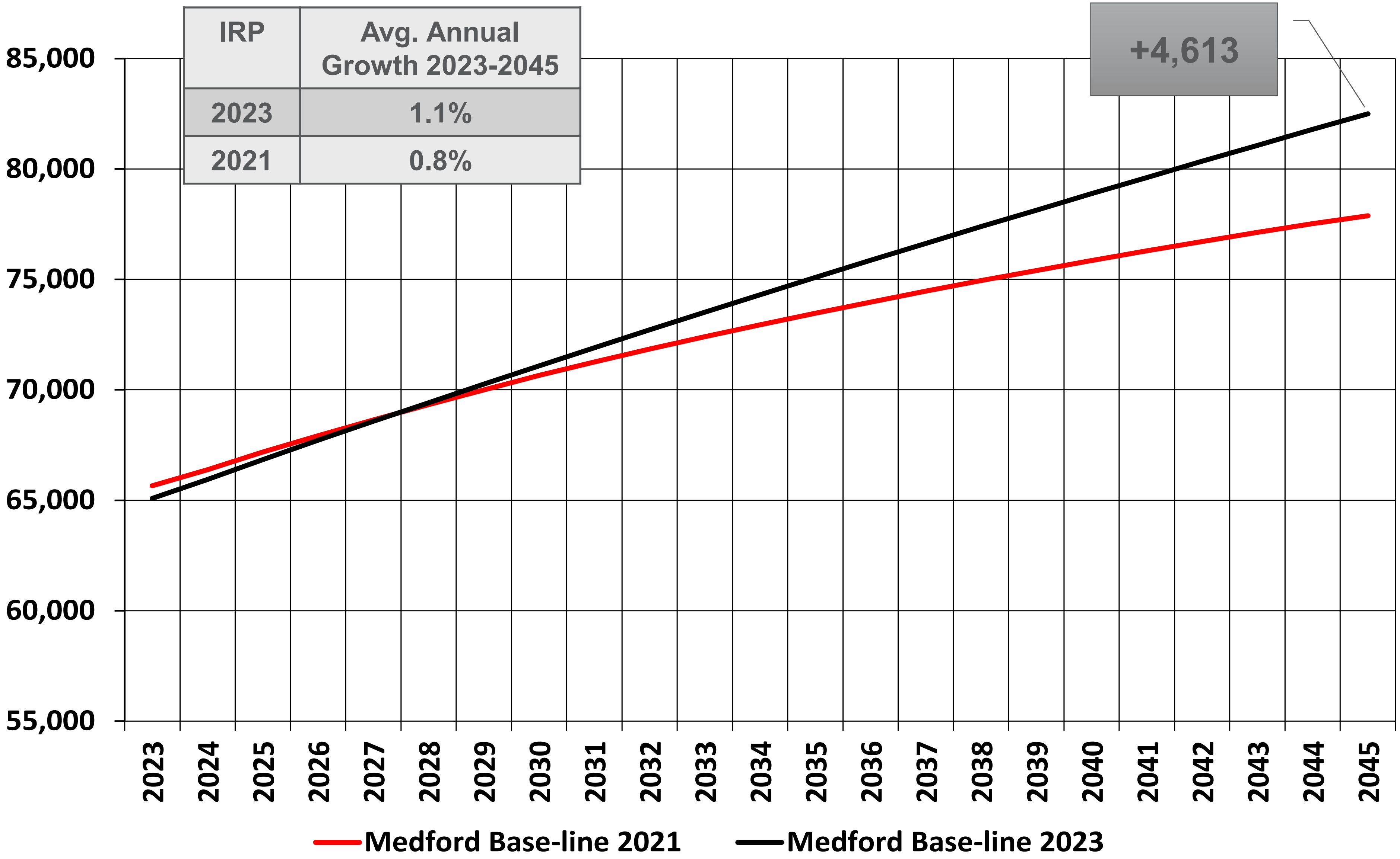
OR Region Firm Customers (2023-2045)

IRP	Avg. Annual Growth 2023-2045
2023	0.9%
2021	0.7%



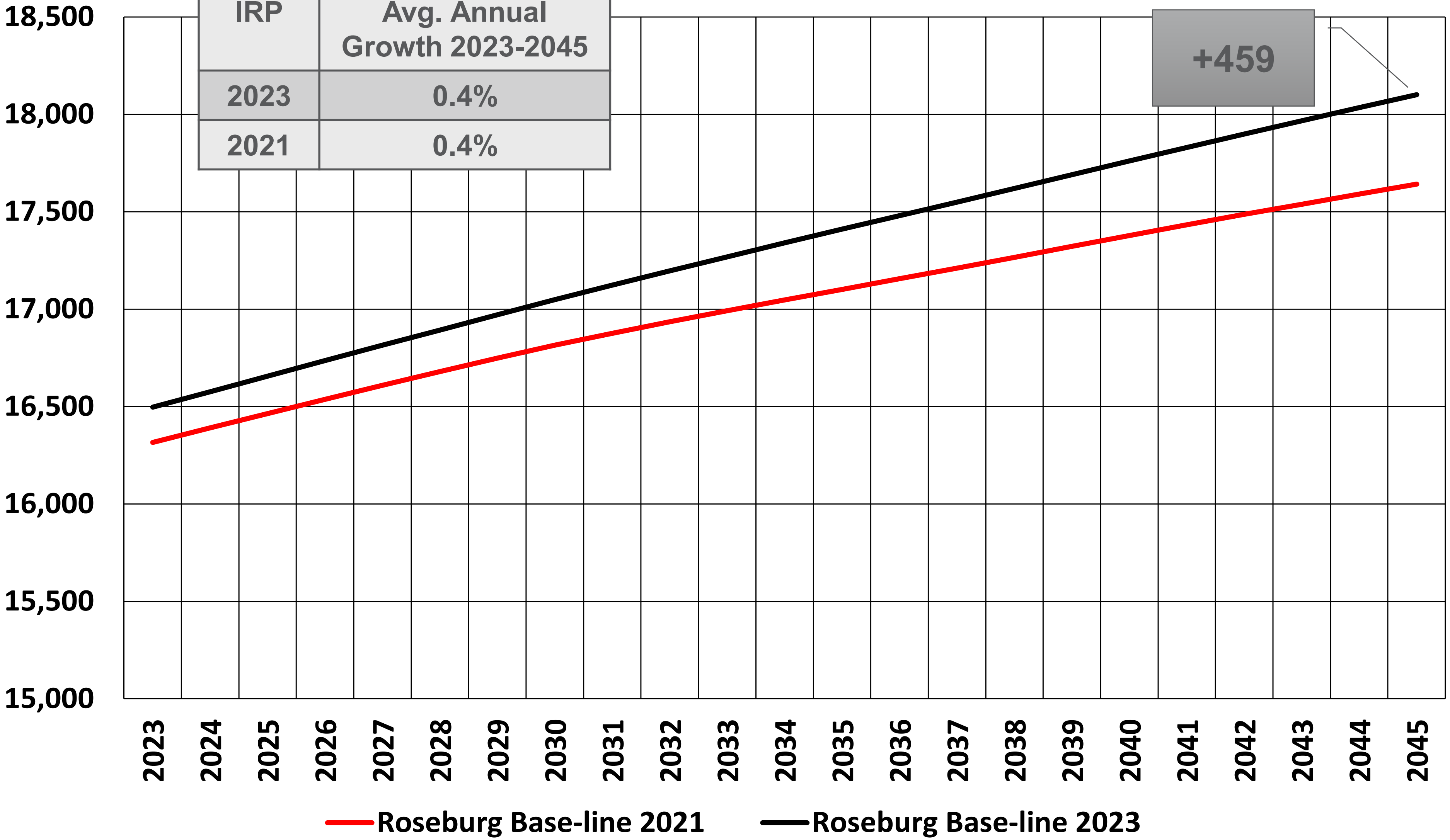
Medford, OR Region Firm Customers (2023-2045)

IRP	Avg. Annual Growth 2023-2045
2023	1.1%
2021	0.8%

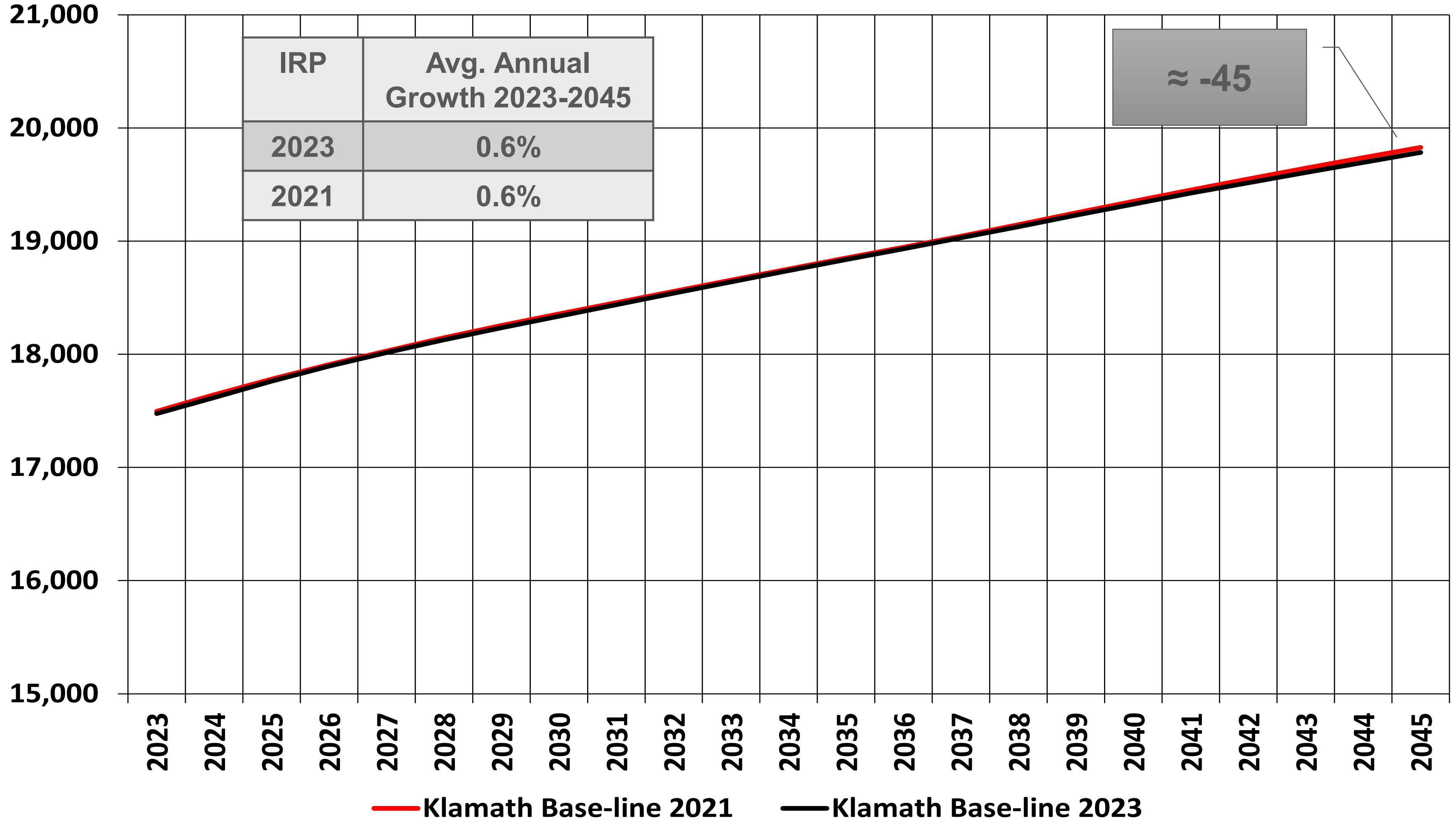


Roseburg, OR Region Firm Customers (2023-2045)

IRP	Avg. Annual Growth 2023-2045
2023	0.4%
2021	0.4%



Klamath, OR Region Firm Customers (2023-2045)

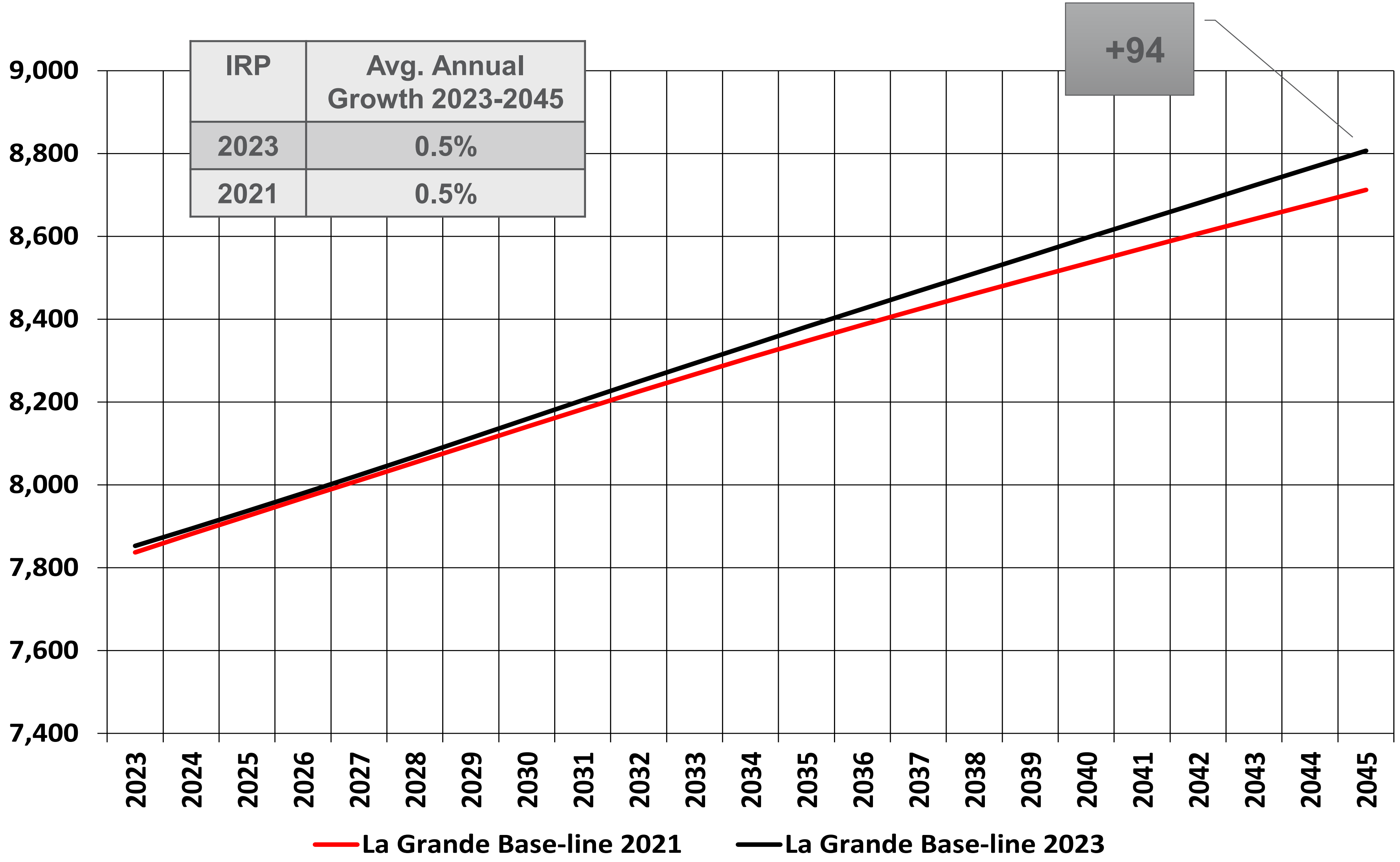


IRP	Avg. Annual Growth 2023-2045
2023	0.6%
2021	0.6%

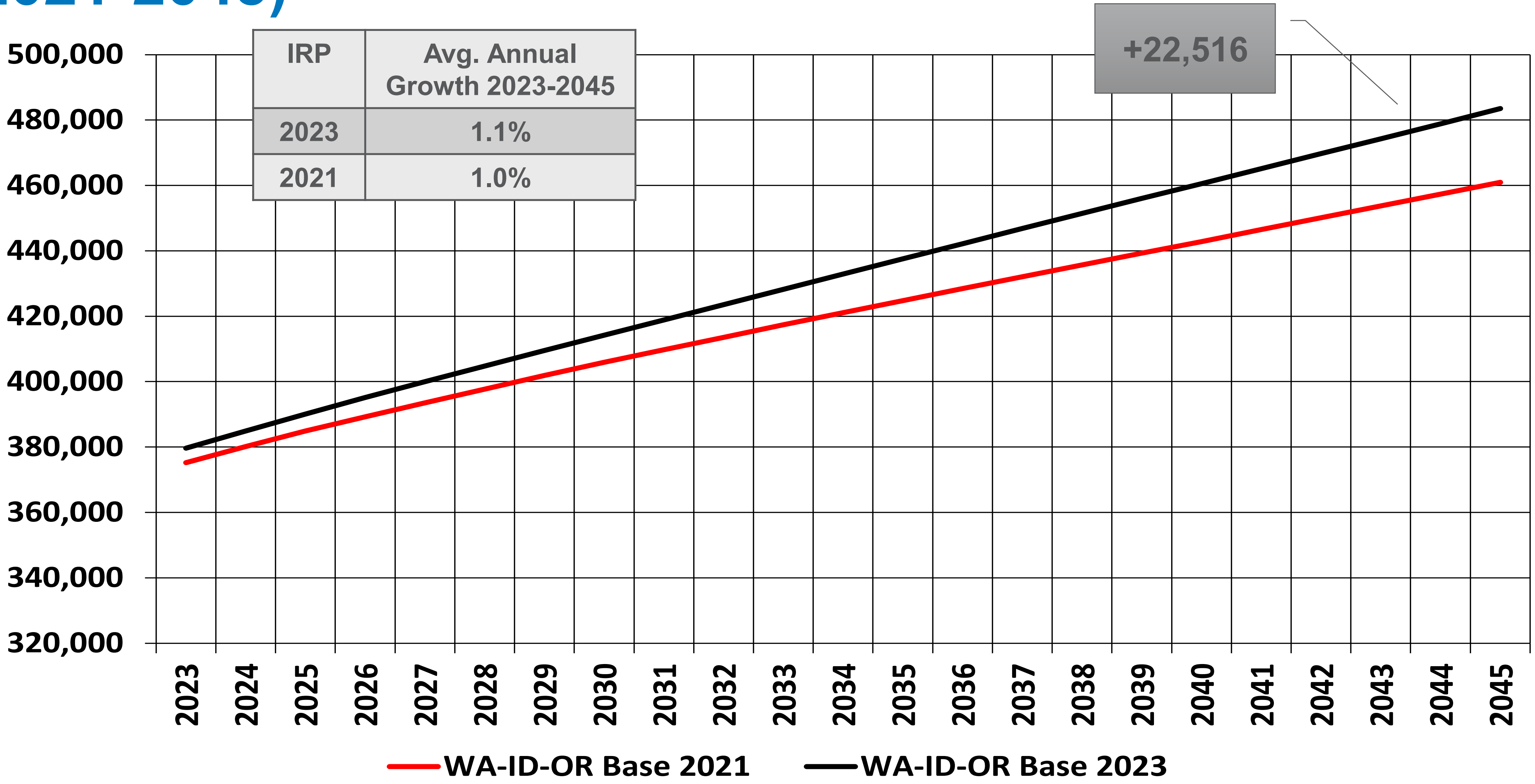
AVISTA

La Grande, OR Region Firm Customers (2023-2045)

IRP	Avg. Annual Growth 2023-2045
2023	0.5%
2021	0.5%



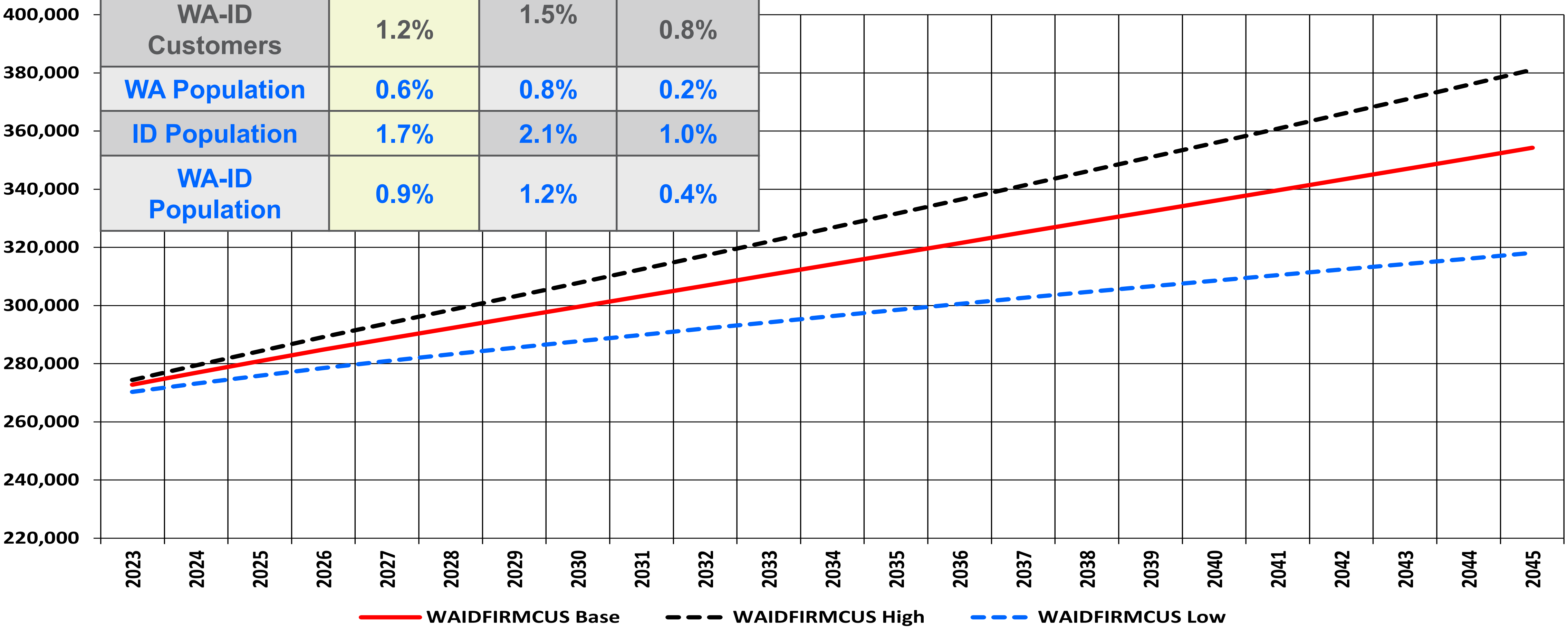
System Firm Customers (2021-2045)



IRP	Avg. Annual Growth 2023-2045
2023	1.1%
2021	1.0%

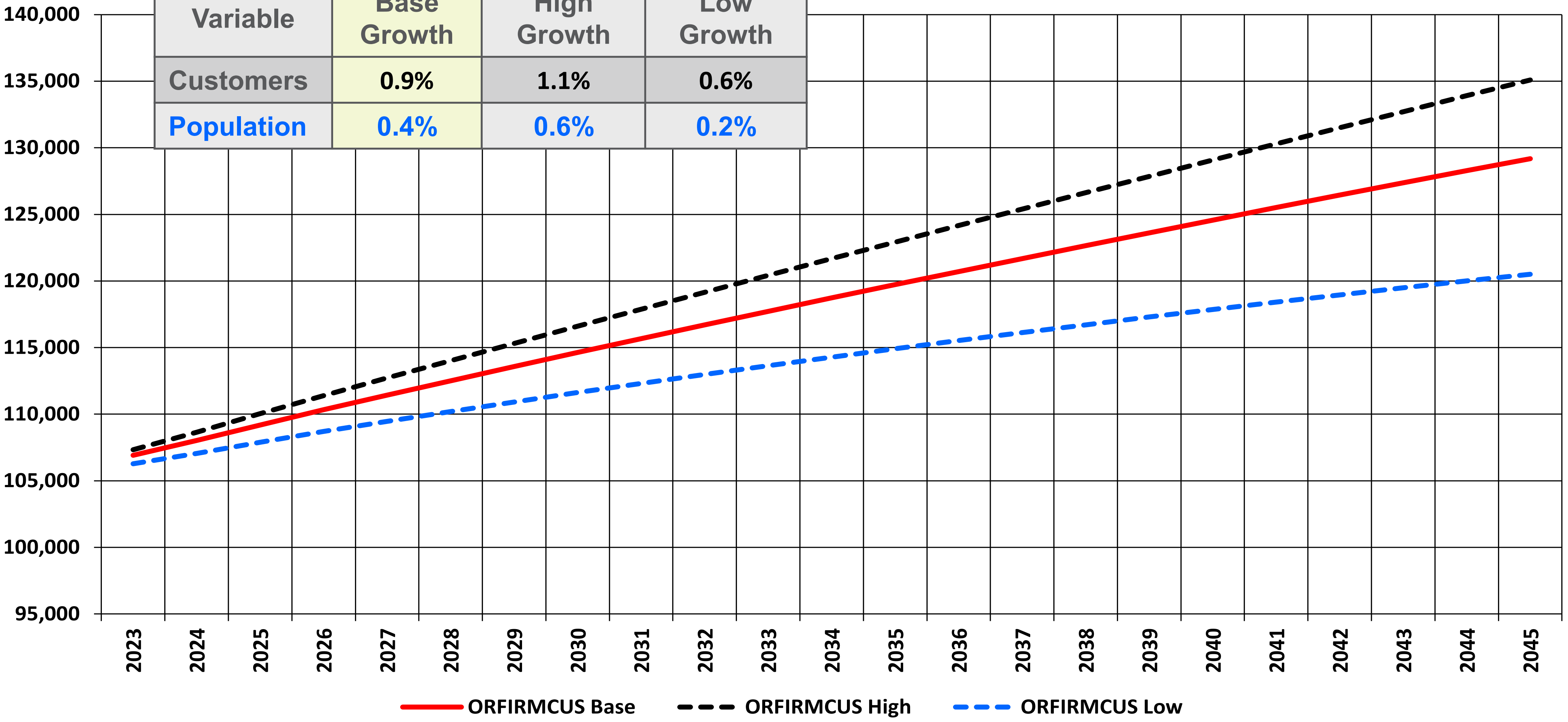
WA-ID Region Firm Customer Range (2023-2045)

Variable	Base Growth	High Growth	Low Growth
WA-ID Customers	1.2%	1.5%	0.8%
WA Population	0.6%	0.8%	0.2%
ID Population	1.7%	2.1%	1.0%
WA-ID Population	0.9%	1.2%	0.4%



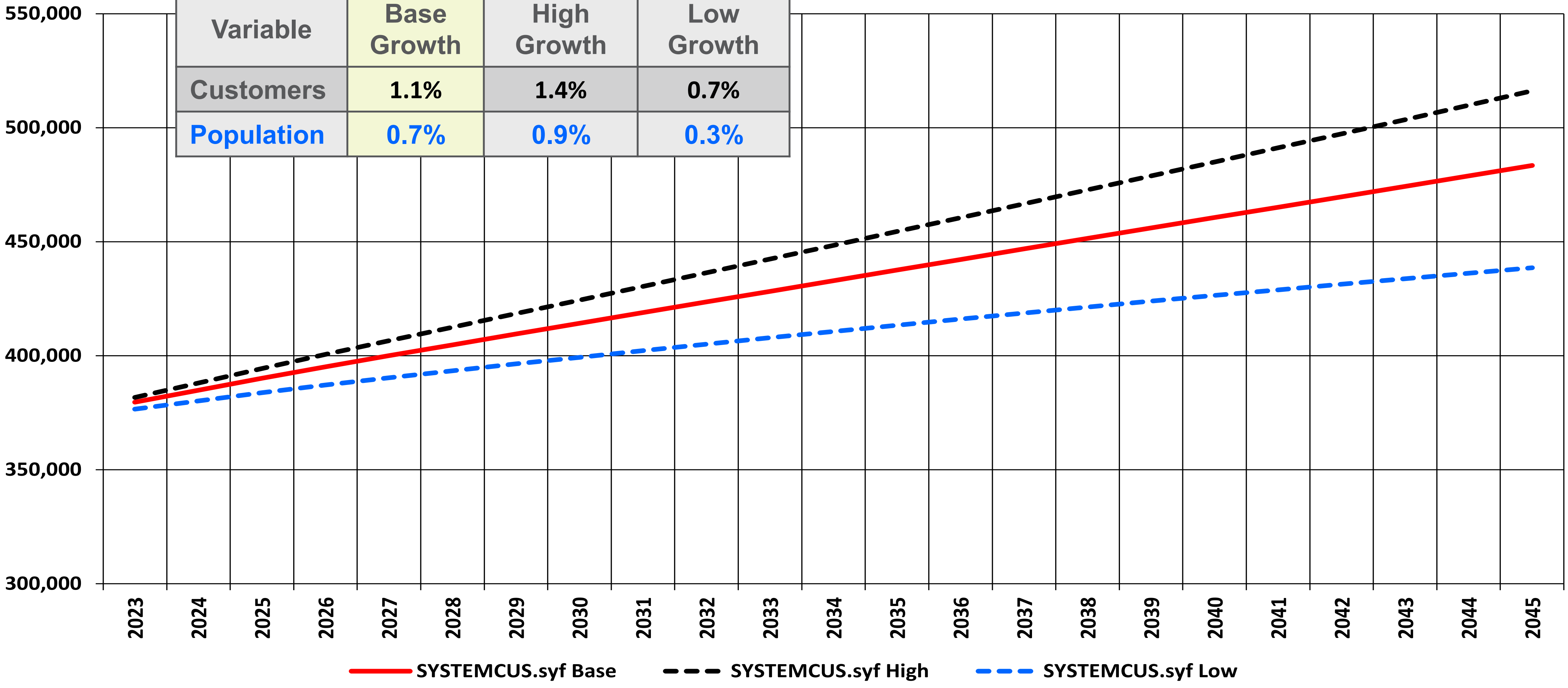
OR Region Firm Customer Range (2023-2045)

Variable	Base Growth	High Growth	Low Growth
Customers	0.9%	1.1%	0.6%
Population	0.4%	0.6%	0.2%



System Firm Customer Range (2023-2045)

Variable	Base Growth	High Growth	Low Growth
Customers	1.1%	1.4%	0.7%
Population	0.7%	0.9%	0.3%



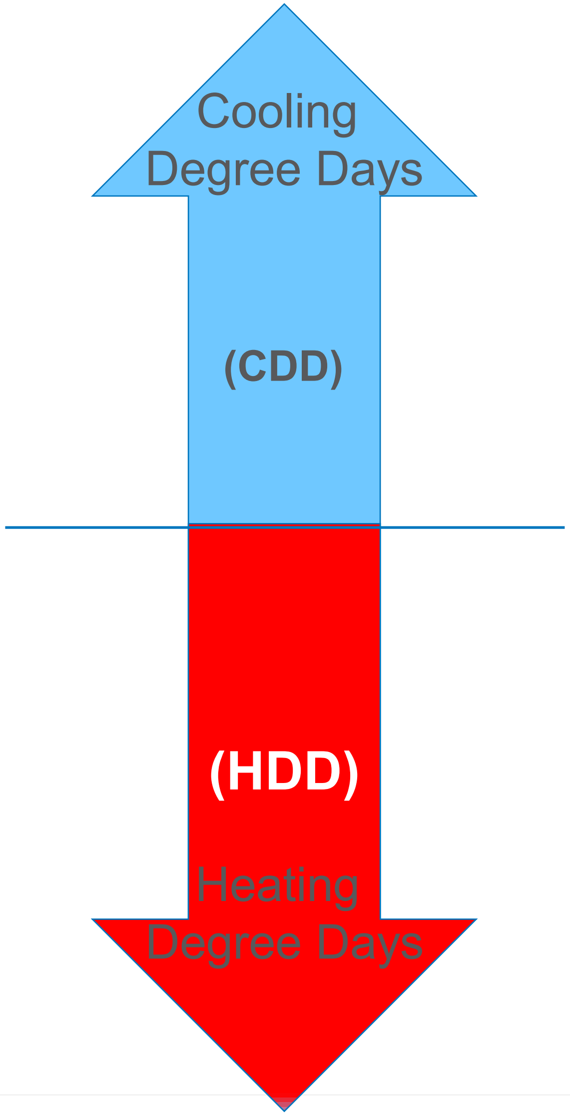
Summary of Growth Rates

System	Base-Case	High	Low
Residential	1.2%	1.5%	0.8%
Commercial	0.5%	0.8%	0.1%
Industrial	0.0%	2.1%	-16.9%
Total	1.1%	1.4%	0.7%
WA	Base-Case	High	Low
Residential	1.1%	1.3%	0.8%
Commercial	0.4%	0.7%	0.1%
Industrial	0.0%	1.8%	-22.6%
Total	1.1%	1.3%	0.7%
ID	Base-Case	High	Low
Residential	1.6%	2.0%	0.9%
Commercial	0.5%	1.0%	-0.1%
Industrial	0.0%	1.3%	-100.0%
Total	1.5%	1.9%	0.8%
OR	Base-Case	High	Low
Residential	0.9%	1.1%	0.6%
Commercial	0.6%	0.8%	0.3%
Industrial	0.0%	4.4%	-9.8%
Total	0.9%	1.1%	0.6%

-100% reflects zero customers by 2045

Use per Customer

Temperature & Degree Days



Temp (°F)		Degree Days
100	=	35
90	=	25
80	=	15
70	=	5
65	=	0
60	=	5
50	=	15
40	=	25
30	=	35
20	=	45
10	=	55
0	=	65
-10	=	75
-20	=	85

Base Coefficients

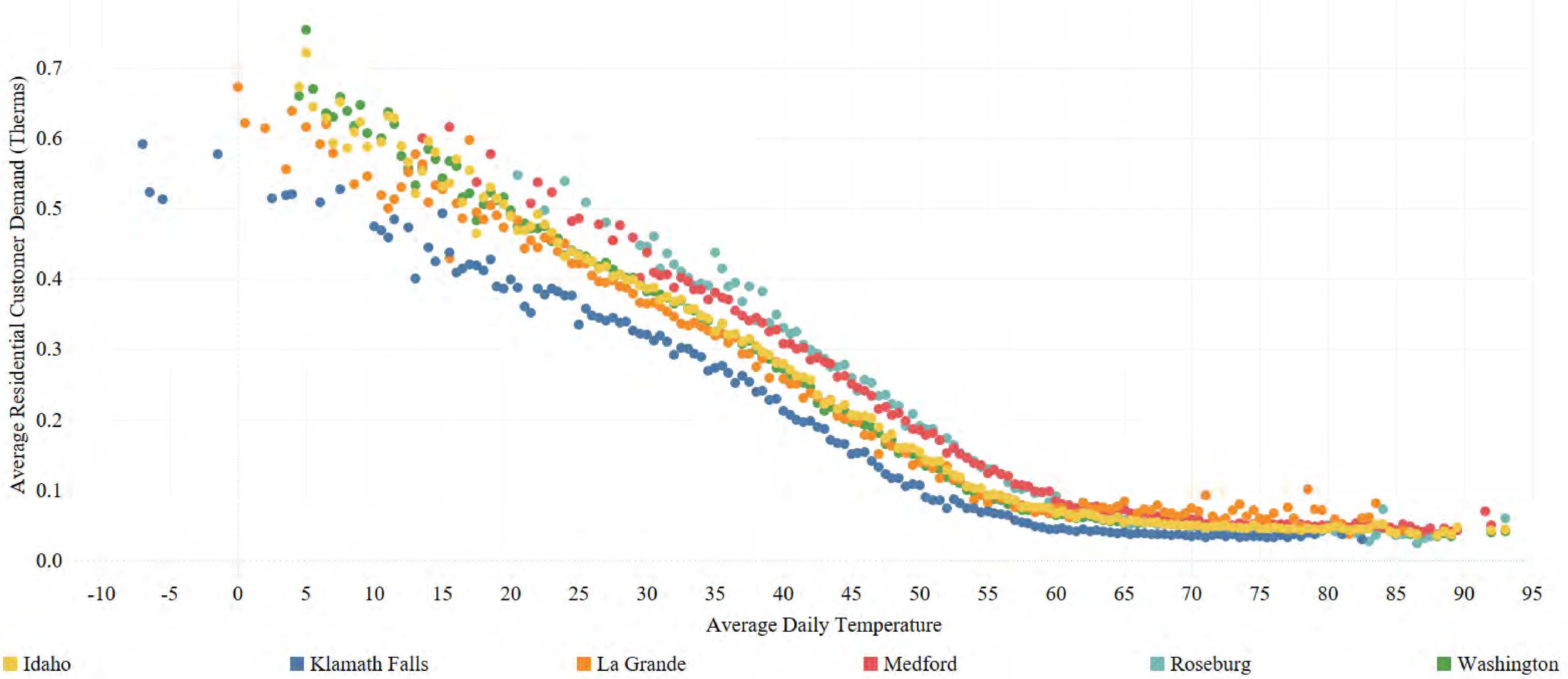
	Residential			Commercial			Industrial		
	2 Year	3 Year	5Year	2 Year	3 Year	5Year	2 Year	3 Year	5Year
Washington	0.04606	**0.04656**	0.04692	0.34753	**0.36691**	0.37156	3.38736	**3.30828**	3.27823
Idaho	0.05007	**0.04931**	0.04813	0.35555	**0.37307**	0.37783	4.44256	**4.85642**	5.05549
Klamath Falls	0.03769	0.03793	**0.03612**	0.23591	0.24248	**0.23301**	4.65297	4.37893	**4.15214**
La Grande	0.05968	0.06263	**0.06556**	0.28766	0.32194	**0.34687**	42.01296	47.95618	**49.61649**
Medford	0.05927	0.05567	**0.05291**	0.43019	0.41408	**0.39437**	4.73881	4.52838	**4.25709**
Roseburg	0.06747	0.06151	**0.05156**	0.47685	0.44512	**0.38135**	5.65826	5.60567	**4.07662**

Heat Coefficients

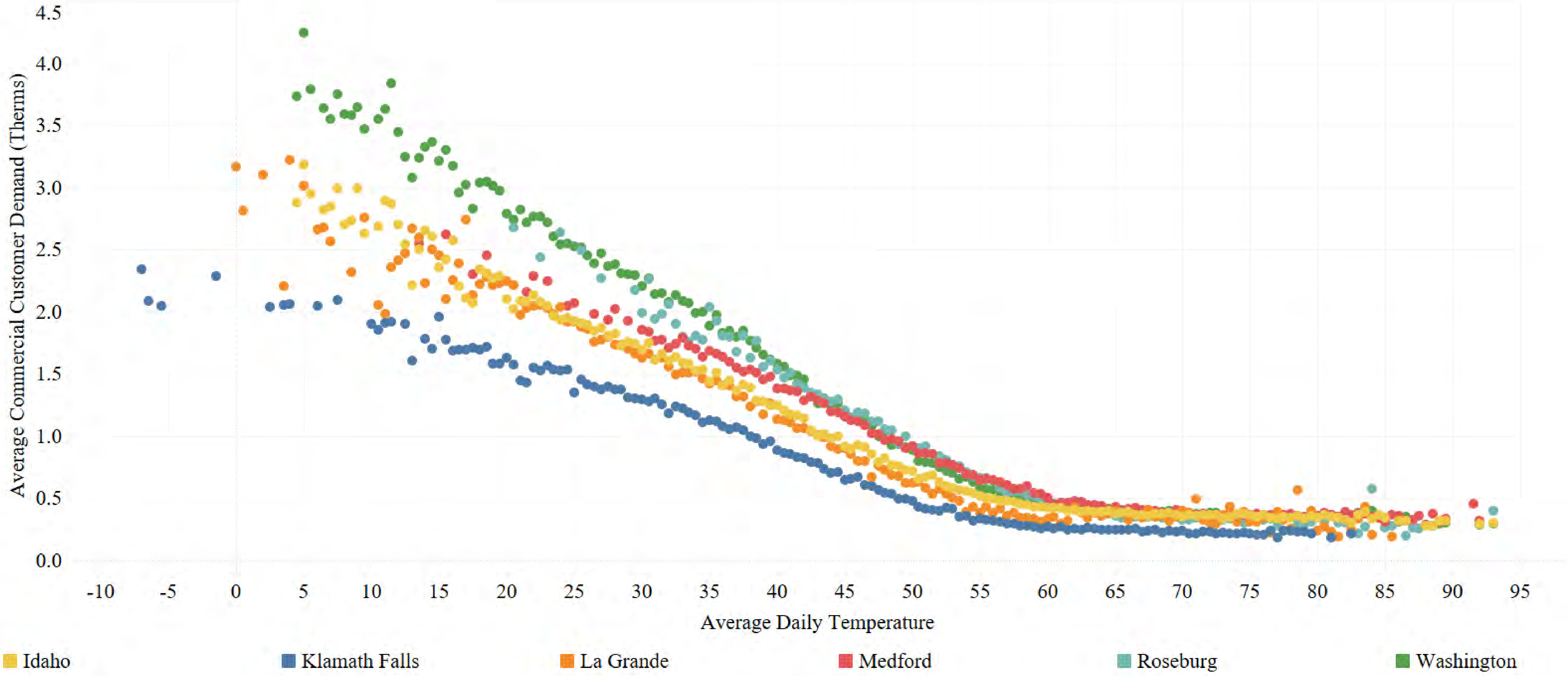
	Residential			Commercial			Industrial		
	2 Year	3 Year	5Year	2 Year	3 Year	5Year	2 Year	3 Year	5Year
Washington	0.00629	**0.00631**	0.00633	0.03554	**0.03714**	0.03687	0.20622	**0.18381**	0.16876
Idaho	0.00666	**0.00663**	0.00649	0.02769	**0.02806**	0.02842	0.23788	**0.23223**	0.22321
Klamath Falls	0.00514	0.00526	**0.00513**	0.01921	0.01995	**0.01946**	0.18185	0.17935	**0.14478**
La Grande	0.00542	0.00551	**0.00600**	0.02254	0.02395	**0.02688**	0.51825	0.88173	**1.58695**
Medford	0.00869	0.00789	**0.00723**	0.03860	0.03446	**0.03030**	0.22523	0.16844	**0.12185**
Roseburg	0.00855	0.00847	**0.00717**	0.03672	0.03783	**0.03086**	0.06607	0.05201	**0.03476**

*Values reflect 12-month average heat coefficient

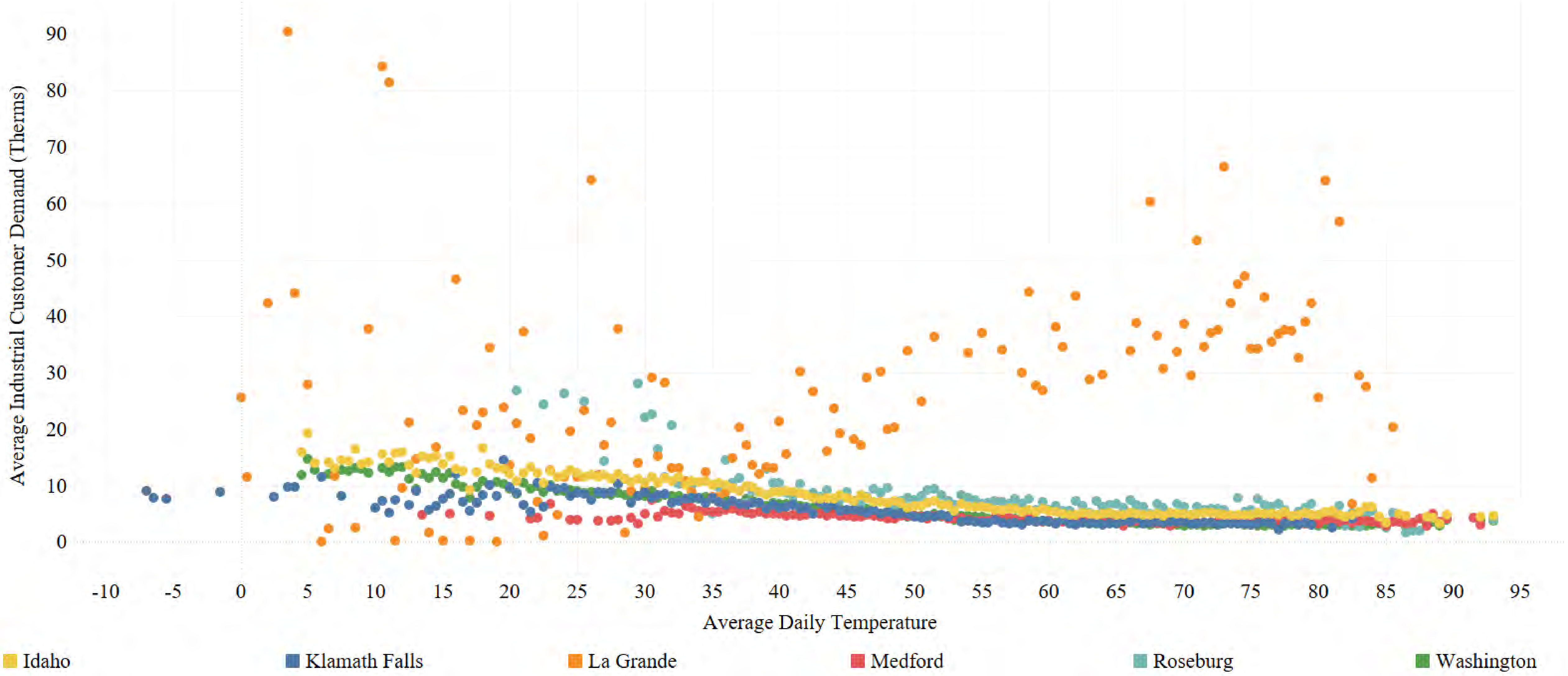
Residential (2012-2021)



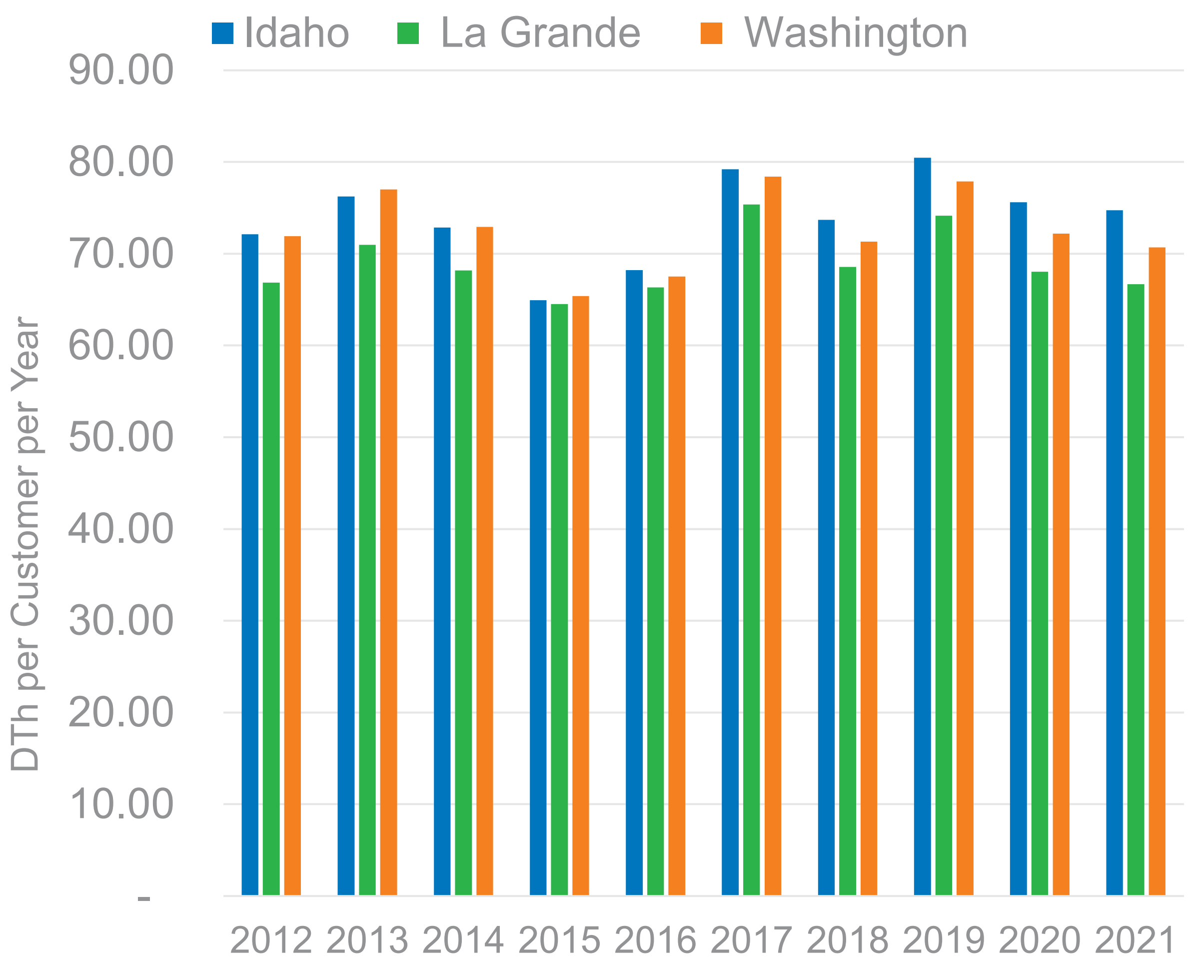
Commercial (2012-2021)

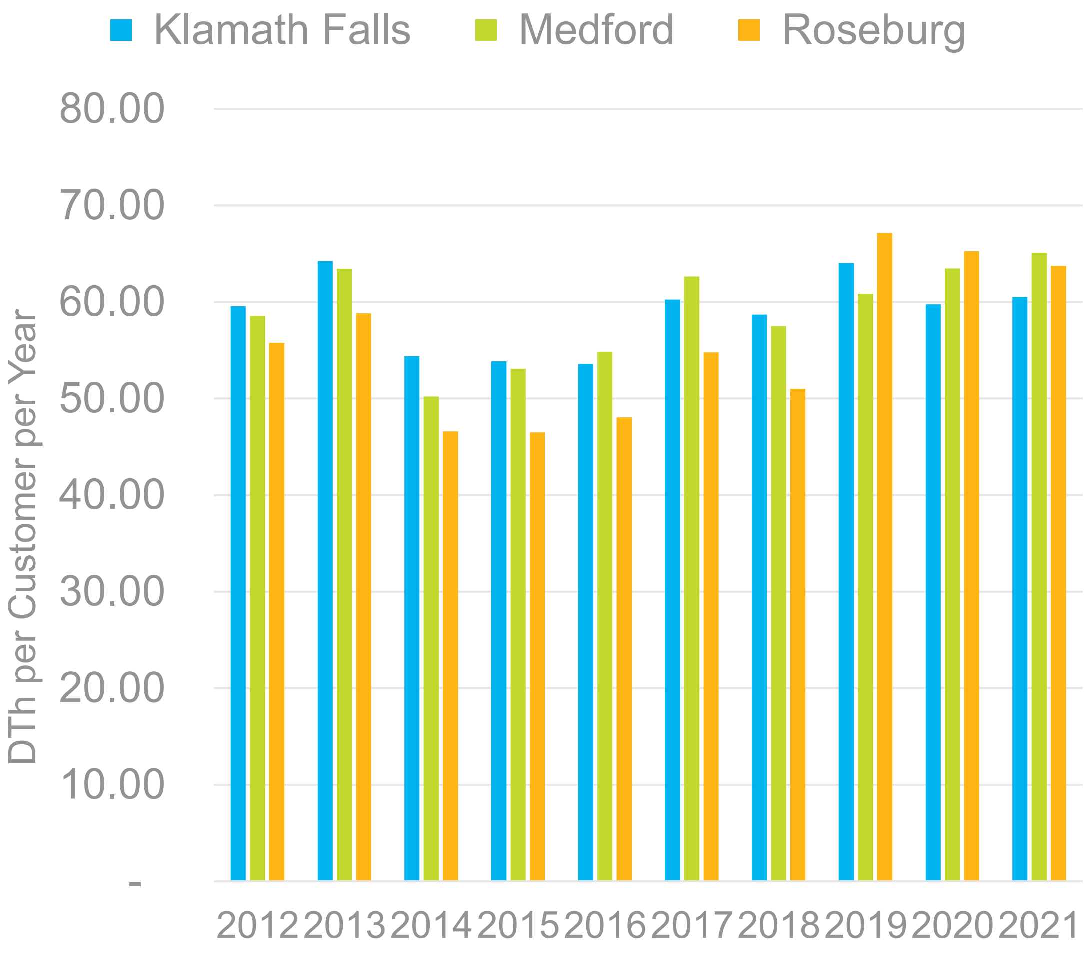


Industrial (2012-2021)

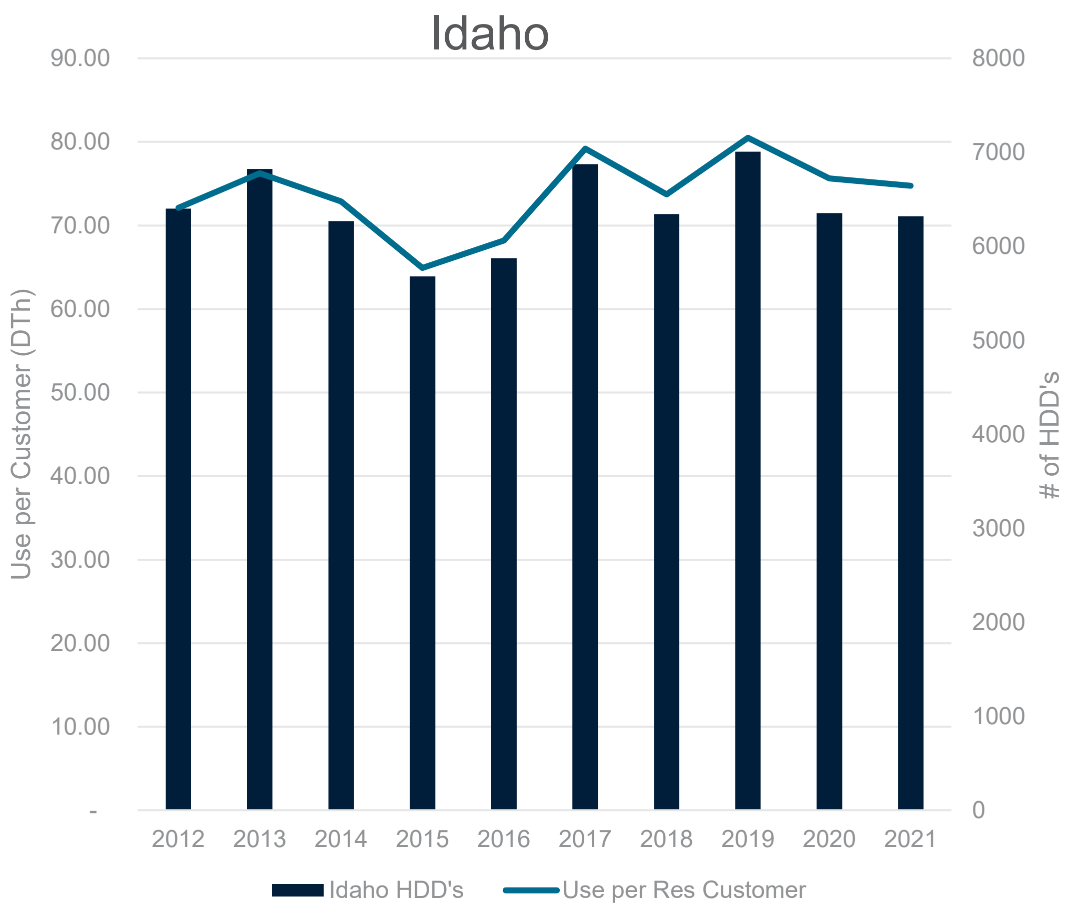


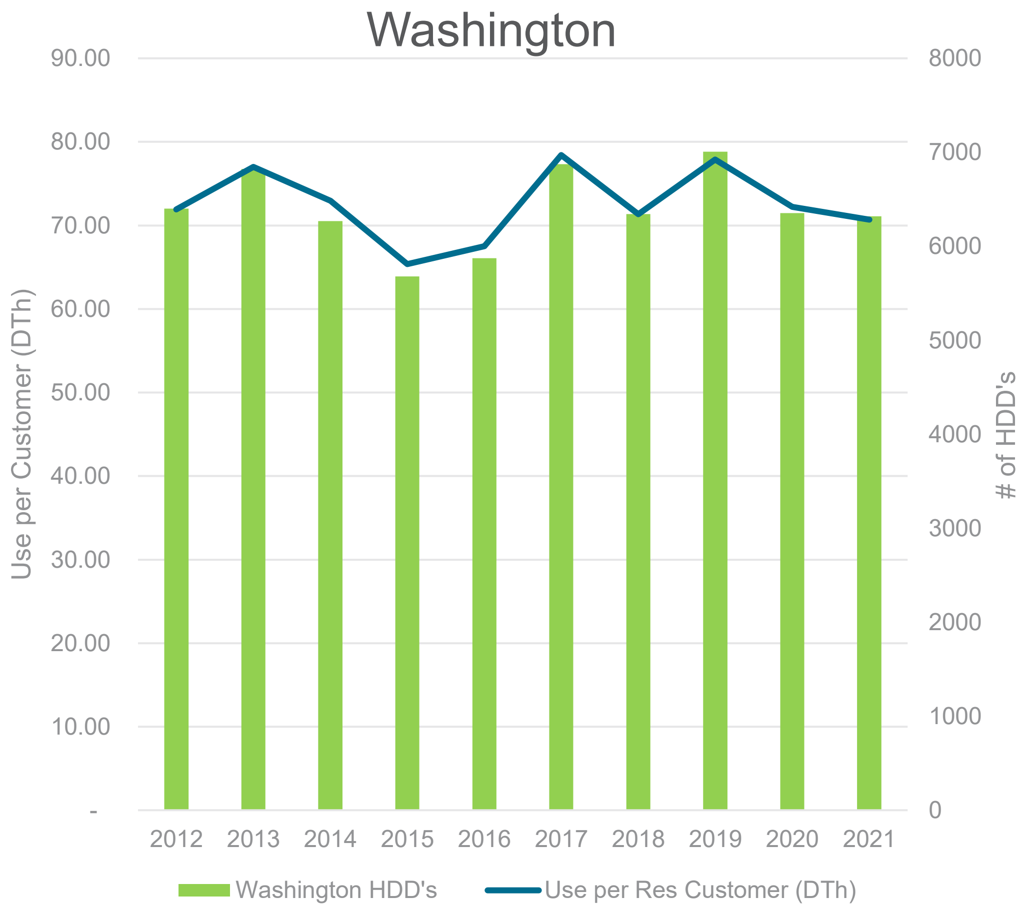
Use Per Customer



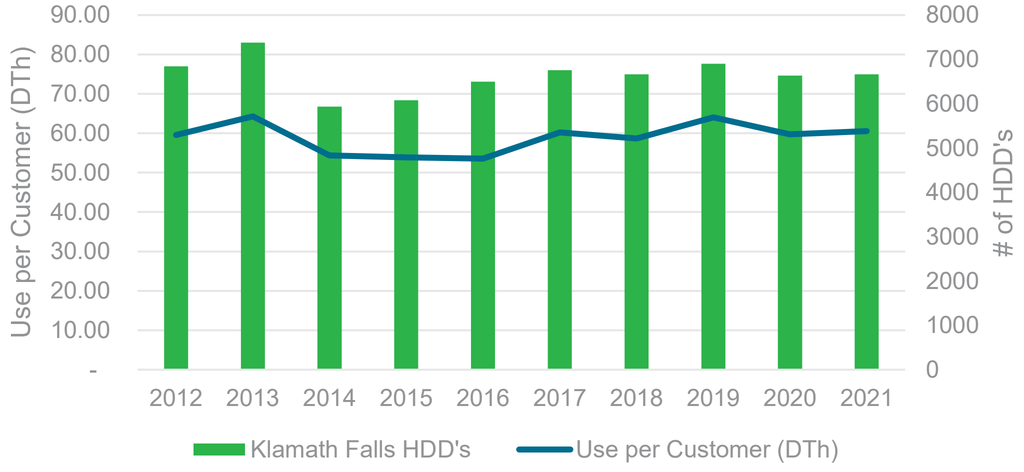


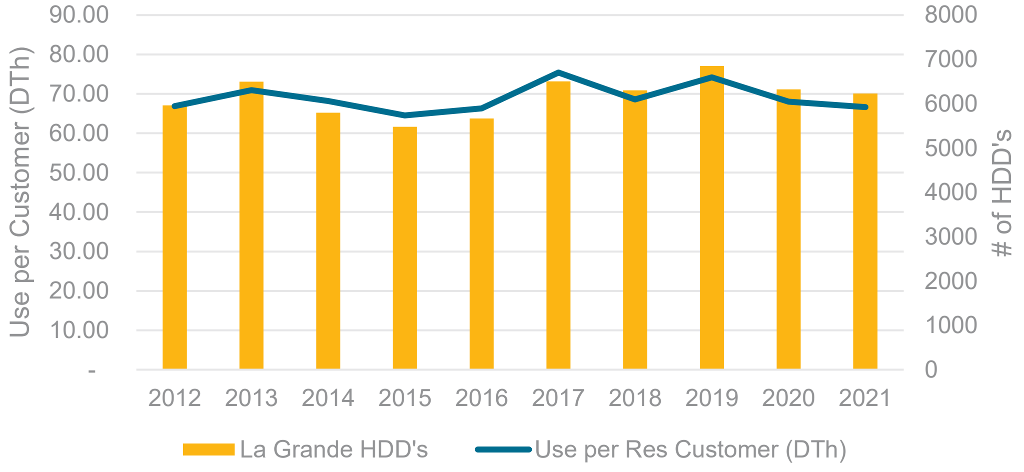
Residential Use per Customer (Idaho and Washington)

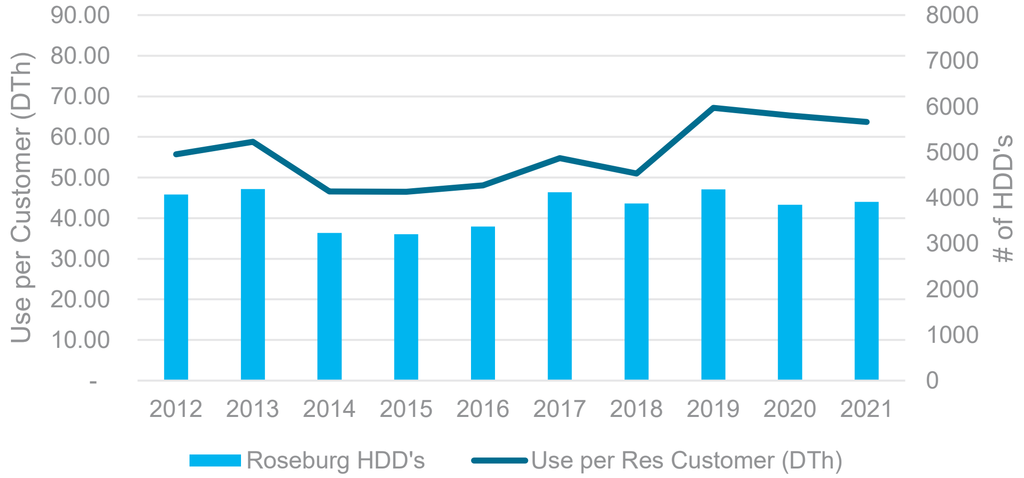


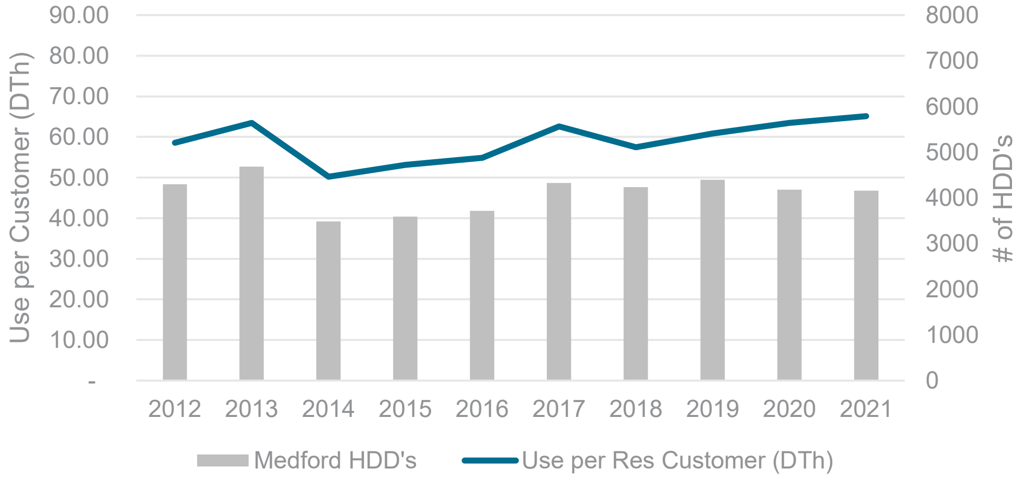


Residential Use per Customer (Oregon)

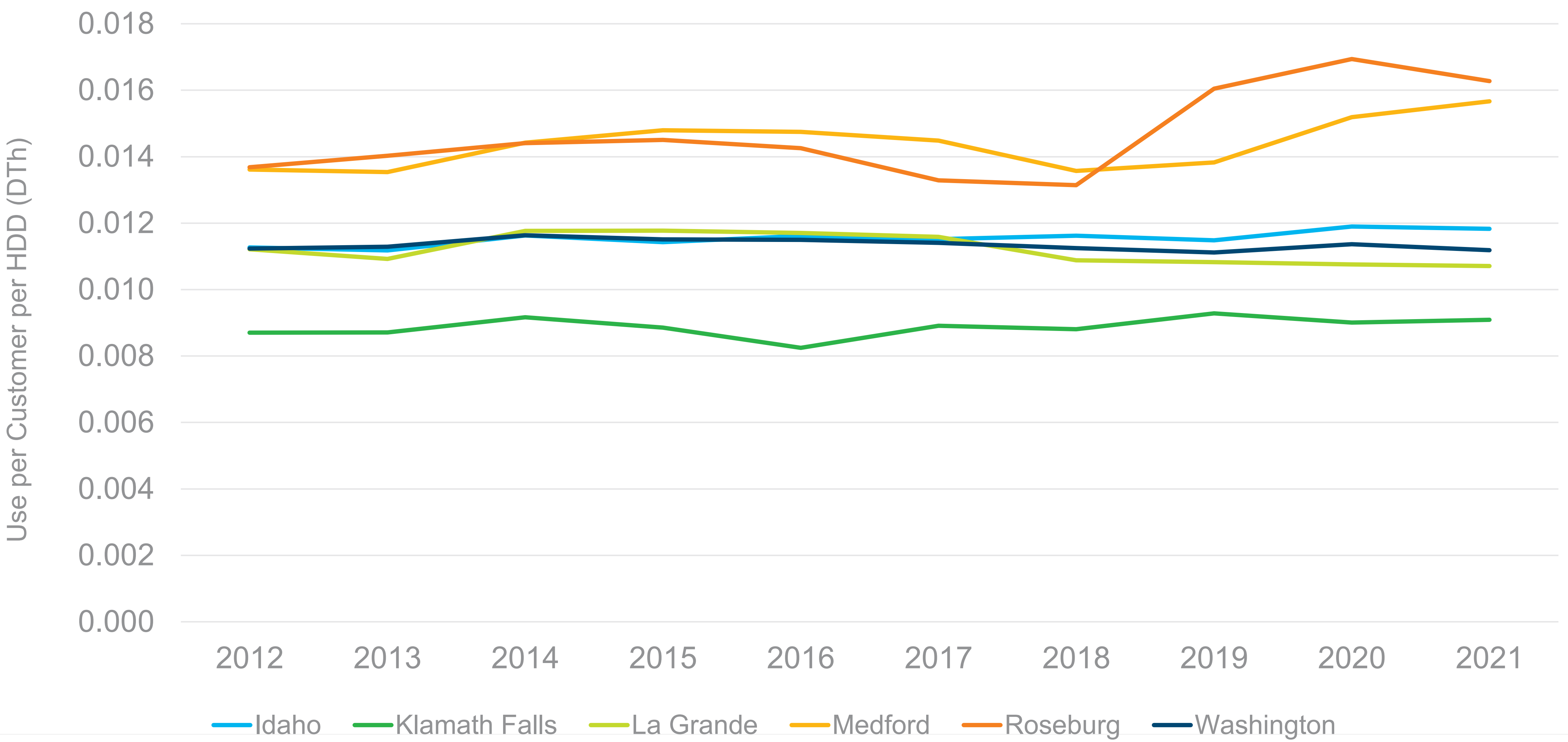








Residential Use per Customer per HDD



Developing a Reference Case

Customer count forecast + Use per customer coefficients + Weather = Reference Case Demand

1. Expected customer count forecast by each of the 6 areas
2. Use per customer coefficients: 5-, 3-, or 2-year average use per HDD per customer
3. Current weather planning standard

Demand Modeling Equation – a closer look

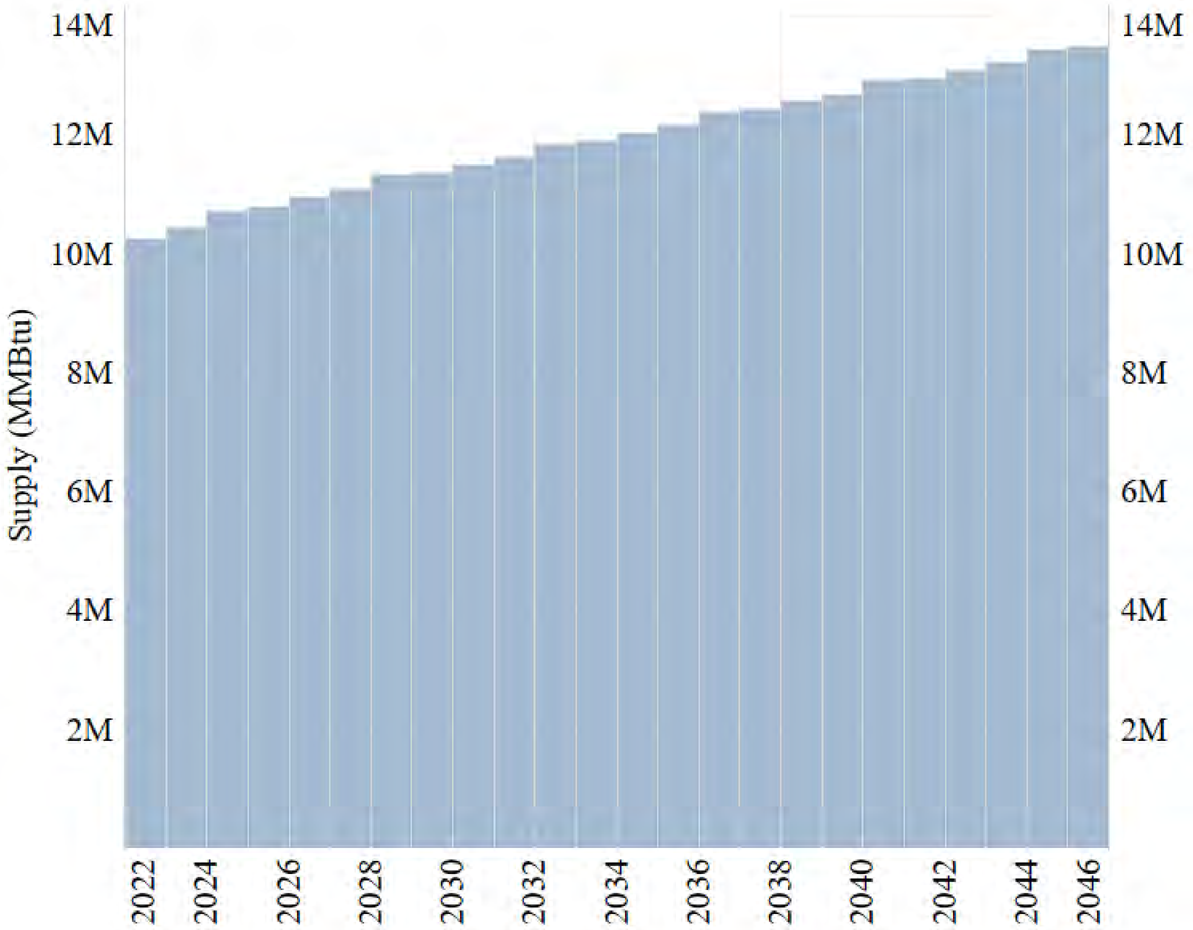
The **base** and **weather sensitive** usage (degree-day usage) factors are developed outside the model and capture a variety of demand usage assumptions.

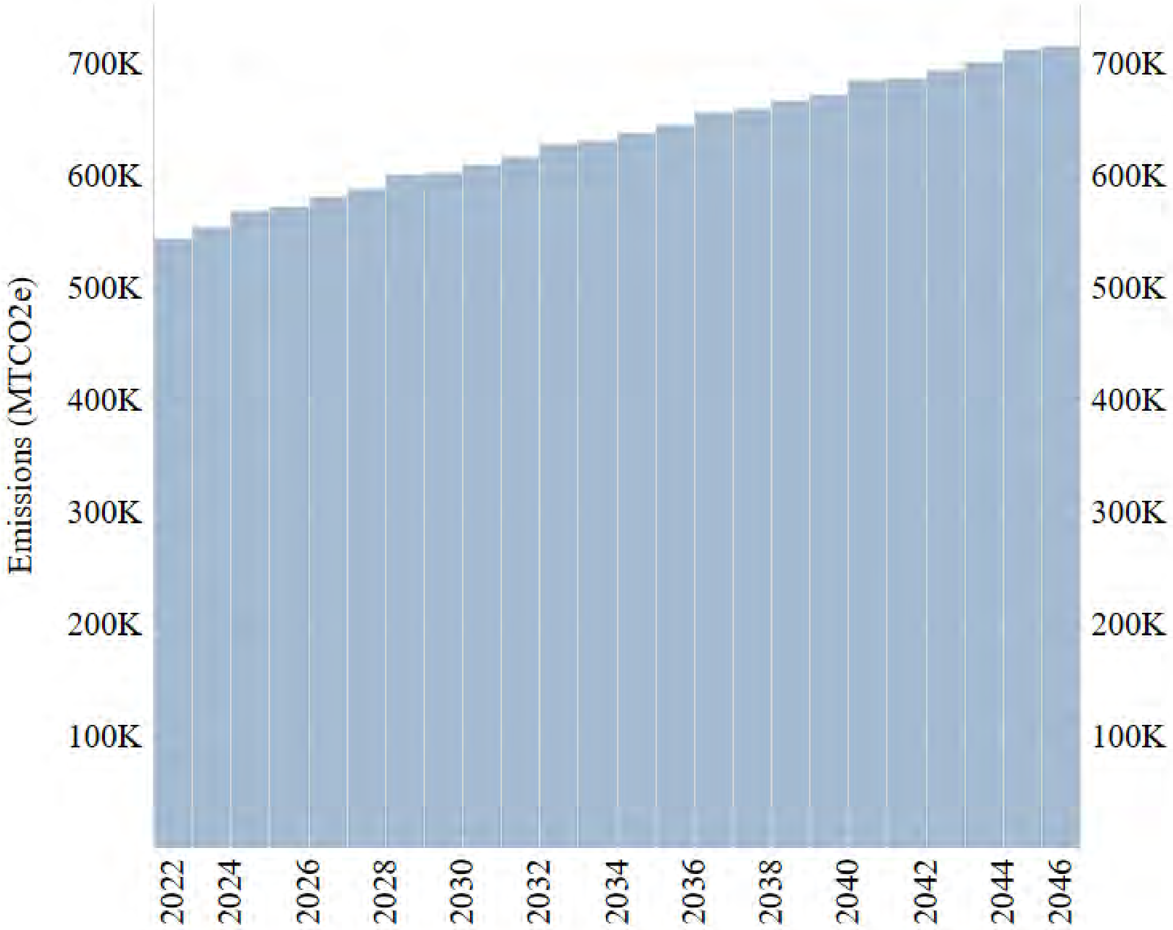
# of customers **x** Daily **base usage** / customer

Plus

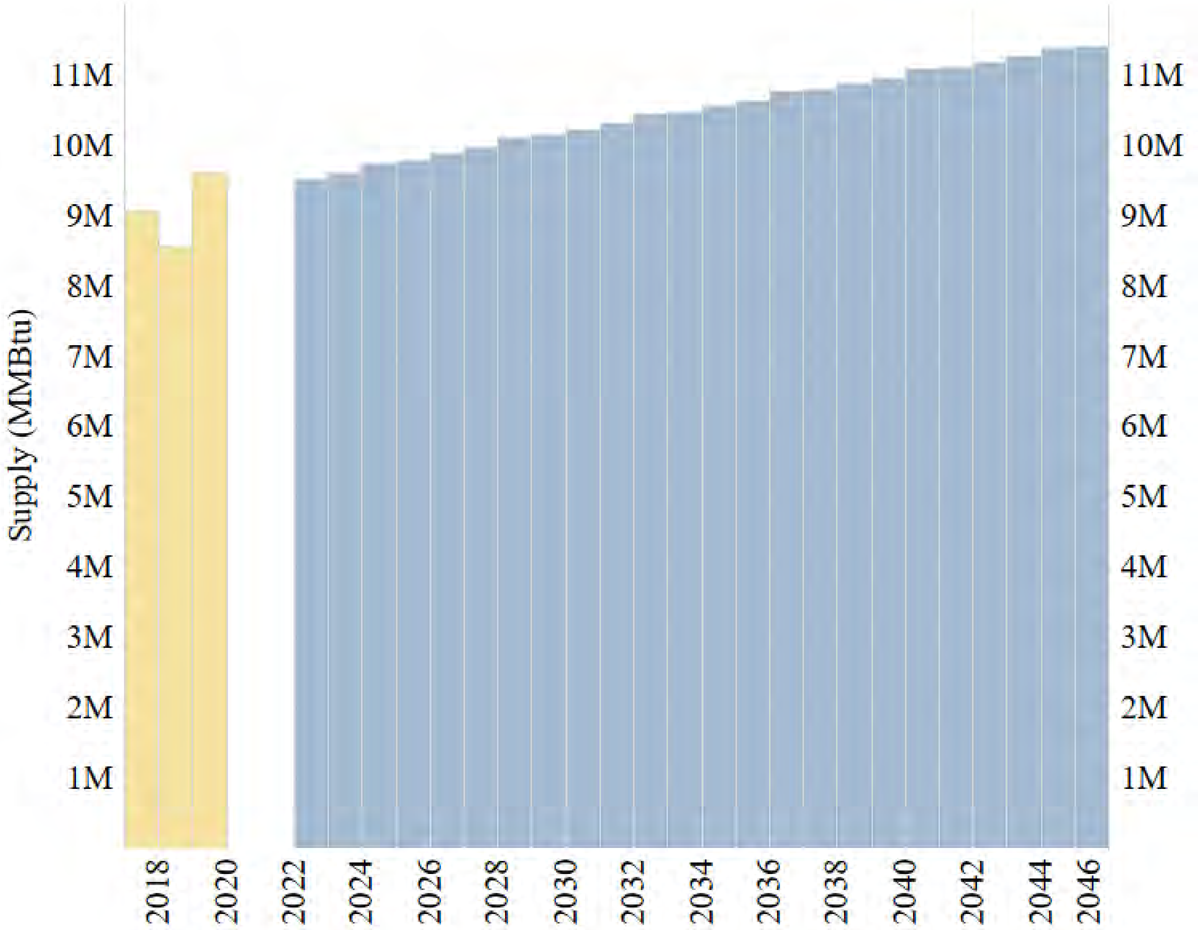
# of customers **x** Daily **weather sensitive** usage / customer

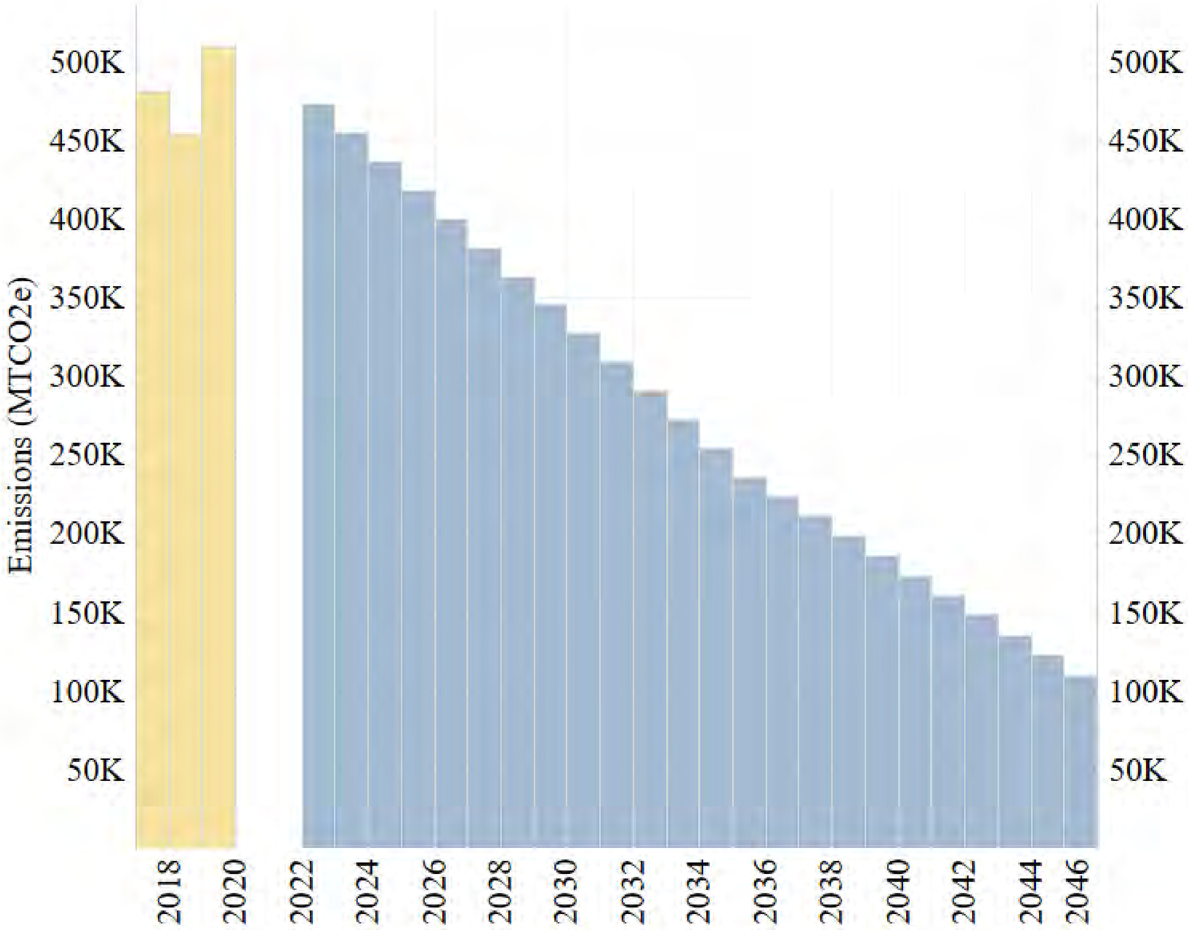
Idaho


Supply (MMBtu)
14M
12M
10M
8M
6M
4M
2M
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046

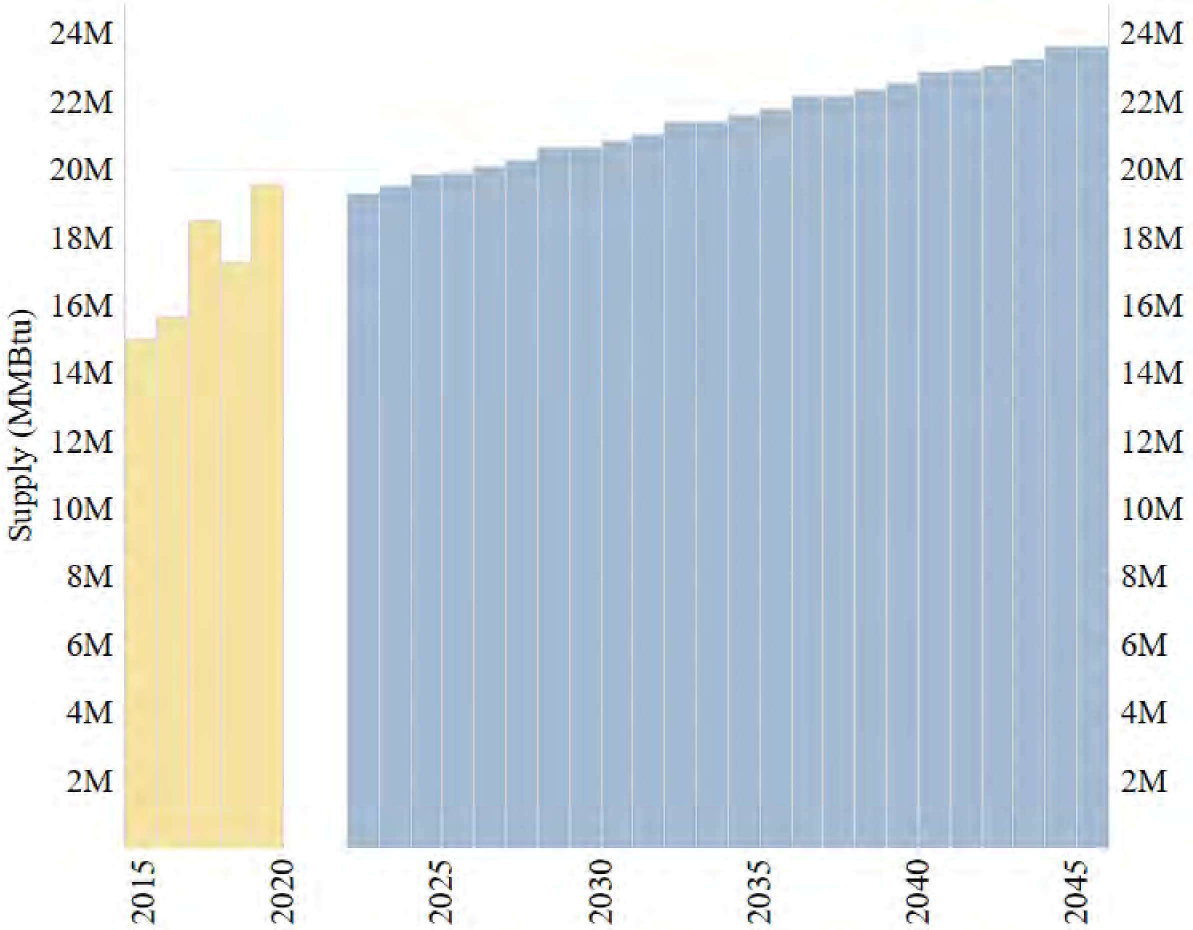

Emissions (MTCO2e)
700K
600K
500K
400K
300K
200K
100K
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046

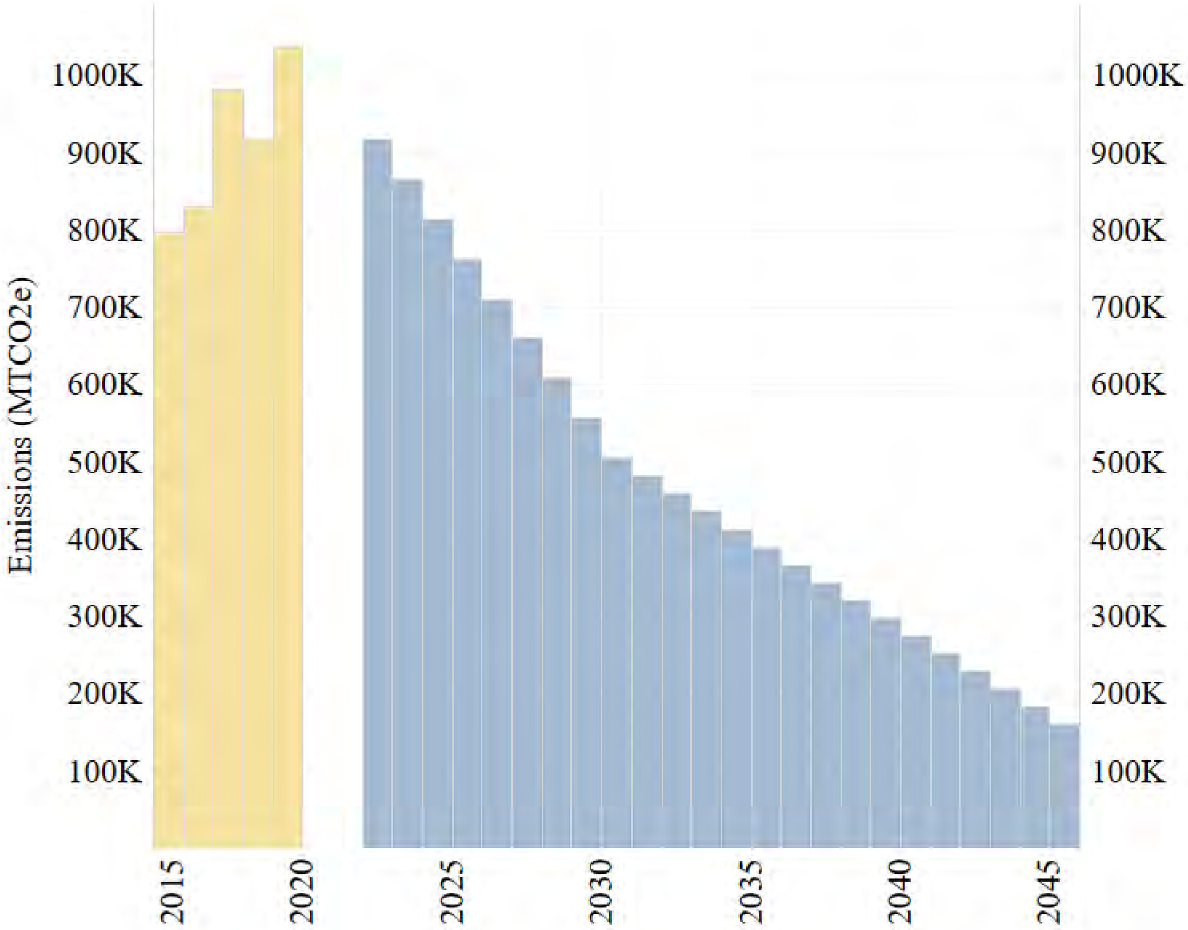
Oregon


Supply (MMBtu)
11M
10M
9M
8M
7M
6M
5M
4M
3M
2M
1M
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046


Emissions (MTCO2e)
500K
450K
400K
350K
300K
250K
200K
150K
100K
50K
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046

Washington


24M
22M
20M
18M
16M
14M
12M
10M
8M
6M
4M
2M
Supply (MMBtu)
2015
2020
2025
2030
2035
2040
2045


1000K
900K
800K
700K
600K
500K
400K
300K
200K
100K
Emissions (MTCO2e)
2015
2020
2025
2030
2035
2040
2045

Supply Side Resources

Justin Dorr

Manager of Natural Gas Resources

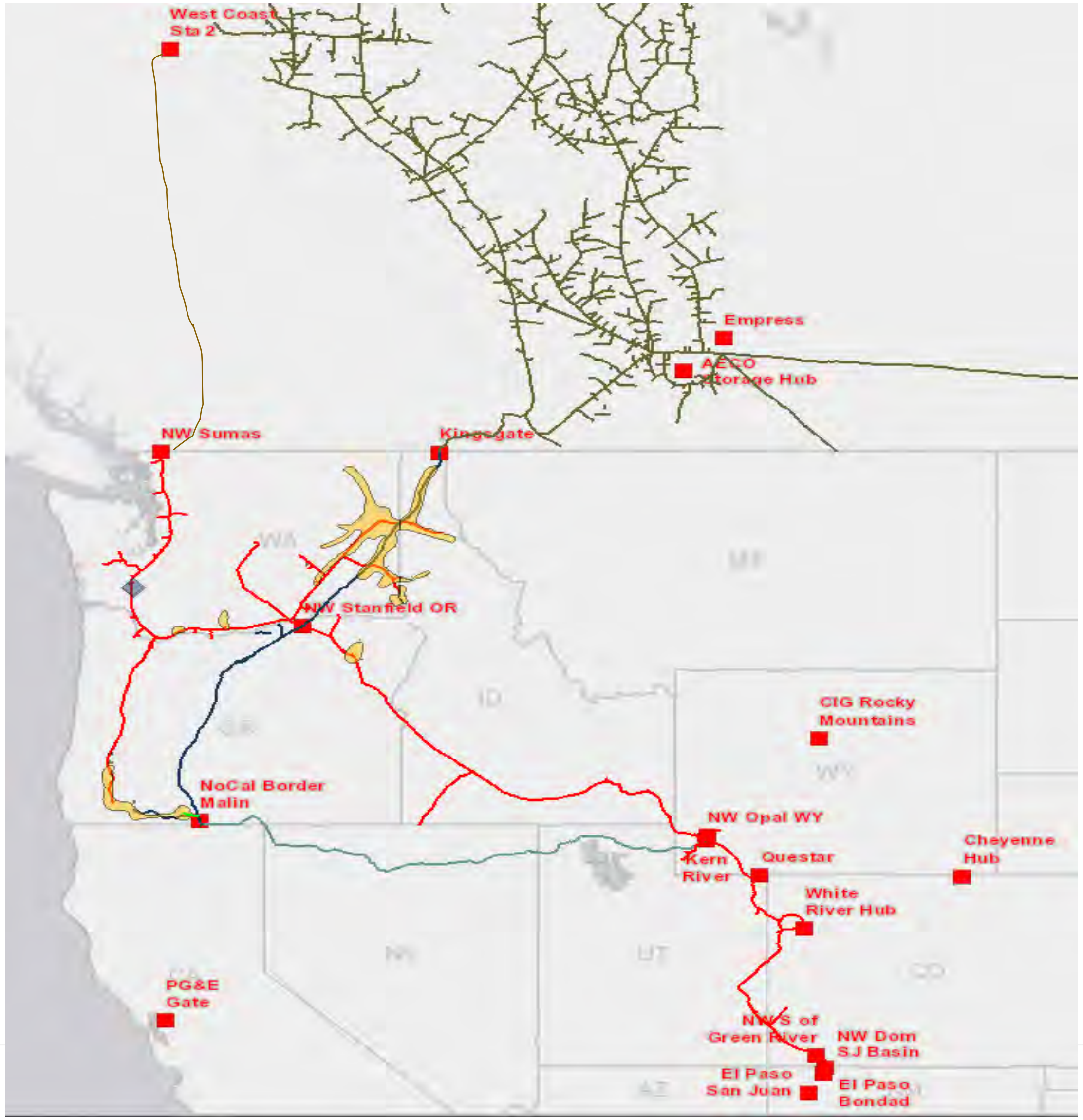
Interstate Pipeline Resources

- The Integrated Resource Plan (IRP) brings together the various components necessary to ensure proper resource planning for reliable service to utility customers.

- One of the key components for natural gas service is interstate pipeline transportation. Low prices, firm supply and storage resources are meaningless to a utility customer without the ability to transport the gas reliably during cold weather events.

- Acquiring firm interstate pipeline transportation provides the most reliable delivery of supply.

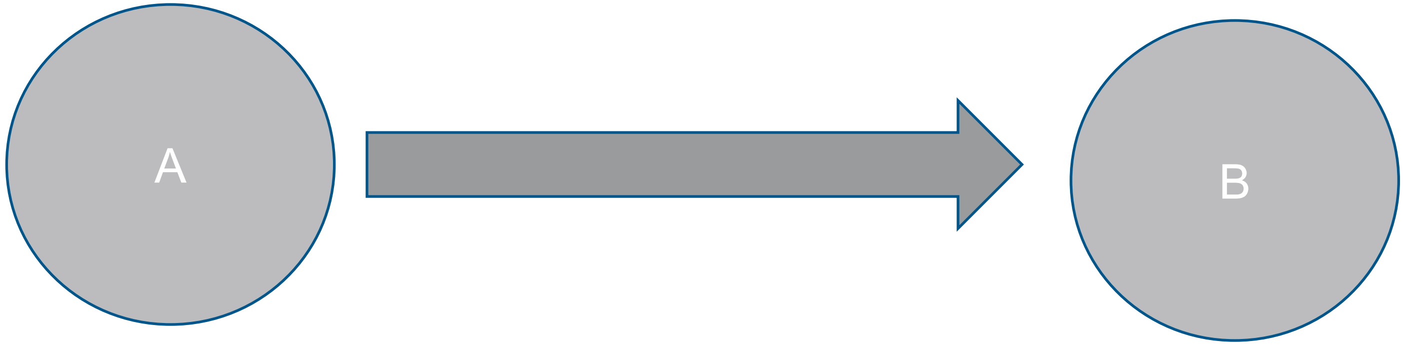
Pipeline Overview



AVISTA

Pipeline Contracting

Simply stated: The right to move (transport) a specified amount of gas from Point A to Point B



Contract Types

- Firm transport
  - Point A to Point B
  - Kingsgate to Malin
- Alternate firm
  - Point C to Point D
  - Kingsgate to Stanfield
- Seasonal firm
  - Point A to Point B but only in winter
- Interruptible
  - Maybe it flows, maybe it doesn’t

Pipeline Rate Design

- Mileage Rate (GTN)
  - Distance between receipt and delivery determines price
  - Plus variable charges
- Postage Stamp (NWP)
  - 1 mile from receipt to deliver same price as 1000 miles
  - Plus variable charges

Avista's Transportation Contract Portfolio

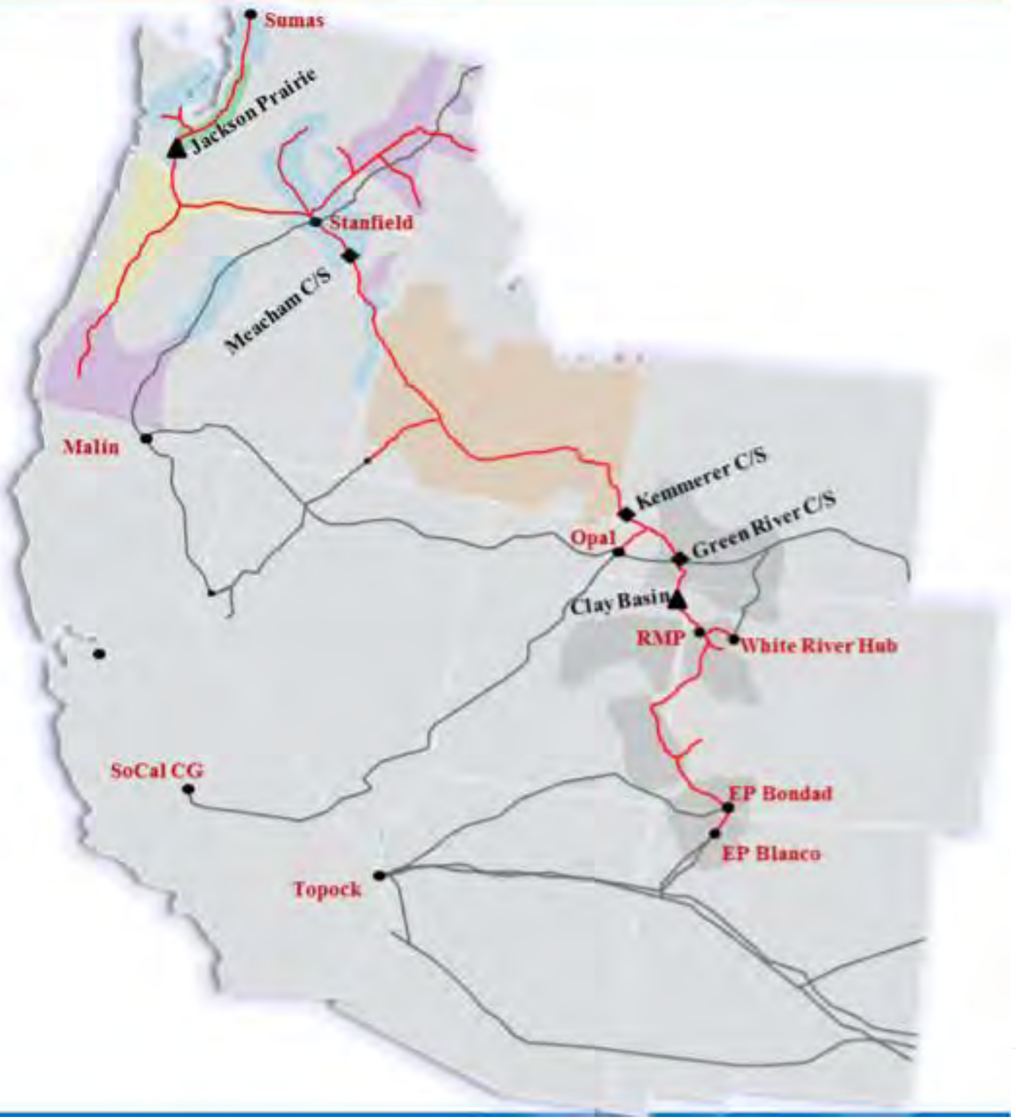
Avista holds firm transportation capacity on 6 interstate pipelines:

Pipeline	Expirations	Base Capacity Dth
Williams NWP	2025 – 2042 (2035)	285,000
Westcoast (Enbridge)	2026	10,000
TransCanada - NGTL	2024-2046	208,000
TransCanada - Foothills	2024-2046	204,000
TransCanada - GTN	2023-2028	210,000 164,000
TransCanada-Tuscarora	2023	200

1) Pipe reservations and modeling are only for LDC customers
2) Pipe reservations and model explicitly DO NOT CONSIDER electric side of business.

Northwest System – Strategically Located

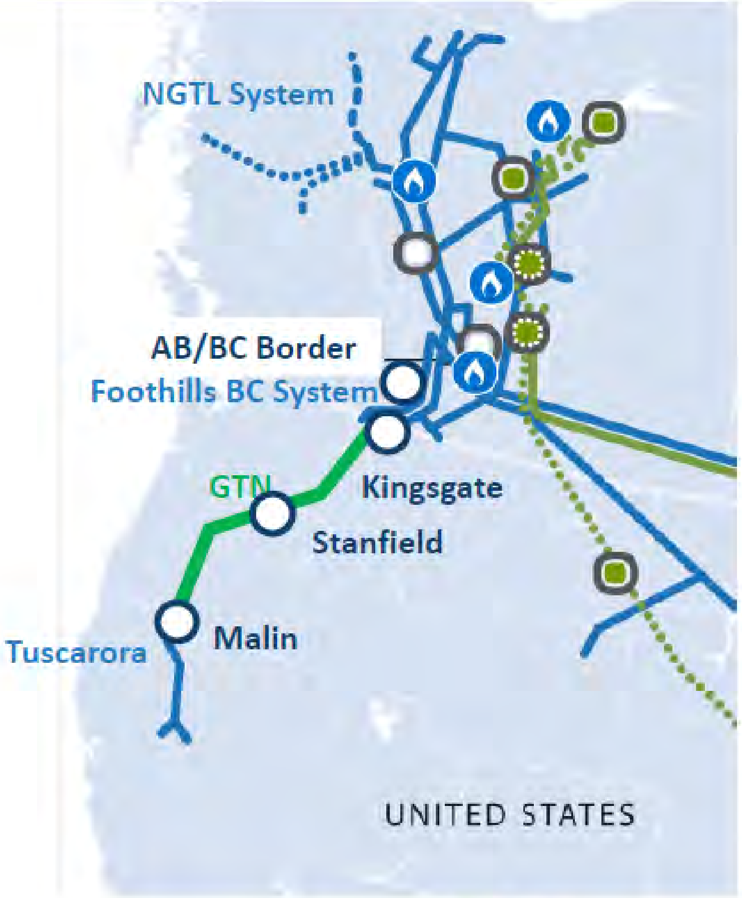
- **Low-cost, primary service provider in the Pacific Northwest**
  - 3,900-mile system with 3.8 Bcf/d peak design capacity
  - ~120 Bcf of access to storage along pipeline, with high injection and deliverability capability in market area
- **Bi-directional design**
  - Provides flexibility (Rockies to market and Sumas to market)
  - Cheapest supply drives flow patterns
  - Provides operational efficiencies through displacement
- **Supply and market flexibility**
  - 65 receipt points totaling 11.6 Bcf/d of supply from Rockies, Sumas, WCSB, San Juan, emerging shales
  - 366 delivery points totaling 9.7 Bcf/d of delivery capacity



Alternate slide for GTN

GTN Overview

- **Transports WCSB and Rockies natural gas to Washington, Oregon and California**
- **Approximately 1,377 miles of pipeline**
- **Kingsgate best efforts receipt capability of approx. 2.87 Bcfd and throughput capacity of approx. 2 Bcfd through Station 14**
- **Deliveries of up to 1.5 Bcfd to non-California Markets**
- **Concurrent transport expansions from NIT to Malin:**
  - Tranche 1
    - 110 TJ/d (NGTL and FHBC), 100 MDth/d (GTN)
    - November 1, 2022 - Targeted in-service
  - Tranche 2
    - 175 TJ/d (NGTL and FHBC), 150 MDth/d (GTN)
    - November 1, 2023 - Targeted in-service



FOR DISCUSSION PURPOSES ONLY | SEPTEMBER 2020

TC Energy

AVISTA

NGTL to Malin West Path expansion

Connecting WCSB supply to key North American markets

Valued transport path for both Supply and End Use Shippers

Concurrent transport expansions from NIT to Malin:

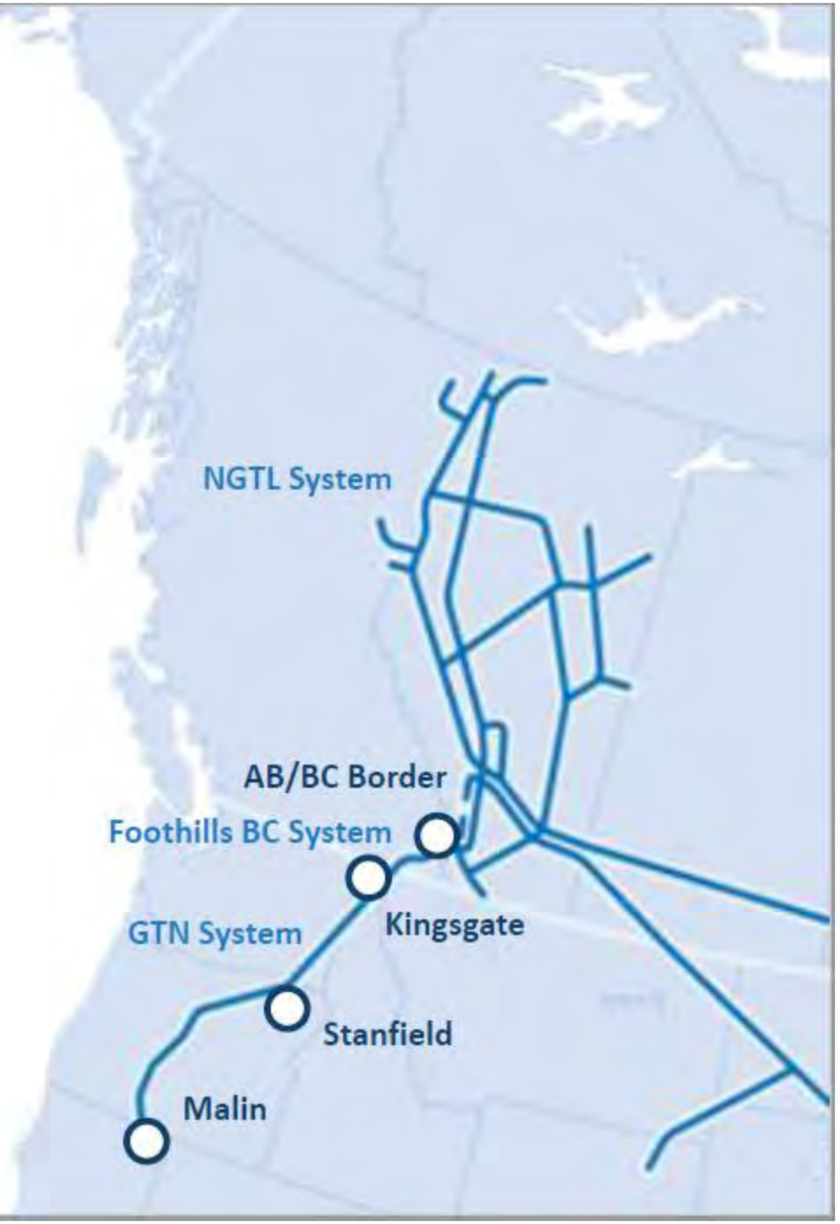
Tranche 1

- 110 TJ/d (NGTL and FHBC), 100 MDth/d (GTN)
- November 1, 2022 - Targeted in-service

Tranche 2

- 175 TJ/d (NGTL and FHBC), 150 MDth/d (GTN)
- November 1, 2023 - Targeted in-service

- Average term of awarded capacity:
- 31.3 years NGTL
- 31.4 years Foothills BC

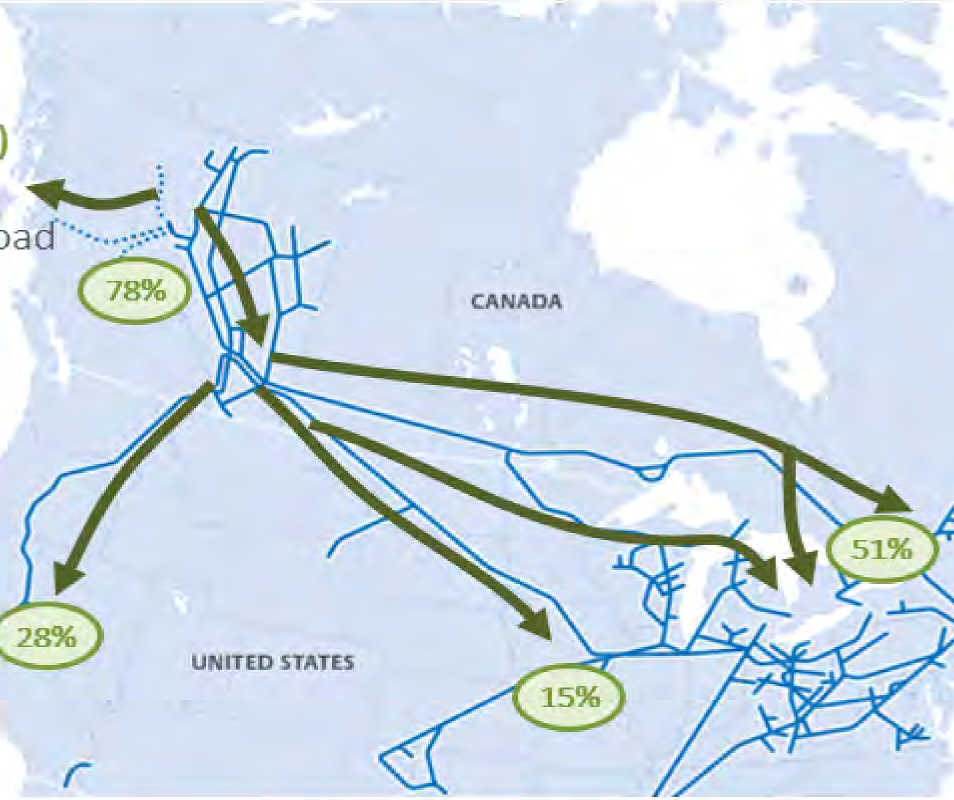


FOR DISCUSSION PURPOSES ONLY | SEPTEMBER 2020

WCSB gas is competitive in key markets, **Safety, Toll Competitiveness & Reliability** is Our Focus

WCSB (78% TC Energy)
16.1 Bcf/d supply
7.1 Bcf/d intra basin load
8.9 Bcf/d export
4 Bcf/d LNG projected

NGTL System provides access to **stable supply source** for WCSB **end users** and allows **unique** opportunity **producers** to **compete** in multiple export markets



Pacific
8.2 Bcf/d market
2.3 Bcf/d via TC

U.S. Northeast
7.8 Bcf/d market
0.8 Bcf/d via TC

Eastern Canada
4.1 Bcf/d market
2.1 Bcf/d from WCSB via TC

Chicago (Mid-West)
11.9 Bcf/d end use market
1.5 Bcf/d from WCSB via TC

Flow data based on 2021 Calendar year
Source: TC Energy, EIA and Downstream Pipeline Nominations

Storage – A Valuable Asset

- Peaking resource
- Improves reliability
- Enables capture of price spreads between time periods
- Enables efficient counter cyclical utilization of transportation (i.e. summer injections)
- May require transportation to service territory
- In-service territory storage offers most flexibility

Avista's Storage Resources

Washington and Idaho
Owned Jackson Prairie

- 7.7 Bcf of Capacity with approximately 346,000 Dth/d of deliverability

Oregon

Owned Jackson Prairie

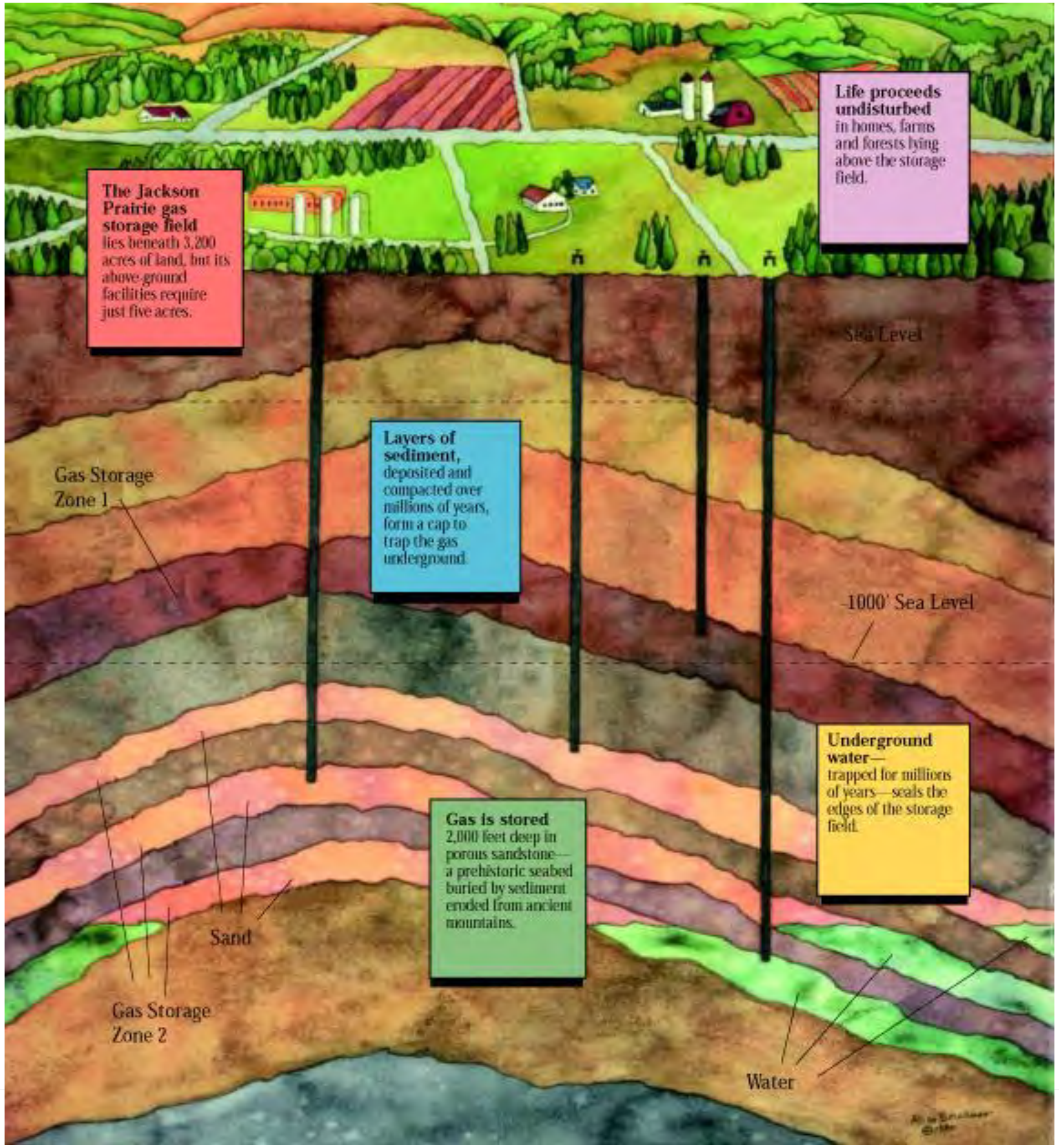
- 823,000 Dth of Capacity with approximately 52,000 Dth/d of deliverability

Leased Jackson Prairie

- 95,565 Dth of Capacity with approximately 2,654 Dth/d of deliverability

The Facility

- Jackson Prairie is a series of deep, underground reservoirs – basically thick, porous sandstone deposits.
- The sand layers lie approximately 1,000 to 3,000 feet below the ground surface.
- Large compressors and pipelines are employed to both inject and withdraw natural gas at 54 wells spread across the 3,200 acre facility.



Jackson Prairie Energy Comparisons

1.2 Bcf per day (energy equivalent)

- 10 coal trains with 100 - 50 ton cars each
- 29 - 500 MW gas-fired power plants
- 13 Hanford-sized nuclear power plants
- 2 Grand Coulee-sized hydro plants (biggest in US)

45 Bcf of stored gas

- 12" pipeline 11,000,000 miles long (226,000 miles to the moon)
- 1,400 Safeco Fields (Baseball Stadiums)
- Average flow of the Columbia River for 2 days
- Cube - 3,550 feet on a side

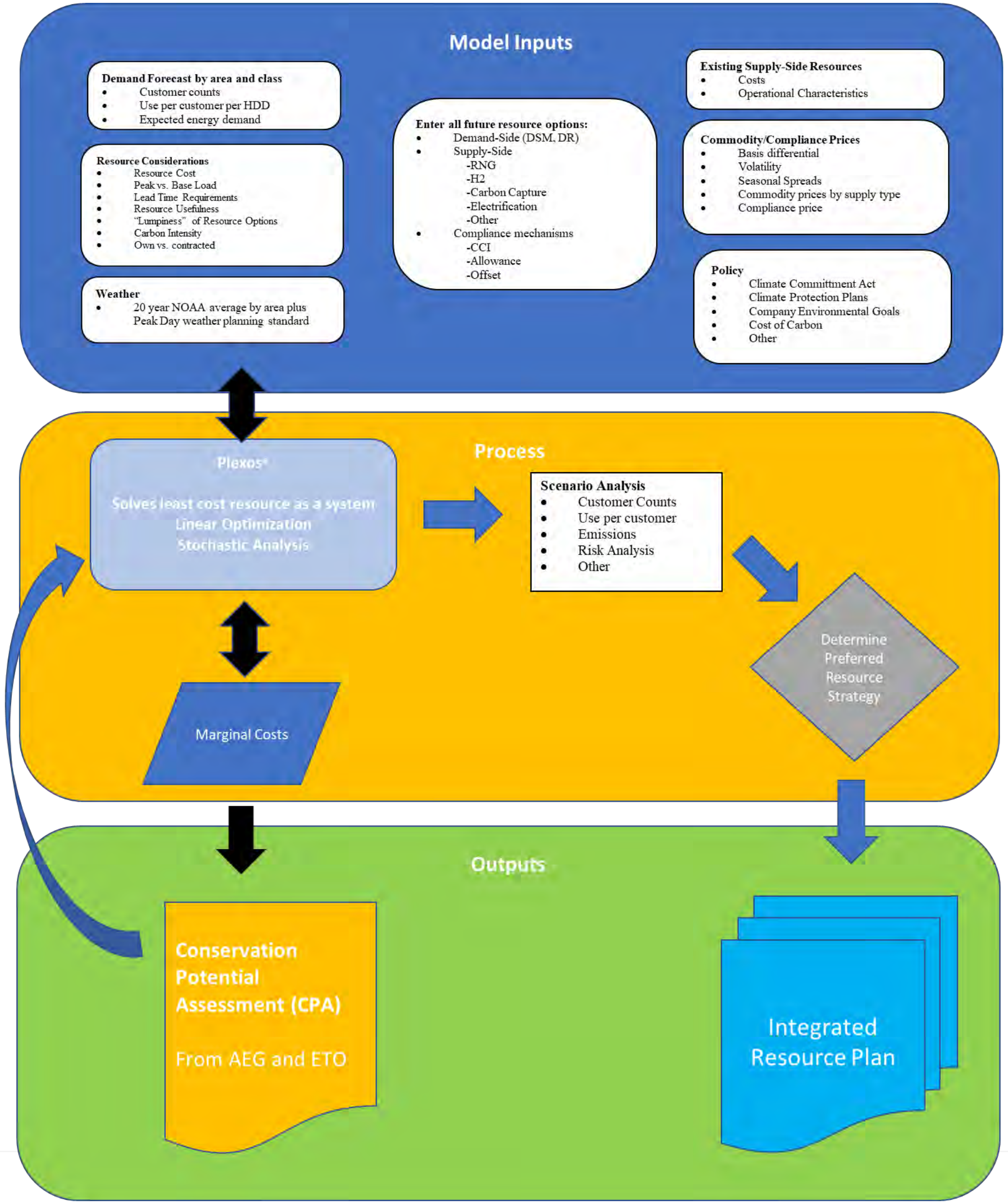
AVISTA

Plexos

New Optimization Model

- Prior model, SENDOUT, had not been updated by the vendor since 2013
- Increasing complexity in planning for new rules, emissions constraints and fuel types was not easily handled within SENDOUT

Model Diagram



Gas Portfolio Optimization

Portfolio Optimization and Resource Planning

- Determine **optimal utilization of resources,** assets and contracts owned or **managed by the entity.**
- Supported by customer specific **asset and contract parameters & data.**

Components include

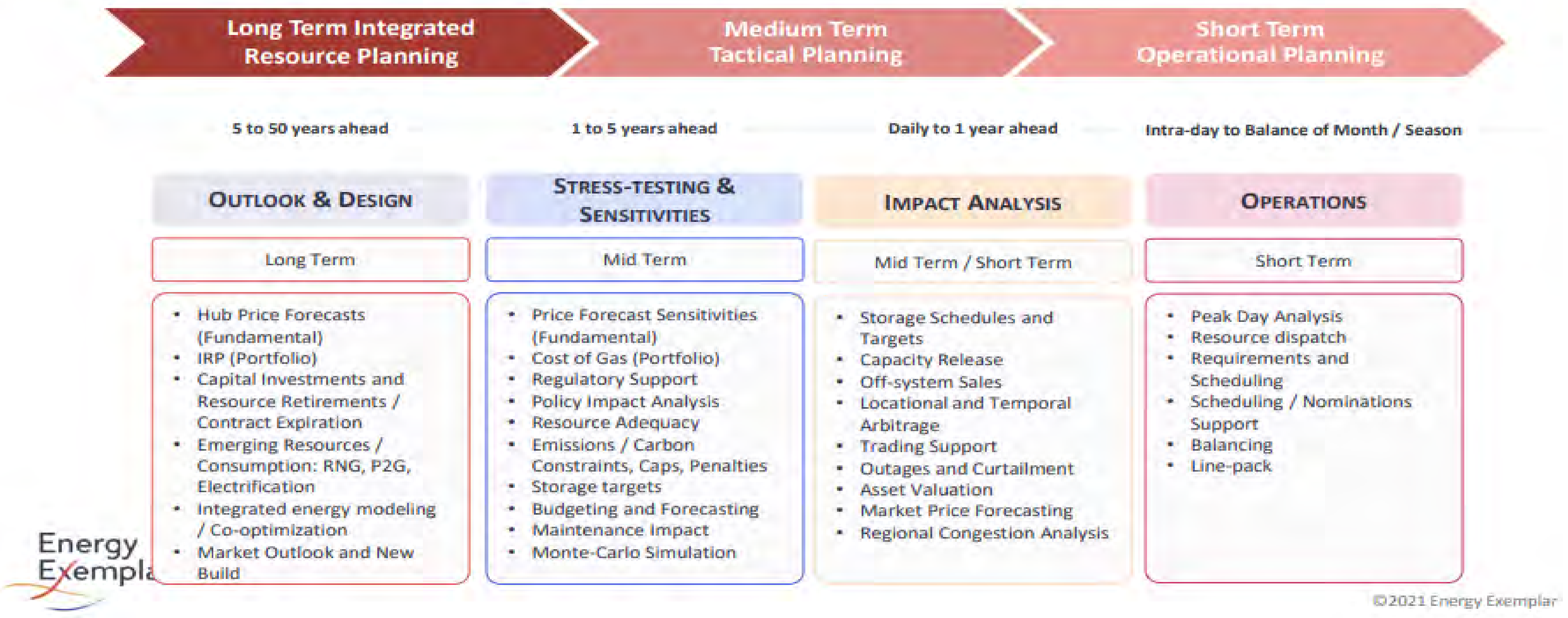
- PLEXOS Gas Module
- Customer Portfolio Data (Assets, Parameters, Assumptions)

Applications		
Cost of Gas (CGA / PGA)	**Gas Resource Planning and IRP** (Portfolio Design)	**Capacity & Contract Evaluation**
Reliability and Stress-testing (Resource Adequacy)	**Scenario Analysis and Portfolio Risk Assessment**	**Daily, Monthly, Seasonal Dispatch Plans and Schedules**
Policy and Regulation Impact Analysis Emissions, Carbon Caps / Penalties, RNG	**Capacity Release, Off-system Sales and Arbitrage Opportunities**	**Co-optimization and Portfolio Synergies**

Energy Exemplar

PLEXOS Gas: Chronological Modeling

Representative Study-types Across Optimization Horizons



Balancing Resources & Requirements

Objective Function: Satisfy Demand at Best Cost

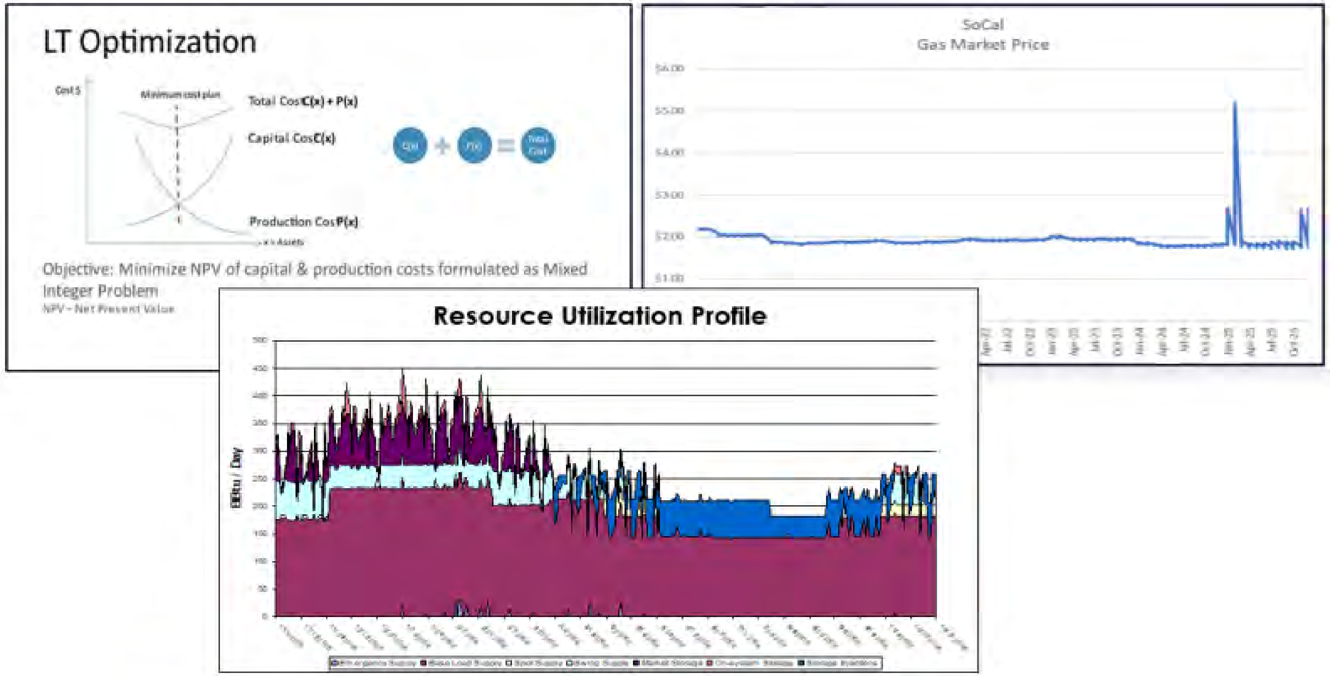
- Given available resources
- Bound by Constraints
- Considering economic assumptions and market opportunities
- Within criteria for reliability / priority to serve

Supports Multiple Objective Functions

- Prioritized (Weighted)
- Example:
- Minimize Gas Costs
- Minimize System Costs (Gas + Generation)
- Minimize CO2
- Maximize Revenue (Net Cost)

Advances in Technology

- Modeling Detail
- Scalability
- Granularity
- Solvers & Methodologies
- Simulations
- Performance



Energy Exemplar

Deterministic Scenarios

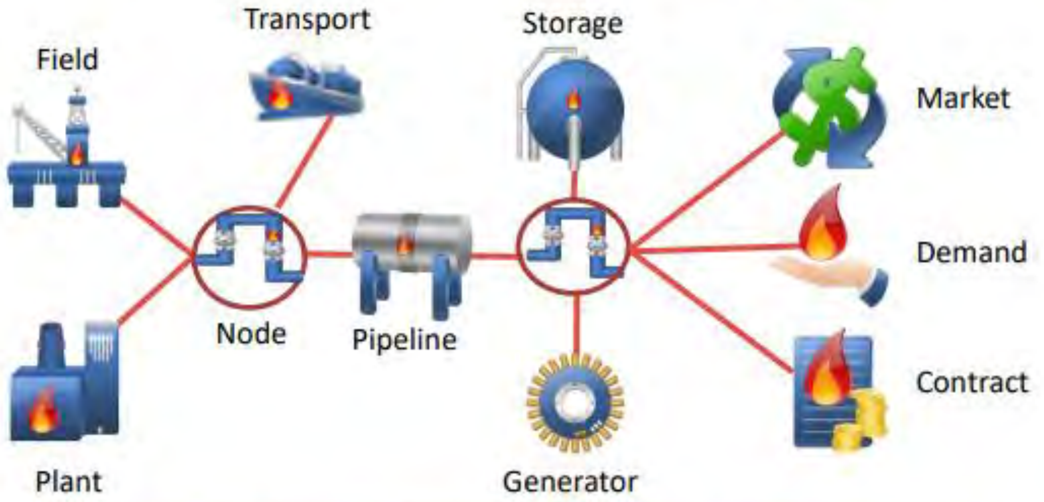
Monte-Carlo Simulation

Stochastic Optimization

 4

AVISTA

Comprehensive Gas Modelling and Operational Detail



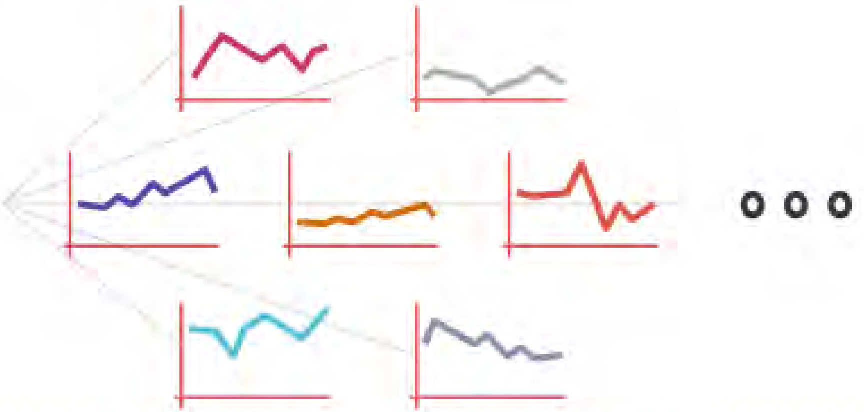
Symbol	Class	Description
	Gas Field	Field from which gas is extracted
	Gas Basin	A summary class to contain a collection of Gas Fields
	Gas Storage	Storage where gas can be injected & extracted
	Gas Pipeline	Pipeline for transporting gas
	Gas Node	Connection point to gas network
	Gas Demand	Demand for gas covering one or more nodes
	Gas Zone	A collection of Gas Nodes

Energy Exemplar PLEXOS

AVISTA

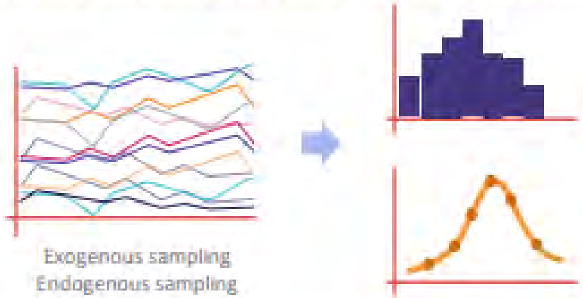
Uncertainty Modelling

Deterministic Scenarios



- One optimal solution for each deterministic scenario.
- Scenario comparison for decision support.

Monte-Carlo Simulations



- One optimal solution for each Monte-Carlo sample.
- Statistical analysis required for decision support.

Stochastic Optimization

- One optimal solution (Storage Schedules) for the entire stochastic sample set.
- Multi-stage stochastic optimization

Energy Exemplar

AVISTA

What Makes PLEXOS Unique

Delivering value ahead of the industry transformation curve

Unified Energy Model
- Global co-optimization
- Short-term through Long-term Horizons
- Emissions and Renewable Integration
- Flexible and Configurable

Modeling Detail & Custom Constraints
- Linear constraints
- Non-linear constraints
- User-defined Constraints

Uncertainty Modeling
- Deterministic scenarios
- Monte-Carlo simulations
- Stochastic optimization

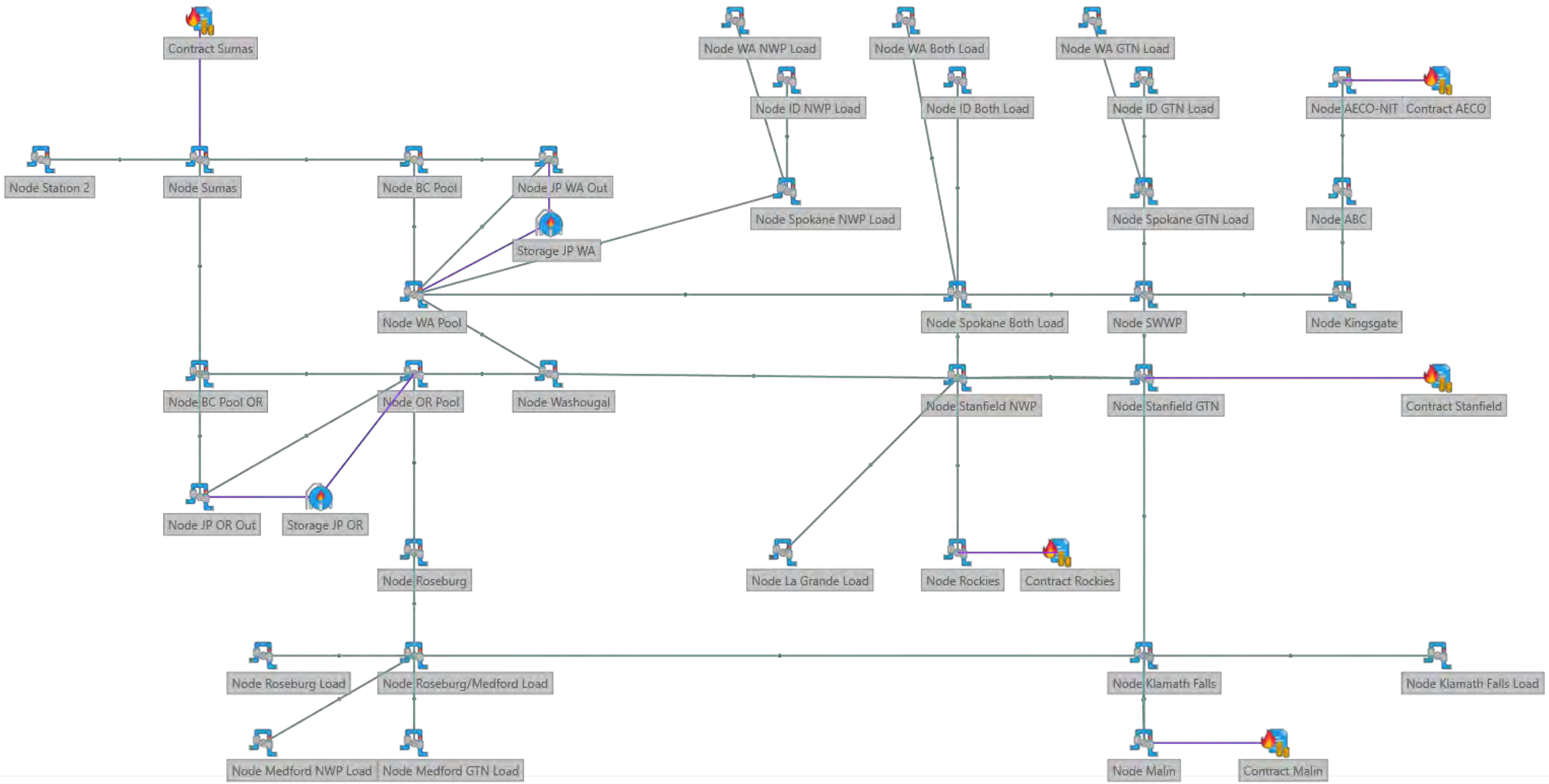
Flexible Deployment & Infrastructure
- On-premise
- Cloud based SaaS

Performance & Scalability
- Grid & cloud computing
- Distributed Processing
- Burst cloud

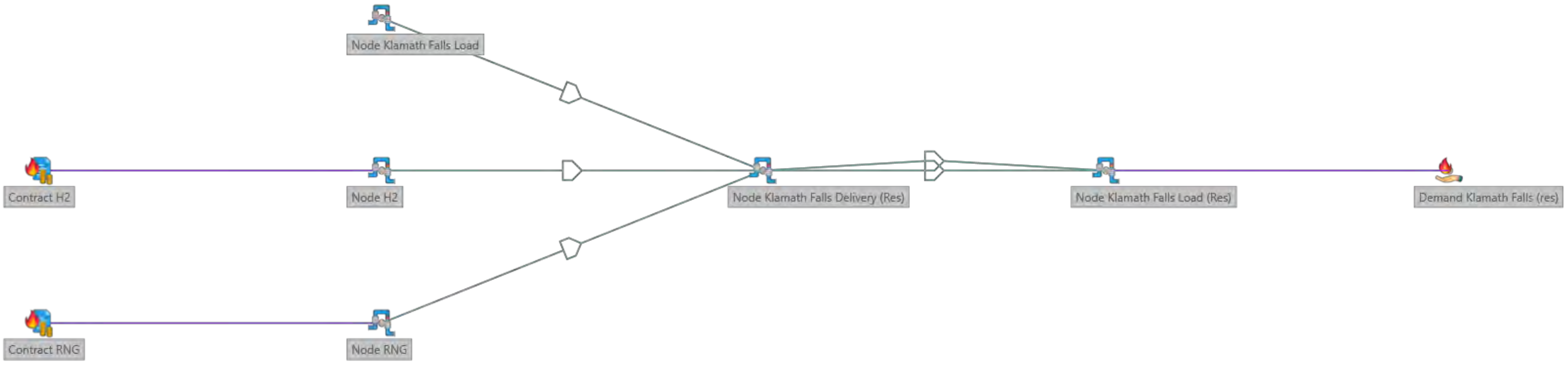
Advanced Analytics
- Advanced visualization
- PLEXOS API
- Faster time to insights

Energy Exemplar

Plexos Model Visual – Pipeline Network

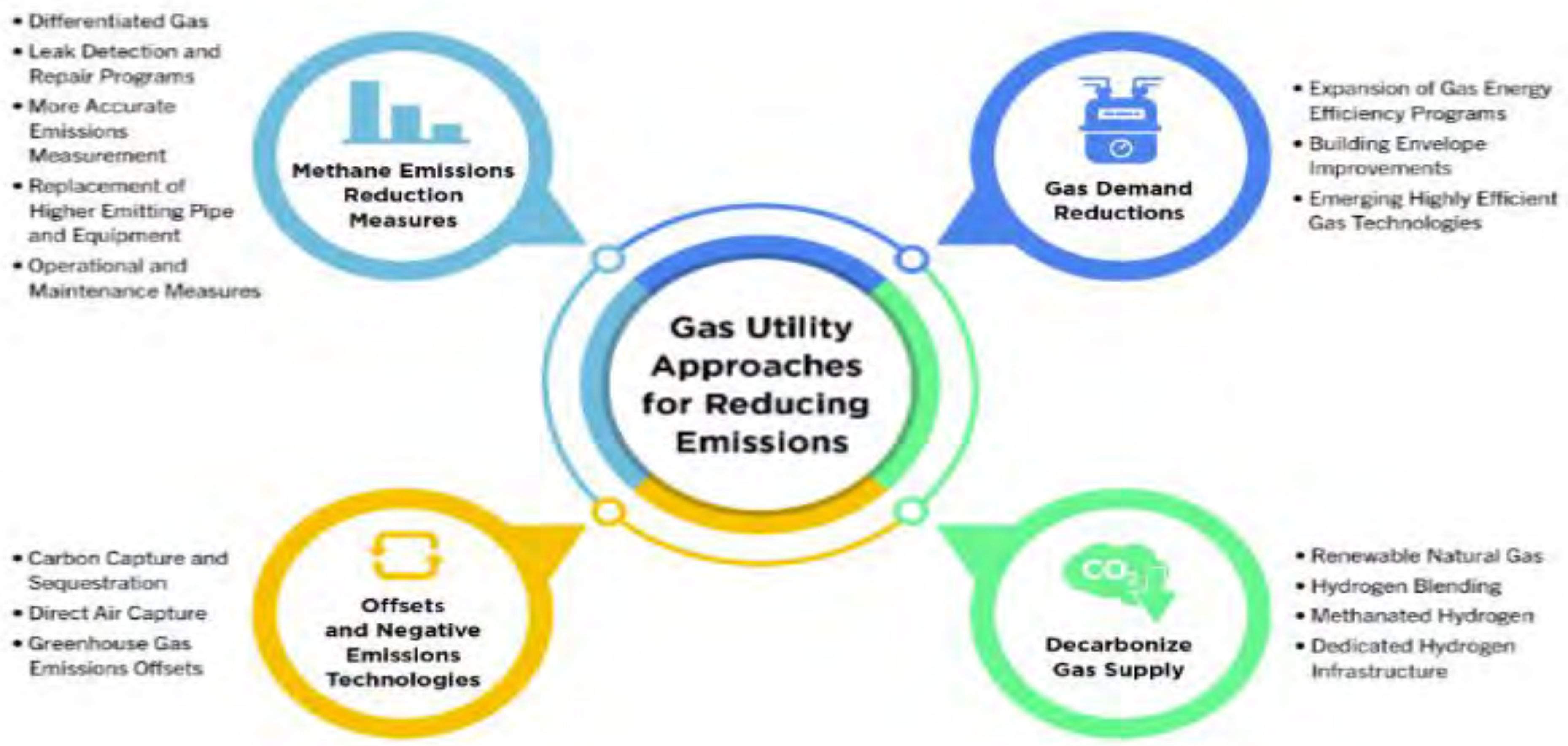


Plexos Model Visual – Emissions Constraint



Proposed Scenarios

Emission Reduction Paths



Proposed Scenarios

	Preferred Resource Case	Avista company goal Carbon Neutral by 2045	Electrification Push	High Customer Case	Limited RNG Availability	High Prices	Interrupted Supply
Customer Growth	Expected Customer Growth		No New Customers after 2023 in Oregon and Washington	High Customer growth	Expected Customer Growth		
Use Per Customer	Expected UPC						
Expected Price	Blend of 2 fundamental consultants, 1 fwd price						
Hydrogen (Green and Synthetic Methane)	20% blend by volume 6% by energy						
RNG - Dairy, Waste Water Treatment, Landfill, Food Waste, Carbon Capture and Recycle (CC&R)	125% of Population Weighted national supply curve from ICF	150% of Population Weighted national supply curve from ICF	125% of Population Weighted national supply curve from ICF		Low Resource Potential from ICF	125% of Population Weighted national supply curve from ICF	
OR - Community Climate Investments	Cost, limits and restrictions defined in CPP rule						
WA - Allowances and Offsets	TBD - Currently in Draft						
Energy Efficiency	ETO CPA in Oregon and AEG CPA in Idaho and Washington						
Weather	20 year rolling Average						
Peak Weather	99% Probability based on prior 30 year annual peak, by planning area						
Environmental Program	CCA (WA), CPP (OR)						
Demand Response	Expected						
Climate Protection Plan - OR	Per Rules						
Climate Commitment Act - WA	Per Rules						

Scenarios - Draft

- **Preferred Resource Case** – Our expected case based on assumptions and costs with a least risk and least cost resource selection
- **Avista company goal - Carbon Neutral by 2045** – Intended to move the 2050 state/federal goals up to the company goal of 2045
- **Electrification Push –** A low demand case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **High Customer Case** – A high case to measure risk of additional customer and meeting our emissions and energy obligations
- **Limited RNG Availability** – A scenario to show costs and supply options if RNG availability is smaller than expected
- **High Prices - Interrupted Supply** – A scenario to show the impacts and risks associated with large scale supply impacts and the ability for Avista to provide the needed energy to our customers
- **Other?**

Questions?

2023 – Avista Natural Gas IRP

Major Milestone	Date	Topics
TAC 1	Wednesday, February 16, 2022	RNG Discussion, Compliance To EO 20-04, Policy, Peak Day Weather Planning Standard
TAC 2	Tuesday, May 3, 2022	Use Per Customer, Planned Scenarios, Customer Forecast, Current Supply Side Resources, Plexos Model Overview, Baseline Demand Projections
TAC 3	Wednesday, June 22, 2022	Customer Survey Results,CCA Overview, Distribution
TAC 4	Tuesday, August 23, 2022	Future Supply Side Resource Options, CPA, Demand Response
TAC 5	Tuesday, October 25, 2022	Final Results / Stochastics, Scenario Results
Draft Feedback Due	Wednesday, February 1, 2023	
File	Friday, March 31, 2023	

AEG
APPLIED ENERGY GROUP

Avista 2022 Natural Gas Potential Assessments

Date: August 10, 2022
Prepared for: Avista Technical Advisory Committee

Overview

- Introduction
- Methodology Overview
- WA & ID Conservation Potential Assessment
  - **Energy Efficiency**
  - **Demand Response**
- Oregon Low-Income Energy Efficiency Potential Study
- OR-WA Transport Customer Energy Efficiency Potential Study

Consulting Client History

Eli Morris
Project Director

Ken Walter
Analysis Lead

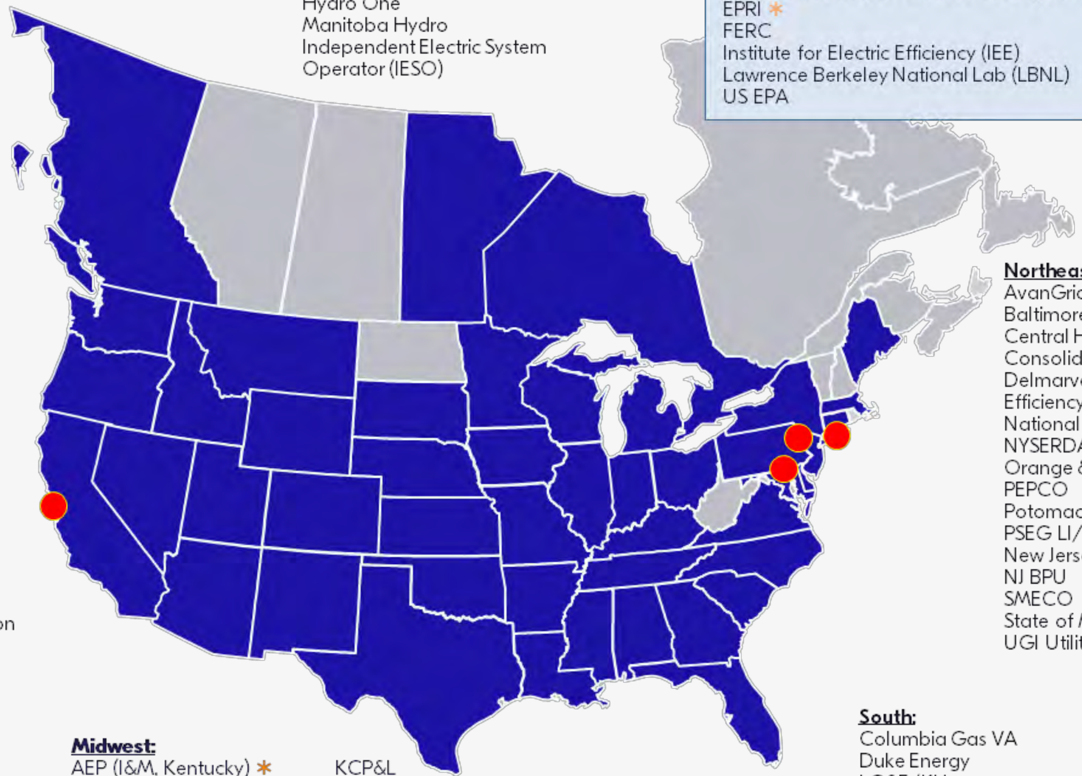
Kelly Marrin
Demand Response Lead

Andy Hudson
Project Manager

Northwest & Mountain:
Avista Energy *
Bonneville Power Ad. (BPA)
Black Hills Energy *
Cascade Natural Gas *
Chelan PUD
City of Fort Collins
Colorado Electric *
Cowlitz PUD
Energy Trust of OR
Idaho Power *
Inland P&L
Northwest EE Alliance *
Northwest Power & Conservation Council *
Oregon Trail Electric Co-op
PacifiCorp *
PNGC
Portland General Electric
Seattle City Light
Snohomish PUD
Tacoma Power *

Canada:
BC Hydro
Hydro One
Manitoba Hydro
Independent Electric System Operator (IESO)

National:
American Society of Mechanical Engineers (ASME)
EPRI *
FERC
Institute for Electric Efficiency (IEE)
Lawrence Berkeley National Lab (LBNL)
US EPA



Northeast & Mid Atlantic:
AvanGrid (RG&E & NYSEG)
Baltimore Gas & Electric
Central Hudson Electric & Gas *
Consolidated Edison of NY
Delmarva Power
Efficiency Maine *
National Grid
NYSERDA
Orange & Rockland *
PEPCO
Potomac Energy
PSEG LI/LIPA *
New Jersey Natural Gas *
NJ BPU
SMECO
State of Maryland
UGI Utilities

Southwest:
Alameda Municipal Power
Burbank W&P
California Energy Commission
HECO *
LADWP
NV Energy
PNM *
PG&E *
SCE *
SDG&E *
SMUD
State of NM
State of HI *
Tucson Electric Power
Xcel/SPS

Midwest:
AEP (I&M, Kentucky) *
Alliant Energy
Ameren Missouri
Ameren Illinois *
Black Hills Energy *
Citizens Energy
ComEd
Empire District Electric *
First Energy *
Indianapolis P&L
KCP&L
Minnesota Energy Resources *
Midcontinent ISO *
NIPSCO
Omaha Public Power District *
Peoples Gas/North Shore Gas * Spire *
State of Michigan
Sunflower Electric Power Vectren (IN & OH)
Wisconsin PSC

South:
Columbia Gas VA
Duke Energy
LG&E/KU
Oklahoma Gas & Electric (OK and AR) *
South Mississippi Electric Power Association
Southern Company (Services and utilities) *
TVA

States and Provinces in which we've worked
* Current Work
AEG offices
As of May 2021

Methodology Overview

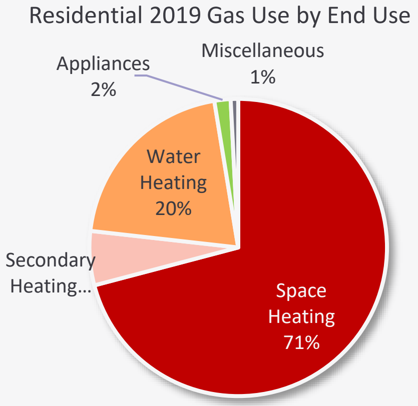
AEG Modeling Approach

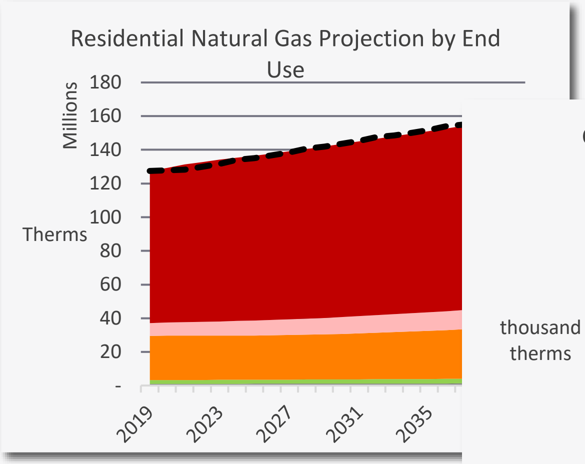
Market Characterization
- Baseline studies
- Utility data
- Secondary data

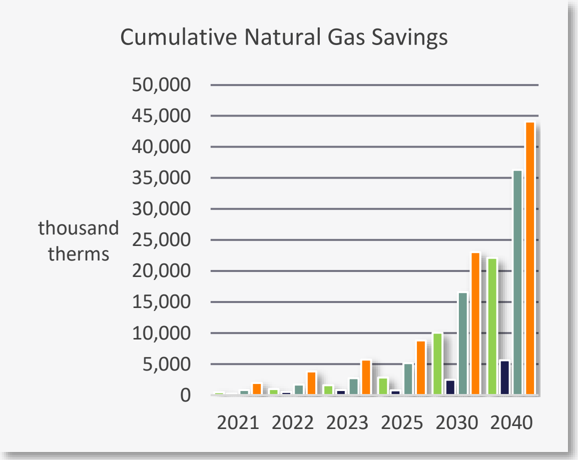
Identify Demand-Side Resources
- EE equipment
- EE measures
- Emerging tech.

Baseline Projection
- Utility forecasts
- Standards and building codes

Potential Estimation
- Technical
- Achievable Tech.
- Economic Achiev.







Washington & Idaho CPA

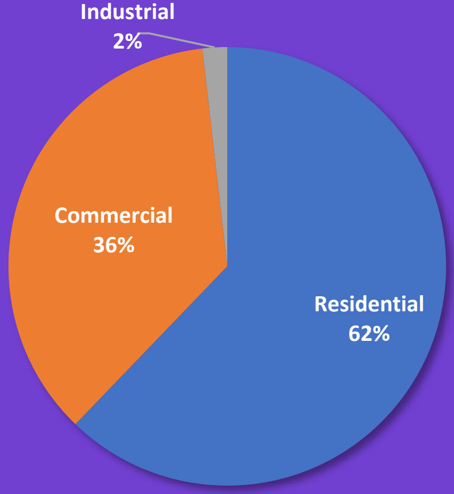
CPA Objectives

1. Conduct an independent assessment of available and cost-effective natural gas energy efficiency opportunities in Avista's service area, consistent with HB 1257.
2. Use methodology consistent with the Northwest Power and Conservation Council while recognizing differences between electricity and natural gas resources.
3. Estimate opportunities for energy efficiency by residential household income.
4. Understand energy efficiency opportunities in commercial and industrial sectors

Market Characterization

- The first step in the CPA process is to define energy-consumption characteristics in the base year of the study (2021).
- AEG incorporates Avista's actual consumption and customer counts to develop "Control Totals" — values to which the model will be calibrated.
- Market characterization is an important step in the CPA process as it grounds the analysis in Avista's data and provides us with enough details to project assumptions forward, developing a baseline energy projection.
- After separating gas consumption into sectors and segments, it is allocated to specific end uses and technologies in the Market Profile (next slide).

Natural Gas Use by Sector 2021

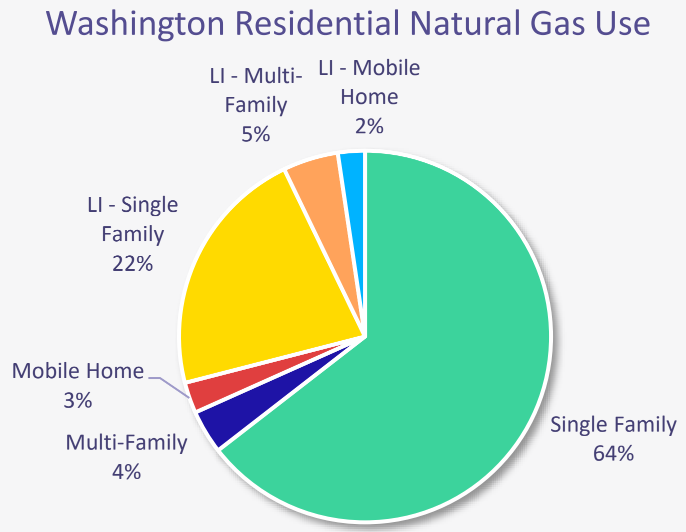


Sector	Accounts	2021 Dth	Segmentation
Residential	237,935	16,973,954	Single Family, Multi-Family, Manufactured Home, and by Income Group within housing type
Commercial	24,454	9,814,874	Office, Retail, Restaurant, Grocery, College, School, Hospital, Lodging, Warehouse, Other
Industrial	194	496,972	Mix of industries from customer data will inform presence of end uses and measure applicability
Total	**262,584**	**27,285,801**	

Energy Market Profile

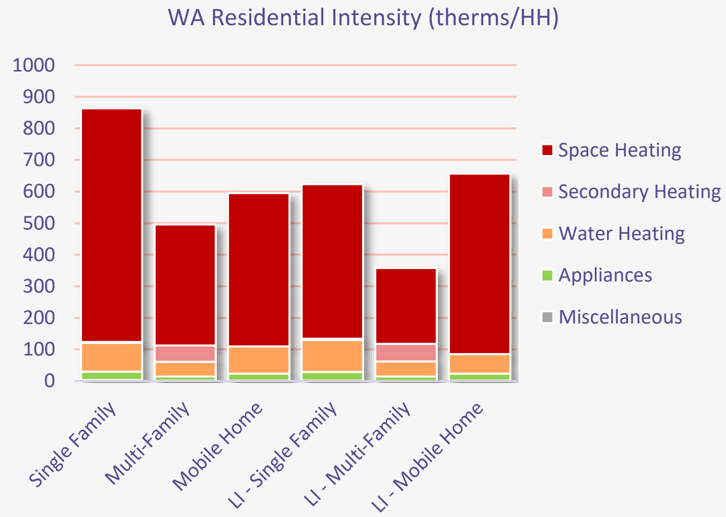
Example – Washington Residential

- Calibrated to Avista's use-per-customer at the household level
- Breaks down energy consumption to the end use and technology level
- Defines the **saturation** (presence of equipment) and the annual consumption of a given technology where it is present **(Unit Energy Consumption – UEC)**
  - Data taken from NEEA's RBSA / CBSA surveys, US DOE Annual Energy Outlook, and Avista's 2013 GenPop Survey



Single Family Profile

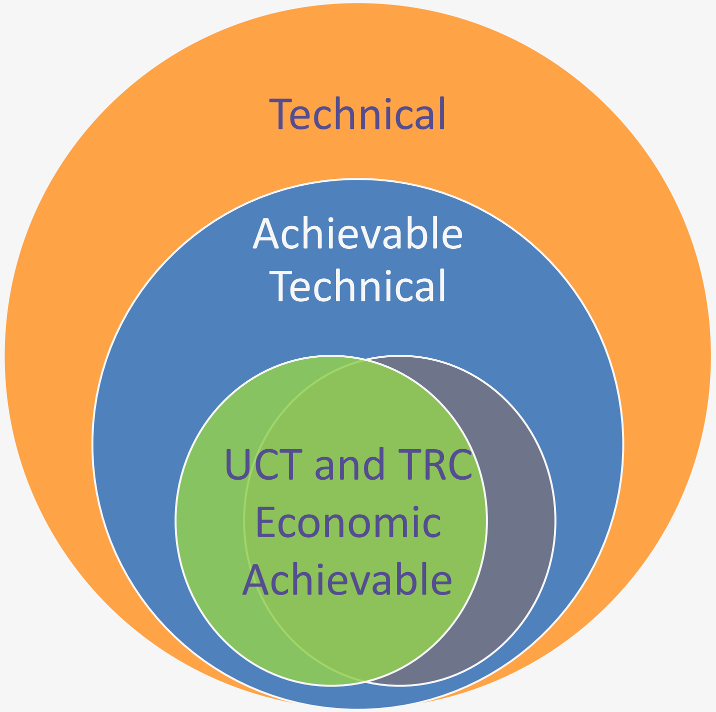
End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (Dth)
Space Heating	Furnace	85%	646	548	8,648,686
	Boiler	2%	432	10	160,215
Secondary Heating	Fireplace	5%	110	6	88,017
Water Heating	Water Heater (<= 55 Gal)	55%	145	80	1,258,802
	Water Heater (> 55 Gal)	0%	52	0	162
Appliances	Clothes Dryer	28%	22	6	97,826
	Stove/Oven	59%	28	17	260,523
Miscellaneous	Pool Heater	1%	106	1	15,120
	Miscellaneous	100%	1	1	14,482



Estimating Energy Efficiency Potential

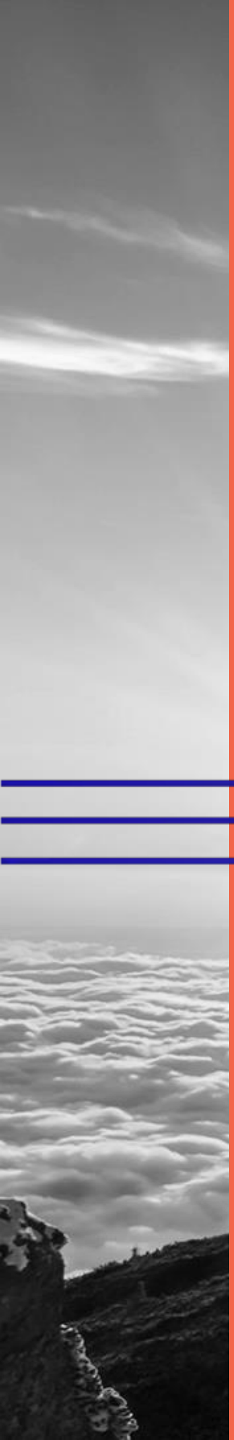
We estimate three levels of potential. These are standard practice for CPAs in the Northwest:

- **Technical**: everyone chooses the most efficient option when equipment fails regardless of cost.
- **Achievable Technical** is a subset of technical that accounts for achievable participation within utility programs as well as non-utility mechanisms, such as regional initiatives and market transformation.
- **Achievable Economic** is a subset of achievable technical potential that includes only cost-effective measures. Tests considered within this study were the UCT for Idaho and TRC for Washington.



Measure Ramp Rates

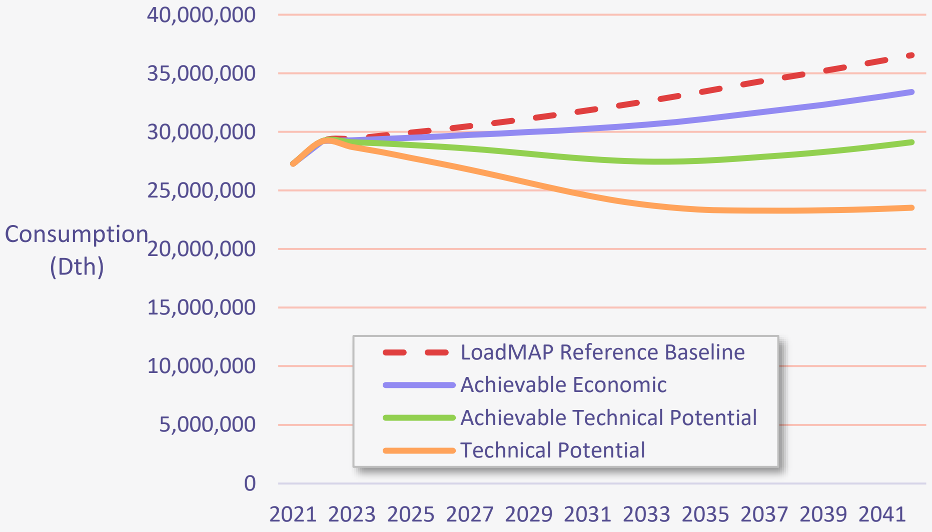
- For this study, AEG adapted the 2021 Power Plan ramp rates for use in a natural gas CPA.
- All measures "ramp up" over time to a maximum of 85% adoption
  - In the 2021 plan, some electric measures have had their maximum achievability increased beyond 85%. None of those specific measures apply to natural gas, and AEG has not increased the achievability for any measures in this study.
  - Power Council's ramp rates include potential realized from outside of utility DSM programs, including regional initiatives and market transformation.
  - A cost-effectiveness screen is applied to equipment measures to address very high-cost measures before ramp rates are applied, consistent with Council methodology.
- AEG considered Avista's recent program achievement when assigning ramp rates to reflect differences between electric and natural gas markets.

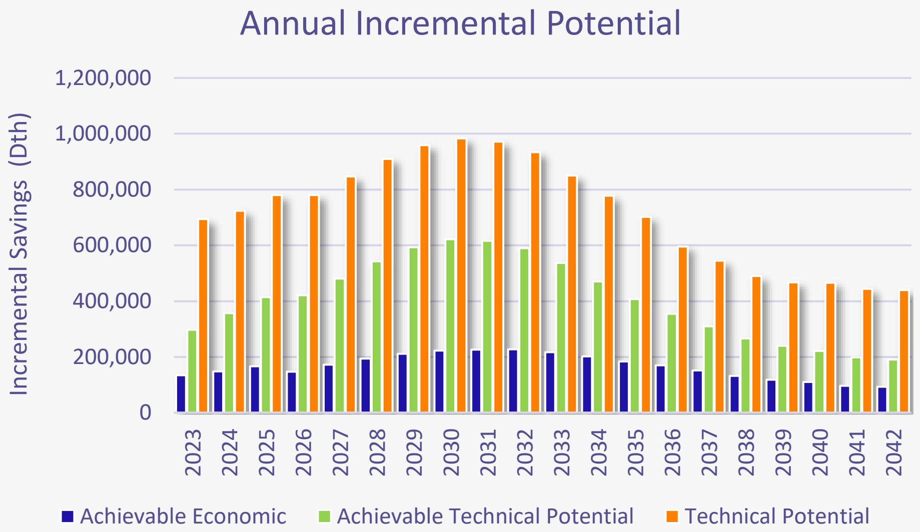


Draft Potential Results (All Sectors)

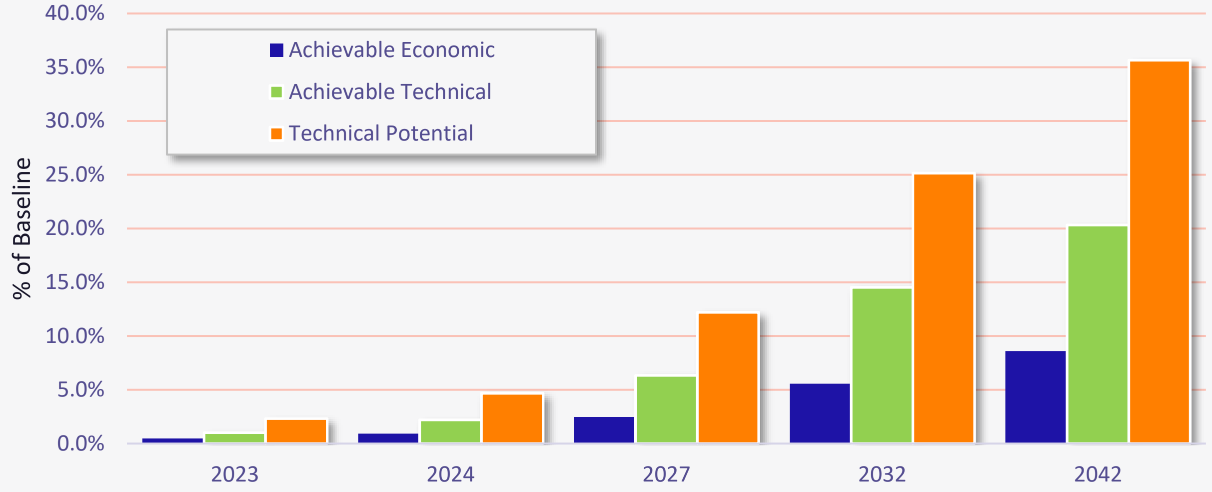
Summary Results (All Sectors, WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 7,427,167 Dth, or 20.3% of the reference baseline by the end of the 20-year study period
- Cumulative Achievable Economic Potential reaches 3,136,202 Dth, or 8.6% of the baseline over the study period





Summary Results Continued

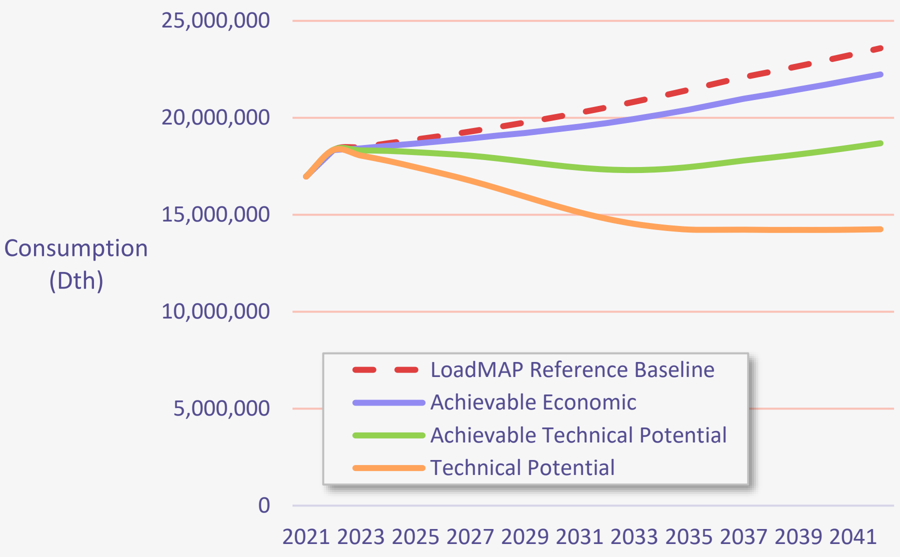


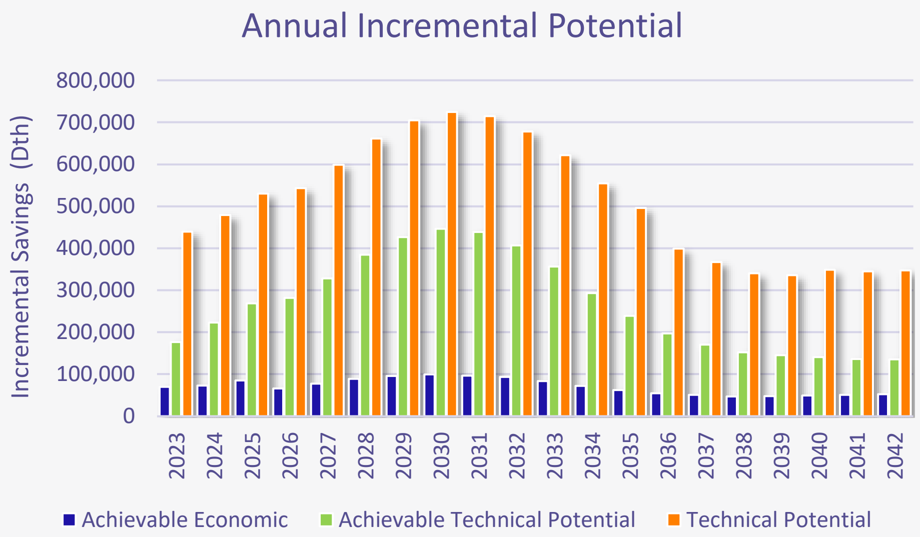
Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	29,414,120	29,675,685	30,496,490	32,215,067	36,547,665
Cumulative Savings (Dth)					
Achievable Economic	134,786	272,271	749,007	1,786,294	3,136,102
Achievable Technical	297,165	651,909	1,927,022	4,672,773	7,427,167
Technical Potential	683,777	1,382,691	3,717,219	8,099,510	13,024,530
Energy Savings (% of Baseline)					
Achievable Economic	0.5%	0.9%	2.5%	5.5%	8.6%
Achievable Technical	1.0%	2.2%	6.3%	14.5%	20.3%
Technical Potential	2.3%	4.7%	12.2%	25.1%	35.6%
Incremental Savings (Dth)					
Achievable Economic	134,786	148,614	172,490	227,703	93,621
Achievable Technical	297,165	357,151	480,848	589,559	190,622
Technical Potential	693,690	723,398	846,959	934,311	439,915

Draft Residential Potential Results

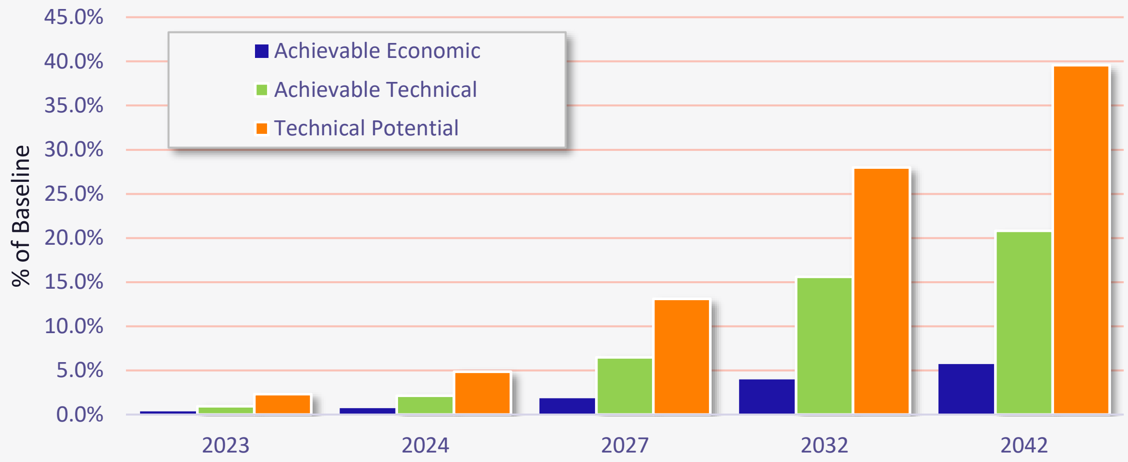
Residential Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 4,911,795 Dth, or 20.8% of the reference baseline by the end of the 20-year study period
- Cumulative Achievable Economic Potential reaches 1,353,411 Dth, or 5.7% of baseline over the study period





Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	18,489,822	18,688,449	19,295,674	20,539,977	23,591,578
Cumulative Savings (Dth)					
Achievable Economic	69,555	132,295	356,199	815,071	1,353,411
Achievable Technical	176,790	399,302	1,252,962	3,206,725	4,911,795
Technical Potential	429,994	905,601	2,530,507	5,747,603	9,337,234
Energy Savings (% of Baseline)					
Achievable Economic	0.4%	0.7%	1.8%	4.0%	5.7%
Achievable Technical	1.0%	2.1%	6.5%	15.6%	20.8%
Technical Potential	2.3%	4.8%	13.1%	28.0%	39.6%
Incremental Savings (Dth)					
Achievable Economic	69,555	73,083	77,290	93,201	52,239
Achievable Technical	176,790	223,252	327,945	406,973	135,250
Technical Potential	439,907	479,545	598,656	678,285	347,207

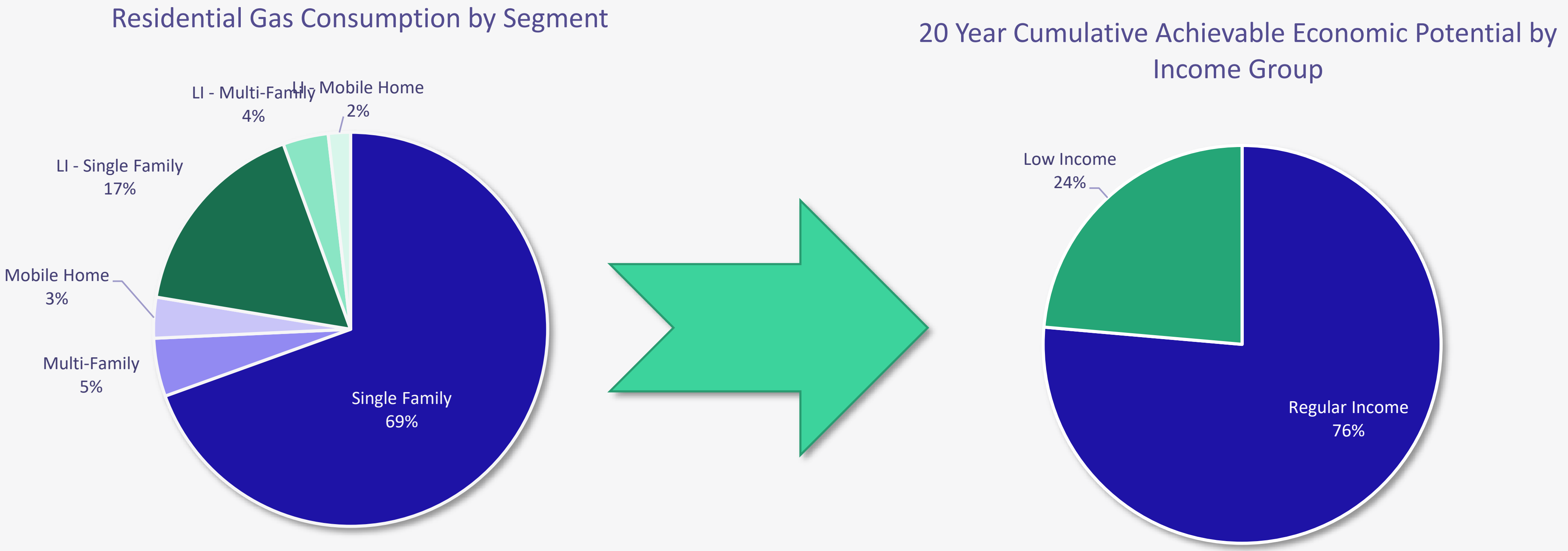
Residential Top Measures (Achievable Economic)

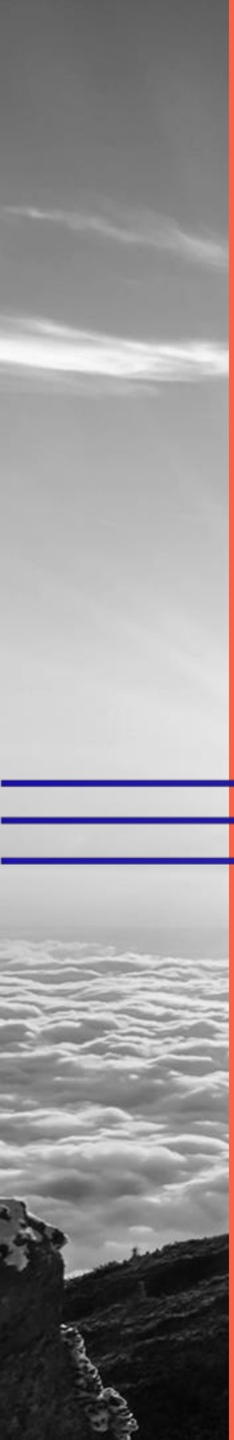
Rank	**Idaho** – Achievable Economic UCT Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Furnace	216,304	37.1%
2	Connected Thermostat - ENERGY STAR (1.0)	155,844	26.7%
3	ENERGY STAR Home Design	65,417	11.2%
4	Building Shell - Whole-Home Aerosol Sealing	53,919	9.3%
5	Insulation - Ceiling Installation	38,952	6.7%
6	Gas Furnace - Maintenance	27,441	4.7%
7	Windows - Low-e Storm Addition	9,508	1.6%
8	Behavioral Programs	4,155	0.7%
9	Circulation Pump - Timer	2,744	0.5%
10	Insulation - Wall Sheathing	2,433	0.4%
	Subtotal	**576,716**	**99.0%**
	Total Savings in Year	**582,595**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Furnace	420,956	54.6%
2	Building Shell - Whole-Home Aerosol Sealing	124,541	16.2%
3	Insulation - Ceiling Installation	70,670	9.2%
4	Gas Furnace - Maintenance	51,736	6.7%
5	Connected Thermostat - ENERGY STAR (1.0)	30,781	4.0%
6	Boiler	18,677	2.4%
7	ENERGY STAR Home Design	9,959	1.3%
8	Behavioral Programs	9,196	1.2%
9	Building Shell - Liquid-Applied Weather-Resistive Barrier	8,367	1.1%
10	Windows - Low-e Storm Addition	5,914	0.8%
	Subtotal	**750,798**	**97.4%**
	Total Savings in Year	**770,816**	**100.0%**

Residential Potential by Income Group

Low Income potential is proportional to the low-income share of natural gas consumption

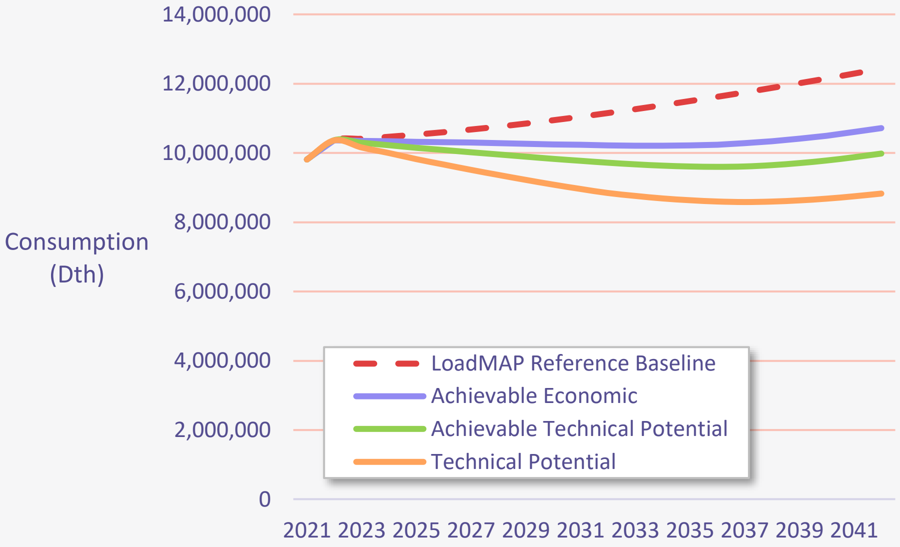


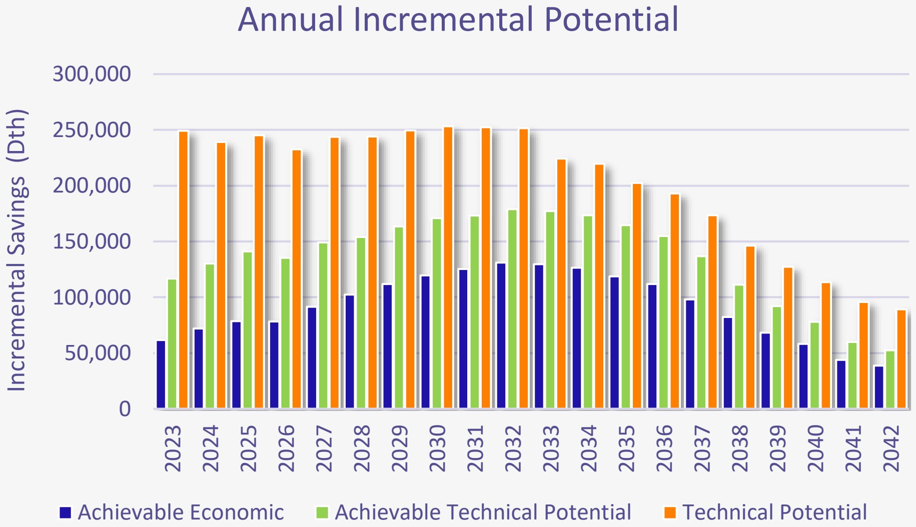


Draft Commercial Potential Results

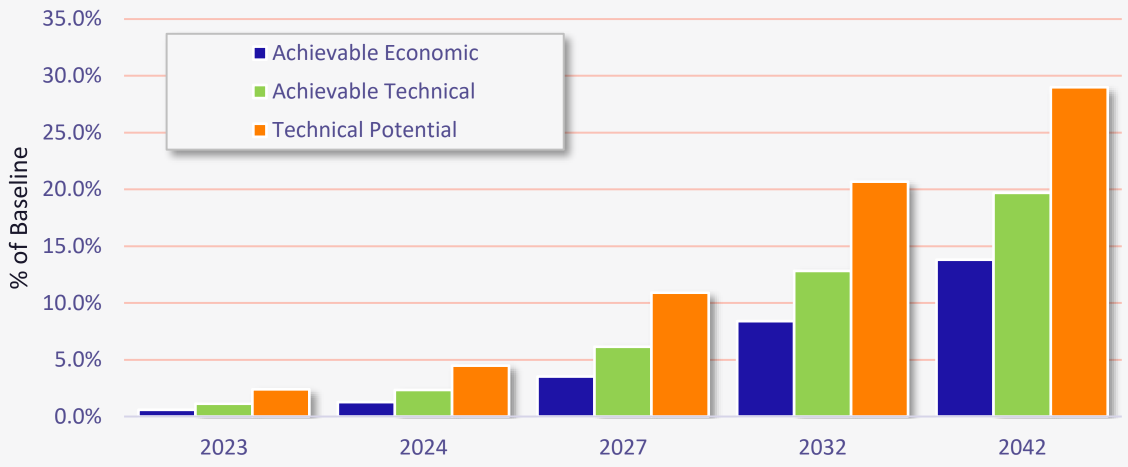
Commercial Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 2,450,164 Dth, or 19.7% of the reference baseline over the 20-year study period.
- Cumulative Achievable Economic Potential reaches 1,717,894 Dth, or 13.8% of the baseline.





Commercial Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	10,412,372	10,470,104	10,678,947	11,153,754	12,435,557
Cumulative Savings (Dth)					
Achievable Economic	61,744	132,968	375,053	935,651	1,717,894
Achievable Technical	116,869	245,560	656,182	1,430,257	2,450,164
Technical Potential	249,222	468,009	1,163,993	2,307,056	3,606,368
Energy Savings (% of Baseline)					
Achievable Economic	0.6%	1.3%	3.5%	8.4%	13.8%
Achievable Technical	1.1%	2.3%	6.1%	12.8%	19.7%
Technical Potential	2.4%	4.5%	10.9%	20.7%	29.0%
Incremental Savings (Dth)					
Achievable Economic	61,744	72,005	91,557	130,956	38,704
Achievable Technical	116,869	130,350	149,230	179,030	52,649
Technical Potential	249,222	239,290	243,712	251,628	89,333

Commercial Top Measures (Achievable Economic)

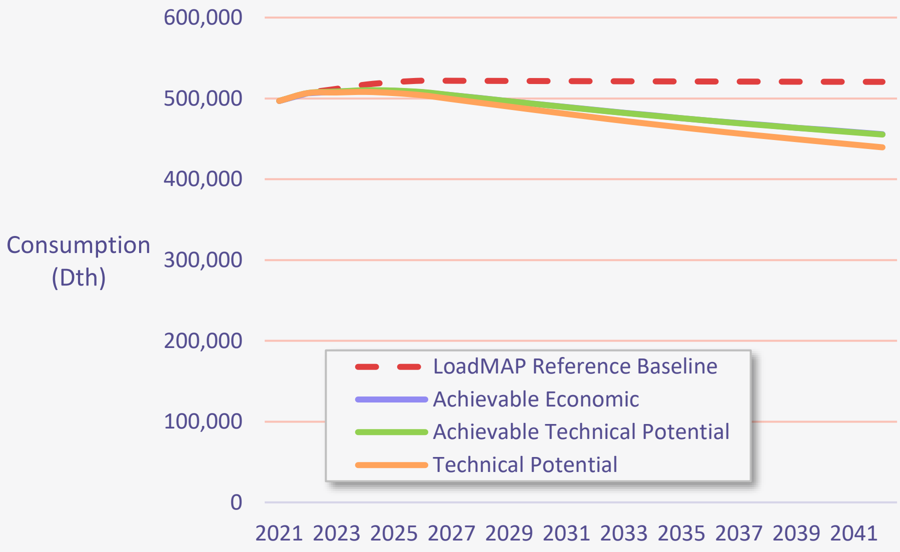
Rank	**Idaho** – Achievable Economic UCT Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Insulation - Wall Cavity	113,825	22.1%
2	Windows - Secondary Glazing Systems	57,922	11.2%
3	Insulation - Ceiling	57,598	11.2%
4	Ducting - Repair and Sealing	53,296	10.3%
5	Water Heater	40,158	7.8%
6	Furnace	38,787	7.5%
7	Fryer	29,491	5.7%
8	Gas Boiler - Thermostatic Radiator Valves	15,741	3.1%
9	Water Heater - Circulation Pump Controls	15,684	3.0%
10	HVAC - Energy Recovery Ventilator	14,140	2.7%
	Subtotal	**436,642**	**84.6%**
	Total Savings in Year	**516,012**	**100.0%**

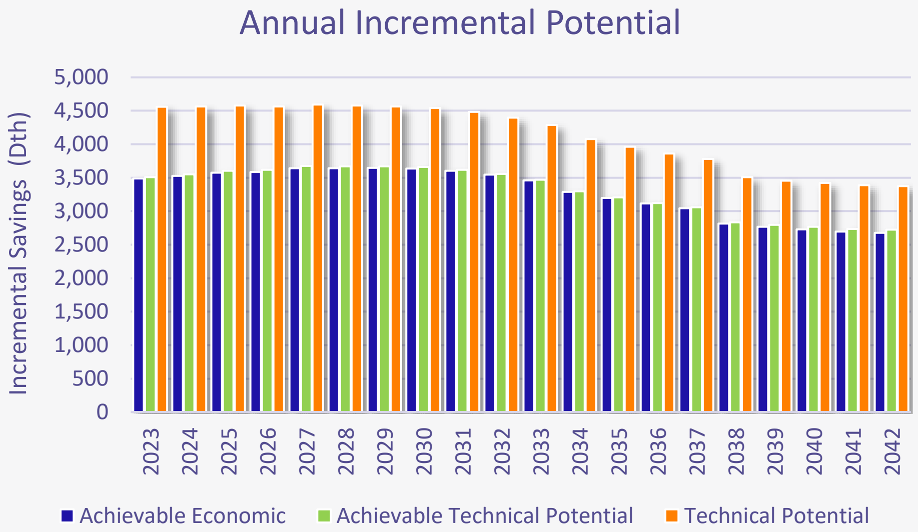
Rank	**Washington** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Insulation - Wall Cavity	146,946	12.2%
2	Boiler	138,797	11.5%
3	Ducting - Repair and Sealing	121,645	10.1%
4	Windows - Secondary Glazing Systems	111,172	9.2%
5	Insulation - Ceiling	84,303	7.0%
6	Water Heater	79,479	6.6%
7	Furnace	78,323	6.5%
8	HVAC - Energy Recovery Ventilator	58,049	4.8%
9	Strategic Energy Management	41,377	3.4%
10	Broiler	36,258	3.0%
	Subtotal	**896,351**	**74.6%**
	Total Savings in Year	**1,201,882**	**100.0%**

Draft Industrial Potential Results

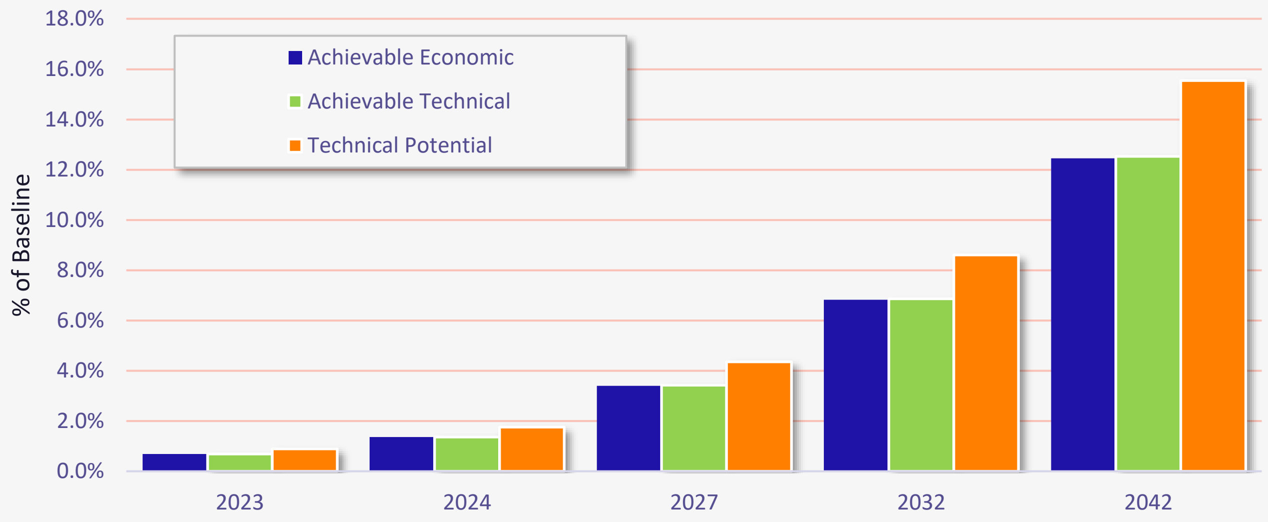
Industrial Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 65,208 Dth, or 12.5% of the reference baseline over the 20-year study period.
- Cumulative Achievable Economic Potential reaches 64,795 Dth, or 12.4% of the baseline.





Industrial Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	511,926	517,132	521,869	521,336	520,530
Cumulative Savings (Dth)					
Achievable Economic	3,487	7,008	17,756	35,571	64,796
Achievable Technical	3,506	7,047	17,879	35,791	65,208
Technical Potential	4,561	9,081	22,719	44,852	80,927
Energy Savings (% of Baseline)					
Achievable Economic	0.7%	1.4%	3.4%	6.8%	12.4%
Achievable Technical	0.7%	1.4%	3.4%	6.9%	12.5%
Technical Potential	0.9%	1.8%	4.4%	8.6%	15.5%
Incremental Savings (Dth)					
Achievable Economic	3,487	3,526	3,643	3,546	2,679
Achievable Technical	3,506	3,549	3,673	3,557	2,723
Technical Potential	4,561	4,563	4,591	4,397	3,376

Industrial Top Measures (Achievable Economic)

Rank	**Idaho** – Achievable Economic UCT Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	22,382	79.8%
2	Process Boiler - Hot Water Reset	1,207	4.3%
3	Process Boiler - Stack Economizer	814	2.9%
4	Process Boiler - Insulate Steam Lines/Condensate Tank	785	2.8%
5	Process Boiler - Burner Control Optimization	568	2.0%
6	Process Boiler - Insulate Hot Water Lines	395	1.4%
7	Destratification Fans (HVLS)	344	1.2%
8	Insulation - Wall Cavity	332	1.2%
9	Insulation - Ceiling	257	0.9%
10	Unit Heater	146	0.5%
	Subtotal	**27,230**	**97.1%**
	Total Savings in Year	**28,042**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	29,905	81.4%
2	Process Boiler - Hot Water Reset	1,398	3.8%
3	Process Boiler - Stack Economizer	1,086	3.0%
4	Process Boiler - Insulate Steam Lines/Condensate Tank	919	2.5%
5	Process Boiler - Burner Control Optimization	760	2.1%
6	Process Boiler - Insulate Hot Water Lines	462	1.3%
7	Destratification Fans (HVLS)	453	1.2%
8	Insulation - Wall Cavity	374	1.0%
9	Insulation - Ceiling	298	0.8%
10	Unit Heater	183	0.5%
	Subtotal	**35,838**	**97.5%**
	Total Savings in Year	**36,754**	**100.0%**

Natural Gas Demand Response

Approach to the Study

Data Collection → Characterize the Market → Develop list of DR Options → Characterize the Options → Estimate Potential

Align with EE Potential Study
- Market Profiles

Secondary Sources
- DR Program Evaluation Reports from other Utilities

Segmentation by Customer Class
- Residential
- Commercial
- Industrial

Program Options
- Behavioral
- DLC Water Heating
- DLC Smart Thermostats – BYOT
- Third Party Contracts
- Time-of-Use
- Variable Peak Pricing

Develop Program Assumptions
- Impacts
- Participation
- End Use Saturations
- Costs
- Incentives

Achievable Potential
- Integrated program options without participant overlap

Assumptions

Study Assumptions

- The programs in this study target the peak hour of the peak day (therms)
- Winter only

Program Impact and Cost assumptions

- Derived Primarily from other Gas DR Programs
  - Smart Thermostat Program based on SoCalGas' Smart Therm Program
  - Third Party Contracts Program based on National Grid and ConEdison Programs
- Diverged where gaps in research
  - Customized for Avista's service territory
  - Pulled remaining assumptions from Electric DR Model and scaled down where appropriate

Advanced Metering Infrastructure (AMI) Assumptions

Some of the options require AMI

- DLC Options- No AMI Metering Required
- Dynamic Rates- require AMI for billing

Washington

- Utilized current Avista AMI saturation rates by sector and held constant
  - Residential 85%
  - Commercial – Firm 86%
  - Industrial – Firm 97%

Idaho starting AMI rollout in 2024

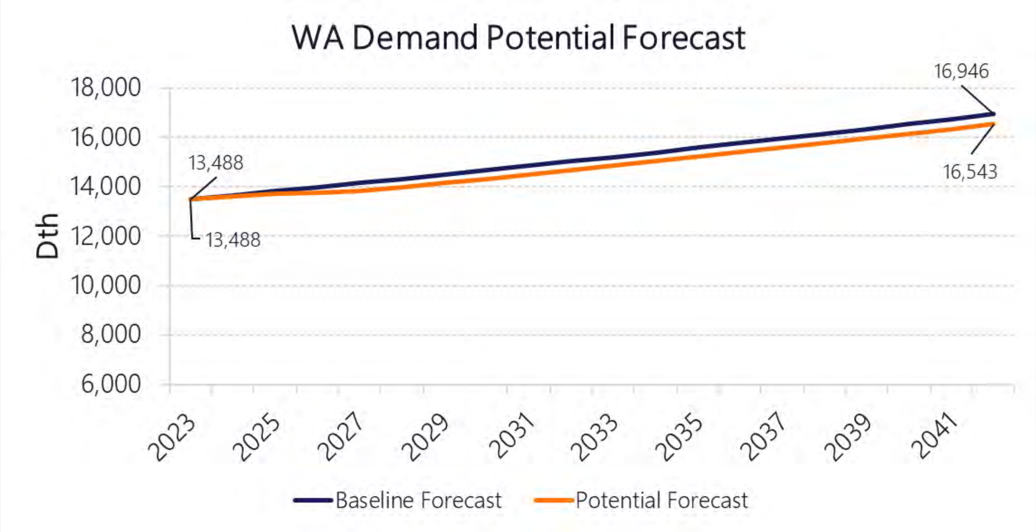
- No AMI Projected in Idaho
- Dynamic Rate Programs not estimated in Idaho

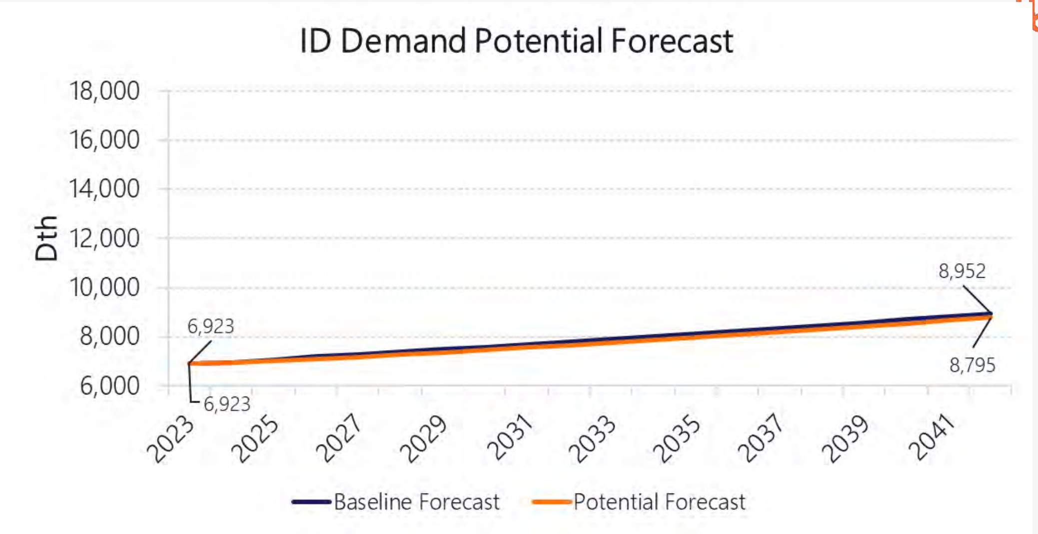
Achievable Potential

Program Impact Calculation

$$\begin{aligned}&Program\ Impact_{year,program}\\&= Per\ Customer\ Peak\ Impact_{y,p} * Eligible\ Participants_{y,p} * Participation\ Rate_{y,p}\\&* Equipment\ Saturation\ Rate\ _{y,p}\end{aligned}$$

Achievable Potential Forecast by State

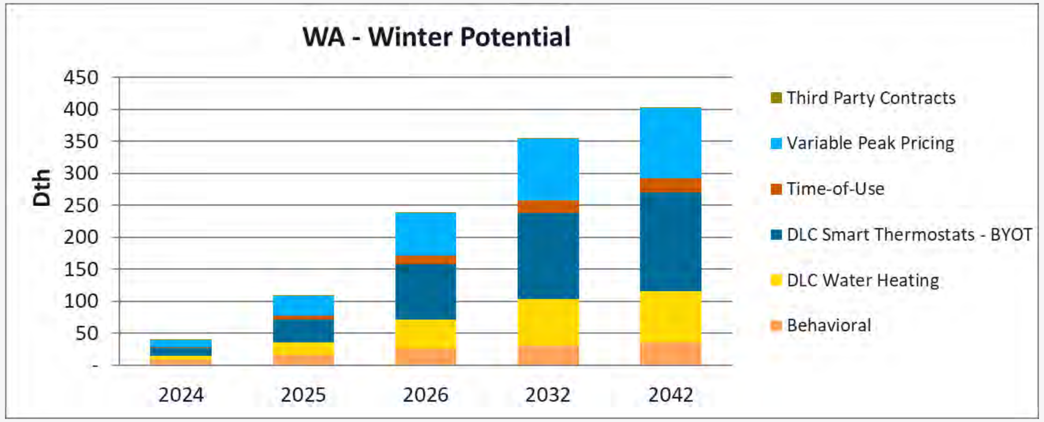




Washington Potential	2024	2025	2026	2032	2042
Baseline Forecast (Dth)	13,643	13,812	13,982	15,025	16,946
Market Potential	39	108	238	355	403
Peak Reduction % of Baseline	0.3%	0.8%	1.7%	2.4%	2.4%
Potential Forecast	13,604	13,704	13,743	14,670	16,543

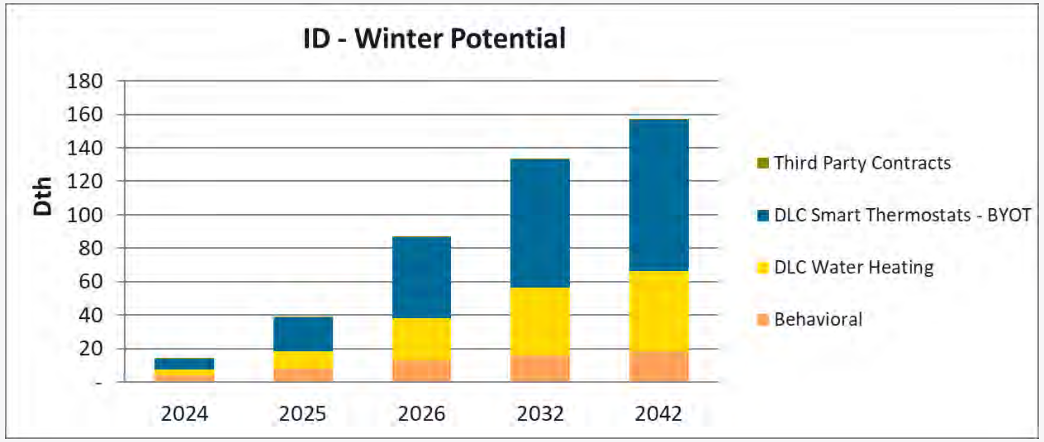
Idaho Potential	2024	2025	2026	2032	2042
Baseline Forecast (Dth)	6,955	7,073	7,203	7,806	8,952
Market Potential	14	39	87	134	157
Peak Reduction % of Baseline	0.2%	0.6%	1.2%	1.7%	1.8%
Potential Forecast	6,941	7,034	7,115	7,672	8,795

Washington Potential by Program



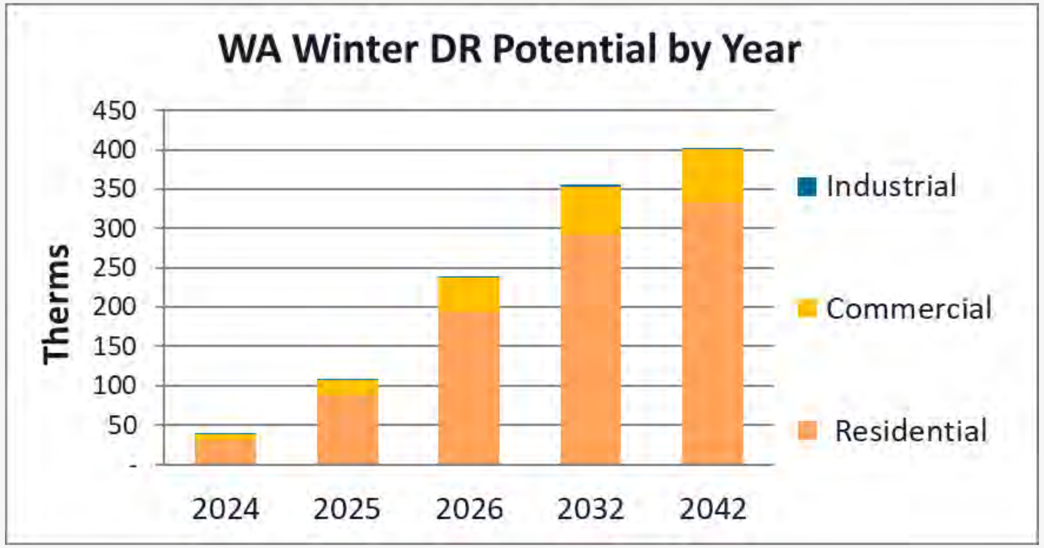
WA - Winter Potential	2024	2025	2026	2032	2042
Baseline Forecast (Dth)	13,643	13,812	13,982	15,025	16,946
Achievable Potential (Dth)	39	108	238	355	403
Behavioral	8	15	25	31	35
DLC Water Heating	6	19	46	72	81
DLC Smart Thermostats - BYOT	12	37	86	135	154
Time-of-Use	2	6	14	20	23
Variable Peak Pricing	10	30	66	96	109
Third Party Contracts	0	1	1	1	1

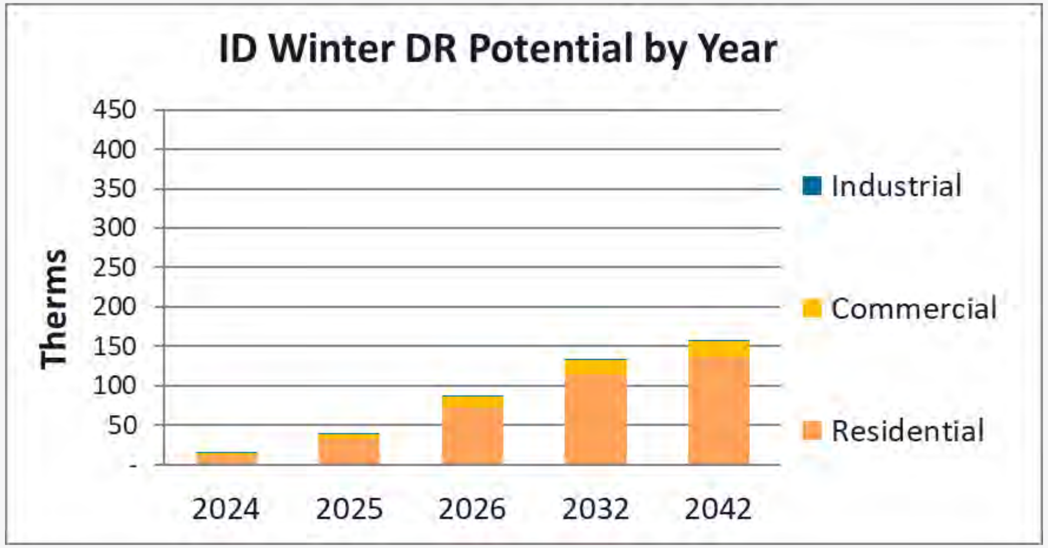
Idaho Potential by Program



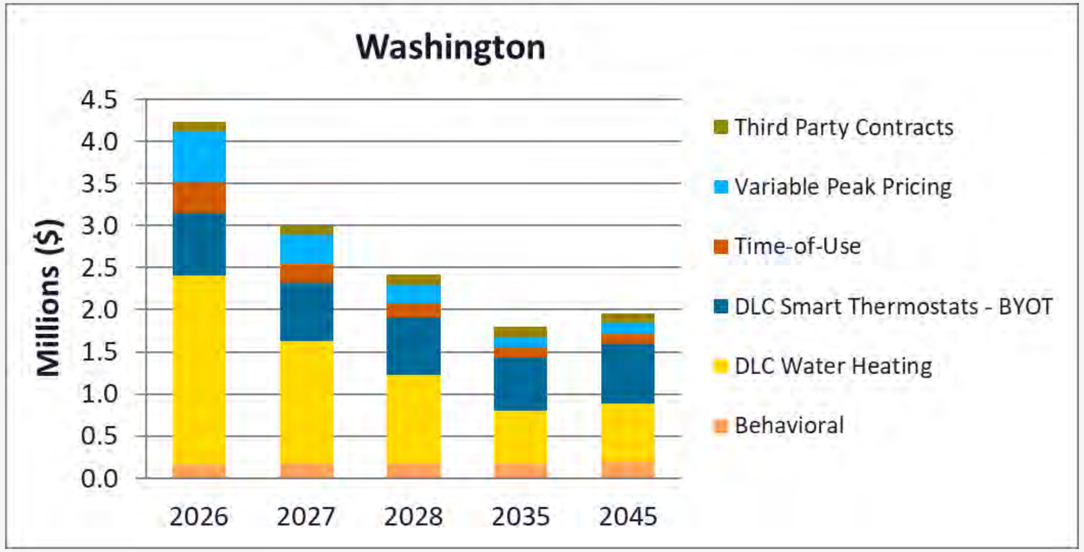
ID - Winter Potential	2024	2025	2026	2032	2042
Baseline Forecast (Dth)	6,955	7,073	7,203	7,806	8,952
Achievable Potential (Dth)	14	39	87	134	157
Behavioral	4	8	13	16	18
DLC Water Heating	3	11	25	40	48
DLC Smart Thermostats - BYOT	7	20	48	77	90
Time-of-Use	-	-	-	-	-

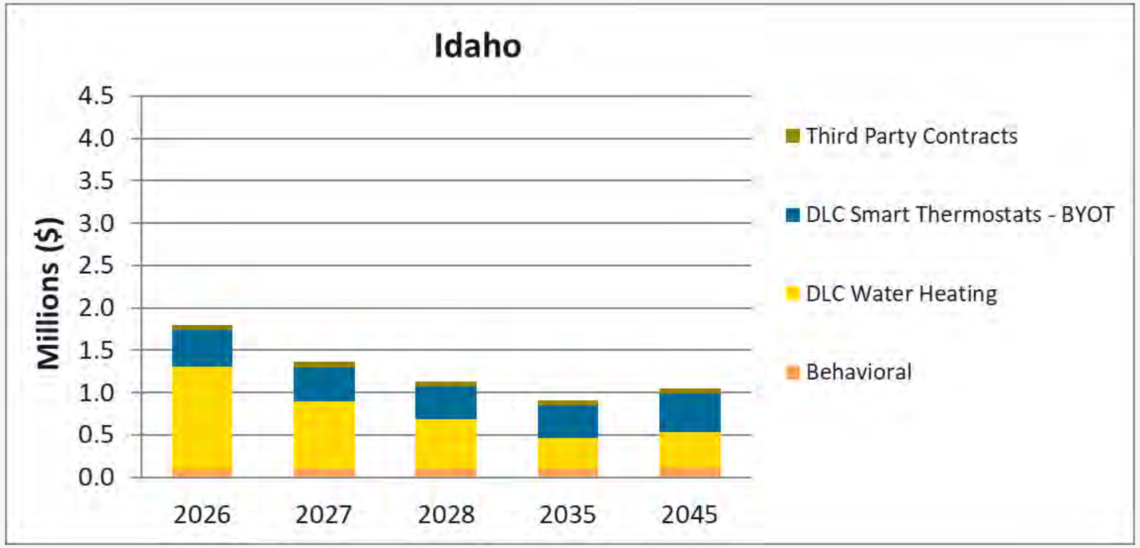
Results by Sector





Program Costs





Gas DR Key Findings

Natural Gas DR is an emerging resource

- Small number of programs in existence
- Numerous questions surround applicability and reliability of Gas DR

Program Potential

- DLC Water Heating
  - **Expensive to implement**
  - **Low savings potential**
- Smart Thermostats – Heating
  - **Largest savings potential**
- Third Party Contracts
  - **Small amount of customers**
  - **Not a lot of discretionary load to reduce**

OR Low-Income Energy Efficiency Potential Study

Objectives and Data Sources

- Income group segmentation provides Avista an understanding of where these customers are located, differences in their consumption, and levels of energy efficiency savings opportunities.
  - US Census data provides the basis of household demographics by location
- Detailed surveys like RBSA capture differences in how customers at different income levels use energy, which affects savings potential and cost-effectiveness:
  - Household intensity (therms per home)
  - Building shell
  - Presence of equipment

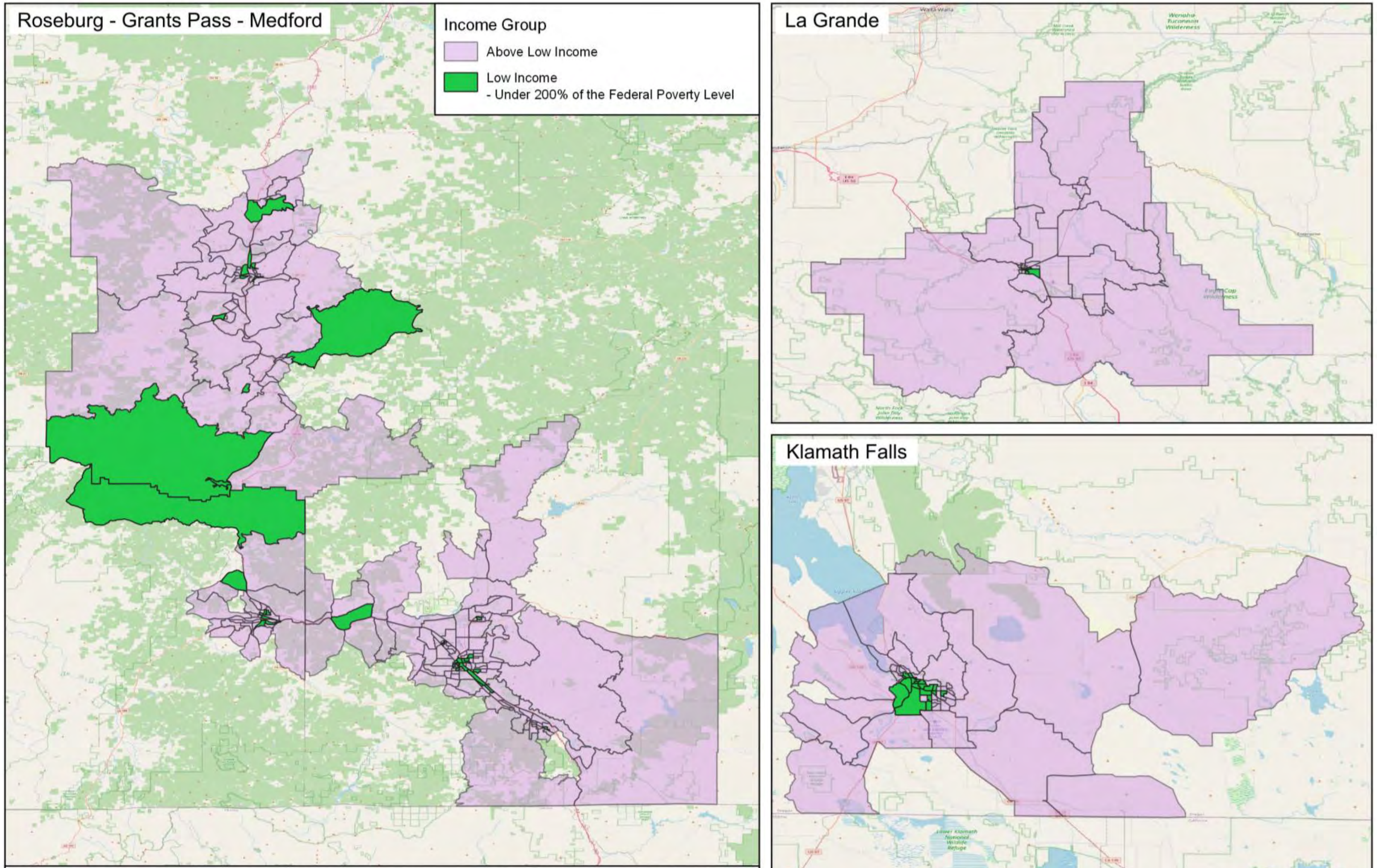
Gas Customer Intensity by Income Level – RBSA II

Income Class	Responses	Avg. Therms/HH	Δ from Regular
Non-Low-Income	180	636	n/a
Low Income	55	544	-14%

Income Groups by Household Size

HH Size	Low Income Threshold
1	$25,760
2	$34,840
3	$43,920
4	$53,000
5	$62,080
6	$71,160
7	$80,240
8	$89,320

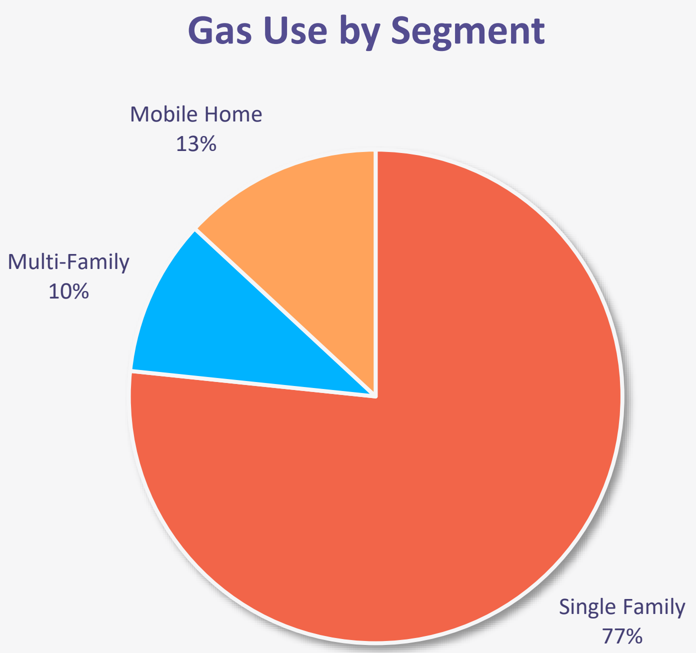
Income by Region



Source: Census American Community Survey 2019, provides accurate estimates of household median income, household size, and structure type within each block group.

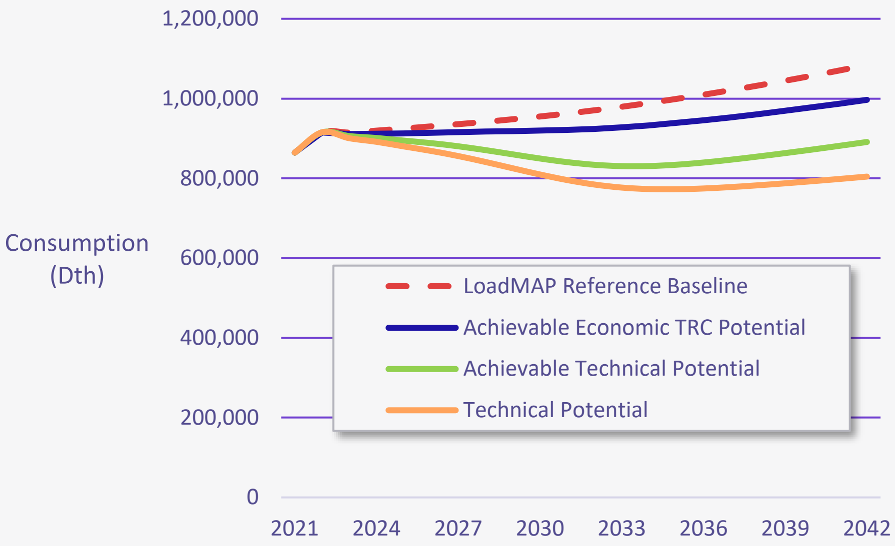
OR Low-Income Customers and Energy Consumption by Home Type

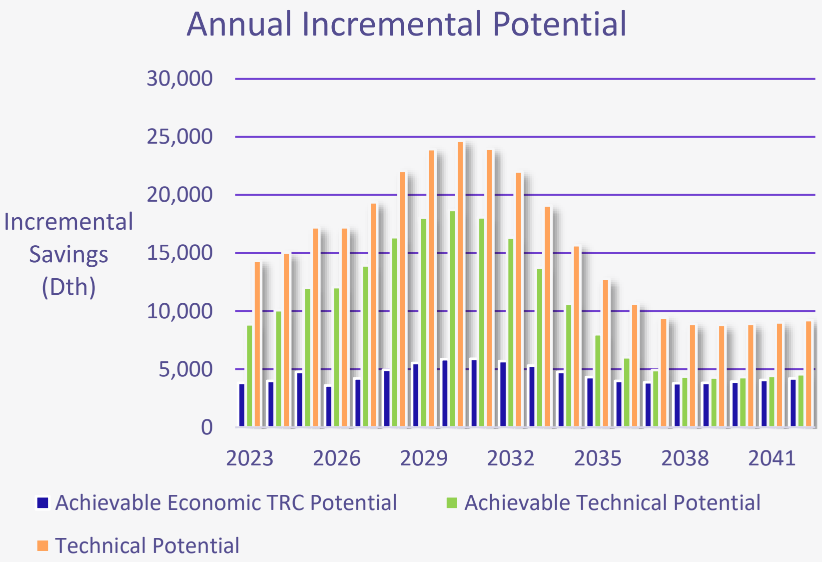
Segment	Households	% of All Homes	Usage (Dth)	Therms / HH
Single Family	12,289	65.0%	622,559	539
Multi-Family	4,428	23.4%	88,679	200
Mobile Home	2,197	11.6%	113,191	515
Total	**18,914**	**100.0%**	**864,429**	**457**



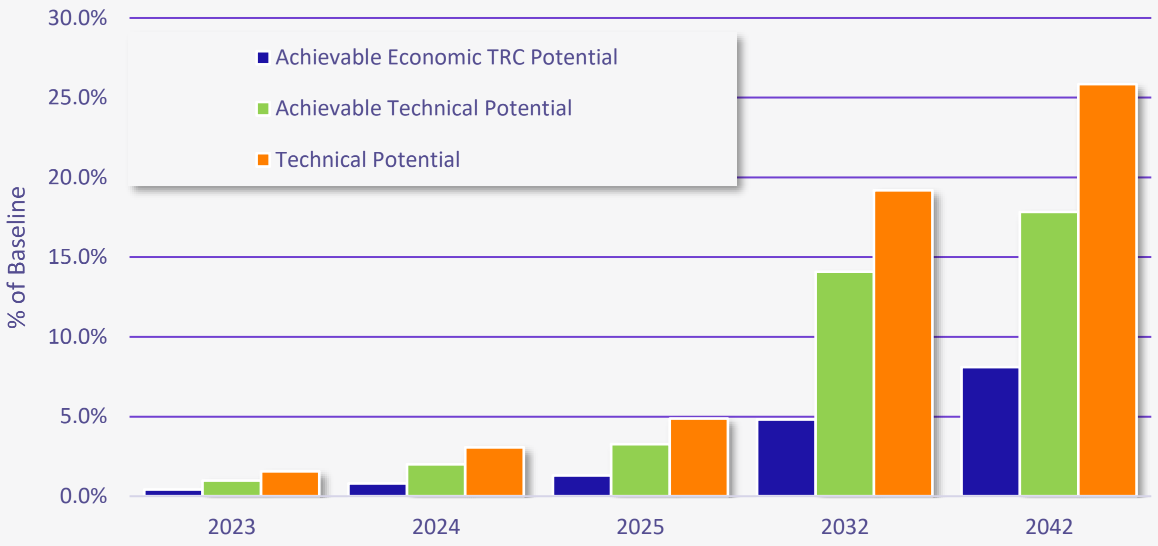
Summary Results

- For Oregon Low-Income Customers, Cumulative Achievable Technical Potential is 193,386 Dth, or 17.8% of the baseline over 20 years
- Cumulative Achievable Economic Potential (TRC) is 87,816 Dth, or 8.1 % of the baseline





Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2023	2024	2025	2032	2042
Baseline Forecast (Dth)	914,784	919,566	924,873	970,712	1,084,508
Cumulative Savings (Dth)					
Achievable Economic TRC Potential	3,816	7,383	12,114	46,713	87,816
Achievable Technical Potential	8,877	18,471	30,274	136,654	193,386
Technical Potential	14,319	28,147	44,987	186,349	280,253
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.4%	0.8%	1.3%	4.8%	8.1%
Achievable Technical Potential	1.0%	2.0%	3.3%	14.1%	17.8%
Technical Potential	1.6%	3.1%	4.9%	19.2%	25.8%
Incremental Savings (Dth)					
Achievable Economic TRC Potential	3,816	3,991	4,768	5,691	4,215
Achievable Technical Potential	8,877	10,082	12,013	16,345	4,560
Technical Potential	14,319	15,043	17,214	22,036	9,225

OR LI Top Measures

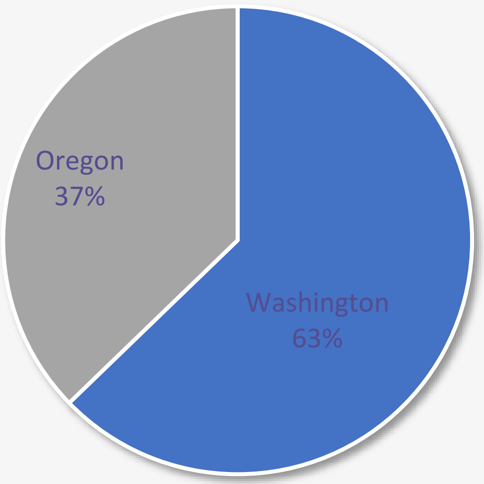
Rank	Oregon – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Water Heater - Intermittent Ignition System	20,106	22.9%
2	Connected Thermostat - ENERGY STAR (1.0)	17,561	20.0%
3	Furnace	14,529	16.5%
4	ENERGY STAR Home Design	13,955	15.9%
5	Insulation - Ceiling Installation	6,757	7.7%
6	Gas Furnace - Maintenance	4,885	5.6%
7	Circulation Pump - Timer	1,625	1.9%
8	Windows - Low-e Storm Addition	1,530	1.7%
9	Clothes Washer - ENERGY STAR (8.0)	1,475	1.7%
10	Water Heater - Thermostatic Shower Restriction Valve	1,313	1.5%
	Subtotal	83,737	**95.4**
	Total Savings in Year	**87,816**	**100.0%**

OR-WA Transport Customer Energy Efficiency Potential Study

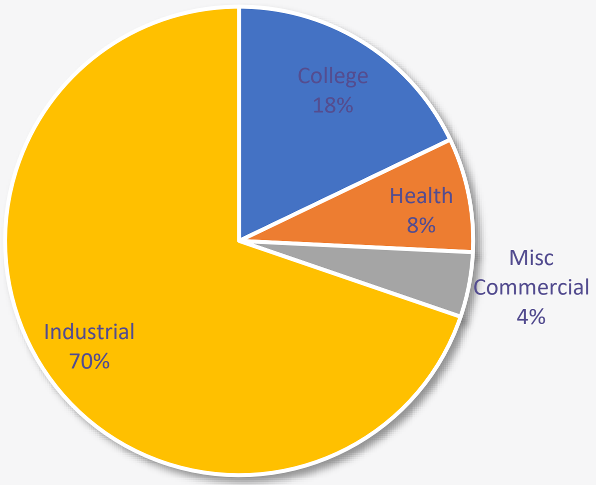
Market Characterization

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

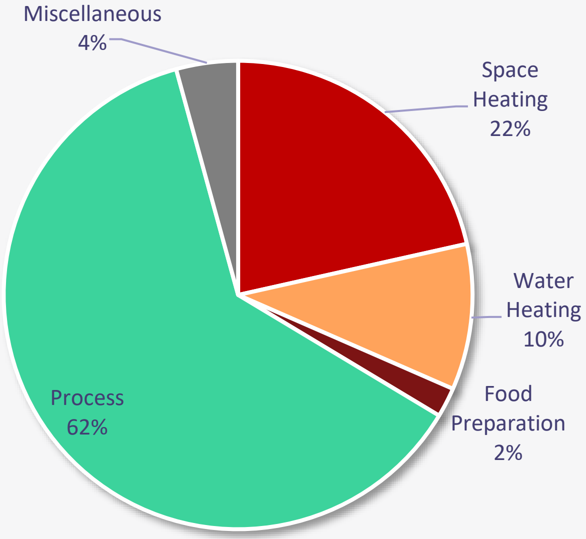
Transport Gas Use by State (2021)



Transport Gas Use by Segment (2021)



Transport Gas Use by End Use (2021)



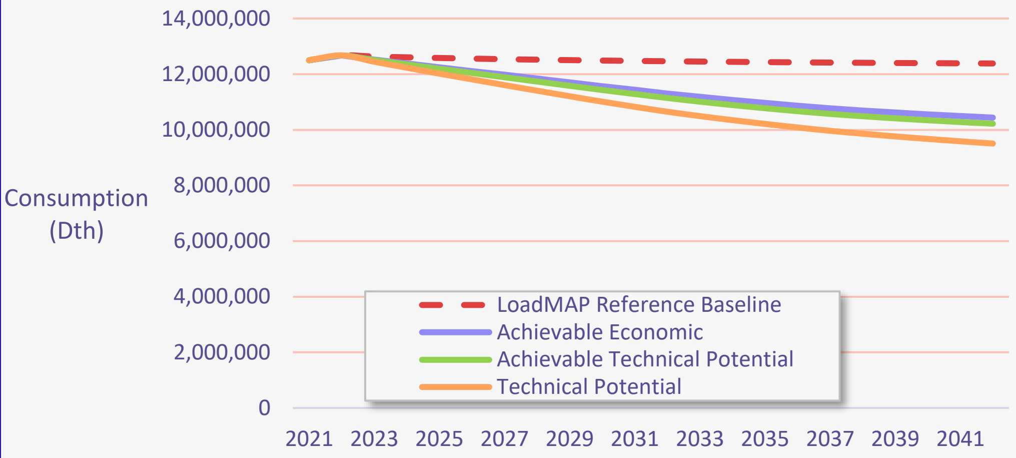
Applied Energy Group, Inc. | appliedenergygroup.com

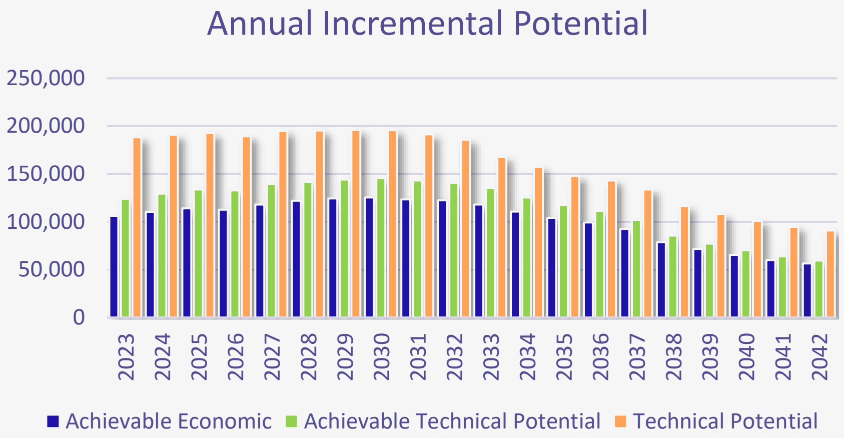
Considerations for this Analysis

- Available potential is largely a function of baseline consumption — segments with the highest baseline consumption are likely to have the highest potential
- Potential studies rely on average information, which may not reflect conditions or opportunities for any single customer
  - **This is particularly relevant for this study, where a small number of customers represent a large share of transport load**
  - **Ramp rates are derived from the Northwest Power and Conservation Council's 2021 Power Plan and reflect expected adoption across a broad set of customers. Actual adoption of energy efficiency for large transport customers may be lumpier based on cycles for implementing large capital projects**
- Survey sent to Transport customers to gather info on past and future projects, equipment, and interest in energy efficiency. Initial response rate was low so AEG and Avista are working to gather more responses

Draft Potential Results

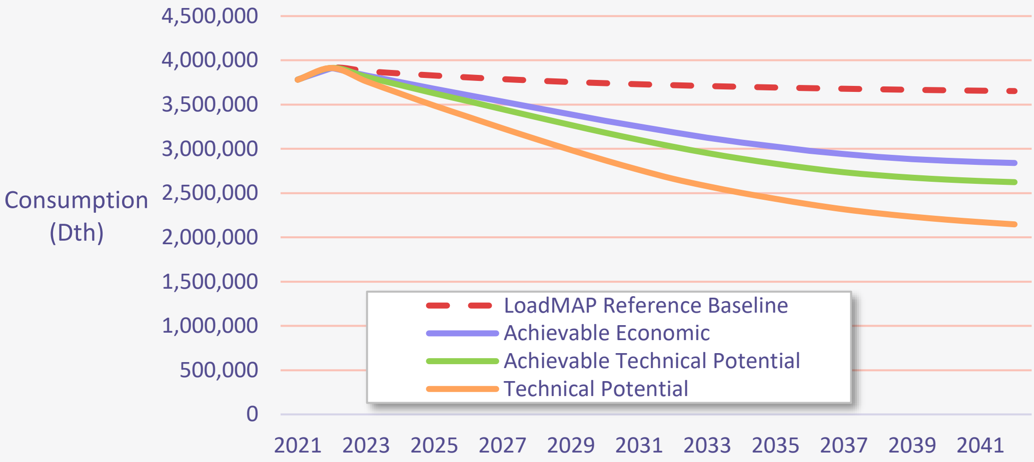
Summary Results (All States & Sectors)

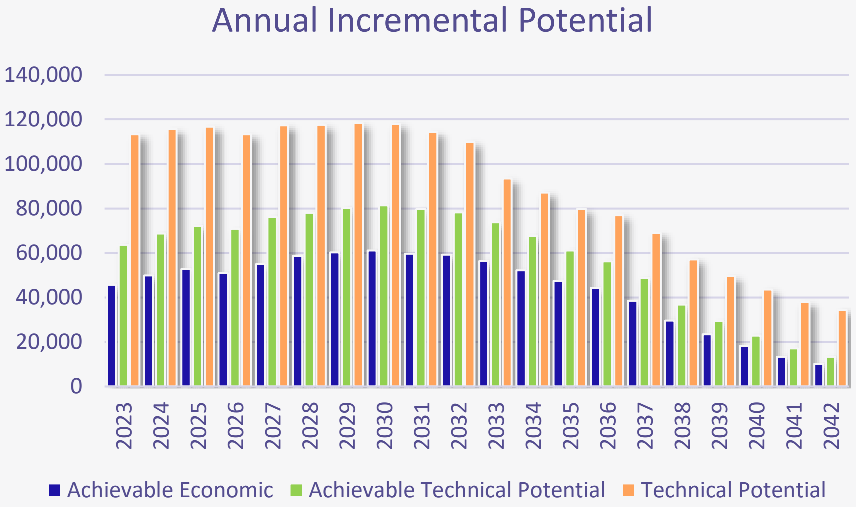




Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	12,630,414	12,603,587	12,536,256	12,461,252	12,381,843
Cumulative Savings (Dth)					
Achievable Economic	107,191	218,064	559,247	1,152,647	1,948,052
Achievable Technical	124,024	252,377	647,251	1,314,951	2,159,878
Technical Potential	188,234	376,388	933,031	1,815,113	2,880,756
Energy Savings (% of Baseline)					
Achievable Economic	0.8%	1.7%	4.5%	9.2%	15.7%
Achievable Technical	1.0%	2.0%	5.2%	10.6%	17.4%
Technical Potential	1.5%	3.0%	7.4%	14.6%	23.3%
Incremental Savings (Dth)					
Achievable Economic	105,937	110,468	118,059	122,313	56,419
Achievable Technical	124,024	129,555	139,511	140,942	59,652
Technical Potential	188,234	190,900	194,773	185,788	90,879

Commercial Summary Results (All States)





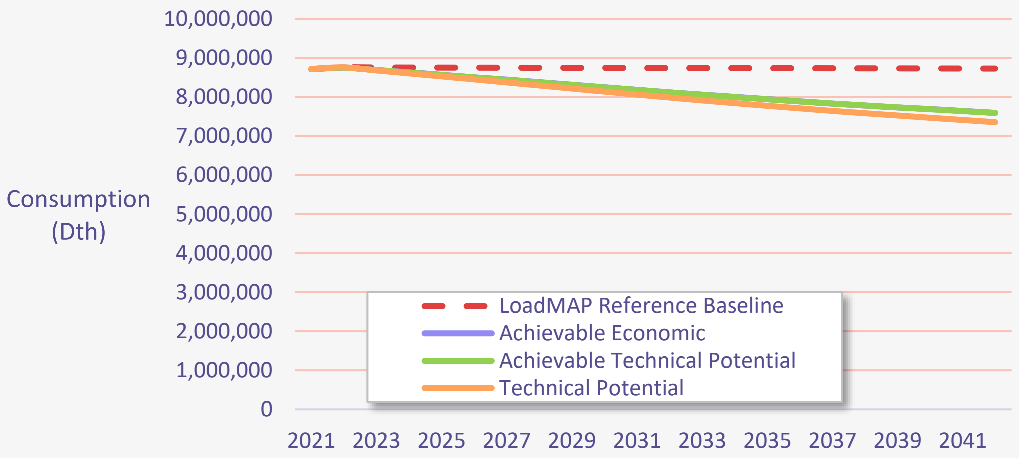
Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	3,876,336	3,850,572	3,786,849	3,718,685	3,652,695
Cumulative Savings (Dth)					
Achievable Economic	46,984	97,364	253,184	532,339	813,871
Achievable Technical	63,623	131,295	340,370	694,783	1,028,470
Technical Potential	113,277	226,642	555,555	1,058,457	1,507,428
Energy Savings (% of Baseline)					
Achievable Economic	1.2%	2.5%	6.7%	14.3%	22.3%
Achievable Technical	1.6%	3.4%	9.0%	18.7%	28.2%
Technical Potential	2.9%	5.9%	14.7%	28.5%	41.3%
Incremental Savings (Dth)					
Achievable Economic	45,776	49,907	54,949	59,216	10,220
Achievable Technical	63,623	68,758	76,240	78,244	13,377
Technical Potential	113,277	115,781	117,358	109,862	34,382

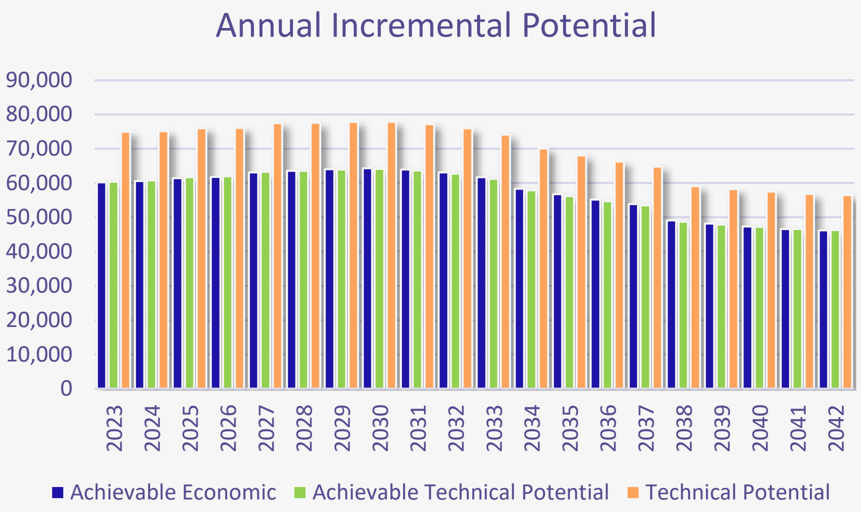
Commercial Transport Top Measures

Rank	**Oregon** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Water Heater - Circulation Pump Controls	16,536	11.7%
2	Boiler	13,554	9.6%
3	Insulation - Wall Cavity	11,059	7.8%
4	Ducting - Repair and Sealing	10,949	7.7%
5	Windows - Secondary Glazing Systems	9,204	6.5%
6	Water Heater - Solar System	9,040	6.4%
7	Water Heater	8,241	5.8%
8	Insulation - Ceiling	7,362	5.2%
9	Gas Boiler - Thermostatic Radiator Valves	7,030	5.0%
10	HVAC - Energy Recovery Ventilator	6,801	4.8%
	Subtotal	**99,777**	**70.5%**
	Total Savings in Year	**141,627**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Insulation - Wall Cavity	88,949	13.5%
2	Ducting - Repair and Sealing	75,713	11.5%
3	Windows - Secondary Glazing Systems	75,654	8.3%
4	HVAC - Energy Recovery Ventilator	54,894	7.8%
5	Insulation - Ceiling	51,005	7.5%
6	Gas Boiler - Thermostatic Radiator Valves	49,198	6.0%
7	Water Heater	39,310	5.5%
8	Water Heater - Circulation Pump Controls	36,069	5.2%
9	Gas Boiler - Insulate Steam Lines/Condensate Tank	34,275	3.6%
10	Hydronic Heating Radiator Replacement	33,280	3.5%
	Subtotal	**538,346**	**72.3%**
	Total Savings in Year	**771,266**	**100.0%**

Industrial Summary Results (All States)





Summary of Energy Savings (Dth), Selected Years	2023	2024	2027	2032	2042
Reference Baseline (Dth)	8,754,078	8,753,015	8,749,407	8,742,566	8,729,148
Cumulative Savings (Dth)					
Achievable Economic	60,207	120,700	306,063	620,308	1,134,181
Achievable Technical	60,401	121,082	306,881	620,168	1,131,408
Technical Potential	74,957	149,746	377,476	756,657	1,373,328
Energy Savings (% of Baseline)					
Achievable Economic	0.7%	1.4%	3.5%	7.1%	13.0%
Achievable Technical	0.7%	1.4%	3.5%	7.1%	13.0%
Technical Potential	0.9%	1.7%	4.3%	8.7%	15.7%
Incremental Savings (Dth)					
Achievable Economic	60,161	60,562	63,109	63,097	46,199
Achievable Technical	60,401	60,798	63,272	62,698	46,275
Technical Potential	74,957	75,119	77,414	75,926	56,497

Industrial Transport Top Measures

Rank	**Oregon** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	409,396	77.5%
2	Process Boiler - Hot Water Reset	24,562	4.6%
3	Process Boiler - Insulate Steam Lines/Condensate Tank	16,222	3.1%
4	Process Boiler - Stack Economizer	15,124	2.9%
5	Process Boiler - Burner Control Optimization	10,364	2.0%
6	Process Boiler - Insulate Hot Water Lines	7,905	1.5%
7	Insulation - Wall Cavity	7,332	1.4%
8	Boiler	6,480	1.2%
9	Destratification Fans (HVLS)	5,839	1.1%
10	Insulation - Ceiling	5,645	1.1%
	Subtotal	**508,868**	**96.3%**
	Total Savings in Year	**528,593**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2042 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	467,011	77.2%
2	Process Boiler - Hot Water Reset	28,019	4.6%
3	Process Boiler - Insulate Steam Lines/Condensate Tank	18,505	3.1%
4	Process Boiler - Stack Economizer	17,253	2.9%
5	Process Boiler - Burner Control Optimization	11,822	2.0%
6	Boiler	10,861	1.8%
7	Process Boiler - Insulate Hot Water Lines	9,017	1.5%
8	Insulation - Wall Cavity	8,260	1.4%
9	Destratification Fans (HVLS)	6,612	1.1%
10	Insulation - Ceiling	6,360	1.1%
	Subtotal	**583,720**	**96.4%**
	Total Savings in Year	**605,243**	**100.0%**

Thank You.

Eli Morris, Managing Director
emorris@appliedenergygroup.com

Kelly Marrin, Managing Director
kmarrin@appliedenergygroup.com

Ken Walter, Manager
kwalter@appliedenergygroup.com

Andy Hudson, Project Manager
ahudson@appliedenergygroup.com

AEG
APPLIED ENERGY GROUP

Supplemental Slides

Baseline Projection

The baseline projection is an independent end-use forecast of natural gas consumption at the same level of detail as the market profile.

"How much energy would customers use in the future if Avista stopped running conservation programs now and in the absence of naturally occurring efficiency?"

- The baseline projection answers this question

The baseline projection:

Includes	Excludes
• To the extent possible, the same forecast drivers used in the official load forecast, particularly customer growth, natural gas prices, normal weather, income growth, etc. • Trends in appliance saturations, including distinctions for new construction. • Efficiency options available for each technology , with share of purchases reflecting codes and standards (current and finalized future standards) • Expected impact of appliance standards that are "on the books" • Expected impact of building codes, as reflected in market profiles for new construction • Market baselines when present in regional planning assumptions	• Expected impact of naturally occurring efficiency (except market baselines) • **Exception:** RTF workbooks have a market baseline for lighting, which AEG's models also use. • Impacts of current and future demand-side management programs • Potential future codes and standards not yet enacted

Economic Achievable Potential

In assessing cost-effective, achievable potential within Avista's territory, AEG considered two perspectives:

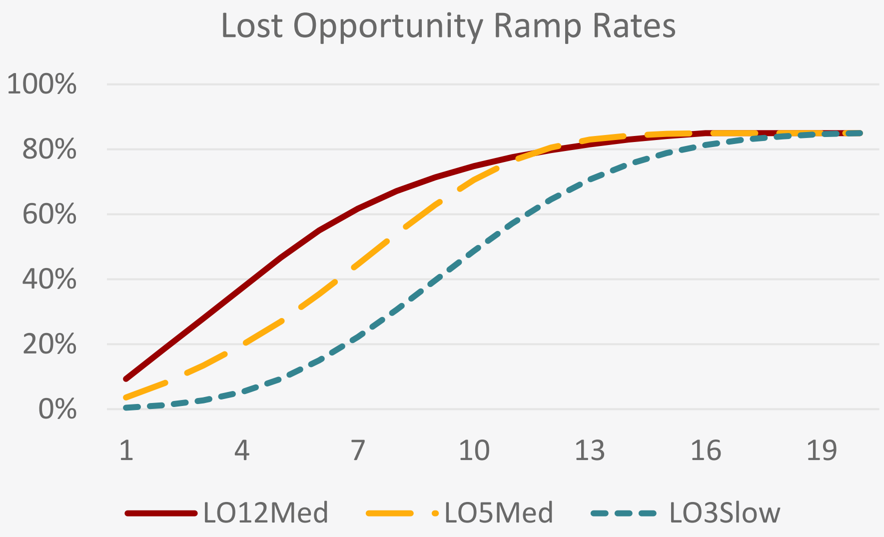
- Washington - Total Resource Cost Test (TRC): Assesses cost-effectiveness from the perspective of the utility and its customers. Includes non-energy impacts if they can be quantified and monetized.
- Idaho - Utility Cost Test (UCT): Assesses cost-effectiveness from a utility or program administrator's perspective.

Component	TRC	UCT
Avoided Energy	Benefit	Benefit
Non-Energy Impacts*	Cost/Benefit	
Incremental Cost	Cost	
Incentive		Cost
Administrative Cost	Cost	Cost
10% Conservation Credit	Benefit	

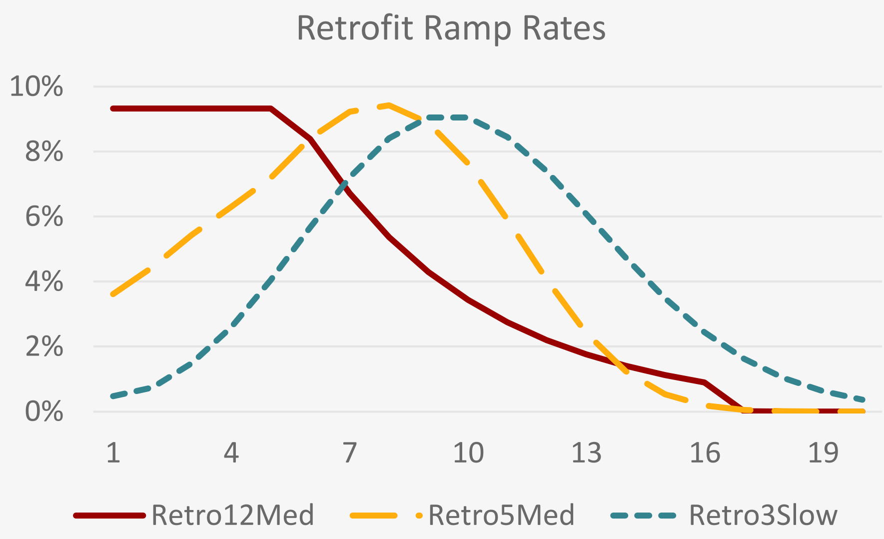
*NEI Categories

- Quantified and monetized non-energy impacts (e.g. water, detergent, wood)
- Projected cost of carbon in Washington
- Heating calibration credit for secondary fuels (12% for space heating, 6% for secondary heating)
- Electric benefits for applicable measures

Council Methodology: Ramp Rate Examples



- Describe the % of units assumed to be adopted relative to all units purchased in that year (based on lifetime/turnover)
- Approach their maximum limit over time, but reach that limit at different speeds



- Describe the % of the **total market** that is acquired in each year
- **Add up** to 100% over time, but reach that total at different speeds

MDC Research
Your Trusted Insights Partner Since 1978

Avista IRP Clean Energy Research

April 2022

Research Overview

Objectives

Determine willingness to pay for the implementation of clean energy among Avista customers

- Establish baseline of environmental concerns; perceived responsibility of individuals, businesses, and Avista specifically
- Understand customer tradeoffs between bill increases and carbon emission goals
- Explore perceptions associated with Avista should they invest in carbon-neutral or carbon-free emissions
- Gauge perceptions specific to natural gas preferences and tradeoffs
- Quantify differences by state, customer type, green perceptions, and demographic factors

Methodology

Web survey with Avista customers.

- Customers from Washington, Idaho, and Oregon sourced randomly by email
- Survey optimized for both desktop and mobile
- Conducted in April 2022
- Final sample size of n=1,100

Proportional representation of state and service type.

WA	ID	OR	G	GE	E
52%	29%	20%	25%	47%	29%

Respondents screened to ensure appropriate target

- Avista customer age 18+
- Has or shares household finance and utility bill responsibility
- Not employed by a utility company, or in media, advertising, or market research firm

Report Interpretation

- All significant differences are reported at the 95% confidence level or higher. The total sample size of n=1,100 has a maximum sampling variability of +/-3.0% at the 95% level.
- Some percentages may not add to 100% due to rounding

Analysis Approach

This study incorporates a conjoint exercise to force tradeoffs between various green initiatives and customer willingness to pay.

Respondents review various combinations of **energy goals**, **timeframes for that goal**, **energy sources**, and **potential bill increases**, and select their "most preferred" from a series of options (including an option for "none" each time).

Subsequent analysis produces utility scores for each individual attribute, allowing us to calculate which combination has the broadest appeal.

Energy Goal	Investing in renewables to achieve carbon neutrality Providing 100% carbon-free power by only generating energy through clean energy sources
Goal Timeframe	In the next year In the next 5 years (by 2027) In the next 10 years (by 2032) In the next 25 years (by 2047)
Bill Increase	2% monthly increase 5% monthly increase 10% monthly increase 20% monthly increase 50% monthly increase 100% monthly increase
Energy Source	Sourced locally Sourced regionally Sourced from anywhere

Key Takeaways

Price is Important. 

When faced with tradeoffs, price is the prevailing factor. While the majority of customers find importance in sourcing green or local energy, they are only willing to pay so much. Anything beyond a 10% monthly bill increase shows significant declines in popularity.

If bill increases to invest in carbon-free or carbon-neutral options are kept below 10%, the specific energy goal, timeframe, local vs. regional source are less important.

Some customers see beyond price 

Increases beyond 10% monthly still appeal to a certain subset of customers, particularly those who place great importance on "green," and/or when the goal can be achieved within the next 10 years.

***Any* increase to invest in "green" energy will alienate some customers**

Overall, roughly one in five do not find importance in being "green"

When evaluating various green investment options, 17% reject all, including more ambitious outcomes for just a 2% increase

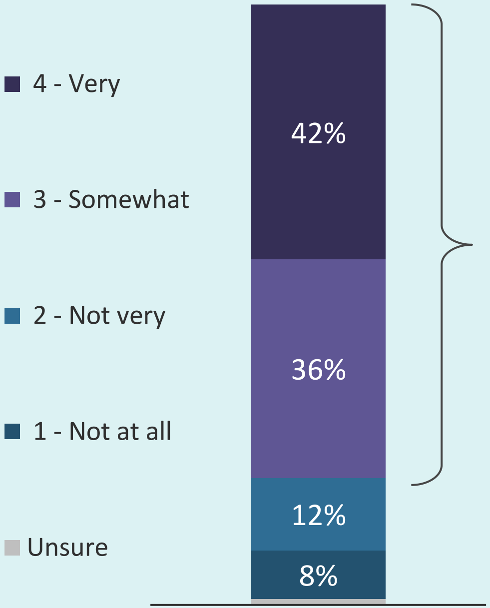
Three in ten say they would be likely to seek bill assistance or consider moving to another state if bill were to increase due to Avista investing in carbon-free or carbon-neutral energy

Detailed Findings:
Green Insights

At a personal level, the concept of being environmentally friendly or "green" is important to nearly eight in ten customers

Personal Importance of "Green"

(n=1,100)



78% find the concept of being "green" important

Key Differences and Insights

Green importance differs by state.
Customers in **Oregon** and **Washington** are significantly more likely than those in Idaho to find the concept of "green" to be important.

83% | 80% | 71%

Green importance differs by area.
Customers in **urban** areas are significantly more likely than those in rural areas to find the concept important.

urban 84% | suburban 80% | rural 75%

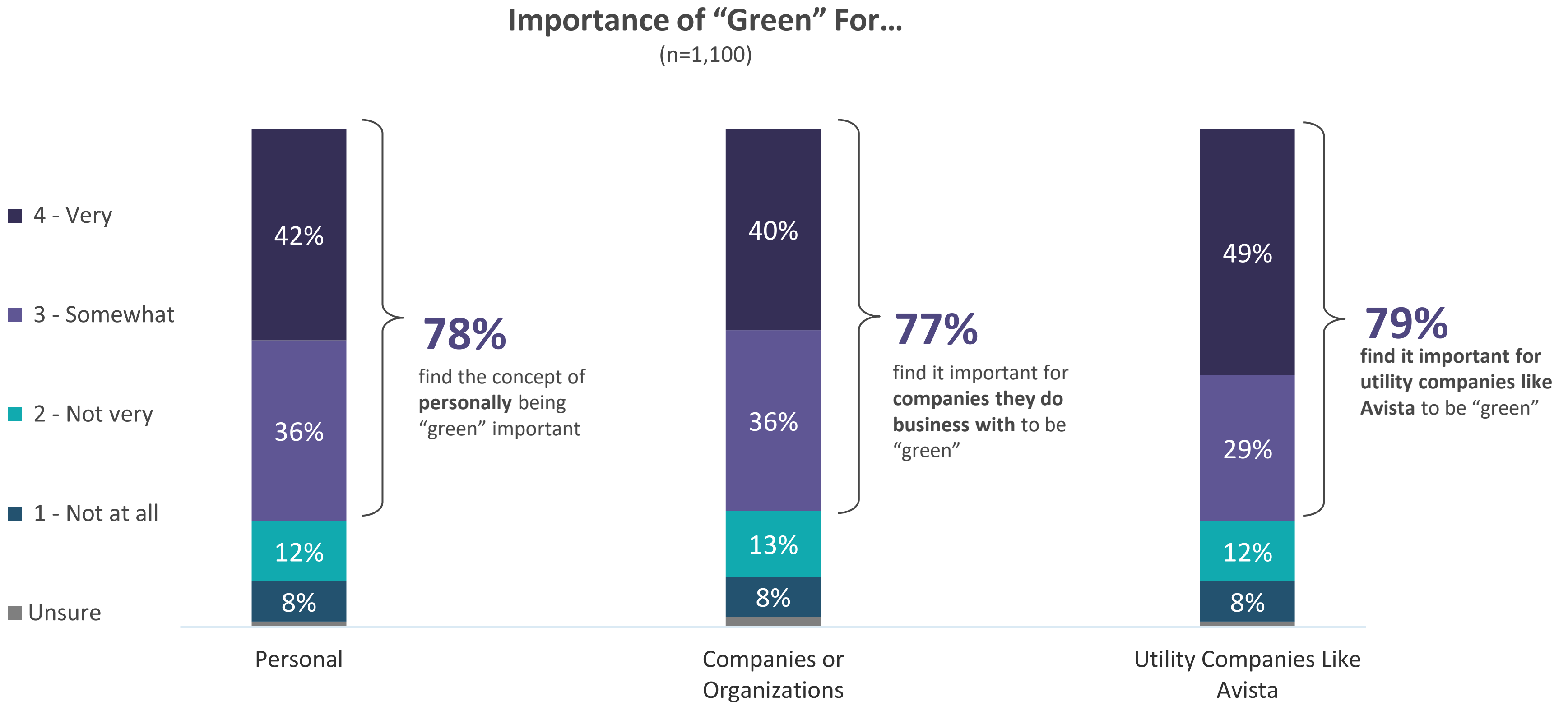
Green importance differs by gender.
Women are significantly more likely than men to find it important.

85% | 73%

Green importance is <u>consistent across age and income categories</u>.

Q1. How important is the concept of being environmentally friendly or "green" to you personally?

Customers place similar importance on the "green" responsibility of themselves, businesses, and utility companies



Q1. How important is the concept of being environmentally friendly or "green" to you personally?
Q3. How important is it for general companies or organizations you do business with to be environmentally friendly or "green?"
Q4. How important is it specifically for utility companies like Avista to be environmentally friendly or "green?"

Personal importance to be "green" is driven by responsibility to protect the planet; for those believing it is not important to personally be green, cost is the main reason

Why is it Important?

(n=860)

- To protect our planet/environment (38%)
- Good for the future/future generations (24%)
- Responsibility/right thing to do/stewardship (16%)
- To address climate change/global warming (13%)

"If we take care of our planet, it will in turn last for generations to come. If we take care of it, it will always take care of us."

"Every person has to take responsibility for the environment. We are stewards of the Earth after all. That responsibility cannot, and should, not be abrogated. If we don't stand up and insist on choices that protect that for which we are responsible then no one will and we necessarily choose a very dark alternative for an uncertain and unjust future."

Why is it NOT Important?

(n=224)

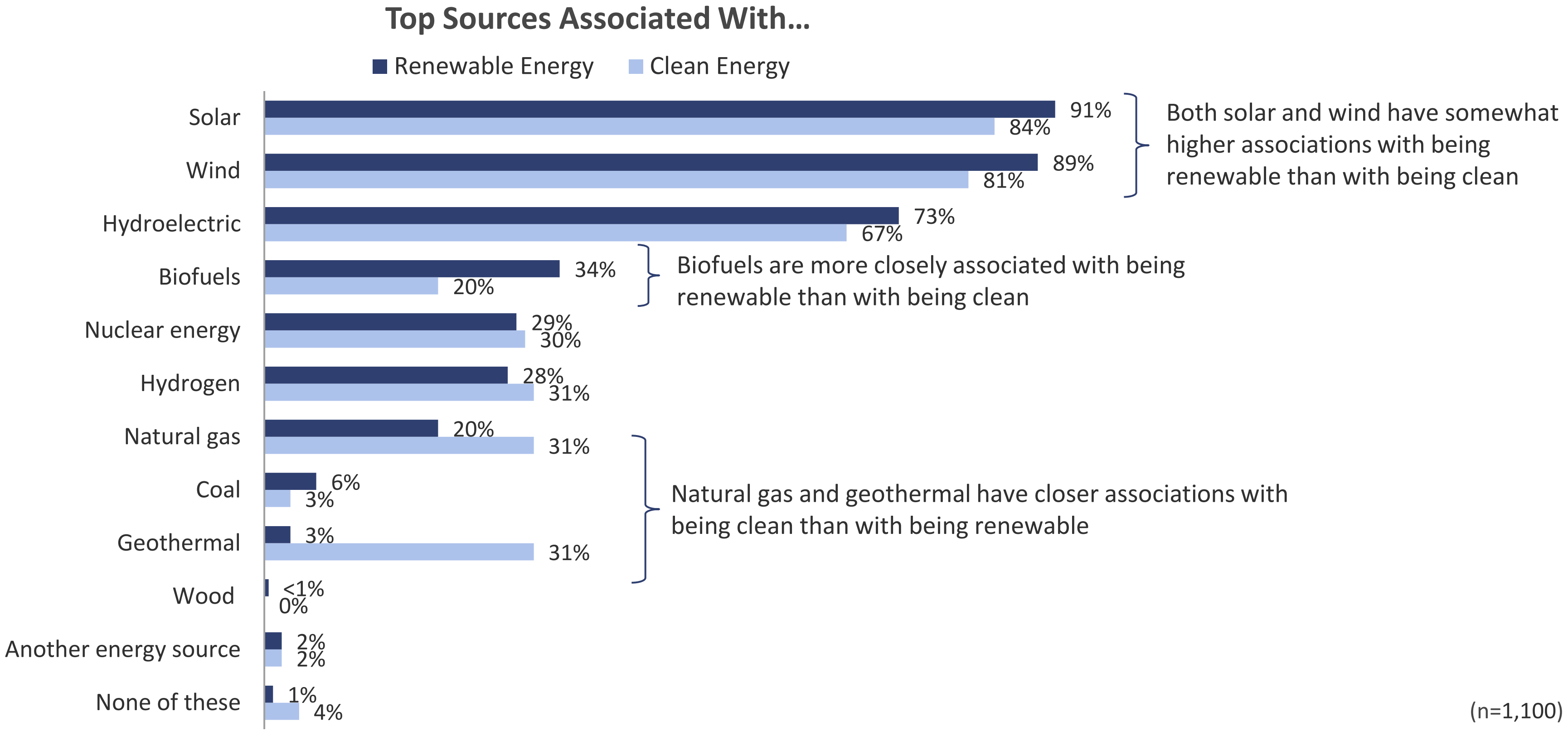
- Cost/it's expensive (29%)
- Not real/hoax/misinformation (25%)
- "Green" is worse for the environment, not better (20%)
- Politics/Political Agenda (17%)

"In the 60+ years I've been around, the air land and waters have markedly improved. As the current crop of 'renewables' are unreliable and expensive, good ol' fossil fuels are the best bang for bucks."

"Because the terms 'environmentally friendly' and 'green' have been distorted to the point where they have little relevance to actually protecting the environment."

Q2A. Why is it [very/somewhat important] to personally be environmentally friendly or "green?"
Q2B. Why is it [not very/not at all important] to personally be environmentally friendly or "green?"

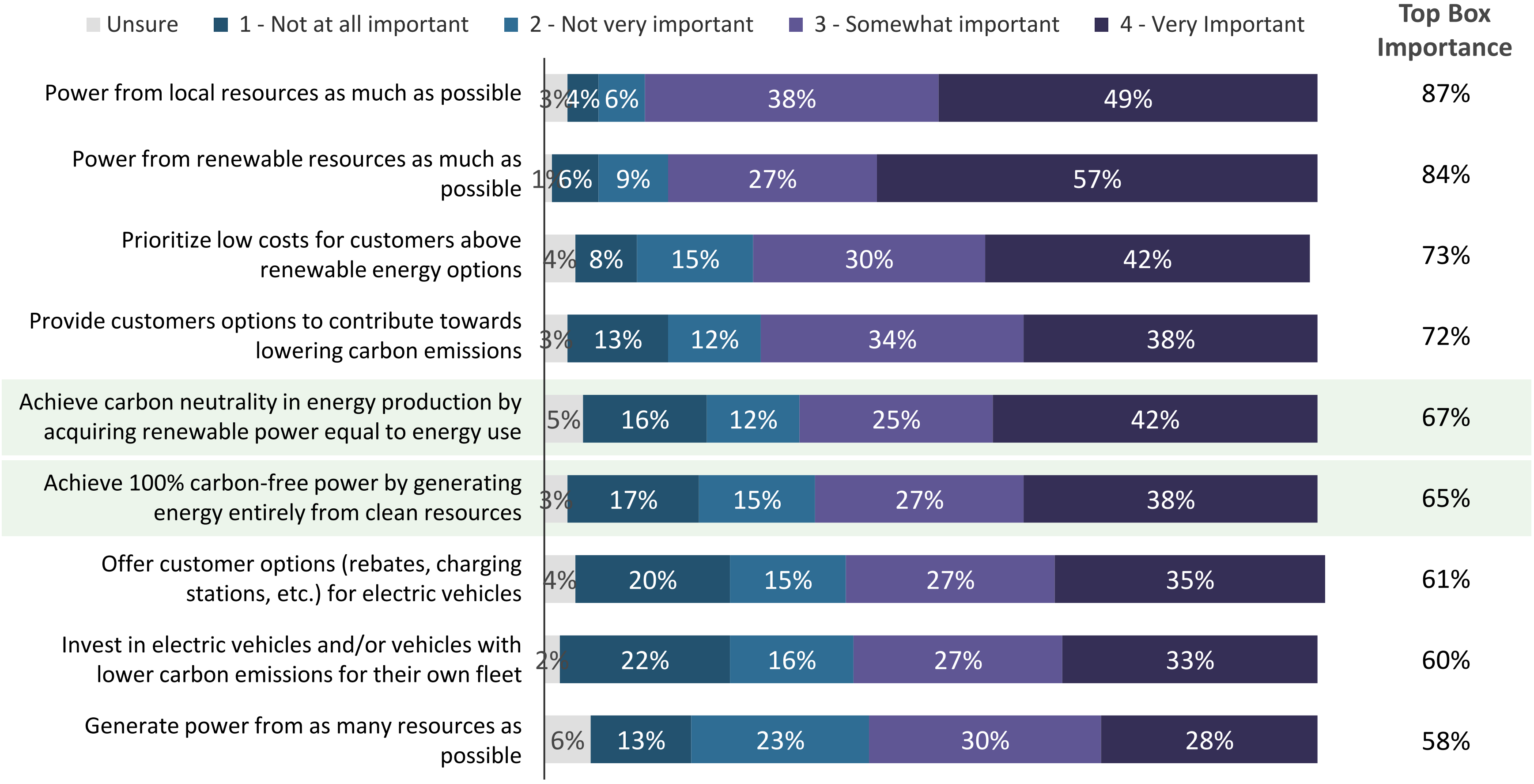
Solar and wind are commonly associated with both renewable and clean energy



(n=1,100)

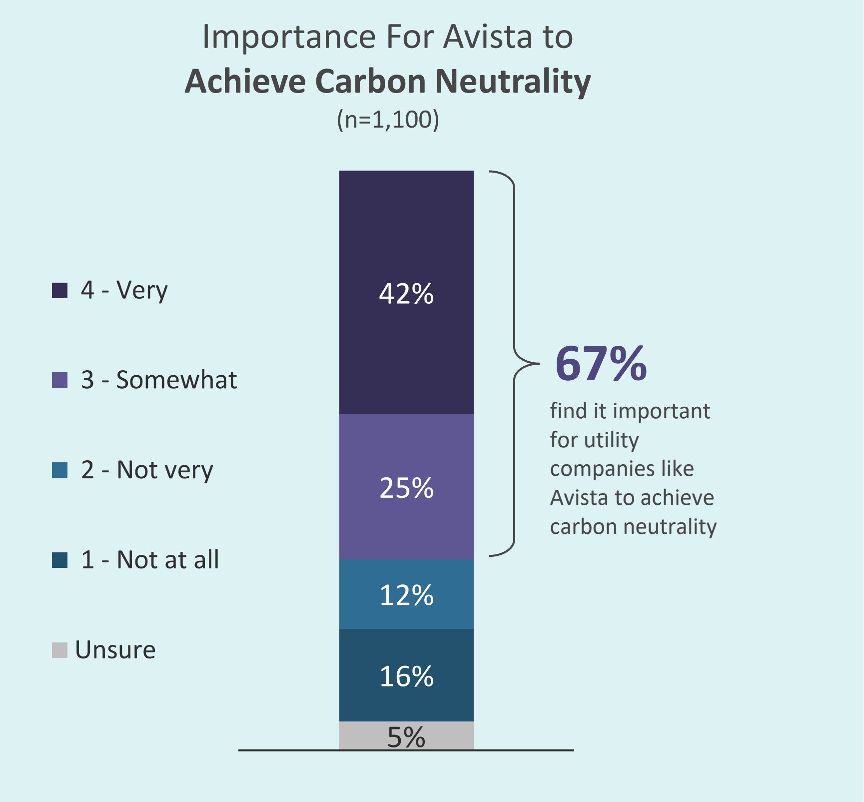
Q6. When you hear the words "renewable energy," what sources come to mind?
Q7. When you hear the words "clean energy," what sources come to mind?

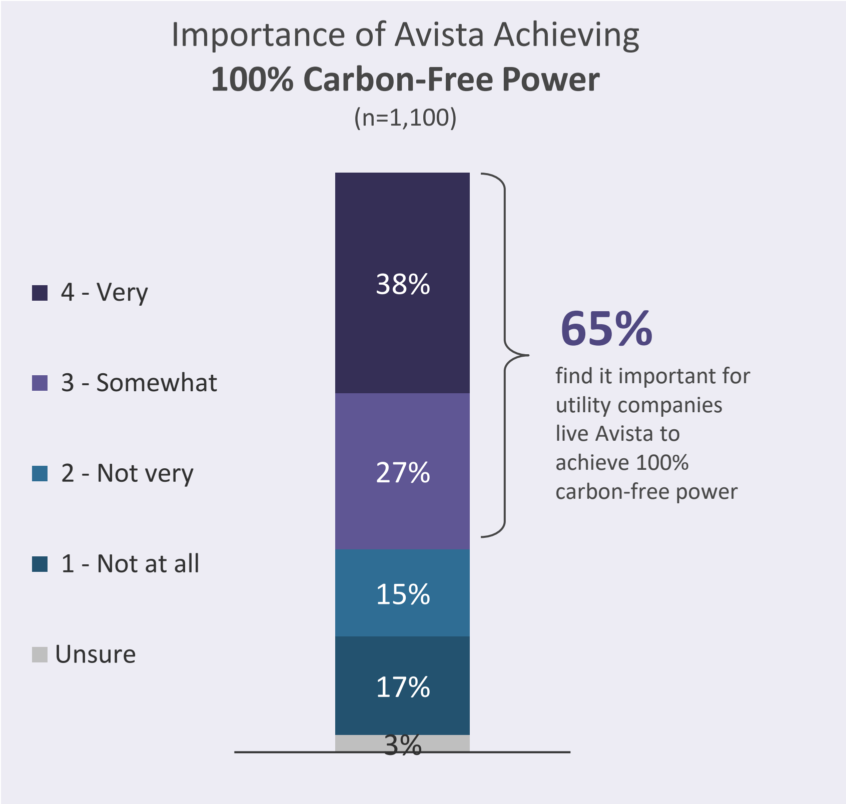
When considering potential utility company initiatives, customers place highest importance on generating power from local and renewable resources



Q5. How important is it for utility companies like Avista to do each of the following?

Customers place near equal importance on Avista achieving carbon neutrality and on achieving 100% carbon-free power





Q5. How important is it for utility companies like Avista to do each of the following?
Achieve carbon neutrality in energy production by acquiring renewable power equal to energy use.
Achieve 100% carbon-free power by generating energy entirely from clean resources.

The importance of Avista achieving these goals differs by certain key audiences

Key Differences and Insights: Carbon Neutrality

Carbon neutrality importance differs by state.

Customers in **Oregon** are significantly more likely than those in Idaho to say it is important for to achieve carbon neutrality.

73% 67% 61%

Carbon neutrality importance differs by area.

Customers in **urban** areas are significantly more likely than those in rural areas to find the achievement important.

urban 72% | suburban 69% | rural 63%

Carbon neutrality importance differs by gender.

Women are significantly more likely than men to find it important. 75% 60%

Importance of carbon neutrality differs by income.

Those making **$150K+ in household income** are significantly more likely than those making less than $60K to say it is important.

<$60K	$150K+
62%	72%

Key Differences and Insights: 100% Carbon-Free

Carbon-free power importance differs by state.

Customers in **Oregon** are significantly more likely than those in Idaho to find an achievement of 100% carbon-free to be important.

69% 66% 60%

Carbon-free power importance differs by area.

Customers in **urban** and **suburban** areas are significantly more likely than those in rural areas to find the achievement important.

urban 74% | suburban 67% | rural 59%

Importance of 100% carbon-free power differs by gender.

Women are significantly more likely than men to find it important. 73% 59%

Importance is consistent across age and income categories.

Q5H. How important is it for utility companies like Avista to do each of the following? *Achieve carbon neutrality in energy production by acquiring renewable power equal to energy use. | Achieve 100% carbon-free power by generating energy entirely from clean resources.*

Detailed Findings:
Green Investment

Conjoint Results Summary: Overall Feature Scoring

Category	Attribute	Result	Meaning
Energy Goal	Investing in renewables to achieve carbon neutrality	0.55	If all other factors are held consistent, providing 100% carbon-free energy vs. investing in carbon neutrality has almost no impact
	Providing 100% carbon-free power by only generating energy through clean energy sources	0.59	
Goal Timeframe	In the next year	0.60	There is a drop-off in utility at the 25-year level; however, there is little differentiation between *in the next year*, *five years*, or *ten years* when all other factors are held consistent
	In the next 5 years (by 2027)	0.59	
	In the next 10 years (by 2032)	0.59	
	In the next 25 years (by 2047)	0.52	
Bill Increase	2% monthly increase	0.83	If all other factors are held consistent, the monthly bill increase has the biggest impact; utility drops off considerably with more than a 10% increase
	5% monthly increase	0.78	
	10% monthly increase	0.69	
	20% monthly increase	0.53	It should be noted, however, that those placing high importance on being green demonstrate a willingness to pay beyond the 10% mark
	50% monthly increase	0.36	
	100% monthly increase	0.25	
Energy Source	Sourced locally	0.59	Though 87% find sourcing power locally to be important, ultimately there is little differentiation between *local*, *regional*, and *anywhere*, when considering other factors along with locality
	Sourced regionally	0.58	
	Sourced from anywhere	0.55	
None		0.39	Overall, 17% of respondents said no to all options presented, indicating no willingness to pay for green investments

(n=1,100)

C2. Now, we will present you with a series of 12 screens, each with a set of options for an energy package that could be made available in the future for your home. For each set, please indicate the one you would be most likely to choose. You can always select "none" if you would not select any of the options.

Conjoint Results Summary: Feature Scores by Personal Green Importance

Category	Attribute	Feature Score by Green Importance: Very (n=445)	Somewhat (n=399)	Not (n=331)
Energy Goal	Investing in renewables to achieve carbon neutrality	0.67	0.53	0.38
	Providing 100% carbon-free power by only generating energy through clean energy sources	0.76	0.54	0.35
Goal Timeframe	In the next year	0.79	0.54	0.33
	In the next 5 years (by 2027)	0.76	0.54	0.35
	In the next 10 years (by 2032)	0.72	0.55	0.38
	In the next 25 years (by 2047)	0.59	0.52	0.39
Bill Increase	2% monthly increase	0.87	0.86	0.71
	5% monthly increase	0.88	0.78	0.60
	10% monthly increase	0.85	0.65	0.45
	20% monthly increase	0.74	0.46	0.24
	50% monthly increase	0.53	0.30	0.13
	100% monthly increase	0.42	0.17	0.04
Energy Source	Sourced locally	0.72	0.55	0.39
	Sourced regionally	0.73	0.55	0.37
	Sourced from anywhere	0.69	0.51	0.34
None		0.14	0.43	0.80

C2. Now, we will present you with a series of 12 screens, each with a set of options for an energy package that could be made available in the future for your home. For each set, please indicate the one you would be most likely to choose. You can always select “none” if you would not select any of the options.

Conjoint Results Summary: Feature Scores by Service Type

Category	Attribute	Feature Score by Service Type: Gas Only (n=271)	Dual (n=513)	Electric Only (n=316)
Energy Goal	Investing in renewables to achieve carbon neutrality	0.57	0.56	0.54
	Providing 100% carbon-free power by only generating energy through clean energy sources	0.61	0.60	0.58
Goal Timeframe	In the next year	0.63	0.60	0.58
	In the next 5 years (by 2027)	0.62	0.59	0.57
	In the next 10 years (by 2032)	0.61	0.59	0.57
	In the next 25 years (by 2047)	0.52	0.52	0.51
Bill Increase	2% monthly increase	0.83	0.84	0.82
	5% monthly increase	0.79	0.79	0.76
	10% monthly increase	0.71	0.70	0.66
	20% monthly increase	0.56	0.53	0.50
	50% monthly increase	0.39	0.35	0.35
	100% monthly increase	0.28	0.24	0.24
Energy Source	Sourced locally	0.61	0.59	0.57
	Sourced regionally	0.60	0.59	0.56
	Sourced from anywhere	0.57	0.55	0.53
None		0.36	0.38	0.42

C2. Now, we will present you with a series of 12 screens, each with a set of options for an energy package that could be made available in the future for your home. For each set, please indicate the one you would be most likely to choose. You can always select "none" if you would not select any of the options.

Conjoint Results Summary: Optimal Feature Combination

Unsurprisingly, the optimal utility results from customers achieving the most for the lowest cost. While this is not a realistic scenario, it provides a baseline for any changes made to move toward carbon-free or carbon-neutral energy in the future. Subsequent slides show change from optimal should other factors be considered.

Category	Attribute
Energy Goal	Investing in renewables to achieve carbon neutrality
Goal Timeframe	In the next year
Bill Increase	2% monthly increase
Energy Source	Sourced locally

(n=1,100)

C2. Now, we will present you with a series of 12 screens, each with a set of options for an energy package that could be made available in the future for your home. For each set, please indicate the one you would be most likely to choose. You can always select “none” if you would not select any of the options.

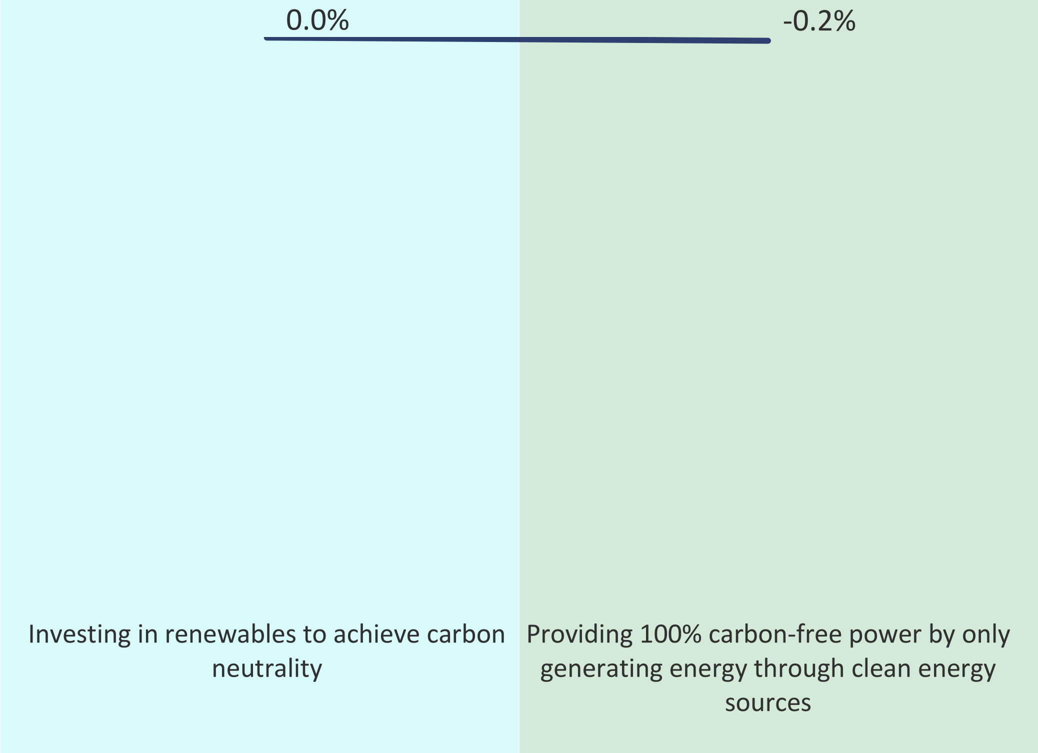
Conjoint Summary: Difference from Optimal Combination (Based on Goal)

Optimal Feature Combination

Energy Goal	Investing in renewables to achieve carbon neutrality
Goal Timeframe	In the next year
Bill Increase	2% monthly increase
Energy Source	Sourced locally

If all other factors are held consistent, providing 100% carbon-free energy vs. investing in carbon neutrality has almost no impact

Change from Optimal Based on **Goal**



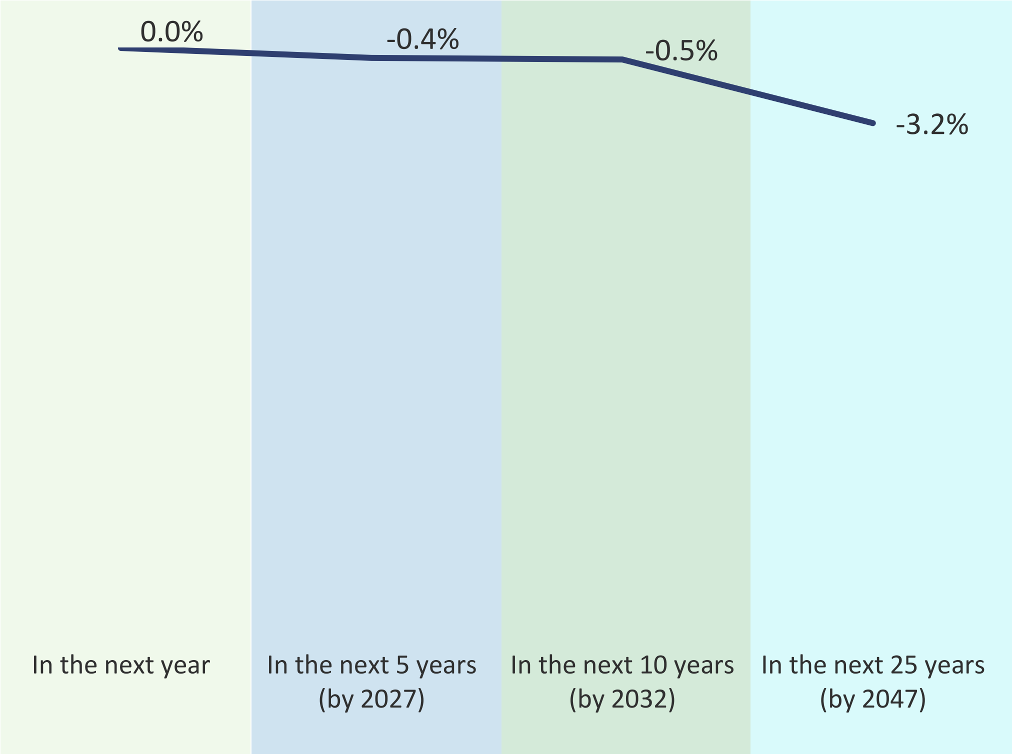
Conjoint Summary: Difference from Optimal Combination (Based on Timeframe)

Optimal Feature Combination

Energy Goal	Investing in renewables to achieve carbon neutrality
Goal Timeframe	In the next year
Bill Increase	2% monthly increase
Energy Source	Sourced locally

If all other factors are held consistent, a shorter timeline has minimal impact; utility drops off after 10 years

Change from Optimal Based on **Timeframe**



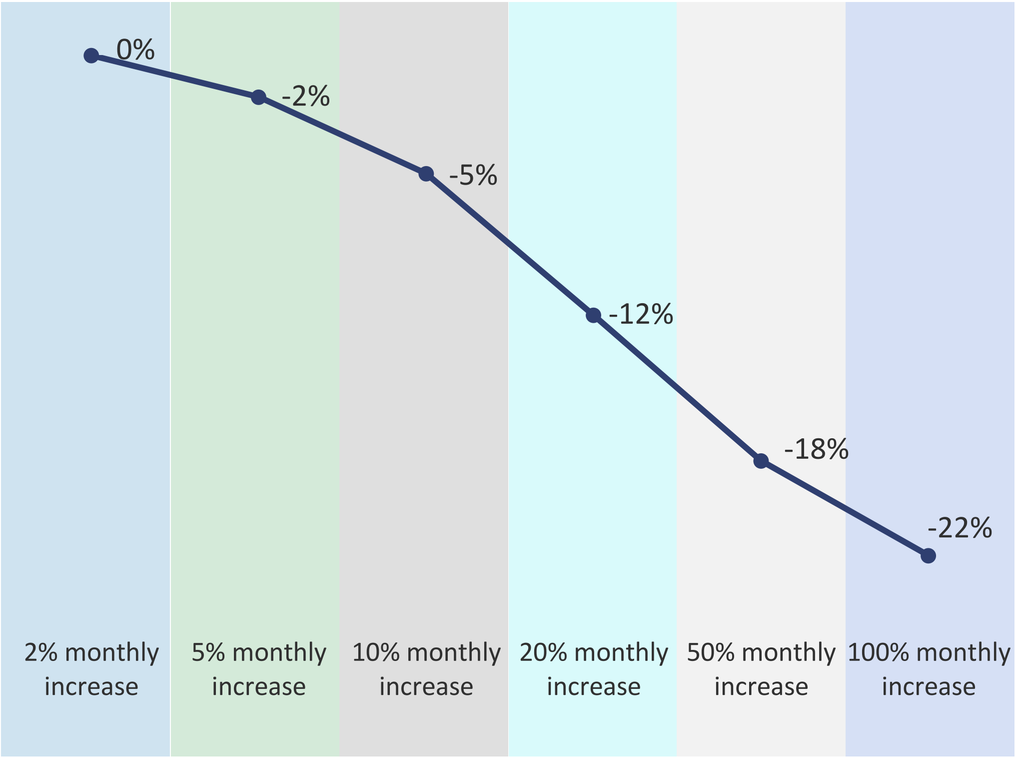
Conjoint Summary: Difference from Optimal Combination (Based on Bill Increase)

Optimal Feature Combination

Energy Goal	Investing in renewables to achieve carbon neutrality
Goal Timeframe	In the next year
Bill Increase	2% monthly increase
Energy Source	Sourced locally

If all other factors are held consistent, the monthly bill increase has the biggest impact; utility drops off considerably with more than a 10% increase

Change from Optimal Based on **Monthly Bill Increase**



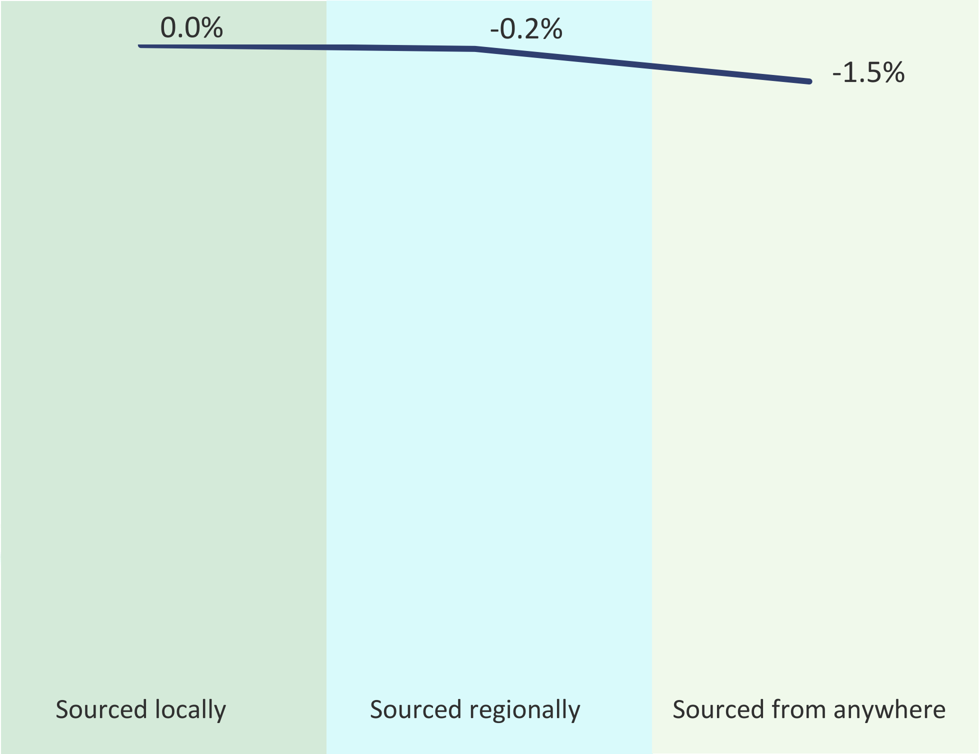
Conjoint Summary: Difference from Optimal Combination (Based on Source)

Optimal Feature Combination

Energy Goal	Investing in renewables to achieve carbon neutrality
Goal Timeframe	In the next year
Bill Increase	2% monthly increase
Energy Source	Sourced locally

If all other factors are held consistent, the source of energy has almost no impact; energy sourced locally or regionally is only slightly more preferred

Change from Optimal Based on **Source**

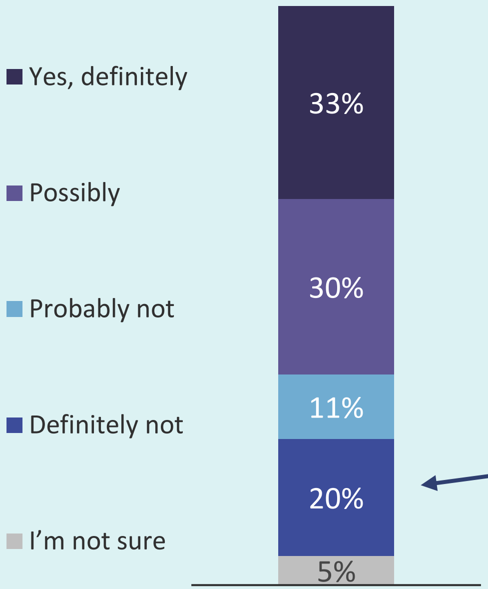


Detailed Findings:
Investment Support

Three in five customers say Avista should invest in carbon-neutral energy even if it involves a rate increase for customers

Should Avista invest in carbon-neutral or carbon-free energy, even if it involves a rate increase for customers?

(n=1,100)



Key Differences and Insights

Investment sentiment differs by income.

Those with **higher household incomes** are significantly more likely than those making $60K or less to agree Avista definitely should invest, even if it involves a rate increase.

<$60K	$60K+
28%	**42%**

Investment sentiment differs by area.

Customers in **urban** areas are significantly more likely than those in rural areas to believe Avista should definitely invest.

urban	suburban	rural
40%	**36%**	**29%**

Lack of investment support differs by gender.

While those **supporting** investment is consistent across gender, **men** are significantly more likely than women to **definitely not** support investment.

♀	♂
15%	**23%**

Support is consistent across age and state.

C3. Should Avista invest in carbon-neutral or carbon-free energy, even if it involves a rate increase for customers?

Supporters say the main reason Avista should invest in carbon-neutral energy is to "save the planet," while the main reason to not invest among detractors is "consumer cost"

What is the main reason to invest?

(n=697)

- To save the planet (21%)
- For a cleaner environment (19%)
- For cleaner air (16%)
- To fight climate change (16%)
- Depends on cost effectiveness (16%)
- It's the right thing to do (16%)

"Finite resources are finite. It doesn't matter that you save money today but have fewer or no energy sources later."

What is the main reason to NOT invest?

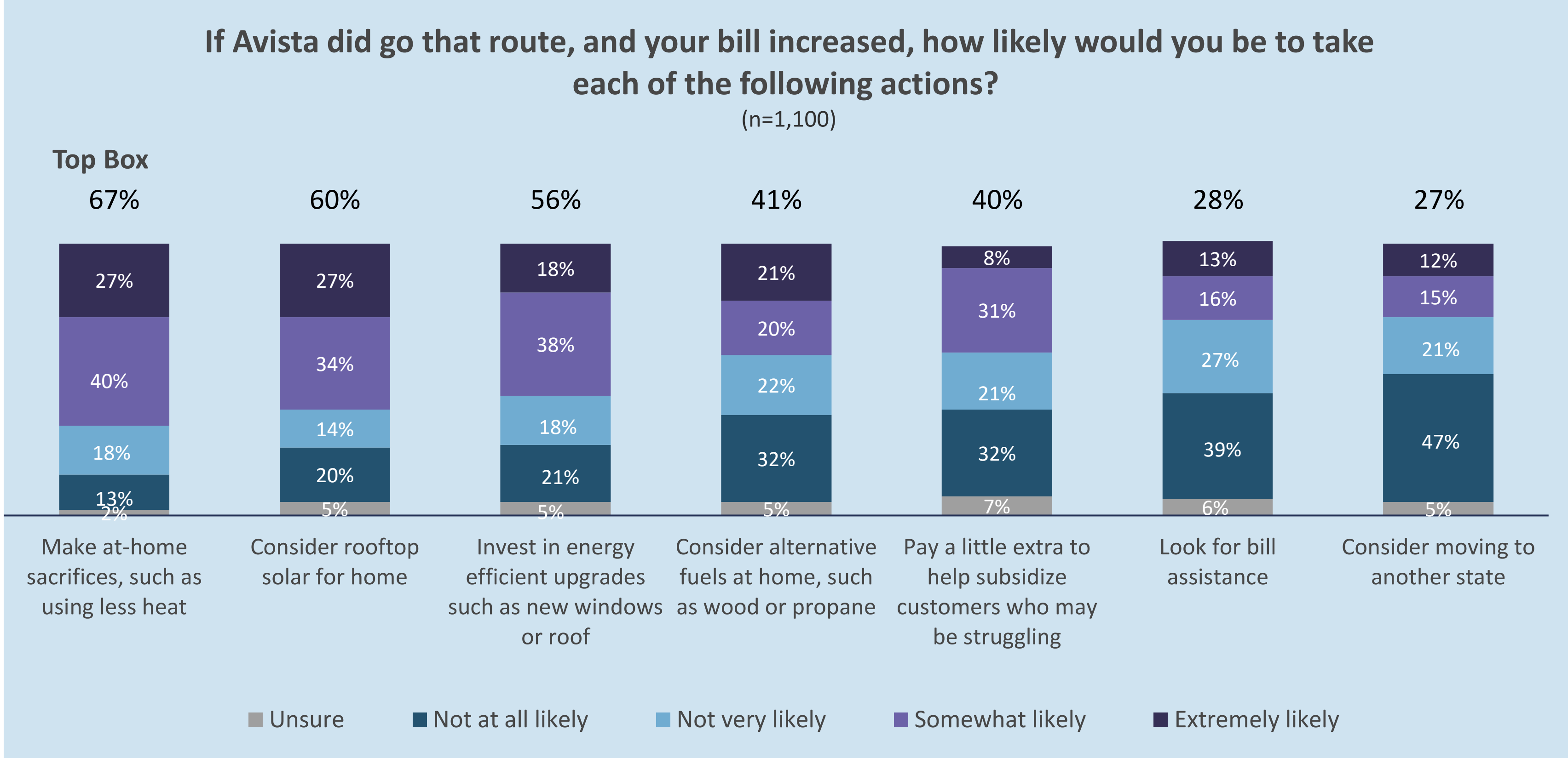
(n=345)

- Consumer costs/expensive (57%)
- Don't believe in it/hoax/impossible (17%)
- Unnecessary/will not change anything (16%)
- Politics/political agenda (10%)

"Carbon neutral and carbon free energy are ridiculous ideas that only increase the cost of energy for everyone."

C3A. In your opinion, what is the main reason Avista should invest in carbon-neutral or carbon-free energy, even if it involves a rate increase for customers?
C3B. In your opinion, what is the main reason or reasons Avista should not invest in carbon-neutral or carbon-free energy?

Nearly seven in ten customers would be likely to "make at home-sacrifices" if their bill increased due to Avista's investment in carbon-neutral energy

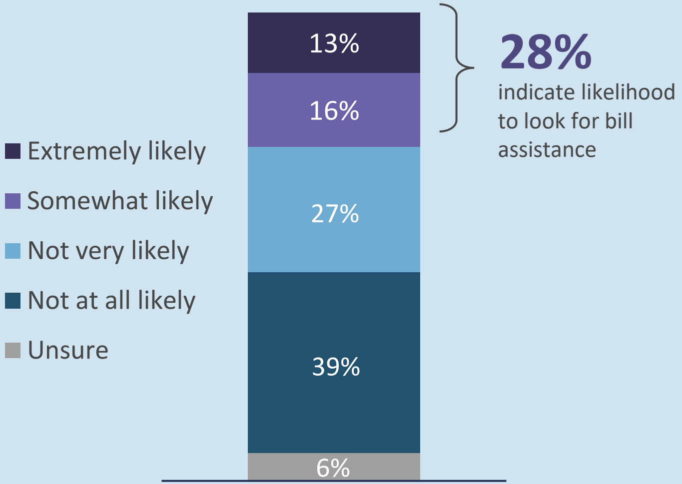


C4. If Avista did go that route, and your bill increased, how likely would you be to take each of the following actions?

Just over a quarter indicate they'd seek bill assistance should rates rise due to Avista pursuing carbon-neutral or carbon-free options; for over half, this would take a 10% increase or more

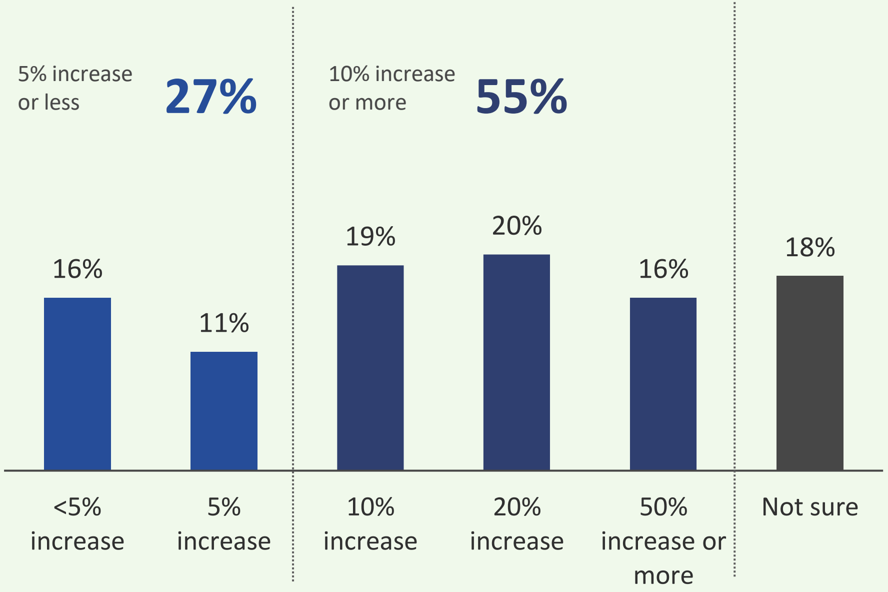
Likelihood to Seek Bill Assistance if Bill Increased

(n=1,100)



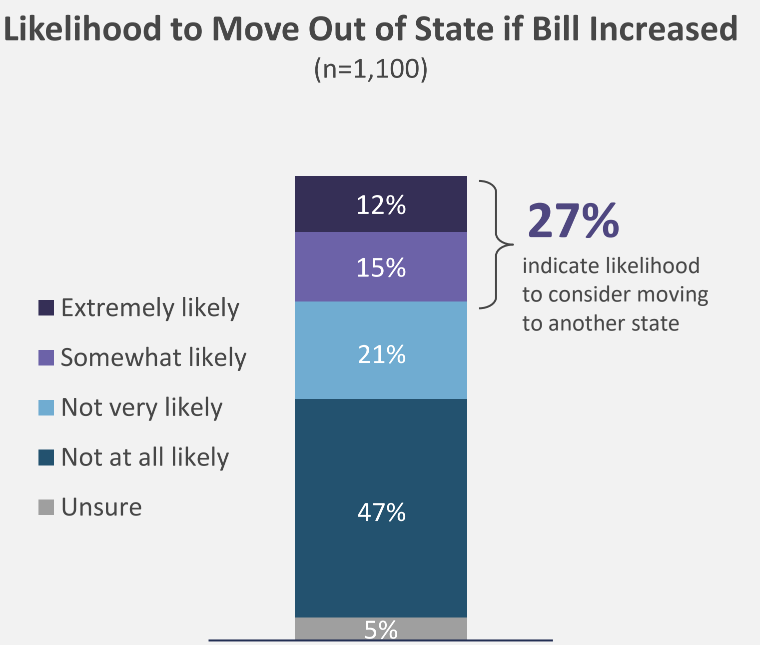
Level of Bill Increase That Would Drive Seeking Assistance

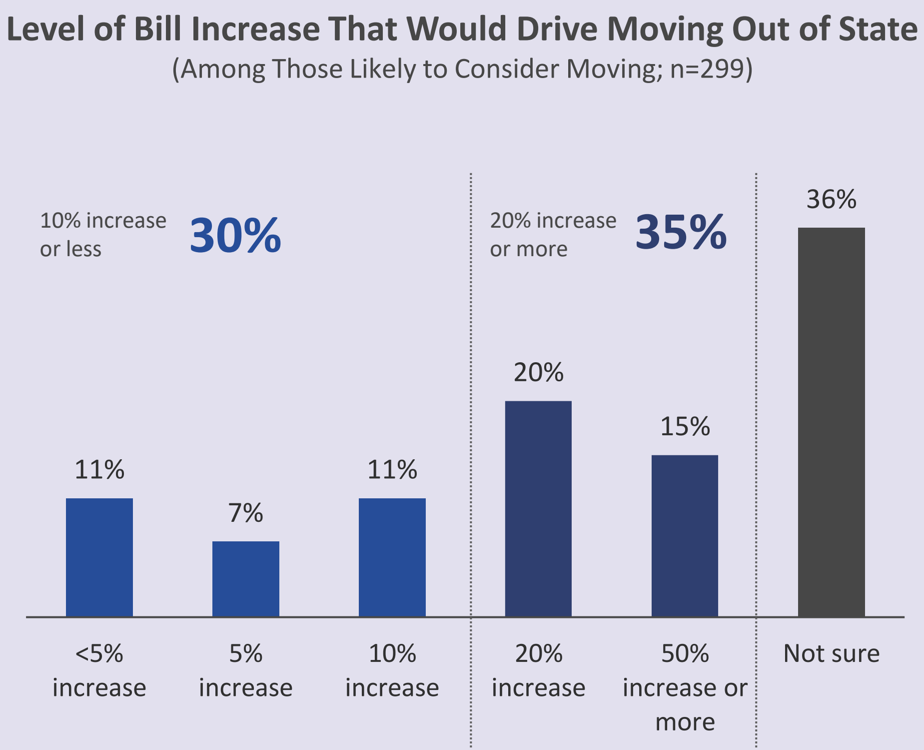
(Among Those Likely to Seek Assistance; n=313)



C4. If Avista did go that route, and your bill increased, how likely would you be to take each of the following actions? *Look for bill assistance*
C5. What level of bill increase would you envision driving you to seek bill assistance?

Roughly a third indicate they'd consider moving to another state should rates rise; however, there is uncertainty around what threshold of increase would drive this decision



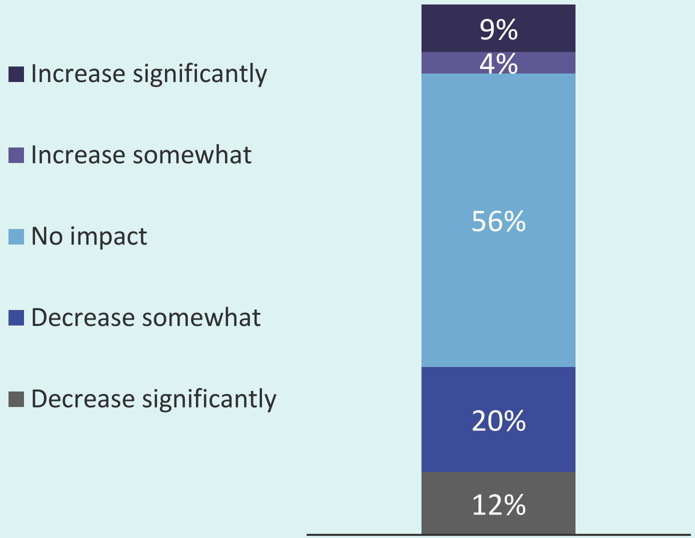


C4. If Avista did go that route, and your bill increased, how likely would you be to take each of the following actions? *Consider moving to another state*
C6. What level of bill increase would you envision driving you to consider moving to another state?

Over half of customers say their favorability would not be impacted if Avista does not achieve carbon neutrality by 2027

Favorability of the Company if Avista is not able to Achieve Carbon Neutrality by 2027

(n=1,100)



Potential decreased favorability differs by age.

Younger participants are significantly more likely than older participants to say their favorability of Avista would decrease significantly if Avista is not able to achieve carbon neutrality by 2027.

18-54	55+
15%	**10%**

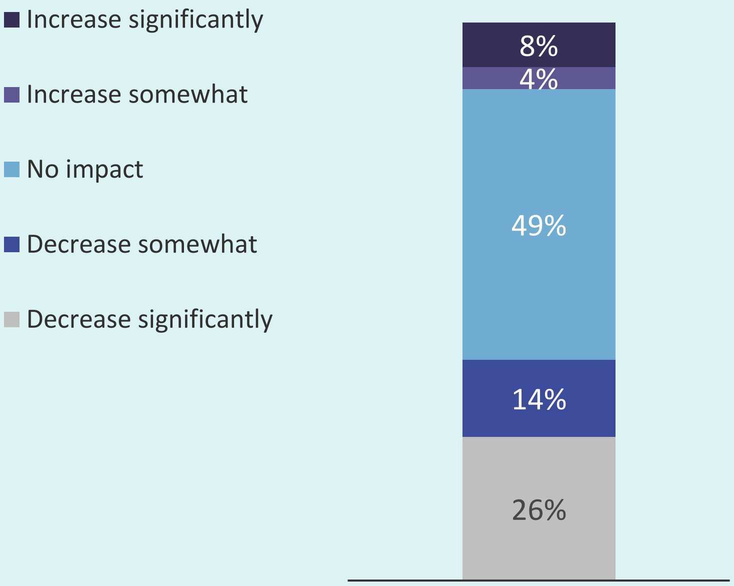
Potential decreased favorability is consistent across state, gender, area of residence, and income categories.

C7. If Avista is not able to achieve carbon neutrality by 2027, how would this affect your favorability of the company?

Nearly half say their favorability would not change if Avista does not achieve carbon free by 2045

Favorability of the Company if Avista is not able to Provide 100% Carbon-Free Power by 2045

(n=1,100)



Potential favorability differs by state.

Customers in **Oregon** and **Washington** are significantly more likely than those in Idaho say their favorability of Avista would decrease significantly.

29% 27% 21%

Potential favorability differs by area.

Customers in **urban** and **suburban** areas are significantly more likely than those in rural areas to decrease favorability.

urban	suburban	rural
32%	28%	21%

Potential favorability differs by household income

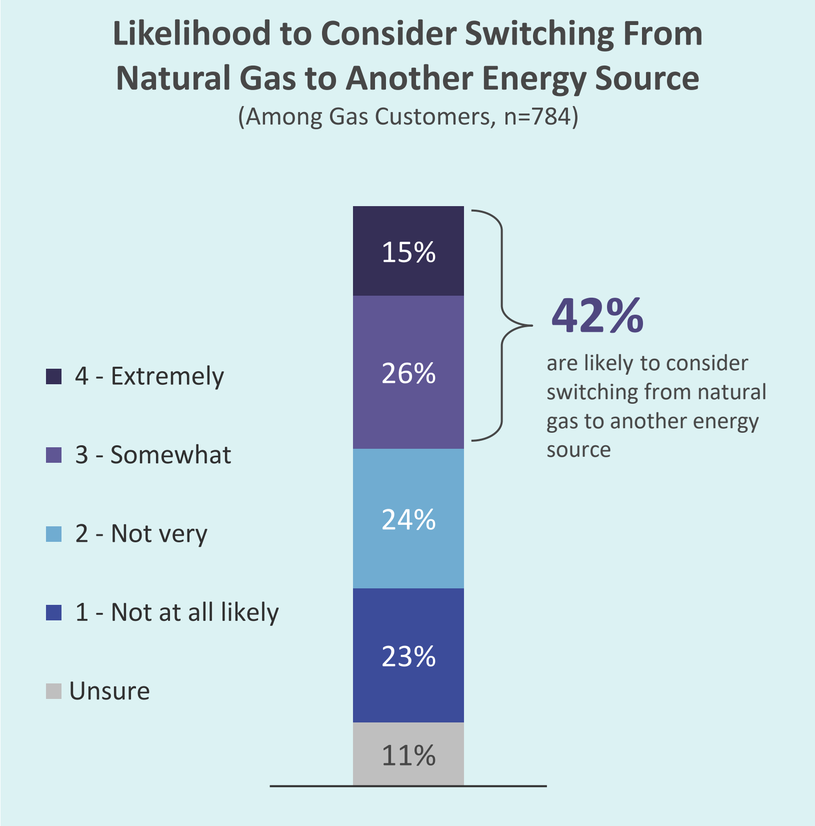
Those with **higher household incomes** are significantly more likely than those making $80K or less to decrease favorability.

<$80K	$80K+
23%	33%

C8. If Avista is not able to provide 100% carbon-free power by 2045, how would this affect your favorability of the company?

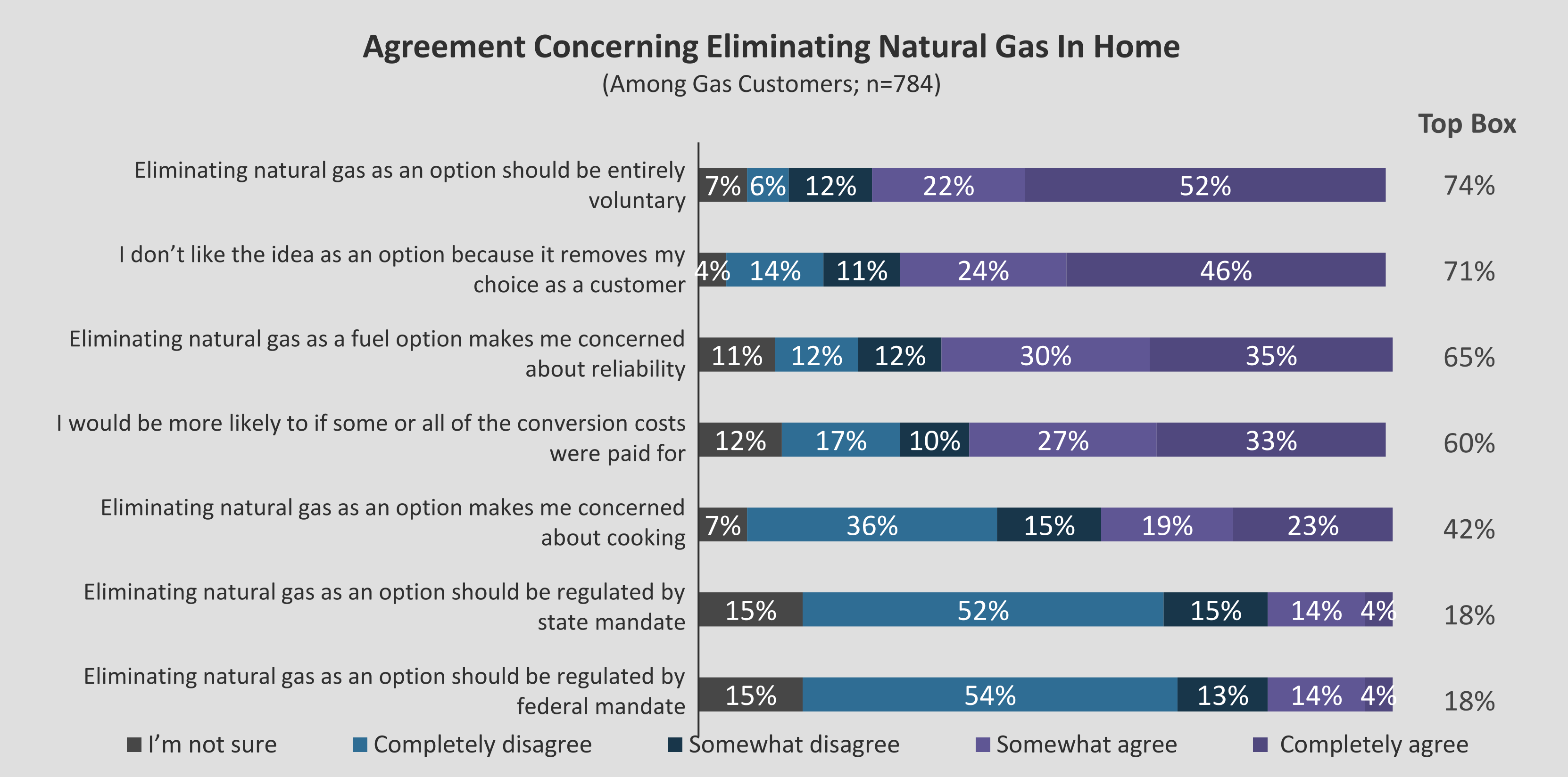
Detailed Findings:
Natural Gas Insights

Nearly half of customers would **not** consider switching from natural gas to help reduce carbon emissions



N1. How likely would you be to consider switching from natural gas to another energy source to help reduce carbon emissions?

Three-quarters gas customers agree eliminating natural gas should be entirely voluntary

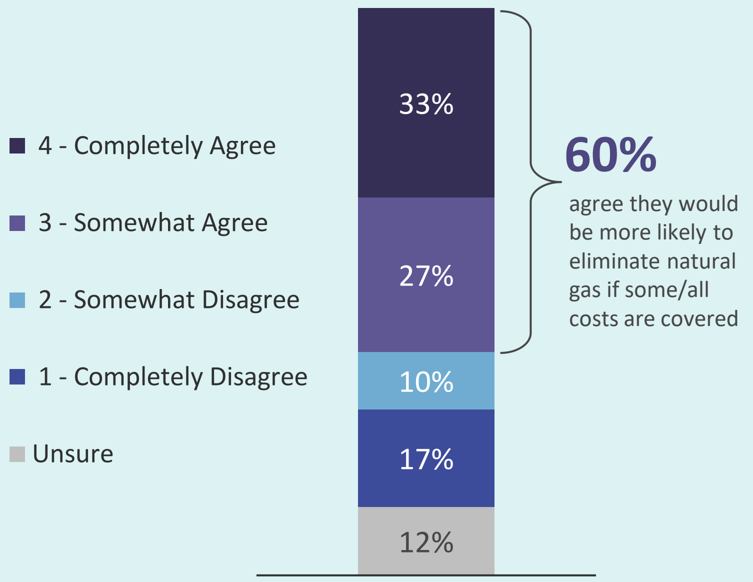


N2. How much do you agree or disagree with the following statements concerning natural gas in your home?

Six in ten would be more likely to convert from natural gas if some or all conversion costs were covered; of these, 59% would be willing to pay under $1000

Would be More Likely to Convert if Some or All Conversion Costs are Covered

(Among Gas Customers, n=784)



Maximum Personal Contribution

(Among Gas Customers More Likely to Convert If Some/All Costs Are Covered; n=473)

N2. How much do you agree or disagree with the following statements concerning natural gas in your home?

I would be more likely to eliminate natural gas as an option in my home if some or all of the conversion costs were paid for by the electric utility and/or government incentives

N3. If you did have to contribute some costs towards converting from natural gas in your home, how much would you consider your max level of contribution?

Customer Demographics

Demographics

Education	Total (n=1,100)	WA (n=569)	ID (n=316)	OR (n=215)
High school or less	7%	5%	10%	7%
Trade or Technical School	6%	6%	9%	4%
Some college	20%	20%	20%	21%
Graduated college	36%	37%	35%	33%
Graduate/professional school	26%	28%	22%	30%
Age				
18-24	1%	<1%	2%	--
25-34	5%	4%	9%	4%
35-44	13%	15%	14%	9%
45-54	14%	14%	14%	12%
55-64	23%	21%	26%	22%
65-74	25%	24%	24%	31%
75+	12%	16%	4%	16%
Refused	6%	5%	7%	7%

Home Type	Total (n=1,100)	WA (n=569)	ID (n=316)	OR (n=215)
Single family dwelling	83%	92%	64%	87%
A duplex or triplex	4%	2%	7%	3%
In a building with 4 or more units	6%	2%	16%	2%
Income				
Median	~$70K	~$78K	~$62K	~$66K
Household				
Mean # of people	2.4	2.5	2.2	2.2
Gender				
Women	46%	44%	47%	53%
Men	46%	49%	45%	40%
Non-binary or Other	<1%	1%	1%	--
Prefer not to say	7%	7%	7%	8%

Natural Gas Integrated Resource Plan - Draft

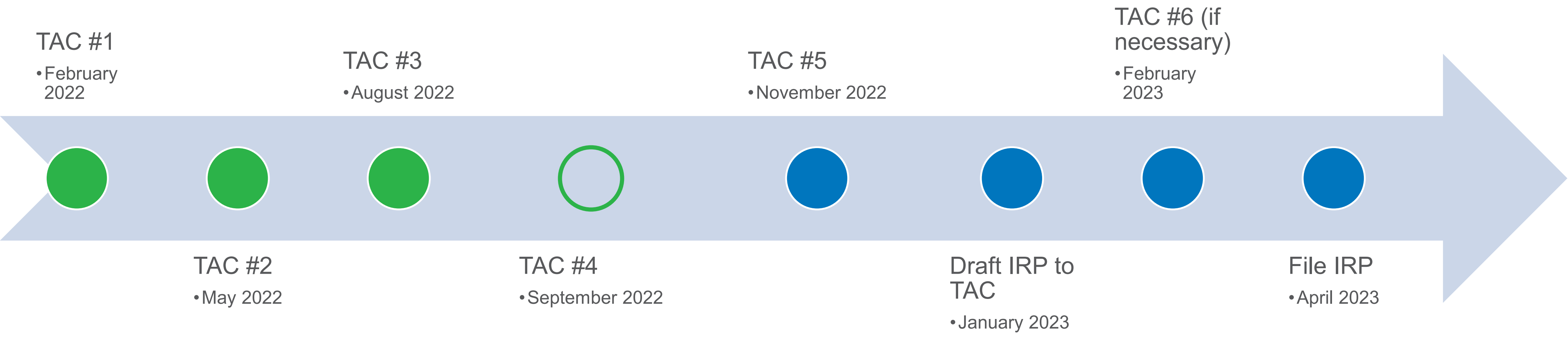
Technical Advisory Committee (TAC) # 4

September 29, 2022

Agenda

Item	Time
ETO - CPA	12:30pm – 1:15pm
Natural Gas Market Dynamics and Prices	1:15pm – 2:00pm
break	2:00pm – 2:15pm
Supply Side Resource Options	2:15pm – 3:00pm
CCA Overview	3:00pm – 3:15pm
Climate Change Weather	3:15pm – 4:00pm
Updated Load Forecast and Scenarios	4:00pm – 4:30pm

2023 – Avista Natural Gas IRP



Energy Efficiency Resource Assessment for AVA's 2023 IRP (DRAFT)

September 29th, 2022

Energy Trust of Oregon

Agenda

- About Energy Trust
- Energy Trust's Resource Assessment Model Overview and Methodology
- IRP Savings Projection Overview
  - The Deployment of Cost-Effective Achievable Savings
- Forecast Results

About us

Independent nonprofit

Serving 1.8 million customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista

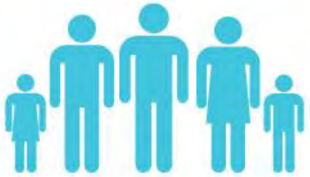
Providing access to affordable energy

Generating homegrown, renewable power

Building a stronger Oregon and SW Washington

Clean and affordable energy since 2002

From Energy Trust's investment of $2.2 billion in utility customer funds:



Nearly 770,000 sites transformed into energy efficient, healthy, comfortable and productive homes and businesses

18,000 clean energy systems generating renewable power from the sun, wind, water, geothermal heat and biopower

$8.9 billion in savings over time on participant utility bills from their energy-efficiency and solar investments

36.2 million tons of carbon dioxide emissions kept out of our air, equal to removing 7 million cars from our roads for a year

2022 Programs – Acquiring all C/E Efficiency

- Residential – Existing and New Homes
  - Single family, moderate income, rental, manufactured homes
  - Weatherization (insulation, windows, air sealing)
  - Gas fireplaces, furnaces
  - Water heaters

- Commercial – Existing, New, Multifamily, SEM
  - Retail, offices, schools, groceries….all market segments
  - HVAC, controls, water heating, windows, insulation

- Industrial & Agriculture – Non transport sites
  - Manufacturing facilities, greenhouses
  - HVAC, O&M, process improvements

Avista & Energy Trust

- Serving Avista Territory in Oregon for over 5 years, since 2016:
  - Served over 10,500 households, over 600 commercial sites and 20 industrial sites

Energy Trust's Resource Assessment Model Overview

Resource Assessment (RA) Purpose

- Informs utility Integrated Resource Planning (IRP)
- Provides estimates of 20-year energy efficiency potential and the associated load reduction
- Helps utilities to strategically plan future investment in both demand and supply side resources

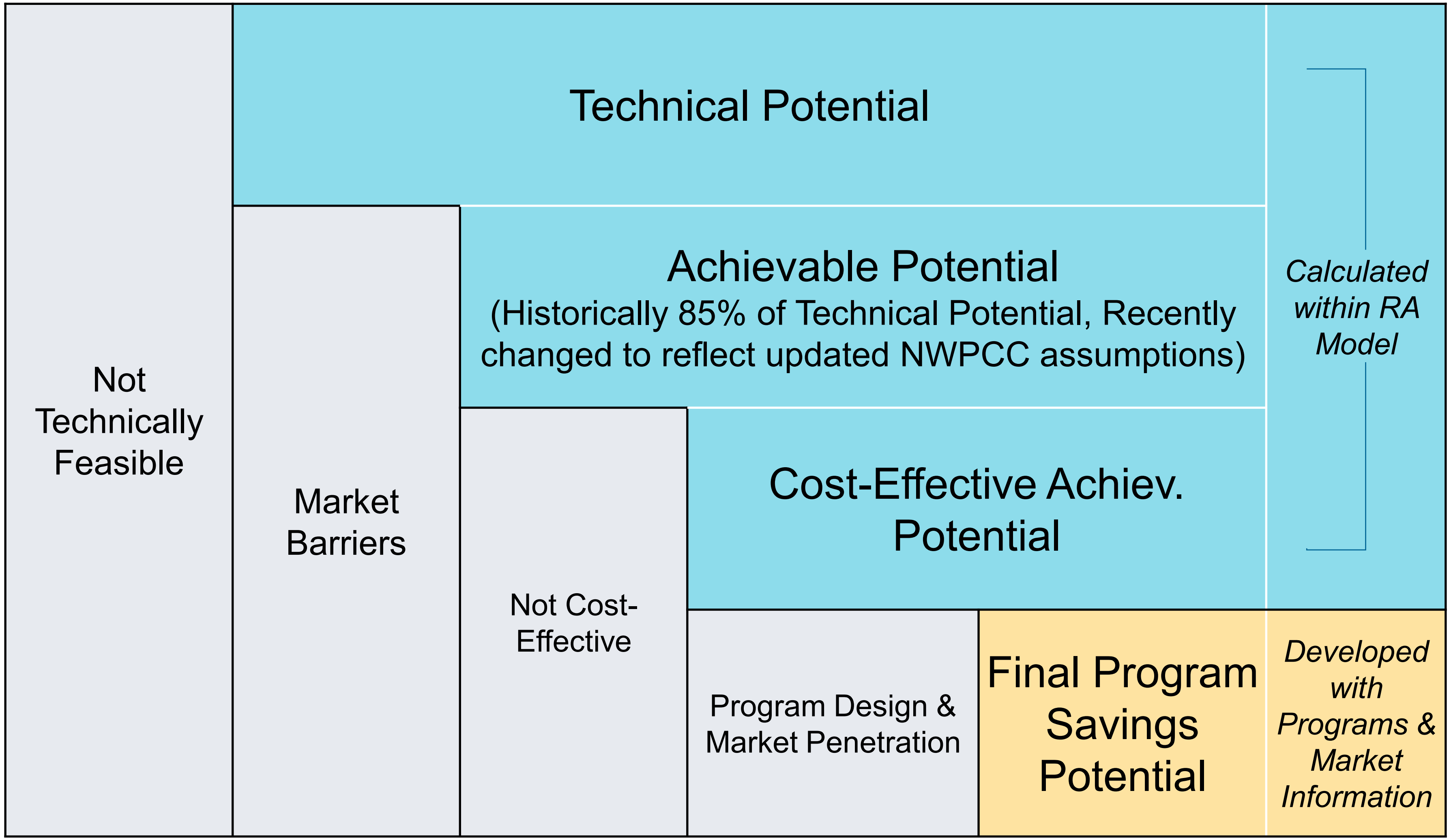
RA Model Background

- 20-year energy efficiency potential estimates
- “Bottom-up” modeling approach – measure level inputs are scaled to utility level efficiency potential
- Energy Trust uses a model in *Analytica* that was developed by Navigant Consulting in 2014
  - The *Analytica* RA Model calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential.
  - Final program/IRP targets are established via a deployment protocol exogenous of the model.
- Inputs refreshed to reflect most up to date assumptions according to IRP schedules
- A “living model” which is constantly being improved

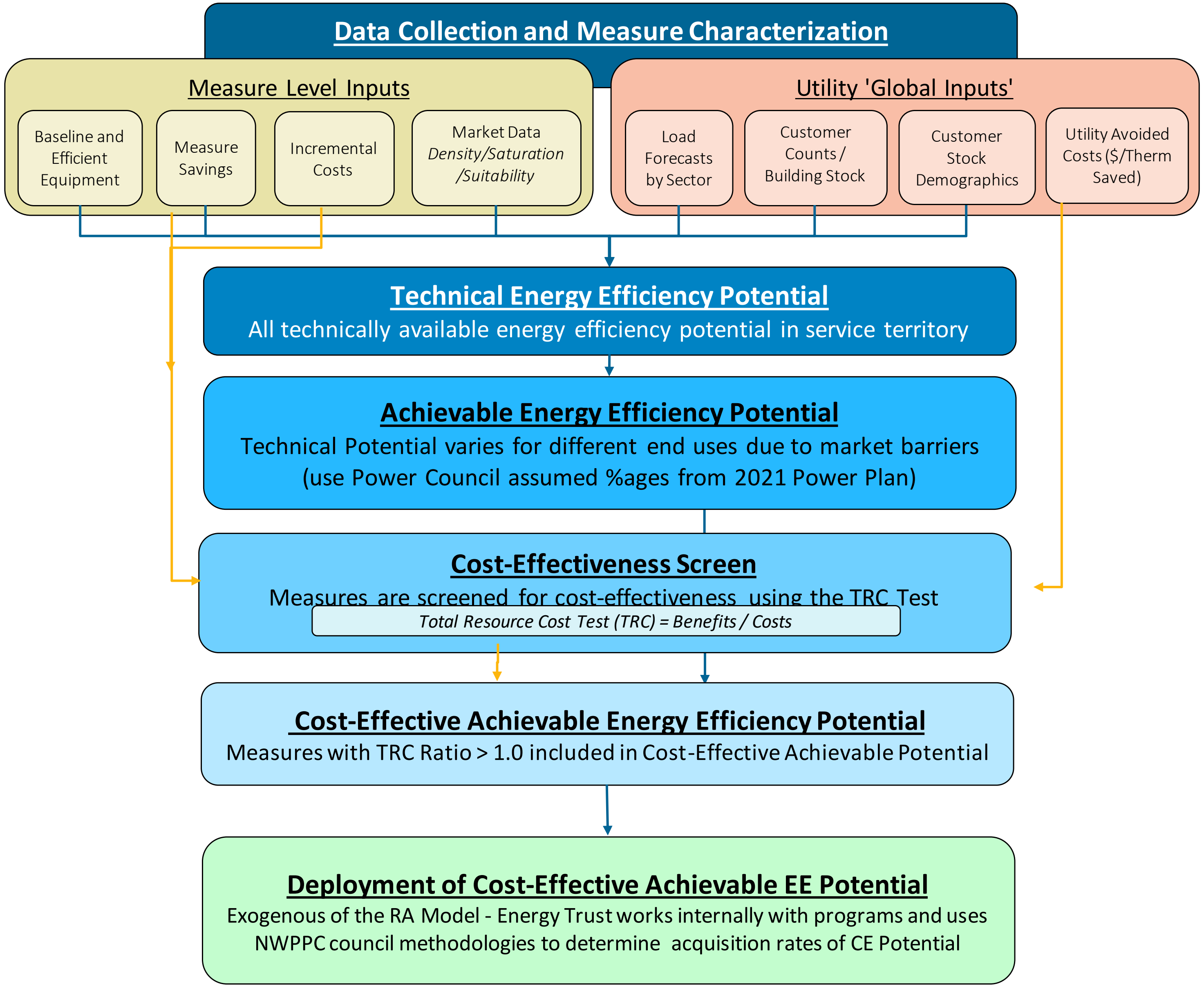
Changes to Modeling Since 2020 IRP

- Lost opportunity/unconstrained potential
- Align with NWPCC achievability assumptions
- Measure updates, new measures and new emerging technologies included in the model

Forecasted Potential Types



20-Year IRP EE Forecast Flow Chart



Methodology Overview

'Bottom-up' modeling approach:

1. Measure inputs are characterized per unit
2. Number of units per scaling basis are estimated
    - *Residential*: # of Homes Served
    - *Commercial*: 1000s of Sq. Ft. Served
    - *Industrial*: Customer Segment Load Forecasts
3. The savings and costs of each measure are scaled to the utility level based on scaling basis inputs provided by AVA

Simple Example *(Illustrative Numbers)*

Eff. Gas Furnace – 100 Therms Savings	1 Gas Furnace per home and 50% at baseline efficiency	25,000 Homes served by utility	100 x 1 x 0.50 x 25,000 = 1,250,000 savings potential
• Measure Data	• Market Data	• Utility Data	• Total Potential

RA Model inputs

Measure Level Inputs

Measure Definition and Application:
- Baseline/efficient equip. definition
- Applicable customer segments
- Installation type (RET/ROB/NEW)*
- Measure life

Measure Savings

Measure Cost
- Incremental cost for ROB/NEW measures
- Full cost for retrofit measures

Market Data (for scaling)
- Density
- Baseline/efficient equipment saturations
- Suitability

Utility 'Global' Inputs

Customer and Load Forecasts
- Used to scale measure level savings to a service territory
  - Residential Stocks: # of homes
  - Commercial Stocks: 1000s of Sq.Ft.
  - Industrial Stocks: Customer load

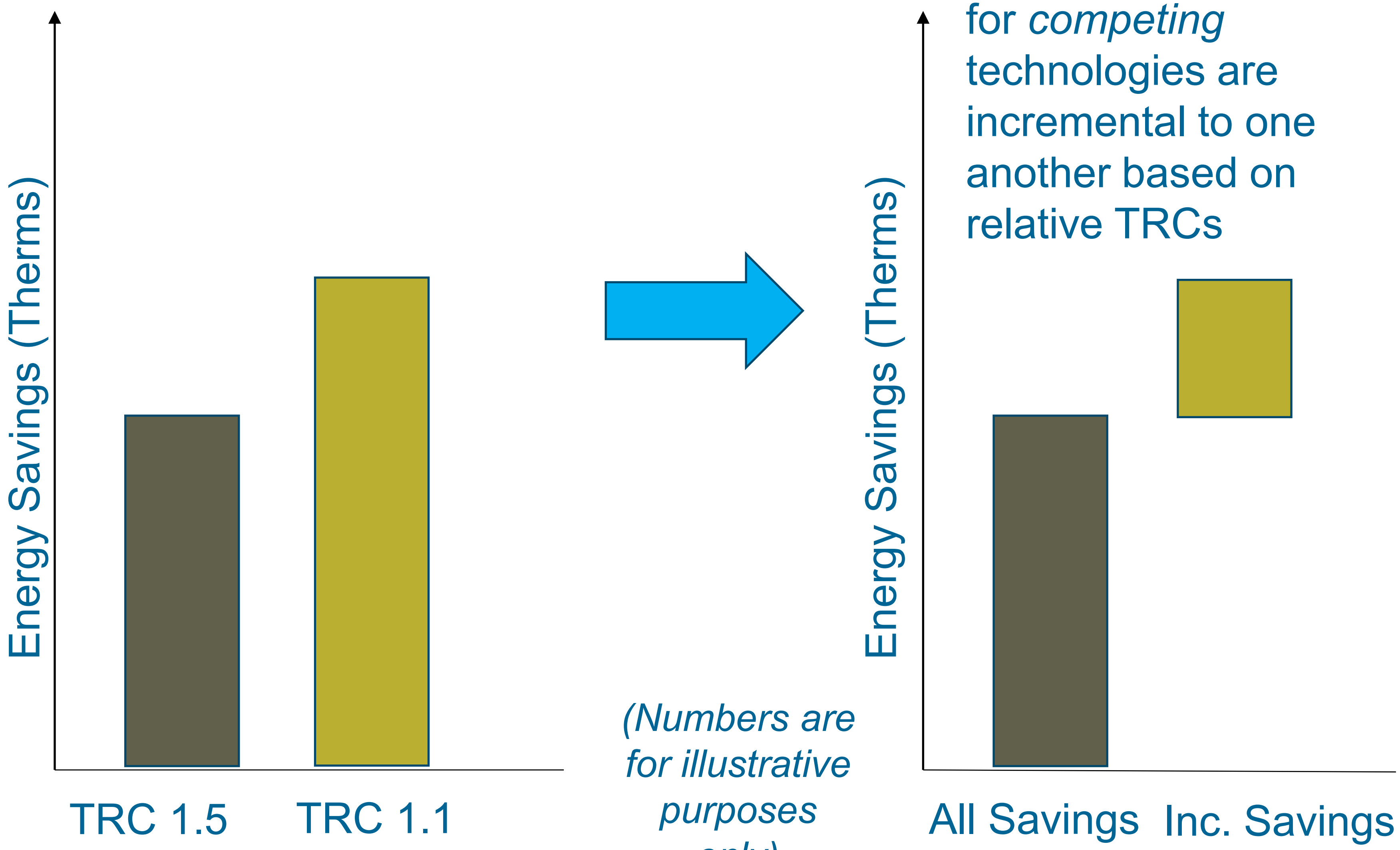
Avoided Costs (provided by utilities)

Customer Stock Demographics:
- Heating fuel splits
- Water heat fuel splits

** RET = Retrofit; ROB = Replace on Burnout; NEW = New Construction*

EnergyTrust of Oregon

Incremental Measure Savings Approach
Competition groups



Savings potential for *competing* technologies are incremental to one another based on relative TRCs

(Numbers are for illustrative purposes only)

Cost-Effectiveness Screen

- Energy Trust utilizes the Total Resource Cost (TRC) test to screen measures for cost effectiveness

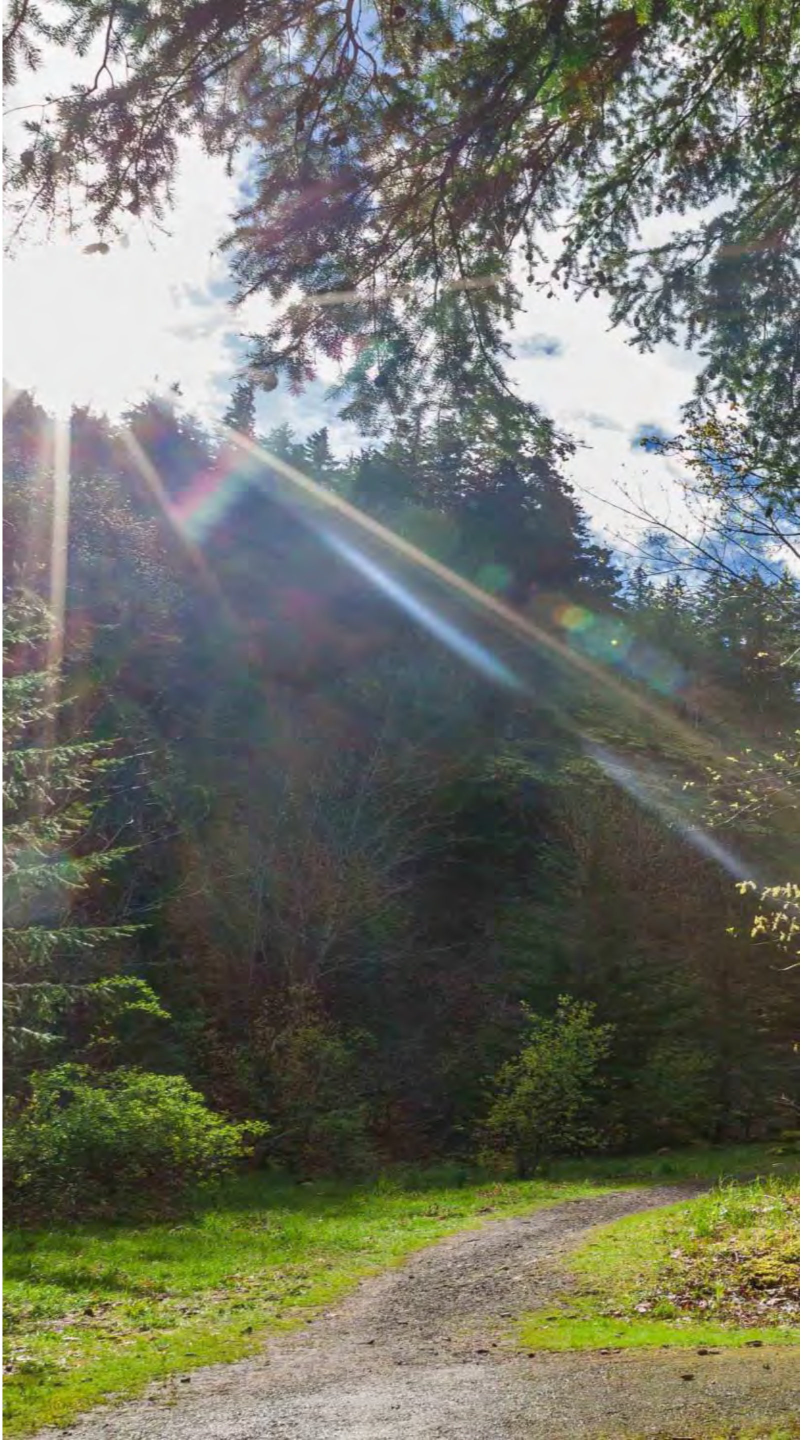
$$\mathrm{TRC} = \frac{\boldsymbol{Measure\ Benefits}}{\boldsymbol{Total\ Measure\ Cost}}$$

- If TRC is > 1.0, it is cost-effective

- Measure Benefits:
  - Avoided Costs (provided by AVA)
    - Annual measure savings x NPV avoided costs per therm
  - Quantifiable Non-Energy Benefits
    - Water savings, etc.

Total Measure Costs:

- The customer cost of installing an EE measure (full cost if retrofit, incremental over baseline if replacement)



Cost-Effectiveness Override in Model

Energy Trust applied this feature to measures found to be NOT Cost-Effective in the model but are offered through Energy Trust programs.

Reasons:

1. Blended avoided costs may produce different results than utility specific avoided costs
2. Measures offered under an OPUC exception per UM 551 criteria.

Model Outputs

Types of Potential:
- Technical
- Achievable
- Cost-Effective Achievable

Levelized Cost

Measure Costs & Benefits

Supply Curves

IRP Savings Projections:
Methodology to Deploy Cost-Effective Achievable Potential

Why Deploy?

- The RA model results represent the maximum savings potential in a given year.
- Ramp rates are an estimate of how much of that available potential will come off AVA's system each year.
- Energy Trust ramp rates are based on NWPCC methods and ramp rates, but calibrated to be specific to Energy Trust.

Ramp Rate Overview

- Total RA Model cost-effective potential is different depending on the measure type.
  - **Retrofit measure savings** are 100% of all potential in every year, therefore must be distributed in a curve that adds to 100% over the forecast timeframe (bell curve)
  - **Lost opportunity measure savings** are the savings available in that year only and deployment rates are what % of that available potential rate can be achieved – results in an s-curve
- Generally follows the NWPCC deployment methodology
  - 100% cumulative penetration for retrofit measures over 20-year forecast
  - 100% annual penetration for lost opportunity by end of 20-year forecast (program or code achieved)
  - Hard to reach measures or emerging technologies do not ramp to 100%

Ramp Rate Examples

Ramp Rate Calibration

Energy Trust calibrates the first five years of energy efficiency acquisition ramp rates to program performance and budget goals.

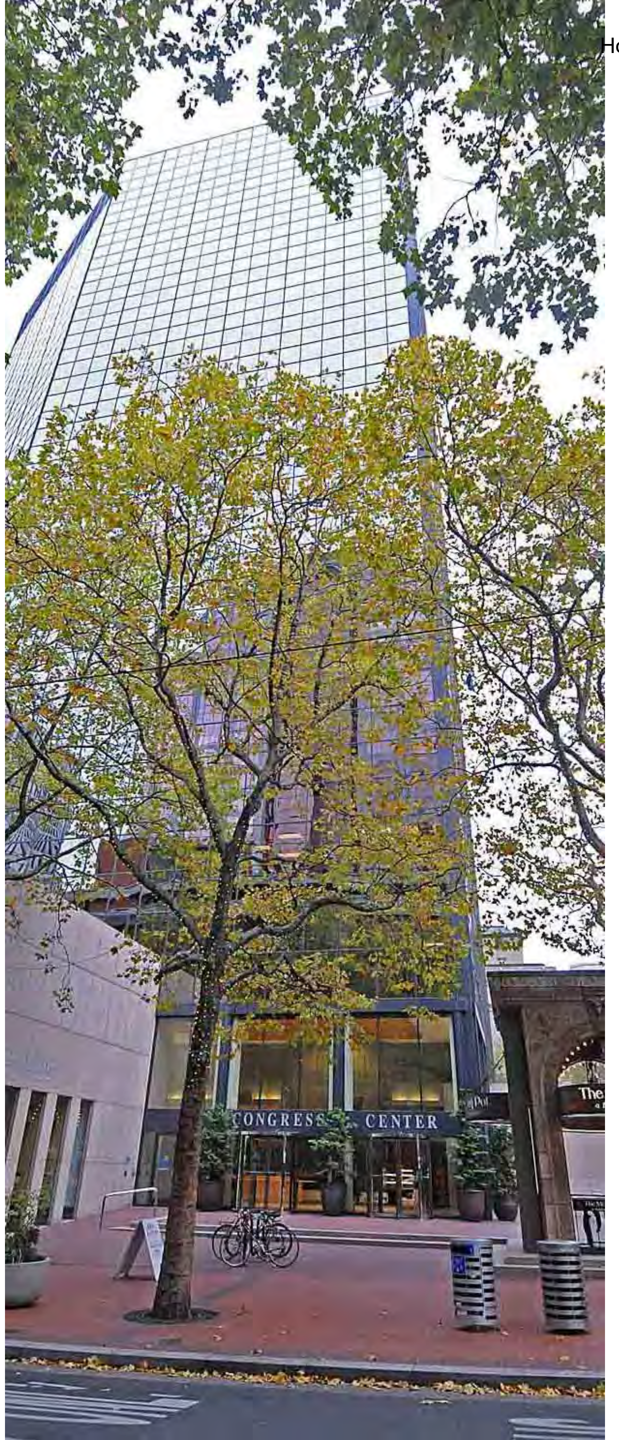
Years 1-2
- Program forecasts – based on budget and current market conditions

Years 3-5
- Planning and Programs work together to create forecast

Years 6-20
- Planning forecasts long-term acquisition rate to generally align NWPCC

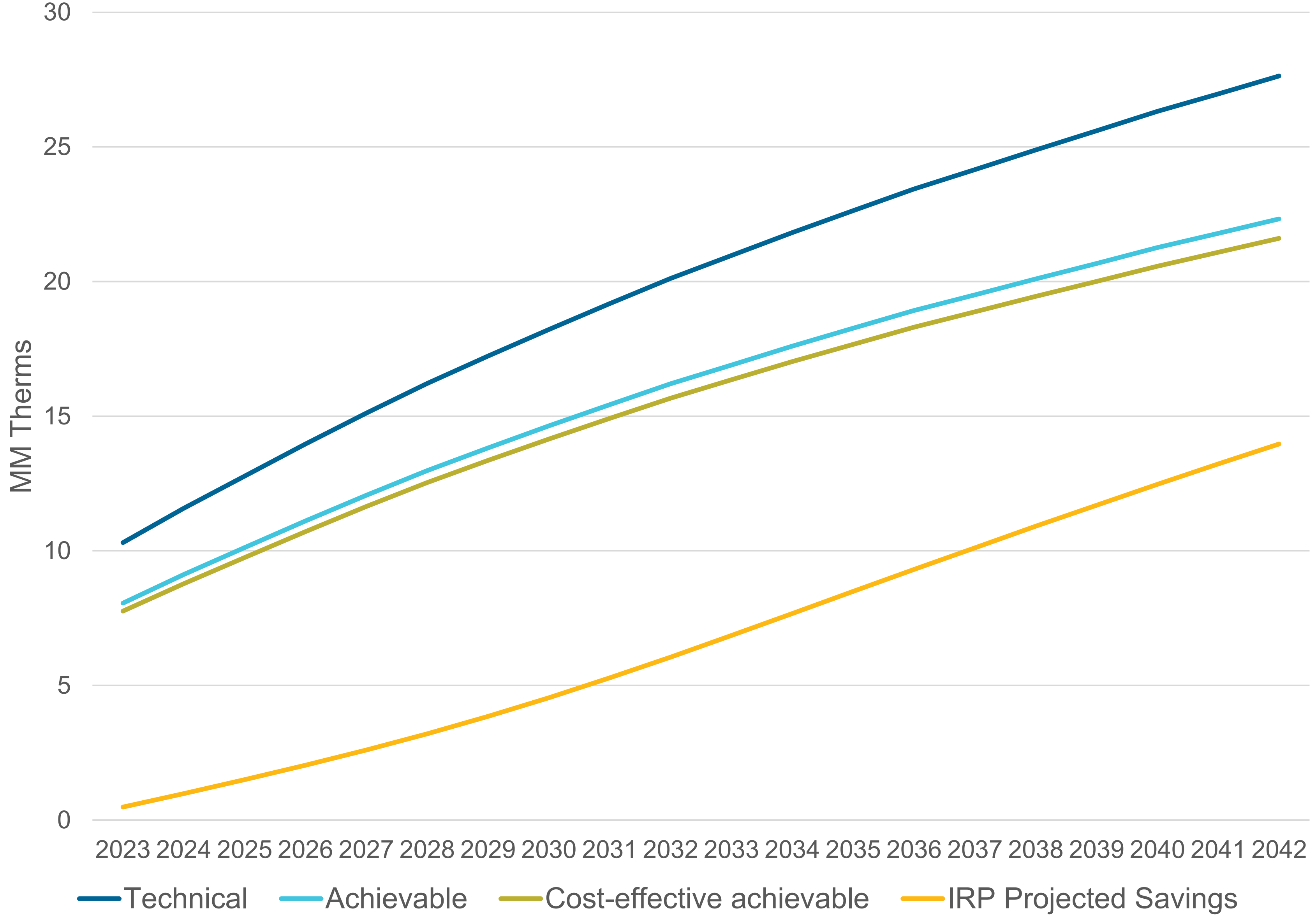
Application of Ramp Rates & Relation to RA Model Results

- Energy Trust's calibration process means ramp rates are not the same as the NWPCC, but follow similar methods.
- Ramp rates are specific to AVA.
- The application of these ramp rates is the reason why not all of the RA Model Cost-Effective Achievable Potential is forecasted to be acquired.
- The deployment process is done exogenously of the RA Model.

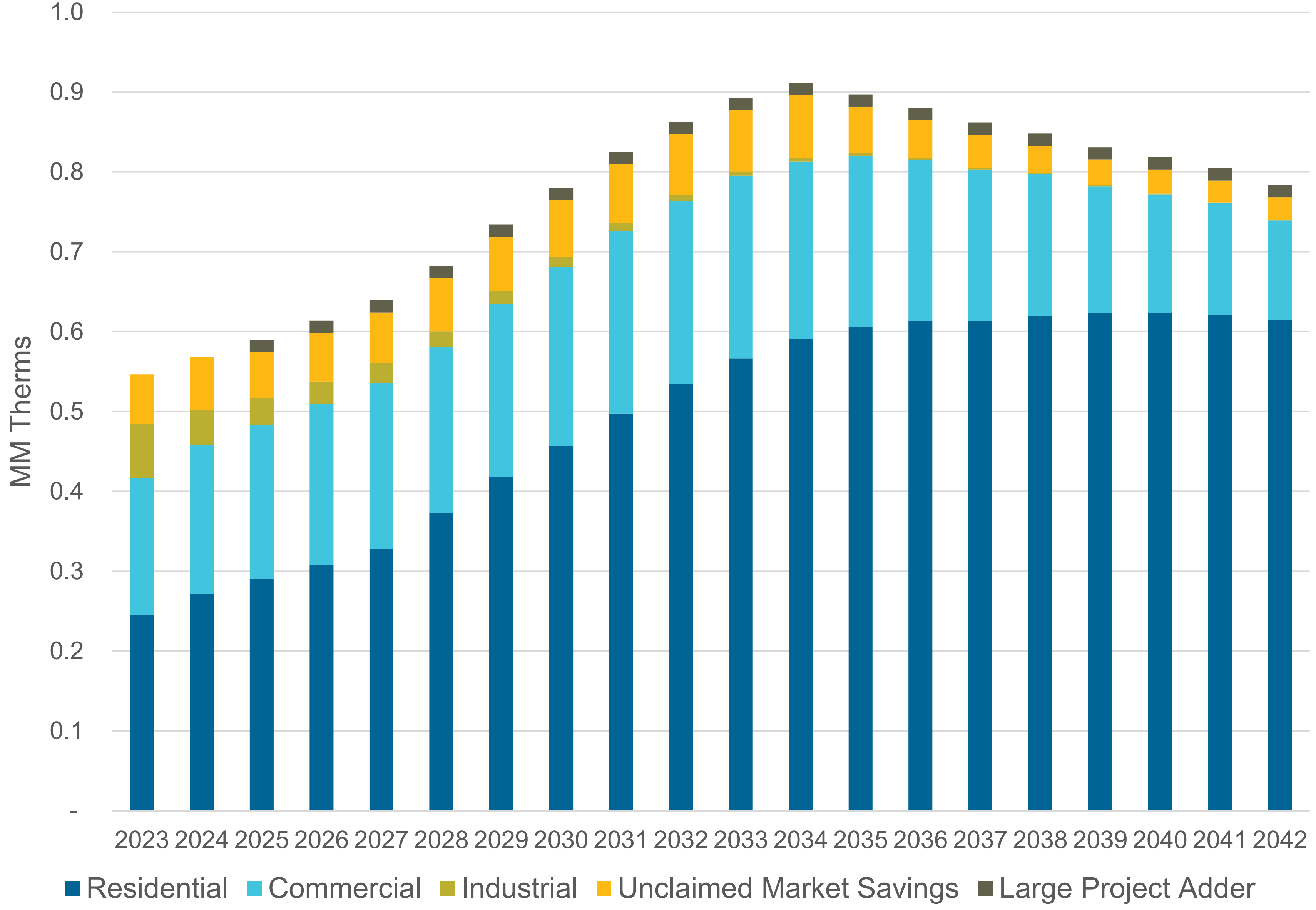


AVA’s 2023 IRP Results

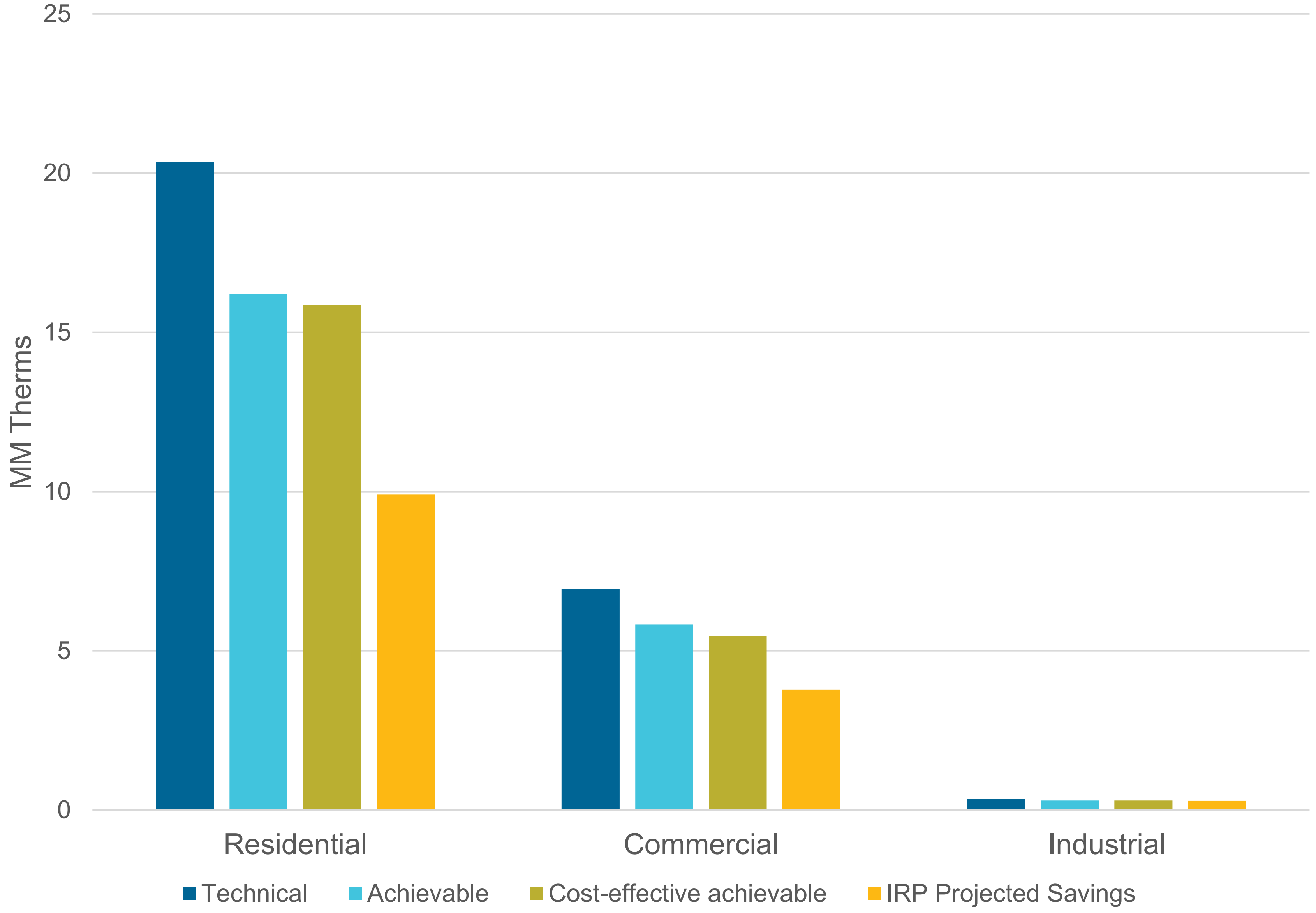
Cumulative Savings by Type and Year



Annual Deployed IRP Forecasted Savings



Cumulative Savings by Sector and Type

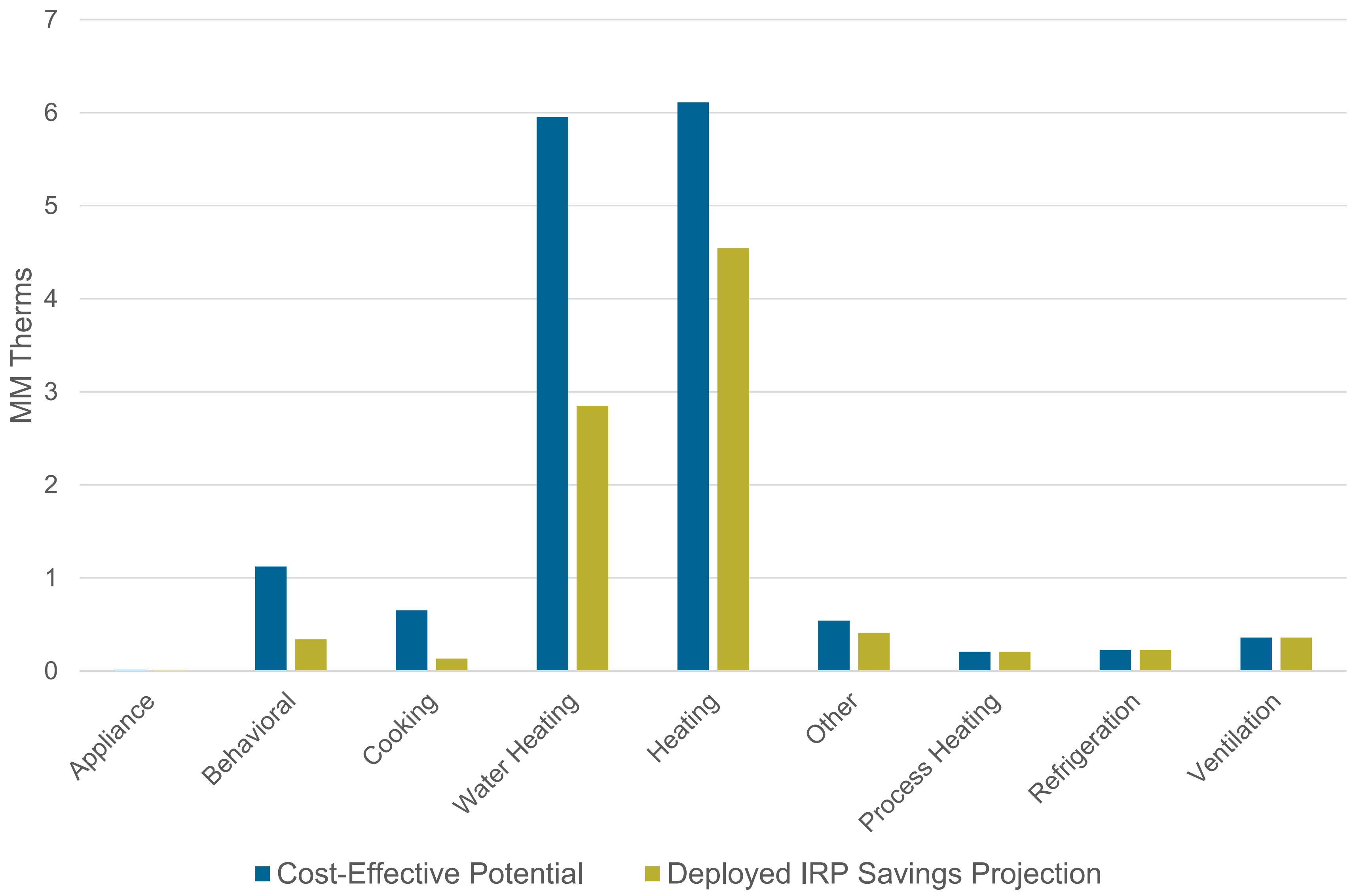


Cumulative Savings by Sector and Type (Therms)

	Residential	Commercial	Industrial	All Sectors
Technical Potential	20,345,233	6,942,478	345,190	27,632,901
Achievable Potential	16,213,842	5,817,303	293,412	22,324,557
Cost-effective Achievable Potential	15,852,804	5,458,700	293,412	21,604,916
IRP Projected Savings	9,903,449	3,782,116	283,961	13,969,526

Study years include 2023 - 2042

Cumulative Cost-Effective Savings & IRP Savings Projections by End-Use Compared



Cost Effective Override Effect

Energy Trust applied this feature to measures found to be NOT Cost-Effective in the model but are offered through Energy Trust programs under OPUC Exception

Measures that are Overridden	Override Applied?	Notes
Res - Attic/Ceiling insulation	TRUE	OPUC Exception
Res - Floor insulation	TRUE	OPUC Exception
Res - Wall insulation	TRUE	OPUC Exception
Res – Efficient Gas Clothes Washer	TRUE	OPUC Exception
Res – Gas heated new manufactured homes	TRUE	OPUC Exception
Com – Wall insulation	TRUE	OPUC Exception
Com – Flat roof insulation	TRUE	OPUC Exception

Cost Effective Override Effect

Energy Trust applied this feature to measures found to be NOT Cost-Effective in the model but are offered through Energy Trust programs under OPUC Exception

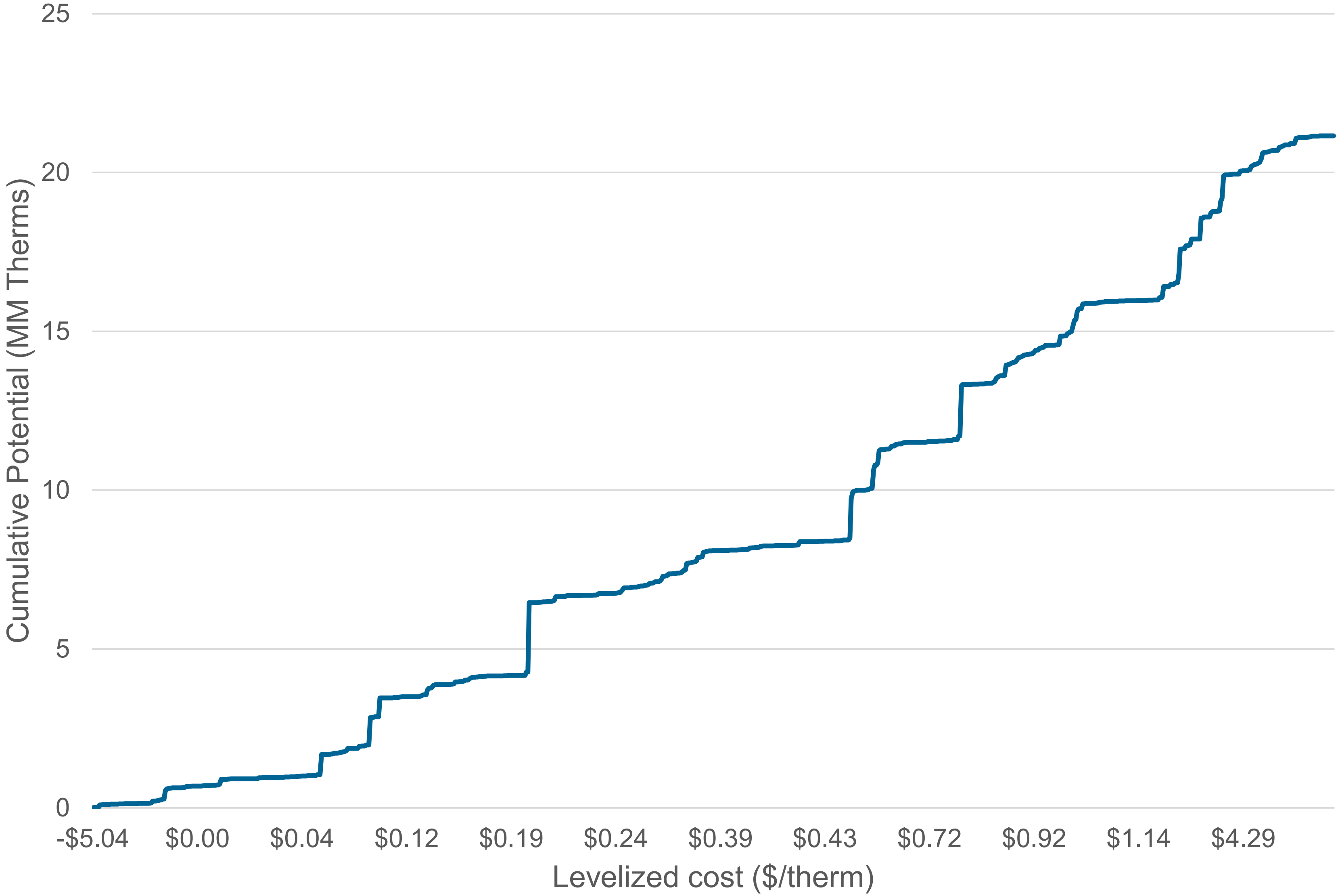
Total Cumulative Potential	Cost-Effective Potential	Deployed IRP Savings Projection
Savings with CE Override (MM Therms)	21.60	13.97
Savings with NO CE Override (MM Therms)	20.78	13.17
Variance (MM Therms)	0.83	0.80
CE Overridden % of Total Potential	**3.8%**	**5.7%**

Peak Day Factors and Cumulative Peak Day Savings Estimates

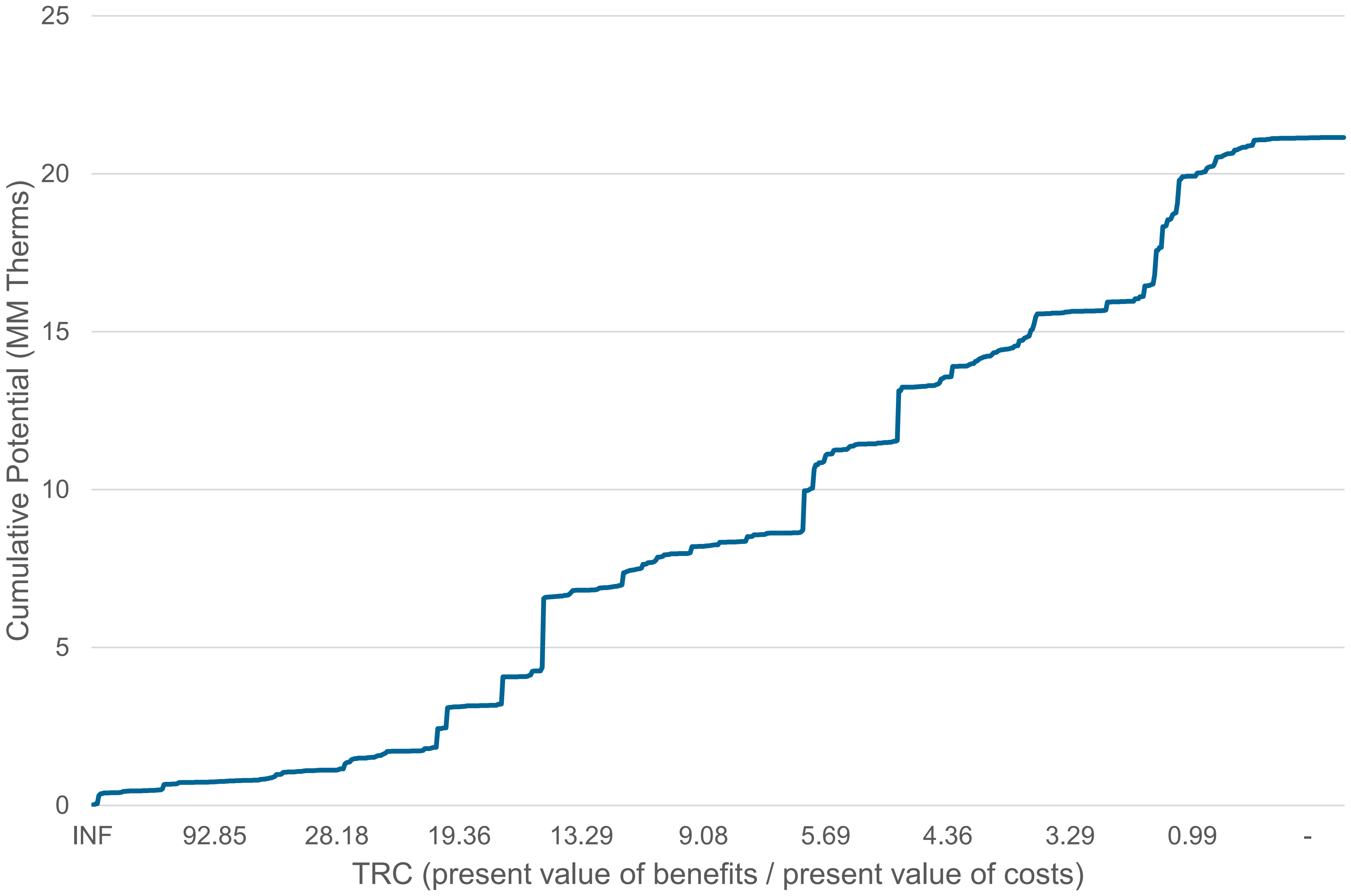
- Energy Trust also provides estimates of a peak day reduction in peak day consumption
- Peak Day factors derived from Energy Trust avoided cost calculations

	Peak Day Factor	CE Potential Peak Day Therms (cumulative)	IRP Savings Targets Peak Day Therms (cumulative)
Cooking	0.36%	643	406
Com Heating	1.77%	72,375	52,833
Domestic Hot Water	0.33%	13,711	7,569
FLAT	0.27%	577	575
Res Heating	1.98%	247,555	165,245
Res Clothes Washer	0.20%	-	-

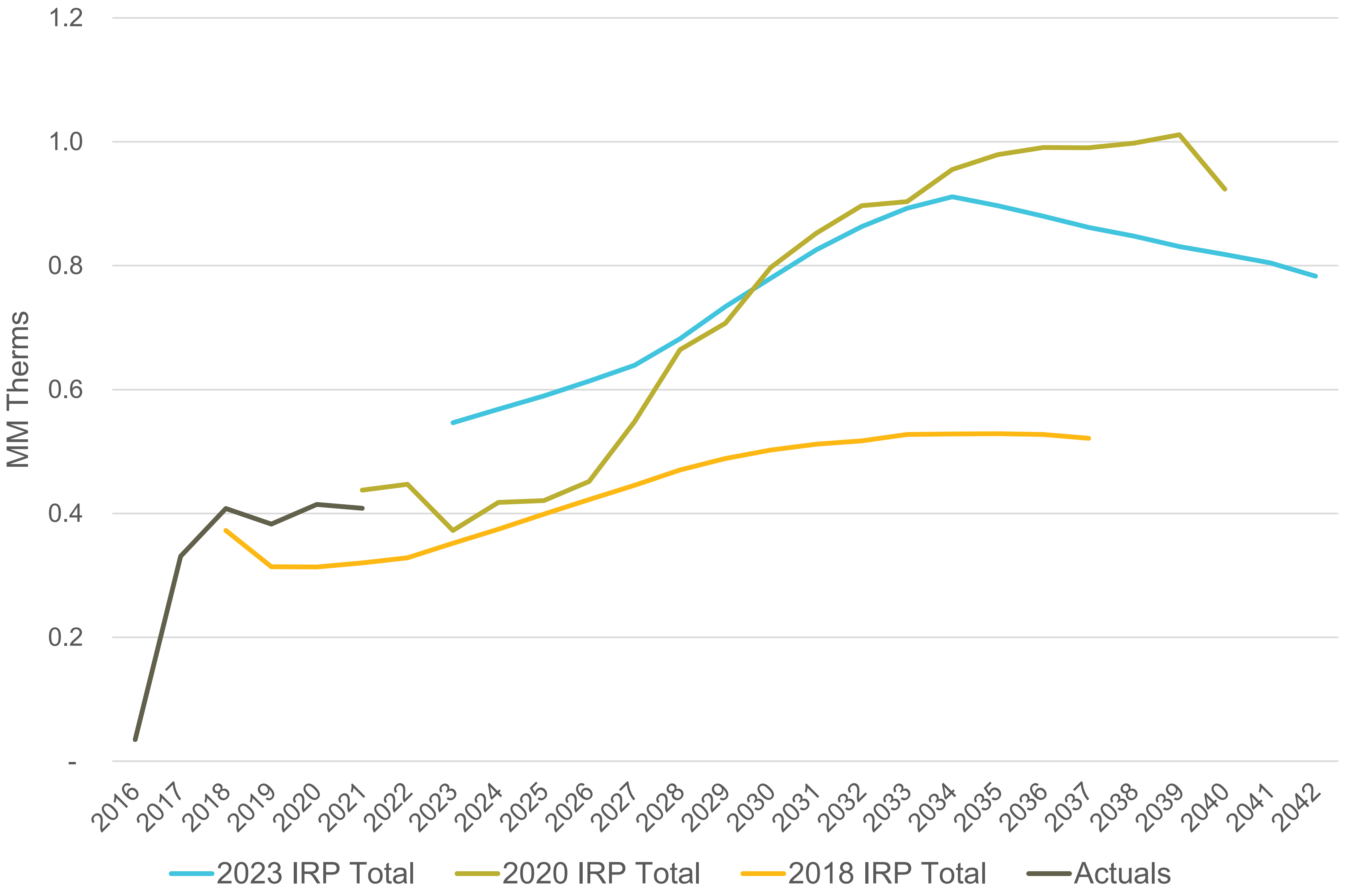
Supply Curve by Levelized Cost (20-year Cumulative Achievable Potential)



Supply Curve by TRC Ratio (20-year Cumulative Achievable Potential)



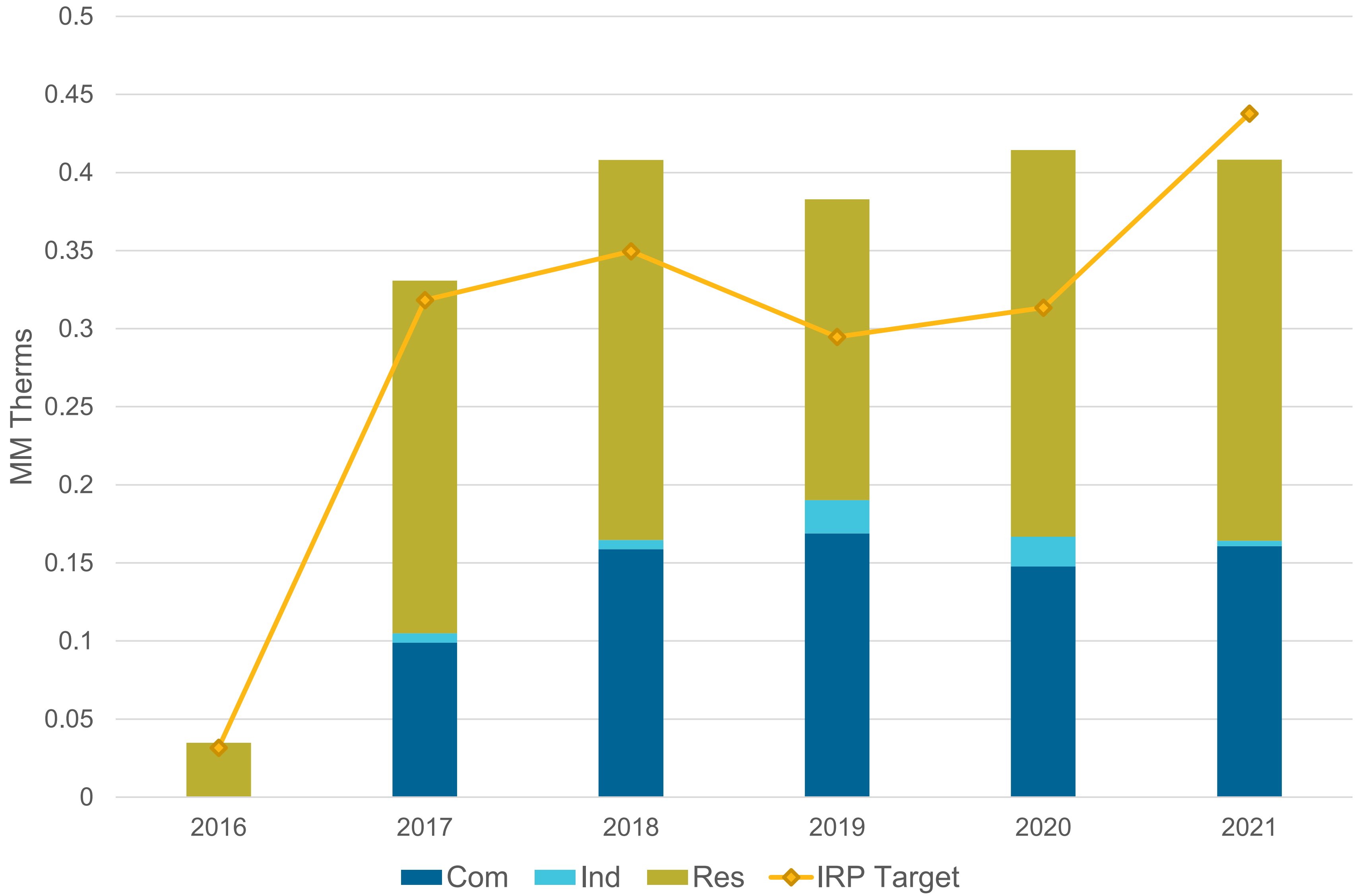
IRP Forecasts Compared to Actual Savings (Annual MM Therms)



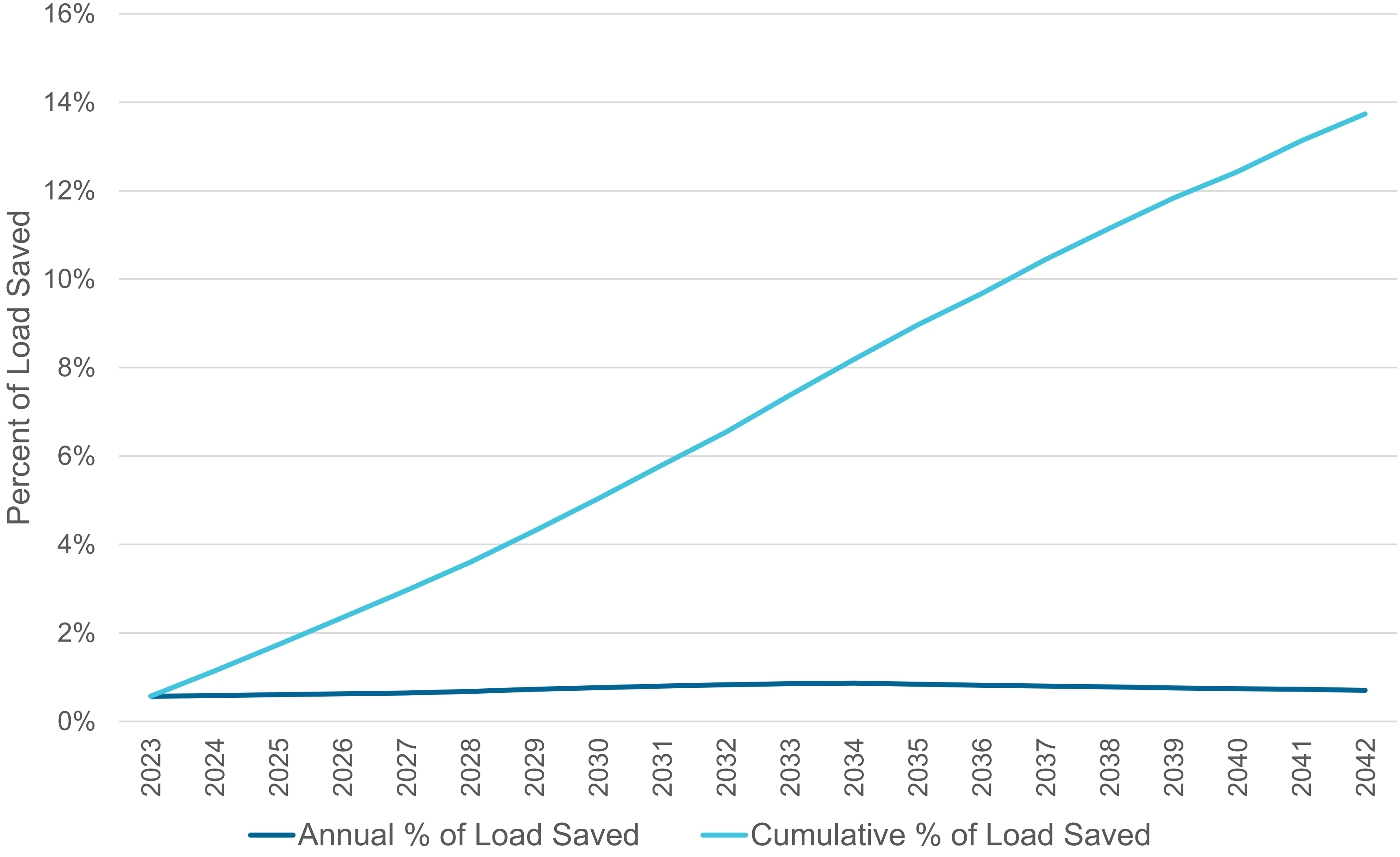
2020 and 2023 Cumulative Cost-Effective Achievable Potential Compared (MM therms)

	Difference	Share of Difference
Load and Stock Forecast	+ 1.29	36%
Emerging Technology	+ 0.84	23%
Measure Updates	+ 0.68	19%
Avoided Costs	+ 0.48	13%
Discount Rate	+ 0.34	9%
CE Override	- 0.01	0%
Total	**+ 3.63**	

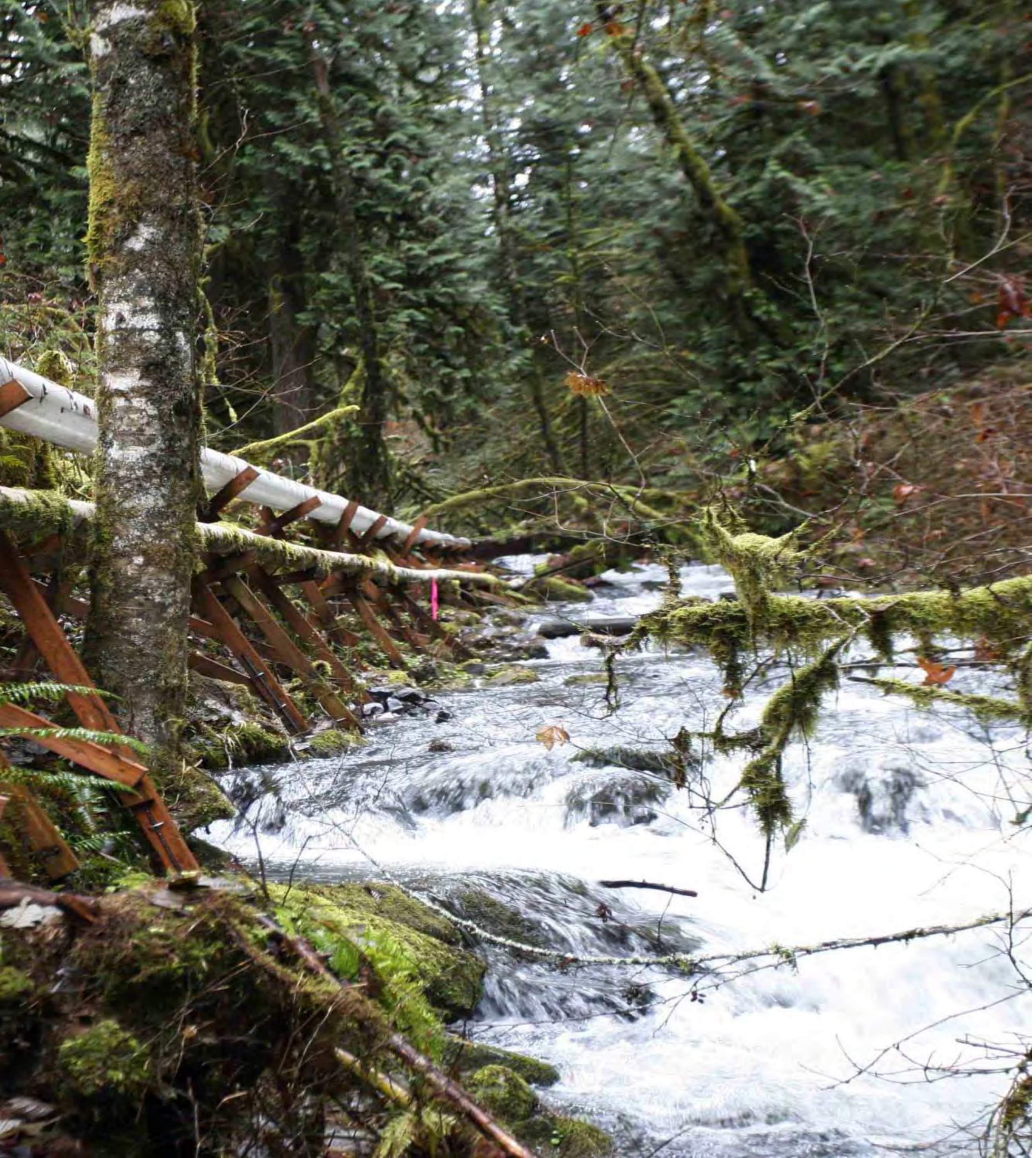
Historical Performance compared to IRP targets (Annual MM Therms)



Savings as a Percent of Load Forecast



Average Annual % of Load Saved = 0.73%



Thank you

Kyle Morrill
Sr. Project Manager, Planning

Kyle.Morrill@energytrust.org

Natural Gas Market Dynamics and Prices

Michael Brutocao

Tom Pardee

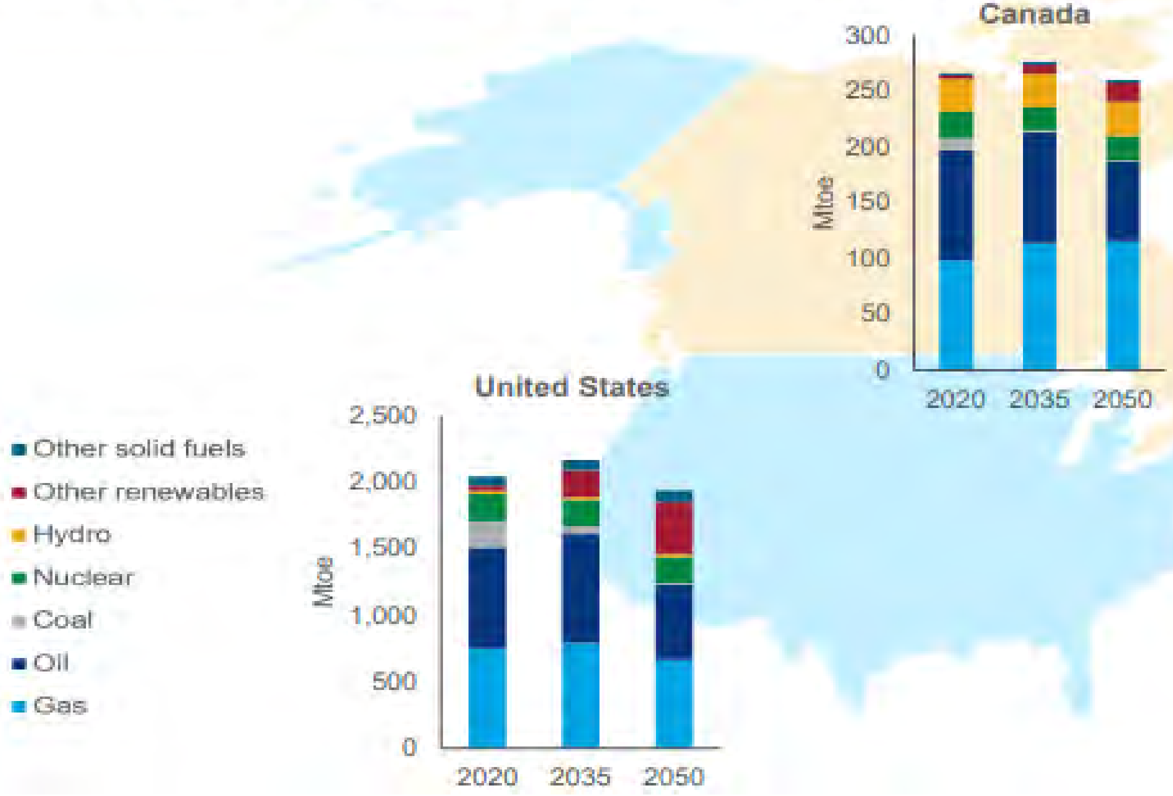
Wood Mackenzie – Legal Disclaimer

The foregoing [chart/graph/table/information] was obtained from the North America Gas Service™, a product of Wood Mackenzie.” Any Information disclosed pursuant to this agreement shall further include the following disclaimer: "The data and information provided by Wood Mackenzie should not be interpreted as advice and you should not rely on it for any purpose. You may not copy or use this data and information except as expressly permitted by Wood Mackenzie in writing. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for your use of this data and information except as specified in a written agreement you have entered into with Wood Mackenzie for the provision of such of such data and information."

Natural gas remains strategically important in North America as it represents at least a third of total energy demand over the next 30 years

The pace of energy transition threatens gas demand growth as fossil fuel demand wanes in the long term

Primary energy demand mix in North America



Canada

- Domestic gas demand is expected to grow mainly due to rising blue hydrogen demand as local and federal governments support the development of CCS industry.
- The oil sands sector could drive incremental industrial demand growth but the future role of oil in the energy mix limits market potential beyond 2035.
- Rising renewable penetration will impact gas demand in the power sector post 2040 but the impact of displacement is less severe than the US due to renewable resource potential.

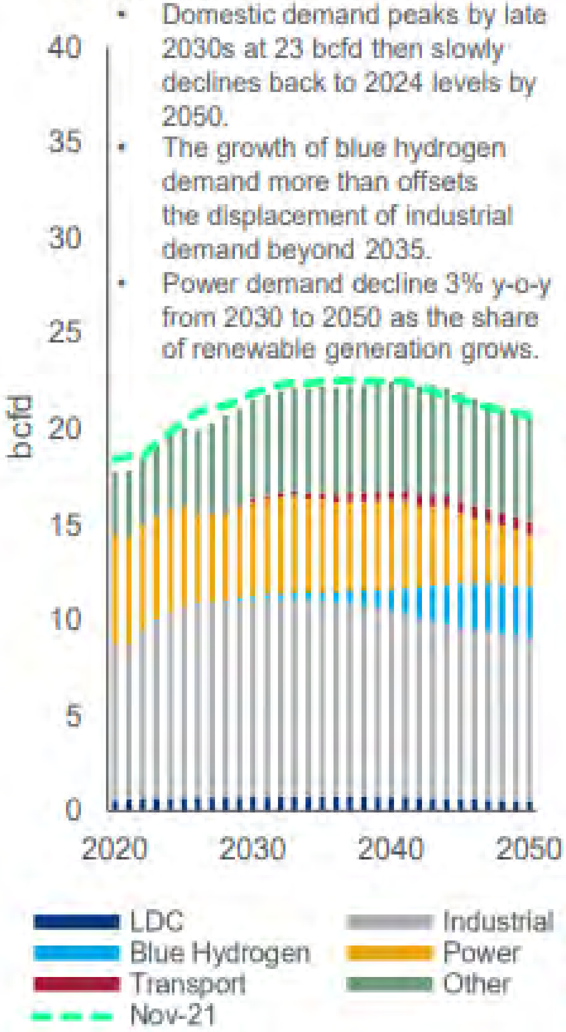
United States

- Gas continues to play a vital role in the United States even as the economy announces emissions reduction targets for 2030
- Industrial demand and other demand lead growth in the mid-term to 2035 while blue hydrogen demand reaches 1 bcfd by 2030 and accelerates to the end of our outlook
- Post 2024, power demand falls due to higher renewable penetration, resulting from policies that support low-carbon generation

US regional demand: the Gulf Coast stands out as domestic demand increases despite peaking in late 2030s

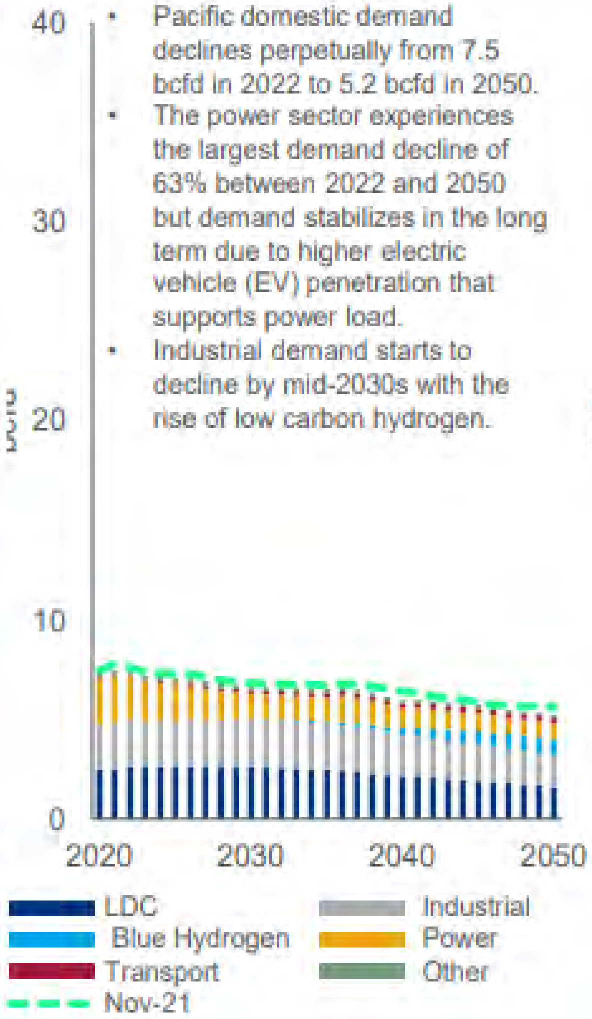
Gulf Coast

- Domestic demand peaks by late 2030s at 23 bcfd then slowly declines back to 2024 levels by 2050.
- The growth of blue hydrogen demand more than offsets the displacement of industrial demand beyond 2035.
- Power demand decline 3% y-o-y from 2030 to 2050 as the share of renewable generation grows.



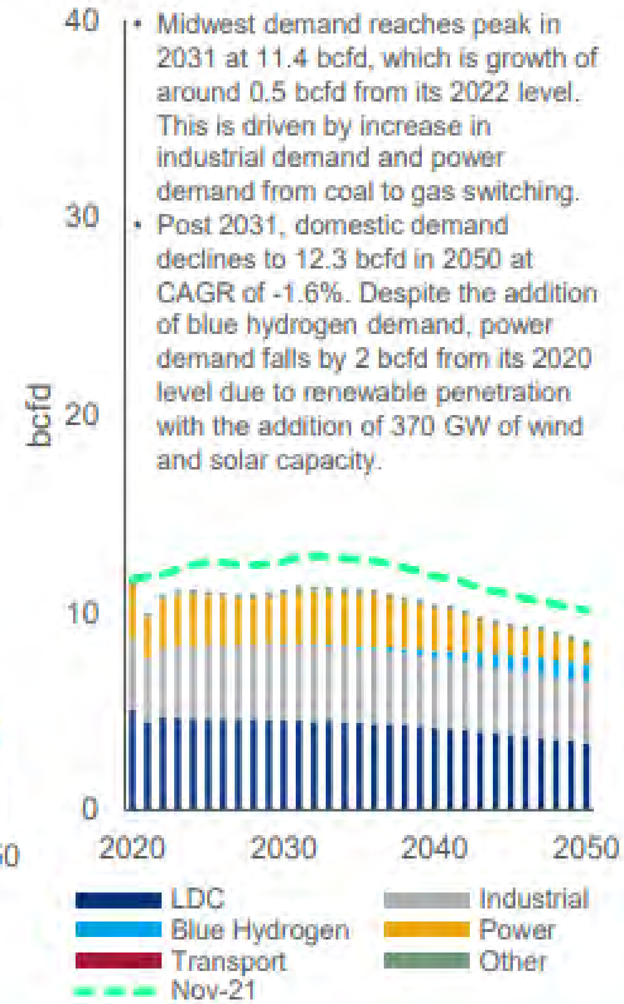
Pacific

- Pacific domestic demand declines perpetually from 7.5 bcfd in 2022 to 5.2 bcfd in 2050.
- The power sector experiences the largest demand decline of 63% between 2022 and 2050 but demand stabilizes in the long term due to higher electric vehicle (EV) penetration that supports power load.
- Industrial demand starts to decline by mid-2030s with the rise of low carbon hydrogen.



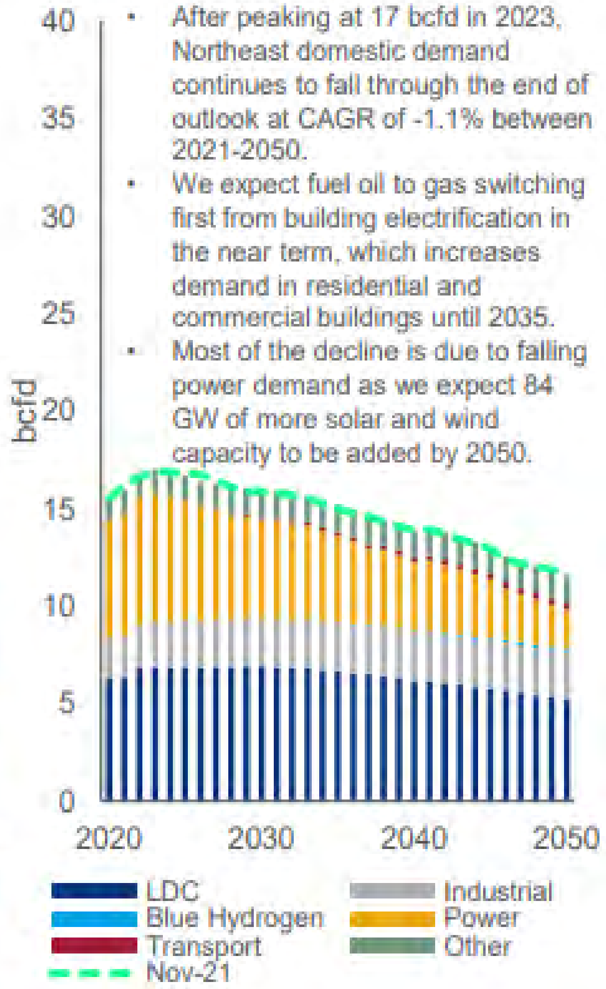
Midwest

- Midwest demand reaches peak in 2031 at 11.4 bcfd, which is growth of around 0.5 bcfd from its 2022 level. This is driven by increase in industrial demand and power demand from coal to gas switching.
- Post 2031, domestic demand declines to 12.3 bcfd in 2050 at CAGR of -1.6%. Despite the addition of blue hydrogen demand, power demand falls by 2 bcfd from its 2020 level due to renewable penetration with the addition of 370 GW of wind and solar capacity.



Northeast

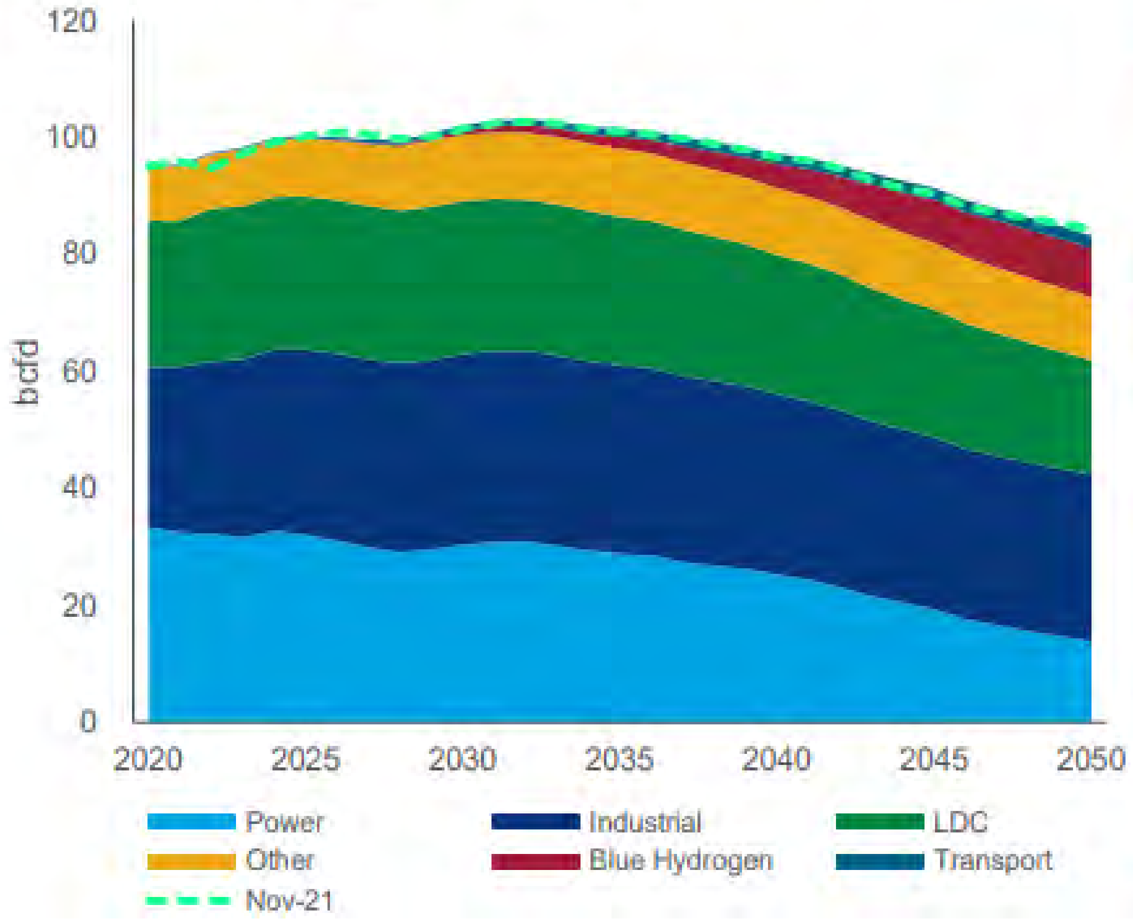
- After peaking at 17 bcfd in 2023, Northeast domestic demand continues to fall through the end of outlook at CAGR of -1.1% between 2021-2050.
- We expect fuel oil to gas switching first from building electrification in the near term, which increases demand in residential and commercial buildings until 2035.
- Most of the decline is due to falling power demand as we expect 84 GW of more solar and wind capacity to be added by 2050.



North American domestic demand reaches its peak in the early 2030s; longer term growth only from blue hydrogen and transport sectors

Energy transition impacts power demand the most with demand falling by almost two thirds between 2022 and 2050

North America gas demand by sector



Transport: Transportation demand includes gas consumed in natural gas vehicles (NGV) and small-scale bunkers. Most of the growth is attributed to NGV demand, driven by heavy long-haul trucks and freight rails

Blue hydrogen: Low-cost natural gas supply in both US and Canada support blue hydrogen projects where demand grows to 8.5 bcfd by 2050. We expect clean energy policies, such as Canada's federal carbon price and US 45Q incentive, to drive its growth.

Other: Other demand includes lease & plant fuel and pipeline losses, which is the gas used within the industry. The two biggest components to its growth are supply and LNG export losses

LDC: Residential and commercial demand reach a peak in 2029 and declines as hydrogen and building electrification accelerate to displace gas in the long-term. Heating electrification in the US will reach 68% penetration by 2050.

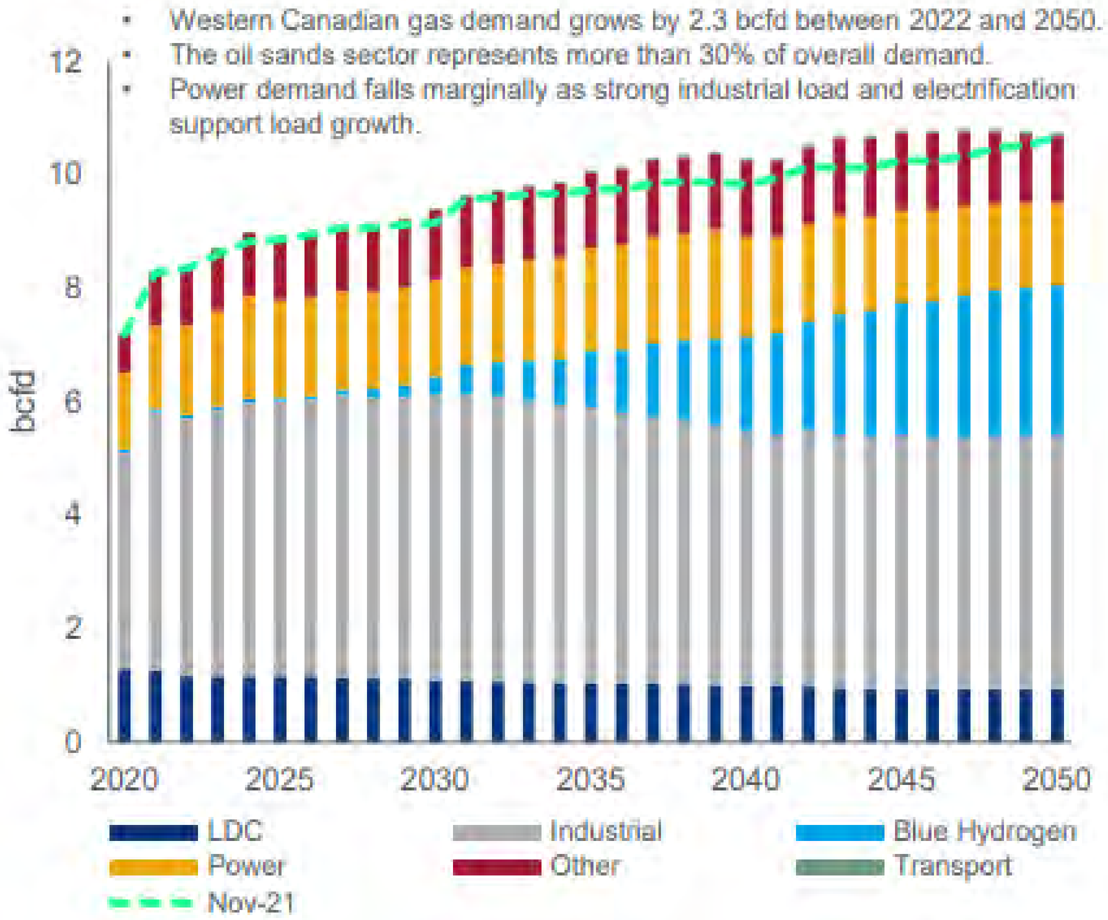
Industrial: Post 2031, industrial demand deviates from GDP growth and continues to decline as we expect net zero targets and clean energy policies to drive low-carbon hydrogen to replace grey hydrogen from Steam Methane Reformers (SMRs) in the ammonia, refining, and methanol sectors.

Power: In the near term out to 2024, power demand grows due to coal-to-gas switching and retirements. Post-2024, gas demand in the power sector starts to structurally decline with the accelerated renewable build-out spurred by policy incentives.

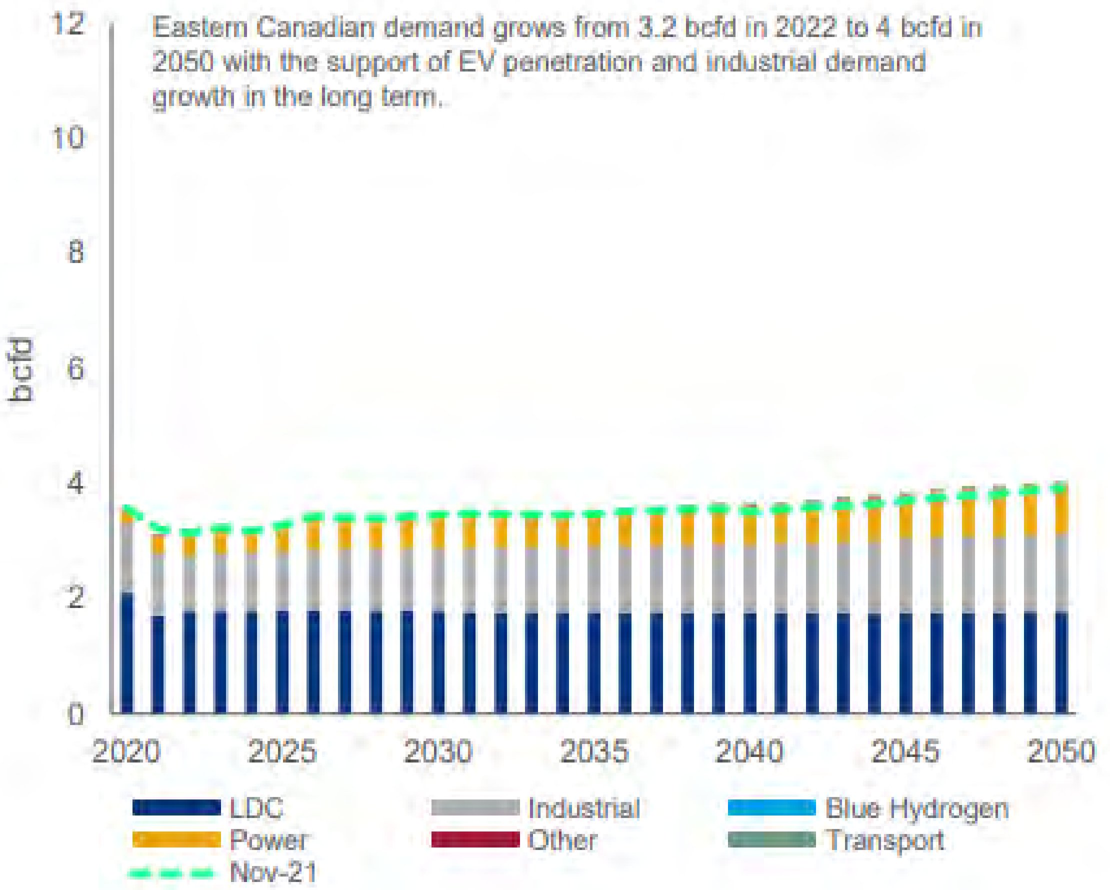
Canadian gas demand in major provinces grows over time

Blue hydrogen drives demand growth in the long term as local and Federal policies support CCS and blue hydrogen industries for resource monetization

Western Canada demand



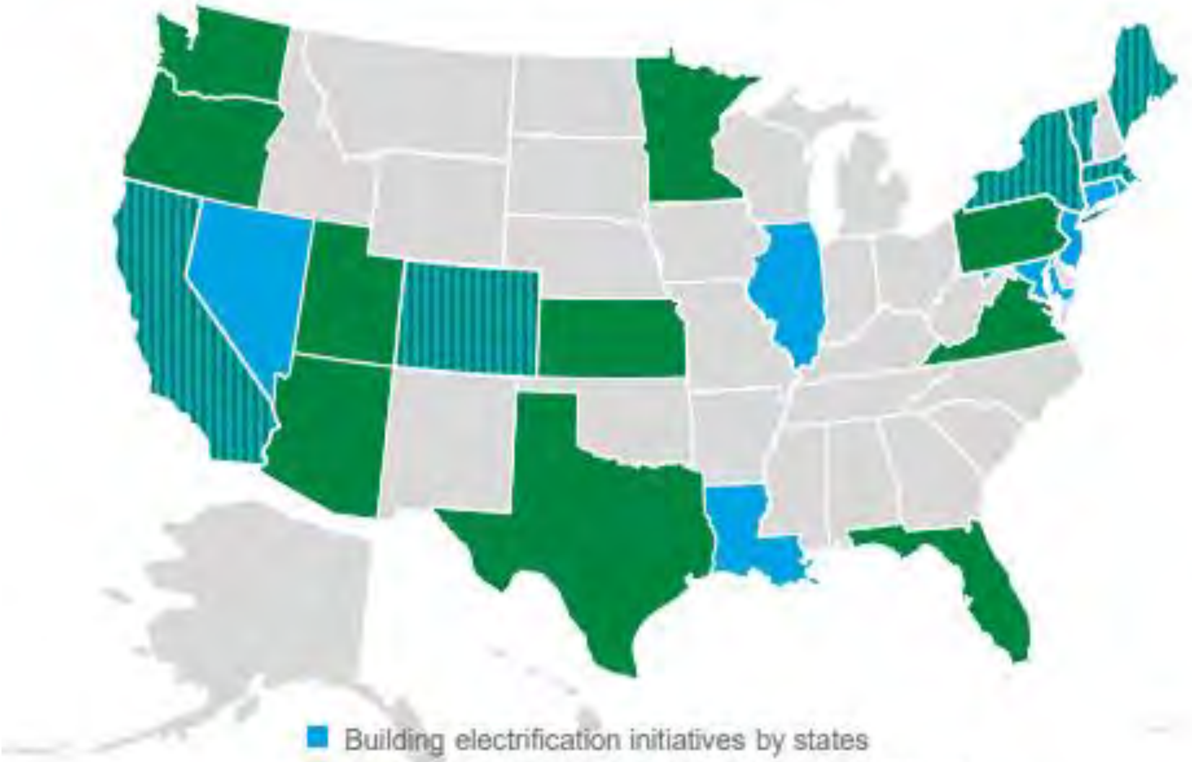
Eastern Canada demand



Heating electrification in the US will reach 68% penetration by 2050 for all residential and commercial heating

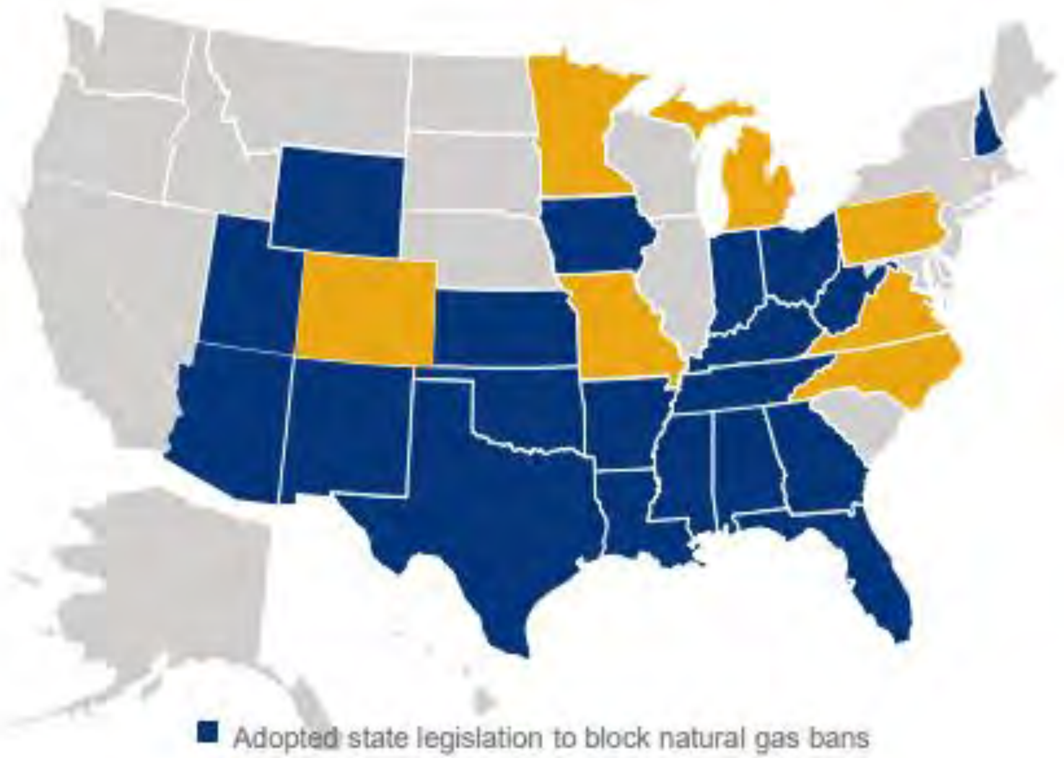
Pacific, New England, and the Middle Atlantic regions have strong local action and share pro-electrification policies while electrification will progress more slowly in the southern states

Local and state policies enabling building electrification initiatives



- Building electrification initiatives by states
- Building electrification initiatives by municipalities

States' positions on banning gas hookups in new building

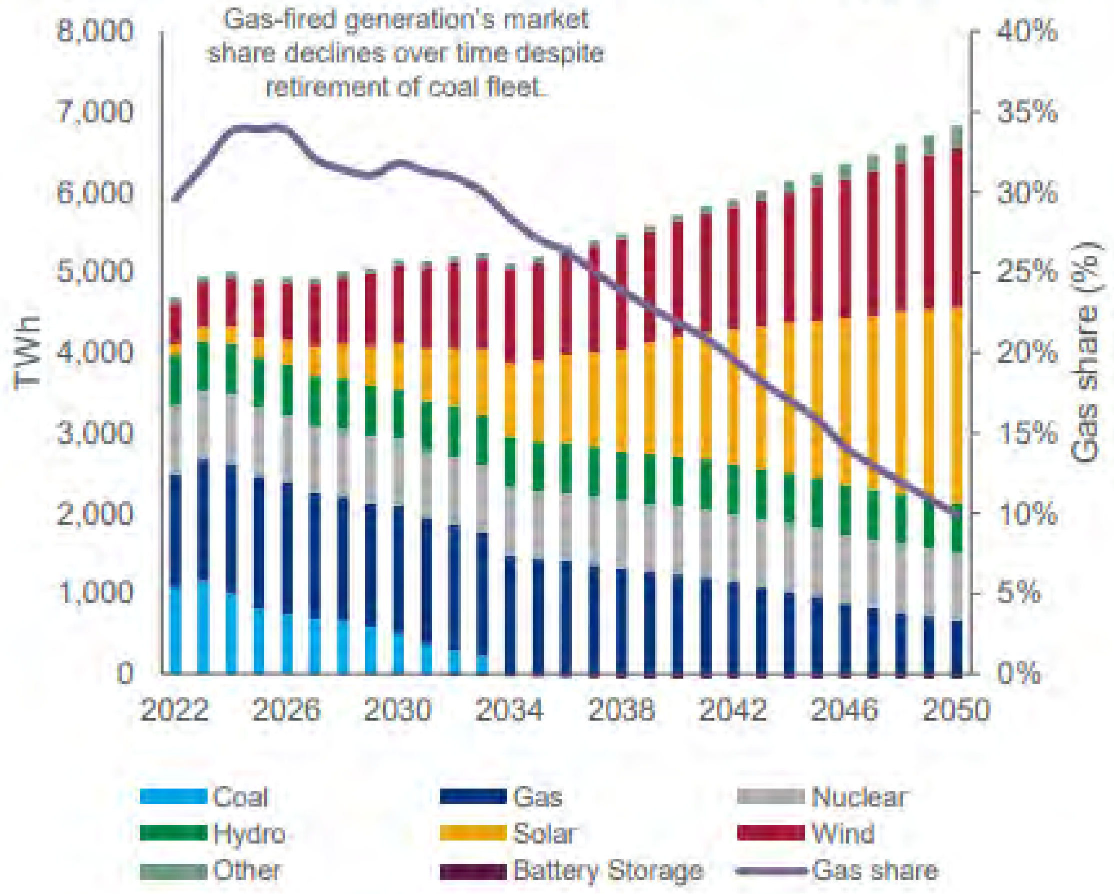


- Adopted state legislation to block natural gas bans
- Introduced legislation to block natural gas bans

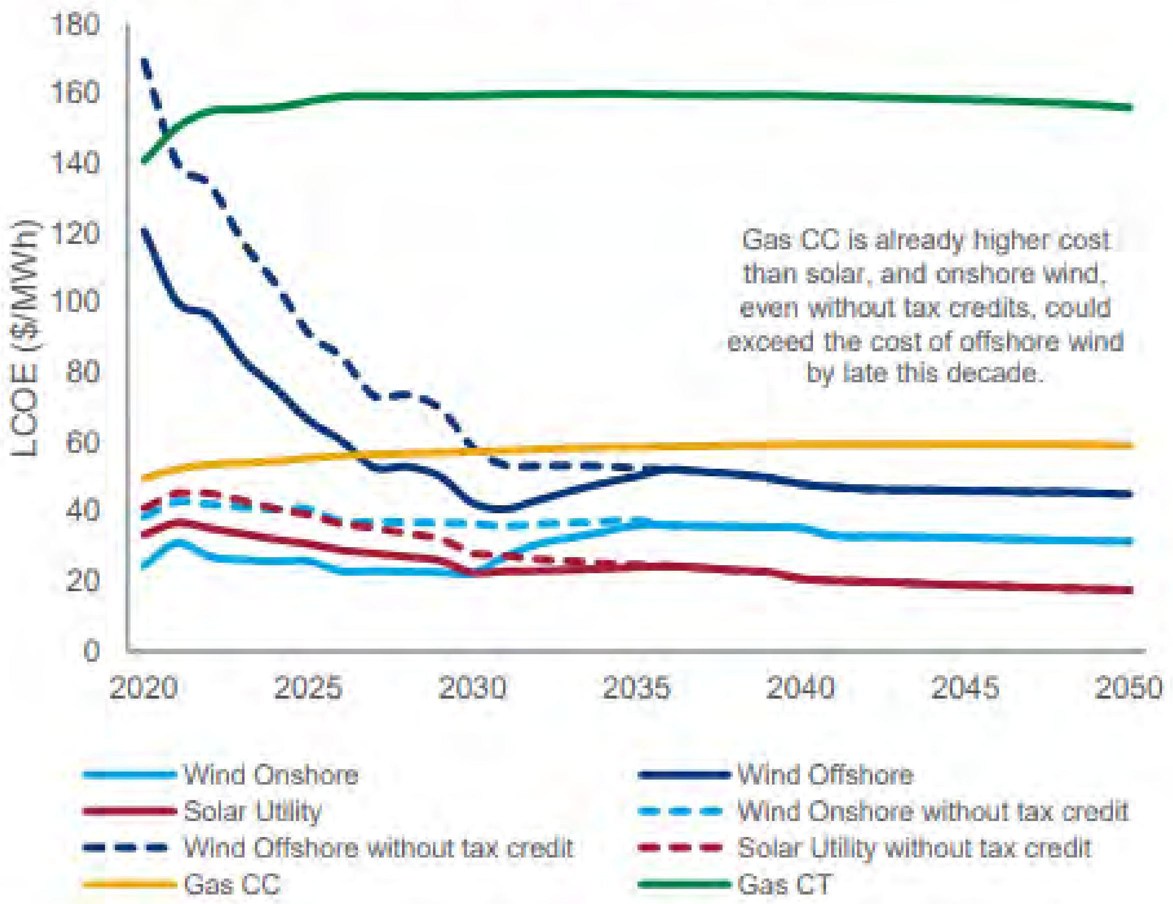
Accelerated coal retirements allows for more coal-to-gas switching in the 2020s but gas burns decline over time with higher renewable penetration

Power load has been revised higher mostly in the late 2040s due to higher EV conversion, heating electrification and stronger industrial requirements

North America power generation by type



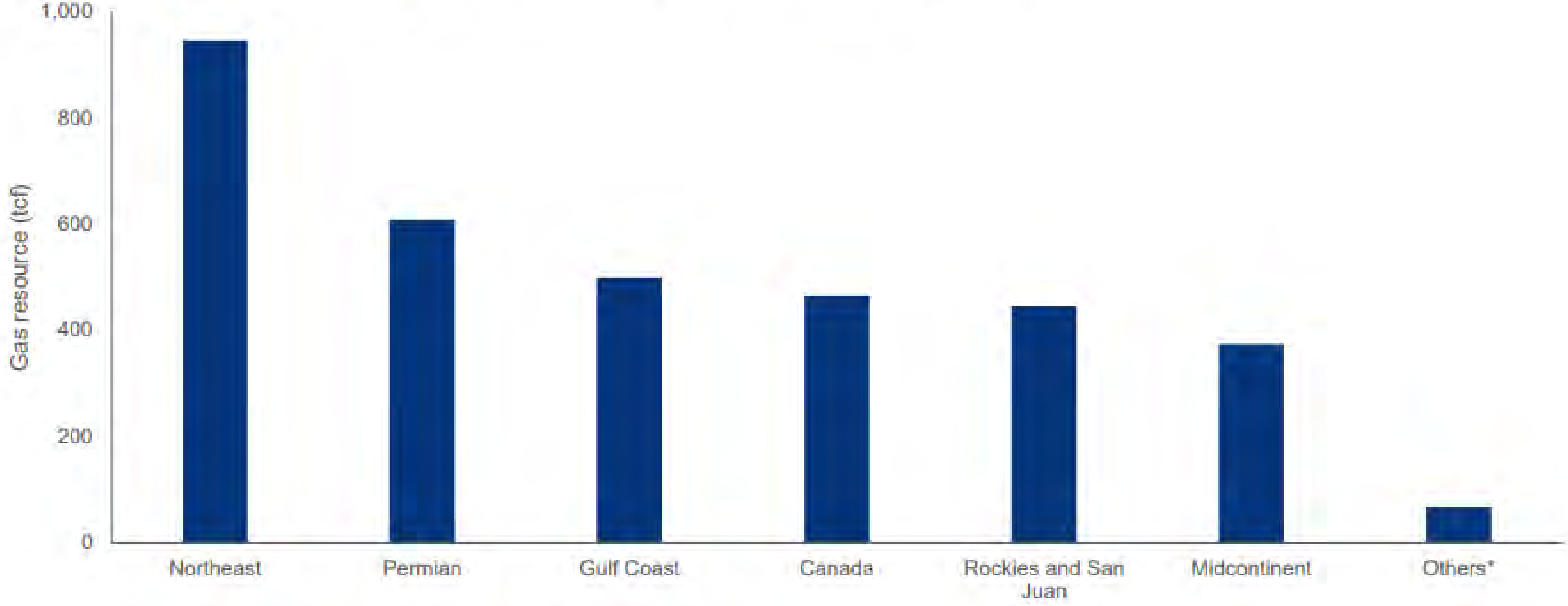
Levelized cost of energy (LCOE)



North America has large quantities of gas resources available

In addition to commodity prices, factors such as well economics, infrastructure development, and investor sentiment will dictate how much resource is ultimately produced

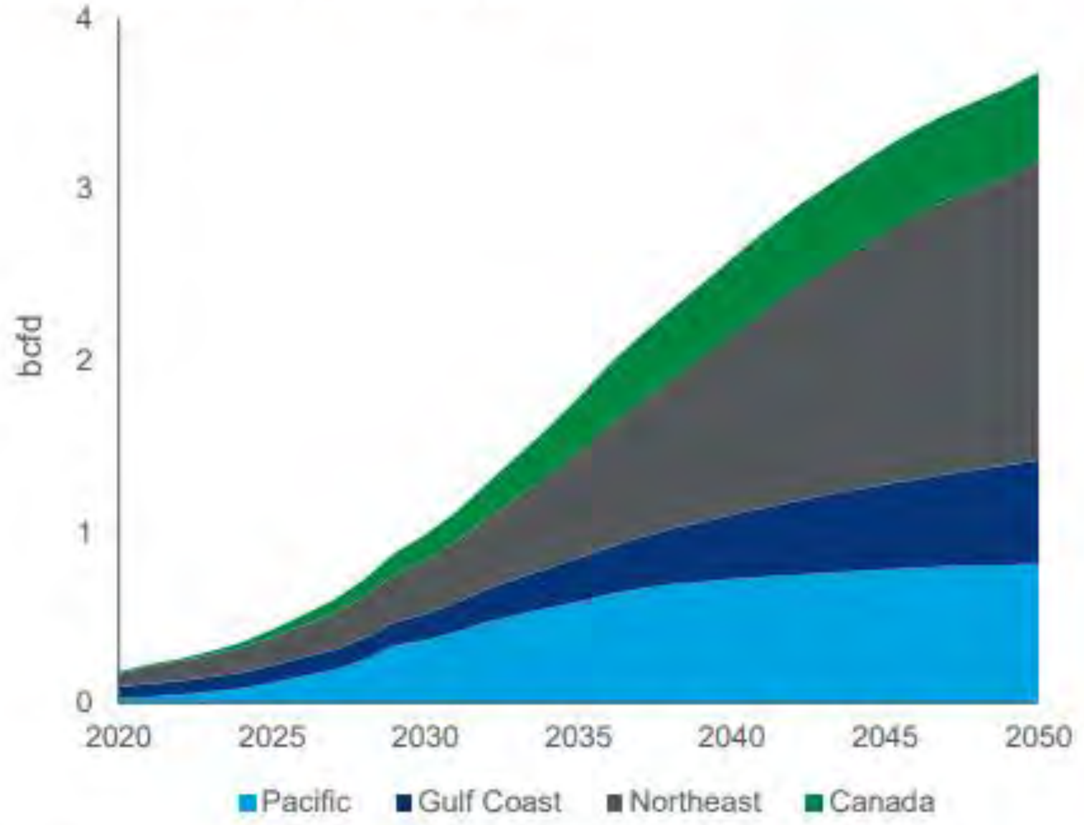
Remaining gas resources for key onshore North America regions



RNG production capacity has increased 25% since 2020, with more projects to come online in longer-term

Growth can further expand as low-carbon policies, which are currently focused on RNG consumption primarily for transportation, include additional sectors for environmental credits

RNG production outlook



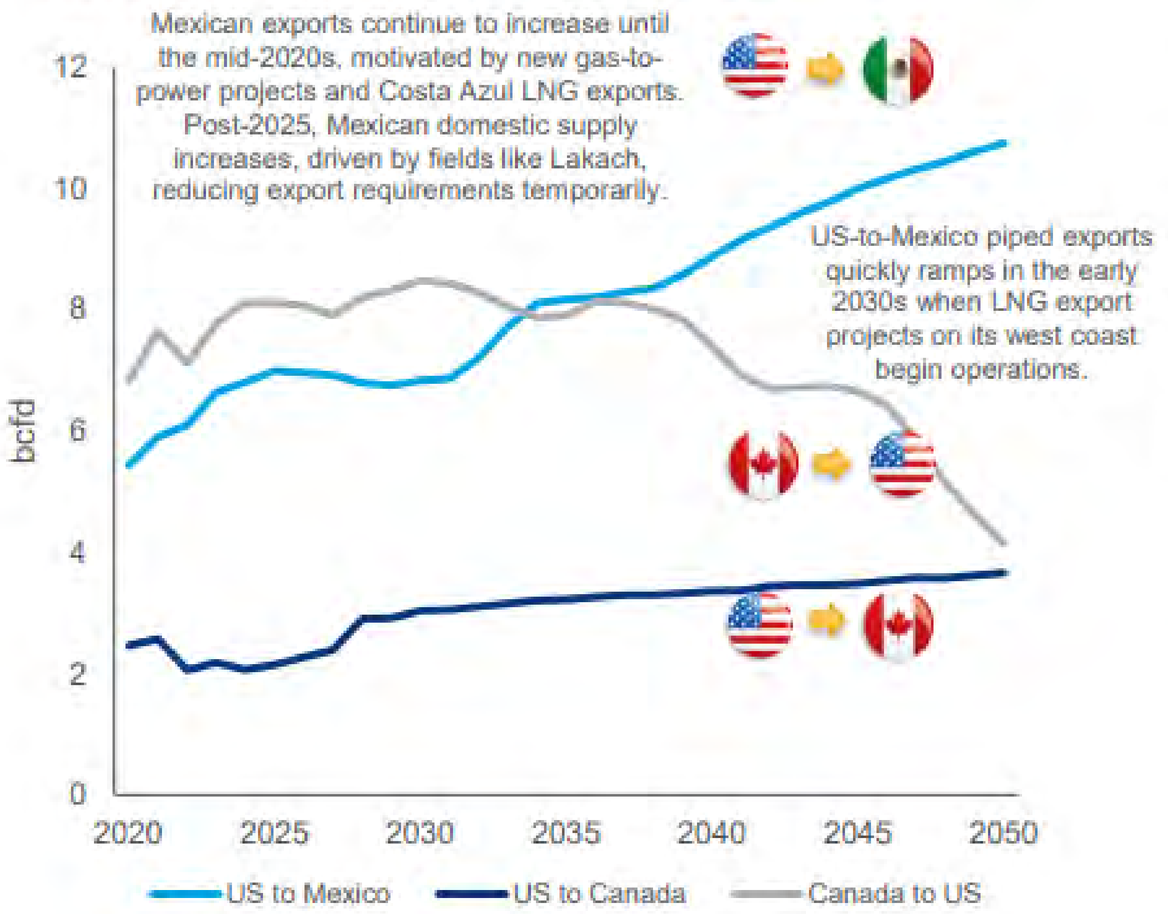
Canada	British Columbia, Quebec and Ontario lead RNG production as local utilities and governments aggressively commit to net carbon-zero targets and stakeholders capitalize on credits from the Clean Fuel Standard.
US Northeast*	More RNG facilities come online as utilities and agencies seek to fulfill GHG emission reduction goals, which are one of the most aggressive in the nation. The Midwest continues to export RNG to the west coast as well as fulfilling local demand.
US Gulf Coast*	Large-scale RNG in landfill sites dominates the supply mix for the region in the near-term. The large dairy potential in the area will attract developments with appropriate regulatory support.
US Pacific	Pioneering the nation with its progressive low-carbon policies, the west leads in new dairy project developments until late 2020s. RNG demand is primarily fed into fueling NGVs in the near term, but we expect more utility programs to adopt renewable gas standards.

*Note: Northeast includes the Midwest, including Indiana and Ohio. The Gulf Coast includes the Southeast.
Source: Wood Mackenzie, Argonne National Laboratory RNG Database, IEA Outlook for biogas and biomethane (2020)

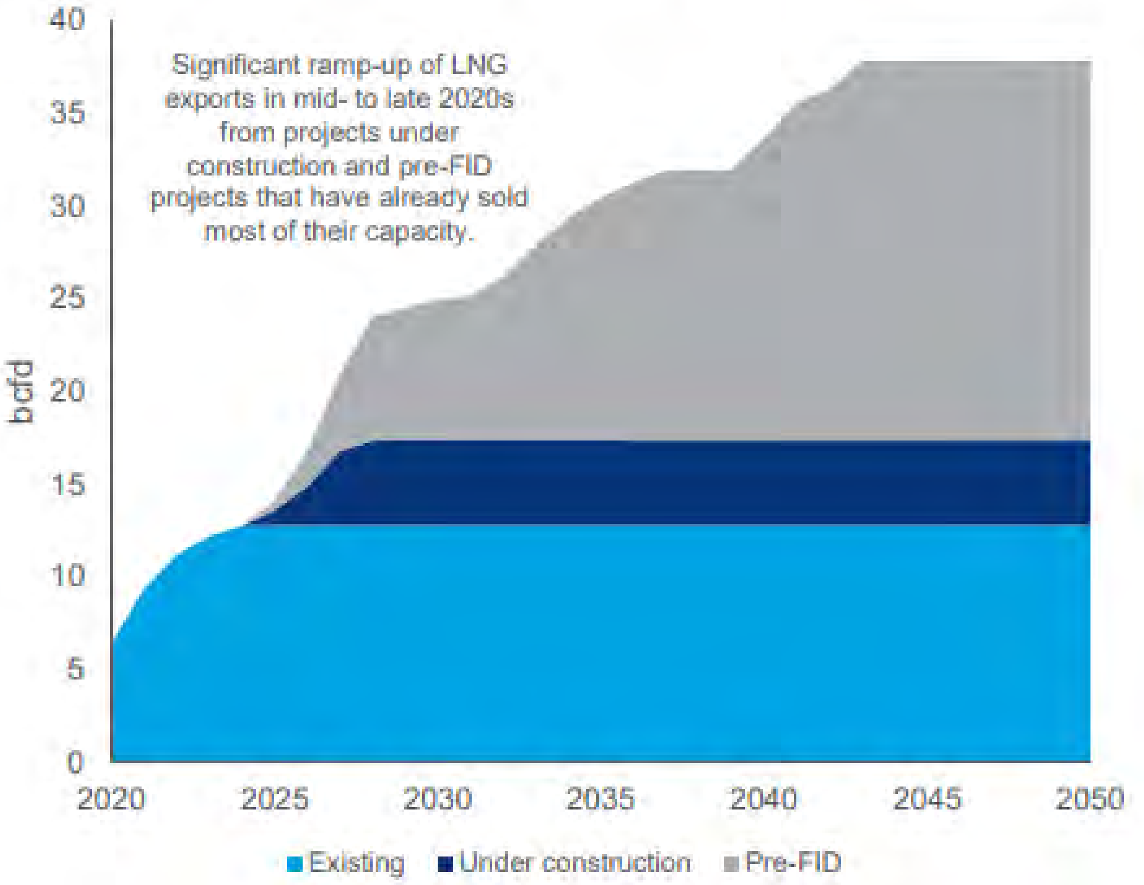
LNG exports from US, Canada and Mexico reach 38 bcfd by 2050

WCSB's low-cost resources help Canadian exports maintain market share in the Midwest and Pacific markets

North American piped trade flows



North America LNG export outlook

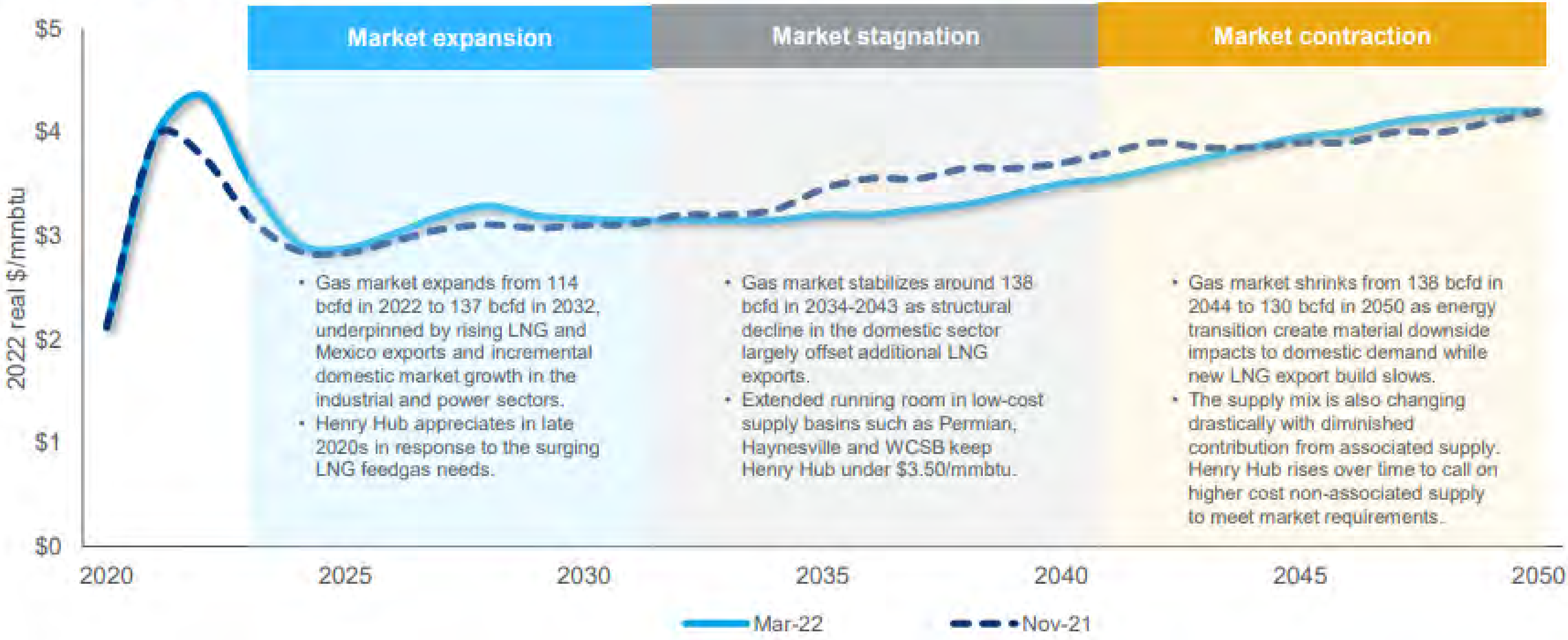


AVISTA

Henry Hub ramps upward with the next wave of LNG projects but expanded low-cost resources hold prices steady in the medium term

The call on non-associated supply in the 2040s raises supply costs and elevates Henry Hub to above $4/mmbtu

Henry Hub price outlook



- Gas market expands from 114 bcfd in 2022 to 137 bcfd in 2032, underpinned by rising LNG and Mexico exports and incremental domestic market growth in the industrial and power sectors.
- Henry Hub appreciates in late 2020s in response to the surging LNG feedgas needs.

- Gas market stabilizes around 138 bcfd in 2034-2043 as structural decline in the domestic sector largely offset additional LNG exports.
- Extended running room in low-cost supply basins such as Permian, Haynesville and WCSB keep Henry Hub under $3.50/mmbtu.

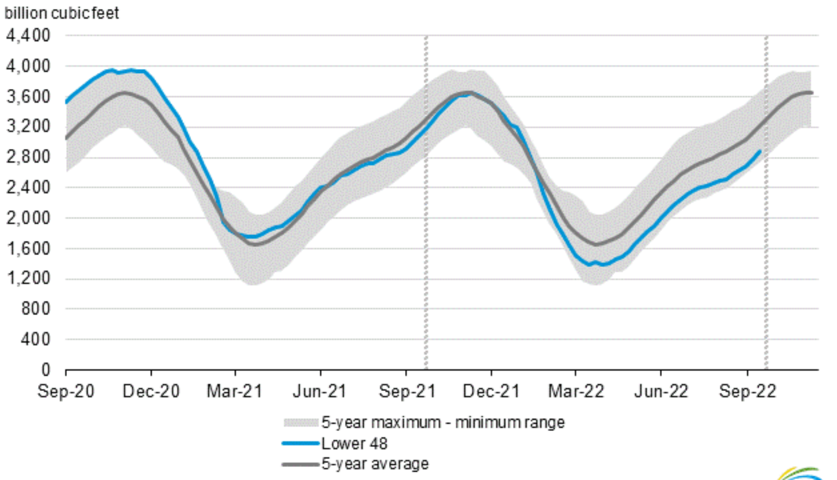
- Gas market shrinks from 138 bcfd in 2044 to 130 bcfd in 2050 as energy transition create material downside impacts to domestic demand while new LNG export build slows.
- The supply mix is also changing drastically with diminished contribution from associated supply. Henry Hub rises over time to call on higher cost non-associated supply to meet market requirements.

AVISTA

US Storage

	Stocks billion cubic feet (Bcf)				Historical Comparisons: Year ago (09/16/21)		Historical Comparisons: 5-year average (2017-21)	
Region	09/16/22	09/09/22	net change	implied flow	Bcf	% change	Bcf	% change
East	690	661	29	29	748	-7.8	784	-12.0
Midwest	844	809	35	35	900	-6.2	907	-6.9
Mountain	168	163	5	5	196	-14.3	199	-15.6
Pacific	237	235	2	2	240	-1.3	278	-14.7
South Central	935	904	31	31	986	-5.2	1,038	-9.9
Salt	199	187	12	12	226	-11.9	253	-21.3
Nonsalt	736	717	19	19	760	-3.2	786	-6.4
Total	2,874	2,771	103	103	3,071	-6.4	3,206	-10.4

Working gas in underground storage compared with the 5-year maximum and minimum



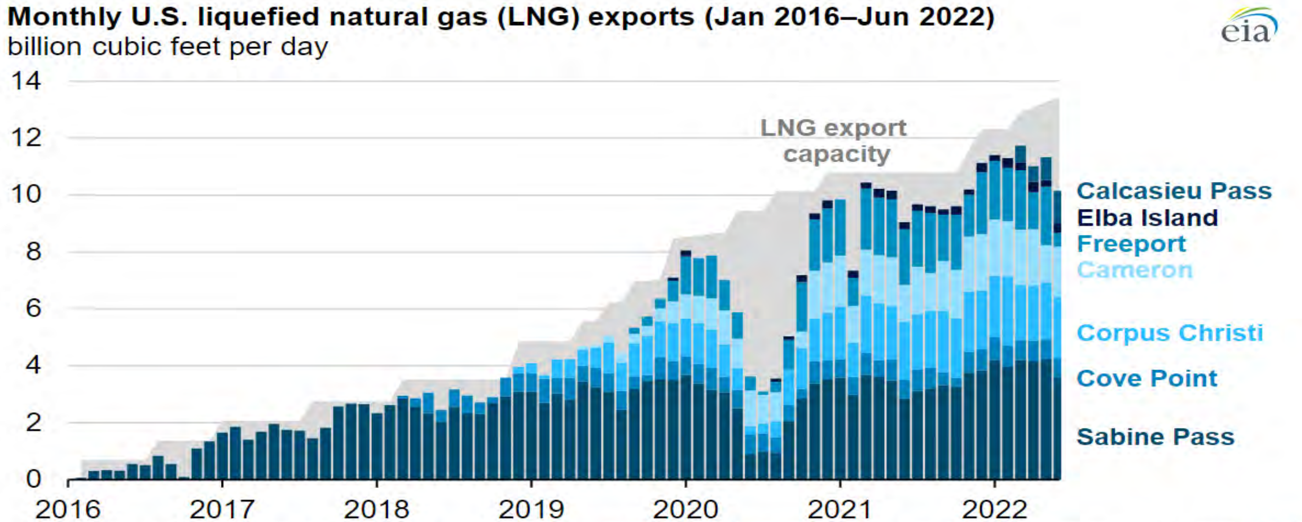
Source: U.S. Energy Information Administration

Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2017 through 2021. The dashed vertical lines indicate current and year-ago weekly periods.

LNG Exports

The United States became the world's largest LNG exporter in the first half of 2022

Monthly U.S. liquefied natural gas (LNG) exports (Jan 2016–Jun 2022)
billion cubic feet per day



Data source: U.S. Energy Information Administration, *Liquefaction Capacity Table*, and U.S. Department of Energy *LNG reports*
Note: June 2022 LNG exports are EIA estimates based on tanker shipping data. LNG export capacity is an estimated peak LNG production capacity of all operational U.S. LNG export facilities.

US exports more LNG to Europe, less to Asia, Brazil, Mexico.

Exports of U.S. liquified natural gas, first half 2021 vs. first half 2022.

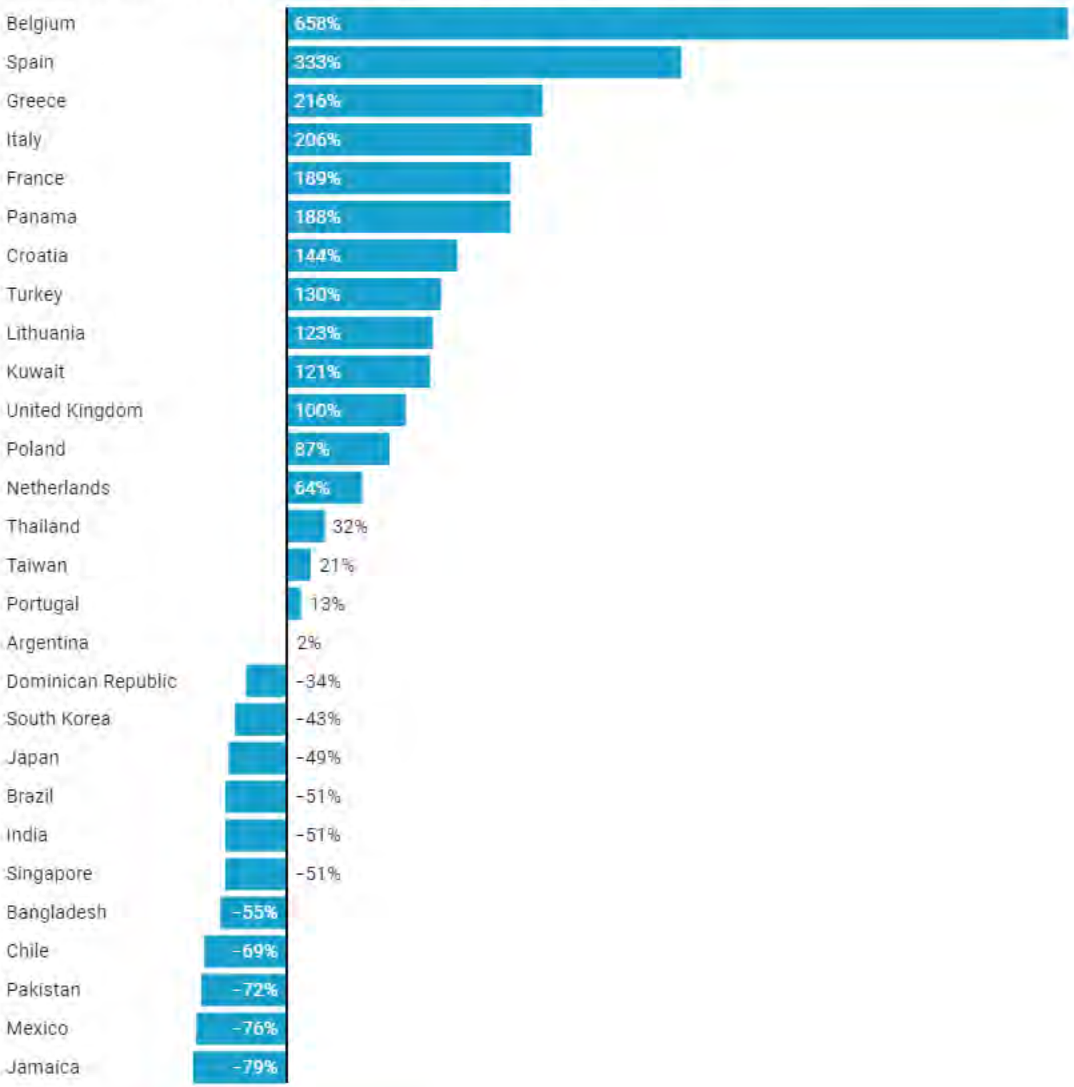
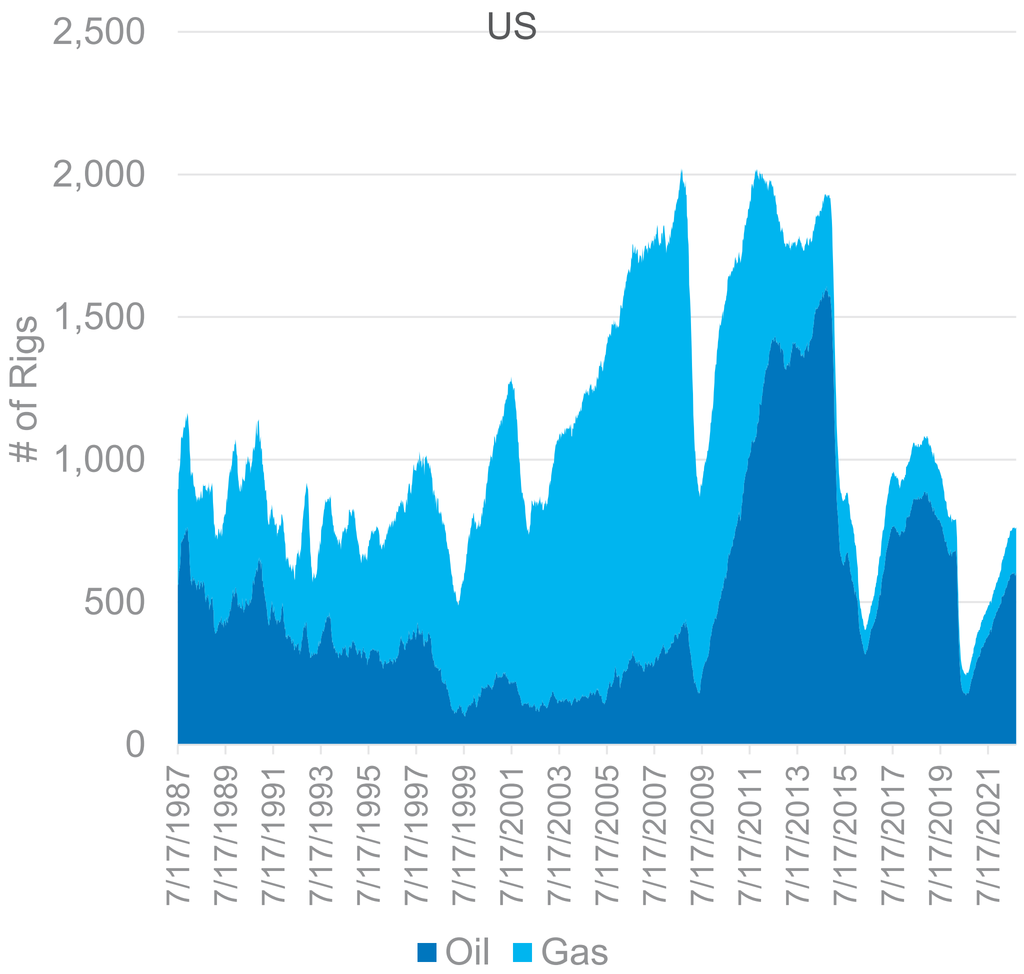
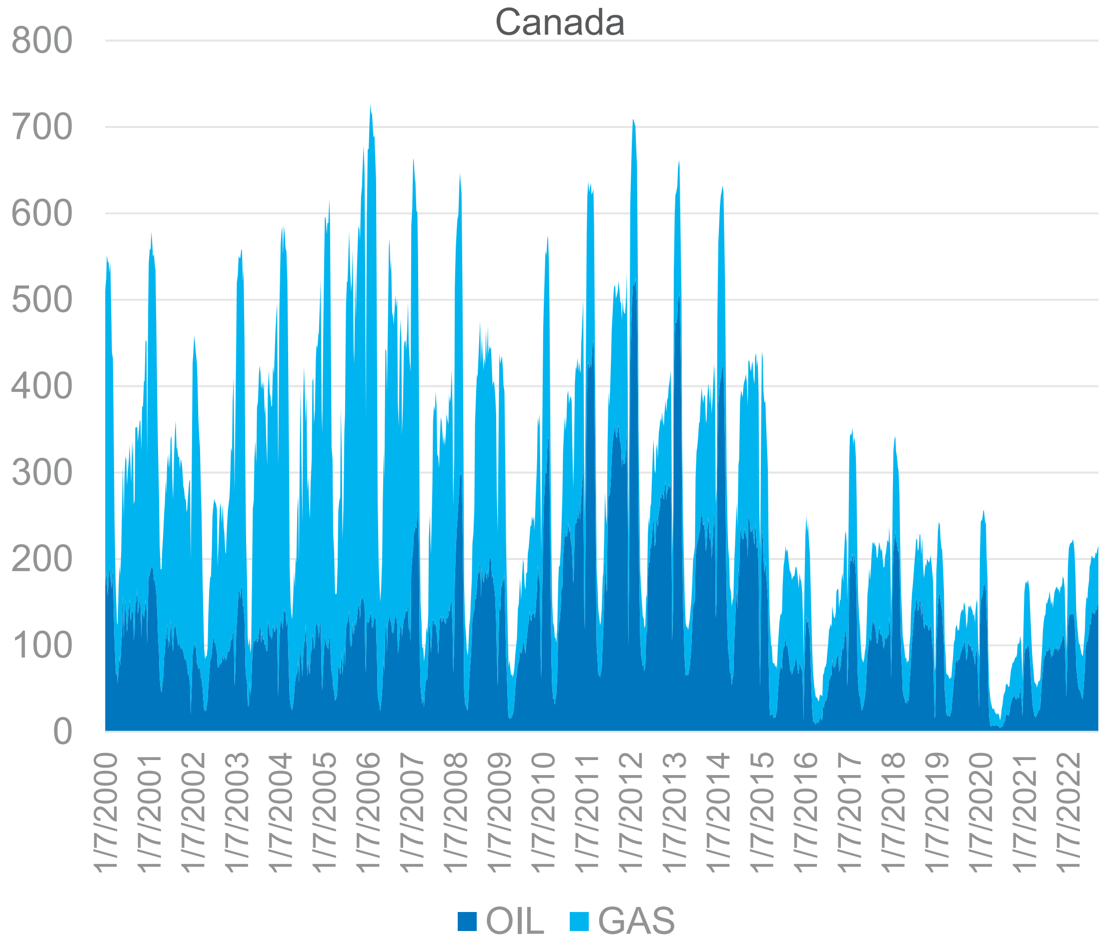


Chart: Reuters staff • Source: Refinitiv • Get the data

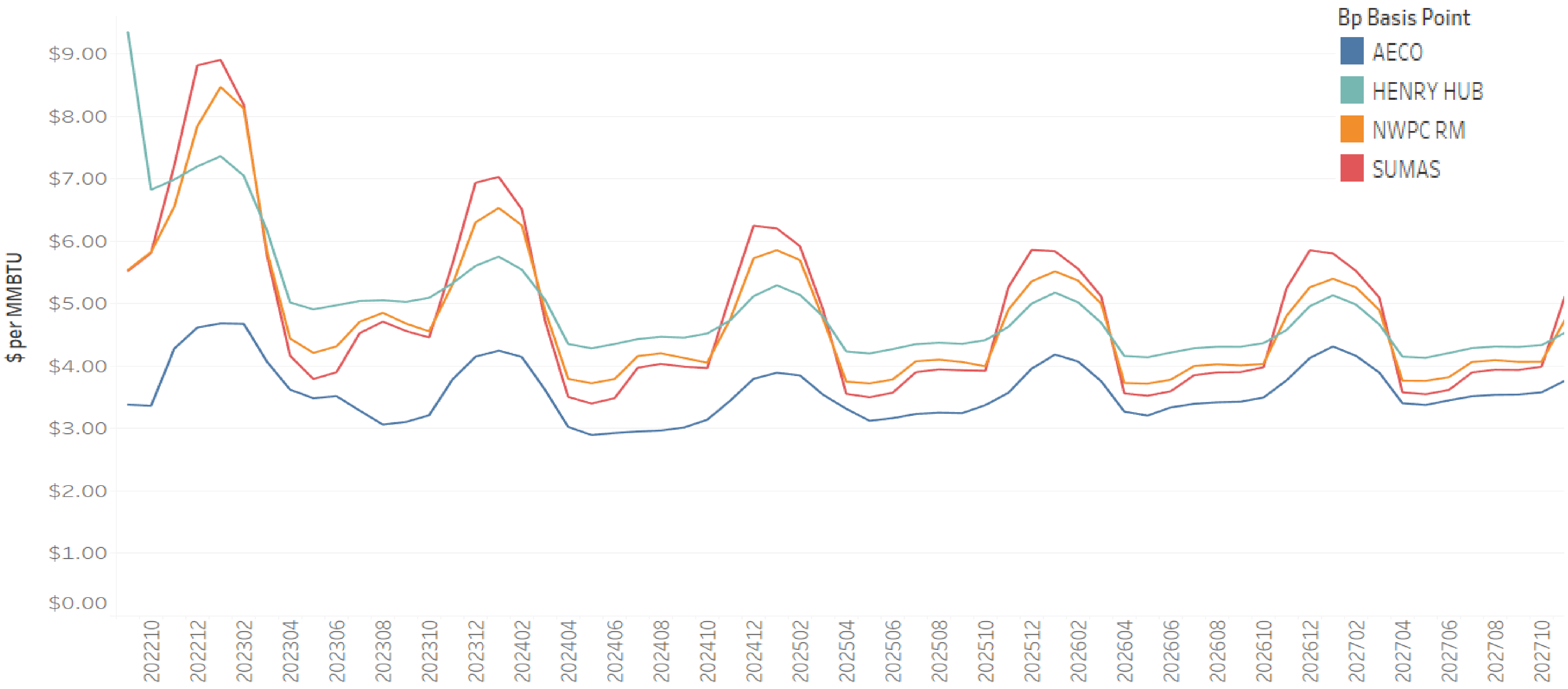
North American Rig Count





Source: Baker Hughes

Forward Prices (9/23/2022)



AVISTA

Daily Prices

Average Prices 9/2012 – 9/2022

	January	February	March	April	May	June	July	August	Septemb..	October	November	December
AECO	$2.37	$2.71	$2.46	$2.39	$2.51	$2.43	$2.27	$1.96	$2.01	$2.32	$2.53	$2.38
HENRY HUB	$3.22	$3.37	$3.06	$3.24	$3.44	$3.43	$3.39	$3.58	$3.53	$3.21	$3.30	$3.16
HUNT	$3.27	$4.87	$4.54	$2.88	$2.93	$2.90	$2.85	$3.24	$3.28	$3.59	$4.32	$3.87
MALIN	$3.25	$3.74	$2.93	$2.99	$3.14	$3.17	$3.22	$3.44	$3.40	$3.14	$3.42	$3.60
ROCKIES	$3.09	$3.55	$2.77	$2.52	$2.57	$2.77	$2.83	$2.76	$2.80	$2.90	$3.18	$3.30

Max Prices 9/2012 – 9/2022

	January	February	March	April	May	June	July	August	September	October	November	December
AECO	$4.52	$17.42	$7.64	$6.31	$6.85	$6.79	$5.38	$5.04	$4.71	$5.27	$4.77	$3.86
HENRY HUB	$6.88	$23.60	$7.94	$7.55	$9.29	$9.46	$9.32	$9.85	$9.24	$6.22	$5.70	$4.63
HUNT	$6.93	$49.08	$161.11	$7.60	$8.82	$8.55	$7.96	$9.00	$9.32	$14.12	$69.60	$10.78
MALIN	$6.92	$26.03	$8.13	$7.62	$9.07	$8.93	$8.93	$9.59	$9.66	$6.34	$6.21	$8.11
ROCKIES	$5.49	$29.50	$8.75	$4.63	$4.65	$4.64	$4.42	$3.90	$3.96	$3.94	$6.22	$7.12

PLEXOS Stochastics

4.3.1. Autocorrelation Model

In the autocorrelation model, the differential equation is:

$$e_t = a \times e_{t-1} + (1-a) \times r_t \times P_t \times S$$

where:

e_t is the error for time period t

a is the autocorrelation parameter (between 0 and 1)

r_t is a normal distributed random number

P_t is the expected value (profile value) in period t

S is the error standard deviation

The input parameters here are the Autocorrelation and the Error Std Dev (alternatively Abs Error Std Dev. Autocorrelation is expressed as percentage value (between 0 and 100). The higher the autocorrelation, the more the 'randomness' of the errors is dampened and smoothed out over time. The higher the standard deviation, the greater the volatility of the errors. Because the error function can produce any positive or negative value (at least in theory) it is often necessary to bound the profile sample values produced by this method. The Variable properties Min Value and Max Value are used for this purpose. The actual sample value used at any time is simply the sum of the profile value and the error (which may be positive or negative) bounded by the min and max values.

Table 2 shows some simple example input where the profile value is static but has an error function with standard deviation of 28%. In a real application the profile value would change across time *e.g.* read from a flat file. Figure 6 shows the resulting distribution of sample values from 1000 samples, which follows a normal distribution. Figures 7 and 8 shows the output sample 1 profiles with the autocorrelation parameter set to 0% and 75% respectively. Note that the overall distribution of the sample values is still normal as in Figure 6, but the individual sample volatility is damped.

PLEXOS Stochastics Continued

Without Autocorrelation

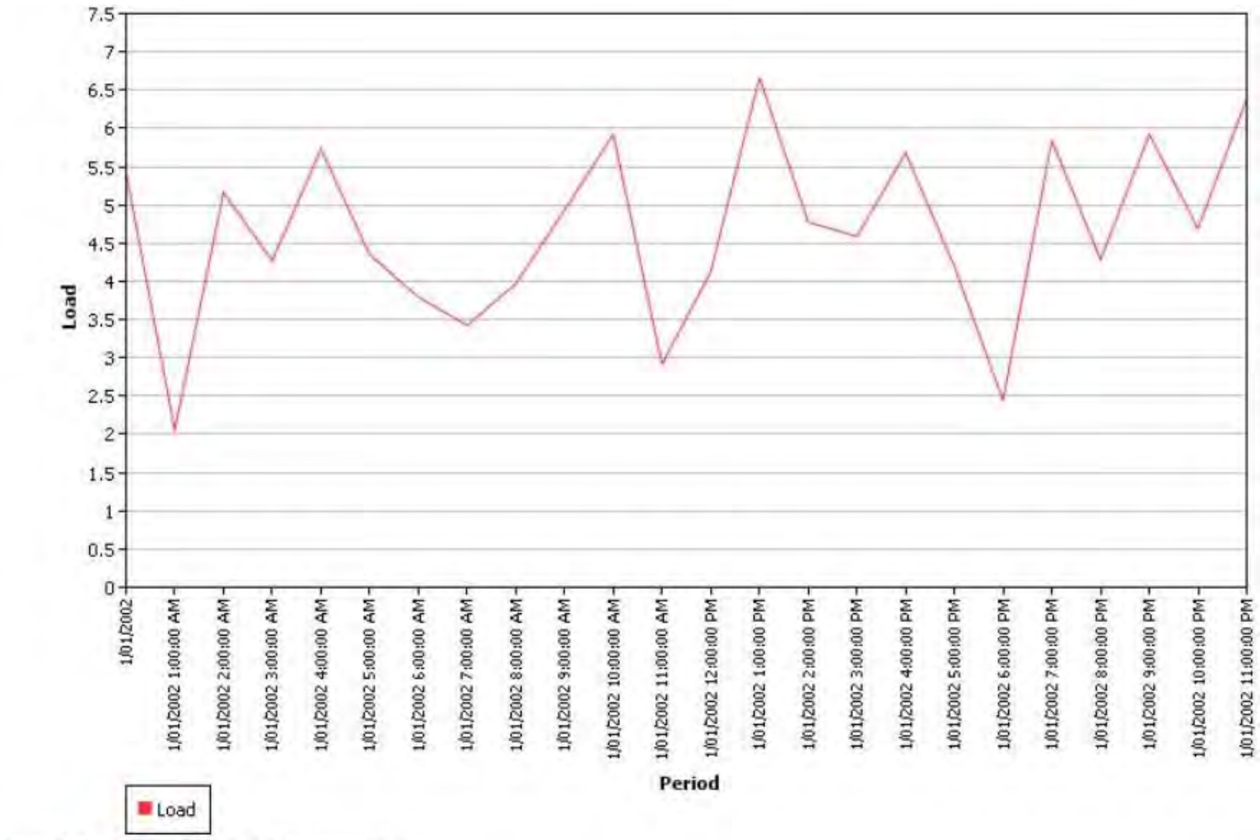


Figure 7: Sample 1 Profile with No Autocorrelation

With Autocorrelation

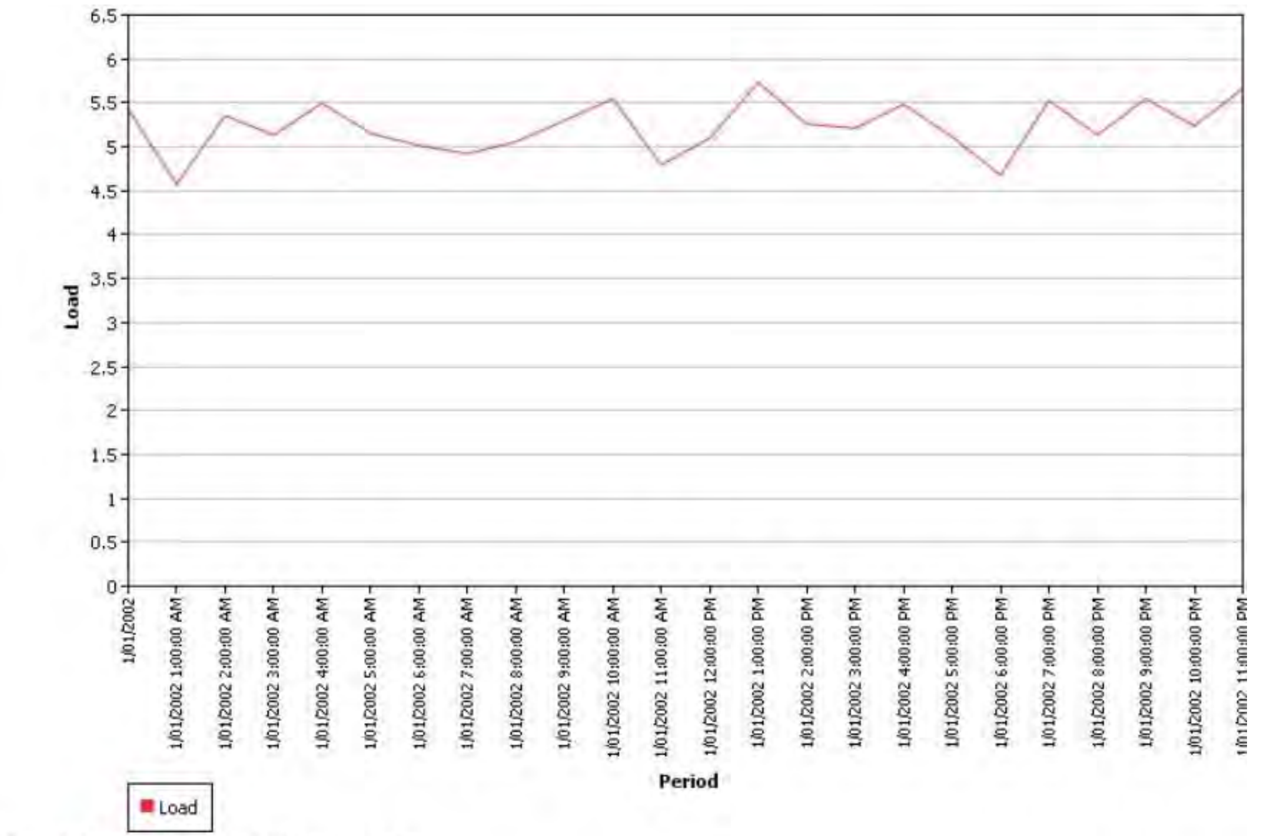


Figure 8: Sample 1 Profile with 75% Autocorrelation

Stochastics Setup

Plexos Example

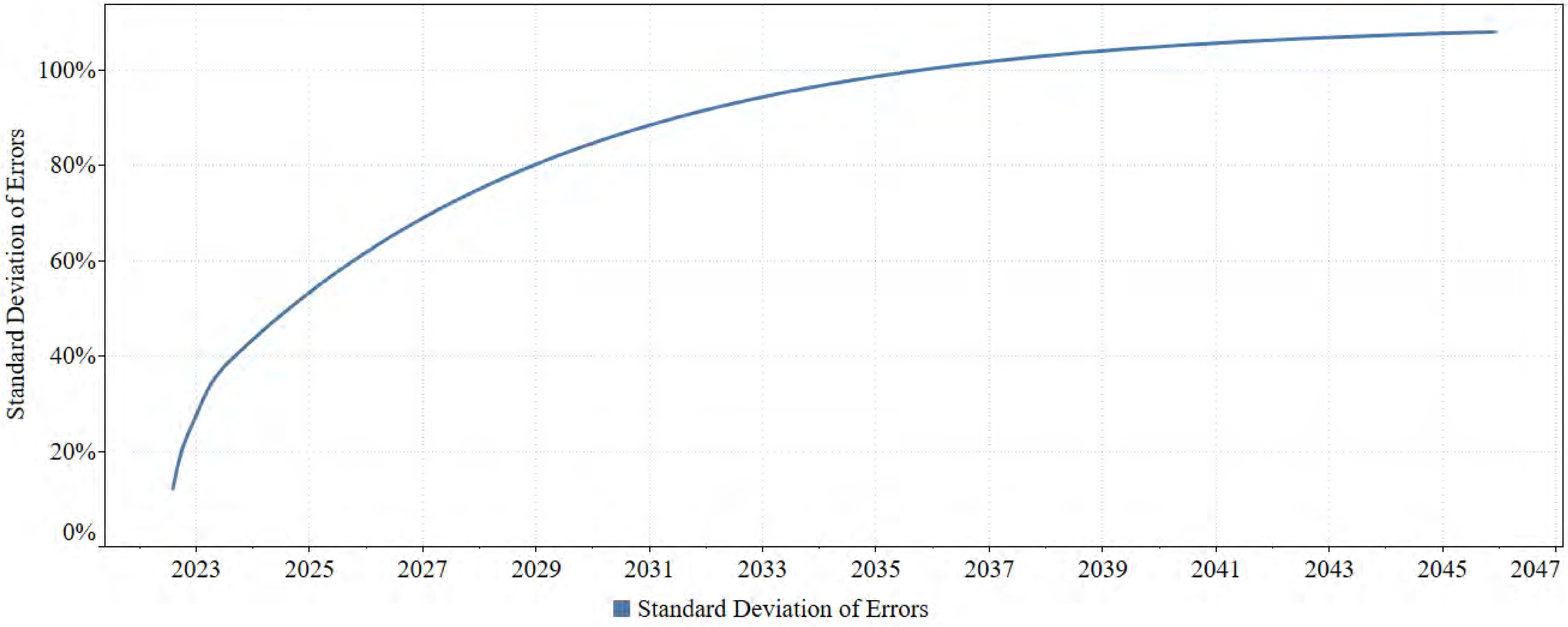
Property	Value	Units	Band
Profile	5.5	-	1
Error Std Dev	28	%	1
Min Value	1	-	1
Max Value	10	-	1
Auto Correlation	75	%	1

Avista Setup

	Property	Value	Data File	Units	Band
	Distribution Type	Lognormal		-	1
	Profile Month	0	Henry Hub Prices	-	1
	Min Value	0.5		-	1
	Max Value	100		-	1
	Error Std Dev	0	Standard Deviation of Errors	%	1
	Auto Correlation	94.2		%	1

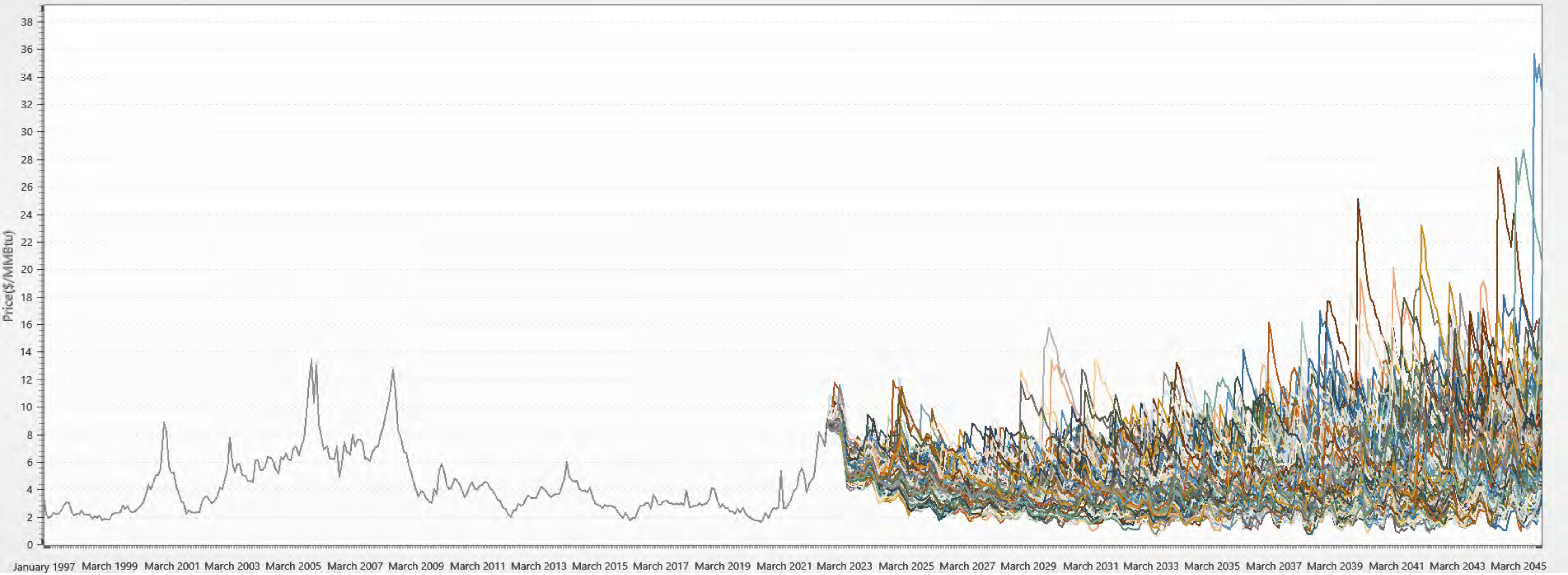
Auto Correlation calculation performed on data from 6/1/1997 – 6/1/2022 (25 years)

Input: Standard Deviation of Errors

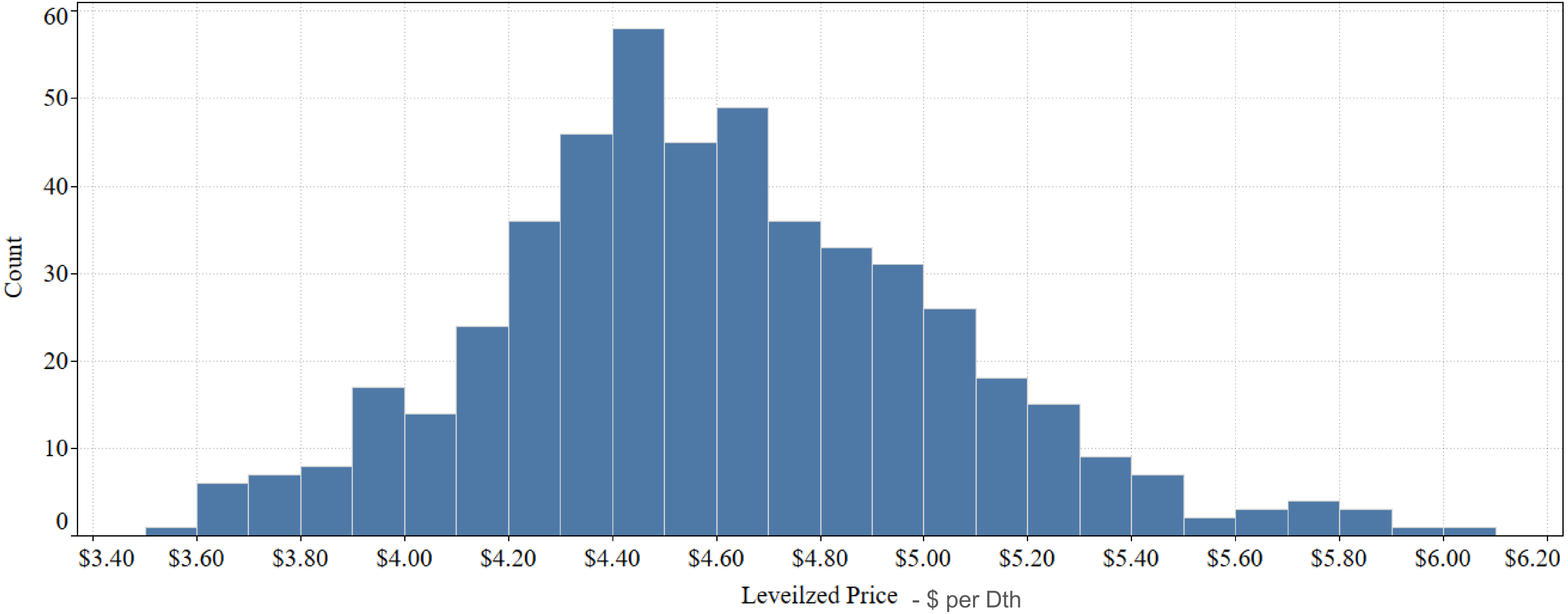


Calculations performed on data from 6/1/2011 – 6/1/2022 (11 years)

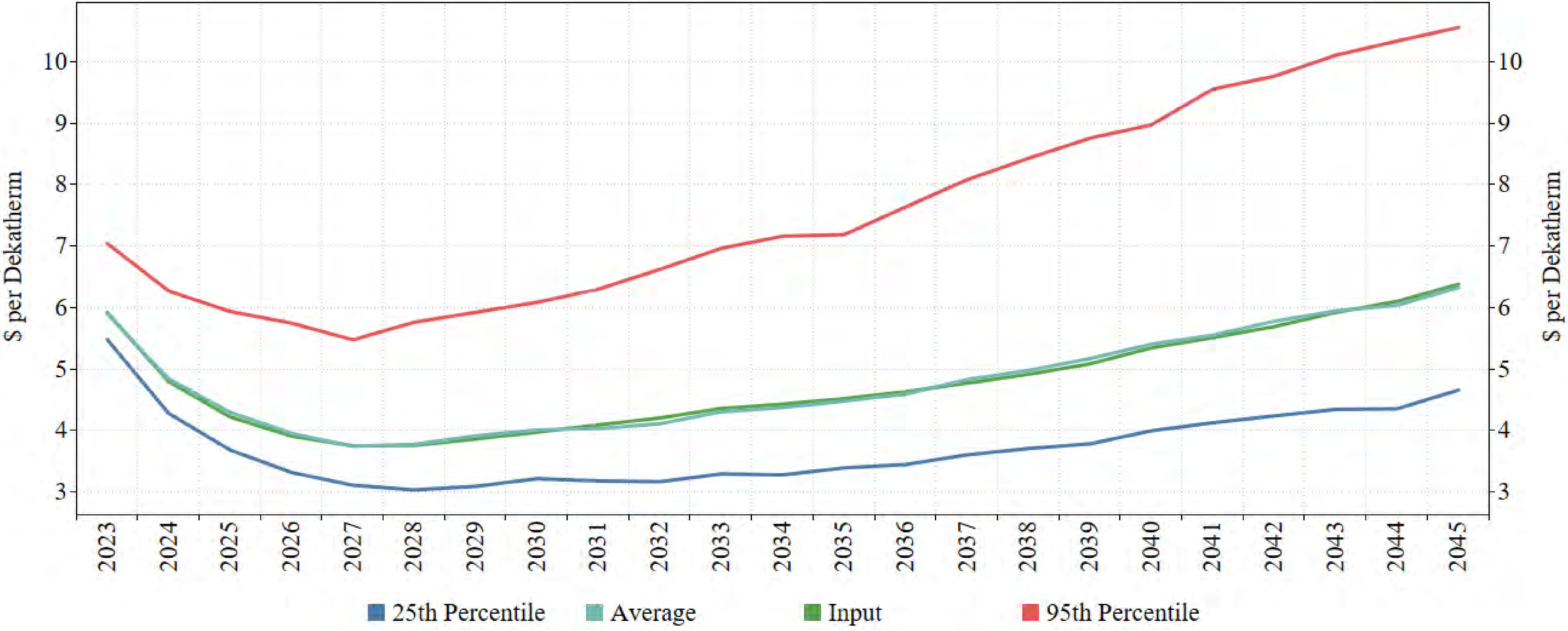
Stochastics: Henry Hub (500 Draws)



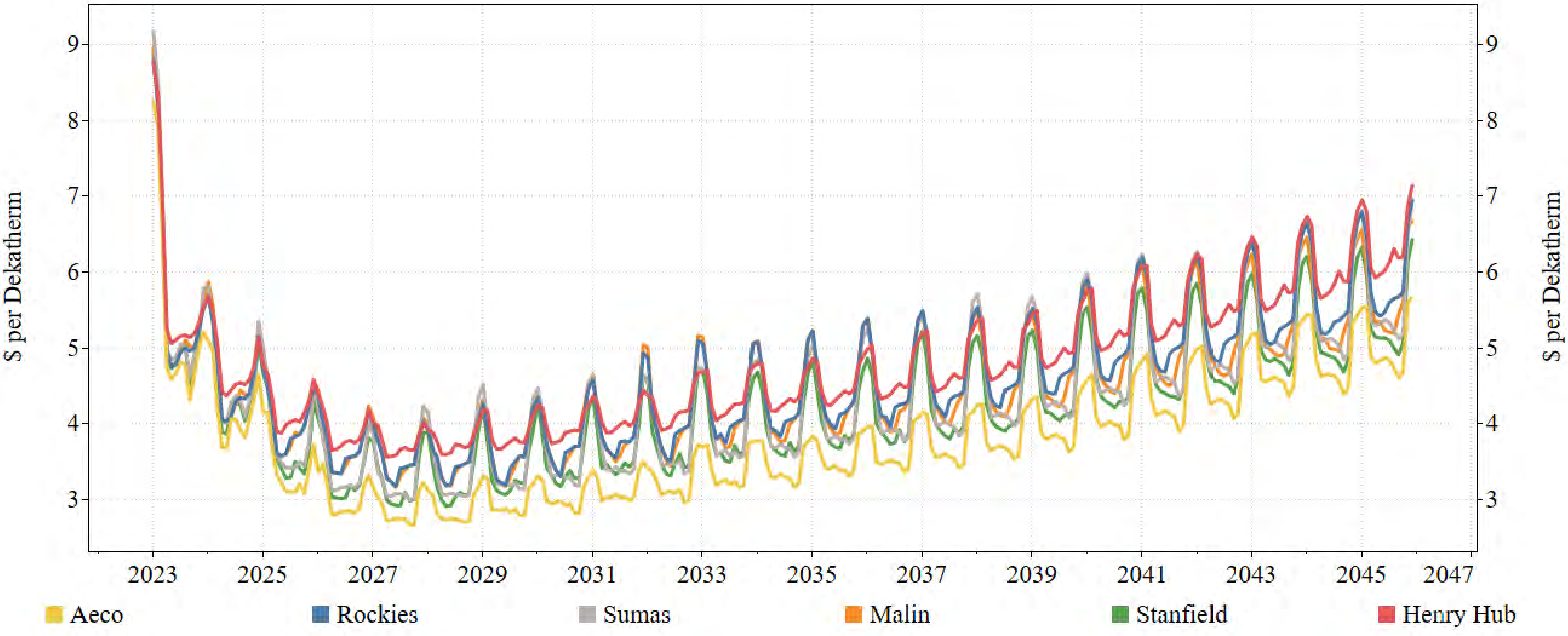
Stochastics: Henry Hub Levelized Prices (500 Draws)



Results: Henry Hub Stochastics (500 Draws)



Expected Case Price Forecasts



Supply Side Resource Options

Tom Pardee

RNG Project Development Challenges

Lessons learned from pursuing RNG projects directly with feedstock owners:

- Competition
- The California transportation market dominates the supply
- Federal RIN & California LCFS markets influence commercial terms
- Reaching commercial terms is challenging
- The utility cost of service model is a foreign concept
- Every RNG project is unique
- Economies of scale
- New RNG Projects can take 2-3 years to develop
- Limited feedstock supply
- Partnering strategy
- Picking partners

RNG Procurement & Potential Project Pipeline

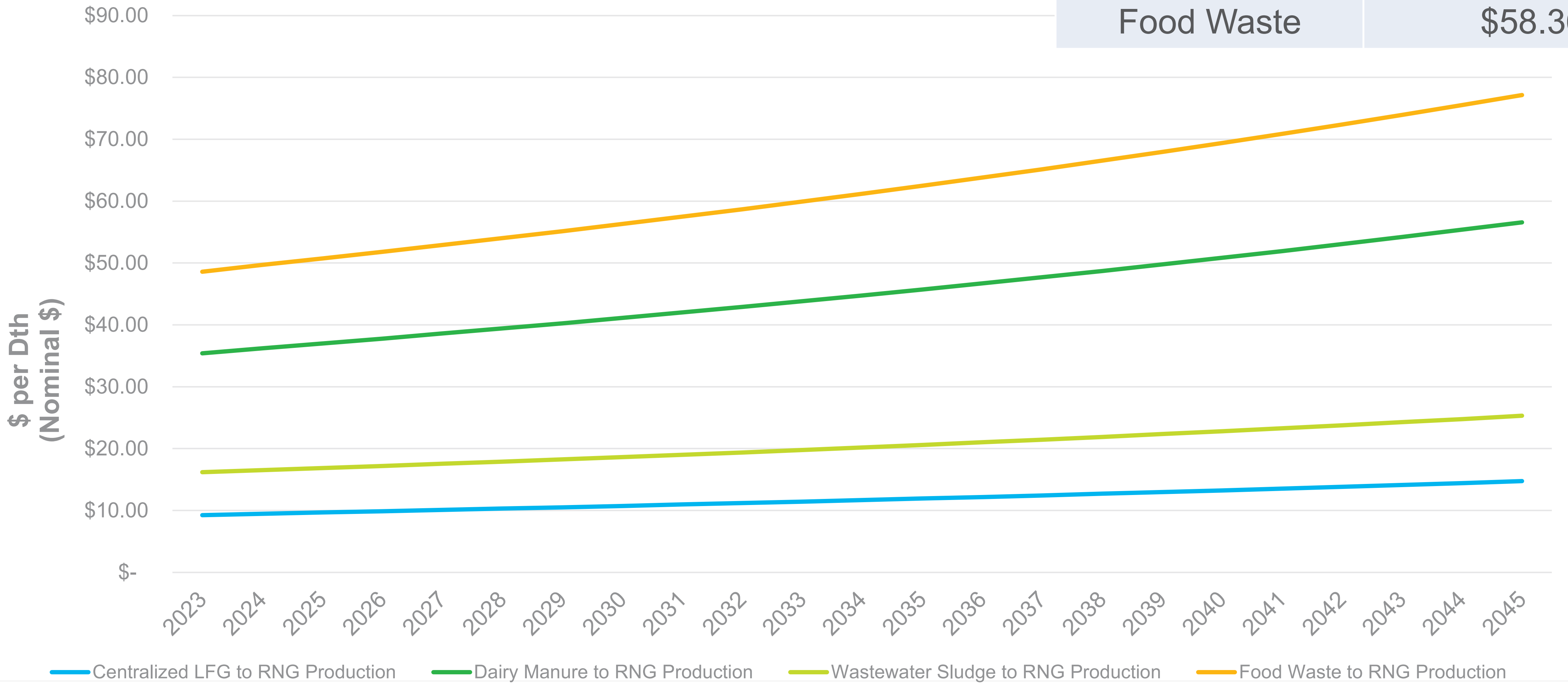
Avista has been pursuing RNG projects with a host of feedstock owners for the past few years. The table below captures these efforts by type & volume

#	Project Pathway Type	In Service Avista Territory (Y/N)	Partnering Considered	Estimated Supply (Dth/YR) (Avista only)	Est. Online Date
1	Conventional RNG	Yes	Yes	~ 200K - 350K	2024
2	Unconventional RNG	Yes	Yes	~ 150K - 250K	TBD
3	Unconventional RNG	Yes	Yes	~ 70K - 120K	2024-25
4	Conventional RNG	Yes	Yes	~ 30K - 50K	TBD
5	Conventional RNG	Yes	Yes	~ 20K - 30K	TBD
6	Innovative CC&R RNG	Yes	Yes	~ 50K - 80K	2024-25
7	Thermal Gasification	Yes	Yes	~ 70K - 200K	TBD
8	Conventional RNG	Yes	Yes	~ 60K - 140K	TBD
9	Pyro Catalytic Hydrogenation	Yes	Yes	~ 70K - 150K	TBD
10	Purchased RNG	Yes	No	~ 5K - 10.8K	2022

Action Item Feedback: "Engage with stakeholders early in the development process to discuss potential RNG project types and ownership structures and ways to mitigate or balance project risks fairly."

RNG Cost Estimate by type

RNG Type	Levelized Price (Dth)
Landfill	$11.14
Dairy	$42.65
Wastewater	$19.29
Food Waste	$58.36



Source: Black and Veatch estimates

2018 Oregon SB 344 Report Highlights

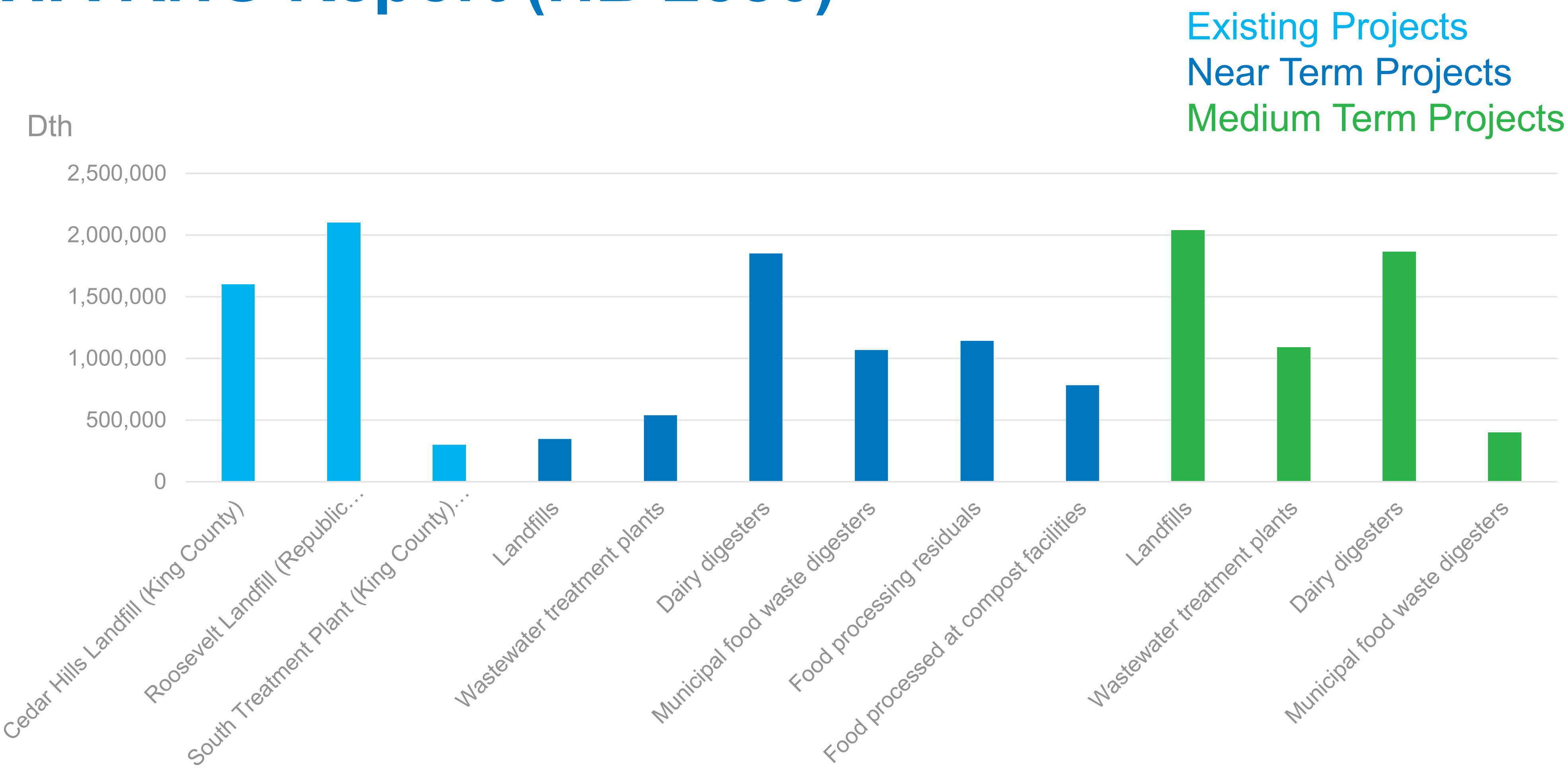
Total Potential Annual Methane Production = 50 Bcf

Source - Anaerobic	Cubic Feet of CH4 per Year
Agricultural Manure	4,639,626,825
Wastewater	1,225,228,606
Food Waste	138,571,656
Landfill	4,351,052,420
Total	**10,354,479,507**

Source - Gasification	Cubic Feet of CH4 per Year
Forest Industry Residuals	16,998,109,000
Agricultural Industry Residuals	22,686,775,000
Total	**39,684,884,000**

Oregon Department of Energy, 2018 Biogas and Renewable Natural Gas Inventory SB 334 Report

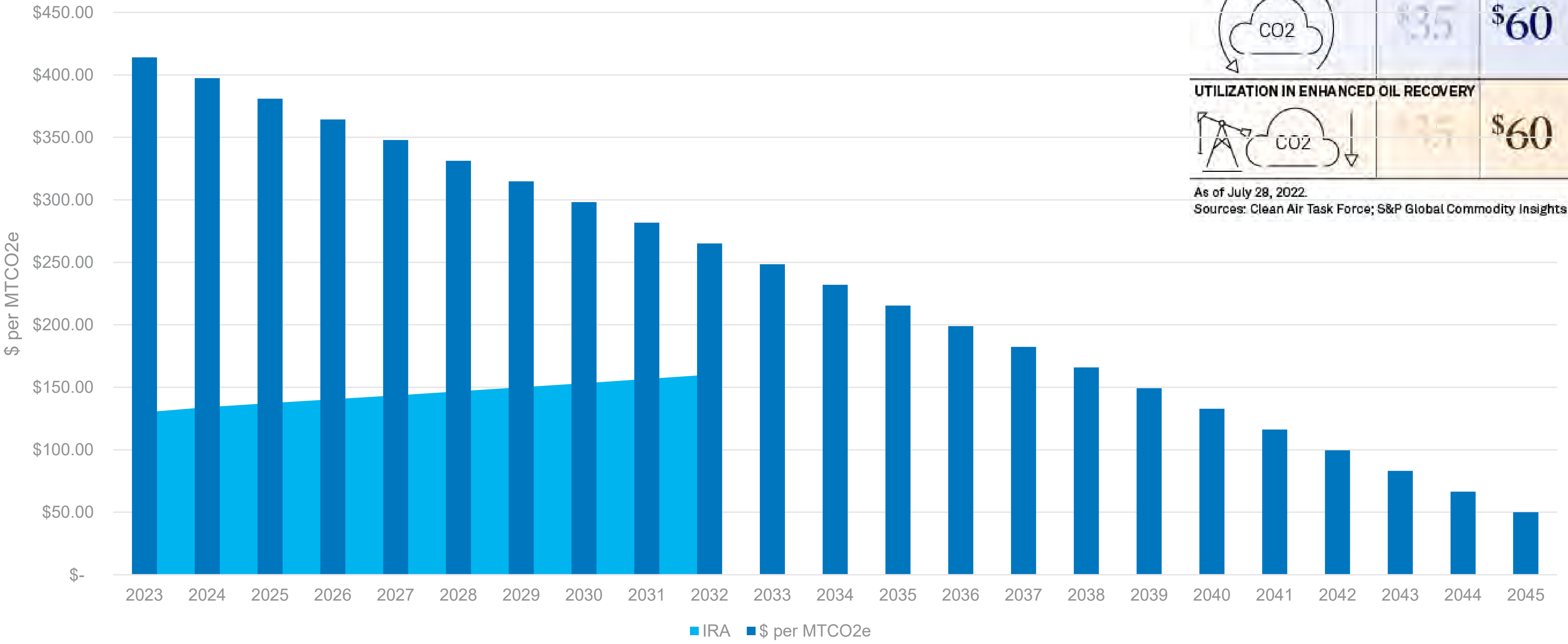
WA RNG Report (HB 2580)



WSU Energy Program, Harnessing Renewable Natural Gas for Low-Carbon Fuel: A Roadmap for Washington State

*Released December 1, 2018

Direct Air Capture



Carbon capture tax credit increases under Inflation Reduction Act ($/tonne)

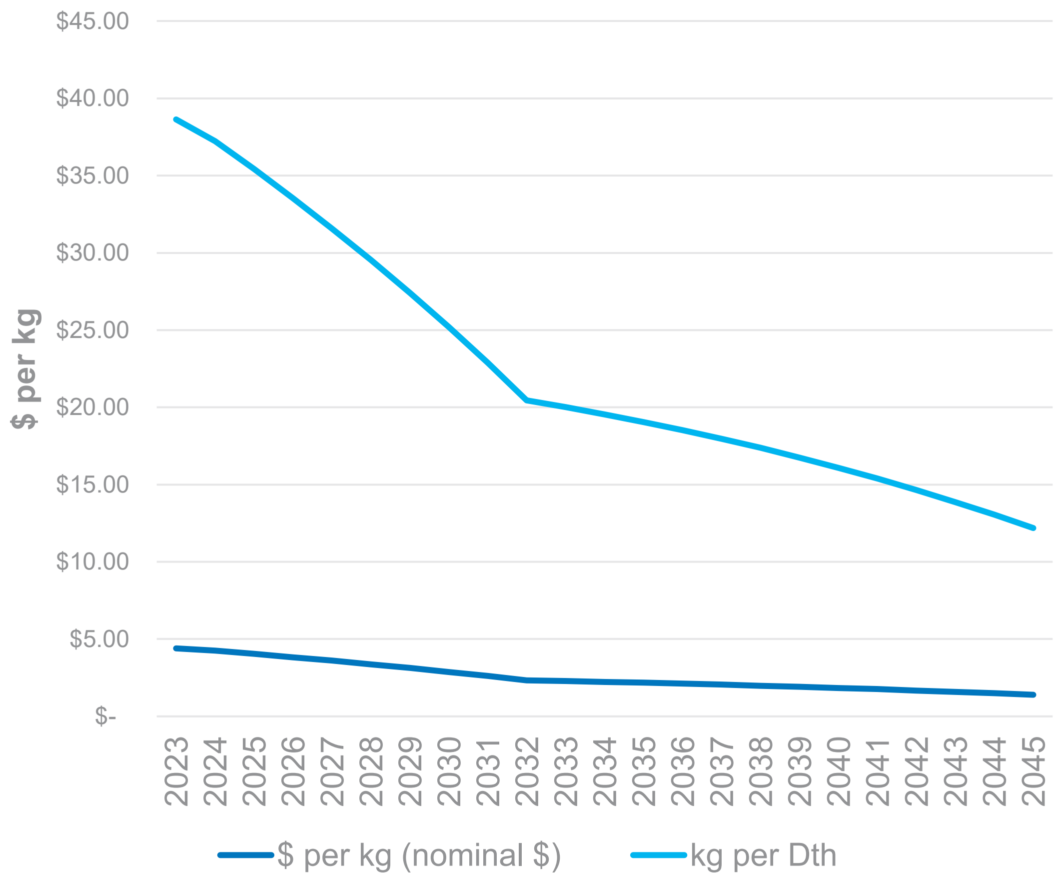
	Previous	Inflation Reduction Act: POINT SOURCE	Inflation Reduction Act: DIRECT AIR CAPTURE
UNDERGROUND STORAGE (CO2)	$50	$85	$180
UTILIZATION (CO2)	$35	$60	$130
UTILIZATION IN ENHANCED OIL RECOVERY (CO2)	$35	$60	$130

As of July 28, 2022.
Sources: Clean Air Task Force; S&P Global Commodity Insights

Source: science direct

Green Hydrogen (H2)

- Hydrogen is the most abundant element in the universe
- The lightest element and wants to escape making it harder to contain
- Highly combustible
- Tax credits from IRA assumed at a levelized credit for the full $3 per kg incentive from green H2

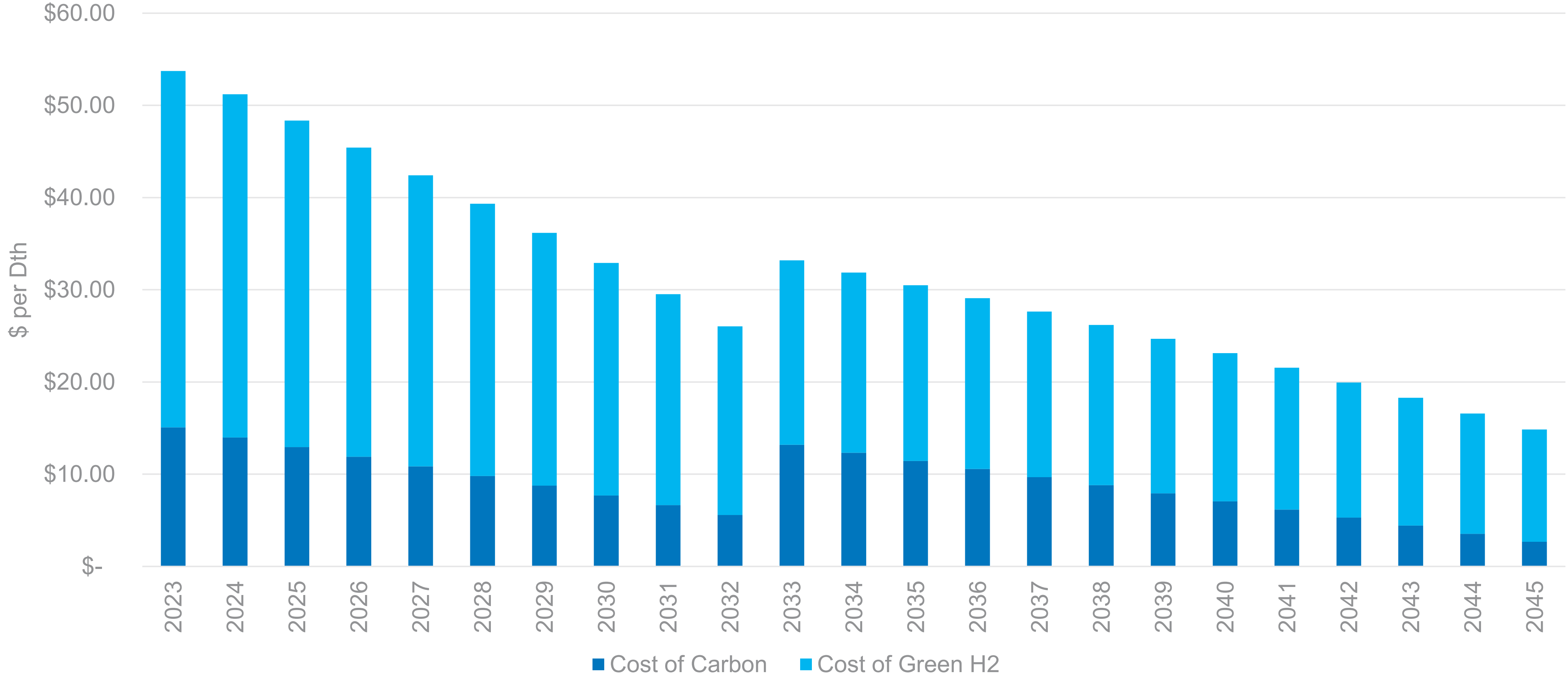


Synthetic Methane

- Can be used in existing pipelines with no upgrades
- Unlimited potential, based solely on capacity of transportation or distribution pipeline
- Sourced from carbon capture and green hydrogen
  - Assume Inflation Reduction Act (IRA) benefits of:
    - $130 per MTCO2e for carbon capture
    - $3 per kg for green hydrogen

Levelized Price (year 1) $35.78

Synthetic Methane Costs



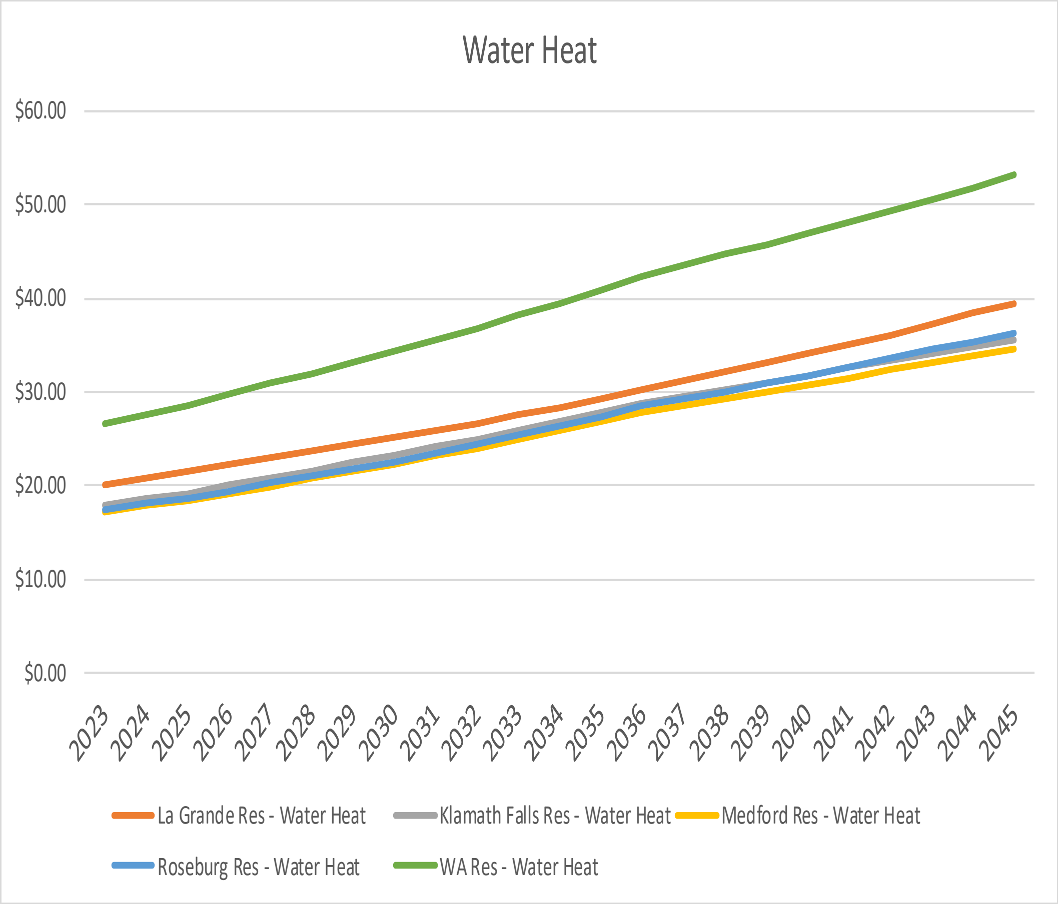
Electrification Estimates

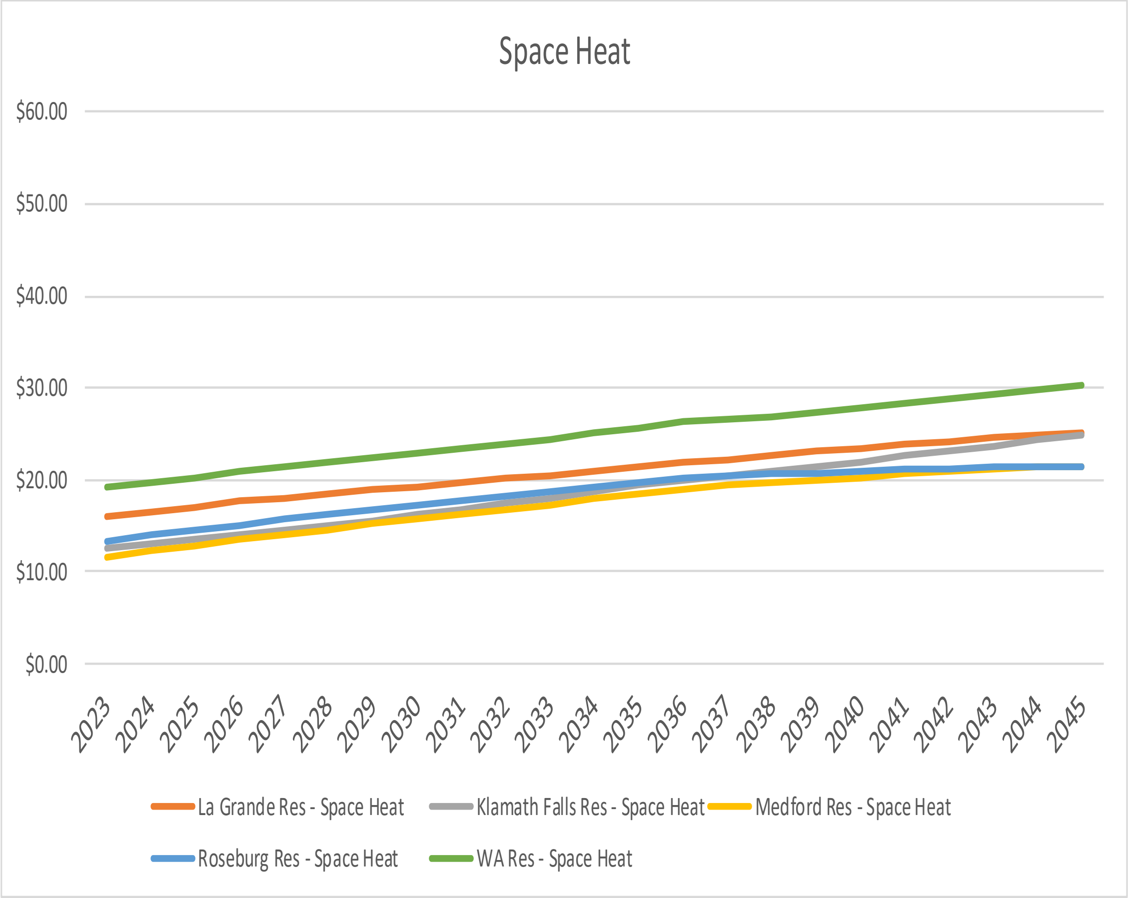
- Look at a daily efficiency and conversion by area
- Roll up this daily efficiency into a monthly average conversion (therms to kwh)
- Uses rates by area from electric providers
  - Oregon Trail rises by 3% per year
  - All other rates rise by Avista expected cost increase and includes transmission and distribution estimates
  - Pacific Power
  - Inland Power/VERA/Modern Electric
  - Base rates are not included as it is assumed customers currently have electricity from these providers
  - Maximum rate, per MMBTU, for low use months is the cost to convert plus energy

- Conversion costs
  - Levelized 20-year costs each year by end use type
  - Includes Inflation Reduction Act cost estimates from 2023-2032 to help offset costs
  - Conversion costs grown by inflation each year
  - Estimates for equipment from Home Innovation Research Labs – February 2021 (Denver, CO)
  - Commercial estimates are double the residential conversion costs
  - LDC Capital costs for distribution pipelines and gate stations and other equipment are not included in electrification estimate

Residential Electrification – Levelized Energy Costs

$ per Dth
(nominal $)

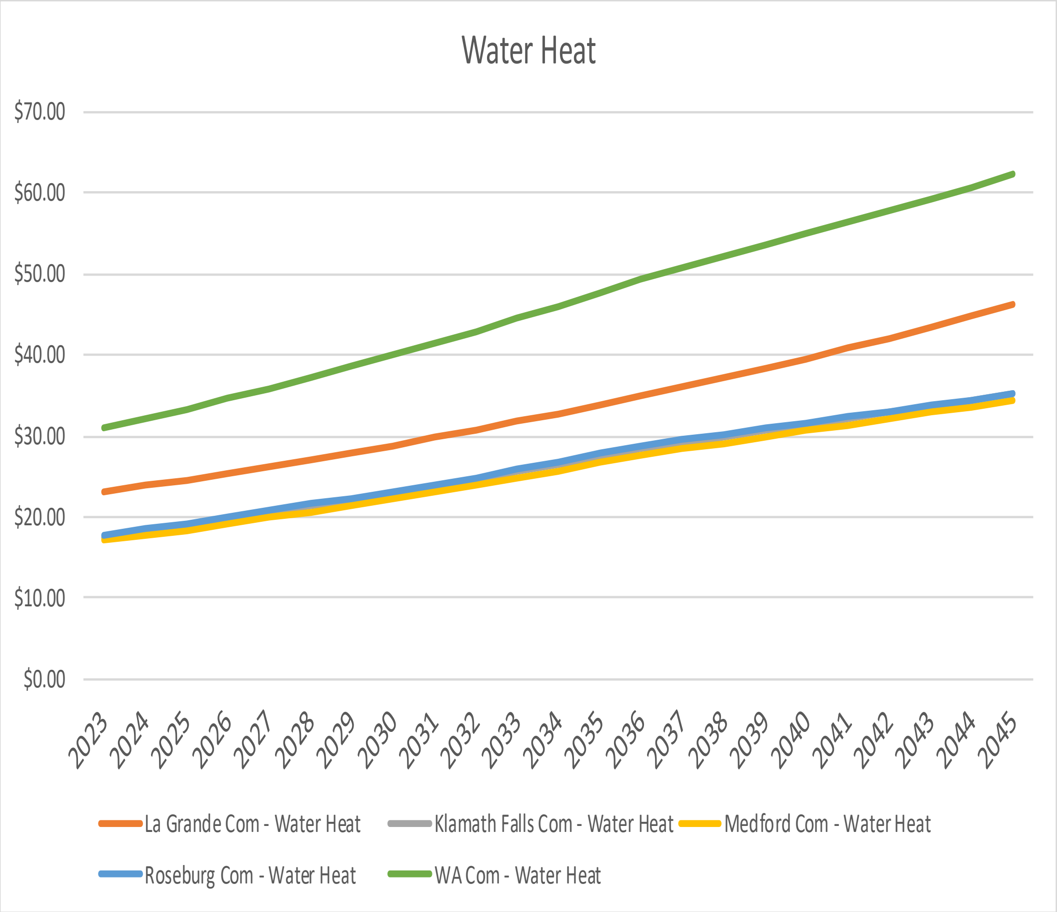


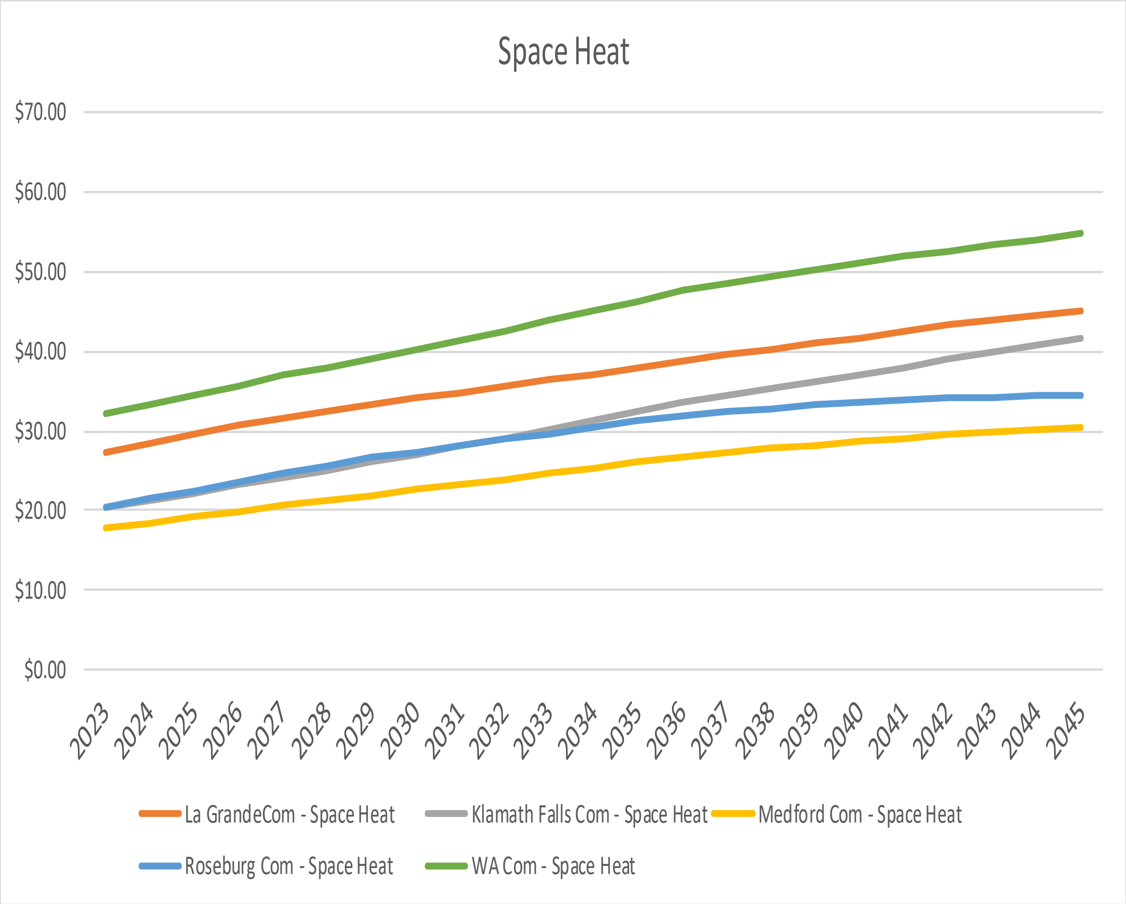


*convert from natural gas to electric with daily efficiencies by source

Commercial Electrification – Levelized Energy Costs

$ per Dth
(nominal $)





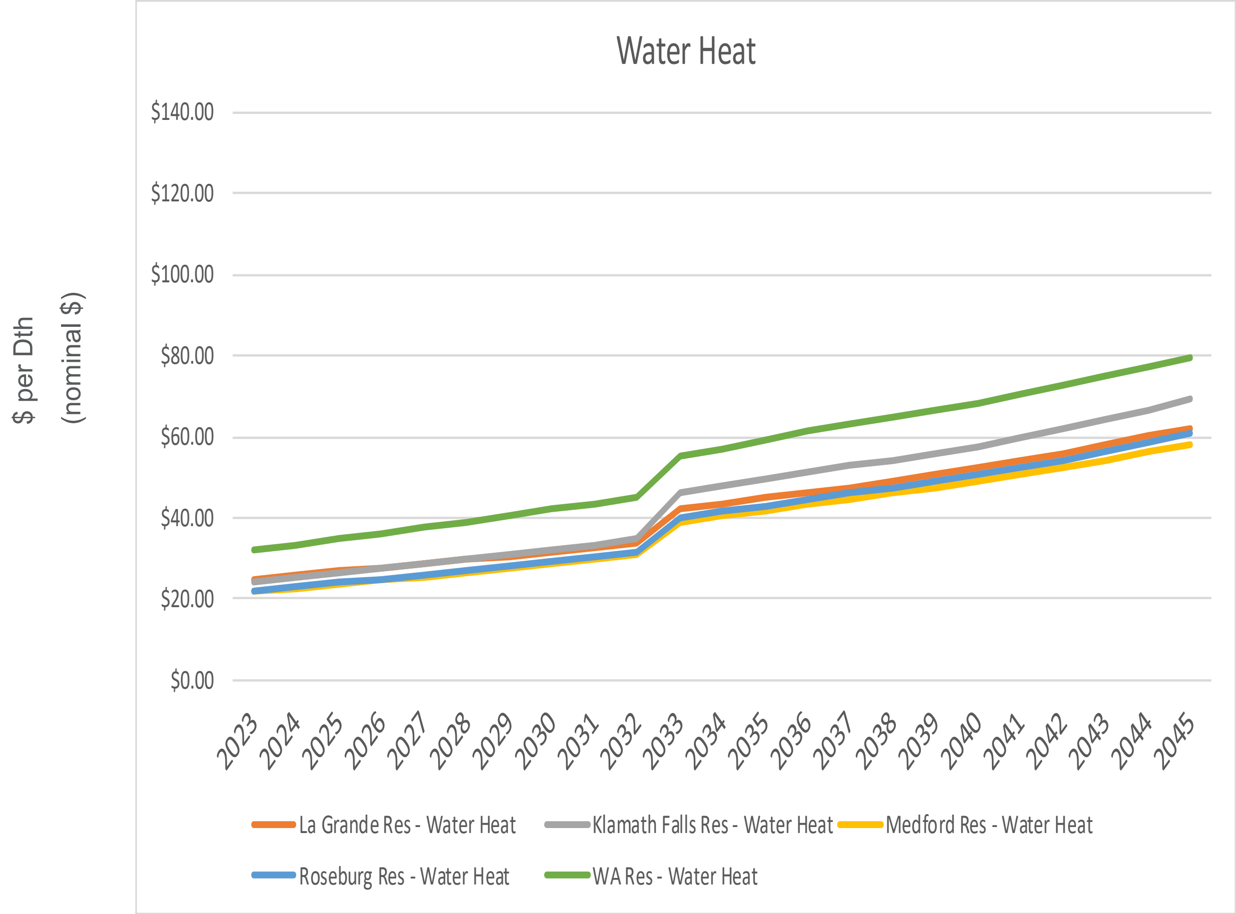
*convert from natural gas to electric with daily efficiencies by source

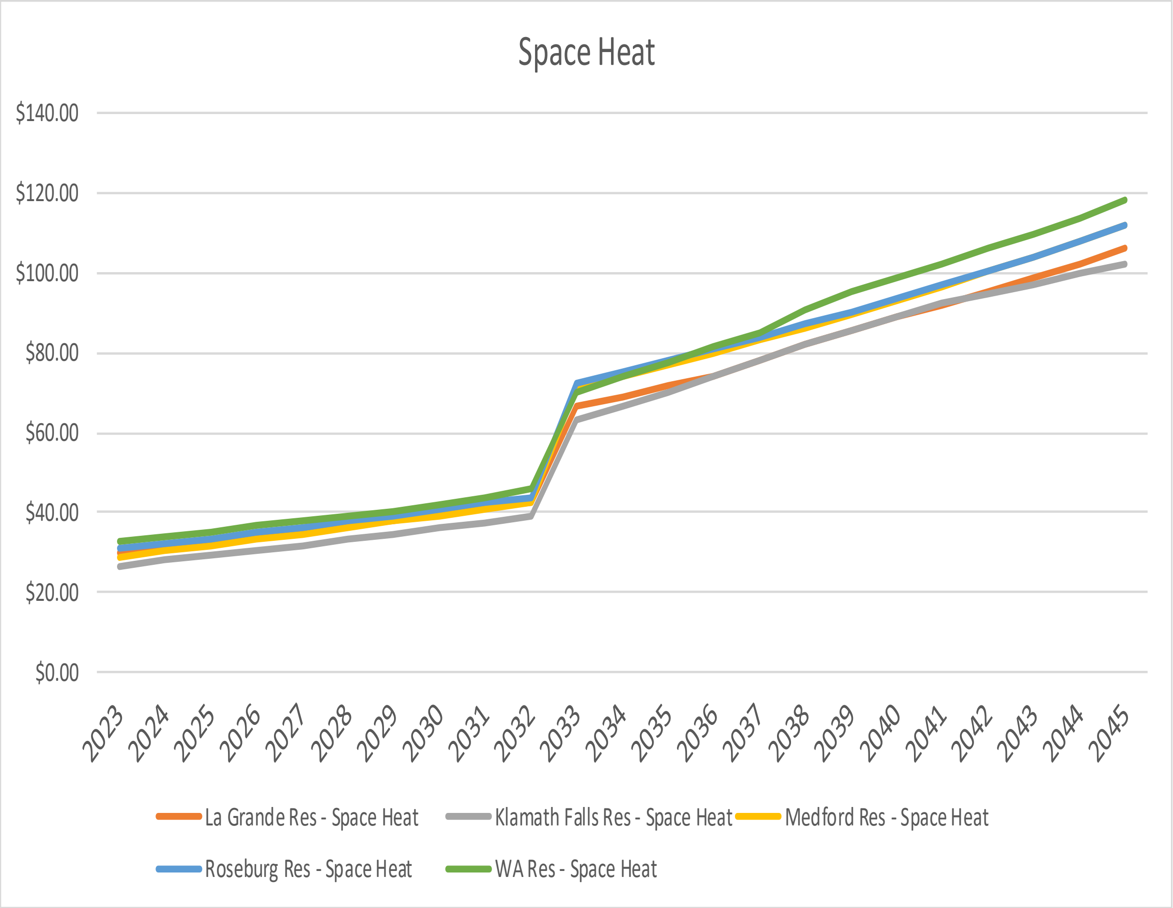
Electrification – Estimated Conversion Costs

	Res - Water Heat	Com - Water Heat	Res - Space Heat	Com - Space Heat	Res - Other
Rate	3%	3%	3%	3%	3%
Years	5	5	5	5	5
Capital Amount	$ 2,325	$ 4,650	$ 5,891	$ 11,782	$ 596
Electric Panel Upgrade	$ -	$ -	$ -	$ -	$ -
IRA Tax incentives	$ 1,163	$ -	$ 2,946	$ -	$ 298
Capital Amount	$ 1,163	$ 4,650	$ 2,946	$ 11,782	$ 298

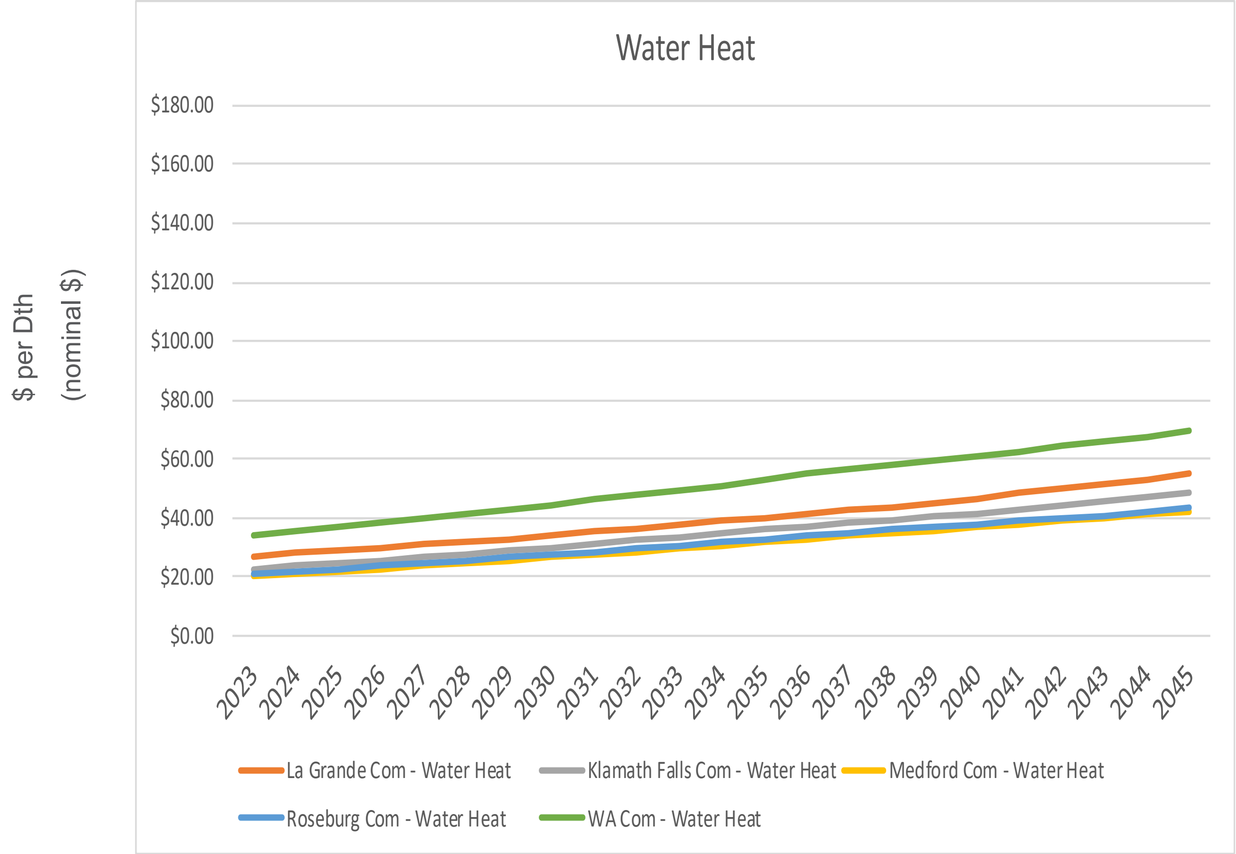
Source: Home Innovation Research Labs – February 2021

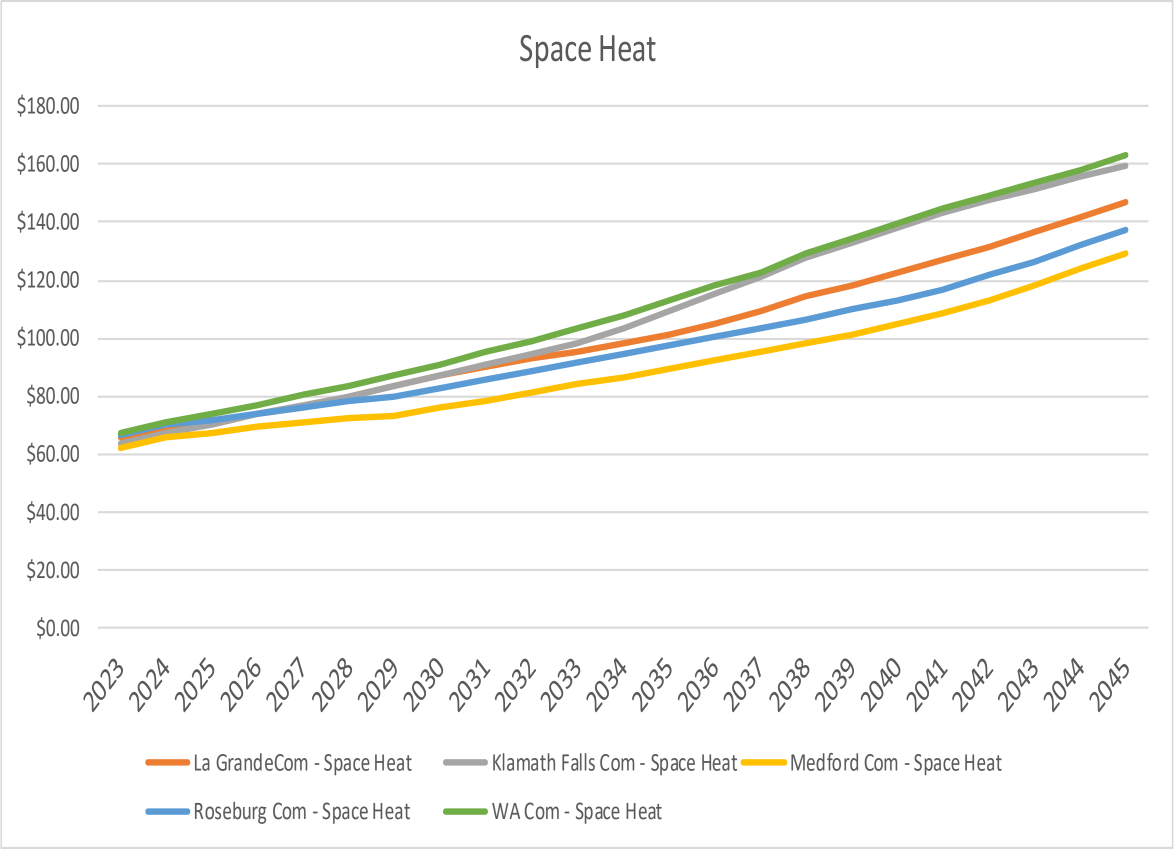
Residential Electrification Costs – Levelized (energy + conversion costs)



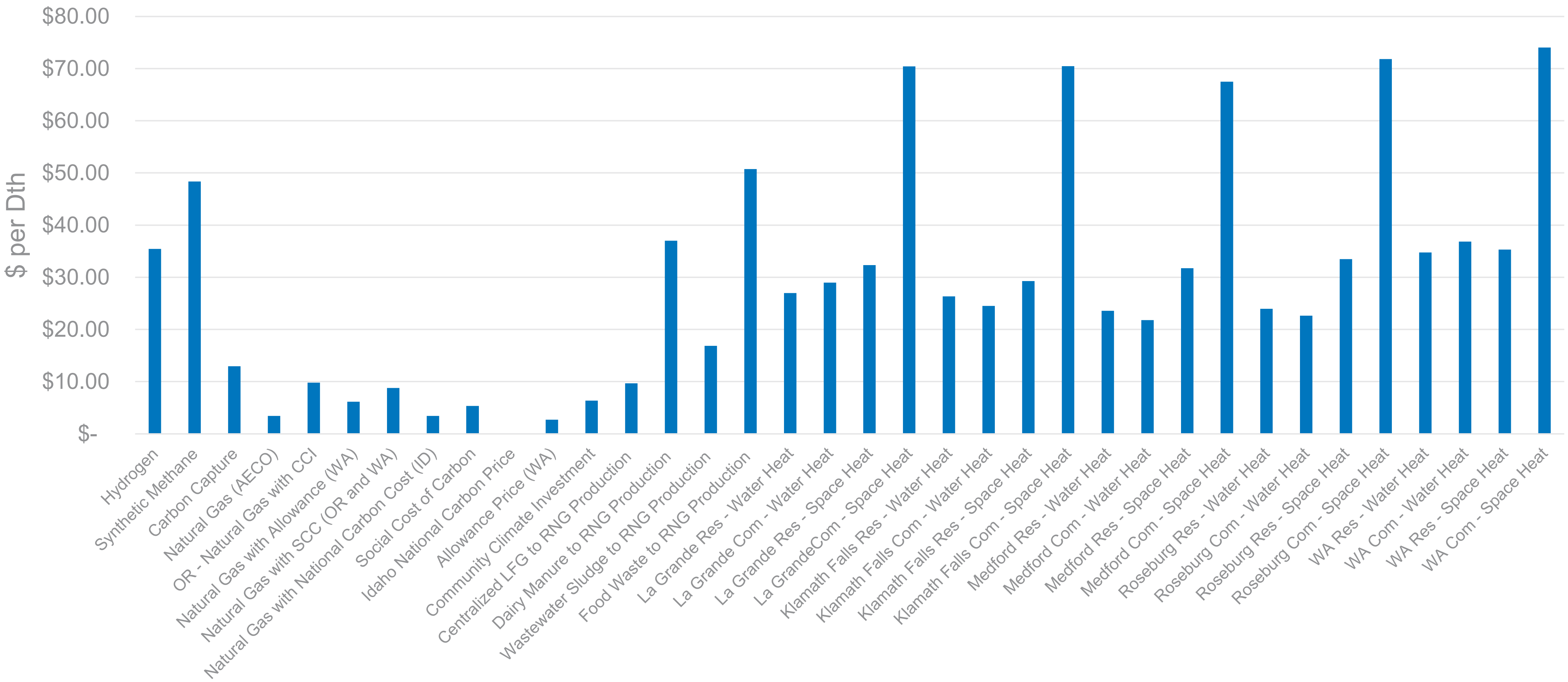


Commercial Electrification Costs – Levelized (energy + conversion costs)





Supply Side Options Summary - 2025



Request For Proposal

- Avista is going out for an RFP in the next few months
- The RFP will help determine pricing and market availability to size RNG and other fuels to help meet climate change programs in Oregon and Washington
- Avista will inform the TAC members when RFP is released

AVISTA®

CCA Overview

Tom Pardee

Washington State Climate Commitment Act

- SB 5126, passed in the Summer 2021
- We will create a cap-and-invest program starting Jan. 1, 2023, by setting emissions allowance budgets that meet the greenhouse gas limits in RCW 70A.45.020.
- Starting on Jan. 1, 2023, the cap-and-invest program will cover industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual greenhouse gas emissions above 25,000 metric tons of carbon dioxide equivalent.
- On Jan. 1, 2027, the program adds waste-to-energy facilities.
- On Jan. 1, 2031, the program adds certain landfills and railroad companies.

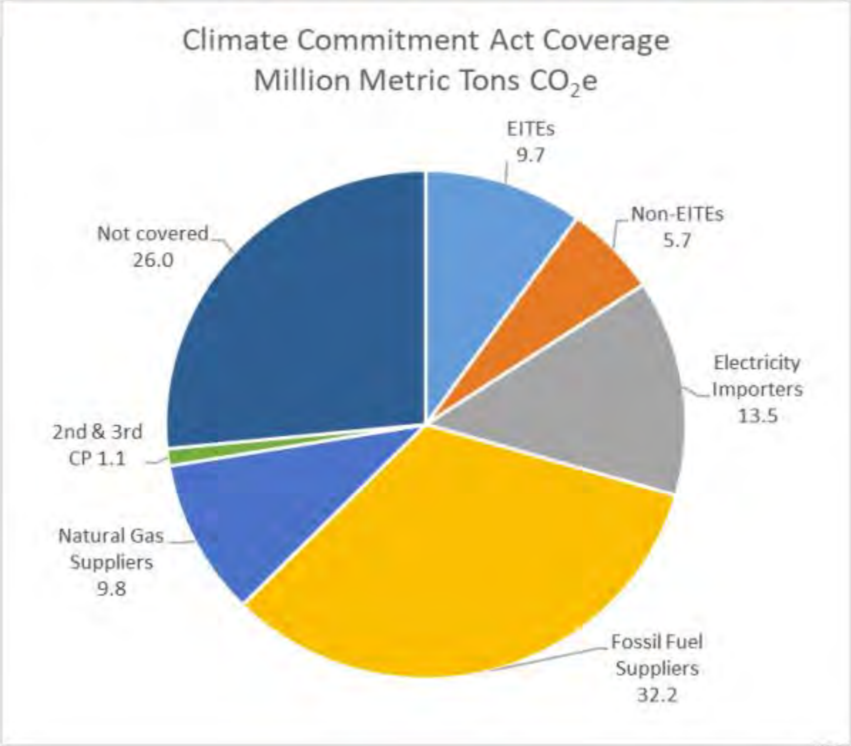
Baseline Emissions

DEPARTMENT OF ECOLOGY
State of Washington

Total Program Baseline: Covered Emissions

Covered – 75%
- Gasoline and on-road diesel
- Electricity consumed in Washington
- Facilities generating more than 25,000 metric tons/year or more of greenhouse gas emissions
- Natural gas distributed to homes and commercial businesses
- 2027 – waste to energy facilities
- 2031 – railroads and certain landfills

Not Covered – 25%
- Agricultural operations
- Small businesses with under 25,000 metric tons/year of greenhouse gas emissions
- Aviation fuels
- Some marine fuels



https://ecology.wa.gov/DOE/files/5b/5bdc1ffb-01dc-49de-b0cf-e5758aa5c1f6.pdf, page 18

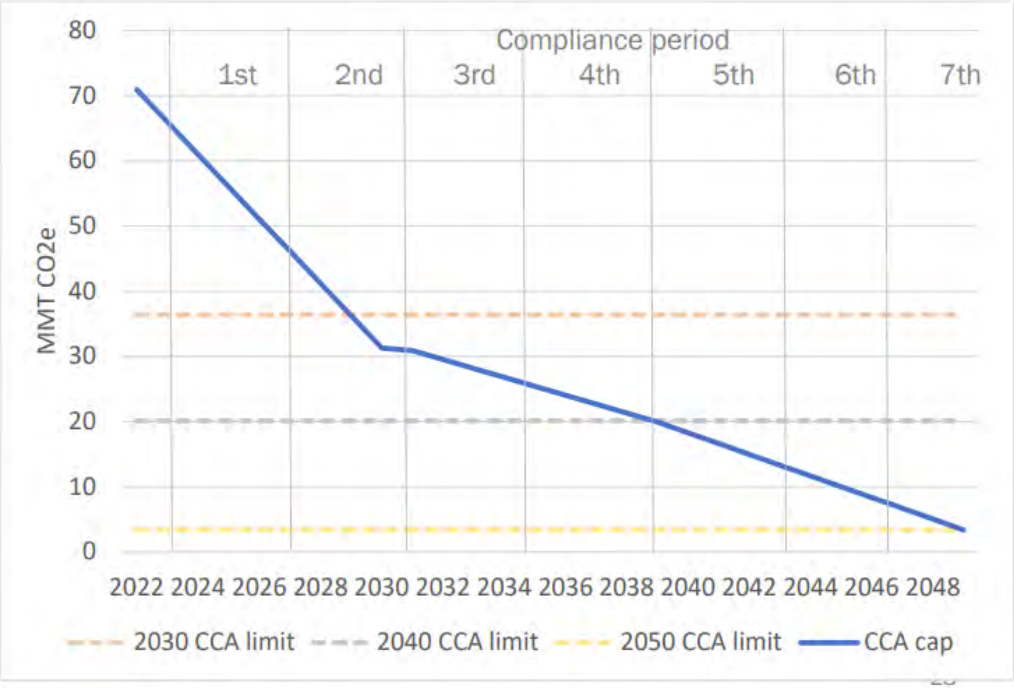
AVISTA

Allowance Reduction

DEPARTMENT OF ECOLOGY State of Washington

Total Program Allowance Budgets: Reductions

- % annual reduction based on statewide GHG limits from RCW 70A.45.020
  - By 2020: 1990 levels = 90.5 million MT CO_2e
  - By 2030: 45% below 1990 levels = 50 million MT CO_2e
  - By 2040: 70% below 1990 levels = 27 million MT CO_2e
  - By 2050: 95% below 1990 levels = 5 million MT CO_2e
- Compliance periods
  - 2023 – 2026
  - 2027 – 2030
  - 2031 – 2034
  - 2034 – 2037
  - 2038 – 2041
  - 2042 – 2045
  - 2046 – 2049



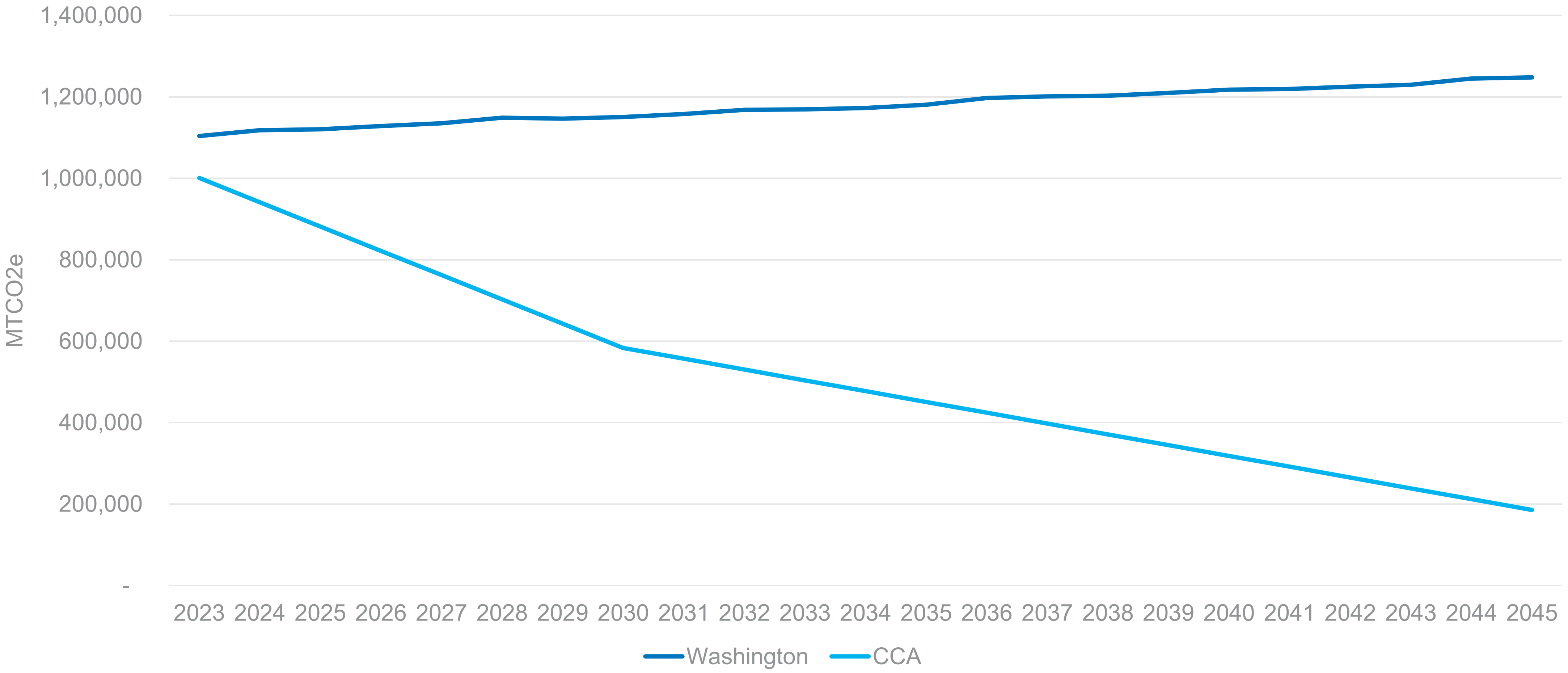
https://ecology.wa.gov/DOE/files/5b/5bdc1ffb-01dc-49de-b0cf-e5758aa5c1f6.pdf, page 28

Major Rule Components

- 7% initial years decline in cap
  - Cap is average deliveries for customers less than 25,000 MTCO2e from 2015-2019
- Offset projects can qualify
  - 8% in first timeframe, 6% in second 4-year timeframe and 6% thereafter
- Allowances given to meet the initial target
  - 93% first year of which 35% can be used for compliance by the LDC
    - Free allowance reduce 5% each year until reaching zero.
  - All allowance revenue from the auctions is to be used to offset costs for low-income residential customers.
  - Allowances do not expire and may be banked
  - No cost allowances may not be traded, transferred or sold

Emissions

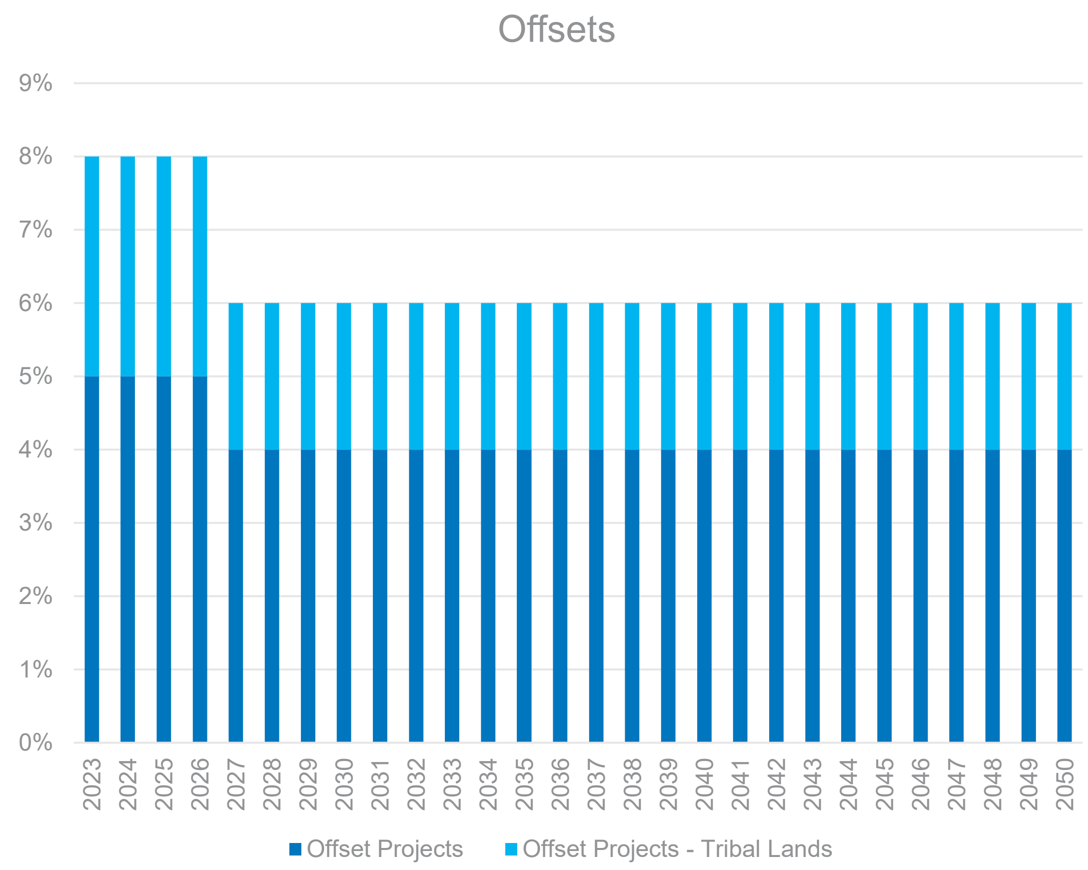
(Metric Tons of Carbon Dioxide equivalent (MTCO2e)



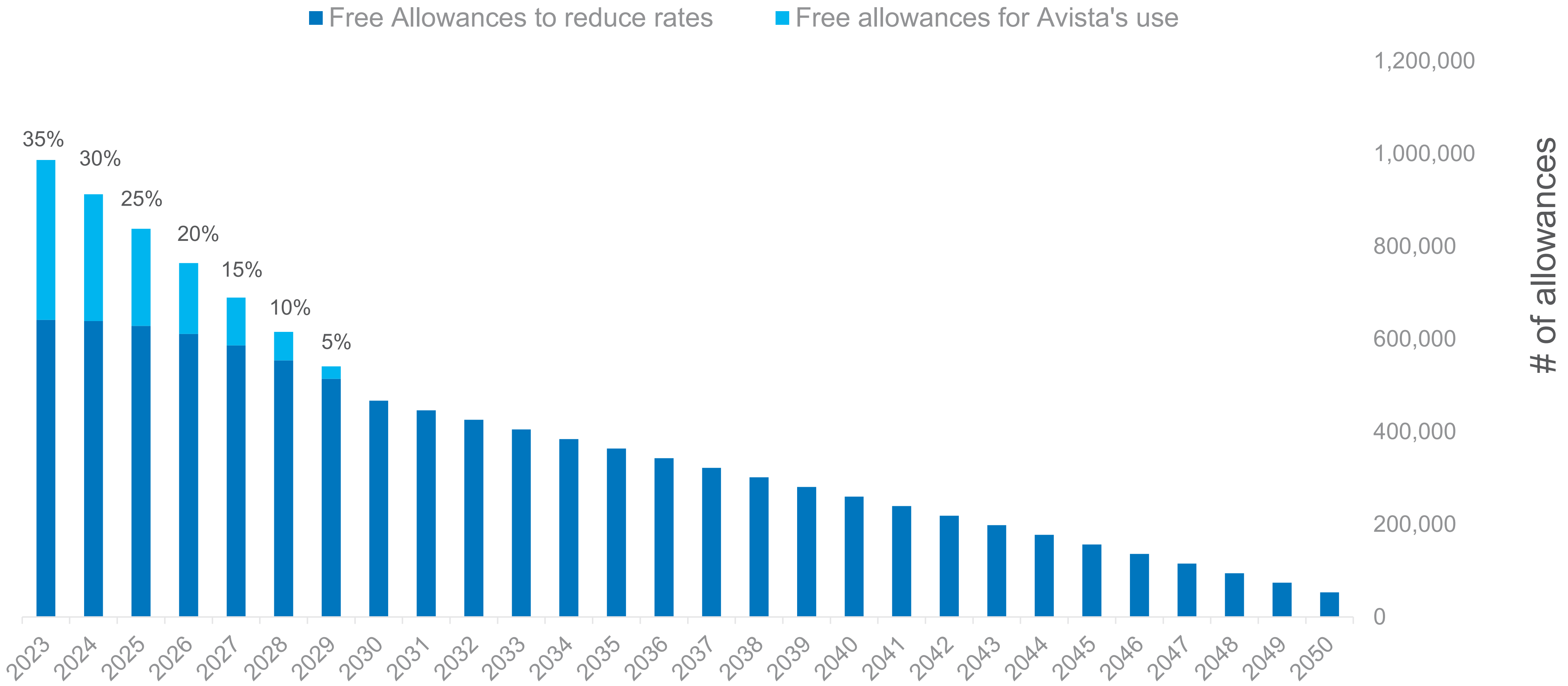
Offsets

- Interchangeable with allowances and purchased if cheaper than allowance price

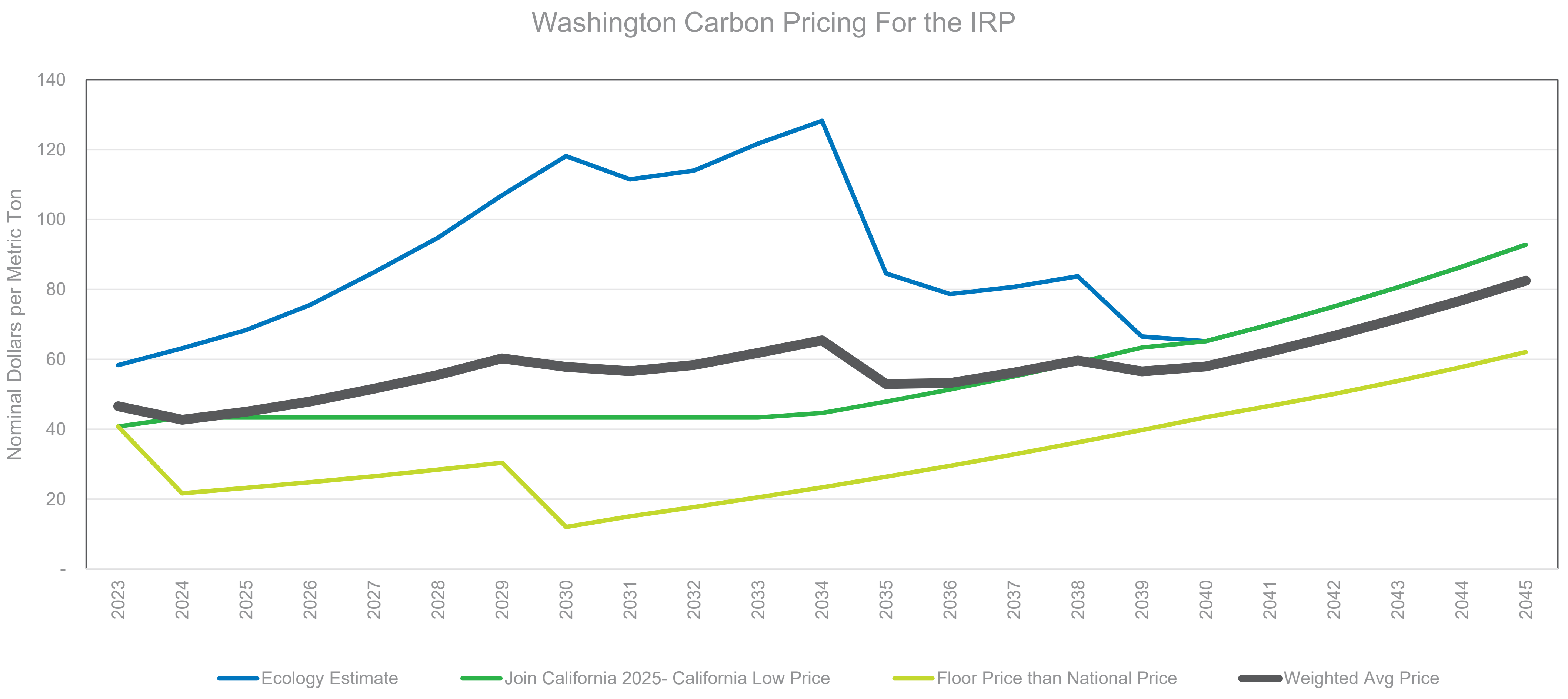
- Offsets remove allowances from the cap



Free Allowances



Allowance Price



CCA Summary

	Climate Commitment Act (CCA) Washington
Start Date	January 1, 2023
Avista Compliance obligation	All emissions less than 25,000 MTCO2e
Compliance Periods	4 years (2023 – 2026)
2050 Goal	95% below 2015-2019 avg.
First Year offset	7.00% - (2023-2030) 1.95% - (2031-2050)
Violation	$10k per MTCO2e
Offset projects	All projects are below cap (remove available allowances) -Up to 8% for four years (3% tribal) -After first four years 6% (2% tribal)
Program offsets	Allowances

AVISTA

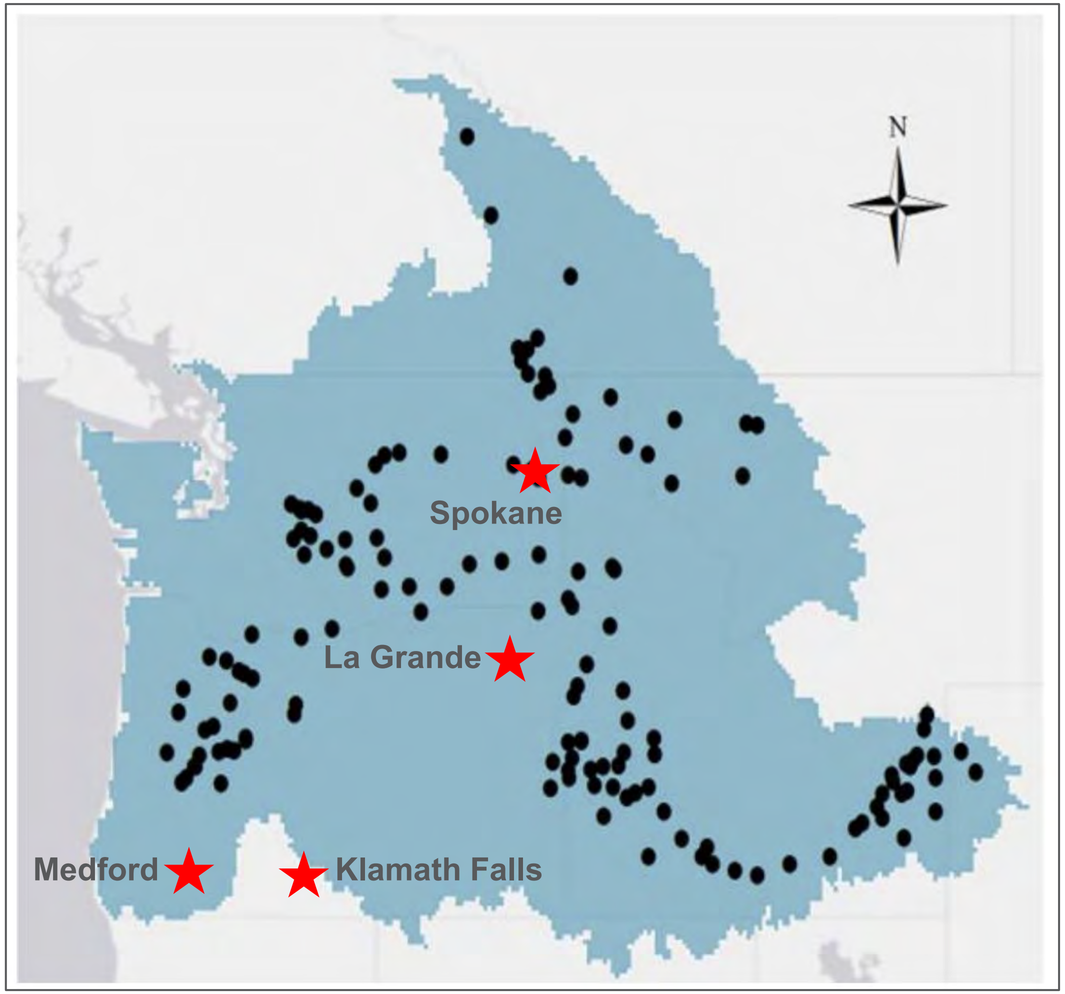
Climate Change Weather

Mike Hermanson

Tom Pardee

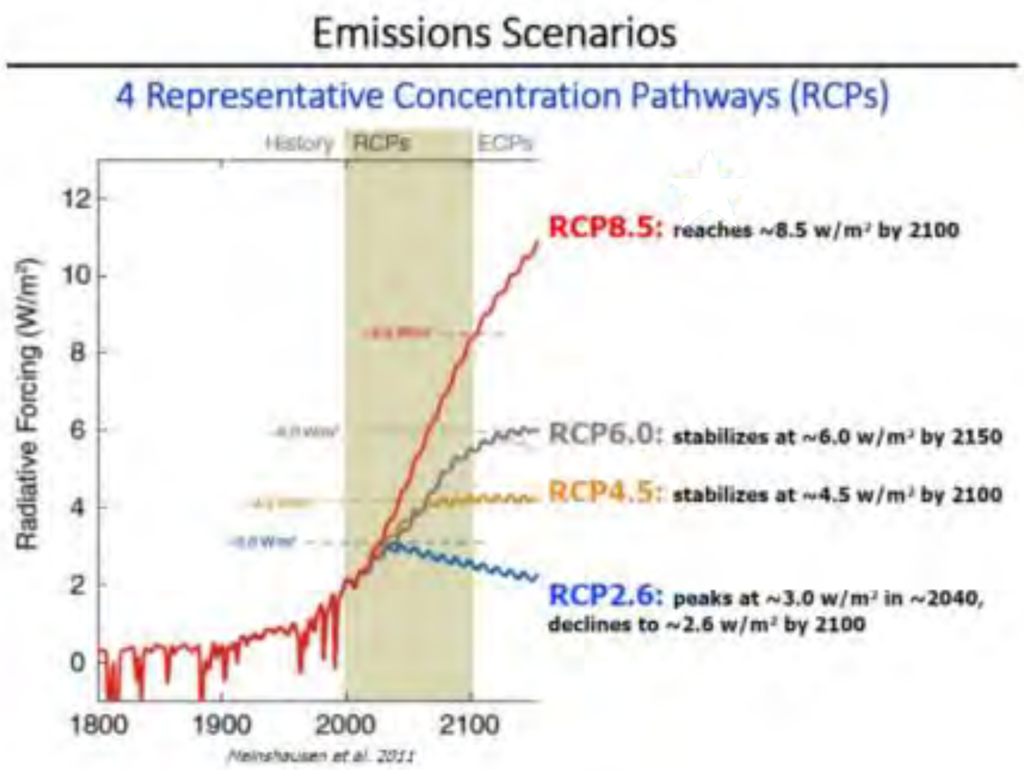
Climate Change Data Sources

- Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition
  - River Management Joint Operating Committee (RMJOC)
    - BPA, US Army Corps of Engineers, US Bureau of Reclamation
  - Research Team
    - University of Washington, Oregon State University
- Daily Max/Min Temp available for 1950-2099



Global Climate Models

- Global Climate Models (GCMs)
  - Coarse resolution ranging from 75 to 300 km grid size
  - Provides projections of temperature and precipitation
  - Multiple Representative Concentration Pathways (RCF 8.5)
  - 10 GCM models used in study
    - CanESM2 (Canada)
    - CCSM4 (US)
    - CNRM-CM5 (France)
    - CSIRO-Mk3-6-0 (Australia)
    - GFDL-ESM2M (US)
    - HadGEM2-CC (UK)
    - HadGEM2-ES (UK)
    - inmcm4 (Russia)
    - IPSL-CM5-MR (France)
    - MIROC5 (Japan)



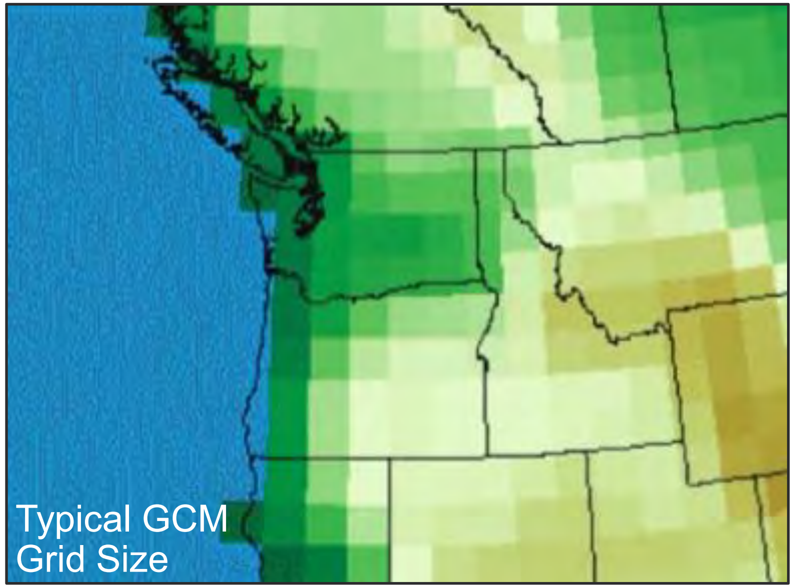
Representative Concentration Pathways

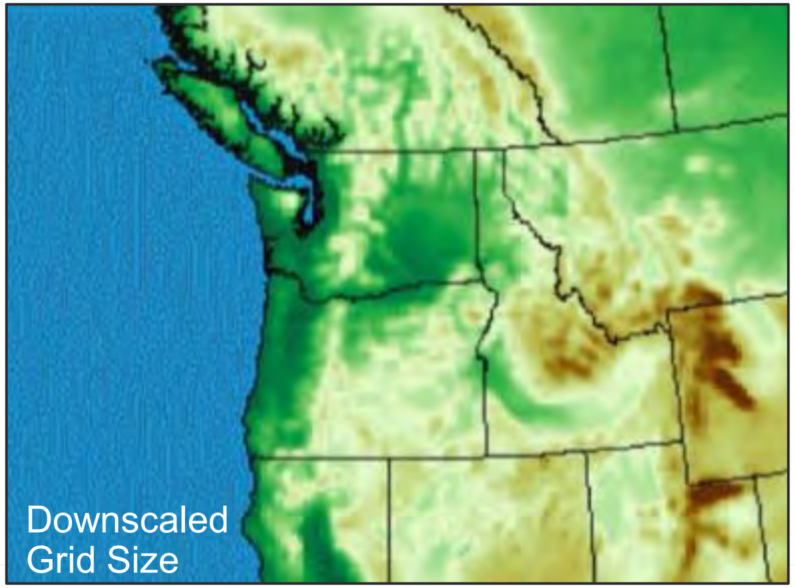
- Description by Intergovernmental Panel on Climate Change (IPCC)
  - RCP2.6 – stringent mitigation scenario
  - RCP4.5 & RCP6.0 – intermediate scenarios
  - RCP8.5 – very high GHG emissions
- RMJOCII Study evaluated RCP4.5 and RCP8.5
- RCP4.5 and RCP6.0 similar within the IRP planning horizon

	Scenario	2046-2065		2081-2100	
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (C°)	RCP2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

Downscaling Techniques

- Downscale GCM data to finer resolution necessary to model hydrology
  - Statistical methods to represent variation within large grid size
  - Two methods used (BCSD, MACA)
    - Bias Corrected Spatial Disaggregation
    - Multivariate Adaptive Constructed Analog
- 18 modeled data sets available for Spokane, Medford, and La Grande
- 9 modeled data sets available for Klamath Falls



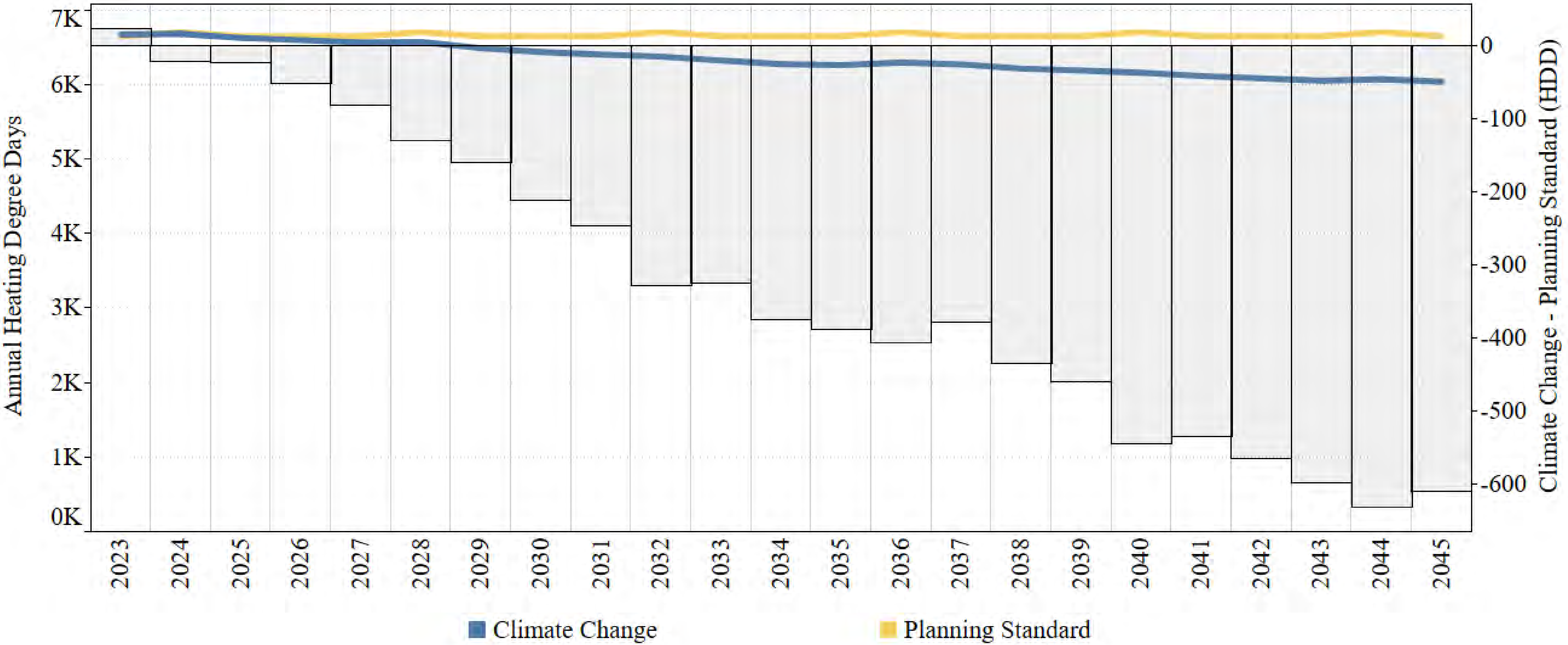


Weather Summary

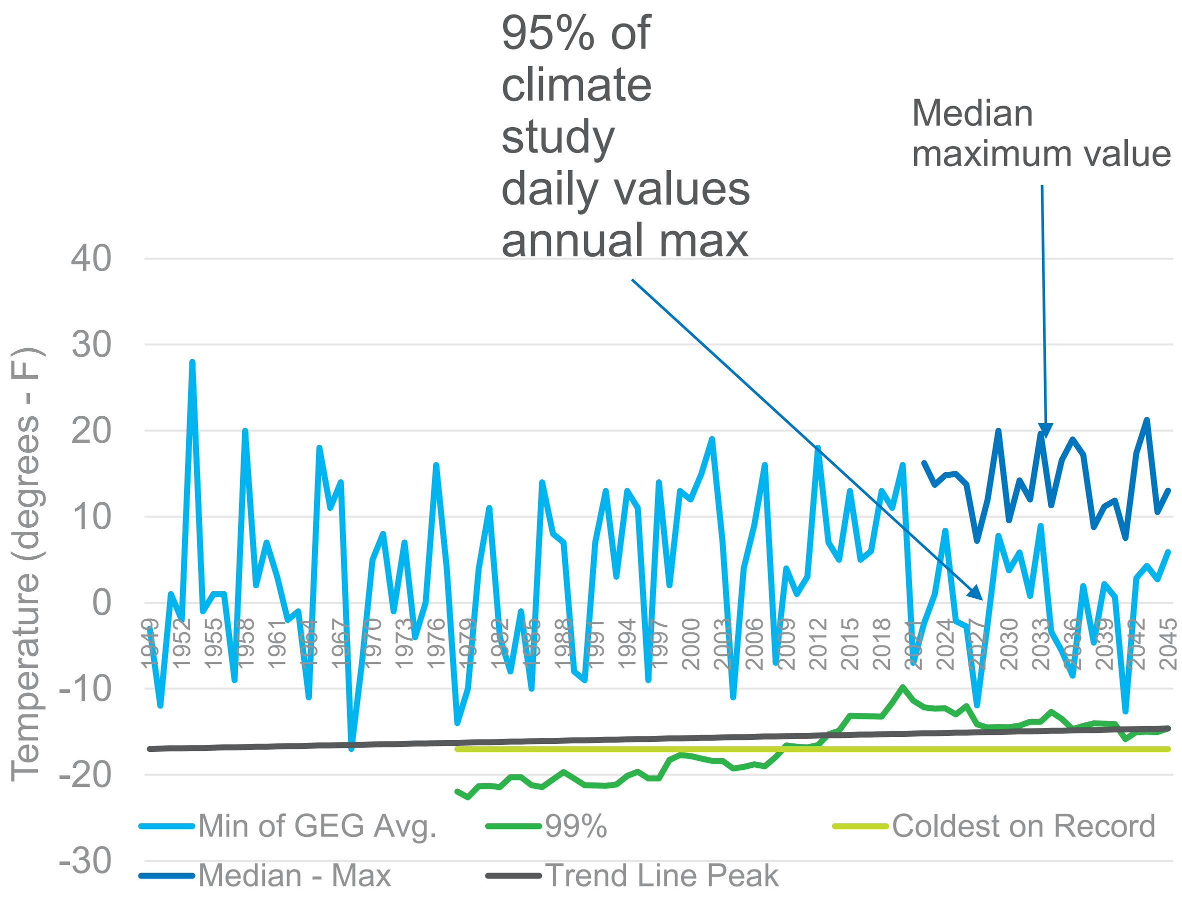
- Average daily weather by planning region for the prior 20 years including climate change weather data.
  - Example:
    - 2022 data is from 2002 – 2021
    - 2030 data is from 2010 – 2029
  - Median of daily values for all climate study results by area

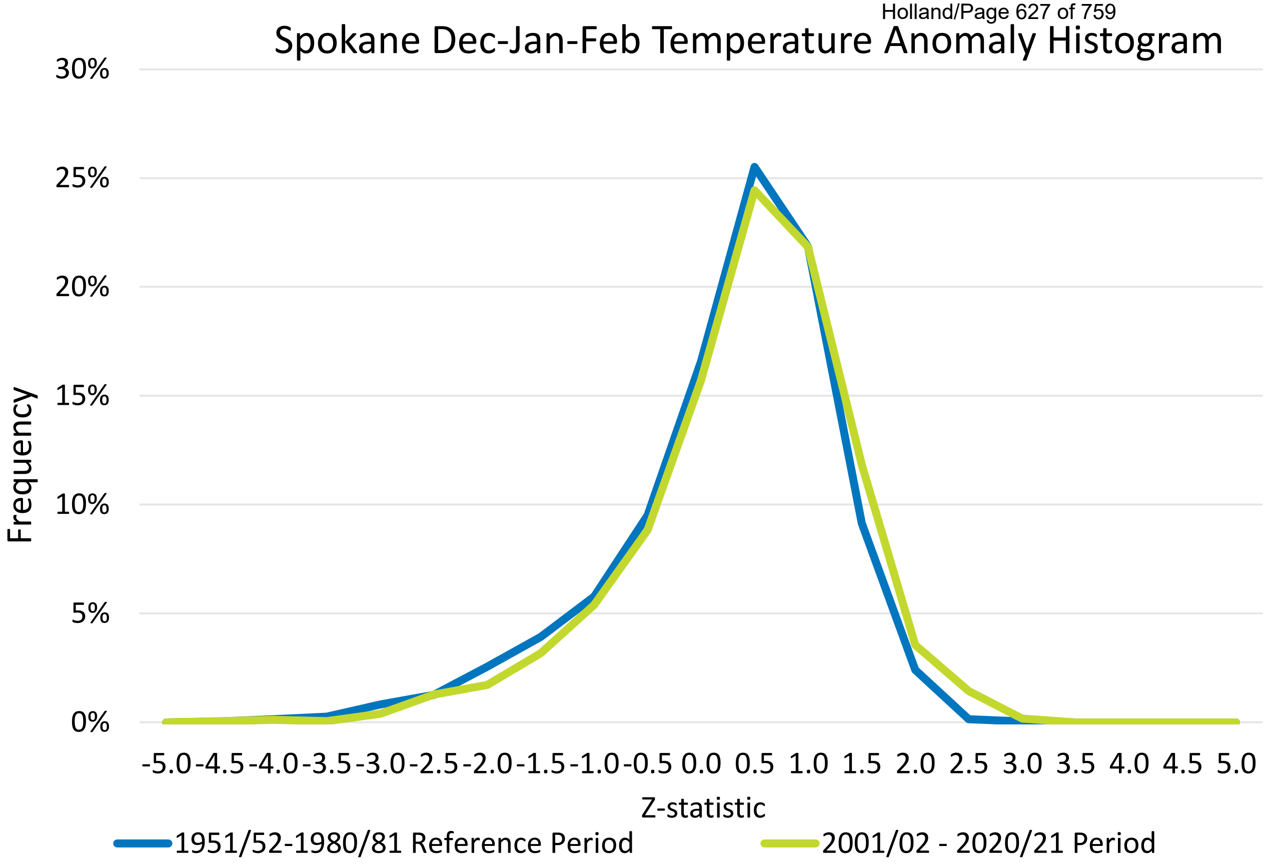
- A peak event by planning region based on the past 30 years of the coldest average day, each year, combined with a 1% probability of a weather occurrence
  - Calculation now includes future projected peak values and is trended to the 2045 value from the historic coldest on record to smooth out volatility of peak day temperatures
  - Using the median values as peak day drastically reduces the temperatures for the design weather day
  - Taking the 95th percentage of climate models daily results and utilizing the highest annual value to include in the peak calculation reduces this risk of unserved customers

Idaho – Washington

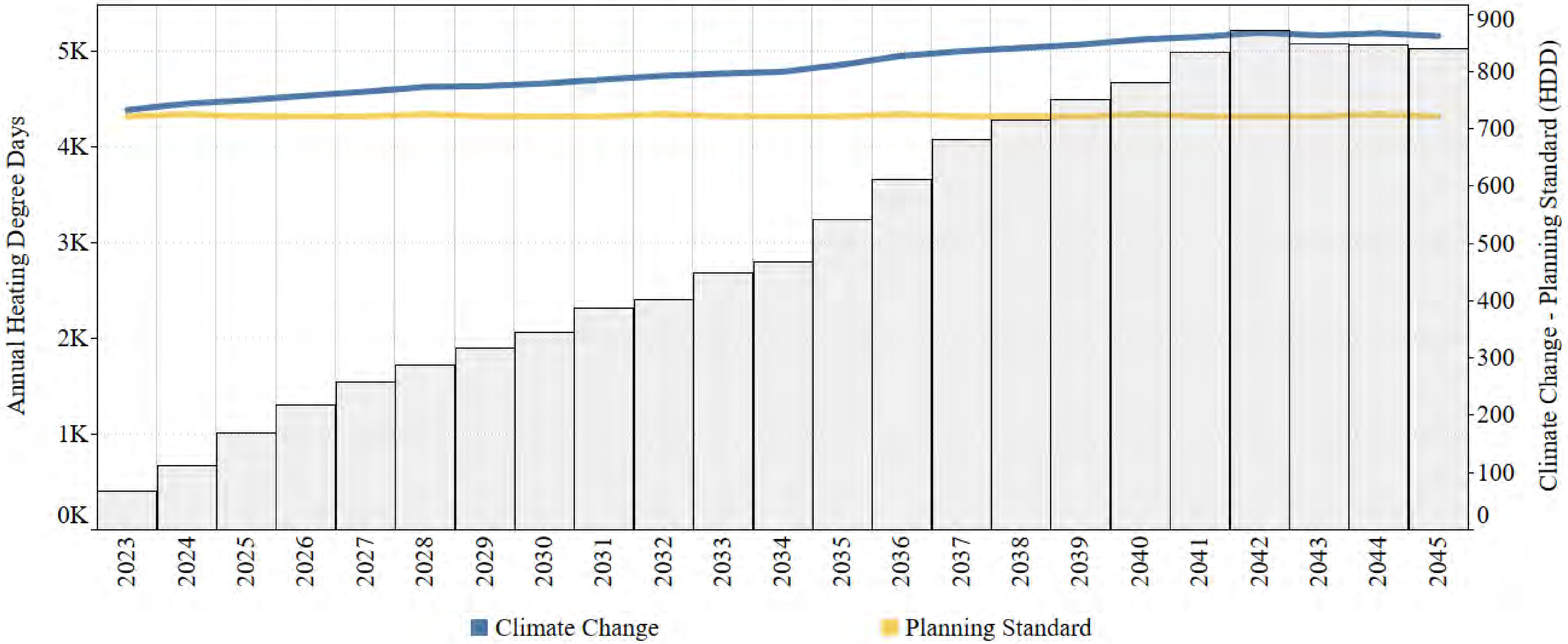


Idaho – Washington

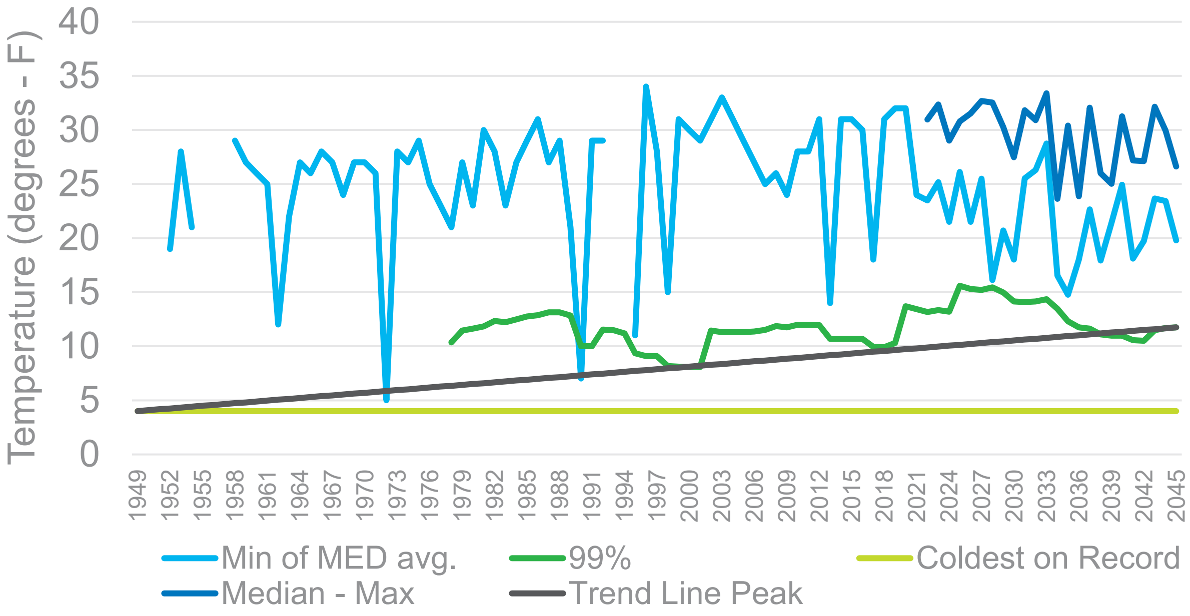


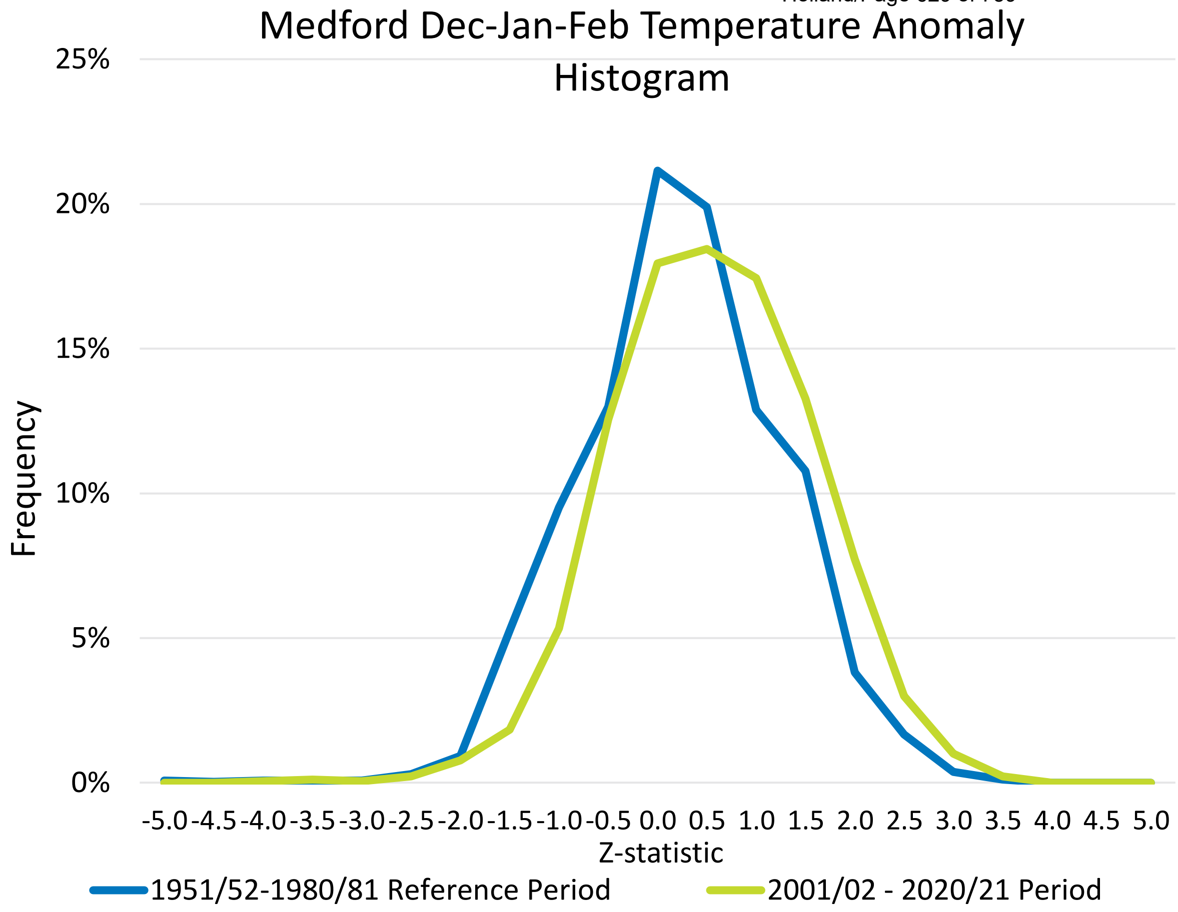


Medford

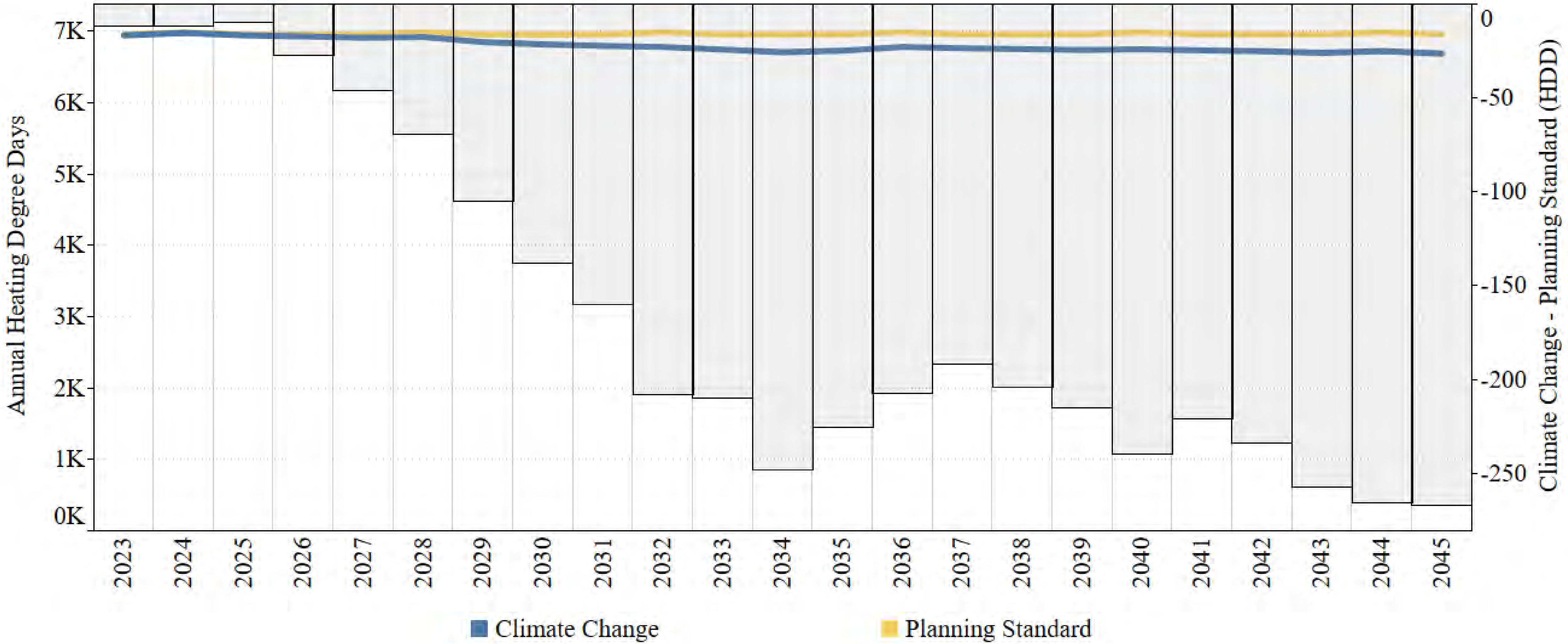

Annual Heating Degree Days
5K
4K
3K
2K
1K
0K
900
800
700
600
500
400
300
200
100
0
Climate Change - Planning Standard (HDD)
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Climate Change
Planning Standard

Medford

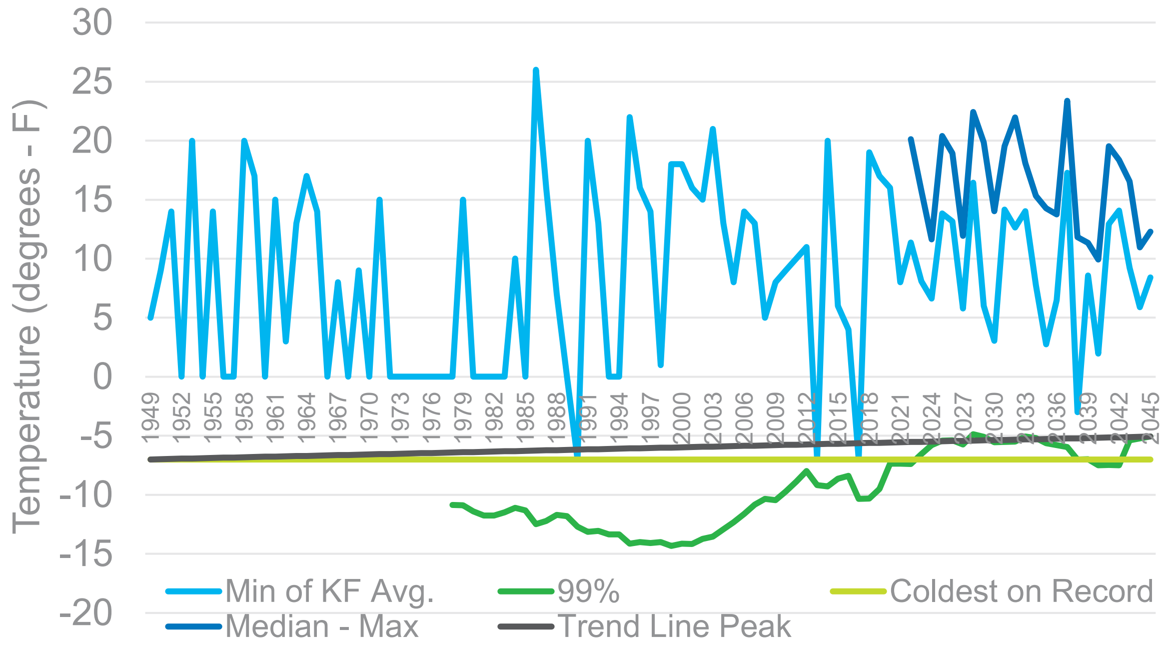

Temperature (degrees - F)
40
35
30
25
20
15
10
5
0
1949
1952
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
2012
2015
2018
2021
2024
2027
2030
2033
2036
2039
2042
2045
Min of MED avg.
99%
Coldest on Record
Median - Max
Trend Line Peak

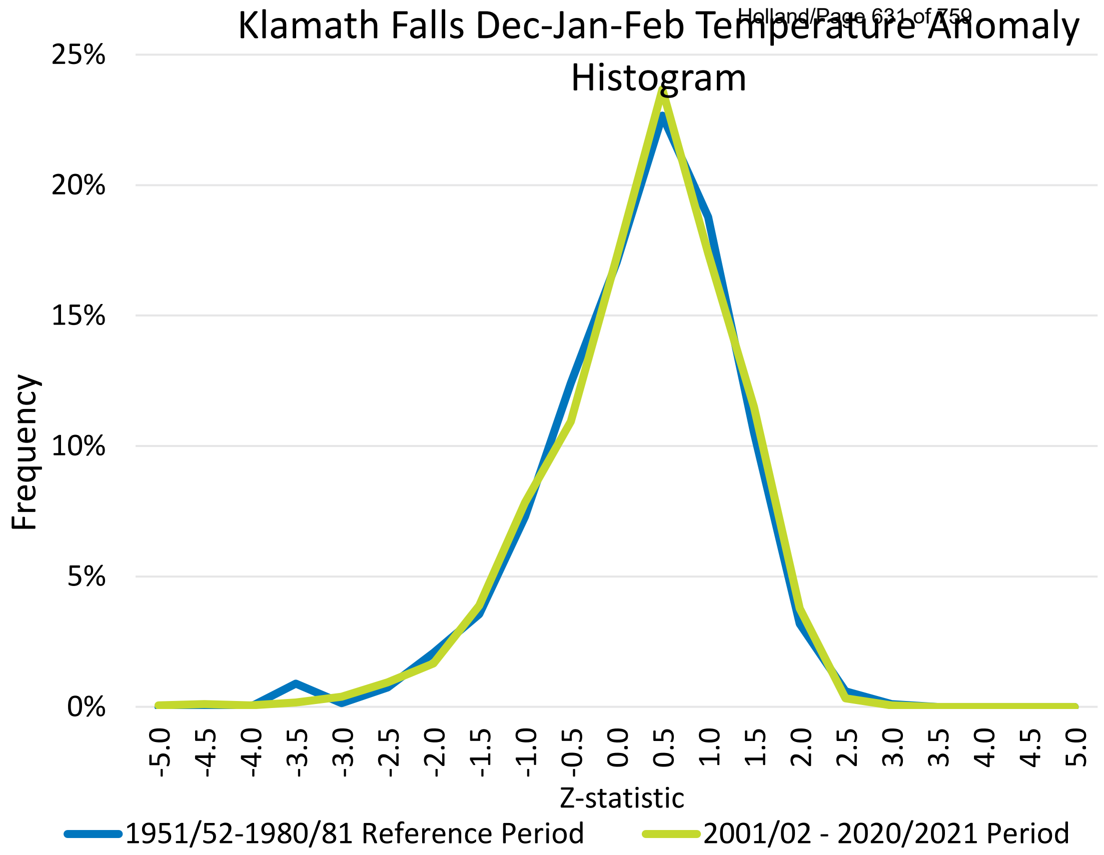

Medford Dec-Jan-Feb Temperature Anomaly Histogram
Frequency
25%
20%
15%
10%
5%
0%
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2020/21 Period

Klamath Falls

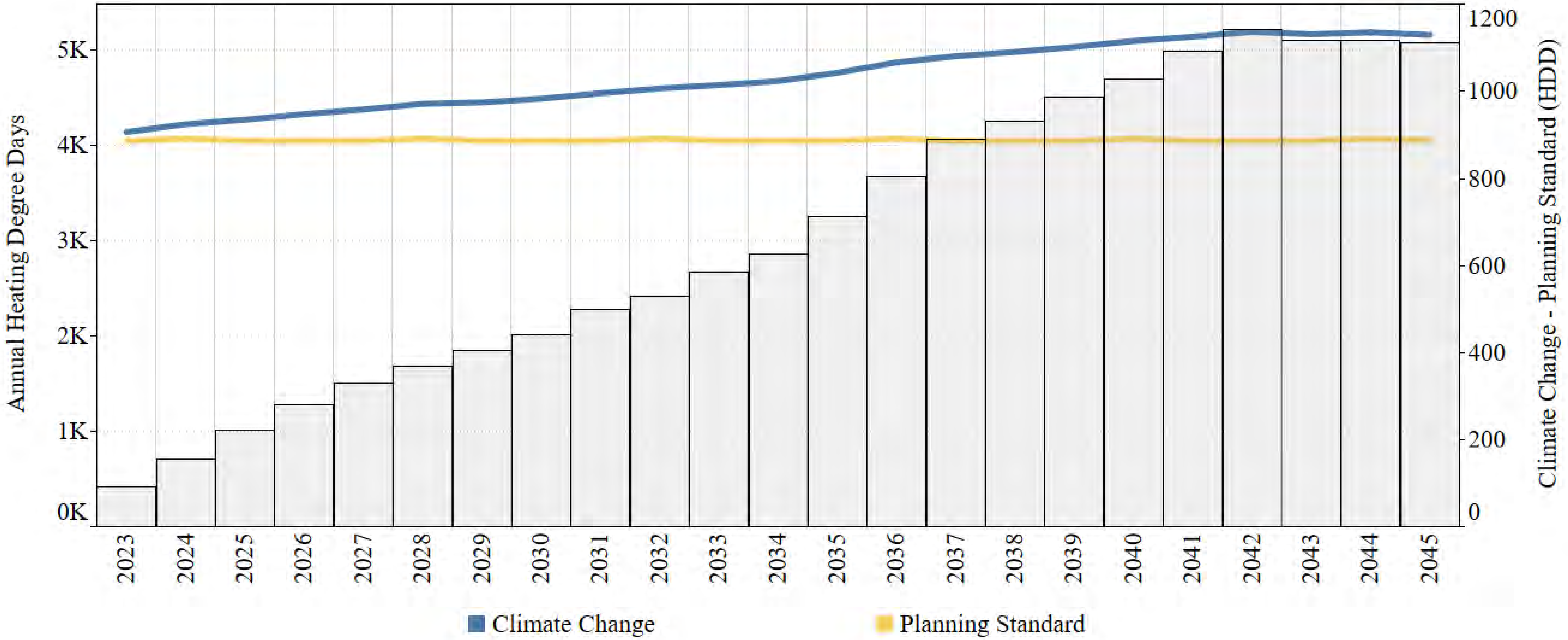


Klamath Falls

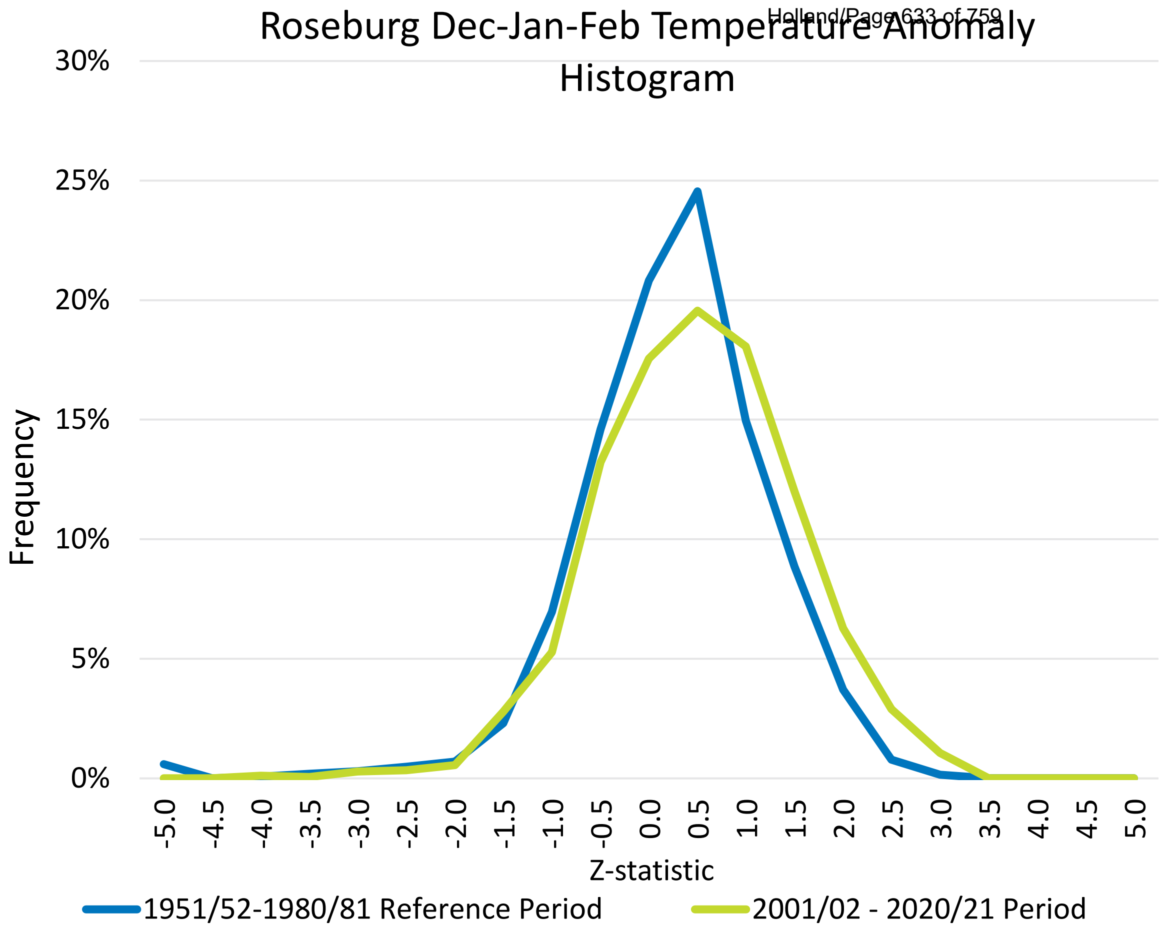


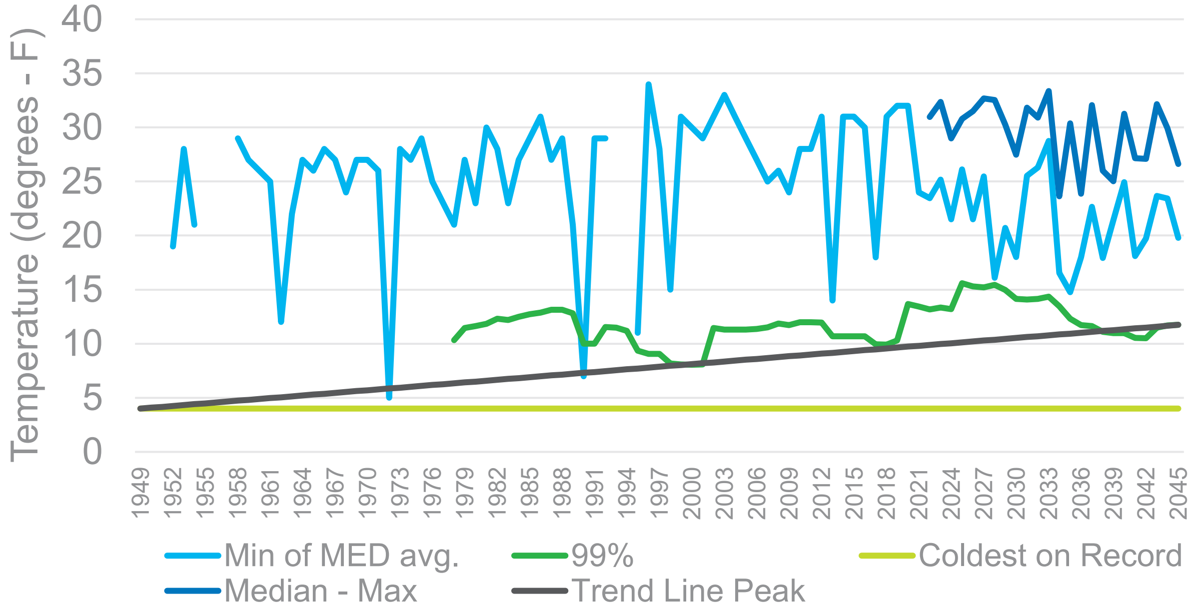


Roseburg

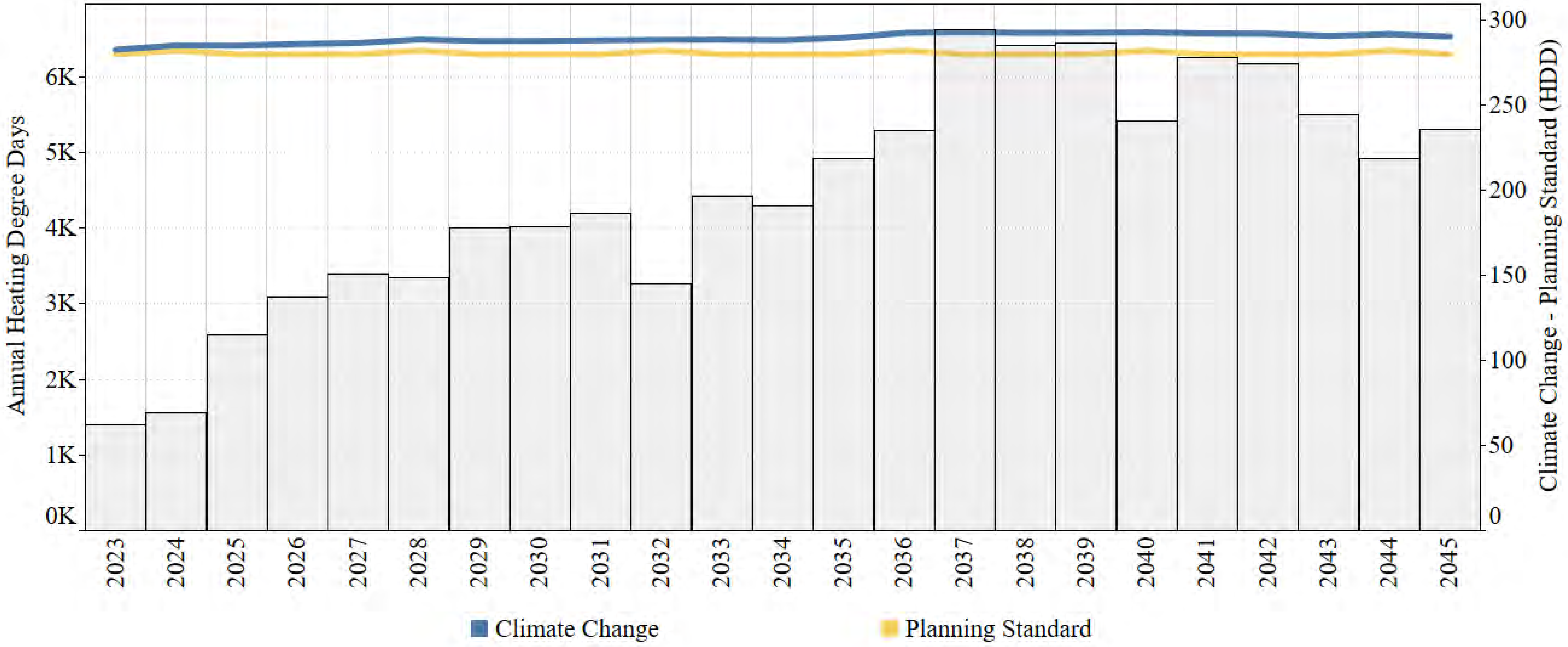

Annual Heating Degree Days
5K
4K
3K
2K
1K
0K
1200
1000
800
600
400
200
0
Climate Change - Planning Standard (HDD)
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Climate Change
Planning Standard

Roseburg

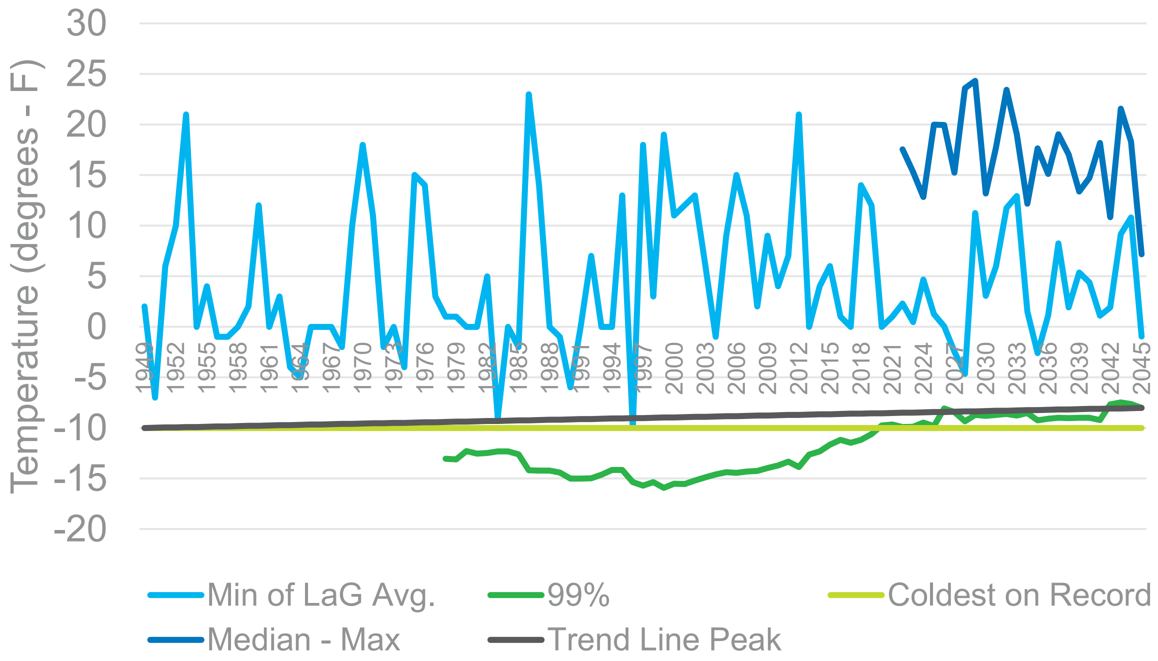

Roseburg Dec-Jan-Feb Temperature Anomaly Histogram
Frequency
30%
25%
20%
15%
10%
5%
0%
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2020/21 Period

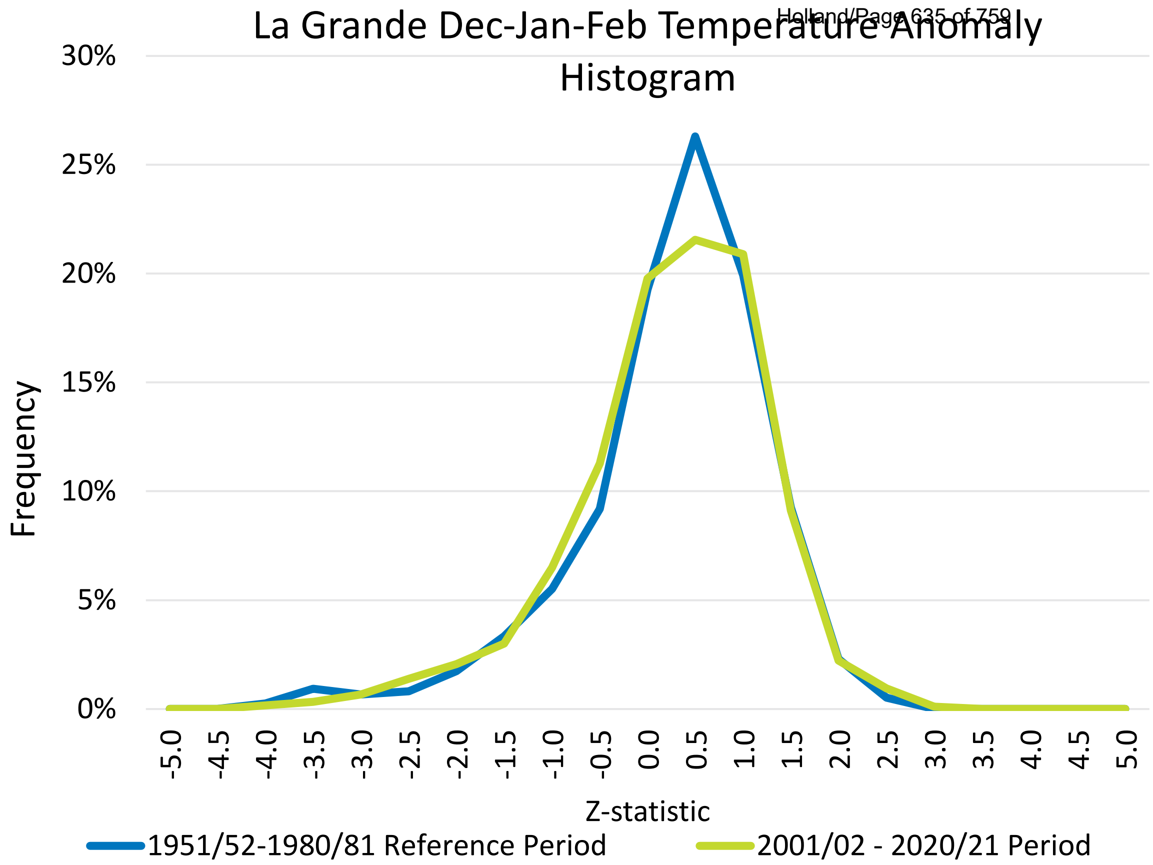

Temperature (degrees - F)
40
35
30
25
20
15
10
5
0
1949 1952 1955 1958 1961 1964 1967 1970 1973 1976 1979 1982 1985 1988 1991 1994 1997 2000 2003 2006 2009 2012 2015 2018 2021 2024 2027 2030 2033 2036 2039 2042 2045
Min of MED avg.
99%
Coldest on Record
Median - Max
Trend Line Peak

La Grande


Annual Heating Degree Days
0K
1K
2K
3K
4K
5K
6K
Climate Change - Planning Standard (HDD)
0
50
100
150
200
250
300
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Climate Change
Planning Standard

La Grande





AVISTA

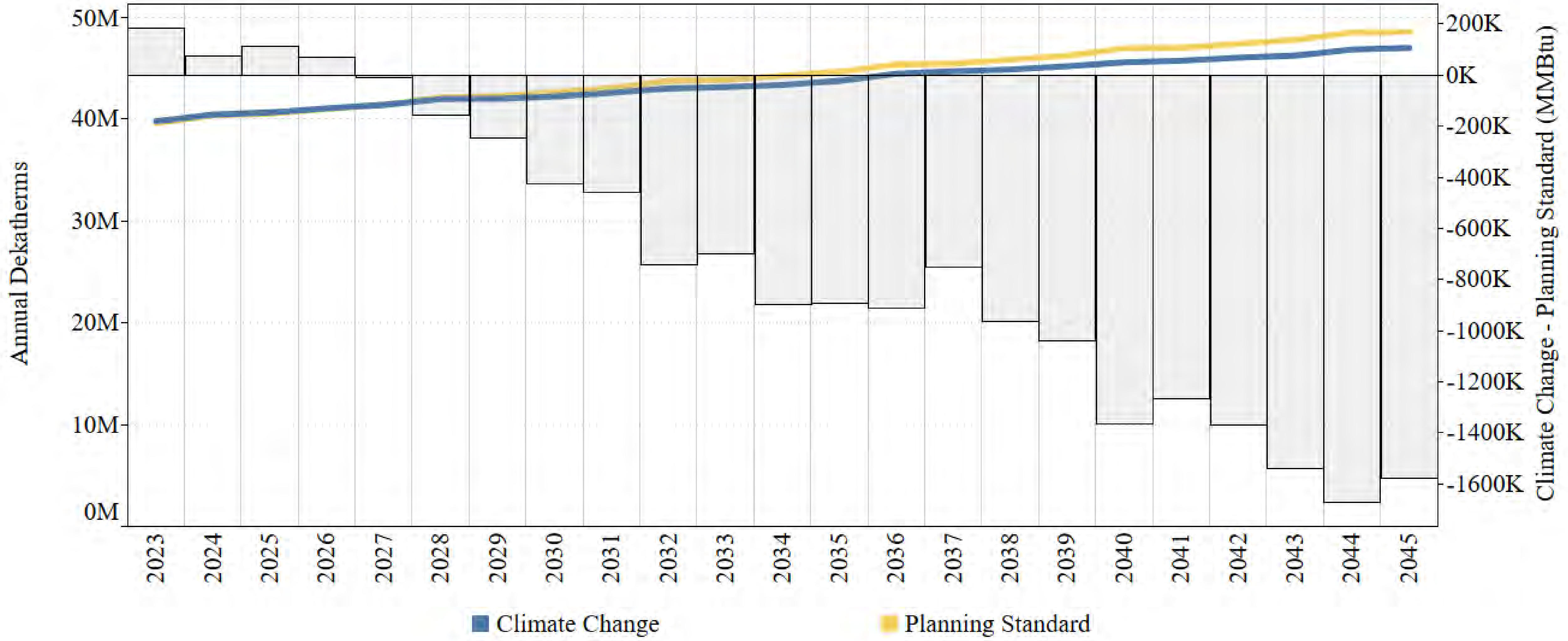
Peak Temp Changes
(degrees Fahrenheit)

Planning Region	Coldest on Record	2021 IRP Peak	Trended Peak 2045
La Grande, Oregon	-10	-11	-8.0
Klamath Falls, Oregon	-7	-9	-5.1
Medford/Roseburg, Oregon	4	11	11.7
Spokane, ID/WA	-17	-12	-14.6

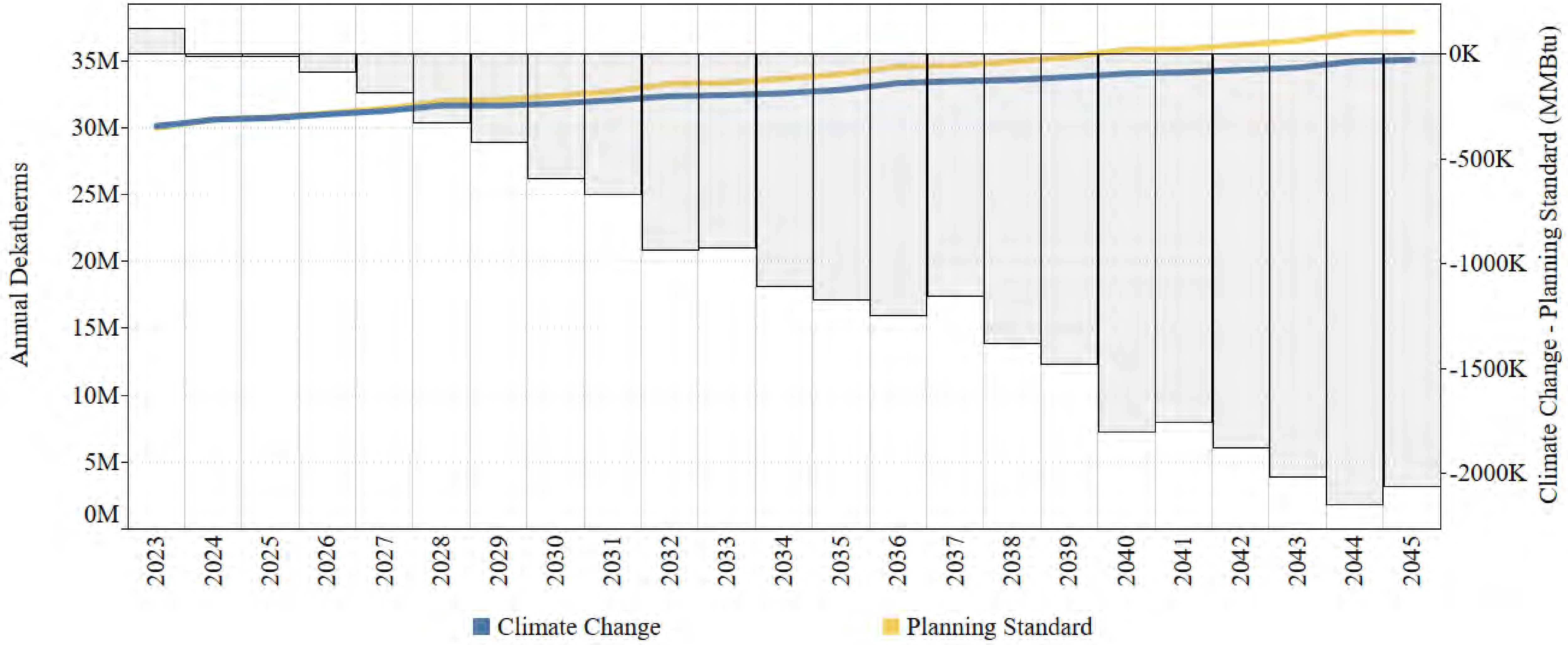
Updated Load Forecast
(includes climate change weather)

Michael Brutocao

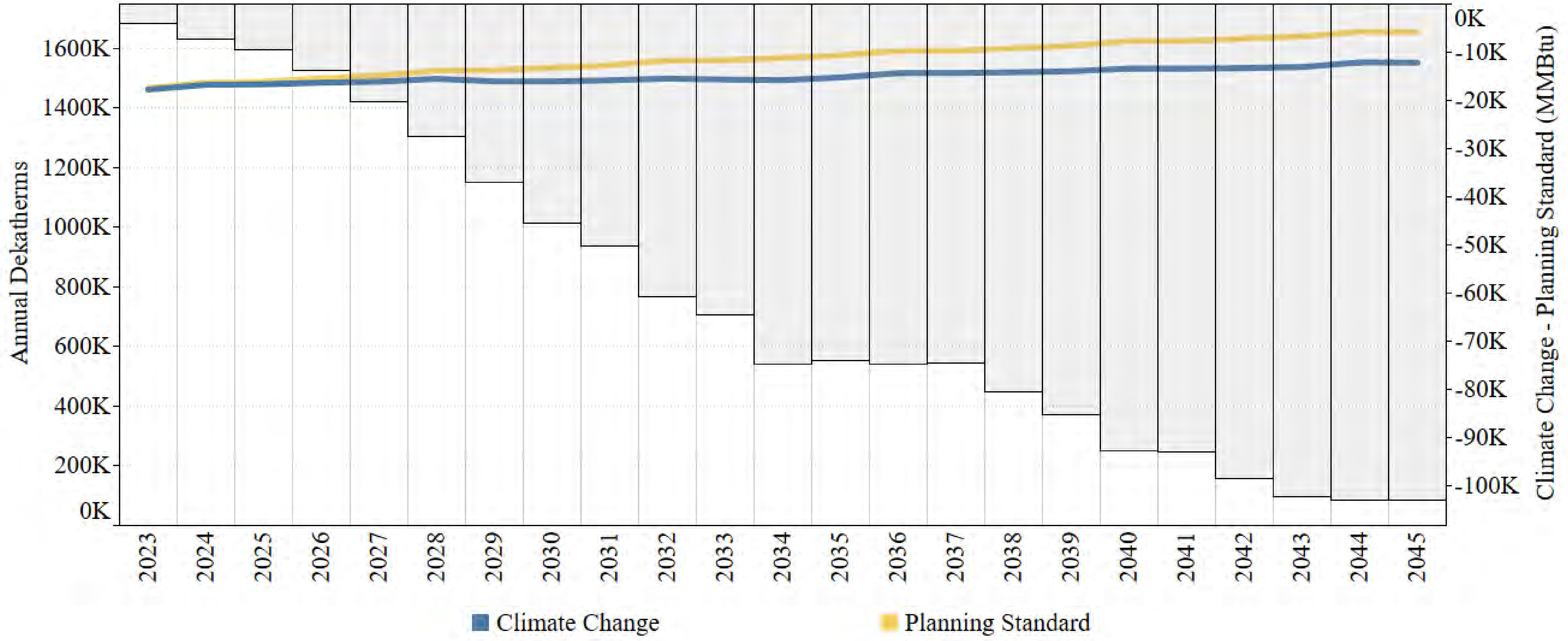
Annual System



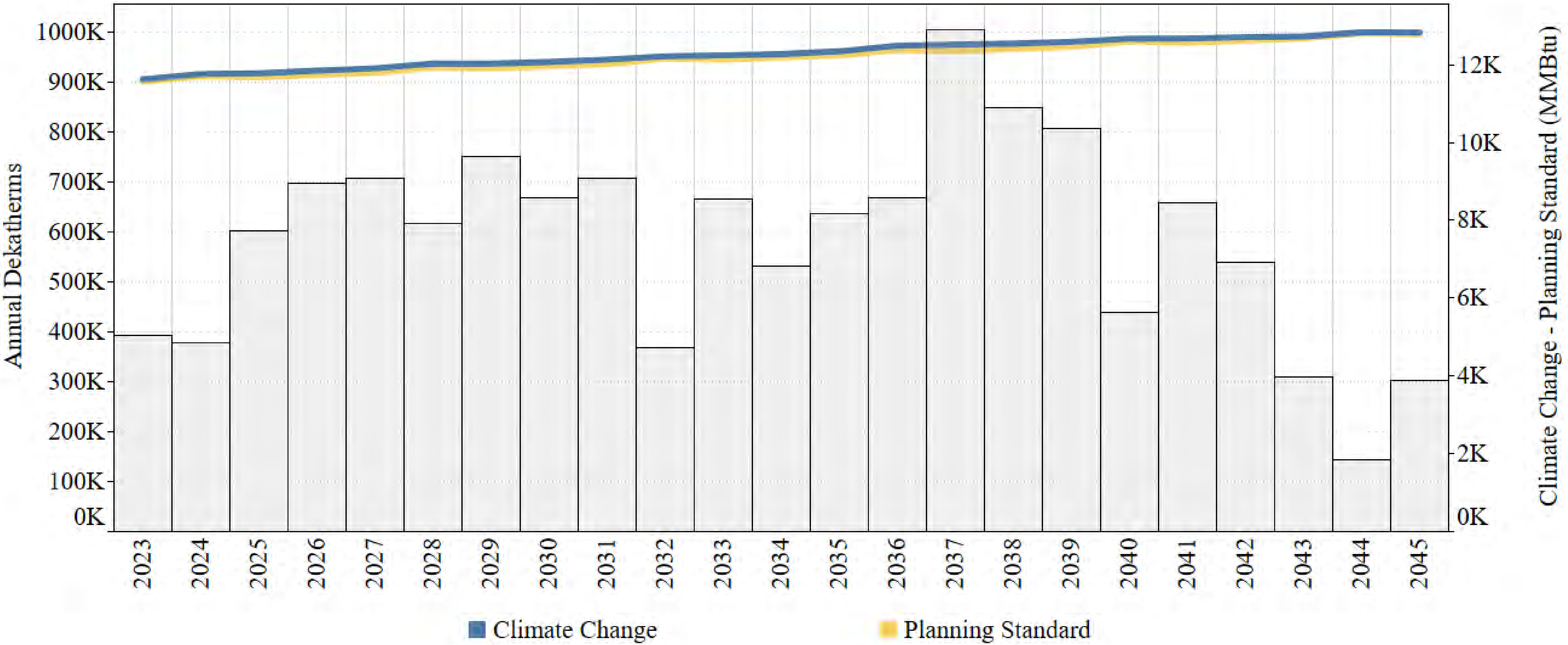
Annual Idaho – Washington



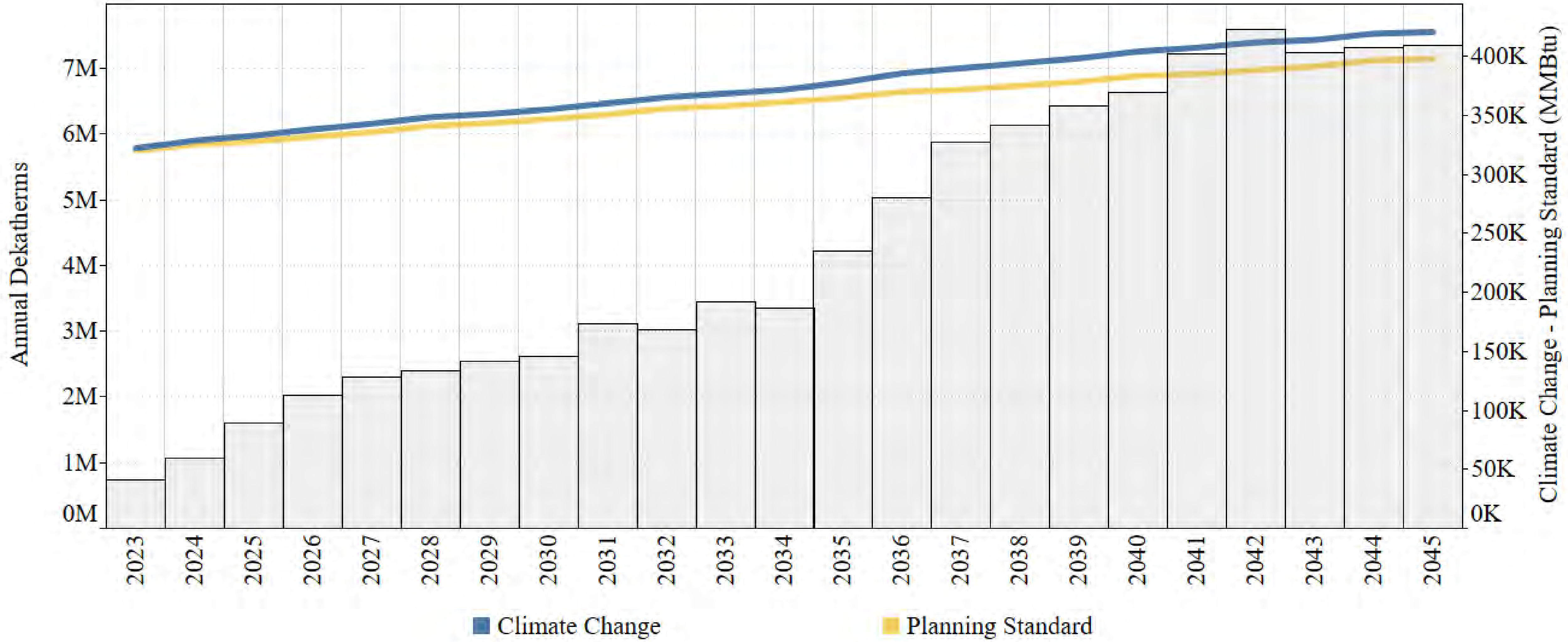
Annual Klamath Falls



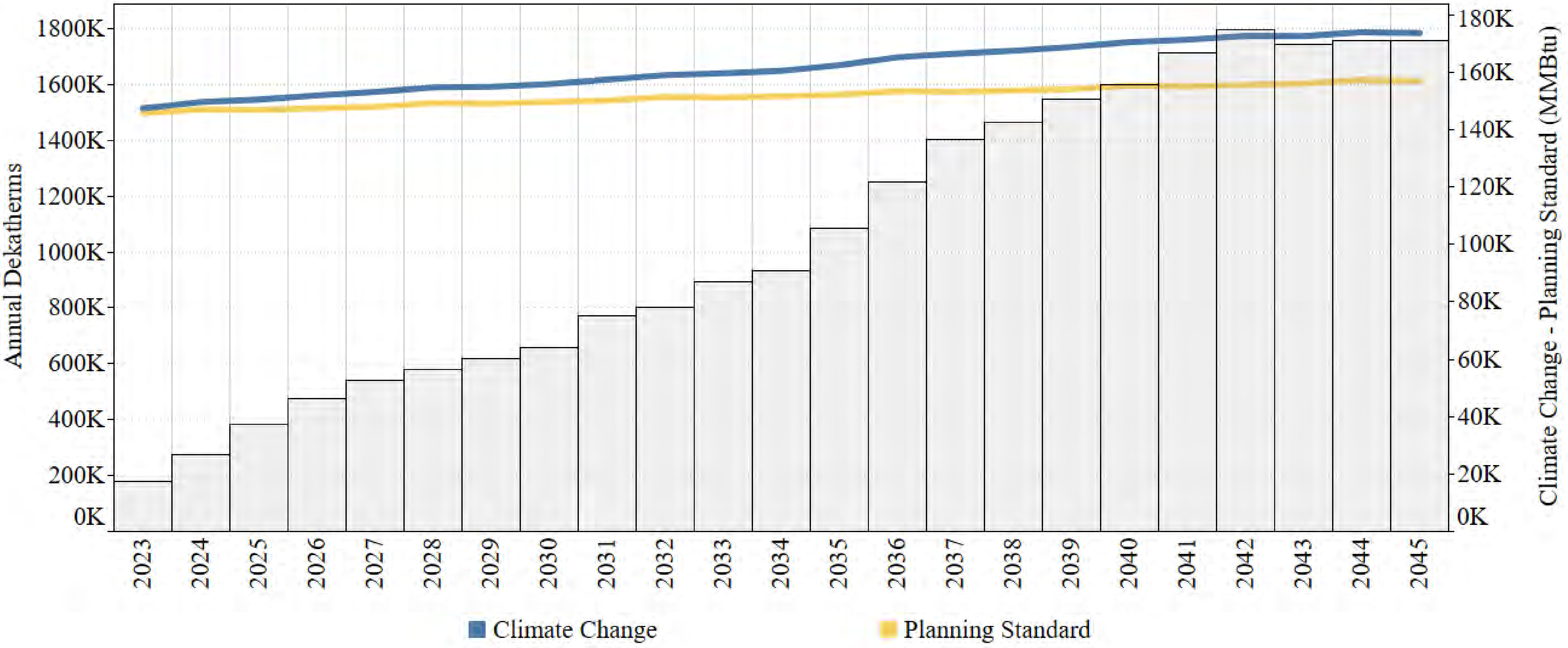
Annual La Grande



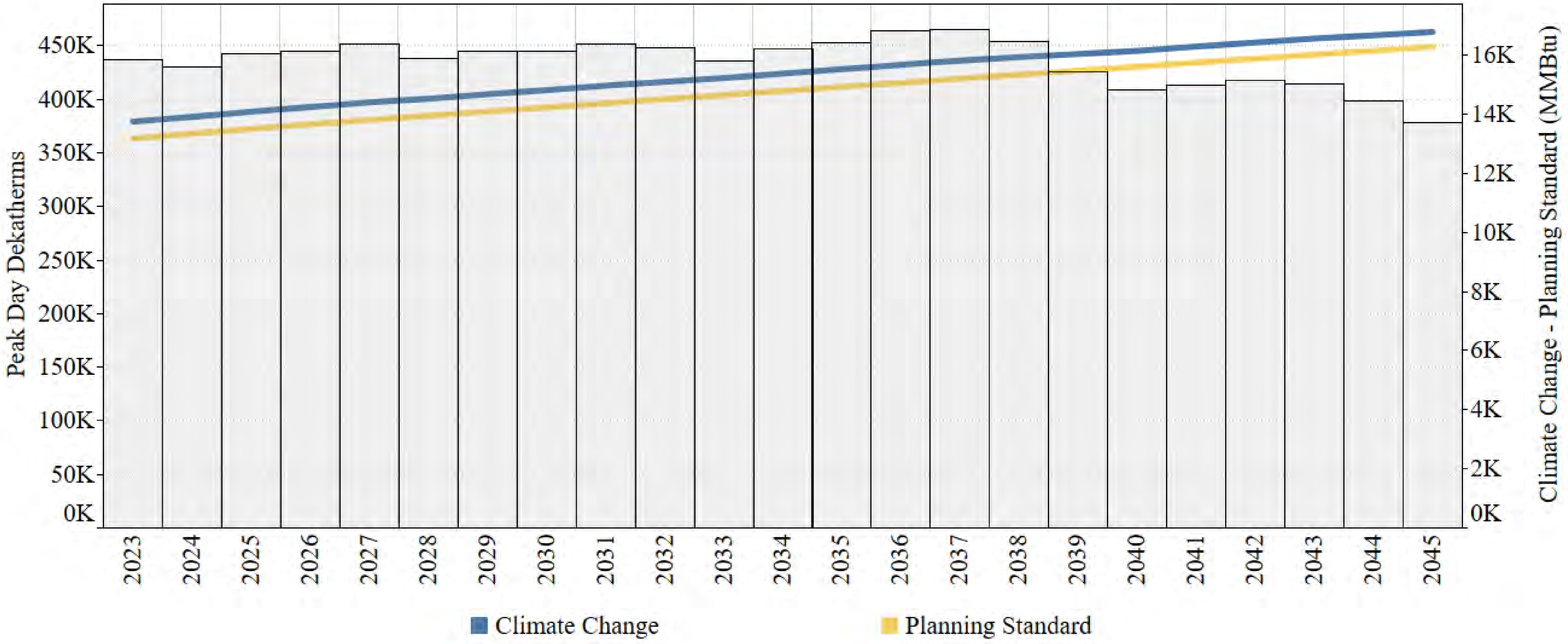
Annual Medford



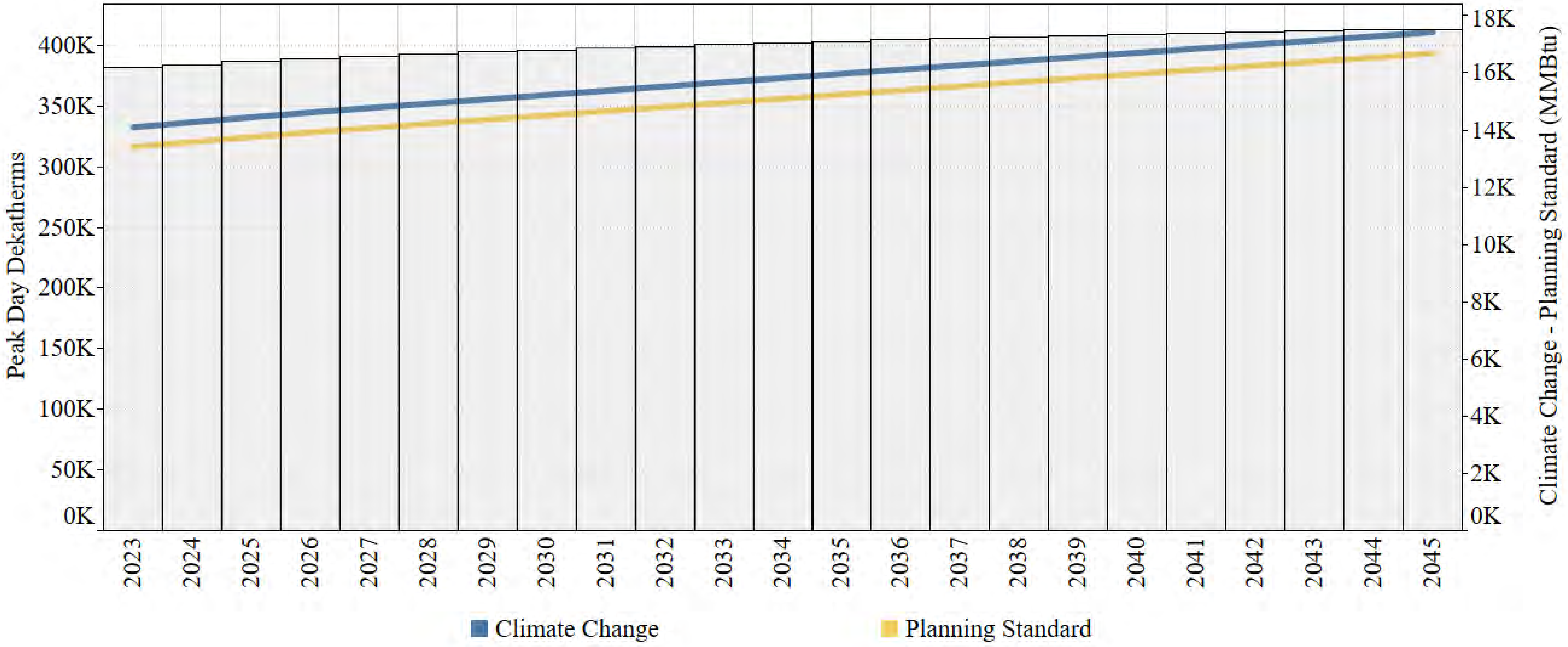
Annual Roseburg



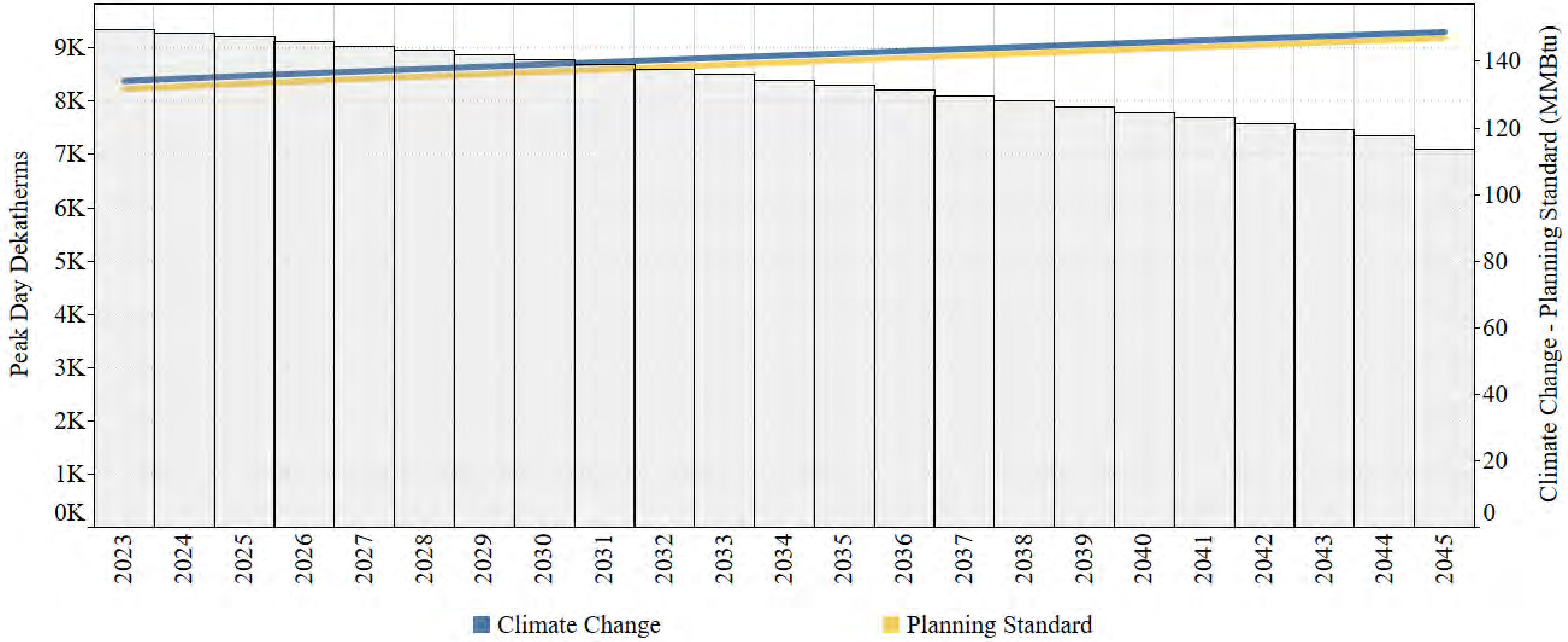
System Peak Day (Feb 28)



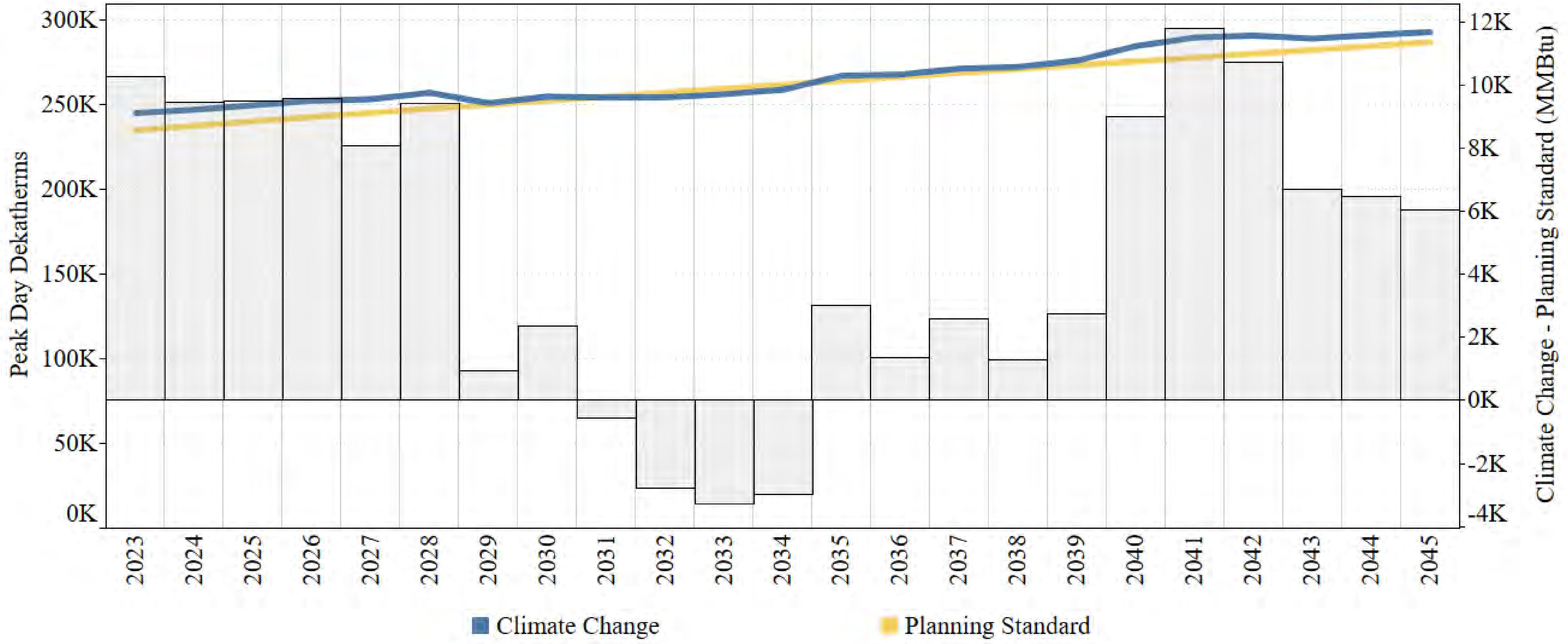
Idaho – Washington Peak Day (Feb 28)



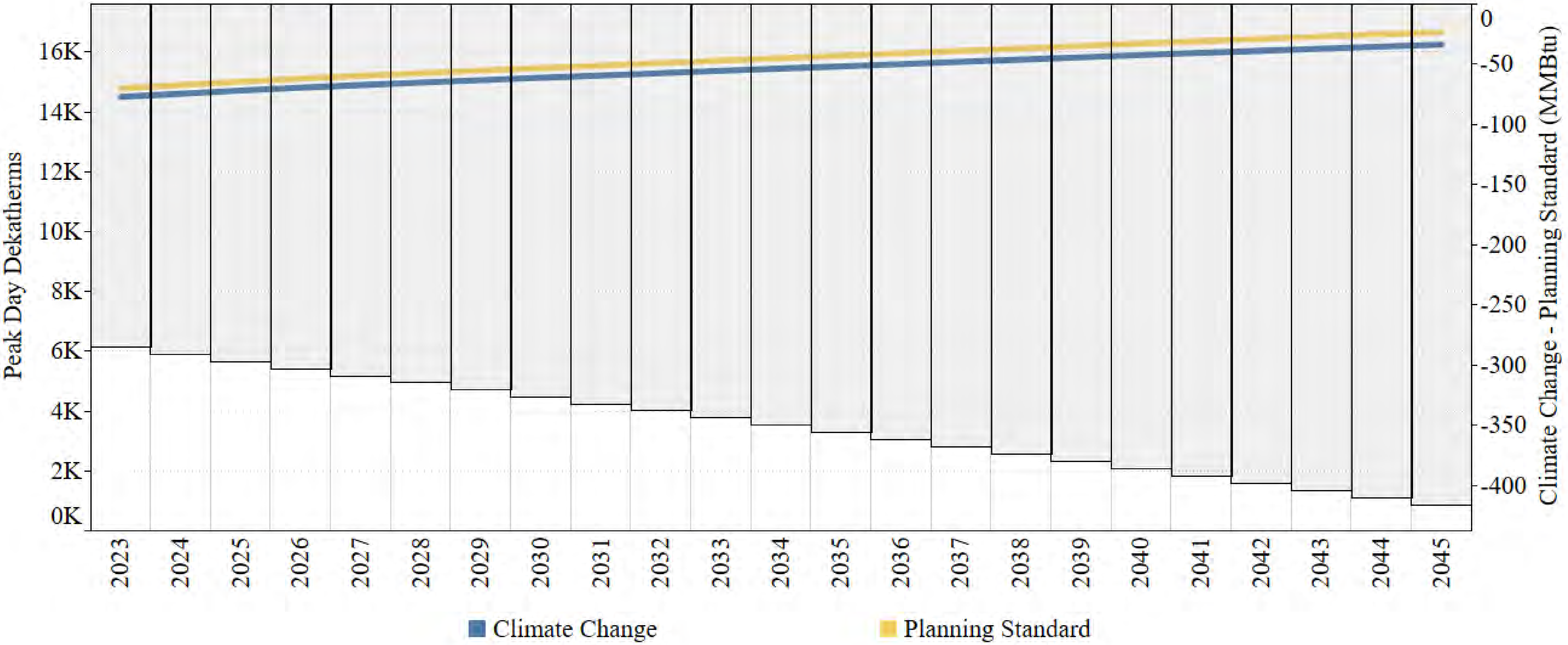
La Grande Peak Day (Feb 28)



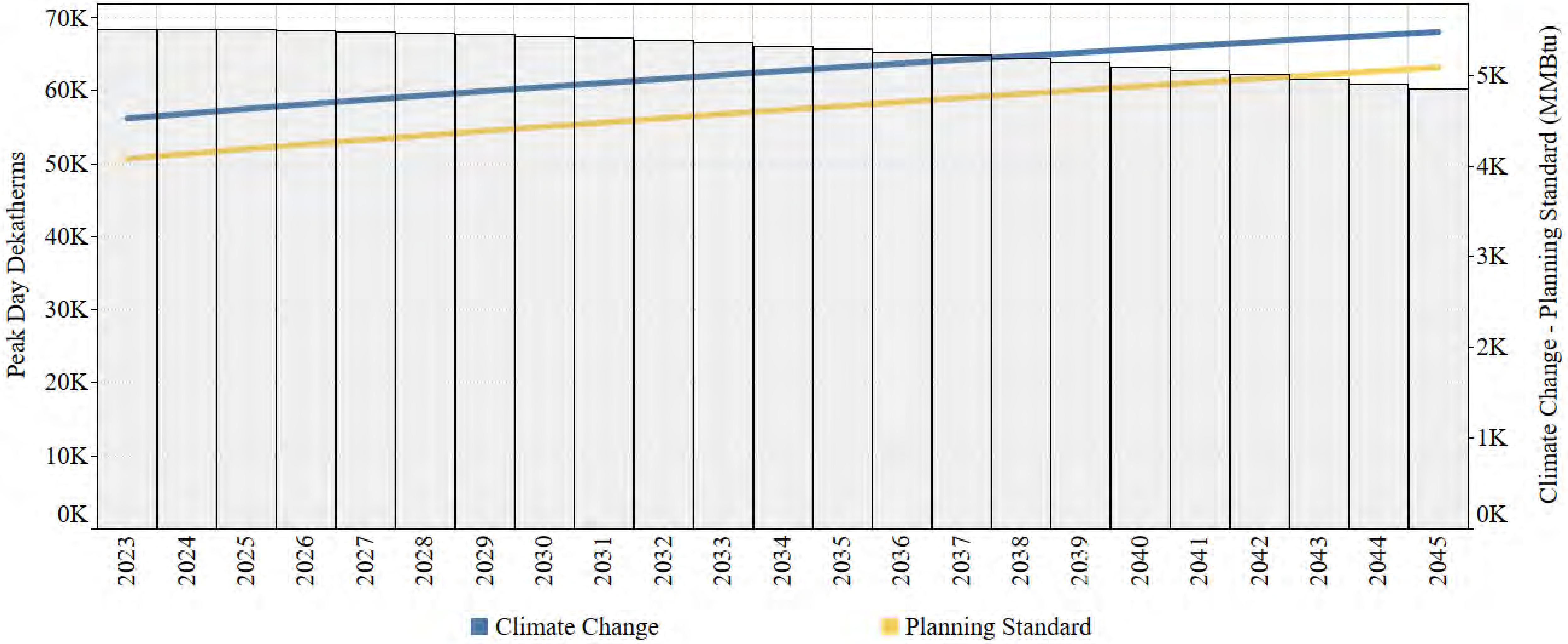
System Peak Day (Dec 20)



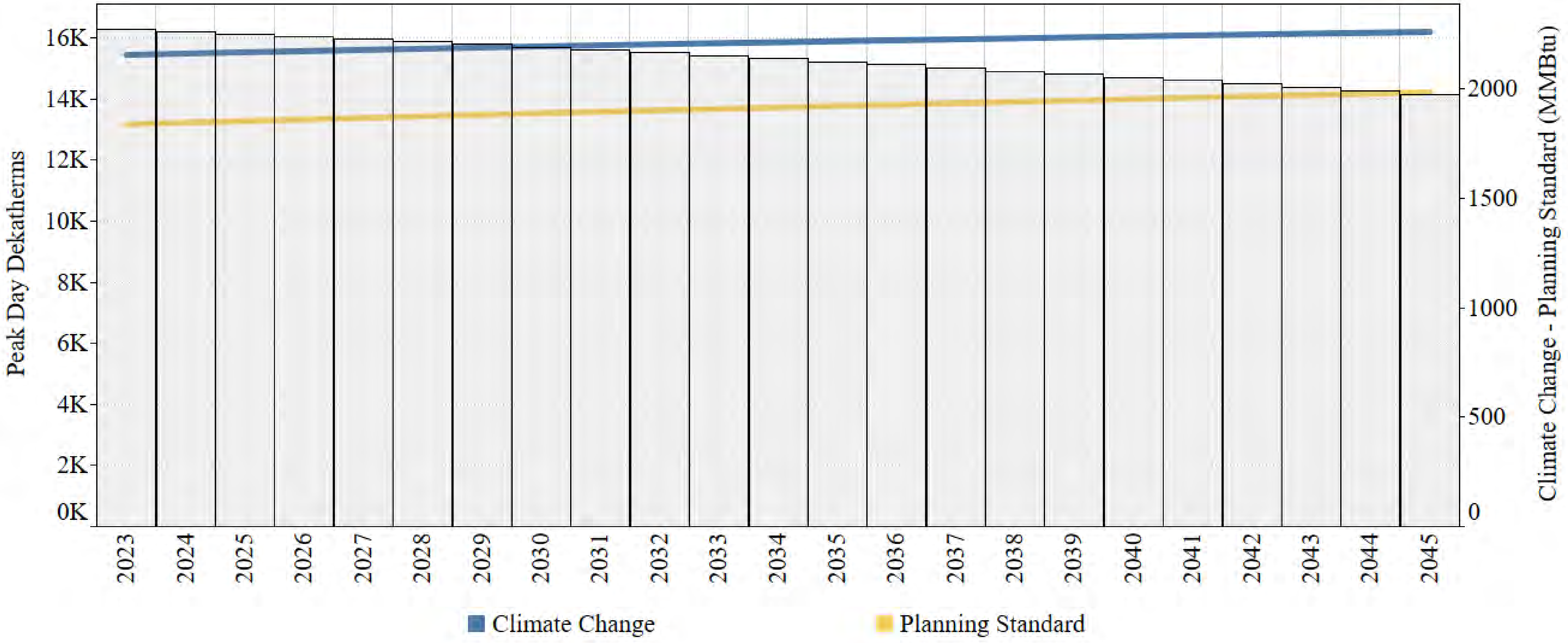
Klamath Falls Peak Day (Dec 20)



Medford Peak Day (Dec 20)



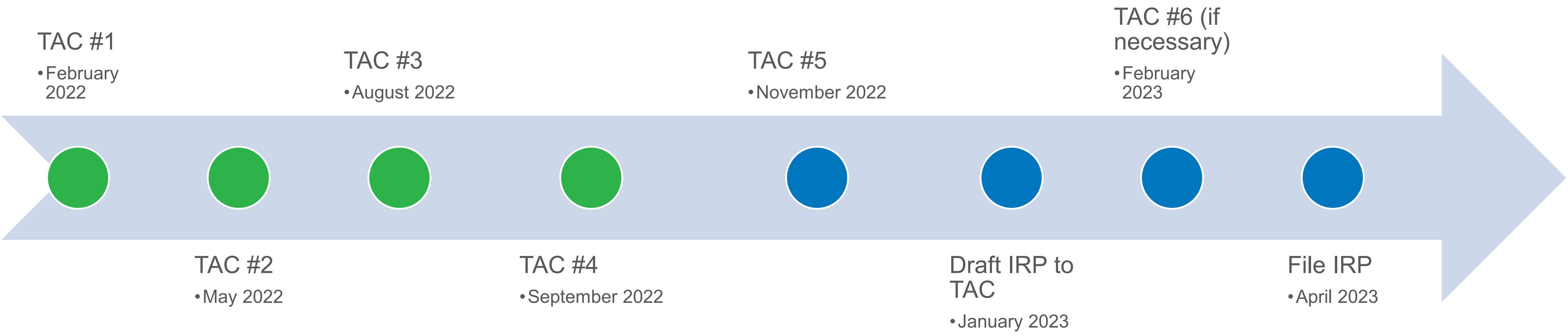
Roseburg Peak Day (Dec 20)



Scenarios

- **Preferred Resource Case** – Our expected case based on assumptions and costs with a least risk and least cost resource selection
- **Preferred Resource Case Low Prices** – Same as PRS, but includes low price curve for natural gas
- **Preferred Resource Case High Prices** - Same as PRS, but includes high price curve for natural gas
- **Electrification Expected Conversion Costs –** Expected conversion costs case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **Electrification Low Conversion Costs –** A low conversion cost case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **High Customer Case** – A high case to measure risk of additional customer and meeting our emissions and energy obligations
- **Limited RNG Availability** – A scenario to show costs and supply options if RNG availability is smaller than expected
- **Interrupted Supply** – A scenario to show the impacts and risks associated with large scale supply impacts and the ability for Avista to provide the needed energy to our customers
- **Carbon Intensity –** Include carbon intensity of all resources from Preferred Resource Case including upstream emissions on natural gas
- **Social Cost of Carbon** – A scenario to value resources in all locations using the Social Cost of Carbon @ 2.5% and includes upstream emissions
- **Average Case** – Non climate change projected 20-year history of average daily weather and excludes peak day
- **Hybrid Case** – Natural Gas used for space heat below 40º F while transferring all other usage to electricity.

2023 – Avista Natural Gas IRP



Natural Gas Integrated Resource Plan

Technical Advisory Committee (TAC) # 5

December 15, 2022

Safe Harbor Statement

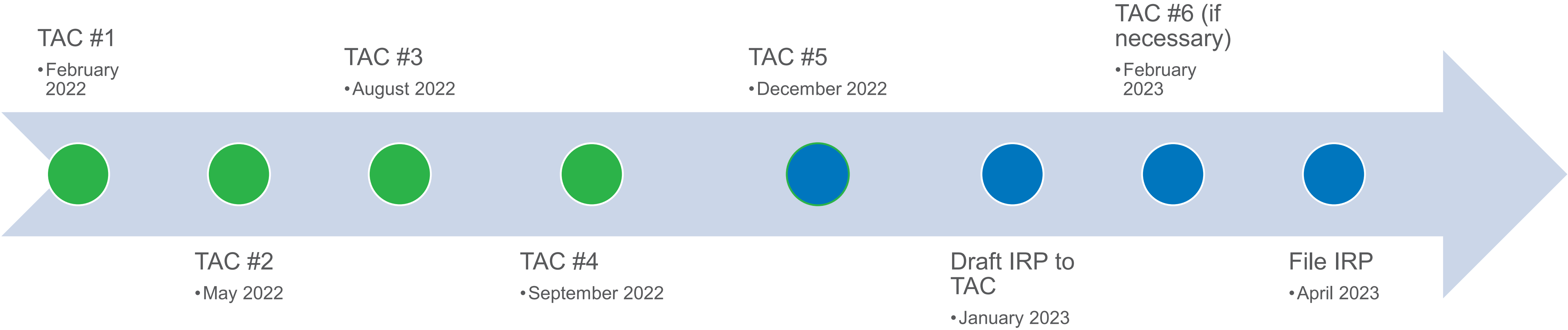
This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition,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

Agenda

Item	Time
Applied Energy Group – Demand Response	9:00am – 9:30am
Distribution	9:30am – 10:15am
Review Assumptions	10:15am – 10:30am
Break	10:30am – 10:40am
Preferred Resource Strategy and Scenario Results	10:40am – 11:30am
WA GRC Commitments - Action Plan - Next Steps	11:30am – 12:00pm

2023 – Avista Natural Gas IRP



Natural Gas Demand Response

Date: 12/15/2022
Prepared for: Avista Technical Advisory Committee

Program Options and Eligibility

DSM Option	States Eligible	Classes Eligible
Behavioral	WA	Res, Com
DLC Smart Thermostats - BYOT	WA, ID, OR	Res, Com
Time-of-Use	WA	Res, C&I
Variable Peak Pricing	WA	Res, C&I
Third Party Contracts	WA, ID, OR	C&I

Assumptions

Study Assumptions

- The programs in this study target the peak hour of the peak day (Dekatherms)
- Winter only

Program Impact and Cost assumptions

- Derived primarily from other Gas DR Programs
  - Smart Thermostat Program based on SoCalGas's Smart Therm Program
  - Third Party Contracts Program based on National Grid and ConEdison Programs
- Diverged where gaps in research exist
  - Customized for Avista's service territory
  - Pulled remaining assumptions from Electric DR Model and scaled down where appropriate

Advanced Metering Infrastructure (AMI) Assumptions

Some of the options require AMI

- DLC Options- No AMI Metering Required
- Dynamic Rates and Behavioral- require AMI for billing

Washington

- Utilized current Avista AMI saturation rates by sector and held constant

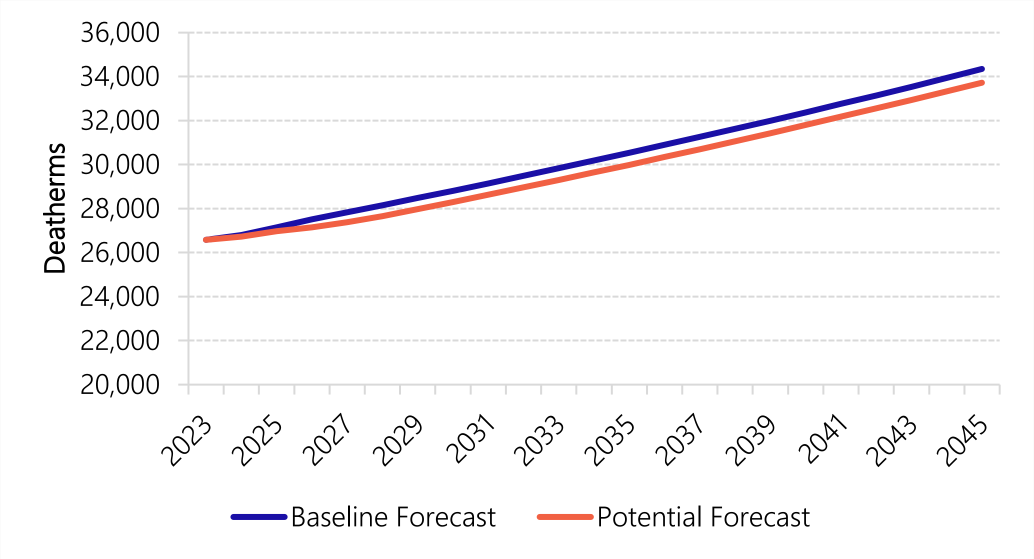
Idaho and Oregon

- No AMI Projected
- Dynamic Rates and Behavioral Programs not estimated

Achievable Potential

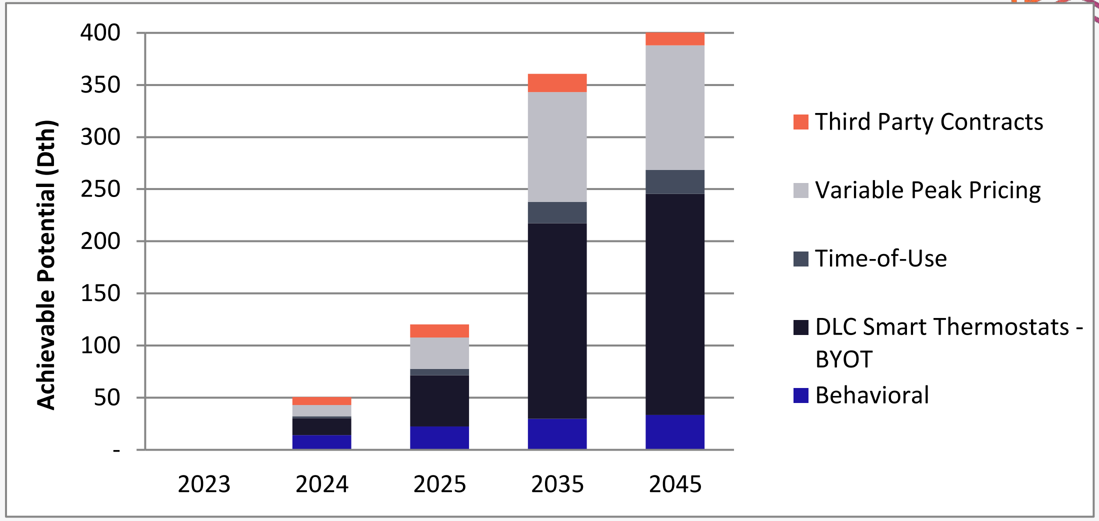
Overall Potential

	2023	2024	2025	2035	2045
Baseline Forecast	26,574	26,801	27,145	30,533	34,338
Potential	-	72	176	545	614
Potential (%)	0%	0%	1%	2%	2%
Potential Forecast	26,574	26,729	26,969	29,988	33,724



Achievable Potential - Washington

Winter Potential (Dth)	2023	2024	2025	2035	2045
Baseline Forecast	13,399	13,553	13,721	15,474	17,454
Achievable Potential	-	51	120	361	407
Behavioral	-	14	22	30	33
DLC Smart Thermostats - BYOT	-	16	49	188	212
Time-of-Use	-	2	6	21	23
Variable Peak Pricing	-	10	30	105	119
Third Party Contracts	-	8	13	17	19

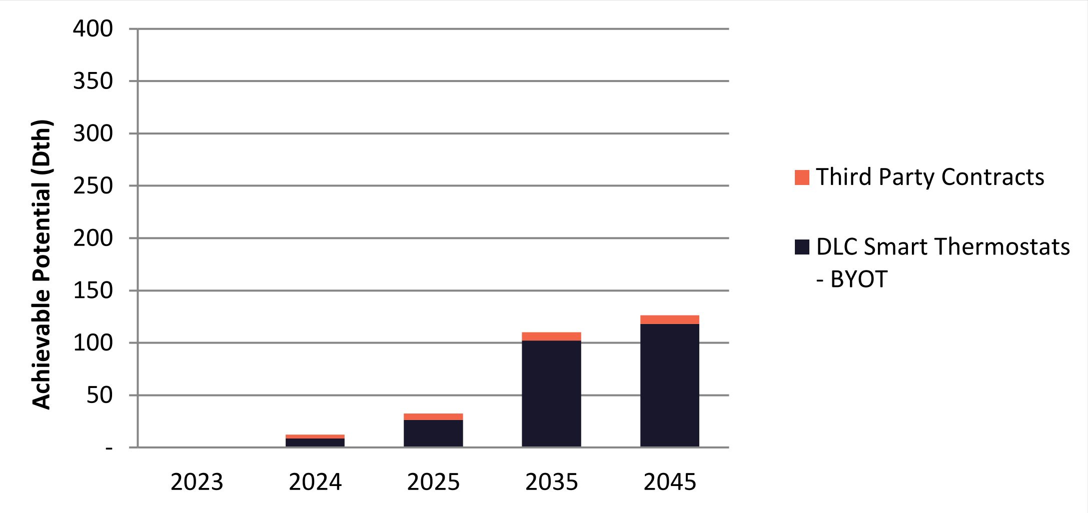


Key Findings:

- All five options available due to AMI saturation
- Largest potential option is DLC Smart Thermostats – BYOT (52% of potential)
- Next largest is VPP (29% of potential)

Achievable Potential - Idaho

Winter Potential (Dth)	2023	2024	2025	2035	2045
Baseline Forecast	**6,877**	**6,909**	**7,026**	**8,077**	**9,273**
Achievable Potential	**-**	**12**	**32**	**110**	**126**
Behavioral	-	-	-	-	-
DLC Smart Thermostats - BYOT	-	9	26	102	118
Time-of-Use	-	-	-	-	-
Variable Peak Pricing	-	-	-	-	-
Third Party Contracts	-	4	6	8	8

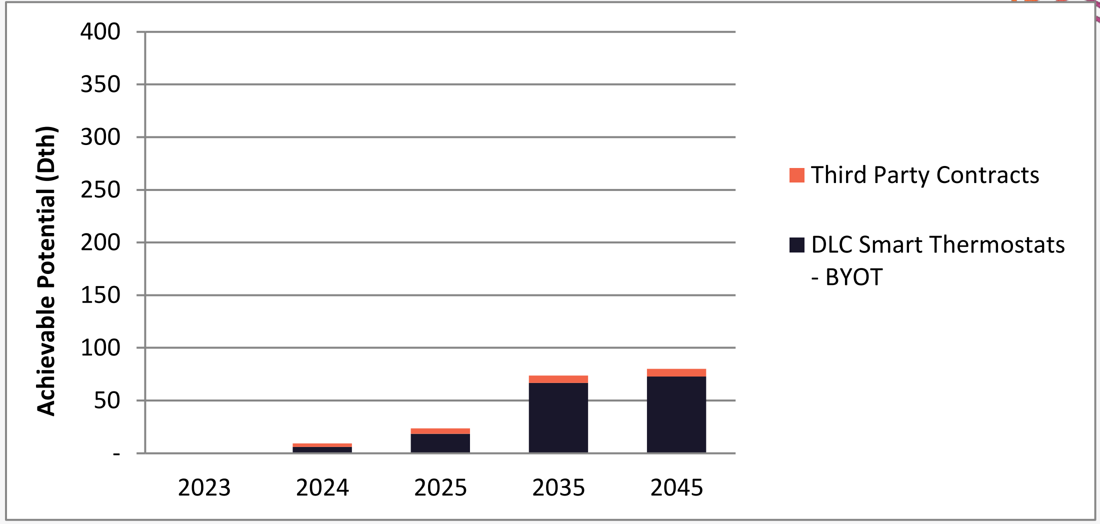


Key Findings:

- Rates and Behavioral options unavailable
- DLC Smart Thermostats – BYOT (94% of potential)
- Third Party Contracts (6% of potential)

Achievable Potential - Oregon

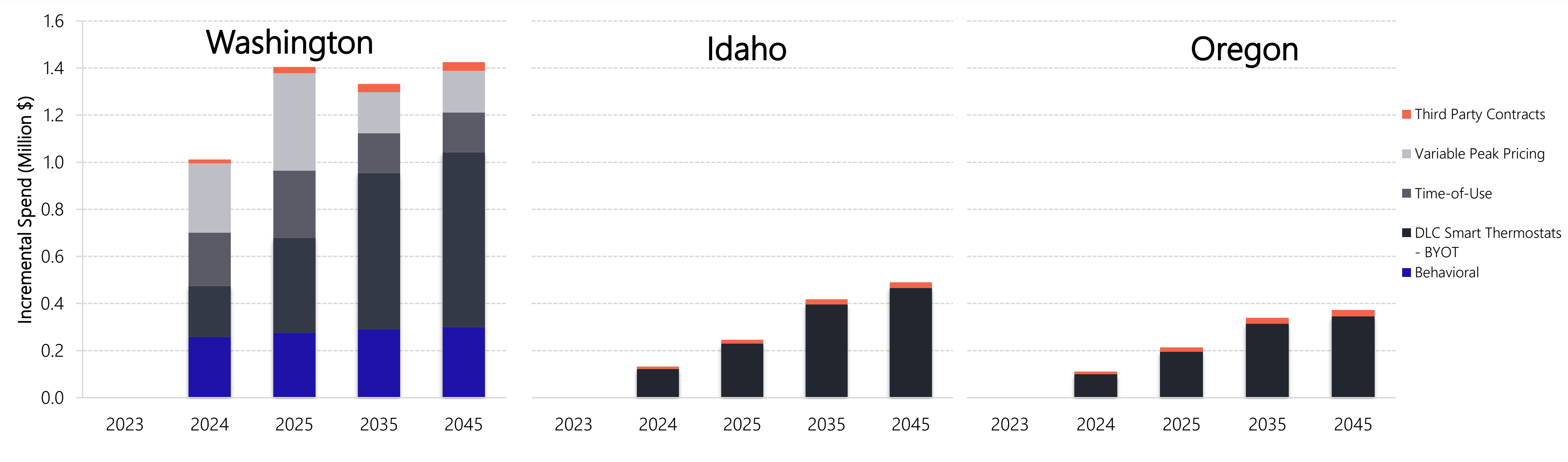
Winter Potential (Dth)	2023	2024	2025	2035	2045
Baseline Forecast	**6,123**	**6,162**	**6,219**	**6,781**	**7,384**
Achievable Potential	**-**	**9**	**24**	**74**	**80**
Behavioral	-	-	-	-	-
DLC Smart Thermostats - BYOT	-	6	18	67	73
Time-of-Use	-	-	-	-	-
Variable Peak Pricing	-	-	-	-	-
Third Party Contracts	-	3	5	7	7



Key Findings:

- Rates and Behavioral options unavailable
- DLC Smart Thermostats – BYOT (91% of potential)
- Third Party Contracts (9% of potential)

Program Costs by State



Gas DR Key Findings

Natural Gas DR is an emerging resource

- Small number of programs in existence
- Numerous questions surround applicability and reliability of Gas DR

Program Potential

- Smart Thermostats – Gas Heating
  - Largest savings potential – Available to all states
- Variable Peak Pricing
  - Largest potential among rates – WA only
- Third Party Contracts
  - 6% of overall potential – Third largest
  - Small amount of industrial gas customers
    - Not a lot of discretionary load to reduce

Thank You.

Kelly Marrin, Managing Director
kmarrin@appliedenergygroup.com

Andy Hudson, Project Manager
ahudson@appliedenergygroup.com

Eli Morris, Managing Director
emorris@appliedenergygroup.com

Tommy Williams, Associate Consultant
twilliams@appliedenergygroup.com

AEG
APPLIED ENERGY GROUP

Modeled DR Inputs – Levelized

Idaho

Input into Plexos	Per Dth Price
Behavioral	$0
DLC Water Heating	$0
DLC Smart Thermostats - BYOT	$5,754
Time-of-Use	$0
Variable Peak Pricing	$0
Third Party Contracts	$137,045

Oregon

Input into Plexos	Per Dth Price
Behavioral	$0
DLC Water Heating	$0
DLC Smart Thermostats - BYOT	$5,767
Time-of-Use	$0
Variable Peak Pricing	$0
Third Party Contracts	$136,783

Washington

Input into Plexos	Per Dth Price
Behavioral	$11,849
DLC Water Heating	$0
DLC Smart Thermostats - BYOT	$5,756
Time-of-Use	$18,883
Variable Peak Pricing	$4,474
Third Party Contracts	$135,937

Distribution System Planning

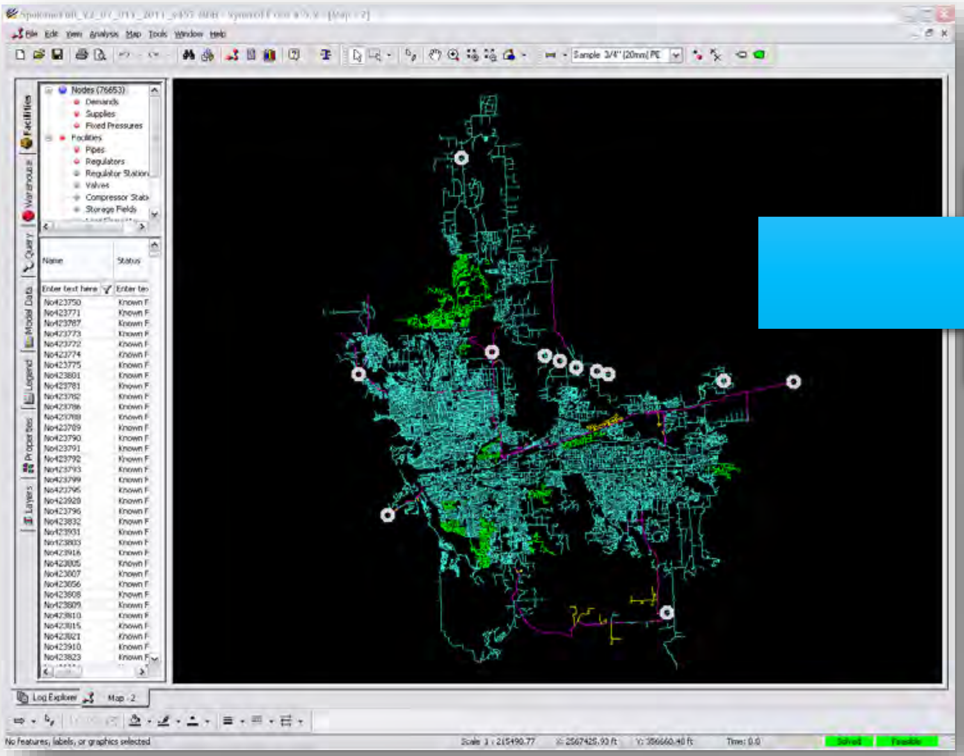
Natural Gas Technical Advisory Committee

December 15, 2022

Terrence Browne PE, Senior Gas Planning Engineer

Mission

- Using technology to plan and design a safe, reliable, and economical distribution system

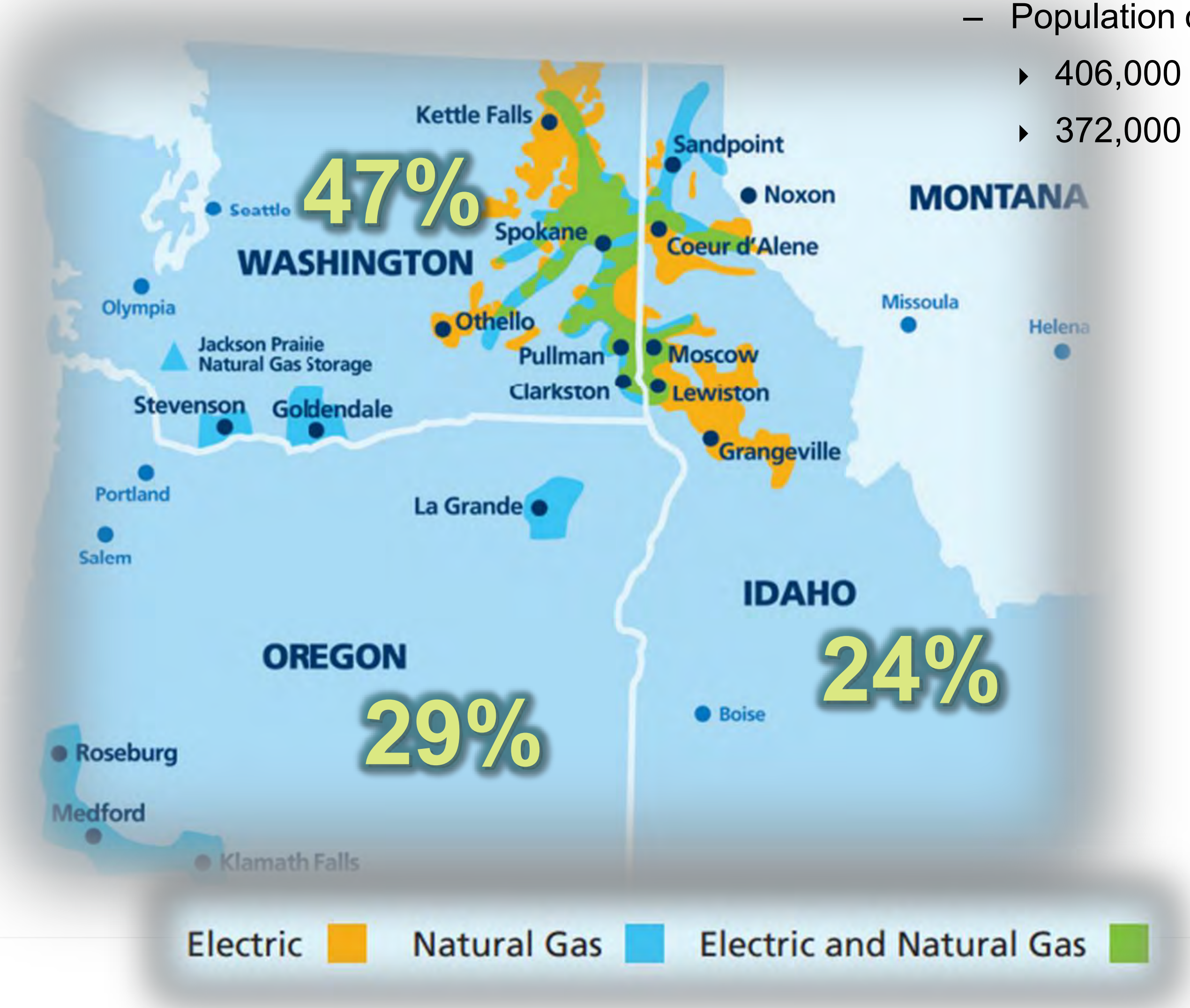


Gas Distribution Planning

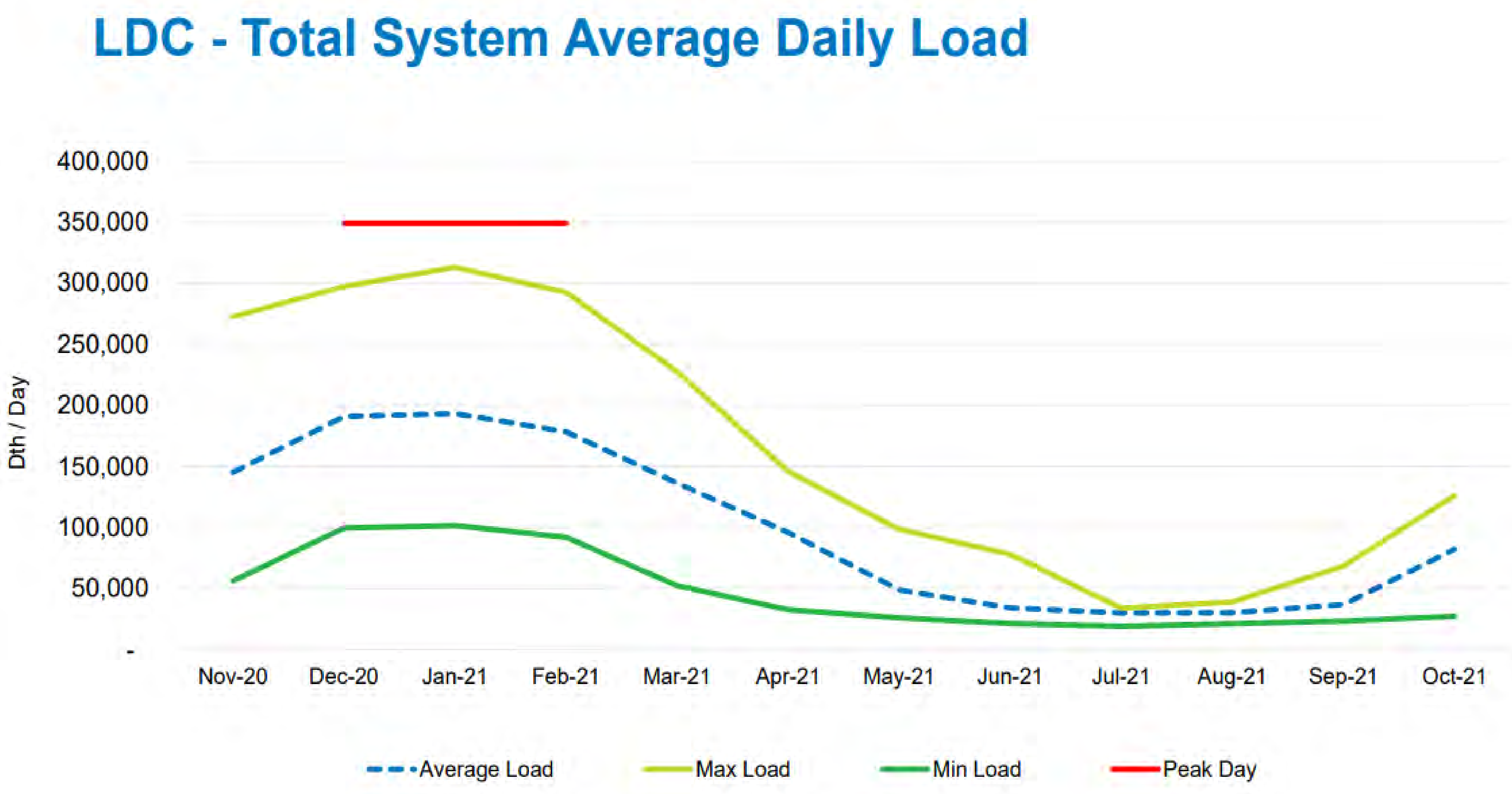
- Service Territory and Customer Overview
- Scope of Gas Distribution Planning
- SynerGi Load Study Tool
- Planning Criteria
- Interpreting Results
- Monitoring Our System
- Areas Currently Monitoring for Low Pressure and Proposed Solutions
- Gate Station Capacity Review
- Avista's Capability To Accommodate Hydrogen

Service Territory and Customer Overview

- Serves electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in southern and eastern Oregon
  - Population of service area 1.7 million
    - 406,000 electric customers
    - 372,000 natural gas customers



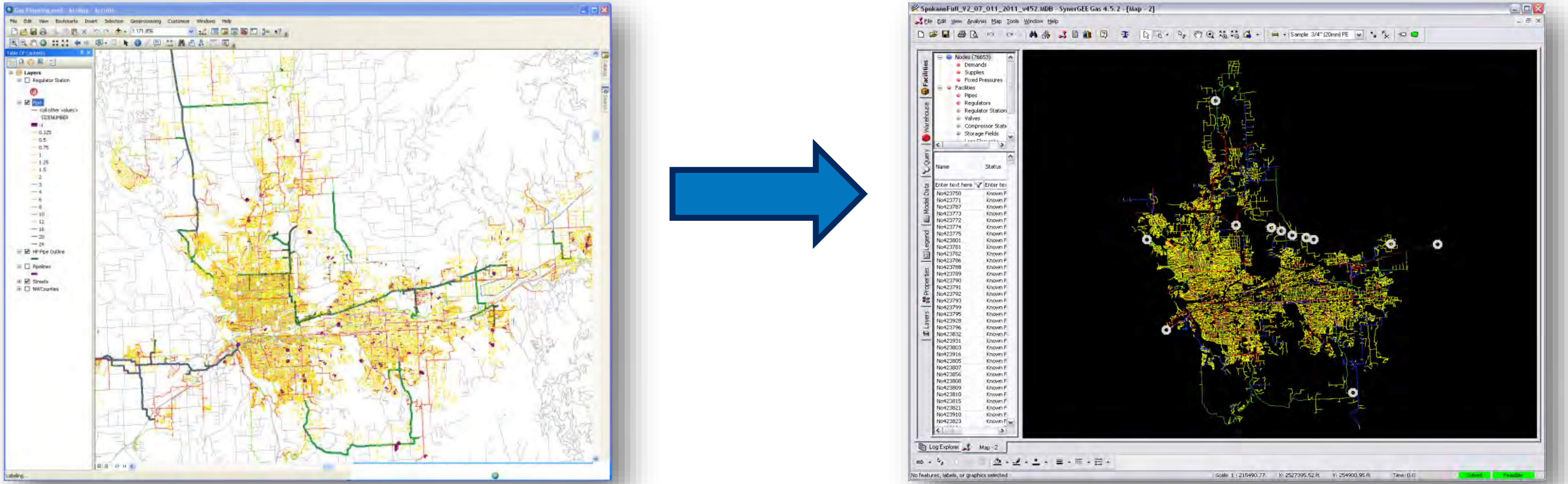
Winter Peaking Profile



Technical Advisory Committee (TAC) # 1
February 16, 2022

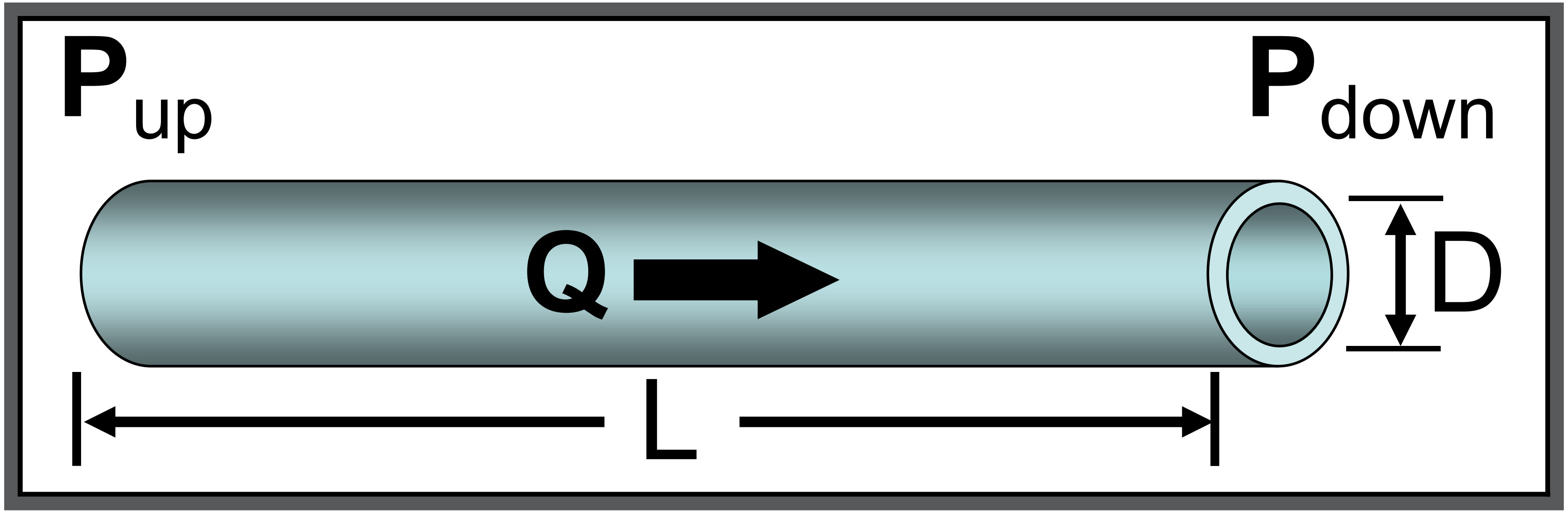
Our Planning Models

- 8,000 miles of distribution main
- 120 cities
- 40 load study models

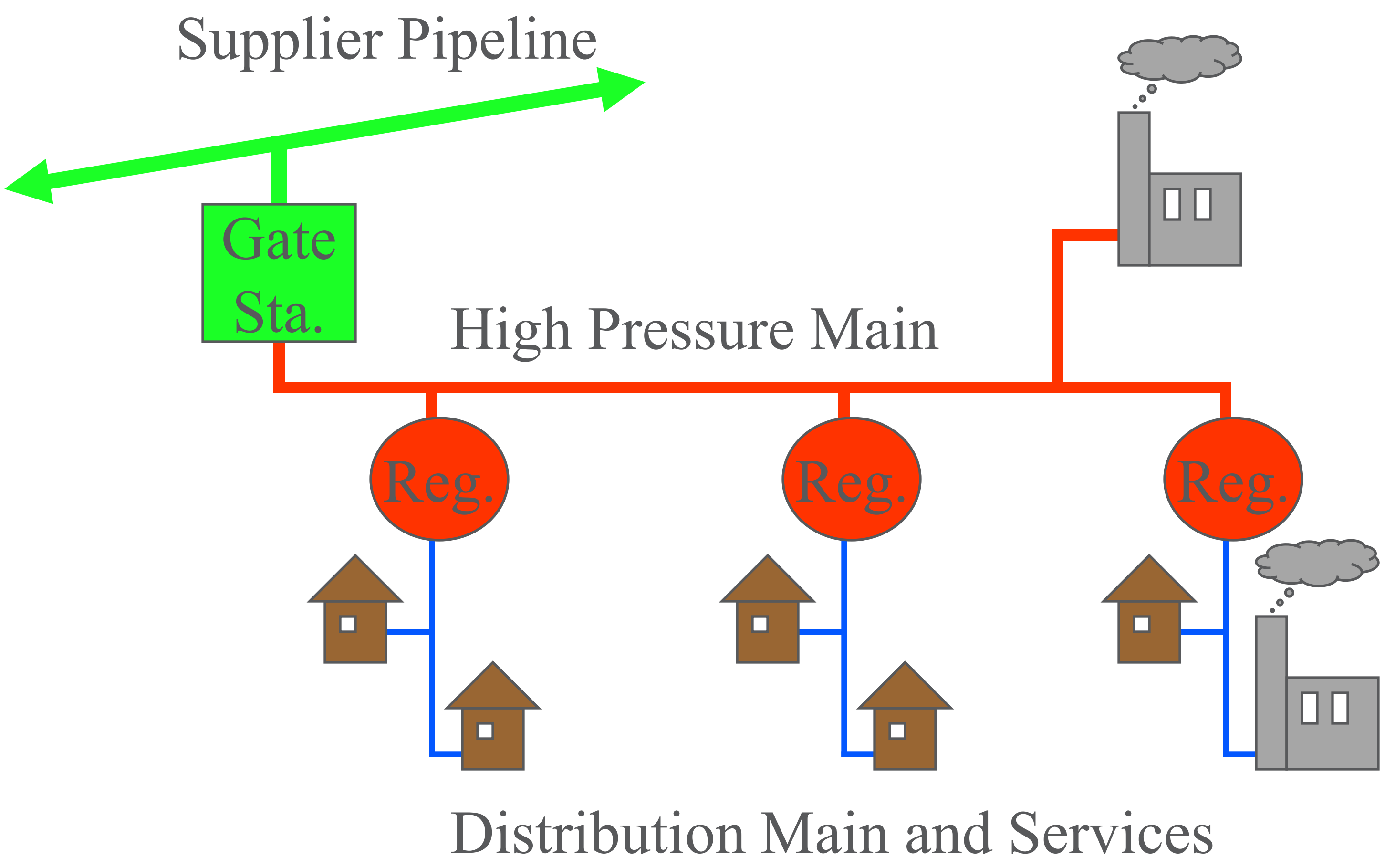


AVISTA

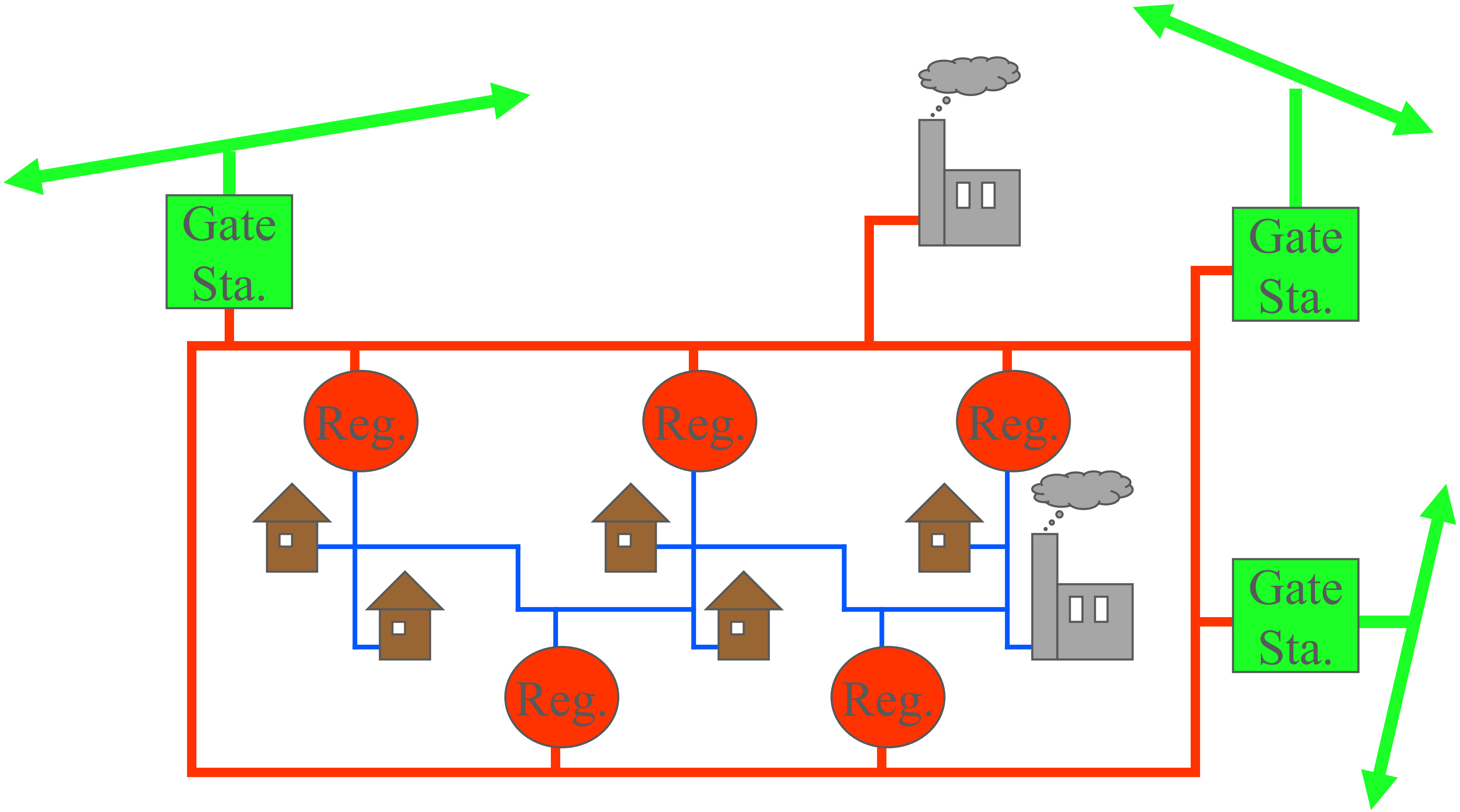
5 Variables for Any Given Pipe



Scope of Gas Distribution Planning

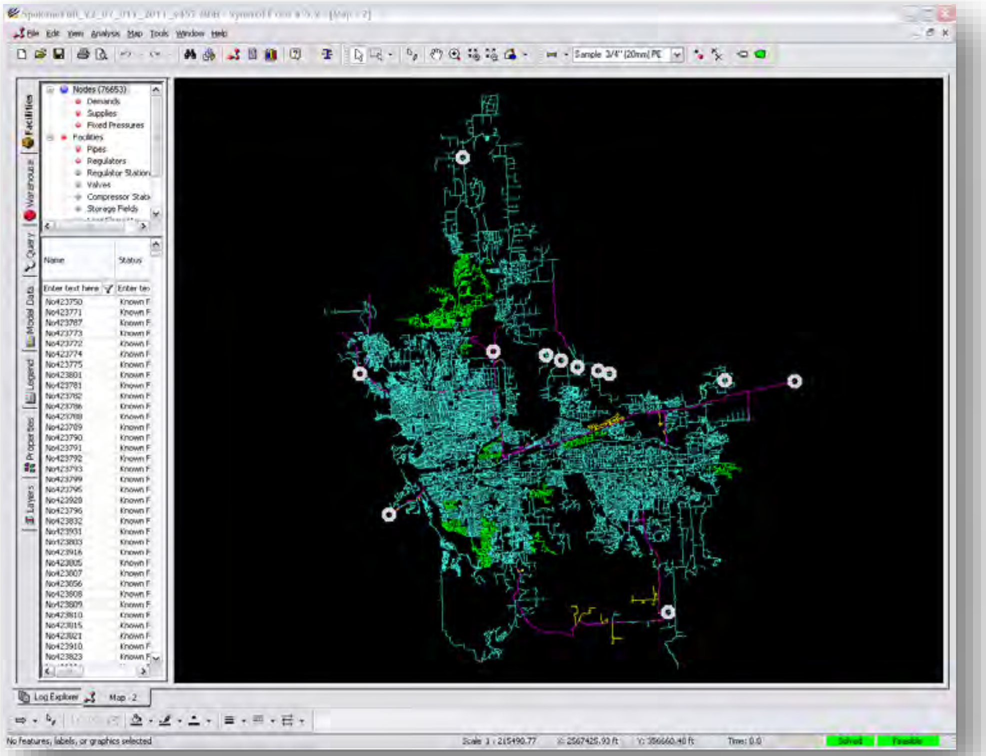


Scope of Gas Distrib. Planning cont.



SynerGi (SynerGEE, Stoner) Load Study

- Simulate distribution behavior
- Identify low pressure areas
- Test reinforcements against future growth/expansion
- Measure reliability



Preparing a Load Study

- Estimating Customer Usage
- Creating a Pipeline Network
- Join Customer Loads to Pipes
- Convert to Load Study

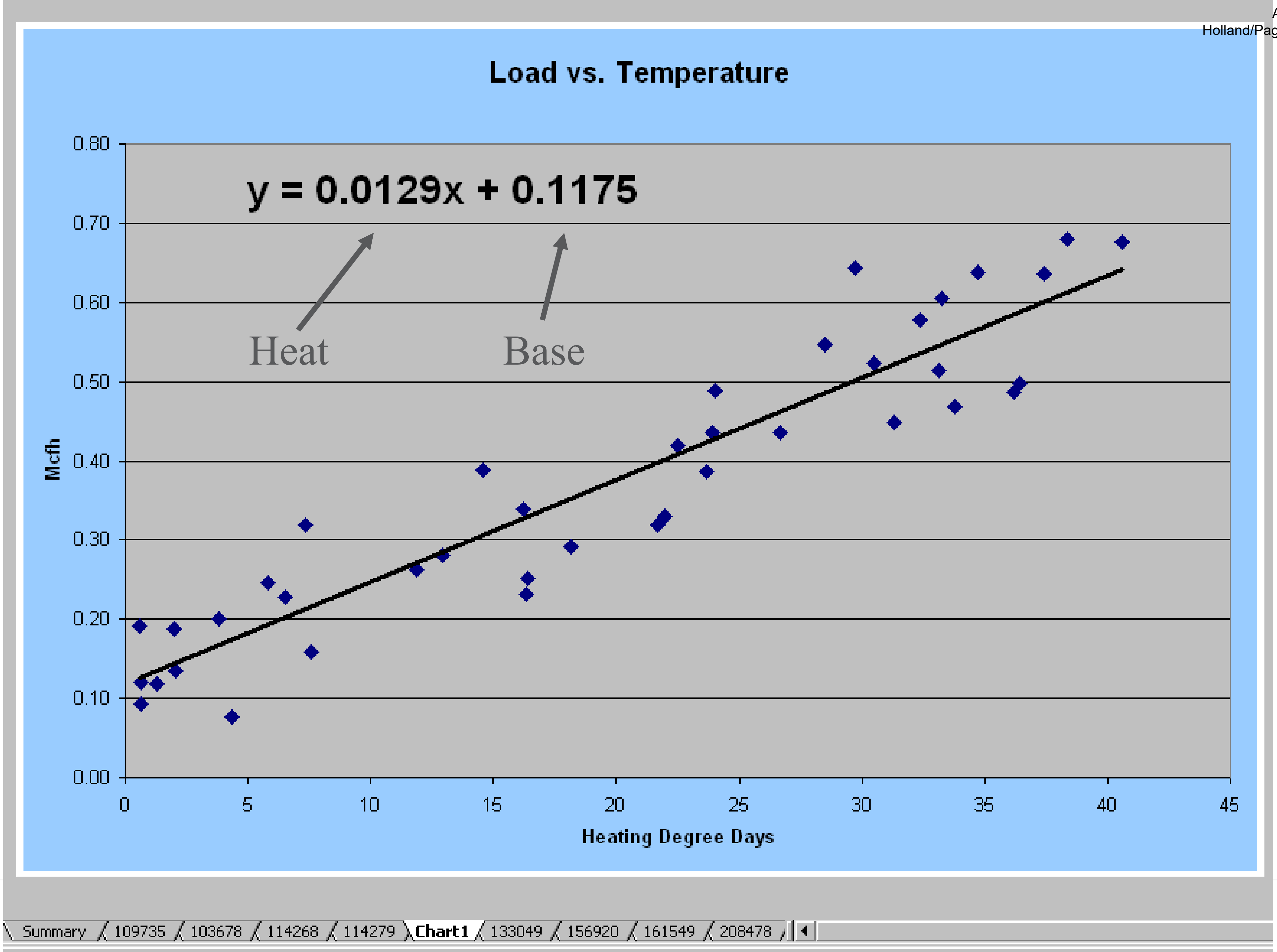
Estimating Customer Usage

- Gathering Data
  - Days of service
  - Degree Days
  - Usage
  - Name, Address, Revenue Class, Rate Schedule…

Estimating Customer Usage cont.

- Degree Days
  - Heating (HDD)
  - Cooling (CDD)
- Temperature - Usage Relationship
  - Load vs. HDD's
  - Base Load (constant)
  - Heat Load (variable)
  - High correlation with residential

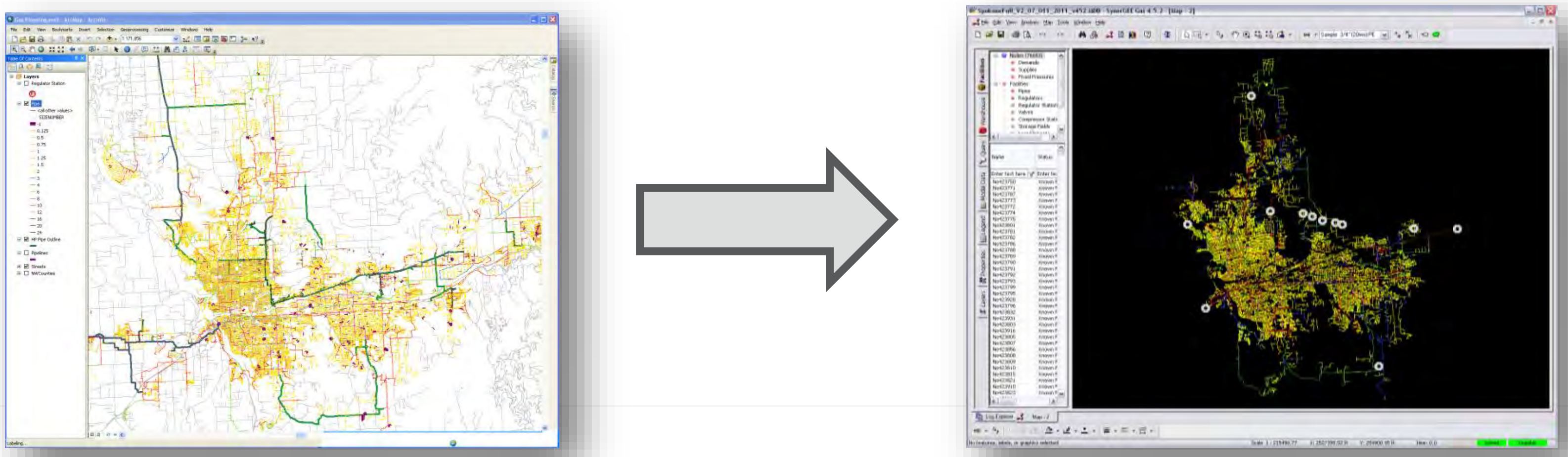
Avg. Daily Temperature ('Fahrenheit)	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
85		20
80		15
75		10
70		5
65	***0***	***0***
60	5	
55	10	
50	15	
45	20	
40	25	
35	30	
30	35	
25	40	
20	45	
15	50	
10	55	
5	60	
4	61	
0	65	
-5	70	
-10	75	
-15	80	

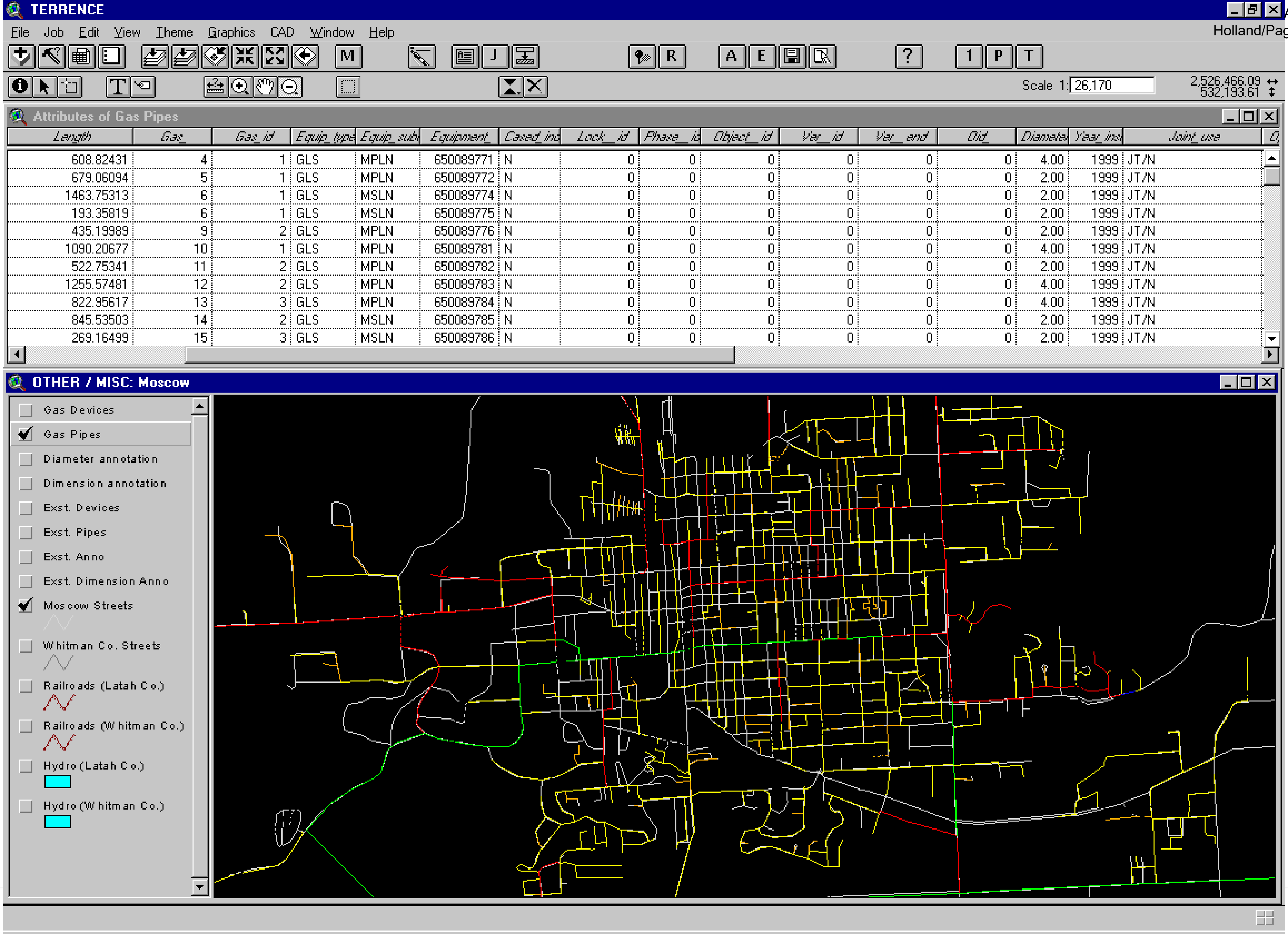

Load vs. Temperature
y = 0.0129x + 0.1175
Heat
Base
Mcfh
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
5
10
15
20
25
30
35
40
45
Heating Degree Days
Summary
109735
103678
114268
114279
Chart1
133049
156920
161549
208478

Creating a Pipeline Model

- Elements
  - Pipes, regulators, valves
  - Attributes: Length, internal diameter, roughness

- Nodes
  - Sources, usage points, pipe ends
  - Attributes: Flow, pressure

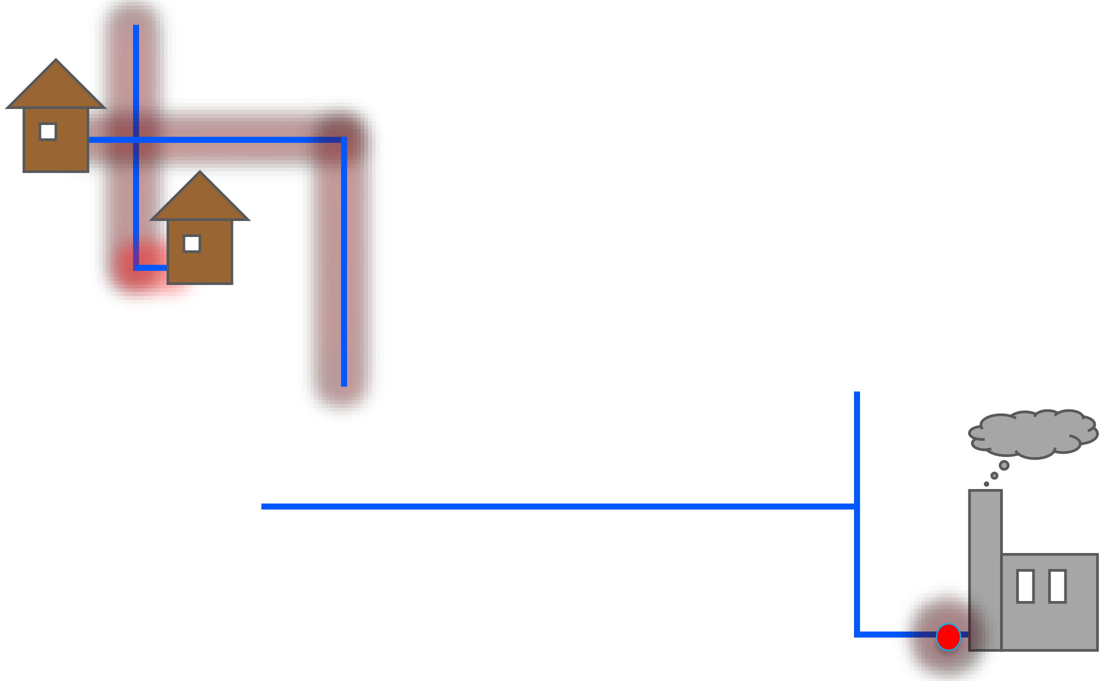




Length	Gas_	Gas_id	Equip_type	Equip_sub	Equipment_	Cased_ind	Lock_id	Phase_id	Object_id	Ver_id	Ver_end	Oid	Diameter	Year_ins	Joint_use
608.82431	4	1	GLS	MPLN	650089771	N	0	0	0	0	0	0	4.00	1999	JT/N
679.06094	5	1	GLS	MPLN	650089772	N	0	0	0	0	0	0	2.00	1999	JT/N
1463.75313	6	1	GLS	MSLN	650089774	N	0	0	0	0	0	0	2.00	1999	JT/N
193.35819	6	1	GLS	MSLN	650089775	N	0	0	0	0	0	0	2.00	1999	JT/N
435.19989	9	2	GLS	MPLN	650089776	N	0	0	0	0	0	0	2.00	1999	JT/N
1090.20677	10	1	GLS	MPLN	650089781	N	0	0	0	0	0	0	4.00	1999	JT/N
522.75341	11	2	GLS	MPLN	650089782	N	0	0	0	0	0	0	2.00	1999	JT/N
1255.57481	12	2	GLS	MPLN	650089783	N	0	0	0	0	0	0	4.00	1999	JT/N
822.95617	13	3	GLS	MPLN	650089784	N	0	0	0	0	0	0	4.00	1999	JT/N
845.53503	14	2	GLS	MSLN	650089785	N	0	0	0	0	0	0	2.00	1999	JT/N
269.16499	15	3	GLS	MSLN	650089786	N	0	0	0	0	0	0	2.00	1999	JT/N

Join Customer Loads to a Model

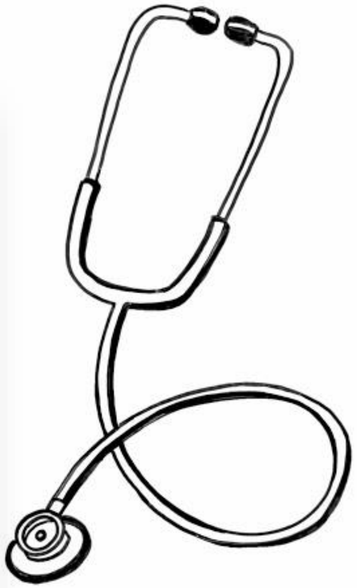
- Residential and commercial loads are assigned to ***pipes***
- Industrial or other large loads are assigned to ***nodes***
  - Model "firm" loads only for identifying reinforcements



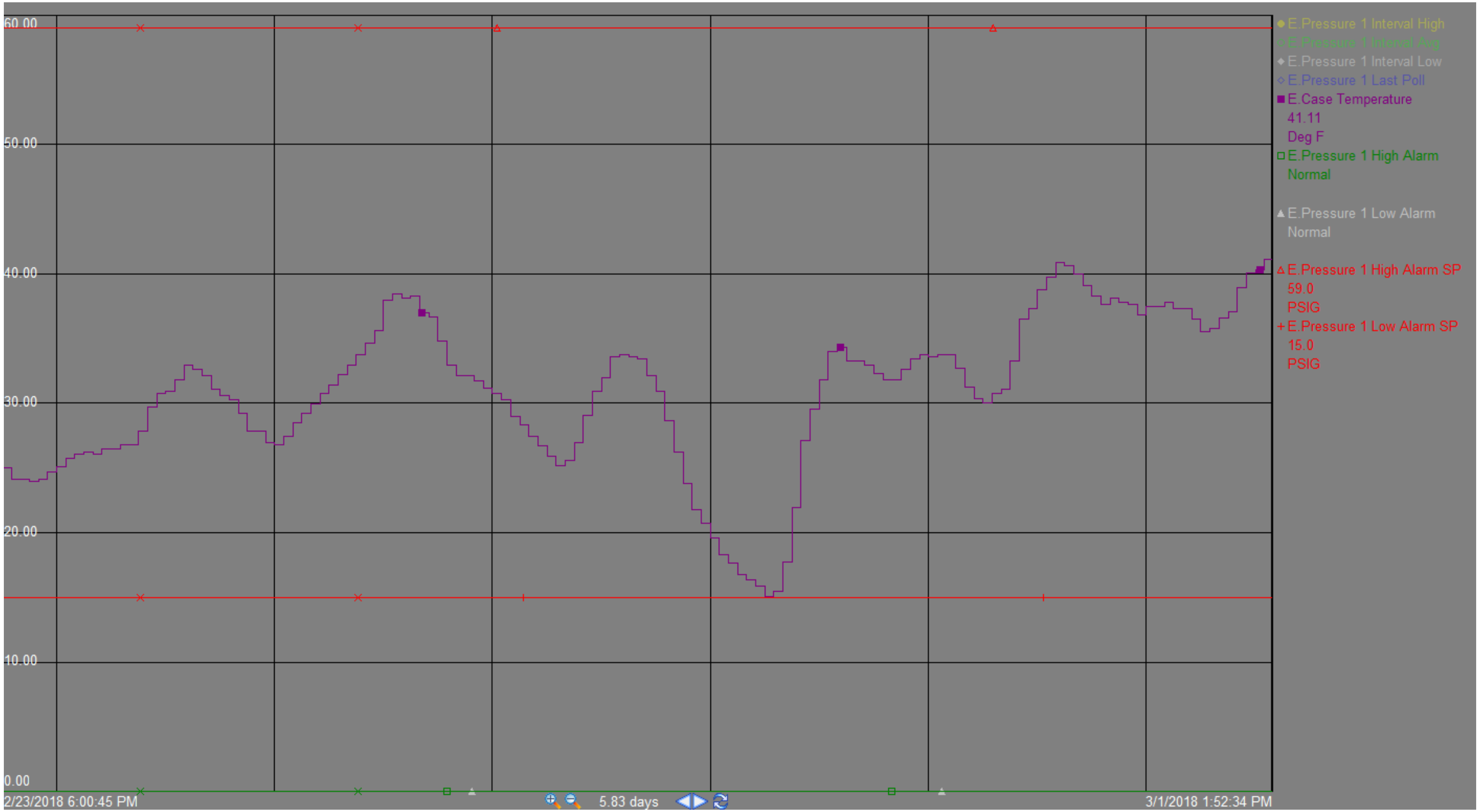
Balancing Model

- Simulate system for any temperature
  - HDD's
- Solve for pressure at all nodes

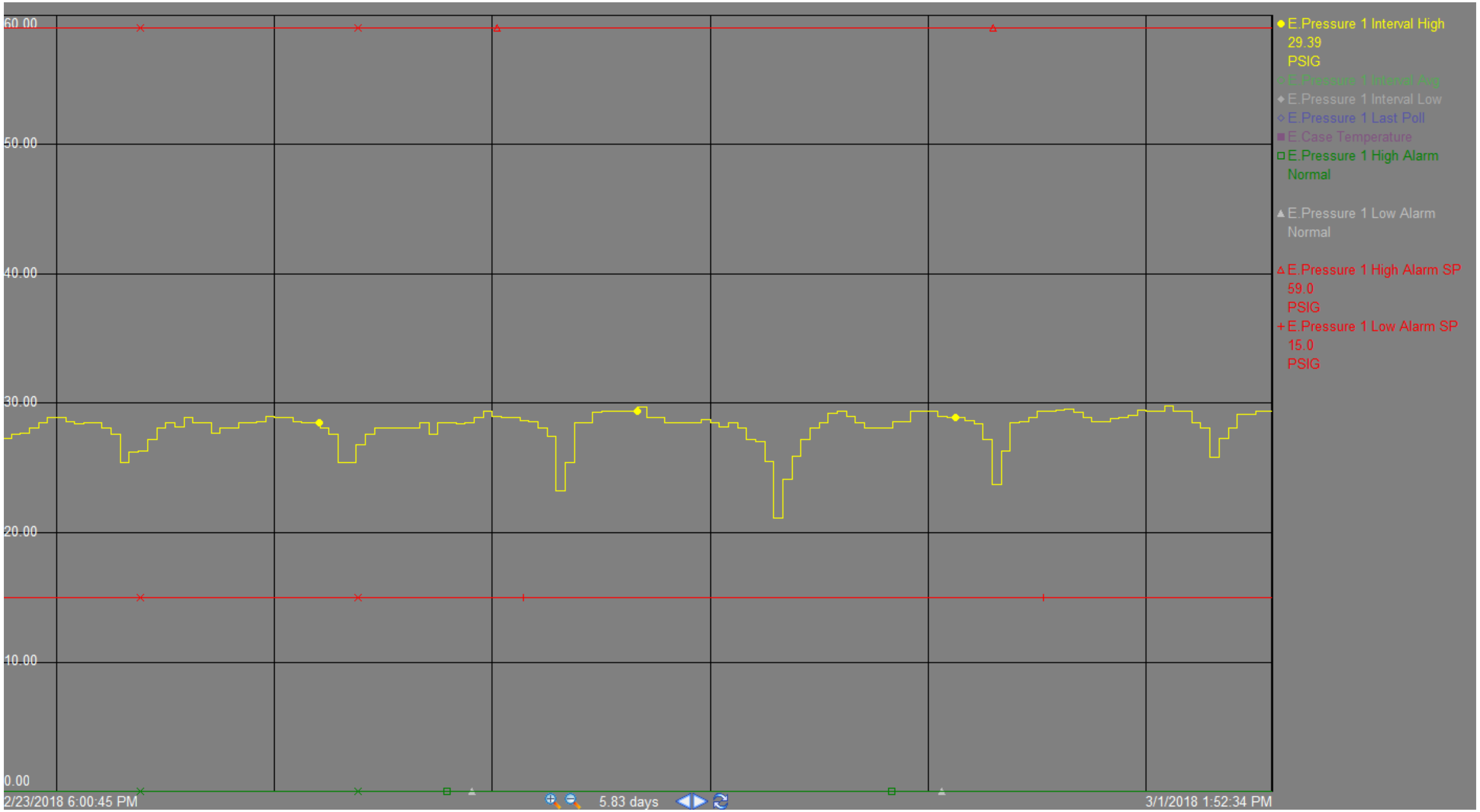
Validating Model



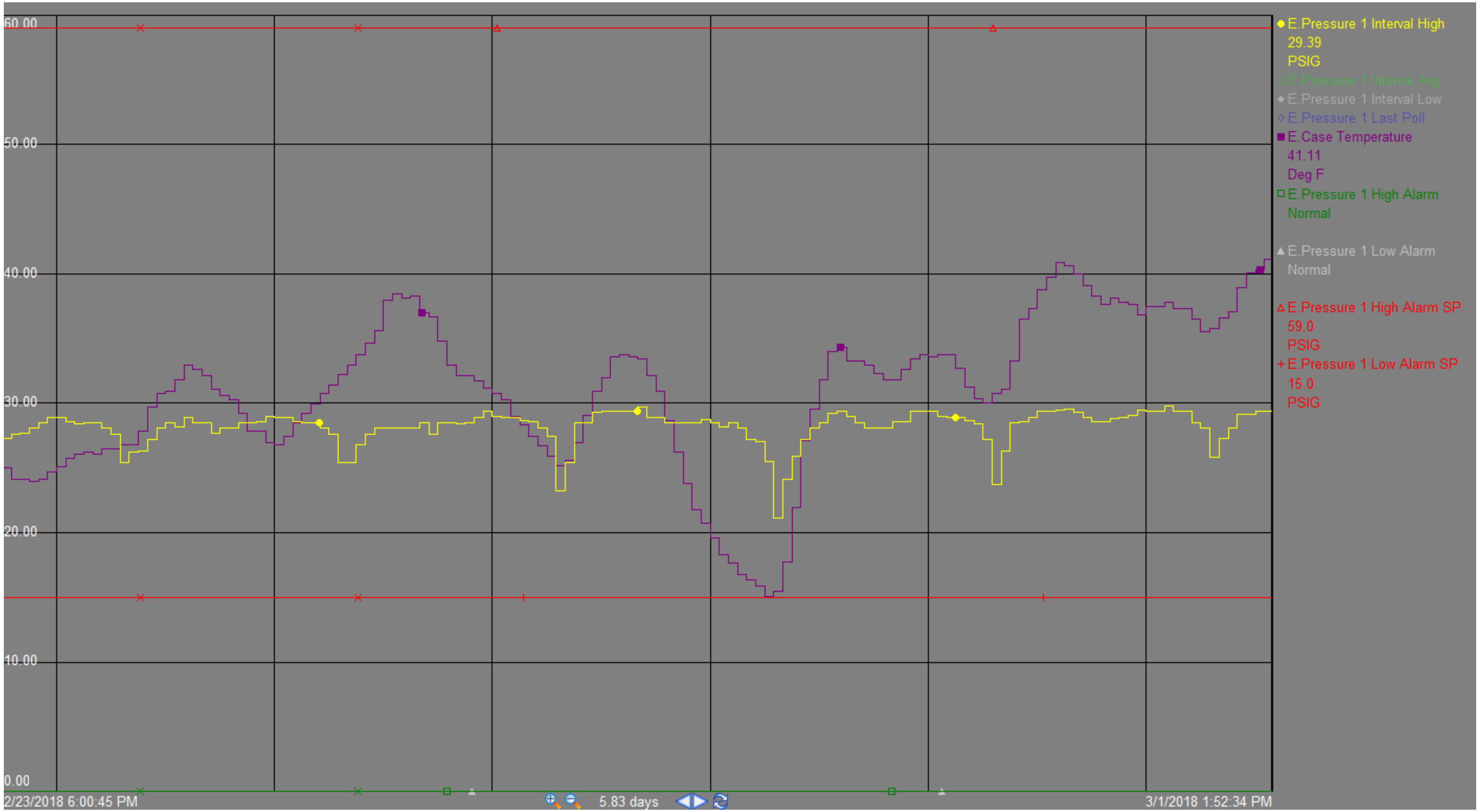
Validating Model cont.



Validating Model cont.



Validating Model cont.



Validating Model cont.

- Simulate recorded condition
- Electronic Pressure Recorders
  - Do calculated results match *field* data?
- Gate Station Telemetry
  - Do calculated results match *source* data?
- Possible Errors
  - Missing pipe
  - Source pressure changed
  - Industrial loads

Planning Criteria – 2022

- Reliability during design HDD
  - Spokane 76 HDD
  - Medford 49 HDD
  - Klamath Falls 72 HDD
  - La Grande 72 HDD
  - Roseburg 46 HDD

- Maintain minimum of 15 psig in system at all times
  - 5 psig in lower MAOP areas
  - 3 psig in Medford 6 psig systems

Planning Criteria – 2022

- Reliability during design HDD
  - Spokane **76 HDD** *(avg. daily temp. -11' F)*
  - Medford **49 HDD** *(avg. daily temp. 16' F)*
  - Klamath Falls **72 HDD** *(avg. daily temp. -7' F)*
  - La Grande **72 HDD** *(avg. daily temp. -7' F)*
  - Roseburg **46 HDD** *(avg. daily temp. 19' F)*

- Maintain minimum of 15 psig in system at all times
  - 5 psig in lower MAOP areas
  - 3 psig in Medford 6 psig systems

*Planning Criteria from 2021 Natural Gas IRP

Interpreting Results

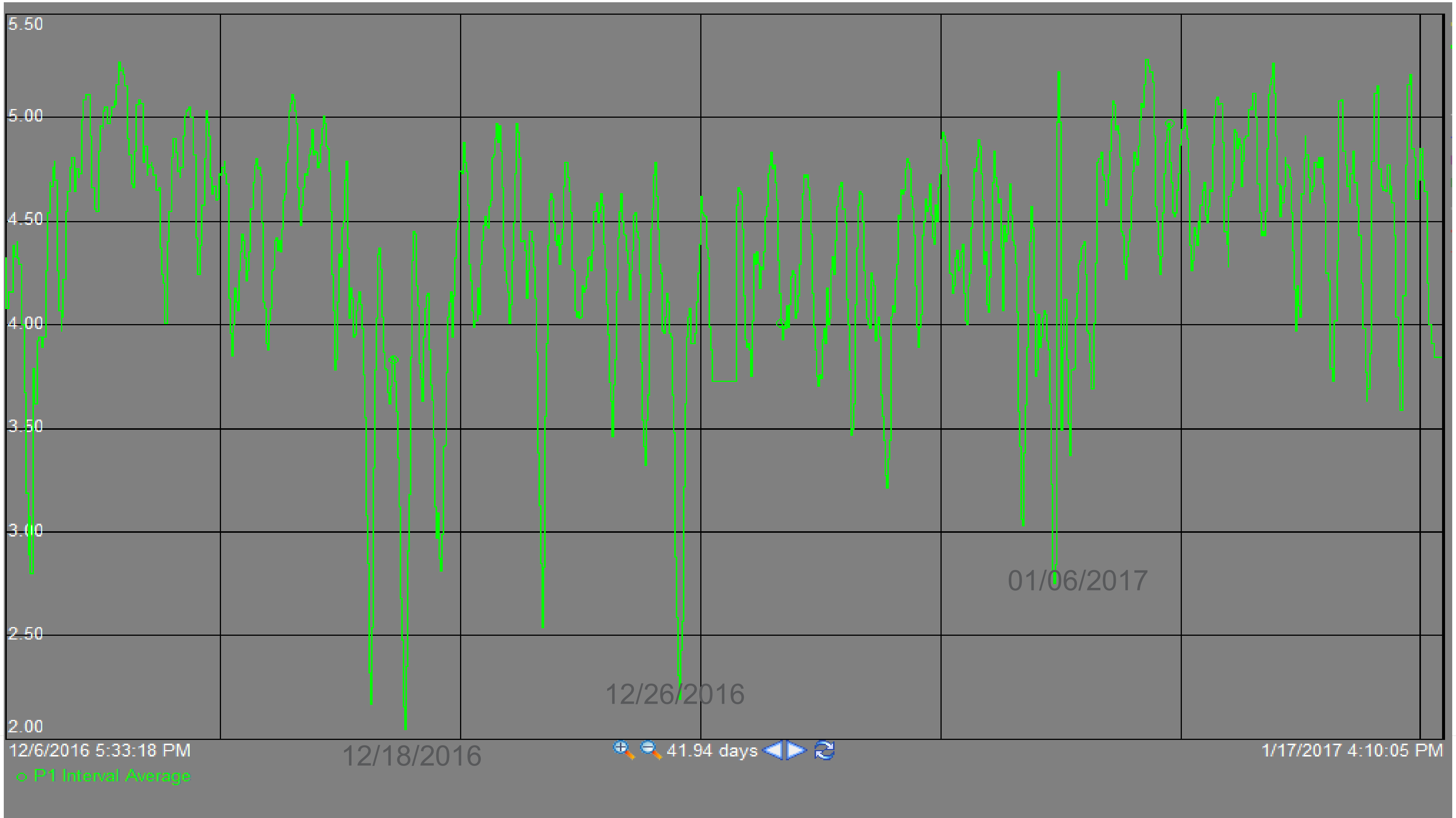
- Identify Low Pressure Areas
  - Number of feeds
  - Proximity to source
- Looking for Most Economical Solution
  - Length (minimize)
  - Construction obstacles (minimize)
  - Customer growth (maximize)

Monitoring Our System

- Electronic Pressure Recorders
  - Daily Feedback
  - Real time if necessary
- Validates our Load Studies

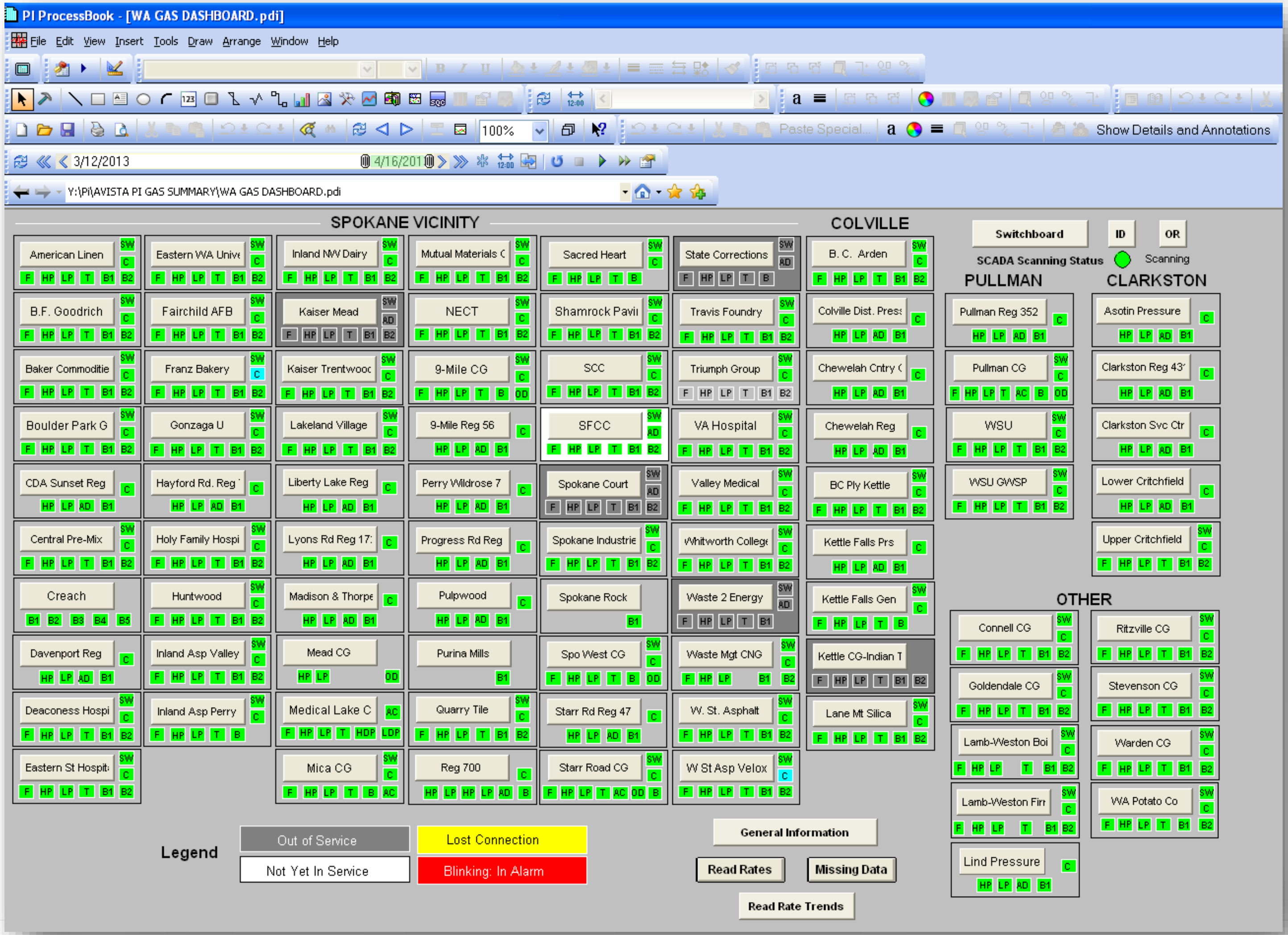
ERX #015: Loon Lake, WA

ERX #007: West Medford 6 psig System, OR



AVISTA

Real-time Pressure & Flow Monitoring



AVISTA

2022-2023 Winter

AVISTA

Gas Load And Weather Forecast Report

Page: 1
Date: 12/09/22 01:00 PM
Database: NUCPRD
gs_fore_temp

Date: 12/09/2022

Area: LAGRANDE

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	31	19	37	4,615
WED	12/07/22	34	17	37	4,943
THU	12/08/22	33	27	35	4,865
FRI	12/09/22	35	27	32	4,485
SAT	12/10/22	40	34	28	3,926
SUN	12/11/22	39	31	30	3,783
MON	12/12/22	35	25	34	4,348
TUE	12/13/22	32	20	39	4,961
WED	12/14/22	30	19	42	5,163
THU	12/15/22	28	16	44	5,382
	Average:				4,647

Area: KLAMATH FALLS

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	36	13	40	8,276
WED	12/07/22	25	19	42	9,272
THU	12/08/22	37	18	37	8,434
FRI	12/09/22	37	17	34	8,065
SAT	12/10/22	38	29	31	7,266
SUN	12/11/22	33	20	38	7,980
MON	12/12/22	32	14	41	8,949
TUE	12/13/22	27	13	46	9,563
WED	12/14/22	25	12	47	9,724
THU	12/15/22	27	11	46	9,543
	Average:				8,707

Area: MEDFORD

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	47	26	29	31,904
WED	12/07/22	32	29	34	36,261
THU	12/08/22	44	30	28	28,159
FRI	12/09/22	45	33	24	29,178
SAT	12/10/22	47	36	23	27,792
SUN	12/11/22	44	32	28	29,737
MON	12/12/22	44	26	31	33,984
TUE	12/13/22	44	25	33	35,729
WED	12/14/22	45	26	32	35,414
THU	12/15/22	46	28	31	34,419
	Average:				32,258

Area: ROSEBURG

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	46	33	26	8,443
WED	12/07/22	50	38	20	7,400
THU	12/08/22	48	36	23	8,309
FRI	12/09/22	46	38	22	7,229
SAT	12/10/22	45	36	23	6,995
SUN	12/11/22	45	35	26	8,001
MON	12/12/22	45	34	27	9,004
TUE	12/13/22	45	32	29	9,409
WED	12/14/22	46	30	29	9,583
THU	12/15/22	45	31	29	9,329
	Average:				8,370

Area: SPOKANE

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	25	22	42	156,599
WED	12/07/22	29	19	39	148,068
THU	12/08/22	32	22	36	141,226
FRI	12/09/22	33	23	38	148,465
SAT	12/10/22	39	32	29	121,803
SUN	12/11/22	34	25	35	129,829
MON	12/12/22	27	15	43	159,574
TUE	12/13/22	22	14	47	176,241
WED	12/14/22	24	13	47	178,331
THU	12/15/22	22	10	49	183,111
	Average:				154,325

Area: LEWISTON

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	35	24	36	20,619
WED	12/07/22	30	24	38	21,866
THU	12/08/22	38	29	31	20,803
FRI	12/09/22	36	27	33	1,641
SAT	12/10/22	39	30	31	18,372
SUN	12/11/22	37	32	30	17,277
MON	12/12/22	36	29	32	18,822
TUE	12/13/22	31	24	38	21,708
WED	12/14/22	28	21	41	23,192
THU	12/15/22	26	16	44	24,527
	Average:				18,883

Area: OTHER

	Date:	Hi	Lo	HDD	Load
TUE	12/06/22	0	0	0	304
WED	12/07/22	0	0	0	303
THU	12/08/22	0	0	0	304
	Average:				304

AVISTA

2013-2014 Winter

Area: LaGrande

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	18	-4	58	6,615
SUN	12/8/2013	9	-9	65	6,695
MON	12/9/2013	21	-4	56	5,389
TUE	12/10/2013	29	16	42	4,897
WED	12/11/2013	30	15	42	4,689
THU	12/12/2013	35	20	37	4,131
FRI	12/13/2013	41	27	31	3,398
SAT	12/14/2013	38	22	35	3,618
SUN	12/15/2013	41	23	33	3,491
MON	12/16/2013	40	22	34	3,642

Area: Klamath Falls

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	21	-16	63	11,170
SUN	12/8/2013	6	-20	72	12,002
MON	12/9/2013	14	-17	66	11,474
TUE	12/10/2013	31	-6	52	9,299
WED	12/11/2013	36	7	43	8,799
THU	12/12/2013	39	9	41	8,191
FRI	12/13/2013	42	17	35	7,206
SAT	12/14/2013	45	15	35	6,887
SUN	12/15/2013	47	16	33	6,681
MON	12/16/2013	47	16	33	6,812

Area: Medford

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	32	11	44	40,462
SUN	12/8/2013	25	2	52	47,855
MON	12/9/2013	27	4	50	48,999
TUE	12/10/2013	38	9	41	44,095
WED	12/11/2013	42	17	35	35,943
THU	12/12/2013	42	20	34	35,273
FRI	12/13/2013	44	29	28	29,966
SAT	12/14/2013	48	26	28	27,507
SUN	12/15/2013	50	25	27	26,954
MON	12/16/2013	49	27	27	27,580

Area: Roseburg

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	27	18	43	11,843
SUN	12/8/2013	26	15	44	13,011
MON	12/9/2013	31	17	41	9,984
TUE	12/10/2013	34	19	38	10,867
WED	12/11/2013	40	28	31	9,197
THU	12/12/2013	40	30	30	8,730
FRI	12/13/2013	42	33	27	8,112
SAT	12/14/2013	43	30	28	7,686
SUN	12/15/2013	45	32	26	7,418
MON	12/16/2013	44	34	26	7,682

Area: Spokane

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	15	0	57	195,583
SUN	12/8/2013	15	-2	58	183,544
MON	12/9/2013	20	9	51	166,628
TUE	12/10/2013	25	12	46	156,433
WED	12/11/2013	29	15	43	145,441
THU	12/12/2013	31	20	39	134,506
FRI	12/13/2013	33	26	35	120,774
SAT	12/14/2013	35	27	34	114,257
SUN	12/15/2013	36	27	33	114,089
MON	12/16/2013	34	26	35	120,924

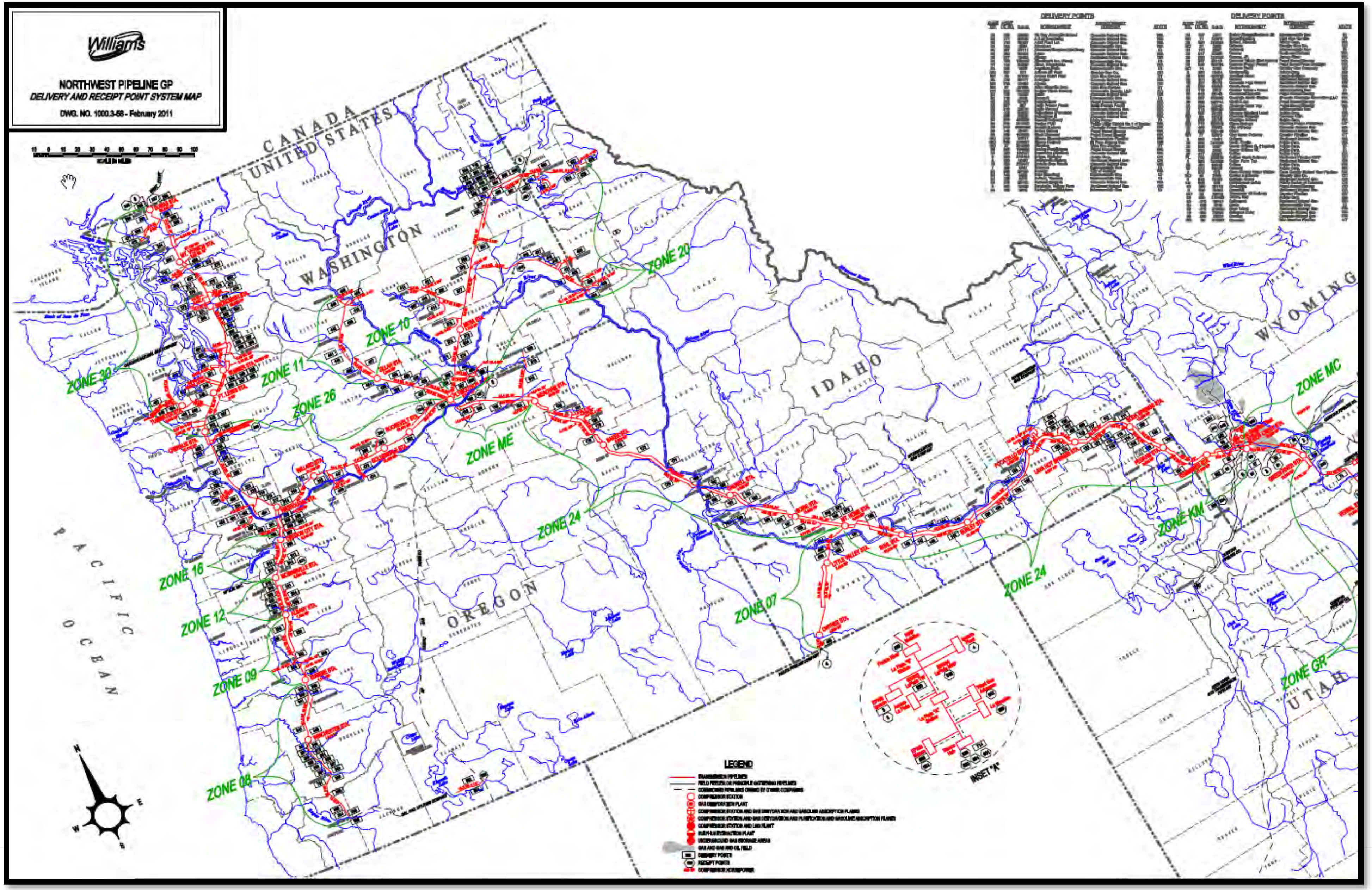
Area: Lewiston

	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	18	2	55	31,016
SUN	12/8/2013	13	0	59	31,386
MON	12/9/2013	26	8	48	25,901
TUE	12/10/2013	28	22	40	21,715
WED	12/11/2013	31	17	41	22,022
THU	12/12/2013	34	21	37	19,886
FRI	12/13/2013	38	29	31	17,448
SAT	12/14/2013	36	27	33	17,579
SUN	12/15/2013	38	27	32	17,570
MON	12/16/2013	36	27	33	18,079

Areas Currently Monitoring for Low Pressure and Proposed Solutions*

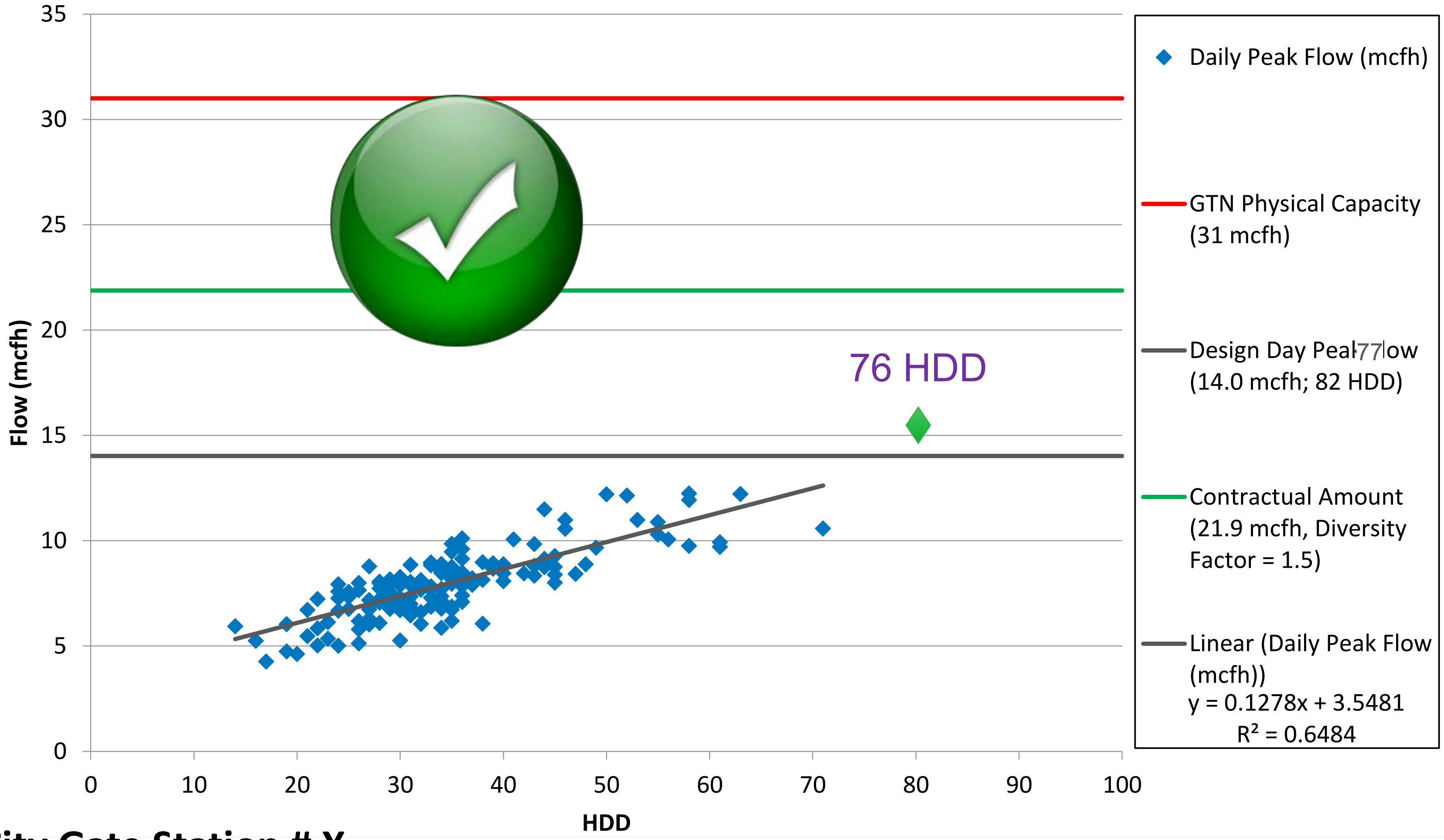
- Jacksonville, OR
- Medford 6 psig system, OR
- Palouse, WA
- South Hill Spokane, WA
- *Notes:
  - List not comprehensive
  - projects are subject to change and will be reviewed on a regular basis

Gate Station Capacity Review



AVISTA

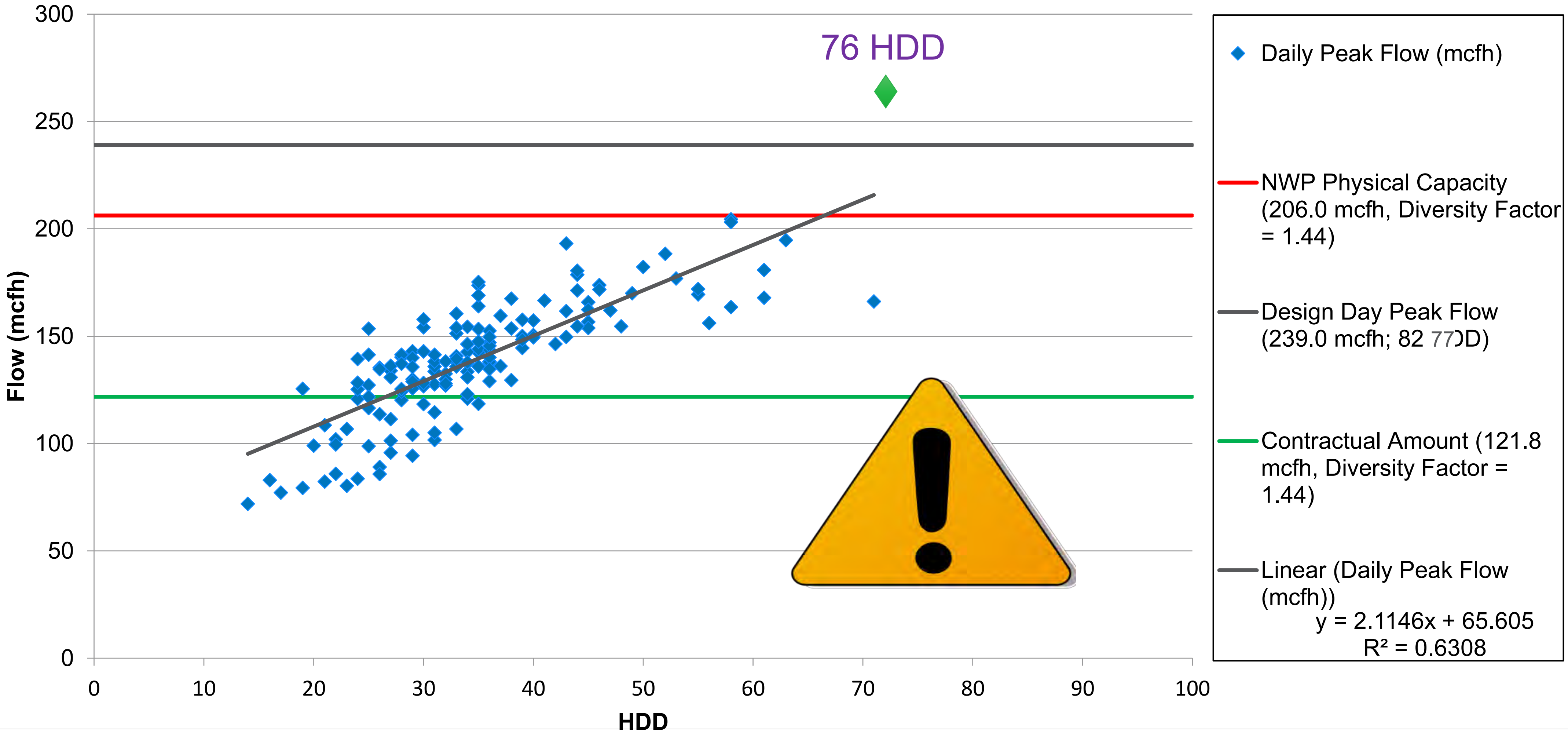
Gate Station Capacity Review (example)



City Gate Station # X

AVISTA

Gate Station Capacity Review (example)



City Gate Station # Y

City Gate Stations Currently Monitoring and Proposed Solutions*

- Sutherlin, OR: *rebuild/enhance in 2024+*
- Medford, OR: *work with pipeline to increase capacity*
- Klamath Falls – Keno, OR: *completed in 2020*
- Pullman, WA: *work with pipeline to increase capacity*
- *Notes:
  - List not comprehensive
  - projects are subject to change and will be reviewed on a regular basis

Avista's Capability To Accommodate Hydrogen

- Requirements (physical):
  - Meets existing tariff gas quality standards
  - Injection in a contained system with customer equipment that is capable of accepting a hydrogen blend
  - Metering at interconnect point for volume and gas quality
  - Pressure regulation at interconnect point

Avista’s Capability To Accommodate Hydrogen

- Other
  - Interconnection application process
  - Interconnection agreement

- Where, when, & costs of upgrades required:
  - Each project will be different
  - Dependent on:
    - the proximity of the project to our distribution system
    - Size/scale of project

Questions and Discussion

Mission

Using technology to plan and design a safe, reliable, and economical distribution system

Review of Assumptions

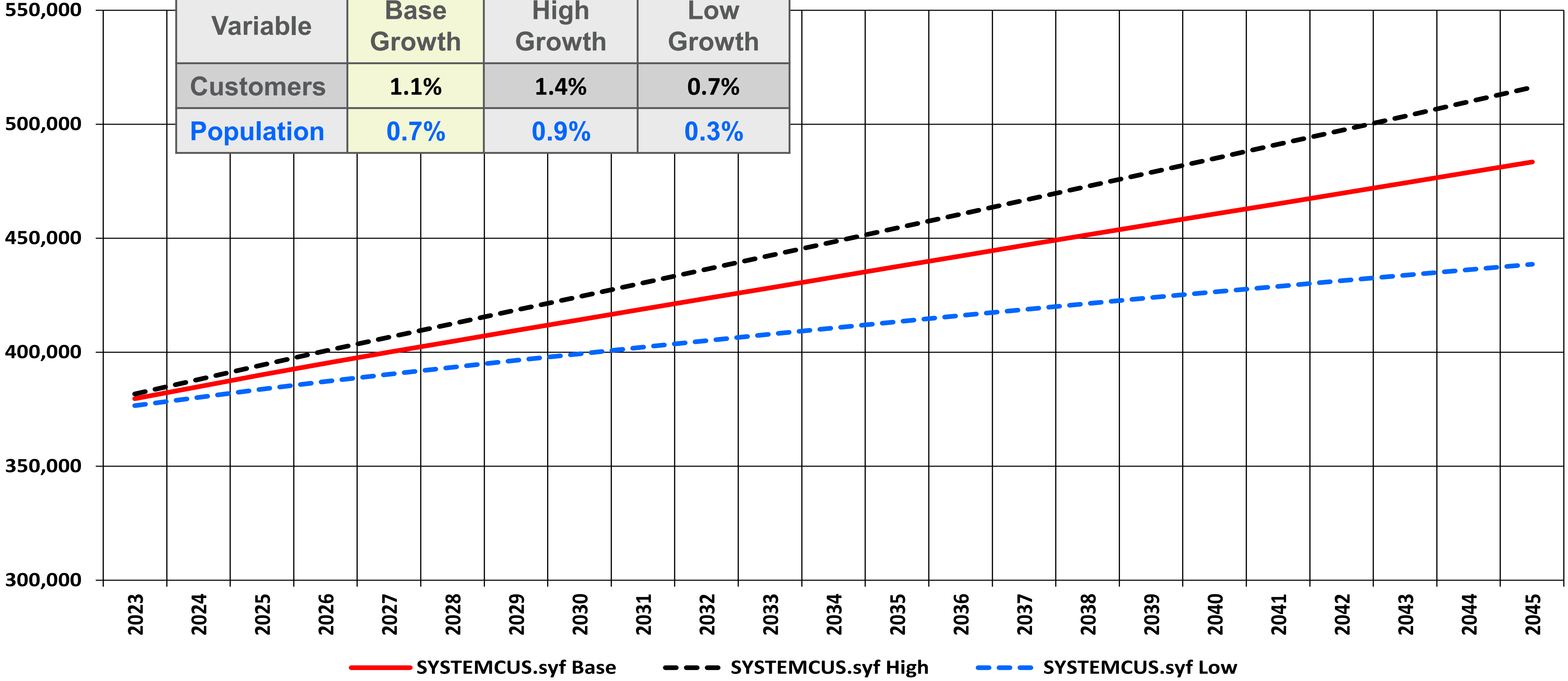
Tom Pardee

Expected Growth

- In 2022 Washington State Building Code Council passed a commercial building and residential customer building requirement starting July 1, 2023.
    - Requires the use of a heat pump as the primary heat source in new buildings
    - Does not require a specific fuel type
    - Does not require current customers to switch equipment at any time to electricity
- New residential and commercial customers in Washington starting July 2023 will be treated as hybrid heating where natural gas use begins at temperatures lower than 40 degrees Fahrenheit

System Firm Customer Range (2023-2045)

Variable	Base Growth	High Growth	Low Growth
Customers	1.1%	1.4%	0.7%
Population	0.7%	0.9%	0.3%



Weather Summary

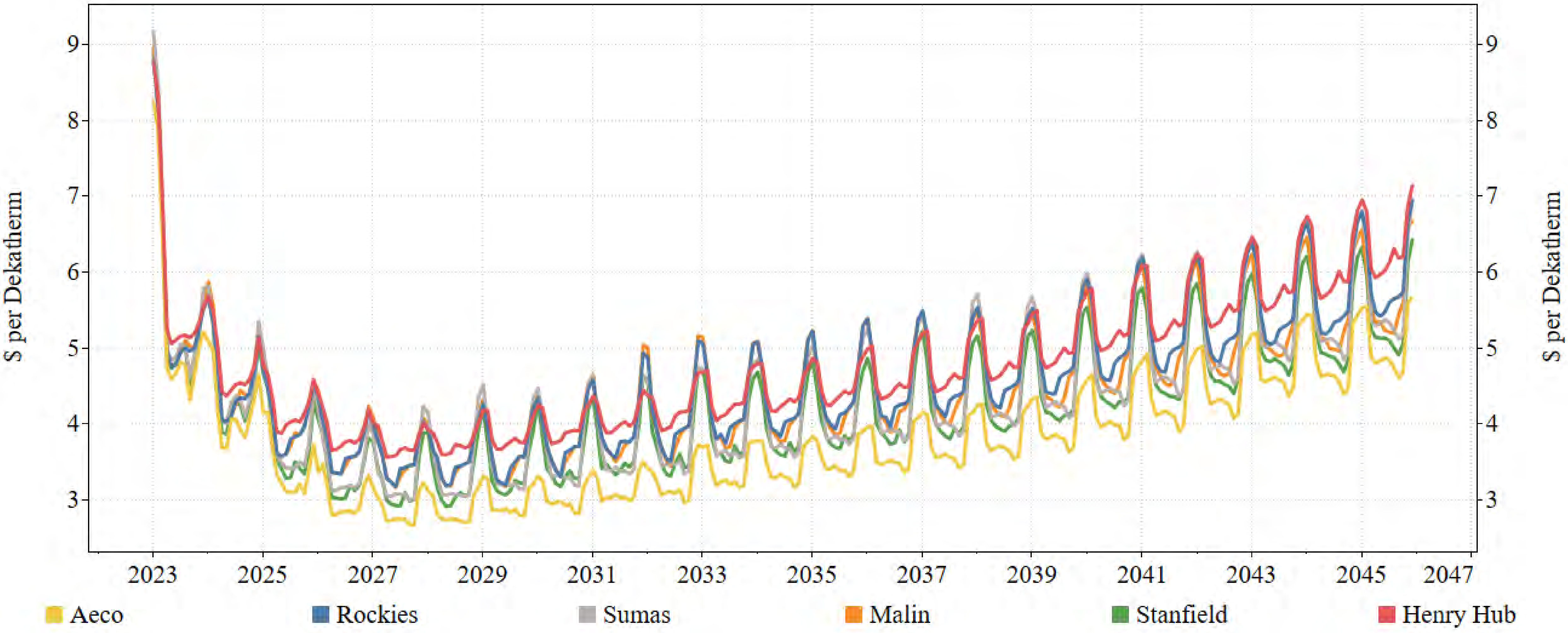
- Average daily weather by planning region for the prior 20 years including climate change weather data.
  - Example:
    - 2022 data is from 2002 – 2021
    - 2030 data is from 2010 – 2029
  - Median of daily values for all climate study results by area

- A peak event by planning region based on the past 30 years of the coldest average day, each year, combined with a 1% probability of a weather occurrence
  - Calculation now includes future projected peak values and is trended to the 2045 value from the historic coldest on record to smooth out volatility of peak day temperatures
  - Using the median values as peak day drastically reduces the temperatures for the design weather day
  - Taking the 95th percentage of climate models daily results and utilizing the highest annual value to include in the peak calculation reduces this risk of unserved customers

Peak Temp Changes
(degrees Fahrenheit)

Planning Region	Trended Peak 2045
La Grande, Oregon	-8.0
Klamath Falls, Oregon	-5.1
Medford/Roseburg, Oregon	11.7
Spokane, ID/WA	-14.6

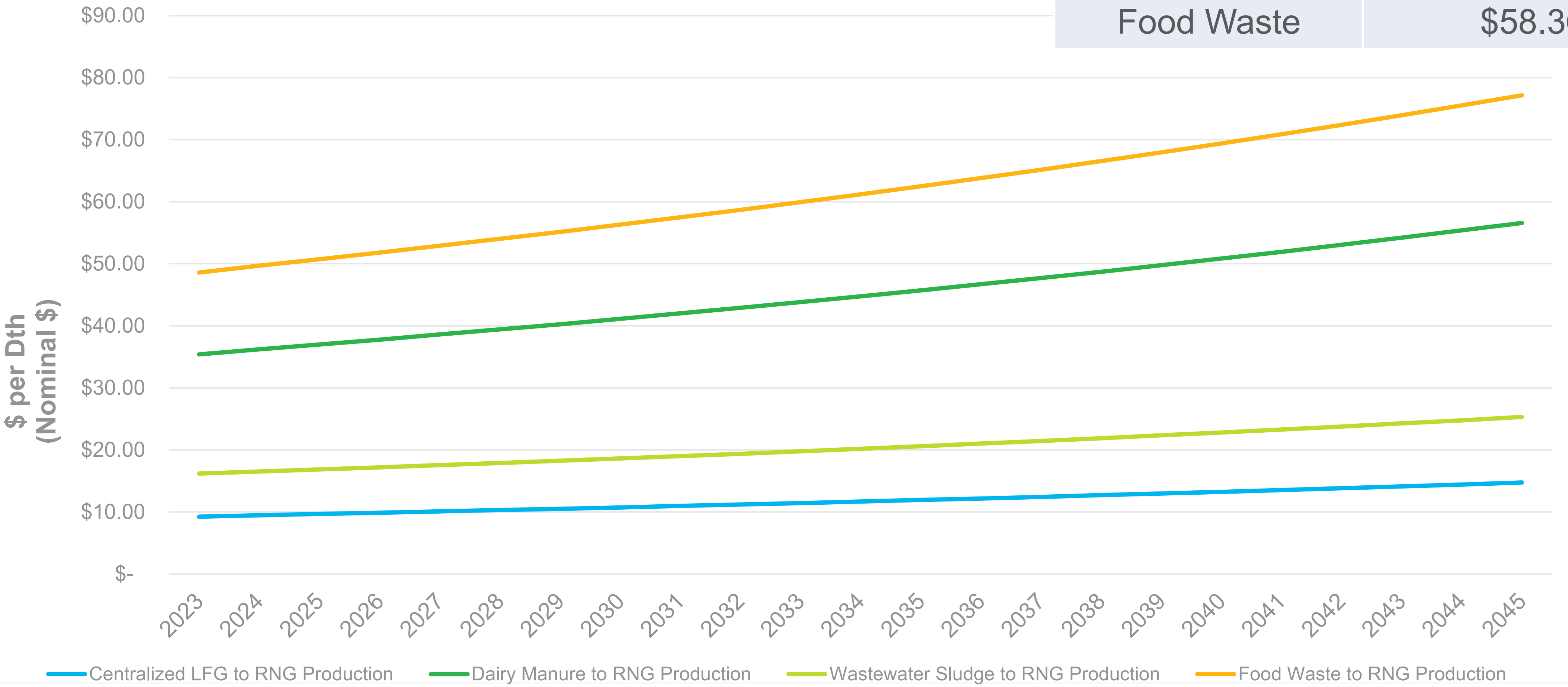
Expected Natural Gas Price Forecasts



AVISTA

RNG Cost Estimate by type

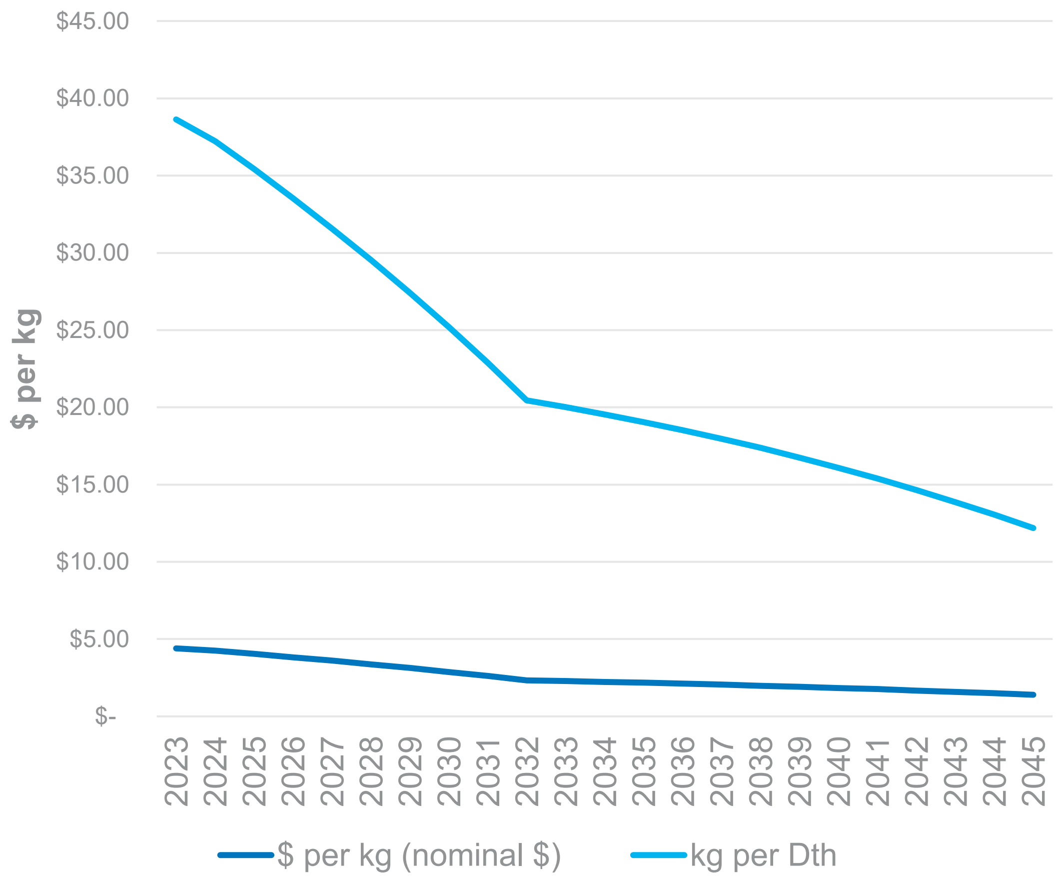
RNG Type	Levelized Price (Dth)
Landfill	$11.14
Dairy	$42.65
Wastewater	$19.29
Food Waste	$58.36



Source: Black and Veatch estimates

Green Hydrogen (H2)

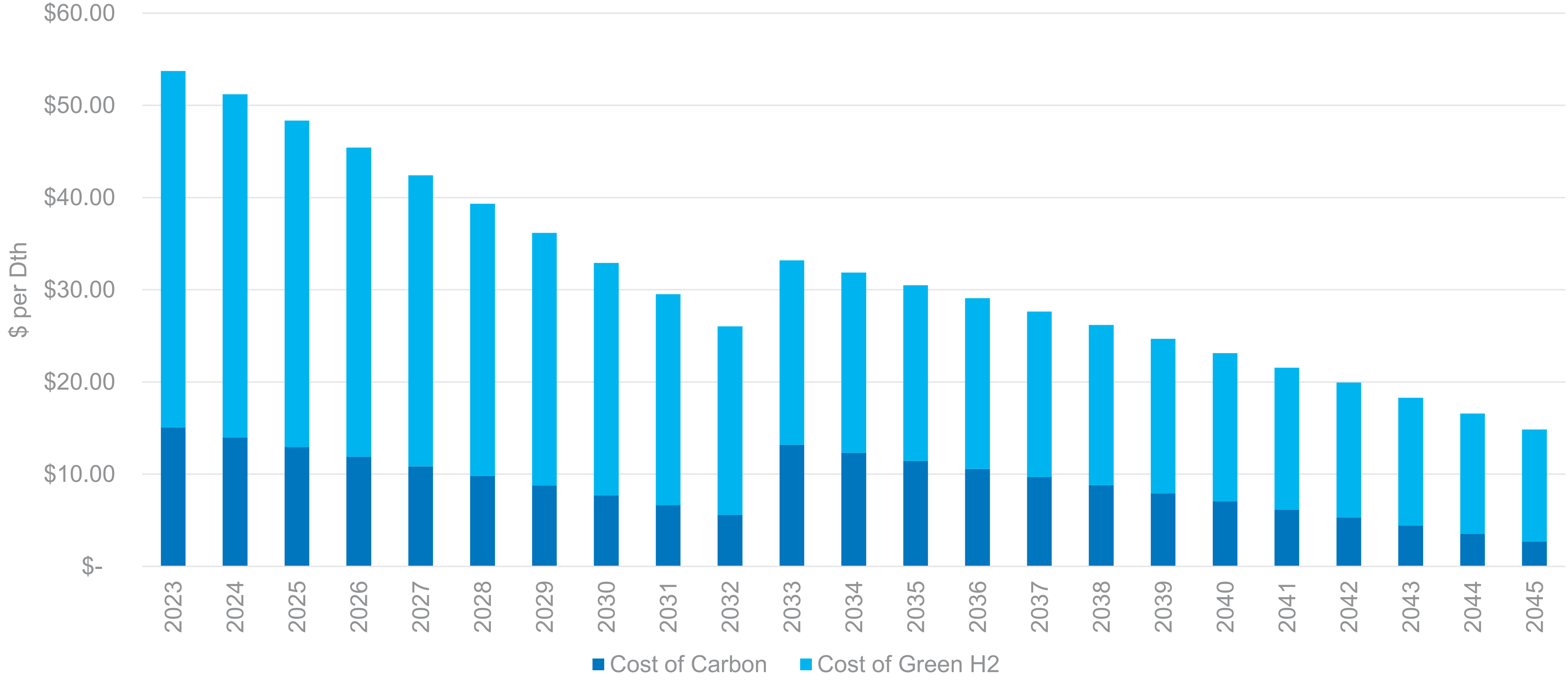
- Hydrogen is the most abundant element in the universe
- The lightest element and wants to escape making it harder to contain
- Highly combustible
- Tax credits from IRA assumed at a levelized credit for the full $3 per kg incentive from green H2



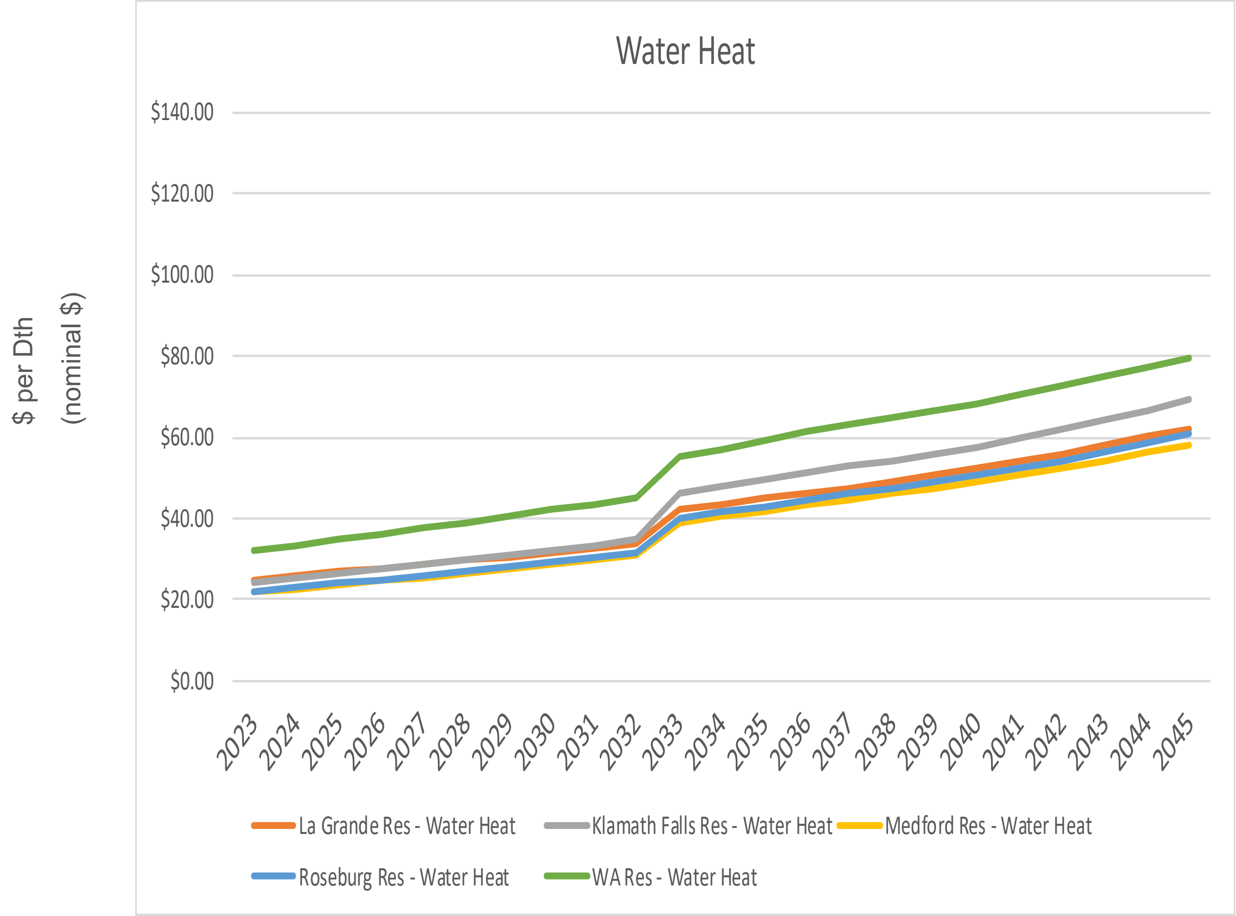
AVISTA

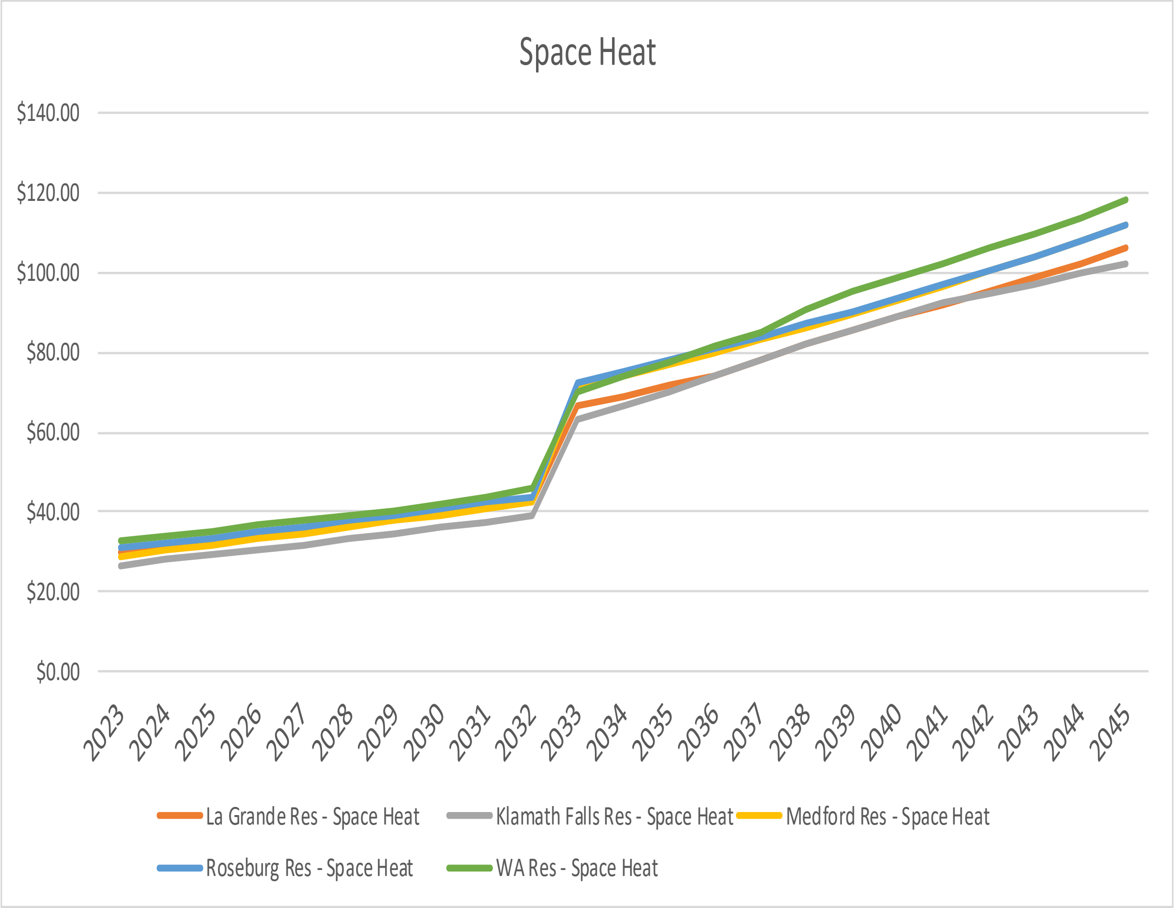
Levelized Price (year 1)	$35.78

Synthetic Methane Costs

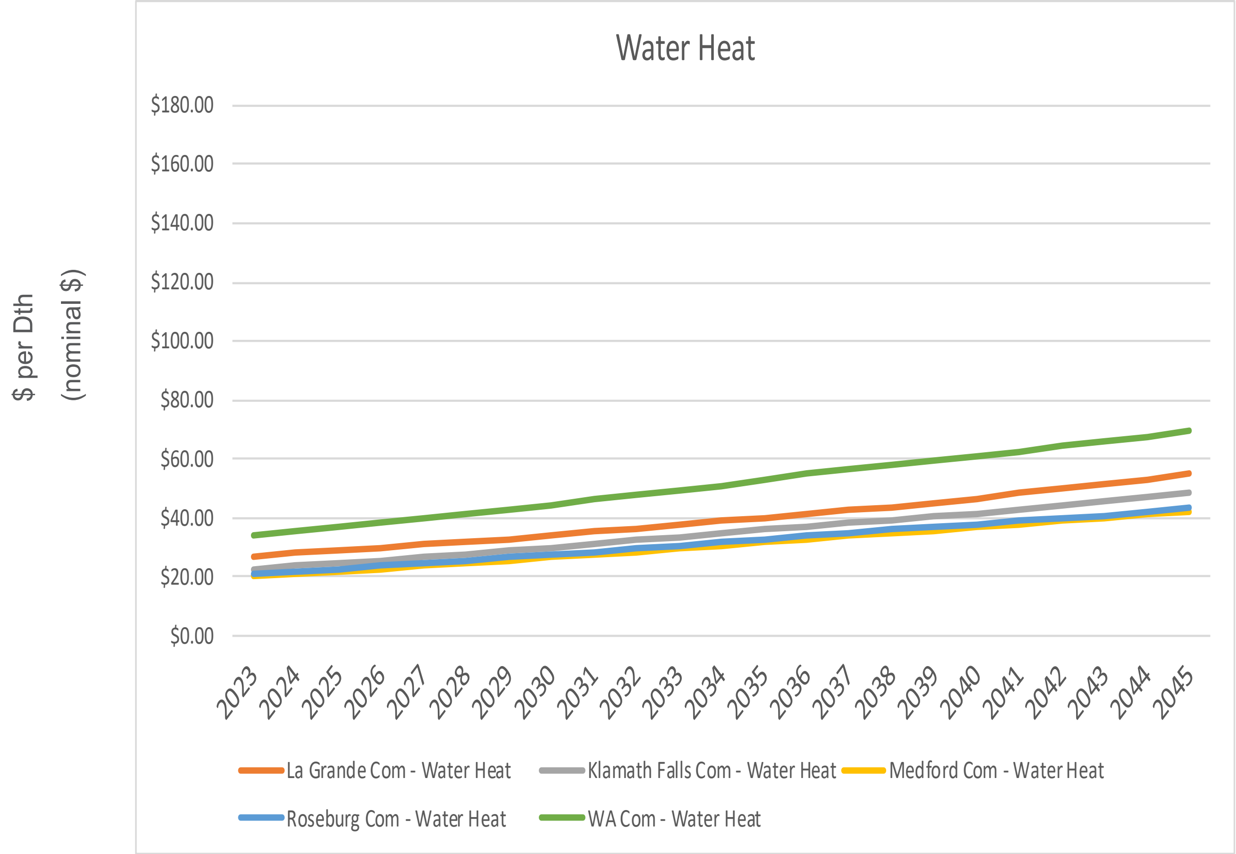


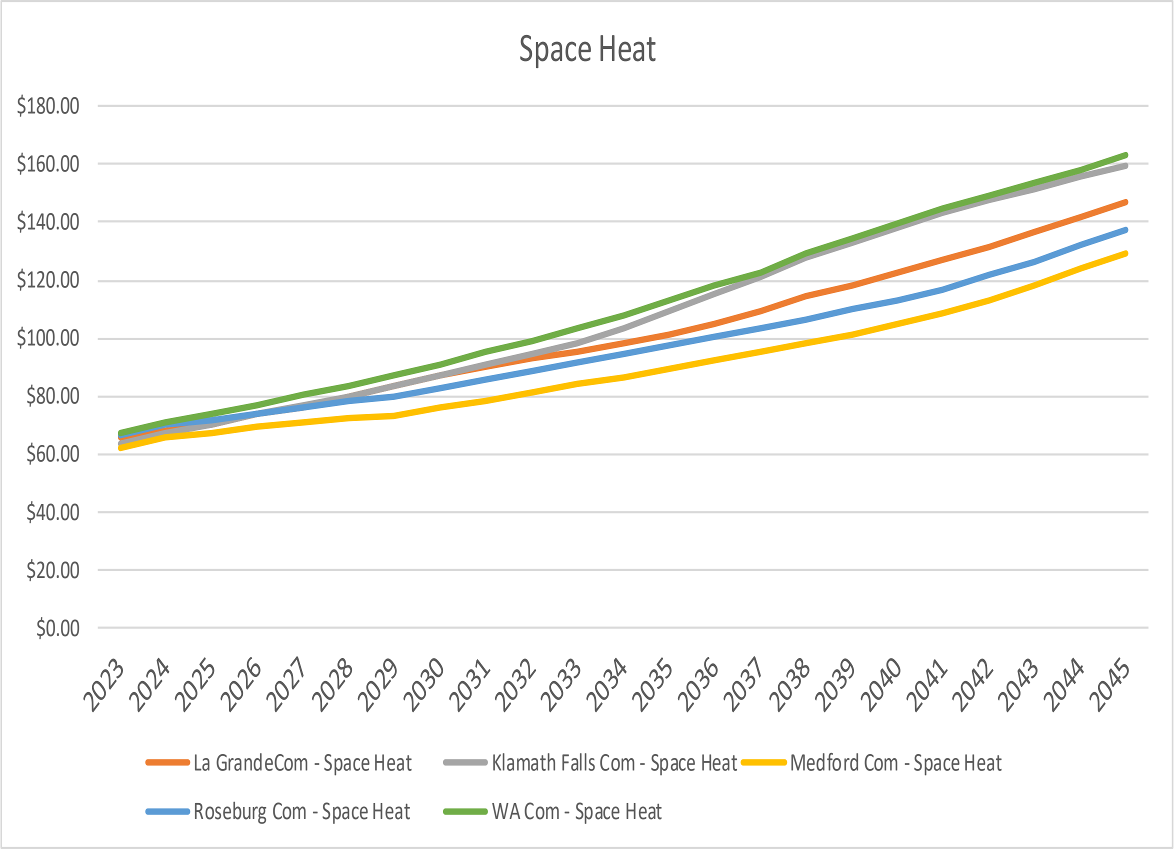
Residential Electrification Costs – Levelized (energy + conversion costs)



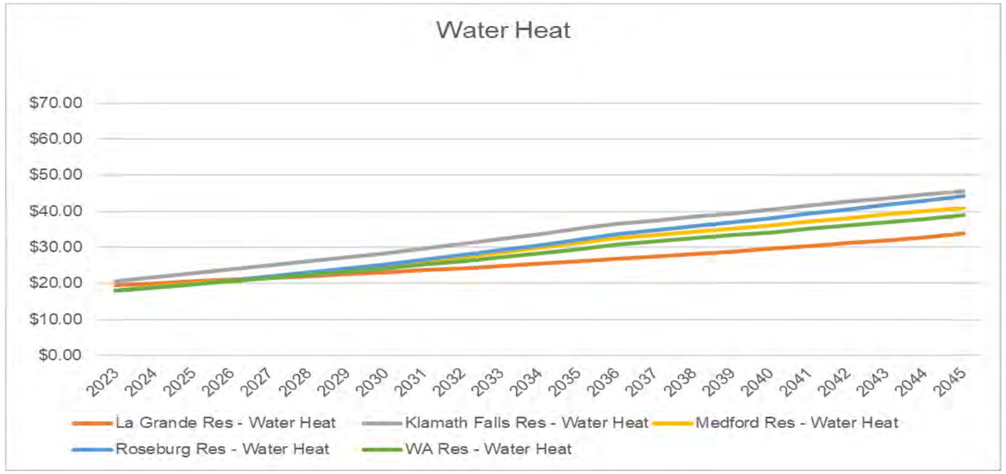


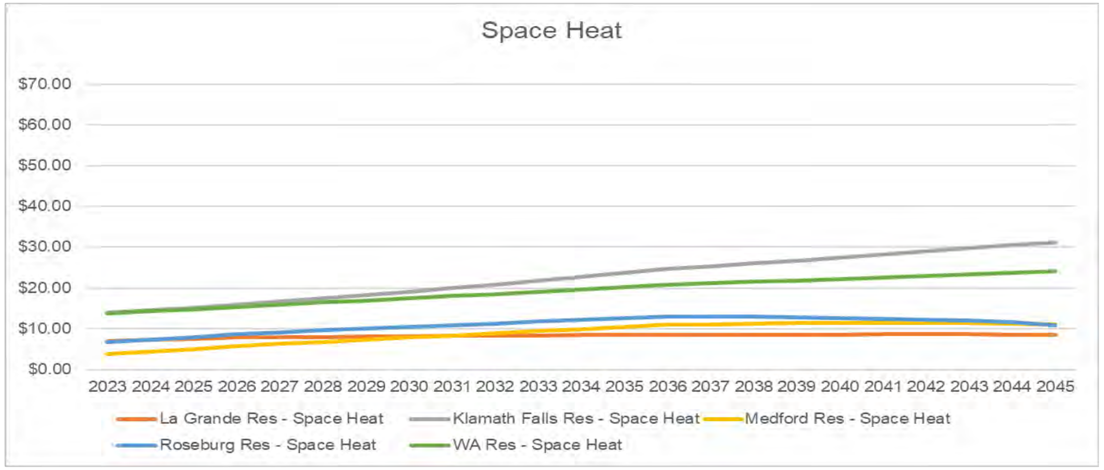
Commercial Electrification Costs – Levelized (energy + conversion costs)

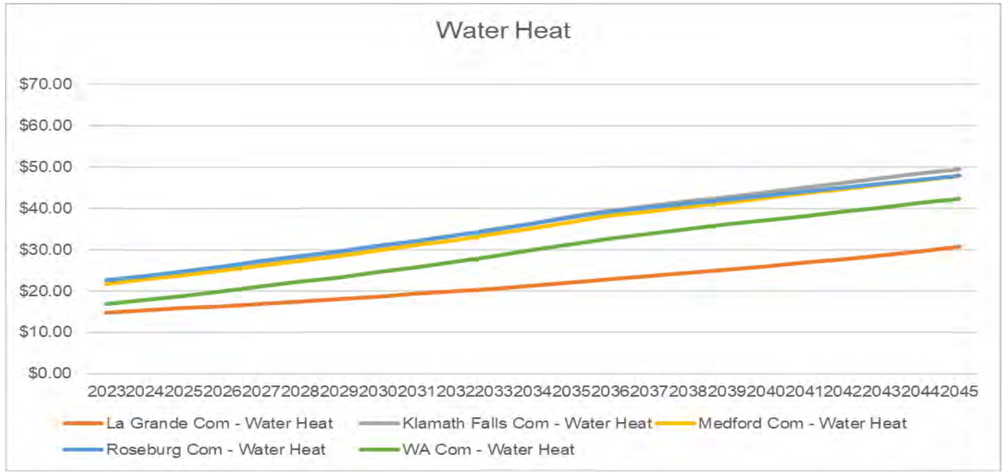


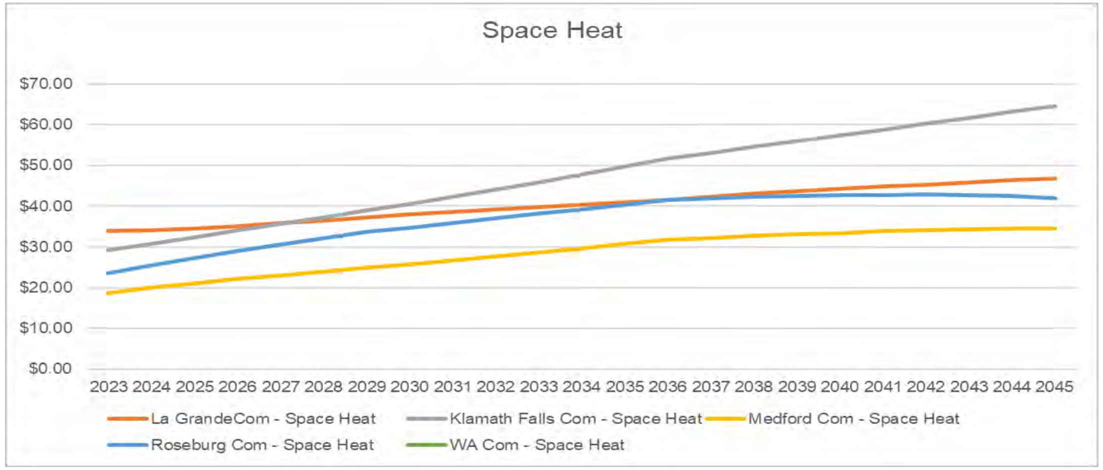


Electrification – No Capital Costs

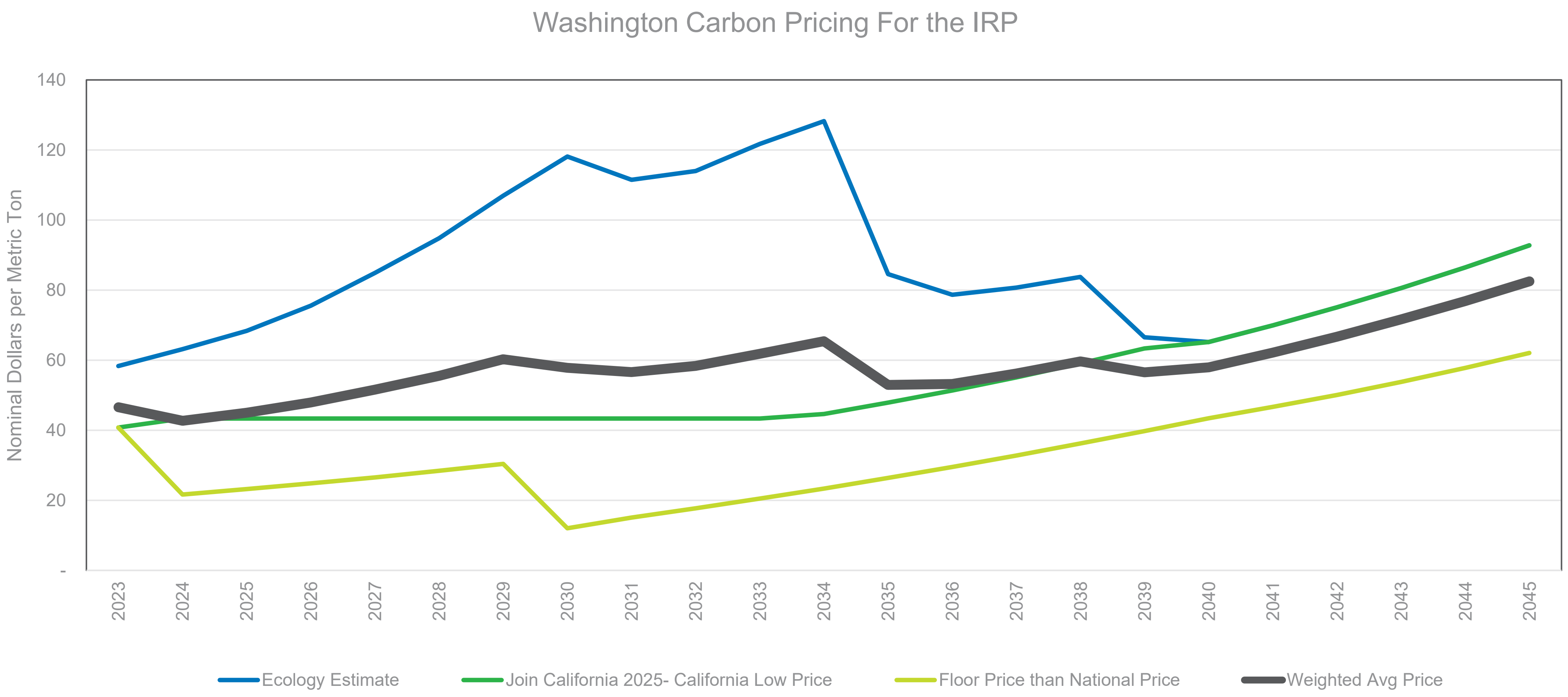




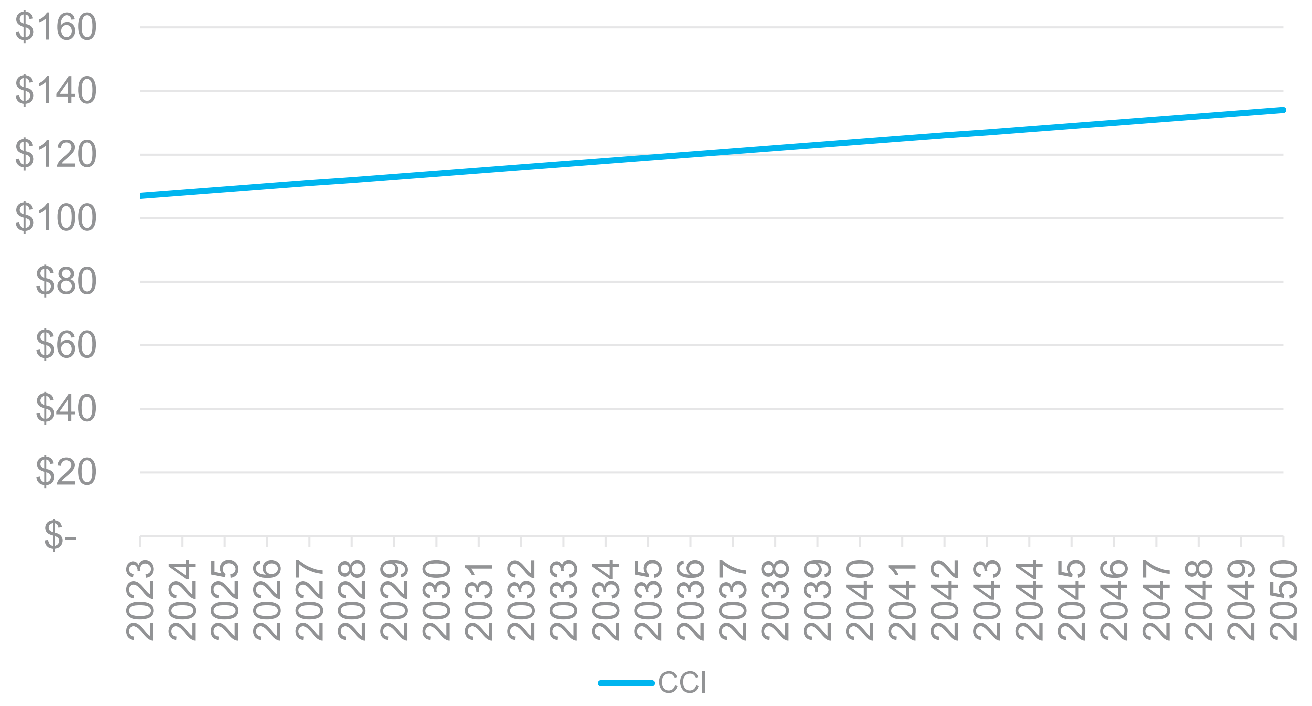




Allowance Price



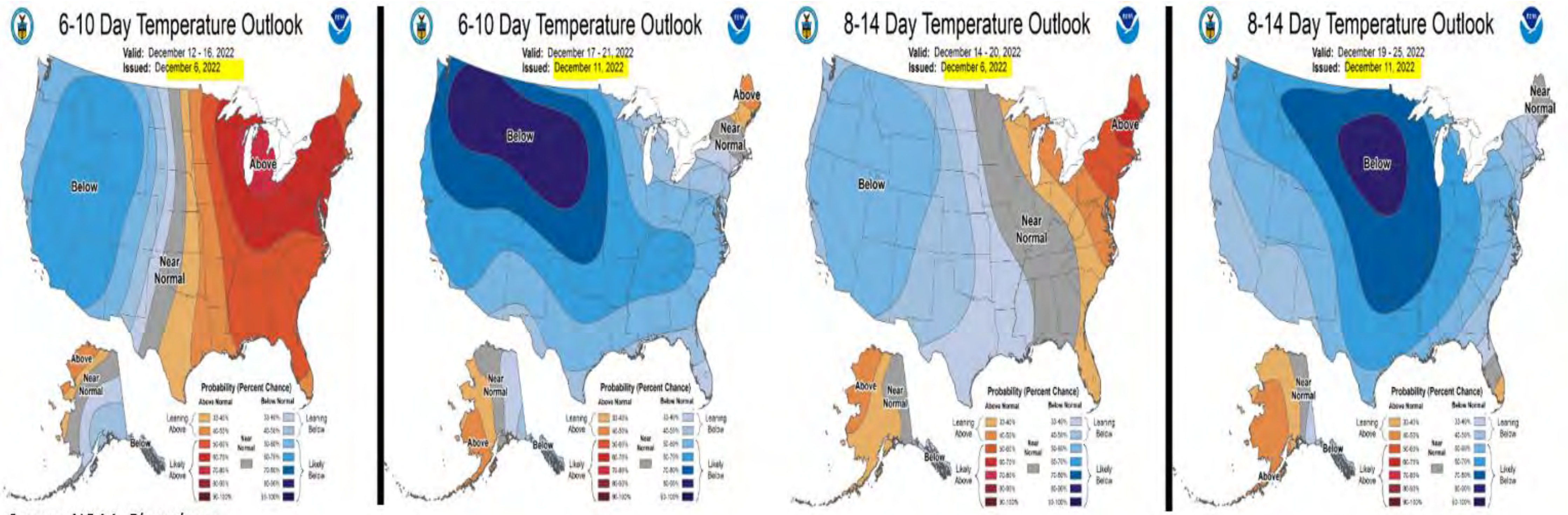
CCI Costs



OAR 340-271-9000
Table 7
CCI credit contribution amount

Effective date	CCI credit contribution amount in 2021 dollars, to be adjusted according to OAR 340-271-0820(3)
March 1, 2023	$107
March 1, 2024	$108
March 1, 2025	$109
March 1, 2026	$110
March 1, 2027	$111
March 1, 2028	$112
March 1, 2029	$113
March 1, 2030	$114
March 1, 2031	$115
March 1, 2032	$116
March 1, 2033	$117
March 1, 2034	$118
March 1, 2035	$119
March 1, 2036	$120
March 1, 2037	$121
March 1, 2038	$122
March 1, 2039	$123
March 1, 2040	$124
March 1, 2041	$125
March 1, 2042	$126
March 1, 2043	$127
March 1, 2044	$128
March 1, 2045	$129
March 1, 2046	$130
March 1, 2047	$131
March 1, 2048	$132
March 1, 2049	$133
March 1, 2050	$134

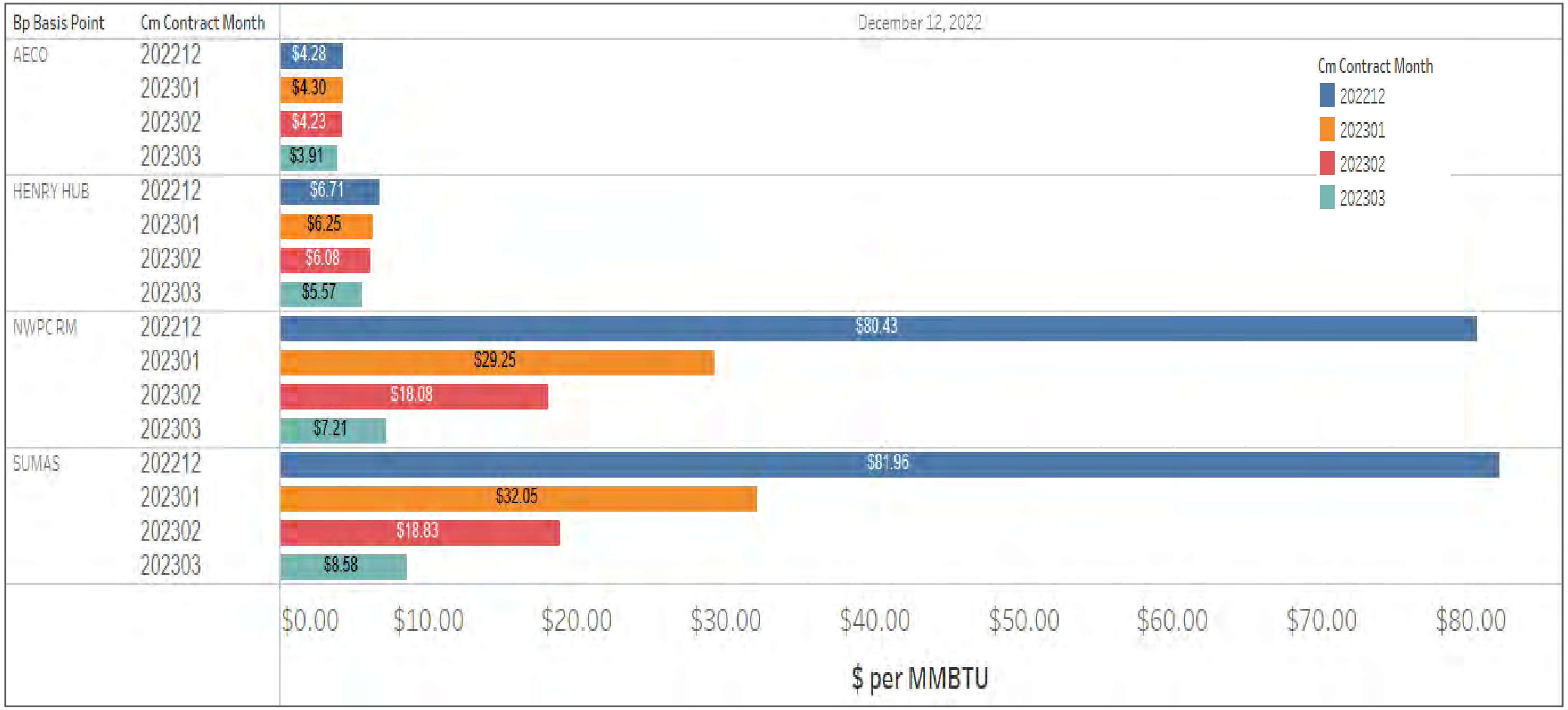
Quick Market Update



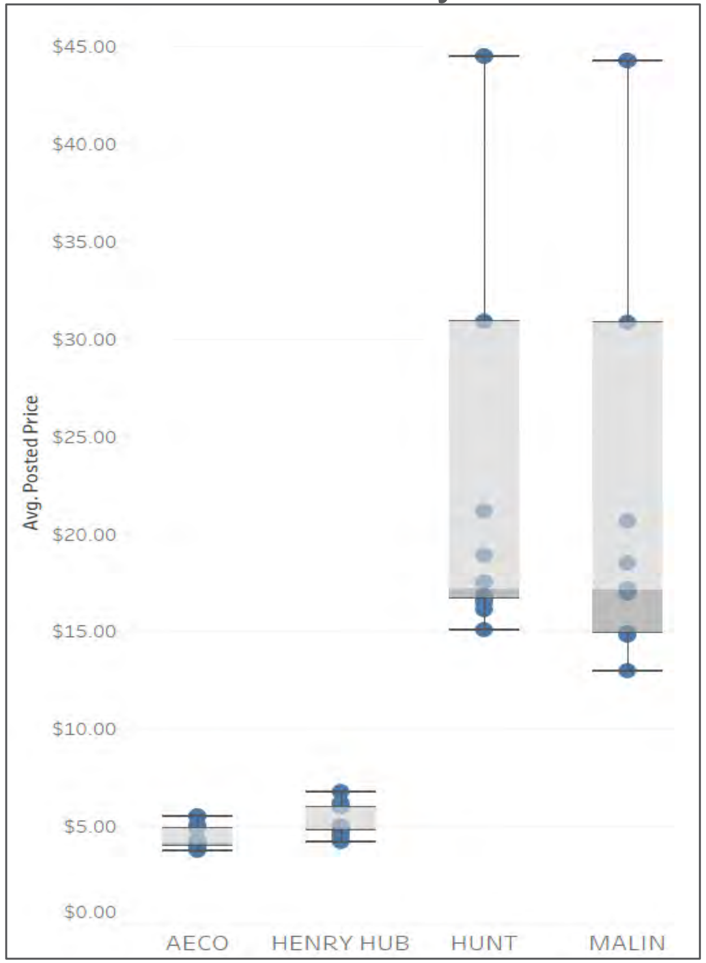
Source: NOAA, Bloomberg

Natural Gas Prices

Forwards



Daily



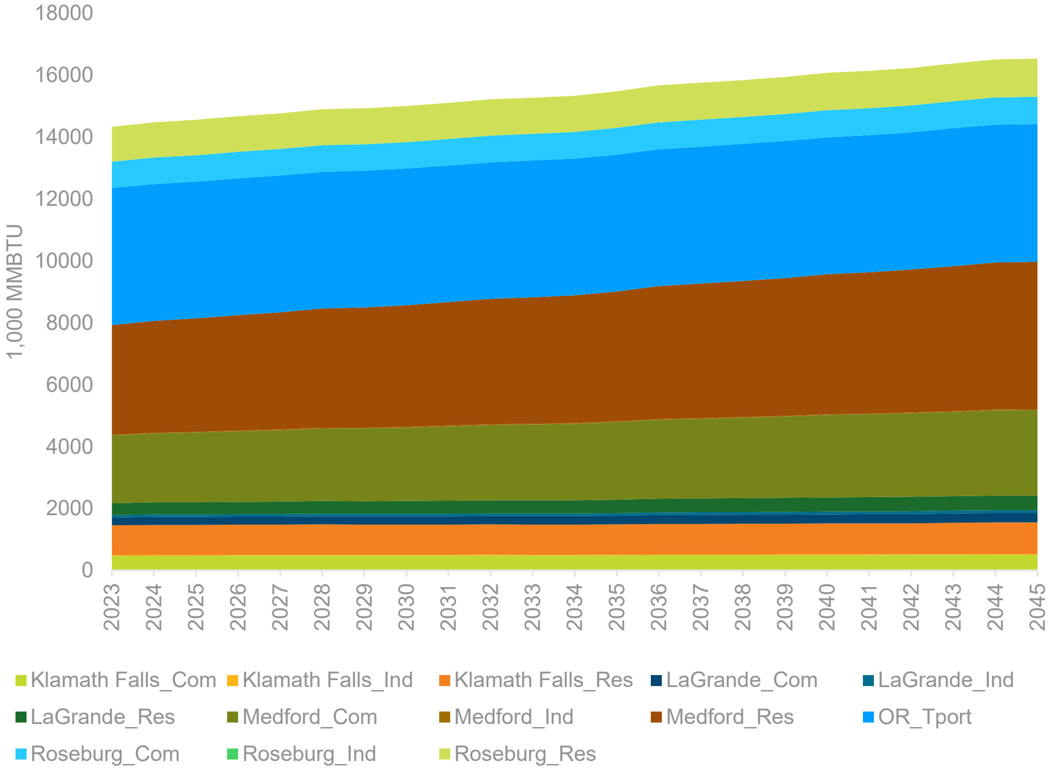
*prior two weeks of daily prices

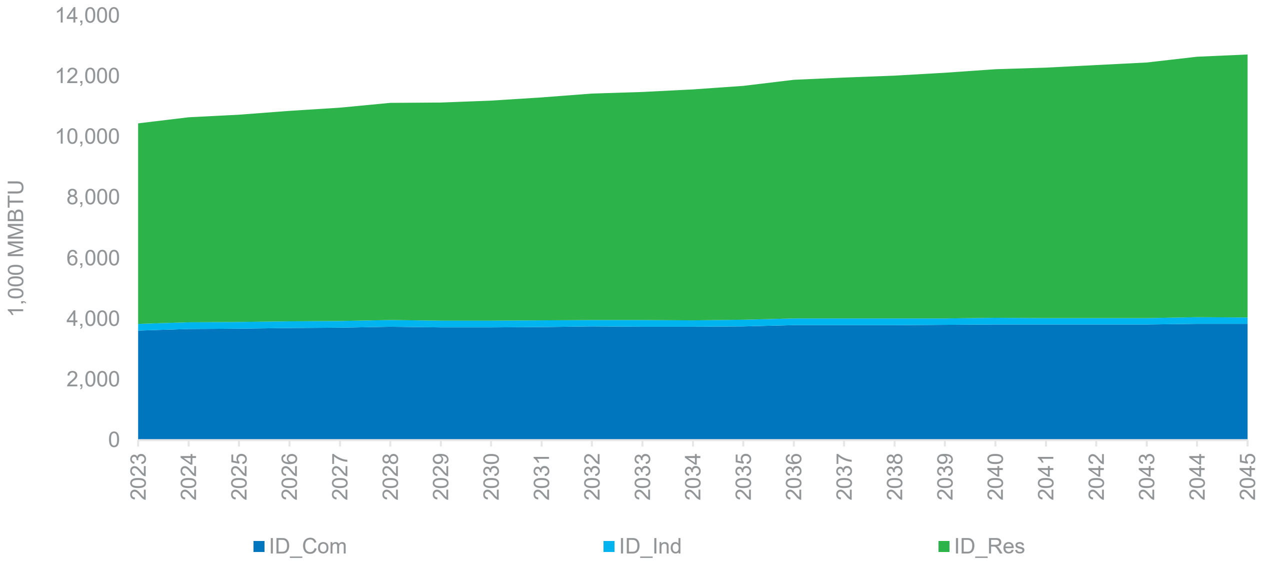
Preferred Resource Strategy (PRS)

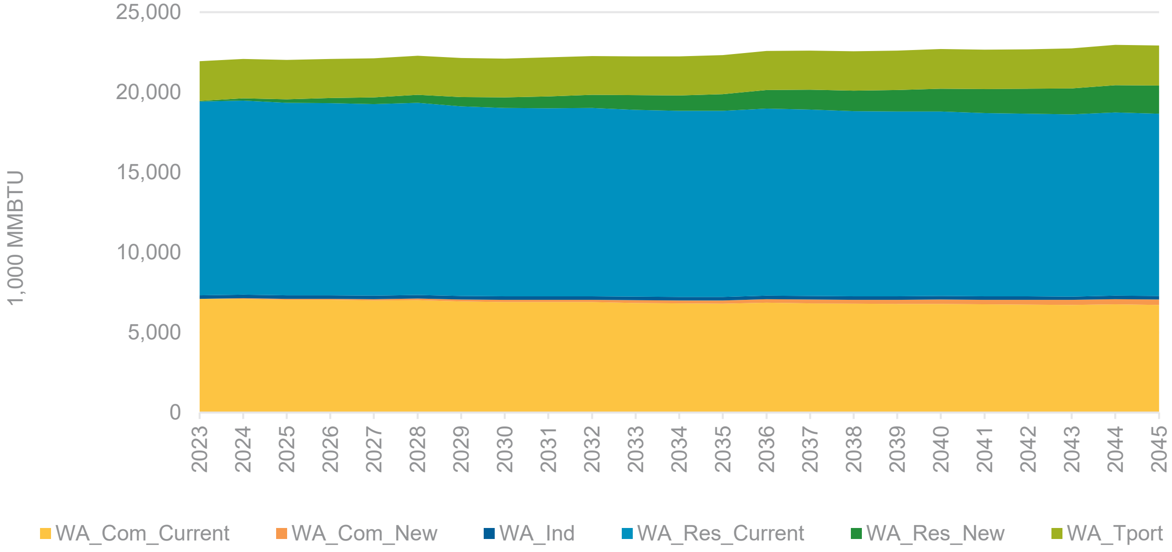
Simulation Analysis

- Simulation analysis is performed using stochastic simulation paired with Monte Carlo simulation to understand risk
- Stochastic simulation provides a single solution based on the number of simulations performed
    - 5 future simulations
- Monte Carlo simulation is used to provide risk analysis around the resources selected stochastically
    - 500 MC simulations

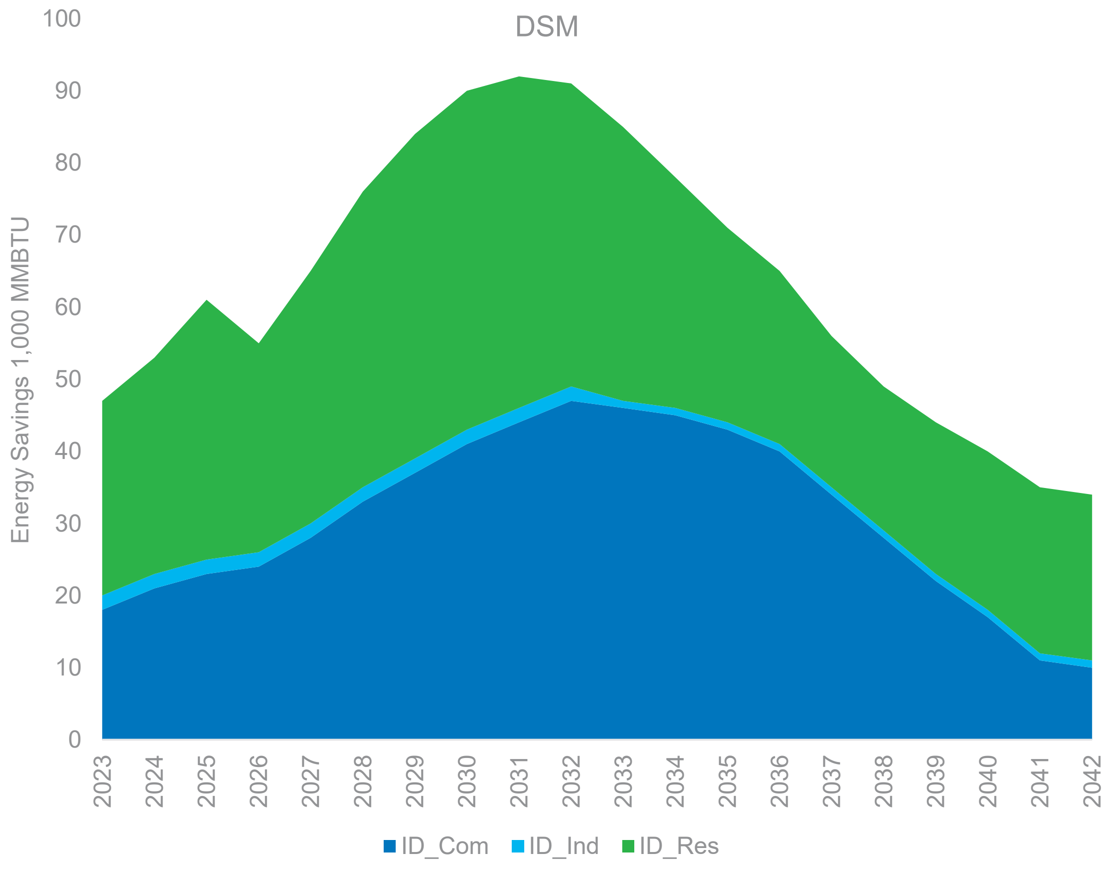
Demand by State

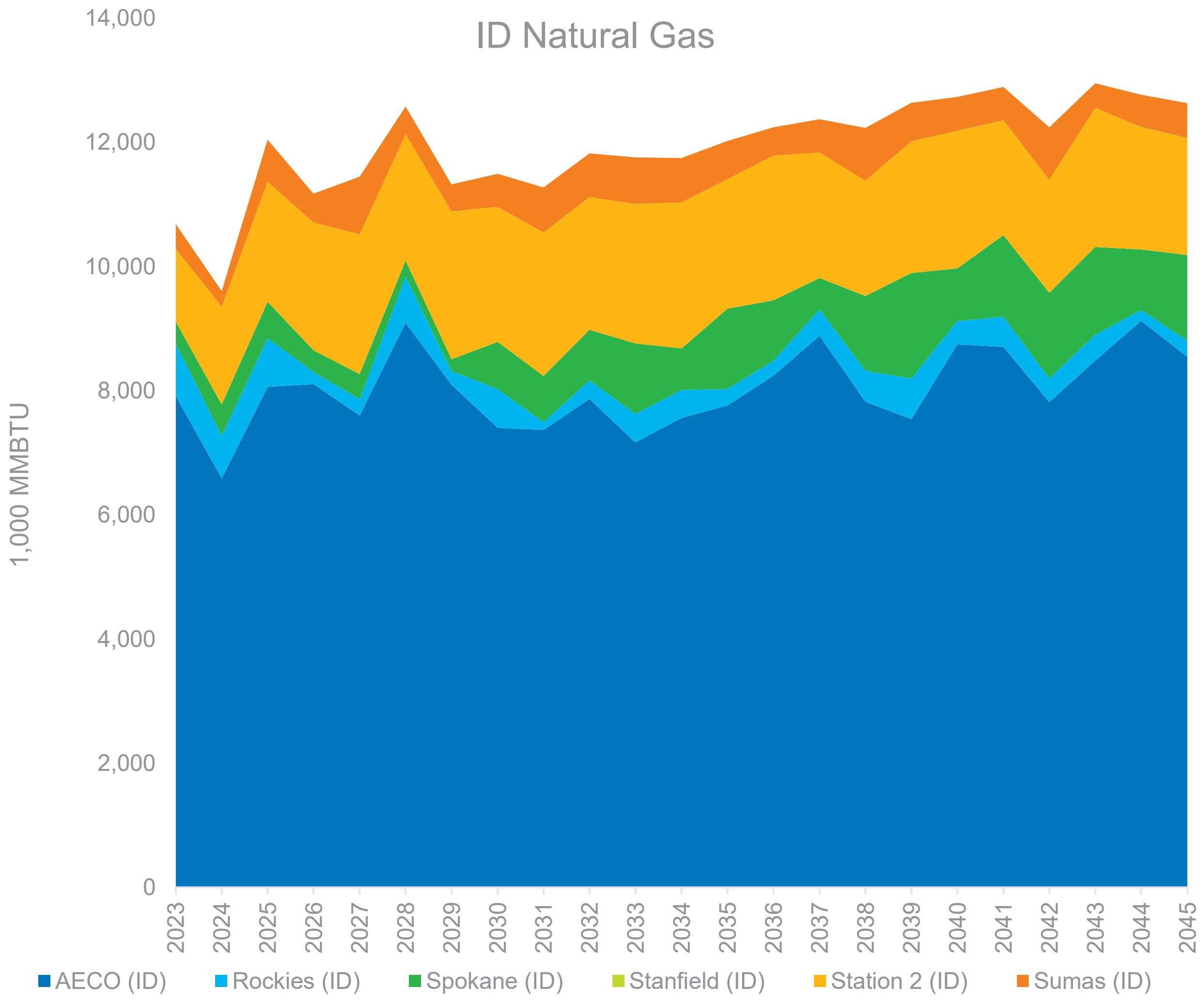




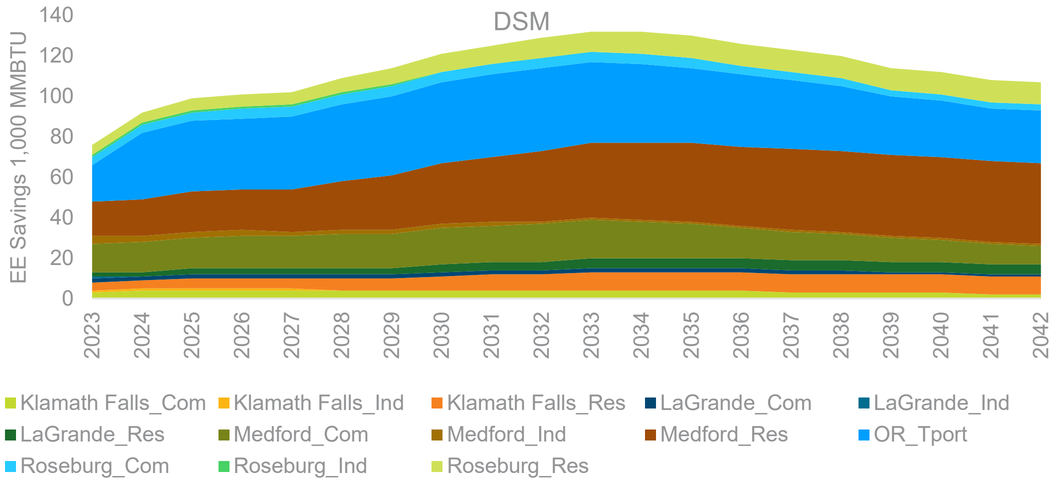


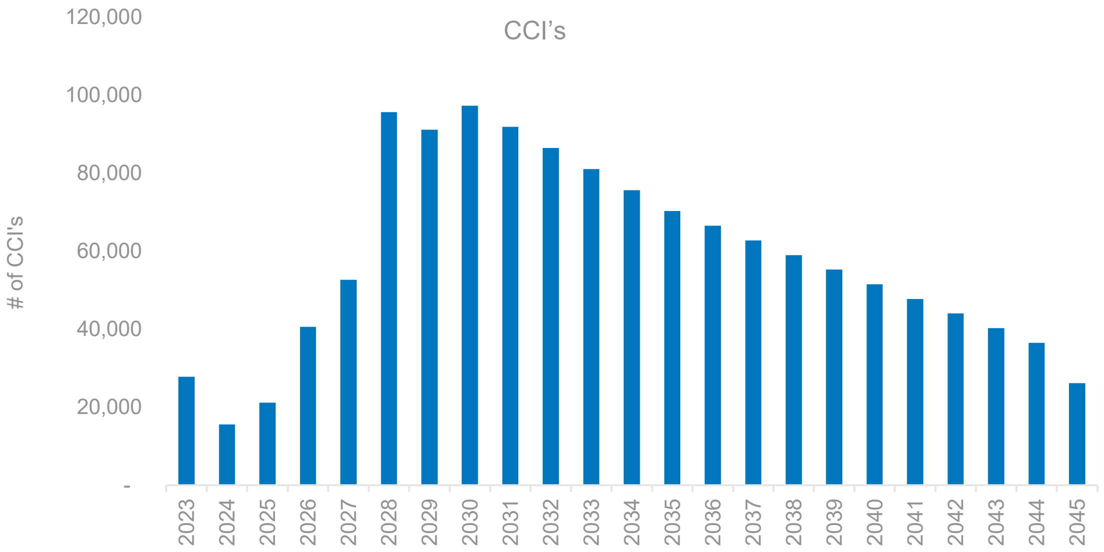
Idaho

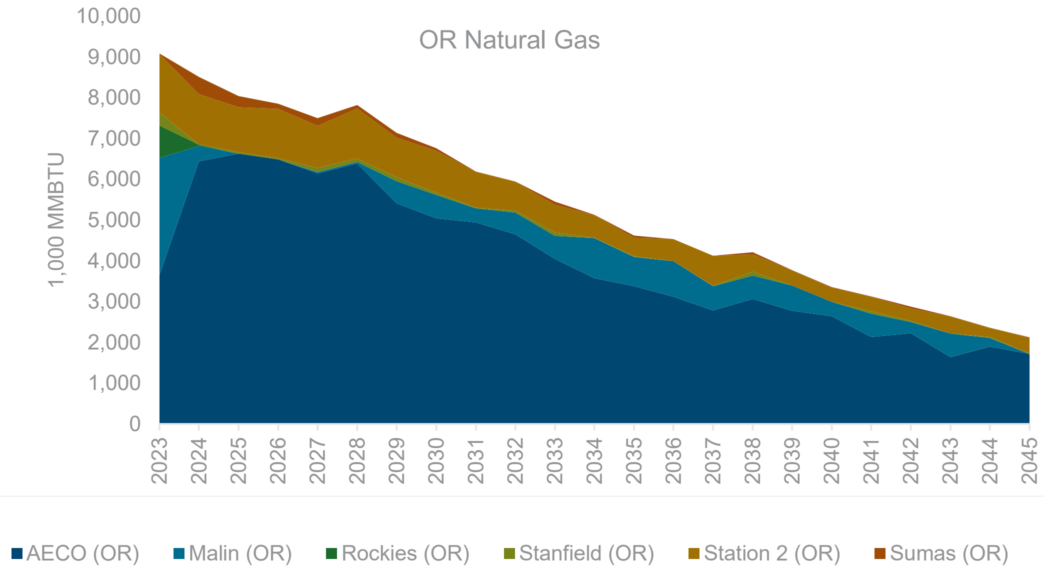

DSM
Energy Savings 1,000 MMBTU
100
90
80
70
60
50
40
30
20
10
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
ID_Com
ID_Ind
ID_Res

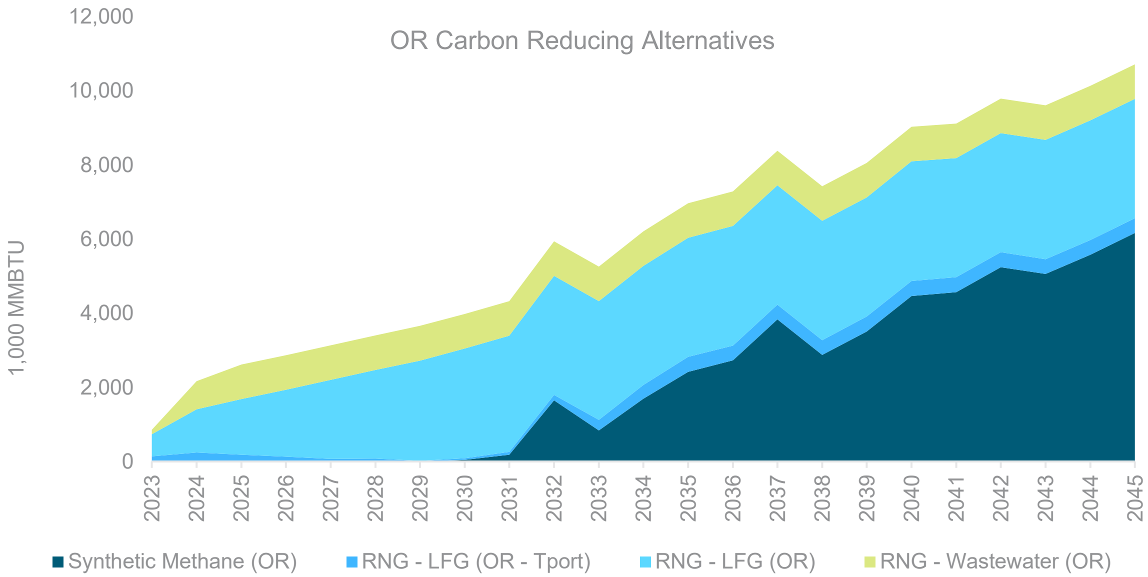

ID Natural Gas
1,000 MMBTU
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
AECO (ID)
Rockies (ID)
Spokane (ID)
Stanfield (ID)
Station 2 (ID)
Sumas (ID)

Oregon

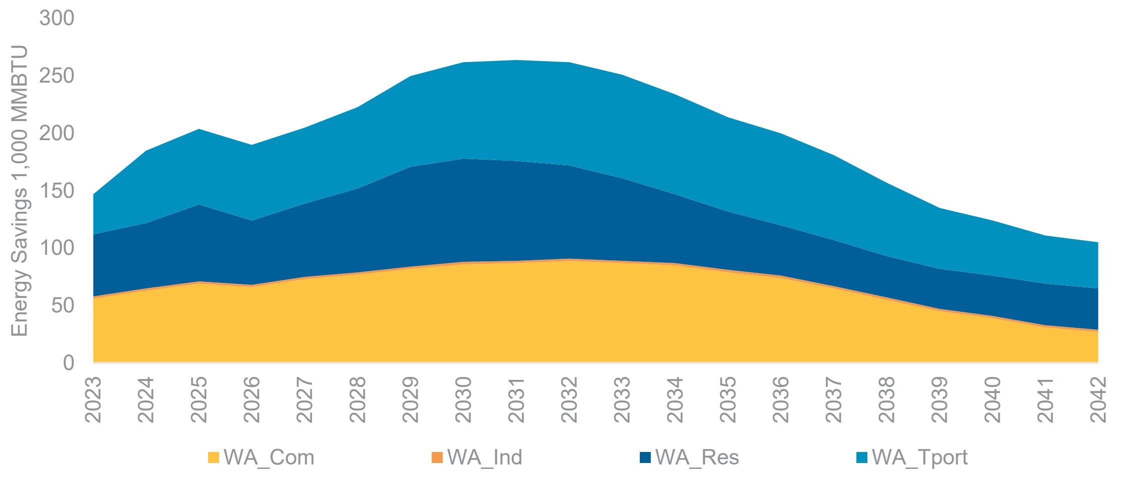

DSM
EE Savings 1,000 MMBTU
140
120
100
80
60
40
20
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
Klamath Falls_Com
Klamath Falls_Ind
Klamath Falls_Res
LaGrande_Com
LaGrande_Ind
LaGrande_Res
Medford_Com
Medford_Ind
Medford_Res
OR_Tport
Roseburg_Com
Roseburg_Ind
Roseburg_Res

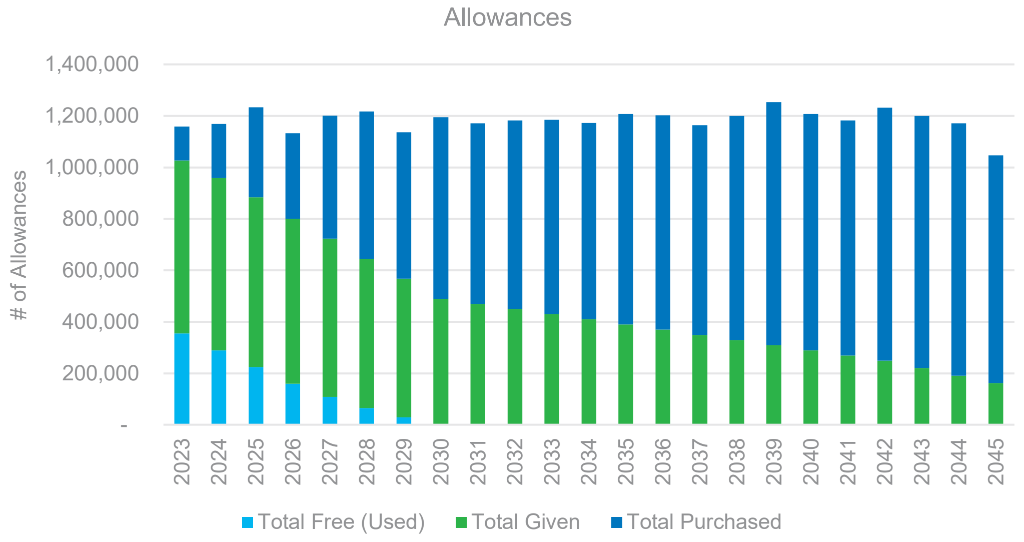

CCI's
# of CCI's
120,000
100,000
80,000
60,000
40,000
20,000
-
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045

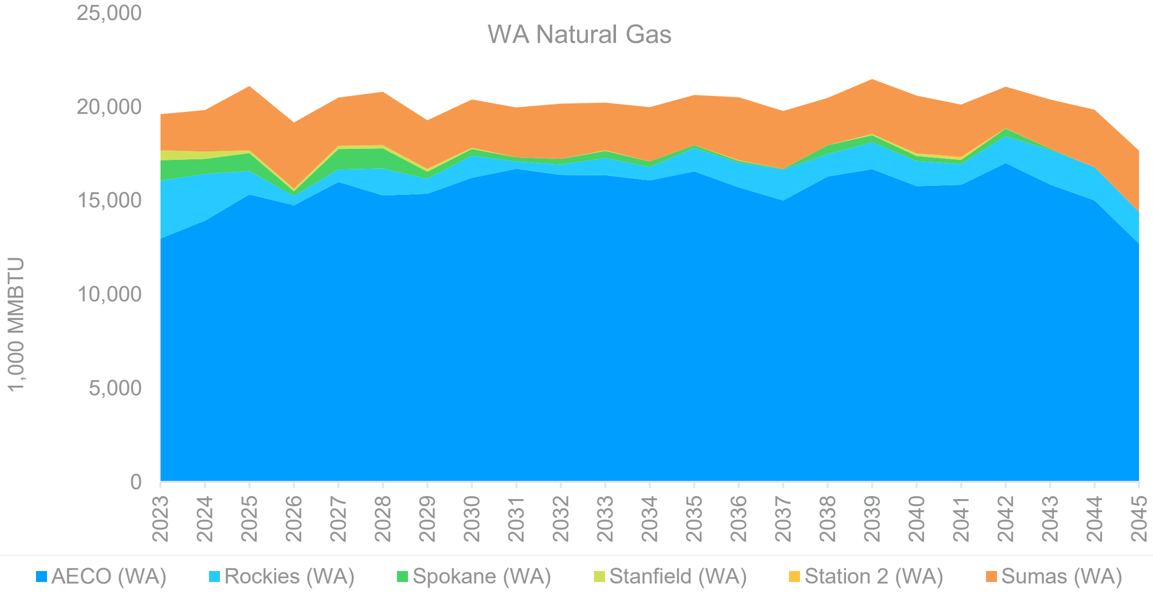

OR Natural Gas
1,000 MMBTU
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
AECO (OR)
Malin (OR)
Rockies (OR)
Stanfield (OR)
Station 2 (OR)
Sumas (OR)

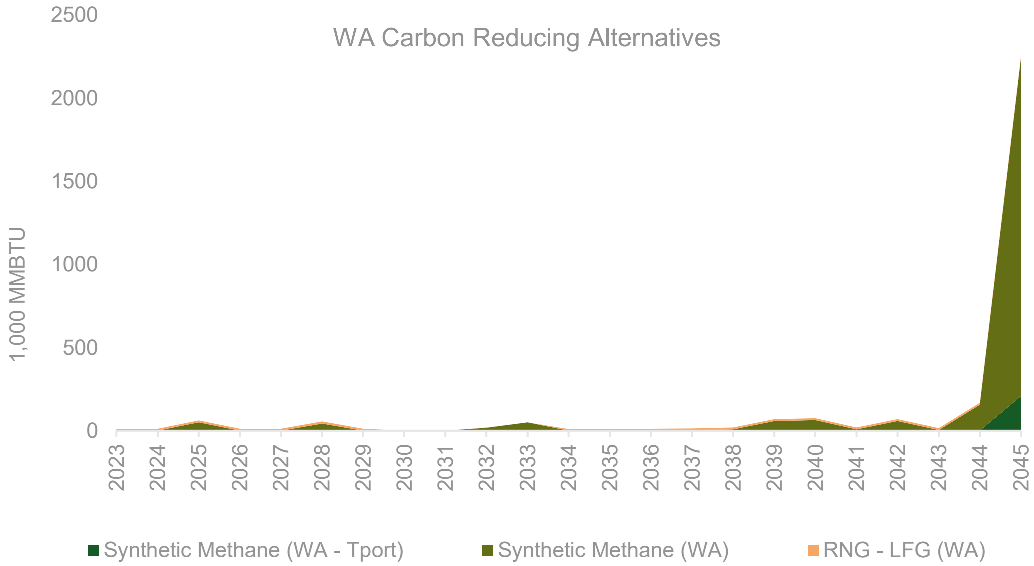

OR Carbon Reducing Alternatives
1,000 MMBTU
12,000
10,000
8,000
6,000
4,000
2,000
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Synthetic Methane (OR)
RNG - LFG (OR - Tport)
RNG - LFG (OR)
RNG - Wastewater (OR)

Washington

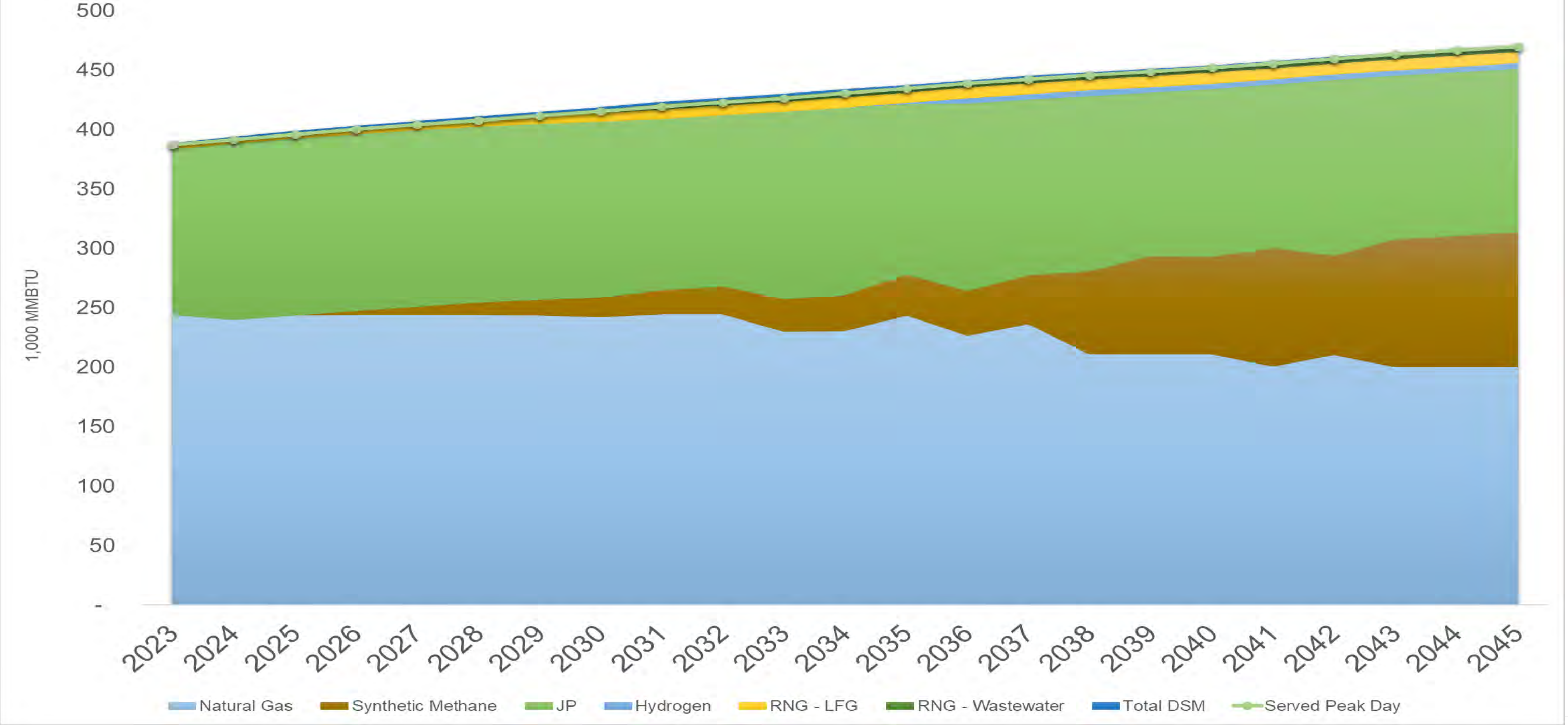

Energy Savings 1,000 MMBTU
300
250
200
150
100
50
0
2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042
WA_Com
WA_Ind
WA_Res
WA_Tport


Allowances
# of Allowances
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
Total Free (Used)
Total Given
Total Purchased


WA Natural Gas
1,000 MMBTU
25,000
20,000
15,000
10,000
5,000
0
2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
AECO (WA)
Rockies (WA)
Spokane (WA)
Stanfield (WA)
Station 2 (WA)
Sumas (WA)

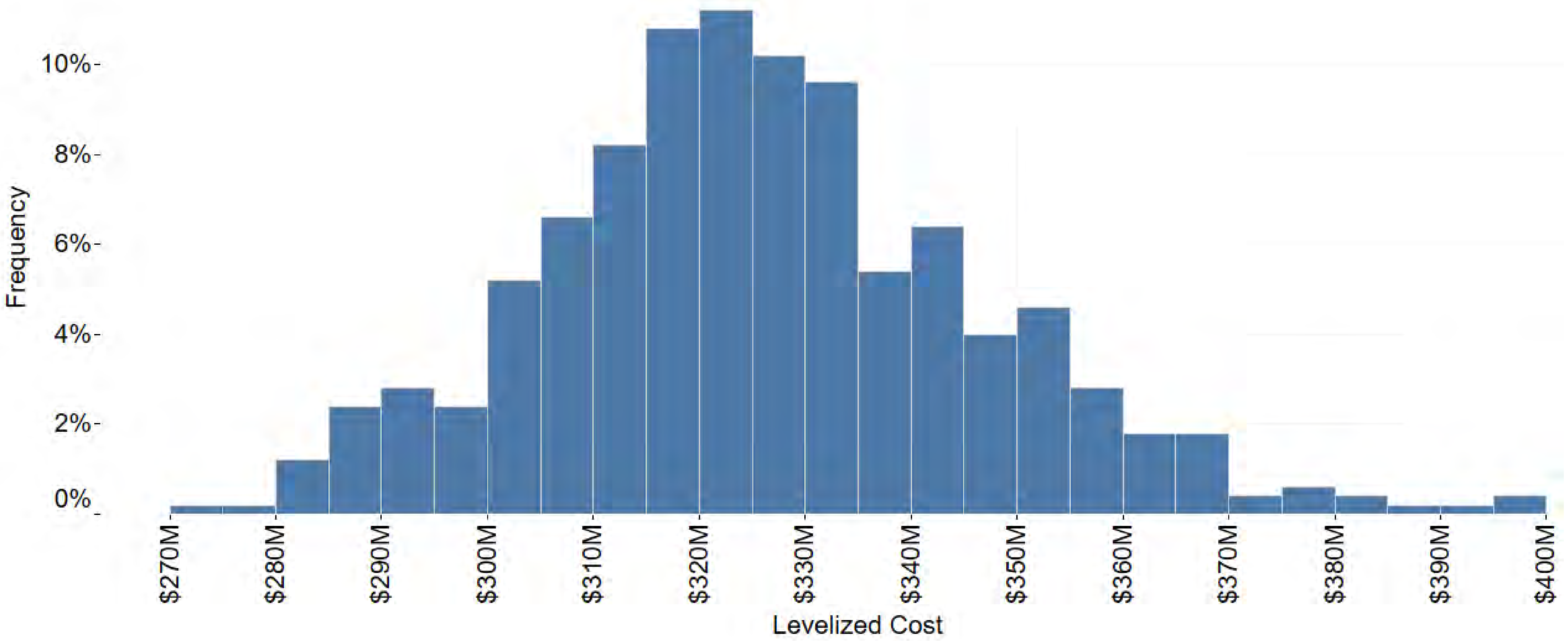

WA Carbon Reducing Alternatives
1,000 MMBTU
2500
2000
1500
1000
500
0
2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
Synthetic Methane (WA - Tport)
Synthetic Methane (WA)
RNG - LFG (WA)

PRS - System Peak Day



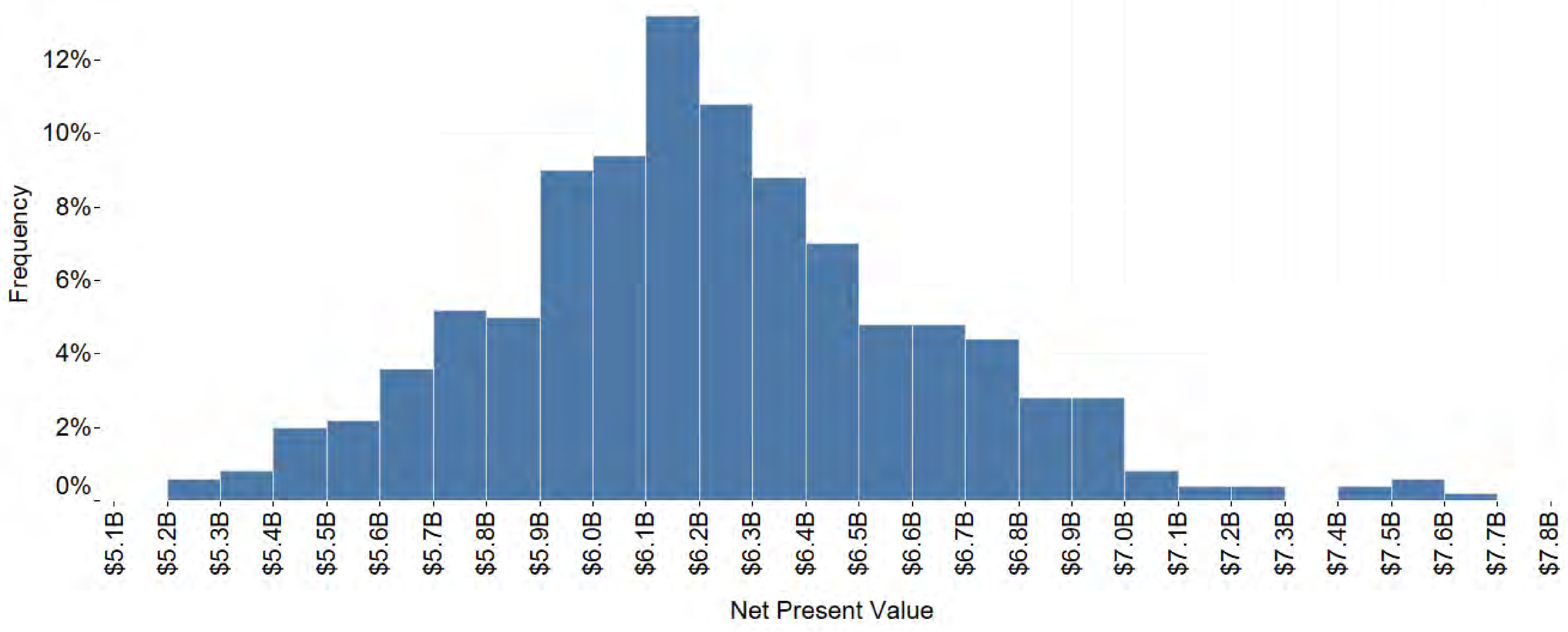
Residential PGA Impact

Monte Carlo – Levelized System Cost (500 Draws)

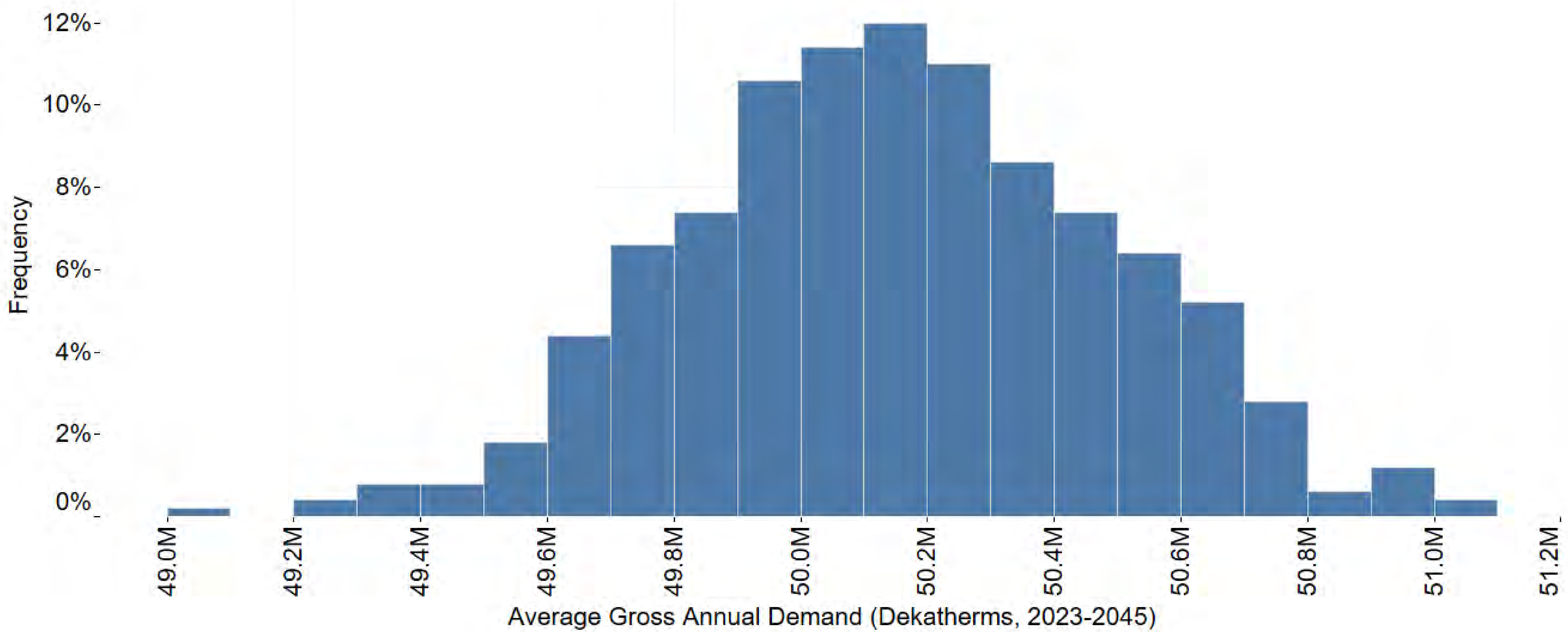


AVISTA

Monte Carlo – System Cost Net Present Value (500 Draws)

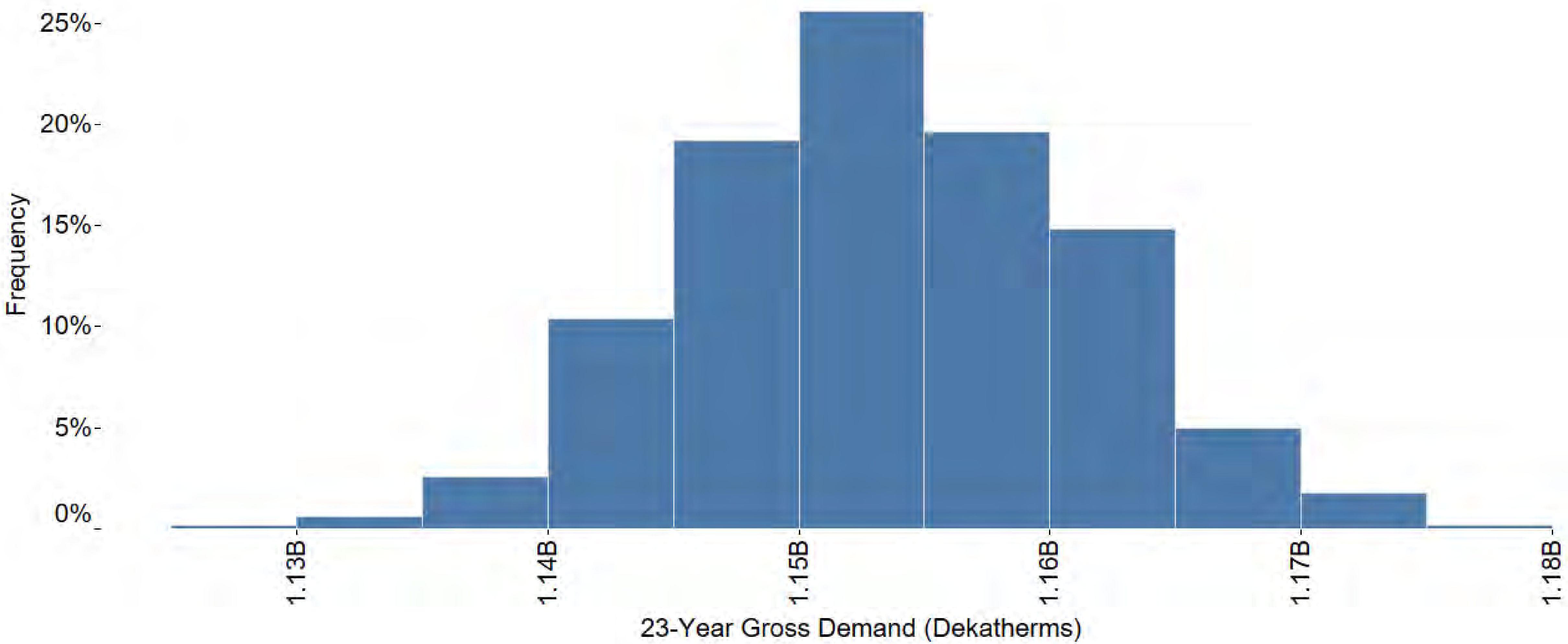


Monte Carlo – Average Annual Gross System Demand (500 Draws)



AVISTA

Monte Carlo – Gross System Demand 2023-2045 (500 Draws)



AVISTA

Scenario Results

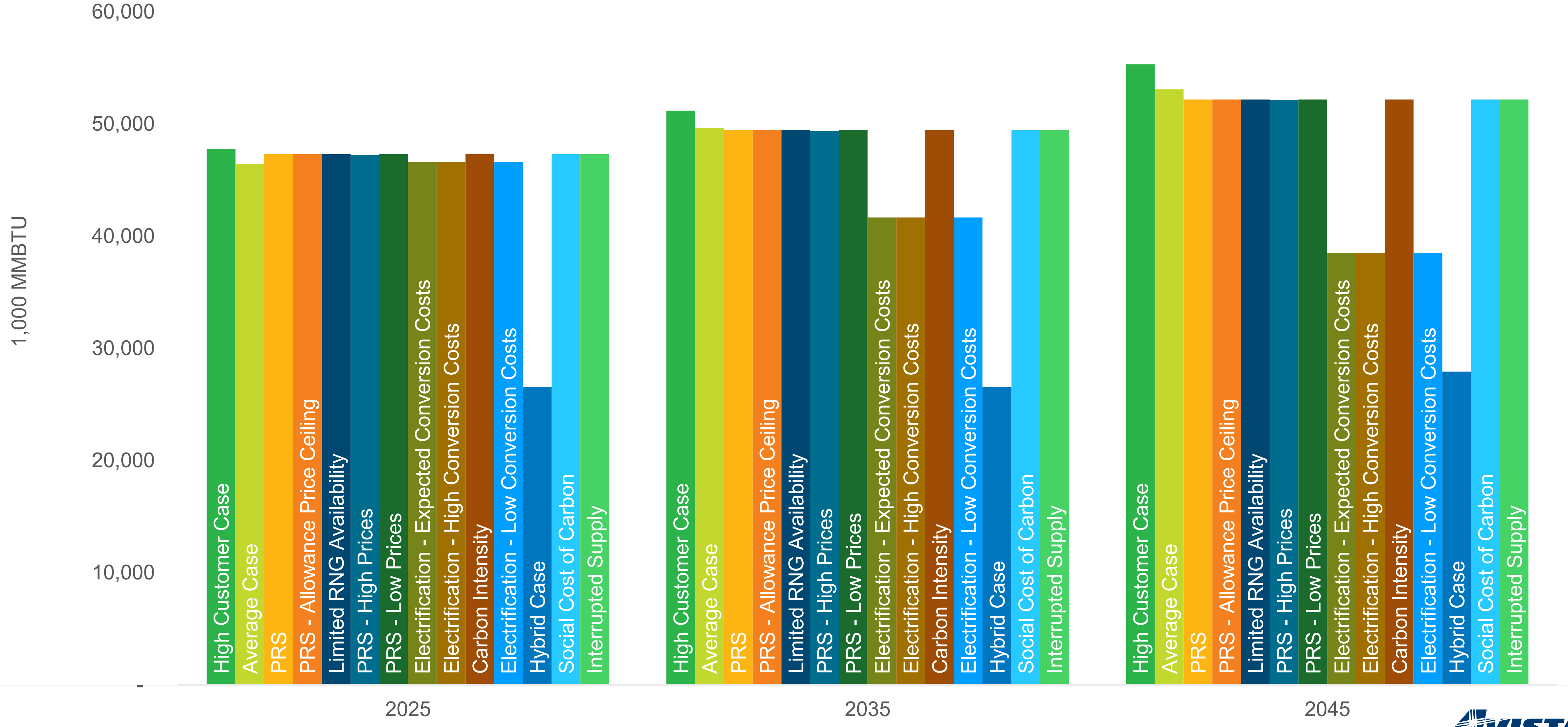
Scenarios

- **Preferred Resource Case** – Our expected case based on assumptions and costs with a least risk and least cost resource selection
- **Preferred Resource Case Low Prices** – Same as PRS, but includes low price curve for natural gas
- **Preferred Resource Case High Prices** - Same as PRS, but includes high price curve for natural gas
- **Preferred Resource Case CCA Ceiling Prices** – Same as PRS, but our expected case based on assumptions with a yearly ceiling price for allowances in the CCA program
- **Electrification Expected Conversion Costs –** Expected conversion costs case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **Electrification Low Conversion Costs –** A low conversion cost case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **Electrification High Conversion Costs** - A high conversion cost case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system
- **High Customer Case** – A high case to measure risk of additional customer and meeting our emissions and energy obligations
- **Limited RNG Availability** – A scenario to show costs and supply options if RNG availability is smaller than expected
- **Interrupted Supply** – A scenario to show the impacts and risks associated with large scale supply impacts and the ability for Avista to provide the needed energy to our customers
- **Carbon Intensity –** Include carbon intensity of all resources from Preferred Resource Case including upstream emissions on natural gas
- **Social Cost of Carbon** – A scenario to value resources in all locations using the Social Cost of Carbon @ 2.5% and includes upstream emissions
- **Average Case** – Non climate change projected 20-year history of average daily weather and excludes peak day
- **Hybrid Case** – Natural Gas used for space heat below 40º F while transferring all other usage to electricity.

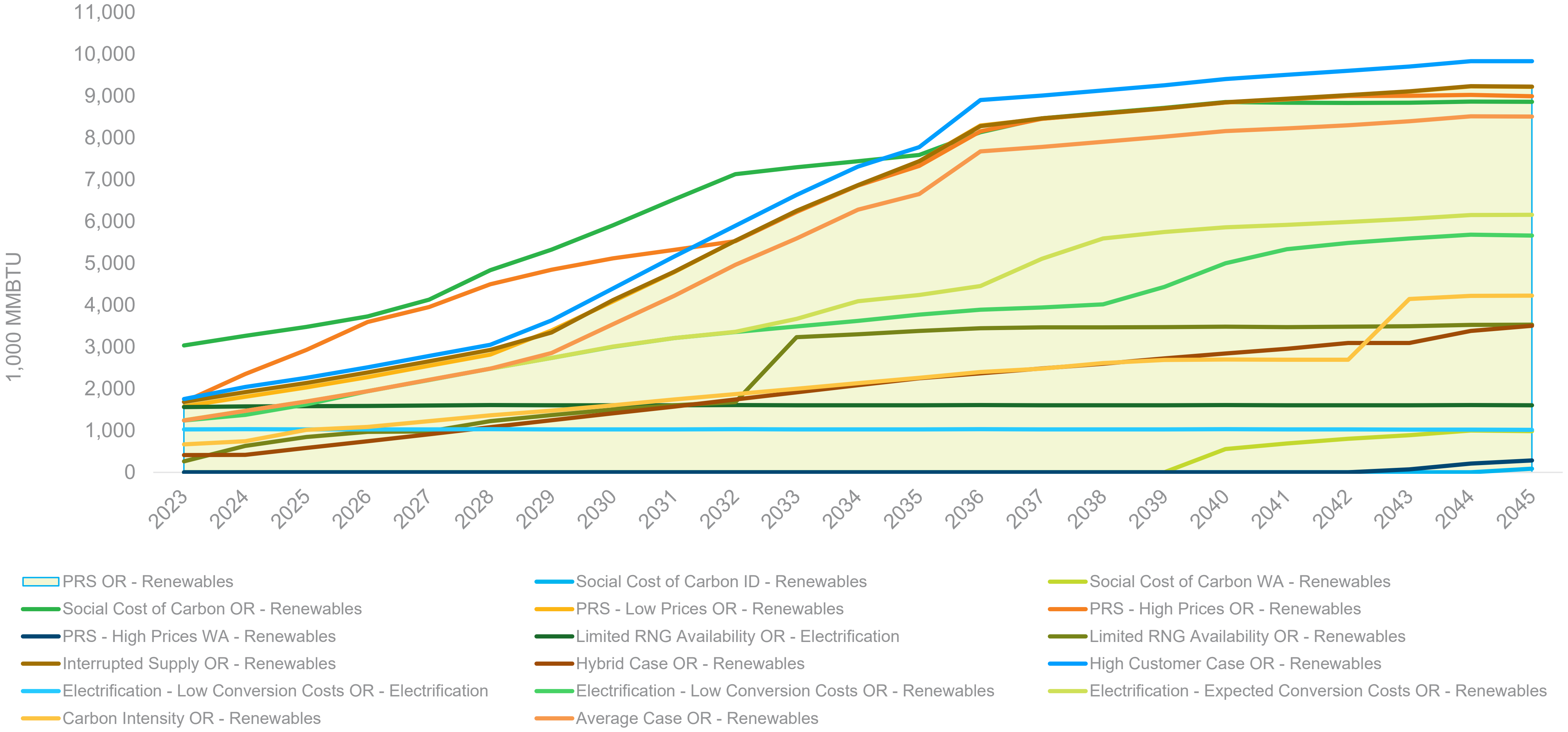
Scenario Analysis

- Uncertainty in future outcomes
- Understanding potential future outcomes through varying scenarios can help determine risk levels

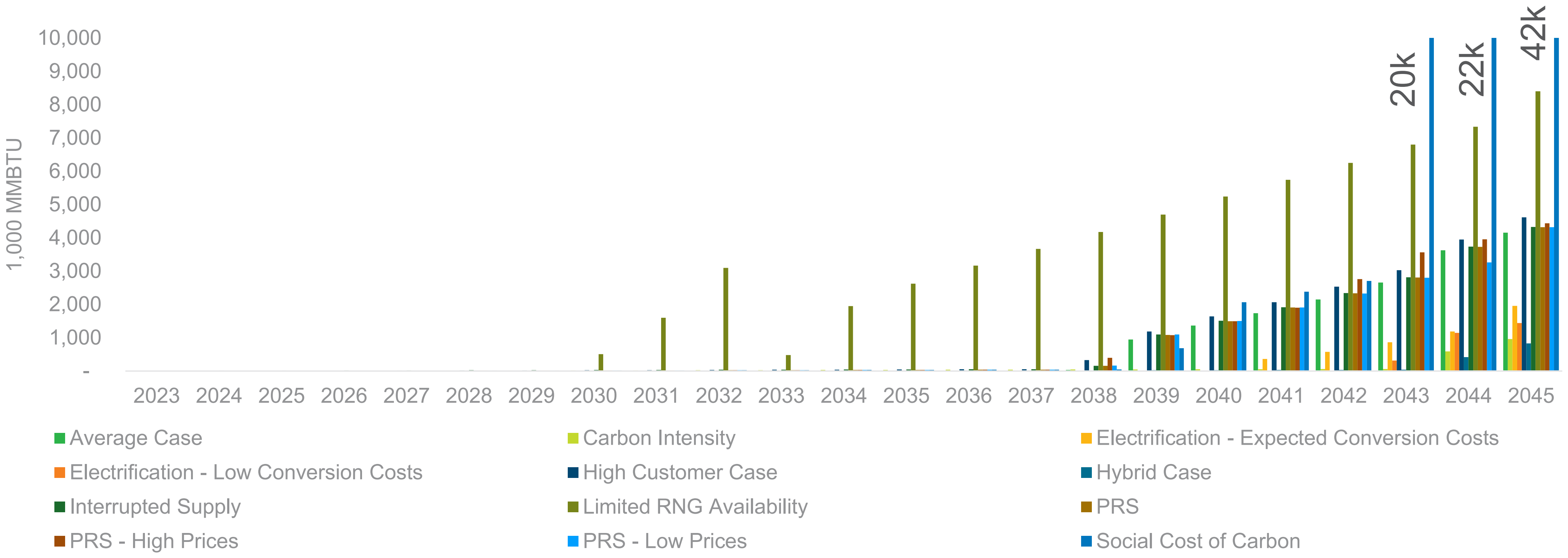
System Demand by Scenario



RNG Supply

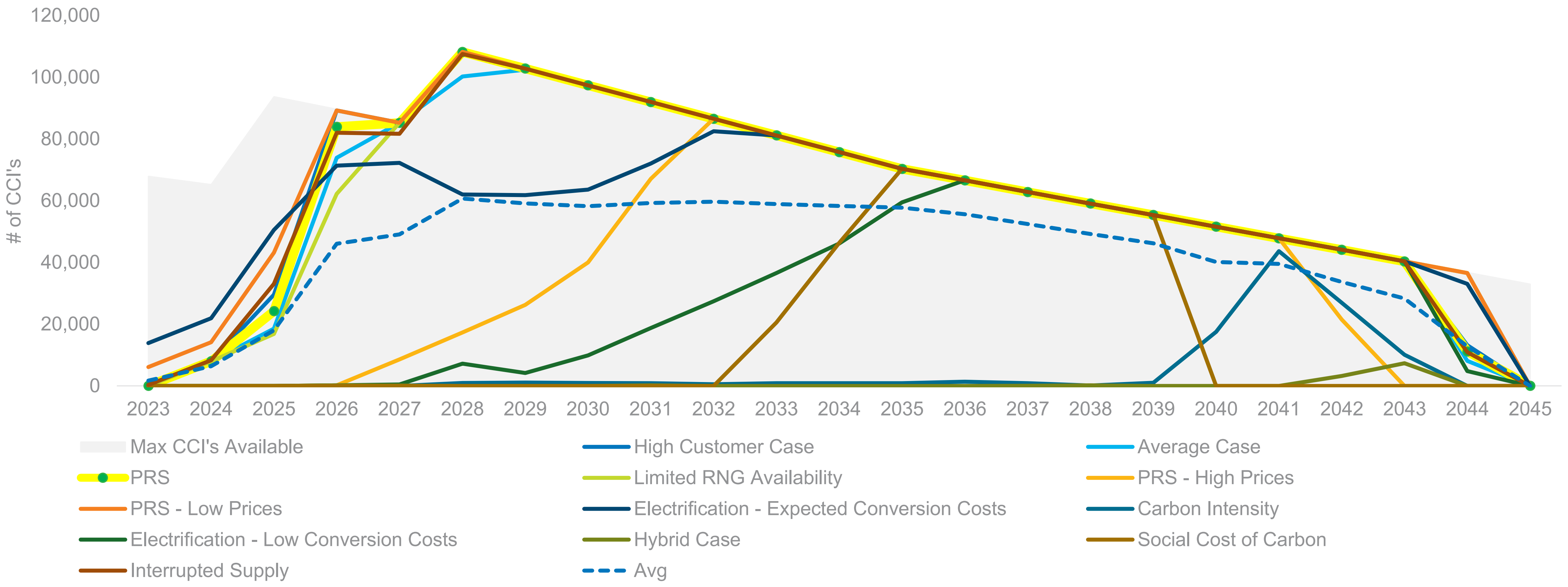

11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1,000 MMBTU
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
PRS OR - Renewables
Social Cost of Carbon ID - Renewables
Social Cost of Carbon WA - Renewables
Social Cost of Carbon OR - Renewables
PRS - Low Prices OR - Renewables
PRS - High Prices OR - Renewables
PRS - High Prices WA - Renewables
Limited RNG Availability OR - Electrification
Limited RNG Availability OR - Renewables
Interrupted Supply OR - Renewables
Hybrid Case OR - Renewables
High Customer Case OR - Renewables
Electrification - Low Conversion Costs OR - Electrification
Electrification - Low Conversion Costs OR - Renewables
Electrification - Expected Conversion Costs OR - Renewables
Carbon Intensity OR - Renewables
Average Case OR - Renewables

Synthetic Methane

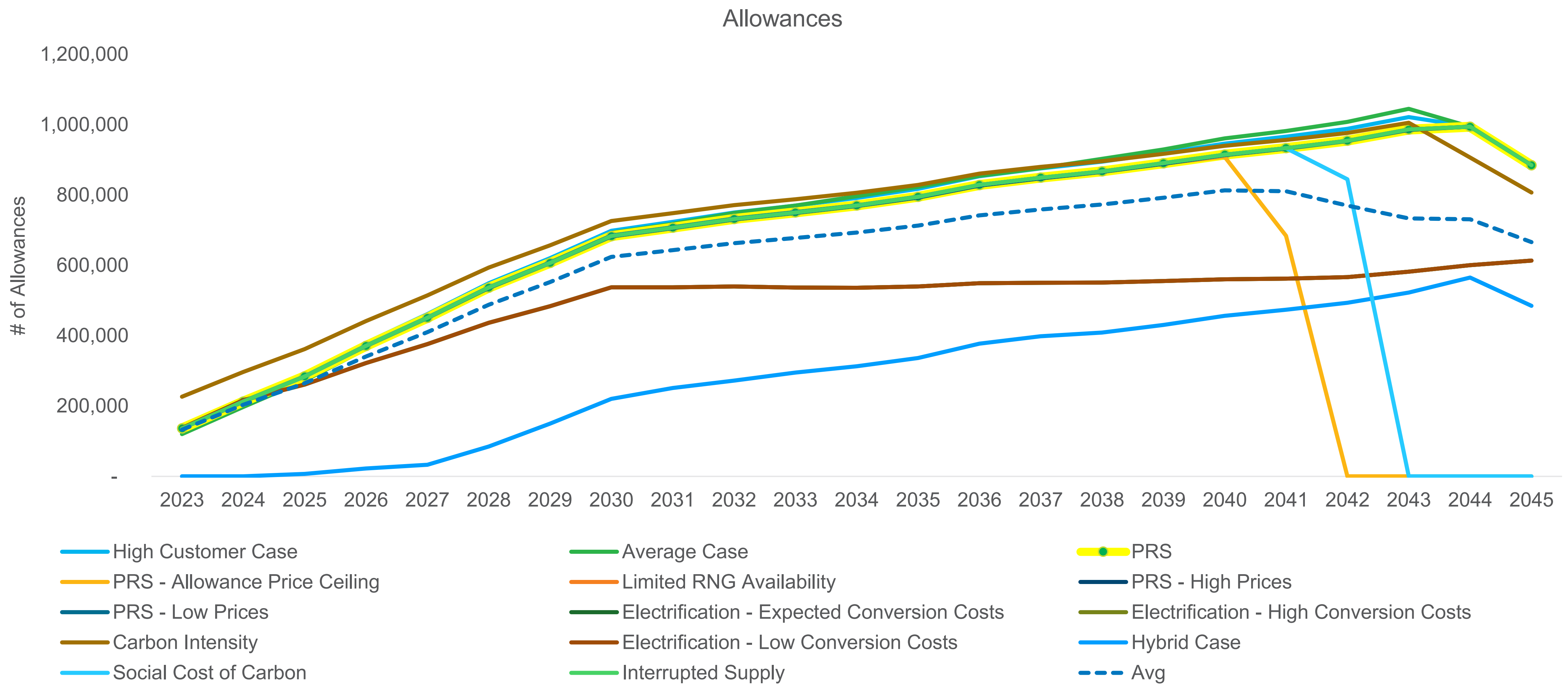


Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Case	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	948	1,364	1,735	2,148	2,657	3,627	4,152
Carbon Intensity	-	-	0	4	7	10	13	17	20	24	27	31	34	38	41	44	48	51	55	58	61	589	960
Electrification - Expected Conversion Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	362	575	865	1,187	1,953
Electrification - Low Conversion Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	316	1,148	1,438
High Customer Case	-	-	3	7	11	15	20	24	28	32	37	41	45	50	54	329	1,187	1,642	2,069	2,532	3,026	3,947	4,615
Hybrid Case	-	-	-	-	-	-	-	-	-	1	4	8	11	15	18	21	25	28	31	34	38	413	827
Interrupted Supply	5	9	13	17	20	24	27	30	34	37	41	44	48	51	55	155	1,095	1,506	1,914	2,341	2,817	3,737	4,325
Limited RNG Availability	-	-	-	4	7	10	13	506	1,597	3,097	477	1,946	2,624	3,168	3,669	4,174	4,699	5,243	5,743	6,251	6,804	7,338	8,401
PRS	-	-	-	3	7	10	13	17	20	24	27	31	34	38	41	154	1,081	1,497	1,905	2,332	2,810	3,726	4,318
PRS - High Prices	-	-	-	3	6	10	13	16	20	23	27	30	34	37	41	399	1,076	1,493	1,902	2,761	3,567	3,953	4,437
PRS - Low Prices	-	-	-	3	7	10	14	17	20	24	27	31	34	38	41	162	1,094	1,504	1,907	2,329	2,804	3,261	4,318
Social Cost of Carbon	-	-	-	3	7	10	13	17	20	24	27	31	34	38	41	44	687	2,068	2,380	2,703	20,729	22,664	42,385

Oregon
Community Climate Investments



Washington
Allowances and/or Offsets



If offset projects are cheaper than allowance price, an offset will be purchased

Levelized Cost 2023 – 2042

*Natural gas system cost only

AVISTA®

WA GRC Commitments Applicable to Natural Gas IRP

December 15, 2022

Shawn Bonfield, Sr. Manager of Regulatory Policy & Strategy

WA General Rate Case Natural Gas Transition Issues

Avista agrees to include in its 2023 Natural Gas IRP, a natural gas system decarbonization plan for complying with the Climate Commitment Act.

i. The Natural Gas IRP's decarbonization plan shall include a supply curve of decarbonization resources by price and availability, e.g. energy efficiency bundle 1 costs X$/ton of carbon dioxide equivalent (CO_2e) reduction and can reduce Y tons of CO_2e, dairy RNG costs A$/ton and can reduce B tons of CO_2e.

ii. The decarbonization plan shall consider a comprehensive set of strategies, programs, incentives and other measures to encourage new and existing customers to adopt fully energy efficient appliances and equipment or other decarbonization measures, which could include electrification.

iii. The decarbonization plan shall include targets for the ratio of new gas customers added relative to new electric customers added in future years.

WA General Rate Case CCA Commitments

Within 60 days of the adoption of the final Department of Ecology rules), Avista will begin consulting with its applicable advisory groups concerning its plans for complying with the CCA for electric and gas service, and the terms of any future tariff filing, including the following:

i. Reporting requirements for the consignment of no-cost allowances for the benefit of ratepayers,

ii. The accounting treatment of any proceeds from the consignment of allowances, and

iii. The investment of any proceeds from the sale of allowances during the rate plan including investments in projects that provide benefits to ratepayers including, but not limited to, weatherization, decarbonization, conservation and efficiency services, and bill assistance. (RCW 70A.65.130)

Note: Department of Ecology final rules adopted on September 29th and go into effect on October 30th with program beginning on January 1st. Avista provided initial CCA Overview provided at September 29th TAC Meeting.

AVISTA

CCA Deferred Accounting Petition

- Filed CCA deferred accounting petition on November 1st for natural gas costs and revenues related to compliance with the CCA
- Expect to begin incurring compliance costs in Q1 2023.
- Expect to receive revenues from consigned allowances in Q3 2023.
- Proposed to file annual tariff revisions to recover deferred costs. Current thinking is to begin recovery on November 1, 2023.
- Did not include proposal for what to do with revenues as more conversation is needed with WUTC.

Regulatory Next Steps for CCA Compliance

- Expect deferred accounting petition to be processed by WUTC in January 2023.

- WUTC initiating CCA compliance discussions in Q1 2023

- Thinking through needed rate schedule changes for allocating costs and revenues attributed to CCA.
  - Continuation of low-income bill discount tariff.
  - Transport customers – separating those above and below 25,000 MTC02e.
  - General Service – separating those on the system before and after July 25, 2021.
  - Special Contracts - separating those above and below 25,000 MTC02e.
  - Tariff riders for CCA costs and benefits and which rate schedules tariff riders are applicable to.

Key Regulatory CCA Questions

- How are low-income customers determined?
- Can low-income customers not be charged CCA compliance costs to avoid complexity of providing them bill credits to offset costs?
- What is “reasonable distance” when considering RNG resources? (Note: Ecology expected to release guidance on RNG reporting soon.)
- What falls into the category of “decarbonization” that revenues from no-cost allowances can be used for?

Action Items

2025 Natural Gas IRP

Oregon Action Items

- Purchase Community Climate Investments for compliance to the Climate Protection Plan for years 2022, 2023 and 2024 to comply with emissions levels
- ETO identified 2023 gross savings of 546 thousand therms in the IRP verses 427 thousand therms of planned savings in the 2023 ETO Budget and Action Plan. Work with ETO to meet IRP gross savings target of 568 thousand therms in 2024
- New program offered by ETO for interruptible customers in 2023 to save 15 thousand therms.
- Engage stakeholders to explore additional new offerings for interruptible, transport and low-income customers to work towards identified savings of 375 thousand therms in 2024
- Acquire 8.64 million therms of RNG in 2023 and 21.80 million therms of RNG in 2024

Washington Action Items

- Purchase Allowances or offsets for compliance to the Climate Commitment Act for years 2023 and 2024 to comply with emissions levels

- Begin to offer a transport customer EE program by 2024 with the goal of saving 35 thousand therms

- Explore methods for using Non Energy Indicators (NEI) in future IRP analysis

Other Action Items

- Explore modeling alternatives like end use model to compliment time series

Next Steps

Next Steps

- Include Monte Carlo risk analysis and send out prior to IRP draft
- Determine electricity costs for Hybrid scenario
- Review RPF and incorporate selection in IRP
- Draft IRP January 25, 2023
- Virtual Public meeting March 8, 2023
- File final IRP March 31, 2023

2023 – Avista Natural Gas IRP